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Bipole III and Keeyask

Brad Wall
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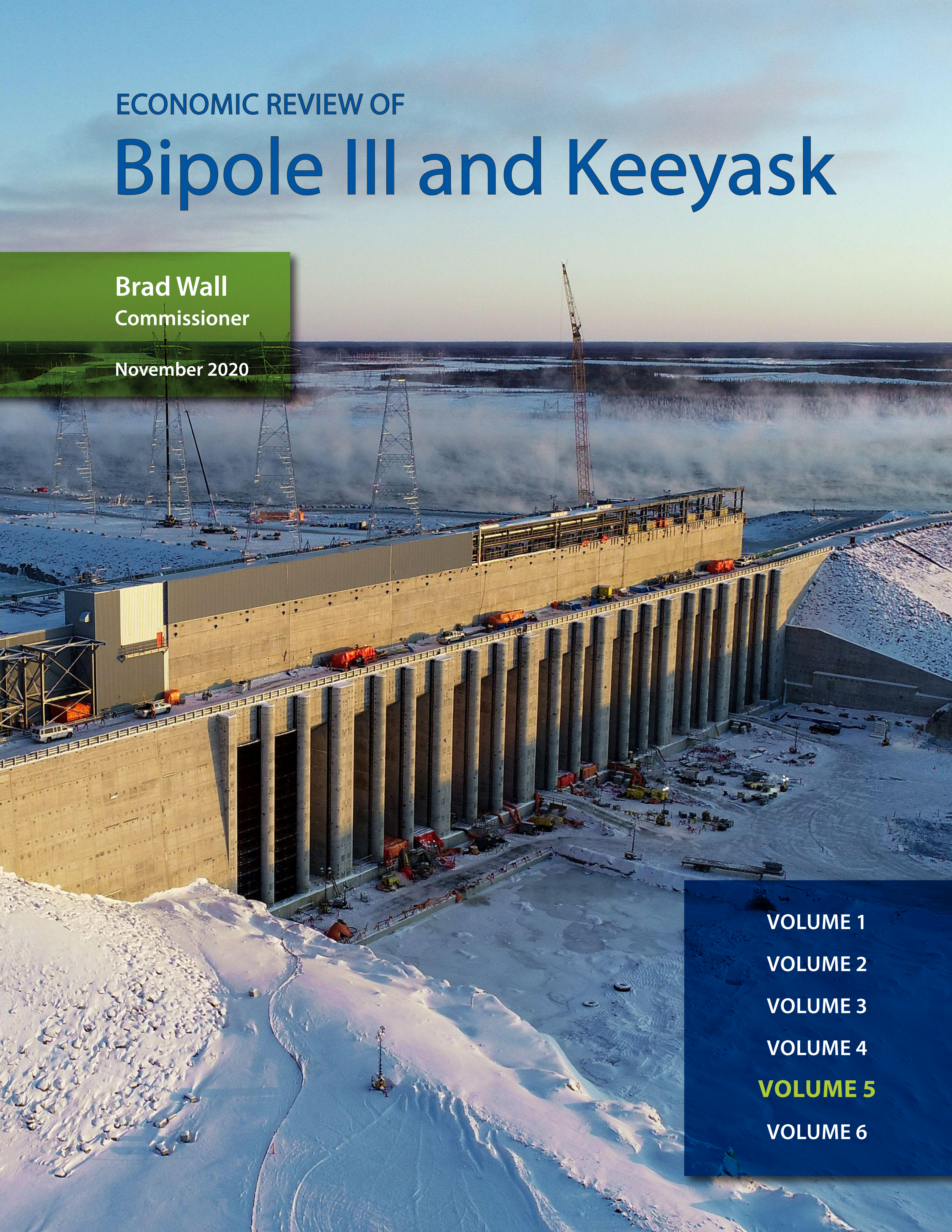

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Cracks on the Wall: Why States Should be Allowed to Lead on Climate Change

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CRACKS ON THE WALL: WHY STATES SHOULD BE ALLOWED TO LEAD ON CLIMATE CHANGE

William R. Montalvo *

INTRODUCTION

When it comes to tackling climate change, the policies pursued will have a profound impact on the kind of world that future generations will inherit.[1] The recent debate about climate change has mostly centered on measures to be taken on the national stage,[2] but state and local governments present other avenues for environmental leadership. State and local governments have the ability to tackle climate change much faster and can implement environmental policies that are stronger and more effective than the compromises reached at the national level.[3] Often, setting a plan into action is more important than perpetually seeking to develop the perfect plan. This note seeks to show how and why state policies have had a significant impact on the climate change debate, and why those policies should continue to be allowed by avoiding preemption at the national level.

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1. "There is broad scientific consensus that the greenhouse gases (GHGs) must be reduced 60 to 80 percent relative to 2000 levels by 2050 to avoid dangerous anthropogenic climate change, including sea-level rise of 3 ft or more." STEPHEN MULKEY, CLIMATE CHANGE AND LAND USE IN FLORIDA: INTERDEPENDENCIES AND OPPORTUNITIES 5 (2007) (citations omitted).

2. Posting of John Lorinc to Green Inc., http://greeninc.blogs.nytimes.com/2009/11/02/winners-and-losers-of-cap-and-trade (Mar. 8, 2010).

3. Ann E. Carlson, *Iterative Federalism and Climate Change*, 103 NW. U. L. REV. 1097, 1098-99 (2009) ("Many states have enacted renewable portfolio standards, created inceptives for carbon capture and sequestration, mandated energy efficient standards, and established public benefit funds to support energy efficiency and renewable energy. Other states have gone further, adopting overall greenhouse gas emissions caps, crafting greenhouse gas emissions standards for new automobiles, and capping utility emissions.").

Part I of this note deals with the need for quick action on climate change, given the dangers posed by hesitation on this issue. Part II considers the stake states have in dealing with climate change. Part III discusses the benefits of state level action. Part IV details some of the problems and pitfalls of state action, but explains why these should not discourage the federal government from allowing states to continue to experiment with their own climate change policies.

I. THE NEED FOR DRAMATIC SPEED IN TACKLING CLIMATE CHANGE

If you had ten minutes to get from Point A to Point B, it is likely that you would rather take a seven minute cab ride for $5.00 than a fifteen minute subway right for $2.50, especially if being late would be disastrous. Man-made greenhouse gas emissions increased by fifteen percent between 2000 and 2005.[4] One major reason to set emissions limits (be they international, national or state) is that they allow governments to set up a climate budget and allocate that budget between countries of the world.[5] Avoiding the worst effects of climate change will require limiting temperature rise to two degrees Celsius.[6] In order to achieve that target, leading scientists argue that global emissions of all green house gases [GHGs] must peak by no later than 2015 and global emissions must be reduced at least fifty percent below 1990 levels by the year 2050.[7] Developed countries "have to aim for a 25-40% reduction by 2020."[8] The Energy

4. Press Release, Joint Research Center, European Commission, Greenhouse Gas Emissions Growing Faster Since 2000: New Data on Worldwide Emissions 1970-2005 (May 25, 2009), *available at* http://ec.europa.eu/dgs/jrc/downloads/jrc_090525_newsrelease_edgar.pdf.

5. *See* Jonathan G. Koomey & Florentin Krause, *Why Two Degrees Really Matters*, CLIMATEPROGRESS.COM, Dec. 6, 2009, http://climateprogress.org/2009/12/06/copenhagen-two-degrees-warming-target/#_edn2.

6. *See id.* Even limiting GHG increases to two degrees Celsius might not be enough to prevent disastrous effects from anthropogenic climate change. *See* James Murray, *Updated: IPCC Chief Warns Even Two Degree Rise Spells "Bad News"*, BUSINESSGREEN.COM, Mar. 10, 2009, http://www.businessgreen.com/business-green/news/2238184/ipcc-chief-warns-two-degree.

7. St. James's Palace Nobel Laureate Symposium, The St James Palace Memorandum (2009), *available at* http://www.ourplanet.com/imgversn/nobel/St_James_Palace_Memorandum.pdf.

8. *Id.*

Information Administration predicted in 2009 that world energy consumption will increase forty-four percent from its 2006 level by 2030.[9] The journal, *Science*, predicted that the potential for growth in energy consumption from China alone could reach eight gigatons of carbon dioxide emissions per year by 2030, which equals the output of the entire world today.[10] Taking such dramatic rises in energy consumption and expected global economic growth into consideration, the long-term challenge posed by climate change will only grow larger the longer the world waits to act.

II. CLIMATE CHANGE IS ALSO A STATE ISSUE

Enacting a strong federal program would be a major achievement and the preferred course of action in dealing with climate change.[11] A strong federal program, as part of a broad international climate change treaty, could be very cost effective, and, provided its adequacy, it would present the best chance of achieving the GHG emission peaks, temperature targets and deadlines set forth by prevailing scientific opinion.[12]

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9. U.S. ENERGY INFO. ADMIN., INTERNATIONAL ENERGY OUTLOOK 2009 1 (2009), http://www.eia.doe.gov/oiaf/ieo/world.html; *see also* INT'L ENERGY AGENCY, WORLD ENERGY OUTLOOK 2009 FACT SHEET 1 (2009), *available at* http://www.worldenergyoutlook.org/docs/weo2009/fact_sheets_WEO_2009.pdf (predicting energy demand in 2030 to be 40% higher than in 2007).

10. Alexis Madrigal, *China's 2030 CO2 Emissions Could Equal the Entire World's Today*, WIRED SCIENCE, Feb. 8, 2008, http://www.wired.com/wiredscience/2008/02/chinas-2030-co2.

11. *See generally* STAFF OF H. COMM. ON ENERGY AND COM., 110TH CONG., CLIMATE CHANGE LEGISLATION DESIGN WHITE PAPER: APPROPRIATE ROLES FOR DIFFERENT LEVELS OF GOVERNMENT (2008) (concluding that a federal program would be preferable over many state programs); Meghan McGuinness & A. Denny Ellerman, *The Effects of Interactions Between Federal and State Climate Policies*, SP028 A.L.I.-A.B.A. 175, 180 (2008) (indicating a number of reasons why having a federal program would be important, the main reasons being efficiency and the scale of the climate change problem); Doug Struck, *Local Climate Solutions Constrain Federal Options*, THE DAILY CLIMATE, Feb. 10, 2010, http://wwwp.dailyclimate.org/tdc-newsroom/federal-constraint/local-climate-solutions-constrain-federal-options (noting the divided opinion among economists).

12. If the United States, by itself, substantially reduced its emissions it could put the world closer in line with the requirements noted in Part I of this paper, given that the United States emitted 5,746 million metric tons of carbon dioxide in 2003 compared to total global emissions of 24,405 million metric tons. The 2010 projections estimate the U.S. carbon dioxide emissions at 6,365 million metric tons

Although many Americans would like to see stronger action on climate change from the national government, meaningful movement is unlikely in the near future,[13] even with the current political leadership which favors stronger environmental policies.[14] Factors, like the economic crisis that began in 2008, continue to hamper climate reform efforts.[15] Additionally, many people benefit from the current situation in which there is no substantive federal program in place to tackle GHGs emissions.[16]

The United States' geography, economy and population density is very diverse.[17] Different states and regions have different

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out of a world total of 30,005 million metric tons. *See* ENERGY INFO. ADMIN., DEP'T OF ENERGY, EMISSIONS OF GREENHOUSE GASES IN THE UNITED STATES 2004 4 (2005) (noting U.S. and global CO_2 and greenhouse gas emissions); OFF. OF TRANSP. AND AIR QUALITY, ENVTL. PROT. AGENCY, CALCULATING EMISSIONS OF GREENHOUSE GASES: KEY FACTS AND FIGURES 3 (2005).

13. Suzanne Goldenberg, *Barack Obama in New Global Warming Fight*, THE OBSERVER (London), Oct. 25, 2009, at 46.

14. Helene Cooper & John M. Broder, *At M.I.T., Obama Presses Case for Focus on Using Renewable Energy*, N.Y. TIMES, Oct. 24, 2009, at A13.

15. Mark Rice-Oxley, *Financial Crisis Threatens Climate-Change Momentum*, THE CHRISTIAN SCIENCE MONITOR, Nov. 13, 2008, http://features.csmonitor.com/environment/2008/11/13/financial-crisis-threatens-climate-change-momentum. As noted by Yvo de Boer, it is "undeniable that the financial crisis will have an impact on the climate-change negotiations." *Id.* Internationally there have even been some setbacks in terms of climate policy, as some businesses are thought to be challenging existing climate change based limitations in Europe. *Id.*

16. *See* Murphy Oil USA, Inc., Take a Stand and Support Keeping Energy Costs Low, http://www.bipac.net/page.asp?content=current_topic&g=arenergy (noting some of the benefits of cheap energy prices in the United States) (last visited Feb. 1, 2010); *see also* Steve Hargreaves, *U.S. Gas: So Cheap it Hurts*, CNN.COM, July 15, 2008, http://money.cnn.com/2008/05/01/news/international/usgas_price (noting how people in the United States enjoy cheaper gas prices than other countries abroad, and how this is often more because of policy than supply); Michael R. Campbell, Comment, *The Employer Trip Reduction Program: Driving Restrictions Arrive In Pennsylvania Via The Clean Air Act*, 3 DICK. J. ENVTL. L. & POL'Y 71, 86 (1994) (noting how automobile travel is subsidized in the United States).

17. *See* ENERGY INFO. ADMIN., STATE ENERGY DATA 2007: CONSUMPTION 3 (2007), *available at* http://www.eia.doe.gov/emeu/states/sep_sum/html/pdf/sum_btu_1.pdf (providing comparisons of state energy consumption); JONATHAN L. RAMSEUR, CONG. RESEARCH SERV., STATE GREENHOUSE GAS EMISSIONS: COMPARISON AND ANALYSIS 14, 22 (2007), *available at*

dependencies on industries and infrastructure with high GHG emissions; those states that require a high amount of energy and do not have very diversified sources for that energy, or have large industries devoted to the production of natural gas, oil, or coal, have a lot to lose from a federal program on GHGs (in the short term).[18] For example, Vermont derives one hundred percent of its energy from renewable sources, while West Virginia derives ninety-eight percent of its energy from coal.[19] In those states that have much to lose, the general population and the local political establishment will certainly be against any strong action from the federal government.[20] However, regardless of local policies, all states have cause for climate change concerns, as was noted by the Environmental Protection Agency's (EPA's) Analysis of the Effects of Global Change on Human Health and Welfare and Human Systems,[21] and could substantially benefit from moving towards green energy.[22]

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http://www.au.af.mil/au/awc/awcgate/crs/rl34272.pdf (providing a comparison of state greenhouse gas emissions).

18. *See* ENERGY INFO. ADMIN., *supra* note 17 (for a comparison of different states sources of energy, as can be noted from these charts); *see also* RAMSEUR *supra* note 17, at 18 (noting vast disparities in the sources of energy in states).

19. RAMSEUR, *supra* note 17, at 14. There are also many other examples of the differences in state energy profiles. *See* ENERGY INFO. ADMIN., *supra* note 17 (providing a very detailed list).

20. In fact, a number of the states that have not joined regional agreements get over ninety percent of their energy from coal, while a number of the states with strong renewable energy portfolios have joined regional agreements. *Compare* RAMSEUR, *supra* note 17, at 14 *and* Pew Ctr. on Global Climate Change, Regional Initiatives (last visited Dec. 2, 2009), http://www.pewclimate.org/what_s_being_done/in_the_states/regional_initiatives.cfm (note the map showing membership in regional climate agreement), *with* New York Times, *Election Results, President Map*, N.Y. TIMES, Dec. 9, 2008, http://elections.nytimes.com/2008/results/president/map.html (providing a map of the 2008 presidential election, which seems to indicate more acceptance of regional agreements when compared with the previous Pew Research Center map about membership in regional climate agreements).

21. *See generally* U.S. CLIMATE CHANGE SCI. PROGRAM, ANALYSES OF THE EFFECTS OF GLOBAL CHANGE ON HUMAN HEALTH AND WELFARE AND HUMAN SYSTEMS, July 17, 2008, *available at* http://www.climatescience.gov/Library/sap/sap4-6/final-report/default.htm.

22. *Id.*; *see also A Long Game*, ECONOMIST, Dec. 3, 2009, *available at* http://www.economist.com/specialreports/displaystory.cfm?story_id=14994880 (noting China's opinion on the value of green technology); *Wanted: Green Engineers*, ECONOMIST.COM, NOV. 13, 2009,

Yet, the federal government may continue to face popular skepticism on the existence and danger of climate change.[23] Furthermore, recent national events demonstrate that many Americans' interest and concern for environmental problems wanes when compared to other national crises.[24] However, there is no need to lose all momentum on climate change mitigation. Even in difficult times, states could continue, as they have in recent years, to take the lead in tackling climate change with tough state legislation.[25] For this to happen, state legislative action depends upon on how future environmental policies are structured at the state, regional and national level, especially when it comes to GHG emissions controls.

State governments represent fewer people, and often there is a much more coherent, entrenched and dominant political faction or philosophy in state politics.[26] Individual states also have vastly

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http://www.economist.com/theworldin/displaystory.cfm?story_id=14742179 (noting that green engineering might be an emerging career field for students).

23. Lydia Saad, *Increased Number Think Global Warming Is "Exaggerated"*, GALLUP DAILY NEWS, Mar. 11, 2009, http://www.gallup.com/poll/116590/increased-number-think-global-warming-exaggerated.aspx ("[T]he global warming message may have lost some footing with Americans over the past year."); *see also* Nathanial Gronewold & Christa Marshall, *Rising Partisanship Sharply Erodes U.S. Public's Belief in Global Warming*, N.Y. TIMES, Dec. 3, 2009, http://www.nytimes.com/cwire/2009/12/03/03climatewire-rising-partisanship-sharply-erodes-us-public-47381.html (noting that just fifty-one percent of Americans now believe that GHG emissions could lead to increased temperature compared to seventy-one percent two years ago).

24. Saad, *supra* note 23 ("Gallup has documented declines in public concern about the environment at times when other issues, such as a major economic downturn or a national crisis like 9/11, absorbed Americans' attention.").

25. Jared Snyder & Jonathan Binder, *The Changing Climate of Cooperative Federalism: The Dynamic Role of the States in a National Strategy to Combat Climate Change*, 27 UCLA J. ENVTL. L. & POL'Y 231, 232 (2009) ("[A] silver lining of the federal inaction on climate change over the past eight years has been that it fostered the development of innovative and pioneering efforts by state and local governments to combat climate change."); Carlson, *supra* note 3 ("While the federal government has remained idle, as numerous commentators have observed, a surprisingly large number of states have stepped in to fill the policy void.").

26. Posting of Tom Schaller to FiveThirtyEight, http://www.fivethirtyeight.com/2009/08/state-legislative-partisan-gains-since.html (Aug. 21, 2009, 10:33) (showing how many states have strong partisan majorities, some of which have been widening, which helps explain why environmental policies in some states might be stronger than others).

different breakdowns in terms of energy consumption, energy sources and net importation versus exportation of energy.[27] States that require a large amount of energy, like Texas, which consumed 11,834.5 British Thermal Units (BTUs) of electricity in 2007,[28] mostly from non-renewable sources,[29] and states which have very high carbon intensity, such as Wyoming,[30] will probably be less flexible in pursuing regulatory strategies. Other states, however, feature different energy situations. Some states, such as Alabama, have well diversified energy sources.[31] While states such as California do not have well diversified energy sources or such low emissions levels,[32] they have the political will to enact policies that seek reductions in GHG emissions.[33] States more vulnerable to the dangerous effects of climate change—such as coastal and grain belt states—have greater incentives to move faster on emissions regulations than other states or the federal government.[34]

Throughout history, states have acted before the federal government in implementing difficult reforms.[35] Long before the Thirteenth Amendment to the United States Constitution was enacted

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27. *See* ENERGY INFO. ADMIN., *supra* note 17, (showing the breakdown of state consumption and sources of energy in 2007).

28. *Id.*

29. *Id.*; *see also* RAMSEUR, *supra* note 17, at 4 (showing that Texas had the highest emissions of any state in the country in 2007).

30. RAMSEUR, *supra* note 17, at 6.

31. *See* ENERGY INFO. ADMIN., *supra* note 17 (comparing Alabama's energy consumption numbers, by energy source, to that of other states shows diverse methods of power consumption).

32. *Id.*

33. *Id.* (outlining California's energy consumption); *see also infra* Part III.A (detailing just some of the actions that California has taken on Climate Change).

34. *See* Thomas Joo, *Global Warming and the Management-Centered Corporation*, 44 WAKE FOREST L. REV. 671, 698 (2009); *see also* United Nations Framework Convention on Climate Change, Future Effects, http://unfccc.int/essential_background/feeling_the_heat/items/2905.php (last visited Feb. 1, 2010) ("Mid-continental areas – such as the United States' 'grain belt' and vast areas of Asia – are likely to dry.") [hereinafter Future Effects].

35. *See, e.g.*, Andrew C. Revkin & Jennifer Lee, *White House Attacked for Letting States Lead on Climate Policy*, N.Y. TIMES, Dec. 11, 2003, at A32 (noting that in the Bush Administration, as the government slowed its efforts to tackle climate change it was the states that began to take strong actions).

in 1865,[36] several states had already abolished slavery.[37] Slavery was abolished in Vermont (1777), Pennsylvania (1780), Massachusetts (1783), Connecticut (1783), Rhode Island (1784), New York (1799), and New Jersey (1804).[38] States also beat the federal government in granting women's suffrage.[39] The first state to grant women's suffrage was New Jersey, which, in its first constitution of 1776, included the women's right to vote.[40] Additionally, it was the states (or territories) of Wyoming (1869), Utah (1870), Colorado (1893), Idaho (1896), Washington (1883), California (1911), Kansas(1912), Oregon(1912), and Arizona (1912) that first gave women the right to vote.[41] Federal action on women's suffrage did not occur until the enactment of the Nineteenth Amendment in 1920.[42] Indeed, states have taken the lead on almost every major question that the nation has ever faced.[43] Often this is because state politicians have to respond to the local beliefs of their constituents, which may favor

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36. U.S. CONST. amend. XIII; *see also* Kimberly L. Alderman, *Slave Artists As Powerful Reality Creators: Taking Responsibility and Rejecting Race Consciousness*, 33 T. MARSHALL L. REV. 261, 270 n.47 (2008).

37. As noted earlier, the Thirteenth Amendment was enacted in 1865, while states had been individually abolishing slavery from 1777. Wilma Sur, *Hawai'i's Masters And Servants Act: Brutal Slavery?*, 31 U. HAW. L. REV. 87, 89 (2008).

38. *Id.*

39. *See* Nikolaus Benke, *Women in the Courts: An Old Thorn in Men's Sides,* 3 MICH. J. GENDER & L. 195, 221 (noting that New Jersey gave the right to women in 1776); *see also* Kerry Abrams, *The Hidden Dimension of Nineteenth-Century Immigration Law*, 62 VAND. L. REV. 1353, 1407 (2009) ("State and territorial laws were passed [granting women the right to vote] in an attempt to induce women to immigrate west.").

40. *See* Benke, *supra* note 39, at 221.

41. *See* Abrams, *supra* note 39, at 1408.

42. *See id.*; *see also* U.S. CONST. amend. XIX (prohibiting gender based restrictions on voting).

43. *See* Darren Lenard Hutchinson, *Racial Exhaustion*, 86 WASH. U. L. REV. 917, 947 (2009) (noting how New York was the first state to enact a racial discrimination law in employment matters—the Ives-Quinn Act); Peter Salsich et al., *Affordable Workforce Housing—An Agenda for the Show Me State: A Report from an Interactive Forum on Housing Issues in Missouri*, 27 ST. LOUIS U. PUB. L. REV. 45, 68 (2007) (discussing state leadership in finding affordable workforce housing); *see also* Melody Finnemore, *A Growing Array of Legal Services--and Legislation--Is Making Oregon a National Leader in Protecting Animals*, 68 OR. ST. B. BULL. 28, 31 (2008) (discussing state leadership in animal law).

greater and more radical reform than that desired at the national level.[44]

A. Federal Attempts at Regulation of Climate Change:

On November 25, 2009, the White House outlined expected federal targets for emissions reduction of "17% below 2005 levels in 2020."[45] However, to date, most attempts at federal regulation on climate change, like the British Thermal Unit Tax proposed under the Clinton Administration,[46] have failed to pass.[47] In 1993, the British Thermal Unit Tax attempted to reduce pollution and promote conservation equitably.[48] The tax proposed effected varied carbon producing products differently and was dependent on output and exempted several renewable energy sources.[49] Even today, a national carbon tax approach would face a significant uphill battle.[50]

On June 26, 2009, the United States House of Representatives narrowly approved H.R. 2454, the "American Clean Energy and Security Act," by just seven votes.[51] There was much criticism of the

44. Judith Resnik, *Fairness to Whom? Perspectives on the Class Action Fairness Act of 2005*, 156 U. PA. L. REV. 1929, 1931 (2008).

45. Press Release, The White House, Office of the Press Sec'y, President to Attend Copenhagen Climate Talks, Nov. 25, 2009, http://www.whitehouse.gov/the-press-office/president-attend-copenhagen-climate-talks.

46. British Thermal Unit Tax, H.R. 2141, 103rd Cong. (1993).

47. *See* Steven Greenhouse, *Clinton's Economic Plan: The Energy Plan; Fuels Tax; Spreading the Burden*, N.Y. TIMES, Feb. 17, 1993, at A18; *see also* Paul Horvitz, *Clinton Retreats on Energy Tax in Fight Over Budget*, NYTIMES.COM, June 9, 1993, http://www.nytimes.com/1993/06/09/news/09iht-plan_1.html?scp=1&sq=Clinton%20Retreats%20on%20Energy%20Tax%20in%20Fight%20Over%20Budget&st=cse (stating possible changes to the energy tax); Brian C. Murray & Heather Hosterman, *Climate Change, Cap-And-Trade And The Outlook For U.S. Policy*, 34 N.C. J. INT'L L. & COM. REG. 699, 706 (2009).

48. Murray & Hosterman, *supra* note 47.

49. *Id.*

50. *See id.* ("Many economists believe a carbon tax . . . would be a superior policy alternative to an emissions-trading regime. The irony is that there is a broad consensus in favor of a carbon tax everywhere but on Capitol Hill, where the 'T' word is anathema." (citation omitted)).

51. Open Congress, H.R.2454 - American Clean Energy And Security Act of 2009, http://www.opencongress.org/bill/111-h2454/actions_votes (last visited Feb. 1, 2010).

bill and the support for it has been lukewarm.[52] Carroll Muffett, the USA Deputy Campaigns Director for Greenpeace, noted that the bill had essentially been a "victory for coal industry lobbyists, oil industry lobbyists, agriculture industry lobbyists, steel and cement industry lobbyists, among many others" because "to avoid the worst effects of global warming, we must reduce emissions by 25-40% below 1990 levels by 2020, and the short-term target of this bill is a paltry 4%."[53]

The Waxman-Markey bill, because of the compromises needed for it to pass through Congress, would not have been nearly as strong as required—especially according to the estimates of the highest authorities on climate change.[54] Some commentators have even gone

52. Posting of Teryn Norris to Breakthrough Blog, http://thebreakthrough.org/blog/2009/06/critics_condemn_aces_climate_b.shtml (June 30, 2009, 19:51).

53. Dan Shapley, *House Cap-and-Trade Bill: The Good, the Bad and the Ugly*, THE DAILY GREEN, June 6, 2009, http://www.thedailygreen.com/environmental-news/latest/house-cap-and-trade-bill-47062902. In fact, in the IPCC's 2007 Synthesis Report, the IPCC showed that the reductions in GHG emissions would have to be far higher than even the percentages noted by Carroll Muffett. Under the IPCC's models, even with a reduction of more than thirty percent, there could still be global temperature rises of 2.8–3.2 degrees Celsius. INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, CLIMATE CHANGE 2007: SYNTHESIS REPORT 6, *available at* http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr.pdf (last visited Feb. 1, 2010); *see also* Shapley, *supra* ("[t]his bill will produce nowhere near the emissions reductions that are needed to solve global warming, and – astonishingly – it will eliminate existing EPA authority to fight pollution from coal-fired power plants." (internal quotation marks omitted) (quoting Brent Blackwelder, president of Friends of the Earth)); Press Release, Greenpeace, Greenpeace Opposes Waxman-Markey: Climate Bill not Science-Based; Benefits Polluters (June 25, 2009), http://www.greenpeace.org/usa/press-center/releases2/greenpeace-opposes-waxman-mark (noting Greenpeace's criticism of the Waxman-Markey Bill, in particular that "the Waxman-Markey bill sets emission reduction targets far lower than science demands, then undermines even those targets with massive offsets . . . . To support such a bill is to abandon the real leadership that is called for at this pivotal moment in history. We simply no longer have the time for legislation this weak."). Even if the White House's announced target of seventeen percent reductions below 1995 levels by 2020 could be reached, President to Attend Copenhagen Talks Press Release, *supra* note 45, it would still not reach the levels of reductions that experts say are required, the levels which have informed Carol Muffett's statement. Press Release, *supra*.

54. Like the chairman of the UN's Intergovernmental Panel on Climate Change (IPCC), Dr. Rajendra K. Pachauri, who noted that even a two degree rise in temperature could have serious consequences. Murray, *supra* note 6.

so far as to say that the House cap-and-trade bill "rewards polluters with massive giveaways that can be gamed by Wall Street" and it provides an incentive for companies to continue to use outdated, unsustainable technology and business models.[55]

There have been several other proposals at the federal level, as well.[56] For example, the Kerry-Boxer bill recently passed through committee without Republican support.[57] Like the Waxman-Markey bill, the Kerry-Boxer bill appears likely to stall in Congress, given the lack of moderate support.[58] Nonetheless, only time will tell what the final composition of federal legislation will be; until then, however, state governments will be the best vessels to take action on climate change.

B. Effects of Climate Change on States:

Taking New York State as an example, climate change has the potential to produce noticeable, if not considerable, effects that its state government should be concerned with.[59] According to the New York State Department of Environmental Conservation:

> Average temperatures in the state are 2 degrees Fahrenheit higher than they were as recently as 1970. New York's winter temperatures are almost 5 degrees higher than in 1970. Plants in New York now bloom as much as 8 days earlier in the spring than they did in 1970. Birds that traditionally breed in New York have moved their ranges northward by as much as 40 miles in the past two decades.

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55. Shapley, *supra* note 53.

56. Nadia Zakir, *Emissions Trading Initiatives: Responding to Climate Change Through Market Forces*, 16 BUS. L. TODAY 19, 23 (2007).

57. Posting of Keith Johnson to Environmental Capital, http://blogs.wsj.com/environmentalcapital/2009/11/05/boxer-rebellion-senate-panel-approves-climate-bill-without-gop (Nov. 5, 2009, 10:05 EST).

58. Lisa Lerer, *Senators Look Past Barbara Boxer's Climate Bill*, POLITICO.COM, June 11, 2009, http://www.politico.com/news/stories/1109/29223.html.

59. New York State Department of Environmental Conservation, Climate Change: New Yorkers are Working on Many Fronts, http://www.dec.ny.gov/energy/44992.html (last visited Feb. 1, 2010).

> Diseases from the tropics, such as West Nile disease and Lyme disease, are appearing further north.[60]

If climate change continues unabated, New Yorkers could expect to see:

> Additional warming, estimated at 2 to 3 degrees Fahrenheit, because of greenhouse gases already in the atmosphere. Dry spells of several weeks' duration, punctuated by extreme rains and storms. Winter snow cover reduced enough to affect the recreation industry. Loss of cool-weather plants and animals that have traditionally lived in New York, such as sugar maples and some marine species. Sea levels rising by between 4 inches and 33 inches (or even more if the earth's large ice sheets are destabilized).[61]

Among other things, there is also the potential for dramatic rises in sea level.[62] With twenty-five percent of U.S.'s population living just ten meters above sea level, even a small sea level rise could have a big impact.[63] In Florida and Louisiana, there is a great risk of danger because of sea level rise, given the states' low altitude near the coast.[64] Some studies project that average temperatures in New York State could increase by as much as two to eight degrees Fahrenheit by 2100, "with the largest increases in the coastal regions such as New

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60. *Id.*

61. *Id.*

62. *See* CHRIS WOLD ET AL., CLIMATE CHANGE AND THE LAW 20 (2009) (noting that the major ice sheets contain vast amount of ice, for example that the West Antarctic ice sheet alone contains enough ice to raise sea levels by eight meters); *see also* James Randerson, *Climate Change: Prepare for Global Temperature Rise of 4C, Warns Top Scientist*, GUARDIAN, Aug. 7, 2008, at 1, *available at* http://www.guardian.co.uk/environment/2008/aug/06/climatechange.scienceofclimatechange (last visited Feb. 1, 2010). The IPCC 2007 report actually predicted global sea level rise over the next century of just 0.17 meters, although that report has been criticized. *See* WOLD, *supra*, at 62.

63. *See* WOLD, *supra* note 62.

64. James G. Titus & Charlie Richman, *Maps of Lands Vulnerable to Sea Level Rise: Modeled Elevations Along the U.S. Atlantic and Gulf Coasts*, 18 CLIMATE RESEARCH 205, 221, *available at* http://www.int-res.com/articles/cr/18/c018p205.pdf ("In the case of Louisiana, our maps depict 25,000 square kilometers below the 1.5-meter contour[.]").

York City."[65] In addition, long-term temperature increases in the Midwestern states could be dramatically high in the long term, according to the Nature Conservancy.[66]

III. BENEFITS OF A STATE LEVEL APPROACH

As Justice Brandeis once noted "[i]t is one of the happy incidents of the federal system that a single courageous state may, if its citizens choose, serve as a laboratory; and try novel social and economic experiments without risk to the rest of the country."[67] States have the advantage of speed, a track record of proven policy implementation, and the ability to plan strategies tailored to the individual needs of their constituents based on their differing economies, geography, and resources.[68] So far the states have taken substantial steps in battling climate change.[69] They have essentially been fighting a guerrilla war against apathy, entrenched interest groups, inaction by the federal government, and misinformation on climate change at all levels of

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65. OFFICE OF LONG-TERM PLANNING AND SUSTAINABILITY, MAYOR'S OFFICE OF OPERATIONS, INVENTORY OF NEW YORK CITY GREENHOUSE GAS EMISSIONS 3 (Jonathan Dickinson ed., 2007), *available at* http://www.nyc.gov/html/om/pdf/ccp_report041007.pdf.

66. THE NATURE CONSERVANCY, TEMPERATURE PROJECTIONS FOR THE 50 US STATES OVER THE NEXT 100 YEARS: AN ANALYSIS BASED ON DATA CONTAINED IN THE CLIMATE WIZARD INTERACTIVE TOOL 5, *available at* http://www.nature.org/initiatives/climatechange/files/climate_wizard_analysis.pdf (containing an analysis of temperature rises in several states); *see also* Future Effects, *supra* note 34 (noting that at the very least the Midwestern states, the grain basket of the United States, will get considerably drier from the effects of climate change).

67. *See* New State Ice Co. v. Liebmann, 285 U.S. 262, 311 (1932) (Brandeis, J., dissenting).

68. *See infra* Part III.A. In addition:

> [i]n a large region there are often vast differences in geographical, ecological, and industrial conditions. As a result, pollution assimilates at different rates and environmental quality may vary greatly. Because of their knowledge of the local environment, regions may be in a better position to assess local environmental needs, local environmental consequences of certain levels of pollution, and locally appropriate remedies.

Cliona J. M. Kimber, *A Comparison of Environmental Federalism in the United States and the European Union*, 54 MD. L. REV. 1658, 1661–62 (1995).

69. *See infra* Part III.A.

society.[70] They have had many successes that, while looked at individually may seem small, taken together they amount to something larger.[71]

A. What States Have Done and What They Are Doing

Since the federal government has dragged its collective feet in producing substantial climate change regulation, it has been the states that have moved in with tough reforms.[72] For instance, California was given special regulatory power by the federal government

70. *See* Janet Larsen, *Mayors Respond to Washington Leadership Vacuum on Climate Change*, 66 THE HUMANIST 4, 5 (2006) ("Response to the Washington climate action void isn't limited to cities. States and businesses also are taking part."); *U.S. States Go It Alone on Climate Change*, ECOLOGIST, Oct. 2005, at 8 ("Unwilling to wait on the recalcitrant president, nine states . . . are developing a scheme to cap and then reduce the level of greenhouse gas emissions from power plants[.]"); *see also* Revkin & Lee, *supra* note 35, at A32 ("The states are taking action for one simple reason: because the federal government is not[.]" (internal quotation marks omitted) (quoting Gov. Gary Locke of Washington State)), *available at* http://www.nytimes.com/2003/12/11/us/white-house-attacked-for-letting-states-lead-on-climate.html?scp=1&sq=White%20House%20Attacked%20 for%20Letting%20States%20Lead%20on%20Climate&st=cse; Andrew Revkin & Jennifer Lee, *Warming Feud: States vs. Bush Team*, INT'L HERALD TRIB., Dec. 11, 2003 ("Many Democratic state officials said the administration was using state initiatives as cover for its own inaction.").

71. *See infra* Part III.A.

72. *See* Revkin & Lee, *supra* note 35, at A32 (noting that during the Bush Administration, as the government slowed its efforts to tackle climate change, it was the states that began to take strong actions); *see also* Michael D. Lichtenstein, *Climate Change and the Environment - Law Firms Regulating Climate Change: A Summary Of Federal And State Action*, METRO. CORP. J., Apr. 2008, at 30, *available at* http://www.metrocorpcounsel.com/current.php?artType=view&artMonth=November&artYear=2009&EntryNo=813 (providing a summary of state level actions to tackle climate change); Struck, *supra* note 11; Pew Center on Global Climate Change, US Climate Policy Maps, http://www.pewclimate.org/what_s_being_done/in_the_states/state_action_maps.cfm (detailing the activities of the states in climate action, the energy sector, the building sector and the transportation sector) (last visited Feb. 1, 2010); State Environmental Resource Center, Issue: Carbon Taxing, http://www.serconline.org/carbontaxing/stateactivity.html (last visited Feb. 1, 2010).

through the Clean Air Act to regulate automobile emissions.[73] New Jersey, in particular, passed the New Jersey Global Warming Response Act, which seeks to reduce New Jersey's GHG emissions down to 1990 levels by 2020 and by eighty percent of 2006 levels by 2050.[74] In the northeast, there is the Regional Greenhouse Gas Initiative ("RGGI"), a state-level regional greenhouse gas reduction agreement.[75] California, Maryland, Minnesota, Oregon, Texas, and Vermont have all considered carbon taxes as an option in dealing with climate change[76] and New York has an existing gasoline tax.[77] Many western states are members of the Western Climate Initiative (WCI), a collaboration of several states to reduce aggregate GHG emissions "by 15 percent below 2005 levels by 2020."[78]

States have even gone to the courts to pursue climate change offenders, with California and Connecticut suing major emitters of GHGs.[79] As a result of *Connecticut v. American Electric Power Co.* (brought by Connecticut, New York, California, Iowa, New Jersey, Rhode Island, Vermont, Wisconsin, and New York City), the U.S. Court of Appeals for the Second Circuit held on appeal that states

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73. *See* Clean Air Act 42 U.S.C. § 7543(b)(1) (2007); *see also* Carlson, *supra* note 3; Alan C. Swan, *NAFTA Chapter 11--"Direct Effect" and Interpretive Method: Lessons From Methanex v. United States*, 64 U. MIAMI L. REV. 21, 69 (2009).

74. Lichtenstein, supra note 72; *see also* Lauren E. Schmidt & Geoffrey M. Williamson, *Recent Developments in Climate Change Law*, 37 COLO. LAW. 63, 70 (2008).

75. *See* Regional Greenhouse Gas Initiative Website, http://www.rggi.org/home ("The Regional Greenhouse Gas Initiative (RGGI) is the first mandatory, market-based effort in the United States to reduce greenhouse gas emissions. Ten Northeastern and Mid-Atlantic states have capped and will reduce CO_2 emissions from the power sector 10% by 2018.") (last visited Feb. 1, 2010).

76. *See* CAL. ENERGY COMM'N, 1997 GLOBAL CLIMATE CHANGE REPORT: GREENHOUSE GAS EMISSIONS REDUCTION STRATEGIES FOR CALIFORNIA VOLUME 1 (2008), *available at* http://www.climatechange.ca.gov/publications/97GLOBALVOL1.PDF (detailing a report from California's Air Review Board recommending a carbon tax on vehicle emissions).

77. *See* N.Y. TAX LAW §§ 282-289-f (Consol. 2010).

78. Schmidt & Williamson, *supra* note 74.

79. *See* California v. Gen. Motors, No. C06-05755 MJJ, 2007 WL 2726871 (N.D. Cal. Sept. 17, 2007); Connecticut v. American Elec. Power Co., 406 F. Supp. 2d 265 (S.D.N.Y. 2005). Both suits were dismissed because the courts held that climate change implicated "nonjusticiable 'political questions.'" Joo, *supra* note 34, at 698, n. 160.

have standing to bring actions against major emitters under common law public nuisance.[80] The court remanded the case to the lower courts to for further proceedings.[81]

In *Massachusetts v. EPA*, the State of Massachusetts filed a lawsuit against federal agencies for not taking action on climate change.[82] In that case, the U.S. Supreme Court held the following: that Massachusetts had standing to petition for review; that the Clean Air Act authorized the EPA to regulate greenhouse gas emissions if it could form a judgment that those emissions were contributing to climate change; and that the EPA could avoid taking action with respect to GHG emissions from motor vehicles only if it determined that GHG's do not contribute to climate change or if it could provide a reasonable explanation as to why it could not or would not exercise its discretion to determine if they do.[83] Taken together, these efforts illustrate that while the states have done much to tackle the climate change problem, the federal government has been sleeping on the issue.

B. Analogy To Smaller Nations

U.S. states have land areas and populations that are comparable to those of states in the European Union and to other nations abroad that have implemented policies on climate change. To illustrate, consider the following table:

80. Conn.v. Amer. Elec. Power Co., 582 F.3d 309, 392 (2d Cir. 2009).
81. *Id.* at 393.
82. Mass. v. EPA, 549 U.S. 497 (2007).
83. *Id.* at 518-34.

Comparison of Emissions Between States and Countries		
Nation	***Population***[84]	***GHG emissions (MMT CO^2 Eq.)***[85]
UK	61,113,205	636.7
Poland	38,482,919	398.9
Spain	40,525,002	442.3
State	***Population***[86]	***GHG emissions (MMT CO^2 Eq.)***[87]
California	36,553,215	453
New York	19,297,729	244
Texas	23,904,380	782

In Europe, although there is a broad Emissions Trading System implemented at the European Union level, there are also a multitude of "state" level programs that have been implemented individually by European member states.[88] Small European nations have set up

84. Based on the 2009 Central Intelligence Agency estimates. *See* CENT. INTELLIGENCE AGENCY, THE WORLD FACTBOOK (2009), *available at* https://www.cia.gov/library/publications/the-world-factbook/region/region_eur.html (providing links to individual entries for the UK, Poland and Spain, entries which detail the population of each country).

85. Press Release, European Environment Agency, EU Greenhouse Gas Emissions Fall for Third Consecutive Year (May 29, 2009), http://www.eea.europa.eu/pressroom/newsreleases/2009-greenhouse-inventory-report (2007 estimate in million metric tons of Carbon Dioxide equivalent: [MMT CO_2 Eq.]).

86. U.S. Census Bureau, 2007 Population Estimates, http://factfinder.census.gov/servlet/GCTTable?_bm=y&-%20bm=y&-ds_name=PEP_2007_EST&-mt_name=PEP_2007_EST_GCTT1R_US9S&-CONTEXT=gct&-redoLog=true&-geo_id=&-format=US-9|US-9S|US-9Sa|US-9Sb|US-9Sc|US-9Sd|US-9Se|US-9Sf|US-9Sg|US-9Sh&-_lang=en (last visited Feb. 1, 2010).

87. RAMSEUR, *supra* note 17, at 3.

88. *See* European Commission, Climate Action: The Climate action and renewable energy package, Europe's climate change opportunity, Jan. 1, 2008, http://ec.europa.eu/environment/climat/climate_action.htm (detailing some of the European top-level initiatives on climate change); *see also* NORWEGIAN MINISTRY OF THE ENVIRONMENT, NORWEGIAN CLIMATE POLICY 5 (2006-2007), *available at* http://www.regjeringen.no/pages/2065909/PDFS/STM200620070034000EN_PDF

national emissions trading programs, caps, carbon taxes and a large number of other policies.[89] The actions of these smaller nations should not be dismissed just because they are small, since they have acted as a valuable "laboratory" for environmental policies and neither should the actions of a state.

Based on the numbers, the contribution that states can make is not small; the top ten GHG emitting states accounted "for almost 50% of total U.S. GHG emissions in 2003."[90] According to the U.S. Energy Information Agency (2007), the top twenty energy consuming states in the country accounted for 69.5% of all energy consumed in the United States in 2007 and the top ten states accounted for 47.3%.[91] Therefore, there is a significant amount of progress that could be made if the top ten emitting states or the top ten energy consuming states were to enact strong policies on climate change. Furthermore, of the top ten emitting states (Texas, California, Pennsylvania, Ohio, Florida, Illinois, Indiana, New York, Michigan and Louisiana)[92] many have either enacted local programs on climate change and

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S.pdf (detailing measures taken by the government of Norway on climate change); Kateri Jochum, *EU Environment Ministers Unite on Climate Change Action*, DEUTSCHE WELLE, July 25, 2007, *available at* http://www.dw-world.de/dw/article/0,,4517921,00.html (noting political unity at the European level on climate change); Stefan Speck, *The Design of Carbon and Broad-Based Energy Taxes in European Countries*, 10 VT. J. ENVTL. L. 31, 31-32 (2008); Michael T. Hatch, The Europeanization of German Climate Change Policy (May 17-19, 2007) (unpublished draft paper), *available at* http://www.unc.edu/euce/eusa2007/papers/hatch-m-06b.pdf (noting some of the details of German climate change programs); Swedish Environmental Protection Agency, Sweden's Climate Policy, http://www.naturvardsverket.se/en/In-English/Menu/Climate-change/Climate-policy/Swedens-climate-policy (last updated July 9, 2009) (detailing some of Sweden's actions on climate change). *See generally* XAVIER LABANDEIRA ET AL., CLIMATE CHANGE POLICIES IN SPAIN. AN EVALUATION OF POLLUTION MARKETS, *available at* http://aerna2006.de.iscte.pt/papers/S3C Rodriguez.pdf (detailing some of the climate change policies in Spain) (last visited Feb. 1, 2010).

89. *See* NORWEGIAN MINISTRY OF THE ENVIRONMENT, *supra* note 88; Hatch, *supra* note 88; Swedish Environmental Protection Agency, *supra* note 88. *See generally* LABANDEIRA ET AL., *supra* note 88.

90. RAMSEUR, *supra* note 17, at 3.

91. ENERGY INFO. ADMIN., *supra* note 17 (indicating total U.S. consumption was 101,468.00 BTU, while total consumption in the top twenty states was 70,527.90 and 47,989.70 in the top 10).

92. RAMSEUR, *supra* note 17, at 3.

GHG reduction, are members of regional agreements or have a large incentive to act, as they are either coastal or Midwestern states.[93]

IV. PROBLEMS WITH A STATE LEVEL APPROACH

A. Generally

There are several problems with adopting a state-based approach. Climate change is the kind of issue where not just a national, but a global plan should be enacted; one that would organize all of the resources of the world in a coordinated fashion to tackle the issue of climate change in an intelligent manner.[94] It is a problem that encompasses many people, across traditional borders, and the effects will not be evenly felt.[95] However, there is also a need for speed in tackling climate change, since waiting too long to take action could be disastrous, even in a country like the United States, which is and has been one of the per capita leaders on climate changing emissions.[96] That is why state regulation, which can come into effect faster, stronger and be more effectively than federal action, should not be discouraged.[97]

However, one of the major concerns with state-by-state regulation is that, if permitted, it could result in several, disparate policies that would affect people differently, making it harder for companies to do business.[98] This is a legitimate drawback to having a state approach

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93. *See supra* Part III.A.

94. *See generally* NICHOLAS STERN, THE GLOBAL DEAL: CLIMATE CHANGE AND THE CREATION OF A NEW ERA OF PROGRESS AND PROSPERITY (2009) (discussing a global, holistic approach to environmental problems that attempts to integrate several international problems, including energy, economic, and justice issues with climate change policy).

95. *See* Parliament of Australia, Parlimentary Library, Social Effects of Climate Change, http://www.aph.gov.au/LIBRARY/Pubs/ClimateChange/effects/social/social.htm (last revised Sept. 11, 2009).

96. *See* Union of Concerned Scientists, Each Country's Share of CO2 Emissions, http://www.ucsusa.org/global_warming/science_and_impacts/science/each-countrys-share-of-co2.html (last revised May 13, 2009) (showing that the U.S. is currently behind Australia in Per Capita Carbon Emissions).

97. *See supra* Part III (discussing the advantages of state level regulation).

98. *See* Steven Mufson & Juliet Eilperin, *Energy Firms Come to Terms with Climate Change*, WASH. POST, Nov. 25, 2006, at A1 ("'We cannot deal with 50

to regulation. On the other hand, national proposals have been much weaker than what some of the states have been willing to implement.[99] The chance of enacting a national program, which is likely to be a weak program, is not an effective argument against permitting state action. Furthermore, allowing states to adopt individual climate policies does not prevent future federal action. Such federal legislation could be implemented in a way that allows states to go beyond what the federal approach might dictate, using the federal requirements as a minimum.[100] Additionally, companies often manufacture their products taking into account economies of scale.[101] If these companies find themselves priced out of certain states, they can decide to: (1) not to sell products in those states, (2) design a separate product line just for those states, or (3) raise the standard of all of their products to avoid future problems with tough state climate change regulation.

B. Preemption

Another problem that arises when states choose to act before the federal government is that preemption issues arise.[102] What happens

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different policies,' said [a representative of Shell], 'We need a national approach to greenhouse gases.'"); *see also* Charlie Crist, *Florida's Energy Policy: A Model For The Nation*, 39 ENVTL. L. REP. NEWS & ANALYSIS 10061 (2009).

99. *See* Press Release, *supra* note 53.

100. The EPA has often allowed states to enact stricter regulations than what is enacted by the federal government. *See* Sharon Tomkins et al., *Litigating Global Warming: Likely Legal Challenges To Emerging Greenhouse Gas Cap-And-Trade Programs In The United States*, 39 ENVTL. L. REP. NEWS & ANALYSIS 10389, 10407 (2009).

101. *Management Idea: Economies of Scale and Scope*, THE ECONOMIST.COM, Oct. 20, 2008, http://www.economist.com/businessfinance/management/displaystory.cfm?story_id=12446567 ("Economies of scale are factors that cause the average cost of producing something to fall as the volume of its output increases. Hence it might cost $3,000 to produce 100 copies of a magazine but only $4,000 to produce 1,000 copies.").

102. Yvonne Gross, Note, *Kyoto, Congress, or Bust: The Constitutional Invalidity of State CO_2 Cap-and-Trade Programs*, 28 T. JEFFERSON L. REV. 205, 233 (2005) ("[T]hrough field preemption, such state-implemented cap-and-trade programs are unconstitutional as violative of the Supremacy Clause."); *see also* Ann E. Carlson, *Federalism, Preemption, and Greenhouse Gas Emissions*, 37 U.C. DAVIS L. REV. 281, 299-303 (2005) (discussing potential Clean Air Act preemption of California's regulatory efforts toward addressing greenhouse gas emissions).

if and when the federal government enacts legislation that deals with climate change after states have already adopted their own policies? The issue of preemption between federal and state regulation is extremely broad. There are solutions to this problem, however, because the majority of federal environmental laws do not "invoke explicit preemption"[103]; state regulations can be designed to address preemption before it becomes an issue.[104] Congress often encourages states to enact their own, stricter legislation.[105] In addition, there are often savings clauses in federal environmental law which preserve certain areas of regulation to the states or leave states free to regulate beyond what the federal government would be able to do on its own.[106]

RGGI provides in its Memorandum of Understanding for what to do in the event of friction between the states and the federal government.[107] RGGI determines questions of federal preemption based on "(1) whether or not the federal bill allows for established state programs to remain in existence; and (2) the degree to which a federal program is comparable to RGGI."[108]

The issue of preemption was raised, and ultimately decided, in the discussion draft of the Waxman-Markey bill. The bill allows states to implement tougher standards on GHG emissions, but state programs will be suspended for the period between 2012-2017 so that federal carbon markets have time to develop.[109] Additionally, the Clean Air

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103. Tomkins et al., *supra* note 100 at 10407.

104. Memorandum of Understanding, Regional Greenhouse Gas Initiative 10, (Dec. 20, 2005), *available at* http://www.rggi.org/docs/mou_12_20_05.pdf [hereinafter RGGI Memorandum].

105. Tomkins et al., *supra* note 100, at 10407.

106. *Id.*; *see also* BLACK'S LAW DICTIONARY 1371 (8th ed. 2004) (defining a saving clause as a "statutory provision exempting from coverage something that would otherwise be included.").

107. RGGI Memorandum, *supra* note 104, at 10.

108. Kevin Gaynor & Mara Zimmerman, *Federal Approaches to Climate Change: Federal Preemption of State Climate Change Laws*, SN062 A.L.I.-A.B.A. 813, 829 (2008).

109. Tomkins, *supra* note 100, at 10407; *see also* Discussion Draft: American Clean Energy and Security Act of 2009 (Mar. 31, 2009), *available at* http://energycommerce.house.gov/Press_111/20090331/acesa_discussiondraft.pdf (submitted by Rep. Henry Waxman (D-Cal.) and Rep. Edward Markey (D-Mass.)).

Act, as noted earlier, specifically designated certain areas where the state of California would be allowed to regulate vehicle emissions.[110]

Thus, preemption issues can be anticipated and prevented through creative language in the legislation. All that is required for state regulations to avoid preemption issues is insertion of provisions similar to those included in RGGI.[111] With regards to federal legislation, it must account for the existence of prior state regulation, as was done in the Waxman-Markey bill.[112] Despite this, there is some doubt as to whether the design of the RGGI will be enough to avoid problems with preemption when it comes to due process claims.[113]

C. Claims Against States for Climate Initiatives

Because there is still some uncertainty as to the legality of state actions on climate change, there is a risk that entities that stand to lose from state level regulations will sue the states, under various legal doctrines and theories.[114] For instance, one risk for states is that local businesses negatively affected by regulation will bring due process claims against the regulating state, claiming it exceeded its authority by enacting local legislation that is beyond their constitutional power.[115] However, the most significant legal challenges to state programs and regional agreements will be brought under the following constitutional doctrines: the Supremacy Clause, the Compacts Clause, and the Commerce Clause.[116]

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110. Clean Air Act, 42 U.S.C. § 7543(b)(1) (2007).

111. RGGI Memorandum, *supra* note 104, at 10.

112. *See* McGuinness & Ellerman, *supra* note 11.

113. *See infra* Part IV.C.

114. Benjamin K. Sovacool, *The Best of Both Worlds: Environmental Federalism and the Need for Federal Action on Renewable Energy and Climate Change*, 27 STAN. ENVTL. L.J. 397, 467-68 (2008).

115. *Id.*

116. *Id.* Although that is just a sampling of the kinds of claims that could be brought against state regulations, claims could have also been brought under, *inter alia*, the Sherman Act and the Dormant Commerce Clause. Cent. Valley Chrysler-Jeep v. Witherspoon, 456 F. Supp. 2d 1160, 1183-86 (E.D. Cal. 2006).

1. The Supremacy Clause

The preemption doctrine is the ordinary way in which the Supremacy Clause questions are analyzed,[117] but it must be balanced against historic and constitutional precedent that recognizes the states' ability to govern their individual territories.[118] The actions states have taken have pushed the limits of what is constitutionally permissible. While the preemption concerns raised by the existence of state environmental programs have yet to be fully answered, the initial cases that have been brought against California, Vermont and Rhode Island have had promising results for proponents of state level regulation.[119]

However, in the case of *Central Valley Chrysler-Jeep v. Witherspoon*, California was sued by automobile manufacturers claiming that California GHG regulations were preempted by the federal government (and the President's power over foreign policy).[120] The Eastern District Court of California held that California's GHG regulations were preempted by the Energy Policy and Conservation Act (EPCA),[121] reasoning that California's policies were an obstacle to the accomplishment of the EPCA.[122]

When Vermont adopted California's carbon dioxide regulations, it resulted in another lawsuit, *Green Mountain Chrysler-Plymouth v. Crombie*.[123] In this case, the plaintiffs were a group of automobile dealers, who sought declaratory and injunctive relief from Vermont's

117. This is why the design of regional and state level programs must be done in a way that avoids preemption as much as possible. *See supra* Part IV.C.

118. *See* Rice v. Santa Fe Elevator Corp., 331 U.S. 218, 230 (1947) (explaining that a Supremacy Clause analysis begins "with the assumption that the historic police powers of the States [are] not to be superseded by the Federal Act unless that [is] the clear and manifest purpose of Congress"); *see also supra* Part IV.B. (for a discussion of the design problems when facing federal preemption).

119. *See* Green Mountain Chrysler Plymouth Dodge Jeep v. Crombie, 508 F. Supp. 2d 295 (D. Vt. 2007) (holding that the Vermont's automobile emission standards were not in violation of express preemption, field preemption, conflict preemption, or foreign-policy preemption); *see also Cent. Valley*, 456 F. Supp. 2d at 1163 (case brought under the preemption doctrine in California); Lincoln-Dodge, Inc. v. Sullivan, 588 F. Supp. 2d 224 (D. R.I. 2008) (case brought under the preemption doctrine in Rhode Island).

120. *Cent. Valley*, 456 F. Supp. 2d at 1163, 1165-66.

121. *Id.* at 1168-74.

122. *Id.*

123. Joo, *supra* note 34, at 700.

climate change regulations that established GHG emissions standards for automobiles.[124] The Federal District Court of Vermont held that Vermont's regulations were not preempted by federal law.[125] The court noted that state policies are assumed to not be superseded by a federal act unless it is "the clear and manifest purpose of Congress."[126] The court also referred to earlier acknowledgements by Congress that the regulation of "mobile sources" of air pollution was traditionally the responsibility of the states.[127]

2. The Compacts Clause

The Compacts Clause could also be an obstacle to state action. The Compacts Clause of the U.S. Constitution, states that "[n]o State shall, without the Consent of Congress . . . enter into any Agreement or Compact with another State, or with a foreign Power[.]"[128] In Compacts Clause cases, interstate agreements that increase the power of the states at the expense of the federal government fall within the scope of this clause, while those agreements that do not, do not fall within its scope.[129]

In reviewing the applicability of the Compacts Clause, courts first determine whether the agreement is a "compact," which would require: (1) "some sort of joint organization or body to govern the agreement, if necessary,"[130] (2) that it is binding, and (3) that it requires "reciprocity of the regional limitation, meaning that one party cannot agree to a nationwide program while another believes the agreement only covers a handful of states."[131] When regional programs allow member states to leave at any time, these regional programs should not be considered compacts.[132]

However, in order for regional agreements linked into the international system, like the RGGI, to be effective, they should not

124. *See Green Mountain*, 508 F. Supp. 2d at 300, 302.

125. *Id.* at 343-50.

126. *Id.* at 350.

127. *Id.*

128. U.S. Const. art. I, § 10, cl. 3.

129. Cuyler v. Adams, 449 U.S. 433, 440 (1981).

130. *See* Robert K. Huffman & Jonathan M. Weisgall, *Climate Change and the States: Constitutional Issues Arising from State Climate Protection Leadership*, 8 SUSTAINABLE DEV. L. & POL'Y 6, at 11.

131. *See id.*

132. *See id.*

allow member states to abandon easily. Internationally linked climate change agreements could be considered compacts if the states are not allowed to back out of the agreement because then it starts to look a lot more like what was not permitted in *Bancorp*.[133]

However, even if an agreement is found to be a compact, it can still be approved by Congress. After such approval it "reaches the level of federal law" and no longer presents a problem.[134] Therefore, there are two simple solutions to the Compacts Clause problem: either sacrifice efficiency by allowing states to back out, or have the state agreements authorized by Congress.

3. The Commerce Clause

Another area of potential litigation, especially against regional agreements, is the Commerce Clause.[135] The Commerce Clause states that Congress has the power "[t]o regulate Commerce with foreign Nations, and among the several States, and with the Indian Tribes."[136] Under the Dormant Commerce Clause theory, the Supreme Court has read the Commerce Clause in a negative sense to mean that because Congress has the aforementioned power, the states do not.[137] The Dormant Commerce Clause will not be violated by state action "merely because it affects in some way the flow of commerce between the States."[138] Generally it is a matter of whether the state action is protectionism.[139] If the action is determined not to

133. *See id*, at 11.

134. *Id.* at 10; *see also* U.S. Const. art. 1, § 10, cl. 3 (containing the language "without the Consent of Congress," meaning that if Congress has consented there should not be a violation of the Compacts Clause).

135. *See* Heddy Bolster, *The Commerce Clause Meets Environmental Protection: The Compensatory Tax Doctrine as a Defense of Potential Regional Carbon Dioxide Regulation,* 47 B.C. L. REV. 737, at 737-38 (2006), *available at* http://lawdigitalcommons.bc.edu/bclr/vol47/iss4/3 ("[T]he regulatory approaches available to RGGI states . . . may be subject to attack as violations of the Commerce Clause of the U.S. Constitution.").

136. U.S. CONST. art. 1, § 8, cl. 3.

137. Juliet Howland, Comment, *Not All Carbon Credits Are Created Equal: The Constitution and the Cost of Regional Cap-and-Trade Market Linkage*, 27 UCLA J. ENVTL. L. & POL'Y 413, 446-48 (2009).

138. Great Atl. & Pac. Tea Co. v. Cottrell, 424 U.S. 366, 371 (1976).

139. *See* Minnesota v. Clover Leaf Creamery Co., 449 U.S. 456, 471 (1981).

be protectionist, then the *Pike* test is applied.[140] It is not entirely clear what the result of the *Pike* test would be for regional greenhouse gas initiatives, although at least one case has upheld regional agreements under a Dormant Commerce Clause attack.[141]

Regardless of the challenge of legal suits, however, states should continue to push the boundaries of climate change regulation. Not every policy will be perfect since the legality of many of these issues remains unresolved, but not every policy will be defeated either.[142] If the dangers of climate change are as great as some forecast, and if green industry becomes the next great market, then it is better to risk facing and overcoming a few obstacles on the path to adopting an environmental program, even one that is not prefect or ideal, than it is to remain paralyzed. Until some of these legal questions are settled, states have an open window to enact more regulation, allowing for emissions reductions where they are politically feasible and providing Congress an opportunity to watch and consider various climate change regulation models.

D. Leakage And The Race To The Bottom

If environmental regulation is taken at the state level, one of the most serious issues would be a "classic collective action problem" because climate change is a global problem.[143] "Carbon leakage is defined as the increase in emissions outside a region as a direct result of the policy to cap emission in this region."[144] As some states reduce their emissions and enact tougher climate legislation, states that have yet to take action would continue to allow for high carbon emitting industries to operate in their borders, potentially resulting in a migration of companies from those states which enact tougher standards to those with lower standards.[145] In fact, some states might

140. Pike v. Bruce Church, Inc., 397 U.S. 137, 142 (1970) ("Where the statute regulates even-handedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits.").

141. *Cent. Valley*, 456 F. Supp. 2d at 1186.

142. *See Green Mountain*, 508 F. Supp. 2d at 350.

143. Carlson, *supra* note 3.

144. INT'L ENERGY AGENCY, CLIMATE POLICY AND CARBON LEAKAGE 2 (2008), *available at* http://www.iea.org/papers/2008/Aluminium_EU_ETS.pdf.

145. *See id.*; *see also* Carlson, *supra* note 3.

even be incentivized to allow for greater emissions since there is potential for large monetary rewards.[146]

While carbon leakage is a serious concern, there are several responses to the question of whether it is sufficiently detrimental to make a state-based approach economically and environmentally unsound. First, federal action on climate change could also result in carbon leakage, now at a national level, since companies could shift intensive GHG emitting operations out of the U.S.[147] Few environmentalists, however, consider that sufficiently strong grounds to forego implementing a federal climate regime. Thus, the same argument can be made with regards to a state-based approach—the prospect of leakage should not obstruct state action.

Second, other nations have enacted climate legislation that is considerably stronger than what has been done in the U.S.[148] In many cases, these programs have served to provide momentum on the issue of climate change, offering the U.S. insight into effective and ineffective regulatory schemes. As noted earlier, some of these countries have populations and geographical dimensions no larger than U.S. states.[149] Therefore, the effect of regulations of GHG emissions in a high emission U.S. state can be as great as that of a comparably sized foreign nation.[150]

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146. Carlson, *supra* note 3.

147. Richard Saines, *Changing Developments in Climate Change Law: Looking Ahead to Copenhagen and Beyond*, *in* THE IMPACT OF INTERNATIONAL CLIMATE CHANGE POLICIES: LEADING LAWYERS ON COUNSELING CLIENTS, NAVIGATING RECENT AND UPCOMING DEVELOPMENTS, AND RECOGNIZING THE ECONOMIC IMPACT OF CLIMATE CHANGE POLICY 61, 63 (2009).

148. Barrett Sheridan, *Green-Listed: Yale University's Newest Ranking of the World's Greenest Countries Offers a Few Surprises—and Some Useful Lessons for Business Leaders*, NEWSWEEK.COM, Jan. 23, 2008, http://www.newsweek.com/id/97279; *see also The World's Greenest Countries: Yale University's Ranking of 149 Countries According to an Environmental Performance Index (EPI)--a Weighting of Carbon and Sulfur Emissions, Water Purity and Conservation Practices,* NEWSWEEK.COM, Jan. 23, 2008, http://www.newsweek.com/id/98010; Newsweek.com, Environmental Performance Index 2010, http://www.newsweek.com//frameset.aspx/?url=http://www.yale.edu/epi (last visited Jan. 29, 2010).

149. *See supra* Part III.B.

150. *Compare* U.S. Census Bureau, California QuickFacts from the U.S. Census Bureau, http://quickfacts.census.gov/qfd/states/06000.html (last visited Feb. 1, 2010) (noting the size of California's population of 36,756,666 (2008) and high

Another potential problem is that states might actually take advantage of having the ability to go beyond federal regulations by adopting tough standards, knowing that they can externalize the costs to other states.[151] This results in what appears to be reverse leakage—where states would want to have strong environmental regulation in areas where it might confer an economic or social advantage. A state that is a producer of a particular product, for example, which competes with products manufactured in other states, could chose to strengthen environmental standards within its borders in a way that benefits local producers at the expense of out of state producers.[152]

This can also upset manufacturing of products that rely on economies of scale.[153] But a disruption to economies of scale might actually be an argument in favor of state level regulation. If a car manufacturer is faced with a significantly large group of states implementing tough emissions standards, they could be essentially regulated out of certain markets, providing a stimulus for having their automobiles meet the highest possible energy standards, so that they can continue to expand their brand everywhere.

The RGGI Emissions Leakage Multi-State Staff Working Group looked into possible mitigation strategies in dealing with carbon leakage.[154] They came up with several strategies that could be pursued by RGGI member states to reduce leakage.[155] In particular, they recommended that participating states should pursue aggressive investment in "energy efficiency market transformation programs," and "implementation and expansion of complementary policies such as building energy codes and appliance and equipment efficiency

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economic numbers), *with* Encyc. Britannica Online, Spain, http://www.britannica.com/EBchecked/topic/557573/Spain (last visited Feb. 1, 2010) (noting the size of Spain's population, 45,661,000, and economy). *See generally* Part III.B.

151. Posting of Brian T. Burges to The Legal Workshop, http://legalworkshop.org/2009/10/28/the-case-for-limiting-federal-preemption-of-state-environmental-regulations (Oct. 28, 2009).

152. *Id.*

153. *Id.*

154. *See generally* THE RGGI EMISSIONS LEAKAGE MULTI-STATE STAFF WORKING GROUP, REGIONAL GREENHOUSE GAS INITIATIVE, POTENTIAL EMISSIONS LEAKAGE AND THE REGIONAL GREENHOUSE GAS INITIATIVE (RGGI) (2008), *available at* http://rggi.org/docs/20080331leakage.pdf.

155. *Id.*

standards" that could speed the development of "end-use energy efficiency technologies and measures."[156] The study cautioned that the potential for leakage was still uncertain and that waiting for further evidence as to whether carbon leakage was actually occurring was warranted.[157]

E. Efficiency

If and when the federal government does implement a federal program to tackle climate change, existing state programs will have to be aligned with the new federal emissions trading program.[158] Here, actions by the states that intersect with those of the federal government could have additional efficiency costs.[159] However, there are some methods states could utilize to continue to implement policies more stringent than a federal program. One of these techniques, is a state level "carve-out" that maintains links to the federal program.[160] That is, a state could have its own system of tackling climate change that leaves an option for transferring credits or other methods of abatement into the national program.[161] However, even if there are additional costs at the state level, climate risks are predicted to worsen if preventative action is not taken soon. Furthermore, as noted earlier, as long as states take action faster than the federal government, they can test out tough economic policies and generate momentum for tackling climate change while federal programs try to catch up.[162] The relative efficiency costs of state plans might pale in comparison to the costs of letting the climate continue to deteriorate.[163]

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156. *Id.* at 41.

157. *Id.* at 42.

158. *See* McGuinness & Ellerman, *supra* note 11, at 179.

159. *Id.*

160. *Id.* ("[R]edistributive effects and the associated economic inefficiency are avoided under either federal preemption of duplicative state programs or a 'carve out' of state programs from the federal cap with linkage to the federal allowance market.").

161. *Id.*

162. *Id.* at 179 ("Since marginal costs are not equalized among all sources nationally, economic efficiency is sacrificed and total compliance costs for achieving the national cap are greater than they would be under the national program alone.").

163. Steve Connor & Michael McCarthy, *World on Course for Catastrophic 6° Rise, Reveal Scientists*, THE INDEPENDENT, Nov. 18, 2009, at 1, *available at*

State actions will not prevent the federal government from also taking action; much of the action already taken by states has fallen within the framework set up by the federal government.[164] As mentioned earlier, the federal government often drafts legislation in a way that allows states to go beyond the measures taken at the federal level.[165] Therefore, state action should be supplemental to federal action, as an additional layer of regulation.[166] As President Barrack Obama said, "[t]he federal government must work with, not against, states to reduce greenhouse gas emissions."[167]

Finally, preserving the states' ability to regulate climate change will allow for "tailoring" environmental policies at the local level.[168] Geography, climate, and industry needs might be different in each state, providing further incentive to allow states to continue to develop their own environmental policies and provide innovative climate initiatives.[169] Furthermore, there are benefits to having a decentralized democratic process which allows people to have more control over how their lives are run.[170] States are the backdoor for tougher climate standards that cannot get through on the national level.

V. CONCLUSION

The ultimate goal in permitting states to create their own environmental policy goals is for states to have the ability to go

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http://www.independent.co.uk/environment/climate-change/world-on-course-for-catastrophic-6deg-rise-reveal-scientists-1822396.html (noting that world is currently on track to meet the worst climate change scenario).

164. Carlson, *supra* note 3.

165. *See supra* Part IV.B.

166. *See* Sovacool, *supra* note 114, at 472.

167. Ken Bensinger & Jim Tankersley, *Obama Moves to Force Automakers to Produce More Fuel-Efficient Vehicles*, L.A. TIMES.COM, Jan. 27, 2009, http://articles.latimes.com/2009/jan/27/business/fi-emissions27.

168. Burges, *supra* note 151.

169. *Id.*

170. *Id.* Some of the benefits of decentralization are "(1) economic efficiency and development; (2) localities as instruments for community empowerment and pluralism; and (3) vehicles for spreading democracy around the world." Ileana M. Porras, *The City and International Law: In Pursuit of Sustainable Development*, 36 FORDHAM URB. L.J. 537, 601 (2009).

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Good for You, Bad for Us: The Financial Disincentive for Net Demand Reduction

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Good for You, Bad for Us: The Financial Disincentive for Net Demand Reduction

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** Professor of Law, Vanderbilt University Law School. This Article was supported by the Vanderbilt University Law School and Vanderbilt Climate Change Research Network. We thank Linda Breggin, Joel Eisen, David Krantz, and J.B. Ruhl for helpful comments on this project. Will Airhart, Maria Banda, Christian Carlson, Seth Mullikin, Austin Payne, and Audrey Singleton provided excellent research assistance.

An unexpected drop in U.S. electricity consumption has utility companies worried that the trend isn't a byproduct of the economic downturn and could reflect a permanent shift in consumption that will require sweeping change in their industry.

—Rebecca Smith, Wall Street Journal[1]

Good for you, bad for us.

—Electric Utility Official[2]

INTRODUCTION

Energy policy debates often focus on increasing the supply of renewable energy, but energy demand merits equal attention. Low-carbon energy sources will not be able to displace fossil fuels at the levels necessary to achieve climate goals if global demand continues to grow at projected rates.[3] To meet the widely endorsed goal of 50% global carbon emissions reductions by 2050, including 80% reductions from developed countries, global emissions from fossil fuel use will need to decline by more than seven billion tons from projected levels by 2050.[4] Major new sources of low-carbon energy will become available, but it is unrealistic to assume that new low-carbon sources will expand quickly enough to displace existing fossil fuel sources if

1. Rebecca Smith, *Surprise Drop in Power Use Delivers Jolt to Utilities*, WALL. ST. J., Nov. 21, 2008, at B1.

2. The electric utility official made this comment at a recent installation of a household solar photovoltaic system. Email from Linda Breggin, Senior Att'y & Dir., Nanotechnology Program, Envtl. Law Inst., to Michael Vandenbergh (on file with author) (quoting the utility official). Although this example involves household energy supply, not demand, a utility's gatekeeping role and incentives regarding household solar programs are often similar to those regarding household energy efficiency and conservation programs.

3. Nathan S. Lewis & David G. Nocera, *Powering the Planet: Chemical Challenges in Solar Energy Utilization*, 103 PROC. NAT'L. ACAD. SCI. 15729, 15730 (2006); Nathan S. Lewis, *Powering the Planet*, ENGINEERING & SCI., No. 2, 2007, at 12, 16, *available at* http://www.ccser.caltech.edu/outreach/powering.pdf. By low-carbon, we mean sources that generate little or no carbon emissions (e.g., solar, wind, and nuclear energy) or that capture and store the emissions (e.g., fossil fuel plants with effective carbon capture and storage). We use the term "carbon" as shorthand for the six greenhouse gases included in the Framework Convention on Climate Change ("FCCC") and typically expressed as carbon dioxide equivalents ("CO_2e"). *See Fact Sheet: The Need for Mitigation*, UNITED NATIONS FRAMEWORK CONVENTION ON CLIMATE CHANGE (November 2009), http://unfccc.int/files/press/backgrounders/application/pdf/press_factsh_mitigation.pdf. Our focus here is on energy demand, and we do not take a position on the optimal mix of energy sources.

4. *See, e.g.*, S. Pacala & R. Socolow, *Stabilization Wedges: Solving the Climate Problem for the Next Fifty Years with Current Technologies*, 305 SCIENCE 968, 968 (2004) (identifying strategies that would enable emissions to "be held near the present level of seven billion tons per year (GtC/year) for the next fifty years, even though they are currently on course to more than double" by 2054).

global demand doubles as projected.[5] In fact, although the percentage of global electricity generation from fossil fuels has decreased in recent years, the total amount of fossil fuels consumed has increased.[6] The same analysis holds true for energy supply and demand in the United States: the supply of low-carbon energy is projected to grow, but without a substantial reduction from projected levels of demand, it is difficult to imagine how low-carbon sources can supply enough energy to enable the United States to achieve its share of global carbon emissions reductions.[7]

Recognition of the need to reduce energy demand has spawned a vast literature on energy policy measures that will increase efficiency and conservation at the industrial, commercial, and household levels.[8] Although the precise magnitude of the opportunity is the subject of debate, the literature has identified large, low-cost opportunities to reduce energy use and carbon emissions from these sectors.[9] For example, recent research in the social and behavioral sciences suggests that the use of information and other nonintrusive interventions could achieve a "behavioral wedge" of carbon emissions reductions at the household level.[10] Behavioral wedge strategies

5. Lewis, *supra* note 3, at 12, 16.

6. INT'L ENERGY AGENCY, WORLD ENERGY OUTLOOK 2010 EXECUTIVE SUMMARY 5, 9 (2010).

7. *See* discussion *infra* Part II.A (highlighting the projected increase in energy use in the United States in the coming decades).

8. *See, e.g.*, DAN YORK ET AL., AM. COUNCIL FOR AN ENERGY EFFICIENT ECON., THREE DECADES AND COUNTING: A HISTORICAL REVIEW AND CURRENT ASSESSMENT OF ELECTRIC UTILITY ENERGY EFFICIENCY ACTIVITY IN THE STATES 1 (2012); Michael P. Vandenbergh & Anne C. Steinemann, *The Carbon-Neutral Individual*, 82 N.Y.U. L. REV. 1673, 1675 (2007) (discussing household energy efficiency and carbon emissions reductions); *see also* John Dernbach, *Stabilizing and Then Reducing U.S. Energy Consumption: Legal and Policy Tools for Efficiency and Conservation*, 37 ENVTL. L. REP. 10003, 10003 (2007); Noah Sachs, *Greening Demand: Energy Consumption and U.S. Climate Policy*, 19 DUKE ENVTL. L. & POL'Y F. 295, 298 (2009).

9. *See, e.g.*, HANNAH CHOI GRANADE ET AL., MCKINSEY & CO., UNLOCKING ENERGY EFFICIENCY IN THE U.S. ECONOMY 4 (2009), *available at* http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/unlocking_energy_efficiency_in_the_us_economy (concluding based on an engineering study that large increases in efficiency can be achieved in the United States at a net negative cost). *But see* Hunt Alcott & Michael Greenstone, *Is There an Energy Efficiency Gap?* 3–4 (Energy Inst. at Haas, Working Paper No. 228, 2012), *available at* http://ei.haas.berkeley.edu/pdf/working_papers/WP228.pdf (arguing based on economic theory that the efficiency gap is smaller than claimed by engineers); MALCOLM KEAY, OXFORD INST. FOR ENERGY STUDIES, ENERGY EFFICIENCY—SHOULD WE TAKE IT SERIOUSLY? 20 (2011) (same).

10. *See* Thomas Dietz et al., *Household Actions Can Provide a Behavioral Wedge to Rapidly Reduce U.S. Carbon Emissions*, 106 PROC. NAT'L ACAD. SCI. 18452, 18452 (2009) (describing "behaviorally oriented policies and interventions" as a potential behavioral wedge). The wedge concept was introduced in Pacala & Socolow, *supra* note 4, at 968–69. *See also* JASON CZARNESKI, EVERYDAY ENVIRONMENTALISM: LAW, NATURE AND INDIVIDUAL BEHAVIOR 1–4 (2011); Dernbach,

reduce carbon emissions by reducing household energy demand through improved efficiency (e.g., purchase of less energy-intensive appliances) and conservation (e.g., reduced use of existing appliances).[11] Any one strategy could have a small effect on its own, but aggregate behavioral efforts have the potential to produce reasonably achievable reductions in total U.S. emissions of 7% by 2020. This amount exceeds the total emissions of many major industrial sectors and is larger than all of the emissions from France.[12]

Notable reductions in the growth of household energy use have occurred in recent years,[13] but the United States is not on track to achieve a behavioral wedge.[14] Although many scholars have emphasized demand reduction as an important area for new legal and policy tools,[15] few have focused on the institutional barriers to its achievement.[16] In this Article, we identify the incentives of electric distribution utilities as a frequently overlooked barrier to achieving household energy demand reductions in the United States, examine the conceptual obstacles to overcoming this barrier, and explore a range of potential responses.[17] Although we focus on U.S. household

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supra note 8, at 10003; Katrina F. Kuh, *When Government Intrudes: Regulating Individual Behaviors That Harm the Environment*, 61 DUKE L.J. 1111, 1112 (2012).

11. Although improved efficiency and conservation are distinct mechanisms for achieving demand reduction, many commentators treat them together as "low-hanging fruit" among possible behavioral wedge measures. Michael P. Vandenbergh, Jack Barkenbus & Jonathan Gilligan, *Climate Change: The Low-Hanging Fruit*, 55 UCLA L. REV. 1701, 1705–06 (2008).

12. *Id.* at 1731. For a discussion of the importance of the cumulative effects of multiple small reductions in energy use and carbon emissions, see Elinor Ostrom, *Nested Externalities and Polycentric Institutions: Must We Wait for Global Solutions to Climate Change Before Taking Actions at Other Scales?*, 49 ECON. THEORY 353, 356–57 (2012).

13. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2012 WITH PROJECTIONS TO 2035, at 85–86 (2012) (discussing how increasing efficiency has led to slowing demand growth for electricity since 1950).

14. *See, e.g.*, U.S. DEP'T OF COMMERCE, U.S. CARBON DIOXIDE EMISSIONS AND INTENSITIES OVER TIME: A DETAILED ACCOUNTING OF INDUSTRIES, GOVERNMENT, AND HOUSEHOLDS 16–18 (2010) (predicting improvement in household emissions efficiency for the 2006 to 2010 period); Smith, *supra* note 1, at B1.

15. *E.g.*, Dernbach, *supra* note 8, at 10003; Sachs, *supra* note 8, at 295; Vandenbergh & Steinemann, *supra* note 8, at 1675.

16. *See, e.g.*, Paul C. Stern et al., *Design Principles for Carbon Emissions Reduction Programs*, 44 ENVTL. SCI. & TECH. 4847, 4847 (2010) (noting the importance of institutional barriers); Jiyong Eom & James L. Sweeney, Shareholder Incentives for Utility-Delivered Energy Efficiency Programs in California 2–3 (May 8, 2009) (unpublished manuscript, Precourt Energy Efficiency Ctr., Stanford Univ., 2009), *available at* http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1401529.

17. We focus on the demand for electricity in the United States at the household or residential level, but our analysis is also relevant to other energy users (e.g., small businesses) and to other energy sources (e.g., natural gas). *See* discussion *infra* Part II.A; *see also* Daniel A. Farber, *Controlling Pollution by Individuals and Other Dispersed Sources*, 35 ENVTL. L. REP.

demand, global household demand is projected to increase dramatically over the next several decades, and utilities' incentives to reduce household demand are important at the global level as well.[18]

The incentives of retail electric distribution utilities are essential because these utilities are critical gatekeepers for household demand reduction programs. This is an important but easily overlooked point. Retail electric distributors, both public and private, interact regularly with consumers, and they control much of the flow of information to and from households and the access to opportunities for demand reduction. They can act aggressively to induce widespread adoption of new practices and more efficient equipment. Or they can conduct widely publicized programs that comply with applicable mandates and generate goodwill without actually generating major reductions in demand. In addition, by controlling access to information and connection with the grid, they can encourage or discourage other firms from selling goods and services that may reduce household demand.[19] All of this can occur with little transparency to regulators and the public.

Despite the gatekeeping role of electric distribution utilities and the importance of reducing household energy demand, distributors in most jurisdictions do not have incentives to ensure that demand reduction strategies succeed on a wide scale.[20] In fact, under the regulatory regimes in most states, utilities would suffer revenue erosion if they induced substantial reductions in demand. Instead, the rate structure in most jurisdictions creates incentives for utilities to promote demand growth. If an essential gatekeeper has financial incentives to increase aggregate demand, it should not be surprising that large-scale demand reduction is not occurring.

10745, 10745 (2005) (noting the importance of behavioral interventions for small businesses). Reductions in U.S. energy demand from projected levels are necessary whether nuclear power or coal with capture and storage are part of the energy supply mix.

18. For example, China is expected to add as many new households between 2005 and 2030 as existed in the Western Hemisphere in 2000. Jianguo Liu & Jared Diamond, *China's Environment in a Globalizing World*, 435 NATURE 1179, 1184 (2005), *available at* http://archive.csis.msu.edu/Publications/JLiu_2005_Nature.pdfhttp://archive.csis.msu.edu/Publications/JLiu_2005_Nature.pdf. A recent study suggests that fifty million new household air conditioning units were added in China in 2010 alone. *See* Stan Cox, *Cooling a Warming Planet: A Global Air Conditioning Surge*, YALE ENV'T 360 (July 10, 2012), http://e360.yale.edu/feature/cooling_a_warming_planet_a_global_air_conditioning_surge/2550/.

19. For example, Carbon Salon, through online carbon emissions tracking, has provided individuals with carbon reduction strategies and data if the local utility allows disclosure of electric bills. CARBON SALON, http://www.carbonsalon.com (last visited Sept. 6, 2012).

20. *See* discussion *infra* Part II (noting the lack of incentives for utilities to achieve an NDR).

Two conceptual barriers undermine efforts to create incentives for electric distribution utilities to sell less of their product. The first is the use of policy efforts known as "demand-side management" ("DSM"), which we discuss in Part II. On the surface, DSM appears to address all forms of demand management, including demand reduction, but DSM efforts have focused on shifting the timing of demand, not on reducing the total amount of demand. DSM efforts typically involve reducing electricity generation costs by shifting demand from peak to off-peak periods. This shift allows utilities to fully deploy their lowest-cost sources of electric power, while under-deploying or under-investing in higher-cost sources, including renewable energy. For example, in areas where air conditioning is a large component of total electricity use, peak summer use occurs during the late afternoon and early evening. Utilities have generating units standing by to provide the additional electricity necessary at peak times. These "peaker" units are often natural gas turbines that are more expensive to operate than the coal-fired units that supply base load electricity for about half of the country.

If the costs of operation captured all of the important considerations, this approach to demand would not be problematic. But the social costs of carbon are externalized, and coal-fired units generate roughly twice the carbon emissions of natural gas units. As a result, in many areas, DSM programs that shift electricity use to off-peak periods may increase total carbon emissions from electricity generation.[21] DSM efforts thus may be working at cross-purposes with efforts to reduce carbon emissions. With increasing concerns about the carbon emissions of electricity generation, policymakers have begun to emphasize demand response options, renewable or clean power standards, and other measures. DSM programs may undermine these efforts, however, by increasing carbon emissions in those areas dependent on high-carbon base load units. DSM thus has facilitated a subtle shift in energy debates and policies from how much electricity is used to when it is used, yet DSM can actually increase carbon emissions by increasing overall electricity use and by shifting the mix of base load and peak generation sources.

To address the conceptual confusion caused by the use of the term DSM, in this Article we advance "net demand reduction" ("NDR") as an important, but oft-overlooked, concept. By NDR, we mean

21. As used in this Article, "base load" refers to the minimum amount of power that a utility must make available to meet its customer demand by providing reliable electricity during "peak" periods. Base load plants are plants that are dedicated to the production of base load power supply. Such plants typically are characterized by efficiencies that favor operating at or near capacity and very stable and predictable fuel availability and operational characteristics.

reductions in the total demand for energy, including electricity. Part II defines the problem by examining how carbon constraints affect projected energy supply and demand, and by highlighting the potential carbon emission reductions from NDR. It shows how well-entrenched policy instruments such as DSM mask NDR's benefits by assuming a demand curve that is largely fixed. This conventional approach to demand reinforces the strategic business purposes of a utility, whose regulatory incentives lead it to view NDR as revenue erosion. We argue that the conventional approach is not likely to yield long-term energy demand at levels that can be satisfied by low-carbon energy sources.

Part II also demonstrates how utilities' financial incentives, reinforced by state regulators, sustain this NDR blind spot, despite many laudatory federal goals. In theory, DSM and NDR are fully compatible, or at least are not inconsistent. Any effort to manage demand, however, should include careful attention to total energy demand—not merely to the timing of demand or industry efforts to expand total customer usage. This is consistent with many of the stated goals of DSM, and perhaps even with its conservation roots as endorsed in statutes such as Public Utility Regulatory Policies Act ("PURPA").[22] However, given the financial incentives faced by firms, as reinforced by the treatment of price and risk in the regulatory process, DSM has failed to meet its promises. For utilities in many jurisdictions, efficiency and conservation promotion make good business sense to a point, especially where firms are guaranteed compensation for investing in these efforts, but aggressive implementation of sophisticated NDR efforts could lead to revenue erosion and financial hardship.[23] The incentive to shift energy usage from peak to off-peak periods but not to achieve NDR affects a wide range of household efficiency and conservation programs on the ground, including the design and implementation of smart meter programs, electric car recharging programs, and others.[24]

A second conceptual barrier makes shifting the regulatory regime for utilities particularly difficult. For almost a century, the principal focus of energy regulation has been to keep per-unit rates for consumers as low as possible. The goal under the dominant approach

22. Public Utility Regulatory Policies Act, Pub. L. No. 95-617, 92 Stat. 3117 (1978).

23. *See* AM. PUB. POWER ASS'N, THE EFFECT OF ENERGY EFFICIENCY PROGRAMS ON ELECTRIC UTILITY REVENUE REQUIREMENTS 1–2 (2010), *available at* http://appanet.cms-plus.com/files//PDFs/EffectofEnergyEfficiency.pdf.

24. *See, e.g.*, Michael P. Vandenbergh, Amanda R. Carrico & Lisa Schultz Bressman, *Regulation in the Behavioral Era*, 95 MINN. L. REV. 715, 766–73 (2011) (discussing electric car recharging).

has been to ensure efficient supply in the face of a limited monopoly for electricity distribution and, to an extent, generation. This goal assumes that market prices are the best indicator of the true costs of production. Under this approach, externalities are largely ignored, and policymakers instead focus on various ways that competition can yield lower-cost supplies of energy through innovations such as wheeling power, deregulation, and unbundling generation from distribution.[25] We demonstrate, however, that although pursuing low rates is politically convenient for regulators, utilities, and consumer advocates, it is acceptable to utilities for precisely the reason that it is often not in consumers' long-term interest: by discouraging efficiency and conservation and encouraging additional energy use, it leads to overall demand increases that yield higher total energy costs to the consumer. If a low-rate approach did not achieve this outcome, in most areas of the country, utilities would suffer revenue erosion and would have strong incentives to oppose the low-rate approach. Instead, emphasizing low rates allows each participant in regulatory debates to take a popular position, but at the cost of ever-increasing energy use and total energy costs.

In Part III, we argue that large-scale NDR will not occur without specific policy instruments that address the financial incentives of electric distribution utilities. We evaluate how those incentives must change to produce effective demand reduction policies. We then survey how options such as carbon pricing, performance mandates, and decoupling might be used to advance NDR. Ultimately, we conclude that widespread demand reduction is not likely to occur until utilities shift from viewing NDR as revenue erosion to viewing it as a financial opportunity. Achieving this shift will require a more aggressive commitment by utilities, regulators, and consumer groups to a different business model—one that treats prices and risks in a fundamentally different manner from traditional ratemaking.[26]

Part IV concludes. We note that our goal in this Article is not to explore the specific options necessary to achieve NDR but rather to emphasize the importance of NDR and the conceptual barriers that

25. For a discussion describing how deregulation has made it more difficult to get an accurate price signal given the externalities, see, for example, Richard J. Pierce, Jr., *Natural Gas Regulation, Deregulation, and Contracts*, 68 VA. L. REV. 63, 90–99 (1982) (discussing the likely inefficiencies in natural gas markets resulting from deregulation in 1978).

26. *See* Ronald Brownstein, *The California Experiment*, THE ATLANTIC, Oct. 2009, at 66, 70 (quoting Peter Darbee, Pacific Gas and Electric's Chief Executive Officer, for the proposition that customers sometimes tell him that "you would love us" because they are using large amounts of power, but, due to California's decoupled rates, he responds, "Well, actually I'd prefer that you use a lot less. . . . We actually make more money if we sell you less power, and we make less if we sell you more power.").

must be overcome to achieve it. Moving forward, reducing net demand is an important goal alongside increasing the efficiency of supply. Regardless of the precise regulatory instrument selected, achieving NDR will require laws and policies that create incentives for electricity distributors to implement demand reduction programs with the same vigor as they implement programs to sell power. Pricing carbon could shift utilities' incentives, but the adoption and implementation of laws requiring electricity prices to reflect the social cost of carbon will not occur for some time. Direct regulatory commands to adopt programs or spend specific amounts will have some effect, but these efforts will not be implemented as a strategic priority and may fail for many nontransparent reasons. Major reductions in demand, in contrast, will require the creation of ongoing, genuine incentives for utilities to sell less of their product.

II. UTILITY INCENTIVES

We begin by briefly examining why NDR is an important social goal and by addressing the conceptual and practical barriers to achieving NDR. Policies and programs that achieve NDR decrease the need for power supply and thus can directly reduce carbon emissions. Equally important, NDR reduces the need for power supply infrastructure,[27] thus creating system-side benefits that can improve the viability of renewable power supply options. Yet the predominant industry initiatives and policy instruments aimed at addressing demand assume that energy usage levels will grow. These efforts view total customer demand as largely fixed, focusing on exploiting differences in demand across time or fuel types. Despite laudatory federal efforts beginning in the 1970s to make efficiency and conservation the thrust of a nationwide demand response initiative, demand regulation has deviated from a demand reduction path. The financial incentives of both utility firms and customers, along with the approach of state public utility laws, create an NDR blind spot in U.S. energy policy.

A. The Carbon Reduction Benefits of NDR

A starting point for our analysis is the widely held view that substantial reductions in carbon emissions from the domestic and global energy sectors will be a necessary part of any successful climate

27. Such infrastructure includes base load power generation facilities, as well as transmission and distribution facilities built to serve peak demand.

change mitigation effort.[28] Global carbon emissions are projected to double by 2050.[29] To reduce the likelihood that global average temperature increases will exceed two degrees Celsius, however, global emissions will need to be reduced by 50% or more.[30] For developed countries, the common target is 80% to account for greater contributions to existing carbon stocks and ability to pay for reductions.[31]

Despite the need for 50 to 80% emissions reductions by 2050, the business-as-usual projection of the U.S. Energy Information Administration ("EIA") suggests that electricity use in the United States will increase by 45% by 2030 (the EIA does not publish projections for 2050).[32] Global electricity use is projected to increase by over 300% by 2030.[33] Increases in energy demand at these levels will make it very difficult to reduce overall carbon emissions from the energy sector. Even if new sources of low-carbon energy are brought online at extraordinary rates, these new sources will be necessary just to meet the increases in projected demand, and it will be very difficult to replace existing fossil fuel–based sources with low-carbon sources.[34]

28. To reduce the risk of catastrophic climate change, a consensus has emerged that temperature increases should not exceed two degrees Celsius over pre-industrial levels, and that to reduce the risk of exceeding two degrees Celsius, atmospheric concentrations should not exceed 550 ppm of CO_2e. INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, SUMMARY FOR POLICYMAKERS (2007). The views of the Intergovernmental Panel on Climate Change ("IPCC") represent mainstream thought among climate scientists. *See* William R. L. Anderegg et al., *Expert Credibility in Climate Change*, 107 PROC. NAT'L ACAD. SCI. 12107, 12107 (2010); Naomi Oreskes, *Behind the Ivory Tower: The Scientific Consensus on Climate Change*, 306 SCIENCE 1686, 1686 (2004). A growing literature suggests that there is a substantial risk of reaching a climate tipping point even if CO_2e levels do not exceed 550 ppm. *See, e.g.*, Michael Vandenbergh & Jonathan Gilligan, *Macro Risks: The Challenge for Rational Risk Regulation*, 21 DUKE ENVTL. L. & POL'Y F. 401, 403 n.8 (2011) (reviewing tail risk literature).

29. *See* Pacala & Socolow, *supra* note 4, at 968–69 (describing 2050 emissions projections and targets "likely to occur in the absence of a focus on carbon").

30. *See, e.g.*, INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *supra* note 28, at 16 fig.2 (providing chart of temperature targets and atmospheric concentrations); *see also* UNITED NATIONS DEV. PROGRAM, U.N. HUMAN DEVELOPMENT REPORT 2007/2008: FIGHTING CLIMATE CHANGE: HUMAN SOLIDARITY IN A DIVIDED WORLD 26, 46 (2007), *available at* http://hdr.undp.org /en/media/HDR_20072008_EN_Complete.pdf.

31. *See* UNITED NATIONS FRAMEWORK CONVENTION ON CLIMATE CHANGE, REPORT OF THE CONFERENCE OF THE PARTIES 6 (2009), *available at* http://unfccc.int/resource/docs/2009/cop15 /eng/11a01.pdf (setting forth specific targets for various countries); *see also* American Clean Energy and Security Act, H.R. 2454, 111th Cong. (2009) (proposing to statutorily mandate specific emissions cuts in coming years); U.S. CLIMATE ACTION P'SHIP, A CALL FOR ACTION 7 (2007), *available at* http://us-cap.org/USCAPCallForAction.pdf.

32. *See* ENERGY INFO. ADMIN., INTERNATIONAL ENERGY OUTLOOK 2011, at tbl.D3 (2011) (providing projections on "total world energy consumption by end-use sector and fuel").

33. *Id.* at tbl.D1.

34. *See id.* at 86 (demonstrating a projected increase in utilization for various types of energy). Under a business-as-usual scenario regarding energy use, we will need ten terawatts

In short, meeting widespread carbon targets will be difficult even with major reductions from projected levels of demand, but it will be almost impossible without them.[35] Although remarkable advances in low-carbon technologies are likely over the coming decades,[36] there is some maximum amount of renewable or low-carbon energy that can reasonably be expected to be produced in any given year or over this period as a whole.[37] In the absence of near-miraculous new technologies or major efficiency gains, high carbon-emitting sources will step in to fill the gap.

Extraordinary efforts will be required to achieve even modest annual reductions in net energy demand. Professor Nathan Lewis has examined the role of energy supply and demand in light of the need for climate change mitigation, and his analysis provides a good example of the extent of the demand reductions necessary by 2050 if low-carbon sources are to displace fossil fuels, not just meet new demand. His business-as-usual scenario assumes that the ratio of energy consumption to GDP, which has been declining at about 1% per year,

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(i.e., ten trillion watts) of carbon-free power. Lewis, *supra* note 3, at 17. Current global energy use is now roughly thirteen terawatts. Nathan S. Lewis, *Powering the Planet*, 32 MRS BULL. 808, 808–09 (2007), *available at* http://authors.library.caltech.edu/9302/1/LEWmrsb07.pdf. More than 80% of that energy demand is supplied by fossil fuels, which contribute roughly two-thirds of anthropogenic greenhouse gas emissions. Thus, even with a 1% efficiency gain per year assumption, carbon-free sources will need to supply fifteen to twenty terawatts of energy by 2050. These types of efficiency gains and deployment of carbon-free sources must continue for the foreseeable future after 2050, leading to a carbon-free supply of almost all energy by 2100. Lewis, *supra* note 3, at 14, 16. Not all commentators agree that carbon emissions goals cannot be achieved in the United States or globally without a reduction in energy demand growth at less than business-as-usual rates. Jeff Goodell, *Q&A: Bill Gates on How to Stop Global Warming*, ROLLING STONE (Dec. 9, 2010, 11:05 AM), http://www.rollingstone.com/politics/news/the-miracle-seeker-20101028 (noting Gates's view that the climate problem arises from supply—not consumption—issues).

35. Scott Barrett, *The Coming Global Climate-Technology Revolution*, 23 J. ECON. PERSP. 53, 54 (2009); *cf.* Tim Foxon & Peter Pearson, *Overcoming Barriers to Innovation and Diffusion of Cleaner Technologies: Some Features of a Sustainable Innovation Policy Regime*, 16 J. CLEANER PRODUCTION S148, S151 (2008) (discussing advances in energy technology from an innovation-systems perspective).

36. The IPCC assumes a substantial amount of "spontaneous" technological development leading to reduced energy intensity. *See* Roger Pielke, Jr., Tom Wigley & Christopher Green, *Dangerous Assumptions*, 452 NATURE 531, 531–32 (2008).

37. Peak renewable energy is a subset of peak low-carbon energy. The concept of "peak oil" has been discussed at length, and Peter Gleick has applied the concept to "peak renewable water." *See* Peter H. Gleick, *Global Freshwater Resources: Soft-Path Solutions for the 21st Century*, 302 SCIENCE 1524, 1525 (2003). It is notable that there are significant differences with how "peak" is used by economists and policymakers in different contexts. Within the context of "peak oil," the term signifies the historical point at which there are diminishing returns to extracting more of a supply resource. In the context of electric power generation, the term describes the power supply deployed to meet total "peak" demand forecasts, regardless of whether there are diminishing returns to any particular type of electric power generation source.

globally averaged, will continue until 2050.[38] As Lewis notes, this would mean that in 2050 each person around the world would demand on average only two kilowatts a year.[39] Currently, the average demand per person in the United States is ten kilowatts.[40] According to Lewis, to achieve this two kilowatt demand in the United States, "we would need to start today to do everything possible—including using 100 mpg cars and zero-energy homes—to conserve energy."[41] Furthermore, food production alone in Western societies requires one kilowatt per person.[42] Reducing net energy demand thus is an essential element of successful climate mitigation efforts.[43]

B. Existing Demand-Related Policy Instruments and NDR

When energy demand is at issue, energy policy debates have largely ignored NDR and instead focused on a policy tool known as demand-side management ("DSM"). Beginning with PURPA in the

38. Lewis, *supra* note 3, at 16. This assumption has also been made by the IPCC. Lewis also notes that the United States "actually saves energy at a faster rate, about two percent per year" because of the high per capita energy baseline consumption in the United States, relative to developing countries. *Id.*

39. Lewis, *supra* note 34, at 812.

40. *Id.*

41. *Id.* at 812–13.

42. *Id.* at 813.

43. Although our primary focus is on NDR through increases in household efficiency and conservation, many of the same opportunities for demand reduction may exist in the small business sector. To date, energy and climate scholars have not focused on the small business sector as a separate category of analysis. The Environmental Protection Agency does not distinguish between small and large businesses in its annual greenhouse gas inventory. *See* U.S. ENVTL. PROT. AGENCY, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990–2010, at 1-9–1-12 (2012), *available at* http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2012-Main-Text.pdf . Similarly, the Department of Commerce categorizes small business emissions by the economic sector in which the business operates, despite including household emissions as a separate category of analysis. *See* U.S. DEP'T OF COMMERCE, *supra* note 14, at 7. For the purposes of reducing energy use and carbon emissions, however, a small business often resembles a household more than a multinational corporation. More than twenty million Americans work for small businesses that employ fewer than twenty people, a category constituting 18% of the total private sector workforce. U.S. SMALL BUS. ADMIN., OFFICE OF ADVOCACY, SMALL BUSINESS PROFILE: UNITED STATES 2, tbl.1 (2012), *available at* http://www.sba.gov/sites/default/files/us11.pdf (calculating percentage from "Total" row (20,738.3 / 114,509.6 = 0.181)). If these businesses are responsible for 18% of the total private sector emissions, then they are responsible for 711 million metric tons of carbon dioxide emissions. *See id.* (multiplying total private sector emissions, GRANADE, *supra* note 9, at 7, by the percentage of small businesses employing fewer than twenty people, U.S. SMALL BUS. ADMIN., *supra* at 2 tbl.1). Given the minimal number of employees, these businesses are likely to produce emissions that more closely resemble a large household than a small factory, and if these small businesses often resemble households, then they are ripe for efficiency gains.

1970s, federal law envisioned a conservation direction for DSM.[44] But PURPA and later amendments did not mandate the adoption of conservation-minded DSM and left most implementation of federal goals to the state and local authorities that regulate distribution utilities. PURPA also emphasized utility rate design only, and it did not purport to regulate how states provided for overall cost recovery to produce revenue for utilities.

For firms in the industry and many state regulators, DSM seems to have long left the conservation path that PURPA envisioned. Although DSM policies might have held some promise for electric power demand reduction in theory, as implemented, the policies often led only to load shifting and even increased total energy usage and electricity production. For example, many in the industry define DSM to mean active efforts by utilities to modify use patterns in the consumption of energy, conceding that the total level of use is not of concern to DSM.[45] DSM appears to conflate many different concepts, but it often emphasizes two narrow goals: (1) load shifting, or changing the timing of energy use within one energy type (e.g., electricity);[46] and (2) fuel substitution, or shifting between different energy sources (e.g., petroleum to electricity).[47]

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44. *See* James W. Moeller, *Electric Demand-Side Management Under Federal Law*, 13 VA. ENVT'L L.J. 57, 57–62 (1993).

45. *See* JOSEPH ETO, LAWRENCE BERKELEY NAT'L LAB., THE PAST, PRESENT, AND FUTURE OF U.S. UTILITY DEMAND-SIDE MANAGEMENT PROGRAMS 1 (1996) ("DSM refers to active efforts by electric and gas utilities to modify customers' energy use patterns."); MICHAEL F. HORDESKI, NEW TECHNOLOGIES FOR ENERGY EFFICIENCY 105 (2003) ("DSM involves peak clipping, strategic conservation, valley filling, load shifting, strategic load growth and flexible load shaping."). Others define DSM more expansively to emphasize conservation—a goal that seems quite consistent with federal policies to promote DSM under statutes such as PURPA, but that we argue is hobbled by the financial incentives faced by firms in the industry and state public utility laws. *But see* Bernard S. Black & Richard J. Pierce, Jr., *The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry*, 93 COLUM. L. REV. 1339, 1354–55 (1994) (noting that utilities consider DSM to include load shifting).

46. The EIA defines DSM as "[a] utility action that reduces or curtails end-use equipment or processes," but emphasizes that "DSM is often used in order to reduce customer load during peak demand and/or in times of supply constraint." *See Glossary*, ENERGY INFO. ADMIN., http://205.254.135.7/tools/glossary/index.cfm?id=D (last visited Sept. 6, 2012).

47. A classic example is utility-sponsored electric lawn mower exchange programs, which would reduce emissions from combustion lawnmowers in certain areas but increase the amount of electricity used. *See* LeRoy C. Paddock, *Green Governance: Building the Competencies Necessary for Effective Environmental Management*, 38 ENVTL. L. REP. 10609, 10622 (2008) (describing exchange program implemented by Clean Air Minnesota, a program managed by the Chamber of Commerce via the Minnesota Environmental Initiative). DSM for natural gas utilities has also encouraged switching from electric to natural gas water heaters and stoves. *See* Steven D. Czajkowski, Note, *Focusing on Demand Side Management in the Future of the Electric Grid*, 4 PITT. J. ENVTL. & PUB. HEALTH L. 115, 132 (2010).

Contemporary energy policy proposals at the national level highlight this problem. For example, so-called "Smart Grid" programs, a major funding priority of the Department of Energy ("DOE") under the Obama Administration, emphasize load shifting through critical-peak, time-of-day, and real-time pricing.[48] Electric car programs, another major DOE priority, emphasize fuel substitution by shifting the automobile fleet from petroleum to electricity.[49] The carbon reduction benefits of shifting from petroleum to electricity vary based on the timing of vehicle recharge. In many areas of the country, utilities have incentives to shift recharging to off-peak, low-cost times. The effect is to shift the electricity source from natural gas turbines to coal-fired units, however, and in many areas this shift will increase the carbon emissions attributable to use of the electric vehicles. In these situations, the time-shifting form of DSM may actually increase total carbon emissions.[50]

Smart meter programs also reflect the focus of DSM on shifting electricity use from peak to off-peak hours rather than on reducing total energy demand. Smart meter programs, which provide immediate information on household electricity use, are often used to shift household energy demand from peak to off-peak periods (e.g., by facilitating variable rate pricing schemes or allowing remote shutdown of air conditioners or pool pumps at peak periods). These programs could give customers real-time information about the price and amount of electricity used in the household. Although over the long run retail electricity prices can be expected to have a substantial effect on household energy demand, rate regulation of electric power in most states has kept consumers from having experience with electricity price fluctuations. Research suggests that people often have limited or incorrect information about what activities use the most electricity.[51]

48. Elias L. Quinn & Adam L. Reed, *Envisioning the Smart Grid: Network Architecture, Information Control, and the Public Policy Balancing Act*, 81 U. COLO. L. REV. 833, 842 (2010).

49. *See, e.g.*, Ashley Morris Bale, *The Newest Frontier in Motor Vehicle Emission Control: The Clean Fuel Vehicle*, 15 VA. ENVTL. L.J. 213, 268 (1995–96).

50. *See, e.g.*, Joshua Graff Zivin, Matthew T. Kotchen & Erin T. Mansur, *Spatial and Temporal Heterogeneity of Marginal Emissions: Implications for Electric Cars and Other Electricity-Shifting Policies* (Nat'l Bureau of Econ. Research, Working Paper No. 18462, Oct. 2012) (noting that in the upper Midwest charging electric vehicles during recommended nighttime hours increases electric car emissions to levels that are higher than the average gas-powered vehicle on the road); *see also* Vandenbergh, Carrico & Bressman, *supra* note 24, at 766–68 (examining research on the implications of peak versus off-peak electricity generation for the carbon emissions associated with recharging electric cars).

51. Shazeen Attari et al., *Public Perceptions of Energy Consumption and Savings*, 107 PROC. NAT'L. ACAD. SCI. 16054, 16057 (2010). This is true about other forms of energy use as well. *See, e.g.*, Amanda R. Carrico et al., *Costly Myths: An Analysis of Idling Beliefs and Behavior*

Not surprisingly, consumer responses to variable or dynamic pricing have been disappointing.[52] Notably, just providing real-time information in homes about costs and impacts associated with electric power usage, without introducing price variations, can reduce electricity use by roughly 5 to 15%.[53] Yet from the perspective of utilities in many parts of the United States, this kind of demand reduction, when not tied to dynamic pricing, might occur at times when electricity production is low cost, leading to utility revenue erosion. Not surprisingly, utilities have focused less on using smart meters and other devices to provide households with information that would reduce overall household electricity use than on shifting use to off-peak periods. Shifting use to off-peak periods will reduce the need for firms to invest in new base load plants and will save money by allowing them to deploy their existing base load resources at capacity. But this timing shift often can increase carbon emissions. The focus on load shifting has induced utilities to link smart meter programs to dynamic pricing schemes, even though the higher rates at peak periods have often been very unpopular with customers.[54]

DSM that is directed toward shifting peak use to off-peak use is popular with utilities, and as we discuss below, policies that follow this view of DSM seem especially attractive to incumbent firms to the extent they help firms maximize their revenues from energy sales. Utilities often have an incentive to shift demand from high-cost natural gas turbines at peak load periods to lower-cost coal-fired or

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in Personal Motor Vehicles, 37 ENERGY POL'Y 2881, 2882–84 (2009) (examining myths about motor vehicle idling).

52. On the effects of dynamic pricing, see Paul L. Joskow & Catherine D. Wolfram, *Dynamic Pricing of Electricity*, 102 AM. ECON. REV. PAPERS & PROC. 381 (2012); *Electricity Prices and Conservation: Do Current Policies Reduce Consumption?*, RES. REV. (Energy Institute at HAAS, Berkeley, CA), Spring 2011, at 1, 4–5, 7 (discussing the effects of changes of electricity pricing in California).

53. KAREN EHRHARDT-MARTINEZ ET AL., AM. COUNCIL FOR AN ENERGY EFFICIENT ECON., ADVANCED METERING INITIATIVES AND RESIDENTIAL FEEDBACK PROGRAMS: A META-REVIEW FOR HOUSEHOLD ELECTRICITY-SAVING OPPORTUNITIES 39 (2010), *available at* http://www.acee.org/research-report/e105 (discussing real-time household electricity feedback); *see also* Hunt Allcott & Sendhil Mullainathan, *Behavior and Energy Policy*, 327 SCIENCE 1204, 1204 (2010) (discussing monthly feedback on electricity use); Ian Ayres et al., *Evidence from Two Large Field Experiments that Peer Comparison Feedback Can Reduce Residential Energy Usage* 13–15 (Nat'l Bureau of Econ. Research, Working Paper No. 15386, 2009), *available at* http://www.nber.org/papers/w15386.pdf (finding significant reductions in home energy caused by peer comparison reports). The effects of information on energy use have been shown to occur even for individuals who are not responsible for paying for the bills. *See* Amanda Carrico & Manuel Riemer, *Motivating Energy Conservation in the Workplace: An Evaluation of the Use of Group-Level Feedback and Peer Education*, 31 J. ENVTL. PSYCHOL. 1, 10 (2011).

54. *See* Vandenbergh, Carrico & Bressman, *supra* note 24, at 730–40 (discussing consumer responses to dynamic pricing).

nuclear base load units at off-peak periods because deploying resources in an off-peak period can lead to overall increases in total kilowatt-hour sales of electricity without any need for any additional capital investment.[55] At the extreme, DSM can increase a utility's strategic overall load, increase the overall demand for electricity, and maximize its revenues—a profitable strategy some in the industry call "strategic load management."[56] Although approaches vary from state to state, because of the failure to fully embrace NDR, DSM programs have had only a modest impact on the total demand for electricity—decreasing less than 2% of demand over the long term.[57]

The carbon implications of shifting the timing of energy demand or the source of energy supply are also very different when NDR is emphasized as an independent goal. NDR does not assume energy usage is constant, that the shape of the demand curve is fixed over time or across fuels, or that the demand curve is inevitably shifting outward. Instead, NDR also emphasizes reducing aggregate demand by changing the shape of the demand curve or shifting it inward. We focus here on reductions in aggregate demand.[58] By subtly shifting the debate from reducing the amount of energy used to the timing of the use, many DSM policy initiatives claim to focus on demand but only do so in a way that focuses on timing of use, not reducing overall consumption.

Less explored, but equally important, DSM policies may lead to increases in carbon emissions by increasing the importance of high-carbon base load units to the utility. DSM can shift load to avoid deployment of gas peakers, but this might cause total demand to increase. Even if total demand does not increase, DSM may increase

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55. BRANDON DAVITO ET AL., MCKINSEY & CO., THE SMART GRID AND THE PROMISE OF DEMAND-SIDE MANAGEMENT 38–39 (2010), *available at* http://www.mckinsey.com/Search.aspx?q=demand%20side %20management.

56. *See* C.W. Gellings, *The Concept of Demand Side Management for Electric Utilities*, 73 PROC. INST. ELECTRICAL & ELECTRONICS ENGINEERS 1468, 1468 (1985) (describing marketing and strategic load growth as benefits of DSM).

57. *See* TOSHI H. ARIMURA ET AL., RESOURCES FOR THE FUTURE, COST-EFFECTIVENESS OF ELECTRICITY ENERGY EFFICIENCY PROGRAMS 3–4 (2011), *available at* http://www.rff.org/rff/Documents/RFF-DP-09-48-REV.pdf (estimating that DSM expenditures from 1992 to 2006 produced a 0.9% savings over that period and a 1.8% longer term savings); *see also* Nic Rivers & Mark Jaccard, *Electric Utility Demand Side Management in Canada*, ENERGY J., No. 4, 2011, at 93, 108–12 (finding that investments in DSM in Canada did not have a substantial impact on overall electricity consumption).

58. *See* Douglas A. Kysar & Michael P. Vandenbergh, *Introduction: Climate Change and Consumption*, 38 ENVTL. L. REP. 10825, 10825–33 (2008) (discussing the need to address aggregate consumption of energy and goods and the reluctance of the Supreme Court to interpret the National Environmental Policy Act to require evaluation of consumption reduction as opposed to the effects of building new generation units).

dependence on the lowest-cost base load plants, which are often coal-fired units.[59] In fact, emphasizing peak capacity as a way of allocating energy usage over time may be pushing demand to base load through DSM. This focus on peak capacity feeds on itself, as more consistent demand over time means that base load units become even more important to a utility's system. The more that a utility invests in base load generation units, the more electricity it needs to sell to pay for them.

More recent federal policy efforts also do not require DSM to address NDR and may even undermine it. In 2005, Congress passed legislation that required DOE to evaluate the impacts of demand response.[60] DOE reported to Congress on demand response initiatives in 2006, finding that limited demand response opportunities currently exist and that "[s]tates should consider aggressive implementation of price-based demand response for retail customers as a high priority."[61] DOE found that demand response potential in 2004 was "about 20,500 megawatts (MW), 3% of total U.S. peak demand, while actual delivered peak demand reduction was about 9,000 MW," or 1.3% of total peak demand.[62] These initiatives conflate DSM and NDR, however, rather than address the distinct challenge of NDR.

In addition, two aspects of DOE's recent push towards DSM further entrench the NDR blind spot in energy demand policy. The first is DOE's emphasis on reducing peak consumption as its primary demand response goal. This is consistent with the dominant approach to DSM and to preserving a focus on regulation designed to ensure revenue recovery for capital costs associated with a peak that is defined with respect to individual base load plants. Second, DOE continues to look to states, rather than the federal government, as the primary innovators for demand response policies. DOE's emphasis on states for demand response solutions is not surprising, given that the Federal Power Act protects state jurisdiction over retail rates.[63] But this also means that the ultimate responsibility for demand initiatives that flow through to the customer level will remain with state

59. Clean Air Act standards might help to soften this effect to some extent regarding coal if the standards regulate hourly emissions rather than average or daily, weekly, or monthly emissions. For example, this may be effective for sulfur dioxide.

60. BENEFITS OF DEMAND RESPONSE IN ELECTRICITY MARKETS AND RECOMMENDATIONS FOR ACHIEVING THEM, A REPORT TO THE UNITED STATES CONGRESS PURSUANT TO SECTION 1252 OF THE ENERGY POLICY ACT OF 2005, at v (2006), *available at* http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/DOE_Benefits_of_Demand_Response_in_Electricity_Markets_and_Recommendations_for_Achieving_Them_Report_to_Congress.pdf.

61. *Id.*

62. *Id.* at v n.2.

63. *See id.* at 52 n.58.

regulators, rather than the federal government, and that their regulatory approach will be important to meeting federal goals related to DSM.

C. Distribution Utilities as NDR Gatekeepers

Electric distributors are perhaps the most important actors for demand reduction. The traditional electric utility provides bundled generation, transmission, and distribution services to retail customers under rates regulated based on the cost of service, as determined based on the costs of producing electricity. Such firms set or affect retail prices in most jurisdictions; have monthly communications with retail consumers; control access to efficiency, conservation, and renewable energy generation options; determine the transaction costs households will occur in adopting new technologies or participating in conservation programs; and lobby for and against demand-related measures with federal, state, and local governments.[64] Electric distributors also set standards and require approvals for connecting with the local grid, such as the approvals necessary for installation of solar photovoltaic systems. They provide information through bills and advertising that can promote[65] or discourage[66] demand reduction. They also maintain large staffs of technicians that interact with households on a frequent basis.

In these ways, the distribution utility serves as an intermediary and gatekeeper between the consumer and the electric grid. A utility that has incentives to reduce household or other demand for electricity can play its information, service, and access roles in ways that will induce widespread uptake of efficiency and conservation measures. A utility that does not can discourage widespread uptake of these measures and can do so in a variety of nontransparent ways, whether by increasing consumers' transaction costs (e.g., by requiring numerous or slow approvals for household solar photovoltaic installation, by understaffing key positions necessary for promotion of efficiency and conservation programs, and

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64. *See, e.g.*, Brandon Hofmeister, *Bridging the Gap: Using Social Psychology to Design Market Interventions to Overcome the Energy Efficiency Gap in Residential Energy Markets*, 19 SOUTHEASTERN ENVTL. L.J. 1, 62 (2010) (noting that if private utilities can be properly incentivized to maximize energy efficiency, they can be "particularly effective delivery mechanisms for energy efficiency programs," and that "utilities are perceived to be a trusted source of information on efficiency and energy use . . . [and] that information provided by utilities will often have more impact than information provided by other sources").

65. An example would include switching incandescent bulbs to compact fluorescent lamps.

66. Examples include encouraging the purchase of larger electric water heaters, or electric as opposed to gas water heaters.

by imposing stringent requirements on grid access), or by limiting the extent or efficacy of information provided to consumers (e.g., by not making prompt, in-home energy use feedback easily available).[67]

D. Regulatory Incentives for Efficiency and Conservation

Whether a public entity (such as a municipal utility) or a private firm, the distribution utility historically operated as a monopoly and was (and in many respects largely remains) regulated by a state regulatory commission whose mission emphasizes protection of consumers from abuses by the monopolist. In the early era of energy regulation, efficient supply was the goal, so protecting consumers became a priority. Importantly, protecting consumers was framed as providing low rates for customers, not necessarily low total consumer expenditures on electricity. Regulators used ratemaking as the principal tool to provide low electric rates for consumers. Low electric rates resonated politically with many consumers and consumer advocacy groups, and this "low rate mindset" continues to resonate, even if it is not always in the interest of consumers.

Although low rates have obvious appeal to consumers and consumer advocates, the impacts of low rates on consumers are mixed. To the extent they enable increased energy use, low rates allow consumers to satisfy preferences for more energy-using services, such as the additional cooling provided by lowering the thermostat in the summer or the entertainment from new electronic equipment. At the same time, low rates undermine incentives to acquire information about energy use, to purchase more efficient appliances, and to reduce waste, such as by taking simple behavioral steps that have very small pecuniary or cognitive costs but large effects on the quantity of electricity used (e.g., turning up the thermostat when leaving the home for long periods in the summer). In addition, by creating incentives for utilities to increase the overall quantity of electricity that customers purchase, low rates create hydraulic pressure in the system for increasing supply, undermining the ability to substitute low-carbon for high-carbon sources. Low rates thus can lead to higher total consumer costs in the long run by undermining incentives for efficiency and conservation and can undercut efforts to reduce the carbon emissions from electricity generation.

Less obvious is why the low-rate mindset found favor with regulated utilities. A monopoly firm with market power typically will

67. As discussed above, such feedback has been shown to reduce residential electricity use by 5% to 15%. EHRHARDT-MARTINEZ ET AL., *supra* note 53, at 39.

favor charging higher rather than lower per-unit prices, but rate regulation guaranteed cost recovery for capital investments associated with generating electricity while also ensuring a high volume of power sales. Volumetric pricing—selling more units at lower cost—remains the dominant business model for electric utilities. The NDR blind spot can be traced to the incentives under which both firms and regulators operate with volumetric pricing and its related approach to investment risks. To the extent the dominant approach to utility rate structures favors volumetric rates, utilities are encouraged to offer low per-unit rates while increasing their total sales. This allows them to recoup the business costs associated with their capital investments in base load power and transmission, and to increase net revenues over the long term.

Low rates are not problematic to a utility so long as the volume of power sold increases sufficiently to make up for the lost revenue from the low rate. If low rates undermine incentives for consumers to invest in more energy efficient technologies or to avoid waste, and thus increase total consumer expenditures on electricity that exceed the revenue loss from low per-unit rates, the utility prospers. So long as consumer advocates focus on low per-unit rates as the goal of ratemaking proceedings, rather than consumers' total electricity costs, consumer advocates can achieve their goal in a way that the utility is happy to accommodate. Consumer advocates can announce success in holding down rates, and utilities can increase their revenue each year as low rates induce increased consumption and undermine incentives to invest in efficiency and conservation.

Thus, although often against consumers' long-term interests, consumer advocacy groups often take the bait offered and focus on low rates, and utilities are quite happy to feed it to them. On the surface, both groups win: utilities increase revenues, and consumer groups report success to their stakeholders on lower rates, even though consumers' total costs will go up in the long run. The total costs to consumers are more important but less obvious to consumers and voters. In addition, the regulator is in a sweet spot, since both utilities and consumer advocacy groups are placated. The losers in this arrangement are consumers, who end up spending more money each year on electricity, as increased usage outstrips low rates, and everyone who is adversely affected by an electricity generation and distribution system that is constantly in need of increasing supply.

The incentives of consumer advocates, utilities, and regulators in the low-rate regime are reflected in the dominant approach to DSM. The shift in timing of consumption that many energy policies seek to achieve under current conceptions of DSM promises firms enhanced revenue with their current business model under the rate structures applicable in most states. By focusing on shifting the timing of demand, not on reducing net demand with efficiency and conservation programs, DSM programs offer the near-term appeal of less costly power, but they miss the opportunity to enable customers to use less electricity overall and to spend less on electricity in the long run. So long as consumer advocates, utilities, and regulators focus on low per-unit rates, however, it should not be surprising that utilities favor DSM over NDR and view efficiency and conservation as revenue erosion; effective overall demand reduction programs will lead to less total electricity use and thus less total revenue from consumers.

Given electric distribution utilities' incentives in most jurisdictions, it is hardly a surprise that utilities' implementation of demand reduction measures has been inconsistent. Serious initiatives to reduce demand have occurred on a one-off, local basis, not with the aggressive, widespread implementation necessary to achieve a behavioral wedge. As a general matter, state regulators have not been very effective at changing firms' financial incentives. In fact, DSM policies were adopted in most states under the cost recovery model of traditional rate regulation, which sees stabilizing and increasing the sales of energy as the main business model for generating revenue—a strong business incentive that is at direct odds with efficiency and conservation goals. Of course, efforts to manage demand produce costs for electric utilities, just as new generation facilities can produce costs. If deemed prudent by regulators, these costs are typically built into the approved rates for regulated utilities. Yet the kinds of DSM programs that regulated firms have sought, and that regulators tend to approve, emphasize load-shifting and fuel substitution along with marketing and strategic load growth, and they ignore, or at least underemphasize, NDR. An Electric Power Research Institute–sponsored report bluntly highlights the problem: "The heart of a DSM program is a series of measures intended to encourage one or more specific groups of customers to modify their energy usage patterns *in a manner consistent with the utility's objectives*."[68]

Empirical analysis has determined that utility estimates of the actual conservation savings associated with DSM investments to date are often overstated.[69] One reason is that DSM's emphasis on load

68. AHMAD FARUQUI & JOHN H. CHAMBERLIN, ELEC. POWER RESEARCH INST., PRINCIPLES AND PRACTICE OF DEMAND-SIDE MANAGEMENT, at ES-1 (1993) (emphasis added).

69. *See* Maximilian Auffhammer, Carl Blumstein & Meredith Fowlie, *Demand-Side Management and Energy Efficiency Revisited*, ENERGY J., No. 3, 2008, at 91, 91 ("The key finding of Loughran and Kulick (2004) . . . is that utilities have been overstating electricity savings . . .

management, fuel substitution, and strategic load growth has masked the impacts of energy policies on total demand. NDR emphasizes the need to confront these impacts. NDR therefore captures an important goal that DSM, in its practical implementation, fails to emphasize, and that merits attention in its own right as a regulatory tool in discussions regarding efficiency, conservation, and demand reduction.

Even in states with traditional rate structures, utilities may feel some public pressure to promote conservation and efficiency. For a firm that is rewarded on a volumetric sales basis, demand shifting to off-peak periods can lower costs and produce some limited efficiencies. For these firms, however, aggregate demand reduction also comes at a significant cost. In retail rate–regulated environments, utilities can be expected to seek demand reduction only if regulators offer to provide them a guaranteed return for it. Similar incentives can be expected for gas and water utilities.

In sum, so long as volumetric pricing and guaranteed cost recovery through regulated rates leads utilities to view efficiency and conservation as revenue erosion, they will have incentives to create an appearance of demand reduction (e.g., to maintain reputation, satisfy regulators' demands, etc.), but under the existing approach neither utilities nor customers can be expected to be firmly committed to reducing the aggregate usage of electricity. In fact, many utilities would be lowering their short-term return on investment and risking their ability to recover the capital costs of their investment in generation plants if they induced meaningful aggregate demand reduction among their residential or business customers. Aware of this implication of NDR, the American Public Power Association has warned, "[a] reduction in sales . . . leads to a greater reduction in revenues than in costs, and potentially can threaten a utility's financial health."[70] The history of utility efficiency and conservation programs around the country—highly touted programs that are not designed or implemented to exploit the full potential for household demand reduction, as opposed to programs and innovations designed to "go viral" among customers or reduce electricity use on a widespread basis—reflects this mixed incentive.[71]

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associated with energy efficiency . . . (DSM) programs."). *But see id.* ("Our results suggest that the evidence for rejecting utility estimates of DSM savings and costs should be re-interpreted.").

70. AM. PUB. POWER ASS'N, *supra* note 23, at 3.

71. For example, the utility industry has been slow to adopt social media techniques. Carolyn Elefant, *The "Power" of Social Media: Legal Issues & Best Practices for Utilities Engaging Social Media*, 32 ENERGY L.J. 1, 5 (2011).

E. NDR and Incentives for Alternative Supply Options

Similar issues arise regarding generation of electricity at the household level. Penetration of renewables into power supply is unlikely to occur if electric distributors lack incentives to permit, much less actively encourage, substantial increases in the supply of household-generated electricity.[72] As a general rule, investments in alternative supply options are not consistent with volumetric rates, such as investments in distributed renewable generation by either consumers or nonutility firms. The historic emphasis on promoting low rates influences how regulated utilities and regulators view the risks associated with infrastructure investments in power production and delivery, reinforcing an industry-wide approach to planning and building power generators that favors base load plants over renewable projects.

Small-scale, low-carbon energy projects (such as household solar photovoltaic installation) share many characteristics with household efficiency and conservation since they reduce the demand for centralized generation and transmission by supplying energy onsite. As with efforts to reduce demand, renewable energy scholars have noted that the process of installing household renewable generation systems must become routine if these systems are to make a substantial contribution to the supply of low-carbon energy.[73] Yet firms and regulators have a strong preference for base load generators over renewable plants, because investments in base load plants (which tend to be large-scale nuclear and coal plants, or hydro facilities) can be justified as providing power on a reliable basis twenty-four hours a day.[74]

Diversification of electric power generation towards renewable resources is especially responsive to reductions in demand because most renewable resources deploy at a smaller scale and do not immediately scale up the way traditional fossil fuel plants do. To the extent these renewable sources reduce a customer's demand and this effect is multiplied across all customers on a utility's network, this

72. *See generally* Joel B. Eisen, *Residential Renewable Energy: By Whom?*, 31 UTAH ENVTL. L. REV. 339, 339–40 (2010) (discussing the importance of incentives to overcome the current distributional status quo of utilities).

73. *See, e.g.*, *id.* at 340 (discussing the need for "routinization" of household solar services).

74. Fuel storage *after* generation, a serious problem that plagues nuclear generation, is an issue beyond the scope of this Article.

total reduction in demand can offset the need for larger scale investments in base load fossil plants and transmission facilities.[75]

A formidable obstacle to this kind of penetration for renewable energy is that the conventional approach to planning and building base load power plants assumes that the statistical certainty that customers are able to receive reliable power twenty-four hours a day is a requirement for every generation unit. That approach keeps both regulators and distribution utilities from valuing smaller-scale distributed renewable facilities. Once built, a base load unit will operate most efficiently at or near its capacity level. The large capital investment in a base load plant can crowd out alternative sources of electricity supply as utility engineers make decisions to dispatch individual plants to meet demand at the margin, and operation of a base load plant will typically be most efficient where it is working at or near capacity. Also, expanded transmission, once built, creates an incentive for utilities to wheel in the lowest-cost power options from the wholesale market, which will tend to be from base load plants. Although some of these plants are low-carbon nuclear plants, most of the power generated at these plants is drawn from coal-fired generators.

Instead of evaluating the statistical certainty of reliability plant-by-plant, an alternative approach views reliability as a characteristic of the power system as a whole. For example, a widespread network of renewable resources could provide a stable and predictable source of electricity without expanding transmission or the number of base load power plants.[76] Interconnected and redundant smaller-scale generators, including distributed renewable projects, can serve as a type of insurance against reliability interruptions. Moreover, viewing reliability at the systems level allows demand reduction to play a role as a mechanism for enhancing reliability. Power engineers who operate the grid on a daily basis for regional transmission systems already see their risk management challenge from the perspective of the complete mix of power generation options, rather than focusing on reliability as a feature of an individual power

75. Terms such as "demand" and "energy" are terms of art among utility regulators, especially in the ratemaking process. For them, "demand" frequently refers to the capacity designed to meet customer peaks. "Energy" often refers to the fuel costs associated with deploying demand to serve particular customers. In this Article we use the terms in a more conventional manner, consistent with lay and economic understandings of demand.

76. For an example of how a combined heat and power natural gas distributed generation can produce similar system benefits, see DRAGOLJUB KOSANOVIC & CHRISTOPHER BEEBE, CTR. FOR ENERGY EFFICIENCY & RENEWABLE ENERGY, SYSTEM WIDE ECONOMIC BENEFITS OF DISTRIBUTED GENERATION IN THE NEW ENGLAND ENERGY MARKET (2005), *available at* http://ceere.org/iac/pubsdownloads/DG%20Benefits%20Report.pdf.

plant. Despite this, for the firm, rather than a larger regional system operator, the dominant approach to building and planning power plants conflates an individual firm's business risks with the risks of reliability interruptions, leading firms to invest in overcapacity, large-scale power plants, and transmission as the main mechanisms for reliability enhancement. This preference for overcapacity fits with the history of most electric power investments in the twentieth century, which were primarily base load plants. Low customer rates financed these investments, as accompanying demand growth provided a predictable source of revenue to protect the firm's large-scale investment risks and encouraged firms to conflate minimizing reliability risks with minimizing business risks associated with potential revenue decreases. As wholesale markets have evolved, and day-to-day operation decisions about the grid are increasingly made by power system operators, the separation between the operational decisions regarding the grid as a system and the investment decisions of the firm have become even greater.

The preference for low rates and their accompanying base load plant investment cycle is not a purely private phenomenon. By emphasizing volumetric rates, public regulators' ratemaking practices for most distribution utilities reinforce a consumption mentality that takes supply for granted. By focusing primarily on low per-unit rates, utilities can get what they are incentivized to want: the appearance of responsiveness to consumers along with growing total payments from consumers to utilities. And the public utility commissions ("PUCs") and consumer groups can say they are delivering what consumers want, but that is only true if the issue is framed as low rates, not low bills. Volumetric rates help keep per-unit prices low and encourage firms to sell as much electricity as possible, rather than increase price and decrease unit sales. They are also consistent with the idea of keeping per-customer demand charges low; investing in base load capacity leads to high "demand" charges on bills (the portion of fixed costs allocated to customers), so that once such investments are made, the base load cycle is reinforced by regulators allocating demand charges plus energy charges on a per-unit basis. By keeping energy charges low, this increases per-unit consumption and also increases overall bills.

III. POTENTIAL SOLUTIONS

This is a propitious time for state and local regulators to take the aggregate demand for electricity seriously in their policy initiatives and to examine new approaches to overcome the conceptual and practical barriers to NDR. In 2011, five years after DOE's initial report on demand response, DOE and the Federal Energy Regulatory Commission ("FERC") issued a new report calling for a national demand response policy, responding in part to Congress's request in the Energy Independence & Security Act ("EISA") in 2007.[77] In contrast to previous demand response efforts, in the new report DOE and FERC promote a greater federal role in demand response efforts, including development of tools and templates to assist states in demand response initiatives.[78]

Memorializing such efforts, FERC's landmark new rule on demand reduction provides wholesale utilities with incentives to reduce their demand for electricity,[79] an approach that FERC Chairman Wellinghoff has referred to as the "killer application" for the electric power industry.[80] This approach could introduce incentives for demand reduction for the largest-scale transactions, but whether it will lead to reductions in actual customer demand will depend on the responses of individual utilities in the pricing of retail sales to customers. We see two particular impediments, however, to current federal demand response policy fully realizing its potential. The first is a lack of a carbon-pricing apparatus, which we discuss further below. The second is that, even if federal efforts to address demand are well intended, the retail sales of electric distribution utilities remain regulated by states, not FERC. To the extent retail utilities still have strong volumetric sales incentives, as they do in most jurisdictions, any attempt at wholesale demand reduction will be muted. The scope of the federal jurisdiction to address demand for electric power is limited,[81] and many demand response solutions remain vague.

We examine three policy options that are being deployed to address the demand growth problem: (1) social cost approaches such

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77. FED. ENERGY REGULATORY COMM'N & DEP'T OF ENERGY, IMPLEMENTATION PROPOSAL FOR THE NATIONAL ACTION PLAN ON DEMAND RESPONSE iii (2011), *available at* http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/ImplementationProposalforNAPDRFinal.pdf.

78. *Id.* at 4–10.

79. Demand Response Compensation in Organized Wholesale Energy Markets, 76 Fed. Reg. 16,658, 16,678 (Mar. 24, 2011) (to be codified at 18 C.F.R. pt. 35).

80. Kate Galbraith, *Dimming the Lights to Meet Demand*, N.Y. TIMES GREEN BLOG (Apr. 17, 2009, 8:02 AM), http://green.blogs.nytimes.com/2009/04/17/dimming-the-lights-to-meet-demand/.

81. The FERC's jurisdiction extends only to wholesale power supply transactions, and states retain jurisdiction over retail sales to customers. For discussion of the limited jurisdiction FERC has in implementing demand response, see Richard J. Pierce, *A Primer on Demand Response and a Critique of FERC Order 745*, 3 GEO. WASH. J. ENERGY & ENVTL. L. 102, 105–06 (2012) (noting that the FERC has limited ability to overcome the reluctance of states to adopt retail systems that will create appropriate incentives and pass the savings of demand response on to customers).

as carbon pricing; (2) performance standards such as demand reduction mandates; and (3) decoupling initiatives. We conclude that a combination of all three approaches will be necessary to overcome the long history of financial incentives created by volumetric pricing and the accompanying mindset that limits utility, consumer, and PUC commitment to NDR. Embracing all three policies would recognize that electricity distribution utilities should not be viewed as simply selling electricity to customers, but as providing a service that produces positive social and economic value for the energy system. Energy services may actually include selling technologies or services that enable the sale of less electricity. Such a model holds promise to induce demand reduction, in the form of both improved efficiency and conservation, by creating positive value for firms. Large, sophisticated customers, such as large industrial consumers of electricity, already know that it is in their interest to focus on demand reduction. They have strong incentives to invest in demand reduction, and many have already taken the initiative to reduce their demand.[82] Smaller-scale household customers achieve less obvious benefits (they have lower energy costs), but as the discussion in Part II.A demonstrates, the collective benefit of all customers reducing demand is substantial. The energy services business model would have far-reaching implications for utility decisions that affect NDR.

A. Carbon Pricing and Social Cost Approaches to Demand Reduction

The emphasis of volumetric pricing on low rates provides little incentive for utilities and customers to pay attention to the carbon impacts of energy use. The commonplace policy solution to environmental externalities such as carbon emissions focuses on internalizing social costs by making them private. In theory, the optimal policy instrument is a carbon tax. Such a tax would increase the cost of producing and selling electricity from high-carbon fuels, encouraging firms and customers to adjust their energy production and use in response to prices that fully reflect the social cost of carbon emissions. In the electricity context, high prices for electricity generated from high-carbon fuels would make alternative supply options, such as renewable energy, more attractive, and would lead to reductions in demand by consumers. Yet a national carbon tax or cap-and-trade system is unlikely to be adopted and implemented in the

82. This is because energy costs for larger customers will be greater, producing greater dollar savings per individual customer. Any expensive meters or energy audits will be more affordable to larger customers with cash flow, such as businesses, which also face competitive pressure to reduce their energy costs as much as possible.

United States in the near term. Failure to bend the carbon curve during this time will mean not only greater stocks of carbon in the atmosphere, but substantial growth in annual carbon emissions and the possibility of passing tipping points in the climate system.[83]

Even though adoption of a national carbon tax or cap-and-trade system is unlikely in the near term, however, state regulators may be able to internalize the social costs of carbon indirectly if they reengineer the ratemaking process to emphasize the actual costs of carbon emissions rather than the private market costs of supplying electricity. A social cost approach could readily fit within the existing process by which state regulators determine utility rates based on the cost of service. Now that the Office of Management and Budget has established a range for the social cost of carbon,[84] designing an electricity rate to be welfare enhancing could readily incorporate the social cost of the carbon emitted from the generation of the electricity.[85] If state utility regulators were to price carbon emissions and build them into utility rates as a cost, it would produce higher per-unit rates.

The effect would be twofold: customers would have incentives to use less electricity as the per-unit price goes up, and utilities would have incentives to invest in reducing demand for fossil fuel–generated electricity. Even if the current measure of carbon costs is not precise, utility regulators have mechanisms at their disposal to true up adjustments as new information is gathered in the future. For

83. *See* Vandenbergh & Gilligan, *supra* note 28, at 403–04 (discussing tipping points and feedback effects in the climate system).

84. The social cost of carbon is the present value of future damages caused by one metric ton of greenhouse gas emissions; the working group that calculated the social cost of carbon produced a range of $5 to $65 per metric ton, with $21 per metric ton as the central figure of analysis. INTERAGENCY WORKING GRP. ON SOC. COST OF CARBON, U.S. GOV'T, APPENDIX 15A, SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866, at 3 (2010), *available at* http://www1.eere.energy.gov/buildings/appliance_standards/commercial/pdfs/smallmotors_tsd/sem_finalrule_appendix15a.pdf. There is reason to believe that the range of social costs of carbon generated through the OMB process does not fully reflect the tail risks that many climate scientists have identified. *See* Jonathan S. Masur & Eric A. Posner, *Climate Regulation and the Limits of Cost-Benefit Analysis*, 99 CALIF. L. REV. 1557, 1581 (2011) ("[T]he IWG's recommendations are not adequately defended. Many of its errors are likely errors of underestimation: it is likely that the IWG does not incorporate all the potential harms of global warming, and thus underestimates the benefits of curbing emissions.").

85. For commentary on the working group results and process, see Jody Freeman & Andrew Guzman, *Climate Change and U.S. Interests*, 41 ENVTL. L. REP 10695, 10721–23 (2010); Douglas A. Kysar, *Politics by Other Meanings: A Comment on "Retaking Rationality Two Years Later"*, 48 HOUS. L. REV. 43, 57–66 (2011); Vandenbergh & Gilligan, *supra* note 28, at 406–07. For a discussion on the prevalent approach to evaluating discount rates for cost-benefit analysis of climate change mitigation efforts, see generally Richard L. Revesz & Matthew R. Shahabian, *Climate Change and Future Generations*, 84 S. CAL. L. REV. 1097 (2011).

example, based on the likelihood of error in carbon cost calculations, regulators could contribute a percentage of the cost to a trust fund, which would allow for adjustments in the future as new information about carbon impacts is processed.

We favor such an approach, but we think it also is not politically feasible in the near term and is unlikely to be a complete solution to the problem. Increasing utility rates to reflect social costs, rather than business costs, is likely to be politically unpopular at the state and local level, where a populist consumer protection message dominates in the rate-setting process and focuses on near-term consumer pecuniary interests, not long-term consumer welfare. The political appeal of a decentralized, state-centric approach to adopting implicit carbon pricing in ratemaking varies geographically, and opposition to carbon regulation appears strongest in states that use the most carbon-intense fuels.[86] Moreover, using a state ratemaking process to impose a carbon tax implicitly does not guarantee changes in generation choices if utilities simply pass that cost through to customers and increase their own profits rather than invest in lower-carbon power sources. Given the strong financial incentives that attract firms to large-scale base load sources of energy, use of carbon-intensive fuels is likely to continue at high levels without some kind of supplemental regulatory approach designed to change firm investment decisions. A carbon-pricing approach, if adopted in isolation, thus does not guarantee changes in the supply of new low-carbon electricity sources and places its bet almost entirely on a hope that the demand for electricity is elastic.

A more feasible approach would be for PUCs to be more mindful of social costs in evaluating utilities' investments in NDR during the ratemaking process. Efforts to reduce demand may require the expenditure of dollars by utilities, and thus regulators will need to determine whether NDR investments (e.g., investments in infrastructure such as metering and other energy efficiency services) are prudent or cost effective. A social cost approach to evaluating NDR would not only be attentive to NDR's costs but also would recognize its benefits, including its potential for reductions in carbon emissions over the fuel cycle of various sources of electricity. This would require regulators to take a broader approach to assessing the cost effectiveness of various utility investments and fuels than occurs with the current emphasis on volumetric rates and near-term consumer protection goals. Many states use a rate impact measure ("RIM") test

86. *See, e.g.*, Felicity Barringer, *Climate Legislation Sends Chill Through Areas Fueled by Coal*, N.Y. TIMES, Apr. 9, 2009, at A17.

to evaluate the prudency of investments in DSM, examining the overall effect of DSM investments on customer rates. The RIM approach encourages overinvestment in the kind of DSM that is at odds with NDR and with carbon-pricing strategies that may be adopted in the future.[87]

States should consider and evaluate the use of alternative tests for investments in NDR, focusing on total resource costs or societal costs in comparing NDR investments to their alternatives.[88] Such approaches might assess the cost effectiveness of NDR from a larger system perspective, taking into account positive environmental externalities associated with these investments, including the cost of the full fuel cycle for alternative approaches to generating electricity.[89] Even if regulators do not price carbon in ratemaking, if they begin to look at carbon impacts in evaluating the cost effectiveness of various investments, this could improve firms' ability to evaluate the risks of reliability from a systems perspective, could provide a way out of the current overemphasis on base load plants, and could make NDR a more appealing option to utilities.[90]

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87. As discussed in Part II, it is important to highlight that the current energy policy emphasis at the federal and state levels on smart meters does not adequately confront the problem, and may even reinforce it. Smart meter technology holds promise to give customers information about their power usage to influence when and how they use energy. *See* Vandenbergh, Carrico & Bressman, *supra* note 24, at 739 ("Behavioral research on household responses to energy information suggests that a proposal to install smart meters that simply provide feedback to household energy users might have yielded substantial use reductions . . . ."). Many smart meter discussions to date are limited to load-shifting strategies such as critical-peak pricing, however, and do not focus on communicating real-time information to customers about electricity use and its carbon implications. *See id.* at 739, 739 n.97 (discussing the rejection of a smart meter program in Maryland linked directly to demand peak pricing and the recognition that the success of such initiatives depends on customer education and communication). Research shows that the types of information that can be gathered and disclosed to the consumer through smart meter programs can reduce electricity use by 5.5% to 14%. *See* EHRHARDT-MARTINEZ ET AL., *supra* note 53, at 48 ("[M]edian household savings vary from 5.5% for programs that employ enhanced billing strategies to 14% for those that provide real-time feedback disaggregated by energy end use."). *See generally* Ahmad Faruqui & Jenny Palmer, The Discovery of Price Responsiveness—A Survey of Experiments Involving Dynamic Pricing of Electricity 1, 11 (Mar. 12, 2012) (unpublished manuscript), *available at* http://ssrn.com/abstract=2020587 (surveying 126 pricing experiments with dynamic pricing and time-of-use pricing of electricity to show that "the presence of enabling technology allows customers to increase their peak reduction").

88. For example, Florida law requires the Florida Public Service Commission to contract for an independent evaluation of the Florida Energy Efficiency and Conservation Act ("FEECA") to determine if the Act remains in the public interest, including whether it is cost effective in reducing peak demand and overall consumption. 2012 Fla. Laws 117.

89. *See* ARIMURA ET AL., *supra* note 57, at 23–24 (discussing previous studies that overstated the benefits of DSM).

90. *See* COLUMBIA LAW SCH., CTR. FOR CLIMATE CHANGE LAW, PUBLIC UTILITIES COMMISSIONS AND ENERGY EFFICIENCY: A HANDBOOK OF LEGAL AND REGULATORY TOOLS FOR

B. Performance Standards for Demand Reduction

Another option for state regulators is to mandate that the electric distribution utility reduce demand by specific amounts or that it spend specific amounts on demand reduction activities.[91] Roughly twenty states have mandated reductions in overall demand, including Maryland and New York.[92] Many of these mandates emphasize efficiency improvements, which can be realized in power supply investments or at the customer level, but they also include efforts to encourage conservation. The strength of these approaches is that they provide clear, unequivocal direction to a utility that might otherwise be tempted by volumetric rates to favor investing in large-scale base load plants over reducing demand.

These approaches do not confront the underlying problem of utility incentives, however, and thus are unlikely to lead to widespread change. Under the mandated reductions approach, utilities may comply with the mandate at the cost of pursuing other desirable goals such as investment in renewable projects. Perhaps most important, utilities may have incentives to lobby against large mandated reductions and may lack incentives to exceed the mandates. As a result, utilities cannot be expected to be subject to aggressive targets or to exceed the targets that are set. Similarly, under the mandated spending approach, to the extent the utility's revenues are derived from its volume, it does not have an incentive to spend more than the mandated amount or to spend the funds any more effectively than necessary to satisfy regulatory oversight. In short, utilities lack incentives for innovation and for exceeding minimum standards.

As a modest alternative, state policymakers might consider merging demand reduction performance standards into other policy tools to promote innovation in NDR at the state and local level. A clean energy standard, such as that favored by the Obama Administration, differs from a state renewable power standard ("RPS") in that it does not focus entirely on power supply but allows efficiency and conservation to compete with energy supply options on a one-to-one basis. Many states already allow conservation and efficiency savings to qualify as a type of renewable energy for an RPS or renewable energy credit purposes, although some of these states

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COMMISSIONERS AND ADVOCATES 25–27 (2012) [hereinafter ENERGY EFFICIENCY HANDBOOK], *available at* http://www.smartgridnews.com/artman/uploads/1/PUC_Handbook_August_2012.pdf (contrasting rate impact measures with other approaches to analyzing energy efficiency programs, including the total resource cost test).

91. This approach is discussed in ENERGY EFFICIENCY HANDBOOK, *supra* note 90, at 46–47.

92. *See* ARIMURA ET AL., *supra* note 57, at 2.

discount the value of conservation and efficiency.[93] If the goal is NDR, there is no reason for discounting the value of conservation and efficiency, given that these can be even more valuable than investments in renewable projects. Indeed, such an approach could have broader appeal than an RPS, and it may be attractive to some additional state legislatures for the same reasons that an RPS originally was—the promise of jobs and new technologies.

However, any benefits of these more modest approaches as compared to a stand-alone NDR mandate would be limited. Even if NDR is compared one to one with investments in renewable energy, this will place NDR in direct competition with renewable investments, which will undermine the ability to reduce overall fossil fuel use. Perhaps there is a natural limit on the combination of NDR and renewable energy that any jurisdiction will tolerate, but this seems unlikely, at least in the near term. Moreover, since many renewable resources also qualify for both state and local tax credits, and few NDR initiatives enjoy such subsidies, unless these programs focus heavily on explicit NDR goals they are likely to produce underinvestment in NDR.

C. Revenue Decoupling and Shared Savings in Demand Reduction

Neither the social cost of carbon nor the performance mandate approach acknowledges the principal issue of how the distribution utilities sell power. Addressing how utilities sell power is the only solution that simultaneously confronts how volumetric pricing has contributed to utilities' strong preference for investments in base load and to the preference among policymakers for low rates and increasing use. This is also the only approach that has the prospect of inducing levels of management attention, staffing, innovation, and investment in demand reduction that are comparable to the utilities' investments in increasing revenue under a volumetric-pricing regime. "Revenue decoupling" initiatives separate a distribution utility's revenues from its incentives to increase the amount of power it sells to customers.[94] These decoupling programs may be the best way to

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93. For a discussion on the need for a national RPS, see generally Lincoln L. Davies, *Power Forward: The Argument for a National RPS*, 42 CONN. L. REV. 1339 (2010). *See also* American Clean Energy and Security Act, H.R. 2454, 111th Cong. § 610(f)(1)(A) (2009) (calling for the FERC to "specify the types of energy efficiency and energy conservation measures that can be counted" when defining and measuring electricity savings).

94. The term "decoupling" is loaded with different meanings depending on the policy context. In discussion about competition in electric power, "decoupling" might be taken to mean the separation of distribution and generation. "Bundled" rates, reflecting the costs of generation, transmission, and distribution are offered in many states (e.g., Tennessee and Florida). These

ensure that utilities have ongoing incentives to develop, fund, and implement highly effective efficiency and conservation measures. Decoupling has been adopted, in varying forms and degrees, by roughly twenty states, although many of these states have not adopted decoupling in a form that is likely to create ongoing incentives for NDR.[95] The American Recovery and Reinvestment Act also included language that promoted but did not require state adoption of revenue decoupling.[96]

Revenue decoupling can be implemented through a variety of policy instruments.[97] A common approach is a type of "decoupling lite" that provides for lost revenue adjustments designed to compensate utilities for lost revenue and presumably make them neutral between lost sales and new investments.[98] These approaches remove disincentives for NDR, but they do not create incentives to achieve NDR. More proactive approaches to decoupling offer utilities affirmative incentives for retail demand reduction. For example, some regulators offer utilities incentives by rewarding them post sale for NDR savings associated with conservation and efficiency. If a utility

differ from the unbundled prices customers are offered in states with retail choice (e.g., Texas), where an electric distribution utility provides distribution lines and the meter, and it simply passes through the cost of the power from generators. In these types of jurisdictions, in a sense the distributor has been "decoupled" from the generator. We choose to call this unbundling, and our emphasis is on a different kind of decoupling, what we call "revenue decoupling." For a discussion on the different degrees of decoupling, see THE REGULATORY ASSISTANCE PROJECT, REVENUE REGULATION AND DECOUPLING: A GUIDE TO THEORY AND APPLICATION 11–13 (2011). For a recent analysis of decoupling in the economics literature, see TIMOTHY J. BRENNAN & KAREN PALMER, RES. FOR THE FUTURE, ENERGY EFFICIENCY RESOURCE STANDARDS: ECONOMICS AND POLICY (2011), *available at* http://www.rff.org/RFF/Documents/RFF-DP-12-10.pdf.

95. *See Decoupling Policies*, CTR. FOR CLIMATE AND ENERGY SOLUTIONS, http://www.c2es.org/sites/default/modules/usmap/pdf.php?file=7016 (last updated July 5, 2012) (identifying the states that have adopted decoupling measures); *see also Decoupling in Detail*, CTR. FOR CLIMATE AND ENERGY SOLUTIONS, http://www.pewclimate.org/what_s_being_done /in_the_states/decoupling_detail (last visited Sept. 6, 2012) (explaining the general issues of revenue decoupling in energy markets using electricity-specific examples). For a recent article that is skeptical of decoupling approaches, see Brian S. Tomasovic, *Revenue Decoupling for Electricity Distributors: Current Approaches and Future Outlook*, 6 TEX. J. OIL, GAS, & ENERGY L. 176, 180–82 (2010-2011). *See also* Shannon Baker-Branstetter, *Distributed Renewable Generation: The Trifecta of Energy Solutions to Curb Carbon Emissions, Reduce Pollutants, and Empower Ratepayers*, 22 VILL. ENVTL. L.J. 1, 19 n.113 (2011); Davies, *supra* note 93, at 1356. Both show a lack of enthusiasm for the effects of decoupling measures.

96. American Recovery and Reinvestment Act, Pub. L. No. 111-5, § 410, 123 Stat. 115, 147 (2009); *see also* Tomasovic, *supra* note 95, at 177 (noting that the final version of the bill softened any pressure on states to "adopt or experiment with decoupling measures" in order to receive $3.1 billion in state grants).

97. For further discussion of revenue decoupling, see ENERGY EFFICIENCY HANDBOOK, *supra* note 90, at 31–35.

98. *Id.* at 33 (noting that this approach has been critiqued for failing to remove utility incentives to invest in supply-side resources and being subject to strategic gaming by utilities).

meets some annual NDR target, regulators might provide that firm a more beneficial rate of return in approving its rates. Or if the utility fails to meet an annual NDR target, regulators might penalize the firm by reducing its rate of return. This approach directly incentivizes the firm to focus on NDR in its business decisions.[99]

Another approach, akin to the social cost approach discussed above, is to build the benefits from NDR more directly into the pricing of electricity by directly decoupling revenue from sales prior to the point of sale. For example, firms could explicitly propose to produce "negawatts" (basically, a reduction in capacity corresponding to a decrease in demand) and could be compensated for the costs of the negawatts in the same way they are compensated for building a new power plant or expanding the plant's operation. The costs might include the opportunity cost of lost sales, since the firm might suffer some short-term financial losses due to demand reduction. The basic point is that if negawatt investments are built into a utility's rate base, competing side by side with alternatives such as building a new power plant, this will challenge the firm to consider NDR along with base load power options in its business decisions.

Whatever policy instrument is chosen as a vehicle for implementing it, revenue decoupling rejects the conventional emphasis on volumetric rates. Decoupling also has important implications for changing firm behavior and consumer perceptions; when revenue is decoupled from sales, it can be recoupled to some other goal, such as improved efficiency or the climate change benefits from NDR. With decoupling, firms are less likely to focus on investing in base load power plants and allocating these costs among customers, a cycle that volumetric rates reinforce. For electric distribution utilities, building new base load capacity would no longer be seen as the only guaranteed revenue source. Investing in conservation and efficiency programs would now be seen as equally significant to the bottom line of the firm.

With revenue decoupling, customers also are less likely to focus on low rates, especially if firms offer incentives to reduce energy usage in order to share in the rewards of NDR. This can be viewed as a type of "decoupling-plus."[100] Shared savings programs such as the decoupling-plus approach adopted in California have analogues in

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99. For an example based on an experience in Idaho, see Ralph Cavanagh, *Graphs, Words, and Deeds: Reflections on Commissioner Rosenfeld and California's Energy Efficiency Leadership*, INNOVATIONS, Fall 2009, at App. (paid subscription required).

100. *See* Sachs, *supra* note 8, at 316 (discussing California's efforts to supplement decoupling and characterizing this effort as a type of shared savings).

health care regulation and can take many forms.[101] For example, a decoupling approach might invite nonutility energy services firms to sell demand reduction or efficiency directly to consumers (e.g., Energy Service Companies or "ESCOs" at the industrial, small business, and household scales). Large industrial and commercial customers have achieved substantial savings from the use of ESCOs. A collective action problem, however, discourages the spread of the ESCO approach to small businesses and residential customers. Once the savings are aggregated, they may be large enough to make it attractive to invest in the services they provide, which again highlights the significance of the utility's selling power.

Revenue decoupling has strengths and weaknesses in terms of political viability and policy implications. Many details need to be resolved, including how incentives are allocated between utilities and customers and who will pay for NDR. Still, revenue decoupling ultimately merits serious consideration alongside both social cost and performance standard approaches to demand reduction. It also has advantages over alternative approaches. One advantage is that it is the only option that directly confronts both the low-rate approach of volumetric pricing and the reliability approach that favors investments in base load plants by utilities. Revenue decoupling

101. Health care regulators confront a comparable problem: how to create incentives for hospitals and doctors to sell less of their product—health care. They have turned to the shared savings model as well. For example, the Accountable Care Organization Demonstration Project ("ACO"), established by the Patient Protection and Affordable Care Act, is a new Medicare program designed to achieve quality and savings improvements in healthcare by efficiently coordinating primary care doctors, specialists, hospitals, and other providers. News Release, Dep't of Health and Human Servs., HHS Announces New Incentives for Providers to Work Together Through Accountable Care Organizations When Caring for People with Medicare (Oct. 20, 2011), *available at* http://www.hhs.gov/news/press/2011pres/10/20111020a.html. The coordinating providers are encouraged to participate in the program through a shared savings model. *See* Mark McClellan et al., *A National Strategy to Put Accountable Care into Practice*, 29 HEALTH AFF. 982, 983–84 (2010), *available at* http://content.healthaffairs.org/content/29/5/982.abstract (noting that the ACO model builds on similar shared savings initiatives that Medicare has implemented in the past several years). The Patient Protection and Affordable Care Act states that "the Secretary shall establish a shared savings program . . . that promotes accountability for a patient population and coordinates items and services . . . and encourages investment in infrastructure and redesigned care processes for high quality and efficient service delivery." 42 U.S.C. § 1395jjj(a)(1) (2011). Eligible providers may opt into the ACO program but they must "be willing to become accountable for the quality, cost, and overall care of the Medicare fee-for-service beneficiaries assigned to it." *Id.* § 1395jjj(b)(2)(A). Under the ACO program, the Secretary sets savings benchmarks based on "average per capita Medicare expenditures . . . adjusted for beneficiary characteristics" and also sets "quality performance standards to assess the quality of care furnished by ACOs." *Id.* § 1395jjj(b)(3)(c)–(d)(1)(b). However, "ACOs will only share in savings if they meet both the quality performance standards and generate shareable savings." 76 Fed. Reg. 67,801, 67,804 (Nov. 2, 2011) (to be codified at 42 C.F.R. pt. 425).

provides an opportunity to address incentives for some customers and to allow them to share in the savings. Decoupling also may be the only option that is likely to overcome utilities' emphasis on volumetric rates and on investment in base load plants, as well as the emphasis among PUCs on low consumer rates, as opposed to low total consumer expenditures.

IV. CONCLUSION

For many decades, the goal of efficient provision of supply based on an assumption of continued demand growth was considered sacrosanct in utility regulation. An emerging new approach focuses on reducing externalities from supply, challenging the longstanding assumption of demand growth on which many regulatory solutions have been built.[102] Assumed growth in demand limits how firms and regulators see their options in approaching low-carbon sources of supply.

A full transformation in the scholarship and the industry may not occur until a new generation of scholars and decisionmakers are in place who view the electricity regulatory goal not simply as a matter of efficient supply, with efficiency narrowly defined to exclude consideration of effects that are not priced, such as carbon emissions. But initial movement is underway. In recent years, a growing literature has examined how a combination of legal, economic, and social influences can reduce the growth in energy demand.[103] This literature suggests that the demand side of the equation is as important as the supply side, but this literature has focused largely on the incentives of households and other consumers, not on the incentives of utilities, the key gatekeepers for demand reduction.

Our logic is simple. The scientific consensus is that catastrophic climate change poses a genuine threat and that substantial reductions in global carbon emissions are necessary over the next several decades. Energy supply accounts for by far the largest source of carbon emissions. Energy experts project that global energy demand will double by 2050 if we follow the business-as-usual path.

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102. This is occurring with water supply and demand as well. *See* Gleick, *supra* note 37, at 1525–26 (discussing a new approach to water services that shifts focus away from decades of inconsistent demand projections to one that relies on the users' needs).

103. *See generally* Dernbach, *supra* note 8, at 10003 (evaluating a range of legal and policy tools to promote greater efficiency and conservation of energy in the United States); Vandenbergh & Steinemann, *supra* note 8, at 1674–75 (relying on norms theory and empirical studies to propose legal reforms for reducing individual contributions to greenhouse gas emissions).

Energy experts also suggest that major carbon emissions reductions are possible from a variety of low-carbon and non-carbon-emitting sources, but that it is unrealistic to assume that these sources will be able to displace existing fossil fuel sources and keep up with the anticipated growth in energy demand. Some miraculous technological fix could solve this problem, but energy experts are doubtful that this will occur. The physics of energy and the scope of the energy infrastructure are such that a single miraculous breakthrough or group of breakthroughs is unlikely to occur and to be deployed at the scale and in the time necessary.[104]

Something has to give. Countries will either miss their carbon emissions targets (and hope the consensus targets were too conservative), or they will need to invest in reducing demand as well as increasing the supply of low-carbon energy sources. For the most part, the United States has focused on the supply side. Regulators and firms have made some investments in low-carbon energy supply and have taken occasional steps to reduce demand, but they have not treated demand reduction as a priority at the federal level or in many states and localities.

We argue not only that legal and policy interventions can affect demand growth, but also that policymakers should recognize the important gatekeeping role that utilities play for the uptake of various efficiency and conservation measures. Electricity distributors alone probably cannot induce households to achieve an adequate level of NDR, but they are an essential intermediary. Yet in most U.S. jurisdictions, electricity distributors lack the financial incentives to achieve widespread success with NDR programs. Instead, the regulatory structure induces these utilities to view NDR as revenue erosion. Programs that provide financial or social incentives for households to reduce demand will not achieve their potential if electricity distributors do not consistently face incentives to sell less electricity—or at least no longer face incentives to sell more electricity to finance their base load plant investments.

Many law and policy options are available for shifting utilities' incentives to induce reduced household energy demand. We do not believe the choice of a specific regulatory intervention is as important as the conceptual shift toward recognizing the need to treat NDR as an important goal and to provide ongoing incentives for utilities to pursue NDR with gusto. Once regulators and firms begin to make the conceptual shift, the policy debate is more likely to yield productive

104. *See, e.g.*, Nathan Lewis, *Toward Cost-Effective Solar Energy Use*, 315 SCIENCE 798, 798–801 (2007) (discussing the challenges facing the widespread implementation of solar energy).

regulatory changes. To the extent regulatory changes are possible, some mix of shared savings and other approaches may create sufficient incentives for utilities to view demand reduction not as "good for you, bad for us," but as "good for you, good for us."

Tab 117

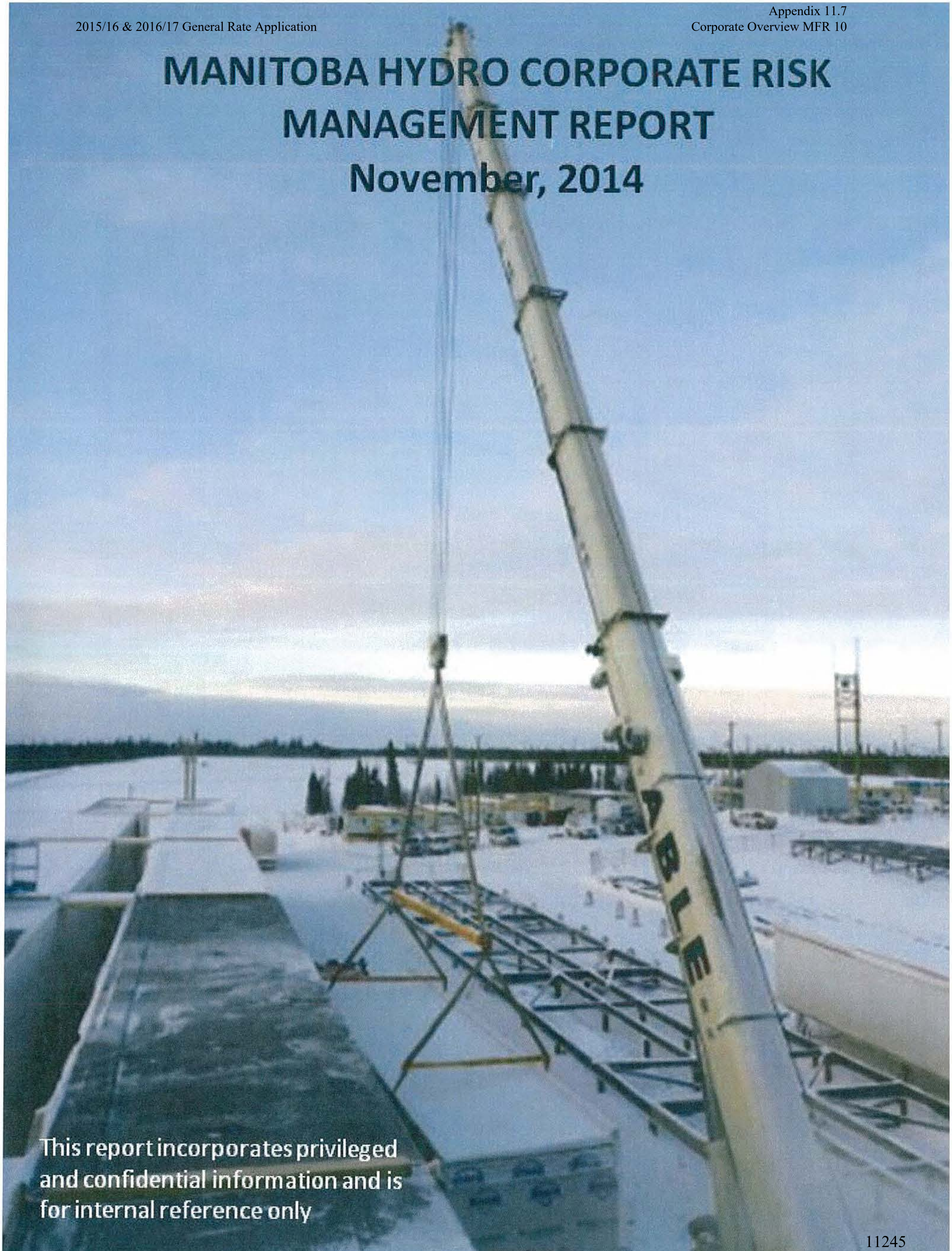
Corporate Overview MFR 10

Corporate Risk Analysis Report and Specific Risk Management Plans for all Major Risks including Drought.

Please find attached the redacted version of Manitoba Hydro's Corporate Risk Management Report.

In addition, Manitoba Hydro has provided a full copy of its Corporate Risk Management Report to the PUB, in confidence, as requested in PUB/MH I-84b.

MANITOBA HYDRO CORPORATE RISK MANAGEMENT REPORT
November, 2014



This report incorporates privileged and confidential information and is for internal reference only

Cover: Keewatinohk Construction Camp
When completed the Keewatinohk Converter Station will improve power reliability and expand exporting capabilities.

TABLE OF CONTENTS

I. INTRODUCTION

The Corporate Risk Management Report is normally updated on an annual basis to provide Manitoba Hydro's stakeholders with information on the status of major risks facing the Corporation as it carries out its mandate. The report identifies and assesses each risk, describes activities used to manage the risk and provides estimates of the potential residual impact to the Corporation in terms of likelihood and consequence after mitigation actions have been taken. The Corporation's tolerance for each risk and an assessment of whether the risk is within or outside the desired tolerance level is also provided.

As a Crown-owned utility providing an essential and life-sustaining energy service to Manitobans, Manitoba Hydro has a relatively low tolerance for risk. However, because Manitoba Hydro is also an important economic driver for the Province, some risks are necessary in order to take advantage of opportunities to maximize value for stakeholders. These risks are managed through a systematic, proactive and integrated process which is designed to balance the objectives of:

- identifying threats that affect the achievement of the Corporation's mission and mandate;
- mitigating the consequences of negative occurrences; and
- taking advantage of opportunities to provide benefits to all stakeholders.

Most risk management efforts are focused on reducing the occurrence of negative events. However, the Corporation also has plans in place to reduce the impacts should a negative event occur. These plans are under continual assessment. In addition, all safety and reliability risks are managed through strict adherence to design, construction and operating standards and practices together with extensive public education and employee training programs. A comprehensive Emergency Response Program is also in place to ensure an effective and coordinated response to possible emergencies or disasters.

The financial and operational risks associated with the management of an integrated electricity and natural gas utility are significant. These risks include the impacts of weather on supply and demand, price and market uncertainties, interest, inflation and foreign exchange rates, skilled labour availability and costs, aging infrastructure maintenance and replacement, increasing regulatory, environmental and legal requirements, and accelerated technological change. Manitoba Hydro manages these risks through an integrated control framework and through the maintenance of an adequate level of retained earnings.

Manitoba Hydro's Corporate Risk Management Report is structured to provide the following:

- A summary of the high consequence risks including:
  - Loss of major infrastructure
  - Drought
  - Loss of export markets
- An overview of significant and emerging risks and actions taken to address those risks.
- A Corporate Risk Map providing a visual depiction of Manitoba Hydro's risks categorized into high, medium and low likelihood of occurrence and the corresponding consequences.
- A Corporate Risk Tolerance Assessment of each risk.
- Corporate Risk Profiles - one page summaries of each of Manitoba Hydro's risks.

II. HIGH CONSEQUENCE RISKS

The most significant risks facing Manitoba Hydro are those rated as high consequence due to the potential magnitude of impact on the Corporation's ability to achieve its mandate and strategic goals and are quantified in the following table:

RISK	POTENTIAL FINANCIAL IMPACT
INFRASTRUCTURE Prolonged loss of supply	> $2 billion
DROUGHT Water Supply Variation / Drought	>$1.7 billion for a 5 year drought commencing in 2017 (IFF 14)
LOSS OF EXPORT MARKET ACCESS	> 30 % of electricity revenue

Infrastructure Risk (Category D)

A catastrophic infrastructure failure continues to be the most significant risk facing the Corporation and its customers. Potential impacts include prolonged loss of system supply, the inability to maintain minimum energy services, loss of life, severe environmental damage and significant costs to the Manitoba economy. Failure can be caused by a number of factors including an extreme weather event, sabotage, fire, human error, or technical malfunction.

By the nature of its business, Manitoba Hydro has an especially low tolerance for infrastructure risk. Significant efforts are expended on managing this risk in a manner that avoids the occurrence of a catastrophic event and minimizing consequences should a catastrophic event occur.

Risk Treatment

In the short term, actions are continually being taken to enhance emergency response and disaster management processes. In the longer term, major investment in renewal and expansion of the infrastructure system are underway to maintain and improve system reliability, energy security and safety. Key management plans and projects include:

- Construction of Bipole III with a planned in-service date of 2018.

- Re-termination of the 500 kV Interconnection at Riel (2014).

- Renewal and replacement of aging electric and gas infrastructure over a long term period to improve system capacity and reliability. This includes critical distribution assets and stations, rehabilitation of existing generators, wood poles, cable and gas pipe replacement, cyber and physical security upgrades, and changes to gas distribution operations and pipelines to respond to changes in geographic gas production and shipment patterns. These changes to gas distribution operations also include lessons learned from a four day loss of gas supply to a large number of customers as a result of an explosion of the TransCanada main gas pipeline.

- Moving forward with implementation of Manitoba Hydro's Development Plan to meet export sales and forecasted domestic load growth. The provincial government and Public Utilities Board endorsed proceeding with the Keeyask Generating Station, the new 500 kV line to Minnesota and increased levels of Demand Side Management activity. In addition to meeting domestic demand, these projects will allow the Corporation to increase firm export obligations and access greater amounts of energy with additional import capability provided by the new interconnection.

- Water retaining structures and flow control management, including: surveillance inspections, instrumentation monitoring, and engineering analyses of dams and dykes including emergency plans for individual facilities; systematic utilization of failure modes-based condition assessment techniques; and rehabilitation of the Pointe du Bois spillway facility.

- Continual improvement of the Corporate Emergency Management Program that includes a long term plan for managing the available resources, load and system supply following the loss of infrastructure; development of business continuity plans; constructing an emergency fuel depot; spare infrastructure material and equipment inventory to enable timely re-building and restoration of potentially affected assets. The corporation also has short term emergency energy and mutual aid agreements with Ontario, Saskatchewan and U.S. Utilities.

Water Supply Variation / Drought Risk (C.1 and D.2)

On average, there is a high likelihood of a drought occurring about once in every ten years. In the circumstances of an extreme drought that is more severe than the worst on record, there is a possibility of insufficient energy supplies being available to meet firm load demands. This would result in extreme financial and reputational impacts on the Corporation. The cost of a five year drought similar to the worst on record is estimated to be $1.7 billion (IFF 14) for a drought commencing in 2017.

Risk Treatment

There are several measures in place to manage the impacts of a drought, as follows:

- Manitoba Hydro's current generation and transmission facilities are designed and operated to ensure firm demand can be supplied given a repeat of the lowest river flows since 1912. A drought more severe than the worst on record could occur and would require non-normal operations. This may include operating reservoirs outside of the normal range for power production. Non-normal operation may also include demand reduction measures such as public appeal for conservation, enforced conservation, or rotating reductions of non-essential load. Actions to manage drought will depend on its duration and severity and any other conditions that prevail at the time.

- Once built, the new interconnection with the U.S. in combination with additional long term exports in the Development Plan will provide the Corporation with increased ability to access additional amounts of energy through higher imports than planned and through financial settlement of firm export contracts.

- Adequate retained earnings are required to protect against a repeat of the worst drought on record. At March 31, 2014 retained earnings totaled $2.7 billion. It should be noted, however, that while drought is a major quantifiable risk, an adequate level of retained earnings is required to recover from other significant risks such as a prolonged loss of supply or the loss of export market access.

Export Market Access Risk (Category A.2)

On average Manitoba Hydro derives a significant portion of its revenue from export sales to U.S. and Canadian markets. The prime impact of restricted market access would be significantly reduced net export revenues which are fundamental in keeping domestic rates low and offsetting the upfront costs of capital investments. Market access risk also includes restrictions on Manitoba Hydro's ability to import which could increase the cost of droughts, and degrade system reliability.

Risk Treatment

Manitoba Hydro continues to actively work to mitigate and manage market access uncertainties, as follows:

- In alliance with other industry participants such as the Canadian Electricity Association, and other stakeholders, Manitoba Hydro continues to lobby MISO, IESO and FERC for the development or elimination of market rules that affect electricity trade and facilitate full participation of Manitoba Hydro in US and Canadian electricity markets.

- Manitoba Hydro also engages in extensive lobbying efforts in the US to promote waterpower as a clean, reliable and renewable source of energy and to counter anti-hydro special interest group lobbying.

- The Corporation also engages with environmental, consumer and business stakeholder groups to discuss and promote its development plans.

- Market access risk is also reduced by having long term contracts and strong relationships in place with major export counterparties.

III. SIGNIFICANT AND EMERGING RISKS

While loss of infrastructure, drought and potential loss of export markets remain as the highest consequence risks for the Corporation, there are other significant and emerging risks that can affect the achievement of the Corporation's mission and mandate. These are:

Infrastructure Investment (Category D / A.2.6)

Manitoba Hydro is moving forward with a number of major initiatives (e.g. construction of Bipole III, replacement of aging infrastructure, Keeyask generating station, a new interconnection to the U.S and increased Demand-Side Management activities) in order to further improve electrical and gas system reliability, meet the future energy needs of the province, and take advantage of export opportunities. These plans will require the investment of approximately $18 billion (CEF 14) over the next 10 years.

There are a number of risks associated with such large initiatives that will challenge the Corporation's ability to meet Manitoba's energy needs while keeping customer rates affordable, and maintaining the Corporation's financial strength. These challenges include managing the costs of Bipole III, Keeyask and the new interconnection project; [redacted] Mitigation measures to address these cost risks include the use of best practices in cost estimating, contracting practices, the inclusion of appropriate contingencies and management reserves. [redacted]

With regard to Conawapa, the Corporation has suspended the majority of expenditures associated with that project consistent with government direction following the PUB's NFAT report. Conawapa is now seen as an opportunity that will only proceed if sufficient additional profitable export sales materialize that will shoulder most of the financial risk associated with building Conawapa much earlier than needed for domestic purposes. Without those contracts further expenditures to protect an early in-service date for Conawapa will not be made. The consequences of that will be a lost opportunity resulting in higher rates in the very long term, reduced near term provincial economic activity and reduced socio-economic benefits to northern aboriginal communities who would partner with Manitoba Hydro on the project.

Financial Strength (B.7)

Maintaining financial strength is essential in order to make the necessary investments in infrastructure, to continue to provide safe and reliable service to customers, financially withstand the risks and uncertainties that are inherent in the Corporation's operations and to provide customers with long-term rate stability and predictability and avoid the need for large or sudden rate increases in the future. The required investment in new and existing infrastructure is expected to place a certain degree of pressure on the Corporation's key financial targets, and if not carefully managed, there is a risk of higher required future rate increases or potential negative impacts to the credit rating of the Province.

Key areas of focus to maintain financial strength include:

- Continuing cost containment measures. This includes utilizing resources effectively and efficiently while diligently managing capital projects to be on time and on budget. Management continues to evaluate the need to fill positions vacated as a result of attrition, considering opportunities for process improvement, technological enhancements and organizational restructuring. This also involves leveraging experience from the development of new tools and past projects to improve upon capital cost estimating, project and contract management.

- Aggressively pursuing a balanced portfolio of domestic and profitable export sales to provide the highest financial benefits to ratepayers and all Manitobans over the long term.

- Managing and mitigating financial risk by closely monitoring economic factors, financial markets, and energy markets.

- Implementing modest, regular domestic electricity rate increases necessary to achieve financial targets over the long term.

Domestic Electricity Rate Increases (B.7)

The infrastructure system that served Manitoba well for decades now needs significant re-investment to continue meeting the province's needs. Electricity rates in Manitoba must rise to ensure the ongoing safety and reliability of the electricity supply and delivery system. This is an issue that is present across North America, as other utilities address aging infrastructure and growing demand.

Manitoba's electricity rates continue to be among the lowest overall in North America, due in large part to past investments in hydroelectric generating stations and the contribution to earnings from the sales of surplus energy into the export market. However, Manitoba Hydro's plan for re-powering the province requires a significant capital investment. This investment in the replacement and refurbishment of plant will require increased revenues, which must be obtained from a series of future electricity rate increases, at levels higher than the historical average.

It is a significant challenge to convince stakeholders that higher rate increases are in the best long-term interests of all ratepayers to ensure ongoing safe and reliable service. Significant efforts will need to be focused on delivering compelling and convincing arguments before the PUB to obtain the required level of rate increases going into the future. Even with the projected rate increases, it is expected that Manitoba Hydro's domestic customers will continue to have electricity rates that are affordable and competitive.

Offering new and expanded Power Smart programs aggressively targeting additional electricity and natural gas savings, as outlined in the Corporation's development plan, will aid customers in managing their overall energy costs.

Export Sales (Category A.2)

As was previously mentioned, increased export sales are fundamental to achieving the Corporation's strategy of reducing the costs of building new generation supply for Manitoba ratepayers.

Key factors affecting the ability to increase export volumes and revenues are:

- **Export Market Prices -** In recent years export prices for electricity have been affected by the economic slowdown in the U.S. and the availability of low-cost natural gas made possible by new production techniques. The corporation has endeavored to reflect these factors as accurately as possible in its forecasts of future export market prices. Based on the input of external industry specialists, the corporation is forecasting a moderate rise in export prices over the long term, restrained by the continued impact of natural gas pricing. There is a residual risk that export prices could be lower than industry experts are predicting, and that would be a downside risk that could hamper the Corporation's ability to achieve forecasted export revenues and other financial targets with projected rate increases.

- **Cost of New Hydraulic Generation** – The resources in the Corporation's development plan are supported by a number of export agreements, including a 250-megawatt sale to Minnesota Power, a 125 MW sale to Northern States Power and a 108–megawatt sale to Wisconsin Public Service. [redacted]

  Commencement of construction of Conawapa is not required in the near term to serve Manitoba load. As a result resumption of planning and capital expenditures for Conawapa will only proceed if sufficient firm export interest materializes in the next two years that convince the Corporation that there are significant benefits with proceeding and that the risks of the project will not be borne by Manitoba ratepayers. To date only the 308 MW Power Sale Agreement with Wisconsin

Public Service has been signed. By itself that sale only requires 30% of Conawapa's output until 2035. Commitments tied to a large portion of its remaining output will be necessary before resumption of expenditures can be justified.

- **Market Access -** Manitoba Hydro's development plan includes the construction of a new 500 kV interconnection with the U.S. The interconnection will increase export capability by 883 MW and import capability by 683 MW. These increases in transfer capability will increase the amount of firm load that can be served by the Manitoba generating system, will enhance the value of new DSM initiatives and will result in Manitoba Hydro achieving higher export prices and lower import prices. The line will increase export volumes by reducing water spillage in high water years.

  Critical to receiving regulatory and political approval to build the US portion of the interconnection is having a US utility who will champion and build the line in the US. The risks of this project not moving forward are significantly reduced this year as Manitoba Hydro and Minnesota Power have now signed several agreements which establish the business arrangements necessary for the Minnesota Power to proceed with the permitting, and route selection processes. These permitting processes are underway and MP expects to receive approval by the end of 2015 with actual construction of the Great Northern Transmission Line commencing in 2016.

  In addition, Manitoba Hydro's subsidiary (6600271 MB. Ltd), Minnesota Power and MISO have signed a Facilities Construction Agreement. These agreements are subject to several conditions and regulatory approvals which still must be satisfied before construction can commence.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Gas Price Volatility (B.5)

There is significant upward cost pressure for transportation services on the TCPL Canadian Mainline (the "Mainline"), to which Centra is currently captive in bringing natural gas to its load centre. The Mainline is significantly underutilized resulting in less revenue than that which is required to cover the Mainline's relatively high embedded cost structure. As a result, the pipeline has been seeking regular toll increases since 2010, which costs are passed through to Manitoba natural gas ratepayers. Tolls on the Mainline also affect transportation services that Centra obtains from third parties.

This market circumstance was recently compounded by a proposal by TCPL to segment the Mainline's cost allocation and tolls post-2020 between the under-utilized Western Mainline (on which Centra moves gas) and the highly utilized Eastern Ontario Triangle, which would facilitate the avoidance of cost responsibility for under-utilized or stranded assets on the Mainline by eastern shippers at the expense of Centra and other captive shippers on the Western Mainline. Centra is the largest captive shipper on the Western

Mainline. The proposal, if approved by the National Energy Board ("NEB"), is expected to result in significantly higher costs and risk for Centra than it would bear if the Mainline were to remain integrated.

Centra actively intervened to oppose Mainline segmentation in the recent Oral Hearing RH-001-2014 before the NEB regarding the Application by TCPL for Approval of Mainline 2015-2030 Tolls & Restructuring. Interested parties are awaiting a Decision by the NEB, which is expected in November, 2014. In the event that the Decision is unfavourable for Centra, work will be undertaken to explore alternatives to continuing to move gas on the Mainline.

Interest Rates (B.2)

As a result of the intensive capital investment period, it is projected that Manitoba Hydro's level of debt will significantly increase and financial results will be affected by market interest rates. Over the next 10 years the potential cumulative financial impact of a one-percent change in interest rates is estimated at $1.1 billion (IFF 14).

Manitoba Hydro's interest rate policy on its existing debt portfolio is to limit the aggregate of short term debt, floating rate debt and debt to be refinanced within the subsequent 12 month period to a maximum of 35% of the total debt portfolio. When selecting terms for its new borrowings, Manitoba Hydro gives careful consideration to the debt maturity schedule and the total level of annual financing requirements. The debt management strategy guidance is to have less than 15% of the long term debt portfolio maturing within a fiscal year. In order to mitigate refinancing risk, to maintain financing flexibility during the intensive capital investment period, and in keeping with the concept of matching the Corporation's long-lived assets with long term debt, Manitoba Hydro will continue to favour long term financings with maturities of 10+ years, while maintaining short term debt and floating rate long term debt within policy limits.

As a result of the low interest rate environment over the past several years Manitoba Hydro has been able to reduce its net weighted average interest rate by approximately 2.0% since 2006/07 and increase its weighted average term to maturity by over three years during the same period.

Environmental (Category C)

There are a number of environmental issues currently facing the Corporation that could impact operations if they are not addressed.

A potentially significant environmental issue arises as a result of the 2013 Clean Environment Commission (CEC) recommendation to have both the Province and Manitoba Hydro conduct a Regional Cumulative Environmental Effects Assessment (RCEEA) of all Manitoba Hydro projects in the lower Nelson River sub-basin before any more projects are licensed for construction. [redacted] Manitoba Hydro has completed Phase I of the Study and submitted it to the government. Phase II is now underway and a new committee has been formed with the Province.

Another significant environmental issue deals with the listing of Lake Sturgeon under the Species at Risk Act (SARA). Almost all of the Corporation's hydroelectric generating stations are located where Lake Sturgeon are found and it is likely that at most sites the infrastructure and operations have negatively affected the fish and/or its habitat. Due primarily to historical commercial overharvest, plus additional stressors including hydroelectric development and ongoing [redacted] Lake Sturgeon populations have been severely depleted over the past 100 years and the species is currently under review for listing as endangered under SARA at most locations in Manitoba. If Lake Sturgeon is listed as "Endangered" under the SARA, the Corporation could face restrictions on current operations, structural modifications to infrastructure, delays in developing new generation due to difficulties with securing permits, and high costs of recovery measures that are potentially mandated. There is also a remote chance that new projects could be cancelled. The Corporation continues to take significant action to minimize the need for and likelihood of listing Lake Sturgeon under SARA, however uncertainty remains.

Regulation and Licensing (H.1)

The Corporation requires a variety of regulatory approvals and licenses to carry out its activities. Key approvals and licenses include the National Energy Board, water power and environmental approvals to build new generation or transmission facilities or to maintain or improve the efficiency of existing facilities. Failure to obtain approvals and licenses on favourable terms or in a timely fashion could have significant financial, operating and water regime impacts. These could result in increased costs, reduced hydraulic generation, capacity and export sales. Expiration of a license without renewal could expose the Corporation to embarrassment and loss of reputation and cancelation of a license could expose the Corporation to the possibility that a third party could acquire the water power rights at a location and Manitoba Hydro would lose the asset and associated capacity and generation.

There are several measures in place to manage these risks. These include:

- Incorporating regulatory/licensing concerns into the planning of new rate programs and facilities (e.g. low-head Wuskwatim to minimize environmental impact).

- Pursuing regulatory/license approvals with appropriate diligence and explaining the merits of the corporate position at any public proceedings where the scope of regulation is under debate.

- Maintaining systems to ensure ongoing compliance with regulatory/license requirements and focusing attention on overall corporate image.

- Making recommendations for an efficient and streamlined regulatory framework.

- With respect to Water Power Licenses: (1) Manitoba Hydro has a strong working relationship with the WPA Licensing Section at Water Stewardship. This ensures proper understanding of licensing condition implications and to ensure timely licensing activities; (2) Manitoba Hydro monitors compliance with its WPA licenses and self reports annually on compliance; (3) Manitoba Hydro applies for short term license extensions when licenses would otherwise expire. Historically Manitoba Hydro had several WPA licenses that had expired. Although this was a potential source of embarrassment, it did not result in a disruption of operations; and (4) Manitoba Hydro operates its facilities within the limits established in the WPA licenses. To the extent that deviations are necessary or occur, authorization is requested when possible from Water Stewardship. As a result there is no risk of license cancelation as a result of non-compliance.

Workforce (Category E)

Attracting, developing and retaining a highly skilled and motivated workforce that reflects the demographics of Manitoba is critical to the Corporation's success. Key factors that impact the ability to achieve this are the number of employees that are eligible for retirement, competition for highly skilled workers, and the ability to keep up with technological and other changes. Manitoba Hydro's contractors will also be impacted by the same competition.

The Corporation is looking at the demographic shift that is occurring in its workforce as a challenge as well as an opportunity. Nearly 900 employees are eligible for retirement in 2014. With years of accumulated experience and knowledge, many of those nearing retirement age are key contributors to the Corporation's success. It is important therefore that appropriate succession planning, recruitment and retention activities are in place to maintain safe and reliable service and to manage the loss of valuable experience and knowledge that can result from the retirement of key contributors. At the same time there is opportunity to achieve efficiencies and cost reductions by evaluating the need for positions that are vacated.

Infectious Disease – Ebola Virus (E.1.1)

In June 2014 an outbreak of the Ebola virus occurred in West Africa that could potentially impact Manitoba Hydro operations if the virus is not contained. A number of Hydro employees seconded to the subsidiary company Manitoba Hydro International, as well as several MHI Independent contractors, were working in West Africa during the time of this outbreak and were relocated to various other countries in order to continue their work remotely. None were affected by this virus and they will not return to the area until such time that it is considered safe.

As is the case with any infectious disease, the Corporation needs to be ready and respond appropriately to the events as they occur. The developing and changing nature of this Ebola crisis is being assessed and any changes to established practices and/or policies will be performed to meet the declared requirements of the health authorities. A communication strategy to employees is also under development.

Cyber Security (F.2.1)

The growth of electronic communication and automation, while delivering significant benefits to Manitoba Hydro, has also increased risk to the Corporation. This risk includes any cyber attack that could impact the resiliency, reliability, confidentiality, availability or the integrity of Manitoba Hydro Information and Operational Technology assets, including the theft of personal and or business information, and or the disruption/misuse of critical operations/assets. Any computer or control system if not secured properly may be considered a potential target. These cyber attacks could have a significant impact on Manitoba Hydro operationally and financially, and may have a rippling effect on the Manitoba economy.

Countermeasures, management controls and processes are in place to mitigate this risk. The corporation is also developing a series of measures to further augment cyber-security efforts consistent with recommendations of the Office of the Auditor General. Steps to address the recommendations include establishing an Enterprise Security Council comprised of senior executives to provide oversight for all physical and technology security. The Auditor General's report consisted of eight recommendations and the Corporation has developed action plans to address each.

Reputation (G.1)

The Corporation has recently completed a number of significant regulatory hearings, including the Clean Environment Commission and Needs For and Alternatives To (NFAT) Manitoba Hydro's Preferred Development Plan. [redacted] Similar to other Canadian electric utilities, the Corporation's customer satisfaction ratings have been recently declining below its typical range.

A Public Communication Plan continues to be developed to aid in managing customer perceptions of the Corporation's efforts to meet their mandate as outlined under the Manitoba Hydro Act while balancing the need for future domestic rate increases. A component of the plan will use the Corporation's existing communications channels, stakeholder engagement and media relations efforts to address issues that may continue to arise. [redacted]

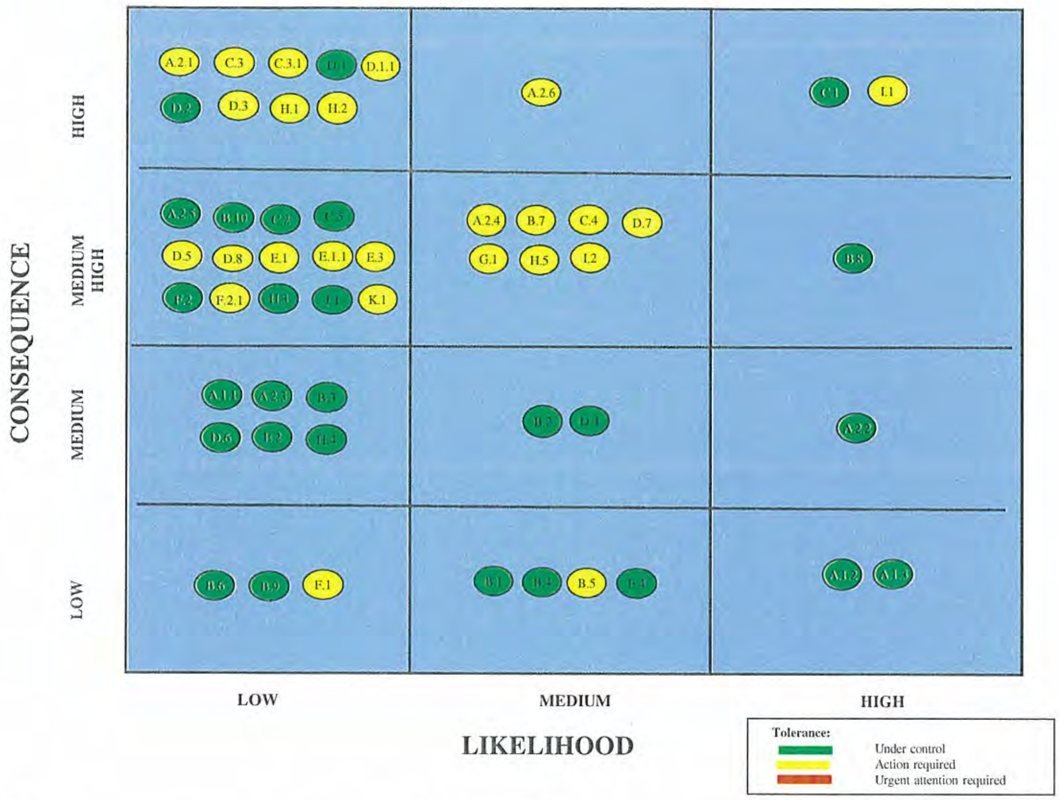
[redacted] The Corporation will take all steps possible to try to ensure that its customer satisfaction rating and current positive reputation are maintained.

IV. CORPORATE RISK MAP

Corporate Risk Profiles (see Appendix B) identify and assess each risk facing the Corporation, describe activities used to manage the risk, and provide estimates of the potential residual impact to the Corporation in terms of likelihood and consequence after mitigation actions have been taken. The Corporation's tolerance for each risk and an assessment of whether the risk is within or outside the desired tolerance level is also provided. The risk rating and tolerance criteria are provided in Appendix C. As well, further detail of the risk tolerance assessment for each risk is provided in Appendix A.

The following Corporate Risk Map illustrates the results of a residual risk assessment for all risks facing the Corporation.

CORPORATE RISK MAP



A. Market
1. Domestic
   1. Competition
   2. Uneconomic Loads
   3. Load Growth Uncertainty

2. Export
   1. Regulatory Environment
   2. Long Term Price Uncertainty
   3. Transmission
   4. Special Interest Groups
   5. Protectionism
   6. Major Export Contracts Requiring Early Conawapa ISD

B. Financial
1. Exchange
2. Interest Rates
3. Credit
4. Inflation
5. Gas Price Volatility
6. Gas Derivative Instruments
7. Financial Targets
8. Energy / Fuel Price Volatility
9. Power Financial Instruments
10. Liquidity

C. Environmental
1. Water Supply Variation / Drought
2. Climate Change
3. Operational Impact and Infrastructure
   1. Legal - Species at Risk Act
4. Reliability of Supply
5. Upstream Regulation and Water Withdrawals

D. Infrastructure
1. Loss of Plant (all property, all perils)

1.1. Water Retaining Structures and Flow Control

2. Extreme Drought – Shortfall Energy
3. Prolonged Loss of System Supply
4. System Shutdown (Short Term)
5. System Shutdown (Natural Gas)
6. Technology
7. Special Interest Groups
8. Emergency Management Program

E. Human
1. Safety and Health
   1. Infectious Disease
2. Union / Employee Issues
3. Workforce
4. Technology

F. Business Operational
1. Supply Chain
2. Operational Controls
   1. Cyber Security

G. Reputation
1. Reputation

H. Governance / Regulatory / Legal
1. Regulation and Licensing
2. Export Market Access
3. Legal Compliance
4. Contracts and Ventures
5. NERC/MRO Reliability Standards

[redacted]

J. Emerging Energy Technologies
1. Emerging Energy Technologies

K. Strategic
1. Strategic Direction and Implementation

Risks that are coded yellow on the risk map indicate that some emerging issues need to be monitored and additional action may be required. A summary of the yellow coded risks that are not discussed in the previous sections of this report is provided below.

- [redacted] **A.2.1 Export Regulatory Environment –** Export market rules continually evolve with new rules being imposed that could impact future access to export markets. [redacted]

  [redacted]

  [redacted]

  Manitoba Hydro collectively manages its market access risks through a comprehensive set of activities to monitor and address any potential threats to market access.

- **A.2.4 Export Special Interest Groups –** A positive corporate and product image enables the Corporation to maximize export sales opportunities and to develop generation and transmission projects required for both domestic needs and exports. Negative lobbying efforts by Special Interest Groups can tarnish the Corporation's image or the image of hydropower, limiting its marketability. Manitoba Hydro is managing this risk by: (1) Continuing to promote waterpower as clean, reliable and a renewable source of electricity; (2) Aggressively countering Special Interest Group activities with Manitoba Hydro's perspective; and (3) Expanding engagement with groups who may lobby for or against Manitoba Hydro.

- **A.2.6 Major Export Contracts Requiring Early Conawapa ISD -** There is a lost opportunity to Manitoba Hydro if it's export customers do not commit to additional large power sales agreements [redacted] These new agreements will justify an early in-service date for Conawapa, otherwise spending on Conawapa will end.

  Several actions are being taken to manage this risk, including: (1) Aggressively pursuing discussions with export customers to ensure that they understand that their [redacted] commitment is required if they are counting on purchasing generation from Conawapa, and (2) Advocating with US legislative and regulatory bodies to provide incentives for US utilities to contract for new hydro from Manitoba as part of their plans to address emerging carbon regulations and generation retirements.

- **C.4 Reliability of Supply –** The Corporation is at risk that environmental licensing concerns could obstruct the Corporation's ability to build the necessary transmission facilities required to provide a reliable supply of energy. The Corporation will continue to be proactive in addressing these concerns and ensuring adequate lead times to resolve issues.

- **D.1.1 Water Retaining Structures and Flow Control** – Dam or dyke structures can fail resulting in impacts ranging from insignificant to catastrophic. [redacted]

- **D.7 Special Interest Groups –** [redacted]

- **D.8 Emergency Management Program -** As discussed throughout the Category D Infrastructure section, the Corporation's energy infrastructure is highly exposed to events that can have impacts ranging from insignificant to catastrophic. These include prolonged loss of system supply, the inability to maintain minimum energy services, loss of life, severe environmental damage and significant costs to the Manitoba economy. To ensure that appropriate plans and programs are in place, there are: (1) policies and procedures to guide actions, (2) staff training and emergency preparedness exercises on a regular basis, (3) actions to follow up on and address identified deficiencies, and (4) continual enhancements to the program to ensure the state of readiness. Initiatives currently underway include developing a corporate plan for business continuity for continuation of critical operations and constructing an emergency fuel depot. Several other initiatives are being considered.

- **E.1 Safety and Health –** Employee safety is always a key concern to the Corporation due to the inherent nature of the operational work performed by Manitoba Hydro. To date a focus on continuous safety improvements has resulted in a steady decline in workplace accident severity and frequency rates. The Corporation will continue to focus on making improvements to the safety program.

- **F.1 Supply Chain –** The Corporation requires a variety of critical goods and services to achieve its objectives. [redacted]

- **H.5 NERC/MRO Reliability Standards –** Achieving the highest level of reliability is one of the core tenets of Manitoba Hydro's Vision statement. In support of this vision, Manitoba Hydro is a member of the North American Electric Reliability Corporation (NERC) and has been legally required to comply with nearly 100 of its reliability standards since 2007. These standards specify requirements for planning, operating and maintaining the bulk electric system. The Corporation has developed a Corporate NERC Reliability Compliance Program to manage the demands of compliance.

- **K.1 Strategic Direction and Implementation –** Manitoba Hydro continues to be at a critical point in renewing and expanding Manitoba's electrical and gas system. Major strategic decisions, plans and assumptions are subject to significant internal and external review and approval processes. Decisions for future power generation, transmission and distribution will depend on the best information at the time, and plans will be modified at key decision points if circumstances warrant.

Tab 118

PUB MFR 9 (Revised)
Corporate Overview

Corporate Risk Analysis Report and Specific Risk Management Plans for all major risks including drought. [Appendix 11.7, 2015/16 GRA]

The response to PUB MFR 9 has been updated to include the redacted version of Manitoba Hydro's Corporate Risk Management Report Appendices.

Public disclosure of the response to this MFR (or portions thereof) would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro has filed a motion seeking confidential treatment of the redacted information contained in the attachment to this response pursuant to Rule 13.


Manitoba Hydro Corporate Risk
Management Report
December 2015
THIS REPORT INCORPORATES
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INFORMATION AND IS FOR INTERNAL
REFERENCE ONLY

TABLE OF CONTENTS

1.0 INTRODUCTION

The Corporate Risk Management Report is normally updated on an annual basis to provide Manitoba Hydro's stakeholders with information on the status of major risks facing the Corporation as it carries out its mandate. The report identifies and assesses each risk, describes activities used to manage the risk and provides estimates of the potential residual impact to the Corporation in terms of likelihood and consequence after mitigation actions have been taken. The Corporation's tolerance for each risk and an assessment of whether the risk is within or outside the desired tolerance level is also provided.

As a Crown-owned utility providing an essential and life-sustaining energy service to Manitobans, Manitoba Hydro has a relatively low tolerance for risk. However, because Manitoba Hydro is also an important economic driver for the Province, some risks are necessary in order to take advantage of opportunities to maximize value for stakeholders. These risks are managed through a systematic, proactive and integrated process which is designed to balance the objectives of:

- identifying threats that affect the achievement of the Corporation's mission and mandate;
- mitigating the consequences of negative occurrences; and
- taking advantage of opportunities to provide benefits to all stakeholders.

Most risk management efforts are focused on reducing the occurrence of negative events. However, the Corporation also has plans in place to reduce the impacts should a negative event occur. These plans are under continual assessment. In addition, all safety and reliability risks are managed through strict adherence to design, construction and operating standards and practices together with extensive public education and employee training programs. A comprehensive Emergency Response Program is also in place to ensure an effective and coordinated response to possible emergencies or disasters.

The financial and operational risks associated with the management of an integrated electricity and natural gas utility are significant. These risks include the impacts of weather on supply and demand, price and market uncertainties, interest, inflation and foreign exchange rates, skilled labour availability and costs, aging infrastructure maintenance and replacement, increasing regulatory, environmental and legal requirements, and accelerated technological change. Manitoba Hydro manages these risks through an integrated control framework and through the maintenance of an adequate level of financial reserves through retained earnings.

Manitoba Hydro's Corporate Risk Management Report is structured to provide the following:

- A summary of the high consequence risks including:
  - Loss of major infrastructure
  - Drought
  - Loss of export markets
- An overview of significant and emerging risks and actions taken to address those risks.
- A Corporate Risk Map providing a visual depiction of Manitoba Hydro's risks categorized into high, medium and low likelihood of occurrence and the corresponding consequences.
- A Corporate Risk Tolerance Assessment of each risk.
- Corporate Risk Profiles - one page summaries of each of Manitoba Hydro's risks.

2.0 HIGH CONSEQUENCE RISKS

The most significant risks facing Manitoba Hydro are those rated as high consequence due to the potential magnitude of impact on the Corporation's ability to achieve its mandate and strategic goals and are quantified in the following table:

RISK	POTENTIAL FINANCIAL IMPACT
INFRASTRUCTURE	
Prolonged loss of supply	> $2 billion
DROUGHT	
Water Supply Variation / Drought	>$1.9 billion for a 5 year drought commencing in 2017/18 (IFF 15)
LOSS OF EXPORT MARKET ACCESS	> 30 % of electricity revenue

2.1 Infrastructure Risk (Category D)

A catastrophic infrastructure failure continues to be the most significant risk facing the Corporation and its customers. Potential impacts include prolonged loss of system supply, the inability to maintain minimum energy services, loss of life, severe environmental damage and significant costs to the Manitoba economy. Failure can be caused by a number of factors including an extreme weather event, sabotage, fire, human error, or technical malfunction.

By the nature of its business, Manitoba Hydro has an especially low tolerance for infrastructure risk. Significant efforts are expended on managing this risk in a manner that avoids the occurrence of a catastrophic event and minimizing consequences should a catastrophic event occur.

Risk Treatment

In the short term, actions are continually being taken to enhance emergency response and disaster management processes. In the longer term, major investment in renewal and expansion of the infrastructure system are underway to maintain and improve system reliability, energy security and safety. Key management plans and projects include:

- Major New Generation & Transmission projects which increase capacity and energy or provide increased reliability. These include building the Bipole III Reliability project with a planned in-service date of 2018/19 and construction of the Keeyask Generating Station with a planned in-service date of 2019/20. Manitoba Hydro is proceeding with the Manitoba-Minnesota Transmission Project, a transmission interconnection into the U.S. which supports enhanced export capability, reliability and drought risk mitigation.

- Renewal and replacement of aging electric and gas infrastructure through execution of a long term plan to improve system capacity and reliability. This includes critical distribution assets and stations, rehabilitation of existing generators, wood poles, cable and gas pipe replacement, cyber and physical security upgrades, and changes to gas distribution operations and pipelines to address emerging issues with respect to pipeline integrity and load growth. In response to the 2014 rupture of the TransCanada main gas pipeline, the Corporation is constructing a compressed natural gas facility to help mitigate small scale outages during a natural gas supply interruption.

- Water retaining structures and flow control management, including: surveillance inspections, instrumentation monitoring, and engineering analyses of dams and dykes including emergency plans for individual facilities; systematic utilization of failure modes-based condition assessment techniques; and rehabilitation of the Pointe du Bois spillway facility.

- Continual improvement to enhance and strengthen the Corporate Emergency Management Program. In 2015, the Emergency Preparedness Policy was revised, and an Executive Emergency Management Committee was created to provide oversight of the program and to directly support the Corporate Emergency Center during an emergency event. In addition the Corporation continues to develop and maintain emergency preparedness and response management plans.

2.2 Water Supply Variation / Drought Risk (C.1 and D.2)

On average, there is a high likelihood of a drought occurring about once in every ten years. In the circumstances of an extreme drought that is more severe than the worst on record, there is a possibility of insufficient energy supplies being available to meet firm load demands. This would result in extreme financial and reputational impacts on the Corporation. The cost of a five year drought similar to the worst on record is estimated to be $1.9 billion (IFF 15) for a drought commencing in 2017/18.

Risk Treatment

There are several measures in place to manage the impacts of a drought, as follows:

- Manitoba Hydro's current generation and transmission facilities are designed and operated to ensure firm demand can be supplied given a repeat of the lowest river flows since 1912. A drought more severe than the worst on record could occur and would require non-normal operations. This may include operating reservoirs outside of the normal range for power production. Non-normal operation may also include demand reduction measures such as public appeal for conservation, enforced conservation, or rotating reductions of non-essential load. Actions to manage drought will depend on its duration and severity and any other conditions that prevail at the time.

- Once built, the new Manitoba-Minnesota Transmission interconnection with the U.S. will provide the Corporation with increased ability to access additional amounts of energy through higher imports and through financial settlement of firm export contracts.

- Adequate financial reserves are required to protect against a repeat of the worst drought on record. At March 31, 2015 retained earnings totaled $2.8 billion. It should be noted, however, that while drought is a major quantifiable risk, an adequate level of retained earnings is required to recover from other significant risks such as a prolonged loss of supply or the loss of export market access.

2.3 Export Market Access Risk (Category A.2)

On average Manitoba Hydro derives a significant portion of its revenue from export sales to U.S. and Canadian markets. The prime impact of restricted market access would be significantly reduced net export revenues which are fundamental in keeping domestic rates low and offsetting the upfront costs of capital investments. Market access risk also includes restrictions on Manitoba Hydro's ability to import which could increase the cost of droughts, and degrade system reliability.

Risk Treatment

Manitoba Hydro continues to actively work to mitigate and manage market access uncertainties, as follows:

- In alliance with other industry participants such as the Canadian Electricity Association, and other stakeholders, Manitoba Hydro continues to lobby MISO, IESO and FERC for the development or elimination of market rules that affect electricity trade and facilitate full participation of Manitoba Hydro in US and Canadian electricity markets.

- Manitoba Hydro also engages in extensive lobbying efforts in the US to promote waterpower as a clean, reliable and renewable source of energy and to counter anti-hydro special interest group lobbying.

- The Corporation also engages with environmental, consumer and business stakeholder groups to discuss and promote its development plans.

- Market access risk is also reduced by having long term contracts and strong relationships in place with major export counterparties.

3.0 SIGNIFICANT AND EMERGING RISKS

While loss of infrastructure, drought and potential loss of export markets remain as the highest consequence risks for the Corporation, there are other significant and emerging risks that can affect the achievement of the Corporation's mission and mandate. These risks include:

3.1 Infrastructure Investment (Category D)

As noted above, Manitoba Hydro is making significant investments in a number of major new Generation and Transmission projects and initiatives in order to increase capacity and energy or provide increased reliability. These projects include construction of Bipole III and the Keeyask generating station, development of the Manitoba-Minnesota Transmission Project, replacement of aging infrastructure, and execution of new, more aggressive demand side management initiatives which target a significant increase in energy consumption savings. These plans will require the investment of approximately $17 billion (CEF 15) over the next 10 years. These projects are well into their construction cycles and any significant delays or cancellations would have significant financial, reputational and contractual consequences.

There are a number of very significant risks associated with such large initiatives that will challenge the Corporation's ability to meet Manitoba's energy needs while keeping customer rates affordable, and maintaining the Corporation's financial strength. These challenges include completing the projects on time and on budget, maintaining relationships with all stakeholders that could affect execution of these projects, and funding the investments while preserving the financial integrity of the Corporation.

Mitigation measures to address cost risks include the use of best practices in cost estimating, contracting practices and the inclusion of appropriate contingencies and management reserves. Preserving financial strength and managing stakeholder relationship issues are discussed below.

3.2 Financial Strength (B.7)

Maintaining financial strength is essential in order to make the necessary investments in infrastructure, to continue to provide safe and reliable service to customers, financially withstand the risks and uncertainties that are inherent in the Corporation's operations and to provide customers with long-term rate stability and predictability and avoid the need for large or sudden rate increases in the future.

The extensive capital investment in new and existing infrastructure will significantly weaken the Corporation's key financial ratios given that these investments will be largely funded through increased borrowing. Careful management of the Corporation's financial position is necessary in order to mitigate the risk of leaving customers exposed to sharp rate increases in the event of a prolonged drought or catastrophic outage. As well, there could be negative impacts to the credit rating of the Province if credit rating agencies were to deem Manitoba Hydro to no longer be financially self-supporting.

The Corporation has a solid plan to balance the need for investment to maintain safe and reliable service with the need to provide stable and predictable rates for customers. Key areas of focus and associated challenges are:

3.2.1 Continuing Cost Containment Measures

The Corporation continues to find and implement innovative ways to control costs without compromising the ability to deliver safe and reliable service. For example, since over 75 per cent of operating costs are comprised of wages and benefits, Manitoba Hydro has committed to reducing over 300 positions through attrition by 2016-17, resulting in annual savings of approximately $30 million. Manitoba Hydro is also targeting to limit increases in operating costs to 1% to 2021/22, excluding the impacts of accounting changes.

Other initiatives include a multi-year program to review and improve supply chain performance. The initial phase of the program has identified opportunities to reduce costs and increase operational efficiencies in materials management, fleet services and purchasing. In addition, the Corporation continues to effectively manage costs associated with its sustaining capital investment requirements by engaging in a number of asset management strategies in order to prolong the economic life of its assets and replace assets in poor health in the most cost-effective manner.

3.2.2 Pursuing Export Sales (A.2)

Net extraprovincial revenues have enabled Manitoba Hydro to maintain low electricity rates for Manitobans and as such, the Corporation will continue to aggressively pursue a balanced portfolio of profitable export sales to provide the highest financial benefits to ratepayers and all Manitobans over the long term.

Key factors affecting the ability to increase export volumes and revenues are:

- **Export Market Prices** - In recent years export prices for electricity have been affected by the economic slowdown in the U.S. and the availability of low-cost natural gas made possible by new production techniques and wind generation. The Corporation has endeavored to reflect these factors as accurately as possible in its forecasts of future export market prices. Based on the input of external industry specialists, the Corporation is forecasting a moderate rise in export prices over the long term, restrained by the continued impact of natural gas pricing and other generation options. There is a risk that export prices could be lower than industry experts are predicting, and that would be a downside risk which could hamper the Corporation's ability to achieve forecasted export revenues. This would put pressure on financial ratios and result in the requirement for higher projected rate increases.

- **Cost of New Hydraulic Generation** – The resources currently in development are supported by a number of export agreements, including a 250-megawatt sale to Minnesota Power, a 125 MW sale to Northern States Power and a 108–megawatt sale to Wisconsin Public Service. [redacted] Should their costs exceed those forecasted, the

Corporation's ability to achieve forecasted financial targets with projected rate increases would be challenging.

- **Market Access -** The new Manitoba – Minnesota transmission interconnection will help increase export revenues by increasing export capability by 883 MW and import capability by 683 MW. These increases in transfer capability will increase the amount of firm load that can be served by the Manitoba Hydro's generating system, will enhance the value of new DSM initiatives and will result in achieving higher export prices and lower import prices. The line, while increasing export volumes, will also reduce water spillage in high water years.

3.2.3 Controlling Finance Expenses

In order to maintain business continuity in times of drought or catastrophic system outage, bridge cash flow financing will be required. Therefore, it remains critically important to maintain access to sufficient market liquidity through the use of the Corporation's short term debt credit facility, as well as ready access to the debt capital markets.

Projected finance expense is expected to double over the first ten years of the IFF15 forecast, due mainly to the borrowing requirements arising from the planned capital expenditures required to meet the growing energy needs of Manitoba and to replace aging infrastructure. In addition, the potential cumulative financial impact of a one-percent change in interest rates over the next ten years is estimated at $1.0 billion (IFF 15).

Manitoba Hydro will endeavor to manage financial expense exposure by continuing to closely monitor financial markets and take action to reduce costs where prudent and feasible. As a result of the low interest rate environment over the past several years Manitoba Hydro has been able to reduce its net weighted average interest rate by approximately 2.0% since 2006/07 and increase its weighted average term to maturity by over three years during the same period.

3.2.4 Implementing Domestic Sales Rate Increases (B.7)

Manitoba Hydro's financial forecast projects the requirement for reasonable and predictable domestic rate increases of 3.95 per cent per year over the next decade.

Implementing these rate increases to ensure ongoing safe and reliable service continues to be a significant challenge in convincing stakeholders that the projected level of rate increases are in the best long-term interests of all ratepayers. Significant efforts have, and will continue to be focused on delivering compelling and convincing arguments before the PUB to obtain the required level of rate increases going into the future. Even with the projected rate increases, it is expected that Manitoba Hydro's domestic customers will continue to have electricity rates that are affordable and competitive. As well, offering new and expanded Power Smart programs are aggressively targeting additional electricity and natural gas savings, which will aid customers in managing their overall energy costs.

3.3 Regulation and Licencing (H.1)

The Corporation requires a variety of regulatory approvals and licences to carry out its activities. Key approvals and licences include those issued under the National Energy Board Act, Water Power Act and Environment Act either to build new generation and transmission facilities or to maintain the operation of existing facilities. Failure to obtain approvals and licences on favourable terms or in a timely fashion could have significant financial, operating and water regime impacts, increasing costs, and reducing hydraulic generation, capacity and export sales. Expiration of a licence without renewal will expose the Corporation to embarrassment and loss of reputation. Although highly unlikely, cancelation of a licence could expose the Corporation to the possibility that a third party could acquire the water power rights at a location and potentially the loss of the asset.

There are two significant issues currently facing the Corporation that could have significant impact on operations and reputation if they are not addressed. These are:

3.3.1 The Listing of Lake Sturgeon under the Species at Risk Act (C.3.1)

Almost all of the Corporation's hydroelectric generating stations are located where Lake Sturgeon are found. It is possible that at most sites the Department of

Fisheries and Ocean could determine that the stations are negatively affecting the fish and/or its habitat. Due primarily to historical commercial overharvest, plus additional stressors including hydroelectric development and ongoing Indigenous domestic harvest, Lake Sturgeon populations have been severely depleted over the past 100 years and the species is currently under review for listing as endangered under SARA at most locations in Manitoba. If Lake Sturgeon is listed as "Endangered" under the SARA, the Corporation could face restrictions on current operations, structural modifications to infrastructure, delays in developing new generation due to difficulties with securing permits, and high costs of recovery measures that are potentially mandated. The Corporation continues to take significant action to minimize the need for and likelihood of listing Lake Sturgeon under SARA (see detail of risk treatment on profile C.3.1), however uncertainty remains.

3.3.2 Environmental and Social Impacts of Legacy Facilities

Many of Manitoba Hydro's legacy facilities such as Grand Rapids, Kelsey, Churchill River Diversion (CRD), Lake Winnipeg Regulation (LWR), Kettle G.S., Long Spruce G.S. and the HVDC facilities were constructed without the benefit of modern environment reviews and community and Indigenous consultations.

Manitoba Hydro is now having to deal with the impacts of these legacy projects in the context of modern societal and environmental values. This is unlike recent projects such as Wuskwatim, Bipole III and Keeyask where the impacts were studied, understood and communicated up front and consultations were held. So although legacy projects have all the necessary permits and are legally compliant, the expectations of Manitobans for legacy projects reach beyond what was legally required in the past. This gap in expectations exposes the Corporation to controversy whenever it is seeking a new licence or a change to an existing licence unless it proactively addresses all legacy issues before a licencing decision is required.

This situation arose during both the Wuskwatim and BiPole III Environment Act licencing processes where the public had opportunities to express concerns associated with the environmental and social impacts of CRD and LWR projects.

In these processes the fact their Water Power Act licences were not finalized after 30 years became a point of issue leading to the Clean Environment Commission (CEC) making a non-licencing recommendation on the need to acquire final licences.

Similarly in the BiPole III process the fact that legacy hydro projects in northern Manitoba had not undergone modern environmental reviews lead the CEC to make a non-licencing recommendation that both the Province and Manitoba Hydro conduct a Regional Cumulative Environmental Effects Assessment (RCEEA) of all Manitoba Hydro projects in the lower Nelson River sub-basin before any more projects are licenced for construction.

In the recently completed LWR Final Licence hearing the CEC went even further and recommended that all legacy hydro projects in the Province should be licenced under the Environment Act.

The issue of reviewing the environmental and social impacts from legacy projects is problematic in several ways for the Corporation. Base line data is lacking, the reviews are very costly, they take many years to complete and they can lead to delays in re-licencing existing facilities or constructing future facilities.

Over the next ten years, twelve of Manitoba Hydro’s Water Power Act licences will have to be renewed. Although legally this should be a relatively simple process as prescribed under the Water Power Act regulations, public expectations, the requirement for the Province of Manitoba to consult under Section 35 of the Constitution with Indigenous peoples on all licencing decisions and the recent recommendations from the CEC on re-licencing that includes full environmental assessments and public reviews will expose Manitoba Hydro to significant costs, and potential operational restrictions. Manitoba Hydro is currently in discussions with the Province on how to proceed with re-licencing.

3.4 Indigenous Relationships and Legal (Section I)

Manitoba Hydro’s relationships with Indigenous peoples and communities are complex and have been identified as one of the key areas of focus in Manitoba Hydro’s Corporate Strategic Plan, where it is acknowledged that, “engaging impacted Indigenous communities in a positive way is vital to enhance working relationships.”

While Manitoba Hydro has made extensive efforts to address impacts arising from its existing development, some legacy issues still remain. These issues remain a negative influence on Manitoba Hydro's ongoing relationships and engagement with communities, as well as on public perception of Manitoba Hydro's role in that relationship.

Recent judicial decisions, notably the Supreme Court of Canada decisions in the Manitoba Métis Federation and Tsilhqot'in Nation cases, provide additional complexity and have the potential to impact Manitoba Hydro's relationships with First Nation and Métis peoples in terms of the specific legal principles flowing from the decisions, and from the increased confidence communities might have to explore and assert their rights.

The recently elected federal government included the acceptance of the UN Declaration on the Rights of Indigenous Peoples (the UNDRIP) in its platform. The full adoption and implementation of UNDRIP is also included in the Truth and Reconciliation Commissions Calls to Action. The current movement towards acceptance of the UNDRIP, including its references to "Free, Prior and Informed Consent" (FPIC), has the potential to affect new project development and, potentially, changes to current operations. This may include increased process, negotiation and development costs, as well as enhanced prospects for impact benefit agreements (IBAs) on all projects (generating and transmission). How the concept of FPIC will be interpreted and approached by regulators and the courts going forward is also not known.

Risk to the Corporation from the issues noted above include the potential for strained relationships, prolonged negotiations, legal challenges, work stoppages, blockades, demonstrations and other forms of civil disobedience. Each of these in turn has the potential to impact project costs and schedule, adversely affect corporate financial strength, reduce export sales, lengthen the time and increase the cost of regulatory approvals, and damage the Corporation's reputation.

The Corporation has a number of measures in place to manage these risks. These include:

- continuing to work with Indigenous communities, groups and individuals to resolve outstanding issues and grievances to the extent possible and reasonable;

- pursuing enhanced working relationships through mutually beneficial arrangements with Indigenous groups when developing new hydro facilities;

- the development, use and/or enhancement of management systems to flag obligations and to follow up on compliance;

- where faced with legal challenges, responding with appropriate legal defences; and to this end, monitoring developments in the field of Aboriginal law to ensure ongoing awareness of evolutions in jurisprudence on Aboriginal and Treaty rights and other Aboriginal law issues;

- ongoing engagement with government to identify appropriate strategies for managing challenges in the relationships, particularly in cases where acts of civil disobedience are being used as a response to relationship impasses;

- consistent with recent Clean Environment Commission and Provincial recommendations, and the Truth and Reconciliation *Calls to Action*, shifting the corporate focus to reconciliation efforts and the development of a strategy to work with communities towards reconciliation.

3.5 Emerging Energy Technologies (J.1)

Improvements and production cost reductions are occurring in competing supply options that have set a trajectory where commercial viability of these supply sources will influence decisions of future alternative resource options. At the present time these competing options do not face the same environmental, regulatory and stakeholder challenges as constructing new hydro facilities.

Emerging technologies have also put downward pressure on export market prices and this could continue well into the future. Continued low export prices could affect the viability of new future hydro-electric generation and may also reduce a portion of existing generating facility values due to the long life spans of these facilities.

Manitoba Hydro’s current resource plans indicate that no new generation is required until 2033. This requirement is based on current load forecasts that include new DSM targets that are updated annually to reflect information that is available. This time frame allows the Corporation to assess new alternative energy technologies and work towards an integrated resource plan which determines the appropriate combination of resources to meet multiple objectives (technical, environmental etc) at the lowest cost to Manitobans.

3.6 Human Resources

Attracting, developing, retaining and protecting a highly skilled and motivated workforce that reflects the demographics of Manitoba is critical to Manitoba Hydro's success. Key risks related to human resources are as follows:

3.6.1 Safety in the Workplace (E.1)

Employee safety is always a key concern to the Corporation due to the inherent nature of the operational work performed by Manitoba Hydro. To date a focus on continuous safety improvements has resulted in a steady decline in workplace accident severity and frequency rates. The Corporation is committed to continuously improving safety performance and focusing on strategies to instill a safe and health culture in all Corporate activities. Strategies include implementing a seven point safety enhancement strategy that includes annual executive site safety reviews, developing Corporate Rapid Response Teams for various issues, and moving the Corporation beyond compliance by forming a new high performance Risk Prevention Services team.

Manitoba Hydro's international operations in developing countries exposes employees and their families to increased risk of disease, crime, or injuries from political, ethnic or religious conflict. A number of measures are taken to mitigate these risks, including providing employees with medical advice and medi-vac transportation, specialized location security advice, secure accommodations and having emergency response and evacuation plans.

3.6.2 Workforce Management (E.3)

Attracting, developing and retaining a highly skilled and motivated workforce that can effectively carry out the very important, complex and new corporate initiatives are critical to the Corporation's success. Key factors that impact the ability to achieve this are the number of employees that are eligible for retirement, competition for highly skilled workers, and the ability to keep up with technological and other changes. Manitoba Hydro's contractors will also be impacted by the same competition.

The Corporation is looking at the demographic shift that is occurring in its workforce as a challenge as well as an opportunity. Nearly 900 employees are eligible for retirement in 2015. With years of accumulated experience and knowledge, many of those nearing retirement age are key contributors to the Corporation's success, and that knowledge can be lost with little notice. It is important therefore that appropriate leadership, management, succession planning, recruitment and retention activities are in place to maintain safe and reliable service and to manage the loss of valuable experience and knowledge that can result from the retirement of key contributors. Given that business needs are changing and new technologies are available, there is an opportunity to achieve efficiencies and cost reductions through attrition.

3.7 Other Significant and Emerging Risks

Other significant and emerging risks that can affect the achievement of the Corporation's mission and mandate are as follows:

3.7.1 Reputation (G.1)

The Corporation's reputation has been impacted by issues related to trust and transparency, rate increases, labour relations, and major projects (e.g. need, financial management, local reaction). Many of these challenges are likely to continue and others may emerge (e.g. new licencing requirements and Power Smart arrangements). As a result, there is a continuing need to focus on sustaining and enhancing corporate reputation. Accordingly, the Corporation will continue to take steps to enhance its reputation through all its daily actions, including comprehensive, timely communications, respectful interactions with stakeholders, and provision of safe, reliable, and affordable energy services to customers.

3.7.2 Upstream Gas Cost Uncertainty (B.5)

There is significant upward cost pressure for transportation services on the TCPL Canadian Mainline (the "Mainline"), to which Centra is currently captive in bringing natural gas to its load centre. The Mainline is significantly underutilized resulting in less revenue than that which is required to cover the Mainline's relatively high embedded cost structure. As a result, the pipeline has been seeking regular toll increases since 2010, which costs are passed through to Manitoba natural gas ratepayers. Tolls on the Mainline also affect transportation services that Centra obtains from third parties.

This market risk is compounded by a proposal by TCPL to segment the Mainline's cost allocation and tolls post-2020 between the under-utilized Western Mainline (on which Centra moves gas) and the highly utilized Eastern Ontario Triangle, which would facilitate the avoidance of cost responsibility for under-utilized or stranded assets on the Mainline by eastern shippers at the expense of Centra and other captive shippers on the Western Mainline. Centra is the largest captive shipper on the Western Mainline. The outcome is highly uncertain at this time. The NEB has approved segmentation in principle and intends to review it and other pricing issues in future proceedings. Centra will mitigate TCPL tolls risk by actively participating in TCPL's regulatory proceedings before the NEB as appropriate in order to ensure that Manitoba natural gas consumers' interests are adequately represented.

3.7.3 Cyber Security (F.2.1)

The growth of electronic communication and automation, while delivering significant benefits, has also increased risk to the Corporation. This risk includes any cyber attack that could impact the resiliency, reliability, confidentiality, availability or the integrity of Manitoba Hydro information and operational technology assets, including the theft of personal and or business information, and or the disruption/misuse of critical operations/assets. Any computer or control system if not secured properly may be considered a potential target.

Countermeasures, management controls and processes are in place to mitigate this risk. The Corporation has implemented a series of measures to further augment cyber-security efforts consistent with recommendations of the Office of the Auditor General. Concurrently, to meet current NERC security standards Manitoba Hydro has also undertaken several projects targeted at increasing safeguards over critical cyber assets.

Ongoing assessment and enhanced mitigation strategies are required as the sophistication of external cyber threats increases, and as more computer and control systems are inter-connected. The Enterprise Security Council comprised of senior executives provides oversight for all aspects of physical and technology security including NERC related projects and the implementation of the Auditor General's eight recommendations, of which four have now been completed.

To protect Manitoba Hydro's information technology environment an advanced corporate firewall is in place to protect the data network. Additionally, anti-virus software and security patches are closely monitored and updated immediately to prevent data corruption. The Corporation is finalizing the implementation of a Security Information & Event Management (SIEM) tool to further raise the level of protection. It will be fully operational by spring, 2016.

3.7.4 Wholesale Electricity Markets Compliance Program (A.2.1 / H.3)

To maintain market access and mitigate exposure to market manipulation risk, the Corporation is in the process of implementing a Wholesale Electricity Markets Compliance Program to establish policies, procedures and guidelines pursuant to anti-market manipulation laws in place in the U.S. and Canada. This program will outline roles and responsibilities of those identified in the program, provide direction to employees transacting in the export markets, identify permissible and prohibited trading considerations and specify policy with respect to potential violation investigations, disputes and reporting, training requirements, record retention practices and compliance monitoring related to the Corporation's participation in the wholesale electricity markets.

3.7.5 NERC/MRO Reliability Standards (H.5)

Achieving the highest level of reliability is one of the core tenets of Manitoba Hydro's Vision statement. In support of this vision, Manitoba Hydro is a member of the North American Electric Reliability Corporation (NERC) and has been legally required to comply with nearly 100 of its reliability standards since 2007. These standards specify requirements for planning, operating and maintaining the bulk electric system. The Corporation has developed a Corporate NERC Reliability Compliance Program to manage the demands of compliance, however uncertainty continues to exist with respect to the interpretation of some standards. As well existing standards are also continually being revised and new ones are being adopted on a regular basis.

3.7.6 Supply Chain (F.1)

The Corporation requires a variety of critical goods and services to achieve its objectives. [redacted] Action is being taken to review [redacted] requirements and contingency plans.

3.7.7 Strategic Direction and Execution K.1)

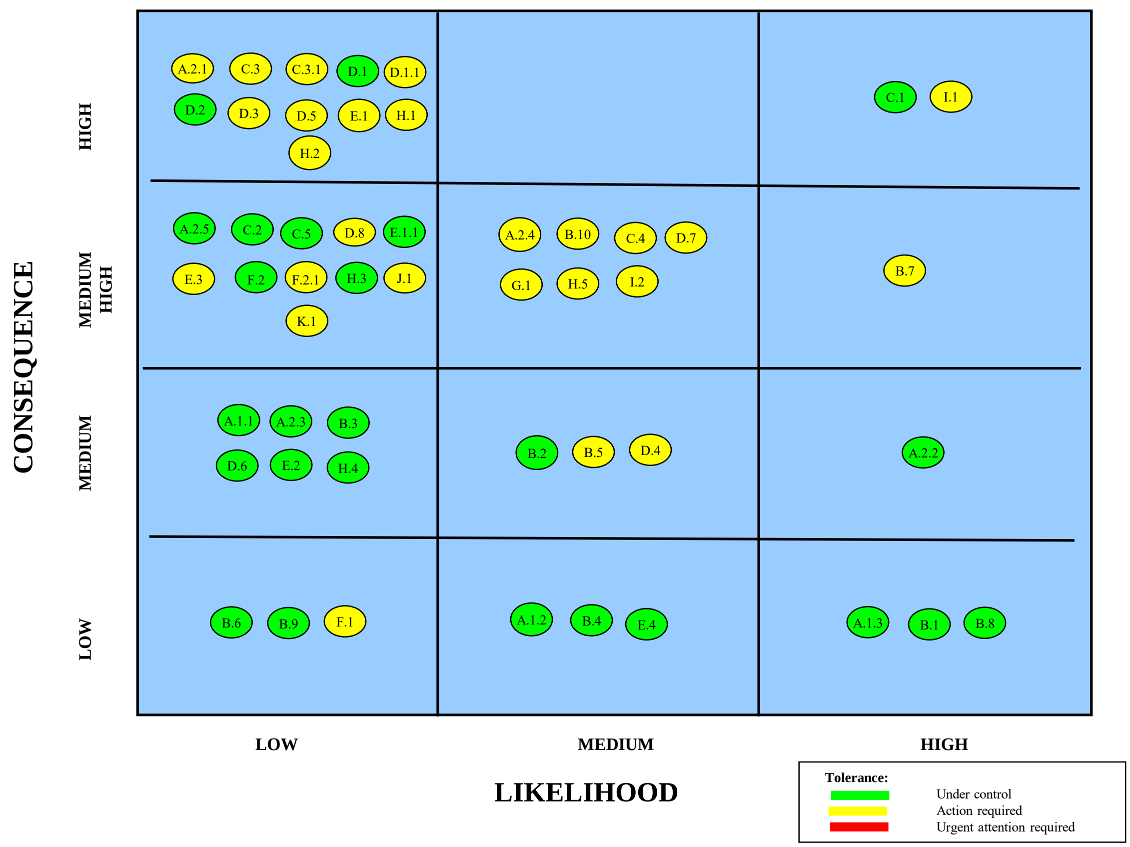
Manitoba Hydro continues to be at a critical point in renewing and expanding Manitoba's electrical and gas system. Major strategic decisions, plans and assumptions are subject to significant internal and external review and approval processes. Decisions for future power generation, transmission and distribution will depend on the best information at the time, and plans will be modified at key decision points if circumstances warrant.

4.0 CORPORATE RISK MAP

Corporate Risk Profiles (see Appendix B) identify and assess each risk facing the Corporation, describe activities used to manage the risk, and provide estimates of the potential residual impact to the Corporation in terms of likelihood and consequence after mitigation actions have been taken. The Corporation's tolerance for each risk and an assessment of whether the risk is within or outside the desired tolerance level is also provided. The risk rating and tolerance criteria are provided in Appendix C. As well, further detail of the risk tolerance assessment for each risk is provided in Appendix A.

The following Corporate Risk Map illustrates the results of a residual risk assessment for all risks facing the Corporation.

CORPORATE RISK MAP



A. Market
1. Domestic
   1. Competition
   2. Uneconomic Loads
   3. Load Growth Uncertainty

2. Export
   1. Regulatory Environment
   2. Long Term Price Uncertainty
   3. Transmission Interconnection Capacity
   4. Special Interest Groups
   5. Protectionism

B. Financial
1. Exchange
2. Interest Rates
3. Credit
4. Inflation
5. Upstream Gas Cost Uncertainty
6. Gas Derivative Instruments
7. Financial Targets
8. Energy / Fuel Price Volatility
9. Power Financial Instruments
10. Liquidity

C. Environmental
1. Water Supply Variation / Drought
2. Climate Change
3. Operational Impact and Infrastructure
   1. Legal - Species at Risk Act
4. Reliability of Supply
5. Upstream Regulation and Water Withdrawals

D. Infrastructure
1. Loss of Plant (all property, all perils)

1.1. Water Retaining Structures and Flow Control

2. Extreme Drought – Shortfall Energy
3. Prolonged Loss of System Supply
4. System Shutdown (Short Term)
5. System Shutdown (Natural Gas)
6. Technology
7. Concerned Stakeholders
8. Emergency Management Program

E. Human
1. Safety and Health
   1. Infectious Disease
2. Union / Employee Issues
3. Workforce Management
4. Technology

F. Business Operational
1. Supply Chain
2. Operational Controls
   1. Cyber Security

G. Reputation
1. Reputation

H. Governance / Regulatory / Legal
1. Regulation and Licencing
2. Export Market Access
3. Legal Compliance
4. Contracts and Ventures
5. NERC/MRO Reliability Standards

I. Indigenous
1. Relationships
2. Legal

+

J. Emerging Energy Technologies
1. Emerging Energy Technologies

K. Strategic
1. Strategic Direction and Execution

APPENDIX A

CORPORATE

RISK TOLERANCE

ASSESSMENT

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
A. MARKET				
1. Domestic				
1.1 Competition	Medium	Natural gas market share, greater than or equal to 60%.	Manitoba Hydro's natural gas market share is currently at approximately 60%.	Manitoba Hydro intends to continue offering fixed-price primary gas products to small volume consumers compatible with product demand as well as Power Smart programs and services to meet customer needs.
1.2 Uneconomic Loads	Medium	Intensive loads do not materially exceed 25 MWs.	Substantial expansion of energy intensive industry at current rates has the potential for adverse impact on financial strength.	Continue to explore rate concepts based on marginal cost. Advance Time of Use proposal for regulatory approval.
1.3 Load Growth Uncertainty	Medium	Variations in load growth from forecast are manageable.	An extensive load growth forecast that includes DSM actions and IFF update are completed annually. Development plans to meet resource requirements are revised as necessary.	Update load forecast and resource development plans as required. Implement integrated resource planning.
2. Export				
2.1 Regulatory Environment	Medium	Unfettered market access.	Market rules are continually evolving with new rules being imposed that could impact future access. These include jurisdictional overreach by FERC and MISO Tariff changes including changes to PPA requirements. Ontario recently implemented a General Conduct Rule which will potentially sanction otherwise legitimate market behaviour.	Manitoba Hydro collectively manages its market access risks through a comprehensive set of activities to monitor and address any potential threats to market access. The Corporation is in the process of implementing a Market Compliance Program to manage the risk of any potential market manipulation activities in the wholesale electricity markets.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
2.2 Long Term Price Uncertainty	Medium	Downward price pressure due to new technologies limited to $100 million per year.	Technological developments for natural gas production & policy for wind incentives for wind development are occurring but are within tolerance limits.	Manitoba Hydro maintains a balanced portfolio with long-term contracts to reduce exposure to price variation.
2.3. Transmission Interconnection Capacity	Low	Maintain adequate transmission interconnection capacity.	Manitoba Hydro influences ratings through a cooperative process with MISO, and tie line partners. The Corporation also participates in reserve sharing agreements to maximize transfer capability. Ratings have not changed.	Maintain current efforts. To further mitigate risk, Manitoba Hydro is proceeding with a second 500 KV interconnection to the US and an additional 230 kV interconnection with Saskatchewan.
2.4 Special Interest Groups	Low	No negative image impact that materially affects opportunities for long-term firm power sales or the price that can be obtained.	Some residual risk remains. In spite of best efforts to counter anti-hydro lobbying, legislators and customers may still be negatively influenced. Regulators decisions may extend the regulatory process, deny approval or require onerous terms.	Continue to promote waterpower as clean, reliable and a renewable source of electricity. Aggressively counter Special Interest Group activities with Manitoba Hydro perspective. Expand engagement with groups who may lobby for or against Manitoba Hydro.
2.5 Protectionism	Low	Full participation in export markets	Manitoba Hydro offers a carbon-neutral energy alternative which many states will require in order to meet recently announced EPA rules requiring states to reduce CO2 emissions and develop plans as to how it will achieve those goals. MH is a sought after supplier and imports of hydropower into the US have recently been accepted as a qualifying resource in the US Clean Power Plan.	Maintain industry and regulatory representation. Continue monitoring and lobbying efforts in US and Canada for energy policy and market rules.

(green)	Risk is being managed appropriately and is not expected to materially change.
(yellow)	Some emerging issues need to be monitored and additional action may be required.
(red)	Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
B. FINANCIAL				
1. Exchange	Medium	As defined in the Foreign Currency Exchange Risk Management Program.	Current exposure falls within the target. As well a $0.10 change in FX rate results in less than a $7.6M change in net income.	Continue to monitor USD cash forecast and take appropriate actions to stay within the risk targets.
2. Interest Rates	Medium	The aggregate of: i) floating rate debt, ii) short term debt, and iii) fixed rate long term debt to be refinanced within the subsequent 12 month period; is limited to a maximum of 35% of the total debt portfolio.	Within established policies and guidelines.	Continue to monitor economic and financial market conditions, while undertaking appropriate debt management strategies and operating within policy limits.
3. Credit	Medium	As defined by counterparty credit rating, limits and arrears policy.	Within established policies and guidelines. .	Maintain existing controls, closely monitor global credit issues, establish enhanced credit risk measurement capability to quantify credit risk exposure and ensure use of consistently applied practices to mitigate exposure.
4. Inflation	Medium	Sales rate increases within justifiable and acceptable limits.	Prolonged high levels of inflation could begin to jeopardize the achievement of Manitoba Hydro financial targets and necessary capital program. Cost constraint measures have been further implemented.	Continue to monitor inflation impacts, insert inflation adjustments into export contracts if possible, ensure all costs fully justified and monitor effectiveness of cost constraint measures.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
5. Upstream Gas Cost Uncertainty	Medium	Sales rate increases due to increases in upstream gas commodity, transportation and / or storage costs within acceptable limits. Financial impacts from Fixed Rate Program also within acceptable limits.	There is the potential for significant future upward cost pressure for transportation services on the TCPL Canadian Mainline to which Centra is currently captive, as well as the ANR and GLGT systems which are wholly owned by TCPL. Gas cost rate uncertainty for the primary gas service is mitigated through a Rate Volatility Management Program, a fixed rate service or a third party marketer, and an equal payment plan. A self insurance risk premium and risk thresholds will mitigate financial impacts and trigger a review of the program.	Participate in NEB and FERC regulatory proceedings on matters related to the TCPL mainline and the ANR and GLGT systems in the U.S. Explore alternatives as required, such as the development of local underground natural gas storage.
6. Gas Derivative Instruments	Medium	Gas derivatives will not be used in the normal course.	Changes to the program were approved by the PUB and derivatives will not be used in the normal course.	Further use of derivatives justified and approved as required.
7. Financial Targets	Medium	Maintain adequate capital structure and other financial targets	Significant progress has been made toward achieving financial targets; however targets are expected to deteriorate for several years due to new major generation and transmission facilities and other significant capital expenditures. Targets are expected to recover towards the end of the 20 year IFF period.	Manage by adopting and updating appropriate targets, making annual contributions to retained earnings, achieving annual contributions through a combination of cost controls, high export revenues, and regular reasonable domestic rate increases.
8. Energy / Fuel Price Volatility	Medium	Included in drought tolerance for power purchase requirements.	Good water conditions currently exist, however volatility in prices has increased with the development of competitive energy markets.	Diverse sales portfolio and effective use of the MISO day ahead market. Hedging is a possibility. Retained earnings sufficient for any variations.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
9. Power Financial Instruments	Low	As defined in the Wholesale Export Power Policy.	Within established guidelines.	Corporate Risk Management is finalizing the installation of risk software that will provide enhanced risk measurement capability.
10. Liquidity	Low	As per the Manitoba Hydro Act, the temporary borrowing limit shall not exceed in the aggregate the sum of $500 million.	Within established guidelines.	Cash receipts and disbursements are closely monitored on a daily basis. Short term debt balances and forecasted cash requirements are also monitored, with short term debt converted to long term debt as required. Fund three months in advance of requirements.
C. ENVIRONMENTAL				
1. Water Supply Variation / Drought	Medium	Operation Planning Criteria and adequate financial reserves. Potential 5 year drought impact is $1.9 billion for a drought commencing in 2017/18 (IFF 15)	Good water conditions that could change within a year. Sufficient retained earnings to withstand extended drought. Natural gas and power prices are expected to be low for the near-term.	Retained earnings sufficient for reduced flow/revenue due to drought.
2. Climate Change	Low	Climate change impacts expected to occur gradually	Climate change issues on water supply are being studied. Any required adaptation to operations and resource plans will be made as information becomes available.	Continue to monitor progress on determining climate change impacts and respond accordingly.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
3. Operational Impact and infrastructure	Medium	No unplanned environmental impacts, ISO 14001 compliant, CSP environmental targets met.	There are a number of environmental issues that are or could affect future operations of the Corporation. The most significant include the potential of Lake Sturgeon being listed as endangered (see 3.1 below), and the need to address environmental and societal impacts and expectation for legacy facilities. See risk profile H.1.	Complete the RCEEA and continue discussions with the Province on how to proceed with re-licencing.
3.1 Legal - Species at Risk Act	Medium	No undue restrictions on current operations and ability to build future projects.	The Corporation has taken significant action to minimize the need for and likelihood of listing Lake Sturgeon under SARA. However uncertainty remains regarding whether the Federal Government will decide to list Lake Sturgeon under SARA.	Continue actions to minimize the need for listing Lake Sturgeon under SARA.
4. Reliability of Supply	Low	No major obstruction to plans and operations to build necessary facilities.	Enhanced scrutiny and regulatory oversight of proposed system improvements and the added time and cost needed to obtain licences and permits.	Be proactive in addressing concerns and ensure adequate lead times to resolve issues.
5. Upstream Regulation and Water Withdrawals	Low	Changes in water supply expected to be gradual.	Good water conditions exist reducing pressure on water supply diversions in the short term.	Continue monitoring responsible entities.

(green)	Risk is being managed appropriately and is not expected to materially change.
(yellow)	Some emerging issues need to be monitored and additional action may be required.
(red)	Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
D. INFRASTRUCTURE				
1. Loss of Plant (all property, all perils)	Low	No major facility loss. CSP reliability targets and contingency standards. Max insurance coverage is $7.0 billion.	Maintain Reliability, Dam Safety and Insurance programs including annual reviews.	Continue to assess exposures of loss and develop appropriate risk reduction alternatives and emergency plans.
1.1. Water Retaining Structures and Flow Control	Low	No water retaining structure failures, following Canadian Dam Association guidelines, maintain appropriate emergency preparedness plans.	The risk of dam breach is addressed by ensuring the integrity and reliability of water control equipment and structures through diligent maintenance and vigilant surveillance, as well as preparing for emergencies, as per Cdn Dam Assoc guidelines. Residual risk of dam failure can be mitigated but not eliminated.	Maintain Dam safety program and improve structures where deficiencies are known.
2. Extreme Drought - Shortfall of Energy Supply	Low	Historical low flows determine firm supply and operating reservoir levels.	Current water conditions suggest that loads will be met.	Maintain current water resource management systems.
3. Prolonged Loss of System Supply	Low	. No long term system outages, compliant with reliability standards, appropriate continuity plans in place.	No long term events have been experienced recently. However, an aging system has areas of significant concern.	Several capital items have been approved which will reduce exposure to a catastrophic event. Regularly maintain, review and update business continuity plans.

Green: Risk is being managed appropriately and is not expected to materially change.
Yellow: Some emerging issues need to be monitored and additional action may be required.
Red: Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
4. System Shutdown (Short Term)	Low	No major system outages, CSP targets for reliability of service (e.g. SAIDI, SAIFI), compliance to reliability standards, emergency response plans in place.	Manitoba Hydro's reliability performance shows an increased trend of outage frequency and duration, and generation forced outage rates have increased in the last four years. The Corporation is continually upgrading the system.	Maintain reliability standards and ensure system reliability through planned maintenance and upgrades. Regularly maintain, review and update emergency preparedness plans for system restoration and response.
5. System Shutdown (Natural Gas)	Low	Gas supply is available to meet the needs of the province. No undue impact on electrical grid due to gas system failure.	TransCanada Pipelines has incorporated design practices to minimize the possibility of a catastrophic event occurring. The design practices have been effective over the course of several incidents in past decade with the exception of the 2014 Otterburne pipeline rupture that resulted in a loss of service to a number of communities. MH has retained standby services to provide compressed natural gas (CNG) for small scale outages during a supply interruption for the 2015/16 winter.	Ongoing monitoring to ensure that TransCanada Pipelines maintains a safe and secure natural gas transmission system. Maintain and review emergency response procedures and conduct exercises. CNG equipment and facilities are being purchased and constructed.
6 Technology	Low	Computer operations will not be compromised. Compliance with all security standards.	Highly complex area that is constantly changing and operations have not been compromised.	Continuous review and updating of the comprehensive disaster recovery plans. Complete actions to address security risks in the Enterprise IT Security Assessment

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
7. Concerned Stakeholders	Low	No restrictions to infrastructure requirements, particularly projects that are required for safety and reliability reasons.	Lobbying has caused delays and resultant impact on reliability in a number of projects, including BiPole III.	Proactively identify and address issues to ensure construction schedule.
8. Corporate Emergency Management Program (CEMP)	Low	Ability to provide emergency response to maintain or restore minimum acceptable energy services to protect human life and the environment. No undue financial consequences to the Corporation and Manitoba economy.	The CEMP continues to be enhanced with the revision of the Emergency Preparedness Policy and the establishment of the Executive Emergency Management Committee (EEMC). Initiatives currently underway include developing a corporate plan for business continuity for continuation of essential services and critical functions (electrical and gas restoration, bill collection, power trading) and constructing an emergency fuel depot.	Continuous oversight by the Executive Emergency Management Committee (EEMC) to confirm Business Continuity Plans (BCP), Hazard Risk Assessment (HRA), Preparedness, Response and Recovery Plans are reviewed and tested to ensure Manitoba Hydro has the ability and can respond to emergency events.
E. HUMAN				
1. Safety and Health	Low	Within CSP targets for high-risk accidents accident severity and frequency.	Focus on continuous safety improvements has resulted in a steady decline in workplace severity and frequency rates. MH is committed to continuously improving safety performance and instilling a safe and health culture in all activities.	Continue to focus on continuous safety improvements and instilling a safe and health culture. Strategies include implementing a seven point safety enhancement strategy and developing programs with an internal Rapid Response Team for various issues.
1.1. Infectious Disease	Low	Effective response to disease outbreak.	An Influenza Pandemic Plan was reviewed and updated in September, 2009. Monitor health authority requirements and make changes as required.	Continue to monitor and make any required changes to meet health authority requirements.

Green	Risk is being managed appropriately and is not expected to materially change.
Yellow	Some emerging issues need to be monitored and additional action may be required.
Red	Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
2. Union / Employee Issues	Low	Continued positive relations and contract settlements.	A new three year agreement negotiated between the Corporation and IBEW was ratified in early January, 2016. The other three agreements were renewed in 2013 and expire in 2016.	Continue to address employee issues in good faith to ensure that relationships remain positive.
3. Workforce Management	Low	Key vacant positions filled with qualified people. Continue strong relationships and enhance partnerships with post secondary institutions.	Significant retirements in the near future combined with a shrinking labour pool. Implementation of a comprehensive succession planning program.	Completion and maintenance of detailed succession plans for all key strategic & critical positions. Continuous update of retirement forecasts and recruitment plans. Continued redeployment training programs.
4. Technology	Low	Technology issues fully understood and effectively incorporated into existing systems.	Several different technologies exist within Manitoba Hydro's infrastructure and staff have been able to keep up to both older and newer technologies. This risk will increase with time.	Maintain an appropriate level of resources to manage this increasing risk.
F. BUSINESS OPERATIONAL				
1. Supply Chain	Low	Established 90 day supply for critical items. Emergency spares maintained. Materials available when needed.	Material and services delivered within policy however the demand for construction services in some trades is still a concern. In some cases have exceeded budget expectations. .	Continue risk management protocol, including monitoring market trends, sourcing strategic alliance partners, reducing single source provider and stocking emergency spares of critical items.
2. Operational Controls	Low	Adherence to all established guidelines, procedures, policies and programs.	Adequate control structures in place and working. Exceptions reported and appropriate corrective action taken.	Maintain effective control mechanisms.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
2.1 Cyber Security	Low	No undue impacts from cyber attacks on information or critical operational assets.	Controls and processes are in place to mitigate risk. Further measures are being developed and implemented to augment efforts, consistent with recommendations of the provincial Auditor General.	Continue to develop and implement further measures under the governance of the Enterprise Security Council.
G. REPUTATION	Low	No negative image impacts. Meet CSP customer service and public attitude index targets.	Manitoba Hydro's customer satisfaction rating is just above its five year average and is well above the average for Canadian utilities. Reputation could be impacted by issues related to construction of major projects, labour relations, new Power Smart arrangements, new licencing requirements, rate increases, and corporate trust and transparency.	Continue to take steps to enhance the Corporation's reputation, through all its daily actions, including comprehensive, timely communications, respectful interactions with stakeholders, and provision of safe, reliable, and affordable energy services to customers.
H. GOVERNANCE / REGULATORY / LEGAL				
1. Regulation and Licencing	Low	Current restrictions and licences maintained. New facilities receive favourable licencing.	Issues that could have significant impact on operations and reputation include Lake Sturgeon being listed as endangered (see profile C.3.1) and addressing environmental and societal impacts and expectations for legacy facilities. These include addressing CEC recommendations for completion of a Regional Cumulative Environmental Effects Assessment (RCEEA), as well as that all legacy hydro projects be licenced under the Environment Act.	Continue to take action to minimize the need for and likelihood of Lake Sturgeon. Complete the RCEEA and continue discussions with the Province on how to proceed with re-licencing.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
2. Export market Access	Low	Current capacity to export continues (100%)	Rules are constantly changing in export markets. Corporation vigilant in monitoring changes, assessing possible impacts and advocating resolution consistent with corporate interests.	Actively participate in organizations and processes related to rule development and application. Ongoing assessment.
3. Legal Compliance	Low	Compliant with all laws and regulations.	For a large diverse company it is not realistic to reduce the risk of non-compliance to zero. Actions are intended to provide realistic assurance that compliance risks are being addressed.	Ongoing actions to address compliance issues at various levels of the Corporation.
4. Contacts and Ventures	Low	Adherence to all terms and conditions. High risk agreements appropriately reviewed and executed.	Corporation ensures adherence through an effective contract and venture control system.	Maintain control systems.
5. NERC/MRO Reliability Standards	Low	Full compliance to all applicable NERC / MRO standards.	Uncertainty continues to exist with respect to interpretation of some standards. Existing standards are also continually being revised and new ones are being adopted on a regular basis.	Continue to build a strong culture of compliance where all staff understand the impact of day-to-day activities and make corresponding decisions that support on-going compliance.

Risk is being managed appropriately and is not expected to materially change.
Some emerging issues need to be monitored and additional action may be required.
Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
I. INDIGENOUS				
1. Relationships	Low	Workable impact management frameworks or reasonable offsetting arrangements in place with all Indigenous communities adversely affected by Manitoba Hydro operations. Indigenous employment targets achieved. No Strained relations.	Reasonable arrangements are in place with the communities that do not have workable management frameworks. If a community raises an adverse effects concern, Manitoba Hydro will endeavour to investigate and address the concern. Employment numbers are generally exceeding targets. There are strained relations with many communities and resource user groups, including groups who have impact arrangements in place with Manitoba Hydro.	Continue working with indigenous communities to resolve outstanding issues to the extent possible and reasonable. Engage with government to identify appropriate strategies for managing challenges in the relationships, particularly in cases where acts of civil disobedience are used as a response to relationship impasses.
2. Legal	Low	No unfavourable rulings, Compliant with all existing legal requirements.	Demands exist from several sources which could ultimately result in unfavourable rulings. Management systems have not identified any compliance concerns that are not being addressed. Statements of Claims have been filed against Manitoba Hydro.	Measures include (1) Legal responses to legal challenges. (2) Maintain and continuously improve compliance management systems (3) Filing statements of defence, and (4) Monitoring developments in the field of Indigenous law, including Supreme Court decisions.

(green)	Risk is being managed appropriately and is not expected to materially change.
(yellow)	Some emerging issues need to be monitored and additional action may be required.
(red)	Urgent attention required

RISK	RATING	TOLERANCE	STATUS	MGMT ACTION
J. EMERGING ENERGY TECHNOLOGIES	Low	Develop integrated resource plan which uses appropriate combination of resources to meet MH objectives.	Significant improvements and cost reductions in new emerging energy technologies could put downward pressure on market prices and affect MH marketing opportunities, thus reducing revenues from existing assets. MH is actively assessing and working towards an integrated resource plan that determines the appropriate combination of resources to meet objectives.	Continue to assess new technologies and develop integrated resource plan that determines the appropriate combination of resources to meet objectives.
K. STRATEGIC	Low	Long term goals are pursued. No missed opportunities. No unfavourable business decisions.	High level strategic considerations include large scale capital projects to meet future needs of the province and re-investment of the existing energy system. Major strategic decisions, plans and assumptions are subject to significant internal and external review and approval processes.	Decisions for future power generation, transmission and distribution will depend on the best information at the time, and plans will be modified at key decision points if circumstances warrant.

APPENDIX B

CORPORATE

RISK PROFILES

RISK PROFILE INDEX

Likelihood	Low
Consequence	Med
Tolerance	Med

CATEGORY: A. Market

TITLE: 1.1 Domestic – Competition

RISK: Increasing competition may result in a reduction of domestic market share.

DESCRIPTION:

Over the past few decades, the energy utility industry has seen some structural changes with these changes varying somewhat throughout North America. Within these changes, there has been some movement towards creating a more competitive energy services environment with customers having a choice of energy supplier and more choice in energy products (e.g. time of use rates/green energy with electricity, customer self-generation, fixed price products with natural gas and a carbon neutral option).

In Manitoba, customers have a choice in their Primary Gas supplier and no choice with all other system supply electricity and natural gas related services. In the early 2000's, some regions including Manitoba reassessed their respective market structures involving primary natural gas services. In Manitoba, competition in the supply of primary natural gas is quite limited with only two brokers (Just Energy Manitoba and Planet Energy) offering service within the SGS Residential market and six offering services to Commercial and Industrial customers. Currently, a declining number of natural gas residential customers (approximately 6%) have entered into contractual arrangements with brokers involving four to five year terms to deliver their primary gas needs. The number of SGS Commercial and LGS customers combined in contractual arrangements with brokers has also declined (approximately 5%).

During 2007, following a review of the competitive landscape of the natural gas market in Manitoba, the PUB concluded that it was not satisfied with the service options and pricing currently available to Manitoba consumers for Primary Gas service. As a consequence, the PUB ordered Centra, a subsidiary of Manitoba Hydro to file a comprehensive proposal to enter the fixed-price primary gas market. In 2009, Manitoba Hydro started offering consumers the choice of 1, 3 or 5 year fixed-price primary gas products with the price and offering terms varying during various marketing periods. As of November 2015, less than 1% of SGS and LGS customers have entered into fixed rate contracts with Manitoba Hydro.

Although Manitoba Hydro enjoys a significant monopoly environment within the electricity and natural gas utility market, pressures may arise in the future which could change this situation. For this reason, the Corporation is exposed to risks associated with market share loss.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Enhanced competition in the natural gas business would impact Manitoba Hydro's strategic goal of providing customers with exceptional value and meeting its target market share in natural gas (i.e. greater than or equal to 60% of commodity sales). Loss of market share would have a negative impact on the Corporation in terms of realizing the benefits and synergies associated with serving a larger customer base. Introduction of competition in the electric business would impact Manitoba Hydro's position of being the sole supplier of electricity in Manitoba. This would result in the loss of synergies associated with being an integrated company and those benefits provided through economics of scale.

RISK TREATMENT:

The risk associated with this category is managed through all of the Corporation's strategic goals and actions. These initiatives are dynamic in nature and are outlined within the Corporation's Strategic Plan.

Likelihood	Med
Consequence	Low
Tolerance	Med

CATEGORY: A. Market

TITLE: 1.2 Domestic – Uneconomic Loads

RISK: Manitoba Hydro's low electricity rates could attract energy intensive industries which may impact short term export revenue and cause the advancement of new generation.

DESCRIPTION:

Manitoba Hydro's rates to Manitoba consumers are based on the embedded cost of its operations less a credit for net export revenues. Manitoba Hydro is one of the lowest cost producers in the world, with substantial sales into export markets at prices which reflect the real value of electricity. As a result of this export revenue subsidy, domestic loads could be considered "uneconomic" in the sense that absent the subsidization by export revenues, domestic rates do not recover the full embedded cost to serve.

While the decisions of most new businesses or residents to locate to Manitoba are not driven substantially by electricity rates, there are some energy-intensive industries that may be attracted by the low electricity rates. In some cases, it is not apparent that other benefits to the province, such as taxes and employment derived from energy-intensive industry, outweigh the losses due to foregone export revenue.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Substantial expansion of energy intensive industry at current rates has the potential for adverse affects on attainment of the Corporation's strategic objective to protect and improve its Financial Strength, as it may affect our ability to:1) Utilize resources efficiently and effectively to fulfill our mandate and provide maximum value to our stakeholders and ratepayers, and 2) Aggressively pursue a balanced portfolio of domestic and profitable export sales to provide the highest financial benefits to ratepayers and all Manitobans over the long term.

RISK TREATMENT:

Manitoba Hydro supports Time of Use rate concepts as well as rate concepts based on marginal cost which could be generally applicable to all major loads, not just energy intensive industrial loads. These types of rates have the virtue of being applicable to much more usage as well as being more specific with respect to time periods of usage.

As directed by the Public Utilities Board, a review of the Time of Use proposal and proposed changes to the Corporations Cost of Service Study will be addressed at a regulatory proceeding to be scheduled in 2016.

Likelihood	High
Consequence	Low
Tolerance	Med

CATEGORY: A. Market

TITLE: 1.3 Domestic – Load Growth Uncertainty

RISK: Variation in the domestic load from forecast can impact when new resources are required and the quantity of surplus available for export.

DESCRIPTION:

There is financial risk associated with uncertainty in the domestic load forecast. Lower than forecast domestic load will result in lower net revenues as unit revenues from the domestic market generally exceed those from the export market.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The prime impact of this risk is reduced corporate net revenues. To some extent this risk may be mitigated by an increase in MH's export sales activities. If additional long term firm sales can be arranged this may offset the decline in domestic revenues. If not, additional export market sales may be insufficient in offsetting the domestic revenue reduction

RISK TREATMENT:

The Corporation can manage load forecast uncertainty by appropriately distributing export sales commitments over the complete range of power sales time horizons from long-term down to real time. If the Manitoba load growth is higher than expected, then long term export sales commitments can be reduced over the long term. Similarly, if the Manitoba load growth is less than expected, additional long term export sales can be committed.

The Manitoba load forecast, power resource plan and IFF are updated annually to reflect any changes in long-term domestic demand due to factors such as energy pricing, economic activity, population and housing, among others. The Corporation also considers higher and lower load forecast scenarios along with the base load forecast when preparing resource development plans or long-term contract recommendations.

Likelihood	Low
Consequence	High
Tolerance	Med

CATEGORY: A. Market

TITLE: 2.1 Export – Regulatory Environment

RISK: Changes in regulation could restrict access to the export market.

DESCRIPTION:

Unfettered market access is key to the Corporation's ability to maximize export revenues. Regulatory and/or industry change both in Canada and the US is considered to be a fundamental export market risk. These changes may lead to increased costs for the Corporation or limit its access to, the US and Canadian markets as market rules may conflict with the legal requirements governing the Corporation or because they lead to discriminatory treatment of Manitoba Hydro. Entities that may contribute to or influence market access risks include MISO, IESO, AESO, FERC, NERC, MRO, NAESB, State governments (Wisconsin and Minnesota), Provincial and Federal Industry and Trade departments and the Canadian Electricity Association (CEA).

This risk profile is related to Export Market Access, Governance / Regulatory / Legal (H.2). Collectively, market access risks are legal, regulatory, or structural issues which could prevent or restrict Manitoba Hydro's surplus power from reaching a competitive marketplace.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The prime impact of restricted market access is reduced net revenue from the export power market. Similarly, the business case for building new hydro generation would also be at risk. Furthermore, changing market structure and access rules may require both legal and organizational change (e.g. adherence to reciprocity requirements of the export market).

RISK TREATMENT:

The Corporation, and when appropriate, in alliance with other industry participants such as the CEA, MISO, Transmission Owners, and other stakeholders, continues to lobby entities including MISO, IESO, AESO and FERC to develop market rules that support the elimination of barriers to trade and facilitate full participation by Canadian electrical energy producers within the US and Canadian markets. The Corporation has entered into a specialized agreement with MISO, which allows for the co-ordination and comparability in operations and tariffs, while minimizing impacts on corporate structure and maintaining Manitoba Hydro's sovereignty requirements.

Likelihood	High
Consequence	Med
Tolerance	Med

CATEGORY: A. Market

TITLE: 2.2 Export – Long Term Price Uncertainty

RISK: The average price received from future export sales may differ from forecast.

DESCRIPTION:

New technology, cost reductions or potential subsidies to various competing generation resources in Manitoba Hydro's export market may put downward pressure on the market price and result in reduced demand for the Corporation's export products.

This risk profile is related to J.1 Emerging Energy Technologies

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The impact of this risk is reduced net revenue from the export power market. Downward pressure on the market price will also negatively impact the business case for the advancement of new generation.

RISK TREATMENT:

By maintaining market intelligence associated with many factors, including resource plans in other jurisdictions and developments in technology, policy and market design, the Corporation ensures that business case analyses for the advancement of new generation or for new contracts reflect a reasonable range of possible pressures on market price.

The Corporation continues to promote waterpower as a clean, reliable and renewable source of electricity. By maintaining a positive image for its hydroelectric power, Manitoba Hydro's intention is to be seen as a responsible, competitive alternative to other renewable energy sources available in the market.

The Corporation advocates both within Canada and the US for equitable treatment for hydropower relative to other renewable sources and advocates hydropower's role in addressing climate change and air quality.
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Likelihood	Low
Consequence	Med
Tolerance	Low

CATEGORY: A. Market

TITLE: 2.3 Export – Transmission Interconnection Capacity

RISK: Reduction in transmission interconnection capacity will reduce export revenue.

DESCRIPTION:

Maximizing export revenues and reducing import purchase costs is directly linked to available interconnection capacity and maintaining market access. Changes to reliability standards, public policy, infrastructure, load growth, and operating reserve requirements on the interconnected grid can lead to the degradation of available interconnection capacity over time. Reduced export capacity limits the volume of sales during high value times. Furthermore, limited export capability results in an increase in the volume of spilled energy during higher water years. Reduced import ratings would cause significant increased costs during low flow or high demand periods. Under these conditions, the Corporation would be forced to import energy during higher priced or on-peak periods.

Entities that influence this risk include NERC, IESO, HydroOne, SaskPower, MISO and other non-MISO Transmission Owners.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

A reduction in transmission interconnection capacity will decrease potential net revenue from the export power market.

RISK TREATMENT:

The Corporation endeavors to maintain a leadership role in and influence the policies and processes of the organizations and bodies in the USA involved with congestion management and regional transmission operations as well as those involved with transmission planning approvals. Manitoba Hydro staff also takes a leadership role in the activities associated with the formulation of transmission transfer limits for those facilities that affect Manitoba Hydro transfers with the USA. This activity occurs in a cooperative fashion (peer reviewed) with MISO and our tie line partners. Manitoba Hydro mitigates this risk by having skilled, knowledgeable staff representing the Corporation's interests at industry meetings.

In order to maximize transfer capability for commercial use, Manitoba Hydro participates in reserve sharing agreements (currently with MISO through its Coordination Agreement). The benefits of reserve sharing agreements to Manitoba Hydro include increased transmission and generator availability for commercial use.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: A. Market

TITLE: 2.4 Export – Special Interest Groups

RISK: Successful negative lobbying will result in reduced exports.

DESCRIPTION:

A positive corporate and product image enables the Corporation to maximize export sales opportunities and to develop generation and transmission projects required for both domestic needs and exports. Negative lobbying efforts by Special Interest Groups can tarnish the Corporation's image or the image of hydropower, limiting its marketability. Target groups of negative lobbying include [redacted] These Special Interest Groups can also intervene directly in capital and environmental regulatory processes (e.g. Clean Environment Commission).

Aspects of this risk profile parallel Achievement of Strategic and Operational Goals, Reputation / Image (G.1).

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Successful anti-hydro lobbying could result in fewer opportunities for long-term firm power sales or affect the price that can be obtained. Another example of a negative outcome would be the adoption of state implementation plans under the American Clean Power Plan that discriminate against Canadian hydro projects. Such discrimination could result in reduced net export revenues. In addition merchant plant decisions based upon the potential sale of firm power would be less attractive, with potential negative effects on any associated First Nation partnership (e.g. income sharing). If successful, regulatory and government approvals (e.g. environmental licences) required for export sales, generation and transmission initiatives could experience significant delays or even be denied.

RISK TREATMENT:

The Corporation continues to promote waterpower as clean, reliable and a renewable source of electricity. It engages with environmental, consumer and business stakeholder groups to discuss and promote its development plans. It is active directly and indirectly through industry groups such as CHA, IHA, and CEA and through hiring representative firms in the USA and Canada.

The Corporation aggressively counters Special Interest Group activities by sharing Manitoba Hydro's perspectives with government and community leaders, regulators, customers, industry associations, and business groups.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: A. Market

TITLE: 2.5 Export – Protectionism

RISK: Customer sentiment towards imports may negatively impact Manitoba Hydro's export sales.

DESCRIPTION:

Manitoba Hydro's energy competitors in the US may attempt to have limits or protective tariffs placed on imports of electricity from Canada for local economic benefit e.g. job creation. Alternatively, subsidies to US producers may add downward pressure on the market price.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The impact of this risk would be reduced net revenue from export power sales. The business case for building new generation would also be at risk.

RISK TREATMENT:

The Corporation actively lobbies, in alliance with other Canadian industry representatives via trade organizations such as the Canadian Electricity Association as well as US federal and state governments and regulatory bodies for full and unfettered access by Canadian power producers to the US markets. In addition, Manitoba Hydro conforms to the same Standards of Conduct as American competitors to avoid accusations of unfair trade advantage.

The Corporation supports efforts to counter US federal and state legislation that would disadvantage Canadian producers through the CEA, direct lobbying of governments and if necessary, through legal (NAFTA) avenues. In addition, the Corporation engages the services of external legal and public relations entities to stay apprised of trends and legislative activities which might threaten its export activities in the US.

Manitoba Hydro actively participates in the development of market rules in MISO and Ontario through the stakeholder process and through its customers to ensure that market rules enhance or at the very least, do not discriminate against the Corporation's export activities in those jurisdictions.

Likelihood	High
Consequence	Low
Tolerance	Med

CATEGORY: B. Financial

TITLE: 1. Exchange

RISK: Fluctuations in foreign currency impact financial performance.

DESCRIPTION:

The risk of the potential for economic gain or loss due to foreign exchange movements for any transaction denominated in a currency other than Canadian (CAD) funds. This exposure is predominantly in United States dollars ('USD') resulting from U.S. electricity exports, electricity imports, and USD long-term debt.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Manitoba Hydro has exposure to U.S. dollar foreign exchange rate fluctuations primarily through the sale and purchase of electricity in the U.S. and through borrowing in the U.S. markets.

In the current year's offset strategy, temporary fluctuations in net USD electricity exports create the risk of having a USD short or long position in which USD cash outflows will exceed or be less than USD cash inflows. These net short or long positions would be exposed to fluctuations in the USD/CAD exchange rate.

RISK TREATMENT:

Manitoba Hydro's exposures to foreign currency rate fluctuations are managed with the combination of natural and accounting hedges, along with applicable financial instruments. A natural hedge for USD is established by balancing USD cash inflows (primarily U.S. export revenues) and USD cash outflows (primarily U.S. debt coupon and principal payments). In order to bridge the actual timing of cash flows within a 12 month period, the Corporation may also execute applicable foreign currency financial instruments at appropriate times, such as spot, FX forward and FX swap transactions. As well, USD temporary investments and USD commercial paper can be utilized to bridge timing differences. Should the imbalance of USD inflows and USD outflows persist beyond the forecasted near term, Manitoba Hydro may adjust the volume of USD outflows; for example by issuing new USD long term debt to create USD coupon payments or by executing a cross-currency debt swap.

The Corporation has accounting cash flow hedging relationships between U.S. long-term debt balances and future U.S. export revenues as well as between U.S. interest payments on dual currency bonds and future U.S. export revenues. Accordingly, foreign exchange translation gains and losses for U.S. long-term debt obligations in effective hedging relationships with future export revenues are recorded in Other Comprehensive Income (OCI) until future hedged U.S. export revenues are realized, at which time the associated gains or losses in Accumulated OCI (AOCI) are recognized in net income.

Manitoba Hydro has conducted sensitivity analysis in IFF15 with respect to +/- $0.10 change in the USD/CAD exchange rate. As the incremental cumulative increase or decrease in retained earnings over a six year period to 2021/22 is only +/- $22 million, the Corporation's net exposure to USD/CAD currency fluctuations during this timeframe is largely eliminated.

Likelihood	Med
Consequence	Med
Tolerance	Med

CATEGORY: B. Financial

TITLE: 2. Interest Rates

RISK: Changes in interest rates impact financial performance.

DESCRIPTION:

Interest rate risk is the risk that the future cash flows will fluctuate due to changes in market interest rates. There are a number of forms of interest rate risk affecting the existing debt portfolio. Floating or variable rate debt is subject to interest rate reset risk during the life of the debt as the interest rate becomes adjusted at the periodic reset dates. Refinancing risk pertains to the interest rate exposure that exists upon refinancing a short or long term debt issue at its maturity. On a prospective basis, there is also interest rate risk on borrowings for new cash requirements.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

A one-percent increase in interest rates on Manitoba Hydro's existing floating rate and short term debt portfolio at March 31, 2015, offset by a change in the interest capitalization rate, would impact net income by approximately CAD $11.0 million (a 1% interest rate increase on a floating rate debt portfolio of $1.3 billion at March 31, 2015 is $13 million, less a $2 million offset from the change in the interest capitalization rate).

On a consolidated basis, risk sensitivity analysis in IFF15 shows that a +/- 1% change in interest rates may result in an incremental change to retained earnings of approximately $26 million to 2017/18. However, given the large size of the existing debt portfolio, as well as the need to add further debt to support the capital investments, the incremental change to 2024/25 arising from a +/- 1% change in interest rate rises is forecasted to be nearly $1 billion.

RISK TREATMENT:

Manitoba Hydro's interest rate policy on its existing debt portfolio is to limit the aggregate of: i) floating rate debt, ii) short term debt, and iii) fixed rate long term debt to be refinanced within the subsequent 12 month period; to a maximum of 35% of the total debt portfolio. Manitoba Hydro's interest rate risk guidelines for its existing debt portfolio include maintaining an aggregate of floating rate debt and short term debt within 15 – 25% of the total debt portfolio, and having the fixed rate long term debt to be refinanced within a 12 month period being less than 15% of the total debt portfolio.

Against the backdrop of unprecedented capital borrowing requirements and potentially rising interest rates, Manitoba Hydro is in a period of elevated sensitivity to interest rate changes. In order to mitigate this risk, the interest rate risk on the existing debt portfolio has been reduced by decreasing the percentage of floating rate debt within the existing debt portfolio and by selecting debt maturities, that upon refinancing will not compete with new borrowing requirements. Manitoba Hydro will continue to favor long term fixed rate financing at low interest rates.

Likelihood	Low
Consequence	Med
Tolerance	Med

CATEGORY: B. Financial

TITLE: 3. Credit

RISK: The Corporation is exposed to financial loss through credit default.

DESCRIPTION:

Credit risk is the risk that one party to a financial instrument will cause a financial loss to the other party by failing to discharge an obligation. Manitoba Hydro is exposed to credit risk related to sinking fund investments, short term investments and pension fund investments. Manitoba Hydro's gas and electric operations are exposed to credit risk related to domestic and export energy sales, and physical gas supply activities.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Credit risk on sinking fund investments, short-term investments, and pension fund assets is minimized as the Corporation invests exclusively in government-guaranteed bonds, highly rated investments and well-diversified investment portfolios. The majority of the Corporation's accounts receivable is owed from domestic consumers who are in diversified industries. Credit risk exists from wholesale export power transactions with bilateral counterparties and within markets (ISOs).

During the period, total credit exposure due to export power transactions peaked at approximately $54 million in August. Export power bilateral transactions peaked at $39 million in August. On average, approximately 60% of the credit settlement exposure to bilateral counterparties each month is from Northern States Power (NSP). NSP had a peak credit settlement exposure of $24 million in August. Export market transactions peaked at $28 million in April.

Manitoba Hydro's accounts receivable for energy bills outstanding in excess of 60 days is approximately $16.9 million. Of this amount, $15.8 million relates to electric operations and $1.2 million to gas operations. For the electric operations $10.8 million is associated with amounts outstanding in Northern Manitoba.

Derivative instruments will no longer be used in the normal course to manage natural gas market price risk for the Fixed Rate Primary Gas Service. The Credit-Value-at-Risk limit for the gross provincial derivative exposure is $100 million per counterparty. The Province of Manitoba will act to mitigate Manitoba Hydro's risk exposure per counterparty in the context of the gross exposure per counterparty.

RISK TREATMENT:

Credit risk for physical gas supply counterparties and derivative counterparties is mitigated by establishing credit requirements, conducting standard credit reviews of all counterparties and setting and monitoring exposure limits for each of these counterparties. Financial security (letters of credit etc) and contract provisions are also in place to provide further credit risk mitigation. Credit risk resulting from export power transactions is mitigated by aligning credit limits with counterparty creditworthiness using approved credit policies and procedures. Counterparties are assigned unsecured or secured credit limits, based on generally accepted industry standards, which are monitored and reported on a regular basis. Credit risk for domestic energy sales is managed through various reporting, control and collection procedures for overdue accounts. In addition, Manitoba Hydro continues to negotiate with northern communities to resolve the outstanding accounts receivable balance in conjunction with mitigation issues. Manitoba Hydro's First Nation Accounts Department works with Manitoba's First Nation communities to establish manageable ways for the communities to get their accounts paid in full.

Likelihood	Med
Consequence	Low
Tolerance	Med

CATEGORY: B. Financial

TITLE: 4. Inflation

RISK: Increases in inflation rates result in cost increases which the Corporation is forced to recover through increases in domestic customer rates.

DESCRIPTION:

In addition to the capital costs associated with major capital projects, Manitoba Hydro expends approximately $2.0 billion annually for its routine ongoing operating and capital expenditures including fuel and power purchases. Inflationary increases to these costs result in higher costs to the Corporation. Prices charged for the sale of electricity and natural gas within Manitoba are subject to review and approval by the PUB. The Consumer Price Index (CPI) for Manitoba is often used by stakeholders as a benchmark to determine the reasonableness of proposed Manitoba Hydro general rate increases for electricity and for the non-commodity portion of natural gas rates. Manitoba Hydro uses projections of the U.S GDP implicit price deflator to forecast future electricity export prices in the opportunity market. Other, more specific, inflation indices are also used in purchasing and sales contracts negotiated by Manitoba Hydro. In addition to CPI, composite inflation indices associated with generation resources are developed and used to reflect the forecasted costs of specific commodities that are not included in the CPI basket of goods and services.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The impact of a short duration period of inflation on the achievement of Manitoba Hydro's financial objectives and on the priority of providing excellent customer value which includes affordable rates for all Manitobans has historically been relatively small as a large portion of costs are capitalized, spreading the impact out over a longer period of time. However, as capital requirements grow for system improvements and expansion, the effects of sustained high inflation, especially with specific commodities associated with new generation or transmission construction, are more marked.. Moreover, as inflation changes, the monetary policy response from the Bank of Canada may result in impacts on Manitoba Hydro.

Current indications for Canada and the United States are that inflation expectations in the general economy are low and stable With respect to near-term outlooks of inflation for specific commodities that are significant inputs to Manitoba Hydro's capital projects, IHS Global Insight expects base metal prices to remain within a relatively tight range for the foreseeable future due to reduced demand. There has been a clear slowdown in metal and other commodity consumption growth in emerging economies such as Brazil, India, China and Indonesia and this slowdown has created an oversupply of steel products. IHS attributes the shift from strong economic activity in Asia to sluggish emerging-market demand growth and a tighter U.S. monetary policy that has weakened investor interest in commodities. In addition, sustained low oil prices over the past 18 months has caused activity in the Alberta oil sands to slow down resulting in a tempering of construction labour costs throughout western Canada. With that said, experience from the recent past has proven that sustained higher costs display resiliency to downward pressures such as reduced electricity consumption. Higher construction and operating costs driven by increases in aggregate demand both domestically and internationally may have substantial impacts on the costs and economic benefits of capital projects. Prolonged higher levels of inflation will begin to have a more significant impact if export prices do not reflect the same inflationary trends in concert with rising expenses and the costs of new plant coming into service. Inflation rates in Canada and in the US, the main export market, tend to follow similar long-run patterns, but can deviate in the short-term. Higher levels of inflation for Manitoba Hydro's costs which are not offset by similar increases in export revenues could place pressure on domestic rates for electricity and/or gas. Further, as inflation increases, there is also a risk that interest rates will be increased by the Bank of Canada, which can compound the effect cost increases will have on the Corporation.

RISK TREATMENT:

To the degree that export revenues rise as a result of corresponding increases in inflation in export markets, they can provide an offset to the higher costs of labour and materials. The Corporation's budgeting process typically imposes limits of inflation or less on baseline spending plans. With the continued downward pressure on export revenues, the Corporation has further implemented cost constraint measures. During the period of cost estimating and budgeting for major capital projects, the Corporation does not have an offset or hedge to manage the risks associated with increases in specific commodities which emphasize the need for continued cost constraint measures. Once the Corporation is in the process of negotiating contracts for major capital projects, mitigating accommodations such as including specific escalators can be incorporated. The future impacts on consumer rates due to higher capital costs will depend in part upon the long term price growth of energy exports.

Likelihood	Med
Consequence	Med
Tolerance	Med

CATEGORY: B. Financial

TITLE: 5. Upstream Gas Cost Uncertainty

RISK: A significant increase in the cost of natural gas could result in an adverse reaction from customers.

DESCRIPTION:

The cost of the physical natural gas commodity, transportation and underground gas storage represent approximately 60% of the Company's total overall annual natural gas revenue requirement in a normal weather year. Manitoba Hydro buys Primary Gas from the Western Canadian Sedimentary Basin ("WCSB") at a fairly constant level over the course of the year, with winter purchases flowing directly to customers, while a significant portion of summer purchases flow to storage. In the winter months, gas purchases flowing from the WCSB are supplemented by gas withdrawn and transported from storage. In addition, Supplemental Gas supplies are also purchased throughout the year for both immediate consumption in Manitoba and for replenishing storage inventories for use the following winter. The Corporation is currently prohibited by regulatory order from the PUB from hedging customers' exposure to volatile natural gas market prices.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Financial - The financial exposure of significant gas cost increases to the Corporation is minimal as long as gas costs are considered to be prudently incurred. This is because the cost of gas for the quarterly rate primary gas service is considered a flow-through for rate-setting purposes and follows a prescribed regulatory process. There is some market price risk associated with the Fixed Rate Primary Gas Service whereby commodity gas is acquired at market prices while selling to customers at fixed rates for a given contract duration. If the self insurance premium imbedded in the fixed rate is insufficient and residual market price risks are not properly managed, there could be program losses.

Reputation – Although natural gas market price volatility has generally been greatly reduced during the past few years, there was a short term sharp increase in Supplemental Gas costs in the first quarter of 2014 due to the extreme cold winter and the need to purchase additional supply If the extreme upward price volatility experienced during this period continued or the 2000 through 2008 period were to return and continue, the Corporation could experience an adverse reaction from customers because of their exposure to a sharp increase in their cost of gas. In addition there continues to be significant upward cost pressure for transportation services on the TransCanada Pipelines Ltd. ("TCPL") Canadian Mainline, to which Centra is currently captive, due to underutilization of the pipeline. This market risk is compounded by a proposal by TCPL to segment the Mainline's cost allocation and tolls post – 2020 between the underutilized Western Mainline (on which Centra moves gas) and the highly utilized Eastern Ontario Triangle. The outcome is highly uncertain at this time however. The National Energy Board has approved segmentation in principle and intends to review it and other pricing issues in future proceedings.

RISK TREATMENT:

The Corporation has a number or risk measures in place to manage gas cost increases, including: (1) The Rate Volatility Management Program which includes setting quarterly Primary Gas rates based on the 12-month forward average of futures prices to remove seasonality from rates; disposing of Gas Purchase Variance Account ("PGVA") balances over the coming 12-month period; the physical price hedge provided by filling underground storage inventory during the seven-month summer period and then providing this gas to customers during the five winter months at a single average inventory value; and the management of all other non-Primary Gas PGVA's over the November through October gas year period to further reduce the rate volatility associated with bringing forward large residual balances for disposition in future periods. (2) Giving customers who are concerned about potential future rate volatility the option of either subscribing to MB Hydro's Fixed Rate Primary Gas Service ("FRPGS") or contracting for a fixed Primary Gas rate with a third-party marketer under the Western Transportation Service. (3) Mitigating market price risk associated with the Fixed Rate Program by charging an 8% self insurance risk premium in rates and establishing risk thresholds (customer migration, volumes, risk margins) that will trigger a review of the FRPGS program. (4) Providing all customers, whether on the Corporation's default Primary Gas rate, or on a fixed Primary Gas rate under either the FRPGS or with a marketer, with the option to fix the amount of their overall monthly natural gas bill by enrolling in the Equal Payment Plan. (5) Participate in TCPL's. regulatory proceedings before the National Energy Board ("NEB") as appropriate in order to ensure that Manitoba natural gas consumers' interests are adequately represented., as occurred at the NEB RH-001-2014 proceeding.

Likelihood	Low
Consequence	Low
Tolerance	Med

CATEGORY: B. Financial

TITLE: 6. Gas Derivative Instruments

RISK: By their nature, derivatives have various risks (e.g. Regulatory, market, operational) associated with them which must be managed.

DESCRIPTION:

Manitoba Hydro utilized financial gas derivatives to manage market price associated with the Fixed Rate Primary Gas Service from the inception of the program until August, 2011. Changes to the program were approved by the PUB whereby derivatives will not be used in the normal course and a self insurance premium will be employed to manage market price risk. There are however some derivative positions outstanding that will not fully expire until 2016.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES

The Corporation continues to be exposed to the risk of financial losses for outstanding positions in cases where market prices fell significantly after the placement of past hedges in support of FRPGS offerings and customer demand for those offerings was materially less than that forecast. This could result in excess out-of-the-money hedges on unsubscribed volumes having to be written off against Manitoba Hydro's retained earnings. The key operational risk borne by the Corporation with respect to gas hedging activities relates to the execution of the hedge purchase transactions. Similarly, if credit limits are not established and managed, and the appropriate legal documentation is not put into place, a credit default could give rise to a financial loss. Credit risks must be identified, measured and managed.

RISK TREATMENT:

The Gas Supply Risk Management Committee in coordination with the Executive Committee has oversight over all derivative related transactions and practices. A well structured control framework continues to be in place; however no further derivative transactions will be entered into in the normal course and the exposure to current derivatives is low.

Likelihood	High
Consequence	M High
Tolerance	Med

CATEGORY: B. Financial

TITLE: 7. Financial Targets

RISK: Weak financial ratios may impede the opportunity to adequately address aging infrastructure and invest in new major generation and transmission.

DESCRIPTION:

The Corporation is subject to increased risk if it fails to maintain an adequate capital structure. This is defined, under revised financial targets approved in December 2015, as maintaining a minimum debt/equity ratio of 75:25, an annual Earnings Before Interest, Taxes and Depreciation and Amortization (EBITDA) interest coverage ratio with a minimum target of 1.80 and a capital coverage ratio (excluding major new generation and transmission) of greater than 1.20. It is recognized that financial targets may not be achieved during years of major investment in the generation and transmission system.

The current 20-year Integrated Financial Forecast (IFF15) projects that the equity ratio deteriorates to 12% by 2021/22, largely due to capital investments in generation, transmission and distribution, as well as softened export market prices before recovering to the target 25% by 2031/32. Reduced income levels also weaken the interest coverage below the 1.80 target for a period of 9 years until income levels are sufficient for the target to be met in the remaining years of the forecast as a result of the 3.95% even annual rate increases and additional export revenues following the in-service of Keeyask. Capital coverage is below target for the first 6 years of IFF15 due to capital requirements to replace aging infrastructure and address capacity constraints. Thereafter, cash flows are sufficient to enable this target to be met in the remaining years of the forecast.

Manitoba Hydro is prepared to accept weaker financial ratios during the period of significant capital investment in order to spread the recovery of costs from customers over a longer period of time and minimize the impacts to customer bills. However, it will be necessary for Manitoba Hydro to demonstrate progress towards attaining its financial targets to credit rating agencies and other stakeholders over the long-term.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

An inadequate capital structure could jeopardize the self-supporting naturkae of Manitoba Hydro’s debt and negatively impact the credit ratings of the Province. As well, an inadequate capital structure could lead to the need for higher rate increases and volatility in rates.

RISK TREATMENT:

The risk of an inadequate capital structure is mitigated by: (1) formally adopting and periodically updating appropriate financial targets such as the debt/equity ratio, interest coverage and capital coverage; (2) making annual contributions to retained earnings sufficient to maintain these targets; and (3) achieving these annual contributions through a combination of cost controls, export revenues and regular reasonable domestic rate increases even in years with favourable water conditions. The latter is necessary, recognizing the unpredictability and potentially severe impacts of individual drought years.

Likelihood	High
Consequence	Low
Tolerance	Med

CATEGORY: B. Financial

TITLE: 8. Energy / Fuel Price Volatility

RISK: Market energy / fuel prices are high when Manitoba Hydro requires additional energy supply or low in adverse economic cycles resulting in low export prices.

DESCRIPTION:

Manitoba Hydro is subject to significant price risk on power sales and power and gas purchases as a result of energy price volatility. Recent history has demonstrated that energy prices in the short term are volatile. There is a risk that the price of purchased energy and natural gas will be high due to energy price and/or due to limitations in the mid-western United States transmission system (i.e. congestion). The impact of the energy price volatility is the greatest in a drought where under lowest flow conditions the Corporation may have to generate about 3 million MWh from gas-fired generation and purchase in excess of 7 million MWh from the market. Conversely, even under more favourable water flow conditions, opportunity sales revenues may be lower than forecast because of lower opportunity prices due to factors such as adverse economic conditions and / or low fuel prices. Such economic cycles may last several years and could result in lower than forecast revenues. This risk profile is related to Commodity Availability (C.5) and Water Supply Variation/ Drought (C.1)

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

While there is no risk of a significant drought in the current year, Manitoba Hydro continues to experience lower than forecast export prices that despite favourable water conditions, is resulting in a significant reduction in revenues compared to previous long term export revenue forecasts. It is very difficult to hedge the price risk for opportunity energy on a long-term basis due to the uncertainty as to whether this energy will be available in any given year.

The risk resulting from high fuel / purchased energy prices would significantly reduce the Corporation's ability to maintain stable rates for Manitoba customers were it to materialize during severe drought. Maximum exposure to this risk occurs during the winter demand period when gas-fired generation is required to meet peak loads and year round during drought conditions when gas-fired generation is required for energy supply. The risk from low prices for opportunity export energy would reduce Manitoba Hydro's equity compared to forecast and could result in rate increases.

Should a severe drought occur in 2015/16, the Corporation is exposed to a risk from energy price volatility estimated to be on the order of $200 million per year should fuel prices double compared to the prices assumed in the IFF. This $200 million figure is on top of reduced revenue of $300 million at expected export prices due to reduced flows in a severe one year drought. Past volatility in natural gas prices indicates that a doubling of gas prices compared to forecast is quite possible, but given the current supply situation appears to be unlikely in the near term. The overall cost of a drought has been reduced significantly since 2008/09 as a result of the economic decline and low natural gas prices.

RISK TREATMENT:

The Corporation's strategy in managing risk due to an adverse cycle of low export prices is largely based on having sufficient retained earnings. A number of changes in the power and energy market design over the last 10 years have improved the market liquidity and helped to reduce Manitoba Hydro's exposure to short-term energy price volatility and congestion pricing. The creation of an open, competitive market in the US has resulted in mechanisms for financial settlement, financial transmission rights and the use of brokers, which allow Manitoba Hydro to obtain more competitive pricing on imports. Since the 2003/04 drought, Manitoba Hydro has also secured almost 100% of the firm import transmission from the US, which will allow Manitoba Hydro to import power with lower risk of curtailment while not exposing Manitoba Hydro to non-competitive pricing for the use of another party's firm transmission. One objective of Manitoba Hydro's export strategy is to maintain a diverse portfolio of export products to mitigate exposure to price volatility.

Likelihood	Low
Consequence	Low
Tolerance	Low

CATEGORY: B. Financial

TITLE: 9. Power Financial Instruments

RISK: By their nature, financial instruments have various risks associated with them which must be managed.

DESCRIPTION:

Manitoba Hydro participates in the MISO and IESO standard markets. Prior to the advent of these standard markets, all of Manitoba Hydro's export sales and purchases were executed via physical bilateral transactions with inter-connected customers and utilities. With the introduction of these markets, Manitoba Hydro gained the capability to utilize financial instruments to settle contracts and hedge physical flow. Approved financial instruments are: (1) Contracts for Differences and/or Swaps (including MISO FinScheds); (2) MISO Auction Revenue Rights (ARRs) MISO Financial Transmission Rights (FTRs) or IESO Transmission Rights (TRs); (3) Virtual Bids and Virtual Offers; and (4) Put and Call Options for electricity and natural gas.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Inappropriate use of financial instruments would expose Manitoba Hydro to costs beyond those necessary for the prudent management of its assets or load obligations.

RISK TREATMENT:

Manitoba Hydro has a Board approved Wholesale Export Power Policy that governs Manitoba Hydro's export market activities including the use of financial instruments. In addition an Export Power Risk Management Committee provides executive oversight of the management of the energy supply and financial risks as a result of Manitoba Hydro's participation in the export market. In addition, a management committee approves bid/offer strategies and oversees all major transactions.

The Wholesale Export Power Policy governs the use of all financial instruments related to the purchase or sale of power/natural gas. The Approval Authority for Wholesale Power Related Transactions (P190-1) sets out volume limits, approval and execution authorities and limits by transaction type in accordance with the Wholesale Export Power Policy. Front, middle and back office duties are segregated. Manitoba Hydro uses a state-of-the-art trading, scheduling, billing and settlement system to record all physical and financial transactions.

Manitoba Hydro ensures that appropriate master agreements are in place to govern all financial instrument transactions.

As per the Wholesale Export Power Policy and the Approval Authority for Wholesale Power Related Procedures, financial instruments are required to have a high level of certainty that they will be backed by energy supplies at the time the contract is entered or the transaction is executed. This restriction ensures that financial instruments are supported by Manitoba Hydro's underlying physical power position and that financial instruments are not utilized in a speculative manner.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: B. Financial

TITLE: 10. Liquidity

RISK: Having sufficient cash or cash equivalents to meet financial obligations as they come due.

DESCRIPTION:

Liquidity risk refers to the risk that Manitoba Hydro will not have sufficient cash or cash equivalents to meet its financial obligations as they come due. Liquidity risk can generally be subdivided into two categories: 1) operational liquidity risk and 2) market liquidity risk.

Operational liquidity risk arising from the availability of internally generated cash flow from operations is most pronounced for Manitoba Hydro during drought conditions as cash shortfalls occur.

Market liquidity risk has become elevated due to the high levels of required debt financing and evolving investor responses to changing financial market conditions. During 2015, issuance was characterized by periods of volatility and uneven market tone.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Liquidity challenges arising from cash shortfalls would have potentially significant business and reputational consequences.

RISK TREATMENT:

The Corporation closely monitors its cash receipts and disbursements on a daily basis as part of regular cash balancing activities, and also monitors short term debt balances and forecasted cash requirements.

To support the Corporation’s temporary cash requirements, the Manitoba Hydro Act grants the Corporation the power to issue short term borrowings in the name of the Manitoba Hydro-Electric Board up to a limit of $500 million and to have this debt unconditionally guaranteed as to principal and interest by the Province of Manitoba. With the high levels of Manitoba Hydro’s cash requirements in the next few years, this short term facility provides less than two months of cash requirements.

To ensure smooth business continuity and financing flexibility during periods of intensive capital expenditures and uneven market tone, Manitoba Hydro has expanded its practice of maintaining positive cash balances. Manitoba Hydro’s liquidity guideline is to be funded approximately three months in advance of the Corporation’s cash requirements. Sinking fund balances, used to accumulate cash to repay future debt maturities, are another source of cash but are a restricted source of liquidity as the balances can only be withdrawn for debt maturities. In the next few years, in order to optimize the Corporation’s liquidity practices and to reduce finance expense, Manitoba Hydro will seek to minimize its sinking fund balances where feasible.

Likelihood	High
Consequence	High
Tolerance	Med

CATEGORY: C. Environmental

TITLE: 1. Water Supply Variation / Drought

RISK: Reduced water supply impacts generation output

DESCRIPTION:

Variation in water (fuel) supply is a fundamental characteristic of a predominately hydro system. Actual annual hydraulic generation will vary from the long term average of all flow conditions assumed in the planning process with lower than average flows occurring approximately 40% of the time. Reduced water supply has a direct financial impact through reduced hydro generation and in turn reduced export revenues and/or the need for more expensive replacement of supply

Water Supply Variation/Drought risk is defined as a change in revenue due to deviations from average flows, under expected export market prices. The overall cost of a drought to the Corporation is a combination of this Water Supply Variation/Drought risk (i.e. volumetric risk) and the Short-Term Energy Price Volatility / Fuel Price Volatility (B.8). The possibility of a drought more severe than the drought of record is discussed in Extreme Drought-Shortfall of Energy Supply (D.2).

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Reduced water supplies impact the Corporation's ability to maximize net export revenues and maintain the projected electricity rates for Manitoba customers. The severity of impacts ranges from relatively modest costs due to subtle change in the timing of inflows, up to extreme financial losses as a result of a multi-year drought. The lost revenue due to a five year drought at expected export prices was estimated to be $1.9 billion (IFF 15) including financing costs. Risk due to Energy / Fuel Price Volatility (B.8) would be in addition to this amount.

Regulation changes that limit hydraulic operating flexibility may reduce dependable energy and, consequently, reduce net export revenue and add costs due to advancement of the in-service date for new generation. Similar effects may be realized if regulation changes upstream of Manitoba or climate change impacts alter the timing or supply of flows entering the province.

RISK TREATMENT:

The Corporation intends to have adequate retained earnings to protect against a repeat of the worst recorded drought. In addition, the Corporation constantly monitors supply conditions, updates inflow forecasts, and reviews long-term weather forecasts.

At least quarterly, the Export Power Risk Management Committee (EPRMC) reviews a quantitative assessment of the current water supply conditions and any potential financial impacts resulting from variations in market prices and water supplies including the consequences of extreme drought. During periods of increased risk, the EPRMC increases the frequency of its meetings to review and approve risk tolerances, risk mitigation strategies and significant operational decisions. The Manitoba Hydro Electric Board is also kept updated in periods of increased drought risk. Energy purchase decisions are timed and distributed appropriately to protect against price risk of electricity purchases. To protect against gas price risk, purchases are structured such that a portion of the gas needs are purchased in advance, with the option to take, store or sell the fuel.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: C. Environmental

TITLE: 2. Climate Change

RISK: A changing climate can impact hydro-electric generation, Manitoba load and export revenues.

DESCRIPTION:

There is a risk that climate change impacts could result in reduced overall hydroelectric production due to lower annual runoff, changes to the variability of the water supply, and/or extreme flooding. There is also a financial risk that climate change will increase temperatures in Manitoba which will result in increased air conditioning loads in the summer and reduced heating loads in the winter and thereby displace export sales and potentially reduce overall revenues.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Reduced hydroelectric generation would lead to a reduction in overall energy supplies to meet firm load and reduced surplus energy available for export resulting in lower export revenues to the Corporation. Extreme flooding would increase spilling at the generating stations and raise challenges for the operation which could lead to loss of potential energy supplies.

An increase in average temperature due to climate change has the potential to increase cooling loads in the summer and reduce heating loads in the winter. Increased summer loads will potentially displace on-peak export sales. Reduced heating loads in the winter will increase on-peak and off-peak export sales which will offset some of the revenue losses in the summer. In addition, reduced winter loads could delay the in-service date of future generation options if the requirement for new resources is driven by a shortage of winter peak capacity.

RISK TREATMENT:

Manitoba Hydro is currently engaged in understanding climate change processes and is actively pursuing studies to develop future climate change scenarios for its power system. These climate scenarios are being developed by using the direct outputs from an ensemble of international Global/Regional Climate Models and by using post-treatment methods to scale the information to match Manitoba Hydro’s hydraulic system. These climate scenarios can then be used in combination with hydrological and load forecast models to develop an ensemble of future conditions, which can be tested in Manitoba Hydro’s generation system models as a step towards reducing the uncertainties regarding future water supply, power demands and corporate finances.

Manitoba Hydro collaborates with a number of national and international bodies involved in climate change including the Ouranos Consortium, University of Manitoba, and the Center for Energy Advancement through Technological Innovation to ensure its studies meet the industry standards and to stay informed about the latest advances in the climate change field. Manitoba Hydro expects to have sufficient lead time to adapt its operations and resource plans to accommodate long-term impacts of climate change.

Likelihood	Low
Consequence	High
Tolerance	Med

CATEGORY: C. Environment

TITLE: 3. Operational Impact and Infrastructure

RISK: Environmental concerns real or perceived can negatively impact corporate operations.

DESCRIPTION:

The Corporation operates its existing electricity supply facilities and systems on a continuous basis to meet the energy needs of its customers. While the Corporation goal is to minimize operational impacts on the environment there still remains a certain amount of negative impact. The principal risks the Corporation is faced with are interruption of operations, and/or, restrictions on how operations are carried out. These risks arise as a result of pressure from changes in stakeholder sentiment, changes to licences and/or legislation and high profile noncompliance(s) and/or environmentally damaging event(s).

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The implications of imposed restrictions on facility and system operations can vary considerably and if significant could ultimately impact the operations of the Corporation. These restrictions could impact hydraulic/thermal generating facilities, water management programs, transmission facilities and distribution infrastructure. These restrictions could impact the costs/revenues of the Corporation and force future domestic rates to increase.

RISK TREATMENT:

Manitoba Hydro utilizes many different types of controls and tools to manage the environmental risk to its operations and infrastructure. These include but are not limited to:

- Management and staff whose primary responsibility is to help address environmental issues and risks that the Corporation is facing.
- An ISO 14001 registered Environmental Management Systems covering all corporate activities.
- Agreements with stakeholders suffering adverse affects from some of the Corporation’s developments.
- Identification of and responsiveness to stakeholder concerns.
- Water regime monitoring and communication with affected communities about forecasted water regimes.
- Conducting environmental research and monitoring programs that address societal expectations and meet corporate environmental management practices.
- Shaping and responding to public policy and keeping abreast of and influencing regulatory and licence changes.
- Continuously improving and implementing best management practices to anticipate and address environmental concerns.
- The development and implementation of Corporate policies and procedures intended to address environmental concerns
- Training of staff whose jobs may result in impacts to the environment.
- Emergency prevention and response planning.

Likelihood	Low
Consequence	High
Tolerance	Med

CATEGORY: C. Environment

TITLE: 3. Operational Impact and Infrastructure

SUBTITLE: 1. Legal - Species at Risk Act (SARA)

RISK: If Lake Sturgeon is listed as "Endangered" the Corporation could face restrictions on current operations, structural modifications to infrastructure, significant delays and high costs of development at Keeyask , and possible cancellation of new projects.

DESCRIPTION:

Almost all of the Corporation's hydroelectric generating stations are located where Lake Sturgeon are found. It is likely that at most generating sites infrastructure and operations have negatively affected the fish and/or their habitat to some degree. Due primarily to historical commercial overharvest, plus additional stressors including hydroelectric development and ongoing Indigenous domestic harvest, Lake Sturgeon populations have been severely depleted over the past 100 years and the species is currently under review for listing as endangered under the Species at Risk Act (SARA) at most locations in Manitoba. Decisions for Churchill River, Nelson River, Saskatchewan River, Winnipeg River, Red-Assiniboine Rivers and Lake Winnipeg populations are expected in early 2018, at the earliest.

If listed under the SARA, harm to individual fish will automatically be prohibited and protection of critical habitat will be required, once it is identified. The Corporation will immediately be at risk of non-compliance with the SARA at most of its facilities due to ongoing risk of harm to individual fish as they pass through facilities. The most likely protection measures that would be required by DFO are fish screens, provisions for upstream fish passage and flow modifications at existing generating stations. There would also be a possibility that the commissioning of Keeyask would be delayed while incidental take permits are secured. There could also be high costs for recovery measures potentially mandated under the SARA.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Affects: (1) The revenues the Corporation will receive from existing operations; (2) The ability to build future projects and meet future requirements for electricity supply; (3) The goal to strengthen working relationships with Indigenous peoples; and (4) The goal to maintain financial strength. It could entail increased mitigation costs to Manitoba Hydro and its First Nations partners on Keeyask (and potentially Conawapa were it to proceed), although it is expected that these would not be sufficient to make the project uneconomic.

RISK TREATMENT:

The Corporation is proactive in addressing this risk by: (1) Conducting a Lake Sturgeon Stewardship and Enhancement Program to assist in recovery of the species., (2) Negotiating and implementing a Memorandum of Understanding on Lake Sturgeon with the Manitoba Government to guide cooperation on Lake Sturgeon stewardship and research in the province. (3) Regular coordination with the Manitoba Department of Conservation and Water Stewardship (Fisheries Branch (4) Regular communication with staff from DFO to keep them informed about Manitoba Hydro's approach to Lake Sturgeon stewardship, current activities, progress and outcomes. (5) Establishing a process with DFO and MCWS for negotiating a Lake Sturgeon Conservation Agreement under the SARA, (6) Working with the CHA and CEA in pursuing changes to the SARA and/or its implementation (7) Informing newly elected Manitoba Members of Parliament, who will be involved in the listing decision, that the social and economic costs and risks of listing Lake Sturgeon far outweigh any potential benefits and is not needed to provide stewardship necessary for Lake Sturgeon recovery. (8) Encouraging the Province to continue to take action with the DFO (9) Expanding its long-term commitment to the recovery of the species through the membership in, and funding for the Kischi Sipi Namao (formerly the Lower Nelson River Sturgeon Stewardship Committee) (10)Working to establish Lake Sturgeon stewardship arrangements for the lower Churchill River.

Likelihood	Med
Consequence	M High
Tolerance	Low

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CATEGORY: C. Environmental

TITLE: 4. Reliability of Supply

RISK: On-going public scrutiny and further environmental licencing regulatory oversight could obstruct the Corporation's ability to build the necessary facilities required to provide a reliable supply of energy in a timely and cost effective manner.

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DESCRIPTION:

Concerns over the environment will influence the Corporation's future facility requirements by either placing highly restrictive conditions on their operations, altering the design specifications, delaying or ultimately denying their construction.

The environmental review process could result in excessive time and cost that would result in the commissioning of facilities well after their required in service dates. Time delays will expose the system to increased reliability issues.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

This risk will cause the system reliability to degrade by delaying project in-service dates, thus causing more service interruptions. The Corporation will face increased costs to satisfy these environmental concerns as more costly alternatives and mitigation measures will be required to meet these higher standards.

RISK TREATMENT:

The Corporation is proactive in addressing this risk by:

- Ensuring environmental implications of its actions are understood.
- Possessing the knowledge and skills to make the right decision that minimizes the environmental impact of these facilities.
- Being proactive in the sharing of information with stakeholders
- Increasing dialogue with government early on and throughout the process
- Promoting efficient use of resources.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: C. Environmental

TITLE: 5. Upstream Regulation and Water Withdrawals

RISK: Upstream regulation, water withdrawals or climate change may reduce water supplies and hydraulic generation.

DESCRIPTION:

Reduced water supply is a fundamental risk to the financial position of the Corporation. The peril associated with this risk is that future water supplies are on average lower as a result of upstream reservoir regulation changes and water diversions for irrigation or other purposes. Water supply may also be reduced as a result of climate change.

This risk profile is related to risk profile C.2 Climate Change.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Upstream regulation that affects the timing of inflows and diversion or extraction of water for irrigation or other purposes can limit the Corporation's ability to generate hydroelectric energy thereby increasing operating costs and reducing net revenues. Climate change may also cause similar effects if the consequence is reduced water flows or changes in the timing of flows that result in negative consequences for hydroelectric generation. In addition, these events can make the development of new hydraulic generation less economic and cause the advancement of future generation in-service dates.

RISK TREATMENT:

Since the upstream regulation is often influenced by outside entities such as Canadian Provincial and Federal Government, U.S. State and Federal Government, and other water resource management entities, Manitoba Hydro participates in providing input, where possible, to these entities. Manitoba Hydro participates in the Lake of the Woods Control Board process and can influence decisions of the Prairie Provinces Water Board. Manitoba Hydro is also a member of the Canadian Hydropower Association and participates in other organizations that have hydroelectric affiliations that can lead to discussions and cooperation.

The Corporation maintains a record of long-term streamflow data from 1912 to present which has been modified to reflect current use patterns accounting for increased consumption and regulation strategy changes upstream. This record is used for resource planning purposes. Manitoba Hydro is also engaged in developing an understanding of the potential impacts on water supply due to climate change in its watersheds. This activity is described in more detail in risk profile C.2 Climate Change.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 1. Loss of Plant (all property, all perils)

RISK: Loss of plant can affect the Corporation's finances, reputation and impact human life.

DESCRIPTION:

The Corporation is subject to a variety of scenarios whereby physical plant is exposed to loss. The types of value exposed to loss include property, net income, liability and personnel. Loss from a property value perspective includes equipment breakdown, loss of facility, dam failure, and other property damage.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Potential impact from a loss of plant infrastructure will affect the Corporation's ability to: continuously improve safety performance, provide excellent customer service from a reliability perspective, maintain our financial strength due to reduced revenues and increased costs, and maximize export power net revenues due to reduced availability.

RISK TREATMENT:

A risk management decision-making process is used to manage each exposure (identify exposure, examining feasibility of alternative techniques, selecting best technique, implement and monitor chosen techniques). Equipment failure, for example, is identified at the department level. Alternative techniques to deal with exposure include preventative maintenance (loss prevention), Reliability Centered Maintenance (RCM) and loss reduction (fire sprinkler systems, fire brigades). Alternative techniques to finance the property loss include risk retention and commercial insurance. Equipment failure from a net income exposure to loss is recognized at the department level and alternative risk control techniques are used such as spare equipment, replacement contracts for equipment or replacement energy.

The loss of a facility from a property value aspect is identified at the division/department level. Perils are identified and treatment determined. Risk control techniques include loss prevention and loss reduction. Examples include fire and wind resistive construction materials, smoke and heat detection units, and automatic sprinkler protection, dyking and other measures. Property insurance is purchased to finance losses to high valued locations. The loss of a facility from a net income exposure aspect is identified at the corporate/division level. Loss prevention and reduction control techniques includes duplication and segregation of exposure units, automatic sprinkler systems, emergency response plans and replacement contracts. The Corporation retains the risk financing cost of net income losses resulting from the loss of a facility.

The impact of loss of a facility from the perspective of safety and customer service is identified at the corporate/division level. Loss prevention and reduction control techniques in place to mitigate other impacts are also designed to mitigate the impact on safety and customer service. Techniques include duplication and segregation of exposure units, emergency response plans, automatic sprinkler systems, and replacement contracts.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 1. Loss of Plant

SUBTITLE: 1. Water Retaining Structures and Flow Control

RISK: The failure of water retaining structures could have impacts which range from insignificant to catastrophic, and could include loss of life, financial/economic costs, damage to the environment, and loss of system reliability, reputation, public confidence and heritage resources.

DESCRIPTION:

Manitoba Hydro operates 17 major facilities for hydro power generation and water storage, comprising an inventory of some 220 individual dams and dykes with a net asset value exceeding $4 billion and an installed generating capacity of approximately 5000 MW. The facilities were designed to meet established standards at the time of their construction and are systematically maintained and upgraded to ensure they meet current standards and operate safely. The facilities are the major source of system supply for Manitoba Hydro.

Water retaining structures are vulnerable to different “failure modes” including external erosion (wave attack), internal erosion (piping), sliding or overturning, inability to pass sufficient water during floods resulting in overtopping of water retaining structures, or inability to pass sufficient water due to spillway equipment failure or personnel errors resulting in overtopping of water retaining structures. Terrorism is also a recognized risk to the safety of water retaining structures. Each facility’s location, its proximity to other Manitoba Hydro facilities, the closeness of human settlement and environmental factors are some of the major considerations determining the extent of impacts of a dam or dyke failure. Water retaining structure failures cannot generally be controlled once they are initiated and mitigation/remediation is only feasible once flows have abated following the flood event or once the forebay has emptied. Hence, downstream effects and damage can be catastrophic.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Possible consequences include loss of life, financial/economic costs, environmental damages, reduced system reliability (worst case scenario is a maximum loss of over 70% of Manitoba Hydro’s generating capacity for years), and loss of reputation and public confidence.

RISK TREATMENT:

The risk of dam breach is addressed by ensuring the integrity and reliability of water control equipment and structures through diligent maintenance and vigilant surveillance, as well as preparing for emergencies, as per the Canadian Dam Association (CDA) Dam Safety Guidelines. The Corporation has established a Dam Safety Program based on the CDA Dam Safety Guidelines. The principal activities for managing risks include:

- Surveillance inspections, instrumentation monitoring, and engineering analyses of water retaining structures and related flow control equipment within a consequence category framework.
- Systematic utilization of failure modes-based condition assessment techniques.
- Preparation, maintenance, training and testing of Emergency Preparedness Plans (EPPs).
- Periodic Dam Safety Reviews by independent consultants to examine the adequacy of the design, construction, operation, maintenance, surveillance, and emergency preparedness plans

Water retaining structures and flow control equipment are designed and assessed according to the CDA Guidelines and maintenance programs address dam safety deficiencies of existing in a prioritized manner. Operating guidelines for each facility are established with inherent dam safety considerations.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 2. Extreme Drought – Shortfall of Energy Supply

RISK: Extreme drought with a severity worse than the drought of record has the potential to cause a shortfall in energy supply.

DESCRIPTION:

The Corporation's generation and transmission facilities are designed and operated to ensure firm demand can be supplied given a repeat of the lowest river flows since 1912. Since the Manitoba Hydro system is comprised primarily of hydroelectric resources, the design criterion translates into a requirement for power resources that will be able to supply sufficient energy under the condition of a repeat of the lowest river flows on record. In the circumstance of an extreme drought that is more severe than the worst on record, there is the possibility of insufficient energy supplies being available to meet firm load demands, which will in addition, result in extreme financial and reputational impacts to the Corporation. This risk profile is related to risk profiles Energy / Fuel Price Volatility (B.8) and Water Supply / Drought (C.1).

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The peril of an extreme drought, one that is more severe than the worst on record of approximately 100 years, may limit the Corporation's ability to provide dependable power to its customers especially those served under long term export contracts. There is the potential that some portion of the firm domestic load would have to be curtailed through enforced conservation. In addition to service limitations, there would be severe financial impacts to the Corporation in excess of those estimated for the worst drought on record (ref. profiles C.5, B.8 and C.1). Financial impacts would extend to the Corporation's domestic customers through rate increases and the Province by requiring debt financing.

RISK TREATMENT:

Water flows worse than the drought of record would be deemed to be a force majeure event under Manitoba Hydro's long term export contracts. Therefore to the extent that Manitoba Hydro needed to curtail export deliveries to serve domestic load, Manitoba Hydro anticipates that it would have the right to curtail without penalty. To the extent that these actions were insufficient and domestic energy shortages were occurring in spite of maximum imports, partial curtailment of domestic load may be required.

Non-normal hydraulic operations could also be required during a drought more severe than the drought of record. This may include operating reservoirs outside of the normal range for power production. For example, the Lake Winnipeg Regulation Water Power Licence provides for operation below the minimum level for power production limit with approval from the Minister of Conservation. Non-normal operation may also include demand reduction measures such as public appeal for conservation, enforced conservation or rotating reductions of non-essential load (e.g. street lighting). To better quantify this risk, the Corporation has participated in a number of research initiatives, using both statistical techniques and techniques that employ indicators of past extremes such as tree-rings and lake sediments. Both initiatives are aimed at defining the probability of recurrence of the worst drought on record and the likelihood of more extreme drought events. However, the results of these research initiatives to date have not been able to provide definitive conclusions on the probability of drought. The best estimate is that the Manitoba Hydro system is designed for a 1 in 100 year drought event based on the fact that the design condition occurred once in the last 100 years of record.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 3. Prolonged Loss of System Supply

RISK: The Corporation is exposed to a catastrophic event resulting in prolonged loss of system supply and therefore not able to meet its energy supply requirements.

DESCRIPTION:

System Blackout due to the loss of key infrastructure, specifically: Dorsey Converter station or HVDC corridor and 500 kV line.. Reason for loss could be severe weather events such as tornado/downburst (Dorsey 1996, Elie 2007), wide front wind, combined wind and icing, lightning (Dorsey August 2007), sabotage, flood or fire.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Key potential impacts of a prolonged loss of system supply are:

- Unable to serve Manitoba load continuously (approximately 42% of the time based on 2013 calendar year loading profile). Depending on time of day and time of year, a deficiency of up to 1550 MWs resulting in rotating blackouts throughout the province. Deficiency increases with time due to load growth and assumes the availability of maximum energy imports from neighboring regions.
- Severely impact business operations and the Manitoba economy.
- Unable to provide customers with exceptional value due to high infrastructure replacement costs.
- Threat to public safety due to an inability to supply energy needs during the coldest months of the year.
- Prolonged rolling blackouts affecting customer service and potentially damaging corporate assets such as breakers.
- Potentially weaken the Corporation's financial strength due to reduced revenues from domestic and export energy sales, and increased costs for infrastructure replacement and the purchase of import energy.
- Loss of reputation as a dependable source of supply in the export market.
- Potential political and legal consequences for the Corporation.

RISK TREATMENT:

Key risk treatment activities are:

- System expansion involving Bipole III (2018) re and a new 500 kV Interconnection to the U.S (2020)
- Additional AC network generation (Keeyask 2019)
- Hardening of Dorsey facilities
- Implementation of physical and cyber security upgrades
- Emergency Preparedness initiatives - Long term deficiency plan for managing the available resources, load and system following loss of infrastructure.
- Spare infrastructure material and equipment inventory to enable timely re-building and restoration of potentially affected assets.
- Short term emergency energy agreements with Ontario, Saskatchewan and U.S. utilities
- Mutual aid agreements with Ontario, SaskPower and U.S. utilities for labour, materials, and equipment.
- Corporate Emergency Response Program.

Likelihood	Med
Consequence	Med
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 4. System Shutdown (Short Term)

RISK: The Corporation is vulnerable to an event(s) that would cause a short term loss of system supply (electricity) resulting in the inability to meet its energy supplies requirements**.**

DESCRIPTION:

Partial or total system blackout for 8 hours or as long as several days, caused by extreme weather events, sabotage, human error, equipment failure, or an inability to import energy from the market.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

- Unable to meet customer load serving obligations and expectations.
- Threat to public safety due to inability to supply energy needs.
- Threat to Corporate reputation.

RISK TREATMENT:

- System expansion involving Bipole III (2018), an additional 500 kV interconnection to the US (2020), St. Vital – LaVerendrye 230kV transmission line (2021), and AC breaker enhancement projects (2016-2018).
- Additional AC network generation (Keeyask 2019)
- Standard Operating Practice agreements with Ontario and SaskPower for short term emergency energy.
- Restoration Plan, which includes local station restoration procedures (with/without communications) and restoration diagrams, that identify step by step restoration procedures.
- Annual participation in MISO's regional restoration drills and the development of its regional restoration plans.
- Semi-annual restoration training for System Operators.
- Annual restoration training for field staff.
- Disturbance Scenario training, such as annual ice melt training for System Operators.
- Station battery bank upgrade program.
- Regular testing of regional staffing plans that supports System Control Centre operation upon the loss of RTU communications.
- Annual black start testing at each black start facility.
- Compliance with NERC reliability standards
- Redundant communication systems (PAX, VHF, MSAT) in addition to the public telephone system.
- Storm tracker application and installed ice detection stations in ice prone areas of the province.
- Corporate Emergency Response Program.
- Actively participate and provide leadership in Congestion Management forums to exert influence on parties, such as MISO and other Congestion Process Management Council members, to ensure fair treatment of Manitoba Hydro in the formulation of industry congestion management practices.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 5. System Shutdown (Natural Gas)

RISK: Catastrophic system failure could result in an interruption of the supply of natural gas to approximately 267,000 customers in Manitoba. An associated risk is the impact on the electrical grid due to increased loading.

DESCRIPTION:

A secure and continuous supply of natural gas is critical, particularly during the coldest months of the year. TransCanada Pipelines ("TCPL") has five high-pressure lines entering Manitoba (with a couple of sections looped making some areas six lines on its Canadian Mainline. Manitoba Hydro's meter stations are tied into two of these five lines. At Ile des Chenes, MB (Station 41 on the Mainline), three pipes divert south to Emerson through which gas interconnects with Great Lakes Gas Transmission Company and Viking Gas Transmission Company in the U.S. The three remaining pipes continue through Manitoba in an eastward direction into Northern Ontario. Separate from TCPL and on a much smaller scale, Manitoba Hydro also relies on the TransGas Limited ("TransGas) and Many Islands Pipe Lines (Canada) Limited ("MIPL") systems for delivery of natural gas supply to the Swan Valley area of the province. Gas supply to the Swan Valley area of MH's distribution system via MIPL is from the TransGas system in Saskatchewan. Gas from one or more of three storage caverns in Melville, Regina and Moosomin can deliver gas that will flow to the Swan Valley area, depending upon the requirements and operations of the TransGas system.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

A catastrophic event could occur, resulting in a total or partial loss of supply of natural gas from the Mainline, TransGas or MIPL to the respective service areas of Manitoba for a period of four to six weeks. The potential impact could be significant. Manitoba natural gas customers could be left without natural gas for heating purposes, resulting in significant collateral damage. As well, an inordinate number of workers would need to visit each and every home at least two times before service could be restored. Gas supply connections would first have to be shut-off at all homes and then the homes would have to be entered when the lines are re-energized to ensure the appliances are re-lit and working properly. There could be substantial economic losses for customers and businesses arising from such a catastrophic event.

RISK TREATMENT:

TCPL has incorporated design practices to minimize the possibility of a catastrophic event occurring. While their large diameter, high pressure pipelines are all contained within the same right-of-way, there is physical separation between the pipes. The failure of any one segment of pipe is likely to have limited impact on the system. This design practice has proven to be effective during the course of several incidents over the past decade with the exception of the 2014 rupture of one of the Emerson laterals of the Mainline near Otterburne MB, which resulted in a loss of service to a number of communities in the south-east corner of the province.

In addition, TCPL has developed and employs a rigorous safety and inspection program. Regulatory oversight is provided by the National Energy Board. MIPL relies on a single pipeline and therefore does not have the same level of redundancy built into its system as the Mainline. MIPL does, however, employ a rigorous safety and inspection program. Regulatory oversight for MIPL is provided by the NEB.

As a result of the 2014 Mainline rupture, Manitoba Hydro has determined that Compressed Natural Gas should be used to help mitigate small scale outages during a natural gas supply interruption. For the 2015-2016 season, standby services have been retained from a supplier who has the proven capability and availability to supply requirements during a supply interruption for small scale outages. For the longer term CNG equipment and facilities are being purchased and constructed. The equipment being purchased will consist of two 170 mcf CNG trailers (capable of supplying small communities or critical loads), a decanting unit for off loading the CNG and a compressor station to allow for refilling the units locally.

An emerging risk in the coming years relating to the TCPL Mainline is that of the potential for significantly reduced physical redundancy and excess capacity on the prairies segment of the Mainline. TCPL appears to be taking steps to prepare for the decommissioning of two of the six lines currently running through Manitoba. In addition, TCPL plans to convert a third line to oil transportation as part of its Energy East project proposal. If these changes are undertaken, natural gas transportation capacity and redundancy on the TCPL Mainline will be reduced by approximately 50% relative to today.

Likelihood	Low
Consequence	Med
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 6. Technology

RISK: Unforeseen physical events could impact computer operations and this would affect business processes.

DESCRIPTION:

The Corporation develops, implements and manages information systems to support core business processes and provides a secure, stable computing infrastructure to support non core business processes.

Manitoba Hydro's Corporate IT environment is housed in 2 data centres, one located at 820 Taylor, one located at 360 Portage.

The factors that could lead to a loss of all or part of our computing environments are either physical such as fire, flood, HVAC or power failure, and major weather related disasters or human in nature resulting in sabotage to key IT system components. Specifically, Manitoba Hydro has no diesel backup for the 820 Taylor Data Centre.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The extended loss of Manitoba Hydro's computing environment may limit the Corporation's ability to provide customers with exceptional value (rates, service, public safety, reliability and power quality). A physical-event of significance could negatively impact all Hydro systems, with the exception of Energy Trading and the EMS/SCADA systems.

RISK TREATMENT:

Physical risks have been mitigated through the utilization of multiple computing facilities interconnected with high-speed data lines to reduce the risk of the failure of a single data centre. Improved data backup, recovery, and restore procedures have also mitigated risk. The two Winnipeg Computing centres are equipped with fire protection systems and are secured from unauthorized access. IT Services continues to work with Facilities, System Control and Station Design to investigate the costs and options of using the existing Diesel at 700 Harrow.

An initiative to formalize and harmonize the disaster recovery plans for key Information Technology Infrastructure components and Information Systems is currently underway.

A Corporate IT Security Assessment was done in 2014 on key IT functions and operations. It identified security gaps, level of risk and recommended mitigating actions to be undertaken.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 7. Concerned Stakeholders

RISK: Successful lobbying efforts by concerned stakeholders could restrict implementation of the Corporation's infrastructure requirements.

DESCRIPTION:

Increased concerns voiced publically (directly or through media) may influence regulatory bodies and Governments to place restrictions on and in some cases deny the infrastructure needs of the Corporation. As well, the review process over new facilities could become excessive in regards to time and cost due to the intervention of these stakeholders. This could result in commissioning of facilities after their required in-service dates.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Successful lobbying efforts by concerned stakeholders could result in adverse impacts on the infrastructure needs of the Corporation. These impacts could be financial and system operational and may ultimately have a negative effect on the Corporation's image, on degrading the reliability of supply from Transmission systems, and the ability to satisfy export sales agreements.

The impact of lobbying on higher profile projects such as BiPole III where delays have been imposed on the project and a resultant negative impact to reliability of supply to southern Manitoba is recognized. Lobbying also has an impact on other projects and some examples include Kilkenny Drive, Sage Creek, and now the Manitoba Minnesota Transmission Project (MMTP). In the instance of Kilkenny Drive, local lobbying resulted in delays on a subtransmission line that was required for reliability of supply. In the instance of Sage Creek, local residents raised concerns about a future Manitoba Hydro facility planned in a Manitoba Hydro owned right-of-way, which resulted in changes to the project. In both examples, local residents were objecting to Manitoba Hydro facilities being developed in their neighbourhoods. With respect to MMTP lobbying by various stakeholders could result in relocation of parts of the project, extra expense, and/or project delays.

RISK TREATMENT:

The Corporation addresses the concerns of stakeholders, where feasible, through mitigation measures. Manitoba Hydro encourages stakeholder participation in its projects early in the process which permits the identification of concerns and provides the opportunity to mitigate these concerns before they become larger issues.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: D. Infrastructure

TITLE: 8. Emergency Management Program

RISK: The Corporation is exposed to a catastrophic event, likely weather induced, that results in an extended outage of the electric and natural gas infrastructure with a limited ability to restore damaged infrastructure.

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DESCRIPTION:

System failure caused by an extended severe weather event similar to an ice storm challenges the Corporation's ability to respond and to maintain a minimum continuity of business operations

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

In today's interconnected world, all institutions depend on others to perform their daily activities. Manitoba Hydro provides essential services and has critical functions that must be maintained in the face of disruptions, emergencies, and catastrophic events

Since the creation of the Corporate Emergency Management Program in 2008, Manitoba Hydro has responded to many large scale power and natural gas outages. Manitoba Hydro infrastructure continues to be impacted by natural, manmade, accidental and deliberate events.

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RISK TREATMENT:

Manitoba Hydro revised the Emergency Preparedness Policy in 2015 to enhance and strengthen the Corporate Emergency Management Program. Also, the Executive Emergency Management Committee was created to provide oversight of the program and to directly support the Corporate Emergency Center during an event. Manitoba Hydro continues to develop and maintain emergency preparedness and response management plans for reasonably foreseeable emergencies and risks arising from natural or man-made events that pose a real or potential threat to:

- the safety and health of employees, contractors, and the general public
- the physical assets of the Corporation and related environmental protection
- the ability to generate, transmit and distribute electricity and distribute natural gas and provide related services, and
- the ability of the Corporation to continue business in the normal course

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: E. Human

TITLE: 1. Safety and Health

RISK: An accident will occur that will result in loss of life or significant injury.

DESCRIPTION:

Due to the inherent nature of the operational work performed by Manitoba Hydro employee safety is always of key concern to the Corporation. Beyond the human suffering element, are the tangible and intangible costs of incidents to the Corporation for compensation and benefits, lost productivity, loss of equipment, loss of revenue, and loss of public confidence.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Safety is the Corporation's principal goal. As such, safety is reflected in the Corporate Strategic Plan to ensure the Corporation has measures that safeguard the safety and health of Manitoba Hydro employees. The Corporation is focused on activities that promote accountability, safety and health leadership, safe work practices, strict compliance with environmental regulations, and preservation of employee health. These programs are put in place to reduce risk to a tolerable level and address any potential risk to the operations side of the business.

RISK TREATMENT:

The opportunity for an incident in the workplace is high. The Corporation has built upon the recommendations of the 2006 and 2015 Safety Improvement Process Teams to further address workplace risk and to change the safety culture to positively affect the resulting safety performance of Manitoba Hydro.

Significant changes planned for the 2015/16 year include: (1) Implementing a seven point safety enhancement strategy which includes annual executive site safety reviews; in-person reporting of serious incidents at EC meetings, and a modified safety stand downs as examples; (2) Developing corporate programs with an internal Rapid Response Team on Safe Driving, Close Call Reporting, and Human Error Reduction; (3) Promoting Manitoba Hydro's safety culture through research and recommend a strategy for a safety branding, marketing, promotion and recognition program; (4) Moving the Corporation beyond compliance by forming a new high performance Risk Prevention Services team (under Workplace Safety) dedicated to working with line management to proactively identify and eliminate risk; a forensic audit of operations/incidents with the intent to define improvement opportunities; and benchmark to industry standards for safety assessments of operations; (5) Implement a SAP Environmental Health & Safety module to address technical currency issues with the data management surrounding hazardous materials, as well as streamline and enhance the processes involved with incident management, analysis and reporting; (6) Managing Contractor Safety by revising contractor safety guidelines and incorporating the guidelines into the procurement tendering process to further development the contractor safety model; (7) Developing a program to identify arc flash and clothing ignition hazards and tasks and ensure that proper communication (including labeling of equipment) and protective measures are in place throughout the Corporation; (8) Safe Work Procedures program enhancement to ensure that employees have the safe work procedures that they need to assist in planning of work, reduce incidents and increase legal compliance with MR217; (9) Updating Safety Publications; and (10) Medical Screening improvements in the hiring process to analyze, evaluate, and modify current health evaluation steps in hiring process to ensure potential employees are fit for the work, reducing potential for on-the-job injuries.

Manitoba Hydro's international operations in developing countries exposes employees and their families to increased risk of disease, crime, or injuries from political, ethnic or religious conflict. A number of measures are taken to mitigate these risks, including providing employees with medical advice and medi-vac transportation, specialized location security advice, secure accommodations and having emergency response and evacuation plans.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: E. Human

TITLE: 1. Safety and Health

SUBTITLE: 1. Infectious Disease

RISK: A significant disease outbreak will impact a large number of employees resulting in major disruptions to business operations.

DESCRIPTION:

In response to the influenza A, H1N1 (Swine Flu) outbreak in April 2009 and the World Health Organization setting the pandemic alert level globally to phase six, Manitoba Hydro formed a task force on H1N1 to address the impact an infectious outbreak would have on the Corporation. The June 2014 outbreak of the Ebola virus in West Africa also had the potential to directly impact Manitoba Hydro's operations, as a number of Hydro employees seconded to the subsidiary company Manitoba Hydro International were working in West Africa at the time.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

While neither the H1N1 nor Ebola situations resulted in large scale outbreaks in North America, the impact of such a pandemic could be significant. There are predictions that suggest that up to 35% of the population could be impacted by the next global pandemic, or over 2,000 Hydro employees.

It is expected that a pandemic will result in significant and prolonged shortages with regard to the availability of employees, supplies and services. This may be enough to possibly compromise Manitoba Hydro's ability to provide safe, reliable service to customers. These impacts could further result in financial losses as revenues diminish putting added pressure on business operations. The inability to respond to system outages and customer requests could further impact the Corporations reputation. In addition, if the Corporation is unable to meet its export commitments, the utility could face potential liabilities.

RISK TREATMENT:

A pandemic is much more than just a problem for the health care system. It is a societal problem and is best managed by the coordinated participation and cooperation of governments, businesses, organizations and citizens. All parties need to be prepared for the potential outbreak of a pandemic. Manitoba Hydro monitors Health Canada briefings and directives, along with announcements from the World Health Organization (WHO) and local health publications. Employees that returned from West Africa were instructed by Hydro's Occupational Health Nurse to see their local doctor and report any symptoms.

Likelihood	Low
Consequence	Med
Tolerance	Low

CATEGORY: E. Human

TITLE: 2. Union/Employee Issues

RISK: Employee and union demands may not be satisfied which could result in inability to attract and retain skilled workers and / or possible labour disruption.

DESCRIPTION:

Interaction between the Corporation and its unions remain positive and co-operative. The IBEW collective agreement expired on December 31, 2015. A new three year renewal agreement negotiated between the Corporation and IBEW was ratified by the IBEW membership in early January.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Employee and union demands may not be satisfied which could result in strained relationships and potential strike.

RISK TREATMENT:

Minor issues and disputes arising during the year are resolved through informal discussions, or occasionally via the grievance and arbitration process.

A comprehensive bargaining framework has been developed that includes an early start to the process and agreement to limit the number of issues at the table.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: E. Human

TITLE: 3. Workforce Management

RISK: The Corporation will not be able to attract and retain the necessary qualified workforce to meet its operational needs.

DESCRIPTION:

The electricity and gas industry will be facing significant labour force challenges in the years ahead. For Manitoba Hydro, the workforce will be impacted by the following factors: retirements; new requirements resulting from major construction and technology changes; and, a changing labour market. Retirement will have the most significant impact on Manitoba Hydro's human resource requirements due to the movement of the large cohort of "Baby Boomer" employees into retirement. Retirements have shifted from a long-term average of approximately 80 employees per year to a new long-term average of approximately 190 per year. Approximately 1000 employees are expected to leave within five years.

Voluntary resignations at Manitoba Hydro are still fairly low (< 1% of the workforce annually) when compared to the industry average (>2%). More recently, as a result of our demographic shift and cyclical economic conditions, voluntary resignations have risen over the last two years (>1%).Despite Manitoba Hydro's low rate of attrition, utilities across Canada are experiencing the same Baby Boomer retirement phenomena. Manitoba Hydro employees possess skill, education and experience valuable to other utilities. The need to retain knowledge and ensure the right employees are ready to fill key positions at Manitoba Hydro is essential for long term success.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

A loss of knowledgeable and experienced employees has significant effects on all the areas of the Corporation including reduced reliability, increased cost of production, infrastructure project delays and decreased safety and productivity. By way of example, a reduced skill base in Major Capital Projects or Transmission would negatively impact the Corporation's ability to plan, construct, commission and put into service the significant projects currently underway. In the Gas Supply area, capacity management and gas supply strategies would be impaired as it could diminish Manitoba Hydro's ability to deliver reliable, safe, sustainable and competitively priced gas.

RISK TREATMENT:

To ensure knowledge retention and transfer and the supply of qualified candidates, the completion and maintenance of detailed succession plans for all key strategic and critical positions is necessary. The Corporation has implemented a comprehensive executive and senior management succession planning program including the identification of key positions and high potential employees. In addition, the Corporation is conducting succession planning at lower levels in order to identify high potential candidates earlier.

Manitoba Hydro continuously updates retirement forecasts and recruitment plans. This provides the multiple benefit of an accurate corporate-wide forecast of recruitment needs, the ability to respond to changing labour market conditions and the integration of this information into related financial forecasts and budgets. The Corporation has undertaken a more systematic approach to workforce planning and its ability to respond to the changing internal and external workforce environment. Training programs continue to be deployed to existing staff resulting in the development and improvement of technical skills in key areas. This assists in providing an adequate supply of qualified internal applicants to fill most vacancies. In addition, individual development is a priority for all staff through the completion of personal development plans on an annual basis. Although recent resignation rates at Manitoba Hydro have increased they still remain below normal rates however we continue to monitor departures and conduct exit interviews to collect information and make recommendations to address any concerns identified by departing individuals.

Likelihood	Med
Consequence	Low
Tolerance	Low

CATEGORY: E. Human

TITLE: 4. Technology

RISK: The rapid change in technology and work requirements may present challenges to system reliability, safety or productivity.

DESCRIPTION:

The pace of change in the workforce has never been as rapid as it is today with new technologies being developed that require staff to study and assess these technological changes and their usefulness within the current business and energy systems. This situation is further compounded by maintaining systems that are older which require appropriate interfaces with these new technologies and having fewer capable resources to analyze their impacts on the Corporation's present systems. The demographics of the workforce suggest that this risk will only increase in the future.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The Corporation's energy systems are both reliable and safe and its business systems are effective in meeting the Corporation's present day requirements. However, it is also important to adapt to technological advances that are required to meet changing conditions. It is conceivable that decisions or the lack of a decision in the future could reduce system reliability, safety or productivity.

RISK TREATMENT:

Manitoba Hydro has a research and development program that will help meet the needs of its business and operations, using both internal and external personnel and facilities. The primary thrust of this program will be the creation of new or significantly improved products and processes so as to obtain operational and economic benefits that will increase efficiency, reduce costs and improve the quality of service to the Corporation's customers.

The Corporation supports research and development projects carried out by students at Manitoba universities. The Corporation also supports research chairs, in collaboration with other industrial partners and with the Natural Sciences and Engineering Council (NSERC), or equivalent funding agencies at Manitoba universities, where the area of research is of direct and continuing interest to the Corporation.

New technologies are assessed to determine whether they will meet the further anticipated needs of the Corporation and detailed studies are performed when significant changes are planned so that negative outcomes are minimized. The current wind integration project which assesses the impacts of various levels of wind generation on system operations is an example of these types of studies.

All staff are encouraged to maintain their professional standards which includes keeping abreast of changes occurring within their discipline.

Likelihood	Low
Consequence	Low
Tolerance	Low

CATEGORY: F. Business Operational

TITLE: I. Supply Chain

RISK: Goods and services may not be available when required resulting in potential reliability issues, major delays, disruptions or complete loss of service to customers.

DESCRIPTION:

Managing the Supply Chain ensures the supply of goods and services are obtained in order to maintain and upgrade the current infrastructure and capital project work. The supply chain is critical in maintaining service to customers. Manitoba Hydro is dependent upon a variety of suppliers. Market trends impact the economical and financial aspects of business and the ability of suppliers to provide required goods and services on a timely basis.

The risk to Manitoba Hydro includes:

- Increased costs and lead-times due to supplier capacity, quality of workmanship and the global demand for raw materials and finished products,
- A limited diversity of supply due to company mergers, acquisitions or insolvency and a shortage of skilled labour in some trades,
- Loss and / or inability to restore service to customers due to poor supplier delivery, availability or quality of workmanship.
- Public perception and financial implications related to fraud, corruption and unethical business transactions stemming from tendering/contracting processes.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

A disruption in the supply chain impacts a majority of Manitoba Hydro's strategic goals and objectives. The Corporation requires a variety of critical goods and services to meet its obligations and commitments. An effective supply chain contributes to the Corporation's financial strength through cost minimization, planned upgrades and maintenance and the reduction in the downtime of our major assets.

Although the market has improved, the demand for construction services, particularly skilled labour, in some trades, is still a concern. In addition, recent tenders for construction have resulted in higher levels of participation, however in some cases tenders have exceeded budget estimates.

[redacted] Lead time is approximately 18 months and growing. Equipment failure may result in an extended period of reduced transmission capability of northern generation.

RISK TREATMENT:

The supply chain will continue to be managed by monitoring all market trends, identifying critical products and services, sourcing Strategic Alliance Partners, evaluating and tracking vendor performance, performing reference checks and validating vendor credentials, reducing single sources of supply, maintaining optimum inventories and identifying alternate sources of supply in case of emergency.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: F. Business Operational

TITLE: 2. Operational Controls

RISK: Unexpected operational outcomes adversely impact the Corporation's performance.

DESCRIPTION:

The Corporation has defined a vision, mission, operating principles and goals that are supported by measures, targets and strategies to direct corporate efforts toward common strategic achievements. The only manner in which the Corporation can be certain that its efforts are intended to result in a preferred outcome is to ensure that adequate controls are built into its processes. All efforts to direct, promote, restrain, govern and check progress can be described as a control. Where an operation is subject to adequate control, the odds of a positive outcome are enhanced. Where inadequate control is practiced, the result is less certain to be as intended. Where operational controls are ineffective the chance of the Corporation achieving its vision, or a subcomponent thereof, is reduced. Some of the types of operational risks that the Corporation faces include ineffective and inefficient operations, unreliable reporting and modeling systems and technology, non-compliance with applicable laws, regulations and internal policies, inability to attract and retain knowledgeable human resources and inadequate maintenance and replacement of infrastructure, to name a few.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES

The essential purpose of operational control is to encourage the accomplishment of the goals or objectives for which each employee or manager is responsible. Ineffective operational control increases the likelihood of an adverse outcome which could mean that a goal or objective is not met. The potential impacts of ineffective operational control are many and varied. They can range from infrastructure failure due to ineffective maintenance programs or systems to fraudulent activity to lawsuits and jail.

RISK TREATMENT

The governance process designed by the Corporation has objectives inclusive of promoting appropriate ethics and values; ensuring effective organizational performance management and accountability; effectively communicating risk and control information to appropriate responsibility areas; and effectively coordinating the activities of and communicating information among the Board, external and internal auditors, and management. This framework has been adopted with the intention of ensuring reliability and integrity of financial and operational information; effectiveness and efficiency of operations; adequate safeguarding of assets; and compliance with laws, regulations and contracts. The design of operational controls rests with line management. The effectiveness of control systems are subject to ongoing monitoring through the corporate governance process (inclusive of various committees, regulatory review, the Board, etc.) and are tested through an internal audit program and an annual external attestation audit. The Internal Audit Division Charter has been approved by the Audit Committee of the Board as is the annual audit program. Line management also engages consultants and experts as deemed appropriate to aid in the design of operational control systems and practices as well as to test the effectiveness of the implemented design. The Corporation also has an integrity program which complies with the requirements of the Provincial Whistleblowing legislation. The program provides a mechanism for anyone to report a situation in which operational controls are not functioning at any level.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: F. Business Operational

TITLE: 2. Operational Controls

SUBTITLE: 1. Cyber-Security

RISK: Cyber Security incidents that could result in the theft of information and / or the disruption or misuse of critical operations / assets

DESCRIPTION:

The growth of electronic communication and automation, while delivering significant benefits, has also increased risk to the Corporation. This risk includes any cyber attack that could impact the resiliency, reliability, confidentiality, availability or the integrity of Manitoba Hydro information and \operational technology assets, including the theft of personal and or business information, and or the disruption/misuse of critical operations/assets. Any computer or control system if not secured properly may be considered a potential target.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES

These cyber attacks could have a significant impact on Manitoba Hydro operationally and financially, and may have a rippling effect on the Manitoba economy.

RISK TREATMENT

Countermeasures, management controls and processes are in place to mitigate this risk. The Corporation is has implemented a series of measures to further augment cyber-security efforts consistent with recommendations of the Office of the Auditor General. Concurrently, to meet current NERC security standards Manitoba Hydro has also undertaken several projects targeted at increasing safeguards over critical cyber assets.

Ongoing assessment and enhanced mitigation strategies are required as the sophistication of external cyber threats increases, and as more computer and control systems are inter-connected. The Enterprise Security Council comprised of senior executives provides oversight for all aspects of physical and technology security including NERC related projects and the implementation of the Auditor General's eight recommendations, of which four have now been completed.

To protect Manitoba Hydro’s information technology environment an advanced corporate firewall is in place to protect the data network. Additionally, anti-virus software and security patches are closely monitored and updated immediately to prevent data corruption. The Corporation is finalizing the implementation of a Security Information & Event Management (SIEM) tool to further raise the level of protection. It will be fully operational by spring, 2016.

The Industrial Data Network has measures of protection and is being assessed to identify any required actions necessary to raise the levels of protection.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: G. Reputation

TITLE: 1. Reputation

RISK: The occurrence of a negatively public perceived event which receives significant attention and affects the Corporation's operations in a significant negative manner.

DESCRIPTION:

Reputation risk exposes Manitoba Hydro's ability to achieve its overall strategic and operational goals in an effective and efficient manner.

The impacts of reputation cover a broad range of activities at Manitoba Hydro and include many significant initiatives, including:

- Obtaining approvals and constructing new generating stations, both hydraulic and other types;
- Renewing licences (e.g. Lake Winnipeg Regulation, Churchill River Diversion, and various generating stations);
- Obtaining approvals and constructing new transmission lines and maintaining existing transmission lines;
- Extending export opportunities and protecting access to export markets;
- Maintaining market share in the domestic retail natural gas market;
- Receiving favorable regulatory (e.g. PUB) approvals;
- International operations in developing countries and emerging economies where corrupt or unethical practices are common to varying degrees, and
- Other activities.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The significance of the impact varies depending on the strategic or operational goal, however the impact can range from having insignificant costs to significant costs (e.g. the potential impact can result in the Corporation not achieving its strategic goals or achieving significant objectives such as constructing a new generating station or a major transmission line). As a publicly owned entity, Manitoba Hydro cannot under any circumstances operate outside the laws of Canada, internationally accepted standards of conduct, or the laws of the countries in which it does business.

RISK TREATMENT:

To support fulfillment of its mandate, Manitoba Hydro has identified key areas of focus which are directly related to enhancing its Corporate reputation including:

- Customer Value
- Indigenous Relations
- Financial Strength
- Protect the Environment
- Demand Side Management

Manitoba Hydro has developed and is undertaking a range of comprehensive communication actions to protect and enhance its reputation to secure trust in its ability to serve customer energy needs and gain acceptance for corporate activities. This includes effective engagement with stakeholders.

For all domestic and international operations, the Corporation requires that employees are aware of and comply with all applicable laws, regulations, standards of conduct and policies.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: H. Governance / Regulatory / Legal

TITLE: 1. Regulation and Licencing

RISK: The Corporation could face regulatory and licencing issues that restrict its operations.

DESCRIPTION:

The Corporation requires a variety of regulatory approvals and licences to carry out its activities. Key approvals and licences include those issued under the National Energy Board Act, Water Power Act and Environment Act either to build new generation and transmission facilities or to maintain the operation of existing facilities.

There are two significant issues currently facing the Corporation that could have significant impact on operations and reputation if they are not addressed. These are the risk of Lake Sturgeon being listed as endangered under the Species at Risk Act (see risk profile C.3.1) and addressing environmental and societal impacts and expectations for legacy facilities. Specifically the Clean Environmental Commission (CEC) made a non-licencing recommendation that both the Province and Manitoba Hydro conduct a Regional Cumulative Environmental Effects Assessment (RCEEA) of all Manitoba Hydro projects in the lower Nelson River sub-basin before any more projects are licenced for construction. In the recently completed Lake Winnipeg Regulation (LWR) Final Licence hearing the CEC went even further and recommended that all legacy hydro projects in the Province should be licenced under the Environment Act.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Failure to obtain approvals and licences on favourable terms or in a timely fashion could have significant financial, operating and water regime impacts, increasing costs, and reducing hydraulic generation, capacity and export sales. Expiration of a licence without renewal will expose the Corporation to embarrassment and loss of reputation. Although highly unlikely, cancelation of a licence could expose the Corporation to the possibility that a third party could acquire the water power rights at a location and potentially the loss of the asset.

RISK TREATMENT:

With respect to the Lake Sturgeon issue, the Corporation continues to take significant action to minimize the need for and likelihood of listing Lake Sturgeon under SARA (see detail of risk treatment on profile C.3.1), however uncertainty remains.

Over the next ten years, twelve of Manitoba Hydro's Water Power Act licences will have to be renewed. Although legally this should be a relatively simple process as prescribed under the Water Power Act regulations, public expectations, the requirement for the Province of Manitoba to consult under Section 35 of the Constitution with Indigenous peoples on all licencing decisions and the recent recommendations from the CEC on re-licencing that includes full environmental assessments and public reviews will expose Manitoba Hydro to significant costs, and potential operational restrictions. Manitoba Hydro is currently in discussions with the Province on how to proceed with re-licencing.

Likelihood	Low
Consequence	High
Tolerance	Low

CATEGORY: H. Governance / Regulatory / Legal

TITLE: 2. Export Market Access

RISK: The Corporation loses its legal capability to sell power outside the province due to legal and industry change issues.

DESCRIPTION:

The energy industry in North America has undergone fundamental restructuring. There are now in place market-based approaches to generation, transmission, distribution and sale of energy in the Midwest region of North America in which Manitoba is located, and new industry bodies have been formed to facilitate these activities. Opportunities for the Corporation include (1) Opportunities to export power to new markets or further develop existing markets, and (2) Opportunity to define new roles for the Corporation in the delivery of gas services in Manitoba to better serve consumers.

Manitoba Hydro's access to the U.S. market is to an extent conditioned on the adoption of measures in Manitoba to level the playing field e.g. transmission tariff, standards of conduct. Risks include: (1) Measures adopted in Manitoba to level the playing field could affect rates to Manitobans or quality of service. (2) Risk of Manitoba Hydro losing functional control of its transmission facilities in Manitoba to U.S.-based transmission operators (i.e. loss of sovereignty, lose control of transmission facilities). (3) The risk of losing market access or receiving access on adverse terms (e.g. transmission pancaking, less competitive, more costly).

As well, the Corporation requires the legal ability to sell power into other provinces and the U.S. on favourable terms. Risks include: (1) The Corporation may be prevented from selling into a particular market or obtaining transmission or ancillary services that are necessary for the sale to take place. (2) Unfavourable terms may be imposed on sales, by U.S. regulators or trading partners (3) May affect amount of power Manitoba Hydro can be assured of importing during times of drought.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The above opportunities and risks may affect the amount of revenue from export sales and could impact the reliability of supply and service to Manitobans. They might also impact Manitoba Hydro's mandate, control over facilities and raise issues of Canadian and Manitoba sovereignty.

RISK TREATMENT:

The rules are constantly changing in export markets. Accordingly, corporate strategies for ensuring market access will continue to require ongoing management. Strategies (all subject to change) include: (1) Ongoing development and assessment of strategic plans. (2) Ongoing alignment of strategic plans and participation by Manitoba Hydro personnel in export based operations. This includes: coordination agreement with MISO; membership in Midwest Reliability Organization; active input into MISO committees and bodies; FERC filings; Ontario marketing licence; adoption in Manitoba of transmission tariff, standards of conduct, reliability, security and operating procedures consistent with U.S. requirements; promotion of the corporate image in export markets; and active engagement with Manitoba Hydro's principal export customers to confirm they are able to obtain needed regulatory approvals.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: H. Governance / Regulatory / Legal

TITLE: 3. Legal Compliance

RISK: The Corporation does not comply with legal requirements

DESCRIPTION:

The Corporation must comply with a broad variety of legislation, regulations, common law and other legal requirements.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Depending on the type of legal requirement the consequences of non-compliance may include:

- Financial penalties for the Corporation.
- Fines / imprisonment for individual directors, officers or employees.
- Impact on corporate reputation.
- Restrictions on corporate operations.

RISK TREATMENT:

The Corporation fosters a positive culture of compliance through measures such as a Corporate Code of Ethics, periodic messages from the President to all employees emphasizing the importance of compliance with the Law, and an Integrity Program to enable employees to report any violations of the Code of Ethics without fear of reprisal.

Management has identified a short list of compliance risks that pose the most material risk to the Corporation. Management has developed for the Audit Committee of the Board profiles of the compliance programs for these risks and provides to the Committee annual updates and metrics associated with them.

An Integrity Officer coordinates the investigation of all Integrity Program reports. Summaries and analysis of reports received pursuant to the Integrity Program are shared with the Audit Committee annually (with identifying details removed to protect confidentiality). Summaries of all material litigation, communications with licensors and other potential indicia of compliance or non-compliance are also reviewed by the Audit Committee on an annual basis.

In order to mitigate exposure to market manipulation risk, the Corporation is in the process of implementing a Wholesale Electricity Markets Compliance Program to establish policies, procedures and guidelines pursuant to anti-market manipulation laws in place in the U.S. and Canada. This program will outline roles and responsibilities of those identified in the program, provide direction to employees transacting in the export markets, identify permissible and prohibited trading considerations and specify policy with respect to potential violation investigations, disputes and reporting, training requirements, record retention practices and compliance monitoring related to the Corporation's participation in the wholesale electricity markets.

In all cases it is the responsibility of management to ensure compliance with the law. The generally accepted elements of a corporate compliance program are:

- Standards and procedures that are reasonably capable of reducing non-compliance.
- Assign specific high-level personnel to oversee compliance.
- Prevent delegation of discretion to individuals likely to engage in non-compliance.
- Effectively communicate standards and procedures to relevant employees.
- Implement monitoring, auditing and reporting systems.
- Use disciplinary measures to enforce standards and procedures.
- Respond to breaches that are detected including modification for systemic problems.
- Continually evaluate the risk of non-compliance.

Likelihood	Low
Consequence	Med
Tolerance	Low

CATEGORY: H. Governance / Regulatory / Legal

TITLE: 4. Contracts & Ventures

RISK: Contracts are not fulfilled or business ventures expose the Corporation to undesirable events.

DESCRIPTION:

The Corporation engages in a variety of commercial activities. It purchases goods and services, sells its own goods and services, purchases and sells land and intellectual property and signs a variety of other contracts and agreements. The Corporation also purchases businesses such as Centra and Winnipeg Hydro, and sets up subsidiaries and joint-ventures to pursue particular opportunities. Some of the risks include:

- Failure to comply with contract obligations and contract law (e.g. anti-corruption law).
- Acceptance of unfavourable contract risk, liability clauses or indemnity requirements.
- Failure to obtain property rights and easements needed for corporate activities.
- Failure to obtain software licences or other intellectual property.
- Failure to secure sufficient audit rights to protect the corporate interest.
- Entanglement in foreign legal proceedings.
- Failure to exercise appropriate governance over joint-ventures / subsidiaries.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Management of the above risks will impact the revenues or other advantages that the Corporation is seeking to achieve, and the potential lawsuits and financial liabilities that the Corporation may be exposed to.

RISK TREATMENT:

The Corporation has risk management programs in place for particular, high risk commercial activities such as the purchase of gas hedges and power trading.

Board approval is required for all contracts of first importance to the Corporation (meaning contracts with high impact on the Corporation's ongoing operations over the long term (e.g. Northern Flood Agreement, Joint Keeyask Development Agreement, Winnipeg Hydro Purchase Agreement), contracts introducing fundamental change to the Corporation and purchases beyond specified signing limits and discretionary payments over $5 million. There are Board guidelines for the creation of subsidiaries and joint-ventures.

The majority of commercial risks are managed within the Business Units. Management is responsible to manage the opportunities, obligations, adherence to contract law (e.g. anti-corruption law), and risks in all documents that are signed. Policy requires the approval of a Division Manager for any contract containing non-standard risk, liability or indemnity provisions. Contracts and ventures of first importance to the Corporation are coordinated at the executive level with Board reporting and approvals. Policy requires legal approval of all contracts of first importance to the Corporation. Policy requires legal approval of all consulting contracts, with any exceptions approved by a Vice-President and reported to the Audit Committee.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: H. Governance / Regulatory / Legal

TITLE: 5. NERC/MRO Reliability Standards

RISK: The Corporation could face negative consequences if it does not comply with mandatory NERC/MRO reliability standards.

DESCRIPTION:

NERC/MRO standards identify specific reliability requirements for the planning, design, reliable operation, and maintenance and security of the North American bulk power system. NERC reliability standards are binding on the Corporation pursuant to the Reliability Standards Regulation under the Manitoba Hydro Act. The National Energy Board, which regulates international power lines also requires Manitoba Hydro to comply with applicable Reliability Standards under its General Order on Mandatory Reliability Standards.

A finding of non-compliance to these standards could result in the following potential consequences: (1) Financial penalties up to $1 million per day per violation; (2) Increased regulatory scrutiny by the PUB and NEB as a result of violations; (3) Public disclosure of non-compliances, which may result in a negative impact on the Corporation's reputation and its exceptional standing in the industry; (4) Immediate Remedial Action Directives imposed by NERC/MRO on the Corporation; (5) Negative impact to Manitoba Hydro's export capability; and (6) Monetary penalties to both employees and the Corporation up to $100,000 pursuant to the NEB's Administrative Monetary Penalties (AMPs) Regulation

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The violation of mandatory standards could threaten the reliability of the bulk power system. Manitoba Hydro recognizes reliability as an important priority; one which provides exceptional value to customers. Public disclosure of non-compliance on a single significant matter, or numerous times on points of lesser significance, could put negative pressure on the Corporation's image. Furthermore, financial penalties imposed on the Corporation could be substantial.

RISK TREATMENT:

To mitigate the risks of non-compliance to reliability standards, the Corporation has developed a Corporate NERC Reliability Compliance Program to manage the demands of compliance. The role of the program is to promote a culture of compliance, act as the primary contact with external entities, manage the flow of information both internally and externally, and provide high level support for corporate compliance-related activities. A decentralized approach to the assignment of responsibility for each standard has placed accountability for the Corporation's compliance squarely in the hands of subject matter experts who can assess current practices against the requirements of the standards and take action to ensure compliance. These subject matter experts (generally Department Managers) are designated as either standard owners or requirement owners depending on their level of involvement relative to the specific requirements of the standards. The Program has created clearly defined roles and responsibilities for both standard owners and requirement owners. In addition, standard owners and requirement owners are expected to participate in the MRO/NERC standards development process, through commenting periods, voting strategies, and/or as members of standard drafting teams, to influence the development of a standard before it becomes mandatory and enforceable.

Under the Reliability Standards Regulation, the Corporation works collectively with the Province to update the list of reliability standards applicable in Manitoba as well as the NERC Rules of Procedure applicable in Manitoba, providing flexibility to deal with future events and changing circumstances.

Likelihood	High
Consequence	High
Tolerance	Low

CATEGORY: I. Indigenous

TITLE: 1. Relationships

RISK: Poor relationships will have negative impacts on future Corporate activities.

DESCRIPTION:

Manitoba Hydro ("MH") has a goal in its Corporate Strategic Plan to " Engage impacted communities in a positive way to enhance working relationships". Effective working relationships adhere to the basic principles of mutual recognition, mutual respect, sharing and mutual responsibility Working relationships encompass activities in the areas of employment, training, environmental stewardship, purchasing, contract work, customer service, business opportunities and addressing adverse effects.

Working relationships exist with Indigenous individuals, communities and organizations. In managing relationships Manitoba Hydro takes into consideration issues and concerns raised by the community, Indigenous and Treaty rights, impacts of hydro-electric development, employment equity and human rights concerns, and the societal need to move towards reconciliation.

The risks in this area include both substantive and process issues such as disputes arising in relation to: adequacy and continuation of process funding; adequacy and eligibility for compensation arising from existing and future development; eligibility for and adequacy of corporate programs and initiatives; equitable allocation of programming dollars and opportunities; and the representative capacity with respect to Indigenous interests. Any of the above can result in legal action.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

- Lack of trust on the part of many Communities which were impacted by hydro-electric development.
- Continued existence of ongoing impacts that cannot be totally eliminated even with decommissioning of the project which would have other impacts.
- Significant needs of many Indigenous communities that have resulted from numerous social, political and economic issues most of which are not related to hydro development.
- Need to create a level playing field in dealing with Indigenous communities requiring significant expenditures for the Corporation for consultants, lawyers and capacity building.
- Widely different views on respective obligations. Compensation paid under settlement agreements that does not address ongoing impacts leave future groups dissatisfied.
- Dissatisfied groups and/or their supporters damage Manitoba Hydro's image with export customers in particular and domestic stakeholders generally.
- Requests for financial donations and sponsorships increase, while fiscal constraints minimize the amount of discretionary funding available..
- Intervention by disaffected Indigenous entities adversely affects the outcome of regulatory processes.
- Significant reduction in process funding may impact communities' ability to manage their relationships with Manitoba Hydro.
- Dissatisfied groups and/or their supporters may take legal action and/or engage in acts of civil disobedience resulting in financial, operational and reputational impacts.

RISK TREATMENT:

- Behave in ways that earn trust and respect and contribute to mutual gains.
- Build on the mutual interests in the land and water that Manitoba Hydro shares with Indigenous peoples and seek to understand and accept different world views.
- Continue to design and deliver meaningful programs, projects and activities to address NFA obligations.
- Encourage fair public comment on hydropower issues and facilitate open communication with customers and government entities.
- Operate in compliance with corporate goals, operating principles and sustainable development principles.
- Agree on work plans and budgets for negotiating processes that include community assurances that a local expenditure control system exists, with expenditure control procedures in place, for both internal and external service providers.

Likelihood	Med
Consequence	M High
Tolerance	Low

CATEGORY: I. Indigenous

TITLE: 2. Legal

RISK: Unfavourable relationships and rulings could negatively impact Corporate operations.

DESCRIPTION:

Manitoba Hydro facilities can adversely affect Indigenous people with rights and interests in the area of the facilities. Interactions with Indigenous people and organizations are undertaken within a unique framework created by the following factors:

- Canada's constitution and legislation recognizes rights and provides protections to Indigenous peoples and Indian Reserve land in particular.
- Manitoba Hydro has significant contractual obligations under the NFA, the related NFA Implementation Agreements and other agreements with First Nations, the Manitoba Metis Federation (MMF), northern Indigenous communities and resource users.
- Manitoba Hydro's issues are often interwoven with broader federal and provincial responsibilities and Indigenous Self-Government issues.
- Indigenous concerns frequently command a high public profile.
- The Corporation is committed to enhancing working relationships with Indigenous peoples.
- There is often a lack of legal clarity, agreement, or common understanding with First Nations or Metis regarding the nature of Treaty and Indigenous rights (including Indigenous Title) and the obligations that arise for the Crown or proponent of a project in relation to such rights.

The risks in this area include:

- Inadvertent breach of legal obligations under contracts, legislation, regulations and constitutional requirements
- Restrictions on the use of land and water for energy production.
- Imposition of post project environmental reviews and assessments.
- Claims (e.g. breach of contract, interference with the exercise of rights, trespass, negligence) resulting in adverse orders including orders for damages or injunctions
- Delayed government approvals and unfavorable licence conditions for new projects
- Operating restrictions placed on existing projects
- Political interventions and civil disobedience (e.g. blockades)
- Lack of suitable judicial remedies
- Loss of export market opportunities
- Project delays and cost escalation.
- Competing interpretation of contractual arrangements.
- Long and costly arbitration processes and/or litigation.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Damage claims and operating restrictions have monetary implications. In an extreme case there could be risk to persons or property. Depending on the management of the risks, there is potential for damage to the corporate reputation and export market opportunities.

RISK TREATMENT:

Management systems exist or are being developed to flag obligations and to follow up on compliance which reduce the likelihood of inadvertent non-compliance with legal obligations. The Corporation is pursuing enhanced working relationships through mutually beneficial arrangements with Indigenous groups when developing new hydro facilities and is continually seeking improvements to its relationship with Indigenous peoples. The Corporation monitors developments in the field of Indigenous law to ensure ongoing awareness of evolutions in jurisprudence on Indigenous rights.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: J. Emerging Energy Technologies

TITLE: 1. Emerging Energy Technologies

RISK: New technology renders current facilities cost excessive.

DESCRIPTION:

Significant breakthroughs or improvements involving large scale mass production of new emerging technologies (energy storage, bioenergy, solar, wind, etc.) could result in lower electricity capital or production costs. Such technology breakthroughs could impact both Manitoba Hydro's export revenue and domestic revenue. The potential impact on export revenue is one of the factors discussed in category A2.2 Export - Long Term Price Uncertainty. Emerging renewables put downward pressure on export market prices along with providing more fixed price/non-emitting resource options to counterparties which affects the export marketing opportunities and related long term pricing premiums available to Manitoba Hydro. New small scale domestic emerging technology resources such as solar could reduce expected load growth, and reduce energy revenue in Manitoba over the long run, if the cost of the resources becomes low enough to become economic.

Alternative generation technologies, without tax incentives or subsidies, are currently more expensive than conventional generation. Generally the more mature alternative technologies, such as utility scale wind power, are closer to commercial parity even without subsidy as their costs continue to decrease slowly. With subsidies, new wind power in the Midwest US is currently being contacted at below market prices, creating substantial challenges for merchant generators. There remains substantial uncertainty around the availability of these subsidies (specifically for wind power) post-2015. Less mature technologies, such as solar photovoltaics, have costs which are decreasing more quickly, but costs would still need to decrease by at least a factor of two for them to be commercially viable without subsidy or mandate. However drastic technology cost reductions in the past few years has set a trajectory where commercial viability in many medium/higher cost regions of the US within the next five to ten years.

Manitoba has biomass resources, primarily from crop residues, but individual utility scale generating plants would be small (<30 MW) and disbursed. Costs associated with biomass fuel collection and transportation continue to limit the development potential for this option in Manitoba. Utilization of biomass resources would also be subject to competition from other bio-product demand such as heating.

Energy storage technology is predicted to play a significant role in future electrical grids with distributed generation components by helping to manage intermittency, which could enable the integration of more non-dispatchable energy sources such as wind or solar. The historical price drop for lithium-ion batteries has accelerated with the recent expenditures of multiple billions of dollars on new higher-scale manufacturing facilities and larger battery chemistry research laboratories.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

The impact of this risk is reduced revenue from both domestic and export energy sales from existing assets while also impacting the business case for new hydro-electric generation. Development changes in emerging energy technologies have tended to be more evolutionary than sudden, which means that relative value thresholds between conventional and emerging generation are likely to be approached gradually.

RISK TREATMENT:

Manitoba Hydro retains expertise and keeps well informed of the direction occurring within the industry. The current resource plan indicates that no new generation is required until 2033. This requirement is based on current load forecasts that include new DSM targets both of which are updated annually to reflect information that is available. This time frame allows the Corporation to assess new alternative energy technologies and work towards an integrated resource plan which determines the appropriate combination of resources to meet multiple objectives (technical, environmental etc) at the lowest cost to Manitobans.

Likelihood	Low
Consequence	M High
Tolerance	Low

CATEGORY: K. Strategic

TITLE: 1. Strategic Direction and Execution

RISK: Missed opportunities, unfavourable business decisions.

DESCRIPTION:

Strategic planning is the overarching methodology by which the Corporation sets direction and aligns corporate priorities and resources.

POTENTIAL IMPACT ON ACHIEVING CORPORATE OBJECTIVES:

Establishing, communicating and implementing strategic direction is essential in managing threats and opportunities. Strategic decisions have the potential to significantly impact corporate performance and the achievement of financial targets, either positively or negatively, pertaining to any of the Corporate Strategic Plan (CSP) goals and/or identified risk categories. High level strategic considerations may include: large scale capital projects to meet the future needs of the province, re-investment in the existing energy system to maintain high reliability, attraction and retention of a high caliber workforce, stakeholder and indigenous relationships, implications of evolving power markets including access to export markets, potential industry-wide implications of shale gas, prioritization of capital projects and resource optimization, performance management and process improvement.

RISK TREATMENT:

Manitoba Hydro’s integrated planning cycle commences annually with key inputs such as: economic variables and energy price forecast, load forecast, demand side management forecast, export price assumptions, capital costs and OM&A forecasts. These inputs drive the Integrated Resource Plan (IRP), capital expenditure forecasts and ultimately the Integrated Financial Forecast (IFF). The CSP is a companion document for consideration throughout the planning cycle.

Major strategic decisions and strategic, plans are subject to an internal review and approval process. Many strategic decisions are also subject to external review and approval through regulatory processes.

Senior management is responsible for communicating and ensuring the implementation of strategy throughout the Corporation. Manitoba Hydro’s Vision, Mission and corporate targets are communicated to employees via the CSP.

Business units incorporate the CSP into their respective business plans as appropriate. Applicable goals, measures and strategies become increasingly oriented to operations as the process moves downward through the organization.

APPENDIX C

CORPORATE

RISK MANAGEMENT

FRAMEWORK

APPENDIX C - CORPORATE RISK MANAGEMENT FRAMEWORK

The Corporation has adopted the following six step Risk Management Process, Risk Rating Criteria and Risk Tolerance Rating Criteria to consistently identify, assess and manage risks:

Six Step Risk Management Process

1) **Mission / Mandate**
The process of identifying and managing risk is initiated at the Corporate, Business Unit, Division, Department, or project level by focusing on the underlying mission / mandate and specific strategic goals established for that particular area of the Corporation.

2) **Risk Identification**
Risks are identified based on the factors that influence the performance of the area of the Corporation being assessed.

3) **Potential Impact**
Risks are analyzed for potential impact and measured in terms of consequence and likelihood. Consequence is quantified in terms of system reliability, safety, finance, environmental impact and customer satisfaction. For each consequence identified, the likelihood (probability) is determined of the event occurring.

4) **Risk Treatment**
Actions are taken to reduce the likelihood of a negative event occurring or to reduce the negative consequences should a negative event occur. Risk treatment can include a reduction of the risk through modification of operational activities, a sharing of the risk through external insurance or acceptance of the risk as a normal consequence of the business and/or operations. The acceptance of risk is subject to that risk being within the approved tolerance levels of the Corporation.

5) **Residual Risk**
Certain levels of residual risk may remain even after actions have been taken to reduce their likelihood and consequences. An assessment is performed to confirm that the residual risk levels are within approved tolerances.

6) **Reporting and Monitoring**
Systems are implemented to monitor key risks, and information provided by these systems are used to facilitate management actions. Reporting systems ensure that senior management and other stakeholders are appropriately informed and risks are managed within the Corporation’s approved risk tolerances.

Corporate Risk Rating Criteria

CORPORATE RISK PROFILE
RATING CRITERIA

	MEASURES	RATING		
		Low	Medium	Medium High
ANNUAL CONSEQUENCE -				
Financial	Net income / capital investment	$0 - $50 million	$51 - $150 million	> $150 million
System Reliability	Domestic Customers	Outage affecting 50 customers for 4 hours Not life threatening	Outage affecting 500 customers for up to 24 hours. Have ability to serve critical loads. Not life threatening as critical loads served.	Do not have capacity to serve Manitoba load for extended period of time. Life threatening. Loss of public confidence.
	MW generation or interconnection capacity	NERC level 1 In compliance with industry reliability standards.	Loss of 2000 MW. NERC level 2 - load management procedures in effect. In compliance with industry reliability standards.	Loss of > 2000 MW. NERC level 3 - firm load interruption imminent or in progress; and / or non-compliance with industry reliability standards.
Safety - Employee and Public	High risk accidents, severity rate, frequency rate and public contacts.	Minor injuries. In compliance with laws and industry standards.	Disabling injuries. In compliance with laws and industry standards.	Severe injuries and fatalities; and / or non- compliance with legislation and industry standards resulting in imprisonment for MH mgmt, significant fines and loss public trust.
Environment	Environmental impact - air emissions, water mgmt, spills, land & habitat disturbances, etc.	Minor impact to environment. In compliance with stakeholder expectations and laws and regulations. Ability to obtain / renew environmental licensing and operating approvals.	Local and contained damage to environment. In compliance with stakeholder expectations and laws and regulations. Ability to obtain / renew environmental licensing operating approvals.	Severe widespread and uncontained damage to environment; and / or non-compliance with stakeholder expectations, laws, and regulations resulting in imprisonment for MH mgmt, significant fines, loss of public trust and long term operating restrictions
Customer Value	Customer perception service with regard to:			
	Retail electricity rates	No rate increase	Annual increase < 10%	Annual increase > 10%
	Reliability and quality service	Restoration service within 4 hours, no threat to public safety,. < 1.3 outages/customer/ year, provision energy related services.	Restoration service within 24 hours with no threat to public safety. 2 outages/customer/year,	Outage for extended period of time. Life threatening. Loss of public confidence.
	Reputation	Local media coverage with negligible impact on stakeholders.	A highly visible event attracting national media coverage or environmental concern; and /or a moderate negative impact on stakeholders.	A highly visible event attracting international media coverage or environmental concern; and / or a significant negative impact on stakeholders such as breach of privacy, contractual obligation or environmental stewardship.
LIKELIHOOD		Event is not likely to occur within 10 years.	Event is likely to occur within 5 - 10 years.	Event is likely to occur within 1 to 10 years.

Note: While risk impact ratings are outlined for low, medium and medium-high those considered more significant than others in the medium-high category are elevated to a high category to signify their potential higher impact on the Corporation.

Corporate Risk Tolerance Definition / Rating Criteria

Tolerance is defined as the allowable or permissible variation from a standard. For Manitoba Hydro's purposes, tolerance is further defined as the extent to which the amount of residual risk is deemed to be reasonably acceptable within the resources available to the Corporation. To the extent that tolerances fall beyond reasonably acceptable levels, actions have been taken (or are being taken) to mitigate that risk.

Typically, risks with high consequence have corresponding low tolerances. Safety and Health (E.1) and Reliability of Service (C.4) are examples where the Corporation has a low tolerance for risk due to the severe consequences of negative events.

Tolerance is rated as either, low, medium or high based on the following parameters:

- Low – Zero or limited variability is accepted. Low tolerance is usually associated with an area where the consequences of negative events are significant and the Corporation has the ability to control the risk.
- Medium - Some variability is accepted. Medium tolerance may also be associated with high risk but the ability of the Corporation to control the risk may be limited.
- High – Significant variability is accepted. Consequence is always low.

To ensure adequate control and monitoring of risk, management establishes rules, limits, targets and guidelines and continually monitors these indicators and responses accordingly. The Corporation has created three levels to illustrate this:

- Green: no additional action required at this time as the risk is under control and is not subject to significant change.
- Yellow: there are or appears to be some emerging issues that need to be closely monitored and addressed. Additional action is required to bring the risk back to the established tolerance. Management has time to respond in an orderly manner.
- Red: the risk has become critical to business operations and requires day to day senior management attention. If not resolved quickly, it could have catastrophic impacts on the organization.

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15 Implementation and Risk Management Plan for Preferred Development Plan

15.0 Chapter Overview

The Preferred Development Plan was created to serve the growing electricity demand in Manitoba and to take advantage of new export sale opportunities, including the 250 MW MP sale, the 125 MW NSP sale, the 100 MW WPS sale and the potential 300 MW WPS sale.

As described in ***Chapter 2 – Manitoba Hydro's Preferred Development Plan Facilities***, the Preferred Development Plan includes four main components:

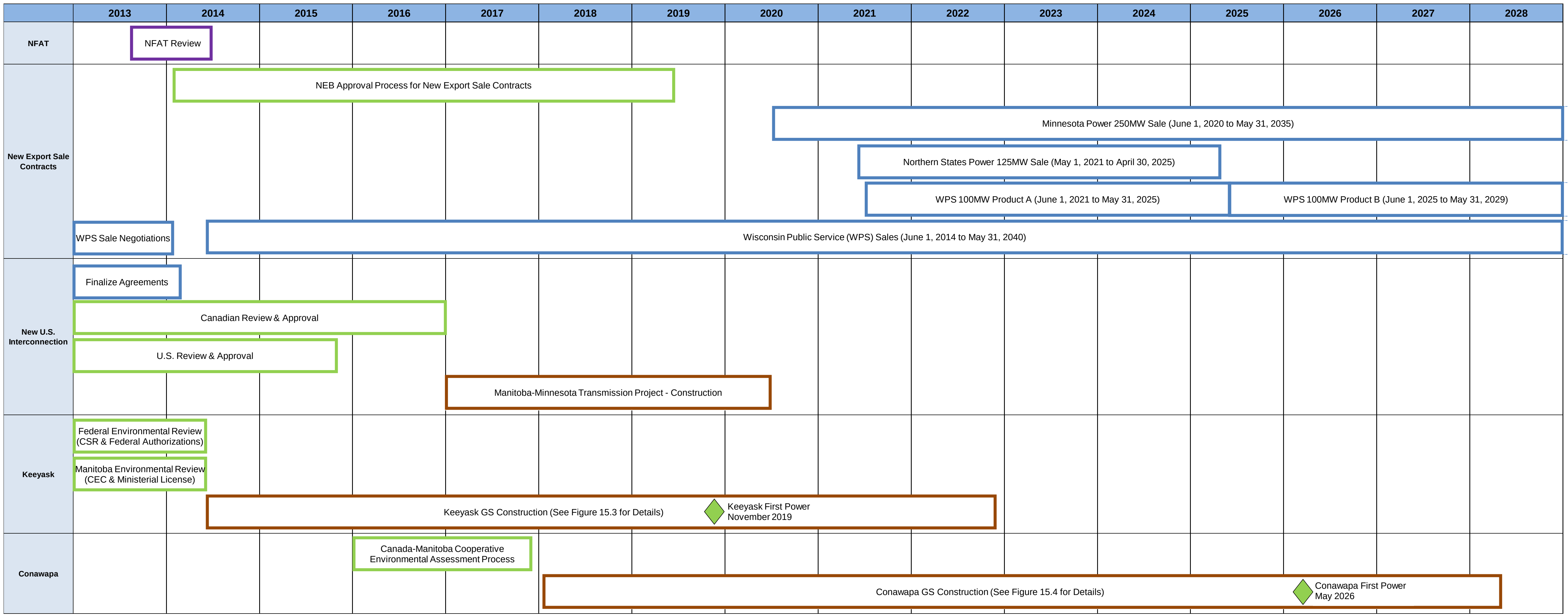
- 695 megawatt (MW) Keeyask Project with a November, 2019 in-service date (ISD)
- 1,485 MW Conawapa Project with a May, 2026 ISD (the ISD is subject to revision)
- 185 MW North-South Transmission Upgrade Project, with an ISD to coincide with Conawapa
- 750 MW/500 kV Manitoba – Minnesota Transmission Project with a June, 2020 ISD.

This chapter explains how Manitoba Hydro intends to implement the Preferred Development Plan and manage the associated risks. Implementation includes the finalization of all required agreements, including the export sale contracts; submission of regulatory applications and participation in regulatory review processes; and project delivery.

Figure 15.1 shows a schedule of the main activities and key dates related to implementation of the Preferred Development Plan that are discussed in this chapter.

The schedule represents the period from 2013-2028, inclusive. Please note that some of the sale agreements extend beyond 2028.

Figure 15.1 MANITOBA HYDRO IMPLEMENATION SCHEDULE – PREFERRED DEVELOPMENT PLAN



15.1 Pathways Associated with the Preferred Development Plan

Chapter 14 – Conclusions, Section 14.2 presents five distinct pathways for new resource development currently being considered by Manitoba Hydro. Each pathway is based on a specific commitment decision to be made regarding the next new resource and represents a range of alternative development plans that could unfold thereafter.

Chapter 14 – Conclusions concluded that Manitoba Hydro should proceed with the Preferred Development Plan and its associated pathways.

The immediate commitments in June 2014 are:

- start construction of Keeyask G.S. for a 2019 ISD
- proceed with the 250 MW export agreements with Minnesota Power(MP)
- proceed with the 100 MW export agreement with Wisconsin Public Service (WPS)
- proceed with the 750 MW/500 kV U.S. interconnection subject to regulatory approvals
- proceed with the 300 MW export agreements with WPS subject to satisfactory conclusion of negotiations currently underway.

As both Pathways 4 and 5 are based on developing Keeyask G.S. for an ISD of 2019 in conjunction with a new 750 MW U.S. interconnection, they will be the focus of this chapter.

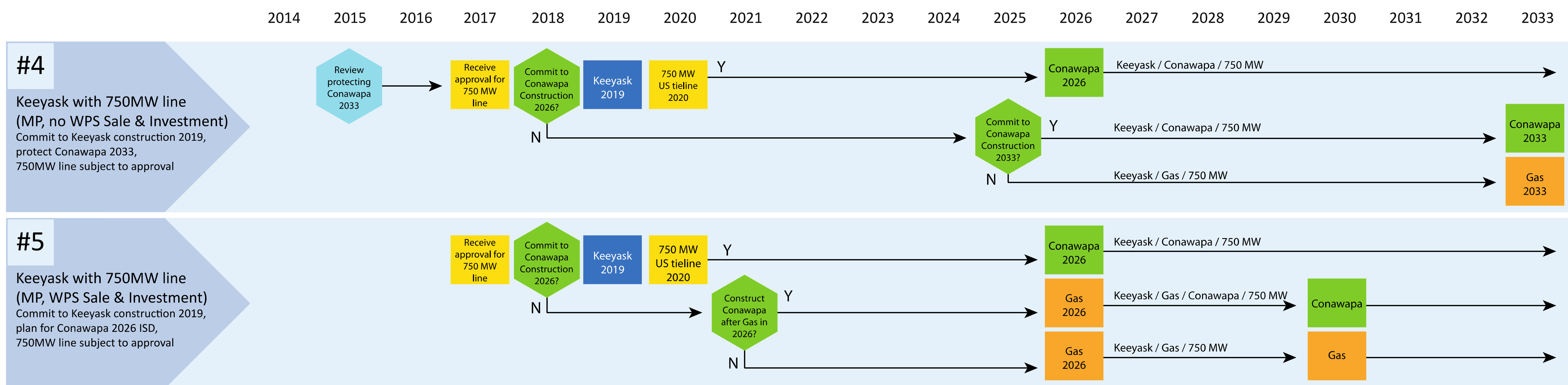
Figure 15.2 illustrates Pathways 4 and 5 and shows the development plans that are represented by these pathways. The majority of the development plan analysis throughout this submission utilizes resource in-service dates based on the 2012 load forecast; however, Figure 15.2 is based on the 2013 Load Forecast resource in-service dates.

Both Pathways 4 and 5 include Conawapa G.S. and have flexibility as to its ISD. Manitoba Hydro will continue to evaluate the Conawapa Project through the annual Power Resource Plan and otherwise as required. Should conditions not be favourable to constructing Conawapa for a 2026 ISD, a decision could be made as late as 2018 to defer its ISD or displace Conawapa with other resources such as gas. Displacing Conawapa G.S. by an alternate resource would reduce some of the benefits associated with the plan as described in this report, but this would be offset by a corresponding reduction in downside risk.

There is a risk the 750 MW interconnection may not receive regulatory approval; however, this risk can also be mitigated because the Conawapa G.S. construction commitment in 2018 falls one year after the scheduled approval date for the interconnection. Conawapa G.S. could therefore be deferred or cancelled should the interconnection approval be delayed or denied.

With all required approvals in place, construction can begin on the Keeyask Project without having received the final approval for the interconnection. In the event that the interconnection does not proceed and the 250 MW MP Power Sale Agreement (PSA) is cancelled, Keeyask G.S. is still the logical choice for a new resource option to meet Manitoba's growing electricity needs. With sufficient notice, the Keeyask G.S. construction timeline could be adjusted to correspond to a later ISD if conditions so indicate, likely around 2023, and the value of all Keeyask G.S. efforts and expenditures would still be retained.

Figure 15.2 PATHWAYS ASSOCIATED WITH THE PREFERRED DEVELOPMENT PLAN (PATHWAYS 4 AND 5)



15.2 New Long-Term Export Contract Agreements

Manitoba Hydro sale commitments that are contingent upon construction of the Preferred Development Plan are at risk of not commencing if the new generation and transmission projects are not completed. Refer to ***Table 6.4 - Long Term Export Commitments Contingent Upon New Hydro Development*** which summarizes the new long-term export contract agreements that are contingent on new hydro development and the new U.S. interconnection: agreements with Minnesota Power, Northern States Power and Wisconsin Public Service. A summary of the major terms and conditions for these contracts is contained in ***Appendix 6.1 - Summary of Terms and Conditions of Export Contracts.***

15.2.1 Long-Term Export Contracts Associated with the Preferred Development Plan

The 250 MW MP sale and the MP Energy Exchange have been signed by both parties and are dependant on the construction of Keeyask generating station (G.S). The Keeyask G.S. ISD of November 2019 in the Preferred Development Plan is a function of the export contracts start dates of June 2020. In addition, MP and Manitoba Hydro have agreed to construct a new transmission interconnection through the 250 MW MP sale.

The 125 MW NSP sale has been signed and is contingent on new hydro development. The start date for this sale is May 2021.

There are three agreements with WPS, of which two are signed agreements that are contingent on development of the Keeyask G.S. These signed agreements start in June 2021 and June 2025.

The third WPS agreement for up to 300 MW remains under negotiation. In the event that no agreement is reached with WPS, Manitoba Hydro will continue to pursue export sales with other utilities. A Conawapa G.S. ISD of May 2026 is based on serving the 300 MW WPS sale.

An interconnection with a transfer capability larger than 250 MW is required to accommodate new sales to MP and WPS (beyond 100 MW). In the event that the 300 MW sale to WPS does not materialize, a 250 MW transmission interconnection would be sufficient to meet the 250 MW Minnesota Power sale, although MP and Manitoba Hydro prefer a 750 MW interconnection as explained in ***Chapter 14 – Conclusions.*** The 100 MW WPS and 125 MW NSP sales will utilize existing transmission service and are not dependant on a new interconnection.

15.2.2 Managing Export Contract Risk

Manitoba Hydro's export sales associated with the Preferred Development Plan involve physical delivery risks and financial risks from a multitude of factors such as delays in placing the new generation and/or transmission facilities in service, increases and decreases in the domestic load forecast, water supply variability, facility outages, customer creditworthiness, etc. Manitoba Hydro manages these physical and financial risks through a variety of means, including specific long-term export contract provisions, transmission access, and customized market products.

15.2.2.1 Long-Term Export Contract Provisions

Manitoba Hydro enters long-term export contracts for the sale of capacity, dependable energy and opportunity energy in excess of the requirements for domestic customers. These export sales can be dependant on the construction of interconnecting transmission facilities. Export sales provide financial benefits to Manitoba Hydro, but also involve additional risks related to the physical delivery and the financial obligations associated with these sales. Manitoba Hydro's long-term export contracts contain numerous provisions that are designed to mitigate the risks associated with these contracts. The following sections describe these provisions.

Market Access

A common provision contained in Manitoba Hydro's export contracts that improves market access for sales is the right to use the firm transmission service that is not being utilized for the sale of must-take energy under the contract. This right to use the firm transmission service allows Manitoba Hydro to maximize the value of additional energy that may be available from time to time, avoiding the risks of non-firm transmission service—which is frequently not available or subject to interruption, preventing the corporation from maximizing additional opportunities.

Curtailments and Curtailment Priority Criteria

Manitoba Hydro's service to domestic customers is protected under the curtailment provision incorporated into export sales agreements. Manitoba Hydro can curtail energy deliveries to the export customer without penalty if there is a physical problem on the Manitoba Hydro generation or transmission system that prevents continued deliveries. If a curtailment event does occur, then Manitoba Hydro is entitled to curtail energy deliveries according to a curtailment priority stack. Manitoba domestic load is at the highest priority, which means all export contracts would be curtailed before affecting Manitoba Hydro's domestic load in Manitoba.

Alternative Supply

Manitoba Hydro's service to domestic customers and export sales obligations are protected under the alternative supply provision. Manitoba Hydro has the right to meet contracted energy obligations from more than its own generating stations. Flexibility to meet contracted energy obligations from energy markets (i.e. Midwest Independent System Operator, Inc. (MISO)) and third-party purchases allows Manitoba Hydro to meet its sale obligations at lowest cost and during circumstances when all Manitoba Hydro generating resources are needed to serve domestic load in Manitoba.

Adverse Water Conditions

Manitoba Hydro's service to domestic customers is protected under the adverse water conditions provision. Manitoba Hydro utilizes adverse water provisions in long-term export contracts to reduce the volume of contracted energy to be delivered if Manitoba Hydro anticipates conditions where it cannot meet its energy supply obligations from its own generating resources. These adverse water provisions provide the corporation with physical and financial protection in event of drought conditions.

Creditworthiness

Financial risks related to Manitoba Hydro's export sales are mitigated by the creditworthiness provision. Manitoba Hydro's export contracts are executed with bilateral customers who are financially strong and creditworthy based on the financial metrics, investment grade credit ratings, and the regulatory support that the customers receive from their respective regulatory commission to ensure their continued financial integrity. However, if a customer's creditworthiness becomes unsatisfactory to Manitoba Hydro at any point during the term of the sale, Manitoba Hydro's export contracts contain provisions that allow Manitoba Hydro to request performance assurance from the customer. The performance assurance is typically in the form of a letter of credit issued by an investment-grade bank and can be drawn upon by Manitoba Hydro to ensure collection on any amounts owing under the export contract.

Conditions and Options

Flexibility is needed to address the uncertainties associated with the timing of regulatory approvals and permitting for large generation and transmission facilities. Export contracts that depend on new generation or transmission facilities contain conditions and options that allow for a potential delay in the start of the sale or the termination of the sale. In the case of the 250 MW MP sale and the 100 MW WPS sale, there are provisions for up to two years delay in the start of the contracts if regulatory approvals are delayed. It is anticipated that the 300 MW WPS sale will have the same regulatory delay provision.

Conditions Precedent

Conditions precedent ensure that Manitoba Hydro's obligations under export sale contracts do not take effect unless specific key conditions are met. These include receipt of all needed approvals and authorizations (i.e. Orders in Council, licences, permits and National Energy Board authorization) for the contracts by specified dates.

Conditions precedent in favour of Manitoba Hydro can also protect Manitoba Hydro should financial or economic circumstances materially change.

15.2.3 Transmission Rights

Manitoba Hydro currently has the rights to 1,850 MW of export and 750 MW of import capacity to and from MISO. In addition, the 500 kilovolt (kV) Great Northern Transmission Line (GNTL) is expected to provide an additional 750 MW of firm import and export capacity, bringing total capabilities to 2,600 MW export and 1,500 MW import. These transmission rights will be used to market all energy produced by Manitoba Hydro's generating resources in excess of Manitoba domestic load and to purchase energy when needed to meet Manitoba Hydro's domestic and export commitments. Manitoba Hydro's ability to sell and/or purchase energy from the MISO market using existing and future firm transmission service gives Manitoba Hydro the flexibility to export and/or import electricity to address any over- or under-supply or reliability risks associated with the Preferred Development Plan.

15.2.4 Market Products

Manitoba Hydro's participation in the MISO market provides an opportunity to utilize various market related products to manage the physical and financial risks associated with the Preferred Development Plan and the associated export contracts. Market-related products that can be utilized to manage these physical and financial risks include the day-ahead and real-time markets (to sell or purchase energy), financial transmission rights (to manage congestion cost risks), and financial swaps.

Manitoba Hydro's participation in the MISO market has provided an opportunity to develop and/or utilize a number of unique customized market products. These products include:

- Module E[1] - use limited capacity (capacity sales with a daily four-hour energy offer obligation that recognizes that hydraulic generation facilities can have limited water supplies)
- Module B[2] energy sales (utilized by Manitoba Hydro for surplus energy sales)
- system participation sales
- seasonal diversity agreements.

Manitoba Hydro will continue to utilize these products to manage the capacity and energy associated with the Preferred Development Plan.

[1] Module E is a product of the MISO Tariff that provides mandatory requirements to be met by the transmission provider, load serving entity and other market participants to ensure a load-serving entity has sufficient access to deliverable, reliable and adequate capacity resources to meet its anticipated peak demand requirements plus an appropriate reserve margin.

[2] Module B is a product of the MISO Tariff that provides details on a host of transmission-related issues, including the types of service (Network and Point-to Point), procedures and rules for requesting transmission service, and the treatment of grandfathered transmission service.

15.3 New U.S. Transmission Interconnection Project

As introduced in ***Chapter 2- Manitoba Hydro's Preferred Development Plan Facilities***, the proposed new transmission interconnection is an international transmission line with two distinct components – the Manitoba-Minnesota Transmission Project (MMTP) in Manitoba (a 500 kV/750 MW transmission line between Dorsey and U.S. border) and the GNTL in Minnesota (Manitoba Hydro would contribute financially to the U.S. component of the interconnection to be built by MP). The interconnection would have an incremental transfer capability of 750 MW for both exports from and imports into Manitoba. For a more detailed description of the interconnection projects, refer to ***Chapter 6 – The Window of Opportunity,*** section 6.5.3.

Actual transmission line routing in Manitoba will be the subject of subsequent environmental and technical studies which started in May 2013. No preliminary routes or corridors have been identified for the MMTP.

15.3.1 Related Agreements

There are several agreements being developed in relation to the construction of the new transmission interconnection. A Memorandum of Understanding (MOU) was entered into between Manitoba Hydro and MP on January 25, 2013 for the purpose of outlining a framework for further discussions between Manitoba Hydro and MP regarding:

- the general line route and arrangement for a 500-kV interconnection and
- an agreement to work towards both a term sheet relating to the development of the 500-kV interconnection and a cost sharing agreement for development expenses.

A Cost Sharing Agreement between Manitoba Hydro and MP was subsequently signed on March 31, 2013. In order to realize the target ISD of the GNTL, MP has incurred development expenses in advance of having executed a MISO Facilities Construction Agreement. Manitoba Hydro has committed to funding a portion of planning and engineering expenses as outlined in ***Chapter 6 – The Window of Opportunity,*** Section 6.5.3.3.

In addition, the following agreements are under development in relation to the construction of the new transmission interconnection:

- MISO Facilities Construction Agreement
- Manitoba Hydro Facilities Construction Agreement
- Transmission Service and Generator Interconnection Agreements
- Letter of Intent and Term Sheet (providing a framework for agreements required to proceed through the construction phase of the interconnection project)
- Project Development Agreement, scheduled for completion February 28, 2014.

For more details pertaining to these agreements, refer to ***Chapter 6 – The Window of Opportunity,*** section 6.5.3.

15.3.2 Reviews and Approvals

The new 750 MW U.S. interconnection is subject to regulatory review in both Canada and the U.S. With each regulatory hurdle, there is a risk that approval may not be granted. Without a new U.S. interconnection, neither the 250 MW MP sale nor the proposed 300 MW WPS sale would proceed.

Canadian Approvals

On the Canadian side, federal permitting is required from the National Energy Board for the MMTP interconnection project. Permitting is anticipated to be received by December 2016.

The Manitoba Hydro Act requires the corporation obtain approval of the Lieutenant-Governor in Council in order to develop new power generation stations. By Order In Council 00128/2013 dated April 17, 2013, the Government of Manitoba directed the PUB to conduct an Needs For and Alternatives To (NFAT) review and provide a report outlining its recommendations. The Government of Manitoba will make its determination as to what orders will be issued following consideration of the report.

The MMTP will require an environmental assessment and review under *The Environment Act.* At the conclusion of that process, the Minister of Conservation and Water Stewardship will determine if a licence will be issued. The assessment and review process, including the Minister's decision, is expected to be completed by June 2016.

U.S. Approvals

The major permits required on the U.S. side of the border are a Certificate of Need and a Route Permit—both granted by the Minnesota Public Utilities Commission—and are anticipated to be received by October 2015. Other required approvals include a Presidential Permit from the United States Department of Energy and a Wetland Permit from the U.S. Army Corps of Engineers. During the certification phase, additional state and federal approvals are also required.

15.3.3 Project Delivery — MMTP

The ISD of the new 750 MW interconnection is planned to coincide with the start of the 250 MW MP export sale beginning June 1, 2020. The engineering phase of this project will begin in 2015 and continue to the end of the project. Construction is scheduled to occur from 2017 to 2020, subject to all of the required agreements and regulatory approvals discussed earlier.

During the engineering and construction phase of this project, project risks will be identified in a project risk registry. This registry, which is an industry best practice, will serve as a project management tool to aid in managing the construction and decision making and in ensuring that the overall project remains within schedule and budget.

Manitoba Hydro will have to begin Keeyask G.S. construction before it receives National Energy Board approvals (for the export sales and the MMTP interconnection) or a *Manitoba Environment Act* licence for the MMTP. Manitoba Hydro expects to receive transmission interconnection approvals from the NEB by the spring of 2016. Complete applications to the NEB are expected to include evidence that environmental approvals have been received to construct Keeyask G.S.

Under the 250 MW MP sale and the 100 MW WPS sale, Manitoba Hydro assumes Keeyask G.S. construction schedule risk on the date when Manitoba Hydro starts constructing the Keeyask cofferdam. The 125 MW NSP sale provides Manitoba Hydro with the option of not proceeding with the PSA up to 2018 should circumstances warrant. The agreements protect Manitoba Hydro from uncontrollable events during this construction period via the force majeure provisions, with the exception of Manitoba Hydro labour strikes. If Keeyask G.S. construction schedule is delayed, Manitoba Hydro would, if necessary, be required to purchase energy/capacity from the market to fulfill its contractual obligations to MP, WPS and NSP. If the transmission interconnection construction schedule is delayed, Manitoba Hydro has the option, but not obligation, to fulfill the MP sale through existing transmission service.

15.4 Keeyask and Conawapa Generation Projects

This section discusses two categories of risks: those risks associated with Manitoba Hydro's agreements to engage Cree Nations in the planning and development of the Keeyask and Conawapa Projects; and those risks associated with gaining regulatory approval for the projects.

15.4.1 Agreements for Aboriginal Participation

Under existing agreements stemming from the settlement for adverse effects of the Churchill River Diversion and Lake Winnipeg Regulation projects, Manitoba Hydro is obligated to achieve adverse effects agreements with Tataskweyak Cree Nation (TCN), War Lake First Nation (WLFN), York Factory First Nation (YFFN); and Fox Lake Cree Nation (FLCN). Agreements may be arbitrated if negotiations are not successful.

There is no similar legal requirement to achieve benefit-sharing agreements. Nevertheless, Manitoba Hydro was at the forefront of such agreements in Canada when it began negotiations for the Wuskwatim and Keeyask Projects, and it views benefit-sharing as a foundational element to the successful development of its next major hydroelectric generation project on the Nelson River, Conawapa G.S.
There are risks associated in the process to develop an agreement, and there are risks once an agreement is reached. The following sections discuss the risks associated with the Keeyask and Conawapa Projects.

15.4.1.1 Keeyask Hydropower Limited Partnership

Manitoba Hydro and the four Keeyask Cree Nations (KCNs) – TCN and WLFN, working together as the Cree Nation Partners; YFFN; and FLCN – have ratified the Joint Keeyask Development Agreement (JKDA) under which the Keeyask Hydropower Limited Partnership was established. In the agreement the KCNs and Manitoba Hydro have explicitly committed their support to the project.

The process of negotiating the agreement, and the agreement itself, address potential risks. In this regard, Manitoba Hydro shared financial projections with the KCNs while the JKDA was being negotiated. These included many different assumptions, resulting in low, medium and high estimates. The KCNs are thus aware there is a wide range of potential returns from their investments, and that the Keeyask financial results modelled during negotiations used the forecasting information available at that time. Manitoba Hydro has continued to keep the KCNs informed of the Keeyask Project economics.

The economic circumstances of Hydro's major projects have changed during the past several years, due in part to lower energy prices. Manitoba Hydro and Nisichawayasihk Cree Nation, its partner in Wuskwatim, G.S. are currently negotiating amendments to the Wuskwatim Development Agreement to deal with this issue.

Manitoba Hydro believes adjustments it has made to its development plans for Keeyask, G.S. in part through learnings from the Wuskwatim Project, will assist in managing risks related to project costs, revenues and schedule. The JKDA includes two investment options, common and preferred. The availability of these two options provides each of the KCNs with an investment choice depending upon their risk tolerance.

For more discussion about risks associated with this partnership model, see ***Appendix 15.1 - Keeyask Aboriginal Partnership Business Risks***.

15.4.1.2 Conawapa Project Agreements

Manitoba Hydro and the five Cree Nations on or in the vicinity of the lower Nelson River (FLCN, YFFN, TCN, WLFN and Shamattawa First Nation) have protocols to discuss benefit agreements related to the Conawapa Project. These processes are ongoing.

It is expected that without adverse effects and benefit-sharing agreements, and the corresponding support of the local First Nations, there could be significant challenges to achieving the required licences and approvals for Conawapa G.S.

15.4.2 Reviews and Approvals

The federal and provincial governments each have regulatory regimes that must be satisfied before the major projects in the Preferred Development Plan can be constructed. Each jurisdiction has foundational legislation for its environmental reviews: the *Canadian Environmental Assessment Act* and *National Energy Board Act* for federal authorizations and *The Environment Act* and *The Water Power Act* for provincial authorizations. Without successful conclusions under these Acts, the Keeyask Project, Conawapa Project, North-South Transmission Upgrade and, as noted in Section 15.3.2, the Manitoba-Minnesota Transmission Project, will not be developed.

The potential listing of Lake Sturgeon under the *Species at Risk Act (SARA)* also poses a significant regulatory risk. *SARA* could impose restrictions on the potential development (and operations) of the Keeyask and Conawapa Projects.

The following sections discuss the risks associated with *The Environment Act* (Manitoba), *Canadian Environmental Assessment Act,* and *SARA.*

15.4.2.1 The Environment Act (Manitoba)

The Keeyask Generation and Transmission projects are currently being reviewed under *The Environment Act.* The Minister has asked the Clean Environment Commission (CEC) to hold hearings and provide recommendations regarding the generation project. The Minister will determine if a licence should be issued and, if so, what conditions should apply. Appeals of the Minister's decision are made to the Lieutenant-Governor in Council. The Director of Environmental Assessment and Licensing will determine if a license will be issued for the transmission project; appeals of the Director's decision are made to the Minister.

To manage the licensing risk, Manitoba Hydro and its Cree Nation partners, through the Keeyask Hydropower Limited Partnership, have undertaken a thorough environmental impact assessment using technical sciences and Aboriginal traditional knowledge. As recorded in ***Chapter 2 – Manitoba Hydro's Preferred Development Plan Facilities***, potential adverse effects have been identified and then avoided, reduced or mitigated; and potential benefits have been enhanced.

Manitoba Hydro also undertook a complete environmental assessment of the Keeyask Transmission Project, a process which included engagement with the local Cree Nations. Manitoba Hydro has a long, successful record of planning, assessing and licensing transmission projects.

Before the Province issues licences, it will also consult with First Nations and Métis people. The four KCNs have adverse effects agreements which they acknowledge address impacts to the exercise of their Treaty and Aboriginal rights. The Province has initiated consultations with the KCNs and other aboriginal communities.

The CEC, in its report on the Bipole III Project, proposed as a non-licensing recommendation that “Manitoba Hydro, in cooperation with the Manitoba Government, conduct a Regional Cumulative Effects Assessment for all Manitoba Hydro projects and associated infrastructure in the Nelson River sub-watershed” before any additional projects after Bipole III are licensed. If the Government of Manitoba were to adopt this recommendation and require such an assessment be carried out prior to licensing the Keeyask Generating Project, a delay could ensue.

It should be noted that the Keeyask Environmental Impact Statement (EIS) was filed in July 2012. Consistent with the EIS Guidelines issued by environmental regulators, the environmental impact statement includes a cumulative effects assessment, and, where appropriate, takes a regional perspective to assess cumulative effects on specific Valued Environmental Components. The ultimate decision whether the CEC’s recommendation be adopted rests with the same party with approval power for the Keeyask Project, i.e. the Government of Manitoba. While adoption of the CEC recommendation is a risk to the Keeyask Project, it is not a third-party risk that is outside the control or consciousness of the decision maker, the Manitoba Government.

The Conawapa Project, as well as the North-South Transmission System Upgrade and the Manitoba-Minnesota Transmission Projects, are still under study and no applications have been filed for regulatory review.

15.4.2.2 Canadian Environmental Assessment Act

The Canadian Environmental Assessment Agency is leading the development and production of a Comprehensive Study Report (CSR) of the Keeyask Generation Project. If the CSR determines the project will not causes a significant adverse effect, the Minister of Environment may inform federal departments with regulatory functions to issue authorizations for the project. If the CSR determines Keeyask G.S. will cause a significant adverse effect, the Minister may inform departments to issue authorizations only if the federal Governor-in-Council concludes the adverse effect is justified in this circumstance.

As noted previously, Manitoba Hydro and its Cree Nation partners, through the Keeyask Hydropower Limited Partnership, have undertaken a thorough environmental impact assessment using technical sciences and Aboriginal traditional knowledge. As explained in ***Chapter 2 – Manitoba Hydro's Preferred Development Plan Facilities***, potential adverse effects have been identified and then avoided, reduced or mitigated; and potential benefits have been enhanced. As such, Manitoba Hydro does not believe the project will cause a significant adverse effect. However, should the CSR arrive at that conclusion, the many socio-economic benefits (e.g., reductions in greenhouse gases; increases in Lake Sturgeon populations; training and employment for northern Aboriginal workers; Cree Nation business opportunities; capacity building and profits for the Keeyask Cree Nations; and clean renewable energy for Manitobans and export markets) may lead to a conclusion that the adverse effect is justified in the circumstance.

As with the provincial process, the federal government must also conduct Aboriginal consultations in accordance with section 35 of the Constitution.

The Conawapa Project will also require federal authorizations. This project is still under study and applications have not been filed for regulatory review.

15.4.2.3 Species at Risk Act

As discussed in Section 10.6.5, the federal government is considering whether to list Lake Sturgeon in the Nelson River as endangered under the *SARA.* Manitoba Hydro is proactively engaging in discussions with both provincial and federal regulators on its Lake Sturgeon stewardship plans. Activities include coordinating with the Manitoba Department of Conservation and Water Stewardship (Fisheries Branch) to ensure that stewardship activities are consistent with the provincial Lake Sturgeon Management Strategy. Manitoba Hydro is also communicating with staff from DFO to keep them informed about its approach to Lake Sturgeon stewardship, current activities, progress and outcomes. Manitoba Hydro's commitment and approach to Lake Sturgeon stewardship, with examples of stewardship activities, are explained in detail in ***Appendix 2.1 - Lake Sturgeon: Mitigation and Enhancement***.

If Lake Sturgeon were to be listed under *SARA*, provisions would be implemented to protect individual fish and critical habitat. Fisheries and Oceans Canada (DFO) would develop a Recovery Strategy for Lake Sturgeon, followed by an Action Plan setting out the activities that would have to be undertaken to prevent harm to Lake Sturgeon and protect their habitat. If Manitoba Hydro (and, in the case of Keeyask, the partnership) wished to proceed with the Keeyask and/or Conawapa Projects, federal permits would have to be secured under the *SARA* in order to build and operate any new hydroelectric generating stations on the waterways where Lake Sturgeon were listed as endangered. The Keeyask and Conawapa Projects could be delayed or possibly cancelled if Lake Sturgeon are listed under *SARA*.

The federal decision may not occur until after June 2014, when construction on Keeyask is schedule to begin. If this were to occur, Manitoba Hydro would evaluate the situation at the time, including the likelihood of a future listing under *SARA*, and the costs and risks of delaying construction versus proceeding with construction.

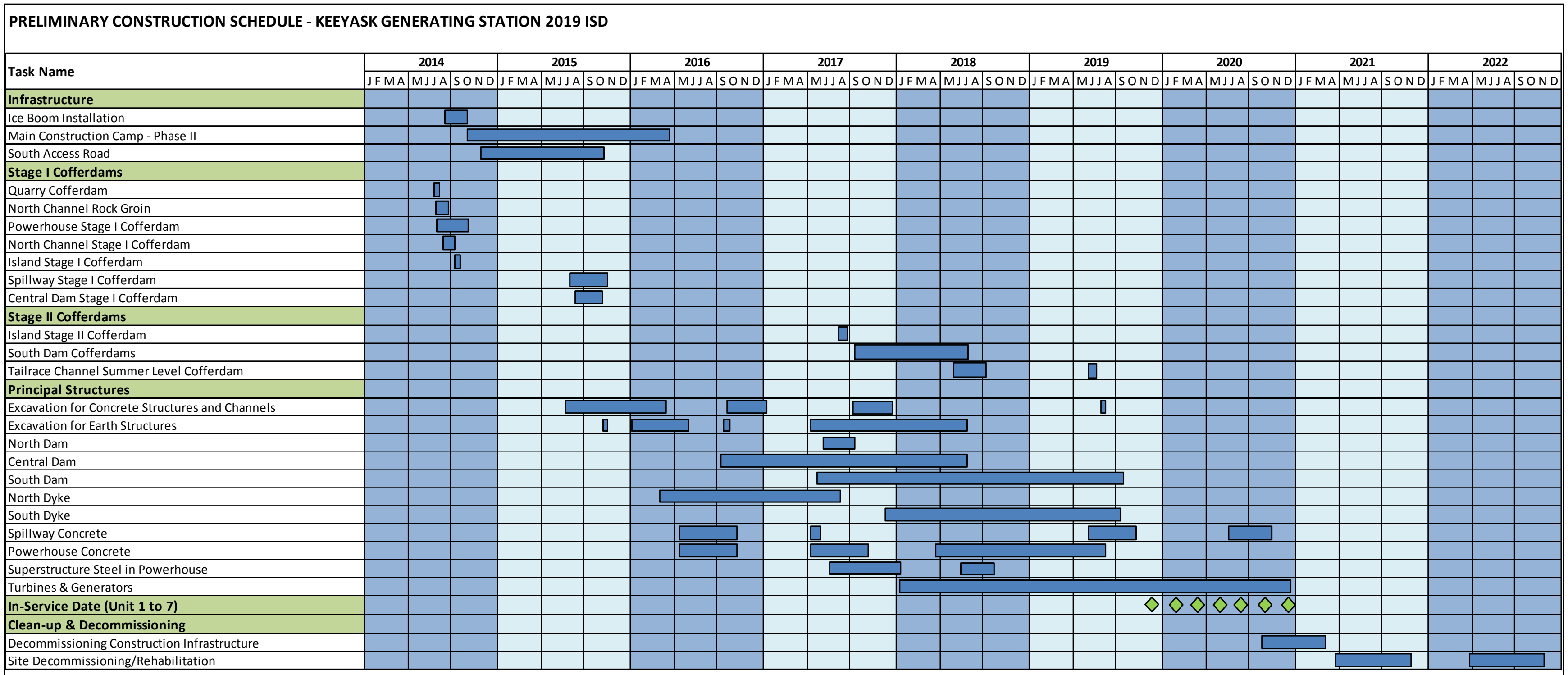
15.5 Generating Station Project Delivery

This section outlines the methodology Manitoba Hydro follows in selecting a delivery model and contract packaging for a project and outlines how this has been done on the Keeyask Project. Additionally, the section provides an overview of Manitoba Hydro's key project management plans/processes used to successfully deliver major generation projects.

As detailed Stage V Engineering[3] on Conawapa G.S. has not yet begun, a formal project delivery strategy has not yet been established. Manitoba Hydro will continue to monitor the attractiveness of Conawapa's 2026 ISD. The EIS will be needed to be filed in 2015 and construction will need to begin in 2018 to meet the 2026 ISD. At any point, Manitoba Hydro may decide to defer the Conawapa G.S. ISD based on the evolution of conditions including export sale agreements, domestic energy requirements and other factors. Based on this approach, a decision on project delivery strategy for Conawapa G.S. is not anticipated until the project has progressed to Stage V—anticipated to occur around 2016, based on a 2026 ISD.
Constructions schedules for Keeyask G.S. 2019 ISD and Conawapa G.S. 2026 ISD are shown in Figures 15.3 and 15.4, respectively:

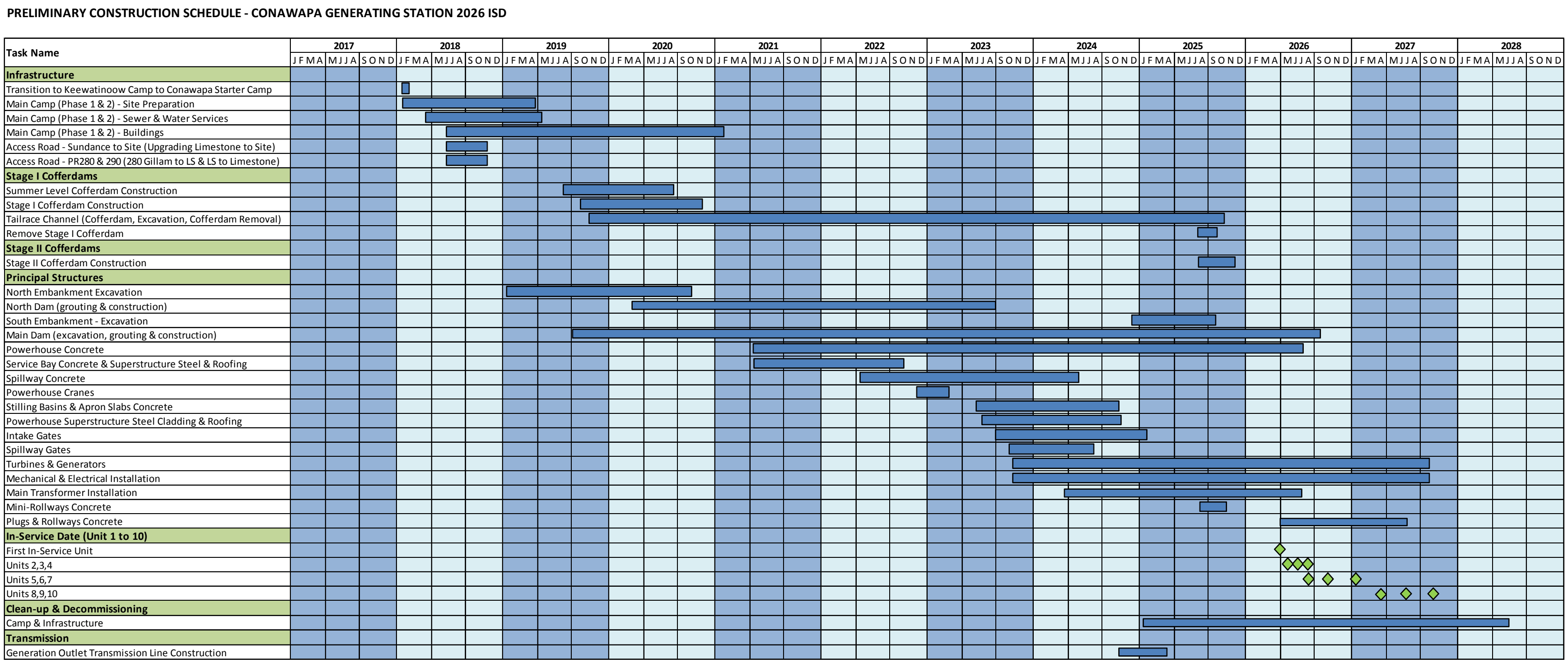
[3] Refer to Appendix 7.2 Resource Options Report for a detailed explanation of Manitoba Hydro's project development stages.

Figure 15.3 **KEEYASK 2019 ISD PRELIMINARY CONSTRUCTION SCHEDULE**



NOTE: The timelines above show the start and end dates of each activity, but do not reflect the downtime periods that may occur throughout the activity.

Figure 15.4 CONAWAPA 2026 ISD PRELIMINARY CONSTRUCTION SCHEDULE



NOTE: The timelines above show the start and end dates of each activity, but do not reflect the downtime periods that may occur throughout the activity.

15.5.1 Selection of Project Delivery Strategy

A project delivery strategy refers to the model or approach that will be followed to execute a project. As such, the project delivery strategy is a critical factor in successful project implementation. Selection of a project delivery strategy is based on numerous factors that include the project objectives, its key success factors and project risks. Project delivery strategies typically considered for the construction of major hydroelectric generating stations include the following:

- **Design Bid Build (DBB)** – A staged contracting approach whereby Manitoba Hydro as the owner contracts the design and then competitively tenders the work to a contractor who constructs the work.
- **Construction Management (CM)** – The owner contracts the design and, in parallel, contracts a Construction Manager who may act as the owner's agent in managing the construction, or is considered "at risk" and assumes the majority risk by guaranteeing the schedule and budget, and who contracts all of the trades to construct the work. In either case the Construction Manager provides essential design input from the beginning of the detailed design phase.
- **Design Build (DB) or Engineer Procure Construct (EPC)** – The owner contracts a single entity that is responsible for both the design and construction of the work. This entity holds the majority of risks related to both design and construction. However, this type of risk allocation is reflected in the entity's pricing of the work.
- **Integrated Project Delivery (IPD)** – The owner contracts a designer to carry out detailed design and, in parallel, contracts a contractor to provide early contractor input to the detailed design. The owner creates a multi-party contract (or teaming agreement) between the owner, designer, and contractor to undertake the collaborative approach to the design with an opportunity to award the construction phase to the contractor (the term "Integrated Design-Build" was used for the Pointe du Bois Spillway Replacement Project). This model provides a

more collaborative structure than a typical Design Build, which allows for more equitable risk allocation.

- **Alliance** – The owner contracts the designer and contractor under a single unifying teaming or partnership agreement to execute all phases of the project. Project risk and opportunities are shared equitably and project management decisions are made by the alliance. All parties share in the financial stake success or failure of the project (i.e. share in the cost overrun or underrun from the budgeted amount).

Contract Packaging

As a result of the broad type of work (i.e. civil, mechanical, electrical) required in the construction of a hydroelectric generating station, work is generally divided into defined contract packages. The contract must properly allocate the risk to the contractor and fit with other contracts within the project delivery system. Additional considerations in the development of the contract packaging include contractor capabilities, general construction market conditions and the ability to meet obligations to project partners. Typical major contract packages include:

- General Civil Contract
- Turbines and Generators Contract
- Electrical and Mechanical Contract
- Construction Camp Contract
- Camp Operation and Services Contracts and
- Stage V Detailed Design Contract.

15.5.2 Keeyask Project Delivery Strategy and Contract Packaging

The Keeyask Project delivery strategy will employ a hybrid Design Bid Build model utilizing Integrated Project Delivery and Engineer Procure Construct approaches that best suit certain portions of the project. This delivery model is structured as follows:

- Manitoba Hydro acts as the Project Manager and Construction Manager responsible for the overall project costs, schedule and quality. Manitoba Hydro holds separate contracts with each contractor and has overall responsibility for interface management.
- A single project designer is responsible for the majority of the project design. This design team is lead by Hatch and includes SNC Lavalin and KGS. Internal Manitoba Hydro resources provide design and define performance specifications for some of the specialized EPC contracts.
- An Engineer, Procure, Construct model has been selected for the turbine and generators contract, with the contractor being responsible for design, manufacturing and installation. The performance specification is defined by Manitoba Hydro's design team. In addition, this model will be utilized for the spillway gates, intake gates, cranes, and majority of the electrical equipment contracts.
- An integrated design build approach with a target price model will be implemented for the General Civil Contract, which is described further in the section that follows.

Keeyask General Civil Contract (GCC)

The GCC will be the largest contract on the Project and is made up of a range of work packages including excavation, cofferdam construction, river management, dams, dykes, and electrical and mechanical works, as well as construction of the powerhouse and spillway structures. Design Build, Design Bid Build and Integrated Design Build project delivery methods were considered for the delivery of the Keeyask GCC. Other project delivery methods including turnkey options were not considered as they remove Manitoba Hydro from the project execution phase, jeopardizing both budget and quality goals. Prior to selecting a delivery strategy for the project, critical success factors were identified including safety and environment considerations; ability to meet approved budget and in-service dates; maximizing opportunities for KCN partners where capacity exists; developing project and construction management expertise within Manitoba Hydro; and obtaining early constructability input to maximize value to the project. Project delivery methods were ranked against one another based on these critical success factors.

The GCC for the Keeyask Generation Project will be executed using an Integrated Design Build or Early Contractor involvement process. In this model, the designer carries out the detailed design and the contractor provides constructability input as the design is developed. Involving the contractor early in the detailed design phase helps to ensure that the contractor's extensive construction knowledge is incorporated into the design and the opportunity for cost savings in the form of value engineering is increased. Since the contractor is involved in the process nearly two years before major GCC construction begins, they have the opportunity to refine the schedule, secure the necessary labour and form alliances with Manitoba suppliers and sub-contractors. Once construction starts, it is likely that claims will be minimized and costly disputes avoided because the contractor will have all available information and an opportunity to provide input into the final design.

To help reduce scheduling risk and potential interface issues, a number of contracts will be bundled with the GCC, including the Electrical and Mechanical contract, excavation, cofferdams and draft tube forms. The reduction of interface risk was a lesson learned from the Wuskwatim project, which had several different contracts. Other construction contracts for the Keeyask G.S., such as the turbines and generations, will be executed by the Design Build method.

Selection of the contractor is based on target prices submitted through a Request for Proposal process and assessment of the best value offered to Manitoba Hydro. Determining best value includes consideration of the contractor's ability to reduce risks to the schedule and increase the possibility of early in-service dates, as these outcomes have substantial financial benefits.

Project Management Roles and Responsibilities in Keeyask Delivery Strategy

Manitoba Hydro acts as the Project Manager and Construction Manager responsible for the overall project cost, schedule and quality. Manitoba Hydro holds separate contracts with each contractor and has overall responsibility for interface management. Additionally, Manitoba Hydro holds project responsibility over environmental, stakeholder and partnership issues. The contractors are responsible for managing their specific scope of work and the Stage V Design consultant is responsible for the majority of engineering and design for the project. The respective responsibilities are outlined further in Figure 15.5 below.

Figure 15.5 PROJECT MANAGEMENT RESPONSIBILITIES

Project Management Responsibilities

OWNER – MANITOBA HYDRO:

- The Owner provides the overall direction and governance on the project.
- The Project Owner has responsibility for overall performance of the project. Specific areas of project responsibility include: financial, regulatory, environmental, stakeholder management, partnership, etc.

DESIGNER ENGINEER – HATCH:

- The project Designer is a 3rd party Engineer firm hired by the Owner (Manitoba Hydro) who is responsible for the majority of the project design
- The Design Engineer also plays a support role during construction

CONTRACTORS AND VENDORS:

- Contractors and Vendors carry out the actual construction and supply of equipment
- Each Contractor manages their own work with overall coordination between Contractor managed by the Owner
- Includes GCC, T & G Contractor, etc.

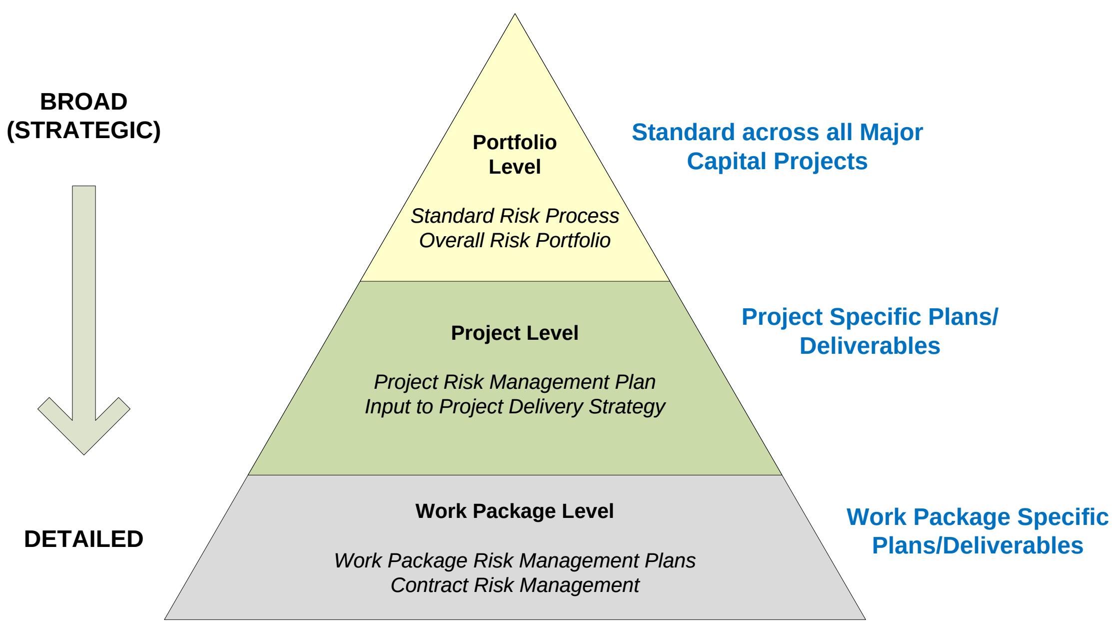
15.6 Project Management and Control for Generation Projects

The following sections outline key project management plans/processes that enable successful project implementation.

15.6.1 Risk Management

Effective risk management is a critical aspect of Manitoba Hydro's project management practices and is necessary to ensure the required project objectives are achieved. The risk management process implemented on capital projects considers three levels of risk: i) portfolio, ii) project, and iii) work package. Risk management is driven from the portfolio level. Project-level risk documents are developed based on the portfolio-level documents and likewise work package-level risk documents are developed based on both portfolio and project-level documents. A top-down approach ensures approaches followed on portfolio-level risk documents are applied to all detailed risk documents, and strategies for risk management are driven down into the development of the detailed documents/plans (see Figure 15.6).

Figure 15.6 STAGES OF RISK MANAGEMENT PROCESS



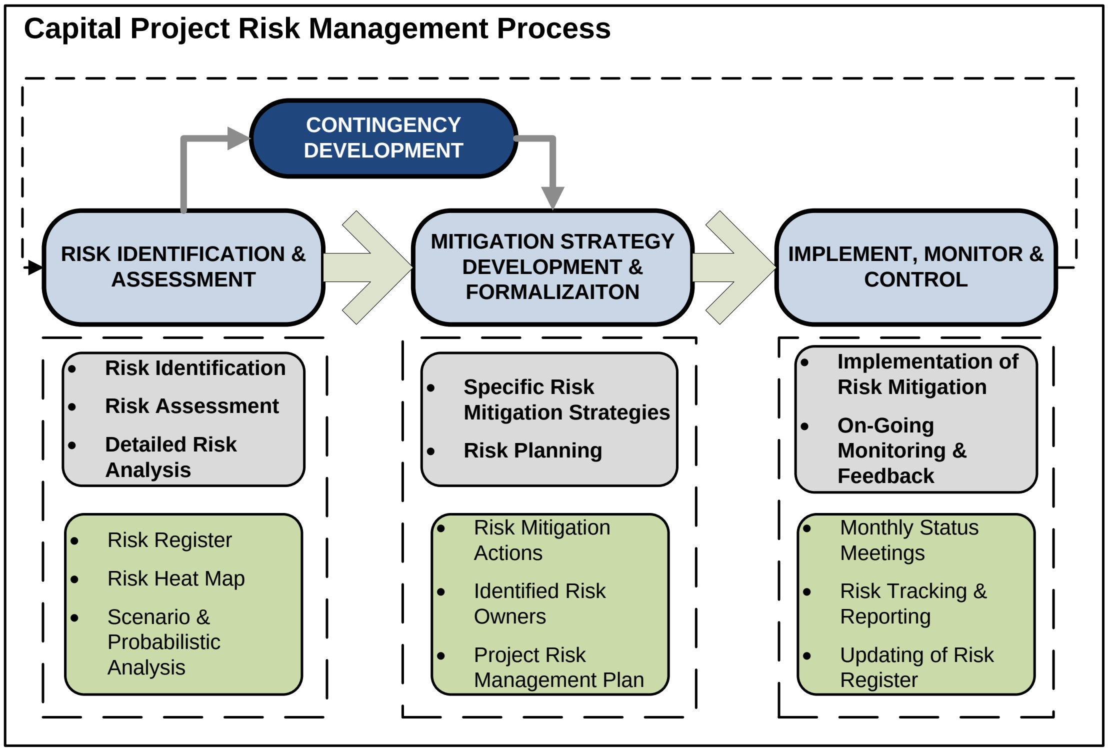
Risk Management through Project Progression

Risk management is an iterative process and occurs frequently from early design through completion of construction. The end of Stage IV Engineering or the beginning of Stage V Engineering are the typical points for implementing the first detailed risk management activities. At this stage of project development the desired output of the risk management process is a detailed, actionable risk management plan for the entire project. As the project progresses through Stage V Engineering, risk management activities become specific to the project's work packages (contracts). These activities are described in more detail below.

Project Risk Management Process

The basic project risk management process applied to Keeyask G.S. and Conawapa G.S. follows recognized project management best practices. The process includes risk identification, quantification, mitigation planning, mitigation, implementation, and monitoring and tracking. This process is shown below and described in the sections that follow:

Figure 15.7 CAPITAL PROJECT RISK MANAGEMENT PROCESS



Risk Assessment

Risk assessment is the process of identifying risk items that influence/drive uncertainty on the project; these risk items are captured in a project risk register, a living document that acts as the repository for all identified project risks throughout the life of the project. The impact and probability for each risk event is scored, allowing identified risks to be prioritized based on a risk score (impact x probability) to help focus risk management activities on the most critical items.

Detailed Risk Analysis

Detailed risk analysis involves developing a quantitative assessment of each risk's impact and probability. The key output of this stage is a detailed profile of each risk event in order to facilitate development of a detailed risk mitigation strategy. Actions taken during this stage include activities such as development of schedule "what if" scenarios, probabilistic (Monte-Carlo) analysis and constructability reviews.

Risk Mitigation Development

Risk mitigation strategies are developed specific to each identified risk. Mitigation strategies include: acceptance, elimination, mitigation or transfer. Selection of the appropriate strategy will depend on numerous factors and is assessed on a risk-by-risk basis.

Risk Tracking

Risk tracking involves establishing metrics that allow the project team to assess the level of success of risk mitigation actions. Information from this step feeds back into the risk management process for future analyses.

Contingency Development

Contingency development is a subset of risk mitigation and is both a part of the risk management process and the cost estimate development process. Methodologies used to determine contingency are described further as part of the description of Manitoba Hydro's cost estimating methodology described in ***Appendix 2.4 – Developing the Keeyask and Conawapa Capital Cost Estimates***.

15.6.2 Key Lessons Learned from Wuskwatim

Manitoba Hydro undertook "lessons learned" reviews during the pre-construction and construction phases of Wuskwatim and has applied these lessons to the Keeyask and Conawapa planning and cost estimating processes as a key additional risk management step. Specific actions taken from these lessons learned in the pre-construction phase are:

- development of a comprehensive master pre-construction schedule

- early inputs from and engagement with stakeholders (regulators and affected communities) to ensure the project scope is well defined, understood and agreed to by all parties and
- more engineering and environmental information developed earlier in the planning process to support partnership and regulatory work.

Specific actions taken from these lessons learned in the construction phase are:

- moving supporting infrastructure design and construction activities (such as those for access roads and camps) out of the generation project and into separate earlier projects. This allows for increased benefits to First Nations and reduces construction delay risks associated with infrastructure work
- ensuring the construction camp provides craft workers with remote-site living conditions of the highest quality that are on par with other remote major project sites across Canada
- consideration of new approaches to contract frameworks (e.g., "target price" contracts) to improve alignment with prevailing market conditions, attract contractor interest, and provide incentives for contractor performance
- early input from contractors to maximize opportunities for optimization of design cost-effectiveness and constructability. Also, to allow for development of a detailed labour plan for the project
- work packaging and contract scoping optimized to mitigate schedule and contract risks. Specifically, eliminating interfaces between the General Civil Contractor and the Electrical and Mechanical Contractor.

15.6.3 Risk Management on Keeyask and Conawapa

Risks to the Keeyask and Conawapa Projects will be managed following the previously described capital project risk management process. The general categories of risk that each project is exposed to and that must be managed during the pre-construction and construction phases are as follows:

- Regulatory: Includes risks related to regulatory approvals, SARA, on-going environmental protection, etc.
- Stakeholder: Includes risks related to negotiated agreements, stakeholder engagement, etc.
- Execution: Includes risks related to procurement, design, construction and installation
- Safety: Includes risks related to ensuring safe operations during construction
- Labour: Risks related to attraction and retention of labour and overall productivity of labour
- Cost Escalation: Risk related to adverse changes in the marketplace resulting in increased cost escalation.

A number of risk mitigation measures have already been implemented for Keeyask and Conawapa Projects to address the above risks. The following are some of the key actions being taken on the Keeyask Project:

- Early Contractor Involvement: The General Civil Contractor will be brought on nearly two years before major GCC construction is scheduled to begin. The primary advantage of such an approach is that it allows the GCC to incorporate constructability into the project design and optimize the project construction schedule to mitigate construction risks. Additionally, it allows the GCC to work with Manitoba Hydro in addressing labour attraction, retention and productivity risks.
- Contract Packaging: The work on the Keeyask Project has been packaged to minimize contractor interfaces that could affect project schedule. The most notable instance of this is the inclusion of the Electrical & Mechanical work in the

General Civil Contract, which, as noted, was a key lesson learned from Wuskwatim.

- Regulatory and Stakeholder Engagement: Manitoba Hydro is actively engaged with key regulatory bodies and project stakeholders to manage the pre-construction process. This engagement is intended to help ensure the project can move forward and all groups benefit from construction of the project.
- Sufficient Project Contingency Fund: Contingency is the primary financial measure applied in managing project risks. Carrying a sufficient project contingency ensures funds have been planned for and are available to address the uncertainties that exist in the construction of a hydroelectric generating station.

15.6.3.1 Application of Labour and Escalation Reserves in Managing Risk

The additional requirement of management reserve funds was identified as required to properly address both labour and cost escalation risks, based on current market conditions and labour restrictions. The use of these reserves and mitigation of the associated risks are discussed below.

Labour Reserve

As outlined, the potential impact of labour availability and productivity issues is anticipated to exceed what is included in the P50 contingency in the Base Estimate. This issue is largely due to the restrictions that could be placed on the projects' ability to address the current and expected state of the Canadian construction labour market.

The labour risk has been calculated based on a series of correlated and cumulative impacts that together act as a single major event. As a result, it is difficult to say what portion of this risk would apply at different probabilities. The use of a labour risk is similar to a scope change in which, if that scope change occurred, the associated cost would be added to the estimate.

A number of steps are being taken by Manitoba Hydro to mitigate labour risk and the need to draw from the labour reserve. Key steps that have been or are being taken related to the Keeyask Project are as follows:

- *High-Quality Construction Camp*: The camp currently in construction for the Keeyask Project has seen a significant increase in the level of quality compared to the camp that was in place at the Wuskwatim project. Feedback to-date from both contractor and union groups on camp quality has been very positive.
- *Changes to Isolation Leaves and Travel Costs in the Burntwood Nelson Agreement*[4]: The isolation-leave provisions in the BNA have been successfully changed from five weeks in and one week out for craft workers to three weeks in and one week out. This change aligns the projects more closely with other remote projects across Canada, improving the ability to attract and retain labour.
- *Stakeholder Engagement*: Discussions are being held with both the Construction Labour Relations Association of Manitoba (group representing the contractors) and the Allied Hydro Council (group representing the unions) to collaborate on identifying opportunities to address craft labour supply concerns on the projects.
- *Early Contractor Involvement*: As already outlined, the General Civil Contractor will have the time to take critical steps to improve the recruitment of labour on the project.

[4] The Burntwood Nelson Agreement (BNA) is a no-strike, no-lockout collective bargaining agreement which applies to major northern Manitoba Hydro projects. The BNA defines items such as hiring preferences, wage rates, overtime provisions etc. for “on the tools” (or “craft”) workers. Supervisory employees (e.g. superintendents, engineers, management) are not included under the BNA.

- *Labour Strategy Development*: In addition to the items above, Manitoba Hydro continues to develop a strategy related to improving labour attraction and retention as well as labour productivity. This strategy considers both short- and medium-term actions to be taken. In developing this strategy, Manitoba Hydro is working with owner groups across Canada to learn what has been successful in those provinces.

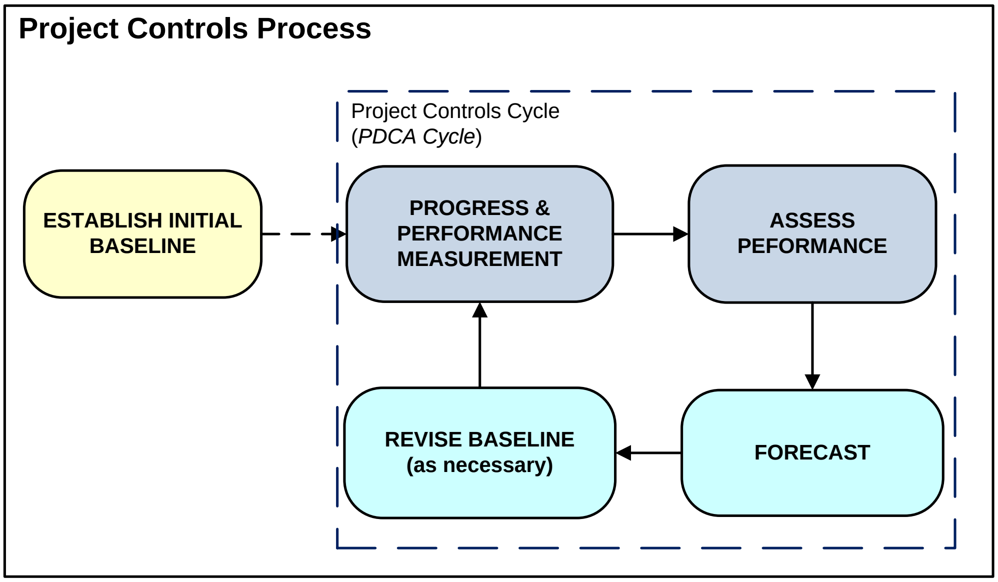
15.6.4 Project Controls

One of the critical roles of Manitoba Hydro's project management team is the monitoring and control of project scope, schedule and budget on the Keeyask and Conawapa Projects through a project controls process. As such, the purpose of the project controls process is to provide timely and accurate information and forecasts that allow project scope to be managed to the approved budget and schedule.

The project controls process applied on the Keeyask and Conawapa Projects is based on the Plan-Do-Check-Act cycle, which is a well recognized continuous improvement management model. The project controls process is intended to answer the questions below and is outlined further in the figure that follows:

- How does actual performance compare to planned (baseline) performance?
- What is the forecast for future performance based on performance to-date?
- What are the areas requiring action to bring actual performance in-line with expected performance?
- What are the results of any corrective actions taken?

Figure 15.8 PROJECT CONTROLS PROCESS



The general principles of the above process are as follows:

- The approved project scope, schedule and budget together form the baseline for performance measurement and control.
- Monitoring and control activities occur on all costs items, with the greatest degree of focus on large dollar or high-risks portions of the work (e.g., the General Civil Contract).
- Monitoring and control is the responsibility of the Project Manager and all work package leads on the projects. Project controls staff support the Project Manager and his/her team by helping facilitate the controls process.
- Outputs from the project controls process support both the contingency management and change management processes.

Specific to the Keeyask General Civil Contract, the target price provided by the contractor will include a detailed breakdown of the cost to execute the work (e.g. labour, equipment and material costs, overhead, profit, etc.) for each component of the work. This cost structure will be used to manage changes to the target price as the project progresses.

Change Management

Project changes are managed closely on the Keeyask and Conawpa Projectss following established change management processes. Processes for managing change are needed to ensure approved changes are clearly communicated and managed in a consistent manner. The scope of the change management process covers from the design phase through the close of construction. Specific items covered under the change management process include:

- Identification of potential changes
- Assessment of the need for the identified change
- Assessment of budget impact of the change, including the impact on project contingency
- Assessment of the impact of the change to the baseline schedule
- Process to approve changes
- Mechanisms to execute approved changes
- Documentation of the executed change.

The change management process ensures someone is identified to execute the required change, all documents are updated appropriately to account for the change, and the change itself is documented appropriately.

The approval level for a project change follows a hierarchical structure and is dependent on the size of the change. As the cost and schedule impact of a change increases, the approval level required increases. Significant changes will require the approval of the Manitoba Hydroelectric Board.

Other Management Processes

There are a number of other management processes that are being implemented on the Keeyask and Conawapa Projects. These additional management processes include:

- Quality Management – The quality management process is in place to manage quality at all levels in the project to ensure all deliverables meet or exceed requirements. Quality management applies continuous improvement practices to all project work to minimize the risk of not meeting requirements. Quality management involves planning, doing, checking, and acting to improve both project and product quality. Quality management is generally divided into three key activities: quality planning, quality control and quality assurance.
- Health and Safety Management – The health and safety management plan ensures that all actions undertaken as part of the project are done so in a safe manner. More specifically, the plan outlines how contractor safety plans will interact with Manitoba Hydro's safe work procedures and processes. It is expected that every contractor will operate safely and participate in ensuring overall safety throughout the project work.
- Human Resource Management – The human resources management process manages the overall staffing needs required for construction including: Manitoba Hydro internal project staff, Manitoba Hydro support services (e.g. legal, purchasing, etc.), external consultants and contractor workforce.
- Communications Management – The communications management plan outlines the methods for ensuring all stakeholders and project team members remain informed of the progress of the work. Requirements for information distribution and reporting performance are found within the project communication plan.
- Document Management – The document management plan is in place to identify the appropriate classification and storage location of drawings and documents associated with the project.

15.7 Summary of Risk Mitigation Actions

The following table summarizes the risk mitigation actions that have either already been implemented by Manitoba Hydro or will be implemented once the projects are committed. These include risks and mitigation actions described in this chapter, as well as other chapters in the NFAT submission. The content is grouped using the same key risk factors as presented in ***Chapter 10 – Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities,***

Table 10.15 Economic Evaluation - Uncertainty Matrix.

1 **Figure 15.9** **SUMMARY OF MANITOBA HYDRO'S RISK MITIGATION ACTIONS FOR THE PREFERRED DEVELOPMENT PLAN**

Driver	Description	Potential Risk to Preferred Plan	Risk Mitigation Actions: Pre-commitment	Risk Mitigation Actions: Post-commitment (Planned)
Key Risk Factor - Energy Prices				
Electricity Price Forecast	Lower electricity prices than forecast	Lower export revenues	Utilize a concensus-based forecast of five independent consultants to produce high, expected and low forecasts Negotiate term sheets and contract agreements prior to committing to hydro development	Conawapa development will continue to be re-assessed prior to project commitment in 2018
Natural Gas Price Forecast	Lower natural gas prices than forecast	Lower export revenues and lower thermal operating costs in the long run	Negotiate term sheets and contract agreements prior to committing to hydro development	Conawapa development will continue to be re-assessed prior to project commitment in 2018
MISO Load	Diminished sale opportunities in the export market (firm and opportunity)	Lower export revenues	Negotiate term sheets and contract agreements prior to committing to hydro development	Conawapa development will continue to be re-assessed prior to project commitment in 2018
Carbon Policy	Uncertainty towards implementation, timing and level of carbon pricing	Lower export revenues	Negotiate term sheets and contract agreements prior to committing to hydro development	Conawapa development will continue to be re-assessed prior to project commitment in 2018
Other U.S. Environmental Policies	Uncertainty towards implementing a series of proposed U.S. environmental policies, their stringency and overall impact. (MATS, ash lagoon, CO2 for new coal, CASPR, US RPS)	Lower export revenues	Negotiate term sheets and contract agreements prior to committing to hydro development	Conawapa development will continue to be re-assessed prior to project commitment in 2018

2

Driver	Description	Potential Risk to Preferred Plan	Risk Mitigation Actions	
			Pre-commitment	Post-commitment (Planned)
Key Risk Factor - Capital Cost or In-Service Date				
Keeyask and Conawapa	Labour escalation, labour shortages, low productivity rates and associated increased indirect costs.	Higher capital costs and potential for ISD delays	Labour and Escalation Management Reserve Fund created for budgeting purposes High quality camp accommodations to aid in attracting workers, comparable to other northern remote Canadian project camps Modifications to isolation leaves in the BNA Early Contractor Involvement contractor for the General Civil Contract	Increased staff-to-craft ratios and turnarounds relative to Burntwood Nelson Agreement Implementation of labour strategy
	Higher commodity prices, equipment and material costs (direct costs)	Higher capital costs	Escalation Management Reserve Fund created for budgeting purposes	Transfer of portion of commodity price risk to contractors through contract terms
	Delays incurred after start of construction	Higher capital costs, delay to ISD	Utilizing contracting strategies that involve contractors in the design phase and minimize Contractor interfaces	Input from General Civil Contractor to maximize constructability and optimize schedule
	Lack of competitive bidding on contracts	Higher capital costs, limited contractor availability, potential for schedule delays	Consulted with potential bidders for major contracts in the design phase to gauge interest (vendor development) Contract packaging that aligns with prevailing market conditions, attracting contractor interest Improved engineering process	Improved contract management process and coordination
	Contract estimate accuracy	Higher capital costs	Adjusted contract estimates based on Wuskwatim experience and prevailing market conditions	Effective management of contracts and project schedule

1

Driver	Description	Potential Risk to Preferred Plan	Risk Mitigation Actions	
			Pre-commitment	Post-commitment (Planned)
Thermal Generation	Commodity escalation, schedule overruns and environmental legislation	Higher capital costs	Thermal resources have been minimized in the Preferred Development Plan	
Transmission in Manitoba	Final routing, commodity escalation, schedule overruns and environmental legislation	Higher capital costs, lower export revenues if export sales cannot be served	The approval process for the interconnection has been initiated and sale contracts provide for up to two year delay. Community consultations on the Keeyask Generator Outlet Transmission are completed and the licensing process is underway. Planning is underway for North-South Manitoba transmission; signed and proposed firm contracts can proceed without this infrastructure.	Generation ISDs could be adjusted if transmission is delayed.
Key Risk Factor - Economic Factors				
Exchange Rate (CAD/USD)	Future exchange rates	Higher volumes of export sale revenues and U.S. denominated debt exposed to U.S. exchange rate risk	Manitoba Hydro maintains a natural hedge with U.S. dollar cash flows, including outflows from US denominated debt. The U.S. debt portfolio may occasionally be rebalanced in accordance with US dollar cash flows.	
Inflation Rates (U.S. & Cdn)	Future inflation rates	Erosion of export revenues from long term contracted sales due to inflation. High upfront capital investment and commodity / labour cost increases subject to inflation	Price escalators are included in export contract terms and conditions. Construction contracts share escalation risk with the contractor by indexing the supply price of major commodity based materials (e.g. reinforcing steel, copper, cement etc.) to market indices and allowing for pre-purchase of materials to take advantage of lower market prices if and when they exist. Capital costs include an allowance for real escalation as described in Appendix 9.3, Section 2.1.3, Table 2.4.	
Interest Rates	Future interest rates	Interest rates would affect capital cost and finance expense	Manitoba Hydro manages the aggregate level of interest risk rate within the debt portfolio arising from short-term debt, floating rate long-term debt, as well as the amount of long-term debt to be refinanced. When selecting terms for its new borrowing, Manitoba Hydro gives careful consideration to the debt maturity schedule and the total level of annual financing requirements.	

Driver	Description	Potential Risk to Preferred Plan	Risk Mitigation Actions: Pre-commitment	Risk Mitigation Actions: Post-commitment (Planned)
Specific Risk Factor - Drought				
Multi-year drought	Extended periods of low flows in the hydraulic system	Preferred Development Plan is not sufficient to meet load commitments	Under drought conditions, Manitoba Hydro has the contractual right to curtail firm export deliveries in order to serve Manitoba load first. Retained earnings are being maintained to protect against the financial impact of potential droughts. Equity provides buffer to absorb adverse events so that compensating rate increases can be smoothed out over a period of time.	
Drought worse than drought of record used for system energy planning occurs	Extreme low flows for one season	Preferred Development Plan is not sufficient to meet load commitments		
Specific Risk Factor - Climate Change				
Long-Term Climate Change	Impact on precipitation and temperature	Lower export revenues or inability to meet load commitments	Monitoring potential impacts of climate change scenarios on NPV of Preferred Plan and All Gas plan.	Climate change will continue to be studied. New interconnection capacity will provide enhanced ability to adapt to load changes.
Specific Risk Factor - Manitoba Load/ DSM				
Manitoba Load Growth	Potential for higher/lower than expected load Also potential for large industrial load addition or subtraction	Potential impact to the need date for new resources Higher load could require new thermal generation Lower load would increase surplus energy and capacity which in turn would increase export revenue potential and may defer in-service dates	Manitoba Hydro's NFAT analysis and pre-construction planning consider varying levels of load growth and the Preferred Development Plan provides the most flexibility to adapt to changing load (See Chapter 14)	Utilize imports or may need to build thermal as a short term solution. Conawapa development will continue to be re-assessed prior to project commitment in 2018. New interconnection capacity will provide enhanced ability to adapt to load changes.
Manitoba DSM	Potential for higher/lower than expected load due to Future Power Smart programs and/or customer response		Manitoba Hydro's NFAT analysis and pre-construction planning consider varying levels of load growth and the Preferred Development Plan provides the most flexibility to adapt to changing load (See Chapter 14) Engaged EnerNOC to work with Manitoba Hydro to assess the 20-year potentials of energy efficiency for electricity (See Appendix 4.3)	Continual review and pursuit of new program opportunities and current program effectiveness. Conawapa development will continue to be re-assessed prior to project commitment in 2018. New interconnection capacity will provide enhanced ability to adapt to load changes.
Driver	**Description**	**Potential Risk to**	**Risk Mitigation Actions**	

		Preferred Plan	Pre-commitment	Post-commitment (Planned)
Other Risk Factors				
Export Contract Terms	Final terms of WPS sale not determined Other future firm contract terms subject to future contract negotiations	Lower export revenues	Firm export contracts signed prior to project commitment including provisions that exempt Manitoba Hydro in the case of regulatory delay or cancellation. New, additional contracts are being pursued with both existing and new customers. Ongoing efforts to maintain existing and establish new relationships to meet customer needs.	Conawapa development will continue to be re-assessed prior to project commitment in 2018.
New U.S. Transmission Interconnection Capacity and Ownership	Final design and capital allocation among proponents	Higher Manitoba Hydro capital cost contribution and higher ongoing operating costs	Minnesota Power is the proponent for the new U.S. portion of the interconnection and sales agreements are contingent on required approvals. Conawapa development will continue to be re-assessed prior to project commitment in 2018.	
Market Access	Potential for legal or regulatory restrictions which would prevent Manitoba Hydro's surplus power from reaching the competitive marketplace free from unreasonable legal, regulatory, structural or tariff barriers	Lower export revenues	Ongoing efforts to maintain existing and establish new relationships to meet customer needs. Pursuing large tie line to expand ability to serve new markets with firm transmission access. Continue participation in MISO tariff task forces. Ensure legal requirements are understood and Manitoba Hydro legal interests are represented in establishing tariffs.	

Driver	Description	Potential Risk to Preferred Plan	Risk Mitigation Actions	
			Pre-commitment	Post-commitment (Planned)
Species at Risk Act (SARA)	The federal government is considering listing Lake Sturgeon under SARA.	If Lake Sturgeon are listed, the projects could be delayed or cancelled; if the projects proceed, they will require permits	Manitoba Hydro is working with northern communities and resource managers to develop and implement programs to benefit Lake Sturgeon (Appendix 2.1); recent studies have indicated results from these programs, some of which go back two decades.	Manitoba Hydro will continue to work on Lake Sturgeon management and enhancement programs. For the Keeyask and Conawpa Projects, habitant will be enhanced to address the loss of existing sturgeon habitat, and stocking will be implemented to increase regional populations.
Legislation for Environmental Reviews	The federal and provincial legislation require public reviews of the potential environmental effects of the projects	If approval is not receive, the project(s) cannot proceed	A thorough environmental assessment using “Western” science and Aboriginal traditional knowledge has been completed for the Keeyask Project and is underway for the Conawapa Project. During the process, many potential adverse effects are avoided and extensive mitigation measures address other potential adverse effects (section 2.1.3).	Once regulatory approval is received, monitoring will be undertaken to determine if predictions in the assessment are correct and, if not, to help inform the development of adaptive management measures. The Keeyask G.S. will be designed to enable it to be retrofitted should monitoring determine that a fish passage structure is required.
Aboriginal Participation and Support	Manitoba Hydro is seeking Aboriginal support for northern hydroelectric projects	If support is not forthcoming, the projects could face challenges in getting regulatory approval and in marketing product in the U.S.	Negotiate agreements with Cree Nations prior to start of construction. Benefit-sharing (i.e. the Joint Keeyask Development Agreement) and adverse effects agreements have been negotiated with the four Keeyask Cree Nations. Process protocols have been established for negotiating Conawapa agreements (section 2.1.3.1).	While there are risks inherent to a business partnership, the Joint Keeyask Development Agreement incorporates a variety of terms intended to eliminate, mitigate, or provide mechanisms to deal with risks associated with developing the Keeyask Project as a partnership.
Socio-economic impacts to Gillam			Collaboration between Manitoba Hydro, Town of Gillam, Fox Lake Cree Nation, Northern Regional Health Authority, RCMP and others Harmonized Gillam development	

Tab 120

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January 29, 2018

Mr. D. Christle
Secretary and Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba R3C 0C4

Dear Mr. Christle:

RE: MANITOBA HYDRO 2017/18 & 2018/19 GENERAL RATE APPLICATION – REDACTIONS FOR MANITOBA HYDRO'S REBUTTAL EVIDENCE ON THE MGF REPORT AND COALITION/IEC (MGF) - 3

On January 16, 2018, Manitoba Hydro filed its written Rebuttal Evidence with respect to the written evidence of MGF Project Services Inc ("MGF"). In its letter, Manitoba Hydro requested that the Public Utilities Board of Manitoba ("PUB") receive and hold in confidence the proposed redactions contained within its Rebuttal Evidence pursuant to Rule 13 of The Public Utilities Board Rules of Practice and Procedure.

On January 29, 2018, the PUB directed Manitoba Hydro to release on the public record the redacted information contained in rows one, three and four of the table on page 27 of its Rebuttal Evidence. In addition, the PUB directed Manitoba Hydro to release on the public record the first three words of the first redacted section, and the first word of the last redacted section, of the response to the Information Request Coalition/IEC (MGF) – 3. Accordingly, please see attached the updated public versions of these two documents.

If you have any questions or comments with respect to this submission, please contact the writer at 204-360-3946 or Odette Fernandes at 204-360-3633.

Yours truly,

MANITOBA HYDRO LEGAL SERVICES DIVISION
Per:

PATRICIA J. RAMAGE
Barrister & Solicitor

cc:

All Registered Interveners
Odette Fernandes, Manitoba Hydro
Bob Peters, Board Counsel
Dayna Steinfeld, PUB Counsel

MANITOBA HYDRO PUBLIC UTILITIES BOARD

IN THE MATTER OF *The Crown Corporation Public Review and Accountability Act*

AND IN THE MATTER OF Manitoba Hydro's 2017/18 & 2018/19 General Rate Application

REBUTTAL EVIDENCE OF MANITOBA HYDRO

WITH RESPECT TO THE WRITTEN EVIDENCE OF:

MGF Project Services Inc., Independent Expert Consultant for the Public Utilities Board, on the Manitoba Hydro Capital Expenditure Review for the Keeyask Hydroelectric Dam, the Bipole III, Manitoba-Minnesota, and GNTL Transmission Lines

Manitoba Hydro

January 16, 2018

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In its 2017/18 & 2018/19 General Rate Application ("Application") filed on May 12, 2017, Manitoba Hydro provided a brief description of its Bipole III Reliability Project ("Bipole III"), its Keeyask Generating Station Project ("Keeyask"), and the U.S. Tie-Line Project made up of the Manitoba-Minnesota Transmission Project in Manitoba ("MMTP") and the Great Northern Transmission Line in Minnesota ("GNTL"). Included in those descriptions were the budget estimates in place as at that time, and the projected In-Service Dates for each as of May, 2017. The Application also made reference to the review of those projects by the Boston Consulting Group.

On December 8, 2017, Manitoba Hydro was provided with a copy of the Report from MGF Project Services Inc. ("MGF"), an entity retained by The Public Utilities Board of Manitoba ("PUB") to review Manitoba Hydro's capital expenditure program in relation to the above projects and to provide its opinion on Manitoba Hydro's updated costs for each. Manitoba Hydro has had the opportunity to review that report, to put forward its Information Requests, and to review the answers provided by MGF on or about January 5, 2018, to all of the Information Requests it received.

In order to provide background and context to the remarks made in the Report of MGF, and to fully respond to the opinions expressed therein, Manitoba Hydro has prepared separate rebuttal for each of Bipole III, Keeyask and MMTP. It was not felt necessary to provide rebuttal on GNTL and the Manitoba-Saskatchewan Transmission Project.

1. KEEYASK GENERATING STATION PROJECT

The Keeyask Generating Station is a 7 unit 695-megawatt hydroelectric generating station situated at Gull Rapids on the lower Nelson River in northern Manitoba. Keeyask will be the fourth largest generating station in Manitoba and the sixth generating station located on the Nelson River. The Keeyask Project is owned by a partnership between Manitoba Hydro and four Manitoba First Nations, known as the Keeyask Hydropower Limited Partnership ("KHLP"). Manitoba Hydro has been tasked with the responsibility of managing the construction of the Keeyask Project and the operation of the facility when it enters into service on behalf of the KHLP. Construction of the Keeyask Project consists of the construction of the generating station as well as construction of supporting infrastructure and the Keeyask Transmission Project which will transport the power produced at Keeyask onto the Manitoba Hydro system when the generating station enters into service.

MGF was retained on Keeyask to review and explain the increases in cost estimates and capital cost increases, as well as project cost overruns. It was to determine and assess the reasonableness of the updated forecast and to identify aspects of the updated cost estimate and schedule that are at risk. It was also to recommend risk mitigation strategies and, further, to review and make recommendations with respect to Manitoba Hydro's:

- practices on its pre-construction design and engineering work;
- its methodologies for costing, for tendering and contracting, for management of construction, contractors and construction risk management, and for scheduling;
- its choice of contract types;
- geotechnical analysis; and
- the governance structure.

Manitoba Hydro staff received dozens of requests for information and data, and staff was fully transparent in sharing more than 1,900 documents including contracts, cost estimates, schedules and various other project management documents.

Key Manitoba Hydro project staff had more than two dozen meetings by phone and in person with MGF representatives and hundreds of emails were exchanged between the parties over the course of the review. MGF also met with senior staff from the General Civil Contractor BBE Hydro Constructors Ltd ("BBE"), and the project design engineer ("Hatch"). MGF personnel attended the Keeyask site on three separate site visits.

In MGF's *Report for Manitoba-Hydro Capital Expenditure Review for The Keeyask Hydroelectric Dam, The Bipole III, Manitoba-Minnesota and GNTL Transmission Line* report dated December 8, 2017 ("MGF's Report or the Report"), MGF and their sub-consultant Klohn Crippen Berger ("KCB"), provide a number of observations, findings, recommendations and conclusions related to Keeyask. Manitoba Hydro has grouped a majority of these items into three major themes which Manitoba Hydro will comment on in the subsequent sections of this rebuttal. The three major areas which Manitoba Hydro will address are as follows:

1) The contract model selected for the General Civil Contract ("GCC");
2) The people and the competency of the people managing the construction of the Keeyask Project; and
3) MGF's findings related to the forecasted cost and schedule of the Keeyask Project.

The key responses to those three major areas (detailed more fully below) are:

1) The contract model selected for the General Civil Contract;

- The GCC is being managed under a target price contract where the contractor is reimbursed for actual costs. The contractor is incentivized to perform and minimize cost and schedule as their profit and General Administration and Overhead are at risk if they exceed their target price. The contractor is also subject to liquidated damages for delays to the project schedule.
- The decision to proceed under the cost reimbursable target price contract model was made in 2012/2013 and was part of a larger Project Delivery Strategy for the Keeyask Project. This decision was informed by lessons learned on the recently completed Wuskwatim Generating Station Project and prevailing market conditions at the time.
- The North American major capital project market around the time of the GCC procurement was extremely competitive. Contract models that transferred additional risk to the contractor including fixed price and unit price would have been cost prohibitive as contractors were not willing to accept additional risk in a competitive environment.
- An extensive 24 month, three phase procurement process was undertaken to select a General Civil Contractor. BBE was the selected contractor as they were determined to be the best value contractor based on the evaluated criteria.

2) The people and the competency of the people managing the construction of the Keeyask Project.

- The Manitoba Hydro team delivering the Keeyask Project is comprised of project management and construction management professionals with experience in managing some of the largest construction projects in Manitoba over the past decade.
- Manitoba Hydro has contracted BBE as the GCC to serve as Construction Manager for General Civil scope of work. Manitoba Hydro taking over the role of Construction Manager as implied by MGF throughout their report would expose Manitoba Hydro to additional risk and claims from the contractor.
- From the start of construction, Manitoba Hydro has continually attempted to undertake actions to progress the work while not crossing the line of explicitly directing the means and methods of the contractor. Crossing this line will expose Manitoba Hydro to interference claims from the contractor and increase the level of risk assumed by Manitoba Hydro.

3) MGF's findings related to the forecasted cost and schedule of the Keeyask Project.

- MGF does not provide data to support its conclusion that the expected cost of Keeyask will be $9.5 B to $10.5 B. Manitoba Hydro and the PUB submitted Information Requests to MGF requesting the details underpinning these calculations; however, MGF failed to provide the requested backup.
- Without the backup to substantiate MGF's claims, Manitoba Hydro reviewed the data in an attempt to understand how MGF arrived at their conclusions. From the information available, it is Manitoba Hydro's opinion that MGF has likely overstated the range of potential costs as they incorrectly applied General Administration and Overhead and indirect costs to their estimated cost overruns.
- MGF's forecasting methods are overly simplistic and do not consider the efforts undertaken by Manitoba Hydro and BBE to reduce cost and schedule outcomes.

1.1. The General Civil Contract, Contracting Strategy, and Selection of the Contractor.

<u>GCC Contracting Strategy:</u>

<u>MGF Report:</u>

Section 1 - Executive Summary, page 1

Scope Item 5: Finding # 1 page 50; Finding # 5 and 6 page 56; Finding # 12 page 62

Scope Item 9: Finding #10 page 80
Section 8 – Conclusion, page 161

<u>KCB Report:</u>
Section 5 page 33 – 35
Section 7 Pages 39 -40

Recognizing that the GCC was the largest and most important contract on Keeyask, in 2012 Manitoba Hydro developed and executed a detailed project delivery strategy which included a procurement strategy for the General Civil Contractor. The project delivery strategy was provided to Knight Piésold ("KP") (the independent expert consultant retained by the PUB) during the Need for and Alternatives To ("NFAT") review in 2014 and more recently to MGF in July 2017 during the current review of the Keeyask Project. On Executive Summary page II of IV of Knight Piésold Independent Expert Consultant Report Rev.1 dated January 23, 2014, in reference to construction management, schedule and contracting plans, KP stated that:

> *"The overall approach follows well documented internal standards developed by Hydro's NGCD. The contracting method varies by project component but the principal civil works contracting strategy is an Early Contractor Involvement (ECI) Project Delivery Strategy. Overall the project delivery strategy has been to transfer risk away from Contractors and to Hydro in order to better understand and share the risks and obtain a better contract price as a result."*

Manitoba Hydro's selection of a contracting strategy was informed by a number of factors including, but not limited to, the following:

- Market conditions that influence the availability of major contractors willing to bid on the work;
- Allocation of risk to the party best suited to manage the project's most significant risks;
- The project schedule;
- Completeness of engineering at the time of tender;
- Lessons learned from past projects including Wuskwatim and Pointe du Bois; and

- Internal expertise and resource availability. Manitoba Hydro evaluated its internal expertise, resource availability and corporate structure as part of its analysis of an appropriate contracting strategy. It was recognized that although Manitoba Hydro had significant and expert resources required to function as the overall project and site manager, it lacked the experience necessary to manage the day-to-day activities typically performed by the general civil contractor. To perform this role would require significant changes and the addition of considerable construction and support staff to Manitoba Hydro's organization.

KCB states:

> *"While we were not part of the process that selected the contracting model, we surmise that MH either had success with this model elsewhere, or there were significant reasons to push the project into construction quickly relying on the early contractor involvement, the expectations of a quality design from Hatch and an experienced contractor with a realistic target price to make the project a success."* (Page 39)

KCB is correct in its assumption that Manitoba Hydro was applying lessons learned from previous major capital projects that it had managed, including the recently completed Wuskwatim Generating Station and Pointe du Bois Spillway Replacement Project. It is not accurate in its assumption that the contract was impacted by any desire or need to push the project into construction quickly.

The lessons learned by Manitoba Hydro that led to its selection of the cost reimbursable target price contract for the GCC are explained below. Lessons learned from past projects were also previously discussed at a high level during the NFAT in 2014 hearings as well as during the 2015/16 and 2016/17 General Rate Application (Manitoba Hydro Exhibit #104 – Undertaking #44).

> *"Manitoba Hydro originally tendered the General Civil Contract for the Wuskwatim Generating Station in 2007 as a unit price contract using the design, bid, build model. This resulted in receiving only one bid from the market with a price nearly double the Engineer's Estimate and well beyond the expected value*

of the work. After suffering schedule delay because of the lack of reasonable bids, the work was re-tendered and four competitive proposals were received with a cost-reimbursable, target price contract awarded to the successful proponent in November 2008.

Based on the Wuskwatim Project experience, Manitoba Hydro also chose to include the river management, rock excavation, and electrical/mechanical scope into the Keeyask GCC to reduce the interface risk between contractors otherwise held by Manitoba Hydro. The rock excavation and electrical/mechanical work were packaged as separate contracts on the Wuskwatim Project leading to many challenges in interface management between the various contractors. On Keeyask, this work is bundled together within the GCC's scope.

At the time when Manitoba Hydro was developing the contracting strategy for the GCC, potash was increasing in demand, oil prices were more than $100/barrel and any available forecasts anticipated continued price increases. As a result, there was a boom in the major capital project market in North America, particularly in the energy industry including the Northern Alberta oilfields as well as many oil and natural gas projects within the Bakken Formation underlying portions of Saskatchewan, Montana and North Dakota and the Muskrat Falls project in Labrador, which resulted in increased competition for skilled labour (See for example http://publications.gov.sk.ca/documents/310/81353-2014-MPI.pdf). In this 'hot' construction market, many of the major contractors had already committed experienced personnel and resources to the other projects and were not as hungry for opportunity. In this type of economic environment, Manitoba Hydro's experience was that contractors were also not as willing to accept risk in a job and their pricing reflects this reality. Economic conditions were similar for the procurement phase of Keeyask as they were for procurement during Wuskwatim when the original General Civil Contract was unsuccessfully tendered as a unit priced contract and then re-tendered competitively as a cost reimbursable target priced contract.

> *Labour productivity (amount of hours per unit of work) has been one of, if not the largest risk for contractors since the early 2000's across Canada, particularly in remote, fly-in fly-out operations such as Keeyask. As was learned on Wuskwatim, this caused contractors to avoid or submit extremely high bids for any contract that transferred this risk to them (such as fixed cost or unit price contracts). For Canadian hydro, the absence of large scale projects from 1990 to the mid-2000's magnified the productivity issue creating a skilled labour shortage across the country and a shortage of qualified supervision. Manitoba Hydro was well aware that many contractors were wary to provide competitive estimates for hydro work."*

In 2012, Manitoba Hydro selected a cost-reimbursable target price model with Early Contractor Involvement ("ECI") that balances project risk between two parties. If the contractor completes the work under the target price, they earn profit plus a share of the savings. However, if the contractor exceeds the target price, they forfeit a substantial portion of their profit for every dollar of overrun, up to the value of their total profit amount. A contractor will not go bankrupt on the job, but they are at risk of not earning any profit if they exceed the target price by a certain threshold. No return (i.e. profit) on a 5+ year investment of resources by a major contractor is not what shareholders want to see and thus the contractor is incentivized and motivated to perform.

A fixed price model was considered but would have necessitated a contractor bidding higher to factor in risks over which they have no control (e.g. geological conditions, interest rates, commodity price escalations over the duration of the work, labour skill and availability, etc.). This would have raised the initial cost of the project and limited the number of parties interested in proposing on Keeyask, thus driving up the project cost.

Another reason the target price model was chosen was because it allowed for an opportunity to leverage ECI. As the final design engineering was not yet complete, there was an opportunity to engage a contractor early to help influence the design from a constructability standpoint. Engaging a contractor earlier also allowed the contractor more lead time to establish project process and work plans, understand the labour agreement and understand the local labour and supplier market.

Manitoba Hydro also had experience with the target price model having recently completed Wuskwatim in 2012 ($1.4B) and Point du Bois in 2014 ($0.6B).

KPMG, a consultant experienced in the management of major capital projects, was engaged by Manitoba Hydro in May 2016 to undertake an independent review of the current status of Keeyask. KPMG subsequently provided advice on the development and implementation of a Recovery Plan for Keeyask and has provided project management support since that time for the Manitoba Hydro project delivery team. Manitoba Hydro requested KPMG to provide commentary on the following three topics:

1. Provide commentary on the contract model and any incentives included.
2. Define Manitoba Hydro's role in the GCC contract. Define the role of the Contractor and comment on Manitoba Hydro's ability to manage the Contractor in this role.
3. Provide commentary on Manitoba Hydro acting as the builder and taking on a Construction Management role.

KPMG's response to these items is attached as Keeyask – Appendix A. In terms of contract type, KPMG's response indicates the incentives used in this contract have been used in other cost reimbursable contracts as well as other forms of contracts. The incentives align the owner's and contractor's interests and help to mitigate the exposure the owner has to poor performance by the contractor.

<u>General Civil Contract Procurement:</u>

MGF Report – Scope Item 5: Finding #12, page 62
KCB Report – Section 5: page 33

Manitoba Hydro undertook an extensive three phase procurement process for the GCC beginning in 2012. This included a six month market-sounding exercise where 21 major international contractors were contacted to determine their level of interest in the

Keeyask Project. This process served as a marketing effort to generate interest for Keeyask in the marketplace with the intent of maximizing the number of capable contractors responding to the Request for Pre-Qualification to obtain competitive pricing. This process also served to inform Manitoba Hydro on the factors that were of interest to the potential contractors. Feedback on contracting models was also solicited from these organizations. Many of these experienced companies indicated they would not bid on a project the size and remoteness of Keeyask on a fixed price model due to the risks involved.

The second phase of procurement was the prequalification phase. Seven contractors submitted proposals in response to Manitoba Hydro's call for submissions. The contractor submissions were evaluated on 17 different criteria including demonstrated experience in remote, arctic heavy civil construction projects with an emphasis on concrete, earthworks and river management. Other factors that were considered in the evaluation included schedule, risk mitigation and safety. Four contractors that Manitoba Hydro believed were capable of building the work were pre-qualified and were provided the opportunity to bid on the Keeyask General Civil Works Contract in a competitive, cost-based evaluation.

The proposal stage was the third and final step in the procurement process. Manitoba Hydro engaged a third party ("Chant Construction") to provide their estimated price for the work as an additional pricing comparator (in addition to Manitoba Hydro's Engineer's Estimate). The pricing proposed by Chant Construction was generally in line with the Engineer's Estimate and was within the range of bids received from the four Proponents. A summary of the pricing information from the GCC proposals was provided in confidence to MGF as part of their review, and to the PUB and its independent expert KP during the NFAT hearings as exhibit NFAT CSI Manitoba Hydro-3.

As part of the evaluation of the contractors' proposals, Manitoba Hydro evaluated the initial target price proposed by the contractors based upon a number of pre-defined factors that were valued by Manitoba Hydro including potential schedule advancements, size of workforce against available camp capacity, and quantity change sensitivities to ensure that the contractor who provided the best value was selected.

The bids were also compared against one another and against the estimate provided by Chant Construction for reasonableness. After nearly a two year procurement process to conduct the market sounding, prequalify capable proponents and evaluate proposals to select the best value for Manitoba Hydro, the General Civil Works Contract was awarded to BBE, a limited partnership between Bechtel Canada Co., Barnard Construction of Canada Ltd. and EllisDon Civil Ltd. in March 2014.

Throughout its report, MGF is critical of the form of contract selected for the GCC. On page 80, MGF states:

> *"The GCC Contract strategy of adopting a cost reimbursable commercial arrangement for this project was flawed from the outset, with a predictable outcome, i.e. it promotes and rewards inefficient work and doesn't encourage efficient work."*

MGF fails to identify and understand the factors that led to Manitoba Hydro proceeding with the selected form of contract for the GCC. MGF's comment also does not address the target price aspect of the contract that puts the contractor's profit and General Administration & Overhead ("GA&O") at risk. The opportunity for profit and maintaining the GA&O incentivizes the contractor to attempt to meet or beat its target price. Manitoba Hydro provided MGF with the procurement documents for the GCC, evaluation matrix and criteria, related recommendations and presentations to the Manitoba Hydro Electric Board, the awarded contract with BBE and all seven amending agreements. These documents provide the rationale for selecting BBE as the GCC and clearly articulate the incentives that are intended to motivate contractor performance.

The Keeyask Project standards and procedures referenced on pages 50 – 53 of the MGF report were used to support the development of the contracting strategy and throughout the procurement process for the GCC. On page 53 of the report, MGF states that *"the standards, procedures and processes supporting Contracting Strategy, Contractor Prequalification, Individual Contract Plans and Tender, Evaluate, Negotiate and Award are sufficient and well documented."*

The contracting strategy, the GCC contract documents and a summary of proposal was reviewed with KP as part of the NFAT process. KP did not raise any significant concerns with the contracting strategy at the time of their review and the benefits and risks of the contract model were understood and communicated during the NFAT hearings.

It is not clear to Manitoba Hydro whether MGF and KCB were aware of the information provided to the PUB during the NFAT, or of the NFAT conclusions. As seen below, Manitoba Hydro addressed the contracting strategy with the PUB's independent expert in the NFAT process and the PUB's decision reflects that this, along with the risks, were discussed and reviewed.

On page 132 of the PUB's final NFAT report dated June 20, 2014, section 7.6.0 Conclusions of the Panel, the PUB stated the following regarding the Keeyask Project:

> *"The actual construction cost of Keeyask will increase beyond Manitoba Hydro's currently projected capital cost of $6.5 billion. Budgeting at least for Manitoba Hydro's "high" estimate of $7.2 billion would be prudent. This conclusion is not reached as a result of the history of past capital cost increases. The Panel accepts Manitoba Hydro's argument that the past is not necessarily a predictor of the future. Rather, the Panel bases its conclusion on its review of the Keeyask general civil contract, which is a cost-reimbursable contract that leaves a significant portion of cost risk with Manitoba Hydro. It would be a fallacy to assume that the contract provides anywhere near the same level of cost certainty as a fixed-price contract, which would be more expensive. This is not a criticism of the Keeyask general civil contract or Manitoba Hydro's approach to contracting. The Panel is satisfied that Manitoba Hydro's approach to developing and negotiating the contract, as well as its approach to managing risk, has been appropriate to date. Rather, it reflects the general nature of a large infrastructure project with inherent risks that can be mitigated, but not avoided."*

1.2. The People and the Competency of the People Managing the Construction of the Keeyask Project

MGF Report: Section 1 – Executive Summary, page 1

On page 1 of MGF's report, MGF states that:

> *"There is an opportunity for Manitoba Hydro to implement contract management improvements, take ownership for the GCC and drive the GCC contractor to higher levels of predictable performance, to accelerate project schedule and to lower the likely forecast cost at completion".*

MGF goes on to say that:

> *"Manitoba Hydro staff are competent and professional but they are not a construction manager with the experience and skills to direct the GCC. As such, its project management and control effectiveness is low."*

MGF makes these assertions without describing the skills and experience of Manitoba's senior team managing Keeyask, the roles and responsibilities under the General Civil Works contract, or even the actions that Manitoba Hydro has taken to improve outcomes from this contract. As MGF has failed to address these points in its report, the following section describes Keeyask's governance structure, an assessment of skills and experience of Manitoba Hydro's senior project team from a third party and a description of some of the key actions Manitoba Hydro has taken to enhance performance.

Governance:

Manitoba Hydro is experienced in the execution of major capital projects having delivered some of the largest capital projects in Manitoba over the last 10+ years.

In early 2016, Manitoba Hydro established the Major Projects Executive Committee ("MPEC") which is chaired by Manitoba Hydro's President & CEO and consists of five Vice Presidents who have accountability over the areas of the company responsible for the execution of major capital projects. MPEC is an executive management forum that provides oversight, direction and executive/strategic decision making with respect to major capital projects (i.e. Keeyask, Bipole III, MMTP and the GNTL Project in Minnesota). MPEC meets every two weeks or as required.

The Manitoba Hydro executive team is ultimately accountable to the Manitoba Hydro-Electric Board ("MHEB"). Periodically (and conforming to the corporate approval authority levels), major project decisions are reviewed and approved by the MHEB. The Keeyask Project team also provides project update reports and presentations to the MHEB on a regular basis. Site visits by both the Manitoba Hydro executive team and MHEB members have taken place.

As Keeyask Project is owned by the KHLP, there are additional accountabilities beyond the Manitoba Hydro organization structure. The Keeyask Project team is also accountable to the KHLP Board that is comprised of representatives from each of the four Keeyask Cree Nation ("KCN") Partner Communities and Manitoba Hydro. The KHLP Board is chaired by the Manitoba Hydro Vice President of Generation and Wholesale. The Keeyask Project team provides monthly update reports to the KHLP, as well as makes quarterly update presentations at the Board meetings.

The Keeyask Project team is comprised of project management and construction professionals with significant experience in the execution of major capital projects. As stated, Manitoba Hydro requested that KPMG review and comment on the experience of Manitoba Hydro's senior leadership team responsible for delivering Keeyask, and those comments are also found in Keeyask – Appendix A.

Management of the General Civil Contract:

MGF Report: Section 1: Executive Summary – page 1.

On page 1 of their report, MGF states that Manitoba Hydro's *"project management and control effectiveness is low".* MGF does not recognize the efforts of the Manitoba Hydro team in helping to manage the GCC.

Manitoba Hydro has been pushing, and will continue to aggressively push, the General Civil Contractor to perform. To be successful, this will require that Manitoba Hydro and BBE work together. After the award of the GCC in March 2014, work commenced on July 16, 2014 following receipt of all required regulatory approvals. Work by the GCC for the remainder of 2014 and all of 2015 was focused on establishing infrastructure including temporary buildings, haul roads, rock quarries as well as temporary river management structures (cofferdams) to control the flow of the Nelson River. These cofferdams allowed for the areas to be dewatered and rock excavated to allow for the construction of the permanent structures. In early January 2016, work on the North

Dyke commenced representing the milestone of the first permanent earthworks on the project.

At the beginning of the 2016 construction season, the project was generally on track and the project team was forecasting that the control budget and schedule of $6.5B and November 2019 unit 1 ISD (established during the NFAT hearings) would be achieved.

Manitoba Hydro reported to the PUB on March 2016 that the project was on schedule and on budget. Manitoba continued to actively monitor the progress of the GCC through the beginning of the construction season as it has throughout the project. Concrete work on the principle structures (Spillway, Intake, Powerhouse, Service Bay and Tailrace) began in early May 2016.

<u>2016 Issues:</u>

In early June 2016, approximately 6 weeks into concrete activities it was evident that the contractor's actual volume of concrete completed to date was significantly less than the contractor's plan. On June 19, 2016, Manitoba Hydro formally requested that the Contractor develop a recovery plan to increase their manpower ramp-up and concrete production in order to bring their production back in line with the 2016 plan. Manitoba Hydro staff continued to monitor the progress carefully during this time.

By July 2016, it was apparent that that the initial recovery efforts by the contractor were not going to be impactful enough to recover to the original plan. As well, both the GCC and Manitoba Hydro were becoming aware that the work could not be built as it was originally planned. As work continued to progress, the need for a new execution plan crystallized and required the team to understand the issues and problems and address them going forward. This led to the Recovery Plan described below.

By the end of the 2016 construction season, concrete placement was at 41% complete of the original plan for the year while earthworks were at 65% complete of the original plan. The concrete plan was to complete nearly 200,000 cubic metres of the 360,000 cubic metres required for Keeyask in the first year, while only 77,000 cubic metres were completed in the first year of concrete (2016). The production rates accomplished during the first concrete construction season saw the project schedule rapidly change from having a potential 6-month advancement opportunity at the start of the year shift to a potential of up to 2+ year delay by the end of the year. At this time it was also apparent that the $304M Labour Management Reserve in the $6.5B control budget to help offset productivity risk would not be sufficient. The large variance between actual and planned production also resulted in the Contractor having no opportunity to earn profit for the remainder of the project under the existing contract structure. This was already making for disengagement and the risk of worsening performance could occur for the remainder of the project if not addressed.

Recovery Plan:

Manitoba Hydro could not wait until the end of the 2016 construction season to begin to address the issues and plot a new path forward. Manitoba Hydro, with the assistance of industry experts KPMG, developed a Recovery Plan in September 2016 that covered both short and long term issues. The Recovery Plan incorporated a number of key features required to address the trajectory of the Project in order to achieve successful completion. The Recovery Plan needed to improve production and remove inefficiencies, and included:

- The development of a plan for the continuation of concrete through the winter months (previously not included in the original schedule);
- Identification of root causes of performance issues;
- Engagement of senior leadership, Executive Sponsors and CEOs;
- Development of refined processes, systems and tool based upon the findings of the root cause analysis;
- Implementation of a change management program to enable a culture shift within the project team;
- Initialization of activities to reforecast the cost and schedule for the project;
- Analysis of the Contractor's claims; and
- Supplementing of the commercial expertise of the Manitoba Hydro team.

Manitoba Hydro and BBE assessed the underlying causes of the challenges experienced to date. The main contributing factors to the underperformance included:

- Unachievable labor productivity rates in the current market which were contained within the contractor's bid;
- Slower than planned progress in ramping-up the on-site labour force in preparation for the concrete works beginning in 2016. This ramp up required a doubling of the labour force of roughly 1,000 workers to 2,000 workers in a period of roughly three months.

- Geotechnical and geological conditions different than anticipated based upon the extensive pre-construction geotechnical testing, resulting in additional effort to "get off the rock" to allow for construction of the concrete and earthworks structures off of the bedrock.

As part of the Recovery Plan, Manitoba Hydro, leveraging support from third party experts, including KPMG (Recovery Plan support), Revay (claims valuation and management), Borden Ladner Gervais LLP (legal support) and Validation Estimating (contingency development) undertook a thorough process to evaluate alternatives for, and impacts, to the GCC. The review demonstrated that the best course of action was to amend the existing contract with BBE, specifically to lower the overall cost and schedule risk for Manitoba Hydro and permit BBE an opportunity to re-establish a reasonable profit level. All other alternatives introduced significant additional risks to the Project as well as guaranteed impacts to cost and schedule that were greater than the selected alternative of amending the contract with BBE.

General Civil Works Contract Amendment:

In early 2017, Manitoba Hydro and BBE were able to achieve the mutual agreement that was required to amend the contract. The negotiation required 'gives and takes' from both parties and the outcome was a contract that lowered the overall cost and schedule risk for Manitoba Hydro and allowed the Contractor an opportunity to re-establish a reasonable profit level if they are able to perform relative to their revised target price. This aligned the interests of both parties to deliver a "Best for Project" approach.

The details of the amendment to the contract are formalized in Amending Agreement #7 between Manitoba Hydro and BBE. Amending Agreement #7, in addition to all previous versions of the agreement between Manitoba Hydro and BBE were provided to MGF in support of their review. The key features of the amendment include:

- Cost and schedule incentives providing motivation for BBE to earn profit by delivering the work to Manitoba Hydro with minimum cost and best schedule;
- Outstanding contractor claims were reconciled;
- GA&O mark-up was capped at target price;
- Narrowed ability for future claims;
- New liquidated damages provisions were established for late delivery;
- Productivity rates in line with 2016 actual performance used to inform the estimate of remaining costs on this contract.

Both MGF (MGF Report page 80) and KCB (KCB Report page 34-35) are critical of the contract model for the GCC. In Keeyask-Appendix A, KPMG describes the original and the amended contract for the GCC. KPMG describes the challenges inherent in attempting to renegotiate a contract in a non-competitive environment on page 2 of their submission:

> *"The amended contract continues to be a Target Price Cost Reimbursable contract, fundamentally the same as the original contract. The ability to transfer additional risk, such as geotechnical, hydrology, labour, extreme weather, and northern logistics to BBE by changing the contract to a Unit Rate or Lump Sum contract, would have required directly negotiating a new form of contract with BBE in a non-competitive environment or descoping/terminating BBE and going back to the market for a Unit Rate contract. It was expected that in a non-competitive environment and given BBE's performance in 2016, the costs of transferring this risk to BBE would have been prohibitive and/or not achievable."*

<u>New Control Budget and Schedule Established:</u>

With the General Civil Works Contract amended, further efforts were required to re-establish a new control budget and schedule for Keeyask. Manitoba Hydro reviewed the impact of the delay, along with known trends for the impacted work packages. The outcome of the review process was a revised control budget of $8.7B with a P50 contingency and a first unit in service date ("ISD") of August 2021. The revised control budget and schedule was formally approved by the MHEB in February 2017. The following table from PUB/MH MFR-122 highlights the major changes between the control budget established at the NFAT in 2014 and the revised control budget:

Figure 1.0

Keeyask Budget Summary (in Billions $)				
Item #	**Item**	**Previously Approved Budget (2014$)**	**Current Approved Budget(2016$)**	**Variance**
1.1	Generating Station	4.046	5.948	1.902
1.2	Generation Outlet Transmission (GOT)	0.164	0.202	0.038
1.3	Escalation @ CPI	0.244	0.249	0.005
1.4	Interest (including Interest on Equity)	1.343	1.749	0.406
1.5	Contingency	0.307	0.578	0.271
1.6	Labour Management Reserve	0.304	0.000	-0.304
1.7	Escalation Management Reserve	0.088	0.000	-0.088
1.8	**Total**	**6.496 B**	**8.726**	**2.230**
1.9	First in-service Date	Nov-2019	Aug-2021	21 months.

<u>2017 Performance:</u>

The 2017 construction season saw improved performance over the 2016 season with approximately 12% more concrete placed in 2017. This improvement is significant as the work done in 2017 was more complex, specifically, most of the placements in 2017 were generally smaller, required more formwork and were greater complexity pours (such as draft tubes) and concrete at height (head blocks and piers).

For the earthworks, productivity rates improved by 15% and the total of material placed in permanent structures in 2017 was 1.03 M cubic metres, an improvement of roughly 90%.

Contributing factors that influenced performance in 2017 included:

- Improved contractor leadership/management and their ability to plan and manage the work;
- More complex and better developed sequencing of concrete work and interfaces with earthworks;
- Learning curve to perform "first" work on the concrete in the Intake, Powerhouse and Service Bay;
- Challenges with the craft labour including maximizing work time at the work front.

Despite the improvements over 2016 described above, the target quantities for concrete and earthworks were not fully achieved. By the end of the 2017 construction season, while the Contractor had achieved considerably more concrete and earthworks volume than the previous year, concrete was approximately 20% less than planned and earthworks was 25% less than planned. Despite these shortfalls in volume, the key milestones for the year were achieved allowing the Keeyask project to remain on schedule. Achieving the following major milestones in 2017 ensures that the project will be delivered within the shortest duration schedule possible and protect the opportunity for schedule advancement of the unit 1 ISD:

- Completion of the Spillway concrete and handoff of the Spillway to the Gates, Guides and Hoists Contractor (Canmec) on November 15, 2017 (on schedule);
- Installation of the Powerhouse Cranes in the Service Bay in November (on schedule);
- Enclosure of Powerhouse Units 1 and Service Bay completed by December 31, 2017 (on schedule);
- Enclosure of Powerhouse Units 2-3 by February 2018 is on track to allow for the start of turbine and generator work;
- Significant progress on earth structures (dams and dyke) such that Keeyask is on track to divert the river through the Spillway in July/August 2018

As a consequence of the above milestones being met the project is still on track to be completed on or below the revised budget with the first turbine coming in service in or before August 2021.

<u>Management of the GCC:</u>

MGF Report – Section 1: Executive Summary, page 1

It was suggested by MGF on page 1 of their report that "*There is an opportunity for Manitoba Hydro to implement contract management improvements, take ownership for the GCC and drive the GCC contractor to higher levels of predictable performance, to accelerate project schedule and to lower the likely forecast cost at completion*". This statement appears to suggest that MGF is recommending that Manitoba Hydro should take over the role of Construction Manager from BBE. MGF goes on to soften this recommendation in MH/MGF I-2j and state that "*the recommendation is not for*

Manitoba Hydro to become the construction manager and replace BBE, but for Manitoba Hydro to exert more control and hold BBE accountable for its performance."

Manitoba Hydro is not a general contractor, nor does it have on hand the necessary personnel to manage and build Keeyask as the general contractor. If it were to undertake some or all of this task as recommended by MGF, it would have to retain significantly more staff with sufficient experience and expertise to take on the work without any delays. Such personnel are not readily available and, as outlined in more detail in Appendix A, there would be risk to the schedule because of the time it would take to find the personnel, to give them time to get up to speed on the project, and to develop a team to surround themselves with whom they would have confidence. As stated by experts KPMG and Hatch, this would simply introduce more risk to the project at this stage.

Hatch has been involved in Keeyask as the detailed design engineer and as an organization, has considerable experience in the delivery of major capital projects. Hatch was asked to provide commentary around expanding Manitoba Hydro's role with the GCC, as recommended by MGF. Hatch's response can be found in Keeyask - Appendix B, and like the response from KPMG, Hatch did not recommend such action.

According to Hatch (page 3 of Keeyask - Appendix B), Manitoba Hydro taking a greater role in the construction is of equal or greater risk to the project than the status quo. Hiring a Construction Management team to manage the construction on behalf of Manitoba Hydro would also carry risk until proven. Some of the risks identified in the Hatch review that informed their opinion include:

- Lack of availability of qualified professionals required to staff an entire team;
- Time to recruit, hire and mobilize a team;
- The new team would have a steep learning curve which would add risk to the successful execution of the project;
- Manitoba Hydro would lose leverage within the BBE contract.

BBE was hired by Manitoba Hydro as the Construction Manager to complete the General Civil Works scope. Keeyask – Appendix A provided by KPMG defines Manitoba Hydro's role in the GCC contract and provides commentary on the expected implications of Manitoba Hydro acting, instead, as the builder and taking on a Construction Management role, rather than acting in its capacity as owner.

MGF states on page 1 that Manitoba Hydro is "*not a construction manager with the experience and skills to direct the GCC"*. However it fails to address the activities Manitoba Hydro has undertaken to progress the work, without crossing the line of explicitly directing the means and methods of the Contractor, and without exposing Manitoba Hydro to interference claims. If Manitoba Hydro did step into the role of Construction Manager, it would be likely that the Contractor could claim for their entire performance bonus(es) regardless of the final cost and in-service date of the project. This would also inhibit ownership/accountability of the Contractor to perform.

KPMG was asked to provide commentary on Manitoba Hydro acting as the builder and taking on the Construction Management role. KPMG has indicated that they are unaware of any Canadian public sector owner with the skill-set required to directly manage a multi-billion dollar construction project (Keeyask – Appendix A).

In an attempt to better understand MGF's perspective, Manitoba Hydro requested additional information related to this conclusion in MH/MGF I–2. Specifically, Manitoba Hydro was interested in understanding if other owners/utilities have successfully taken ownership in the middle of a major capital project and the outcomes of those interventions. Manitoba Hydro was also interested in the Corporation's exposure to risks arising from undertaking such a change however MGF did not provide a response to MH/MGF I–2 that provided an answer to these questions. Manitoba Hydro posed this question to KPMG and requested their professional assessment. This information can be found in Keeyask – Appendix A. Hatch also provided commentary on the potential liabilities associated with taking over the role of Construction Manager in Keeyask - Appendix B.

Throughout 2017, Manitoba Hydro has increased the pressure on the Contractor to perform, and to have its workers become more productive. Some of these areas include:

- Contractor's management of the trades;
- Travel logistics for the contractor's workforce;
- Site wide respectful workplace campaign;
- Contractor's revised organizational structure and increased supervision capacity and experience;

- The development of an effective monitoring and control system to provide daily feedback to contractor workforce;
- Combining and streamlining BBE's and Manitoba Hydro's quality control and assurance teams and processes;
- Establishment of single mission and team ethics for the Manitoba Hydro and BBE teams.

Manitoba Hydro has also been leading efforts to gain efficiencies, improve methods/processes and achieve cost and schedule savings. A few examples of key initiatives where Manitoba Hydro spearheaded efforts that led to significant cost and/or schedule benefits:

- The decision to procure a new draft tube formwork system to utilize on the remaining 5 units. This decision shortened the schedule to install the bottom portion of the draft tube and improved cost performance.
- The decision to utilize column extenders in the Powerhouse and Intake allowed for structural steel to be installed at lower elevations. This provided an opportunity to enclose the Powerhouse and Service Bay earlier. A schedule savings of over 1 year resulted.
- Advancement of the south dyke in 2018 and supporting design changes. This will allow for additional quantities to be placed during the winter 2018 and reduce risk to the project schedule.

<u>2018 Plan:</u>

In 2018, a 10% increase in performance by the GCC is required to meet control budget ($8.7B) and achieve IDS's for the units that are in advance of the control schedule of August 2021. This also assumes that no significant risks materialize with other contracts or risks that could impact the critical path. Manitoba Hydro is confident that this rate of improvement is attainable as the year-over-year improvement between 2016 and 2017 was similar. In addition, much of the remaining concrete work in 2018 is similar to the work completed over the previous year and lessons learned over the last year and the inherent repeatability of seven nearly identical units is expected to improve productivity. Manitoba Hydro and BBE are currently working on their planning for 2018. Some of the key initiatives in 2018 include:

- 2018 winter work (placement of additional concrete over the 2018 winter months);
- Building a high performance culture at site;

- Cold eyes review;
- Manitoba Hydro and BBE leads identifying efficiencies and improvement;
- Improved management of indirects;
- Productivity studies and planning.

Third Party Reviews and Involvement:

Continuous improvement is ingrained in the culture of the Keeyask team but can always be improved. Prior to, and during the construction of Keeyask, external experts have been engaged to support and, in some cases, augment the skills of the existing project team. The project recognizes that the decision to manage the project using a team with strong internal expertise and knowledge brings both benefits and risks. To reduce the risk of an internal-only perspective, external expertise from across the utility and construction industries was retained and reviews were completed in the areas noted below. In addition, a handful of experts/consultants are used on a regular basis to support the project. Key reviews and supports external to Hydro alone include:

Figure 1.1

Third Party	Scope	Date
KPMG	KPMG was engaged due to their industry expertise in the areas of project management and contract administration to assess the health of the Keeyask Project. KPMG has since been regularly involved in helping to augment Manitoba Hydro's project management expertise.	2016 - current
Boston Consulting Group	In spring 2016, the Manitoba Hydro Electric Board retained Boston Consulting Group (BCG) to among other things, undertake a review of the Keeyask Project. The report of BCG's findings was released in September 2016.	2016
BBE/MH Cold Eyes Review	BBE & MH jointly carried out a review of BBE's operations on April 25 – 28, 2016. Teams consisted of 3 individuals from Bechtel and 3 individuals from MH (2 of which are Hydro-X and 1 construction management expert consultant). The purpose was to review BBE's operations and to ensure readiness of site project team for the upcoming first season of concrete.	2016
KPMG	In early 2016, KPMG carried out an independent review of the catering contract and the Keeyask Project Safety Management Plan. The purpose of the catering review was to ensure quality of service is sustained and to develop strategies to provide this level of service at the least cost. The purpose of the safety review was to ensure the Keeyask Project Safety Management Plan was	2016

	focused on the right things to achieve our safety goals with all contractors.	
Hatch	Quality Management support for Hatch's quality lead from the Mississauga office supports the project through the preparation of key Quality Program documents and the review of quality initiatives for the project. This support is especially strategic at this time given work underway to reset BBE's focus on its strategy for meeting quality requirements for the GCC.	2015 - current
Nalcor and BC Hydro	On-going informal dialog is taking place with Nalcor's Lower Churchill Project team and BC Hydro's Site C team to exchange ideas and lessons learned. Muskrat Falls is about one year ahead of the Keeyask schedule and their 824 MW project is similar to Keeyask's scope.	2015 - current
Validation Estimating	John Hollman of Validation Estimating is retained for assistance in the development of the project control budget, contingency pool, and management reserves. The risk profile for the project is reviewed at regular intervals in comparison to projects of similar size and complexity.	2012 - current
Hatch	A panel of Hatch senior engineers/managers from outside the Keeyask Project was retained to conduct a "cold eyes" review of the management of the engineering in an effort to identify gaps in the scope and quality of the engineering design, and ability to deliver the required product.	2014/2015
Knight Piésold	Knight Piésold (KP), the independent expert consultant retained by the PUB during the NFAT process in 2013/2014 reviewed project processes, the estimate, and contingency, KP was generally satisfied with these practices and methodologies stating that they were consistent with industry best practices.	2013/2014

1.3. MGF's Findings Related to the Forecasted Cost and Schedule of the Keeyask Project

MGF Report: Scope Item 5 – Finding #13, pages 63 – 64

In its report, MGF states that the expected cost of Keeyask will be \$9.5 B to \$10.5 B (MGF report page 63 & 64). However, MGF did not provide or substantiate how it arrived at these values. Manitoba Hydro (MH/MGF I-26), as well as the PUB (PUB/MGF–14), requested a breakdown of how MGF arrived at these values. MGF provided the following in response (MH/MGF I-26a):

> *"MGF used MH's spent to date and cost to go figures, on top of these MGF applied additional costs for items such as earthwork productivity; concrete productivity; additional scaffold & crane costs; additional indirect costs; etc.*
>
> *In addition, MGF applied interest and escalation in line with MH's percentage.*
>
> *Finally, MGF applied a 10% contingency to take into account project risk and uncertainty."*

Manitoba Hydro has attempted to understand how MGF came to their expected cost of Keeyask of $9.5 B to $10.5 B. Manitoba Hydro does not know exactly how MGF developed the values as they have failed to provide the requested supporting information (MH/MGF I-26).

Manitoba Hydro notes that the range of values identified by MGF happen to align with the potential range of outcomes identified in Manitoba Hydro's own analysis done when the Keeyask project budget was revised early in 2017. At that time, the potential cost of the project with P90 contingency was identified to be $9.6 B which roughly aligns with the lower end of MGF's range. The sum of a potential management reserve budget to cover severe event risk (that would result in a one-year delay and costs between $500M to $800M) added to the potential P90 budget would closely align with the $10.5B upper end of the range identified by MGF.

In early 2017, when Manitoba Hydro revised the control budget, the Keeyask Project budget with P50 contingency was selected. This established the $8.7B control budget to ensure Manitoba Hydro was proceeding with the lowest cost execution for the project. Other alternatives were considered at the time; however considering the level of completeness of the project (roughly halfway through with many key risks still remaining) the P50 contingency balances the potential costs from the remaining risks and provides a challenge to the execution team. This approach drives the lowest cost delivery and the most efficient outcome.

The following is a summary of items that MGF states will result in additional costs to the Project:

Figure 1.2

MGF Scope #	MGF Finding #	MGF Report Page	Description of Finding	MGF Order of Magnitude Estimate
5	9	60	Increased use of overtime and double time	$40.9 M
5	10	61	BBE indirect costs	[redacted]
9	3	74	Earthworks productivity	$88.4 M
9	5	76	Scaffold and crane costs	$103M
9	7	78	Concrete productivity direct costs	[redacted]
9	7	78	Concrete productivity indirect costs	[redacted]
			Total	**$678M**

1a

In the MGF report, the sum of the estimated value of the Findings that MGF states will result in an increase to the cost of Keeyask of approximately $678 M. By applying the methodology described by MGF in their response to MH/MGF I-26a, it could be assumed that applying interest, escalation and a 10% contingency to the $678 M and adding the value to the $8.7B control budget would arrive within MGF's expected cost of $9.5 B to $10.5 B. For most of their Findings, MGF included a factor for GA&O and Indirect Costs. GA&O and Indirect Costs as they relate to the GCC are described below:

General Administration & Overhead - GA&O is intended to cover support to the project from the Contractor's home offices including but not limited to expenses such as Human Resource Management, Corporate Procurement, and I.T support.

Indirect Costs – Costs that are required to support the direct work at site including temporary buildings, small tools, and worker transportation expenses.

It is Manitoba Hydro's opinion that these "order of magnitude" costs are overstated in the MGF report and result in an inflated forecasted cost for the following reasons:

1) MGF has incorrectly applied the GA&O mark-up percentage to potential cost increases.

As part of Amending Agreement #7, GA&O has been capped at the target price to disincentive the Contractor for exceeding the revised target price established in AA#7. This also encourages the Contractor to complete the work at the lowest cost. It appears that MGF did not account for this GA&O cap in their values, but rather applied the full amount on all of the forecasted increased costs disregarding the cap. This results in an over-estimate of at least $26 M.

2) MGF has overstated their forecasted indirect costs for BBE by simply extrapolating the current spend.

MGF Report: Scope Item 5, Finding #10, page 61

On page 61 of their report, MGF provided a forecasted value for an increase to the indirect costs. It appears to Manitoba Hydro that MGF used the overall physical percent complete from the Bill of Quantities for their estimate and assumed that the indirect costs from the BBE Cost Report will continue similarly for the remainder of the work (i.e. they extrapolated these values for the remainder of the contract on a straight line basis).

The forecasting method used by MGF is overly simplistic and flawed as it does not consider upfront costs that will not occur again in the future such as temporary buildings, and roads (i.e. fixed indirect costs) and progress on areas of the work that may incur more (or less) indirect costs than others. The values also do not consider the efforts that Manitoba Hydro is undertaking with BBE to manage BBE's indirect costs. Managing BBE's indirect costs is a key area of focus for Manitoba Hydro in 2018. Manitoba Hydro hired an Indirects Lead with over 19 years of related experience in project controls, project management and accounting in the major capital project environment to help manage BBE's indirect costs. These factors are considered in Manitoba Hydro's forecasting methodology. However, they do not appear to be considered in MGF's cost estimate, as they should.

In addition to the specific forecasted indirect cost value presented on page 61 of its report, in other findings including: Scope Item 9: Finding 3, page 74; Scope Item 9: Finding 5, page 76; Scope Item 9: Finding 7, page 78, MGF has added a factor for indirect costs calculated by dividing the total direct costs by total indirect costs. This suggests that MGF double counted indirect costs by identifying indirect costs related to earthworks productivity, concrete productivity, and scaffolding/crane costs beyond the values MGF provided on page 61 of its report in the calculated "BBE Indirect Costs" value.

Manitoba Hydro is of the opinion that utilizing this indirect to direct cost ratio for potential cost increases is inappropriate as this ratio includes both **variable indirect costs** such as maintenance costs, transportation costs for workers, additional supervision, and consumables/small tools, as well as **fixed indirect costs** such as installation of temporary buildings and roads. These fixed indirect costs would not be impacted by changes in directs work. For example, if concrete productivity is worse than expected and additional labour hours are required (i.e. direct work); costs that were originally incurred to build the carpentry shop **(i.e. fixed indirect cost)** would <u>not</u> be incurred again. It appears as though MGF has failed to account for this reality in its report, resulting in an overestimate of future costs.

Manitoba Hydro has conducted a line by line analysis of the cost accounts to determine which indirects could be affected by direct work and has concluded that a lower ratio is more appropriate. However, the nature of the direct work in question is important. For example, if concrete productivity would cause the project to be extended, it is likely that most indirects would be impacted and therefore a ratio on the higher end of Manitoba Hydro's range would provide a reasonable estimate of the associated indirect costs. In contrast, if the craft-to-foreman ratio were to change, it would not impact as many indirect cost accounts and the ratio of indirects could be significantly lower. In its analysis, MGF failed to recognize that the relevant indirect costs need to be considered when estimating the cost impact associated with a potential increase to direct costs rather than using a broad ratio of total indirect to direct budgets.

<u>The following are additional miscellaneous points that Manitoba Hydro would like to rebut that fall outside the 3 main areas addressed:</u>

<u>1) Selection of the Contractor:</u>

Scope Item 5, Finding #12, page 62

On page 62 of their report, MGF states that they *"were advised by Manitoba Hydro that Bechtel were self-performing Contractor's on Limestone and this predicated their decision to appoint BBE"*. Manitoba Hydro provided MGF with the documentation related to the procurement of the GCC including the RFPQ and evaluation criteria. Manitoba Hydro did not select BBE, a limited partnership that included Bechtel, strictly on the basis of Bechtel's Limestone experience as it is implied in the MGF report. In addition to considering the work self-performed by Bechtel, the pre-qualification process described above also considered the experience with self-performed work by both Barnard and Ellis Don. It is the combination of experience and knowledge across all three partner companies that informed the decision to select BBE as one of the four contractors that would ultimately compete on a cost basis for the work during the final phase of the three-phase competitive tendering process.

A strength of the joint venture was that each partner would lead different areas, but would still share overall responsibility. The division was as follows: Bechtel for concrete structures, Barnard for earthworks, and Ellis Don for their infrastructure work and knowledge of the Canadian labour marketplace. Each proponent offered key personnel that had experience in all of these areas.

<u>2) Earthworks Embankment Fill Measurement</u>

Scope Item 9, Finding 2, and page 73

On page 73 of their report, MGF describes a site visit to Keeyask on November 9 and 10, 2017 where the two MGF staff who attended the site visit performed a survey of the earthworks to compare to the value reported by BBE. From this assessment, MGF concluded that the embankment fill claimed by BBE is approximately 10% higher than the quantity assessed by MGF.

During this site visit, MGF representatives spent approximately 12 hours in the field which included safety orientations, a site tour, and meetings with Manitoba Hydro staff, in addition to their time surveying quantities. In MH/MGF I–28, Manitoba Hydro requested that MGF describe the methodology used to calculate this value. MGF provided the following description of the methodology they employed:

> *"Average end area method was used to calculate the volume. Heights of existing embankment and remaining fill heights were determined by referencing the existing known elevation point at concrete structures, survey stakes and speaking with MH site personnel. Survey profiles of existing embankment and center line profiles provided to MGF staff on site by MH were also used in the calculation of the volumes."*

Manitoba Hydro was present during this survey and reports that the review was rudimentary and involved measuring the structures with no equipment but a borrowed measuring tape and 100 metre chain. While these methods are appropriate for checks to determine approximate quantities, they are not as reliable as the detailed methodology employed by Manitoba Hydro numbering thousands of checks on BBE's performance over the course of the last three and a half years, described below.

In their report, MGF did not refer to the actual methods used by Manitoba Hydro and BBE to measure quantities for the earth structures on the Keeyask site. In addition to the Manitoba Hydro earthworks inspectors that monitor performance of the Contractor, Manitoba Hydro has a survey crew of seven full time staff dedicated to earthworks with at least four staff on site at all times (2 on day shift, 2 on night shift). BBE also employs an earthworks survey crew of 12 staff with at least 8 staff on site at all times (4 day shift, 4 night shifts). There are additional surveyors from both organizations dedicated to the concrete structures as well (e.g. Powerhouse and

Spillway). Manitoba Hydro and BBE earthworks surveyors take independent measurements before, during and after the placement of material on each earth structure. Both crews use a combination of Trimble GPS and total station survey equipment to measure quantities. The survey data is used to develop detailed 3D models using AutoCAD 3-D for modeling and calculating quantities. These models are updated weekly and quantity runs by both Manitoba Hydro and BBE are generated to report on weekly production. Typically, the difference between the survey data captured by Manitoba Hydro and BBE surveyors is between 3-5% and is reconciled regularly. Manitoba Hydro and BBE meet to review these numbers and agree upon the final installed quantities.

On page 73 of their report, MGF recommends that Manitoba Hydro performs "spot checks" on the quantities claimed by BBE to ensure the quantity progress being relied upon for scheduling is accurate. Manitoba Hydro and BBE are continuously measuring quantities via their respective survey teams. As an example of the degree of rigor with respect to the survey process, on a portion of the Central Dam, 104,820 survey points were collected for the foundation (bedrock and back slopes) and 127,729 survey points were collected for the fill (including dental concrete). This methodology is superior to spot checks because data is gathered continuously at every stage of construction to ensure quantity measurements are accurate. The suggestion that the methods employed by the MGF employees on the two-day site visit are superior to the methods employed by Manitoba Hydro's constant and continuous surveillance of the work site are nothing short of ridiculous.

<u>3) Issues with methodology employed on Keeyask</u>

Scope Item 9, Finding 10, and page 81

On page 80 and 81 of their report, MGF provides a picture of earthworks from summer 2016 from a Manitoba Hydro report and has overlaid a number of notations. In addition to this picture, MGF states that:

> *"The application of incorrect machinery and work methods causes delay and additional cost. The following picture depicts an example where both Schedule*

and Cost are pushed out in favour of the Contractor and at the expense of the Client.

While the above is an example, the poor productivity achieved on site reflects poor Supervision and Management by the Contractor. If Manitoba Hydro wants to reduce cost and schedule overruns they should have a more hands on approach."

The date stamp on the photo is July 28, 2016, approximately 1 year prior to MGF first attending the Keeyask site. In MH/MGF I-32a, MGF has confirmed that their notations are based on the photo and personal experience, and therefore, not as a result of directly observing the work taking place or speaking to Manitoba Hydro staff at the Keeyask site who were involved in the specific work depicted in the photo.

In MH/MGF I-32e, MGF states that a technical specification does not necessarily need to be followed in instances where there are opportunities to improve productivity and cost. MGF goes on to say a test program may be implemented.

The scope of work depicted in the photo occurred on the North Dyke and when the excavation occurred in this area, four distinct areas of saturated clay material were discovered requiring additional excavation. The resulting excavation of the localized area was 1-2 metres lower than the surrounding areas and susceptible to ground water infiltration. In this case, BBE attempted to follow the Technical Specification but found it challenging due to the prevailing ground conditions. The Manitoba Hydro Earthworks and Excavations Resident Engineer and the BBE earthworks team worked together to engage in a test program which was successful in keeping the work moving. In the case of the photo on page 81 of MGF's report, MGF has taken a situation with limited context, without speaking to Manitoba Hydro to understand the situation, and applied the finding in an attempt to substantiate an unfounded conclusion.

<u>4) Extended Overtime:</u>

Scope Item 9, Finding #8, page 79

On page 79 of its report, MGF states that, upon reviewing BBE's progress payments from May and June 2017, there were 73 instances of individuals working over 16 hours in a day during that 2 month period. MGF goes on to state that these extended hours will not be as productive as straight time hours and will result in diminishing output for every hour worked, in addition to raising concerns about potential personnel safety. Manitoba Hydro reviewed these 73 instances and found that a majority of the records were either supervisory staff or craft workers performing concrete-related work. In most cases, when a concrete placement is started, it needs to be taken to conclusion to avoid a cold joint (which is a potential water pathway through the concrete structure). During larger concrete placements, additional overtime is periodically warranted meaning that some of these cases where individuals were required to work extended hours were justified. However, safety was not sacrificed as supervisors were on hand to ensure the work was performed safely and in accordance with the established procedures.

To put these 73 instances of individuals working over 16 hours in a day into perspective, in May and June 2017 there were a total of 61 days worked. Considering that BBE had an onsite workforce on average of approximately 1,500 individuals, this would result in more than 90,000 days worked by the contractor's workers. These 73 instances account for less than 0.08% of the total days worked by the contractor's workforce during that 2 month period, and are the exception rather than the rule.

Manitoba Hydro reviewed the May and June 2017 progress payments and found that the average hours worked by the entire field workforce is approximately 10.7 hours per day and 10.5 hours per day for the field workforce for all of 2017. This average does exceed the standard onsite working day of 10 hours. Manitoba Hydro agrees that extended overtime could impact worker productivity and could have cost implications. As such, it will continue to work with the contractors in 2018 to more effectively manage overtime. These changes will help to minimize the need for additional overtime and is expected to increase productivity.

Manitoba Hydro also prides itself on its safety record and works diligently in this regard. From project commencement to November 30, 2017, there have been approximately 15 million person hours worked on the project and only 22 lost time incidents averaging slightly over 6 lost time days per incident. In addition, BBE has gone more than 14 months (over five million person hours worked) without a lost time incident. This safety record is impressive given the size and remoteness of the project, but Manitoba Hydro and BBE will continue to focus on eliminating safety incidents until the goal of "zero hurts" is reached.

<u>5) Inconsistencies in Estimate Documentation:</u>

Scope Item 3, Finding #2, page 36

MGF reviewed Manitoba Hydro's estimate documentation on Keeyask and stated the following on page 36 of their report:

> *"CEF 2016 Estimate Sheets were provided in the Basis of Estimate appendices as supporting details to the cost estimate, however, the values included within these estimate sheets did not align with the values carried in the actual estimate. In the 2014 Capital Project Justification Addendum, Basis of Estimate variances occur because of SAP's use of a more accurate treatment of overhead. It was also noted through conversations that these variances are the result of updated labour rates themselves which are to be applied throughout the next fiscal year. Rates current at the time the CEF 2016 Estimate Sheets were generated, and then adjusted prior to being carried in the final estimate. This was not specified within the 2017 Capital Project Justification Addendum, Basis of Estimate and the reconciled estimate sheets that were provided in 2014 were also neither provided nor developed for the 2017 Estimate. This made one-for-one reconciliations difficult to perform."*

Manitoba Hydro has calculated the approximate "discrepancy" between the estimate sheets (item 1.0 below) and the Capital Expenditure Forecast ("CEF") 2016 Plan in SAP (item 2.0 below) referred to on page 36 of MGF's report. The total variance (item 3.0 below) is under $500K on a total value of almost $3.5B resulting in a difference of 0.013%.

To understand this statement, in MH/MGF I-13, Manitoba Hydro requested that MGF provide the specific networks which are misaligned along with the dollar value and what percentage of the CEF2016 estimate the value of the total misalignment represents. MGF did not provide this detail in their response to MH/MGF I-13. Manitoba Hydro reviewed the total budget values found in the available CEF2016 estimate sheets and compared to the values in SAP, and focused on networks valued over $1M. The outcome of the analysis is listed below:

Figure 1.3

Item	Description	Value
1.0	CEF2016 estimate sheets	$3,488,545,769
2.0	CEF2016 Plan in SAP	$3,489,007,738
3.0	**Variance**	**$461,969**
4.0	**% difference**	**0.013%.**

As part of the estimating process that feeds into Manitoba Hydro's CEF, the Work Package Leads on the Keeyask Project who are responsible for managing the scope, schedule and budget for their respective work packages, complete estimate spreadsheets where they estimate the costs of managing their scope of work (i.e. work packages). As part of this exercise, the Work Package Leads estimate the level of effort (labour hours) in managing their work package. These hours are multiplied against a labour rate that is extracted from SAP, the corporation's cost management system (item 1.0 above). After a verification process, the estimated hours from the Work Package Leads are then loaded into SAP to form the CEF Plan in SAP (item 2.0 above). In some cases it may take 1-3 months for this process to be completed. Some of the labour rates that were taken from SAP and included in the estimate spreadsheets may change slightly from the time they are extracted for the spreadsheet and the labour hours are uploaded to SAP. The labour rate in SAP multiplied by the labour hours provided by the Work Package Leads is the value that becomes part of the CEF plan (item 2.0 above). The labour rates carried in SAP trump the labour rates in the spreadsheets. The labour hours captured in the spreadsheet by the Work Package Leads (and subsequently uploaded into SAP) is the key deliverable. The labour rate in the spreadsheet that may have changed in SAP since it was originally extracted is not updated on the spreadsheet (because the labour hours have already been entered into SAP to form the Plan).

While there is technically a minor difference in the values referenced above, MGF has failed to recognize if this difference is a material one. Manitoba Hydro is alert to any changes which might impact the estimates and monitors these factors. In the context of the budget the issue raised by MGF does not materially impact the estimates.

6) Cash and Trade Discounts

Scope item #5, Finding #8 – Keeyask Cash and Trade Discounts (page 59 and 60)

MGF reviewed progress payments for BBE for the months of October 2016 and June 2017 and noted that trade discounts were "negligible" and no cash (prompt payment) discounts were identified. MGF goes on to recommend that all contractors negotiate trade discounts with their subcontractors and suppliers.

In MGF's observations and findings, MGF implies that BBE could achieve 10% savings from their suppliers and pass this savings on to Manitoba Hydro. When considering BBE's total purchases for the entire Keeyask project, MGF believes this equates to a potential savings of approximately $115.8 million for Manitoba Hydro.

Manitoba Hydro provided MGF with a copy of the General Civil Works Contract with BBE. In the contract, Section 7.8 Process of Selection of Subcontractors outlines the process that BBE is required to follow for the award of major subcontracts (includes contracts for both subcontractors performing work under BBE and suppliers of equipment/material). BBE is required to solicit three competitive bids for every contract valued over $500,000. The contract also provides Manitoba Hydro the ability to review and sign off on procurement over $500,000. If the contractor does not follow this procedure and subcontracts work without receiving the required approval from Manitoba Hydro, the work is not eligible for reimbursement under the contract. Therefore it is in the contractor's best interest to follow the terms of the contract. BBE has operationalized this section in the contract as a Desktop Procedure for

Subcontractor Selection Process. Manitoba Hydro provided MGF this document on October 7, 2017.

In MGF's conclusion regarding cash and trade discounts, MGF fails to mention how BBE can realistically achieve this 10% savings from their suppliers and if this is even possible under the existing agreements BBE has with their suppliers and subcontractors. Since BBE is required to competitively tender work valued over $500,000, the vendor selected should already provide the lowest cost or best value proposal. Manitoba Hydro reviews these tenders to ensure that this philosophy is maintained. Manitoba Hydro is skeptical that a further 10% savings as implied by MGF could be achieved as the major subcontracts are already competitively tendered by BBE.

7) Hatch Schedule

Scope Item #4, Finding #2 – Hatch Schedule (page 41)

MGF reviewed the schedule for the detailed design engineer Hatch and concluded that while the schedule is well-developed, many activities are behind schedule.

Manitoba Hydro and MGF had a number of discussions regarding the engineering schedule and the status of engineering deliverables. During these discussions, Manitoba Hydro described that during the time of Amending Agreement #7 with BBE, the decision was made to manage engineering deliverables based on Construction Work Packages (the pieces of work to be undertaken by the GCC) rather than on the specific engineering deliverables that were incorporated into Hatch's baseline schedule (i.e. on a drawing by drawing basis). This ensures that the contractor has all the drawings they require to build a specific piece of work (such as a Powerhouse Unit 1 base slab) with the required lead time to plan and procure materials.

Since neither Manitoba Hydro, Hatch nor BBE are no longer managing their respective work to Hatch's baseline schedule, efforts have not been expended to update the Hatch baseline schedule.

On page 33 of MGF's report (Scope Item #2, Finding #1), MGF confirms that on October 23, 2017, in a video conference with senior representatives from BBE, BBE advised MGF that construction had not been delayed on account of the issue of Issued for Construction drawings. This informed MGF's conclusion that "*The production of Issued for Construction drawings has not impacted BBE's progress*".

<u>8) BBE Schedule – Negative Float</u>

Scope Item #4, Finding #3 - Keeyask – BBE Schedule: Negative Float (page 42)

In reviewing BBE's schedule, MGF identified a number of activities in BBE's schedule that have negative float. MGF concludes that until these deficiencies are reviewed and corrected, Manitoba Hydro cannot have confidence in BBE's schedule. Manitoba Hydro was aware of the presence of negative float in BBE's schedule and its significance and has been working with BBE over the last few weeks to develop a valid recovery schedule. This recovery schedule recovers the delays in BBE's baseline schedule and eliminates negative float. This recovery schedule was submitted to Manitoba Hydro in 2017.

<u>9) BBE Forecast at Completion Date</u>

Scope Item #4, Finding #6 – BBE Forecast at Completion Date (page 44)

MGF reviewed Manitoba Hydro's schedules and methodologies and believe the first unit ISD will be approximately 3 months later while the last unit will be 4 months late. MGF goes on to context this finding stating that no mitigation strategies or schedule recovery options have been added to this forecast. In MH/MGF I-19F, MGF confirms that the forecasted delay could be reduced using schedule mitigation activities and successful improvements at site. Some of these mitigation activities are referenced previously in this report.

On page 78, MGF indicates that actual average concrete productivity is likely to worsen, as there are more complicated pours to come and three more winter seasons to work through. Manitoba Hydro expects that concrete productivity to improve. A majority of the progress to date on the Powerhouse structure has been on units 1, 2 and 3. There has been a learning curve for the contractor and the craft labour who are building the work on these first three units. Given that a generating station is comprised of seven nearly identical units, it is expected that performance on the remaining units will be improved. It should be noted that on page 78, MGF states that the expected cost increase due to lower than planned productivity on the concrete structures is approximately $136.5 M. In MH/MGF I-30c, MGF indicates that they have not included factors such as improvements due to repeatability into their estimated costs. It could also be assumed that this factor was also not considered in the finding related to schedule.

2. Bipole III Transmission Reliability Project

The Bipole III Transmission Reliability Project, currently under construction, is a high-voltage direct-current ("HVDC") transmission project that will enhance the reliability and increase capacity of Manitoba's electricity supply. More than 70 percent of electricity generated in Manitoba is delivered to customers on the two existing HVDC transmission lines (Bipole I and Bipole II). These lines run alongside each other for much of their route and end at the same point in southern Manitoba at the Dorsey Converter Station. Due to their proximity to each other and the single terminus point for both lines, damage to Bipole I and II or Dorsey Converter Station could mean Manitoba Hydro cannot carry enough electricity to meet its customers' demand. Bipole III will add 2,000 megawatts to Manitoba Hydro's HVDC transmission capacity.

MGF was retained by the PUB on Bipole III to review and explain the increases in cost estimates and capital cost increases, as well as project cost overruns. It was to determine and assess the reasonableness of its updated forecast and to identify aspects of the updated cost estimate and schedule that are at risk. It was also to recommend risk mitigation strategies and, further, to review Manitoba Hydro's:

- practices on its pre-construction design and engineering work; and
- its methodologies for costing, for tendering and contracting, for management of construction, contractors and construction risk management, and for scheduling.

MGF's evidence was that Bipole III Transmission Line is generally well organized and managed efficiently. It stated that it was on schedule and had used contracting strategies that were commercially astute, allocating risk appropriately. It also stated that Manitoba Hydro was managing a key risk, cause by poor performance of a contractor. MGF, in its Executive Summary on page 1 of its report, have highlighted that the HVDC Converter Stations "are well managed by Manitoba Hydro and the potential for cost over-runs is low."

Manitoba Hydro generally agrees with the MGF findings related to the Bipole III Project. Manitoba Hydro continues to manage the project appropriately, and maintain and affirm that Bipole III will be in service by the end of July 2018. This will be achieved within the approved $5.04 billion control budget.

Manitoba Hydro agrees with MGF that there remains risk to completing Bipole III on time. Specific risks related to Transmission Line contractor Rokstad's performance have been highlighted. As noted in the MGF report, Manitoba Hydro is managing this risk by de-scoping work from Rokstad and awarding it to another contractor. Manitoba Hydro was in the process of taking the action independently from this review. However, as noted on page 112 of MGF's report, the contingency amount for the Transmission Line will be sufficient to address this mitigation action and remaining risks on the work.

Despite Manitoba Hydro's general agreement with MGF's findings on Bipole III, there remain some areas within MGF's report that Manitoba Hydro disagrees with, and some areas in which it would like to provide clarifying information. There are also a number of instances where MGF has misunderstood the information provided, or drew an incorrect assumption that Manitoba Hydro would like to clarify on the record. In some of these instances, MGF was provided clarifications by Manitoba Hydro prior to the report being completed. However, it did not incorporate those into its final report.

2.1. Additional information to provide some clarity on the MGF report.

There are a number of items on which Manitoba Hydro would like to provide some additional information to provide some clarity on the MGF report.

Scope Item 10, Finding 2, page 84

MGF recommends that "the Manitoba Hydro Estimating Team prepare the overall estimate with input from each department." Manitoba Hydro can advise that approach to managing the estimate update process through the Estimating Team was in place prior to the MGF review. The Estimating Team coordinates all inputs from contributing areas/Departments. The Estimating Team also conducts reconciliations and confirmation of values for items input and updated within SAP.

Scope Item 15, Finding 2, page 99

On page 99 of its report MGF concludes that the 2014 pre-construction Basis of Estimate was extremely well done, however recommends further improvements in the supporting backup documentation to align costs captured within the SAP accounting software used by Manitoba Hydro and the project Work Breakdown Structure.

A Basis of Estimate document details the scope of the project on which the estimate is developed, the estimating methodologies applied and key assumptions upon which the estimate is based. As noted by MGF, the 2014 Basis of Estimate document was extremely well done. Part of the Basis of Estimate is to document project costs entered directly into Manitoba Hydro's SAP accounting system. These costs would include internal labour hour estimates, expense estimates and similar internal costs. In contrast to MGF's recommendations, Manitoba Hydro considers the backup documentation included within the Basis of Estimate document associated with these costs to be aligned with the Work Breakdown Structure and considers the level of documentation of these costs included within the Basis of Estimate document to be sufficient.

Scope Item 17, Findings 5 and 6, page 105

MGF has correctly identified that Rokstad Power's work remains one of the critical risks to the on-time completion of the Bipole III Project. Manitoba Hydro would like to clarify the following regarding this scope item:

- The report notes an end date of April 21, 2018 for Rokstad's work. In IR MH/MGF I – 44 MGF clarified that the activity considered the end date "Final Record and As Built Submissions" is in fact a trailing /post-construction activity and does not correspond directly with the completion of construction work. Construction work will be completed in March 2018.
- MGF correctly states on page 106 of its report that "A recovery plan has been developed and submitted by Rokstad Power Company to Manitoba Hydro, but has not been approved at this time." Manitoba Hydro continues to work with Rokstad to develop a sufficient recovery plan for their remaining scope and Rokstad's progress will be closely monitored to determine whether any further actions are required. .
- Manitoba Hydro agrees with MGF that removal of scope from Rokstad and placement of this work with another contractor does not guarantee the project will finish on schedule. However, Manitoba Hydro can advise that the new contractor has mobilized and has begun construction on this removed scope. The new contractor has committed to a schedule that will ensure on-time completion of the transmission line and they are currently on-track to this schedule. As such, this risk is substantially mitigated.

Scope Item 20, Finding 3, Page 117

MGF recommends that Manitoba Hydro properly record costs associated with placing the removed scope with another contractor and record the extra over costs it has incurred in having the new contractor in place. Manitoba Hydro agrees with MGF and is in the process of recording these costs appropriately and taking the appropriate steps contractually to recover any additional costs from Rokstad that are associated with the scope removal and Rokstad's lack of performance.

There is a finding on page 111 of the report regarding the Bipole III Project cost estimates for the Rokstad contract and a recommendation that the estimate be updated to reflect this change. Manitoba Hydro's estimate has already been updated with these costs. All reductions to the contract budget are returned to the project control budget, Transmission Line Contingency, as part of ongoing change management on the project.

2.2. Areas of the report that Manitoba disagrees with the conclusions drawn by MGF

There are a few areas of the report that Manitoba disagrees with the conclusions drawn by MGF.

Scope Item 18, Finding 1, page 108

On page 111 of its report, when determining the reason for project cost overruns since the final pre-construction control budget, MGF concludes that "Many of the additional costs appear to be a result of a project that was perhaps not at a stage of readiness at the time of project approval in terms of permit approvals, design development, land acquisitions and execution planning (i.e. procurement cycle and delivery time, market underpinned costing based on a tested and firm strategy, etc.)." Manitoba Hydro does not agree with this assessment.

The project was at an appropriate stage of "readiness" to proceed recognizing that the environmental License had been received and a sufficient number of winter construction seasons were necessary to execute the work. Specifically, as the transmission line work proceeds sequentially from clearing, to anchors and foundations, to tower erection and stringing, it was appropriate that clearing, work began immediately after the Licence was obtained and the tower erection and stringing contracts proceeded later. The project correctly identified uncertainty in the transmission line construction marketplace and carried both contingency and management reserve related to this. Events related to weather and material procurement that transpired were not an issue of "readiness", but rather general and typical areas of uncertainty and specific contractor issues/challenges.

Scope Item 10, Finding 1, page 83

MGF identified Manitoba Hydro as having internal labour costs budgeted beyond the project in-service date that are being incorrectly applied to capital expenditures as opposed to operating expenditures. Manitoba Hydro provided clarification and, through the IR process, MGF responded that it was their "..opinion these costs should not be part of a capital budget." Manitoba Hydro disagrees with the treatment of all costs immediately after the ISD being classified as operating expenses (as opposed to capital). After the ISD, there are still significant construction activities to be completed; such as:

- completion of synchronous condensers 3 and 4 at Riel,
- demobilization and clean-up by Contractors at each construction site,
- decommissioning of the camp infrastructure at Keewatinohk, and
- deficiency clean-up and commercial contract close-out.

All of these activities will require Manitoba Hydro labour after ISD that is directly attributable to capital construction costs associated with the asset. To ensure appropriate allocation of costs to capital or operating expenses, all project costs are carefully scrutinized by Manitoba Hydro accounting professionals to ensure that costs meet the criteria for capitalization as set out in International Financial Reporting Standards. When costs are deemed not to be eligible for capitalization, they are charged directly as an operating expense to the Corporation. Additionally, the allocation to capital or operating is considered in the annual external accounting audit that the Corporation undertakes as part of preparing its yearly financial statements.

Scope Item 13, Finding 3, page 95

On page 97 of their report MGF states "The current value of contingency at a P75 confidence level does not appear to be based on a current or updated Contingency review. As such, this would not take into consideration the events and updated risks that the project has been or may be exposed to. Manitoba Hydro's corporate standard states that contingency is set at a P50 or 50% confidence level." Manitoba Hydro disagrees with this statement. The current P75 contingency value for the Converter Stations was developed based on the 2014 risk and contingency assessment as the general risk profile of the project was unchanged. This approach does appropriately account for risks realized to-date.

Scope Item 19, Finding 3, page 112

MGF further concluded on page 114 when reviewing the Bipole III transmission line that the current P80 confidence level does not appear to be based on a current or updated review. The current P80 contingency value for the Transmission Line was also developed based on the 2014 risk and contingency assessment as the general risk profile of the project was unchanged. This approach does appropriately account for risks realized to-date. It was also reviewed against the Risk Register at the time, contrary to MFG's finding that it does "not appear to be based on current or updated review." The Risk Register is a document used as a tool to track issues and address problems as they arise. It acts as a repository for all risks identified and includes additional information about each risk such as the nature of the risk, the owner of the risk, and mitigation measures.

The decision to increase the P-value of the contingency for the Bipole III Project (transmission line and converter stations) in 2016 from a P50 to an overall P75 contingency level on the project was based on a number of anticipated risks having been realized and the desire to have an increased confidence level in the Bipole III control budget recognizing that there was only 2 years remaining on the work before the project was brought into service. With construction work on the project now largely complete, the project has progressed to a point where budget risks are largely reduced and the primary risk relates to schedule. This is supported by MGF's findings that the contingency on both the transmission line and converter stations are sufficient to complete the work on-budget.

It is the project management team's responsibility to recommend the appropriate P-level for contingency on a project. While this can be a P50 contingency, the project management team may alternatively recommend a different P-value (e.g. P75 contingency) based on factors such as: realized risks, project status, remaining work-to-complete, and remaining risks. The recommended P-level of the contingency together with the project estimate is reviewed and approved at the Executive level.

2.3. Misinterpretations, errors and incorrect characterizations in the MGF findings.

MGF provided many of their findings to Manitoba Hydro in advance of issue the report as drafts and Manitoba Hydro advised MGF that, in its opinion, there were a number of misinterpretations, errors and incorrect characterizations in the findings.

It also suggested corrections. However, based on the MGF responses obtained through the Information Requests process, MGF did not include any of these suggested corrections within its final report. As such, Manitoba Hydro will provide this information directly to the PUB through this Rebuttal.

Scope Item 10, Finding 3, page 86

MGF has incorrectly stated a risk identified in the June 2017 Bipole III Converter Stations Project Controls Report was repeated/again identified in the September 2017 Controls Report, although the wording in the report was in no way the same. The risk from the June 2017 report addressed both concerns related to the on-time completion of work by the Keewatinohk 230kV AC Switchyard contractor and the commissioning schedule for the Riel Converter Station Synchronous Condensers, whereas The risk from the September 2017 report identified concerns related to the overall complexity of interface work between the major contractors, potential delays to commissioning due to HVDC equipment damaged during installation, the risk of commissioning delays on the AC Switchyard and equipment delivery delays potentially impacting commissioning schedules.

Based on MGF's interpretation that the identified risks were identical, they incorrectly concluded that Manitoba Hydro did not mitigate the risk originally identified in June 2017. These two risk items were, in fact, different issues. Regarding the June 2017 risk, Manitoba Hydro took specific actions, including taking-over the work in parts from the contractor to ensure the AC Switchyard work was completed and handed over to Manitoba Hydro in time to accommodate commissioning. Similarly, Manitoba Hydro has required the Riel Synchronous Condenser Contractor to review its commissioning plan and ensure it is achievable. The risks noted in the September 2017 report were addressed as follows:

The "complexity of interfaces" risk relates to schedule risks on the overall interface work that is to be executed to "connect" or "link" the major components of work on the converter stations (for example linking the HVDC station to the Synchronous Condensers). Manitoba Hydro is actively managing and mitigating this risk through execution of its interface contracts and interface schedule management

The damaged HVDC equipment identified as having the potential to impact commissioning, relates to damage that occurred to Converter Transformer turrets during installation. The Contractor has addressed this risk by obtaining replacement turrets. There will be no impact to schedule.

The delays related to commissioning of the Keewatinohk AC Switchyard, related to new delays that had arisen in the completion of installation and finalization of equipment. These items were addressed and recovered by the contractor and the final handover of the switchyard to Manitoba Hydro for commissioning occurred on schedule.

The risk related to delayed equipment delivery potentially impacting commissioning schedules, related primarily to remaining (minor) equipment deliveries on the HVDC contract and remaining equipment deliveries on the Riel Synchronous Condensers. These delays are both being actively managed and mitigated by the Contractors and both are not anticipated to have any impact to schedule and the in-service date of the project

Scope Item 11, Finding 3, page 90

MGF has misinterpreted the application of mark-up on several of the lumps sum Variations reviewed. MGF have indicated that the contractor improperly applied mark-up to lump sum Variation values already including mark-up (i.e. double application of mark-up). This double application of mark-up did not occur. The instances identified by MGF only included a single markup of 15% as part of the total lump sum pricing. This mark-up happens to be the same as prescribed for on Actual Cost Variations but was not additional application (or double counting) of mark-up. As such, in the identified Variation, the amount paid by Manitoba Hydro was equal to the agreed upon lump sum price included in the approved variation.

Scope Item 15, Finding 1, page 98

MGF stated "CEF 16 carried a cost of [redacted] Manitoba Hydro wishes to clarify that the entire Rokstad Contract budget has been adjusted for reduced scope (primarily foundations scope removed in N4) and updated unit rates once the contract was awarded in December 2016, which was post the finalization of CPJA 08a (2016). All reductions to the contract budget are returned to the project control budget, Transmission Line Contingency as part of the ongoing budget alignment process for changes. 1a, 7a, 8a

Scope Item 15, Finding 3, page 100

MGF has incorrectly identified that the CEF2016 estimate failed to include costs for Distribution Line Crossings and the Transmission Line Construction Yard. These costs were included in the CEF2016 and current CPJA 08a approved control budget in the 2016 estimate and summaries provided to MGF. Bipole III – Appendix A is a summary of an extensive spreadsheet that was provided to MGF with relevant items expanded that summarizes the approved budgets and that these items were in fact included in the control budget.

Scope Item 17, Finding 1, page 102

MGF alleged that there were several missing attributes to the Bipole III Risk Register. These attributes are actually addressed in the Risk Register and have been missed by MGF. MH wishes to clarify that the Risk Register was originally developed through SharePoint and as such there is an identified creation date for each risk. However, in the spreadsheet output of the Risk Register provided to MGF a column outlining the creation date of each risk had not been included.

Scope Item 20, Finding 1, page 115

On page 115 in its review of the Risk Register, MGF recommended that the Risk Register be updated to include the date the Register was last updated and the date the risk ID was last updated. In fact, the Risk Register is actively and properly managed and the Risk Register information suggested by MGF to be collected is already captured within the SharePoint document management and collaboration tool where the Risk Register is held and is updated regularly.

Scope Item 17, Findings 2, 3 and 4, page 102

On page 103 and 104 of its report, MGF states that the Variation Summary only records those variations that are "approved." Manitoba Hydro does maintain variation log/summaries with all variations, and further reviews those for cost impact through the "Project Change Authorization" or PCA process, which is a document that authorizes and documents the use of contingency or return of contingency on the project budget and is key component of the change management process that Manitoba Hydro follows on Bipole III.

On page 102 of its report, MGF identifies Contract 031074 with Valard Construction as open, with a contingency remaining of [redacted]. This contract is shown as closed in 1a, 7a the Contracts Listing. All un-used Purchase Order funds that were held in budget and/or in allocated contingency for the Order are returned to the project control budget, Transmission Line Contingency, as part of the ongoing budget alignment process for changes.

While Manitoba Hydro generally agrees with the MGF findings related to Bipole III and agrees that construction of the project is tracking on budget and on schedule with all equipment installations nearing completion, and commissioning of the project underway, it did want the record to accurately reflect the facts above. Manitoba Hydro will continue to manage the project appropriately and is committed to meeting the scheduled ISD of July 2018 and completing within the $5.04 billion control budget.

3. MANITOBA-MINNESOTA TRANSMISSION PROJECT

The Manitoba-Minnesota Transmission Project consists of a 500 kV transmission line from the Winnipeg area to the U.S. border in southeastern Manitoba, as well as upgrades to three existing electrical stations in southern Manitoba. If the Project receives environmental licences and approvals from both the Provincial and Federal Governments, it will transport power to the United States to meet sales contracts, improve reliability of the transmission system, and bring electricity to Canada from the United States in emergencies.

MGF was retained by the PUB on MMTP to review Manitoba Hydro's:

- practices on its pre-construction design and engineering work;
- its methodologies for costing, for tendering and contracting, for management of construction, contractors and construction risk management, and for scheduling; and
- capital cost estimates.

MGF's review was generally favourable, indicating that MMTP was currently on schedule and that Manitoba Hydro's estimating methodology is consistent with industry standard. Manitoba Hydro does wish to respond to three areas contained within the MGF Report, as set out below.

3.1. Acumen Fuse

Acumen Fuse is a software tool used for reviewing the quality of schedules prepared in Primavera. Primavera is a scheduling tool that Manitoba Hydro uses to create project schedules.

Project schedules are comprised of activities associated with the work involved to construct the project, such as designing towers, ordering materials, constructing foundations, etc.

Manitoba Hydro links these activities together within Primavera using "schedule logic" to ensure that changes to durations and start dates are reflected in the schedule as the project progresses. An example of this "schedule logic" would be a link between a tower steel delivery activity and an installation of the tower steel activity. The tower can't be installed until the material is delivered, thus these activities would be linked in the scheduled using finish to start "schedule logic".

On the MMTP Manitoba Hydro also used Primavera to schedule the spending on the project. Activities in Primavera were also linked to the budget for the project and spending associated with activities was distributed from the start of the activity until the end of the activity. Using this technique Manitoba Hydro creates two types of activities, those that impact the duration of the project, and those that are solely used to record labour charges against the project, which Manitoba Hydro refers to as "Charging Activities". An example of this would be an activity used by our material procurement staff to record their time against while they answer questions about delivery dates, Manitoba Hydro would refer to this activity as a "Support" activity.

In the case of the 500kV Transmission Line schedule MGF stated the following (Reference: On page 125 of the MGF report):

> *"Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The Dorsey Stn: Manitoba – US 500kV baseline schedule scored 42, giving it a 30% probability of success."*

In addition, MGF responded the following with respect to Manitoba Hydro's information request pertaining to Acumen Fuse (In response to MH/MGF I-4 on page 13 and 11 respectively):

> *"MGF agrees that activities within the schedules that are used for capturing internal labour expenses significantly reduce the Acumen Fuse score. MGF disagrees they would have no actual impact to the project schedule success."*

In essence, MGF is stating that missing "schedule logic" is impacting the Acumen Fuse score which is reducing the project success rate.

Manitoba Hydro is of the opinion that its scheduling methodologies are appropriate and accurate. Manitoba Hydro has successfully used these scheduling practices to deliver numerous transmission line projects in the past and have refined our scheduling practices and templates based on our experience on previous projects, most recently the Bipole III, Lake Winnipeg East 115kV line, and two 138kV transmission lines built for Keeyask.

Manitoba Hydro is of the opinion that Acumen Fuse has a number of limitations with regards to scoring the success rate of the project. These include:

- Acumen Fuse cannot recognize if "schedule logic" between activities is correct, for example if the activity to install the material was linked to start before the material delivery activity Acumen Fuse would not penalize the schedule rating.
- Acumen Fuse doesn't recognize if there are missing activities.
- Acumen Fuse penalizes the project success rating for missing logic, even if the logic is associated with activities that are not influential in the project schedule.
- Acumen Fuse doesn't measure the typical duration of a transmission line schedule in comparison to the time allotted by Manitoba Hydro.
- Acumen Fuse does not consider any other factors that contribute to project success beyond the quality of scheduling practices used to create the schedule.
- Acumen Fuse rates project success on schedule quality, and has no measure for a project team's ability to execute a project, their past experience, or if the current schedule has activities in the correct sequence.

Manitoba Hydro is of the opinion that MGF has overstated the relevance of the Acumen Fuse score with respect to missing "schedule logic" and project success. In Manitoba Hydro's opinion, the activities identified by MGF will not impact the schedule because of the nature of the activities with missing "schedule logic". The majority of these activities are not used by Manitoba Hydro to control the start and finish dates of activities within the schedule and therefore don't impact the duration of the project schedule. Instead they are used for accounting and reporting purposes only.

For example a "Support" activity is scheduled during the procurement and construction of the transmission line, which is used by procurement staff to record their labour against the project while they provide support to design and construction staff, such as answering questions pertaining to material delivery. If this activity is late to start in the schedule it won't prevent the procurement staff from answering questions and providing support and since it's not linked to other activities it will have no impact on project duration or success. This is a standalone activity that spans a long duration of work and its purpose is only to schedule the spending budget for the support work. Normally these activities are omitted by the Acumen Fuse analysis however a certain activity type needs to be assigned within the Primavera software for this to occur automatically, which was not done by Manitoba Hydro. Not assigning the activity type doesn't change the intent of these activities, it just lowers the result of the Acumen Fuse output, which is not a tool that Manitoba Hydro uses.

Manitoba Hydro believes these activities are of little relevance to the project success because these activities are not used by Manitoba Hydro to control the duration of the project schedule. These activities do not influence start and finish dates of other activities in the schedule and whether or not they have started is irrelevant to when actual critical activities would start. Tangible events are more likely to have impacts on the project success, such as delivery delays or incremental weather, than missing "schedule logic" on activities used to record labour

Acumen Fuse is a tool to help improve the quality of the project schedule but can't be used to evaluate the success rate of a project. While poor scheduling can have negative effects on the project outcome, scheduling errors which Acumen Fuse can't identify such as missing activities, overstated durations, and incorrect logic would have more substantial impacts than missing "schedule logic" on activities not used to control the project's duration. The Acumen Fuse tool can't take away from the experience of the project team and their ability to execute the project.

3.2. Industry Standard Costs

MGF (Stanley) has compared the MMTP estimate for the Transmission Line portion of the project to a white paper prepared by the Western Electricity Coordinating Council ("WECC") and a report prepared by the Midcontinent Independent System Operator ("MISO") in which an "Industry Standard" cost per kilometer of transmission line was developed. MGF believes that Manitoba Hydro's estimate is lower than the industry standard and that Manitoba Hydro should revise its cost estimate.

Through the information request process Manitoba Hydro questioned, whether or not the "industry standard" costs took into account the tower type used on each project when developing the measure, to which MGF (Stanley) responded there was no significant impact on the costs based on tower type.

More specifically, in response to MH/MGF IR I-47, MGF (Stanley) has stated:

"WECC and MISO data have indeterminate structure design. Calculated data projects included self-supporting lattice tower (1 project) and tubular steel structures (5 projects). None of the projects included guyed tangent lattice towers. It is worth noting that type of transmission structures does not have a significant impact on overall cost per mile for comparison purposes."

Manitoba Hydro disagrees with this position as it previously stated in its Information Request Round 2 response in the Clean Environment Commission Hearing, Question #MWL-IR-89:

"based on an internal cost comparison for transmission structures in southern Manitoba, installed construction cost (not including line hardware) for a single tubular tower is approximately 70% of the installed cost for a single self supporting lattice tower. However, with the increased number of tubular structures required, the total cost of a tubular line is higher. Assuming 500m spans for lattice and 250m spans for tubular structures, a line constructed with tubular towers would increase the cost of the line by as much as 40%. This is based on 240 kV structure costs in southern Manitoba."

The Western Electricity Coordinating Council ("WECC") white paper on Capital Costs for Transmission and Substations developed by Black & Veatch in 2014 which Stanley Consultants has used in preparing the industry standard comparison states on page 2-4 that there is a 1.5 multiplier for using tubular steel compared to lattice as shown in the figure below.

Figure 3.0

2.2.3 Transmission Structure Type

In 2012, Black & Veatch quantified the capital cost multipliers associated with each type of transmission support structure. Structure types included lattice towers and tubular steel.

Table 2-3 below shows the transmission structure type cost multipliers for all voltage classes. An additional voltage class was added for the 600 kV HVDC bi-pole alternative based on the 500 kV HVDC bi-pole multiplier. The 500 kV HVDC bi-pole multiplier was originally developed based on the relative costs of lattice structures and tubular steel at very high voltage.

Table 2-3 Transmission Structure Type Cost Multipliers

STRUCTURE	230 KV SINGLE	230 KV DOUBLE	345 KV SINGLE	345 KV DOUBLE	500 KV SINGLE	500 KV DOUBLE	500 KV HVDC BI-POLE	600 KV HVDC BI-POLE
Lattice	0.90	0.90	1.00	1.00	1.00	1.00	1.00	1.00
Tubular Steel	1.00	1.00	1.30	1.30	1.50	1.50	1.50	1.50

This multiplier is used in the Transmission Calculation Methodology stated on page 2-8 of the WECC white paper.

Figure 3.1

2.6 TRANSMISSION CALCULATION METHODOLOGY

Multiplying the right of way acres per mile by the land cost per acre yields the total right of way cost per mile of transmission line. This value was added to the base transmission costs discussed in Sections 2.2, 2.3, and 2.4 to develop the total transmission line capital cost.

Total Transmission Line Cost = [(2014 Base Transmission Cost) x (Conductor Multiplier) x (Structure Multiplier) x (Re-conductor Multiplier) x (Terrain Multiplier) + (ROW Acres/Mile) x (Land Cost/Acre)] x (# of Miles)

It is clear from the equation that the WECC agrees with Manitoba Hydro's assessment that the structure type does have an impact. In the equation above, the base costs would be multiplied by a factor of 1.5.

In summary, Manitoba Hydro is of the opinion that structure type does have an impact on the costs per kilometer, and that using tubular steel towers typically increases the project costs. This could explain why Manitoba Hydro's estimates are lower than industry standard costs which seem to be determined mainly from tubular steel projects as stated above in the response to MH/MGF IR I-47. Manitoba Hydro's current estimates are based off of recent construction bids that were provided for the Bipole III Project which Manitoba Hydro believes is the best source of comparison as it reflects current market conditions for 500kV towers in the Manitoba market place, compared to historical industry costs in differing market conditions. Manitoba Hydro is committed to keeping the costs of capital work as low as possible and is confident in its estimating process.

3.3. Internal vs. External Design

MGF (Stanley) has stated that the project delivery model, with respect to internal compared to external designs have no significant impact on the overall cost per mile of transmission line.

In response to MH/MGF IR I-47, page79 MGF (Stanley) states,

> *"WECC and MISO project delivery methods are indeterminate. Calculated data projects were design-build with mixture of internally designed (2 projects) and contracted design (4 projects).*
>
> *It is worth noting that internal vs. externally contracted design does not have a significant impact on overall cost per mile for comparison purposes."*

Manitoba Hydro is of the opinion that its approach to tower design is appropriate and cost effective. It disagrees with MGF's position regarding the impact of internal or external design on project costs. While the labour costs associated with internal design and contracted design firms are negligible in terms of the overall project budget, the indirect benefits of the internal design approach are significant.

The internal design approach protects Manitoba Hydro from design firms and material vendors "over designing" towers in order to protect themselves from risk, such that the costs of materials on the project could increase.

Manitoba Hydro's design approach is to design towers all the way to fabrication drawings, which prescribes to vendors exactly what is to be built. In addition, Manitoba Hydro arranges for tower testing which verifies the minimum amount of steel required on each tower and allows Manitoba Hydro to optimize its design and reduce costs.

Manitoba Hydro generally agrees with the MGF findings related to the MMTP. Manitoba Hydro continues to manage the project appropriately and is committed to continuing efforts to secure the June 2020 ISD. MGF recommends that Manitoba Hydro should update the project estimate and include awarded contracted values instead of estimates whenever possible. Manitoba Hydro intends to do so at an appropriate time when those contract values become available.

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January 11, 2018

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RE: Response to Manitoba Hydro's Questions

KPMG was engaged by Manitoba Hydro ("MH") on May 2, 2016 to undertake an independant review of the current status of the Keeyask Generating Station ("Project") and subsequently provide advice on the development and implementation of a Recovery Plan for the Project. The Recovery Plan was approved by the Manitoba Hydro Executive Board ("MHEB") in February 2017 and the implementation of the Recovery Plan has been the focus of the Project Team throughout 2017. In mid-December 2017, as part of MH's information gathering related to the Public Utility Board General Rate Application, MH requested KPMG to provide comments on the following matters:

1. Provide commentary on the contract model and any incentives included.
2. Define MH's role in the GCC contract. Define the role of the Contractor. Comment on MH's ability to manage the Contractor in this role.
3. Provide commentary on MH acting as the builder and taking on a Construction Management role.

In responding to the three matters in this letter, KPMG reviewed the documents provided by Manitoba Hydro as well as incorporated leading industry practices from both the Hydro industry and public sector projects greater than $1 billion. The documents provided by MH were: Recovery Plan Strategy (undated), the Capital Project Healthcheck, Cost and Schedule Assessment (July 2016), monthly Manitoba Hydro Status Update and Step Change Incentive Profit reports, the amended Keeyask Generating Station General Civil Works Contract #016203 (Feb 28, 2017), and weekly Issues Logs.

The response to Manitoba Hydro's questions was led by Gary Webster, National Lead for KPMG Global Infrastructure Advisory. Gary has more than 30 years of experience as a Professional Engineer specializing in the organization, procurement and implementation of large scale infrastructure projects.

Please note that this letter is subject to KPMG's engagement terms dated December 2015 with MH related to its work on the Keeyask Project. This letter is provided to MH and based on the review of the documents provided by MH and KPMG experience with industry leading practices. KPMG does not accept any liability or responsibility to any third party who may use or place reliance on this letter.

Question 1: Provide commentary on the contract model and any incentives included

MH awarded the General Civil Works Contract ("GCC") to a limited partnership between Bechtel Canada Co., Barnard Construction of Canada Ltd and Ellis Don Civil Ltd. ("BBE"), three recognized, experienced and well established companies. The contract was a Target Price contract, where payment to BBE was on a cost reimbursable basis with a gain share/pain share incentive formula. The gain share/pain share formula was introduced into the contract to incent BBE to deliver the Project under or on the target price.

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There was no early delivery incentives in the original contract but liquidated damages were included for late delivery.

As a cost reimbursable contract, the owner was responsible for all of BBE's actual costs. However, with the inclusion of the incentives, it ensured that the contractor's profit (and to a limited extent their general administration and overhead ("GA&O")) was at risk based on their performance. The incentives used in this contract have been used in other cost reimbursable contracts as well as other forms of contracts. The incentives align the owner's and contractor's interests and help to mitigate the exposure the owner has to poor performance by the contractor.

The gain share/pain share formula was structured as follows:

- The gain share formula for cost savings was 80% for MH and 20% for BBE. If BBE delivered a project under the Adjusted Target Price (as defined in the contract), their profit increased from 1[redacted]% by [redacted]% of the additional savings. 1a
- The pain share formula, however, was more punitive to the contractor. If the costs went over the adjusted target price, BBE was responsible for 80% of the cost overruns and their [redacted]% profit could erode to zero profit based on the amount of cost overrun. 1a

Additionally, once the actual costs exceeded the target price by 1.3 times, BBE would no longer receive their [redacted]% GA&O. The objective of this cap on GA&O was to ensure that the contractor would not benefit from escalating project costs and removed the incentive for the contractor to increase project costs to improve their overall position. 1a

By fall of 2016, MH realized that BBE's opportunity for profit would likely be eroded and that there were no longer any achievable incentives remaining in the original contract. The result was a mis-aligned relationship between MH and BBE where BBE could be motivated to regain their profit to the detriment of the Project. During this period, MH developed and implemented a Recovery Plan. As part of the Recovery Plan, MH addressed a number of root causes that led to cost and schedule overruns that were being incurred. They also negotiated an amended contract with BBE.

The amended contract continues to be a Target Price Cost Reimbursable contract, fundamentally the same as the original contract. The ability to transfer additional risk, such as geotechnical, hydrology, labour, extreme weather, and northern logistics to BBE by changing the contract to a Unit Rate or Lump Sum contract, would have required directly negotiating a new form of contract with BBE in a non-competitive environment or descoping/terminating BBE and going back to the market for a Unit Rate contract. It was expected that in a non-competitive environment and given BBE's performance in 2016, the costs of transferring this risk to BBE would have been prohibitive and/or not achievable. Additionally, in its Recovery Plan, MH analyzed the impact of terminating or descoping BBE's work. MH analysis shows that the additional delay to the project required for the re-procurement of this work along with additional risks associated with re-procurement, would have resulted in an additional increase to the Adjusted Project Budget.

The amended contract remains a Target Price Cost Reimbursable contract with limits on GA&O and performance incentives tied to achieving the target price. The amended contract was designed to achieve the following:

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- Reset the target price and schedule milestones;
- Improved gain share/pain share incentive formula. The new incentive program is now structured around cost, schedule and management performance;
- Limited BBE's right to claim for additional adjustments to the target price;
- Improved the relationship with BBE that allows for a more collaboration on site; and
- Allow MH, as they deem necessary, to alter the scope of BBE.

The amended contract now includes incentives for not only cost, but also schedule and management performance. The balance of the incentives is now [redacted]% of any cost savings that it may generate capped at [redacted]M and [redacted]M based on meeting schedule milestones. Cumulatively, BBE could earn up [redacted]M 1a
profit for meeting all their cost, schedule and management targets, conversely they risk losing not only all their profit and GA&O expenses above the capped amount but an additional [redacted]M for poor project performance. The amended incentive pool was designed to further motivate BBE to perform and take day to day responsibility for the work it has been contracted for.

It should be noted that in contract management, a high risk exists when cost performance incentives are entirely disconnected from schedule. Namely, a perverse incentive could exist for a contractor to forsake schedule in an effort to maintain a low cost position. To address this risk, the amended contract contains a deduction associated with very strong cost performance and very weak schedule performance. This incentive structure is designed to eliminate the incentive to ignore schedule performance in order to capitalize on cost incentives.

The amended contract also has a component where BBE can gain an additional [redacted]M (included in the [redacted]M referred to above) for improved management performance ("Step Change Incentive") based on 1a
their ability to better perform their construction management responsibilities. This includes improvements such as site leadership, planning and scheduling, reporting and better coordination with MH.

Finally, the general administration and overhead ("GA&O") is [redacted]%. The provision of GA&O expenses, 1a
which are standard in the construction industry for any contractor, affords for cross-functional and project-wide resources to be accessed throughout the initiative and allows for ease and efficiency in administration without the need for micro-management. MH was able to cap the GA&O at the Final Target Price versus the original 1.3x the target price.

MH has taken reasonable steps to renegotiate the contract. The amended contract addressed a number of concerns MH had with BBE and their performance. It includes multiple systems of financial incentives and disincentives to mitigate risks associated with cost reimbursable contracts. The contract amendments were designed to promote better alignment of BBE and MH objectives, and create a collaborative environment that allows MH to take on a more proactive management style with BBE.

Question 2: Define MH's role in the GCC contract. Define the role of the Contractor. Comment on MH's ability to manage the Contractor in this role.

MH's Role in the GCC Contract.

Manitoba Hydro's Role in the GCC Contract is to function as the overall Project and Site Construction Manager. As Project Manager, MH is responsible to ensure integration, alignment and quality of the

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project as a whole. As Site Construction Manager, MH is responsible for the overall coordination and oversight of site work, while delegating the construction planning, management of labour and construction means and methods (along with other responsibilities) to the contractor. It should be noted that construction management is a term used which can cover a wide range of responsibilities and functions. From public sector owners' perspective, construction management is often the term used to oversee the construction of the project. Canadian public sector owners do have experience managing construction works; however, these works tend to be routine and relatively minor. KPMG is unaware of any Canadian public sector owner who would have the capabilities, systems and processes to allow for direct management of complex multi-billion construction projects.

In its role, Manitoba Hydro provides oversight and approval of BBE's activities by providing channels for controls, as well as strategic level issue and risk management. Their general duties would include:

- Overall responsibility to complete the planning, design and engineering and to oversee the construction and commissioning of the proposed Keeyask Generating Station which includes the General Civil Works contract;
- Overall responsibility of the site and coordinating the interfaces with the various contractors and suppliers they enter into contracts with;
- Approving contract changes;
- Agreeing to the Contract Schedule, and all amendments thereto, in the course of BBE's performance;
- Providing oversight and surveillance audits of BBE's processes;
- Reviewing any potential changes to the overall work plan, that could alter the target price and/or construction schedule;
- Addressing stakeholder issues;
- Acquiring Project permits; and
- Providing access to the Site and timely payment to the contractor.

Ongoing monitoring and collaboration by MH continues to be essential. MH has retained an experienced construction management consortium to undertake the direct management of the construction works. If MH drives for more aggressive involvement in the direct construction management, MH could be potentially frustrating BBE in their execution of the work. This could result in a number of reactions from BBE including claims for lost profit if the project does not meet the performance requirements associated with the gain share/pain share incentives. Furthermore, it may also result in MH unintentionally taking on additional risk with respect to performance results that are currently under BBE's control that MH does not have the experience to manage.

The Role of the Contractor

MH has a contract with BBE to manage the construction of the general civil works. As per their contract, BBE is obligated to construct and commission the GCC work. This would include providing the material, labor, construction planning and supervision expertise to construct an end product that meets the cost, schedule and specifications outlined in the contract. The general responsibilities of BBE include:

- Working with MH to deliver their work;
- Executing site safety processes and procedures as outlined in the project safety plan;

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- Providing construction planning expertise and collaborating with MH (and other parties), throughout the design development phase (in particular reviewing constructability and completeness of detail of the design);
- Developing the contract budget and schedule;
- Procuring equipment, material and labour;
- Providing qualified management and supervision;
- Planning and supervising construction;
- Implementing quality control and assurance program and maintaining quality management records;
- Maintaining and meetings all permit and environmental requirements;
- Monitoring the costs and schedule; and
- Reporting on progress. This would include costs, productivity, down time, schedule, work plans, etc.

MH's Ability to Manage the Contractor Based on the Contract

MH and the current Project team have experience managing large complex hydro projects and have completed Pointe du Bois and Wuskwatim ($0.6B and $1.4B respectively). The table below highlights the relative experience of each of the key leadership team members.

Name	Project Role	Experience
Senior Management Team		
Dave Bowen	Project Director	20 Years
Ryan Ward	Commercial Contracts Manager	19 Years
Barry Nazar	Site Construction Manager	32 Years
Jeff Strongman	Business Manager	24 Years
Tom Tonner	Engineer Manager	25 Years
Senior Technical Team		
Terry Armstrong	Construction Quality Engineer	27 Years
Dave Little	Site Support Manager	30 Years
Gene Piasta	Head of Project Controls	27 Years
Glen Schick	Head of Infrastructure	29 Years
Charles Wright	Structures Resident Engineer	25 Years
Guy Remillard	Mechanical/Electrical Resident Engineer	32 Years
Brian Beyak	Earthworks & Excavations Resident Engineer	26 Years

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As summarized in the above table, the Senior Management Team has 120 years of combined experience managing and overseeing large complex projects.

Over the course of 2017, Manitoba Hydro has managed their internal responsibilities while managing BBE to meet their contractual obligations. MH has demonstrated they understand their role in administering the contract with BBE as well as the risk they have to manage associated with the contract.

MH has enhanced its internal systems and processes to manage the overall project since the commencement of the project. This included initiating a “Step Change Program” that focused on their own improvement as well as that of BBE. The Step Change program was designed to address the root causes identified in the Recovery Plan and implement the following improvements for MH and BBE respectively.

Manitoba Hydro:

- Organizational structure to reflect the stage of Project;
- Leadership accountability;
- Authority residing at the Site;
- Communications between the Site and Winnipeg offices;
- Project controls function;
- Risk management and project reporting; and
- Escalation of issues to senior leadership team.

BBE:

- Organizational structure to reflect the construction management activities required by BBE;
- Alignment with MH counterparts;
- Contract reporting;
- Management of indirect costs;
- Travel logistics;
- Collaborative working environment;
- Relationship with Allied Hydro Council;
- Construction planning; and
- Construction supervision personnel.

Based on the above, the current division of roles and responsibilities between MH and BBE is appropriate and the Project team has experience and qualifications to manage and oversee the GCC Target Price contract.

Question 3: Provide commentary on MH acting as the builder and taking on construction management role

As highlighted in Question 2, we are unaware of any Canadian public sector owner who would have the capabilities, systems and processes to allow for direct management of complex multi-billion dollar

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construction projects. The contractor brings a significant amount of skills to a project that an owner does not have. The following is a brief, non-exhaustive list of such skills:

- Construction labour recruitment and labour relations expertise;
- Corporate construction safety plan;
- Construction equipment corporate discounts;
- Extensive cost control system;
- Management, supervision and engineering personnel with construction experience;
- Access to labour; and
- Previous work experience in order to better plan and perform the work.

Some project owners do have the internal capabilities and experience to act as the builder and to take on a construction management role. Generally, this skillset is developed through experience with multiple projects and owners have gained experience in building and managing projects of scale which they regularly undertake. However, public sector owners do not perform large projects with sufficient frequency to have developed the internal skills to manage the additional complexity that are associated with multi-billion dollar projects.

MH has relied on general contractors to manage large projects in the recent past. The most recent hydro projects completed by MH are Limestone ($1.43B and 1,350MW completed in 1990), Wuskwatim ($1.37B and 211MW completed in 2012), and Pointe du Bois Spillway Replacement, ($600M completed in 2016). MH has only completed these three projects since 1990 and all of these were executed using external general contractors. This would generally not be considered adequate experience for MH to be considered a low-risk builder or construction manager.

This letter is addressed to Manitoba Hydro and in response to MH's three matters. As noted on page 1, we will not accept any liability or responsibility to any other party to whom the letter may be shown or who may require a copy of the letter.

Yours Sincerely,

Gary Webster, P. Eng.
Partner, National Lead Infrastructure Advisory
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Project Memo

H341433

January 15, 2018

TO: Dave Bowen FROM: Alan O'Brien/Sylvain Laramee

cc: Ian Ainslie

Manitoba Hydro
Keeyask GS Engineering Consulting Services

MGF Report on Keeyask

1. Introduction

At the request of The Manitoba Public Utilities Board, MGF Project Services Inc have conducted an independent review of Manitoba Hydro's Capital Expenditures program. The conclusion of their finding presented in their report issued at the end of 2017 was inclusive of a certain number of recommendations especially with regard to the Keeyask Hydroelectric Dam.

Following their receiving of the said report, Manitoba Hydro has mandated Hatch to provide commentary regarding MGF's suggestion that Manitoba Hydro expand its role with the GCC. Alan O'Brien and Sylvain Laramee have reviewed MGF's report and subsequently prepared their joint response which follows their own personal bios.

2. Bios

2.1 Alan O'Brien

Alan is a seasoned project and business manager with more than forty (40) years of experience in Engineering design, project, business and commercial management. He has been involved in projects of various sizes in a variety of industries including Oil & Gas, Petrochemical, and Power (Hydro, Nuclear, Thermal and Wind). He has managed contracts both domestically and internationally.

He has worked for two major engineering Contractors (Amec/Agra and Hatch). In his capacity of Project Manager and/or Director, he has delivered projects using various execution models, such as EPCM, EPC, fixed fee, target price and cost reimbursable. As Global Director of Commercial Management he was responsible for overseeing the group that undertook commercial and implementation reviews on all major contracts. The experience gained over many years working both in the engineering office and at site has given him a broad exposure to different types of contract execution strategies and their advantages and disadvantages.

Alan is currently acting as Project Sponsor on a few Hatch projects. In this role, he works with the Project Manager and his/her team in an oversight role to provide ongoing review, guidance and support.

2.2 Sylvain Laramee

Sylvain is an experienced project professional with thirty-four (34) years' experience in project and construction management of major capital projects in the Mining and Energy sectors which have allowed him to develop a broad range of management skills that are uniquely adapted for project work. His experience, both on the EPCM and contractor's side, coupled with the diversified leadership roles (Engineering Manager, Area Manager and Construction Manager) held on major capital projects has provided him a unique perspective of innovative implementation strategies and successful project outcomes.

For the past decade, Sylvain has fulfilled the role of Managing Director, Construction Management, leading Hatch's global group of construction management professionals and taking responsibility for all domestic and international major capital project construction assignments. He has considerable experience in developing implementation strategies suited to specific project challenges including, project remoteness, complex logistics, lack of skilled labor, extreme weather conditions and security issues. During this period, he assembled and mentored a core group of competent construction professionals as well as developing and implementing construction tools and work processes targeted at addressing and overcoming the complexity of each of those projects.

3. Hatch commentary around expanding Manitoba Hydro's role with the GCC as suggested by MGF

MGF's recommendation at the end of their Executive Summary reads as follows: "The recovery of this project will require Manitoba Hydro taking a construction management, hands-on approach to design and implement a recovery plan and hold the GCC contractor to perform" (Page 3, Dec 8/17 MGF Report). There is no doubt that MH has the experience of similar major projects and could put together a team of construction managers as suggested. However, given that this was not the implementation strategy that was chosen initially to execute this project and given that MH does not have available the type of construction resources needed to take over the construction lead, one would question how viable it is to significantly change at this late stage the current approach and make MH the "Constructor". It would be our views that the proposed suggestion is of equal risk if not riskier than the status quo, as described below.

Interestingly, MGF when referring to the GCC contract points out that: "The largest single contributor to the budget increase is the sum to the original GCC on account of the Contractor's poor productivity and increased indirect costs as the GCC would take longer to perform" (Page 1, Dec 8/17 MGF Report). Unfortunately, their report fails to identify the reasons behind BBE's poor productivity performance. Hence it is unreasonable to make any recommendations for changes without the root causes being identified and solutions being proposed as well as those solutions and/or recommendations then being evaluated against the costs and risks inherent to their implementation. Naturally, MGF was unable to identify potential solutions to improve the productivity for the very same reasons.

The absence of a clear understanding of the said root causes makes it impossible to identify and implement the proper corrective measures. As an example, MGF suggest as a potential saving by modifying the ratio of craft to foreman from roughly 4:1 to 6:1. Should one of the problems be the quality of the supervision then this suggestion would in fact creates the opposite effect as there would be a further deterioration of the productivity.

Based on our experience, what MGF is suggesting, is of equal or greater risk than the status quo. Whilst MH would have the experience and capability to hire a competent CM team, such a team would carry a risk until proven. Hence to create this new CM team in the midst of this mega Project, is more likely to cause the overall Project to forecast to keep increasing because it introduces pitfalls and unknowns.

The risks associated with a major shift in the contracting strategy, especially for the single most important contract, include:

- It will remain a challenge to gather a team of construction professionals from the open market that will commit to the Project for the long haul knowing that the required caliber is typically under employment by the large constructions firms hence, and not readily available
- It will likely take several months to recruit, hire, onboard and mobilize such a team. And likely not in the optimal sequence.
- Clearly it will take some time for the new CM team with no previous working together experience, to understand the challenges, find the appropriate solutions, get efficient as a team and finally drive the performance improvement. Considering the complexity of this major Project, its remote location and its many work fronts, this team will undergo a steep learning curve regardless of their experience.
- In our experience in such drastic organizational changes, there is a fair chance of MH losing critical resources that are knowledgeable, and up to now, committed to the success of this Project.
- Until a new CM organization is in place, there would be transition period of high uncertainty that inevitably will prevent people from making decision and thus, some of the initiatives currently being developed to help driving the Project in the right direction could be lost.
- Should MH follow the recommendation, it will change the nature of BBE’s contract, leaving the contractor the freedom to maximize their revenue under a de facto time and material with fee contract. MH leverage over BBE using the pain/gain sharing and liquidated damages would not be retained.
- Once BBE would become aware of MH plan to take over the management of their contract, it is doubtful that they will remain engaged in finding ways to drive productivity or find solutions to existing challenges.

- It cannot be ruled out that BBE could walk away from the Project considering that MH would be effectively breaking the terms of their current contract thus leaving MH with an even greater challenge to overcome.

Contrary to what MGF is stating in their report, and based on our limited knowledge of the contract between MH and BBE, we understand from MH that the GCC contract is a target price with contractor's fee at risk which includes schedule incentives and liquidated damages for late delivery. It is very difficult to imagine that MH would take over as the builder as this could result in a forfeiture of their contractual rights and a forfeiture of their leverage over the contractor to get their full attention and cooperation in addressing the seriousness of the situation. We're of the opinion that enforcing the contract to force the contractor to come to the table, put its best foot forward and make available their strengths and wherewithal will produce more upside than downside.

One interesting recommendation can be found in the report under Scope Item 9, Finding No. 1: Keeyask – Structural Steel Progress which states: "*MGF recommends that Manitoba Hydro work with BBE on a recovery plan to improve BBE's construction management, construction planning, coordination and supervision of construction work.*" This in our views is the logical beginning of a solution that ought to be applied to the overall contract and is currently being pursued by Manitoba Hydro

We understand that Manitoba Hydro is actively involved with the contractor in addressing the situation and we can only encourage them to remain focused on the work at hands and continue to hold BBE accountable by working jointly with them in accomplishing the following:

- Re-assess the final forecast
- Understand the root causes behind the poor performance and identify ways to improve and/or execute the works differently
- Identify all the risks that could impact the final forecast and elaborate a mitigation plan for each one
- Find innovative ways to improve productivity using latest technology available on the market
- Develop an optimal execution schedule that could be used as a baseline moving forward
- Deliver a comprehensive recovery plan that can be easily monitored and audited on a regular basis

There is an advantage to developing a plan jointly and making sure in the process to understand the areas where the GCC contractor could try to take advantage at the end for claims. In short, by doing this, it allows MH to limit or eliminate the General Contractor's ability to make claims by removing the obstacles and ultimately leaving the GC with only the burden of performing. Even in circumstances where there may be a requirement to supplement temporarily the Owner's team with some ad hoc resources, we believe the benefits will by far outweigh the investment and bring the best value to the Project. As time is of the essence, such exercise must take place sooner rather than later and should not disrupt what is happening at site

HATCH™

In summary, the suggestion by MGF to make such a fundamental change at this stage is, in our opinion, a mistake which could lead to a serious disruption of the Project with a very high potential of adding both to the costs and the schedule.

Al O'Brien/ Sylvain Laramee

SL:wlp
Attachment(s)/Enclosure

Bipole III Transmission Reliability Project

Attachment 1 – Response to Scope Item 15, Finding 3, page 100

BPIII 500kV Transmission Line

CPJA7 / CPJA8 Comparison

Row	ID	Activity ID	Cost Element/Work Centre	(2016) CPJA8 Plan ($)	(2014) CPJA7 Plan ($)	variance ($)
21	P:04218		BPIII Eastern Route 500kV T/L-Sunk Cost			
543	P:04221		BPIII Licensing & Env Assessment			
993	239224		340 TransLine Materials Yard (Const/deve			
1072	239224		342 Trans Line Materials Yard (Operation			
1906	239224		Bipole III Western Route T/L			
2188	251480		BPIII N1 Construction			
2475	251481		BPIII N2 Construction			
2733	251482		BPIII N3 Construction			
2992	251483		BPIII N4 Construction			
3223	251484		BPIII C2 Construction			
3490	251485		BPIII S1 Construction			
3769	251865		BPIII C1 Construction			
3918	253789		BPIII S2 Construction			
3938	255540		Logistics contract - Intelliwave			
4090	P:10155		BPIII 500kV HVDC Transmission Line			
4437	P:14518		BPIII Transmission Line Property			
4965	P:18414		BPIII Communications System			
5014	P:18767		BPIII Electrical Effects Monitoring			
5190	[illegible]255		BPIII T-Line Vehicles (print w/ P10155)*			
5682	P:23622		BPIII Distribution Relocation			
5819	P:23817		BPIII Transmission Line Contingency			
5964	P:2[illegible]05		BPIII Distribution Relocation N4			
6128	P:25508		BPIII Distribution Relocation C1			
6219	P:25509		BPIII Distribution Relocation C2			
6602	P:25510		BPIII Distribution Relocation S1			
7014	P:25511		BPIII Distribution Relocation S2			
7015						
7016	TOTAL FOR SELECTION			$1,957,615,	$1,655,370,	$302,244,

KCB RESPONSES TO COALITION/IEC INFORMATION REQUESTS

Coalition/IEC (MGF) -1 and 2- No KCB response needed

Coalition/IEC (MGF) – 3

a) Based on the August 2017 contract revision register data, the Voith contract is expected to be increased between [redacted] (depending on contingency usage) for extra work and delays. Based on the register data descriptions, approximately [redacted] of the total approved or expected extra work is related to delay [redacted]. 1a, 7a

Coalition/IEC (MGF) – 4 to 19 - No KCB response needed

Tab 121

REFERENCE:

Coalition/MH I-206g

PREAMBLE TO IR (IF ANY):

Two of the top three risks identified in the response to Coalition/MH I-206g were not in the top five risks included in the Keeyask Risk Registry at the time of the NFAT.

QUESTION:

a) Please confirm whether the former top risks have been reduced, either through lower probability or lower consequence, leaving the three risks in the response to Coalition/MH I-206g as the top risks.

b) If the Keeyask Risk Registry has changed since the NFAT, please provide an updated Registry (unless provided in PUB MFR 129).

RATIONALE FOR QUESTION:

RESPONSE:

a) At the time of NFAT, the Keeyask risk register was a pre-construction assessment of the risks within the Keeyask Project. Throughout the three years of construction on the project, the register has been continually updated to reflect the current risk forecast. Updating activities include closing risks that have passed, adding any newly identified risks, and updating probability and consequence assessments to reflect changes in the project environment.

   The top Keeyask project risks identified at the time of NFAT have been updated to reflect the current status and the potential consequence and probability of occurrence. A summary of these former top risks can be found in the table below.

The three risks stated in the response to Coalition/MH I-206g are the current assessment of the top risks facing the Keeyask Project as of July 2017, and are slightly different from those identified in the pre-construction assessment below.

Risks	Status
Inability to attract/retain labour through the BNA due to competition for qualified resources from other Manitoba Hydro Projects, national projects, and aging construction workforce.	The impact and probability were reduced due to changes implemented in the Burntwood Nelson Agreement that improved attraction and retention of qualified labour since the start of construction. Market conditions have also improved thereby reducing the likelihood of competition for qualified resources from other national projects. This risk may increase in future with work beginning at Site C.
Insufficient Construction Management Resource Budget due to external resources required at a higher cost due to the inability to attract internal resources for short durations.	The impact and probability were reduced as adequate internal staffing levels have been achieved to date and external resources were acquired within budget. It is expected that this risk will continue to decrease.
Escalation exceeding G911 due to market conditions.	Escalation is a function of a number of variables, including escalation rates, and the time remaining on the project. The time remaining on the project until the first unit in-service date is reduced relative to NFAT which reduces the escalation risk. In addition, since 2013, market conditions have been favourable for some escalation indices such as fuel. Unless there is a significant upward trend in escalation rates, it is expected that this risk will continue to decrease, as the remaining to-go cost of the project decreases over time.

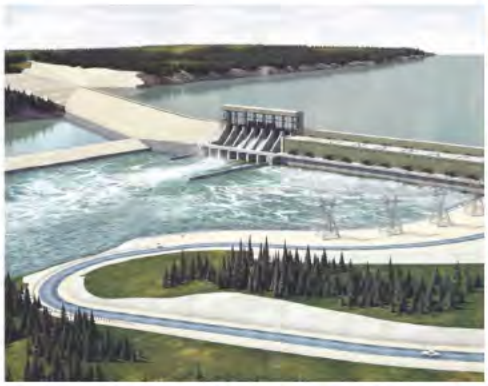
Risks	Status
Skilled labour shortage resulting in an increase of labour hours to complete construction activities.	The impact and probability were reduced for this risk as staffing levels were achieved during the 2017 construction season. However, there is the potential for this risk to increase in the future as skilled labour may be at risk as work begins at Site C.
Delayed start to Stage 1 Cofferdams due to Contractor unable to meet mobilization duration allowed in Project Schedule.	This risk was closed as cofferdam construction was started as planned, and Stage 1 work is completed.

b) Public disclosure of the Risk Registry would result in the release of information considered to be confidential and commercially sensitive. The Risk Registry will be filed in confidence with the PUB and has been provided to the PUB's IEC. 1a, 4b and 8

Tab 122

April 2014 Redacted

MANITOBA PUBLIC UTILITIES BOARD
NFAT REVIEW OF KEEYASK AND CONAWAPA GS



KNIGHT PIESOLD INDEPENDENT EXPERT CONSULTANT SUPPLEMENTAL REPORT - CONFIDENTIAL

PREPARED FOR:

Manitoba Public Utilities Board
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MANITOBA PUBLIC UTILITIES BOARD
NFAT REVIEW OF KEEYASK AND CONAWAPA GS

KNIGHT PIÉSOLD INDEPENDENT EXPERT CONSULTANT SUPPLEMENTAL REPORT - CONFIDENTIAL
VA103-449/1-2

Rev	Description	Date	Approved
0	Issued to PUB (Confidential Report)	April 8, 2014	SRM
A	Issued to the PUB in Draft form for review by MH for confidential material and factual inaccuracies.	February 18, 2014	SRM

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CONSULTING

EXECUTIVE SUMMARY

Overview

Through the intermediary of the Manitoba Public Utilities Board (PUB), the Government of Manitoba is carrying out a public Needs For and Alternatives To (NFAT) review and assessment of Manitoba Hydro's (MH's) Proposed Development Plan (Plan) which includes the Keeyask Infrastructure Project (KIP) and the Keeyask Generating Station Project (KGSP).

The PUB has engaged Knight Piésold Ltd. (KP) as an Independent Expert Consultant (IEC) to review the construction management and capital and operating costs for select resource options. KP filed an IEC Report on their initial review on January 23, 2014. The PUB has asked KP to review additional information in relation to the report and Manitoba Hydro's award of the Keeyask General Civil Contract early in 2014.

This supplemental report summarizes KP findings on the additional scope of work provided by the PUB on January 10, 2014. It does not include any further review of proposals for Conawapa. The content of this report is confidential and for the PUB only as it contains references to confidential material provided by MH.

Item 1: Overall Management Strategy and Scheduling for the Tendering of Contracts for the Keeyask Generating Station.

The overall management strategy and scheduling for the Keeyask Project is following a new process within MH. This has been explained to KP in the form of confidential documents and conference calls. The approach for the tendering of contracts is deemed to be comprehensive, well documented and applied, and the timing of the tendering appears to be on track. Since MH's systems are maturing there it was not possible to observe the full effectiveness of the management strategy at this time, there remains a notable systemic risk exposure associated with the project.

Item 2: Construction Risk Management Strategy

KP has reviewed MH's construction risk management strategy in the form of the Risk Management Procedure (whose purpose is to "detail the activities of planning, identifying, evaluating, responding, and monitoring for effective risk management as well as detailing the standard risk reporting templates…"), the Project Contingency Management Procedure, the 2014 Risk Analysis and Contingency Estimate by Validation Estimating and the Keeyask Project Risk Register.

The approach to construction risk management is industry standard and consistent with best practices, with specific roles and responsibilities associated with risk management in the overall management process. As far as can be seen, the risk management strategy is well set up and is being monitored and acted upon appropriately.

It can be assumed that at this stage of project development the technical risks have been addressed or mitigated. Having chosen a suitable, reputable and experienced company for the GCC contract, remaining construction risks are associated with contractor performance, in terms of quality, cost and schedule. Portions of the overall contingency have been allocated to the individual contracts to provide allowances to cover these risks.

[redacted]

Item 3: Contract Documents for the Major Keeyask Components

Copies of various Keeyask contract documents were made available to KP as part of the original scope of work and commented upon in the earlier KP report. The contracting method varies by project component but the principal civil works contracting strategy is an Early Contractor Involvement (ECI) Project Delivery Strategy. The contract documents and drawings that KP has seen have clearly been drawn up by experienced engineers, from within MH and from reputable experienced consultants and include appropriate performance incentives.

Item 4: Construction and Equipment Procurement Bonding and Liquidated Damage Requirements

MH has made available to KP details of the bonding or letter of credit requirements for a selection of the major Keeyask contracts, in both the KIP and the KGSP. The amounts are based on risks associated with the individual contracts, past experience, and industry norms. These values are deemed by KP to be appropriate. Current practice is to strike a reasonable balance between protecting the interests of the owner and not paying an excessive premium for this insurance.

KP believes that the Liquidated Damages stated in the various contracts made available appear to be reasonable and in keeping with their purpose.

Item 5: Quality Assurance and Quality Control (QA/QC) Requirements

The most common arrangement for addressing quality in procuring hydroelectric power generating facilities is to make the Contractor responsible for Quality Control (QC) and the Owner (or his Engineer) responsible for Quality Assurance (QA). MH is conforming to this usual practice.

Quality Management in MH is specified at a high level in the various MH procedures and standards. These documents define the processes required in MH to establish and operate a quality management program, including a third main activity that takes place prior to QC and QA, Quality Planning (QP).

Items 6: Overall Civil Contract(s) Project Management Approach

The General Civil Contract (GCC) has been procured in an Early Contractor Involvement (ECI) process which provides an opportunity for MH and a selected contractor to work together to refine the contract. All aspects of the work, including design details, schedule, risk sharing and project management, are open for discussion. KP believes that this process reflects a genuine and appropriate opportunity for MH to optimise and bring as much certainty to the contract as possible. The KGSP contracts (including the GCC) have been and are being managed within a new project management system.

Item 7: Pre-Tender Construction Estimates Compared to Actual Tender Prices

MH has provided KP with summary presentation material and Bills of Quantities comparing the GCC proposals, the independent estimators estimate (by Chant), and an escalated original Engineers Estimate by KGS Acres. [redacted]

Item 8: Expected In-Service Capital Cost for Keeyask

Overall the Expected In-Service Cost for Keeyask has been prepared by MH with as much completeness as can be reasonably expected. The current estimate is no longer a bottom-up estimate as presented in 2009, but a blended estimate that includes awarded contracts. As a result of the GCC award the anticipated Direct Costs are deemed to be fairly accurate, when the risk portion is excluded. The Indirect costs include elements that were not fully described and as such are subject to possible escalation, but this amount should be reasonably captured through the project contingency.

MH was diligent in evaluating the project risk and translating these risks into monetary terms through the contingency and management reserve estimates. The risk associated with labour shortages and productivity, [redacted] all lead KP to believe that the Management Reserves will be fully utilized and that a larger Management Reserve may be desirable for a more risk adverse maker.

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ABBREVIATIONS

AACE(I)	Association for the Advancement of Cost Engineering (International)
BNA	Burntwood Nelson Agreement
CCCT	Combined Cycle Combustion Turbine
CCGT	Combined Cycle Gas Turbine
CRC	Cost Reimbursable Contract
DB	Design Build
DBB	Design Bid Build
ECI	Early Contractor Involvement
EIS	Environmental Impact Statement
EPC	Engineering, Procurement and Construction
EPCM	Engineering, Procurement and Construction Management
FLCN	Fox Lake Cree Nation
GCC	General Civil Contract
GS	Generating Station
IDB	Integrated Design Build
IEC	Independent Expert Consultant
IFF	Integrated Financial Forecast
KCN	Keeyask Cree Nation
KGSP	Keeyask Generating Station Project
KHLP	Keeyask Hydropower Limited Partnership
KIP	Keeyask Infrastructure Project
NFAT	Needs For and Alternatives To
NGCD	Manitoba Hydro New Generation Construction Division
O&M	Operations and Maintenance
PDP	Proposed (or Preferred) Development Plan
PDS	Project Delivery Strategy
PEP	Project Execution Plan
PUB	Manitoba Public Utilities Board
RP	Recommended Practice (AACE International)
TCN	Tataskweyak Cree Nation
TCSM	Total Cost and Schedule Management
WLFN	War Lake First Nation
YFFN	York Factory First Nation

1 – INTRODUCTION

1.1 PURPOSE AND FORMAT OF REPORT

Through the intermediary of the Manitoba Public Utilities Board (PUB), the Government of Manitoba is carrying out a public Needs For and Alternatives To (NFAT) review and assessment of Manitoba Hydro's (MH's or Hydro's) Proposed Development Plan (Plan) for the Keeyask and Conawapa Generating Stations (GSs) and their associated transmission facilities. The PUB has engaged Knight Piésold Ltd. (KP) as an Independent Expert Consultant (IEC) to review the construction management and capital and operating costs for select resource options. KP has filed an IEC Report on their initial review of MH's proposals (KP Ref. VA103-449/1-1 Rev 1 of January 23, 2014). The PUB on January 10, 2014 asked KP to review additional information in relation to the report and Manitoba Hydro's intention to award the Keeyask General Civil Contract early in 2014 (see scope of work in Appendix A).

The following supplemental report summarizes KP findings on the additional scope of work. It does not include any further review of proposals for Conawapa. The content of this report is confidential and for the PUB only as it contains references to confidential material provided by MH.

1.2 APPROACH

1.2.1 Reporting and Outline

Except for this Section 1, which highlights the report structure and particular aspects to bear in mind, the rest of the report is structured to address each of the PUB's questions to KP in turn, as per Appendix A.

1.2.2 Source of Information (Manitoba Hydro)

The information reviewed for this supplemental report was obtained from MH, through a combination of teleconference presentations, email and hard copy transmittals - blue containing information deemed confidential by MH, and white for information not deemed confidential (that which is basically available as part of the public record).

A complete list of the material provided by MH and used in this review can be found in Appendix B.

1.2.3 Limitations

As mentioned in KP's earlier report, the Capital Cost Estimate prepared by MH for the alternatives development was based on an initial "bottom up" approach in 2009 that considered construction productivity and schedules along with the cost of materials, equipment, and labour required for construction. This estimate was revised or "Stress Tested' in 2012, with major changes as a result of the experience gained at the recently completed MH Wuskwatim Project together with adjustments for escalation and some improvements in project definition. The focus of this supplemental report has been to examine in more detail MH's estimates and processes, ultimately in order to be able to comment on the likelihood that Keeyask will end up being constructed within the current MH budget estimate (of $6.5 billion) but it should be cautioned that this examination has still been at a relatively high level, in accordance with the scope, budget and schedule available to KP, and that no guarantees can be given that the outcome will be as planned. With the award of the General Civil Contract (GCC) all parties have additional confidence in the eventual outcome than they did prior to this award, as this contract constitutes by far the largest element of the works.

2 – OVERALL MANAGEMENT STRATEGY AND SCHEDULING FOR TENDERING AND PROCUREMENT OF CONTRACTS

2.1 SCOPE OF WORK

Question 1: "Review MH's overall management strategy and scheduling for the tendering of contracts for the Keeyask Generating Station and the procurement of other major facility components such as spillways, dams, dykes, powerhouse, turbines, intake gates, generators, controls etc. Comment on the effectiveness of this management approach for minimizing capital costs, securing competitive bids, and managing construction and procurement cost escalation and construction risks."

2.2 MANAGEMENT STRATEGY FOR TENDERING

2.2.1 Hydro's Management Strategy

As mentioned in Section 4.3.2 of KP's earlier IEC Report, the Keeyask Hydropower Limited Partnership (the Partnership) who owns the Keeyask Project has contracted all the planning, construction and operation of the project to MH. MH (through the New Generation Construction Division (NGCD) acts as the Project Manager and Construction Manager responsible for the overall project cost, schedule and quality. MH subcontracts a majority of the services and supplies required to actually build the project, and therefore manages and schedules the tendering and procurement.

MH's systems are still maturing and MH has recently included an outsourcing some of the construction management as part of their estimate. As such the full management strategy is not truly finalized.

2.2.2 Manitoba Hydro Documentation

As mentioned in Section 4.4 of KPs earlier report, the NGCD has a Project Execution Plan (PEP) for the development of the Keeyask Project. The draft document seen by KP acts as a high-level guideline to manage both the Keeyask Infrastructure Project (KIP) and the Keeyask Generating Station Project (KGSP).

The document:

- Is a guideline of the means, methods, tools and techniques used by MH to manage the KIP and the KGSP
- Serves as a record of the planning effort undertaken by the NGCD for the construction phase of the project, and
- Serves as a resource for staff to ensure the project is managed consistently.

The tendering and procurement of contracts is part of the overall procedures and processes described in the PEP and the associated documents. For the purpose of this report, KP was also provided with copies of the following NGCD policy and procedure documents to illustrate parts of the PEP:

- Total Cost and Schedule Management
- Engineering Consulting Contract Monitoring and Controls
- Construction Contract Monitoring and Controls
- Contract Change Management

- Risk Management
- Project Contingency Management, and
- Project Change Authorisation.

2.2.3 Total Cost and Schedule Management (TCSM)

In order to manage the scope of work to the approved budget and schedule MH has developed the TCSM procedure. The procedure outlines the approach to coordinating all the project service functions that support the monitoring and control the projects, using an iterative management approach called PDCA (Plan Do Check Act).

- The Plan stage involves establishing the project baseline schedule and budget.
- The Do stage involves implementing the project controls plan on awarded contracts and internal labour.
- The Check stage involves retrieving actual costs from the MH management system, SAP, and the latest schedule and forecasts from project leads.
- The Act stage involves assessing performance and managing change and contingency.

2.2.4 Overall Tendering and Procurement Management Strategy

The work required to complete the Keeyask Project has been divided into work packages. A MH Project Controls Coordinator is responsible for contract monitoring and controls process from the contract drafting to early periods of the contract execution. For each contract awarded the contract value is measured up against the base estimate and the relevant amount of contingency is allocated from the contingency pool (see Section 3). The PDCA iterative management approach ensures that the project estimate and schedule are updated accordingly.

A Work Package Lead (WPL) reviews the Contractor progress reports and ensures their timely weekly submission and communicates discrepancies/issues to the Contractor. A Cost and Schedule Section (CSS) is responsible for reviewing the updated contract schedules and updating the comprehensive schedules and checking against the contractor progress reports. The Project Accounting Section (PAS) tracks project-to-date cumulative actual dollars.

2.2.5 Contracts

MH intends to form separate contracts with the various contractors and has overall responsibility for interface management. MH's management strategy for tendering is a mixture of methods, tailored to the individual contracts. Thus the strategy for tendering the supply and installation of the turbine-generating equipment (TG Supply) is essentially fixed price whilst that for procuring the main civil works is essentially design-bid-build but with a target price and a process whereby the selected contractor is engaged early so that he might be involved in helping finalise contract details. KP deems this overall approach to be appropriate in principle. Section 4 of the previous KP report gives details of the various forms of contract used by MH.

2.2.6 GCC Early Contractor Involvement Process

The General Civil Contract (GCC) for the KGSP is to be executed using an Early Contractor Involvement (ECI) Process that has now begun. Having civil contractor involvement in the process two years before major construction begins offers the opportunity to:

- Ensure the contractors construction knowledge is incorporated into the design
- Refine the delivery schedule
- Secure the necessary labour; and
- Form alliances with Manitoba suppliers and sub-contractors.

2.3 SCHEDULING FOR TENDERING

The PEP states that project execution will follow the Hydro Cost and Schedule Standard (CSS) for schedule management. The overall schedule anticipates construction starting in July 2014 and being complete in January 2021. Procurement of long lead time items of equipment is already under way, in order to ensure delivery to site in time for incorporation in the works. Schedule performance is one of the key performance indicators tracked by MH.

Detailed and complete schedules for KGSP were included in both the 2009 Basis of Cost Estimate Report and the Request for Proposals (RFP) for the Keeyask GCC. The schedules and timelines are deemed to be appropriate and realistic, except for the Stage 1 Coffer Dam which is deemed aggressive. They are consistent with the described developments and the anticipated work breakdown structures. It appears that MH has properly identified and appropriately scheduled items such as preparatory works (through the KIP) and long-lead-time items such as the supply of the turbine-generator equipment. It was not possible, however, to ascertain that adequate time has been built in to the schedule to cover MH's processes and procedures or any external owner requirements, such as reviews by Hydro or independent engineers.

The recent tenders submitted as part of this contract have validated the feasibility and reasonableness of the construction schedule. Validation Estimating has noted that the project team did find the GCC schedule to be very aggressive. See Section 7 for further discussion on this GCC.

MH has been unable to provide a comprehensive overall development schedule that includes design, procurement (all work required to prepare tender documents right to award) and construction (work after contract award to close-out). However, they believe they are presently generally on track with the projects; KP confirms this, based on the information received to date and the fact that the early development items are largely complete and the overall development schedule is now driven by construction and commissioning.

2.4 EFFECTIVENESS OF TENDERING AND PROCUREMENT MANAGEMENT APPROACH

2.4.1 Minimizing Capital Costs

MH is using an appropriate approach towards minimising capital costs by sharing risk with the contractors and suppliers through the principal measures of advancing design prior to procurement, identifying and managing risks, and detailed management of the construction process.

2.4.2 Securing Competitive Bids

The most significant contracts have been or are being procured through a competitive bid process (GCC and Equipment Supply). A number of projects have been procured through non-competitive DNCs because of a preference by MH for particular contractors to undertake specific work assignments. MH has drawn experience with this type of contract from the Wuskwatim project, which had a number of DNCs. Since these contracts are not competitively bid, their value is closely related to the leverage held by MH and the diligence associated with the negotiation.

Internal MH costs may not be deemed competitive but KP does not have sufficient data to be able to offer an opinion on this issue.

2.4.3 Managing Construction and Procurement Cost Escalation

It is difficult to measure MH's effectiveness in managing construction and procurement cost escalation as the current process is relatively new to MH and is significantly different from the old process. MH has a project controls coordinator who has constant access to such data as earned value charts, forecasts, trends and open issues that may affect the project and lead to unanticipated escalation. Opinions on MH's approach to the management of construction and procurement cost escalation are provided in the sections that follow.

2.4.4 Managing Construction Risks

The project team and risk engineer execute the contingency management process, which includes the risk management process and the contingency management process. These are covered in Section 3.

2.4.5 Procurement of other major facility components

To reduce scheduling risk and potential interface issues, a number of contracts were bundled with the GCC, including the Electrical and Mechanical Contract and excavation, cofferdams and draft tube forms. The reduction of interface risk was a lesson learned from the Wuskwatim project, which had several different contracts.

2.4.6 Overall Assessment of Effectiveness

KP is able to see that MH is following a well-documented process despite the PEP presently being in draft form only. The project generally appears to be on schedule as it relates to Tendering and Procurement.

3 – CONSTRUCTION RISK MANAGEMENT STRATEGY

3.1 SCOPE OF WORK

Question 2: "Review Manitoba Hydro's construction risk management strategy and comment on its effectiveness"

3.2 RISK MANAGEMENT STRATEGY

MH has a Risk Management Procedure (NGCD RSK-001 dated October 3, 2013) whose purpose is to *"detail the activities of planning, identifying, evaluating, responding, and monitoring for effective risk management as well as detailing the standard risk reporting templates..."* Related to this document are the Project Contingency Management Procedure (RSK-002 of November 10, 2013), and the Keeyask Project Risk Register. A Project Risk Report is also produced, showing contingency drawdown, schedule, one year look-ahead of project-specific risks based on project schedule, project risk profile, top 5 global and top 5 specific risks, and risk by phase of implementation. Confidential copies of all these documents were made available to KP.

Risks in the Risk Management Procedure are assessed on the basis of the product of Probability and Impact, broken down into the following categories:

- Technical (Requirements, Technology, Complexity and Interfaces, Performance and Reliability, Quality)
- Organisational (Project Dependencies, Resources (MH Staff), Funding, Prioritisation, Customer (Internal))
- Project Management (Estimating, Scheduling, Controlling, Communication)
- External (Regulatory, Market Intelligence, Performance and Reliability, Weather, Stakeholders), and
- Safety (Design Standards, Qualifications, Training and Awareness).

Tables 3.1 and 3.2 provide details for the assessment of Probability and Impact and Tables 3.3 and 3.4 the Risk Factor Matrix (where Probability and Impact are combined) and the Ranking system adopted. Although inevitably largely qualitative, quantitative ranges are given to guide the process. The process is deemed to very standard and appropriate overall for the KIP and KGSP.

Table 3.1 Probability (Risk Management)

Probability Rank	Description		Factor
	Threat	Opportunity	
Very Low (1)	Unlikely to Occur	Unlikely to Occur	<10%
Low (2)	May occasionally occur	Possible opportunity which has yet to be fully investigated.	10% to 30%
Medium (3)	Is as likely as not to occur	Opportunity may be achievable but will require careful management.	30% to 50%
High (4)	Is likely to occur	Clear opportunity which can be relied on with reasonable certainty	50% to 70%
Very High (5)	Is almost certain to occur	Is almost certain to occur	70% to 99%

Table 3.2 Impact (Risk Management)

Impact	Technical	Schedule	Cost
Very Low (1)	[redacted]	[redacted]	[redacted]
Low (2)	[redacted]	[redacted]	[redacted]
Medium (4)	[redacted]	[redacted]	[redacted]
High (8)	[redacted]	[redacted]	[redacted]
Very High (16)	[redacted]	[redacted]	[redacted]

Table 3.3 Risk Factor Matrix (Risk Management)

Probability Factor	>70% (5)	5	10	20	40	80
	50%-70% (4)	4	8	16	32	64
	30%-50% (3)	3	6	12	24	48
	10%-30% (2)	2	4	8	16	32
	<10% (1)	1	2	4	8	16
		Very Low (1)	Low (2)	Medium (4)	High (8)	Very High (16)
		Impact Factor				

Table 3.4 Risk Ranking (Risk Management)

Combined Risk Factor Range	Risk Level	Response for NGC
1 to 4	Minor	Acceptable level of risk. Mitigation of risks is optional.
5 to 15	Moderate	Borderline level of acceptable risk. Must be mitigated to minor in stage 5.
>15 High	Critical	Unacceptable level of risk, must be mitigated to moderate in stage 4, or low in stage 5.

Risk categories in a MH presentation at a PUB Workshop in May 31, 2010 were somewhat different, viz:

- Market (Domestic and Export)
- Financial
- Environmental (including water supply and climate change)
- Infrastructure
- Human (including safety and union and employee issues)
- Business Operational
- Reputation
- Governance / Regulatory / Legal
- Aboriginal
- Emerging Technology, and
- Strategic.

At that time risks were summarised in a Risk Map, a matrix of Consequence and Likelihood.

Categories listed on the Risk Register also do not directly follow the above definitions but are more direct and detailed. Categories include:

- Auxiliary Processes and Services
- Concrete Structures
- Earth Structures
- Electrical and Mechanical Work
- Electrical Power Systems
- Environmental
- Excavation
- Geotechnical
- Global Construction
- Global Other
- Infrastructure
- Licensing
- Logistics
- Power Generation Systems
- Project Management
- River Management, and

* Stakeholder.

The major risks in the Risk Register (total risk score of 80, see Table 3.3) were perceived in August / September 2013 to be:

* [redacted]

MH proposes to deal with these risks by mitigation, through the Contingency and/or the Management Reserve.

3.3 EFFECTIVENESS

It is apparent that the new procedures and systems set up for Keeyask and Conawapa are a direct result of lessons learned on Wuskwatim and reflect a genuine concern on the part of MH to manage the whole process better. As far as can be seen, the risk management strategy is well set up and is being monitored and acted upon appropriately. Having chosen suitable, reputable and experienced contractors, construction risks are associated with contractor performance, in terms of quality, cost and schedule. MH carries some risk for known unknowns like quantities (which risk is mitigated by advanced design, investigations, good takeoffs and the GCC ECI process), and possibly to some degree schedule impacts of inclement weather. Portions of the contingency have been added to each contract, to cover unknown unknowns.

The whole issue ultimately comes down to cost. This is discussed further in Sections 8 and 9 of this report.

3.4 REVIEW OF THE RISK ANALYSIS AND CONTINGENCY ESTIMATE BY VALIDATION ESTIMATING

KP has reviewed the Keeyask Generation Station Project Capital Cost and Schedule Risk Analysis and Contingency Estimate report dated March 9, 2014 prepared for MH by John Hollmann of Validation Estimating LLC; the document describes the updated risk analysis and contingency estimate conducted for the Keeyask Generation Station Project (Project) using Validation Estimating LLC's contingency estimating methodology. KP has not had an opportunity to review other material prepared for MH by Validation Estimating that was included in the previous cost estimates.

Validation Estimating based the review on the updated estimate and schedule prepared by MH in November 2013. The costs were updated based on General Civil Contractor (GCC) bids received in December 2013 and continued assessment of cost and risk through February 8, 2014.

MH also provided KP with some of the associated tables by Validation Estimating that define the scope development and estimate maturity as the lead into the risk analysis. One aspect of the systemic risk analysis is that it is subjective. The interviews done to rate the level of scope development and other systemic risks in view of the analysis were performed with staff internal to MH, which may bias the perspective descriptions.

3.5 HIGH, LOW AND REFERENCE CASE

As per the March 27, 2014 Manitoba Undertaking #27 (MH Exhibit 104-8) the updated Capital Cost Estimates for Keeyask used in the Economic Uncertainty Analysis are as follows:

Table 3.5 Low, Reference, High

	Keeyask 2019		
	Low	Ref	High
Capital Cost	**3.0** B 2014 $	**3.3** B 2014 $	**3.7** B 2014 $
Probability	20%	50%	30%
Capital Cost	**3.1** B 2014 $	**3.6** B 2014 $	**4.2** B 2014 $
Probability	20%	60%	20%

These numbers are in agreement with the values determined by Validation Estimating.

4 – REVIEW OF CONTRACT DOCUMENTS FOR MAJOR KEEYASK COMPONENTS

4.1 SCOPE OF WORK

Question 3: *"Review contract documents prepared by Manitoba Hydro for the major Keeyask components and comment on how such documents have been designed to secure cost effective bids from suppliers and contractors and where Manitoba Hydro may be for vulnerable for cost increases, schedule changes etc. Comment on the overall thoroughness of the contract documents and drawings."*

4.2 CONTRACT DETAILS

The earlier KP report contains a description of the various forms of contract that are typically used for projects like the KGSP and the KIP. It is important to note that the work packages, including major Keeyask component supply, may not always correspond line for line to the Work Breakdown Structure (WBS) developed as part of the bottom-up estimate. As a result it is difficult for KP to reconcile dollars spent to date and anticipated future contract expenses for each specific element of the WBS.

Copies of various Keeyask contract documents were made available to KP as part of the original scope of work and commented upon in the earlier KP report. Details of the recently awarded GCC are discussed in Section 4.5 below.

4.3 OVERALL THOROUGHNESS OF THE CONTRACT DOCUMENTS AND DRAWINGS

The contract documents and drawings that KP has seen have clearly been drawn up by competent, experienced engineers, from within MH and from reputable experienced consultants.

4.4 VULNERABILITY TO COST INCREASE

As indicated in the earlier KP report, MH has stated that as of September, 2013, 29% of the 2012 $3.05 billion Point Estimate had been covered by contracts that had already been awarded. It should be noted that award of contracts had not resulted in a change to the contingency allowance.

The earlier report essentially confirms that MH has made appropriate choices for the various Keeyask contracts – the contracts have been designed to secure the most cost effective bids from suppliers and contractors. All contracts except fixed price contracts (FPC) are somewhat vulnerable to cost increases but should still provide the most cost-effective solution by sharing risk and not insisting the contractor carry all the risk. If the contractor is made to carry all the risk he has to hedge his bets and build in to his price provision for the worst perceived possible outcome. If the worst case does not occur, the contractor pockets the unused provision as extra profit and nothing is returned to MH. Using non FPC contracts does, however, require MH to provide a contingency allowance for any unanticipated possible over-expenditure. Contingency provision is discussed in Sections 3 and 9.

Non FPC contracts have similar implications on schedule as they do on costs. It is necessary to specify the process by which schedule changes might be made if necessary. Any cost implications of schedule change should be included in the contingency.

Where possible increases can be anticipated and defined where they have been acknowledged and accounted for in a professional and competent manner that shares risks between MH and the service provider. KP has not been able to confirm that MH has an adequate level of project definition for the indirect costs (no detailed report describes these cost though KP has seen some high level detail.) in all areas and concludes that the indirects carry more risk of cost escalation than the direct works, which typically has a higher level of project definition.

4.5 GENERAL CIVIL CONTRACT (GCC)

The General Civil Works Contract (GCC) represents the most significant single expenditure on the Keeyask Project. BBE Hydro Constructors Limited Partnership has been awarded a $1.4 billion contract by Manitoba Hydro to construct the 695-MW Keeyask hydroelectric plant; the partnership includes Bechtel, Barnard Construction and EllisDon.

It is made up of a range of work packages including excavation, cofferdam construction, river management, dams, dykes, and electrical and mechanical works, as well as construction of the powerhouse and spillway structures. This contract was awarded in March 2014. MH has provided the following details of the contract document and the bids received.

4.5.1 GCC Contract Document

The GCC has been structured on an Early Contractor Involvement (ECI) model to provide “the opportunity to collaboratively assess, mitigate and then appropriately allocate responsibility for risks in a manner that will align primary participant success with project success”. A two Phase process has been adopted in which Phase I is for the provision of ECI services (ECIS) and Phase II is for the actual construction of the civil and associated works.

The ECIS Phase I comprises:

- Task #1: An initial workshop between the three main entities – MH, the Engineer and the Contractor (on or about March 18, 2014)
- Task #2: Stage I cofferdam construction management plan (to be completed by June 1, 2014)
- Task #3: Contractor to develop concrete mix designs (by April 1, 2016)
- Task #4: Contractor input to design refinement and freeze point activities (by November 1, 2014)
- Task #5: Construction planning Contractor deliverables (by August 1, 2015)
- Task #6: Contract schedule for Phase II construction (before start of rock excavation in spillway)
- Task #7: Risk mitigation plan (by August 1, 2015)
- Task #8: Permit matrix (by August 1, 2015), and
- Task #9: Submittal Schedule (by August 1, 2015).

Phase II comprises the actual construction, on the following basis:

- An Initial Target Price submitted with the Bid based on the direct costs of extending and summing the products of quantities provided by MH and their Engineer and unit rates submitted by the Contractor (as per conventional design-bid-build contracts).
- Indirect costs reimbursed by the application of percentages bid by the Contractor for general administration and overheads (GA & O), and for profit, separate percentages being applied to the direct costs.

- Provisions for the adjustment of the Initial Target Price (to produce an Adjusted Target Price), chiefly due to escalation, and possible changes in the scope of work,
- The Contractor is encouraged at any time to make Value Engineering proposals (which, if accepted by MH, do not affect the Target Price)
- Any savings in cost (Actual Final Cost is less than Final Target Price) are attributed 80% to MH and 20% to the Contractor. Any cost overrun (Actual is more than Target) is attributed 80% to the Contractor (drawn from his Profit Percentage, to the limit of that amount) and 20% to MH. If the overrun exceeds 130% of the Final Target Price the Contractor will not receive his GA & O Percentage on any costs that exceed this amount.
- The Performance Security is in the form of Letters of Credit: [redacted]

4.5.2 Comparison of Bids

[redacted]

4.6 MAJOR EQUIPMENT

Approximately [redacted] of the total costs are for Major Equipment [redacted] i.e. turbine, generator, stop logs, transformers, switchgear, etc.

[redacted]

5 – PROCUREMENT BONDING AND LIQUIDATED DAMAGE REQUIREMENTS

5.1 SCOPE OF WORK

Question 4: "*Review construction and equipment procurement bonding and any liquidated damage requirements and comment on the appropriateness of such bonding and cost implications to the project.*"

5.2 BONDING AND LETTERS OF CREDIT

Performance bonding or letters of credit are normal contract requirements designed to protect an owner/developer against the contractor failing to perform. Bonding is typically used for civil construction work at the project site while letters of credit (LoC) tend to be used to procure mechanical and electrical equipment manufactured off site. MH have advised that the GCC however uses LoCs instead of bonding because it provides more security than a performance bond, given that the GCC is a cost reimbursable contract. The primary difference between the two is that a bond guarantees work will be performed, while a letter of credit promises that payments will be made.

A letter of credit promises to cover payments on an approved project, up to the stated credit amount. A bond puts up a specified amount of money to ensure contractual work will be performed to the contract standards. Both instruments provide a sum of money to enable the owner to repeat the procurement process if the contractor defaults. MH has made available to KP details of the bonding or letter of credit requirements for a selection of the major Keeyask contracts, in both the KIP and the KGSP. This information is summarised in Table 5.1. MH has indicated that the amounts are based on risks associated with the individual contracts, past experience, and industry norms.

It can be seen that where performance bonding has been required this has typically been in the amount of [redacted] of the value of the work whereas letters of credit have typically been for [redacted] of the value of the work. These values are deemed by KP to be appropriate. Performance bonds have sometimes in the past been as high as 100% but this adds a significant amount to the contract cost (the cost of the bonding is inevitably passed on to the owner, either expressly, as with the MH contracts, or elsewhere in the bid price), for an event which is not likely to materialise, certainly not in the full amount of the contract. Current practice is to strike a reasonable balance, protecting the interests of the owner while not paying an excessive premium for this insurance.

Table 5.1 MH Procurement Bonding and Liquidated Damage Requirements

Contract	Description	Bonding or Letter of Credit Details	Liquidated Damages
16102, 16103 and 16104	North Access Road B and A and Start Up Camp (DNCs)	[redacted]	
16120	Looking Back Creek Bridge (DNC)	[redacted]	[redacted]
16121, 16122, 16123, 16124 and 16125	Catering and Janitorial, Maintenance, Security, Employee Retention and Support, Emergency Medical Services (DNCs)	[redacted]	[redacted]
16127	Main Camp Facility - Phase 1	[redacted]	
16132	Work Site Area Development	[redacted]	
16150	PR 280 Upgrades - Spot Upgrade Improvements (DNC)	[redacted]	
16203	General Civil Contract	[redacted]	[redacted]
16321	Turbines and Generators	[redacted]	[redacted]
RFP 016305	Intake Gates, Guides and Hoists (same for Spillway Gates, Guides and Hoists}	[redacted]	[redacted]
	Powerhouse Crane	[redacted]	
	Main Electrical Contracts (Transformers, etc.)	[redacted]	

5.3 LIQUIDATED DAMAGES

Liquidated damages (LDs) are intended to protect the owner from the cost implications of having to live with substandard products and/or the cost impacts of late delivery. [redacted] LDs do not have to be proved and are payable by the contractor to the owner if triggered, regardless of actual cost, in the amount specified in the contract. There is normally a maximum limit to the total LDs that may be claimed. The alternative to LDs for compensation are penalties which suffer the disadvantage that they have to be proved e.g. the owner has to substantiate the costs or revenue loss he actually suffers in the event the turbine-generators produce less power than expected or the actual cost of a delay. Details of LDs for a selection of contracts are included in Table 5.1.

LDs are sometimes associated with a Performance Bonus (i.e. the upside of performing better than guaranteed, to counter the downside of performing worse). This is in principle a more equitable arrangement than one which only contains the downside. [redacted]

KP believes that the LDs stated in the various contracts made available appear to be reasonable and in keeping with their purpose.

6 – QUALITY ASSURANCE AND QUALITY CONTROL REQUIREMENTS

6.1 SCOPE OF WORK

Question 5: "Review Manitoba Hydro's Quality Assurance and Quality Control (QA/QC) requirements for Keeyask construction and comment on the effectiveness and costs."

The most common arrangement for addressing quality in procuring hydroelectric power generating facilities is to make the Contractor responsible for Quality Control (QC) and the Owner (or his Engineer) responsible for Quality Assurance (QA). MH is conforming to this usual practice.

6.1.1 MH Quality Management

Quality Management in MH is specified at a high level in the PEP with more detail being provided in a NGCD standard. Both documents define the processes required in MH to establish and operate a quality management program, including a third main activity that takes place prior to QC and QA, Quality Planning (QP).

MH made available to KP copies of the following documents to illustrate their approach to quality:
- Quality Management Section 5 of the Project Execution Plan (PEP)
- NGCD Standard #204 Quality Management (effective date 2012 07 17)
- QA/QC Requirements for the Turbine and Generator Contract 016321, and
- QA/QC Requirements for the General Civil Works Contract 016203.

6.1.2 Turbine and Generator Contract #016321

With reference to this document, which has been awarded, it is noted in General Requirements Clause 48, Quality that:
- The Contractor's own Quality Management System must "*conform fully to the spirit and intent of* (the international quality management system) *ISO 9001 2000"*.)
- The Contractor is also obliged to have a Project Quality Plan and a Quality Team and various Inspection and Testing Plans (ITPs).
- The document is deemed to be detailed, comprehensive and appropriate for its purpose.

6.1.3 General Civil Works Contract #016203

Clause 7.14 of the General Specifications for the GCC confirms that, for this contract, QC is the responsibility of the Contractor and QA the responsibility of the Engineer. Although details (provided in an appendix) were not made available to KP, KP is of the opinion that the details are likely to be appropriate.

6.2 QUALITY CONTROL

The requirements for QC are laid down in the contract documents and/or various standards (like the Canadian Standards Association CSA A23 for the production, inspection and testing of concrete).

6.3 QUALITY ASSURANCE

QA involves checking that the specified QC has been properly carried out: that the tests have been done, proper records have been kept, the records have been inspected and checked (in real time) and that substandard results have been properly addressed. In the case of MH, QA will be performed by their site construction management team (including consultants).

6.4 COSTS

The costs for the establishment and compliance monitoring of the MH quality requirements are not expressly shown. They form part of both the Contractor's and MH's site administration and management costs.

7 – OVERALL CIVIL CONTRACT PROJECT MANAGEMEMENT APPROACH

7.1 SCOPE OF WORK

Question 6: "Review the overall civil contract(s) project management approach; comment on its effectiveness and what project management controls are in place to minimize cost escalations."

7.2 CIVIL CONTRACT PROJECT MANAGEMENT APPROACH

The General Civil Contract (GCC) is being procured in an Early Contractor Involvement (ECI) process which provides an opportunity for MH and a selected contractor to work together to refine the contract. All aspects of the work, including design details, schedule, risk sharing and project management, are open for discussion. KP believes that this process reflects a genuine and appropriate opportunity for MH to optimise and bring as much certainty to the contract as possible.

For the last year and a half, all the KGSP contracts (including the GCC) have been and are being managed within the system-wide MH accounting system, SAP. The KIP is still largely being managed in the old MH system although efforts are being made by MH to get this project into the new system as well. The change in process makes it difficult to compare the 2012 estimates with the 2009 bottoms up estimates as they are formatted and arranged very differently particularly for the indirect costs.

The basis of the SAP system is "Network" Numbers, effectively WBS line items (or rows in the previous 2009 Excel spreadsheet based estimate). Network Numbers include all costs - directs and indirects (contract items, expenses, internal MH costs, consultants, etc.) whereas these costs were set out differently in the old Excel fields. MH has a big focus on schedule, as any extension of the schedule has inevitable financial consequences.

7.3 PROJECT MANAGEMENT CONTROLS

KP and MH held a conference call to discuss details of MH's management system. The following summary comes from that call and subsequent confidential material mailed to KP.

As contracts come in, or there are other reasons to revise estimates or allocations, "PCA"s (Project Change Authorizations) are used to transfer funds to and from the project contingency, in real time. There is a person in MH responsible only for managing the contingency. All significant Network #s have a portion of the overall contingency allocated to them, and have a contingency drawdown curve against which actuals and revisions to forecast are tracked. The project team only has access to the Contingency but not the Management Reserve.

MH keep a "CRR" (Contract Revision Register) that records budget changes like PCAs. They also have "Dashboards" which are effectively reports tailored to present information to particular audiences. An example of a dashboard report is included in the MH Risk Management Procedure (see Section 3). Another example is shown in Figure 7.1.

Estimates of future expenditure are adjusted in real time by adding inflation and deducting money spent to date. A check is also made at the same time on the expected final cost of each item i.e. that the budget is still appropriate. These changes are also recorded in other parts of the estimate, to keep the overall in-service cost the same. An overall reconciliation is done at the end of March every year, with quarterly reports in interim.

[redacted]

Figure 7.1 Example of Project Dashboard

8 – PRE-TENDER CONSTRUCTION ESTIMATES AND ACTUAL TENDER PRICES

8.1 SCOPE OF WORK

Question 7: "Critically review Manitoba Hydro's pre-tender construction estimates and compare with actual tender prices. Define where significant differences are noted and rationalize the specific differences."

8.2 GCC PRE-TENDER ESTIMATES AND ACTUAL TENDER PRICES

MH has provided KP with summary presentation material and Bills of Quantities comparing the GCC proposals, the independent estimators estimate (by Chant), and an escalated original Engineers Estimate by KGS Acres. KP believes that Hydro has been diligent in their internal comparison between the four GCC tenders, their Engineers estimate and the independent Third Party Estimate.

[redacted]

Generally quantities have been confirmed by the bidding contractors and the independent third party estimator. [redacted]

[redacted]

- [redacted]
- [redacted]

8.3 KEEYASK LABOUR RESERVE CALCULATION

[redacted]

Table 8.1 Labour Reserve

	Feb 2014 Update (in Millions 2013$		
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

9 – EXPECTED IN-SERVICE CAPITAL COST FOR KEEYASK

9.1 SCOPE OF WORK

Question 8: "Provide an opinion as to the expected in-service capital cost for Keeyask once all work has been completed."

9.2 EXPECTED IN-SERVICE COST

MH has indicated in the recent hearings, that based on the results of the GCC bids and the award of that contract that their estimated total in-service cost is now $6.5 billion (was $6.2 billion). Validation Estimating states that "the recent incorporation of GCC contract costs reduced the uncertainty in respect to competitiveness of the estimate." The reassessment included a reappraisal of their contingency (updating their contingency model) and management reserves; KP has no better data to offer a better estimate of the expected in-service capital cost for Keeyask and therefore generally concurs with the estimate with the following reservations:

- KP believes that there remains systemic risks to the project that cannot be easily mitigated. While the direct scope is well-defined the project implementation plan is still in progress and Hydro's management systems are not yet mature, these combined risks lower the level of project definition and could lead to increases in project risks and associated costs. As stated by Validation Estimating cumulatively the schedule risks threaten to drive the project into an additional year of construction and the seasonal nature of the work results in a greater schedule risk than a typical mega-project. [redacted]
- When determining the Management Reserve and Contingency, a more conservative approach would be to adopt a higher escalation reserve (closer to 3.1%) [redacted] A higher contingency based on the P80, as compared to Hydro's use of a P50, would also be recommended for the conservative estimate.
- The Tables 9.1 and 9.2 below compare Hydro's Contingency and Management Reserve amounts to those recommended for a Conservative View.

Table 9.1 Contingency Comparison

	Hydro	Conservative View
	P50	P80
Contingency	327 M$	691 M$

Table 9.2 Reserve Comparison

	Hydro	Conservative View
One Year Delay due to Stage One Coffer Dam Delay	[redacted]	[redacted]
Labour Reserve Case	[redacted]	[redacted]
Escalation	[redacted]	[redacted]
Total Reserve	[redacted]	[redacted]

While Hydro's Reference Cost is appropriate, a more conservative view might be warranted when considering and making allowances for the Total Project Contingency and Management Reserve.

Knight Piésold CONSULTING

TABLE 9.3

MANITOBA PUBLIC UTILITIES BOARD
NFAT REVIEW OF KEEYASK AND CONAWAPA GS

CAPITAL EXPENDITURE FORECAST BREAK DOWN SUMMARY

07/04/2014 13 20

	Keeyask GS 2009 Estimate	CEF2010	CEF2011	CEF2012	CEF2013	March 10, 2014 Update		KP Review
BASE COST								
POINT ESTIMATE								
KEEYASK GENERATING STATION COST ESTIMATE								
DIRECTS								
Overnight Direct Cost of Generating Station								
River Management	[redacted]	[redacted]		[redacted]		[redacted]		
Earthfill Dams and Dykes	[redacted]	[redacted]		[redacted]		[redacted]		
Spillway and Transition Structures	[redacted]	[redacted]		[redacted]		[redacted]		
Powerhouse Complex	[redacted]	[redacted]		[redacted]		[redacted]		
Miscellaneous Directs	[redacted]	[redacted]		[redacted]		[redacted]		
Addition to Reflect GCC Tender						[redacted]		
Total Estimated G.S. Direct Costs (without Contingency)	[redacted]	[redacted]		[redacted]		[redacted]	√	This number has been detailed, has escalated roughly in line with what could be expected. This estimate was recently confirmed through the awarded T/G and the GCC award process, the final increase is accompanied by a decrease in the project contingency. Unknowns and risk captured under uncertainty.
Outlet Transmission Project (without Contingency)	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	√	This cost estimate is developed internally and has escalated, KP has not seen details behind this estimate (it is not developed by NGCD), but expect the increase to be associated with a clearer project definition and therefore should not increase further.
INDIRECTS								
Studies and Investigations	[redacted]	[redacted]		[redacted]		[redacted]	√	
Environmental & Mitigation	[redacted]	[redacted]		[redacted]		[redacted]	?	Inclusion of significant post-construction adverse effects as per accounting direction;
Construction Power	[redacted]	[redacted]		[redacted]		[redacted]	√	
Infrastructure	[redacted]	[redacted]		[redacted]		[redacted]		
K.I.P. (Base Estimate)	[redacted]	[redacted]		[redacted]		[redacted]	?	Has increased from the 2009 basis provided, but contracts now in place and KIP work is underway. The increases included authorisations to withdraw additional amounts from project contingency for Camps and DNC contracts. Would have liked to be able to track performance.
Service Contracts	[redacted]			[redacted]		[redacted]		
Planning / Environmental / Construction	[redacted]	[redacted]		[redacted]		[redacted]	?	
MH Office and Labour	[redacted]	[redacted]		[redacted]		[redacted]		
Expenses & External Groups	[redacted]	[redacted]		[redacted]		[redacted]	X	The decision to move to outsource some of the construction project management aspects and addition of performance bonus management include unknowns or non-defined scopes, that pose a risk of cost escalation. Rejuggling of categories makes it difficult to ascertain inclusions when compared to 2009 estimate.
Labour and Material Provisions	[redacted]	[redacted]		[redacted]		[redacted]	?	Allocations recategorized for a large part. Estimate has remained steady overall through the iterations.
Labour & Expenses	[redacted]	[redacted]		[redacted]		[redacted]	√	
Total Estimated Indirect Costs	1,071	1,141		1,323		1,298	?	Additional breakdowns and written descriptions of indirect costs would help determine adequacy. Doubts remain as to inclusiveness.
Total G.S. Point Estimate	2,705	2,806		3,049	3,060	3,357		
Total Transmission Base Estimate	93	105		137	137	138		
Total "Point Estimate"	2,798	2,911		3,186	3,197	3,495	√	
UNCERTAINTY								
P50 Based Contingency	507	518		547	540	327	X	Could Include a higher amount of contingency than the P50. Number has decreased based on updated risk model.
Management Reserve								
Labour Reserve				384	384	304	X	[redacted]
Escalation Reserve				116	116	88	X	Escalating at 2.5% - CPI when internal studies shows higher escalation. Actual escalation applied has been consistently higher in the last 5 years.
Total Management Reserve				500	500	392		
TOTAL BASE COST	3,305	3,427	3,385	4,233	4,237	4,214		
INTEREST AND ESCALATION								
Escalation at Consumer Price Index Level		459		416	330	311	√	
Capitalized Interest				673	1010	900	√	
Interest on Manitoba Hydro Equity		1347		198	200	218	√	Increase due to higher base costs; GCC cash flow is more front-end loaded
Total Project Interest and Escalation		1,845	1,820	1,485	1,540	1,429	√	
MONEY SPENT TO DATE								
Studies & Investigations		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Environmental & Mitigation		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Transmission		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Construction Power		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
MH Office and Labour		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Expenses & External Groups		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
KIP (excluding MH Labour)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Infrastructure		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
River Management (Test Ice Boom)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Turbines & Generators		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Total Actuals		265	298	356	450	627	√	
Interest on Capital		100	126	158*		225	√	
Total Money Spent to Date		365	422	512	450	852	√	Reported
INSERVICE COST								
In-service Cost		5,637	5,637	6,230	6,227	6,495	√	Adequate if one assumes full expenditure of management reserve
Check Total Project Cost (from CEF Documents)		5,637	5,637	6,220	6,220	6,495		

M:\1\03\00449\01\A\Report\2 - Knight Piesold Supplemental Review Report\Rev 0\Tables\[Table 9.1 Keeyask Cost (SRM).xlsx]Keeyask

Legend

25	Indicates a number that KP can calculate from others.
137	Indicates a number provided by Hydro.
	Information shared with KP but not disclosed to PUB.

REV	DATE	DESCRIPTION	PREP'D	CHK'D	APP'D
1	07APR'1	ISSUED WITH REPORT VA103- 9/1-2	BF	MJR	SRM
0	18FEB'1	ISSUED WITH REPORT VA103- 9/1-2	BF	MJR	SRM

10 – CERTIFICATION

This report was prepared, reviewed and approved by the undersigned.

PROFESSIONAL PROVINCE OF B. S. FICHOT # 30875 BRITISH COLUMBIA ENGINEER

Prepared:

Boris Fichot, P.Eng.
Senior Engineer

for.

Reviewed:

Mike Robertson, P.Eng.
Specialist Engineer

PROVINCE OF MANITOBA S. R. MOTTRAM Member 36712 REGISTERED PROFESSIONAL ENGINEER

8 April 2014

Approved:

Sam Mottram, P.Eng.
Managing Principal – Power Services

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APPENDIX A

TERMS OF REFERENCE FOR NFAT SUPPLEMENTAL REVIEW

(Pages A-1 to A-3)

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Site Web: www.pub.gov.mb.ca

January 13, 2014

Law Department
Manitoba Hydro
22 - 360 Portage Avenue
Winnipeg MB R3C 0G8

Attention: Patti J. Ramage / Marla J. Boyd

Dear Ms. Ramage and Ms. Boyd:

Re: Keeyask Tenders - Approved Scope of Work for Knight Piésold

The Public Utilities Board ('Board') is informing you that the attached Scope of Work has been approved by the Panel to be completed by Knight Piésold. As such Manitoba Hydro is asked to:

1. Place all related Contracts and Tender Documents that pertain to the Keeyask project in the CSI Rooms; and
2. Provide copies of the Keeyask Contracts and Tender Documents to Knight Piésold via the IEC SharePoint site.

The Board is requesting that the requested information be made available as soon as possible, considering that the report requested by Knight Piésold be submitted by February 4th, 2014.

Sincerely,

H.M. Singh
Secretary

cc: Bob Peters/Sven Hombach - Board Counsel
Christian Monnin/Michael Weinstein - IEC Legal Counsel
All Parties

Knight Piesold - Proposed Revised Scope of Work

As approved by the NFAT Panel on January 10, 2014.

Manitoba Hydro has indicated in their correspondence of December 4, 13, and 30th of Manitoba Hydro's intention to award the Keeyask General Civil Contract early in 2014. Manitoba Hydro intends to seek Manitoba Hydro Board approval of the contract in February of 2014. It is the opinion of the Public Utilities Board that the review of tendered costs for Keeyask is of significant importance for the understanding of the projected capital costs.

The overall objective of the revised scope of work for Knight Piésold (KP) would be to validate Manitoba Hydro's overall cost estimate and tendering practices for Keeyask and the accuracy of Manitoba Hydro's cost estimating approach.

The proposed scope of work for KP to complete this objective is provided below.

- Review MH's overall management strategy and scheduling for the tendering of contracts for the Keeyask Generating Station and the procurement of other major facility components such as spillways, dams, dykes, powerhouse, turbines, intake gates, generators, controls etc. Comment on the effectiveness of this management approach for minimizing capital costs, securing competitive bids, and managing construction and procurement cost escalation and construction risks.

- Review Manitoba Hydro's construction risk management strategy and comment on its effectiveness.

- Review contract documents prepared by Manitoba Hydro for the major Keeyask components and comment on how such documents have been designed to secure cost effective bids from suppliers and contractors and where Manitoba Hydro may be for vulnerable for cost increases, schedule changes etc. Comment on the overall thoroughness of the contract documents and drawings.

- Review construction and equipment procurement bonding and any liquidated damage requirements and comment on the appropriateness of such bonding and cost implications to the project.

- Review Manitoba Hydro's Quality Assurance and Quality Control (QA/QC) requirements for Keeyask construction and comment on the effectiveness and costs.

- Review the overall civil contract(s) project management approach; comment on its effectiveness and what project management controls are in place to minimize cost escalations.

...2

- Critically review Manitoba Hydro's pre-tender construction estimates and compare with actual tender prices. Define where significant differences are noted and rationalize the specific differences.

- Provide an opinion as to the expected in-service capital cost for Keeyask once all work has been completed.

- Provide a supplemental report to the Panel incorporating this work by February 4th, 2014.

APPENDIX B

MATERIAL USED IN REVIEW

(Page B-1)

April 2014 Redacted

Appendix B: Material Used in Supplemental Review Report (NFAT - IEC Knight Piésold Ltd.)

M:\1\03\00449\01\A\Report\2 - Knight Piesold Supplemental Review Report\Rev 0\[App B - List of Material Used in Review.xlsx]List

Document Index	Document Title
Addional Information Provided by Manitoba Hydro	
Phone Call April 7, 2014	Reserve Calculation
Email Dated April 2, 2014 and Letter April 2, 2014	Capital Expenditure Forecast Break Down Summary - Updated with CEF 2013 and March 10, 2014 revisions.
Email Dated March 27, 2014	243953-0125-EST-KGS Estimate Cost Breakdown for the New WBS 2014-2014031 Keeyask and Conawapa Labour Reserve Calculation Keeyask Generating Station - Monthly Project Dashboard Report - As at Feb 28, 2014
MH Exhibit #109 - Transcript Page #1816 MH Exhibit #113 - Transcript Page #1820 MH Exhibit #137 - Transcript Page #3806	Manitoba Hydro Undertaking #34 (March 13,2014) Manitoba Hydro Undertaking #35 (March 19,2014) Manitoba Hydro Undertaking #62 (March 27,2014)
Letter March 12, 2014 ("blue paper")	1. Copy of presentation made in conference call March 5 on the Keeyask and Conawapa Estimate Update a. Table Updated: NFAT Results Keeyask i. Base Costs Comparison Added ii. Total In Service Costs 2012 Values Updated b. Table Updated: NFAT Results Conawapa i. Base Costs Comparison Added ii. Total In Service Costs 2012 Values Updated c. Table Updated: Conawapa 2026 NFAT Detailed View i. NFAT Submission Chapter 11, Low and High, Escalation and Capitilized Interest Updated. 2. Keeyask Estimate Summary Sheet a. Table Updated: Interest and Escalation Updated 3. Keeyask Contingency (Risk Consultant) Report and Appendices (Systemic Risk, Risk Tool, Labour Shortage) 4. Presented at Hearings - Updated Capital Costs for Keeyask
Conference Call March 5, 2014	
Letter February 28, 2014 ("blue paper")	KIP Estimate Summary Sheet and Details Labour Reserve Calculations Copy of presentation made in conference call February 27 Keeyask GCC Workforce Proposals Graph, Bidder Contingency Summary, Engineer's Estimate and Proponent's Bid Comparison Summary
Conference Call February 27, 2014	
Emails February 16, 2014	Responses by [redacted] (NGCD) to questions on Bonding and LDs Responses by [redacted] (NGCD) to questions on Risk and Schedule
Letter February 7, 2014 ("blue paper")	Information on contract surety for KIP and KGSP
Conference Call February 6, 2014	
Email January 30, 2014 ("white paper")	QA/QC Requirements from Turbine/Generator Contract Specification (Clause 48) Standard #204 Quality Management - Execution, Detailed Design, Program. Dated 2012-07-17 Excerpt from PEP Section 5 Quality Management
Letter January 30, 2014 ("blue paper")	Response to KP/MH II-027 as filed with the PUB
Letter January 27, 2014 ("blue paper")	MH New Generation Construction policies and procedures: PSD-002 Total Cost and Schedule Management. Dated 2012-06-29 PCC-001 Engineering Consulting Contract Monitoring and Controls. Dated 2013-08-26 PCC-002 Construction Contract Monitoring and Controls. Dated 2013-08-26 PAS-001 Contract Change Management. Dated 2013-10-22 RSK-002 Project Contingency Management. Dated 2013-10-29 Standard #801 Project Change Authorisation. Dated 2013-10-16 Copy of Presentation on Capital Cost Estimates for Keeyask and Conawapa Generating Stations from Conference Call January 23, 2014
Conference Call January 23, 2014	Keeyask GS Cost Estimate (2009), Estimate Summary and Indirects Summary Sheets [redacted] - Cost and Schedule Section Lead [redacted] - Project Services Manager [redacted] - Cost and Schedule Engineer [redacted] - Project Accounting Lead [redacted] - Project Controls Lead [redacted] - Cost and Schedule Officer
Letter January 16, 2014 ("blue paper")	Response to KP/MH II-027 with more detail than PUB version January 30
Conference Call January 16, 2014	
Letter September 12, 2013	Request for Proposal 016203 - General Civil Works
Other	
KP Main Report , VA103-449/1-1 Rev 1 January 23, 2014	Knight Piésold Independent Expert Consultant Report (Confidential)

Tab 123

Asset Management Gap Assessment

Report of Findings to Manitoba Hydro

Conducted by

UMS Group Inc.
Morris Corporate Center 1
300 Interpace Parkway, Suite C380
Parsippany, NJ 07054

December 15, 2016

Table of Contents

INTRODUCTION

Overview of Project

UMS Group was engaged by Manitoba Hydro (Hydro) in September 2016 to conduct a Gap Assessment of its Asset Management capabilities. The scope of this assessment was to evaluate the organization's current asset management capabilities and practices and make recommendations for implementing a best practice Asset Management System.

The project comprised a review of Hydro's existing corporate and business unit level Asset Management practices and comparison to industry best practices, as well as to international standards for Asset Management (PAS 55 and ISO 55000). From this review, UMS developed a detailed and prioritized listing of the gaps between Hydro's current Asset Management practices and industry best practices and identified necessary steps to bridge the gaps.

To perform the assessment, UMS collected and reviewed asset management-related process and practice documentation, as well as current plans to monitor and maintain asset performance, asset condition and risk levels. Additionally, interviews were held with the Executive team to understand their views on asset management, objectives for the assessment, and perceived issues/gaps. Following those interviews, individual interviews were held with personnel involved with asset management from across the Hydro Generation Operations, Transmission, and Customer Service and Distribution business units. The focus of these interviews was to understand current and planned asset management roles and responsibilities, practices, processes, and tools.

Finally, individual workshops were held with each of the Generation Operations, Transmission, and Customer Service and Distribution business units to discuss asset management standards and best practices and walkthrough a self-assessment of the Business Unit maturity compared to industry standards – International Organization for Standardization (ISO) 55000 and Publicly Available Specification (PAS) 55 – and best practice. Individual workshops were also held with each of the Business Units to review the Asset Lifecycle and Risk Strategy Process and gain a better understanding of how Hydro addresses the steps in the process and where gaps exist.

The Gap Assessment Methodology is described in Appendix A. Manitoba Hydro personnel who were interviewed and/or participated in workshops are listed in Appendix B.

As a definitional note, there are several terms used in the report which might not be familiar to readers. There are defined below:

- <u>Management System</u> – The set of interrelated or interacting elements of an organization (i.e., policies, processes and procedures) used to ensure that it can fulfill all the tasks required to achieve its objectives.

- Model – A high level representation of a system made up of concepts which communicate basic facts about the system
- Framework – A high level guide which identifies the key elements of a structure.

What is Asset Management?

Asset Management is a system that uses data-driven decision-making to ensure the right work is being undertaken to achieve the desired performance outcomes in the most efficient way. Its overall objective is to ensure that short term decisions meet the long term needs of stakeholders in the optimal manner.

Good Asset Management means spending limited resources in the most effective way to meet business objectives. It does so by proactively investing in the asset in a way that meets the strategic objectives of the company, rather than merely reacting to asset deficiencies as they occur. This investment is based on economic modeling of benefits versus its costs, rather than historical spend or "pet" projects. By providing the focus and accountability for the best use of its resources, Asset Management optimizes the total expenditure needed to achieve the desired business and asset performance outcomes.

Strategic Value of Asset Management

Improving its Asset Management capabilities has the potential to provide significant strategic benefit to Manitoba Hydro by ensuring that it is optimizing its capital and operating expenditures, managing risk within a set tolerance level, and delivering long-term value to customers by reliably and safely providing service in a cost-effective manner.

Specific benefits that can be achieved by Hydro through the maturation of its asset management system include:

- Improved asset productivity through life extension and reduction in failures
- Increased efficiency in asset maintenance through better targeting of needed work and elimination of non-valued added work
- Reduced uncertainty through better forecasting of failures and understanding of risk
- Ability to compare investments across asset classes through consistent approach and monetization of benefits
- Improved effectiveness of expenditure dollars through focus on performance management and continuous improvement
- Optimizes use of human resources by matching the workforce – in terms of size and composition – to the work required, rather than creating work to keep the workforce busy
- Greater transparency for internal and external stakeholders through use of data-driven decision-making and quantitative analysis

In 10 previous utility asset management transformations we have performed, we have found that utilities see significant improvements in productivity and overall cost savings of 20-30% over 5 years with the application of an asset management system.

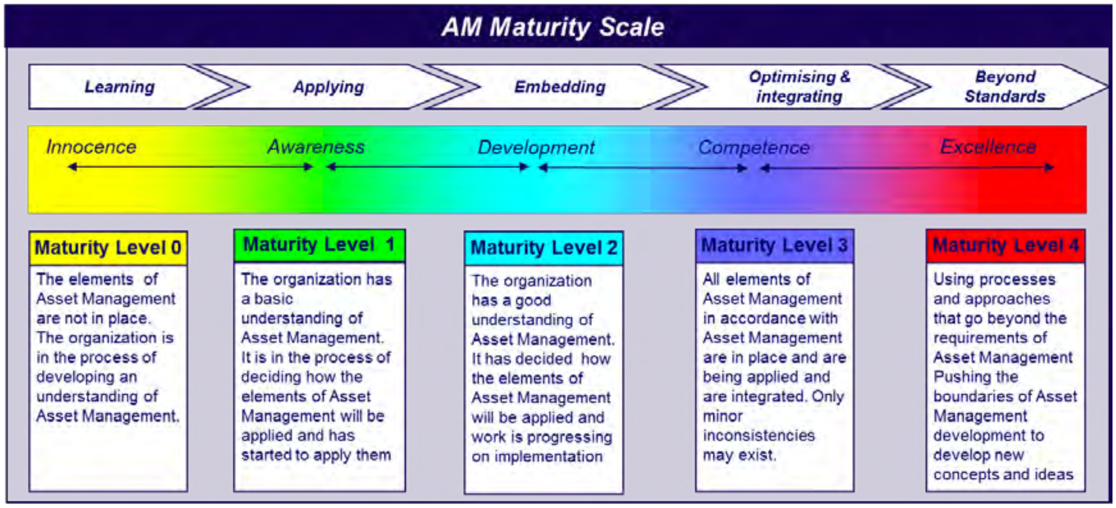
Achieving these benefits means adopting a process model whereby the responsibilities and accountabilities for the different Asset Management roles are clearly defined and understood by personnel. The three key roles in an Asset Management process model are the Asset Owner, Asset Manager, and the Service Provider.

The Asset Owner identifies needs and requirements of stakeholders and sets the business values and risk tolerance levels for the Asset Manager. The Asset Manager then determines what has to be done, when, and where to realize the objectives set by the Asset Owner and agrees on a service level for performing work with the Service Provider(s). In turn, the Service Provider determines how the work is performed while keeping costs to a minimum for the specified levels of work and quality as agreed to with the Asset Manager.

The three roles operate in a chain and need each other to work closely together based on formalized agreements.

EXECUTIVE SUMMARY

Using the methodology described in the *Introduction* above, UMS Group assessed Hydro against ISO 55000 and best practice Asset Management on the following scale:



Notes on the use of the maturity scale:
1 As indicated by the colour transitions, the boundaries of the maturity scale are not hard values
2 Compliance with the AM Standard is at Competence maturity level 3
3 There is no upper limit to excellence as defined by the red colored zone

Overall, Hydro scored a 1.5 with the individual Business Unit Scores as follows: Generation Operations (GO) = 1.7, Transmission = 1.6, and Customer Service & Distribution (CS&D) = 1.3. While these scores may seem low compared to a competence standard of 3, it is important to realize that many North American utilities would rate a 0 (unaware of major Asset Management System requirements) or a 1 (aware of, but not yet developing). In addition, the individual components which make up these average scores ranged from 0.5 to 3.0 corresponding to the fact that while Hydro is fully Competent in some areas, there are others where it is just starting to develop its capabilities.

Against the industry, Manitoba Hydro compares favorably versus North American utilities in terms of its Asset Management maturity level. However, North America lags global Asset Management best practice as embodied by utilities overseas who have been developing their capabilities for more than two decades.

Hydro has followed a typical path along the Asset Management maturity curve by starting with grassroots-led tactical solutions to solve specific problems. As with many utilities, the initial role Leadership played at Hydro with regard to Asset Management has been providing approval and direction when requested. If Hydro seeks to become an asset management-focused company, Leadership will want to place a greater emphasis on the strategic value of asset management, challenge progress within the Business Units, demand accountability for results, and commit the resources needed to achieve its objectives.

Between the three Business Units, Hydro has developed a number of the key components of best practice asset management such as:

- The development of Asset Health Indices (AHIs) and use of Condition Assessment to drive replacement decisions;
- The use of risk (likelihood x consequence), rather than just criticality (consequence) to drive some replacement decisions;
- The use of Reliability Centered Maintenance (RCM) to develop maintenance plans based on specific asset failure modes; and
- The development of Computerized Maintenance Management Systems (CMMS) to tie together asset data, maintenance data, and cost information

In addition, Hydro has already identified a number of existing gaps and plans/actions to close these gaps are underway including:

- The recent adoption of a monetized risk-based decision-support tool for capital planning -- Copperleaf's C55 and the Corporate Value Framework (CVF);
- An alliance with Siemens which aims to develop sophisticated capabilities for managing, maintaining, and evolving Distribution assets; and
- A new CMMS (SAP Plant Maintenance (PM) – Enterprise Asset Management (EAM)) to improve the ability to tie costs to assets

However, there are also a number of key gaps which UMS Group has identified and for which no current initiative is underway to close. Below is a summary of these key gaps along with corresponding key recommendations. A detailed assessment which describes all gaps and all recommendations is provided in the following *Assessment* section.

Key Gaps

The Business Units, and sometimes the functions within the Business Units, have been operating with their own objectives and limits for making asset decisions, as there is confusion over the Asset Owner role. While the Corporate Asset Management Executive Council (CAM EC) has been chartered with most of the responsibilities of the Asset Owner, this role has not been formally communicated to the organization, nor have the Business Units been provided with concise direction on Policy, Strategy, and Objectives, although the CAM does have a plan to develop these over the next few months.

Responsibilities for Asset Management are divided with a lack of clear understanding of what constitutes the Asset Manager and Service Provider roles, as well as what the responsibilities and accountabilities of each are. In addition, the fact that Asset Management has developed independently in each Business Unit and that the Asset Management functions are split within the Business Units has led to a lack of standardization of processes (and systems) and hindered the sharing of best practices.

Risk is a key basis for decision-making in best practice asset management systems and Hydro is increasingly incorporating risk in its asset-related decisions today. However, there are no corporate risk standards, tolerance levels, or risk assessment requirement to guide the Business Units leading to a situation in which risk is being avoided rather than managed.

Some of the key elements of an Asset Management System are missing from Hydro today. These include audits, controls, and performance metrics which Leadership can use to ensure the suitability, adequacy and effectiveness of the system.

Different functions within each business unit have different roles in the asset life-cycle leading to a situation where no one group or function is responsible for optimizing total asset life-cycle cost. In addition, most asset management efforts are focused on Capital spending with minimal attention given to optimizing O&M, which is a key part of the asset life-cycle.

While significant effort is being made to develop and implement sophisticated tools to support Asset Management, there is a lack of formal Data Management and Governance processes and metrics to ensure that sufficient data of sufficient quality is available to use with those tools.

Performance Management at Hydro is currently focused more on compliance than on driving improvement with few metrics available to identify opportunities to continually improve the asset management system.

Key Recommendations

Formally acknowledge the CAM EC's role as the Asset Owner by designating it such with the authority to oversee and approve the development of asset management policy, objectives, risk tolerance, and financial constraints and communicating this role to the organization.

Provide communication on acceptable risk for Manitoba Hydro by defining a risk tolerance level for key strategic objectives, defining a corporate standard for risk assessment, and creating a corporate standard risk register. Establish a formal process to regularly review risks identified by the business units and provide direction as a result of the review.

Decide on and declare the Operating Model for Asset Management – roles, decision-making processes, goals and key performance indicators (KPIs), and the timetable for implementing these changes.

Formalize the Asset Manager and Service Provider roles and clarify accountabilities with regard to responsibilities within the key asset management processes. Group the functions focused on asset management to create a life-cycle orientation in decision-making. Create an Asset Strategist role with overall responsibility for the integrated Asset Life-cycle Strategy. Use this role to develop and document Life-cycle Strategy Plans for key asset classes to optimize total cost

Develop processes and implement tools to address Operations & Maintenance (O&M) spend and the trade-off between O&M and Capital in each business unit. Establish the preeminent role of the Asset Manager in making maintenance decisions, in terms of whether the maintenance is justified by cost versus benefit.

Develop a robust data governance structure to ensure data integrity and validity, and to enable effective data analysis for making asset-related decisions. Identify needed data to support asset management decision-making and assess where data repositories, data collection methodologies, data quality, etc. are out of alignment with needs.

Refine the current Performance Management framework to align asset objectives, plans and KPIs with performance reporting and accountability. Develop metrics for monitoring asset performance, asset management performance, and asset management system performance.

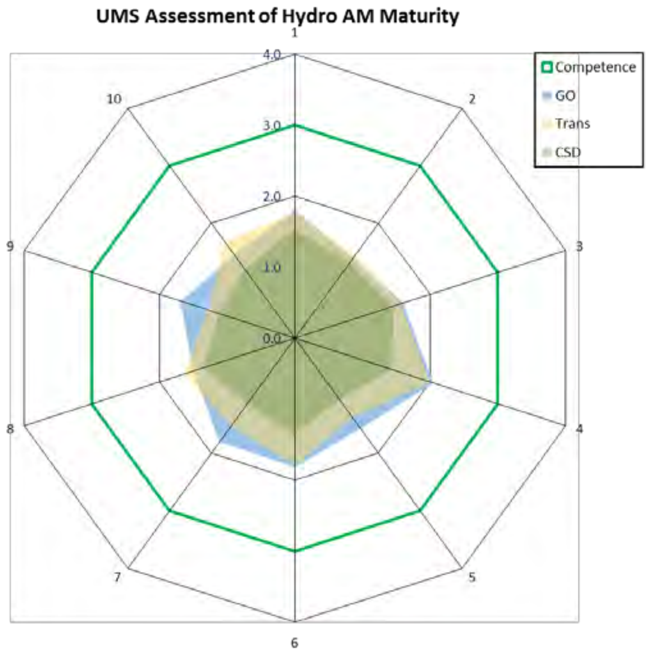
Develop controls and an internal review function for the asset management system to ensure corporate and business-unit level processes and procedures are being followed.

ASSESSMENT

Overall Assessment

UMS Group assessed Hydro against ISO 55000 and best practice asset management using a 0 to 4 scale where 0 = Innocence, 3 = Competence (in compliance with the standard) and 4 = Best Practice.

1	Context of the Organization
2	Leadership
3	Planning
4	Support
5	Operation
6	Improvement
7	Asset Life-Cycle & Risk Strategy
8	Investment Delivery Assurance
9	Performance Management
10	Data Management



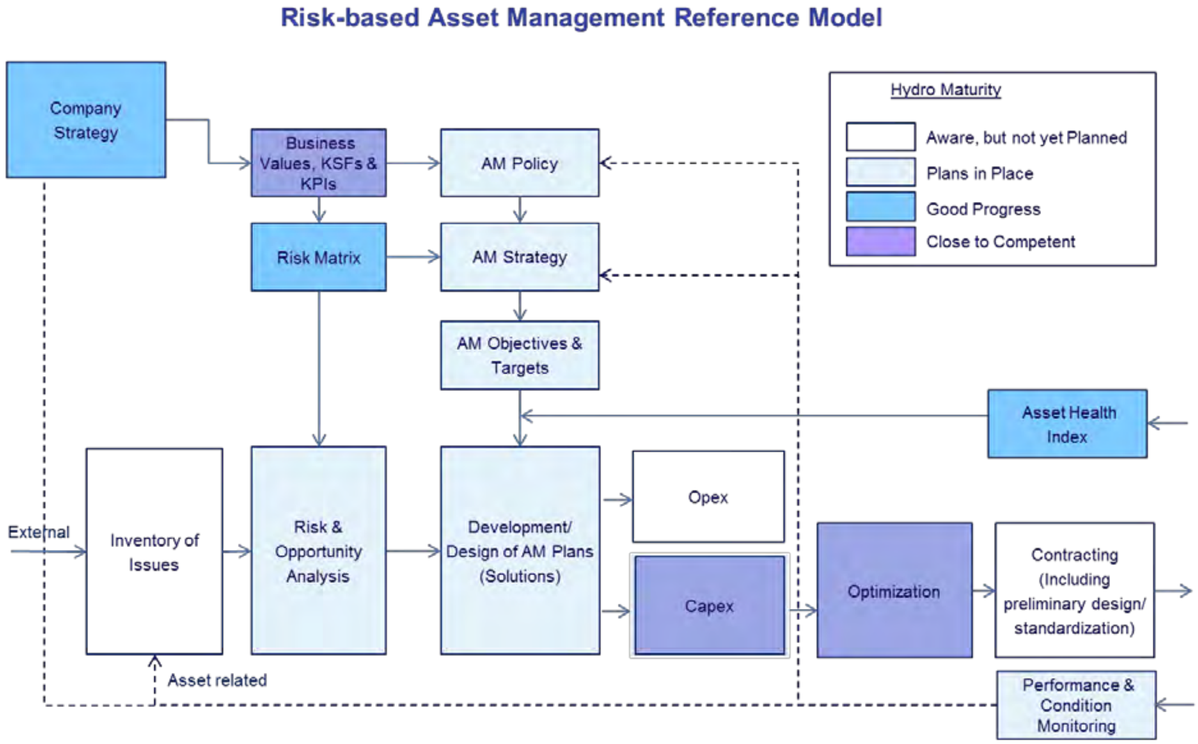
Overall, Hydro scored a 1.5 with the individual Business Unit Scores as follows: Generation Operations (GO) = 1.7, Transmission = 1.6, and Customer Service & Distribution (CS&D) = 1.3.

Each of the 10 domains evaluated has multiple components in which individual scores are averaged. These individual scores ranged from 0.5 to 3, so the averages reflect the fact that while Hydro is Competent in some areas (further described below), it also is missing some key components.

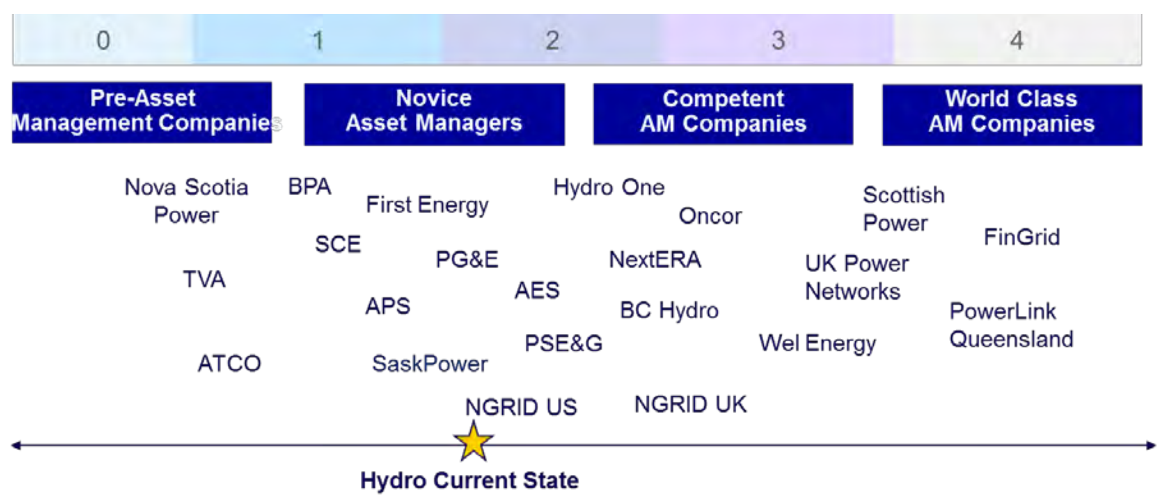
The recommendations provided in this assessment are those that are required to take Hydro to a 3 in every area, which would signify Competence with the ISO 55000 standard. Companies which reach this level, typically push forward towards Excellence (4.0) in a strategic manner where specific areas are targeted for improvement.

The specific level of competence to which Hydro should aspire is a matter for the Corporate Asset Management Executive Council (CAM EC) to determine. While, some of the benefits of Asset Management can be realized with a piecemeal approach, significant improvement only occurs when the entire Asset Management System is functioning at a high level.

The Chart below shows UMS Group's Reference Model for Asset Management. The colored boxes provide an indication of the level of maturity of specific

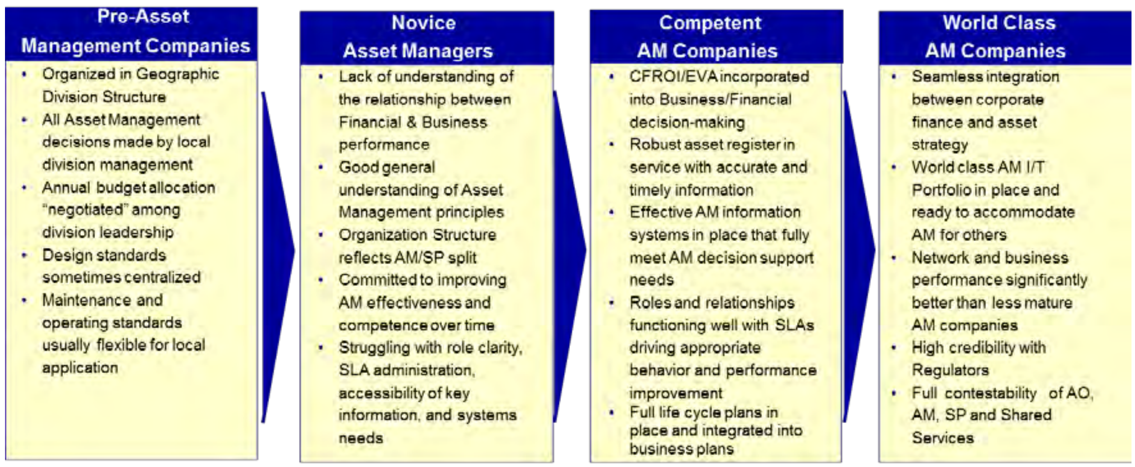


While its score may seem low compared to a competence standard of 3, it is important to realize that many North American utilities would rate a 0 (unaware of major Asset Management System requirements) or a 1 (aware of, but not yet developing). Overall, Manitoba Hydro compares favorably against North American utilities in terms of its Asset Management maturity level, largely as a result of recent progress made (e.g., Capital Investment Optimization-C55, CVF, Asset Health Indices (AHI), Reliability Centered Maintenance (RCM), Failure Curves, etc.).



Note: The above positions reflect UMS' opinion of the relative AM maturity of each company based on a range of source information.

North America lags global asset management best practice as embodied by utilities in Australia, New Zealand, UK, and Northern Europe who have been developing their asset management capabilities for more than two decades and are generally considered global best-in-class. Most North American utilities fall into the Pre-Asset Management or Novice Asset Manager classification. Hydro is on the cusp of moving from the Novice to Competent stage, a process which takes most companies 3-5 years.



As part of its assessment, UMS Group led each of the Business Units through a Self-Assessment of Asset Management Maturity (see Appendix A for details). The table below shows a comparison of the Hydro Self-Assessment scores for each Business Unit, along with the UMS Assessment scores.

	Hydro Self-Assessment			UMS Assessment		
	GO	Trans	CSD	GO	Trans	CSD
Context of the Organization	1.8	1.5	1.9	1.8	1.8	1.5
Leadership	1.8	1.3	1.6	1.4	1.4	1.3
Planning	1.8	1.8	1.3	1.6	1.6	1.5
Support	2.4	2.2	1.2	2.1	2.0	1.4
Operation	2.3	2.0	0.8	1.6	1.4	1.1
Improvement	1.9	2.1	0.8	1.8	1.8	1.4
Asset Life-Cycle & Risk Strategy	1.3	1.6	0.7	1.8	1.5	1.1
Investment Delivery Assurance	1.8	1.4	1.1	1.5	1.6	1.3
Performance Management	1.8	1.1	0.8	1.7	1.3	1.1
Data Management	1.4	1.9	1.0	1.5	1.7	1.2

Detailed Assessment

In its assessment, UMS Group identified a number of gaps in Hydro's Asset Management capabilities and developed recommendations for closing those gaps. These gaps and their corresponding recommendations have been grouped into seven major themes which provide a logical structure for understanding what best practice in that area looks like, what the gaps are for Hydro in that area, and how Hydro can close the gaps in that area. The themes are described below:

- Leadership – Addresses the elements of direction, oversight, and control which are needed to guide the development and operation of Asset Management System at Hydro
- Risk – Addresses the responsibilities of the Asset Owner to establish risk tolerance and standards for risk assessment for the company, as well as to review and direct the application of risk management by the Asset Manager.
- Roles and Responsibilities – Addresses the accountability model for the three key roles in the Asset Management System – Asset Owner, Asset Manager, Service Provider.
- Consolidation of Functions – Addresses the need for organization along process rather than functional lines, as well as the need for a bringing together all pieces of the asset management function to ensure a lifecycle focus on the assets.
- Lifecycle Optimization – Addresses the elements required to ensure that asset decisions are made based on total lifecycle costs. These elements include processes, data, and tools.
- Performance Management – Addresses the components of performance management needed to support asset management. These components include metrics on asset, asset management, and asset management system performance, as well as feedback loops to drive continuous improvement.
- Data and Technology – Addresses the systems and data requirements needed to support the Asset Management System, in addition to data governance and analytical capabilities.

The assessment detailed below is focused on a corporate level and cross-functional assessment. For the individual Business Unit assessments, please refer to Appendices C (Generation Operations), D (Transmission), and E (Customer Service & Distribution).

Leadership

Leadership throughout all levels and across all business units at Manitoba Hydro has been a substantive and critical element in the continuous development of the Asset Management system. Corporate Leadership has recognized the role that Asset Management can play in ensuring that scarce resources are optimally deployed and wishes to further leverage the already considerable progress Hydro has made in this area to achieve greater stability in financial and operational planning, more informed decision-making regarding investment in assets, and enhanced collaboration across the business units.

Best Practice
Leadership demonstrates leadership and commitment to asset management by:

- Ensuring that Asset Management Objectives, Policy, and Strategy are established and compatible with the organizational objectives
- Communicating the importance of effective Asset Management
- Promoting cross-functional collaboration within the organization and continual improvement

Leadership ensures that the responsibilities and authorities for relevant roles are assigned and communicated within the organization.

Leadership exercises control over the Asset Management system to ensure conformity and effectiveness and identify the need for corrective action.

Assessment of Hydro
Corporate Leadership has not formally communicated to the organization its role as the Asset Owner, nor yet provided the Business Units with concise direction on Policy, Strategy, and Objectives. The absence of of a clearly identified Asset Owner at Hydro has led to the Business Units (and sometimes the functions within the business units) operating on their own objectives and limits for making asset decisions, as well as created confusion as to who is being held accountable as the Asset Owner.

The Corporate Asset Management Executive Council will be an important permanent mechanism and is the natural nexus for the role of Asset Owner. It should be formally endowed with that responsibility as well as the task of translating the Business Strategy of the corporation into specific asset management goals and objectives each year.

Similarly, the Corporate Asset Management Steering Committee is an excellent multi-functional body and governance aid for driving Hydro's asset management transformation. Its existence should help channel and accelerate the progress made in Asset Management adoption in each of the three business units by assuring consistency and encouraging shared lessons learned and best practices. The membership is at the right level and has the right diversity to ensure that all required perspectives and capabilities are brought to bear on this significant set of challenges.

Key elements of a mature asset management system that should exist are missing from Hydro today. These include management system audits, controls, and performance metrics which Leadership can use to ensure the suitability, adequacy and effectiveness of the asset management system.

Hydro's assets are long-lived so decisions made today have repercussions decades into the future. The new leadership has yet to express its long-term vision for how it sees the energy industry changing over the next 10, 20, and 40 years, nor for the role that Hydro will play in the industry. Lack of this strategic direction will hamper the Business Unit's ability to develop effective asset strategies to achieve that vision.

Recommendations

1. Decide on and declare the Operating Model for Asset Management – structure, roles (i.e., responsibilities, authorities, accountabilities, internal & external relationships, etc.), decision-making processes, goals and key performance indicators (KPIs), and the timetable for implementing these changes. (Note: more detail is provided in the *Implementing an Operating Model* section below)

2. Formally acknowledge the CAM EC's role as the Asset Owner by communicating to the organization its role in overseeing and approving the development of asset management policy, objectives, risk tolerance, and financial constraints, as well as the responsibility for overseeing the development and update of the Corporate Asset Management Strategy. The Vice President of Strategy and Business Transformation should be added to the CAM EC roster and its charter clarified regarding the responsibility for setting the tolerance/limits that will drive asset-related decision-making. (Note: more detail is provided in the *Implementing an Operating Model* section below)

3. Change the focus of decision-making within the Business Units away from "being the best" towards meeting defined Asset Management Objectives in the most efficient way possible. This means assessing alternatives not solely on their performance or system impact, but also on the cost efficiency of their impact. It also implies an understanding that once an objective has been met, exceeding that objective is an inefficient use of resources that could be more productively applied elsewhere.

4. Develop a formal Asset Management Roadmap and Asset Management Strategy for Hydro. Not only would these documents assist in communicating Leadership's vision for asset management throughout the organization, but they would also provide a guide to ensure that the processes and tools being developed are effectively integrated.

5. Transition to a more competitive process for capital across the Business Units. With the implementation of Copperleaf C55 and the Corporate Value Framework (CVF, Hydro should be able to more directly compare the value of Generation, Transmission, and Distribution projects in terms of monetized risk reduction. While it would be impractical to make the entire capital budget competitive due to resourcing issues, these tools will provide the opportunity to set aside a portion of the budget for competitive projects. This portion should start small and grow over time in line with Management's comfort level with the results.

6. Once the asset management policy, vision and objectives have been clarified, develop and deliver a road show to communicate these changes and their implications for all groups across the organization.

Risk

Hydro is using risk to support its asset management decisions, mainly with regard to Capital Planning. The rigorousness of risk assessment and risk management varies both across the Business Units and within individual Business Units. In addition, risk is just beginning to be monetized (i.e., converted from qualitative impact to a quantitative cost) in most cases, although Generation Operations has been using risk of lost revenue to justify investments. No corporate level risk tolerance has been communicated leading to differing levels of risk avoidance driving decisions made in different parts of the business.

Best Practice

The Asset Owner has defined risk tolerance levels for the key strategic objectives and identified a minimum standard of risk assessment for the Asset Manager

The Asset Owner has established a formal process to regularly review and discuss risks identified by the Asset Manager, and to provide direction to guide decision-making.

A corporate standard and process exists for identifying risks, assessing them against risk tolerance levels, identifying mitigation actions, assigning ownership for mitigation, and tracking action on mitigation. This information is captured in a risk register.

Assessment of Hydro

Risk is a key basis for decision-making in best practice asset management systems. While Hydro is incorporating risk in its asset-related decisions today and implementing more sophisticated risk monetization tools (e.g., C55 / Corporate Value Framework), guidance on and attention to asset-related risk from Leadership has not been provided.

This lack of clear communication on an acceptable “risk tolerance” has led middle managers to use their individual perception of risk levels in the business to make decisions generally resulting in risk avoidance. This risk adverse posture may be too conservative and therefore push up the life-cycle cost of assets due to decisions on design, spares, and maintenance. These factors are targets of opportunity in moving to a more mature Asset Management System in which risk is proactively “managed” rather than “avoided.”

In Generation Operations (GO), outside of Dam Safety, minimal risk assessment is performed on assets. Without asset-level risk assessment, it’s difficult to determine which risks need to mitigated, what opportunities exist to accept more risk (i.e., current risk is below tolerance level), and what strategies should be adopted to manage risk. While GO capital planning processes use risk-based modeling to drive decisions, risk is essentially defined as lost revenue potential. Other types of risk (e.g., safety, environmental, etc.) are not monetized today; however, this should change with the implementation of the CVF.

In Transmission, only HVDC is currently performing risk assessments for their systems and developing mitigation strategies. However, no formal risk register or risk assessment process exists for assessing risk at the asset (rather than project) level for the other Transmission functions. Transmission has made a good start in terms of using risk and criticality in prioritizing projects through development of the System Reliability Risk Model (SRRM) and the Capital Budget Ranking Tool (CBRT). While the SRRM is a quantitative assessment of risk, the CBRT is largely based on a qualitative assessment of risk.

In general, Customer Service & Distribution (CSD) is relatively immature in the measurement and use of risk to drive decision-making. Risk assessment, in most cases, is qualitative and not quantitative. The CSD Business Plan does include a formal high level risk assessment on key threats to the system, and as part of its Asset Condition report, CS&D also has a Risk Evaluation Framework where the different types of risks have been identified, likelihoods developed and risks assessed for the major asset classes. However, this risk assessment is essentially qualitative, rather than quantitative, and does not monetize non-financial risks. Finally, while no risk register exists for electric distribution assets; there is one for gas assets.

Recommendations

7. Provide more oversight and communication on acceptable risk for Manitoba Hydro by defining a risk tolerance level for key strategic objectives, identifying a minimum standard of risk assessment for the business units, and establishing a formal process to regularly review risks identified by the business units and to provide direction as a result of the review.

8. Implement a corporate risk assessment methodology and a risk register addressing each key asset class to identify asset-specific risks, assess them against risk tolerance levels, determine which risks need to be mitigated, create mitigation actions, and track risk status and mitigation.

Roles and Responsibilities

Hydro lacks clarity around the various asset management roles mainly due to a lack of understanding of what the roles are and how they are intended to interact with each other. This lack of clarity has led to a diffusion of responsibilities resulting in a lack of accountability, as well as disagreement over whether some asset management related processes/procedures are rules or suggestions.

Best Practice

The organization has clearly delineated between the Asset Owner (AO), Asset Manager (AM), and Service Provider (SP).

The organization has defined the accompanying responsibilities, authorities, and accountabilities for each role.

Each part of the business understands and accepts the importance of its role in Asset Management.

Assessment of Hydro

The role of the CAM EC as the Asset Owner is not well understood within the organization. In addition, its responsibilities do not appear to be fully understood by all the CAM EC's members.

In each Business Unit, responsibilities for Asset Management are divided and/or unclear. There is a lack of understanding of what constitutes the Asset Manager and Service Provider roles and what the responsibilities and accountabilities of each are. This had led to an environment in which many asset management decisions tend to be made by committee/consensus. The result is that no one is ultimately accountable for the results.

Questionable clarity of goals and responsibilities for individual managers constrains the level of accountability that can be established and enforced. In addition, there is a lack of good practices for holding people accountable and imposing consequences for failure to meet performance targets. For example, measuring productivity across crews, etc. does not seem to be a priority.

Recommendations

9. Formalize the Asset Manager and Service Provider roles within each business unit and clarify accountabilities with regard to responsibilities within the key asset management processes. While the roles do not need to be identical within each business unit, they should be relatively consistent in accountabilities and relationships between key positions. (Note: more detail is provided in the *Implementing an Operating Model* section below)

Consolidation of Functions

The Asset Management functions within Hydro all exist within the business units, rather than at the corporate level. Within each business unit, the various functions are generally spread out among different groups, rather than in one department. In some cases, functions may be duplicated in different departments, to serve specific asset classes that department is responsible for.

Best Practice

The organization appoints (i.e., grants authority to) an owner for each decision and attaches full accountability for the results of the decisions made by that person.

Functional silos are broken apart and restructured into process and responsibility groups.

The organization considers the unique, environmental and political conditions in which it operates and evaluates the trade-offs in synergy and scale versus jurisdictional differences, regulatory drivers and operational uniqueness between functions.

Assessment of Hydro

Asset Management is fragmented across and within the Business Units and the nature in which these silos operate hinders standardization of processes (and systems) and limits the sharing of best practices. While the recent development of an Asset Management Governance Structure (CAM EC and CAM SC) is designed to help remedy this situation, a significant effort will be needed to overcome the existing culture (particularly at lower levels) in which functions and business units are focused primarily on their own interests and responsibilities, rather than those of the company in general.

The fragmentation of Asset Management has also resulted in a duplication of effort and inefficiencies as groups develop their own processes and tools rather than adopt (or modify) those already developed by other groups.

The use of steering committees to make decisions, is a good approach to speed agreement and strengthen ownership. But it will likely slow the rate at which Hydro can make major change in the organization, and will diminish the value Hydro will be able to extract from Asset Management. Compromise is the hallmark of steering committees and usually dilutes the power of resulting decisions. Best performing organizations tend toward decision-making systems that appoint (i.e., grant authority to) an owner for each decision, and attach full accountability for the results of the decisions made by that person.

Recommendations

10. Develop an organizational structure for Hydro which consolidates asset management functions to reduce redundancy and speed development of competency across the corporation. This can either be a centralized model with one Asset Management group serving all the business units, a decentralized model where each business unit has its own Asset Management group, or a hybrid model where some Asset Management functions are in a central group and others are in the business units. (Note: more detail is provided in the *Implementing an Operating Model* section below)

11. At either the Corporate or Business Unit level (depending on the model chosen), group the functions focused on asset management in a single group to create a life-cycle orientation in decision-making. Provide adequate resources to ensure that asset management processes can be successfully executed. (Note: more detail is provided in the *Implementing an Operating Model* section below)

Lifecycle Optimization

Hydro has few processes focused on life-cycle management or life-cycle optimization of the assets. What consideration is given to life-cycles is done in an ad hoc manner with no defined methodology or tools to support such analysis. Hampering Hydro's ability to address life-cycle costs is the fact that the various life-cycle processes are split into different functional groups within the business units. In addition, no single person or group has accountability for managing the assets' life-cycles.

Best Practice

The organization manages its assets with a view towards optimizing the total cost of the asset over its life-cycle.

The organization develops life-cycle strategies for each major asset class which detail how the life-cycle cost of the asset will be optimized while meeting the AM objectives

The organization has an Asset Strategist function which is responsible for the development of the Asset Management Plans for key asset classes

The organization utilizes asset condition data and the probability of failure to drive decision-making about use of sustaining capital.

Assessment of Hydro

There is no assigned accountability for addressing the full asset life-cycle. As different functions within each business unit have different roles in the asset life-cycle (i.e., specifications, procurement, spares, design, construction, operation, maintenance, replacement), decisions are being made to optimize only that part of the life-cycle, resulting in sub-optimization over the total asset life-cycle.

The financial focus of asset management at Hydro is on Capital spending, with minimal attention given to optimizing O&M (i.e., are we doing the right work, are we working efficiently, do we have the right resource mix, etc). This has led to a dearth of processes and tools to support effective decision-making around O&M expenditures, as well as weak productivity management. As operations and maintenance decisions have significant impacts on asset life, life-cycle optimization requires these functions to be managed with the same rigor as capital.

Asset Life-Cycle Plans have not yet been developed for each asset class. This has resulted in the lack of integrated strategies intended to optimize total life-cycle costs. As no clear accountability for Asset Life-cycle Strategy has been assigned, the current ability to generate these plans is questionable.

A relatively advanced Maintenance Engineering function exists with skills (Reliability Centered Maintenance (RCM), Root Cause Analysis (RCA), Preventive Maintenance (PM) Optimization, etc.) which will provide a solid foundation for developing Asset Life-cycle Strategies moving forward. Transmission Apparatus' RCM program is one of the most advanced that we've seen in a North American utility.

In addition, fairly comprehensive condition/inspection strategies and lifecycle approaches have been developed for some critical asset classes. While not full scope life-cycle strategies, these strategies are a step in the right direction.

While capital planning and maintenance planning processes are both strong, they are not integrated so it's difficult to optimize or even understand lifecycle costs when making capital planning decisions, or to trade-off maintenance/capital alternative solutions.

Recommendations

12. Develop and document Life-cycle Strategy Plans (also referred to as an Asset Management Plan in ISO 55000) for the key asset classes, which detail the assets and their current state, evaluate the trade-offs among Asset Management Objectives (including risk), and define an integrated strategy to be followed to optimize life-cycle costs in each area of the asset life-cycle (design, procurement, construction, operation, maintenance, replacement/retirement).

13. Review existing design specifications and maintenance plans with an eye towards life-cycle optimization. Challenge overly conservative, risk adverse standards, and consider varying application based on criticality, age, condition, etc.

14. Create an Asset Strategist with overall responsibility for the integrated Asset Life-cycle Strategy of specific asset classes. This role can be direct in the form of a person who develops the life-cycle strategy with his/her team or indirect in which a person facilitates the integration of content from the various organizations/functions.

15. Develop processes and implement tools to address O&M spend and the trade-off between O&M and Capital in each business unit. This would include establishing the preeminent role of the Asset Manager in making maintenance decisions, modeling the cost/benefit of different maintenance strategies, assessing the value of corrective maintenance vs replacement, and identifying innovative tools and practices for improving maintenance efficiency/effectiveness.

16. Integrate O&M into the existing processes used for optimizing capital spend. This would include using concepts like Asset Health Indices (AHIs), failure probability, and consequence of failure to drive maintenance decisions.

17. Increase the capabilities of processes and tools to enable assessment of the assets as a group. While this type of analysis is performed manually today, existing processes and tools should be adapted to support these analyses. For example, GO shouldn't just consider whether to refurbish a specific unit, but also whether it makes economic sense to maintain smaller and less economic hydro facilities and the dams that support them.

18. Where they don't exist today establish AHIs for all key assets and transition from technical life serving as the basis for driving replacement, to economic life driving such decisions. To the extent possible, AHIs should be based on condition data and failure curves should be based on actual failures experienced at Hydro.

Performance Management

Hydro currently has a performance management framework that is focused on ensuring that work was performed, rather than on identifying opportunities for improvement. In addition, few metrics exist to measure asset management performance or asset management system performance. There is no formal link between asset metrics and investments, so Hydro is unable to ensure that its investments are delivering the benefits promised.

Best Practice

The organization has a set of processes for consistently identifying and implementing continuous sustainable improvements across the business. A framework aligns asset objectives, plans and Key Performance Indicators with performance reporting and accountability, and drives a balance between leading and trailing operational indicators.

There are controls and an internal review function for processes to ensure they are being followed. Additionally, performance metrics are line-of-sight to ensure continuity in performance evaluation and corrective planning.

To assure that investments are meeting their objectives, there is a robust process which ensures that approved investments are delivering the benefits that they are expected to provide. In addition, the performance management framework which supports this Investment Delivery Assurance process tracks budget performance and asset management performance.

Assessment of Hydro

Performance Management at Hydro is currently focused mainly on compliance, with inadequate attention paid to driving improvement. Metrics are designed to ensure work was performed on time and that reliability/availability/safety targets were met, essentially ensuring compliance with processes and procedures. However, they do not provide the degree of insight needed to identify opportunities to continually improve the asset management system.

While a Transmission Asset Strategies function has also been created to propagate best practices across the functions and try to drive consistency across processes within the Business Unit, there is no organized process for identifying asset management best practices/ processes/tools, assessing their effectiveness, and implementing them across the business units. While individuals are participating in industry groups, attending technical conferences, and meeting with vendors, greater efficiency can be achieved with a defined process and assigned roles and responsibilities. Within best practice Asset Management organizations, this process is typically called “Industry Intelligence” and includes benchmarking, new technology monitoring, industry outreach, etc.

Performance metrics are focused mainly on reliability/availability, rather than cost efficiency, making them most effective at monitoring work rather than driving improvement. No metrics exist to measure workforce productivity, work management effectiveness, work quality, etc. Asset performance is measured at the aggregate level rather than at the asset class level and does not tie performance results back to initiatives (i.e., maintenance or replacement) to measure and assure the capture of benefits.

Recommendations

19. Develop controls and an internal review function for the asset management system to ensure corporate level and business-unit level processes and procedures are being followed. The review process should both address the sufficiency of the controls and identify any process issues that may require corrective action.

20. Improve performance accountability by refining the current Performance Management framework to align asset objectives, plans and KPIs with performance reporting and accountability, and drive a balance between leading and trailing operational indicators. Develop metrics for monitoring asset performance, asset management performance, and asset management system performance. While these metrics will differ

somewhat by business unit, they should be consistent in the type of performance they measure.

21. Create a Resource Optimization capability to measure and assure workforce operational effectiveness, efficiency/productivity, and appropriate staffing levels for each business unit and functional groupings within.

22. Create an Investment Delivery Assurance process that tracks execution of approved investments to ensure they are completed, assesses if they are delivering the benefits anticipated, prioritizes work in alignment with business objectives, exercises (or ensures) quality control / quality assurance oversight of work, and drives continuous improvement by the Service Provider.

23. Define and implement a corporate-wide process for identifying and sharing Asset Management best practices. This function would be responsible for identifying best practices in processes, tools, practices, etc. within the Business Units or from outside Hydro, sharing them, and assisting the Business Units in connecting with the right personnel to drive assessment and implementation. This role would be best performed by a corporate level entity, but could also be performed by a team made up of representatives from each business unit.

Data and Technology

Hydro currently lacks formal structures and processes around Data Governance and Data Management. Data quality varies greatly between and within the Business Units with the main driver for quality being use of the data (i.e., data not currently used tends not to be as good quality as that being used). As each Business Unit has developed their own Asset Management/Maintenance Management technology, there is a variety of systems in use with varying capabilities. While some of the systems, such as RMS, have advanced capabilities and perform as well or better than packaged software, the existence of multiple systems performing the same function implies a duplication of effort and inefficient use of resources.

Best Practice

Appropriate enabling technology has been implemented to support the decision making process by providing timely, accurate, accessible data along with tools to support the asset management analyses that need to be performed.

The organization has a data governance structure which ensures data integrity and validity to enable effective data analysis for making asset-related decisions.

There are defined processes for resolving data issues and performance metrics around data quality, consistency and availability.

The organization has a Data Architecture and Asset Register which supports condition, failure, and performance data for assets.

The organization utilizes technology to automate data collection and minimize errors.

Assessment of Hydro

There is no formal Data Governance structure or accountability for Data Quality within the Hydro business units. While efforts are being made to improve and assure data quality within the business units, formal processes and metrics still need some improvement.

Significant effort is being made to develop and implement sophisticated tools for calculating Asset Health Indices (AHIs), determine probability of failure, perform economic modeling, etc. However, it doesn't appear that sufficient condition data currently exists to support these tools on a wide-scale basis.

Current analytical processes and tools to support decision-making using "big data" are rudimentary. This lack of tools has resulted in large condition data sets (i.e., vibration analysis) not being leveraged to the extent possible due to lack of resources to perform unaided, manual analysis.

Different tools and methodologies are being used for key asset management processes. While these tools work well for their intended purpose, this replication of functionality hinders the ability to drive consistent practices across the business unit and is likely an inefficient use of resources.

While some of the Business Units have developed Asset Management Roadmaps/Strategies to guide the development of tools needed to support asset management, there is no such corporate plan to guide efforts or set boundaries for which decisions can be made at the Business Unit level and which at the Corporate level.

The role of Information Technology (IT) in supporting Asset Management is not well-defined in terms of whether it is a control function or support for the Business Units. This has led to a lack of clarity around IT decision-making and been a contributing factor to the number of different systems performing duplicate functions. Hydro has also not set a corporate standard of preference for large, permanent IT solutions that provide consistency and consolidation versus smaller, more flexible approaches which may be less expensive and quicker to implement, but lack integration and may duplicate functionality.

Recommendations

24. Develop a robust Data Governance structure to ensure data integrity and validity, and to enable effective data analysis for making asset-related decisions. The Data Governance structure should have a cross-functional steering group, assigned data stewards in each business unit, clear roles/responsibilities/accountabilities, a defined process for resolving data issues, and performance metrics reported and trended for data quality, consistency and availability.

25. Perform a Data Inventory and Gap Assessment to identify needed data to support asset management decision-making and assess where data repositories, data collection methodologies, data quality, etc. are out of alignment with needs. This will differ by business unit as each has differing levels of data quality. Assess the cost of

collecting needed data vs. the benefit of the data as a precursor to developing a plan to close gaps.

26. Improve AHIs by using more objective, rather than subjective, data; using multi-variate regression to determine weightings, and including failure multipliers (i.e., manufacturer, vintage, operating hours, etc.) as part of the algorithms.

27. Develop a plan/roadmap for improving analytical capabilities to support asset management decision-making using large data sets. The focus should be on moving away from using generic data or averages to support decisions to using very specific data to get to a greater level of granularity. This will likely require new tools as well as new skill sets and perhaps new resources (i.e., data scientists / data analysts).

28. Improve data quality by ensuring that the Field/Plant understands what the data will be used for, highlighting the importance of the data to decision-making, and providing aids to assist in providing good quality data (e.g., examples of degradation/failures, drop-down lists / check boxes, etc.)

IMPLEMENTING AN OPERATING MODEL

In the Assessment above, the first recommendation made is for Hydro to decide on and declare the Operating Model for Asset Management. Asset Management has grown organically at Hydro without a defined Operating Model. This has led to confusion over roles and responsibilities, duplication of efforts, and key gaps in capabilities. While the recommendations above are not listed in priority order (instead they are listed by theme), the Operating Model is important because it defines the key components by which Asset Management will be used to deliver value to its stakeholders. Furthermore, creation of the Operating Model, if done in a collaborative manner, helps build alignment among the Executive Team on the key components – Organization Structure, Roles and Responsibilities, Process Ownership, and Accountability.

Organization Structure

Hydro's current organization structure, with split accountabilities and responsibility for asset management functions diffused throughout the business units, does not provide the optimal platform for enhancing its Asset Management maturity. As identified in the gap assessment, there is significant value in consolidation and reorganization.

There are a number of variations in organization structure used for the Asset Management process model today as multiple approaches to organization can be implemented to successfully manage the business. Typically, the structural variations in organization revolve around the following:

- Where the asset management organization reports within the business
- The level of centralization/decentralization within the Asset Management organization
- The number and focus of groups within the Asset Management organization itself

Various combinations of these can be found within utilities today and competent Asset Management can be performed in a variety of structures as long as roles and responsibilities are clearly defined and processes are in place to support the key asset management functions. Therefore, organization structure decisions are typically driven by existing constraints, culture, and the relative priority of objectives. For example, if resources are constrained or consistency is a key priority, then a centralized model may make more sense. If a premium is placed on keeping close alignment between Asset Management and the Field or there is a desire to identify Best Practices by trialing different methodologies/tools, a decentralized model might be preferred

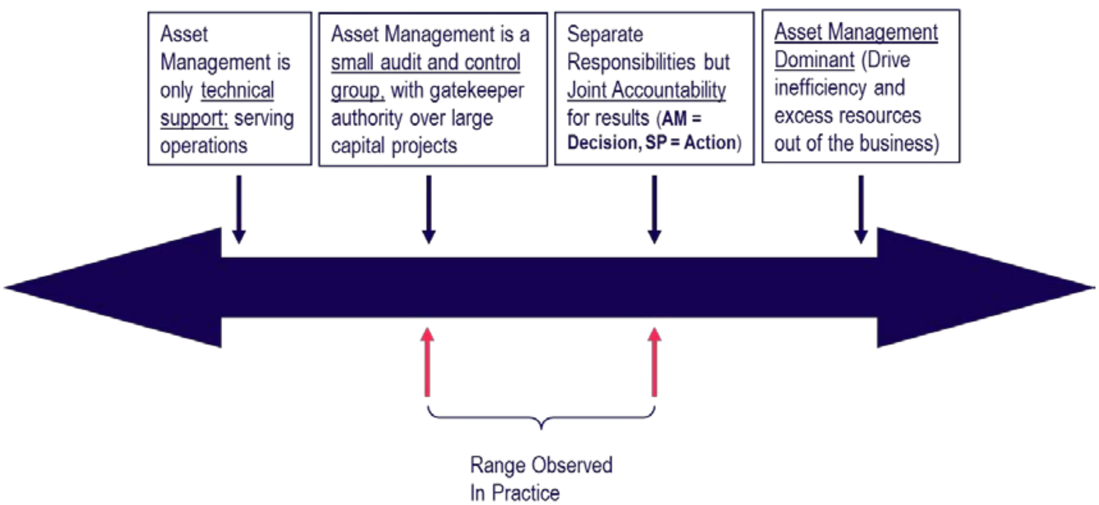
There are also variations in the split of activities between Asset Management and the Service Provider (i.e., the Plant or Field force). These typically occur in the following areas:

- Outage planning and management
- Outsourcing / Contractor Management

- Work planning and scheduling
- Equipment performance management
- Maintenance standards and program design

As with organization structure, the split of activities varies among companies. The key factor is that regardless of the split, Asset Management should have Governance and Oversight of these activities. As long as the oversight is in place, where the actual performance of the activity occurs should not have a significant impact on outcome.

Finally, there are variations in the relationship and degree of separation between the Asset Management group and the Service Provider. These range from "one side dominant" to "balance and partnership." This division is usually driven from historical relationships and authority bases. Getting this relationship correct is a significant element in making the organization work in the Asset Management process model. As with organization structure, the decision where to set this point on the continuum is dependent on the corporation's culture, management style, and objectives.



With regard to the organization itself, there are three main alternatives for an organization seeking to align its structure with best practice Asset Management – Centralized, Decentralized, and Hybrid.

In the Centralized model, there is one corporate Asset Management group which houses all the Asset Manager functions. Typically this group is led by an Executive at the same level of the leaders of the Business Units to ensure it has equal standing in corporate decision-making. The advantages of the Centralized model are as follows:

- Asset Management sponsorship by an Executive with a strong mandate from the CEO and Board can accelerate competence development
- Moving asset strategy decisions from the functional organizations into a central Asset Management group may increase ability to embrace bolder changes
- Provides more consistency in risk management, asset lifecycle strategies, and how tradeoffs are made between Capital and O&M

- Startup cost for new tools and skills development are likely to be lower

The disadvantages of the Centralized model are as follows:

- Requires one additional Executive position
- There is a risk that culture change across the organization may be less sustainable
- Functional Vice Presidents and Division Managers may be less supportive of Asset Management
- Loss of stature among functional managers may raise resistance to Asset Management
- Central group focus on highest leverage areas may disenfranchise and leave other groups behind
- Can lead to misalignment among the executive team and require more direct involvement of the CEO

In the Decentralized model, there is an Asset Management group which houses all the Asset Manager functions within each Business Unit. The advantages of the Decentralized model are as follows:

- Provides a single point of accountability for operating and business results within each Business Unit
- Enables the ability to customize Asset Management solutions to the specific assets within each business unit
- Asset Management sponsorship by functional Vice Presidents can have a larger impact on culture change than a "central program"
- Leveraging lessons learned across three separate Asset Management groups can help accelerate progress

The disadvantages of the Decentralized model are as follows:

- There is a risk of different standards for risk management, asset lifecycle strategies, and tradeoffs between OPEX and CAPEX being adopted across the Company
- Typically takes longer to drive sustainable culture change across the organization
- If Asset Management advocacy by the functional Vice Presidents is tepid, can dramatically reduce the likelihood of success
- Requires more total resources and startup cost for new tools and skills development is likely to be higher

In the Hybrid model, there is a central Asset Management group which houses some of the Asset Manager functions, while others are within each Business Unit. The advantages of the Hybrid model are as follows:

- Supports a more consistent approach than the Decentralized model while also supporting a greater degree of business unit asset strategy customization than the Centralized model
- Reduces some of the duplication of effort found in decentralized structures
- Provides more control over processes that requires greater corporate oversight
- More likely to generate support from functional Vice Presidents than Centralized model
- Having the Asset Strategy function close to the Field (i.e., under the functional Vice Presidents) is more likely to generate support and alignment from Field for Service Provider role

The disadvantages of the Hybrid model are as follows:

- More resource intensive than either the centralized or decentralized model
- Can lead to differing levels of competence in the Functional Areas
- Can lead to confusion on accountability for areas of joint responsibility
- May generate disagreements over "boundaries" between Central group and Decentralized groups

UMS Group believes that any of these models could work for Hydro; however, each comes with its own challenges. The Centralized model would be the most efficient in terms of resource use and would provide the most consistent application of Asset Management. However, it would also likely be the least effective in driving the culture change needed in the Field/Plants to successfully achieve a high level of performance.

The Decentralized model would be the easiest to implement as Asset Management functions are already in the business units today and the close link that already exists between these functions and the field would speed culture change. However, decentralization will require more resources overall and will also require additional effort to ensure consistency.

The hybrid model is a trade-off between these two. By consolidating Asset Management governance and key functions where consistency is most important, Hydro can drive faster change throughout the organization, yet still keep a close connection with the Field in functions like Maintenance Engineering and Life-Cycle Strategy. However, this is likely to be the most resource intensive model and runs the risk of confusion / loss of accountability over results.

Rather than recommend that Hydro adopt a specific model, UMS Group views its role as assisting Leadership in understanding the pros and cons of the different alternatives and facilitating a discussion of which structure makes the most sense for Hydro given its current situation and strategic objectives.

Roles and Responsibilities

Developing an Operating Model will require defining the roles and responsibilities of the Asset Owner, Asset Manager, and Service Provider, as well as designating who in the organization will fulfill these roles.

The Asset Owner's role should be to translate stakeholder needs & objectives into Asset Management business values, critical success factors and key performance indicators. The CAM EC is well positioned to fill this role and should be declared the Asset Owner, with the inclusion of the Vice President of Strategy and Business Transformation as part of this group.

The Asset Manager's role should be to translate the Asset Management business values, critical success factors and key performance indicators into asset investment and maintenance strategies and plans in keeping with the Asset Owner's capital and operating cost constraints and risk tolerance. Specifically, the Asset Manager should:

- Manage and monitor assets
  - Develop and maintain asset register
  - Monitor asset conditions
  - Develop preventive maintenance and diagnostic programs
  - Optimize PM plans based on asset condition and diagnostic program results
- Develop asset strategies and plans
  - Convert owner's needs and objectives into an asset management plan
  - Develop business cases for investments and retirements against a consistent standard
  - Prioritize asset investments given Asset Owner's capital resources and strategy
  - Develop asset life-cycle plans and risk strategies
  - Manage capital projects
- Manage service provider use of assets
  - Provide budgets to Service Provider for routine maintenance and investments
  - Define annual work program and maintenance strategy/standards
  - Monitor and manage service provider performance via Service Level Agreements (SLAs)
  - Define requirements for Service Provider reporting on asset condition
  - Respond to Service Provider's issues with assets

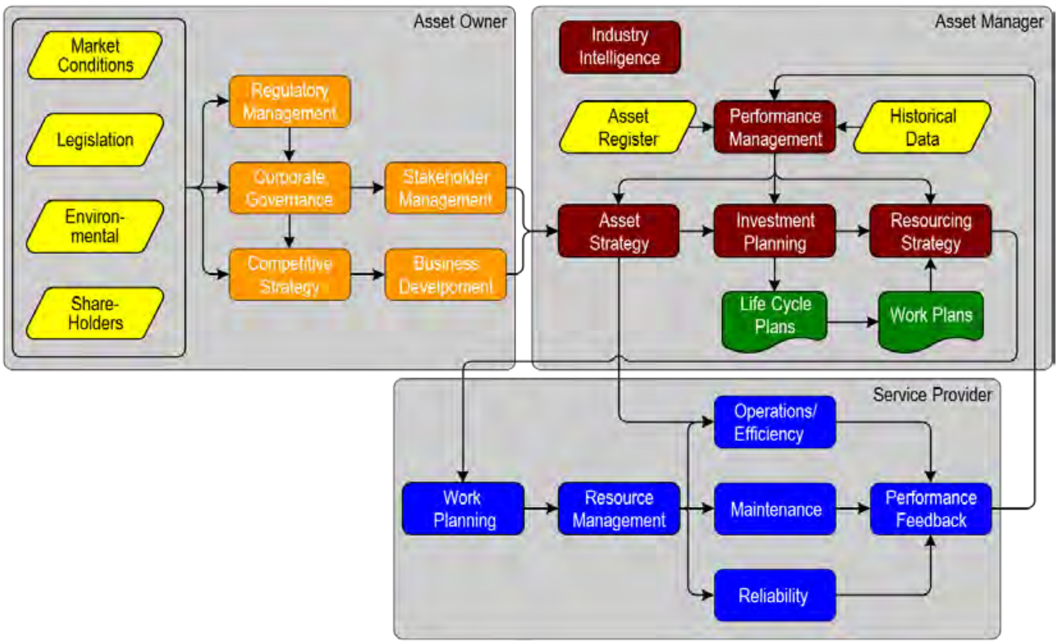
The Service Provider's role should be to operate and maintain the assets in order to achieve the Asset Owner's critical success factors and key performance indicators and within specifications, operating limits, maintenance standards and asset plans set by the Asset Manager. Specifically, the Service Provider should:

- Operate the asset
  - Deliver performance results to the Asset Manager per SLA
  - Operate the assets within specified limits
  - Provide Asset Manager with operational performance data
- Maintain the asset
  - Maintain the assets per the Asset Manager's maintenance plan
  - Provide condition information to the Asset Manager
  - Provide maintenance history and failure analysis data
- Drive continuous improvement
  - Provide recommendations to the Asset Manager and Asset Owner to improve performance and reduce operating costs
  - Manage plant/field work activities to produce results
  - Manage plant/field resources, knowledge and capabilities
  - Drive continuous improvement in safety, productivity, etc.

Identification of which groups/functions should perform which roles is dependent on the decisions made around organization structure. The Maintenance Engineering groups seem to have many of the competencies needed to develop asset life-cycle strategies and would seem to be the natural center for the Asset Manager role.

Process Ownership

As part of defining the Operating Model, there is also a need to ensure that processes are assigned consistent with roles and accountabilities. The Asset Manager has five major processes to perform: Asset and Risk Strategy, Investment Planning, Resourcing Strategy, Performance Management, and Industry Intelligence.



The organization structure which Hydro selects will drive the necessity for having common process ownership in these areas. If a centralized model is chosen, then there will only be one owner for each of these processes and responsibilities will be clear. If a decentralized model is chosen, then for processes which are owned by groups within the business units where consistency is a requirement (e.g., investment planning), Hydro will need to institute common process ownership. This process ownership could be performed by a central group, as in the hybrid model which has a central process owner and decentralized process executors.

Absent a central group to serve as a common process owner, a committee could be used. However, as noted in the gap assessment, management by committee is fraught with difficulties often resulting in compromises, rather than the best solution. In addition, committees are difficult to hold accountable for results, so Hydro should try to avoid this solution if possible.

Authority Model

One of the results of Hydro's current asset management structure is that there is a general lack of accountability for results. Because there is no one group or function with complete responsibility for the assets, there is no one directly accountable for results.

Whether or not Hydro decides to modify its organization structure for Asset Management, it should ensure that accountability for results is clearly defined in the authority model. In addition, the model should focus on establishing behavioral norms biased towards speed of decision making and coordination of action, as well as focusing on improvement rather than just measurement.

A good practice which Hydro should consider implementing is RACI charts for the Asset Management processes (see example chart below). These charts identify the key elements of the process, as well as the functions/personnel involved in the process. Each element and function is charted as either being **R**esponsible, **A**ccountable, **C**onsulted, or **I**nformed. The act of producing these charts requires thought about the Authority Model, identifies unclear or overlapping responsibility/accountability, and provides a tool for communicating roles throughout the organization.

Capital Specifics & IP BLANKETS	Asset Strategy	Investment Delivery Assurance	Transmission Engineering	Distribution Engineering	Substation Engineering	Protection & Telecom Engineering	OH/UG Construction	SPT Construction	Project Management	Project Controls	Procurement / T&D Services	External Affairs	Construction Permitting	Environmental Permitting	Safety	ESO / Operations	Planning, Surveying, Legal
Initiation of Project / Task	R/A		C	C	C	C			C	I							
Development of Budget	C		R	R	R	R	C	C	A	A	C	C	C	C			
Specifics Work Plan	C	R	C	C	C	C	C	C	R/A	R	C	C	C	C	C		C
Blankets Work Plan	C	R	C	C	C	C	C	C	R/A	R	C	C	C	C	C		C
Integrated Work Plan	C	R/A	C	C	C	C	C	C	C	R	C	C	C	C	C		C
Design Scheduling			R	R	R	R	I	I	A	R							
Engineering Design		I	R	R	R	R	I	I	A		I	I	I	I	I	I	I
Construction Permitting	C						I	I	R/A								C
Environmental Permitting							I	I	A				R	R			C
Resource Management	C	C					C	C	R/A	C							
Day-to-Day Construction Scheduling		C					R/C	R/C	C/A								
Create Bill of Material (BOM) / Work Order			R	R	R	R	C	C	A								
Warehousing Materials Management							C	C	A	C	R/A						
Construction							R[1]	R[1]	A	I	I	C	C	C	C	C	C
Construction Management (Outside Contractors)									R/A	C							
Management of in-house crews							R	R	A	C							
Cost and Schedule Forecasting	C	I	C	C	C	C	C	C	A	R	C	C	C	C	C	C	C
Cost and Schedule Tracking	C	I	C	C	C	C	C	C	A	R	C	C	C	C	C	C	C
Stakeholder Engagement & Management			C	C	C	C	C	C	R/A[2]	R	I	R/A[2]		C		C	C
Clearance Scheduling & Management							I	I	A							R	
Scope Change Management	C	I	C	C	C	C	I	I	R/A	I	I	I	I	I	I	I	I
Schedule Management	R	C	C	C	C	C	C	C	A	R							
Project Reporting			C	C	C	C	C	C	A	R							
Risk Management									A	R/A			C	C	C		C
Maintain Action Item List									R/A								
Closeout	R	I							A	R							
Performance Management	R[3]/A	I	C	C	C	C	C	C	R[3]	R[3]	C	C	C	C	C	C	C

[1] Inside plant for SPT construction v/s outside plant for OH/UG construction
[2] PM R/A for internal and external affairs for external stakeholders
[3] AM responsible for portfolio/program level, PM/controls for project level

Responsible: The person who does the work to achieve the task. They have responsibility for getting the work done or decision made. As a rule this is one person; examples might be a business analyst, application developer or technical architect.

Accountable: The person who is accountable for the correct and thorough completion of the task. This must be one person and is often the project executive or project sponsor. This is the role that responsible is accountable to and approves their work.

Consulted: The people who provide information for the project and with whom there is two-way communication. This is usually several people, often subject matter experts.

Informed: The people who are kept informed about progress and with whom there is one-way communication. These are people that are affected by the outcome of the tasks so need to be kept up-to-date.

CLOSING THE GAPS

Benefits from Closing the Gaps

UMS Group has identified a series of recommendation to close the gaps identified in the report. While all of these recommendations are intended to assist Hydro in improving its Asset Management capabilities, some will have a greater impact than others. The table below lists all recommendations and summarizes the benefits that Hydro can expect to achieve from each.

Number	Area	Recommendation	Benefit
1	Leadership	Decide on and declare the Operating Model for Asset Management	Drive alignment on roles and set expectations for achieving progress on improving Asset Management capabilities
2	Leadership	Formally acknowledge the CAM EC's role as the Asset Owner	Provide clarity on who is responsible for setting the parameters for Asset Management, as well as set the specific limits to bound decision-making
3	Leadership	Change the focus of decision-making away from "being the best" towards cost efficient satisfaction of objectives	Re-align culture to focus on understanding the parameters around optimization and making decisions to meet, but not exceed those parameters
4	Leadership	Develop a formal Asset Management roadmap and Asset Management Strategy	Create alignment around and provide direction to personnel on improving AM competency, as well as accelerating development of capabilities through a timetable and defined plan
5	Leadership	Transition to a more competitive process for capital across the Business Units	Maximize corporate value by increasing optimization of capital spend
6	Leadership	Develop and deliver a road show to communicate changes	Signify to the organization the importance of asset management and demonstrate Leadership's commitment to it
7	Risk	Define a risk tolerance level and establish a formal process to regularly review risks	Provide direction to the Business Units to enable them to optimize on meeting risk tolerance levels, rather than overinvesting in risk avoidance
8	Risk	Implement a risk assessment methodology and a risk register	Provide Leadership with the ability to measure and manage risk and provide the Business Units with direction to guide their decision-making
9	Roles and Responsibilities	Formalize the Asset Manager and Service Provider roles within each business unit and clarify accountabilities	Create understanding and alignment on accountability for asset and risk management decisions. Assists in building organizational alignment - vertically and and horizontally for shifts in traditional roles and authorities.
10	Consolidation of Functions	Develop an organizational structure which consolidates asset management functions	Reduce duplication of effort, eliminate inefficiencies, and drive a more consistent application of processes and tools

Number	Area	Recommendation	Benefit
11	Consolidation of Functions	Group the functions focused on asset management under a single group	Enhance ability to implement a life-cycle orientation and clarify responsibility for decision-making.
12	Lifecycle Optimization	Develop and document Life-cycle Strategy Plans for the key asset classes	Provide platform for addressing and optimizing costs across the asset's life-cycle. Ensure all parts of the organization understand the strategy for the asset.
13	Lifecycle Optimization	Review existing design specifications and maintenance plans with an eye towards life-cycle optimization.	Target spending to achieve the greatest impact on meeting objectives and avoid overspending outside risk tolerance
14	Lifecycle Optimization	Create an Asset Strategist role with overall responsibility for the integrated Asset Life-Cycle Strategy	Provide a single point of accountability for asset life-cycle decisions and ensure a coordinated approach to optimizing across the various life-cycle components
15	Lifecycle Optimization	Develop processes and implement tools to address O&M spend and the trade-off between O&M and Capital.	Provide capability to optimize O&M spend (both life-cycle cost and trade-off with Capital) and ensure clarity around role of Asset Management in making maintenance decisions
16	Lifecycle Optimization	Integrate O&M into the existing processes used for optimizing Capital spend	Optimize O&M spend in terms of efficiency and effectiveness.
17	Lifecycle Optimization	Improve processes and tools to enable assessment of assets as a group	Allow for programmatic analysis above the individual asset level and support optimization at a unit, station or system level
18	Lifecycle Optimization	Establish AHIs for all key assets and transition to economic life to drive decisions	Enable application of monetized risk assessment to large volumes of assets in a consistent and programmatic manner
19	Performance Management	Develop controls and an internal review function for the asset management system	Provide assurance to Leadership on the performance of the asset management system and identify need for corrective action
20	Performance Management	Refine the current Performance Management framework	Focus performance management on continuous improvement to enable increasing efficiency and better asset and asset management performance
21	Performance Management	Create a Resource Optimization capability	Assure workforce operational effectiveness, efficiency, and productivity and identify improvement opportunities
22	Performance Management	Create an Investment Delivery Assurance process	Ensure that approved investments are delivering the benefits that they are expected to provide and drive continuous improvement
23	Performance Management	Define a corporate-wide process for identifying and sharing best practices	Accelerate the Asset Management maturation process and increase the efficiency with which practices and processes are implemented
24	Data and Technology	Develop a robust data governance structure to ensure data integrity and validity	Ensure data integrity and validity and enable effective data analysis for making asset-related decisions
25	Data and Technology	Perform a Data Inventory and Gap Assessment	Provide a framework for developing and applying data standards, as well as for resolving data issues

Number	Area	Recommendation	Benefit
26	Data and Technology	Improve AHI algorithms to be more objective	Make decisions more data-driven improving transparency and accuracy of forecasts
27	Data and Technology	Develop a plan/roadmap for improving Operational Analytic capabilities	Improve decision-making by leveraging big data to get a more granular understanding of condition, failures, and system drivers
28	Data and Technology	Improve data quality through better communication with the Field/Plant	Improve data quality at the source to increase accuracy of data-driven decisions

Prioritizing the Recommendations

At the highest level, the recommendations fit into one of four categories along a continuum of driving performance improvement. There is a logical flow along the continuum, and while exceptions can be made, careful thought should be given to the impact of skipping a step. The categories are as follows:

- Create the Right Environment – These are recommendations which set the tone for the business and signal to the corporation the direction which Leadership wants to go and the importance of the initiative. Recommendations in this category include development of a Vision, Strategy, Objective, or similar corporate policy; declarations around roles, accountably, and controls; and communications from Leadership about the importance of the initiative.
- Design the Change – These are recommendations which focus on the design/development of new processes, structures, or technology to provide new capabilities. Recommendations in this category include organizational structure, roles and responsibilities, governance and oversight, and plans/roadmaps.
- Implement the Change and Work the New Processes - These are recommendations in which the “Design the Change” recommendations are implemented. Recommendations in this category include implementing new processes, undertaking activities to improve existing processes, and making incremental changes.
- Get Excellent – These are recommendations focused on improving already established processes or capabilities to exceed Competence in an area.

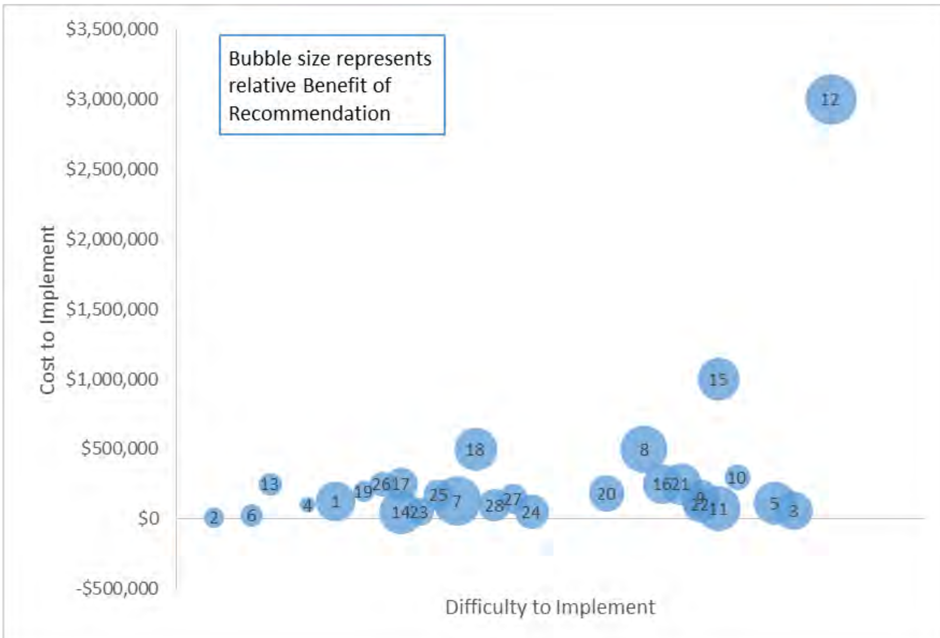
For the 29 recommendations made in the Assessment, UMS Group has designated the category for each on the following pages:

Number	Area	Recommendation	Create the Right Environment	Design the Change	Implement the Change and Work the New Processes	Get Excellent
1	Leadership	Decide on and declare the Operating Model for Asset Management	X			
2	Leadership	Formally acknowledge the CAM EC's role as the Asset Owner	X			
6	Leadership	Develop and deliver a road show to communicate changes	X			
4	Leadership	Develop a formal Asset Management roadmap and Asset Management Strategy	X			
19	Performance Management	Develop controls and an internal review function for the asset management system	X			
3	Leadership	Change the focus of decision-making away from "being the best" towards cost efficient satisfaction of objectives		X		
7	Risk	Define a risk tolerance level and establish a formal process to regularly review risks		X		
9	Roles and Responsibilities	Formalize the Asset Manager and Service Provider roles within each business unit and clarify accountabilities		X		
10	Consolidation of Functions	Develop an organizational structure which consolidates asset management functions		X		
11	Consolidation of Functions	Group the functions focused on asset management under a single group		X		
20	Performance Management	Refine the current Performance Management framework		X		
21	Performance Management	Create a Resource Optimization capability		X		

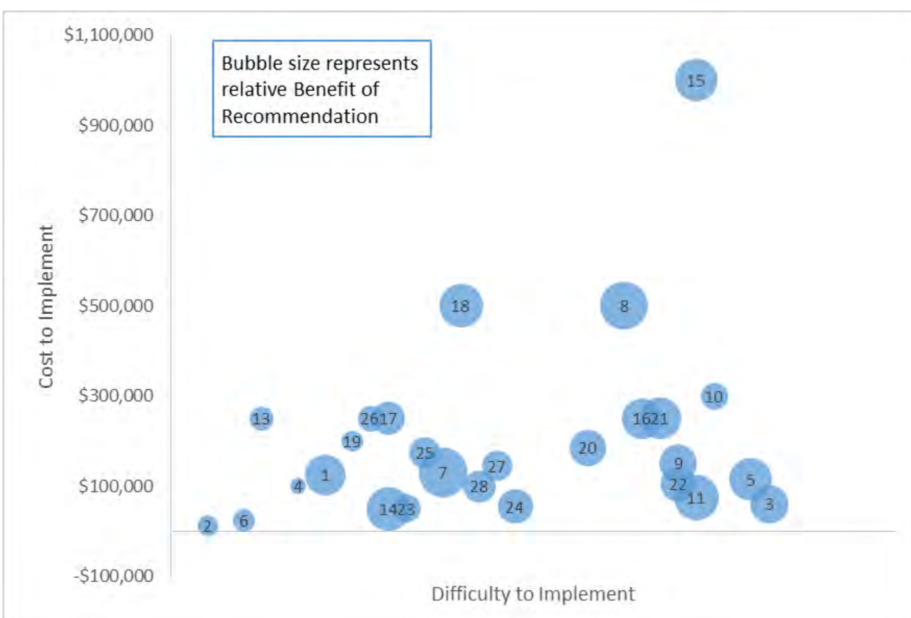
Number	Area	Recommendation	Create the Right Environment	Design the Change	Implement the Change and Work the New Processes	Get Excellent
22	Performance Management	Create an Investment Delivery Assurance process		X		
23	Performance Management	Define a corporate-wide process for identifying and sharing best practices		X		
24	Data and Technology	Develop a robust data governance structure to ensure data integrity and validity		X		
27	Data and Technology	Develop a plan/roadmap for improving Operational Analytic capabilities		X		
5	Leadership	Transition to a more competitive process for capital across the Business Units			X	
8	Risk	Implement a risk assessment methodology and a risk register			X	
14	Lifecycle Optimization	Create an Asset Strategist role with overall responsibility for the integrated Asset Life-Cycle Strategy			X	
15	Lifecycle Optimization	Develop processes and implement tools to address O&M spend and the trade-off between O&M and Capital.			X	
16	Lifecycle Optimization	Integrate O&M into the existing processes used for optimizing Capital spend			X	
17	Lifecycle Optimization	Improve processes and tools to enable assessment of assets as a group			X	
18	Lifecycle Optimization	Establish AHIs for all key assets and transition to economic life to drive decisions			X	

Number	Area	Recommendation	Create the Right Environment	Design the Change	Implement the Change and Work the New Processes	Get Excellent
25	Data and Technology	Perform a Data Inventory and Gap Assessment			X	
12	Lifecycle Optimization	Develop and document Life-cycle Strategy Plans for the key asset classes				X
13	Lifecycle Optimization	Review existing design specifications and maintenance plans with an eye towards life-cycle optimization.				X
26	Data and Technology	Improve AHI algorithms to be more objective				X
28	Data and Technology	Improve data quality through better communication with the Field/Plant				X

While this categorization provides an indication of prioritization in a logical manner, some organizations do not choose to implement all recommendations or may desire to focus in certain areas first. As the recommendations have varying levels of costs, benefits, and difficulty to implement, this decision can be made based either or implementing the "easiest / least expensive" or the "most impactful". To aid in making this decision, UMS Group has assessed each of the recommendations on these factors and created the chart below to provide a relative comparison between them (note the number can be linked to the recommendation in the table above).



The table below has recommendation "12" removed to make it easier to distinguish among the lower cost recommendations.



Potential Issues/Challenges

Asset Management is often difficult to implement and requires tackling specific barriers. These challenges include:

- Silo Thinking - Departmental, functional or regional barriers exist preventing collaboration and shared solutions. This is usually due to strong local management personalities, non-aligned performance/reward mechanisms or organization size and hierarchy
- Short Term Thinking – The total lifecycle is not taken into account, especially where success is often measured as 'on time' and 'on budget', irrespective of subsequent asset performance and value of the work
- Conflicting Performance Measures - Capital and operational spending is usually budgeted separately rather than integrated in terms of asset needs. Even 'balanced scorecards' can reinforce such competing priorities
- Business Focus - Engineers and operational management do not traditionally speak the same language as finance, executives and external stakeholders
- Risk Management - There is limited comprehension of the need for rational and consistent identification, quantification and management of commercial, technical, safety, customer/public perception and other infrastructure risks
- Data/Technology – There is not enough data or it is of inadequate quality or the wrong sort. IT software and hardware infrastructure is not aligned with the business requirements

In addition, organizational capabilities at three levels are critical for achieving world class business performance. At the Leadership level, there is a need for a clearly understood vision, agreed priorities and a well-articulated strategy on how to be a successful organization in an increasingly challenging market. At the organizational level, there is need to have effective processes, information technology, and infrastructure to support business goals. At the individual level, employees need to be able to co-ordinate work effectively, acquire new business, leadership and team practices and skills, and replace old practices and ways of working.

Finally, to fully succeed in building Asset Management competencies, Hydro needs to make changes to its culture. This will require development and implementation of a Change Management Plan designed to address the often forgotten "soft" people issues (leadership, skills, culture, etc.) related to a major business transformation. This plan (likely multiple plans to go along with different initiatives) will need to be executed in parallel with other planned implementation activities (e.g. new processes, systems, organization redesign, etc.). Key elements of the Change Management Plan should include a Vision which lays out the case for changes, an Organizational Readiness and Impact Assessment which identifies the potential enablers and barriers to change, and a Communication and Stakeholder Management plan to ensure a consistent message is put forth.

Monitoring Progress

Performance measures should be put into place in order to ensure that the recommendations are implemented effectively and that Asset Management capabilities are in fact improving. These measures should include ones to track overall progress on implementing Asset Management transformation initiatives, as well as ones to track success in performing Asset Management. Below are examples of the types of metrics that should be tracked. Specific metrics should be developed during the implementation planning phase.

Asset Management Transformation Initiative Metrics:

- Number of tasks completed on schedule
- Number of tasks completed on budget
- Number of communications to employees on Asset Management
- Number of asset life-cycle strategies completed

Asset Management Performance Metrics:

- Equipment outage rate (number of forced and fault outages as % of total asset class)
- Equipment failure rate (number of major failures as % of total asset class)
- Equipment maintenance spend rate (avg. $ of maintenance per asset – by asset class)
- Downtime as a proportion of total operating time (%)
- Number of service interruption per month (by asset class)
- % of AHI distribution good or fair (trend)
- Unplanned capital expenditure/total capital expenditures
- Corrective Maintenance cost / Preventive Maintenance cost (by asset class)
- Emergency maintenance cost / Total maintenance cost (by asset class)
- Maintenance Backlog (cost of maintenance due / average annual maintenance expenditure)
- Preventive Maintenance Compliance %
- Asset Sustainability Ratio (sustainment capital expenditure / depreciation expense)
- Asset Consumption Ratio (current value of asset class / current replacement cost of asset class)
- Percent of Assets with complete, correct demographic data in Asset Register
- Percent of Work Orders with correct failure codes entered by Field

APPENDIX A – GAP ASSESSMENT METHODOLOGY

Basis for the Assessment

The assessment of Hydro's asset management maturity was performed against both international standards for asset management systems (ISO 55000 and PAS 55) and industry best practice. The international standards are focused on the requirements for an asset management system and provide guidelines for the application of the specified requirements.

While these standards provide guidance on what is needed to set-up, operate and maintain the asset management system, they do not provide much insight or detail on how to do so. Therefore, UMS Group has also assessed Manitoba Hydro against its own proprietary Strategic Asset Management (SAM) framework which is aligned with industry best practice in application. The SAM framework is fully compliant with both ISO 55000 and PAS 55, but is more focused on the "how" of asset management, while the standards are focused in the "what." It is also focused specifically on the utility industry.

Combined, these two approaches were intended to provide a holistic view of Hydro's current level of asset management maturity and inform the gap analysis to ensure that actionable recommendations are provided to enable implementation of significant improvement opportunities

Interviews

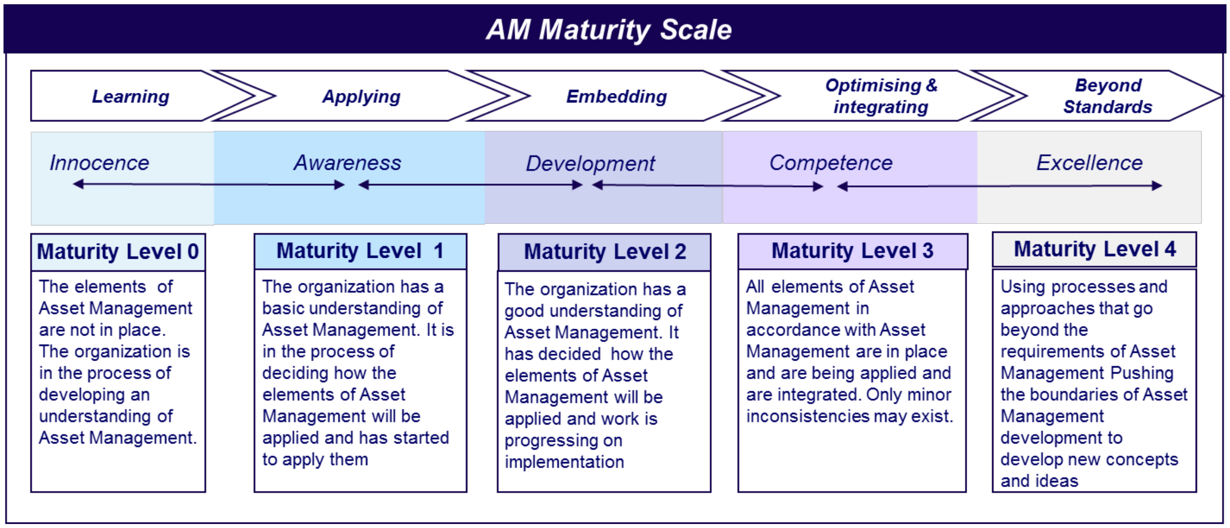
UMS Group held initial interviews with Hydro Leadership to gain some historical context on the development of asset management in the organization, understand their view on perceived gaps/issues, and ascertain their objectives for the engagement. Subsequent to the Executive Interviews, UMS held individual interviews with key personnel in the Generation Operations, Transmission, and Customer Service and Distribution business units. These interviews were designed to understand the current asset management system in terms of processes, tools, and practices. Roles and responsibilities for key asset management functions were also explored.

Workshops

UMS Group facilitated separate workshops with personnel in each of the Generation Operations, Transmission, and Customer Service and Distribution business units (25 personnel in total participated) to perform a self-assessment of Asset Management maturity. The workshops had two objectives:

- Educate personnel on the principles of best practice Asset Management per international standards
- Gain alignment around the current maturity level of Manitoba Hydro with regard to these principles

The main body of the workshop comprised of an explanation of the key requirement of an Asset Management System (per ISO 55000 and PAS 55), as well as the key Asset Management Processes. Discussion was then held with the participants on what maturity in that area meant and where the participants thought the business unit should be rated today versus the maturity standard. The scoring was based on the current level of maturity on a scale where 0=innocence and 4=excellence. Compliance with the Standard is at a competence maturity level of 3 and there is no upper limit to excellence.



The workshops were designed to provide a better understanding by the participants of not only what best practice asset management looks like, but where there is agreement (or disagreement) over where gaps exists and the size of those gaps.

- **Context of the Organization** – When establishing or reviewing the Asset Management System, the organization should take into account its internal and external contexts. External context includes social, cultural, economic and physical environments, as well as regulatory, financial and other constraints. The internal context includes organizational culture and environment, mission, vision and values of the organization.
- **Leadership** – Top leadership is responsible for developing the asset management Policy and asset management Objectives and for aligning them with the organizational objectives. Top management should create the vision and values that guide policy and promote these policies inside and outside of the organization.
- **Planning** – The organizational objectives provide the overarching context and direction to the organization's activities, including its asset management activities. They are generally produced from the organization's strategic level planning activities and are documented in an organizational plan. The principals by which AM is applied should be set out in an asset management Policy and implementation documented in a Strategic Asset Management Plan (SAMP).
- **Support** – Collaboration of resources is a critical component in an asset management System. Asset IT Systems can be extremely complex and it is vital for an organization to create, control and document the necessary information and data as a critical function.

- **Operation** – The asset management System can enable the directing, implementation and control of its asset management activities, including those that have been outsourced. Functional policies, technical standards, plans and processes for implementation of the asset management plans should be fed back into the design and operation of the asset management System. Planning changes to asset management processes or procedures are required and will introduce additional risk and must be continually evaluated.
- **Performance Evaluation** – The organization should evaluate the performance of its assets, its asset management and its asset management system. Performance measures can be direct or indirect, financial or non-financial. Asset performance evaluation is often indirect and complex and the transformation of data into information is a critical component. Monitoring, analysis and evaluation of this information should be a continuous process and the results of performance evaluations should be used as inputs into management reviews for continual improvement.
- **Improvement** – An organization's asset management system is likely to be complex and continually evolving to match its context, organizational objectives and its changing asset portfolio. Continual improvement is a concept that is applicable to the assets, the asset management activities and the asset management system, including those activities or processes which are outsourced.
- **Asset & Risk Strategy -** The decision making process that determines how assets are to be added, removed, and maintained. System Planning, Standards, and Maintenance Optimization (Condition Based Maintenance, Reliability Centered Maintenance, Economic End of Life), and Risk Assessment are all critical elements of the Asset Strategy process. Life Cycle Planning is included in this process.
- **Investment Planning -** The analysis and optimization of all capital and O&M spending. All work and investments are prioritized in this process through an evaluation of business drivers and risk (financial, technical, and socio-political) in order to ensure that projects are selected that provide the greatest financial and customer returns.
- **Performance Management -** The Performance Management framework measures the performance of assets, processes, and people, analyzes identified performance gaps and points to possible gap closure solutions.
- **Resourcing Strategy -** The activities necessary to add, remove and manage service providers, whether they be internal or external.
- **Industry Intelligence –** An organized process to identify, assess, and utilize industry best practices to continually assess and modify policies/procedures/processes to ensure improvement remains a priority throughout the organization.

UMS Group also performed a workshop with each of the Business Units which comprised a comparative walkthrough of their Asset Lifecycle and Risk Strategy process against best practice standards. Through a review of the steps in a model process and a group discussion on how the process matched up to Manitoba Hydro, areas of agreement and areas in contention regarding the current and future state of the process were identified.

APPENDIX B – LIST OF PERSONNEL INVOLVED (INTERVIEWS AND WORKSHOPS)

Corporate, HR and IT Interviews		
Kelvin Shepherd	Darren Rainkie	Lorne Midford
Shane Mailey	Brent Reed	Bryan Luce
Siobhan Vinnish	Sandy Bauerlein	Rob Lanyon
Brad Ireland	Domenic Pellegrino	

Generation Operations Interviews		
Joel Wortley	Val Yereniuk	Rejan Sayak
Hal Turner	Gary Bishop	Terry Miles
Kathy Allard	Karla Skulmoski	John Kreml
Reed Winstone	Don Ans	Krista Halayko
Dave Bowen	Brian Fox	Bob Dandenault
Transmission Interviews		
Gerald Neufeld	Derek Acres	Scott Simons
Rajitha Perera	Kyle Zevena	Joe Petaski
Kerry Walker	Bagen Bagen	David Swatek
Brent Jorowski	Dave Osmond	Glenn Penner
Mark Adamkowicz	John McNichol	Michelle Rheault
Distribution Interviews		
Mark Prydun	Owen Preston	Ken Hamilton
Corey Senkow	Dave Petursson	Jeff Shabaga
Rob Isaac	Kristin Braid	Chuck Steele
David Dudar	Graham Eason	Jesse Perry
Jared Waddell		

Generation Operations Workshop Participants		
Joel Wortley	Don Ans	Rejan Sayak
Hal Turner	Gary Bishop	Kathy Allard
Krista Halayko	Karla Skulmoski	
Transmission Workshop Participants		
Brent Jorowski	Kelvin Kent	Scott Simons
Rajitha Perera	Greg Parent	Gary Lussier
Kerry Walker	Treffle Aussant	
Distribution Workshop Participants		
Jared Waddell	Rob Issac	Dave Petursson
Graham Eason	Chuck Steele	Corey Senkow
Owen Preston	Jeff Shabaga	Ken Hamilton

Tab 124

Knight Piésold CONSULTING

NFAT REVIEW OF KEEYASK AND CONAWAPA GS

KNIGHT PIESOLD INDEPENDENT EXPERT CONSULTANT HEARING PRESENTATION

CONSTRUCTION MANAGEMENT AND CAPITAL COSTS

M J Robertson, P. Eng.

April 14, 2014

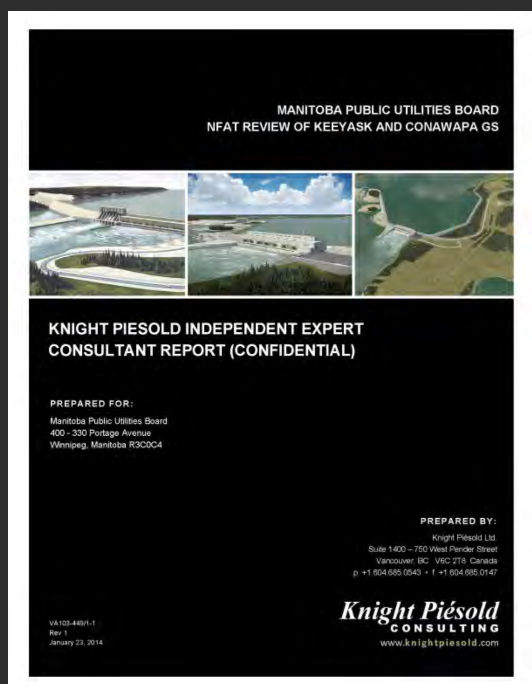
Documents

- Documents and Materials
  - KP Report VA103-449/1-1 Rev 1 of Jan 23, 2014 (CSI).
  - KP Report VA103-449/1-1 Rev 1 of Jan 23, 2014 (Redacted).
  - KP Report VA103-449/1-2 Rev 0 of April 8,2014 (CSI).
  - KP Report VA103-449/1-2 Rev 0 of April 8,2014 (Redacted).
  - KP IRs to Hydro.
  - KP responses to IRs (a few contain CSI).
  - References quoted in those reports (but not separately provided).
  - Information provided by MH (mostly CSI in hard blue paper copy and some emails).
- KP reports produced by me and Boris Fichot and other KP engineers under my supervision and control. Versions quoted are final (no revisions, updates or corrections). (Note CSI version of second report erroneously still labelled Rev A of February 18, 2014). CSI content will be provided tomorrow

Scope

- Scope of work provided by a number of questions posed by PUB. Answered in two reports – first had 9 questions (#1 to #9), second had a further 8 (#S1 to #S8).

- Some data in first 9 is updated/changed in second 8.



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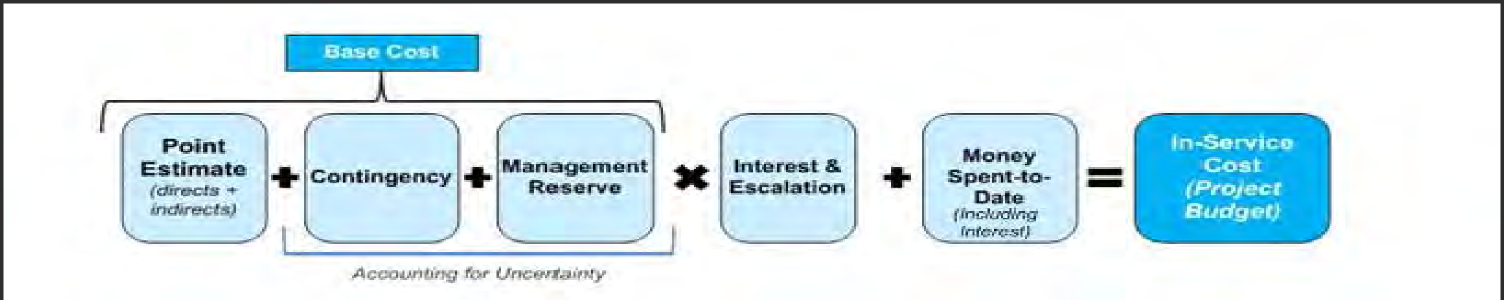
Question 1

"Review and assess Manitoba Hydro's capital and operation and maintenance (O&M) cost estimates for Conawapa GS and Keeyask GS, including the adequacy of management reserves for the projects."

General Methodology for Capital Cost Estimate **(p.11 of KP Report)**:



"Point Estimate" is essentially "Best Estimate". Comprises Direct and Indirect Costs:

- **"Direct Costs"** are those directly related to doing the generating station work e.g. labour, materials and equipment.
- **"Indirect Costs"** are all other capital costs e.g. provision of site infrastructure and services, engineering and project management and environmental activities (see detail in Question 2).

Question 1

Allowances are made for the Uncertainties (in the Point Estimate) through Contingency which includes:

- Systemic Risks (Systemic risk relates to items resulting from the project "system").
- Project Specific Risks (uncertainties specific to Keeyask and Conawapa (e.g.). Latter includes: foundation conditions, northern weather, delivery delays, Constructability, resource availability, and quality issues.

Assessed at the P50 level i.e. there is 50% probability that the final project cost will be less than the chosen number and 50% probability that it will be more **(p.24)**.

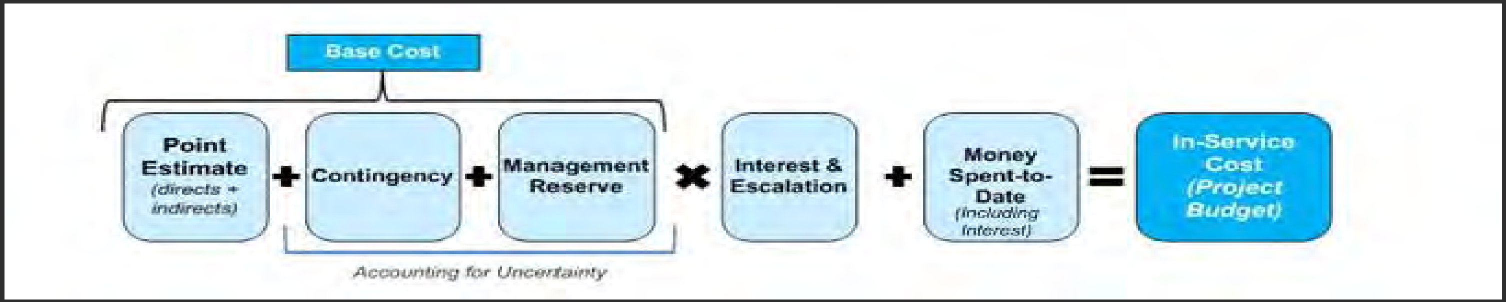
Question 1

- "Management Reserve" – Two specific risks included:
  - Escalation Reserve. Escalation at CPI is included in the Point Estimate. The reserve makes provision for escalation in excess of this amount.
  - Labour Reserve. A special pool of money has been set aside to cater for the possibility of labour costs and/or productivity being different from assumed (in the Point Estimate).

  These reserves set up as a direct result of the Wuskwatim experience (see Question 9).

"Contingency" usually includes Management Reserve but MH have chosen to split them up, if only because the two allowances are managed differently within MH.

Question 1



Point Estimate + Contingency + Management Reserve = **"Base Cost".**
Base Cost is expected final cost before adding:

- the effects of interest on borrowed capital and escalation, and
- money spent to date.

Adding these to the Base Cost provides the **"In-Service Cost".**

Question 1

High Level Comparison of Capital Cost Estimates of Similar Projects in Canada (p.8)

Name	Prov.	Proposed Installed Capacity (MW)	Estimated Average Annual Energy (GWh)	Total Estimated Capital Cost	M$ / MW	M$ / GWh	Source:
Muskrat Falls	NL	824	4,600	6.2 B$	7.5	1.35	Muskrat Falls Review
Site C	BC	1,100	5,100	7.9 B$	7.2	1.55	Site C information fact sheet.
Petit Mecatina Projects	QC	1,200	5,500	not available for review			
La Romaine	QC	1,550	8,000	6.5 B$	4.2	0.80	www.aecom.com
Keeyask	**MB**	**695**	**4,400**	**6.2 B$**	**8.9**	**1.40**	**NFAT Filing**
Conawapa	**MB**	**1,485**	**7,000**	**10.2 B$**	**6.9**	**1.45**	**NFAT Filing**
Wuskwatim	MB	200	1,520	1.78 B$	8.8	1.17	Actual Final

Question 1

Operation and Maintenance Costs have been estimated by MH as follows (p.32):

	Average Lifetime Fixed O&M Cost (2012$)/kW/year	Installed Capacity (MW)	Average Fixed O&M Cost (M 2012$)/year
Keeyask G.S.	17.86	695	12.4
Conawapa G.S.	10.28	1,485	15.3

Costs include:

- Wages, salaries and benefits and training in initial years.
- Insurance.
- Partnership expenses.
- Internal administrative costs.
- Internal and external (consulting) environmental services.
- Accommodation.
- Capital maintenance (in later years) – upgrades, replacements and refurbishments as required.

Question 1

Conclusions on Question 1 regarding capital cost estimates:

- MH's estimating process has been thorough, based on detailed design, estimation of quantities, initial bottom-up approach to unit rates (2009/2010), major updating to 2012 based on results of Wuskwatim, inclusion of allowances for uncertainty.
- There is more clarity in the MH process over direct costs than indirect (see Question 2).
- Many jurisdictions use higher value than P50 estimate to establish contingency (but a significant number of others do not: use P50).

Regarding Operation and Maintenance Costs:

- Estimated costs are commensurate with similar hydro projects elsewhere in Canada.

Question 2

"Review and assess Manitoba Hydro's construction indirect costs including access roads, campsites, and off-site mitigation costs for Conawapa GS and Keeyask GS"

- Indirect Costs include all temporary and permanent items not directly associated with the primary structures but still required to successfully implement the project **(p.34)**:
  - Preconstruction costs.
  - Site infrastructure including access roads and campsites.
  - Site services.
  - Engineering and project management.
  - Environment and mitigation activities.
  - General expenses including consultants, travel, site office, insurance.
  - First Nation participation payments.
- Much of the construction work provided in the Keeyask Infrastructure Project, KIP. KP found the information provided by MH to be sensible but could not offer an opinion on costs like internal MH project management and other costs and general expenses.
- Indirect costs exclude related costs to date (or money spent).

Indirect costs stated by MH to form approx. one third of the Point Estimate.

Question 3

"Review and assess Manitoba Hydro's construction management, schedule, and contracting plans for the design, engineering, procurement, construction, start up, commissioning, testing, and commercial operation of Conawapa GS and Keeyask GS"

MH have created a Project Execution Plan (PEP) for the Keeyask Project **(p.40)**. It is a high-level management guideline which:

- Describes the means, methods, tools and techniques used to manage the KIP and the KGSP.
- Serves as a record of the planning effort undertaken by MH for the construction phase of the project.
- Serves as a resource for staff to ensure the project is managed consistently.

Question 3

The PEP is backed by MH Corporate Policies and Standards:

- Total Cost and Schedule Management (TCSM) Standard.
- Monitor and Control of Engineering Consultants Standard.
- Preparation of Project Dashboards and Trend Analysis Standard.
- Project Change Authorization (PCA) Process.
- Work Package Change Management Process.
- Consultant Communication Plans.
- Division Plan for Managing the Consultants, and
- Engineering Work Package Scope Sheets (EWPSS).

KP is able to see that Hydro has good procedures in place for the management of the projects despite the PEP presently being in draft form only.

Question 3

Contracting methods considered by MH for the various contracts included (p.42):

- Fixed Price Contract (FPC) (or EPC – Engineer, Procure, Construct).
- Cost Reimbursable Contract (CRC).
- Direct Negotiated Contract (DNC).
- Unit Price Contract (UPC).
- Supply Only Contracts (LS).

For contracts seen by KP, apparent that MH has made appropriate choices for different contracts e.g. FPC for turbine generating equipment and CRC for main civil works.

Main civil works contract (GCC) also utilising Early Contractor Involvement (ECI) process to obtain input from chosen contractor to refine design, construction technique, schedule and risk sharing.

Question 3

The Preferred Development Plan includes an implementation schedule. Schedules are also provided in the Basis of Cost Estimate documents. The schedules are consistent with the described developments and the anticipated work breakdown structures.

A more detailed and complete schedule for Keeyask was included with the Tender Package for the GCC. All tenderers essentially confirmed the schedule as part of their bids. The construction schedule is being refined as part of the ECI process.

The schedules do not include details of time needed for input by MH, such as reviews by themselves or independent engineers.

The PEP for Keeyask states that execution will follow the Hydro Cost and Schedule Standard (CSS) for schedule management.

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Question 4

"Review and assess Manitoba Hydro's capital cost and O&M cost estimates for wind, natural gas combined cycle gas turbines, and solar facilities."

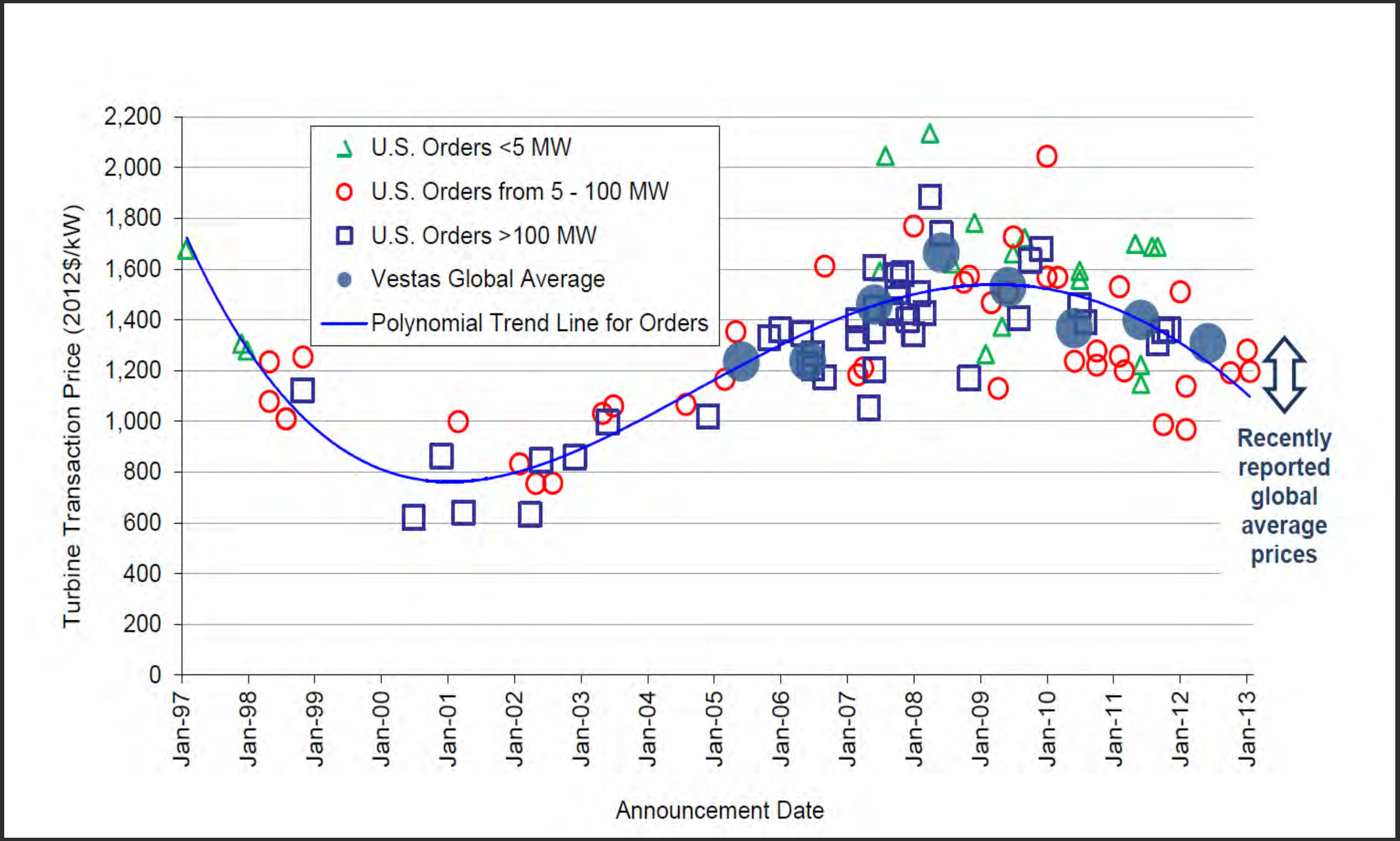
Wind **(p.50)**

Capital cost: MH has assumed an overall capital cost of $2,100/kW (excluding transmission) in the comparative exercises they have undertaken. From the data in next slide and data from other jurisdictions, $1,800/kW is deemed to be more appropriate and sufficiently conservative

O&M cost: MH's assumption of an O&M cost of $39.55/kW is deemed appropriate, with a recommended range of $35-55.

Question 4

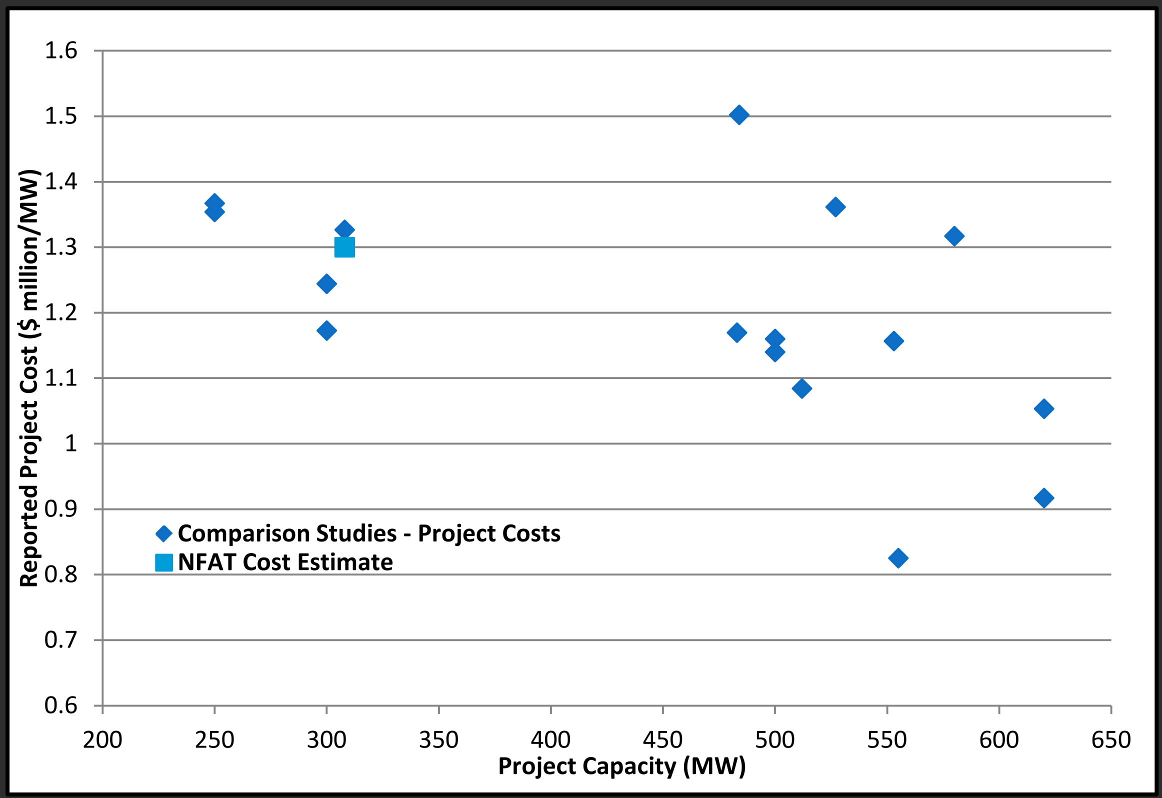
Wind Turbine Cost Trends



Question 4

Natural Gas Combined Cycle (CCGT) **(pp.53,54)**

MH's assumed capital cost of \$1.3 million/MW is deemed appropriate



MH's assumed O&M costs of \$20/kW/yr and \$3.50/kWh are also deemed reasonable, with a recommended range of \$6.30-22/kW/yr.

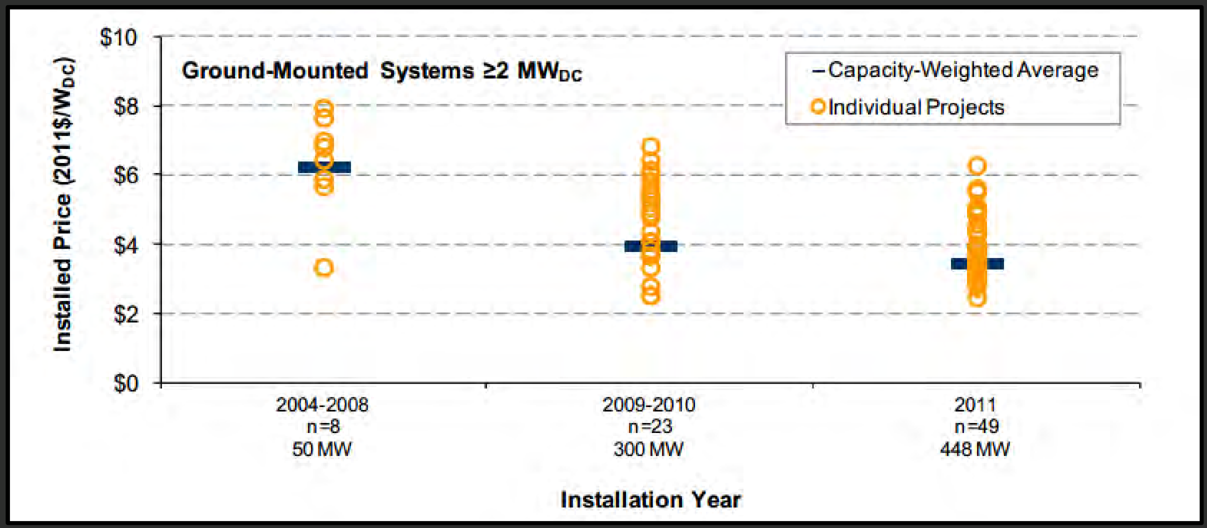
Question 4

Solar (pp.55-57)

MH's present assumptions on capital cost are deemed appropriate – but solar costs have been reducing significantly in recent years

PV System Type	NFAT Capital Cost ($/kW)	Comparison Capital Cost ($/kW)
Fixed Tilt	3,750	3,400-4,300
Single-Axis Tracking	4,500	3,900-4,700
Dual-Axis Tracking	5,000	5,100-5,500

PV System Type	NFAT O&M Cost ($/kW-year)	Comparison O&M Cost ($/kW-year)
Fixed Tilt	19.70	22-50
Single-Axis Tracking	21.10	22-50
Dual-Axis Tracking	24.60	25-50



Question 5

"Review and assess Manitoba Hydro's construction management plans, schedule, and contracting methods for the design, engineering, procurement, construction, start up, commissioning, testing, and commercial operation for wind, natural gas combined cycle gas turbines, and solar facilities."

Wind **(p.58)**

- MH assume wind power projects will be developed in-house (whereas existing Manitoba farms have been developed by IPPs)
- Time frame assumed 3 – 5 years, including resource assessment.
- Asset life ~20 years.
- No further details from MH: will be developed only if and when wind becomes cost competitive.

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Question 5

Natural Gas Combined Cycle (CCGT) **(p.58)**

- NFAT assumes development by MH and construction through EPC contract.
- Time frame assumed 3 – 5 years reasonable but might be shorter (2 – 4 years, depending on turbine supply time).
- No further details from MH: will be developed as preferred development plan proceeds.

Solar **(p.59)**

- MH assume time frame of 3 years for development and construction of generic 20 MW facility. Could be reduced if/when solar perceived to be key energy resource in future.

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Question 6

"Review Manitoba Hydro's capital expenditure forecasts CEF 13/CEF 12/CEF 11/CEF 10/CEF 9 and explore any significant factors that led to cost increases over successive forecasts."

Progression of Project Costs ($ Millions) **(p.60)**

	CEF09	CEF10	CEF11	CEF12	CEF13
Conawapa GS	6,325	7,771	7,771	10,192	10,492
Keeyask GS	4,592	5,637	5,637	6,220	6,220

Significant Factors in Cost Increases **(p.61)**:

- Delay of In-Service Dates (adds PM, interest and escalation costs).

	CEF09	CEF10	CEF11	CEF12	CEF13
Conawapa GS	May 2022	May 2023	May 2024	May 2025	May 2026
Keeyask GS	Dec 2018	Nov 2019	Nov 2019	Nov 2019	Nov 2019

- CEF09 to CEF10 shift due to updated detailed cost estimates by KGS-Acres.
- CEF11 to CEF12 attributed to inclusion of management reserve, increased actual escalations and changing interest rates in light of Wuskwatim experience (details in Question 9).

Question 7

"Provide a historical perspective on the construction cost components of other Lower Nelson River hydraulic generating stations (Limestone/Long Spruce/Kettle) and analyze the major components of direct cost, including (a) Spillways/dams/dikes, (b) Powerhouses, and (c) Turbines and generators, and compare these to the Keeyask and Conawapa GS costs for these components."

Meaningful assessment not possible with information made available. MH provided total but not individual component costs. MH did provide major quantities.

Significant differences between then (1992/1979/1973) and now (Wuskwatim 2012 and Keeyask/Conawapa future) **(p.64)**:

- MH now engaged in partnership framework with FNs.
- Significant increase in rigour of environmental process (came into force after Limestone). Lack of regulatory capacity in Manitoba to follow new requirements.
- Labour costs and productivity.

Question 7

Limestone example **(p.65)**:

- Completed in 1992, on time and within budget ($1.43 billion)
- Ballpark direct capital estimate would be $2.2 billion

	MH Quantity[1]	Unit	KP Unit Cost ($)	Cost ($)
Excavation (assuming 50/50 split of reported total quantity)				
Unclassified	1,600,000	m^3	20	32,000,000
Rock	1,600,000	m^3	100	160,000,000
Coffer Dam removal	3,500,000	m^3	20	70,000,000
Earth Fill	2,900,000	m^3	40	116,000,000
Concrete	650,000	m^3	1,200	780,000,000
Capacity (Generating Plant)	1,350	MW	500,000	675,000,000
				1,833,000,000
+20 % for miscellaneous items				471,380,000
				2,199,600,000

- However, escalating $1.43 billion @2.5% for 11 years yields only $1.88 billion which is short of direct costs alone let alone in-service cost which includes indirect and other costs.
- Capacity of 1,340 MW gives $1.07 million / MW (cf. 8.9 Keeyask, 6.9 Conawapa).

Question 7

Long Spruce (**p.65**):

- Constructed 1971 to 1979 for cost of $508 million.
- Capacity of 1,010 MW gives $0.50 million / MW (~cost of turbine generators alone today).
- No information provided re schedule and cost performance.

Kettle (**p.65**):

- Commissioned 1974 for cost of $240 million.
- Capacity of 1,220 MW gives $0.20 million / MW.
- No information provided re schedule and cost performance.

11620

Knight Piésold

Question 8

"Analyze Manitoba Hydro's justifications for increasing direct costs and for increasing indirect costs with respect to (a) Labour productivity and shortages, (b) Competition with other large civil projects in Canada, (c) Remote location, (d) Northern and First Nation jobs, and (e) Other contractual hiring constraints."

(a) Labour productivity and shortages (**p.66**):

- Labour productivity in construction industry documented to have decreased since a peak in the 1970s, mainly due to reduction in skill level.
- Other factors include decline in # of employees, capital-labour ratio, percentage union and average age of workers.
- Canada has experienced at least a decade of labour shortages.
- MH have attributed lack of productivity to difficulties hiring and/or retaining staff and use of inexperienced staff. As a result of the low productivity experienced at Wuskwatim, MH has, for Keeyask and Conawapa, adjusted contracting methods, added staff and invested in better camp facilities. These are deemed reasonable measures.

Question 8

(b) Competition with other large civil projects in Canada **(p.66)**:

- 40% of overall project workforce for Wuskwatim were out of province: 60% for generating station structure.
- Keeyask demand greater and situation likely to be even worse.
- Eastern labour had to be imported for recent KP hydro projects in BC.
- MH is relying on offering competitive wages and an attractive camp environment.

(c) Remote location **(p.66)**:

- Location is remote but is known and therefore factored in to cost estimates already – should be no surprises. Is factored in to estimated staff rotations.

(d) Northern and First Nation jobs **(p.67)**:

- Remote northern projects always been part of Canada's non-residential construction outlook.
- Natural resource development and mining projected to grow significantly through 2020.

Question 8

(e) Other contractual hiring constraints **(p.67)**:

- Burntwood Nelson Agreement (BNA) sets out terms for "hands-on-tools" workers (including FN) on hydro projects in N Manitoba. Collective agreement between Hydro Projects Management Association (representing Contractors) and Allied Hydro Council of Manitoba (Unions).
- GCC tenders had to include compliance with BNA requirements.
- GCC tenders will reveal large contractors' assessments of labour availability (see Question S7).

Question 9

"Please provide a high level assessment of the construction planning and management of the construction costs of the new Preferred Development Plan projects, including the experience gained from the Wuskwatim project."

See Question 3 re construction planning and management of construction costs (and also Question S1).

Experience Gained from Wuskwatim (Costs) **(p.68)**:

- Wuskwatim witnessed lower than expected labour productivity, occurred during a period of international commodity escalation, and suffered a 3 year delay of In-Service Date.
- Cost went from $988 million in CEF03 to $1,771 million in CEF12 (79% increase, details on next slide).
- Keeyask and Conawapa Cost Estimates updated for Wuskwatim labour, material and equipment rates as well as labour productivity.

Question 9

Integration of Lessons Learned at Wuskwatim (Costs) (p.69)

Cost Breakdown	Increase in Cost 2003-2012 (M$)	Explanation for change by Manitoba Hydro In Undertaking # 47	KP Designated Implications for Keeyask and Conawapa
Pre-construction 2003 to 2006	224	Extended duration of federal and provincial approvals as well as PDA and NCN ratification resulting in the deferral of the construction start date, extended duration of construction, and the 3-year in-service date deferral.	Addressed through the separation of the KIP. Project definition for pre-construction work could still be refined.
General civil contract	178	Lower trade labour productivity, higher labour rates, increased bedrock overbreak, and increased engineering	Awareness of the issue, inclusion of different staffing requirements included. Similar Risks still exist, but are addressed in part (through Labour Management Reserve)
Turbines & generators	19	Higher labor rates, extra work, claims due to schedule delays.	Considered
Site preparation	32	Increased quantities (primarily rock) due to unknown site conditions, increased camp accommodations and operation and maintenance costs.	Remain
Catering	22	Higher camp occupancy and higher offsets required for work performed through a direct negotiated contract.	Addressed through projected increased staff requirements in the 2009 and 2010 estimates.
Electrical & Mechanical	38	Additions to scope of work and engineering, and contractor cost claims due to schedule and access delays.	Risk remains due to Hydro contracting technique.
Gates, Guides & Hoists	20	Extra work and contractor cost claims due to schedule delays.	Gate guides addressed in 2009 Estimate, marginal impact.
(continued ….)			

Question 9

Integration of Lessons Learned at Wuskwatim (Costs, Continued)

Cost Breakdown	Increase in Cost 2003-2012 (M$)	Explanation for change by Manitoba Hydro In Undertaking # 47	KP Designated Implications for Keeyask and Conawapa
Staff house	30	Addition of staff house to meet staffing requirements	Addressed through projected increased staff requirements in the 2009 and 2010 estimates.
Transmission	109	Increases in market costs experienced for labour, materials and contracts partially offset by reductions in contingency, project management and contract costs nearing construction completion.	Not investigated but should be part of escalation.
Other	47	Actual escalation in excess of original estimated inflation and other cost increases	Predictable, low CPI still included in escalation rate, addressed partially with escalation reserve
Interest allocated to construction capital	64	Due to increases in costs and deferral of in-service date partially offset by lower interest rates	Justified
Total Increase	**783**		

Knight Piésold

Question 9

Experience Gained from Wuskwatim (cont'd):

Access and FN Engagement **(p.70)**:

- Advancing infrastructure work ahead of GS benefits FN through increased and advanced employment, training and capacity building opportunities. Also reduces financial risks to FN joint venture partners.
- Pursued on Keeyask to avoid repetition of difficulties experienced with FN JV partner at Wuskwatim.
- Allows developer to focus on engagement of GCC.

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Question 9

Experience Gained from Wuskwatim (cont'd):

Changes to Construction Planning and Management (p.70):

- Wuskwatim originally bid as UPC in 2007 but only one bid received.
- Four bids received for subsequent CRC, with better prices.
- Provision of better camp conditions for Keeyask.
- Evidence that process review has resulted in changes:
  - Target Price contracts used for Keeyask to improve alignment with prevailing market and to share cost escalation risk.
  - Market research into craft labour and heavy construction costs and productivity and development of strategies for labour recruitment and retention.
  - Earlier scheduling for development arrangements, agreements and adverse effects and careful management through integration of engineering, regulatory and procurement processes.
  - Inclusion of Management Reserves for escalation and labour costs (on top of contingency).

Question 9

Cost Estimate Appreciation **(p.71)**:

A high quality cost estimate satisfies four characteristics:

- *Credibility* – In the case of Keeyask and Conawapa the direct point estimate is credible as it has been prepared by a reputable engineering firm with a wealth of recognised hydropower expertise (KGS-Acres).
- *Documentation* – layout and design of GSs well documented, as is makeup of direct cost estimates. Indirect cost estimates not as well documented (or not provided to KP). Project management processes and standards are well documented.
- *Accuracy* – current estimates likely as accurate as they can be prior to GCC award (see Questions S7 and S8).
- *Comprehensiveness* – KP believes estimate to be comprehensive. Includes all perceivable possible project costs and is structured in sufficient detail to insure that costs are not omitted or duplicated. Has been formulated by a suitably experienced estimating team.

Question S1

"Review MH's overall management strategy and scheduling for the tendering of contracts for the Keeyask Generating Station and the procurement of other major facility components such as spillways, dams, dykes, powerhouse, turbines, intake gates, generators, controls etc. Comment on the effectiveness of this management approach for minimizing capital costs, securing competitive bids, and managing construction and procurement cost escalation and construction risks."

Management Strategy for Tendering **(p.2)**

- MH's Project Execution Plan (PEP) is high level guideline to manage KIP and KGSP. Provides means, methods, tools and techniques used by MH to manage the projects. Serves as record of planning effort for construction phase and as resource for staff to ensure consistent project management.

Question S1

- Process of procurement of contracts detailed in PEP. KP has seen:
  - Total Cost and Schedule Management.
  - Engineering Consulting Contract Monitoring and Controls.
  - Construction Contract Monitoring and Controls.
  - Contract Change Management.
  - Risk Management.
  - Project Contingency Management.
  - Project Change Authorisation.
- Total Cost and Schedule Management (TCSM) **(p.3)**
  - PDCA Process.
  - Plan – Establish project baseline schedule and budget.
  - Do – Implement project controls on contracts and internal labour.
  - Check – Retrieve actual costs (from SAP) and latest schedule and budget forecasts from project leads.
  - Act – Assess performance and manage change and contingency.

Question S1

- Overall Tendering and Procurement Management Strategy **(p.3)**
  - Work divided into Work Packages.
  - Hydro Project Controls Coordinator responsible from contract drafting to early periods of the contract execution.
  - For each contract awarded contract value compared to base estimate and relevant amount of contingency allocated from contingency pool (see Question S2).
  - PDCA iterative management approach ensures project estimate and schedule are updated accordingly.
- Tendering mixture of methods, tailored to individual contracts. Supply and installation of turbine-generating equipment essentially fixed price whilst main civil works essentially design-bid-build but with target price and ECI process. KP deems overall approach appropriate in principle. Question 3 gives details of various forms of contract used by MH.

Knight Piésold

Question S1

- In GCC Early Contractor Involvement (ECI) process, selected contractor engaged early (2 years before major construction) so involved in helping finalise contract details. Main objectives:
  - Ensure contractor construction knowledge incorporated in design.
  - Refine delivery schedule.
  - Secure necessary labour.
  - Form alliances with Manitoba suppliers and sub-contractors.

Question S1

Scheduling for Tendering (p.4)

- PEP requires project execution to follow the Hydro Cost and Schedule Standard (CSS) for schedule management. Schedule performance one of key performance indicators tracked by MH.
- Overall schedule anticipates construction starting in July 2014 and being complete in January 2021. Procurement of long lead time items of equipment already under way, in order to ensure delivery to site in time for incorporation in the works.
- Detailed schedules for KGSP included in 2009 Cost Estimate and in GCC RFP. No details of MH contributions. GCC tenderers all confirmed schedule. First Stage Coffer Dam Aggressive.

Question S1

Procurement of Major Facility Components **(p.5)**

- Long lead time items (e.g. TG supply) procured early.
- Wrapped most mechanical and electrical equipment supply into GCC to minimise interface issues (lesson from Wuskwatim). Also included excavation, cofferdams and draft tube forms.

Question S1

Effectiveness of Tendering and Procurement Management Approach (p.4)

- MH using appropriate approach to minimising capital costs by sharing risk with contractors and suppliers through advancing design prior to procurement, identifying and managing risks, and detailed management of the construction process.

- Most significant contracts have been or are being procured through competitive bid process (GCC and Equipment Supply). Number of projects procured through non-competitive DNCs because of preference by MH for particular contractors to undertake specific work assignments - Wuskwatim experience.

- Internal MH costs may not be deemed competitive but KP has insufficient data to offer opinion on this issue.

Knight Piésold

Question S1

(p.5)

- Difficult to measure MH effectiveness managing construction and procurement cost escalation as current process relatively new and significantly different from the old.

- Project team and risk engineer execute the construction risk management process and the contingency management process during construction (see Question S2).

- As an overall assessment of effectiveness, KP able to see MH is following well-documented process (despite the PEP presently being in draft form only). The project generally appears to be on schedule.

Question S2

"Review Manitoba Hydro's construction risk management strategy and comment on its effectiveness"

Confidential copies of following documents made available to KP (p.6):

- Risk Management Procedure. Purpose is to *"detail the activities of planning, identifying, evaluating, responding, and monitoring for effective risk management as well as detailing the standard risk reporting templates..."*
- Project Contingency Management Procedure.
- (Keeyask) Project Risk Register.
- Project Risk Report (showing contingency drawdown, schedule, one year look-ahead of project-specific risks based on project schedule, project risk profile, top 5 global and top 5 specific risks, and risk by phase of implementation).

Question S2

Risks in the Risk Management Procedure assessed as product of Probability and Impact, in following categories:

- Technical (Requirements, Technology, Complexity and Interfaces, Performance and Reliability, Quality).
- Organisational (Project Dependencies, Resources (MH Staff), Funding, Prioritisation, Customer (Internal)).
- Project Management (Estimating, Scheduling, Controlling, Communication).
- External (Regulatory, Market Intelligence, Performance and Reliability, Weather, Stakeholders).
- Safety (Design Standards, Qualifications, Training and Awareness).

Knight Piésold

Question S2

(p.8)

Probability Factor	>70% (5)	5	10	20	40	80
	50%-70% (4)	4	8	16	32	64
	30%-50% (3)	3	6	12	24	48
	10%-30% (2)	2	4	8	16	32
	<10% (1)	1	2	4	8	16
		Very Low (1)	Low (2)	Medium (4)	High (8)	Very High (16)
		Impact Factor				

Combined Risk Factor Range	Risk Level	Response for NGC
1 to 4	Minor	Acceptable level of risk. Mitigation of risks are optional.
5 to 15	Moderate	Borderline level of acceptable risk. Must be mitigated to minor in stage 5.
>15 High	Critical	Unacceptable level of risk, must be mitigated to moderate in stage 4, or low in stage 5.

Question S2

Major risks in the Risk Register (total risk score of 80) were perceived in August / September 2013 to be **(p.9)** :

- Cost of labour and other associated labour issues.
- Increased costs for project management as a result of insufficient capacity in MH and consequent need to hire consultants.
- Escalation / market conditions (leading to higher tender prices).
- Inexperienced craft labour work force (leading to increased time and cost to perform construction).

MH proposes to deal with these risks by mitigation, through the Contingency and/or the Management Reserve.

Question S2

Apparent that new procedures and systems set up for Keeyask and Conawapa are direct result of lessons learned on Wuskwatim and reflect genuine MH concern to manage the whole process better. Risk management strategy appears to be well set up and being followed.

Appreciation of present risks:

- Can be assumed at this stage of project that most significant *technical risks* have been addressed (reputable experienced designers of large hydropower facilities in Northern Canada and extensive geotechnical investigations).
- A significant *financial risk* has been removed with the award of the GCC, but others still remain.

Question S2

- *Environmental risks* remain – contractor activities and impacts and remediation and/or compensation. KP has not examined Adverse Effects Agreement that has led to increase in indirect costs in successive cost estimates.
- Having chosen suitable, reputable and experienced contractors, *construction risks* are associated with contractor performance, in terms of quality, cost and schedule. MH carries some risk like quantities and to some degree impacts of inclement weather. Portions of the contingency have been added to each contract, to cover unknowns.

Whole issue ultimately comes down to cost. Discussed further in Questions S7 and S8.

Question S3

"Review contract documents prepared by Manitoba Hydro for the major Keeyask components and comment on how such documents have been designed to secure cost effective bids from suppliers and contractors and where Manitoba Hydro may be for vulnerable for cost increases, schedule changes etc. Comment on the overall thoroughness of the contract documents and drawings." **(p.11)**

- Question 3 details forms of contracts typically used to procure works like KIP and KGSP. KP confirms, based on contracts seen, MH has made appropriate choices for Keeyask contracts – contracts designed to secure most cost effective bids from suppliers and contractors.
- All contracts except FPC vulnerable to cost increases but MH has attempted to mitigate by sharing risk. Remaining risks and possible increases in cost have been acknowledged and accounted for in professional and competent manner – through contingency and management reserves; see Questions S2 and S8.

Question S3

- Non FPC contracts also have possible implications on schedule. Process of schedule changes has been defined. Costs associated with schedule risks are included in contingency and management reserve.
- Contract documents seen by KP clearly drawn up by competent, experienced engineers, from MH and reputable consultants.
- GCC contract involves ECI (to maximise benefit of Contactor input) and Target Price. Variations from Initial Target Price shared between MH and Contractor, generally to greater benefit of MH (80%) than Contractor (20%).

Knight Piésold

Question S4

"Review construction and equipment procurement bonding and any liquidated damage requirements and comment on the appropriateness of such bonding and cost implications to the project."

"Bonding" either (**p.14**) :

- Performance Bond provides assurance that the work will be done (normally used for civil site construction works).
- Letter of Credit provides assurance that MH will not be out of pocket (used to procure equipment manufactured off-site).

MH has used both, different for each contract.

KP believes MH process to be appropriate, including the required amounts - reasonable balance between protecting MH interests and paying excessive premium for this insurance.

MH have also handled Liquidated Damages appropriately.

Question S5

"Review Manitoba Hydro's Quality Assurance and Quality Control (QA/QC) requirements for Keeyask construction and comment on the effectiveness and costs." (**p.17**)

Most common arrangement in hydropower construction has Contractor responsible for Quality Control (QC) and Owner (or his Engineer) responsible for Quality Assurance (QA). MH is conforming to this practice

Quality Management in MH specified at high level in PEP with more detail in New Generation Construction Division (NGCD) standard. Also include third main activity, Quality Planning (QP). MH made available to KP copies of:

- Quality Management Section 5 of PEP.
- NGCD Standard #204 Quality Management (effect. 2012 07 17).
- QA/QC Requirements for Turbine Generator Contract 016321.
- QA/QC Requirements for the General Civil Works Contract 016203.

Question S5

Wrt Turbine Generator Contract:

- Contractor's own Quality Management System must "*conform fully to the spirit and intent of* (the international quality management system) *ISO 9001 2000"*.)
- Contractor also obliged to have a Project Quality Plan, a Quality Team and various Inspection and Testing Plans (ITPs).
- The document is deemed to be detailed, comprehensive and appropriate for its purpose.

Wrt General Civil Works Contract:

- Document confirms QC is responsibility of Contractor and QA responsibility of Engineer. Details not made available to KP but likely to be appropriate.

Costs of QA/QC not expressly shown – part of MH and Contractor overheads.

Knight Piésold

Question S6

“Review the overall civil contract(s) project management approach; comment on its effectiveness and what project management controls are in place to minimize cost escalations.” **(p.19)**

- GCC being managed with all procedures, processes and standards mentioned in earlier questions. Financial activities part of SAP, MH’s system-wide accounting system. Some processes new and still not finalised.
- Details provided to KP by MH in conference call:
  - "PCA"s (Project Change Authorizations) used to transfer funds to and from the project contingency, in real time.
  - There is a person in MH responsible only for managing the contingency. All significant Network #s have portion of overall contingency allocated to them and actuals and revisions to forecast are tracked.
  - MH keep a "CRR" (Contract Revision Register) that records budget changes like PCAs.

Question S6

- Also have "Dashboards" - reports tailored to present information to particular audiences. Example of dashboard included in KP report .
- Estimates of future expenditure adjusted in real time by adding inflation and deducting money spent to date. Check made at same time on expected final cost of each item i.e. budget still appropriate. Changes also recorded in other parts of estimate, to keep overall In-Service cost the same. Overall reconciliation done annually, with quarterly reports in interim. MH presently working to make this reconciliation possible more in real time.
- Schedule management correctly perceived to be as important as cost.

Question S7

"Critically review Manitoba Hydro's pre-tender construction estimates and compare with actual tender prices. Define where significant differences are noted and rationalize the specific differences." (**p.21**)

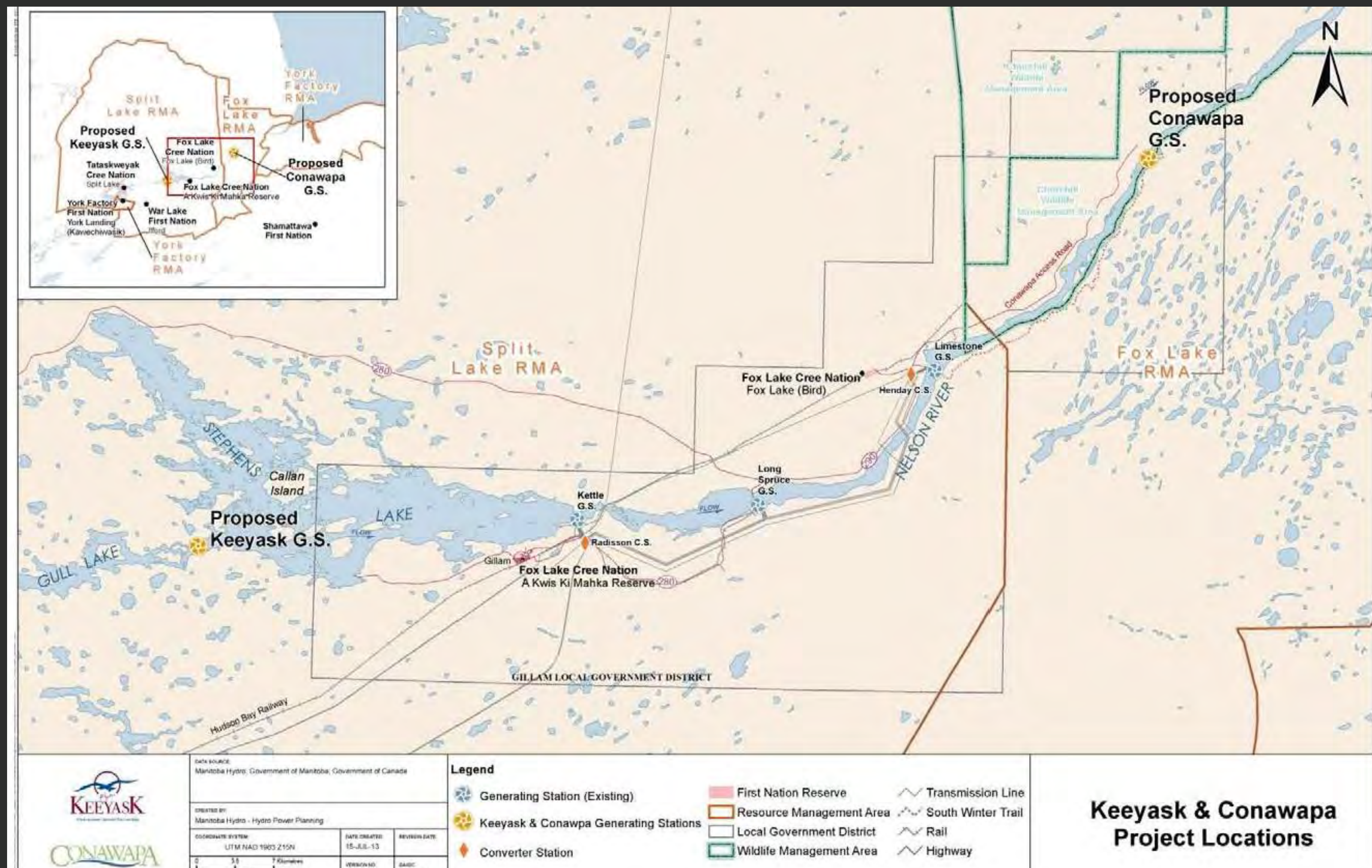
MH has provided KP with summary presentation material and Bills of Quantities comparing the GCC proposals, the independent estimators estimate (by Chant), and an escalated original Engineers Estimate by KGS Acres. KP believes that MH has been diligent in their internal comparison between the GCC tenders, their Engineers estimate and the independent Third Party Estimate. The tenderers have built into their bids their assessment of labour availability, productivity and costs.

Question S8

"Provide an opinion as to the expected in-service capital cost for Keeyask once all work has been completed." (**p.23**)

KP essentially confirms MH <u>expected</u> in-service capital cost of 6.5 B$ but is of the opinion that a more risk averse decision maker would incorporate a higher Contingency (e.g. P80 as opposed to P50) and a Management Reserve that incorporates greater allowances for labour and escalation, plus an allowance for schedule delay (primarily 2014 start date not achieved).

Conclusion


Split Lake RMA
Fox Lake RMA
York Factory RMA
Proposed Keeyask G.S.
Proposed Conawapa G.S.
Fox Lake Cree Nation
Tataskweyak Cree Nation
York Factory First Nation
War Lake First Nation
Shamattawa First Nation
N
Split Lake RMA
Fox Lake RMA
Proposed Conawapa G.S.
Limestone G.S.
Fox Lake Cree Nation
Fox Lake (Bird)
Henday C.S.
NELSON RIVER
Long Spruce G.S.
Kettle G.S.
Radisson C.S.
STEPHENS
Callan Island
LAKE
Proposed Keeyask G.S.
GULL LAKE
Gillam
Fox Lake Cree Nation
A Kwis Ki Mahka Reserve
GILLAM LOCAL GOVERNMENT DISTRICT
Hudson Bay Railway
KEEYASK
CONAWAPA
Legend
Generating Station (Existing)
Keeyask & Conawpa Generating Stations
Converter Station
First Nation Reserve
Resource Management Area
Local Government District
Wildlife Management Area
Transmission Line
South Winter Trail
Rail
Highway
Keeyask & Conawapa Project Locations

Tab 125

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

NEEDS FOR AND ALTERNATIVES TO

REVIEW OF MANITOBA HYDRO'S

PREFERRED DEVELOPMENT PLAN

Regis Gosselin - Chairperson

Marilyn Kapitany - Board Member

Larry Soldier - Board Member

Richard Bel - Board Member

Hugh Grant - Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

April 14, 2014

Pages 6675 to 6939

APPEARANCES

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Marla Boyd	(np)	)
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Helga Van Iderstine		)
Jennifer Moroz	(np)	)
Byron Williams		)CAC
William Gange	(np)	)GAC
Peter Miller	(np)	)
Antoine Hacault		)MIPUG
George Orle		)MKO
Michael Anderson	(np)	)
Jessica Saunders	(np)	)MMF
Corey Shefman	(np)	)
Christian Monnin		)IEC
Michael Weinstein		)

TABLE OF CONTENTS

LIST OF EXHIBITS

LIST OF UNDERTAKINGS

NO.	DESCRIPTION	PAGE NO.
117	Knight Piesold to update Table 9.1 in Exhibit 3-2 to include the P90 value and the P95 values	6832

--- Upon commencing at 9:02 a.m.

THE CHAIRPERSON: Good morning. I believe that we are in a position to begin today's proceedings. And before I ask Mr. Hombach to introduce the proceedings today, I have a statement I'd like to read.

Last Friday there was a mention on the transcript that the Winnipeg Free Press had published an editorial column, and had also quoted from the executive summary of the January 24th, 2014, La Capra Associates initial expert analysis report. All parties should be advised that on Saturday, April 12th, 2014, as Chair of the Public Utilities Board I received an email from Mr. Laliberte also related to the evidence of La Capra Associates.

The email that was also sent by Mr. Laliberte to counsel for CAC, MMF, and MIPUG, as well as the -- to one of the La Capra witnesses. I've instructed the NFAT project coordinator, Madam Lemoine, to post that email on the Board's NFAT website as an additional presentation from Mr. Laliberte, should others wish to read it.

I should also remind everyone that any presentations should be sent directly to the NFAT project coordinator, Madam Lemoine, or to the panel -- or the Board's executive director, Mr. Singh, rather than directly to any panel member. Those presentations will then be posted on the Board's NFAT website.

Thank you very much. Over to you, Mr. Hombach.

MR. SVEN HOMBACH: Yes, good morning, Mr. Chairman. Good morning, members of the panel. Today is reserved for the evidence of Knight Piesold, an independent expert consultant appointed by the NFAT panel to review construction and capital cost matters.

Knight Piesold is scheduled to be on for a day and a half. Today is reserved for the public session. The morning tomorrow on April 15th is reserved for the confidential, or CSI, session. And I've been advised by Manitoba Hydro that Manitoba Hydro has retained Ms. Helga Van Iderstine to handle the examination of Knight Piesold on behalf of Manitoba Hydro. I'd welcome her to the hearing room.

At 12:45 today there will also be a presentation by Mr. David Barber, so I suggest that we break on time. Lastly, Mr. Chairman, before we get started I was advised by Mr. Bill Gange on behalf of GAC this morning that GAC will not be in attendance today and will not be taking any position with respect to the evidence of Knight Piesold.

With that, Mr. Chairman, I would suggest that we turn it over to Me. Monnin to introduce and qualify the witnesses.

THE CHAIRPERSON: Thank you, Mr. Hombach. Me. Monnin, bonjour.

MR. CHRISTIAN MONNIN: Bonjour, M. President, members of the panel. Before I move to the qualifying -- qualification questions for Mr. Robertson and Mr. Fichot, I would propose to submit some documents for filing.

Mr. Secretary, the report dated March 2014 redacted, which is the first report, should be KP-3-1.

MR. KURT SIMONSEN: All right.

--- EXHIBIT NO. KP-3-1: Redacted report, dated March 2014

MR. CHRISTIAN MONNIN: The supplemental report, which is April 2014 redacted, should be 3-2.

--- EXHIBIT NO. KP-3-2: Redacted supplement report, dated April 2014

MR. CHRISTIAN MONNIN: And earlier this morning Ms. Van -- Van Iderstine, counsel for Hydro, indicated that in the supplemental report which is now KP-3-2 there was a redacted -- or a redaction that was unredacted, and that would be found at page Roman numeral II of III, and those documents -- that document has been circulated. And I would propose that that be filed as Exhibit KP-3-3.

--- EXHIBIT NO. KP-3-3: Unredacted page II of III of Exhibit KP-3-2

MR. CHRISTIAN MONNIN: We also have a slide deck for the presentation which will be provided by KP today, and that would -- I propose that would be KP number 4.

--- EXHIBIT NO. KP-4: Slide deck for presentation

MR. CHRISTIAN MONNIN: There's the scope of work for KP dated September 20th, 2013. I would propose that that be KP number 5.

--- EXHIBIT NO. KP-5: Scope of work for KP, dated September 20th, 2013

MR. CHRISTIAN MONNIN: The supplementary scope of work, which sets out the work that -- that was done on the supplementary report that's dated January 13th, 2014, I would suggest that that be KP number 6.

--- EXHIBIT NO. KP-6: Scope of work for KP, dated January 13th, 2014

MR. KURT SIMONSEN: Thank you very much.

MR. CHRISTIAN MONNIN: Thank you, Mr. Secretary. With that, I would propose to put the qualification questions to Mr. Robertson, who's immediately to my left, and then to Mr. Fichot, and then I would ask the panel to take the next step with regards to qualifications.

THE CHAIRPERSON: Did swear these witnesses in?

MR. CHRISTIAN MONNIN: We did not. Thank you, Mr. President.

IEC KNIGHT PIESOLD PANEL:

MICHAEL ROBERTSON, Sworn (Qual.)

BORIS FICHOT, Affirmed (Qual.)

QUALIFICATION OF WITNESSES:

MR. CHRISTIAN MONNIN: Mr. Robertson, you're here on behalf on Knight Piesold, which has been retained by Manitoba Public -- by the Manitoba Public Utilities Board in order to assist the PUB to conduct a Needs For and Alternatives To review of Manitoba Hydro's proposed Preferred Development Plan.

Is that correct?

MR. MICHAEL ROBERTSON: Yes.

MR. CHRISTIAN MONNIN: Knight Piesold has prepared two (2) reports which have been filed in accordance with the terms of reference of the NFAT and in accordance with Knight Piesold's scope -- scopes of work dated September 20th, 2013, and January 13th, 2014, to critically review certain aspects of Manitoba Hydro's Preferred Development Plan and filings.

Is that correct?

MR. MICHAEL ROBERTSON: Yes.

MR. CHRISTIAN MONNIN: Were these reports prepared by you or under your supervision and control?

MR. MICHAEL ROBERTSON: The -- the reports were prepared by myself and Mr. Fichot as co-authors and co-reviewers, and I take full responsibility for the final product.

MR. CHRISTIAN MONNIN: Can you please describe for the Board the primary areas of focus in -- in your work for the PUB?

MR. MICHAEL ROBERTSON: We -- we were asked by the PUB to comment on Manitoba Hydro's proposals with regard to construction management and capital costs. In more detail, we -- we were posed in the first scope of work nine (9) questions by the -- by the Board, and in the second one, a further eight (8) questions.

The first nine (9) questions were to comment on the capital and operation and maintenance cost estimates for Conawapa and Keeyask generating station, to comment on the construction indirect costs for Conawapa and Keeyask generating stations; to assess the construction management schedule and contracting plans for Conawapa and Keeyask generating stations; to review the capital and operation and maintenan -- maintenance cost estimates for wind, natural gas, combined-cycle gas turbines, and solar facilities; comment on the construction management plan's schedule and contracting methods for wind, natural gas, combined-cycle gas turbines, and solar facilities; to look into the factors that led to the cost increases over successive capital expenditure forecasts; to provide a historical perspective of construction costs of other Lower Nelson River generating stations; to provide a justification for the increasing direct and indirect costs; and to provide a high-level assessment of the construction planning and management of construction costs of Manitoba Hydro's Preferred Development Plan.

So those were the first nine (9) questions in the -- which have been covered off in the main first report that we produced.

The second report and the second scope of work comprised eight (8) questions, which were overall management strategy and scheduling for the tendering of the contracts for the Keeyask generating station; to comment on the construction risk management strategy that Manitoba Hydro is following; to comment on the documents from the major Keeyask component; to review the construction and equipment procurement bonding and liquidated damage requirements; to comment on the quality assurance and quality control requirements; to review the overall civil contract project management approach; to comment on the pre-tender construction estimates compared to the actual tender prices; and finally, to review the expected in service capital cost for Keeyask.

MR. CHRISTIAN MONNIN: Thank you, Mr. Robertson. Your curriculum vitae has been filed with the -- the PUB as part of Exhibit Hill Co. number 9, specifically, Tab 5B.

Can you describe your qualifications and experience generally and specifically as they relate to the work undertaken by KP?

MR. MICHAEL ROBERTSON: Yes, I am -- I'm a civil engineer with a British degree. I have been in the business for forty-four (44) years, since I graduated. Pretty much all of that experience has been with water resource development, dams, large dams, irrigation schemes, hydro power, and some work on -- on mining. But most of it has been dams and hydro power schemes.

Of -- of particular relevance, I believe, to -- to today's proceedings is the work that I did with the consumer advocate for Newfoundland and Labrador in a similar process to this when the Muskrat Falls proposals were being reviewed, and we -- we were the engineers that -- that advised the consumer advocate.

And apart from that, I've been involved with any number of hydro electric power developments, primarily in British Columbia, but also looking at providing hydro power for mines around the world in remote locations, where diesel power generation is -- is very expensive. So we've -- I have worked in countries all around the world doing that.

MR. CHRISTIAN MONNIN: Thank you, Mr. Robertson. Can you generally -- can you describe generally the type of clientele that Knight Piesold does work for?

MR. MICHAEL ROBERTSON: Primarily independent commercial entities, independent power producers in British Columbia and around the world, and mining companies. As I -- as I mentioned, mining companies, we -- Knight Piesold does do a lot of geotechnical engineering for mining companies. But my experience on mine -- mining developments has been in -- in the provision of hydro power to power those mines.

We've also worked for -- for BC Hydro, in terms of detailed engineering on -- on replacement projects for them such as Aberfeldie in Southeast BC. I've done a lot of dam safety review work for people like TransAlta and FortisBC, and -- and some engineering also for -- for TransAlta replacement projects.

So -- but -- so mostly independent commercial owners, but some utilities like -- like

Manitoba Hydro.

MR. CHRISTIAN MONNIN: Thank you, Mr. Robertson. Mr. Chair, before I ask for the -- the Board to accept Mr. Robertson as a -- as an expert, I would suggest I put the same questions to Mr. Fichot.

Mr. Fichot, you're here on behalf of Knight Piesold, which has been retained by the Manitoba Public Utilities Board in order to assist the PUB to conduct a Needs For and Alternatives To Review of Manitoba Hydro's Preferred proposed -- sorry, proposed Preferred Development Plan.

Is that correct?

MR. BORIS FICHOT: That is correct.

MR. CHRISTIAN MONNIN: Mr. Fichot, Knight Piesold has prepared two (2) reports which have been filed in accordance with the terms of reference and also in accordance with the scopes of work for Knight Piesold dated September 20th, 2013, and January 13th, 2014, to critically review a certain aspect of Manitoba Hydro's Preferred Development Plan and filings.

Is that correct?

MR. BORIS FICHOT: That is correct.

MR. CHRISTIAN MONNIN: Were these reports prepared by you or under your supervision or control?

MR. BORIS FICHOT: Yes, I co-authored those reports with Mike Robertson.

MR. CHRISTIAN MONNIN: Now, you heard Mr. Robertson provide a -- a description of the primary areas of the focus in the -- in the work conducted by Knight Piesold.

Do you care to add to that?

MR. BORIS FICHOT: No.

MR. CHRISTIAN MONNIN: Mr. Fichot, your curriculum vitae has been filed with the PUB as part of Exhibit Hill Co. number 8, Tab 5A.

Can you please describe your qualifications generally and specifically as they relate to the work undertaken by Knight Piesold in these proceedings?

MR. BORIS FICHOT: Yes. I'm a civil engineer, bachelor's degree from McGill, master's degree from Colorado State 'U' in water resources planning and management. I've got over twelve (12) years' experience. I've worked for three and a half (3 1/2) years with the Lower Colorado River Authority, which is a similar entity to Manitoba Hydro. I worked in the -- the planning department there.

Then I've worked with Knight Piesold

after that, mainly working on hydro power projects in the consulting fields. I've worked on everything in hydro power from green-field assessments all the way through detailed construction, supervision, and -- and implementation.

I've worked on due diligence for a number of entities on hydro power projects. I've done due diligence on wind power -- power projects, as well.

MR. CHRISTIAN MONNIN: Mr. Fichot, you've also heard Mr. Robertson provide a description of the general clientele that Knight Piesold does work for.

Do you care to add to that?

MR. BORIS FICHOT: I'll add that Knight Piesold is a -- is a consulting firm that works a lot with mining clients. But one of the primary focus when you work with mining clients is on tailings dams, so it relates to embankment construction, as well.

I've personally worked with First Nations and INAC on some due diligence on hydro power projects, as well. We do due diligence on hydro power projects for investment firms that are looking to invest in -- in hydro power projects. So we'll write reports and do -- do an analysis on that front for them.

But the -- the bulk of the clientele, as -- as Mike Robertson said, is -- is independent power producers with some work for -- for major utilities. And the -- the mining clients that we work for typically are mines in remote places that are looking for resources to -- to supply electricity for them. So we'll do a comparative analysis of hydro power and, on occasion, wind power and some other options to -- to supply the mines.

MR. CHRISTIAN MONNIN: Merci, Mr. Fichot. Mr. Chair, with that, I would ask that Mr. -- Mr. Robertson and Mr. Fichot be accepted by the Board as experts for the purposes of giving evidence on the work performed by Knight Piesold according to their respective scopes of work under the NFAT.

THE CHAIRPERSON: Thank you, Me. Monnin. I'd like to hear from the Intervenors, starting with you, Ms. Menzies.

MS. MEGHAN MENZIES: Thank you, and good morning. CAC (Manitoba) has no objections to these qualifications.

THE CHAIRPERSON: Thank you, Ms. Menzies. Me. Hacault, s'il vous plait.

MR. ANTOINE HACAULT: On behalf of

MIPUG -- MIPUG, we have no objections to the qualifications of these two (2) experts.

THE CHAIRPERSON: Merci, Me. Hacault. Mr. Orle, please, on behalf of MKO?

MR. GEORGE ORLE: We have no objection to the witnesses being qualified as experts. Thank you.

THE CHAIRPERSON: Thank you, Mr. Orle. Could I hear from Manitoba Hydro, please?

MS. HELGA VAN IDERSTINE: We have no objection to their being qualified, as well. I would, however, just alert you to the -- during the cross of these witnesses, I may ask some questions about their qualifications, but it's not going to go towards their -- whether or not they are qualified to give this evidence. So we accept them as experts. Thanks.

THE CHAIRPERSON: Thank you, Ms. Van Iderstine. Mr. Hombach, would you like to comment or do you...?

MR. SVEN HOMBACH: I have no further comments. If the panel is satisfied with the witnesses' credentials, it is up to the panel whether or not to accept them as expert witnesses.

THE CHAIRPERSON: Thank you, Mr. Hombach. Just a second, please.

The panel is in agreement. We'll accept both Mr. Robertson and Mr. Fichot as expert witnesses for the purposes of these proceedings. So back to you, Me. Monnin.

EXAMINATION-IN-CHIEF BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: Merci, Me. President. I can advise that Mr. Robertson will be doing the presentation on behalf of Knight Piesold this morning. I advised Mr. Hombach yesterday evening they are making a presentation for two (2) reports, and we expect that presentation to be about an hour and fifteen (15), an hour and twenty (20) minutes.

On the CSI portion of their presentation, I advised again My -- My Friend, Mr. Hombach, that I don't expect that to be more than fifteen (15), twenty (20) minutes, so just to give you an idea of time.

MR. MICHAEL ROBERTSON: Excuse me. Good morning, ladies and gentlemen. The presentation that is -- that I'm going to do now is formatted along the lines of the -- the nine (9) questions in the first report and the eight (8) questions in the second report. So the documents and materials that I'm relying on are those two (2) reports, both the CSI and the redacted or public versions.

There were a number of Information Requests from us to -- to Hydro, which are -- which we used in -- in producing our opinions. And there are Knight Piesold responses to the IRs, a few of which contain CSI.

We quoted a number of references in our reports, but we're not providing separate -- separately copies of those in this proceeding. And as a general comment, most of the information that we have relied upon has been provided by Manitoba Hydro, mostly CSI in hard blue paper copy, and in some emails.

And as -- as Christian has -- has allude -- has mentioned, these reports were produced by me and Boris Fichot, and some contributions obviously from other Knight Piesold engineers, but all under my supervision and control. Versions that are quoted here are the final versions. There are no revisions, updates, or corrections that we wish to make to them.

The -- we -- we need to note that the -- the CSI version of the report in -- in the bottom right-hand corner erroneously is still labelled Revision A of February the 18th, 2014. And my apologies. That should have been Revision 0 of April the 8th, 2014. And then, as you know, we will talk to the CSI content tomorrow.

Moving on to slide 3, the scope of work was provided by those nine (9) questions which I have numbered 1 to 9 in the first report, and the second set of questions I have labelled S1 to S8.

And because of the timing, some of the data that I am talking to in the first nine (9) questions was out of date by the time we did the second. And so there have been some updates and some changes, and that will be detailed in the presentation.

So slide 4, Question 1, the question was:

"Review and assess Manitoba Hydro's capital and operation and maintenance cost estimates for Conawapa generating station and Keeyask generating station, including the adequacy of the management reserves for the project."

So the general methodology for forming the capital cost estimates used by Manitoba Hydro -- and in yellow here on these -- on this slide deck I have referenced the page of the report that I am quoting for ease of reference. So that's -- this is on page 11 of the first report.

The -- the graphic there shows that Manitoba Hydro builds up their estimated in-service cost by starting with a point estimate, which comprises direct costs and indirect costs. And it essentially is the -- the best estimate.

To that is added an allowance -- two (2) allowances for uncertainty: contingency and a management reserve. And together, that is known as the base cost. That is at a particular date. And then to bring that up to any other date, like today, you multiply by the interest and escalation from that date to today, and you add the money spent to date, and you end up with the total expected in-service cost for the project.

The direct costs are those directly related to doing the generation station work; in other words, the labour, materials, and equipment involved in providing the structures.

The indirect costs are all the other capital costs; for example, the provision of site infrastructure and services, the costs of the engineering and project management, and environmental activities. And this is expanded upon in our answer to Question 2.

Moving on to slide 5, allowances are

made for the uncertainties in the point estimate through the contingency which includes two (2) types of risks: systemic risks, which are risks associated with a process that is being followed by Manitoba Hydro -- in other words, the system that they are using to manage the -- the project; and then project-specific risks, which are uncertainties specific to Keeyask and Conawapa. For example, in -- in that case, we are talking about things like foundation conditions, the weather up north, delay in delivery of items, constructability, the availability of resources, and quality.

Now, Manitoba Hydro has elected to assess the contingency at what is known as the P50 level, i.e., there is a 50 percent probability that the final project cost will be less than the number given, and there's a 50 percent probability that it'll be more, and on page 24 of our report, you can obtain more detail of that.

Slide 6. The other allowance for contingency is the management reserve, and this includes an allowance for two (2) specific risks for escalation over and above CPI. So escalation at CPI is included in the point estimate, and this reserve makes a provision for escalation in excess of CPI.

And then the second part of the management reserve is a labour reserve, which is a special pool of money that has been set aside to cater for the possibility of labour costs and/or productivity being different from what was assumed in the point estimate, and these reserves were set up as a direct result of the Wuskwatim experience, and that Wuskwatim experience is examined in further detail in question 9 that follows.

Now, in -- in my experience -- in Knight Piesold's experience, contingency usually includes the management reserve, but Manitoba Hydro have chosen to split them up, if only, we understand, because the two (2) allowances are managed differently within Manitoba Hydro.

So slide 7, just reminding you how the in-service cost is built up. You start with a point estimate. You add the allowances for uncertainty. You end -- you end up with a base cost. You then -- so the base cost is the expected final cost before adding the effects of interest on borrowed capital and escalation, and money spent to date. And you add all of those up, and you have the in-service cost.

So the first thing we did, looking at Manitoba Hydro's cost estimates for these two (2) projects, was try and ballpark them by comparing them with the capital cost estimates of similar projects in Canada. And on the table there, you can see that we looked at Muskrat Falls, and as I mentioned, we -- we were involved in that review.

Site C in British Columbia is at a similar stage of development as -- as Keeyask, although somewhat behind. Petit -- Petit Mecatina Projects in Quebec. Unfortunately we're not able to get capital costs, but it's another big project that is being developed at the moment. La Romaine in Quebec, and then to those big hydro projects in Canada being developed by others, we have compared Keeyask, Conawapa, and we put Wuskwatim in there.

The -- the two (2) yardsticks we -- we used are the capital cost in billion dollars per megawatt of capacity, and also the capital cost in million dollars divided by the average annual energy that that project is slated to produce.

And you can see that Keeyask and Conawapa are in the ballpark. They are high within that ballpark, but they are in the ballpark, and so they are not radically different.

The second part of the question, slide 9, relates to operation and maintenance costs, which I show in that table. These costs include wages, salaries and benefits, and training. In the initial years insurance, partnership expenses, internal administrative costs, internal and external consulting environmental services, accommodation, and then in later years, capital maintenance as the mechanical/electrical equipment requires upgrades, replacements, and/or refurbishments as required.

On slide 10, the conclusions on question 1 regarding capital cost estimates. We believe that Manitoba Hydro's estimating process has been thorough based on a detailed design, estimation of quantities, and initial bottom-up approach to unit rates in 2009 for Keeyask and 2010 for Conawapa, major updates to 2012 based on the results of Wuskwatim, and then inclusion of allowances for uncertainty.

We'd make the point that there is more clarity in the Manitoba Hydro process of a direct costs than an indirect. And I'll pick up on that again in Question 2. And make the comment that many jurisdictions use a higher value than a P50 estimate to establish the contingency, but a significant number of others do not. They also use the P50.

Regarding operation and maintenance costs, we believe the estimated costs are commensurate with similar hydro projects elsewhere in Canada.

So that was a long question. I don't know if there are any questions from the panel or anybody else at this stage? Okay. Moving on to Question 2 at page 11.

(BRIEF PAUSE)

MS. MARILYN KAPITANY: The capital estimates here are the -- I think we have revised information on those capital estimates. So did you look at this table in the context of the revised estimates, and would your judgment still remain the same of whether or not Keeyask and Conawapa fall into the category of high but reasonable?

MR. MICHAEL ROBERTSON: Yes, we -- we have -- we are aware, obviously, of the -- the increase in the in service estimated capital cost. And we will be dealing with that in the second set of questions, once that information became available from Hydro. And, no, I don't believe that increase changes our essential conclusion that it -- that these projects are in the ballpark, but at the high end of it.

MS. MARILYN KAPITANY: Okay.

MR. MICHAEL ROBERTSON: So moving on to

Question 2, slide 11:

"Review and assess Manitoba Hydro's construction indirect costs including the access roads, campsites, and offsite mitigation costs for Conawapa GS and Keeyask GS."

The -- a reminder, the indirect costs include all temporary and permanent items not directly associated with the primary structures but still required to successfully implement the project. And you can find details on page 34 of our report. So that includes the preconstruction costs; site infrastructure, including access roads and campsites; site services; engineering and project management; environment and litigation activities; general expenses, including consultants, travel, site office, insurance; and First Nation participation payments.

So much of the construction work, the indirect construction work, was provided in the Keeyask Infrastructure Project, KIP. In general we found the information provided by Manitoba Hydro to be sensible. But as I alluded to earlier, we could not offer an opinion on costs like the internal Manitoba Hydro project management and other costs and general expenses.

The indirect costs, just to note, exclude related costs to date, or money spent. And Manitoba Hydro has stated that the indirect costs form approximately one-third (1/3) of the point estimate.

Moving on to Question 3, slide 12: r

"Review and assess Manitoba Hydro's construction management schedule and contracting plans for the design, engineering, procurement, construction, startup, commissioning, testing, and commercial operation of Conawapa generating station and Keeyask generating station."

So Manitoba Hydro created a Project Execution Plan, PEP, for the Keeyask project. The details are on page 40 of our report. It is a high-level management guideline which describes the means, methods, tools, and techniques used to manage the KIP and the KGSP. The KGSP is the Keeyask Generating Station Project. So Keeyask comprises these two (2) projects.

It serves as a record of the planning effort undertaken by Manitoba Hydro for the construction phase of the project, and it serves as a resource for staff to ensure that the project is managed consistently.

Slide 13. The PEP is backed by a number of Manitoba Hydro corporate policies and standards, the most important of which that we have seen are the total cost and schedule management standard, monitor and control of engineering consultant standard, preparation of project dashboards and tren -- trend analysis standard, project change authorization process, work package change management process, consultant communication plans, division plan for managing the consultants, and engineering work package scope sheets.

So Knight Piesold is able to see that Hydro has good procedures in place for the management of the projects, despite the fact that the PEP is presently only in its draft form.

THE CHAIRPERSON: That last set of words, Despite the PEP pres -- presently being in draft form only, should we attach any significance to that?

MR. MICHAEL ROBERTSON: My opinion would be probably not, but it's -- it would be nice to see that finalized if that is the management tool that is being used by BC Hydro, as they -- Manitoba Hydro, forgive me. Manitoba Hydro are -- are moving into serious expenditure and construction. I believe that should be finalized.

Moving on to slide 14, contracting methods considered by Manitoba Hydro for the various contracts included -- details on page 42 -- fixed-price contract, FPC; or otherwise known as EPC, engineer, procure, construct; and also known in the trade as design bid -- design build. Essentially, they're different names for the same thing.

Second alternative would be a cost-reimbursable contract, or CRC; direct negotiated contracts, DNCs; unit price contract, UPC, which is the traditional way of procuring large civil construction works in the industry historically; and then supply-only contracts, which are lump sum.

From the contracts seen by Knight Piesold, it is apparent that Manitoba Hydro has made appropriate choices for different contracts. For example, it is using a fixed-price contract for the turbine generating equipment and a cost-reimbursable contract for the main civil works.

The main civil works contract -- the acronym is GCC -- is also utilizing an early contractor involvement process to obtain input from the chosen contractor to refine the design, the construction technique, the schedule, and risk sharing. And we believe that to be entirely appropriate.

Slide 15. The Preferred Development Plan includes an implementation schedule. Schedules are also provided in the basis of cost estimate documents. The schedules are consistent, we believe, with the described developments and the anticipated work breakdown structures.

A more detailed and complete schedule for Keeyask was included with the tender package for the general civil contract, and all tenderers essentially confirmed that schedule as part of their bids. And the -- the details of that schedule are being refined as part of the ECI process.

The one (1) omission in the schedules was the details of time needed for input by Manitoba Hydro, such as refused by them -- reviews by themselves or their independent engineers.

And then the PEP for Keeyask states that execution will follow the Hydro cost and schedule standard for schedule management.

THE CHAIRPERSON: Mr. Robertson, that reference to the fact that the schedule did not include time for review by Manitoba Hydro or the independent engineers, that suggests that the schedule could be impacted if they haven't planned for it?

MR. MICHAEL ROBERTSON: Yes, it could

be impacted. I -- we just don't know whether there is any time associated with approvals of the contractors' plans, for instance, which -- which might be significant, or whether effectively that is built into the -- into the existing bars in the Gantt shot.

I guess it's just a caution that, if Manitoba Hydro do take a long time to approve things, it could impact the schedule.

THE CHAIRPERSON: There was an earlier reference to the fact that the indirect cost represented about a third of the -- of the costs associated with the -- the Keeyask plant.

Is that unusual that it be one-third (1/3) as opposed to some other figure?

MR. MICHAEL ROBERTSON: It -- it's -- it's very much site specific, obviously, things like access and remote camps and things like that. But it is also very much a reflection of the -- the management by the developer, the management costs, internal management costs.

So I would have to say that's probably higher than our independent power plants, who -- who possibly don't spend so much money on that kind of thing.

THE CHAIRPERSON: I think that one (1)

of the questions I had -- as I recall reading in your report, there was a -- a -- sort of a side reference to the fact that this was a government-utility-run project, and kind of an allusion -- allusion to the fact it would be more expensive than a -- than a private project?

Did I misread that, or -- is that what you were trying to convey?

MR. MICHAEL ROBERTSON: You did not misread that. In my experience, that is the case. And it's not unique to Manitoba Hydro.

THE CHAIRPERSON: And -- and what is the cause of that? What -- what would be different in --

MR. MICHAEL ROBERTSON: I -- I think it's just a bigger machine that -- that needs feeding, and the -- the backup costs are -- are higher, for whatever reason.

MS. MARILYN KAPITANY: Could we just go back to the contract methods for one (1) minute?

Did I hear you say that the unit price contract would be the type of contract most usually used for this type of project?

MR. MICHAEL ROBERTSON: No. What I meant to say was that unit price contracts certainly used to be the traditional method of -- of procurement. In fact, the -- the cost reimbursable contact that Manitoba Hydro is using for the GCC is -- is a variation of -- on that.

It -- it is still based on quantities and on unit prices, but there is a target set, and there are procedures for dealing with anything over and above the target. So it -- it's like a refinement, or a halfway house, if you like, between a unit price contract and fixed price contract.

MS. MARILYN KAPITANY: Thank you.

THE CHAIRPERSON: There's also reference in your report -- and I'm not sure if this is an appropriate time to ask the question, but there was also a reference in the report -- a discussion in the report, rather, about escalation of capital costs and the appropriateness of using CPI as the measure for escalation.

I can't remember offhand; I'm just trying to recollect what -- how it concluded. But you indicated -- I believe you indicated that that is a measure used by most utilities, although it may not be the most appropriate measure. Now, you provided some data as well from another source that indicated what would represent a more appropriate inflation factor for capital projects.

Could you discuss that just for a second, please?

MR. MICHAEL ROBERTSON: We -- we do address that further down the line, but essentially historical evidence is that capital works like this have not escalated at CPI. They've -- they've escalated a higher than CPI. And therefore -- you know, and -- and Manitoba Hydro does recognize that and they have provided one (1) part of their management reserve to cater for the possibility or likelihood that, in fact, escalation is going to be higher than CPI. I'm sorry, does that answer your question?

THE CHAIRPERSON: It does in part. I'm just trying to get a sense of what factor was used by Manitoba Hydro as an escalation factor. Do -- do you recall, or do you...?

MR. BORIS FICHOT: Yes. Our understanding is that they've calculated an index based on a number of sour -- reputable sources related to materials and projected costs of materials that come up with what they called a 'Hydro index of escalation'. And then they used that number -- a variation of that number to come up with the anticipated escalation, and then calculate the difference between that number and CPI, and use that to calculate the management reserve.

The basis -- they've got a scientific basis behind that number that they -- that they've used to justify. And their internal standard dictates that when they're escalating projects, it must be accord -- in accordance with CPI.

THE CHAIRPERSON: So the figure that -- well, ultimately used, is it much different than regular capital projects undertaken by a utility?

In other words, I'm trying to get at -- trying to understand the difference between CPI appropriate to a large construction project like this one and CPI that would relate to a regular capital update program that Manitoba Hydro would undertake.

MR. BORIS FICHOT: I believe that in -- in most instances you would use the scientific number, which is the -- what you anticipate the -- the escalation to actually be, as opposed to CPI. And in the report, we refer to what's in the public domain as Muskrat Falls anticipated escalation, which is higher than CPI.

THE CHAIRPERSON: Thank you.

MR. MICHAEL ROBERTSON: And -- and we will -- Mr. Chair, we will be examining that further.

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: Okay, if we're moving back now to slide 16, question 4:

> "Review and assess Manitoba Hydro's capital cost and O&M cost estimates for wind, natural gas, combined cycle gas turbines, and solar facilities."

So firstly, wind, page 50 of our report, the capital cost. Manitoba Hydro has assumed an overall capital cost of twenty-one hundred dollars ($2,100) per kilowatt, excluding major transmission, in the comparative exercises they have undertaken.

From the data in the next slide and data from other jurisdictions, we believe that a figure of eighteen hundred dollars ($1,800) per kilowatt is deemed to be more appropriate, and yet still sufficiently conservative for this exercise.

I'll turn to the O&M costs. Manitoba Hydro's assumption of an O&M cost of approximately forty dollars ($40) per kilowatt is appropriate and it is within the recommended range of thirty-five (35) to fifty-five dollars ($55).

Now slide 17 shows the trend in prices of wind turbines, and -- and, essentially, the point we're making is that, whilst twenty-one hundred dollars ($2,100) per megawatt might have been appropriate in 2009 at the peak of the costs, those costs have dropped significantly since, and there is no thought in the industry that they are going to go back up again in -- in any significant manner, and therefore, in the exercise, a -- a figure of eighteen hundred dollars ($1,800) per kilowatt would have been more appropriate than twenty-one hundred (2,100).

On slide 18, to do with natural gas combined cycle turbines, the details are on page 53 and 4 of our report, Manitoba Hydro has assumed a capital cost of 1.3 million per megawatt. We've deemed that to be appropriate. On the chart there, you will see where my cursor is, that's Manitoba Hydro's point, and you can see that it's very much in the middle of the scatter of the historical record.

So in -- so in terms of capital costs, we believe they're -- they're okay. In terms of the operation and maintenance costs, they've assumed twenty dollars ($20) per kilowatt per year, and three dollars fifty ($3.50) per kilowatt hour, which we are -- which we also deem to be reasonable, and they're within the recommended range of six dollars thirty ($6.30) to twenty-two (22) kilowatts -- dollars per kilowatt per year.

Slide 19, solar on pages 55 and -- to 57 of our report. The -- Manitoba Hydro's present assumptions on capital costs are deemed appropriate, but again, solar costs have been reducing significantly in recent years, and so one could logically use a -- a lower number, and the chart basically shows how the prices have been coming down.

That's all we have to say on question 4. Moving on to question 5, slide 20:

"Review and assess Manitoba Hydro's construction management plan schedule and contracting methods for the design engineering procurement construction start-up, commissioning testing and commercial operation for wind, natural gas, combined cycle gas, turbines, and solar facilities."

Wind, on page 58, Manitoba Hydro assumed that wind power projects will be developed in-house, whereas an observation is that the existing Manitoba wind farms have been developed by independent power producers. The time frame is assumed to be three (3) to five (5) years, including the resource assessment.

Asset life is assumed to be

approximately twenty (20) years. We have no further details from Manitoba Hydro, and we understand that wind will only be developed if and when wind becomes cost competitive.

Slide 21. With regard to natural gas combined cycle gas turbines, the NFAT assumes the development by Manitoba Hydro and construction through EPC contract. The time frame is assumed to be three (3) to five (5) years, which is reasonable, but it might be shorter. It could be two (2) to four (4) years, depending on turbine supply time and how much demand there is at the time.

Again, we have no further details from Manitoba Hydro, and we understand that this energy source will be developed as the Preferred Development Plan proceeds.

Solar page 59, the Manitoba Hydro assumes a time frame of three (3) years for development and construction of a generic 20 megawatt facility. This could be reduced if and when solar is perceived to be a key energy resource in the future.

Moving on to Question 6, page 22 -- slide 22. Review Manitoba Hydro's capital expenditure forecasts, essentially from the capital expenditure forecast of 2009 through 2013. That first table, which is from page 60 of our report, shows that, for example, Keeyask has gone from 4.6 billion in 2009 to 6.2 billion in 2013, and as we know, in 2014, it went up a little bit more.

Now, the significant factors in those cost increases, which are detailed in page 61, are the delay of in-service dates, which adds project management interest and escalation costs, and you can see in the -- in the table below there that Keeyask effectively has lost a year over those four (4) -- five (5) year estimates, and Conawapa has lost four (4) years.

There was a big shift from '09 to -- to 2010 due to the update -- updated detailed cost estimates by KGS-Acres. In other words, a much better project definition in terms of design and -- and real quantities, and cost estimates from the bottom up. So I guess 2010 was the first real -- real detailed cost estimate.

And then the other big jump came from 2011 to 2012, and that essentially is the Wuskwatim experience, whereby the -- a -- a management reserve was added to deal with the -- the probability that you're going to have a -- a higher escalation than they had assumed, and changing interest rates, and that is detailed further in our reply to Question 9.

Slide 23, Question 7.

"Provide a historical perspective on the construction cost components of other Lower Nelson River hydraulic generating stations, which were Limestone, Long Spruce, and Kettle, and analyze the major components of direct costs, including: a) spillways, dams, dikes; b) power houses; and c) turbines and generators, and compare these to the Keeyask and Conawapa GS costs for these components."

At the outset, we have to say that a meaningful assessment is not possible with the information that has been made available to us. Manitoba Hydro did provide the total costs of those projects, but not the individual component costs, so we cannot comment on it component by component. They also did provide the major quantities.

As a general observation, the -- there have been very significant differences between the contracting construction environment at that time, which was 1992 back to 1973 for those three (3) projects and now. And in now, we include Wuskwatim and the estimates for Keeyask and Conawapa. Page 64 of our report is the reference.

First the -- the Manitoba Hydro is now engaged in a partnership framework with the First Nations. There has been a significant increase in the rigour of the environmental process, which came into force after Limestone, and -- and associated with that is that, certainly initially, there was a lack of regulatory capacity in Manitoba to deal with these new requirements and to ensure that proponents were following them, and labour costs and productivity.

My apology, we were -- I was going to try to move this table so that you could see what was underneath it, but... The Limestone example, page 65, this is slide 24. It was completed in 1992 on time and within budget, at a total cost of 1.43 billion. Using the quantities that we obtained from Manitoba Hydro and Knight Piesold's typical unit costs for -- or unit rates for those types of work, the excavation, the earthfill concrete, the generating plant, et cetera, we would estimate that at about 2.2 billion today. However, if you escalate the 1.43 billion at, say, 2 1/2 percent for eleven (11) years, we only get 1.88 billion, which is less than the direct cost alone, let alone adding all the other costs to provide the in-service cost.

So -- and -- and going back to that first ballparking yardstick which I showed you, with a capacity of 1,314 megawatts that gives a cost of $1 million per megawatt, which was a very traditional figure back in the day, and you compare that with eight point nine (8.9) for Keeyask and six point nine (6.9) for Conawapa, clearly things are very different now from what they were.

Slide 25. Long Spruce. Very little information. We -- we were told that it cost 508 million when it was completed in 1979, with a capacity of approximately, you know, 1,010 megawatts. That gives you a cost of point five (.5) of a million dollars per megawatt, which is about the cost of the turbine generators alone today. And we have no information regarding the schedule and the cost performance.

Kettle, even further back. Commissioned in 1974 for a cost of 240 million. Capacity of 1,220 megawatts gives this ballpark parameter of $.2 million per megawatt. And again, we have no information regarding the schedule and the cost performance.

Slide 26. Question 8:

"Analyze Manitoba Hydro's
justifications for increasing the
direct costs and for increasing the
indirect costs with respect to: a)
labour productivity and shortages,
competition with other large civil
projects in Canada, remote location,
Northern and First Nation jobs, and
other contractual hiring
constraints."

Dealing first with labour productivity and shortages, the details are on page 66 of our report. The labour productivity and the construction industry is documented to have decreased since a peak in the 1970s, mainly due to a reduction in skill level. Other factors include a decline in the number of employees, the capital to labour ratio, percentage union, and average age of workers. And Canada has experienced at least a decade of labour shortages.

Manitoba Hydro have attribulated -- have attributed the lack of productivity to the difficulties in hiring and/or retaining staff and the use of inexperienced staff. As a result of the low productivity experienced at Wuskwatim, Manitoba Hydro has, for Keeyask and Conawapa, adjusted the contracting methods, added staff, and invested in better camp facilities. And these are deemed to be reasonable measures.

Slide 27. Competition with other large civil projects in Canada. Details on page 66 of our report. Forty (40) percent of the overall project workforce for Wuskwatim was out of province; and for the generating structure itself specifically, it was more 60 percent of the labour had to come from out of province. Keeyask's demand on labour is greater, and the situation is likely to be even worse. In other words, probably going to have to find even more than 60 percent of the labour from outside of the province.

As -- as -- in support of that, we have found in British Columbia that, for our recent hydro projects that Knight Piesold has been involved with, there has had to be a significant importation of labour from Eastern Canada. And Manitoba Hydro is relying on offering competitive wages and an attractive camp environment in -- in this competitive situation.

The third point with regard to labour was the remote location, dealt with on page 66 of our report. Yes, the location is remote but it is known, and therefore is factored into the cost estimates already, and it's factored into the contractor's bid prices. So there should be no surprises. And also factored in are the fact that staff rotations are necessary to -- to get people in and out of these remote sites and to keep them happy.

Northern and First Nation jobs on page 67, similarly, yes, it's a remote Northern project, but that's always been part of Canada's nonresidential construction outlook. There are a number of other natural resource development and mining projects in the pipeline, and we expect that to grow significantly through 2020.

Slide 28, other contractual hiring constraints, details on page 67. The Burntwood Nelson agreement sets out the terms for the hands-on tools, basically, the -- the labour -- the -- the craft labour workers, including the First Nations contributors, on hydro projects in Northern Manitoba.

This is a collective agreement between the Hydro Project Management Associating representing the contractors and the Allied Hydro Council of Manitoba representing the unions.

The general civil contract tenders that were expressly included that the tenders had to comply with the BNA requirements. And then it was anticipated at the time we produced that first report that the --

the assessment of the bidders, the large contractors, they -- they would effectively provide their assessment of the difficulties of hiring and retaining labour for that work. And that's picked up further in Question S7.

Question 9, "Provide" -- this is slide 29:

"Please provide a high-level assessment of the construction planning and management of the construction costs of the new Preferred Development Plan project, including the experience gained from Wuskwatim."

So just referring back to Question 3 to do with construction planning and management of construction costs. And we'd also pick that up on -- under Question S1.

So the experience gained from Wuskwatim, in terms of costs detailed on page 68, Wuskwatim witnessed a lower than expected labour productivity. It occurred during a period of international commodity escalation, and it suffered a three (3) year delay of in-service date.

The cost went from 988 million in CEF03

to 1.771 billion in CEF12, in other words, a 79 percent increase. And the details behind that are shown on the next slide. In light of that, the Keeyask and Conawapa cost estimates were updated on -- based on the actual labour material and equipment rates, as well as labour productivity.

So on this slide 30, there is the -- the breakdown of the extra cost. The slide carries on, on -- on -- on slide 31. The table continues on slide 31. The explanation given by Manitoba Hydro in the -- part of the NFAT submittals, number 47, is in the third column. And then we have added a column on what we believe the implications are for Keeyask and Conawapa.

I don't plan to go through this table. I can if anybody would like to, but the -- the main points are picked up in other points made during the presentation. That's the -- the other half of the table on slide 31.

Continuing the experience gained from Wuskwatim on slide 32, access and First Nation enga -- First Nation engagement on page 70 of our report. Advancing the infrastructure work ahead of the generating station benefits the First Nation through increased and advanced employment, training, and capacity building opportunities. It also reduces financial risks to the First Nation joint venture partners.

And this process was pursued on Keeyask to avoid repetition of some difficulties experienced with a First Nation joint venture partner at Wuskwatim. And the other bonus of advancing this infrastructure work is that it allows the developer, i.e., Manitoba Hydro, to focus then on the engagement of the general civil contractor.

Slide 33, changes to the construction planning and management process that Manitoba Hydro uses as a result of Wuskwatim. Initially, they bid Wuskwatim as a unit-price contract in 2007, but they only received one (1) bid, which was basically too expensive.

They then went out with a -- a CRC, for which they received four (4) bids, and much -- much better prices, a cost-reimbursable contract. They -- they -- one (1) of the other changes to -- to the construction planning and management is that they will be providing better camp conditions at Keeyask.

And other evidence that the process review has resulted in changes, a target-price contract is being used for Keeyask to improve the alignment with the prevailing market and to share cost escalation risk, and that is being explored in detail with this ECI process.

Market research into craft labour and heavy construction costs and productivity and development of strategies for labour recruitment and retention -- for example, much better camp conditions.

Earlier scheduling for the development arrangements, which we dealt with in the previous slide, agreements and adverse effects and careful management through integration of engineering, regulatory and procurement processes, and then finally, inclusion of management reserves for escalation and labour costs on top of the normal contingency.

Slide 34. In terms of the cost estimate, a high-quality cost estimate has to satisfy four (4) basic characteristics. It has to be credible. In the case of Keeyask and Conawapa, the direct-point estimate is credible, as it has been prepared by a reputable engineering firm with a wealth of recognized hydro power expertise.

Documentation. The -- the layout and design of the generating stations is well-documented, as is the makeup of direct-cost estimates. The indirect-cost estimates, as I've alluded to before, are not as well-documented, or at least, they have not been provided to Knight Piesold. Project management processes and standards are well-documented.

The third characteristic that a high-quality cost estimate has to satisfy is accuracy, and essentially, we believe the current estimates are likely as accurate as they can be. This was still prior to the general civil contractor award, but we talk further about that in questions S7 and S8.

And then the estimate needs to be comprehensive, and we believe that estimate is comprehensive. It includes, as far as we can see, all the possible project costs, and is structured in sufficient detail to ensure that costs are not omitted or duplicated, and it has been put together by a suitably experienced estimating team.

So perhaps at the end of those nine (9) questions on the first report, I'll ask if there are any other questions.

THE CHAIRPERSON: The previous slide to this one, the comments that you have made apply to both the generating -- both generating stations, both Conawapa and Keeyask.

MR. MICHAEL ROBERTSON: Correct.

THE CHAIRPERSON: Is that correct? Yes. Okay.

MR. MICHAEL ROBERTSON: So if we move on to the second set of questions, which, essentially, were asked because when we -- when we produced our first report in January, we -- we had to say with regard to the cost estimate that all would be revealed, or much would be revealed, when we got the results of the general civil contract tender, which is the single biggest cost item in the -- in the makeup of the costs for -- for Keeyask. And -- and from now on, we're pretty much talking only Keeyask, not -- not Conawapa.

And so the Board came back and said, Because we had reservations or we felt we couldn't make any definite statements at that time, or -- or that it would be advisable to wait until we did get that data to make a sensible observation, we -- we were given these extra eight (8) questions, the first of which, on slide 35, Question S1 is to:

"Review Manitoba Hydro's overall management strategy and scheduling for the tendering of contracts for the Keeyask generating station, and their procurement of other major facility components such as spillways, dams, dikes, powerhouse turbines, intake gates, generators, control, et cetera. Comment on the effectiveness of this management approach for minimizing capital costs, securing competitive bids, and managing construction and procurement, cost escalation, and construction risks."

So the first point, the management strategy for tendering, this is detailed on page 2 of the supplemental report. Manitoba Hydro's Project Execution Plan is a high-level guideline to manage both the Keeyask infrastructure project and the Keeyask generating station project. It provides the means, methods, tools, and techniques used by Manitoba Hydro to manage the project. It serves as a record of the planning effort for the construction phase, and as a resource for staff to ensure consistent project management.

Slide 36. The process of procurement of the contracts is detailed in the Project Execution Plan. We have seen copies of the following documents: the total cost and schedule management; engineering consulting contract monitoring and controls; construction contract monitoring and controls; contract change management; risk management, project contingency management; and project change authorization.

And a breakdown of the total cost and schedule management document, which is detailed on page 3, it -- it follows what is -- what they describe as a PDCA process: plan, do, check, act. 'Planning' comprises establishing the project baseline schedule and budget. 'Do' is the implementation of the project controls on the contracts and internal labour. 'Check', retrieve the actual costs from SAP, which is Manitoba Hydro's proprietary accounting software, and later schedule and budget for costs from project leads. And then 'act', assess the performance, and management change and the contingency.

Slide 37. The overall tendering and project -- and -- and procurement management strategy, detailed on page 3 of our second report. The work is divided into work packages. There is a project controls coordinator in Manitoba Hydro who is responsible for the process all the way from contact drafting to the early periods of the contract execution.

For each contract, the awarded contract value is compared to the based estimate, and relevant amounts of the contingency are allocated from the contingency pool to each contract. And this is examined further in our reply to Question S2. The PDCA iterative management approach ensures that project estimate and schedule are updated accordingly.

The tendering has been a mixture of methods tailored to individual contracts. For example, the supply and installation of turbine generating equipment is essentially fixed price, while the main civil works is essentially designed bid build or unit price but with a target price and an ECI process. Knight Piesold deems the overall approach to be appropriate in principle.

And then just a reminder that Question 3 gives details of the various forms of contacts used or considered by Manitoba Hydro.

Slide 38. In the general civil contract early contract involvement process, the selected contractor has been engaged early, two (2) years before major construction, so is involved in helping finalize contract details. The main objectives are to ensure that the constract -- contractor's construction knowledge is incorporated into the design and constructability issues. It -- they -- he is helping to refine the delivery schedule, helping to secure the necessary labour, and he is forming alliances with Manitoba suppliers and subcontractors.

Slide 39. The schedule for tendering, details on page 4. The Project Execution Plan requires the execution to follow the Hydro cost and scheduling standard for schedule management. Schedule performance is one of the key performance indicators tracked by Manitoba Hydro. The overall schedule anticipates construction starting in July 2014 and being complete in January 2021.

The procurement of long lead time items of equipment is already underway in order to ensure deliver to site on -- in time for incorporation in the works.

The detailed schedules for the Keeyask Generating Station Project were included in the 2009 cost estimate and in the general civil contractor RFP, request for proposals. Again, just making the point that neither of these schedules include time for Manitoba Hydro's contributions.

All of the GCC tenderers confirmed that basic schedule. And as a general comment, Knight Piesold would say that the overall schedule is not deemed to be overly aggressive, with the singular exception that it is assumed that the first-stage coffer dam will be able to go in this year, starting in July. And you'll see later that we -- we believe there is a risk associated with that assumption.

Slide 40, procurement of the major facility components, on page 5 of our report. The long leads time items, for example, the turbine generator supply, is being procured early. And the -- the rest, the -- the balance of plant, as it is sometimes known, the remaining mechanical and electrical equipment supply has been wrapped into the general civil contract to minimize interface issues, which was another lesson learned from Wuskwatim.

There were some other activities which initially were scheduled to be outside of the GCC but have now been wrapped into it, as well. And this includes excavation, coffer dams, and draft tube forms. And certainly it is Knight Piesold's experience and mine personally that that is a very sound move.

THE CHAIRPERSON: The previous slide indicated a project completion date of 2021. Now, I was working under the assumption that it was in-service date of 2019.

Am I misreading that reference or -- or is it a matter where some of the work will be completed after the in -- the dam started generating power?

MR. MICHAEL ROBERTSON: To -- to be honest, I -- I am -- I can't from memory recall exactly when the various units were going to come online. It is -- normally, they come in on sequence, so your first unit is -- is up some months before the -- the final project is absolutely complete and -- and all the demobilization has happened.

From the slide, I don't know. Boris, can you comment?

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: Yeah. So probably the first unit might come online in 2019. I don't know. We -- we could go and check if...

THE CHAIRPERSON: Perhaps Manitoba Hydro could clarify that directly instead of my stewing in this.

MR. MICHAEL ROBERTSON: They should know.

MR. DAVE BOWEN: Sure. It's -- it's Dave Bowen. So our first unit comes online in November 2019. The subsequent units come online about the two (2) month interval thereafter. So the -- the end of the project is expected in 2021, but our first unit comes in -- the 2019 date always refers to our first unit in service.

THE CHAIRPERSON: Thank you.

MR. MICHAEL ROBERTSON: Thank you, Dave. Okay, moving on to slide 41, which deals with the effectiveness of tendering and procurement management approach. The details are on page 4 of our report. We believe that Manitoba Hydro is using an appropriate approach to minimizing capital costs primarily by sharing the risk with contractors and suppliers through advancing the design prior to procurement so there is less uncertainty there, identifying and managing the risks, sharing them with the contractor, and detailed management of the construction process.

Most significant contracts have been or are being procured through a competitive bid process, basically, the GCC and the equipment supply being the -- the major two (2) contracts. A number of projects have been or are being procured through non-competitive direct negotiated contracts because of a preference by Manitoba Hydro for particular contractors to undertake specific work assi -- assignments. And we understand that is also based on the Wuskwatim experience.

And then finally, repeating that the internal management -- sorry, the internal Manitoba Hydro costs may not be deemed to be competitive, but

Knight Piesold has insufficient data to offer an opinion on this issue. And, Mr. Chair, you've -- you've picked up on that point.

THE CHAIRPERSON: The use of non-competitive DNCs is it -- is that unusual in respect of hydro projects that you've examined?

MR. BORIS FICHOT: In British Columbia we've -- we've seen that occur with a number of independent power producers where -- for initial engagement with First Nation or local communities, usually -- especially basic infrastructure costs or road construction costs, those contracts would be awarded very early on in a non-competitive process, and then the main civil works would be engaged in a -- in a competitive process.

So we -- we have seen that before.

MR. MICHAEL ROBERTSON: And it -- it also depends somewhat on the capacity of the First Nations to do that work. We -- we don't have too many First Nations with construction divisions that can do it, for instance. They can certainly provide a lot of the -- the assistance in terms of environmental data collection and survey and -- and labour of one (1) sort or another; some equipment hire. But there's -- there's not been a lot of capacity in British Columbia, certainly, the -- the projects we've been involved with.

Boris is correct, yeah.

MS. MARILYN KAPITANY: You mentioned a couple of times that there isn't time built into the schedule for Manitoba Hydro contributions.

Could you say a bit more about that and how significant that is?

MR. MICHAEL ROBERTSON: Well -- well, I guess I would say I don't know if there's time built into the schedule for Manitoba Hydro's input. It's not expressly shown, and then it sometimes is. And I don't know details of their review process.

The -- the fear might be that if -- if the contractor is required to provide details of all his plans and his drawings and everything else, and -- and that that takes time within the overall process for approval by Manitoba Hydro before he can go ahead and do it, that that might trip up the project. But I don't believe it's -- it's an issue, but I just don't know.

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: Now, I believe

we are halfway through slide -- no, we finished slide 41, I think. Slide 42, on page 5 of our report, it's difficult to measure Manitoba Hydro's effectiveness in managing construction and procurement cost escalation, as the current process is relatively new and it's significantly different from the old. And so they -- they are using -- they're using a new process. It seems to be well documented and -- and thorough and sensible, but I do not believe it's been tested yet with another project. So we're not really able to comment on that.

In terms of the new processes, the project team and the risk engineer execute the contract -- construction risk management process and the contingency management process during construction. And there's some more comment on that under Question S2.

But as an overall assessment of effectiveness, we are able to see that Manitoba Hydro is following a well-documented process; again, despite the fact that the PEP is presently only in draft, and that the project generally appears to be on schedule.

Moving on to Question S2, page -- slide 43: "Review Manitoba Hydro's construction risk management strategy and comment on its effectiveness."

We were given, confidentially, copies of the following documents by Manitoba Hydro, the risk management procedure. The purpose of that is to, quote:

"Detail the activities of planning, identifying, evaluating, responding, and monitoring for effective risk management, as well as detailing the standard risk reporting templates."

We also got a copy of the project contingency management procedure; a copy of the project risk register for Keeyask specifically; and project risk report, which shows the -- drawn out on the contingency; the schedule, a one (1) year look-ahead of project specific risks based on the project schedule; the project risk profile, top five (5) global, and top five (5) specific risks; and risk by phase of implementation.

Slide 44. Now, the risks in the risk management procedure are assessed as the product of probability and impact in the following categories.

Technical requirements: technology, complexity, and interfaces, performance and reliability, quality; organizational: project dependencies, resources, including Manitoba Hydro staff, funding, prioritization and customer, which includes, again, Manitoba Hydro; project management: estimating, scheduling, controlling, communication; external: regulatory, market intelligence, performance and reliability, weather, stakeholders; and safety: design standards, qualifications, training, and awareness.

So on -- sorry.

MS. MARILYN KAPITANY: You mentioned Manitoba Hydro's staff.

MR. MICHAEL ROBERTSON: Yes.

MS. MARILYN KAPITANY: What about contracted labour? Where would that fall in here?

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: Not sure exactly where one would put that. Yes, clearly, the contractor has risks. To be honest with you, I'm not sure, on the fly, how I would -- how I would answer that. Boris, can you...?

MR. BORIS FICHOT: Rephrase the entire question. If you could rephrase the entire question?

MS. MARILYN KAPITANY: Sure. I was

just looking in the risks that were outlined here, and I saw resources defined as Manitoba Hydro staff.

But we had talked before about contract labour and the difficulty of finding labour and keeping labour engaged, and I wondered where that risk would fall in these items.

(BRIEF PAUSE)

MR. BORIS FICHOT: I'm sure it wouldn't be -- it's not reflected in this -- in this list here.

MR. MICHAEL ROBERTSON: I -- I think, in fact, we're -- we're not able to answer directly which of those five (5) boxes that should go in. Clearly, it is a risk. It should -- and -- and it is encompassed in the whole risk assessment, as you will see later.

But when we're talking about organization, we're kind of talking about what I had previously referred to as systemic risk. It's part of the process, and the process is driven by Manitoba Hydro.

So if we move on to slide 45, there are two (2) charts there. Essentially, this shows the -- the matrix of probability and impact, and the -- the risk is statistically always defined as the product of probability and impact.

So you can see that for those risks which are deemed to have a probability of, say, greater than 70 percent occurring, and will have a very high impact, there is a total score of 80 in the top right-hand corner, and in the second chart, there is -- there are three (3) risk ranges which dictate the defined level of risk, and the necessary response from the new generation construction division.

Anything more than fifteen (15), in other words, the -- the dark grey, is deemed to be a critical risk. It's deemed to be unacceptable, and it must be mitigated, and they say to moderate in stage 4 and low in stage 5. Well, when you're going into construction, that's -- that's the final stage, and that's low, and we will pick up on that later.

So on slide 46, the major risks in the risk -- risk register, i.e., those with a total risk score of eighty (80), were perceived in August/September of 2013 to be -- details on page 9 -- the costs of labour and associated labour issues, which is your point, madam, increased costs for project management as a result of insufficient capacity in Manitoba Hydro, and the consequent need to hire consultants to -- for construction management, escalation and market conditions leading to higher tender prices, inexperienced craft labour workforce leading to increased time and cost to perform construction. And these are all themes that we have heard on a recurring basis throughout our assessments, and -- and in my presentation today.

And Manitoba Hydro proposed to deal with these risks by mitigation, basically through the contingency and/or the management reserve.

MR. BORIS FICHOT: I was just going to anser that first question from -- from Marilyn Kapitany a little bit more clearly.

If the -- the risk associated with -- with performance and reliability was in -- in the first question there where, If productivity wasn't within what was expected, then that falls under the -- on their performance expectation.

MR. MICHAEL ROBERTSON: Thanks, Boris. So on slide 47, it is apparent that new procedures and systems have been set up for Keeyask and Conawapa as a direct result of the lessons learned on Wuskwatim and that they reflect a genuine concern on the part of Manitoba Hydro to manage the whole process better. The risk management strategy appears to be well set up, and it appears to be being followed.

So an appreciation of the present risks faced by the project -- and this is a Knight Piesold opinion -- it can be assumed at this stage of the project that most significant technical risks have been addressed. The -- they have employed a reputable experienced designer of large hydro power facilities in Northern Canada. And they have done extensive geotechnical investigations, so we should not expect significant technical risks remaining.

A significant financial risk has been removed with the award of the general civil contract, but there are still other financial risks remaining. Environmental risks remain. The contractor's activities may lead to impacts which will have consequences, in terms of remediation and/or compensation. He -- he is no doubt bound by a construction environmental management plan of some description, and a reputable contractor should not get himself into trouble, but there is a risk.

And then the other environmental consequence of the development of the project is the Adverse Effects Agreement with the First Nation. We've not examined that in any detail, but we have observed that it has led to an increase in the indirect cost estimates in successive estimates.

And then in terms of construction, Manitoba Hydro have chosen suitable, reputable, and experienced contractors, and the remaining construction risks are associated with contractor performance, in terms of quality, cost, and scheduling.

Manitoba Hydro also carries some risk during the construction phase: a risk that the quantities have not been estimated accurately, and to some degree impacts of inclement weather. And to cover those, portions of the contingency have been added to each contract to cover these unknowns.

But the whole issue ultimate comes down to cost, and this is discussed further in Questions S7 and S8. So Question S3, slide 39 -- sorry --

THE CHAIRPERSON: Excuse me, Mr. Robertson --

MR. MICHAEL ROBERTSON: -- beg your pardon.

THE CHAIRPERSON: -- I think that it's probably an appropriate time to take a break.

MR. MICHAEL ROBERTSON: M-hm.

THE CHAIRPERSON: I'd suggest we take ten (10) minutes and -- and resume the proceedings after that.

MR. MICHAEL ROBERTSON: Thank you.

--- Upon recessing at 10:35 a.m.
--- Upon resuming at 10:48 a.m.

THE CHAIRPERSON: I believe that we're ready to continue with the proceedings, so back to you, Mr. Robertson.

MR. MICHAEL ROBERTSON: Right. We're now on slide 49, Question S3:

"Review the contract documents prepared by Manitoba Hydro for the major Keeyask components and comment on how such documents have been designed to secure cost-effective bids from suppliers and contractors and where Manitoba Hydro may be vulnerable for cost increases, schedule changes, et cetera. Comment on the overall thoroughness of the contract documents and the drawings."

Reference page 11 of our report. So Question 3 provides details of the forms of contracts typically used to procure works like the Keeyask Infrastructure Project and the Keeyask Generating

Station Project.

Knight Piesold confirms, based on the contracts that they have seen, that Manitoba Hydro has made appropriate choices for the Keeyask contracts. Contracts are designed to secure the most cost-effective bids from suppliers and contractors.

That said, all contracts, except fixed price contracts, are vulnerable to cost increases. But Manitoba Hydro has attempted to mitigate these risks by sharing them -- sorry, to mitigate cost increases by sharing the risk.

Remaining risks and possible increases in costs have been acknowledged and accounted for in a professional and competent manner through the contingency and the management reserves. See Questions S2 and, further in, Question S8 to come.

Slide 50. Non-fixed price contracts also have possible implications on schedule. The process of schedule changes has been defined, and costs associated with schedule risks are included in the contingency and management reserve to a certain extent. And we'll pick up on that later.

Contract documents seen by Knight Piesold have clearly been drawn up by competent, experienced engineers from within Manitoba Hydro and reputable consultants. The general civil contract involves the earlier -- early contract involvement to maximize the benefit of input from the contractor, and it has a target price.

Variations from the initial agreed target price are shared between Manitoba Hydro and the contractor, generally, and certainly initially, to the greater benefit of Manitoba Hydro to the tune of approximately -- of -- of 80 percent, specifically, than the contractor.

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Page 51 -- slide 51, Question S4:

> "Review the construction and equipment procurement bonding and any liquidated damage requirements and comment on the appropriateness of such bonding and cost implications to the project."

Well, in general terms, bonding' refers

either to -- this is on page 14 of our report -- either to a performance bond which provides assurance that the work will be done, it's normally used for a civil site construction works, in my experience; or a letter of credit which provides assurance that Manitoba Hydro will not be out-of-pocket. And that is used to procure equipment manufactured off site typically. Manitoba Hydro has used both; different requirements for each contract suited to those contracts.

Knight Piesold believes that the Manitoba Hydro process is appropriate, including the required amounts. They provide a reasonable balance between protecting Manitoba Hydro interests and paying excessive premiums for this insurance. We believe that Manitoba Hydro have also handled liquidated damages in an appropriate manner.

Slide 52, Question S5:

"Review Manitoba Hydro's quality assurance and quality control, QA/QC, requirements for Keeyask construction and comment on the effectiveness and costs."

That's dealt with on page 17 of our report. So the best common arrangement in hydro power construction has the contractor responsible for quality control, QC, and the owner or his engineer responsible for quality assurance. Manitoba Hydro is conforming to this practice.

Quality management in Manitoba Hydro is specified at a high level in the project execution plan, with more detail in a new generation construction division standard. That standard also includes a third main activity, which is called quality planning.

Manitoba Hydro made available to Knight Piesold copies of quality management section 5 of the Project Execution Plan, a copy of the NGCD standard number 20 -- 204 on quality management, QA/QC requirements built into the turbine generator contract, and QA/QC requirements built into the general civil works contract.

Slide 53. With regard to the turbine generator contract, the contractor's own quality management system, it is -- it is a requirement that the contractor's quality management system must conform fully to the spirit and intent of the International Quality Management System, ISO 9001. The contractor is also obliged to have a project quality plan, a quality team, and various inspection and testing plans.

The document is deemed to be detailed, comprehensive, and appropriate for its purpose. With regard to the general civil works contract, the document confirms that quality control is the responsibility of the contractor and quality assurance is the respol -- the responsibility of the engineer.

Details were not made available to Knight Piesold, but we believe they are likely to be entirely appropriate.

THE CHAIRPERSON: Could you draw a distinction for -- between quality assurance and quality control, very high level?

MR. MICHAEL ROBERTSON: Right. So the -- the quality control, essentially the -- the contract documents tells the contractor what the owner/engineer is expecting, in terms of evidence that the contractor has met the stated requirements. So, for example, they say that the density of the earth will -- will be no less than 98 percent of some international standard or that the strength of the concrete will be no less than a certain value.

Now, the quality control is the process of documenting proof that indeed those requirements have been met. So the documents will typically specify that for every 1,000 cubic metres of concrete that you place, you have to do these tests and they have to pass these results. And that has to be documented and so that they -- the contractor can show the owner that he has indeed met those requirements.

So that is basically providing the data. Now, the quality assurance process is one of inspecting that data to make sure that sufficient tests have been done, that they have been reported, that they have been -- that they passed the requirements, and that where they haven't, suitable processes have taken place to correct non-conforming products.

So, yes, the final point I was going to make on slide 53 is that the costs of QA/QC are not expressly shown anywhere. They are essentially part of Manitoba Hydro's overhead with regard to QA, and the contract is overhead with regard to QC.

Questionnaire 6, page 54:

"Review the overall civil contract project management approach. Comment on its effectiveness and what project management controls are in place to minimize cost escalations."

So the general civil contract is being managed with all the procedures, processes, and standards mentioned in replies to the earlier questions.

Financial activities are part of SAP,

which is Manitoba Hydro's systemwide accounting system. Some processes being used for Keeyask are new and they're still not finalized. We had a number of conference calls with Manitoba Hydro, and these details were provided to us by them. They have project change authorizations which are used to transfer funds to and from the project contingency in real time. There is a single person in Manitoba Hydro responsible for managing this contingency.

All significant network numbers. Now, network numbers are basically the work breakdown structure items within SAP. They call them network numbers. They have a portion of the overall contingency allocated to them, and actuals and revisions to forecast are tracked, and they keep a contract revision register that records budget changes like the PCAs.

Slide 55. They also have what they call 'dashboards', which are reports tailored to present the information to particular audiences, and there is an example of a dashboard included in the KP report.

Estimates of future expenditure are adjusted in real time by adding inflation and deducting money spent to date. The check is made at the same time on the expected final cost of each item; i.e., is the budget still appropriate?

Changes are also recorded in other parts of the estimate to keep the overall in-service costs the same. So, for example, if -- if the tenders come in, and they now think that a particular contract is going to cost more, they will draw from the contingency pool and allocate part of that contingency to that particular contract, and the remaining contract pool will go down by that amount. So the -- the inter -- the overall in-service cost remains the same.

They do a -- a reconciliation overall every year with quarterly reports in the interim, and they are presently working to making this reconciliation possible more in real time. They perceive that schedule management is as -- as important as costs, and this -- this is certainly true.

Question S7, slide 56. Critically review Manitoba Hydro's pre-tender construction estimates and compare with actual tender prices. Define where significant differences are noted, and rationalize the specific differences.

It's page 21 of our report. Manitoba Hydro has provided Knight Piesold with a summary presentation material and bills or quantities comparing the general civil contractor proposals, the independent estimator's estimate -- a company named Chant -- and an escalated original engineer's estimate, the original of which was produced by KGS-Acres.

We believe that Manitoba Hydro -- Hydro has been diligent in their internal comparison between the GCC tenders, their engineer's estimate, and the independent third-party estimate.

The tender -- tenderers have, and this is picking up on a point I made earlier, have built into their bids their assessment of labour availability, productivity, and costs.

Slide 57, finally, Question S8:

"Provide an opinion as to the expected in-service capital cost for Keeyask once all work has been completed."

That's on page 23 of our report.

So Knight Piesold essentially confirms that Manitoba Hydro's expected in-service capital cost of $6.5 billion, which was the March 2014 revision, but we are of the opinion that a more risk-averse decision maker would incorporate a higher contingency -- for example, a P80 as opposed to a P50 -- and a management reserve that incorporates greater allowances for labour and escalation, plus an allowance for schedule delay, primarily the risk that the 2014 start date will not be achieved.

And that, Mr. Chairman, is our presentation.

THE CHAIRPERSON: Coming back to the last -- the previous slide to this one, now, you indicated that 'P' -- a P80 as opposed to P50, are you in a position to quantify what that would mean for the contingency in terms of dollars?

MR. MICHAEL ROBERTSON: Yes.

MR. BORIS FICHOT: Tho -- those numbers are in the report.

THE CHAIRPERSON: And -- and also --

MR. BORIS FICHOT: I -- I'll add that the numbers are considered CSI material.

THE CHAIRPERSON: I'm sorry, the -- the management reserve, the -- the -- is also part of the CSI, your expectation? Okay. I have --

MR. BORIS FICHOT: Yes.

THE CHAIRPERSON: -- another question that relates to an earlier comment you made, and it's with respect of a -- an unidentified project in BC. Remember that table that indicated the -- Muskrat Falls and the other projects, and you indicated there was -- the BC project was delayed. Could you -- it was right at the outset.

MR. MICHAEL ROBERTSON: It was in that first ballparking exercise. I think --

THE CHAIRPERSON: Yes.

MR. MICHAEL ROBERTSON: -- that's the one.

THE CHAIRPERSON: And you indicated as -- as an aside that that project was delayed. Could you -- could you explain that, please?

MR. MICHAEL ROBERTSON: Oh, Site C? No -- no, sorry, I -- I think I said it -- it's not delayed, it's just slightly further back on the track than is Keeyask.

THE CHAIRPERSON: Yes.

(BRIEF PAUSE)

DR. HUGH GRANT: I'm just wondering if the big elephant, or big gorilla in the room is the fact that a -- a lot of these large construction projects seem to have a habit of going seriously wrong in terms of the cost estimate, and you referred in many cases to Hydro relying upon reputable consultants and following industry standards, but is it quite possible that those standards in the industry aren't terribly good ones in the sense that this area seems particularly plagued by cost overruns?

And I'm wondering if you could comment on why that seems to have been the case in the past?

MR. MICHAEL ROBERTSON: Well, they -- they are. They're -- they're very big projects. There are many uncertainties. Obviously, one needs to eliminate or mitigate those risks as far as possible, and -- and I -- I do believe that Manitoba Hydro has done that.

And -- and the main things that tend to go wrong is that a -- a major civil engineering project in the ground like this, you really don't know what you've got until you open it up. You -- you do investigations, and they've done a good, thorough job of that, but there are always surprises. There's always something different.

If you put a series of drill holes along a dam centerline, Murphy's Law is that you'll put them into the high points where the rock is, and you will miss the low points where the rock isn't. I mean, it just -- Murphy's Law dictates that.

But -- but at the same time, I mean, I do believe from what we've seen that that risk in this case has been mitigated as -- as well as possible. The

-- the construction climate is -- is another big factor in -- in terms of -- of prices that -- that tenders can afford to ask for. That risk is now largely removed because -- because they have the bids.

I -- I -- there is no logical reason, in my opinion, that -- and -- and as I've -- as I've said, that the 6.5 billion as an expected cost, I -- I wouldn't revise it. I -- I have no grounds to make it more or less. I mean, it -- it's a -- it's a sensible best estimate. We're -- we're just waving a couple of flags on -- on where it might go, just because of these outstanding risks.

And, yes, they do -- these -- these big projects do tend to, it seems on -- on the historical record, to -- to overrun, but you -- you -- as I say, you -- you mitigate the risks as -- as well as you can. I mean, I -- I would point out that a -- a lot of the independent power projects that we have been involved with in British Columbia with, primarily, contractor Kiewit, a big international North American company.

They've all come in early, and they've all come in on budget, because they're a fixed price, so our experiences may be very fortunate, but it's not the same as -- as we have seen elsewhere.

DR. HUGH GRANT: I -- I guess to follow

up, I -- I just wanted to clarify my question. There's really been two (2) issues, and one (1) would be the escalation in construction costs, large projects over the past 'X' number of years, and why they seem to have increased so rapidly? And the other one (1) would be, once a project is given a go-ahead, why the cost may escalate within that particular project?

On -- on the first issue, you mentioned the decline in labour productivity in the construction industry, and the only data I've ever looked at shows -- or recently, for example, the productivity -- labour productivity in construction has been increasing rapidly and dramatically in the last eight (8) years in Canada, but that may be dominated by the residential housing sector, I'm not sure. But there's -- there doesn't seem to be clear evidence of a decline in labour productivity -- physical labour productivity, so that would be one (1) sort of question, I guess, I'm putting out there.

And -- and the other thing I was wondering about, in terms of once a project is actually contracted, and quite apart from the nature of the contract, are there not always hold-up costs in these sorts of contracts? I -- I mean, no matter how thick the contract may be, there's incomplete -- and it's incompleted contracting, and it seems to be that the person doing the contracting is able to hold up, in a sense, if there's -- if there's a cost over and to pass those costs on.

Could you comment on both of those?

MR. MICHAEL ROBERTSON: Well -- well, with regard to the first one, I don't know, Boris, if you can quote that reference? I mean, maybe -- maybe we should dig back and -- and remind ourselves what that reference was that -- that basically said that labour productivity had decreased over the recent years.

I have certainly found on construction sites, supervising construction as the engineer, that even -- even a good contractor like Kiewit there, their staff has not been particularly skilled or experienced, and -- and is, therefore, not particularly productive. I have certainly seen that in the last ten (10) years.

MR. BORIS FICHOT: I couldn't quote the references outright, but I'm pretty sure that the -- the references -- all the reference material that I've seen, it's all said that labour productivity has -- has gone down. Anecdotally, it's just a -- a change in era, the -- the era where a bunch of guys would put all their stuff in a backpack and go and bunk eight (8) to a room up north and live there for two (2) years, until the -- the project was done. It's different now, and everybody expects to have their own room, to be able to go home every two (2) weeks, and that's just a major, major shift in -- in your ability to be productive.

If the guy that was doing the concrete one (1) week is different from the guy that was doing the concrete a week ago, there's a rotation, you need to allot for a lot more staff to do the same type of work. It's just a result of the --

DR. HUGH GRANT: Trying to --

MR. BORIS FICHOT: -- the conditions, and people expect that. I've worked in camps up in Alaska where you had to bunk two (2) to a room, and some guys wouldn't show up the -- the next week, because they found a job that was giving them their own room, so I've seen that firsthand.

DR. HUGH GRANT: That's interesting. The issue -- labour productivity is most closely associated with the amount of capital per worker. So if you give me a pick and shovel, I'm not so productive. You give me a tractor, I'm very productive. And so usually, it's identified with something in the nature of the technology in the organisation, economies of scale and things of that nature, as opposed to just, you know, I want my own bedroom, or something.

MR. MICHAEL ROBERTSON: Yeah.

DR. HUGH GRANT: I was just looking at STAT Canada data, and it's -- it's a bit ambiguous, and I suspect it's dominated by the residential construction industry, where we've seen housing prices surmising up -- rising dramatically that's probably driven this, but --

MR. MICHAEL ROBERTSON: Yeah.

DR. HUGH GRANT: -- in any event...

MR. MICHAEL ROBERTSON: Yeah. So -- and -- and your second question, sir?

DR. HUGH GRANT: I'm just wondering about -- I think the term is 'holdup costs' --

MR. MICHAEL ROBERTSON: Oh, yeah.

DR. HUGH GRANT: -- the nature of incomplete contracting and -- and that nature.

MR. MICHAEL ROBERTSON: Well, you -- you know, we -- we all are at -- to some extent, at the mercy of a contractor who may take a litigious approach to -- to his work. You cannot write a document that doesn't -- that -- that a smart lawyer will not find a hole in, and if -- if that is the attitude of the contractor, then you -- you would expect some claims.

Now, hopefully, the contract document is well enough written that they won't get very far. I think, in general, Manitoba Hydro have done a good job with that main civil contract. I -- I think the -- the whole idea of bringing the contractor in early -- early, getting his buy and getting him to be part of the establishment at this initial target price should diffuse a lot of his ammunition if he then comes later and wants to argue that things are different from what he assumed, because he's worked through this whole process with them for a year.

And as -- as I've tried to say that, you know, I think the information -- they have as much information as they can reasonably at this time to -- before they actually open up the ground. The weather's always something that you can't anticipate exactly how that's going to turn out.

The schedule is not unduly aggressive. I -- I don't really see any reason why, as I say, that expected value should be different. I -- I don't see any big loopholes that the jump -- the contractor can jump into. I -- I won't say I've read every word of the document, but it's -- it's -- the -- the whole idea of the target price and basing quantities and what happens if it's different from the target price is --

is well defined. And as I said, it's -- certainly initially it's -- it's to the benefit of Manitoba Hydro if there is a variation and not to the contractor.

So there's a big incentive on the -- to the contractor to performing properly. Essentially, in terms of cost overrun, it's going to be things outside of his control, like labour availability and productivity, that -- that might cause concern.

THE CHAIRPERSON: I think that's all the questions that the panel has. Mr. --

MR. SVEN HOMBACH: Mr. Chairman, before we proceed with cross-examination I've been advised that there's a matter that counsel may need to add -- address for ten (10) minutes. I'm wondering if it's possible to step down for ten (10) minutes for counsel to speak?

THE CHAIRPERSON: Yes, let's do that. Ten (10) minutes then. So back here at twenty-five (25) after.

--- Upon recessing at 11:15 a.m.
--- Upon resuming at 11:46 a.m.

THE CHAIRPERSON: I believe that we're ready to resume the proceedings. So, Ms. Menzies, do you have questions for these witnesses?

CROSS-EXAMINATION BY MS. MEGHAN MENZIES:

MS. MEGHAN MENZIES: I do, yes. Thank you. Bonne matin, tout le monde. Good morning, Board members, and good morning Mr. Robertson and Mr. Fichot. Before I begin today -- first of all, my name is Meghan Menzies and I represent the Manitoba branch of the Consumers' Association of Canada.

I was just recently advised that it is someone's special day today, and I just wanted to acknowledge that on the record. Apparently Patti Ramage -- Ms. Patti Ramage is turning thirty-five (35) today I figured that we should all... So happy birthday, bonne fete. Is that bonne anniversaire or -- not sure.

So many of my questions for you today are based in the original report from January 2014. However, there will be a little bit of jumping back and forth between that and then the supplemental report of April 2014. So I would just ask -- and I'm sure you -- you already have them ready, but just make sure to have both reports before you. And I ask for the forgiveness of Ms. Villegas for all the jumping back and forth, but I'll -- I'll try to stick to one (1) report at a time.

So first off, I would like to direct you to page 9 of your March 2014 redacted report.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: And so here we see Table 2.2, which is from the International Association for the Advancement of Cost Engineering.

Is that correct?

MR. MICHAEL ROBERTSON: Yes, that's correct.

MS. MEGHAN MENZIES: And I should have said before, I'll be directing my questions generally to both of you, so please feel free to answer wherever it's appropriate. And I'll just be referring to them as the AACE, as you do in your report, if that works.

Okay. And so can you please confirm that this table provides AACE's internationally recommended generic cost estimate classification matrix?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: Thank you. And looking to the left-hand side of the table, what we see here are five (5) different classes.

Is that correct?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: And my understanding of these classes is that each is used to identify the level of certainty of a particular cost estimate.

Am I correct in my understanding?

MR. BORIS FICHOT: That's the intent.

MS. MEGHAN MENZIES: That's the intent. Thank you. And it appears to me that a project that has received a Class 5 would have less certainty than a project that has received a Class 4.

Is that correct?

MR. BORIS FICHOT: That's correct.

MS. MEGHAN MENZIES: This is going to move a little slow at the beginning. So the lower the number of class, the higher the certainty in cost estimates? Yes?

MR. BORIS FICHOT: That's correct.

MS. MEGHAN MENZIES: Thank you. And looking at this table, am I again correct in saying that the more developed a project is, the more certain it is likely to be? Would that be --

MR. MICHAEL ROBERTSON: Just -- just rephrase that.

MS. MEGHAN MENZIES: So looking at the

different characteristics that are considered in classifying a project, would it be appropriate to assume that the more developed a project is, the more -- the more certain it is likely to be, or the lower the class number it's likely to be given?

MR. BORIS FICHOT: What do you mean, 'to be'?

MS. MEGHAN MENZIES: So the -- the more certain it is likely to be classified as.

MR. MICHAEL ROBERTSON: I -- I think perhaps -- with respect, I think perhaps where you're going is -- is that the -- the lower the class --

MS. MEGHAN MENZIES: M-hm.

MR. MICHAEL ROBERTSON: -- the more certain you should be of what you're saying about it, in terms of cost estimates.

MS. MEGHAN MENZIES: Yes, and I was trying to move one (1) step further from that to suggest that the more developed a project ism the more likely that it is to receive a lower class.

Would that be an appropriate assumption? I'm kind of making a bit of a jump here.

MR. MICHAEL ROBERTSON: Well, the -- they've broken it up into five (5) classes. And one of the ways to help you put it in the right box is the degree of definition of the project.

MS. MEGHAN MENZIES: M-hm.

MR. MICHAEL ROBERTSON: And so, yes, the better defined the project, the lower classification that fits into this process.

MS. MEGHAN MENZIES: Perfect.

MR. MICHAEL ROBERTSON: And the more certain you are about what you're going to do.

MS. MEGHAN MENZIES: Thank you. That's exactly what I was trying to get at. Thank you. So looking at -- looking at this table, am I also -- am I correct in my understanding that within each class, there does exist a range of certainty?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: And so for instance, two (2) separate projects could be classified as a Class 3, with one being towards the lower range of certainty within Class 3 and the other towards the higher range?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: Yes? Thank you. So I would now like to take you to page 10 of that report, just the next page. And here we see at the far right column that the Keeyask Generating Project and the Conawapa Generating Station Project have both been categorized as Class 2s.

Is that correct?

MR. BORIS FICHOT: In this table, that's correct.

MS. MEGHAN MENZIES: Okay.

MR. MICHAEL ROBERTSON: No. In this table, KIP is Class 1 -- oh, Class 3.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: If you look just below -- so that's the infrastructure, and then just below is the generating station project. Does that --

MR. MICHAEL ROBERTSON: The -- the Conawapa Generating Station Project is two (2).

MR. BORIS FICHOT: That -- that was our appreciation at the time, yes.

MS. MEGHAN MENZIES: Okay. And when you say, "at the time," what is your appreciation now?

MR. BORIS FICHOT: It would probably be more in the line with the Class 3, but it's with a lot of reservations. You have to see that -- if you look at what the associated accuracy of the estimate is, that doesn't necessarily have to change. Like these things are -- are kind of -- there's a range where these things go on top of each other.

MS. MEGHAN MENZIES: Okay. Fair enough. And I think -- I do think that you responded to that in an IR previously, and I'm just following up on that.

And so just to surmise what -- just to summarize what you've just said, so Conawapa could be classified now as a Class 3?

MR. BORIS FICHOT: Yes.

MS. MEGHAN MENZIES: Yes?

MR. BORIS FICHOT: Yes.

MS. MEGHAN MENZIES: Thank you. Okay. And so now if we could move to page 22 of your report. And now I would like to discuss with you the concepts of systemic risk and project specific risks, which I think you also mentioned in your presentation this morning.

So looking at page 22, and if we could just move just a little over; thank you very much. Here I see that it says -- and I'm just going to read it to you and if you could just confirm that this is what you see -- that:

"Systemic risks are those that are inherent to the project development process and are not unique to the project."

Can you confirm that?

MR. BORIS FICHOT: Correct.

MS. MEGHAN MENZIES: Thank you. And then:

"Secondly, in general, as a project advances in development, system risks are reduced or developed -- or develop into project-specific risks."

Is that correct?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: Yes. Thank you.

MR. BORIS FICHOT: I would -- I would underline the 'in general'. MS. MEGHAN MENZIES: Fair enough. Thank you. And...

(BRIEF PAUSE)

MS. MEGHAN MENZIES: All right. And so according to what I've gotten from your report, and please correct me if I'm wrong, but Cona -- the Conawapa Generating Station Project is less developed than the Keeyask Generating Station Project?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: And so would I be

correct in saying that, as compared to Keeyask, Conawapa is more likely to face systemic risks?

MR. BORIS FICHOT: That's correct.

MS. MEGHAN MENZIES: And Keeyask, being further developed, is more likely to face project-specific risks?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: Thank you.

MR. BORIS FICHOT: It's -- are you talking about magnitude or in terms of -- like they both face those risks.

MS. MEGHAN MENZIES: And -- and fair enough, and I take your point. More I'm just trying to get at the -- get at the point that where they are in their development right now, the types of risks that they're facing, not -- not comparing the magnitudes to each project, but just the types of risks that they will generally be facing are probably syste -- systemic risks for Conawapa and project-specific risks for Keeyask, more generally?

Did I say that wrong?

MR. BORIS FICHOT: I -- I wouldn't state -- I wouldn't say it that way. I would say they -- they both face those risks in an equal way. The systemic risks are -- are a lot more significant for

Conawapa, but since there's no -- there's no association with the actual magnitude, it's -- it's something that can be very subjective.

MS. MEGHAN MENZIES: Thank you. I appreciate that.

MR. MICHAEL ROBERTSON: I'd also say that the project-specific risks on Keeyask are now less than they are for Conawapa because there's more known about Keeyask.

MS. MEGHAN MENZIES: Okay. And that's good to know. Thank you.

THE CHAIRPERSON: Could we go back to the previous document that we were examining? I'm a little bit confused here. And I want to make sure I clarify it in my own mind. This is a table that showed the hydro classification versus the KP class -- KP classification?

MS. MEGHAN MENZIES: Yes, and that's at page 10.

(BRIEF PAUSE)

THE CHAIRPERSON: I understood you to say that the KP classification for Keeyask is now Class 3 as opposed to what's here?

MR. BORIS FICHOT: I think it's -- it reflects a little bit more of our appreciation of we've delved deeper into the material. I think the first thing, as engineers, that we've reviewed that was provided to us was the -- the estimate of the direct costs for Keeyask and Conawapa. And those were very well documented. They had a lot of backup material, engineering studies. And that gave us some confidence that the degree of definition in the project was fairly -- was -- was fairly elaborate.

I think, in -- in retrospect, especially examining the validating estimating report, which is their -- their specialized risk analysis report, the -- the overall systemic risk described, there's a lot more risk attributed to that and a lower level of -- of definition and certainty with those -- attributed to those.

So as a result, I'd probably be more inclined to classify it as a Class 3 today.

THE CHAIRPERSON: So that even now knowing the -- having seen the GCC contract or bid, that would still cause you to classify it as a Class 3?

MR. BORIS FICHOT: That -- that is the case. That is the case. And I'd highlight that the -- one of the things that we did outline in this report when we wrote is that, irregardless of the class, we still thought that the accuracy was -- did not change as a result of changing. It's really just an appreciation of what the definition of the project is.

But our appreciation is the -- of the risk and the uncertainty around the project is almost independent from whatever ball -- whatever category you want to put it in, with all respect to AACE.

CONTINUED BY MS. MEGHAN MENZIES:

MS. MEGHAN MENZIES: Thank you. And actually just following up on the Chair's question, can I just get it confirmed for the record that you would still classify the Keeyask Generating Station Project as a Class 2?

MR. MICHAEL ROBERTSON: Okay. Can we just take that offline a second?

MS. MEGHAN MENZIES: Yes.

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: No, I'm just confirming with my colleague here that, essentially, because of the reappreciation of the systemic risk, which validating, estimating did, together with Manitoba Hydro, we would go back to Class 3, essentially, as per Manitoba Hydro's original submission.

MS. MEGHAN MENZIES: For the Keeyask generating --

MR. MICHAEL ROBERTSON: For -- for both those projects.

MS. MEGHAN MENZIES: Okay. So now both -- I'm going to call them the KGSP and CGSP would be classified as Class 3?

MR. MICHAEL ROBERTSON: Yes. Well, all three (3), the first three (3) rows.

MS. MEGHAN MENZIES: So the -- the Keeyask Infrastructure Project as well?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: Okay. Thank you very much.

THE CHAIRPERSON: Just to make sure that the panel members are on -- on the same wavelength, so the first three (3) listed there would be Class 3 according to KP?

MR. MICHAEL ROBERTSON: Correct.

THE CHAIRPERSON: The KIP, the KG -- GSP, and the CGSP, all three (3) will be Class 3?

MR. MICHAEL ROBERTSON: Yes.

MS. MARILYN KAPITANY: Sorry, Ms. Menzies. Could you just go over again what you said about -- even though you had decreased the level of classification that you gave these projects, that doesn't necessarily mean -- I thought I heard you say it doesn't necessarily mean you have less confidence in them, but somehow that doesn't make sense to me?

MR. MICHAEL ROBERTSON: No. I -- I think what -- what has happened is that, when we first did this, we -- we saw that Manitoba Hydro had classified all three (3) projects into Class 3.

We believed that based on the -- the level of definition, the maturity of the projects, that that class should be lower, because there was more definition than the general guidelines of AACE would indicate should be in Class 3.

So the KIP, a lot of the contracts had been awarded. There should be much better project definition and more certainty, and to -- to some extent, but not to the same extent, the KGSP had a number of contract awarded -- contracts awarded, like the turbine generator, for instance, at that time.

And we deemed that there was perhaps more definition than was implicit in Manitoba Hydro's classification, and therefore, we recommended that it should rather be Class 2.

However, the -- the validating estimating exercise that was undertaken once the -- or undertaken again once the general civil contracts came in highlighted a number of systemic risks, not the project-specific risks, which essentially drove us to reclassify KIP and KGSP, but the systemic risks are still very significant, and therefore, in the light of that, we would want to go back and classify all of those as Class 3.

CONTINUED BY MS. MEGHAN MENZIES:

MS. MEGHAN MENZIES: And thank you for that clarification. I might ask that -- would you be able to expand -- you -- you had just said that the systemic risks are still very significant.

Could you expand on -- on those risks? And I guess specifically for -- for the Keeyask Generating Project, but then to follow up with, specifically, the Conawapa Generation -- Generating Project.

MR. BORIS FICHOT: One of the things that we're thinking is that it ventures into CSI territory pretty readily, so.

MS. MEGHAN MENZIES: Okay. All right. But -- and you can stop me if -- if I'm venturing into CSI, but -- but today, as compared to when you originally wrote the report, your opinion is that there are -- there are more systemic -- there are more systemic risks at play than -- than you originally -- than you originally thought.

Is that correct?

MR. BORIS FICHOT: Yeah. I think a lot -- as I -- as I stated earlier, a lot of our original appreciation was -- I'd almost say, like, we hone in on the engineering aspects --

MS. MEGHAN MENZIES: M-hm.

MR. BORIS FICHOT: -- and those were clearly done out well. The -- the thing that I think took us a bit longer to -- to gain an appreciation was for all the underlying project management organisational driven type costs or -- or risks.

For example, one (1) of the -- the ones that came to light more recently was for the overall construction project management, would that be do -- done on -- in-house, or would that be done externally? To us, if they didn't have enough knowledge about whether it should be done internally before or after, that's kind of a major flag that says, Well, maybe this whole process of how it would be carried forward is not clearly defined. Therefore, lower level of project definition, therefore, lower level of certainty, and incidently, AACE classification of three (3) instead of two (2).

THE CHAIRPERSON: I think it's probably an appropriate time to -- to break for lunch. We are going to be resuming our proceedings at a quarter to 1:00. We are expecting a presenter at a quarter to 1:00, Mr. David Barber, so we will see each other again at a quarter to 1:00. Thank you.

--- Upon recessing at 12:05 p.m.

--- Upon resuming at 12:54 p.m.

THE CHAIRPERSON: I don't like to be a grinch, but we should go back to our proceedings. The cake was wonderful. Thank you very much.

MR. RICHARD BEL: Yes, thank you. Thank you.

MS. MARILYN KAPITANY: Yes, thank you for having a birthday party.

THE CHAIRPERSON: With -- with that, I'll turn the microphone over to Mr. Hombach, please.

MR. SVEN HOMBACH: Thank you, Mr.

Chairman. I note that this morning I indicated that there would be a presentation by Mr. David Barber at 12:45. Mr. Barber has not shown up yet, so it would be my suggestion that we proceed with the cross-examination of Knight Piesold by Ms. Menzies, and perhaps if Mr. Barber subsequently shows up, he could deliver his presentation after the afternoon break.

THE CHAIRPERSON: Agreed. Ms. Menzies, please...?

CONTINUED BY MS. MEGHAN MENZIES:

MS. MEGHAN MENZIES: Okay. Well, I'm glad that this begins before the sugar crash, so all right. Good afternoon. So the first document that I'd like to direct you to this afternoon is KP-3-3, and that's the updated Roman numeral II of the supplemental report.

And I note that this morning when I was asking about systemic risks, there was some concern about some contracting deals or -- or possibly some CSI being discussed. And so I do want to flag that again. And -- and I appreciate that you -- I appreciate your response with regard to CSI, and I do want to make sure that I don't push into CSI. So again if at any point I'm -- I'm pushing a little too far, please feel free to let me know.

So what I'm hoping is, at the beginning, at -- at the top here it says:

"The highlighted key risks confirmed by a validation estimating..."

And there's five (5) bullets, and I'm wondering if, possibly, we could walk through those bullets and you could provide a bit of a description, or -- or a -- a bit of an -- a further explanation on each of those risks to the extent that you're able, so starting with the resource challenges?

(BRIEF PAUSE)

MR. BORIS FICHOT: Yes. So the -- the main resources challenges are basically staff availability and all those. That aspect has been highlighted by -- by Hydro, and we -- we concur with that. Systemic risks associated with a Manitoba Hydro maturing system, that's again, the fact that they've recently defined a process. That process is in draft form. They -- they haven't fully fleshed out how they're actually going to manage the construction, at least, to -- to date.

So we've seen that the process is in

place. It's evolving a little bit because of the -- the recent enva -- engagement with the civil contractors. So since all that system for the management is not clearly elaborated, there's -- there's risks associated with that, that it -- and then -- that it carries through and it has an impact on the cost.

MR. MICHAEL ROBERTSON: So I just add to that, that it's -- it's a new system that has not yet been tested.

MR. BORIS FICHOT: The -- just -- just a second, here.

(BRIEF PAUSE)

MR. BORIS FICHOT: We won't go over why there's schedule risk, whether we'll -- we'll skip over that one.

MS. MEGHAN MENZIES: Okay.

MR. BORIS FICHOT: Adverse labour productivity, again, there's assumptions in the management reserve that -- which has made allowances for the productivity not being what's expected. The -- the detailed content of that is deemed CSI material, but there's reason to believe that the labour productivity assumed may not be as -- as -- may -- may or may not be adequate with the base estimate that they've provided, and they've allowed for some management reserve to deal with that.

And then the risk that could cause a year of delay associated with the -- with the stage coffer dam, that's a -- that's a risk that I'll -- I'll highlight here, is that it's a element of the risk that's not categorized in the current estimate. Some of it falls through this whole process.

And there's dollars attributed to whether or not Manitoba Hydro will be able to proceed with the whole construction development, and that's a risk that's not quite categorized in the -- in the current estimate, but that is there, and so it's highlighted in this independent report.

MS. MEGHAN MENZIES: Okay. Thank you. And I actually want to go back to the systemic risks. So part of what was stated, I believe, on systemic risks, was that the new system has not yet been tested.

And I just want to get an understanding of -- of how serious of a risk that is, or how serious of a risk does Knight Piesold see that to be?

MR. MICHAEL ROBERTSON: It -- it's an unknown. It -- it's a new process. It's patently very thorough, and so one can give a hundred percent for intent, but to the extent that it hasn't had a practical outworking, we -- you -- you don't have any kind of real experience to say, yes, this is the system that has been shown to work.

MS. MEGHAN MENZIES: M-hm. Okay. Thank you. And still on the issue of systemic risks. Previously, you had said that Conawapa has greater systemic risks than Keeyask, and so to -- to what extent are those -- are those systemic risks greater, and -- and can you elaborate on that just slightly?

MR. BORIS FICHOT: Just by virtue of the fact that they have a little bit more of appreciation of what the process may be for Keeyask than they do for Conawapa.

MR. MICHAEL ROBERTSON: Well -- well, sorry. Actually, I -- I might vary with my colleague, there. In -- in terms of systemic risk, both will be developed according to the same system, so really, there's not much difference in -- in terms of systemic risk. Project-specific risks? Yes, certainly, because Keeyask is better defined, and therefore, Conawapa has more, we would say.

But the systemic risk, it's -- it's really the process that's been followed. I guess, in a way, Conawapa will happen if it happens after Keeyask, by which time the system will have been tested. So in a way, I guess you might argue that Conawapa has less systemic risk by the time it goes for development, but it's...

MS. MEGHAN MENZIES: Thank you.

THE CHAIRPERSON: I have a question with respect to winter concrete. Very specifically, why is it that the -- this contractor would not be pouring concrete during the winter?

What -- what's unique about their process?

MR. BORIS FICHOT: That -- that'll be CSI.

THE CHAIRPERSON: Okay.

CONTINUED BY MS. MEGHAN MENZIES:

MS. MEGHAN MENZIES: All right. So I'd like to move to page 42 of your original report, and specifically at point -- four point six (4.6), where you discuss the contracting methods that were considered. And in particular, I think that these were highlighted in your presentation this morning, and I would like to again highlight the fixed price contract and the cost reimbursable contracts.

And so if you could have some patience with me, I would just like to walk through my understanding of these contracts, and if you could help me with that? So first of all, my understanding of a fixed price contract is that generally, the risk falls primarily on the contractor.

Is that correct?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: And often to account for this risk, the cost would be higher.

MR. MICHAEL ROBERTSON: Yes, correct.

MS. MEGHAN MENZIES: Thank you. And then my understanding with regard to the cost reimbursable contracts is that more risk is likely to be borne by the contracting party.

MR. MICHAEL ROBERTSON: Not in essence. The cost reimbursable contract seeks to share risk.

MS. MEGHAN MENZIES: Okay. So it would be more --

MR. MICHAEL ROBERTSON: In between the two (2) parties in the interests of bringing down the price.

MS. MEGHAN MENZIES: All right. And so in that case, the contracting party is bearing more risk than in the fixed price contract, but it's about equal with the contractor.

Did that make sense on this?

MR. MICHAEL ROBERTSON: Well, there are two (2) contracting parties in each case.

MS. MEGHAN MENZIES: Fair enough, yeah.

MR. MICHAEL ROBERTSON: In the fixed price contract, essentially, the -- the owner/developer, Manitoba Hydro, has very little risk.

MS. MEGHAN MENZIES: M-hm.

MR. MICHAEL ROBERTSON: And -- and all the risk is with the contractor, whereas in the cost reimbursable contract, you are sharing those risks. So Manitoba Hydro inherits some risk, takes on some risk as a tradeoff to paying probably a lower price at the end of the day.

MS. MEGHAN MENZIES: All right. And the owner and the contractor, then, have about equal risks? Are they -- are they taking on about the same level of risk with the cost reimbursable contracts?

MR. MICHAEL ROBERTSON: Depending on which part of the contact you're looking at. No, I -- I wouldn't say in general that that is the case. I mentioned that, for example, the document for the civil contract is written in such a way that any -- any or -- or the first amount by which the final contract price goes over the agreed target price is absorbed 80 percent by the contractor and 20 percent by Manitoba Hydro.

MS. MEGHAN MENZIES: Right. Okay. Yes. So it's just -- it's in the drafting of the contract. It's not particular to the type of contract.

MR. MICHAEL ROBERTSON: No. It's in the details of the contract.

THE CHAIRPERSON: Just to clarify in my own mind, so the first part is the contractor bears 80 percent of the -- of the cost of the first portion of the contract --

MR. MICHAEL ROBERTSON: Of the -- of the overrun.

THE CHAIRPERSON: Overrun. And after that point?

MR. MICHAEL ROBERTSON: Well, it -- it reaches a limit, and then there is a -- a second sum of money which is sort of set aside within the contract amount which is shared differently, but I -- I think we're getting into CSI when we're talking those differences in details.

THE CHAIRPERSON: So the -- the reference in your presentation to a 80/20 split was in ref -- in -- in relation to that first tranche?

MR. MICHAEL ROBERTSON: Yes.

THE CHAIRPERSON: Okay.

CONTINUED BY MS. MEGHAN MENZIES:

MS. MEGHAN MENZIES: Thank you. And now I'd like to move to page 40 of your original contract -- sorry, your original report. And here, just at -- if we could go a little bit -- perfect. So here, it states, "KP further believes" -- sorry:

"KP has not been able to fully ascertain that these risks have been adequately captured in the contingency calculation."

And that was with regard to interface management.

Is that correct?

MR. BORIS FICHOT: That is correct at the time of writing it.

MS. MEGHAN MENZIES: Okay. And -- and has that changed now?

MR. BORIS FICHOT: A little bit, because some -- some portion of the -- the interface, especially between some of the electrical/mechanical subs, have been integrated in the GCC contract. So there's a little bit less in that respect, but there's still some very important risks associated with the interfaces.

MS. MEGHAN MENZIES: Okay. Thank you. And I think I'll touch on that a little further on.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: Okay. If we could go to page 23 of your supplemental report. Sorry, there will be a bit of flipping at this moment.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: So if we read -- and if we could go down just a little further, Diana. Thank you so much. I read:

> "A higher contingency based on the P80, as compared to Hydro's use of a P50, would also be recommended for the conservative estimate."

So I just want to walk through this for a moment. What I'm getting from this is that Hydro is using a P50, and a conservative position or a conservative estimate would be a higher contingency of -- based on the P80.

Can you provide for me, what is Knight Piesold's position? Is it that there should be a conservative estimate here, or is there a number that Knight Piesold is recommending specifically?

MR. BORIS FICHOT: We -- we couldn't recommend a specific number. It's very associated with who ultimately is the decision maker and how comfortable are they with the risk that they're taking. So it -- it's within each decision maker to -- to assume how much risk that they want to take. And there's no -- if you look at the standards out there, there's no -- there's no prescribed number that people should be using. There's some recommenda -- different people have differing opinions on what to use.

MS. MEGHAN MENZIES: Okay.

MR. MICHAEL ROBERTSON: And I suppose the general point though is that it's not -- it's not unduly cons -- the P50 is not unduly conservative. And -- and many would say it's not sufficiently conservative.

MS. MEGHAN MENZIES: All right. Thank you.

MS. MARILYN KAPITANY: Sorry to interrupt, but your report does say that a higher contingency, based on the P80, would be recommended for the conservative estimate. So it sounds like you're making a recommendation.

MR. MICHAEL ROBERTSON: Well, we are if -- if you want to go with a conservative estimate. It -- it's Manitoba Hydro's choice, you know, and I guess ultimately the people of Manitoba, whether they would be more comfortable with a more conservative estimate. And if they -- if they would like that, then we should be using something more like a P80, we believe.

CONTINUED BY MS. MEGHAN MENZIES:

MS. MEGHAN MENZIES: Thank you. And could you provide -- could you provide me with some examples of what the tradeoffs would be between a conservative P80 and Manitoba Hydro's P50?

MR. MICHAEL ROBERTSON: Well -- well, there's not really a tradeoff. I mean, there -- there's just a -- an appreciation upfront that perhaps the final cost might be nearer what the P80 is -- is indicating than the P50-based estimate that is being put out by Manitoba Hydro now.

MS. MEGHAN MENZIES: I guess what I'm hoping to -- to understand is, can you say as -- in as plain language as possible, why would a decision maker want a P80 as opposed to a P50, or the opposite?

MR. MICHAEL ROBERTSON: Because he doesn't want to exceed his budget.

MS. MEGHAN MENZIES: Okay.

MR. MICHAEL ROBERTSON: And he doesn't want egg on his face or what -- whatever.

MS. MEGHAN MENZIES: That's a very helpful visual. Thank you very much.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: All right. And so I think that for those of us with hard copies, if we could go back to page 40 of your original report. So I think I had directed you there before.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: And as I'd gone over before, it says here at that KP identifies interface management by Manitoba Hydro as one of the most important systemic risks associated with the implementation of the Preferred Development Plan, correct?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: And you had

qualified before that there are some -- that there are some uncertainties that are now more certain, but generally, this is still -- would this -- would this still be the most important systemic risk for KP, or for Knight Piesold?

MR. MICHAEL ROBERTSON: Probably not. Probably -- I wouldn't say it's the most important systemic risk.

MS. MEGHAN MENZIES: Okay. And what would be the most important systemic risk now?

MR. MICHAEL ROBERTSON: Essentially, their new process.

MS. MEGHAN MENZIES: Thank you. Yes. Okay. But interface management is still a risk that Knight Piesold is concerned with?

MR. MICHAEL ROBERTSON: It -- it is a risk. I -- I wouldn't say that we're particularly concerned about it. It's -- it's not different from other developments of this nature.

MS. MEGHAN MENZIES: Okay. What I would like to do now is direct you to the response to PUB/KP I-10b. And that'll be up on the screen. Thank you very much, Diana. And so at line 18, it states:

"The more the scope of work can be wrapped up and managed by a single

responsible entity, the easier the
interface management process is and
the less likely scopes of work will
be difficult to define and administer
separately."

Can you confirm this?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: Yes. And so there are two (2) places that I would like to direct you to. First of all, page 2 of your supplemental report; and just a little bit lower. Perfect. It says:

"MH's systems are still maturing, and
MH has recently included an outsource
-- outsourcing some of the
construction management as part of
their estimate."

So is -- does this outsourcing, does this play into the concern of interface management?

MR. BORIS FICHOT: In my opinion, yes.

MS. MEGHAN MENZIES: Thank you. And so that would then -- that would add to the risk?

MR. BORIS FICHOT: Yes.

MS. MEGHAN MENZIES: Thank you. And then -- or I don't want to --

MR. MICHAEL ROBERTSON: No. I mean, it

-- it was a risk. It's -- it's something that's identified. It's been dealt with. It's added to the cost. I'm not sure there's a residual risk associated with essentially using consultants to manage the construction as opposed to in-house. Maybe I better take this offline.

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: Okay. My response stands.

MS. MEGHAN MENZIES: Okay. Thank you. And now I would like to direct you to page 46 of your presentation this morning. I'm giving Diana carpal tunnel back there. I apologize. And here, the second bullet states:

"Increased costs for the project management as a result of insufficient capacity in MH and consequences -- consequent need to hire consultants."

So the hiring of consultants again is that interface management issue, correct?

MR. MICHAEL ROBERTSON: Yes. I -- I would say, though, that we're talking now the risks that were perceived in August/September of last year. Subsequent to that, the decision -- at that time, it was perceived there was a risk that they may have to go to consultants --

MS. MEGHAN MENZIES: M-hm.

MR. MICHAEL ROBERTSON: -- for construction management. That has materialized, and so I would say that that is no longer a major risk in their risk register because it's happened. But again... I mean, what Boris was saying is that it does produce another interface, obviously. But I'm not sure that, within Manitoba Hydro, that people on site reporting back to their people in head office is very different from the engineer -- appointed consulting engineer reporting back to Manitoba Hydro. But I -- I personally don't see that it'll be a significant issue.

MS. MEGHAN MENZIES: Okay. Thank you. And I'm soon going to leave the issue of -- of interface management. But as you can see, I'm a dog with a bone right now.

So on that issue, you had stated that Manitoba Hydro was mitigating that risk with increase costs?

MR. MICHAEL ROBERTSON: With respect to hiring consultants to do the construction management, that ended up -- resulted in an increase cost.

MS. MEGHAN MENZIES: Sorry. And previously to that, when we were discussing the issue of interface management, that perhaps an increased contin -- I -- I'm forgetting exactly what you had said.

But essentially, that was mitigated by Manitoba Hydro, those risks?

MR. BORIS FICHOT: In -- in the very original report, the interface that we had, looking at the information that we had available at the time, the concern was some of the electrical and mechanical scope, because as soon as you chop up all these little, tiny pieces of contracts and they were purchasing the material internally, then you have to subcontract all these different parties to do different pieces of that scope of work. And the you had the general civil contractor on the side doing his own work.

Our experience has been that, with all these different parties involved in the project, that there was always scopes of work that were missed and so forth, and that usually led to an increase in cost.

Now, in the new signed terms, there's a lot more inclusion of some of these little different elements which reduces the number of interfaces on that front. Where we have a slight different opinion is whether or not, once you go on the management side, because there's a different interface in managing the overall construction, if bringing in another party to the table creates some -- some schedule risk and some -- some overall risk to the project.

MR. MICHAEL ROBERTSON: Does that answer?

MS. MEGHAN MENZIES: Yes. And I'm -- I'm going to leave that for you -- leave that now, so you will all be relieved.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: Okay, if we could go to slide 26 of your presentation.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: And at the bottom, at the last bullet, it states:

"Manitoba Hydro have attributed lack of productivity to difficulties hiring and retaining staff and use of inexperienced staff. And then as a

result of the low productivity
experience at Wuskwatim, Manitoba
Hydro has, for Keeyask and Conawapa,
adjusted contracting methods, added
staff, and invested in better camp
facilities."

Do you see that there?

MR. MICHAEL ROBERTSON: Yes.

MS. MEGHAN MENZIES: Thank you. And then when we had reached slide 33 of your presentation, in discussing the issue of labour retention, I believe that you had expanded on that by stating that the much better camp conditions would assist in mitigating that.

Is that correct?

MR. MICHAEL ROBERTSON: That is certainly Manitoba Hydro's belief, and it is logical.

MS. MEGHAN MENZIES: Okay. Did you have any opportunity prior to today to review the Deloitte report -- the Deloitte report on Wuskwatim?

MR. MICHAEL ROBERTSON: Certainly not personally, no.

MS. MEGHAN MENZIES: Okay. Well, then I will leave that there.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: I will not leave that there. Just to confirm then, you are not able to confirm or to speak to any of the observations that were made by Deloitte with regard to the camp conditions in Wuskwatim?

MR. MICHAEL ROBERTSON: Correct. Everything that we have to say about Wuskwatim was based on what we were given by Manitoba Hydro.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: And Manitoba Hydro did not give you the Deloitte report?

MR. MICHAEL ROBERTSON: I don't believe so.

MS. MEGHAN MENZIES: Thank you. Subject to check, that is all that I will be saying on -- on the Deloitte report.

(BRIEF PAUSE)

MS. MEGHAN MENZIES: All right. I have two (2) last areas to touch on, and then I -- then I will be finished with my questioning. The first is a follow-up to the question of Board member Kapitany this morning, and it was related to page 8 of your presentation.

And I believe that we had established that -- or you had established that that report is not based on the updated capital cost estimates, correct?

MR. MICHAEL ROBERTSON: Correct.

MS. MEGHAN MENZIES: And -- but you had also stated that the updated capital cost estimates would not change your conclusions in this report --

MR. MICHAEL ROBERTSON: Correct.

MS. MEGHAN MENZIES: -- in this table, sorry. In -- in the interests of being as up to date as possible, would you be willing to undertake to update this table with the updated capital cost estimates?

(BRIEF PAUSE)

MR. BORIS FICHOT: We -- we could do that. It's -- but we don't think it's really the intent of the table. The -- the overall intent is on a very, very high level. If you pull away from the whole thing, our first impression of any hydro project that we're given, or any renewable project that we're given, is usually we'll just look at, overall, here's how much it costs and what's the bang for the buck on a very, very high level.

And we're used to looking at projects and we say, Okay, wind power is between one point five (1.5) and two point five (2.5), or we'll say a hydro project is between two (2) and ten (10). And that's -- that's our first gut feel when we -- when we look at any of these projects is, Okay, well this ones around nine (9) in this case. It doesn't matter if it's eight point five (8.5) or it's ten (10), but it's around that number, and that gives us a feel that, Oh this is expensive, or if it's a dollar -- a million dollars per megawatt, Oh, let's -- I'd throw my money in there right away because it looks like it's worthwhile.

So that was the overall intent of that table. Whether the number is exact kind of defies the -- the purpose of the impression that we get firsthand of the -- the value of the project. It has a lot of catches to that. There's no attribution -- attributes, for example, of the firmness of the energy or anything like that. That's just overall our impression of the -- kind of where that project ranks in -- as an overall project in the big pool of hydro power resources.

It's -- it's on the expensive side comparatively, but that's -- it -- it doesn't give us a better indication than that. But it's not crazy out there either.

MR. MICHAEL ROBERTSON: But -- but to be specific, I mean if you take -- for Keeyask you put in six point five (6.5) instead of six point two (6.2), your million dollars per gigawatt hour will now be one point four-seven (1.47) instead of one point four-zero (1.40).

MS. MEGHAN MENZIES: Yes.

MR. MICHAEL ROBERTSON: It's -- as Boris said, It's not significant. And it's not relevant to whether or not this project is in the ballpark of experience.

MS. MEGHAN MENZIES: And that's fair. And with that caveat in mind, would you still be able to undertake to update the table? And we will keep in mind that it's from a high level.

MR. CHRISTIAN MONNIN: It seems to me that Mr. Robertson has provided a partial answer to that already by saying that Keeyask would be one point four-seven (1.47). If I can invite him to do the Conawapa calculation right now, we might be able to satisfy the undertaking right now.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: He just rightly advised me that Conawapa hasn't changed. So if I understand correctly, the -- the reboot of this table would be with the new capital costs. You would have one point four (1.4), one point four-seven (1.47), and that would be the substance of the changes.

MR. MICHAEL ROBERTSON: Well, that's the -- that's the second-last column. The -- the million dollars per gigawatt hour would go from one point four (1.4) to one point four-seven (1.47). The million dollars per megawatt would go from eight point nine (8.9) to nine point three (9.3). That's putting six point five (6.5) in instead of six point two (6.2) for the in-service cost.

CONTINUED BY MS. MEGHAN MENZIES:

MS. MEGHAN MENZIES: Perfect. Well, undertaken now satisfied -- undertaking now satisfied. Thank you very much.

(BRIEF PAUSE)

MS. MARILYN KAPITANY: So I thought we also had a -- a change of cost for Conawapa, but maybe that was CSI.

So my understanding was that the updates we received per Manitoba Hydro were for both of the generating stations, not just for Keeyask?

MR. SVEN HOMBACH: If it's -- if it's of assistance to the panel, it may help to flash up Manitoba Hydro Exhibit 113 for a moment, that deals with the new capital costs.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Yeah, the second page of the document shows the updated capital costs.

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: Yes, I -- I see indeed that the Conawapa cost was updated in March 2014. So it's now 10.662 billion, where in CEF13 it was ten point four-nine-two (10.492). So that's public record from Manitoba Hydro.

THE CHAIRPERSON: Since we're there, we might as well -- can you give us the revised numbers as well for that table, the -- the impact of --

MR. MICHAEL ROBERTSON: Oh, right.

THE CHAIRPERSON: -- that change?

(BRIEF PAUSE)

MR. BORIS FICHOT: That -- that results in $7.2 million per megawatt for -- for Conawapa and then one point five-two (1.52) for -- dollars per gigawatt hours.

CONTINUED BY MS. MEGHAN MENZIES:

MS. MEGHAN MENZIES: Thank you. That was impressively quick. And so in drafting this table, did you employ a discount rate?

MR. BORIS FICHOT: Yeah, I -- I didn't mention that, but, yeah, these -- we -- we didn't really refer to what years these dollars apply to, so there is -- there may be some differences in these numbers. As I said, the intent is really at a high level, where we -- it doesn't matter if it's 2 percent off. It's what category are we in.

MR. MICHAEL ROBERTSON: So strictly speaking, the answer is no.

MS. MEGHAN MENZIES: Thank you.

MR. MICHAEL ROBERTSON: They're essentially -- inasmuch as they're present day project projects, they're present day costs.

MS. MEGHAN MENZIES: Thank you. And

we've now reached the last area of questioning. At page 23 of your original report; and if we go down just a little bit. Thank you. Perfect.

Knight Piesold states that:

"It appears as though expected val -- value modelling of -- the expected value modelling of Manitoba Hydro is akin to what KP would call a Monte Carlo simulation."

Is that correct?

MR. BORIS FICHOT: That's correct.

MS. MEGHAN MENZIES: And so could you provide just a little more information or a little more detail on how Manitoba Hydro's process was akin to a Monte Carlo simulation?

MR. BORIS FICHOT: It's -- it's essentially the same thing, except that they -- they separate out the subsets of risk into two (2) categories, versus we would just do one (1) general thing where we would categorize all the different risks and put a statistical variation on each of those elements, and then run this through to kind of get a -- a statistical distribution of the end costs of the -- of the project.

They -- they've used an external

specialist, and we've now seen the -- the most recent report produced by that specialist, and then they go through an interview process to derive the systemic risk portion, and then the same processes we would be used to for the -- for the rest of the risk.

MS. MEGHAN MENZIES: Thank you.

And so either separately or all risk factors together, can you speak to how many risk factors were assessed?

MR. BORIS FICHOT: We do have a list of those in the material that was provided, but it's quite a number. The -- the systemic risk is, I think, the -- the more valuable to review if somebody were to review it, and I believe there was, like, twenty-five (25) assumption factors. I could be wrong on the exact number, but it's around those numbers on the systemic side.

MS. MEGHAN MENZIES: Thank you.

And are you able to speak to what types of factors were assessed?

MR. MICHAEL ROBERTSON: Well, in -- in essence, the -- the cost is broken down into a number of different items, and in this kind of simulation, whatever you call it, you -- you basically assign three (3) valuable -- three (3) values to each of those parameters --

MS. MEGHAN MENZIES: M-hm.

MR. MICHAEL ROBERTSON: -- which typically are called a reference and a low and a high, and you throw them in the box, and the box combines all possible combinations of -- of those parameters, and it spits out, essentially, a -- an expected value, and it gives you some idea of -- of the range of what it might be in terms of probability --

MS. MEGHAN MENZIES: M-hm.

MR. MICHAEL ROBERTSON: -- which gives you the P50s and the P80s and that sort of thing.

MS. MEGHAN MENZIES: Exactly. Sorry, I wasn't -- I'm not wanting a -- a description of Monte Carlo, but more just what -- what factors -- what risk factors were assessed specifically?

MR. MICHAEL ROBERTSON: Not risk factors per se. It -- it's -- it's the -- the possible range of costs of the different parts of the overall cost estimate, so, for instance, the -- the value of concrete.

MS. MEGHAN MENZIES: And precisely, that's -- so that's what I'm speaking to. So the value of concrete was one (1).

MR. MICHAEL ROBERTSON: Right.

MS. MEGHAN MENZIES: Can you speak to any other?

MR. MICHAEL ROBERTSON: Well, the other component costs. The earthfill, the -- the turbine generator, the -- the indirect costs. I mean, they're all part of the overall cost makeup.

MS. MEGHAN MENZIES: Perfect. And on that note, thank you for your patience. And those are done -- those are my questions for today.

THE CHAIRPERSON: Thank you, Ms. Menzies. Now it's your -- your turn, Me. Hacault.

MR. ANTOINE HACAULT: Can I just have a five (5) minute break? I'd like to speak to Diana on some of the documents I might be asking her to bring up, and -- and there's going to be one (1) filing when we -- that should be distributed -- or was distributed earlier this morning, will be.

THE CHAIRPERSON: So five (5) minutes it is, then.

--- Upon recessing at 1:35 p.m.

--- Upon resuming at 1:42 p.m.

THE CHAIRPERSON: I think we're ready to resume the proceedings, and I -- we just had documents distributed, so perhaps we should acknowledge them, Ms. Ramage, please?

MS. PATTI RAMAGE: Yes. Thank you. Three (3) documents were distributed. The first one on my list is the economic summary tables, assuming flat load growth beyond '22/'23, and that is marked as Exhibit Manitoba Hydro-104-13.

--- EXHIBIT NO. MH-104-13: Economic summary table assuming flat load growth beyond 2022/2023

MS. PATTI RAMAGE: Next is a -- a response to a -- to MIPUG Exhibit 21 Question 3, and that -- that would be marked as Exhibit 174.

--- EXHIBIT NO. MH-174: Response to MIPUG Exhibit 21 Question 3

MS. PATTI RAMAGE: And then lastly, Exhibit 175 is Manitoba Hydro's response to Undertaking number 67, which is a -- a detailed supporting schedule showing the calculations used to arrive at the return on equity shown on page 4 of Manitoba Hydro's Exhibit 129.

--- EXHIBIT NO. MH-175: Response to Undertaking 67

MS. PATTI RAMAGE: So those are the three (3) documents.

THE CHAIRPERSON: Thank you.. And Me. Hacault, you have a document as well to -- to --

MR. ANTOINE HACAULT: Oui, M. President. We have a Volume VIII, which I understand will be marked as MIPUG Exhibit 20-8.

--- EXHIBIT NO. MIPUG-20-8: Volume VIII

CROSS-EXAMINATION BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Good afternoon, members of the panel. My name is Antoine Hacault. I act on behalf of Manitoba Industrial Power Users Group.

And we'll start on slide 8. With respect to the projects, and let me -- I'll try to explain the context of this -- this particular line of questioning.

We have two (2) potential generating stations, Keeyask, which is well underway, and Conawapa, which is a merchant generating station whose construction date -- the earliest in-service date might be 2026.

In the context of that, could you, sir, and it doesn't matter who, advise where is Muskrat Falls in its construction project -- process in relation to this estimate?

MR. MICHAEL ROBERTSON: My -- I stand to be corrected. My understanding is that Muskrat Falls is well underway. It's under construction. I do not recall when its target in-service date is. I don't know. I know it's ahead of --

MR. ANTOINE HACAULT: Can you --

MR. MICHAEL ROBERTSON: -- Keeyask.

MR. ANTOINE HACAULT: -- can you help this Board understand whether or not the 7.5 billion doll -- sorry, $6.2 billion number is an estimate prior to awarding the general service -- or civil contract under that particular project?

MR. MICHAEL ROBERTSON: I cannot.

MR. BORIS FICHOT: The -- the number was taken straight from the similar proceeding they had to this one, where they -- they went through something similar to the NFAT process. So that -- at that stage, they -- they weren't there yet. They -- they have a process where it was Gateway 2 or 3. I don't remember what it was -- but it was at -- at a similar stage in the -- in a process prior to GCC.

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: I was just confirming with -- with Boris there that at the time that that review took place, they did not have the general civil contract bids in, and therefore, to some extent, they were further behind than we are today on Keeyask.

MR. ANTOINE HACAULT: Thank you very much, sir. Now, do you have -- can you give us an answer at this point whether or not -- when this information was put on the record, how far they were away from awarding the general service contracts? Was it two (2) or three (3) years?

MR. MICHAEL ROBERTSON: No, not with any accuracy. I can't tell you that answer.

MR. ANTOINE HACAULT: Okay. Thank you very much. What about Site C? How close to construction was that $7.9 billion project?

MR. MICHAEL ROBERTSON: The $7.9 billion question. They are planning, my understanding, is to start involving contractors eminently in -- in April or May of this year. I'm sure they will go through a pre-qualification process. I don't imagine that they're going to get any real numbers in the form of bids until -- till next year, but I stand to be corrected. That's just my speculation.

MR. ANTOINE HACAULT: But we are talking in Muskrat Falls or Site C for an in-service date which is some ten (10) or twelve (12) years out, are we?

MR. MICHAEL ROBERTSON: Site C, probably; Muskrat Falls, maybe somewhat less inasmuch as they've started construction.

MR. ANTOINE HACAULT: So Site C, you think that the in-service date might be in the 2026 range for the first turbines?

MR. MICHAEL ROBERTSON: I don't know. I wouldn't say -- I would suggest probably less.

MR. ANTOINE HACAULT: Probably less? Okay. What about La Romaine? That's another one for which we have a capital cost estimate.

MR. MICHAEL ROBERTSON: That -- that is -- is well underway. It's -- it's -- it may even be ahead of -- oh, I'm not sure, to be honest. I -- I would say it's -- it's started, so it's ahead of Site C. But where it sits with regard to Muskrat, I don't know.

MR. ANTOINE HACAULT: So that capital costs estimate, when was it made in relation to the construction, which is, as you say, underway?

MR. MICHAEL ROBERTSON: I don't know.

MR. ANTOINE HACAULT: Okay. Just trying to see if we could get some sense of how close the capital cost estimates were to actual definition of the project and -- and costs of the project. With respect --

THE CHAIRPERSON: Let's just situate this table in time. This -- this is -- this table dates from what time frame?

MR. MICHAEL ROBERTSON: Well, as -- as we said to -- to Meghan, essentially, I think that table is present day over the last three (3) years. Whether the costs have significantly changed for the precise same scope of work in the last three (3) years, I don't know. I -- I think, given again, as Boris says, this is a -- really a ballparking exercise, it -- it doesn't stand up to detailed examination.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: With respect to the projects that are listed on slide 8, which of these would be built on a merchant basis as opposed to a needs basis for either capacity or energy?

MR. MICHAEL ROBERTSON: Well,

certainly, Muskrat Falls was -- is being built to serve the people of Newfoundland and Labrador. That's what it's being sold as. Site C, BC Hydro believed that that is needed for internal demand. I -- I imagine the -- the Hydro-Quebec projects would have a large element of export driver; so, by your definition, market plans. I -- I don't know for sure, but I suspect that's the case.

Boris...?

MR. BORIS FICHOT: Overall, it's not something that can easily be assessed because there's so many side attributes to -- to the value of energy there that a dollar per gigawatt hour never shows. The firmness of the value of energy is -- is something on its own that you can't compare to a renewable energy source output like a wind farm. It -- there's a different value to that energy, and it's -- it's too difficult to -- to evaluate on a simple level.

MR. ANTOINE HACAULT: Understood, but the context of my question, sir, was to see, for some of these projects -- there's a theme, at least from our perspective, that the PUB will have to make a decision whether it looks at risk in a different way when a project is constructed for needs of the residents as opposed to an opportunity on export.

So I was trying to identify which of the products -- projects that were -- potentially had more opportunity perspective. And you've answered that, Mr. Robertson. You believe that the projects in Quebec might have more kind of an export attribute than Muskrat Falls and Site C, which are being built by the utilities for the needs of the residents in those areas, correct?

MR. MICHAEL ROBERTSON: That's my opinion. I -- I might be wrong.

MR. ANTOINE HACAULT: Okay. And that leads me to slide 10 of that same presentation. The third bullet down, you make a statement:

"Many jurisdictions use higher than P50 estimate to establish consis -- contingency [and then in parentheses] (but a significant number of others do not; they use P50)."

Did I kind of interpret that correctly, that bullet?

MR. BORIS FICHOT: That's correct.

MR. ANTOINE HACAULT: Okay. Now, if we go to Exhibit 3-1 at page 24, one of the discussions on that page relates to the use of the P50 by others and the view of Knight Piesold on that particular discussion point.

Now, as I read the information under paragraph 2.9.3.3 in the second paragraph, there's a view that perhaps using a P50 might not be appropriate for large projects.

Is that correct?

MR. MICHAEL ROBERTSON: That is correct.

MR. ANTOINE HACAULT: Okay. And there's also, as I understand, the view -- and it's at the very bottom of what we see on this screen; this is in an article that you've quoted -- that the 50 percent probability guideline is not necessarily applied to very large projects or to strategic projects outside the annual capital budget.

So that also is one view, correct?

MR. MICHAEL ROBERTSON: Yes.

MR. ANTOINE HACAULT: So we do see this being used by Manitoba Hydro for capital budgets.

Why, in your view, do we have to think about the use that we're making of the budget in deciding whether to use a P50 or, as you had later explained in your slides and the cross-examination of Ms. Menzies, you may, for other purposes, wish to use a different level of probability?

MR. MICHAEL ROBERTSON: Well, as -- as we tried to explain, it -- it is very much dependent on the appetite for risk on the -- on behalf of the developer. Manitoba Hydro have chosen to go with the P50 backed up by a management reserve which, to some extent, takes it higher than that, while other jurisdictions will stick with their P50.

The argument there is that if you've got a whole suite of large projects, then it -- it makes some sense perhaps to -- to work on the P50 on the whole package. But when it comes to an individual project and you want more reassurance that you're not going to run out of budget, you should probably be working with a higher number than the P50.

MR. ANTOINE HACAULT: Now, if we turn to the next page, please, Diana, at the top of the page, this is in Exhibit 3-1, there is a table. And initially, your response to the Chair was that you believed that the contingency amounts were part of CSI. There's two (2) places, one (1) in this report and one (1) in your supplemental, where some of the 'P' values are given.

Am I understanding correctly that in this January report the probability values were not yet updated to reflect the award of the contract later in -

- and the updated capital costs?

MR. MICHAEL ROBERTSON: Correct. That was your initial -- this data came from Manitoba Hydro, and it's based on the initial risk assessment that was done.

MR. ANTOINE HACAULT: So I'll take --

MR. BORIS FICHOT: Not -- not the numbers that are on the screen. The numbers that are on the screen are from the updated 2014 study.

MR. ANTOINE HACAULT: I -- I'll take you to the -- so -- yeah, just to -- there is an updated table in your supplementary report.

MR. BORIS FICHOT: Okay.

MR. ANTOINE HACAULT: So as of January, when this report is being written, what assumptions, or what are the kind of back -- what's the background? Do we have the 2013 capital update in by this time? Because there was a further update in March of 2014.

MR. MICHAEL ROBERTSON: No, the table on the screen in front of us was produced in the January report, at which time the -- the capital cost estimate had not been redone for 2013. As I say, there's data from Manitoba Hydro and it was based on their previous -- essentially, their risk assessment.

MR. ANTOINE HACAULT: So I always have

a little bit of difficulty understanding probabilities. If I go to P90, does that mean one (1) times -- one (1) time out of ten (10) we're actually going to be higher than 950 million, and the other nine (9) times we hope to be doing better than a $950 million contingency overrun?

MR. MICHAEL ROBERTSON: Well, it -- well, it's not the 950 million number. What we're saying is that if you apply a 950 million contingency to your best estimate, that cost is short and you'd be exceeded 10 percent of the time.

MR. ANTOINE HACAULT: Okay. So again, that just speaks to the level of tolerance we've seen in other parts of this proceedings, some of the P10 and P90s being used on certainty. Here, one (1) conservative view that Knight Piesold has put forward is that we -- we might want to look at P80. And if we want it to be more conservative, the way would -- we'd have to go is go to a P90.

Am I understanding you correctly?

MR. MICHAEL ROBERTSON: In principle, correct.

MR. ANTOINE HACAULT: Yes. So there was roughly a $300 million difference between P50 and P80 in the initial filing. And if we go to Exhibit 3-

2, at page 23 of 26, at the bottom of the page we have another contingency comparison. This time we haven't included the P90 and the P95. And the P50 has actually gone down from -- from 527 million to 327 million.

Now, is that just because of the runs of the Monte Carlo simulation that we get that reduction, or is that something that your company independently assessed?

MR. MICHAEL ROBERTSON: No, it's -- it's not a result of rerunning the thing, except that at this time you have removed a large measure of uncertainty, because you now have the GCC results. So the capital cost has not gone down, the -- the contract cost went up. But because it's now more firm, the contingency that you need to add to it to get to the P50 is less.

MR. ANTOINE HACAULT: Now, and this is something that the Chairman has asked questions about...

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: Yes, sorry. Sorry. Boris was just clarifying, yes, they -- they are reruns from the model. But the essential difference is that the model parameters have been changed.

MR. ANTOINE HACAULT: Now, if we go from P50 to P80 on this revised calculation, we subtract from six ninety-one (691) the three twenty-seven (327) and come to -- in the range of 360 to $70 million difference between those two (2) probabilities, correct?

MR. MICHAEL ROBERTSON: M-hm, yes.

MR. ANTOINE HACAULT: And before, the range was -- we would subtract if we -- I don't know if you still have handy, Diane (sic), page 25 of the prior exhibit, from the P80, 848 million, we would subtract the 527 million. So we actually have a little bit smaller of a range.

One of the questions the Chair, and quite frankly I nothing, when we introduced some certainty with respect to the contract, why are we seeing such a wide range at the P80 continue to exist, and in fact, get a bit wider?

MR. MICHAEL ROBERTSON: Well, essentially, if you look at it graphically, it's a flatter curve with a lower peak, but are more extended. So your -- your limits are wider, so the differences between your centre point and any chosen point are greater. So you -- as you say, it's three (3) -- three sixty (360) difference now, and it was three twenty (320) difference.

That comes out in the math, and -- and in the readjusted factors that you put into re-running the model. But it is still -- the P80 at six ninety-one (691) is still less than it was at eight forty-eight (848). It's just a different shape of distribution that comes mathematically out of the exercise.

MR. ANTOINE HACAULT: And, sir, would you be able to provide us with the probability value on Table 9.1 of Exhibit 3.2 for the probability points of P90 and P95?

MR. MICHAEL ROBERTSON: Manitoba Hydro might be able to, but I don't have the data.

MR. BORIS FICHOT: We actually do have the data, but I don't know if we can share it, so. I -- I don't have it with me.

MR. MICHAEL ROBERTSON: I -- I don't have it with me either.

MR. ANTOINE HACAULT: Okay. Well, my request, as long as it's not commercially sensitive information, and I don't see why it would be if we already have one (1) table, is to update Table 9.1 in

Exhibit 3.2 -- or 3-2 to also include the P90 value and the P95 values.

Do I have that undertaking, subject to availability of information?

MR. CHRISTIAN MONNIN: Yes, we undertake to do that, subject to the availability of information.

--- UNDERTAKING NO. 117: Knight Piesold to update Table 9.1 in Exhibit 3-2 to include the P90 value and the P95 values

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: If I go back to the executive summary of Exhibit 3.1, it's Roman numeral II of IV, and one of the issues that's discussed in that executive summary is the issue of indirect costs, which, as I understand it, contribute about one-third of the total costs of the project.

Am I right, that it's about one-third (1/3) of the cost of the project?

MR. MICHAEL ROBERTSON: You are correctly stating that Manitoba Hydro have told us that.

MR. ANTOINE HACAULT: And one of the issues that was raised was that -- I'm looking at the bottom of the first paragraph under Item 2:

"KP would have liked to see more Hydro documentation of the indirect cost."

Why would it have wanted to see that?

MR. MICHAEL ROBERTSON: So that we could offer an opinion as to whether or not they had been well-documented and covered the requisite territory.

MR. ANTOINE HACAULT: Is it just the question of well-documenting? How are you bil -- able to assess whether or not the estimate of indirect costs have been reasonably assessed if you don't have the detail to make that examination, sir?

MR. BORIS FICHOT: We -- we had some level of comfort with a -- a first level -- level of breakdown of the cost estimate they'd given us, as well as some of the -- some of the contracts that were in place that kind of fit under that category. But the detailed, detailed breakdown and a documentation of those indirect costs would have been desirable to -- to firm up those numbers.

But at the same time, in terms of the

limited scope that we can do -- go, there's only so many levels of detail that we can go into.

MR. ANTOINE HACAULT: So are you able to give me any sense as to the extent to which your ability to provide your opinion was impaired as a result of not having the documentation to the level that you would have liked to have it?

MR. MICHAEL ROBERTSON: I -- I think what we can honestly say is what we have said, i.e., that we -- we saw a lot of data on the direct costs and can confirm that that has been handled well and in good detail. We cannot say quite the same about the indirect costs for whatever reason.

MR. ANTOINE HACAULT: So trying to search some kind of a -- a suggestion or a fairness issue that I might be able to suggest to you. You've got about a third of the costs which you believe you don't have in -- enough information about.

Are you satisfied that, for example, that's adequately dealt with in the contingency allowance?

MR. MICHAEL ROBERTSON: Ultimately, if -- if you were going to hang me on my answer, I would say no. We -- we would have liked to have seen more detail, as -- as we say; we didn't. We -- we therefore cannot offer the same degree of confidence as we can on the direct costs.

MR. ANTOINE HACAULT: Okay. On the issue of confidence, and I'll get into some of the details, Conawapa now has projected in-service dates which might be deferred to 2031.

Were you aware of that, sir? Depending on the level of DSM being introduced.

MR. BORIS FICHOT: We -- we didn't look further into Conawapa after issuing the first report. Our additional scope of work really just covered Keeyask.

MR. ANTOINE HACAULT: Okay. Diana, could you bring up Exhibit 104-1? It'll show us the in-service dates under the various DSM plans.

And, gentlemen, as you can perhaps see in the middle of the page, there's Level 2 DSM, which is the level of DSM that we've been discussing in this hearing as being achievable, somewhere between Level 1 and Level 2. As you can see, the new resources and dates, at the very bottom of the screen, we have a date 2031 for Conawapa.

Do you see that, sir?

MR. MICHAEL ROBERTSON: Yes.

MR. ANTOINE HACAULT: Now, is this a

limitation with respect to your report, that your analysis and your comments relate to the estimate with an in-service date for Conawapa of 2026?

Is that a limitation to your report?

MR. MICHAEL ROBERTSON: I would say no.

MR. ANTOINE HACAULT: Okay.

MR. MICHAEL ROBERTSON: If -- if only, because as Boris says, the focus certainly of the second report has been specifically Keeyask. On -- Conawapa is -- is a long way away. I mean, some -- many things will change before then.

MR. ANTOINE HACAULT: And perhaps I didn't word my question correctly when I said, "a limitation to your report."

If there's a deferral of Conawapa from 2026 to 2031, have you considered in your report whether or not your comments on the soundness and accuracy of the estimates, as it relates to Conawapa, can still be relied on?

MR. MICHAEL ROBERTSON: I -- I don't think I can answer that question.

MR. ANTOINE HACAULT: So you're uncertain as to whether or not we -- that would be MIPUG and this Board -- can rely on your conclusions with respect to Conawapa estimates and the reasonable of those -- reasonableness of those estimates if the construction date is pushed to 2031?

You can't comment on that?

MR. MICHAEL ROBERTSON: Sorry. Boris is itching to say something as well. But we are not expressing an opinion on the total in-service cost of Conawapa and whether or not Manitoba Hydro have got that even in the right ballpark.

MR. ANTOINE HACAULT: That's useful. I hadn't understood that there was that limitation with respect --

MR. BORIS FICHOT: I would put in the context --

MR. ANTOINE HACAULT: -- to Conawapa.

MR. BORIS FICHOT: -- of the economic analysis specifically. So we -- we looked at the capital costs as they were presented and have our opinion on the capital costs. But we don't look into the change of in-service dates as affecting it.

So we don't look at the -- beyond the immediate calculation of the amortization as it's portrayed, whether there's a delay, that wasn't part of our scope of work in terms of what we look at.

MR. ANTOINE HACAULT: I want to understand that a bit better, because in your report --

and I had a line of questioning on this; I maybe can jump to it -- you had some comments on the escalation of prices if the -- for the two (2) projects, and whether or not you thought Manitoba Hydro's view of escalation costs was reasonable.

Can I simply, for Conawapa, apply your view of escalation, which I think was three (3) point something percent, to the Conawapa estimates and -- and change those from 2026 to 2031?

MR. MICHAEL ROBERTSON: If -- if you wish. Discounted back to present day, it's a long way ahead. It's not an exercise that, as Boris says, is -- is within our scope.

MR. ANTOINE HACAULT: Now, if we can go to slide 18, you had mentioned, and perhaps I just didn't see it in your report, you've got what I would consider, firstly, the capital cost of a CCGT at 1.3 million.

Then you've done some for the other types of units, correct?

MR. MICHAEL ROBERTSON: That's correct.

MR. ANTOINE HACAULT: And that was basically looking as to whether or not the reference value assigned by Manitoba Hydro to this -- these units were appropriate?

MR. MICHAEL ROBERTSON: Correct.
MR. ANTOINE HACAULT: Now, I didn't see any analysis as to whether or not the lows and highs with respect to those units were appropriate.
MR. MICHAEL ROBERTSON: And that's because we didn't do it.
MR. ANTOINE HACAULT: Okay.
MR. MICHAEL ROBERTSON: So we -- we were not asked to do it. We were asked to comment on Manitoba Hydro's capital costs and operating and maintenance cost estimates for these alternative energy generation.
MR. ANTOINE HACAULT: And in addition not to commenting on whether Manitoba Hydro chose an appropriate high to stress test the plan, you also didn't address, sir, whether or not the reference capital costs might go down between now and, say, for example if we go back to Exhibit 104-1, the first in-service of one (1) of these units would -- under Plan 2 would be 2042.
Do you see that under Plan 1-2, under the CCGT, we have the year 2042?
MR. MICHAEL ROBERTSON: Yes.
MR. ANTOINE HACAULT: You didn't make any assessment, sir, as to whether or not what Hydro

was using as a ref value for that first unit to be in service, whether that ref value was something that was appropriate.

You just did a current day value, correct?

MR. MICHAEL ROBERTSON: Correct.

MR. ANTOINE HACAULT: And is the same true with respect to the SCGTs, the first of which would be in 2031?

You didn't assess, sir, whether or not the reference value was something that could be reasonably expected in 2031, as used by Manitoba Hydro?

MR. MICHAEL ROBERTSON: No.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: And just to make it clear, you didn't assess the reasonableness of any numbers that were used for SCGTs any time thereafter? That's after 2031.

MR. MICHAEL ROBERTSON: No.

MR. ANTOINE HACAULT: Now, with respect to...

(BRIEF PAUSE)

MR. ANTOINE HACAULT: The next subject was -- we've heard in addition to the contingency reserve, which we've had some discussion about, whether or not the management reserve was appropriate and whether its been fully disclosed. So in Exhibit 3.1 at -- it's Roman number I of IV; it's, I believe, the last item. There's discussion about the management reserve. And in -- it's about the middle of the page that's being shown on the screen, there's some words in parentheses, "Not fully disclosed."

What did you feel you needed more with respect to the description of management reserve to be able to assess whether or not that was an appropriate amount --

MR. CHRISTIAN MONNIN: Sorry, Mr. Hacault, you're referring to management reserve, but if I'm reading the sentence correctly it's -- it refers to labour reserve.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Just wait.

(BRIEF PAUSE)

MR. BORIS FICHOT: We -- we can

probably address that question, just understanding that the management reserve is the addition of labour reserve and escalation reserve, so it's probably labour reserve. We weren't given, at -- at the time of writing the first report, the -- the details of how about -- how they came about the labour reserve, and now we -- we have a better indication of how that was calculated. And that -- that's where we go into CSI material, in terms of how they came about the labour reserve.

MR. ANTOINE HACAULT: Okay.

MR. BORIS FICHOT: So they've -- they've made some assumptions about productivity in their comparison, and that -- those lead them to believe that the labour reserve is 'X' dollars --

MR. ANTOINE HACAULT: Yes.

MR. BORIS FICHOT: -- the two (2) estimates.

MR. ANTOINE HACAULT: And one of the comments was that the assumption was that the -- there would not be a repeat of the inefficiencies encountered at Wuskwatim in the new estimates.

Is that correct?

MR. BORIS FICHOT: That is an allowance for that experience.

MR. ANTOINE HACAULT: But it's not as high as what was experienced as -- at the Wuskwatim project, correct?

MR. BORIS FICHOT: We'll go into CSI material if we talk about it.

MR. ANTOINE HACAULT: Okay. There is the -- the comment in -- in this report that the labour reserve for the new estimates was lower than the experience. And this is at page 4 of 4 in the -- in this index.

MR. BORIS FICHOT: That is correct.

MR. ANTOINE HACAULT: The very last sentence on -- on the slide here of the second paragraph under Item 9:

"The cost estimate rates, however, do not incorporate the actual Wuskwatim productivity rates, and Hydro has made the general assumption that the labour conditions will not be as bad during the construction of Keeyask and Conawapa, because they plan to offer better labour conditions."

MR. BORIS FICHOT: That's correct.

MR. ANTOINE HACAULT: So was Knight Piesold able to assess whether or not, based on experience of other projects, this assumption was a sound one?

MR. BORIS FICHOT: No.

MR. ANTOINE HACAULT: Was Knight Piesold able to assess in any way whether or not this assumption, that labour conditions would not be as bad, was a sound one?

MR. MICHAEL ROBERTSON: Beyond the observation that they are going to offer better labour conditions, and logically, that should improve the situation, I cannot comment.

MR. ANTOINE HACAULT: Okay.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: If we go to page 6 of 73 in this document, or there's a -- there's a section called 'Gaps', and Knight Piesold explains that it provided its best efforts in answering the PUB inquiries, but it notes three (3) gaps in its ability to answer the questions that were asked by this Board.

Now, firstly, and -- and I'll deal with each point, does the first point affect the conclusion? And if so, which one?

MR. BORIS FICHOT: The -- the first

point dealing with the methodology, numerical breakdown of the systemic risk calculation, we have had more recently, as a result of the -- the whole reevaluation of the GCC tenderers being able to -- to view a document produced by a -- by a third party, they're detailing some of the methodology behind the numbers. So we've got more confidence that there's some rigour to -- to calculating those numbers.

MR. ANTOINE HACAULT: So is that still a gap? And --

MR. BORIS FICHOT: I -- I would say that's no longer a gap in terms of our appreciation of whether or not they've done a good job in -- in coming up with a -- with a number.

MR. ANTOINE HACAULT: Okay. So I can strike that one off as a gap. The second one at -- listed there is contingency determination on the indirects.

Does that affect your conclusion? If so, what? And does it continue to be a concern?

MR. MICHAEL ROBERTSON: It -- it's -- there is a remaining risk, we believe, that -- that the quantification of that risk we -- we cannot in any way verify, because we don't have the details.

MR. ANTOINE HACAULT: So it does

continue to be a concern as compared to the fli -- first bullet, which is now dealt with, correct?

MR. MICHAEL ROBERTSON: I would say so.

MR. ANTOINE HACAULT: And what about the last one? And does it continue to be a gap? It is a justification for not using the Hydro escalation factor estimated.

MR. MICHAEL ROBERTSON: Yes, that is still a gap, and that is CSI.

MR. ANTOINE HACAULT: Okay. Now...

(BRIEF PAUSE)

MR. ANTOINE HACAULT: I had a line of questioning with respect to the class estimates on Conawapa, and that's been clarified, because as I understand it now, we've revised it from a Class 2 to a Class 3, correct?

MR. MICHAEL ROBERTSON: Yes.

MR. ANTOINE HACAULT: And, sir, how does this Board deal with the challenge of determining what a ref cost is, a low cost, and a high cost for a plant like Conawapa, assuming DSM 2, would have an in-service date starting -- that's the first turbine -- out of 2031?

MR. MICHAEL ROBERTSON: With great difficulty.

MR. ANTOINE HACAULT: Now, that leads me to the discussion of escalation reserve at page --

THE CHAIRPERSON: Just a second, Me. Hacault, s'il vous plait.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: Merci. Now, just to advise Mr. Hacault and -- and the balance of the room that we've been advised that under the gap section of M. Hacault's canvassing questions on the -- we touched upon the justification for not using the hydro escalation factor estimated. That -- and the answer that was provided, that that would sway into CSI. And -- and we determined that that's not the case.

And therefore, M. Hacault can return on that subject and ask questions.

MR. MICHAEL ROBERTSON: In which case the

----answer is that we still see it as a gap. We haven't seen the justification and we think it's a risk.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Thank you very much for that. And just to get a little bit more detail on that, at page 23 -- or 27, 2-7, of the report. At the bottom of the page there's some discussion with respect to the escalation rate and the comparison to Muskrat Falls. Now, is there any reason why Muskrat Falls was chosen?

Is it just because you had the data for Muskrat Falls to compare?

MR. BORIS FICHOT: That's correct. We thought it was al -- along the same magnitudes and we had corresponding periods, so we -- we just showed that this is what they use, this is what we thought they calculated, and this is what the two point five (2.5) looks like.

MR. ANTOINE HACAULT: And with respect to Muskrat Falls, am I correct in interpreting this paragraph that your understanding is that they used a rate of about 3.4 percent as an escalation rate in -- when compared to Manitoba Hydro at 2.5 percent?

MR. BORIS FICHOT: Yes, it's -- but it's our understanding that they calculate a hydro power escalation factor of three point one (3.1). At least from the report, that's our understanding.

MR. ANTOINE HACAULT: Could -- could you explain that? Sorry. What's the distinction between the 3.4 percent and the three point one (3.1)? Not that it's a huge amount, but I've learned that the small percentage on billions of dollars can make a little bit of a difference.

(BRIEF PAUSE)

MR. BORIS FICHOT: I believe there's a -- a portion of the official submission that discusses those numbers, and that's what we're referring to. I'm advised that it -- it would be an undertaking to go and dig that out and show it.

MR. ANTOINE HACAULT: You're not too sure what the difference is between the 3.4 percent number and the 3.1 percent number --

MR. BORIS FICHOT: Oh, that's -- that's the -- basically, they would go and solicit and look at their act -- exact quantities of material that they anticipate, look at what all these different market studies would project the price of different commodities to be, and then bring all these aggregate numbers to an index, which is, in Muskrat Falls, three point four (3.4), and which I understand in the

Manitoba Hydro case to be three point one (3.1).

So you -- they -- they do a -- a detailed study where they look at the commodities that they expect to have to use, get labour -- get market studies for the different materials, copper, steel, and so forth, and then bring it back to a composite index. And that's what Muskrat Falls has done.

And they -- they have different quantities. So they -- they would get a different number as a result of that -- of that evaluation.

MR. ANTOINE HACAULT: So is it the opinion of Knight Piesold that an appropriate escalation rate should be 3.1 percent? I believe that number is referenced in your --

MR. BORIS FICHOT: Yes.

MR. ANTOINE HACAULT: -- supplemental report.

MR. BORIS FICHOT: Yes. We believe that might be more appropriate, especially when you're talking about management reserve and -- and a pool of money that you're setting aside for that purpose in case the escalation occurs.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Now, the other thing that occurred in the updates -- and this is in our book of documents at page 5. There was a re-weighting of the high capital costs, low capital costs, and reference costs.

Is that your understanding also, sir?

MR. BORIS FICHOT: That's my understanding, although our scope of work does not cover the economic analysis and these -- these alterative analyses. So the -- the relationship between our review of the capital cost estimate and these numbers is not straightforward, as you're -- you're deducting a number of things that were considered in the economic analysis that we didn't necessarily look at.

MR. ANTOINE HACAULT: And I'm not trying to get you to answer things --

MR. BORIS FICHOT: Yeah.

MR. ANTOINE HACAULT: -- about the economic analysis, sir. But there was some discussion in your report with respect to the probabilities of certain values, certain construction values, and it's in that context that I was going to ask a couple questions.

If we flip back to the previous page,

page 4, and it's at the very bottom of that page. There's a table, and there's a range of values with the high and low probabilities. And that's why I referenced that previous number, so we could come back to this table and understand what 'low' meant.

We've assigned a 20 percent value to the low, a 60 percent value to the ref, and a 20 percent value of probability to the high. And there's the swings that we were looking at when I started the cross-examination for the P80s, P90s, et cetera.

With respect to the swing, is it the view that we should use an expected value or is the range, for example for Conawapa26 because that's what you looked at, appropriate from the ref to the high because we looked at the change from P50 to -- to P80?

MR. BORIS FICHOT: That's where we can't really draw a relationship between what we've evaluated and the statistical numbers that they've attributed to these different buckets. What we have looked at is the statistical variation around the contingency, as well as the -- the thinking behind the number used to come up with the management reserve.

And we don't have a good understanding because it wasn't part of our work to take that information and relate it back to this economic uncertainty analysis. And there's a jump there. There's something that needs to be analyzed but we haven't looked at that because that's not part of our scope of work.

MR. ANTOINE HACAULT: Okay.

MR. BORIS FICHOT: But what we have looked at is statistical variation around the contingency numbers, and the justification around the management reserve, and whether or not it's high or low.

MR. ANTOINE HACAULT: Diana, if we could go to Exhibit 161. I just want to try and better understand what you weren't looking at and weren't doing then. If we look -- actually, it would be page 2 of 3, please.

You may recall, sir, when we were looking at contingency amounts; and this was the first table. I'm asking you to kind of stretch your memory. When we were doing -- first let's look on this table. Under the point estimate, there's another heading, 'Contingency'. And the ref contingency is point five three (.53), and the high contingency is point five three (.53).

Now, if we can kind of keep that number in our minds for a little bit and quickly revert back to page 25 of Exhibit 3-1.

So we were looking, and in Exhibit 161 under the contingency, we had both for the ref and the high a contingency reserve of point five-three (.53), and that corresponds to the P50 of 523 million.

Are you following me so far, sir?

MR. MICHAEL ROBERTSON: Yeah.

MR. BORIS FICHOT: This table.

MR. ANTOINE HACAULT: Yeah. Now, if I understood your evidence correctly, if we were going to attribute a more conservative number, we'd go to either the P80 or P90 and put that, because we'd have more certainty that our high costs -- it wouldn't come higher than what that number is.

Is that correct?

MR. BORIS FICHOT: That's correct.

MR. ANTOINE HACAULT: So although I know you can't comment on why Manitoba Hydro chose to keep -- keep it at $.53 billion, you would agree with me that the point five-three (.53), if it's kept constant, does not give us a higher certainty that you'll come in within the agreed numbers.

MR. MICHAEL ROBERTSON: I -- I think, probably, we -- we should just repeat what Boris said. I mean, we -- we were not part of the economic analysis at all, and so we're really not in a position to make sensible commentary on it.

The other point I would make is that the process that we've followed in our reporting related specifically to the probability that the -- that the estimate that we're given of 6.5 billion for Keeyask is sensible and -- and a probability distribution around where those values might be.

This other process that -- that you're looking at was one that was used to compare all the different alternatives, and -- and essentially support the -- the PDP, and -- and we had no part in that, so it --

MR. ANTOINE HACAULT: Yeah.

MR. MICHAEL ROBERTSON: -- it would be inappropriate for us to comment on that.

MR. ANTOINE HACAULT: I'm not asking you to comment on why Hydro chose it, but I'm just -- I just wanted to confirm that, if we keep -- kept the number at the same, it wouldn't reflect this different 'P' value that you've talked about.

MR. MICHAEL ROBERTSON: That's a logical conclusion.

MR. ANTOINE HACAULT: Okay. And if we go back to Exhibit 161, because I don't just want to dwell on one when I see a difference, and the update, if we continued along that line, we see that they've chosen a -- a different number this time under the reference number, but this time, they didn't choose to keep the three (3) -- point three-one (.31) consistent across the different -- different scenarios.

MR. MICHAEL ROBERTSON: I see that.

MR. ANTOINE HACAULT: Okay.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Diana, if you go to page 2, please, of our book of documents? Now, this is not a Manitoba Hydro document. It's a document that was created by the consultants hired by MIPUG. If we can make a little bit smaller so we can see the -- all the writing?

I had just gone to the -- the different ranges and the different probabilities, and you've indicated you can't comment on that.

Had you done any S-curves for the probabilities that you speak of in your report, sir?

MR. MICHAEL ROBERTSON: No.

MR. ANTOINE HACAULT: Okay.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Okay. I don't think I can ask you any other questions about that. If I could just have thirty (30) seconds to check my notes? And then I believe I'm finished. But I'd just like to have an opportunity to double check my notes.

THE CHAIRPERSON: Agreed.

(BRIEF PAUSE)

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Just one (1) question, page 12 of Exhibit 3 -- 3-1. Diana, could you bring that up, please. And under the heading, "Intended use of cost estimate," and 2.4.1.3 there's a paragraph, and I'll quote it.

"It is important to note that the PUB and Manitoba Hydro are making different uses of the same cost estimate [in parentheses] (with a specific level of prove -- project definition) [closed parentheses] and as a result may have a different perspective on risks and accounting

for uncertainty which are built into
the relevant contingency and
reserves."

Can you just expand on why you think that there's different uses being made of the same cost estimate?

MR. BORIS FICHOT: It -- it was in the context if you're making decisions with -- where you have a large number of pools with different projects, it'll have a 50 percent chance of going over or under. It's a different decision-making context than if you're deciding on a single project.

MR. MICHAEL ROBERTSON: And it's also the appetite for risk that we've been discussing. You know, the PUB may look at it very differently from Manitoba Hydro.

MR. ANTOINE HACAULT: Thank you. Those are all my questions.

THE CHAIRPERSON: I think it would be an appropriate time to take a break. Let's take ten (10). Thank you.

--- Upon recessing at 2:45 p.m.

--- Upon resuming at 3:00 p.m.

THE CHAIRPERSON: I believe that everybody's in position to resume the proceedings. So I will turn the microphone over to you, Ms. Van Iderstine, sorry.

CROSS-EXAMINATION BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: Thank you very much. I would like to start by saying this may be a bit disjointed because we've been adding and subtracting and I have all these coloured points on here, and I'm not really sure I'm supposed to be watching the -- the orange or the green.

But I have to say a couple thank-yous. First of all, Ms. Bowen will appreciate me thanking you for -- because I've been bugging him since I started working on this for definitions, and so I will be coming back to definitions, but I was delighted to see them in your -- in your presentation.

And the second thing is I love the photographs. I was try -- I was -- I kept saying, I want to see pictures of the project. And here it is right on the front of their presentation. So thank you very much for that. Well...

MR. MICHAEL ROBERTSON: I have to say that is your photograph.

MS. HELGA VAN IDERSTINE: Regardless, I haven't seen it often enough. So what I'm going to do and what I'd appreciate you doing is keeping handy the two (2) reports that you've written and that are in -- in evidence and on the record. And, as well, I've got a book of author -- or documents which I'll be referring to. But other than that, I think that is about it.

So just in general terms, I'd like to ask you a few questions, some -- a bit about some experience issues and expertise that goes into producing this type of report. And as I was reviewing your materials, I noticed, of course, that KP has been involved in providing construction advice and quality control advice for construction of hydroelectric projects in the past.

Is that right?

MR. MICHAEL ROBERTSON: That's correct.

MS. HELGA VAN IDERSTINE: And you have had some expertise in wind power generation, as well?

MR. MICHAEL ROBERTSON: That's correct.

MS. HELGA VAN IDERSTINE: But with respect to the wind power gen -- generation, have you done any wind power generation in Manitoba?

MR. MICHAEL ROBERTSON: No.

MS. HELGA VAN IDERSTINE: And as I understood from the report you prepared, the way you compiled the information was -- on the wind issue was to do a literature review primarily?

MR. BORIS FICHOT: I -- I would rel -- I would also say that we relied heavily on Garrad Hassan's opinion in the published a report for Manitoba Hydro.

MS. HELGA VAN IDERSTINE: Thank you very much. And so when the PUB commissioned you to do a review that -- of Manitoba Hydro's plans, you felt that it was within your expertise to do so?

MR. MICHAEL ROBERTSON: In general, yes.

MS. HELGA VAN IDERSTINE: And that's because you and your team have expertise in cost estimating?

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: And as I understand it, there was about six (6) of you involved in this project.

Is that right?

MR. MICHAEL ROBERTSON: Up to.

MS. HELGA VAN IDERSTINE: And would you, Mr. Robertson, have -- be the person who has the most expertise?

MR. MICHAEL ROBERTSON: Yes, I would believe so. And -- and I'm certainly responsible for the collective viewpoint that's expressed.

MS. HELGA VAN IDERSTINE: And as I understand it, the area of cost estimating and quality control risk management is a very specialized area?

MR. MICHAEL ROBERTSON: It can be in the detail.

MS. HELGA VAN IDERSTINE: Which requires both experience in cost estimating, education, and training?

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: All of which you obviously have?

MR. MICHAEL ROBERTSON: Obviously.

MS. HELGA VAN IDERSTINE: So -- and in your dealings with the Manitoba Hydro staff, as I understand it, you dealt with a number of the staff in obtaining information from them and understanding what was going on in their development of this project?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And would it be fair to say that many of them also had expertise in these areas?

MR. MICHAEL ROBERTSON: Absolutely.

MS. HELGA VAN IDERSTINE: And in addition to the internal expertise that Manitoba Hydro had, they also went to external persons and companies to obtain further expertise to ensure that the -- their processes and estimating was as good as it could be?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And one of those would be a company called Validation Estimating?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And a fellow named John Hollmann?

MR. MICHAEL ROBERTSON: I don't know him.

MS. HELGA VAN IDERSTINE: But that's Validation Estimating.

MR. MICHAEL ROBERTSON: Okay.

MS. HELGA VAN IDERSTINE: Do you know that -- whether he -- do you know of, or have you been read any of the reports he's written?

MR. MICHAEL ROBERTSON: We have.

MS. HELGA VAN IDERSTINE: Would you -- do you know whether or not he is -- would be considered one of the experts in this area?

MR. MICHAEL ROBERTSON: I -- I would

say he -- he is, if only by virtue of the fact that Manitoba Hydro elected to employ him.

MS. HELGA VAN IDERSTINE: Okay. One of the things that occurred to me as I listened to your evidence is that all of this expertise that you've gained is something beyond -- and with all due respect to the engineers in this room, it's something beyond that you would get just simply as just having an engineering degree?

MR. MICHAEL ROBERTSON: Oh, absolutely.

MS. HELGA VAN IDERSTINE: And so the information you reviewed and all of the data that you collected, it's something which -- that you take, you put together, and you have to utilize your judgment as well in putting -- coming up to a conclusion?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And that judgment is based on expertise and experience?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And again, you'd agree that there's people within Manitoba Hydro who have that expertise and judgment as well?

MR. MICHAEL ROBERTSON: I have no doubt.

MS. HELGA VAN IDERSTINE: And I don't

want to belabour this point, but it's not just as simple as pulling out some spread -- and I -- I -- with all due respect to the accountants in the room -- who may be in the room, it's not just reading a spreadsheet?

MR. MICHAEL ROBERTSON: No.

MS. HELGA VAN IDERSTINE: Well, that's something I can't do either, so I'm all... So in the scope of your -- I want to address a few things on the scope of your work.

You've outlined in your documentation, and I appreciate it very much, all the documents that you reviewed to the extent you could; but I also gather that beyond that, there were conversations you had with people from Manitoba Hydro?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: To obtain information?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: There was emails that you would have had with people from Manitoba Hydro?

MR. MICHAEL ROBERTSON: M-hm.

MS. HELGA VAN IDERSTINE: There were meet -- teleconferences you had with people from

Manitoba Hydro?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And all of that gets incorporated into your report.

Is that right?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: Now, one (1) of the things -- and I'm sorry, Mr. Hombach, I probably should have addressed this earlier -- is I understood that there was a presentation you reci -- had with the PUB in September?

It was -- it was an IR that you answered and you identified that there was a September 17th meet -- presentation and a slide deck?

MR. BORIS FICHOT: Yes, that's when we were first given the scope of work.

MS. HELGA VAN IDERSTINE: Okay. Was there any -- Mr. Hombach, is that available to be provided somewhere?

MR. SVEN HOMBACH: Sorry, this is which slide deck?

MS. HELGA VAN IDERSTINE: The presentation from September 17th, and the September 18th slide deck.

MR. SVEN HOMBACH: That's Manitoba

Hydro's presentation?

MS. HELGA VAN IDERSTINE: I don't know.

MR. BORIS FICHOT: The -- the --

MS. HELGA VAN IDERSTINE: The --

MR. BORIS FICHOT: -- yeah, the only listed reference was the -- when we first came to -- to work for the PUB, there was a series of presentations, and I believe there was a IR that asked for them, and we don't know if that's disclosable. We leave it to -- we left it to the PUB to disclose it if it's --

MR. SVEN HOMBACH: I take --

MR. BORIS FICHOT: -- supposed to be disclosed.

MR. SVEN HOMBACH: -- I take that under advisement, Ms. Iderstine, and we can have an offline discussion.

MS. HELGA VAN IDERSTINE: Thank you.

CONTINUED BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: Now, in broad general terms, can we describe the first report that you prepared as being one (1) that addressed processes for estimating construction costs and the overall project execution plan?

MR. BORIS FICHOT: To -- to the state

of our knowledge at that time --

MS. HELGA VAN IDERSTINE: Yeah.

MR. BORIS FICHOT: -- so we had a certain amount of time to review information. At that -- at that end date, we -- we had to reach those conclusions.

MS. HELGA VAN IDERSTINE: And --

MR. MICHAEL ROBERTSON: And -- and, sorry, if I may interrupt. Some of that was revisited with the more detailed questions that were asked in the second scope.

MS. HELGA VAN IDERSTINE: Yes. And -- and I was just trying to draw a distinction that the first one was -- was planning and the project execution plans, and the second report, you -- was after you had the -- some firmer numbers and were able to then, in the second report, deal with more of the execution plans as opposed to the planning process, per se.

MR. MICHAEL ROBERTSON: With -- with some overlap.

MS. HELGA VAN IDERSTINE: Okay.

MR. MICHAEL ROBERTSON: And -- and also with the singular focus in the second lot of Keeyask.

MS. HELGA VAN IDERSTINE: Right. In one (1) of the IRs that you responded to from the

Public Utilities Board, it was 1031A, that's at Tab 1 of the book of documents, you commented that, "Hydro was generally very" -- it's about halfway down the answer.

"Hydro was generally very cooperative with KP's review, but full disclosure of all information was never forthcoming, as Hydro is rightfully protective of their commercially sensitive information, and the information often required internal screening and processing."

So a couple questions on that.

First of all, after that time, I understand you were then provided with information about the general civil contract?

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: In fact, as I understand it from Manitoba Hydro, that on February 27th, that within two (2) days of the Board approving the Keeyask GCC, they were having conversations with you about it?

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: And on March 5th, a day after the executive committee reviews of the corresponding impacts, they were providing you with some information on the NFAT references, and they met with you on a teleconference call about the updated capital costs for both Keeyask and Conawapa?

MR. MICHAEL ROBERTSON: March 5th does sound like the date we had that call, yes.

MS. HELGA VAN IDERSTINE: And they provided confidential information to you relating to the development of the estimate, development of the project contingency, and the development of the labour reserves?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: So it would be fair to say that now, the concern that was addressed in that response has generally been addressed?

MR. MICHAEL ROBERTSON: Generally, with some exceptions.

MS. HELGA VAN IDERSTINE: The exceptions, I -- I think you talked about earlier with some of the detail, that you -- is that what you're referring to?

MR. MICHAEL ROBERTSON: Well, particularly the indirects.

MS. HELGA VAN IDERSTINE: Oh. But nevertheless, you were still able to, by January 13th or 17th, I think maybe this date of the report was, you were able to come -- complete the report with -- within the scope of the work from the first project, despite not yet having the GCC at that point.

MR. MICHAEL ROBERTSON: Well, we did, because that was the deadline, but we had to make a comment that we couldn't really fully answer some of the questions until we had that data.

MS. HELGA VAN IDERSTINE: And that's identified in the places in your report as gaps, and that sort of thing?

MR. MICHAEL ROBERTSON: Or comments that, you know, when -- when we get the GCC data, we will be in a better position to comment on those.

MS. HELGA VAN IDERSTINE: Would it be fair to say that you draw on your -- drew on your abilities from your experience and training to be able to pull out salient details from the huge amount of information that was available and selectively identify the information that you required?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: So that you didn't feel you had to read every single detail in order to come up with your opinion?

MR. MICHAEL ROBERTSON: Well, first it

was not possible to read everything that's posted on the -- on the website, but yes, I -- I believe that we were able to get what we needed to come to our opinions.

MR. BORIS FICHOT: I'll -- I'll just add that sometimes even if you don't review the information, it's nice to have a little checkbox to say, Yes, they have indeed prepared a document that describes this. You don't necessarily need to go through the details, but to know that it exists and has been prepared does give some comfort in -- in the numbers.

MS. HELGA VAN IDERSTINE: And what you're saying there is -- is, in terms of the process, you want to know that Manitoba Hydro's thought about it and considered it and has the backup. Much the way when I do my income tax, the income tax return, they don't always ask for all the information. They just want to know I've got it.

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And I -- I think you may have answered that in -- if you look at Tab 2, you know, there was a -- an IR asked of you, PUB/KP I-021a. And you were asked about some of the difficulties obtaining information, and you commented that:

"The difficulties stem from obtaining the right level of information without being either overwhelmed or receiving too little."

And then you went on to say that:

"Hydro had retained rights not to share all the information available and only wishes to release enough information to be convincing without revealing details inside commercially sensitive information."

Do you see that?

MR. MICHAEL ROBERTSON: I do.

MS. HELGA VAN IDERSTINE: And that reflects what your thinking was, I take it, about the -- obtaining the information and the level of detail you needed?

MR. MICHAEL ROBERTSON: At -- at that time, yes.

MS. HELGA VAN IDERSTINE: We'll talk about this a little bit later, but I -- I take it from that comment in that IR that you understood from Manitoba Hydro and appreciated their need to keep some information confidential.

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And that would be because, if that information got out in any public way, it could drive up the costs associated with the project?

MR. MICHAEL ROBERTSON: Conceivably.

MS. HELGA VAN IDERSTINE: It might harm the relationship with some of their contractors?

MR. MICHAEL ROBERTSON: Possibly.

MS. HELGA VAN IDERSTINE: And you didn't need -- as we've talked about, you didn't need every single detail in order to feel confident enough to put your stamp on the first -- first and then the second report?

MR. MICHAEL ROBERTSON: I -- I think the -- the overall tone of the conclusions of the first report were that what we're seeing is good. But really, at the end of the day, we need to see a lot more very significant stuff before we can provide a good opinion back to the -- to the Board.

MS. HELGA VAN IDERSTINE: And that's what you got for the second report?

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: Okay. So I just want to talk about the estimating process for

Keeyask and Conawapa a little bit

And would it be fair to say that there, fairly similar processes were applied in Manitoba Hydro with respect to both of those?

MR. MICHAEL ROBERTSON: For the two (2) projects?

MS. HELGA VAN IDERSTINE: Yes.

MR. MICHAEL ROBERTSON: It would appear so.

MS. HELGA VAN IDERSTINE: And to the extent that the Keeyask process is similar to the Conawapa one, we can have some confidence in the estimates with Conawapa, given the lack of development of that process?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And you would anticipate, I would take it -- well, first of all, you saw and comment on the fact that Manitoba Hydro has learned from the experience they had with Wuskwatim?

MR. MICHAEL ROBERTSON: I believe so.

MS. HELGA VAN IDERSTINE: And you would expect, based on what you've seen of the Manitoba Hydro staff, that they would take any other learning points they get from Keeyask and apply that to Conawapa when they go to build that?

MR. MICHAEL ROBERTSON: You would logically assume that.

MS. HELGA VAN IDERSTINE: Nothing you saw or discussed within Manitoba Hydro would suggest that they wouldn't be doing that kind of constant learning and appro -- improvements in their practices?

MR. MICHAEL ROBERTSON: No.

MS. HELGA VAN IDERSTINE: Now, as we've gone through, you were advised about the -- you were part -- saw the process leading up to the awarding of the GCC. And when I say that, one of things I understand you were aware of and you had some discussions about was the fact that Manitoba Hydro qualifi -- pre-qualified four (4) bidders for their project.

Is that right?

MR. MICHAEL ROBERTSON: To be honest, I don't recall that directly, but it's a sensible thing to do and it's a very typical thing to do.

MS. HELGA VAN IDERSTINE: And these were all builders that were experienced in building large sim -- similar, large-scale, hydroelectric-type projects?

MR. MICHAEL ROBERTSON: yes.

MS. HELGA VAN IDERSTINE: And they've

been described -- and -- and you described Manitoba Hydro as being diligent in their internal comparisons between the four (4) GCC tenders, their engineers, estimates, and the independent third-party estimate.

Is that --

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: And you'll recall that after that due diligence, they selected a company called -- the acro -- the acronym BBE?

MR. MICHAEL ROBERTSON: I am aware of that.

MS. HELGA VAN IDERSTINE: And did you know that one (1) of the main partners in BBE, being Bechtel, was involved in the building of Limestone?

MR. MICHAEL ROBERTSON: I do.

MS. HELGA VAN IDERSTINE: And that would suggest that they are, therefore, familiar with both the geography and complexity of the project they're undertaking?

MR. MICHAEL ROBERTSON: Correct, it does suggest that.

MS. HELGA VAN IDERSTINE: Now, we've -- you talked this morning a couple times about the early contractor involvement process which was being used.

Do you recall that?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And as I understand, that the early contractor involvement in the -- is used in projects in the expectation that it may mitigate some of the project costs?

MR. MICHAEL ROBERTSON: It'll mitigate the -- the project risks, which should -- should come up with a better defined cost, amongst other things.

MS. HELGA VAN IDERSTINE: Will optimize and bring as much certainty to the process as possible?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And the hope is that they will bring -- they con -- they will bring their knowledge to the process to help improve the processes and the ultimate execution of the project?

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: And it provides opportunities to identify and share risk?

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: And that includes the geotechnical conditions, a scheduled design, input costs, and contract conditions?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And I take it that would be an example of how Manitoba Hydro is working to eliminate as much risk as they can in this -- in this project?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And I think -- I think you mentioned, but if you didn't, then I'll raise it right now, that about -- with the GCC in place, about 80 percent of all the project costs have now been defined?

MR. MICHAEL ROBERTSON: That's the statement made by Hydro.

MS. HELGA VAN IDERSTINE: Well, Mr. Bowen's correcting me. The project contract costs, so I don't...

MR. MICHAEL ROBERTSON: But it's not a state -- not a statement that we originated.

MS. HELGA VAN IDERSTINE: Okay. And that would give you, again, a fairly strong level of certainty with respect to the costs that you're talking about in the estimates and the ultimate cost?

MR. MICHAEL ROBERTSON: Certainly as far as the direct costs are concerned.

MS. HELGA VAN IDERSTINE: Now, returning to those definitions that I like so much. So I wanted to make sure that when we're talking about the estimates, that we're talking about the capital cost estimates.

And I think it's been interchangeably used with the term 'point estimate'?

MR. MICHAEL ROBERTSON: Well, there -- there are a number of terms along the line of that chart. They -- they are different parts of the capital costs. I mean, they -- they talk about in-service. They talk about point. They talk about base. So, yeah, you've got to be specific.

MS. HELGA VAN IDERSTINE: Yes. So if we can look over to Tab 4 of the -- of the book of documents that I provided to you. Mr. Bowen provided these definitions for the panel in Exhibit 95 at the -- maybe in Exhibit 95; I'm forgetting the number. The presentation that was done on the first day, and this is from page 94.

So if you look at the definition of 'estimate', would you agree with that -- that definition?

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: Essentially.

MS. HELGA VAN IDERSTINE: And so that would be the calculation of a range of costs to complete the project based on a set of assumptions. The critical assumptions include the project scope, level of defin -- definition, schedule, and in-service date?

You actually have to say a word.

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: Thank you. Now, you would take this budget -- or this estimate, excuse me; that's where I'm getting in trouble.

You take this estimate, and you would use it to establish what's been called the control budget of the project cost?

MR. MICHAEL ROBERTSON: Forgive me, I -- I need to read this.

MS. HELGA VAN IDERSTINE: Yeah.

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: I -- I think that is a statement of Manitoba Hydro's process.

MS. HELGA VAN IDERSTINE: I don't want to -- I'm not suggesting -- it -- what I would -- what I would like to hear from you is if you've got any concerns about that being the definition, because one of the concerns, as we've talked about a moment ago, is making sure that when we're talking about the estimates and we're talking about a control budget, that we're talking about two (2) separate things and why they might be different.

And in your report when you start adding things like escalation and things like that, that's where we're going to get to the control budget, right? We start with the estimate, and then we add some things to get to the control budget.

Is that right?

MR. MICHAEL ROBERTSON: Well, you start with the point estimate.

MS. HELGA VAN IDERSTINE: Yes.

MR. MICHAEL ROBERTSON: And then you add a bunch of things and you get a base -- well, you then add uncertainty and you get a base cost. Then you multiply that by interest and inflation, then you add money spent to date, and you get what is called an in-service cost. Now, I would say to some extent those are all estimates.

MS. HELGA VAN IDERSTINE: Okay.

MR. MICHAEL ROBERTSON: Generically.

MS. HELGA VAN IDERSTINE: Mr. Bowen had used the term 'control budget' to talk about the budget as -- once it's been approved, and it being the benchmark for measuring project cost performance. Is that --

MR. MICHAEL ROBERTSON: If -- if he so chooses.

MS. HELGA VAN IDERSTINE: Well, this is actually an important distinction. So I want to make sure that we under -- we're both talking about the same thing, that -- let me maybe to do it this way...

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: So if we -- if you turn over to Tab 8.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: And you'll see that we've -- there was a point estimate at the beginning of the three point three-six (3.36). And if you come down to the bottom, a total in service, number of six point five (6.5). The six point five (6.5) is what I'm talking about as being the control budget.

Can we agree on that?

MR. MICHAEL ROBERTSON: If -- if that's the way you want to set up your management system, yes.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: And in order to get to that $6.5 billion, Manitoba Hydro included a contingency of a P50 value, as well as labour and escalation management reserves.

Is that what your understanding was?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And by doing so, by both adding the contingency -- the P50 value and the labour and escalation management reserves, would you agree that that pushes Manitoba Hydro over a P50 value?

MR. MICHAEL ROBERTSON: Big picture, yes. Because as I mentioned in my presentation, the -- the contingency quote -- quote typically on a project includes the issues which Manitoba Hydro has chosen to deal with separately under the term 'management reserve'. So if you added those sums of money into the contingency, into one (1) contingency, it would represent, effectively, something greater than P50.

MS. HELGA VAN IDERSTINE: And if you look over to page 24 of the book of documents, you'll see what's identified, or called, "Keeyask Low, Reference, and High." And this is what we've been calling the NFAT analysis.

Did anyone talk to you about that at all at any time during your -- your processes?

MR. MICHAEL ROBERTSON: Not really, except the talking that was done was by me asking for details of it, which -- which I don't believe we ever got.

MS. HELGA VAN IDERSTINE: You didn't get, or you didn't get information that enabled you to understand that process?

MR. MICHAEL ROBERTSON: We -- can we take this offline?

MS. HELGA VAN IDERSTINE: Yeah.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: Oh, I'm sorry. Yeah, please go ahead, Mr. Robertson.

MR. MICHAEL ROBERTSON: I was -- I was just going to say that it -- you know, going back to some of the discussions we've had earlier today, this whole process of low/reference/high in the economic analysis is more properly part of the whole development alternatives decision, and it is not directly relevant to what we were asked to do. The reason I was asking for it was really to get some measure of how high Manitoba Hydro thinks the price might go above the 6.5 billion expected in-service costs that they are now forecasting.

MS. HELGA VAN IDERSTINE: Okay. Thank you.

MR. MICHAEL ROBERTSON: And I didn't get that answer.

MS. HELGA VAN IDERSTINE: Okay. Thank you. The -- looking at -- just -- I'm going to stop here so I don't forget. I should have mark -- requested and marked that the book of documents be marked as the next exhibit, Exhibit Manitoba Hydro 173.

MR. KURT SIMONSEN: Correct, thank you.

--- EXHIBIT NO. MH-173: Book of documents

THE CHAIRPERSON: Could I -- I'm sorry, could I intervene here? I just wanted to clarify something in my mind because I -- you indicated that -- correct me if I'm wrong, please. You indicated that the inclusion of management reserve along with contingency would address your concerns around establishing contingency at P50.

Now, did I hear you wrong? I mean, I --

I understood you, and at least I under -- I interpreted your report as indicating that contingency at a P80 level would -- would indicate a higher number exclusive of any consideration of the management reserve.

MR. MICHAEL ROBERTSON: It would.

THE CHAIRPERSON: Okay. So we're in agreement on that point. In other words, a more conservative assessment of contingency would -- would be addressed separately from any concerns you might have around the management reserve.

MR. MICHAEL ROBERTSON: Well, they're -- they're both aimed at quantifying possible uncertainty. Uncertainty; not possible uncertainty. Whether you chose to break that up into two (2) packets and label them differently is up to you.

Effectively though, if your contingency, quote/quote, is based on a P50 assessment and you separately have a separate allowance for other uncertainties, if you were to add them together and put them all into a contingency box, it would effectively be higher than P50.

I'm not prepared to say that the amount of the management reserve that has been quantified by Manitoba Hydro added to Manitoba Hydro's P50 contingency would be the same as a P80 contingency.

I'm just saying it would be higher than P50.

THE CHAIRPERSON: So they are, to some extent, correlated.

MR. MICHAEL ROBERTSON: Yes.

CONTINUED BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: And as you said this morning, part of the decision making around what 'P' value you use is the decision maker's appetite for risk.

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: So one of the -- again, one of the IRs that was -- you answered, MH/KPI-010 at -- reproduced it at Tab 6, you were asked about other projects that used different 'P' values, and I'd like to talk a little bit about these.

MR. MICHAEL ROBERTSON: Okay.

MS. HELGA VAN IDERSTINE: So if you look down to Quebec-Hydro, one -- a little further down -- you'll see -- and it goes over onto the second page -- that Quebec-Hydro uses a P50.

Is that right?

MR. BORIS FICHOT: So we're told, yes.

MS. HELGA VAN IDERSTINE: And BC Hydro uses a P50 estimate but carries a reserve equal to the difference between P50 and P90?

MR. BORIS FICHOT: That's what we were told, yes.

MR. MICHAEL ROBERTSON: Well, and -- and we have experienced that --

MS. HELGA VAN IDERSTINE: And as I understood from your report, you weren't able to identify any standards that outlined a correct level of contingency for these reserves.

MR. BORIS FICHOT: That's correct.

MR. MICHAEL ROBERTSON: No, it's -- it's subjective.

MS. HELGA VAN IDERSTINE: And what interested me about some of the information provided in this report is if you look at what was asked here and -- so in this IR is what the recommendation was for the 'P' value, and then the positives and negatives of the approach.

And so if you look at the United States Army Corps of Army of -- United States Army Corps of Engineers, which is the first item, you'll see that they use a P80 for cost contingency calculation.

And can you just elaborate a little bit for me why -- the positive -- the positives of this approach and the negatives of this approach?

MR. MICHAEL ROBERTSON: Boris...?

MR. BORIS FICHOT: I'd have to jog my memory there in terms of what the article actually said, but -- oh, as -- as stated there, the -- the positive side of using a P80 is that you're more likely to be within your budget.

And the negative side of using a P80 is that you're -- you're more risk averse and therefore you're -- you're more pessimistic about what the likely outcome might be.

MS. HELGA VAN IDERSTINE: And -- and the language you use is -- you say they're more likely to be spent, meaning -- I take it meaning the money's more likely to get spent.

MR. BORIS FICHOT: That's -- that's correct. That's the impression: If the money's in the pool, we'll find something to spend it on.

MS. HELGA VAN IDERSTINE: Yeah. That's what I thought you were getting at.

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: So that -- that's what the US Army Corp of Engineers stated. I'm not sure I totally agreed that it's more likely to be spent.

MS. HELGA VAN IDERSTINE: It doesn't appear to me that any of these organizations are using both a 'P' value and a management reserve, are they?

MR. MICHAEL ROBERTSON: Well, I -- I guess Hydro, BC Hydro. Between their P50 and their P90, you might call that a management reserve. A "project reserve" they call it.

MS. HELGA VAN IDERSTINE: Okay. So they've got a 'P' val -- 'P' value -- a -- a P50 value, and then they add to it in some capacity to come up, right?

MR. BORIS FICHOT: We -- we wouldn't be able to actually answer that question, I think. We'd have to look into it.

MR. MICHAEL ROBERTSON: Well, I -- I mean, I -- I do have direct experience of one (1) project we did for -- for BC Hydro where the -- the budget that we were all working to essentially was the P90 budget, included this allowance.

MS. HELGA VAN IDERSTINE: And I -- the language you just used was that the budget you were working to was to -- to the P90 level. So that would be the goal that you set -- setting a target that you think is reasonable to meet the budget under.

MR. MICHAEL ROBERTSON: Probably not reasonable, but more like you better not go over it.

MS. HELGA VAN IDERSTINE: So if I were to say that the -- a controlled budget was trying to set a -- a benchmark for performance that's rea -- that is reasonable without being either too high or too low, that would be another way -- another reason why somebody might set a lower 'P' value.

MR. MICHAEL ROBERTSON: If -- if that's your stated intent, yes.

MS. HELGA VAN IDERSTINE: Because the concern in those cases would be, if you set it too high, there might be a tendency to build to that higher cost.

MR. MICHAEL ROBERTSON: I would not agree with that.

MS. HELGA VAN IDERSTINE: But certainly if you set it too low, you're going to exceed the budget.

MR. MICHAEL ROBERTSON: You're more likely to. Let's take something offline here.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: Sorry. Are

you ready to start again?

MR. MICHAEL ROBERTSON: Well, I mean, I -- I -- Boris was essentially saying, you know, your ability to manage your budget is a different issue from whether or not that budget's set at the right level.

MS. HELGA VAN IDERSTINE: So I'm going to change topics a little bit at the moment. I wanted to talk about some of the items that you identified in your second report, and specifically the items that we've identified at -- and put in as document 3.3 or 3-3. Yes, that's the one. Thank you very much.

Now, as I understand that, just from the comment, you -- you highlighted some key risks which you describe as being confirmed by validation estimating. So that would be information then that you obtained from validation estimating, or is it information that you identified separately?

MR. BORIS FICHOT: At least we concurred with their opinion on those.

MS. HELGA VAN IDERSTINE: So one (1) of the things we talked about earlier was that validation estimating was somebody with whom Manitoba Hydro's been working.

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: So a -- fair

to say that Manitoba Hydro is aware of these concerns?

MR. MICHAEL ROBERTSON: They -- they gave us those, probably, yes.

MS. HELGA VAN IDERSTINE: I was -- I was going to say before -- before they saw it in your report, I mean.

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: Thank you.

MR. MICHAEL ROBERTSON: Sorry, Boris would like to say something.

MR. BORIS FICHOT: I -- I'd add that you guys provided us with a complete risk register for Keeyask and a lot of these overlap with each other, and there's -- there is a process by which you identify risks, and...

MS. HELGA VAN IDERSTINE: And I -- as I think you commented earlier, you thought that they were doing a good job in creating that register, and -- and monitoring that. Is that right?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: Thank you. Now, so back to validation estimating. So Manitoba Hydro would be aware of these issues, and would it be fair to say that they're working to address these issues?

MR. MICHAEL ROBERTSON: At the end of the day, we understand that they are addressing the issues through the provision of the contingency and management reserve.

MS. HELGA VAN IDERSTINE: So in terms of the resource challenges, if I understood you correctly, that concern related to the fact that you thought -- there was a concern, at least in September 2013, that Manitoba Hydro might not be able to staff the onsite construction team with all Manitoba Hydro employees?

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: And this -- so this is an issue of the number of people that they might be able to -- to hire, and -- or have in place, as opposed to the quality of their knowledge?

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: And I know you had a lot of meetings with Manitoba Hydro, and they provided you with a lot of information, but do you recall them advising you in one (1) of your discussions that they were aware of the risk, that it was included in the risk register, and they've addressed it in their current capital cost update by including a budget for external consultants?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And that would effectively mitigate that risk?

MR. MICHAEL ROBERTSON: Correct, and I think we said that this morning.

MS. HELGA VAN IDERSTINE: And in terms of the sys --

MR. MICHAEL ROBERTSON: Sorry.

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: Yes, I -- I mean, it's -- it's -- it was highlighted by you in September that this was a risk that needed mitigation, and you have mitigated it. It's cost you more, but the risk itself has been reduced.

MS. HELGA VAN IDERSTINE: And it's been -- and -- and it's now included their budget?

MR. MICHAEL ROBERTSON: Correct. We understand so.

MS. HELGA VAN IDERSTINE: One (1) of the other areas that you identified is the systemic risks associated with their maturing system, and you've talked a bit about it. It's a system to monitor controls.

Is that right?

MR. MICHAEL ROBERTSON: It's -- it's essentially to monitor the -- the whole performance of the project going forward.

MS. HELGA VAN IDERSTINE: So I -- I've got it described here as, "To monitor and control actual costs and forecasts." That would be...?

MR. MICHAEL ROBERTSON: And schedule and everything else.

MS. HELGA VAN IDERSTINE: It's a way of monetizing the maturity of the project, and at the -- at the time, the contingency was calculated by asking some key questions of the staff on an ongoing basis?

MR. MICHAEL ROBERTSON: Are -- are you talking now about the internal Manitoba Hydro process, or what --

MS. HELGA VAN IDERSTINE: Yes.

MR. MICHAEL ROBERTSON: -- validation estimating did?

MS. HELGA VAN IDERSTINE: Validation estimating did that to establish that.

MR. MICHAEL ROBERTSON: As we understand, that they'd talked to the staff in order to provide some measure of uncertainty related to the systemic risks of Manitoba Hydro's process.

MS. HELGA VAN IDERSTINE: And did you do anything independent of validation estimating?

MR. MICHAEL ROBERTSON: No.

MS. HELGA VAN IDERSTINE: So again, something that Manitoba Hydro is aware of. Now, this process -- this -- that you've talked about, and described as a new system, was that your impression, that it was a new system, or is it one that they've had in place, and they're making enhancements and improvements to?

MR. MICHAEL ROBERTSON: No, we were very explicitly told that it was a new system, and that the -- it is different from the process that was used from Wuskwatim, and details were given of various parts of the change.

And -- and the statement's quite often made that it was very difficult to compare old estimates for Keeyask with new ones, because essentially, the boxes have all been resorted, and they're being managed differently.

And so -- and -- and some of the questions we asked, we -- the reply was that there were some things that were still being developed, and that they couldn't get -- share them with us. Okay?

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: Sorry, I'm trying to think how I can address this without giving evidence, so -- and I -- I think I better just leave it, because I think that maybe there is a -- a miscommunication somewhere along the way. In any event, a -- along with the other systems, it's more -- something that Mari -- Manitoba Hydro is working with. They're continuing to monitor, and they're trying to improve on it.

MR. MICHAEL ROBERTSON: Yes, that is apparent.

MS. HELGA VAN IDERSTINE: Now, one (1) of the other issues that you identify in here is the concern about a potential deferral due to the stage 1 cofferdam delay as being a potential risk?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And if I understood you earlier, the driver for that deferral would be due of -- some kind of reason for a deferral in construction from starting on July -- in July?

MR. MICHAEL ROBERTSON: There is a risk that something will come along that will prevent Manitoba Hydro from starting construction in July.

MS. HELGA VAN IDERSTINE: For example, inability to get regulatory approval?

MR. MICHAEL ROBERTSON: Correct.

MS. HELGA VAN IDERSTINE: And if that was the case, did -- were you aware that Manitoba Hydro has identified that that would cost somewhere around $250 million to the project?

MR. MICHAEL ROBERTSON: I am aware of that. I don't see it included in any of the contingencies or management reserves.

MS. HELGA VAN IDERSTINE: Okay. And would you agree that that -- the inclusion of that in a management reserve at this stage would be a question of judgment as opposed -- dependent on whether or not the project is, in -- in fact -- goes forward? So including it in a -- in a management reserve may not be the appro -- or a -- a contingency may not be the appropriate place for it, but you should be aware of it?

MR. MICHAEL ROBERTSON: I wouldn't put it in a different box from the other risks.

MS. HELGA VAN IDERSTINE: Would you agree that the change in scope, if it was a --

MR. MICHAEL ROBERTSON: No. It -- it's a risk. It's a schedule risk.

MS. HELGA VAN IDERSTINE: Now, the reason I was identifying -- talking about it a little bit was -- and I -- am I -- talking earlier about the NFAT is because if you look over to that Tab 8 again, one (1) of the things that has -- that may not be apparent to you, looking over at page 24, when establishing the low, reference, and high, that that risk is something that's included in that NFAT analysis? And I'm -- I'm not sure that you were aware of that, just given what our discussion was earlier.

MR. MICHAEL ROBERTSON: I think my reaction would be -- I have said that's irrelevant.

MS. HELGA VAN IDERSTINE: Okay.

MR. MICHAEL ROBERTSON: Because in terms of what we were asked to do, and -- and this will come out tomorrow in CSI.

MS. HELGA VAN IDERSTINE: Okay.

MR. MICHAEL ROBERTSON: We -- we'd been asked by the PUB to provide the expected in-service cost of this project. We -- we feel that we should also indicate -- give some indication or some -- wave a few flags about where it may end up.

MS. HELGA VAN IDERSTINE: Yeah, I -- I think, actually, we're talking about the same thing, that the -- the analysis done, and the -- the scope of the project for Manitoba Hydro in establishing what we've been calling the control budget was to -- to plan for an in-service date of two (2) -- 2019, and so that's where their direction is. If you assume that, then you wouldn't include, I take it, the -- that risk of delay of -- of starting, because of regulatory processes, because that would assume an in-service date of 2020.

MR. MICHAEL ROBERTSON: Which will lead to extra costs.

MS. HELGA VAN IDERSTINE: Yes. And I think we're both saying the same thing. It's just a question of where you put it.

MR. MICHAEL ROBERTSON: Well, to some extent in what we've seen, apart from this table, it's a question of if you've put it.

MS. HELGA VAN IDERSTINE: Sorry, the table we're looking to is the NFAT table --

MR. MICHAEL ROBERTSON: Page 24.

MS. HELGA VAN IDERSTINE: Yeah. And -- and --

MR. MICHAEL ROBERTSON: I mean, for -- for where we're coming from, we see the 6.5 billion. We don't see anything else. And the 6.5 billion does not include what we perceive to be a significant risk.

MS. HELGA VAN IDERSTINE: So looking at -- another area, again, that's part of the NFAT analysis -- I may be getting it confused between the NFAT analysis and the way you've approached the -- the contingencies, is your discussion of escalation. And as you commented, Manitoba Hydro used a 2.5 percent inflation factor in their estimate.

Do you recall that?

MR. MICHAEL ROBERTSON: We understand that they used one point nine (1.9), being CPI in their point estimate.

MS. HELGA VAN IDERSTINE: Yes.

MR. MICHAEL ROBERTSON: And that in their escalation reserve they have bumped that up to two point five (2.5).

MS. HELGA VAN IDERSTINE: Sorry, I -- now, I'm -- thank you for correcting me, because as I said at the outset that the definitions is where the -- the details sometimes is problematic.

MR. MICHAEL ROBERTSON: M-hm.

MS. HELGA VAN IDERSTINE: So they used a two point five (2.5) inflation factor in their escalation reserve and their estimate.

And you suggested they should have used a 3.1 percent?

MR. MICHAEL ROBERTSON: We're suggesting, based on evidence of escalation of hydro pro -- projects, and we gave the example of Muskrat Falls, that two point five (2.5) is probably not adequate and that it would be more like three point one (3.1) or three point four (3.4).

And in fact, the number of three point one (3.1) resulted as a back calculation of the two (2) data points which we were given by Manitoba Hydro, which was the one point nine (1.9) CPI and the two point five (2.5). And two point five (2.5) was stated as the average of -- average escalation for hydro power projects and the CPI.

So you can work backwards and say, Well, oh, that means that they think the hydro power projects are three point one (3.1).

MS. HELGA VAN IDERSTINE: Did you know that they used a -- a variety of different interest calculations in the NFAT analysis? Escalation, sorry. Excuse me.

MR. MICHAEL ROBERTSON: No.

MS. HELGA VAN IDERSTINE: Do you know what BC Hydro uses as an escalation factor?

MR. MICHAEL ROBERTSON: No.

MS. HELGA VAN IDERSTINE: Now, you have

commented on some of the things that Manitoba Hydro -- or you have commented -- or you're aware that Manitoba Hydro has used a number of things to mitigate some of the risks of the project.

And would you agree that some of those include per -- the use of performance bonds, liquidated damages, letters of credit with respect to the contract with the GCC?

MR. MICHAEL ROBERTSON: Yes, we've been given details of -- of some of those details. It is though a very standard procedure, and I wouldn't say that those are measures which deal specifically with the specific risks for Keeyask.

MS. HELGA VAN IDERSTINE: And you've concluded that the approach to the con -- construction risk management is industry standard and cons -- consistent with best practices?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: Now, one (1) of the things you've referred to is Manitoba Hydro's experience with Wuskwatim?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: Now, in earlier testimony we'd heard that there was a 10 to 13 percent increase from the point of awarding the GCC contract in Wuskwatim to project completion.

Was that infor -- information ever provided to you?

MR. MICHAEL ROBERTSON: I don't recall that particular data. But all of the information that we are quoting on Wuskwatim and lessons learned from it have come directly from Manitoba Hydro.

MS. HELGA VAN IDERSTINE: Would you call the time frame in which Wuskwatim was built an escalation super cycle?

MR. MICHAEL ROBERTSON: I don't think I'd want to go there.

MS. HELGA VAN IDERSTINE: Okay. Again, going back to Tab 8. And looking at that first page, you'll see the cont -- Keeyask control budget is $6.5 billion?

MR. MICHAEL ROBERTSON: I see that.

MS. HELGA VAN IDERSTINE: Towards the bottom of the page.

And if you look at the numbers under the point estimate, you'll see contingency management reserve, labour reserve, and escalation reserve?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And those total approximately $600 million?

MR. MICHAEL ROBERTSON: Seven hundred (700), yeah.

MS. HELGA VAN IDERSTINE: So looking -- if you took 6.5 billion and took the $700 million off, that you'd come down to about 5.7 billion?

MR. MICHAEL ROBERTSON: Five point eight (5.8), yes. Your math is correct.

MS. HELGA VAN IDERSTINE: Which would suggest that that cost would -- would go up about 10 percent. That's about a 10 percent -- that 600 million is about 10 percent of the entire cost of the project?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: Which would similar, again, to the increase in price between Wuskwatim after the -- the GCC was awarded and the project was completed?

MR. MICHAEL ROBERTSON: If you -- if you say so. I don't have that data.

MS. HELGA VAN IDERSTINE: I just want to turn to one (1) other topic. In your report with respect to wind, you commented on the wind costs and suggested that those construction costs are likely to decrease.

Do you recall that?

MR. MICHAEL ROBERTSON: Yes.

MS. HELGA VAN IDERSTINE: And one of the citations you referred to support that was the EIA reports from the -- which are, as I understand it, and they're at Tab 8 -- or, sorry, Tab 7, the US Energy Information Administration?

MR. MICHAEL ROBERTSON: Boris will talk to this.

MR. BORIS FICHOT: Yeah. Did we use it as a reference? Yes.

MS. HELGA VAN IDERSTINE: Yes. And if you look at Tab 7, we've given you the cover page from the April 2013 report, and on the opposite side of the page the overnight cost comparison with 2010 estimates from that report.

Do you see that?

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: I think we've highlighted it so you can find it.

MR. BORIS FICHOT: Okay, I see it.

MS. HELGA VAN IDERSTINE: And that -- would that be the onshore wind cost that you were using and suggesting there had been a 10 percent -- or 13 percent decrease in cost between 2013 -- or 2010 --

yeah, 2010 to '13?

MR. BORIS FICHOT: To justify the decrease?

MS. HELGA VAN IDERSTINE: Yes.

MR. BORIS FICHOT: No, it's a different source.

MS. HELGA VAN IDERSTINE: Maybe check the next -- try the -- try the next one. It might be the one you were using, updated capital cost estimates for electricity generation plants, again, November 2010.

MR. BORIS FICHOT: Just give me maybe one (1) second here to look through our report to see where --

MS. HELGA VAN IDERSTINE: Okay.

MR. BORIS FICHOT: -- it was coming from.

(BRIEF PAUSE)

MR. BORIS FICHOT: Sorry, we've just quoted -- we've looked at a number of sources, and I'm just trying to get the -- the original one. The -- the basis for our reduction was a DOE document.

MS. HELGA VAN IDERSTINE: And that's

the Department of Energy again from the United -- US government?

MR. BORIS FICHOT: That's correct.

MS. HELGA VAN IDERSTINE: You do refer, however, in your report to the Energy Information Administration?

MR. BORIS FICHOT: That's likely.

MS. HELGA VAN IDERSTINE: So you were looking at these reports in some form of capacity?

MR. BORIS FICHOT: That's correct.

MS. HELGA VAN IDERSTINE: So looking at this one, using the onshore wind cost there, it does demonstrate -- and I don't want to be proving your point too hard -- but that there was -- appears to have been a 13 percent decrease between 2010 to 2013.

Is that what it shows?

MR. BORIS FICHOT: Yes.

MS. HELGA VAN IDERSTINE: And if you look over to the estimates for electricity, again for November 2010, and that's again from the US Energy Information Administration, they also provide a comparison of costs this time between -- for wind and a bunch of other resources that demonstrate a change -- the changes in costs.

And do you see that there was a change

in costs between 2010 to 2011 with a 21 percent increase there?

MR. BORIS FICHOT: Okay.

MS. HELGA VAN IDERSTINE: So at least between 2010 to 2011 there appears to have been an increase in cost, not a decrease in cost?

MR. BORIS FICHOT: From what these guys compiled, yes.

MS. HELGA VAN IDERSTINE: So another -- some -- somebody else is obtaining liter -- obtaining information from the industry in the US, which is where I understand you got your information from.

Is that right?

MR. BORIS FICHOT: Yes, we -- we looked at a number of sources. If I -- I'll just go straight to the point in terms -- I think I feel like I know where this is going, and to me the analysis for why we came up with the capital cost estimate for wind was relatively simple.

We based most of the assessment at the end of the day on the Garrad Hassan report, which was done professionally Manitoba Hydro -- Manitoba specific, and came up with a capital cost. The documentation that we had that's in the slide deck shows that for specifically the equipment -- and we're not talking about context because what's difficult with the overall study is that you've got different regional effects that enter into consideration.

So you go back to the Garrad Hassan one, which is Manitoba Hydro -- Manitoba specific. And then you look at what they think the cost is going to be and you ratio what the specific wind turbine generator is going to cost. And the trend overall has been that the equipment piece, not the rest of it, but the equipment piece which constitutes the majority of the cost, has decreased. And that's the basis for our -- our explanation of the decrease.

MS. HELGA VAN IDERSTINE: Thank you for clarifying that for me, because I did want to raise that issue.

What you were talking about in your slide presentation and the -- the slide you gave with the graph on it, which was slide number --

MR. BORIS FICHOT: Seventeen (17).

MS. HELGA VAN IDERSTINE: Thank you very much.

That is a graph demonstrating the costs of wind equipment, turbines and towers?

MR. BORIS FICHOT: That's correct.

MS. HELGA VAN IDERSTINE: It doesn't

include the costs of the foundations, the road access, the transmission hook up, any of that?

MR. BORIS FICHOT: It doesn't include any of that.

MS. HELGA VAN IDERSTINE: So it's not a direct comparison then to the numbers that Manitoba Hydro was using of twenty-two hundred (2,200).

MR. BORIS FICHOT: It -- it comp --

MS. HELGA VAN IDERSTINE: Or twenty-four hundred (2,400) --

MR. BORIS FICHOT: -- we're -- we're just talking about the equipment portion. The -- the overall twenty-two hundred (2,200) includes all those elements that you mentioned.

MS. HELGA VAN IDERSTINE: Right. So -- so, yes, you're showing a decrease there, but you haven't accounted for labour or any of those other items in this, correct?

MR. MICHAEL ROBERTSON: Well -- well, perhaps if -- if I can intervene here. I mean, if you look at that chart we're saying in January '09 maybe the equipment cost was fifteen hundred dollars ($1,500) a kilowatt, and since then there has been a steady decline in costs. And so in January '13, it's eleven hundred dollars ($1,100) a kilowatt for the turbine.

MS. HELGA VAN IDERSTINE: Yes.

MR. MICHAEL ROBERTSON: And that's maybe 75 percent of the cost.

MS. HELGA VAN IDERSTINE: And do you know that the -- often the turbines come in somewhere around -- in Texas and have to be shipped north, which would include an additional cost then?

MR. MICHAEL ROBERTSON: But the Garrad Hassan report was talking about Manitoba.

MR. BORIS FICHOT: Yeah.

MS. HELGA VAN IDERSTINE: So looking --

MR. BORIS FICHOT: We -- we just -- we -- it was very simple. We didn't include anything else. We just went the equipment piece cost less, and we ratioed it to what the -- what the work -- what the breakdown structure showed us in the Manitoba context.

MS. HELGA VAN IDERSTINE: So I just want to close this off by taking you to that last page of the -- of the report that we put in at Tab 7 at page 19, just because it does seem to demonstrate that although there was an increase -- that the increase -- total overnight costs on the -- that's the fifth column -- would demonstrate that in 2008 you have a cost of two thousand and eighty-nine (2,089).

It then had a significant increase into

2009, to two -- two thousand five hundred and thirty-eight (2,538). And then you see some -- a decrease in 2000 -- to two thousand five hundred and thirty-three (2,533) in 2010. A de -- a decrease in 2011 to twenty-two fourteen (2,214). And, yes, a decrease in 2012 to two thousand two hundred and thirteen (2,213).

But they're all still costs that are higher than the 2010 year. So there are some -- and there -- anomalies, obviously, in these numbers.

MR. BORIS FICHOT: I'd have to look into what the context of what those numbers correspond to.

MS. HELGA VAN IDERSTINE: Thank you very much. Those are my questions.

(BRIEF PAUSE)

THE CHAIRPERSON: I think we're ready for your questions now, Mr. Hombach.

MR. SVEN HOMBACH: Okay. Thank you, Mr. Chairman. Demonstrating what I've learned today, my point estimate is about twenty (20) minutes, but I may need ten (10) minutes as a contingency.

CROSS-EXAMINATION BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Good afternoon. My name is Sven Hombach. I act as counsel to the Public Utilities Board. And I appreciate that a lot of the comments we've heard today were somewhat general, because a lot of the specifics with respect to the contract are CSI. We'll have an opportunity to explore those tomorrow.

So my questions are going to be at a fairly high level to -- to get a better understanding of what the systemic risks are, and on a higher level how to mitigate it so that the CSI session can be put into context.

Before we get started, I did circulate on the weekend a Volume VI of Board counsel's book of documents. I would like to have that entered as PUB Exhibit 58-6, and I'll be referring to the document. At that point I'd ask Ms. Villegas to just put it up on screen.

--- EXHIBIT NO. PUB-58-6: Volume VI of Board counsel's book of documents

CONTINUED BY MR. SVEN HOMBACH:

MR. SVEN HOMBACH: Hearing all this talk about a P50 contingency, can you provide me with a general understanding of how many P50 projects in the past twenty (20) years you've actually seen come in on or under budget?

MR. MICHAEL ROBERTSON: Short answer, no.

MR. SVEN HOMBACH: But you've seen some?

MR. MICHAEL ROBERTSON: I would have to -- I mean, that's a very specific question. I would have to check that indeed the budget was set at P50 and compare it to what it ended up at.

MR. SVEN HOMBACH: Okay.

MR. MICHAEL ROBERTSON: I mean, in many ways the budget is not set at P50.

MR. SVEN HOMBACH: Well, appreciating the comment that we heard from you on Ms. Van Iderstine's question, it takes years to gain the experience in -- in cost estimating. I, unfortunately, didn't have the opportunity to get years of experience. I've got some general high-level literature in this book of documents. And Tab 1 of the book of documents is a paper by a gentleman named Bent Flyvbjerg from the Said Business School at Oxford entitled, "Delusion and Deception in Large Infrastructure Projects, Two (2) Models for Explaining and Preventing Executive

Disaster."

And I assume you haven't had an opportunity to -- to read it, but I want to take you to a specific section to determine if -- if you agree with the way he describes risk. So maybe we can go to page 26 of the document. And let's scroll down to the bottom half of the page.

There's a discussion in the -- in the middle of the page that states that:

"In fact, during the tender bidders can act opportunistically by assessing the probability that compensation is possible after the construction state has been initiated. If compensation is possible, bidders will bid the lowest possible value in order to win the tender. The winning bidder will be typically the bidder who most underestimates the true cost of the project. We call this the 'winner's blessing'. After the project has been initiated, the initial low price will be compensated through overpricing the expected scope

increases, which the experienced
bidders know are almost certain.
When compensation is not possible,
there is less chance that the bidding
price is artificially low."

So do you generally agree with this analysis?

MR. MICHAEL ROBERTSON: It's -- it's an oft voiced fear. And it's -- it's obviously based sensibly. There -- there are jurisdictions which, for this very reason, do not award the contract to the lowest bidder. I mean, I understand that in Germany, for instance, they will award the contract to -- public service contracts to the bidder closest to the average, rather than the lowest. So the bidder next lowest -- lower than the -- than the average of all the bids.

If you have a contractor that goes into a tender looking for loopholes and planing to exploit them later, yes, there are contractors who do that and there is a risk that that will happen. And the defence is that you have a well-defined project. You have a very good contract document. You have suitable measures to address change.

MR. SVEN HOMBACH: So in your view then, is the primary way of addressing this issue, a, for lack of a better word, bulletproof contract?

MR. MICHAEL ROBERTSON: As -- as good a contract as you can. And in -- in this case the -- the whole process of the early contractor involvement should contribute to reducing the risk of this happening.

MR. SVEN HOMBACH: And generally speaking, that would mean what? Placing quantity risk or pricing -- placing escalation risk to a large extent with the contractor?

MR. MICHAEL ROBERTSON: Well, not escalation risk. That's something outside of the control of all the parties, and there is a management reserve for that. But -- sorry, what was your other example?

MR. SVEN HOMBACH: Quantity risk.

MR. MICHAEL ROBERTSON: Quantity risk. Quantity risk is -- is there. And -- and to the extent that Manitoba Hydro is working with a contractor in a target price, but unit price contract, yes, there is some risk to -- to Manitoba Hydro. And -- and the defence there is that they have advanced the design to a level where the quantification of those quantities should be good. And they have done a significant amount of investigation of the foundations to -- to mitigate that risk.

MR. SVEN HOMBACH: Okay. If we could go to Knight Piesold Exhibit 2. That's Knight Piesold Second Round Information Requests to Manitoba Hydro, page 6.

(BRIEF PAUSE)

MR. SVEN HOMBACH: That is a chart that you're no doubt familiar with?

MR. MICHAEL ROBERTSON: In principle.

MR. SVEN HOMBACH: And what that shows is generally you have your point estimate, you apply your escalation to go to P50.

And generally, the probability of under- or overruns are following some type of a bell curve?

MR. MICHAEL ROBERTSON: Yes. Just a -- a slight correction there. The -- you add the contingency to the point estimate to get to P50.

MR. SVEN HOMBACH: Right.

MR. MICHAEL ROBERTSON: I -- I don't think it's quite what you said.

MR. SVEN HOMBACH: I -- I thought it's what I said, but I appreciate the correction. Thank you.

If we could go to Tab 2 of Volume VI of Board counsel's book of documents, page 47, that is another paper published by somebody at Said Business School at Oxford, a gentleman names Atif Ansar, entitled, "Should We Build More Large Dams? The Actual Costs of Hydro Power Megaproject Development." And you may have heard about it. This paper was in the news a little while ago.

And I just want to take you to page 51 of the book of documents. That suggests that, for large dams, you're not dealing with a classical bell curve. You've got a -- a long tail where your P90 probability of overruns can be fairly high.

Is that something that you've seen in your experience as well?

MR. MICHAEL ROBERTSON: Personally, no, although there is very well-documented evidence of this happening with a large -- number of large megaprojects throughout the world.

MR. SVEN HOMBACH: But the conclusion of this paper is that, on average, for large dams, the final tally is 96 percent over budget. But it doesn't state whether that's a Class 1, 2, 3, 4, or 5 estimate.

MR. MICHAEL ROBERTSON: Well -- well, I -- I don't think it matters what the designated class of the estimate was, but it is certainly not my experience that, on average, the projects that certainly we've been involved with go 96 percent over budget.

MR. SVEN HOMBACH: So let me then take you to the third document in the book of documents. It's Tab 3, page 63. There's been reference to Mr. Hollmann before, and just so that I can be clear, was Mr. Hollmann a -- a person retained by you, or is it your understanding that he was a Manitoba Hydro consultant?

MR. BORIS FICHOT: We -- we just reviewed one (1) report that was supplied to us that was authored by -- by him.

MR. SVEN HOMBACH: You just reviewed a paper, but you didn't consult with him and --

MR. BORIS FICHOT: No.

MR. SVEN HOMBACH: Have you reviewed the paper that we're looking at, which is entitled "Variability in Accuracy Ranges: A Case Study in the Canadian Hydro Power Industry"?

MR. BORIS FICHOT: I haven't. It looks like it's dated 20 -- 2014.

MR. SVEN HOMBACH: It is quite a recent paper from the AACE International Technical Conference.

And AACE is Association for the Advancement of Cost Engineering.

Do I have that right?

MR. BORIS FICHOT: Correct.

MR. SVEN HOMBACH: Okay. Let's go to page 65 of the book of documents, two (2) pages in, and scroll to the bottom. That is a chart from AACE RP 69R12.

And 'RP' stands for recommended practice under AACE, correct?

MR. BORIS FICHOT: Yes, that's correct.

MR. SVEN HOMBACH: And this shows the percentage of project definition for the different classes, starting in Class 1 on the right and then moving to Class 5 on the left?

MR. BORIS FICHOT: That -- that is the -- the documented standard, yeah, by -- by AACE -- by AACE.

MR. SVEN HOMBACH: And if I heard you correctly this morning, you testified that you now think that with systemic risk, the Keeyask Infrastructure Project, the Keeyask Generating Station Project, and the Conawapa Project are all Class 3?

MR. BORIS FICHOT: That -- that's correct.

MR. SVEN HOMBACH: So that would be somewhere on the left side, where you'd have a project definition between 20 to 80 percent?

MR. BORIS FICHOT: According to this graph, yes.

MR. SVEN HOMBACH: Where, generally speaking, taking into the account -- taking into account the systemic risk, would you see the Keeyask Generating Station Project?

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: What we said this morning was that in the first report, you will notice that we deemed Manitoba Hydro's classification of Class 3 for certainly the Keeyask -- two (2) Keeyask projects to be unnecessarily pessimistic, and that given the level of project definition, if you use that as the variable, with the amount of information that -- that was to hand and the number of contracts that had actually been led, they would be better classified in the system as Class 2 and Class 1.

In the discussion this morning, we advised that, because of the reapprecion -- reappreciation of system risk by -- by the independent risk assessment people, we -- we believed that it would be appropriate to -- to put the projects back into Class 3. And -- and essentially, the -- the reasoning is just that there are significant systemic risks remaining that -- as -- as we believe.

MR. SVEN HOMBACH: Let's go to page 68 of the book of document, and scroll down onto the page. Now, the -- the -- again, this is a paper that looks at the Canadian hydro power industry, and it ultimately concludes, and you can see that in the table on the screen in front of you, that for a Class 3 estimate, the suggested contingency on a P50 probability is 24 percent, on a P90 probability, it's 63 percent, and on a P10, or 10 percent probability, it would actually be a -- a negative 1 percent.

You -- you follow the reasoning on this chart?

MR. MICHAEL ROBERTSON: I -- I follow the data.

MR. SVEN HOMBACH: Do you have any reason to disagree with those general percentages?

MR. MICHAEL ROBERTSON: No. I don't. I equally don't confirm or otherwise comment on them. It's -- it's their interpretation of the data that they've chosen to use.

MR. SVEN HOMBACH: Well, the reason I'm asking you, sir, is that My Friend, Ms. Van Iderstine, took you through some of the probabilities, as did Mr. Hacault. And I just wanted to have an opportunity to put those into context. Could I ask you, Ms. Villegas, to put Manitoba Hydro Exhibit 161 on the screen, please? And I believe we have to go three (3) pages in.

(BRIEF PAUSE)

MR. SVEN HOMBACH: Sorry, two (2) pages and the previous page. Do you recall Ms. Van Iderstine taking you through this chart?

MR. MICHAEL ROBERTSON: I do, yes.

MR. SVEN HOMBACH: And on the right, we see the current update for Keeyask. This is on the second page of Manitoba Hydro Exhibit 161, and there's a $310 million contingency for the P50. You see that?

MR. MICHAEL ROBERTSON: I do.

MR. SVEN HOMBACH: And the point estimate is 3.36 million -- sorry, billion?

MR. MICHAEL ROBERTSON: Yes.

MR. SVEN HOMBACH: If my basic lawyer math is correct, that's only about 9.2 percent, so significantly less than the suggestion in the Hollmann paper of 24 percent. Are you comfortable with a 9.2 percent contingency?

MR. MICHAEL ROBERTSON: I -- I think the question, really, is not how the nine point two (9.2), which is a derived number, fits into the AACE classification system. I think it's more -- well, there's a philosophy around whether you're using P50 or some other number.

And then given that, this is really being superceded by the -- the detailed risk analysis that has been done by the consultants, out of which has come the number there for contingency to get to P50.

So I -- I think what I'm saying is that the -- the reference that produced this is now background noise to Keeyask.

MR. SVEN HOMBACH: Well, the -- the understanding that I'm trying to get is how you reconcile the fairly clear project definition for Keeyask on the one (1) hand with a systemic risk that you discussed this morning. And if you're then saying it's a P3 estimate, but the contingency can actually be relatively low, can you explain that without actually delving into the details of the risk and engaging the panel in CSI?

MR. MICHAEL ROBERTSON: Sorry, you -- you mean a Class 3 estimate --

MR. SVEN HOMBACH: Yes.

MR. MICHAEL ROBERTSON: -- not -- not a P3 estimate?

MR. SVEN HOMBACH: Sorry, yes.

MR. MICHAEL ROBERTSON: Well, I -- I -- as I say, to -- to be honest, I -- I don't think it's relevant. You know, we've -- when -- when you're in the early stages of -- of cost estimating, and -- and project appreciation, those are good guidelines. They're useful. They help you put things in boxes and -- and assign a sensible contingency or a provision for uncertainty to the process at any particular time in that process.

I think once you've got as far as -- as Manitoba Hydro has with Keeyask, you -- you've got to look at -- at what you've -- you've specifically got there. You've got to look at your processes. You -- you've got to have a really good appreciation of the -- of the risks, both systemic and project-specific, and you respond accordingly in terms of making provision for what might happen.

MR. SVEN HOMBACH: Now, before we move away from this page, Ms. Van Iderstine engaged you in a discussion about the management reserve, and whether that's usually part of the contingency.

Again, by my math, if we simply add the labour reserve to the contingency on a P50 basis, we get to 14.8 percent. If we also include the escalation reserve, we get to 17.6 percent, so still less than the 24 percent suggested in the Hollmann paper, but closer.

The escalation reserve that you see here, is that a reserve in case Manitoba Hydro's 2.5 percent escalation is not sufficient, or is this supposed to be the escalation period?

MR. MICHAEL ROBERTSON: That -- my understanding is that that is an allowance for the difference between CPI at one point nine (1.9) and 2.5 percent.

MR. SVEN HOMBACH: Okay. So would you contin -- would you consider both of these items, labour reserve and the escalation reserve, to be part of the contingency, and just be a contingency by a different name?

MR. MICHAEL ROBERTSON: Not necessarily. It just goes to how you want to define that allowance.

MR. SVEN HOMBACH: Let's go over one (1) page and have a look at the Conawapa numbers. Now, you also said Conawapa is a -- a Class 3 estimate?

MR. BORIS FICHOT: Sorry, just a second.

(BRIEF PAUSE)

MR. MICHAEL ROBERTSON: I mean, just to support what I was saying earlier in -- in that I -- I don't think that this is an appropriate document with respect that we should be looking at any longer, because we've moved beyond it. We -- we do not know how these numbers were put together.

MR. SVEN HOMBACH: I appreciate that qualification, but I -- I still want to ask you on Conawapa as well, because on Keeyask, you indicated that Keeyask is well-defined and you -- you indicated Manitoba Hydro seems to have an appreciation of what the specific risks are?

MR. MICHAEL ROBERTSON: M-hm.

MR. SVEN HOMBACH: Does that hold true for Conawapa as well, or is Conawapa not as defined, in your view?

MR. MICHAEL ROBERTSON: I don't know, because we have not been given the same level of detail as we have for Keeyask, particularly in the second report and the second round of questions, which were aimed specifically at Keeyask, and which we therefore asked Manitoba Hydro to provide us details for.

We didn't ask them to provide similar details for Conawapa. I would expect the -- the level of definition to be somewhat lower for Conawapa. I would expect the process, the systemic risks to be pretty much the same. That's probably all I could say.

MR. SVEN HOMBACH: Well, again, let's go to the Conawapa P50 contingency on this page, which, based on the most recent cost update, is 460 million.

You see that?

MR. MICHAEL ROBERTSON: The contingency, yes.

MR. SVEN HOMBACH: Compared to a point estimate of 4.93 billion?

MR. MICHAEL ROBERTSON: Yes.

MR. SVEN HOMBACH: And again, by my math, that is 9.3 percent, so significantly less than the suggestion in the Hollmann paper of 24 percent?

MR. MICHAEL ROBERTSON: Yeah.

MR. SVEN HOMBACH: Would that cause you any cause for concern at all, or do you believe that that is a realistic estimate?

MR. MICHAEL ROBERTSON: Not at all,

because I'm not going to hang my hat on what's shown on this table.

THE CHAIRPERSON: We -- I need to clarify something in my mind, because I -- I think where -- where we're getting into -- we're -- we're getting confused is we heard from Power Engineers last week that typically, the labour reserve and escalation reserve were part of the contingency. Here we've seen them split out, and I guess where the confusion's arising in our minds is, when we talk about modifying the probability from P50 to P90, are we talking about the collective modification of contingency management, labour, and escalation to the P90 level, or are we talking separately, specifically, the contingency as defined here?

MR. MICHAEL ROBERTSON: Well, as -- as I -- as I tried to indicate, we would typically combine all of this into one (1) provision for uncertainty, which would be contingency, quote/quote, and all of these would be factors within that contingency allowance.

And I did also make the point that if you were to add what is provided for here in terms of reserves to what is stated to be the contingency, then you would be getting a contingency, in my normal practice, which is obviously significantly greater than P50, but I -- I'm not really in the position to put a number to that.

MR. SVEN HOMBACH: So just to briefly follow up on the Chairman's point, if we do actually add in the labour reserve and the escalation reserve, we get to a P50 contingency of about 1.13 billion for Conawapa, which would be about 22.9 percent? That's --

MR. MICHAEL ROBERTSON: You -- you would get a contingency, but not a P50 contingency.

MR. SVEN HOMBACH: Well, that's based on the reference contingency. Is it your understanding that in this chart, the reference contingency is a P50?

MR. MICHAEL ROBERTSON: For those items that were included in the analysis that -- that produced that, but it didn't include all the items. It didn't include the items that are in the reserve.

MR. SVEN HOMBACH: The items that are in the management reserve itself?

MR. MICHAEL ROBERTSON: Correct. So -- so if you add point three-six (.36) and point three-one (.31) to point four-six (.46), really, you do not have any longer an overall P50 contingency.

MR. SVEN HOMBACH: Because you're stating that the contingency of point four-six (.46), that's the P50?

MR. MICHAEL ROBERTSON: For those items that are included in that analysis.

MR. SVEN HOMBACH: Okay. When one develops a P50 contingency for a project, is it your understanding that the overall number that is given, including what Manitoba Hydro here calls the management reserve, would be lumped into the P50?

MR. MICHAEL ROBERTSON: That would be my normal practice, but that is not the way Manitoba Hydro has chosen to do it. I mean, to -- to some extent, it's -- this is semantics. It's -- it's really what allowance has been made for uncertainty, and is the amount appropriate.

MR. SVEN HOMBACH: Well, it's relevant, though, because if -- if, when you add the labour reserve and the escalation reserve, you don't have a P50 anymore, then you're basically -- you're left with a higher probability, correct?

MR. MICHAEL ROBERTSON: Right.

MR. SVEN HOMBACH: And if we do the math, adding those three (3), that's about 1.13 billion. It indicates in the right-most column that the high estimate is about one point five six (1.56), so pre -- we're presumably looking at something like a

P70, P75?

MR. MICHAEL ROBERTSON: I wouldn't put a number to it, but it's higher than P50.

MR. SVEN HOMBACH: Somewhere in that ballpark.

MR. MICHAEL ROBERTSON: It's higher than P50.

MR. SVEN HOMBACH: Yeah.

MR. BORIS FICHOT: I'm just going to add a -- a small point to this is that, when we're talking about the contingency, that is -- that is statistically derived. So we can talk about P50s and P80s.

But when we're talking about the labour reserve and escalation reserve, those are subjective-based quantities. They have no statistical basis to them. They -- they're -- they're a judgment call that we make on what are some of the things that can happen, and as a result we come up with a number.

So one is subjective, which is the management reserve, and one has a statistical basis. And those -- there's no link to it.

The way we have seen traditionally, and it seems like power engineers have seen traditionally, is you qualify all these elements statistically, and then you roll them up and come up with one (1) number based on the statistics.

But in this case, contingency has statistical basis, but management reserve doesn't. And there's a little bit of a -- I feel like there's a little bit of a mix there.

MR. SVEN HOMBACH: Did you actually examine the statistical analysis for either of the two (2) projects?

MR. BORIS FICHOT: No. That's far beyond what -- what we could do. We -- we observe -- we -- we read the validation estimating report that had results that showed statistical distributions. And we've seen Manitoba Hydro's justification behind the -- the labour reserve and why they came up with the labour reserve that they came up with.

MR. SVEN HOMBACH: And are you satisfied that the statistical distributions are accurate? Or perhaps I should say reasonably, appreciating that accuracy can only --

MR. BORIS FICHOT: To -- to the -- to the extent that they went to a specialized firm who does this, they produced a document, they ran models, they had input from Manitoba Hydro staff that went into this to come up with this distribution.

So there's a process. It's documented. We can't check the nitty-gritty of that, and they've given an output that has a distribution to it.

MR. SVEN HOMBACH: Okay. Thank you, Mr. Chairman. I don't have any further questions to this panel in the public session.

THE CHAIRPERSON: I wonder if there's any other business to attend to before we adjourn for the day.

Ms. Ramage...?

We're not getting anything from the Intervenors.

MR. SVEN HOMBACH: Mr. Chairman, in the -- in the meantime, if I briefly may, I would like to remind members of the public that the morning session tomorrow is reserved for CSI. So it's not going to be available to the public.

The public session with respect to Typlan, the independent expert speaking to socioeconomic issues, is scheduled to come in after the lunch break.

THE CHAIRPERSON: I think that completes today's business. Me. Monnin, have you -- no. That completes today's business, so we'll adjourn for the day, and we'll see each other again at nine

o'clock, those of you who are eligible to consider CSI.
Thank you. Have a good evening, everyone.

(PANEL RETIRES)

--- Upon adjourning at 4:31 p.m.

Certified Correct,

____
Cheryl Lavigne, Ms.

Tab 126

Construction Cost Consultants
Quantity Surveyors ▪ Project Managers

MGF
PROJECT SERVICES

~~Confidential~~

Report
For
Manitoba-Hydro
Capital Expenditure Review
For
The Keeyask Hydroelectric Dam
The Bipole III, Manitoba-Minnesota
and GNTL Transmission Lines

The Public Utilities Board

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Project No: P1051-09-03
Document No: 01758

Disclaimer

This report has been prepared by MGF Project Services Inc. on the instruction of the The Manitoba Public Utilities Board to provide an independent review of Manitoba Hydro's Capital Expenditure Program.

It has been completed in accordance with generally accepted professional practices using information solely and exclusively provided by The Manitoba Public Utilities Board, their independent consultants, Manitoba Hydro and information in the public domain.

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- A: Klohn Crippen Berger Report
- B: Amplitude Consultants Report
- C: Scheduling Best Practices

SECTION 1 - Executive Summary

This Report is confidential and for the sole review of The Manitoba Public Utilities Board and Manitoba Hydro.

MGF Project Services Inc. was retained by The Manitoba Public Utilities Board as an Independent Expert Consultant to review Manitoba Hydro's capital expenditure program and to provide expert opinion on Manitoba Hydro's updated costs for the Keeyask Hydroelectric Dam, the Bipole III Transmission Line and Converter Stations, the Manitoba - Minnesota Transmission Line and The Great Northern Transmission Line.

The following is a summary of this Report:

Keeyask Hydro Electric Dam

The Joint Keeyask Development Agreement between the Keeyask Cree Nations is in our opinion inline with industry best practice.

The General Civil Contract (GCC) and its performance is the largest single contributor to planned cost and schedule not being met.

The contracting strategy was schedule driven and resulted in using a cost reimbursable pricing mechanism for the GCC. The Contractor gets paid for its actual costs rather than the performance of the construction work. The Contractor is currently behind schedule and over budget.

The largest single contributor to the budget increase from $6.5 billion to $8.7 billion is the [redacted] sum 1a, 8a
added to the original GCC on account of the Contractor's poor productivity and increased indirect costs as the GCC would take longer to perform.

Other major cost contributors comprise delay claims, management costs, project support services, interest & escalation and contingency.

The GCC Contractor is not meeting the revised productivity factors for concreting and earthworks in the Amending Agreement No. 7 dated 28th February 2017, adding further cost and schedule pressure to the likely forecasted final cost and completion date.

The current contingency is insufficient and will soon be fully committed to cover other increasing costs.

The performance issues related to the GCC and their consequent impacts on other contracts will result in the Final Project Cost being in the $9.5 billion to $10.5 billion range.

Manitoba Hydro staff are competent and professional but they are not a construction manager with the experience and skills to direct the GCC. As such, its project management and control effectiveness is low.

There is an opportunity for Manitoba Hydro to implement contract management improvements, take ownership for the GCC and drive the GCC contractor to higher levels of predictable performance, to accelerate project schedule and to lower the likely forecast cost at completion

HVDC Converter Stations

This project is well managed by Manitoba Hydro and the potential for cost over-runs is low.

Manitoba Hydro's contracting strategies are commercially astute, allocating risk appropriately between the parties and using predominantly lump sum or unit rate pricing mechanisms which place the risks of productivity, cost and schedule on its contractors.

The HVDC Converter Stations were competitively tendered to three of the most experienced technology vendors and two bids were very close in price, indicating a successful competitive tender. The same observation applies to the Synchronous Condensers scope.

The Bipole III Basis of Estimate (which includes the Converter Stations) document is well written and documented. It would be improved if benchmarking and industry metrics were included.

We would recommend that Manitoba Hydro's Estimating Team prepare the overall estimate with input from each department, thereby ensuring consistency and accuracy in the Estimates.

Bipole III Transmission Line

This project is generally well organized and managed efficiently.

Manitoba Hydro's contracting strategies are commercially astute, allocating risk appropriately between the parties and using predominantly lump sum or unit rate pricing mechanisms which place the risks of productivity, cost and schedule on its contractors.

The project is currently on schedule although some activities are slipping from their critical paths which may jeopardize the August 2018 completion.

A key risk to completion by August 2018 is the poor performance by Rokstad Power Corporation. Manitoba Hydro is managing this risk by de-scoping the under-performing contractor. Whether this maintains the August 2018 is uncertain at this time.

Manitoba – Minnesota Transmission Line

This project is currently on schedule. As it further develops, its schedule should be updated more frequently than the current two month frequency.

Manitoba Hydro's estimating methodology is consistent with industry standard. Industry benchmarking suggests the cost estimate is below market value.

MGF recommends that the cost estimate is updated pursuant to an Estimate Preparation Plan and in accordance with a Basis of Estimate. Where possible the values of awarded contracts should be incorporated rather than previous estimated costs.

Great Northern Transmission Line

This project is well organized and managed efficiently.

The project is progressing, with Rights of Way being cleared in advance of subsequent construction activity.

The Construction Management Agreement meets exceptional commercial business practice and protects Manitoba Hydro's interest.

Minnesota Power's cost estimating methodology is consistent with industry standard for the class of Estimate produced. The cost estimate is considered high when benchmarked to other similar projects so further reviews are recommended.

General

The Manitoba Hydro teams on all projects are very capable and dedicated.

The Keeyask Generating Station project presents the greatest threat to Manitoba Hydro on account of the GCC contract with a contractor that is under performing and being compensated on cost reimbursable pricing mechanism.

The recovery of this project will require Manitoba Hydro taking a construction management, hands-on approach to design and implement a recovery plan and hold the GCC contractor to perform.

SECTION 2 - Introduction

MGF Project Services Inc. (MGF) have been requested by the Manitoba Public Utilities Board to carry out a review of Manitoba Hydro's (MH) Capital Expenditure, associated with a public evidentiary process.

Manitoba Hydro is undertaking a substantial capital program expansion through the construction of a large new generating station and transmission lines. As many of these projects have seen a substantial increase in capital cost since project inception, The Manitoba Utilities Board has requested this review.

This Report is confidential and for the review of The Manitoba Public Utilities Board and Manitoba Hydro only.

The Projects include:

- The Keeyask Hydroelectric Dam: is a large, complex and remotely located project 725 kilometers northeast of Winnipeg on the Lower Nelson River. The Keeyask Generating Station will include the following structures:
  - 695 megawatt seven-unit Powerhouse/Service Bay complex on the north side of Gull Rapids
  - Seven bay Spillway on the south side of Gull Rapids
  - 23 Km of dykes built on the north and south sides of the reservoir
  - North, central and south dams across Gull Rapids
- The Bipole III HVDC Converter Stations: are specialized stations which form the terminal equipment for the 500kV HVDC Transmission Line, converting alternating current (AC) to direct current (DC), for transmission and back to AC for distribution. The Bipole III project consists of two (2) converter stations, namely the Keewatinohk Converter Station located in northern Manitoba, northeast of Gillam and the Riel Converter Station located in southern Manitoba, east of Winnipeg.
- The Bipole III Transmission Line: is a 1,385 kilometer 500kV DC transmission line originating at the Keewatinohk Converter Station travelling west of Lake Manitoba and terminating at the Riel Converter Station
- The Manitoba to Minnesota Transmission Line: is a 213 kilometer 500kV AC transmission line from the Dorsey Converter Station northwest of Winnipeg, terminating at the United States border near Piney MB
- The Great Northern Transmission Line: is a 361 kilometers single-circuit 500kV AC transmission line from the Minnesota-Manitoba border to the Iron Range Substation near Grand Rapids, Minnesota

The process adopted while compiling the report was to work closely with Manitoba Hydro and where time permitted, exchanging our Observations and Findings with them for their viewpoint. Manitoba Hydro was very co-operative and engaging throughout the process.

This Report details our Observations, Findings, Conclusions and Recommendations.

SECTION 3 - The Keeyask Hydroelectric Dam

SCOPE ITEM 1:

Review, assess, and determine the reasons for project cost overruns from the $6.5 billion final pre-construction budget with respect to:

i. Design or project scope changes;
ii. Deviations from estimated quantities;
iii. Labour productivity;
iv. Labour costs;
v. Labour hiring constraints with respect to: Competition with other large civil projects in Canada; Remote location; and Northern and First Nations jobs.

Inputs into the $6.5 billion budget should be reviewed and assessed as required.

Finding No. 1: Keeyask - Community Initiatives (Payment Obligations)

Observations & Findings

The table below compares community initiatives for 2014 and 2017.

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$)	2017 CPJA Budget (2016$)	Variance ($)	Variance (%)
255740	Keeyask Adverse Effects	[redacted]			
255741	Keeyask Operational Employment				
244009	K-Operational Employment PMT Obligation				
243996	K-Ad Effects Payment Obligation (LCKD)				

1a, 8a 7a

Manitoba Hydro has committed the above funds to various community initiatives. Variations in estimates are due to the 2017 estimate including interest capitalized on cash payments – the CEF2014 estimate was the present value of future payments.

Conclusions & Recommendations

Community initiatives are an industry norm for major capital projects being developed and Manitoba Hydro's approach is very effective.

Source of Information & Reference Materials

- Map to Comparison of Keeyask 2014 to 2017.xlsx
- Keeyask Generating Station, Basis of Estimate Document, 2014 Capital Project Justification Addendum, dated August 2014
- Keeyask Generating Station, Basis of Estimate Document, 2017 Capital Project Justification Addendum, dated January 2017
- Keeyask Generating Station, 2017 Capital Project Justification Addendum, Comparison of 2014 Estimate to 2017 Estimate, dated August 2017

Finding No. 2: Keeyask - Licensing and Planning

Observations & Findings

Manitoba Hydro has indicated that the "Licensing Phase is substantially complete and remaining funds were removed." This results in a $5 million saving to the project.

Conclusions & Recommendations

Manitoba Hydro is reporting that the Licensing Phase is "substantially complete" and as such, we would expect little to no cost variation costs associated with this activity.

Source of Information & Reference Materials

- Map to Comparison of Keeyask 2014 to 2017.xlsx
- Keeyask Generating Station, 2017 Capital Project Justification Addendum, Comparison of 2014 Estimate to 2017 Estimate, dated August 2017

Finding No. 3: Keeyask - Labour Costs & Labour Hiring Constraints

Observations & Findings

Upon a review of the market place and demand for labour over the period that the Keeyask Project commenced development to date, indicates that there has been ample supply of labour for the development of the Keeyask Project. However, the choice of a 21 days on, 7 days off rotation cycle is not as attractive as the more common 14 days on, 7 days off rotation (as in Northern Alberta).

To compete for labour, Schedule 12-3 entitled "Proposed Letter of Agreement, Burntwood/Nelson Agreement" of the Joint Keeyask Development Agreement was developed to stipulate that special measures needed to be implemented during the construction of the project to facilitate the employment, training and retention of First Nations members and other Northern Aboriginals, which measures might conflict with existing Burntwood/Nelson Agreement provisions relating to referral, recruitment or placement procedures.

LOA 35 executed on 1st January 2016 instituted a 13% completion bonus to attract and retain labour for the project. It is difficult to ascertain whether this was a critical component to project cost over-runs as most major capital projects in Canada have some form of retention mechanism, so this could have been reasonably predictable and costed for.

The Joint Keeyask Development Agreement provides for the consultation with, participation of and business opportunities for members of the Keeyask Cree Nation (KCN). There is the potential for equity participation in the project and for Direct Negotiated Contracts with KCN joint ventures.

Manitoba Hydro advised MGF that they have had great success with local Aboriginal labour, however they have exhausted all availability.

Conclusions & Recommendations

The commitments in the Joint Keeyask Development Agreement to KCN and other Northern Aboriginal groups is, in our opinion, an industry best practice. LOA 35 provides an industry typical attraction and retention mechanism. The 21 days on, 7 days off rotation cycle is not as attractive as the more typical 14 days on, 7 days off used on many other capital projects.

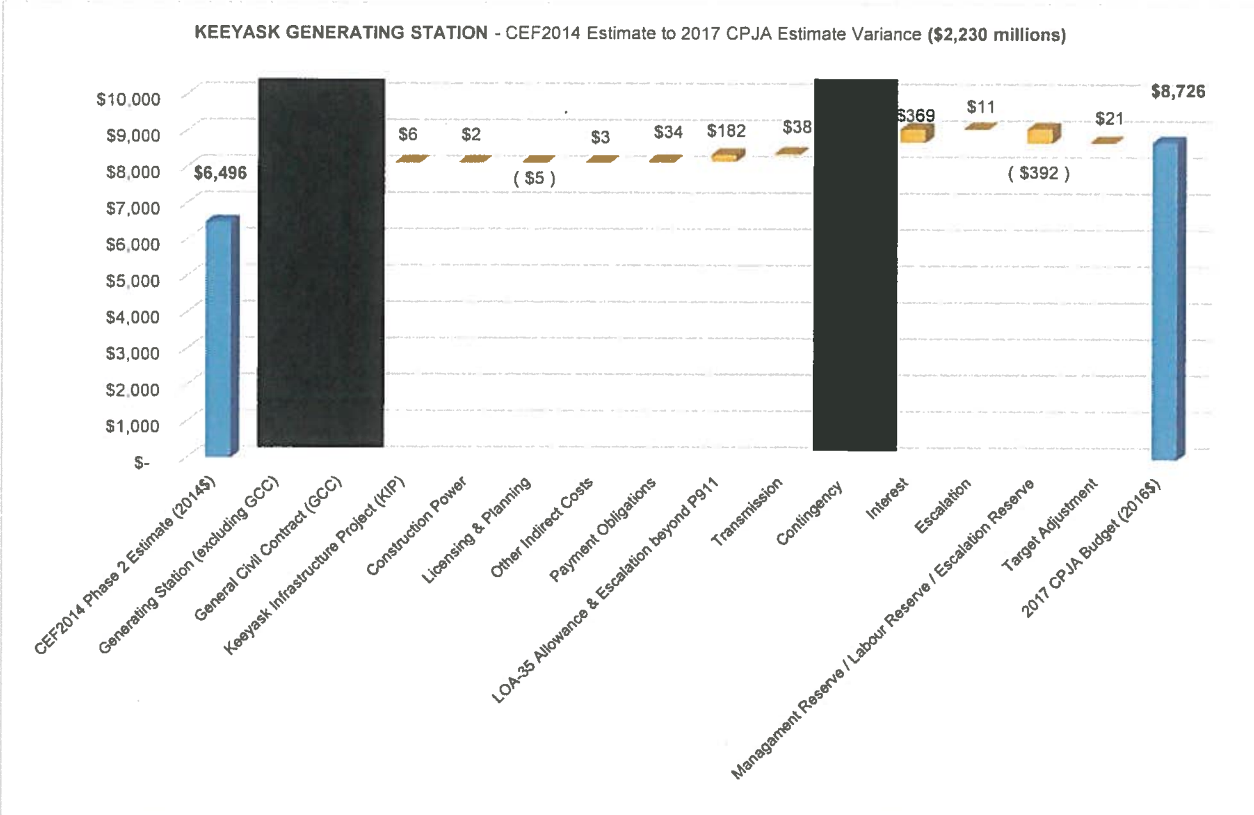
Source of Information & Reference Materials

- The Joint Keeyask Development Agreement (JKDA)
- JKDA Schedule 1-2 Construction Agreement
- JKDA Schedule 4-6 Construction Advisory Committee
- JKDA Schedule 4-7 Monitoring Advisory Committee
- JKDA Schedule 12-3 Proposed Letter of Agreement, Burntwood/Nelson Agreement
- JKDA Schedule 13-1 Identified Work Packages and Allocation

Finding No. 4: Keeyask - Project Cost Variance Review

Observations & Findings

Based on our review, the following provides a build-up of how the project costs have evolved from the CEF2014 ($6.496 billion) to the 2017 CPJA ($8.726 billion):



1a , 7a
4b

- 2013$: Expressed in fiscal year 2013/2014
- 2014$: Expressed in fiscal year 2014/2015
- 2016$: Expressed in fiscal year 2016/2017

The following provides a summary of key project variances from the $6.5 billion final pre-construction budget to the $8.7 billion current budget.

Final Pre-Construction Budget	6,496,076,546
Additions	2,783,971,637
Omissions	-554,009,510
Total	**8,726,038,673**

Total Budget Additions: $2.784 billion

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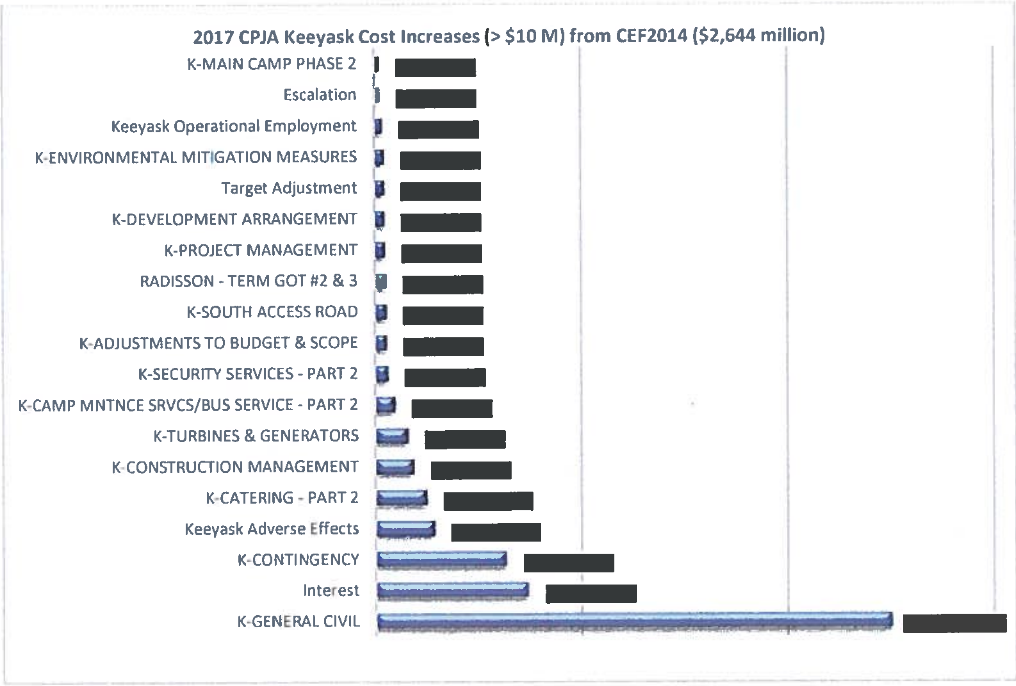
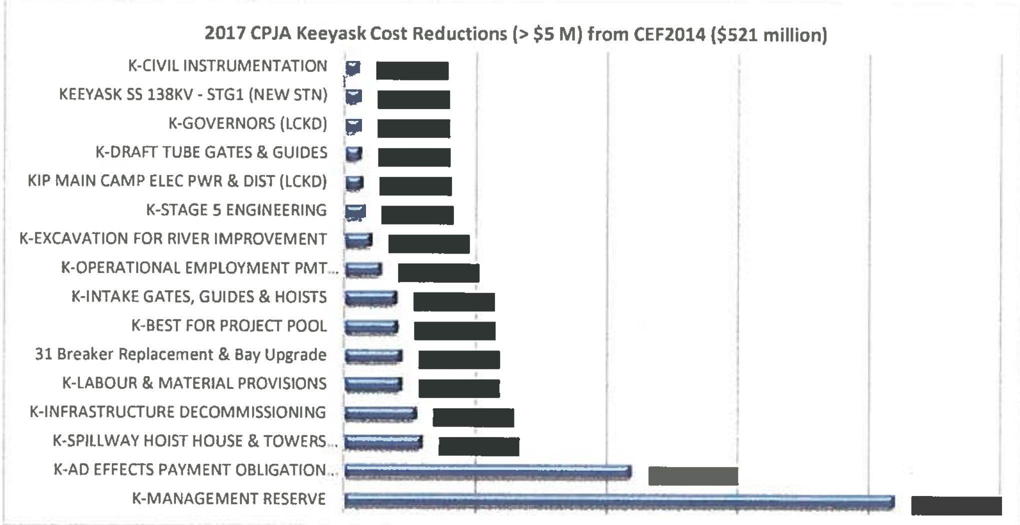
The following table sets out $2.644 billion of project cost increases out of the $2,784 million. The remaining $140 million is distributed across several other cost elements.



1a 7a

Total Budget Omissions: $554 million

The table below table sets out $521 million in project omissions. The remaining $33 million is distributed across several other cost elements.



1a 7a

Conclusions & Recommendations

The largest contributor to the overall project cost is the [redacted] increase in the value of the General Civil Contract (GCC) on account of Amending Agreement No. 7. Over [redacted] of the \$2.23 billion net addition 1a
is due to the GCC, caused by concrete and earthwork productivity that is less than planned and additional indirect costs.

Source of Information & Reference Materials

- Keeyask Generating Station, 2017 Capital Project Justification Addendum, Comparison of 2014 Estimate to 2017 Estimate, dated August 2017
- Map to Comparison of Keeyask 2014 to 2017.xlsx
- Keeyask Generating Station, Basis of Estimate Document, 2014 Capital Project Justification Addendum, dated August 2014
- Keeyask Generating Station, Basis of Estimate Document, 2017 Capital Project Justification Addendum, dated January 2017

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Finding No. 5: Keeyask - Project Cost Overruns – Interest

Observations & Findings

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$)	2017 CPJA Budget (2016$)	Variance ($)	Variance (%)
	Interest	1,379,944,641	1,749,184,959	369,240,318	26.8%

Manitoba Hydro has noted that increases to the project's base costs have increased interest costs.

Currently, interest represents 20% of the budgeted "Total In-Service Cost" ($8.7 billion).

Conclusions & Recommendations

MGF concludes that the costs associated with the interest rate are a function of funding the overall capital project.

MGF's recommendation is that contingency carried should consider the risk exposures associated with interest in the same manner it does with escalation.

MGF views Manitoba Hydro's current contingency as insufficient and further interest adjustments will likely be required.

Source of Information & Reference Materials

- Keeyask Generation Station Project Capital Cost and Schedule Risk Analysis and Contingency Estimate for Manitoba Hydro, 9th March 2014
- Keeyask Generation Station Project Capital Cost and Schedule Risk Analysis and Contingency Estimate Final for Manitoba Hydro, 7th March 2017
- Keeyask Generating Station, Basis of Estimate Document, 2014 Capital Project Justification Addendum, dated August 2014
- Keeyask Generating Station, Basis of Estimate Document, 2017 Capital Project Justification Addendum, dated January 2017
- Capital Project Justification Addendum No.4, dated 4th November 2014

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Finding No. 6: Keeyask - Project Cost Overruns – General Civil Contract (GCC)

Observations & Findings

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$)	2017 CPJA Budget (2016$)	Variance ($)	Variance (%)
243994	K-General Civil	[redacted]	[redacted]	[redacted]	[redacted]

1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value:[redacted]

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted] 1a 7a
- Delay Estimate - [redacted]
- Trends - [redacted]
- Approved Contract Changes - [redacted]
- Forecasted Contract Changes - [redacted]

Total Estimated Value:[redacted]

In comparing the Bill of Quantities (BOQ) provided within Amending Agreement No. 7, dated 28th February 2017 and the Original Contract, dated 10th March 2014, MGF has identified variances in both quantities and unit prices which have resulted in the increase to the overall cost.

Increased cost relating to the General Civil Contract is directly due to the adjustments in unit rates, on account of poor productivity experienced on the project. Poor productivity results in additional man-hours being required to perform the work compared to the man-hour assumptions carried in the Original Contract.

Based on documents viewed, [redacted] of the increased costs relate directly to the revision of unit prices. [redacted] are due to the increase of the "to-go" costs which are noted as being more than the total 1a previous budget for Indirects, Temporary Utilities, Construction Facilities, Contingency and Crane Operator cost elements.

[redacted] of the increase was due to quantities, [redacted] resulting from Proposed Extra Work and another [redacted] in schedule incentive profit.

The total of these contributing factors account for 80% of the [redacted] increase related to this cost element. 1a

Conclusions & Recommendations

MGF concludes that the increased costs from the Original Contract to the Amending Agreement No.7, are a direct result of the revised productivity rates and increased man-hours required to complete the project.

Source of Information & Reference Materials

- Schedule J, "Volume 4 – Bill of Quantities, Prices and Target Price Estimated" of the Manitoba Hydro and BBE Hydro Constructors Limited Partnership Contract, Amending Agreement #7, dated 28th February 2017
- "Volume 4 – Bill of Quantities, Prices and Target Price Estimated" of the Original Contract, dated 10th March 2014
- BBE Hydro Constructors LP, Keeyask Project Re-Baseline, December 2016, Basis and Assumptions, Dated 9th December 2016
- BBE Hydro Constructors LP, Keeyask Project Re-Baseline, December 2016, Basis and Assumptions, dated 9th December 2016, Attachment 2 – Construction Bill of Quantities, Rev. 2, Dated 23rd September 2016
- BBE Bid BOQ - 243994-0020-016203-RFP-BBE JV-FoP Keeyask BBE JV Final BOQ-2013-12-05
- BOQ Sent to BBE on Sept 25 - 243994-0030-016203-EST-Construction BOQ-20160705
- AA7 BOQ - extract from AA7 243994-0020-016203-CON-Amending Agreement 7-20170228
- Design BOQ - Hatch to Manitoba Hydro on Sept 23, 2017 - 243955x0010-016002-BOM-Design BOQ-20160308
- RFP BOQ with Sourcing- 243994-0020-016203-RFP-Part1 Form II Bill of Quantities
- 243994-0030-016203-EST-Construction BOQ-20160705
- 243994-0020-016203-RFP-BBE JV-FoP Keeyask BBE JV Final BOQ-2013-12-05

Finding No. 7: Keeyask - Project Cost Overruns – Generating Station

Observations & Findings

The following observation relates to the cost elements within the MGF reviewed line item "Generating Station (excluding GCC)".

A point to highlight are those costs which are attributed to "Delay Estimates". This is a result of an additional 11 months added to the project schedule.

Direct Cost Work Packages - Turbines & Generators (Including Governors):

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
244021	K-Turbines and Generators	[redacted]	[redacted]	[redacted]	[redacted]
244023	K-Governors (LCKD)	[redacted]	[redacted]	[redacted]	[redacted]
	TOTAL	[redacted]	[redacted]	[redacted]	[redacted]

1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted]
- Trends - [redacted] 1a 7a

Total Estimated Value: [redacted]

The following are the noted variances provided by Manitoba Hydro:

- [redacted] change to offset currency risk
- [redacted] change to accelerate schedule
- [redacted] for offloading and handling equipment
- [redacted] estimated delay impact from GCC delay 1a 7a
- [redacted] for escalation of contract
- [redacted] Miscellaneous

Direct Cost Work Packages - Intake Gates:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
244026	K-Intake Gates, Guides and Hoists	[redacted]	[redacted]	[redacted]	[redacted]

1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted]
- Trends - [redacted]
- Approved Contract Changes - [redacted]

Total Estimated Value: [redacted]

1a 7a

The following are variances provided by Manitoba Hydro:

- [redacted]

1a

Direct Cost Work Packages - Spillway Gates (Including Hoist House & Towers):

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
244025	K-Spillway Gates, Guides, HST & MNRL Crane	[redacted]	[redacted]	[redacted]	[redacted]
250580	K-Spillway Hoist House & Towers (LCKD)	[redacted]	[redacted]	[redacted]	[redacted]
	TOTAL	[redacted]	[redacted]	[redacted]	[redacted]

1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted]
- Trends - [redacted]
- Approved Contract Changes - [redacted]

1a 7a

Total Estimated Value: [redacted]

The following are variances provided by Manitoba Hydro:

- [redacted] 1a

Direct Cost Work Packages - Excavation for River Improvement:

- Scope was deleted in 2016 Estimte

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Service Work Packages – Catering (delay estimate is for increased man-hours & delay):

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)	
243960	K-Catering – Part 2	[redacted]	[redacted]	[redacted]	[redacted]	1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted] 1a 7a
- Trends - [redacted]
- Approved Contract Changes - [redacted]

Total Estimated Value: [redacted]

The following are variances provided by Manitoba Hydro:

- Increased in CPJ Addendum; related to increased man-hours in GCC estimate

Service Work Packages – Maintenance:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)	
243961	K-Camp Mntnce Srvcs/Bus Service – Part 2	[redacted]	[redacted]	[redacted]	[redacted]	1a 7a

CEF2014 – Phase 2 Budget (2014$)

1a 7a

Total Estimated Value: [redacted]

12018

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2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted]
- Trends - [redacted]
- Approved Contract Changes - [redacted]

Total Estimated Value: [redacted]

1a 7a

The following are variances provided by Manitoba Hydro:

- Increased in CPJ Addendum; related to increased staffing requirements at site & delay of GCC

Service Work Packages – Security:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
243962	K-Security Services – Part 2	[redacted]	[redacted]	[redacted]	[redacted]

1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted]
- Trends - [redacted]
- Approved Contract Changes - [redacted]

Total Estimated Value: [redacted]

1a 7a

The following are variances provided by Manitoba Hydro:

- Increased in CPJ Addendum; related to increased staffing requirements at site & delay of GCC

Service Work Packages – First Aid:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
243964	K-First Aid Services – Part 2	[redacted]	[redacted]	[redacted]	[redacted]

1a, 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted]
- Trends - [redacted]
- Approved Contract Changes - [redacted]

Total Estimated Value: [redacted]

1a, 7a

The following are variances provided by Manitoba Hydro:

- Increased in CPJ Addendum; related to increased staffing requirements at site & delay of GCC

Other Indirect Work Packages – Construction Management:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
243954	K-Construction Management	[redacted]	[redacted]	[redacted]	[redacted]

1a, 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

MGF
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2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted]
- Trends - [redacted]
- Approved Contract Changes - [redacted]
- Forecasted Contract Changes - [redacted]

Total Estimated Value: [redacted]

1a, 7a

The following are variances provided by Manitoba Hydro:

- [redacted] to increase site staff as a result of cultural action plan
- [redacted] increase due to GCC delay
- [redacted] transfer of Hatch Scope for Support during Construction
- Remainder Miscellaneous & Escalation

1a, 7a

Other Indirect Work Packages – Project Management:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
243953	K-Project Management	[redacted]	[redacted]	[redacted]	[redacted]

1a, 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted]
- Trends - [redacted]
- Approved Contract Changes - [redacted]
- Forecasted Contract Changes - [redacted]

Total Estimated Value: [redacted]

1a, 7a

The following are variances provided by Manitoba Hydro: 1a, 7a

- [redacted] for support consultants in CPJ Addendum
- [redacted] delay estimate in CPJ Addendum
- Remainder Escalation & Miscellaneous

Variances in Cost Summaries and Supporting Cost Detail Sheets (By Network) were noted in 2014 estimate.

Other Indirect Work Packages – Best for Project Pool:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
243982	K-Best for Project Pool	[redacted]	[redacted]	[redacted]	[redacted]

1a, 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted] 1a, 7a
- Trends - [redacted]

Total Estimated Value: [redacted]

The following are the noted variances provided by Manitoba Hydro:

- Best for Project Pool was used to incentivize other contractors to meet GCC Schedule; it is no longer required

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Other Indirect Work Packages – South Access Road:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
243958	K-South Access Road	[redacted]	[redacted]	[redacted]	[redacted]

1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$)

1a 7a

- CEF2016 Plan - [redacted]
- Approved Contract Changes - [redacted]
- Forecasted Contract Changes - [redacted]

Total Estimated Value: [redacted]

The following are variances provided by Manitoba Hydro:

- The contract award for the south access road exceeded the original estimates; this was offset by a transfer of [redacted] from labour & material provisions 1a

Other Indirect Work Packages – Permanent Ice Boom:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
243741	K-Permanent Ice Boom	[redacted]	[redacted]	[redacted]	[redacted]

1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted] 1a 7a

MGF PROJECT SERVICES

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted] 1a 7a
- Trends - [redacted]
- Approved Contract Changes - [redacted]

Total Estimated Value: [redacted]

The following are variances provided by Manitoba Hydro:

- Ice boom modifications as a result of ice boom failures

Other Indirect Work Packages – Main Camp – Phase 2:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)	
243966	K-Main Camp Phase 2	[redacted]	[redacted]	[redacted]	[redacted]	1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted] 1a 7a
- Delay Estimate - [redacted]
- Approved Contract Changes - [redacted]
- Forecasted Contract Changes - [redacted]

Total Estimated Value: [redacted]

The following are variances provided by Manitoba Hydro:

- Increase of [redacted] to expand camp; remainder miscellaneous changes 1a 7a

12024

Other Indirect Work Packages – Infrastructure Decommissioning:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)	
243969	K-Infrastructure Decommissioning	[redacted]	[redacted]	[redacted]	[redacted]	1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$) 1a 7a

- CEF2016 Plan - [redacted]

Total Estimated Value: [redacted]

The following are variances provided by Manitoba Hydro:

- Primarily related to the inclusion of salvage in the estimates

Other Indirect Work Packages – Labour & Material Provisions:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)	
243983	K-Labour & Material Provisions	[redacted]	[redacted]	[redacted]	[redacted]	1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$) 1a 7a

- CEF2016 Plan - [redacted]

Total Estimated Value: [redacted]

The following are variances provided by Manitoba Hydro:

- Labour & Material Provisions were used to offset the awarded contract values for direct negotiated contracts such as the south access road and reservoir clearing

Partnership, Monitoring, Mitigation – Development Agreement:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)	
243977	K-Development Arrangement	[redacted]	[redacted]	[redacted]	[redacted]	1c 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

2017 CPJA Budget (2016$) 1c 7a

- CEF2016 Plan - [redacted]
- Delay Estimate - [redacted]
- Trends - [redacted]

Total Estimated Value: [redacted]

The following are variances provided by Manitoba Hydro:

- Increase in partnership implementation funding

Partnership, Monitoring, Mitigation – Environment:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
243980	K-Environmental Mitigation Measures	[redacted]	[redacted]	[redacted]	[redacted]

1c 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted] 1c 7a

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted] 1c 7a
- Delay Estimate - [redacted]
- Trends - [redacted]

Total Estimated Value: [redacted]

The following are variances provided by Manitoba Hydro:

- [redacted] increase related to delay of GCC 1c 7a
- [redacted] for mercury management, socioeconomic monitoring, and heritage protection
- remainder escalation & miscellaneous

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Partnership, Monitoring, Mitigation – Adjustment for Budget & Scope:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
255786	K-Adjustments to Budget & Scope	[redacted]	[redacted]	[redacted]	[redacted]

1a 7a

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: [redacted]

1a 7a

2017 CPJA Budget (2016$)

- CEF2016 Plan - [redacted]
- Trends - [redacted]

Total Estimated Value: [redacted]

The following are variances provided by Manitoba Hydro:

- Each year, escalation is added to the base cost estimates based on policy P911 escalation rates. At the same time, remaining escalation is calculated by financial planning, which results in a reduction in the allowance for remaining P911 escalation. In 2014 and 2015, the amount of escalation removed by financial planning exceeded the amount of escalation added to the base costs by $25 million. Because of concerns that the remaining P911 escalation allowance was not sufficient, these funds from the original escalation allowance were retained in the estimate.

Other Expenditures:

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
243976	K-Transportation – Part 2	[redacted]			
244013	K-Reservoir Clearing				
243986	K-Stage 1 Cofferdams				
243972	K-Main Camp Communications Phase 2				
244024	K-Powerhouse Cranes				
243959	K-Camp Operations				
244037	K-600V Switchgear & Switchboard				
244039	K-MV Station Service Equipment				
244001	K-North & South Dykes				
243974	K-Job Referral Service – Part 2				
243998	K-Social Mitigation & Waterways Management				
243984	K-Management Agreement				
246440	K-PH Complex Suprstrctr & Buiding Env				
243971	K-Main Camp Electrical Power – Phase 2				
250581	K-Station AC Distribution				
243975	K-Construction Office – Part 2				
244036	K-Unit Control & Monitoring System				
246442	K-Transition Concrete Structures				
243978	K-Project-Wide Technical Information				

1a 7a

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
244035	K-Gen/XFMR Protective Relaying Equipment	[redacted]	[redacted]	[redacted]	[redacted]
246433	K-Service Bay Concrete Structure	[redacted]	[redacted]	[redacted]	[redacted]
244011	K-Operational Employment	[redacted]	[redacted]	[redacted]	[redacted]
244038	K-Motor Control Centers	[redacted]	[redacted]	[redacted]	[redacted]
244027	K-Draft Tube Crane	[redacted]	[redacted]	[redacted]	[redacted]
243999	K-Rock & Unclassified Excavation	[redacted]	[redacted]	[redacted]	[redacted]
250589	K-Waste Water System	[redacted]	[redacted]	[redacted]	[redacted]
246431	K-Powerhouse Concrete Structure	[redacted]	[redacted]	[redacted]	[redacted]
244006	K-North, Central, South Dams	[redacted]	[redacted]	[redacted]	[redacted]
243967	K-3D Model Development	[redacted]	[redacted]	[redacted]	[redacted]
250593	K-Station HVAC System	[redacted]	[redacted]	[redacted]	[redacted]
243979	K-Lowering/Rmval of River Mngmnt Strctres	[redacted]	[redacted]	[redacted]	[redacted]
244014	K-Architectural Finishing	[redacted]	[redacted]	[redacted]	[redacted]
250590	K-Stations Service & Cooling Water Syst	[redacted]	[redacted]	[redacted]	[redacted]
243995	K-Stage 2 Cofferdams	[redacted]	[redacted]	[redacted]	[redacted]
250583	K-Cable Raceways & Support System	[redacted]	[redacted]	[redacted]	[redacted]
244045	K-Generating Station Communications	[redacted]	[redacted]	[redacted]	[redacted]
244003	K-Powerhouse Approach Channel	[redacted]	[redacted]	[redacted]	[redacted]
244017	K-North Access Road Ramp	[redacted]	[redacted]	[redacted]	[redacted]
246432	K-Trailrace Concrete Structure	[redacted]	[redacted]	[redacted]	[redacted]
250588	K-Fuel Oil Piping System	[redacted]	[redacted]	[redacted]	[redacted]

1a 7a

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)	
244002	K-Access Road to Powerhouse & Parking LT	[redacted]				
250596	K-Intake Monorail Crane	[redacted]				
244007	K-Spillway Approach Channel	[redacted]				
244042	K-Elec & Mech Systems & Services (LCKD)	[redacted]				
244018	K-South Access Road Ramp	[redacted]				
250585	K-Station Lighting System	[redacted]				
244043	K-Air Gap & Vibration Monitoring Systems	[redacted]				
244004	K-Intake Concrete Structure	[redacted]				
250595	K-Spillway Fire Suppression System	[redacted]				1a 7a
243943	K-Compressed Air System	[redacted]				
244008	K-Spillway Concrete Structure	[redacted]				
243985	K-Temporary Ice Boom (LCKD)	[redacted]				
244020	K-Piezometer System	[redacted]				
246444	K-Transmission Tower Spur	[redacted]				
244031	K-Station Bonding & Ground Grid	[redacted]				
250582	K-Station DC Distribution	[redacted]				
250587	K-Station Fire Alarm/Detection System	[redacted]				
249021	K-Stg 2 River Diversion Erosion P (LCKD)	[redacted]				
249035	K-Service Bay – Main Door	[redacted]				
250586	K-Station Security System	[redacted]				

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Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
244029	K-Shaft Seal Water System	[redacted]			
244005	K-Powerhouse Discharge Channel (LCKD)	[redacted]			
249023	K-Stg 1 River Divrsn Erosion Prot (LCKD)	[redacted]			
243997	K-Hydr Design Input to Stg 2 Cofferdams	[redacted]			
244030	K-Oil Management System	[redacted]			
250594	K-Powerhouse Complex Fire Suppression Sy	[redacted]			
250592	K-Unit Dewatering System	[redacted]			
244032	K-Exciters	[redacted]			
249022	K-Powerhouse Complex Elevators	[redacted]			
244019	K-Domestic Water System	[redacted]			
243990	K-Stg 1 Spillway Cofferdam (LCKD)	[redacted]			
243963	K-Employee Retentn Support Srvs – Part 2	[redacted]			
250591	K-Clearwater Drainage System	[redacted]			
246443	K-Wing Wall Concrete Structures (LCKD)	[redacted]			
244000	K-Quarry Development	[redacted]			
243838	K-Spillway Excavation (LCKD)	[redacted]			
250584	K-Blackstart Standby Power System	[redacted]			
244012	K-Powerhouse Excavation (LCKD)	[redacted]			
244041	K-Isolated Phase Bus	[redacted]			
244040	K-Spillway Standby Power Supply	[redacted]			
249026	K-Stoplogs, Bkhd/DT Tube Gates & Folls	[redacted]			

1a 7a

Network / Project Number	Work Package	CEF2014 Phase 2 Estimate (2014$) CAD$	2017 CPJA Budget (2016$) CAD$	Variance ($) CAD$	Variance (%)
249025	K-Permanent Spillway Stoplogs & Guides	[redacted]			
244044	K-138KV Surge Arrstrs & Discnct Swtch	[redacted]			
244033	K-Generator Circuit Breakers	[redacted]			
244034	K-Generator Step-Up Transformers	[redacted]			
249027	K-Intake Trashracks & Guides	[redacted]			
244016	K-Civil Instrumentation	[redacted]			
249028	K-Draft Tubes Gates & Guides	[redacted]			
243955	K-Stage 5 Engineering	[redacted]			

1a 7a

The above table only shows variances.

CEF2014 – Phase 2 Budget (2014$)

Total Estimated Value: $376.2 million

2017 CPJA Budget (2016$)

- CEF2016 Plan - $357.4 million
- Delay Estimate - $17.7 million
- Trends - $6.9 million
- Approved Contract Changes - $4.3 million
- Forecasted Contract Changes - $10.3 million

Total Estimated Value: $396.6 million

This category "Other," within the Cost Estimate, in the sum of $396.6 million appears to be a "catch-all" for various scope and service elements. The largest cost increases are due to Transportation, Reservoir Cleaning, Stage 1 Cofferdam and Camp Communications requirements.

Conclusions & Recommendations

The cost increases are due to the performance of the General Civil Contract (GCC) contractor. The GCC contractor is behind schedule which causes delays and cost increases on other services and scopes of work related to the project, therefore raising the total project cost.

Source of Information & Reference Materials

- Map to Comparison of Keeyask 2014 to 2017.xlsx
- Keeyask Generating Station, Basis of Estimate Document, 2014 Capital Project Justification Addendum, dated August 2014
- Keeyask Generating Station, Basis of Estimate Document, 2017 Capital Project Justification Addendum, dated January 2017
- Keeyask Generating Station, 2017 Capital Project Justification Addendum, Comparison of 2014 Estimate to 2017 Estimate, dated August 2017

SCOPE ITEM 2:

Determine whether the current state of design work, engineering work and geotechnical analysis supports the $8.7 billion cost estimate. If not, identify what changes in the contingencies, reserves or forecast at completion cost are required.

Finding No. 1: Keeyask - Klohn Crippen Berger Report

Observations & Findings

The last bullet point on page 15 of the Klohn Crippen Berger Report states "The only potential issue may be the timing of the drawing production, which may have created some delays in construction".

In the video conference with BBE Hydro Constructors Limited Partnership (BBE) on 23rd October 2017, BBE advised MGF that construction had not been delayed on account of the issue of Issued for Construction (IFC) drawings.

Conclusions & Recommendations

The production of Issued for Construction drawings has not impacted BBE's progress.

Source of Information & Reference Materials

- Video conference with BBE on Monday 23rd October 2017

SCOPE ITEM 3:

Review and assess Manitoba Hydro's cost estimating methodologies, identifying best practices and short-comings, beginning with the development of the $6.5 billion final pre-construction budget and with specific attention to the changes that have resulted in the $8.7 billion forecast at completion budget. Identify whether sufficient contingency amounts are included in the $8.7 billion forecast at completion budget.

Finding No. 1: Keeyask - Manitoba Hydro Cost Estimating Methodologies

Observations & Findings

The review of the Basis of Estimate and associated attachments identified areas of significant disconnects and insufficient details with which to understand the development of the $6.5 billion final pre-construction budget and the $8.7 billion forecast at completion budget.

Manitoba Hydro's Basis of Estimate for the "2014 Capital Project Justification Addendum" provides, at a high level, the evolution of the estimate. KGS Acres Ltd. produced the cost estimate in 2007 which was later updated in December 2009. Price adjustments over the years were made using escalation calculations to select cost elements of the cost estimate. This is an area upon which Manitoba Hydro can improve.

It was difficult to align the levels of detail and structure of the estimates with the various cost reports, despite the fact that the project has an established Work Breakdown Structure (WBS). The estimate basis has not been aligned with either the WBS or the summary tables provided within the Basis of Estimate itself. The detailed cost summary in the Basis of Estimate seems to align with Manitoba Hydro's SAP cost reports which appear to drive much of Manitoba Hydro's estimating formats, development process and ultimately its estimating philosophies.

The following are examples of items we expected to find in the Basis of Estimate but which were missing:

- Estimate classification
- Benchmarking references
- Estimate deliverables checklist
- Listing of documents available or relied upon at the time of the estimate
- Engineering progress
- Change logs (by date, number, value and parties impacted). Only a summary of Contract Change values was provided. Attachments noted as being included within the BBE Basis of Estimate were not available upon request and it was indicated that these may not have been provided to Manitoba Hydro
- Basis for quantities (model, manual take-offs, factors, allowances, etc.)
- Schedule basis (identifying major milestone dates)

Conclusions & Recommendations

In general Manitoba Hydro is very strong in capturing and reporting costs and has a very capable group. It is MGF's opinion that additional governance and cost control, not accounting, measures need to be implemented. Tighter pre-tender and project sanction estimates can be developed by addressing the observations and findings above.

More consistent alignment is recommended between the level of project execution reporting and financial reporting (i.e. different metrics are used to benefit both groups in different ways). Development and use of a logical Work Breakdown Structure and Cost Breakdown Structure is recommended and to use these to structure budgets and reports in a consistent manner throughout the project.

Source of Information & Reference Materials

- AACE International Recommended Practice No. 34R-05, BASIS OF ESTIMATE, TCM Framework: 7.3 – Costs Estimating and Budgeting.
- Keeyask Generating Station, Chronological History of Approved Project Budget (CEF08 – CEF16)
- Keeyask Generating Station, Final Design Phase, Basis of Cost Estimate Report December 2009 Cost Estimate, dated June 1, 2010
- Keeyask Generating Station, Basis of Estimate Document, 2014 Capital Project Justification Addendum, dated August 2014

Finding No. 2: Keeyask - Manitoba Hydro Cost Estimating Methodologies

Observations & Findings

2017 CPJA Budget (2016$)

The 2017 CPJA Budget has been developed through the combination of estimates as well as values represented as Approved Contract Changes and Forecasted Contract Changes which, depending on the compensation method and terms outlined within the Contract to which the Contract Change applies to, could also be considered only an estimate (i.e. Cost Reimbursable vs. Fixed Price). The following categories of estimate update "type" have been presented by Manitoba Hydro, as a basis for the 2017 CPJA Budget (2016$).

- CEF2016 Plan: These are estimates that were generated by the respective Work Package Lead (WPL) assigned to a given work package (there have been some 59 WPLs identified as preparing 149 work packages).

  Templates were provided by Manitoba Hydro's Cost & Schedule Section which were then issued to the WPL for population. Upon completion of these templates, the estimates were loaded into SAP, Manitoba Hydro's cost management system. Based on a distribution curve assigned to the costs, in terms of when and how the expected spend would occur, cash flows were produced and various time driven cost adjustments could be accounted for.

The templates included the following "Sunk Costs" and "Planned Costs" for the following fiscal years until completion of the project. These have been presented per the following categories:

- Labour
- Expenses
- Contracts
- Consulting (Consulting was new to the 2017 Estimate)

- Delay Estimate: WPL's generated estimates associated to their respective work package(s) based on a one-year schedule delay to the first unit In-Service Date, which was driven by the contractor's schedule. Costs were allocated into Labour, Expenses, Contracts and Consulting categories.
- Trends: WPL's generated estimates for other known trending costs not associated with delay. These have been identified as including Project Change Authorizations (PCA) waiting for approval and other potential PCAs not yet formalized.
- Approved Contract Changes: Approved contract changes were based on information compiled from the Contract Revision Register (CRR).
- Forecasted Contract Changes: These are referenced in the basis as pending Contract Changes and were based on information compiled from the Contract Revision Register (CRR).

Pending Contract Changes are identified by WPLs for changes that are known, but not yet finalized. Manitoba Hydro's Cost & Schedule Section confirmed that no delay costs or trends identified by the WPLs were duplicated in the list of pending Contract Changes.

CEF2016 Plan: Costs noted within the CEF2016 Plan Estimate Summary Sheets are planned for as late as 31st March 2023.

CEF 2016 Estimate Sheets were provided in the Basis of Estimate appendices as supporting details to the cost estimate, however, the values included within these estimate sheets did not align with the values carried in the actual estimate. In the 2014 Capital Project Justification Addendum, Basis of Estimate variances occur because of SAP's use of a more accurate treatment of overhead. It was also noted through conversations that these variances are the result of updated labour rates themselves which are to be applied throughout the next fiscal year. Rates current at the time the CEF 2016 Estimate Sheets were generated, and then adjusted prior to being carried in the final estimate. This was not specified within the 2017 Capital Project Justification Addendum, Basis of Estimate and the reconciled estimate sheets that were provided in 2014 were also neither provided nor developed for the 2017 Estimate. This made one-for-one reconciliations difficult to perform.

Manitoba Hydro's overhead is calculated at 5% and includes:

- Personal Computers
- Tools and Consumables
- Accounts Payable Group
- Supply Chain Management Group
- Software Licensing & Maintenance (i.e. Autocad, Mapinfo, etc.)

Delay Estimate: Delay estimate values and descriptions have been presented within the Basis of Estimate document.

Trends: Manitoba Hydro has indicated that these costs are largely due to estimates that had been completed by the Transmission Group. The Keeyask Project Team did not have copies of these.

Approved Contract Changes: Manitoba Hydro provided the Project Contract Revision Register and an appendix within the Basis of Estimate. There was not a list of Approved Contract Changes in the estimate.

Forecasted Contract Changes: Manitoba Hydro provided a copy of the Project Contract Revision Register and an appendix within the Basis of Estimate. There was not a list of Pending Contract Changes included in the estimate.

Conclusions & Recommendations

CEF2016 Plan: MGF recommends that future estimates have appropriate reconciliations to reflect the control budget, including narratives to support the Basis of Estimate developed by WPLs.

MGF was provided with the detailed CEF 2016 Estimate Sheets used as the input basis to SAP, however, no reconciled details were provided in relation to the output of SAP and the eventual build-up of costs associated to the CEF 2016 Plan costs.

Estimated values carried in the budget are based on SAP cost modelled and time phased outputs which is an excellent approach for generating a control budget that considers future matters such as escalation and interest, albeit the estimate and SAP reporting structures need to align.

Delay Estimates & Trends: Manitoba Hydro's Keeyask Project, Costs and Schedule Group should hold the accountability for all change management, including the review and approval process associated with potential, proposed and approved project changes. A Change Log should be developed and used for tracking and managing changes for current projects.

MGF has not seen a Consolidated Project Change Log. What has been expressed as the project Change Log is simply a document management tool, which does not provide a summary of values by change, the history of the change nor how changes have evolved from either trends or Project Change Authorizations (PCAs). The Change Log is an important project management tool which should capture all potential, pending and approved changes on the project and provide an increased level of traceability. This is extremely valuable when attempting to reconcile actual costs with the approved changes.

Source of Information & Reference Materials

- Keeyask Generating Station, Basis of Estimate Document, 2014 Capital Project Justification Addendum, dated August 2014
- Keeyask Generating Station, Basis of Estimate Document, 2017 Capital Project Justification Addendum, dated January 2017
- Email dated 15th November 2017 (Blair Purvis), Subject: "Re: PEWS"

MGF PROJECT SERVICES

Finding No. 3: Keeyask - Inconsistent Estimate and Cost Structure

Observations & Findings

MGF reviewed the line item entitled "Keeyask Generating Station (excluding GCC)" as reported in the CEF 2014 and 2017 CPJA Budget, to understand how the costs were assembled.

Manitoba Hydro has used a variety of different formats and structures with which to assign costs to Scopes of Work. Note the following:

- The structure of the Cost Summary Tables included in the CPJA Basis of Estimate was not explained
- The Work Package WBS Summary was logical but the estimate summaries did not follow this structure
- The Detailed Estimate Summary was by Network, by Project and aligned with SAP, not the WBS or summaries within the Basis of Estimate

Conclusions & Recommendations

MGF recommends utilizing a single Work Breakdown Structure for consistent cost and schedule reporting.

Source of Information & Reference Materials

- Map to Comparison of Keeyask 2014 to 2017.xlsx
- Keeyask Generating Station, Basis of Estimate Document, 2014 Capital Project Justification Addendum, dated August 2014
- Keeyask Generating Station, Basis of Estimate Document, 2017 Capital Project Justification Addendum, dated January 2017
- Keeyask Generating Station, 2017 Capital Project Justification Addendum, Comparison of 2014 Estimate to 2017 Estimate, dated August 2017
- Capital Project Justification Addendum No.3, dated 30th October 2012
- Capital Project Justification Addendum No.4, dated 4th November 2014

Finding No. 4: Keeyask - $6.5 billion Estimate Adjustments, Updates and Inputs

Observations & Findings

Estimate updates used in developing the "Final Pre-Construction" Budget have been generated by Manitoba Hydro's Work Package Leads and based on various Manitoba Hydro internal and external sources at various points in time.

Estimate reference information came through market underpinned contract values, data from recently completed projects, namely Wuskwatim and costs that were based on information included and prepared for previously issued estimates, from as early as 2006.

For these previously developed estimates, escalation adjustment methods have been applied in consideration of year over year market conditions experienced since the source pricing was established, ultimately with the intention of achieving a price reflective of the current market.

These costs were noted to include Internal Labour, Expenses as well as items identified as contract estimates.

The Basis of Estimate document provided in 2014, representing the $6.496 billion project value is said to be:

> *"...generally based on the phase 2 estimate, unless noted otherwise."*

"Other Direct Cost" elements, noted below have been specifically identified in the 2014 Basis of Estimate as being based on escalated 2009/10 Estimates:

- Intake and Spillway Gates
- Other Water-to-Wire Contracts
- Balance of Plant Contracts
- Reservoir Clearing Contracts (was adjusted in the Phase 1 Estimate)

In review of the estimate detail summary sheets it was stated some costs were based on an escalated cost from 2009$, or earlier.

Conclusions & Recommendations

In general, many of the earlier Manitoba Hydro estimates used for the Pre-Construction Budget are very well detailed and clearly outline the sources and methodology applied to the development.

Adjusting previously prepared estimates to later points in time is a common estimating practice. It is MGF's opinion that a complete re-estimate should have been performed as part of the pre-tender estimate.

Many variables including scope, market conditions, foreign exchange rates, commodity indices, labour rates (agreement specific), labour composition, productivities, regulations, cash flow assumptions for escalation and even technologies are likely to have changed greatly over a 5 to 8 year period.

Any estimate inaccuracies are potentially further compounded over time and even more if the escalation itself is improperly calculated or the selected indices are inappropriate for the application.

There were numerous adjusted estimates noted through our review and the adjustment methods appear to have been very broadly applied. This method of adjustment would be more suitable to a preliminary type estimate. A control budget should have more relevant and accurate market underpinning prior to execution.

Source of Information & Reference Materials

- Keeyask Generating Station, Basis of Estimate Document, 2014 Capital Project Justification Addendum, dated August 2014

MGF
PROJECT SERVICES

SCOPE ITEM 4:

Review and assess Manitoba Hydro's scheduling methodologies, identifying best practices and short-comings.

Finding No. 1: Keeyask - Basis of Schedule

Observations & Findings

Currently there is no Basis of Schedule for the Integrated Master Schedules developed and managed by Manitoba Hydro.

BBE had provided a Basis of Schedule with the original baseline schedule. Since the re-baseline, a revised Basis of Schedule was submitted by BBE to Manitoba Hydro for approval. However, this was rejected by Manitoba Hydro due to a lack of sufficient detail.

As of 23rd October 2017 BBE has not re-submitted a more detailed Basis of Schedule.

Conclusions & Recommendations

A Basis of Schedule is an industry best practice and typically includes information about the Scope of Work (e.g. inclusions and exclusions), assumptions, execution strategy (e.g. standard or aggressive approach to the Work), options to accelerate the schedule and average and peak resource demand during the project.

The Basis of Schedule should be a "live" document which is frequently updated as any of the key aspects change and is generally updated and maintained by the scheduler.

Manitoba Hydro does have a "Develop Baseline Schedule" Procedure (CSS-011) that is noted as "Draft", dated 26th June 2013, which does address some of the above-mentioned requirements.

MGF would recommend that Manitoba Hydro implements its "Develop Baseline Schedule" Procedure CSS-011 to develop and maintain a Basis of Schedule so that the Basis of Schedule exists, is commonly understood and guides the consistent development and maintenance of the project's schedules.

Source of Information & Reference Materials

- AACE – 38R – 06, Documenting the Schedule Basis
- Manitoba Hydro "Develop Baseline Schedule" Procedure (Procedure Number: CSS-011) dated 26th June 2013

Finding No. 2: Keeyask - Hatch Schedule

Observations & Findings

The Keeyask Hatch schedule has a start date of 20th February 2013 and a completion date of 31st December 2020. The project is currently in progress with a status date of 5th November 2017. It has 3,871 normal activities of which 3,210 are complete, 132 are in progress and 529 are still planned. It contains 1,782 milestones, 1 summary and 634 LOE (Level of Effort) activities. The project baseline start date was 18th February 2013 with the baseline finish date of 29th May 2020. The project is currently behind schedule by 154 days.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The Keeyask - Hatch baseline and forecast schedules each scored 82, giving them an 85% probability of success.
- Schedule Quality: Scored 82% versus a score of 75% or better which is considered a 'good' schedule.
- High float: Schedule paths with high amounts of float typically arise due to artificially constrained activities. The metric identifies activities with total float greater than 2 months and should not exceed 5%. This schedule scored 57%. Paths with float more than 2 months should be considered for acceleration and schedule optimization.
- Critical Path Length Index (CPLI): Measures the relative efficiency required to complete a milestone on time or how close a critical path is to the project target completion date. A project with an aggressive or conservative completion date may not carry the same overall duration as that of the critical path through the network. CPLI of greater than 1 indicates that a schedule is conservative with a very high chance of early completion. A CPLI of less than 1 is very aggressive with a very high chance that completion will overrun beyond the target project completion date. The Keeyask - Hatch schedule scored 0.89.
- Baseline Execution Index (BEI): Measures the efficiency with which actual work has been accomplished when measured against the baseline. The BEI score for this schedule is 0.78. The more activities that are completed on time or ahead of the baseline schedule will reflect a BEI of 1 or more. Conversely, a BEI of less than 1 indicates that the actual work is behind schedule.

Conclusions & Recommendations

With a Fuse score of 82%, this is a well-developed schedule. However, it is worth noting that many of their activities are currently behind schedule.

Source of Information & Reference Materials

- 2017.11.05 H341433-FSOW Updated Schedule to 5th November 2017.xer
- H341433 Baseline Rev13 25th September 2017

Finding No. 3: Keeyask - Schedule Baseline

Observations & Findings

Manitoba Hydro defines Baseline Revision as "…partially [changing] the baseline schedule without affecting the contract dates or budget. In other words, it is just re-sequencing of the work due to any opportunity. Contract Change Management procedure does not apply."

As per industry best and common practice, baseline schedules should not be modified outside of the Change Management process. The baseline schedule should only change if there is a change in cost (cost loaded Schedules) or Scope of Work. If the Scope remains the same, revised schedule dates should be made in the forecast schedule only, so Earned Value Management (EVM) metrics can be used.

Conclusions & Recommendations

Manitoba Hydro's Baseline Revision definition limits their ability to see a true picture of planned versus actual effort, as each new baseline resets the planned effort. This makes the schedule impact on subsequent contracts, such as Voith, impossible to ascertain with any accuracy.

Source of Information & Reference Materials

- Schedule Change Management CSS-010

Finding No. 4: Keeyask - BBE Schedule: Negative Float

Observations & Findings

The review of BBE's schedules revealed that 15 activities are slipping their constrained dates causing 1,030 activities to have negative float. The negative float ranges from 2 hours to 204 days. Negative float generally occurs when date constrained activities are slipping or have slipped from their scheduled finish date. Negative float indicates that the activity cannot finish by its scheduled finish date.

Further, there are 97 activities with negative float that are on the critical path.

Conclusions & Recommendations

Each additional day the critical path activities are delayed has the potential to delay the schedule by the amount of such delay or longer. Until these deficiencies in BBE's schedule are reviewed and corrected, Manitoba Hydro cannot have confidence in BBE's schedule, its completion date or the impact on interfaces with other contractors.

Manitoba Hydro should remind BBE of its obligations with respect to Contract Schedule (Article 3, General Specification) and ensure that BBE complies with this going forward. For example, Article 3.1 (i) states that the Contract Schedule shall "not have any negative float", yet BBE is currently maintaining a schedule with 1,030 activities with negative float, 97 of which are on the critical path. This is unacceptable schedule sanagement and, more importantly, not in accordance with the Contract.

Source of Information & Reference Materials

- BBE Approved Revised Baseline (Rev.01) - AA7.xer
- BBE updated schedule_DD Oct 06 2017(3) – Current Schedule.xer
- BBE Constrained Activities with Negative Float OB04-02.pdf
- BBE Activities with Negative Float – OB04-02.pdf
- BBE Critical Activities with Negative Float – OB04-2.pdf

Finding No. 5: Keeyask - BBE Schedule Quality

Observations & Findings

The BBE schedule has a start date of 10th March 2014 and has 23rd January 2022 as the completion date. The project is currently in progress with a status date of 6th October 2017. It has 7,781 normal activities of which 2,021 are complete, 186 are in progress and 5,574 are still planned. It contains 745 milestones, no summaries and 17 LOE (Level of Effort) activities.

The project baseline start date was 10th March 2014 with the baseline finish date being 8th October 2021. The project is currently behind schedule by 102 days.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of the detailed analysis. The BBE schedule scored 62, giving it an 59% probability of success.
- Schedule Quality: Scored 62% versus a score of 75% or better which is a considered a "good" schedule.
- Hard Constraints: Is the number of activities with hard or two-way constraints. Two-way activity constraints completely override Critical Path Methodology (CPM) calculations and break the schedule into two parts. This schedule contains 121 hard constraints.
- Negative Float: Is the number of activities with total finish float less than 0 working days. Negative float is a result of an artificially accelerated or constrained schedule and indicates the schedule is not possible based on the current completion dates. This schedule has 17% of the activities with negative float.

Conclusions & Recommendations

With a Fuse score of 62%, this is a medium quality schedule. We would recommend removing the hard constraints. If constraints are absolutely necessary, they should be soft or one-way constraints which do not violate CPM calculations. All constraints on the schedule should be reviewed as activities which are slipping the constraint dates are causing the negative float on the schedule.

Source of Information & Reference Materials

- BBE Approved Revised Baseline (Rev.01) – AA7.xer
- September 2017 – KGS-BBE Phase II Contract Schedule Rev 1 DD Oct 06 2017 (013).xer

Finding No. 6: Keeyask - BBE Forecast Completion Date

Observations & Findings

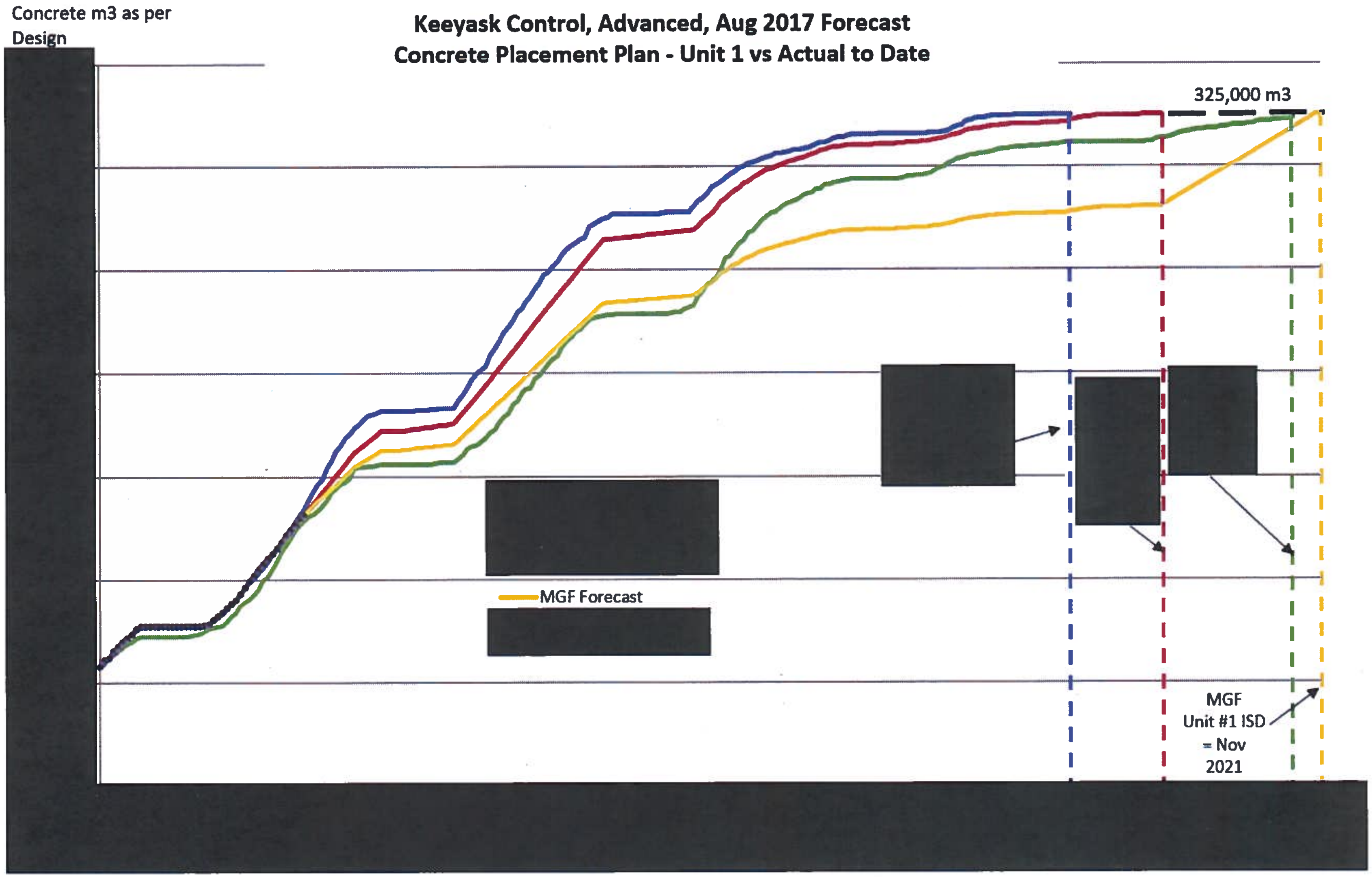
BBE is currently forecasting a completion date of 23rd January 2022 versus the planned completion date of 8th October 2021. Based on the September monthly progress figures, BBE has a concreting productivity factor of [redacted]

Assuming the [redacted] productivity factor remains constant, we have applied a [redacted] increase to the duration of each concreting activity, excluding completed work, work being performed by others and activities involving curing of concrete, to estimate the potential impact to the completion date. 1a

This results in a completion date of 25th November 2022, which is later than Manitoba Hydro's control date of 4th August 2022 for unit 7 to be in service.

It is important to note that no mitigation strategies or schedule recovery options have been added to this forecast. Therefore, the order of magnitude estimated delay is the difference between 8th October 2021 and 25th November 2022.

ORDER OF MAGNITUDE DELAY IS 410 DAYS (progress to 6th October 2017)


Concrete m3 as per Design
Keeyask Control, Advanced, Aug 2017 Forecast
Concrete Placement Plan - Unit 1 vs Actual to Date
325,000 m3
[redacted]
MGF Forecast
[redacted]
MGF
Unit #1 ISD
= Nov
2021

1a

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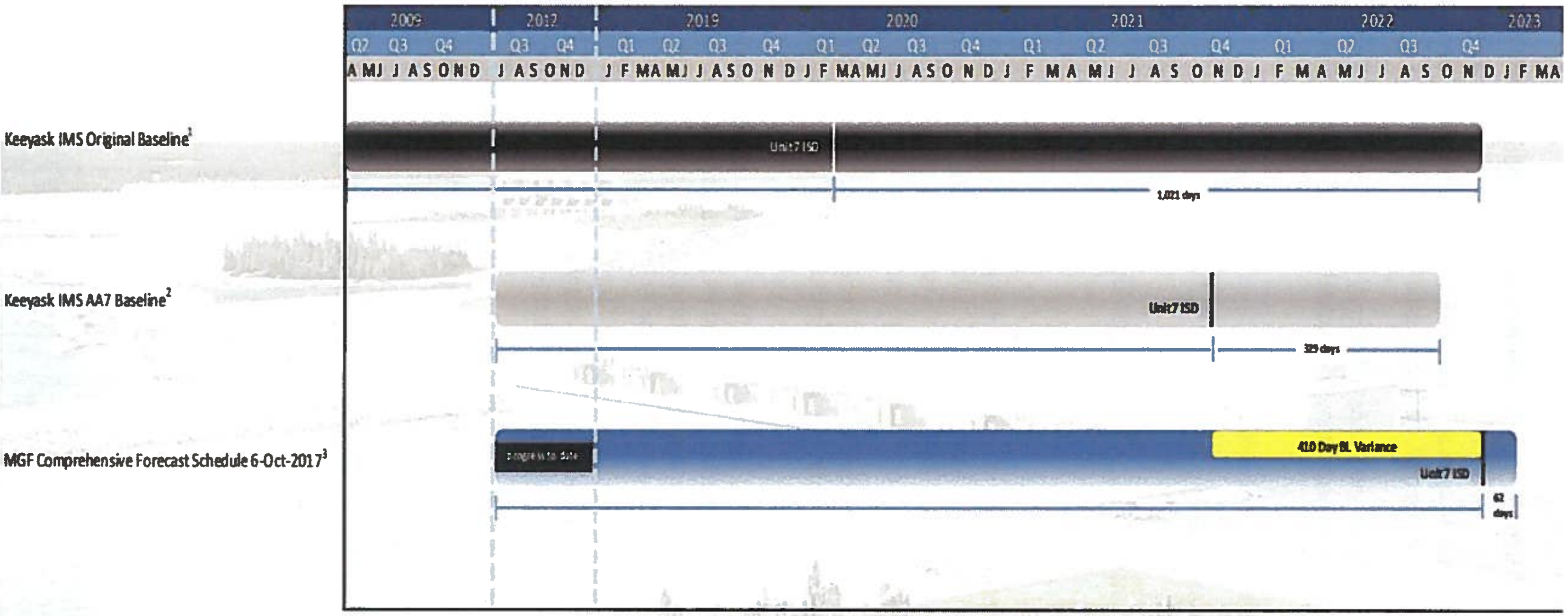
Keeyask Project Planned vs Forecast Dates Including Unit 7 In-Service Dates to Completion



1. **Keeyask IMS Original Baseline: The 1,021 days after Unit 7 In Service date reflects the completion of Generating Station Site Decommissioning and Rehabilitation which does not appear on the current schedule.**
2. **Keeyask IMS AA7 Baseline: The 329 days after Unit 7 In Service date reflects the completion of construction of Egress Channels downstream of spillway which was constrained to start on or after 1st July 2022, followed by an Ancestral Feast 2022 (Fall).**
3. **MGF Comprehensive Forecast Schedule: The 62 days after Unit 7 In Service date reflects the completion of construction of Egress Channels downstream of spillway but no constraint has been added. If this activity can only happen in the summer months, the completion date would be 1st September 2023.**

Conclusions & Recommendations

There are several factors which limit BBE's options to recover its schedule, such as environmental restrictions, weather, physical space and workforce accommodation. Two ways in which a schedule can be recovered are working longer hours or adding more resources. As productivity is an issue for BBE, neither of these strategies may produce the desired result as both will add cost and may further diminish the actual productivity.

A third way to recover the schedule is to change how the work is being executed. To recover the schedule BBE is proposing a winter concrete campaign which may help recover its schedule but this will add extra cost.

Source of Information & Reference Materials

- KGS-BBE Phase II Contract Schedule Rev 1 DD Cot 06 2017 (#013)

Finding No. 7: Keeyask - Integrated Master Schedule (IMS)

Observations & Findings

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

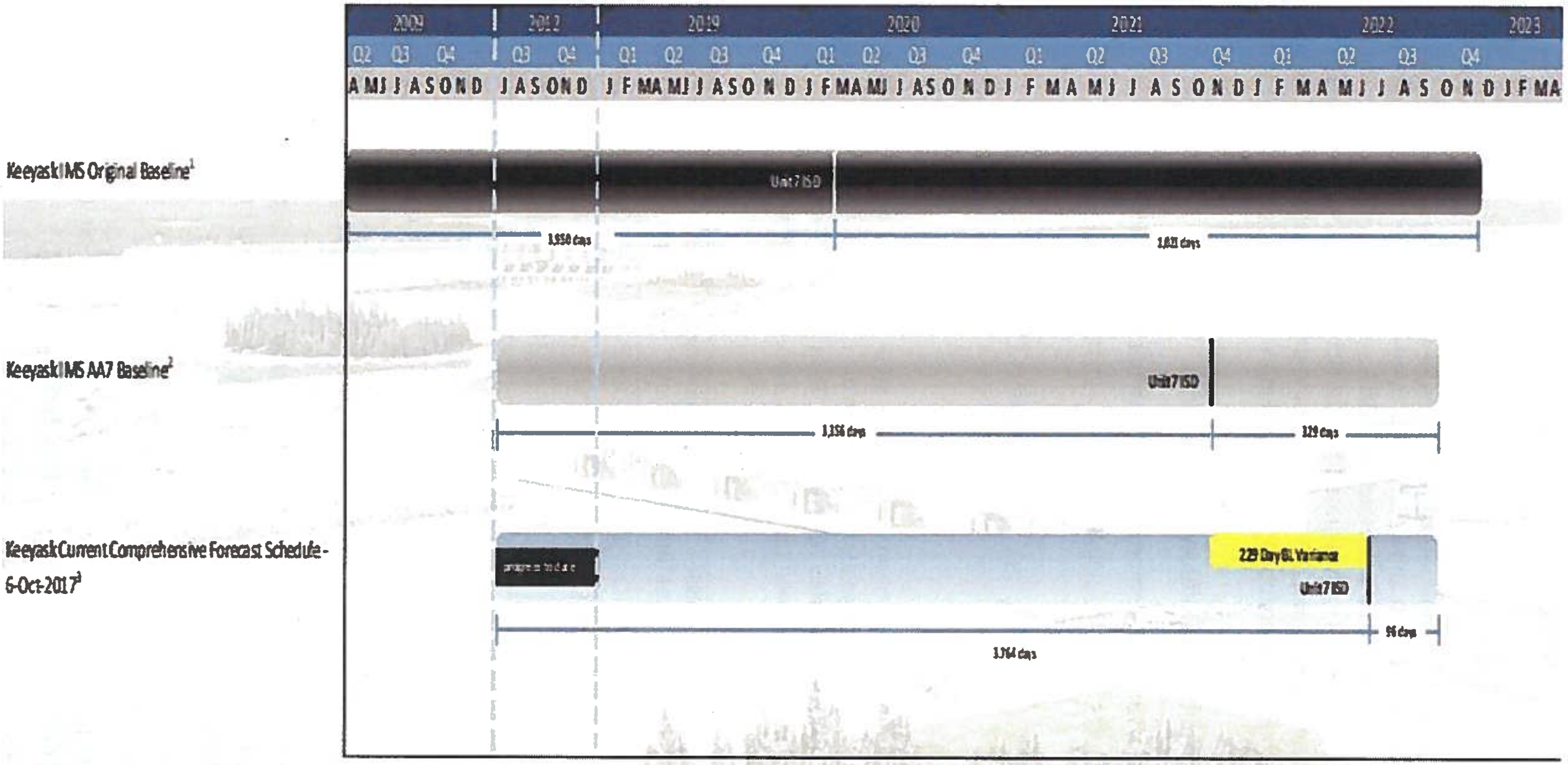
- Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The Keeyask Integrated Master Schedule forecast schedule scored 72%. The forecast schedule is rated as having a 72% probability of success.
- High float: Schedule paths with high amounts of float typically arise due to artificially constrained activities or much longer competing critical paths. This metric identifies activities with total float greater than 2 months and should not exceed 5%. The Integrated Master Schedule scored 77%. Schedule paths with float more than 2 months should be considered for acceleration and schedule optimization.

The review of the Integrated Master Schedule indicated that it did not show the latest General Civil Contract dates. We discussed this matter with Manitoba Hydro who concurred with our observation, correcting the dates and returning the revised schedule now correctly showing progress from all the contractors' schedules.

ORDER OF MAGNITUDE DELAY FOR UNIT 7 ISD 229 Days (progress to 6th October 2017)

MGF

Keeyask Project Planned vs Forecast Dates Including Unit 7 In-Service Dates to Completion



1. **Keeyask IMS Original Baseline: The 1,021 days after Unit 7 In Service date reflects the completion of Generating Station Site Decommissioning and Rehabilitation which does not appear on the current schedule.**
2. **Keeyask IMS AA7 Baseline: The 329 days after Unit 7 In Service date reflects the completion of construction of Egress Channels downstream of spillway which was constrained to start on or after 1st July 2022, followed by an Ancestral Feast 2022 (Fall).**
3. **Keeyask Current Comprehensive Forecast Schedule – 6th October 2017: The 96 days after Unit 7 In Service date reflects the completion of construction on the Egress Channels downstream of the spillways.**

Conclusions & Recommendations

With a Fuse score of 72%, MGF considers this schedule to be of medium quality. As with any Integrated Master Schedule, its quality in large part is directly related to the quality of the contractor schedules which are incorporated in to it. The Voith, Hatch and BBE schedules are imported directly in to this schedule and directly impact the score. The Integrated Master Schedule is showing slippage of 81 days on in service dates of turbine units 1 to 4 and 229 days on turbine units 5 to 7 as a result of slippage on the BBE schedule and the Voith schedule. Manitoba Hydro is working with both contractors to resolve the slippages.

Source of Information & Reference Materials

- Keeyask GS – IMS Comprehensive Schedule DD 171006.xer
- Keeyask GS – IMS Baseline Schedule – 20161008 - AA7.xer

Finding No. 8: Keeyask – Completion Dates

Observations & Findings

Dates: Multiple dates have been provided to MGF representing the same activities and completions. Outlined below are forecast and planned dates in the Integrated Master Schedule, the forecast and planned dates in the BBE schedule (also referred to as Target Date in some reporting), and the Manitoba Hydro Control Dates which are ten months later than the baseline dates.

	IMS Baseline	BBE Baseline (Target)	IMS Forecast	BBE Forecast	Control Date
Unit 1 In Service	17-Oct-20	17-Oct-20	29-Jan-21	29-Jan-21	14-Aug-21
Unit 2 In Service	16-Dec-20	16-Dec-20	30-Mar-21	30-Mar-21	13-Oct-21
Unit 3 In Service	14-Feb-21	14-Feb-21	29-May-21	29-May-21	12-Dec-21
Unit 4 In Service	15-Apr-21	15-Apr-21	28-Jul-21	28-Jul-21	10-Feb-22
Unit 5 In Service	14-Jun-21	14-Jun-21	2-Feb-22	26-Sep-21	11-Apr-22
Unit 6 In Service	13-Aug-21	13-Aug-21	3-Apr-22	25-Nov-21	10-Jun-22
Unit 7 In Service	7-Oct-21	7-Oct-21	28-May-22	23-Jan-22	4-Aug-22

Using the control dates, the in service dates are currently forecast to finish earlier than planned; however, using the baseline (contract dates), BBE is behind schedule and their delay has caused delays to the Voith in service dates for Generating Units 5 through 7.

Conclusions & Recommendations

To avoid confusion with the various dates, the significance of the different dates should be documented in the Basis of Schedule for the Integrated Master Schedule.

Source of Information & Reference Materials

- Email – Blair Purvis, Manitoba Hydro, dated 23rd November 2017
- KGS BBE Phase II Contract Schedule Rev 1 DD Oct 06 2017 (#13)

SCOPE ITEM 5:

Review and assess Manitoba Hydro's tender, contract management and cost control methodologies, and determine whether these methodologies support the $8.7 billion forecast at completion cost. If not, identify what changes in the contingencies, reserves or forecast at completion cost are required.

Finding No. 1: Keeyask - Tender Management

Observations & Findings

The key components of Tender Management are:

- Contracting Strategy
- Contractor Pre-qualification
- Individual Contract Plans
- Tender, Evaluate, Negotiate and Award

The review and assessment of Manitoba Hydro's Tender Management involved reviewing its documentation related to the key components above and testing the extent these were used on the following contracts:

- General Civil Contract – BBE
- Generators and Turbines – Voith
- Catering – Sodexo

Contracting Strategy

Standard # 103 Project Delivery Evaluation and Strategy dated 12th March 2015 was used in developing the contracting strategies for the above referenced contracts. The standard is sufficient, requiring the project team to consider or perform the following:

- Define key success factors
- Identify project drivers, e.g. schedule or cost
- Identify work packages, delivery options and contract types
- Screen possible work packages against key success factor and project drivers
- Create schedule for various project delivery strategy options
- Perform project risk analysis

- Determine preferred strategy and prepare board recommendation

No significant deficiencies were noted and no notable deviations were identified.

Prequalification

The purpose of prequalification is to ensure that owners have access to contractors with the capabilities, capacity and expertise to perform the required work and services. It is an important step to ensuring a successful project outcome.

Manitoba Hydro's prequalification procedure is available on its website and was used in prequalifying tenderers for both the General Civil Contract and the Generators and Turbines scopes. The Camp Services contract was pursuant to a Request for Information from a joint venture comprised of Sodexo and the Fox Lake and York Factory First Nations as a Direct Negotiated Contract in accordance with Schedule13-1 Identified Work Packages and Allocation.

The sample matrix to evaluate contractors for prequalification is comprehensive and addresses the following areas:

- Safety: safety program reviewed; WCB in good standing; overally safety record and number of accidents
- Experience: demonstrated construction experience on similar projects
- Availability: contractor available to perform the work within the desired timeframe
- Personnel: key contractor staff, including project manager, supervisors and office staff much have relevant experience of contract scope
- Track Record: contractor must have evidence of successful project completions on previous projects
- Qualification Statement: financial references given; principal projects listed
- Conflicts of Interest: conflict of interest forms completed
- Manitoba Content: contractor to maximize use of Manitoba labour (not used in prequalification but may be used in Tender Evaluation)
- Bonding: contractor eligible to bond for 50% of work or more than $500,000

The standard provides a Sample Evaluation Summary together with a Sample Scoring Guide to be used by evaluators to rank proposals.

A review of the prequalification practice produced no significant deficiencies or deviations from the corporate requirement.

Individual Contract Plans

The purpose of an Individual Contract Plan is to outline the key components required for a successful contract formation process and eventual post award contract management. For each work package or tender, this typically requires decisions on the following matters to allow the contract formation process to be successfully progressed:

- Scope of Work
- Estimated contract value
- Form of contract
- Compensation mechanism
- Approach to market (competitive tender or direct negotiation)
- Pre-qualified bidders
- Schedule milestones e.g. prepare tender, issue, evaluate, award, commence work, completion date.
- Evaluation plan

Manitoba Hydro addressed these matters in the following documents:

- Standard #206 Design Development and Procurement Document Preparation
- Standard #302 Develop Work Package Procurement Plan
- Standard #105 Developing the Work Breakdown Structure (WBS)
- Standard #103 Project Delivery System Evaluation and Strategy
- Standard #104 Work Package Charter Development
- Standard #402 Project Quality Plan
- ENV-003 Contractor Environmental Protection Plan

Standard #104 Work Package Charter Development was structured to reflect the chosen contracting type:

- Cost reimbursable contract – General Civil Work
- Fixed price contract – Generators and Turbines
- Direct negotiated contract – Catering Services

No significant deficiencies were noted and no notable deviations were identified.

Tender, Evaluate, Negotiate and Award

Standard #303 Tender, Evaluate, Negotiate and Award dated 12th July 2013 provides guidance and standardization on how contracts on the Keeyask Project are to be tendered, evaluated, negotiated and awarded. It sets out the necessary steps to conduct a bid process, evaluate bids received from tenderers, select a successful tenderer/proponent, negotiate a contract and award a purchase order.

The standard encompasses the following related documentation:

- Corporate Policy P1-6 Purchase Approvals
- Standard #206 Design Development and Procurement Document Preparation

- Standard #305 Changes to Procurement Documents
- Standard #801 Project Change Authorization
- KCP-001 Executive Approval Preparation
- PAS-001 Contract Change Management
- PAS-006 Consulting Purchase Order
- PLS-001 Project TEBO Strategy Development
- Partnership Agreements
- eform 0136 Purchase Recommendation & Authorization
- DOC-F-008 Project Change Authorization Form
- DOC-F-010 Notice of Contract Award
- F-301 Procurement Checklist

Standard #303 sets out its Tender, Evaluate, Negotiate and Award process as follows:

- Prepare Purchase Requisition (PR) and Obtain Approvals
- Prepare Procurement Documents and Issue
- Obtain Bids
- Evaluate Bids
- Obtain Approvals
- Negotiate (if applicable)
- Prepare Contract Binders
- Award

The Tender, Evaluate Negotiate and Award process was followed for the three referenced contracts and appears comprehensive. No significant deficiencies were noted and no notable deviations were identified.

Conclusions & Recommendations

The standards, procedures and processes supporting Contracting Strategy, Contractor Prequalification, Individual Contract Plans and Tender, Evaluate, Negotiate and Award are sufficient and well documents.

Source of Information & Reference Materials

- Manitoba Hydro Tender Management Documentation referenced in the Observations & Findings section

MGF PROJECT SERVICES

Finding No. 2: Keeyask - Contract Management

Observations & Findings

Standard #505 Contract and Work Package Management dated 29th June 2015 addresses work package management during the execution phases of a contract and outlines the requirement of the Work Package Lead (WPL) to manage the work package and associated contracts. The standard encompasses the following related documentation:

- Standard #204 Quality Management
- Standard #801 Project Change Authorization
- DOC-002 Naming, Filing and Format Conventions
- PSD-001 Lessons Learned
- PCC-002 Construction Contract Monitoring and Controls
- PAS-001 Contract Change Management
- DOC-F-009 Project Change Authorization Info-path form

Standard #505 describes the responsibilities of the Work Package Lead, the Engineer and the Purchaser who work together to manage the work packages and contracts. It also describes their roles in relation to the following major aspects of contract management:

- Scope Management
- Schedule Management
- Cost Management
- Payment and Accruals
- Purchase Order Maintenance
- Quality Management
- Document Management
- Communication Plan
- Resource Management
- Reporting Requirements
- Lessons Learned

It is industry best practice to perform contract audits to ensure the parties to the contract are complying with them. In our review, we only found one instance of a contract audit being performed, which we consider to be too low and infrequent for the number of contracts on Keeyask.

Conclusions & Recommendations

The Contract Management process appears comprehensive in terms of the standards to guide Manitoba Hydro in managing contracts. Manitoba Hydro should consider having periodic contract management audits to ensure Manitoba Hydro and their contractors are complying with their respective contracts.

MGF PROJECT SERVICES

Source of Information & Reference Materials

- Manitoba Hydro Contract Management Documentation referenced in the Observations & Findings section

Finding No. 3: Keeyask - Extra Work Orders (EWOs) – Indirects

Observations & Findings

MGF has reviewed the indirect percentage applied to Extra Work Orders.

MGF has reviewed extra work orders for the BBE contract and has observed that [redacted] is used for indirects. This figure is considerably less than the actual percentage for indirects. 1a

A low indirect percentage will underestimate the projected cost to complete.

Conclusions & Recommendations

Manitoba Hydro should use indirects that reflect actuals.

Source of Information & Reference Materials

- Manitoba Hydro-000172, Manitoba Hydro-000211 rev 02, Manitoba Hydro-000247, Manitoba Hydro-000225

Finding No. 4: Keeyask - Cost Performance Index (Earned Value)

Observations and Findings

The Cost Performance Index (CPI) specifies how much you are earning for each dollar spent on the project. The Cost Performance Index is an indication of how well the project is remaining on budget.

If the CPI is less than one, you are earning less than the amount spent. In other words, you are over budget.

If the CPI is greater than one, you are earning more than the amount spent. In other words, you are under budget.

If the CPI is equal to one, this means earning and spending are equal.

Overall CPI (which is determined by dividing earned value by actual cost) for the Keeyask Project is 0.96, as per September 2017 Project Management Report. "It is near 1 because budgets were re-set in the Capital Project Justification Addendum".

The CPI index for the cost incurred prior to 8th October 2016 was set to 1 rather than actual to date.

Conclusions & Recommendations

This results in inflating the CPI for the overall Keeyask project and does not reflect the actual, thereby giving a false view of performance. Manitoba Hydro should consider tracking the CPI from either the Amending Agreement No. 7 or project commencement, to give a more realistic figure.

Source of Information & Reference Materials

- Manitoba Hydro Monthly Project Management Report September 2017

Finding No. 5: Keeyask - Interest Earned on Advance Funding

Observations & Findings

BBE, as per its contract, is paid 2 months in advance since the start of the project, BBE were not requested to pass the interest on the advance monies to Manitoba Hydro.

This type of funding mechanism is not typical.

We have been advised by Manitoba Hydro that they have identified the issue and are in the process of recouping the interest monies.

Total cost is a follows:

Order of Magnitude Estimate $1,400,000

Notes:

- The costs are from project commencement to October 2017.

Conclusions & Recommendations

This issue is in the process of being rectified.

Source of Information & Reference Materials

- Meeting with Manitoba Hydro 28th September 2017
- BBE Contract

Finding No. 6: Keeyask - General Administration and Overhead (GA&O) on Procurement

Observations & Findings

BBE procurement personnel are reimbursed for time spent on purchasing equipment, tools and materials for the Keeyask project on behalf of Manitoba Hydro. In addition, BBE also includes [redacted] for GA&O for the cost of purchased equipment. 1a

This finding addresses the Construction Equipment and Construction Material/Tools categories.

Manitoba Hydro may wish to carry out this activity with their own personnel so as to save paying for GA&O

Order of Magnitude Estimate $65,500,000

Notes:

- The costs are based on project commencement to completion
- The above estimate excludes BBE's procurement personnel

Conclusions & Recommendations

If Manitoba Hydro processes future purchases internally, this will result in a reduction in GA&O.

The risk is, if materials are purchased late, it may give rise to BBE claiming delays.

However, MGF does not see the same level of risk with equipment purchases. A turnaround timeframe would need to be agreed upon.

Source of Information & Reference Materials

- October 2016 and June 2017 BBE Progress Statement
- To date costs for Non-Labour category provided by Manitoba Hydro up to July 2017

MGF PROJECT SERVICES

Finding No. 7: Keeyask - Craft to Foreman Ratio

Observations & Findings

On reviewing BBE's October 2017 Construction Monthly Report, the ratio of Craft to Foreman is 3.97:1. This appears to be high.

Page 19 of the report states "Ratios of Workers" (apprentices, journeymen and lead hands) to foremen are used to evaluate:

- whether there is sufficient supervision to support the work; and,
- the impact on wage rate if supervision counts are too high.

Typical ratios for similar construction projects have higher craft to supervision ratios. MGF has allowed for a craft to foreman ratio of 6:1. This ratio is applied to the total project direct hours to determine the variance in supervision hours. An average blended labour rate for foreman is used to determine the extra cost.

Ratio of 6:1 versus actual Ratio of 3.97:1

Applying these ratios to the total 7,078,000 direct labour hours will result in a 603,205 hours' variance at a rate of $ 76.32, which will result in:

Order of Magnitude Estimate $91,600,000

Note the above figures include [redacted] for GA&O and Indirect costs. 1a

Conclusions & Recommendations

Manitoba Hydro to review Craft Foreman mixes with the goal of improving the ratios.

Source of Information & Reference Materials

- BBE October 2017 Monthly Cost Report No 7 Rev 0
- 2006 AACE Construction Productivity Article by James D. Whiteside

MGF PROJECT SERVICES

Finding No. 8: Keeyask - Trade & Cash Discounts

Observations & Findings

On reviewing BBE's Progress Payments relating to Construction Equipment and Construction Materials/Tools categories for October 2016 and June 2017, it was noted that Trade Discounts were negligible.

No cash (prompt payment) discounts were identified.

Trade Discount

If we take an average 10% as an example that BBE could achieve with the suppliers, this would represent Trade Discounts **to date** in the sum of:

Order of Magnitude Estimate $ 54,000,000

If we take an average 10% as an example that BBE could achieve with the suppliers, this would represent Trade Discounts **to completion** in the sum of:

Order of Magnitude Estimate $ 61,800,000

Total Overall Trade Discount:

Order of Magnitude Estimate $ 115,800,000

Cash Discount

If we take an average 2% as an example that BBE could achieve with the suppliers, this would represent Cash Discounts **to date** in the sum of:

Order of Magnitude Estimate $ 10,800,000

If we take an average 2% as an example that BBE could achieve with the suppliers, this would represent Cash Discounts **to completion** in the sum of:

Order of Magnitude Estimate $ 12,400,000

Total Overall Cash Discount:

Order of Magnitude Estimate $ 23,200,000

Conclusions & Recommendations

Manitoba Hydro to ensure all Contractors are negotiating Trade Discounts.

Also as BBE is receiving Progress Payments 2 months in advance all Cash Discounts should be passed to Manitoba Hydro.

Source of Information & Reference Materials

- Progress Payment Applications - October 2016 and June 2017
- BBE Projected Cash Flow

Finding No. 9: Keeyask - Increased use of Overtime and Double Time

Observations & Findings

The CPJ 2017 Addendum, Appendix 1 "Basis, Assumptions and Exclusions", Section 2 sets out that the construction work week will be 7 days per week, 10 hours per shift, with labour on a 21 day on and 7 day off rotation and assumed that standard time (ST), overtime (OT) and double time (DT) would be 63%, 23% and 14% respectively.

From analysis of the progress payments of October 2016, May 2017 and June 2017, the actual split is 54% standard time (ST), 22% overtime (OT) and 24% double time (DT).

From the above referenced progress payments, we have calculated a weighted average blended rate per hour of $61.70 and a [redacted] ratio to direct cost to allow for indirect costs. 1a

Assuming 5,552,196 hours from 7th October 2016 to the end of the contract, then excluding indirects, with the actual mix of ST, OT and DT, this results in:

Additional Cost Order of Magnitude $ 20,900,000

As DT is never 100% efficient, if and we assume a 30% loss in productivity for illustration purposes, then the increase in labour costs based on 5,552,196 hours, including indirects, rises to:

Additional Cost Order of Magnitude $ 40,900,000

MGF PROJECT SERVICES

Conclusions & Recommendations

The concern is that with a different mix of ST, OT and DT, the cost of labour will continue to rise, potentially resulting in a higher cost for the BBE Contract.

Manitoba Hydro should carry out an exercise on the cost of additional camp versus additional labour costs.

Sources of Information & Reference Materials

- BBE Monthly Progress Statement for October 2016, May 2017 and June 2017.
- CPJ 2017 Addendum, Appendix 1 "Basis, Assumptions and Exclusions", Section 2
- Burntwood Nelson Agreement analysis by Manitoba Hydro for craft rates for ST, OT and DT

Finding No. 10: Keeyask - BBE Indirect Costs

Observations & Findings

On reviewing BBE's September 2017 Construction Monthly Report for Indirect Costs to date, there is a cost difference of 6.4%. The cost overrun is determined by the variance between actual spend to date of 30.4% compared to actual physical progress of 24%.

Currently, the indirect budget is [redacted] 1a

If the cost overrun trend continues, the potential cost impact is:

Order of Magnitude Estimate [redacted] 1a

Notes:

- The above figure includes [redacted] for GA&O.
- We have used the physical percentage complete from direct progress. 1a

Conclusions & Recommendations

Manitoba Hydro to review and implement cost reductions on BBE's Indirect costs.

Source of Information & Reference Materials

- BBE September 2017 Monthly Cost Report No 6 Rev 1

MGF PROJECT SERVICES

Finding No. 11: Keeyask - Transmission

Observations & Findings

This scope of work and costs are managed by Manitoba Hydro's Transmission Group.

Manitoba Hydro has noted variations in estimates due to:

- Increase of $21 million for 138 kV Generation Outlet Transmission (GOT) Lines
- Increase of $3 million for Terminations at Radisson
- Increase of $14 million for 138 kV Unit Lines

Conclusions & Recommendations

MGF recommends that Manitoba Hydro assigns a single owner of Cost Estimating and Scheduling. This will ensure no scopes of work are missed or overlapping, promote consistency in the development and appoint a custodian for all estimate back-up, methodologies and history.

This ensures that clear accountability is assigned and would align Manitoba Hydro's approach with industry best practice.

Source of Information & Reference Materials

- Map to Comparison of Keeyask 2014 to 2017.xlsx
- Keeyask Generating Station, 2017 Capital Project Justification Addendum, Comparison of 2014 Estimate to 2017 Estimate, dated August 2017

Finding No. 12: Keeyask - Board Recommendation

Observations & Findings

The Board Recommendation records the decision to approve a contract to the BBE joint venture for the General Civil Works "at a price not to exceed [redacted] billion excluding taxes and escalation." Please note the following: 1a

- Reference is made to Bechtel being "an experienced contractor", having been involved in the "construction of the civil works for the Limestone Generating Station". The Limestone Generating Station was completed in 1992 and involved 650,000 cubic metres of concrete and 7,100,000 cubic metres of earthwork; compared to the Keeyask Generating Station that was to commence work 22 years later in 2014 involving 350,000 cubic metres of concrete and 12,400,000 cubic metres of earthworks.

  What Bechtel did 22 years ago is only remotely relevant if its Limestone Generating Station construction management and supervision team was to be used on Keeyask.

  Note: We were advised by Manitoba Hydro that Bechtel were self-performing Contractor's on Limestone and this predicated their decision to appoint BBE, however was the question asked, what was Bechtel's history self-performing contracts in North America since Limestone.

- It is stated that BBE are "…the lowest cost and offer best value to the project". This is not strictly correct as BBE and the other proponents did not offer the "cost", but their assessment of an "Initial Target Price" that would equate to the total of all Actual Costs to be paid by Manitoba Hydro.
- The Board Recommendation further identifies the risk of concrete productivity, stating "[redacted] There is no further commentary on why this primary difference is not a high risk in the recommendation to award to BBE which is of concern. In addition, no mention of this risk is made or accounted for in the Contingency for Manitoba Hydro Held Risks' section of the Total Purchase Order Upset Limit calculation. 1a

Conclusions & Recommendations

The above raises concerns on whether the risks inherent in the contracting strategy, e.g. a cost reimbursable compensation mechanism and potentially too aggressive concreting productivity factors were fully understood by Manitoba Hydro and how it would set up the contract to manage and mitigate such risks with their chosen contractor.

Source of Information & Reference Materials

- Board Recommendation dated 26th February 2014

Finding No. 13: Keeyask - Estimated Final Cost Range

Observations & Findings

Based on our findings in this Capital Review, in our opinion the Final Cost for the Keeyask project will not meet the budget of $8.7 billon, but rather be in the range of:

Order of Magnitude Estimate Range $ 9.5 billion to 10.5 billon

This Order of Magnitude Range addresses the current status and issues related to:

- Productivity
- Schedule
- Costs
- Indirects
- Craft to Foremen ratios
- Other related matters

It is difficult for MGF to advise where the Final Cost will land in this range, given the Productivity and Schedule performance of BBE and the fact the GCC Contract is Cost Reimbursable. However, we would advise:

1. If Manitoba Hydro addresses the current issues, taking control of the Project and its Contractors, the Final Cost will be at the lower end of the range
2. Keeping the status quo and leaving control with the Contractors will result in a Final Cost at the upper end of the range

Conclusions & Recommendations

These are many cost saving and contract management exercises that Manitoba Hydro can implement, which will drive down the Final Cost.

Our recommendation is to do this without delay.

Source of Information & Reference Materials

- This report and its findings

SCOPE ITEM 6:

Review and assess Manitoba Hydro's and the Keeyask Cree Nations' project governance structure and processes comparing to best practices and shortcomings. Provide an opinion how the governance has affected – both positively and negatively – project management, contractor management, and scheduling.

Finding No. 1: Keeyask - Joint Keeyask Development Agreement

Observations & Findings

Overview

The purpose of the Joint Keeyask Development Agreement ("JKDA") is to establish the Keeyask Hydropower Limited Partnership ("KHLP") comprised of:

- Cree Nations Partners
- York Factory First Nation
- Fox Lake Cree Nation
- The Manitoba Hydro-Electric Board

to complete the planning and design of the Keeyask Generating Station and all related works (the "Keeyask Project") and to carry on the business and affairs of the KHLP, including "...the design and the ownership, construction, operation, maintenance and control of the Keeyask Project".

Section 2.6 "Employment, Training and Business Opportunities" sets out opportunities for members of the Keeyask Cree Nations ("KCN") with respect to:

- Pre-project training
- Construction employment
- Operational job
- Business opportunities during construction

The following articles set out how the KHLP will be established and financed; how the Keeyask Project will be developed and constructed; sets out the services Hydro will perform together with the arrangements for Power Purchase and Transmission:

- Article 4: The Limited Partnership and the General Partner
- Article 5: Financing the Limited Partnership
- Article 6: Project Development
- Article 7: Description of the Keeyask Project
- Article 8: Construction of the Project
- Article 9: Hydro Services
- Article 10: Power Purchase and Transmission Arrangements.

Construction Agreement

Schedule 1-2 "Construction Agreement" is part of the Joint Keeyask Development Agreement. The Construction Agreement identifies the "Owner" as the Limited Partnership and Hydro as the "Project Manager" to carry out the Scope of Work of the Keeyask Project, comprised of:

1. All required planning, engineering and designing
2. The Purchase of Insurance
3. Award of the contracts for construction
4. Commissioning of each of the turbines / generators and associated works to be supplied and installed
5. Procurement, award and administration of related contracts including Identified Work Packages
6. De-commissioning of camps and the clean-up of the construction site

Article 2 "Schedule for Construction" stipulates that:

1. The Project Manager ("Hydro") shall commence the Scope of Work on the date specified by the Owner (the Limited Partnership)
2. The Project Manager shall develop detailed schedules with construction contracts, manufacturers and suppliers to construct, supply, install or commission specific parts of the Scope of Work
3. Parties agree to use their respective best efforts to complete the Scope of Work in approximately eight (8) years from the start of construction

Article 3 "Project Manager Responsibilities" sets out the responsibilities of the Project Manager as follows:

1. Solely responsible for the planning, designing, engineering and procurement to complete the Scope of Work
2. Responsible for obtaining and maintaining throughout the term of the Construction Agreement, all required licences, permits, orders, authorizations and approvals

3. Allocation and negotiation of Identified Work Packages
4. Supply of construction power
5. Supervise, control and direct all aspects of the Scope of Work
6. Provide timely updates of costs to the Owner and Owner shall use these updates to forecast and arrange the necessary funds to meet its cash flow requirements
7. Inform Owner of any material changes to the plan, design, engineering or actual costs to complete
8. Prepare and provide written monthly reports
9. Conduct all testing to complete the satisfactory installation and commissioning of each turbine/generator and related equipment
10. Ensure that all product, equipment and material warranties for components of the Keeyask Generating Station shall be assigned by contractors to the Owner upon the Final Completion Date

Article 4 "Invoices" requires the Project Manager to prepare and submit invoices to Owner for costs incurred in carrying out the Scope of Work. The Owner shall pay these invoices within ten (10) Business Days.

Construction Advisory Committee

Schedule 4-6 sets out the terms of reference of the Construction Advisory Committee (the "CAC"). The CAC is an advisory committee to KHLP and has no decision-making authority. It is intended to be a communication forum to discuss timely, accurate and pertinent information related to the Keeyask Project construction activities.

The CAC is comprised of five (5) Keeyask Cree Nations' Members, two (2) for TCN and one (1) each for War Lake, York Factory and Fox Lake and two (2) Hydro employees.

The purposes of the CAC and CAC meetings are summarized as follows:

- Provision of non-privileged information related to the Keeyask Project
- Discussion of major activities and events planned for or occurring during construction e.g. updates on engineering activities; contracts planned and awarded to date; project schedule status and reports on current and upcoming cultural events

Following the Construction Start Date, the CAC will meet monthly until the Final Closing Date, which is the first Business Day, one hundred and eighty (180) days following the date on which the last of the turbines comprising the Keeyask Generating Station is fully commissioned and comes in to service.

Monitoring Advisory Committee

Schedule 4-7 sets out the terms of reference of the Monitoring Advisory Committee (the "MAC"). Like the CAC, the MAC is an advisory committee to KHLP and has no decision-making authority. The MAC is comprised of five (5) Keeyask Cree Nations' Members, two (2) for TCN and one (1) each for War Lake, York Factory and Fox Lake and five (5) Hydro employees.

The purpose of the MAC and MAC meetings is summarized as follows:

- Discuss the environmental, social and economic monitoring activities planned to occur during construction, commissioning, operations and decommissioning of the Keeyask Project
- Review and comment on regulatory and public reporting materials

Proposed Letter of Agreement, Burntwood/Nelson Agreement

Schedule 12-3 entitled "Proposed Letter of Agreement, Burntwood/Nelson Agreement" of the Joint Keeyask Development Agreement is between Hydro Projects Management Association and Allied Hydro Council of Manitoba. Schedule 12-3 requires that special measures need to be implemented during construction to facilitate the employment, training and retention of First Nations members and other Northern Aboriginals, which measures might conflict with existing Burntwood/Nelson Agreement (BNA) provisions relating to referral, recruitment or placement procedures.

The Limited Partnership has recognized the importance of successful recruitment, referral, placement, training and retention of Aboriginal employees on the Project and that Aboriginal cultural issues are addressed at all stages of the recruitment, referral, placement, training and retention process.

Schedule 12-3 amends the Burntwood/Nelson Agreement (BNA) as follows:

1. The Hydro Projects Management Association's membership will include the Limited Partnership
2. KCN shall appoint two representatives from their communities to the Project Site as advisors to the resident Site Manager
3. An Aboriginal union representative shall be hired to facilitate union interaction with Aboriginal employees, assist Aboriginal employees in matters related to discipline, liaise with the HR departments of major contractors and the Project's third-party retention service providers
4. The parties agree that no person covered by the BNA shall be subject to discrimination or harassment on the basis of any characteristics referred to in subsection 9(2) of the Human Rights Code of the Province of Manitoba and sets out the procedure to be followed regarding claims of discrimination or harassment
5. Sets out the goal to maximize the number of Aboriginal apprentices and trainees and encourages member unions to approach and recruit Aboriginal apprentices, trainees and journey persons.
6. Union site representatives will be required to take appropriate cross-cultural sensitivity and awareness training

Identified Work Packages and Allocation

Schedule 13-1 "Identified Work Packages and Allocation" of the Joint Keeyask Development Agreement details the following types of contracts:

1. Service Contracts
2. Infrastructure Contracts – Camps
3. Infrastructure Contracts – Roads
4. Principal Structures Contracts
5. Principal Structures Contracts (Schedule and Cost Critical)

All contract scopes include the supply of all supervision, administration, labour, mobilization/demobilization, materials, plant, tools, equipment, transportation, insurance and warranty of workmanship and materials. Each contract has been allocated to either the Cree Nations Partners, York Factory First Nation or the Fox Lake Cree Nation. As of 31st October 2017, the aggregate spend to date on these contracts is in excess of [redacted], as advised by Manitoba Hydro.

Conclusions & Recommendations

The JKDA and its associated Schedules provide an appropriate structure for the Keeyask Project:

- The JKDA establishes the Keeyask Hydropower Limited Partnership (KHLP) to carry on the business and affairs e.g. ownership, financing, construction, operation, maintenance and control of the Keeyask Project
- Section 2.6 "Employment, Training and Business Opportunities" sets out opportunities for members of the Keeyask Cree Nation
- Schedule 1-2 Construction Agreement defines the Scope of Work of the Keeyask Project, the Schedule for Construction and the responsibilities of the Project Manager
- Schedule 12-3 Proposed Letter of Agreement, Burntwood/Nelson Agreement addresses special measures to be implemented during construction to facilitate the employment, training and retention of First Nations members and other Northern Aboriginals
- Schedule 13-1 Identified Work Packages and Allocation - sets out the Contract Scopes to be directly negotiated with and performed by the Keeyask Cree Nations.

The Joint Keeyask Development Agreement embraces and implements the ownership and participation in the Keeyask Project with Manitoba Hydro. The JKDA itself does not directly impact Project Management, Construction Management and Scheduling. However, the appointment of Manitoba Hydro as the Project Manager does place the responsibility for Project Management, Construction Management and Scheduling on Manitoba Hydro.

Source of Information & Reference Materials

- The Joint Keeyask Development Agreement (JKDA).
- JKDA Schedule 1-2 Construction Agreement.
- JKDA Schedule 4-6 Construction Advisory Committee.
- JKDA Schedule 4-7 Monitoring Advisory Committee.
- JKDA Schedule 12-3 Proposed Letter of Agreement, Burntwood/Nelson Agreement.
- JKDA Schedule 13-1 Identified Work Packages and Allocation

MGF PROJECT SERVICES

SCOPE ITEM 7:

Assess Manitoba Hydro's updated Keeyask cost estimate for reasonableness, including whether appropriate contingencies and reserves have been provisioned.

Finding No. 1: Keeyask - Cost Contingency

Observations & Findings

In the Keeyask Generating Station Basis of Estimate Document 2017 Capital Project Justification Addendum, 14.0 Risk, Contingency on pages 4 and 5 it states "The contingency that was incorporated into the CPJ Addendum estimate was based on a P50 confidence level. Also, an additional 10 months of schedule contingency was added to the estimates, resulting in a total schedule delay of 21 months to the first unit In-Service Date".

In Appendix O - Contingency of Keeyask Generating Station Project Capital Cost and Schedule Risk Analysis and Contingency Estimates FINAL for Manitoba-Hydro dated 7th March 2017, contingency at the P90 confidence level is [redacted] as per Manitoba Hydro's presentation to MGF on 25th July 2017. 4b

Conclusions & Recommendations

BBE has not made its planned progress for either 2016 or 2017 and continues to plan work based on productivities it does not appear capable of achieving, hence MGF would recommend that Manitoba Hydro carry the P90 figure of [redacted] 4b

Source of Information & Reference Materials

- Keeyask Contract Summary as at 30th September 2017
- Keeyask Generating Station Basis of Estimate Document 2017 Capital Project Justification Addendum
- Appendix O – Contingency of Keeyask Generating Station Project Capital Cost and Schedule Risk Analysis and Contingency Estimates FINAL for Manitoba Hydro 7th March 2017 by Validation Estimating LLC.

MGF PROJECT SERVICES

SCOPE ITEM 8:

Identify aspects of the updated cost estimate and schedule that are at heightened levels of risk and recommend risk mitigation strategies that Manitoba Hydro should use.

Finding No. 1: Keeyask - Concrete Quantity Reporting

Observations & Findings

The concrete quantity in BBE's September 2017 Monthly Cost Report 06 Rev.0 is reported in three different places, each time with a different value.

On page 31:

- Total concrete to be placed is 278,962 cubic metres
- Installed concrete is nearly 100,000 cubic metres complete
- Concrete quantity to be installed is 278,962 - 100,000 = 178,962 cubic metres

On page 211:

- Total concrete to be placed is 341,480 cubic metres
- Installed concrete is 158,121 cubic metres complete
- Concrete quantity to be installed is 341,480 - 158,121 = 183,359 cubic metres

On page 264:

- Total concrete to be placed is 269,027 cubic metres
- Installed concrete is 81,213 cubic metres complete
- Concrete quantity to be installed is 269,027 - 81,213 = 187,814 cubic metres

Conclusions & Recommendations

Cost reports should be accurate as they are an important project controls tool. The estimates of total concrete to be placed have a range of 72,453 cubic metres (341,480 – 269,027) and the installed concrete estimates have a range of 76,908 cubic metres (158,121 – 81,213). Manitoba Hydro should not accept such inconsistent, inaccurate and unreliable reporting and should request BBE to review and revise with correct figures and improve their reporting going forward.

Source of Information & Reference Materials

- BBE September 2017 Monthly Cost Report 06 Rev. 0

MGF PROJECT SERVICES

Finding No. 2: Keeyask - Earthworks Total Fill

Observations & Findings

The document "Control, Advanced, Aug 2017 Forecast Earthworks Total Fill Placement Plan vs Actual to Date (Permanent Structures – Dams & Dykes)" was reviewed to determine if the completion dates depicted were achievable.

As per the October 2017 QURR and the BOQ-Rev 2 Monthly Report, the quantity of fill remaining is 5,874,585 cubic metres and the average fill placement for July and August 2017 was 237,216 cubic metres.

To meet the August 2021 completion date monthly production must be 244,774 cubic metres. This is an increase of 7,558 cubic metres or 3.2% per month over the 2017 July and August average of 237,216 cubic metres. This can likely be achieved by working longer shifts (less productivity) during the summer months to take advantage of the longer daylight hours or deploying more manpower if the camp can accommodate additional personnel.

To meet the February 2021 completion date monthly production would also have to be 244,774 cubic metres. This is an increase of 7,558 cubic metres or 3.2% per month over the 2017 July and August average of 237,216 cubic metres. This would include four (4) months of winter placement from October 2020 to February 2021 with fewer daylight hours and the potential for severe winter conditions. In view of the winter work, this schedule will likely be difficult to meet.

To meet the October 2020 completion date monthly production must be 293,729 cubic metres. This is an increase of 56,515 cubic metres or 23.8% per month over the 2017 July and August average of 237,216 cubic metres. Operating a double shift might make this monthly production possible, but camp space could be a constraint. This schedule does not appear to be achievable.

Other considerations that might preclude the required monthly production being achieved are:

1. Production is dramatically reduced for the initial lifts covering bedrock and invert.
2. Production is dramatically reduced nearing the crest elevation as the zones become very narrow as the rate of spread and compaction governs production.
3. Potential for heavy rains and/or impact from snowmelt and high water levels in local creeks, ponds, etc.

Conclusions & Recommendations

Manitoba Hydro should work with BBE to examine the basis of these proposed completion dates to test them for realism and achievability. The August 2021 completion date appears achievable with extra effort. The completion dates of October 2020 and February 2021 appear unlikely to be achieved.

Source of Information & Reference Materials

- Control, Advanced, Aug 2017 Forecast Earthworks Total Fill Placement Plan vs Actual to Date (Permanent Structures – Dams & Dykes)
- October 2017 QURR and BOQ-Rev 2 Monthly Report

MGF PROJECT SERVICES

SCOPE ITEM 9:

Identify changes to project governance or project management that would beneficially improve the execution of the remaining work and minimize risks.

Finding No. 1: Keeyask - Structural Steel Progress

Observations & Findings

The review of the Weekly Construction Report - week ending 6th October 2017 revealed the following weekly period and year to date performance:

The following table analyzes planned and actual structural steel quantities and hours spent installing structural steel for the period:

Period	Unit of Measure	Plan	Actual
Installed Quantity	Kilograms	132,472	78,124
Job Hours	Hours	[redacted]	[redacted]
		[redacted]	[redacted]

1a

The installed quantity in the period is 54,348 kgs or [redacted] less than planned, although actual productivity was [redacted] per man hour better than planned.

The following table analyzes planned and actual structural steel quantities and hours spent in installing structural steel year to date:

Year to Date	Unit of Measure	Plan	Actual
Installed Quantity	Kilograms	506,636	292,163
Job Hours	Hours	[redacted]	[redacted]
		[redacted]	[redacted]

1a

Year to date, BBE installed 214,473 kgs or [redacted] less structural steel than planned and its average productivity is [redacted] per man hour less than planned.

12073

Conclusions & Recommendations

BBE failed to meet its schedule in 2016 and continues to do the same in 2017, even after the Amending Agreement No. 7 and renegotiation of target price and schedule. The analysis raises serious concerns with BBE's optimistic productivity rates, its ability to plan construction activities and to coordinate and supervise its construction workforce. The constant slippage brings in to question the finish date, the impact such delay will have on other contractors and what the final cost will be to Manitoba Hydro.

At the moment, Manitoba Hydro cannot have confidence in BBE's completion date and the final cost.

MGF recommends that Manitoba Hydro works with BBE on a recovery plan to improve BBE's construction management, construction planning, co-ordination and supervision of construction work. The schedule should be adjusted based on productivity factors that BBE can realistically achieve based on historic data and revise its forecast at completion cost based on this new schedule.

Source of Information & Reference Materials

- BBE Weekly Construction Report – week ending 6th October 2017

Finding No. 2: Keeyask - Earthworks Embankment Fill Measurement

Observations & Findings

During the site visit to the Keeyask site on 9th and 10th November 2017, MGF performed a survey of earthworks to compare to the value reported by BBE. The quantity of embankment fill claimed by BBE is approximately 10% higher than the quantity assessed by MGF.

Conclusions & Recommendations

Whilst the physical quantity of work performed does not impact payment to BBE, relying on incorrect quantities may result in an inaccurate assessment of progress made in the period or in the year to date analysis.

Manitoba Hydro should perform spot checks on the quantities claimed by BBE to ensure quantity progress being relied upon for scheduling is accurate.

Source of Information & Reference Materials

- Site visit and physical remeasurement

MGF PROJECT SERVICES

Finding No. 3: Keeyask - Earthworks Productivity

Observations & Findings

As per the BBE Quantity Unit Rate Report (QURR) of 25th September 2017, the budgeted man-hours per cubic metre for earthwork is [redacted] The actual average productivity achieved to date is [redacted] man-hours per cubic metre as per the QURR Report dated 25th September 2017. The lower productivity will result in increased direct costs, indirect costs and a longer schedule. 1a

We applied the [redacted] difference in earthwork productivity between actual and forecast to the to-go earthwork quantity using an average blended labour rate of $61.70 to determine the direct cost impact. In addition, we added the [redacted] mark-up for GA&O and applied the [redacted] ratio of indirect cost / direct. This results in an increase in earthworks cost of: 1a

Order of Magnitude Estimate $88,400,000

Conclusions & Recommendations

If BBE continue to miss their productivity targets then completion is likely to be delayed, resulting in higher earthwork cost and increased indirect costs for the BBE contract. This cost should be set against the project contingency.

Source of Information & Reference Materials

- KGS 2017 Capital Project Justification Addendum section 3.5
- BBE Monthly Cost Report run date 25th September 2017 (QURR)
- BBE Amended Contract bid item level to go estimate volume 4

Finding No. 4: Keeyask - Review of Earthmoving Equipment

Observations & Findings

MGF has reviewed the most recent hour meter readings for major pieces of earthmoving equipment and we comment on potential cost impacts to completion of project. The schedule indicates that earthworks will be completed within 35 months from December 2017.

MGF have observed idle Manitoba Hydro purchased CAT 740 articulated trucks, while similar rental equipment is in use. The possible explanation for this could be that the purchased trucks have meter readings in excess of 10,000 hours and are not economical.

Running repairs and maintenance costs tend to rise steeply starting around the 6,500-hour mark for heavy earthmoving equipment. At 8,500 hours, most owners decide if they are going to invest more funds in maintenance or replace with new. At 10,000 hours, earthmoving equipment, generally speaking, is economically at the end of its useful life.

Hour meter readings for the earthmoving equipment at Keeyask on 11/19/17 were as follows:

- CAT 740 articulated trucks have an average hour meter reading of 10,198
- CAT dozers have an average hour meter reading of 7,033
- CAT rigid frame trucks have an average meter reading of 8,944
- CAT excavators have an hour meter reading of 9,255

The project has recently rented Komatsu HM400 articulated trucks to replace the aging fleet of CAT 740 articulated trucks. Is this a permanent or temporary measure?

A decision will have to be made in the very near future whether to rent or purchase replacement units for the dozers, excavators, and rigid frame trucks. If the decision is to replace in kind, the cost to do so will be $38,000,000. If the decision is to rent in kind, the cost to do so for 35 months will be $39,900,000 ($1,140,000 per month).

MGF has done a comparison of rental vs. purchase for the earthmoving equipment over a 35-month period. For the 35-month period, purchase would cost $1,900,000 less than rental. However, 33 months is the "break even" point. For any period less than 33 months, it would be cheaper to rent than purchase.

For the rental period stipulated by Manitoba Hydro for Multitiek-700KCA, and the Herman Nelson 1.2M BTU heaters, it would be cheaper by $423,500 to purchase these units.

Conclusions & Recommendations

Rent in lieu of purchasing of earthmoving equipment if planned to work for less than 33 months.

Schedule impact: None

Source of Information & Reference Materials

- MGF Calculation Sheet #1 and #2
- The salvage rates used in the calculations are from the equipment hourly calculation sheet provided to MGF and marked "Reference Doc. C"
- The hour meter readings used are from the "Equipment Up and Down" list provided to MGF and marked "Reference Doc. B"
- The equipment and rental rates and durations used are from the 19th November, 2017 rental list provided to MGF and marked "Reference Doc. C"
- MGF narrative marked "Reference Doc. D"
- Excerpts from CAT handbook marked "CAT 1", "CAT 2" and "CAT 3"
- Email equipment rental and purchase quotes from K-Rents (Komatsu) and Finning (CAT)

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PROJECT SERVICES

Finding No. 5: Keeyask - Scaffold and Crane Costs

Observations & Findings

The October 2017 BBE Monthly Cost Report shows spend to date from Amending Agreement No. 7 for the Scaffold and Crane category in the sum of [redacted] compared to the total budget of [redacted] for the period October 2016 to completion. 1a

The physical progress to date based on attachment 12.10 QURR in the October 2017 BBE Monthly Cost Report is at [redacted]

Additional Scaffold cost will result in:

Order of Magnitude Estimate CAD $103,500,000

Notes:

- The above figure includes Indirects and [redacted] for GA &O 1a
- We have used the physical percentage complete
- In the October 2017 Report, the following was the expenditure for the month:

Labour	[redacted]
Material	[redacted]
Total	**4,344,935**

1a

Conclusions & Recommendations

Manitoba Hydro to review and implement cost reductions.

MGF recommends Manitoba Hydro retains a Scaffold Inspector on site to ensure cost effective scaffolding strategies.

Source of Information & Reference Materials

- BBE Monthly Cost Report 07 Rev 0 for October 2017

MGF PROJECT SERVICES

Finding No. 6: Keeyask - Concrete Placement

Observations & Findings

The review of the Weekly Construction Report – week ending 6th October 2017 revealed the following:

- 2017 Planned Quantities - 78,877 cubic metres
- 2017 Year to Date Plan - 61,172 cubic metres
- 2017 Year to Date Placed - 48,834 cubic metres

Year to date concrete placement is down 12,338 cubic metres from the plan or 20%.

The following table analyzes planned and actual placed quantities and hours spent in concrete placement in the period:

Period	Unit of Measure	Plan	Actual
Placed Quantity	Cubic Metres	3,149	1,085
Job Hours	Hours	[redacted]	[redacted]
No. of placements	Each	15	11

1a

The planned number of placements was not achieved in the period; BBE performed 73% of its plan.

BBE expended [redacted] extra hours in placing 2,064 cubic metres **less** concrete.

Conclusions & Recommendations

BBE failed to meet its schedule in 2016 and continues to do the same in 2017, even after the Amending Agreement No. 7 and renegotiation of target price and schedule.

The analysis raises serious concerns with BBE's optimistic productivity rates and its ability to plan and execute concreting activities. The constant slippage brings in to question when BBE will most likely finish and at what final cost to Manitoba Hydro.

BBE needs to improve its construction management practices and, more accurately, plan and execute concreting activities. We would recommend that BBE revises its schedule with productivity rates that it has actually achieved on this project to produce a more accurate and realistic schedule and associated cost. This will allow Manitoba Hydro to better understand BBE's forecast at completion cost and a more probable completion date. This information will help plan and sequence other contractors interfacing with BBE to avoid potential delay and disruption claims.

Source of Information & Reference Materials

- BBE Weekly Construction Report – week ending 6th October 2017

MGF PROJECT SERVICES

Finding No. 7: Keeyask - Concrete Productivity

Observations & Findings

The cost and schedule of the Amending Agreement No. 7 is based on an average concrete productivity rate of [redacted] man-hours per cubic metre. The actual average productivity achieved to date is [redacted] man-hours per cubic metre. The difference in concrete productivity between forecast and actual is [redacted] man-hours per cubic metre. 1a

If the actual average productivity of [redacted] man-hours per cubic metre remains the same, then applying the shortfall in productivity to the total concrete quantity as measured from 7th October 2016 until the end of the contract using an average blended labour rate of $61.70 results in additional costs: 1a

Order of Magnitude Estimate

Direct cost (including GA&O)	[redacted]	1a
Indirect costs	[redacted]	
Total	**136,500,000**	

It should be noted that the original Contract was based on the Limestone project, built 25 years ago, which achieved [redacted] man-hours per cubic metre. 1a

In addition, the actual average productivity is likely to worsen as the Contract has more complicated structures to pour and three further winter seasons to work through.

Conclusions & Recommendations

If concrete productivity is not brought back in line with the assumption in the contract schedule and forecast to completion, then the cost of concrete will increase by approximately $136.4 million.

Manitoba Hydro should closely monitor and manage productivity as with winter work been planned for this season and the fact that more intricate pours are being performed the productivity factor may further deteriorate.

Source of Information & Reference Materials

- Manitoba Hydro concrete productivity analysis tables November 23, 2017 File
- BBE Monthly Progress Statement for October 2016, May 2017 and June 2017

Finding No. 8: Keeyask - Extended Overtime

Observations & Findings

MGF reviewed BBE's Progress Payments for May and June 2017 and noted that some personnel were working greater than 16 hours per day.

There were 73 instances of personnel working greater than 16 hours per day. In some instances, there are personnel working up to 21 hours per day and, in some cases, working 16 hours per day for three consecutive days.

These extended hours will not be as productive as straight time hours and will result in diminishing output for every hour worked. This raises concerns about personnel safety.

Note: In May and June 2017, the total hours worked were 726,354, of which 326,000 were overtime.

Conclusions & Recommendations

Manitoba Hydro should consider working in line with the standard 10 hours per day where possible, to improve productivity. The camp expansion cost would need to be considered in this decision.

Source of Information & Reference Materials

- May and June 2017 BBE Progress Payment backup

Finding No. 9: Keeyask - Reporting

Observations & Findings

MGF's review has identified issues related to reporting that may impact successful project management. Examples identified comprise:

- Late reporting, e.g. BBE's monthly report is due by the 7th of the following month and as advised by Manitoba Hydro, is typically not submitted to Manitoba Hydro until the 14th of the month
- Incorrect reporting
  - potential discrepancy in quantities of earthworks claimed by BBE
  - schedule reporting based on 1,030 activities with negative float, of which 97 are on the critical path whilst the Contract stipulates that the Schedule shall have no activities with negative float
- Inconsistent reporting e.g. BBE has reported in its September 2017 Monthly Report three differing figures for both the total concrete quantity to be placed and the installed concrete to date

The risk is that Manitoba Hydro is treating reports as "rely upon" and making decisions potentially based on incorrect data.

Conclusions & Recommendations

Persistent late submission of the monthly report and provision of reports with inaccurate and conflicting data is unacceptable. This situation would be serious enough on a lump sum fixed price contract but is amplified considering the BBE contract is cost reimbursable, with Manitoba Hydro holding the risks of schedule, productivity and cost.

We recommend Manitoba Hydro enforces its contract with BBE and demands BBE's compliance with it so that Manitoba Hydro receives timely report with the required accuracy of content so that Manitoba Hydro can make data driven decisions on matters of progress and cost.

Source of Information & Reference Materials

Finding No. 10: Keeyask - Construction Management

Observations & Findings

In Construction **"Time is Money"**

In Traditional Fixed Contracts **"Time is the Contractor's Money"**

In Cost Reimbursable Contracts **"Time is the Owner's Money"**

The three main Contract types to consider are:

- Fixed Price Lump Sum (FPLS): The Contractor is paid FPLS amount regardless of incurred expenses or duration
- Unit Price: The Contract is based on estimated quantities. The Contractor is paid unit rates against actual quantities. Generally, the unit rates will include the Contractors overheads & profit
- Cost Reimbursable (in this case): The Contractor is paid for all its allowed costs, plus profit and General Administration & Overheads (GA&O)

The GCC Contract strategy of adopting a cost reimbursable commercial arrangement for this project was flawed from the outset, with a predictable outcome, i.e. it promotes and rewards inefficient work and doesn't encourage efficient work.

However, the design and construction methods for such a project are predictable, therefore, there is no reason why the Contract strategy adopted could not have been Lump Sum or at the very least Unit Rate (with Provisional Sums/Quantities for unforeseen below surface work).

Ensuring a good level of design upfront would have lent itself to these Contract types, thereby transferring the Construction risk from the Client to the Contractor.

With the current Contract strategy, the Client is taking all the risk on Productivity, Schedule and Cost.

As all construction decisions affect Manitoba Hydro financially, therefore they need to move actively into the role of a Construction Manager. Guiding & instructing the Contractor on more efficient:

- Crew make-ups
- Work methods
- Shift lengths
- Supervision
- Etc.

The application of incorrect machinery and work methods causes delay and additional cost. The following picture depicts an example where both Schedule and Cost are pushed out in favour of the Contractor and at the expense of the Client.

While the above is an example, the poor productivity achieved on site reflects poor Supervision and Management by the Contractor. If Manitoba Hydro want to reduce cost and schedule overruns they should have a more hands on approach.

Conclusions & Recommendations

Manitoba Hydro needs to take ownership of the site, as they are the party exposed. They need to hire experienced site supervisors (with trade backgrounds) to implement a more efficient workplan.

Source of Information & Reference Materials

- Site visits and general findings

MGF PROJECT SERVICES

SECTION 4 - HVDC Converter Stations

SCOPE ITEM 10:

Review and assess Manitoba Hydro's cost estimating methodologies with respect to the final pre-construction budget of $2.68 billion and forecast at completion budget of $2.78 billion, identifying best practices and short-comings.

Finding No. 1: HVDC Converter Stations - Manitoba Hydro Internal Labour Cost Capital Expense vs. Operational Expense (Beyond Finish Date)

Observations & Findings

On reviewing back-up files provided by Manitoba Hydro to support the CEF-16 Estimate, budgeted "Labour Costs", we have noted costs that extend beyond the July 2018 "In-Service Date" and into 2021. These costs are included in the $2.78 billion Capital budget.

The following are the budgeted values for Labour Costs by year:

Year	Budget (CEF-16)	(Assumed) CapEX	(Assumed) OpEX
2017	$35,694,634	$35,694,634	
2018	$40,226,246	$23,465,310	$16,760,736
2019	$28,338,108		$28,338,108
2020	$6,503,469		$6,503,469
2021	$106,668		$106,668
	$110,869,125.02	**$59,159,944**	**$51,708,981**

Note: The above costs are based on the budget relating to the July 2018 In-Service Date.

Conclusions & Recommendations

Based on the schedule presented by Manitoba Hydro, the In-Service Date is noted as occurring during year 2018. It would be expected that a significant portion of the costs associated with any period following the In-Service Date should be allocated as Operational Expenditures, i.e. $51,708,981.

Source of Information & Reference Materials

- BPIII_MCP_Labour_FY2017(20160531).xlsm
- Manitoba Hydro 2017/18 & 2018/19 General Rate Application, Appendix 5.4, Page 12
- BPIII Master Programme (MGF Planned vs. Actual)

Finding No. 2: HVDC Converter Stations - Manitoba Hydro Cost Estimating Methodologies

Observations & Findings

Based on the level of information available and the intended use of the cost estimate, we reviewed the estimate classifications that have been indicated by Manitoba Hydro for the following budgets:

- CEF14 ($2.68 billion)
- CEF16 ($2.78 billion)

MGF's review of Manitoba Hydro's cost estimating methodology for Bipole III Converter Stations with respect to the final pre-construction budget of $2.68 billion and forecast at completion budget of $2.78 billion is outlined within this section.

The pre-construction budget of $2.68 billion cost estimating methodology is explained in detail in the BPIII 2014 Basis of Estimate Document and is "Deterministic" as defined by AACE RP – 18R-97. Manitoba Hydro's cost estimating methodology is consistent with industry standard for the particular Class of Estimate and for the estimate's intended purpose.

A summary of the estimating basis for quantity and unit rates, is as follows:

- Internal Labour Estimate – based on estimated hours by year by labour rates and overhead. Generally internal labour hours were estimated on the basis of similar past work. BOE item 11.1.5
- Outsourced Labour Estimate – based on estimated contract costs for each specific contract for the network. Generally based upon similar past work packages or budget quotations BOE item 11.1.2
- Material and Expenses – Material Take Off quantities were provided by Engineering. Material costs were then estimated based on recent quotations, pricing and invoices. BOE item 11.1.3
- Contract Estimates – Based on similar proposals that had recently been received. 'Budget bids' BOE item 11.1.4

The estimating methodology for the forecast at completion budget of $2.78 billion is also "deterministic". Quantities, rates and unit costs remained unchanged except for the inclusions of the "previously out of scope provincial road upgrades and an increase in contingency levels to a P75 confidence level to better address project risks to the completion of the work."

Best Practices that have been identified:

- The BPIII 2014 Basis of Estimate document is well-written and closely aligns with the suggested structure and content outlined within AACE Recommended Practice Number 34R-05
- The use of estimating templates promotes consistency and familiarity with the estimate

Short-comings:

- The Basis of Estimate did not include Benchmarking and/or Industry Metrics based on data from similar projects
- A Basis of Estimate document was not developed for CEF16, identifying the changes in project scope definition, scope of work, Contingency development and updated pricing
- Design/Material Take Off and Construction Waste Allowances are neither identified nor included for Material Key Quantities
- Use of Estimating Software will eliminate possible math errors and familiarity with estimate reports. Manitoba Hydro's cost estimating methodology for the final pre-construction estimate for the Bipole III Converter Station Project was based on a first principle estimating methodology "using quantities and historical project unit rates dependent on design criteria"

It was indicated that each department, section or business unit with assigned scope to the project were responsible for producing their cost estimates and cash flows for internal labour, external labour, materials, equipment and contracts required for their respective project component.

Conclusions & Recommendations

MGF recommends that the Manitoba Hydro Estimating Team prepare the overall estimate with input from each department. The Manitoba Hydro Estimating Team would detail and reconcile scope, quantities and unit rates provided by each department. This would ensure consistency and accuracy in the estimates produced.

The method with which the financial aspects of the project are reconciled and revised for past and future expenditure each year within SAP, appear sound from a budget management perspective.

The fact that many of the project cost adjustments and calculations occur within SAP does reduce the level of transparency. Reconciliations should be conducted to update the physical quantity and item based cost estimates, to which rates of placement, production rates, and quantities can be detailed. This too, would aid in aligning with the project Work Breakdown Structure (WBS) and Cost Breakdown Structure (CBS).

Source of Information & Reference Materials

- 2016 Estimate Basis Notes
- CPJ Update Notes (Final)
- BPIII 2014 Basis of Estimate (BOE) Document

MGF PROJECT SERVICES

Finding No. 3: HVDC Converter Stations - Risk Management

Observations & Findings

The Bipole III Converter Stations Project Controls Report of June 2017 identified in the Risk Management section the following: "Future Risk: Majority or major component installation occurring this summer. Interfaces with SLI may cause delays to system installation. Concern with aggressiveness of Synchronous Condensers commissioning schedule".

The Bipole III Converter Stations Project Controls Report of September 2017 states "There is a risk to the project ISD due to the following - Complexity of interfaces between Contractors and installation damage causing delays to system installation and pre-commissioning, installation delays impacting system commissioning (AC Switchyard), delivery delay of components impacting aggressive commissioning schedules submitted by contractors".

The 'Dashboard' page of the September 2017 report goes on to state "Recent Contractor submissions show delays in activities that could jeopardize the ISD and the Contractor's critical paths keep changing, increase the difficulty to forecast any potential impact to ISD."

The September 2017 report further states "HVDC contractor critical path changes in every weekly submission and does not reflect the plan that is being discussed during the progress meeting and RFI responses which is the risk."

Conclusions & Recommendations

The risk which was identified in June 2017 was not mitigated by September 2017 and poses a risk to the In-Service Date (ISD) being met. It is unacceptable for a project at this stage to have the critical path changing from week to week.

It raises concerns with the contractor's ability to plan and execute its work and equally, why Manitoba Hydro having been aware of the risk, has failed to mitigate it. Risk management is a dynamic and ever present activity on a project and needs to be proactively performed if projects are to be successful.

Source of Information & Reference Materials

- Bipole III 2017 06 Converter Stations Project Controls Report
- Bipole III 2017 07 Converter Stations Project Controls Report
- Bipole III 2017 08 Converter Stations Project Controls Report
- Bipole III 2017 09 Converter Stations Project Controls Report
- Page Dashboard_Bipole III 2017 09 Project Controls Report
- Page Risk Management_Bipole III 2017 09 Project Controls Report
- Page Risk Management_Bipole III 2017 08 Project Controls Report
- Page Risk Management_Bipole III 2017 07 Project Controls Report
- Page Risk Management_Bipole III 2017 06 Project Controls Report

Finding No. 4: Bipole III - Integrated Master Schedule for Converter Stations

Observations & Findings

The Bipole III Integrated Master schedule contains 25,650 activities versus the baseline schedule which contains 19,386 activities.

As with any Integrated Master Schedule, its quality in large part is directly related to the quality of the schedules which are incorporated in to it. The Keewatinohk Converter Station (KCS) schedule, the Riel Converter Station (RCS) schedule, General Converter Stations, and the Transmission Connector Line schedules are imported weekly into the IMS with progress updates. This method for updating the IMS is precise; however, it isn't without risk. If certain elements of the individual schedules are changed, the progress may not be imported correctly into the IMS resulting in inaccurate dates.

Whilst an Acumen Fuse was not done on these individual schedules, the following describes the overall findings for these schedules.

Keewatinohk 230 kV AC Switchyard schedule:

The Keewatinohk schedule has a start date of 11th Jun, 2014 and has 17th January, 2018 as the completion date. The project is currently in progress with a status date of 27th October, 2017. It has 2,206 normal activities of which 2,080 (94%) are complete, 18 (1%) are in progress and 108 (5%) are still planned. It contains 118 milestones, 0 summaries, and 228 Level of Efforts (LOE).

The project baseline start date was 3rd July, 2014 with the baseline finish date being 7th October, 2017. The project is currently 93 days behind schedule.

The main issues on this schedule are the percentage of activities (70%) using a relationship type other than Finish to Start (FS) and the percentage of missed activities (46%).

Riel Synchronous Condensers schedule:

The Riel Synchronous Condenser schedule has a start date of 1st April, 2015 and has 25th December, 2018 as the completion date. The project is currently in progress with a status date of 16th October 2017. It has 7,602 normal activities of which 4,107 (54%) are complete, 330 (4%) are in progress and 3,165 (42%) are still planned. It contains 1,238 milestones, 0 summaries, and 452 Level of Efforts (LOE). As a re-baseline was just approved in October, 2017, the baseline and forecast dates are the same.

The main issues in this schedule are activities using the Start to Start, Finish to Finish, and Start to Finish (SS/FF/SF) relation (13%), missed activities (35%), and activities with a high duration (10%).

Transmission Department Schedules

The Transmission Project Department schedules include the following:

- Long Spruce 230kV Station
- Riel Electrode Line
- Ridgeway 230kV/66kV Breaker Replacement
- Rosser 230kV Breaker Replacement
- Rosser 230kv Breaker Replacement
- R49R T/L Sectionalization at Riel

- Dorsey Station
- Richer Station
- Ridgeway Station
- Riel Expansion
- Keewatinoow Collector Lines Henday
- Keewatinoow Electrode Line
- McPhillips 115kV Breaker Replacemnt
- Keewatinohk – Limestone U/G Fibre Optic Installation
- Henday 230kV Station Modification
- Keewantinoow CS Collector Line Long Spruce to Henday L61K

Across all of the Transmission Department schedules residing in the Bipole III Master schedule, the main issues are the activities missing logic (57%), activities using the Start to Start, Finish to Finish, and Start to Finish (SS/FF/SF) relation (48%), missed activities (61%), and activities with a high duration (39%).

As these schedules are built using critical path methodology (CPM), it is essential to have all activities linked together. Activities with high durations can be symptomatic of incorrectly identified support activities or activities that have not been broken down into enough detail. Supporting activities need to be identified as LOE activities in the schedule so they do not drive the critical path. Other high duration activities need to be decomposed into smaller discrete units so logic can be properly assigned to the network. A schedule containing primarily Start to Start and Finish to Finish (SS/FF) relations is a strong indicator the activities are too high level. The level of confidence in the forecast start and finish dates on this schedule would improve significantly if the logic issues are resolved.

Conclusions & Recommendations

The mechanical aspects of these schedules should be fixed to improve the quality and reliability of the completion dates for the project.

Source of Information & Reference Materials

- BPIII Master Schedule Aug-11-17-DD.xer
- 033102 HVDC SMC Original Baseline.xer
- 033401 – KCS 230 kV AC Switchyard Project – Latest Rev – 20171027.xer
- 033401 – KCS 230 kV AC Switchard Project – Original Baseline 20141125.xer
- 033852 Synchronous Condenser Over Target – Baseline and Lastest Rev Oct. 2017.xer
- BPIII OCT 2016-(CEF 16).xer

SCOPE ITEM 11:

Review and assess the tendering and contracting methodologies for the converter stations, identifying best practices and short-comings.

Finding No. 1: HVDC Converter Stations - Tendering & Contracting

Observations & Findings

MGF's review of the Manitoba Hydro's tendering of major HVDC converter station contracts > $25 million produced the following considerations.

- Approach to Market: appropriate use of competitive tender e.g. HVDC converter equipment & Keewatinohk 230kV AC switchyard and single sourced directly negotiated contracts e.g. Keewatinohk Site Development
- Contract types: appropriate use of contract types and allocation of risks was made e.g. HVDC Equipment on a design, supply, construct, install and commission contract. The Keewatinohk Camp Operations Services scope on a services based contract
- Pricing mechanism: appropriate choices were made for pricing mechanisms relative to contract scope, the degree of scope definition and risk. For example, HVDC Converter Equipment with payment against key lump sum milestones achieved by the Contractor that are defined in the Contract; and the Keewatinohk Camp Operations Services on a cost reimbursable pricing mechanism, comprised of reimbursing actual costs incurred plus a management fee

Conclusions & Recommendations

In tendering the HVDC converter station contracts, Manitoba Hydro has made has appropriate use of approaches to market, contract types and pricing mechanisms to successfully manage the scopes and risks associated with their contracts.

Finding No. 2: HVDC Converter Stations - Compensation Mechanisms

Observations & Findings

The Converter Station Contract Revision Register (CRR) as of 30th September 2017 shows open contracts with a remaining spend of $302,704,674. This is broken down by compensation mechanism as follows:

- Lump sum $253,083,916
- Unit price $12,234,989
- Cost reimbursable $37,385,769

Lump sum and unit rate priced contracts amount to 88% of the remaining spend which provides higher predictability in the forecast final cost.

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Conclusions & Recommendations

Manitoba Hydro's choice of compensation mechanisms is appropriate for the contracts required for the converter station projects and is a sensible allocation of risk between Manitoba Hydro and its contractors.

Source of Information & Reference Materials

- Converter Stations Contract Summary

Finding No. 3: HVDC Converter Stations - Variation Management

Observations & Findings

We reviewed random variations to test if the management of variations was performed in accordance with the contract in terms of appropriate documentation, scope description and pricing. We found that most of the approvals were in accordance with the process outlined in the respective contract and Manitoba Hydro's corporate Contract Change Management Procedure.

It was noted that a few lump sum priced variations had a 15% mark-up added to the lump sum. This is in error; lump sum prices should be inclusive of all costs associated with the variation as per Section 5.7.2 of Schedule XV – Variation Procedures of the Contract. Section 5.7.3 of Schedule XV - Variation Procedure states that the 15% mark-up is only to be applied where a variation is priced on the basis of actual costs incurred. For example, the variation for the [redacted] should have the 15% fee removed from the calculation of its cost. 1a

Conclusions & Recommendations

Variations previously processed should be reviewed to ensure that the 15% mark-up has not been incorrectly applied and paid to the contractors.

Source of Information & Reference Materials

- Sample Variation Orders
- Manitoba Hydro Schedule XV Variation Procedure

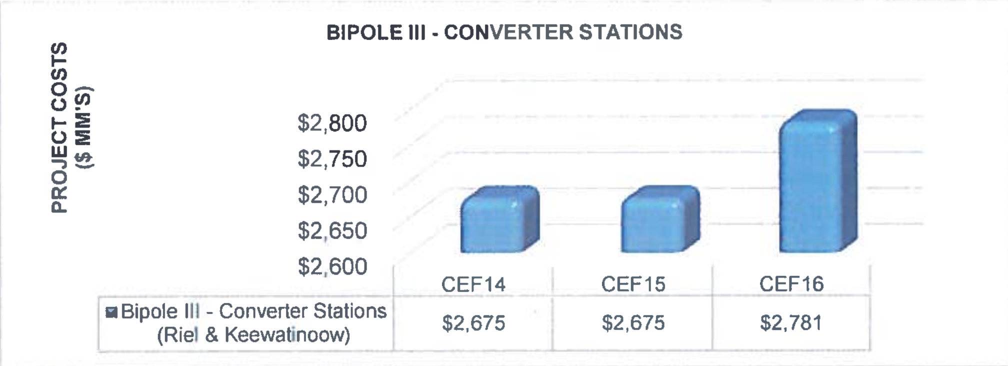
SCOPE ITEM 12:

Review and assess the reasons for the capital cost increases from the 2014 control budget of $2.68 billion to the current forecast at completion amount of $2.78 billion.

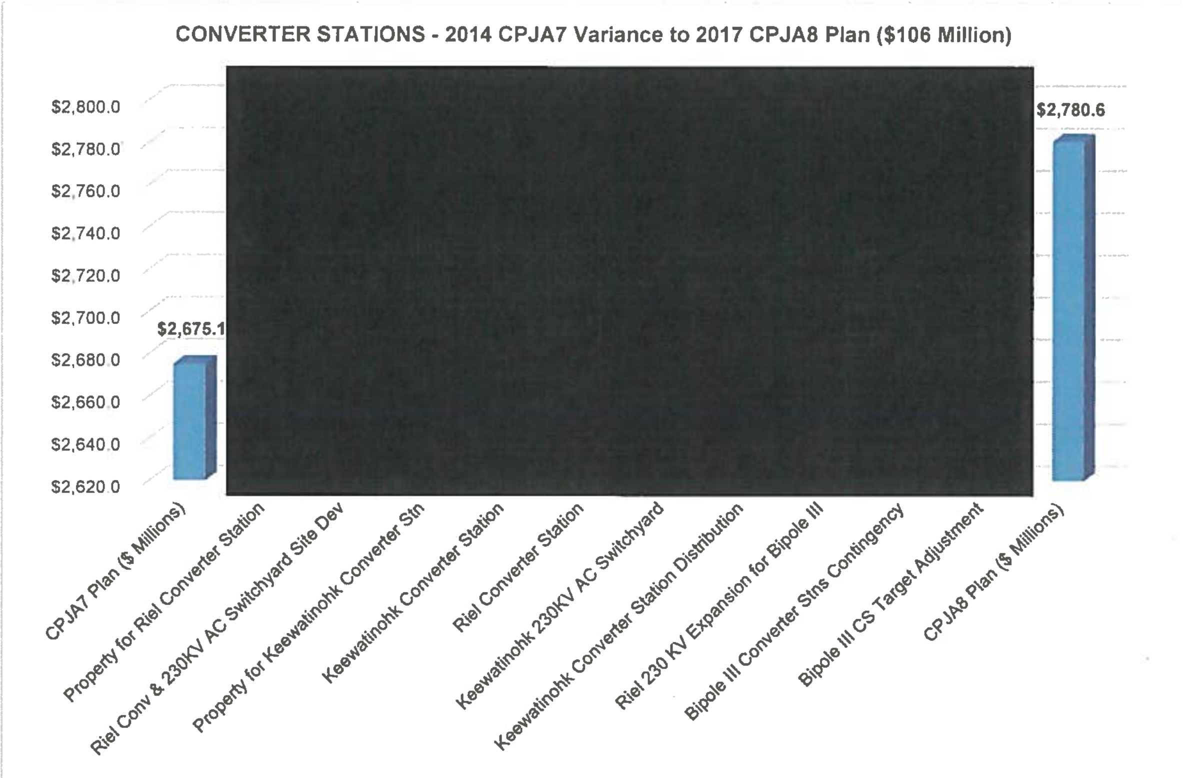
Finding No. 1: HVDC Converter Stations - Project Cost Overruns

Observations & Findings

MGF reviewed the "Bipole III Project, Basis of Estimate Document, September 2014 Cost Estimate Update", in addition to the justification for adjustments to the current budget of $2.78 billion. The budget comparison between CEF14, CEF15 and CEF16 are summarized below:



The budget increased by $106 million between CEF14 and CEF16. The revised budget maintains an In-Service Date of July 2018. The table below illustrates the cost elements, identifying variances to the original budget.



1a

Manitoba Hydro increased the 2014 Control Budget in CPJ Addendum #08(b) by approximately $106 million. This increase was subsequently approved by the MHEB on 26th October 2016. Changes to the scope included within the justification were as follows:

- Provincial Road 280 Upgrade
- Provincial Road 290 Upgrade
- Conawapa Access Road Upgrades

In addition, the estimate was adjusted to an increased confidence level of P75, i.e. 75% chance of achieving the estimate value. This confidence level adjustment increased the Contingency.

Costs which were once shared between the Bipole III and Conawapa Projects have now been fully allocated to the Bipole III Project in light of the Conawapa Generating Station project being "shelved".

Manitoba Hydro provided MGF with an additional document entitled "Basis for the Current Converter Stations Budget" which was reviewed in early September. Whilst this document does not satisfy the requirements of a formal Basis of Estimate document, it did provide an explanation for some of the increases to the current budget.

Key changes from the pre-construction budget have been attributed to the following:

- Unallocated Contingency adjustment to increase budget confidence: [redacted]
- Cost Recovery from loss of Conawapa Project cost sharing: [redacted]
- HVDC Contract commodity escalation reserve to increase budget confidence: [redacted] 1a
- BNA Agreement LOA payments reserve amount: [redacted]
- Possible Post-Construction PR280/290 upgrade agreement with MHI: [redacted]

Conclusions & Recommendations

The budget was primarily increased to account for scope items mentioned above and to add further Contingency to address remaining project uncertainties.

Source of Information & Reference Materials

- 2016 Estimate Basis Notes
- CPJ Update Notes (Final)
- Bipole III Estimate Details by Network CEF 14 vs CEF16 MGF

SCOPE ITEM 13:

Assess Manitoba Hydro's updated converter station cost estimate for reasonableness, including whether appropriate contingencies and reserves have been provisioned in relation to outstanding uncertainties.

Finding No. 1: HVDC Converter Stations - Estimate Reasonableness

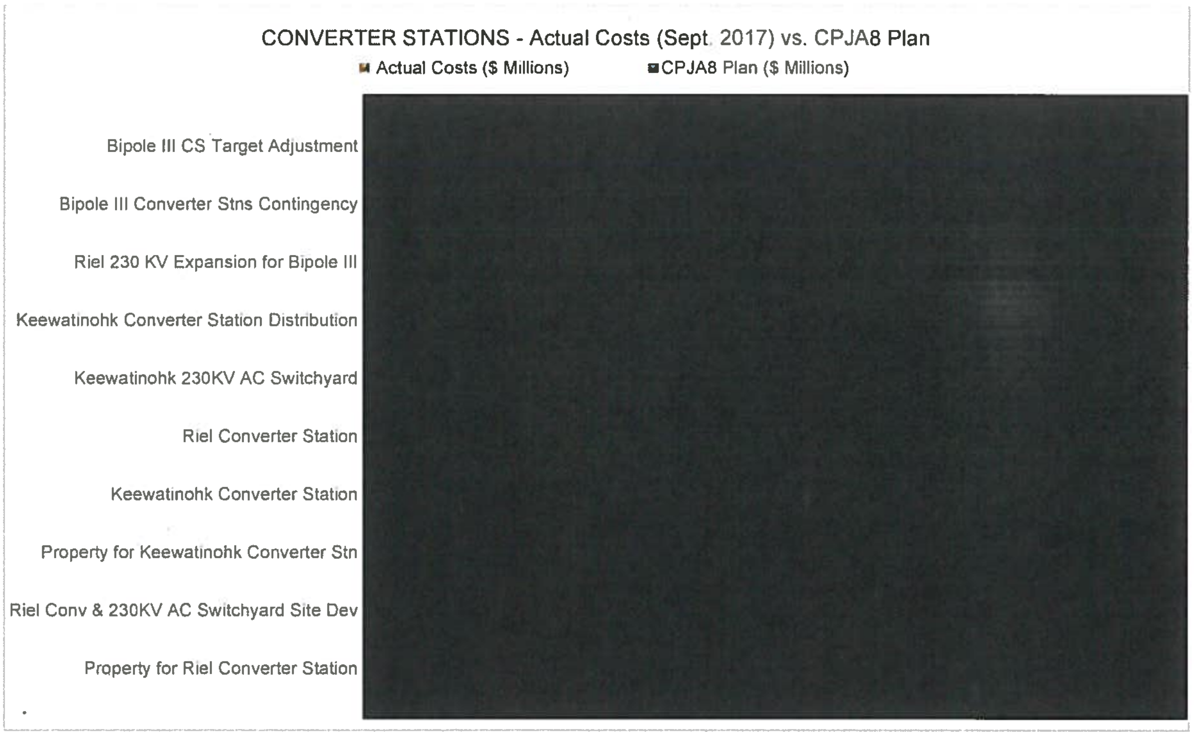
Observations & Findings

MGF's review of various reports produced the following observations and assessments:

- The review of "Actual Life to Date Amount" indicates $2,136,260,097 in actual spend to 30th September 2017. This represents 77% of the current project budget and aligns with that reported in the September 2017 Monthly Project Controls Report
- The September 2017 Monthly Project Controls Report indicates a Contingency of [redacted] broken down as follows:
    - Dispersed - [redacted] 1a
    - Allocated to Scope - [redacted]
    - Allocated to Contracts - [redacted]
    - Unallocated - [redacted]
- In reviewing the Risk Management section of the September 2017 Monthly Project Controls Report, the primary risk is schedule. There are no current risks impacting the project In-Service Date, but instances of late equipment delivery and component installation damage have been noted
- Future risks to the project In-Service Date have are on account of the following:

  - Complexity of interfaces between Contractors
  - Installation damage causing delays to system installation and pre-commissioning
  - Installation delays impacting the system commissioning (AC switchyard)
  - Delivery delay of components impacting aggressive commissioning schedules submitted by Contractors
- Whilst mitigation actions have been addressed, schedule and cost risks still exist and plans to potentially accelerate activities will result in additional costs
- The last entry on the Bipole III Risk Register, MFR 169 Converter Station tab was April 2017 which would imply that the Risk Register may not be up to date

The following table compares the Actual Costs (September 2017) to the CPJA 8 Plan



[redacted]

1a, 7a

Cost Summary

- CPJA8 (CEF-16): $2,780.56 MM
- Actual Costs (September 2017): $2,136.26 MM
- Costs To-Go (September 2017), Excl. Contingency: [redacted]
- Costs To-Go (September 2017), Incl. Contingency: $644.3 MM 1a

MGF PROJECT SERVICES

Conclusions & Recommendations

Based on the selected contracting strategies and the fact that a large portion of the project is based on a lump sum commercial model, the estimate is considered reasonable. Remaining project risks have been identified in relation to achieving the planned In-Service Date and it is MGF's view that the remaining unallocated contingency is reasonable.

Source of Information & Reference Materials

- BPIII CS CPJ Comparison vC14 vs vC16 Actual spend to Sept 30, 2017.xls
- 2017 09 Project Controls Report
- Bipole III Risk Register, MFR 169 Converter Station tab
- Transmission Bipole III Converter Stations, Project Controls Monthly Report September 2017

Finding No. 2: HVDC Converter Stations - Variation Management

Observations & Findings

The converter stations have approximately $320 million of spend to completion in August 2018. Of this value, the respective percentage spend by pricing mechanism is as follows:

- 83% on a lump sum basis
- 4% on a unit rate basis; and
- 13% on a cost reimbursable basis

Variations to date have not had a significant impact.

Conclusions & Recommendations

The potential for a cost over-run is low for the converter station scopes.

Source of Information & Reference Materials

- Converter Stations CRR Report
- September 2017 Project Controls Risk Management
- September 2017 Project Controls Risk Management

Finding No. 3: HVDC Converter Stations - Contingency Review

Observations & Findings

Contingency was carried in the final pre-construction budget at a value of [redacted] with no provisions for a management reserve, as this had been addressed within the Transmission Line Project. Contingency was set using a P50 value on an estimate value of $2.107 billion, which was inclusive of the Riel 230kV 7a

Expansion ($229 million) and Keewatinoow Converter ($1.878 billion). It was noted that at the time the contingency was assessed there were sunk costs against the project at a value of $307 million.

The Converter Station has a scheduled In-Service Date of July 2018. The total contingency carried for the project was [redacted] 7a

MGF has reviewed a third-party consultant's report that had been developed as part of the Bipole III Project risk and contingency review in August of 2014. In this report, suggested contingencies and reserves had been identified and presented as follows:

- Contingency (Cost) - Riel 230kV Expansion
  - P10, [redacted]
  - P50, [redacted]
  - P90, [redacted]
- Contingency (Cost) - Keewatinoow Converter (KCS) 7a
  - P10, [redacted]
  - P50, [redacted]
  - P90, [redacted]
- Bipole III - Contingency (Schedule)
  - P50, [redacted]
- Converter - Reserve Risks
  - Lost Season - [redacted]
  - Labour Shortage - [redacted]

The justification and recommendation for the reserves within the report were outlined as follows and it was suggested that Manitoba Hydro fund an amount to cover the costs of one of the risks:

- Lost Season, [redacted] a moderate to high probability was identified for one of the following to occur, which would result in an additional construction season. These are noted as delay impacts: 1a
  - Weather – KCS
  - Labour shortage
- Labour Shortages, [redacted] moderate probability that suppliers would experience poor productivity. The reserve did address the fact that the commercial strategy was based on EPC lump sums. Not a delay impact 1a

It was recommended that for the project business case analysis, Manitoba Hydro use the P95 value, plus escalation.

CPJA 8b authorized an additional [redacted] to address previously out of scope items and remaining risks. This authorization increases the Contingency carried within the project to a "P75 confidence level." The difference between the P50 and P90 values carried within the third-party report for the Converter Station scope was [redacted] This value did not account for any reserve, as indicated above. 7a

The noted variance between the contingency (P50) value presented by the third party consultant and the value carried by Manitoba Hydro within the project was approximately [redacted] 7a

Conclusions & Recommendations

The current value of contingency at a P75 confidence level does not appear to be based on a current or updated Contingency review. As such, this would not take into consideration the events and updated risks that the project has been or may be exposed to.

Manitoba Hydro's corporate standard states that contingency is set at a P50 or 50% confidence level.

Source of Information & Reference Materials

- Bipole III Project, Capital Cost and Schedule Risk Analysis and Contingency Estimate, dated 29th August 2014
- 2016 Estimate Basis Notes
- CPJ Update Notes (Final)
- BPIII 2014 Basis of Estimate (BOE) Document
- CPJA 8b

SECTION 5 - Bipole III Transmission Line

SCOPE ITEM 14:

Determine whether the current state of design and engineering work supports the $1.96 billion cost estimate. If not, identify what changes in the contingencies, reserves, or forecast at completion cost are required.

Finding No. 1: Bipole III Transmission Line - Stanley Consultants Inc.

Observations & Findings

On account of the one-week timeframe that Stanley Consultants Inc. ("Stanley") had to perform their work, MGF directed Stanley to those areas where it was felt that Stanley's efforts in the one week available would add best input and content for the review.

Stanley, through its review of the estimates, did review certain aspects of the design and engineering drawings and specifications but have not commented specifically on these.

Conclusions & Recommendations

As such, Stanley did not address this scope.

SCOPE ITEM 15:

Review and assess Manitoba Hydro's cost estimating methodologies, identifying best practices and short-comings.

Finding No. 1: Bipole III Transmission Line - Section N4

Observations & Findings

We performed a unit price comparison between CEF 16 Estimate and the Rokstad Power Company's Contract for section N4 of the transmission line. CEF 16 carried a cost of [redacted] The actual cost based on Rokstad's contract unit prices is [redacted] thereby reducing CEF 2016 by [redacted] 1a, 7a, 8a

Conclusions & Recommendations

As contracts are placed, prior estimates should be updated with the contract rates to ensure the accuracy of estimates and forecast costs to completion. [redacted] Such low rates might indicate that Rokstad may have had an insufficient understanding of the scope and the cost to perform it. 1a, 8a

Source of Information & Reference Materials

- BPIII Estimate Rev 2 _ TLCC
- BPIII Transmission Line CPJA8 (2016) – 05

Finding No. 2: Bipole III Transmission Line - Manitoba Hydro Cost Estimating Methodologies

Observations & Findings

Manitoba Hydro's cost estimating methodology for the final pre-construction estimate for the Bipole III Transmission Line project was based on a first principles estimating methodology "*using quantities and historical project unit rates dependent on design criteria*".

This is also known as Deterministic Estimating methodology as defined by AACE RP – 18R-97, which is predominantly based on the use of unit cost line items. Manitoba Hydro's cost estimating methodology is consistent with the industry standard for the Class of Estimate and for the estimate's intended purpose.

It was indicated that each department, section or business unit with assigned scope to the project was responsible for producing their cost estimates and cash flows for internal labour, external labour, materials, equipment and contracts required for their respective project component.

It was difficult aligning the detail and structure of the various cost reports. The estimate basis did not align with either the Work Breakdown Structure or the summary tables provided in the Basis of Estimate. The detailed summary provided within the estimate packages did not align with the SAP cost reports.

Quantities, man-hours and unit rates associated with the physical scope were not clearly defined within the estimate summary sheets included within the estimate packages. From the estimate package provided, the information was not consolidated in any one location. This was limited to the estimate summary sheets that had been populated with accounting codes, descriptions and costs, which when checked and calculated, did not match the values carried in the estimate.

Conclusions & Recommendations

Manitoba Hydro is very strong in capturing and reporting costs. The team is comprised of a very knowledgeable and capable group; however, it is MGF's opinion that additional governance and control (not accounting) measures be implemented.

The 2014 pre-construction Basis of Estimate was extremely well done. Supporting back-up and more detailed explanation outlining the structure and relationship between the physical scope of work and resources with the cost / financial reporting system is suggested for the future.

MGF PROJECT SERVICES

Summaries should align with the Work Breakdown Structure and provide base costs, free of any escalation, taxes, contingency, interest, etc., as these should be shown separately.

Summaries should also be presented, outlining owner's costs, direct costs, indirect costs, etc. in accordance with the project Work Breakdown Structure and Cost Breakdown Structure. SAP reports and data dumps does not satisfy the requirements of an estimate summary or basis for the build-up of the estimate.

Source of Information & Reference Materials

- "Bipole III Design Parameters and Tower Quantities for Budgeting Purposes - 2014 07 16"
- Bipole III Project, Basis of Estimate Document, September 2014 Cost Estimate Update, dated March 2015
- BPIII Material Requirement Calculation Details - 2014 05 06
- BPIII T Line CPJA8 (2016) 2016-05 - BPIII Estimate Rev 2 _TLCC

Finding No. 3: Bipole III Transmission Line - CEF 2016 Estimate

Observations & Findings

The concern raised is with respect to Manitoba Hydro's cost estimating and forecasting capability as the "Estimate of Go Forward Costs" dated 16th June 2016 fails to include costs for Distribution Line Crossings and the Transmission Line Construction Yard. The notation advises that these costs are to be provided by others, but no cost is carried in the Total Estimated Cost of Construction.

Conclusions & Recommendations

The omission of these costs means that Manitoba Hydro is understating the "Estimate of Go Forward Costs." The degree to which this is replicated elsewhere is not defined or known, but it raises concerns on Manitoba Hydro's forecast costs to completion. MGF recommends that Manitoba Hydro implement a quality review of its "Estimated to Go Forward Costs" during its next review cycle to ensure adequate costs are provided for.

Source of Information & Reference Materials

- Estimate of Go Forward Costs dated 16th June 2016

MGF PROJECT SERVICES

SCOPE ITEM 16:

Review and assess Manitoba Hydro's tendering and contracting methodologies, including choices of contract types for the major contracts, identifying best practices and short-comings.

Finding No. 1: Bipole III Transmission Line - Contracting

Observations & Findings

Manitoba Hydro has used lump sum, unit rate, cost reimbursable and material supply contracts effectively. Examples of lump sum price contracts are as follows:

- Transmission Line Clearing
- GIS Upgrade

Examples of unit rate priced contracts are as follows:

- Precast Concrete Self-supporting Tower
- Transmission Line Construction Package

Examples of cost reimbursable or "Service Release Order" contracts are as follows:

- Inspection Services
- Lidar & Digital Imagery

Conclusions & Recommendations

Manitoba Hydro has made appropriate use of lump sum, unit rate and cost reimbursable contract types for the Bipole III Transmission Line project.

Source of Information & Reference Materials

- BPIII Transmission Contract Summary dated 30th September 2017

MGF PROJECT SERVICES

SCOPE ITEM 17:

Review and assess Manitoba Hydro's contract management and cost control methodologies, and determine whether these methodologies support the $1.96 billion forecast at completion cost. If not, identify what changes in the contingencies, reserves, or forecast at completion cost are required.

Finding No. 1: Bipole III Transmission Line - Risk Register

Observations & Findings

Upon review of the Bipole III risk register the following deficiencies were identified:

- The date of creation of the risk is not identified
- The dates that risks are to be potentially resolved are not identified
- The person responsible for the risk is not identified

Conclusions & Recommendations

Manitoba Hydro to add the missing attributes to its risk register. This complies with industry best practice and will enhance their effectiveness in managing risks.

Source of Information & Reference Materials

- Risk Register "MFR-169 Transmission Line

Finding No. 2: Bipole III Transmission Line - Contract Management

Observations & Findings

The Bipole III Project Charter states that Contract 031074 with Valard Construction LP for Specialty Anchors & Foundations Installation (N1) had been closed out in the amount of [redacted] The Bipole III Transmission Contract Summary as at 30th September 2017 identifies this contract to be open with an actual expenditure of [redacted] and with a contingency remaining of [redacted] 1a, 7a

Conclusions & Recommendations

The Transmission Contract Summary should be corrected to status this Contract as closed and ascertain whether the remaining contingency of [redacted] can be reallocated. 1a, 7a

Source of Information & Reference Materials

- Bipole III Project Charter dated 17th February 2017
- Bipole III Transmission Contract Summary as at 30th September 2017

Finding No. 3: Bipole III Transmission Line - Variation Management

Observations & Findings

Bipole III contract 031061 with Forbes is for transmission line sections N2, N3, S1 and S2. We reviewed BPIII 031061 Variation Summary to understand how variations were being managed. The Variation Summary generally follows good practice in that it:

- Allocates a variation number
- Identifies the transmission line section reference to which the variation pertains
- Provides a description of the variation
- Records the value of the variation
- Identifies if the variation is an increase or reduction in cost
- Provides the basis of determining the cost of the variation

The variation number sequence runs from 1 to 54. However, variations 24, 30, 31, 36, 37, 43, 45 and 49 do not appear on the summary, and therefore, it's not possible to determine whether these are variations pending a decision by Manitoba Hydro or agreement with the contractor, or whether they have been rejected.

The Variation Summary only records those variations that are "approved." A better practice would be to retain all variations on the Variation Summary and provide a status to each of these e.g. Approved, Under Negotiation/Pending or Rejected.

If the variations that are not identified on the Variation Summary are under consideration by Manitoba Hydro then there is potential for an increase in cost to Contract 031061. The biggest risk with contract variations is when potential or pending variations are not visibly being tracked or recorded.

Conclusions & Recommendations

Maintaining the Variation Summary with all variations, e.g. approved, pending and rejected would be a more effective way for Manitoba Hydro to manage variations. With respect to the 8 variations that are not reported on the Variation Summary, Manitoba Hydro should review and confirm that these variations are rejected and will have no further cost impact or if they are pending, put these variations in to the Variation Summary for proper variation management.

Source of Information & Reference Materials

- BPIII 031061 Variation Summary

Finding No. 4: Bipole III Transmission Line - Variation Management

Observations & Findings

Bipole III contract 031063 with Rokstad Power Company is for transmission line sections N1, N4, C1 and C2.

We reviewed the BPIII 031063 Variation Summary to understand how variations are being managed. The Variation Summary generally follows good practice in that it:

- Allocates a variation number
- Identifies the transmission line section reference to which the variation pertains
- Provides a description of the variation
- Records the value of the variation
- Identifies if the variation is an increase or reduction in cost
- Provides the basis of determining the cost of the variation

The variation number sequence runs from 1 to 29. However, variations 3, 4, 6, 7, 12, 14, 15, 19, 21, 22, 24 and 25 do not appear on the summary, and therefore, it's not possible to understand whether these are variations pending a decision by Manitoba Hydro or agreement with the contractor or whether they have been rejected.

The Variation Summary only records those variations that are "approved." A better practice would be to retain all variations on the Variation Summary and provide a status to each of these, e.g. Approved, Under Negotiation/Pending or Rejected.

If the variations that are not identified on the Variation Summary are under consideration by Manitoba Hydro, then there is potential for an increase in cost to Contract 031063.

The biggest risk with contract variations is when potential or pending variations are not visibly being tracked or recorded.

Conclusions & Recommendations

Maintaining the Variation Summary with all variations, e.g. approved, pending and rejected would be a more effective way for Manitoba Hydro to manage variations. With respect to the 12 variations that are not reported on the Variation Summary, Manitoba Hydro should review and confirm that these variations are rejected and will have no further cost impact, or if they are pending, put these variations in to the Variation Summary for proper variation management.

Source of Information & Reference Materials

- BPIII 031063 Variation Summary

MGF PROJECT SERVICES

Finding No. 5: Bipole III Transmission Line - Rokstad Power Company Schedule

Observations & Findings

Based on the proposed recovery plan dated 17th October 2017, Rokstad Power Corporation's contract has a completion [redacted] Rokstad has only one season to perform the remaining work in sections N1, N4, C1 and C2. Close monitoring of construction of [redacted] is important, especially for stringing in the winter construction period. 4, 8a

Work in sections N1, N4, C1 and C2 has not progressed to plan since the contract start. The risk is if construction in these sections is not progressed as per the schedule, work will need to be performed in another construction season, with a schedule impact of one year.

Conclusions & Recommendations

In-Service Date (ISD) is critical and there remains only one season of work before ISD. The construction work requires close planning and the schedule needs close monitoring to ensure the completion date of 21st April 2018.

Source of Information & Reference Materials

- Bipole III – Transmission Line Construction Report, July 27, 2017
- BPIII Transmission Line CPJA8 (2016) – 05
- Bipole III Project Construction Report, June 2017

Finding No. 6: Bipole III Transmission Line - Rokstad Power Company Schedule

Observations & Findings

The Rokstad Power Company Schedule has a start date of 21st Sep 2015 and a completion date of [redacted] The project is currently in progress with a status date of 20th August 2017. It has 4,794 normal activities of which 2,721 are complete, 16 are in progress and 2,057 are still planned. It contains 178 milestones, no summaries and 86 LOE (Level of Effort) activities. [redacted] The project is currently behind schedule by 8 days. 4b, 8a

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The Rokstad Power Company Schedule scored 69, giving it a 69% probability of success
- Schedule Quality: Scored 69% versus a score of 75% or better which is considered a 'good' schedule

- [redacted] Schedule paths with [redacted] typically arise due to artificially constrained activities. The metric identifies activities with [redacted] and should not exceed 5%. This schedule scored 49%. [redacted] 4b, 8a
- Baseline Execution Index (BEI): Measures the efficiency with which actual work has been accomplished when measured against the baseline. The BEI score for this schedule is 0.87. The more activities that are completed on time or ahead of the baseline schedule will reflect a BEI of 1 or more. Conversely, a BEI of less than 1 indicates that the actual work accomplished is unlikely to achieve the completion date

Conclusions & Recommendations

In our opinion, this is a medium quality schedule. Although the schedule is only 8 days behind the baseline finish date, approximately 50% of the activities are slipping from the November 2016 approved baseline dates. The concern is that as many of the slipping activities are on the critical path, any further delays to these activities will further delay the completion date of the project. A recovery plan has been developed and submitted by Rokstad Power Company to Manitoba Hydro, but has not been approved at this time.

Source of Information & Reference Materials

- 031063 RPC Update to 20th August 2017 – POBS Removed.xer
- 031063 RPC Approved Baseline November 2016 – POBS Removed.xe5

Finding No. 7: Bipole III Transmission Line - Master Schedule

Observations & Findings

The Bipole III Transmission Line Master Schedule has a start date of 25th January 2014 and a completion date of 31st July 2018. The project is currently in progress with a status date of 1st October 2017. It has 131 normal activities of which 93 are complete, 22 are in progress and 16 are still planned. It contains 54 milestones, no summaries and 40 LOE (Level of Effort) activities. The project baseline start date was 14th February 2014 with the baseline finish date of 31st July 2018. The project is currently on schedule.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The Bipole III Transmission Line Master Schedule scored 36, giving it a 22% probability of success
- Schedule Quality: Scored 36% versus a score of 75% or better which is considered a 'good' schedule

- Missing Logic: This metric measures the total number of activities that are missing a predecessor, a successor or both. Missing Logic is a core project quality check and the score should not exceed 5%. The score for this schedule is 41%
- [redacted] Schedule paths with [redacted] typically arise due to artificially constrained activities. The metric identifies activities with total float greater than 2 months and should not exceed 5%. This schedule scored 74%. [redacted] 4b, 8a
- High Duration: Measures the number of activities with [redacted] and typically this should not exceed 5%. The score for this schedule is 47% and this generally indicates that the schedule is too high level for adequate planning and controls
- Baseline Execution Index (BEI): Measures the efficiency with which actual work has been accomplished when measured against the baseline. The BEI score for this schedule is 0.87. The more activities that are completed on time or ahead of the baseline schedule will reflect a BEI of 1 or more. Conversely, a BEI of less than 1 reflects work that is finishing behind schedule

Conclusions & Recommendations

The overall quality of the schedule is considered low. In speaking with Manitoba Hydro's scheduler, we were advised that the Bipole III Master Transmission Line Schedule is a high-level schedule only. For detailed information, the Bipole III Master Programme schedule should be used.

As the Bipole III Transmission Line In-Service Date is 31st July 2018, this project has been identified as progressing on schedule. However, it is worth noting that approximately 61% of the normal activities are slipping from their baseline dates.

The overall Bipole III project is on schedule but the transmission line contractors are not. Recovery plans from both contractors have been submitted to Manitoba Hydro for review.

Source of Information & Reference Materials

- BPIII TL Master Schedule September 2017 POBS Removed.xer
- BPIII TL Master Schedule Baseline 2016 POBS Removed.xer

SCOPE ITEM 18:

Review, assess, and determine the reasons for project cost overruns since the final pre-construction control budget of $1.66 billion.

Finding No. 1: Bipole III Transmission Line - Project Cost Overruns from $1.66 billion Final Pre-Construction Budget

Observations & Findings

We reviewed the "Bipole III Project, Basis of Estimate Document, September 2014 Cost Estimate Update". The overall project cost has increased by $302 million from the $1.66 billion final pre-construction control budget to $1.96 billion.

Table 1: Comparison of Budgets

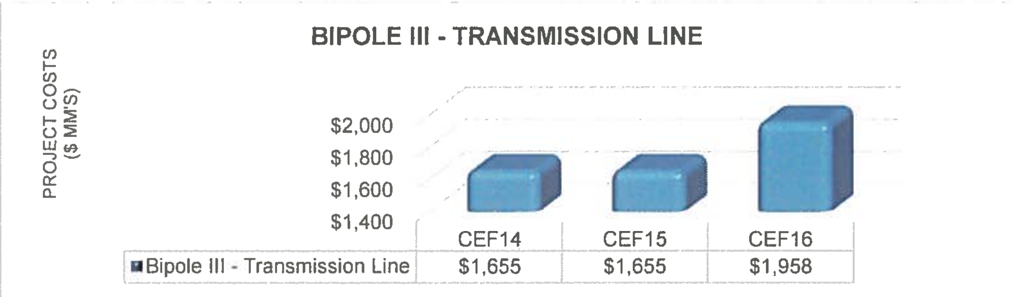
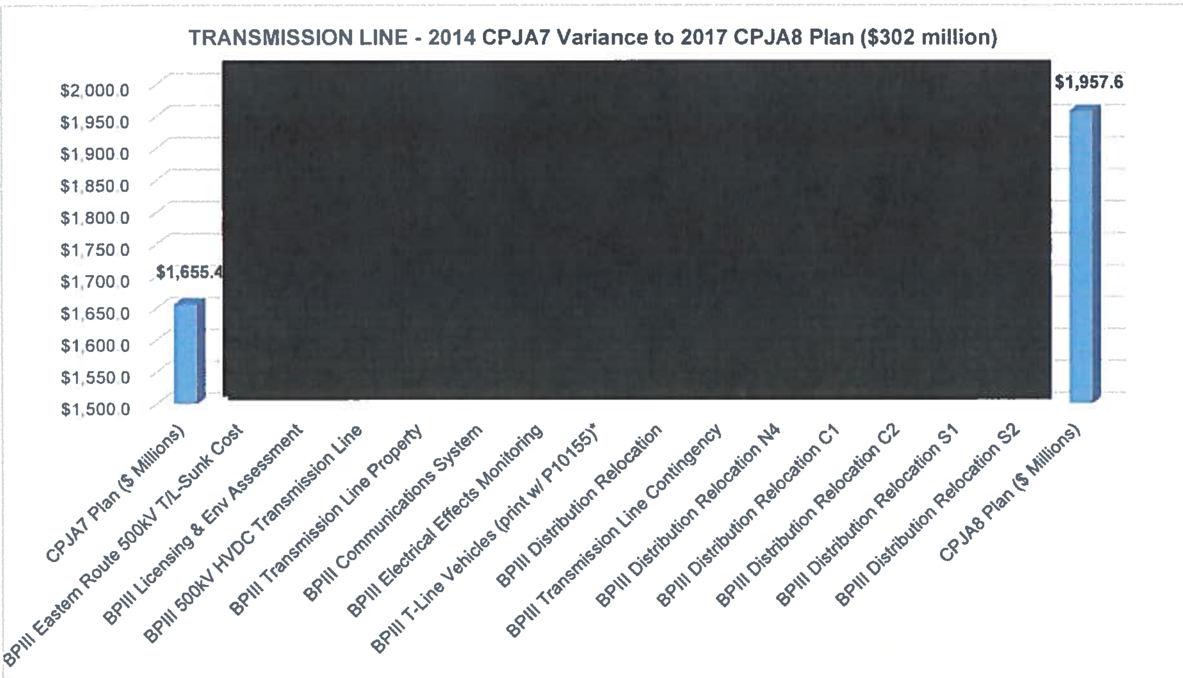


Table 2, below identifies the variances resulting in the project cost increase of $302 million.



1a

Values above are reflective of Manitoba Hydro planned costs, that were provided by Manitoba Hydro in September 2017.

Key contributing factors driving the overall project cost increases are related to the following cost elements:

- BPIII 500 kV HVDC Transmission Line (P:10155) - [redacted]
- BPIII Transmission Line Property (P:14518) - [redacted] 1a, 4b, 8a,
- BPIII Transmission Line Vehicles (P:20255) - [redacted]
- BPIII Transmission Line Contingency (P:23817) - [redacted]

These cost elements account for [redacted] project cost increase. There is a $5 million cost reduction related to the communications system that reduces the project cost increase to $302 million. 1a, 4b, 8a,

Manitoba Hydro provided MGF with an additional document entitled "Scope Summary - from Bipole III TL CPJ 8A," that was referred to during a meeting in early September. This document does not satisfy the requirements of a formal Basis of Estimate, but does provide high level explanations for variations to the budgets presented in CEF16 from CEF14.

MGF PROJECT SERVICES

The justification for the $302 million cost increase is presented in this document as follows:

[redacted] increase: 1a, 4b, 8a

- Higher than planned "actual" market rates associated to anchors and foundations, tower assembly, erection and stringing contracts
- Delay claims (weather and material)
- Construction schedule compression (including schedule acceleration by helicopter tower erection in sections N2, N3, S1 and S2
- Biosecurity matting in S1 & S2
- Increased equipment and vehicles to support construction

[redacted] increase: 1a, 4b, 8a

- Additional materials required for southern route changes
- Costs associated with delays in materials
- Premiums to accelerate materials
- Engineering and material management contract cost increases

[redacted] increase: 1a, 4b, 8a

- Increased property costs for finalized southern route
- Inclusion of Land Valuation Appraisal Council (LVAC) certification
- Legal fees

[redacted] increase: 1a, 4b, 8a

- Increase in material management costs
- Increase in project and construction management costs

[redacted] increase:

- [redacted] 1a, 4b, 8a
- [redacted]

[redacted] increase: 1a, 4b, 8a

- Increase to project contingency (from P50 to P80)

$48 million decrease:

- Interest and escalation reduction due to compressed schedule and later than planned spends

Conclusions & Recommendations

Many of the additional costs appear to be a result of a project that was perhaps not at a stage of readiness at the time of project approval in terms of permit approvals, design development, land acquisitions and execution planning (i.e. procurement cycle and delivery time, market underpinned costing based on a tested and firm strategy, etc.).

Addressing many of the above elements prior to entering the project execution phase would have likely de-risked many of the project costs incurred.

Source of Information & Reference Materials

- Bipole III Project, Capital Cost and Schedule Risk Analysis and Contingency Estimate, dated 29th August 2014
- Scope Summary – from Bipole III TL CPJ 8A, presented 5th September 2017
- BPIII T Line actual costs to Sept. 2017 – ACTUALS
- BPIII T Line Contingency Drawdown Tracking_2017 08 09
- CPJA8 CPJA7 Comparison

SCOPE ITEM 19:

Assess Manitoba Hydro's updated forecast at completion capital cost, including whether appropriate contingencies and reserves have been provisioned, and schedule estimates for reasonableness.

Finding No. 1: Bipole III Transmission Line - Sections N1 and N4

Observations & Findings

Manitoba Hydro carries [redacted] its Estimate to Go Forward dated 16th June 2016 for the counterpoise scope. The cost of this work valued in accordance with Rokstad Power Company's Contract No. 031063 is [redacted] 1a, 4b, 8a

Conclusions & Recommendations

The estimated cost should be updated in accordance with Rokstad's contract. This will reduce the forecast at completion cost by [redacted] 1a, 4b, 8a

Source of Information & Reference Materials

- BPIII Estimate Rev 2 _ TLCC
- BPIII Transmission Line CPJA8 (2016) – 05
- Manitoba Hydro Contract No. 031063

Finding No. 2: Bipole III Transmission Line - Contingency

Observations & Findings

The following observations are taken from the September 2017 Bipole III Project Construction Report and the October 2017 Milestone Schedule:

- Project is 68% complete
- Targeted completion is 31st July 2018
- Contingency balance as of 1st November 2017 is [redacted] of the forecast work to go 7a

Conclusions & Recommendations

Based on the performance to date, it would appear that the contingency amount for the 500kV Transmission Line will be sufficient. The contracts for the 500kV Transmission Line are either lump sum or unit rate, so the risk is low that the contingency would be exceeded. This may be impacted by Rokstad's performance issues.

Source of Information & Reference Materials

- September 2017 Bipole III Project Construction Report
- PCS Log
- PCA Log
- October 2017 Milestone Schedule

Finding No. 3: Bipole III Transmission Line - Contingency Review

Observations & Findings

Contingency and management reserve carried in the final pre-construction budget was [redacted] in Contingency and [redacted] in Management Reserve). Contingency was set using a P50 value 7a
on an estimate value of $1.191 billion and a scheduled In-Service Date of July 2018. The total Contingency plus Management Reserve carried for the project was [redacted]

MGF has reviewed a Manitoba Hydro third-party consultant's report that was developed as part of the Bipole III Project Risk and contingency review in August of 2014. This report identified and proposed the following contingencies and reserves:

- Contingency (Cost)
    - P10, [redacted]
    - P50, [redacted]
    - P90, [redacted] 7a
- Bipole III - Contingency (Schedule)
    - P50, [redacted]
- Transmission - Reserve Risks

- Lost Season, [redacted]
- Bidding Market, [redacted] 7a
- Biosecurity, [redacted]

The justification and recommendation for the reserves within the report were outlined as follows and it was suggested that Manitoba Hydro fund an amount to cover the costs of the risks:

- Lost Season, [redacted] - a moderate to high probability was identified for one of the following to occur, which would result in an additional construction season. These are noted as delay impacts: 7a 8a
  - Late permits
  - Weather
  - Labour Shortage
- Bidding Market, [redacted] - moderate probability that the "historical" cost of local suppliers used in the estimate will not reflect the pricing of international contractors faced with a mega-project in a tough environment. Not a delay impact 7a 8a
- Biosecurity, [redacted] - a moderate probability that permit requirements will require the use of matting to be used for construction of Southern segments. Not a delay impact
- Two additional risks associated to the Converter Stations had been included within the listing of reserves:
  - Lost Season, [redacted] 7a 8a
  - Labour Shortage, [redacted]

It was recommended that for the project business case analysis, Manitoba Hydro use the P95 value, plus escalation.

CPJA 8a authorized an additional [redacted] to address remaining risks and schedule protection. This authorization increases the contingency carried within the project to [redacted] or as stated by Manitoba Hydro, a P80 or 80% confidence level. The difference between the P50 and P90 values carried within the third-party report for the Transmission Line scope was [redacted] This value does not account for any reserve, as indicated above. 7a 8a

In the "Scope Summary – from Bipole III TL CPJ 8A" document provided to MGF, Manitoba Hydro has indicated that "*...it is assumed that at completion of the project risks will have materialized and budget dollars previously allocated for Contingency will be depleted.*".

The remaining risks and the allocation of the available contingency [redacted] were provided by Manitoba Hydro as follows:

- [redacted] - biosecurity measures, schedule acceleration [redacted], and route alterations 1a, 7a, 8a
- [redacted]

- [redacted]
- [redacted]- potential material changes and quantity variations, [redacted]
- [redacted]- cover contract contingency for material supply and anchor foundation installation 1a, 7a, 8a
- [redacted]
- [redacted] potential schedule acceleration resultant interest and escalation changes to maintain the In-Service Date

Conclusions & Recommendations

The current value that Manitoba Hydro has indicated is at the P80 confidence level, and does not appear to be based on a current or updated review. This does not take into consideration events and updated risks that the project has been or may be exposed to.

Manitoba Hydro's corporate standard currently states that a set contingency of P50 or 50% confidence level is used.

This may be impacted by Rokstad's performance issues.

Source of Information & Reference Materials

- Bipole III Project, Capital Cost and Schedule Risk Analysis and Contingency Estimate, dated 29th August 2014
- Scope Summary – from Bipole III TL CPJ 8A, presented 5th September 2017
- BPIII T Line actual costs to Sept. 2017 – ACTUALS
- BPIII TLine Contingency Drawdown Tracking_2017 08 09
- CPJA8 CPJA7 Comparison

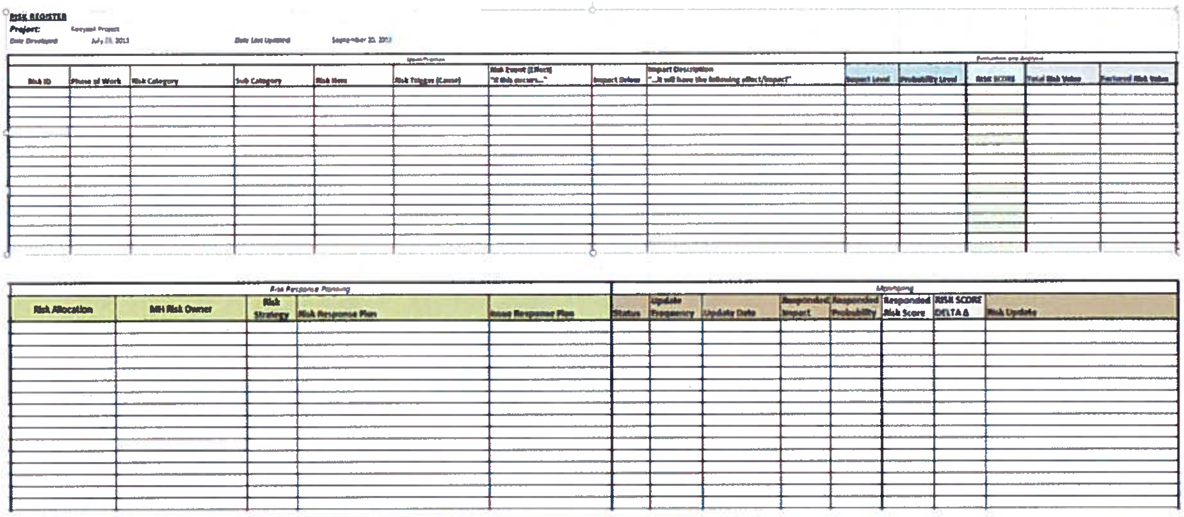
SCOPE ITEM 20:

Identify aspects of the updated cost estimate and schedule that are at heightened levels of risk and recommend risk mitigation strategies that Manitoba Hydro should use.

Finding No. 1: Bipole III Transmission Line - Risk Review

Observations & Findings

Manitoba Hydro does not have a specific Risk Management Plan for the Bipole III Transmission Line Project which has been identified as a requirement for all projects in the Keeyask and Converter Station Projects Procedure (RSK-001). Illustrated below is the Risk Register template included in the Procedure.


RISK REGISTER
Project: Keeyask Project
Date Developed: July 23, 2013 Date Last Updated: September 20, 2013

Risk ID	Phase of Work	Risk Category	Sub Category	Risk Item	Risk Trigger (Cause)	Risk Event (Effect) "If this occurs..."	Impact Driver	Impact Description "...it will have the following effect/impact"	Impact Level	Probability Level	RISK SCORE	Total Risk Value	Factored Risk Value

Risk Allocation	MH Risk Owner	Risk Strategy	Risk Response Plan	Issue Response Plan	Status	Update Frequency	Update Date	Responded Impact	Responded Probability	Responded Risk Score	RISK SCORE DELTA Δ	Risk Update

Overall, the Risk Register used for the Bipole III Transmission Line project appears to be thorough, containing typical information necessary to track and monitor potential projects risks; however, key information that is missing includes the date the Register was last updated and the date the specific Risk line item was last updated.

Some of the "potential" risks identified in the register related to specific issues that had already occurred on the project (e.g., BPIII TLR 38 - Section [redacted] Tower steel damaged by Contractor during Tower Erection Operation) and they were classified with a low probability which puts into question whether risks are being assessed correctly. 1a, 1c, 4b

Conclusions & Recommendations

MGF recommends the date the Register was last updated and the date the Risk ID was last updated be added to the Risk Register. The probability assessed to the specific risks should also be reviewed for accuracy.

Source of Information & Reference Materials

- RSK-001 Keeyask and Converter Station Projects Procedure
- Practice Standard for Risk Management (Project Management Institute)
- Bipole III Risk Register

Finding No. 2: Bipole III Transmission Line - Schedule Risk

Observations & Findings

The Transmission Line Integrated Master Schedule is a high level schedule which uses constraints rather than logic to set the start date for many of the activities. The schedule is currently progressing on schedule; however, the majority of the activities are slipping from their baseline dates. The biggest risk to the schedule is the stringing productivity by Rokstad. Manitoba Hydro requested a recovery plan from Rokstad which was not approved. Effective 9th November 2017, Manitoba Hydro removed scope of work from Rokstad Power Company for Tower 1 to 231 (inclusive) in the N1 section only.

Conclusions & Recommendations

Replacing Rokstad Power Company with another contractor for work located in Section N1 does not guarantee the project will finish as planned. The risk to the project in service date is still high and will remain so until a new contractor is assigned the work.

Source of Information & Reference Materials

- Letter to Mr. Chris Poullis, Vice President Transmission Services dated 8th November 2017
- MH BPIII TL Maser Schedule Sept 2017 POBS Removed.xer
- MH BPIII TL Master Schedule Baseline 2016 POBS Removed.xer

Finding No. 3: Bipole III Transmission Line - Contractor Risk

Observations & Findings

Both Rokstad Power Corporation (Rokstad) and Forbes Brothers Ltd. (Forbes) have had performance issues which continue in to the 2017/2018 winter season.

An analysis of the respective unit prices provided by Rokstad and Forbes would suggest that Rokstad may have front loaded its tender. [redacted] 1a, 4b, 7a, 8a

Manitoba Hydro in its letter dated 3rd October 2017, Manitoba Hydro addressed lack of progress issues with Rokstad, [redacted]

[redacted]

[redacted] 1a, 4b, 7a, 8a

[redacted]

Conclusions & Recommendations

Manitoba Hydro needs to properly record its cost associated with placing the removed scope with another contractor and to record the extra over costs it has incurred in having the new contractor perform Rokstad's removed scope.

Source of Information & Reference Materials

- Transmission, Bipole III Project Construction Report, September 2017
- Scope Summary – from Bipole III TL CPJ 8A
- Forbes Contract, Submission Form C.1.1 – Cost of Performing the Work, Section N2
- Manitoba Hydro letter dated 8th November 2017

SECTION 6 - Manitoba – Minnesota Transmission Project

SCOPE ITEM 21:

Determine whether the current state of design and engineering work supports the $453 million cost estimate. If not, identify what changes in the contingencies, reserves, or forecast at completion cost are required.

Finding No. 1: MMTP Transmission Line - Stanley Consultants Inc.

Observations & Findings

On account of the one-week timeframe that Stanley Consultants Inc. ("Stanley") had to perform their work, MGF directed Stanley to those areas where it was felt that Stanley's efforts in the one week available would add best input and content for the review.

Stanley, through its review of the estimates, did review certain aspects of the design and engineering drawings and specifications but have not commented specifically on these.

Conclusions & Recommendations

As such, Stanley did not address this scope.

Source of Information & Reference Materials

SCOPE ITEM 22:

Review and assess Manitoba Hydro's cost estimating methodologies that support the $453 million cost estimate, identifying best practices and short-comings.

Finding No. 1: MMTP - Cost Estimating Methodologies

Observations & Findings

A formal Basis of Estimate document which normally describes the cost estimating methodologies for the project was not prepared by Manitoba Hydro.

MGF describes Manitoba Hydro's cost estimating methodology as follows:

- Estimate methodology is "deterministic" as defined by AACE RP – 18R-97, which involves the predominant use of unit cost line items. Manitoba Hydro's cost estimating methodology is consistent with industry standard
- Detailed Estimates sheets are developed by Manitoba Hydro's subject matter experts in each respective field involved in the project (civil design, controls, apparatus procurement,

construction, commissioning, etc.) Some Excel estimate sheets include estimate preparation background and assumptions

- The estimate reflects Manitoba Hydro's most detailed scoping exercise, which includes a final preferred route for the transmission line, planning for indigenous opportunities in the project and final system studies out of Manitoba Hydro's planning and design groups
- Details for the breakdown of costs are included for the Transmission Line Construction and Design spreadsheets that includes estimated quantities and unit rates
- Estimate details for other Network/WBS were likewise developed in Excel spreadsheets and were input into SAP
- Interest and Escalation calculations are done automatically within Manitoba Hydro's accounting software (SAP)

Best Practices Identified

- The level of project definition as described in the scope of work is considered reasonable to develop the quantities
- Historical project unit rates and recent pricing is reasonable for the class of estimate
- Using Project Estimate templates provides consistency and familiarity with the estimate

Short-comings

- A Basis of Estimate was not created for the $453 million cost estimate
- Estimate detail sheets provided do not capture the level of detail provided in the Network / WBS scope of work
- Scopes of work for each Work Breakdown Structure are outdated and need revising
- Design/Material Take Off and Construction Waste Allowances are not identified or included for Equipment and Material Key Quantities. Allowances will be developed by the estimating team and department leads

Conclusions & Recommendations

MGF recommends that an appropriate Basis of Estimate (BoE) be developed for the project. Preparing a BoE is an industry Best Practice for all levels of estimates as it supports in ensuring many aspects of the project are understood, and/or necessary assumptions made at the time of estimate development have been documented.

As outlined by AACE International Recommended Practice No. 34R-05, "a well written basis of estimate will:

- Document the overall project scope
- Communicate the estimator's knowledge of the project by demonstrating and understanding of the scope and schedule as it relates to cost
- Alert the project team of potential cost risks and opportunities
- Provide a record of key communications made during estimate preparation

- Provide a record of all documents used to prepare the estimate
- Act as a source of support during dispute resolution
- Establish the initial baseline for scope, quantities and cost for use in the cost trending throughout the project
- Provide historical relationships between estimates throughout the project lifecycle
- Facilitate the review and validation of the cost estimate"

A Basis of Estimate should:

- Be factually complete, but concise
- Be able to support facts and findings
- Identify estimating team members and their roles
- Describe tools, techniques, estimating methodology and data used to develop the cost estimate
- Identify other projects that were referenced or benchmarked during the estimate preparation
- Be prepared in parallel with the cost estimate
- Establish the context of the estimate, and support estimate review and validation
- Qualify any rates or factors that are referenced either in the estimate or BoE"

Suggested guidelines for the structure, topics and contents are also included within the Recommended Practice that will assist Manitoba Hydro in ensuring consistent and transparent cost estimates.

Source of Information & Reference Materials

- email from Patrick Allan, Section Head, Transmission Projects Management Section, dated 15th November 2017
- TL and CD Estimate - Dorsey 500kv Tie Line – 246409.xls
- MMTP Summary of the Environmental Impact Statement – file name mmtp_is_summary
- Network P:16957 WBS 246409 based on Overall SOW - MMTP - 500kV Transmission Line dated 2016-11-16
- Network P:16958 WBS 246410 based on Overall SOW - MMTP - Dorsey Stn dated 2015-06-01
- Network P:21616 WBS 250480 based on Overall SOW - MMTP - Glenboro Station dated 2015-06-01
- Network P:16959 WBS 246411 based on Overall SOW - MMTP – Riel Transformer Addition dated 2016-09-30
- AACE International Recommended Practice No. 34R-05, Basis of Estimate, TCM Framework: 7.3 – Cost Estimating and Budgeting, dated 2nd May 2014

SCOPE ITEM 23:

Review and assess Manitoba Hydro's proposed tendering and contracting methodologies, including choices of contract types for the major contracts.

Finding No. 1: MMTP - Tendering & Contracting

Observations & Findings

Manitoba Hydro has not placed significant contracts for this project as yet. However, it should follow and learn from the experience of performing the Bipole III Transmission Line contracts. These were a mix of lump sum, unit rate, cost reimbursable and material supply contracts. Any variations arising on these contracts should be taken account of in the development of tenders for the MMTP project so that issues are not repeated.

Conclusions & Recommendations

Manitoba Hydro can apply the lessons learned on the Bipole III Transmission Line project in developing its contracting strategy for this project and the required suite of contracts with which to execute the project.

SCOPE ITEM 24:

Review and assess Manitoba Hydro's proposed construction management, contractor management, construction risk management, and scheduling methodologies.

Finding No. 1: MMTP - Schedule

Observations & Findings

The 26410 Dorsey 500kV Station Terminate Tie Line Project schedule was created from an existing template which promotes and ensures consistency between similar projects. It had a start date of 23rd July 2013 and is currently in progress with a completion date of 13th November 2020. The project is currently on schedule. As of 2nd October 2017, the schedule has 151 normal activities of which 9 are complete, 14 are in progress and 128 are still planned. The schedule is being updated every two months but should be updated more frequently once construction activities commence.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defense Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Schedule Quality: Scored 61% versus a score of 75% or better which is considered a 'good' schedule
- Logic Density: Assesses the average number of logic links per activity. An average of less than two indicates the schedule should be reviewed and updated with additional logic links. The

schedule scored 3.71. An upper limit of four is also recommended as logic density above this threshold indicates an overly complex logic within the schedule. The logic density peaks at 4.11 in 2019. These activities should be reviewed and updated

- Missed Activities: This measures the number of activities that have slipped from their baseline performance and is a measure of how good execution performance is. The schedule has 33 missing activities and all of these have high float thereby have no impact on the currently forecasted project finish date

Conclusions & Recommendations

The project is on schedule as per status date of 2nd October 2017. Once construction activities commence, the schedule should be reviewed and updated more frequently than the current every two months. Activities related to the logic density peaking at 4.11 in 2019 should be reviewed and updated to reduce potential complexity.

Finding No. 2: MMTP - Riel 500 or 230KV Stn. – Inst. Transformer Schedule

Observations & Findings

The Riel 500 or 230kV Stn – Inst. Transformer schedule has a start date of 23rd July 2013 and a completion date of 16th November 2020. The project is currently in progress with a status date of 2nd October 2017. It has 87 normal activities of which 10 are complete, 2 are in progress and 75 are still planned. It contains 16 milestones, no summaries and 17 LOE (Level of Effort) activities. The project baseline start date was the 5th January 2016 with the baseline finish date being 16th November 2020. The project is currently on schedule.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: is a single quality indicator resulting from a summary of detailed analysis. The Riel 500 or 230kV Stn – Inst. Transformer forecast schedule scored 64, giving it a 62% probability of success
- Schedule Quality: Scored 64% versus a score of 75% or better which is considered a 'good' schedule
- Missing Logic: This metric measures the total number of activities that are missing a predecessor, a successor or both. Missing Logic is a core project quality check and the score should not exceed 5%. The score for this schedule is 15%
- High float: Schedule paths with high amounts of float typically arise due to artificially constrained activities. The metric identifies activities with total float greater than 2 months and should not exceed 5%. This schedule scored 86%. Paths with float more than 2 months should be considered for acceleration and schedule optimization

- High Duration: Measures the number of activities with total float greater than 2 months and typically this should not exceed 5%. The score for this schedule is 41% and this generally indicates that the schedule is too high level for adequate planning and controls

Conclusions & Recommendations

The overall quality of the schedule is medium quality. The biggest areas for improvement include fixing logic areas, removing hard constraints on completed activities and modifying remaining hard constraints to soft constraints. The high duration is a concern, however Manitoba Hydro indicated that construction contracts have not been awarded. We recommend that these long duration activities be decomposed into more detail once contracts have been awarded and contractor schedules have been approved.

Finding No. 3: MMTP - Glenboro Transmission Line Re-Alignment Schedule

Observations & Findings

The Glenboro Transmission Line Re-Alignment has a start date of 1st July 2015 with a completion date of 13th November 2020. As of 2nd October 2017, the schedule has 26 normal activities of which 2 are complete, 1 is in progress and 23 are still planned. It contains 5 milestones, no summaries and 19 LOE (Level of effort) activities.

There is no baseline schedule for this scope of work. The schedule was recently created (no date on the information reviewed) to address some additional scope which was estimated but not scheduled in the 2016 budget. As there is no baseline schedule, Earned Value Management cannot be performed.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Schedule Quality: Scored 64% versus a score of 75% or better which is considered a 'good' schedule
- Missing Logic: This metric measures the total number of activities that are missing a predecessor, a successor or both. Missing Logic is a core project quality check and the score should not exceed 5%. The score for this schedule is 39%
- High Duration: measures the number of activities with total float greater than 2 months and typically this should not exceed 5%. The score for this schedule is 28% and this generally indicates that the schedule is too high level for adequate planning and controls

Conclusions & Recommendations

The schedule should be reviewed and address issues related to Missing Logic. Inaccurate logic in a schedule may put the project finish date at risk, as the correct critical path may not be identified or understood.

The identified High Duration activities should be decomposed into more detail to properly understand and monitor the plan.

Source of Information & Reference Materials

- MMTP – MGF Request – October 2017

Finding No. 4: MMTP - Glenboro Phase Shifter Schedule

Observations & Findings

The Glenboro Line G82R Phase Shifter schedule has a start date of 1st March 2013 and a completion date 5th May 2021. The project is currently in progress with a status date of 2nd October 2017. It has 117 normal activities of which 5 are complete, 7 are in progress and 105 are still planned. It contains 31 milestones, no summaries and 23 LOE (Level of Effort) activities.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office (GAO) Scheduling Best Practices and the US National Defence Industrial Association (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The Glenboro Line G82R Phase Shifter forecast schedule scored 60, giving it a 55% probability of success
- Schedule Quality: Scored 60% versus a score of 75% or better which is considered a 'good' schedule
- Missing Logic: This metric measures the total number of activities that are missing a predecessor, a successor or both. Missing Logic is a core project quality check and the score should not exceed 5%. The score for this schedule is 40%
- Negative float: Ideally there should not be any negative float in a schedule. Negative float is a result of an artificially accelerated or constrained schedule and indicates that a schedule is not possible based on current completion dates. The analysis determined that 11% of activities contained negative float
- High Duration: Measures the number of activities with total float greater than 2 months and typically this should not exceed 5%. The score for this schedule is 40% and this generally indicates that the schedule is too high level for adequate planning and controls

Conclusions & Recommendations

The overall quality of the schedule is medium quality. The biggest areas for improvement include fixing logic areas, removing hard constraints on completed activities, modifying remaining hard constraints to soft constraints.

Source of Information & Reference Materials

- MMTP – MGF Request – October 2017

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Finding No. 5: MMTP - Dorsey Stn: Manitoba – US 500kV Tie Line schedule

Observations & Findings

Dorsey Stn: Manitoba - US 500kV Tie Line schedule has a start date of 1st April 2010 and a completion date of 13th November 2020. The project is currently in progress with a status date of 31st July 2017. It has 84 normal activities of which 23 are complete, 23 are in progress and 38 are still planned. It contains 28 milestones, no summaries and 14 LOE (Level of Effort) activities. The project baseline start date was 12th July 2013 with the baseline finish date of 13th November 2020. The project is currently on schedule.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office (GAO) Scheduling Best Practices and the US National Defence Industrial Association (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The Dorsey Stn: Manitoba – US 500kV baseline schedule scored 42, giving it a 30% probability of success
- Schedule Quality: Scored 45% versus a score of 75% or better which is considered a 'good' schedule
- Missing Logic: This metric measures the total number of activities that are missing a predecessor, a successor or both. Missing Logic is a core project quality check and the score should not exceed 5%. The score for this schedule is 29%
- Logic Density: Assesses the average number of logic links per activity. An average of less than two indicates the schedule should be reviewed and updated with additional logic links. The schedule scored 3.00. An upper limit of four is also recommended as logic density above this threshold indicates an overly complex logic within the schedule. The logic density rises to 4.2 and 4.71 in years 2019 and 2020. These activities should be reviewed and updated
- High float: Schedule paths with high amounts of float typically arise due to artificially constrained activities. The metric identifies activities with total float greater than 2 months and should not exceed 5%. This schedule scored 66%. Paths with float more than 2 months should be considered for acceleration and schedule optimization
- High Duration: Measures the number of activities with total float greater than 2 months and typically this should not exceed 5%. The score for this schedule is 38% and this generally indicates that the schedule is too high level for adequate planning and controls
- Baseline Execution Index (BEI): Measures the efficiency with which actual work has been accomplished when measured against the baseline. The BEI score for this schedule is 0.27. The more activities that are completed on time or ahead of the baseline schedule will reflect a BEI of 1 or more. Conversely, a BEI of less than 1 reflects less than forecasted schedule execution

Conclusions & Recommendations

The overall quality of the schedule is medium quality. Manitoba Hydro uses a common template for these schedules which is good for consistency across schedules. However, the template should be modified as required for project specific information. The most important improvement required to this schedule is to review the logic which is the leading contributor to the poor Acumen Fuse score. Missing logic needs to be added to this schedule; leads should be removed; Start to Start and Finish to Finish Relations should be replaced with Finish to Start relations where possible. The High Duration and insufficient detail is a concern. Manitoba Hydro has indicated that construction contracts have not been awarded yet and we would recommend that these long duration activities are decomposed into more detail once contracts have been awarded and contractor schedules are approved.

Source of Information & Reference Materials

- MMTP – MGF Request – October 2017

SCOPE ITEM 25:

Assess Manitoba Hydro's updated capital cost estimate of $453 million for reasonableness, including whether appropriate contingencies and reserves have been provisioned.

Finding No. 1: MMTP - Estimate Reasonableness

Observations & Findings

Manitoba Hydro's Development Plan presently includes the construction of a new 500kV Transmission Line between Winnipeg and Duluth, Minnesota. The transmission line will originate at Dorsey Converter station and head south to the Manitoba-Minnesota border.

The project also includes associated upgrades at Dorsey, Riel and Glenboro stations. This scope of work addresses the design and construction of the new 500kV transmission line and the associated licensing, environmental assessment and property acquisition requirements. The In-Service Date for the project is 31st May 2020.

The following table is the summary provided by Manitoba Hydro outlining the MMTP Network Level Budget.

Manitoba Minnesota Transmission Project

Network Level Budget

Plan version: CPJ

Investment program: 2.5.13.1.01.1

Network/WBS	Description	Planned Dollars (CAD$)
246409	Dorsey-U.S 500kV Tie Line	[redacted]
P:16957	WBS level plan (interest & esc.)	
P:16957	**Dorsey-U.S 500kV Tie Line**	
246410	Dorsey 500 kV Stn- Terminate Tie Line	
P:16958	WBS level plan (interest & esc.)	
P:16958	Dorsey 500kV Stn - Terminate Tie Line	
246411	Riel 230/500 kV Stn - Install Transfrmr	
P:16959	WBS level plan (interest & esc.)	
P:16959	Riel 230/500kV Stn-Auto Transform Instal	
246416	MB-US 500 kV Facilities-Communication	
P:16961	WBS level plan (interest & esc.)	
P:16961	MB-US 500kV Facilities - Communication	
246417	MB-US 500 kV Facilities-Lic.& Env	
P:16962	WBS level plan (interest & esc.)	
P:16962	**MB-US 500kV Facilities-Lic. & Env.**	
250480	Glenboro Phase Shifter	
P:21180	WBS level plan (interest & esc.)	
P:21180	Glenboro Phase Shifter	
250863	Glenboro Transmission Line Re-Alignment	
4304577	Glenboro South 66kV Line Relocation	
P:21616	WBS level plan (interest & esc.)	
P:21616	Glenboro Transmission Line Re-Alignment	
254740	Project Contingency	

1a, 4b, 7a

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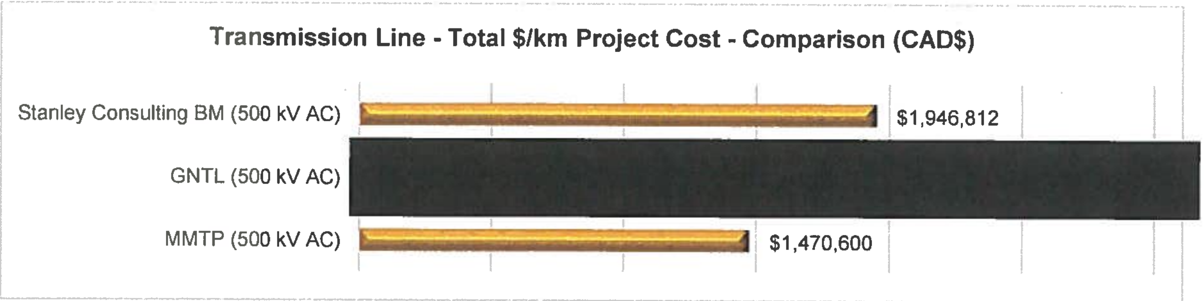
255903	Management Reserve	$	[redacted]
255904	Indigenous Relations Opportunities	$	[redacted]
P:25309	WBS level plan (interest & esc.)	$	[redacted]
P:25309	MMTP Contingency	$	[redacted]
257274	MMTP Indigenous Agreements	$	[redacted]
P:28314	WBS level plan (interest & esc.)	$	[redacted]
P:28314	MMTP Agreements and Programs	$	[redacted]
		TOTAL	**453,209,197.65**

1a, 4b, 7a,

MGF's review has focused on the transmission line and related scope of work, which represents [redacted] of the total project budget ([redacted] excl. Contingency).

- Dorsey 500kV T/L - [redacted]
- 500kV Facilities - [redacted]
- Glenboro Tie T/L - [redacted]
- Subtotal - [redacted]
- Contingency Prorated ([redacted] - [redacted]
- Total - [redacted]

These costs were broken down line item by line item to align with benchmark categories. The total value was converted to USD$ (at 0.787 USD per 1 CAD$) for a total of [redacted] The current project metrics suggest the costs for MMTP are lower than what other similar industry projects.



1d

We have set out below those activities whose costs are lower than other similar industry projects:

- Site Access Materials - Site access is based on ground conditions. This project corridor based on route maps provided, passes through areas requiring a higher level of site access than benchmark projects. Given probable conditions and standard site access methods this category is worth further review.
- Material Receipt Yards - Material receipt yard costs vary depending on the amount of civil work that is required to be performed to establish material laydown yards. Additions such as civil upgrades can increase costs. Further review is required to determine the extent to which yards are being upgraded and thus requiring restoration upon completion of use.
- Access Road/Clearing - Access/road clearing is the work required to be performed to provide off-ROW access. There appears to be no budget for this activity and given the expected ground conditions, this is of high concern and needs review, unless the budget for this resides elsewhere in the cost estimate.
- Clearing - Clearing cost is a function of the amount of vegetation to be removed to allow for construction access and installation. Given the existing conditions based on route selection, this appears to be low.
- Anchors - Anchor costs are a function of the foundation design. MMTP and GNTL have similar foundations; additional review to explain why costs for MMTP are much lower than GNTL is required.
- BFD/Aerial Markers – these costs are a function of environmental requirements; the included costs are much lower than benchmark and GNTL. This warrants additional review to confirm if BFD/Aerial Markers estimate is sufficient.
- Optical Fiber Ground Wire – these costs are a function of the OPGW selected. The costs appear low based on length of line.
- Overhead Ground Wire (OHGW) – these costs are a function of the OHGW selected. The costs appear low based length of line.
- Reclamation - Reclamation drivers are the amount of ground disturbed during construction and the extent to which grounds need to be restored to original conditions. Given the region in which the line is being routed it should be expected that restoration costs would be lower than typical.
- Construction Management (CM) & Inspection - CM and inspection costs are a function of the duration of construction as well as the number of inspectors required to verify construction compliance. Based on project complexity and length of construction these costs appear low.
- Construction Management (CM) - CM costs appear to be low based on scope and length of construction. The cost included appears low compared with benchmark values.
- CM Indirects - CM Indirects are a function of additional inspection, design work, or other construction related work. These costs should be reviewed in conjunction with CM cost.
- Legal (Internal) - Legal costs are a function of the amount of effort required to acquire land and permitting functions. Lower values indicate an easier approval process.
- Design Engineering - Design engineering costs are a function of the time and effort to develop operating design. Lower values would indicate either usage of standardized design or a more streamlined design process.

- Permitting - Permitting costs are a function of the effort required to research, develop applications, and obtain approvals of permitting applications for the line. Lower costs indicate a more streamlined permitting plan.

Areas of higher than expected costs have been identified as follows:

- Tower Steel - Tower steel is a function of the type and design of the towers required for the project. Given the type and configuration this costs appear high.
- Conductor - Line appears to be utilizing ACSR, key drivers are conductor type and whether conductor is bundled adding additional cost. Given voltage and load factors, the cost appears to be a little high but not excessive.
- Environmental – Environmental costs are driven by the level of environmental inspection and approvals required to permit the project. Given a greater amount of approval/review and a satisfactory permitting of the project, this may not be a concern but requires additional review based on difference to similar project (GNTL). MMTP appears to be at a higher cost.
- Survey & Geotech - Survey & Geotech work is based on work scope and amount of activities necessary to permit and perform construction. Higher number of survey activities required can drive up this cost. This activity needs further review.
- Community Affairs - Community affairs are driven much like public involvement and are a function of company outreach to inform public of the project and receive public input related to the permitting process. Harder to permit areas will drive community affairs costs higher.
- [redacted] 8a
- Public Involvement - Public involvement costs are driven by the required effort to obtain permitting. Project costs can vary based on the level of effort as public involvement can be viewed as an 'up front' permitting cost. Higher permitting costs can indicate project resistance early on but can result in lower follow-on permitting costs.

Conclusions & Recommendations

For comparison purposes, using similar project metrics converted from USD/mile, MMTP's current budget appears to be in the lower range of benchmarking metrics used.

MGF recommends that the items identified above are reviewed in further detail to ensure adequate budget has been provisioned.

MGF also recommends implementing an industry standard project stage gate process is recommended.

Source of Information & Reference Materials

- Overall SOW - MMTP - 500kV Transmission Line
- MMTP Network Level Budget
- Stanley Consulting Email, Re: Memo #1 – MGF High Level Cost Estimate Validation (GNTL and MMTP), dated 5th December 2017

SECTION 7 - Great Northern Transmission Line

SCOPE ITEM 26:

Compare the current GNTL estimated capital costs with estimates for similar projects and assess whether the estimated cost is reasonable.

Finding No. 1: GNTL - Capital Cost Comparison – Similar Projects

Observations & Findings

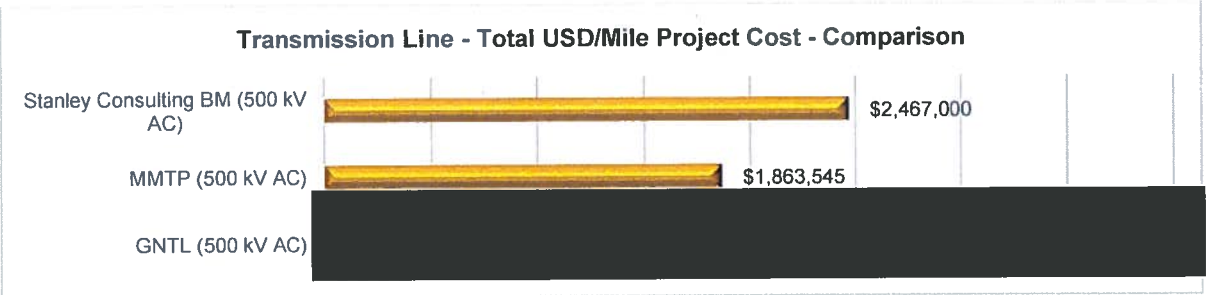
The transmission line scope of work represents 89% of the overall project budget, which is where MGF has focused this project review.

The following table represents a comparison of the GNTL Project to the Manitoba Minnesota Transmission Project (MMTP) and benchmarking data provided by Stanley Consultants Inc. ("Stanley"). These projects are based on AC transmission and a per mile cost.

Data provided by Stanley was based on the following assumptions. Currency assumed by Stanley's is US dollars, who based their estimate on referenced material from Midcontinent Independent System Operator (MISO), Western Electricity Coordinating Council (WECC) and various projects located in the great northern plains (Minnesota, North Dakota, Montana, Nebraska and Alberta Canada). The estimates are regionally based on actual project costs, with pricing escalated to reflect 2018 costs.

The costs were broken down line item by line item to align with benchmark categories. The CAD$ values were converted to USD$ (at 0.787 USD per 1 CAD$).

The current project metrics indicate that the costs for GNTL are higher than other similar industry projects.



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We have set out below those activities whose costs are lower than other similar industry projects:

- Conductor - Line appears to be utilizing ACSR, key drivers are conductor type and whether conductor is bundled adding additional cost. Given voltage and load factors, the cost appears to be a little high but not excessive
- Site Access Materials - Site access is based on ground conditions. This project corridor based on route maps provided, passes through areas requiring a higher level of site access than benchmark projects. This value appears very high given probable conditions and standard site access methods and should be further reviewed
- Material Receipt Yards - Material receipt yard costs vary depending on the amount of civil work required to establish material laydown yards. Additions such as civil upgrades can increase costs. Further review is required to determine to what extent the yards are being upgraded and thus likely restoration upon completion of use
- Construction Management (CM) & Inspection - CM and inspection costs are a function of duration of construction as well as the number of inspectors required to verify construction compliance. Longer working hours, additional work days, and longer planned construction periods drive this cost
- Project Development - Project development costs are an internal function driven by the complexity of the project. Given an international project with project specific structures and high voltage, this cost is expected to be higher than benchmark values. Routing and permitting values also drive this cost
- PM & Engineering - Project management and engineering costs are an internal function that is driven by the complexity of the project. Given an international project with project specific structures and high voltage, this cost is higher than benchmark values
- Construction Management - CM costs appear to be high based on scope and length of construction relative to benchmark projects. This category needs further review
- CM Indirects - CM Indirects are a function of additional inspection, design work, or other construction related work. These costs should be reviewed in conjunction with CM cost
- Permitting Fees - Permitting fees are a function of required regulatory fees
- Public Involvement - Public involvement costs are driven by the required effort to obtain permitting. Project costs can vary based on the level of effort as public involvement can be viewed as an 'up front' permitting cost. Higher permitting costs can indicate project resistance early on but can result in lower follow-on permitting costs
- Land Analysis - Land analysis is a function of determining the land value and ownership on potential routes. Land analysis can be driven higher with multiple routes being considered and a larger number of routes being investigated
- Total Development CPM - Project development portion is higher than benchmark data and requires additional review to understand the reasons for the additional costs

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Areas of lower than expected costs have been identified as follows:

- Grounding - Grounding costs are based on soil conditions and resistivity. The soils in the region of this project appear to be favourable to grounding conditions. For a 500kV line, the cost differential should not be this great even with these favourable conditions, so it is probable that additional grounding costs are nested within other budgetary areas
- Material Subtotal - Material costs in this format are being driven by the site access costs. Overall, removing the site access costs, this line item is lower than benchmark for material costs
- Reclamation - Reclamation cost drivers are related to the amount of ground disturbed during construction and the extent to which ground needs to be restored to original conditions. Given the region in which the line is being routed we would recommend that these restoration costs are further evaluated
- Environmental - Environmental is driven by the level of environmental inspection and approvals required to permit the project. Given a lesser amount of approval/review and satisfactory permitting of the project, these lower costs are the result
- Legal - Legal costs are a function of the amount of effort required to acquire land and permitting functions. Lower values may represent an anticipated easier approval process
- Design Engineering - Design engineering costs are a function of the time and effort to develop operating design. Lower values would indicate either usage of standardized design or a more streamlined design process
- Permitting - Permitting costs are a function of the effort required to research, develop applications, and obtain approval of permitting applications for the line. Lower costs indicate a more streamlined permitting plan

Conclusions & Recommendations

MGF finds the [redacted] transmission line estimate for the GNTL Project to be high when compared to 1d
other similar projects.

MGF recommends that further review is required and the items identified above are reviewed in further detail to ensure adequate budget has been provisioned.

Implementing an industry standard project stage gate process is recommended.

It is understood that there are provisions in place for the management of contingency draw-downs and as it stands the budget has been approved. MGF does, however, recommend that Manitoba Hydro maintain the greatest level of involvement in the areas of planning, selecting and implementation of contracting strategies, contract awarding process, management of change reviews and approvals as well as design reviews to ensure maximum value to Manitoba Hydro is achieved at a reasonable cost.

MGF recommends a detailed review of the revised estimate is performed as soon as possible. This review should be accompanied with a Basis of Estimate which addresses the items identified above.

Source of Information & Reference Materials

- CMA Pre-Constr - T-Line Project Scope Document,pdf
- GNTL Preconstruction Budget and Basis of Estimate Rev 5.26.2016.xls
- 500kV-MP_RouteCosts-5.17.2016.rev.h4.xls
- 500kV-MP_RouteCosts-5.17.2016.rev.h4.xls
- AACE International Recommended Practice No. 34R-05, BASIS OF ESTIMATE, TCM Framework: 7.3 – Costs Estimating and Budgeting.
- GNTL Preconstruction Budget and Basis of Estimate Rev 5.26.2016.xls
- Stanley Consulting Email, Re: Memo #1 – MGF High Level Cost Estimate Validation (GNTL and MMTP), dated 5th December 2017

SCOPE ITEM 27:

Review and assess the Construction Management Agreement between Minnesota Power and Manitoba Hydro's subsidiary for reasonableness, identifying whether the agreements follow best practices or have short-comings and whether Manitoba Hydro's interests are protected.

Finding No. 1: GNTL - Structure of Construction Management Agreement

Observations & Findings

The Great Northern Transmission Line (GNTL) Construction Management Agreement (CMA) between Minnesota Power (MP) and 6690271 Manitoba Ltd. (6690271) governs the finalization of pre-construction activities and construction related activities of the GNTL Project and remains in effect until construction is complete and the Project is placed in service.

The CMA provides key definitions to understand the roles of the Parties to the CMA and how it is designed to operate. Minnesota Power is a:

(i) CUU Transmission Owner (CUU TO) – transmission function.
(ii) Transmission Line Payer (TLP) – merchant function.
(iii) Construction Manager (CM) – appointed by the Participants and retained by the CUU TO's

A Participant means any CUU TO or TLP but does not include the Construction Manager. 6690271 performs the following roles:

- CUU Transmission Owner
- Transmission Line Payer (TLP)

CUU Transmission Owners are defined as Owners of the Facilities, the Discretely Owned Substation Assets and the Underlying System Improvements (USI). MP is 100% owner of Discretely Owned Substation Assets and USI; and ownership of the Facilities was divided between MP (51%) and 6690271 (49%). Immediately after the CMA was executed, 6690271 assigned its 49% ownership to MP resulting in MP being the sole owner of the Project.

The Project is comprised of the following components:

(i) Facilities (all aspects of the 500kV transmission line.)

(ii) Discretely Owned Substation Assets (the Warroad River Series Compensation Station & the 500/230kV Iron Range Substation.)

(iii) Underlying System Improvements (specified MP system improvements that are identified in Appendix G of the CMA.)

Transmission Line Payers (TLP) are the Parties funding the development and construction of the Project. Under the CMA there are two (2) TLP's, MP and 6690271 respectively responsible for 46% and 54% of the costs of the Projects (the "CM Costs").

The Management Committee (MC) is established pursuant to Article 9: Participants' Rights, Duties and Obligations for the oversight and management of matters arising under the CMA. Each Participant shall be represented on the MC. All decisions by the MC must be unanimous, therefore 6690271 has a veto right.

The table of contents of the CMA is comprehensive, follows best practice and is as follows:

- Article 2: Management of the Construction Manager
- Article 3: Contracting Responsibilities
- Article 4: Certain Pre-Construction Duties
- Article 5: Project Budget and Management of CM Costs
- Article 6: Funding
- Article 7: Description of Construction Manager Duties
- Article 8: Financial Accounting; Reporting; Independent Oversight
- Article 9: Participants' Rights, Duties and Obligations
- Article 10: Representations and Warranties
- Article 11: Completion and Acceptance of Work
- Article 12: Construction Work Warranties
- Article 13: Indemnification
- Article 14: Confidentiality Provisions
- Article 15: Breach, Cure and Default
- Article 16: Term and Termination of Agreement
- Article 17: Limitations of Liability
- Article 18: Dispute Resolution
- Article 19: Notices
- Article 20 Miscellaneous Provisions

Conclusions & Recommendations

The structure of the Construction Management Agreement meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 2: GNTL - Management of the Construction Manager (Article 2)

Observations & Findings

Article 2: Management of the Construction Manager provides for the engagement of the Construction Manager to perform the CM Services, Real Property Management Services and the Agency Authority given to and accepted by the Construction Manager.

Section 2.1 addresses the appointment of Minnesota Power to act as Construction Manager for each Participant and the fact that a Participant is serving in the capacity of Construction Manager as well as Participant, does not in any way change, modify or release such Person from its rights, interest and obligations in its capacity as a Participant under the Construction Management Agreement.

Section 2.2 requires the Construction Manager to furnish its Services at no charge in excess of its actual cost to coordinate, manage, administer, oversee and enforce the performance of the Construction Work through the Final Completion of the Project.

The Construction Manager owes the Participants a duty of care to apply the skill and judgement of its organization to the Construction Management Services in accordance with the Construction Management Agreement, all Applicable Laws, Good Utility Practice and the directives and policies of the Management Committee.

In addition to the Construction Management Services, the Construction Manager shall provide Real Property Management Services to acquire Real Property in accordance with the Right of Way Strategies and Guidelines Plan.

Each CUU TO designates and appoints the Construction Manager as its designated and disclosed agent to carry out on behalf of each Participant, the Construction Management Services and the Real Property Management Services.

Conclusions & Recommendations

Article 2 Management of the Construction Manager of the Construction Management Agreement meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

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Finding No. 3: GNTL - Contracting Responsibilities (Article 3)

Observations & Findings

Article 3: Contracting Responsibilities addresses the contracting and bidding requirements that the Construction Manager is to comply with together with identifying which approvals are required from the Management Committee (MC) in relation thereto. For example:

(i) Section 3.2.1.2 (i): MC approves CM's pre-bid qualification process.
(ii) Section 3.2.1.2 (ii): MC approves the list of interested bidders who will be invited to pre-qualify and will approve the eventual "Approved Bidders' List.
(iii) Section 3.2.1.6: MC shall approve the Bid Process Guidelines setting out the guidelines and procedures to be utilized during the bid process.
(iv) Section 3.2.2.1: CM shall provide a copy of all contracts, amendments and change orders to the MC.
(v) Section 3.2.3: CM may only enter into a Project Construction Contract with a Participant with the approval of the MC.
(vi) Section 3.2.4: CM can only amend or revise the Approved Bidders List with MC consent.
(vii) Section 3.2.5: CM shall present all Major Contracts, Major Change Orders and Material Actions to MC for approval *prior* to entering in to or undertaking such Major Contracts, Major Change Orders and Material Action,

Conclusions & Recommendations

Article 3 Contracting Responsibilities of the Construction Management Agreement meets acceptable commercial business practice. It provides Manitoba Hydro's subsidiary 6690271 with the right of approval to key decisions on the tendering, award and management of contracting.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 4: GNTL - Certain Pre-Construction Duties (Article 4)

Observations & Findings

Article 4: Certain Pre-Construction Duties addresses the Construction Work Schedule, Scope of Work, Project Plan, Approved Design and Pre-Construction Estimated Project Budget that shall be developed by the Construction Manager and submitted to the Management Committee for approval. These pre-construction duties shall be performed in accordance with Good Utility Practice and Applicable Law, compromising the following:

(i) Section 4.1: Preparing the Project Plan.
(ii) Section 4.2: Identifies the Approved Design for the Project that must be developed in accordance with Section 4.10 Design Criteria.
(iii) Section 4.3: Development Period Government Approvals.
(iv) Section 4.4: Preparation of Pre-Construction Estimated Project Budget.
(v) Section 4.5: Preparing the Equipment and Materials Procurement Plan.
(vi) Section 4.6: Implementing the Right of Way and Guidelines Plan.
(vii) Section 4.7: Develop and implement the Risk Management Plan.
(viii) Section 4.8: Prepare the Basis of Estimate.
(ix) Section 4.9: Implement the Change Control Guidelines.
(x) Section 4.10: Design Criteria.
(xi) Section 4.12: Use the Standard Forms (contracts and purchase orders) approved by the Management Committee.

Conclusions & Recommendations

Article 4 Certain Pre-Construction Duties meet acceptable commercial business practice. The above activities shall be approved by the Management Committee and any changes require the approval of the Management Committee before the Construction Manager may proceed with any change, thereby protecting the interests of 6690271.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 5: GNTL - Project Budget and Management of CM Costs (Article 5)

Observations & Findings

Article 5: Project Budget and Management addresses the project budget and cost accounting. Key components of this Article are:

(i) Section 5.1: describes the Construction Manager's responsibility for updating the Pre-Construction Estimated Budget and submitting to MC for approval.

(ii) Section 5.4.1.3: Construction Manager will evaluate and in good faith determine the projected effect of any Participant-Directed Program Change Request affecting the Construction Work or the Project Budget. The Management Committee will approve such determination before the Project Budget or Construction Work Schedule is adjusted.

(iii) Section 5.4.2: modifications to the Approved Design, the Project Plan or the Project Budget may be proposed by the Construction Manager as a Program Change Request to the Management Committee for approval.

(iv) Section 5.5: addresses specifically what are eligible and recoverable CM Costs and those cost that are not chargeable to the Project.

Conclusions & Recommendations

Article 5 Project Budget and Management meets acceptable commercial business practice. The activities are appropriate for the successful and transparent management of the Construction Management Agreement and these activities require approval by the Management Committee.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 6: GNTL - Funding (Article 6)

Observations & Findings

Article 6 generally describes the processes by which the Construction Manager shall be compensated for the CM Costs expended by it in performing the Services.

Section 6.1 states that the Construction Manager shall be compensated for CM Costs expended by it in the performance of the Services or in connection with the Construction Work. Section 6.2 sets out the Application for Payment process with invoices submitted to each Transmission Line Payer on a monthly basis complete with Supporting Documentation and in accordance with each Transmission Line Payer's Participant Payment Percentage. The Construction Manager has the obligation to reconcile all payments made and if the Construction Manager has received funds in excess of the actual CM Costs to which it is entitled, then the Construction Manager shall pay to each Participant the applicable Participant Payment Percentage of such excess.

Section 6.5 sets out the process by which the Final Payment will be calculated and any under or over payment to the Construction Manager will be processed. This shall be undertaken within ninety (90) days after the Final Completion.

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Section 6.12 provides that the obligations of the Transmission Line Payers are several in proportion to their respective Participant Payment Percentages. This means each TLP is severally obligated to the extent of its Participant Payment Percentage for the payment of the CM Costs.

Conclusions & Recommendations

Article 6 Funding meets acceptable commercial business practice. The activities are appropriate for the successful and transparent management of the Funding requirements of the Construction Management Agreement and reinforces that the Parties are severally liable to the extent of their Participant Payment Percentages.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 7: GNTL - Description of Construction Management Duties (Article 7)

Observations & Findings

Article 7.1 provides a series of conditions precedent that have to be satisfied before the Construction Manager may commence construction thereby protecting the Transmission Line Payers. These conditions precedent are as follows:

(i) Management Committee has approved the Approved Design
(ii) Management Committee has approved the Updated Right of Way Strategies and Guidelines Plan
(iii) Management Committee has approved the Project Insurance
(iv) Management Committee has approved the Procurement Plan
(v) Management Committee has approved the Risk Management Plan
(vi) 6690271 has provided notice of its satisfaction or waiver of all 6690271 Construction Phase Conditions Precedent
(vii) MPM (Minnesota Power in its capacity as a Transmission Line Payer) has provided notice of its satisfaction or waiver of all MPM Construction Phase Conditions Precedent.
(viii) Management Committee has retained its Independent Oversight Engineer.
(ix) Management Committee has approved the Bid Process Guidelines
(x) Management Committee has approved the Project Plan
(xi) Management Committee has approved the Design Criteria

Section 7.3 Material Documents requires the Construction Manager to use commercially reasonable efforts to provide to each of the Participants all material documents related to the Project such as engineering and design matters, procurement and contracting strategies, final Permits, overall coordination and administration of the Project, project controls and processes, meeting minutes, etc.

Section 7.4 Project Meetings provides a list of planned meetings for GNTL. These include Discipline Team Meetings, Full Team Meetings and Management Team Meetings, which each Participant has the right to participate in and the Construction Manager must provide each Participant with notice of such meetings including copies of all agendas, meeting documentation and prior meeting minutes.

Section 7.5 Consultation and Approval obliges the Construction Manager to consult with and discuss with 6690271 any material decision it proposes to make in respect of the matters identified in Appendix N –

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Proposed Appendix N Decision. The Construction Manager shall provide 6690271 with a written outline and supporting basis for each Proposed Appendix N decision. 6690271 has the right to provide to the Construction Manager written revisions to the Proposed Appendix N Decision for the Construction Manager's consideration. The Construction Manager shall not proceed with implementing any Proposed Appendix N Decision until it has received the approval of the Management Committee.

Proposed Appendix N Decision comprise matters such as revisions to:

(i) Integrated Baseline, Budget, Schedule and Cash Flow
(ii) Risk Management
(iii) Procurement Plan
(iv) Tower Evaluation Studies
(v) Conductor Design
(vi) Construction Specification
(vii) Major Equipment Specifications
(viii) Commissioning

Section 7.6 Approval obliges the Construction Manager not to proceed with making any material decision in respect of the matters identified in Appendix O – Proposed Appendix O Decision. Proposed Appendix O Decision matters comprise:

(i) Insulator Type Selection
(ii) Tower Testing
(iii) Sub-Synchronous Resonance Screening
(iv) Structure Design
(v) Control and Relay Schematics
(vi) Emergency Response Plan

The Construction Manager shall provide the Management Committee with a written outline and supporting basis for each Proposed Appendix O Decision. If the Management Committee does not approve the Proposed Appendix O Decision, 6690271 has the right to provide the Construction Manager with written revisions to the Proposed Appendix O Decision for the Construction Manager's consideration ("Appendix O Revisions"). The Construction Manager has the right to again seek approval from the Management Committee of the Proposed Appendix O Decision with or without incorporating the Appendix O Revisions. If not approved by the Management Committee, then the dispute resolution process set out in Section 18.1.2.1 shall resolve the dispute.

Section 7.8 Contract Administration addresses the contract administration duties of the Construction Manager. It is worth noting that the Construction Manager shall not enter into any Major Change Order or take any Material Action until the Management Committee has voted to approve same; sections 7.8.4 (i) and 7.8.4 (ii) refers.

Section 7.15.1.1 Construction Manager Rights and Obligations allows the Construction Manager to adjust, defend and settle insured claims against a Participant, so long as such is within the policy limits provided by any of the applicable insurance policies maintained in accordance with the Project Insurance. The Construction Manager needs the approval of the Management Committee to settle claims above the policy limits.

Section 7.15.2.5 permits the Construction Manager to settle any individual uninsured claim up to [redacted] and to release any Third Party from liability or potential liability up to a limit of [redacted] 1d

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Conclusions & Recommendations

Article 7 Description of Construction Management Duties provides a comprehensive scope of the Construction Manager's duties together with appropriate protective approval mechanisms to protect 6690271's interests.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 8: (Article 8) GNTL - Financial Accounts; Reporting; Independent Oversight

Observations & Findings

Article 8 generally describes the Construction Manager's duties with respect to the preparation and contents of progress and financial accounts and reports. The reports include Progress Reports, Financial Reports, Year-end Financial Reports and Final Completion Reports

Section 8.5 Independent Oversight Engineer provides for the Management Committee to retain an engineering consulting firm to provide objective and independent oversight of the Construction Work and the Construction Manager's performance of the Services. All information and reports provided by the Independent Oversight Engineer may be used by any Participant in furtherance of exercising its rights under the Construction Management Agreement and in resolving any dispute pursuant to Article 18 Dispute Resolution.

The Independent Oversight Engineer, inter alia, will:

(i) Review Funding Requests, Change Orders, Contract Amendments and associated documentation
(ii) Inspect and determine whether Construction Work has been properly performed
(iii) Monitor the obligations of the Construction Manager
(iv) Conduct monthly review of the design, procurement and construction
(v) Verify Project Completion

Conclusions & Recommendations

Article 8 Financial Reports; Reporting; Independent Oversight meets acceptable commercial business practice. The Article provides for comprehensive reporting and the appointment of the Independent Oversight Engineer provides additional protection to the interests of 6690271.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 9: GNTL - Participant's Rights, Duties and Obligations (Article 9)

Observations & Findings

Article 9.1 Participants Act Through Management Committee provides that oversight and management of matters that arise under the Construction Management Agreement will be determined by the Management Committee. The Management Committee has the authority to direct the means, manner and methodology used by:

(i) The Construction Manager to carry out the Services; or

(ii) Any Contractor to carry out Construction Work in accordance with the express provisions of the Construction Management Agreement (Section 9.1.1 refers)

Section 9.1.3 sets out the Management Committee composition with Section 9.1.4 addressing meetings, notice of meetings and associated governance. Section 9.1.4.2 addresses the quorum for a Management Committee meeting. Section 9.1.4.3 provides for each Participant having a representative on the Management Committee and each representative having one vote. Section 9.1.4.4 requires the unanimous affirmative vote of all representatives of the Management Committee, which in effect give 6690271 a veto. Section 9.10 permits the Management Committee to suspend, delay or interrupt Construction Work and Section 9.12 allows each Participant to audit or inspect the Records of the Construction Manager.

Conclusions & Recommendations

Article 9 Participant's Rights, Duties and Obligations provides appropriate mechanisms for oversight and management of the Construction Management Agreement. The requirement for all decisions to be by unanimous affirmative vote provides 6690271 with a right to veto those matters with which it disagrees or would not support.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 10: GNTL - Representations and Warranties (Article 10)

Observations & Findings

Article 10 generally sets out the particular representations and warranties of the Participants and the Construction Manager.

Section 10.1 sets out the Construction Manager's representations and warranties, which representations and warranties survive the execution and delivery of the Construction Management Agreement. Section 10.2 provides the same for the Participants, on a several, not joint basis.

Conclusions & Recommendations

Article 10 Representations and Warranties meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 11: GNTL - Completion and Acceptance of Work (Article 11)

Observations & Findings

Article 11 addresses the terms governing the commissioning, completion and acceptance of the Project. Section 11.1.1 states that the Construction Manager makes no performance guarantees nor guarantees the successful commissioning of the Project, with Section 11.1.2 addressing the procedure and requirements regarding the Initial Notice of Commissioning. Section 11.1.3 obliges the Management Committee to advise the Construction Manager of any inadequacy, inaccuracy or otherwise unacceptable information or result set forth in a Notice of Commissioning and specifies the Construction Manager's responsibility to correct such deficiency.

Section 11.2 sets out the process for the Construction Manager to advise the Management Committee that Substantial Completion has been achieved and Section 11.4 addresses the process for achieving Final Completion. In both cases the Management Committee has the authority to vote to approve or reject such Notices.

Conclusions & Recommendations

Article 11 Completion and Acceptance of Work meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 12: GNTL - Construction Work Warranties (Article 12)

Observations & Findings

Article 12 Construction Work Warranties addresses the warranty requirements for Contractors engaged on the Project, addressing matters such as the scope, duration and enforcement of warranties.

Section 12.1 provides for the Construction Manager to make commercially reasonable efforts to obtain warranties from Contractors with respect to the performance of the Construction Work. The Construction Manager shall also make commercially reasonable efforts to procure from each Contractor pursuant to its respective Project Construction Contract, an undertaking from the Contractor to procure from all its Subcontractors, warranties with respect to any Materials, Equipment or services provided by each such Subcontractor. Such Subcontractor warranties shall be enforceable by, or be assignable to, the Participants (Section 12.1.3 refers).

Conclusions & Recommendations

Article 12 Construction Work Warranties provides appropriate mechanisms to obtain for the benefit of the Participants warranties from Construction Contractor and their Subcontractors.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 13: GNTL - Indemnification (Article 13)

Observations & Findings

Article 13 addresses Third Party Indemnification and Environmental Indemnity by Discrete Substation Owners and USI Owners. Section 13.1.1 provides that each Participant shall severally to the extent of its ownership indemnify the Construction Manager from Third Party claims, except to the extent such claims arise from an act or omission of the Construction Manager for which the Participants are indemnified under Section 13.1.2 or for which there is contributory negligence under Section 13.1.3. Sections 13.3 and 13.4 address Insurer Obligations and Indemnification Costs respectively.

Conclusions & Recommendations

Article 13 Indemnification Representations and Warranties meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 14: GNTL - Confidentiality Provisions (Article 14)

Observations & Findings

Article 14 sets out the confidentiality obligations of the Parties defining matter such as Confidential Information, required disclosure, public disclosure, inadequate remedy at law issues and additional regulatory requirements.

Conclusions & Recommendations

Article 14 Confidentiality Provisions meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

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Finding No. 15: GNTL - Breach, Cure and Default (Article 15)

Observations & Findings

Article 15 sets out the provisions relating to Breach, Cure and Default addressing matters such as Events of Breach, Notice of Breach, Cure, Default and Default Rights. The Participants further agree in this Article that the dispute resolution provisions set forth in Article 18 are and shall be the sole and exclusive remedy of the Participants for the resolution of all disputes, claims or controversies arising under this Agreement.

Conclusions & Recommendations

Article 15 Breach, Cure and Default meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 16: GNTL - Term and Termination of Agreement (Article 16)

Observations & Findings

Article 16 generally addresses the:

(i) Effective Time
(ii) Term
(iii) Termination by Participants
(iv) Termination by the Construction Manager; and
(v) the Effect of Termination.

Section 16.2.1.2 provides the right by Participants to terminate the Construction Management Agreement for convenience and for the Management Committee to terminate for cause as per Section 16.2.1.3, if the Construction Manager has:

1. Committed an act of material fraud
2. Failed to follow any material policy or directive of the Management Committee
3. Abandoned or suspended performance of the services for at least thirty (30) consecutive days
4. Assigned its rights or obligations without the prior written consent of the Management Committee
5. Failed or refused to perform any obligations under the Construction Management Agreement
6. Failed or refused to comply with any Applicable Law
7. Breached a Major Contract as a result of intentional misconduct or wilful misconduct
8. Experienced an Insolvency Event
9. Committed a breach of fiduciary duty when acting as an agent under the Construction Management Agreement.

The Construction Manager has the opportunity to cure in accordance with Section 16.2.1.3.1 failing which the Process for Termination in Section 16.2.1.3.4 is followed.

The Construction Manager may terminate the Construction Management Agreement for Good Reason in accordance with Section 16.2.1.4 where Good Reason means:

- Failure of 6690271 to make the required payments
- Failure or refusal of 6690271 to perform any other obligation under the Construction Management Agreement

and 6690271 fails or refuses to cure such default within the proscribed period. Section 16.2.3 Effect of Termination addresses matters such as Duties upon Termination, Property Rights, winding up the Services and Construction Work together with any payment obligations to Contractors and Third Parties.

Conclusions & Recommendations

Article 16 Term and Termination of Agreement meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 17: GNTL - Limitations of Liability (Article 17)

Observations & Findings

Section 17.1 provides that no party under the Construction Management Agreement shall be liable to the other party for any "special, incidental, consequential, indirect, exemplary, treble or punitive Damages or any other penalty, with the exception of Third Party claims set out in Section 13.1.

In accordance with Section 17.2 the Construction Manager shall not be liable for Damages to the Participants, except for Damages arising from:

- Construction Manager's fraud; or
- Construction Manager's gross negligence, intentional misconduct or wilful misconduct

with the exception of the Construction Manager's liability for Third Party claims that are indemnified pursuant to Section 13.1.2

Conclusions & Recommendations

Article 17 Limitations of Liability Term meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

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Finding No. 18: GNTL - Dispute Resolution (Article 18)

Observations & Findings

Subject to the provisions of Articles 16 and 17 of the Construction Management Agreement, Article 18 sets out the dispute resolution provisions that govern all disputes, claims and controversies arising out of the Construction Management Agreement. Section 18.1.1 addresses disputes between the Participants and Section 18.1.2 between the Construction Manager and the Participants.

Appendix Q: Dispute Resolution Procedures sets out the procedures for resolution for all disputes arising under the Construction Management Agreement. The procedure is comprehensive, addressing:

1. Notification to all Parties of a Dispute
2. Resolution of the Dispute by each Participant assigning an executive for the purpose of resolving such dispute or controversy within ten (10) Business Days following the commencement of discussions to resolve such Dispute.
3. If the Dispute remains unresolved then the disputing Participant may initiate non-binding mediation. Section 2.2 Non-Binding Mediation addresses the selection of the mediator, location in Minneapolis-St. Paul, MN, the governing rules and how the mediation shall be terminated.
4. Disputes not resolved by either the executives of the Participants or pursuant to Non-Binding Mediation shall be finally settled under the Regular Track Procedures of the Construction Industry Arbitration Rules of the American Arbitration Association by three (3) arbitrators appointed in accordance with the Arbitration Rules.
5. The proceedings comprised of all documents and testimony including depositions and expert reports shall be confidential.
6. Both Participants have the right to seek immediate injunctive and other equitable relief through the courts in the event of any material breach of the Construction Management Agreement by the other Party that would cause the non-breaching party irreparable injury for which there would be no adequate remedy at law.

Conclusions & Recommendations

Article 18 Dispute Resolution meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 19: GNTL - Notices (Article 19)

Observations & Findings

Article 19 Notices contains the Notice provisions for the Construction Management Agreement.

Conclusions & Recommendations

Article 19 Notices meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

Finding No. 20: GNTL - Miscellaneous Provisions (Article 20)

Observations & Findings

Article 20 Miscellaneous Provisions contains the usual miscellaneous provisions found in a contract for example, 'binding obligations', 'amendment and waiver', 'severability', 'survival', 'execution in counterparts', 'force majeure', 'governing law' and 'venue'.

Conclusions & Recommendations

Article 20 Miscellaneous Provisions meets acceptable commercial business practice.

Source of Information & Reference Materials

- Great Northern Transmission Line Construction Management Agreement dated April 12, 2016

SCOPE ITEM 28:

Assess the current forecast at completion capital cost for reasonableness, including whether appropriate contingencies and reserves have been provisioned.

Finding No. 1: GNTL - Estimate Review -- Forecast at Completion (FAC)

Observations & Findings

In May 2016, Minnesota Power submitted an updated estimate for the GNTL Project. Since the 2013 USD$677 million cost estimate, project costs have [redacted]

The variance noted between the estimate total and the total approved budget is [redacted]

The table below summarizes the project costs. The transmission line scope of work represents 89% of the overall approved budget of [redacted] The supporting back-up provided to MGF for review is the 2016 Cost Estimate totalling [redacted] prepared by Minnesota Power. 1d

MGF's findings within this review are based upon the 2016 Cost Estimate provided. The noted variance between the cost estimate and the approved budget is a [redacted]

A cost estimate review was addressed in "Scope Item 26", reviewing many of the cost elements included in the transmission line scope of work. It was noted in this review that costs are considered to be at the high range as compared to other similar projects.

Scope of Work	MP (2013 USD) Cost Estimate	MP (2016 USD) Cost Estimate	Variance (USD) Cost Estimate	Approved Budget (USD) (June 2017 Mo. Rpt)	Variance (USD) Est. vs. Budget	Project %
GNTL 500kV Transmission Line	**$579,685,986.81**	[redacted]				**89%**
Iron Range 500kV Substation	$42,994,380.00					7%
Warroad River Series Compensation Station	$49,258,220.00					3%
Existing 230kV Transmission System Modifications – 230 kV Line Portion	$3,891,710.90					1%
Substation Upgrades – Blackberry	$275,000.00					0%
Substation Upgrades – Arrowhead	$137,500.00					0%
Substation Upgrades – Forbes	$137,500.00					0%
Substation Upgrades – Hilltop	$137,500.00					0%
Required Network Upgrades	$430,000.00					0%
Project Total Cost	**$676,947,798**					**00%**

1d

Note: Values above, include Contingency (No Contingency Incl. for Network Upgrades) and Capitalized Property Taxes ($44.2 million)

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MGF's reference for the "Approved Budget" was taken from Minnesota Power's "Monthly Progress Report (June 2017)".

The following elements have been carried as Contingency in the sum of [redacted] of the base cost.

- Landowner Payment Contingency - [redacted]
- Engineering and Program Management, Construction Phase Contingency - [redacted]
- Construction Phase Contingency - [redacted]
- 500kV Line - [redacted]
- Iron Range 500kV Substation, Construction Phase Contingency - [redacted]
- Iron Range 500kV Substation - [redacted]
- Warroad River Series Compensation Station, Construction Phase Contingency - [redacted] 1d
- Warroad River Series Compensation Station - [redacted]
- Existing 230kV Transmission System Modifications, Construction Phase Contingency - [redacted]
- Existing 230kV Transmission System Modifications - [redacted]
- 230 kV Substation Upgrades - [redacted]

Minnesota Power's cost estimating methodology is consistent with the industry standard for the class of estimate and for the estimate's intended purpose. The level of project definition is considered reasonable to develop quantities and unit prices.

MGF considers that the cost estimate prepared is comparable to a Class 4 estimate, as per AACE standards and based on the level of scope definition and estimate methodology used in developing the estimate.

A "COST ASSUMPTIONS" summary was provided; however, a detailed Basis of Estimate was not.

Expected items to be included would consist of the following:

- Purpose
- Project Scope Definition
- Methodology
- Estimate Classification
- Design Basis
- Planning Basis
- Cost Basis
- Allowances
- Reconciliation
- Benchmarking
- Estimate Quality Assurance

- Estimating Team
- Attachments
- Estimate Deliverable Checklists
- Reference Documents
- Exclusions
- Exceptions
- Risks and Opportunities
- Containments
- Contingencies
- Management Reserve

Based on USD/mile metrics for the project, GNTL ([redacted] is significantly higher than those project metrics seen for past projects (USD$2.47 million) and compared to MMTP (USD$1.86 million). 1d

Conclusions & Recommendations

The Contingency is reasonable for this project, but would point out that the overall project cost is considered high when compared with other similar projects.

MGF recommends that an updated estimate, which has been supported through additional technical and commercial deliverables, as well as market underpinning (i.e. quotations or even awarded contracts) be developed and reviewed as soon as possible. This will ensure a higher level of confidence.

MGF also recommends that regardless of which stage the cost estimates are produced, that a Basis of Estimate is produced.

It was noted that Manitoba Hydro's Transmission Projects Department (TPD) has collaborated with internal Manitoba Hydro subject matter experts to conduct a review of the "Pre-Construction Estimate Project Budget and Basis of Estimate" provided by Minnesota Power. This is good practice, and it was also noted that the transmission line approved budget has been reduced, but the overall project total remains unchanged.

This would further reinforce MGF's view that continued oversight should be maintained.

Source of Information & Reference Materials

- Great Northern Transmission Line Project Scope Document – Revision 1
- AACE International Recommended Practice No. 34R-05, BASIS OF ESTIMATE, TCM Framework: 7.3 – Costs Estimating and Budgeting.

SCOPE ITEM 29:

Assess Minnesota Power's approach to establishing the contingency for GNTL and whether appropriate risk areas and magnitudes of uncertainty are recognized.

Finding No. 1: GNTL - Iron Range 500/320kV Sub – MTEP 3831 Schedule

Observations & Findings

The GNTL 107621 – Iron Range 500/230kV Sub-MTEP 3831 schedule has a start date of 1st December 2015 and a completion date of 2nd February 2021. The project is currently in progress with a status date of 31st October 2017. It has 353 normal activities of which 77 are complete, 31 are in progress and 245 are still planned. It contains 188 milestones, 4 summaries and 0 LOE (Level of effort) activities.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The GNTL 107621 Iron Range 500/230kV Sub-MTEP 3831 schedule scored 81, giving it an 84% probability of success
- Schedule Quality: Scored 81% versus a score of 75% or better which is considered a 'good' schedule
- High duration: Is the total number of activities that have a duration longer than 2 months. High duration activities are generally an indication that a plan is too high level for adequate planning and controls. The number of high duration activities should not exceed 5% and this schedule scored 32%. Four of the activities identified with high durations are the summary activities of Engineering, Procurement, Construction and Project Closeout. These activities are planning packages which should be broken down into more detail as the project proceeds and more details become available

Conclusions & Recommendations

With a Fuse score of 81, we consider this to be a "good" schedule. The schedule will be improved when the summary activities of Engineering, Procurement, Construction and Project Closeout can be broken down in to more detail as the project proceeds and these details become available.

Source of Information & Reference Materials

- GNTL Program Master Schedule DD 10.31.17.xer

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Finding No. 2: GNTL - 500kV MTEP 3831 Schedule

Observations & Findings

The GNTL 105471 500kV Transmission Line MTEP 3831 schedule has a start date of 1st October 2011 and a completion date of 2nd February 2021. The project is currently in progress with a status date of 16th September 2017. It has 868 normal activities of which 277 are complete, 114 are in progress and 477 are still planned. It contains 249 milestones, 6 summaries and 21 LOE (Level of effort) activities.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The GNTL 105471 500kV Transmission Line MTEP 3831 schedule scored 60, giving it a 55% probability of success
- Schedule Quality: Scored 60% versus a score of 75% or better which is considered a 'good' schedule
- High Float: is the number of activities with total float greater than 2 months and this should not exceed 5%. This schedule scored 51% which indicates that schedule paths have artificially constrained activities. Schedule paths with float of more than two months should be considered for acceleration and schedule optimization
- High duration: is the total number of activities that have a duration longer than 2 months. High duration activities are generally an indication that a plan is too high level for adequate planning and controls. The number of high duration activities should not exceed 5% and this schedule scored 44%. Four of the activities identified with High Duration are summary activities, namely Engineering, Procurement, Construction and Project Closeout

Conclusions & Recommendations

With a Fuse score of 60%, we consider this to be a "medium quality" schedule. We recommend that all logic issues should be corrected to improve the quality and reliability of the schedule and that activities with high duration should be reviewed and broken down into more detail as the information becomes available.

Source of Information & Reference Materials

- 105471 – GNTL 500kV Transmission Line MTEP 3831 - GNTL Program Master Schedule DD 10.31.17.xer

Finding No. 3: GNTL - 107626 Blackberry Sub Mods MTEP 3831

Observations & Findings

The 107626 Blackberry Sub Mods MTEP 3831 schedule has a start date of 3rd September 2019 and has 25th January 2021 as the completion date. The project is currently planned with a status date of 16th September 2017. It has 14 planned activities and contains 3 milestones, 4 summaries and no LOEs (Level of Effort).

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of the detailed analysis. The 107626 Blackberry Sub Mods MTEP 3831 schedule scored 67, giving it a 65% probability of success.
- Schedule Quality: Scored 67% versus a score of 75% or better which is a considered a "good" schedule.
- Missing Logic: Is the total number of activities that are missing a predecessor, a successor, or both. This number should not exceed 5% and 12% of the activities on this schedule are missing logic. Missing logic impacts the quality of results derived from a time and risk analysis.
- High Duration: Is the total number of activities that have a duration longer than 2 months. High duration activities are generally an indication that a plan is too high level for adequate planning and controls. The number of high duration activities should not exceed 5% and this schedule scored 18%. This project is still in the planning phase. Activities should be broken down into more as the planning phase proceeds.

Conclusions & Recommendations

With a Fuse score of 67, we consider this to be a "medium quality" schedule. We recommend that all logic issues should be corrected to improve the quality and reliability of the schedule and that activities with high duration should be reviewed and broken down into more detail as the information becomes available.

Source of Information & Reference Materials

- GNTL Program Master Schedule DD 10.31.17

Finding No. 4: GNTL - 107625 230kV Line Mods MTEP 3831

Observations & Findings

The GNTL 107625 230kV Line Mods MTEP 3831 schedule has a start date of 2nd January 2019 and has 15th January 2020 as the completion date. The project is currently planned with a status date of 1st January 2019. It has 15 normal activities of which 0 are complete, 0 are in progress and 15 are still planned. It contains 3 milestones, 4 summaries and no LOEs (Level of Effort).

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of the detailed analysis. The GNTL 107625 230kV Line Mods MTEP 3831 schedule scored 55, giving it a 48% probability of success.
- Schedule Quality: Scored 55% versus a score of 75% or better which is a considered a "good" schedule.
- Missing Logic: Is the total number of activities that are missing a predecessor, a successor, or both. This number should not exceed 5%. On this schedule, 17% of the activities are missing logic which impacts the quality and reliability of the schedule.
- High Duration: Is the total number of activities that have a duration longer than 2 months. High duration activities are generally an indication that a plan is too high level for adequate planning and controls. The number of high duration activities should not exceed 5% and this schedule scored 39%. This project is still in the planning phase. Activities should be broken down into more as the planning phase proceeds.

Conclusions & Recommendations

With a Fuse score of 55, we consider this to be a "medium quality" schedule. We recommend that all logic issues should be corrected to improve the quality and reliability of the schedule and that activities with high duration should be reviewed and broken down into more detail as the information becomes available.

Source of Information & Reference Materials

- GNTL Program Master Schedule DD 10.31.17

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Finding No. 5: GNTL - 107623 500kV Series Comp – MTEP 3831 Schedule

Observations & Findings

The GNTL 107623 – 500kV Series Comp-MTEP 3831 schedule has a start date of 1st December 2015 and a completion date of 2nd February 2021. The project is currently in progress with a status date of 31st October 2017. It has 71 normal activities of which 5 are complete, 14 are in progress and 52 are still planned. It contains 22 milestones, 3 summaries and zero LOE (Level of effort) activities. The project baseline start date was 18th February 2013 with the baseline finish date of 29th May 2020. The project is currently behind schedule by 154 days.

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, the US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The schedule scored 69, giving it a 68% probability of success.
- Schedule Quality: Scored 69% versus a score of 75% or better which is considered a 'good' schedule.
- Insufficient Detail: measures the number of activities that have a duration longer than 10% of the total duration of the project. This number should not exceed 5% and this schedule scored 28%. Activities with a high duration relative to the duration of the project are generally an indication that a plan is too high level for adequate planning and controls. In this schedule, these activities are used to define effort that does not directly generate a deliverable. These activities are cost loaded and will expand and contract with the critical path. These activities are currently set as Task Dependent activities but should be set as LOE activities. With these activities set as Task Dependent activities, there is the potential for these activities to incorrectly drive the critical path.
- High float: Schedule paths with high amounts of float typically arise due to artificially constrained activities. The metric identifies activities with total float greater than 2 months and should not exceed 5%. This schedule scored 37%. Paths with float more than 2 months should be considered for acceleration and schedule optimization.
- High duration: identifies the total number of activities that have a duration longer than 2 months. This number should not exceed 5% and this schedule scored 32%. High duration activities are generally an indication that a plan is too high for adequate planning and control. Three of the activities identified with high duration are summary activities i.e. Engineering, Procurement and Construction. These are planning packages which should be broken down into more detail as the project proceeds and more details are available.

Conclusions & Recommendations

With a Fuse score of 69%, this is a medium quality schedule. We would recommend changing the activities currently set as Task Dependent to Level of Effort activities to improve the overall quality of the schedule.

Source of Information & Reference Materials

- GNTL Master Schedule DD 10.31.17

Finding No. 6: GNTL - 107627 - Arrowhead Sub Mods, 107628 Forbes Sub Mods, 107629 – Hilltop Sub Mods

Observations & Findings

The 107627 - Arrowhead Sub Mods, 107628 Forbes Sub Mods and 107629 - Hilltop Sub Mods schedules each have a start date of 3rd September 2019 and have 17th December 2019 as the completion date. These projects are currently planned with a status date of 16th September 2017. Each schedule has 11 planned activities and contain 3 milestones, 4 summaries and no LOEs (Level of Effort).

Acumen Fuse is a software application which uses metrics to identify problematic areas and activities in a project schedule. It has hundreds of industry metric libraries including DCMA 14-Point Assessment, US Government Accountability Office's (GAO) Scheduling Best Practices and the US National Defence Industrial Association's (NDIA) Generally Accepted Scheduling Practices (GASP). The Acumen Fuse analysis produced the following:

- Fuse Schedule Index: Is a single quality indicator resulting from a summary of the detailed analysis. The 107627 - Arrowhead Sub Mods, 107628 Forbes Sub Mods, 107629 - Hilltop Sub Mods schedules each scored 61, giving them a 57% probability of success.
- Schedule Quality: Each schedule scored 61% versus a score of 75% or better which is a considered a "good" schedule.
- Missing Logic: Is the total number of activities that are missing a predecessor, a successor, or both. This number should not exceed 5%. On these schedules, 14% of the activities are missing logic which impacts the quality and reliability of these schedules.
- High Duration: Is the total number of activities that have a duration longer than 2 months. High duration activities are generally an indication that a plan is too high level for adequate planning and controls. The number of high duration activities should not exceed 5% and these schedules scored 14%. These projects are still in the planning phase. Activities should be broken down into more as the planning phase proceeds.

Conclusions & Recommendations

With a Fuse score of 61, we consider these schedules to be "medium quality" schedules. We recommend that all logic issues should be corrected to improve the quality and reliability of each schedule and that activities with high duration should be reviewed and broken down into more detail as the information becomes available.

Source of Information & Reference Materials

- GNTL Program Master Schedule DD 10.31.17

Finding No. 7: GNTL - Baseline Schedules

Observations & Findings

For the GNTL project, there is only one Primavera P6 file for each schedule. Three of these schedules have progress (17623 – 500kV Series Comp-MTEP 3831, 107621 – Iron Range 500/230kV Sub-MTEP 3831, and 500kV Transmission Line MTEP 3831). The project team indicated the baseline schedule will reflect actual commencement dates for activities. This practice violates the Manitoba Hydro's Schedule Change Management process (CSS-010) which specifies the baseline schedule "freezes the original plan at the completion of initial planning ... Should not be changed to match performance". This process (CSS-010) aligns with the Project Management Institute's (PMI) definition of a baseline as "the approved version of work product that can be changed using formal change control procedures and is used as the basis for comparison to actual results". .

Conclusions & Recommendations

Baseline schedules reflect the planned schedule progress. In Earned Value Management (EVM), the baseline schedule is compared to the Forecast schedule to determine the value of the work "earned". Without a baseline, the Earned Value cannot be determined.

Source of Information & Reference Materials

- Project Management Institute Practice Standard for Scheduling
- Project Management Institute Practice Standard for Earned Value Management
- Manitoba Hydro CSS-010 - Schedule Change Management
- GNTL Re-Baseline 10.31.17.xer
- GNTL Re-Baseline 09.16.2017.xer
- E-mail from GNTL Project Team

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Finding No. 8: GNTL - Establishing Contingency and Risk Areas

Observations & Findings

The current GNTL Risk Management Plan (RMP) describes the scope, roles and owners risk, management approach risk, risk identification, risk assessment and prioritization, risk monitoring, risk response strategies, risk register, active risks and contingency management.

While reviewing the Risk Register it was noted that the cost estimate was dated 26th May 2016, while the Risk Register was dated 21st June 2017.

In addition, the register has a total of 17 Risk events identified as "High" cost impact amounting to $118 million with Risk item 5 amounting to $100 million.

Risk item 5

Risk Trigger or Cause – "Change in Program parameters, quantities more or less than estimated, unanticipated escalation, additional information"

Risk event or effect – "Budget component cost may be higher than estimated"

Impact – High

Cost Impact of Risk - $100 million

Response Plan - "Review assumptions made in preparing budget; regular monitoring of estimate and program information, fuel adjustment clause in construction contract. Review estimate and quantities after completion of Seg 2 access, clearing and geotech."

Mitigation Action Completed – "Estimate and assumptions were updated in May 2016. Update estimate toward the end of 2017 as bid pricing is received."

Conclusions & Recommendations

The Risk Register was established after the [redacted] pre-construction budget was estimated. Currently, there is no correlation between the Risk Register and Contingency amount. 1d

MGF strongly agrees with the plan to update the estimate at the end of 2017. A risk analysis work session is also suggested with the project team to develop inputs that support cost and schedule contingency development.

MGF considers the that risk mitigation costs to eliminate the "high" risk items should be included within the estimate (e.g. paying premium to have final design completed for the towers to eliminate delays in procurement and ultimately the project).

Source of Information & Reference Materials

- GNTL PGM_Risk Register for 7-12-17 Qtrly Review
- CMA Pre-Const - GNTL Risk Management Plan (Approved)
- Great Northern Transmission Line Project Scope Document – Revision 1

SECTION 8 - Conclusion

This section summarizes the conclusions we have drawn for the various projects reviewed as part of MGF's review of Manitoba Hydro's Capital Expenditures Program. In summary:

- the Keeyask Hydroelectric Dam poses the biggest threat to the Capital Expenditures Program
- the HVDC Converter Stations and Bipole III Transmission Line is nearing the finish line and Manitoba Hydro is aware of the remaining risks and working to mitigate these
- MMTP and GNTL are well organized and being set up for success.

We would provide the following specific conclusions on the specific projects as follows:

Keeyask Hydroelectric Dam

The cost reimbursable compensation mechanism in the General Civil Contract (GCC) is not typical for this kind of project. Rather than linking the compensation of the contractor to the quantity of work performed in accordance with contracted quality and time for completion obligations, the GCC contractor gets paid its actual costs irrespective of the quantity of work performed, the quality or the time it is takes to perform the work.

This cost reimbursable pricing mechanism has placed the following risks on Manitoba Hydro:

- Labour costs
- Labour availability
- Material costs
- Material performance
- Escalation
- Productivity
- Final contract costs
- Contractor's re-work
- Indirect costs
- Schedule
- Time and cost impacts due to GCC contractor

and as such, introduces significant unpredictability to the outcome of the GCC contract, in particular with an under-performing GCC contractor. The reality is that whilst Manitoba Hydro is accountable for the risks above, it is the GCC contractor who is leading and managing the activities that will trigger these risks.

The GCC contractor over promised in its tender, failed to perform the Original Contract and following the Amending Agreement No. 7 dated 28th February 2017, is continuing to miss the revised productivities for concreting and earthwork, which is of high concern given the following:

- There are four more years of this contract to go
- Concreting activities are becoming more complex with productivity likely to deteriorate
- Large earthwork scope still to be performed

The GCC contractor is behaving like a contractor engaged on a cost reimbursable contract where they have no risk. Selected data points are:

- Repeated failure to achieve agreed upon productivities
- 1,030 negative float activities in its schedule, of which 97 are on the critical path, when the Contract demands that the GCC contractor's schedule should not contain any negative float activities.
- Working without an approved basis of schedule
- Monthly progress reports repeatedly submitted 7 days late
- Inconsistent and inaccurate reporting

Unless and until Manitoba Hydro adopts a hands-on role of construction manager for the GCC, the time for completion of this contract, and the Keeyask Generating Station project generally, will take longer. As the GCC takes longer to perform, the GCC contractor's direct costs, indirect costs and escalation costs will continue to rise. The delay in completion of this contract will cause delay and disruption claims from other contractors, which Manitoba Hydro will have to pay.

If Manitoba Hydro is to regain control of this Contract, then it needs to directly exert its influence on the GCC contractor. To do this the following areas will need to be addressed:

- Construction management
- Site supervision
- Recovery plan
- GCC Contractor's role
- Cost control
- Schedule management
- Cost estimating and forecasting

Construction Management:

Manitoba Hydro needs to be proactive in the construction management of the GCC. This scope requires better planning and execution. It is likely that Manitoba Hydro will need to recruit key personnel for this activity.

Site supervision:

Manpower, productivity and co-ordination are critical success factors particularly on a cost reimbursable priced contract. If not done correctly, productivity goals are not met and higher costs are incurred for less output. It is likely that Manitoba Hydro will need to recruit key personnel with trade backgrounds for this activity.

Recovery plan:

The current plan is not working and appears to be continuously changed when progress is not met. This needs to be re-visited with better construction management and site supervision insight and planned with a labour force and productivities that are reasonably achievable.

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GCC Contractor's role:

The GCC contractor has not performed and its role together with some key personnel will need to re-considered.

Schedule management:

The recovery plan with realistic targets and achievable productivity assumptions will need to be input in to a Contract Schedule that meets the requirements of the GCC contract.

Cost estimating, forecasting and cost control:

The Contract Schedule will need to be cost loaded so that activities are characterized by time and costs.

Unless Manitoba Hydro is prepared to make a step change in the management of the GCC contract, then it will continue to limp along, taking longer to perform and costing Manitoba Hydro more money. This could result in a final cost range of $9.5 billion to 10.5 billion.

If Manitoba Hydro is prepared to embrace a new contract management strategy to drive the GCC contractor to perform, then it will bring more predictability in terms of time and cost to this contract.

HVDC Converter Stations

This project is well managed and is expected to complete on time and within budget. Recommendation is to keep close monitoring of progress until completion.

Bipole III Transmission Line

This project is well managed and progressing on schedule. However, the critical paths of both Rokstad Power Corporation and Forbes Brothers Ltd. are slipping which may jeopardize completion in August 2018.

Manitoba – Minnesota Transmission Line

This project is on schedule. Its cost however appears low compared to other similar projects. We recommend that the cost estimate is reviewed and updated in due course.

Great Northern Transmission Line

The project is progressing, with Rights of Way being cleared, amongst other activities. The Construction Management Agreement is well considered commercially and serves to protect the interests of Manitoba Hydro. When benchmarked with other similar projects, its cost estimate is considered high and this should be reviewed in due course.

MGF PROJECT SERVICES

SECTION 9 - Abbreviations

Abbreviation	Definition
AA7	Amending Agreement No. 7
BBE	BBE Hydro Constructors Limited Partnership
BEI	Baseline Execution Index
BNA	Burntwood/Nelson Agreement
BOE	Basis of Estimate
BOQ	Bill of Quantities
CAC	Construction Advisory Committee
CBS	Cost Breakdown Structure
CEF	Capital Expenditure Forecast
CEO	Current Estimate Outlook
CM	Construction Management
CMA	Construction Management Agreement
CPI	Cost Performance Index
CPJA	Capital Project Justification Addendum
CPLI	Critical Path Length Index
CPM	Critical Path Methodology
CRR	Contract Revision Register
CUU TO	CUU Transmission Owner
DT	Double Time
EVM	Earned Value Management
EWO	Extra Work Orders
FAC	Forecast at Completion
Forbes	Forbes Brothers Ltd.
FPLS	Fixed Price Lump Sum
GA&O	General Administration and Overhead
GAO	US Government Accountability Office
GASP	Generally Accepted Scheduling Practices
GCC	General Civil Contract
GNTL	Great Northern Transmission Line
GOT	Generation Outlet Transmission
IFC	Issued for Construction
ISD	In-Service Date
JKDA	Joint Keeyask Development Agreement
KCN	Keeyask Cree Nations

Abbreviation	Definition
KHLP	Keeyask Hydropower Limited Partnership
LCKD	Locked
LOE	Level of Effort
LVAC	Land Valuation Appraisal Council
MAC	Monitoring Advisory Committee
MISO	Midcontinent Independent System Operator
MMTP	Manitoba Minnesota Transmission Project
MP	Minnesota Power
NDIA	US National Defence Industrial Association
OHGW	Overhead Ground Wire
OT	Overtime
PCA	Project Change Authorizations
PMI	Project Management Institute
PR	Purchase Requisition
QURR	Quantity Unit Rate Report
RMP	Risk Management Plan
ROW	Right of Way
Rokstad	Rokstad Power Corporation
ST	Standard Time
Stanley	Stanley Consultants Inc.
TLP	Transmission Line Payer
TPD	Transmission Projects Department
USI	Underlying System Improvements
WBS	Work Breakdown Structure
WECC	Western Electricity Coordinating Council
WPL	Work Package Lead

APPENDIX A

Klohn Clippen Berger Report

Klohn Crippen Berger

MGF Project Services

Keeyask Hydroelectric Project

Engineering Technical Comments on Design, Contracts and Construction Progress

December 2017

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December 2017

ACKNOWLEDGEMENT

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DISCLAIMER

This report is an instrument of service of Klohn Crippen Berger Ltd. The report has been prepared for the exclusive use of MGF Project Services for the specific application to the Keeyask Hydroelectric Project. The report's contents may not be relied upon by any other party without the express written permission of Klohn Crippen Berger. In this report, Klohn Crippen Berger has endeavoured to comply with generally-accepted professional practice common to the local area. Klohn Crippen Berger makes no warranty, express or implied.

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1 INTRODUCTION

The Klohn Crippen Berger scope of work is to assist MGF in reviewing the following areas and activities related to the Keeyask Hydro Project.

- **Project Cost Estimate** – where are the overruns, are they in a specific area or across the project?
- **Project Design** – were the design technical specifications and drawings reasonable, and in particular was the contractor provided with a reasonable amount of information?
- **Cost Estimate changes** – what were they, were they reasonable and how did they impact the project costs?
- **Contracting Methodology** – is the contract format reasonable and appropriate for the project?
- **Schedule Review** – is the current General Civil Contract Amending Agreement #7 schedule reasonable or is there likelihood of additional slippage?
- **Project Execution and Construction Management** – was the project set up to be a success and is the project being managed effectively?

KCB has approached the assignment in a straightforward manner:

- Reviewing the cost overruns to date to identify the areas of concern;
- Reviewing the engineering associated with each area of concern;
- Looking at the changes to the cost estimates caused by extra work orders, quantity changes and the reasonableness of the unit prices;
- Reviewing of the contract format, specifically the measurement and payment sections;
- Reviewing the changes in the schedule for project; and
- Commenting on the project execution and construction management to date.

Finally, KCB has expressed opinions on the likelihood of the project meeting the current contracted costs and schedule.

2 COST REVIEW

2.1 Reference Documents

- Contract Summary – All Contracts – September 2017.xlsx

2.2 Contract Cost Review

Review of the table shows the project has awarded 247 contracts with a forecasted value totaling $4,644,369,106.43.

Adding up the original contract values comes to $2,722,776,658.18.

The increase in the project cost is therefore $1,921,592,448.25, which is one of the main reasons for this review.

To focus our work, we initially sorted all the contract information by contract value. Then we calculated the percentage increase for each contract. The contracts that increased are shown in the Table 1. The base data does show that some contracts did or are predicted to complete under budget for a total of $16,431,830.59 in savings, however the total savings are less than 1% of the total cost increase and are therefore insignificant in the total project cost.

Table 1 Contract Percentage Increase

Name of Vendor	Description	Original Contract Value	Forecasted Contract Value	% increase
HATCH LTD.	Stage V Engineering	[redacted]	[redacted]	[redacted]
U M A ENGINEERING LTD	Stage V Infrastructure Engineering	[redacted]	[redacted]	[redacted]
REVAY AND ASSOCIATES LIMITED	Claims Avoidance & Support	[redacted]	[redacted]	[redacted]
KPMG LLP	Senior Level Staff Augmentation Services	[redacted]	[redacted]	[redacted]
RST INSTRUMENTS LTD.	Analog Thermistor Sensor	[redacted]	[redacted]	[redacted]
RST INSTRUMENTS LTD.	Equipment	[redacted]	[redacted]	[redacted]
COMMSTREAM GIGALINKS INC.	Main Camp Communications Phase II	[redacted]	[redacted]	[redacted]
MIDWEST FENCE COMPANY LTD.	Supply of Fence Materials	[redacted]	[redacted]	[redacted]
MULTICRETE SYSTEMS INC.	Supply of Pre-Cast Manhole Assembly	[redacted]	[redacted]	[redacted]
M. SULLIVAN & SON LIMITED	Ice Boom	[redacted]	[redacted]	[redacted]
VALLEN	Various Equipment	[redacted]	[redacted]	[redacted]
IRON NORTH LIMITED PARTNERSHIP	Miscellaneous Site Construction	[redacted]	[redacted]	[redacted]
ACKLANDS-GRAINGER INC.	Materials, Tools & Equipment	[redacted]	[redacted]	[redacted]
MULTICRETE SYSTEMS INC.	Supply of Pre-Cast Manhole Assembly	[redacted]	[redacted]	[redacted]
RST INSTRUMENTS LTD.	Piezometer	[redacted]	[redacted]	[redacted]
PVA CANINE SERVICES LTD.	Canine substance detection KGS	[redacted]	[redacted]	[redacted]
FOX, YORK AND SODEXO JOINT VENTURE	Security Services	[redacted]	[redacted]	[redacted]

1a

Name of Vendor	Description	Original Contract Value	Forecasted Contract Value	% increase	
KPMG LLP	Project Health Check	[redacted]	[redacted]	[redacted]	
BBE HYDRO CONSTRUCTORS LIMITED - AF	General Civil Works	[redacted]	[redacted]	[redacted]	
CANMEC INDUSTRIEL INC	Intake Gates, Guides & Hoists	[redacted]	[redacted]	[redacted]	
KEEYASK MAINTENANCE SERVICES JOINT	Maintenance Services	[redacted]	[redacted]	[redacted]	
FOX, YORK AND SODEXO JOINT VENTURE	Catering & Janitorial Services	[redacted]	[redacted]	[redacted]	
KEEYASK EMERGENCY MEDICAL SERVICES	Emergency Medical/Ambulance Service	[redacted]	[redacted]	[redacted]	
TRIPLE M MODULAR LTD	Main Camp Facility	[redacted]	[redacted]	[redacted]	
AMISK CONSTRUCTION	Work Area Site Development	[redacted]	[redacted]	[redacted]	
VALIDATION ESTIMATING, LLC	Risk Analysis & Contingency Estimating	[redacted]	[redacted]	[redacted]	
ABB INC.	Static Exciter	[redacted]	[redacted]	[redacted]	
VOITH HYDRO	Turbines & Generators	[redacted]	[redacted]	[redacted]	
ABC FIRE & SAFETY EQUIPMENT LTD.	Fire Prot. Systems Serv. & Insp - Keeyask	[redacted]	[redacted]	[redacted]	
CANMEC INDUSTRIEL INC	Spillway Gates, Guides & Hoists	[redacted]	[redacted]	[redacted]	1a
AMISK CONSTRUCTION	Reservoir Clearing	[redacted]	[redacted]	[redacted]	
STITTCO ENERGY LIMITED	Supply & Rental of Propane Tanks	[redacted]	[redacted]	[redacted]	
NORTH SOUTH CONSULTANTS INC	Coordination of First Nation Labour, Rental, & Disbursements	[redacted]	[redacted]	[redacted]	
KPMG LLP	Keeyask Recovery Plan	[redacted]	[redacted]	[redacted]	
PTI MANITOBA INC.	Generator Step Up Transformer	[redacted]	[redacted]	[redacted]	
VIBROSYSTM INC.	Air Gap & Vibration Monitoring Systems	[redacted]	[redacted]	[redacted]	
COH PROJECTS ET SERVICES INC	Powerhouse Cranes	[redacted]	[redacted]	[redacted]	
AMISK CONSTRUCTION	South Access Road	[redacted]	[redacted]	[redacted]	
ENGLOBE CORP.	E&M QA Inspection & Expediting Services	[redacted]	[redacted]	[redacted]	
ACONEX CANADA LIMITED	Web based Project Collaboration Tool PCT*	[redacted]	[redacted]	[redacted]	
L-KOPIA, INC.	Rail Track Survey; Thompson & Limestone	[redacted]	[redacted]	[redacted]	
CANMEC INDUSTRIEL INC	Fabrication & Mods for Spillway Stoplogs	[redacted]	[redacted]	[redacted]	
MULTICRETE SYSTEMS INC.	Supply of Grout Mix	[redacted]	[redacted]	[redacted]	
CANMEC INDUSTRIEL INC	Draft Tube & Monorail Cranes	[redacted]	[redacted]	[redacted]	
CAPITOL STEEL CORPORATION	Intake Trashracks & Guides	[redacted]	[redacted]	[redacted]	
TOROMONT CAT	Spillway & Blackstart Standby Diesel Gen Set	[redacted]	[redacted]	[redacted]	
CANMEC INDUSTRIEL INC	Stoplogs, Bulkhead/Draft Tube Gates & Followers	[redacted]	[redacted]	[redacted]	

We noted that many of the contracts are relatively small and do not materially affect the overall project cost, for example fence materials have gone up over 1000% but that is still less than $14,000. What is more important is the percentage increase of each contract as percentage of the total project cost, to understand which contract changes are important to the overall project. Therefore, the total project increase was calculated for each contract and then the results were resorted according to the percentage of total project increase, see Table 2. Contracts with variances less than 0.1% or negative are not shown in Table 2.

Table 2 Contract Increase as Percentage of Total Project Cost Increase

Name of Vendor	Description	Original Contract Value	Forecasted Contract Value	% Contract Increase	% Project Increase
BBE HYDRO CONSTRUCTORS LIMITED - AF	General Civil Works	[redacted]	[redacted]	[redacted]	[redacted]
FOX, YORK AND SODEXO JOINT VENTURE	Catering & Janitorial Services	[redacted]	[redacted]	[redacted]	[redacted]
HATCH LTD.	Stage V Engineering	[redacted]	[redacted]	[redacted]	[redacted]
TRIPLE M MODULAR LTD	Main Camp Facility	[redacted]	[redacted]	[redacted]	[redacted]
VOITH HYDRO	Turbines & Generators	[redacted]	[redacted]	[redacted]	[redacted]
KEEYASK MAINTENANCE SERVICES JOINT	Maintenance Services	[redacted]	[redacted]	[redacted]	[redacted]
CANMEC INDUSTRIEL INC	Intake Gates, Guides & Hoists	[redacted]	[redacted]	[redacted]	[redacted]
FOX, YORK AND SODEXO JOINT VENTURE	Security Services	[redacted]	[redacted]	[redacted]	[redacted]
M. SULLIVAN & SON LIMITED	Ice Boom	[redacted]	[redacted]	[redacted]	[redacted]
U M A ENGINEERING LTD	Stage V Infrastructure Engineering	[redacted]	[redacted]	[redacted]	[redacted]
KEEYASK EMERGENCY MEDICAL SERVICES	Emergency Medical/Ambulance Service	[redacted]	[redacted]	[redacted]	[redacted]
AMISK CONSTRUCTION	Work Area Site Development	[redacted]	[redacted]	[redacted]	[redacted]
CANMEC INDUSTRIEL INC	Spillway Gates, Guides & Hoists	[redacted]	[redacted]	[redacted]	[redacted]
AMISK CONSTRUCTION	Reservoir Clearing	[redacted]	[redacted]	[redacted]	[redacted]
COMMSTREAM GIGALINKS INC.	Main Camp Communications Phase II	[redacted]	[redacted]	[redacted]	[redacted]
AMISK CONSTRUCTION	South Access Road	[redacted]	[redacted]	[redacted]	[redacted]
PVA CANINE SERVICES LTD.	Canine substance detection KGS	[redacted]	[redacted]	[redacted]	[redacted]
REVAY AND ASSOCIATES LIMITED	Claims Avoidance & Support	[redacted]	[redacted]	[redacted]	[redacted]
PTI MANITOBA INC.	Generator Step Up Transformer	[redacted]	[redacted]	[redacted]	[redacted]
KPMG LLP	Senior Level Staff Augmentation Services	[redacted]	[redacted]	[redacted]	[redacted]
ABB INC.	Static Exciter	[redacted]	[redacted]	[redacted]	[redacted]

1a

Clearly the General Civil Contract with BBE is the critical contract for the project. If for example BBE was on budget and schedule the total project would only be over budget by $628M or 23%. But much of that 23% is directly related to civil delays, camp costs, turbine supply costs, etc. all would be significantly reduced. Therefore, the majority of our review will examine the General Civil Contract.

3 PROJECT DESIGN

3.1 Reference Documents

Technical Specifications

- V 3 - 243994-0030-016203-SPEC-Technical Specification 20141119, dated 19 Nov 2014
- V 12 - 243994-0030-016203-SPEC-Technical Specification-20130809, dated 18 July 2017

Latest contract documents

- 243994-0020-016203-CON-GCC Volume 5 20140310
- 243994-0020-016203-CON-GCC Volume 4 20170228
- 243994-0020-016203-CON-GCC Volume 3 20170228
- 243994-0020-016203-CON-GCC Volume 2 Drawings 20140310
- 243994-0020-016203-CON-GCC Volume 1 20170228.pdf
- 243994-0020-016203-CON-Amending Agreement 7-20170228
- 243994-0020-016203-CON-Amending Agreement 6-20160720
- 243994-0020-016203-CON-Amending Agreement 5-20160623
- 243994-0020-016203-CON-Amending Agreement 4-20160610
- 243994-0020-016203-CON-Amending Agreement 3-20160610
- 243994-0020-016203-CON-Amending Agreement 2-20160415
- 243994-0020-016203-CON-Amending Agreement 1-20140307

Drawing register

- HATCH IFC DWGS Aconex Report - January 1,2014 to October 5,2017

3.2 General Civil Technical Specification Review

Often increases in projects costs are related to changes in the design which occur after the contract is signed. These changes typically appear as revisions to the Issued for Construction Drawings or the Technical Specifications.

There have been 12 versions of the Technical Specifications produced between March 2014 and July 2017. The amended agreement in volume 2 includes technical specifications dated 10 March 2014.

Table 3 lists the specification sections and shows the revision versions of the sections at three dates, the amended contract version (10 March 2014), Version 3 in May 2015 and Version 12 from July 2017.

Table 3 Specification Revisions

Specification Section	AA#7 Contract March 2014		Version 3 May 2015		Version 12 July 2017	
	Revision	Pages	Revision	Pages	Revision	Pages
Division 01 – General Requirements						
01 10 05 Indirects	A	4	B	4	B	4
01 51 00 Temporary Utilities	B	8	B	8	B	8
01 52 00 Construction Facilities	B	4	B	4	B	4
01 54 11 Powerhouse Crane	A	4	B	4	B	4
Division 03 – Concrete						
03 11 00 Concrete Formwork	A	10	B	9	D	10
03 15 13 Waterstops	A	8	B	8	D	8
03 15 19 Embedded Anchors	B	8	C	7	D	8
03 21 00 Reinforcing Steel	A	8	B	8	B	8
03 30 00 Cast-In-Place Concrete	B	26	C	26	E	26
03 35 00 Concrete Finishing and Repair	A	10	B	9	B	9
03 35 05 Floor Hardener/Surface Sealer	A	4	A	4	B	4
03 39 00 Concrete Curing	A	4	A	4	A	4
03 40 00 Precast Concrete	A	8	B	8	B	8
03 41 33 Precast Concrete Beams and Girders	A	10	B	10	B	10
03 45 13 Precast Wall Panels	A	10	B	10	B	10
03 53 00 Concrete Floor Toppings	A	4	B	4	B	4
03 60 00 Equipment Grouting	A	6	B	6	B	6
Division 04 – Masonry						
04 22 00 Concrete Unit Masonry	A	6	B	6	B	6
Division 05 – Metals						
05 05 19 Drilled-In-Place Anchors	A	3	B	3	B	3
05 12 23 Structural Steel	A	14	B	14	C	14
05 31 23 Steel Decking	A	6	B	6	B	6
05 50 00 Miscellaneous Metal	A	8	B	9	C	10
Division 07 – Thermal and Moisture Protection						
07 11 13 Bituminous Dampproofing	[NOT CURRENTLY INCLUDED]					
07 21 13 Board Insulation	[NOT CURRENTLY INCLUDED]					
07 21 29 Sprayed Insulation	[NOT CURRENTLY INCLUDED]					
07 27 00 Air Barriers	[NOT CURRENTLY INCLUDED]					
07 62 00 Metal Flashing and Trim	[NOT CURRENTLY INCLUDED]					
07 64 00 Metal Wall Cladding	[NOT CURRENTLY INCLUDED]					
07 91 26 Joint Fillers	A	4	A	4	A	4
07 92 00 Joint Sealants	A	6	B	6	B	6
Division 08 – Openings						
08 11 00 Metal Doors and Frames	[NOT CURRENTLY INCLUDED]					

Specification Section	AA#7 Contract March 2014		Version 3 May 2015		Version 12 July 2017	
	Revision	Pages	Revision	Pages	Revision	Pages
08 36 19 Service Bay Door	A	8	A	8	C	10
08 50 00 Windows	[NOT CURRENTLY INCLUDED]					
08 70 05 Cabinet and Miscellaneous Hardware	[NOT CURRENTLY INCLUDED]					
08 71 00 Door Hardware	[NOT CURRENTLY INCLUDED]					
08 80 50 Glazing	[NOT CURRENTLY INCLUDED]					
Division 09 – Finishes						
09 21 16 Gypsum Board Assemblies	[NOT CURRENTLY INCLUDED]					
09 22 16 Non-Structural Metal Framing	[NOT CURRENTLY INCLUDED]					
09 22 26 Metal Suspension Systems	[NOT CURRENTLY INCLUDED]					
09 51 13 Acoustical Panel Ceilings	[NOT CURRENTLY INCLUDED]					
09 65 19 Resilient Tile Flooring	[NOT CURRENTLY INCLUDED]					
09 90 00 Painting and Coating	A	16	A	16	C	16
Division 10 – Specialties						
10 21 13 Metal Toilet Compartments	[NOT CURRENTLY INCLUDED]					
10 21 16 Shower and Dressing Compartments	[NOT CURRENTLY INCLUDED]					
10 28 10 Toilet and Bath Accessories	[NOT CURRENTLY INCLUDED]					
10 51 13 Metal Lockers	[NOT CURRENTLY INCLUDED]					
10 56 16 Fabricated Wood Storage Shelving	[NOT CURRENTLY INCLUDED]					
Division 14 – Conveying Equipment						
14 20 00 Elevators	A	14	B	14	F	16
Division 21 – Fire Suppression						
21 12 00 Fire Protection Standpipe System	A	14	A	14	A	14
21 13 00 Fire Suppression Sprinkler System	A	14	A	14	A	14
Division 22 – Plumbing						
22 11 00 Domestic Water System	A	10	A	10	B	8
22 13 00 Sanitary System	C	6	C	6	D	6
22 14 00 Clearwater Drainage System	B	10	B	10	C	8
22 15 00 Service Air and Brake Air Systems	A	10	A	10	C	12
Division 23 – Heating, Ventilating and Air Conditioning (HVAC)						
23 07 00 HVAC Duct Insulation	A	4	B	4	C	4
23 09 00 Instrumentation and Control for HVAC	C	20	C	20	E	20
23 30 00 Heating Ventilation and Air Conditioning System	A	32	A	30	C	44
Division 25 – Integrated Automation						
25 11 00 Unit Control and Monitoring System (UCMS)	A	16	A	16	A	16
Division 26 – Electrical						
26 05 00 Electrical General Requirements	A	8	B	8	B	8
26 05 21 Wire and Cable Systems	C	18	D	20	E	24
26 05 27 Embedded Grounding	A	4	A	4	B	4
26 05 28 Surface Grounding	A	8	B	6	D	8

Specification Section	AA#7 Contract March 2014		Version 3 May 2015		Version 12 July 2017	
	Revision	Pages	Revision	Pages	Revision	Pages
26 05 29 Cable and Wire Support Systems	A	12	A	12	C	14
26 05 43 Installation of Cables in Trenches and Ducts	A	6	B	6	B	6
26 11 02 600 V Load Centre Switchgear	A	10	B	10	C	6
26 12 25 Installation of MV Equipment	A	6	B	4	B	6
26 12 27 Installation of Motor Control Centres	B	4	C	4	C	4
26 13 19 GCB & IPB Installation	A	8	B	8	B	8
26 22 13 Low-Voltage Distribution System	A	16	B	16	C	14
26 29 10 Motor Starters and Control Stations	A	6	B	6	B	6
26 32 13 Standby Diesel Generators	C	18	D	16	E	18
26 33 00 Battery Systems, UPS and Inverters	C	28	D	28	D	28
26 36 23 Automatic Transfer Switches	A	6	A	6	B	6
26 50 00 Facility Lighting and Controls	C	12	D	12	E	14
Division 27 – Communications						
27 00 00 Communication Systems	C	16	D	16	D	16
Division 28 – Electronic Safety and Security						
28 13 00 Access Control & Intrusion Detection	C	10	C	10	D	10
28 23 00 Video Surveillance	A	8	B	8	C	8
28 31 00 Fire Detection and Alarm Systems	C	12	D	12	E	22
28 33 00 Spillway Warning System	A	6	A	6	A	6
Division 31 – Earthwork						
31 11 00 Clearing, Grubbing and Stripping	B	4	B	4	C	4
31 14 13 Stockpiling of Materials	A	4	B	4	B	4
31 23 01 Weight Scales	A	4	A	2	A	2
31 23 13 Foundation Preparation	D	10	D	10	D	10
31 23 16 Unclassified Excavation	D	6	E	6	E	6
31 23 17 Rock Excavation	B	10	C	8	D	10
31 23 18 Rock Excavation In-the-wet	C	8	C	8	C	8
31 23 19 Control of Water	B	4	B	2	B	2
31 23 23 Impervious Fill and Random Fill	E	10	F	10	G	10
31 23 24 Granular Fill	C	8	D	8	G	8
31 23 25 Road Topping	A	4	B	4	B	4
31 23 26 Riprap Bedding	A	4	B	4	C	4
31 23 27 Rockfill	B	4	C	4	D	4
31 23 33 Trenching and Backfilling	A	6	A	6	A	6
31 23 34 Perimeter Ditches Along the Dykes	B	6	B	6	B	6
31 25 00 Erosion and Sedimentation Control	A	4	A	4	A	4
31 26 00 Excavated Material Placement Areas (EMPA)	[NOT CURRENTLY INCLUDED]					
31 33 13 Rock Support and Protection	A	12	B	12	B	12
31 34 00 Geogrid Soil Reinforcement	[NOT CURRENTLY INCLUDED]					

Specification Section	AA#7 Contract March 2014		Version 3 May 2015		Version 12 July 2017	
	Revision	Pages	Revision	Pages	Revision	Pages
31 35 19 Geotextiles	A	4	A	4	A	4
31 36 13 Gabions	[NOT CURRENTLY INCLUDED]					
31 37 00 Riprap	B	4	B	4	D	4
31 52 00 Cofferdams	D	22	E	20	E	20
31 68 00 Post-Tensioned Foundation Anchors	A	10	A	8	B	10
31 81 00 Foundation Grouting	A	12	B	10	B	10
31 82 00 Foundation Drain Holes	B	4	B	4	B	4
Division 32 – Exterior Improvements						
32 31 13 Chain Link Fences and Gates	A	2	A	2	C	2
Division 33 – Utilities						
33 42 00 Corrugated Steel Pipe Culverts	B	4	B	4	C	4
33 72 00 Unit Protection and Control System	A	6	A	6	A	6
Division 34 – Transportation						
34 71 33 Guard Rails and Posts	A	6	A	6	B	6
Division 35 – Gates and Guides						
35 20 13 Bulkhead Gates, Stoplogs and Trashracks	B	6	B	6	D	8
35 20 17 Embedded Guides	A	6	A	6	C	6
Division 40 – Process Integration						
40 05 00 Mechanical & Piping General Requirements	A	14	A	14	B	16
40 23 19 Station Water, Cooling Water & Shaft Seal Water Systems	A	8	A	8	B	8
40 23 21 Dewatering & Filling System [	A	6	A	6	B	8
40 42 00 Piping Insulation	A	4	A	4	A	4
40 90 00 Piezometer Systems and Instrumentation	A	6	A	6	C	6
40 90 25 Instrumentation for Piping Systems	A	10	A	10	B	10
Division 41 – Material Processing and Handling Equipment						
41 22 00 Small Cranes	A	8	A	8	B	8
41 22 13 Crane Rails	A	6	A	4	B	6
Division 43 – Process Gas and Liquid Handling, Purification, and Storage Equipment						
43 20 00 Oil Storage & Handling System	A	10	A	8	C	12
Division 46 – Water Treatment, Waste Water Treatment and Oil Separation Equipment						
46 07 13 Domestic Water Treatment Plant	C	16	C	16	E	18
46 07 53 Wastewater Treatment Plant	A	30	A	26	C	12
46 25 00 Oil Water Separation Facility	A	6	A	6	B	10

Legend: 1 Revision from previous (green) 2 or more Revisions from previous (yellow)

Table 3 shows that many specifications have been changed over the course of the project, but not that many have been changed multiple times. KCB compared specifications Version 12 with Version 3 looking for major changes. Significant changes were observed in the following sections:

03 11 00 **Concrete Formwork** – revised to include many more payment items, i.e. much more detailed with respect to vertical surfaces and locations.

03 15 19 **Embedded Anchors** – revised to include more types of anchors for specific locations.

03 30 00 **Cast-in Place Concrete** – various changes to make production easier, but also added requirement for a layer of thermal crack protection reinforcing, which would add cost in some areas.

05 50 00 **Miscellaneous Metal** – added davits, bulkhead gate storage slot guides, crane end stops, miscellaneous metal supplier by purchaser, all will increase the costs associated with this section.

09 90 00 **Painting and Coating** – embedded guides were added. This is an expensive item to paint, requiring staging or scaffold and coordination with the gate installations.

14 20 00 **Elevators** – This specification underwent significant rework, including deletion of floors and stops as well as changes to the control system and dimensions, but cost may not have changed dramatically.

22 13 00 **Sanitary System** – many new pipe classes, fitting and valves were added to the specification. Impression is that this section may not have been well developed at bidding, thus costs for this section likely increased significantly.

22 15 00 **Service Air and Brake Air Systems** – revisions include addition of depression air and additional measurement and payment items. The addition of depression air will likely double the costs associated with this specifications section.

23 09 00 **Instrumentation and Control for HVAC** – major revisions, presumably to suit the specific equipment selected and control technology upgrades. Some price increase would be expected.

23 30 00 **HVAC System** – also significant revisions to the specifications, including addition of payment items for embedded piping. Changes also included dampers, AHU's, controls and assorted heaters.

26 11 02 **600V Load Centre Switchgear** – revised to include arcflash requirement.

26 22 13 **Low Voltage Distribution System** – multiple changes in this specification, driven perhaps by changes to the lighting and HVAC systems.

26 32 13 **Standby Diesel Generators** – the spillway genset was added and changes made to the technical details.

26 50 00 **Facility Lighting and Controls** – significant revisions to eliminate fluorescent lights and include LED technology as well as intelligent controls including occupancy sensors. Good technical improvement, but will have a cost impact.

28 31 00 **Fire Detection and Alarm System** – multiple revisions, likely to match up to the ventilation system controls as well as the plant control system.

31 23 24 **Granular Fill** – most of the sieve size percentages for the various fill have been adjusted. We assume this is to better suit the materials in the quarries and borrow areas.

31 37 00 **Riprap** – class 7and 8 riprap percent fines by weight was revised, likely also to suit the quarry materials.

35 20 13 **Bulkhead Gates, Stoplogs and Trashracks** – temporary stoplogs for the spillway have been added as well as the trashracks. These will impact the concrete pier construction as well. We assume the stoplogs were added to make more work areas available, in an attempt to recover some lost schedule.

46 07 13 **Domestic Water Treatment Plant** – the process and type of plant has been revised, but the nominal capacity remains the same.

46 07 53 **Waste Water Treatment Plant** - the process and type of plant has been revised, but the nominal capacity remains the same.

All the changes will have made some impact on the costs and together they show that the mechanical and electrical design was not as well advanced as the civil design back in 2014. Interestingly, very little changes have been made to the excavation, fills and concrete specifications, thus any significant cost changes in those areas should only be due to quantity changes.

3.3 Geotechnical Information Review

Several campaigns of geological/geotechnical investigations were carried out between 1962 and 2010 to investigation the structure foundations and potential borrow materials. These included drill holes, test pits, laboratory testing of materials, reconnaissance and detailed inspections and mapping, and geophysical surveys.

The investigations appear to have been reasonably comprehensive, both for construction materials and, in general, for the structures. There are relatively few investigations in or over water, which is understandable given safety concerns at rapids and fast-flowing river sections; the in-river areas beneath structures are areas of risk with respect to unknowns that are common to many similar projects.

Although geophysical investigations are identified as having been performed, contract drawings of investigations do not show their locations and the results are not included in Volume 5 of Contract 016203. It is not known whether this information was included in a "data room" or as additional information provided by Manitoba Hydro.

The regional bedrock geology drawing (1-00195-DE-11000-001 Rev E) in the contract, which covers the vicinity of the major structures, does not include the locations of drill holes and test pits. Addition of this information would facilitate understanding whether features such as deformation zones and contacts of geologic units had been adequately investigated. One must estimate where these features would occur on the locations of explorations plan (1-00195-DE-0019-0001 Rev D), then review logs of nearby drill holes to determine conditions at those features.

There is a brittle deformation zone (intense jointing and fracturing) which crosses the axis of principal structures beneath the central dam and central dam cofferdam. It was investigated with one drill hole (G-010). Water pressure testing was performed near the bedrock surface; it was not performed in the brittle zone, but the log indicates this zone was healed (i.e. had been broken but subsequent mineralization resulted in a solid rock mass).

A ductile deformation zone (shear or fault) is shown on the geology plan beneath the central dam and its cofferdam, mainly within water. This feature was not investigated, even though it is shown to continue onto the island near Gull Rapids.

KCB would expect identified features such as the deformation zones to be investigated and a description of the features to be provided, in order that bidders could assess potential impacts on cofferdam performance (e.g. need for dewatering) and foundation preparation (depth of excavation, type of treatment) beneath the major structures. We have not received historic investigation reports; it is possible that these features have been addressed. The text of Volume 5 states that “during each of the investigations, the bedrock outcrops and overburden exposures were examined and described.”

Volume 5, Section 6 is “Investigations by Areas of Interest”. It describes the cofferdams, groin, and excavated material placement areas (waste material deposition areas). Section 6 does not describe the main structures – dams, powerhouse and spillway. However, the contractor would perform excavation, grouting and foundation preparation beneath the structures and a description of investigations would be of interest to the contractor.

The material balance – available sources of various fills and aggregates and their possible use for construction – was reviewed (Drawing No. 1-00195-06200-0010 Rev OC). The engineer’s material balance represents one plan that could be followed, thus the term “possible use” to show that identified material volumes are adequate. The Contractor would be expected to develop its own plan. It is desirable to identify material sources well in excess of the actual requirement, in order to allow for wastage, materials for Contractor’s own use, and unanticipated requirements; available volumes of twice those required is a common target. This is generally achieved. The following are noted:

- The required rock excavations are shown as being 100% utilized. This is because demand is much greater than the required excavation volume. Abundant additional rock is available in nearby quarries.

- Impervious borrow source N5 on the north abutment is shown as being 77.6% utilized. This is the closest source to the major earthworks – North and Central Dams – on the north side of the main channel, and using N5 to its maximum extent is logical. In the event that N5 were to be exhausted, source N21 is available at a similar distance from the major structures, and N6 is at a greater distance. The material balance indicates that quantities in the three sources greatly exceed the requirements.

The earthfill dam and dyke designs depicted on the drawings vary somewhat to accommodate, for dams, the cofferdams and nearby concrete structures; and for dykes, the topography and foundation conditions. On the dam sections, some material zones are relatively thin, in particular on the upstream slopes; the materials will be slow to place and (where required) to compact and special placement techniques such as very careful placement to limit their width or the use of "side boards" at the design zone limits with to confine the materials may be required to properly construct them. Other than these narrow zones, the dams appear to be constructible without special placement techniques. The designs are as expected in the northern climate.

Placement of Zone 5 riprap bedding as shown at the upper parts of the dams will be challenging. The zone width narrows to 500 mm. However, the specified maximum size of the material is 500 mm; and 30% of the material by weight must be larger than 300 mm. It is common to specify minimum zone thicknesses of twice the maximum particle size to facilitate placement that permits a uniform distribution of all particle sizes. This narrow placement area is limited to a 2 m vertical height in the dams.

3.4 General Civil Contract Drawing Review

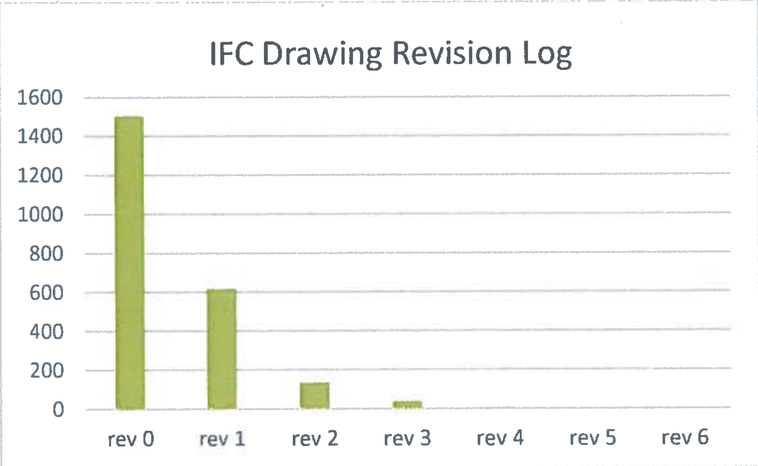
KCB has reviewed the list of approximately 2300 IFC drawings prepared by Hatch and listed in the drawing register (HATCH IFC DWGS Aconex Report - January 1,2014 to October 5,2017). We also reviewed the drawings associated with the General Civil Contract. We did not review each drawing in detail, however we did look to see if the major structures have sufficient detail to enable quantity takeoff and subsequent pricing. In general, the IFC drawing are clear and certainly define the majority of the permanent works.

By comparison we looked at the number of civil drawings for two similar sized projects we have been involved with and they were 2500 drawings and 1100 drawings respectively. For the 1100 drawing project KCB was as the civil designer inside a design build project team and the project included an RCC dam with integral spillway, long large tunnel, significant channels and a large 1100 MW powerhouse. The project with 2500 drawings was a 900 MW project with diversion tunnel, large earthfill dam with complex foundation issues and large spillway and powerhouse structures. The procurement was done with multiple contracts. The large contracts included excavations, concrete structures and generating equipment. In general, the design was substantially completed prior to award, thus there was limited opportunity for design innovations, only construction methodology.

As a further check, we looked at the revision history for the IFC drawings, if the drawings had undergone multiple revisions that would likely indicate changes to the scope or inadequate drawings to start. The revision log is summarized in Table 4 and the associated graph.

Table 4 IFC Drawing Revisions

Rev 0	Rev 1	Rev 2	Rev 3	Rev 4	Rev 5	Rev 6
1503	616	133	35	7	2	1

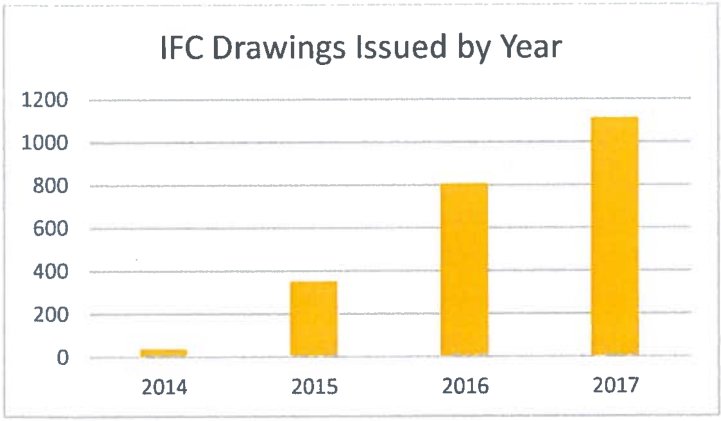


The vast majority of the drawings have not been revised after issued IFC, in fact drawings not rev 0 or Rev 1 are insignificant. This is good from the perspective of limiting the engineering effort and proof that the engineering was almost always on target and not being questioned by the contractor.

Finally, KCB looked at when the drawings were issued, to try and understand if the contractor was getting the drawings in a timely manner. Table 5 and the associated graph shows the IFC drawings by year of issue.

Table 5 IFC Drawing Years Issued

2014	2015	2016	2017
37	351	806	1113



The data shows that in 2014 the contractor priced the job with a limited number of drawings. The majority of the drawings were prepared in 2016 and 2017 which may have created two issues which would impact the costs:

- The contractor missed or did not allow for all the complexity of the project – i.e. underbid; and
- The engineer could have added more detail and work after the contract was signed.

In summary, our conclusions regarding the design engineering, drawings and information presented are:

- The information is generally good to very good based on the low number of IFC drawings revisions;
- The design is reasonable and well detailed;
- The number of drawings produced is reasonable for a project of this size;
- The revisions to the specifications have been generally related to the balance of plant work and generally should be low cost impacts to the entire project; and
- The only potential issue may be the timing of the drawing production, which may have created some delays in construction.

4 COST ESTIMATE CHANGES

4.1 Reference Documents

- Original Contract (OC) dated Mar 10, 2014
- Amending Agreement #7 (AA7) dated Feb 28, 2017
- Keeyask Contract Revision Register for Allocated Contingency - August 2017
- Hatch Stage IV Engineering Summary Report - GN-10.1 Rev 0.pdf

4.2 EWO's

Extra work orders (EWO's) normally occur in construction projects, which is one of the reasons for contingency in the project budget. The value of the EWO's are typically larger for projects where the design is not fully completed at the time of tender which was the situation for Keeyask.

We reviewed the EWO's for the GCC as extracted from the Keeyask Contract Revision Register for Allocated Contingency - August 2017. We sorted the information by year as part of the review.

Table 6 Extract from the Keeyask Contract Revision Register

Change Type	Entered on Date	Work Order #	Header Description	Amt Before PST
Approved				
	2016-10-31	Profit 000001	Profit Adjustment - All EWO's to October 2016	[redacted]
		EWO 000132	VE For CDCD rock groin widening	
		EWO 000129	VE For Sloped Walls and Roughness at Spillway Channel	
		EWO 000130	VE For Selection of Rock Bolt Size	
		EWO 000137	Material Substitutions for CB7A	
		EWO 000105	VE For Sloping Walls at PH Excavation Intake and Tailrace	
	2016-11-30	Profit 000002	Profit Adjustment - Initial Target Price	
	2017-06-30	Profit 000003	Forfeited Step Change Incentive Profit (SCIP) - May 2017	
	2017-07-31	Profit 000004	Forfeited Step Change Incentive Profit (SCIP) - June 2017	
			Approved Total	
Approved-G				
	2015-06-26	EWO - Claim 000022	August 2014 Blockade Costs	
		EWO - Claim 000144	May 2016 Blockade of PR280; BBEHC-NOTIC-000042 determination	
			Approved-G Total	
Approved-GP				
	2014-06-19	EWO 000001	MH Supplied Work Area A Quarry Rock (Deletion of Scope)	
		EWO 000002	Construction Fuel - For the supply and delivery of diesel fuel and gasoline.	
	2014-10-03	EWO 000003	Technical Specification Revision	
	2014-10-04	EWO 000004	Revised Baseline Schedule for the Powerhouse Cofferdam	
	2014-11-15	EWO 000005	Clear North Channel Rock Groin Ext	

1a

Change Type	Entered on Date	Work Order #	Header Description	Amt Before PST
	2014-11-16	EWO 000006	Cofferdams North Channel Rock Groin Ext	[redacted]
		EWO 000007	PHCG Top Up	[redacted]
	2014-11-19	EWO 000008	Technical Specification Revision	[redacted]
	2014-12-05	EWO 000011	Cofferdams North Channel Rock Groin Ext 2	[redacted]
	2015-01-07	EWO 000016	June/July 14 MH Directed Work	[redacted]
		EWO 000017	August 14 MH Directed Work	[redacted]
		EWO 000018	September 14 MH Directed Work	[redacted]
	2015-03-02	EWO 000019	October 14 MH Directed Work	[redacted]
	2015-06-26	EWO 000020	G1 Site Restoration	[redacted]
		EWO 000021	Technical Specification Revision	[redacted]
		EWO 000023	Community Employment Sessions	[redacted]
	2015-07-15	EWO 000024	Premium to work Remembrance Day 2014	[redacted]
	2015-08-05	EWO 000025	Rock Fall Netting Anchors	[redacted]
	2015-09-02	EWO 000028	Rock Excavation on PH North Wall STA 0+989 to 0+996	[redacted]
	2015-09-17	EWO 000029	Cofferdam Top-up Prebuild	[redacted]
		EWO 000030	Central Dam Cofferdam, North Extension	[redacted]
	2015-10-01	EWO 000026	River Management Claim	[redacted]
	2015-10-03	EWO 000031	Developing Estimate for South Access Road - Part A	[redacted]
	2015-10-20	EWO 000038	February 15 MH Directed Work	[redacted]
	2015-10-21	EWO 000039	Technical Specification Revision 05	[redacted]
		EWO 000037	Equipment Delivery Dates	[redacted]
		EWO 000033	January 2015 MH Directed Work	[redacted]
	2015-11-09	EWO 000040	Cofferdam Winter top-up	[redacted]
	2015-11-25	EWO 000041	December 2014 MH Directed Work	[redacted]
	2015-11-27	EWO 000042	G3 Causeway Quantity Reconciliation	[redacted]
		EWO 000043	March 2015 Directed Work	[redacted]
		EWO 000044	Spillway Quantity Changes	[redacted]
	2015-12-23	EWO 000045	N5 Causeway Quantity Reconciliation	[redacted]
		EWO 000046	November 2014 Directed Work	[redacted]
	2016-02-11	EWO 000044 r1	Spillway Quantity Changes (rev 1)	[redacted]
	2016-02-17	EWO 000047	Implementation of Value Engineering Proposal	[redacted]
	2016-02-29	EWO 000048	Spillway South Wall Additional Ex; Engineer's Determination	[redacted]
	2016-03-13	EWO 000050	Technical Specification Revision 06 (EMPA Technical Specification 312600)	[redacted]
	2016-03-14	EWO 000051	Draft tube pier nose armour deletion	[redacted]
	2016-03-23	EWO 000055	Welded Rebar Mats	[redacted]
		EWO 000044 r2	Spillway Quantity Changes (rev 2)	[redacted]
	2016-03-29	EWO 000053	April 2015 Directed Work	[redacted]
		EWO 000052	IFC Drawings for Rebar Replacement	[redacted]
	2016-03-30	EWO 000056	Spillway Guides Member Substitution	[redacted]
		EWO 000059	QCD Quantity Reconciliation	[redacted]

1a

Change Type	Entered on Date	Work Order #	Header Description	Amt Before PST
	2016-03-31	EWO 000006 r1	Cofferdams North Channel Rock Groin Ext 1 Rev 2	[redacted]
		EWO 000011 r3	Cofferdams North Channel Rock Groin Ext 2 Rev 3	[redacted]
	2016-04-12	EWO 000057	Island Cofferdam Quantity Reconciliation	[redacted]
	2016-04-13	EWO 000060	NCRG Quantity Reconciliation	[redacted]
	2016-04-18	EWO 000062	Technical Specification Revision 07 (Riprap Technical Specification 31 37 00)	[redacted]
		EWO 000060 r1	NCRG Quantity Reconciliation Revision 1	[redacted]
		EWO 000061	Technical Specification Revision 08 (Section 03 300 00 Cast-in-Place Concrete)	[redacted]
		EWO 000064	May 2015 Directed Work	[redacted]
		EWO 000063	Original CDCD Quantity Reconciliation (Directs and Indirects)	[redacted]
		EWO 000058	North Channel Cofferdam Quantity Reconciliation	[redacted]
	2016-04-22	EWO 000065	Powerhouse South Slope Erosion Protection	[redacted]
	2016-04-27	EWO 000067	Shape Change for Pier #8 embeds	[redacted]
		EWO 000068	Elevator travelling cables	[redacted]
	2016-04-29	EWO 000071	Rebar Mill Proposal	[redacted]
	2016-05-02	EWO 000073	Spillway gate guide welding revisions	[redacted]
	2016-05-20	EWO 000074	Conduit Substitution	[redacted]
		EWO 000079	Pipe Substitution	[redacted]
		EWO 000080	Lifting Device; Temporary Precast Slab	[redacted]
		EWO 000081	Spillway Precast Box Girder Grout Tube	[redacted] 1a
		EWO 000070	CDCD Off-Ramp Quantity Reconciliation	[redacted]
		EWO 000082	Temporary Bracing Modifications for Spillway Stoplog Guides	[redacted]
		EWO 000083	Spillway Precast Box Girder Drain Pipe	[redacted]
		EWO 000084	On-Boarding Engineer's Determination	[redacted]
	2016-05-31	EWO 000078	Addition of Waterstop type E	[redacted]
		EWO 000077	Construction of Work Area A pads	[redacted]
		EWO 000085	Video Surveillance Cable for Elevators	[redacted]
		EWO 000086	Spillway Precast Box Girder Post Tensioning Pipes	[redacted]
		EWO 000087	Piping Material Substitution	[redacted]
	2016-06-04	EWO 000088	Pipe Material Sub. PH U2, 4-7 Draft Tubes/Dewatering System	[redacted]
	2016-06-27	EWO 000090	Embedded Guide Shop Splice	[redacted]
		EWO 000091	Personnel Risk Assessment	[redacted]
	2016-06-30	EWO 000092	Spillway Precast Concrete Additions	[redacted]
	2016-07-26	EWO 000095	Loss of PHCD as Haul Road Claim	[redacted]
	2016-07-28	EWO 000096	W21 piping material change ERW to SAW	[redacted]
		EWO 000097	North Dyke ZIC Class 2a and Class 6 Removal Outside of Core	[redacted]
		EWO 000098	VE for TR Wall Reconfiguration	[redacted]
		EWO 000099	VE for Modify Spillway Concrete Types	[redacted]

Change Type	Entered on Date	Work Order #	Header Description	Amt Before PST	
	2016-07-29	EWO 000100	VE for Modify PH and Spillway Gravity Section Concrete Types	[redacted]	
		EWO 000101	VE for 2015 PH Concrete Work	[redacted]	
		EWO 000110	Spillway Misc. Metal – Install Only	[redacted]	
		EWO 000102	Electrical Service to MH Site Trailers	[redacted]	
		EWO 000106	VE for Advancement of North Dyke Construction	[redacted]	
		EWO 000107	VE for ND Exploration Test Pits	[redacted]	
		EWO 000112	PHCD Quantity Reconciliation	[redacted]	
		EWO 000114	Finishing Slope on South side of Intake Channel	[redacted]	
		EWO 000113	May, June, July 2015 Directed Work	[redacted]	
		EWO 000094	Floor Hardener Floor Sealer	[redacted]	
		EWO 000111	Scope Deletion Spillway Wet Excavation	[redacted]	
	2016-07-31	EWO 000115	Spillway Base Slab Steel to Waterstop Clearance Issue	[redacted]	
	2016-08-17	EWO 000113r1	May, June, July 2015 Directed Work - Revision 1	[redacted]	
		EWO 000116	BBE Quality Team 2016	[redacted]	
	2016-08-29	EWO 000032	Revision to the Technical Specification 20150904	[redacted]	
		EWO 000104	VE for North Dyke Section Optimization	[redacted]	
		EWO 000108	VE for Island Cofferdam Revised Section	[redacted]	
		EWO 000117	Piping Material Class G CB7A Wall Thickness Change	[redacted]	
		EWO 000119	Class 1 Lift Thickness and Compaction Equipment	[redacted]	1a
		EWO 000122	Structural Steel Material Grade Substitution	[redacted]	
		EWO 000123	Changes to Embedded Anchor Specification for Spillway Piers	[redacted]	
		EWO 000124	Service Bay Waterstop Modification	[redacted]	
		EWO 000126	August 2015 Directed Work	[redacted]	
	2016-08-31	EWO 000120	September 2015 Directed Work	[redacted]	
		EWO 000118	VE for Deepening Channels in PH Excavation	[redacted]	
	2016-09-19	EWO 000125	Embedded Grounding Components	[redacted]	
		EWO 000127	Class 2b Material Engineer's Determination	[redacted]	
	2016-09-28	EWO 000128	January 2016 Directed Work	[redacted]	
	2016-09-30	EWO 000131	October & November 2015 Directed Work	[redacted]	
		EWO 000134	February 2016 Directed Work	[redacted]	
		EWO 000133	Service Bay Anchor Pockets	[redacted]	
	2016-10-11	EWO 000076	2015 Escalation Adjustment	[redacted]	
	2016-10-31	EWO 000076	2015 Escalation Adjustment	[redacted]	
		EWO 000135	Pipe Fittings Substitution	[redacted]	
		EWO 000136	March 2016 Directed Work	[redacted]	
		EWO 000138	QCD Quantity Reconciliation	[redacted]	
		EWO 000093	Spillway Bridge Girder Quantity Change	[redacted]	
		EWO 000139	April 2016 Directed Work	[redacted]	
		EWO 000140	CDCD Winterization	[redacted]	
	2016-11-30	EWO 000142	May 2016 Directed Work	[redacted]	

Change Type	Entered on Date	Work Order #	Header Description	Amt Before PST	
		EWO 000141	VE for Enhancements to Dam Sections	[redacted]	
		EWO 000143	SWCD Quantity Reconciliation	[redacted]	
		EWO 000146	SW Hoist Tower Column Anchor Qty Change	[redacted]	
	2016-12-31	EWO 000145	Technical Specification Revision 10	[redacted]	
		EWO 000147	Fish Exclusion Mounting Plates	[redacted]	
		EWO 000146 R1	SW Hoist Tower Column Anchor Qty Change - Revision 1	[redacted]	
		EWO 000148	Waterstop Technical Specification 031513 Update	[redacted]	
		EWO 000149	Spillway Fueling Platform Precast	[redacted]	
		EWO 000150	Service Bay Box Drain Culvert	[redacted]	
		EWO 000152	Removal of Clearing Quantity for South Dyke	[redacted]	
		EWO 000153	Spillway Warning System	[redacted]	
		EWO 000154	Stage 2 Island CD Excavation	[redacted]	
	2017-01-31	EWO 000155	Material Substitutions for Wall Fittings	[redacted]	
		EWO 000159	June 2016 Directed Work	[redacted]	
		EWO 000147 R1	Fish Exclusion Mounting Plates - Revision 1	[redacted]	
		EWO 000148 R1	Waterstop Technical Specification 031513 Update - Revision 1	[redacted]	
		EWO 000161	Roof & Floor Deck Material Substitutions	[redacted]	
		EWO 000154 R1	Stage 2 Island CD Excavation - Revision 1	[redacted]	
	2017-02-21	EWO 000150 R1	Service Bay Box Drain Culvert - Revision 1	[redacted]	1a
		EWO 000149 R1	Spillway Fueling Platform Precast - Revision 1	[redacted]	
		EWO 000146 R2	SW Hoist Tower Column Anchor Qty Change - Revision 2	[redacted]	
		EWO 000156	Vertical Surface Prep Spillway	[redacted]	
		EWO 000157	Vertical Surface Prep and Additional Joints Service Bay	[redacted]	
		EWO 000158	Vertical Surface Prep Powerhouse Complex	[redacted]	
		EWO 000156 R1	Vertical Surface Prep Spillway - Revision 1	[redacted]	
		EWO 000164	SB Trap Primer	[redacted]	
		EWO 000162	CDCD Redesign and North Extension	[redacted]	
	2017-02-27	EWO 000166	Embedded Guide Scope Change	[redacted]	
	2017-02-28	EWO 000165	Embedded Plate MK7	[redacted]	
	2017-03-31	EWO 000168	Powerhouse Crane Rail Girder Splice at Gridline 27	[redacted]	
		EWO 000167	Alternate for Hex Lock Nuts	[redacted]	
		EWO 000169	SW Ancillary Building Additional Wall Construction Joints	[redacted]	
	2017-04-30	EWO 000170	Central Dam Revision	[redacted]	
		EWO 000171	NCRG Top-up	[redacted]	
	2017-05-31	EWO 000172	Rock Netting Quantity Reconciliation	[redacted]	
		EWO 000176	W21, W34 and W44 inlet fittings (included in AA#7)	[redacted]	
		EWO 000173	Class 2a, 2b Lift Thickness	[redacted]	
		EWO 000181	Class 1 Lift Thickness	[redacted]	
		EWO 000177	Spillway condensed water drainage system (included in AA#7)	[redacted]	

Change Type	Entered on Date	Work Order #	Header Description	Amt Before PST
		EWO 000184	OWS Facility, Oil Storage, W21 & W34 Systems (included in AA#7)	[redacted]
		EWO 000174	W34, A72, HV & W44 Systems (included in AA#7)	[redacted]
		EWO 000182	W21, W34, W44 and W45 Systems (included in AA#7)	[redacted]
		EWO 000180	Diesel Generator Fuel System - Components & Fittings (<$100K)	[redacted]
		EWO 000190	Domed Hatch Substitution	[redacted]
		EWO 000183	Sanitary and Domestic Systems (included in AA#7)	[redacted]
		EWO 000191	Water Treatment Plant (<$20K)	[redacted]
		EWO 000189	Intake headblock lap location change below 151.400	[redacted]
		EWO 000185	Class 2b Production (included in AA#7)	[redacted]
		EWO 000186	North Dyke Modified Low Head Granular Dyke in place of Freeboard Dyke (~-$34K)	[redacted]
		EWO 000195	Unit 2 Intake Walls North Pier	[redacted]
		EWO 000187	Access Control and Video Surveillance design updates (~$100K)	[redacted]
		EWO 000196	Intake LHB Couplers	[redacted]
		EWO 000194	Technical Specification Revision 11	[redacted]
	2017-06-30	EWO 000197	Spillway Complex Infill Concrete (included in AA#7)	[redacted]
		EWO 000198	Embedded Guide Revisions (included in AA#7)	[redacted]
		EWO 000188	Tower Spur Footing Installation	[redacted]
		EWO 000200	Embedded Anchors Update (included in AA#7)	[redacted]
		EWO 000199	Spillway Fencing (included in AA#7)	[redacted]
		EWO 000192	Technical Specification Updates, Sections 260521, 261102, 262213 (included in AA#7)	[redacted]
		EWO 000203	Intake headblock additional vertical laps at el. 151.400	[redacted]
		EWO 000207	Draft Tube Access Hatch Deck Fastening	[redacted]
		EWO 000206	Technical Specification 260529 Update	[redacted]
		EWO 000204	Technical Specification 083619 Update	[redacted]
		EWO 000212	Tailrace Cofferdam Wet Excavation (included in AA#7)	[redacted]
		EWO 000213	Composite Sand for North Dyke (included in AA#7)	[redacted]
		EWO 000214	Permanent Erosion Protection (included in AA#7)	[redacted]
		EWO 000215	Foundation Grouting Plasticizer Substitution	[redacted]
	2017-07-29	EWO 000202	Technical Specification 265000 Update	[redacted]
		EWO 000205	Intake Unit 2 Pier 4, Unit 4 & 6 Pier 1 & 4 single lift rebar	[redacted]
		EWO 000211	Technical Specification 283100 Update	[redacted]
		EWO 000217	Dam Cross Section Modification	[redacted]
		EWO 000220	Service Bay Quantity Reconciliation	[redacted]
		EWO 000210	Updates to HVAC Systems 230700, 230900, 233000	[redacted]
		EWO 000221	Cleanout Substitution	[redacted]
		EWO 000202 R1	Technical Specification 265000 Update Rev 1	[redacted]
		EWO 000223	Misc. Metal & Crane Rail	[redacted]
		EWO 000210 R1	Updates to HVAC Systems 230700, 230900, 233000 Rev 1	[redacted]

1a

Change Type	Entered on Date	Work Order #	Header Description	Amt Before PST	
	2017-07-31	EWO 000171 R1	NCRG Top-up (Revision 1)	[redacted]	
	2017-08-24	EWO 000193	Technical Specification Revision 12	[redacted]	
		EWO 000193 R1	Technical Specification Revision 12 Rev 1	[redacted]	
		EWO 000222	Spillway Fault Treatment	[redacted]	
		EWO 000224	HVAC Embedded Fitting Substitution	[redacted]	
		EWO 000226	Spillway Handrail Material	[redacted]	
		EWO 000209	Technical Specification Update 260528 Surface Grounding	[redacted]	
	2017-08-28	EWO 000211 R2	Technical Specification 283100 Update Rev 2	[redacted]	
	2017-08-31	EWO 000171 R2	NCRG Top-up (Revision 2)	[redacted]	
		EWO 000225	Technical Specification Update 270000	[redacted]	
		EWO 000227	Intake headblock lap location change in IN-X-J-09-05 & INX-J-10-05	[redacted]	
		EWO 000231	PH South Transition Infill Concrete	[redacted]	
		EWO 000219	Updates to PH Fire Protection Standpipe System 211200	[redacted]	
		EWO 000235	Vertical Embedded Piping Supports	[redacted]	
			Approved-GP Total	[redacted]	
Changes				[redacted]	
	2017-02-28	Amending Agreement 000007	Amending Agreement #7 - Revisions to Volume 1, 3 and 4	[redacted]	
			Changes Total	[redacted]	1a
Changes - Contingency				[redacted]	
	2017-03-31	CO 0001	Increase for General Civil contract delay	[redacted]	
			Changes - Contingency Total	[redacted]	
Changes - Escalation Allowance				[redacted]	
	2017-03-31	CO 0001	Escalation Allowance ETC	[redacted]	
			Changes - Escalation Allowance Total	[redacted]	
Changes - LOA 35 Allowance				[redacted]	
	2017-03-31	CO 0001	LOA 35 Allowance ETC	[redacted]	
			Changes - LOA 35 Allowance Total	[redacted]	
Changes - Profit				[redacted]	
	2017-03-31	CO 0001	Profit	[redacted]	
			Changes - Profit Total	[redacted]	
Forecasted - LOA 35				[redacted]	
	(blank)	EWO LOA 2016-1	BNA LOA #35 - 2016 Period 1 Payment (July, 2016)	[redacted]	
		EWO LOA 2016-2	BNA LOA #35 - 2016 Period 2 Payment (September, 2016)	[redacted]	
		EWO LOA 2016-3	BNA LOA #35 - 2016 Period 3 Payment (December, 2016)	[redacted]	
		EWO LOA 2016-4	BNA LOA #35 - 2016 Period 4 Payment (December, 2016)	[redacted]	
		EWO LOA 2016-5	BNA LOA #35 - 2016 Period 5 Payment (January, 2017)	[redacted]	
		EWO LOA 2017-1	BNA LOA #35 - 2017 Period 1 Payment (June, 2017)	[redacted]	
			Forecasted - LOA 35 Total	[redacted]	
Forfeited Bonus				[redacted]	
	2015-10-20	Forfeited Bonus 0001	Forfeited Bonus - December 2014	[redacted]	

Change Type	Entered on Date	Work Order #	Header Description	Amt Before PST
		Forfeited Bonus 0002	Forfeited Bonus - January 2015	[redacted]
		Forfeited Bonus 0003	Forfeited Bonus - February 2015	[redacted]
		Forfeited Bonus 0004	Forfeited Bonus - March 2015	[redacted]
		Forfeited Bonus 0005	Forfeited Bonus - April 2015	[redacted]
		Forfeited Bonus 0006	Forfeited Bonus - May 2015	[redacted]
		Forfeited Bonus 0007	Forfeited Bonus - June 2015	[redacted]
		Forfeited Bonus 0008	Forfeited Bonus - July 2015	[redacted]
		Forfeited Bonus 0009	Forfeited Bonus - August 2015	[redacted]
	2015-11-30	Forfeited Bonus 0010	Forfeited Bonus - September 2015	[redacted]
	2016-03-31	Forfeited Bonus 0011	Forfeited Bonus - February 2016	[redacted]
	2016-07-11	Forfeited Bonus 0012	Forfeited Bonus - December 2015	[redacted]
		Amending Agreement 0013	Forfeited Bonus - As a result of Amending Agreement #7	[redacted]
			Forfeited Bonus Total	[redacted]
Proposed Future Work				[redacted]
	(blank)	PEW MH-0065	[redacted]	[redacted]
		PEW MH-0071	[redacted]	[redacted]
		FQA 0001	[redacted]	[redacted]
		FQA 0002	[redacted]	[redacted]
		FQA 0003	[redacted]	[redacted]
		PEW MH-0075	[redacted]	[redacted]
		PEW MH-0076	[redacted]	[redacted]
		FQA 0004	[redacted]	[redacted]
		NIC 0077	[redacted]	[redacted]
		PEW BBEHC-0091	[redacted]	[redacted]
		PEW BBEHC-0093	[redacted]	[redacted]
			Proposed Future Work Total	[redacted]

1a

Table 7 MH Directed EWO's

MH Directed Work to BBE Hydro Construction	Value
February 15 MH Directed Work	[redacted]
January 2015 MH Directed Work	[redacted]
December 2014 MH Directed Work	[redacted]
April 2015 Directed Work	[redacted]
May 2016 Directed Work	[redacted]
June 2016 Directed Work	[redacted]
March 2016 Directed Work	[redacted]
April 2016 Directed Work	[redacted]
May, June, July 2015 Directed Work	[redacted]
February 2016 Directed Work	[redacted]

1a

MH Directed Work to BBE Hydro Construction	Value
November 2014 Directed Work	[redacted]
August 2015 Directed Work	
September 2015 Directed Work	
August 14 MH Directed Work	
October 14 MH Directed Work	
September 14 MH Directed Work	
June/July 14 MH Directed Work	
January 2016 Directed Work	
Total	

1a

Review of Tables 6 and 7 shows the total additional for all the "Approved GP" EWO's, which is where the technically driven changes are recorded, adds up to [redacted] which includes [redacted] in 1a
MH directed work. The EWO values per year are:

Year	EWO Value
2014	[redacted]
2015	
2016	
2017	
Total	

1a

Clearly the total project increase in price is not driven by the technical EWO's. In fact, the technical changes in 2017 have saved [redacted] according to the data provided.

Furthermore, the negative values for profit reductions add up to a savings of [redacted] so there 1a
is actually a net savings of approximately [redacted] between the profit reductions and the approved technical EWO's.

The GCC price change to date is fundamentally all in the renegotiation of the contract AA#7 for
[redacted] 1a

Normally the cost estimate for the majority of General Civil Contract components should be built up from the unit prices times the quantities. Given the dramatic change in the contract cost in AA#7 both the unit prices and the quantities deserve scrutiny.

As mentioned previously, the schedule changes to the GCC have impacted the other contracts, for example review of the [redacted] Voith contract for the supply of the units shows [redacted] in
total revisions to the contingency of which [redacted] is associated with delays to the GCC. Similar 1a
impacts have occurred on the camp supply and operation.

4.3 Quantities

The MH review of the cost increases to date lists changes in quantities as one of the factors in the price change. Most of the work to date has been related to earthworks and concrete. The mechanical and electrical costs associated with the balance of plant for the powerhouse and spillway are proportionally small relative to the entire project and have generally not been started. Therefore, KCB concentrated our review on the earthworks and concrete quantities and their changes. Table 8 shows the values from the Original Contract (OC) dated Mar 10, 2014 compared with the Amending Agreement #7 (AA7) dated Feb 28 and also compared with some values from the original Hatch report titled the Stage IV Engineering Summary Report - GN-10.1 Rev 0.pdf.

Table 8 Civil Quantities changes

Work Class	Work Type	UoM	Stage IV Hatch Report	Original Budget (OC)	Current Budget (AA7)	%	Variance
				A	B	C	D=B-A
Concrete Works							
	Formwork	*m*^{2}		*199,794.00*	*209,304.81*	*4.76%*	*9,510.81*
QTY	Spillway			18,395.00	24,656.16	34.04%	6,261.16
	Powerhouse (incl. Transitions)			63,814.00	65,747.76	3.03%	1,933.76
	Tailrace			51,841.00	52,298.97	0.88%	457.97
	Intake			50,231.00	50,249.66	0.04%	18.66
	Service Bay			15,513.00	16,352.26	5.41%	839.26
	Embedded Anchors	*kg*		*323,592.16*	*408,285.07*	*26.17%*	*84,692.91*
QTY	Spillway			40,604.00	125,296.91	208.58%	84,692.91
	Powerhouse (incl. Transitions)			282,988.16	282,988.16	0.00%	-
	Tailrace			-	-		-
	Intake			-	-		-
	Service Bay			-	-		-
	Reinforcing Steel	*kg*		*23,448,787.00*	*23,413,316.00*	*-0.15%*	*(35,471.00)*
QTY	Spillway			3,069,931.00	2,332,481.00	-24.02%	(737,450.00)
	Powerhouse (incl. Transitions)			8,431,035.00	8,431,035.00	0.00%	-
	Tailrace			4,892,100.00	4,892,100.00	0.00%	-
	Intake			5,811,260.00	5,811,260.00	0.00%	-
	Service Bay			1,244,461.00	1,946,440.00	56.41%	701,979.00
	Cast-In-Place Concrete	*m*^{3}	*356,800*	*329,713.00*	*322,194.07*	*-2.28%*	*(7,518.93)*
QTY	Spillway			57,290.00	58,438.25	2.00%	1,148.25
	Powerhouse (incl. Transitions)			118,348.00	118,303.50	-0.04%	(44.50)
	Tailrace			47,879.00	45,975.00	-3.98%	(1,904.00)
	Intake			71,760.00	71,530.72	-0.32%	(229.28)
	Service Bay			34,436.00	27,946.60	-18.84%	(6,489.40)
Structural Steel		kg		1,684,784.00	2,081,500.00	23.55%	396,716.00
QTY	Light Weight < 24.9 Kg/m			115,952.00	84,500.00	-27.13%	(31,452.00)
	Medium Weight > 25 kg/m and < 124.9 kg/m			388,306.00	1,052,000.00	170.92%	663,694.00
	Heavy Weight > 125 kg/m			377,076.00	80,000.00	-78.78%	(297,076.00)
	Shop Fabricated Beams and Columns (WWF)			803,450.00	865,000.00	7.66%	61,550.00

Work Class	Work Type	UoM	Stage IV Hatch Report	Original Budget (OC)	Current Budget (AA7)	%	Variance
				A	B	C	D=B-A
Earthwork							
	Unclassified Excavations	*m^3*	*3,078,700*	*3,226,490.00*	*3,937,244.49*	*22.03%*	*710,754.49*
	for Central Dam			595,150.00	651,270.00	9.43%	56,120.00
	for North Dam			100,700.00	285,680.06	183.69%	184,980.06
	for South Dam			71,800.00	174,300.00	142.76%	102,500.00
	for North Dyke			567,340.00	600,000.00	5.76%	32,660.00
	for South Dyke			622,950.00	758,100.00	21.70%	135,150.00
QTY	for North Access Road Ramp			32,750.00	32,750.00	0.00%	-
	for South Access Road Ramp			8,900.00	8,900.00	0.00%	-
	for all concrete structures in Powerhouse area			1,078,100.00	1,216,685.00	12.85%	138,585.00
	for all concrete structures in Spillway area			17,200.00	77,959.43	353.25%	60,759.43
	for Tailrace Channel Improvement			131,600.00	131,600.00	0.00%	-
	Rock Excavations	*m^3*	*1,976,400*	*1,937,975.00*	*2,079,870.40*	*7.32%*	*141,895.40*
	Spillway			359,250.00	346,049.00	-3.67%	(13,201.00)
	Powerhouse (incl. Transitions)			433,500.00	317,904.00	-26.67%	(115,596.00)
QTY	Tailrace			603,800.00	806,200.00	33.52%	202,400.00
	Intake			283,700.00	609,465.94	114.83%	325,765.94
	Service Bay			257,725.00	251.46	-99.90%	(257,473.54)
	Impervious Fill (Class 1)	*m^3*	*1,567,100*	*1,006,300.00*	*714,084.00*	*-29.04%*	*(292,216.00)*
	for Central Dam			242,800.00	294,884.00	21.45%	52,084.00
	for North Dam			26,500.00	76,500.00	188.68%	50,000.00
	for South Dam			111,500.00	107,500.00	-3.59%	(4,000.00)
QTY	for North Dyke			292,500.00	95,400.00	-67.38%	(197,100.00)
	for South Dyke			321,000.00	139,800.00	-56.45%	(181,200.00)
	for North Access Road Ramp			6,000.00	-	-100.00%	(6,000.00)
	for South Access Road Ramp			6,000.00	-	-100.00%	(6,000.00)
	Granular Fill	*m^3*	*1,437,550*	*3,800,135.00*	*2,248,242.00*	*-40.84%*	*(1,551,893.00)*
	for Central Dam			773,100.00	633,842.00	-18.01%	(139,258.00)
	for North Dam			69,600.00	165,200.00	137.36%	95,600.00
	for South Dam			177,550.00	185,000.00	4.20%	7,450.00
QTY	for North Dyke			1,295,990.00	508,600.00	-60.76%	(787,390.00)
	for South Dyke			1,467,895.00	734,400.00	-49.97%	(733,495.00)
	for North Access Road Ramp			10,000.00	15,200.00	52.00%	5,200.00
	for South Access Road Ramp			6,000.00	6,000.00	0.00%	-
	Rockfill	*m^3*		*1,567,750.00*	*2,917,677.00*	*86.11%*	*1,349,927.00*
	for Central Dam			396,500.00	896,230.00	126.04%	499,730.00
QTY	for North Dam			54,800.00	220,500.00	302.37%	165,700.00
	for South Dam			368,500.00	248,000.00	-32.70%	(120,500.00)
	for North Dyke			160,550.00	489,000.00	204.58%	328,450.00

Work Class	Work Type	UoM	Stage IV Hatch Report	Original Budget (OC)	Current Budget (AA7)	%	Variance
				A	B	C	D=B-A
	for South Dyke			158,900.00	623,003.00	292.07%	464,103.00
	for North Access Road Ramp			257,800.00	258,200.00	0.16%	400.00
	for South Access Road Ramp			56,300.00	56,300.00	0.00%	-
	Powerhouse (incl. Transitions)			114,400.00	126,443.00	10.53%	12,043.00
	Intake			-	1.00		1.00
	Riprap	*m^3*		*469,550.00*	*486,248.00*	*3.56%*	*16,698.00*
QTY	for Central Dam			111,400.00	110,300.00	-0.99%	(1,100.00)
	for North Dam			11,300.00	14,400.00	27.43%	3,100.00
	for South Dam			43,300.00	33,744.00	-22.07%	(9,556.00)
	for North Dyke			107,100.00	109,300.00	2.05%	2,200.00
	for South Dyke			175,650.00	179,400.00	2.13%	3,750.00
	for North Access Road Ramp			1,100.00	2,000.00	81.82%	900.00
	for South Access Road Ramp			500.00	500.00	0.00%	-
	Powerhouse (incl. Transitions)			19,200.00	36,604.00	90.65%	17,404.00
	Intake			-			

Examination of the table shows variances ranging from -41% for granular fill to +86% for rockfill, which suggests there may have been some volumes changed from one category to the other. The variance between the sum of the two is approximately 200,000 m3 or about 4%.

The concrete volumes starting with the Hatch project report are remarkably close for all the estimates.

In conclusion, the change in quantities in total do not justify the large increase in the contract value. If the basis for payment for the project was the original Unit Prices together with the actual quantities were the project would likely be within the contingency, i.e. on budget.

4.4 Unit Prices

The unit prices in the Bill of Quantities, Prices and Target Price Estimate- are very detailed, comparison with the unit prices of the original contract and later agreement amendments is difficult. For our review, and to enable comparisons, similar items in the Bill of Quantities have been grouped together and an equivalent unit price has been calculated by dividing the total cost of the grouped items by the total quantity.

KCB made a comparison of the consolidated unit prices thus calculated between the original contract, as provided in Amending Agreement 3 (March 2014) and the latest amendment with unit prices, as provided in Amending Agreement 7 (February 2017).

The following consolidated items are selected to provide an overview of the unit prices for the civil works:

- Cast-in-Place Concrete. The consolidated unit prices include the formwork costs. The ratio of formwork area to concrete volume differ for the various structures as follows:
  - Intake: formwork area to concrete volume = 0.7 m^2/m^3.
  - Powerhouse and service bay: formwork area to concrete volume = 0.52 m^2/m^3.
  - Tailrace: formwork area to concrete volume = 1.08 m^2/m^3.
  - Spillway: formwork area to concrete volume = 0.32 m^2/m^3.
- Reinforcing Steel.
- Structural Steel. The consolidated unit price included all main structural steelwork.
- Unclassified Excavation for concrete structures, for dams and dykes and for dykes in winter.
- Rock excavation.
- Impervious fill.
- Granular fill, all classes.
- Rockfill.

Table 9 presents the changes in the consolidated unit prices between the initial contract provided in Amending Agreement 3 and Amending Agreement 7.

Table 9 Consolidated Unit Prices Extract from Amending Agreement 3 and 7

Description	Unit	Amending Agreement 3		Amending Agreement 7		Consolidated Unit Price Increase
		Quantity	Consolidated Unit Price	Quantity	Consolidated Unit Price	
Cast-in-Place Concrete			[redacted]		[redacted]	[redacted]
Intake	m^3	72,210	[redacted]	71,530	[redacted]	[redacted]
Powerhouse and service bay	m^3	151,334	[redacted]	146,248	[redacted]	[redacted]
Tailrace	m^3	47,879	[redacted]	45,975	[redacted]	[redacted]
Spillway	m^3	57,290	[redacted]	58,436	[redacted]	[redacted]
			[redacted]		[redacted]	[redacted]
Reinforcing Steel			[redacted]		[redacted]	[redacted]
All structures	kg	23,448,787	[redacted]	23,218,582	[redacted]	[redacted]
			[redacted]		[redacted]	[redacted]
Structural Steel			[redacted]		[redacted]	[redacted]
All structures	kg	1,684,784	[redacted]	2,081,500	[redacted]	[redacted]
			[redacted]		[redacted]	[redacted]
Unclassified Excavation			[redacted]		[redacted]	[redacted]
For concrete structures	m^3	1,226700	[redacted]	1,426,044	[redacted]	[redacted]
For dams and dykes	m^3	809,500	[redacted]	1,070,548	[redacted]	[redacted]
For Dykes in winter	m^3	1,109,290	[redacted]	1.346,100	[redacted]	[redacted]
			[redacted]		[redacted]	[redacted]
Rock Excavation			[redacted]		[redacted]	[redacted]
All rock excavations	m^3	1,937,975	[redacted]	2,079,869	[redacted]	[redacted]

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Description	Unit	Amending Agreement 3		Amending Agreement 7		Consolidated Unit Price Increase
		Quantity	Consolidated Unit Price	Quantity	Consolidated Unit Price	
Compacted Fill			[redacted]		[redacted]	[redacted]
Impervious fill	m^3	1,006,050	[redacted]	714,084	[redacted]	[redacted]
Granular fill	m^3	3,811,935	[redacted]	2,260,042	[redacted]	[redacted]
			[redacted]		[redacted]	[redacted]
Rockfill	m^3	1,567,750	[redacted]	2,319,923	[redacted]	[redacted]

1a

The percentage increase in the consolidated unit prices from Amending Agreement 3 to Amending Agreement 7 in the samples provided in Table 9 vary between 67% to 366%. Reviewing the entire Bill of Quantities, Prices and Target Price Estimate in the two respective Amending Agreement, virtually all the unit prices show similar increases as demonstrated above. KCB believe that the substantial increases in the unit prices in Amending Agreement 7 is largely responsible for the substantial increase in the Target Price Estimate in Amending Agreement 7.

To be able to comment on the reasonableness of the unit prices in the Amending Agreements 3 and 7, KCB compared the unit prices with some historical information obtained for similar work for the construction of a large hydroelectric power project in northern Canada. Table 10 present the comparison between the consolidated unit prices for Amending Agreements 3 and 7 and the historical information.

Table 10 Comparison between Consolidated Unit Prices

Description	Unit	Consolidated Unit Price		
		Amending Agreement 3	Amending Agreement 7	Historical Information
Cast-in-Place Concrete		[redacted]	[redacted]	
Intake	m^3	[redacted]	[redacted]	$1,000
Powerhouse and service bay	m^3	[redacted]	[redacted]	$1,000
Tailrace	m^3	[redacted]	[redacted]	$1,200
Spillway	m^3	[redacted]	[redacted]	$600
		[redacted]	[redacted]	
Reinforcing Steel		[redacted]	[redacted]	
All structures	kg	[redacted]	[redacted]	$4.00
		[redacted]	[redacted]	
Structural Steel		[redacted]	[redacted]	
All structures	kg	[redacted]	[redacted]	$9.00
		[redacted]	[redacted]	
Unclassified Excavation		[redacted]	[redacted]	
For concrete structures	m^3	[redacted]	[redacted]	$10.00
For dams and dykes	m^3	[redacted]	[redacted]	$10.00
For Dykes in winter	m^3	[redacted]	[redacted]	$10.00
		[redacted]	[redacted]	
Rock Excavation		[redacted]	[redacted]	
All rock excavations	m^3	[redacted]	[redacted]	$20.00
		[redacted]	[redacted]	
Compacted Fill		[redacted]	[redacted]	
Impervious fill	m^3	[redacted]	[redacted]	$25.00
Granular fill	m^3	[redacted]	[redacted]	$10.00
		[redacted]	[redacted]	
Rockfill	m^3	[redacted]	[redacted]	$80.00

1a

The following comments are made regarding the comparison between the consolidated unit prices:

- Cast-in-Place Concrete. The consolidated unit prices in the initial contract appear to be low but those in the Amending Agreement 7 appear high compared to the KCB historical information.
- Reinforcing Steel. The consolidated unit prices in the initial contract appear to be low but those in the Amending Agreement 7 appear reasonable compared to the KCB historical information.
- Structural Steel. Both the consolidated unit prices in the initial contract and the Amending Agreement 7 appear to be low compared that in the KCB historical information. This difference could be the result of the difference locations for sourcing the structural steel.
- Unclassified Excavations. The consolidated rates for unclassified excavation appears to be reasonable but those in the Amending Agreement 7 appear high compared to the KCB historical information.
- Rock Excavation for both the initial contract and the Amending Agreement 7 appear to be higher than the KCB historical information. The higher rock excavation unit price could relate to the hardness of the rock being excavated.
- Impervious fill. The consolidated unit prices in the initial contract appear to be low but those in the Amending Agreement 7 appear very high compared to the KCB historical information.
- Granular fill. Both the consolidated unit prices in the initial contract and the Amending Agreement 7 appear to be low compared that in the KCB historical information.
- Rockfill. The consolidated unit price for both the initial contract and Amending Agreement 7 are significantly lower than the KCB historical information. The haul distance for the rockfill for the KCB historical information is very substantial as the quarry for this rockfill is located far away from the site, whereas the rockfill for the Keeyask GS is sourced locally.

In summary, the unit prices in the initial contract appear to be generally lower when compared with the corresponding KCB unit price data, whereas the unit prices in Amending Agreement 7 appear to be generally significantly high.

KCB was interested in the impact of the unit prices on the associated costs and therefore performed the following calculations using the consolidated unit prices from Table 9 and the associated quantities.

Initial Contract - The consolidated unit prices times the original estimated quantities = cost

Historical Information - The KCB historical unit prices times the original estimated quantities = cost

AA#7 – the AA#7 unit prices times the new estimated <u>total</u> quantities = cost. (Could be viewed as what the price should have been)

The results of our analysis are shown in Table 11.

Table 11 Unit Price and Cost Comparison

Description	Unit	Amending Agreement (AA) 3 Basis			Amending Agreement(AA) 7 Basis			KCB Historical Information Unit Prices		
		Total Quantity	Consolidated Unit Price	Total Cost ('000$)	Total Quantity	Consolidated Unit Price	Total Cost ('000$)	AA3 Total Quantity	Historical Unit Price	Total Cost (thousand $)
Cast-in-Place Concrete			[redacted]	[redacted]		[redacted]	[redacted]			
Intake	m^3	72,210	[redacted]	[redacted]	71,530	[redacted]	[redacted]	72,210	$1,000	$72,210
Powerhouse and service bay	m^3	151,334	[redacted]	[redacted]	146,248	[redacted]	[redacted]	151,334	$1,000	$151,334
Tailrace	m^3	47,879	[redacted]	[redacted]	45,975	[redacted]	[redacted]	47,879	$1,200	$57,454
Spillway	m^3	57,290	[redacted]	[redacted]	58,436	[redacted]	[redacted]	57,290	$600	$34,374
			[redacted]	[redacted]		[redacted]	[redacted]			
Reinforcing Steel			[redacted]	[redacted]		[redacted]	[redacted]			
All structures	kg	23,448,787	[redacted]	[redacted]	23,218,582	[redacted]	[redacted]	23,448,787	$4.00	$93,795
			[redacted]	[redacted]		[redacted]	[redacted]			
Structural Steel			[redacted]	[redacted]		[redacted]	[redacted]			
All structures	kg	1,684,784	[redacted]	[redacted]	2,081,500	[redacted]	[redacted]	1,684,784	$9.00	$15,163
			[redacted]	[redacted]		[redacted]	[redacted]			
Unclassified Excavation			[redacted]	[redacted]		[redacted]	[redacted]			
For concrete structures	m^3	1,226,700	[redacted]	[redacted]	1,426,044	[redacted]	[redacted]	1,226,700	$10.00	$12,267
For dams and dykes	m^3	809,500	[redacted]	[redacted]	1,070,548	[redacted]	[redacted]	809,500	$10.00	$8,095
For Dykes in winter	m^3	1,109,290	[redacted]	[redacted]	1.346,100	[redacted]	[redacted]	1,109,290	$10.00	$11,092
			[redacted]	[redacted]		[redacted]	[redacted]			
Rock Excavation			[redacted]	[redacted]		[redacted]	[redacted]			
All rock excavations	m^3	1,937,975	[redacted]	[redacted]	2,079,869	[redacted]	[redacted]	1,937,975	$20.00	$38,759
			[redacted]	[redacted]		[redacted]	[redacted]			
Compacted Fill			[redacted]	[redacted]		[redacted]	[redacted]			
Impervious fill	m^3	1,006,050	[redacted]	[redacted]	714,084	[redacted]	[redacted]	1,006,050	$25.00	$25,151
Granular fill	m^3	3,811,935	[redacted]	[redacted]	2,260,042	[redacted]	[redacted]	3,811,935	$10.00	$38,119
			[redacted]	[redacted]		[redacted]	[redacted]			
Rockfill	m^3	1,567,750	[redacted]	[redacted]	2,319,923	[redacted]	[redacted]	1,567,750	$80.00	$125,420
			[redacted]	[redacted]		[redacted]	[redacted]			
TOTAL			[redacted]	[redacted]		[redacted]	[redacted]			**$683,236**

1a

The table shows that, for the subset of quantities we examined, using the original unit rates the price
would have been [redacted], and with the blended original and AA#7 rates the same work will be [redacted] 1a
or about [redacted] times the original target price. Using the AA#7 [redacted] multiplier the BBE original contract
price might have been [redacted]

Using KCB's assumed unit rates BBE's original Target Price was low by at least [redacted] or a factor of
[redacted]. If the [redacted] were to have been included the BBE original contract price ([redacted]) would have 1a
been [redacted]

There are other costs associated with the project that this simple analysis does not consider, for example mobilization, dewatering and coffer dam costs, which, if done in detail, will adjust these figures. But the conclusion is that the original BBE project target price was very optimistic and that a more realistic price might have been between $1.8B and $2.2B.

5 CONTRACTING METHODOLOGY

5.1 References

- Original Contract - 243994-0020-016203-CON-GCC Volume 1 20140310
- AA#7 - 243994-0020-016203-CON-GCC Volume 1 20170228.pdf

5.2 Discussion

The original 2014 contract was a cost reimbursable model with early contractor involvement. Early contractor involvement is currently one of the more favoured aspects of contracting. The advantages of working with a contractor to optimize the design, is intended to fairly apportion the risks and settle on fair profits and incentives for the contractor.

Based on our analysis of the design, the quantity estimates, the extra work orders and the unit prices, we could not initially understand how the project could be as far over budget as it is, because the variances in quantities are not that high and the initial unit prices were in fact low.

Then we read the 2014 contract terms, and in particular the Terms of Payment sections. Section 5 Price and Payment of the Work says:

> *"The general basis of payment for the Work will be on a cost reimbursable basis with provisions for an Initial Target Price and Final Target Price in accordance with and subject to the terms of the Contract."*

> *"For purposes of payment, the Work shall be measured as set out in the Contract documents."*

The Initial Target Price is defined, the Target Price Assumptions and calculation are defined and presented in sections 5 and 6. Most importantly the Adjustments to the target price are also defined and include:

- Escalation including;
- Extra Work Orders, *based on variations in quantities;*
- Additional scope items added to the contract;
- Extensions of time and delay payments; and
- Cash allowance overruns.

These adjustments are reasonable clauses and logical reasons for additional funds.

To that point the project risk seems to be clearly defined, and in fact Section 6.2.2 defines how the target price is to be adjusted for changes in quantities. Specifically, the unit prices are not to be changed unless the quantity variance is more than +/- 15%.

> *"....there shall be no changes to the Unit Prices originally submitted by the Contractor, unless the actual quantities vary from the estimated quantities by +/- 15% of the estimated quantities...."*

These are all reasonable and relatively typical contract clauses for a contract where the payment is based on unit prices and quantities for work actually performed.

Reading Section 9 Basis for Payment also seems generally reasonable for a cost reimbursable contract, with profit and GA&O defined as a percentage using formulas based on the Actual Costs and the Final Target Price.

However, the payment wording definition for Actual Costs does not seem to include any exclusions or amendment possibility and does **not seem to be related to quantities x unit prices**.

> *"Subject to these Terms and Conditions of Payment, the Purchaser shall pay the Contractor the Contractor's Actual Costs incurred in the performance of the Work."*

Thus, the definition of Actual Costs is critically important to the payment process. The Definition of Actual Costs from section 11 is:

> *""Actual Costs", for the purposes of the Contract, shall mean only the following:*
>
> *(a) **all actual, indirect and direct costs** incurred by the Contractor in performing the Work including, but not limited to (and specifically excluding GST and RST required to be collected from Purchaser by Contractor but including any RST required to be paid by Contractor to its suppliers or required to be self-assessed and paid by Contractor), all costs incurred for **all labour** (including the cost of workers' compensation assessments, vacation pay, employment insurance, pension plan payments, payroll taxes, and any other employee benefits paid by the Contractor), **equipment rentals, all supplies and materials, services, delivery and transportation, or any other direct, indirect and actual cost incurred by the Contractor in the performance of the Work** as is more fully set out in this Section 11;*
>
> *(b) all actual, indirect and direct costs incurred by the Contractor (in accordance with paragraph (a) above) resulting from an addition to, deletion from or modification of the Work as documented in an Extra Work Order or Change Order; and*
>
> *(c) all actual, indirect and direct costs incurred by the Contractor (in accordance with paragraph (a) above) resulting from a termination for convenience by the Purchaser of the Contract in accordance with Section 29.3 TERMINATION FOR CONVENIENCE of the General Specification..."*

As noted there is no connection between actual costs and the quantities and unit prices in the Bill of Quantities. This is a critical omission, because as has been demonstrated, the contractor may have little incentive to actually perform the work.

Another interesting clause relates to Progress and Cost Forecasts, whereby the contractor is paid two months in advance for planned work. We have never seen a contract with that clause, typically the way a contractor ensures his cashflow remains positive is through the mobilization payment and actually performing the work and earning revenue based on quantities times unit prices.

Interestingly even after the project schedule and budget went awry and was renegotiated, the 2017 contract AA#7 still has the same method of payment as the 2014 original contract using Actual Costs and still has little or no direct connection to measured work done or the approved unit prices except with respect to small changes dependent on the Target Price.

In summary, we have never seen a large contract where payment was not related to actual performance of the construction work as measured in some manner. Where we have seen cost reimbursable contracts is for small work directly controlled by the owner, for example drilling contracts where the owner tell the drillers where to drill, when to stop and then pays for actual equipment and crew time. MH is not a contractor and likely does not have the staff and experience to direct all aspects of a major project like Keeyask day to day, in sufficient detail, thus KCB believe the contract is very one sided benefiting the contractor.

6 SCHEDULE REVIEW

6.1 References

- BBE - High Level Schedule (current)
- BBE High Level Approved A7 Baseline
- BBE High Level Original Contract Schedule

6.2 Schedule

MGF has examined the schedule in detail however KCB also examined the overall schedule from a high level perspective, looking at the overall durations for the major structures.

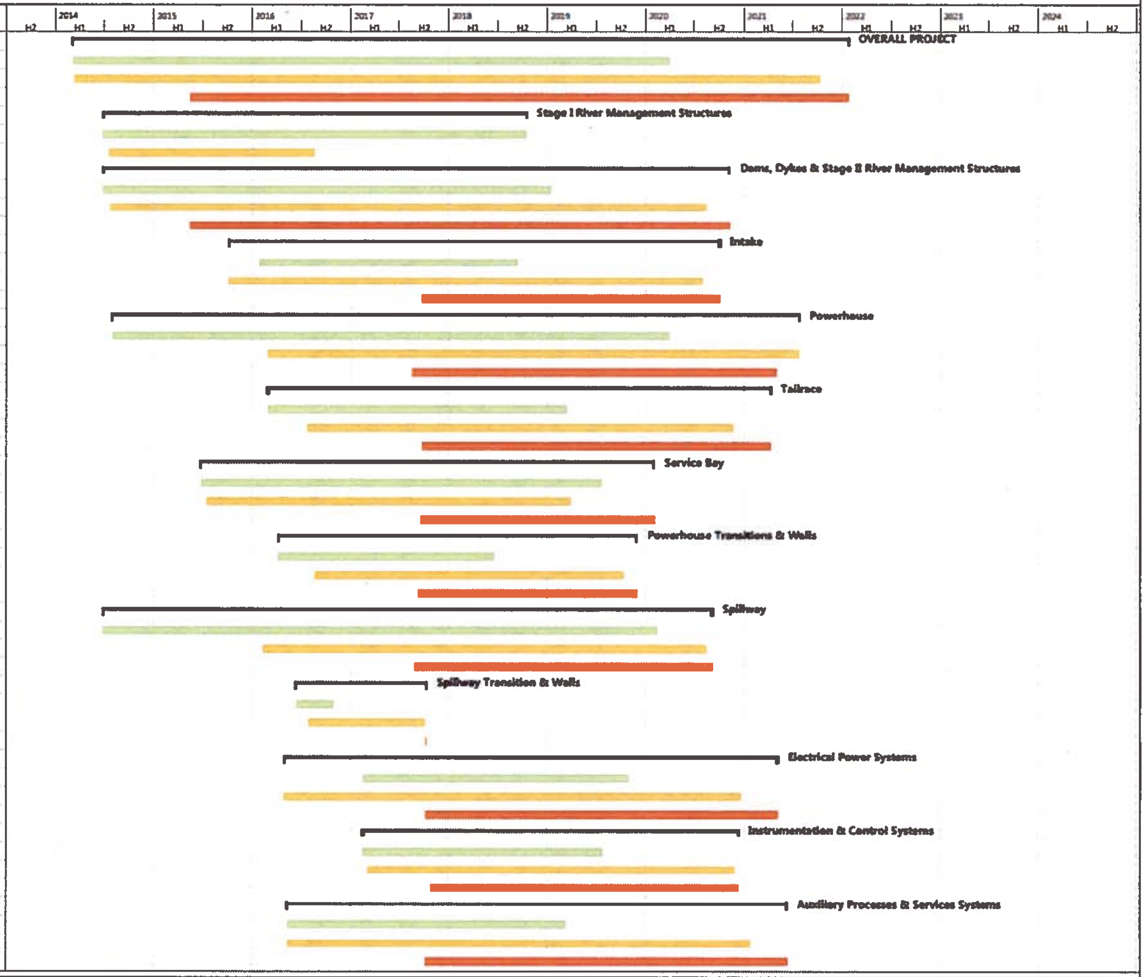
The original schedule, the AA#7 Baseline and a current schedule provided by MGF were all compared. The durations for the major activities are shown in the following table and schedule figure.

Table 12 Schedule Dates

Task Name	Original Schedule		Amendment #7 Schedule		Slippage	Current Schedule		Slippage
	Start	Finish	Start	Finish	Original vs #7 (Months)	Start	Finish	#7 vs Current (Months)
Stage I River Management Structures	27-Jun-2014	15-Oct-2018	16-Jul-2014	15-Aug-2016	-26.4	N/A	N/A	N/A
Dams, Dykes & Stage II River Management Structures	27-Jun-2014	11-Jan-2019	23-Jul-2014	13-Aug-2020	19.3	30-May-2016	08-Nov-2020	2.9
Intake	28-Jan-2016	10-Sep-2018	08-Oct-2015	30-Jul-2020	23.0	22-Sep-2017	02-Oct-2020	2.1
Powerhouse	31-Jul-2014	26-Mar-2020	01-Mar-2016	24-Jul-2021	16.2	18-Aug-2017	01-May-2021	-2.8
Tailrace	01-Mar-2016	12-Mar-2019	25-Jul-2016	23-Nov-2020	20.7	22-Sep-2017	09-Apr-2021	4.6
Service Bay	26-Jun-2015	19-Jul-2019	14-Jul-2015	27-Mar-2019	-3.8	20-Sep-2017	02-Feb-2020	10.4
Powerhouse Transitions & Walls	08-Apr-2016	15-Jun-2018	23-Aug-2016	08-Oct-2019	16.0	15-Sep-2017	30-Nov-2019	1.8
Spillway	27-Jun-2014	09-Feb-2020	10-Feb-2016	11-Aug-2020	6.1	25-Aug-2017	05-Sep-2020	0.8
Spillway Transition & Walls	13-Jun-2016	28-Oct-2016	29-Jul-2016	02-Oct-2017	11.3	06-Oct-2017	09-Oct-2017	0.2
Electrical Power Systems	17-Feb-2017	29-Oct-2019	01-May-2016	20-Dec-2020	13.9	06-Oct-2017	06-May-2021	4.6
Instrumentation & Control Systems	17-Feb-2017	26-Jul-2019	08-Mar-2017	27-Nov-2020	16.3	25-Oct-2017	11-Dec-2020	0.5
Auxiliary Processes & Services Systems	14-May-2016	07-Mar-2019	11-May-2016	24-Jan-2021	23.0	06-Oct-2017	10-Jun-2021	4.6

KGS High Level Schedule Comparison

ID	Task Name	Start	Finish
1	**OVERALL PROJECT**	**05 March 2014**	**23 January 2022**
2	Original Schedule	05 March 2014	26 March 2020
3	Amendment #7	10 March 2014	08 October 2021
4	Current Schedule	18 May 2015	23 January 2022
5	**Stage I River Management Structures**	**27 June 2014**	**15 October 2018**
6	Original Schedule	27 June 2014	15 October 2018
7	Amendment #7	16 July 2014	15 August 2016
8	**Dams, Dykes & Stage II River Management Structures**	**27 June 2014**	**08 November 2020**
9	Original Schedule	27 June 2014	11 January 2019
10	Amendment #7	23 July 2014	13 August 2020
11	Current Schedule	18 May 2015	08 November 2020
12	**Intake**	**08 October 2015**	**02 October 2020**
13	Original Schedule	28 January 2016	10 September 2018
14	Amendment #7	08 October 2015	30 July 2020
15	Current Schedule	22 September 2017	02 October 2020
16	**Powerhouse**	**31 July 2014**	**24 July 2021**
17	Original Schedule	31 July 2014	26 March 2020
18	Amendment #7	01 March 2016	24 July 2021
19	Current Schedule	18 August 2017	01 May 2021
20	**Tailrace**	**01 March 2016**	**09 April 2021**
21	Original Schedule	01 March 2016	12 March 2019
22	Amendment #7	25 July 2016	23 November 2020
23	Current Schedule	22 September 2017	09 April 2021
24	**Service Bay**	**26 June 2015**	**02 February 2020**
25	Original Schedule	26 June 2015	19 July 2019
26	Amendment #7	14 July 2015	27 March 2019
27	Current Schedule	20 September 2017	02 February 2020
28	**Powerhouse Transitions & Walls**	**08 April 2016**	**30 November 2019**
29	Original Schedule	08 April 2016	15 June 2018
30	Amendment #7	23 August 2016	08 October 2019
31	Current Schedule	11 September 2017	30 November 2019
32	**Spillway**	**27 June 2014**	**05 September 2020**
33	Original Schedule	27 June 2014	09 February 2020
34	Amendment #7	10 February 2016	11 August 2020
35	Current Schedule	25 August 2017	05 September 2020
36	**Spillway Transition & Walls**	**13 June 2016**	**09 October 2017**
37	Original Schedule	13 June 2016	28 October 2016
38	Amendment #7	29 July 2016	02 October 2017
39	Current Schedule	06 October 2017	09 October 2017
40	**Electrical Power Systems**	**01 May 2016**	**06 May 2021**
41	Original Schedule	17 February 2017	29 October 2019
42	Amendment #7	01 May 2016	20 December 2020
43	Current Schedule	06 October 2017	06 May 2021
44	**Instrumentation & Control Systems**	**17 February 2017**	**11 December 2020**
45	Original Schedule	17 February 2017	26 July 2019
46	Amendment #7	08 March 2017	27 November 2020
47	Current Schedule	25 October 2017	11 December 2020
48	**Auxiliary Processes & Services Systems**	**11 May 2016**	**10 June 2021**
49	Original Schedule	14 May 2016	07 March 2019
50	Amendment #7	11 May 2016	24 January 2021
51	Current Schedule	06 October 2017	10 June 2021



Project: KGS High Level Schedu
Date: 16 November 2017

Original | Amendment #7 | Current

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Some observations are:

- The earthworks, dams dykes and stage II river management structures are two years late, and that obviously impact other components.
- Compared with the original, the intake was started late on the AA7 schedule and based on work to date we do not understand how the long duration shown in AA7 can be compressed as shown on the current schedule.
- Similarly, the spillway work in the current schedule is a much shorter duration than either the original or the AA7 schedule, which may not be reasonable.
- The powerhouse duration in the current schedule is also dramatically shorter than the previous schedules.
- The Electrical Power system, Instrumentation and Control System and auxiliary Processes & Service Systems are all heavily dependent on the powerhouse schedule and in particular, require a weatherproof structure with all the walls and primary concrete installed to enable cable tray and pipe racks to be installed followed by the cables, pipes, cubicles and equipment and then all the terminations, connections, testing and commissioning. We do not understand how that work can start as close to the powerhouse start as shown on the current schedule and finish as close to the end of the powerhouse structure as shown.

In summary, the current schedule looks to be aggressive and unlikely to be met.

Note that the schedule evaluation considers the completion of all the units, and that some of the units may be complete and operational for the dates shown and that may be enough to handle the river flows at that time. Thus, there may be no hydrological reason to have all the units completed by October 2021 as shown, however there are likely strong commercial reasons to complete the project.

7 PROJECT EXECUTION AND CONSTRUCTION MANAGEMENT

7.1 References

- 243994-0020-016203-REC-Keeyask GCC Board Recommendation-2014 02 24
- KPMG Project Health Check_V10 - July 2016.
- Keeyask Recovery Plan Strategy for Implementation - 2016 10 26

7.2 Discussion

The execution of the work is behind schedule and over budget. As noted, the majority of the cost and schedule slippage can be traced back to the General Civil Contract and the lack of performance by the contractor.

KCB has not examined in any detail the manpower or the nominal productivity at site, however we understand from the changes in unit prices between the original and AA#7 Target Prices, and comments in reports related to the worker benefits, in particular booking time away from site, that productivity has not been as presented by BBE in their original bid.

Reading the Board Recommendations related to the contract price change, the KPMG project Health Check and the Recovery Plan strategy, we also understand there have been significant staff turnovers in the contractor's management and supervision, all of which will/have contributed towards delays on the project.

However, in our opinion the most significant issue for the project is the almost 100% decoupling of work performance from payment by paying Actual Costs instead of Quantities times Unit Prices for actual work done.

While we were not part of the process that selected the contracting model, we surmise that MH either had success with this model elsewhere, or there were significant reasons to push the project into construction quickly relying on the early contractor involvement, the expectations of a quality design from Hatch and an experienced contractor with a realistic target price to make the project a 4b
success. MH only assigned a contingency of [redacted] to the contract for MH held risks, which when added to the BBE target price is still lower than the costs of the project. While hindsight is 20:20 and we were not party to the bid evaluations, the contingency now looks to have been significantly too low.

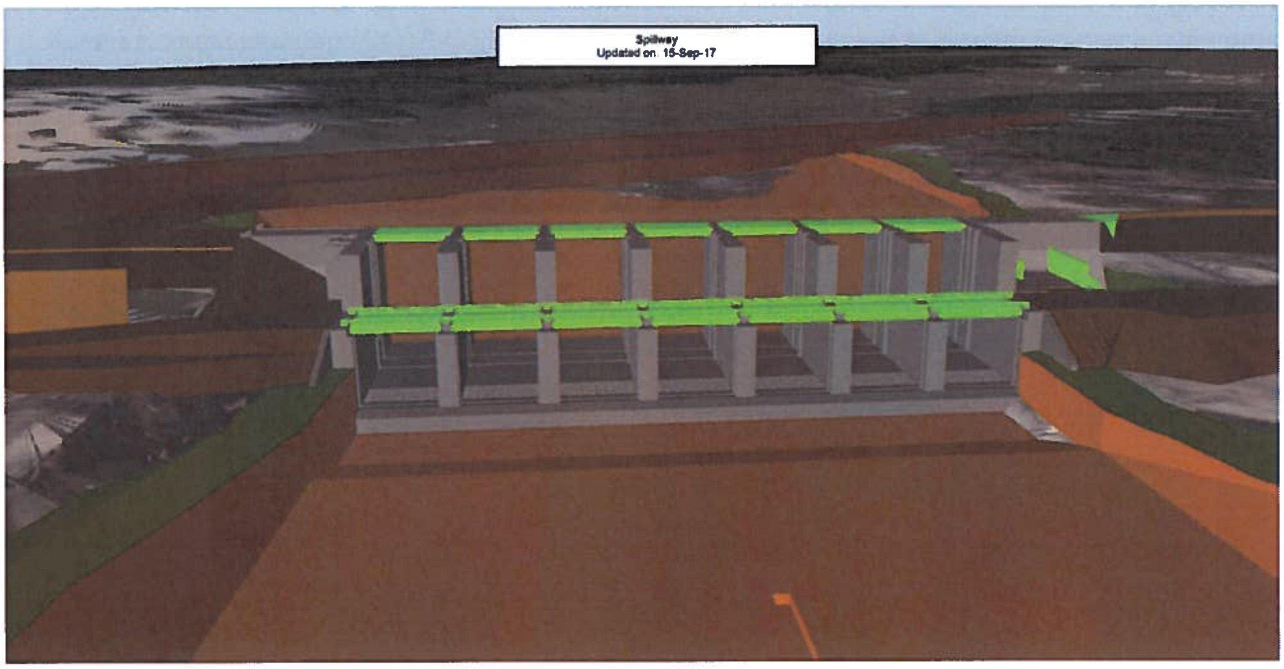
Interestingly during the discussions leading to AA#7 we understand there were serious considerations given to removing the contractor for all or part of the work.

Again, KCB was not part of the discussions and in all likelihood, would have also recommended continuing with the contractor as the likely least cost alternative. But we do not understand why the Actual Cost payment model remained almost unchanged without any modifications to connect payments to actual progress. We can only surmise there were legal issues preventing that much revision to the contract.

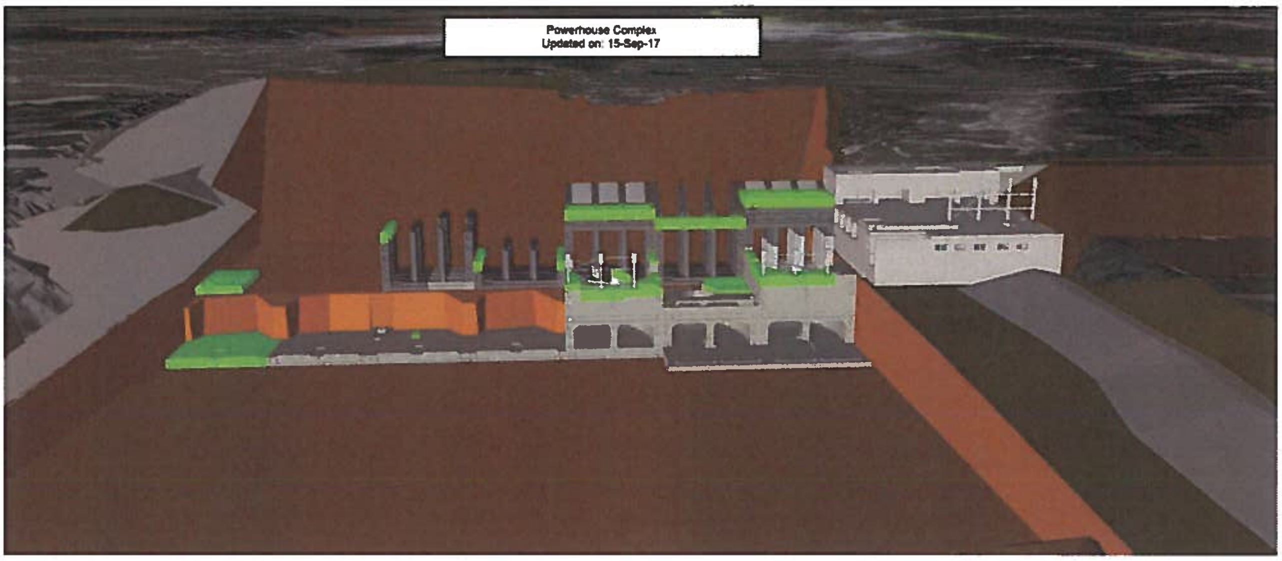
Review of the other major contracts for gates and the units found they are all more conventional, with payment tied to delivery and installation of various components.

KCB has observed that MH appears to have a robust and organized system for documenting changes, recording and filing information during construction which suggests the information needed for construction management is being collected and prepared. KCB has not been to site, and is unaware of the relationships between the MH and Hatch site staff and the BBE site staff, but we have read that getting staff for site for all parties has been somewhat of a problem. Changing staff at site makes building relationships harder and most certainly will affect speed of decision making at site and the level of trust which is always needed between owner and contractors staff.

After review of the referenced information, KCB is of the opinion that BBE will not be able to complete the project according to the AA#7 schedule and that the Actual Cost will therefore be higher than the current AA#7 value. The two figures below show the September 2017 work status on the spillway and powerhouse.



The spillway is relatively far advanced, however none of the ogee's are installed and none of the gates have been started. With reasonable progress next summer we would expect that the spillway will not be on the critical path.



The powerhouse is on the critical path and based on the current status KCB does not expect the powerhouse to be ready for any significant unit installation on schedule. Consequently, in addition to the additional costs for the civil work, there are likely to be additional claims for delay payment from Voith and almost all the other mechanical and electrical contractors and suppliers.

KCB has not examined the schedule in detail or the productivity rates, but MGF has, and after discussion with KCB, together our opinion is that we are forecasting a further delay.

APPENDIX B

Amplitude Consultants Report

Amplitude
CONSULTANTS

Capital Expenditure Review

For the Bipole III Project

Converter Stations

Revision	Date	Prepared	Reviewed	Approved
0	28/11/17	L. Brand	K. Hua	L. Brand
1	1/12/17	L. Brand	K. Hua	L. Brand
2	2/12/17	L. Brand	K. Hua	L. Brand

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1 Introduction

Amplitude Consultants (Amplitude) were requested to undertake a review of the converter station component of the Bipole III HVDC project currently being built by Manitoba Hydro. Amplitude's scope of work was to, for the Keewatinohk and Riel high voltage direct current converter stations, and as directed by MGF, assist MGF with the assessment for reasonableness of the current forecast at completion capital costs, including whether appropriate contingencies and reserves have been provisioned.

Amplitude performed the required scope of work with the information made available through the Manitoba Hydro online document system and subsequent email responses to queries posed to Manitoba Hydro.

Amplitude experienced some difficulties related to the timing of PRA approvals for members of the team and in getting access to the Manitoba Hydro online document system, including:

1. Late advice of the PRA approval of the technical team members – the PRA process took longer than expected, with some team members not getting advised of the success of their PRA approval until a number of weeks after submission.
2. Difficulties getting access to and logging into the Manitoba Hydro online document system – despite being eventually provided user names and passwords, team members were unable to access the system due to a variety of IT and permission related issues. On the date of the submission of the first draft of the report to MGF, only one out of Amplitude's five team members was able to access the system using their credentials.

The issues above led to a late start on the review of the documentation, and some team members being unable to commence work and contribute as expected. The lead reviewer, who was the only person able to access the system, had to spend more time accessing documents and dealing with access and IT issues.

The outcomes of the review presented in this report are provided with the caveat that the issues described above reduced the effective amount of time that Amplitude had to review the vast amount of data and information provided.

Amplitude has addressed this scope item through two findings:

1. Our view on the reasonableness of the current (2016) forecast completion costs for the converter stations;
2. Our view on whether reasonable contingencies and reserves have been provisioned.

2 Reasonableness of the 2016 forecast completion costs for the converter stations

2.1 Observations & Findings

The most recent revision to the cost estimate and budget for the Keewatinohk and Riel converter stations was completed in 2016. This cost estimate applied the same structure as that used in the 2014 cost estimate, which is explained in detail in the Manitoba Hydro document "Bipole III Project, Basis of Estimate Document, September 2014 Cost Estimate Update" dated March 2015.

The 2014 cost estimate applied a Work Breakdown Structure level (WBS) and each WBS was broken down further into a number of networks. The cost estimate for the converter stations were grouped into nine WBS. The same WBS structure was applied to the 2016 estimate. Table 1 provides a summary of 2014 and 2016 cost estimates for the converter station WBSs.

Table 1 - Converter Station Cost Estimates - 2014 and 2016

WBS No.	Description	2014 Estimate (CAD)	2016 Estimate (CAD)
14363	Property – Riel Converter Station	[redacted]	[redacted]
14364	Riel Converter Station & 230kV AC Switchyard Site Development	[redacted]	[redacted]
15533	Property – Keewatinohk Converter Station	[redacted]	[redacted]
15540	Keewatinohk Converter Station	[redacted]	[redacted]
15541	Riel Converter Station	[redacted]	[redacted]
15544	Keewatinohk 230kV AC Switchyard	[redacted]	[redacted]
21082	Keewatinohk Converter Station Distribution	[redacted]	[redacted]
23788	Riel 230kV Expansion for Bipole III	[redacted]	[redacted]
23837	Converter Stations Contingency	[redacted]	[redacted]
	Totals	2,675,082,692.80	2,779,633,110.33

1a, 7a

The documents indicate that the values in Table 1 include Manitoba's Provincial Sales Tax. This was assumed to be 8% on "applicable items" in the 2014 estimate, and Amplitude has assumed that this same assumption was carried over to the 2016 estimate update.

Table 1 shows an increase in the estimate/budget between 2014 and 2016 for the converter stations of $104,550,417.53. Some WBS values were increased materially (15540, 15541 and 23837) while others were reduced. The most notable increase in budget is an increase in contingency by [redacted] 1a, 4b

Documents reviewed have identified a need to increase contingency during the April 2016 cost estimate revision, due to risks identified by the Boston Consulting Group. We understand that additional funds were requested as the confidence level of P50 was not considered "*appropriate to address the remaining risks on the work*"[1] and that the project management team requested additional funds to bring the confidence level to P75 "*in order to complete the project on budget and to address costs that had been drawn from contingency as a result of cost sharing with the now-shelved Conawapa Project*"[1]. A summary of the contingency adjustments is provided in the Manitoba Hydro document. These amounts add up to [redacted] The difference between the budget increase and this amount has been explained by Manitoba Hydro as due to a reduction in the target adjustment account that is held, from [redacted] These are accounting elements and Amplitude is not qualified to comment on such transactions. 1a, 7a

[1] Manitoba Document "CEF-16 Budget Update and CPJA Budget Increase Summary", August 29, 2017.

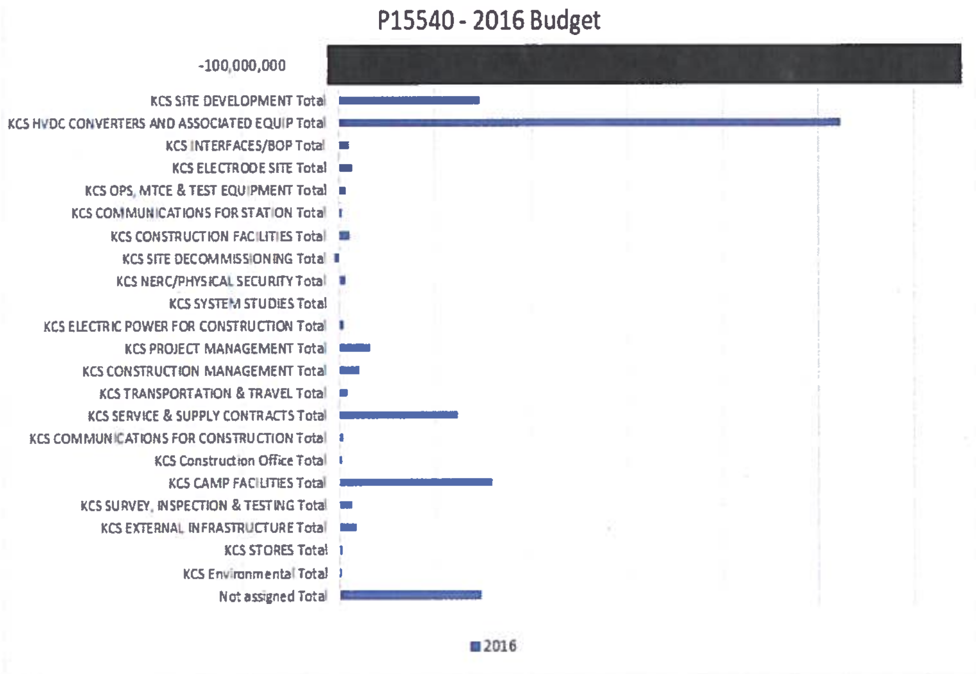
The only scope change identified in the documents provided is the additional funding for the access road for Conawapa, the cost of which was originally to be shared with the Conawapa Project, which was since shelved[2]. This resulted in an increase to the converter station contingency of [redacted] 7a

The WBS values in Table 1 show that the major cost items for the converter stations are (in descending order):

1. WBS 15540 - Keewatinohk Converter Station
2. WBS 15541 - Riel Converter Station
3. WBS 23837 - Converter Stations Contingency.
4. WBS 15544 - Keewatinohk 230kV AC Switchyard
5. WBS 14364 - Riel Converter Station & 230kV AC Switchyard Site Development

The first two WBS (15540 and 15541) make up close to 78% of the total budget for the overall converter station costs. These two WBS have a high number of cost networks, compared to the others, having each 22 networks. A breakdown of the 2016 budget allocations for each of the 22 networks for P15540 an P15541 is provided in Table 2 and Table 3 respectively.

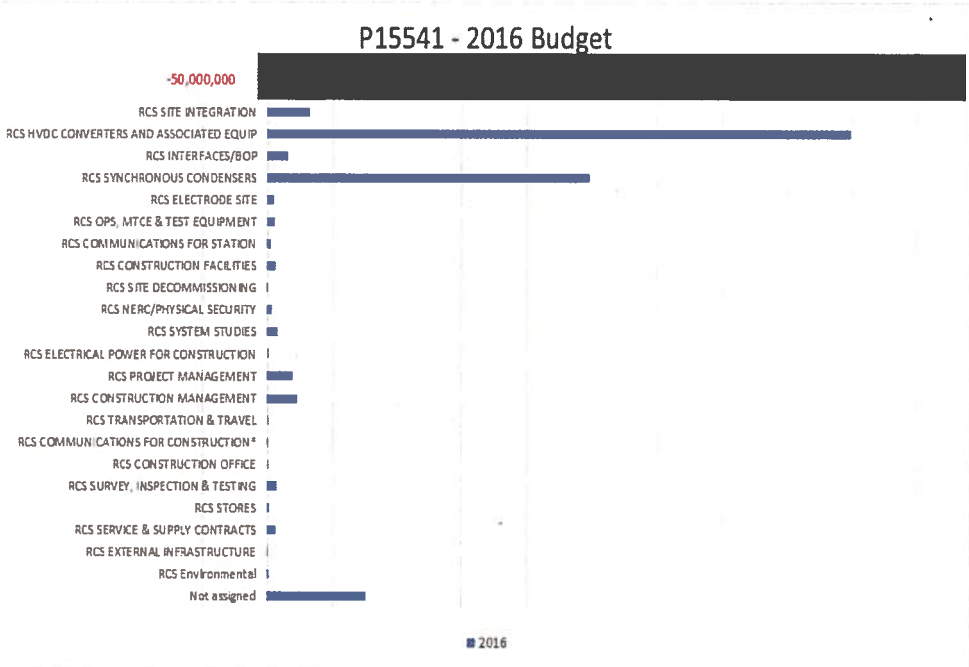
Table 2 - Breakdown of Cost Networks for P15540 - Keewatinohk Converter Station



1a, 7a

[2] Manitoba Hydro Document, "Basis for the Current Converter Stations Budget", page 1.

Table 3 - Breakdown of Cost Networks for P15541 - Riel Converter Station



1a, 7a

For Keewatinohk (P15540), it can be seen that the cost network for the HVDC converters and associated equipment (Network 244644) is the dominant cost, as would be expected. This is followed by the camp facilities (Network 244633), site development (Network 244643) and not assigned amounts.

For Riel (P15541), the dominant cost is again the HVDC converters and associated equipment (Network 244616) followed by the cost of the Synchronous Condensers (Network 244618) and unassigned amounts.

The sum of the HVDC converters and associated equipment networks (for both sites) and the synchronous condensers at Riel (i.e. the major EPC contracts) makes up over [redacted] or about [redacted] 1a, 7a
of the total estimate for the HVDC converters. In our experience, this proportion of "EPC costs" to "non-EPC costs" appears low, although we acknowledge that there are some unique major cost elements to this project, such as the extensive work on the AC switchyards and the provision of the camp at Keewatinohk that do not fall within the scope of the EPC contracts for the converter stations and synchronous condensers.

For the large part, the overall cost of the converter stations is made up of three major contracts:

- HVDC Converter Stations and Associated Equipment – Siemens/Mortensen.
- Synchronous Condensers – Voith.
- Keewatinohk AC Switchyards – SNC Lavalin.

The information provided indicates there is also an EPC contract for the Riel Converter Station 230kV Switchyard Expansion and Switchyard, although no information on such a contract was provided.

2.1.1 Siemens/Mortensen Contract

The Siemens/Mortensen EPC Contract covers the engineering, procurement, construction and commissioning of both HVDC converter stations including all equipment associated with the converter valves, converter transformers, civil and structural, AC and DC yards, auxiliary power, control and protection and mechanical plant.

The contract was awarded following a competitive tender process. Tender documentation provided shows that there were three bidders:

1. Siemens / Mortenson Construction (Siemens)
2. ABB/Kiewit (ABB)
3. Alstom / PCL Constructors Canada Inc. (Alstom)

All three companies are well known in the HVDC industry and have a long history of providing LCC HVDC transmission solutions globally. Copies of the individual tender submissions were provided to Amplitude, along with a spreadsheet summarising the outcomes of the tender analysis conducted by Manitoba Hydro[3].

The original bid price from Siemens/Mortensen for the main engineering, construction, installation testing, commissioning and project management component of the works (excluding spares, provisional sums, training and other optional components) was approximately [redacted] 1a, 7a, 8a

In our view, the technology partners of all three bidders (i.e. Siemens, ABB and Alstom Grid) are all in the "top three" in terms of experience with the development and delivery of LCC HVDC projects worldwide.

In our view, the comparison of three competitive bids from the three most experienced vendors of this technology provides some comfort that the EPC contract costs of the HVDC converter stations for Bipole III are within market for the scope of the project and location.

The tender evaluation sheet provided by Manitoba Hydro[3] identifies all three bidders as having passed the mandatory requirements. [redacted] 8a Amplitude did not explore these evaluations in detail, however the techno-economic evaluation of the bidders appears to have been thorough with consideration was given to technical capability, compliance with technical requirements, performance (including losses and expected replacement costs), technology proposed, schedule and overall value.

Siemens/Mortensen were the selected tenderer. The final contract price, assumed to be after post-tender clarification and negotiation (excluding spares, provisional sums, training and other optional components) was approximately [redacted][4]. 8a

The breakdown of the initial contract price for the Siemens/Mortensen contract is shown in Table 4.

Table 4 - Major Cost Components of Siemens/Mortensen Contract - Initial Contract Price

No.	Description	Cost
1	System Engineering and System Studies	[redacted]
2	Keewatinohk Converter Station – Design, Supply, construction, installation, testing, commissioning and mandatory spares for converter equipment and civil works.	
3	Riel Converter Station – Design, Supply, construction, installation, testing, commissioning and mandatory spares for converter equipment and civil works.	
4	Project Management Services and Performance Bond	
5	Optional Spares and Training	
	Total:	$819,773,930.35

1a, 7a, 8a

[3] 244616-244644-0020-033102-SHT-Final Proposal Evaluation-20140627.xlsx
[4] Converter Equipment Contract, Schedule III "Payment Milestones & Contract Price".

Note that item 4 in Table 4 (project management services and performance bond) makes up [redacted] of the whole contract price, with the "Performance Bond" component (we expect to be a requirement of the contract) called out as just under [redacted] of that amount (i.e. just under [redacted] of item 4). 1a, 8a

The initial contract price presented here is exclusive of PST. Manitoba Hydro has advised that the calculated PST amount for the base contract is [redacted][5], bringing the initial contract price to [redacted] including PST.

2.1.1.1 Contract Variations

The copies of the approved project variations that were provided have been reviewed by Amplitude. A total of 115 variations were reviewed. The status of the variations received is summarised below:

- The total value of approved variations reviewed was [redacted] This is close to the number determined from the combination of the variation amounts from the latest Siemens and Mortensen progress statements of [redacted] (to end of September 2017). Manitoba Hydro has since emailed an updated value of [redacted] for the combined Siemens/Mortensen variations. All these values are exclusive of PST. 1a, 8a
- There are some variations that still have no value, although most of these are expected to be not material. It is expected that the difference between the two values above are due to these "actual cost" variations.
- The variations are broken down by site as approximately 66% at Keewatinohk and 34% at Riel. In some cases, assumptions as to which site was affected or whether the costs would be roughly 50/50 between the sites have been made by Amplitude.
- Approximately 80% of the total value of approved variations are due to 14 variations (out of 115), all with a value greater than $1M.

Manitoba Hydro has advised a calculated PST amount on the variations of $1,086,687.74. Therefore, the sum of the Siemens/Mortensen original contract price and the value of approved variations (taking the latest advised by Manitoba Hydro), up to end of September 2017, comes to $904,604,618.48 including PST.

In the spreadsheet "2018 06 BPIII CS September 2017 Monthly Contracts Report 20171011.xlsx", the following information is provided:

- Current Contract Value - [redacted]
- Actuals including accruals - [redacted] 1a, 7a, 8a
- Dollars Remaining - [redacted]

There is a discrepancy between the original contract price plus variations determined by Amplitude ([redacted]) and the stated current contract value ([redacted]) of [redacted] which has been explained by Manitoba Hydro as the difference is due to escalations for steel, copper, on-site labour and concrete costs which are allowed under Schedule III of the contract[6]. 1a, 7a, 8a

For the purpose of determining adequacy of remaining budget and contingency, a post-PST contract value of [redacted] will be used.

2.1.1.2 Overall Cost Compared to Other Projects

The pricing of HVDC converter stations can be very complex, and dependent on many factors. In our view, the most accurate cost estimates and pricing is delivered by the vendors themselves, who can

[5] Email from Alastair Fogg of Manitoba Hydro dated 17 November 2017.
[6] Email from Alastair Fogg of Manitoba Hydro dated 17 November 2017.

take account of these factors and have access to detailed design and up to date pricing for components and materials. Our experience shows that accurate estimates should involve the submission of budgetary estimates from the HVDC vendors. Any attempts to build a check price from the bottom up with limited information is likely to result in large discrepancies that will be difficult or impossible to explain.

Some factors that influence pricing when comparing converter station EPC costs between projects include:

1. Cost of raw materials and metals – HVDC converter stations costs are dependent on the cost of certain raw materials and metals at the time – including concrete, steel, iron and copper. The cost of these materials will vary from year to year, either due to fluctuations in global markets or due to changes in local supply and demand.
2. Global demand for HVDC and vendor manufacturing capacity – there are only a relatively small number of HVDC vendors globally and their engineering resources and manufacturing capacities are finite. The global demand for HVDC projects can vary from year to year, although we are observing an overall increase in demand annually. If the vendors cannot increase resources and capacity in proportion to the increase in demand, this may push up costs and push back delivery schedules. In a situation where all vendors have many projects underway and have their manufacturing "slots" already filled, the submitted costs for the work, even in a competitive tender, could be higher across the board than previous projects.
3. Location – The location of the project can drive the project cost in a number of ways. The "top three" major HVDC vendors are all based in Europe (UK, Sweden and Germany). Projects that are a large distance from the HVDC vendors' facilities, especially those that require a long inland journey or require equipment to be flown to site, will incur higher transportation charges and longer lead times. Remote locations tend to require labour to be brought in from outside (leading to higher travel and accommodation costs) and the provision of higher wages or salaries to compensate for the remote location.

Most reported costs for HVDC projects are published exclusive of local taxes. Therefore, the estimated pre-PST current contract value of [redacted] will be used for comparison, less the performance bond component ([redacted][7]). The cost per kW for both terminals, based on 2,000MW continuous rating comes to approximately $422.6/kW. In the case of Bipole III, the entire converter station is specified to a 15% 1a, 8a
"continuous overload", which from an equipment and materials point of view is more or less a 2,300MW converter. Based on 2,300MW the cost per kW becomes approximately [redacted].

Amplitude presents here a selection of reported HVDC EPC costs for a variety of LCC projects, and has scaled these to 2016 levels for comparative purposes. These values represent actual announced costs and often represent the initial contract price (i.e. public announcement by the vendors on project award, without variations). Representative projects have been identified based on these being relatively recent (since 2006), utilising LCC HVDC technology, bipolar configuration and where a statement as to the converter station (only) contract has been issued from a reliable source. All of these projects except one (China) are based on one valve group per pole. These are the EPC contract costs only and does not include other non-EPC costs, such as owner's costs, environmental, permitting and land acquisitions. The selection is presented in Table 5.

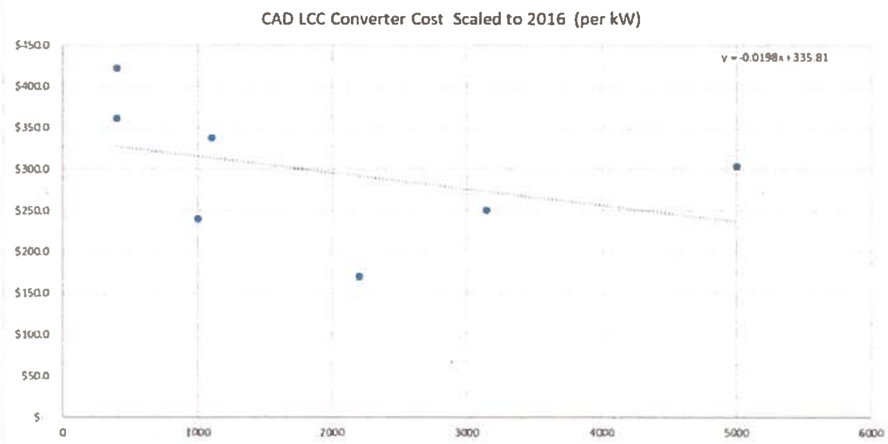
[7] Converter Equipment Contract, Schedule III "Payment Milestones & Contract Price"

Table 5 -Sample of HVDC LCC Projects - Reported Converter Station Contract Costs

Project	Year Published	Type	Converter Type and Rating	Converter EPC Costs (Original Currency, Published Date)	Converter EPC Costs (CAD/kW, Scaled to 2016)[8]	Source
COMETA (Romulus) Project, Spain	2007	Vendor Release	400MW Bipole	EUR 100m	CAD422.97/kW	https://www.energy.siemens.com/us/pool/hq/power-transmission/HVDC/HVDC-Classic/pm-pdf/pm-1-COMETA.pdf
Jeju-Jindo HVDC, South Korea	2009	News Release	400MW Bipole	USD 112.9m	CAD361.6/kW	http://asian-power.com/project/news/areva-gets-us1129m-contract-in-south-korea
SA.PE.I HVDC, Italy	2006	Vendor Release	1,000MW Bipole	EUR 143.4m	CAD240.5/kW	http://www.abb.com/cawp/seitp202/9e5c1f1a1cb0675ac12571800058456d.aspx
BritNed, UK-Netherlands	2007	Vendor Release	1,100MW Bipole	EUR 220m	CAD338.3/kW	http://www.ptd.siemens.de/artikel0906_high.pdf
Western HVDC Link, United Kingdom	2012	Vendor Release	2,200MW Bipole	GBP 223.8m	CAD170/kW	https://www.ofgem.gov.uk/ofgem-publications/52669/jul12whvdcdecisionfinal-pdf
Rio Madeira Bipole 2, Brazil	2009	Vendor Release	3,150MW Bipole	USD 480m	CAD251.2/kW	https://energy.gov/sites/prod/files/2013/05/f0/HVDC2013-Kirby_0.pdf
Yunnan-Guangdong HVDC, China	2007	News Release	5,000MW Bipole	USD 1,230m	CAD304.4/kW	http://www.tdworld.com/transmission/dc-answer

The converter station costs from Table 5, in CAD/kW, are shown graphically in Figure 1.

Figure 1 - Cost/kW for Two-Terminal Converter Stations



[8] For both converters, converted to CAD and scaled as follow: Scaling has been performed as follows: The value is converted to Canadian currency using annual average exchange rate for the year of publication and then scaled to 2016 amounts using published inflation rates for Canada.

Using the trend line, the sample produces a cost per kW for a 2,000MW of CAD296/kW and for a 2,300MW HVDC system, CAD290/kW. Multiplying these by their respective ratings results in an EPC contract cost between $592M and $667M.

It should be stressed again that these values are based on initial contract price (announcements made on award) and are not reflective of final converter station EPC contract costs at or toward the end of each project.

There also exists some Cigre documents that provide good benchmarks for pricing, although one of these uses quite old data. Two such references are:

- Technical Brochure 186 – "Economic Assessment of HVDC Links" published in June 2001. The document provides some costing information for LCC HVDC converters (Table 4.1). This document presents costing information that are stated as being "typical turnkey costs of the vendor's HVDC supply and installation" or in other words, the total expected vendor contract (EPC) cost. The values provided cover both terminals of a two-terminal scheme and they assume the DC bipole is made up of only one valve group per pole and no requirement for additional reactive power compensation due to connection to a weak AC system (i.e. synchronous condensers). The costs specifically do not include owner's costs, taxes, IDC or borrowing costs and are quoted to be at an accuracy of "no better than ±20%".
- Technical Brochure 492 – "Voltage Source Converter (VSC) HVDC for Power Transmission – Economic Aspects and Comparison with other AC and DC Technologies" published in April 2012. Although this document is a reference for VSC projects, some indicative pricing for a bipole LCC project (1,000MW) is provided. The values are stated as having an accuracy of ±30%.

By applying the same scaling assumptions as applied to the values in Table 5, the indicative cost per kW values become:

- TB186 – 2,000MW Bipole - $294.7 / kW; and
- TB492 – 1,000MW Bipole - $298.2 / kW.

In recent years, Canada has seen two new HVDC systems installed in Alberta. Both of these projects were built by Siemens, and both utilise the same LCC HVDC technology, albeit using one valve group per pole. While the ultimate design of these projects is for a bipole configuration, only one pole was built for each, with the individual pole being rated at 1,000MW. In both cases, we could not locate a vendor announcement for the overall contract price. However, there is information available publicly issued by the Alberta Utilities Commission (AUC) that provides the following information.

- Western Alberta Transmission Line (WATL) – Estimated cost of the converter station contract after deducting costs associated with significant works undertaken by the contractor for nearby AC substations, was $360M[9]/[10]. After scaling, and based on 1,000MW converters, we estimate this at $376.4/kW.
- Eastern Alberta Transmission Line (EATL) – Estimated forecast cost for the converter stations was $481.8M, but after removing AC interconnection facilities, reactive power compensation

[9] Alberta Utilites Commission, "Decision 2013-407: AltaLink Management Ltd. 2013-2014 Genreal Tariff Application," AUC, Nov. 2013.
[10] Transsmission Facilities Cost Monitoring Committee, "Review of the cost status of major transmission projects in Alberta," TFCMC, Dec. 2013.

and ATCO in-house labour, the estimate for the contractor works becomes $374.4M[11]. Further adjustments to the contract price (downwards) resulted in an estimated at the time (2012) of $349.8M[12]. After scaling, and based on 1,000MW converters, we estimate this at $369.1/kW.

These values are more in line with the cost per kW for Bipole III, and are likely more relevant given they are located in Canada and would have experienced similar circumstances as the Bipole III project, particularly in relation to proximity to the vendor facilities, construction and operation in harsh environmental conditions and the remoteness of at least one converter station site.

2.1.1.3 Price Differentiators

There are certain differentiators associated with the scope of the Bipole III project that are likely to impact the comparison of the cost of this HVDC scheme with others, particularly those outside of Canada. Some key differentiators that would lead to a higher cost compared to other HVDC LCC projects include:

- Each pole of the Bipole III project comprises two series valve groups. The majority of HVDC projects built up to now have only one valve group per pole. Poles can be split into series valve groups particularly where there are certain practical limitations with the project size – such as the manufacture and transportation to site of the converter transformers. Splitting the pole into valve groups results in double the number of valve halls and converter transformers, although these will have lower power ratings each, and one of these valve halls/transformers will have a much lower line to ground voltage (shorter clearances, smaller building, smaller transformer). The overall effect however would be that a two-valve group pole would be more expensive than a single valve group pole of the same rating and voltage. On page 24 of Cigre Technical Brochure 186, the following statement is made:

  "*It is estimated that there would be about a 20% total cost premium to the turnkey supply for a same-size bipole having two parallel valve groups per pole instead of one. If the two valve groups are in series, however, this extra cost applies only to the second (higher-voltage) valve groups.*"[13]

  The statement is not helpful in determining an actual cost difference for multiple series valve groups, but does identify that there will be a cost premium associated with it when compared to the cost of projects with only one valve group per pole.
- Extreme temperature and environmental conditions to be experienced both during construction (at both sites) and during operations.
- The remoteness of the Keewatinohk Converter Station site, and the additional costs associated with performing work in these locations (personnel, travel, transportation etc.).
- Unique controls, including:
  - De-icing controls – the capability to operate with each pole in opposite directions to de-ice the transmission lines.
  - SPS interface, frequency controls, damping controls and reduction ("run-back") capability.
  - NERC cyber security requirements.

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[11] Alberta Utilities Commission, "Decision 2013-358: ATCO Electric Ltd. 2013-2014 Transmission General Tariff Application," AUC, Sept. 2013.
[12] ATCO Electric Ltd., "Updated cost for Eastern Alberta Transmission Line project," AUC, Dec. 2013.
[13] Cigre Technical Brochure 186 "Economic Assessment of HVDC Links", June 2001, Page 24.

- External TFR systems in addition to those provided with the Vendor's C&P systems (typical).
- Control system replica for the RTDS lab at Riel and the control system simulators at each converter.
- Interface to the Manitoba Hydro supplied DC line fault locator.

These price differentiators are expected to result in a higher EPC contract price than other projects that do not have these characteristics. It is not possible to quantify by how much with the information available and the time provided.

2.1.1.4 Summary of Outcomes

The comparison of three competitive bids from the three most experienced vendors of this technology provides some comfort in the validity of the EPC contract costs of the HVDC converter stations for Bipole III. The Siemens-Mortensen price was selected as having a lower "Total Evaluation Price" than the other two bidders.

In terms of comparing the Bipole III Siemens-Mortensen current contract value of [redacted] (without PST) with comparative projects and cost references: 1a, 8a

1. The values drawn from Figure 1 will result in a vendor (EPC contract) price for 2,000MW-2,300MW bipole converter stations between $592M and $667M. These values will be based on initial contract prices, are based on projects that have one valve group per pole and will have some error associated with scaling assumptions and due to each comparative HVDC project having slight differences in scope that impact price.
2. The values drawn from the Cigre technical brochures will result in a vendor (EPC contract) price for 2,000MW-2,300MW bipole converter stations between $589.4M and $685.8M. These values are stated as having an accuracy no better than ±20%, widening the range to between $471.5M and $822.9M. These values are based on projects that have one valve group per pole.
3. The values drawn from information from recently completed HVDC LCC projects in Canada, the WATL and EATL projects in Alberta, will result in a vendor (EPC contract) price for 2,000MW-2,300MW bipole converter stations between $738M and $865.7M. These projects have only one valve group per pole.

Due to the expected cost premium for two valve groups per pole and for the challenges associated with the remoteness of the Keewatinohk Converter Station, it is expected that the Bipole III costs will be higher than representative single valve group per phase projects not located in remote areas, as would be the case for those identified in items 1 and 2 above.

2.1.2 Voith Contract

The synchronous condenser contract makes up over [redacted] of the estimate for WBS P15541 Network 244618. The contract covers the design, manufacture, supply, install, construct and commission four synchronous condensers, each rated at 250MVAr, at the Riel Converter Station. 1a, 8a

The contract was awarded following a competitive tender process. Tender documentation provided shows that there were three bidders – Siemens, Alstom and Voith.

The original bid price from Voith was [redacted] 1a, 8a

From the tender evaluation sheet provided, we observe that all three bidders passed the mandatory requirements[14]. [redacted]

1a, 8a

Voith was the selected tenderer. The final contract price (assumed to be after post-tender clarification and negotiation) was [redacted] not including PST.

The breakdown of the initial contract price for the Voith contract is shown in Table 6.

Table 6 - Major Cost Components of Voith Contract - Initial Contract Price

No.	Description	Cost
1	Engineering and Design	[redacted]
2	Manufacture and Supply of Equipment and Materials	
2a	Synchronous Condensers and Associated Equipment	
2b	Civil Works	
3	Installation and Construction	
3a	Synchronous Condensers and Associated Equipment	
3b	Civil Works	
4	Testing and Commissioning	
5	Spare Parts	
6	Project Management	
7	Training	
	Total:	**$213,896,689**

1a, 7a, 8a

In the cost breakdown, site installation and construction costs make up [redacted] of the total contract price, while project management makes up [redacted] of the total contract price. The actual supply of the synchronous condensers and associated equipment is only just above [redacted] of the total contract price. This shows the strong influence of local conditions and project/construction management on the pricing for this contract. 1a, 8a

2.1.2.1 Contract Variations

The copies of the approved project variations that were provided have been reviewed by Amplitude. A total of [redacted] variations were reviewed. The status of the variations received is summarised below:

- The total value of approved variations reviewed was [redacted] This is significantly lower than the number determined from the combination of the variation amounts from the latest Voith/Stuart Olsen progress statements of [redacted] (to end of September 2017) 1a, 8a
- There are some variations that still have no value. We anticipate that the difference between the amount of approved variation reported by Voith and Stuart Olsen and the numbers we have looked at is due to these types of variations, or we have not been provided with all variations for this contract.
- Of those provided to Amplitude, only one variation had a value greater than $1M and the value of this variation ([redacted]) makes up almost 50% of the total variations provided to Amplitude (over 26% of the total approved variations reported by Voith and Stuart Olsen). 1a, 8a [redacted]

[14] 244618-0020-033852-MAT-Riel Synchronous Condenser Final Evaluation Matrix-20150206.xlsx

The sum of the Voith original contract price and the value of approved variations (using the end of September value reported by Voith and Stuart Olsen) comes to [redacted] (not including PST). 1a, 8a
No calculated PST amount has been provided by Manitoba Hydro.

In the spreadsheet "2018 06 BPIII CS September 2017 Monthly Contracts Report 20171011.xlsx", the following information is provided:

- Current Contract Value - [redacted]
- Actuals including accruals - [redacted] 1a, 8a
- Dollars Remaining - [redacted]

There is a discrepancy between the original contract price plus variations determined by Amplitude ([redacted]) and the stated current contract value ([redacted]). The latter values are post-PST amounts, and likely the difference is due to both PST and escalation for metal, material and labour prices as allowed under Schedule III of the contract [15]. 1a, 8a

2.1.2.2 Overall Cost Compared to Other Projects

Similar limitations and influencing factors to those identified for the cost of the converter stations would apply here. Table 7 provides a sample of publicly available information related to the cost of synchronous condensers globally.

Table 7 – Publicly Available Pricing Information on Synchronous Condenser Projects

Reference	Year Published	Source Type	Synchrnous Condenser Type and Rating	EPC Costs (Original Currency, Published Date)	EPC Costs (CAD/kVAr, Scaled to 2016) [16]	Source
Cigre TB186	2000	Estimate	250MVAr	€ 20,000,000	$159.92	Cigre TB186 "Economic Assessment of HVDC Links"
Codrongianos Substation on Sardinia island	2014	Actual	2 x 250MVAr	€ 40,100,000	$120.66	http://integrated.terna-reports.it/2014/sites/default/files/pdf-header/Terna_Annual_Report_2014.pdf
Favara and Partinico Substations near Sicily	2015	Actual	2 x 160MVAr	€ 30,800,000	$138.51	http://integrated.terna-reports.it/2015/sites/default/files/pdf-header/Terna_Integrated_Report_2015.pdf
Bjæverskov Substaion, Denmark	2012	Actual	1 x 250MVAr	€175,000,000	$127.47	https://energinet.dk/Om-nyheder/Nyheder/2017/04/25/Energinet-dk-sikrer-spandingen-pa-Sjalland
Fraugde and Herslev Substation, Denmark	2013	Actual	2 x 200MVAr	€340,000,000	$163.07	https://energinet.dk/Om-nyheder/Nyheder/2017/04/25/Energinet-dk-bygger-nye-anlag-pa-Fyn-og-Vestsjalland

[15] Email from Alastair Fogg of Manitoba Hydro dated 15 November 2017.
[16] Reported amount converted to CAD and scaled as follow: Scaling has been performed as follows: The value is converted to Canadian currency using annual average exchange rate for the year of publication and then scaled to 2016 amounts using published inflation rates for Canada.

Reference	Year Published	Source Type	Synchrnous Condenser Type and Rating	EPC Costs (Original Currency, Published Date)	EPC Costs (CAD/kVAr, Scaled to 2016)[16]	Source
Otahuhu, Auckland New Zealand	2005	Estimate	1 x 100MVAr	NZD22,686,000	$232.26	https://www.ea.govt.nz/dmsdocument/4715
Grid Upgrade Plan 2007, New Zealand	2008	Estimate	1 x 120MVAr	NZD34,000,000	$240.60	https://www.transpower.co.nz/sites/default/files/plain-page/attachments/hvdc-gup-vol-l-may-2008.pdf
Proposed Haywards, New Zealand	2005	Estimate	1 x 65MVAr	NZD12,900,000	$203.18	https://www.ea.govt.nz/dmsdocument/180

The values in Table 7 show costs per kVAr ranging from $120.66/kVAr to $240.60/kVAr. The estimated current contract value (pre-tax and escalation) of $220.2M for 1,000MVar equates to $220.2 per kVAr.

Based on these amounts, the Voith contract is within the range of other projects, although it is on the high side of this range. The costing factors and price differentiators unique to the Bipole III project as discussed for the converter station pricing are likely to apply when comparing the cost of Bipole III to the cost of projects elsewhere in the world – including the extreme temperature and environmental conditions to be experienced both during construction and during operations.

2.1.3 SNC-Lavalin Contract

The AC switchyard contract makes up over [redacted] of the estimate for WBS P15544. The work included in this contract consists of system studies, supervision, design, manufacture, factory testing, supply, delivery to site, installation, site testing, commissioning of the nine-bay Keewatinohk 230 kV air insulated AC switchyard located adjacent to the Keewatinohk converter building, with all associated buildings and equipment. 1a, 8a

The contract was awarded under a competitive tender process. Tender documentation provided shows that there were three bidders – Burns & McDonnell, Siemens Canada and SNC-Lavalin.

The original adjusted proposal price from SNC-Lavalin was [redacted] 1a, 8a

[redacted]

SNC-Lavalin was the selected tenderer. The final contract price (assumed to be after post-tender clarification and negotiation) was [redacted] including spare parts and training, not including PST. 1a, 8a

The breakdown of the initial contract price for the SNC-Lavalin is shown in Table 8.

Table 8 - Major Cost Components of SNC-Lavalin Contract - Initial Contract Price

No.	Description	Cost (CAD)
1	Design, Supply, Installation, Testing & Pre-Commissioning of Switchyard and Equipment	[redacted]
2	Design, Supply, Construction, Testing and Commissioning of Civil Works, Structures, Foundations and Buildings	
3	Site and Interface Support	1a, 7a, 8a
4	Switchyard Commissioning Support	
5	Project Management Services	
6	Aboriginal Awareness Training and Ceremonies	
7	Performance and Payment Securities	

No.	Description	Cost (CAD)
8	Spare Parts and Special Tools	[redacted]
9	On-the-Job Training Plan	
10	Training of the Purchaser's Personnel for the Operation and Maintenance of the Switchyard	
	Total:	$123,838,715.43

1a, 7a, 8a

In the cost breakdown, the equipment, site installation and construction make up [redacted] of the whole project, while project management makes up only [redacted] of the total contract price. 1a, 8a

2.1.3.1 Contract Variations

The copies of the approved project variations that were provided have been reviewed by Amplitude. A total of [redacted] variations were reviewed. The status of the variations received is summarised below: 1a, 8a

- The total value of approved variations reviewed was [redacted] This is slightly lower than the number determined from the reported variation amounts from the latest SNC-Lavalin progress statement of [redacted] (to end of August 2017).
- Of those provided to Amplitude, three variations had a value greater than $1M and the value of the largest variation ([redacted]) makes up almost [redacted] of the total variations provided to Amplitude. This variation was a request for SNC-Lavalin to implement the revised circuit breaker requirements for the design of the 230kV AC Switchyard. 1a, 8a

The sum of the original contract price and the value of approved variations (using higher number from the sum of the variations provided) comes to [redacted] (not including PST). No calculated PST amount has been provided by Manitoba Hydro. 1a, 8a

In the spreadsheet "2018 06 BPIII CS September 2017 Monthly Contracts Report 20171011.xlsx", the following information is provided:

- Current Contract Value - [redacted]
- Actuals including accruals - [redacted] 1a, 8a
- Dollars Remaining - [redacted]

There is a discrepancy between the original contract price plus variations determined by Amplitude ([redacted]) and the stated current contract value ([redacted]). The latter values are post-PST amounts, and likely the difference is due to both PST and the escalation for metal, material and labour prices as allowed under Schedule III of the contract [17]. 1a, 8a

2.2 Conclusions & Recommendations

- The comparison of three competitive bids from the three most experienced vendors of this technology, with at least two of these being very close in price – provides some comfort in the validity of the EPC contract costs of the HVDC converter stations for Bipole III.
- Comparing the Bipole III HVDC EPC contract cost with other comparative projects and cost references in the public domain, we conclude that the EPC costs are reasonable after taking into consideration the use of two valve groups per pole, the remoteness of the Keewatinohk Converter Station and the extreme temperature and environmental conditions to be experienced both during construction and during operations.

[17] Email from Alastair Fogg of Manitoba Hydro dated 15 November 2017.

- Similarly, we are on the view that the EPC costs for the synchronous condensers are reasonable, after comparison to publicly available cost references and consideration of the extreme temperature and environmental conditions to be experienced both during construction and during operations.

2.3 Source of Information & Reference materials

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3 Reasonableness of contingencies and reserves Observations & Findings

3.1 Observations & Findings

Information on actual costs incurred per WBS and per network, up to September 2017, has been provided and reviewed by Amplitude[18].

The actual costs incurred to September 2017 versus the 2016 budget is presented in Table 9 and graphically in Figure 2.

Table 9 - Bipole III - Actual Costs incurred to September 2017 versus the 2016 Budget

WBS	Description	2016 Budget	Sept 2017 Actual	Remaining Budget
P:15533	Property for Keewatinohk Converter Station	[redacted]		
P:15540	Keewatinohk Converter Station			
P:15544	Keewatinohk 230KV AC Switchyard			
P:21082	Keewatinohk Converter Station Distribution			

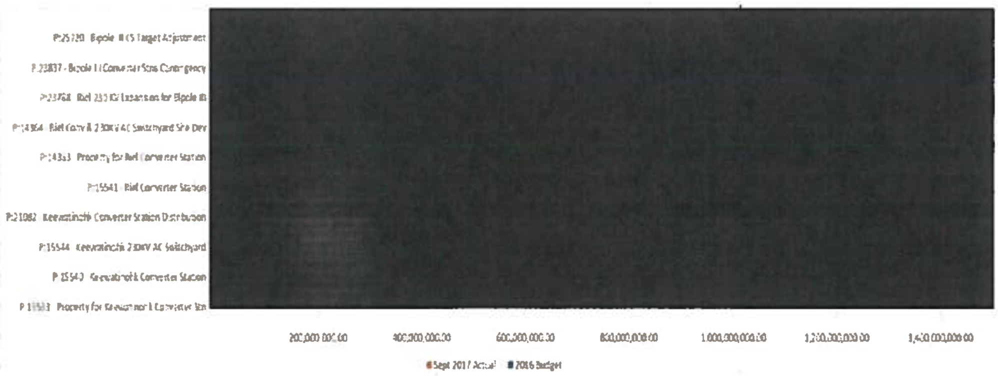
1a, 7a, 8a

[18] BPIII CS CPJ Comparison vC14 vs vC16 Actual spend to Sept 30, 2017.xlsx

WBS	Description	2016 Budget	Sept 2017 Actual	Remaining Budget
P:15541	Riel Converter Station	[redacted]		
P:14363	Property for Riel Converter Station			
P:14364	Riel Conv & 230KV AC Switchyard Site Dev			
P:23788	Riel 230 KV Expansion for Bipole III			
P:23837	Bipole III Converter Stns Contingency			
P:25720	Bipole III CS Target Adjustment			
	Totals	2,780,556,950.46	2,136,788,968.93	644,691,821.66

1a, 7a, 8a

Figure 2 - Bipole III Converter Station Costs - 2016 Budget vs Sept 2017 Actual - WBS Level



1a, 7a, 8a

Table 9 and Figure 2 both show that as at September 2017, all WBSs are running under budget with a substantial contingency remaining on the project.

As at the end of September 2017, the project has been progressed to the point that significant progress has been made on the construction and installation of the converter stations and AC switchyards at both sites and of the synchronous condensers at Riel.

An overall picture of the remaining activities of the converter station component of the project is shown in Table 10 which is based on our interpretation from the latest schedules provided in .XER format for the three major contracts (HVDC converters, synchronous condensers and AC switchyards).

Table 10 - Bipole III – Converter Station Works – Major Remaining Activities

Contract	Activity
HVDC	Loss Measurements and Losses Study
HVDC	Manufacture of Spare Transformers
HVDC	Manufacture of HVDC Line Coupling Capacitors
HVDC	Operator Training Simulator – Preparation for Shipment
Converter Stations	
HVDC	Completion of Civil Works, Structural Erection and Installation – Converter Building, AC Yard and DC Yard
HVDC	Civil works for spare transformer bays
HVDC	Completion of equipment installation and pre-commissioning - Filter Bays
HVDC	Completion of equipment installation and pre-commissioning - Valve and Valve Cooling

Contract	Activity
HVDC	Completion of equipment installation and pre-commissioning – Valve hall equipment
HVDC	Completion of pre-commissioning – Converter transformers
HVDC	Completion of pre-commissioning – AC and DC yards
HVDC	AC Yard - High voltage connections to filter banks and converter transformers
HVDC	DC Yard – High voltage connections to DC equipment and HVDC line
HVDC	Completion of installation and termination of control and fibre optic cable installations in converter building
HVDC	Completion of drywall and internal finishing in converter building
HVDC	Completion of HVAC, fire and auxiliary systems in converter building
HVDC	Completion of overhead wire installation – AC and DC yards
HVDC	Completion of yard fencing and grounding
HVDC	Sub-Systems Tests and Station Tests
Synchronous Condensers	
Synch Cond	Complete Manufacturing rotor and stator – SC5
Synch Cond	Complete Manufacturing of Unit Transformer – SC4 and SC5
Synch Cond	Complete installation works – electrical, cabling, auxiliary systems and mechanical systems – SC2, SC3, SC4 and SC5
Synch Cond	Mechanical Completion of SC2, SC3, SC4 and SC5
Keewatinohk 230kV Switchyard	
230kV Switchyard	Complete cable installation, interface to converter stations – controls and communications
230kV Switchyard	Complete 600V building feeder cable installations
230kV Switchyard	Complete switchgear building and control building
230kV Switchyard	Complete fire protection works
230kV Switchyard	Pre-commissioning of buswork, lighting and grounding
230kV Switchyard	Pre-commissioning of AC and DC station services
230kV Switchyard	Complete grounding works
230kV Switchyard	Pre-commissioning of CBF bays and switchgear buildings
230kV Switchyard	Sub-Systems Testing
Testing and Commissioning	
HVDC	System Tests – KCS and RCS
HVDC	Acceptance Tests – KCS and RCS
HVDC	Trial Operation
Synch Cond	Testing and commissioning of SC2, SC3, SC4 and SC5
230kV Switchyard	System Testing

The expected status of each WBS, based on the information provided, is summarised in the following sections.

3.1.1 P15533 - Property for Keewatinohk Converter Station

Manitoba have advised that typically property for transmission lines are acquired by easement and converter station sites by ownership[19]. The estimate for the property components for the converter stations (P15533 and P14363) includes internal and external labour to conduct property appraisals, property acquisitions and surveys.

Manitoba Hydro will own the land for the Keewatinohk Converter station at the end of the project. As this site is on Crown land, a flat rate annual fee is paid up front for permission for construction rights and access to the land[20].

This WBS has only one Network (243352). The breakdown of actual versus 2016 budgeted expenditure is shown in Table 11.

Table 11 - WBS15533 - Budget vs Actual

Description	2016 Budget	Sept 2017 Actual	Budget Remaining
LAND PURCHASES-NRTHRN CNVRTR STATION* Total	[redacted]		
Conawapa Access Road* Total			
Keewatinohk Infrastructure Total			
Not assigned Total			
Totals	**486,556.41**	**463,957.75**	**22,598.66**

1a, 7a, 8a

The majority of costs associated with this project has been related to the land purchase. Given the project site works are close to completion, it is reasonable to expect that any further expenditure on this WBS, if any, would be non-material.

3.1.2 P15540 - Keewatinohk Converter Station and P15541 - Riel Converter Station

These WBS cover the largest component of the overall converter station costs. Each WBS contains 22 cost networks, covering various cost elements for the converter station. A summary of these networks, along with the 2016 budget and Sept 2017 actual costs (assumed to include PST) is provided in Table 12 and Table 13 for P15540 (Keewatinohk) and P15541 (Riel) respectively.

Table 12 - WBS15540 - Budget vs Actual

Network No.	Description	2016 Budget	Sept 2017 Actual	Budget Remaining
244643	KCS SITE DEVELOPMENT	[redacted]		
244644	KCS HVDC CONVERTERS AND ASSOCIATED EQUIP			
244645	KCS INTERFACES/BOP			
244646	KCS ELECTRODE SITE			
244647	KCS OPS, MTCE & TEST EQUIPMENT			
244648	KCS COMMUNICATIONS FOR STATION			
244649	KCS CONSTRUCTION FACILITIES			
244650	KCS SITE DECOMMISSIONING			
244651	KCS NERC/PHYSICAL SECURITY			
244652	KCS SYSTEM STUDIES			
244653	KCS ELECTRIC POWER FOR CONSTRUCTION			
244654	KCS PROJECT MANAGEMENT			
244655	KCS CONSTRUCTION MANAGEMENT			

1a, 7a, 8a

[19] Manitoba Hydro, “Bipole III Project, Basis of Estimate Document, September 2014 Cost Estimate Update”, Revision 0, March 2015, Page 85.
[20] Manitoba Hydro, “Bipole III Project, Basis of Estimate Document, September 2014 Cost Estimate Update”, Revision 0, March 2015, Page 87.

Network No.	Description	2016 Budget	Sept 2017 Actual	Budget Remaining
244657	KCS TRANSPORTATION & TRAVEL	[redacted]		
244658	KCS SERVICE & SUPPLY CONTRACTS			
244660	KCS COMMUNICATIONS FOR CONSTRUCTION			
244662	KCS Construction Office			
244663	KCS CAMP FACILITIES			
244664	KCS SURVEY, INSPECTION & TESTING			
244674	KCS EXTERNAL INFRASTRUCTURE			
244676	KCS STORES			
250135	KCS Environmental			
#	Not assigned			
		1,247,788,230.87	1,048,335,823.44	199,452,407.43

1a, 7a, 8a

Table 13 - WBS15541 - Budget vs Actual

Network No.	Description	2016 Budget	Sept 2017 Actual	Budget Remaining
244615	RCS SITE INTEGRATION	[redacted]		
244616	RCS HVDC CONVERTERS AND ASSOCIATED EQUIP			
244617	RCS INTERFACES/BOP			
244618	RCS SYNCHRONOUS CONDENSERS			
244619	RCS ELECTRODE SITE			
244620	RCS OPS, MTCE & TEST EQUIPMENT			
244621	RCS COMMUNICATIONS FOR STATION			
244622	RCS CONSTRUCTION FACILITIES			
244623	RCS SITE DECOMMISSIONING			
244624	RCS NERC/PHYSICAL SECURITY			
244625	RCS SYSTEM STUDIES			
244626	RCS ELECTRICAL POWER FOR CONSTRUCTION			
244627	RCS PROJECT MANAGEMENT			
244628	RCS CONSTRUCTION MANAGEMENT			
244630	RCS TRANSPORTATION & TRAVEL			
244632	RCS COMMUNICATIONS FOR CONSTRUCTION*			
244633	RCS CONSTRUCTION OFFICE			
244634	RCS SURVEY, INSPECTION & TESTING			
244635	RCS STORES			
244636	RCS SERVICE & SUPPLY CONTRACTS			
244675	RCS EXTERNAL INFRASTRUCTURE			
250136	RCS Environmental			
	Not assigned			
		913,888,428.46	701,884,398.56	212,004,029.90

1a, 7a, 8a

The reported status of the payment milestones for the Siemens/Mortensen Contract is shown in Table 14. Note that while the table shows reporting from Siemens to end August, Amplitude was advised that this is because no payment milestones were claimed by Siemens during September 2017[21].

[21] Email from Kimberley Savage of Manitoba Hydro dated 18 November 2017.

Table 14 - Progress Payments Made for Siemens/Mortensen Contract – Up to End September 2017

Contract No. 033102	Siemens (end August-2017)			Mortenson (end September-2017)			Total Paid to Date (September 2017)	Total Remaining to Date (September 2017)
	Payment to Date	Remaining	%Spent	Payment to Date	Remaining	%Spent		
Item 1: System Engineering & System Studies	[redacted]							
Item 2: Design & Supply of HVDC Converters and Associated Equipment for Keewatinohk Station	[redacted]							
Item 3: Design & Supply of HVDC Converters and Associated Equipment for Riel Station	[redacted]							
Item 4: Design and Supply of Civil Works for Keewatinohk Station	[redacted]							
Item 5: Design and Supply of Civil Works for Riel Station	[redacted]							
Item 6: Construction and Installation of Keewatinohk Station	[redacted]							
Item 7: Construction and Installation of Riel Station	[redacted]							
Item 8: Testing and Commissioning of Keewatinohk Station	[redacted]							
Item 9: Testing and Commissioning of Riel Station	[redacted]							
Item 10: Mandatory and Recommended Spares for Keewatinohk	[redacted]							
Item 11: Mandatory and Recommended Spares for Riel	[redacted]							
Item 14: Project Management Services & Performance Guarantee	[redacted]							
Item 15: Aboriginal Awareness Training and Ceremonies - Keewatinohk	[redacted]							
Item 16: Optional Spares, Special Tools and Maintenance Equipment for Keewatinohk (Purchaser's Option)	[redacted]							
Item 17: Optional Spares, Special Tools and Maintenance Equipment for Riel (Purchaser's Option)	[redacted]							
Item 18: On-the-Job Training Plan for Keewatinohk Site (Purchaser's Option)	[redacted]							
Item 19: On-the-Job Training Plan for Riel Site (Purchaser's Option)	[redacted]							
Item 20: Training of Personnel for the Operation & Maintenance of Bipole III HVDC Converter Stations (Purchaser's Option)	[redacted]							
Variations	[redacted]							
Variations: LOA 35 Completion Bonus	[redacted]							

1a, 7a, 8a

Contract No. 033102	Siemens (end August-2017)			Mortenson (end September-2017)			Total Paid to Date (September 2017)	Total Remaining to Date (September 2017)
	Payment to Date	Remaining	%Spent	Payment to Date	Remaining	%Spent		
Totals	$329,034,656.24	$69,253,644.12		$418,788,573.31	$51,471,625.86		$747,823,229.55	$120,725,269.98

Table 14 shows that as of end of September 2017, there is a commitment to pay the Siemens/Mortensen contract $120.7M (not including PST). Using an assumed overall PST of 4%[22], this comes to approximately $125.5M including PST. All approved variations are included in Table 14. Amplitude are not aware of any pending variations that are pending and have not already been approved.

Table 9 shows approximately [redacted] of budget remaining between WBS P15540 and P15541 (including PST). In terms of the networks in each of these WBSs that contain the Siemens/Mortensen contract (244644 and 244616 respectively), the remaining budgets for these networks add up to about [redacted]. This means that assuming no variations, and no other activity under 244644 and 244616 not 1a, 7a, 8a
already costed under the Siemens/Mortensen contract, at least [redacted] will need to come out of the other budgets and/or contingency (P23837). Table 9 shows there to be [redacted] remaining in the contingency.

The other significant contract element is the Voith contract for the Synchronous Condensers at Riel Converter Station. Table 13 shows that for the cost network associated with the synchronous condensers (244618), the actual expenditure to end September 2017 is approximately [redacted] compared to a budget of [redacted] (inclusive of PST), leaving a remaining budget for the network of 1a, 7a, 8a
approximately [redacted] This cost network includes the Voith contract, which makes up about [redacted] of the budget, with the remaining budget covering Manitoba Hydro staff and contractor works.
The reported status of the payment milestones for the Voith Contract is shown in Table 15.

Table 15 - Progress Payments Made for Voith Contract – Up to End September 2017

Contract No. 033852	Voith Hydro (September-2017)			STUART OLSON (September-2017)			Total Paid to Date (September 2017)	Total Remaining to Date (September 2017)
	Payment to Date	Remaining	%Spent	Payment to Date	Remaining	%Spent		
Item 1: Design of Synchronous Condensers & Associated Equipment	[redacted]							
Item 2: Design of Civil Works								
Item 3: Manufacture & Supply								
Item 4: Installation & Construction								
Item 5: Testing & Commissioning								
Item 6: Mandatory & Recommended Spares								
Item 7: Project Management Services								
Item 8: Optional Spares, Special Tools & Maintenance Equipment								
Item 9: Training of Purchaser's Personnel for O&M of Synchronous Condensers								

1a, 7a, 8a

[22] Amplitude has not calculated the elements of these contracts that are subject to PST. However, the percentage of PST to contract values provided by Manitoba Hydro in an email dated 17 November 2017 shows this proportion to vary between 2% and 4%, depending on the proportion of labour and materials. We have used 4% as a conservative estimate, for comparative purposes.

Contract No. 033852	Voith Hydro (September-2017)			STUART OLSON (September-2017)			Total Paid to Date (September 2017)	Total Remaining to Date (September 2017)
	Payment to Date	Remaining	%Spent	Payment to Date	Remaining	%Spent		
(Purchaser's option - not exercised yet)	[redacted]							
Variations	[redacted]							
Totals	$113,891,199.99	$21,443,921.75		$57,106,532.23	$27,776,037.43		$170,997,732.22	$49,219,959.18

1a, 7a, 8a

Table 15 shows that as of end of September 2017, there is a commitment to pay the Voith contract a further $49.2M (not including PST) or, using the same PST assumptions previously, approximately $51.17M including PST. All approved variations are included in Table 15. Amplitude are not aware of any pending variations that are pending and have not already been approved.

Table 13 shows approximately [redacted] of budget remaining for WBS P15541/ cost network 244618 (including PST). This means that assuming no variations, and no other activity under cost network 244618 not already costed under the Voith contract, at least [redacted] will need to come out of the other budgets and/or contingency (P23837). 1a, 7a, 8a

The analysis above covers cost network 244644 in WBS 15540 (Keewatinohk Converter Station) and cost networks 244616 and 244618 in WBS 15541 (Riel Converter Station). Combined, it is expected that at least [redacted] will need to come out of contingency just to cover off outstanding committed values to the contracts – assuming no further Manitoba Hydro costs are to be charged to these networks (which is unlikely) and no further variations are received (also unlikely). There is not enough information or time for Amplitude to attempt to analyse these costs to project completion. 1a, 7a, 8a

However collectively, these three WBS account for only [redacted] of the 2016 budget and [redacted] of actual expenditure to date. These costs are mostly Manitoba Hydro staff and contractor costs and associated smaller contracts. There is not enough information or time for Amplitude to attempt to analyse these costs to project completion. However, Table 16 and Table 17 provide some commentary on these activities for Keewatinohk and Riel respectively, including whether there is expected to be substantial activity going forward (from end of September 2017) based on the estimated remaining activities provided in Table 10. 1a, 7a, 8a

Table 16 - P15540 - Keewatinohk Converter Station - Status of Other Networks

Network No.	Description	Scope Inclusions[23]	Budget Remaining	Anticipated Future Activity
244643	KCS SITE DEVELOPMENT	• Civil site development, ancillary and auxiliary buildings, insulation stone, concrete supply and aggregate, asphalt pavement, re-vegetation, landscaping and signage. • Includes draining and improvement to existing site prior to construction, plus clearing and winter excavation, and placement of materials. • Mostly internal labour, supply and installation contracts and expenses.	[redacted]	• The bulk of this work should be complete, covering site preparation, civil and earthworks. • There will still potentially be some insulation stone, asphalt, re-vegetation and landscaping to be done. • No information available on the status of these works. • Assume the remaining budget will be spent.
244644	KCS HVDC CONVERTERS AND ASSOCIATED EQUIP	• Elements not directly associated with the Siemens/Mortensen contract includes line fault locators and special protection schemes, grounding studies, construction work oversight and support services. • Also includes HVDC expertise for early phases of the project.		• Assume line fault locators and SPS schemes installed. • Grounding studies should be complete. • Early phase of project sunk cost. • Some outstanding activity for oversight completion of Siemens/Mortensen Contract.

1a, 7a, 8a

[23] Taken from Manitoba Hydro document "Bipole III Project, basis of Estimate Document, September 2014 Cost Estimate Update", Revision 0, March 2015.

Network No.	Description	Scope Inclusions[23]	Budget Remaining	Anticipated Future Activity
			[redacted]	• With an anticipated site completion date of 20 July 2018, there remains another 9 months of construction oversight for this contract. • No information available on ongoing costs for construction oversight. • Assume a portion of the remaining budget will be spent on these activities.
244645	KCS INTERFACES/BOP	• Includes supplementary electrical and mechanical works, transition structures, 230kV and 12kV connections, DC line connections, ground grid, electrode connections and lightning protection.		• Some of these activities are likely complete – electrical and mechanical interfaces, ground grid, lightning protection and some of the high voltage connections. • There may be remaining activities for the 230KV, DC line and electrode connections although no information available on the status of these works. • Assume the remaining budget will be spent.
244646	KCS ELECTRODE SITE	• Covers the design, installation and construction of the electrode and the access road to electrode site. • Includes internal costs for detailed design, construction management and oversight, support services.		• This component is already overbudget. • There should be no further work on site improvement and preliminary engineering. • Manitoba Hydro advised that "The Keewatinohk Electrode work is complete and no additional costs are anticipated."[24] • The overrun was due to significant construction issues and challenges encountered, including excessively wet conditions, extra de-watering and excavation and added costs for blasting larger rocks and boulders[24]. • Based on advice from Manitoba Hydro, assume no further expenditure on this item.
244647	KCS OPS, MTCE & TEST EQUIPMENT	• Includes furniture for all site buildings, test equipment and motor vehicles, plus internal labour to procure these.		• No information provided on the progress of these items. • These items tend to be procured towards the end of the project, so it is reasonable to expect that much of this had not been procured as of the end of September 2017. • Assume the remaining budget will be spent.
244648	KCS COMMUNICATIONS FOR STATION	• Includes OPGW to Long Spruce and Henday, internal comms installed with the distribution networks plus communications equipment for between KCS and RCS and from the site to SCC and BUCC.		• No information provided on the progress of these items. • Some of these items tend to be procured in the leadup to commissioning. • Assume the remaining budget will be spent.
244649	KCS CONSTRUCTION FACILITIES	• Includes procure of fire equipment, fire truck, modular and pre-engineered buildings, motor vehicles, forklifts, load, grader et. • Some site electrical panels and fuel tanks.		• Cost information shows the fire truck has been procured and significant expenditure of fire protection, vehicles and buildings already. • As these are all procured for the purpose of construction, and site construction is in its final stages (moving into commissioning), assume all expenditures are complete and no further activity.
244650	KCS SITE DECOMMISSIONING	• Includes salvage for main camp and construction facilities.		• The site has not yet been decommissioned (as of September 2017). • Keep in full anticipated salvage.
244651	KCS NERC/PHYSICAL SECURITY	• Includes physical security and NERC compliant cyber security, including all consulting and construction.		• Very little has been spent on this item as of September 2017. • Possibly this is an activity that will incur costs later in the project. • Assume the remaining budget will be spent.
244652	KCS SYSTEM STUDIES	• Includes system studies for both KCS and RCS, with the costs divided equally between both sites.		• These studies are usually performed before the project commences. • Assume no more activity on this item.
244653	KCS ELECTRIC POWER FOR CONSTRUCTION	• Includes site electrical distribution and the cost of taxes for consumption of electrical power.		• While the construction and installation components would have been completed prior to commencement of construction, there will be continued consumption of electrical power for the next 9 months+. • No information available on how much power consumption and the value of these taxes going forward. • Assume the remaining budget will be spent.
244654	KCS PROJECT MANAGEMENT	• Includes costs for Manitoba Hydro personnel to provide: - cost and scheduling services - project accounting services		• These activities would be expected to continue until the end of project works (July 2018). • No information available on forecast costs for these activities.

1a, 7a, 8a

[24] Email from Alastair Fogg of Manitoba Hydro on 14 November 2017.

Network No.	Description	Scope Inclusions[23]	Budget	Anticipated Future Activity
		- project and engineering management - health and safety management - project insurance - quality assurance (third party) - builder's risk insurance at KCS - wrap up liability, builder's risk, deductible expenses and policy extensions	[redacted]	• 75% has been spent. • Given the converter station contracts were signed in October 2014 (3 years ago) and there is approximately 9 months remaining after September 2017 (i.e. 20% of project duration remaining), it is reasonable to assume the remaining 25% will be spent.
244655	KCS CONSTRUCTION MANAGEMENT	• Includes both Manitoba Hydro and contracted personnel to undertake site management, construction management, contract administration, cost and scheduling services, site engineering and work package management.		• This item includes budgeted amounts close to $3.8M for commissioning activities. • Just over 60% of the site construction and safety management has been spent. • Converter station site construction commenced approximately 24 months ago with 9 months remaining, it is reasonable to expect that the remaining 40% will be spent (plus commissioning budget). • Assume the remaining budget will be spent.
244657	KCS TRANSPORTATION & TRAVEL	• Incudes travel and transportation costs for Manitoba Hydro personnel and contracted personnel. • Includes all costs directly to MH personnel (including contracted personnel) travelling to and from KCS		• Just over 55% has been spent to date. • Assume the remaining budget will be spent.
244658	KCS SERVICE & SUPPLY CONTRACTS	• Services required during KCS construction, including catering, janitorial, security, maintenance, emergency medical services, employee retention and support, Manitoba Advanced Education and Training Referral Services, satellite services, TV, internet and telephone, landfill and parking, sewage removal and portable toilets, propane gas, fuel and septic services and interim camp accommodations.		• With the exception of interim camp accommodations, these costs will be expected to continue to be incurred until the end of site activities. • Just over 65% of the original budget has been spent. • Converter station site construction commenced approximately 24 months ago with 9 months remaining, it is reasonable to expect that the remaining 35% will be spent. • Assume the remaining budget will be spent.
244660	KCS COMMUNICATIONS FOR CONSTRUCTION	• Includes communications in site trailers during construction - telephone, FAX and LAN and fibre optic messenger cables and internal labour, supply contracts.		• Those items associated with general infrastructure should be complete. • The remaining items are well under-budget – only 43% spent to date. • Assume the remaining budget will be spent. 1a, 7a, 8a
244662	KCS CONSTRUCTION OFFICE	• Include miscellaneous purchase orders to procure materials and equipment as needed. • Purchase cost of office equipment, office furniture, printers and supplies.		• It is expected that the majority of the more expensive items required for the construction office would have already been procured with only office supplies (non-material) outstanding. • Assume no further activity on this item.
244663	KCS CAMP FACILITIES	• Site improvement, engineering, construction of a high quality 600 person residence including kitchen, lounge and common room facilities. • Furnishings, finishings and equipment 3 x pre-engineered buildings for recreation centre, emergency response and maintenance building. • Supply and setup of all furnishings and equipment, including gym, appliances and furniture. • All camp and camp lagoon construction, - potable water treatment plant, fire suppression storage tank and domestic water systems.		• All of these activities should have been completed early in the project. • Assume no further activity on this item.
244664	KCS SURVEY, INSPECTION & TESTING	• Includes supplies and services required for quality assurance. • Set up of new concrete testing lab, aggregate testing, new mobile soils testing lab, survey equipment and seismic and vibration monitoring equipment. • Site inspection services, concrete inspection and water testing, engineering survey services.		• It is expected that the various labs and civil testing facilities have already been procured with very little ongoing need for concrete inspection, water testing and engineering survey services. • Assume no further activity on this item.
244674	KCS EXTERNAL INFRASTRUCTURE	• Includes upgrades to the existing stores and staging area, repairs to existing buildings, regrading 160,000m2 of fenced area and general site improvements. • 1.4km of ballast and rail and remediation of existing rail.		• Many of these activities are expected to have occurred early in the project. • Includes provincial road upgrades. • No information available as to the status of these activities. • Assume no further activity on this item.

Network No.	Description	Scope Inclusions[23]	Budget Remaining	Anticipated Future Activity
244676	KCS STORES	• Includes the cost of miscellaneous local purchases, the relocation of foldaway and existing "coverall" buildings and maintenance costs for yard and fabric storage buildings. • Yard fencing, wheeler storage trailer, shelving, tarps, slings, barriers and warehousing in Winnipeg.	[redacted]	• The vast majority of equipment now installed. • Expect that the cost of warehousing buildings and yards was incurred early in the project. • Assume no further activity on this item.
250135	KCS Environmental	• Includes the management and administration of Environmental Protection Program during construction. • The preparation of documents, correspondence, work permit preparation on crown land, familiarity with water rights act and related activities • Costs for consultants for monitoring work (vegetation, heritage, aquatic and mammals), including 2 years post-construction		• Budget included need for monitoring for 2 years post construction. • Assume the remaining budget will be spent.

1a, 7a, 8a

Table 17 - P15541 - Riel Converter Station - Status of Other Networks

Network No.	Description	Scope Inclusions[25]	Budget Remaining	Anticipated Future Activity
244615	RCS SITE INTEGRATION	• Civil site development, ancillary and auxiliary buildings, insulation stone, asphalt pavement, re-vegetation, landscaping and signage. • Includes underground infrastructure (drain extensions, fire water line, fire hydrants etc)	[redacted]	• The bulk of this work should be complete, covering site preparation, civil and underground works. • There will still potentially be some insulation stone, asphalt, re-vegetation and landscaping to be done. • No information available on the status of these works. • Assume the remaining budget will be spent.
244616	RCS HVDC CONVERTERS AND ASSOCIATED EQUIP	• Elements not directly associated with the Siemens/Mortensen contract includes line fault locators and special protection schemes, grounding studies, construction work oversight and support services • Also includes HVDC expertise for early phases of the project.		• Assume line fault locators and SPS schemes installed. • Grounding studies should be complete. • Early phase of project sunk cost. • Some outstanding activity for oversight completion of Siemens/Mortensen Contract. • With an anticipated site completion date of 20 July 2018, there remains another 9 months of construction oversight for this contract. • No information available on ongoing costs for construction oversight. • Assume a portion of the remaining budget will be spent on these activities.
244617	RCS INTERFACES/BOP	• Includes supplementary electrical and mechanical works, transition structures, 230kV and 12kV connections, DC line connections, ground grid, electrode connections and lightning protection.		• Some of these activities are likely complete – electrical and mechanical interfaces, ground grid, lightning protection and some of the high voltage connections. • There may be remaining activities for the 230KV, DC line and electrode connections although no information available on the status of these works. • Assume the remaining budget will be spent.
244618	RCS SYNCHRONOUS CONDENSERS	• Elements not directly associated with the Voith contract includes construction work oversight and support services. • Also includes expertise for earlier contract phases.		• Early phase of project sunk cost. • Some outstanding activity for oversight completion of Voith Contract. • With an anticipated site completion date of August 2018 (SC5), there remains another12 months of construction oversight for this contract. • No information available on ongoing costs for construction oversight. • Assume a portion of the remaining budget will be spent on these activities.
244619	RCS ELECTRODE SITE	• Covers the design, installation and construction of the electrode and the access road to electrode site. • Includes internal costs for detailed design, construction		• Based on advice from Manitoba Hydro, assume no further expenditure on this item.

1a, 7a, 8a

[25] Taken from Manitoba Hydro document "Bipole III Project, basis of Estimate Document, September 2014 Cost Estimate Update", Revision 0, March 2015.

Network No.	Description	Scope Inclusions[25]	Budget	Anticipated Future Activity
		management and oversight, support services.	[redacted]	
244620	RCS OPS, MTCE & TEST EQUIPMENT	• Includes furniture for all site buildings, test equipment and motor vehicles, plus internal labour to procure these.	[redacted]	• No information provided on the progress of these items. • These items tend to be procured towards the end of the project, so it is reasonable to expect that much of this had not been procured as of the end of September 2017. • Assume the remaining budget will be spent.
244621	RCS COMMUNICATIONS FOR STATION	• Includes communications equipment for between KCS and RCS and from the site to SCC and BUCC. • Also communications to Dorsey	[redacted]	• No information provided on the progress of these items. • Some of these items tend to be procured in the leadup to commissioning. • Assume the remaining budget will be spent.
244622	RCS CONSTRUCTION FACILITIES	• Includes procure of modular and pre-engineered buildings, motor vehicles, forklifts, loaders, etc. • Some site electrical panels, toilets, washcars and fuel tanks.	[redacted]	• Cost information shows the expenditure to date on vehicles and buildings are significantly below budget. • As these are all procured for the purpose of construction, and site construction is in its final stages (moving into commissioning), assume all expenditures are complete and no further activity.
244623	RCS SITE DECOMMISSIONING	• Includes salvage for main camp and construction facilities.	[redacted]	• The site has not yet been decommissioned (as of September 2017). • Keep in full anticipated salvage.
244624	RCS NERC/PHYSICAL SECURITY	• Includes physical security and NERC compliant cyber security, including all consulting and construction.	[redacted]	• Very little has been spent on this item as of September 2017. • Possibly this is an activity that will incur costs later in the project. • Assume the remaining budget will be spent.
244625	RCS SYSTEM STUDIES	• Includes system studies for both KCS and RCS, with the costs divided equally between both sites.	[redacted]	• These studies are usually performed before the project commences. • Assume no more activity on this item.
244626	RCS ELECTRICAL POWER FOR CONSTRUCTION	• Includes site electrical distribution and the cost of taxes for consumption of electrical power.	[redacted]	• While the construction and installation components would have been completed prior to commencement of construction, there will be continued consumption of electrical power for the next 9 months+. • No information available on how much power consumption and the value of these taxes going forward. • Assume the remaining budget will be spent. 1a, 7a, 8a
244627	RCS PROJECT MANAGEMENT	• Includes costs for Manitoba Hydro personnel to provide: - cost and scheduling services - project accounting services - project and engineering management - health and safety management - project insurance - quality assurance (third party)	[redacted]	• These activities would be expected to continue until the end of project works (July 2018). • No information available on forecast costs for these activities. • 60% has been spent. • Given the converter station contracts were signed in October 2014 (3 years ago) and there is approximately 9 months remaining after September 2017 (i.e. 20% of project duration remaining), it is reasonable to assume at least 25% will be spent. • Reduce remaining budget by 15% of original budget (approx. $2.8M).
244628	RCS CONSTRUCTION MANAGEMENT	• Includes both Manitoba Hydro and contracted personnel to undertake site management, construction management, contract administration, cost and scheduling services, site engineering and work package management.	[redacted]	• This item includes budgeted amounts close to $4.0M for commissioning activities. • Only 37.5% of the site construction, safety management and HVDC construction support has been spent. • Converter station site construction commenced approximately 24 months ago with 9 months remaining, it is reasonable to expect that another 25% will be spent (plus commissioning budget). • Reduce remaining budget by 37.5% of original budget for these three activities (approx. $7M).
244630	RCS TRANSPORTATION & TRAVEL	• Incudes travel and transportation costs for Manitoba Hydro personnel and contracted personnel. • Includes all costs directly to MH personnel (including contracted personnel) travelling to and from RCS.	[redacted]	• Just over 30% has been spent to date. • Assume the remaining budget will be spent.
244632	RCS COMMUNICATIONS FOR CONSTRUCTION*	• Includes communications in site trailers during construction - telephone, FAX and LAN and fibre optic messenger cables and internal labour, supply contracts.	[redacted]	• Those items associated with general infrastructure should be complete. • Assume the remaining budget will be spent.
244633	RCS CONSTRUCTION OFFICE	• Include miscellaneous purchase orders to procure materials and equipment as needed. • Purchase cost of office equipment, office furniture, printers and supplies.	[redacted]	• It is expected that the majority of the more expensive items required for the construction office would have already been procured with only office supplies (non-material) outstanding. • Assume only the remaining consumables budget ($0.264M).

Network No.	Description	Scope Inclusions[25]	Budget Remaining	Anticipated Future Activity
244634	RCS SURVEY, INSPECTION & TESTING	• Includes supplies and services required for quality assurance. • Set up of new concrete testing lab, seismic and vibration monitoring equipment. • Site inspection services, concrete inspection, engineering survey services.	[redacted]	• It is expected that the various labs and monitoring equipment have already been procured with very little ongoing need for concrete inspection and engineering survey services. • Assume no further activity on this item.
244635	RCS STORES	• Includes shelving for storages and warehousing in Winnipeg, along with maintenance costs for the stores building and internal labour for a storekeeper and utility worker. •	[redacted]	• The vast majority of equipment now installed. • Expect that the cost of warehousing buildings and yards was incurred early in the project. • Assume no further activity on this item.
244636	RCS SERVICE & SUPPLY CONTRACTS	• Services required during RCS construction, including site engineering, cost and schedule services, janitorial, security, maintenance, emergency medical, telephone services, landfill charges, sewage removal, maintenance of portable toilets and supply of fuel.	[redacted]	• Many of these costs will be expected to continue to be incurred until the end of site activities. • Only 28% of the original budget has been spent. • Converter station site construction commenced approximately 24 months ago with 9 months remaining. • It is reasonable to expect that no more than 30% of the original estimate will be spent to end of the work. • Assume only $1.92M to remain in the budget. 1a, 7a, 8a
244675	RCS EXTERNAL INFRASTRUCTURE	• Includes rail upgrades at the RCS site (2km) and turnout. • Also includes internal labour for procurement and legal services.	[redacted]	• These activities should have occurred early in the project. • Assume no further activity on this item.
250136	RCS Environmental	• Includes the management and administration of Environmental Protection Program during construction. • The preparation of documents, correspondence, work permit preparation on crown land, familiarity with water rights act and related activities. • Costs for consultants for monitoring work (vegetation, heritage, aquatic and mammals), including 2 years post-construction.	[redacted]	• Budget included need for monitoring for 2 years post construction. • Assume the remaining budget will be spent.

For Keewatinohk, the assumptions summarised in Table 16 mean that of the remaining budget of [redacted] for this WBS, at least another [redacted] will be expected to be incurred, plus what assumptions can be made for ongoing activities for cost network 244644. If we assume 10% of remaining budget for continued oversight of the HVDC converter installation works (i.e. [redacted]) – that means approximately [redacted] remaining plus the outstanding commitment on the Siemens Mortensen contract. 1a, 8a

For Riel, the assumptions summarised in Table 17 mean that of the remaining budget of [redacted] for this WBS, at least another $58.1M will be expected to be incurred, plus what assumptions can be made for ongoing activities for cost networks 244616 and 244618. If we assume 10% of remaining budget for oversight of the HVDC converter installation works and the synchronous condenser installations works (i.e. [redacted]) – that means approximately [redacted] remaining plus the outstanding commitment on the Siemens Mortensen and Voith contracts. 1a, 8a

Combining these two amounts ([redacted] including PST) with the amounts owing on the Siemens/Mortensen contract (estimated at approximately [redacted] including PST) and the Voith contract (estimated at approximately [redacted] including PST), this comes to approximately [redacted] (including PST), well below the combined remaining budget of [redacted], without having to dip into contingency (P23837). 1a, 8a

3.1.3 P15544 - Keewatinohk 230KV AC Switchyard

According to the costing information provided, this WBS has a number of networks covering preliminary engineering, foundations, buildings linear infrastructure, circuit breakers, station services, control and protection, communications and AC switchgear for the new 230kV switchyard located adjacent to the

Keewatinohk Converter Station. This includes an EPC contract for the substation works. The breakdown of actual versus 2016 budgeted expenditure is shown in Table 18.

Table 18 - WBS15544 - Budget vs Actual

Network No	Description	2016 Budget	Sept 2017 Actual	Budget Remaining
244671	KCS 230kV AC Switchyard	[redacted]		
244673	Spare network – 230kV Switchyard			
	Not assigned			
		164,235,230.53	160,823,007.09	3,412,223.44

1a, 7a, 8a

Table 18 shows that majority of the budget has been spent as of September 2017.

In cost network 244671, the largest single cost will be the SNC Lavalin contract, which has a reported current contract value of [redacted] (including PST), making up close to [redacted] of the budgeted amount. The estimated amount outstanding on this is estimated to be $30M (not including PST) or, using the same PST assumptions previously, approximately [redacted] including PST. Assuming no further Manitoba Hydro activity (which is unlikely), the deficit will be about [redacted] Including another [redacted] for Manitoba Hydro costs, this will require at least [redacted] from contingency. 1a, 8a

3.1.4 P21082 - Keewatinohk Converter Station Distribution

The 2014 Basis of Estimate does not provide any detail as to what is and is not included within this WBS.

From the detailed cost estimate data, the scope covered by this WBS covers a number of smaller activities associated with providing power distribution to the site, and includes:

- Relocation of Keewatinohk LC9 Line
- Power to the Keewatinohk Start Up Camp
- Power to the Security Gate House
- EMPA Distribution
- Converter Station Distribution
- Converter Station Batch Plant

The reported amount incurred to September 2017 is [redacted] With a 2016 budget of [redacted] there is [redacted] remaining in the budget. 1a

While no details are provided, these activities appear related to the initial provision of power and a number of site construction and up-front works. It is reasonable to expect that any further expenditure on this WBS, if any, would be non-material.

3.1.5 P14363 - Property for Riel Converter Station

Manitoba Hydro owns the land for the Riel Converter station[26]. The land was privately owned and purchased prior to construction. The Manitoba Report published in 2014 advised that the costs included in the estimate are the sunk costs of purchasing the land[26].

This WBS has only one Network (243351). The breakdown of actual versus 2016 budgeted expenditure is shown in Table 19.

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[26] Manitoba Hydro, "Bipole III Project, Basis of Estimate Document, September 2014 Cost Estimate Update", Revision 0, March 2015, Page 85.

Table 19 - WBS14363 - Budget vs Actual

Description	2016 Budget	Sept 2017 Actual	Budget Remaining
REQUIRED LAND PURCHASE* Total	[redacted]		
OPTIONAL LAND PURCHASES Total			
LAND - SALE OF SURPLUS ITEMS Total			
Not assigned Total			
-	18,030,907.33	17,842,418.11	188,489.22

1a, 7a

The majority of costs associated with this project has been related to the land purchase. Given the project site works are close to completion and advice that the Riel Converter Station land was purchased before 2014, it is reasonable to expect that any further expenditure on this WBS, if any, would be non-material.

3.1.6 P14364 - Riel Conv & 230KV AC Switchyard Site Dev

Amplitude has received no information on the major contract associated with this work.

According to the costing information provided, this WBS has a number of networks covering site development (including contract and protection management, provision of circuit breakers, grounding and technical studies, civil and electrical works and commissioning), an EPC contract for the work at Riel Converter Station, some old (assumed to be sunk) costs for the Bipole III 230kV expansion and some communication works. The breakdown of actual versus 2016 budgeted expenditure is shown in Table 20.

Table 20 - WBS14364 - Budget vs Actual

Network No	Description	2016 Budget	Sept 2017 Actual	Budget Remaining
243371	Riel Converter Site Development Total	[redacted]		
243400	Design/Construct for Riel Convert Total			
243443	Riel Station Eng. Procurement Contract Total			
244172	(OLD)Riel C.S. 230KV Expansion for BPIII Total			
246108	Riel Converter Site Dvlpmt-Const Pwr Total			
246242	Riel Communications Total			
4302550	Riel Station 230 kV Expansion Ph2 Total			
#	Not Assigned Total			
		132,721,211.72	131,855,257.75	865,953.97

1a, 7a, 8a

Table 20 shows that majority of the budget to be spent as of September 2017. As we have not received any updated schedules or contract reports for this work, Amplitude is unable to provide an opinion as to whether this budget is expected to be used or if this work will require anything from contingency.

3.1.7 P:23788 - Riel 230 KV Expansion for Bipole III

Amplitude has received no information on the major contract associated with this work.

The breakdown of actual versus 2016 budgeted expenditure is shown in Table 21.

Table 21 – WBS23788 - Budget vs Actual

Network No	Description	2016 Budget	Sept 2017 Actual	Budget Remaining
253035	Riel C.S. 230kV Expansion for BPIII	[redacted]		
253036	Riel HVDC Reduction for Riel Expansion			
#	Not Assigned Total			
		86,810,310.68	72,245,731.04	14,564,579.64

1a, 7a

Table 20 shows that majority of the budget to be spent as of September 2017. As we have not received any updated schedules or contract reports for this work, Amplitude is unable to provide an opinion as to whether this budget is expected to be used or if this work will require anything from contingency.

However, it is expected from observations of other parts of the project that the majority of this work should be complete, and therefore it is assumed that the remaining budget will be adequate to finalise any outstanding activity.

3.2 Conclusions & Recommendations

- In our view, the remaining budget for the Keewatinohk 230kV AC Switchyard (P15544) will not be enough to cover the outstanding contract amounts payable to SNC Lavalin and will require a draw from contingency of the order of at least [redacted] 1a, 7a, 8a
- For the remaining WBS numbers associated with the HVDC converter stations (i.e. P14363, P14364, P15533, P15540, P15541, P21082, and P23788), the information made available indicates that there should be satisfactory amounts remaining in the budgets for each WBS to complete the project without having to draw from contingency.
- The current contingency budget for the converter stations (P23837) is [redacted] Taking out the [redacted] from P15544 should leave approximately [redacted] remaining to cover the impact of any unexpected events or activities which cannot be ascertained from the information made available for this review. 1a, 7a, 8a
- No information has been provided on outstanding contracts associated with P14354 and P23788, covering the Riel 230kV AC switchyard site development and the Riel 230kV expansion. It has been assumed that given the current status of the site works, these activities are expected to be complete or close to completion and no further material costs are expected.

3.3 Source of Information & Reference materials

- Manitoba Hydro, “BPIII CS CPJ Comparison vC14 vs vC16 Actual spend to Sept 30, 2017.xlsx”.
- Manitoba Hydro, “Bipole III Project, Basis of Estimate Document, September 2014 Cost Estimate Update, Revision 0,” March 2015.
- K. Savage, “Email,” 18 Nov. 2017.
- A. Fogg, “Email,” 14 Nov. 2017.

APPENDIX C

Scheduling Best Practices

MGF
PROJECT SERVICES

Scheduling Best Practices

Manitoba Hydro has developed procedures for the Keeyask and Converter Station projects which generally follow recommended best practices by the Project Management Institute and/or AACE International; however, there does not appear to be any mechanism for enforcement of these procedures.

Due to the size, complexity and dollar value of these projects, a Project Management Office (PMO) would provide governance to Manitoba Hydro's major projects. The role of the PMO could include defining and updating existing standards and processes, developing and delivering project management training, mentoring, and conducting periodic audits on projects to identify non-conformance to documented schedule, cost, and risk procedures. The establishment of a PMO should reduce bureaucracy and duplication of effort across the projects while ensuring consistency and transparency.

Areas Requiring Improvement

- Basis of Schedule: There is no Basis of Schedule for the Keeyask Integrated Master schedule (IMS), the MMTP, nor the GNTL schedules. There is a Basis of Schedule for the Bipole III Converter Station. The General Civil Contractor for Keeyask, BBE, appears to be the only major contractor who submitted a Basis of Schedule. The Amending Agreement #7 (AA7) Basis of Schedule submitted by BBE was rejected by Manitoba Hydro. The Basis of Schedule should be a live document with updates as the schedule changes.
- Schedule Development: Bid packages should clearly identify schedule expectations and schedules not meeting these expectations should be rejected. Manitoba Hydro scheduling procedures should outline acceptable logic types within a schedule (e.g., Finish to Start (FS) versus Start to Start (SS), Finish to Finish (FF), or Start to Finsh (SF), maximum duration for any activity, maximum amount of lag, number and type of constraints allowed, removal of negative float, and how to handle planning packages (latest timing on decomposing the activities). How change orders are reflected in the schedule should also be considered. For example, if an activity has already started, how is additional scope handled in the schedule?
- Schedule Quality:
  - Missing logic: only the start activity should not have a predecessor and only the finish activity should not have a successor.
  - High duration: if they are planning packages, they should be identified as such in the schedule. These planning packages should be broken down into more detail before the work commences.
  - Use of relations other than Finish to Start (FS). Activities using other types of relations should be reviewed and changed where possible.
  - Hard constraints should be removed. If a constraint is required, change the constraint to a soft constraint which does not violate critical path method logic this should also resolve much of the negative float.
  - Lags: Consider replacing lag with activities to add visibility to the schedule.
- Schedules should be fully resource loaded.

- The Work Breakdown Structure developed for the project should be the same Work Breakdown Structure used in the schedule.
- Ensure activity names use a verb/noun construct (e.g., Pour Concrete) and that each activity name clearly identifies the work being performed and is unique so when the schedule is grouped or filtered differently, the activity name will still make sense. Avoid the use of acronyms and abbreviations.
- Pick one system to track costs, quality and progress. For example, Ecosys is system which integrates a variety of tools such as P6, SAP, and estimating systems to facilitate the creation of a "single version of the truth".

Tab 127

Section:	Tab 4, App. 4.1	Page No.:	CEF 14, p.3
Topic:	Capital Expenditures		
Subtopic:	Bipole III Project Cost		
Issue:	Current Cost Projections and Cost Risk		

PREAMBLE TO IR (IF ANY):

During the NFAT hearing, Bipole III project cost was $3.24B, but in 2014 Manitoba Hydro revised the estimate to $4.65B.

QUESTION:

Please detail the reasons for the cost increases to Bipole III. In particular, please detail the reasons for the cost increases to the converter stations and the decision to add synchronous condensers.

RATIONALE FOR QUESTION:

This Information Request seeks to explore the risk of Bipole III cost increases, which would impact Manitoba Hydro's revenue requirement and domestic rates.

RESPONSE:

The table below provides a comparison of the capital cost of Bipole III from CEF12 to CEF14. Material variances are explained below.

MANITOBA HYDRO
BIPOLE III PROJECT COMPARISON

(in millions of $)

Project	CEF 12	CEF 14	Inc/(Dec)
Transmission Lines	$ 1,259.9	$ 1,655.4	$ 395.5
Converter Stations	1,828.5	2,675.1	846.6
Collector Lines	191.4	260.2	68.8
Community Development Initiative	-	62.0	62.0
Total	**$ 3,279.8**	**$ 4,652.7**	**$ 1,372.9**

The increase to the project cost of Bipole III versus the previous approved amount has been driven by several factors as discussed below:

1. **The finalization of the HVDC Converters contract and resulting need for Synchronous Condensers:**

   The largest contributing factor to the increase in the Bipole III Control Budget was the final fixed pricing received for the HVDC Converters Equipment and the direct current converter technology selected. Vendors were given the freedom to offer Line Commuted Conversion (LCC) technology or Voltage Source Converter (VSC) technology based upon their own technical and risk assessment of the work. All bids received by Manitoba Hydro recommended the reliable and proven LCC technology. The LCC technology requires the use of synchronous condensers. As a result, converters and related equipment costs came in higher than the estimate which had assumed the use of VSC technology.

2. **The finalization of the Transmission Line route and subsequent route adjustments based on the CEC recommendations:**

   The items related to the Transmission Line route were preliminary and not yet finalized in the previous budget. The 2014 Bipole III Control Budget incorporates all costs associated with the finalization of the Transmission Line route and incorporates all project Licence requirements as recommended by the Clean Environment Commission.

   The finalized Transmission Line route has been adjusted to minimize environmental and agricultural impacts of the transmission line. This includes adjustments to help protect caribou and their habitats, protect and reduce effects on mineral resources and mining interests, minimize effects on agriculture, and minimize effects on landowners. The impact of these adjustments increases the length, turns and bends in the line and constrains tower placements requiring additional stronger and heavier structures. This includes 31 route adjustments and approximately 200 additional towers.

3. Increase in the capacity of the converter equipment to 2300 MW:

Bipole III converter equipment rating was increased to 2300 MW (from 2000 MW) to ensure sufficient capacity for future generation development and flexibility to take advantage of emerging export opportunities. The increased cost for capacity is marginal in comparison to the costs that would be incurred to add this additional transmission capacity at a later date.

4. Incorporation of Awarded Contract Amounts:

In addition to the inclusion of the awarded, fixed price contract amount for the HVDC Converter Equipment, the awarded contract prices for the Keewatinohk Camp, Keewatinohk Site Development and the Keewatinohk 230kV AC Switchyard have been incorporated into the revised Control Budget.

5. Revised In-Service Date:

The previous Bipole III budget assumed an October 2017 in-service date (ISD) for the project. Delays in obtaining the Licence and subsequent delays in obtaining environmental and work permits resulted in Manitoba Hydro having construction delayed by a year and a half. As a result of the delays, the ISD was updated to July 2018 which impacts interest and escalation costs.

6. Increased Project Contingency and Reserves:

A complete risk and contingency review was conducted as part of establishing the revised Control Budget. The same risk identification and contingency development process applied on the Keeyask project (as presented during the NFAT process) was applied to the Bipole III Project. A revised P50 contingency and Management Reserve fund were developed.

7. Funds Associated with the Community Development Initiative (CDI):

Funds associated with the Community Development Initiative (CDI) have been included within the revised $4.65B Bipole III Control Budget.

Tab 128

Bipole III - Converter Stations

Description:
Design and build an HVdc converter station with a rating of 2300MW at the proposed Keewatinohk site, including property acquisition costs and the Keewatinohk 230kV AC switch yard. Design and build an HVdc converter station with 2300MW of converters at Riel, including four LCC HVdc synchronous condensers, property acquisition costs and expansion of the Riel 230kV AC switch yard.

Justification:
Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole I and II) corridor outage or a Dorsey station common mode outage. The rating for Bipole III was increased from 2000MW to 2300MW to ensure adequate spare HVdc transmission on the northern collector system. The increased rating ensures future generation can be transmitted via Bipole I, Bipole II and Bipole III in the event of a single valve group outage.

In-Service Date:
July 2018

Revision:
The increase in the estimate is due to the inclusion of additional provincial road upgrades and an increase in contingency levels to a higher (P75) confidence level to better address project risks. The 2014 estimate was based on a P50 confidence level.

	Total	2017	2018	2019	2020	2021	2022-27
Previously Approved	$ 2 675.1	$ 943.4	$ 372.9	$ 180.3	$ 12.2	$ 1.8	$ -
Increase (Decrease)	105.6	(121.9)	306.1	106.0	(4.2)	(1.3)	-
Revised Forecast	$ 2 780.7	$ 821.5	$ 679.0	$ 286.3	$ 8.0	$ 0.6	$ -

Tab 129

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

2017/18 and 2018/19

GENERAL RATE APPLICATION

PUBLIC HEARING

Before Board Panel:

Robert Gabor	- Board Chairperson
Marilyn Kapitany	- Vice-Chairperson
Larry Ring, QC	- Board Member
Shawn McCutcheon	- Board Member
Sharon McKay	- Board Member
Hugh Grant	- Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

January 30th, 2018

Pages 7149 to 7460

APPEARANCES

Bob Peters		)Board Counsel
Dayna Steinfeld		)
Patti Ramage		)Manitoba Hydro
Odette Fernandes	(np)	)
Helga Van Iderstine		)
Doug Bedford	(np)	)
Marla Boyd	(np)	)
Matthew Ghikas	(np)	)
Brent Czarnecki	(np)	)
Byron Williams		)Consumers Coalition
Katrine Dilay	(np)	)
William Gange	(np)	)GAC
Peter Miller	(np)	)
David Cordingley	(np)	)
Antoine Hacault		)MIPUG
George Orle	(np)	)MKO
Senwung Luk	(np)	) Assembly of
Corey Shefman	(np)	) Manitoba Chiefs

LIST OF APPEARANCES (cont'd)

Kevin Williams (np)	) Business Council
Douglas Finkbeiner (np)	) of Manitoba
Daryl Ferguson (np)	) City of Winnipeg
Christian Monnin	)General Service
	)Small, General
	)Service Medium
	)Customer Classes
William Haight	)Independent Expert
William Gardner	)Witnesses
Kimberley Gilson (np)	)

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LIST OF EXHIBITS

--- Upon commencing at 9:02 a.m.

THE CHAIRPERSON: Good morning, everyone. Good morning to the people on line. Mr. Peters, I understand that you're going to tell us what we're doing today.

MR. BOB PETERS: Yes, I too have that understanding now. Mr. Chair, we're pleased to welcome to the hearing the independent expert consultant witness panel, which is comprised of representatives of MGF, KCB and Amplitude recognizing that -- and Stanley.

I should indicate, as Mr. Simonsen has done, that on the conference call and the video link we have, I believe, Mr. Les Brand from Australia. We also have Mr. Potter and Mr. Phillips from Stanley. They're in the United States. And I should have mentioned that Mr. Les Brand is with Amplitude and is in Australia.

I'll leave it to My Friends opposite to introduce the witness panel that is present today. As -- after they are sworn and we can proceed. We expect the entire morning will be on the direct evidence. And then there will be questioning throughout the day today and tomorrow. Thank you, sir.

THE CHAIRPERSON: Thank you. Thank you. Mr. Simonsen, can you swear in the witnesses, please.

MR. KURT SIMONSEN: Mr. Chair, I'll swear the witnesses who are in the hearing room first then I'll swear the witnesses over the telephone, if that's acceptable?

THE CHAIRPERSON: Yes.

INDEPENDENT WITNESS PANEL - MFG, KCB and Amplitude

RYAN DEVEREUX, Sworn
CAMPBELL ADAMS, Sworn
KIERANN FLANAGAN, Sworn
VAL MUSFELT, Sworn
DAN CAMPBELL, Sworn
LESLIE BRAND, Affirmed (by video)
JIM POTTER, Affirmed (by video)
DWAYNE PHILLIPS, Affirmed (by video)

THE CHAIRPERSON: Thank you very much. I'll just note for the record that this is the first time we've lived streamed such a large panel so we're hoping that it goes well and I thank Mr. Simonsen and Ms. Schubert because they've been testing this out for quite a while.

With that, Mr. Haight, if you'd like to start.

EXAMINATION-IN-CHIEF BY MR. WILLIAM HAIGHT:

MR. WILLIAM HAIGHT: Thank you. Good to remember that. As I said, I will begin with my immediate right and take the members of the MGF panel through their background and qualifications. Then I will move to Mr. Campbell from KCB at the back, and then I will move to the witnesses that are attending by way of video stream.

So to my immediate right is Ryan Devereux. Mr. Devereux, you are one (1) of the authors of MGF report, which is Exhibit 2(r); correct?

MR. RYAN DEVEREUX: That's correct.

MR. WILLIAM HAIGHT: And you are a professional quantity surveyor?

MR. RYAN DEVEREUX: That's correct.

MR. WILLIAM HAIGHT: And you have over fifteen (15) years experience with heavy industrial natural resource energy and utility infrastructure construction?

MR. RYAN DEVEREUX: That is correct.

MR. WILLIAM HAIGHT: And you have a

degree in construction --

THE CHAIRPERSON: Maybe I will just warn the witnesses. These microphones are -- need to be at a certain distance from you. The light needs to be on that indicates that it's on. If you're too far away the reporter won't pick it up and we'll have to -- have to interrupt to -- to tell you to move it closer. I have been told on numerous occasions to move it closer, so don't take it personally.

MR. KURT SIMONSEN: Mr. Chair, they'll also need to be very articulate and ensure that they're -- they are close to the microphones so our friends on the telephone can also hear them clearly.

MR. WILLIAM HAIGHT: Thank you, Mr. Chair and Mr. Simonsen.

Mr. Devereux, you hold a diploma in -- in construction engineering technology, which you received from the Northern Alberta Institute of Technology?

MR. RYAN DEVEREUX: That is correct.

MR. WILLIAM HAIGHT: And your experience in the construction section -- sectors has resulted in your providing advice to both contractors, as well as owners of projects?

MR. RYAN DEVEREUX: Correct.

MR. WILLIAM HAIGHT: And the range of skills that you have provided to contractors and owners over the last fifteen (15) years, sir, includes strategic asset management, estimating, variation analysis, contractual advice, contract management administration, contract negotiations and lifecycle costing, to name but a few?

MR. RYAN DEVEREUX: Yes.

MR. WILLIAM HAIGHT: I will then move to Mr. Devereux's immediate right and introduce Campbell Adams.

Mr. Adams, you are here on behalf of MGF Project Services, and you are one (1) of the authors of the report that is Exhibit MGF-2(r)?

MR. CAMPBELL ADAMS: That's correct.

MR. WILLIAM HAIGHT: And as I understand it, sir, you will be the principal spokesperson today for the MGF representatives?

MR. CAMPBELL ADAMS: Correct.

MR. WILLIAM HAIGHT: You are a chartered quantity surveyor and have been so for over thirty (30) years?

MR. CAMPBELL ADAMS: I've been a chartered quantity surveyor for probably thirty (30) of those thirty-three (33).

MR. WILLIAM HAIGHT: Okay. You hold a diploma in quantity surveying from University of Ulster in Northern Ireland?

MR. CAMPBELL ADAMS: Correct.

MR. WILLIAM HAIGHT: You also hold a Masters in Business Administration from the University of Bradford Management Centre in England?

MR. CAMPBELL ADAMS: Correct.

MR. WILLIAM HAIGHT: You are a member of the Chartered Institute of Arbitrators of England?

MR. CAMPBELL ADAMS: Yes.

MR. WILLIAM HAIGHT: And I understand that in the course of your evidence today, you will provide the panel and -- and all the other members here with some information as to what exactly a quantity surveyor is and does?

MR. CAMPBELL ADAMS: That will be revealed.

MR. WILLIAM HAIGHT: Yes, okay. And in your years as a quantity surveyor, you've been involved with the construction of major capital projects?

MR. CAMPBELL ADAMS: Yes.

MR. WILLIAM HAIGHT: And by the use of the word "major," I'm talking about projects in excess of a billion dollars?

MR. CAMPBELL ADAMS: From 1 billion to 27 billion.

MR. WILLIAM HAIGHT: Okay. And your involvement in these projects -- some of your involvement has been on behalf of owners and some has been on behalf of contractors?

MR. CAMPBELL ADAMS: That's correct.

MR. WILLIAM HAIGHT: So you've seen these projects from both sides of the owner/ contractor fence?

MR. CAMPBELL ADAMS: Yes, that's correct.

MR. WILLIAM HAIGHT: And your projects have ranged geographically from North America, Europe, the Middle East, Russia, West African and Southeast Asia?

MR. CAMPBELL ADAMS: Correct.

MR. WILLIAM HAIGHT: And as a quantity surveyor providing advice and services to contractors and owners, the -- the skills that you have brought include development of project contracting strategies and specific contract tactics, contract formation, estimating and tendering, replacement assessments and reporting, post award contract management, design, development and implication of contract management policies, procedures and processes, preparing and leading negotiations and dispute resolution to name but some?

MR. CAMPBELL ADAMS: Yes.

MR. WILLIAM HAIGHT: Thank you. Moving then next to Mr. Adams' immediate right and I'll introduce Mr. Kieran Flanagan.

Mr. Flanagan, you are one (1) of the founders of MGF Project Services.

MR. KIERAN FLANAGAN: Correct, yep.

MR. WILLIAM HAIGHT: And you hold the position of managing director?

MR. KIERAN FLANAGAN: Yes.

MR. WILLIAM HAIGHT: And you are one (1) of the authors of the MGF report?

MR. KIERAN FLANAGAN: Correct.

MR. WILLIAM HAIGHT: And you are also a quantity surveyor and have been so for over twenty-five (25) years.

MR. KIERAN FLANAGAN: Yes, and chartered for twenty (20).

MR. WILLIAM HAIGHT: And MGF is a quantity surveying and construction cost consultancy firm?

MR. KIERAN FLANAGAN: Correct.

MR. WILLIAM HAIGHT: So origins begin in Europe and Australia?

MR. KIERAN FLANAGAN: Yes.

MR. WILLIAM HAIGHT: It's now located in and operates out of Calgary, Alberta?

MR. KIERAN FLANAGAN: Correct.

MR. WILLIAM HAIGHT: And as I indicated, you are a quantity surveyor. You obtained your Bachelor of Science in quantity surveying from Harriet Wyatt University in Edinburgh, Scotland?

MR. KIERAN FLANAGAN: Yes.

MR. WILLIAM HAIGHT: You hold a professional diploma in quantity surveying from Limerick, Ireland?

MR. KIERAN FLANAGAN: Yes.

MR. WILLIAM HAIGHT: You have experience in commercial, residential, oil, gas resources, infrastructure and heavy industry sectors?

MR. KIERAN FLANAGAN: Correct.

MR. WILLIAM HAIGHT: And you, as well, sir, have -- as a quantity surveyor have provided advice and services to both owners and contractors?

MR. KIERAN FLANAGAN: Yes.

MR. WILLIAM HAIGHT: And those --

those skills include development management, estimating, replacement assessments, contractual advice, contract management and administration, asset management, to name just some of them?

MR. KIERAN FLANAGAN: Yes.

MR. WILLIAM HAIGHT: Moving to Mr. Flanagan's far right, I will introduce Valerie Musfelt.

Ms. Musfelt, you are also one (1) of the authors of the MGF report?

MS. VALERIE MUSFELT: That's correct.

MR. WILLIAM HAIGHT: And you are employed as the lead scheduler for MGF Project Services?

MS. VALERIE MUSFELT: Yes.

MR. WILLIAM HAIGHT: And you have a project leadership certificate and project management certificate from the Northern Alberta Institute of Technology?

MS. VALERIE MUSFELT: Yes.

MR. WILLIAM HAIGHT: You're also an instructor at that Institute as I understand?

MS. VALERIE MUSFELT: That is correct.

MR. WILLIAM HAIGHT: And a technical writer and a facilitator for that Institute?

MS. VALERIE MUSFELT: Yes.

MR. WILLIAM HAIGHT: You have over fifteen (15) years of experiences scheduling, facilitation and software specialists in the oil and gas, mining, infrastructure, environmental and general construction sectors?

MS. VALERIE MUSFELT: That's correct.

MR. WILLIAM HAIGHT: You assist both owners and contractors on projects with facilitating planning, construction scheduling, incorporating change management into schedules, and critical path analysis?

MS. VALERIE MUSFELT: That is correct.

MR. WILLIAM HAIGHT: And you are -- the skills that you bring to both owners and contractors include critical path analysis and reporting on schedule progress?

MS. VALERIE MUSFELT: Correct.

MR. WILLIAM HAIGHT: Moving then next to -- t behind me, Mr. Dan Campbell.

Mr. Campbell -- and by the way, all of these CVs for these individuals are on the record as MGF Exhibits 3-1 to 3-8. The record, I note from the Public Utilities' website does misstate some -- who works for who so to speak. Mr. Campbell who I'm just about to introduce is from Klohn Crippen Berger who you've heard a fair bit about in these proceedings.

For ease of reference, Mr. Campbell, I'll refer to them as KCB. You are one (1) of the principles of KCB, Mr. Campbell?

MR. DAN CAMPBELL: Yes.

MR. WILLIAM HAIGHT: And KCB provides engineering, geoscience and environmental services to an array of different clients throughout the world?

MR. DAN CAMPBELL: Yes.

MR. WILLIAM HAIGHT: Since 1951 KCB has participated in some of the largest and most challenging engineering projects in the world; is that a fair statement?

MR. DAN CAMPBELL: We like to think so.

MR. WILLIAM HAIGHT: Okay. You hold a Bachelor of Science in Mechanical Engineering from the University of British Columbia?

MR. DAN CAMPBELL: Correct.

MR. WILLIAM HAIGHT: You obtained that in 1979?

MR. DAN CAMPBELL: Yes.

MR. WILLIAM HAIGHT: And for the past thirty-six (36) years, you've been involved in a broad

range of major construction projects, including a
number of hydroelectric projects?
MR. DAN CAMPBELL: Yes.
MR. WILLIAM HAIGHT: These projects
have varied geographically from Canada to the United
States, Argentina, Columbia, Brazil, Peru, Vietnam,
Thailand, Sri Lanka and India?
MR. DAN CAMPBELL: Yes.
MR. WILLIAM HAIGHT: And your
experience that you brought to these projects include
project planning, design, construction supervision,
site inspection, asset evaluation, contract
negotiation and project management, to name just some
of them?
MR. DAN CAMPBELL: Yes.
MR. WILLIAM HAIGHT: KCB was asked by
MGF to provide assistance with its review of the Keey
-- the Keeyask project in the areas of project cost
estimate, project design, cost estimate changes and
contracting methodology, correct?
MR. DAN CAMPBELL: Yes.
MR. WILLIAM HAIGHT: And you prepared
a report that is dated December of 2017, which is
attached as appendix A to the MGF report?
MR. DAN CAMPBELL: I was one (1) of

the authors, yes.

MR. WILLIAM HAIGHT: Yes, and you've also prepared a PowerPoint summary. I'm not sure whether that PowerPoint presentation has been provided with an exhibit number yet today.

MR. KURT SIMONSEN: Yes, it has and it's MGF-6.

MR. WILLIAM HAIGHT: Thank you, Mr. Simonsen.

--- EXHIBIT NO. MGF-6: PowerPoint presentation by KCB

CONTINUED BY MR. WILLIAM HAIGHT:

MR. WILLIAM HAIGHT: Moving then to our participants that are attending by way of video. I'll begin with Mr. Les Brand please.

MR. KURT SIMONSEN: Just timeout for a minute as we get Les.

MR. WILLIAM HAIGHT: Yes. Mr. Brand, can you hear me?

MR. LESLIE BRAND: I can, thank you.

MR. WILLIAM HAIGHT: And thank you for attending today, sir. Nice to finally meet you somewhat face-to-face.

Mr. Brand, you are an author of a report that reviewed the capital expenditure review for Bipole III and the converter stations; is that correct, sir?

MR. LESLIE BRAND: That's correct.

MR. WILLIAM HAIGHT: And that report has been attached as appendix B to the MGF report.

You're aware of that?

MR. LESLIE BRAND: Yes, I am.

MR. WILLIAM HAIGHT: And you were the director and principal consultant for Amplitude Consultants which is based out of Australia?

MR. LESLIE BRAND: Correct.

MR. WILLIAM HAIGHT: You hold a degree in Electrical Engineering from the University of Western Australia, as well as a Bachelor of Commerce from that same university?

MR. LESLIE BRAND: That's correct.

MR. WILLIAM HAIGHT: For approximately twenty-five (25) years, sir, you have been providing engineering -- engineering services for electrical utilities and -- and companies that provide services to electrical utilities?

MR. LESLIE BRAND: That's correct.

MR. WILLIAM HAIGHT: You have

significant experience in this -- in these sectors in Australia, United States, Canada and China, to name just some of the countries?

MR. LESLIE BRAND: That's correct.

MR. WILLIAM HAIGHT: You have significant experience in -- in assessing HVD systems, as well as converter stations?

MR. LESLIE BRAND: Correct.

MR. WILLIAM HAIGHT: Your review of these systems include both design review, development of systems and technical specifications and replacement of converter stations?

MR. LESLIE BRAND: That's correct.

MR. WILLIAM HAIGHT: Would it be safe to say, sir, that your areas of expertise involve all of the nuts and bolts for transmission lines, as well as converter stations?

MR. LESLIE BRAND: Predominantly converter stations but I've had some involvement with transmission lines, that's correct.

MR. WILLIAM HAIGHT: Right. And the -- in the course of providing services to this industry, sir, I understand that you have provided advice to both contractors, as well as owners?

MR. LESLIE BRAND: That's correct.

MR. WILLIAM HAIGHT: Thank you, sir. If we can then move to Mr. Potter who is on the screen.

Mr. Potter, nice to meet you somewhat face-to-face. You are the transmission group manager and senior engineer with Stanley Consultants?

MR. JIM POTTER: Correct.

MR. WILLIAM HAIGHT: I understand that Stanley Consultants is one of the world's largest consulting engineering firms with a focus on energy, water transportation and environmental work?

MR. JIM POTTER: I like to think so, yes.

MR. WILLIAM HAIGHT: Okay. You hold degrees in both civil and structural engineering from Iowa State University and the University of Iowa, respectively?

MR. JIM POTTER: That's correct.

MR. WILLIAM HAIGHT: And Stanley was asked to provide advisory services to MGF regarding the transmission lines that will originate from the Keeyask generating station?

MR. JIM POTTER: That's correct.

MR. WILLIAM HAIGHT: And you have significant experience with design and construction of transmission lines, ranging from 69 kVA to 345 kV?

MR. JIM POTTER: Correct.

MR. WILLIAM HAIGHT: And you have provided design -- both design, as well as project management services for transmission line projects?

MR. JIM POTTER: Yes, I have.

MR. WILLIAM HAIGHT: And you've been doing so for over thirty (30) years?

MR. JIM POTTER: No, that should be twenty-one (21) years.

MR. WILLIAM HAIGHT: Excuse me, I have been known to misread a CV on occasion. Thank you very much, Jim. If we can then move to Mr. Phillips.

MR. DWAYNE PHILLIPS: Yes, good morning.

MR. WILLIAM HAIGHT: Good morning, sir. Nice again to meet you as well, almost face-to-face.

Sir, you are constructability lead with Stanley Consultants?

MR. DWAYNE PHILLIPS: I am.

MR. WILLIAM HAIGHT: And you have over thirty (30) years in construction and operational management in both generation, as well as the transmission of electricity projects?

MR. DWAYNE PHILLIPS: I do.

MR. WILLIAM HAIGHT: And you have a technical engineering training with -- in nuclear energy through the U.S. Navy?

MR. DWAYNE PHILLIPS: Yes, I do.

MR. WILLIAM HAIGHT: And you also hold a technical engineering degree through the U.S. Navy in electrical engineering?

MR. DWAYNE PHILLIPS: That's correct.

MR. WILLIAM HAIGHT: And in your role with Stanley, you've been responsible for project scope, technical design, coordination, construction and scheduling of both transmission, as well as generation projects?

MR. DWAYNE PHILLIPS: That's correct.

MR. WILLIAM HAIGHT: And prior to joining Stanley, you held managerial positions with several large utilities?

MR. DWAYNE PHILLIPS: That's correct.

MR. WILLIAM HAIGHT: And you have developed and published a number of training manuals and a number of dif -- on a number of different tropic -- topics relevant to generation transmission, including project management -- and including project management and analysis?

MR. DWAYNE PHILLIPS: That's correct.

MR. WILLIAM HAIGHT: And like Mr. Potter you provided anal -- analysis to MGF regarding the transmission lines which originate or are to originate from the Keeyask generating station?

MR. DWAYNE PHILLIPS: Yes, I did.

MR. WILLIAM HAIGHT: Thank you, sir.

MR. DWAYNE PHILLIPS: Thank you.

MR. WILLIAM HAIGHT: With that background, I will now turn it, with your permission, Mr. Chair over to Mr. Adams who will begin the presentation on behalf of MGF.

THE CHAIRPERSON: Thank you, Mr. Haight, please proceed.

MR. KURT SIMONSEN: Mr. Haight, before we do that, I'd just like to put on the record that the Amplitude presentation will be MGF-5 and the MGF presentation is MGF-4.

And I would ask all parties during the course of their presentation that they introduce the slide number so our friends on the telephone can follow along exactly where we are in the presentation.

MR. WILLIAM HAIGHT: Thank you, Mr. Simonsen.

--- EXHIBIT NO. MGF-4: MGF presentation.

--- EXHIBIT NO. MGF-5: Amplitude presentation

CONTINUED BY MR. HAIGHT:
PRESENTATION BY MFG

MR. CAMPBELL ADAMS: Good morning, everyone. Could we please move to the slide entitled Contents, please. And this is slide number 3.

This is the overview of what we will be presenting this morning to everyone. I'll tell you a little bit about the company; decipher what a quantity surveyor is because they're not common in Canada. And then we'll go through the -- the main sections of our -- our report; most likely, focusing more on the -- the Keeyask hydroelectric dam and to a lesser extent the other -- the other components of the -- of the report.

MGF Project Services is a quantity surveying construction cost consultancy firm. Oh, next slide, sorry, is number 4. Its origins are in Europe and Australia where quantity surveying is more common. There -- they work in multiple industrial sectors, offering services starting from when the owner has the idea of a project; helping the owner put their first cost proposal together for that; looking at contracting strategies; how to build it; which contractors tendering; giving award recommendations to the owners; and then helping to manage that -- or those contracts through to successful completion.

The team who -- who worked in this assignment has a broad geographic experience set on major capital projects working across many jurisdictions, as you can see there, from North America, Australia, Europe and certain parts of -- of Africa.

If we move to slide 5. If you go back over the last three (3) centuries the year '59 has had some amazing events. In 1959 Arthur Guinness invented a wonderful nutritional drink called Guinness. In 1959, yours truly made his debut. However, in 1859, we have the first recorded role of someone called a quantity surveyor.

And a quantity surveyor, our -- our training is -- it's all about the construction process from the start of it to the end of it. We're -- we not only cover contrite law, the law of tort, we do building economics. We cover construction technologies or disciplines like structural engineering, electrical engineering, civil engineering and we are the -- the centre point of bringing all that information together to put it into a contract -- a tendering and contracting process so these major capital projects get built.

The services we offer start from strategy, or cost estimating, a strategy, preparing tender documents, evaluating the bids that come back, and risk those, and give an evaluation to award. And then we move into what's called the post-award contact management fee is where we're -- we get the contract in place. We manage the contract. We look at -- we -- we try to ensure that the obligations of both parties are actually performed. We value the work as it goes along so the contractor company paid the proper amount, and the owner doesn't overpay.

Like most contracts, they don't always run smoothly. We -- we try our best to -- to mitigate, avoid, minimize. Sometimes that works. Sometimes it doesn't. You get involved in dispute resolution that be a negotiation. It can be a mediation. It can be escalated to arbitration, or even worse, we end up in court. So the QS, for short, is a very broadly experienced individual relative to the major capital projects arena.

Slide 6, please. Now, there's a

wonderful picture of the dam. Slide 7, if I can see okay. This slide gives a summary of the -- of Manitoba Hydro's revised budget. It started about six point five (6.5). There was some additional scope added. There was some scope removed. That was a, what, $2.23 billion net increase. And I think the -- the point this slide makes is that a significant portion of that increase is due to the outcome of the amending agreement number 7 negotiated between Hydro and its contractor BBE.

The reason for the -- the greater contract value or target price is additional man hours to perform the contract and extending the cost based on higher productivity rates.

Number 8, please. The next two (2) -- the next two (2) slides will provide the cost categories of how the increases were built up, and also the cost reductions. There are no numbers there, because that is commercially sensitive, and it's not within our permission to share this in this -- this forum.

Slide 9, please. Again, this is the -- the cost reduction slide -- slide. Down on the left-hand side, you can see the -- the categories of cost that built up to reduce the -- the overall new project budget of eight point seven (8.7).

Number 10, please. Cost reimbursable. Cost reimbursable is not a bad pricing mechanism, despite some of the conversations we have had. If it is used appropriately and well-managed, it can be the right choice for an owner in which to place a contract.

Cost reimbursable with an underperforming contractor who continually lets down its owner is a world of pain. The mechanism, in essence, means that whatever costs the contractor incurs in performing the work, it gets paid that cost by the owner. That means that the items there like labour costs, material costs, escalation, productivity, those risks all fall onto the owner who agrees to a cost reimbursable pricing mechanism.

In other pricing mechanisms, some of those risks are placed on the contractor. Productivity is a classic one. Whether you're building a hydroelectric project, or you're building an oil battery, contractors learn -- they know how to manage productivity. It's what they do. Owners typically don't know how to do that, because it's not their skill set. It's not their game.

At this point, I'd like to pass the --

the microphone to my colleague Mme. Val, who's going to take us through the next number of slides.

MS. VAL MUSFELT: Thank you, Campbell. Next slide, please. Okay. On the -- this slide here, BBE forecast completion dates, what we're really trying to show is the -- the different dates that are on the different schedules.

So first off, we have the 8th of October, 2021, and this is the planned completion date. So this is the date as per amending agreement number 7. And this is for the Unit 7 generator. If you look at the most recent forecast schedule, and that would have been dated the 6th of October, 2017, they're forecasting a completion date on that same unit for the 23rd of January, 2022.

Now, Manitoba Hydro has a -- a control date for when they -- the unit should be ready, and that control date is the baseline date of October of 2021, plus approximately ten (10) months of contingency. So that date is the 4th of August, 2022. Now, when we went in and took a look at the productivity of BBE, we applied that productivity onto all the concreting activities and determined that based on that level of productivity, the completion date for the Unit 7 would be the 25th of November,

2022. So that represents an order of magnitude delay of four hundred and ten (410) days from the baseline date of 8th of October, 2021 to our forecast date of the 25th of November, 2022.

Next slide, please. The next slide is -- really, what we're trying to show is this -- the schedule history of the different dates. So in this slide, if we start from the top bar and work our way down, the first bar shows the date of 19th of August, 2020, and that would have been on the original baseline schedule. So that was when Unit 7 was to be -- that was the in-service date for Unit 7.

The next date directly below that, the blue bar showing 7th of October, as discussed in the previous slide, that is the baseline date as of the amending agreement number 7.

Now, what we're showing in the third bar, the purple bar, this is a new bar that -- or a new date that wasn't in the previous slide. And this represents the Manitoba Hydro integrated master schedule. So in the -- in schedules, typically you would have a baseline schedule, and you would have a forecast schedule. The baseline schedule represents the planned dates, so as per the contract, whereas the forecast is based on progress. So this particular schedule would show the progress as at the 6th of October, 2017. So on this schedule, Manitoba Hydro is showing that the completion date for that same Unit 7 is the 28th of May, 2022.

Now, as you can see, this date is still prior to the control date of the 4th August that Manitoba Hydro -- Hydro has. And again, that was the baseline date, plus approximately ten (10) months of contingency. And then just to show that with our forecast, based on the level of productivity, the date would slip out to the 25th of November.

So what we're showing are two (2) main dates, here, the two hundred and twenty-nine (229) day delay represents the delay from BBE's date to Manitoba Hydro's date. So the BBE slippage date would have been approximately a hundred and three (103) days. But when you integrate it with other contractors on the schedule, what you're going to see is they may not be on the interface quite the same way. So that's pushing out Units 5 through 7 to the two hundred and twenty-nine (229) days. So that's -- this slide is really just trying to summarize all the different dates that we have going on on the project.

Can we see the next slide, please? So this slide really just recaps the dates that I just talked about on that graph. Can we move to the next slide, please. Now, the next thing that we're talking about here is a basis of schedule. And a basis of schedule is a document that describes what's going on on a schedule. Just like you would have a basis of estimate from a cost perspective, you usually have a basis of schedule for all of your -- like, your integrated master schedule. You would have it usually on some of your main contractor schedules.

What this document does is it really explains what's going on in the schedule. So it's going to show you this scope of work. It's going to tell you if there are specific constraints. It's going to talk about different calendars that may be in play. So it's such a very important document that describes what's going on in the schedule. It would also indicate whether things are being fast-tracked, whether there's winter work that's occurring. So all of this is typically in that document.

So we've noticed that BBE did have a basis of schedule prior to amending agreement number 7, but after amending agreement number 7, they did -- BBE did submit one, but unfortunately, it wasn't detailed enough, so it was rejected by Manitoba Hydro. And to -- at the point of the writing this document, there was no revised basis of schedule for BBE.

Next slide. Now, the next thing that we talk about is negative float. And negative float, by definition, really means that an activity is extremely critical. Now, when you're looking at it from a scheduling perspective, negative float basically means that you have activities that are slipping that can't happen on the scheduled date. Now, going through and analyzing the BBE schedule, I came across a thousand and thirty (1,030) activities that were with negative float.

So then the next thing is, Okay, why -- what's causing the negative float? So I went in and took a look, and there were approximately fifteen (15) activities that had constraints that were causing all of this negative float. And when you looked at these activities that were impacted by this negative float, ninety some of them -- ninety-seven (97) of them were on the critical path. And what that's really saying is that anything on the critical path, any delay means that you will delay the end date of the project. So we're basically just saying that it's important that this negative float gets removed from the schedule so that you can get a true picture of where things are really at on the schedule.

Now at this point, we're moving on to the next slide. I will hand the microphone back to my colleague, Campbell.

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: Sorry. Okay. I'm on the air again. Just to build on what Val said, there, the -- that third bullet point about the ninety-seven (97) activities on the critical path, our view of the -- this project is that the concreting activities are the critical path for this project. Of that ninety-seven (97), eighty-five (85) are concreting activities. So that brings into question whether there is a coherent schedule to build the -- the project, and that is something we were recommending gets -- gets addressed as quickly as possible.

Next slide, please, number 16. There -- there has been some commercially-sensitive information in this that we've had to -- to remove. I think the -- the bottom line, and the message here is that this is a problem area, earthworks productivity. It hasn't gone well in 2016. When their plan was re-cast for 2017, it still hasn't gone particularly well, with the contractor taking more -- more time than planned to do the -- to do the work. This deteriorating productivity is going to cost more in terms of the direct costs of doing the work, the indirect costs associated with that, and will drive a longer -- a longer schedule.

There is a figure there of 88.4 million. That is not a precise cost. It's an order of magnitude. It's to give a sliver of perhaps this is -- perhaps it might end up -- could be higher, could be lower, could be lower if more control is brought to bear on this contractor to get them to perform better. The -- the message is that the -- the contractor's inefficiencies is causing Hydro to pay more.

Slide 17, please. Concrete placement has been another area of under performance by Hydro's contractor. Their promises to what they would deliver in 2016 were not met, were not kept. They revised their -- their schedule with new productivities as part of the amending agreement number 7, and those have not been met in 2017. And it really -- it -- it demonstrates to us the BBE is very optimistic with its productivity rates, and that they're not realistic within their capability to -- to deliver against.

We -- we have to say that we -- we can't change the past, but we can influence the future. The recommendation there is to -- is to work with BBE, find out what it is they can, what -- what are they capable of doing, of realistic productivities that they can achieve, agree that, re-cast the schedule, redo the forecast and completion cost, and give -- give Hydro a realistic plan to get these guys to work and see where we're -- where we're going.

The last bullet point there refers to the -- the sequencing of subsequent contractors. The contractor who follow in the -- the path of BBE have been told there's a time they're required to come and perform their works, and they plan for that, and they price for that. The more that those dates get delayed or pushed back raises the opportunity for them to rightly seek compensation in terms of extra money and more time to perform their contract. BBE is cost reimbursable, so most likely, I would suggest that the cost of those delay and disruption claims will fall on to Hydro to pay for.

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: This is slide 18.

Yes, some of the -- our information has been redacted for commerciality reasons. It is the -- it's -- it's the same comment. It's the contractor is inefficient. They're taking longer to do the work. And -- and the concreting activities that we believe they are moving to perform are more complex. They're more complicated than what they have had to do hitherto. That begs the question: Why would we think that their productivities will improve? We put an order of magnitude additional cost in there. Again, it's -- it's a best forecast at this point in time, could be a bit higher, could be lower, but directionally, this is where the cost for this activity is likely to head.

Next slide, please. This is number 19. We were asked to look at the -- the approaches of tender management and contract management. Both were very well written, comprehensive. Tendering was sufficient, lots of document to support the teams and what they -- what they had to do to guide them in their -- in their job. Same for contract management.

The -- the concern we have is the -- whilst the written documentation is there, that there's still this concern of BBE's noncompliance with their contractor. There's some obligations they have that they seem to repeatedly get away with, so they don't do it.

Our recommendation is that Hydro initiates periodic contract compliance reviews. We have seen these in other industries. They are -- they're -- they're very effective. Both parties to the contract get to be measured against what it is they should be doing. Are they doing it? If they're not doing it, why are they not? It can be done by an internal team. It can be done by an external team. But the -- the outcome of this is it -- it pro -- promotes assurance. It promotes compliance with the contract, and makes sure that both parties are doing what they -- they signed up to do.

The next slide is number 20. The message of this slide is the physical construction progress. We -- we're advised by the -- the construction monthly report, there, as stating 24 percent, whilst the actual spend in indirects is -- is over 30 percent. So that's telling us that we're spending more money on indirects than for the -- the con -- the actual construction progress we're -- we're getting. This is a -- another inefficiency finding, I would suggest. And again, if that 6.4 percent cost variance continues, then the indirects budget will have to be funded with further monies to get the -- to get to the end of the contract.

Slide 21. As part of our assignment, we -- we come up with the final cost range, a final potential forecast, a range within which we felt that all other things being equal, that the cost of Keeyask would fall somewhere within that billion dollar range. It's currently reported at eight point seven (8.7). We think there's a lot of pressure to going above that. The issues that drive that are the -- it's really the ongoing under performance of BBE, their productivities for concreting, earthworks, is pushing the schedule to the right. The costs are going up further, indirects are being consumed, and there is the potential delay and disruption to other contractors.

The last bullet point is trying to convey that this -- this range is not fixed and firm. There -- there may be actions that Hydro can take to bring more control to its contractor and try to mitigate the costs going -- going higher.

The next slide deals with construction management.

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: The -- the evidence we have found suggests to us the -- that BBE is struggling to plan, manage, and execute its work. 2016 for concreting earthworks didn't go well. 2017 didn't go well. So unless something changes, you can reasonably expect this to continue.

The impact of the cost reimbursable compensation mechanism means that all construction decisions, all inefficiencies of its contractor, ends up being paid by -- by the owner, in this case, Hydro. As I said, plan productivity is not being achieved. It's -- it's startling that the -- the contract that Hydro has stipulates that the schedule shall not have one (1) negative float activity, yet we find one thousand and thirty (1,030) that don't meet the planned schedule. They spend more in directs budgets than for less construction progress.

In our view, this -- this is endemic of inadequate supervision, inefficient supervision, and we -- we believe that this is one (1) of the levers that Hydro can pull to try and arrest and then help BBE improve its -- its performance.

Slide 23, please. So just in summary...

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: In summary, BBE is not performing as they promised Hydro. They've let them down in 2016. As we say in golf, they got a Mulligan and they got to renegotiate the amending agreement number 7. And they recast their productivity through schedule and the final cost. And they have not performed in 2017.

XXX billion was added to the GCC on account of their poor productivity and the additional indirect spend. They are being paid their actual costs rather than for quantities of work performed against fixed-price unit risk, which would drive them to be responsible for both time, cost, productivity. With this upward pressure, our view is that the current contingency is likely to be insufficient if this performance continues.

The final bullet point restates the -- the wide range of potential outcomes for this. So I think to -- to conclude, if we don't hear them, the alarm bells are ringing. We can't change the past, but there's four (4) years to run. And I believe there's an opportunity to try and get this contractor to perform better for its owner, Manitoba Hydro. That ends the Keeyask presentation. Just move straight on to the converter stations, Mr. Chairman?

THE CHAIRPERSON: Sorry, Mr. Adams. I've got one (1) question, if I could. When you're -- when you're citing the -- the nine-point-five (9.5) and ten-point-five (10.5), is nine-point-five (9.5), the P50 and ten-point-five (10.5) the P90? Or are we looking at a different standard of estimate?

MR. CAMPBELL ADAMS: You're looking at a different approach to estimate.

THE CHAIRPERSON: Okay.

MR. CAMPBELL ADAMS: In my experience, the -- we -- we prefer to build up estimates as construction and project professionals. We do that understanding activity, understanding cost, understanding risk, understanding time. The -- the use of Monte Carlo P50s, P75, P90s, I think is a good test of a well thought through plan. I -- I don't believe in rolling the dice when it comes to determining what the final cost would be? We -- we build this up from -- from a bottoms up perspective.

THE CHAIRPERSON: Okay. Thank you. Certainly. Ms. Kapitany...?

THE VICE-CHAIRPERSON: Mr. Adams, just looking at your slide 19. I see your comment at the bottom that the recommendation is for Hydro to initiate period cont -- periodic contract compliance reviews.

Given the structure of this contract as you know what, what levers does Hydro have to improve the performance of the contractor

MR. CAMPBELL ADAMS: They're paying them money. They've got a contractor who has let them down in 2016/2017. Our -- our view would be you've got to sit with your contractor and understand that if you planned a process to pour concrete a certain way, and that's your plan and it's not working, you've got to get down to the root cause of why is that not working. And it's -- in the -- in the past I've seen this just is constant vigilance when an owner has gone down the cost reimbursable path and it's not working. It's -- my father used to say, Hold their feet to the fire. It's that kind of scrutiny.

On a cost reimbursable price contract you cannot stand away from what's going on. It's your money they are spending. As opposed -- as opposed to a lump sum where -- well, let me see. You build me this and I pay you this. It's lump sum. The contractor has the responsibility for performing the work within the right time, to the right quality for that price. You stand off and you watch that. You don't tinker and tamper with the lump sum.

Cost reimbursable is better managed when you've got a -- oh, what's that saying? It's a -- a salt-and-pepper team. You've got the owner's team embedded, co-located with the contractor. What are they doing day-to-day? What's working well? What's not working well? How do we learn? ow do we correct? It's quite high level, but I -- I'm sure within that contract there are -- there are levers to be pulled that the negative float -- if you're not allowed to have negative float and it's stipulated in your contract, why the heck let it happen?

MR. WILLIAM HAIGHT: So for the purposes of the record, just to the written record, when Mr. Adams held up two (2) objects, one (1) was this, one (1) was that, one (1) was a pen. The other was -- was an eyeglass case. So two (2) different -- very different objects, for the purpose of the record.

BOARD MEMBER GRANT: Let me just follow-up on that in terms of the nature of the contract. So suppose it was a fixed-price contract, and you got into a situation of inadequate productivity. I'm -- I'm thinking of these holdup costs that the contractor often has a certain leverage.

And so I guess going back to Board Member Kapitany's question, would the world really be that much different? Does the -- are you held hostage to a certain extent by your contractor if the threat of walking away from the project? I guess I'm wondering -- there's -- I'm -- I'm sure there's lots of cost overruns in fixed-price contracts that you must've seen. And so...

MR. CAMPBELL ADAMS: If -- if I may, the -- the cost overrun on a fixed-price compensation strategy belongs to the contractor, not the owner.

BOARD MEMBER GRANT: No, I understand that. But if they -- they walk up to you halfway through building your house and say, You know, by the way, I've already -- I'm -- I'm going to lose money doing this. I'm going to walk away from it.

How easy -- you know, what sort of position does that put the homeowner in?

MR. CAMPBELL ADAMS: Well, I think you should enforce your contract. If the -- the contractor, if he walks away then you're going to sue him for damages. There is something about -- the -- the contracts typically say that the time and the price are sufficient for performing the work. We had that in the original contract from BBE.

The -- the -- that price, I'm not going to say it in case I get off side of someone, there's an undertaking in that contract that that price is sufficient to perform the work. The work hasn't changed. You get to the -- the Mulligan I spoke to and you get the amending agreement, and then it becomes that next target price. There's still an undertaking in the contract that their price is sufficient for doing the work. They are representing that. They have to stand over that.

BOARD MEMBER GRANT: But surely you've seen fixed-price contracts which have -- I'm going to use the homeowner as the example -- has simply agreed to absorb the higher cost.

MR. CAMPBELL ADAMS: Yes.

BOARD MEMBER GRANT: Have you observed that's --

MR. CAMPBELL ADAMS: Well, that -- that's the -- that's the contractor's risk. That's how they make -- they make more money. If it goes badly wrong, and it's not that that happens, that's -- there may be reasons for that, but it doesn't affect the position of the -- the owner. Otherwise, everybody will be -- all -- all owners will be held to ransom.

BOARD MEMBER GRANT: That was my point.

MR. CAMPBELL ADAMS: I've only seen -- I've only seen one (1) walk away.

BOARD MEMBER GRANT: Okay. Thank you.

THE CHAIRPERSON: Sorry, Mr. Adams, for your nine-point-five (9.5) to ten-point-five (10.5), what assumptions did you make about the south dam, considering they haven't done geotech on it yet?

MR. CAMPBELL ADAMS: Just a second.

THE CHAIRPERSON: Yeah.

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: We -- we took figures that were given to us as part of the assignment, and we put some contingency in against that. There's no way we know what that could be me. There's no way Hydro today would know what that would be, unless somebody's got a crystal ball, which I haven't found in my thirty-three (33) years.

THE CHAIRPERSON: Yes. Thank you.

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: Converter stations. So we're on slide 25. The team did a review of the -- as part of the assignment to look at how cost estimating was performed. They -- they found it was -- it was well done. The basis of estimate, which is a narrative that explains how the costs were derived, was well written, aligns with best practices.

The -- their approach was consistent with industry standards, and there was -- they made -- Hydro made great use of estimating templates to promote -- to promote consistency. As ever, when somebody looks at something, one (1) of the folks thought that a bit more detail would've been good, but overall it was a -- it was a good -- good review from our perspective.

Tendering and contracting. Okay. Let me -- let me give you some background as to what this means because it might just be our termin -- our -- our terms, given that we're the quantity surveyors. The -- the approach to market speaks to how you -- how you get your price. You can competitively tender to a number of firms that have got the right technical skills, commercial skills, financial backing to do the work. You can single source where you take one (1) of those companies that you could competitively tender to, and you can decide to negotiate directly with them.

You can also sole source. And sole source is when you've got to deal with one (1) company who only can provide that product or service. An example of that would be if you wanted the LNG skid technology, you could only deal with ConocoPhillips to get that. You cannot competitively tender that. So that is the -- that is the range of the opportunity when it comes to approach -- approach to market.

Contract types are the -- are the -- what I call the terms and conditions around whether you are buying construction, or a service, or you're asking somebody to design, procure, and build your project. The -- the risk allocations are different. The rules are different. The skills to perform them are different. And that's what I mean by contract types in this slide.

The pricing mechanism is one (1) of the key functions of the contract that allocates risk. At one (1) end of the continuum, if it's cost reimbursable, the risk -- the risks are largely held by the owner. At the other end of the continuum, if it's lump-sum, the risks are probably better allocated with the contractor, in particular, being responsible for time, cost, and schedule.

Our review of the -- the tender and contracting of the converter stations, we thought it was very well done. The con -- HVDC converter equipment was -- it was competitively tendered to, I think, three (3) world-renowned companies. It was a design, supply, construct, install, and commission contract, and the contractor was paid on achieving key lumps -- lump-sum milestones.

The camp operations was a -- was a single source contract. It was placed on a services -- service-based contract, and it was -- used a cost reimbursable pricing mechanism because the -- of the fluctuation and variability in what would be consumed. And they were compensated for managing that with a management fee. All -- all good choices in -- in our --in our view.

Slide 27, please. As I said in the previous slide, the -- the choice -- choices made by Hydro for the contract pricing mechanism were -- were excellent. They -- they are -- they -- they promote predictability in outcomes, which is something that we always want as owners in terms of final cost and schedule. At the time of the report there was around 320 million to be spent between then and August or the

31st of July, if I'm more precise, this year.

The 83 percent on lump-sum and 4 percent in unit rate, that's 87 percent on a fixed pricing mechanism and 13 percent was cost reimbursable. We thought cost control was -- was well exercised. There were some variations, but they had not had a significant cost impact in our -- in our opinion.

28, please. Oh, summary. We -- we came away with thinking this was a well-managed project. Estimating was well done, well-written pieces of estimate, which is not something we always find. We concur that the likelihood of a cost overrun was low, and effective use was made of the -- those fixed-price compensation mechanisms, the lump-sum, the unit price that placed those -- the risk of productivity cost and schedule on to the contractor market.

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: Moving to slide 30. We're now on Bipole III transmission line. The team was impressed with the -- how the final preconstruction estimate was compiled. We like using quantity since we're quantity surveyors, and they used applicable unit rates to come up with the values of those -- of the estimate. It's an approach that was consistent with our industry standard.

In working with Hydro's team, we find them a knowledgeable and very capable group of people. As ever, you ask somebody to look at something, they will find something to tell you can do better. And the -- the guys felt that a bit more transparency or backup would be good for the estimate. And if you're using a value in one (1) summary that it's the same value you use in another so they align. But all in all it found to be that it was fine.

31, please. As with the -- the converter stations, Hydro's contracting strategy, their approach to market, their use of lump-sum on unit rate and cost reimbursable pricing mechanisms was -- was highly appropriate. Examples there are transmission line clearing as a lump-sum, the stringing contract as a unit rate. And where, for example, they required inspection services, which you call out from time to time, that was done on a cost reimbursable basis which just makes a lot of sense.

32. During our review we came across the performance of Rokstad Power Corporation. They

seem to have struggled achieving their promised work plan. In November, many of their dates appeared to be slipping from the approved baseline dates. This is obviously a risk that Hydro became aware of. They stepped in. They -- they took immediate action. They -- they requested a recovery plan from RPC. I'm not sure that we saw that, but I know on the 9th of November, to try and de-escalate this risk are de-risk it, sorry, they removed scope -- a part of the scope of work from Rokstad, so they could focus on the other -- the other three (3) dominion areas, and they gave that scope to another contractor to perform.

Whilst we -- we believe that is -- that was the right course of action, you've still got a contractor who may still incur some progress issues between now and the end of the winter season. If that does come to pass, then there may be a further schedule impact of one (1) year if they don't finish their reduced scope of work.

Thank you. We're on slide 33 for the record. So the preconstruction control budget was 1.66 billion. It increased by around 300 million. Nothing untoward in that. The -- the key contributing factors that you can see there were just additional scope that was required and it was added to the -- to the to the project.

Slide 34, please. So in summary, the team found the -- the transmission line project well-managed, well-organized, great use of the compensation mechanisms to manage risk better, place that appropriately on the contractor market rather than keeping that in-house within Hydro.

We believe it's on schedule to complete on the 31st of July this year, although it's worth noting that some contractors did have some slippage on the critical path. And the -- probably the biggest risk to a successful conclusion to this is Rokstad Power Corporation. And just to repeat, Hydro is aware. They stepped in and they're taking action to -- to de-risk that to the extent that they can.

Moving on to the Manitoba-Minnesota Transmission Project. The cost estimate is 453 million. I hope that that's not commercially sensitive because it's on my screen. We found a lot of good practices when we reviewed this. The -- the level of project definition was excellent in terms of being able to take quantities off to get your cost estimate. Again, good -- good use of historic project unit rates and the use of existing project templates to promote consistency and accuracy in building --

building your estimate.

As ever, a little shortcoming. We -- we like to have a basis of estimate to read when we look at an estimate, so we understand -- we get a narrative to explain where did the costs come from, how were they compiled. And we don't believe from what we reviewed that one (1) was prepared for this. A small point.

So let me -- let me take you slowly through this because I'm not a scheduler, but I try to understand things and as best I can. If get into difficulty you'll be hearing from -- from Val again. In looking at schedules, the -- the use of a common template was -- was very well used. It did promote consistency across the schedules.

If you look at the third bullet point where it refers to "high logic density," and let me look at my notes. Logic density, the metric of logic density assesses the average number of logic links per activity. If the score is greater than four (4), then that would indicate an overly complex schedule that we would recommend gets reviewed to take out the complexity and make it -- place it better for success.

Missing logic, in the next bullet point, means that either the activity before that activity, the predecessor or the successor or both are missing. So it's sort of standing out its own. Where we identify that, then it means that we have not got a critical path with which to follow to complete the project on the due date.

High duration activities indicate that -- where you have activities that are greater than two (2) months, it points that there is insufficient detail to manage that activity. And they -- these need to be further reviewed, deconstructed, decomposed into more granular activity so you understand what has to happen to establish your critical path and get you to finish by the -- the due date. So within this there is some stuff that was really well done, but there's some homework, I believe, that can be done in the coming months just to -- to raise the schedule to a better place.

38, please. Inn looking at the -- the estimated cost for -- for the MMTP, our colleagues Stanley Consulting focused on a significant percentage of the estimated project cost. The -- the outcome of that analysis would suggest that the estimate that's being carried is lower at its highest level than other similar industry projects. When Stanley drilled down into the cost components, as ever you find some are higher than you thought and you find some that are lower than you thought.

I think the -- the message here is that we would recommend a review of that, just test the points that we have made to see whether they agree, or they need to amend them, or otherwise. And just re -- refine the -- that -- that estimated cost because in our view it was -- it was on the low slide.

Slide 39, please. So in summary, project's on schedule. The estimating methodology was -- was consistent with industry standard and what we would expect. In performing subsequent cost estimates we -- we believe that the process would be improved upon, if it's done pursuant to an estimate preparation plan of hat are we going to do to build this cost estimate. And as they build the cost estimate, just compile that basis of estimate to provide a narrative to explain to the reader how the costs were -- were derived, were compiled/

So moving to the Great Northern Transmission Line. The review concluded that the -- the estimate appeared on the high side. We can't talk too much about some of the pricing because it's commercially sensitive. We believe that further review is required to establish the reasonableness of the cost estimate. And again, as -- as before, having a basis of estimate to explain the -- the estimate would be -- would be very, very useful.

42, please. We reviewed the -- we reviewed the construction management agreement that sets out the obligations and rights of Hydro's 669 company with Minnesota Power. This was a -- this was a very well drafted, very well thought through, very well written agreement. It would operate well at the operational level. We felt that it protects Hydro's risks, business interests very well. It identifies the risks, provides mechanisms to deal with those.

And I -- and I think it's worth -- it's worth reporting that not only was the document, well -- well-written, but I've seen documents that are well written, but badly understood by those who have to manage them. But in -- in speaking with the folks at Hydro, they -- their key personnel had a common and shared understanding of the content of that agreement, which -- which is a great thing to report back on.

Slide 44. The schedules generally were assessed as -- as medium quality. Some areas that would improve would be breaking down activities into greater detail. We did find high duration activities that in future, for more adequate planning control purposes, need to be broken down.

THE CHAIRPERSON: Excuse me for a second. I think we may have skipped a page.

MR. CAMPBELL ADAMS: Oh, did we? Well, beg your pardon.

THE CHAIRPERSON: Yeah, I think we're at the forecast at completion page.

MR. CAMPBELL ADAMS: Oh, sorry.

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: Oh, okay. Apologies. So this has been redacted for some commercial sensitivities. However, the cost estimate in 2013 is the 677 million. No comment on the next one (1). We find, as ever, the cost estimate methodology was -- was consistent and well done. Solid project definition with -- which, again, to get quantities to evaluate unit risk to give you a better feel for what the cost is likely to be.

There was, in this case, a summary of cost assumption that -- that was provided that gave you an understanding of how the cost estimate was built up. However, the more formal basis of estimate was not. The conclusion from the team was that the --

the overall cost was high and the recommendation was for this to be -- to be revisited.

I think now we can go to 40 -- 44. The schedules were assessed as medium quality. As touched on earlier, we -- we find a number of activities that were -- which suffered from either high duration or missing logic, and -- and these -- these matters need to be addressed to give more -- what's the word -- more integrity to the schedule that's being presented and is to be followed.

So in conclusion, we found the project be well -- well-organized, well-managed. The construction management agreement, we were impressed with how it was drafted from an operational and a risk perspective. The estimate methodology was -- was consistent with what we would've expected. And the -- the last comment there is, it was considered high when benchmarked with other projects. And this is something that we would expect Hydro over time as it progresses this project to have a look at that again. I think that's me done.

THE CHAIRPERSON: Thank you. Mr. Haight, are you planning to proceed with Amplitude next?

MR. WILLIAM HAIGHT: No. Planning

just to proceed with Mr. Campbell from KCB next.

THE CHAIRPERSON: Okay. With Mr. Campbell. You know, I think it might be a good point to take the morning break. So we'll -- we'll break for fifteen (15) minutes now. Okay. Thank you.

--- Upon recessing at 10:22 a.m.

--- Upon resuming at 10:40 a.m.

THE CHAIRPERSON: Mr. Haight...?

MR. WILLIAM HAIGHT: Mr. Chair, we're ready to proceed with -- with Dan Campbell's presentation.

THE CHAIRPERSON: Thank you.

CONTINUED BY MR. WILLIAM HAIGHT:

PRESENTATION BY KCB

MR. DAN CAMPBELL: Thank you and good morning to all. I apologize for the lateness of our presentation being provided. There was some confusion with MGF and I happened to be in Mexico and it was warmer there than here, I must confess.

Okay. Can you hear me now? Okay. First, a brief history of KCB and we're a consulting engineering company. Some of our major clients include BC Hydro. We're working on Site C. I'm sure you've heard of that project. Ontario Power Generation, SaskPower. We work for contractors as well.

Our typical competitors are Hatch and SNC is two (2) examples. The flowchart on the -- on the cover here is just to give an idea of what I'm going to be covering in my presentation this morning. The -- our report was a team effort. I was not the only author. Garry Stevenson, one of our geotechnical engineers with over forty (40) years of experience was -- he did the -- the geotechnical portion and he did the northern -- he has northern climate experience as well.

Neil Heidstra, a structural engineer with thirty-five (35) plus years of experience was the lead on the -- on the structural piece and he was also recently the lead on the powerhouse design for Site C.

Unfortunately, the others could not be available today. For example, Garry is at -- at a review board meeting on Site C. So I guess I drew the short straw, please bear with me.

Next slide. The presentation is going to cover the project costs where -- specifically where -- where the overruns in terms of the contracts, the project design, the -- the -- where the specifications -- was the design generally reasonable and was -- fundamentally, did the contractor seem to be provided with enough information to be able to proceed with -- with his work.

A review of the extra work orders as -- as the information was provided by Manitoba Hydro. Did they have a significant impact in the project cost to date. We looked at the unit prices. We compared them with other costs -- other projects I should say. We also looked finally at the contracting methodology from the perspective of the contract format. Did it make sense to us, right? And we did not go to site, so we don't have any comments on what -- what happened there. And MGF has already commented in detail about the -- the schedule and so I'm not mentioning that today.

Thank you. Slide 3. We reviewed the cost overruns in the different contracts and the information that was provided by Manitoba Hydro to identify -- to identify the contracts that were important and of concern. Then we looked in more detail about the information on those contracts to see if we could identify anything that, again, was of concern to us.

Again, as I said, we looked at the extra work orders. We looked at the -- then we looked to the contract format. Specifically, the measurement and payment sections.

Next slide, please. In the -- in the contracting summary table that was provided by Manitoba Hydro, there were two hundred and forty-seven (247) contracts which as you see were 4.6 billion, and the increase was 1.9 billion to date or -- or that was shown in the information that we -- we saw.

We looked at that and we said, what are the -- where and what are the important contract increases. So we sorted all the information by contract value. Then we calculated the percentage increase for each contract to see if that was of interest and that was provided in -- in the report.

Then we sorted the percentage increase of each contract as a percentage of the total project cost to try and understand which contract changes were important to the overall project, right.

There's a bunch of information that's not shown here, obviously, for commercially sensitive reasons, but the list here lists the order of contracts, and for most important to least important. Everything that's not on that list is effectively insignificant.

And I think the only comment I can probably make about this is that the general civil contract is about ten (10) times more important than -- than the second contract in terms of cost increase. I don't think I can say any more than that.

Next slide, please. So, obviously, the general civil contract with BBE is the critical contract for the project, with a significant -- responsible for a significant portion of the project overrun, right. We tired and did a calculation or we did a calculation, and we said if they were on budget and schedule, how much would the project be over budget? And that's that number there, 628 million, right, or 23 percent.

But not all of that 23 percent is directly -- is -- is directly related to work that was -- that other contractors would've been able to claim. A lot of it is directly -- is directly related to delays in the civil contract. For example, Voith used the delay to date to significantly increase the value of their contract. Obviously, things like the camp were also major contract increases, both in percentage and dollar value because of the increase in the schedule and the higher manpower then maybe was originally planned. So the impact of the delay is not only on the civil contractor.

Next slide, please.

THE VICE-CHAIRPERSON: Could I just ask you one question before you leave that slide?

MR. DAN CAMPBELL: Sure.

THE VICE-CHAIRPERSON: You say if BBE was on budget and schedule the project would only be over budget by 23 percent.

Is 23 percent something that you would think is normally, acceptable? How would you place that?

MR. DAN CAMPBELL: That 23 percent includes the cost overruns -- or sorry, the additional costs claimed by the other contractors, like Voith and the camp and people like that. So the -- we didn't calculate -- because we have no really good way to do it, what the cost overrun would have been if those other delay costs had not been incorporated.

So that number should be less and less is better. Normally.

(BRIEF PAUSE)

MR. DAN CAMPBELL: Just find -- okay.

Then we sort of said, okay, where the design change is a major driver of the cost increases because we're looking at -- we're engineers, we're looking at this from an engineering perspective, trying to see if -- if the design is reasonable.

From our experience design changes typically appear as revisions to drawings and specifications, right. So we review the drawing and specification logs which were provided by Manitoba Hydro, right. We noticed that there -- to date or to July 2017, there were twelve (12) versions of the technical specifications between March and July -- March 2014 and July 2017. So we looked at those three (3) dates. We looked at them in 2014; we looked at them on version 3 in May 2015; and we looked at version 12 from July 2017, and then we reproduced a table, which is I think the next slide, please.

Slide eight. And this is just an extract of that table and what we did is we looked at those dates and we looked -- we coloured the revisions to see revision 1, for example -- or -- is -- is green, right. So that's a -- one (1) revision. And if it's more than -- two (2) or more revisions, it got coloured yellow. So we had a bit of a colour coding to try and see where the important revisions were because then our next move was to go back and look at those -- at those sections in more detail.

Okay, next slide, please. And that table -- and it's a multipage table and you just had an extract in this presentation. So there were many, many sections that were changed; at least twenty (20) sections were changed in the -- between those two (2) versions, right. All of the changes have some impact on the costs, always, right. Sometimes it goes up; sometimes it goes down. Most of the time it goes up, right.

What we saw is that a lot of mechanical and electrical changes were being made and some of them were technic -- technically astute. For example, the lighting was incor -- it was made to be much more environmentally sensitive with the use of LEDs and so that was upgraded and that was a reasonable change.

Now, those costs inside the civil contract, the mechanical/electrical changes that were -- that we noticed were generally small dollar values in the total value of the contract because the mechanical/electrical inside the civil contract is generally a small dollar value compared with the excavation and civil work and concrete work.

Very little changes were actually made

in the excavation, the fills and the concrete specifications. They were very consistent through all of the documents that we looked at in terms of the specifications. So, therefore, we couldn't -- we couldn't actually's blame the specifications, quote unquote, for the cost increase that we saw in the civil contract. So then we said, okay, maybe it's the quantities.

Next slide, please. Sorry geotechnical. This may address somebody else's question from earlier in the day. So then we said, okay, maybe it's the basis of the geotechnical information. Was the information insignificant or inadequate; was it -- were there a lot of changes as a result of -- of investigations that weren't there.

And I'm not a geotechnical engineer but this is what I get from my -- from my geotechnical engineer Garry is that the investigations appear to have been reasonably comprehensive, both for construction materials and for the structures. In other words, do they have the materials that are needed to build the project. The borrow areas and all that good stuff. And do they actually -- have they actually investigated where the structures are going to be so that they try -- are -- are minimizing the risk when the excavation is done of -- of surprise. I'll use that phrase.

Of course, as MGF noted in their presentation, you can always find things that can be done better. And we found a few things which causes a little bit of interest, one of which the regional bedrock geology drawings in the contract, which in the vicinity of the major structures do not actually show clearly and easily the locations of the drill holes and test pits, which is a -- means that the contractor has go and search for it and try and put those two (2) pieces of information together.

The information is there, as far as we can see, right. So it was more of a pres -- of a presentation issue and make it easy for the contractor, but there's obviously an opportunity for the information to be missed or misinterpreted if it's not presented that way.

There was a brittle deformation zone which crosses the axis of the principal structures beneath the central dam and the coffer dam, and that only had one (1) drill hole in it. Now the comment was that that was healed. In other words, it was -- I'll use -- I'll just leave it at that being -- not being a geotechnical engineer, but the issue being really it was not an issue. Although there was only one (1) hole, to investigate it.

And then there was a ductile deformation zone, a shearer fault, shown on the geology plan beneath the central dam which is mainly in the water, and that was not investigated and we understand why because it's in the water, and it's hard to get to, and it's dangerous. But we noticed that it did -- that deformation zone did continue on to the island near Gull Rapids, but there didn't seem to be particularly a lot of investigation of that. So there's -- those are three (3) issues which were -- were noted.

Next slide, please. As I mentioned, was there enough material for construction? Did you actually have all the rock that you needed. The material balance was reviewed. The engineer had a material balance plan which he showed which is one way of doing it, right, and he had identified that there was enough material to build the project, which is obviously good. He -- that plan showed that the rock excavations were being 100 percent utilized.

You might think there's a risk there, but we don't think so because there's certainly abundant additional rock available in nearby qua --

quarries so we don't see that as an issue.

Ditto with the impervious borrow material which goes in this -- in the core of the dams, right. We'd -- there were three (3) locations identified and the material volumes, they greatly exceeded what was needed. So we're saying to ourselves, okay, that looks good.

Next slide, please. Oh, sorry, back one, please. Okay. Forward again, please. Then the question of: Can you actually build the structures? We've seen some designs and -- in earth-filled structures which are actually not possible to construct. So that -- we thought that was worthy of investigation. Can you actually build what was -- what was shown on the drawings, right?

Yes, there's some areas which are going to be slow to construct, right and -- and compact, right, and there are some narrow zones, but we didn't see -- other than those little narrow zones, we didn't see any particular need for special placement techniques, or any fancy -- fancywork there. So we weren't -- we didn't see a problem there.

The designs, from our experience, and our design skills are appropriate for a northern climate. So we were happy with that. We did note that the placement of the zone 5 riprap bedding as shown in the upper parts of the dams will be challenging. The zone widths are narrow. This -- and -- but it's only two (2) vertical metres in height. So it's not a lot of volume in the grand scheme of the amount of materials that have to be placed on this project.

So from a geotechnical design perspective, in summary, as I say, there -- there are a few areas where more investigations might have helped but overall the geotechnical information is sufficient, and there's plenty of material available to build the project.

So from our perspective, we said, okay, the information the contractor had and what appears to be there from a geotechnical perspective and from a specifications perspective we're happy.

So next slide, please. What about the drawings? Were the drawing sufficient and in enough detail to be able to build the project, right. There's a drawing list which has twenty-three hundred (2300) drawings in it, IFC, associated for the general civil contract. We did not read every drawing. We didn't have time, right. We looked at them in some detail and we particularly looked at them -- Garry looked at them from the geotechnical perspective just because there's a lot of -- a lot of effort and money in the -- in the earthworks piece to see whether or not they looked reasonable from his perspective. And the answer is yes, right. And generally IFC drawings are clear and certainly define the majority of the permanent works. We didn't have a problem with the drawings, right.

The information that was presented on the drawings showed a design that was substantially complete, right, prior -- prior to award, to the actual contract, right. So we didn't see a lot of opportunity for the contractor to actually go back and say, well, that you've revised the drawings many times or you didn't tell me about something in particular that, I needed a dam here or something like that. You didn't tell me about it. So, we were looking -- we were looking at that to see if there was an issue there and the only real thing that we saw that the -- that the contractor had to do was figure out his construction methodology. What he had to do was defined.

So then we said, okay, what about the drawings. Were they revised lots of times? Did he -- can the contractor come back and claim that the drawings -- the drawings were -- were inadequate and designed and revised and there was multiple times and every time it cost us money. So we looked at the revision history.

Next slide, please. This is just a graph showing the IFC wri -- drawing revision log that shows the drawings that were issued -- issued for construction, revision 0, revision 1, revision 2, et cetera.

You can clearly see that the majority of the drawings were not revised after issued IFC. This is very good because this -- this tells the cont -- tells us that the contractor generally had the information that he needed to be able to design from. So, that's a positive thing. So far everything looks good.

Next slide, please. So then we said, maybe they were late. Maybe the drawings came late. So we looked at the issue of when -- when they were issued by year. Okay. And there you can see it. There's a graph as well. Okay. We know the contractor priced the job in 2014 with a limited number of drawings. You can see there, the IFC drawing list, right. The majority of the drawings were prepared later in 2016 and '17, possibly, but we don't have particular proof that the contractor missed or did not allow for the complexity of the job. Maybe that explains some of the -- some of the issues, right, and therefore underbid the pro -- the project, right.

And certainly there's the possibility that the engineer could have added more detail in the drawings that he's produced in 2015, '16 and '17 and, certainly, he did because he produced the mechanical drawings in more detail and there's a bunch of information there. But they were issued IFC and the technical specs weren't revised and so those are -- I'll use the word "if" questions, "maybe" questions. They're not cast in stone facts, definitely questions -- or -- or reasons for some -- for some of the issues, some of the cost overrun.

Slide 16, please. So from a design perspective, the revision to the specifications have been generally related to the balance of plant work, i.e., the mechanical/electrical work and should be low -- low cost impacts on the entire project. Some more geotechnical investigations might have helped but overall we don't think that -- that the information was insufficient. We think there's enough information there and there's lots of materials to build it. The drawing information is good. The design is reasonable and well detailed. The number of drawings produced is reasonable for a project of this size. It's not like he had to build it with two (2) drawings on the back of a cigarette box. He had lots of drawings and lots of information, right. The only niggling potential issue may be the timing of the drawing production, which may have created some delays, not sure.

In summary, design changes do not account for, in our opinion, for the major cost increase.

Next slide, please. So then we looked at the extra work order information that was provided. Do the extra work orders show where the costs came from? So we reviewed the extra work orders from the general civil contractor as extracted from the Keeyask contract revision register for allocated contingency August 2017.

And I must say that I want to complement Manitoba Hydro for all of the information that they provide and -- and the quality of the information, for the excellent job of tracking the extra work order and the extra -- and generally supplying the -- providing the data. They've -- they are doing an excellent job from our obser -- from our observation.

What we saw there is that the extra work orders which are driven by technical information add up to a number which includes another number, a small number, about 10 percent of that directed by Manitoba Hydro and direct work that they asked for. We'll leave it at that.

Next slide, please. We looked to the information by year to see if there was a -- an issue there in terms of: Was the extra work orders, were they a function of -- of year? What we found was that the majority of the informa -- of the extra work that was -- that was listed was done in 2015 and '16, which makes sense because of the great rece -- reset of the project in 2017, right.

The number which is we can't tell you was -- was noticeable, but we also noticed that the profit reductions were a bigger number than the extra work orders. So there's actually a -- a net savings when you subtract the extra work orders. When you take the extra work orders and subtract the profit reductions, there's actually been a net savings to the project to date, based on the information that was provided.

Next slide, please. So on that basis

we can't sort of say the extra work that's been claimed to date or paid to date is driving the project cost either, right. And in fact, in 2017, there's been some additional money saved by technical changes.

Quantity estimates. This goes back to the question of target price and unit rates, times -- times quantities equals the target price. Manitoba Hydro mentioned in one (1) of the documents that the cost increases to date are -- was a reflection of the change in quantities. They believe that's part of the -- one (1) of the issues that have -- that has impacted the price change.

Most of the work to date was related to earthworks and concrete. As we said, the civil -- or sorry, the mechanical/electrical turbine installation and gates, all the good things for a person like myself as a mechanical engineer, that hasn't been done yet. So -- but we did look at the -- we concentrated our review on the earthworks and the concrete quantities and their changes.

Next slide. We looked at the -- at the concrete works and the formwork and there's a long table, which is in our report. This is just an extract of it. We looked at the variances there to see whether or not the variance percentages and that's column C there, vary dramatically between the original budget, the current budget so -- and we also reviewed some of the information that was provided in a Hatch report, a Stage IV Hatch Report which was in 2012 or '13, I believe. I'm not sure of the date on that one.

So we want -- because we were looking to see if there was a trend from the very early part of the -- of the project to the end to see whether or not the quantity changes were significant enough to actually drive a cost change, a major cost change.

Next slide, please. We saw variances ranging from minus 41 percent for granular fill to plus 86 percent for rockfill. Remember, we've identified there's lots of materials, right. So our suspicion is in the way it was priced or the way it was -- it was -- was being considered there is that there's been some category changes in some of those rockfills in particular, and then that shows when you look at some of the definitions I believe of what the rockfill is in terms of the sizes and the sieve mixes for some of the -- for some of the fills from what one -- from early in the project to later in the project.

So -- and I think that -- that's not entirely unreasonable because you will classify your rock based on what you can make from the quarries that you have, and then you'll use it appropriately. But, when you add it all up, you've only got a variance of about 4 percent in terms of the total volumes of all these different bits and pieces.

Now, I know there was some geotechnical issues with some additional excavation. And I've heard that there's some issues with additional heights of cofferdams and so some of that may account for some of that but still 4 percent is not a huge number. And if you were to do it on a unit price basis, that would presumably change your price by something similar, maybe.

The concrete volumes going right back to the initial Hatch report are remarkably close throughout the estimates. So, the changing quantities in total doesn't seem, from our perspective, to justify the change in the contract value.

Next slide, please. So where are we at this point? The design is reasonable. The drawings and specifications have very few revisions, i.e., they're reasonable. The geotechnical investigations are reasonable and generally good. The extra work orders technically have -- don't seem to have been excessive, right. The quantity estimates are in total reasonable close. We're thinking as we're going through this project at this point, everything looks pretty good. We haven't figured out -- found the smoking gun yet.

Next slide, please. And we looked at unit prices. Were the unit prices changed in '87 (sic) and if so, what was the impact? This was a difficult thing to do because what we found was that the -- there was (a) a lot of information. There was a very, very, very detailed breakup -- breakdown and development of unit prices in the -- in the -- in the different contracts and they weren't always -- or the different versions and they weren't always directly comparable. We had a limited time.

And so we kind of struggled with this. And so what we did is we took similar items in the -- in the bill of quantities and we grouped them together into consolidated unit prices, right, so that we could have a fewer -- a fewer -- a smaller grouping and we could also bundle things together, which were not easy to -- to directly comparable from one document to another. And then we divided the total cost of the grouped items by the total quantities.

Next slide, please. The following consolidated items were reviewed. The cast-in-place concrete. Now, we recognize -- and I think it's really important to understand -- that concrete construction is different for the spillway, for example, compared with the powerhouse, or the te -- and/or the intake in terms of the complexity, the amount of rebar, the formwork, all of these things have an impact on the -- on the unit price nominally of your cast -- cast-in-place concrete. So that one we broke out into those four -- four (4) groupings and you can see we -- we chose a formwork ratio -- formwork area to concrete volume ratio, which is defined there. We looked at the volumes of reinforcing steel, structural steel, right, the unclassified excavations, the rock excavations, the impervious fills, the granular -- granular fills together as a -- and the rockfills.

Next slide, please. We compared the -- all of that information after we consolidated it altogether in a -- in our own spreadsheet between the March 2014 contract AA3 and the AA7 version of 2017.

Next slide, please. And you can see there's the -- the quantity -- the quantities are shown on this table, right, and you can see that there's similar. They're not identical, but there's certainly similar, right. So this goes back to the comment that I made earlier that the quantities generally were -- were similar.

I think the thing that I can say that the blacked out piece in terms of unit price --

THE CHAIRPERSON: Technology is wonderful when it works.

(BRIEF PAUSE)

MR. KURT SIMONSEN: Whoever just joined, can you please mute your phone. Thank you.

THE CHAIRPERSON: Mr. Campbell...?

MR. DAN CAMPBELL: Could I stop saying I've lost my train of thought?

The unit prices all increased between three (3) and seven (7) significantly, as a comment.

Next slide, please. Between, as I say in the slide there, between 67 to 366 percent. When you looked at the entire bill of quantities, not just those that -- subset that I was talking about there, we saw that there were similar increases through the entire bill of quantities comparing 3 and 7.

(BRIEF PAUSE)

MR. DAN CAMPBELL: So if you were to assume that the quantities times the unit price equals the target price, which is true, right, the target price estimate in 7 is much larger than in 3, and it's a function of the unit price increase, not the quantity increase. Next slide, please.

(BRIEF PAUSE)

MR. DAN CAMPBELL: Then we said, Okay, somebody's going to ask, I'm assuming, so we did, are the Keeyask unit prices comparable to other similar projects? I have to be careful when I say here because of confidentiality reasons on other similar projects, but what we did is we compared the unit prices that were present -- that were available to us on Keeyask with some historical information for similar work for a large hydroelectric project in Northern Canada. One (1) of the reasons we consolidated the projects is because that information is commercially sensitive to other clients. We couldn't present it anyhow.

And we -- the next slide shows -- well, is was supposed to show the his -- the comparison between 3 and 7, and our estimates. Unfortunately, the good bits aren't shown. So we might as well move on to the next slide, please.

What it's -- so we saw there is that the initial contract appears to be generally low compared with what we are -- that we have for historical information, and that the amending agreement 7 prices would be -- appeared to be significantly higher compared with what we have.

Thank you. So being engineers, we then said, Well, what impact does that have on the subset of information that we're actually looking at in terms of that unit price comparison? So we did that calculation. It's nicely shown in the black, right? The -- unfortunately, I can't tell you the numbers, but looking at the numbers and I would say that the original contract was dramatically low, and that the existing for the AA7 version is, while higher than what -- what our math showed it might be, is much closer to what our math showed it should be.

So fundamentally, we don't think the contractor could have done the job for the price he bid it, all right, if the target price was high -- was -- was ultimately how he was being paid. So we said, This is a bit of an issue. So we said, Well, how is he be -- getting -- getting paid?

Next slide, please. So we read the contract. This was after we've done all of the good engineering bits to see if we can figure out what's going on. And the blue bit is a direct quotation, more or less, out of the contract, and it talks about the work being on a cost reimbursable basis, fine, with an initial target price and final target price, which is subject to terms of the contract and measured -- and there's going to be measurement in the contract documents, and there would be no change to the unit price unless actual quantities vary by some numbers, and this all looks sort of initially pretty good, all right? So that -- because this is certainly reasonable for a contract with unit prices and measured qualities leading to a final target price with some ultimate adjustments.

Next slide, please. Basis for payment, section 9:

> "Subject to these terms and conditions of payment, the purchaser shall pay the contractor and contractor's actual costs, emphasis by us], incurred in the performance of the work."

Now, section 9 has a bunch of

modifications to the -- to the contract related to profit, and GA&O, and there's a bunch of formulas based on actual costs, and the final target price. And generally, the -- the wording seems reasonable, except it never actually says what the actual costs are. It says -- it never actually says the actual costs are equal to the quantities times the unit price.

So we had to read some more. So we went looking for the definition of actual costs. In section 11, "actual costs shall mean only the following." And I've shortened that section, but basically, and I think you people already know this all probably way to well, it's all the actual indirect and direct costs, all the labour, equipment, et cetera, et cetera, et cetera, incurred by the contractor. Again, the definition of actual cost -- there is no connection between actual costs and the quantities and unit prices.

We have never seen a contract of this size, in our experience, that does this. In fact, I went around and I had a discussion with some of our senior management about contracts of this value and this particular contracting strategy. And I asked other people who have experienced, like, thirty-five

(35), forty (40) years experience, have they seen a major project with this as the contract format, payment format? And the answer was no.

Yes, there are certainly, as MGF mentioned in the -- in the transmission contracts, there are sections of contracts that have cost reimbursable sections, all right? For example, typically on drilling contracts, where you have a driller, and you're drilling -- doing in-field investigations, those are that way because fundamentally, someone is telling the contractor exactly when to do, Drill down till you -- till now. Okay, we're down far enough. Stop. Move over, let's do another hole over here, all right? Someone is directing the contractor specifically in controlling when he stops and starts, telling him what to do.

But we don't -- we've never seen -- and I'm not saying this hasn't been done. I'm just saying, we've never seen it, right, on a contract of this size, of the -- in this industry, or in the mining industry that we're familiar with, and we work in that industry as well, contracts that are set up like this.

Next slide, please. So our conclusions. Design is reasonable. Drawings and specs are reasonable. Geotechnical inf -- investigations are reasonable. Technical -- extra work orders have been okay. Quantity estimates are okay. The unit price -- original unit prices were -- were optimistically low. As I said, the contractor would not, in our opinion, have been able to do the work for the original target price, and that the actual costs are not based on the quantities and unit prices. And I mean, MGF commented on that as well, and I think that's really the -- the crux of the matter, from our perspective, and our review of what is happened, is that the contractor basically did not have the incentive -- I'll use that word -- to be able to perform to meet his unit price times quantity calculation. Thank you.

(BRIEF PAUSE)

THE CHAIRPERSON: Mr. Haight, did you want to proceed with your next witness?

MR. WILLIAM HAIGHT: Yeah, I -- I think that we should be able to deal with the Amplitude presentation before the lunch hour?

THE CHAIRPERSON: Well, we will go late if required into the lunch hour --

MR. WILLIAM HAIGHT: Sure.

THE CHAIRPERSON: -- but I think it'd be better to go through -- go through it now.

MR. WILLIAM HAIGHT: Yes, sir.

(BRIEF PAUSE)

MR. WILLIAM HAIGHT: Mr. Brand, can you hear us now, sir?

MR. LES BRAND: Yes, I can hear you. So can -- good morning, everyone. Can everyone hear me okay?

MR. KURT SIMONSEN: Yes, we're okay, Mr. Brand.

MR. LES BRAND: Okay. So we'll go through my present -- our -- Amplitude's presentation. So if we can go to slide -- to slide 2.

MR. KURT SIMONSEN: We have slide 2.

PRESENTATION BY AMPLITUDE CONSULTANTS:

MR. LES BRAND: Okay. Great, thank you. Right. So this presentation, it's -- it's relatively shorter than the others, and it's really just a summary of our report. Just by way of introduction, Amplitude Consultants are an Australian-based consultancy. We specialize in the various technical issues associated with the transmission and distribution of electricity, and in particular, we specialize in the high-voltage direct current technology, as well as a few other things. We're based down here in Australia, but our consultants have experience with HVDC projects globally.

So going through the presentation, we were asked to -- to look at the HVDC converter stations in particular. Amplitude's scope of work, as -- as I'm showing here, was to assist MGF with the assessment of reasonable of the current forecast at completion capital cost of the converter stations, and to provide an opinion on whether appropriate contingencies and reserves have been provisioned. As I pointed out, it's only in relation to -- to the two (2) converter stations associated with the Bipole III project.

Can we go to slide 3. Now, what we found when we -- when we looked through the documents, most -- the most recent revision to the cost estimates was completed in 2016. We were specifically asked to look at the difference between the previous cost estimate, 2014, and -- and compare it against the -- the 2016 cost estimate.

As MGF have already mentioned, there was a -- a -- quite a -- a detailed basis for estimate document, so the 2014 estimate. It was a good document, and I think the point was made earlier, it did lack a -- a bit of detail, but it was -- it was sufficient for our purpose.

What we found was during the estimate, Manitoba Hydro applied a work breakdown structure method. When I broke down the converter station costs into a number of work breakdown structures, and you can see them there in the table, quite an appropriate way to -- to divide up the -- the various technical elements of -- of the converter station.

But we found that the -- the difference between the 2014 and the 2000 and -- 2016 estimates...

(BRIEF PAUSE)

MR. KURT SIMONSEN: We've clearly lost him. We're going to send him a note to try and get him to sign in again.

THE CHAIRPERSON: We'll -- we'll -- yeah. We'll wait to see the response. Mr. Simonsen, is there way that he would know that the call's been dropped? Do you know?

MR. KURT SIMONSEN: If he's not hearing us, he should know.

THE CHAIRPERSON: Yeah, but we're not --

MR. KURT SIMONSEN: No, I know.

THE CHAIRPERSON: -- okay.

MR. KURT SIMONSEN: So that's why we're sending him an email.

(BRIEF PAUSE)

MR. LES BRAND: Good morning. Apologies. Can everyone hear me okay?

MR. KURT SIMONSEN: Yeah, welcome back. I -- that must be the Australian telephone, I assume.

MR. LES BRAND: Yes, well, we -- we have -- we have dropped out two (2) or three (3) times this morning already, so we should be okay.

So where did we get up to, slide 4?

MR. KURT SIMONSEN: We're -- slide -- slide 3, we were looking at the table.

MR. WILLIAM HAIGHT: Your last words, Mr. brand, was "comparing the 2014 and 2016 estimates," and that's where you cut out.

MR. LES BRAND: Okay. Thank you. Apologies. And what we found was that the -- it was a difference of -- of the order of just over 104 million between the two (2) estimates.

Now, if we go to slide 4, comparing the 2014 to 2016 estimates, we noted some material changes to the work breakdown structures for the convert -- the two (2) converter stations, Keewatinohk and Riel. But the most notable increase was to the contingency value, and the -- the numbers were -- have been removed from -- commercially-sensitive information.

But what we -- what we did note, when we drilled down into it, is that the increase in contingency was -- was due to an increase -- a requested increase in confidence from P50 to P75, as was recommended by the Boston Consulting Group.

In terms of scope change, the only significant scope change that we could notice between 2014 and 2016 was additional funding required for an access road to Conawapa, which is related to a project that was shelved, but originally, there was a plan to share the costs associated with that access road.

Exploring the -- the work breakdown structures for the KCS, and Keewat -- Keewatinohk converter station, and Riel converter station, we found that those two (2) work breakdown structures make up close to 78 percent of the total budget for the converter stations, which -- which is to be expected. The EPC contract for the -- for the HVDC converter stations, and the EPC contract for the synchronous condensers make up a significant portion of those two (2) work breakdown structure elements.

The next slide, slide 5. So this was already touched on by MGF in their presentation, but there was a competitive tender process applied to the converter station contracts. The technology -- the three (3) bidders each had a -- a international technology partner, Siemens, ABB, and Alstom. In our view, the technology -- the technology partners, all three (3) bidders, which -- which are Siemens, ABB, and Alstom, which is now GE, are well -- well-known in the HVDC industry, and have a long history of providing this technology globally.

We reviewed the techno-economic evaluation of the bidders. These appear -- these appear to have been thorough, with consideration given to technical capability compliance, performance technology, schedule, and overall value, and the contract was awarded to Siemens Mortenson.

Go to slide 6, please. When it comes

to checking the reasonableness of converter station pricing, we -- we make the point, and we've made the point in our report that the pricing of HVDC converters depends on a number -- many factors, and many of those factors are known only to the vendors at the time of pricing. It's a -- it's a common trait of HVDC projects that each project is quite unique, and offers a -- an opportunity for the vendors to -- to apply unique charac -- characteristics -- characteristics, but it gets to the point that every converter station is -- that's built every year is more or less the spoke design.

It does make it a little bit difficult to compare the cost of one (1) converter station to the other. There's also a -- a general reluctance of the vendors, because it is such a -- a tight and competitive area, and is -- is a -- a -- often, a leading-edge technology that costing information can be quite difficult to find, or reliable cost information can be quite difficult to find in the public domain.

There are also other elements that impact the cost of one (1) project to another, the cost of raw materials or metals at the time, lots of copper, lots of aluminum, and steel, associated with the project. The global demand for HVDC and the capacity -- manufacturing capacity of the vendors can impact pricing as well. For example, if -- if all the major vendors have pretty full order books, that could increase the price, and often, the schedule of the project. If it's the -- the opposite, we could end up with lower prices in the market. And project location is -- is an issue as well with the three (3) vendors here all European-based, Sweden, Germany and -- and the UK, and therefore the further away from the -- from the -- the manufacturing facilities, then the -- the higher the price can be. So overall, the comparison of proj -- of the cost of an HVDC converter station to other projects requires an understanding of the scope of each project, and an understanding of any key differences between them.

Go to the next slide, slide 7. Looking at the scope of the Bipole III project, there are -- there are a couple of specific characteristics associated with Bipole III that may influence the costs, in most cases -- in all cases, result in a higher cost than other HVDC projects would not normally have these characteristics.

So the first one is that, from a technical perspective, the project required two (2) series valve groups per pole, and without getting too technical, it's -- it's a way of -- of providing additional reliability and availability to the project, and it can also be driven by the general size of the equipment, in particular, the transformers. I could not find anywhere as to why that was charged for this particular project.

But suffice it to say, when compared to the price of other projects, the majority of other projects that have been built up until now had only had one (1) valve group per pole. And public -- public information and -- and documentation quite clearly points out that a two (2) series valve group pole project should have a -- a higher price than one (1) valve group per pole.

Also, in the Bipole III project, there are extreme temperature and environmental conditions to be experienced both during construction and during operation. There's the remoteness factor of the Keewatinohk converter station, which would have added some -- some costs to -- to a project when compared to others, and there are some unique controls applied to this project which wouldn't normally occur to projects in warmer climates or outside of North America, and I've listed a few of them here: De-icing, some SPS requirements, run-back capability, and NERC cyber-security requirements.

The other interesting thing about Bipole III converter station specification is it requires a continuous overlay of 2,300 megawatts. So although it's a 2,000 megawatt project, this continuous overload would, in our view, require that the converter stations themselves have its major project elements, mostly primary equipment, rated for the higher value because of the requirement for a continuous overload. Now, from a cost perspective, when we did a comparison, we actually used 2,300 megawatts when trying to determine a -- a cost per megawatt.

So I'm going to slide 8. Thank you. So we performed a comparison of the overall cost per megawatt. We can't show that number for commercially-sensitive reasons, but we compared that against published costs of similar projects. These -- we've -- we had to apply at a -- it's -- it's a very high-level comparison, so we had to apply time and for -- foreign exchange assumptions to those other projects.

We noted that of the projects we were able to -- to source costing information, all but one (1) was based on one (1) valve group per pole. What we found was that looking at the different types of information, we found ranges -- a -- a range of a costing based on that -- that quite high-level dollars per megawatt value that was often in the order of -- or marginally below the value of the EPC contract for the converter station. However, we concluded, and we are of the view that the EPC costs for the Bipole III converter station, which concludes variations to date, are reasonable, after taking into consideration the use of two (2) valve groups per pole, the remoteness of the Keewatinohk converter station, and the extreme temperature and environmental conditions associated with this project.

Now it's slide 9. Thank you. So another significant part of the cost of the converter stations was the synchronous condenser costs. We have performed a -- a similar activity -- similar comparison as we did for the HVDC converters. So the scope of the EPC contract is for four (4) 250 MVAr synchronous condensers at the Riel converter station. Once again, it was taken through a competitive tender process. The contract was awarded to Voith. And we performed an analysis of similar published costs. We found a range where on our dollars per MVAr level and we found that the Voith contract is within that range, although it -- it is on the high side of the range, and we're of the view that this is reasonable to expect for -- for similar reasons as we mentioned for the HVDC converter station, but in particular, the extreme temperature and environmental conditions associated with the Bipole III project.

And we'll go to slide 10. So the second part of our scope was to comment on the reasonableness of contingencies and reserves, and unfortunately, with this part of the -- our scope for this presentation, we -- we had to remove, obviously, some -- a fair amount of information for commercially-sensitive reasons. But the process we followed, we -- we compared the reported actual costs at -- as of September 2017 to the 2016 budget. The comparison showed a remaining budget as of September '17 for the -- for the whole converter station, all converter station work breakdown structures of about 614 million.

Go to the next slide, slide 11. So we -- we reviewed the monthly reports and the schedule updates in order to get an understanding of the status of the project. We also looked at the -- the progress payments to date, the current vendor of each contract, the -- the major contracts, particularly the Siemens and the -- and the Voith contracts, and compared the progress payments to date against our -- against our outstanding payment past amounts due.

From there, we -- we concluded, or we're of the view that the remaining budgets for the converter stations in general should be satisfactory, and -- and should not, without an event, that's -- that's unforeseen at this point, should not lead to a draw from contingency. We found that for the Keewatinohk 230 kVA switch yard there was only a small -- the budget that's -- exceeded the amount of progress payments that are due, so they will -- will -- it will require a draw from contingency.

However, when you combine the expectations that the converter station contracts will come in on budget and the -- the relatively small draw from contingency, our -- our conclusion in this respect was that the remaining contingency should be considered reasonable to cover the impact of any unexpected activities, which cannot be ascertained from the information made available for this review.

So that's slide 12. That's -- that's our presentation. Thank you.

THE CHAIRPERSON: Thank you, sir. Dr. Williams, I've got you down for fifteen (15) minutes.

Did you want to start now, or afterwards?

DR. BYRON WILLIAMS: I think -- I think I can manage it, sir.

THE CHAIRPERSON: Okay. Thank you.

MR. WILLIAM HAIGHT: I should just say, Mr. Chair, that we have been in contact with Misters Phillips and Potter, just to determine whether they, after hearing the presentations, had anything that they wished to add. And they have indicated that they do not. And so we can proceed with the cross-examination.

THE CHAIRPERSON: Thank you.

MS. HELGA VAN IDERSTINE: Mr. Chair, if I could just have a couple of minutes to consult with counsel for MGF and Board counsel, I'd appreciate it.

THE CHAIRPERSON: Certainly.

(BRIEF PAUSE)

THE CHAIRPERSON: Mr. Haight, I understand you have something to say.

MR. WILLIAM HAIGHT: Yes, I do. Thank you, Mr. Chair. Ms. van Iderstine has brought to my attention, as well as counsel to PUB, a portion of the

MGF presentation which was not included in the public presentation, and which Manitoba Hydro has no objection to it being included in the public presentation. It was inadvertently left out. MGF believed it to be CSI and so, therefore, it was not included. We have had a discussion and there's no objection to it being included in the public presentation.

The only caveat that -- that because MGF assumed that it would be part of the CSI presentation, it really didn't come here today prepared to answer any involved questions regarding this page. And -- and, of course, it just wants to reserve its rights to -- to answer fully and completely any questions about this page at -- at a point in time when they are more fully prepared to do so. So be that this afternoon, be that tomorrow morning, whatever that might be.

THE CHAIRPERSON: Fine. Ms. Van Iderstine...? It's fine. It's not CSI?

MS. HELGA VAN IDERSTINE: No, I mean --

THE CHAIRPERSON: Hydro's okay with the --

MS. HELGA VAN IDERSTINE: -- we just wondered when they took it off the record whether they thought they couldn't speak to it because there were some -- in order to answer questions they had to disclose CSI. But the document itself is not CSI, no.

THE CHAIRPERSON: Okay. So if -- if we could proceed and, I guess, put the document on the record and then have MGF go through it.

(BRIEF PAUSE)

THE CHAIRPERSON: That -- Mr. Haight, is this going to be a separate exhibit number or just part of the --

MR. WILLIAM HAIGHT: No, it would be part of the public presentation, sir. Yeah.

MR. KURT SIMONSEN: We'll call it 4-1, Mr. Haight.

MR. WILLIAM HAIGHT: Thank you, Mr. Simonsen.

--- EXHIBIT NO. MGF-4-1: MGF Presentation

PRESENTATION CONTINUED BY MGF:

MR. CAMPBELL ADAMS: The -- earlier on today we gave the -- the range again of 9.5 to 10.5 billion. In front of you we have our calculation as to what the project value might be, around the 9.9 billion. What I'll do for a minute or two (2) is just talk you through the construct of that, taking us to the 9.9 billion total. The -- the basis of this was taking the expenditure to date that was reported by Hydro as at the 31st of December 2016, and adding to that Hydro's estimated cost to completion from the 1st of January 2017 through to the end.

The next bullet points, craft to foreman ratio, trade in cash discounts, increased use of overtime, net BBE indirect costs, the earthwork productivity, scaffold and crane costs, and concrete productivity are -- have been calculated and taken directly from our final report. Those were our assessments of the costs associated with those cost categories.

With the data that we find, we've added in additional costs associated with the delay and disruption to Voith, and to ongoing service contracts that will be required to support the project. For example, camp operations. I believe, in accordance with -- I'll watch my language -- in accordance with Hydro's interest and escalation, we have used their percentage to that. And given some of the -- the risks that lie ahead over the next four (4) years, we have added to this a contingency of -- of 10 percent. When you add it all up -- up together that order of magnitude estimate of project cost comes to 9.9 billion.

MR. WILLIAM HAIGHT: So that is it, essentially, for that particular Exhibit 4.1. And the panel is now able to answer questions under cross-examination, if you should so -- so choose, Mr. Chair.

THE CHAIRPERSON: Thank you. I've been advised by counsel for the Consumers Coalition, GSS, GSM, and MIPUG that they do have questions, but they should not take too long. So I would suggest that we'll proceed now with those questions, and maybe if we can finish, you know, on or before 12:30 we'll just take a break later on. And then we would just have Manitoba Hydro and -- and Board counsel in the afternoon. So, Mr. Williams...? Dr. Williams, sorry.

CROSS-EXAMINATION BY DR. BYRON WILLIAMS:

DR. BYRON WILLIAMS: Good morning, members of the panel, and good morning, MGF, et al team. Perhaps we can go -- and my first few questions are to Mr. Campbell in the back. Mr. Campbell, can you -- can you see me, sir? Okay. Perhaps we can go to the pre-filed evidence from December of 2017 of

Klohn Crippen Berger, appendix A to MGF's evidence, page 33, towards the bottom, please, Kristen.

MR. DAN CAMPBELL: Klohn Crippen Berger, by the way, is how you say it. KCB for short.

DR. BYRON WILLIAMS: And, excuse me, I misspoke. It should be page 34. And, sir, I apologize for the mispronunciation and I'll govern myself with KCB going forward. And -- and certainly, just so you know, sir, I know you'll see me sitting beside a number of Hydro employees or external counsel. I just want you to -- not that I don't think highly of my friends to my left, but I want you to distinguish me from -- I'm not part of Hydro, okay, sir? You understand that?

Going down towards the bottom of this page, just scroll down a bit more, Kristen. Okay. So at KCB and -- and Mr. Campbell, first of all, thank you for the way that you unraveled that story like a detective story. That was very entertaining and -- and informative. Obviously, towards the end of your presentation you raised the concern with the -- with the contract, the -- the March 2014 contract, and -- and what you saw as an absence of connection between actual costs and quantities and unit price -- prices.

You recall that, sir?

MR. DAN CAMPBELL: Yes, sir.

DR. BYRON WILLIAMS: Would -- to my knowledge, sir, you -- you didn't talk about is in the last paragraph of page 34, which is a clause within the contract by which the contractor, presumably the general civil contractor, is paid two (2) months in advance -- advance for planned work.

You didn't refer to that in your presentation this morning, sir?

MR. DAN CAMPBELL: That's correct.

DR. BYRON WILLIAMS: Sir, you characterize -- to -- to back up for a moment, you noted when you began your presentation this morning that you have had some involvement with Site C in British Columbia?

MR. DAN CAMPBELL: I personally have not, but Klohn Crippen Burger is one (1) of the co-designers of it.

DR. BYRON WILLIAMS: Okay. And, sir, in terms of the -- the clause in which the contractor is paid two (2) months in advance for planned work, you suggest that that is a con -- a clause that you've not seen previously before in a contract, sir?

MR. DAN CAMPBELL: Correct.

DR. BYRON WILLIAMS: And, sir, from

the issue of incentives or -- what is the implication of this unusual clause? Why does it matter, sir?

MR. DAN CAMPBELL: We made an assumption that the contractor was being paid in advance for work he had yet to do so that his cash flow would remain positive, which is what I said in the paragraph. It's an interesting way to do it. We haven't seen it done that way before.

Typically, where we've seen it to make the contractor have a positive cash flow he's given a mobilization payment. And that mobilization payment is enough to get him going and hopefully make sure that when his regular billings come in, based on the work that he does, that his cash flow remains positive and he's happy. We don't know the ne -- what the negotiation logic was or the rationale was. We just made the assumption and I'm just saying we haven't seen it that way before.

DR. BYRON WILLIAMS: Okay. And the observation that you've not seen it before, that would extend to the Site C contract to your knowledge, sir?

MR. DAN CAMPBELL: I don't believe I can comment on that.

DR. BYRON WILLIAMS: Fair enough. Let -- let us go to the top of the next page. And, sir, you may have a similar answer. In -- in the last paragraph on page 35 you're describing again the fact that KCB has not seen a large contract previously where payment was not related to actual performance of the cont -- construction work.

Do you see that reference, sir?

MR. DAN CAMPBELL: Yes.

DR. BYRON WILLIAMS: And, sir, if you're able to comment, would that comment extend to Site C as well?

MR. DAN CAMPBELL: Yes, I believe those contracts, in terms of the bid documents, were publicly -- generally publicly available and I believe that the Site C contracts are based on -- generally based on unit prices, times, quantities, or lump sums.

DR. BYRON WILLIAMS: And, sir, do you have any sense of when the contracts related to Site C were let?

MR. DAN CAMPBELL: Over the last three (3) years, perhaps.

DR. BYRON WILLIAMS: And regulatory approval via the National Energy Board decision would have been three (3) or four (4) years ago, sir, subject to check?

MR. DAN CAMPBELL: I'm not able to

comment. Don't know.

DR. BYRON WILLIAMS: Thank you for that. Mr. Adams, perhaps we can go to the pre-filed written evidence of MGF, and specifically page 80 under Finding Number 10, Keeyask construction management. And, sir, likewise we'll -- you didn't unravel a detective story, but our clients do thank you for your lyrical presentation this morning. I've never heard the word endemic pronounced with such vigour.

Sir, we don't need to go there, but you'll recall in -- in your PowerPoint presentation today, and specifically at slide 10 in your verbal description of it, I believe you used words to the -- to the sense that cost reimbursable pricing mechanisms are not necessarily a bad mechanism.

Do -- do you recall using words to that effect, sir?

MR. CAMPBELL ADAMS: Yes.

DR. BYRON WILLIAMS: What our clients took to be the thrust of your commentary on that page though, sir, is that they can become an inefficient mechanism in circumstances where Hydro bears all of the productivity and schedule risk and fails to hold the general civil contractor's feet to the fire.

Would that be fair, sir? You're nodding your head?

MR. CAMPBELL ADAMS: Yes.

DR. BYRON WILLIAMS: Yes. In that context, sir, directing your attention to the third last paragraph, your concern is with the cost reimbursable contract as entered into with regard to Keeyask, that it promoted and rewarded inefficient work, sir?

MR. CAMPBELL ADAMS: What are you looking at? Sorry.

DR. BYRON WILLIAMS: The third last paragraph, sir.

MR. CAMPBELL ADAMS: Yes, I see it.

DR. BYRON WILLIAMS: And that it did not encourage efficient work, sir? That was your conclusion?

MR. CAMPBELL ADAMS: Yes.

DR. BYRON WILLIAMS: And generally, sir, would you agree that in terms of business practices that pass-through costs, regardless of productivity or adherence to schedule, those could generally be described as not efficient and not prudent?

MR. CAMPBELL ADAMS: Cost reimbursable

contracts work well when the scope is not defined and it's difficult to -- to define the scope and to put a boundary around it. An example would be you're going to build a house, and you believe there are services, pipes under your plot, but you don't where they are. You can't get that really on a lump price because you can't show the contractor what it is he or she has to do. So cost reimbursable is appropriate for that. When you know what it is you want to have built, you've got project definition. Cost reimbursable is an unusual pricing mechanism to choose.

DR. BYRON WILLIAMS: And ultimately inefficient, sir?

MR. CAMPBELL ADAMS: It can be, yes.

DR. BYRON WILLIAMS: I think, Mr. Chair and members of the panel, I thank MGF for those comments, and I'll move on -- or I'm -- I'm completed our cross, sir.

THE CHAIRPERSON: Thank you, Dr. Williams. Sorry. M. Monnin...?

CROSS-EXAMINATION BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: Thank you, Mr. Chair, members of the panel. Good morning. I'm counsel for General Service Small, General Service

Medium customer class and also Keystone Agricultural Producers. I have a few questions. I'll start with Mr. Adams, and then a few short questions for Mr. Campbell.

Mr. Adams, with respect to MGF is it safe to say that MGF's view is that Keeyask poses the greatest threat to the capital expenditures program?

MR. CAMPBELL ADAMS: Yes.

MR. CHRISTIAN MONNIN: And I want to explore the notion of Mulligan which you've raised a few times in -- in your evidence this morning. Now, you'd agree with me that Mulligan in golf is a shot -- it's a -- it's a chance to perform a shot, usually after the first chance went wrong either through bad luck or for -- or through a blunder.

You agree with that?

MR. CAMPBELL ADAMS: A do-over, yes.

MR. CHRISTIAN MONNIN: And in -- in golf the result is that the hole is played and scored as if that errant shot had never been made.

Is that fair to say?

MR. CAMPBELL ADAMS: Yes.

MR. CHRISTIAN MONNIN: Now, you referred to the Amending Agreement Number 7 as a Mulligan. Is it fair to say that Amending Agreement

Number 7 doesn't undo the bad luck or the blunders that occurred previous to February 20 of 2017?

MR. CAMPBELL ADAMS: Yes. What I was trying to convey was the contractor was given a second chance to get it right.

MR. CHRISTIAN MONNIN: Right. And with -- let's refer to that as a correction shot, perhaps.

With that correction shot, is it safe to say that it's MGF's view that even with the Amending Agree -- Amending Agreement Number 7, BBE or Manitoba Hydro is continuing to miss the revised productivities for concreting and earthworks?

MR. CAMPBELL ADAMS: Yes. Those have been missed, both in 2016 and 2017.

MR. CHRISTIAN MONNIN: And, Kristen, if you can please go to page 63 and 64 of the MGF report. If you scroll down. Under the order of magnitude estimate, we have the range of 9.5 billion to 10.5 billion. And on the next page over, please, MGF's view was that it's difficult to advise where the final cost will land in this range and it gives two (2) points of -- of advice. First, that if Manitoba Hydro addresses the current issues, taking control of the project and its contractors, the final cost will be at the lower end of the range. And that -- that would be the 9.5 billion that we see on the previous page.

Is that...

MR. CAMPBELL ADAMS: Yes.

MR. CHRISTIAN MONNIN: And then, number 2, keeping the status quo and leaving control with the contractor result in the final cost at the upper of the range. And that would be the 10.5 million (sic)?

MR. CAMPBELL ADAMS: Yes.

MR. CHRISTIAN MONNIN: So looking at number 1, and -- and staying with the -- the golf vernacular, would you agree with me that BBE would need to be a scratch golfer in order to ensure that they -- they're at the 9.5 -- the lower range? Meaning they'd have to be -- they'd -- they'd have to correct every single outstanding issue that you have identified in your report in order to be at the lower end of the range.

Is that fair to say?

MR. CAMPBELL ADAMS: Our -- our view is they've got to get control of their productivities. They've got to be able to provide productivities and achieve them. That has not happened between the --

their tender and 2016. They get a chance to restate them in the Amending Agreement, and those are still not being met.

MR. CHRISTIAN MONNIN: And they would have to take control of all of the productivities?

MR. CAMPBELL ADAMS: Yes.

MR. CHRISTIAN MONNIN: Thank you very much, Mr. -- Mr. Adams. Mr. Campbell, a few questions for you with regards to the Klohn Crippen Berger report. At page 35, My Friend Dr. Williams took you through two (2) outliers regarding -- or concerns that were raised with respect to the contract, the first being the actual costs and the other one (1).

If you go one (1) page up, page 34, apologize, Kristen. And the other one (1) being referred to in the second -- or the last paragraph, another interesting clause. I think the answer is on the second page -- on the next page over. I just want to make sure that when Manitoba Hydro had this second shot or second bite at the apple with the Amending Agreement Number 7, they didn't correct the language or those clauses.

Is that fair -- fair to say?

MR. DAN CAMPBELL: I believe that to be correct.

MR. CHRISTIAN MONNIN: Thank you. No further questions. Thank you, Mr. Chair.

THE CHAIRPERSON: Thank you, Mr. Monnin. M. Hacault...?

CROSS-EXAMINATION BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Yes, my name is that Mr. Hacault. I represent industrial users in this province. And my question is a follow-up to -- or my series of questions is a follow-up to those asked by Counsel Monnin, and also relates to MGF-4-1, which is the last exhibit with the numbers on it.

In this process we have been looking at estimates and probabilities. And you had one (1) question from the Chair on that issue. I'd like to explore it. I really don't care who answers this.

Are there any stages or critical points in the schedule or the works at which we should be looking to have a better idea of where we're going to land in final costs of Keeyask?

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: I think you've asked a really good and important question. Given what we've reviewed again here today, the -- the first activity, in -- in our professional opinion, is to work with BBE to understand what productivities they can realistically achieve. And whatever advice they give, test those productivities, that they -- they makes sense, that they look achievable that they're -- they're thoughtful, they're thought through, they're considered, they're backed up, hopefully with some kind of historic data to underpin those assumptions.

Once you get to a point that you believe you've tested and challenged and you've got now the real productivity they can do for the -- the structures and concrete ahead, then we would suggest that the schedule is -- is recast with those realistic achievable productivities.

In concert with that, you should look at the associated estimate of costs that go with that, the directs, the indirect. There is the -- the issue of other contracts that will interface with the progress of the BBE contract, like Voith, for example, and figure out where is that going to play. And if it's a different date, are we facing further delay and disruption impacts.

Until we get to what I would call that steady state, I -- I couldn't sit here and predict a point in time when you will know better. I think that Hydro needs to see that BBE is going to deliver as they have promised. They haven't. They -- they were let down in 2016. They've been let down in 2017. But until we correct the productivity issue for concreting and earthworks, it's difficult for us to sit here and -- and give you a date in the future, a milestone in the future by which you'll have a better handle.

I -- I think one (1) -- one (1) more point to add is, given -- given the history with this contractor, that once we've got a better schedule and cost that that is just rigorously enforced, making sure that it happens. If it doesn't happen on one (1) day, step in and figure out why did the plan not work. Where did it go wrong? What can we learn? How does it impacts subsequent activities? That's my answer.

MR. ANTOINE HACAULT: Mr. Campbell, do you have anything further to add on that issue?

MR. DAN CAMPBELL: The classic issues related to construction of a hydro project in terms of impacts on cost often have to do with the excavation piece. And if all of the excavation has not yet been completed, so the contractor knows or can -- someone can predict and measure how much additional volume or how much -- if there are changes, or what the actual volume of material that has to be placed.

If that work has not been done when that point is reached, that's a -- certainly a point where the future is hopefully easier to predict. So that's one (1) point that I think should be considered. I agree with what Campbell said, but I -- and MGF said, but I think that's -- I think in answering your question a little more specifically, that's one (1) point.

The other one (1) would be when you look at where the handover points are to Voith and to the spillway contractor, who I don't believe is on the critical path, but could eventually become there. The -- and how they perform, those are -- those are points where I think you -- you want to look very carefully because those contractors may well be looking for other opportunities to ask for additional funding at some point in the future. And it all counts, whether it's the civil contractor's money, or whether it's Voith asking for more money, or whoever. It's all money.

And the coordination, in particular, inside the powerhouse going forward when the ser -- when -- when Voith finally comes on to site, and how they have to interface with the civil construction, which are particularly the concrete placement which won't be complete, how they share the powerhouse crane is a excellent example, is an area where care needs to be taken. And certainly I would anticipate that Manitoba Hydro, based on their experience in the past, is going to be intimately involved in the -- in the coordination of the powerhouse crane sharing.

I think that those are a couple of areas where I think maybe you would want to get back and get a review or get a confirmation that things are still on track.

Does that help?

MR. ANTOINE HACAULT: Yes, it does. Now, so I may be oversimplifying this, but if after Hydro sits down with its general contractor and believes it's come to get a reasonable handle on what's going to happen with respect to productivity and redoes a schedule according to that, there might be natural points at which all parties, including this Board, might want to revisit estimates to see whether we're on track for an eight-point-seven (8.7) number, a nine-point-five (9.5) number, or a ten-point-five (10.5) number.

Is that fair?

MR. CAMPBELL ADAMS: Yes, that's fair.

MR. ANTOINE HACAULT: And then we talk about handover points, you know the works inside and out, gentlemen sitting in front of me, is that the completion of the concrete works that allows coordination of the powerhouse work? Could you provide a little bit more explanation on those handover points, what you meant by that?

MR. DAN CAMPBELL: When you build a hydroelectric unit there's a bunch of concrete that's poured in the excavation, I should say, and then there's the foundation that's poured and there's some concrete built to a certain point. And then at that point in time, the equipment supplier comes in and he has to install the turbine. And often significant portions of that are embedded in concrete. So he has to put it in and position it, and then the civil contractor has to come in and put concrete around it.

And they work their way up basically from the basement up to the operating floor, a bit in lockstep with the mechanical contractor doing work, the civil contractor coming back to do a little bit, the mechanical contractor doing some more, eventually the electrical contractor putting in the generator pieces. And eventually the unit is complete to a point where you can walk around on the floors and it's all -- it's all built.

That coordination is something that while that is happening on a particular unit, the contractor is also attempting to pour concrete around, for example, the basement or the -- the walls even of the other units further down in the powerhouse. So he's wanting to be able to work overtop of or past, beyond where, for example, the mechanical contractor is working.

There's issues with the powerhouse crane. Often there's more than one (1) powerhouse crane. I suspect there is in this particular project. There's temporary cranes sometimes used, concrete pumps, all kinds of equipment. At some point in time down the road you then get into actual electrical commissioning of the first unit while you may well still be building the last unit.

Care has to be taken that -- that you can do that without interference. And the coordination of that, and there's a -- there's -- that is, in our experience, in a contract where -- in a contracting situation where you have multiple contractors responsible to the owner, it's the owner's responsibility to take some significant hands-on management of all of those contracts during that construction phase when they're all working in the same place.

Where there's a specific point in time, I think it would be prudent to suggest that at the point in time when it looks like they've got a fixed point in time where the -- Voith can start the installation of the first unit, you would want to be able to understand whether or not you're -- you have a high likelihood of continuing on successfully.

Thereafter, then it becomes a coordination issue and -- and the owner will know just as much, if not more, than either of the contractor because he's actually balancing the wishes of both of them, because they will both at certain times be asking for the same space and place. And nei -- you -- they can't be in the same place in space at the same time. So sometimes you -- you tell Voith, No, you can't do it today. But they -- do they have float in their schedule? They should have, because they've done this before.

Ditto if the -- the civil contractor wants to pour concrete and do a major pour. You may tell him, Sorry, you can't do it during day shift. You have to do it during night shift because Voith is on day shift on the cranes and you can't have the crane. So that's when the intensity ramps up in terms of the coordination. Everything outside the powerhouse, with the exception of the spillway, I believe is something that the civil contractor has fundamentally control of.

Does that help?

MR. ANTOINE HACAULT: Yes, it does. So in a general way if parties here were going to review the progress of where we are at between an 8.5 billion number and a 10.5 billion number, would it make sense to come back annually, if that was somebody's wish? Say, for example, later in the fall of 2018 and later in the fall of 2019 to keep track of this project and -- and what's happening.

(BRIEF PAUSE)

MR. DAN CAMPBELL: My opinion on that one (1), and MGF may have a different opinion, is that it's not an annual review. It's a point review. And so you need to look at the schedule of what's being planned. Then you have to look at what they actually achieve, and you have to pick some points in the future. And so that's when we want to do it.

When -- when they get to this point,

for example, and Voith is being -- going to come on site, prior to that you want to make sure that they can come on-site on schedule. Then after they've done some significant portion of unit 1, to the point where the civil contractor is fundamentally not involved, you want to look at the timing of that and see whether or not you can extrapolate what might happen when you get the unit 7 in terms of schedule. So it's not a let's do it every -- every March. Its let's do it at certain specific points in time, in my opinion.

MR. ANTOINE HACAULT: And right now is there a best estimate of a range of months, say four (4) to six (6) months, as to when that point in time might be?

(BRIEF PAUSE)

MR. DAN CAMPBELL: I don't think Klohn Crippen knows the schedule well enough to be able to answer that specific question. That would be something that we would have to go away and study. And certainly I think I would ask -- suggest that you might want to ask Manitoba Hydro that question as well.

MR. ANTOINE HACAULT: Thank you,

members of the panel. And, Mr. Chair, those are all of my questions.

THE CHAIRPERSON: Thank you, M. Hacault. We will break for lunch until 1:30. Thank you.

--- Upon recessing at 12:26 p.m.

--- Upon resuming at 1:32 p.m.

THE CHAIRPERSON: Good afternoon. Ms. Ramage, I understand you wanted to put something on the record? Are you doing it in a Newfoundland accent?

MS. PATTI RAMAGE: I wish. My husband can do a great one, I can't. Yes, Mr. Chair, earlier in the proceedings with respect to rebuttal and the one transcript reference I don't have on me is -- is where you said this, but you had -- when you ruled that Manitoba Hydro could deal with certain issues on rebuttal you indic -- an issue that if there was any additional we should come back to you.

And we have one (1) additional issue that we wish to bring to your attention that we would intend to address in rebuttal and that is a -- an item that came in MPA's presentation at page 33 of their presentation where MPA introduced new information for the first time on the record, which was a Moody's report titled US Public Power Utilities With Generation Ownership. That's what its title is and they indicated it's available at Moodys.com.

That document, nod its contents, were on -- referenced in MPA's prefiled evidence and the first we saw of it was in the January 15th slidedeck. And as a -- it's -- it's not a public document. In fact, it's a pay to review document. Mr. Colaiacovo spoke to the Moody's report at transcript page 4919 and the comments he made, in short, Manitoba Hydro disagreed. Mr. Ghikas attempted to deal with them in cross but was unsuccessful.

And we have a disagreement in opinion or -- or what Moody's -- I -- I don't want to jump ahead of myself. There was a term. Mr. Colaiacovo gave his definition. Manitoba Hydro staff believe it is incorrect, and they wish to put on the record their view of what it means and what that means to Manitoba Hydro. So, we are requesting that -- that we be allowed to refer to that in rebuttal.

I am advised by Mr. McCallum, who was working out a couple of slides in order to address these things, that he expects the entire rebuttal to take roughly fifteen (15) minutes.

THE CHAIRPERSON: Thank you.

MS. PATTI RAMAGE: So the -- and the -- the notion is that we -- we would just have Mr. McCallum address it by slide to -- similar to a direct in short, and then keep it short. So we -- we wanted to give you notice of that. I have already spoken to counsel for MIPUG and the Coalition, as well as Mr. Peters. They have not had an opportunity, I don't think, to look at the transcript references and provide their comments.

And before I turn the -- turn the mic over, the one other thing I should bring to the Board's attention is Board counsel following MIPUG's evidence requested Manitoba Hydro do some additional IFF runs. Manitoba Hydro is undertaking those runs. One (1) of the issues we'll have to address is in Board counsels' request, they indicated that this may actually be CSI. We have to look at that for that, but I can advise that Manitoba Hydro is looking at those runs and working on them. And I have to say much to my chagrin because I'm telling these people they need to help me with final argument but, in any event, wanted to bring that to your attention also.

THE CHAIRPERSON: And Ms. Ramage, I

understand that at least from Board counsel that we're looking at Thursday morning for the rebuttal rather than Friday morning?

MS. PATTI RAMAGE: Yes, that's what we're work -- working to.

THE CHAIRPERSON: Thank you very much. And by --

MS. PATTI RAMAGE: And we're expecting the presentation will be distributed then Wednesday evening is the goal for us.

THE CHAIRPERSON: Thank you. Just for the record when I made the comment to Ms. Ramage, it's because we both saw the play Come from Away, which if any of you have a chance of seeing is spectacular so.

MS. PATTI RAMAGE: It may be the one thing everyone in the room could agree on.

THE CHAIRPERSON: That's true, thank you very much. Ms. Van Iderstine...?

CROSS-EXAMINATION BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: Thank you. So I'm going to address a couple comments, first of all, to Mr. Phillips and Mr. Potter and Mr. Brand and that is, I have no questions for you so you're off the hook at least for a couple of hours from my perspective.

And then if I can address the questions to both Mr. --

MR. WILLIAM HAIGHT: Perhaps, Ms. Van Iderstine, sorry to interrupt, if we could just have Mr. Brand, Phillips and Potter acknowledge that they received that. Are they on the line?

MR. JIM POTTER: So, we're having a very hard time hearing you.

MR. WILLIAM HAIGHT: Try it again.

MS. HELGA VAN IDERSTINE: Do you want me to start --

MR. LESLIE BRAND: Yes, I'm on the line and likewise having trouble hearing.

MS. HELGA VAN IDERSTINE: Well, from -- this is Ms. Helga Van Iderstine. I'm couns -- external counsel for Manitoba Hydro, and I was just going to address you by saying that I don't have any questions for you.

MR. WILLIAM HAIGHT: And -- and what I will say to all of those individuals is that even though Ms. Van Iderstine doesn't have direct questions for you, there may be areas that you can assist the MGF and KCB personnel with and so, I would invite you to -- to stay on the line.

MR. DWAYNE PHILLIPS: Understand, we'll stay on the line.

(BRIEF PAUSE)

MR. WILLIAM HAIGHT: You -- you heard from Mr. Brand, Mr. Potter and Mr. Phillips.

MR. KURT SIMONSEN: And could I ask Mr. Brand, Mr. Potter and Mr. Phillips to make sure their telephones are -- are on mute.

MR. LESLIE BRAND: Yes, will do.

CONTINUED BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: Okay. And Mr. Campbell, I know that you will be answering for KCB and am I right, Mr. Adams, that your pri -- I should primarily direct my questions to you and if somebody else wants to chime in they can do so at that point?

MR. CAMPBELL ADAMS: Absolutely.

MS. HELGA VAN IDERSTINE: Okay. So this is to both Mr. Adams and Mr. Campbell, did you have an opportunity prior to preparing your reports to review the Needs For and Alternatives To report from the Manitoba Public Utilities Board relating to the

Keeyask project?

MR. DAN CAMPBELL: No, KCB did not review it.

MR. CAMPBELL ADAMS: We had received it but I'm not -- I can't speak to the extent to which it was fully reviewed.

MS. HELGA VAN IDERSTINE: Okay.

MR. CAMPBELL ADAMS: I know I certainly personally did not.

MS. HELGA VAN IDERSTINE: Were you -- and so again, Mr. Campbell or Mr. -- Mr. Adams, were you aware that the contract model was discussed at that proceeding, the NFAT proceeding, and reviewed by the independent assessor Knighte Piesold?

First of all, Mr. Campbell.

MR. DAN CAMPBELL: In reviewing the documentation that was provided, it became clear to us that the contracting model had been discussed with Knighte Piesold and others.

MS. HELGA VAN IDERSTINE: And just to clarify that would be after you received the probably the IR responses or the rebuttal from Manitoba Hydro?

MR. DAN CAMPBELL: Not, it was actually prior to that.

MS. HELGA VAN IDERSTINE: Mr.

Adams...?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: So you had -- you were aware of that that Knighte Piesold had reviewed it, the contracting model?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And again, that was after you had -- was that before or after you'd prepared your report?

MR. CAMPBELL ADAMS: It would've been before, I believe.

MS. HELGA VAN IDERSTINE: So Mr. Campbell, I have a few questions about the KCB report and your comments about the contracting model.

And first of all, on page 39 which is 217 of the KCB report and that's MG -- sorry, that is MGF-217. It's page 39 so I guess I went a little too far.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: Sorry, I'm confusing you, I'm sorry, Kristen, that was 39 of the KCB report, but you know what, we'll just leave that for a second, because the question really was, and I think Mr. Campbell probably knows the area.

In that report you had stated that in your opinion:

"The most significant issue for the project was the almost 100 percent decoupling of work performance from payment by paying actual costs instead of quantities times unit prices for actual work done."

Do you recall that?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And what you would be describing there is a cost reimbursable contract?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And I just want to make sure we're all on the same page so if you'll bear with me.

A target price contract would be established by multiplying the quantities in the contract to the unit prices bid by the contractor to reach a target price?

MR. DAN CAMPBELL: That would be the definition of target price, yes.

MS. HELGA VAN IDERSTINE: And if you

were paying quantities multiplied by the unit price for actual work completed, that would more closely relate to a unit price contract?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And did you review the KPMG report attached to Manitoba Hydro's rebuttal evidence, and that's at Manitoba Hydro Exhibit 117 and page 64, bottom of the page. It's the second page of the appendix. Go down to the bottom of the page.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: And did you review where it states... My apologies. Where they say:

"The gain share/pain share formula was structured as follows: The gain share formula for cost savings was 80 percent for Manitoba Hydro and 20 percent for BBE. If BBE delivered a project under the adjusted target price, as defined in the contract, the profit increased from a percentage to another percentage of the additional savings. The pain share formula, however, was more punitive to the contractor if the cost went over the adjusted target price BBE was responsible for 80 percent of the cost overruns and their percentage of profit would erode to zero profit based on the amount of cost overrun. Additionally, once the actual costs exceeded the target price by 1.3 times, BBE would no longer receive their percentage GA&O and the objective of this cap on GA&O was to ensure that the contractor would not benefit from escalating project costs and remove the incentive for the contractor to increase project cost to improve their overall position."

I'm sorry if I didn't have the site there correctly for you. Do you want me to find that site properly for you so you can review that?

Okay, so, -- it's at the top of the page, up on page 2. There we go. And where the bullets are.

MR. DAN CAMPBELL: What is the question?

MS. HELGA VAN IDERSTINE: So did you have a chance to review that?

MR. DAN CAMPBELL: Briefly.

MS. HELGA VAN IDERSTINE: And if you -- now that you've reviewed it, can we agree that the original price -- original contract that Manitoba Hydro signed with BBE was not a pure cost reimbursable contract but more accurately described a cost reimbursable contract with a target price?

(BRIEF PAUSE)

MR. DAN CAMPBELL: I don't think I would describe it that way.

MS. HELGA VAN IDERSTINE: Okay. And so you are aware, though, that the GA&O was capped?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And that would take -- that would provide some incentive then to the contractor to ensure that their -- they came in within the target?

MR. DAN CAMPBELL: It should.

MS. HELGA VAN IDERSTINE: And so in that sense, it's not a pure cost reimbursable contract?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: Meaning that the contractor is sharing some of the risk?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: Now before I go any further, GA&O means general administration and overhead; is that right?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And that would typically support the -- meaning it supports the project from the contractor's home offices, including but not limited to expenses such as human resource, management, corporate procurement, IT, that sort of thing?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And Mr. Campbell, I see from your CV and for the comments you've made this morning that you've been involved in several hydroelectric projects?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And in a variety of capacities?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: As a consultant to the owner?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: Project manager?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: You've done design?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And it would be fair to say that every one of those projects is different?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: They have different risks?

MR. DAN CAMPBELL: There's different roles for the engineer.

MS. HELGA VAN IDERSTINE: Yeah, different roles for the engineers but the project as a total would have different risks depending on the circumstances of the project, where it was located, that sort of thing?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: There'd be

different design challenges, again, depending on where it's located?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And so, although there are similarities obviously between a hydroelectric project in one place and another hydroelectric project, there's also a lot of differences?

MR. DAN CAMPBELL: All hydro -- all significant hydroelectric projects are fundamentally custom objects.

MS. HELGA VAN IDERSTINE: And we look at Keeyask, the complexity of that would be associated, that would be things like location.

You agree with that?

MR. DAN CAMPBELL: It's certainly a significant factor, yes.

MS. HELGA VAN IDERSTINE: Some of the geotechnical issues associated with it?

MR. DAN CAMPBELL: I think there's, as I said, in -- in our report and in my comments this morning, I think there was enough investigation that from the perspective of the complexity of the project it's not as complex and it's reasonably well-known.

MS. HELGA VAN IDERSTINE: You say not

as complex as some; more complex than others?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: It's subject to extreme weather conditions given its location?

MR. DAN CAMPBELL: Certainly.

MS. HELGA VAN IDERSTINE: And Mr. Campbell, in your report one (1) of the things you speculated on was the --

"The potential reason for the cost reimbursable contract being selected may have been to push the construction project quickly."

Do you recall having said that?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And I understand that from the Manitoba Hydro staff that you didn't have any discussions with them about that?

MR. DAN CAMPBELL: That's why it was speculation.

MS. HELGA VAN IDERSTINE: Exactly. So I just want to talk to you a little bit about some of -- and put to you some of the evidence about why that contract was selected and see what your thoughts are.

So, first of all, when selecting a contract delivery strategy, would you agree that one

(1) of the considerations is the market conditions that might influence the availability of major con -- contractors willing to bed on a project?

MR. DAN CAMPBELL: No argument.

MS. HELGA VAN IDERSTINE: And so the example that came to us was in Vancouver recently or Toronto where the housing prices have been so hot, a buyer was really subject to the whims of the seller. If the seller wanted to sell it to them they could buy it, but the prices were going up and the seller had the choice of who they wanted to -- to sell to.

Would that be a good analogy to a hot construction market where the experienced contractors have a choice of who they might decide to bid on and what projects they would bid on.

MR. DAN CAMPBELL: All contractors have a choice on whether they want to bid or not.

MS. HELGA VAN IDERSTINE: Okay. Well, let me take you back a bit. Do you recall the period of time just before mid-2014 when oil prices were escalating quite quickly?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And there were a number of projects across North America that were on the way -- under way, particularly, in the oil industry that were attracting a lot of labour, general contractors to them?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And in that kind of market, would you agree that senior project managers and general contractors would've had their pick of what projects they might want to bid on?

MR. DAN CAMPBELL: Yes, they -- they always have the choice of what project to bid -- to bid on and certainly, there were more projects perhaps at the time.

MS. HELGA VAN IDERSTINE: And therefore, owners would have less negotiating room with respect to choosing contractors and the terms that contractors might be prepared to take on?

MR. DAN CAMPBELL: I think that the decision about whether you proceed or not is a function of the negotiation that you make with the contractor and/or the price that is presented. And if the price was presented as being too high under a contracting model that shared the risks or put the risk on one side or the other, then the owner has -- obviously, has the right and the opportunity to reflect and perhaps redo it.

MS. HELGA VAN IDERSTINE: So one (1)

of the other things you speculated -- one (1) of the other matters that you had speculated on in terms of why Manitoba Hydro might've selected that type of contracting model was what -- if they'd had experience with it in a similar project.

Do you recall that?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And so, were you aware that Manitoba Hydro's experience with Wuskwatim, they had attempted to tender a general civil contract as a unit race contract and it only received one (1) bid and it was at two (2) times the engineer's estimate?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: You were aware of that?

MR. DAN CAMPBELL: Yes, that was in the documentation that was made available.

MS. HELGA VAN IDERSTINE: And was that before or after you had prepared your report?

MR. DAN CAMPBELL: It was during the preparation of our report.

MS. HELGA VAN IDERSTINE: So it -- was that what you were talking about then when you say that they may have had success with that model in past?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And so you were aware then that the Wuskwatim contract was a cost reimbursable target price model?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And Manitoba Hydro has given evidence that they started doing their procurement for Keeyask two (2) years prior to signing a contract with BBE.

Were you aware of that?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And that they had gone out to the market and had done an initial sounding of the market to determine if there was interest?

MR. DAN CAMPBELL: Yes, that's typical.

MS. HELGA VAN IDERSTINE: And based on that feedback, they had prequalified four (4) contractors who they thought were capable of performing the work?

And again, that would be a reasonable thing to do?

MR. DAN CAMPBELL: Yes and it's also

typical.

MS. HELGA VAN IDERSTINE: And in their market sounding they would also had some in -- opportunity to determine what type of contracts were likely to be acceptable to bidders in that market?

MR. DAN CAMPBELL: It's a question that's often asked and sometimes viewed with a bit of suspicion on occasion by the owner relative to what the contractor says.

But yes, it's -- the question would have likely been asked.

MS. HELGA VAN IDERSTINE: So in those circumstances, it would not appear that there was any rush to construction, given that they had taken two (2) years to do the -- their diligence in terms of getting the contractors bids together?

MR. DAN CAMPBELL: I don't know the -- the schedule that they were looking at in terms of ultimately delivering power to wherever they had to do it in terms of other commitments. So, whether or not they were in a rush or not, given the long duration that it takes to design, build and construct and commission a hydroelectric project, I can't comment on that.

MS. HELGA VAN IDERSTINE: You are

somewhat familiar, though, I understand with the Site C project?

MR. DAN CAMPBELL: Somewhat.

MS. HELGA VAN IDERSTINE: And I'm not going to ask anything that you consider confidential and I'm -- I'm -- hopefully I've -- my questions will be such that you'll still feel comfortable answering them without being put in a difficult spot, so. If you think so, please, let me know and I'll see if I can answer -- ask them in a different way. And for any of you, quite frankly. I'm not asking anything that's CSI. If you think I'm going there, then please stop me.

So, Mr. Campbell, I just wanted to ask you a couple questions about the Site C project and we have a book of documents that you should have. I think your counsel may have or put it forward to you.

And one (1) of the things that I just wanted to comment on too is that the documents we've put in here were ones that were -- we got off the internet. So -- or from -- either from Manitoba's -- or BC Hydro's website or from the BC Utilities Commission's website. So, they are public documents.

And when I'm saying that, I'm referring to the first two (2) items. So first of all, the Site

C hydroelectric project is a project of the BC -- BC Hydro; is that right?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And it's located in northern BC near Fort St. John?

MR. DAN CAMPBELL: Correct.

MS. HELGA VAN IDERSTINE: Which is, again, is a remote town, but fairly sizable?

MR. DAN CAMPBELL: Depends on your definition of "sizable" but...

MS. HELGA VAN IDERSTINE: Bigger than Keeyask?

MR. DAN CAMPBELL: Yes, certainly.

MS. HELGA VAN IDERSTINE: And when it's completed, it will provide about 1100 megawatts of energy?

MR. DAN CAMPBELL: Correct.

MS. HELGA VAN IDERSTINE: And if you'll look at the first item in the book of documents that -- which is at page 3 and it starts -- actually it's starting on page 2 is where I'd like to start.

This is the Site C main civil works contract, as I understand it, and -- and I also understand that this is just a tiny little portion of what it would be but this is what's on the website.

So, if you look at the date of it you'll see that it's dated -- the contract was dated December 8th, 2015; is that correct?

MR. DAN CAMPBELL: Yes.

THE CHAIRPERSON: Sorry, I believe it's December 18th.

MS. HELGA VAN IDERSTINE: Well, thank you for that correction, sir.

CONTINUED BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: The December 18th, 2015, so about eighteen (18) months or so or actually twenty (20) months -- or one month after that Manitoba Hydro project was signed with BBE?

MR. DAN CAMPBELL: If your math is correct, yes.

MS. HELGA VAN IDERSTINE: And that's a dangerous thing, I will warn you. The -- the -- so again, looking back to the market in that period of time, you'll recall that sometime in mid 2014, the market, the oil prices dropped and a lot of the big oil projects that had been planned dropped out of the marketplace.

Do you recall that?

MR. DAN CAMPBELL: Unfortunately, yes.

It affected the engineers as well.

MS. HELGA VAN IDERSTINE: I guess. That's why I thought you might actually remember it.

So -- so a different market than that this contract was ca -- signed in?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And if you look at page 5 of that contract, page 7 of the book of documents, you'll see under Contract Price and then entire compensation and if you look at that, would you agree that that's a unit price contract?

(BRIEF PAUSE)

MR. DAN CAMPBELL: Yes, fundamentally.

MS. HELGA VAN IDERSTINE: There's always nuances.

MR. DAN CAMPBELL: Exactly.

MS. HELGA VAN IDERSTINE: And so if we look over then -- so then, as you would also be aware, and I'm -- I'm -- you can confirm, you didn't give evidence before the BC Utilities Commission when the Site C project was being reviewed last summer, did you?

MR. DAN CAMPBELL: No.

MS. HELGA VAN IDERSTINE: Okay. But you were aware that it was going on.

MR. DAN CAMPBELL: Obviously, yes.

MS. HELGA VAN IDERSTINE: So if you look over to page 15 of the documentation in our book of authorities and what this is is an excerpt from the BCUC's decision and on this section there -- on page 15, they are just -- their reviewing the comments made by Deloitte in a report they provided to PU -- the BCUC.

And if you look down at the bottom of the page, you'll note that it says:

> "Deloitte noted that PRHP plans to submit a claim to BC Hydro for the delay caused by the first tension crack on left bank. Also Deloitte reported that discussions were underway between BC Hydro and the -- and PRHP regarding how the delays caused by the second left bank to crack in May 2017 could be mitigated, and that PRHP had suggested that more claims are to come."

And PRHP, of course, is the contractor?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And as a consequence of delays they appear to be issuing claims?

MR. DAN CAMPBELL: In the contract of the nature of that BC Hydro signed with them, the way for the contractor to get additional funding is often through claims. And there's certainly claims have been filed on the project and there's certainly dispute as to whether those claims are a function of the contractor's work, or others.

MS. HELGA VAN IDERSTINE: And, no, I wasn't trying to cast aspersions one way or the other --

MR. DAN CAMPBELL: No, I'm just commenting.

MS. HELGA VAN IDERSTINE: -- and that's -- but I -- I agree. That's one of the troubling problems that results when as soon as the contractor's profit is at risk; is that correct?

MR. DAN CAMPBELL: I don't think the contractor's profit necessarily has to be at risk. He's just looking for -- he may just be looking for additional profit.

MS. HELGA VAN IDERSTINE: And if we

look over to -- and again, in the summer when BCUC was reviewing the Site C budget, it was initially presented as being at 8.3 billion, and was being described at that time as a P50 and if you look over at page -- the top of page 16, you can see where that's being described by Deloitte.

Do you see that?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And they go on to state that BC Hydro was using up a large part -- portion of their contingency, in fact, on page 12 -- going back one page, sorry for jumping around a bit, but going back one page. They describe it as having used up 45 percent of their contingency when they were only two (2) years into the project.

MR. DAN CAMPBELL: Do you mean total project contingency or just contingency for this contract because this particular contract is only for the earthworks piece, it's not for the concrete work or for the equipment supply?

MS. HELGA VAN IDERSTINE: Okay, so I'm -- what I'm referring to is actually the third bullet -- third paragraph from the bottom on page 15 of the book of documents.

"Deloitte further noted that

"contingency at 356 million committed to date represents 45 percent of the budgeted cost contingency of 794 million, a percent significantly higher than the 22 percent of the total budget spent to date."

So again, the co -- the contingency appeared to be used -- being used up faster than the project was progressing?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And then if I can take you to page 18, which is in the BCUC's findings section and it's just above the line where they say "other implications of continuing Site C."

"BC Hydro comes to the conclusion [and then they say] however, given the nature of this type of project and what has incurred to date total cost of the project may be in excess of 10 billion and there are significant risks that could lead to further budget overruns."

Now the reason -- and you'll be aware, of course, that the initial budget that they were represent -- that BC Hydro was presenting was 8.3

billion, is that what -- correct?

MR. DAN CAMPBELL: Again, if your math is correct. Sure.

MS. HELGA VAN IDERSTINE: So and as I understand it, Site C is behind in its estimated completion dates?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: And am I right when I say that they're about two (2) years into a nine (9) year project?

MR. DAN CAMPBELL: That's I believe approximately correct.

MS. HELGA VAN IDERSTINE: Okay and now I'd like to look -- ask you a few questions about Muskrat Falls.

Were you involved at all in Muskrat Falls?

MR. DAN CAMPBELL: No.

MS. HELGA VAN IDERSTINE: So you and I and may be subject then to what we read in the news and so I put forward on -- on tabs -- or pages 19 an article which appeared in the -- in Global News on June 23rd, 2017. And I'm going to ask you -- take you to something on that in a minute, but first of all, you are familiar with Muskrat Falls just generally because of your knowledge of the hydroelectric projects in Canada.

MR. DAN CAMPBELL: Yes, I'm aware of that particular project, and that it's overbudget if that's where you're going.

MS. HELGA VAN IDERSTINE: Well, I am going there but I was going to say -- start off by saying, again, like Keeyask, it's a remote project?

MR. DAN CAMPBELL: Yes.

MS. HELGA VAN IDERSTINE: But unlike Keeyask there's a large town -- a larger town nearby being Goose Bay?

MR. DAN CAMPBELL: Having been to Goose Bay I wouldn't describe it as large, but okay.

MS. HELGA VAN IDERSTINE: I think I said "larger." And do -- do you happen to know what the contract model on that was?

MR. DAN CAMPBELL: No.

MS. HELGA VAN IDERSTINE: And I don't think Global reported on that either. So, we'll have to leave it at that.

And you've ment -- commented that they're overbudget and this budget suggests that the budget from 5 billion to 12 billion.

Does that sort of meet with what you

understand the magnitude of the overruns to be?

MR. DAN CAMPBELL: My understanding is the magnitude of the overruns on Muskrat are significantly more than on Keeyask or what is anticipated for Site C.

MS. HELGA VAN IDERSTINE: And so -- and one (1) of the current issues and a major dispute right now for Muskrat Falls -- and again, the reason I put this article in was because if you look over at page... Sorry, if you look over to page 26 which is actually the CBC report, there is the headline that the -- about the dispute with their contractor and they say:

> "Both sides are at odds with a stall demanding hundreds of millions in additional payments from Nalcor."

And again, challenges with the con -- managing the contractor in this site -- at site -- at Muskrat Falls? That's what appears to be the problem or a problem? I shouldn't say --

MR. DAN CAMPBELL: I don't know what the problems are because I haven't looked at it.

MS. HELGA VAN IDERSTINE: We'll leave that then. But I think it -- would it be fair to say that contracting strategy alone doesn't define the success or even a guarantee that a project will be on time?

MR. DAN CAMPBELL: Yes, I would say that's true. It helps to have a contractor who is responsive to the contracting strategy he's working with.

MS. HELGA VAN IDERSTINE: And fair to say that in huge hydroelectric generating projects that regardless of the type of project -- contractor project, that once the contractor seeing its profit eroded, we see those types of claims starting to -- to come forward?

MR. DAN CAMPBELL: As I said earlier, all contractors are looking for opportunity to make additional funding and it's been my experience whether or not it's a large contract or a small contract, whether it's domestic or international, the -- the contractor is looking for reasons to claim often, not always, but often.

MS. HELGA VAN IDERSTINE: So I'd like to -- to turn to the -- another topic now. And, Mr. Adams, I think I may have some questions for you.

First, can we agree that until May of 2016, when the contractor fell behind on the permanent earthworks and concrete, that Keeyask was generally on budget and schedule?

MR. CAMPBELL ADAMS: I believe it was for the first couple of years, yes.

MS. HELGA VAN IDERSTINE: And that when it became apparent that there were problems sometime in the summer of 2016, meaning that when those events occurred that the contractor fell behind and in putting in the concrete, that Manitoba Hydro then acted upon it.

And I'm going to ask you some questions about -- about that and specifics about what they did but, is it fair to say that they -- they did act upon it?

MR. CAMPBELL ADAMS: Yes, my understanding is that the -- the volume of concrete, I think it was, that was placed in quarter two of 2016 was so small that you didn't need really to look at the schedule to understand there was an issue.

And I believe a recovery plan was requested by Hydro, which was appropriate in accordance with the contract as I understand.

MS. HELGA VAN IDERSTINE: Right. And so some of the things they took over this -- summer, falls -- they took it in a stepwise fashion to get things moving and some of the things they did, as I understand it, was -- and -- they met with the GCC -- or GCC to -- to discuss it which would be appropriate.

MR. CAMPBELL ADAMS: Yeah.

MS. HELGA VAN IDERSTINE: They determined what -- they started working to determine what the root causes of the problem were that the contractor was experiencing and that would be appropriate?

MR. CAMPBELL ADAMS: That would be appropriate.

MS. HELGA VAN IDERSTINE: And I think you would -- you said earlier that you'd need to identify those roots -- causes before you could successfully plan how to remediate?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And Manitoba Hydro and the GC then developed a plan for continuing concrete through the winter months?

MR. CAMPBELL ADAMS: I believe so.

MS. HELGA VAN IDERSTINE: And they initiated activities to reforecast the cost and the schedule for the project?

MR. CAMPBELL ADAMS: As part of the negotiation do you mean?

MS. HELGA VAN IDERSTINE: Both part of

the negot -- prior to the negotiations of the amending contract, they started doing those discussions?

MR. CAMPBELL ADAMS: I don't know about that.

MS. HELGA VAN IDERSTINE: But that would be something appropriate to do?

MR. CAMPBELL ADAMS: If you've got an underperforming contractor, yes, you've got to be engaged.

MS. HELGA VAN IDERSTINE: Yeah and that's what you were saying. You've got to be engaged with them?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And they started looking at the contractor's claims as well as -- another thing just to do as you are moving forward?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And they supplemented and -- and I think you under -- saw and from the evidence that they supplemented the expertise of the Manitoba Hydro team by retaining KPMG?

MR. CAMPBELL ADAMS: I believe so. I don't know -- I don't know the expertise that was provided.

MS. HELGA VAN IDERSTINE: They sought legal advice from a large law firm BLG, did you know that?

MR. CAMPBELL ADAMS: Yes, I read that.

MS. HELGA VAN IDERSTINE: Again, that would be a reasonable thing to do?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And they sought advice from an estimating -- from validation estimating?

MR. CAMPBELL ADAMS: I believe they did, yes.

MS. HELGA VAN IDERSTINE: Perhaps to assist with their budgeting process and how this might impact their costs going forward?

MR. CAMPBELL ADAMS: At a high level, yes. The actual work they did, I don't know.

MS. HELGA VAN IDERSTINE: Okay. They retain --

MR. CAMPBELL ADAMS: So, just -- my point is, I don't know the degree to which work was undertaken to get done to the root causes that caused the issues in 2016.

MS. HELGA VAN IDERSTINE: Fair enough. They retained a claims company called Revay.

Are you familiar with them?

MR. CAMPBELL ADAMS: I have heard of Revay, yes.

MS. HELGA VAN IDERSTINE: And, of course, we know that there was a review conducted by the Boston Consulting Group around the same time?

MR. CAMPBELL ADAMS: Yes, I've heard of that.

MS. HELGA VAN IDERSTINE: Then I had a cold eyes review done to give them some advice, generally?

MR. CAMPBELL ADAMS: By -- by whom?

MS. HELGA VAN IDERSTINE: Does it matter?

MR. CAMPBELL ADAMS: It might be depends who it is.

MS. HELGA VAN IDERSTINE: Okay.

MR. CAMPBELL ADAMS: Like in relation to the issues, if you've got productivity issues and you pick the wrong person to give you advice it's not going to be very helpful.

MS. HELGA VAN IDERSTINE: Sorry, I'm -- you said depend on -- on the personnel --

MR. CAMPBELL ADAMS: Depends on the nature of the issue you're trying to understand who you would turn to to get that advice. Like KPMG, I didn't think did construction work.

MS. HELGA VAN IDERSTINE: Okay, what about --

MR. CAMPBELL ADAMS: That might be my ignorance.

MS. HELGA VAN IDERSTINE: -- some of -- utilizing people such as retired Manitoba Hydro employees who had construction experience that conn -- people with general contracting experience in the area; that sort of --

MR. CAMPBELL ADAMS: I think if they drew upon people who had work for contractors and planned activities like concreting, how to place formwork, how to place rebar, how to pour, that would be useful given the productivity issues experienced.

MS. HELGA VAN IDERSTINE: And they involved Hatch Engineering to provide them with some further advice and assistance?

MR. CAMPBELL ADAMS: They're -- they're an engineer --

MS. HELGA VAN IDERSTINE: And again --

MR. CAMPBELL ADAMS: I don't -- I don't know how that helps.

MS. HELGA VAN IDERSTINE: Well, it

might -- I'm going to get to that but one (1) of the areas that they might engage an engineer to do and Mr. Campbell might be able to provide us with some assistance on that, would be to help them with some design choices that would help move the project forward in a more efficient manner?

MR. CAMPBELL ADAMS: Yes, that would be a worthwhile activity.

MS. HELGA VAN IDERSTINE: Mr. -- Mr. Campbell, that would be correct? Since we've got our expert here.

MR. DAN CAMPBELL: It's always good to have an engineer on board.

MR. CAMPBELL ADAMS: I say the same for quantity surveyors.

MS. HELGA VAN IDERSTINE: And as we know, when things didn't resolve over the summer they moved to the next step and the next step was to -- looking at the contract and determining whether -- how they would proceed forward with the contract.

And in this circumstance, what they did was amended it. You're of aware?

MR. CAMPBELL ADAMS: Yes, I'm aware they considered dispensing with the contractor and looking at other options but they ended up deciding to stay with BBE.

MS. HELGA VAN IDERSTINE: And again, having that -- doing that kind of analysis and making those kind of decisions would be the appropriate review and decision-making tree that somebody would -- that you'd expect an organization to do in those kind of circumstances?

MR. CAMPBELL ADAMS: Yes. The -- the thing I haven't seen, and you referred to earlier, is the working on the root causes of what caused the poor productivity.

MS. HELGA VAN IDERSTINE: Okay.

MR. CAMPBELL ADAMS: But that, to our team, seems to be the root of the evil.

MS. HELGA VAN IDERSTINE: Okay. And in terms of amending the contract, I think you'll agree that that can only be done by mutual agreement?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: In fact, I think in response to one (1) of the Coalition questions you actually said:

> "To attempt to change this would significant change the risk allocation of the contract currently in place, and might be difficult to

achieve."

MR. CAMPBELL ADAMS: Yeah.

MS. HELGA VAN IDERSTINE: And again, if you tried to make unilateral changes to a contract as some had suggested, what would happen is you risk breaching the contract or -- and any other -- and the fallout that might come from that?

MR. CAMPBELL ADAMS: You can't amend the contract without the -- the agreement of the other party. So, I don't believe it could be imposed on the other party.

MS. HELGA VAN IDERSTINE: And so --

MR. CAMPBELL ADAMS: The other -- other comment or observation I would make the -- you mentioned about the -- the hot market. I'm not sure the market was that hot at the time this amending agreement was reconsidered, or considered.

MS. HELGA VAN IDERSTINE: Okay.

MR. CAMPBELL ADAMS: Oil was a lot less. Alberta was pretty quiet.

MS. HELGA VAN IDERSTINE: So again, using that as an example, then one (1) of the things that goes into the -- even doing something like the amending agreements or the gives and takes of things like the market conditions and what strength two negotiating parties have with respect to the -- to moving forward?

MR. CAMPBELL ADAMS: Yes, and how each party views the risks of where the -- what's happened to get them where they are today and what's it likely to be going forward. And the biggest risk to Hydro was cost.

MS. HELGA VAN IDERSTINE: Well and -- and -- or not having a complete project?

MR. CAMPBELL ADAMS: Why would you say that?

MS. HELGA VAN IDERSTINE: Well, if the contractor decides to walk away then there's a -- they've got a problem.

MR. CAMPBELL ADAMS: Well, you can get another contractor.

MS. HELGA VAN IDERSTINE: So let's talk about your recommendations for -- from your report. And if we ignore -- sorry, can we go to IR Manitoba Hydro/MGF-1 -- or round 1, question 2(j).

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: So -- and just before I ask you some questions on this one, Mr.

Adams, I just want to follow-up on the last response you had.

In order to get another contractor in place, obviously, the time would -- it would take time to re-tender that?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And during that time there'd be delay costs associated with all the indirect and directs that have of -- or all the other contracts that -- and contractors that are now not working because that's not pro -- work is not proceeding?

MR. CAMPBELL ADAMS: There is normally a provision to suspend work, but there would be cost, for sure, yes.

MS. HELGA VAN IDERSTINE: And you've got a -- the camp at Keeyask is about twenty-four hundred (2400) people and those people would not be working?

MR. CAMPBELL ADAMS: That's the -- that's a capacity if the contractor has left and those people go with him.

MS. HELGA VAN IDERSTINE: Yeah. So, those would be some of the problems you'd have if the contractor just walked away?

MR. CAMPBELL ADAMS: Those would be part of the switching costs, I agree, yes. It's not an easy decision to make but it's...

MS. HELGA VAN IDERSTINE: No, it's not and there'd be other costs of equipment sitting dormant; the -- the work that had been done, possibly deteriorating while that stoppage of work occurs?

MR. CAMPBELL ADAMS: Yes. Typically, we would have to protect the work that had been built and if there's other equipment sitting on site that has to be preserved and maintained.

MS. HELGA VAN IDERSTINE: And then after you do get a new contract, it would take time to bring onboard the new staff, get them up to speed, get the -- get the site recommissioned and then move forward?

MR. CAMPBELL ADAMS: Yes, there is -- there's a learning curve for another contractor, yes.

MS. HELGA VAN IDERSTINE: And all that would have additional costs?

MR. CAMPBELL ADAMS: There would be costs to that, yes.

MS. HELGA VAN IDERSTINE: So as -- so if we can look at this IR that I've got right here, the recommendation -- the question was: Can MGF please identify the risks to the Keeyask project that aros -- arr -- would arise by Manitoba Hydro taking on this type of role?

And the type of role that was being asked about was -- was the -- was construction manager. And your answer was:

"The recommendation is not for Manitoba Hydro to become the construction manager and replace BBE but for Manitoba Hydro to exert more control and hold BBE accountable for its performance."

Do you see that?

MR. CAMPBELL ADAMS: I do see that.

MS. HELGA VAN IDERSTINE: So I take it then with that answer, we can ignore the recommendation that you make on page 81 of your report where you had stated, all:

"As all construction decisions affect Manitoba Hydro financially, therefore, they need to move actively into the role of construction manager guiding and instructing the contractor on more efficient crew makeups, work

methods, shift lengths and
supervision."

MR. CAMPBELL ADAMS: Can I see that on the screen, please.

MS. HELGA VAN IDERSTINE: Yep, you can. It's the top of the page.

MR. CAMPBELL ADAMS: No, I don't think that they're mutually exclusive. The cost reimbursable is the -- if an owner needs to be more engaged on a contract, that is a pricing mechanism on which it has to be engaged because there's no ceiling or lid on it. For every day that is not spent well, that adds to the cost of -- to the -- to the owner.

Our -- our view is the -- that BBE has let Hydro down in two (2) consecutive years. Our experience of managing cost reimbursable projects in the past, is you've got to get -- you've got to work side-by-side. You've got to watch what they do because if they get it right, great; if they don't get it right, it's your money that's being wasted.

There's a different approach to managing a cost reimbursable priced contract versus that of the lump-sum. And when things are going wrong repeatedly, I don't see how an owner can stand off. You've -- you've got to get involved and getting down to those root causes as we spoke to you earlier.

MS. HELGA VAN IDERSTINE: But the term "construction manager" has a specific definition, and you're not suggesting that Manitoba Hydro, as I understood from this IR, step in and replace BBE as the construction manager?

MR. CAMPBELL ADAMS: That is correct, we're not saying replace them -- Hydro becomes the construction manager. It's perform the role of a construction manager. It's manage -- it's help manage your own money.

MS. HELGA VAN IDERSTINE: Yeah, but I -- I want to be clear, the activities you identify here: crew makeup, work methods, shift length, supervision, those are all the means and methods of a general contractor; aren't they.

MR. CAMPBELL ADAMS: Yes, they are and something's not working so I don't -- I can't agree to just letting it go on beca -- if it's not working. They've got to understand how crews are made up; how the work is being planned; understand the resources then watch it happen and if you let me finish.

As -- as you're watching it unfold. If it works understand that and repeat that, but if it didn't work as planned, why did it not work as planned

How do we learn from this so that subsequent concrete pours, for example, are done better.

MS. HELGA VAN IDERSTINE: But you'll agree there's a distinction by -- about learning from something and putting in some changes to the project being distinct and different from taking over managing crew makeup, work methods, shift lengths or supervision, which are all the means and methods of the construction manager, i.e., GC --

MR. CAMPBELL ADAMS: Exactly.

MS. HELGA VAN IDERSTINE: So that's quite something different. And it would be appropriate -- because if Manitoba Hydro were to step in and take active role over doing those things, it would lead to an allegation that they had -- were then acting as the construction manager or the GC?

MR. CAMPBELL ADAMS: Okay.

MS. HELGA VAN IDERSTINE: And if they were to do that they would expose themselves to financial risk.

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: Again, let me try to clarify this. It is not -- we're not recommending that Hydro replace BBE and Hydro becomes the construction manager.

We are recommending that Hydro understands how work is being planned, how the crews are being made, how the -- the work is being sequenced. To understand that it's going to work and if doesn't, why does it not.

That typically, in our experience, means that Hydro would have people in the field as work is being planned and work is being executed. I think I heard an example that quality control wasn't working that well originally and that the two (2) quality divisions of the contractor and Hydro were actually merged to make it work more efficiently.

MS. HELGA VAN IDERSTINE: So, Mr. Adams yester -- or earlier this morning, you used the two (2) phrases that I noted down to des -- I think to describe what you're talking about now. And one (1) of those you said:

"Is that the owner needs to hold the contractor's feet to the fire and you want --

Do you remember saying that?

MR. DAN CAMPBELL: Yes, I do.

MS. HELGA VAN IDERSTINE: And you also

used the phrase:

"They need to work hand-in-hand with their contractor..."

Or words to that effect. Do you recall saying that?

MR. CAMPBELL ADAMS: Okay.

MS. HELGA VAN IDERSTINE: And so if I understood what you're saying this morning and perhaps this afternoon, is that there's a fine balance that the owner has to work with at that point where they are both trying to move the contractor ahead through perhaps the stick method, but at the same time using the carrot to help to work with them to move things cooperatively and collaboratively ahead?

MR. CAMPBELL ADAMS: My experience of cost reimbursable contracts, the -- the owner's team and the contractor's team are typically working side-by-side. They've -- they've got staff in the same place.

The comment about holding a contractor's feet to the fire is there is a contract in place that needs to be managed. The contractor needs to perform his -- his obligations. For example, if -- if Hydro has stated in its contract that no activity should have negative float, why do you lie

1,030; that to me -- that to me is an opportunity to enforce the contract.

If your monthly report should come in at a certain day why accept it ten (10) days later? These -- these are --

MS. HELGA VAN IDERSTINE: So I -- and -- so I'll come back to that. I just want to correct you on that --

MR. WILLIAM HAIGHT: I -- I think he was -- wasn't finished answering his question there.

MR. CAMPBELL ADAMS: The rigour with which -- thank you. The rigour with which you manage a contract I think -- I don't think -- it's -- it's different from a lump-sum to a cost reimbursable priced one. They're -- they're different risks, but you still have to manage the contract.

CONTINUED BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: So -- so let's talk a little bit about what Manitoba Hydro does and -- and I think you used the word this morning or earlier about, you want to embed some of the Hydro staff with BBE or the contractor?

MR. CAMPBELL ADAMS: Sorry, could you repeat that please.

MS. HELGA VAN IDERSTINE: You used the -- you used the phrase "embedding" -- or maybe that was Mr. Campbell -- the contractor with the -- now, he's shaking his head.

MR. CAMPBELL ADAMS: Co-location is -- as a normal description of that.

MS. HELGA VAN IDERSTINE: Correct. And so were you aware that Manitoba Hydro has a hundred and twenty (120) to a hundred and fifty (150) staff working on site at Keeyask on the project helping to address issues as they arise on a day-to-day basis?

MR. CAMPBELL ADAMS: I'll take you at their word. I'm only looking at the output of the performance.

MS. HELGA VAN IDERSTINE: But that's the sort of thing that you would expect Manitoba Hydro to just now put in place just to monitor that cost reimbursable contract?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And that when the problems occurred in 2016, one (1) of the things that Manitoba Hydro did was they matched up approximately thirty (30) of their area lead staff who were tasked then with keeping a very close interface with their co -- counterparts at BBE.

And that, again, would be the type of thing that you would want them to do to make sure that they were working closely with BBE to move things forward?

MR. CAMPBELL ADAMS: I guess it depends on the next level down of what those work activities are and how decisions are made. I say that because the -- the performance didn't improve in 2017. So colocation is one (1) thing, whether it's effective is another.

MS. HELGA VAN IDERSTINE: Well, let's -- I can't leave that. That's not where I was going right now, but you've used that phrase that it didn't improve in 2017 and the fact is that in 2016 things were behind. 2017, things did improve. They may not have improved as much as they would've liked, but they certainly improve.

MR. CAMPBELL ADAMS: My comment is based on the contractor promise to do X and the contractor did less than X.

MS. HELGA VAN IDERSTINE: But they improved?

MR. CAMPBELL ADAMS: Productivity didn't, it got worse.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: And at that point in the contract, again, -- or in the project, the complexity of those items that were being installed in 2017 were more complex?

MR. CAMPBELL ADAMS: I believe they were but the contractor's plan should have taken note of that.

MS. HELGA VAN IDERSTINE: And that with that complexity of the first unit, you'd expect productivity to improve as they moved along repeating those tasks?

MR. CAMPBELL ADAMS: That's what you'd expect.

MS. HELGA VAN IDERSTINE: Yeah. And so as they put the -- some of the concrete -- the more complicated concrete in this summer, as they move forward on those tasks over the next year or so you would expect the productivities to start to improve?

MR. CAMPBELL ADAMS: Possibly if it's the same people doing the work.

MS. HELGA VAN IDERSTINE: Were you aware -- we talked about some of the things that Manitoba Hydro's done and does to stay closely aligned with its contractor, and were you aware that one (1) of the things that they've done is they've got -- a cost control team led by a Mr. Strongman who monitors budget and expenses and performance on a day-to-day basis? Are you aware of that?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And that would, again, be something that would be a reasonable thing to be doing?

MR. CAMPBELL ADAMS: Yes, it's a cost reimbursable contract. You keep a score of the costs and then you pay them.

MS. HELGA VAN IDERSTINE: One of the things you -- I think -- and again, maybe I do have this one right, Mr. Campbell had raised this morning was a concern that delays may have -- might occur as scheduling moves forward.

And one (1) of the things you mentioned was the -- the competition for the crane by various -- by the two (2) contractors? Or was that you, Mr. Adams?

MR. DAN CAMPBELL: That was me and yes.

MS. HELGA VAN IDERSTINE: And so were you aware and perhaps you wouldn't be, that Manitoba

Hydro has hired a crane coordinator to make -- to deal with just that type of problem?

MR. DAN CAMPBELL: I was not aware of that but it does make sense.

MS. HELGA VAN IDERSTINE: And again that would -- again help address these potential problems of scheduling that might occur.

MR. DAN CAMPBELL: Hopefully.

MS. HELGA VAN IDERSTINE: And, Ms. Musfelt, I think earlier today you mentioned something about concern about BBE not having their schedule in.

MS. VALERIE MUSFELT: I don't remember making that statement about them not having a schedule in.

MS. HELGA VAN IDERSTINE: Sorry, the schedule was negative float that they were to address?

MS. VALERIE MUSFELT: Yes, basically the schedule that I was looking at which was dated the 6th of October, 2017, the BBE contract or BBE schedule was showing one thousand and thirty (1,030) activities that were showing negative float.

And those were a direct result of fifteen (15) constraints that were within the schedule. So that -- those fifteen (15) constraints were causing the one thousand and thirty (1030) negative float items.

MS. HELGA VAN IDERSTINE: And if that -- if I were to tell you that by November of 2017 that schedule had been addressed and there was no longer a negative float would that --

MS. VALERIE MUSFELT: I never seen that schedule so I can't comment as to that.

MS. HELGA VAN IDERSTINE: Okay but that's sort of thing you'd expect them to be moving forward with and doing and that would help resolve some of the concerns you have?

MS. VALERIE MUSFELT: That is correct.

MS. HELGA VAN IDERSTINE: And, Ms. Musfelt, in your -- on -- if I could get you to go to slide 12 of your presentation. And in -- and this is a presentation you have a graph that provides a different timelines for the completion of Keeyask?

MS. VALERIE MUSFELT: Yes, this is the Unit 7 turbine generator.

MS. HELGA VAN IDERSTINE: And in those slides you have October 21st as the plan completion date?

MS. VALERIE MUSFELT: Yes.

MS. HELGA VAN IDERSTINE: And January 20 -- 2022 as the BBE forecast completion date?

MS. VALERIE MUSFELT: I think that's on the previous slide, the date. So there's two (2) different things that this -- this particular slide here is referring to just really the BBE schedule. This one here is referring to the integrated master schedule.

So what you're basically seeing here is that as a result of BBE's slippage, it's ca -- when they integrate the -- the Voith schedule into the integrated master, their -- Voith is forecasting an additional delay on Units 5 through 7 which is pushing it out to the 28th of May as opposed to BBE's date of January.

MS. HELGA VAN IDERSTINE: So if we go back to the previous slide. Using that January 22nd -- or January 2022 date that -- what you're suggesting is that BBE is forecasting a delay --

MS. VALERIE MUSFELT: Of a hundred and three (103) days, yes. So as of 6th of October, their progress or their forecast schedule, which is the schedule that shows progress on the project, they're forecasting that they are now going to put Unit 7 in-service on the 23rd of January, 2022.

MS. HELGA VAN IDERSTINE: And again, appreciating that you don't have -- haven't seen their updated schedule that may -- may change the information that you would have?

MS. VALERIE MUSFELT: Absolutely. Every -- every single progress update made to a schedule is going to change the impact.

MS. HELGA VAN IDERSTINE: And if that was the case then there'd be no negative floats and we wouldn't have to worry about the -- the delay date that you've identified?

MS. VALERIE MUSFELT: It's very -- I can't comment without seeing what the schedule looks like.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: And in preparing those kind of -- that schedule, it would be important and I think -- and if -- to include and -- and I'd think you'd agree, that the work being planned use actual production rates for concrete and earthworks to be achieved by BBE in 2016 and 2017?

MS. VALERIE MUSFELT: Yes. So it was a -- a document provided by Manitoba Hydro, which showed the actual productivity of BBE from the period October 2016 to September 2017.

MS. HELGA VAN IDERSTINE: And then using the -- the updated materials and information that Manitoba Hydro has and BBE had, they would then submit monthly targets for concrete and earthworks consistent with the information they have going forward?

MS. VALERIE MUSFELT: That is correct.

MS. HELGA VAN IDERSTINE: And that could, again, rollback that -- that date closer to the planned-in service dates?

MS. VALERIE MUSFELT: Well, there again, a forecast date is exactly that, a forecast so it's going to be based on them correctly forecasting their productivity.

So if they're forecasting a higher level of productivity than what they're actually achieving then I -- I can't verify what the dates would be.

MS. HELGA VAN IDERSTINE: And if they included more time and -- for winter concrete work and winter work on the south dike, for example, that would tend to improve the forecasts?

MS. VALERIE MUSFELT: The -- the winter concrete is -- is -- is an option to help bring the schedule back in line. But winter concrete number

1 is typically less productive, and number 2, it's extremely expensive.

MS. HELGA VAN IDERSTINE: Okay. And if -- and if they were getting better productivity rates using the -- as they move forward that too would impact the schedule?

MS. VALERIE MUSFELT: I'm sorry, could you repeat the question?

MS. HELGA VAN IDERSTINE: So if they're getting better production rates that too would impact the schedule?

MS. VALERIE MUSFELT: Definitely.

MS. HELGA VAN IDERSTINE: Again, some of the other things that might help improve the schedule and would be things like design changes that Manitoba Hydro took on to improve cost and performance; things such as investing in new forms which are easier to use and then thus will shorten the time required to install portions of the draft tube on the remaining five (5) units.

MS. VALERIE MUSFELT: I think I would defer that question to a subject matter expert.

MS. HELGA VAN IDERSTINE: Okay, Mr. Campbell perhaps.

MR. DAN CAMPBELL: Making the draft

tubes easier to build is definitely going to improve the schedule.

MS. HELGA VAN IDERSTINE: And how about you -- they're going to use column extenders in the powerhouse and intake to allow structural steel to be installed at lower elevations; would that improve -- that's an anticipated improvement on the schedule?

MR. DAN CAMPBELL: I can't comment on that specifically. A general comment would be that the schedule has to fundamentally make sense and the integration of it together with the -- with the other contractors and, particularly, Voith and in specifically looking at the powerhouse, because without referring back to the schedule, I'm suspecting that the powerhouse is the critical path object and that the dikes and the spillway are I presume -- there's hope that they'll be done on time, right.

MS. HELGA VAN IDERSTINE: So if I -- if I added to that comment and said that the reason that -- by using the column extenders they're going to have an opportunity to enclose the powerhouse and service bay earlier and thereby improve the schedule by a year on that item, that would obviously be something that would improve and lead to better outcomes?

MR. DAN CAMPBELL: The sooner you get the powerhouse enclosed the better off you're going to be.

MS. HELGA VAN IDERSTINE: And you mentioned this dike work that was being -- needed to be done. As I understand, they've had some supporting design changes to -- on that to get the south dike work done in 2018 so that it doesn't delay any project -- any further -- the project any further.

Would that also assist in the final scheduling and the costs?

MR. DAN CAMPBELL: It may or may not impact the cost. I suspect the cost might go up but that's my cynical view. The -- it -- it may improve the schedule for that item which, if it's on the critical path, would be of -- advantageous.

MS. HELGA VAN IDERSTINE: In any event, these types of initiatives, this sort of thought process that Manitoba Hydro has gone through and the steps they're taking, are all the sort of things that you would expect to improve the chances for their having -- coming in on budget and on schedule?

MR. DAN CAMPBELL: Is that a question for me or for Campbell?

MS. HELGA VAN IDERSTINE: You'll do.

MR. DAN CAMPBELL: It's better than some people say. Yes, all of the things that you've mentioned are reasonable -- are proper things that should be done.

MS. HELGA VAN IDERSTINE: So, Mr. Adams, I am going to move on to another topic and what I wanted to talk to you about is the 9.5 to 10.5 billion --

THE CHAIRPERSON: Ms. Van Iderstine, I'm just wondering if it's appropriate to take a short break at this time?

MS. HELGA VAN IDERSTINE: Perfect.

THE CHAIRPERSON: Great.

MS. HELGA VAN IDERSTINE: Thank you.

THE CHAIRPERSON: As soon as she said "new topic" I -- fifteen (15) minutes.

--- Upon recessing at 2:42 p.m.

--- Upon resuming at 3:03 p.m.

THE CHAIRPERSON: Before we start, Ms. Kapitany had a question.

THE VICE-CHAIRPERSON: So my question is on this issue of negative float and I did read about it in your report at page 43. And I must confess, before that I didn't know what negative float was, and I'm still not totally sure I know what it is.

But what I heard the discussion between Ms. Van Iderstine and you was that in your report in October you talked about a number of incidents of negative float and some constraints that had caused that. And that that was a real bottleneck or real problem for the schedule.

MS. VALERIE MUSFELT: Yes.

THE VICE-CHAIRPERSON: Could you expand on that a bit?

MS. VALERIE MUSFELT: Okay, the definition of negative float is activities that are extremely critical, but when you're looking at a P6 schedule, what causes negative float are constraints on the schedule. So if you're putting constraints into the schedule and those dates then aren't met, now, you start getting into a negative float situation.

So what it's really highlighting are activities that -- that either have not met their -- a scheduled or constrained dates or that will not in future meet those scheduled or constrained dates.

So that's really what it's telling you.

So, it just means that these are all activities that have missed the dates, the hard dates that have been put into the schedule. So they're activities that have slipped.

THE VICE-CHAIRPERSON: Okay. And so you said when you reviewed the schedule in October, October of 2017, there were these incidents of negative float?

MS. VALERIE MUSFELT: That is correct.

THE VICE-CHAIRPERSON: And, Ms. Van Iderstine, you said that in November of 2017 they were gone but I didn't see that in either the Manitoba Hydro rebuttal evidence. I didn't see it in the direct evidence. So I'm just wondering where that has come on the public record and what we should be making of that.

MS. VALERIE MUSFELT: I've -- having not seen the schedule, the last schedule that I seen was stated 6th of October, so it is possible that in their next update that they may have removed some of the constraints that might have caused some of that negative float, but I -- I can't really speak to it because I haven't seen the schedule.

THE VICE-CHAIRPERSON: That would be a good thing if that had happened.

MS. VALERIE MUSFELT: Yes, that would be a good thing.

MS. HELGA VAN IDERSTINE: Yeah and I'm informed, just to give some clarity to that, that an undertaking was given with respect to the schedule and when that schedule is like fully completed in terms of ... in a form that can be provided, it will be provided as part of the undertaking.

THE VICE-CHAIRPERSON: Okay. So then that evidence will be on the --

MS. HELGA VAN IDERSTINE: Sorry, I've switched microphones. It's a further away then I -- then the previous one, so. How's that?

So what I -- so what I just said was that there was an undertaking given to produce the schedule and it is just being completed now and is put into a form that can be produced as the undertaking and when that's done, it will be evidence in the proceeding.

THE VICE-CHAIRPERSON: Okay, thank you.

THE CHAIRPERSON: Thank you. Ms. Van Iderstine, do you want to -- would you like to continue? Yes, thank you.

MS. HELGA VAN IDERSTINE: So let me

know if I'm too close or too far to the microphone.

MS. VALERIE MUSFELT: One (1) of the -- the things that I seen on the -- the integrated master schedule is it's very hard the way it sits right now because of the constraints, you can't see a true critical path on the schedule.

So, for example, the integrated master schedule is showing of -- I think it was -- the date was the 23rd of May for unit 7 to come in service, but the actual -- there's an activity that isn't happening till September 1st, 2022. So what that means is there's constraints in the schedule that you do not allow you to see the correct critical path to start with, and that's been -- you know, that's part of the problem and then the negative float, all you're really saying is that there are activities that have missed the date that they -- when they were supposed to happen.

THE VICE-CHAIRPERSON: Okay, I didn't really get that so apologies, but you are talking then about a schedule item for 2022, that could impact something that's going to happen before that or after that. And so, how does that relate to the whole concept of negative float?

MS. VALERIE MUSFELT: Okay. I -- I've

been told it's called schedule mumbo-jumbo. Okay, what causes negative float on a schedule are when people put hard dates in. So rather than letting the logic dictate when an activity is going to start and finish, you're basically putting a date in and saying, this is when it's going to happen.

So on the integrated master schedule there are such dates in there. So, for example, the unit 7 would go into service in May, but the last activity on the schedule is not until September 2022, which means there are several months in there that -- afloat. So you can't really tell what the finished -- or what the critical path is because as long as there's float on the schedule, there is no critical path.

And that's part of the problem when you're talking about constraints is they lead to negative float because if any of those dates are missed. So if I say that I'm going to have an activity that supposed to finish by, let's say, March, 2018, March 31st, 2018, if it does not finish on time now it will have negative float.

So that's really what you're saying and when you're working with a critical path method, which is the scheduling method used by Manitoba Hydro, every single activity really should be dictated by the logic. So what has to happen before this activity and what can't happen until this activity is finished. When you put a whole bunch of fixed dates in their, you're not seeing the true logic of the schedule, and that's really what the negative float is pointing to is that there's a lot of dates that have been put into the schedule that are not necessarily being driven by logic. They're just dates that have been put in there. Does that help?

THE VICE-CHAIRPERSON: That's very helpful. Thank you. And then I'm hoping when we see the answer to this IR that that will provide the -- the other part of the picture. Thank you very much.

Sorry, an undertaking not an IR, apologies.

CONTINUED BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: So, Mr. Adam -- Mr. Adams, so I am going to just turn now I think I had said to you before the break to your estimate of 9.5 to $10.5 billion into -- as the Keeyask final budget estimate.

And I understand from your evidence this morning that that is something that is neither fixed nor firm and not precise.

MR. CAMPBELL ADAMS: It's an order of magnitude estimate.

MS. HELGA VAN IDERSTINE: Meaning what I just referred to; not fixed, not firm, not precise?

MR. CAMPBELL ADAMS: If we were building an estimate based on anticipated quantities against fixed price unit rates then there would be certainly more -- more precision in a cost reimbursable price contract with the contractor who has not performed as they have promised for two (2) consecutive years, then there is a -- there's a wide ban.

MS. HELGA VAN IDERSTINE: And those numbers could go up and they could go down?

MR. CAMPBELL ADAMS: I -- I believe so depending what actions are taken.

MS. HELGA VAN IDERSTINE: And looking at your report -- and again, because you've used this order of magnitude, is that why there's nothing in your report that identifies any of the data or analysis behind that 9.5 to 10.5 billion?

MR. CAMPBELL ADAMS: What are you looking for by way of data?

MS. HELGA VAN IDERSTINE: Some

supporting information that would support the numbers 9.5 or 10.5?

MR. CAMPBELL ADAMS: The -- the numbers are taken from the final report and then summarize there to come up with the 9.9 billion and then the range is either side of that.

MS. HELGA VAN IDERSTINE: And when you say the 9.9 billion, that's the -- that's the Exhibit 4.1 from MGF that we put up this morning?

MR. CAMPBELL ADAMS: Correct.

MS. HELGA VAN IDERSTINE: And I'm going to go through some of those components, but the -- the data behind some of the information in those components is that all in your report?

MR. CAMPBELL ADAMS: The methodology is.

MS. HELGA VAN IDERSTINE: Well, we'll go through that in a moment then. So you'd agree that in order for Manitoba Hydro or the PUB to go forward and understand these calculations and act on them, it is important that they understand how those estimates were achieved at?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And then again, understanding the methodology behind those numbers that you're presenting?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: Now, you understand that Manitoba Hydro has presented an 8.75 -- or $8.7 billion number, which they described as P50 and there's now on the record that a P90 number of $9.6 billion has been presented.

When you presented your 9.5 to 10.5, are you using a P50 or a P90 number?

MR. CAMPBELL ADAMS: No. As I mentioned earlier, we did not build up the estimate on that basis.

MS. HELGA VAN IDERSTINE: And as I understand it that what you would typically do -- or -- in building up an estimate is you'd start at the ground up and work your numbers up to a point?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And that, as you understand it, I would expect from the thousands of documents you received from Manitoba Hydro is how they developed their estimate?

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: The way we built

up our -- our cost, our estimated project value was based on information we received from Hydro.

I think that the difference is we probably take a different view on the impact of the poor productivity in contra to date.

MS. HELGA VAN IDERSTINE: But just in terms of the way that one builds an estimate, you'd agree that if Manitoba Hydro built it from the ground up to getting a number and then they test that number against probabilities, that would be a way of identifying whether that number that they have is accurate and reasonable?

MR. CAMPBELL ADAMS: The method doesn't always result in an accurate and reasonable estimate. The method you speak to, I can agree to but it's how it's worked may come up -- may result in different figures.

MS. HELGA VAN IDERSTINE: And after Manitoba Hydro reaches their estimate, were you aware that they both used their in-house expertise and then they go to Validation Estimating to assist with the contingency analysis?

MR. CAMPBELL ADAMS: We believe so.

MS. HELGA VAN IDERSTINE: And are you familiar with the Validation Estimating and Mr. John

Holman?

MR. CAMPBELL ADAMS: MGF is, yes.

MS. HELGA VAN IDERSTINE: And I noticed that it was Mr. Devereux who was nodding so is that because your -- of your background with having your AACE designation or certification, membership?

MR. RYAN DEVEREUX: Yes, and he is very common in providing publications.

MS. HELGA VAN IDERSTINE: That's what I was going to say, he's a very -- he's published extensively.

MR. RYAN DEVEREUX: Correct.

MS. HELGA VAN IDERSTINE: An expert in his field?

MR. RYAN DEVEREUX: Correct.

MS. HELGA VAN IDERSTINE: And as we've heard evidence on this hearing, that P50 and P90 is a way of expressing the likelihood of the budget as presented being met.

Is that an accurate description of what the P50 or P90 is?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And it's created by doing a Monte Carlo analysis meaning the budget and the probability -- addressing the budget and the probabilities of reaching that budget?

MR. CAMPBELL ADAMS: Yes. We're not clear on the work that this fellow did. I don't know if he build up the estimate or whether he was given data and then just ran the Monte Carlo simulation.

MS. HELGA VAN IDERSTINE: But certainly -- running the Monte Carlo simulation as part of establishing the P50 or P90 bud -- budget numbers?

MR. CAMPBELL ADAMS: As a -- as a method, yes. As guaranteeing what the outcome will be, no.

MS. HELGA VAN IDERSTINE: And as I understand it, it's quite a complicated mathematical analysis in which the probability of a number of different scenarios are run against one another to come up with an outcome?

MR. CAMPBELL ADAMS: That's the definition.

MS. HELGA VAN IDERSTINE: And the primary purpose is often to provide risk-based confidence forecasts for the achievement of key milestones, including the budget end milestone?

MR. CAMPBELL ADAMS: In my experience it's to give a degree of confidence around what the party team has developed as their estimate for a contract or for a project.

MS. HELGA VAN IDERSTINE: And that's -- as you said this morning, you did not do the Monte Carlo analysis on your numbers?

MR. CAMPBELL ADAMS: Correct, we did not.

MS. HELGA VAN IDERSTINE: So, looking at the slide that's on the -- up on the monitors and that's MGF-4.1. Is it fair to say that what you've done is you've taken Manitoba Hydro's number for, as you say, spent to December 2016, that's a path number you got from Manitoba Hydro and then you've added what their estimate is excluding contingency as the second big number?

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: What was your question, sorry?

MS. HELGA VAN IDERSTINE: So you've taken information that Manitoba Hydro has given you and the first being what their costs to date or to December 31st was, together with their estimate and that's the first two (2) numbers in that chart that you've presented.

MR. CAMPBELL ADAMS: Correct, yes.

MS. HELGA VAN IDERSTINE: And after that the items from the -- are the -- between craft to foreman down to interest and escalation, you've done your own calculations on of some sort.

MR. CAMPBELL ADAMS: Yes, if you want to go to our report we can discuss those.

MS. HELGA VAN IDERSTINE: Yep, well come to that in a minute. And then you've added just a 10 percent contingency to come up with the 9.85?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And one (1_ of the areas that -- that you have in your report that you talked about was GA&O.

Do you recall that?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And GA&O is included on a number of MGS finding within the Keeyask section of your report, including, as I understand it, craft to foreman ratio, the MR. LESLIE BRAND: -- the trade and -- sorry, the increased use of overtime hours, net BBE indirects, earthwork productivity, et cetera; is that fair?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And I think you received and have reviewed the Amending Agreement Number 7, that Manitoba Hydro has with BBE?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And as part of the incentive for BBE to perform the contract, the GA&O is capped at their target price, meaning that they'll not receive GA&O overpayments on costs beyond their target price.

Do you recall that?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And so what that would mean is that GA&O would not be applied on costs beyond the target price?

MR. CAMPBELL ADAMS: Sorry, could you repeat that, please.

MS. HELGA VAN IDERSTINE: The GA&O would not then be applied on costs that exceeded the target price?

MR. CAMPBELL ADAMS: That is correct and Hydro would just pay those costs above that figure.

MS. HELGA VAN IDERSTINE: Yeah, just to clarify, it's -- Hydro would just pay the actual costs but not the GA&O above that number?

MR. CAMPBELL ADAMS: Correct, yes.

MS. HELGA VAN IDERSTINE: And so if we look at the estimate that you've got here: craft to foreman ratio, BBE indirects, earthworks, scaffolding and crane costs, concrete productivity.

You'd already included the GA&O in the numbers you presented?

MR. WILLIAM HAIGHT: I'm going to just jump in here now and remind, Ms. Van Iderstine, what I said about this document when it was introduced as -- as 4.1, and that was, was that it was the understanding, Mr. Adams that he would be addressing this in the CSI. He wasn't fully prepared to be addressing it today. If there's going to be any reference to this document, it should be to the specific portions of the report from which this document summarizes those portions.

CONTINUED BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: Okay. So -- but let's look at page -- if we can go to the MGF report. That's MGF-2 at page 58 of the report or page 65 of -- on the PDF person.

And if you look there, just below the order of magnitude of 91.6 million. Just roll it up just a little bit further so we can see it.

Note the above figures include GA&O and indirect costs.

MR. CAMPBELL ADAMS: Yes, we see that.

MS. HELGA VAN IDERSTINE: So when you look back at your budget number of 91 mill -- sorry, budget number for craft to foreman, you'd alr -- it appears to us that you included -- had already included the GA&O on that number on the 91 million, so that once you -- once you exceed the target price, GA&O should be deducted from it.

MR. CAMPBELL ADAMS: That is correct. We -- we kept that figure in out of an abundance of caution in case that didn't happen.

MS. HELGA VAN IDERSTINE: And you did that the same with each of the other items on that chart being, sorry, the indirect costs, earthworks, productivity, scaffolding and crane and concrete productivity direct costs?

MR. CAMPBELL ADAMS: Yes. So that -- that to us sets out the -- like the maximum exposure. If you wanted to remove that, that figure, then that would refine the 9.9, assuming there's no amending agreement number something else in the future.

MS. HELGA VAN IDERSTINE: So it would

bring that 9.87 down further?

MR. CAMPBELL ADAMS: It would bring the 9.8 down, yes.

MS. HELGA VAN IDERSTINE: Okay. Now one (1) of the other items you've identified as cash, the trade in cash discounts.

And I have to confess I don't quite understand if -- from the way you've described trade and cash discounts if Manitoba Hydro did what you're suggesting shouldn't that be a negative number?

MR. KIERAN FLANAGAN: No, from the point of that estimates are price on trade discount, they're not priced on this price. So it's actually an addition. Any competent contractor would do a competitive tender based on trade a price -- sorry.

Any -- generally a contractor would do his estimates based on trade price not list price. So it would be after discounts. So this is actually an additional cost to Manitoba Hydro.

MS. HELGA VAN IDERSTINE: Okay, I'm sorry, I'm still not following. If Manitoba Hydro did what you're suggesting and took the approximate 12 percent discount on trade.

MR. KIERAN FLANAGAN: Yes. But I'm doing an estimate it's based on trade prices, not list prices. So if you were paying at list price, you're paying above what you should be on the estimate.

MS. HELGA VAN IDERSTINE: So this is what you're saying that they're paying above by virtue of the 12 percent additional that you're suggesting they're paying?

MR. KIERAN FLANAGAN: Yeah, it would be trade price in an estimate.

MS. HELGA VAN IDERSTINE: So just to be clear, what you're talking about is that you are suggesting that MGF -- that Manitoba Hydro could negotiate with BBE that BBE should seek a 10 percent trade discount with its suppliers and pass that on to Manitoba Hydro?

MR. KIERAN FLANAGAN: I -- any contractor would be getting trade prices. They wouldn't be working off list prices.

MS. HELGA VAN IDERSTINE: Okay, fair enough.

MR. KIERAN FLANAGAN: So it should pass on to the client.

MS. HELGA VAN IDERSTINE: So it should already be passed on to the client. And furt -- and which if it's being done, then the additional 10 percent would be meaningless?

MR. KIERAN FLANAGAN: From the hundreds of invoices we looked at we found one trade discount.

MS. HELGA VAN IDERSTINE: Okay. So if you look -- and if -- and are you aware that in the contract that BBE has with Manitoba Hydro, they have to solicit three (3) competitive bids for all purchases over $500,000?

MR. KIERAN FLANAGAN: Yes.

MS. HELGA VAN IDERSTINE: And so on those items, after getting a competitive bid and low bidder having been selected, what incentive would the low bidder have to further discount their prices by 10 percent?

MR. KIERAN FLANAGAN: If that is done most of the items that -- when we randomly checked the invoices, 99 percent of them were under 500,000, even more than 99 percentage.

MS. HELGA VAN IDERSTINE: Okay. The number of -- the percentages of the invoices might be under 500,000 but the total value of those is not?

MR. KIERAN FLANAGAN: Just to confirm that this has been an issue with Manitoba Hydro as well and you've been looking into it?

MS. HELGA VAN IDERSTINE: Pardon me?

MR. KIERAN FLANAGAN: Manitoba Hydro have been looking into this issue as well and are concerned about it.

MS. HELGA VAN IDERSTINE: And appropriately addressing it?

MR. KIERAN FLANAGAN: I don't know about that. They only recently started looking into it and I think that was kickstarted by MGF.

MS. HELGA VAN IDERSTINE: So if we -- but if we left out the 12 percent or the 10 or 12 percent that you've now included for the -- for all contracts, but we left it out -- left out the tendered contracts, your number here of 74 million would drop?

MR. KIERAN FLANAGAN: In relation to the discounts, is it?

MS. HELGA VAN IDERSTINE: Yes.

MR. KIERAN FLANAGAN: And I don't see why it should drop because we haven't seen any evidence of the discounts being past on to Manitoba Hydro. And to be honest, we're being very conservative. If you look at steel, it could be up to 30 percent discount.

MS. HELGA VAN IDERSTINE: And do you have some data on that, Mr. Flanagan?

MR. KIERAN FLANAGAN: Experience.

I've -- electric work can go up to 50 percent discount.

MS. HELGA VAN IDERSTINE: And you've got --

MR. KIERAN FLANAGAN: It -- it depends on if it's cable, if it's junction boxes, it depends.

MS. HELGA VAN IDERSTINE: And that was built into your estimate how?

MR. KIERAN FLANAGAN: That was built in -- we were being conservative at 10 percent.

MS. HELGA VAN IDERSTINE: Using your experience, but no data?

MR. KIERAN FLANAGAN: Experience, well, I think all of MGF's data is based on experience.

MS. HELGA VAN IDERSTINE: So looking at the craft-to-foreman ratio, you have estimated -- you've looked at and come to the conclusion that it's essentially four (4) workers for every one (1) foreman; is that correct?

MR. KIERAN FLANAGAN: Four (4) craft for one (1) foreman, yes.

MS. HELGA VAN IDERSTINE: The other way around, thanks. And what you seem to be suggesting is that Keeyask has too many foreman for the number of craft labourers?

MR. KIERAN FLANAGAN: Correct.

MS. HELGA VAN IDERSTINE: And this would be something that would be appropriate for Manitoba Hydro and desirable for them to be addressing with the GC?

MR. KIERAN FLANAGAN: Once again it's back to a good estimate. Would not be including. If it was a unit price estimate or a lump sum, they'd be far more craft to foreman. So, it's an overspend that's being passed on to Hydro in relation to the estimate.

MS. HELGA VAN IDERSTINE: Did you review the Hatch report, Mr. Flanagan? That's the one at the back of Manitoba Hydro -- which I think is 117, the rebuttal?

MR. KIERAN FLANAGAN: Yes.

MS. HELGA VAN IDERSTINE: Did you have a chance to review that?

MR. KIERAN FLANAGAN: I personally didn't but the team have.

MS. HELGA VAN IDERSTINE: And did you -- do you note this concern that if the con -- the issue -- and if the issue is that supervision -- more supervision was required in order to get better productivity, that going to a lower foreman to craft might be a detriment?

MR. KIERAN FLANAGAN: Sorry, could you repeat that again, just we'll get it the right way around.

MS. HELGA VAN IDERSTINE: If the root cause turned out to be -- officially, you don't know what the root cause of the productivity issue is, do you?

MR. KIERAN FLANAGAN: It's obviously being badly managed if the productivity isn't being met.

MS. HELGA VAN IDERSTINE: So if the root cause was that there needed to be more supervision to the craft to foreman then reducing the number of foreman is not going to --

MR. KIERAN FLANAGAN: I -- I disagree because the -- under -- the directs the foreman, foreman, by their nature, and especially in the northern territories or northern sections of the provinces and if they're call -- if they're being called a foreman, they're not allowed to work the tools and that's on the majority of jobs.

So your productivity is down by having more foreman to craft than less foreman to craft.

MS. HELGA VAN IDERSTINE: And in -- we've talked about this before, as the site progresses and as the concrete is being installed, you would expect that there will be increases in productivity as they -- the workers start to repeat activities.

MR. KIERAN FLANAGAN: That hasn't been the case to date, though.

MS. HELGA VAN IDERSTINE: But as you know, they are just moving from one type of -- of -- they're just in -- having just installed the initial units now, and they're going to start completing the further units from now on.

So that would be a repeatable task, wouldn't it be?

MR. KIERAN FLANAGAN: Yeah, and you would to see that there would be lessons learnt; if the same crews were following through, if the same supervision was following through but I'm -- we can only base it on the trend today.

MS. HELGA VAN IDERSTINE: Okay and the trend to date --

MR. KIERAN FLANAGAN: And sorry, excuse me, we didn't into account in the -- in the productivity the more intricate are coming -- are coming up so we're being conservative on that as well.

MS. HELGA VAN IDERSTINE: And the trend to date, as we've talked about, is that the -- there is going to be some repeatability of these units as we move forward?

MR. KIERAN FLANAGAN: Correct, but there's only seven (7) units on an unusual contract.

MS. HELGA VAN IDERSTINE: And if, in fact, they obtain those increases in productivity, that number would decrease?

MR. KIERAN FLANAGAN: We haven't taken into account the more intricate work to be honest. I think we've been conservative on it. We've been conservative on the foreman where we've used 6:1 in our adjustment where documents we've referred to would be over 10:1.

MS. HELGA VAN IDERSTINE: And the documents you referred to that would be?

MR. KIERAN FLANAGAN: That would be Burntwood national agreement and the Alberta oper -- operating engineers. The operating engineers is 1:18.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: But if Manitoba Hydro is able to mitigate that, that would decrease that number?

MR. KIERAN FLANAGAN: I -- I -- to be honest, I don't think so. It's going to -- it's going to improve things for you, but it's -- this is what's been happening to date.

I don't -- 6:1 is being conservative, I suppose that's what I'm trying to say.

MS. HELGA VAN IDERSTINE: So if you look over at the indirect costs.

MR. KIERAN FLANAGAN: Yes.

MS. HELGA VAN IDERSTINE: And you've calculated a -- an increase in that, I take it --

MR. KIERAN FLANAGAN: Yeah, but I have --

MS. HELGA VAN IDERSTINE: -- I understand that to be?

MR. KIERAN FLANAGAN: If we go back to the exhibit today.

(BRIEF PAUSE)

MR. KIERAN FLANAGAN: And yes, but it's not a double up. We done a line item for indir -- indirect costs, which, off the cuff, I think was around the 300 million, then we allowed for the indirect to be included in all of them items and offset it, so that's the net increase on indirects.

MS. HELGA VAN IDERSTINE: And -- and do I understand with indirects that those cost -- those are costs that are required to support the direct work at the site, so including things like temporary buildings, small tools, worker transportation, that kind of thing?

MR. KIERAN FLANAGAN: Supervision as well, yes.

MS. HELGA VAN IDERSTINE: Supervision, yeah. And so for things like the temporary buildings, like a carpentry shed that's been built, that kind of thing, you build it once and you're not building it another time?

MR. KIERAN FLANAGAN: Correct, but if you look at it, it says from amendment 7, so they would have been in place prior to amendment 7.

MS. HELGA VAN IDERSTINE: And so having been in place, as I said, you're not repeating some of those items?

MR. KIERAN FLANAGAN: But we haven't taken them into account, things prior to amendment 7.

MS. HELGA VAN IDERSTINE: And as you move forward on the contract, one (1) of the concerns you've expressed, Mr. Adams, and a number of times is the -- the importance of Manitoba Hydro having appropriate supervision on these things?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And were you aware that in -- in 2017, Manitoba Hydro had an indirect lead at -- at the site of -- who has almost twenty (20) years of experience of project controls and construction experience?

MR. CAMPBELL ADAMS: I -- I wasn't personally aware of that.

MS. HELGA VAN IDERSTINE: And --

MR. CAMPBELL ADAMS: As I said earlier, we're -- having a person doesn't guarantee you're going to be successful. We can only react to the -- to the contractor who has not promised -- hasn't delivered to the promises he's given Hydro.

MS. HELGA VAN IDERSTINE: And -- but having somebody like that on site would be the sort of positive steps that Manitoba Hydro could take to try and ensure that they are addressing some of the costs on site?

MR. CAMPBELL ADAMS: I believe if role that person is to challenge the costs that are being generated in indirect space, then yes. So if the contractor's telling you, This is what I'm going to do, these are indirect costs I will incur, if there's a conversation around the -- the cost benefit of that, or the need of that, then that -- that would be appropriate.

MS. HELGA VAN IDERSTINE: And then looking at scaffolding concrete earthworks project, did they -- did you use a straight-line escalation for calculating those numbers?

MR. KIERAN FLANAGAN: We done three (3) exercise in working it out from three (3) kind of industry standards, and then we put a tapering off factor as the job would slow down, and to include for upfront costs, but it's from amendment 7 as well.

MS. HELGA VAN IDERSTINE: I appreciate --

MR. KIERAN FLANAGAN: And just -- sorry, just in relation to it, the majority costs, if you look at -- I don't have the -- I think it was October, we can check, 90 percent of the costs were labour, not equipment.

MS. HELGA VAN IDERSTINE: Was that scaffolding?

MR. KIERAN FLANAGAN: Scaffold and crane.

MS. HELGA VAN IDERSTINE: And crane, but about earthworks and concrete productivity?

MR. KIERAN FLANAGAN: Concrete productivity? That's -- that's from amendment seven as well.

MS. HELGA VAN IDERSTINE: And again, did you use that number just to use a straight line, continuing outwards?

MR. KIERAN FLANAGAN: We basically used the information that we got from Manitoba Hydro, which showed the accumulative to date. We didn't take into account the further intricate work. We didn't take into account the winter work that was planned just before we produced the report. So as I say again, in our opinion, that's probably conservative too.

MS. HELGA VAN IDERSTINE: And if you look at your report, can you show me where you address the mitigation strategies that Manitoba Hydro has been utilizing to try and bring these costs down?

MR. KIERAN FLANAGAN: I -- unless -- from recollection, I have -- I don't know if the mitigative strategies are talked about it.

MR. CAMPBELL ADAMS: What are they?

MS. HELGA VAN IDERSTINE: No, I'm just

asking you if you addressed any mitigation strategies.

MR. WILLIAM HAIGHT: I think in fairness to the witnesses -- in fairness to the witnesses, this report was prepared in December. The mitigation strategies that this Board has heard about came out through the direct panel -- or through the panel presentation by Manitoba Hydro's capital project. The first we heard of that was last week, so they've seen it in the transcripts, but that's it.

(BRIEF PAUSE)

CONTINUED BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: So I'm just -- I appreciate that last comment by your counsel. So as you know, Manitoba Hydro did give evidence this past week, or a week or so ago, provided rebuttal evidence in which they do describe some mitigation strategies that they're implementing, and you have not amended your report subsequently?

MR. WILLIAM HAIGHT: I -- I --

(BRIEF PAUSE)

MR. WILLIAM HAIGHT: Okay. I don't

think that's a fair question.

CONTINUED BY MS. HELGA VAN IDERSTINE:

MS. HELGA VAN IDERSTINE: So the contingency that you've addressed in your report, now that's based on -- you -- you've attributed a 10 percent number to that, and attributed it as 896 million.

Now, can you tell us why you chose 10 percent rather than, say, 5 percent, or 2 percent, or 12 percent?

MR. CAMPBELL ADAMS: Probably the best guess that we have is we don't see the point -- I don't know -- why we would lower it when we've got such an unstable base upon which to predict the future. We considered what those issues might be in going forward, worsening productivity, more intricate concrete to do, expensive interworking, possibly, further claims by contractors who are delayed.

There could be re-work to be paid for. Like Hydro, we don't know what the geotech will be like under the site dam. So that -- that was the -- the sort of thought process we went through, and we -- we landed on 10 percent.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: So just to understand that, the numbers that you've presented, nine point eight-five (9.85), that number is, I think in your words earlier, sort of an order of magnitude number. You've picked nine point eight (9.8). And as we've talked about, there are -- you've also included in that contingency some issues surrounding productivity. So if that contingency includes both productivity there, and you've identified productivity earlier, is that double counting that productivity?

MR. KIERAN FLANAGAN: It includes a worsening productivity. We've taken the accumulative to date. We haven't taken into productivity for winter work. We haven't taken into productivity for the more intricate -- the work that's going on is more intricate, so obviously, there's a good chance productivity will worsen. We've taken the accumulative date, given the benefit of the doubt that it won't worsen, but obviously in a contingency, we have to take into account that it may worsen.

MR. CAMPBELL ADAMS: The other comment I would make is -- was we're trying to come up with the -- the best advice that we could. We -- we shouldn't lose sight of the fact there's four (4) years of this to run. There's plenty of opportunity for other things to go awry, here. You're not within the finish line. You're building a project in the lower Nelson River in Northern Manitoba. That's not easy. That's a fantastic undertaking. There's still plenty of risks to -- to be managed and avoided, hopefully.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: If you just give me a second, I'm just going to look through my notes for a moment, if I may.

(BRIEF PAUSE)

MS. HELGA VAN IDERSTINE: So just a -- a couple more questions if I may. Mr. -- Mr. Campbell, you were asked by one (1) of my colleagues, who is no longer here, about reporting back to the PUB on progress. Do you recall that line of questioning?

MR. DAN CAMPBELL: Somewhat.

MS. HELGA VAN IDERSTINE: And you had suggested that, I think, that Manitoba Hydro would be the pers -- best situated to say what schedule points it was appropriate to report on, because they would know when they're getting to a -- a point which had a valid report. I think that's the --

MR. DAN CAMPBELL: I think my -- my intent was that the integrated schedule where it shows some of the contractual dates between the civil contractor in Voith, for example, or the spillway gates contractor, plus the information or the -- the start of the fills after the excavations of the -- have been completed, and the geotechnical issues, if there are any, have been identified, are points where it is easier to predict the future.

MS. HELGA VAN IDERSTINE: So using that so it -- those -- that's those sort of examples, and -- and thinking about the amount of work that is required for you and all of your colleagues at the table to put together sort of the information that they've provided here, you would appreciate the amount of interface and time that Manitoba Hydro employees put into helping answer those questions to you. Is that a fair -- there was a lot of -- a lot of interface providing that answers and information to you?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: A lot of time that -- and effort by senior staff to try and answer your questions?

MR. CAMPBELL ADAMS: Yes.

MS. HELGA VAN IDERSTINE: And staff who were otherwise engaged at the time, trying to monitor and continue the Keeyask build?

MR. CAMPBELL ADAMS: Correct, I agree with that.

MS. HELGA VAN IDERSTINE: And so would it be fair when you talk about that sched -- that Mr. Campbell back -- the reporting, that what you're talking about is not the type of hearing that we're talking about here, but something that would be a little bit more focused?

MR. DAN CAMPBELL: What I'm talking about is that the integrated master schedule for the whole project should be established or if it -- or reestablished, I guess, and may it had -- maybe it has been, or is being, right, and that some key points be identified and a plan be put forward whereby those -- those are points where Manitoba Hydro and the contractors sit down, and they go around and they make sure that they -- everybody agrees what's going to happen is reasonable and -- and coherent.

Now, whether that involves this group of people, as a reviewer of the results of that, I'm not at a point to -- I can't comment on it.

MS. HELGA VAN IDERSTINE: Thank you. Oops, I may have pushed that a little further onto than I intended just by the way I described it, but what I was trying to get was that you weren't looking at having -- suggesting that they should be having a hearing every --

MR. DAN CAMPBELL: I believe the proper response would be: God, no.

MS. HELGA VAN IDERSTINE: So just a -- it -- if I can finish off, we had talked about some of the things that Manitoba Hydro's been doing to address some of the issues, and it can be either of you, I think, and fair to say that I think Manitoba Hydro having meetings with the leads between Manitoba Hydro and BBE to identify efficiencies and improvements would be a good step to take?

MR. CAMPBELL ADAMS: Yeah -- yes -- the answer is yes to that. I -- I would have thought in the -- this cost reimbursable price contract, that should be an ongoing activity.

MS. HELGA VAN IDERSTINE: And the -- the more they can push that, and the better those --

that relationship is, then the chances are that they can mitigate some of the expected costs?

MR. CAMPBELL ADAMS: Yes, I believe that to be true.

MS. HELGA VAN IDERSTINE: Thank you. Those are my questions.

THE CHAIRPERSON: Thank you. Mr. Peters...?

CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: Yes. Thank you. Let's stay with the exhibit MGF-4-1 that's on the screen, please. And I'm going to start with one (1) that -- that My Friend Ms. Van Iderstine dealt with, and I -- I want to make sure the panel understands the position of MGF.

We see on the second line item, Manitoba Hydro's estimated cost to completion, there's a $3.5 billion number, correct?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: Leave your microphone on. Pull it close. We're -- we're good. That 3.5 billion includes the actual costs that Manitoba Hydro is forecasting it's going to have to spend not just on labour, but on equipment, materials, trucks, vehicles, all of that?

MR. CAMPBELL ADAMS: That's our understanding, yes.

MR. BOB PETERS: And then when I drop down two (2) line items for trade and cash discounts, I'm understanding MGF to be saying that Manitoba Hydro has been leaving money on the table when it's buying -- when BBE is buying the goods and services that it's buying?

MR. KIERAN FLANAGAN: From the evidence we've seen, it's not apparent that they're getting trade discounts, because they're not shown on invoices.

MR. BOB PETERS: Okay, your answer was, you don't see the trade discounts on the invoices?

MR. KIERAN FLANAGAN: So that -- that would only lead us, I believe, on your average invoice, it would be normal to see the trade discount on the invoice, so.

MR. BOB PETERS: So -- so what's included in the $3.5 billion number doesn't contain --

MR. KIERAN FLANAGAN: Not --

MR. BOB PETERS: -- a trade discount, is what you're suggesting?

MR. KIERAN FLANAGAN: No. Normally when you do estimates, the difference between a list price, which the average person off the street, if you went into a builder provider, so you get the list price. A contractor goes into a builder provider so he'll get a trade price.

Sorry. The average person going to a builder providers, you get a list price. If the -- a contractor that has an ongoing relationship with them, or a big project ahead, he'll get a trade price. That could range from 10 percent up to 50 percent. And when you're doing a competitive tender, you will always inch -- include a trade price, not the list price, otherwise it wouldn't be competitive.

MR. BOB PETERS: Do you know if BBE is getting the trade discount?

MR. KIERAN FLANAGAN: I -- I've never heard of a of a contractor not to.

MR. BOB PETERS: All right. So then the suggestion is that if BBE is getting the trade discount, it's not being passed on to Manitoba Hydro?

MR. KIERAN FLANAGAN: From the evidence we've seen.

MR. BOB PETERS: And under the agreement that's between Manitoba Hydro and BBE, who was supposed to get the --

MR. KIERAN FLANAGAN: Trade discount --

MR. BOB PETERS: Trade discount?

MR. KIERAN FLANAGAN: Sorry. Sorry. Apologies. Trade discounts, industry practice, it's always passed on to the client. Cash discounts is another thing. It's prompt payment. So if the contractor pays a supplier within thirty (30) days, he gets, on average, around a 2 percent discount. But because in this scenario the contractor is getting paid two (2) months in advance, it's being financed by Manitoba Hydro, the cash discount should all be -- should also be passed on, because it's actual cost.

MR. BOB PETERS: So, Mr. Flanagan, if those trade discounts are not included in the $3.5 billion number, why should they be added in below that?

MR. KIERAN FLANAGAN: No, what I'm saying is that the three point five (3.5), if it's estimated correctly, would allow for the discount, but Manitoba Hydro is paying actual costs based on invoices without trade discounts, so that means they're overpaying over and above what the budget would have been based on.

MR. BOB PETERS: All right. So you're

telling this Board that that $3.5 billion number should be lower by $74 million?

MR. KIERAN FLANAGAN: No, no. I'm -- sorry, correct. Correct.

MR. BOB PETERS: While we're on this exhibit MGF-4-1, and gentlemen, I -- I jumped right in. In my excitement, I should have said at the outset, as we've done, this is a public hearing today, and so none of my questions are to elicit answers that may contain confidential information. You're aware of that?

MR. KIERAN FLANAGAN: Yes.

MR. BOB PETERS: And Ms. Musfelt, likewise? And for Mr. Potter, Mr. Phillips, and Mr. Brand on the phone, if at any time they believe that they can answer and bring some additional information to the Board's attention, they are certainly to interrupt at any time. I'm hoping they're listening.

MR. KIERAN FLANAGAN: Mr. Peters, just one (1) thing --

MR. LESLIE BRAND: Yes.

MR. JIM POTTER: Understood.

MR. DWAYNE PHILLIPS: We understand as well, thank you.

MR. BOB PETERS: All right, and thank

you.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Brand, Mr. Potter, and Mr. Phillips, in that order.

MR. KIERAN FLANAGAN: Mr. Peters, just one (1) thing, if I can go back on, in relation to the MH spent to date, that doesn't include -- the seventy-four (74) isn't included in that, so there's probably recovery money that could be got in the three point zero-five (3.05) as well for trade and cash discounts.

MR. BOB PETERS: All right. In answer to My Friend, you mentioned that this was something that Manitoba Hydro was now investigating.

Did I hear that correctly?

MR. KIERAN FLANAGAN: That's what we've been advised through meetings in Manitoba Hydro.

MR. BOB PETERS: So is it your understanding that until MGF raised this, Manitoba Hydro wasn't aware of this situation?

MR. KIERAN FLANAGAN: I can't say that, to be honest. I'm -- it was through a discussion that they were looking at it.

MR. BOB PETERS: So after you brought

it to Manitoba Hydro's attention, they're now looking at it?

MR. KIERAN FLANAGAN: I couldn't say that. They could have been looking at it prior.

MR. BOB PETERS: And as a result of Manitoba Hydro's looking at it, have they reported to MGF what, if anything, has happened?

MR. KIERAN FLANAGAN: No, just that they were looking at those.

MR. BOB PETERS: All right. I want to turn to the earthwork productivity line item, and that brings in an additional $88 million of projected costs according to MGF, correct?

MR. KIERAN FLANAGAN: Correct.

MR. BOB PETERS: Help the panel -- the Board understand that number that's 88 million over and above what amending agreement number 7 would call for, correct?

MR. KIERAN FLANAGAN: Correct, based on the accumulative to date.

MR. BOB PETERS: So MGF has taken the productivity of BBE on the earthworks, their actual productivity, and determined that they're -- they're going to be $88 million over the budget that was set out in amending agreement 7?

MR. KIERAN FLANAGAN: Correct.

MR. BOB PETERS: If Manitoba Hydro take steps to -- to improve the earthwork productivity, MGF will acknowledge that that $88 million number will be less?

MR. KIERAN FLANAGAN: It's difficult to say, because we believe because of winter programs and more intricate work, it could rise, but we haven't taken that into account. We've taken into account the accumulative to date, and there's certainly mitigation measures that could reduce it, but that eighty-eight (88) could be a hundred. It could be seventy (70).

MR. BOB PETERS: All right. I think you've answered my question in that answer, Mr. Flanagan, but we're talking here earthworks, not concrete, correct?

MR. KIERAN FLANAGAN: Sorry. Yes, earthworks.

MR. BOB PETERS: All right. Is there intricacies coming up on the earthwork schedule that -- that'll give rise to greater risk?

MR. KIERAN FLANAGAN: Not that I'm aware of, but that's -- the accumulative to date and the trend is that it's been rising, not reducing.

MR. BOB PETERS: All right. And --

and that's probably a matter best left for our discussions tomorrow?

MR. KIERAN FLANAGAN: Yeah, because obviously, I can't get into the man hours and so on.

MR. BOB PETERS: That's -- that's fair.

MR. DAN CAMPBELL: Excuse me. I made -- I made some comments --

MR. BOB PETERS: Mr. Campbell --

MR. DAN CAMPBELL: -- sorry -- sorry to interrupt. I made some comments earlier about the earthworks, and how, as you got closer to the top, you got to narrow zones, which were -- I'll use the word more intricate. And so yes, there are some intricacies as you reach the top of things. It's not very much, as I said in my presentation earlier, but there is -- there is opportunity to be less productive coming forward.

MR. BOB PETERS: And, Mr. Campbell, you attached a percentage number to that, did you not?

MR. DAN CAMPBELL: No, I did -- I don't believe I did.

MR. BOB PETERS: All right.

MR. DAN CAMPBELL: I'd have to go back and look in that, because it was done by Garry.

MR. BOB PETERS: The essence of that comment, Mr. Campbell, was as you get to the top of the earthen dike, or the earthen dam, it narrows at the top. And I think it was 500 -- was it 500 millimetres wide at the top? Is that -- is that what I recall?

MR. DAN CAMPBELL: Yes, some portions of it. You can imagine that the -- the way the dams are built, that there's a clay core in the middle, and that there's different zones of filter of different sizes of rock on each side. And as -- and there's -- obviously, it's wide at the bottom, because it's a tapered structure.

And when you get to the top that taper eventually goes to zero, more or less, it goes to 500 millimetres at the top for, I think, the core, so. That's the -- intent of that. As you get up to how -- and becomes more difficult, because your trucks cannot pass each other. You have to you -- there's -- so you may have to use batter boards, or formwork, effectively, to place the materials.

So there's the -- it does become more intricate as you get closer to the top.

MR. BOB PETERS: But Mr. Campbell --

MR. DAN CAMPBELL: That was -- that

was only my -- that was my only point.

MR. BOB PETERS: No, you answered, so let's stay -- let's keep talking. The contractor knows of those intricacies that are forthcoming on the earthworks, correct?

MR. DAN CAMPBELL: Yes.

MR. BOB PETERS: And so would you expect the contractor would build that intricacy into the contractor's productivity numbers?

MR. DAN CAMPBELL: He should build that into his plan, yes.

MR. BOB PETERS: It's not a surprise that comes out of the --

MR. DAN CAMPBELL: No.

MR. BOB PETERS: All right. Then I want to turn with our friends from MGF and anybody else who wants to offer comments, the concrete productivity line item. You're telling the Board here that based on what MGF has seen from the concrete productivity, the actual productivity, it's going to exceed the amending agreement number 7 by $137 million?

MR. KIERAN FLANAGAN: Correct, based on the accumulative to date, which is not a figure we invented. It's -- it's reported.

MR. BOB PETERS: It's mathematically derived based on actual performance --

MR. KIERAN FLANAGAN: Yeah, it's -- it's reported --

MR. BOB PETERS: -- today?

MR. KIERAN FLANAGAN: -- it's an actual reported on the job.

MR. BOB PETERS: Reported by whom?

MR. KIERAN FLANAGAN: Reported by BBE through Manitoba Hydro.

MR. BOB PETERS: And so what -- what you're telling this Board is that if that concrete productivity is exactly the same as what it has been up until December 31st of 2017, it's going to add an extra $137 million of costs?

MR. KIERAN FLANAGAN: Yeah. I'd have to go to the page in the report, but that was either October or November of the report.

MR. BOB PETERS: Okay. Well, and that was a question I actually had of you. When the Vice Chair was asking questions of Ms. Musfelt, at what point in time did Mani -- did MGF have to put down the Manitoba Hydro information and start drafting the report? You know, what -- what's the vintage of the information that's in the MGF report?

MS. VAL MUSFELT: From a scheduling perspective, the last set of schedules I had for Keeyask was 6th of October, 2017.

MR. BOB PETERS: That's only part of the answer. And so gentlemen, for the rest of the report --

MR. KIERAN FLANAGAN: Yeah, the --

MR. BOB PETERS: Sorry, at what -- what day did -- did you stop adding new information for Manitoba Hydro?

MR. KIERAN FLANAGAN: I suppose it's not as simple as that, that a lot of the reports come out between a month to a month and half after the date, let's say. The -- so if you're working in -- on a the report in November, you might be dealing with information from October or prior, depending on when the information was reported.

MR. BOB PETERS: And that's what I'm trying to get at, is your report was in December, so is it current to the 1st of December? Is it current to the 15th of November?

MR. KIERAN FLANAGAN: It would be closer to October.

MR. CAMPBELL ADAMS: Yeah, it -- we've referenced in the final report that some data comes from the -- a construction weekly report dated the 6th of October, and also the construction reports for the month of September, which were probably received, I don't know, towards the -- the end of -- of October. But by that time, you would had a -- pretty much a full season of the amending agreement, going back over the past twelve (12) months, so that -- that's a source of the -- the data that we've used.

MR. BOB PETERS: You're telling the Board, Mr. Adams, that you've used the data generated under the amending agreement number 7 to forecast the additional costs that are shown on MGF-4-1? On Exhibit MGF-4-1, there's a -- there's a line item for Voith and service contracts, and that's, I believe 46 additional million dol -- million dollars, correct?

MR. KIERAN FLANAGAN: Correct.

MR. BOB PETERS: And is it correct to understand that these contracts haven't yet been called into -- into play? They're not -- they're not due to be performed yet?

MR. KIERAN FLANAGAN: They're not due to be performed, but there's some claim and other issues with Voith. I don't have the details in front of me. And then because of extensions of time, the likes of camp services for roads and so on will be impacted, so that's the makeup of the 46 million.

MR. BOB PETERS: So the 46 million reflects the delay that is being -- the delay claims that are expected as a result of the general civil contractor's being late on delivery of his project?

MR. KIERAN FLANAGAN: From...

(BRIEF PAUSE)

MR. KIERAN FLANAGAN: Yeah, the Voith is based on a trend delay, and the -- the services are based on an extension of time on the overall project.

MR. BOB PETERS: And if we can turn to MGF-4 and look at the -- the scheduling history, this $46 million of delay claims on page -- unnumbered slide 12, this $46 million delay claim by Voith in the service contracts is from which of these dates to which of these dates on -- on the screen in front of you?

MR. KIERAN FLANAGAN: The delay claim with Voith, and I don't have the background here to -- but that's something that's documented. It's not in relation to that schedule.

MR. BOB PETERS: But it's in relation to Manitoba Hydro requiring the services of Voith at a later point in time than initially planned?

MR. KIERAN FLANAGAN: Correct.

MR. BOB PETERS: And so how -- my -- my question -- and maybe it's not very well asked is: What's the delay to Voith? How many months? How many years?

MR. KIERAN FLANAGAN: I don't have the data in front of me, to be honest, to answer that question, but it's not in relation to them schedules. That was a claim between Manitoba Hydro and Voith themselves.

(BRIEF PAUSE)

MR. BOB PETERS: Manitoba Hydro has suggested in their questioning to MGF that MGF is starting to take, or has -- is taking steps to mitigate the impact of the lack of productivity and additional costs to Amending Agreement 7.

Are you generally aware of that?

MR. KIERAN FLANAGAN: We've been made aware of it I think more so today than -- well, today.

MR. BOB PETERS: MGF hasn't assessed the impact of those mitigation steps, have they?

MR. KIERAN FLANAGAN: We weren't aware

of it until today.

MR. DAN CAMPBELL: Excuse me again.

MR. BOB PETERS: Yes, Mr. Campbell...?

MR. DAN CAMPBELL: I don't know if I'm allowed to actually say the number but I --

MR. BOB PETERS: Well, presume you're not.

MR. DAN CAMPBELL: Okay.

MR. BOB PETERS: Presume you're not and -- and maybe --

MR. DAN CAMPBELL: For the -- for the --

MR. BOB PETERS: -- we can chat about this in -- in the confidential in-camera session tomorrow, if that's important --

MR. DAN CAMPBELL: Okay, my only point --

MR. LESLIE BRAND: -- to you providing information to the Board.

MR. DAN CAMPBELL: -- my only point would be that a substantial number of the 49 million that was being discussed a moment ago is a Voith number which is directly related to the delay claim, delay issue.

MR. BOB PETERS: All right and it's 46

million --

MR. DAN CAMPBELL: Sorry.

MR. BOB PETERS: -- if we go back to Exhibit MGF-4-1?

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Campbell, it's the $46 million number?

MR. DAN CAMPBELL: Yes.

MR. BOB PETERS: And the delay claim, you're saying it's mostly related to the Voith contract as opposed to the service contracts.

Is that what I'm supposed to understand.

MR. KIERAN FLANAGAN: There's exposure on a larger claim from them Voith but we -- that figure is made up of approximately Voith 50 percent and approximately services 50 percent.

MR. BOB PETERS: And can you remind us, Mr. Campbell or Mr. Flanagan, what Voith were doing or what services they were providing?

MR. DAN CAMPBELL: Voith is providing the unit, so they're building the turbines and they're also purchasing the generators and doing other associated items, which actually generate the electricity when it's all said and done.

MR. BOB PETERS: And, Mr. Campbell, your understanding of their delay claim is that they're charging Manitoba Hydro more money on account of delivering the product -- the products later?

MR. DAN CAMPBELL: Yes.

MR. BOB PETERS: And does that take into account then the -- the interest costs that Voith may have had to incur to build these -- these generators?

MR. DAN CAMPBELL: I don't know the makeup -- of their of their claim, but I'm presuming that some of it is cost of materials, some of it is interest. Who knows. But they -- they asked for and were given a substantial amount of money.

MR. BOB PETERS: Before I leave this slide, just one (1) last question. Do you need a minute, Mr. Flanagan?

MR. KIERAN FLANAGAN: No.

MR. BOB PETERS: We talked about the concrete and the earthworks productivity. And related to that, it's my understanding, from the evidence of Manitoba Hydro, that after 2017, BBE is 20 percent behind in concrete and 25 percent behind on the earthworks.

Do you agree with those numbers?

MR. CAMPBELL ADAMS: Yes, that's what's been -- that's what we've read in reports. Or been advised.

MR. BOB PETERS: Has your investigation been able to confirm that?

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: We believe we have because of the -- the productivity calculations we've done.

MR. BOB PETERS: All right. And we're also -- if you can accept that this hearing's been told that BBE's productivity in 2018 will have to improve in order for the Amending Agreement 7 targets to be met on productivity and costs, correct?

MR. CAMPBELL ADAMS: I would agree, yes.

MR. BOB PETERS: And I'm hearing from MGF that, while that's the stated position, that the productivity will have to perform, you've approached it with your project estimated value that's on the screen in front of us, on the assumption that productivity does not improve?

MR. KIERAN FLANAGAN: No, we've based it on a cumulative to date, so that it won't improve from the cumulative to date, bef -- to be honest, we believe there's a good chance that it may worse.

MR. BOB PETERS: Okay. Well, let's -- let's jump to that then, Mr. Flanagan. Why does MGF think that the productivity may worsen.

MR. KIERAN FLANAGAN: Because on the concrete, for example, we have not taken into the winter work coming up, because that was only planned in late -- or sorry, I think it was past. I don't know the exact date in late November.

So it wasn't something we could take into account. And then more intricate work -- if it's an cumulative to date, and the work is getting more intricate, you would assume that the productivity is going to worsen. And we can only base it on the trend to date.

MR. BOB PETERS: But you acknowledge that Manitoba Hydro is suggesting that some of this intricate work that you've identified may be efficiencies because it's repeatable, and that we're going to have to do it more than once?

MR. KIERAN FLANAGAN: I cor -- I

agree. And there may be some offset, but we have to understand there's only seven (7) units. It's not -- it's not you're doing a hundred story building and he drywaller gets better as he goes up.

MR. DAN CAMPBELL: There's also been some opportunities for efficiency gains in the less intricate work to date, which may or may not have occurred.

MR. BOB PETERS: Mr. Campbell, of what -- what are you ref -- referencing?

MR. DAN CAMPBELL: If you look at the -- at the mass concrete work to date, much of it is repeatable. So presumably some of the efficiencies in the crews, et cetera, have been noticed to date, so then I don't -- I have -- should have occurred to date. And I don't know if that's been reflected in the productivity numbers that are being used to date because I didn't analyze those. So, Mr. Flanagan, might have a better answer on that.

MR. KIERAN FLANAGAN: Obviously, we can't get into the -- the man-hours per cube, but the figures we've used are accumulative to date, so they would have taken into simpler concrete pours. What -- sorry, "simple" is probably the -- the wrong word, but less complex.

MR. BOB PETERS: All right. Let's turn to Manitoba Hydro's rebuttal evidence, page 2 of Appendix A. And I'm sorry, I don't have the page of the PDF. I believe it's the KPMG document.

(BRIEF PAUSE)

MR. BOB PETERS: And if we scroll to the bottom of the page, the second last paragraph, in the middle of that. The consulting firm of KPMG came in -- and this is dated January 11th of 2018 -- had given advice to Manitoba Hydro in response to the MGF report, that, in respect of what's happened in the past with BBE, there were essentially three (3) options that Manitoba Hydro had, in terms of dealing with BBE when the productivity wasn't met.

Are you aware that?

(BRIEF PAUSE)

MR. BOB PETERS: All right. And so --

MR. CAMPBELL ADAMS: Sorry, say it again. Sorry.

MR. BOB PETERS: One (1) of the options that Manitoba Hydro's consultant is giving advice on, is that Manitoba Hydro could have the descoped the work from BBE, which would mean, I understand, to limit the amount of work that BBE does going forward.

Is that what descoping means?

MR. CAMPBELL ADAMS: Yes, it's to remove -- sorr -- sorry.

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: Can I just clarify. You're asking about the options that Hydro considered in the quar -- end of Quarter 3/Quarter 4, 2016?

MR. BOB PETERS: You're correct.

MR. CAMPBELL ADAMS: Thank you. Yeah.

MR. BOB PETERS: And -- and this was -- this was at a point in time when Manitoba Hydro realized the productivity was a problem, correct?

MR. CAMPBELL ADAMS: Absolutely, yeah.

MR. BOB PETERS: And they'd actually recognized that --

MR. CAMPBELL ADAMS: Well --

MR. BOB PETERS: -- long before that?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And at -- at this time, one (1) of the options was to descope it, Mr. Adams, and that was essentially to take portions of the work away from BBE and give them to some other contractor?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: The other option -- or another option would have been to continue with BBE under some form of a new arrangement?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And of course, that's the option that has come to pass?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And a third option would be to terminate the arrangement with BBE, correct?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: If we go to...

(BRIEF PAUSE)

MR. BOB PETERS: I suppose, slide 23 from MGF Exhibit 4 the -- of this morning...

(BRIEF PAUSE)

MR. BOB PETERS: And we look to see whether the options to terminate BBE were seriously examined by Manitoba Hydro.

First of all, maybe we could put up Tab 2 of Manitoba Hydro's application, page 45, and scroll down to line 14.

This is Manitoba Hydro's application, and they're telling the Board that BBE Hydro Contractors LP -- I'm sorry, I've read it wrong again -- BBE Hydro Constructors LP, or Limited Partnership, was the successful general civil contractor, correct?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And you understand that this limited partnership is a consortium between Bechtel Canada, Barnard Canada, and EllisDon Civil Limited?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: Can you explain, and perhaps, Mr. Campbell, you can provide some help to the Board here, as to why do these construction companies form a consortium to come in on a project like Keeyask? You can answer too, Mr. Campbell -- or, Mr. Adams, sorry.

MR. CAMPBELL ADAMS: Joint ventures tend to come together because of the respective strengths of the -- the parties to the joint venture, or the skills that they have. That can be prior working experience in that industrial sector. It could be experience with the owner. Joint ventures tend to be stronger when they've worked together before and they're not doing it for the first time.

Each company has its own culture, ways of doing things. I've seen some successful JVs. I've also seen some that are quite difficult to -- to manage.

MR. BOB PETERS: When you say "JVs" you're -- you're saying that short form for joint ventures, correct?

MR. CAMPBELL ADAMS: Yes, sorry, joint --

MR. BOB PETERS: When --

MR. CAMPBELL ADAMS: -- ventures.

MR. BOB PETERS: When I say limited partnerships, does that mean the same thing to you, or do you know?

MR. CAMPBELL ADAMS: That's my understanding, although we have not -- I don't we reviewed the joint venture or the -- the agreement between those three (3) parties making up BBE Hydro Constructors LP.

MR. BOB PETERS: So you're not aware that BBE Hydro Constructors GP Incorporated is the general partner in the limited partnership? You -- you didn't go back to look at that?

MR. CAMPBELL ADAMS: Can you repeat the question, please, Mr. Peter?

MR. BOB PETERS: Do you know who the -- the general partner was in this limited partnership?

MR. CAMPBELL ADAMS: I don't believe I do.

MR. BOB PETERS: Do you know whether or not a performance bond was posted by BBE, in terms of this contract with Manitoba Hydro?

MR. CAMPBELL ADAMS: I don't know the answer to that.

MR. BOB PETERS: You're not aware of any surety that was posted by BBE --

MR. CAMPBELL ADAMS: I don't believe -- I don't believe we have reviewed that.

MR. BOB PETERS: In an earlier part of the presentation, I believe it was MGF's view that if the contractor wasn't delivering on its promises, one (1) of the remedies was to sue the contractor

MR. CAMPBELL ADAMS: I think it was in response from Mr. Grant and the panel, that if a contractor, in a lump-sum price doesn't perform, what do you do? Certainly being held to ransom, I don't think is the appropriate way. You've a contract between the parties, and that's what governs their relationship, including performance, and remedies in the event of nonperformance.

MR. BOB PETERS: Does that same answer apply when it's a limited partnership like BBE Hydro Constructors Limited Partnership?

MR. WILLIAM HAIGHT: I think you're asking for a legal opinion, Mr. Peters. It's beyond the scope of the MGF panel. While they have experience in negotiating and viewing contracts, that's a legal question and I don't think it's fair for this panel.

MR. BOB PETERS: You're at a depth on that, Mr. Haight, that I wasn't intending to go. So let's -- let's not ask you for a -- we're not asking for a legal opinion.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: But have you been involved in situations under a limited partnership, where the owner has terminated the arrangement and sued the limited partner?

MR. CAMPBELL ADAMS: Not of a limited partnership, no.

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: If -- if I can just add. The -- this partnership is the contracting entity in the -- with -- with BBE and with Hydro. They -- they share the risk of this nonperformance. They -- they have to stand up to be accounted -- be accountable for that.

MR. BOB PETERS: And I have your point. And -- and Mr. Haight's going to put his hand close to the microphone because even though BBE has to stand up for the contract, Mr. Adams, do you know what Limited Partnership?

MR. WILLIAM HAIGHT: I got -- you're right, Mr. Peters. My hand is close to the mic. And that's well beyond the scope of the work that MGF or KCB.

(BRIEF PAUSE)

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: At Board counsels'

book of documents, Volume VI, on page 43, I want to turn to the -- the MGF response. And the part that's not highlighted is where I want to go.

And it relates to a matter that you were in discussion with Ms. Van Iderstine on. And one (1) of the answers here is:

"MGF believes that a more hands-on construction management approach is required to improve BBE's performance."

Do you see that?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And I want to -- I just want to make sure this panel understands the depth to which you say Manitoba Hydro should be more hands-on on this particular project. Is it more than just having these meetings with the leads for BBE on the various projects?

MR. CAMPBELL ADAMS: Yes, I believe it is.

MR. BOB PETERS: So -- so how --

MR. CAMPBELL ADAMS: You -- sorry, you -- you can have meeting and you -- you work at a certain altitude that you -- you hear but you don't see, and you're not involved in finding better ways of working. I don't know how long you sit back watching a contractor underperform for you before you've got to take some action.

MR. BOB PETERS: Well, when you say that, Mr. Adams, what does that look like on the job site? So does that mean that there's a Manitoba Hydro worker with -- with a foreman from BBE as the craft labour is performing its job?

MR. CAMPBELL ADAMS: I -- I think, to me, it -- it looks like: We've been doing this for however long, you consistently don't deliver your promises. That might suggest that there's issues around how you plan, manage, and execute the works. It's cost reimbursable. You're spending my money. What do we need to do to address this? Help us understand what are you struggling with. If you're planning to do it this way, but you end up doing it this way and it's not working, and it's costing more time, more money, why is it? Is this the best that's going to be achieved? And if that's the case, then we need to re-look at schedule and cost. Are there ways that we can get you back to where you want to be as our contractor and perform as promised?

MR. BOB PETERS: What I hear you telling the Board is that Hydro should be giving more guidance and instruction.

If it -- is that what I hear?

MR. CAMPBELL ADAMS: I wouldn't say it like that. It's -- it's about the cost reimbursable pricing mechanism. You have a contractor spending your money, it's not going well, that needs to be arrested. So let's get involved in understanding why you're not performing to how you promised.

There -- there was a -- I got to be careful what I say -- but that there was an assumption in the -- I wouldn't call it even a tender -- but the -- the original target price of what productivity was. That was over -- overly optimistic.

You run into 2016, and it's not working. And Hydro stepped in, did the amending agreement. Let's restart, let's rethink. You go into 2017, and we find that -- that's not being met.

I wouldn't say it's about telling the contractor what to do. It's about understanding what are their challenges and how can we help them get it better. They've got to perform it.

MR. BOB PETERS: And what's the contractor's motivation for even listening to Manitoba Hydro provide that advice?

MR. CAMPBELL ADAMS: Well, I don't

know: reputation, loss of their profit. They're not at risk for cost, that's, in our view, a weakness.

MR. BOB PETERS: Yeah. From a cost perspective, their actual costs are going to be reimbursed by Manitoba Hydro?

MR. CAMPBELL ADAMS: Yeah.

MR. BOB PETERS: And only when Manitoba Hydro encroaches on the target price is the profit at risk for -- the for the contractor, correct?

MR. CAMPBELL ADAMS: Correct.

MR. BOB PETERS: So -- so back to my question. Is it the contractor's reputation that's what's -- what -- what is motivating the contractor to pay attention to advice for Manitoba Hydro?

MR. CAMPBELL ADAMS: I think that most contractors are aware of their reputation in the marketplace. I'm sure they -- they want to do a good job. But reputations take long years to build and a few years to lose.

MR. BOB PETERS: But BBE Hydro Constructors Limited Partnership hasn't done previous Hydro projects, has it?

MR. CAMPBELL ADAMS: I would -- I would be referring to the constituent members of that limited partnership who would take pride in what they do.

MR. BOB PETERS: All right. On page 48 of Board counsels' book of documents, Volume VI, we see in the paragraph underneath the bullets at the top:

"Unless and until Manitoba Hydro adopts a hands-on role of construction manager for the general civil contract, the time for completion of this contract and the Keeyask Generating Station Project generally will take longer."

That's in your report?

MR. CAMPBELL ADAMS: Yeah.

MR. BOB PETERS: We're back to the hands-on comment again. But here it's "hands-on role of construction manager."

Is it construction manager or is it contract manager that we're -- we're focusing on?

MR. KIERAN FLANAGAN: What we're inferring there is not for them to be the contract construction manager that -- which is the role of the GCC. We're saying they need to act more like a construction manager, collaborate and get involved with the GCC, and come up with ways to improve.

And get people on site -- and I'm -- I'm not saying they don't have people on site, but maybe get more people on site that come from a craft background, that they work methods. And if the GCC is doing it one (1) way, suggest another way that may improve. And there's no reason why you shouldn't buy into another way, if it can improve productivity.

MR. BOB PETERS: Did MGF see any evidence that Manitoba Hydro was doing that in 2016?

MR. KIERAN FLANAGAN: Yes.

MR. BOB PETERS: Did MGF see any results from those efforts by Manitoba Hydro in 2016?

MR. KIERAN FLANAGAN: We weren't on the job in 2016.

MR. BOB PETERS: Then my -- my second last question to you, Mr. Flanagan, was -- I asked whether you -- MGF had seen Manitoba Hydro trying to do those hands-on approaches that you've talked about in 2016?

MR. KIERAN FLANAGAN: We believe, from our site visit and discussions with people, that issues still exist.

MR. BOB PETERS: Okay. You're going to have to help this Board understand a bit more.

You're saying that whatever efforts

Manitoba Hydro had made, they weren't bearing the fruit that was expected?

MR. KIERAN FLANAGAN: Well, It's all in the -- it's all in the figures. Since the amending agreement, the new man-hours per cube of earthworks or concrete, it's dis-improving; it's not improving. So while we use an example in the report, it's -- it's all in the matter. It's still ongoing.

So you get -- productivity is based on methods of doing work, and if -- if it's still isn't proving, well, I don't know what to say. It's the -- the interaction isn't -- if -- if there isn't improved interaction, it's not helping.

MR. BOB PETERS: All right. So, MGF is saying that you -- you accept that Manitoba Hydro is intent -- is attempting to take steps to motivate the contractor to be more productive? Does --

MR. KIERAN FLANAGAN: We've heard -- we've heard there's mitigation factors today. I can only take that on board as true.

MR. BOB PETERS: And then what you say in response is that the numbers don't bear that there's been an increase in improvement in productivity?

MR. KIERAN FLANAGAN: Correct.

MR. BOB PETERS: On page 49 of Board counsels' document, MGF introduces a different word in the paragraph. It says:

"Unless Manitoba Hydro is prepared to make a step-change in the management of the general civil contract, then it will continue to limp along, and it could result in a range of 9.5 to 10.5 billion."

Correct? Did I --

MR. CAMPBELL ADAMS: Yes, that's, correct.

MR. BOB PETERS: And when you say "a step-change," is that anything different than what you've told me about the hands-on comment?

MR. CAMPBELL ADAMS: I think that's a component of it, Mr. Peters. If things continue the way they are, then this is going to cost more than 8.7 billion. Year after year of not meeting targets is not going to end up in a good place.

MR. BOB PETERS: Does Manitoba Hydro expose itself to risk by doing what you're suggesting, in terms of trying to assist BBE in doing its job?

MR. KIERAN FLANAGAN: I don't believe so if it's collaborative, and whatever suggestions made are -- well, whatever suggestion is made, that they buy into it.

MR. BOB PETERS: All right. On Manitoba Hydro's rebuttal, page -- sorry, Manitoba Hydro Exhibit 117, and this is on page 4 of the KPMG letter, which is Appendix A to the evidence, and at the -- below the bullets, there's a paragraph that starts -- and I'll just let you read that paragraph, if you could.

MR. CAMPBELL ADAMS: Is it the one, "commencing ongoing monitoring"?

MR. BOB PETERS: Correct.

MR. CAMPBELL ADAMS: Thank you.

(BRIEF PAUSE)

MR. BOB PETERS: You've had a chance to read it?

MR. KIERAN FLANAGAN: Yes, but it needs to be weighed up, that's -- it's trending that it's going to cost a lot more than the amended agreement. It -- so much needs to be take -- taken. You can't just stand back and let it trend the way it's going.

MR. BOB PETERS: No, but the -- the

essence of this -- I'm going to assure Mr. Haight for the third time that I'm not seeking a legal opinion -- but the suggestion here, from Manitoba Hydro's consultant, is that if Manitoba Hydro gets aggressive in the direct construction management, it could be opening itself up to legal claims from BBE?

Do you, first of all, see that's --

MR. CAMPBELL ADAMS: On -- on what grounds?

MR. BOB PETERS: Do you see that's being said?

MR. CAMPBELL ADAMS: Yes, but what are the grounds for that?

MR. BOB PETERS: Well, I can tell you what -- what's written here, is they say that that may be frustrating the contract as between Manitoba Hydro and BBE.

(BRIEF PAUSE)

MR. BOB PETERS: Do you accept that's -- that's a risk Manitoba Hydro has to be aware of?

MR. CAMPBELL ADAMS: Yes, I think that is a risk they need to be aware of. It's an extreme one, but I think it's a risk, yes.

MR. BOB PETERS: And so how does Manitoba Hydro ensure they don't cross that line?

MR. CAMPBELL ADAMS: I think that's part of the collaboration with BBE that needs to be had to help them raise their game. If -- if the works were slowed done, I guess I'd have to figure out what are those activities or decisions that would frustrate the BBE consortium.

But the flipside is, if you don't do anything, and you continue down the path that they've been on for the last two (2) years, then where will that take you?

MR. BOB PETERS: On page -- sorry, on Board -- sorry, on MGF -- Exhibit MGF 2-1 -- or maybe even 2(r). It's the report. On page 70, the last paragraph...

(BRIEF PAUSE)

MR. BOB PETERS: BBE -- sorry, MGF is telling this Board that Manitoba Hydro should not accept inconsistent, inaccurate, and unreliable reporting from BBE, correct? So how does -- how does Manitoba Hydro change that?

Did -- did you follow where I am, Mr.

Adams?

MR. CAMPBELL ADAMS: Yes, Mr. Peters. It -- if -- if your contractor is not complying with the contract that you have signed with them, you have the -- the right to have that correct. If there's inaccuracies in the information they provide, that should be corrected.

Owners needs solid information with which to understand where they stand today, and to make decisions going forward. I -- I don't think it's too much to ask that contractors get their reporting accurate.

MR. BOB PETERS: So that's a voluntary compliance then by BBE to meet that standard?

MR. CAMPBELL ADAMS: No, I think it would be a contractual one.

MR. BOB PETERS: And how does Manitoba Hydro enforce that?

MR. BOB PETERS: They point to the contract and say, You've got a report -- there's a section in the contract about monthly reporting, what must be in there?

If they're not getting that, you politely say, Here's the -- the section in the contract, this is not in compliance with that, can you kindly please redo it.

MR. BOB PETERS: Okay. And take it a step further and BBE doesn't redo it, what happens next?

MR. CAMPBELL ADAMS: I wouldn't pay them for their people. It's cost reimbursable. We're paying for a team of 'X' to give me something you don't want.

MR. BOB PETERS: Is it MGF's view that Manitoba Hydro is not taking advantage of all of its powers under the Amending Agreement 7?

MR. CAMPBELL ADAMS: I think that we have seen instances where BBE is not complying with the requirements, its obligations under the contract, and that -- that continues or has continued for a period of time. Negative float is one. The other one that was shared with us was the monthly report always coming in at least seven (7) days after the due date in the contract.

They're -- they're small examples, but I would say they're symptomatic of a bit bigger issue.

MR. BOB PETERS: All right. Let's turn to contract types for a few minutes.

Maybe, Mr. Chair, we could to take a short break.

THE CHAIRPERSON: We'll take -- we'll take a break until ten (10) to 5:00. Thank you.

MR. BOB PETERS: Thank you.

--- Upon recessing at 4:38 p.m.

--- Upon resuming at 4:53 p.m.

THE CHAIRPERSON: Mr. Peters...?

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: Yes, thank you. I'd like to start at page 54 of Board counsels' book of documents, volume 6, Exhibit 42-6 and on page 54, I'm going to the off-cited quote:

> "In construction time is money; in traditional fixed contracts time is the contractor's money; and in cost reimbursable contracts time is the owner's money."

That's a long-standing saying in the construction industry, is it?

MR. CAMPBELL ADAMS: Yeah, pretty much.

MR. BOB PETERS: Mr. Campbell, you're aware of that?

MR. DAN CAMPBELL: I'm going to agree with him pretty much.

MR. BOB PETERS: And, Mr. Adams, we've had a little discussion about cost reimbursable contracts and is it correct that the essence of that is, whatever cost is incurred by the contractor is paid to the contractor?

MR. CAMPBELL ADAMS: Correct.

MR. BOB PETERS: Now Manitoba Hydro has said that theirs is not a pure cost reimbursable contract because they have introduced a target price component.

Are you aware of that?

MR. CAMPBELL ADAMS: I am.

MR. BOB PETERS: Does the target price component change the essence of the contract to something other than a cost reimbursable contract?

MR. CAMPBELL ADAMS: No.

MR. BOB PETERS: Can you explain why you say that?

MR. CAMPBELL ADAMS: A cost reimbursable component, as you've said, the contractor gets paid for its cost of performing the work; that is not necessarily coupled with a target price. A target price is a -- it's a target. It's a goal. It's something to attempt to achieve. But it does -- it does not put a cap on the costs that the owner would pay to the contractor in a cost reimbursable basis.

MR. BOB PETERS: So the target price is introduced by Manitoba Hydro to incent the contractor not to exceed the target price?

MR. CAMPBELL ADAMS: I believe that's the intent because if the contractor exceeds the target price, then it loses its profit and the GN&O as opposed to other targets where some owners insist that if the contractor who typically represents and warrants that its estimated price is sufficient for the work, if they go above that ceiling, then the contractor can bear some of that cost overrun.

MR. BOB PETERS: I'm sorry, I didn't -- I didn't follow that last answer, Mr. Adams.

MR. CAMPBELL ADAMS: On some cost reimbursable price contracts, the owners introduce of where you've got the target or the -- the -- the target price. If the actual cost goes above that, the contractor will share in the cost overrun.

So if the contract -- if the target price is 100 and the eventual cost is 110, the owner and the contractor will share in the paying of the $10 in whatever proportion they decide.

MR. BOB PETERS: And you understand, in this arrangement, there is some sharing of the pain up until a certain level?

MR. CAMPBELL ADAMS: Not -- not on cost, there isn't. But on losing profit, yes, and in losing the GN&O, yes.

MR. BOB PETERS: Let's turn to --

THE CHAIRPERSON: Sorry, Mr. Peters, can I just --

MR. BOB PETERS: Yes.

THE CHAIRPERSON: -- can I ask a question?

MR. BOB PETERS: Please.

THE CHAIRPERSON: Mr. Adams, these are categories of contracts, correct? The fixed-price, lump-sum, unit price and cost reimbursable, these -- these are just broad descriptions for contracts.

MR. CAMPBELL ADAMS: These are pricing mechanisms, Mr. Gabor.

THE CHAIRPERSON: Right but in terms of the contract and you can have varieties within the contract, you actually have to look at the specific terms in the contract?

MR. CAMPBELL ADAMS: Yes because they will vary from contract to contract from owner to owner and from contractor to contractor.

THE CHAIRPERSON: Right. So the rights and obligations, while you may have a unit price contractor it's described that way, going from contract to contract, you need to look exactly at what the terms are in that contract because somebody may call a contract a unit price contract and another contract, may call it a units price contract, but depending on what the specific terms are in the contract may actually be different --

MR. CAMPBELL ADAMS: That's -- that's correct.

THE CHAIRPERSON: -- concepts. Thank you.

CONTINUED BY MR. BOB PETERS:

MR. BOB PETERS: I'm going to ask that Manitoba Hydro's Exhibit 120, which was the slidedeck from Manitoba Hydro's witnesses and slide 31 be brought up, if it could.

Mr. Adams, in your discussions just a minute ago with the Chairman, you talked about the different types of contracts. This slide from Manitoba Hydro suggests that different types of contracts were used for different contractors on the job site at Keeyask?

Are you aware of that?

MR. CAMPBELL ADAMS: I see it, yes.

MR. BOB PETERS: In some of these situations, and I'm going to take camp operations services as an example. Was it your evidence today that that's appropriate that that be a cost reimbursable contract?

MR. CAMPBELL ADAMS: That's correct.

MR. BOB PETERS: Why is that appropriate for that to be a cost reimbursable contract?

MR. CAMPBELL ADAMS: One (1) of the defining conditions about -- around pricing is the level of definition or finalization of -- of what the contract is intended to procure. If you have a house and it's fully designed, you can get that in a lump-sum because it's fully designed. The camp operations would be -- would have variability in the number of people, for example, staying on the camp. So you wouldn't get that as a lump-sum because you don't know who is staying when.

So it's more appropriate to have that either as a cost reimbursable pricing mechanism or like in a hotel, a rate per bed per night.

MR. BOB PETERS: Under your example, Manitoba Hydro carries all the risk for the camp, then, is that correct?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: Why is that appropriate?

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: We -- we have seen this done in two (2) ways, one is cost reimbursable and the other is on a like a hotel rate per night per bed.

And on the -- on the rate per night per bed, which is unit rate, then the kind of menus and the services is fixed and firm. With cost reimbursable there's more -- there's more scope for flexibility.

A lump-sum, as I've said, would be inappropriate because you don't know. No contractor can predict exactly what kind of occupancy level they would have.

MR. BOB PETERS: We've heard evidence in these -- in this proceeding, that Manitoba Hydro still has to do some work, I think it's been called, the south channel.

Do you know what that is?

MR. CAMPBELL ADAMS: The south dam?

MR. BOB PETERS: Yes.

MR. CAMPBELL ADAMS: Yep.

MR. BOB PETERS: Manitoba Hydro has to put a -- a dam on the south side of the generating station.

Is that your understanding?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And is it your understanding that that hasn't yet been done because the river is still running?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And because the river is still running Manitoba Hydro is not in a position to understand the geotechnical issues under the river?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And, Mr. Campbell, you spoke to this also today so -- so -- so don't sit too far back but -- and Mr. Campbell, your evidence that I remember was to the effect that Manitoba Hydro drilled, was it one (1) hole on that south dam area to test the geotech?

MR. DAN CAMPBELL: No.

MR. BOB PETERS: What was your evidence?

MR. DAN CAMPBELL: My evidence was that the area which I think it's in the river if we're speaking about the same issue that -- and I'm not the geotechnical engineer, is that that fault which they're concerned about extends, according to the information presented, on to land and that the investigations and information there was less or -- or perhaps enabled them to investigate it, right.

So consequently we und -- we -- we agree and understand why they didn't go and play in the river, but we believe that they had the opportunity to do the investigation or do enough investigation to get a reasonable idea about what is under the river.

MR. BOB PETERS: And that reasonable exploration, to your evidence, has -- has generally been done?

MR. DAN CAMPBELL: That -- it was an area where we thought there -- there could have been more work done. I believe that's what -- what I indicated earlier.

MR. BOB PETERS: All right, so -- so why should --

MR. DAN CAMPBELL: There's always a risk.

MR. BOB PETERS: Why should BBE carry the risk for what happens with the geotechnical issues under the river when it comes time to putting in those south dams?

MR. CAMPBELL ADAMS: They -- they shouldn't carry that risk.

MR. BOB PETERS: And they shouldn't carry that risk, Mr. Adams, because they don't know any better than you and I know what's underneath there; correct?

MR. CAMPBELL ADAMS: Exactly.

MR. BOB PETERS: And -- all right. If Manitoba Hydro -- then Manitoba Hydro should carry that risk?

MR. CAMPBELL ADAMS: Manitoba Hydro carries that risk because it's their project, and they -- they don't know either.

MR. BOB PETERS: And so as between BBE and Manitoba Hydro, it is more appropriate that Manitoba Hydro bear 100 percent of that risk?

MR. CAMPBELL ADAMS: That would be correct, yes.

MR. BOB PETERS: And to bear 100

percent of that risk it would be a cost reimbursable contract that would be used?

MR. CAMPBELL ADAMS: Not necessarily. There is -- if you know what the -- the design is and you don't know what the geotech conditions precisely are, you can get rates for concrete rates for excavation, rates for formwork and if you've got to go deeper, for example, than what you put into your tender document, then you would measure more quantities and reimburse your contractor on a unit rate basis.

MR. KIERAN FLANAGAN: Just alternatively, you could have a hybrid contract as well which would be unit rate for everything aboveground, including provision and sums for everything below ground, which will be cost reimbursable belowground and then once you get out of the ground, where you know the design to make it a unit rate or a lump sump.

MR. BOB PETERS: Mr. Campbell, you are in agreement with Mr. Flanagan on that latter point of the hybrid contract?

MR. DAN CAMPBELL: Yes.

MR. BOB PETERS: Have you se --

MR. DAN CAMPBELL: It's quite common

to actually have multiple -- multiple pieces inside a contract where some are unit rates and some are reimbursable based on what you don't know yet.

MR. BOB PETERS: And that's to the same general civil contractor?

MR. DAN CAMPBELL: Yes.

MR. BOB PETERS: So is it one (1) contractor has more than one (1) con -- sorry.

Is it such then that the general civil contractor has more than one (1) contract with Manitoba Hydro?

MR. DAN CAMPBELL: No.

MR. BOB PETERS: It's one (1) contract with many subcomponents?

MR. DAN CAMPBELL: Yes. There'll be a different payment item for excavation, for example, for the south down. Might be paid on -- in a different manner much the same as the table you have on the screen right now, right, where that would be a cost reimbursable piece but another piece like the construction of the -- of all the fills, et cetera, is paid on the unit rate basis, for example.

MR. BOB PETERS: All right. And your point, Mr. Flanagan, is that if it was belowground Manitoba Hydro should carry a hundred percent of the risk; but if it's aboveground, the contractor should carry the risk in accordance with what Manitoba Hydro has designed?

MR. KIERAN FLANAGAN: Where there isn't a full geotech study, and the contractor can't properly price the work ahead to fix it, yes, generally the risk will be taken by the client.

MR. BOB PETERS: All right. Let's -- let's transfer that answer to the Keeyask generating station. The -- the geotech work or the work below the ground, MGF is saying is properly in a cost reimbursable contract as one example?

MR. KIERAN FLANAGAN: Due to the geotech knowledge at the time of the work, yeah.

MR. BOB PETERS: And, Mr. Adams, you gave us an alternative view that you could use different contracts for the same unknown work.

MR. CAMPBELL ADAMS: You can use different pricing mechanisms that would be contained within the one (1) contract.

MR. BOB PETERS: All right, so --

MR. CAMPBELL ADAMS: Not different contracts.

MR. BOB PETERS: You've corrected me. It's still one (1) contract but it's the pricing mechanism under the contract could be cost reimbursable if it's underground or it could be unit price or fixed price and --

MR. CAMPBELL ADAMS: Yes, and generally, what we do we -- we stratify the scope of work and the scope of work that is, say, cost reimbursable would point to a that section in the pricing schedule that would set out how that scope would be valued and paid to the -- to the contractor.

MR. BOB PETERS: And, Mr. Campbell, you're saying that in major hydro-generating station constructions, the hybrid contract is used regularly?

MR. DAN CAMPBELL: Yes. And not only is the -- is it used that way to price it, but the contingency when you figure out your contingencies on it may be applied differently to the different pieces. Because you're trying to mitigate the risks and if the risks are high, you have -- obviously have a higher contingency.

So if you're -- if you're -- if you know exactly what you're going to build, presumably the contingency would be lower than if you're doing excavation to an unspecified depth.

MR. BOB PETERS: I'm not sure I follow, Mr. Campbell. Does that suggest that the contingency then isn't just a percentage of the overall contract but --

MR. DAN CAMPBELL: Correct.

MR. BOB PETERS: -- it's based on the stratification of the components of the contract?

MR. DAN CAMPBELL: Often, if you have multiple types of -- of payment in there the contingency for the different payment items might be dependent on the payment item or what you're doing.

MR. BOB PETERS: Okay. I think I have your point. So if we rewind the clock and, witnesses, you heard earlier today some of the steps that Manitoba Hydro took dating back to 2012 when they were investigating going to market. I believe the evidence suggests that Manitoba Hydro held meetings with various contractors. And that's what you would expect before they go to -- go to market for a project of this size?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And when they met with various contractors, would you expect those contractors to indicate a preference as to what type of contract they would like to -- or what pricing mechanism under the contract they'd like to work to?

MR. CAMPBELL ADAMS: It -- it's

possible. Typically, when owners go to market they have their preferred contracting strategy and they're trying to test the doability, achievability of that rather than go out and say, well, what would you like?

MR. KIERAN FLANAGAN: I believe the contractors were asked -- or given an opportunity for their opinions what they'd like to see in the contract.

MR. BOB PETERS: Is that right or wrong?

MR. KIERAN FLANAGAN: That's what I bel -- that's what we were advised.

MR. BOB PETERS: No, I'm sorry, but is that -- is that a good thing to do, or a bad thing to do?

MR. KIERAN FLANAGAN: Personally, I haven't come across it before.

MR. BOB PETERS: So the owner doesn't ask the contractors what kind of a contract they'd like?

MR. KIERAN FLANAGAN: No, it was elements what they'd like to see in the contract and then each contractor put forward what they'd like to see and, from my recollection, Manitoba Hydro then took on board what they -- what they agreed was reasonable to see in the contract. So I'm not saying it's wrong or right, I just haven't experienced it before.

MR. BOB PETERS: My understanding of the evidence is that back in 2013 there was an indication to Manitoba Hydro that contractors weren't interested in hard money contracts.

Do you have the same understanding?

MR. KIERAN FLANAGAN: I don't think we can speak to that. We weren't involved in the project in 2013.

MR. BOB PETERS: You were involved in the Alberta market in 2013, were you?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: Was it a hot market in the oil sands?

MR. CAMPBELL ADAMS: Yes, it was busy.

MR. BOB PETERS: Can you indicate to this Board how the contracts in the oil sands projects are structured for payment?

MR. CAMPBELL ADAMS: They -- they use all of the above depending on scope, depending on risk, depending on whether there's a design for the facility, but if there's no design and you want to get out tomorrow and start digging and building then it's cost reimbursable.

If you've got an idea of what your design is, you can take off estimated quantities and tender it unit rates.

MR. BOB PETERS: In your review of the Manitoba Hydro documents, did you go back to the tender documents that applied to the original contract with BBE?

MR. CAMPBELL ADAMS: Yes, I believe.

MR. BOB PETERS: And I'm not asking you to get into any depth or any numbers in respect of these questions, but you're aware that Manitoba Hydro received multiple bids for the work that they were tendering?

MR. CAMPBELL ADAMS: Do you mean bids or responses to prequalification?

MR. BOB PETERS: To me they mean the sa -- oh, sorry, not -- not prequalification, I'm talking about bids in response to the tender for the Keeyask general civil contract?

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: There was more than one (1) and less than six (6). I'm not sure if it's commercially sensitive, so I'm...

MR. BOB PETERS: You know what, I -- I think we'll stick with that answer because I don't think it is CSI, but I'm not the purveyor of all of that knowledge.

So, you're aware that Manitoba Hydro had a number of contractors that responded to its tender?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And as a result, Manitoba Hydro selected one (1) of those contractors that submitted a response, correct?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: Maybe on the screen if we could just go to Manitoba Hydro's Exhibit 120 to slide 34. Yes.

In 2013, there were four (4) proponents prequalified?

MR. CAMPBELL ADAMS: Yep.

MR. BOB PETERS: All right that tells me that it's not necessarily a CSI number.

You had an opportunity to look at the proposals and -- and that -- that were submitted in response to Manitoba Hydro's issuing a tender?

MR. CAMPBELL ADAMS: We looked at the

-- the -- the tabulation of that, the evaluation of what figures were given by each proponent.

MR. BOB PETERS: And did you look at the productivities; is that which you're telling the Board?

MR. CAMPBELL ADAMS: No, I am telling you that the -- each -- if you call it a bid because this is a cost reimbursable contract that they -- they give an assessment of what they thought direct costs would be; what their indirects would be; I believe what their profit was; what -- what contingency they would -- they had included in their -- their target price. They were -- they -- they were very -- they were very different in terms of value and percentage. I'm not sure how else to characterize that without going too far.

MR. BOB PETERS: All right.

(BRIEF PAUSE)

MR. BOB PETERS: In volume 6 on page -- of Board counsels' book of documents, page 44 at the bottom, you make -- MGF makes a finding with respect to Keeyask board recommendation; correct?

MR. CAMPBELL ADAMS: Correct.

MR. BOB PETERS: And when you say "board recommendation," you're meaning the Manitoba Hydro Electric Board of Directors?

MR. CAMPBELL ADAMS: I believe so.

MR. BOB PETERS: And in this particular case reference is shown as to -- the information that you were provided from the -- the minutes of those board meetings?

MR. CAMPBELL ADAMS: Correct.

MR. BOB PETERS: And in it, Manitoba Hydro was advised that Bechtel was a self-performing contractor on the Limestone project in Manitoba, correct?

MR. CAMPBELL ADAMS: Correct.

MR. BOB PETERS: Is it also MGF's view that -- that in and of itself shouldn't have been accepted at face value? Well, first of all, what is a self-performing contractor?

MR. CAMPBELL ADAMS: A self-performing contractor in our world is a contractor who -- who directly employs within their organization the -- the construction disciplines with will -- with which to build a project as opposed to a contractor who predominantly would outsource or subcontract to others or opposed to a construction manager who directs many smaller companies in performing the work.

MR. BOB PETERS: So that suggests that when Bechtel was working on the Limestone project, it had its own employees under the various disciplines needed?

MR. CAMPBELL ADAMS: That is our understanding, yes.

MR. BOB PETERS: And on this project, did BBE have its own employees under the various disciplines or did it go out and hire the sub-trades?

MR. CAMPBELL ADAMS: BBE or Bechtel?

MR. BOB PETERS: BBE.

MR. CAMPBELL ADAMS: I believe the majority are -- are directly employed in accordance with the -- the Burntwood Nelson agreement.

But the -- but the -- I think the difference is, up until they started working for BBE they weren't with BBE; whereas a self-performing contractor moves their direct employees from one contract to the next. So they understand who their supervisors are. They understand the language. They understand the systems of that organization.

In -- in this construct, you've got a joint venture limited partner with three (3) parties, and I don't know the degree to which they've actually worked together before.

MR. BOB PETERS: But you're saying that BBE was not a self-performing contractor then.

MR. CAMPBELL ADAMS: I wouldn't describe BBE as a self-performing contractor. Sorry.

(BRIEF PAUSE)

MR. BOB PETERS: Any comments to add, Mr. Campbell?

MR. DAN CAMPBELL: Both Barnard and EllisDon are self-performing contractors, as far as I'm aware.

MR. BOB PETERS: And do you know if they brought their own resources to the Keeyask site?

MR. DAN CAMPBELL: I believe that they brought some of their own resources to the Keeyask site.

MR. BOB PETERS: Do you have any different information on MGF side?

MR. CAMPBELL ADAMS: No, we're not aware of that.

MR. BOB PETERS: On the top of page 45 there is a -- an observation and a finding by MGF related to the lowest cost and offer best value to the project in description of BBE.

Do you see that?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And MGF doesn't agree that that's accurate?

MR. CAMPBELL ADAMS: Correct.

MR. BOB PETERS: And can you explain why not?

MR. CAMPBELL ADAMS: We don't believe that the offer was -- was cost. It was an estimate. There were -- I believe there were -- I think there were -- I think quantities put into the tender documents. The proponents put in unit rates to come up with their initial target price. But that's not the basis upon which the contractors would be compensated.

So to have a -- to -- so four (4) proponents, four (4) very differing initial target price -- prices, they're not firm and fixed. It's a -- it's a -- it's a target. It's a goal. What is clear, that they get compensated on whatever their actual costs will eventually be.

MR. BOB PETERS: So the information that -- that the Board of Directors is referring to wasn't fully fleshed out in the information --

MR. CAMPBELL ADAMS: That's -- that's
my view. Mr. Flanagan...?

MR. KIERAN FLANAGAN: And the lowest
cost wasn't realistic, as we all know today.

MR. BOB PETERS: All right. But --
but, let's say, we don't have the rearview mirror, Mr.
Flanagan, and we're -- we're back in -- in the day
when this contract had to be considered.

Are you saying that it was too good to
be true?

MR. KIERAN FLANAGAN: Put it this way,
I was shocked to see that the labour norms used for
concrete were based on a contract twenty-five (25)
years ago.

MR. BOB PETERS: And you're shocked
because you would've expected there to be something
against which that could be checked in a more -- a
more recent past?

MR. KIERAN FLANAGAN: Old fashion way,
people worked twenty-five (25) years ago.

MR. BOB PETERS: I'm sorry?

MR. KIERAN FLANAGAN: People worked
twenty-five (25) years ago. They were more
productive.

MR. BOB PETERS: And I suppose there's

reasons for -- for that; perhaps attributed to safety standards --

MR. KIERAN FLANAGAN: Of course there's safety standards. There's different work methods but one (1) of the main things is when the craft people were working, they worked hard all day. A fifteen (15) minute break was a fifteen (15) minute break.

MR. BOB PETERS: And you're saying you saw different standards apply on the Keeyask site?

MR. KIERAN FLANAGAN: I'm not saying the Keeyask site. I -- throughout the whole industry. So it's not -- there's an element that people worked harder, there's an element at the fifteen (15) minute break you had to eat your lunch in the fifteen (15) minute break. The same with lunchtime.

But there's also an element with safety and other elements, that should've been taken into account; that a project twenty-five (25) years ago is not achievable today. On productivity, sorry.

MR. CAMPBELL ADAMS: There's also some assumptions arou -- around the productivity, not to get into the numbers, but that they're much, much better than what was achieved on the last -- the last project. That -- that to us seems somewhat

optimistic, somewhat unrealistic, and I think that
history, sadly, has borne that to be true.

MR. BOB PETERS: So when you say that
the productivity was better than the last project,
you're referring to Manitoba Hydro's Wuskwatim
project?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: And then your answer
is that because of Manitoba Hydro's relatively recent
experience with Wuskwatim, that should have let
Manitoba Hydro know that the productivity being
forecast by at least one (1) of the bidders wasn't
likely to materialize?

MR. CAMPBELL ADAMS: I think it
should've raised the question as to why did to the --
why did that proponent think that they could do that,
and also compare that to what the other proponents
were offering, and a take -- take a realistic view as
to how achievable this is, because that underpins what
was a -- a low, as it turned out to be, initial target
price.

MR. BOB PETERS: And if Manitoba Hydro
then meets with the contractor and discusses the --
the relative size of the productivity forecast and is
given assurances that can be met, what is Manitoba

Hydro supposed to do differently?

MR. CAMPBELL ADAMS: Well, convert your price to a lump sum. If you think you can do for that, you can stand over. And you're competent contractor and you're warranting that your price is sufficient for doing the work, well stand over them. And then watch their face lose its blood.

MR. BOB PETERS: I want to turn in the few minutes that I have remaining to one (1) other area. On Volume VI, page 25, of Board counsels' book of documents, in one (1) of the answers that Manitoba Hydro has provided to the Public Utilities Board, and it's at the bottom of the page, the main contributing factors to the underperformance of BBE were set out, and there were three (3) of them.

And you're familiar with those?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: First of all, without indicating any dollar amounts, are you able to rank them based on the highest contributor to cost overruns to the lowest contributor of cost overruns, from what you've seen?

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: We -- we could accept the -- the bullets in the order in which they're given.

MR. BOB PETERS: And, Mr. Campbell, because one (1) of them deals with geotechnical issues, and you have a colleague that specializes in that, have you looked at it from that perspective as well?

MR. DAN CAMPBELL: We didn't look at bullet 2, but certainly the order between 1 and 3 is correct.

MR. BOB PETERS: Thank you. Mr. Campbell, can you explain to this Board why geotech caused a problem, when KCB finds that the quantities estimated by Manitoba Hydro were very accurate?

MR. DAN CAMPBELL: No, I don't believe I -- I can.

MR. BOB PETERS: That's not something that KCB investigated?

MR. DAN CAMPBELL: When we looked at them, as I -- as we said in our report, we found some issues which -- would it -- change the costs a bit, but we were not able to come up with anything that would make such a dramatic change, as has -- has actually occurred.

MR. BOB PETERS: And that -- and that's specifically tied to the geotechnical issues?

MR. DAN CAMPBELL: Yes.

MR. BOB PETERS: And, Mr. Adams, is the impact of geotechnical issues found in the contingency? Is that where it -- it -- where it lies?

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: Could you please rephrase your question, so I can better understand what you're seeking from me?

MR. BOB PETERS: I'll ask it better, or I try -- I'll try.

MR. CAMPBELL ADAMS: Thank you.

MR. BOB PETERS: If there are additional costs related to the actual experience with geotechnical and geological conditions, where's the money to pay for that in Amending Agreement Number 7?

MR. CAMPBELL ADAMS: I'm not sure -- I'm not sure where that -- where that is. I believe Amending Agreement Number 7...

(BRIEF PAUSE)

MR. BOB PETERS: Gentlemen, it may have been asked poorly, or maybe it's late in the day, or both, but --

MR. CAMPBELL ADAMS: Sorry, is -- is your question to determine whether the -- the cost of geotech was included in the -- the target price that is included in Amending Agreement Number 7, or how was it paid for eventually?

MR. BOB PETERS: No, we're talking about the construction year 2016, and that there were a number of problems, and three (3) of them are listed here on the screen. One (1) of them is the productivity, the other --

MR. CAMPBELL ADAMS: Okay.

MR. BOB PETERS: -- is the slow ramp-up, and the third is the geotechnical issues.

And is it correct that the geotechnical issues and the additional cost that that drives is born a hundred percent by Manitoba Hydro?

MR. CAMPBELL ADAMS: That is correct, yes.

MR. BOB PETERS: And so for Manitoba Hydro to cover that expense, it would have to be included in the -- in the contingency account?

MR. CAMPBELL ADAMS: It -- it might

come from there, yes.

MR. BOB PETERS: All right. A last area is on the -- well, the same area, but Exhibit 117, page 2, of the Appendix A. Again, we're back to that KPMG report. And the very last -- sorry, the second last paragraph, it indicates that, in talking about MGF and the analysis -- I'm sorry, I've given you the wrong reference.

It's Appendix B, on page 2. And this is in the Hatch Report. And it is on page 2. It is in the last paragraph. And it's a comment about MGF.

Have you had a chance to see this report before? This was attached to Manitoba Hydro's rebuttal evidence?

MR. CAMPBELL ADAMS: Yes.

MR. BOB PETERS: In this report, the last part of the paragraph, the last paragraph on page 2, indicates that the MGF report fails to identify reasons behind BBE's poor productivity performance.

Do you agree with that?

(BRIEF PAUSE)

MR. CAMPBELL ADAMS: We -- we have not identified the reasons behind the poor productivity.

We have taken the -- the actuals provided from BBE via Hydro into -- into consideration.

(BRIEF PAUSE)

MR. BOB PETERS: Mr. Chair, I'd suggest this is a good time today to adjourn. I was just a -- I just want talk about -- to Keeyask scheduling tomorrow, as well as some remaining risks, and then I wanted to shift over to Bipole III, and the transmission lines, and the converter stations. I'm expecting I can finish that within an hour in the morning.

And after I am complete, and subject to any re-examination, the public evidence would be finished, and we would be in a position to move right into the in camera session.

In terms of a direct presentation from the witnesses in camera, I'm expecting it would be approximately a third as long as it was today, but Mr. Haight might have a better time estimate than I.

MR. WILLIAM HAIGHT: I -- I think that's reasonable. Perhaps, even less than a third.

MR. BOB PETERS: And My Friend opposite, Ms. Van Iderstine, hasn't suggested a lot of time would be needed for Manitoba Hydro's view in camera. I don't know if that -- that view has changed. And she can speak for herself.

MS. HELGA VAN IDERSTINE: No, we're not anticipating a lengthy cross-examination. Probably -- much less than we -- I think -- I'm not sure how much we had anticipated. I say an hour. I'll be well --- I'll be down -- if -- if I'm a half hour I would be very surprised.

MR. BOB PETERS: All right. What you're hearing, Mr. Chairman, is an indication that I think the parties in this room would like to finish before the Board adjourns for lunch tomorrow, even if it means we slip a little bit into the lunch hour. But the promise, or the carrot, we can hold out as the afternoon would -- would be -- would be yours.

So until tomorrow morning at nine o'clock, I have no further questions.

THE CHAIRPERSON: I don't know what to do with all that freedom. Thank you, we'll adjourn till nine o'clock tomorrow morning.

(PANEL RETIRES)

--- Upon adjourning at 5:33 p.m.

Certified Correct,

____

Cheryl Lavigne, Ms.

Tab 130

Manitoba Hydro

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January 16, 2018

Mr. D. Christle
Secretary and Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba R3C 0C4

Dear Mr. Christle:

RE: MANITOBA HYDRO 2017/18 & 2018/19 GENERAL RATE APPLICATION ("GRA") – REBUTTAL EVIDENCE ON THE MGF REPORT

Please find attached Manitoba Hydro's Rebuttal Evidence with respect to the written evidence of MGF Project Services Inc., on their report titled *Manitoba Hydro Capital Expenditure Review for the Keeyask Hydroelectric Dam, the Bipole III, Manitoba-Minnesota, and GNTL Transmission Lines*.

Manitoba Hydro is enclosing, for the public record, copies of its Rebuttal Evidence with confidential information redacted and with redaction codes inserted thereon. Manitoba Hydro Is also enclosing copies (on blue paper) of its Rebuttal Evidence with redactions removed, which copies Manitoba Hydro requests be received and held in confidence pursuant to Rule 13 of The Public Utilities Board Rules of Practice and Procedure.

If you have any questions or comments with respect to this submission, please contact the writer at 204-360-3946 or Odette Fernandes at 204-360-3633.

Yours truly,

MANITOBA HYDRO LEGAL SERVICES DIVISION
Per:

PATRICIA J. RAMAGE
Barrister & Solicitor

cc:

All Registered Interveners
Odette Fernandes, Manitoba Hydro
Bob Peters, Board Counsel
Dayna Steinfeld, PUB Counsel

MANITOBA HYDRO PUBLIC UTILITIES BOARD

IN THE MATTER OF *The Crown Corporation Public Review and Accountability Act*

AND IN THE MATTER OF Manitoba Hydro's 2017/18 & 2018/19 General Rate Application

REBUTTAL EVIDENCE OF MANITOBA HYDRO

WITH RESPECT TO THE WRITTEN EVIDENCE OF:

MGF Project Services Inc., Independent Expert Consultant for the Public Utilities Board, on the Manitoba Hydro Capital Expenditure Review for the Keeyask Hydroelectric Dam, the Bipole III, Manitoba-Minnesota, and GNTL Transmission Lines

Manitoba Hydro

January 16, 2018

Table of Contents

In its 2017/18 & 2018/19 General Rate Application ("Application") filed on May 12, 2017, Manitoba Hydro provided a brief description of its Bipole III Reliability Project ("Bipole III"), its Keeyask Generating Station Project ("Keeyask"), and the U.S. Tie-Line Project made up of the Manitoba-Minnesota Transmission Project in Manitoba ("MMTP") and the Great Northern Transmission Line in Minnesota ("GNTL"). Included in those descriptions were the budget estimates in place as at that time, and the projected In-Service Dates for each as of May, 2017. The Application also made reference to the review of those projects by the Boston Consulting Group.

On December 8, 2017, Manitoba Hydro was provided with a copy of the Report from MGF Project Services Inc. ("MGF"), an entity retained by The Public Utilities Board of Manitoba ("PUB") to review Manitoba Hydro's capital expenditure program in relation to the above projects and to provide its opinion on Manitoba Hydro's updated costs for each. Manitoba Hydro has had the opportunity to review that report, to put forward its Information Requests, and to review the answers provided by MGF on or about January 5, 2018, to all of the Information Requests it received.

In order to provide background and context to the remarks made in the Report of MGF, and to fully respond to the opinions expressed therein, Manitoba Hydro has prepared separate rebuttal for each of Bipole III, Keeyask and MMTP. It was not felt necessary to provide rebuttal on GNTL and the Manitoba-Saskatchewan Transmission Project.

1. KEEYASK GENERATING STATION PROJECT

The Keeyask Generating Station is a 7 unit 695-megawatt hydroelectric generating station situated at Gull Rapids on the lower Nelson River in northern Manitoba. Keeyask will be the fourth largest generating station in Manitoba and the sixth generating station located on the Nelson River. The Keeyask Project is owned by a partnership between Manitoba Hydro and four Manitoba First Nations, known as the Keeyask Hydropower Limited Partnership ("KHLP"). Manitoba Hydro has been tasked with the responsibility of managing the construction of the Keeyask Project and the operation of the facility when it enters into service on behalf of the KHLP. Construction of the Keeyask Project consists of the construction of the generating station as well as construction of supporting infrastructure and the Keeyask Transmission Project which will transport the power produced at Keeyask onto the Manitoba Hydro system when the generating station enters into service.

MGF was retained on Keeyask to review and explain the increases in cost estimates and capital cost increases, as well as project cost overruns. It was to determine and assess the reasonableness of the updated forecast and to identify aspects of the updated cost estimate and schedule that are at risk. It was also to recommend risk mitigation strategies and, further, to review and make recommendations with respect to Manitoba Hydro's:

- practices on its pre-construction design and engineering work;
- its methodologies for costing, for tendering and contracting, for management of construction, contractors and construction risk management, and for scheduling;
- its choice of contract types;
- geotechnical analysis; and
- the governance structure.

Manitoba Hydro staff received dozens of requests for information and data, and staff was fully transparent in sharing more than 1,900 documents including contracts, cost estimates, schedules and various other project management documents.

Key Manitoba Hydro project staff had more than two dozen meetings by phone and in person with MGF representatives and hundreds of emails were exchanged between the parties over the course of the review. MGF also met with senior staff from the General Civil Contractor BBE Hydro Constructors Ltd ("BBE"), and the project design engineer ("Hatch"). MGF personnel attended the Keeyask site on three separate site visits.

In MGF's *Report for Manitoba-Hydro Capital Expenditure Review for The Keeyask Hydroelectric Dam, The Bipole III, Manitoba-Minnesota and GNTL Transmission Line* report dated December 8, 2017 ("MGF's Report or the Report"), MGF and their sub-consultant Klohn Crippen Berger ("KCB"), provide a number of observations, findings, recommendations and conclusions related to Keeyask. Manitoba Hydro has grouped a majority of these items into three major themes which Manitoba Hydro will comment on in the subsequent sections of this rebuttal. The three major areas which Manitoba Hydro will address are as follows:

1) The contract model selected for the General Civil Contract ("GCC");
2) The people and the competency of the people managing the construction of the Keeyask Project; and
3) MGF's findings related to the forecasted cost and schedule of the Keeyask Project.

The key responses to those three major areas (detailed more fully below) are:

1) The contract model selected for the General Civil Contract;

- The GCC is being managed under a target price contract where the contractor is reimbursed for actual costs. The contractor is incentivized to perform and minimize cost and schedule as their profit and General Administration and Overhead are at risk if they exceed their target price. The contractor is also subject to liquidated damages for delays to the project schedule.
- The decision to proceed under the cost reimbursable target price contract model was made in 2012/2013 and was part of a larger Project Delivery Strategy for the Keeyask Project. This decision was informed by lessons learned on the recently completed Wuskwatim Generating Station Project and prevailing market conditions at the time.
- The North American major capital project market around the time of the GCC procurement was extremely competitive. Contract models that transferred additional risk to the contractor including fixed price and unit price would have been cost prohibitive as contractors were not willing to accept additional risk in a competitive environment.
- An extensive 24 month, three phase procurement process was undertaken to select a General Civil Contractor. BBE was the selected contractor as they were determined to be the best value contractor based on the evaluated criteria.

2) The people and the competency of the people managing the construction of the Keeyask Project.

- The Manitoba Hydro team delivering the Keeyask Project is comprised of project management and construction management professionals with experience in managing some of the largest construction projects in Manitoba over the past decade.
- Manitoba Hydro has contracted BBE as the GCC to serve as Construction Manager for General Civil scope of work. Manitoba Hydro taking over the role of Construction Manager as implied by MGF throughout their report would expose Manitoba Hydro to additional risk and claims from the contractor.
- From the start of construction, Manitoba Hydro has continually attempted to undertake actions to progress the work while not crossing the line of explicitly directing the means and methods of the contractor. Crossing this line will expose Manitoba Hydro to interference claims from the contractor and increase the level of risk assumed by Manitoba Hydro.

3) MGF's findings related to the forecasted cost and schedule of the Keeyask Project.

- MGF does not provide data to support its conclusion that the expected cost of Keeyask will be \$9.5 B to \$10.5 B. Manitoba Hydro and the PUB submitted Information Requests to MGF requesting the details underpinning these calculations; however, MGF failed to provide the requested backup.
- Without the backup to substantiate MGF's claims, Manitoba Hydro reviewed the data in an attempt to understand how MGF arrived at their conclusions. From the information available, it is Manitoba Hydro's opinion that MGF has likely overstated the range of potential costs as they incorrectly applied General Administration and Overhead and indirect costs to their estimated cost overruns.
- MGF's forecasting methods are overly simplistic and do not consider the efforts undertaken by Manitoba Hydro and BBE to reduce cost and schedule outcomes.

1.1. The General Civil Contract, Contracting Strategy, and Selection of the Contractor.

<u>GCC Contracting Strategy:</u>

<u>MGF Report:</u>

Section 1 - Executive Summary, page 1

Scope Item 5: Finding # 1 page 50; Finding # 5 and 6 page 56; Finding # 12 page 62

Scope Item 9: Finding #10 page 80
Section 8 – Conclusion, page 161

<u>KCB Report:</u>
Section 5 page 33 – 35
Section 7 Pages 39 -40

Recognizing that the GCC was the largest and most important contract on Keeyask, in 2012 Manitoba Hydro developed and executed a detailed project delivery strategy which included a procurement strategy for the General Civil Contractor. The project delivery strategy was provided to Knight Piésold ("KP") (the independent expert consultant retained by the PUB) during the Need for and Alternatives To ("NFAT") review in 2014 and more recently to MGF in July 2017 during the current review of the Keeyask Project. On Executive Summary page II of IV of Knight Piésold Independent Expert Consultant Report Rev.1 dated January 23, 2014, in reference to construction management, schedule and contracting plans, KP stated that:

> *"The overall approach follows well documented internal standards developed by Hydro's NGCD. The contracting method varies by project component but the principal civil works contracting strategy is an Early Contractor Involvement (ECI) Project Delivery Strategy. Overall the project delivery strategy has been to transfer risk away from Contractors and to Hydro in order to better understand and share the risks and obtain a better contract price as a result."*

Manitoba Hydro's selection of a contracting strategy was informed by a number of factors including, but not limited to, the following:

- Market conditions that influence the availability of major contractors willing to bid on the work;
- Allocation of risk to the party best suited to manage the project's most significant risks;
- The project schedule;
- Completeness of engineering at the time of tender;
- Lessons learned from past projects including Wuskwatim and Pointe du Bois; and

- Internal expertise and resource availability. Manitoba Hydro evaluated its internal expertise, resource availability and corporate structure as part of its analysis of an appropriate contracting strategy. It was recognized that although Manitoba Hydro had significant and expert resources required to function as the overall project and site manager, it lacked the experience necessary to manage the day-to-day activities typically performed by the general civil contractor. To perform this role would require significant changes and the addition of considerable construction and support staff to Manitoba Hydro's organization.

KCB states:

> *"While we were not part of the process that selected the contracting model, we surmise that MH either had success with this model elsewhere, or there were significant reasons to push the project into construction quickly relying on the early contractor involvement, the expectations of a quality design from Hatch and an experienced contractor with a realistic target price to make the project a success."* (Page 39)

KCB is correct in its assumption that Manitoba Hydro was applying lessons learned from previous major capital projects that it had managed, including the recently completed Wuskwatim Generating Station and Pointe du Bois Spillway Replacement Project. It is not accurate in its assumption that the contract was impacted by any desire or need to push the project into construction quickly.

The lessons learned by Manitoba Hydro that led to its selection of the cost reimbursable target price contract for the GCC are explained below. Lessons learned from past projects were also previously discussed at a high level during the NFAT in 2014 hearings as well as during the 2015/16 and 2016/17 General Rate Application (Manitoba Hydro Exhibit #104 – Undertaking #44).

> *"Manitoba Hydro originally tendered the General Civil Contract for the Wuskwatim Generating Station in 2007 as a unit price contract using the design, bid, build model. This resulted in receiving only one bid from the market with a price nearly double the Engineer's Estimate and well beyond the expected value*

of the work. After suffering schedule delay because of the lack of reasonable bids, the work was re-tendered and four competitive proposals were received with a cost-reimbursable, target price contract awarded to the successful proponent in November 2008.

Based on the Wuskwatim Project experience, Manitoba Hydro also chose to include the river management, rock excavation, and electrical/mechanical scope into the Keeyask GCC to reduce the interface risk between contractors otherwise held by Manitoba Hydro. The rock excavation and electrical/mechanical work were packaged as separate contracts on the Wuskwatim Project leading to many challenges in interface management between the various contractors. On Keeyask, this work is bundled together within the GCC's scope.

At the time when Manitoba Hydro was developing the contracting strategy for the GCC, potash was increasing in demand, oil prices were more than $100/barrel and any available forecasts anticipated continued price increases. As a result, there was a boom in the major capital project market in North America, particularly in the energy industry including the Northern Alberta oilfields as well as many oil and natural gas projects within the Bakken Formation underlying portions of Saskatchewan, Montana and North Dakota and the Muskrat Falls project in Labrador, which resulted in increased competition for skilled labour (See for example http://publications.gov.sk.ca/documents/310/81353-2014-MPI.pdf). In this 'hot' construction market, many of the major contractors had already committed experienced personnel and resources to the other projects and were not as hungry for opportunity. In this type of economic environment, Manitoba Hydro's experience was that contractors were also not as willing to accept risk in a job and their pricing reflects this reality. Economic conditions were similar for the procurement phase of Keeyask as they were for procurement during Wuskwatim when the original General Civil Contract was unsuccessfully tendered as a unit priced contract and then re-tendered competitively as a cost reimbursable target priced contract.

> *Labour productivity (amount of hours per unit of work) has been one of, if not the largest risk for contractors since the early 2000's across Canada, particularly in remote, fly-in fly-out operations such as Keeyask. As was learned on Wuskwatim, this caused contractors to avoid or submit extremely high bids for any contract that transferred this risk to them (such as fixed cost or unit price contracts). For Canadian hydro, the absence of large scale projects from 1990 to the mid-2000's magnified the productivity issue creating a skilled labour shortage across the country and a shortage of qualified supervision. Manitoba Hydro was well aware that many contractors were wary to provide competitive estimates for hydro work."*

In 2012, Manitoba Hydro selected a cost-reimbursable target price model with Early Contractor Involvement ("ECI") that balances project risk between two parties. If the contractor completes the work under the target price, they earn profit plus a share of the savings. However, if the contractor exceeds the target price, they forfeit a substantial portion of their profit for every dollar of overrun, up to the value of their total profit amount. A contractor will not go bankrupt on the job, but they are at risk of not earning any profit if they exceed the target price by a certain threshold. No return (i.e. profit) on a 5+ year investment of resources by a major contractor is not what shareholders want to see and thus the contractor is incentivized and motivated to perform.

A fixed price model was considered but would have necessitated a contractor bidding higher to factor in risks over which they have no control (e.g. geological conditions, interest rates, commodity price escalations over the duration of the work, labour skill and availability, etc.). This would have raised the initial cost of the project and limited the number of parties interested in proposing on Keeyask, thus driving up the project cost.

Another reason the target price model was chosen was because it allowed for an opportunity to leverage ECI. As the final design engineering was not yet complete, there was an opportunity to engage a contractor early to help influence the design from a constructability standpoint. Engaging a contractor earlier also allowed the contractor more lead time to establish project process and work plans, understand the labour agreement and understand the local labour and supplier market.

Manitoba Hydro also had experience with the target price model having recently completed Wuskwatim in 2012 ($1.4B) and Point du Bois in 2014 ($0.6B).

KPMG, a consultant experienced in the management of major capital projects, was engaged by Manitoba Hydro in May 2016 to undertake an independent review of the current status of Keeyask. KPMG subsequently provided advice on the development and implementation of a Recovery Plan for Keeyask and has provided project management support since that time for the Manitoba Hydro project delivery team. Manitoba Hydro requested KPMG to provide commentary on the following three topics:

1. Provide commentary on the contract model and any incentives included.
2. Define Manitoba Hydro's role in the GCC contract. Define the role of the Contractor and comment on Manitoba Hydro's ability to manage the Contractor in this role.
3. Provide commentary on Manitoba Hydro acting as the builder and taking on a Construction Management role.

KPMG's response to these items is attached as Keeyask – Appendix A. In terms of contract type, KPMG's response indicates the incentives used in this contract have been used in other cost reimbursable contracts as well as other forms of contracts. The incentives align the owner's and contractor's interests and help to mitigate the exposure the owner has to poor performance by the contractor.

General Civil Contract Procurement:

MGF Report – Scope Item 5: Finding #12, page 62
KCB Report – Section 5: page 33

Manitoba Hydro undertook an extensive three phase procurement process for the GCC beginning in 2012. This included a six month market-sounding exercise where 21 major international contractors were contacted to determine their level of interest in the

Keeyask Project. This process served as a marketing effort to generate interest for Keeyask in the marketplace with the intent of maximizing the number of capable contractors responding to the Request for Pre-Qualification to obtain competitive pricing. This process also served to inform Manitoba Hydro on the factors that were of interest to the potential contractors. Feedback on contracting models was also solicited from these organizations. Many of these experienced companies indicated they would not bid on a project the size and remoteness of Keeyask on a fixed price model due to the risks involved.

The second phase of procurement was the prequalification phase. Seven contractors submitted proposals in response to Manitoba Hydro's call for submissions. The contractor submissions were evaluated on 17 different criteria including demonstrated experience in remote, arctic heavy civil construction projects with an emphasis on concrete, earthworks and river management. Other factors that were considered in the evaluation included schedule, risk mitigation and safety. Four contractors that Manitoba Hydro believed were capable of building the work were pre-qualified and were provided the opportunity to bid on the Keeyask General Civil Works Contract in a competitive, cost-based evaluation.

The proposal stage was the third and final step in the procurement process. Manitoba Hydro engaged a third party ("Chant Construction") to provide their estimated price for the work as an additional pricing comparator (in addition to Manitoba Hydro's Engineer's Estimate). The pricing proposed by Chant Construction was generally in line with the Engineer's Estimate and was within the range of bids received from the four Proponents. A summary of the pricing information from the GCC proposals was provided in confidence to MGF as part of their review, and to the PUB and its independent expert KP during the NFAT hearings as exhibit NFAT CSI Manitoba Hydro-3.

As part of the evaluation of the contractors' proposals, Manitoba Hydro evaluated the initial target price proposed by the contractors based upon a number of pre-defined factors that were valued by Manitoba Hydro including potential schedule advancements, size of workforce against available camp capacity, and quantity change sensitivities to ensure that the contractor who provided the best value was selected.

The bids were also compared against one another and against the estimate provided by Chant Construction for reasonableness. After nearly a two year procurement process to conduct the market sounding, prequalify capable proponents and evaluate proposals to select the best value for Manitoba Hydro, the General Civil Works Contract was awarded to BBE, a limited partnership between Bechtel Canada Co., Barnard Construction of Canada Ltd. and EllisDon Civil Ltd. in March 2014.

Throughout its report, MGF is critical of the form of contract selected for the GCC. On page 80, MGF states:

> *"The GCC Contract strategy of adopting a cost reimbursable commercial arrangement for this project was flawed from the outset, with a predictable outcome, i.e. it promotes and rewards inefficient work and doesn't encourage efficient work."*

MGF fails to identify and understand the factors that led to Manitoba Hydro proceeding with the selected form of contract for the GCC. MGF's comment also does not address the target price aspect of the contract that puts the contractor's profit and General Administration & Overhead ("GA&O") at risk. The opportunity for profit and maintaining the GA&O incentivizes the contractor to attempt to meet or beat its target price. Manitoba Hydro provided MGF with the procurement documents for the GCC, evaluation matrix and criteria, related recommendations and presentations to the Manitoba Hydro Electric Board, the awarded contract with BBE and all seven amending agreements. These documents provide the rationale for selecting BBE as the GCC and clearly articulate the incentives that are intended to motivate contractor performance.

The Keeyask Project standards and procedures referenced on pages 50 – 53 of the MGF report were used to support the development of the contracting strategy and throughout the procurement process for the GCC. On page 53 of the report, MGF states that *"the standards, procedures and processes supporting Contracting Strategy, Contractor Prequalification, Individual Contract Plans and Tender, Evaluate, Negotiate and Award are sufficient and well documented."*

The contracting strategy, the GCC contract documents and a summary of proposal was reviewed with KP as part of the NFAT process. KP did not raise any significant concerns with the contracting strategy at the time of their review and the benefits and risks of the contract model were understood and communicated during the NFAT hearings.

It is not clear to Manitoba Hydro whether MGF and KCB were aware of the information provided to the PUB during the NFAT, or of the NFAT conclusions. As seen below, Manitoba Hydro addressed the contracting strategy with the PUB's independent expert in the NFAT process and the PUB's decision reflects that this, along with the risks, were discussed and reviewed.

On page 132 of the PUB's final NFAT report dated June 20, 2014, section 7.6.0 Conclusions of the Panel, the PUB stated the following regarding the Keeyask Project:

> *"The actual construction cost of Keeyask will increase beyond Manitoba Hydro's currently projected capital cost of $6.5 billion. Budgeting at least for Manitoba Hydro's "high" estimate of $7.2 billion would be prudent. This conclusion is not reached as a result of the history of past capital cost increases. The Panel accepts Manitoba Hydro's argument that the past is not necessarily a predictor of the future. Rather, the Panel bases its conclusion on its review of the Keeyask general civil contract, which is a cost-reimbursable contract that leaves a significant portion of cost risk with Manitoba Hydro. It would be a fallacy to assume that the contract provides anywhere near the same level of cost certainty as a fixed-price contract, which would be more expensive. This is not a criticism of the Keeyask general civil contract or Manitoba Hydro's approach to contracting. The Panel is satisfied that Manitoba Hydro's approach to developing and negotiating the contract, as well as its approach to managing risk, has been appropriate to date. Rather, it reflects the general nature of a large infrastructure project with inherent risks that can be mitigated, but not avoided."*

1.2. The People and the Competency of the People Managing the Construction of the Keeyask Project

MGF Report: Section 1 – Executive Summary, page 1

On page 1 of MGF's report, MGF states that:

> *"There is an opportunity for Manitoba Hydro to implement contract management improvements, take ownership for the GCC and drive the GCC contractor to higher levels of predictable performance, to accelerate project schedule and to lower the likely forecast cost at completion".*

MGF goes on to say that:

> *"Manitoba Hydro staff are competent and professional but they are not a construction manager with the experience and skills to direct the GCC. As such, its project management and control effectiveness is low."*

MGF makes these assertions without describing the skills and experience of Manitoba's senior team managing Keeyask, the roles and responsibilities under the General Civil Works contract, or even the actions that Manitoba Hydro has taken to improve outcomes from this contract. As MGF has failed to address these points in its report, the following section describes Keeyask's governance structure, an assessment of skills and experience of Manitoba Hydro's senior project team from a third party and a description of some of the key actions Manitoba Hydro has taken to enhance performance.

Governance:

Manitoba Hydro is experienced in the execution of major capital projects having delivered some of the largest capital projects in Manitoba over the last 10+ years.

In early 2016, Manitoba Hydro established the Major Projects Executive Committee ("MPEC") which is chaired by Manitoba Hydro's President & CEO and consists of five Vice Presidents who have accountability over the areas of the company responsible for the execution of major capital projects. MPEC is an executive management forum that provides oversight, direction and executive/strategic decision making with respect to major capital projects (i.e. Keeyask, Bipole III, MMTP and the GNTL Project in Minnesota). MPEC meets every two weeks or as required.

The Manitoba Hydro executive team is ultimately accountable to the Manitoba Hydro-Electric Board ("MHEB"). Periodically (and conforming to the corporate approval authority levels), major project decisions are reviewed and approved by the MHEB. The Keeyask Project team also provides project update reports and presentations to the MHEB on a regular basis. Site visits by both the Manitoba Hydro executive team and MHEB members have taken place.

As Keeyask Project is owned by the KHLP, there are additional accountabilities beyond the Manitoba Hydro organization structure. The Keeyask Project team is also accountable to the KHLP Board that is comprised of representatives from each of the four Keeyask Cree Nation ("KCN") Partner Communities and Manitoba Hydro. The KHLP Board is chaired by the Manitoba Hydro Vice President of Generation and Wholesale. The Keeyask Project team provides monthly update reports to the KHLP, as well as makes quarterly update presentations at the Board meetings.

The Keeyask Project team is comprised of project management and construction professionals with significant experience in the execution of major capital projects. As stated, Manitoba Hydro requested that KPMG review and comment on the experience of Manitoba Hydro's senior leadership team responsible for delivering Keeyask, and those comments are also found in Keeyask – Appendix A.

<u>Management of the General Civil Contract:</u>

MGF Report: Section 1: Executive Summary – page 1.

On page 1 of their report, MGF states that Manitoba Hydro's *"project management and control effectiveness is low".* MGF does not recognize the efforts of the Manitoba Hydro team in helping to manage the GCC.

Manitoba Hydro has been pushing, and will continue to aggressively push, the General Civil Contractor to perform. To be successful, this will require that Manitoba Hydro and BBE work together. After the award of the GCC in March 2014, work commenced on July 16, 2014 following receipt of all required regulatory approvals. Work by the GCC for the remainder of 2014 and all of 2015 was focused on establishing infrastructure including temporary buildings, haul roads, rock quarries as well as temporary river management structures (cofferdams) to control the flow of the Nelson River. These cofferdams allowed for the areas to be dewatered and rock excavated to allow for the construction of the permanent structures. In early January 2016, work on the North

Dyke commenced representing the milestone of the first permanent earthworks on the project.

At the beginning of the 2016 construction season, the project was generally on track and the project team was forecasting that the control budget and schedule of $6.5B and November 2019 unit 1 ISD (established during the NFAT hearings) would be achieved.

Manitoba Hydro reported to the PUB on March 2016 that the project was on schedule and on budget. Manitoba continued to actively monitor the progress of the GCC through the beginning of the construction season as it has throughout the project. Concrete work on the principle structures (Spillway, Intake, Powerhouse, Service Bay and Tailrace) began in early May 2016.

<u>2016 Issues:</u>

In early June 2016, approximately 6 weeks into concrete activities it was evident that the contractor's actual volume of concrete completed to date was significantly less than the contractor's plan. On June 19, 2016, Manitoba Hydro formally requested that the Contractor develop a recovery plan to increase their manpower ramp-up and concrete production in order to bring their production back in line with the 2016 plan. Manitoba Hydro staff continued to monitor the progress carefully during this time.

By July 2016, it was apparent that that the initial recovery efforts by the contractor were not going to be impactful enough to recover to the original plan. As well, both the GCC and Manitoba Hydro were becoming aware that the work could not be built as it was originally planned. As work continued to progress, the need for a new execution plan crystallized and required the team to understand the issues and problems and address them going forward. This led to the Recovery Plan described below.

By the end of the 2016 construction season, concrete placement was at 41% complete of the original plan for the year while earthworks were at 65% complete of the original plan. The concrete plan was to complete nearly 200,000 cubic metres of the 360,000 cubic metres required for Keeyask in the first year, while only 77,000 cubic metres were completed in the first year of concrete (2016). The production rates accomplished during the first concrete construction season saw the project schedule rapidly change from having a potential 6-month advancement opportunity at the start of the year shift to a potential of up to 2+ year delay by the end of the year. At this time it was also apparent that the $304M Labour Management Reserve in the $6.5B control budget to help offset productivity risk would not be sufficient. The large variance between actual and planned production also resulted in the Contractor having no opportunity to earn profit for the remainder of the project under the existing contract structure. This was already making for disengagement and the risk of worsening performance could occur for the remainder of the project if not addressed.

Recovery Plan:

Manitoba Hydro could not wait until the end of the 2016 construction season to begin to address the issues and plot a new path forward. Manitoba Hydro, with the assistance of industry experts KPMG, developed a Recovery Plan in September 2016 that covered both short and long term issues. The Recovery Plan incorporated a number of key features required to address the trajectory of the Project in order to achieve successful completion. The Recovery Plan needed to improve production and remove inefficiencies, and included:

- The development of a plan for the continuation of concrete through the winter months (previously not included in the original schedule);
- Identification of root causes of performance issues;
- Engagement of senior leadership, Executive Sponsors and CEOs;
- Development of refined processes, systems and tool based upon the findings of the root cause analysis;
- Implementation of a change management program to enable a culture shift within the project team;
- Initialization of activities to reforecast the cost and schedule for the project;
- Analysis of the Contractor’s claims; and
- Supplementing of the commercial expertise of the Manitoba Hydro team.

Manitoba Hydro and BBE assessed the underlying causes of the challenges experienced to date. The main contributing factors to the underperformance included:

- Unachievable labor productivity rates in the current market which were contained within the contractor’s bid;
- Slower than planned progress in ramping-up the on-site labour force in preparation for the concrete works beginning in 2016. This ramp up required a doubling of the labour force of roughly 1,000 workers to 2,000 workers in a period of roughly three months.

- Geotechnical and geological conditions different than anticipated based upon the extensive pre-construction geotechnical testing, resulting in additional effort to "get off the rock" to allow for construction of the concrete and earthworks structures off of the bedrock.

As part of the Recovery Plan, Manitoba Hydro, leveraging support from third party experts, including KPMG (Recovery Plan support), Revay (claims valuation and management), Borden Ladner Gervais LLP (legal support) and Validation Estimating (contingency development) undertook a thorough process to evaluate alternatives for, and impacts, to the GCC. The review demonstrated that the best course of action was to amend the existing contract with BBE, specifically to lower the overall cost and schedule risk for Manitoba Hydro and permit BBE an opportunity to re-establish a reasonable profit level. All other alternatives introduced significant additional risks to the Project as well as guaranteed impacts to cost and schedule that were greater than the selected alternative of amending the contract with BBE.

General Civil Works Contract Amendment:

In early 2017, Manitoba Hydro and BBE were able to achieve the mutual agreement that was required to amend the contract. The negotiation required 'gives and takes' from both parties and the outcome was a contract that lowered the overall cost and schedule risk for Manitoba Hydro and allowed the Contractor an opportunity to re-establish a reasonable profit level if they are able to perform relative to their revised target price. This aligned the interests of both parties to deliver a "Best for Project" approach.

The details of the amendment to the contract are formalized in Amending Agreement #7 between Manitoba Hydro and BBE. Amending Agreement #7, in addition to all previous versions of the agreement between Manitoba Hydro and BBE were provided to MGF in support of their review. The key features of the amendment include:

- Cost and schedule incentives providing motivation for BBE to earn profit by delivering the work to Manitoba Hydro with minimum cost and best schedule;
- Outstanding contractor claims were reconciled;
- GA&O mark-up was capped at target price;
- Narrowed ability for future claims;
- New liquidated damages provisions were established for late delivery;
- Productivity rates in line with 2016 actual performance used to inform the estimate of remaining costs on this contract.

Both MGF (MGF Report page 80) and KCB (KCB Report page 34-35) are critical of the contract model for the GCC. In Keeyask-Appendix A, KPMG describes the original and the amended contract for the GCC. KPMG describes the challenges inherent in attempting to renegotiate a contract in a non-competitive environment on page 2 of their submission:

> *"The amended contract continues to be a Target Price Cost Reimbursable contract, fundamentally the same as the original contract. The ability to transfer additional risk, such as geotechnical, hydrology, labour, extreme weather, and northern logistics to BBE by changing the contract to a Unit Rate or Lump Sum contract, would have required directly negotiating a new form of contract with BBE in a non-competitive environment or descoping/terminating BBE and going back to the market for a Unit Rate contract. It was expected that in a non-competitive environment and given BBE's performance in 2016, the costs of transferring this risk to BBE would have been prohibitive and/or not achievable."*

<u>New Control Budget and Schedule Established:</u>

With the General Civil Works Contract amended, further efforts were required to re-establish a new control budget and schedule for Keeyask. Manitoba Hydro reviewed the impact of the delay, along with known trends for the impacted work packages. The outcome of the review process was a revised control budget of $8.7B with a P50 contingency and a first unit in service date ("ISD") of August 2021. The revised control budget and schedule was formally approved by the MHEB in February 2017. The following table from PUB/MH MFR-122 highlights the major changes between the control budget established at the NFAT in 2014 and the revised control budget:

Figure 1.0

Keeyask Budget Summary (in Billions $)				
Item #	**Item**	**Previously Approved Budget (2014$)**	**Current Approved Budget(2016$)**	**Variance**
1.1	Generating Station	4.046	5.948	1.902
1.2	Generation Outlet Transmission (GOT)	0.164	0.202	0.038
1.3	Escalation @ CPI	0.244	0.249	0.005
1.4	Interest (including Interest on Equity)	1.343	1.749	0.406
1.5	Contingency	0.307	0.578	0.271
1.6	Labour Management Reserve	0.304	0.000	-0.304
1.7	Escalation Management Reserve	0.088	0.000	-0.088
1.8	**Total**	**6.496 B**	**8.726**	**2.230**
1.9	First in-service Date	Nov-2019	Aug-2021	21 months.

2017 Performance:

The 2017 construction season saw improved performance over the 2016 season with approximately 12% more concrete placed in 2017. This improvement is significant as the work done in 2017 was more complex, specifically, most of the placements in 2017 were generally smaller, required more formwork and were greater complexity pours (such as draft tubes) and concrete at height (head blocks and piers).

For the earthworks, productivity rates improved by 15% and the total of material placed in permanent structures in 2017 was 1.03 M cubic metres, an improvement of roughly 90%.

Contributing factors that influenced performance in 2017 included:

- Improved contractor leadership/management and their ability to plan and manage the work;
- More complex and better developed sequencing of concrete work and interfaces with earthworks;
- Learning curve to perform "first" work on the concrete in the Intake, Powerhouse and Service Bay;
- Challenges with the craft labour including maximizing work time at the work front.

Despite the improvements over 2016 described above, the target quantities for concrete and earthworks were not fully achieved. By the end of the 2017 construction season, while the Contractor had achieved considerably more concrete and earthworks volume than the previous year, concrete was approximately 20% less than planned and earthworks was 25% less than planned. Despite these shortfalls in volume, the key milestones for the year were achieved allowing the Keeyask project to remain on schedule. Achieving the following major milestones in 2017 ensures that the project will be delivered within the shortest duration schedule possible and protect the opportunity for schedule advancement of the unit 1 ISD:

- Completion of the Spillway concrete and handoff of the Spillway to the Gates, Guides and Hoists Contractor (Canmec) on November 15, 2017 (on schedule);
- Installation of the Powerhouse Cranes in the Service Bay in November (on schedule);
- Enclosure of Powerhouse Units 1 and Service Bay completed by December 31, 2017 (on schedule);
- Enclosure of Powerhouse Units 2-3 by February 2018 is on track to allow for the start of turbine and generator work;
- Significant progress on earth structures (dams and dyke) such that Keeyask is on track to divert the river through the Spillway in July/August 2018

As a consequence of the above milestones being met the project is still on track to be completed on or below the revised budget with the first turbine coming in service in or before August 2021.

<u>Management of the GCC:</u>

MGF Report – Section 1: Executive Summary, page 1

It was suggested by MGF on page 1 of their report that "*There is an opportunity for Manitoba Hydro to implement contract management improvements, take ownership for the GCC and drive the GCC contractor to higher levels of predictable performance, to accelerate project schedule and to lower the likely forecast cost at completion*". This statement appears to suggest that MGF is recommending that Manitoba Hydro should take over the role of Construction Manager from BBE. MGF goes on to soften this recommendation in MH/MGF I-2j and state that "*the recommendation is not for*

Manitoba Hydro to become the construction manager and replace BBE, but for Manitoba Hydro to exert more control and hold BBE accountable for its performance."

Manitoba Hydro is not a general contractor, nor does it have on hand the necessary personnel to manage and build Keeyask as the general contractor. If it were to undertake some or all of this task as recommended by MGF, it would have to retain significantly more staff with sufficient experience and expertise to take on the work without any delays. Such personnel are not readily available and, as outlined in more detail in Appendix A, there would be risk to the schedule because of the time it would take to find the personnel, to give them time to get up to speed on the project, and to develop a team to surround themselves with whom they would have confidence. As stated by experts KPMG and Hatch, this would simply introduce more risk to the project at this stage.

Hatch has been involved in Keeyask as the detailed design engineer and as an organization, has considerable experience in the delivery of major capital projects. Hatch was asked to provide commentary around expanding Manitoba Hydro's role with the GCC, as recommended by MGF. Hatch's response can be found in Keeyask - Appendix B, and like the response from KPMG, Hatch did not recommend such action.

According to Hatch (page 3 of Keeyask - Appendix B), Manitoba Hydro taking a greater role in the construction is of equal or greater risk to the project than the status quo. Hiring a Construction Management team to manage the construction on behalf of Manitoba Hydro would also carry risk until proven. Some of the risks identified in the Hatch review that informed their opinion include:

- Lack of availability of qualified professionals required to staff an entire team;
- Time to recruit, hire and mobilize a team;
- The new team would have a steep learning curve which would add risk to the successful execution of the project;
- Manitoba Hydro would lose leverage within the BBE contract.

BBE was hired by Manitoba Hydro as the Construction Manager to complete the General Civil Works scope. Keeyask – Appendix A provided by KPMG defines Manitoba Hydro's role in the GCC contract and provides commentary on the expected implications of Manitoba Hydro acting, instead, as the builder and taking on a Construction Management role, rather than acting in its capacity as owner.

MGF states on page 1 that Manitoba Hydro is "*not a construction manager with the experience and skills to direct the GCC"*. However it fails to address the activities Manitoba Hydro has undertaken to progress the work, without crossing the line of explicitly directing the means and methods of the Contractor, and without exposing Manitoba Hydro to interference claims. If Manitoba Hydro did step into the role of Construction Manager, it would be likely that the Contractor could claim for their entire performance bonus(es) regardless of the final cost and in-service date of the project. This would also inhibit ownership/accountability of the Contractor to perform.

KPMG was asked to provide commentary on Manitoba Hydro acting as the builder and taking on the Construction Management role. KPMG has indicated that they are unaware of any Canadian public sector owner with the skill-set required to directly manage a multi-billion dollar construction project (Keeyask – Appendix A).

In an attempt to better understand MGF's perspective, Manitoba Hydro requested additional information related to this conclusion in MH/MGF I–2. Specifically, Manitoba Hydro was interested in understanding if other owners/utilities have successfully taken ownership in the middle of a major capital project and the outcomes of those interventions. Manitoba Hydro was also interested in the Corporation's exposure to risks arising from undertaking such a change however MGF did not provide a response to MH/MGF I–2 that provided an answer to these questions. Manitoba Hydro posed this question to KPMG and requested their professional assessment. This information can be found in Keeyask – Appendix A. Hatch also provided commentary on the potential liabilities associated with taking over the role of Construction Manager in Keeyask - Appendix B.

Throughout 2017, Manitoba Hydro has increased the pressure on the Contractor to perform, and to have its workers become more productive. Some of these areas include:

- Contractor's management of the trades;
- Travel logistics for the contractor's workforce;
- Site wide respectful workplace campaign;
- Contractor's revised organizational structure and increased supervision capacity and experience;

- The development of an effective monitoring and control system to provide daily feedback to contractor workforce;
- Combining and streamlining BBE's and Manitoba Hydro's quality control and assurance teams and processes;
- Establishment of single mission and team ethics for the Manitoba Hydro and BBE teams.

Manitoba Hydro has also been leading efforts to gain efficiencies, improve methods/processes and achieve cost and schedule savings. A few examples of key initiatives where Manitoba Hydro spearheaded efforts that led to significant cost and/or schedule benefits:

- The decision to procure a new draft tube formwork system to utilize on the remaining 5 units. This decision shortened the schedule to install the bottom portion of the draft tube and improved cost performance.
- The decision to utilize column extenders in the Powerhouse and Intake allowed for structural steel to be installed at lower elevations. This provided an opportunity to enclose the Powerhouse and Service Bay earlier. A schedule savings of over 1 year resulted.
- Advancement of the south dyke in 2018 and supporting design changes. This will allow for additional quantities to be placed during the winter 2018 and reduce risk to the project schedule.

<u>2018 Plan:</u>

In 2018, a 10% increase in performance by the GCC is required to meet control budget ($8.7B) and achieve IDS's for the units that are in advance of the control schedule of August 2021. This also assumes that no significant risks materialize with other contracts or risks that could impact the critical path. Manitoba Hydro is confident that this rate of improvement is attainable as the year-over-year improvement between 2016 and 2017 was similar. In addition, much of the remaining concrete work in 2018 is similar to the work completed over the previous year and lessons learned over the last year and the inherent repeatability of seven nearly identical units is expected to improve productivity. Manitoba Hydro and BBE are currently working on their planning for 2018. Some of the key initiatives in 2018 include:

- 2018 winter work (placement of additional concrete over the 2018 winter months);
- Building a high performance culture at site;

- Cold eyes review;
- Manitoba Hydro and BBE leads identifying efficiencies and improvement;
- Improved management of indirects;
- Productivity studies and planning.

Third Party Reviews and Involvement:

Continuous improvement is ingrained in the culture of the Keeyask team but can always be improved. Prior to, and during the construction of Keeyask, external experts have been engaged to support and, in some cases, augment the skills of the existing project team. The project recognizes that the decision to manage the project using a team with strong internal expertise and knowledge brings both benefits and risks. To reduce the risk of an internal-only perspective, external expertise from across the utility and construction industries was retained and reviews were completed in the areas noted below. In addition, a handful of experts/consultants are used on a regular basis to support the project. Key reviews and supports external to Hydro alone include:

Figure 1.1

Third Party	Scope	Date
KPMG	KPMG was engaged due to their industry expertise in the areas of project management and contract administration to assess the health of the Keeyask Project. KPMG has since been regularly involved in helping to augment Manitoba Hydro's project management expertise.	2016 - current
Boston Consulting Group	In spring 2016, the Manitoba Hydro Electric Board retained Boston Consulting Group (BCG) to among other things, undertake a review of the Keeyask Project. The report of BCG's findings was released in September 2016.	2016
BBE/MH Cold Eyes Review	BBE & MH jointly carried out a review of BBE's operations on April 25 – 28, 2016. Teams consisted of 3 individuals from Bechtel and 3 individuals from MH (2 of which are Hydro-X and 1 construction management expert consultant). The purpose was to review BBE's operations and to ensure readiness of site project team for the upcoming first season of concrete.	2016
KPMG	In early 2016, KPMG carried out an independent review of the catering contract and the Keeyask Project Safety Management Plan. The purpose of the catering review was to ensure quality of service is sustained and to develop strategies to provide this level of service at the least cost. The purpose of the safety review was to ensure the Keeyask Project Safety Management Plan was	2016

	focused on the right things to achieve our safety goals with all contractors.	
Hatch	Quality Management support for Hatch's quality lead from the Mississauga office supports the project through the preparation of key Quality Program documents and the review of quality initiatives for the project. This support is especially strategic at this time given work underway to reset BBE's focus on its strategy for meeting quality requirements for the GCC.	2015 - current
Nalcor and BC Hydro	On-going informal dialog is taking place with Nalcor's Lower Churchill Project team and BC Hydro's Site C team to exchange ideas and lessons learned. Muskrat Falls is about one year ahead of the Keeyask schedule and their 824 MW project is similar to Keeyask's scope.	2015 - current
Validation Estimating	John Hollman of Validation Estimating is retained for assistance in the development of the project control budget, contingency pool, and management reserves. The risk profile for the project is reviewed at regular intervals in comparison to projects of similar size and complexity.	2012 - current
Hatch	A panel of Hatch senior engineers/managers from outside the Keeyask Project was retained to conduct a "cold eyes" review of the management of the engineering in an effort to identify gaps in the scope and quality of the engineering design, and ability to deliver the required product.	2014/2015
Knight Piésold	Knight Piésold (KP), the independent expert consultant retained by the PUB during the NFAT process in 2013/2014 reviewed project processes, the estimate, and contingency, KP was generally satisfied with these practices and methodologies stating that they were consistent with industry best practices.	2013/2014

1.3. MGF's Findings Related to the Forecasted Cost and Schedule of the Keeyask Project

MGF Report: Scope Item 5 – Finding #13, pages 63 – 64

In its report, MGF states that the expected cost of Keeyask will be \$9.5 B to \$10.5 B (MGF report page 63 & 64). However, MGF did not provide or substantiate how it arrived at these values. Manitoba Hydro (MH/MGF I-26), as well as the PUB (PUB/MGF–14), requested a breakdown of how MGF arrived at these values. MGF provided the following in response (MH/MGF I-26a):

"MGF used MH's spent to date and cost to go figures, on top of these MGF applied additional costs for items such as earthwork productivity; concrete productivity; additional scaffold & crane costs; additional indirect costs; etc.

In addition, MGF applied interest and escalation in line with MH's percentage.

Finally, MGF applied a 10% contingency to take into account project risk and uncertainty."

Manitoba Hydro has attempted to understand how MGF came to their expected cost of Keeyask of \$9.5 B to \$10.5 B. Manitoba Hydro does not know exactly how MGF developed the values as they have failed to provide the requested supporting information (MH/MGF I-26).

Manitoba Hydro notes that the range of values identified by MGF happen to align with the potential range of outcomes identified in Manitoba Hydro's own analysis done when the Keeyask project budget was revised early in 2017. At that time, the potential cost of the project with P90 contingency was identified to be \$9.6 B which roughly aligns with the lower end of MGF's range. The sum of a potential management reserve budget to cover severe event risk (that would result in a one-year delay and costs between \$500M to \$800M) added to the potential P90 budget would closely align with the \$10.5B upper end of the range identified by MGF.

In early 2017, when Manitoba Hydro revised the control budget, the Keeyask Project budget with P50 contingency was selected. This established the \$8.7B control budget to ensure Manitoba Hydro was proceeding with the lowest cost execution for the project. Other alternatives were considered at the time; however considering the level of completeness of the project (roughly halfway through with many key risks still remaining) the P50 contingency balances the potential costs from the remaining risks and provides a challenge to the execution team. This approach drives the lowest cost delivery and the most efficient outcome.

The following is a summary of items that MGF states will result in additional costs to the Project:

Figure 1.2

MGF Scope #	MGF Finding #	MGF Report Page	Description of Finding	MGF Order of Magnitude Estimate
5	9	60	Increased use of overtime and double time	[redacted]
5	10	61	BBE indirect costs	[redacted]
9	3	74	Earthworks productivity	[redacted]
9	5	76	Scaffold and crane costs	[redacted]
9	7	78	Concrete productivity direct costs	[redacted]
9	7	78	Concrete productivity indirect costs	[redacted]
			Total	**$678M**

1a

In the MGF report, the sum of the estimated value of the Findings that MGF states will result in an increase to the cost of Keeyask of approximately $678 M. By applying the methodology described by MGF in their response to MH/MGF I-26a, it could be assumed that applying interest, escalation and a 10% contingency to the $678 M and adding the value to the $8.7B control budget would arrive within MGF's expected cost of $9.5 B to $10.5 B. For most of their Findings, MGF included a factor for GA&O and Indirect Costs. GA&O and Indirect Costs as they relate to the GCC are described below:

General Administration & Overhead - GA&O is intended to cover support to the project from the Contractor's home offices including but not limited to expenses such as Human Resource Management, Corporate Procurement, and I.T. support.

Indirect Costs – Costs that are required to support the direct work at site including temporary buildings, small tools, and worker transportation expenses.

It is Manitoba Hydro's opinion that these "order of magnitude" costs are overstated in the MGF report and result in an inflated forecasted cost for the following reasons:

1) **MGF has incorrectly applied the GA&O mark-up percentage to potential cost increases.**

As part of Amending Agreement #7, GA&O has been capped at the target price to disincentive the Contractor for exceeding the revised target price established in AA#7. This also encourages the Contractor to complete the work at the lowest cost. It appears that MGF did not account for this GA&O cap in their values, but rather applied the full amount on all of the forecasted increased costs disregarding the cap. This results in an over-estimate of at least $26 M.

2) **MGF has overstated their forecasted indirect costs for BBE by simply extrapolating the current spend.**

MGF Report: Scope Item 5, Finding #10, page 61

On page 61 of their report, MGF provided a forecasted value for an increase to the indirect costs. It appears to Manitoba Hydro that MGF used the overall physical percent complete from the Bill of Quantities for their estimate and assumed that the indirect costs from the BBE Cost Report will continue similarly for the remainder of the work (i.e. they extrapolated these values for the remainder of the contract on a straight line basis).

The forecasting method used by MGF is overly simplistic and flawed as it does not consider upfront costs that will not occur again in the future such as temporary buildings, and roads (i.e. fixed indirect costs) and progress on areas of the work that may incur more (or less) indirect costs than others. The values also do not consider the efforts that Manitoba Hydro is undertaking with BBE to manage BBE's indirect costs. Managing BBE's indirect costs is a key area of focus for Manitoba Hydro in 2018. Manitoba Hydro hired an Indirects Lead with over 19 years of related experience in project controls, project management and accounting in the major capital project environment to help manage BBE's indirect costs. These factors are considered in Manitoba Hydro's forecasting methodology. However, they do not appear to be considered in MGF's cost estimate, as they should.

In addition to the specific forecasted indirect cost value presented on page 61 of its report, in other findings including: Scope Item 9: Finding 3, page 74; Scope Item 9: Finding 5, page 76; Scope Item 9: Finding 7, page 78, MGF has added a factor for indirect costs calculated by dividing the total direct costs by total indirect costs. This suggests that MGF double counted indirect costs by identifying indirect costs related to earthworks productivity, concrete productivity, and scaffolding/crane costs beyond the values MGF provided on page 61 of its report in the calculated "BBE Indirect Costs" value.

Manitoba Hydro is of the opinion that utilizing this indirect to direct cost ratio for potential cost increases is inappropriate as this ratio includes both **variable indirect costs** such as maintenance costs, transportation costs for workers, additional supervision, and consumables/small tools, as well as **fixed indirect costs** such as installation of temporary buildings and roads. These fixed indirect costs would not be impacted by changes in directs work. For example, if concrete productivity is worse than expected and additional labour hours are required (i.e. direct work); costs that were originally incurred to build the carpentry shop **(i.e. fixed indirect cost)** would <u>not</u> be incurred again. It appears as though MGF has failed to account for this reality in its report, resulting in an overestimate of future costs.

Manitoba Hydro has conducted a line by line analysis of the cost accounts to determine which indirects could be affected by direct work and has concluded that a lower ratio is more appropriate. However, the nature of the direct work in question is important. For example, if concrete productivity would cause the project to be extended, it is likely that most indirects would be impacted and therefore a ratio on the higher end of Manitoba Hydro's range would provide a reasonable estimate of the associated indirect costs. In contrast, if the craft-to-foreman ratio were to change, it would not impact as many indirect cost accounts and the ratio of indirects could be significantly lower. In its analysis, MGF failed to recognize that the relevant indirect costs need to be considered when estimating the cost impact associated with a potential increase to direct costs rather than using a broad ratio of total indirect to direct budgets.

The following are additional miscellaneous points that Manitoba Hydro would like to rebut that fall outside the 3 main areas addressed:

1) Selection of the Contractor:

Scope Item 5, Finding #12, page 62

On page 62 of their report, MGF states that they *"were advised by Manitoba Hydro that Bechtel were self-performing Contractor's on Limestone and this predicated their decision to appoint BBE"*. Manitoba Hydro provided MGF with the documentation related to the procurement of the GCC including the RFPQ and evaluation criteria. Manitoba Hydro did not select BBE, a limited partnership that included Bechtel, strictly on the basis of Bechtel's Limestone experience as it is implied in the MGF report. In addition to considering the work self-performed by Bechtel, the pre-qualification process described above also considered the experience with self-performed work by both Barnard and Ellis Don. It is the combination of experience and knowledge across all three partner companies that informed the decision to select BBE as one of the four contractors that would ultimately compete on a cost basis for the work during the final phase of the three-phase competitive tendering process.

A strength of the joint venture was that each partner would lead different areas, but would still share overall responsibility. The division was as follows: Bechtel for concrete structures, Barnard for earthworks, and Ellis Don for their infrastructure work and knowledge of the Canadian labour marketplace. Each proponent offered key personnel that had experience in all of these areas.

2) Earthworks Embankment Fill Measurement

Scope Item 9, Finding 2, and page 73

On page 73 of their report, MGF describes a site visit to Keeyask on November 9 and 10, 2017 where the two MGF staff who attended the site visit performed a survey of the earthworks to compare to the value reported by BBE. From this assessment, MGF concluded that the embankment fill claimed by BBE is approximately 10% higher than the quantity assessed by MGF.

During this site visit, MGF representatives spent approximately 12 hours in the field which included safety orientations, a site tour, and meetings with Manitoba Hydro staff, in addition to their time surveying quantities. In MH/MGF I–28, Manitoba Hydro requested that MGF describe the methodology used to calculate this value. MGF provided the following description of the methodology they employed:

> *"Average end area method was used to calculate the volume. Heights of existing embankment and remaining fill heights were determined by referencing the existing known elevation point at concrete structures, survey stakes and speaking with MH site personnel. Survey profiles of existing embankment and center line profiles provided to MGF staff on site by MH were also used in the calculation of the volumes."*

Manitoba Hydro was present during this survey and reports that the review was rudimentary and involved measuring the structures with no equipment but a borrowed measuring tape and 100 metre chain. While these methods are appropriate for checks to determine approximate quantities, they are not as reliable as the detailed methodology employed by Manitoba Hydro numbering thousands of checks on BBE's performance over the course of the last three and a half years, described below.

In their report, MGF did not refer to the actual methods used by Manitoba Hydro and BBE to measure quantities for the earth structures on the Keeyask site. In addition to the Manitoba Hydro earthworks inspectors that monitor performance of the Contractor, Manitoba Hydro has a survey crew of seven full time staff dedicated to earthworks with at least four staff on site at all times (2 on day shift, 2 on night shift). BBE also employs an earthworks survey crew of 12 staff with at least 8 staff on site at all times (4 day shift, 4 night shifts). There are additional surveyors from both organizations dedicated to the concrete structures as well (e.g. Powerhouse and

Spillway). Manitoba Hydro and BBE earthworks surveyors take independent measurements before, during and after the placement of material on each earth structure. Both crews use a combination of Trimble GPS and total station survey equipment to measure quantities. The survey data is used to develop detailed 3D models using AutoCAD 3-D for modeling and calculating quantities. These models are updated weekly and quantity runs by both Manitoba Hydro and BBE are generated to report on weekly production. Typically, the difference between the survey data captured by Manitoba Hydro and BBE surveyors is between 3-5% and is reconciled regularly. Manitoba Hydro and BBE meet to review these numbers and agree upon the final installed quantities.

On page 73 of their report, MGF recommends that Manitoba Hydro performs "spot checks" on the quantities claimed by BBE to ensure the quantity progress being relied upon for scheduling is accurate. Manitoba Hydro and BBE are continuously measuring quantities via their respective survey teams. As an example of the degree of rigor with respect to the survey process, on a portion of the Central Dam, 104,820 survey points were collected for the foundation (bedrock and back slopes) and 127,729 survey points were collected for the fill (including dental concrete). This methodology is superior to spot checks because data is gathered continuously at every stage of construction to ensure quantity measurements are accurate. The suggestion that the methods employed by the MGF employees on the two-day site visit are superior to the methods employed by Manitoba Hydro's constant and continuous surveillance of the work site are nothing short of ridiculous.

<u>3) Issues with methodology employed on Keeyask</u>

Scope Item 9, Finding 10, and page 81

On page 80 and 81 of their report, MGF provides a picture of earthworks from summer 2016 from a Manitoba Hydro report and has overlaid a number of notations. In addition to this picture, MGF states that:

> *"The application of incorrect machinery and work methods causes delay and additional cost. The following picture depicts an example where both Schedule*

> *and Cost are pushed out in favour of the Contractor and at the expense of the Client.*
>
> *While the above is an example, the poor productivity achieved on site reflects poor Supervision and Management by the Contractor. If Manitoba Hydro wants to reduce cost and schedule overruns they should have a more hands on approach."*

The date stamp on the photo is July 28, 2016, approximately 1 year prior to MGF first attending the Keeyask site. In MH/MGF I-32a, MGF has confirmed that their notations are based on the photo and personal experience, and therefore, not as a result of directly observing the work taking place or speaking to Manitoba Hydro staff at the Keeyask site who were involved in the specific work depicted in the photo.

In MH/MGF I-32e, MGF states that a technical specification does not necessarily need to be followed in instances where there are opportunities to improve productivity and cost. MGF goes on to say a test program may be implemented.

The scope of work depicted in the photo occurred on the North Dyke and when the excavation occurred in this area, four distinct areas of saturated clay material were discovered requiring additional excavation. The resulting excavation of the localized area was 1-2 metres lower than the surrounding areas and susceptible to ground water infiltration. In this case, BBE attempted to follow the Technical Specification but found it challenging due to the prevailing ground conditions. The Manitoba Hydro Earthworks and Excavations Resident Engineer and the BBE earthworks team worked together to engage in a test program which was successful in keeping the work moving. In the case of the photo on page 81 of MGF's report, MGF has taken a situation with limited context, without speaking to Manitoba Hydro to understand the situation, and applied the finding in an attempt to substantiate an unfounded conclusion.

<u>4) Extended Overtime:</u>

Scope Item 9, Finding #8, page 79

On page 79 of its report, MGF states that, upon reviewing BBE's progress payments from May and June 2017, there were 73 instances of individuals working over 16 hours in a day during that 2 month period. MGF goes on to state that these extended hours will not be as productive as straight time hours and will result in diminishing output for every hour worked, in addition to raising concerns about potential personnel safety. Manitoba Hydro reviewed these 73 instances and found that a majority of the records were either supervisory staff or craft workers performing concrete-related work. In most cases, when a concrete placement is started, it needs to be taken to conclusion to avoid a cold joint (which is a potential water pathway through the concrete structure). During larger concrete placements, additional overtime is periodically warranted meaning that some of these cases where individuals were required to work extended hours were justified. However, safety was not sacrificed as supervisors were on hand to ensure the work was performed safely and in accordance with the established procedures.

To put these 73 instances of individuals working over 16 hours in a day into perspective, in May and June 2017 there were a total of 61 days worked. Considering that BBE had an onsite workforce on average of approximately 1,500 individuals, this would result in more than 90,000 days worked by the contractor's workers. These 73 instances account for less than 0.08% of the total days worked by the contractor's workforce during that 2 month period, and are the exception rather than the rule.

Manitoba Hydro reviewed the May and June 2017 progress payments and found that the average hours worked by the entire field workforce is approximately 10.7 hours per day and 10.5 hours per day for the field workforce for all of 2017. This average does exceed the standard onsite working day of 10 hours. Manitoba Hydro agrees that extended overtime could impact worker productivity and could have cost implications. As such, it will continue to work with the contractors in 2018 to more effectively manage overtime. These changes will help to minimize the need for additional overtime and is expected to increase productivity.

Manitoba Hydro also prides itself on its safety record and works diligently in this regard. From project commencement to November 30, 2017, there have been approximately 15 million person hours worked on the project and only 22 lost time incidents averaging slightly over 6 lost time days per incident. In addition, BBE has gone more than 14 months (over five million person hours worked) without a lost time incident. This safety record is impressive given the size and remoteness of the project, but Manitoba Hydro and BBE will continue to focus on eliminating safety incidents until the goal of "zero hurts" is reached.

<u>5) Inconsistencies in Estimate Documentation:</u>

Scope Item 3, Finding #2, page 36

MGF reviewed Manitoba Hydro's estimate documentation on Keeyask and stated the following on page 36 of their report:

> *"CEF 2016 Estimate Sheets were provided in the Basis of Estimate appendices as supporting details to the cost estimate, however, the values included within these estimate sheets did not align with the values carried in the actual estimate. In the 2014 Capital Project Justification Addendum, Basis of Estimate variances occur because of SAP's use of a more accurate treatment of overhead. It was also noted through conversations that these variances are the result of updated labour rates themselves which are to be applied throughout the next fiscal year. Rates current at the time the CEF 2016 Estimate Sheets were generated, and then adjusted prior to being carried in the final estimate. This was not specified within the 2017 Capital Project Justification Addendum, Basis of Estimate and the reconciled estimate sheets that were provided in 2014 were also neither provided nor developed for the 2017 Estimate. This made one-for-one reconciliations difficult to perform."*

Manitoba Hydro has calculated the approximate "discrepancy" between the estimate sheets (item 1.0 below) and the Capital Expenditure Forecast ("CEF") 2016 Plan in SAP (item 2.0 below) referred to on page 36 of MGF's report. The total variance (item 3.0 below) is under $500K on a total value of almost $3.5B resulting in a difference of 0.013%.

To understand this statement, in MH/MGF I-13, Manitoba Hydro requested that MGF provide the specific networks which are misaligned along with the dollar value and what percentage of the CEF2016 estimate the value of the total misalignment represents. MGF did not provide this detail in their response to MH/MGF I-13. Manitoba Hydro reviewed the total budget values found in the available CEF2016 estimate sheets and compared to the values in SAP, and focused on networks valued over $1M. The outcome of the analysis is listed below:

Figure 1.3

Item	Description	Value
1.0	CEF2016 estimate sheets	$3,488,545,769
2.0	CEF2016 Plan in SAP	$3,489,007,738
3.0	**Variance**	**$461,969**
4.0	**% difference**	**0.013%.**

As part of the estimating process that feeds into Manitoba Hydro's CEF, the Work Package Leads on the Keeyask Project who are responsible for managing the scope, schedule and budget for their respective work packages, complete estimate spreadsheets where they estimate the costs of managing their scope of work (i.e. work packages). As part of this exercise, the Work Package Leads estimate the level of effort (labour hours) in managing their work package. These hours are multiplied against a labour rate that is extracted from SAP, the corporation's cost management system (item 1.0 above). After a verification process, the estimated hours from the Work Package Leads are then loaded into SAP to form the CEF Plan in SAP (item 2.0 above). In some cases it may take 1-3 months for this process to be completed. Some of the labour rates that were taken from SAP and included in the estimate spreadsheets may change slightly from the time they are extracted for the spreadsheet and the labour hours are uploaded to SAP. The labour rate in SAP multiplied by the labour hours provided by the Work Package Leads is the value that becomes part of the CEF plan (item 2.0 above). The labour rates carried in SAP trump the labour rates in the spreadsheets. The labour hours captured in the spreadsheet by the Work Package Leads (and subsequently uploaded into SAP) is the key deliverable. The labour rate in the spreadsheet that may have changed in SAP since it was originally extracted is not updated on the spreadsheet (because the labour hours have already been entered into SAP to form the Plan).

While there is technically a minor difference in the values referenced above, MGF has failed to recognize if this difference is a material one. Manitoba Hydro is alert to any changes which might impact the estimates and monitors these factors. In the context of the budget the issue raised by MGF does not materially impact the estimates.

6) Cash and Trade Discounts

Scope item #5, Finding #8 – Keeyask Cash and Trade Discounts (page 59 and 60)

MGF reviewed progress payments for BBE for the months of October 2016 and June 2017 and noted that trade discounts were "negligible" and no cash (prompt payment) discounts were identified. MGF goes on to recommend that all contractors negotiate trade discounts with their subcontractors and suppliers.

In MGF's observations and findings, MGF implies that BBE could achieve 10% savings from their suppliers and pass this savings on to Manitoba Hydro. When considering BBE's total purchases for the entire Keeyask project, MGF believes this equates to a potential savings of approximately $115.8 million for Manitoba Hydro.

Manitoba Hydro provided MGF with a copy of the General Civil Works Contract with BBE. In the contract, Section 7.8 Process of Selection of Subcontractors outlines the process that BBE is required to follow for the award of major subcontracts (includes contracts for both subcontractors performing work under BBE and suppliers of equipment/material). BBE is required to solicit three competitive bids for every contract valued over $500,000. The contract also provides Manitoba Hydro the ability to review and sign off on procurement over $500,000. If the contractor does not follow this procedure and subcontracts work without receiving the required approval from Manitoba Hydro, the work is not eligible for reimbursement under the contract. Therefore it is in the contractor's best interest to follow the terms of the contract. BBE has operationalized this section in the contract as a Desktop Procedure for

Subcontractor Selection Process. Manitoba Hydro provided MGF this document on October 7, 2017.

In MGF's conclusion regarding cash and trade discounts, MGF fails to mention how BBE can realistically achieve this 10% savings from their suppliers and if this is even possible under the existing agreements BBE has with their suppliers and subcontractors. Since BBE is required to competitively tender work valued over $500,000, the vendor selected should already provide the lowest cost or best value proposal. Manitoba Hydro reviews these tenders to ensure that this philosophy is maintained. Manitoba Hydro is skeptical that a further 10% savings as implied by MGF could be achieved as the major subcontracts are already competitively tendered by BBE.

7) Hatch Schedule

Scope Item #4, Finding #2 – Hatch Schedule (page 41)

MGF reviewed the schedule for the detailed design engineer Hatch and concluded that while the schedule is well-developed, many activities are behind schedule.

Manitoba Hydro and MGF had a number of discussions regarding the engineering schedule and the status of engineering deliverables. During these discussions, Manitoba Hydro described that during the time of Amending Agreement #7 with BBE, the decision was made to manage engineering deliverables based on Construction Work Packages (the pieces of work to be undertaken by the GCC) rather than on the specific engineering deliverables that were incorporated into Hatch's baseline schedule (i.e. on a drawing by drawing basis). This ensures that the contractor has all the drawings they require to build a specific piece of work (such as a Powerhouse Unit 1 base slab) with the required lead time to plan and procure materials.

Since neither Manitoba Hydro, Hatch nor BBE are no longer managing their respective work to Hatch's baseline schedule, efforts have not been expended to update the Hatch baseline schedule.

On page 33 of MGF's report (Scope Item #2, Finding #1), MGF confirms that on October 23, 2017, in a video conference with senior representatives from BBE, BBE advised MGF that construction had not been delayed on account of the issue of Issued for Construction drawings. This informed MGF's conclusion that "*The production of Issued for Construction drawings has not impacted BBE's progress*".

<u>8) BBE Schedule – Negative Float</u>

Scope Item #4, Finding #3 - Keeyask – BBE Schedule: Negative Float (page 42)

In reviewing BBE's schedule, MGF identified a number of activities in BBE's schedule that have negative float. MGF concludes that until these deficiencies are reviewed and corrected, Manitoba Hydro cannot have confidence in BBE's schedule. Manitoba Hydro was aware of the presence of negative float in BBE's schedule and its significance and has been working with BBE over the last few weeks to develop a valid recovery schedule. This recovery schedule recovers the delays in BBE's baseline schedule and eliminates negative float. This recovery schedule was submitted to Manitoba Hydro in 2017.

<u>9) BBE Forecast at Completion Date</u>

Scope Item #4, Finding #6 – BBE Forecast at Completion Date (page 44)

MGF reviewed Manitoba Hydro's schedules and methodologies and believe the first unit ISD will be approximately 3 months later while the last unit will be 4 months late. MGF goes on to context this finding stating that no mitigation strategies or schedule recovery options have been added to this forecast. In MH/MGF I-19F, MGF confirms that the forecasted delay could be reduced using schedule mitigation activities and successful improvements at site. Some of these mitigation activities are referenced previously in this report.

On page 78, MGF indicates that actual average concrete productivity is likely to worsen, as there are more complicated pours to come and three more winter seasons to work through. Manitoba Hydro expects that concrete productivity to improve. A majority of the progress to date on the Powerhouse structure has been on units 1, 2 and 3. There has been a learning curve for the contractor and the craft labour who are building the work on these first three units. Given that a generating station is comprised of seven nearly identical units, it is expected that performance on the remaining units will be improved. It should be noted that on page 78, MGF states that the expected cost increase due to lower than planned productivity on the concrete structures is approximately $136.5 M. In MH/MGF I-30c, MGF indicates that they have not included factors such as improvements due to repeatability into their estimated costs. It could also be assumed that this factor was also not considered in the finding related to schedule.

2. Bipole III Transmission Reliability Project

The Bipole III Transmission Reliability Project, currently under construction, is a high-voltage direct-current ("HVDC") transmission project that will enhance the reliability and increase capacity of Manitoba's electricity supply. More than 70 percent of electricity generated in Manitoba is delivered to customers on the two existing HVDC transmission lines (Bipole I and Bipole II). These lines run alongside each other for much of their route and end at the same point in southern Manitoba at the Dorsey Converter Station. Due to their proximity to each other and the single terminus point for both lines, damage to Bipole I and II or Dorsey Converter Station could mean Manitoba Hydro cannot carry enough electricity to meet its customers' demand. Bipole III will add 2,000 megawatts to Manitoba Hydro's HVDC transmission capacity.

MGF was retained by the PUB on Bipole III to review and explain the increases in cost estimates and capital cost increases, as well as project cost overruns. It was to determine and assess the reasonableness of its updated forecast and to identify aspects of the updated cost estimate and schedule that are at risk. It was also to recommend risk mitigation strategies and, further, to review Manitoba Hydro's:

- practices on its pre-construction design and engineering work; and
- its methodologies for costing, for tendering and contracting, for management of construction, contractors and construction risk management, and for scheduling.

MGF's evidence was that Bipole III Transmission Line is generally well organized and managed efficiently. It stated that it was on schedule and had used contracting strategies that were commercially astute, allocating risk appropriately. It also stated that Manitoba Hydro was managing a key risk, cause by poor performance of a contractor. MGF, in its Executive Summary on page 1 of its report, have highlighted that the HVDC Converter Stations "are well managed by Manitoba Hydro and the potential for cost over-runs is low."

Manitoba Hydro generally agrees with the MGF findings related to the Bipole III Project. Manitoba Hydro continues to manage the project appropriately, and maintain and affirm that Bipole III will be in service by the end of July 2018. This will be achieved within the approved $5.04 billion control budget.

Manitoba Hydro agrees with MGF that there remains risk to completing Bipole III on time. Specific risks related to Transmission Line contractor Rokstad's performance have been highlighted. As noted in the MGF report, Manitoba Hydro is managing this risk by de-scoping work from Rokstad and awarding it to another contractor. Manitoba Hydro was in the process of taking the action independently from this review. However, as noted on page 112 of MGF's report, the contingency amount for the Transmission Line will be sufficient to address this mitigation action and remaining risks on the work.

Despite Manitoba Hydro's general agreement with MGF's findings on Bipole III, there remain some areas within MGF's report that Manitoba Hydro disagrees with, and some areas in which it would like to provide clarifying information. There are also a number of instances where MGF has misunderstood the information provided, or drew an incorrect assumption that Manitoba Hydro would like to clarify on the record. In some of these instances, MGF was provided clarifications by Manitoba Hydro prior to the report being completed. However, it did not incorporate those into its final report.

2.1. Additional information to provide some clarity on the MGF report.

There are a number of items on which Manitoba Hydro would like to provide some additional information to provide some clarity on the MGF report.

<u>Scope Item 10, Finding 2, page 84</u>

MGF recommends that "the Manitoba Hydro Estimating Team prepare the overall estimate with input from each department." Manitoba Hydro can advise that approach to managing the estimate update process through the Estimating Team was in place prior to the MGF review. The Estimating Team coordinates all inputs from contributing areas/Departments. The Estimating Team also conducts reconciliations and confirmation of values for items input and updated within SAP.

<u>Scope Item 15, Finding 2, page 99</u>

On page 99 of its report MGF concludes that the 2014 pre-construction Basis of Estimate was extremely well done, however recommends further improvements in the supporting backup documentation to align costs captured within the SAP accounting software used by Manitoba Hydro and the project Work Breakdown Structure.

A Basis of Estimate document details the scope of the project on which the estimate is developed, the estimating methodologies applied and key assumptions upon which the estimate is based. As noted by MGF, the 2014 Basis of Estimate document was extremely well done. Part of the Basis of Estimate is to document project costs entered directly into Manitoba Hydro's SAP accounting system. These costs would include internal labour hour estimates, expense estimates and similar internal costs. In contrast to MGF's recommendations, Manitoba Hydro considers the backup documentation included within the Basis of Estimate document associated with these costs to be aligned with the Work Breakdown Structure and considers the level of documentation of these costs included within the Basis of Estimate document to be sufficient.

Scope Item 17, Findings 5 and 6, page 105

MGF has correctly identified that Rokstad Power's work remains one of the critical risks to the on-time completion of the Bipole III Project. Manitoba Hydro would like to clarify the following regarding this scope item:

- The report notes an end date of April 21, 2018 for Rokstad's work. In IR MH/MGF I – 44 MGF clarified that the activity considered the end date "Final Record and As Built Submissions" is in fact a trailing /post-construction activity and does not correspond directly with the completion of construction work. Construction work will be completed in March 2018.
- MGF correctly states on page 106 of its report that "A recovery plan has been developed and submitted by Rokstad Power Company to Manitoba Hydro, but has not been approved at this time." Manitoba Hydro continues to work with Rokstad to develop a sufficient recovery plan for their remaining scope and Rokstad's progress will be closely monitored to determine whether any further actions are required. .
- Manitoba Hydro agrees with MGF that removal of scope from Rokstad and placement of this work with another contractor does not guarantee the project will finish on schedule. However, Manitoba Hydro can advise that the new contractor has mobilized and has begun construction on this removed scope. The new contractor has committed to a schedule that will ensure on-time completion of the transmission line and they are currently on-track to this schedule. As such, this risk is substantially mitigated.

Scope Item 20, Finding 3, Page 117

MGF recommends that Manitoba Hydro properly record costs associated with placing the removed scope with another contractor and record the extra over costs it has incurred in having the new contractor in place. Manitoba Hydro agrees with MGF and is in the process of recording these costs appropriately and taking the appropriate steps contractually to recover any additional costs from Rokstad that are associated with the scope removal and Rokstad's lack of performance.

There is a finding on page 111 of the report regarding the Bipole III Project cost estimates for the Rokstad contract and a recommendation that the estimate be updated to reflect this change. Manitoba Hydro's estimate has already been updated with these costs. All reductions to the contract budget are returned to the project control budget, Transmission Line Contingency, as part of ongoing change management on the project.

2.2. Areas of the report that Manitoba disagrees with the conclusions drawn by MGF

There are a few areas of the report that Manitoba disagrees with the conclusions drawn by MGF.

Scope Item 18, Finding 1, page 108

On page 111 of its report, when determining the reason for project cost overruns since the final pre-construction control budget, MGF concludes that "Many of the additional costs appear to be a result of a project that was perhaps not at a stage of readiness at the time of project approval in terms of permit approvals, design development, land acquisitions and execution planning (i.e. procurement cycle and delivery time, market underpinned costing based on a tested and firm strategy, etc.)." Manitoba Hydro does not agree with this assessment.

The project was at an appropriate stage of "readiness" to proceed recognizing that the environmental License had been received and a sufficient number of winter construction seasons were necessary to execute the work. Specifically, as the transmission line work proceeds sequentially from clearing, to anchors and foundations, to tower erection and stringing, it was appropriate that clearing, work began immediately after the Licence was obtained and the tower erection and stringing contracts proceeded later. The project correctly identified uncertainty in the transmission line construction marketplace and carried both contingency and management reserve related to this. Events related to weather and material procurement that transpired were not an issue of "readiness", but rather general and typical areas of uncertainty and specific contractor issues/challenges.

<u>Scope Item 10, Finding 1, page 83</u>

MGF identified Manitoba Hydro as having internal labour costs budgeted beyond the project in-service date that are being incorrectly applied to capital expenditures as opposed to operating expenditures. Manitoba Hydro provided clarification and, through the IR process, MGF responded that it was their "..opinion these costs should not be part of a capital budget." Manitoba Hydro disagrees with the treatment of all costs immediately after the ISD being classified as operating expenses (as opposed to capital). After the ISD, there are still significant construction activities to be completed; such as:

- completion of synchronous condensers 3 and 4 at Riel,
- demobilization and clean-up by Contractors at each construction site,
- decommissioning of the camp infrastructure at Keewatinohk, and
- deficiency clean-up and commercial contract close-out.

All of these activities will require Manitoba Hydro labour after ISD that is directly attributable to capital construction costs associated with the asset. To ensure appropriate allocation of costs to capital or operating expenses, all project costs are carefully scrutinized by Manitoba Hydro accounting professionals to ensure that costs meet the criteria for capitalization as set out in International Financial Reporting Standards. When costs are deemed not to be eligible for capitalization, they are charged directly as an operating expense to the Corporation. Additionally, the allocation to capital or operating is considered in the annual external accounting audit that the Corporation undertakes as part of preparing its yearly financial statements.

<u>Scope Item 13, Finding 3, page 95</u>

On page 97 of their report MGF states "The current value of contingency at a P75 confidence level does not appear to be based on a current or updated Contingency review. As such, this would not take into consideration the events and updated risks that the project has been or may be exposed to. Manitoba Hydro's corporate standard states that contingency is set at a P50 or 50% confidence level." Manitoba Hydro disagrees with this statement. The current P75 contingency value for the Converter Stations was developed based on the 2014 risk and contingency assessment as the general risk profile of the project was unchanged. This approach does appropriately account for risks realized to-date.

Scope Item 19, Finding 3, page 112

MGF further concluded on page 114 when reviewing the Bipole III transmission line that the current P80 confidence level does not appear to be based on a current or updated review. The current P80 contingency value for the Transmission Line was also developed based on the 2014 risk and contingency assessment as the general risk profile of the project was unchanged. This approach does appropriately account for risks realized to-date. It was also reviewed against the Risk Register at the time, contrary to MFG's finding that it does "not appear to be based on current or updated review." The Risk Register is a document used as a tool to track issues and address problems as they arise. It acts as a repository for all risks identified and includes additional information about each risk such as the nature of the risk, the owner of the risk, and mitigation measures.

The decision to increase the P-value of the contingency for the Bipole III Project (transmission line and converter stations) in 2016 from a P50 to an overall P75 contingency level on the project was based on a number of anticipated risks having been realized and the desire to have an increased confidence level in the Bipole III control budget recognizing that there was only 2 years remaining on the work before the project was brought into service. With construction work on the project now largely complete, the project has progressed to a point where budget risks are largely reduced and the primary risk relates to schedule. This is supported by MGF's findings that the contingency on both the transmission line and converter stations are sufficient to complete the work on-budget.

It is the project management team's responsibility to recommend the appropriate P-level for contingency on a project. While this can be a P50 contingency, the project management team may alternatively recommend a different P-value (e.g. P75 contingency) based on factors such as: realized risks, project status, remaining work-to-complete, and remaining risks. The recommended P-level of the contingency together with the project estimate is reviewed and approved at the Executive level.

2.3. Misinterpretations, errors and incorrect characterizations in the MGF findings.

MGF provided many of their findings to Manitoba Hydro in advance of issue the report as drafts and Manitoba Hydro advised MGF that, in its opinion, there were a number of misinterpretations, errors and incorrect characterizations in the findings.

It also suggested corrections. However, based on the MGF responses obtained through the Information Requests process, MGF did not include any of these suggested corrections within its final report. As such, Manitoba Hydro will provide this information directly to the PUB through this Rebuttal.

Scope Item 10, Finding 3, page 86

MGF has incorrectly stated a risk identified in the June 2017 Bipole III Converter Stations Project Controls Report was repeated/again identified in the September 2017 Controls Report, although the wording in the report was in no way the same. The risk from the June 2017 report addressed both concerns related to the on-time completion of work by the Keewatinohk 230kV AC Switchyard contractor and the commissioning schedule for the Riel Converter Station Synchronous Condensers, whereas The risk from the September 2017 report identified concerns related to the overall complexity of interface work between the major contractors, potential delays to commissioning due to HVDC equipment damaged during installation, the risk of commissioning delays on the AC Switchyard and equipment delivery delays potentially impacting commissioning schedules.

Based on MGF's interpretation that the identified risks were identical, they incorrectly concluded that Manitoba Hydro did not mitigate the risk originally identified in June 2017. These two risk items were, in fact, different issues. Regarding the June 2017 risk, Manitoba Hydro took specific actions, including taking-over the work in parts from the contractor to ensure the AC Switchyard work was completed and handed over to Manitoba Hydro in time to accommodate commissioning. Similarly, Manitoba Hydro has required the Riel Synchronous Condenser Contractor to review its commissioning plan and ensure it is achievable. The risks noted in the September 2017 report were addressed as follows:

The “complexity of interfaces” risk relates to schedule risks on the overall interface work that is to be executed to “connect” or “link” the major components of work on the converter stations (for example linking the HVDC station to the Synchronous Condensers). Manitoba Hydro is actively managing and mitigating this risk through execution of its interface contracts and interface schedule management

The damaged HVDC equipment identified as having the potential to impact commissioning, relates to damage that occurred to Converter Transformer turrets during installation. The Contractor has addressed this risk by obtaining replacement turrets. There will be no impact to schedule.

The delays related to commissioning of the Keewatinohk AC Switchyard, related to new delays that had arisen in the completion of installation and finalization of equipment. These items were addressed and recovered by the contractor and the final handover of the switchyard to Manitoba Hydro for commissioning occurred on schedule.

The risk related to delayed equipment delivery potentially impacting commissioning schedules, related primarily to remaining (minor) equipment deliveries on the HVDC contract and remaining equipment deliveries on the Riel Synchronous Condensers. These delays are both being actively managed and mitigated by the Contractors and both are not anticipated to have any impact to schedule and the in-service date of the project

<u>Scope Item 11, Finding 3, page 90</u>

MGF has misinterpreted the application of mark-up on several of the lumps sum Variations reviewed. MGF have indicated that the contractor improperly applied mark-up to lump sum Variation values already including mark-up (i.e. double application of mark-up). This double application of mark-up did not occur. The instances identified by MGF only included a single markup of 15% as part of the total lump sum pricing. This mark-up happens to be the same as prescribed for on Actual Cost Variations but was not additional application (or double counting) of mark-up. As such, in the identified Variation, the amount paid by Manitoba Hydro was equal to the agreed upon lump sum price included in the approved variation.

<u>Scope Item 15, Finding 1, page 98</u>

MGF stated "CEF 16 carried a cost of [redacted] Manitoba Hydro wishes to clarify that the entire Rokstad Contract budget has been adjusted for reduced scope (primarily foundations scope removed in N4) and updated unit rates once the contract was awarded in December 2016, which was post the finalization of CPJA 08a (2016). All reductions to the contract budget are returned to the project control budget, Transmission Line Contingency as part of the ongoing budget alignment process for changes. 1a, 7a, 8a

<u>Scope Item 15, Finding 3, page 100</u>

MGF has incorrectly identified that the CEF2016 estimate failed to include costs for Distribution Line Crossings and the Transmission Line Construction Yard. These costs were included in the CEF2016 and current CPJA 08a approved control budget in the 2016 estimate and summaries provided to MGF. Bipole III – Appendix A is a summary of an extensive spreadsheet that was provided to MGF with relevant items expanded that summarizes the approved budgets and that these items were in fact included in the control budget.

<u>Scope Item 17, Finding 1, page 102</u>

MGF alleged that there were several missing attributes to the Bipole III Risk Register. These attributes are actually addressed in the Risk Register and have been missed by MGF. MH wishes to clarify that the Risk Register was originally developed through SharePoint and as such there is an identified creation date for each risk. However, in the spreadsheet output of the Risk Register provided to MGF a column outlining the creation date of each risk had not been included.

Scope Item 20, Finding 1, page 115

On page 115 in its review of the Risk Register, MGF recommended that the Risk Register be updated to include the date the Register was last updated and the date the risk ID was last updated. In fact, the Risk Register is actively and properly managed and the Risk Register information suggested by MGF to be collected is already captured within the SharePoint document management and collaboration tool where the Risk Register is held and is updated regularly.

Scope Item 17, Findings 2, 3 and 4, page 102

On page 103 and 104 of its report, MGF states that the Variation Summary only records those variations that are "approved." Manitoba Hydro does maintain variation log/summaries with all variations, and further reviews those for cost impact through the "Project Change Authorization" or PCA process, which is a document that authorizes and documents the use of contingency or return of contingency on the project budget and is key component of the change management process that Manitoba Hydro follows on Bipole III.

On page 102 of its report, MGF identifies Contract 031074 with Valard Construction as open, with a contingency remaining of [redacted]. This contract is shown as closed in 1a, 7a
the Contracts Listing. All un-used Purchase Order funds that were held in budget and/or in allocated contingency for the Order are returned to the project control budget, Transmission Line Contingency, as part of the ongoing budget alignment process for changes.

While Manitoba Hydro generally agrees with the MGF findings related to Bipole III and agrees that construction of the project is tracking on budget and on schedule with all equipment installations nearing completion, and commissioning of the project underway, it did want the record to accurately reflect the facts above. Manitoba Hydro will continue to manage the project appropriately and is committed to meeting the scheduled ISD of July 2018 and completing within the $5.04 billion control budget.

3. MANITOBA-MINNESOTA TRANSMISSION PROJECT

The Manitoba-Minnesota Transmission Project consists of a 500 kV transmission line from the Winnipeg area to the U.S. border in southeastern Manitoba, as well as upgrades to three existing electrical stations in southern Manitoba. If the Project receives environmental licences and approvals from both the Provincial and Federal Governments, it will transport power to the United States to meet sales contracts, improve reliability of the transmission system, and bring electricity to Canada from the United States in emergencies.

MGF was retained by the PUB on MMTP to review Manitoba Hydro's:

- practices on its pre-construction design and engineering work;
- its methodologies for costing, for tendering and contracting, for management of construction, contractors and construction risk management, and for scheduling; and
- capital cost estimates.

MGF's review was generally favourable, indicating that MMTP was currently on schedule and that Manitoba Hydro's estimating methodology is consistent with industry standard. Manitoba Hydro does wish to respond to three areas contained within the MGF Report, as set out below.

3.1. Acumen Fuse

Acumen Fuse is a software tool used for reviewing the quality of schedules prepared in Primavera. Primavera is a scheduling tool that Manitoba Hydro uses to create project schedules.

Project schedules are comprised of activities associated with the work involved to construct the project, such as designing towers, ordering materials, constructing foundations, etc.

Manitoba Hydro links these activities together within Primavera using "schedule logic" to ensure that changes to durations and start dates are reflected in the schedule as the project progresses. An example of this "schedule logic" would be a link between a tower steel delivery activity and an installation of the tower steel activity. The tower can't be installed until the material is delivered, thus these activities would be linked in the scheduled using finish to start "schedule logic".

On the MMTP Manitoba Hydro also used Primavera to schedule the spending on the project. Activities in Primavera were also linked to the budget for the project and spending associated with activities was distributed from the start of the activity until the end of the activity. Using this technique Manitoba Hydro creates two types of activities, those that impact the duration of the project, and those that are solely used to record labour charges against the project, which Manitoba Hydro refers to as "Charging Activities". An example of this would be an activity used by our material procurement staff to record their time against while they answer questions about delivery dates, Manitoba Hydro would refer to this activity as a "Support" activity.

In the case of the 500kV Transmission Line schedule MGF stated the following (Reference: On page 125 of the MGF report):

> *"Fuse Schedule Index: Is a single quality indicator resulting from a summary of detailed analysis. The Dorsey Stn: Manitoba – US 500kV baseline schedule scored 42, giving it a 30% probability of success."*

In addition, MGF responded the following with respect to Manitoba Hydro's information request pertaining to Acumen Fuse (In response to MH/MGF I-4 on page 13 and 11 respectively):

> *"MGF agrees that activities within the schedules that are used for capturing internal labour expenses significantly reduce the Acumen Fuse score. MGF disagrees they would have no actual impact to the project schedule success."*

In essence, MGF is stating that missing "schedule logic" is impacting the Acumen Fuse score which is reducing the project success rate.

Manitoba Hydro is of the opinion that its scheduling methodologies are appropriate and accurate. Manitoba Hydro has successfully used these scheduling practices to deliver numerous transmission line projects in the past and have refined our scheduling practices and templates based on our experience on previous projects, most recently the Bipole III, Lake Winnipeg East 115kV line, and two 138kV transmission lines built for Keeyask.

Manitoba Hydro is of the opinion that Acumen Fuse has a number of limitations with regards to scoring the success rate of the project. These include:

- Acumen Fuse cannot recognize if "schedule logic" between activities is correct, for example if the activity to install the material was linked to start before the material delivery activity Acumen Fuse would not penalize the schedule rating.
- Acumen Fuse doesn't recognize if there are missing activities.
- Acumen Fuse penalizes the project success rating for missing logic, even if the logic is associated with activities that are not influential in the project schedule.
- Acumen Fuse doesn't measure the typical duration of a transmission line schedule in comparison to the time allotted by Manitoba Hydro.
- Acumen Fuse does not consider any other factors that contribute to project success beyond the quality of scheduling practices used to create the schedule.
- Acumen Fuse rates project success on schedule quality, and has no measure for a project team's ability to execute a project, their past experience, or if the current schedule has activities in the correct sequence.

Manitoba Hydro is of the opinion that MGF has overstated the relevance of the Acumen Fuse score with respect to missing "schedule logic" and project success. In Manitoba Hydro's opinion, the activities identified by MGF will not impact the schedule because of the nature of the activities with missing "schedule logic". The majority of these activities are not used by Manitoba Hydro to control the start and finish dates of activities within the schedule and therefore don't impact the duration of the project schedule. Instead they are used for accounting and reporting purposes only.

For example a "Support" activity is scheduled during the procurement and construction of the transmission line, which is used by procurement staff to record their labour against the project while they provide support to design and construction staff, such as answering questions pertaining to material delivery. If this activity is late to start in the schedule it won't prevent the procurement staff from answering questions and providing support and since it's not linked to other activities it will have no impact on project duration or success. This is a standalone activity that spans a long duration of work and its purpose is only to schedule the spending budget for the support work. Normally these activities are omitted by the Acumen Fuse analysis however a certain activity type needs to be assigned within the Primavera software for this to occur automatically, which was not done by Manitoba Hydro. Not assigning the activity type doesn't change the intent of these activities, it just lowers the result of the Acumen Fuse output, which is not a tool that Manitoba Hydro uses.

Manitoba Hydro believes these activities are of little relevance to the project success because these activities are not used by Manitoba Hydro to control the duration of the project schedule. These activities do not influence start and finish dates of other activities in the schedule and whether or not they have started is irrelevant to when actual critical activities would start. Tangible events are more likely to have impacts on the project success, such as delivery delays or incremental weather, than missing "schedule logic" on activities used to record labour

Acumen Fuse is a tool to help improve the quality of the project schedule but can't be used to evaluate the success rate of a project. While poor scheduling can have negative effects on the project outcome, scheduling errors which Acumen Fuse can't identify such as missing activities, overstated durations, and incorrect logic would have more substantial impacts than missing "schedule logic" on activities not used to control the project's duration. The Acumen Fuse tool can't take away from the experience of the project team and their ability to execute the project.

3.2. Industry Standard Costs

MGF (Stanley) has compared the MMTP estimate for the Transmission Line portion of the project to a white paper prepared by the Western Electricity Coordinating Council ("WECC") and a report prepared by the Midcontinent Independent System Operator ("MISO") in which an "Industry Standard" cost per kilometer of transmission line was developed. MGF believes that Manitoba Hydro's estimate is lower than the industry standard and that Manitoba Hydro should revise its cost estimate.

Through the information request process Manitoba Hydro questioned, whether or not the "industry standard" costs took into account the tower type used on each project when developing the measure, to which MGF (Stanley) responded there was no significant impact on the costs based on tower type.

More specifically, in response to MH/MGF IR I-47, MGF (Stanley) has stated:

> *"WECC and MISO data have indeterminate structure design. Calculated data projects included self-supporting lattice tower (1 project) and tubular steel structures (5 projects). None of the projects included guyed tangent lattice towers. It is worth noting that type of transmission structures does not have a significant impact on overall cost per mile for comparison purposes."*

Manitoba Hydro disagrees with this position as it previously stated in its Information Request Round 2 response in the Clean Environment Commission Hearing, Question #MWL-IR-89:

> *"based on an internal cost comparison for transmission structures in southern Manitoba, installed construction cost (not including line hardware) for a single tubular tower is approximately 70% of the installed cost for a single self supporting lattice tower. However, with the increased number of tubular structures required, the total cost of a tubular line is higher. Assuming 500m spans for lattice and 250m spans for tubular structures, a line constructed with tubular towers would increase the cost of the line by as much as 40%. This is based on 240 kV structure costs in southern Manitoba."*

The Western Electricity Coordinating Council ("WECC") white paper on Capital Costs for Transmission and Substations developed by Black & Veatch in 2014 which Stanley Consultants has used in preparing the industry standard comparison states on page 2-4 that there is a 1.5 multiplier for using tubular steel compared to lattice as shown in the figure below.

Figure 3.0

2.2.3 Transmission Structure Type

In 2012, Black & Veatch quantified the capital cost multipliers associated with each type of transmission support structure. Structure types included lattice towers and tubular steel.

Table 2-3 below shows the transmission structure type cost multipliers for all voltage classes. An additional voltage class was added for the 600 kV HVDC bi-pole alternative based on the 500 kV HVDC bi-pole multiplier. The 500 kV HVDC bi-pole multiplier was originally developed based on the relative costs of lattice structures and tubular steel at very high voltage.

Table 2-3 Transmission Structure Type Cost Multipliers

STRUCTURE	230 KV SINGLE	230 KV DOUBLE	345 KV SINGLE	345 KV DOUBLE	500 KV SINGLE	500 KV DOUBLE	500 KV HVDC BI-POLE	600 KV HVDC BI-POLE
Lattice	0.90	0.90	1.00	1.00	1.00	1.00	1.00	1.00
Tubular Steel	1.00	1.00	1.30	1.30	1.50	1.50	1.50	1.50

This multiplier is used in the Transmission Calculation Methodology stated on page 2-8 of the WECC white paper.

Figure 3.1

2.6 TRANSMISSION CALCULATION METHODOLOGY

Multiplying the right of way acres per mile by the land cost per acre yields the total right of way cost per mile of transmission line. This value was added to the base transmission costs discussed in Sections 2.2, 2.3, and 2.4 to develop the total transmission line capital cost.

Total Transmission Line Cost = [(2014 Base Transmission Cost) x (Conductor Multiplier) x (Structure Multiplier) x (Re-conductor Multiplier) x (Terrain Multiplier) + (ROW Acres/Mile) x (Land Cost/Acre)] x (# of Miles)

It is clear from the equation that the WECC agrees with Manitoba Hydro's assessment that the structure type does have an impact. In the equation above, the base costs would be multiplied by a factor of 1.5.

In summary, Manitoba Hydro is of the opinion that structure type does have an impact on the costs per kilometer, and that using tubular steel towers typically increases the project costs. This could explain why Manitoba Hydro's estimates are lower than industry standard costs which seem to be determined mainly from tubular steel projects as stated above in the response to MH/MGF IR I-47. Manitoba Hydro's current estimates are based off of recent construction bids that were provided for the Bipole III Project which Manitoba Hydro believes is the best source of comparison as it reflects current market conditions for 500kV towers in the Manitoba market place, compared to historical industry costs in differing market conditions. Manitoba Hydro is committed to keeping the costs of capital work as low as possible and is confident in its estimating process.

3.3. Internal vs. External Design

MGF (Stanley) has stated that the project delivery model, with respect to internal compared to external designs have no significant impact on the overall cost per mile of transmission line.

In response to MH/MGF IR I-47, page79 MGF (Stanley) states,

> *"WECC and MISO project delivery methods are indeterminate. Calculated data projects were design-build with mixture of internally designed (2 projects) and contracted design (4 projects).*
>
> *It is worth noting that internal vs. externally contracted design does not have a significant impact on overall cost per mile for comparison purposes."*

Manitoba Hydro is of the opinion that its approach to tower design is appropriate and cost effective. It disagrees with MGF's position regarding the impact of internal or external design on project costs. While the labour costs associated with internal design and contracted design firms are negligible in terms of the overall project budget, the indirect benefits of the internal design approach are significant.

The internal design approach protects Manitoba Hydro from design firms and material vendors "over designing" towers in order to protect themselves from risk, such that the costs of materials on the project could increase.

Manitoba Hydro's design approach is to design towers all the way to fabrication drawings, which prescribes to vendors exactly what is to be built. In addition, Manitoba Hydro arranges for tower testing which verifies the minimum amount of steel required on each tower and allows Manitoba Hydro to optimize its design and reduce costs.

Manitoba Hydro generally agrees with the MGF findings related to the MMTP. Manitoba Hydro continues to manage the project appropriately and is committed to continuing efforts to secure the June 2020 ISD. MGF recommends that Manitoba Hydro should update the project estimate and include awarded contracted values instead of estimates whenever possible. Manitoba Hydro intends to do so at an appropriate time when those contract values become available.

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January 11, 2018

Dave Bowen, Keeyask Project Director
Manitoba Hydro
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RE: Response to Manitoba Hydro's Questions

KPMG was engaged by Manitoba Hydro ("MH") on May 2, 2016 to undertake an independant review of the current status of the Keeyask Generating Station ("Project") and subsequently provide advice on the development and implementation of a Recovery Plan for the Project. The Recovery Plan was approved by the Manitoba Hydro Executive Board ("MHEB") in February 2017 and the implementation of the Recovery Plan has been the focus of the Project Team throughout 2017. In mid-December 2017, as part of MH's information gathering related to the Public Utility Board General Rate Application, MH requested KPMG to provide comments on the following matters:

1. Provide commentary on the contract model and any incentives included.
2. Define MH's role in the GCC contract. Define the role of the Contractor. Comment on MH's ability to manage the Contractor in this role.
3. Provide commentary on MH acting as the builder and taking on a Construction Management role.

In responding to the three matters in this letter, KPMG reviewed the documents provided by Manitoba Hydro as well as incorporated leading industry practices from both the Hydro industry and public sector projects greater than $1 billion. The documents provided by MH were: Recovery Plan Strategy (undated), the Capital Project Healthcheck, Cost and Schedule Assessment (July 2016), monthly Manitoba Hydro Status Update and Step Change Incentive Profit reports, the amended Keeyask Generating Station General Civil Works Contract #016203 (Feb 28, 2017), and weekly Issues Logs.

The response to Manitoba Hydro's questions was led by Gary Webster, National Lead for KPMG Global Infrastructure Advisory. Gary has more than 30 years of experience as a Professional Engineer specializing in the organization, procurement and implementation of large scale infrastructure projects.

Please note that this letter is subject to KPMG's engagement terms dated December 2015 with MH related to its work on the Keeyask Project. This letter is provided to MH and based on the review of the documents provided by MH and KPMG experience with industry leading practices. KPMG does not accept any liability or responsibility to any third party who may use or place reliance on this letter.

Question 1: Provide commentary on the contract model and any incentives included

MH awarded the General Civil Works Contract ("GCC") to a limited partnership between Bechtel Canada Co., Barnard Construction of Canada Ltd and Ellis Don Civil Ltd. ("BBE"), three recognized, experienced and well established companies. The contract was a Target Price contract, where payment to BBE was on a cost reimbursable basis with a gain share/pain share incentive formula. The gain share/pain share formula was introduced into the contract to incent BBE to deliver the Project under or on the target price.

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There was no early delivery incentives in the original contract but liquidated damages were included for late delivery.

As a cost reimbursable contract, the owner was responsible for all of BBE's actual costs. However, with the inclusion of the incentives, it ensured that the contractor's profit (and to a limited extent their general administration and overhead ("GA&O")) was at risk based on their performance. The incentives used in this contract have been used in other cost reimbursable contracts as well as other forms of contracts. The incentives align the owner's and contractor's interests and help to mitigate the exposure the owner has to poor performance by the contractor.

The gain share/pain share formula was structured as follows:

- The gain share formula for cost savings was 80% for MH and 20% for BBE. If BBE delivered a project under the Adjusted Target Price (as defined in the contract), their profit increased from 1[redacted]% by [redacted]% of the additional savings. 1a
- The pain share formula, however, was more punitive to the contractor. If the costs went over the adjusted target price, BBE was responsible for 80% of the cost overruns and their [redacted]% profit could erode to zero profit based on the amount of cost overrun. 1a

Additionally, once the actual costs exceeded the target price by 1.3 times, BBE would no longer receive their [redacted]% GA&O. The objective of this cap on GA&O was to ensure that the contractor would not benefit from escalating project costs and removed the incentive for the contractor to increase project costs to improve their overall position. 1a

By fall of 2016, MH realized that BBE's opportunity for profit would likely be eroded and that there were no longer any achievable incentives remaining in the original contract. The result was a mis-aligned relationship between MH and BBE where BBE could be motivated to regain their profit to the detriment of the Project. During this period, MH developed and implemented a Recovery Plan. As part of the Recovery Plan, MH addressed a number of root causes that led to cost and schedule overruns that were being incurred. They also negotiated an amended contract with BBE.

The amended contract continues to be a Target Price Cost Reimbursable contract, fundamentally the same as the original contract. The ability to transfer additional risk, such as geotechnical, hydrology, labour, extreme weather, and northern logistics to BBE by changing the contract to a Unit Rate or Lump Sum contract, would have required directly negotiating a new form of contract with BBE in a non-competitive environment or descoping/terminating BBE and going back to the market for a Unit Rate contract. It was expected that in a non-competitive environment and given BBE's performance in 2016, the costs of transferring this risk to BBE would have been prohibitive and/or not achievable. Additionally, in its Recovery Plan, MH analyzed the impact of terminating or descoping BBE's work. MH analysis shows that the additional delay to the project required for the re-procurement of this work along with additional risks associated with re-procurement, would have resulted in an additional increase to the Adjusted Project Budget.

The amended contract remains a Target Price Cost Reimbursable contract with limits on GA&O and performance incentives tied to achieving the target price. The amended contract was designed to achieve the following:

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- Reset the target price and schedule milestones;
- Improved gain share/pain share incentive formula. The new incentive program is now structured around cost, schedule and management performance;
- Limited BBE's right to claim for additional adjustments to the target price;
- Improved the relationship with BBE that allows for a more collaboration on site; and
- Allow MH, as they deem necessary, to alter the scope of BBE.

The amended contract now includes incentives for not only cost, but also schedule and management performance. The balance of the incentives is now [redacted]% of any cost savings that it may generate capped at [redacted]M and [redacted]M based on meeting schedule milestones. Cumulatively, BBE could earn up [redacted]M 1a
profit for meeting all their cost, schedule and management targets, conversely they risk losing not only all their profit and GA&O expenses above the capped amount but an additional [redacted]M for poor project performance. The amended incentive pool was designed to further motivate BBE to perform and take day to day responsibility for the work it has been contracted for.

It should be noted that in contract management, a high risk exists when cost performance incentives are entirely disconnected from schedule. Namely, a perverse incentive could exist for a contractor to forsake schedule in an effort to maintain a low cost position. To address this risk, the amended contract contains a deduction associated with very strong cost performance and very weak schedule performance. This incentive structure is designed to eliminate the incentive to ignore schedule performance in order to capitalize on cost incentives.

The amended contract also has a component where BBE can gain an additional [redacted]M (included in the [redacted]M referred to above) for improved management performance ("Step Change Incentive") based on 1a
their ability to better perform their construction management responsibilities. This includes improvements such as site leadership, planning and scheduling, reporting and better coordination with MH.

Finally, the general administration and overhead ("GA&O") is [redacted]%. The provision of GA&O expenses, 1a
which are standard in the construction industry for any contractor, affords for cross-functional and project-wide resources to be accessed throughout the initiative and allows for ease and efficiency in administration without the need for micro-management. MH was able to cap the GA&O at the Final Target Price versus the original 1.3x the target price.

MH has taken reasonable steps to renegotiate the contract. The amended contract addressed a number of concerns MH had with BBE and their performance. It includes multiple systems of financial incentives and disincentives to mitigate risks associated with cost reimbursable contracts. The contract amendments were designed to promote better alignment of BBE and MH objectives, and create a collaborative environment that allows MH to take on a more proactive management style with BBE.

Question 2: Define MH's role in the GCC contract. Define the role of the Contractor. Comment on MH's ability to manage the Contractor in this role.

MH's Role in the GCC Contract.

Manitoba Hydro's Role in the GCC Contract is to function as the overall Project and Site Construction Manager. As Project Manager, MH is responsible to ensure integration, alignment and quality of the

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project as a whole. As Site Construction Manager, MH is responsible for the overall coordination and oversight of site work, while delegating the construction planning, management of labour and construction means and methods (along with other responsibilities) to the contractor. It should be noted that construction management is a term used which can cover a wide range of responsibilities and functions. From public sector owners' perspective, construction management is often the term used to oversee the construction of the project. Canadian public sector owners do have experience managing construction works; however, these works tend to be routine and relatively minor. KPMG is unaware of any Canadian public sector owner who would have the capabilities, systems and processes to allow for direct management of complex multi-billion construction projects.

In its role, Manitoba Hydro provides oversight and approval of BBE's activities by providing channels for controls, as well as strategic level issue and risk management. Their general duties would include:

- Overall responsibility to complete the planning, design and engineering and to oversee the construction and commissioning of the proposed Keeyask Generating Station which includes the General Civil Works contract;
- Overall responsibility of the site and coordinating the interfaces with the various contractors and suppliers they enter into contracts with;
- Approving contract changes;
- Agreeing to the Contract Schedule, and all amendments thereto, in the course of BBE's performance;
- Providing oversight and surveillance audits of BBE's processes;
- Reviewing any potential changes to the overall work plan, that could alter the target price and/or construction schedule;
- Addressing stakeholder issues;
- Acquiring Project permits; and
- Providing access to the Site and timely payment to the contractor.

Ongoing monitoring and collaboration by MH continues to be essential. MH has retained an experienced construction management consortium to undertake the direct management of the construction works. If MH drives for more aggressive involvement in the direct construction management, MH could be potentially frustrating BBE in their execution of the work. This could result in a number of reactions from BBE including claims for lost profit if the project does not meet the performance requirements associated with the gain share/pain share incentives. Furthermore, it may also result in MH unintentionally taking on additional risk with respect to performance results that are currently under BBE's control that MH does not have the experience to manage.

The Role of the Contractor

MH has a contract with BBE to manage the construction of the general civil works. As per their contract, BBE is obligated to construct and commission the GCC work. This would include providing the material, labor, construction planning and supervision expertise to construct an end product that meets the cost, schedule and specifications outlined in the contract. The general responsibilities of BBE include:

- Working with MH to deliver their work;
- Executing site safety processes and procedures as outlined in the project safety plan;

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- Providing construction planning expertise and collaborating with MH (and other parties), throughout the design development phase (in particular reviewing constructability and completeness of detail of the design);
- Developing the contract budget and schedule;
- Procuring equipment, material and labour;
- Providing qualified management and supervision;
- Planning and supervising construction;
- Implementing quality control and assurance program and maintaining quality management records;
- Maintaining and meetings all permit and environmental requirements;
- Monitoring the costs and schedule; and
- Reporting on progress. This would include costs, productivity, down time, schedule, work plans, etc.

MH's Ability to Manage the Contractor Based on the Contract

MH and the current Project team have experience managing large complex hydro projects and have completed Pointe du Bois and Wuskwatim ($0.6B and $1.4B respectively). The table below highlights the relative experience of each of the key leadership team members.

Name	Project Role	Experience
Senior Management Team		
Dave Bowen	Project Director	20 Years
Ryan Ward	Commercial Contracts Manager	19 Years
Barry Nazar	Site Construction Manager	32 Years
Jeff Strongman	Business Manager	24 Years
Tom Tonner	Engineer Manager	25 Years
Senior Technical Team		
Terry Armstrong	Construction Quality Engineer	27 Years
Dave Little	Site Support Manager	30 Years
Gene Piasta	Head of Project Controls	27 Years
Glen Schick	Head of Infrastructure	29 Years
Charles Wright	Structures Resident Engineer	25 Years
Guy Remillard	Mechanical/Electrical Resident Engineer	32 Years
Brian Beyak	Earthworks & Excavations Resident Engineer	26 Years

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As summarized in the above table, the Senior Management Team has 120 years of combined experience managing and overseeing large complex projects.

Over the course of 2017, Manitoba Hydro has managed their internal responsibilities while managing BBE to meet their contractual obligations. MH has demonstrated they understand their role in administering the contract with BBE as well as the risk they have to manage associated with the contract.

MH has enhanced its internal systems and processes to manage the overall project since the commencement of the project. This included initiating a "Step Change Program" that focused on their own improvement as well as that of BBE. The Step Change program was designed to address the root causes identified in the Recovery Plan and implement the following improvements for MH and BBE respectively.

Manitoba Hydro:

- Organizational structure to reflect the stage of Project;
- Leadership accountability;
- Authority residing at the Site;
- Communications between the Site and Winnipeg offices;
- Project controls function;
- Risk management and project reporting; and
- Escalation of issues to senior leadership team.

BBE:

- Organizational structure to reflect the construction management activities required by BBE;
- Alignment with MH counterparts;
- Contract reporting;
- Management of indirect costs;
- Travel logistics;
- Collaborative working environment;
- Relationship with Allied Hydro Council;
- Construction planning; and
- Construction supervision personnel.

Based on the above, the current division of roles and responsibilities between MH and BBE is appropriate and the Project team has experience and qualifications to manage and oversee the GCC Target Price contract.

Question 3: Provide commentary on MH acting as the builder and taking on construction management role

As highlighted in Question 2, we are unaware of any Canadian public sector owner who would have the capabilities, systems and processes to allow for direct management of complex multi-billion dollar

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construction projects. The contractor brings a significant amount of skills to a project that an owner does not have. The following is a brief, non-exhaustive list of such skills:

- Construction labour recruitment and labour relations expertise;
- Corporate construction safety plan;
- Construction equipment corporate discounts;
- Extensive cost control system;
- Management, supervision and engineering personnel with construction experience;
- Access to labour; and
- Previous work experience in order to better plan and perform the work.

Some project owners do have the internal capabilities and experience to act as the builder and to take on a construction management role. Generally, this skillset is developed through experience with multiple projects and owners have gained experience in building and managing projects of scale which they regularly undertake. However, public sector owners do not perform large projects with sufficient frequency to have developed the internal skills to manage the additional complexity that are associated with multi-billion dollar projects.

MH has relied on general contractors to manage large projects in the recent past. The most recent hydro projects completed by MH are Limestone ($1.43B and 1,350MW completed in 1990), Wuskwatim ($1.37B and 211MW completed in 2012), and Pointe du Bois Spillway Replacement, ($600M completed in 2016). MH has only completed these three projects since 1990 and all of these were executed using external general contractors. This would generally not be considered adequate experience for MH to be considered a low-risk builder or construction manager.

This letter is addressed to Manitoba Hydro and in response to MH's three matters. As noted on page 1, we will not accept any liability or responsibility to any other party to whom the letter may be shown or who may require a copy of the letter.

Yours Sincerely,

Gary Webster, P. Eng.
Partner, National Lead Infrastructure Advisory
KPMG Canada
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Project Memo

H341433

January 15, 2018

TO: Dave Bowen

FROM: Alan O'Brien/Sylvain Laramee

cc: Ian Ainslie

Manitoba Hydro
Keeyask GS Engineering Consulting Services

MGF Report on Keeyask

1. Introduction

At the request of The Manitoba Public Utilities Board, MGF Project Services Inc have conducted an independent review of Manitoba Hydro's Capital Expenditures program. The conclusion of their finding presented in their report issued at the end of 2017 was inclusive of a certain number of recommendations especially with regard to the Keeyask Hydroelectric Dam.

Following their receiving of the said report, Manitoba Hydro has mandated Hatch to provide commentary regarding MGF's suggestion that Manitoba Hydro expand its role with the GCC. Alan O'Brien and Sylvain Laramee have reviewed MGF's report and subsequently prepared their joint response which follows their own personal bios.

2. Bios

2.1 Alan O'Brien

Alan is a seasoned project and business manager with more than forty (40) years of experience in Engineering design, project, business and commercial management. He has been involved in projects of various sizes in a variety of industries including Oil & Gas, Petrochemical, and Power (Hydro, Nuclear, Thermal and Wind). He has managed contracts both domestically and internationally.

He has worked for two major engineering Contractors (Amec/Agra and Hatch). In his capacity of Project Manager and/or Director, he has delivered projects using various execution models, such as EPCM, EPC, fixed fee, target price and cost reimbursable. As Global Director of Commercial Management he was responsible for overseeing the group that undertook commercial and implementation reviews on all major contracts. The experience gained over many years working both in the engineering office and at site has given him a broad exposure to different types of contract execution strategies and their advantages and disadvantages.

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Alan is currently acting as Project Sponsor on a few Hatch projects. In this role, he works with the Project Manager and his/her team in an oversight role to provide ongoing review, guidance and support.

2.2 Sylvain Laramee

Sylvain is an experienced project professional with thirty-four (34) years' experience in project and construction management of major capital projects in the Mining and Energy sectors which have allowed him to develop a broad range of management skills that are uniquely adapted for project work. His experience, both on the EPCM and contractor's side, coupled with the diversified leadership roles (Engineering Manager, Area Manager and Construction Manager) held on major capital projects has provided him a unique perspective of innovative implementation strategies and successful project outcomes.

For the past decade, Sylvain has fulfilled the role of Managing Director, Construction Management, leading Hatch's global group of construction management professionals and taking responsibility for all domestic and international major capital project construction assignments. He has considerable experience in developing implementation strategies suited to specific project challenges including, project remoteness, complex logistics, lack of skilled labor, extreme weather conditions and security issues. During this period, he assembled and mentored a core group of competent construction professionals as well as developing and implementing construction tools and work processes targeted at addressing and overcoming the complexity of each of those projects.

3. Hatch commentary around expanding Manitoba Hydro's role with the GCC as suggested by MGF

MGF's recommendation at the end of their Executive Summary reads as follows: "The recovery of this project will require Manitoba Hydro taking a construction management, hands-on approach to design and implement a recovery plan and hold the GCC contractor to perform" (Page 3, Dec 8/17 MGF Report). There is no doubt that MH has the experience of similar major projects and could put together a team of construction managers as suggested. However, given that this was not the implementation strategy that was chosen initially to execute this project and given that MH does not have available the type of construction resources needed to take over the construction lead, one would question how viable it is to significantly change at this late stage the current approach and make MH the "Constructor". It would be our views that the proposed suggestion is of equal risk if not riskier than the status quo, as described below.

Interestingly, MGF when referring to the GCC contract points out that: "The largest single contributor to the budget increase is the sum to the original GCC on account of the Contractor's poor productivity and increased indirect costs as the GCC would take longer to perform" (Page 1, Dec 8/17 MGF Report). Unfortunately, their report fails to identify the reasons behind BBE's poor productivity performance. Hence it is unreasonable to make any recommendations for changes without the root causes being identified and solutions being proposed as well as those solutions and/or recommendations then being evaluated against the costs and risks inherent to their implementation. Naturally, MGF was unable to identify potential solutions to improve the productivity for the very same reasons.

The absence of a clear understanding of the said root causes makes it impossible to identify and implement the proper corrective measures. As an example, MGF suggest as a potential saving by modifying the ratio of craft to foreman from roughly 4:1 to 6:1. Should one of the problems be the quality of the supervision then this suggestion would in fact creates the opposite effect as there would be a further deterioration of the productivity.

Based on our experience, what MGF is suggesting, is of equal or greater risk than the status quo. Whilst MH would have the experience and capability to hire a competent CM team, such a team would carry a risk until proven. Hence to create this new CM team in the midst of this mega Project, is more likely to cause the overall Project to forecast to keep increasing because it introduces pitfalls and unknowns.

The risks associated with a major shift in the contracting strategy, especially for the single most important contract, include:

- It will remain a challenge to gather a team of construction professionals from the open market that will commit to the Project for the long haul knowing that the required caliber is typically under employment by the large constructions firms hence, and not readily available
- It will likely take several months to recruit, hire, onboard and mobilize such a team. And likely not in the optimal sequence.
- Clearly it will take some time for the new CM team with no previous working together experience, to understand the challenges, find the appropriate solutions, get efficient as a team and finally drive the performance improvement. Considering the complexity of this major Project, its remote location and its many work fronts, this team will undergo a steep learning curve regardless of their experience.
- In our experience in such drastic organizational changes, there is a fair chance of MH losing critical resources that are knowledgeable, and up to now, committed to the success of this Project.
- Until a new CM organization is in place, there would be transition period of high uncertainty that inevitably will prevent people from making decision and thus, some of the initiatives currently being developed to help driving the Project in the right direction could be lost.
- Should MH follow the recommendation, it will change the nature of BBE’s contract, leaving the contractor the freedom to maximize their revenue under a de facto time and material with fee contract. MH leverage over BBE using the pain/gain sharing and liquidated damages would not be retained.
- Once BBE would become aware of MH plan to take over the management of their contract, it is doubtful that they will remain engaged in finding ways to drive productivity or find solutions to existing challenges.

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- It cannot be ruled out that BBE could walk away from the Project considering that MH would be effectively breaking the terms of their current contract thus leaving MH with an even greater challenge to overcome.

Contrary to what MGF is stating in their report, and based on our limited knowledge of the contract between MH and BBE, we understand from MH that the GCC contract is a target price with contractor's fee at risk which includes schedule incentives and liquidated damages for late delivery. It is very difficult to imagine that MH would take over as the builder as this could result in a forfeiture of their contractual rights and a forfeiture of their leverage over the contractor to get their full attention and cooperation in addressing the seriousness of the situation. We're of the opinion that enforcing the contract to force the contractor to come to the table, put its best foot forward and make available their strengths and wherewithal will produce more upside than downside.

One interesting recommendation can be found in the report under Scope Item 9, Finding No. 1: Keeyask – Structural Steel Progress which states: "*MGF recommends that Manitoba Hydro work with BBE on a recovery plan to improve BBE's construction management, construction planning, coordination and supervision of construction work.*" This in our views is the logical beginning of a solution that ought to be applied to the overall contract and is currently being pursued by Manitoba Hydro

We understand that Manitoba Hydro is actively involved with the contractor in addressing the situation and we can only encourage them to remain focused on the work at hands and continue to hold BBE accountable by working jointly with them in accomplishing the following:

- Re-assess the final forecast
- Understand the root causes behind the poor performance and identify ways to improve and/or execute the works differently
- Identify all the risks that could impact the final forecast and elaborate a mitigation plan for each one
- Find innovative ways to improve productivity using latest technology available on the market
- Develop an optimal execution schedule that could be used as a baseline moving forward
- Deliver a comprehensive recovery plan that can be easily monitored and audited on a regular basis

There is an advantage to developing a plan jointly and making sure in the process to understand the areas where the GCC contractor could try to take advantage at the end for claims. In short, by doing this, it allows MH to limit or eliminate the General Contractor's ability to make claims by removing the obstacles and ultimately leaving the GC with only the burden of performing. Even in circumstances where there may be a requirement to supplement temporarily the Owner's team with some ad hoc resources, we believe the benefits will by far outweigh the investment and bring the best value to the Project. As time is of the essence, such exercise must take place sooner rather than later and should not disrupt what is happening at site

In summary, the suggestion by MGF to make such a fundamental change at this stage is, in our opinion, a mistake which could lead to a serious disruption of the Project with a very high potential of adding both to the costs and the schedule.

Al O'Brien/ Sylvain Laramee

SL:wlp
Attachment(s)/Enclosure

Bipole III Transmission Reliability Project

Attachment 1 – Response to Scope Item 15, Finding 3, page 100

BPIII 500kV Transmission Line

CPJA7 / CPJA8 Comparison

Row	ID	Activity ID	Cost Element/Work Centre	(2016) CPJA8 Plan ($)	(2014) CPJA7 Plan ($)	variance ($)
21	P:04218		BPIII Eastern Route 500kV T/L-Sunk Cost			
543	P:04221		BPIII Licensing & Env Assessment			
993	239224		340 TransLine Materials Yard (Const/deve			
1072	239224		342 Trans Line Materials Yard (Operation			
1906	239224		Bipole III Western Route T/L			
2188	251480		BPIII N1 Construction			
2475	251481		BPIII N2 Construction			
2733	251482		BPIII N3 Construction			
2992	251483		BPIII N4 Construction			
3223	251484		BPIII C2 Construction			
3490	251485		BPIII S1 Construction			
3769	251865		BPIII C1 Construction			
3918	253789		BPIII S2 Construction			
3938	255540		Logistics contract - Intelliwave			
4090	P:10155		BPIII 500kV HVDC Transmission Line			
4437	P:14518		BPIII Transmission Line Property			
4965	P:18414		BPIII Communications System			
5014	P:18767		BPIII Electrical Effects Monitoring			
5190	[illegible]255		BPIII T-Line Vehicles (print w/ P10155)*			
5682	P:23622		BPIII Distribution Relocation			
5819	P:23817		BPIII Transmission Line Contingency			
5964	P:2[illegible]5		BPIII Distribution Relocation N4			
6128	P:25508		BPIII Distribution Relocation C1			
6219	P:25509		BPIII Distribution Relocation C2			
6602	P:25510		BPIII Distribution Relocation S1			
7014	P:25511		BPIII Distribution Relocation S2			
7015						
7016	TOTAL FOR SELECTION			$1,957,615,	$1,655,370,	$302,244,

Tab 131

Keeyask Generating Station
General Civil Contract Procurement

November 26, 2013

Major Capital Projects

Outline

- Summary of Contracts
- Allocation of Risk
- Scope of work
- Lessons Learned – PdB and Wuskwatim
- Project Delivery Strategy
- Contract Model
- Procurement Strategy
- Evaluation Process
- Project Budget
- Procurement Timeline

Summary of Contracts

Keeyask Infrastructure Project (KIP)	<$450 M
Road	
Bridge	
Startup and Main Camps	
Worksite Area Development	
Service Contracts	
Final Design Engineering	<$100 M
General Civil Contract	~$1,700 M
Turbines and Generators	<$260 M
Spillway & Intake Gates and Hoists	~$300 M

Red items indicate contracts negotiated or awarded

Summary of Contracts (con’t)

Governors & Exciters	~$20 M
Transformers	~$35 M
Powerhouse and Draft Tube Cranes	~$25 M
Transmission Lines and Towers	~200 M
Service Contracts	<$260 M
Main Camp Phase 2	<$100 M

Red items indicate contracts negotiated or awarded

Allocation of Risk

- MH Risk
  - Contract Interfaces
  - Design
  - Project Schedule
  - Escalation (labour and commodities)
  - Scope changes
  - Environmental Approval
  - Quantities
  - Geotechnical
  - River Flow

Allocation of Risk

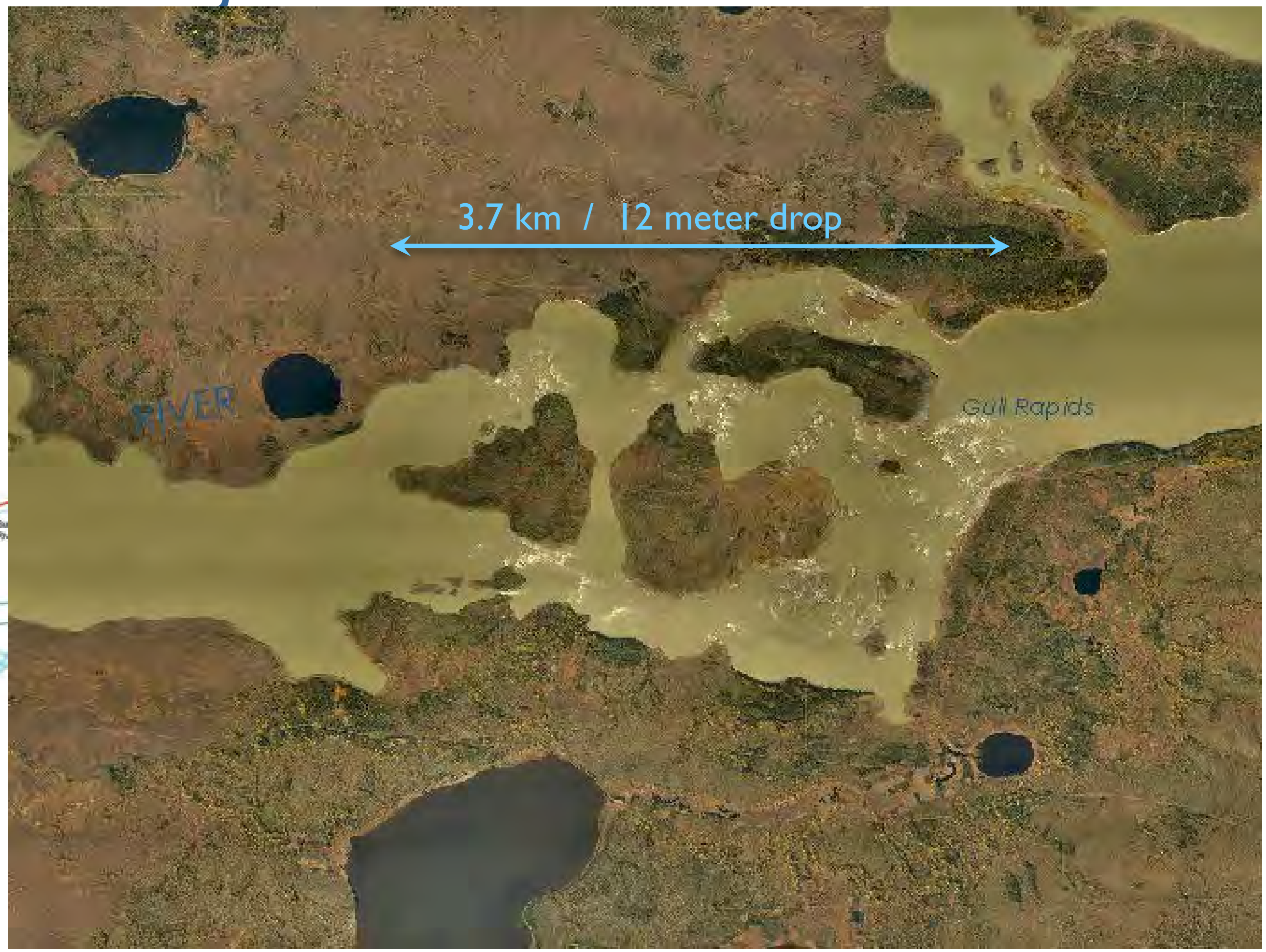
- GCC Risk
  - Contract Schedule
  - Attraction/Retention of Staff and Craft
  - Labour productivity
  - Subcontracts

Scope of Work

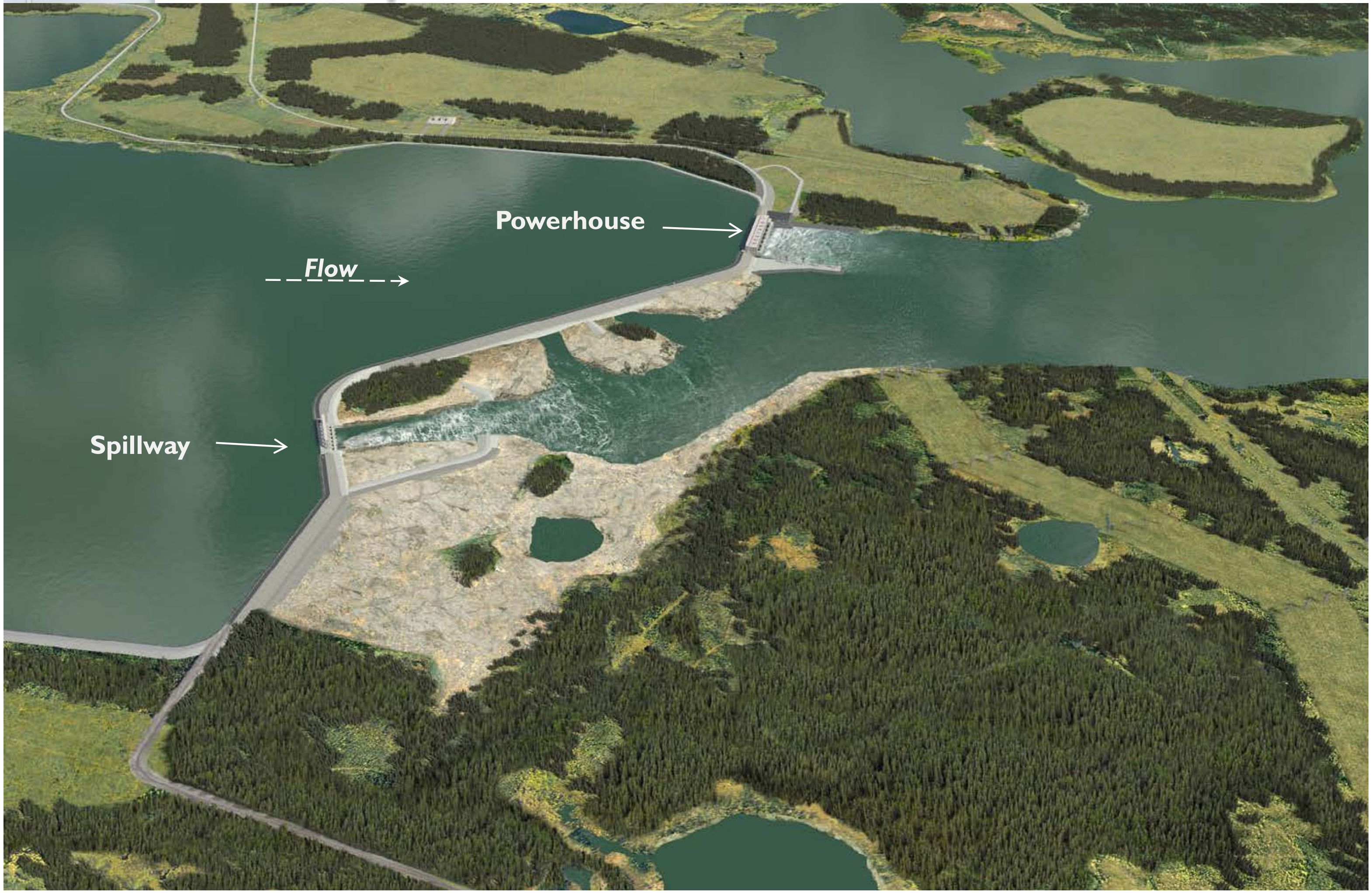
- The Keeyask General Civil Contract (GCC) will be the largest valued contract in Manitoba's history.

- GCC includes:
    - Cofferdam construction & River management
    - Excavation
    - Concrete for Powerhouse Complex and Spillway
    - Earth Dams
    - Containment Dykes
    - Electrical and Mechanical works

Project Location



Principal Structures



Cofferdam/River Management

Excavation

Powerhouse Complex and Spillway


KEEYASK

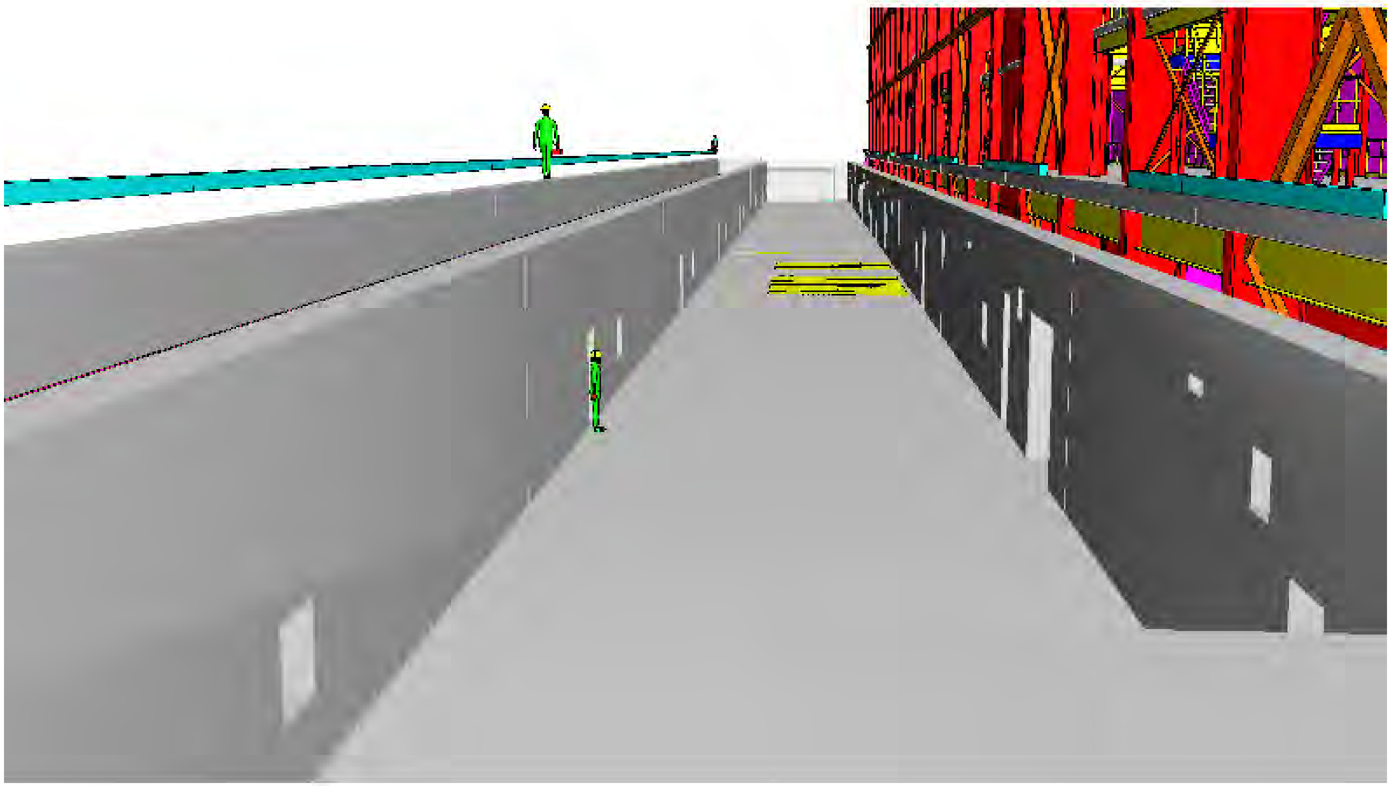
Earth Dams


2010/ 8/ 7


09 07 2011 14 57

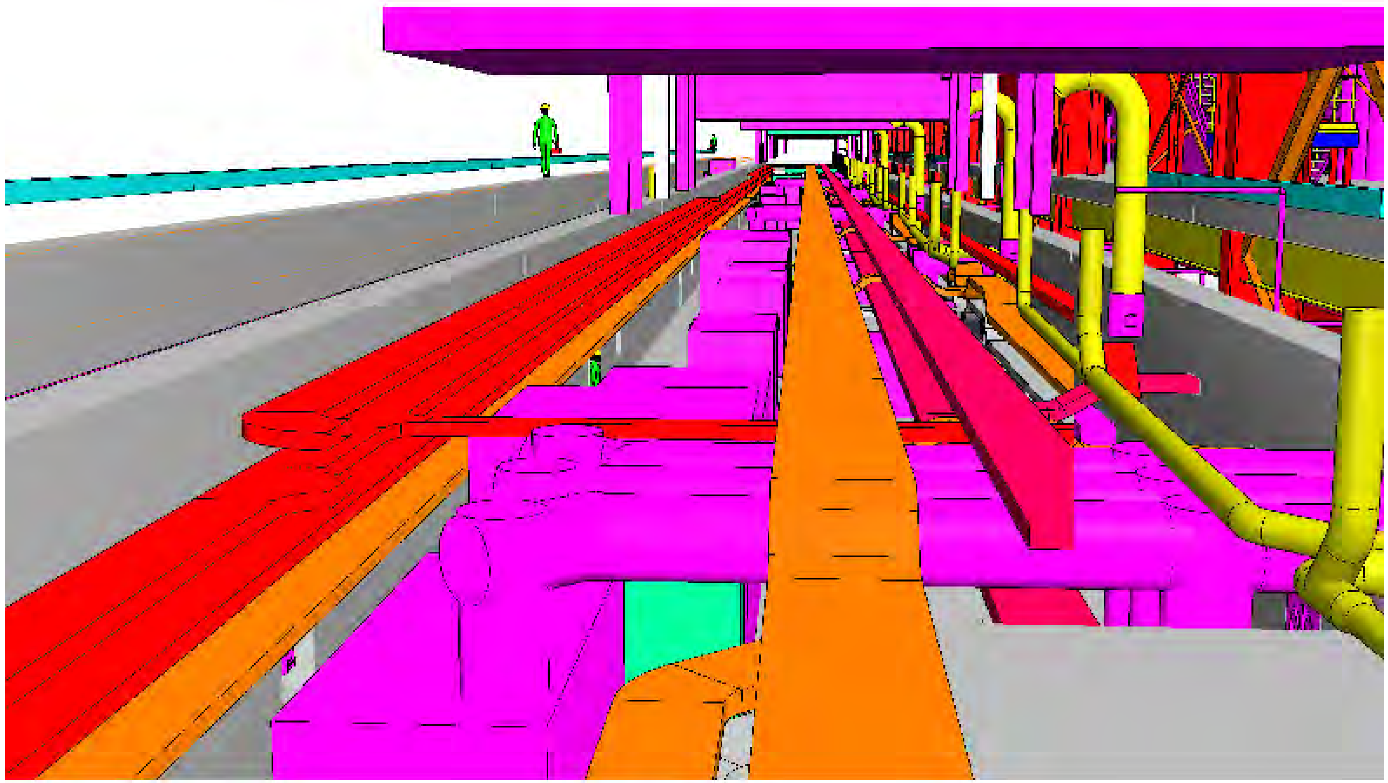
Containment Dykes

Electrical and Mechanical



Electrical and Mechanical

Include E&M works in the GCC



Lessons Learned (PdB and Wuskwatim)

- Include E&M works in the GCC
- Allow time to develop work plans
- Manage engineering to ensure efficient construction
- Initial bid price is not equal to the target price
- Bonuses tied to leading indicators of success
- Market the Contract
- Select a GCC competitively on pricing
- Face time is critical to success.
- Negotiate contract during proposal phase

Project Delivery Strategy

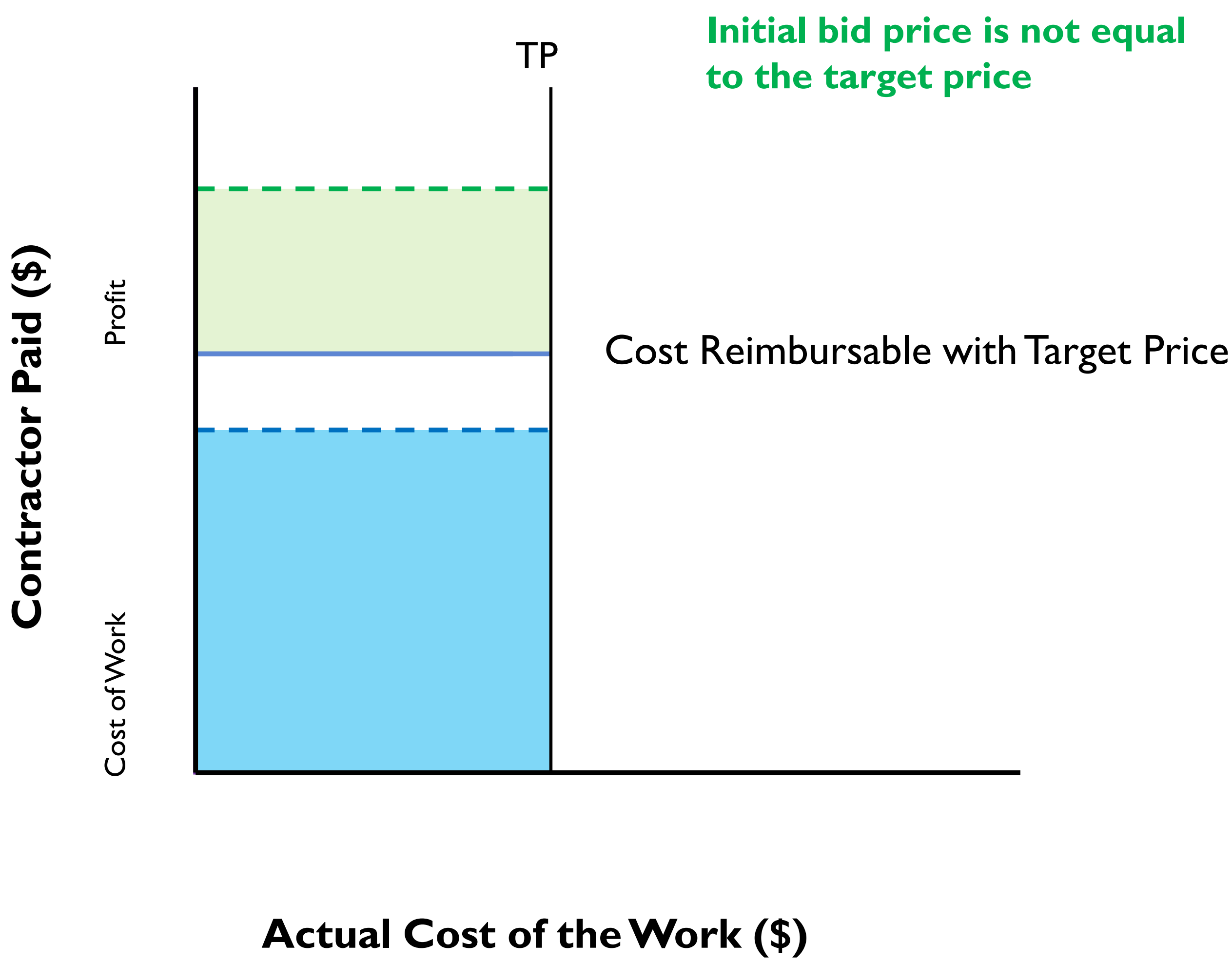
- Early Contractor Involvement (ECI) was selected for the GCC.

Allow time to develop work plans

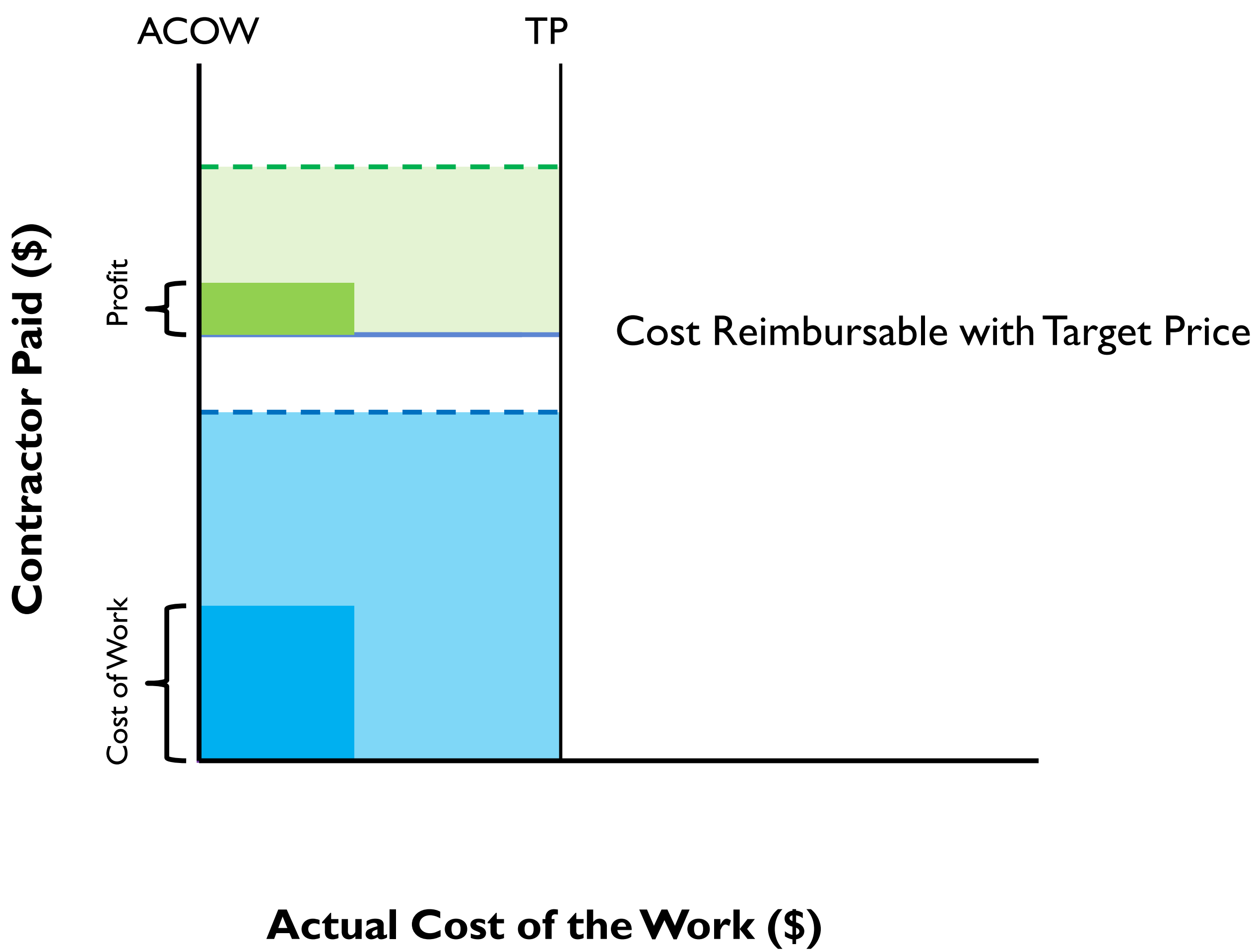
Manage engineering

- Goals of the ECI:
  - Develop Construction Plans
  - Provide opportunity for value engineering and schedule advancements
  - Contractor has a better understanding of our specifications

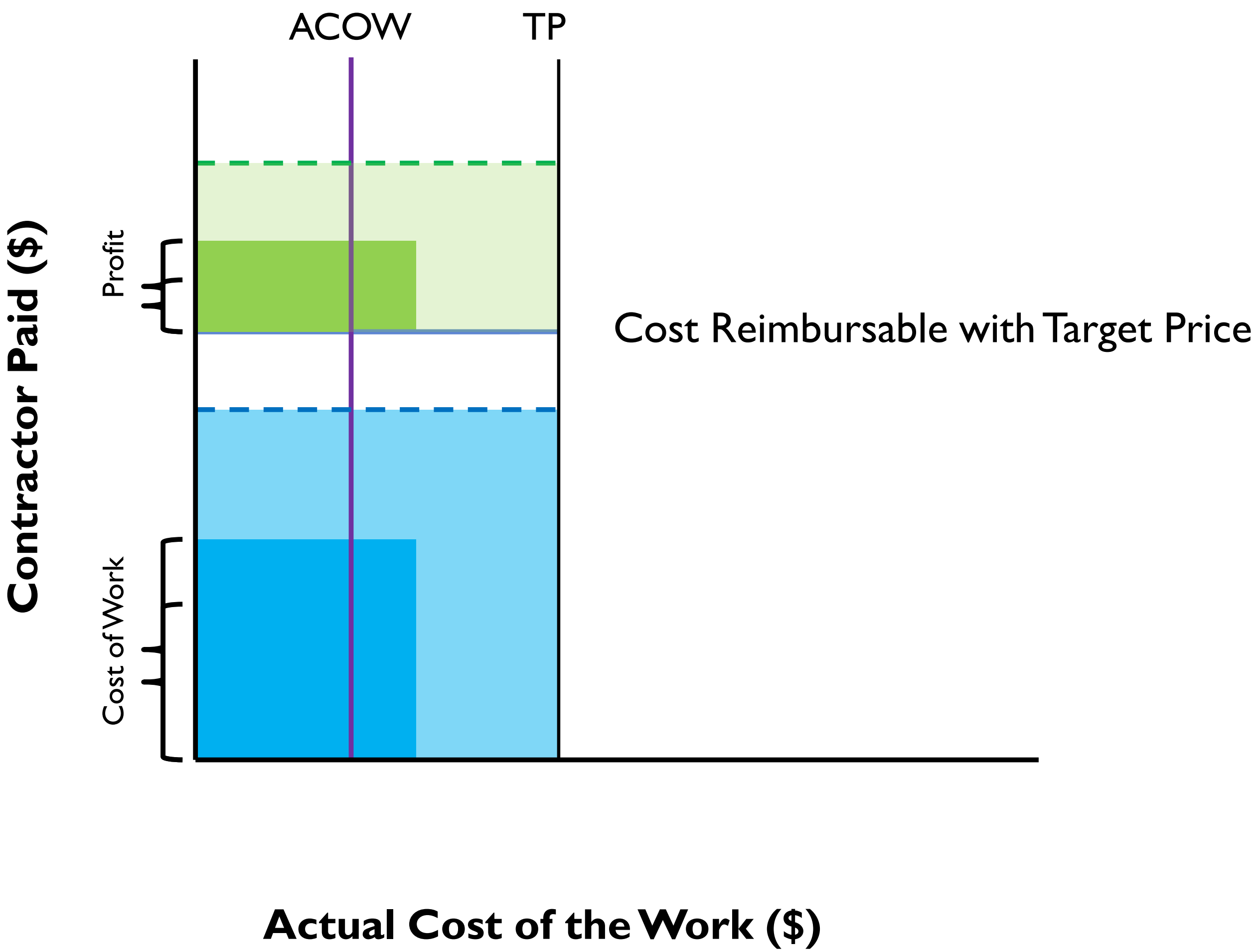
Contract Model



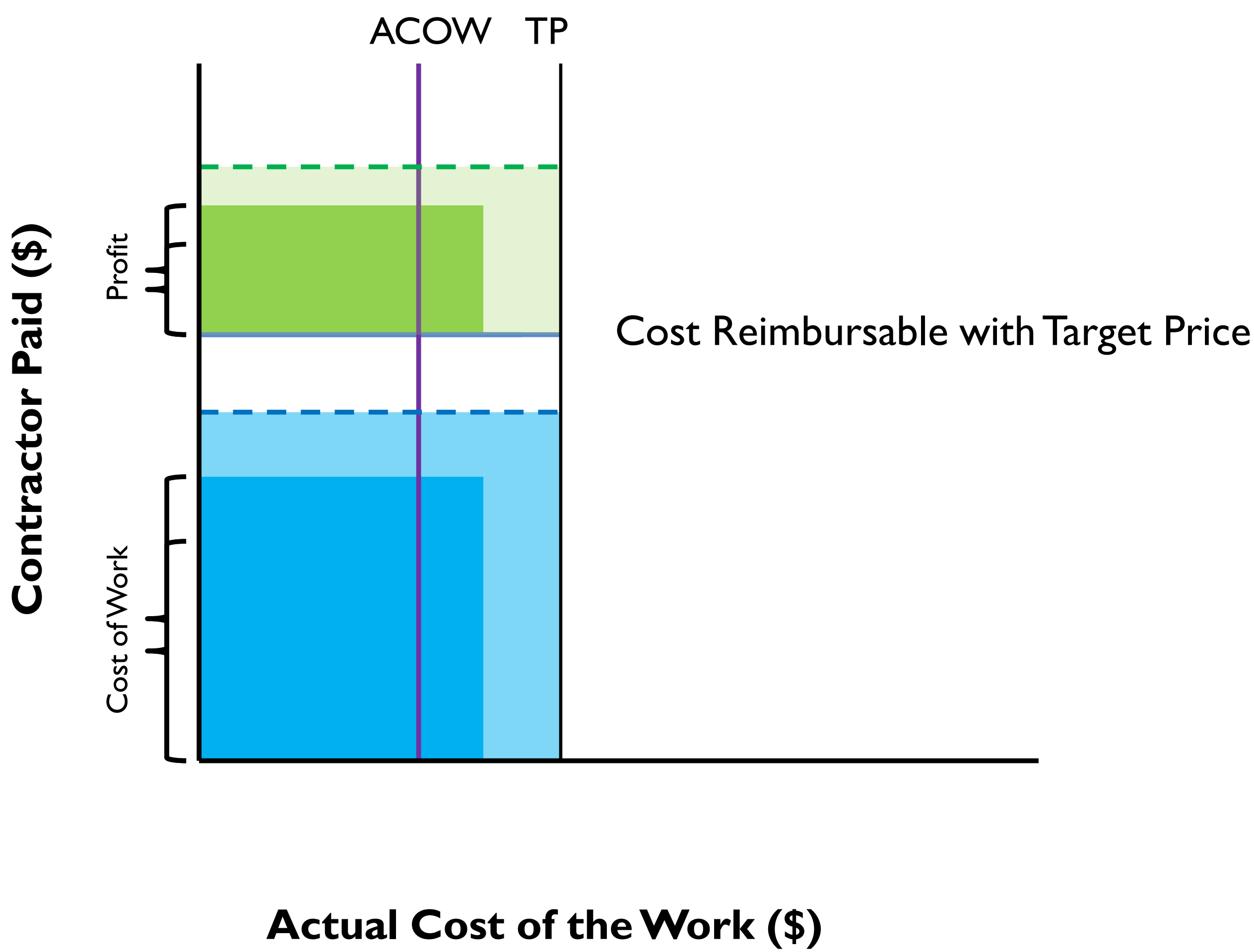
Contract Model



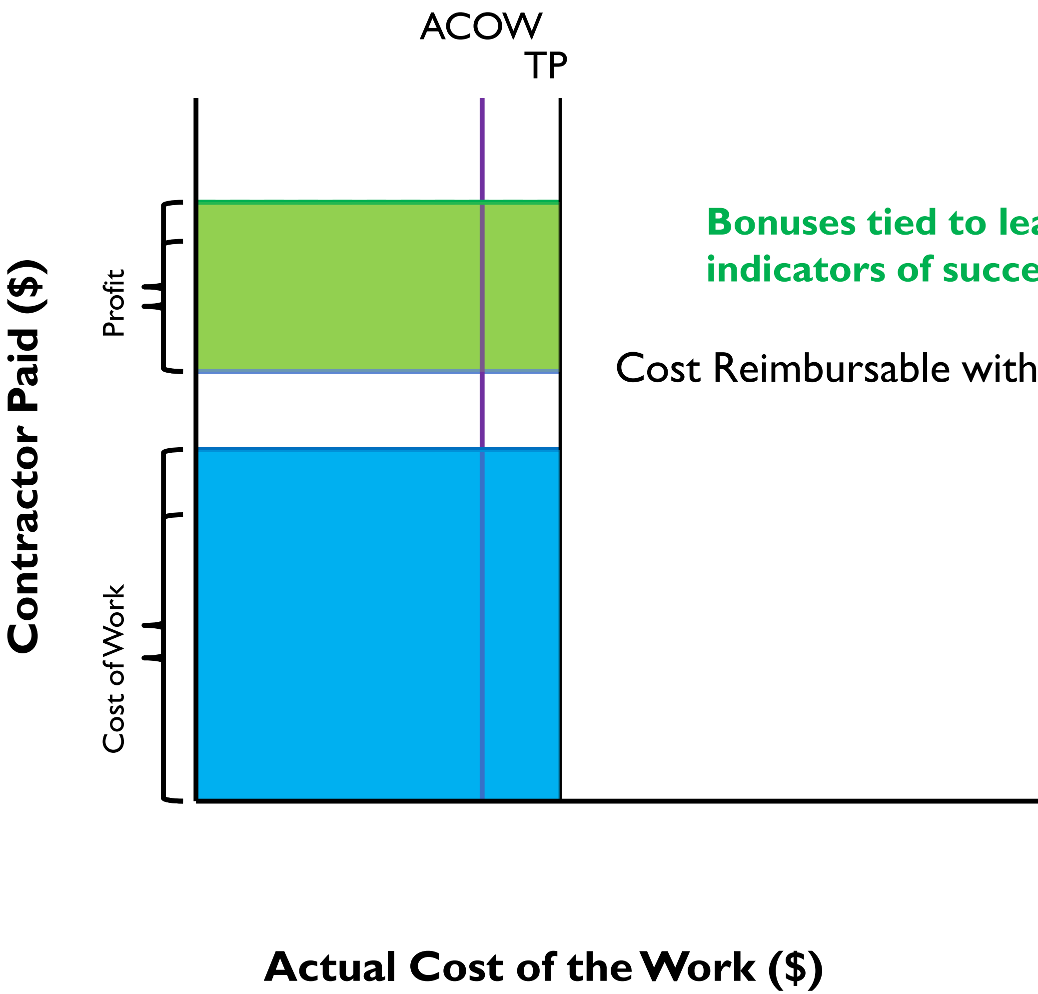
Contract Model



Contract Model



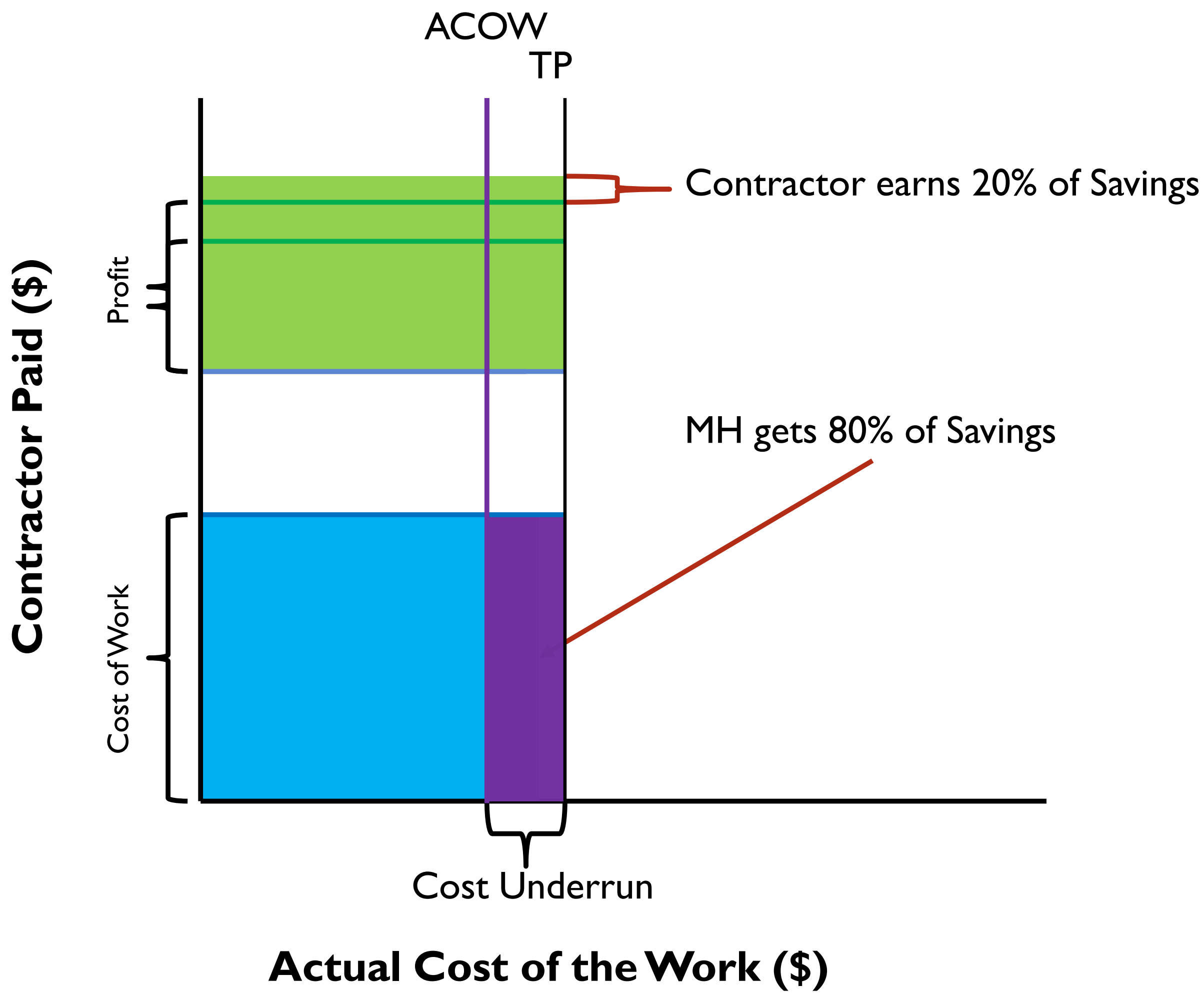
Contract Model



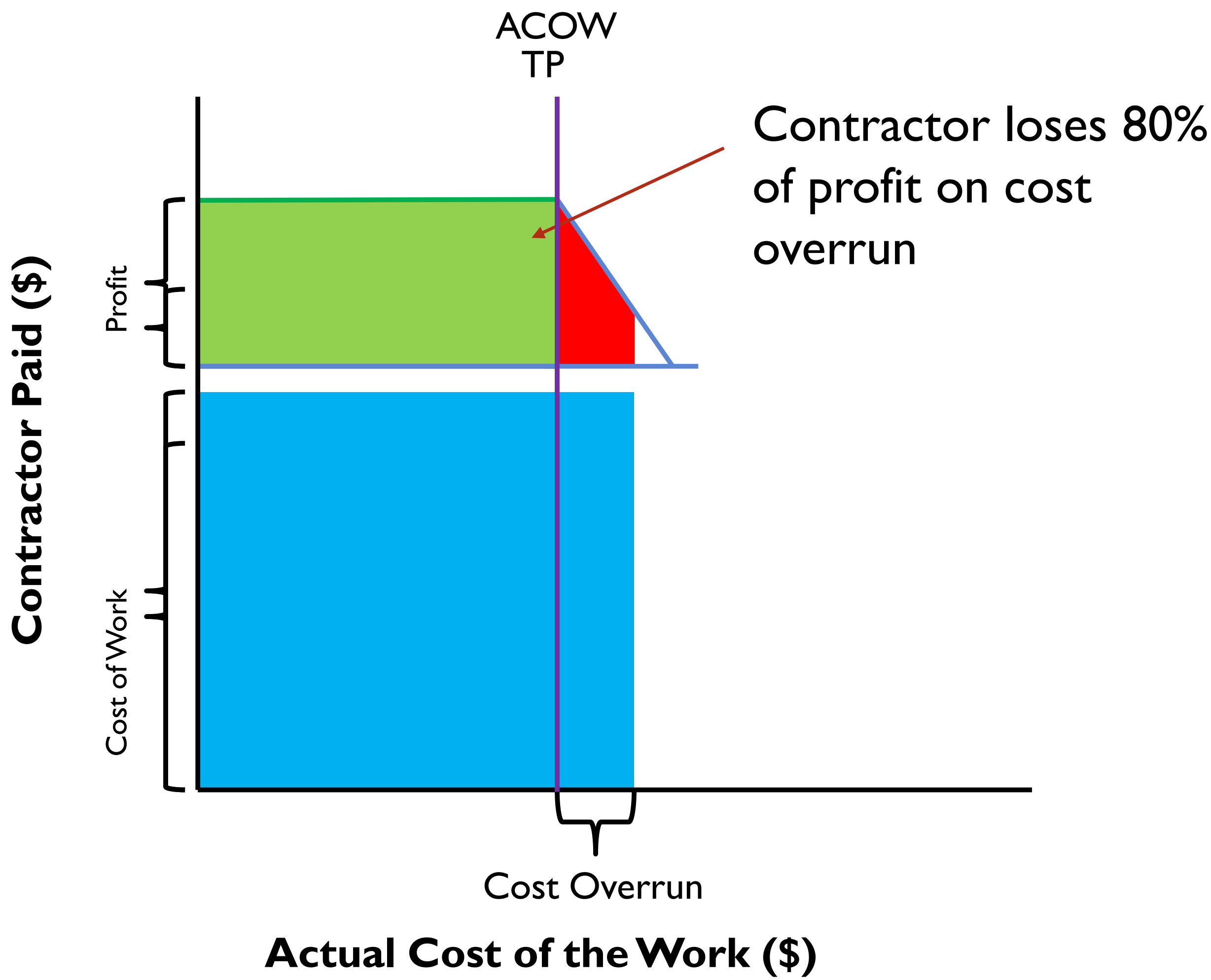
Bonuses tied to leading indicators of success

Cost Reimbursable with Target Price

Contract Model – Below Target



Contract Model – Above Target



GCC Procurement Strategy

- 3-Step Procurement:
- Market Sounding

Market the Contract

- Pre-Qualification Phase
  - 4 of 7 Respondents qualified based on their capacity to meet MH critical success factors

- Proposal Phase

Select GCC competitively on pricing

  - Proposals close December 5th
  - Proposals based on the current design in a competitive process
  - Ensures future changes can be managed based on the competition

Pre-Qualified Proponents (4)

- BBE (JV)
  - Bechtel Canada Co. (lead), Barnard Construction of Canada Ltd. and EllisDon Civil Ltd.
- Dragados/Ledcor/Bird (JV)
  - Dragados (lead), Ledcor & Bird Industrial
- Peter Kiewit Infrastructure Co.
- UAB (JV)
  - URS (lead), Alberici and Black & McDonald

Face time is critical to success

Proposal

- Contractual terms negotiated with the four proponents during the RFP period.

Negotiate contract during proposal phase

- Contractor will be selected based on best value to MH, not strictly based on the Bid Price.

- Proposals will be based on BNA.
  - Will submit recommended modifications to BNA conditions

BNA Modifications

- Proposed changes will likely include:
  - Wage rates
  - Retention incentives
  - Provision for Temporary Foreign Workers

- BNA alternations will improve the project value and project schedule.

Evaluation - Value Adjustments

- Items that will directly impact MH costs:
  - Initial Target Price
  - Corporate Overhead and Profit
  - Benefit for early in-service
  - Penalties for late in-service
  - Changes in camp size
  - Adjustments to other contracts (i.e. T&G)
  - Camp Operating cost
  - Sensitivity adjustment on quantities

Evaluation - Value Adjustments

- Financing cost to proposed cash flow
- Escalation Adjustment
- Cost of Purchaser Delay (1 year)
- Breakage fee for Termination for Convenience
- MB Content

- Quality Items:
  - Project team
  - ECI team
  - Methodology

Project Budget

- Keeyask budget is $6.2B based on a 2019 in-service.

Construction	$3,450 M
Licensing (pre-construction)	$629 M
Interest & Escalation	$1,641 M
Total Budget Authorized to the President	$5,720 M
Management Reserve	$ 500 M
Total Budgeted Cost	$6,220 M

- Use of management reserve requires approval of the board.

GCC Value

- Largest single contract representing half of the construction costs.
- The estimated GCC Purchase Order upset limit is $1.7B.
- Escalation and taxes will be extra.
- May require additional top up from the $500 Management Reserve due to potential BNA changes.

Timeline of Procurement Process

Item	Date
RFP Close	December 5
RFP Evaluations	Dec to Jan
Negotiations with Preferred Proponent	January
Board Recommendation	February
Award Contract	March 4
Construction Start	June 29

February Board Recommendation

- The recommendation will be a value higher than the target price.

- The recommendation will be in the range of $1.7B plus additional top up from the Management Reserve to cover any BNA changes.

Questions?

EXECUTIVE COMMITTEE RECOMMENDATION

SUBJECT:

Keeyask Project – General Civil Works Contract 016203

RECOMMENDATION:

That the Executive Committee recommend to the Manitoba Hydro Electric Board that it approve a contract to the Bechtel Barnard EllisDon joint venture at a price not to exceed [redacted] excluding taxes and escalation.

BACKGROUND:

In March of 2013 four proponents were prequalified to submit a proposal. The proponents included Bechtel Barnard EllisDon joint venture (BBE), Peter Kiewit Infrastructure (PKI), Dragados Ledcor Bird (DLB) and URS, Alberici and Black and MacDonald (UAB). A request for proposal (RFP) was issued to the four proponents on June 7, 2013 with a closing date of December 5, 2013. All four proponents submitted a proposal.

The scope of work for the General Civil Contract includes: river management, rock and unclassified excavation, concrete for the powerhouse and spillway, earth structures and electrical and mechanical works.

The contract is a cost reimbursable, target price contract with an Early Contractor Involvement (ECI) process. In this model, Manitoba Hydro pays the actual cost of the work, but the Contractor is at risk to the limit of the profit and bonus for any target price overruns. Any target price under run is shared, 80% to Hydro and 20% to the Contractor. The ECI will allow the contractor to influence the design for constructability resulting in lower risk and possible cost savings. The ECI will also be used to develop the construction sequence so the site team is better prepared to deliver the project on schedule.

The Initial Target Price (ITP) for the four proposals is outlined below. This includes the Contractors profit percentage and General Administration and Overhead (GA&O).

	BBE	DLB	UAB	PKI
ITP	[redacted]	[redacted]	[redacted]	[redacted]

BBE has the best evaluated cost and demonstrated that they have the knowledge and experience to complete the work. BBE indicated they are willing to enter into a contract with Manitoba Hydro based on the negotiated commercial conditions.

The initial target price of [redacted] is greater than our point estimate of [redacted] and requires the addition of [redacted] from the contingency pool. The upset limit of the Purchase Order consists of the following items:

A) Purchase Order (external) = Initial Target Price:	[redacted]
B) Contractors Bonus	[redacted]
C) Contingency for Manitoba Hydro held risks – this includes quantity variation, engineering scope changes, permitting, Purchaser caused delay, force majeure, etc.	[redacted]
Purchase Order Upset Limit (internal)	[redacted]

JUSTIFICATION:

Bechtel is an experienced contractor and was involved in the construction of the civil works for the Limestone Generating Station. Bechtel also has experience gained from other dam construction projects. Barnard brings extensive experience in construction of large earth structures and has demonstrated they utilize modern technology to manage large earthmoving projects. EllisDon has local experience with the labour markets in Manitoba and Canada with the recent completion of the Winnipeg International Airport.

BBE demonstrated a good understanding of the scope of work in their proposal and during the proponent presentations. They are the lowest cost and offer the best value to the project.

RISKS:

If BBE does not achieve productivity estimates the $0.[redacted]B labour management reserve would have to be used. Concrete productivity assumptions are the primary difference between their price and the price of the other proponents. BBE demonstrated they are carrying contingency for this risk and will work with Manitoba Hydro during the Early Contractor Involvement (ECI) phase to develop plans to recover the schedule in the winter for productivity shortfalls. The contractor is at risk to repay their profit when the target price is exceeded.

Attachments

Table 1: Details of Purchase Order Upset Limit
Table 2: BBE Relevant Project Experience

Table 1: Details of Purchase Order Upset Limit

Initial Target Price	[redacted]
Contractors Bonus	[redacted]
Contingency for Manitoba Hydro held risks – This includes quantity variation, engineering scope changes, permitting, Purchaser caused delay, force majeure, etc. • Quantity Risk – (5% for concrete works, 10% for dams, 15% for embankment dykes, 25-100% for electrical and mechanical works, 20% for cofferdams, 10% for rock and unclassified excavation). • Contract Changes (Extra Work Orders & Change Orders, including contractors profit and Indirects.) Wuskwatim experienced 5% change; therefore carry 5% of ITP. • Purchaser Caused Delays (forest fires, civil unrest, blockades, contract interface issues, etc.) – Carry 2% of ITP.	[redacted] [redacted] [redacted]
Total Purchase Order Upset Limit (internal)	[redacted]

Table 2: BBE Relevant Project Experience

Project - yr completed	Concrete Volume (cubic meters)	Earthwork Volume (cubic meters)	Contract Value	Other Information
Bechtel				
Limestone Generating Station - 1992	650,000	7,100,000	$236 M	Lead JV partner
Itiquira Hydro	77,000	5,500,000		Bechtel provided supervisory personnel, and were responsible for complete direct-hire construction
James Bay Hydro - 1985	1,800,000	203,000,000	$5.8B	Lead JV partner
Kemano Completion Project	3,500	16,000		Prime Contractor
Prairie State Energy Campus - 2012	125,000	2,000,000		Prime Contractor
Surmont Phase 2		2,500,000		Prime Contractor
Ankara – Gerede Motorway Turkey Highway, Bridges - 1998	1,273,000		$1.22B	Integrated JV
Jamnagar Refinery Complex Port, India - 2000	1,200,000		$6B+	Engineering, procurement, project management, and construction consulting
Muscat International Airport, Oman - Current	473,300 of 505,500 placed		$1.8B	Prime Contractor
CSPC Nanhai Petrochem Complex, China - 2006	413,000		$3.0B	Prime Contractor
Croatian Motorway, Croatia - 2004	400,000		738 M Eur	Managing Construction and Design
Khursaniyah Gas Plant Saudi Arabia - 2008	314,000		$3.0B	Prime Contractor
Antamina Peru Dam Excavation - 2001	165,000			Prime Contractor
ALMA Smelter, Canada - 2001	165,000		$1.7 B	Construction, engineering & management
Tacoma Narrows	136,000		$482M	Engineering, procurement,

Suspension Bridge, US - 2007				construction, and project management
Fjardaal Aluminum Smelter - Iceland - 2007	135,322		$1.8 B	Prime Contractor
Barnard				
Saluda Dam Remediation, US - 2006	1,000,000 RCC, 23,000 concrete	11,500,000		Prime Contractor
Snoqualmie Falls Hydro, US - 2013				Prime Contractor
EAA A-1 Reservoir, US - 2006		18,750,000	$400M US	Joint Venture
Los Vaqueros Reservoir, US - 2012	5,200	795,500	$35.3M	Prime Contractor
Gilboa Dam Reconstruction Project, US - Current	84,000		$122M	Prime Contractor
Blue Lake Expansion Project, US - Current	9,230		$89M	Prime Contractor
EllisDon				
Strachan Avenue Overpass - 2014	17,500	224,000	$177M	Prime Contractor
Union Station Subway - 2015	10,000	40,000	$142M	Prime Contractor
Calgary International Airport - 2015	85,000	470,000	$1.4B	Prime Contractor
Winnipeg International Airport - 2010			$366M	Prime Contractor
Seymour Generating Station			$6.3M	Prime Contractor

EXECUTIVE COMMITTEE
MINUTES OF MEETING

Held 2014 02 25 at 8:30 a.m.
in the President's Meeting Room, 22nd floor, 360 Portage Avenue, Winnipeg

1476.02 ***Keeyask GS***

The President reviewed a paper dealing with the award of the Keeyask General Civil Contract and the implications of the contract value being higher than planned. It was agreed that the contract price should be shared with the Board and with the Public Utilities Board at the NFAT review. It was further agreed that, despite the reduced level of profitability, there continues to be a net economic benefit as well as intangible benefits and benefits for Manitobans for proceeding with Keeyask as planned.

BOARD RECOMMENDATION

SUBJECT:

Keeyask Project – General Civil Works Contract 016203

RECOMMENDATION:

That the Manitoba Hydro Electric Board approve a contract to the Bechtel Barnard EllisDon joint venture at a price not to exceed [redacted] excluding taxes and escalation.

BACKGROUND:

In March of 2013 four proponents were prequalified to submit a proposal. The proponents included Bechtel Barnard EllisDon joint venture (BBE), Peter Kiewit Infrastructure (PKI), Dragados Ledcor Bird (DLB) and URS, Alberici and Black and MacDonald (UAB). A request for proposal (RFP) was issued to the four proponents on June 7, 2013 with a closing date of December 5, 2013. All four proponents submitted a proposal.

The scope of work for the General Civil Contract includes: river management, rock and unclassified excavation, concrete for the powerhouse and spillway, earth structures and electrical and mechanical works.

The contract is a cost reimbursable, target price contract with an Early Contractor Involvement (ECI) process. In this model, Manitoba Hydro pays the actual cost of the work, but the Contractor is at risk to the limit of the profit and bonus for any target price overruns. Any target price under run is shared, 80% to Hydro and 20% to the Contractor. The ECI will allow the contractor to influence the design for constructability resulting in lower risk and possible cost savings. The ECI will also be used to develop the construction sequence so the site team is better prepared to deliver the project on schedule.

The Initial Target Price (ITP) for the four proposals is outlined below. This includes the Contractors profit percentage and General Administration and Overhead (GA&O).

	BBE	DLB	UAB	PKI
ITP	[redacted]	[redacted]	[redacted]	[redacted]

BBE has the best evaluated cost and demonstrated that they have the knowledge and experience to complete the work. BBE indicated they are willing to enter into a contract with Manitoba Hydro based on the negotiated commercial conditions.

The initial target price of [redacted] is greater than our point estimate of [redacted] and requires the addition of [redacted] from the contingency pool. The upset limit of the Purchase Order consists of the following items:

A) Purchase Order (external) = Initial Target Price:	[redacted]
B) Contractors Bonus	[redacted]
C) Contingency for Manitoba Hydro held risks – this includes quantity variation, engineering scope changes, permitting, Purchaser caused delay, force majeure, etc.	[redacted]
Purchase Order Upset Limit (internal)	[redacted]

JUSTIFICATION:

Bechtel is an experienced contractor and was involved in the construction of the civil works for the Limestone Generating Station. Bechtel also has experience gained from other dam construction projects. Barnard brings extensive experience in construction of large earth structures and has demonstrated they utilize modern technology to manage large earthmoving projects. EllisDon has local experience with the labour markets in Manitoba and Canada with the recent completion of the Winnipeg International Airport.

BBE demonstrated a good understanding of the scope of work in their proposal and during the proponent presentations. They are the lowest cost and offer the best value to the project.

RISKS:

If BBE does not achieve productivity estimates the $0[redacted]B labour management reserve would have to be used. Concrete productivity assumptions are the primary difference between their price and the price of the other proponents. BBE demonstrated they are carrying contingency for this risk and will work with Manitoba Hydro during the Early Contractor Involvement (ECI) phase to develop plans to recover the schedule in the winter for productivity shortfalls. The contractor is at risk to repay their profit when the target price is exceeded.

Attachments

Table 1: Details of Purchase Order Upset Limit
Table 2: BBE Relevant Project Experience

Table 1: Details of Purchase Order Upset Limit

Initial Target Price	[redacted]
Contractors Bonus	[redacted]
Contingency for Manitoba Hydro held risks – This includes quantity variation, engineering scope changes, permitting, Purchaser caused delay, force majeure, etc. • Quantity Risk – (5% for concrete works, 10% for dams, 15% for embankment dykes, 25-100% for electrical and mechanical works, 20% for cofferdams, 10% for rock and unclassified excavation). • Contract Changes (Extra Work Orders & Change Orders, including contractors profit and Indirects.) Wuskwatim experienced 5% change; therefore carry 5% of ITP. • Purchaser Caused Delays (forest fires, civil unrest, blockades, contract interface issues, etc.) – Carry 2% of ITP.	[redacted] [redacted] [redacted]
Total Purchase Order Upset Limit (internal)	[redacted]

Table 2: BBE Relevant Project Experience

Keeyask estimated quantities: Concrete: 350,000 cubic meters

Earthworks: 12,400,000 cubic meters

Project - yr completed	Concrete Volume (cubic meters)	Earthwork Volume (cubic meters)	Contract Value	Other Information
Bechtel				
Limestone Generating Station - 1992	650,000	7,100,000	$236 M	Lead JV partner
Itiquira Hydro	77,000	5,500,000		Bechtel provided supervisory personnel, and were responsible for complete direct-hire construction
James Bay Hydro - 1985	1,800,000	203,000,000	$5.8B	Lead JV partner
Kemano Completion Project	3,500	16,000		Prime Contractor
Prairie State Energy Campus - 2012	125,000	2,000,000		Prime Contractor
Surmont Phase 2		2,500,000		Prime Contractor
Ankara – Gerede Motorway Turkey Highway, Bridges - 1998	1,273,000		$1.22B	Integrated JV
Jamnagar Refinery Complex Port, India - 2000	1,200,000		$6B+	Engineering, procurement, project management, and construction consulting
Muscat International Airport, Oman - Current	473,300 of 505,500 placed		$1.8B	Prime Contractor
CSPC Nanhai Petrochem Complex, China - 2006	413,000		$3.0B	Prime Contractor
Croatian Motorway, Croatia - 2004	400,000		738 M Eur	Managing Construction and Design
Khursaniyah Gas Plant Saudi Arabia - 2008	314,000		$3.0B	Prime Contractor

Antamina Peru Dam Excavation - 2001	165,000			Prime Contractor
ALMA Smelter, Canada - 2001	165,000		$1.7 B	Construction, engineering & management
Tacoma Narrows Suspension Bridge, US - 2007	136,000		$482M	Engineering, procurement, construction, and project management
Fjardaal Aluminum Smelter - Iceland - 2007	135,322		$1.8 B	Prime Contractor
Barnard				
Saluda Dam Remediation, US - 2006	1,000,000 RCC, 23,000 concrete	11,500,000		Prime Contractor
Snoqualmie Falls Hydro, US - 2013				Prime Contractor
EAA A-1 Reservoir, US - 2006		18,750,000	$400M US	Joint Venture
Los Vaqueros Reservoir, US - 2012	5,200	795,500	$35.3M	Prime Contractor
Gilboa Dam Reconstruction Project, US - Current	84,000		$122M	Prime Contractor
Blue Lake Expansion Project, US - Current	9,230		$89M	Prime Contractor
EllisDon				
Strachan Avenue Overpass - 2014	17,500	224,000	$177M	Prime Contractor
Union Station Subway - 2015	10,000	40,000	$142M	Prime Contractor
Calgary International Airport - 2015	85,000	470,000	$1.4B	Prime Contractor
Winnipeg International Airport - 2010			$366M	Prime Contractor
Seymour Generating Station			$6.3M	Prime Contractor

COMMUNICATIONS IMPLICATIONS:

None.

MINUTES OF MEETING of The Manitoba Hydro-Electric Board held on Wednesday, February 26, 2014, at 8:30 a.m. in the Boardroom, 22nd floor, 360 Portage Avenue, Winnipeg.

845-14-06

G.P.F. Schick and R.J Wittebolle entered the meeting and reviewed a submission dated 2014 02 24 dealing with the award of the Keeyask General Civil Works contract. It was noted that there are provisions in the contract dealing with the risk of cancellation or delay to commencement of the contract.
Following discussion, the Board resolved as follows:
That the corporation be authorized to award the above contract to Bechtel Barnard EllisDon joint venture, at a price of up to [redacted] billion plus escalation.

Keeyask – General Civil Contract

Keeyask Generating Station
General Civil Contract Procurement

February 26, 2014

Major Capital Projects

Outline

- Scope of Work
- Proponents
- Initial Target Price
- GCC Purchase Order
- Contingency
- Management Reserve
- Labour
- Timeline

Scope of Work

- The Keeyask General Civil Contract (GCC) will be the largest valued construction contract in Manitoba Hydro's history.

- GCC includes:
  - Cofferdam construction & river management
  - Excavation
  - Concrete for Powerhouse Complex and Spillway
  - Earth Dams
  - Containment Dykes
  - Electrical and Mechanical works

Scope of Work

- GCC does not include:
  - Turbine and Generators (awarded to Voith)
  - Intake & Spillway Gates (3 companies Prequalified)
  - Environmental Mitigation
  - Cranes
  - Stoplogs
  - South Access Road (DNC)
  - Forebay Clearing (DNC)

Pre-Qualified Proponents (4)

- BBE (JV)
  - Bechtel Canada Co. (lead), Barnard Construction of Canada Ltd. and EllisDon Civil Ltd.
- Dragados/Ledcor/Bird (JV)
  - Dragados (lead), Ledcor & Bird Industrial
- Peter Kiewit Infrastructure Co.
- UAB (JV)
  - URS (lead), Alberici and Black & McDonald

Initial Target Price (ITP) $Billions

	MH	BBE	DLB	UAB	PKI
Initial Target Price *	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Including GAO and Profit

ITP & PO Upset Limit

Initial Target Price [redacted]

Contractors Bonus [redacted]

Contingency for Manitoba Hydro risk [redacted]

Total Purchase Order Upset Limit (internal) [redacted]*

* escalation and taxes extra

Contingency Breakdown

Quantity Risk – (5% for concrete works, 10% for major earth dams, 15% for containment dykes, 25-100% for electrical and mechanical works, 20% for cofferdams, 10% for rock and unclassified excavation).	[redacted]

Contingency Breakdown

Quantity Risk – (5% for concrete works, 10% for major earth dams, 15% for containment dykes, 25-100% for electrical and mechanical works, 20% for cofferdams, 10% for rock and unclassified excavation).	[redacted]
Contract Changes (Extra Work Orders & Change Orders, including contractors profit and indirects). Wuskwatim experienced 5% change, therefore carry 5% of ITP.	[redacted]

Contingency Breakdown

Quantity Risk – (5% for concrete works, 10% for major earth dams, 15% for containment dykes, 25-100% for electrical and mechanical works, 20% for cofferdams, 10% for rock and unclassified excavation).	[redacted]
Contract Changes (Extra Work Orders & Change Orders, including contractors profit and Indirects). Wuskwatim experienced 5% change, therefore carry 5% of ITP.	[redacted]
Purchaser Caused Delays (forest fires, civil unrest, contract interface issues, etc.) – Carry 2% of ITP.	[redacted]

Contingency Breakdown

Quantity Risk – (5% for concrete works, 10% for major earth dams, 15% for containment dykes, 25-100% for electrical and mechanical works, 20% for cofferdams, 10% for rock and unclassified excavation).	[redacted]
Contract Changes (Extra Work Orders & Change Orders, including contractors profit and Indirects). Wuskwatim experienced 5% change, therefore carry 5% of ITP.	[redacted]
Purchaser Caused Delays (forest fires, civil unrest, contract interface issues, etc.) – Carry 2% of ITP.	[redacted]
Total Contingency	[redacted]

Management Reserve

- Labour Productivity of the concrete is one of the items established as a risk that may require access to the Management Reserve funds.

- If required, KECD will present justification and seek Board approval to access the Management Reserve funds.

BBE ITP Lower than Others

- Controls on Costs
  - Bonus plan to assure reporting is undertaken to MH satisfaction
  - Very steep profit draw down
  - Bonus is returned if target is surpassed
  - ECI to assist in planning and increase probability of success

Labour

- Contract Requirements
  - The Contractor must follow the BNA
  - Manitoba Hydro requirement to utilize a minimum number of Manitoba Resident Level I Apprentices on the Site.
  - Manitoba Hydro requirement to conduct Project Employment Information Sessions.

Labour

- Opportunities

BNA	Hiring Preference
Stage 1	Northern Aboriginals residing in the CBNR area
	Northern Resident Union Members
	Other Northern Aboriginals
	Other Northerners
Stage 2	Manitoba Union Members
Stage 3	Other Manitobans
Stage 4	Others

Labour

- Opportunities
  - The Manitoba Resident Level I Apprentice will follow the BNA hiring preference.
  - Direct Negotiated Contract with Fox and York Keeyask JV to provide Employee Retention Services.
  - Up to 150 opportunities to be created for new people to join the Trades

Labour

- BBE Plan for On-the-Job-Training
  - Develop a project-specific staffing plan tailored to the construction schedule
  - Work with the trades unions to determine labour pool availabilities and assess skill levels
  - Implement measures to utilize people of the region
  - Aggressive utilization of Apprentices and other trade development programs.

Labour

- Once on the job BBE to Provide
  - Safety Training
    - Job Hazard Analysis
    - Aerial Work Platforms
    - Harness Awareness
    - Incident Investigation
    - First Aid
    - Confined Space Entry
    - Working at Heights
  - Environmental Training
  - Apprentice Mentoring Program

Labour

- BNA
  - BBE – No BNA Changes Required
  - Other Proponents Proposed BNA Changes
    - Increase hourly rates by 5 to 35%
    - Change isolation leave from 21/7 to 20/10.
    - Bonus of $2.60 to $15.60/hr paid upon return to site after isolation leave.

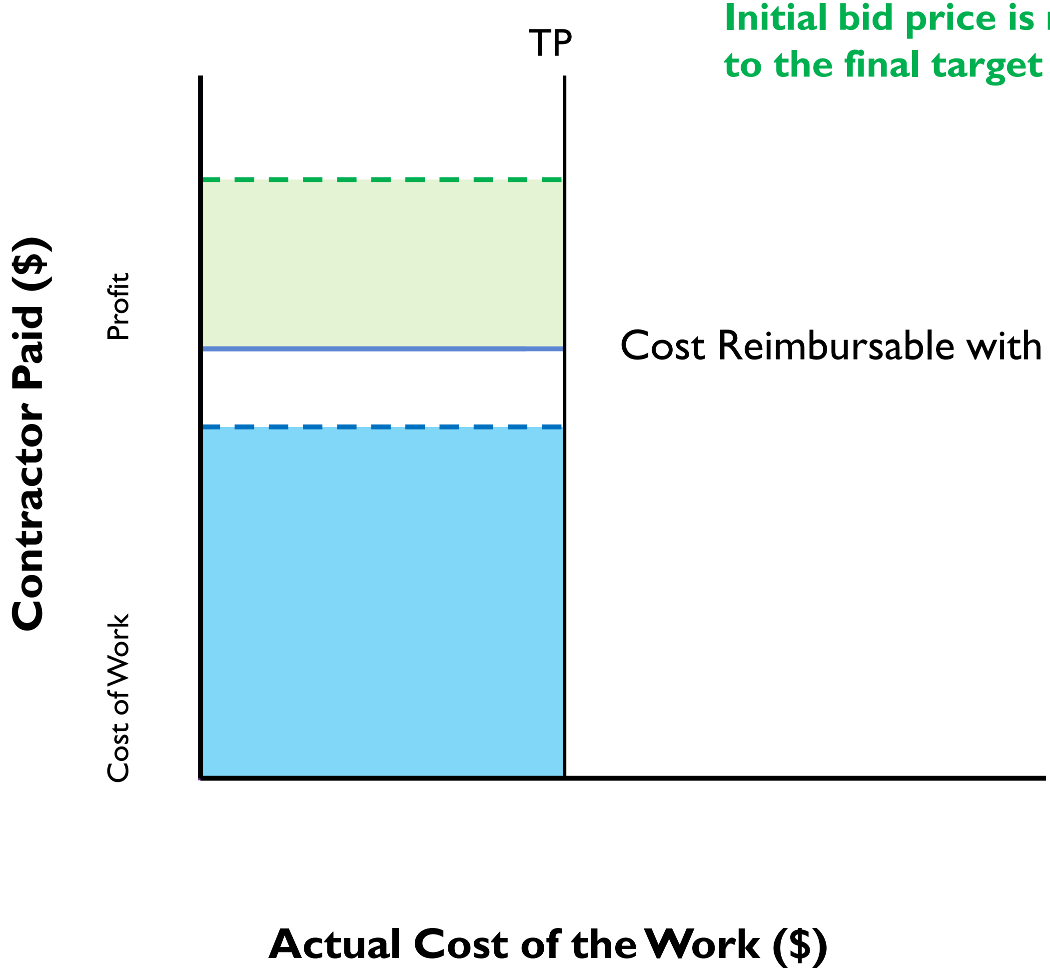
Timeline

- Mar 10th – Contract Signing
- Mar 11th – ECI Mobilization
- June 27th – Order in Council Received and site mobilization for Stage I CD
- July 15th – In-stream work starts
- May 1, 2016 – First Concrete
- November, 2019 – First Power

Questions?

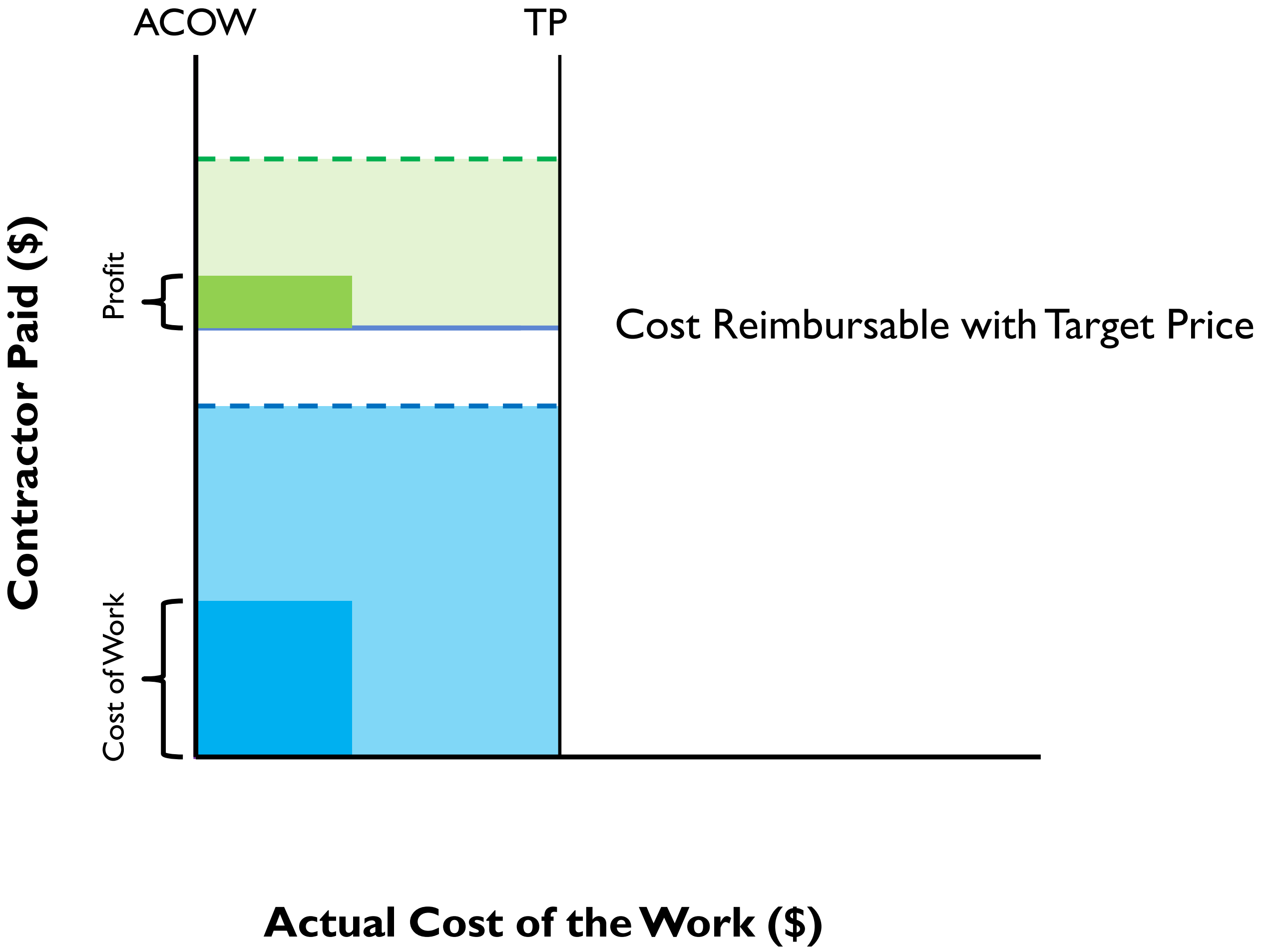
Contract Model

Initial bid price is not equal to the final target price

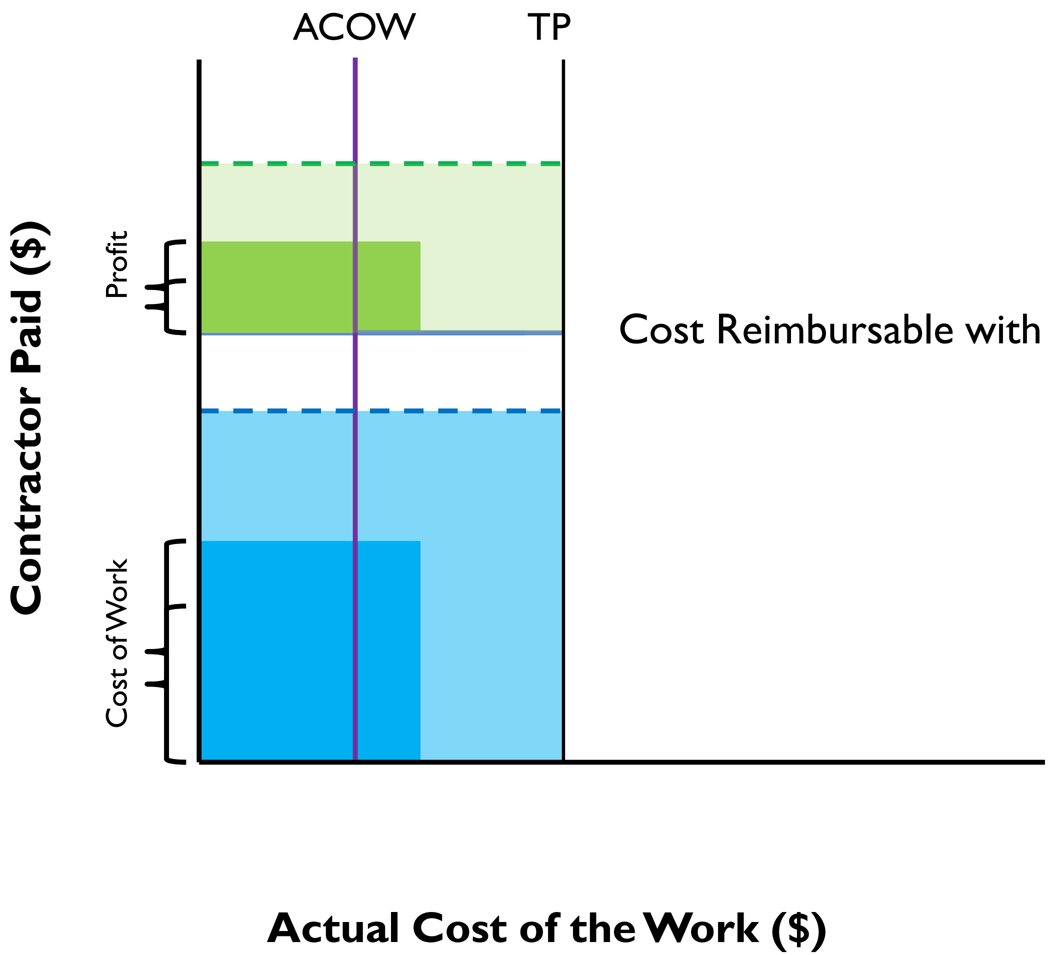


Cost Reimbursable with Target Price

Contract Model

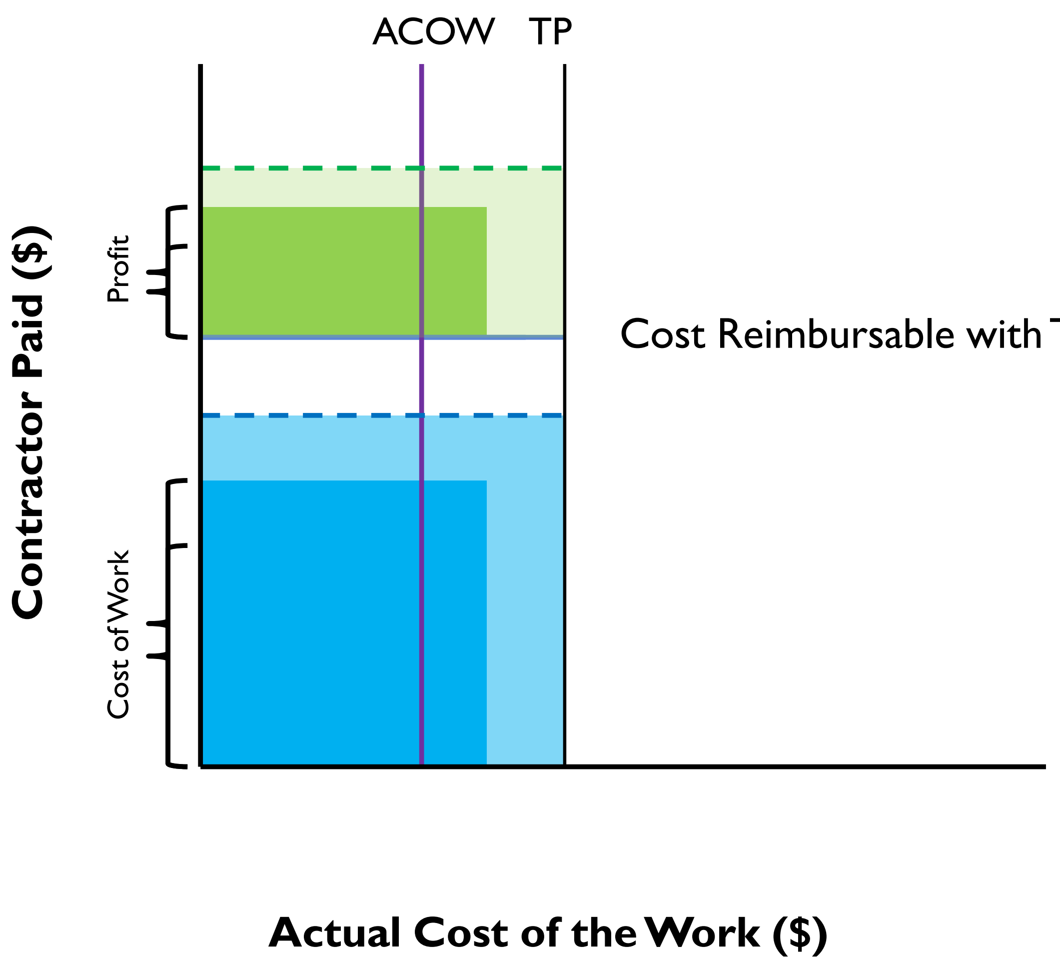


Contract Model



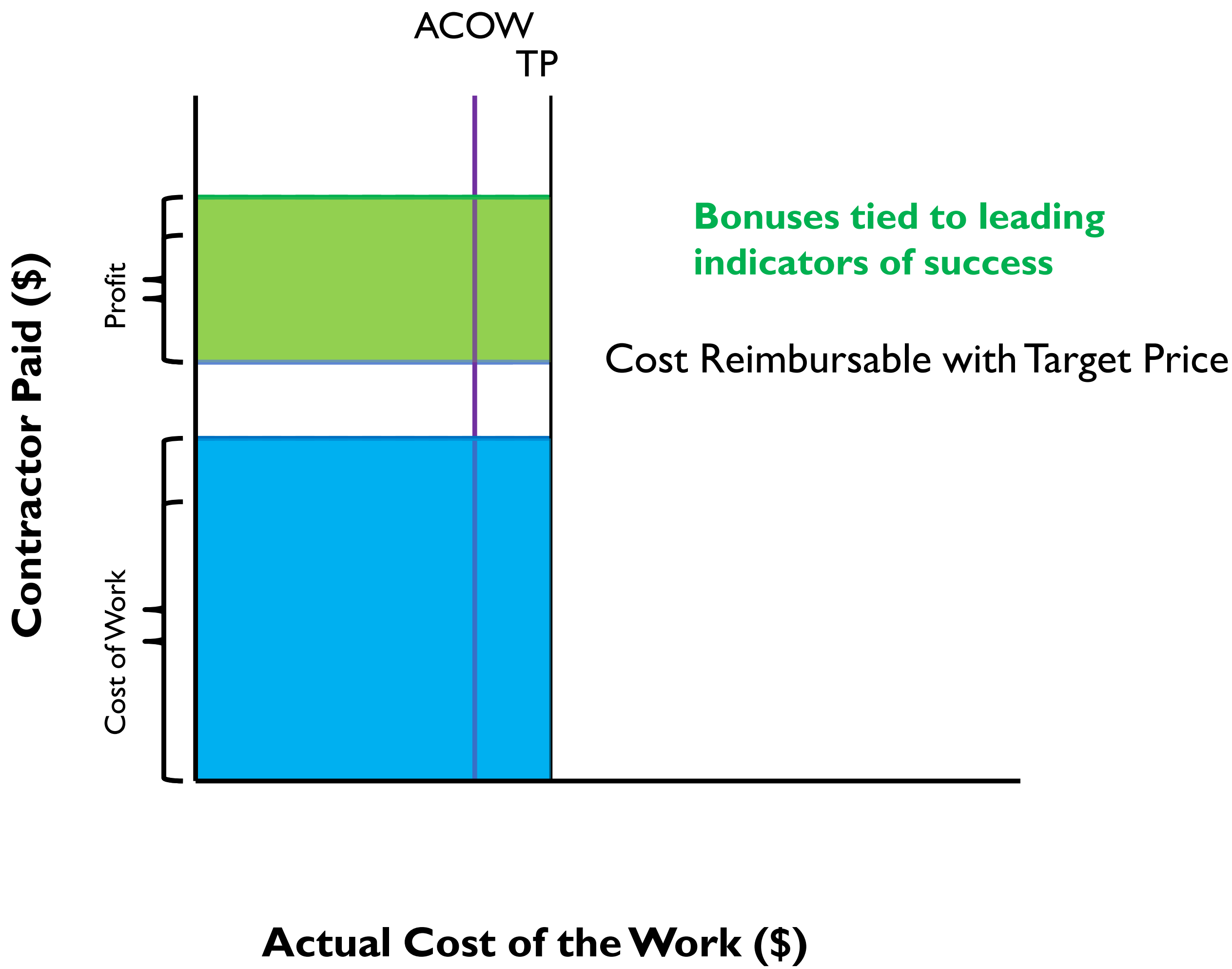
Cost Reimbursable with Target Price

Contract Model

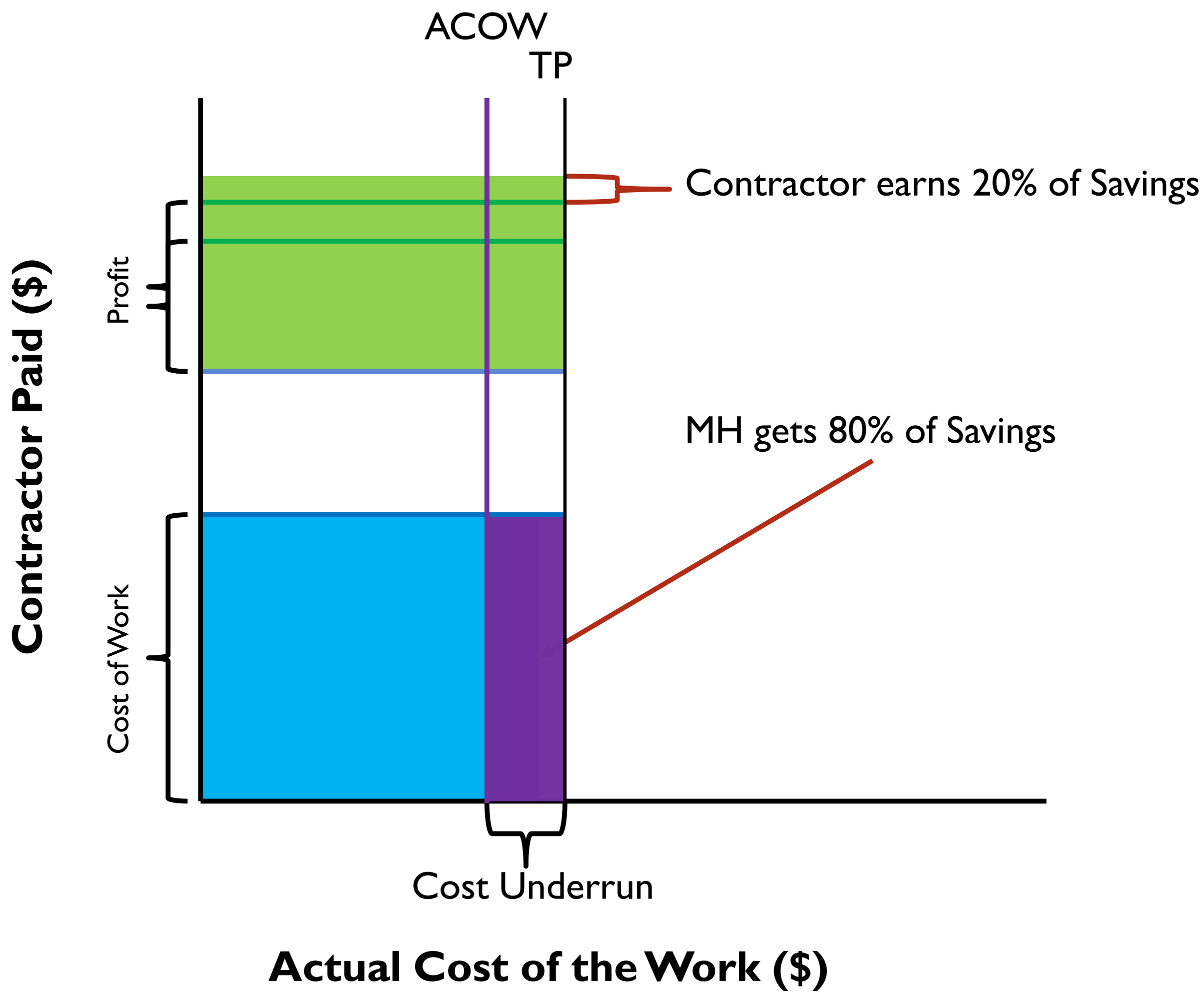


Cost Reimbursable with Target Price

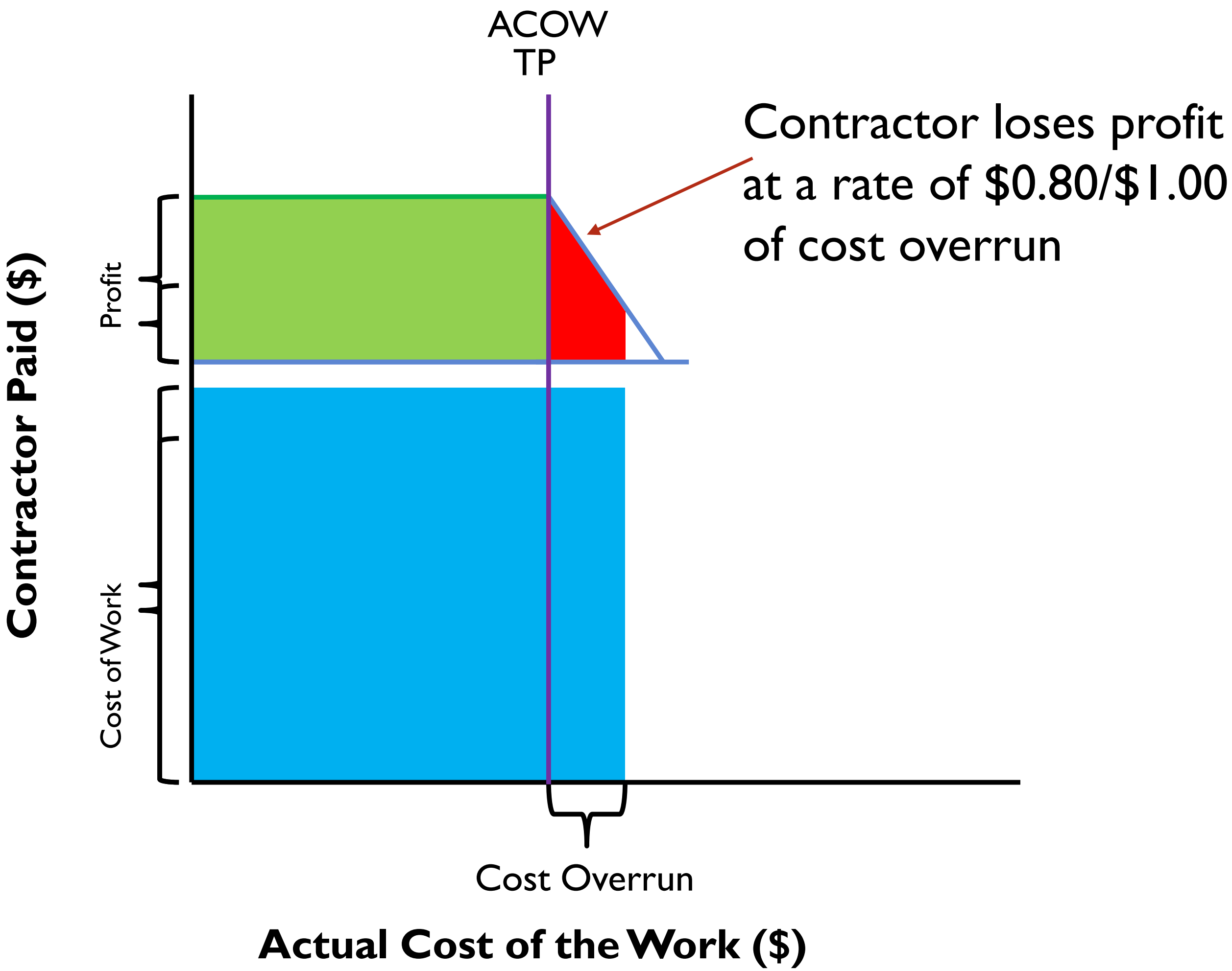
Contract Model



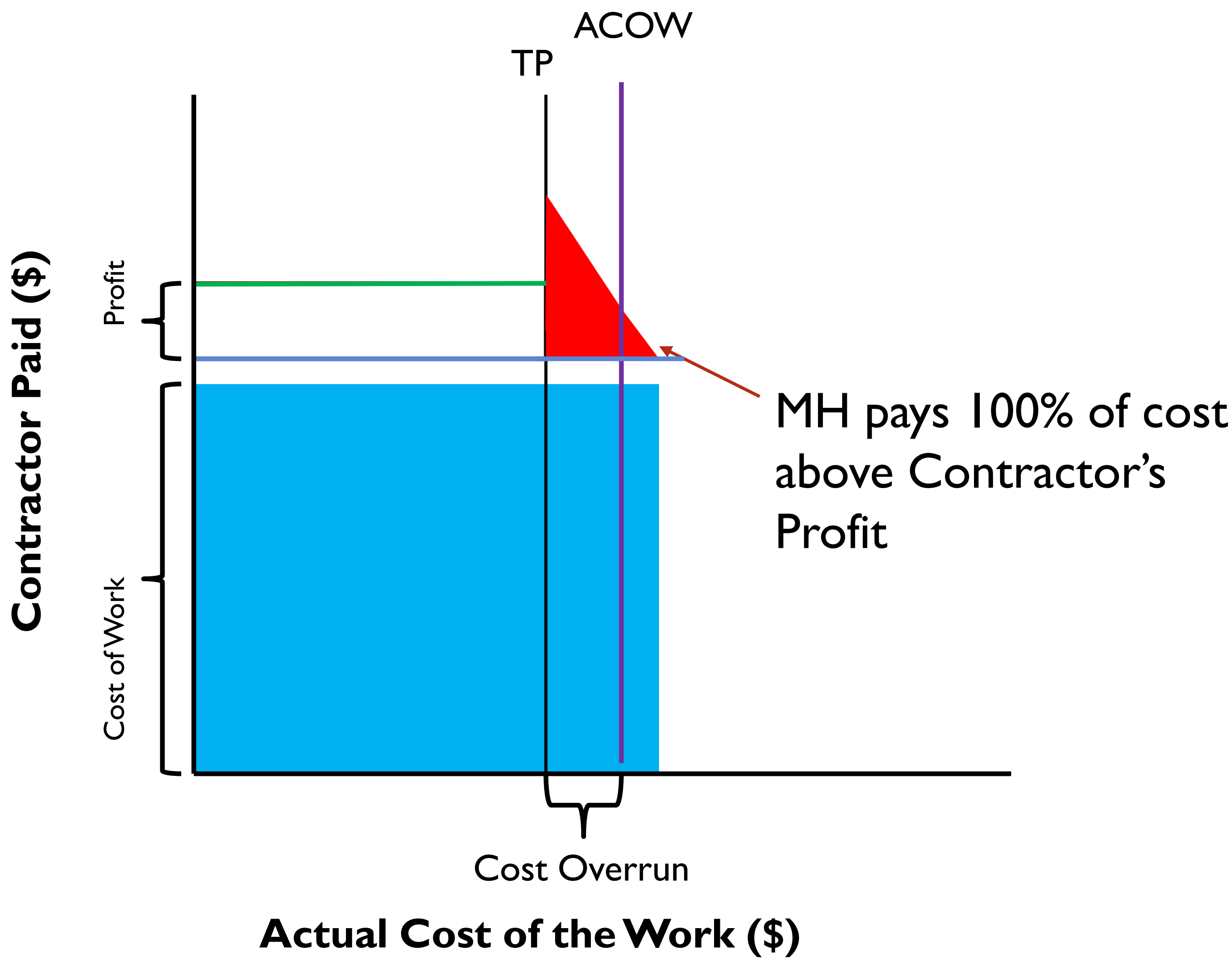
Contract Model – Below Target



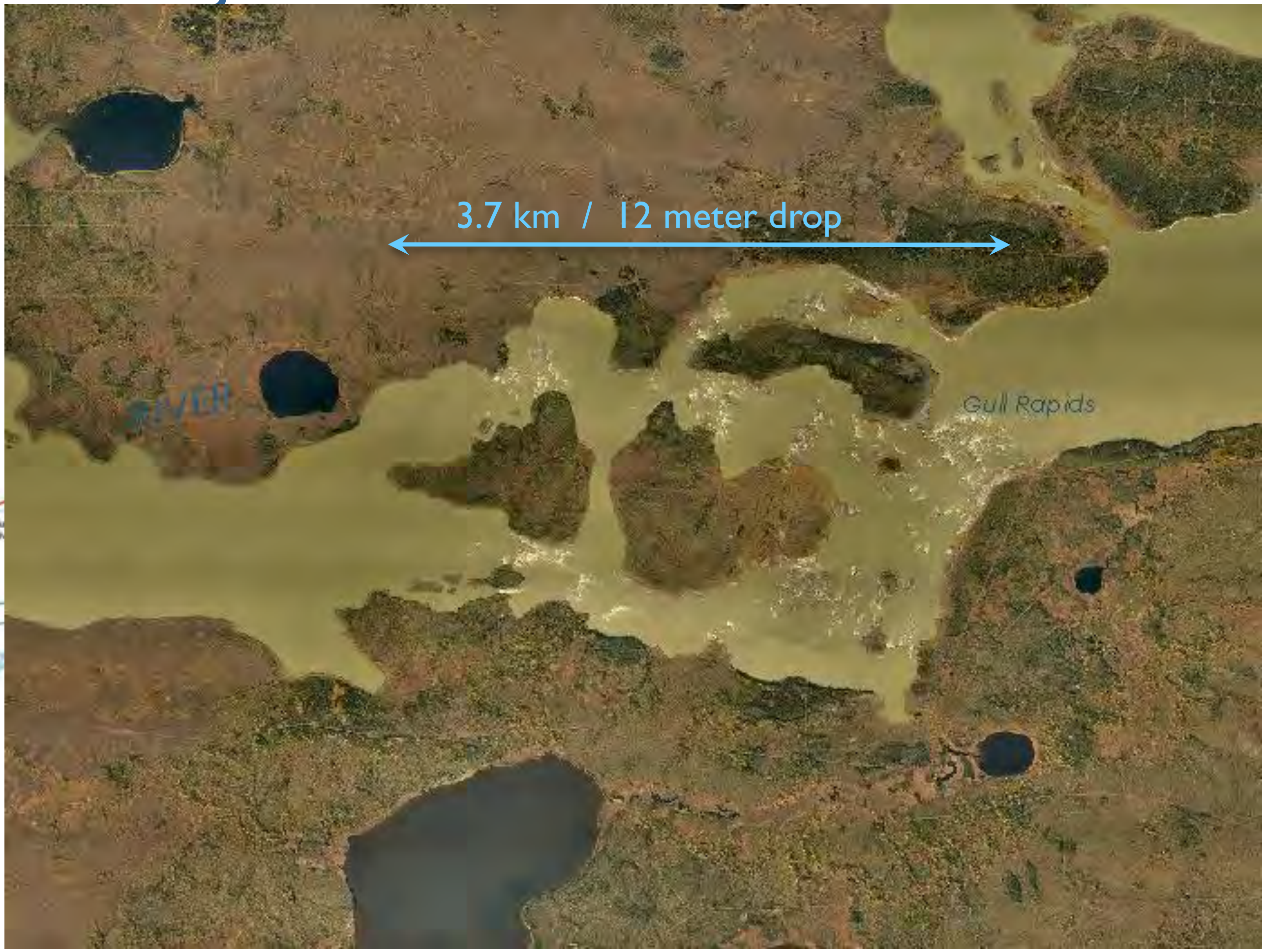
Contract Model – Above Target



Contract Model – Above Target



Project Location



Principal Structures

Cofferdam/River Management

Excavation

Powerhouse Complex and Spillway


KEEYASK

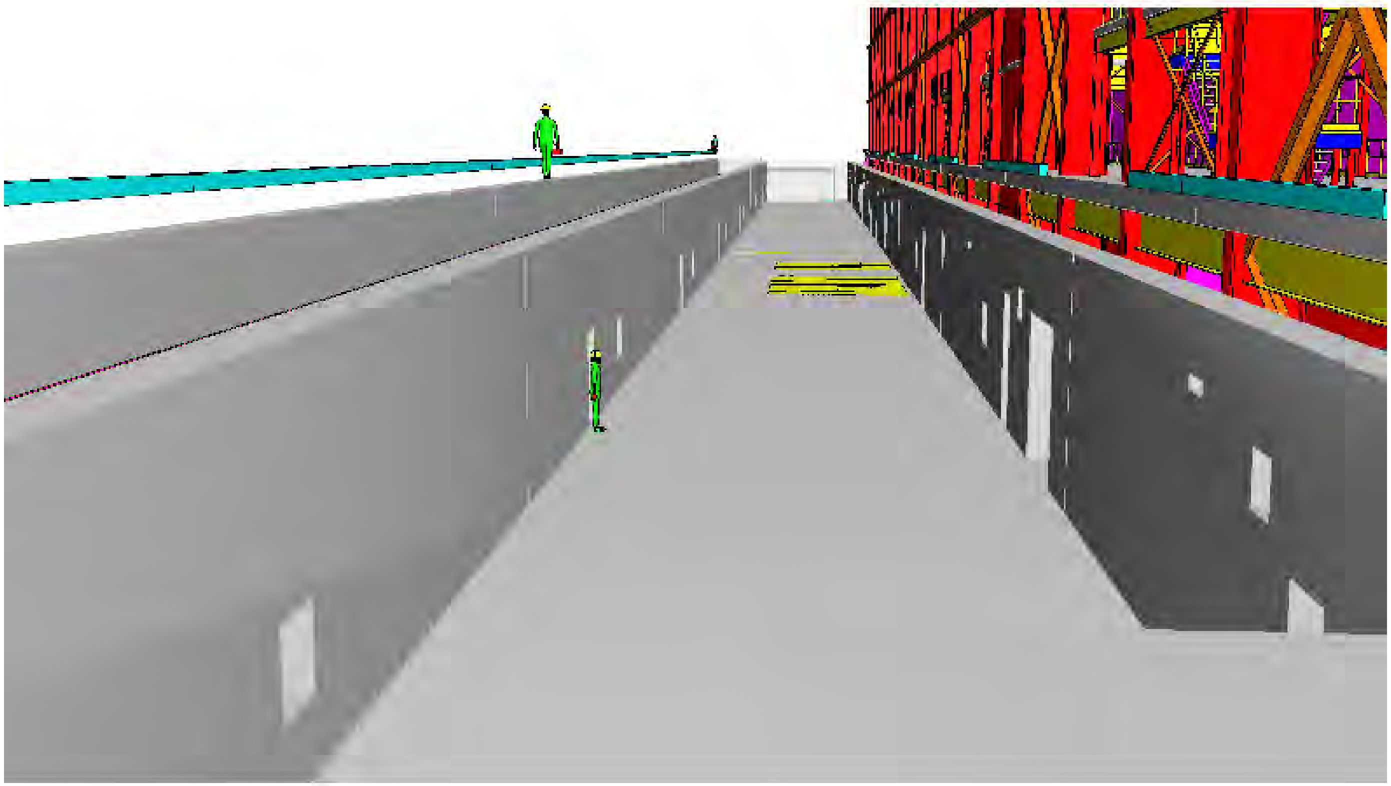
Earth Dams


2010/ 8/ 7


09 07 2011 14 57

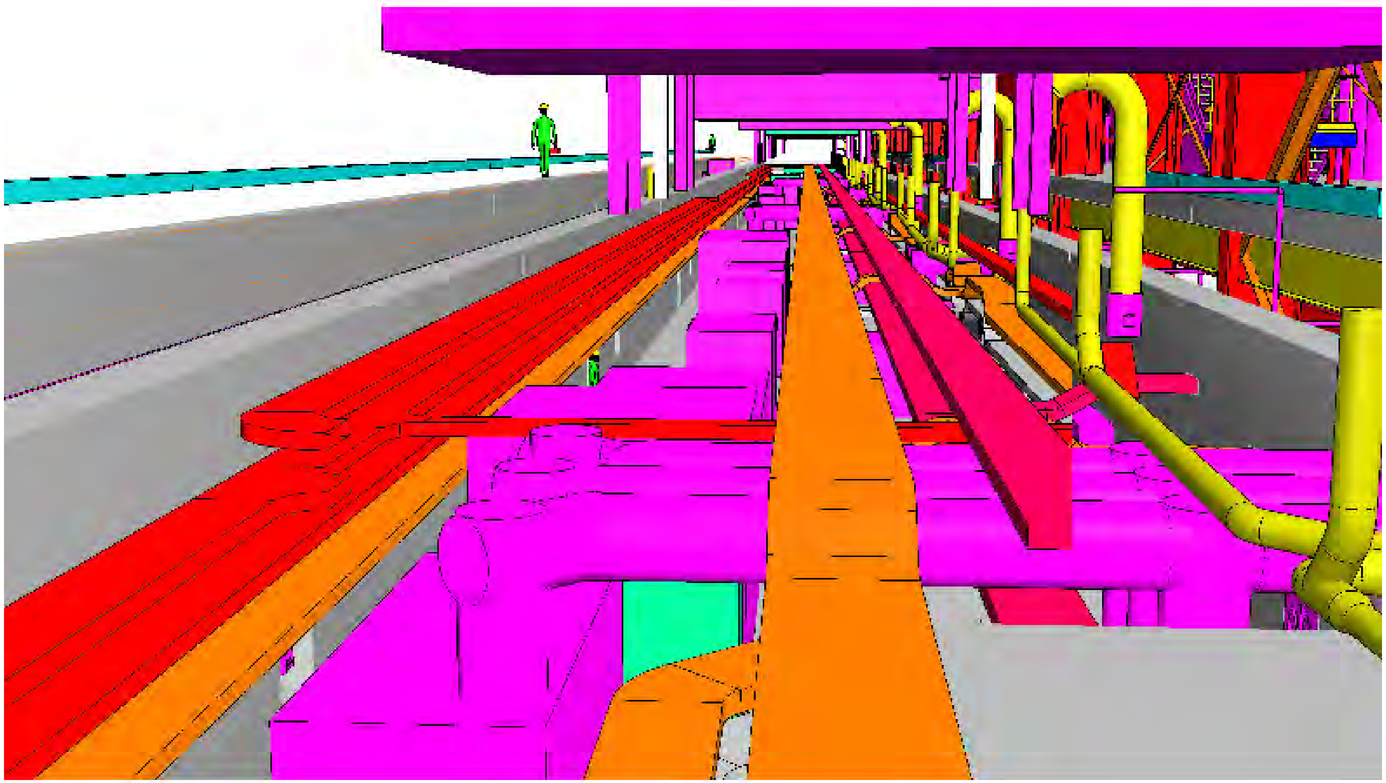
Containment Dykes

Electrical and Mechanical



Electrical and Mechanical

Include E&M works in the GCC



Contract Terms

- 2 rounds of review, comment and revision of the Contract Terms during RFP period.

- All Proponents agreed in principle to the Contract Terms before RFP close.

- MH and the Preferred Proponent completed final negotiations in less than 2 weeks.

Negotiations Highlights

- Reduced Bonus to [redacted]
- Used [redacted] to fund Best for Project Pool
- Set the Camp expectations
- Added wording to make design expectations clear
- No changes required to BNA

Allocation of Risk

- MH Risk
  - Actual Cost of the Work
  - Project Schedule
  - Contract Interfaces
  - Design
  - Escalation (labour and commodities)
  - Scope changes
  - Environmental Approval
  - Quantities
  - Geologic Conditions
  - River Flows above 1:20 yr

Allocation of Risk

- GCC Risk
  - Contract Schedule
  - Attraction/Retention of Staff and Craft
  - Labour productivity
  - Subcontracts

Budget

- Do we announce a CPJ change or is this separate? MH Pres to decide.

BBE ITP Lower than Others

- Major items include;
- Concrete Costs
- Supervisor Costs

BBE ITP Lower than Others

Supervisor Costs

BBE	DLB	PKI	UAB
[redacted]	[redacted]	[redacted]	[redacted]

Keeyask Budget

2012 Estimate			2014 Forecast
$6,220.1 M			
	+ 67.2M	Adverse Effect Accounting	
	+ 60.0 M	3rd party Const Mgmt	
	+ 70.9 M	Overruns on DNC	
	+ 63.0 M	Overruns on Other Scope	
	+190.9	Interest	
	+61.6	Changes to Mgmt Res	
			$6,733.7 M

All-in Concrete Costs ($/m3)

[redacted]

Tab 132

Government of Canada Gouvernement du Canada

Canadian LNG Projects

Context

Much has changed in the North American liquefied natural gas (LNG) market in the past decade. Throughout the early to mid-2000's, concerns over decreasing conventional supplies of domestic natural gas led to bullish predictions about future LNG demand in North America, resulting in an investment boom to build new LNG import facilities.

Around 2008, dramatic changes in the North American natural gas market began, driven by surging U.S. unconventional natural gas production (mostly from shale gas). This changed the outlook for LNG imports. Natural gas production increased, North American prices fell significantly, and the expected need for imported LNG collapsed. In fact, LNG exports began to be contemplated.

As unconventional gas production increases, the U.S. is becoming increasingly self-sufficient with respect to natural gas. Pipeline exports from Canada to the U.S. are decreasing. With ample unconventional resources, industry has shifted its focus from importing LNG into North America to exporting LNG from North America. The export of LNG could facilitate Canadian natural gas production growth and result in significant investment, jobs and economic growth.

Canadian LNG Projects

Eighteen LNG export facilities have been proposed in Canada – 13 in British Columbia, 2 in Quebec and 3 in Nova Scotia – with a total proposed export capacity of 216 Million tons per annum (mtpa) of LNG (approximately 29 Billion cubic feet per day (Bcf/d) of natural gas). Since 2011, 24 LNG projects have been issued long-term export licenses. Canada's only operational LNG terminal (an import terminal) is Canaport LNG's regasification import terminal located in Saint John, New Brunswick.

According to a Conference Board of Canada study, which estimates the potential contributions LNG exports may make to the Canadian economy, an LNG export industry equivalent to 30 mtpa in British Columbia could add roughly $7.4 billion to Canada's annual economy over the next 30 years, and raise national employment by an annual average of 65,000 jobs. The Government of Canada is working closely with British Columbia, other provinces and industry partners to create conditions to support the development of an LNG industry in Canada.

EXISTING IMPORT TERMINAL

Project	Location
Canaport LNG	Saint John, New Brunswick

Canadian LNG Import and Proposed Export Facilities

Project	Export Licence	Export Volume Million Tons per Annum (Mtpa) - Billion Cubic Feet per day (Bcf/d)	Cost of the Project ($Billion)

12765

13 West Coast (British Columbia) Export Terminals			
Kitimat LNG	20 Years	10 Mtpa - 1.3 Bcf/d	$15
LNG Canada	40 Years	26 Mtpa – 3.5 Bcf/d	$25-$40
Cedar LNG Project	25 Years	6.4 Mtpa – 0.8 Bcf/d	
Orca LNG	25 Years	24 Mtpa – 3.2 Bcf/d	
New Times Energy	25 Years	12 Mtpa – 1.6 Bcf/d	
Kitsault Energy Project	20 Years	20 Mtpa – 2.7 Bcf/d	
Stewart LNG Export Project	25 Years	30 Mtpa – 4.0 Bcf/d	
Triton LNG (On Hold)	25 Years	2.3 Mtpa – 0.3 Bcf/d	
Woodfibre LNG	25 Years	2.1 Mtpa – 0.3 Bcf/d	$1.6
WesPac LNG Marine Terminal	25 Years	3 Mtpa – 0.6 Bcf/d	
Discovery LNG	25 Years	20 Mtpa – 2.6 Bcf/d	

Steelhead LNG: Kwispaa LNG	25 Years	30 Mtpa – 4.3 Bcf/d	$30
Watson Island			
5 East Coast Export Terminals			
Goldboro LNG (Nova Scotia)	20 Years	10 Mtpa – 1.4 Bcf/d	$8.3
Bear Head LNG (Nova Scotia)	25 Years	12 Mtpa – 1.6 Bcf/d	$2-$8
A C LNG (Nova Scotia)	25 Years	15 Mtpa – 2.1 Bcf/d	$3
Energie Saguenay (Quebec)	25 Years	11 Mtpa – 1.6 Bcf/d	$7
Stolt LNGaz (Quebec)	25 Years	0.5 Mtpa – 0.7 Bcf/d	$0.6
Total		**216 Mtpa – 29 Bcf/d**	

Canadian Government Position

12767

The Minister of Natural Resources Canada has stated "*The Canadian Government is taking steps to grow the Canadian economy, create good jobs and opportunities for Canadians, while protecting our environment for future generations. As the Prime Minister has emphasized, in the 21st century we must get our resources to market sustainably and responsibly. For all natural resource projects, the government is working closely with provinces and territories, Indigenous peoples, and other interested parties to ensure that the highest standards of public and environmental safety are being met, while creating new export opportunities for Canada's natural resources.*"

Regulations and Permitting

While the ongoing operation of LNG terminals generally falls under provincial regulation, most LNG terminal proposals require both federal and provincial environmental assessments and permits.

Most of the proposed LNG facilities require new pipelines or the expansion of existing pipelines. Intra-provincial pipelines are provincially regulated, while pipelines that cross a provincial or international border are federally regulated. For more information on pipelines, please see Frequently Asked Questions (FAQs) Concerning Federally-Regulated Petroleum Pipelines in Canada.

A permit from the Canada Energy Regulator (CER), Canada's federal energy regulator, is required to export LNG from Canada. The NEB reviews export licence applications to ensure that the proposed volume of gas to be exported is surplus to Canadian requirements. Since 2011, 24 LNG projects have been issued long-term export licenses ranging between 20-40 years. More information on export licences is available on the CER's website.

LNG Facilities and Safety Regulations

LNG facilities are classified as industrial sites and must meet all federal, provincial and municipal standards, codes and safety regulations. These regulations are constantly updated to ensure that the health, safety and security of the environment and Canadian public are protected. The Canadian Standards Association (CSA) has a specific standard for LNG production, storage and handling (CSA Standard CAN/CSA Z276-01). This standard establishes essential requirements for the design, installation and safe operation of LNG facilities.

Useful Links

These websites provide useful background information on LNG and LNG regulatory processes in Canada.

- Generation Energy
- Canada Energy Regulator
- Impact Assessment Agency of Canada
- Major Projects Management Office
- BC Oil and Gas Commission
- LNG Projects in British Columbia
- BC LNG Alliance
- BC LNG First Nations Alliance

Date modified:
2020-08-06

Tab 133

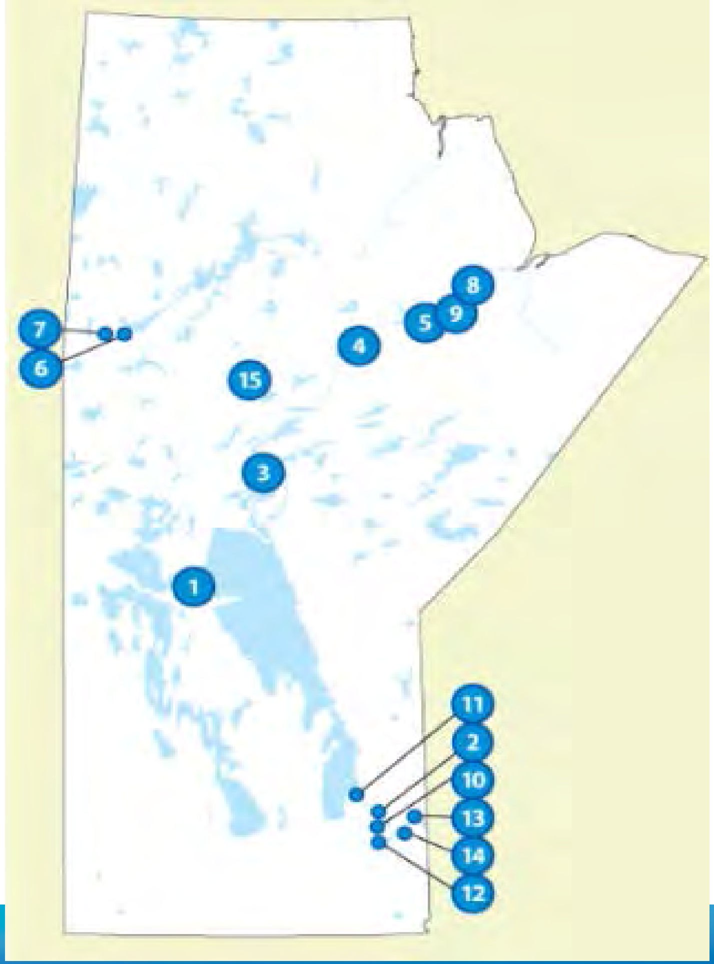
Keeyask Project Overview

- Lorne Midford P. Eng, MSc – Vice President, Generation & Wholesale
- Jeff Strongman P. Eng, MBA – Keeyask Business Manager
- Dave Bowen P. Eng, MSc– Keeyask Project Director

Manitoba Hydro System

Generation:

- 15 Hydro Generating Stations



Transmission:

- 3 HVDC converter stations
- 18,500 km of transmission lines
- Bipole I & Bipole II
  - 1,800 km HVDC

12772

Keeyask Overview

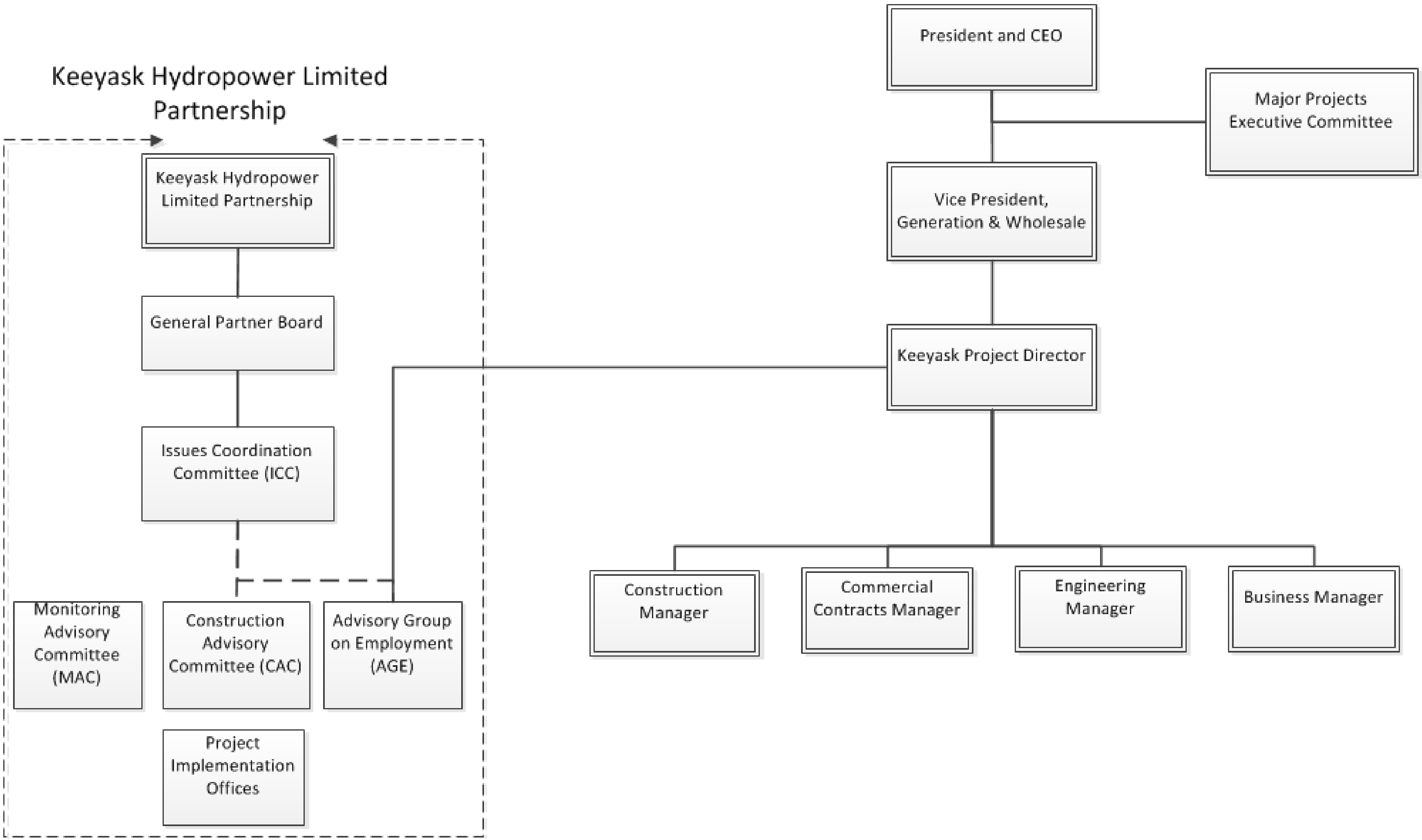
- Collaborative effort between Manitoba Hydro and 4 Manitoba First Nations working together as the Keeyask Hydropower Limited Partnership (KHLP).
  - Tataskweyak Cree Nation and War Lake First Nation (acting as the Cree Nation Partners);
  - York Factory First Nation; and
  - Fox Lake Cree Nation.
- The Partnership is governed by the Joint Keeyask Development Agreement (JKDA).
  - Long-term revenue opportunity for KCN communities
  - Training, employment and business opportunities during construction.

Respecting the Communities

- Incorporating the Cree world view into the project activities
- Face in the rock
- Community Liaison staff
- Involvement from partner communities

12774

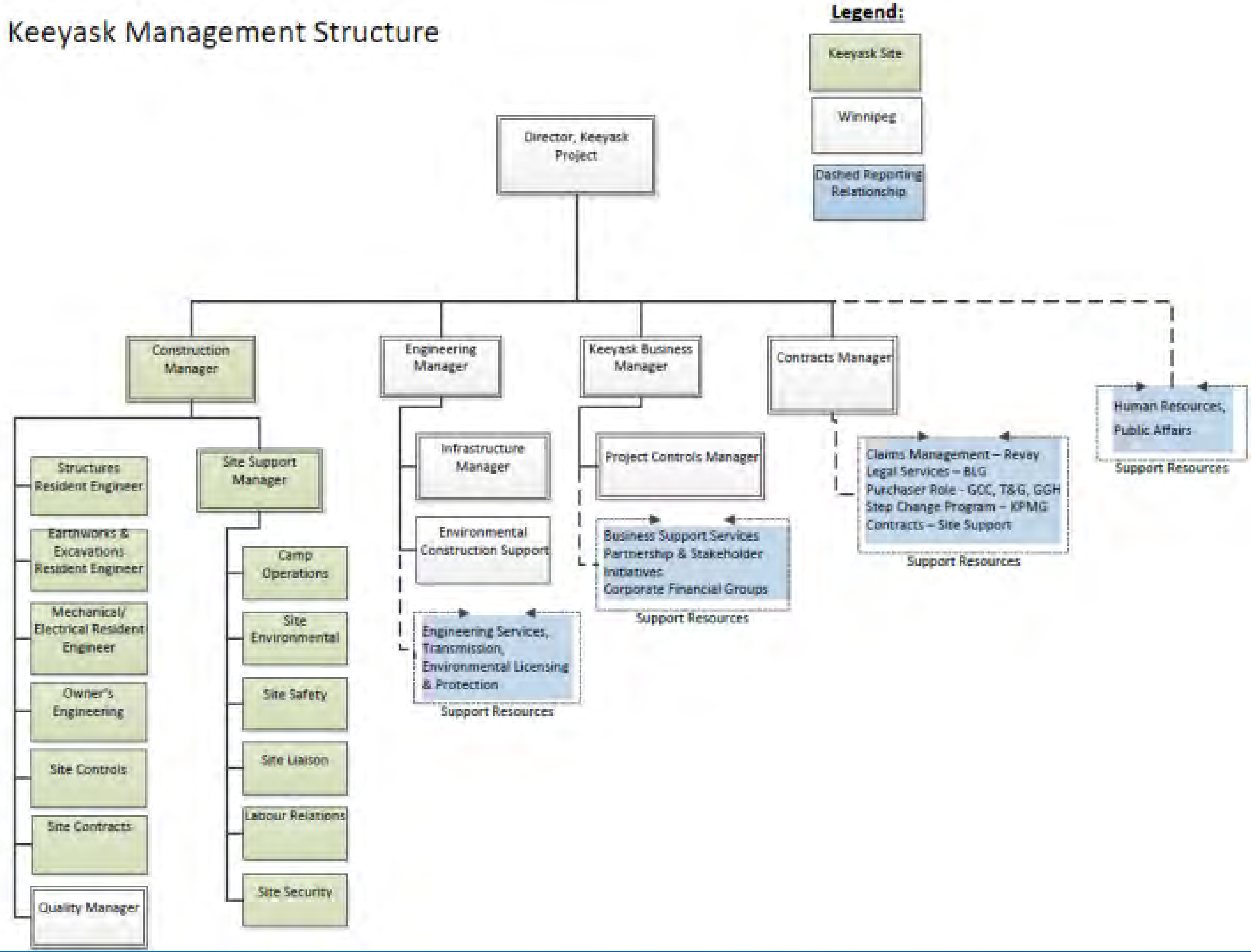
Project Governance Structure



Major Projects Executive Committee

- Established in early 2016.
- Oversees, directs, and make strategic decisions on Manitoba Hydro's major capital projects.
- Membership includes:
  - The President & CEO
  - VP Transmission
  - VP Generation & Wholesale
  - VP HR & Corporate Services
  - VP Indigenous Relations
  - VP Finance & Strategy
- Meeting every 2 weeks (or as required)

Project Execution Team



12777

What are we Building?

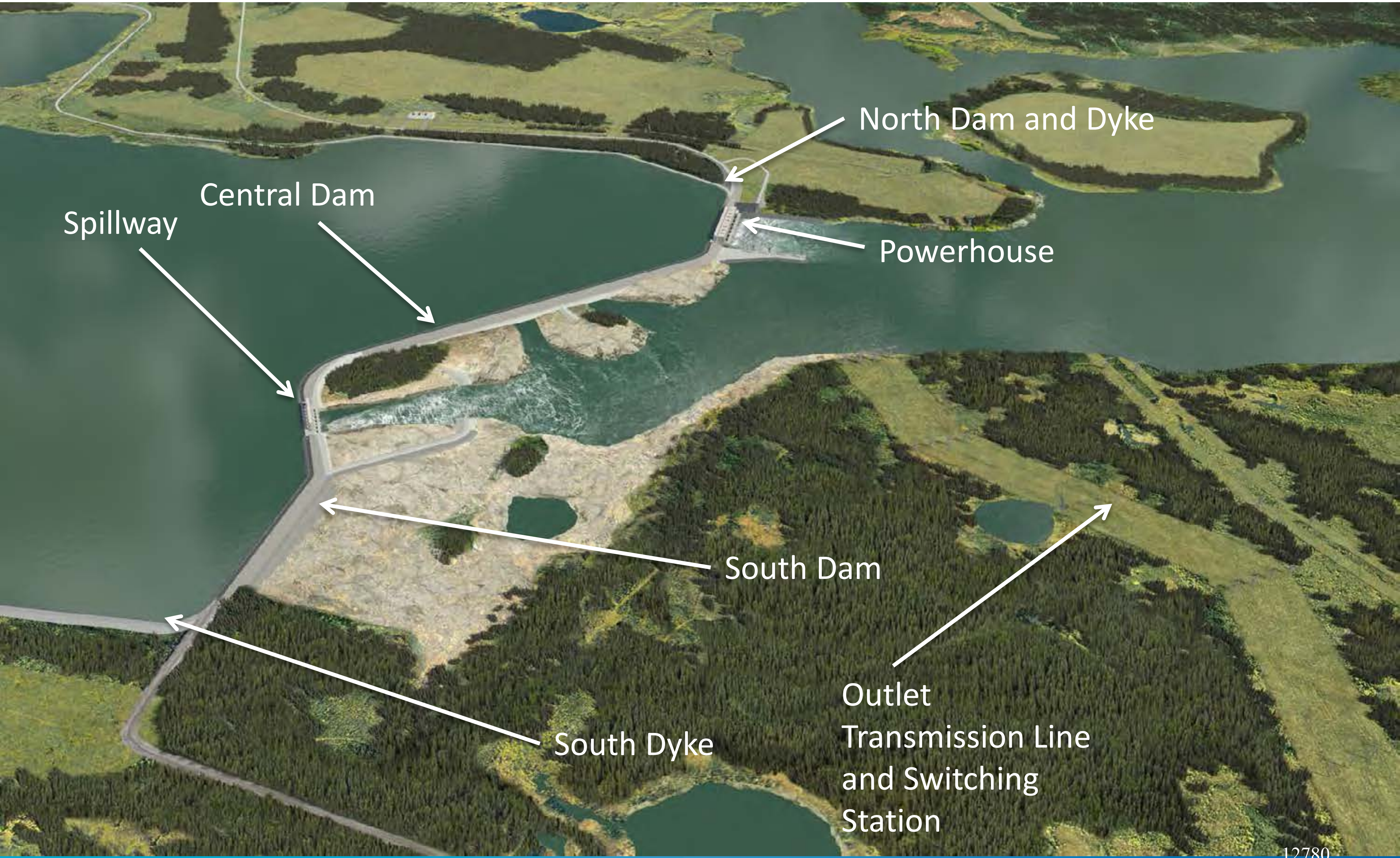
A 695-megawatt hydroelectric generating station

Keeyask Project includes:

- Powerhouse
- Spillway
- Dams & Dykes
- All supporting infrastructure (camp, roads, cofferdams)
- All required transmission facilities

Project Location

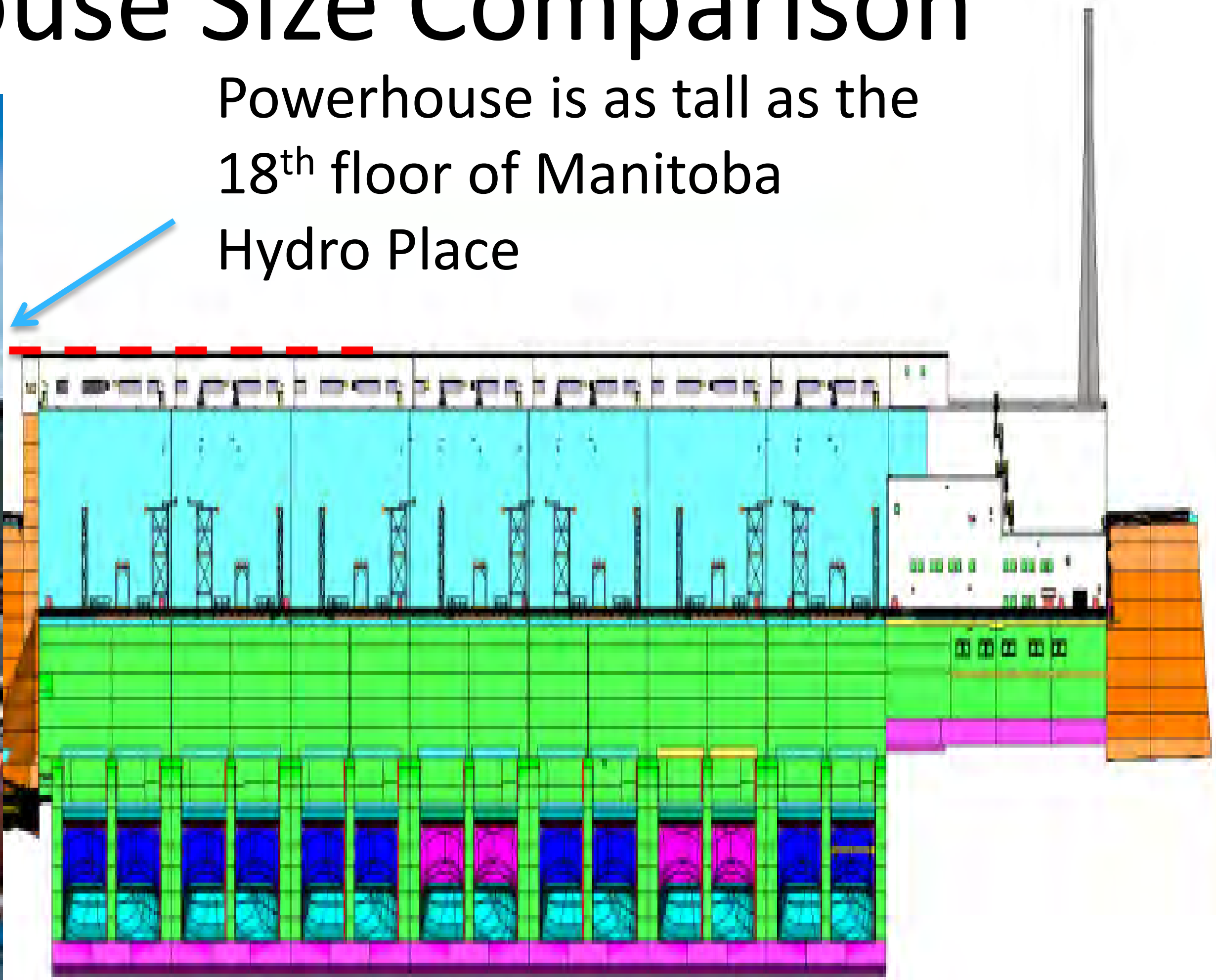
General Arrangement



Powerhouse Rendering

Powerhouse Size Comparison

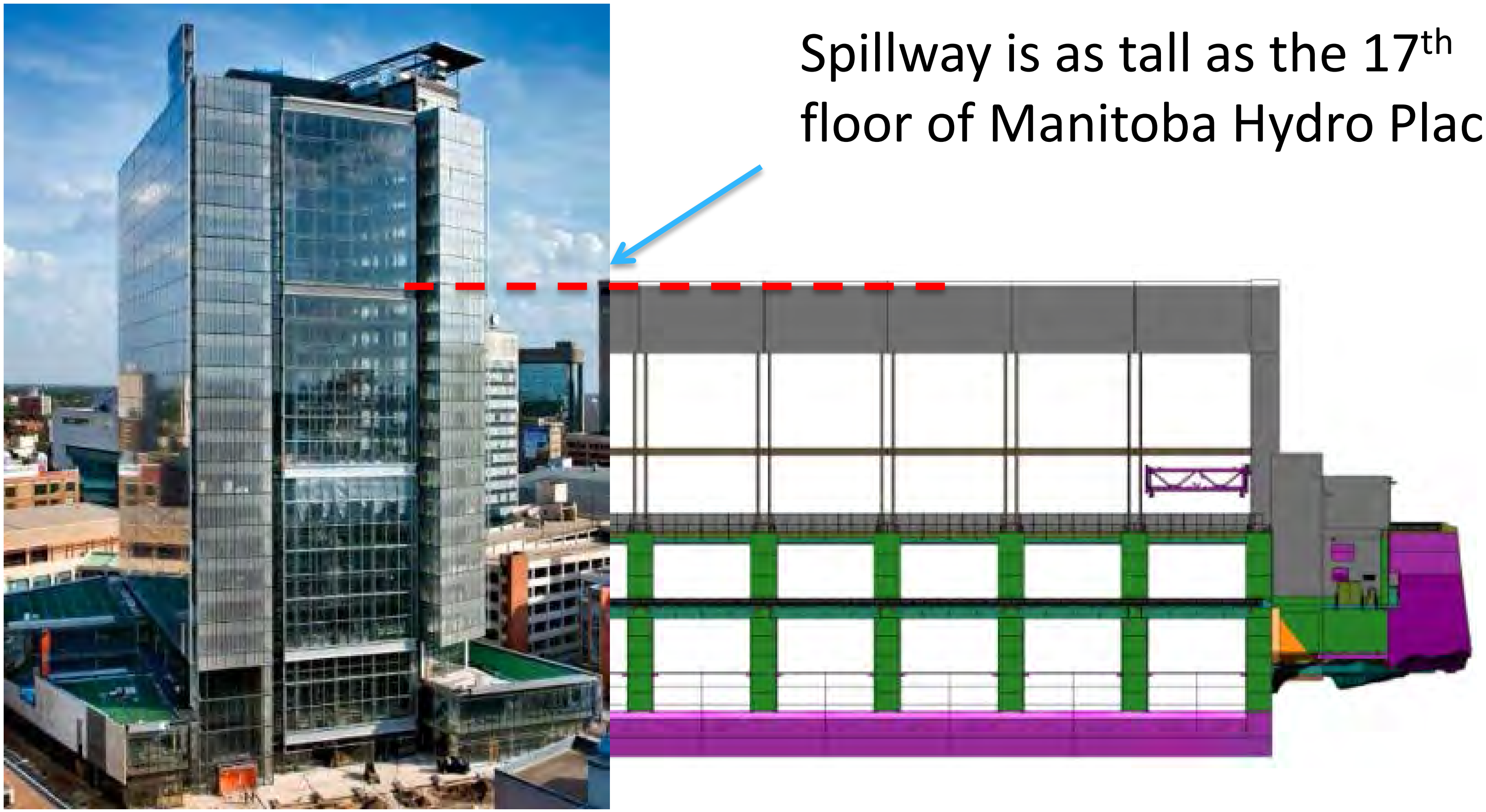
Powerhouse is as tall as the 18th floor of Manitoba Hydro Place



Spillway Rendering

12783

Spillway Size Comparison

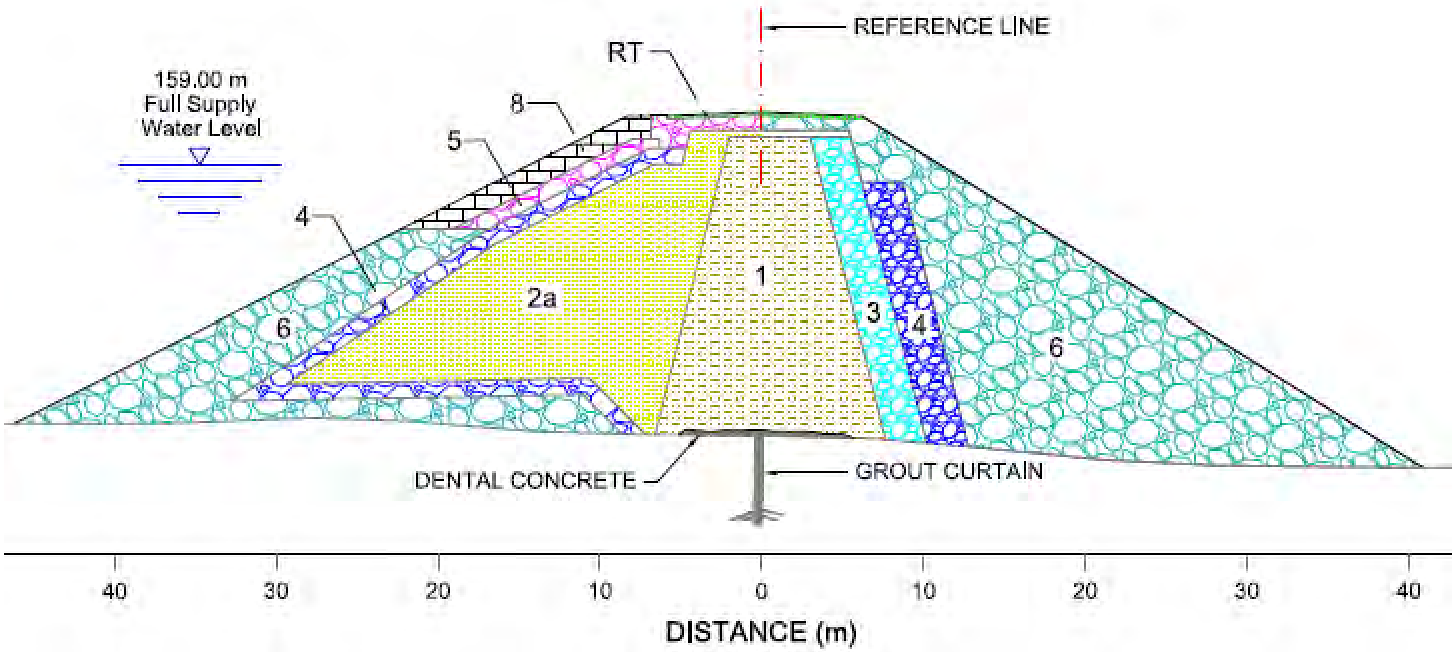


Spillway is as tall as the 17th floor of Manitoba Hydro Place

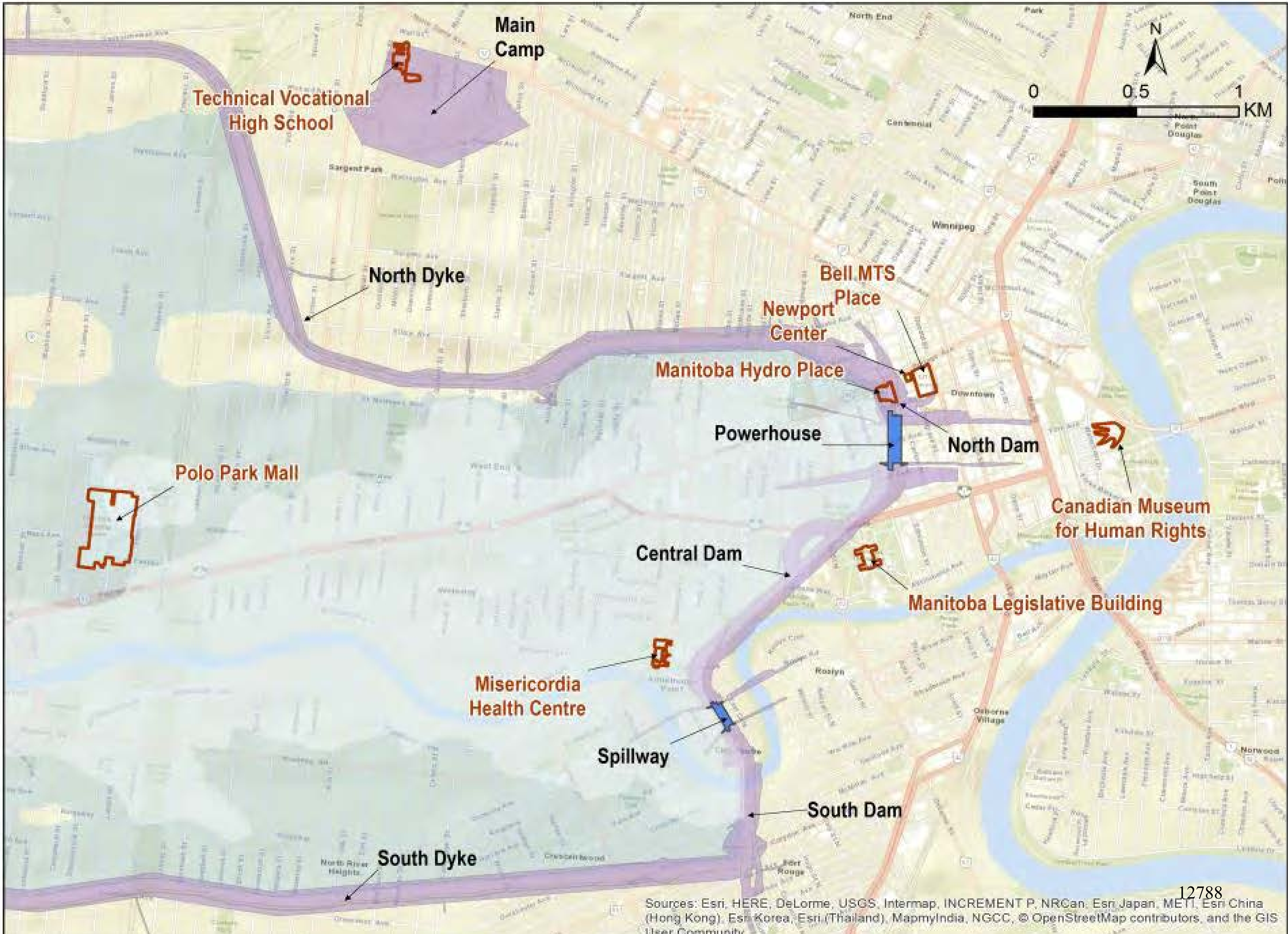
River Management Structures

12785

Typical Cross Section of a Dam



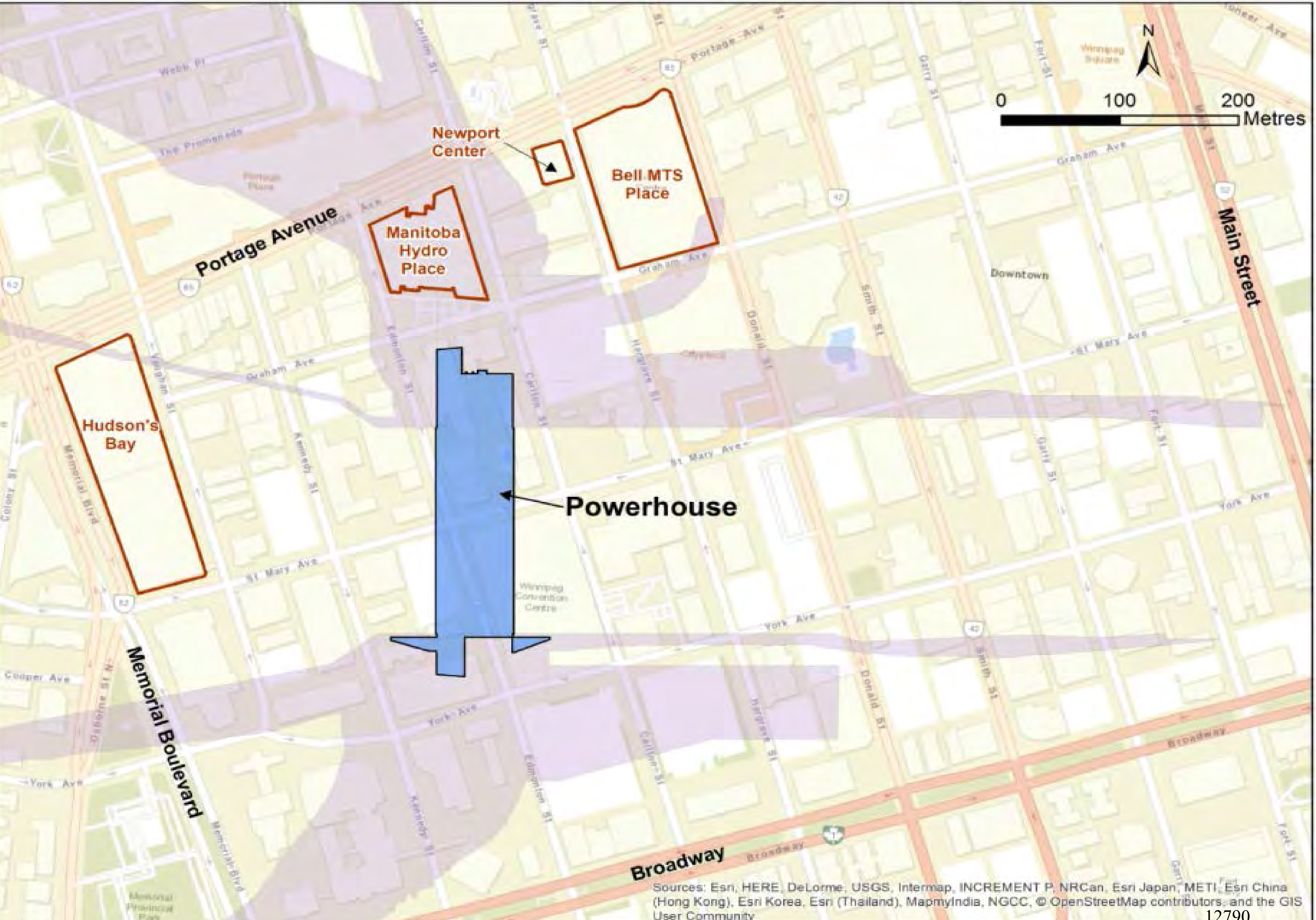
Dam and Dyke Construction
“Getting off the rock”



12788

Sources: Esri, HERE, DeLorme, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), MapmyIndia, NGCC, © OpenStreetMap contributors, and the GIS User Community


Richardson International Airport
North Dyke
Main Camp
Bell MTS Place
Manitoba Hydro Place
Winnipeg
Perimeter Highway
Polo Park Mall
Powerhouse
North Dam
Central Dam
Manitoba Legislative Building
Spillway
South Dam
Assiniboine Park
South Dyke
N
0 1 2 KM
Sources: Esri, HERE, DeLorme, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), MapmyIndia, NGCC, © OpenStreetMap contributors, and the GIS User Community


N
0 100 200
Metres
Newport Center
Bell MTS Place
Manitoba Hydro Place
Portage Avenue
Hudson's Bay
Powerhouse
Main Street
Memorial Boulevard
Broadway
Downtown
Sources: Esri, HERE, DeLorme, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), MapmyIndia, NGCC, © OpenStreetMap contributors, and the GIS User Community

Infrastructure

12791

Keeyask Transmission

The Keeyask Transmission Project fulfills two purposes:

1) Provide power to the Keeyask site during construction of the GS;
2) Facilities required to integrate power generated by Keeyask (when online) into the Manitoba Hydro system.

Lessons learned

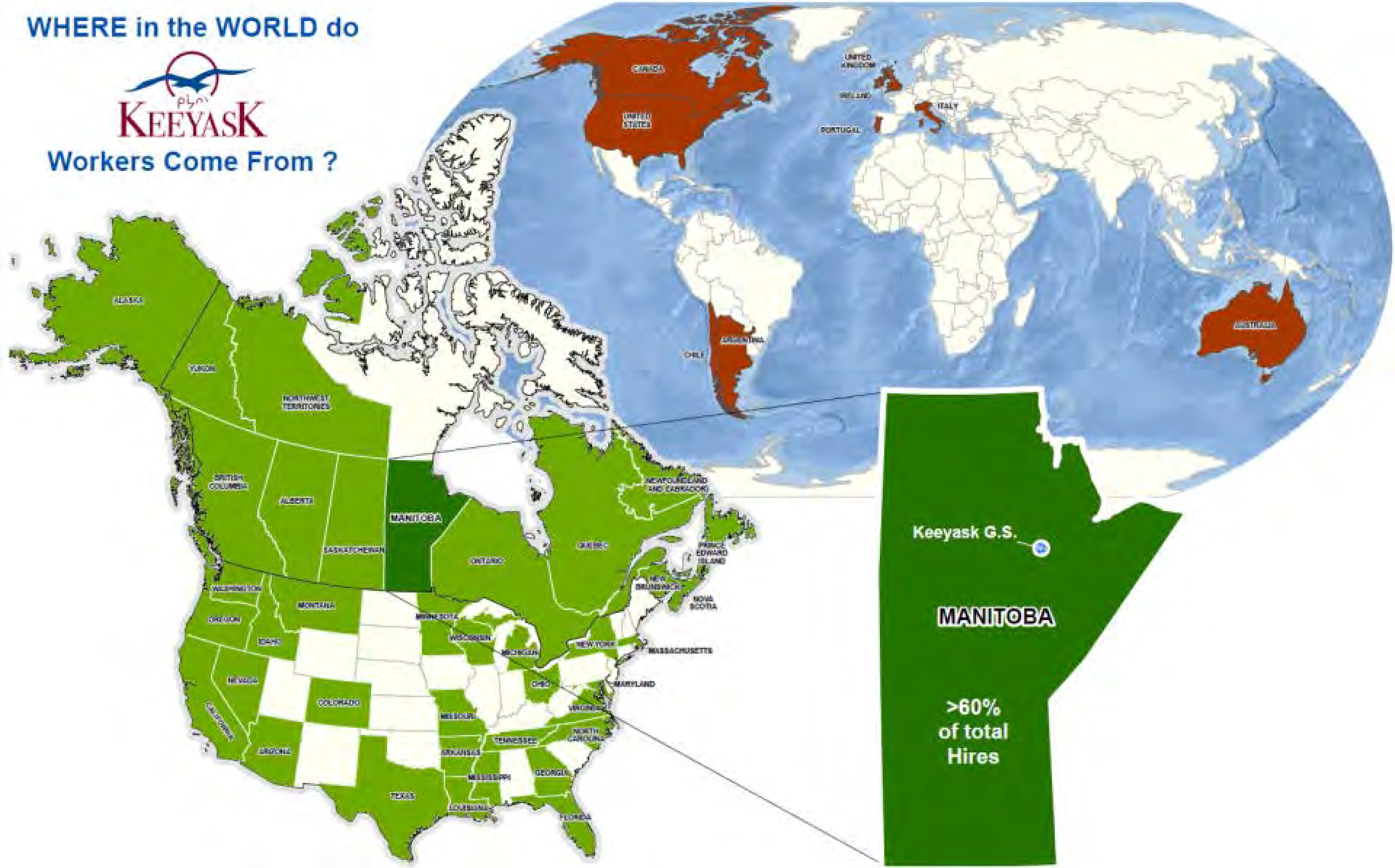
- Experience gained from past projects:
  - Early contractor involvement;
  - Contracting model;
  - Third-party reviews;
  - Continuous improvement and rigorous oversight;
  - Project integration;
  - Contract interfaces;

Complex Project Environment

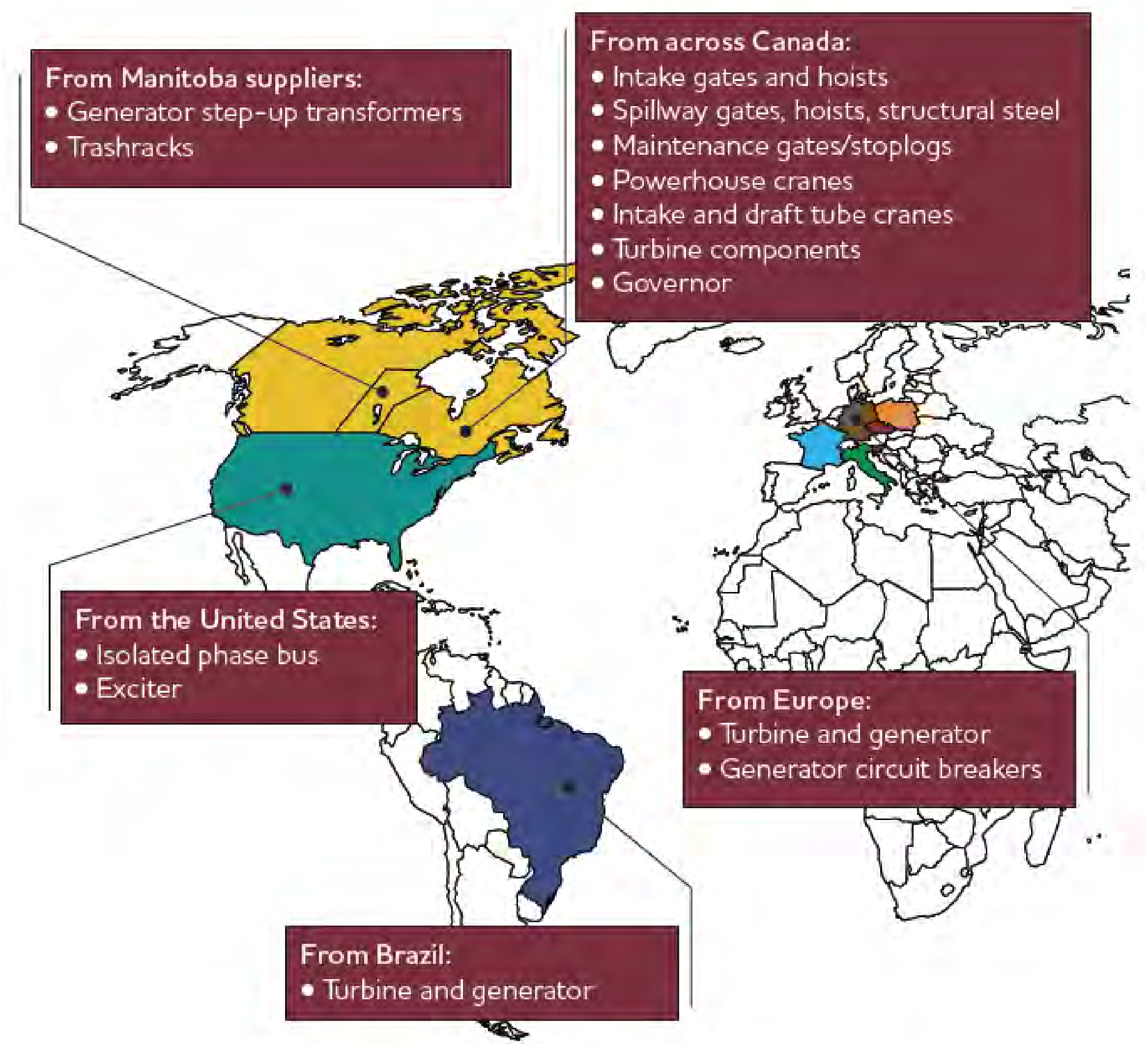
Employment

- Employment milestone reached this summer on Keeyask.
  - 2 million person hours worked by KCN members
  - 4 million person hours worked by Indigenous employees
- 73% of total hires are Manitobans.

WHERE in the WORLD do KEEYASK Workers Come From ?



Global Supply Chain



Keeyask Project Safety

- Strong safety culture
- Over 15 million person hours worked
- Better than industry standards
- GCC has gone over a year without a lost time incident
- MH and all our contractors will continue to focus on our goal of zero injuries

Delivery Strategy

- Contracting model for each scope of work.
- Considers market capacity
- Risk allocation

Types of Contracts

- Cost-reimbursable
- Target price
- Fixed price
- Unit price

Major Contract Types

Contract	Contractor	Contract Model
General Civil Works	BBE Hydro Constructors	Target Price
Camp Operation Services*	Fox, York & Sodexo JV	Cost Reimbursable
Main Camp	Britco	Fixed Price
Turbines & Generators	Voith Hydro	Fixed Price
Engineering – Final Design	Hatch	Cost Reimbursable with Cap
Maintenance Services*	Maintenance Services JV	Cost Reimbursable
South Access Road*	Amisk Construction	Unit Price
Reservoir Clearing*	Amisk Construction	Unit Price
Spillway GGH	Canmec Industriel	Fixed Price
Intake GGH	Canmec Industriel	Fixed Price
Security Services*	Fox, York and Sodexo JV	Cost-reimbursable

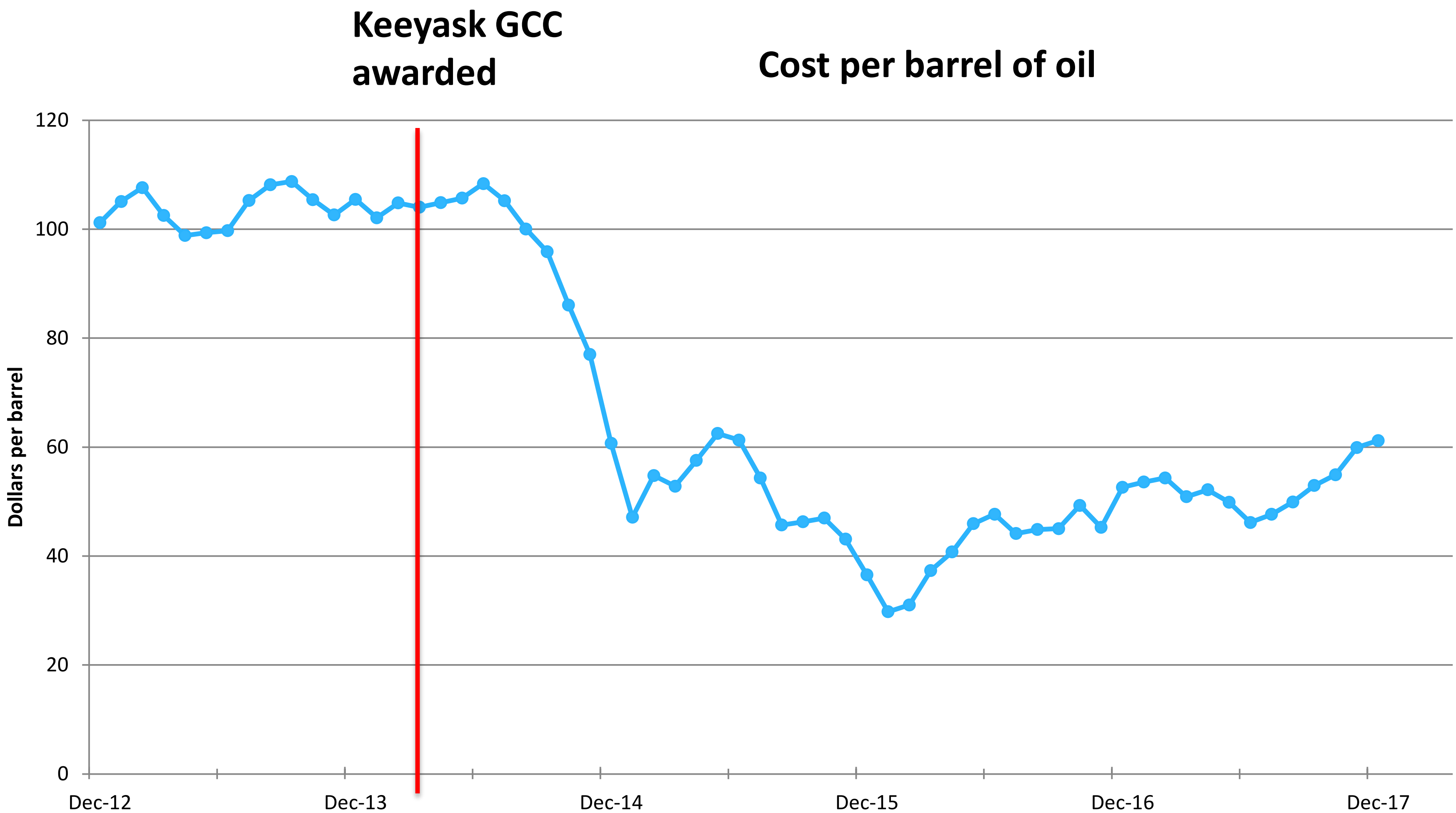
* Directly Negotiated Contract (DNC) with KCN businesses

Contract Complete

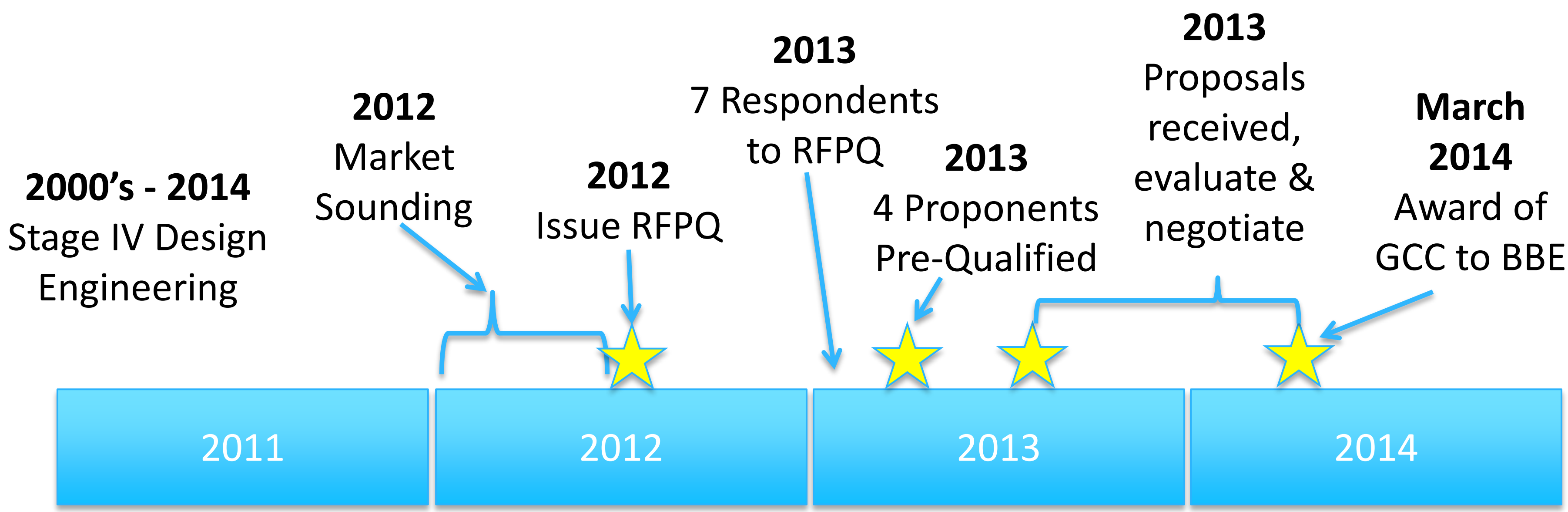
General Civil Contract

- General Civil Contract awarded to BBE in 2014.
- Largest contract on the project and includes:
    - Cofferdams,
    - Rock excavation,
    - Concrete structures,
    - Earthworks structures,
    - Electrical and mechanical work.

Keeyask GCC Tendered in 'Hot' Market



GCC Procurement

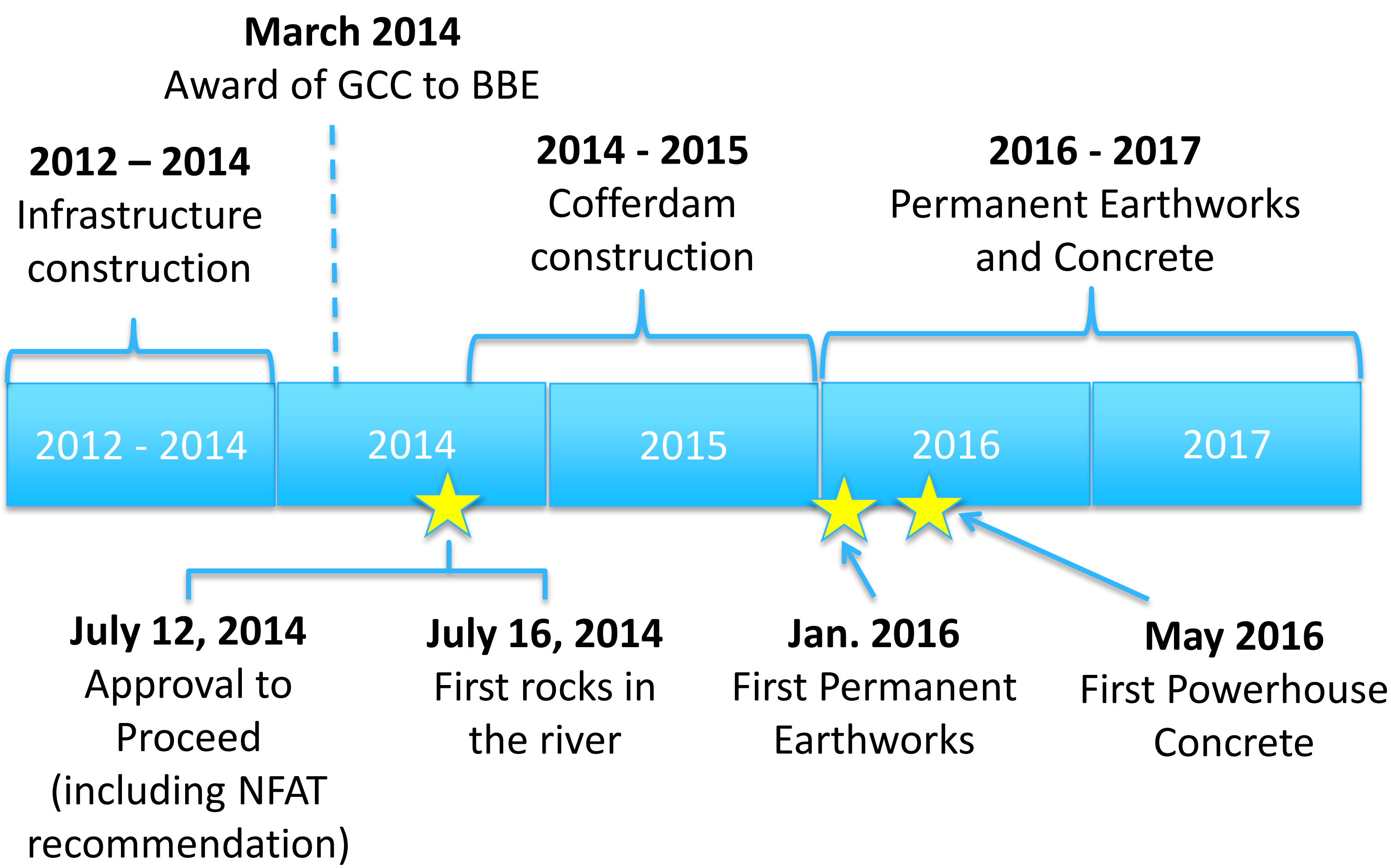


= Milestone

General Civil Contract

- Target price contract where the contractor is reimbursed for actual costs.
- Contractor has profit at risk.
- If the project cost is over the target the contractor loses a proportional amount of his profit margin and overhead.
- If the cost is under the target, the contractor shares a portion of the savings and gets his predetermined profit and overhead set out in the contract.

Construction Milestones Achieved



= Milestone

Future Construction Milestones

January 2018
Start of T&G Installation

July/August 2018
Divert river through spillway

December 2019
Full Powerhouse Enclosure

July 2020
Impoundment

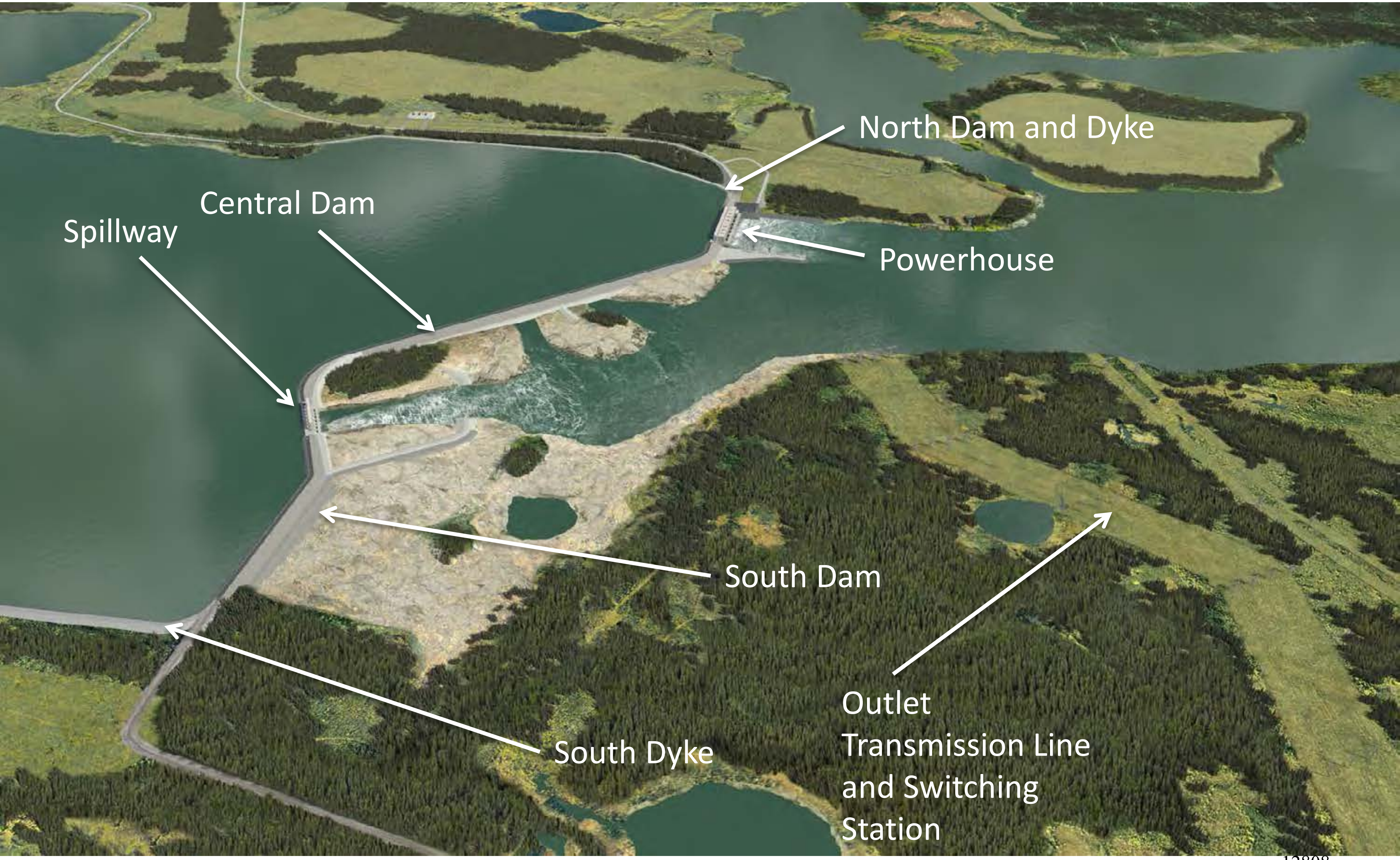
Aug. 2021 - Aug. 2022
Unit ISD’s
(~2 months/unit)

2022 - 2023
Infrastructure decommissioning & environmental rehabilitation.

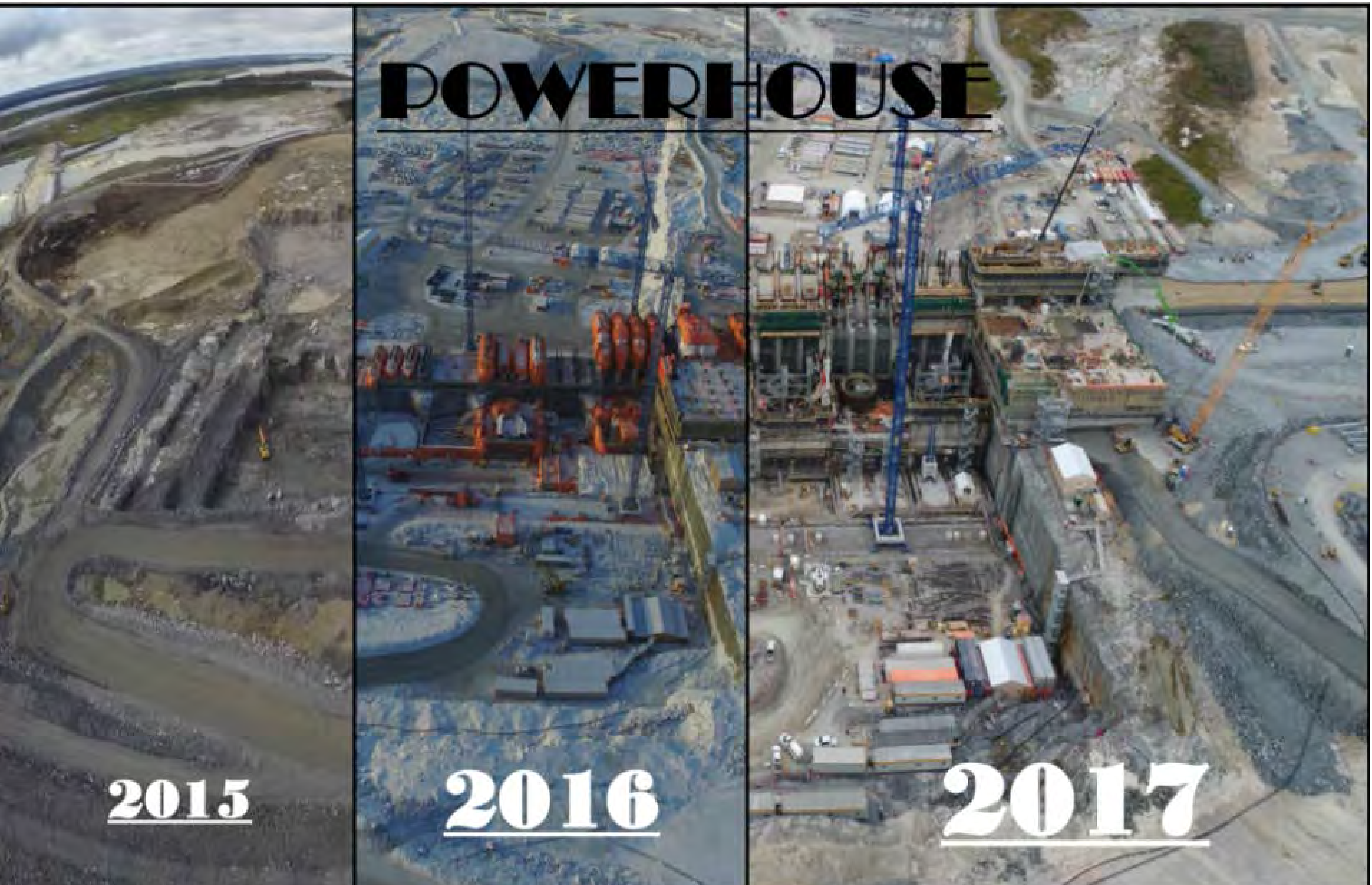
February 2017
Control Budget = $8.7B
Unit 1 ISD = Aug. 2021

★ = Milestone

General Arrangement



Powerhouse Rendering

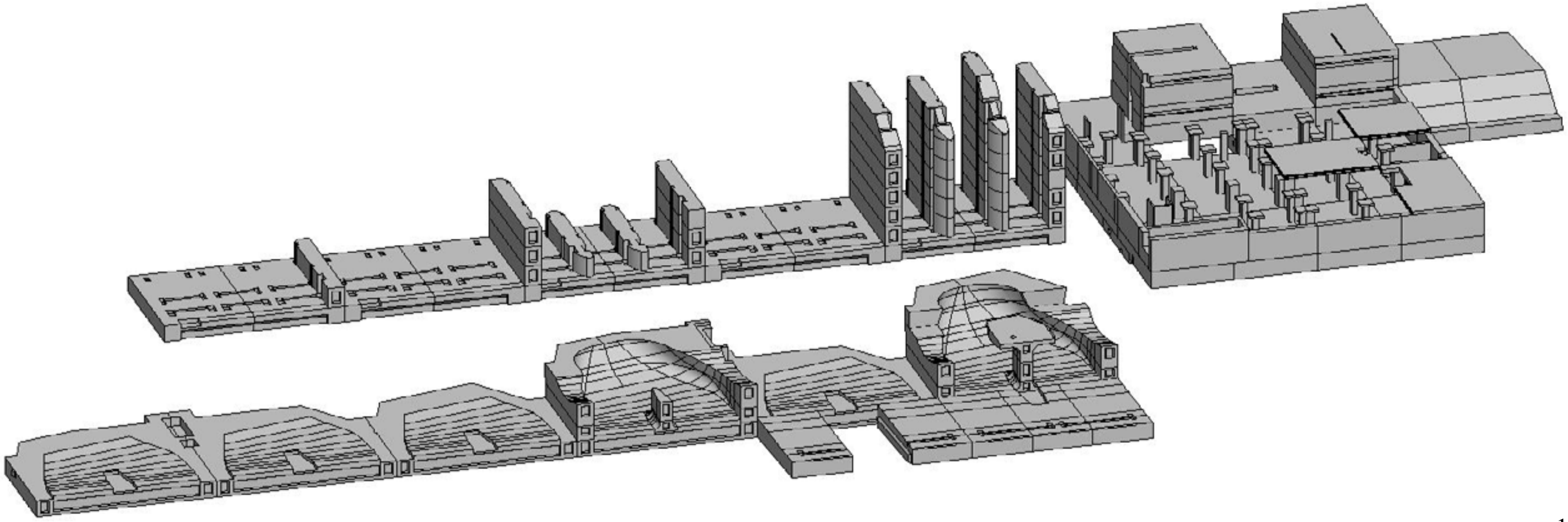

POWERHOUSE
2015
2016
2017

2016 Powerhouse Construction

12811

2016 Powerhouse Construction

Powerhouse Complex



2017 Powerhouse Complex

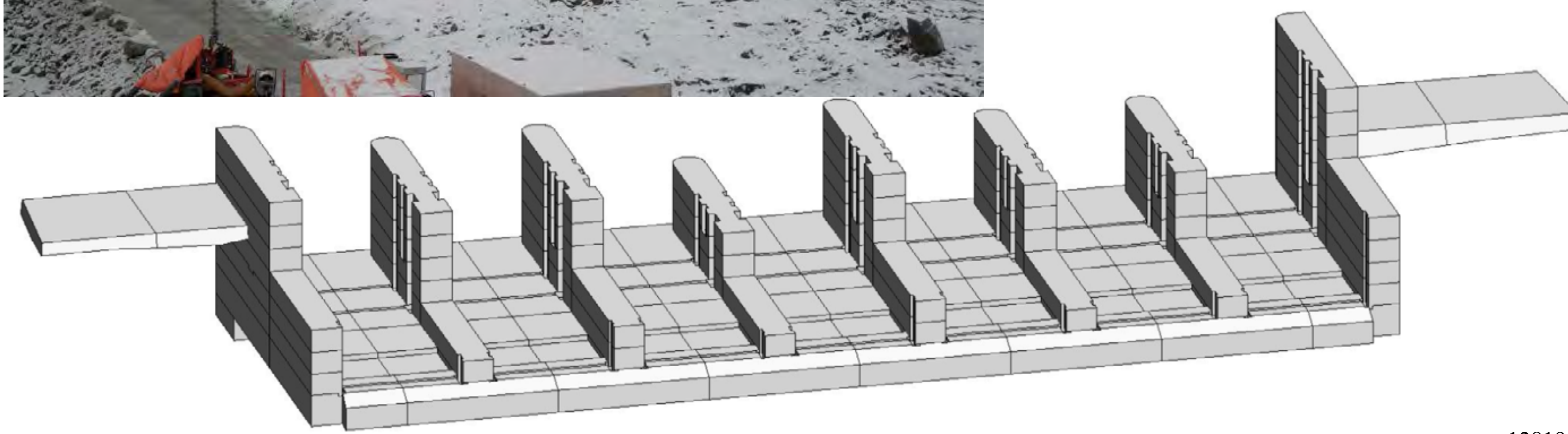
2017 Powerhouse Complex

Powerhouse – Current Status

Spillway Rendering

2016 Spillway Construction

End of 2016 Spillway



2017 Spillway

August 2017

Spillway - Current Status

January 11, 2018


North Dyke
North Dam
Powerhouse Complex
Central Dam
Spillway

12822

Construction Update Video

2 minutes, 30 seconds

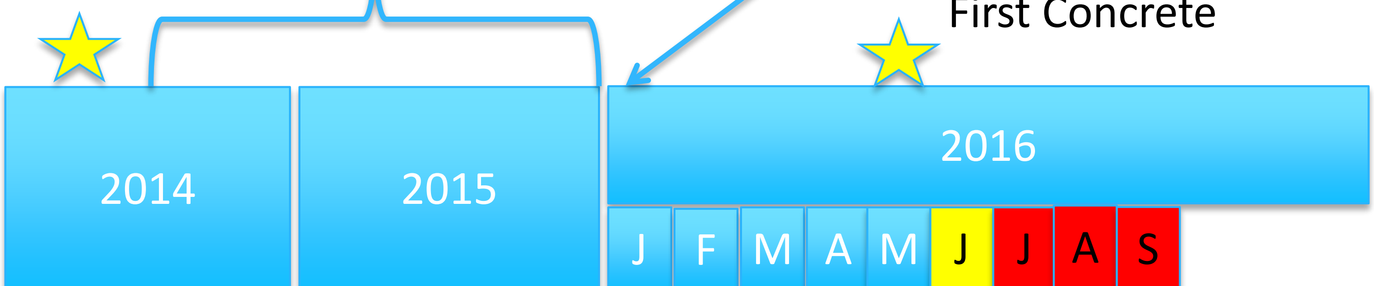
Timeline of 2016 Challenges

March 2014
Award of GCC to BBE

2014 - 2015
Cofferdam construction and rock excavation

January 2016
First Permanent Earthworks (North Dyke)

May 2016
First Concrete



June 2016
Concrete not meeting plan. Letter issued to BBE requiring immediate recovery strategy

July & August 2016
Concrete still not meeting plan

Sept. 2016
Formal Recovery Plan Initiated

★ = Milestone

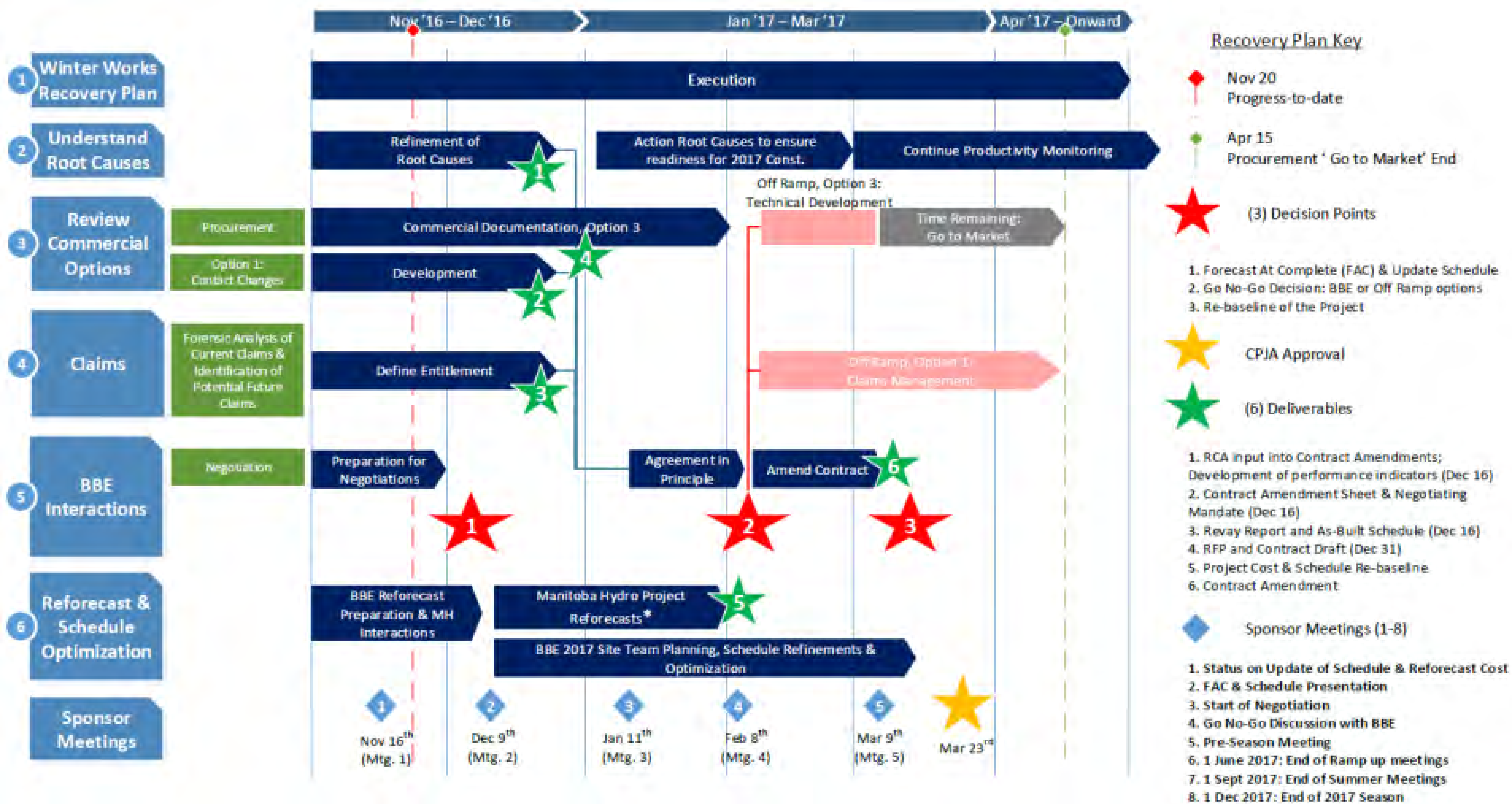
2016 Recovery Plan

- A call to action for BBE’s project team, Executive Sponsors and CEOs.
- The development of a plan for the continuation of concrete through severe winter months.
- Identifying root causes of performance issues
- Initiating activities to reforecast the cost and schedule for the project.
- Undertaking analysis around Contractor’s claims.
- Supplementing the commercial expertise of the Manitoba Hydro team.

2016 Challenges

- In 2016 the GCC only achieved 41% of the concrete plan and 65% of the earthworks plan.
- Main contributing factors were:
  - Aggressive concrete production assumptions by Contractor
  - Slower than planned progress in ramp-up on site, and
  - Actual experience with geotechnical and geological conditions.
- Schedule rapidly changed from having a 6 month advancement opportunity to a potential 2+ year delay.

Recovery Plan Implementation



Commercial Options

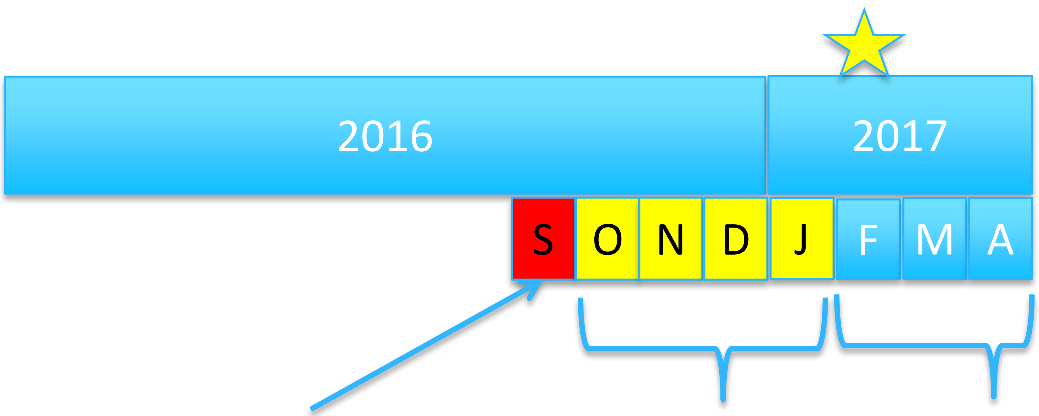
- Manitoba Hydro undertook a thorough process to evaluate alternatives for and impacts to the General Civil Contract.
- The process included input from industry experts including:
  - KPMG – Recovery Plan support.
  - Revay – Claims valuation and management.
  - Borden Ladner Gervais LLP (BLG) – Legal support.
  - Validation Estimating – Contingency development.

Evaluation Outcome

- The review demonstrated that the best course of action was to amend the existing contract with BBE.
- All other alternatives introduced significant additional risks as well as guaranteed impacts to cost and schedule that were greater than the selected option of amending the contract with BBE.

Timeline of Recovery Plan

February 2017
Revised Control Budget and Schedule Approved



Sept. 2016
Formal Recovery Plan Initiated

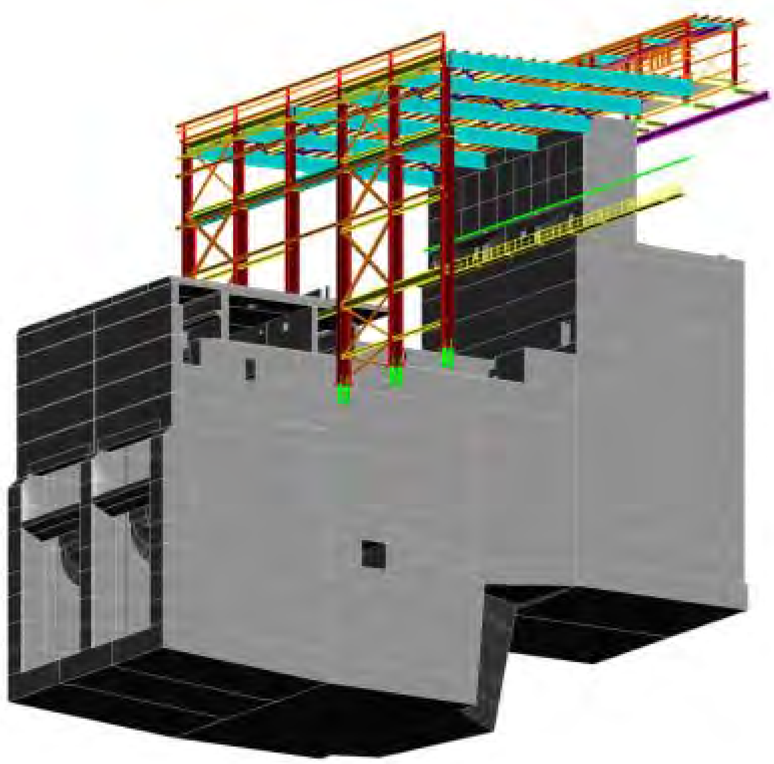
Fall/Winter 2016
a) Improved Production
b) Immediate Plan
c) Long Term Plan

Winter/Spring 2017
Recovery plan implementation

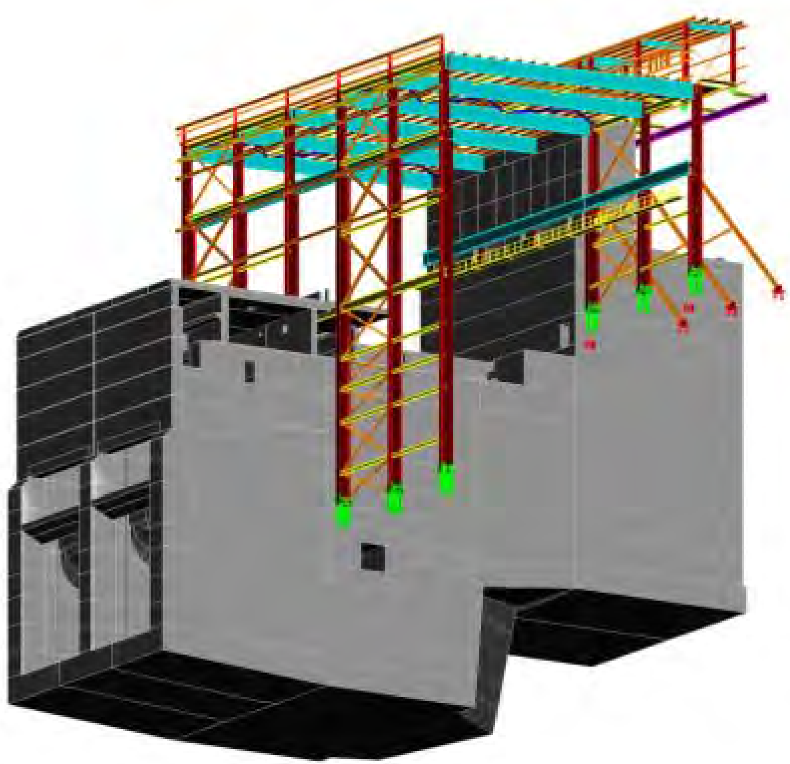
= Milestone

Column Extenders

Previous Design – No Column Extenders



New Design – With Column Extenders



Contract Amendment Achieved

- Manitoba Hydro and BBE were able to achieve mutual agreement that was required to amend the contract.
  - The negotiation required ‘gives and takes’ from both parties.
- Lowered the overall cost and schedule risk for Manitoba Hydro and allowed BBE an opportunity to re-establish a reasonable profit level.
- The terms of the agreement aligned the interests of both parties to deliver a “Best for Project” approach.

Features of the Amendment

- The details of the amendment to the contract are formalized in Amending Agreement #7 between Manitoba Hydro and BBE.
- Key features of the amendment include:
  - Contractor claims “wiped clean”;
  - Schedule and cost incentive pool provides incentive for BBE to earn profit and MH to minimize Project cost and schedule;
  - General Administration & Overhead (GA&O) capped at target price;
  - Narrowed ability for future claims;
  - Liquidated damages.

Establishing a New Control Budget

Project in Service Cost (Billions $)	Original Control Budget	Third Party Recommended Contingency		
Base Estimate Including Spent, Costs to Go, Interest and Escalation				
Delay (months)	-	11		
First Unit In-Service	Nov-19	Oct-20		
Total Base Estimate	**6.2**	**7.8**		
Contingency		**P50**	**P75**	**P90**
Additional Delay (months)	-	10	14	18
First Unit In-Service	**Nov-19**	**Aug-21**	**Dec-21**	**Apr-22**
Estimated Contingency	0.307	0.578	0.914	1.246
Additional Interest & Escalation on Contingency	-	0.339	0.464	0.588
Project Estimate (with Contingency)	**6.5**	**8.7**	**9.1**	**9.6**

Note: Interest and escalation are reasonable approximations; full financial-model calculations will be incorporated into control budget.

12834

Keeyask Budget Summary

(From PUB MFR 122)

Keeyask Budget Summary (in Billions $)				
Item #	Item	NFAT Approved Budget (2014$) CPJA #4	Current Approved Budget (2016$) CPJA #4	Variance
1.1	Generating Station	4.046	5.948	1.902
1.2	Generation Outlet Transmission (GOT)	0.164	0.202	0.038
1.3	Escalation @ CPI	0.244	0.249	0.005
1.4	Interest (including Interest on Equity)	1.343	1.749	0.406
1.5	Contingency	0.307	0.578	0.271
1.6	Labour Management Reserve	0.304	0.000	-0.304
1.7	Escalation Management Reserve	0.088	0.000	-0.088
1.8	Total	6.496 B	8.726	2.230
1.9	First in-service Date	Nov-2019	Aug-2021	21 months.

2017 Performance

	2017 Actual Quantities (m^3 rounded)	% Improvement over 2016
Concrete	86,000	~12%
Earthworks	1,030,000	~90%

- There was a significant improvement in performance over 2016 which occurred in both concrete and earthworks.
- Actual quantities were less than planned.
- However, key milestones were achieved in 2017 which maintain the schedule for the shortest duration.

2017 Key Milestones

Milestone	Date	Status
Completion of the Spillway concrete and handoff of the Spillway to the Gates, Guides and Hoists Contractor (Canmec).	November 2017	Completed on schedule
Installation of the Powerhouse Cranes in the Service Bay.	November 2017	Completed on Schedule
Enclosure of Powerhouse Units 1 and Service Bay	December 2017	Completed on Schedule
Enclosure of Powerhouse Units to allow for the start of turbine and generator work.	February 2018	On track
Significant progress on dams and dykes required to divert the river through the Spillway in July/August 2018.	July/August 2018	On track for river diversion

Milestone - Spillway Concrete Complete

Milestone - Powerhouse Crane Installation Complete

Milestone - Enclosure of Service Bay and Unit 1

Milestone - Earthworks on Track for River Diversion in Summer 2018

2018 Plan

Improved performance by the GCC is required to meet control budget ($8.7B) and a first unit ISD 10 months in advance of control schedule.

Main contributing factors will include:

- 2018 winter concrete and south dyke work;
- Continuing to learn from past experiences;
- Earthwork foundation preparation is now complete for 2018 work;
- Cold eyes review; and
- MH and BBE leads continuing to drive improvement;

2018 Key Risks

- With 4+ years of construction ahead there are still significant risks that have the potential to jeopardize meeting the control budget and schedule.
  - This risk is typical for projects of this scale and complexity.
- The top risks include:
  - Execution/productivity rates of the GCC;
  - Loss of site access/work stoppages;
  - Unexpected geotechnical/geological conditions at the South Dam/Dyke;
  - Unseasonable weather

Current Forecast at Completion

- Manitoba Hydro is currently forecasting the following cost and schedule outcomes for the Keeyask Project:
  - Cost - A final project cost on or below the control budget of $8.7 B.
  - Schedule – A first unit in-service date in advance of the control schedule of August 2021.
    - All seven units are forecasted to be within control schedule dates.

Key Messages

- Manitoba Hydro is capable of successfully delivering the Keeyask Project and has effective governance.
  - Manitoba Hydro will continue to leverage third party expertise as required.
- Amending the contract with BBE was the best path forward with least impact to cost and schedule.
- The necessary milestones were achieved in 2017 to maintain the shortest duration schedule.
- Plans continue to be developed to cause a 10% improvement going forward to achieve our control budget.

Summary

- Hydro has a number of capital projects underway at varying levels of completion
- We are managing the risks
- We are incorporating lessons learned across the projects as we move forward
- There is a strong team in place supported by external expertise
- MH is open and transparent, gave MGF access and answered any question they had
- We want the Panel, intervenors and public to know where we are, what challenges we face, and how we address them

Bipole III Transmission Reliability Project
Overview

Manitoba Hydro

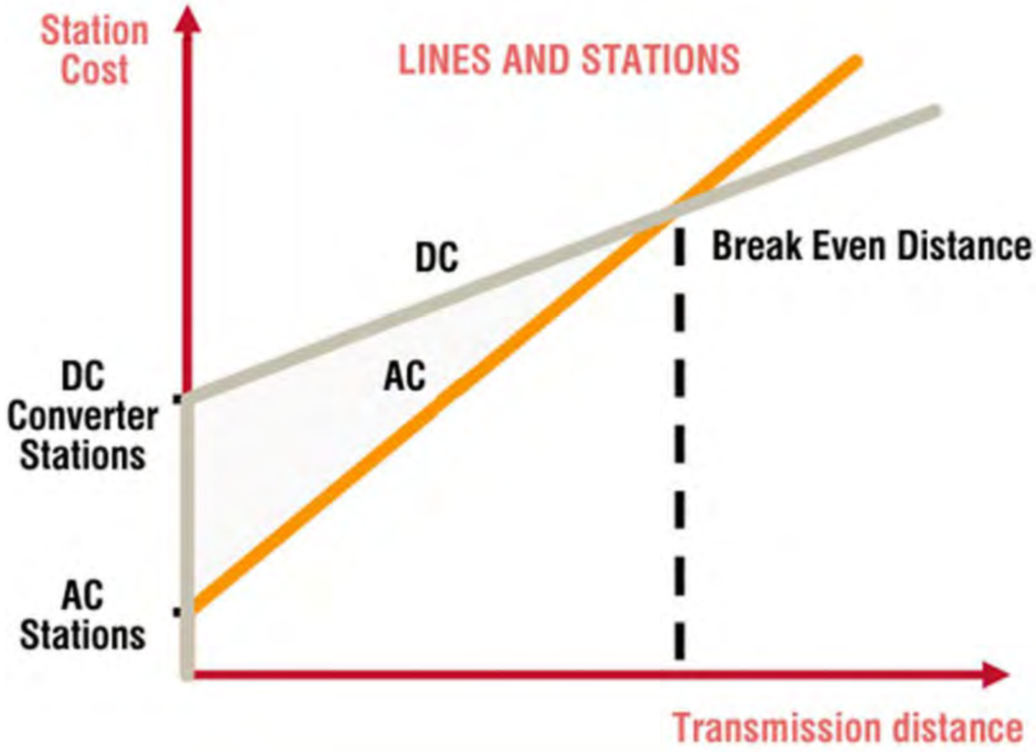
Presentation Outline

- What is HVDC
- Existing HVDC system
- Bipole III overview
- Bipole III status update
- Remaining risks
- Video

Why HVDC?

"Bulk" transmission

Why HVDC?



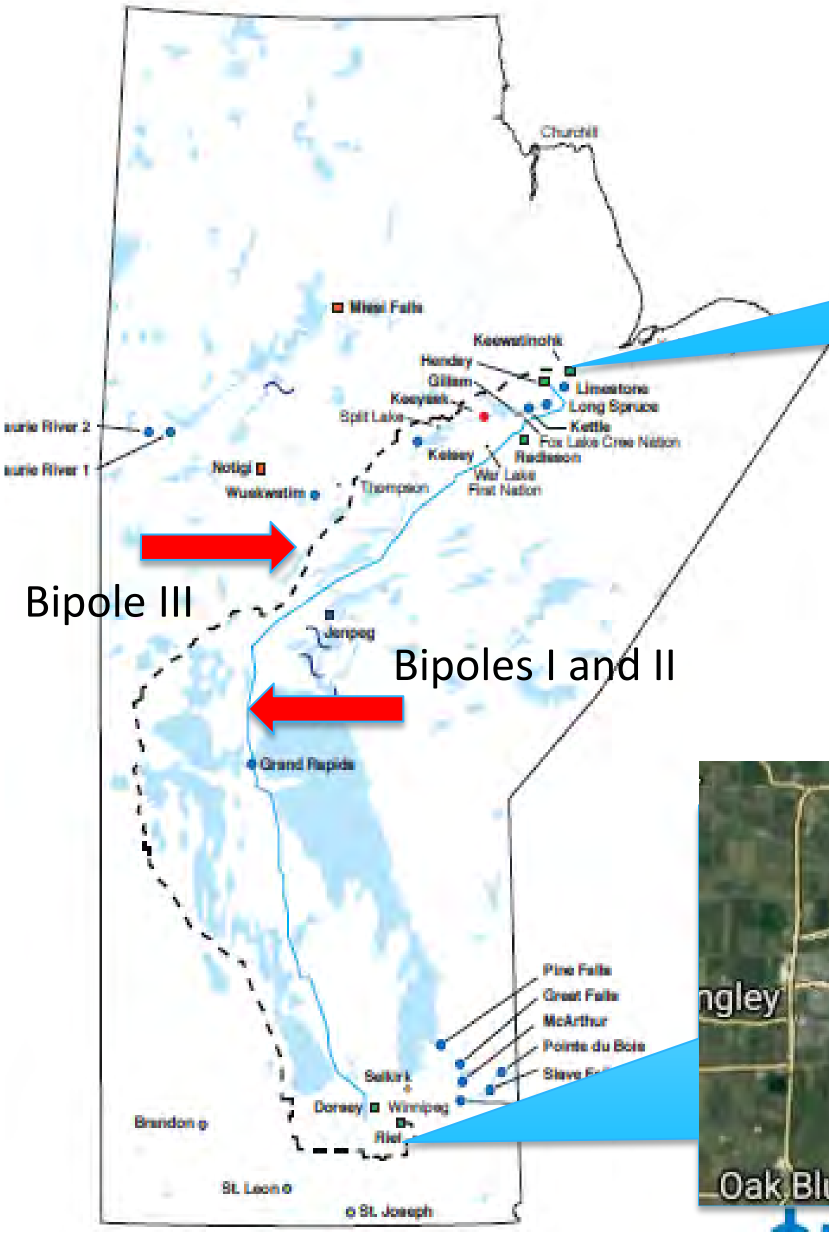
Station Cost
LINES AND STATIONS
DC
AC
Break Even Distance
DC Converter Stations
AC Stations
Transmission distance

The Existing Bipole I and II System

- Link to 70% of the Province's generating capacity
- Bipole I and II HVDC lines constructed on the same Right-of-way (same corridor)
- 900km overhead lines, difficult terrain and access in the north
- Terminated at a common station – Dorsey (inverter)

12851

Keewatinohk Converter Station



Riel Converter Station

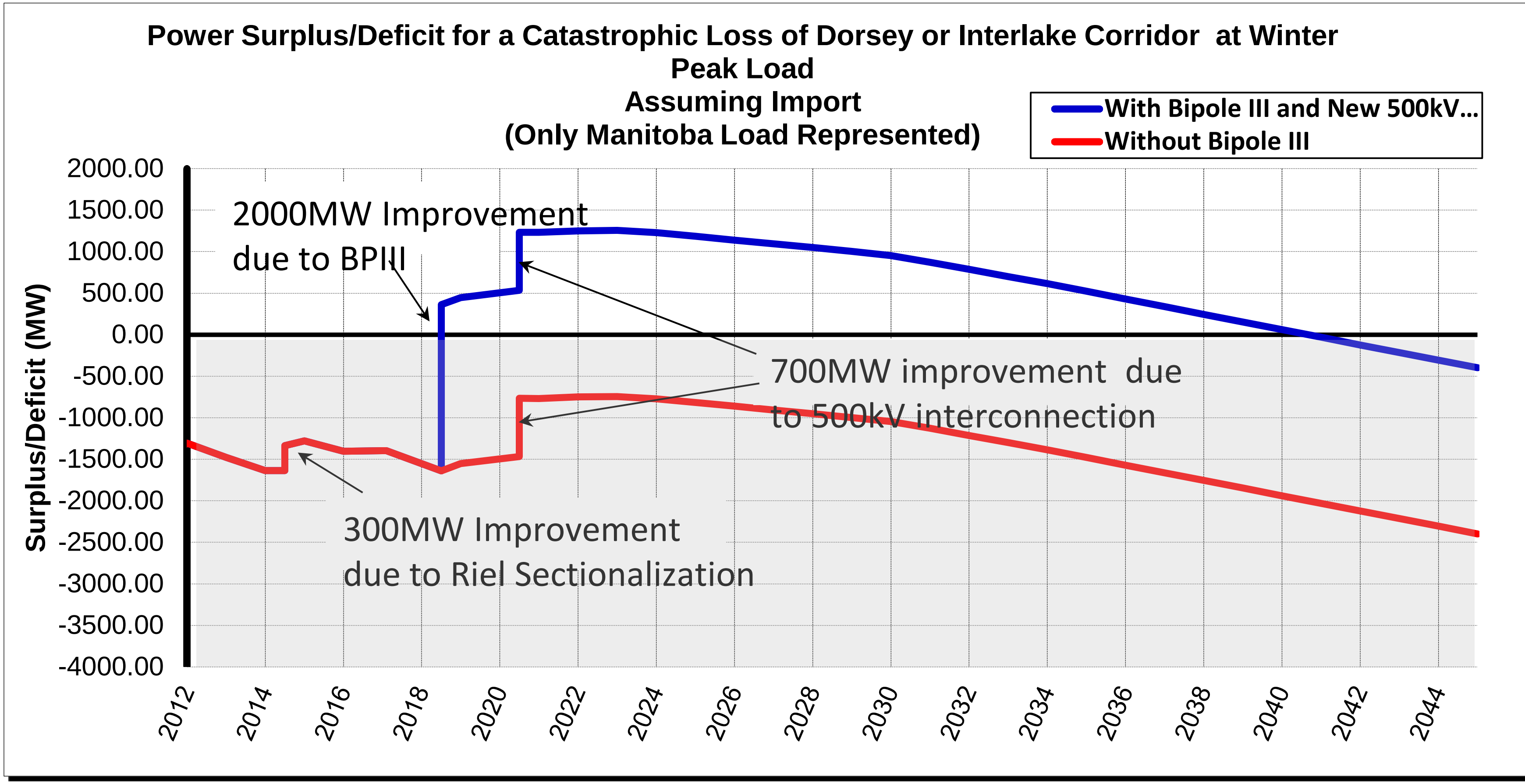
Riel Converter Station

Reliability Risk – Dorsey Converter Station

Elie F5 tornado
Approximately 40 km from Dorsey

- Dorsey is currently single terminus point for HVDC system
- Significant weather events (tornados, etc.) in the vicinity of Dorsey in the past
- A loss at Dorsey could mean loss of connection to northern generation for up to 3 years.

Supply Deficit

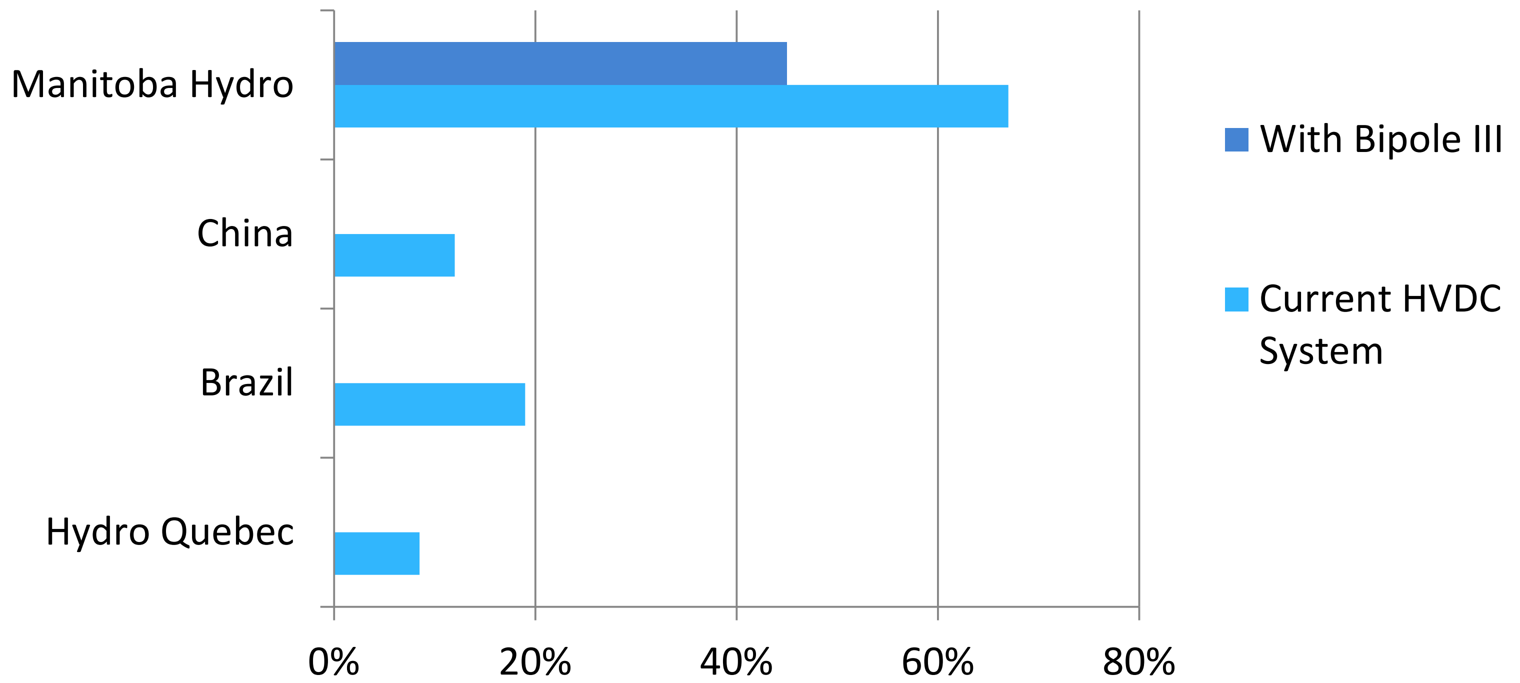


- Supply deficit of approx. 700MW for Bipole I/II line loss in winter of 2020 vs. 1,300MW surplus with Bipole III.
- Rotating blackouts for about 140,000 homes (5kW per household), even with new 500kV import line

12854

Maximum Percentage Power through a Single Facility

- Manitoba has highest percentage of power concentrated in a single facility for a major network in the world.
- "Too many eggs in one basket"

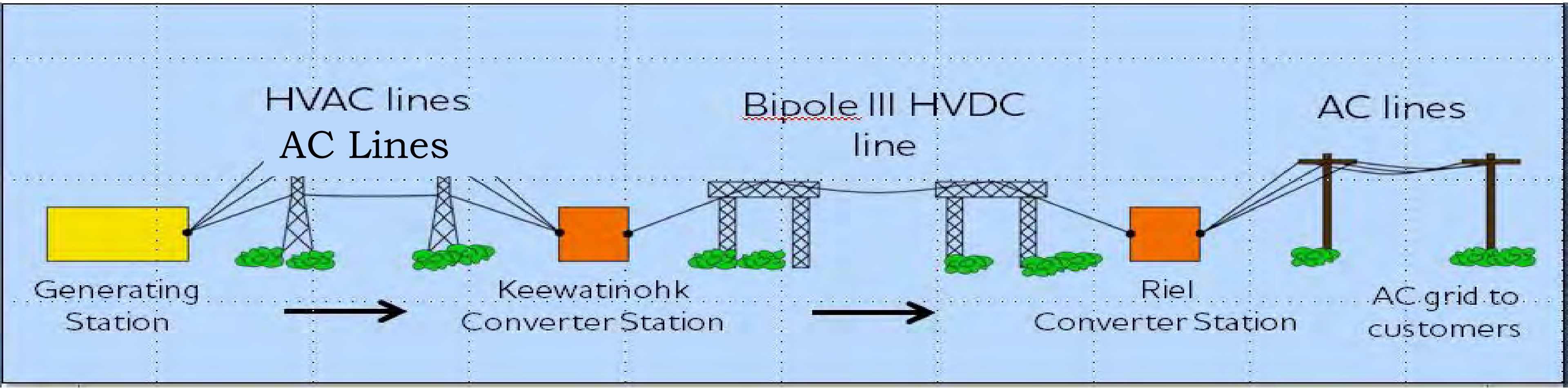


Bipole III Overview

1997 wind events near Dorsey

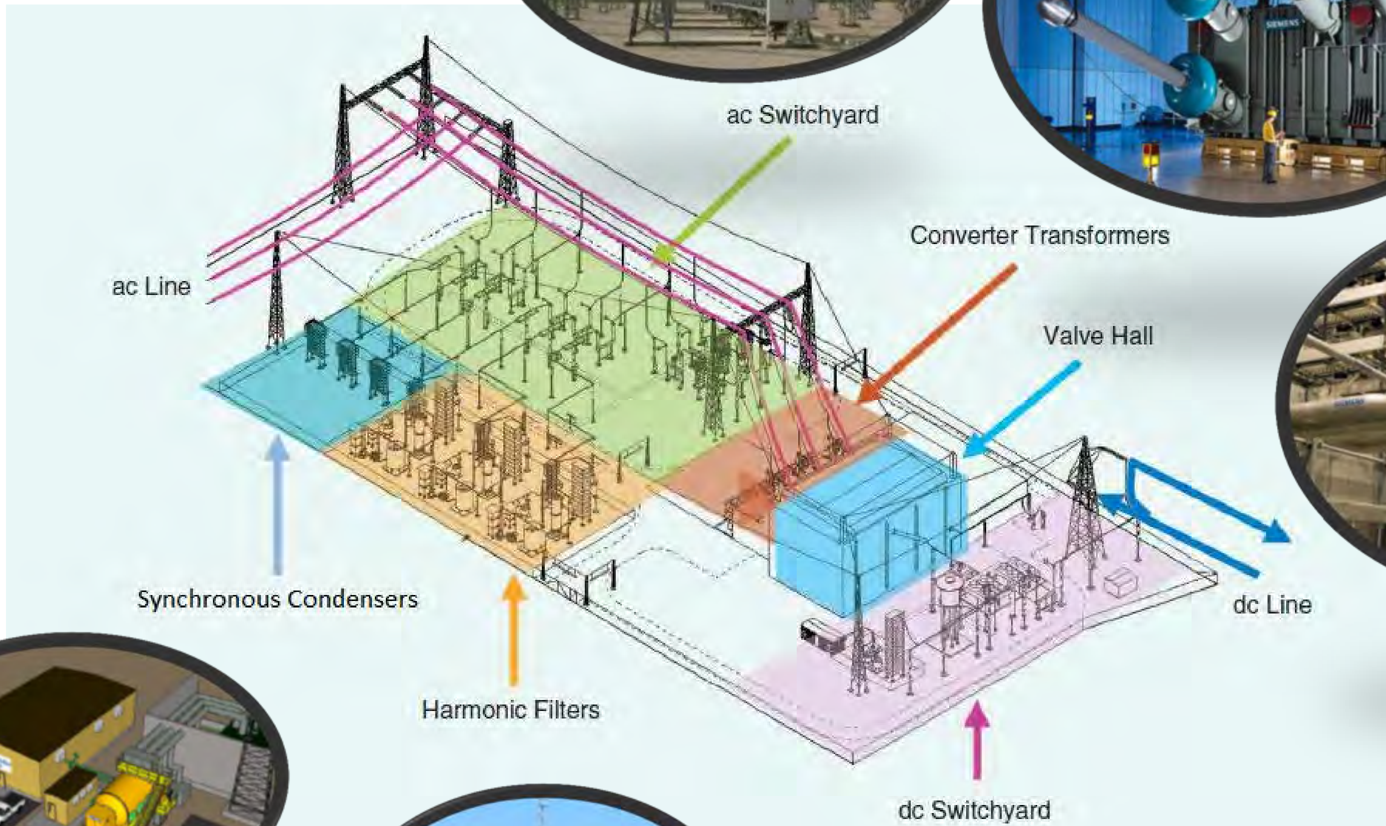
- **Increase reliability**
  - Second corridor for northern generation
  - Supply deficit of 700MW with loss of Bipole 1 & 2 (~140,000 homes)
  - Additional conversion facility
- **Increased capacity**
  - Increase of 2,000MW
  - Keeyask or associated power sale requires the transmission capacity of Bipole III

Bipole III Overview



- 230kV Collector Lines (5) to connect existing system to new Keewatinohk Converter station
- 2 HVDC Converter Stations
  - Keewatinohk Converter Station - 80 Km North East of Gillam Manitoba
  - Riel Converter Station – just East of Winnipeg
- 500kV HVDC Transmission Line (1384 km)
- Keewatinohk 600 person Construction Camp
- Tie into the southern transmission system

Converter Station



Transmission Line

Bipole III-500kV HVDC

- 500kV HVDC Transmission line
- 3,076 towers starting from Keewatinohk to Riel
- 1,388km length (actual constructed length)

Collector Lines-230kV AC

- Five AC collector lines to transfer all AC power from the Henday and Long Spruce stations to Keewatinohk
- Total length of 165km and 384 towers.

Keewatinohk Converter Station

Riel Converter Station

Bipole III Transmission Line

12862

SCOPE HISTORY OF BIPOLE III

Post Licence Control Budget

*In Service Date July 2018

2014

$4,652*

2012 2013 2015 2016

- Complete project re-estimate
- Based on updated line routing and environmental act Licence requirements
- Updated land acquisition costs
- LCC HVDC technology based on vendor pricing
- Includes Synchronous Condensers
- Includes costs for the Community Development Initiative (CDI)

SCOPE HISTORY OF BIPOLE III

Control Budget

*In Service Date July 2018

2016

$5,042

2014 2015 2017 2018

- Actual transmission line construction unit rates (market rates)
- Updated transmission line material costs
- Southern route change
- Actual land acquisition
- Increase contingency

Bipole III Status

- Converter station construction is 91% complete
- Transmission line construction is 84% complete
- Budget is 79% spent and is on target

In Service Date July 2018

- 6 months of work left to test and energize thousands of components
  - The remaining risks are more an impact to schedule, not budget

Keewatinohk CS Current Status

- HVDC equipment has been installed at site
- AC Switchyard construction is complete and energization is well underway
- Construction on Auxiliary Buildings is complete

Riel CS Current Status

- HVDC equipment has been installed at site
- AC Switchyard expansion is complete and has been commissioned
- Three Synchronous Condenser units are onsite and under installation. One Synchronous Condenser unit remains to arrive at Riel

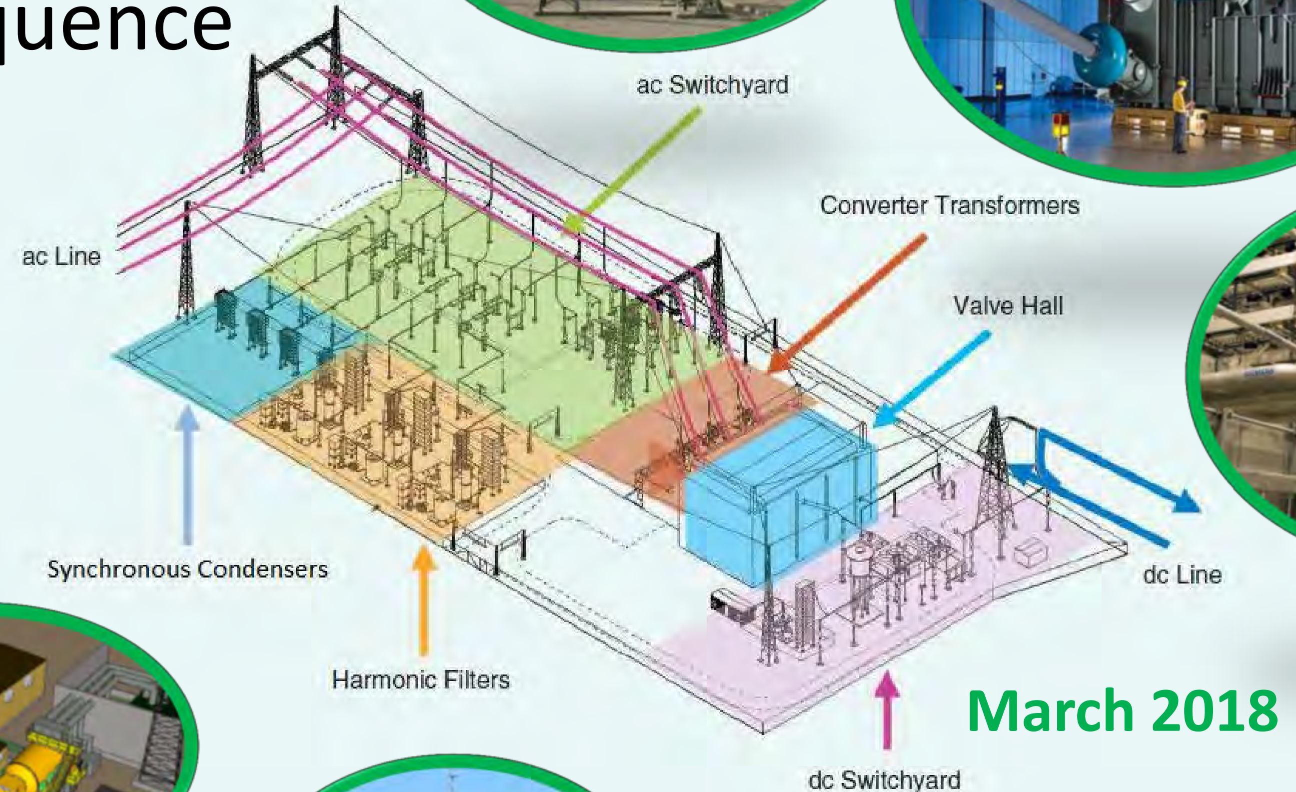
Transmission Line Current Status

- Tower anchor and foundation installation is at 99%
- Tower erection is at 84**%**
- Stringing is at 45%
- Transmission line construction will be complete March 2018

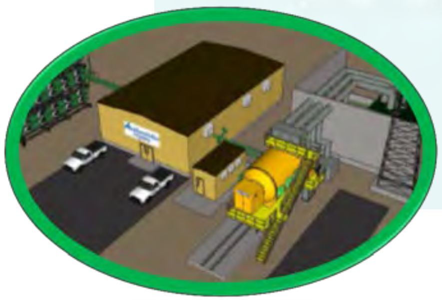
As of January 1, 2018

January 2018

Commissioning Sequence



March 2018



February/March 2018

Bipole III Commissioning

- Quality assurance to ensure manufacturing of equipment meets technical specifications prior to being placed in-service

- Equipment is tested in the factory to ensure technical compliance prior to being shipped to site

- Subsystems are verified on-site prior to being connected to the Manitoba Hydro network

- Energized system testing is conducted to integrate the Bipole III HVDC system to the existing network

Integrating Bipole III into the Existing System

- Integrating a state of the art digitally controlled Bipole into a system that was designed in the 60s and 70s

- Simulated the operation of Bipole III at the factory level with over 2000 tests

- Equipment and sub systems tests - over 500 equipment tests and 450 subsystem tests

- System testing – approximately 250 tests

- Trial operation – 30 days

Remaining Schedule Risks

- Transmission Line
  - Contractor performance
  - Weather
- Converter Stations
  - Synchronous condenser transformer delay
- Commissioning
  - 6 months of work remain to test and energize thousands of components

[Bipole III Video – 3 minutes]

Conclusion

- Construction is on schedule to be in service July 2018
- Budget is tracking to the control budget of $5.04 Billion
- Will be an asset in operation for the upcoming fiscal year
- Capital costs will begin depreciation this year

Great Northern Transmission Line Project

David Cormie, Director

Wholesale Power and Operations

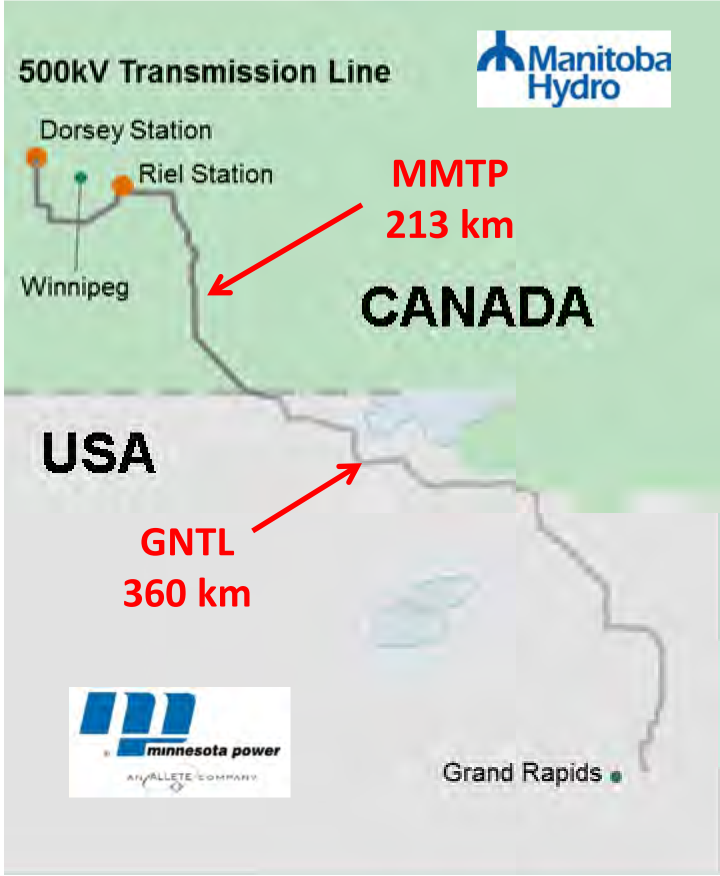
GREAT NORTHERN TRANSMISSION LINE

Connecting Manitoba and Minnesota

Manitoba Hydro

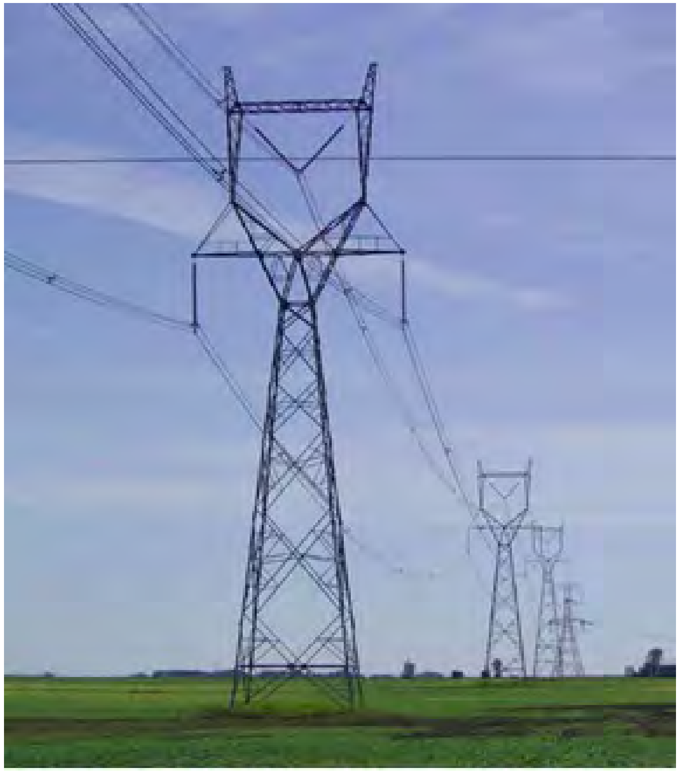
500 kV Manitoba – U.S. Interconnection

- MH Development Plan
  - Keeyask
  - New major interconnection
  - Export sales
    - Minnesota Power
    - Wisconsin Public Service
    - Northern States Power
    - SaskPower (subsequent)
- In Manitoba
  - Minnesota Transmission Project (MMTP)
- In Minnesota
  - Great Northern Transmission Line (GNTL)
- Capital cost is approximately $1 billion



U.S. Interconnection Objectives

- Import
  - Increase import capability by 100% or 700 MW
  - Improve energy security, emergency response and system reliability
  - Reduce import costs
  - Improve market prices
- Export
  - Increase export capability by 50% or 900 MW
  - Increase export market prices
  - Improve bi-lateral market access with Wisconsin utilities by 600%



The 40 year MP Transmission Deal

MH pays 72% of the construction costs

		MH Responsible	MP Responsible
Construction Costs	MMTP	100%	0%
	GNTL	71.7% (54% upfront + 17.7% MTF)[1]	28.3%
Property Taxes	MMTP	0%	0%
	GNTL	66.7% (49% ownership+ 17.7% MTF)	33.3%
Capital Taxes to MB	MMTP	100%	0%
	GNTL	100%	0%
Operating Costs	MMTP	100%	0%
	GNTL	66.7% (49% ownership+ 17.7% MTF)	33.3%
Sustaining Capital	MMTP	100%	0%
	GNTL	0%	100%

Note 1. MTF is the Monthly Must Take Fee established in Section 2.6 133 MW Energy Sale Agreement for MH use of 133 MW of MP capacity. Ownership costs on 500 MW of capacity are established through a Service Fee defined in Article 6 of the Operation and Maintenance Agreement

Manitoba Hydro

6690271's Role is to Protect Manitoba Hydro

- Responsible for MH's interests in the Great Northern Transmission Line

- GNTL Facilities Construction Agreement (FCA)
  - Between 6690271, Minnesota Power and MISO

- GNTL Construction Management Agreement (CMA)
  - Between 6690271 and Minnesota Power
  - Appoints Minnesota Power as Construction Manager
  - Establishes governance structure for the construction project
  - 669 has consultation and veto rights
  - Provides for an independent oversight engineer

GNTL Governance

Executive
(MP and 6690271)

Management Committee
(MP and 6690271)

Construction Manager

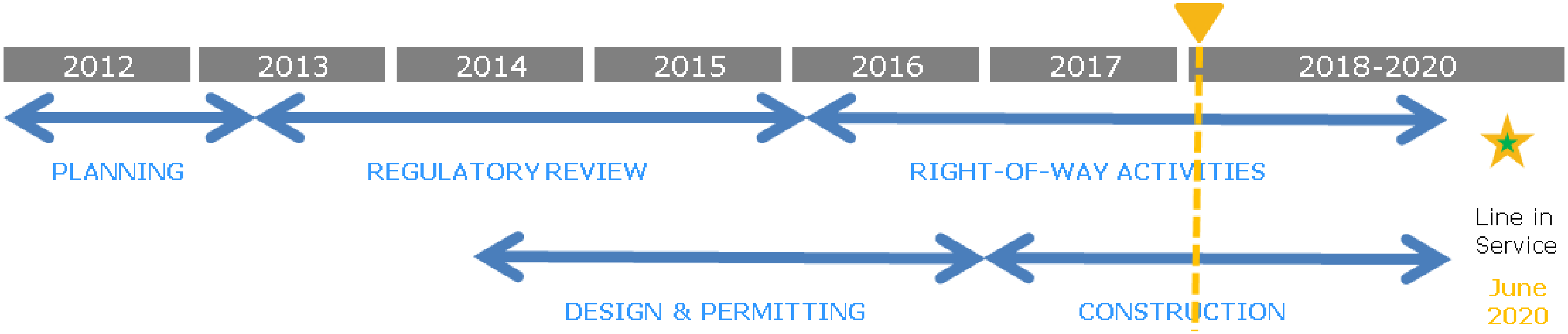
Independent Third Party Engineer

Key approval areas

Pre-construction	• Materials & equipment procurement lists • Project schedule & budget
Contracting	• Major Contracts • Major Change Orders • Material Actions
Bidding	• Pre-qualification guidelines • Approved bidder lists
Construction	• Budgetary change requests • Work schedule changes • Delay/disrupt/suspend orders

GNTL Schedule and Budget

- GNTL is on schedule for June 1, 2020
- GNTL is on budget
  - 10% spent to December 1, 2017
- MH expects GNTL to be under budget



Manitoba – Saskatchewan
230 kV Transmission Project

David Cormie, Director

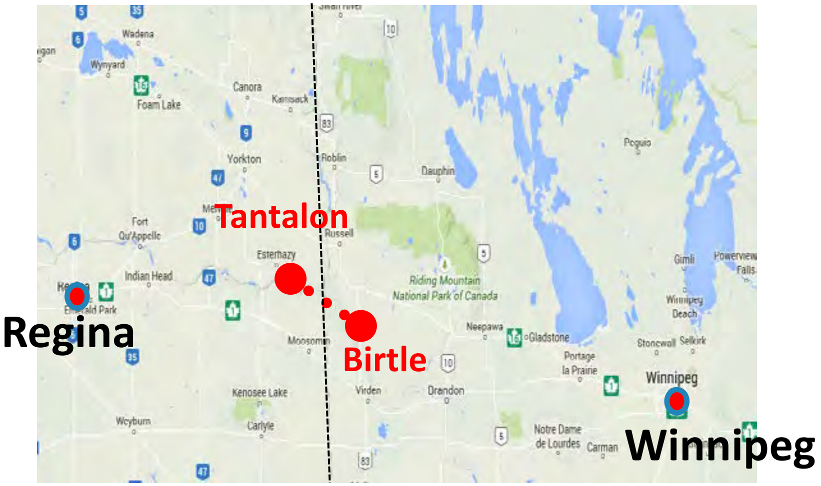
Wholesale Power and Operations

Manitoba Hydro

Saskatchewan System Power Sale Agreement

- 100 MW of capacity and firm energy
- Term is June 1, 2020 to May 31, 2040

- Existing firm export transfer capability is insufficient
- Studies indicate the need for another line
  - If project is delayed use of interim firm service, to the extent it is available, will be used
- "Both power contract and transmission line project remain economic[1]"



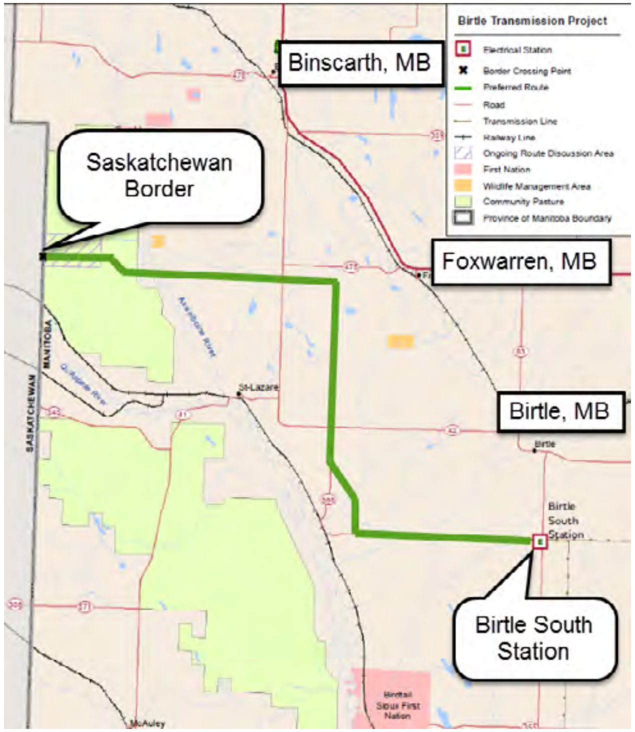
Note 1. Daymark Energy Advisors Independent Expert Consultant Report SaskPower Contract-Economic Review, dated DECEMBER 15, 2017, page 24

Manitoba Hydro

Birtle Transmission Project

- 230kV AC transmission line
  - Length 46 km
  - Birtle Station to Saskatchewan Border
  - ISD June 2021
  - Class 2 Regulatory Approval

- 2015 Approved Budget $57M



Manitoba Hydro

Major Capital Projects Summary

- Keeyask G.S.
  - On budget and schedule for ISD of August 2021
  - Several opportunities to reset for rate setting purposes if necessary
- BiPole III
  - On schedule and budget for ISD July 2018
  - Will impact 2018/19 financial results
- MMTP
  - On budget
  - Projected ISD June 2020
- GNTL
  - Budget is likely high but it is early
  - On schedule for ISD June 2020
- Birtle Transmission
  - Budget is under review
  - On schedule for ISD June 2021

Manitoba Hydro

Manitoba Minnesota Transmission Project (MMTP)

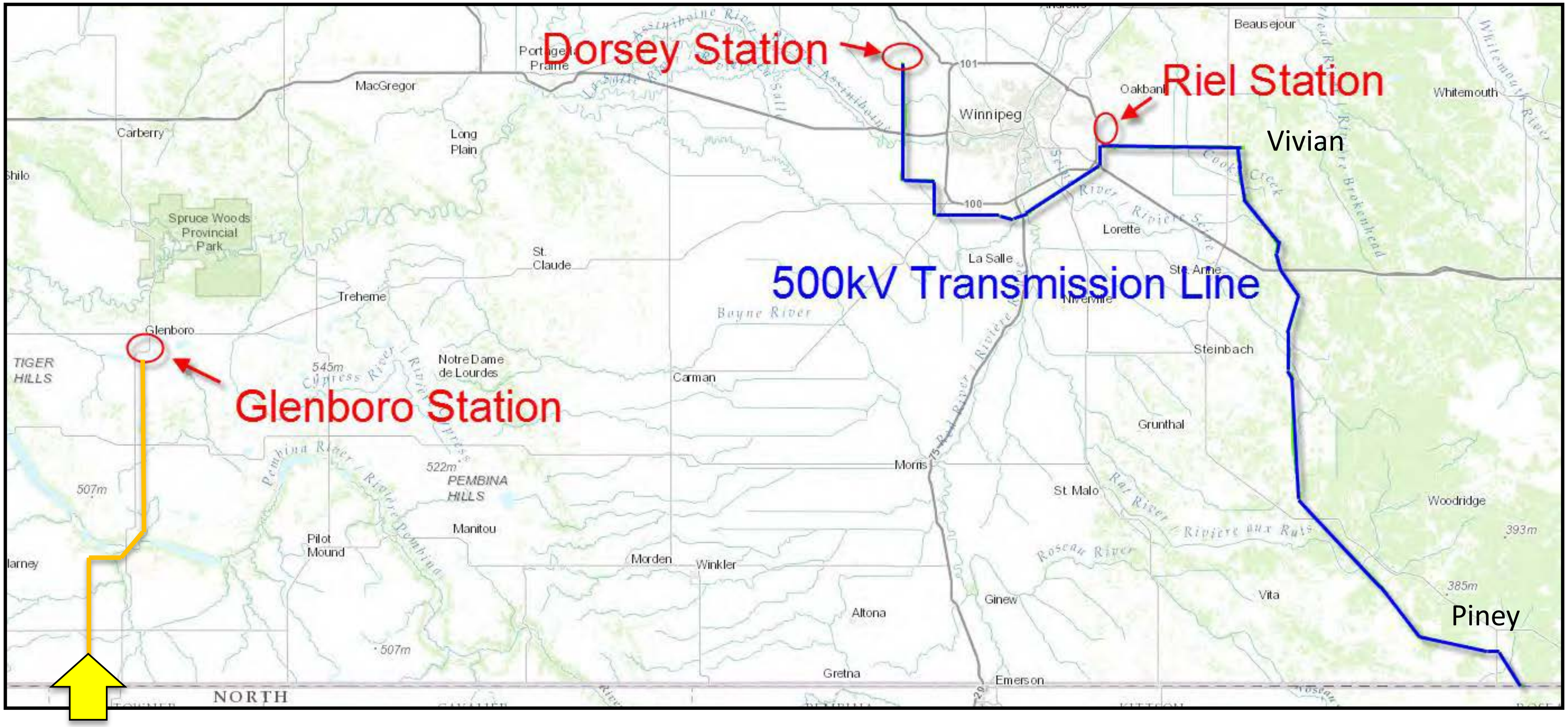
Manitoba Hydro

Project Overview

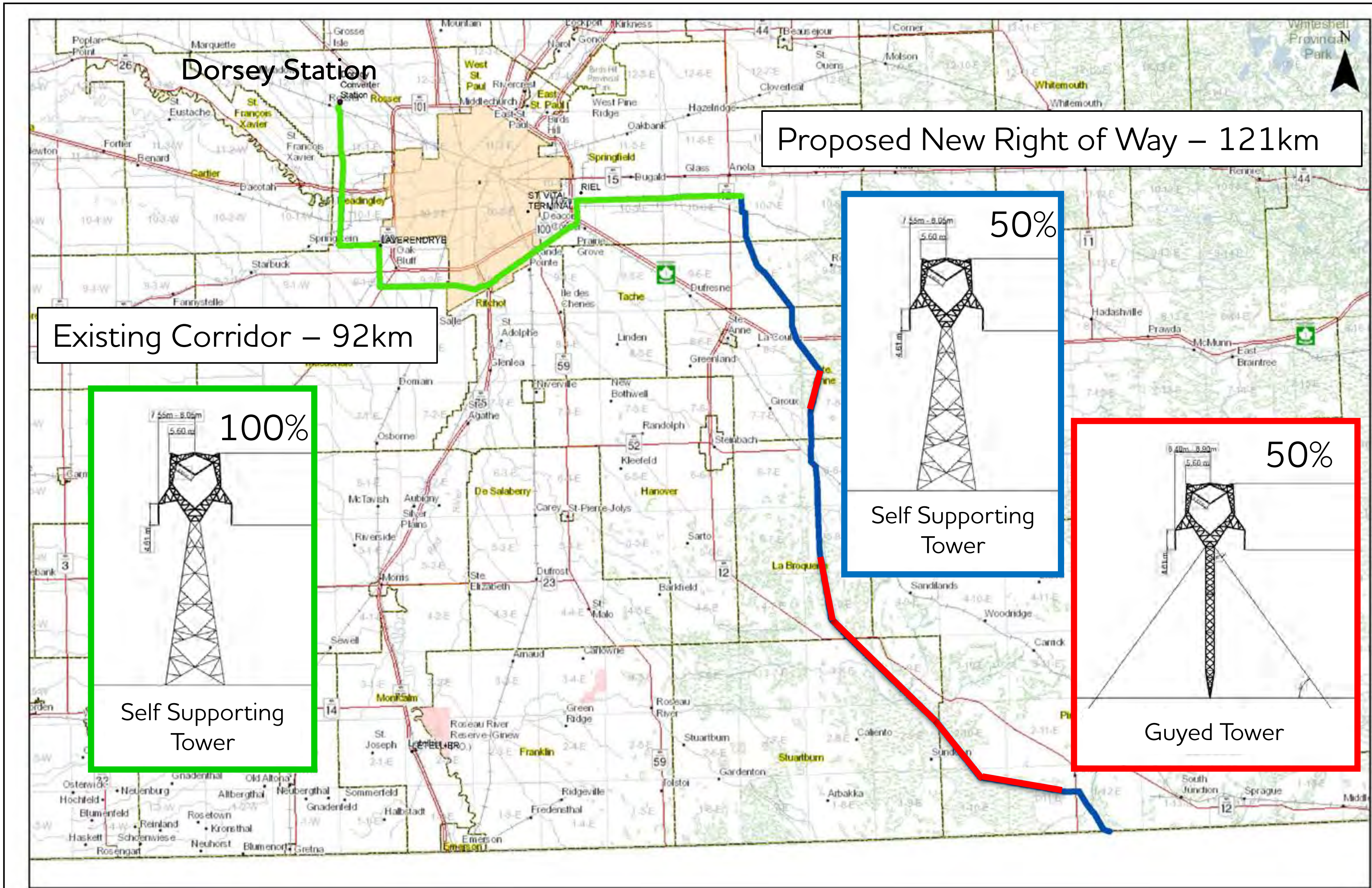
- MMTP Control Budget: $453 M
- Projected In Service Date of June 2020

Project Overview

- MMTP Components



MMTP – Transmission Line Overview



Project Execution Plan

- Internal Resources:
  - ✓ Project Management
  - ✓ Design
  - ✓ Construction Management
- External Contracts:
  - ✓ Material Supply
  - ✓ Transmission line Construction
  - ✓ Majority of station construction

12890

Budget Changes

2013
$350 M

2016
$453 M

Scope Finalization Items

- Increase in self supporting towers due to route selection
- Adding a 2nd Phase Shifting Transformer at Glenboro
- Biosecurity and Environmental Monitoring

Market Conditions Pricing

- Transmission Line Construction

Contingency

Lessons Learned

- Routing Methodologies
- Indigenous Engagement
- Biosecurity
- Contracting Models
- Construction Methods

Project Progress

2012-2015	Environmental Assessment and Public Engagement
2013	Order In Council issued by the Province
2014	NFAT Recommendation to Proceed
2015	Environmental Impact Statement Filed
2016	Application filed with National Energy Board
2017	Clean Environment Commission Hearing & Review

Project Progress

- **2016/2017** — Detailed Design/Material Procurement Underway * 10% of Budget Spent
- **2017** — Property Acquisition Underway
- **2018** — National Energy Board Hearing & Review
- **Spring 2018** — Anticipated Provincial License Decision
- **2018/2019** — Estimated Construction Start Pending Regulatory Decisions
- **2020** — Projected In Service Date


Thank You

Tab 134

Second Session - Thirty-Ninth Legislature

of the

Legislative Assembly of Manitoba

Standing Committee
on
Crown Corporations

Chairperson
Mr. Daryl Reid
Constituency of Transcona

Vol. LX No. 4 - 6 p.m., Wednesday, December 19, 2007

ISSN 1708-6604

MANITOBA LEGISLATIVE ASSEMBLY
Thirty-Ninth Legislature

Member	Constituency	Political Affiliation
ALLAN, Nancy, Hon.	St. Vital	N.D.P.
ALTEMEYER, Rob	Wolseley	N.D.P.
ASHTON, Steve, Hon.	Thompson	N.D.P.
BJORNSON, Peter, Hon.	Gimli	N.D.P.
BLADY, Sharon	Kirkfield Park	N.D.P.
BOROTSIK, Rick	Brandon West	P.C.
BRAUN, Erna	Rossmere	N.D.P.
BRICK, Marilyn	St. Norbert	N.D.P.
BRIESE, Stuart	Ste. Rose	P.C.
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CHOMIAK, Dave, Hon.	Kildonan	N.D.P.
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DERKACH, Leonard	Russell	P.C.
DEWAR, Gregory	Selkirk	N.D.P.
DOER, Gary, Hon.	Concordia	N.D.P.
DRIEDGER, Myrna	Charleswood	P.C.
DYCK, Peter	Pembina	P.C.
EICHLER, Ralph	Lakeside	P.C.
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GERRARD, Jon, Hon.	River Heights	Lib.
GOERTZEN, Kelvin	Steinbach	P.C.
GRAYDON, Cliff	Emerson	P.C.
HAWRANIK, Gerald	Lac du Bonnet	P.C.
HICKES, George, Hon.	Point Douglas	N.D.P.
HOWARD, Jennifer	Fort Rouge	N.D.P.
IRVIN-ROSS, Kerri, Hon.	Fort Garry	N.D.P.
JENNISSEN, Gerard	Flin Flon	N.D.P.
JHA, Bidhu	Radisson	N.D.P.
KORZENIOWSKI, Bonnie	St. James	N.D.P.
LAMOUREUX, Kevin	Inkster	Lib.
LATHLIN, Oscar, Hon.	The Pas	N.D.P.
LEMIEUX, Ron, Hon.	La Verendrye	N.D.P.
MACKINTOSH, Gord, Hon.	St. Johns	N.D.P.
MAGUIRE, Larry	Arthur-Virden	P.C.
MALOWAY, Jim	Elmwood	N.D.P.
MARCELINO, Flor	Wellington	N.D.P.
MARTINDALE, Doug	Burrows	N.D.P.
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McGIFFORD, Diane, Hon.	Lord Roberts	N.D.P.
MELNICK, Christine, Hon.	Riel	N.D.P.
MITCHELSON, Bonnie	River East	P.C.
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OSWALD, Theresa, Hon.	Seine River	N.D.P.
PEDERSEN, Blaine	Carman	P.C.
REID, Daryl	Transcona	N.D.P.
ROBINSON, Eric, Hon.	Rupertsland	N.D.P.
RONDEAU, Jim, Hon.	Assiniboia	N.D.P.
ROWAT, Leanne	Minnedosa	P.C.
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SCHULER, Ron	Springfield	P.C.
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SELINGER, Greg, Hon.	St. Boniface	N.D.P.
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TAILLIEU, Mavis	Morris	P.C.
WOWCHUK, Rosann, Hon.	Swan River	N.D.P.

LEGISLATIVE ASSEMBLY OF MANITOBA

THE STANDING COMMITTEE ON CROWN CORPORATIONS

Wednesday, December 19, 2007

TIME – 6 p.m.

LOCATION – Winnipeg, Manitoba

CHAIRPERSON – Mr. Daryl Reid (Transcona)

VICE-CHAIRPERSON – Ms. Flor Marcelino (Wellington)

ATTENDANCE – 11 QUORUM – 6

Members of the committee present:

Hon. Mr. Selinger

Mr. Altemeyer, Ms. Braun, Messrs. Caldwell, Cullen, Goertzen, Ms. Marcelino, Messrs. McFadyen, Reid, Mrs. Rowat, Mr. Saran

APPEARING:

Hon. Jon Gerrard, MLA for River Heights

Mr. Bob Brennan, President and Chief Executive Officer, Manitoba Hydro

Mr. Victor H. Schroeder, Chairman, Manitoba Hydro-Electric Board

MATTERS UNDER CONSIDERATION:

Annual Report of the Manitoba Hydro-Electric Board for the year ended March 31, 2004

Annual Report of the Manitoba Hydro-Electric Board for the year ended March 31, 2005

Annual Report of the Manitoba Hydro-Electric Board for the year ended March 31, 2006

Annual Report of the Manitoba Hydro-Electric Board for the year ended March 31, 2007

* * *

Mr. Chairperson: Good evening, everyone. Will the Standing Committee on Crown Corporations please come to order.

This meeting has been called to consider the annual reports of Manitoba Hydro for the years ended March 31, 2004, 2005, 2006 and 2007.

Before we get started, are there any suggestions from the committee on how long we wish to sit this evening?

Mr. Cliff Cullen (Turtle Mountain): Mr. Chair, just for the committee's perusal, I wondered about 8:30 and then review at that time.

Mr. Chairperson: It's been suggested that the committee sit until 8:30 and then review at that point in time. Is the committee in agreement? *[Agreed]*

Are there any suggestions as to which order the committee wishes to consider the reports as previously mentioned?

Mr. Cullen: I just wondered if we could maybe review the reports on a global basis.

Mr. Chairperson: It has been suggested that the committee review the reports on a global basis. Is that agreed? *[Agreed]*

Thank you to members of the committee. We'll now proceed.

Does the honourable minister wish to make an opening statement, and to also introduce his officials at the table with us here this evening?

Hon. Greg Selinger (Minister charged with the administration of The Manitoba Hydro Act): Yes. First, I'll like to introduce Chairman of the Board, Vic Schroeder, and President and CEO, Bob Brennan, who are with me tonight.

I was wondering, also, if I could ask the critic: Is there an intention to try and pass a report tonight?

Mr. Cullen: Yes. We'll certainly give it serious consideration to passing a report and probably the oldest report that's on the record.

Mr. Selinger: I appreciate that.

In terms of opening statements, I was wondering if we could indulge the committee for a few minutes and ask the president and CEO just to give us a little short update–I'm not trying to divert the committee from other concerns they have–on where we stand with wind, the short list, and a little bit on the low-income energy efficiency project. Then, of course, I think there may be a lot of follow-up on the questions that were answered. I know the president tabled with this committee, and I believe all members have a copy of the questions and the answers that were given. Then I think the chairman of the board would like to make a statement. Then, of course, I may follow up on that myself. Okay?

Mr. Chairperson: We thank the honourable minister for the opening statement.

We'll now proceed to the critic for the official opposition to make an opening statement.

Mr. Cullen: Just very briefly, certainly, it's nice to have the opportunity to get together with representatives from Manitoba Hydro, and we look forward to questions going forward. That's all I have to say. Thank you.

Mr. Chairperson: We thank the critic for the official opposition.

We'll now proceed to statements by the officers from Manitoba Hydro, Mr. Brennan and Mr. Schroeder. Whichever one you–

Floor Comment: Mr. Brennan.

Mr. Chairperson: Mr. Brennan. Please proceed, sir.

Mr. Bob Brennan (President and Chief Executive Officer, Manitoba Hydro): What a start, eh? Got it right.

On December 14, Manitoba Hydro issued a press release pointing out that we're moving to the next step in our process for the 300 megawatts of wind that we'd like to add to our system. At that point, we came up with a short list of seven various suppliers. The total amount of wind that's included in that is approximately 1000 megawatts, and we're asking those people to firm up their price and come back with a firm price. Some of the technical specifications were changed as to what we require, and now the suppliers have some benefits in terms of the federal government incentive credit, as well as any credits for gas emissions or carbon credits. They are to incorporate that in their firm prices that they're to give back to us. We're hoping to get everything back near the end of January, at which time we'll try to get something available very quickly to take to the Hydro board.

Mr. Selinger: Bob, did you want to just talk a little about the low-income energy efficiency program that we announced last week?

Mr. Brennan: I have copies of the press releases that we did issue at that time should anybody want one.

On the same date, we issued a press release and announced a low-income program for low-income people in Manitoba. The particular program we have is done in conjunction with the Affordable Energy Fund, Manitoba Hydro's Power Smart program, and it's incorporated with the federal ecoENERGY program.

The program is going to be delivered in two ways, through a community-based approach or through individual applications. The program itself is targeted at, as I mentioned, the low-income people of Manitoba, and we have a range on salary depending on whether it's in the city of Winnipeg or outside the city of Winnipeg. All of them are in accordance with the ecoENERGY program, retrofit program, of the federal government. We're going to have to require an audit at the beginning and the end to make sure that the money is directed at the right type of saving for each house, as well as the actual savings having been achieved.

When they go out and do the first audit, they will get compact fluorescent lights, showerhead aerators, low-flow showerheads and the like, and then the program itself includes insulation in basements, attics and crawl spaces as well as high-efficiency natural gas furnaces. That's it, Mr. Chairman.

Mr. Chairperson: Thank you, Mr. Brennan.

Mr. Brennan: One other thing I should mention–I'm sorry.

Mr. Chairperson: Mr. Brennan, please proceed.

Mr. Brennan: When I did commit to responding to some of the questions that were left dangling, and I did that recently, and sent it to the Clerk.

Mr. Chairperson: Thank you.

Mr. Schroeder, please proceed, sir.

Mr. Victor H. Schroeder (Chairman, Manitoba Hydro-Electric Board): I just wanted to give some background. I'm going to be tabling a report. I am hoping there are copies available.

Manitoba Hydro suspended its preliminary consultations with east-side communities back in 2003, in the context of the East Side Planning Initiative. In '04-05, the board asked Manitoba Hydro to consider alternatives to the east side for bipole 3. Hydro studies into a range of options concluded that the west side was the best other viable solution to improve reliability. Based on the technical scope of their studies, in fall 2006, Hydro management recommended proceeding with bipole 3 on the west side if the east side was not available. The Hydro board at that time requested additional information beyond the technical aspects on the routing options, including environmental impacts and risks associated with environmental opposition to the east-side route. The board performed what we believe is thorough due diligence, considering risks to export markets and resultant risks to Hydro customers, potential of licensing delays, capital costs, reliability issues, technical issues, environmental factors, as well as public policy considerations of the government in making its routing decision.

***** (18:10)

This year, CMC Consultants Inc.–David Farlinger is the principal; I think most members of the committee are familiar with his background–was engaged to prepare a report on the environmental considerations and risks benefits associated with environmental opposition, including with respect to Hydro's export markets. His study recommended that government play a major role in routing assessment, noting that many routing considerations fall outside of Manitoba Hydro's mandate, and government is significantly impacted and has much at stake in the decision: debt, reputation, duty to consult, responsibility for environmental stewardship and community and economic development.

In light of the government's election platform statements made ruling out bipole 3, the board requested that government detail its public policy position on the issue. Government was provided with the Farlinger report. Government then provided its position to the Manitoba Hydro board in writing. Management repeated its recommendation to proceed with a west-side routing if the east side is not available. I'd like to table the Farlinger report. The report also has in Appendix I, I believe it is, its terms of reference.

Mr. Chairperson: Thank you, Mr. Schroeder, for the comments.

Before we proceed to open up the floor for questions, I just want to remind committee members, as Chairperson, that for the benefit of our good folks with the *Hansard* behind me here that if you could please pull your microphones close when you're speaking, it would be helpful. Also, if we could have the questions addressed through the Chair and wait until the Chair recognizes you before speaking in response to the question or asking the original question, that would be helpful too, for the benefit of our *Hansard* folks. We hope members of the committee will help us in that regard.

Floor will now be open for questions.

Mr. Selinger: Yes, as a result of the Farlinger report and a request I received from the chairperson of Hydro, I was asked to give the government's perspective on east side versus west side. As we all know, it had been enunciated earlier in the election window, and I provided a letter to the chairman of Manitoba Hydro, Vic Schroeder. I'm proposing to table a copy of that letter tonight with the committee. I'd like to do that and make sure everybody has copies of it. I think I have enough copies for everybody. So I'll take one for myself and you can just distribute as many of them as you can.

In the letter–and I know people will need some time to absorb it, which is why I'm circulating it before I make my comments and we can have the evening to discuss any of these things if you wish–I stated just the history of our experience with the east side since we came to government and start out by pointing out that, as early as August 2000, we made a commitment to initiate broad area planning on the east side of Lake Winnipeg as a result of accepting the Consultation on Sustainable Development and Implementation report, commonly known as COSDI. They had recommended broad area plans.

The east side was chosen for a variety of reasons that are delineated in the letter. Some of them were that the area is unique and environmentally spectacular, containing a vast expanse of undeveloped contiguous boreal forest. The east side is the home to a population that is 96 percent First Nation. It's one of the largest habitats for the threatened woodland caribou and home to the Bloodvein River as well as the Manigotagan River, the Bloodvein being a Canadian Heritage River, both rivers renowned for their marvellous recreational significance and access to transportation and networks. Many economic opportunities are more limited than in other parts of the province. As well, the east side has begun to feel the effects of climate change.

So I go on to make a variety of points in the letter. As well, I identify some of the issues that were discussed in the Farlinger report. The Farlinger report made no recommendations as to routing. It made a process recommendation, which is why I've asked for these items to be tabled tonight. The process recommendation, essentially, is that the issues are broader than the technical considerations for where the line should go. There are broad public policy matters here and that Manitoba Hydro should get the views of government on this, and that's why the chairperson asked me for my views in writing, even though they had been stated in broad terms in the election. So the letter is my commitment to provide the chairperson and the Hydro board with our views in writing. We can discuss the contents of the letter as you wish to go on this evening.

But, in general terms, and we've discussed this in the Legislature as well as in the public, we saw this as an attempt to manage a variety of risks. One risk that we accepted, that needed to be acted on, was to increase the reliability of the hydro-electric system in the province and that had been a concern of Manitoba Hydro for many years. They were suggesting that they needed to take decision and take action on moving on increased reliability. What that really meant was they needed another bipole. The bipole was, in part, a response to the challenge that was identified in the Farlinger report that in 1996 there had been a serious problem with the existing bipoles. I think something to the effect of 16, 17 towers went down and created quite a risk to customers. Fortunately, at the time, it wasn't a peak period for demand. They were able to respond to and manage that risk and get the system back in shape.

But, ever since 1996, there was a heightened awareness that there needed to be action, so the government started working with Hydro on figuring out solutions to this. Previous ministers of Hydro announced that they thought, based on broad consultations with communities on the east side, a west-side option should be considered by Manitoba Hydro. So reliability risk was one of the risks that needed to be addressed in terms of broad public policy.

The other risk was the question of the environment and the boreal forest which has become a higher profile issue throughout North America. We know that many scientists have weighed in on this and many groups have asked that there be consideration to the east side being a UNESCO World Heritage Site. There's a lot of work that's being done on that and more work that needs to be done. We'll have a good discussion about that this evening as well.

Thirdly, there was the issue of insuring that the reputation of Manitoba Hydro, which is a good reputation, continues to be protected as a supplier of green energy, as a corporate entity in the public sector in Manitoba, as a Crown corporation that acts in both an environmentally responsible and a socially responsible way.

So, when you put it together, you've got reliability risk, environmental issues and risks to our reputation in terms of customers and market, maintaining a good reputation in the markets that we sell in, primarily in the Minnesota region and in that part of the United States. Our views in the letter expressed the concern that we consider other alternatives. We didn't say to Manitoba Hydro, you shall pick this route. We asked them to consider another route other than the east side. The Farlinger report was an attempt by Manitoba Hydro, as I understand it, to look at those broader issues, and that led to their request to me to give them some of our views in writing. The reason I'm tabling these documents tonight is I think there's important information in here that we may wish to discuss to get more specificity about where this whole project is going and a greater understanding of the thinking that went into this.

With those comments, I'll leave it and perhaps we can start with questions or any issues that are arising, not only out of the documents we've tabled tonight, but out of the responses that the president tabled as the result of questions that were left unanswered or required further clarification at the last meeting.

Mr. Chairperson: I thank the honourable minister. I take it, then, that all committee members have been presented copies of the letter and the report for their viewing.

The floor is now open for questions.

***** (18:20)

Mr. Hugh McFadyen (Fort Whyte): Thank you, Mr. Chairman, and thank the minister for the comments. Also, thank you, Mr. Schroeder, for your comments and Mr. Brennan as well, and would note that this is the second time this committee has met in as many months. We certainly appreciate the fact that there's time involved in preparing, time involved in following up on questions and the fact that it's been some time since the committee met previously. We appreciate the fact that we're having this opportunity to meet twice in a short period of time and that people have been good enough to make their schedules available.

It is an important process fundamental to legislative oversight of Manitoba Hydro as a

Crown corporation. We certainly acknowledge in that vein that there is a role for government in establishing guidelines and policy and other parameters within which the corporation must operate, and that, certainly, you know, our criticisms and comments have been more directed toward those guidelines and frameworks than they have been toward any decisions made at the level of the corporation. Much of the debate around the location of the bipole line surrounds the guidelines that Hydro has been provided to operate within.

So I just want to say that we have appreciated the very thorough and candid technical information that's been provided to date. Certainly, on reviewing the record and looking at the responses that have been provided, we know that every effort has been made to provide full, candid responses on all of the technical points. We are into a debate that has policy implications certainly, but which is informed by the factual basis and the technical issues that arise.

I would just like to come back, if I could, just initially, with a couple of questions to Mr. Schroeder just arising from his opening statement as chairman of Manitoba Hydro. There were a couple of points that were of particular interest, some of which, I think, is already on the record and has been established, some of which, I think, is at least new to me if not anybody else tonight.

The first question I have is to come back and confirm or clarify that, when the east-side consultations were suspended in 2003, you're saying that they were suspended because of the east side planning process that was then under way. Is that correct?

Mr. Schroeder: That's right, thank you, Mr. Chairman. The minister at that time anticipated that there would be a three-to-six-month process, and then what happened was one of the people involved in that process became the national chief, Phil Fontaine, someone else became–was it–in any event, another person had a career change and so on and there were numerous delays. That certainly was not something anyone was happy about.

The background was the government had announced its wide area planning initiative on the east side in about 2000. We, completely independent of that, started our consultations on the east side in 2001, and by 2003 there were people in the wide area planning initiative process who were not happy with our being out there in the field at the same time as a whole other wider set of consultations was going on.

Mr. McFadyen: The east side planning process you're referring to is a process that ultimately culminated in what's known today as the WNO agreement that was signed in April of this year. Is that correct?

Mr. Schroeder: That's my understanding of it, but from 2003 that was the end of our involvement.

Mr. McFadyen: Can I just ask then, as part of the east side planning process that took place that overtook essentially the consultations that were then ongoing by Manitoba Hydro, was there a proposal in front of east-side communities with respect to the possibility of a transmission line, or was that removed from the table in 2003 as the east side planning process was getting under way?

Mr. Schroeder: I am not aware that it was removed. We were consulting between 2001 and 2003 with east-side communities with respect to proposed bipole 3 on the east side. We temporarily abandoned that and never did get back to it.

Mr. McFadyen: One other comment that you made that got my attention was, you said that in light of election platform commitments made in the general election of earlier this year, the board felt that, or essentially felt that the government had a mandate, or the board had an obligation to remove the east-side route as an option. Are you aware that, in the course of that same election campaign, the Premier (Mr. Doer) committed on two different occasions, publicly, that the west-of-Lake-Winnipegosis route would not be used, and that the next bipole would go through the north?

Mr. Schroeder: I'm not aware of that. We had a presentation from Crown Corporation Council back in 2000, discussing and suggesting to us the role and responsibility of boards of Crown corporations. And, of course, there's a legal responsibility in the Hydro act for me to consult with the minister.

According to the information we received, the board must ensure that the corporate mandate is consistent, obviously, with legislation, but also with government objectives. So the board wanted to make sure that there were no misunderstandings, No. 1. We wanted to make sure that all issues were on the table had been fully considered, and that's one of the reasons we asked for the Farlinger report. At that point it seemed to us that it was appropriate, given that it appeared to be public policy on the part of government that we not proceed down the east side, that that be made clear to us, in which case there really was not a decision for us to make other than what is the best other route, and that's what we did.

Mr. McFadyen: I think we can probably agree, but get your confirmation that, obviously, there are pros and cons to either an east-side route or a west-side route. There are different considerations: financial, environmental, impact on communities, all of these things; impact on species and other things. And I think that there is consensus that the west-side route, which is being pursued currently, compared to the east-side route that had earlier been recommended by Manitoba Hydro; when you consider the cons of that west-side route, that it is more expensive, it will produce a less reliable power grid, it will take two years longer to complete and result in more lost power, would you agree that those are the cons of the west-side option?

***** (18:30)

Mr. Schroeder: I would agree with all except the two years longer to complete, because I think that's a question that's very, very much in play. The question of whether we would've ever been able to get a licence for the east side, certainly, is something that's a legitimate concern. That's, you know, going back to the previous board, back in 1999. They chose to leave 150 megawatts stranded at Wuskwatim because they weren't sure they could get a licence getting the full value. So 150 megawatts will stay there for the next 100 years. They also, as we were very concerned about their green image. The green image of this corporation is important for our sales efforts outside the province. Those sales efforts are what keep our electricity rates low. So I certainly don't think that one could say with any degree of certainty that we would have a line down the east side two years earlier or ever. You know, 30 years ago I represented the Province of Manitoba in the Mackenzie Valley pipeline hearings. We still don't have a pipeline. There are a number of those kinds of examples where you have environmental opposition that can hold things up.

Mr. McFadyen: So you're not prepared necessarily to accept that it will take longer to complete, but you do agree that the west-side route is more expensive, will produce a less reliable power grid, and will result in more lost power than the east-side option.

Mr. Schroeder: Yes, if we could build it.

Mr. McFadyen: If I can just come to Mr. Brennan then, just with respect to the completion times issue. You, the corporation issued, in response to questions from the Manitoba Industrial Power Users Group in connection with the general rate application before the PUB, responded to questions, and in a document dated December 5, 2007, two weeks ago today, the indication or the document states, and I don't know if you've got–do you have a copy of that document in front of you, Mr. Brennan?

Mr. Brennan: It's a huge document.

Mr. McFadyen: Right. There's a specific question and answer that I just want to ask you about. If I may, I am providing, it's a–the reference, sorry.

Floor Comment: Are there copies for tabling?

Mr. McFadyen: Yes, he does.

Mr. Chairperson: Are we okay to proceed?

Floor Comment: We're just making copies for the rest of them.

Mr. Chairperson: Okay. Is everybody ready?

Mr. McFadyen: Thank you, Mr. Chairman.

The document that's being referenced is a document prepared by Manitoba Hydro. The heading is MIPUG\MH I-10 and it's referenced to major projects and its question, lowercase c). In the answer provided by Manitoba Hydro two weeks ago, it states, and I quote: "The longer route will involve dialogue with a larger array of local governments, towns and villages. This is estimated to add one year to complete the multi-year public/community consultation program associated with Manitoba Hydro's site selection and environmental assessment process. Manitoba Hydro believes that the public/community consultation process and related environmental assessment/licensing activities for either a west or east side option are challenging." And then, "Construction of a western routed line is estimated to take a year longer than an eastern routed line."

This is consistent with what you had previously testified to in committee, which is that the western route–setting aside the risk of not being granted a licence, which I want to come to in a second–but that the process of going through consultations and then ultimately building the west-side route is two years longer than it would be on the east-side route. That's the view of Hydro, is it?

Mr. Brennan: Putting aside the possibility of not getting a licence, it is estimated and, at this point, it's only an estimate, that it would take a year longer to go through the consultation process, and it would also take another year longer to go through the construction phase. Those are certainly estimates, but that's our current estimate.

Mr. McFadyen: If I can just come back to a question I put to Mr. Schroeder. Coming to the cons of west side versus east side, and we're going to come to the arguments in favour of west side in a second because I know they are laid out in the report that's been tabled by the minister, but, on the con side, the issue with west side is that it is more expensive; No. 2, it's less reliable; No. 3, it's going to take longer to complete, setting aside the issue of licensing risk which we'll get to, and, No. 4, it is going to result in more lost power.

Would you agree that those are four major problems with the west-side route?

Mr. Brennan: Are you asking me or Mr. Schroeder?

Mr. McFadyen: Sorry, that's to Mr. Brennan.

Mr. Brennan: I think that's correct.

Mr. McFadyen: I would, then, just like to ask you whether it is for those reasons that you recommended an east-side line at the time that you were making recommendations.

Mr. Brennan: We certainly needed to take care of our reliability issues as soon as we could, but, for the most part, the fact that we believed we can handle the environmental issues and the issues associated with it, I guess, we hadn't gone through the consultation process the way the Province did, so we certainly thought we could get a commitment to the east side. So the reasons that you gave, I think, are valid from management's perspective.

Having said that, we did find that, after the Province went in and consulted, they seemed to get a different result than we thought we were going to get.

Mr. McFadyen: So, just to be clear, your view was that you thought you would get agreement to proceed east side, but it was the Province's process that produced a different view on the issue of the likelihood of getting east side approval.

Mr. Brennan: We didn't complete our consultations at all, because, as Mr. Schroeder said, we stopped when the east side planning review started.

Mr. McFadyen: Would it be fair to say at this stage we don't really know which side is going to produce more opposition?

Mr. Brennan: I think that's fair.

Mr. McFadyen: So, if I could, what you're saying then is that, in effect, we don't know because the consultations haven't yet taken place which side will produce more opposition, but that you have been directed by your board to proceed with an option that is more expensive, less reliable, will take longer to complete and will result in more lost power. Is that right?

Mr. Brennan: The board of Manitoba Hydro asked management what was the best alternative if the east side wasn't available. On that basis, we recommended the west side.

Mr. McFadyen: So it was the board that took away the east-side option?

Mr. Brennan: That is correct.

Mr. McFadyen: And who appointed the board?

Mr. Selinger: Well, I can answer that. Government did. Just like all governments appoint the board of the Crown corporations, as you well know.

Mr. McFadyen: On the issue of the process yet to be undertaken, I want to just ask you, who do you need to get licences from in order to proceed with a new bipole line?

***** (18:40)

Mr. Brennan: The provincial regulatory body.

Mr. McFadyen: Which regulatory body is that?

Mr. Brennan: Clean Environment Commission.

Mr. McFadyen: Maybe Mr. Selinger will want to take this question: Who appoints the Clean Environment Commission?

Mr. Selinger: I believe when you were in government, it was the government of the day that appointed it, and when we were in government, we followed the same practice.

Mr. McFadyen: Can I just come back and then get you to indicate, Mr. Brennan, whether you think that this decision is in the best interests of Manitoba Hydro as a corporation?

Mr. Brennan: I don't think it's my job to question policy. My job is to implement policy when it's given to me. I make the best recommendations I can considering what I know, and certainly, if people that make policy decisions have different environment or different considerations, I respect that, and I implement that which they approve.

Mr. McFadyen: So you made one recommendation and that recommendation was rejected, and what you are saying is you are proceeding based on the limited option, the one option that you were provided by your board.

Mr. Brennan: Yes, we're doing it with enthusiasm.

Mr. McFadyen: I want to just come back. You know, I would suggest that the role of a corporate CEO, even of a Crown corporation is broader than simply taking direction from government. There's a statutory duty to do what's in the best interest of the corporation. So, setting aside policy considerations, I wonder if you can indicate whether you think the west-side route is in the best interests of Manitoba Hydro as a corporation.

Mr. Brennan: As a corporation, as being responsible for making recommendations to the board of Manitoba Hydro as to what I thought, and once a policy decision is made though, it's not my job to start arguing about it; it's to get on with the job.

Mr. McFadyen: If I can just turn to the report that was tabled just at the beginning of this meeting, *The Bipole III Transmission Routing Study* prepared by CMC Consultants Inc. dated September 2007. This is the report that was tabled by the minister, and it examined various issues, including environmental considerations and broader policy and procedural issues.

I would just like to, if I could, go to page 1 under the heading of Introduction and ask you, Mr. Brennan, if we can just turn our attention to the second bullet on page 1, there's a question followed by an answer. The question is: "Is there support from the First Nations on the east side of Lake Winnipeg?" The answer given in this report is, and I quote, "Government meetings in 2004 concluded that there was none. However, recent statements made by First Nations to the media and east side planning documents suggest that there is now some support."

I just want to ask you if that indication of recent support is consistent with the indications of earlier support that Hydro was receiving prior to the suspension of the Hydro consultations in 2003.

Mr. Brennan: Although we did not complete ours, the early indications were that we were getting sort of a mixed review. Certainly, some of the elders weren't as supportive as some of the younger people.

Mr. McFadyen: There's been a reference to international opposition. That's referred to in the third bullet of the report that we're referencing right now. Do you have, in your records, any documents outlining international opposition to an east-side bipole route?

Mr. Brennan: After the last meeting we had, I did point out that there are a good number of letters of opposition that did come in. I went back and checked, and, without counting them or anything like that, they estimate the number to be 10,000. But, certainly, environmental groups were getting together. Now with the Internet it's easy to do. The estimate given to me was 10,000, or over 10,000.

Mr. McFadyen: Those are letters from international, from outside of Canada or outside of Manitoba? Or is that–sorry.

Mr. Brennan: They were global.

Mr. McFadyen: Does the opinion of Manitoba engineers and east-side residents who have been writing to express support for the east-side route factor into this, or do we only pay attention to form letters from international organizations?

Mr. Brennan: Probably your question should be directed at the chairman. From my perspective on that question, we listen to everybody.

Mr. McFadyen: If I could just go to the third bullet of page 1 in the report. The question that's posed there is, and I quote: "Will there be international opposition from environmental groups to an east side route even if there were First Nations agreement to proceed?" The response is: "Very likely, but the tenor of the debate may change, as environmental groups could no longer point to a lack of First Nations support for the east side route as part of their opposition, and it could potentially place them in conflict with First Nations communities, with whom they have previously partnered."

Can I just ask you whether, of the international form letters that have come in, is there acknowledgment in those letters of the growing east-side community support for an east-side line that's referenced in the second bullet of this report?

Mr. Brennan: I would say no. They tend to reference the support. Most of it was a, prior to that, I believe, most of the letters coming in to hearing that opinion.

My concern, and I'm not sure if I made this clear at the last time, my concern about a lot of environmental opposition to anything Manitoba Hydro does is getting our purchases of our power outside the Province concerns. Most of them are on a rate of return basis for obtaining rate increases and, consequently, any–and they definitely look at the lowest cost option. Although it's a market we're selling into and market prices prevail, if, in fact, there are a lot of problems with purchasing power from, let's say, Manitoba Hydro, they would just move to say all this concern and hassle on our part is not worth it; we'll go the next lowest cost and not have the hassle. That is the concern that I have. It's a major concern just because of the amount of revenue we get for the power we sell.

Mr. McFadyen: Is it also your observation that there's a desire in the environmental movement globally to reduce the amount of coal-burned energy, whether it be within Manitoba or outside of Manitoba?

Mr. Brennan: For sure, greenhouse gas emissions are a problem everywhere.

Mr. McFadyen: Is that a major factor that would be in Manitoba Hydro's favour when it comes to the environmental arguments that might be made to regulators or companies that might be purchasers of Manitoba Hydro power?

Mr. Brennan: It's certainly an argument we make.

***** (18:50)

Mr. McFadyen: You have indicated that environmental assessment and licensing activities are, and I quote: For either a west- or east-side option are challenging.

Can you just outline what the challenges would be with respect to environmental assessment and licensing activities, or the anticipated challenges because we're not there yet, but the anticipated challenges with respect to the proposed west-side route?

Mr. Brennan: It seems that anybody who's opposed to a line, no matter what the reason, uses environmental issues as a reason not to build. So I would expect there would be opposition on both sides. I think from a straight environmental perspective, though, there would be more opposition for the east side for sure.

Mr. McFadyen: Could it be that the opposition of the east-side route that has been received to date would appear to outweigh the west-side route only because the west-side route was just announced two months ago and there has been little opportunity for analysis of the environmental impacts of a west-side route? Sorry, it was announced three months ago.

Mr. Brennan: I would think from an environmental perspective we'd get more opposition from the east side just because of where it's going. The west side has definitely been more developed.

Mr. McFadyen: So, at this stage, the assumption is that there would be more opposition to east side than west side, but, at this stage, that's only an assumption because the west-side option was only announced three months ago and there has been little opportunity for analysis. Would that be fair?

Mr. Brennan: I think it is fair. I think it's a judgment on my part.

Mr. Selinger: I'm just wondering if I may make a comment there. The rising concern about the boreal forest has been growing for several years in the environmental community and in the scientific community. They have made comments about the intact, large tract of boreal forest on the east side. They've also always had the opportunity to make comments about boreal forest in any other part of Canada. Even before the specifics of this decision became under active debate in the last several years, the environmental community and the scientific community have identified the east side as an area of boreal forest that has outstanding universal value. That's the phrase that's used by UNESCO.

I think the member is asking would there be opposition. I think there will be opposition probably to hydro lines no matter where they are put. I think Farlinger actually does a very fair job of discussing that. There are exposures on both sides, but I think there is something specific and unique about the east side in that it's less developed, in that it has a large intactness to it which I think the report we've tabled with you attempts to try and discuss that. Again, I think they try to discuss it fairly.

So, when the president of Manitoba Hydro says he thinks, he makes an assumption there would be more opposition on the east side. Demonstrably up to this date, knowing about the boreal forests anywhere in Canada, there has been more support to protect the east side than there has been to protect other areas of boreal forest across the country. There is demonstrable support for greater protection on the east side. Would there be opposition on the west side? Likely as well.

Mr. McFadyen: If I could then, the minister has picked up on this and it is the broader policy issue that is at stake here. I just note on page 9 of the report under the second bullet there is reference there, and I'll just quote the passage. It says: "A west side routing will cross not only boreal shield but also boreal plains ecozones (from roughly Ponton to Red Deer Lake). This latter ecozone is considered to be highly impacted and at greater risk – according to Global Forest Watch, less than 15% remains in large, intact areas. This includes the same ecozone that was identified for protection as part of the proposed Manitoba Lowlands National Park. Although there are potential routing options through this ecozone that could parallel existing developments, an argument could be made that this region has greater urgency for protection of ecological integrity than the vaster boreal shield forest of the east side."

So, in light of the fact there is an argument that the west side has greater urgency for protection than the east side, I wonder if this changes the minister's mind with respect to which route the line should go on.

Mr. Selinger: I just wish the member would read into the record the last sentence there, that how this forest on the west side does not have the same profile and emotional appeal as the east side. I think what the comment here that's made by the report is that there are sensitive and important areas to be protected on the west side as there are on the east side, and that's what I think is valuable about the report. It doesn't try to pull any punches in regard to either option. It says that whatever route you choose you're going to have to be very careful to protect ecological values. But later on in the report, and I know the member has just received it tonight and he'll want to read all of it because, I mean, there's so many things in here that are worth discussing, he does discuss the unique notion of the intactness of the boreal forest on the east side, which distinguishes it from other sensitive areas on the west side. There are challenges wherever you route hydro lines these days.

So the report and my letter that follows up on that report, to the Hydro, draws out of the report those points that were of a concern to us with respect to an east-side option. But we have always said that we think there will be concerns on the west side as well. And Manitoba Hydro has acknowledged there would be concerns on the west side as well, and very careful planning and consultation will have to go into whatever option is chosen.

Mr. McFadyen: I can't help but follow up on the very last thing you said, careful planning and consultation for whichever option is chosen. Are you saying that there's still more than one option on the table?

Mr. Selinger: I'm saying the west side has been chosen, but my point is that there had been a lot of work done on the east side, to consider it, and there had been considerable opposition expressed to it. Manitoba Hydro has, after receiving our reviews and knowing where the government stood prior to the election and also being aware of the WNO process, is now proceeding to consider our route on the west side in a wide territory, and they will have to look at the most efficacious, least environmentally sensitive option on that side. That will require careful planning and consultation.

Mr. McFadyen: I want to thank the minister for acknowledging that there are sensitive ecological areas along the west-side route as well as the east side, because what I'm taking from this report, which has been tabled, is that there are issues on both sides. Arguably, they say the west side is more urgent in terms of the need for protection, but let's put that aside. If there is urgency in protecting the forest on both sides–they say more urgency on the west side; you appear to be saying more urgency on the east side–if there is uncertainty, then, as to which route has the least negative environmental impact, then why would you choose an option that is hundreds of millions of dollars more expensive, is going to produce a less reliable transmission system, is going to take two years longer to complete, and it's going to result in more lost power?

Mr. Selinger: I just want the member to be careful about what he is interpreting out of that. It says an argument could be made. It didn't say definitively that an argument should be made. It didn't say that for certain. It says an argument could be made. The point that we are making here is that the Farlinger report brings out many issues that are worthy of consideration with respect to a west-side option. It doesn't definitively come down and make a hard statement. It says that there could be an argument that there are urgent areas to be protected on the west side, and that will have to be considered in the west-side option.

Now, the member says that it will be more expensive. It will be more expensive only if you can actually build it on the east side. I mean, this is a hypothetical example here. If you can't build it, if there's a resistance, and we've seen this with other projects, it could wind up being more expensive. We just saw a project in Alberta that had to be cancelled and redone after many millions of dollars of expense because of the concerns that arose as a result of that.

Clearly, it's a longer route. That's been acknowledged from day one. When you build a longer route, it's more expensive than a shorter route just on the cost of the actual physical requirements to do that. But that longer route, depending on whether or not it achieves acceptance in terms of the constituencies affected by it, may actually wind up being more cost-effective than a route on the east side that has a huge amount of resistance attached to it and can't get built. So these are questions that require careful consideration, as I've said earlier.

***** (19:00)

Then the member also suggests, in his points, that it's less reliability. Well, it's over the base case. The base case is that there is no additional bipole right now. For many years, there've been recommendations to proceed with the bipole. What's happening now is there's a bipole being built which will increase reliability. That's the whole purpose of this exercise, is to increase reliability over the status quo, not over a hypothetical alternative that may not be able to be built.

Mr. McFadyen: You've indicated that there was a global, or Mr. Brennan indicated that there were global signatures or petitions that came in opposing the east side, roughly 10,000. Now, I just want to ask the minister if 10,000 Manitobans sign a petition in opposition to the west side will you withdraw that option and proceed with the more reliable, shorter, less costly, quicker-to-complete route on the east side?

Mr. Selinger: Well, the member is assuming that the volume of e-mails was the critical factor in the decision of which side to pick. I suggest to him that that is a completely inaccurate analysis. There was much more consideration that went into which side should be chosen. Many of those considerations are discussed in the report, and we've had debates on this in the Legislature. So that kind of a question, I think, really misrepresents the basis upon which the decision was made.

Mr. McFadyen: Sorry, but it was you, Minister, that said that the decision to go west side rather than east side was because of international opposition. Mr. Brennan said, when I asked him what form that came in, that there were written submissions, 10,000 of them. So, if the basis for the decision is international opposition as evidenced by letters and petitions, then why would you not give the same weight to 10,000 letters in opposition to a west-side route?

Mr. Selinger: I think the member once again may be misinterpreting and may be misconstruing what was said. What we said was, and we have said this in discussion in the Legislature as well, that there is considerable risk to the reputation of the corporation of Manitoba Hydro in choosing a route that will generate a good deal of controversy. We have examples of this on other projects that have been attempted in other jurisdictions.

That reputational risk is something that has to be accounted for in the public policy decision because it could put at risk our major market. That could be up to $5.5 billion of revenues over 10 years. We never ever said that it depended on the number of e-mails one way or the other. I think the member, to try and put the question that way, really misrepresents the depth and the quality of the debate we've had up till now.

Mr. McFadyen: So what the minister's saying is that, if there is significant opposition to the west-side route, which could damage the reputation of Manitoba Hydro by virtue of the fact that that route is more expensive, less reliable, will take longer to complete, will result in more lost power, is running through highly endangered spaces that, according to this report, say are a greater risk, if opposition should arise for those reasons, then what you're saying, Minister, is that you'll change the decision and go with the less expensive, more reliable, faster to complete, less lost power, more environmentally friendly east-side route?

Mr. Selinger: The member is remarkable for his ability to try to put words into other people's mouths. That's actually what you're saying, and I don't think you should try to suggest that that's what other people are saying.

First of all, just to go back on your statement, there's never been an acknowledgment that it would be faster to complete. You've tried that question many times tonight. There's been *[interjection]*–if you would let me finish the question before you proceed with yours. Courtesy is usually the best way to proceed in this hearing.

So there's never been an acknowledgment it be faster to complete. As a matter of fact, there's considerable concern that an east-side alternative may never get completed. So that negates that point.

Loss of power. Even in your own document tonight, which you provided here to us, it says the differential of 16 megawatts, up to 32 megawatts, which has been far less than what you've been quoting in the Legislature.

On your third point: less reliable. The point is that it increases reliability over the base case where nothing has been done for many years after suggestions have been made that there should be something done. We understand that it will increase the efficiency of the system by up to 76 megawatts and add additional reliability to secure the ability of the corporation to provide energy not only to Manitobans, but to its external customers. So the reliability increases by proceeding with the bipole.

Mr. Chairperson: Before I proceed to the next question, as Chair, I am asking committee members to direct all their questions and answers through the Chair. It would help us with our proceedings here this evening. So, if you would co-operate in that fashion, I would appreciate it.

Mr. McFadyen, with the next question.

Mr. McFadyen: Thank you, Mr. Chairman.

We certainly understand that, from the base case, the debate, obviously, is east versus west in the route. We know that east is less expensive, more reliable, faster to complete. I want to take issue with your point about completion time when, two weeks ago, Manitoba Hydro issued a document that said there will be one year less in consultations by going east side and one less year in construction. So it's two years faster to complete on the east side, assuming it gets licensed by the government-appointed Clean Environment Commission.

So I just want to ask you, Mr. Minister, if there is some particular reason why you think your appointees on the Clean Environment Commission will reject an east-side application, and how it is that you would know at this stage in the process that that will be their conclusion?

Mr. Selinger: I don't think we've ever made a comment one way or the other on a hypothetical case that's being put in front of the Clean Environment Commission.

The one thing I do note, though, is that the member seems to suggest in the way he characterizes the question that perhaps the appointees to the Clean Environment Commission wouldn't exercise independent judgment on what they think would be the best alternative. I would just like to say that the people appointed–and I believe that was the case when you were in government as well–is we try to appoint, everybody, every government, I think, tries to appoint competent people that will exercise due diligence and good judgment on behalf of the public interest. So I think the characterization of your question is really an attack on the independence and credibility of the members of that commission. I would hope the member would consider withdrawing those kinds of comments.

Mr. McFadyen: So you can confirm, then, that you don't know what the Clean Environment Commission would decide with respect to an east-side proposal.

Mr. Selinger: What I can confirm is that, as we appoint people to these bodies, that exercise, as I said earlier, what we hope is good judgment based on their backgrounds and experience, and then try to make decisions in the public interest.

Mr. McFadyen: So you've made a decision that will cost hundreds of millions of dollars more, result in a less reliable energy grid, take longer to complete and result in more lost power on the basis that you're concerned about the ability to get approval from the Clean Environment Commission, but what you're saying right now is you actually don't know right now what they might decide.

Mr. Selinger: Actually, I didn't say any of those things. Those are things that you've been saying. You're, once again, putting words into people's mouths at the same time as you attack the credibility of the people on the commission.

What we've been saying is that we need to proceed with reliability improvements to manage risk in the corporation, improvements that have been recommended for many years, improvements that your government did not act on, even after they had a very serious incident in 1996. There was no follow-up action to increase reliability. We take the reliability risk of the corporation seriously. That's why we've worked with the corporation to find a way to move forward on reliability.

What we are also saying is that we have an historic opportunity to have a UNESCO World Heritage designation that will protect an important tract of boreal forest in Manitoba, which we think will provide long-term benefits not only to the environment, but to the peoples on the east side in terms of economic development, eco-tourism and those kinds of developments that have long-term sustainability.

We also think that we are proceeding in such a way, in co-operation with the corporation, that we will ensure the reputational integrity of the corporation in its marketplace where it sells products, to ensure that the product that is put out there is one that is well received by the consumers of that product, and that the ability to attack the credibility and the quality of that product is reduced so that the product will continue to generate profits, which keep the cost of Manitoba Hydro electricity low for Manitoban companies and citizens and families.

So it's a question of managing risk which is, I think, what good governments do. If you look at it compared to what you've suggested you would do, you have said you will ram a hydro transmission line down the east side regardless of what people think about it, one way or the other, regardless of what the environmental consequences are, regardless of what the potential risk is to customers in the marketplace. You have actually generated an alternative that could create a perfect storm that could put not only the profits and the viability of the corporation at risk, but could put the reputation at risk and also bring an enormous amount of grief not only to the peoples of the east side, but to the people of Manitoba in terms of the UNESCO World Heritage designation and the protection of the boreal forest. When you think about that, that's very high-risk gambling that you're proceeding with in terms of what you say you would do if you were government.

***** (19:10)

Mr. Schroeder: Just for clarification, it's not just the Clean Environment Commission. It's also Fisheries and Oceans. It's also, potentially, the Court of Queen's Bench. It's also, potentially, the Court of Appeal. It's also, potentially, the Supreme Court of Canada. So there are a variety of actors involved. When one says that there are difficulties, one looks at other cases to say that. Nobody can guarantee that that would or would not happen.

Mr. McFadyen: I think to be fair, what I'm pleased to hear tonight is that there is acknowledgment all around the table that there is risk of challenge and opposition regardless of what route is chosen, whether it's east or west. There are people who are going to have issues and are going to raise concerns about various options. Obviously, we have the report today tabled by the minister which says, and I quote, that the latter eco–*[interjection]* Excuse me, it's not a point of order. I thought you were interested in courtesy tonight. Can I just finish?

An Honourable Member: We'd just like to get the record straight.

Mr. Chairperson: Hold on, folks. Hold on a sec here. If there is a legitimate point of order, I have to recognize the attempt, at least, and then make a ruling on that and then we'll proceed with the question.

Point of Order

Mr. Chairperson: Honourable Minister, do you have a point of order?

Mr. Selinger: Yes, twice the member has put on the record that the report was tabled by the minister. I'd just like the record to show that the report was tabled by the chairperson of the Crown corporation in question, Manitoba Hydro.

Mr. Chairperson: Any other comments?

It's not a point of order; it's a dispute over the facts.

* * *

Mr. Chairperson: We'll now proceed back to the questioning.

Mr. McFadyen: Thank you, Mr. Chairman. The report tabled tonight by the chairman of Manitoba Hydro says, and I quote, the ecozone on the west side "is considered to be highly impacted and at greater risk – according to Global Forest Watch, less than 15% remains in large, intact areas. This includes the same ecozone that was identified for protection as part of the proposed Manitoba Lowlands National Park." It goes on to say, ". . . there are potential routing options through this ecozone that could parallel existing developments, an argument could be made that this region has greater urgency for protection of ecological integrity than the vaster boreal shield forest of the east side. However, this forest does not have the same profile and emotional appeal as the east side."

I wonder in light of that statement whether you continue to believe that the Clean Environment Commission is more likely to approve the west-side route than the east-side route, to the minister.

Mr. Selinger: Once again, we appoint people to these bodies such as the Clean Environment Commission that exercise impartial judgment in the public interest. Really, I don't think it's appropriate for me to speculate on what they would decide on a hypothetical case that they haven't had in front of them. I mean, I think we have to let them do their job.

Mr. McFadyen: So, then, when you say that the risk of not getting a licence is one of the reasons for the decision to go west side, what you're saying is that you actually don't know at this stage what the licensing body might decide.

Mr. Selinger: Actually, once again the member keeps trying to interpret other members' statements. The report itself and what we've debated in the Legislature up to now, indicates that there's a lot of concern about a route down the east side and that that concern has the potential to become a cause célèbre. That could bring a great deal of negative reputational risk, not only to the corporation, but to the Province. It could result in the delay, the serious delay, if not the permanent inability to build the route on the east side. We've said that consistently from day one.

We've also said, and this report confirms it, that there are issues wherever you route a hydro line, and they will have to be carefully considered in whichever route is pursued by Manitoba Hydro. But we do know for sure, and the member will see this when he reads the report further, that the east-side address has a high degree of saliency in terms of protection of the boreal forest because of its universal outstanding characteristics.

Those characteristics include the fact that it's a large tract of intact boreal forest. It is one of the primary habitats, which has the best chance of attracting the woodland caribou. It has not only unique environmental features that require protection, but it also has unique cultural communities over there that are part of the designation process for UNESCO. It's extremely rare in an UNESCO-designation process that you both have outstanding universal value of both on the ecological as well as the cultural side. These factors are the factors that needed to be considered in what the routing decision should be for the hydro transmission line. These factors are the kinds of factors that the report suggests Hydro should discuss with the government because they go beyond the mandate of what Manitoba Hydro normally takes into account when they make a decision.

Mr. McFadyen: Minister, to sit on a record that he didn't table the report, can I just ask him, did he issue a news release today releasing the study that we're making reference today to?

Mr. Selinger: There was a news release put out on the report today that was tabled by the chairman of Manitoba Hydro here tonight. Absolutely.

Mr. McFadyen: I've got the release in front of me. It says the Finance Minister and Minister responsible for Manitoba Hydro "today released a study on routing options." So I just want to ask you, Minister, are you the minister that's referenced here that released the study that we're referring to?

Mr. Selinger: Yes. I think the press release is quite clear in that regard. That's completely consistent with the chairman tabling the report here tonight.

Mr. McFadyen: I just want to ask the minister if the news release you put out today makes reference to the threatened boreal forest on the west side, or does it only refer to issues reflecting the east side?

Mr. Selinger: The news release identifies those issues that the government thought were salient in choosing not to recommend an east-side route. The report itself speaks from a broader range of issues which were in front of Hydro after they commissioned a report. We felt it was important that the report not only be tabled here by the chairman of Hydro, but be put into the public domain, because the report looks at a broader range of issues. The government identified those issues they thought were salient on an east-side choice.

Mr. McFadyen: By salient, what you mean are the release points to things in the report that support the government's predetermined position, and makes no reference whatsoever to any of the issues around the threatened west-side boreal forest or any environmental issues on the west side.

Mr. Selinger: Actually, my letter speaks to that in terms of process. The government's position was formed after many consultations. It was formed after, first of all, accepting the COSDI, Sustainable Development Implementation report, in 2000. It was formed after the broad area planning process was initiated with communities on the east side and was formulated after more than 80 meetings that the government undertook with peoples and communities on the east side. So, when the members say it's a predetermined position, it's actually quite the opposite of that. It's a position that was arrived at after our consultations with the peoples on the east side, broad area planning activity and the acceptance of the COSDI report. So quite a bit of process and consideration went into that, including many, many consultations with communities on the east side.

Mr. McFadyen: Mr. Chairman, through you to the minister, does today's news release make reference to the statement in the report that recent statements made by First Nations to the media and east side planning documents suggest there is now some support for an east-side route?

Mr. Selinger: Mr. Chairperson, the news release, I think, accompanies the report. The report itself speaks on page 1, as the member referenced earlier, about the fact that there has been some additional support expressed for an east-side route by some of the chiefs on the east side. So, when I look at the press release released today, it does not specifically mention that, but it comes along with the report itself, which identifies a variety of issues with respect to all of the alternatives that have been under debate for the last several months.

Mr. McFadyen: I just want to ask the minister why he wouldn't have made any reference in today's news release to any of the concerns raised in this report about the west-side route.

***** (19:20)

Mr. Selinger: Well, once again, the news release is simply identifying why the government has decided that an east-side route is not as preferable as others might have thought. The report speaks to the broader issues that go along with that. That's why the report was tabled here tonight and that's why the report was released to the public, so that people can know all the elements that might have been considered, as well as what the government decided were the important elements to it.

Mr. McFadyen: So, if a member of the public wanted to know both sides of the story, they'd have to ignore the government news release and read the report?

Mr. Selinger: If the public wanted to know the broader range of issues, they would review the report which was released by the government and by the chairman here tonight to the committee, and they would know the government's rationale and they could ask questions about any other points that were raised in the report, as we are doing right now.

Mr. McFadyen: Given that the report says that the environmental groups could no longer point to a lack of First Nation support for the east-side route as part of their opposition, I wonder if the minister can indicate–sorry, and I'll go on, the quote says on page 1: "and it could potentially place them"–that's making reference to the environmental groups–"in conflict with First Nations communities, with whom they have previously partnered."

I want to ask the minister: In the event of such a conflict between international environmental organizations and Manitoba First Nations, where First Nations are lining up in favour of an east-side route and international environmental organizations are opposed, which people the minister would line up with: Manitoba First Nations or international environmentalists?

Mr. Selinger: I think, if you read my letter, we make it very clear that there were extensive consultations with the peoples on the east side, and the overwhelming consensus at that time, when the consultations were done, was that there was a great deal of concern about an east-side transmission line. That was one of the important pieces of consultation that contributed to the government deciding that an east-side alternative wasn't appropriate.

Mr. McFadyen: So, to be clear, the opposition you're referring to is the opposition that is four years old?

Mr. Selinger: The concerns were those that were recorded and identified at the time that the experience occurred, and the member is suggesting that there have been different views expressed recently–those are on the public record, we're well aware of them–but the government has gone through a long process of consultation and it's very aware that there are a variety of views on the east side, but there are many, many people over there that are very concerned about an east-side transmission line.

Mr. McFadyen: So, as this issue revolves, given that the consultations stopped in 2003 and at the time the indication was that there was significant opposition on the east side, is the minister open to changing his mind based on more current information about the views of residents on the east side?

Mr. Selinger: Well, I think it's clear that we are now proceeding in consultation with the Manitoba Hydro to look at west-side alternatives.

Mr. McFadyen: If the basis for going west side, or one of the reasons was east side opposition, if that opposition has now turned into support, will that have any impact on the minister's decision making?

Mr. Selinger: Once again, we've had this discussion in the Legislature and the decision for all the reasons I've outlined earlier, the different kinds of risks that have to be managed, is to proceed with the west-side alternative.

Mr. McFadyen: Can the minister just indicate the names of the international organizations that are on the record as being opposed to the east-side route?

Mr. Selinger: Well, we're aware of several organizations that have concerns about protecting the boreal forest and concerns about the east side. The international organizations–the one that the member has referenced in the past is the Natural Resources Defense Council, which is an environmental action organization with 1.2 million members. We're also aware of the Sierra Club of Canada, the Canadian Boreal Initiative, the Western Canada Wilderness Committee, the Canadian Parks and Wilderness Society, sometimes known as CPAWS, the Nature Conservancy of Canada, and the boreal forest initiatives, as well as significant individuals including Sophia Rabliauskas, who has received the Goldman Environmental Prize, is an Aboriginal woman who lives in the Poplar River area on the east side and has been championing the protection of the boreal forest on that side.

We're aware a variety of other significant individuals have expressed their support for protecting the east side in terms of the intact boreal forest.

Mr. McFadyen: Is the minister aware that many of the organizations he has made reference to are opposed to any and all hydro development?

Mr. Selinger: We have not been made aware of these organizations that they're opposed to any and all hydro development.

Mr. McFadyen: Have these organizations taken a look at the impact of a west-side route and offered analysis and comment on the environmental impacts of the proposed west-side route, to the minister's knowledge?

Mr. Selinger: To my knowledge, not at this stage of the game, but they will have full and ample opportunity to do that as the west-side process proceeds.

Mr. McFadyen: In the event that they have concerns about the west-side route, will the minister listen to those concerns and not proceed with a west-side bipole transmission line?

Mr. Selinger: Well, once again, I think there will always be a willingness to listen to concerns that are expressed about the route that is potentially under consideration for the west side. Those concerns will be listened to and then decisions will be made based upon not only that, but other factors that go into the decision-making, including where local communities are at, where the reliability issue, as I've mentioned before, which is important to move forward on, the impact on markets, the impact on the environment, specific environmental aspects of the route chosen compared to the alternatives. All of those risk factors will have to be managed in such a way that we can continue to provide reliable, clean power with a good reputation for the corporation.

Mr. McFadyen: Given that we are in the early stages of that environmental review and the licensing process, I wonder if you can then just confirm that, in the event that persuasive arguments are made by either international organizations or Manitobans or others, that the west-side route is unacceptably damaging to the environment and damaging to the province in other respects, are you open to abandoning that option.

Mr. Selinger: Well, once again, there has been a decision to proceed with the west side. I think hypothetical questions that are unduly speculative really are a little too early to be discussed. I think we have to proceed to increase the reliability of the corporation, which we said earlier, a decision which had been not acted upon for many, many years even after serious incidents have occurred. It's incumbent upon all of us to find a way to move forward to increase the reliability. It's also incumbent upon us to do it in such a way that we don't take away opportunities to protect unique and intact, and some would call pristine boreal forest areas, and the opportunity to get a world class designation under UNESCO for what they call a landscape that has universal value.

Thirdly, it's important to proceed in such a way that we have the ability to market our product to our customers, a product with a good reputation, a good image and a good, quality product in terms of the fact that it's hydro-electricity and it displaces greenhouse gas alternatives.

So, all of those things are factors that have to be considered. It's not a one factor, singly. It's a complex of factors that have to be considered. As you know, we've talked about this earlier, any application to proceed has to be part of a full review by the Clean Environment Commission, which has people on it that act with impartiality and integrity and in the public interest of Manitoba.

Mr. McFadyen: So can you just confirm: you don't know at this stage, one way or another, whether the Clean Environment Commission would prefer the east side or the west side?

Mr. Selinger: I think, once again, we've never tried to second-guess what an independent body should do or what judgments it would have. It would be, I think, irresponsible to try and do that. I think they have to do their work and follow the proper process and render their decisions.

Mr. McFadyen: Since you would respect the process and have no idea at this stage what they might decide, how can you then use licensing risk as an argument for west versus east?

Mr. Selinger: Well, as we said earlier, there is experience in other jurisdictions of what happens when something becomes a cause célèbre. I think the question can be reversed: how could you discount those considerations in any choice you make? You have to make a judgment based on a variety of risk-management factors and without second-guessing, necessarily, what a body would do, but, at the same time, proceeding on something that has a chance of not only being successful, but will reduce risk for liability, will not bring reputational damage to the corporation or to the province, will continue to maximize opportunities to protect the environment and achieve designations which have long-term benefit to the province of Manitoba in terms of what that could do in terms of economic development, eco-tourism and green economic development, and, perhaps equally as important, to ensure that markets are willing to buy the product and accept that that product will have value to them and be prepared to pay a market return price for that.

***** (19:30)

We've heard testimony from the president of Manitoba Hydro that those markets are very important to us, and earlier tonight we heard a suggestion that if something becomes too much of a hot potato, in effect, that there are other alternatives that might be pursued that could put the profitability of the corporation at risk and the result of that could be a very negative impact on rates and Manitobans and the customers that consume that product in Manitoba.

Mr. McFadyen: Two weeks ago, Manitoba Hydro, in response to questions pursuant to the PUB process, said that the western route, because it is 50 percent longer, has and I quote, a greater probability of being interrupted by weather-related events, end of quote.

So the western route has a greater probability of being interrupted by weather-related events. Is that a risk factor you've considered with respect to your preferred western route?

Mr. Selinger: Well, Manitoba Hydro has themselves identified that as a risk factor in their technical review of what route they would have preferred. This is ground we've gone over. We know that at the engineering and technical level that a shorter route was to be preferred by Manitoba Hydro. We also know that in previous decisions to do routing they didn't choose the shorter route. They chose the Interlake route, which was longer, as opposed to the east-side route. So these factors were always on the table, and the corporation and the governments of the day make decisions what they think is in the broader public interest, given all the factors, not just the technical ones. They are important but other factors are important as well.

Mr. McFadyen: Just further to what the minister characterizes as technical quote unquote issues. Hydro said two weeks ago and I quote, further a western routed bipole is generally closer to the existing bipoles 1 and 2 in northern Manitoba than an eastern routed line. So the chances of all three bipoles being interrupted from a weather-related event are greater with a western routing, end of quote.

Has the minister factored in the risk of the interruptions in choosing the west side over the east side?

Mr. Selinger: Well, the west-side route is what's being considered by Manitoba Hydro for a west-side route includes a very wide swath of territory. Presumably they would pick a route that managed risk in terms of reliability to reduce the reliability risk as much as possible. That's the whole point of doing a third bipole and that's the whole point why we believe, based on recommendations and concerns by Hydro, that we have to act on a third bipole. It has been sitting on the books as a concern for many years. Now it has to be acted on.

The reality is that a third bipole will dramatically improve the reliability of the product, not only to Manitoba customers but to export customers as well. The route that is chosen will have to ensure that there is risk that's managed between the existing bipoles, which are right together down the Interlake. We must remember when they were built that was probably the highest risk was to build them together. At that time that was the decision to build them together.

There could have been a decision at that time to build bipoles 1 and 2 in routes that were farther apart in order to manage risk. But they decided to build them together. Now we know that it would probably still be cheaper or easier to put it down the Interlake, but that wouldn't do the job of addressing the reliability risk. So another route is to be preferred other than the Interlake route at this stage of the game unless technologies, cost-effective technologies are available through an Interlake route that would reduce that reliability risk.

Mr. McFadyen: Is it the minister's view that power interruptions are merely a technical issue?

Mr. Selinger: Well, power interruptions are a serious issue of reliability.

Mr. McFadyen: If there's a greater risk of power interruptions on the west side than the east side, which you say is a serious issue, then I wonder what are the reasons on the other side of the ledger given that there's a greater probability of power interruptions with your western route than the eastern route. How can you justify that?

Mr. Selinger: Well, I don’t think the member wants me to go back into the detail that I've mentioned earlier, but there are three types of risk that are being addressed here. One is reliability risk over the base case. The do-nothing option really doesn't seem sensible anymore. The do-nothing option was the one pursued when you were in government. Now we have to move beyond that. We have to actually move to the do-something option to increase reliability. The do-something option is the worst reliability option at this stage of the game, giving existing cost-effective technologies would be to build a third bipole in the Interlake, which was done when one and two were put together.

The recommendation is to look at something that provides separation between existing bipoles. So that's risk No. 1 that needs to be managed. Risk No. 2 that needs to be managed is that relating to the environment and the potential of having the boreal forest protected on the east side where it has some unique universal outstanding characteristics. The third risk that needs to be managed is the risk to markets and the reputational risk that relates to the ability to sell product into other markets. All of these things interact with each other, as we know.

What we're trying to avoid is the scenario that you seem to prefer, which is one that could create a perfect storm, where you would have increased reliability risk because of the controversy around it, delays in building it, increased risks to the environment because the boreal forest on the east side would be under attack and increased risk to markets because of the controversy that would flow out of that that might actually reduce the ability to sell product into those markets which would have enormous financial risk to the corporation and to Manitobans. So all of those things, that perfect storm scenario, seems to be advisable not to enter into that scenario, but to proceed to address reliability, environmental values, as well as market and reputational issues in a way that unpacks those issues so that there's the best chance of succeeding on all three of them.

Mr. McFadyen: Leaving aside base case, you've been in government for eight years and you've had every opportunity to move forward with a decision. But we're pleased that you are moving forward with a decision to build a third bipole.

You've identified three risks that need to be managed. We're talking about east side versus west side. We're not talking about the single west-side option that you've provided to Hydro versus the current status quo. We're talking about east versus west. So, on the first risk, do you agree with what was written by Manitoba Hydro two weeks ago that the west side has greater reliability problems than the east side?

Mr. Selinger: Well, once again, the member likes to isolate the discussion to east side versus west side. I think the most important place to start–

An Honourable Member: Really?

Mr. Selinger: The member likes to ignore the fact that the base case was nothing was happening. There had to be movement forward on the reliability risk management scenario. The option that was the least preferable was the Interlake option because it brings it into direct contact with the existing bipoles.

The alternative that needs to be pursued is one that provides separation between the existing bipoles and a third bipole. The west-side option, in the wide corridor that's being looked at, provides for that alternative.

Mr. McFadyen: We get that there's a need for a new bipole. There's no debate about base case versus west side. If we have the option between having no car or a car, most of us would want to have a car. If the issue is a choice between two cars, one of which is way more expensive, way less reliable, takes longer to get and is less fuel efficient versus one that is less expensive, more reliable, faster to get and more fuel efficient, I would think that most logical people would choose the latter option and so that's why we're having this debate. It's a completely disingenuous issue to argue base case versus moving ahead with a bad west-side option.

I want to ask you again, as between east side and west side, you've identified three risks. Hydro says that west side is less reliable than east side, so that's the first risk you've identified. So that is in favour of east side. Would you agree that, on the reliability argument, east side is better than west side?

Mr. Selinger: What I would say is that the important decision was to move forward off the base case, which was the do-nothing case.

An Honourable Member: Nobody favours that.

Mr. Selinger: Once again, it's important that we started from nothing having been done for a long time. There was a growing concern about increasing the reliability of Manitoba Hydro. A route had to be chosen that would increase reliability, as opposed to the do-nothing option. Then the question was which is the preferable route, considering a broad array of factors, of which I've identified three primary ones.

The first one was the reliability issue. We know that reliability is improved and efficiency gains are achieved by building a third bipole. That is–

***** (19:40)

An Honourable Member: What about versus east side?

Mr. Selinger: We know that by building a new bipole, wherever we build it, we again, except through the Interlake perhaps, that we increase our reliability and we increase the efficiency of the system. We know that on the east side the risks that could come together there, in a possible perfect-storm scenario, could make it impossible to increase reliability in a timely fashion. You insist that it could be built faster on the east side. There is actually no evidence to support that, given the other factors at play here. So that's where there's a major disagreement between us.

We also know that on the east side there are some unique and universal outstanding environmental values that need to be protected which you seem to think are not at risk here, and I think that's another fundamental difference. We do think that those values are at risk.

Thirdly, we think that that risk could interact with the ability to maintain and increase our markets outside of the province which would increase the profitability of the corporation, which I think there is an interaction between the controversy that could be generated on the east side and the ability to maintain market share in terms of our exports. That's something else that I think you underestimate the risk attached to that. So we are saying that we're choosing a methodology here and we're asking Hydro to consider a west-side corridor that will reduce the risk to markets, that will reduce the risk to environmental values, and increase reliability.

Mr. McFadyen: To the minister: He's indicated that there could be a perfect storm and could be a lot of opposition to the east-side route. Would the minister entertain the possibility of putting both options in front of the CEC and see what happens, so that we can get out of theoretical speculation and into reality?

Mr. Selinger: Well, actually, if we want to get to reality, we have to choose an option and proceed to do the due diligence around that. You can't have every option on the table at the same time. The resource requirements for that would be quite extraordinary. You have to pick an option based on good public policy objectives that will increase reliability, reduce environmental risk, and reduce risks to reputation and market, and you have to proceed with that. That was done after there were careful consultations done. That was done after there were broad area planning activities entered into. That was done after there was assessment done of the risk on the east side.

You know, the member suggests that there are changing levels of support on the east side and that is true. I mean there have been some people that have come forward and you've put some of those comments on the record in the Legislature, but there's also been a growing awareness of the need to protect boreal forest. I mean, there are changing conditions as we go forward, and the reality is you have to pick an option and proceed on it and then try to take a look at all the factors that will come up through that process and see what can be done to address them.

Mr. McFadyen: Given that the east-side option has been under study and analysis for more than 20 years and that the detailed work has been done, including examination of all of the impacts of an east-side route, I would just ask the minister: Given that the western route is going to cost hundreds of millions of dollars more, given that it's going to be less reliable, given it's going to take longer to complete, given that it's going to result in more line loss, why not just put all the detailed work done on the east-side option in front of the Clean Environment Commission and see if the theoretical perfect storm arises?

Mr. Selinger: Well, once again, I think to take the considerations up to now and just toss them in front of the Clean Environment Commission, I don't think they'd be very impressed with that kind of a presentation. Anytime you put a submission for an environmental licence in front of an environment commission, there is an enormous amount of due diligence that has to go into that. There's an enormous amount of technical work that has to go into that. There is an enormous amount of cost that goes into preparing those kinds of submissions, and I think that the approach the member is suggesting would ensure a lot of difficulty for the corporation if they proceeded that way.

Mr. McFadyen: So is it your view, then, that putting the 20 years' worth of analysis that's gone into the east-side option in front of the Clean Environment Commission for consideration is going to cost more than $410 million in two years?

Mr. Selinger: Well, once again, we have a disagreement about whether the two years is a realistic assumption that can be made, and it's only an assumption at this point.

Once again, there is a fundamental difference about that assumption based on experiences in other jurisdictions, the most recent one which we've seen in Alberta where, after all the work had gone in, that option had to be withdrawn because of the controversy generated around that and just the enormous amount of resistance to that. The $400-million cost of building a longer line is one that we've said would be more expensive in a perfect scenario, but it also acknowledges the fact that it would avoid other kinds of costs that could attach to a controversial east-side decision. It avoids risk to our markets which could cost us $5.5 billion in lost revenue over 10 years.

So these are factors that had to be considered. It's not a stand-alone additional cost. It's a stand-alone cost that preserves revenues that allows us to enhance markets and to increase sales to our customers. Those are positive things. As we've said earlier, one of the earliest pieces of information we had is that the west-side route would have a 75-, 76-megawatt gain in efficiency which will allow more power to be sold to our customers outside of Manitoba, which in itself would cover the cost of the west-side line. That was a statement that was put on the record by the corporation early on in our discussions.

Mr. McFadyen: So we are never going to know what opposition will arise to the east side because the government is not going to allow that proposal to be put before the CEC.

The minister has made reference to other projects in other places being stopped by regulators. Can the minister just outline what was the basis for the controversy in the Alberta scenario that he continues to refer to?

Mr. Selinger: Well, I was simply illustrating to the member an example of what can happen to any of these kinds of applications and the opposition. Once again, neither of us was there in terms of the details of it, but the opposition was one that they didn't find that that line was suitable for that environment at that level. They wanted a route that was less negative in terms of its impact on those communities. The alternative that they wanted to choose, I believe, was one that made more use of existing corridors and existing infrastructure which would be somewhat similar to some of the positives that could be pursued on the west side. It's well acknowledged, I think even by the member himself, that the west side has more development over the last 90 years of mining and logging and roads, and there are existing transmission corridors over there. So, overall, there is less intactness. There is less undisturbed boreal forest on the west side. There are, however, environmental issues that have to be addressed, but there is also clearly more development on the west side that would suggest that a hydro transmission line would be more readily accepted.

Mr. McFadyen: In the Alberta situation, the line that was rejected was on a corridor between

Edmonton and Calgary. As I understand it, the basis was that the company was engaged in practices that the regulators and the courts found distasteful in terms of the approach to the application, including surveillance of impacted landowners. Does the minister think that's a good analogy for what might happen in Manitoba?

Mr. Selinger: Well, the member will note that I didn't discuss those aspects of the difficulties out there, and some of those issues were going on, including with the regulator. That was one of the dimensions out there, but there was also just concern about the hydro transmission line, it's impact on the environment in the areas that it was going to go through. They were the points that I was referencing which were pertinent to the situation here.

Mr. McFadyen: Is the minister aware that some of those concerns arose from the fact that there were communities in the vicinity of that route who were concerned about the routing of a high transmission line close to highly populated areas?

Mr. Selinger: That may very well have been the case. I'm sure it was. I think what the communities out there were saying was they would prefer transmission lines to go into areas where there was already existing transmission capacity and there were already existing routes and there'd be less disturbance of them.

Mr. McFadyen: Well, the concern was that people didn't want major transmission lines in the vicinity of populated areas. Given that the west-side route is going to run in the vicinity of populated areas, isn't the lesson from Alberta that you should try to route transmission lines where you have fewer people?

***** (19:50)

Mr. Selinger: That might be the member's conclusion. I think the broader lesson is that you should try to choose transmission alternatives through a process that builds consensus and support from the communities that are impacted, as well as avoiding environmental issues; that increases reliability and protects your reputation and your markets. I think that would be the broader lesson.

Mr. McFadyen: I just want to just come back with some technical questions to Mr. Brennan. The prospect or the idea of running the next bipole line underwater has arisen in the public domain recently. I know it came up at committee last time. I wonder if you could just briefly address Hydro's analysis of that as a potential option, as an alternative to the two routes that are currently being debated.

Mr. Brennan: Before the article in the paper I was told that the costs would be significantly greater to do an underwater transmission line from the north, especially that long. After the article appeared in the paper, being a chartered accountant and not an engineer, it sounded like something that I should find out more about so I asked about it, and the problems associated with it are just totally humongous. They're just huge.

The cost is–an estimate which appears to be on the low side is about 10 times as high. The weight of the cable is such that you can't move it except in very small pieces and it has to be spliced together. It is an oil-filled cable so there's environmental concerns. The whole thing just appeared to be a no-starter.

Mr. McFadyen: Thank you, and one other question. There was a CBC story last week from an engineer who had visited Japan, who said that there was the possibility of technology that would allow cables to run underground. My initial reaction was, given that we're talking about thousands of meters of rock covered by a couple of feet of dirt on the boreal shield, it was that it seemed impractical. But I wonder if you're aware of that option or technology and whether you might have any comment on that.

Mr. Brennan: Yes, I asked about that one as well. It could have some merit should there be something that's just totally impossible to proceed with. The cost of that is also pretty high. When you go to go underground, you need a substation, and when you come back up and convert back to an overhead wire, conductor, you would need another one. It just didn't seem to be very practical. It would be if you just came up with something that just, you just didn't–you found impossible to have an overhead conductor going by.

Mr. McFadyen: Can you just indicate what is your estimate of the percentage of the east side boreal forest that would be impacted by an above-ground traditional bipole transmission line?

Mr. Brennan: I'm doing it just off the top of my head, so the actual boreal forest is virtually the whole line if you are on the east side. On the west side, the boreal forest is a smaller part near the top of the west side, then there are the boreal plains that are not as pristine as the boreal forest, and that's what Mr. Farlinger was referring to in the report.

Mr. McFadyen: Is it possible, in order to mitigate the impact on a forest arising from a transmission line, to take steps such as allowing for more undergrowth and other measures that might minimize the impact of a transmission line on a forest, other narrower corridors, more undergrowth, or other steps that could be taken if we assume, which we all do, that there's value in protecting the forest, even though it might give rise to slightly less convenient access for maintenance and upgrade? Is it possible to do those things if one was committed, as we all are, to doing what we can to minimize the impact on the forest?

Mr. Brennan: I think there are things that you could do to mitigate the impact on the forest, some of which are probably more reliable than others and some might have a reliability risk. I think if we had a–if we were ever to study it we could probably come up with some options that would at least mitigate that. Having said that, reliability is really a major issue now, and we should get on with an option that's acceptable. Certainly, without the east-side option, we should get on with the west side as soon as we possibly can.

Mr. McFadyen: I'm going to turn it over to the Member for Minnedosa (Mrs. Rowat). I might have a couple of questions toward the end, but I'm done for now. Thank you, Mr. Chairman.

Mrs. Leanne Rowat (Minnedosa): The question that I have is posed to Mr. Brennan. You had just indicated that time is wasting on movement on the west side and that there seems to be a sensitivity to move the project forward. You had indicated that Manitoba Hydro did not complete their meetings on the east side.

Can Mr. Brennan provide to us the number of communities he did meet with on the west side–or on the east side, sorry?

Mr. Brennan: I'd have to get that for you. We have a record of where the formal consultations took place. There was a separate group looking at that. In addition to that, I met with a–I think they were more tribal council meetings and groups of First Nations together, about three or four of them. But the actual formal consultations I'd have to get back to you.

Mrs. Rowat: The east-side chiefs have maintained that the meetings did not outline the possibility of a bipole line on the east side.

Can you indicate to me what level of involvement your meetings would have played with those communities, or are you aware of the level of involvement the government had in relation to the discussions on bipole 3?

Mr. Brennan: There were three sets of consultations taking place. There were Manitoba Hydro consultations; there was the east side planning group that was also having consultations; and then the government itself had consultations. Manitoba Hydro's consultations were only around the bipole and the transmission line. That's all we talked about was the transmission.

Mrs. Rowat: So, based on what you're saying is that Manitoba Hydro's discussions were specific to the bipole line on the east side. Based on your earlier comments, you had indicated that there were mixed comments coming from the communities.

I guess I would like to know, the meetings that you did have, what type of guidelines or what type of outline was used in the discussions on the east-side bipole? What were the discussions? What type of comments were you looking for from the communities and what type of questions were you asking the communities to participate in dialogue?

Mr. Brennan: As I mentioned, there were two types of consultations done by Manitoba Hydro. The ones I was doing, which were more a description of what we're proposing to do, how we are proposing to get First Nations involved in the process itself, how we intended to get them involved in the building of the line and later operation of the line and that sort of thing. We had a discussion of what we were proposing to do, after which there was a question and answer period.

***** (20:00)

In the case of the ones that were formally done as consultations associated with the line, there was a fixed process that we went through for every community. The whole process involves about three or four–well, probably even more than that–consultations with the various communities for any transmission line.

Mrs. Rowat: Mr. Brennan, would you be willing to share the guidelines that you used in this process?

Mr. Brennan: I don't see any problem with that. We're probably using the same ones on the west side, so I can get those ready.

Mrs. Rowat: Mr. Brennan, could you indicate to me what some of the challenges were that the communities identified on the east side?

Mr. Brennan: I'd have to go back. The meetings I had the concerns were mainly focussed around what kinds of impacts would be involved for the community and what kinds of benefits would the communities get out of it.

Mrs. Rowat: Recently, there have been a number of First Nation communities that have gone on record over the past several months favouring an east-side line, and recently there was a letter from MKO North, which represents all the northern Manitoba First Nation communities, stating that all of the east-side First Nation communities that they represent are in favour of an east-side bipole route. Over this period of time there hasn't been a single chief go on record opposing the line.

I would just like to ask Mr. Brennan: Does he have any documentation to show that any of the east-side chiefs have stated an outright opposition to the bipole line going along the east side?

Mr. Brennan: Yes, there is one First Nation that's been opposed to the line all the way through. As far as I know, they still are opposed. It's the one that's most prominent, and that's Poplar River.

Mrs. Rowat: In my discussions with the communities are on the east side, it would appear that the opposition from the Poplar River First Nations is softening. MKO has issued a proposal that would allow for an east-side route avoiding Poplar River traditional lands and have minimal impact on the proposed UNESCO World Heritage Site. Has Hydro explored this option, and have they been in discussions with MKO?

Mr. Brennan: We continually have discussions with MKO. We have not talked about the routing of the line since the decision was made to come down the west side.

Mrs. Rowat: So, based on your comments and based on earlier comments, can you please confirm then that you have not had discussions with MKO or Poplar River First Nations since 2003 or 2004? If I have the dates wrong, can you please confirm the last opportunity that the east-side line was discussed with either of those communities or groups?

Mr. Brennan: We've had no discussions since 2003 regarding the actual possibility of building a transmission line on the east side.

Mrs. Rowat: So, Mr. Brennan, based on the recent softening of the Poplar River east side and based on MKO's tabling of a route map, those discussions have gone to the wayside because all negotiations are off, is basically what you're saying on looking at an east-side opportunity or proposal?

Mr. Brennan: Once the east side was not available to the management of the corporation, we did not pursue that.

Mrs. Rowat: On page 2 of the document that was shared today by the minister and Manitoba Hydro, page 2 indicates that the west and south of Snow Lake, the position of First Nation on the west side is unknown. Based on that comment, plus the comments that were shared by Manitoba Hydro to MIPUG in their questions to Manitoba Hydro that the longer route will involve dialogue with a larger array of local governments, towns and villages, and that the estimated time frame will be estimated to add one year to complete the multi-year public consultations, can the minister indicate to me, based on your earlier comments about time lines and sensitivity, can Mr. Brennan share with me how many man-hours Manitoba Hydro has spent negotiating with the west-side chiefs on the topic of compensation for traversing traditional First Nations lands on the west side?

Mr. Brennan: We have not started our consultations with the communities on the west side. We're proposing to start that in January.

Mrs. Rowat: Can Mr. Brennan please provide for me how many kilometres of traditional First Nation lands does Manitoba Hydro expect it will traverse on the west-side route?

Mr. Brennan: I'll have to get that number for you.

Mrs. Rowat: The Premier (Mr. Doer) has maintained that the First Nation ownership of the line is not on the table for negotiations of a bipole route. Is this an admission of failure of ownership model of the Wuskwatim Agreement? How would you interpret that comment from the Premier?

Mr. Brennan: Manitoba Hydro all along has not contemplated First Nation ownership of the transmission line. The model with Wuskwatim, from our perspective, is something that we're really, really proud of and certainly hope it proceeds. I really believe it will be a model that in some form will be adopted for any kind of natural resource development in the country.

Mrs. Rowat: One further question and then I'll let the Member for Turtle Mountain (Mr. Cullen) ask a few questions.

Will Manitoba Hydro be offering compensation to the west-side First Nations community or private landowners for access to a bipole route on the west side? If so, how would this compensation differ from that which would be offered to the east-side communities?

Mr. Brennan: We pay compensation for any private land that we go through, no matter where it is, and we would continue to do that.

Mr. Cullen: We discussed earlier some feedback from people who were opposed to the east-side proposal. I know we've asked the Premier from time to time for any customers of Manitoba Hydro, if there are any customers of ours that disagreed with the east-side proposal. I'm wondering, Mr. Brennan, if you could point out if there are any customers that have raised that specific issue.

Mr. Brennan: No. No customers have specifically raised the issue of anything Manitoba Hydro does within its own area. I think my concern with our customers is if a problem comes up and it's a problem that we think we're having, or they think we're having difficulty managing, it would cause them to look at other options within their own system other than Manitoba Hydro as being a purchase option. That concerns us very, very much.

As I mentioned earlier, anybody who's only concerned about the rate of return doesn't have a real concern like Manitoba Hydro does with the least-cost option. They would just go to the next item in their sequence and pass that customer on to the–or the cost on to customers and get their normal returns. As a matter of fact, in a lot of cases, American customers are giving up something on the rate of return because they're not investing capital in their own system by buying from Manitoba Hydro.

So I think we have a good, reliable product that's well considered, and we certainly want to keep it that way.

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Mr. Cullen: Just to confirm then, Mr. Chair, there have been none of Manitoba Hydro's customers specifically concerned about the east-side-proposed bipole 3 when it was proposed by Manitoba Hydro or the proposed UNESCO Heritage Site.

Mr. Brennan: As I mentioned, the concern would come if there's some kind of an outrage or some kind of a public concern about what we're doing, and that is a real major risk that the corporation and, certainly, all our stakeholders should be concerned about.

Mr. Cullen: Mr. Brennan, you pointed out earlier that, and maybe you can just clarify, you were out consulting with the First Nations communities on the east side because that was the proposal, the original proposal. What year did you stop the consultations with the First Nations communities on the east side?

Mr. Brennan: It was 2003.

Mr. Cullen: That corresponded with the Province going in there and having some discussions on the East Side Planning Initiative. I'm just wondering if the government, when they were in consulting with the First Nations communities regarding the east side planning at that time, did the Province of Manitoba, in their consultations, have a proposal for a bipole 3 running on the east side as part of their consultation package? Did they actually propose a bipole 3 as part of the consultation package?

Mr. Selinger: There was a different minister at the time, but as I understand it, the communities themselves had expressed concern about Manitoba Hydro being in there doing their consultations on the east-side bipole. They had, as early as 2000, started into the WNO, the broad area planning process. They were saying, Hydro's out here doing this bipole thing, we're in this WNO broad area planning process, we would like those two things not to be conflicting with each other. So the government went in to listen to the people on the east side and all of their concerns. One of the pieces of feedback they got from many of the people over there was that there was a great concern about the bipole proceeding down the east side.

Mr. Cullen: Would it be safe to say that there was some confusion at the time, then, when the government was in at the same time discussing east side planning and Manitoba Hydro being there discussing their proposal?

Mr. Selinger: I think they were expressing concern that the broad area planning process and the Hydro consultations were clashing with each other. They wanted the broad area planning process to be proceeded with without the other thing going on at the same time. The government's involvement over there was to listen to them as to what their concerns were and where they wanted to go with all of this. The conclusion that the ministers and government came out of it with was that there were major concerns from many communities that they met in about an east-side transmission line.

Mr. Cullen: So, once Manitoba Hydro ended their consultations in 2003, did Manitoba Hydro, the corporation, go back and do any follow-up in terms of a proposal or was there any follow-up after that time?

Mr. Selinger: Well, I think you're posing the question to Manitoba Hydro.

Mr. Brennan: No, we did not.

Mr. Cullen: I appreciate the response. We talked a little bit last meeting about Wuskwatim. Recognizing that there've been some issues come to light there in terms of securing a contractor, I wondered if that particular issue that's come to light in terms of securing a contractor, is that going to be setting back the completion date for that particular dam?

Mr. Brennan: If it goes on for an extended period of time, it will. At this point, it is not. There was on the table an option to advance it as a result of doing it in a different way, and that's being pursued with the contractor. At this point it hasn't, but if it goes on for an extended period of time, it will.

Mr. Cullen: It would appear that there's going to be a significant increase in cost to that particular facility. Would you care to comment on what kind of financial impact it's going to have in terms of just having that one contractor?

Mr. Brennan: What we're proposing to do before we commit to having a general contractor come in, we're proposing to take to the board of Manitoba Hydro an estimate, along with a contract, and look at the benefits of the entire project. We'll be doing it at that time.

Mr. Cullen: Are you saying then, that that entire project is going to be re-evaluated?

Mr. Brennan: No. What I am saying is we're making sure the board of Manitoba Hydro has all the knowledge it needs to make a decision and we always try to do that.

Mr. Cullen: Another issue that's certainly before us downtown here, and it's under construction, as well, is your new office building. We're certainly looking forward to having a tour of that facility sometime in the near future and I'm just wondering if you could comment on a completion date.

Mr. Brennan: We're still proposing to have the completion date, which will allow us to start having some people move in starting in June of this year. It sounds like it's pretty aggressive, but by the middle of June all the glass will be, or middle of January, all the glass will be on the building so it will be closed in and we're expecting to move the first people in at the end of May, or starting in June.

Mr. Cullen: At our last meeting you alluded to the fact that it looked like you were going to be over your budget amount. Do you have any estimate of where the final dollar amount is going to be for that particular structure?

Mr. Brennan: I sure hope I didn't say that. Our present budget is for $278 million and we still have that as our budget. We're on schedule to meet that and I'm hoping that it'll be right on schedule.

Mr. Cullen: Okay, thanks. Well, we certainly will look forward to hearing that and seeing how that turns out.

I want to get back to your–

Floor Comment: Can I just add to that?

Mr. Chairperson: Mr. Brennan.

Mr. Brennan: I think, with the rising costs in the construction business, I'm really pleased with the way the building is going. I think we're going to have a really great building, and I'm pleased with the way the costs have been contained in this wild environment we're in.

Mr. Cullen: I appreciate your response.

Getting back to our earlier discussion, your indication about the requests for proposals on the wind energy projects, I'm just wondering when you expect those particular requests will be submitted and when you intend to move forward on those particular requests.

Mr. Brennan: We are hoping to have the–well, we're expecting, and the schedule provides for those to be in in late January, and we would like the board to approve our direction by March.

Mr. Cullen: Can you provide the committee an idea of how those particular, those specific companies were selected, or those specific locations were selected? What was the criteria used for your selection?

Mr. Brennan: A whole series of criteria. The two most important ones are price and transmission costs related to our system to get the wind power into our system.

Mr. Cullen: When you evaluated the 84 submissions, did you have written criteria that you used, that Manitoba Hydro used to evaluate those?

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Mr. Brennan: Yes. They used a series of criteria to do that and went through the exercise of looking at how the various proposals met against that criteria, the two most important ones being the cost associated with it, as well as the cost associated with transmission in getting it into our system. Those are pretty important criteria.

Mr. Cullen: Mr. Chairperson, I just wondered if Manitoba Hydro would share that rating process, that criteria with the committee.

Mr. Brennan: I think that's a pretty competitive thing that it'd be very difficult for us to do. We expect to go out and get more wind after the 300 megawatts. That's something, you know, I think we can be transparent, but we shouldn't be silly either.

Mr. Cullen: Yes, I'm not referring at the specific submissions. You would provide the analysis on each specific submission. I just kind of like to have it in the context of what Manitoba Hydro is looking at in terms of their logic for making certain criteria and making those selections.

Mr. Brennan: If I was a wind developer, I'd be concerned about those two main criteria I talked about, and that is the actual cost of power to Manitoba Hydro and the cost of any related transmission, both for the developer as well as for Manitoba Hydro. Those are the two main ones, and those are the ones that will make anyone fly.

Mr. Cullen: The Premier (Mr. Doer), within the last two weeks, when questioned about wind energy in Manitoba, made the comment that the numbers don't work. I'm just certainly concerned about that particular comment. Obviously, the 84 submissions that were received by Manitoba Hydro, those particular companies and individuals associated with it certainly would have some reservations.

I'm just wondering, from your perspective, is that a valid concern in terms of the numbers, in terms of wind energy production here in Manitoba?

Mr. Brennan: I didn't hear the Premier's comments, but I'm really pleased he said them.

Wind power is something that has to be compared against hydro power. Most people certainly like wind power. Wind power is something that everybody seems to be able to relate to. Having said that, we have to compare it against the cost of the main alternative we have which is firm, reliable hydro. We got a real good wind resource in Manitoba, but because of the capacity factor of wind it doesn't have the same cost as some of our hydro options. Certainly, in time, as we get through the least expensive hydro we have and get into more expensive one, the wind resource we have in Manitoba can be really, really capitalized on. So I think we got a real good wind resource, and I think we should integrate it into our system as it's cost effective.

Mr. Cullen: In terms of cost, and I don't want you to put yourself in a place where it would negatively impact your discussions that you're having with these developers, can you give me kind of a rate where companies in Manitoba can generate electricity? I'm looking for a range and a rate per kilowatt. Can you kind of give me a ballpark of what the expectation would be?

Mr. Brennan: I think it'd be a little unfair to those people that are trying to come up with a price now that we want them to submit by the end of January. When we went out with our original proposal though there was a price in there that could be used.

Mr. Cullen: Well, what I'm wrestling with here is, and you alluded to it, too, like, obviously, our current price that we're generating electricity for right now is pretty reasonable because we have a relatively old infrastructure. When we start adding infrastructure into the system, what kind of a rate are those new systems going to be? What kind of a rate per kilowatt are we looking at once we get Wuskwatim on and Conawapa? Can you give me some kind of a range of what we're looking at in terms of costs there?

Mr. Brennan: I think I should be real careful with numbers I do give you, but power coming from Conawapa on a per unit basis is really, really cost-effective. It would be the lowest thing in the country by far. It is really, really cost-effective. The big concern we have is we have so much power coming from it that it would be best if we could–you know, it's not like Wuskwatim. It's six times the size of Wuskwatim, so you've got to make sure you have a market for that power to carry all that cost. But it is by far the cheapest.

Mr. Chairperson: Mr. Cullen, did you have further questions?

Mr. Cullen: Yes, I do.

So, in essence, what we're doing with these proposals is these developers will be sharpening their pencils, if you will, and you're looking for probably the least-cost option so that you can buy it at the least cost and then turn around and sell it to your markets. Is that in essence how the process is going to work going forward?

Mr. Brennan: Yes, there's a cost to making sure it's a firm, reliable product because, you know, we have to–wind power comes into our system whenever the wind's blowing. It could be at a time when we don't want to sell it because the market prices are real low, you know, in the middle of the night or something. So what we want to do is cut back on hydro, not sell our hydro, and speculate on a time when we could sell both the wind energy and hydro power at a good rate. So there's a cost to that and that's got to be factored in.

So, to answer your question, we do want to buy the power out from the producer and resell it at a higher rate but there's cost to doing that, and we'd incorporate that into the whole mechanism.

Mr. Cullen: The whole premise of adding a generation capacity to Manitoba hinges on having a market to sell it to. Are you actively pursuing other markets, and what is the future capacity there in terms of export markets?

Mr. Brennan: As long as we don’t get into any of these environmental fiascos that we were talking about earlier, I think the market is just really, really wonderful for Hydro. The American market is very, very hungry for power. You know, there are transmissions constraints that we have to deal with like that we can only use existing transmission at this point. We do have a fair amount of it to the States, you know, 2200 megawatts. So we want to make sure that's fulfilled.

Saskatchewan is a market as well, as is Ontario. So, from my perspective, I think all these are real good markets that we want to take advantage of. I think in the immediate future you will hear more about us making good sales.

Mr. Chairperson: The hour being 8:30 p.m., this committee agreed to review the sitting time. What's the will of the committee?

Mr. Kelvin Goertzen (Steinbach): I understand there's been an agreement between myself and the minister to allow the committee to sit till quarter to nine to allow the leader of the independent party to pose some questions, at which point we'll proceed to pass, I believe, the oldest annual report that's listed on the agenda for tonight.

Mr. Chairperson: It sounds like there's a will of the committee, then, to extend the sitting time for an additional 15 minutes till 8:45 p.m.

Hon. Jon Gerrard (River Heights): A question for Mr. Brennan: At the last meeting, you indicated that the route for the west-side line is not precisely known. Do you have an estimate of when that route will be known in terms of time?

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Mr. Brennan: What we propose to do is go through a consultative process with all the people on the west side and that would be about three or four rounds of that. So I would think that would take a couple of years to come up with, you know, a good route that is sensitive to people's requirements.

Mr. Gerrard: Will there be a look at the cost and a much better estimate of the precise cost of that route at the end of that two-year period? I would ask, in light of what you said last time, that much of the estimate was based on a per kilometre cost on the east side, which may or may not be precisely the same on the west.

Mr. Brennan: Yes, that will happen. Having said that, deviations in the price like the cost per kilometre is relatively high and I'm sure that over the whole length of it, it won't have a real major impact–whatever route we take–but certainly it would be revised as we go.

Mr. Gerrard: I would presume that, if there was an existing transmission line corridor, the costs there are likely to be significantly lower because you've got a route that would be fairly easy to use to get environmental permits for, et cetera. For example, the transmission line from, say, Thompson to Wuskwatim to The Pas; there is a corridor that's being built as a result of Wuskwatim. It, I presume, would be a lot less additional cost to add on to a route like that than it would be in developing a new route, for example, just south and east of Winnipeg itself.

Mr. Brennan: I think the cost of the route itself is, in percentage terms, a relatively small part of it. The cost is quite low, of course, if we go through Crown land versus private land. I don't think that that would have a material impact. I really don't.

Mr. Gerrard: Is there any work currently being done on the east-side option?

Mr. Brennan: No. The east side was ruled out from a management perspective.

Mr. Gerrard: Question to the minister. The minister and his government have talked about putting a road on the east side. I wonder if the minister could table the route for that road.

Mr. Selinger: I'll have to get that precise details for the member, but I'd be happy to get him the information and provide it to him, what they're proposing there.

Mr. Gerrard: Okay, I thank the minister.

With the west side, on page 6, it says: "If the Bipole III line, together with converters, is built along the West Corridor, only about one-third of northern capacity could be transmitted to the south in the event of total loss of transmission on the Interlake corridor."

Could you explain to the committee why only one-third, whereas, if bipole 3 were on the east side of Lake Winnipeg, you would be able to maintain two-thirds?

Mr. Brennan: This is basically a technical issue and I'm probably not the best one to do it, but that's the maximum capability of the line on the west side. With the conversion equipment and the lines it is only able to handle 2000 megawatts.

Mr. Gerrard: So my understanding, in terms of what you're saying, is that the line which is to be built on the west side would have a much smaller carrying capacity for hydro-electric power transmission than the bipole 3 if it were built on the east side?

Mr. Brennan: That's only if there's a loss of transmission on the Interlake route. So it's a paralleling situation that would only occur should we lose the Interlake route. That's the only time this would happen.

Mr. Gerrard: Yes, I understand that this is where you have a complete loss of power transmission capability on the Interlake lines, but why is the west-side line, as proposed, so much smaller in terms of capacity under those circumstances than the east line would be if it were bipole 3 there?

Mr. Brennan: It's my understanding that that was the optimum size for the design of the line based on our system.

Mr. Gerrard: Now, I would ask Mr. Brennan if that is a reflection of the line itself or the converter capacity.

Mr. Brennan: Both.

Mr. Gerrard: Given that the west-side bipole 3 has such a dramatically smaller power transmission capacity if there was failure of the Interlake lines compared to the east-side bipole 3, that's a huge difference if there was a failure. You know, I'm quite surprised at the extent of that difference in terms of what that would mean for backup for southern Manitoba and for export transmission. I'm still having difficulty trying to understand why it should be so big and to what extent this was or wasn't taken into account in terms of the final decision.

Mr. Brennan: Certainly, in the design of any line on these, it was taken into consideration. You know, I think it'd be best to get you a technical answer rather than me trying to continue to do this. I know for sure that the entire system, it cannot be paralleled equal to the Interlake system. I know that. That's a fact, and what the exact numbers are I'm not sure about, but it's definitely less.

Mr. Gerrard: Yes, also on page 6, there's a reference on page 6 to, you know, if there was full development of the northern power capability that you would actually need a bipole 4 or a bipole 5. What is the reference to full development? Which, and how many additional dams are you referring to when you talk about full development?

Mr. Brennan: I have to remind you that this is not Manitoba Hydro's report. I think it's definitely true–what Mr. Farlinger considered to be full development I'm not sure–but we know that we got more than 5000 megawatts that's not been developed so I presume that everything that would be transmitted by DC or the equivalent of DC, that would be impacted, so I would think it probably does get into a bipole 4 and bipole 5. I'm almost positive.

Mr. Gerrard: The dams, Wuskwatim, Gull or Keeyask and then Conawapa, represent something under 4000, so there's another thousand megawatts. Is that right?

Mr. Brennan: There's more than that. We have a map where it's all laid out though. We can provide that for you.

Mr. Gerrard: So, in terms of having a bipole 4 or bipole 5, if those were necessary in the future, could they run alongside of bipole 3, for example, if it was west or east?

Mr. Brennan: Once you get some diversity on lines you could put it almost anywhere, including going back to the Interlake because what you are concerned about is any lines going down in one particular area, and as long as you've got enough that would take care of the Manitoba load in the southern system, both through your AC transmission, any southern generation, as well as whatever DC lines you had coming down, as long as that took care of the Manitoba load it wouldn't matter.

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Mr. Gerrard: Because the capacity on the east-side route is much greater than that on the west-side route. We just talked about that in terms of you being able, if there was no Interlake route, that your security of power, if there's population growth, increased power usage in southern Manitoba, would clearly be greatest on an east-side power route. Is that not right?

Mr. Brennan: I'm not even sure, I don't think that's right. But I'm not sure I agreed with your preliminary part. I don't think I did. I'm not sure if I remember what you said, but I don't think I agree with it.

Mr. Gerrard: My understanding is–and it's referenced here–that if the Interlake goes down, on an east-side power line you're able to maintain two-thirds of your power capacity going to the south. If the Interlake goes down and you've got a west line, you're only able to maintain one-third. So there's a dramatic difference in the amount of power that you can transmit on the proposed east side versus a proposed west-side bipole. And in a future 30, 40, 50 years from now, if you're looking at adding another bipole, and suppose you added that bipole 4 or 5 down the Interlake, you're going to be much more restricted with the design of the west-side line if you're only able to carry one-third of the power that you need versus on the east-side line where you can carry two-thirds.

Mr. Brennan: The whole problem comes about because we can't parallel, because the technical characteristics of the west-side line are not close to the Interlake. The technical characteristics of an east-side line are closer to that of the Interlake. That's why we have to put the conversion equipment in before we'd otherwise want to, and it's the very same reason as that. Once you put an additional generation on the system though, you'll be able to meet the Manitoba load by the additional generation anyway. So I don't think it really matters.

Mr. Gerrard: I mean, I think that you would be able to make the power so long as the lines were intact, but if you had a problem on the Interlake line, for example, then that problem would be much more severe with the west-side line than versus an east-side line.

Mr. Brennan: The real concern is making sure we can supply the Manitoba load until such time as we can fix the line. So we want to make sure that the Manitoba load is reliable until we get the line fixed, and I would think the 2000 megawatts would do it.

Mr. McFadyen: I just have two questions just arising from answers given to questions posed by the Member for River Heights (Mr. Gerrard), and then I think we're done from the perspective of our caucus.

The first is: Did I hear you correctly when you said that this report that was tabled today is not a Manitoba Hydro report?

Mr. Brennan: It is a report that was done for Manitoba Hydro, paid for by Manitoba Hydro, but it was not done by Manitoba Hydro people. Okay? It was done by an external consultant that we, you know, take a look at and use in our deliberations. That's what I meant to say. I probably didn't.

An Honourable Member: Right. That's fair.

Mr. Chairperson: The committee agreed to review our sitting time at 8:45 p.m., and we're at that point in time now. What's the will of the committee?

Mr. Selinger: I think there's one more question. Could we entertain an extension to answer the next question?

Mr. Chairperson: The committee agree to that additional one question, and then we'll proceed with the review of the reports?

Mr. Goertzen: Assuming that government members don't have any questions on this important file, but, certainly, if government members have questions, I think we would be willing to hear them as well.

Mr. Chairperson: Mr. McFadyen, proceed with your question, sir.

Mr. McFadyen: Thank you, Mr. Chairman.

Just arising from questions being asked by the Member for River Heights, and just back to Mr. Brennan on the issue of paralleling, the response provided to the question posed by the Industrial Power Users Group by Manitoba Hydro indicates that in the event the existing two bipoles in the Interlake were inoperative, the west-side route would be able to handle as much as a thousand megawatts less than an east-side route. I wonder if you can just indicate, in practical terms, what the loss of a thousand megawatts would mean in the event that the two existing bipole lines went down and we are left only with bipole 3 on the western route. Loss of a thousand megawatts: what does it mean in terms of the ability to continue to supply power to Manitobans or to export or any other practical ramification of a loss of that much power?

Mr. Brennan: I would have to look at that. I think it's a function of when it happened in terms of the time of day, that sort of thing. Also, whether there's any additional energy that would be coming down the west-side line. In other words, at that point, we could have additional generation coming down anyway. So the thousand that would be picked up, could be offset by any new generation. So it might not even be a problem.

One other comment on this particular question that I probably should have made earlier. I used to review all these answers. This particular one, I probably would've had some comments on had I reviewed, but one thing I don't think is included in here that I think should be, is if we have a major outage on the west side, it would definitely be easier to get at. We have roads and that sort of stuff. If we had to get–just even finding, you know, we'd have to get helicopters up and I'm sure they'd be going from both ends and then we'd have to get equipment in, and everything like that. If it happened on the west side, it probably would–well, I'm convinced it'd be easier. If I had've reviewed it, I would have added that.

Mr. Chairperson: Thank you, members of the committee. Mr. McFadyen?

Mr. McFadyen: Mr. Brennan, you just indicated you would come back with a response on the issue of the practical implications of a loss of a thousand megawatts. In some scenarios, it might have no impact. In others, it might. In preparing that response, would you be good enough just to indicate what the impact of that thousand-megawatt difference would be during a typical day at peak times; if it occurred during non-peak times, overnight, or just what the range of scenarios might be when you consider your response to that?

Mr. Brennan: We certainly will.

Mr. Chairperson: Is the committee ready to proceed with the reports?

An Honourable Member: Yes.

Mr. Chairperson: The annual report of Manitoba Hydro for the year ended March 31, 2004–pass.

Shall the annual report of Manitoba Hydro for the year ended March 31, 2005, pass?

Some Honourable Members: Yes.

Some Honourable Members: No.

Mr. Chairperson: I hear a no. The report is not passed.

Shall the annual report of Manitoba Hydro for the year ended March 31, 2006, pass?

Some Honourable Members: Yes.

Some Honourable Members: No.

Mr. Chairperson: I hear a no. The report is not passed.

Shall the annual report of Manitoba Hydro for the year ended March 31, 2007, pass?

Some Honourable Members: Pass.

Some Honourable Members: No.

Mr. Chairperson: I hear a no. The report is not passed.

Before we rise, it would be appreciated if members of this committee, if they had no need for the reports, if they could leave them behind for subsequent committee meetings, that would be appreciated.

The hour being 8:50 p.m., what's the will of the committee?

An Honourable Member: Committee rise.

Mr. Chairperson: We thank members of Manitoba Hydro for their appearance before the committee here this evening, and we wish everyone a Merry Christmas and Happy New Year.

Committee rise.

COMMITTEE ROSE AT: 8:50 p.m.

The Legislative Assembly of Manitoba Debates and Proceedings
are also available on the Internet at the following address:

http://www.gov.mb.ca/legislature/hansard/index.html

Tab 135

Manitoba Hydro

BR.S

APR 0 9 2008

Why the west side is the best side

Building Manitoba Hydro's new transmission line, known as Bipole III, on the west side of Manitoba makes sense for both environmental and economic reasons. Building westward ensures protection for the unique boreal ecosystem on the east side of Lake Winnipeg, while also ensuring a solid future for Hydro of clean reliable energy and affordable rates. To force the line down the east side is irresponsible because it puts both Hydro and the area at risk.

If Progressive Conservative Leader Hugh McFadyen truly wanted to dispel the myths about Bipole III, he should stop misleading Manitobans about the basic facts of the matter.

We have been open about the fact that the west route is longer and costs more than the east route. How much more? McFadyen claims the difference is $1.5 billion. He makes a gross exaggeration. Manitoba Hydro estimates the number is $400 million or a total of $2.2 billion for a west route versus $1.8 billion for an east route. McFadyen exaggerates again when he says the west side line leaks $700 million worth of energy. Hydro has said line loss could cost between $107 million and $230 million. McFadyen regularly triples Hydro's estimates of the cost difference and he knows it.

How much does protecting the east side forest really cost us? Independent consumer advocate Byron Williams has calculated that the cost difference in routes amounts to a three per cent increase on a hydro bill or approximately $23 per year. The cost of the project will not be accounted for until 2017 and then spread over 40 years. Hydro president and CEO Bob Brennan has stated: "Rate payers will pay for it over the life of the system, and of course, we'll have increased sales, so we'll probably come down at the end of the day to say export customers will probably pay for it."

Greg Selinger

McFadyen further misleads Manitobans by covering up the major risk of forcing a line down the east side. The province and Manitoba Hydro have received 30,000 e-mails from all over the world opposing an east-side line. In attempting an east-side route, Manitoba Hydro would encounter serious opposition campaigns and face a long and divisive licensing process. The project could be delayed indefinitely and permanent damage done to Hydro's reputation in export markets. McFadyen avoids this deal-breaking issue.

McFadyen is also proclaiming that a transmission line would lift the east side First Nations out of poverty. But according to Hydro, a transmission line only provides a total of six months of seasonal construction work per community. McFadyen seems to be promising east-side chiefs much more. He owes it to the chiefs, the people they represent and all Manitobans to be open about what that is.

Unlike McFadyen, this government believes the east side of Lake Winnipeg has more potential than simply being a route for a transmission line. The east side is the second-largest intact forest left on the planet. It is a unique boreal shield forest ecosystem that hosts the threatened woodland caribou, the animal featured on the 25-cent piece. Local communities are making a bid for an UNESCO World Heritage Site designation to recognize the region's natural and cultural "outstanding universal value." If achieved, this designation will bring ecotourism and jobs for decades to come, while protecting the spectacular ecosystem. Work is underway with local communities on the UNESCO bid and comprehensive area planning.

Imagine 10 and 20 years from now. Which route would we prefer to defend to our children and grandchildren: the one chosen because it is cheaper, or the one that cost more but allowed us to protect Canada's largest boreal forest?

It is unfortunate the Leader of the Opposition deals in distortions and exaggerations. We welcome public debate on this issue that is based on facts and accurate information. This government has been open about our position since we first announced it in 2005. We then made it part of our 2007 election commitments, after which it was debated in the media. Manitoba Hydro announced their decision last fall and it has been debated extensively in the Manitoba legislature.

Moving forward, we welcome upcoming public consultations, environmental studies and the determination of a precise western route for the new transmission line. We have also committed to hold Clean Environment Commission hearings on the project.

GREG SELINGER
Minister responsible for Manitoba Hydro

Tab 136

West side is wrong, but you don't have to take my word for it

VP6 A9

BR.S

APR 12 2008

I felt it was important to respond to Minister Greg Selinger's recent statements regarding BiPole III.

He would have Manitobans believe that I am alone crusading for the east side and I wish to set the record straight as to why I am part of the vast, informed and growing majority of Manitobans who know that the NDP making a massive policy mistake with its west-side route.

Former NDP MLA Elijah Harper, former NDP premier Ed Schreyer, Winnipeg Chamber of Commerce president Dave Angus, Manitoba Business Council president Jim Carr, James Blatz and seven fellow engineers, constitutional law expert Bryan Schwartz, 15 of 16 east-side First Nations, law expert Harold Buchwald, former UNESCO World Heritage Committee chair Jim Collinson, MKO (Northern Chiefs) Grand Chief Sydney Garrioch and president and CEO of Manitoba Hydro Bob Brennan — all of these groups and individuals oppose the west-side route for Manitoba's next hydro transmission line, or have directly discredited the arguments for the NDP's route.

Some have stated that it is the "worst policy decision yet" and cautioned about its "potential fiscal carnage." First Nations said they were "devastated" by the government's willingness to leave east-side communities in "poverty in perpetuity." Each agrees the NDP is making the wrong decision.

Selinger contends that the east-side budget is $1.8 billion. This is not true. He includes $1.1 billion for a converter station that is not needed. Hydro CEO Bob Brennan has confirmed this on the record and experts from the engineering community agree. This is why the extra cost of a west-side transmission line is $1.5 billion, not the $400 million the NDP mis-states.

The NDP also contends line losses will be $107 million to $230 million on its route. This assumes that we will never develop another hydro dam. When Conawapa and Gull-Keeyask come online, losses will total $700 million over the life of the line.

Mr. Selinger states that the NDP will not offer economic benefits to First Nations for a power line route on their land. If the NDP is content to leave the east side in poverty, that is its policy agenda, not ours. A PC government would ensure lasting benefit-sharing for east-side communities. This is the position I have stated to east-side residents and one I am committed to.

Mr. Selinger states potential export customers will refuse to buy power from us if we build on the east side. XCEL energy and the Minnesota Public Utilities Commission have said on the record that they do not care where the line goes and the commission has not had a single comment about the hydro line location one way or the other.

Lastly, the boreal forest stretches from Alaska to Newfoundland and Russia to Norway. The impact of a bipole line is minuscule and the longer west-side route will actually cut more trees. We feel it is not worth $1.5 billion — $6,000 for each Manitoba family — and keeping east-side communities impoverished, to build on the west side of the province. We hope the NDP eventually sees the light and rights its wrong.

HUGH McFADYEN
Leader, Progressive Conservative Party of Manitoba

Manitoba Hydro
Progressive Conservative Party
of 1998

Tab 137

Third Session - Thirty-Ninth Legislature

of the

Legislative Assembly of Manitoba

DEBATES
and
PROCEEDINGS

Official Report
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MANITOBA LEGISLATIVE ASSEMBLY
Thirty-Ninth Legislature

Member	Constituency	Political Affiliation
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ALTEMEYER, Rob	Wolseley	N.D.P.
ASHTON, Steve, Hon.	Thompson	N.D.P.
BJORNSON, Peter, Hon.	Gimli	N.D.P.
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WHITEHEAD, Frank	The Pas	N.D.P.
WOWCHUK, Rosann, Hon.	Swan River	N.D.P.

LEGISLATIVE ASSEMBLY OF MANITOBA

Thursday, May 7, 2009

The House met at 1:30 p.m.

ROUTINE PROCEEDINGS

PETITIONS

Winnipeg Regional Health Authority

Mr. Kevin Lamoureux (Inkster): Mr. Speaker, I wish to present the following petition to the Legislative Assembly of Manitoba.

The background to this petition is as follows:

Manitoba's Premier and his NDP government have not recognized the issues of public concern related to the Winnipeg Regional Health Authority.

The WRHA is building an administrative empire at the expense of bedside care.

Winnipeg Regional Health Authority needs to be held accountable for the decisions it is making.

Health-care workers are being pressured into not being able to speak out no matter what the WRHA is doing or has done.

We petition the Legislative Assembly of Manitoba as follows:

To request that the Premier (Mr. Doer) and the NDP government to call a meeting of a standing committee of the Legislature and invite representatives of the WRHA to appear before it.

Mr. Speaker, this is signed by J. Sarinas, J. Chan, K. Bradley and many, many other fine Manitobans. Thank you.

Mr. Speaker: In accordance with our rule 132(6), when petitions are read they are deemed to be received by the House.

Neepawa, Gladstone, Ste. Rose, McCreary–Family Doctors

Mr. Stuart Briese (Ste. Rose): Mr. Speaker, I wish to present the following petition to the Legislative Assembly of Manitoba.

These are the reasons for this petition.

Access to a family doctor is vital to good primary health care. Patients depend on their family doctor for many things, including their routine health-care needs, preventative care and referrals for diagnostic tests and appointments with specialists.

Family doctors in Neepawa, Gladstone and Ste. Rose are unable to accept new patients. The nearby community of McCreary has not had a doctor available to take patients in months.

Without a family doctor, residents of this large geographical area have no option but to look for family doctors in communities as far away as Brandon and Winnipeg.

Residents of these communities are suffering because of the provincial government's continuing failure to effectively address the shortage of doctors in rural Manitoba.

We petition the Legislative Assembly of Manitoba as follows:

To urge the Minister of Health (Ms. Oswald) to consider prioritizing the needs of these communities by ensuring they have access to a family doctor.

To urge the Minister of Health to consider promptly increasing the use of nurse practitioners in these communities in order to improve access to quality health care.

This petition is signed by Leonard Law, Gladys Law, Reine Cameron and many, many other fine Manitobans.

Long-Term Care Facility–Morden

Mr. Peter Dyck (Pembina): Mr. Speaker, I wish to present a petition to the Legislative Assembly.

The background for this petition is as follows:

Tabor Home Incorporated is a time-expired personal care home in Morden with safety, environmental and space deficiencies.

The seniors of Manitoba are valuable members of the community with increasing health-care needs requiring long-term care.

The community of Morden and the surrounding area are experiencing substantial population growth.

We petition the Legislative Assembly of Manitoba as follows:

To request the Minister of Health (Ms. Oswald) to strongly consider giving priority for funding to develop and staff a new 100-bed long-term care facility so that clients are not exposed to unsafe conditions and so that Boundary Trails Health Centre beds remain available for acute-care patients instead of waiting placement clients.

This is signed by Richard Schmidt, Jeff Knaggs, Brent Laverty and many, many others.

Midwifery Services–Interlake Region

Mrs. Myrna Driedger (Charleswood): I wish to present the following petition to the Legislative Assembly.

These are the reasons for this petition.

Residents of the Interlake Regional Health Authority do not have access to midwifery services.

Midwives provide high quality, cost-effective care to childbearing women throughout their pregnancy, birth and in the post-partum period.

Women in the Interlake should have access to midwifery care.

We petition the Legislative Assembly of Manitoba as follows:

To urge the Minister of Health (Ms. Oswald) to consider working with the Interlake Regional Health Authority to provide midwifery services to women in this region.

This is signed by Rebecca Wood, Michelle Santchi, Angela Falk and many, many others.

Introduction of Guests

Mr. Speaker: Prior to oral questions, I'd like to draw the attention of honourable members to the public gallery where we have with us from Riverton Collegiate 25 grade 9 students under the direction of Ms. Linda Stevens. This school is located in the constituency of the honourable Member for Interlake (Mr. Nevakshonoff).

On behalf of all honourable members, I welcome you here today.

ORAL QUESTIONS

Provincial Debt Repayment

Mr. Hugh McFadyen (Leader of the Official Opposition): Mr. Speaker, three weeks ago, this House voted on a budget that contained within it $180 million in debt reductions over the next two years. Only two weeks later, the Minister of Finance (Mr. Selinger) introduced a bill that changed that to a $330-million reduction in debt payments over three years. This is, over two weeks, a change of $150 million in terms of the Finance Minister's budget plans.

Is the Premier not concerned that his Finance Minister, in the middle of this economic crisis, when he changes his plans by tens of millions of dollars in the span of two weeks, is starting to look a little bit unbalanced and unsteady?

Hon. Gary Doer (Premier): I've been meeting with a number of business organizations, labour organizations, community organizations over the last period of time. Members opposite, with their extreme views, are out there on the extreme edge of the debate, Mr. Speaker. The only instability I see is the teetering on this edge, this extremist edge that they're on.

Mr. Speaker, over and over and over again, people think it's sensible, first of all, to have a pension liability payment that wasn't made for 30 or 40 years actually, begun by our Minister of Finance and continued on in this budget. The old days of hiring a jail guard or a highway operator or a public health nurse paid 7 percent less for 40 years, those days were ended in 2001 with that budget.

The hidden liability that was underneath the table from members opposite is now above the table so everybody can see, and there's a payment plan. All the capital expenditures–again, there was no health capital and health capital debt in the budget before. All those are above the table now, not below the table, above the table, fully transparent and an amortization plan. There's some $450 million of obligations in the budget for repayments of past capital, past pension.

I think it does make sense, though, to deal with the stimulus package, to deal with needed priorities, to reduce the debt payment on the operating side of government. It is only reduced. The budget is balanced under GAAP financial planning as the Auditor General has recommended. It's one of only two provinces in Canada that's done so. I'm disappointed the members opposite voted against it, Mr. Speaker.

Mr. McFadyen: Mr. Speaker, again, the self-appointed historical fiction writer of the 1990s again is going off and providing incorrect information. In fact, the 1999 budget that he now seems to have so much difficulty with, how did he vote on that budget? Maybe he'd be honest enough to remind Manitobans he voted for the very budget that today he seems to be criticizing. That Tory budget of 1999, he's on the record voting in favour of.

Now, Mr. Speaker, bringing us to the year 2009, it was only five months ago that the Premier said, and I quote: I would also point out that we have a debt payment that we've also recommitted to of $110 million. So if you look at a potential draw of the rainy day fund of $60 million and you still have a $110-million debt repayment, we are actually at a situation that's very, very positive.

That's what he said five months ago. Now he says that's an extreme position, the position he was putting on the record five months ago. One week ago, Mr. Speaker, they introduced a bill that made a $130-million change in the budget that they introduced and voted on three weeks ago.

Mr. Speaker, where are they going to be next week when it comes to their fiscal plans, and is it going to be anything that resembles where they stand today?

***** (13:40)

Mr. Doer: Mr. Speaker, I would point out that the '99 budget that we voted against, some columnists thought that it was an unwise move. We actually thought–

Some Honourable Members: You voted for it.

Mr. Doer: Or voted for it. We voted for two budgets over 10 years. One was a copy of our election commitments on family tax credits. We thought that was a positive budget, and we voted for the budget in '99.

Now, I would point out, the '99 budget had a $185-million draw from the rainy day fund. It was the second year in a row for a $75-million debt payment.

This budget has $110-million debt payment, reduced to $20 million, which is obviously a $20-million better position, if members can add.

And, Mr. Speaker, not only that, this budget is much better than the '99 budget, even though we voted for it, because it has pension liability payments. That wasn't in the '99 budget. It wasn't in the '98 budget. It wasn't in the '97 budget. It wasn't in any budget right back to 1962. It was a ticking time bomb.

Members opposite, for 11 years, didn't pay one cent down on pension liability. The stability and balance of this budget includes that in this budget, and I'm proud of it, Mr. Speaker.

Mr. McFadyen: Mr. Speaker, five months ago, the Premier said a $110-million debt repayment commitment was a positive thing for Manitoba–this is after the financial crisis started–and then several months later, he said, no, that's wrong; we're going to reduce that to $20 million for the next two years.

Three weeks later, Mr. Speaker, they adopted a third position: We're not going to make any debt repayments for the next three years.

I want to ask the Premier: Will he at least go back to the position that they had three weeks ago, when they voted on the budget, and ask his Minister of Finance (Mr. Selinger) to amend the bill and at least go back to where they were three weeks ago when they voted on the budget, Mr. Speaker.

Mr. Doer: There's been $960 million of operating debt payments made by our government, including the $110 million that the member opposite references. We did not bring this budget in to be retroactive to the '08-09 year, Mr. Speaker. This is an '09-2010 budget.

Mr. Speaker, the federal government has gone from an infrastructure program that's seven years long. It has now gone to an infrastructure program that requires, in two years, to meet the obligations by provincial and municipal governments that were originally scheduled over seven years.

We actually know that the federal government is doing this. It's running a deficit. I know their friends are running a deficit, but they are running a deficit, Mr. Speaker, on the basis of stimulus for the economy.

Luckily, here in Manitoba, with the good work of our workers across the province, with the productive work of our farmers, with the innovation of our businesses, we can match those infrastructure investments by reducing the debt payment but maintaining a balanced budget.

No, we're not going to go backwards to three weeks ago. We always go forward, Mr. Speaker.

Manitoba Hydro
Bipole III West-Side Cost

Mr. Cliff Cullen (Turtle Mountain): It's painfully clear this government has lost touch with Manitobans.

Bill 30 proves we're in financial difficulty, yet this government forges ahead with its west-side bipole decision.

A concerned Manitoba taxpayer wrote to the *Free Press*, and it appeared in today's paper. J. Hugh McMorrow wrote: "Perhaps the NDP government requires bypass surgery to connect its decision-making process to its brain!" Mr. Speaker, this is the average Manitoban speaking.

Mr. Speaker, given our very difficult financial circumstances, will the minister reconsider his west-side decision?

Hon. Greg Selinger (Minister responsible for the administration of The Manitoba Hydro Act): I thank the member for the question because it allows me, once again, to put the accurate facts on the record about what we're doing, with respect to debt repayment, in the province.

There's $20 million on the general purpose debt repayment. There's $135 million for pension liabilities, never paid by members opposite in the entire 11 years they were in office. There's $135 million of amortization debt repayment, and there's $127 million of principal repayment, for a total of $417 million of debt repayments in the budget.

Now, I actually don't think the members were aware of that when they voted against the budget, and I would like to ask the members opposite, now that they know the facts, are they ready to reconsider their position and vote for the budget?

Mr. Cullen: Well, Mr. Speaker, we're hearing from Manitobans and they're speaking out about the bad decisions this government's making. It's clear after 10 years in government, they've simply lost touch with Manitobans. Mr. McMorrow talks about the confusion and dishonesty of the Doer government.

Mr. Speaker, Bill 30 is a classic example of a government losing touch. How can the minister justify running up the credit when we can't even pay off our own obligations right now?

Mr. Selinger: Mr. Speaker, one of the common things that the members opposite do is they like to ask for roads, schools, hospitals and facilities in their area, and then they like to separate from the reality that you have to pay for those things and blame that on the government.

Here are a couple of facts for the members opposite. Since '04-05, the gross domestic product in Manitoba has grown by 26 percent. The book value of our assets has grown by 49 percent, more than double that, and the per capita debt has grown by 6.4 percent.

We are getting value for the money. The amount of value, the amount of wealth in Manitoba, is more than eight times the amount that we have invested in debt. Manitobans are better off. Their debt-to-GDP ratio has gone down and their credit rating has gone up.

Mr. Cullen: Well, Mr. Speaker, here are the facts. There are no plans in place to reduce the debt. There is a plan in place, though, that will blow millions of dollars on a west-side line.

Yesterday, Manitobans were questioning the logic at the Cabinet table. Today, they're saying the government needs brain surgery.

When will this government come to its senses and make decisions in the best interests of all Manitobans?

Mr. Selinger: Mr. Speaker, the government has responded to the challenges of the day. We are in the middle of a global recession, the greatest economic meltdown since the Great Depression, driven by irresponsible financing arrangements made through the barons of Wall Street, the good friends of the members opposite, the members they like to emulate.

In response to that, the global community of all political stripes has said we need to have stimulus in the economy, a 2 percent stimulus. We are creating 10,000 person years of additional employment with this budget. The members opposite would rather that people go on the unemployment rolls so they can make a little debt payment. We think we can have fiscal discipline and more jobs in Manitoba to the betterment of everyone in Manitoba, and you vote against it.

Pediatric Allergy Testing
Wait Times

Mrs. Myrna Driedger (Charleswood): Today there are 575 children with allergies and asthma waiting to be seen for the first time by an allergy specialist at the pediatric allergy clinic at Children's Hospital.

Three hundred of them have appointments between now and the end of July; 275 of them are waiting on a waiting list for appointments to be set up after August 1.

I'd like to ask the Minister of Healthy Living if she thinks that it's safe to have so many children with allergies waiting so long to see a specialist.

Hon. Kerri Irvin-Ross (Minister of Healthy Living): We work with community partners across this province and we work on reducing lists. We have some exceptional programs that we work with: Youville community health centre where we provide a camp for children with asthma to come and play and learn about their disease and how to manage it, and we provide those ongoing supports for their family.

Mrs. Driedger: I don't blame her colleagues for not clapping for that response, Mr. Speaker.

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mrs. Driedger: Mr. Speaker, wait times for these children are broken into three levels: Non-urgent cases wait for nine to 12 months; urgent cases, but non-life-threatening, wait for four to six months; but urgent and life-threatening cases have to wait one to three months.

Mr. Speaker, I cannot believe that children with life-threatening allergies and asthma have to wait one to three months, and this is according to a Freedom of Information document from the WRHA.

So I'd like to ask the Minister of Healthy Living to please explain why a child with life-threatening allergies has to wait one to three months before being seen by a specialist.

Ms. Irvin-Ross: This government has worked very hard to bring nurses and doctors to this province, and we have proven those successes.

I want the people of Manitoba to know, when there's a life-threatening issue, those issues are being dealt with immediately to support those individuals and those families, and that's the truth.

***** (13:50)

Mrs. Driedger: Mr. Speaker, this minister knows absolutely nothing about what she's talking about. Children who have life-threatening allergies and perhaps go into anaphylactic shock after eating a peanut–and we know about dangerous peanut allergies because peanut allergies can be very, very dangerous for children–these kids have to wait one to three months before seeing a specialist.

I'd like to ask the Minister of Healthy Living to explain how such a dangerously high waiting list can exist today for children in this province.

Ms. Irvin-Ross: The facts are that we have made investments in emergency departments across the province, including the Children's Hospital, to provide those emergency life-threatening supports that are required.

What we need to talk about–the member opposite talks about what the facts are. The facts are that we continue to make investments around children's asthma education program. We, right now, currently, have an expanded allergy and asthma clinic under construction, which will be up and running. While that is under construction, we continue to offer those supports through education programs and those emergency supports every day to families and individuals in Manitoba.

Photo Radar Tickets
Construction Zones

Mr. Kelvin Goertzen (Steinbach): Mr. Speaker, after being inundated with e-mails and phone calls, the Minister of Justice was in full retreat yesterday. He now seems close, however reluctantly he wants to do it, to be landing on the right position of refunding tickets to drivers who were driving below the regular posted speed limit at construction zones where there are no construction workers present.

The e-mails and the phone calls kept on coming today. One example is from a mother who was ticketed in a construction site where there were no workers and no equipment and who couldn't pay for the ticket because she was taking care of her sick husband. She and thousands of others now want to know when they're going to be able to apply and be eligible for their refund.

Hon. Dave Chomiak (Minister of Justice and Attorney General): Mr. Speaker, it's very interesting that the member's gone from the, I'm on the side of the angels, a couple of days ago, to say, refund everything to everybody, to now saying, now you should look at those people that were between the overspeeding level and the particular regulations in place, as administered by the police and the City of Winnipeg.

Very interesting that the member's understood the fact that legally we can't step in there and do that. In fact, it's the police and the City who are responsible for it.

Having said that, Mr. Speaker, I want to advise the member that we intend to meet with the mayor and the chief of police tomorrow. We intend to revise the regulation to make it official and move on that. We also intend to go forward with the City to look at their responsibility with respect to retroactive–

Mr. Speaker: Order.

Mr. Goertzen: In performing his political 180-degree turn yesterday, there was a number of surprising revelations from the minister. Among those surprises was his order to take down photo radar in construction sites, even where those construction workers are still present, as he undertakes a review of the regulation.

Can the Minister of Justice please tell us how quickly he expects this review to take place so that police, so that the public and so that construction workers will know where photo radar is eligible?

Mr. Chomiak: Well, the problem with the member's position today is that I don't have the legal authority to do that by just announcing it. We have to change the regulation with respect to that, and we will change the regulation because, Mr. Speaker, as the member indicated–as the member indicated, there are certain criteria that have to be met with respect to guilty pleas, not-guilty pleas, et cetera, and there's certain criteria that the City did not meet with respect to signage. Without the signage in place, we cannot enforce it in the courts.

We have to talk to the City. We intend to change the regulation as early as this weekend. We intend to have the photo radar back in construction sites under the three conditions: condition No. 1, workers present; condition No. 2, safety; condition No. 3, you have to meet the signage commitments that the City agreed to meet with respect to their agreement with the Province when they asked for photo radar to be put in place. I thought members opposite supported that.

Mr. Goertzen: Just as surprising and frankly a little unbelievable was the minister's statement yesterday that he only learned yesterday morning that there were 60,000 tickets given last year, an increase over 3,000 the year before, a 2,000 percent increase.

This is an issue that's been in the news not for days but for months. The Minister of Justice wants Manitobans to believe that he ignored the phone calls, the court cases, the media articles, all the money that was flowing in to the government, and they never, ever piqued his curiosity to ask how many photo radar tickets were coming from the construction zones.

Either this minister is living in a political bubble and he's completely out of touch with his own department, or he wasn't quite forthcoming with the truth yesterday. Which is it?

Mr. Chomiak: As I indicated, the Crown, the independent Crown–I know the member wants to play Crown all the time and stick himself in the decision-making process–decided to do an appeal. An appeal was undertaken. Evidence came forward that signage was inappropriate. The Crown ethically said, we cannot, on the basis of all Manitobans, prosecute these cases. The City is responsible. The police are responsible for this. We can't prosecute because we don't have the legal ability to do so, and we'll stay charges.

The member stood up the next day and said, pay back all the tickets. I said we don't have the legal responsibility. If someone's going 120 miles per hour in a construction zone, he'd want us to pay that back. I said we've got to look at that.

We'll ask the City to sit down and look at that, Mr. Speaker, but the member opposite has gone from his extreme, conservative, right-wing view, as members opposite, to actually realizing that there's a legal issue to be dealt with, an issue of public safety to be dealt with. Welcome aboard.

Building Permits
Value Reduction

Mr. Blaine Pedersen (Carman): Statistics Canada has released figures that show the value of building permits increased by 23 percent in Canada. That's the good news. Unfortunately, the value of building permits decreased by the same 23 percent in Manitoba.

When the NDP introduced their 2009 budget, they claimed it was steady and balanced. We already know it's not balanced. Today's statistics prove that it's anything but steady as the NDP would have us believe.

Mr. Speaker, how can the Minister of Competitiveness, Training and Trade claim that things are steady when the value of building permits is plummeting in Manitoba?

Hon. Andrew Swan (Minister of Competitiveness, Training and Trade): As the Member for Carman and I have discussed, there are issues that arise from month to month, and a much better view of what is going on in the economy is not from month-to-month fluctuations in building permits, which could be affected by cold weather, could be affected by a flood, could be affected by other issues.

If I look, as I suggest the member should, at Manitoba's change in building permits year over year from March 2008 to 2009, indeed, Manitoba compares very well with Saskatchewan. In fact, we are doing substantially better with, I suppose, his dream destinations for himself of Alberta and British Columbia.

Manitoba is indeed doing, relatively speaking, very well among other Canadian provinces.

Mr. Pedersen: Mr. Speaker, I guess with the late spring, they're having a lack of warm weather. That'll be the next excuse why building permits are down, but somehow other provinces, in spite of their weather, have posted increases in the value of their building permits. Yet Manitoba posts a 23 percent loss, according to the minister, because of the weather.

Mr. Speaker, when is this government going to wake up and realize that by crossing their fingers, closing their eyes and hoping for the best, it's not good enough? How can this minister explain to Manitobans why Manitoba's doing so poorly as compared to the rest of Canada?

Mr. Swan: I presume, Mr. Speaker, that the Member for Carman didn't understand what I said so we'll try it another way. Capital investment is actually a very important measure of how public sector and private sector entities believe in the strength of a certain jurisdiction. Indeed, last year, Manitoba ranked No. 1 among all Canadian provinces in the increase in private capital investment.

Private companies across the country, indeed across the world, are seeing that Manitoba is a very good place because of our stability, because of our diverse and our increasingly well-trained work force, that, indeed, they're voting with their feet and they're investing dollars right here in Manitoba.

***** (14:00)

Mr. Pedersen: Mr. Speaker, the minister talks about private capital investment and that's correct as long as you stay small, because the minute you start to grow in Manitoba, you get walloped with the payroll tax. That's not support. That's not how you do it for business. They're taxing growth and now we're seeing the result of this taxing growth in the decreasing value of building permits.

Mr. Speaker, when will this government realize that if we continue on this path, we're not going to reach our potential? Manitobans deserve better, not the rhetoric they hear from this government.

Mr. Swan: Well, Mr. Speaker, let's hear what Jayson Myers who's the president of the Canadian Manufacturers & Exporters Association said, who represents very many large companies across the country, many of which have growing facilities here in Manitoba. What does he say? He said on CJOB on March 11, 2009: I just wish that what's happening here in Manitoba could be replicated elsewhere across the country. When he talked about the recession, he said: Companies are affected by this but they are in a much stronger position right now, and I think a lot of that is because of the support that Manitoba's government's been giving.

What more does he need?

Manitoba Public Insurance Corporation
Enhanced Driver's Licences

Mr. Cliff Graydon (Emerson): There isn't a province in Canada that wouldn't appreciate a $4-billion transfer pay.

Mr. Speaker, we already know that the NDP government's enhanced ID cards projection has been a failure. Thirteen million is budgeted for these cards even though less than 1,500 have applied.

Can the minister responsible for this boondoggle tell the House exactly how much money has been spent on these ID cards and how much will be spent this year?

Hon. Dave Chomiak (Minister charged with the administration of The Manitoba Public Insurance Corporation Act): Mr. Speaker, last year when the members apparently supported enhanced ID cards, we provided the number to them.

The member will know, in fact, that the regulations aren't coming into effect in the United States until June 1. The member will know that only 31 percent of Manitobans have passports. The member will know that there's been a big issue I think with travel as a result of issues relating to perhaps viruses and issues perhaps relating to flood-related matters.

Perhaps travel isn't the first thing on Manitobans' minds, but we expect–as Ontario, as B.C. is doing, as Québec is doing–that there will be a need for an enhanced driver's licence that's totally voluntary. It will be not only convenient; it will be a cost savings giving Manitobans a choice and the ability of which the–

Mr. Speaker: Order.

Mr. Graydon: Mr. Speaker, I don't think the weather should have any effect on the deadlines that they had put on themselves of June 1.

Can the minister tell the House exactly how many staff have been contracted or hired by MPI to implement the enhanced ID card project and how much money it's costing Manitobans to keep them employed?

Mr. Chomiak: When we outlined the steps for the enhanced ID card, we outlined time lines and dates that we would have to establish going towards the June 1 kick-in date of the U.S. regulations. The member knows that. The member's making a point that there hasn't been as large an uptake for Manitobans right now as we expected. We expect more of an intake as we get closer to June 1.

The Emerson border is the third busiest border in the country where people go by car. Thirty-one percent of Manitobans have passports. Are they going to stop going? They'll have an opportunity for another choice of an enhanced driver's licence which will move us towards enhanced identification for all Manitobans that we have to go to anyway.

We think it's convenient for Manitobans. Members last year supported it. The project still is not complete because it's still being worked on according to the time lines. All of a sudden, the members have jumped up prematurely and, as in most cases, have jumped on this issue when, in fact, the issue is still an ongoing matter.

Mr. Graydon: Mr. Speaker, prematurely June 1 is the deadline that's there, the deadline they knew about, the deadline when they started this project. The new ID requirement travel to the United States comes into effect June 1, less than a month from now.

Can the minister tell this House where the ID cards are being printed and does he guarantee that the applicants, the few applicants, will have their cards in their wallet by June 1?

Mr. Chomiak: Mr. Speaker, I don't understand. In the first question, he said it was useless and a boondoggle, and in his third question, he says, can you guarantee that you're going to have it?

That's the problem when you're an extremist and you have extreme views. You go from one end of the equation to the other end of the equation, and it doesn't make any sense in the middle. We decided that we would have a plan, we'd stick to that plan, and we'd provide it to Manitobans, and we're working on that same plan and that same schedule, not, Mr. Speaker, on any kind of extremist viewpoint that we get every day from members opposite.

It's an extreme view, it's an out-of-touch view, and that's one of the reasons why we continue to work with Manitobans and not go on this extreme right-wing agenda.

Hog Industry
Economic Challenges

Hon. Jon Gerrard (River Heights): Mr. Speaker, today's prices for hogs on the Chicago Mercantile Exchange are 38 percent below the price a year ago, and the price a year ago was already low. Shipments of hogs from Manitoba to the U.S. a year ago were 25,000 a week and are now down to 1,000 a week. If you're a hog producer in Manitoba without a farm contract from Maple Leaf or not associated with Hytek in their plant in Neepawa, you may be in big, big trouble.

Yet the Minister of Agriculture (Ms. Wowchuk) insists she is standing by the industry, but she doesn't appear to have any plan to deal with the situation. Her previous plan to deal with country-of-origin labelling was a total disaster.

Will the minister today table her plan for the present situation for dealing with the hog industry?

Hon. Gary Doer (Premier): I know the member knows that the country-of-origin legislation goes back to former Ambassador Frank McKenna and now the Ambassador Michael Wilson and different trade ministers. I think there were seven different trade ministers under the former Liberal government, and a couple now, in Canada–the third one, I think, at this point.

Mr. Speaker, we personally believe that the rules that have been worked on by the hog industry and by the Canadian ministers and the Minister of

Agriculture in Manitoba on predictable issues of country-of-origin legislation, the rule that we worked on was an acceptable compromise. Unfortunately, the Secretary of Agriculture has provided, since then, a voluntary agreement from the producer–

Mr. Speaker: Order. The honourable minister's time has expired.

Mr. Gerrard: The problem is that when you know that a disastrous situation like country-of-origin labelling is coming, you should do something about it in Manitoba to protect Manitoba producers. The industry said, we want to build extra capacity, and you said, put it in Winnipeg, which was a disaster. When the industry said, we're going to put in additional finishing barns, you said, we'll put a moratorium on and end that plan.

What is the minister's plan now to deal with the major problems that the industry is facing? Where is the minister's plan? When is she going to table it? What is she going to do to help the hog industry at a critical time?

Mr. Doer: We know, Mr. Speaker, the member opposite wrote a glowing letter to Mark Chipman and then joined in the opposition to the new MTS Centre downtown, tied a yellow ribbon around his forehead and pranced around with about 10 other people opposing the arena.

We also know, on hog processing, he's got the same duplicitous position. He opposed the Olymel plant and OlyWest plant that was proposed in Winnipeg that would have processed hogs, delayed us a number of years. We're now building that plant in Neepawa. We're building more capacity in Brandon and again, the member opposite, all he can do is vote against it. He makes a lot of noise, votes against it. Why don't you vote for hog processing in Manitoba instead of voting against it, Mr. Speaker?

Mr. Gerrard: Mr. Speaker, I would have supported it if the Premier had had the common sense to locate it in rural Manitoba instead of in the middle of Winnipeg, the wrong place. The fact is that right now, as I was told earlier today by a knowledgeable Manitoban, much of the hog industry in our province is on the brink of disaster.

Where is the minister's plan? When is she going to table it? Is the minister going to offer a buyout to troubled producers? Is the minister, at the very least, going to join with other parties who I'm sure will be onboard with having a summer of pork barbeques to help the industry?

What is the minister's plan? When is she going to table it? What's going on here that you're standing by, standing up and doing nothing?

Mr. Doer: Mr. Speaker, I would point out that the member opposite voted against a new plant in Neepawa. The member opposite voted against the second shift in Brandon. Those are contrary to what he just says now, and he has a similar position about how to treat people with H1N1 as President Hu from China does, a position we don't accept on this side of the House.

***** (14:10)

Communities in Motion
Government Initiative

Mr. Rob Altemeyer (Wolseley): So, Mr. Speaker, in the last five minutes we've seen the Member for River Heights (Mr. Gerrard) say he knows where a rural processing facility should go. The Member for Carman (Mr. Pedersen) doesn't know anything about building permits. I'm going to show members opposite how to ask a question and not look silly. I'll do them a favour.

Could the Minister of Healthy Living please inform the House of any new initiatives her department may have initiated to help young people in Manitoba enjoy our gorgeous Manitoba weather and stay healthy and safe while doing it?

Hon. Kerri Irvin-Ross (Minister of Healthy Living): Well, I'd like to thank the member for that question.

I want to remind the House about an important event that happened today at Luxton School. I was joined with grade 1 students where we celebrated $1-million worth of investments in communities across Manitoba for Communities in Motion. Communities in Motion has been embraced by Manitobans across this province where they are offering programs such as snowshoeing, yoga, physical activity courses in the community as well as in the schools.

There are programs all over the province of Manitoba: St. Theresa Point, Erickson, Matheson Island, Cross Lake, Riverton, Norquay Colony, Swan Lake First Nation, Berens River, Pinawa, Steinbach, Winnipeg, Brandon, Portage la Prairie.

Orthopedic Surgery
Wait Times

Mr. Blaine Pedersen (Carman): Mr. Speaker, that was a hard act to follow, but I really do have a serious question.

There is a serious backlog for Manitobans requiring shoulder surgeries. Without timely surgery, there can be permanent damage to tendons in the shoulder. I ask the Minister of Health (Ms. Oswald): What is the average current wait time from the time of injury to the actual surgery day for shoulder surgeries?

Hon. Kerri Irvin-Ross (Acting Minister of Health): Mr. Speaker, I'd like to inform the House about what we've done about wait times. We have reduced hip and knee surgeries by 60 percent. We have continued to increase nursing and doctors. We have twice as many nurses as they fired; radiation.

What we've done is we've made investments in health across the board. As well as that, we provide healthy living strategies to ensure injury prevention.

Mr. Pedersen: Mr. Speaker, my constituent was referred to two different surgeons for shoulder surgery by his family doctor. Both surgeons declined my constituent as they were not able to do the surgery on a timely basis. My constituent was then referred to a surgeon in North Dakota by his doctor where the shoulder surgery was performed in less than two weeks.

Why is it Manitobans are forced to go outside of Manitoba to get timely surgery to repair tendons in the shoulder?

Ms. Irvin-Ross: Mr. Speaker, I ask the member opposite to please forward that information to us, and we will certainly follow up on this. You cannot talk about specific cases in the House, but I can tell you about what we've done around wait times.

We continue to have the shortest wait times in radiation therapy. We also have the shortest wait times, along with Alberta, in cardiac bypass surgery. Hip and knee wait times are 15 weeks down, 66 percent. CT wait times are down; MRI wait times, down. Ultrasound wait times are down.

We are committed to improving the health-care system and we will continue to do that work.

Mr. Pedersen: Well, Mr. Speaker, the minister will get the chance to hear this because my constituent now has to hire a lawyer, at his own expense, to plead his case to Manitoba Health for remuneration. Manitoba Health will have a lawyer, five directors and a consultant present at the hearing.

Who do you think's going to win this hearing?

Ms. Irvin-Ross: Mr. Speaker, I'll review for the member again the reductions that we've been able to make in wait times. These wait times are making a difference for Manitobans across this province.

We have reduced wait times for radiation therapy, cardiac bypass, MRI, ultrasound. CT wait times are down. We continue to make these investments across the province of Manitoba. There are these services that are provided in hospitals beyond the Perimeter. We will continue to work with Manitobans and we will continue to improve the health-care system.

Mr. Speaker: Time for oral questions has expired.

MEMBERS' STATEMENTS

Junior Achievement Award Recipients

Ms. Sharon Blady (Kirkfield Park): Mr. Speaker, I rise in the House today to share with my fellow members the accomplishments of some outstanding young people involved with Junior Achievement. On April 15, I attended the Futures Unlimited Banquet where achievers were recognized for their accomplishments within the JA Program.

Junior Achievement is the world's largest organization dedicated to educating students about work-force readiness, entrepreneurship and financial literacy through experiential hands-on programs. Junior Achievement programs help prepare young people for the real world by showing them how to generate wealth and effectively manage it, how to create jobs which make their communities more robust and how to apply entrepreneurial thinking to the workplace. Students put these lessons into action and learn the value of contributing to their communities. As a former Achiever, I know the value of this program and the mentorship that community leaders provide to students.

This year, for the first time ever, the students in the JA company programs had to meet the challenge of making their businesses green and address environmental sustainability within their business mandate and products. I am pleased to say that each company rose to the challenge and demonstrated ingenuity and passion in creating and successfully operating green small businesses. This combination of social responsibility and economic development is reassuring as we look towards growing our green economy in Manitoba and globally. I am sure these students will be among the leaders in the next wave of environmentally responsible economic growth.

Mr. Speaker, I would like to make special mention of some of the award recipients at this year's banquet: Web site of the Year went to Green Being; Club G was recognized for Best Business Plan; and Gogee Inc. was successful in three categories: Corporate Citizenship, Best Shareholders' Report and Company of the Year. This year's Achiever of the Year Award went to Caitlin Giesbrecht from Club G.

In closing, I would like to congratulate all of the students who took part in JA programs this year for their dedication and hard work and to recognize the dedicated JA staff, the volunteers and advisers for their contributions to another successful year for Junior Achievement in Manitoba. Thank you, Mr. Speaker.

Intermountain Sport Fishing Enhancement Group

Mr. Hugh McFadyen (Leader of the Official Opposition): Mr. Speaker, last Friday I, along with the Member for Lac du Bonnet (Mr. Hawranik), Member for Tuxedo (Mrs. Stefanson), Member for Arthur-Virden (Mr. Maguire), Member for Russell (Mr. Derkach), Member for Brandon West (Mr. Borotsik), Member for Ste. Rose (Mr. Briese) and Member for Emerson (Mr. Graydon) had the great pleasure of attending the International Sport Fishing Enhancement Group Banquet in Dauphin. This is an extremely popular event in the community, attracting more than 500 guests annually.

The Intermountain Sport Fishing Enhancement Group was established in 1990 to help promote sport fishing and tourism in the Parkland region. Among their stated objectives is to encourage proper management of the ecosystem and support initiatives to that end to guarantee the sustainability of the natural resources.

The group is active on many fronts. For example, they help educate the next generation of fishers, by offering activities like children's ice fishing and a kid's trout pond. The group has been involved in many fish and fish habitat enhancement projects. During the 1990s, they worked with the Dauphin Lake Advisory Board to get pool and riffle structures installed on the Vermillion and Wilson rivers and Edwards Creek to provide walleye spawning habitat. Another very important project in which the group is involved is the rearing ponds at Methley Beach. Approximately 200,000 walleye are reared in these ponds and then distributed to area lakes to help ensure the level of fish stocks is strong.

***** (14:20)

The group is involved with the Manitoba Fisheries Enhancement fund. This fund helps support research and other projects aimed at conserving and enhancing Manitoba's fishery resources.

Group members consult regularly with provincial departments like Manitoba Conservation on fish management issues such as slot limits and cash limits. Behind every successful group is a hardworking board of directors. I would like to take a moment to recognize them. The board includes president, Steve Hogue; vice-president, Todd Gardipie; treasurer, Dean Yarema; secretary, Doug Walker; past-president, John Boyd and directors, Jason Gibbs, Glen Zurba, Shelly Slyziuk, Stan Burdeniuk, Brad Durston, Shawn Bailey, Mark Talbot, Don Stokotelny, Rob Remple, Scott Fordyce, Dean Bodner, Glen Haugen, Malcolm Pelypiw, and Ron Harvey.

Members of the Intermountain Sport Fishing Enhancement group are deeply committed to ensuring the fisheries in Dauphin and area remain healthy for future generations, and we appreciate their ongoing efforts. My colleagues and I would also like to thank them for the tremendous hospitality we enjoyed at the banquet, and we look forward to attending future banquets. Thank you Mr. Speaker.

Collège Saint-Norbert Collegiate Drama Production

Ms. Marilyn Brick (St. Norbert): I'm pleased to rise today to share with this House some information about a play I attended on February 25 at Collège Saint-Norbert Collegiate. *Urinetown* is a satirical tale of industrial corruption in a Gotham-like town that is experiencing a terrible water shortage. In an attempt to regulate water consumption, the government creates a law whereby everyone must pay to use public washrooms which are owned and operated by the heartless Urine Good Company. Any citizen who refuses to pay is sent to the worst place in the world, Urinetown. When young Bobby Strong decides he'd had enough, he takes a lead to have a revolution to overthrow the greedy corporation.

I was incredibly impressed with the students' production. Based on the 2001 Broadway musical by Mark Hollmann, *Urinetown* is an entertaining look at the dark underbelly of capitalism and corporation mismanagement. With memorable characters like Officers Lockstock and Barrel, Caldwell B. Cladwell and Penelope Pennywise, and musical numbers like "Follow Your Heart" and "I See a River," this show was witty, fun and thought-provoking.

I would like to congratulate the cast, crew and band members who worked so hard to make the play a success, including: David Betz, Rebecca Gole, Mitchell Forrester, Shawnee Davis, Troy Jazser, Victoria Rutowski, Max Semchuk, Justin Mann, Aurel Smith, Tarek Rashwan, Lisa Spiers, Justin Willems, Katelyn Giesbrecht, Zack Gerbrandt, Stacey Archer, Dustin Schlag, Samantha Blanchette, Nicole Rosner, Sanna Kocay, Nicole Aubin, Alicia Hoffman, Ella Greer, Belinda Goertzen, Rachelle Garton, Natalie Hocking, Cassie Ralph, Renee Marion, Alana Ramnauth, Karl Enns, Haley Wiens, Caitlin Engel, Reily Mann, Kamini Ramnauth, Kyla Westra, Brooklyn Enrentraut, Nicole Rosner, Rob Woods, Carson Mauthe, Allison DeRuddere, Samantha Erickson, Desiree Waldner, Zona May, Alexis Cherniak, Aynsleigh Kerchak, Adam Benson, Levi Willems, Brittany Kelly, Michelle Claeys, Max Strickland, Stephanie Wallis, Alis Froehlich, Marvin Namaka, Claire Wheeler–

Mr. Speaker: Order. The member has gone quite a bit over the allotted two minutes.

The honourable member's asking for leave?

Ms. Brick: Leave.

Mr. Speaker: Is there leave for her to continue? *[Agreed]*

The honourable Member for St. Norbert, to continue.

Ms. Brick: Kerri Huff, Stuart Harris, Bonnie Dack, Sydney Barton, Caitlynn Taczynski, Breanne Nicole, Amber Lotz, Sawyer Marshall-Stanchuk, Curtis Erickson, Lynn Sumka, Breanna Corlett, Emilie Derksen-Poirier, Chantal Schlamp, Olivia Ballentyne, Kiera Dayholos, Ali Froehlich, Madelaine Crierie, Shamus Dack, Nykol Pishak, Gisele Smith, Eileen Dionne, Matthew Lagace, Logan Sali, Cheyenne Neufeld, Al Omichinski, Rene Ahrens, Andrea DeRuddere, Victoria Jenkins, Cody Smith, Deanna Smith and Suzanne Cormier.

I would also like to congratulate Director Bev Betz and the staff and parent volunteers who participated.

Mr. Speaker, I thoroughly enjoyed St. Norbert's production of *Urinetown*. The school has a long tradition of producing excellent theatre, and I'm so proud to have such talented young people in my constituency. Thank you.

YWCA Women of Distinction

Mrs. Myrna Driedger (Charleswood): I'm proud to rise today and congratulate the well-deserving women who were honoured last night at the YMCA-YWCA Women of Distinction Awards ceremony. This year marked the 33rd anniversary of the prestigious awards which are bestowed upon those women who have displayed exceptional leadership, achievement, imagination and innovation in how they have contributed to the development of others in their community.

The annual presentation of these awards continues to emphasize the importance of publicly recognizing the positive contributions that many different women from a multitude of backgrounds have made in our society.

I was pleased to attend this event last night, along with fellow Progressive Conservative MLAs from Morris, Portage la Prairie, Pembina, as well as our leader.

Nearly 60 women were nominated for the Women of Distinction Awards this year and all of them deserve to be congratulated for the positive spirit and dedication that they bring to their communities, and which merited a nomination for this award. This commitment that each of the nominees has shown deserves our respect, our admiration and our sincere thanks.

Of the 60 nominations, 10 exceptional women were chosen for a Women of Distinction award. Among them are, in the area of Health and Wellness, Leslie Galloway, a nurse at the Children's Hospital; for Community Volunteerism, Elaine Bishop, executive director of the North Point Douglas Women's Centre; for Education and Training, Wanda Wuttunee, director of the Aboriginal Business Education Program at the Asper School of Business and head of Native Studies in the Faculty of Arts; for Arts and Culture, Carmen Infante, founder of Sol de Espana folk dancers; for Business and Professions, Noelle De Pape, executive director of Immigrant and Refugee Community Organization of Manitoba; for

Research and Innovation, Elissavet Kardami, a doctor and principle investigator at the Institute of Cardiovascular Sciences at U of M; for Sport and Recreation, Jo-Anne Clark-Gillespie, a physical education teacher at Portage Collegiate Institute; for Creative Communications, Lisa Meeches, president of Eagle Vision Inc. and Meeches Video Production; for Young Woman of Distinction, Kim Le, a student and active volunteer; and for the Gerrie Hammond Memorial Award of Promise, Jacqueline Proctor, a student and president of her student council in Warren, Manitoba.

Mr. Speaker, I heartily congratulate all of these women on their significant achievements, and a particular acknowledgement to Pat Flaws for chairing an exceptionally wonderful evening and dinner. Thank you.

Youth Parliament of Manitoba

Mr. Bidhu Jha (Radisson): Mr. Speaker, it gives me great pleasure to rise in the House today to speak about a wonderful organization, Youth Parliament of Manitoba. Youth Parliament is a group that seeks to introduce young people to Manitoba and our legislative system by holding a mock parliament twice a year. It is one of the oldest model parliament organizations in the world and has held sessions continuously since 1922.

The organization is run for youth by youth. The board of directors are all members of our community between the ages of 18 to 25, who have been elected by their fellow parliamentarians. The executive appoints a 20-member cabinet who are responsible for the day to day running of the legislative session.

This organization is an institution in our province, an 88-year legacy we should be proud of. Youth Parliament alumni are scattered not only across Manitoba, but the world. Some are working on Parliament Hill; others are lawyers, Rhodes scholars, doctors, journalists, teachers, while some walk the halls of this very Legislature.

Mr. Speaker, it's with great pride that I share with all members about all my three children, Piyoosh Jha, Prabhat Jha and Reena Jha. They were all Manitoba Youth Parliament members and they are the alumni.

We know one member right here, the Member for Elmwood (Mr. Blaikie), ex-dean of the House of Commons in Ottawa, among distinguished alumni of Manitoba Youth Parliament.

Mr. Speaker, it's my view that the world would be much better tomorrow built on solid democratic principles and by participation by our youth from our society. Thank you very much.

ORDERS OF THE DAY (Continued)

GOVERNMENT BUSINESS

Hon. Steve Ashton (Deputy Government House Leader): Mr. Speaker, before resolving into Committee of Supply, I believe there's agreement to also continue Committee of Supply tomorrow. With that in mind, if you could resolve into Committee of Supply, please.

Mr. Speaker: Okay, orders of the day, to remind members that Committee of Supply will continue tomorrow.

COMMITTEE OF SUPPLY (Concurrent Sections)

FAMILY SERVICES AND HOUSING

***** (14:40)

Madam Chairperson (Marilyn Brick): Will the Committee of Supply please come to order. This section of the Committee of Supply will now resume consideration of the Estimates of the Department of Family Services and Housing. As had been previously agreed, questioning for this department will proceed in a global manner.

The floor is now open for questions.

Hon. Gord Mackintosh (Minister of Family Services and Housing): I know the department is rallying some answers to questions we were making best efforts to get back today. There was the boilerplate contribution agreement, and I'll leave that for the member.

The Manitoba Child Benefit changes from CRISP: The '08-09 numbers show 5,325 children. That's an increase of 219.2 percent over the previous year, and part of that–no, that's the right way to put it–and then the other one was the amount. I think that was the question. Wasn't it the number of children on the Manitoba Child Benefit? Yes. We had a 2.8, 35.5, and that's an increase of 305.9 percent.

Then, Madam Chairperson, there was a question around the SPAs: Agency Accountability and Support Unit, one; Children's Special Services, 21; Child Protection branch, 21; Employment Income Assistance, eight; Family Violence Prevention

Program, 27; a multi-division, in other words, involving several areas of the department, 23; Supported Living Program, 87; and Employment and Training Services, 11, for a total of 199. Those are active. There are two SPAs, one with B&L, and the other, essential living assistance services, that are under negotiation for renewals, but the current SPAs continue until such time as the renewals are completed, I understand.

So, if there's other information that we can provide, we will do so.

Mrs. Bonnie Mitchelson (River East): I just want to thank the minister for those very timely responses, and I'll read those in the record that he's put on the record and also take a look at that contribution agreement.

Can we move on, then, to–actually, I don't know whether you'll have this, but this is information that I got out of the last annual report and several annual reports previously. It's on child abuse investigations. It's on page 89 of the last 2007-2008 annual report and, under centralized provincial services, it says that the number of child abuse investigations that were done in that year were one thousand, five hundred and–no, pardon me–2,250. The year before it was 1,535.

I noticed as I went back into annual reports, I guess I went back as far as 2003-2004, and, you know, the number of investigations has gone up and down a little bit. I guess the lowest was 1,100 in '05-06 up to a high of 2,250 in '07-08.

The first question I would have is, as I looked at the annual reports earlier on, there were several agencies that didn't report. In '03-04, 10 of the agencies didn't report child abuse investigations. In '04-05, the Northern Child and Family Services authorities didn't report. In '05-06, there were four agencies that didn't report. I guess I was–in '06-07 and '07-08, there was no mention of agencies not reporting, and I guess I would just ask the question then: Did all agencies report, and that was why it wasn't referred to, or do we have any other information?

Mr. Mackintosh: Yes, I'm advised that in some years there are some agencies that may not get their information in by the time the deadline is in place for the compiling of the annual report's statistical information. I'm advised that with an enhanced emphasis on data collection–we talked about that yesterday in the area headed by Rhonda Warren that we anticipate that for the collection of this year's annual report, that there's going to be more timely reporting. But that has been a pattern that's been noticed over the years with that deadline.

Mrs. Mitchelson: Madam Chair, I'll be watching for that in the annual report, I guess, that comes out. By September, we should have that cleared up and we should have all the information.

It says in a footnote beside child abuse investigations, that this includes investigations completed by the provincial investigator. I guess I would just like to understand a little bit better of what we're talking about and what the difference is between the provincial investigator and whoever else does investigations.

***** (14:50)

Mr. Mackintosh: We someday will move to staff directly answering questions. You know, every hour or so, I wonder why we got into this, but it's about ministerial accountability, I understand that and that's very important. It also sometimes informs the minister of what goes on in the bowels of the department.

The provincial investigator role was set out in section 18.6 of the act. The provincial investigators versus the agency investigators take on those investigations that are in regard to complaints about residential facilities, No. 1, and No. 2, where it concerns usually staff of another child protection agency or organization; in other words, to avoid a conflict of an agency investigating itself. For example, there was that St. Amant example that is well known publicly, where the provincial investigators looked at that situation rather than relying on St. Amant to look at one of its group homes because their allegations were against a staffperson.

It's a province-wide service that's offered. I think that historically there were two investigators. Just last year, we doubled it to four investigators. There's one manager. There are over 200 investigations annually. Of course, they must work closely with police; often there are joint investigations.

Mrs. Mitchelson: So where do I find those positions on the–oh, don't tell me I didn't bring the–I know they were long pieces of paper that you gave me yesterday with the org charts.

Where do I find that increase in positions on the org chart?

Mr. Mackintosh: In the org chart that has Claudia's name at the top–Ash-Ponce. If you move over to Erickson, and under Erickson is Ms. Hanson. She's the manager, and she has a history of being one of the investigators. Then you'll see Ms. Schellenberg and Greeley, Fewster and Yager.

Mrs. Mitchelson: So if there are 200 investigations done by government, approximately, in a year, and there were 2,250 done provincially, that would mean then that the agencies or the authorities, I guess–who else does the investigation?

Mr. Mackintosh: If the investigations aren't done by the branch itself, they would be done by child welfare agencies across Manitoba; generally, the designated intake agencies.

Mrs. Mitchelson: Can the minister tell me how many designated intake agencies there are then across the province? I believe it's ANCR that–and I'll get into some questions around that later, but–does all of the Winnipeg intake, I understand?

Mr. Mackintosh: There are 14 DIAs, Madam Chair. ANCR has jurisdiction in Winnipeg, Headingley and St. Clements.

I am advised it's not all of St.–like I'm using that term generically, but it's part of St. Clements. We can provide a map, if the member seeks that.

Mrs. Mitchelson: Does the department keep statistics and do the agencies keep statistics on how many of those allegations were substantiated and how many were not?

Mr. Mackintosh: Yes.

Mrs. Mitchelson: I wonder whether the minister could tell me, over the last couple of years–and I know we don't have the annual report from last year and you may not have all of the information in from all the agencies because I know you said there was a bit of a backlog sometimes–but for the year 2007-2008 then, could the minister indicate to me by designated intake agency or authority, whatever it is, and the branch, how many of the allegations were substantiated?

Mr. Mackintosh: I am advised that certainly that information can be collated, but the numbers on substantiated allegations, of course, will only deal with investigations concluded in that fiscal year. So that will be the caveat on the information, but I think that's what the member is looking for.

Mrs. Mitchelson: Thanks. I'd just like some sort of general indication of–and can that be done then by category? How many children were in sort of their natural home versus foster care versus residential–all of the different categories that–I might not be thinking of something, but if you could do that breakdown for me and in the most current year, I guess. If they don't have the detail for this year, maybe from the year before, last year.

Mr. Mackintosh: I'm advised that that information is recorded and can be collated.

***** (15:00)

Mrs. Mitchelson: Thank you for that. I notice there's been a significant increase in the number of FTEs in the Child Protection branch and I see, by the org chart, I think the minister indicated to me already two new positions that were created and those would be in investigations, just in his previous answer. But could he just go through the department and indicate to me, because I believe staff has increased from 56 FTEs in 2006-2007 to, I believe it's 72 in this year's budget.

Mr. Mackintosh: The numbers I have are 56 in '07-08, 72 in '09-10.

Mrs. Mitchelson: Madam Chair, I thought I was waiting for an answer. My question was, where are the new positions? There were 56 to 72, and you did indicate that there were two new investigation specialists, but I was wondering where the other positions in the org chart are that would constitute the increase.

Mr. Mackintosh: Yes, '08-09, there was one position out to community service delivery, and the new positions to net out was one management secretary.

Mrs. Mitchelson: Where's that? If we could just have the org chart, if the minister has a copy of the org chart. I've got it in front of me, the one he gave me yesterday, so it would be, you know–I could just put a little mark beside the new positions. If you've got that, it would be helpful.

Mr. Mackintosh: They actually made a list here, so they'll cross-reference that to the org chart. I can go down the list. There's a management secretary, and there's one quality assurance, one admin support, the two provincial investigators we spoke of, one issues management specialist, two CFSIS business analysts and one CFSIS trainer.

Then, in '09-10, two were transferred out, and the new positions are the one authority relations specialist, two policy analysts, one project manager for the child victims centre, one admin assistant, one differential response co-ordinator, one co-ordinator for sexual exploitation, one quality assurance specialist, and the two new sexual exploitation strategy specialists under Tracia's Trust.

Mrs. Mitchelson: Can the minister tell me whether the positions–and I see a position, an acting manager of training, a C. Martinez, and then three trainers underneath in the boxes underneath that–are any of those new positions?

Mr. Mackintosh: One of the three advisers is a new position.

Mrs. Mitchelson: Just for clarification, is this training on the CFSIS system?

Mr. Mackintosh: Yes.

Mrs. Mitchelson: Is there any other training then within the department or any other positions that are responsible for training?

Mr. Mackintosh: The three in the branch, aside from CFSIS training, do an intake training in core competency training, Madam Chairperson. Core competency is supplemented by contractors who deliver training. In addition to that, the joint training unit is a standing committee. That's the organization comprised of the four authorities in the branch. Under the Changes for Children initiative, the Province has four positions there as well that are funded.

Mrs. Mitchelson: So there are four positions in the joint training unit. Where does the budget show for that?

Mr. Mackintosh: The JTU positions are funded under the authorities and maintenance of children line on page 77 of the Estimates–of the detailed supplementary Estimates, joint training unit.

Mrs. Mitchelson: When were those positions created?

Mr. Mackintosh: Those positions, I'm advised, were funded during '06-07 as part of the Changes for Children initiative.

***** (15:10)

Mrs. Mitchelson: Can the minister tell me what has happened? There are four positions funded in the joint training unit by the department.

So, are they part of the FTE component or–I guess I'll ask that question.

Mr. Mackintosh: Those are not FTE expenditures. They're not provincial civil service positions. Those are positions created as a result of a grant to the authorities for the provision of the joint training initiative.

Mrs. Mitchelson: So, are there only four training positions in the joint training unit?

Mr. Mackintosh: The grant to the authorities for the four positions is distributed on the basis of one for each of the authorities. Then the branch is represented at the JTU by Ms. Martinez, which is one of the FTEs in the branch for training.

As well, there is funding for an administrator, and that flowed to an authority for the JTU. I'm advised that, as well, there is funding available for contractors to provide services.

Mrs. Mitchelson: So, then, there are four staff positions in the joint training unit, with one administrative support for those positions, and that joint training unit falls under the standing committee, which is, I understand, the CEOs of the four authorities plus our director.

How often do they meet?

Mr. Mackintosh: They meet twice a month for one-and-a-half days.

Mrs. Mitchelson: I wonder if the minister could tell me what kinds of issues would be discussed at the standing committee.

Mr. Mackintosh: The standing committee is involved in work on, first, the funding model development that we spoke about yesterday that has been approved by our Treasury Board.

Standards development: one of the achievements there has been, 19?–thirty now, 30 new standards that have been developed; 19 I know that were approved and were out the door by summer.

Intersectoral work, which includes work with, for example, Healthy Child Manitoba, Manitoba Adolescent Treatment Centre, Health, FASD, suicide strategy, all of those initiatives that were important to the Changes for Children initiative.

There are regular meetings, formalized meetings now with the office of the Children's Advocate and the Ombudsman quarterly on issues of mutual interest, but as well, the Changes for Children, action on Changes for Children.

Quality assurance matters: budgeting, overall co-ordination of Changes for Children, province-wide shared resource development, the development of the differential response model for Manitoba and how family enhancement should roll out. They can deal with legal presentations from legal services from time to time, the development of common processes and forms.

Madam Chair, getting back to the original question from the member, joint training initiatives and the methodology of that operation. There is problem-solving from time to time, and the CFSIS redevelopment; it's an initiative called Information Matters. Finally, reviewing the work plans for the Changes for Children initiative.

Now, that information comes from both the ADM and the director, so I suspect that it's pretty comprehensive then. But I think there's a catch-all there; matters that arise from time to time as well are dealt with there, but it is the consensus building and co-ordinating part of the child welfare system today in this province.

Mrs. Mitchelson: Madam Chair, the minister talked about the new funding model that has been approved. I guess my question around that would be: Would the funding flow under this contribution agreement that was tabled for me?

That is in the function of this committee, I believe it would be the quality–yes, I'm just wondering, is it the same branch that develops service purchase agreements that would be negotiated with the authorities over this new funding model?

***** (15:20)

Mr. Mackintosh: Essentially, the answer is yes, but there are other complications. But, yes, the dollars do flow under the–they will flow under the auspices of the contribution agreement, and they will have to be amended accordingly to flow those dollars.

There are some conditions that attach. For example, each agency is to conclude a five-year business plan and that has to be approved then by the respective authority. So that will be part of the contribution agreement.

Mrs. Mitchelson: Are there contribution agreements signed now with the four authorities?

Mr. Mackintosh: Yes.

Mrs. Mitchelson: Are there any business plans? Are there five-year business plans presently?

Mr. Mackintosh: The next step in the funding formula's roll out is the agreement with the federal government, then, on the funding formula itself and its components. The next step, then, is to ensure that the dollars flow according to the contribution agreements and the plans of the agencies.

Mrs. Mitchelson: Madam Chair, are the negotiations complete with the federal government, and what commitment do we have from the federal government on funding?

Mr. Mackintosh: The framework is all the product of the ongoing work over the last, what, year and a half or more, of provincial and federal officials; in terms of federal officials, both from the region and from headquarters in Ottawa. As well, there's been discussions at the deputy level and political correspondence. It's our understanding that the federal officials, now that the Province has put in its budget–we had to make that commitment in our budget–and the next step, then, will be for the Cabinet memorandum to be concluded by the officials–or federal officials. Is it Cabinet or Treasury? Well, they call it a memorandum of Cabinet.

Mrs. Mitchelson: Has there been a change in the funding formula from the federal government?

Mr. Mackintosh: Yes. Well, that will be what to watch for, is that change in funding formula from Ottawa.

Mrs. Mitchelson: The minister mentioned new standards, and that that was a function that was discussed and worked on at the standing committee level, and that there were several new standards that were developed or have been developed and they have been implemented.

Can I ask, what is the process for training front-line staff for the new standards? I'm asking this because of a genuine concern that I have when we look at a lot of the reviews of child deaths that have been done. There are a lot of recommendations, but I believe, if more training had been done up front and workers knew what their roles were and what their jobs were, that maybe some of the tragedies that have occurred might have been prevented.

So, when I look at recommendations, I see training as the underlying thread of what's missing for many of the front-line workers, and if they don't have the resources or don't understand their roles and responsibility, that's where we run into trouble. I'm very interested in how much work is going on since the reviews have been tabled with government to ensure front-line workers understand their roles and responsibilities. That can only happen through good training and good training initiatives.

Mr. Mackintosh: The standing committee created a standards training package that provides the basis for all of the authorities to ensure that agency staff receive training on a consistent basis. Of course, the standards manual is available. It's based on the provincial legislation and policy.

There has been an enhanced focus now with the JTU on training. I'm advised that last year approximately 1,600 staff and some foster parents as well received training in core competency and CFSIS and practice approaches co-ordinated by the joint training unit as well. JTU is now working on several joint training initiatives in three prioritized areas: critical incident and stress management, suicide prevention and intervention, child abuse investigations. There's intensive work on a new orientation package for new workers. I've got new numbers here from April '08 to December '08, Madam Chair. Attendance at training sessions exceeded 6,200 participants.

Mrs. Mitchelson: I wonder if the minister could share with me the training packages that have been developed. I'd be really interested in seeing those if I could.

***** (15:30)

Mr. Mackintosh: Just to clarify, then, we don't have them available here, but we can provide them on a timely basis to the member, but just if you could indicate whether it is only with regard to standards or whether core competency as well. There may be other areas that are of interest to the member; in other words, would she like a full training package or just those related to standards training?

Mrs. Mitchelson: I think I'd like the whole training package and I think orientation is one piece that I'm very interested in, so if we could do the whole thing and I could just have a look at it and see what is happening because I feel it's a very critical component to what needs to happen.

Can the minister indicate for me how stable the work force is in the agencies? I do know, if we go back to looking at the Phoenix Sinclair review that was done–certainly in the agency that Phoenix Sinclair was associated with there was significant turnover in staff and there were very few workers on the front line that had any training or any experience. That is of great concern to me. Could we have statistics–maybe let's just start at the top, and could I have a history authority by authority on–now, what do we call them; do we call them CEOs of the authorities? Is that the head person? I just wasn't sure of the title. Could the minister indicate who the CEOs are now of the four authorities and how long they've been in place, and maybe since the authorities were created? What's the history of the CEOs? Who were the initial CEOs and then how has that changed over the years?

While we're getting that information–I understand it may take a few minutes–I wonder if the minister could indicate to me, since 1999-2000, could he just give me a history of the deputy ministers in the Department of Family Services and Housing, the ADMs in–I guess I'm mostly interested in the Child Protection branch, since 1999, if he could just give me the names and the dates that there have been changes in those positions.

Mr. Mackintosh: So far at the table here we're good with names, but the dates are not exact. But we can give time lines in terms of, first of all, the CEOs. The North CEO is Marie Lands, and she will be one year this summer. The southern authority CEO is Elsie Flette, and she's been in place since the authority was created. The general authority, Jay Rodgers is the CEO. He's been there about two years. The Métis, Leilani Buschau. Did I say how long Leilani has been there? One year, approximately, one year.

The deputy ministers, '99, Tannis Mindell–well, the member knows that–followed by Debra Woodgate and then Milton Sussman. I know Martin Billinkoff was appointed, I believe the same day that I was, in September of '06. So we don't have dates for the others, but we could provide those. *[interjection]* If there's no further question on that one, we won't search for the dates.

The ADMs for CFS, as the member knows, David Langtry, a fine person. Peter Dubienski, who was there when I first arrived–for Changes for Children, and then Carolyn Loeppky. Carolyn's been in office as ADM for about two and a half years and still standing.

Madam Chairperson: This is called corporate memory. We're all scared we're going to lose when people retire.

Mrs. Mitchelson: In the position that Carolyn Loeppky is in, I sometimes wonder how you can keep track of the days and years because it is a hectic position.

Could the minister just indicate to me who the directors of Child Welfare have been since '99?

Mr. Mackintosh: The director is Phil Goodman, who the member will know. I had the pleasure of meeting this summer, a northender, who described Alberta's approaches to DR and information management and sexual exploitation. It was very insightful.

I understand there's an interim–is that acting or interim–Bev Ann Murray. The next director was Dennis Schellenberg, who then went on to the general authority's leadership. Joy Cramer, who now heads up Housing. Jay Rodgers, now the general authority CEO. Josie Hill, as the member knows, was briefly director and Claudia Ash-Ponce now who, thankfully, has a life contract with the department.

***** (15:40)

Mrs. Mitchelson: I wonder if the minister could provide for me the–I guess it would be the executive directors of the agencies throughout the province. Do we have that information?

Mr. Mackintosh: We can compile the list of the agencies' directors.

Mrs. Mitchelson: I'm rather interested in both the CEO positions, and I know that besides Elsie Flett, who has been there since the beginning in the southern authority–if I could just have the history of the CEOs, then, and their length of stay in the other authority.

I don't need that today. I'm just saying if I could have that for looking at compiling information that I would appreciate having. That would be one thing. Then, also, the executive directors of the agencies, how long they have been there, and who may have preceded them.

Do both the authorities and the agencies have boards?

Mr. Mackintosh: Yes.

Mrs. Mitchelson: Could the minister tell me who's on the board of the authority? Again, this isn't information that I need right now, but if that could be provided to me, I would appreciate it.

Mr. Mackintosh: Yes, we can provide that very quickly.

Mrs. Mitchelson: Back in 2008, Bill 34 was passed, which was agreed to and supported unanimously in the Legislature, and one of the key standards that was enshrined in that legislation was protection and well-being of children, as the primary consideration. I appreciate that becoming the first and foremost priority.

Can the minister tell me what changed after that legislation was proclaimed? Was there any directive that went out to authorities and agencies in regard to implementing the new legislation?

Mr. Mackintosh: The chief work after the bill was passed was to enhance the standards in this regard, accompanied by the training that rolled out then beginning in that fall.

First of all, the legislation was, as the member knows, intended to make absolutely clear beyond any doubt in The Child and Family Services Act that safety was paramount, which was expressed in the authorities act, but not in The Child and Family Services Act.

As well, the legislation brought in a second emphasis, and that was that when a child is to be seen under the standards, the child must indeed be seen. "Every child seen every time" was the mantra that was developed, and standards, again, reflected that, the dissemination of those standards and the training that followed. That can't be a one-time operation. Know that there has been continued exploration on how and development of reminding front-line workers and everyone in the system about "every child seen every time." There'll be further work on that as well, but there was a comprehensive standard around that with the training component.

Mrs. Mitchelson: I guess I'm still hearing within the system that safety isn't necessarily always first and foremost within the system, so I guess my question is: Is the minister satisfied that the direction and the intent of the legislation is being followed, and what process would there be to ensure that every worker in the system understands and knows that?

Mr. Mackintosh: It was timely that, given a lot of public debate and, quite frankly, insights following tragedies, that all the system understand that while devolution was intended to enhance the importance of culture, it was never intended to diminish the importance of safety. Indeed, the authorities act, which is the devolution act, expressly said that as the first part of the bill. So that expression was made loud and clear, starting with the fundamental document of the system which was the act. The salience of the change depends always, of course, on, then, standards reflecting that and training, which I'm told is part and parcel of strengthening our responses.

Now we also know that every time a child welfare worker or social worker has to make determinations, they have to use professional judgment, and sometimes there is a balancing of many factors. In the balancing, safety underpins the reason why the system exists in the first place, so it's important for that reminder to be there, but there will, I'm sure, always be circumstances where people can argue that safety may not have been a paramount consideration, in which case I'd like to know of those situations, but professional judgment again will balance some often very difficult situations.

Now the development of a risk-assessment tool as well provides meat to the words and the intent of the legislative change. The risk-assessment tool is now being piloted, the new risk-assessment tool. There always have been risk-assessment tools, but there has been the development of one that is stronger, based on practices and experiences elsewhere, which, by the way, has proven not to be an exact science because, again, professional judgment and the human factor always plays a role in individual situations. But we now have, along with the development of DR, differential response, in the family enhancement stream, the new risk-assessment tool that's being piloted.

***** (15:50)

So that is one part of the answer. The other is the funding model will also fund a quality assurance position at each agency, not just at the authority level, to build capacity at the agency level, to monitor compliance with standards.

There was a recent analysis done that every state in the U.S. was failing to meet standards, child welfare standards, and you have to ask, well, what do we have to do to reduce the risk to children when there is that kind of finding? That is all about a multi-faceted response, which is not just strong legislation but the standards, the training, the funding model, quality assurance reviews, the provision of workload relief, which has been so important. We hear that so much from the front lines.

We've been able to put in place 103 new positions as a result of Changes for Children so far. At the same time, we have seen the growth in the number of children coming into care, so we realized that we had to continue this effort, at the same time bringing into place in Manitoba the differential response model, based in part on what Alberta's experience has been, Minnesota and other places. But you have to continue to provide that workload relief, and this budget allows for further workload relief as well as the introduction of differential response in Manitoba.

Mr. Doug Martindale, Acting Chairperson, in the Chair

The member well knows the workload issues in child welfare, not just here, of course, but this is Manitoba where we are elected to work on behalf of children. But it has been an experience all across North America and perhaps beyond that has not adequately, I think, been addressed in most jurisdictions. So here in Manitoba we have made some extraordinary investments now in providing workload relief.

By workload relief, too, I shouldn't just say that it's about more staff. Differential response is really important. When the family enhancement model began in Alberta, Phil Goodman, for example, told me about what a difference that was making to the protection cases. The numbers were going down. Then Alberta had a bit of a bump. It may have been a lot of migration issues at work there, but the numbers certainly are stabilizing in Alberta. The increases are not as great as they had been before their introduction of differential response. That has been the experience in Minnesota as well and I think in other jurisdictions that have been moving to differential response.

So that's one. The other, though, is just better management of agencies, ensuring that CFSIS is continually redeveloped and strengthened, because if CFSIS is inaccessible to workers, if it's too complex, if they're not trained in CFSIS, that's going to take away time from them. It's a matter of organizing activities, too, and getting social workers out of the coffee rooms and into the living rooms. That has been a reason why the workload relief wasn't only for social worker positions. The external review said they also needed relief with the administrative support because the social workers were doing so much paperwork around their files.

So all of these enhancements are expected now to work together to reduce the risk to children and to better ensure that those decisions that the member started her questions around are made by social workers in the best interests of children. So the question, I think, really begs an answer from a number of approaches.

I don't know if the member wants to go into any of those areas where there have been enhancements. I'm getting notes here on examples of the CFSIS enhancements. As well, I just will say maybe in conclusion that I'm seeing the authorities taking on their responsibilities very seriously. We're seeing the quality assurance reviews, the ongoing reviews that are happening not just in response to tragedies or concerns about financial problems as they arise, some very historic. We're going to continue to see that work because the authorities are seeing the impact of those reviews with agencies.

Mrs. Mitchelson: Mr. Acting Chair, I wonder if the minister could provide for me the standard that enshrines Bill 34 and the training document that might highlight Bill 34.

Mr. Mackintosh: We can highlight that with the package of printing materials. I had been carrying that around. Actually, that one for every child seen every time, but we can provide that for the member.

Mrs. Mitchelson: Mr. Acting Chair, the minister mentioned, in his response, 131 positions that have been added–*[interjection]* Oh, sorry, 103 positions. How many of those are front-line positions? And where might they be?

Mr. Mackintosh: We're going to have to provide that information for the member. There were some further numbers, some further positions beyond the statistics that we have here today. But–do we have an idea there?

We'll answer the member's question. We have 103–or 103.5 now? But when we had 99.5 positions, I have those numbers here. So that, I think, pretty well answers the question. Front line was 66; supervisors 10.7; service assistant 2.5; admin 20.3; for a total of 99.5.

Mrs. Mitchelson: Mr. Acting Chair, does the minister have any more detailed information on the 66 front-line positions, where they might be?

Mr. Mackintosh: We have a breakdown, but it's not in the room here. So we can provide that.

Mrs. Mitchelson: Does the minister or the department have any idea how many vacancies there are in the front-line positions, agency by agency, and whether it's an issue?

Mr. Mackintosh: I'm advised we would have to canvass the agencies, unless the authorities have something recent as well, but, of course, that will change, well, almost daily. But I will endeavour to collect that information.

***** (16:00)

Mrs. Mitchelson: Yes. It always will be a snapshot in time, depending on the circumstances. One of my concerns, again, is the number of staff that might have some longevity and some experience versus new staff members because I do know there were some recommendations that talked about mentorship, and ensuring that new staff weren't left on their own to make difficult decisions without some sort of mentorship or supervisory support.

So I'm interested in knowing whether we're retaining our staff at the agency level, or whether they're moving out to some other opportunity. I know it's a little bit or work and I know that it's–but I mean I think that's all about accountability. I'm sure that the authorities would be looking at that very carefully in their monitoring of the agencies and, you know, some red flags went up if there was an agency that seemed to be having difficulty, it would appear to me that either more support and whether that be–whatever kind of support to try to help that agency get on track or get on its feet might be really important.

So I would hope that kind of function is happening and I would hope those kinds of issues would be raised at the standing committee so that everyone can try to work to resolve the problem. I mean, God knows, we know there never will be a perfect child welfare system because we're dealing with human beings that are delivering service and having to make decisions, and we know we don't have a perfect health-care system and there are mistakes that happen. We will never have a perfect child welfare system, but, I guess, you know, all of our goals–and I believe it is the goal of everyone–is to try to ensure that we have the best we possibly can have and that the supports are put in place to try to make sure that the mistakes are minimal, if possible.

So I think that's important information for all of us to have. It's not necessarily information that would be looked for to be critical but to understand where the real issues are, and hopefully we can all work towards finding better solutions. So I think that is all about outcomes and accountability within the system. So I would hope that even if it does take a little bit of time that that information–and I know it would have to be a snapshot in time. I mean, it changes on a regular basis but if I could have that information it would be very helpful.

I do know that one of the things that was talked about in October of 2006 when the Changes for Children was launched, the strategy, there was a bullet in the news release that said foster parents will also see increased support through stronger protocols to build teamwork for social workers and their agencies to ensure a voice for foster parents and planning for children in their care.

I'd like to ask the minister how that's going and how that has happened.

Madam Chairperson in the Chair

Mr. Mackintosh: One of the priorities has been and must continue to be, to better embrace the value of the role of partnership between child welfare agencies and their workers and foster parents. The first piece of that was the development of better recognition of foster parents and their contribution to the lives of children, and there were several pieces to that.

***** (16:10)

The first was significant increase in the foster rates, as well, recognition that sometimes there are other special costs, for example, cribs, car seats, that had not been recognized as eligible for support. As well, it was building the Foster Family Network strength and recognizing them in ways that we hadn't in the past, enabling them to provide more supports and liaison, and working with the authorities in child welfare agencies. In that regard, as well, we've some very significant improvements where the Foster Family Network now is partnering with the authorities and agencies. We're seeing them up in the north doing tremendous work. We're seeing working groups where they are a vital piece of this. Those kinds of protocols make all the difference to remind workers in the child welfare system of the important contribution of foster parents and what they bring to a child's care.

A tangible outcome of that is the new development of a curriculum for fostering in Manitoba. This is developing as a result of the insights of the Foster Family Network and workers in the child welfare system. What is coming to the fore in Manitoba is a made-in-Manitoba approach that builds on some of the practices. There's a model called PRIDE, for example. There's another model in British–what's the other one, Safe, and what they have decided in Manitoba as a result of, I think, a new era of mutual respect, is a made-in-Manitoba model that is near conclusion and ready for being piloted. So this new emphasis on the role and value of fostering is a big part of what was intended with that bullet in that piece.

The other is the training that is ongoing and, of course, the standards, but there, as well, I think, as a result of this, has to be a renewed emphasis on engaging foster parents in the creation of plans, and as well, recognizing the grief that foster parents endure, not only when there is tragedy but when a child leaves the home. It's my view that that has been underestimated. The Children's Advocate, I think, has helped me to understand some of that, but I have heard from foster parents. I know some in my own neighbourhood. I know some that have come to my office as a result of challenges, some that the member knows about. I think that we have a lot of growth to do, and it's not just here, I understand. I understand that this is a challenge elsewhere, as well, where we have professional views of child welfare workers that sometimes don't respect, to the extent, I think, should be taken of the views and insights of the foster parents themselves.

So we now, as well, have foster parents being invited and taking part in the training that workers have been involved in. So those are some examples, and if the member has other ideas–I know I've had some correspondence from her that I think are some examples of the need to enhance those dynamics. But I'm bound and determined to do what is necessary to breathe new life into this respectful relationship that I'm beginning to see unfold now as a result of these changes. I look forward to the conclusion of the new fostering curriculum, and I think that empowering foster parents, as well, in how the system works. They have to have better information on aspects of it, whether it's, you know, like the rules of the system, and that is as well part of it. It's not only changing attitudes on the part of child welfare workers but empowering and helping to provide accessible information for foster parents.

So we'll be continuing to work on those kinds of initiatives, and there are some other initiatives that we have been noodling with that I would like to see develop. But if the member has other information on this one–I know she has a relationship with some foster parents in her community, and I think some of the best ideas come from the foster parents themselves when they get into difficult situations and disagreements about what may be the best interest of a child. Sometimes, there are hard decisions that do have to be made in the end and, often, it's the courts that actually make those decisions. I think we're starting to see the courts, as well, better respect the views of all the parties. I think even recently, I've seen the development of different approaches to reconciling differing views and more recently even the role of mediation, perhaps, was one I'm advised of that is current now that has been a challenging case for family and for others, so maybe when things are really difficult there are ways to remediate it by way of ways that we haven't thought of before. But I think the member has a very important issue. When we recruit this number of foster families, they have to know that they are going to be valued members of a team. I think historically we haven't done the job that's necessary, and that's why that bullet was there which has ushered in these changes that I've talked about, but there may be other ways as well.

Mrs. Mitchelson: That bullet was there three years ago, and we're still seeing significant problems. It's not just in my community, and I know the minister's heard of others, but there are others that I'm working with out in the community that have really felt that they're not recognized and appreciated within the child welfare system the way they should be, and that nothing is provided in writing to foster families. It's verbal, and it's fairly widespread, and I think it's an issue that needs to be looked at and addressed. I do know and I've got lots of issues, but I want to stick to one theme. I've got lots of issues around the recommendations from the reviews that have been done.

There was one recommendation, and you probably have heard it from me in correspondence or seen it in correspondence, and that is the recommendation of the 47 and the Gage Guimond report that indicates that foster families should have something in writing regarding the plan, that there should be an assessment of the circumstances surrounding the placement of children, that there should be a thorough assessment, including that child's relationship and bonding with the foster family that they're in and that that should be provided in writing. I know I asked the minister a question, I think it was back in December, and I know I didn't get an answer to the question. So I'm asking him here now whether he has moved in any way on that recommendation from the Gage Guimond report.

Mr. Mackintosh: I agree with the member that plain language information on processes for foster parents are critical, and that's why the curriculum which is being in large part designed by foster parents themselves is going to–the attention is to address that.

In terms of the situation that the member raised, I'm advised that there are some unique issues with regard to that placement. As we recall here, I understood that there was an agreement of a temporary placement of those children where that had been set out early on with a reunification objective, and then there was an involvement of the courts, I think, as well which played a role here. But I don't dispute that the recommendation is an important one, and that's why we accept that that should be in writing.

***** (16:20)

Mrs. Mitchelson: I did ask a question in question period, too, about foster family rates and a freeze on foster family rates. I think the minister indicated in his answer that there was no freeze and that foster family rates had been increased, and I heard him say that, I think, in his opening statement, again.

It is my understanding that, through the AJI initiative, that special rates were frozen for foster families, and that was back in, well, 2003-2004, possibly, and that those rates haven't changed. They are still frozen.

Will the minister confirm that or can he confirm that today?

Mr. Mackintosh: Yes, I think there may be some confusion on the rates here. The foster care rates increased; I think the real increase is about 23 percent when you compound it. I think there were two increases of 10 percent over two years, effective January 1, '07-08.

That was across the province, and if I recall, too, the member was talking about Anishinaabe Child and Family. That would affect Anishinaabe Child and Family.

There's been no freezing of any foster rates, to my understanding, Anishinaabe–it's across the board–and basic rates are always under review, and, as well, special-needs funding has increased.

The member now is talking about what is called the Winnipeg special rate, and it's my understanding that there was an arrangement entered into because the Winnipeg rate was disproportionately higher than the provincial rate. So, in other words, there was some top-up or some additional funding available at Winnipeg Child and Family that exceeded that anywhere else in the province. So that's what the member must be talking about now.

The other thing that happened, then, we had the external reviews take place, and one of the recommendations in the Changes for Children initiative was to ensure that there was a consistent foster rate across the province, that there were too many inconsistencies.

So, now that Winnipeg's special rate–which, by the way, has seen increases in expenditure. There was no freeze in the sense of there were exceptions. There are exceptions to that you can apply for. I think there's three of them. We can provide those to the member. But that is now under review to determine if that should be adjusted or not beyond what is in place today, but the member shouldn't confuse the foster rates and the Winnipeg special rate.

The review of the Winnipeg special rate is being launched this fiscal year.

Mrs. Mitchelson: But the minister kind of talked around, and I think talked around in circles, and I'm not sure he gave me a straight answer.

Can I ask a very basic question? I'll try to keep my questions very simple. The foster rates are standard at the basic rate, level 1, across the province today?

Mr. Mackintosh: Yes.

Mrs. Mitchelson: What is that basic foster rate?

***** (16:30)

Mr. Mackintosh: The foster care rates in effect, I'm advised, are–and this does not include what's called an agency allowance, which can be for gifts and other recreation. In the south, ages zero to 10, it's $21.57 per day. For ages 11 to 17 in the south, it's $26.78. For the north, ages zero to 10, it's $23.02, and in the north for ages 11 to 17 it's $28.57.

Mrs. Mitchelson: Now, can the minister explain to me what the special rate is for children? That's the rate that's been frozen.

Maybe if I could just read from the Auditor General's report on pre-devolution. The Auditor General says that the department wrote a letter in November, 2004, that stated the freeze of special rates in foster care at Winnipeg, rural and northern CFS is an issue connected with the AJI. As such, discussions have been held. No final decision has been made regarding exactly how or when the freeze will be lifted. That's out of the Auditor General's report in 2004.

I have heard today, and I believe the Foster Family Association has confirmed, that freeze is still in place. I would like to know what freeze we are talking about.

Mr. Mackintosh: In addition to the foster care rate and the numbers that I provided, there's an agency allowance that's available, that's for recreation and special gifts. Also, special needs is recognized for compensation or for clinical services, respite and then–

Mrs. Mitchelson: Before we move on, would that be–we're talking about respite or are we talking about child care and all of those things? Would that all be included in special needs, if there was a need for, you know, sort of one-on-one in a child-care facility? Is that part of the special needs? We're getting to the special rate. I just wanted some clarification around special needs.

Mr. Mackintosh: So in addition to the basic rate then, we're looking at possible remuneration. Basic rate, the agency allowance, then the special needs, which is really about compensating for costs and then special rate that agencies can negotiate with guidelines with foster families. That really is about a compensation for families for exceptional circumstances and needs.

***** (16:40)

When a child comes into care an allocation can be negotiated. In addition to what I've said, there are three exceptions for special rate amounts. Also, that if there are exceptional needs that are not getting recognized by way of special rate, case-by-case consideration is made by the branch on an application. So those, I'm advised, are the different kinds of forms of remuneration available for foster families.

Mrs. Mitchelson: So you're saying that the special rate has guidelines. Is special rate available to all agencies?

Mr. Mackintosh: I'm advised that that's the case.

Mrs. Mitchelson: Now, that special rate then, it's negotiated with guidelines. Do we have a copy of the guidelines?

Mr. Mackintosh: I'm advised that agencies have these guidelines, and we don't have them available here, but one of the problems that has been identified by the external reviews and by the department is the discrepancies between the guidelines across the agencies. That's why we have to move to a standardized approach, but we can get a compilation of those guidelines and provide them to the member.

Mrs. Mitchelson: How many children across the system would be getting a special rate?

Mr. Mackintosh: We can get that information for the member.

Mrs. Mitchelson: Thank you. Could I get a breakdown agency by agency and the cost for the last fiscal year?

Mr. Mackintosh: The cost of the special rate? The expenditure per agency?

Mrs. Mitchelson: I guess what I would like is a breakdown. I think there was a breakdown in the annual report of level 1 funding and then level 2 to 5 funding. There is that breakdown there already, but it doesn't break down.

I guess, is a special rate included in level 2 to 5 or is it over and above?

Mr. Mackintosh: Twelve could be in each one, each level.

Mrs. Mitchelson: So, if we're looking at level 2 to 5 funding, is the special need funding all inclusive in that and the special rate for children?

Mr. Mackintosh: The department advises that they will make best efforts to separate out that from special needs and we'll let the member know of the result of that.

Mrs. Mitchelson: So then the minister is indicating to me–will he confirm today that the special rate has been frozen in Winnipeg, rural, and northern CFS since the AJI initiative was undertaken?

Mr. Mackintosh: As I said earlier, I'm advised that the special rate need in Winnipeg was out of whack with the rates elsewhere, the expenditures. So there was a decision made, apparently, that with regard to Winnipeg there would be no ad hoc increases for family compensation but adjustments are available according to three exceptions and as well if the needs of the child changed. That was for Winnipeg.

Mrs. Mitchelson: So is the minister telling me that if a child remains in that same foster home and the needs of that child change, there is an adjustment and there is no freeze?

Mr. Mackintosh: Well, a couple of points there. When a child comes into the child welfare system, there is a negotiation with the family to recognize needs first of all. There are three exceptions, and as well where needs change, there can be an application to the Child Protection branch.

As well, the big picture here is that in accordance with the Changes for Children recommendation, on this one there is a review being launched so that there can be some more consistent approach across the province for a special rate because Winnipeg was out of whack.

***** (16:50)

Mrs. Mitchelson: I wouldn't be raising this issue if it hadn't come to my attention from foster parents that are hearing that there are other children that are getting special rates significantly higher than their special rates. It has become an issue. A lot of them are long-time foster families that have been providing, obviously, pretty adequate care or the children wouldn't remain in those foster families. So there is some concern that new foster families that are coming into the system are getting different treatment and that their rates have been frozen since 2004.

It's my understanding that this is a Treasury Board directive. There has been reference made in conversations that I've had that it's a Treasury Board directive that this should happen, and there seems to be some inconsistency and unfairness. Now, I heard the minister say that there might have been unfairness in the past, and that's why the rates were frozen. But it appears to have tipped the other way now. So I know that these comments will be on the record for those to see that have felt that there's an issue. So, hopefully, the minister can indicate to me whether there has been an application by the department to lift the freeze, and whether that's been stalled somewhere outside of the department.

Mr. Mackintosh: We thought it advisable that, given the discrepancies of the past and discrepancies that continue, and recognizing that we have to have a more consistent approach, the current approach is going to be maintained until the review is completed and then we can make an application for any adjustments to Treasury people; but that has to be preceded though by that analysis. But, in the meantime, the rates, the basic rates, we've seen historic adjustments now getting back to levels, and I think we're now finally getting back to–*[interjection]* Yes, so there are enhancements to recognize the importance of foster care across the board as a result of the foster rate adjustments.

Mrs. Mitchelson: When can we anticipate that review being completed? How long has it been ongoing?

Mr. Mackintosh: There are two components to that. One first is our review and I should say too, that there's been an analysis of what is taking place, how rates are being dealt with in other provinces and their systems. We've also had an analysis of American rates, which, by the way, place us very favourably and, in fact, very, very favourably. But drilling down in terms of a special rate that analysis has begun now. There will be necessary discussions with the federal government for on-reserve amounts as well so that we can marry the two rates. It's expected that over the next year or so that we can get this completed, and it could be ongoing discussions with our partners as this unfolds with the Foster Family Network, for example.

Mrs. Mitchelson: Are the amounts in the Estimates book purely provincial government support, or is it a combination of provincial and federal government support in the detailed Estimates?

Mr. Mackintosh: That just comprises provincial dollars.

Mrs. Mitchelson: I know we haven't got too much time left today, so I'll try to just ask a very quick question for some clarification. Under the southern authority, we have Animikii Ozoson child and family services–maybe I could just say Animikii. What's the mandate of this agency?

Mr. Mackintosh: Animikii, mandated by the southern authority–the client group served, I believe was the question from the member: First Nations children and families in the Winnipeg area who are members of Ontario First Nations. It doesn't provide direct service to any of the Ontario First Nations communities, but instead provides statutory services in a culturally appropriate manner. I think that answers the question.

Mrs. Mitchelson: So these are children from Ontario that are here in Winnipeg receiving support or services through the Child and Family Services system.

Mr. Mackintosh: Just to clarify, the group served is First Nations families who are resident in the Winnipeg area.

Madam Chairperson: The time being 5 o'clock, I am interrupting proceedings. The Committee of Supply will resume sitting tomorrow at 10 a.m. Thank you.

LABOUR AND IMMIGRATION

***** (14:40)

Mr. Chairperson (Rob Altemeyer): Will the Committee of Supply please come to order. This section of the Committee of Supply will now consider the Estimates of the Department of Labour and Immigration.

Does the honourable minister have an opening statement?

Hon. Nancy Allan (Minister of Labour and Immigration): Thank you very much. I'd like to take this opportunity to just say a few words about what an honour and a privilege it is to be the Minister of Labour and Immigration, and Multiculturalism. I believe that we have a pretty awesome department and an incredible team of people that really do a lot of work in this province in regard to providing a better place to work and live and enjoy this great province that we live in.

The highlights of our 2009-2010 budget, the total request is $51,379,000 and the total increase over last year's Adjusted Vote is 2.9 percent, which is 1.457 k's–I'm doing that because it's easier–so there is a pretty big increase in the transfer of federal funding from CIC, which is Citizenship, Immigration and Immigration Canada. Obviously, that is funding that is in our enabling vote, and that is funding to help us provide programs and services to settle our newest newcomers. There is a 62.8 increase there.

There is also a 293,000 increase, or 18.9 percent of the total increase reflects an increase in the amount that is going into Workplace Safety and Health for our new workplace safety and health officers. We have a net increase this year of 11 full-time equivalent positions: five of those positions will be used to help us with our workplace injury and illness prevention plan; three of those positions, those FTEs, are for the Employment Standards division; and two of those FTEs are for the Immigration division and that will help us implement the new legislation, WRAPA, The Worker Recruitment and Protection Act, which was proclaimed April 1, 2009; and one FTE is going to be used for ITS, it's a business analyst to provide additional information technology support for the immigration initiatives and other departmental programs.

I'm going to keep my comments short because I believe that it's a good opportunity to have lots of time to have question and answers from my critics, and both of them are here today, so I'd like to proceed.

Mr. Chairperson: We thank the minister very much for those comments.

Does the official opposition critic have an opening statement?

Mrs. Mavis Taillieu (Morris): Mr. Chair, I don't really have an opening statement. I have a lot of questions, so I think we'll probably have some dialogue as we go along, but I would just like to thank the staff that are here today and look forward to getting on to some questions.

Mr. Chairperson: We thank the honourable Member for Morris (Mrs. Taillieu) for that.

Under Manitoba practice, debate on the minister's salary is the last item considered for the department of Committee of Supply. Accordingly, we shall now defer consideration of line item 11.1.(a) contained in Resolution 11.1.

At this time we'll also invite the minister's staff to join us at the front table and once they're settled perhaps the minister could introduce the staff in attendance.

Ms. Allan: Thank you very much. I'd like to introduce the officials that are with me from the department. I'd like to introduce: Jeff Parr, the deputy minister of Labour and Immigration; and to his left is Ben Rempel, the assistant deputy minister of our Immigration branch; across the table from Jeff is Victor Minenko, who is the director of research, legislation and policy; and Ken Taylor, who is the director of financial services. We also have with us today: Melissa Whiteside, who is a senior analyst; and Sara Obaid, who is the executive assistant to the deputy minister; and Rebecca Blaikie, who is the assistant to the minister.

Mr. Chairperson: Thank you very much for that, minister.

A question for the committee, do you wish to proceed today through the Estimates of this department chronologically, or to have a global discussion?

Mrs. Taillieu: Mr. Chair, I will likely go through in a global fashion, if that's acceptable. I probably will refer to the Estimates book on certain pages as we go along. I'd like to get through a lot of questions, so I may jump over things today and come back to them tomorrow, if that's acceptable.

Ms. Allan: Agreed.

Mr. Chairperson: Okay. For the record, it is agreed that questioning for this department will proceed in a global manner, with all resolutions to be passed once questioning has concluded.

The floor is now open for questions.

Mrs. Taillieu: I think, in the minister's statement, she did indicate that there were some increases in her department, and indicated the funding and the positions–I may just start with some of the positions, though, just in reference to the org chart. I think that this year is fairly–it's spelled out who the directors of these departments are, so that's fine.

I'm wondering if there's a list of–if the minister can give me a list of the political staff that she has within her office.

Ms. Allan: In the Legislative Building there was one political person, and that is Rebecca Blaikie, who is the special assistant to the minister. In my constituency office there is Brenda Reeve-Deamal, who is my executive assistant, and then there's another staffperson, Jackie, who works with Brenda.

Mrs. Taillieu: In the constituency office, are those political? Is one of those a political staffer?

Ms. Allan: Well, I don't think they're political. They're just staffpeople that work in the constituency office and provide services to my constituents.

Mrs. Taillieu: Would those staff in the constituency office be then paid by member's allowance or paid by the Department of Labour?

Ms. Allan: They're paid through the LAMC budget. That's my understanding. That's what all political staff–or all staff in MLA's constituency offices are paid through that budget.

Mrs. Taillieu: Mr. Chair, the minister indicated that there was an increase in the number of staff. I'm just wanting to clarify if any of these staff–are they employed within her office or are they employed in–I think she said there was one other person. I wasn't quite sure where she said that person was employed. There was some in Workplace Safety and Health, some in Employment Standards.

Ms. Allan: All of them are employed in the department. The five that are employed in Workplace Safety and Health are individuals that we have hired as workplace safety and health officers to help us get our injury rates down. Then, in the Employment Standards branch we have hired three new people to help us roll out enforcement around the WRAP legislation. Also, we have two new people in our Immigration branch who are also helping out with that. Then, the one person you probably might be referring to is one person for computer program analyst to perform business analysis to address immigration initiatives. That individual is in the Immigration branch.

Mrs. Taillieu: Can the minister tell me how many new hires there have been in this last fiscal year?

Ms. Allan: Fourteen–oh, tab 14, oh sorry. Excusez-moi. *[Interjection]* That's better. I didn't think that was very many. That was pretty funny. Where do you see it? Okay. Got it.

That would be 45.

Mrs. Taillieu: Is that a net gain or how many people have left the department?

Ms. Allan: I'm going to ask my officials to figure that out, because they are going to have to look at the staff turnover that was involved in that. If we could go on–if you wouldn't mind with questions and then they'll kind of try to figure that out–the exact number for you.

Mrs. Taillieu: Of the 45 new hires in the last year, how many of these would have been through competition, or how many would have been appointed?

Ms. Allan: Of the 45 hires, 29 were hired through competition. Seven were hired by direct appointment and nine were hired under our employment equity initiatives. The direct appointments were for difficult to recruit positions or short-term positions.

Mrs. Taillieu: Could the minister elaborate on what that exactly means–short-term positions or difficult to fill positions, and where are these positions located?

Ms. Allan: In one department we hired two short-term appointments, actually, a business analyst and a policy analyst. Those two individuals were Kurtis Penner and Andrew Donachuk. In the Manitoba Labour Board we hired two short-term appointments to cover unexpected retirements. There were two administrative secretaries, Annalina Rosit and Monique Racine. In Workplace Safety and Health, we hired a short-term appointment, Jeffrey McCulloch. In the office of the Manitoba Fire– *[interjection]*–Manitoba Fairness Commissioner, a new acronym that I'm not used to yet, is Robert Millman, and it was a short-term appointment.

Mrs. Taillieu: So of those appointments, then, they were short term so they're not presently on staff?

Ms. Allan: They are still on staff.

Mrs. Taillieu: Can the minister indicate, then, what term they were hired for and if they've extended past the term that they were hired for?

Ms. Allan: We'll get that information to the member.

Mrs. Taillieu: I just want to clarify. You indicated seven that were difficult positions to fill by appointment and then you said nine. I just want to clarify what that nine were and whether you had covered those in the people that you mentioned.

Ms. Allan: Nine positions were hired under our employment equity initiative; it's the civil service Gateway program, which encourages people–the Gateway program is a civil service program that encourages people that are already bureaucrats in departments to come on programs to learn senior management. So it's a program where the Civil Service Commission runs competitions for visible minorities ,and then they hire them and they provide them to different departments so that they can get experience.

***** (14:50)

Mrs. Taillieu: It's unclear to me. There were nine people that the minister said were by appointment into the employee equity program. Then she said they were hired by the Civil Service and appointed to different departments for experience. So is this a training program, or are these people hired for a specific job, or is it a training program? Specifically, is there an individual that is in charge of who would hire them?

Ms. Allan: It's a program that is run through the Civil Service Commission, and what they do is they have lists of people, and they interview people, and they put them on a list. Then, if we're looking for certain skilled individuals, we can actually go to the Civil Service Commission and say this is what we're looking for; do you have anyone within the civil service that you have hired in the Gateway program? It helps us create a diverse government when we have more of those individuals that represent the communities that we serve.

Mrs. Taillieu: Where would I find a description of the Gateway program in the Estimates book?

Ms. Allan: In the Civil Service Commission, but it's probably on the Civil Service Commission Web site, as well. We can provide you with that information if you'd like.

Mrs. Taillieu: Yes, thank you. If you could provide that information, it'd be great.

I'm still–

Ms. Allan: I can go back to that again. So, 45 hires, 29 through competition, seven were hired by direct appointment, and those are those ones that I talked to you about in regard to short-term appointments, and then the nine individuals that we hired through the Gateway program where we went, okay, so we've got a retirement, we've got someone who's left, we need somebody in our department to be, you know, let's go to the Civil Service Commission; let's see if they've got someone there because we feel it's important in our department to reflect diversity.

So we did those nine hirings through the Civil Service Commission.

Mrs. Taillieu: Of the seven direct appointments, who hired those seven people?

Ms. Allan: The business analyst and policy analyst in–is the Management Services division which is the IT shop. So the person who was in charge of the IT shop would have hired them.

The Manitoba Labour Board is an arms length adjudicative labour board. So somebody in the labour board would have hired the two administrative secretaries.

The Workplace Safety and Health department, it would have been somebody in the Workplace Safety and Health department, probably our assistant deputy minister, Don Hurst or Jo-Anna Guerra.

The office of the Manitoba Fairness Commissioner, it probably would have been Ximena Munoz.

Then the one other position or appointment that was hired is Rebecca Blaikie, my special assistant.

Mrs. Taillieu: Just to clarify, then, those seven people are still on staff on a temporary basis, or are they hired into full time now?

Ms. Allan: We said we would get you that information. We'll do that for you.

Mrs. Taillieu: Can the minister indicate, of the last fiscal year, people that were appointed at that time, how many of those people are now employed full time? When they were appointed for a temporary or part-time position, how many of those actually gained full-time employment?

Ms. Allan: So you're not asking for the people that I just listed in the '09-2010 year if you want those individuals from the '08-09 year?

Mrs. Taillieu: Mr. Chair, I'm basically asking of last year's Estimates when–how many people would have been appointed on a short-term, temporary or difficult-to-fill position? And then, of those, how many of those would then have gained full-time employment and would still be on staff?

Ms. Allan: We'll get that information for you. This is '08-09 information that I'm giving you because that's the most recent hirings that we have. So we would have to pull the '07-08 information to have a look at that.

Mrs. Taillieu: Are there any positions that are vacant in the Department of Labour at the present time?

Ms. Allan: Mr. Chairperson, 18.3.

Mrs. Taillieu: Eighteen point three vacancies. That's a lot, isn't it? Where are those vacancies? In what specific areas are those vacancies?

Ms. Allan: In the Management Services Division, there is a half-time position which is a revenue clerk. In the Mechanical and Engineering, there is a gas inspector and a boiler inspector and the competitions are under way for the boiler inspector. The gas inspector will be filled by the fall. At the Manitoba Labour Board, there is a labour board position, labour board officer that is vacant. In the Workplace Safety and Health office, division, excuse me, there is a senior safety and health officer in Winnipeg and a mines inspector in Flin Flon. Both of those positions will be filled by September.

In the Employment Standards division, there is a 0.8 admin secretary position that was hired into another position so we will be looking at that position in the future. The administrative assistant position as well, we're going to fill that one by the fall. The Worker Advisor Office, a worker advisor position. Immigration, there are three program officers that are actually–one is working in an

Employment Standards position right now because he went over to the Employment Standards to help with the management training position. There's a PM3 program officer and he or she is actually currently acting in a different position right now. Then another program officer that is also currently acting in a different position. All three of those program officers, we're moving to competition right now.

Then the management of settlement support services, that's Ximena Munoz's position probably. Ximena went to the Fair Practices Office, so we're in the beginning of moving to filling that position. Then there are five other positions that are going to competition, a policy analyst, three program officers, a program co-ordinator and an admin assistant that are also going to competition as we speak.

***** (15:00)

Mr. Kevin Lamoureux (Inkster): I appreciate the answers from the minister, listening to the Member for Morris (Mrs. Taillieu). I did have a couple of very specific questions. One of the things I do respect is that as the minister you do have special assistants, executive assistants, and so forth, and you will have a direct hire. No doubt you would play a role, a personal role, in the individual that you choose. I guess I just look for the minister to provide comment on the other seven that the Member for Morris makes reference to. There's always this concern the public has in terms of ensuring that there's equal opportunity for people that are looking for employment or even from within the union, that they're not going to be overlooked because someone's going to be assigned a position.

What is done, not with respect to the minister's appointment, but to ensure that those other appointments are not short-circuiting or preventing the civil service from being able to hire into these full-time or even short-term spots? What can the minister just tell us just to give us assurance that these are done in an appropriate fashion?

Ms. Allan: Each one of these positions we've referred to in regard to the short-term hire, usually what happened was we didn't have a lot of lead time in regard to the fact that the position was going to be vacated, so what we did was, because we needed to fill them in a hurry, we would put a person, an individual, in that position. Then what would happen is we would, once we had everything lined up and the position was going to competition, they would be invited to apply.

So they could apply for the position just like anyone else can, but it goes to an open competition which is in line with all of the civil service guidelines in the Civil Service Commission, and the individual in the position could apply for it just like anyone else could in the civil service.

Mr. Lamoureux: Again, I'm not trying to imply anything in regard to that. I just want to highlight what I believe is a very important principle, and that is that, generally speaking, when we're hiring, it should be done through teams as opposed to an individual per se, and we should be going through the civil service. Whenever you hear, as the Member for Morris was able to pull out this afternoon, a large number, it does raise some concerns. I think we want to minimize that. So I just wanted to get on the record as saying that.

The question I had for the minister is, when did she hire Ms. Blaikie?

Ms. Allan: I beg to differ with the MLA for Inkster but I don't believe, out of 325 staff, that seven direct appointments, and one of them is political, is a lot of people. I think six direct appointments out of 325 people in a department is not an outrageous amount.

Every one of these people, every one of these positions, are short-term appointments and they're going to go to full competition. With those individuals that are in those spots, they will be allowed to apply for the position, but there is no guarantee they will get the position.

The special assistant that was hired in the minister's office was hired in my office last August after Sharon McLaughlin went to Ottawa.

Mr. Lamoureux: I guess I had misheard. I thought it was only 45 people that were actually hired this year, not 325.

Ms. Allan: We were talking about direct appointments and there were 45 hires; 29 of them were hired through competition, directly went to competition, and seven were hired by direct appointment. Of those seven, one was my special assistant. So there were only six people out of 325 staffpeople in my department that were hired by direct appointment. I read out every one of their names and read out every one of their positions in every place in my department, so you can check the *Hansard* and you'll have that information.

Mr. Lamoureux: But what we're referring to, and I don't want to spend much time on it, was the 45 people in the last year, and seven out of 45 is a significant percentage.

Ms. Allan: I have no comment.

Mr. Lamoureux: The last question is that I understand that the minister did employ–or I was told–did she employ at one point Niki Ashton as a special assistant or employed in some capacity? I don't know.

Ms. Allan: No.

Mrs. Taillieu: Can the minister indicate if there are any staff within the department that have been seconded to another department at the present time?

Ms. Allan: Sixteen–oh, sorry, tab 16. I did it again. You've got to say tab in front of those. Tab 16 everybody, tab 16. Oh, two.

Mrs. Taillieu: And these two people, where have they been seconded? What departments have they been seconded to and who are they and when were they seconded?

Ms. Allan: Sue Barnsley, who was with the Status of Women branch, was seconded to Family Services and Housing, and Betty Brand, who was a policy analyst, was seconded to Seniors and Healthy Aging. That was probably–Betty Brand was in the last couple of weeks and Sue Barnsley was about two years ago, approximately.

Mrs. Taillieu: Does the Department of Labour and Immigration have staff on staff right now that have been seconded from other departments?

Ms. Allan: Judy Fraser, who is the Youth Prevention Education co-ordinator, and she was seconded from the WCB; she's with Workplace Safety and Health. And then three staff in the Immigration branch: one is Pam McConnell, a program co-ordinator; Denise Hanning, director of–oh they've all expired and gone home. Oh, well then, so just got two.

Mrs. Taillieu: The person that's the youth prevention co-ordinator seconded from the WCB, is that person then paid for by WCB or Department of Labour?

Ms. Allan: Well, the individual is in the Workplace Safety and Health branch. As the member knows, monies are transferred from WCB to my department, but we pay for it.

Mrs. Taillieu: What are the duties of that person?

***** (15:10)

Ms. Allan: It's all about getting awareness and programs into the schools with young people, and she co-ordinates a lot of those programs. She works with schools, and she does some programming as well with Red River College.

Mrs. Taillieu: Just a bit more clarification on what she does in the schools. What is the curriculum? What's the mandate here? What exactly, I guess, is the mandate of this person?

Ms. Allan: Well, we know that we have a serious challenge in regard to young people and getting the message out to young people that we have to reduce injuries. So we have really had a concerted effort in regard to trying to develop programs, so that we can get the message out to young people that they have the right, for instance, to refuse unsafe work.

It's important for young people to understand that there are Workplace Safety and Health regs that were approved 18 months ago, that they need knowledge about those. Sometimes they move from employer to employer, and they're not always in a work environment where the employer is providing them with that knowledge in regard to exactly what their rights are.

If you would like her exact job description, we'd be more than happy to provide it to the MLA.

Mrs. Taillieu: Thank you very much. That would be helpful.

I'm just curious, though, the minister mentioned that she talked about the Workplace Safety regs, regulations, and, I guess, legislation and regulations, so I'm wondering if the message that this person is taking into the schools bears any political pamphlets, any political signage or any political message.

Ms. Allan: No, we actually worked with the Department of Education, with the curriculum folks, and we developed some curriculum materials that were age-appropriate for the schools and the age groups that she was going into. So it's certainly not political. It's curriculum-based and has gone through a pedagogical process.

Mrs. Taillieu: I'm just curious as to what particular class in school would be teaching workplace safety?

Ms. Allan: The health and life skills classes.

Mrs. Taillieu: Is this a program that is accepted into all the schools?

Ms. Allan: Teachers make the decision in regard to what they want to teach in those particular classes, and then we provide the resources to the teachers.

Mrs. Taillieu: I wonder if the minister could indicate what the resources are. Perhaps there's a package of information that we might be able to see?

Ms. Allan: Yes, we could put some information together.

Mrs. Taillieu: Thank you. How does this overlap, then, with SAFE Workers of Tomorrow? Are they not doing the same thing?

Ms. Allan: They are independent from–well, we fund them, and they do work in schools as well. We fund them directly, and the deputy minister meets with them on a regular basis to get information from them about what they're doing with schools and the programming that they're providing. But we believe that it complements what this individual is doing in our department.

Mrs. Taillieu: So am I to understand, then, that the department funds the SAFE Workers of Tomorrow to deliver messages into the school about safe work, and there's also another person that delivers the same message, or is it different messages?

Ms. Allan: It's two target audiences. The individual in our department that is providing the curriculum resource materials is working directly with the teachers who are providing the materials and developing the classroom materials and teaching students. The work that is done by SAFE Workers of Tomorrow is that they provide speakers to schools.

Mrs. Taillieu: The SAFE Workers of Tomorrow, they provide speakers. Are these speakers a mix of employer-employee, or are they of a–belong to a specific group, or how do you choose who the speakers are?

Ms. Allan: Well, we don't choose them. The SAFE Workers of Tomorrow chooses them. But I do know that one of them that is a very high profile speaker is Cindy Skanderberg, who lost her 19-year-old son when he was an electrician, working unsupervised and untrained, before we changed The Electricians' Licence Act and helpers were allowed to work on job sites. She also has speakers–I know that I've met one of them this year at the Leaders' Walk, who is a young man who was injured severely, burned on the job, who goes in and makes speeches to young people in schools. I think these are the kinds of speakers that can really make an impact in regard to talking to young people about making sure that they work in safe environments.

Mrs. Taillieu: Just for clarification, then, the Department of Labour funds the SAFE Workers of Tomorrow.

Ms. Allan: Yes, we provide a grant to SAFE Workers of Tomorrow. Yes. We have for years.

Mrs. Taillieu: Where are these SAFE Workers of Tomorrow offices located?

Ms. Allan: They are housed in the Manitoba Safety Council.

Mrs. Taillieu: And where is the Manitoba Safety Council?

Ms. Allan: I don't know. I think the address is probably in the phone book.

Mrs. Taillieu: Well, I just was, with interest, reading this publication called *Union*, and it says, SAFE Workers of Tomorrow moved to the main floor of the training centre on April 1. The training centre would be the training centre on Portage Avenue, the union centre?

Ms. Allan: Well, it may be. Is that the United Food & Commercial Workers magazine? Could be. Actually, a lot of the construction industry has also got programs that go into schools as well. The Winnipeg Construction Association that Ron Hambly is the director of, they have a very advanced program where they go into schools, as well, and talk to young people about keeping safe on the job. They're very involved in this as well. So I think this is a real priority area for those individuals that are interested in making sure that our young people stay safe at work, especially when we have so many people that are going to be going into our apprenticeship programs.

***** (15:20)

Mrs. Taillieu: Can the minister indicate, then, that the SAFE Workers of Tomorrow has just moved into the union training centre on Portage Avenue?

Ms. Allan: I don't know. I have no idea where they moved. We can certainly check that out and get back to you on that. It doesn't worry me where they're housed.

Mrs. Taillieu: Well, I guess the point would be, if the department is funding the SAFE Workers of Tomorrow and the SAFE Workers of Tomorrow have moved into the Union Centre and are paying rent to the Union Centre, then the department is actually paying the rent, and that might be quite a convenient arrangement.

I'm wondering where they were before. Do you know where they moved from?

Ms. Allan: We told you that we thought they were in the Manitoba Safety Council. We said we would check it out, but I don't think it's a big deal who they pay their rent to. I think this is everybody's responsibility in regard to getting injury rates down.

Our government gives money to employers too. We don't just give money to organizations that are interested in giving money to unions. This particular issue is everybody's responsibility, and, quite frankly, it doesn't matter to me who they pay their rent to.

Mrs. Taillieu: If the minister is going to provide me with the last location of the SAFE Workers of Tomorrow and the present location, perhaps she could at the same time provide me with the rent that was paid at the previous location and the rent that's paid at this location.

Ms. Allan: We don't have that information in our department about where the SAFE Workers of Tomorrow pays their rent, so if the MLA for Morris would like to know that, I would suggest she get in touch with Ellen Oldford and ask her who she pays her rent to.

Mrs. Taillieu: I'd just like to ask some questions in regard to Workplace Safety and Health. I'm looking on page 37 in the Estimates book. I'm just looking at where it says: Reducing the time-loss injury rate to 3.5 percent per 100 workers by the year 2012, and so on, and further to that: Continue to implement the joint 2008-2012 injury and illness prevention strategy with the Workers Compensation Board.

I'm wondering if the minister can indicate if she is considering any further expansion of coverage under WCB.

Ms. Allan: When we announced the expansion of coverage, we had good meetings with the employer stakeholders, and we said that what we would do is roll out a voluntary campaign. We had planned to roll out a voluntary campaign in consultation with employers, but what we did when there was a downturn in the economy was we decided to hold off on that campaign for some time until the economy bounced back.

So at this time there are no plans to expand coverage. The only plans I believe that we have is to roll out a voluntary campaign.

Mrs. Taillieu: I believe that that was the mandate originally, is to have a voluntary campaign before actually doing the expansion of coverage. I'm just curious–to my recollection, I didn't see much of a voluntary campaign rolled out from the WCB.

So I'm wondering if the minister can indicate when this voluntary campaign is coming, and what is the plan to do this voluntary campaign?

Ms. Allan: Well, it won't be my campaign; it will be the WCB's. So that is something that the WCB will determine. There's a tripartite board of directors that have employers–three employers, three special interest reps, and three labour reps. It will be them that will decide what that campaign looks like. I will bring to committee tomorrow the letter from Shannon Martin that I received from the head of the CFIB that congratulated me, as minister, and our government, in regard to how we proceeded with the expansion and coverage.

Mrs. Taillieu: I know that the expansion that was planned, Shannon Martin felt very good about it because the minister didn't go as far as she intended to go with that expansion of coverage. She had to pull back on that because the surveys done and sent into the WCB did not indicate that there was a large appetite for that to happen. So, even though she could have forced that expansion to go further, she didn't, and that is what Shannon was saying was a good thing.

I just wanted to also ask about the safety and health officers. Now I notice in the book here it says: hire five new safety and health officers as part of the 20 new FTEs announced on 2007. So, just to clarify then, there were 20 FTEs announced in April of 2007.

Are all of these new 20 people hired, or are we still not there yet?

Ms. Allan: We made a commitment that we would hire 20 new Workplace, Safety and Health officers; we made that commitment during the election campaign in 2007. We hired 10 last year and we're going to be hiring five this year.

Mrs. Taillieu: So of the election commitment of 20, two years later we have 10 with a commitment to go ahead with five more. Do we have those five more now then?

Ms. Allan: The first year after the election–because the promise was made in '07, but the budget year that you would be allowed to hire new staff in would be the '08-09 budget year. So that budget year, the first budget year after the election campaign, we hired 10. This is the second budget year, and we're hiring five more.

Mrs. Taillieu: Are the number of inspections, then, of the Workplace, Safety and Health people–are the number of inspections increased?

Ms. Allan: Yes. They've tripled.

Mrs. Taillieu: So the number of inspections has tripled. Does that mean that there are three times the number of workplaces investigated or that there are certain workplaces that are investigated more than once?

Ms. Allan: It's a bit of a mix.

Mrs. Taillieu: Are there, therefore, more workplace infractions then?

Ms. Allan: In 1999, when we were elected, the number of improvement orders were 1,697. In '08-09, the last full year that we have statistics for, there were 9,725 improvement orders.

***** (15:30)

Mrs. Taillieu: Over 9,000 workplace improvement orders, and yet we still have a time-loss injury of, I think, it's 3.7 per 100. Even with expansion of coverage which is going to, in effect, lower that number just by the simple fact that you're incorporating people that are in lower risk situations, why aren't we seeing an improvement?

Ms. Allan: Well, we have seen an improvement. We just haven't eliminated it yet. One of the concerns that we have, obviously, is the number of people going into the construction industry and the way the construction industry is growing, as well as the manufacturing industry. Then the other sector that is a challenge for us is the agriculture sector. We rolled the agricultural sector in when we did the expansion of coverage.

Mrs. Taillieu: On the following page it does say right at the top under activity identification, develop and distribute occupational safety and health publications. I'm wondering what these publications are and who do they go to?

Ms. Allan: We'll put a package of information together for you.

Mrs. Taillieu: Well, thank you then. Perhaps that could also include, if there is any difference, it says that, develop innovative methods of promoting safety and health in the workplace, establish partnerships to develop innovative methods of promoting.

If you could give me an example of what is an innovative method of promoting safety and health in the work force, and who does that?

Ms. Allan: The work that we do with industry around setting up industry safety associations. One of the really exciting events that we had just this week was the event at New Flyer. New Flyer is a company that is reputable in regard to getting their injury rate down. They were really excited this year to host the national NAOSH breakfast and kick-off to the NAOSH week. The Premier (Mr. Doer) actually went, and we believe it is the very first time in Canada that a premier has attended a national NAOSH event. It was a really exciting partnership where industry and the government were working together to raise awareness about injury prevention.

Mrs. Taillieu: I just want to clarify, then, the note at the bottom of the page does say the new hires in Workplace Safety and Health is going to have an impact on the number of inspections this year. Is it the intent then to do further inspections this year?

Ms. Allan: Well, yes, we want to do more inspections. In fact, that is something that employers have asked us to do. It is something that employer stakeholders have talked to me about. There are 40,000 workplaces in Manitoba, so more officers will help us to do more inspections.

Mrs. Taillieu: On the following page, it does talk about increased funding for prosecutions and that's in explanation note 1, just the very last sentence in there. So I'm wondering, when you're talking about prosecutions, what exactly are we talking about here?

Ms. Allan: The department can make the decision and the authority to prosecute a contravention of the act and that rests with the Attorney General of Manitoba. So Workplace Safety and Health forwards appropriate investigation reports to the Attorney General and then they decide whether or not a matter should be prosecuted. In 2007-2008, there were

11 prosecutions; in 2008-2009, our year-to-date prosecutions are 24.

Mrs. Taillieu: In the second note, it talks about increased legal fees for investigations, and I'm wondering what investigations that would refer to.

Ms. Allan: Sometimes when we do prosecutions, we will get Civil Legal Services involved, so we had more cost for our own lawyers. We have to make sure that we're getting involved appropriately, legally, so what we do is we get Civil Legal Services lawyers involved and those fees are up.

Mrs. Taillieu: I'm just kind of moving through the Estimates book here a bit, so under the Employment Standards on page 41, under activity identification, it says: Recover unpaid wages and fees illegally charged. I'm just curious as to what that exactly means: Recover unpaid wages and fees illegally charged, using statutory collection mechanisms.

Ms. Allan: The provisions in the Employment Standards Code allow for the branch to go after an employer for unpaid wages. These are situations–the Employment Standards branch works with individuals that are not covered by a collective agreement, so if someone was working with an employer and they didn't get paid wages that they should have been getting paid, they can make a complaint to the Employment Standards branch. The Employment Standards branch would investigate that complaint and then, if they believe that those wages were being withheld from the employee unlawfully, they can pursue the employer for those unpaid wages and get them on behalf of the worker.

The changes that we made in the Employment Standards Code, that an employee couldn’t be charged for their Hooters uniform–or whatever, right–if they're charged for those, anything that is not a benefit to them, then we can, if the worker makes a complaint to the department, we can pursue that on their behalf.

***** (15:40)

Mrs. Taillieu: I wanted to ask some questions about the Worker Advisor Office. Where is this office located?

Ms. Allan: In the Norquay Building in the Employment Standards branch.

Mrs. Taillieu: I'm just wondering, as my understanding is, that this would be the office where people that were unsuccessful or unsatisfied or dissatisfied, I guess, with Workers Compensation Board adjudications, they would go to this office for assistance?

Ms. Allan: That is correct, but with the changes that we made with The Workplace, Safety and Health Act, that service is also available to employers. So employers and workers can both go to the Worker Advisor Office and seek help.

Mrs. Taillieu: Mr. Chairperson, I notice in here that there were 600 individuals who were assisted regarding processes and decisions; 400 given advice, 100 resolved claims; 200 through Workers Compensation Board–actually what I'm getting to is there seemed to be about 1,300 people that used this office, so is this an increased amount over last year or is this an average amount, the number of complaints from unsatisfied people?

Ms. Allan: In 2008-2009, the Worker Advisor Office provided services to over 1,411 individuals, and that is about the same as what was done in the previous year.

Mrs. Taillieu: I wanted to ask a few questions in regard to immigration, and I note on page 51 that one of the priorities is improving Manitoba's performance in attracting, settling, and integrating immigrants and achieving in the range of 12,000 to 13,000 landings in 2009. I'm just wondering if the minister can indicate what the numbers are to date.

Ms. Allan: In 2008 it was 11,230.

Mrs. Taillieu: And how many to date in 2009?

Ms. Allan: We usually gather those statistics at the end of the year, so we'll try to track that number down and see if we've got it. We're trying to find it, but those statistics are usually gathered over the course of a year.

As of February 28, which is the most recent statistics that we have, in comparison to the February date in '08, we have received 1,514 landings, and that is an increase of 37.5 percent.

Mrs. Taillieu: Just so I know that we're talking apples to apples here, you said by February 28 this year, so from January 1 to February 28, you had 1,514 and compared to the same time frame last year is a 37 percent increase. Is that what you said?

Ms. Allan: It's a 37.5 percent increase, Mr. Chair. In February '08 we had 1,101 landings. So it's a 37.5 percent increase at February 28, '09 this year over February 28, '08.

Mrs. Taillieu: Is there a particular time of the year that more immigrants come? Is there sort of a peak season I guess, if you will?

Ms. Allan: No.

Mrs. Taillieu: Can the minister indicate if the Employer Direct stream is still suspended?

Ms. Allan: Well, no. It never was suspended. The Employer Direct stream has always been there.

Mr. Lamoureux: I wouldn't mind getting some clarification. The Employer Direct stream, from what I understand, was in fact frozen for applications back in December. Is that not the case?

Ms. Allan: Well, what we did with the Employer Direct stream and, what's really important is to make a distinction between the employer application process. It was the employer application process that we put on hold. What we were doing was getting ready for the WRAPA legislation to come in. What we wanted to do was review our application process to make sure that it was in line with the new WRAPA legislation. We revised the criteria to ensure that our criteria were consistent with the WRAPA regulations. We wanted to do this to respond to concerns that the employer applications were largely being recruiter driven and submitted by third-party recruiters rather than directly from employers. So we wanted to make sure, we wanted to have a look at that process and make sure that it was in line with our new legislation. Anybody coming to Manitoba could still come through Employer Direct.

Mr. Lamoureux: I understand the difference between the employer application and getting the approval prior to actually getting processed through the Employer Direct stream. From what I understand the minister is saying now is that the application itself process is what was on hold so that people that were applying for Employer Direct stream could still do so.

Ms. Allan: I'm being informed by the assistant deputy minister of Immigration in my department that workers could always apply.

Mr. Lamoureux: That's not necessarily the same understanding we would have had several months ago, but I'm pleased to see that we're moving forward, then, on the employer stream.

As of today, there is no freeze whether it's application process for the employer or the employee?

***** (15:50)

Ms. Allan: Workers could always apply, and when they applied, we could match them to employers, so there hasn't been a lot of change. I think what the confusion was–and you asked it in question period, and I tried to explain it to you–and so it really wasn't anybody in our department that ever, ever said that this stream had been cancelled, it was you that said it. What we said was we were reviewing our practices to make sure that they were legal and ethical in relationship to the WRAPA legislation.

Mrs. Taillieu: I have a letter dated November 19, 2008, from the Department of Labour, Promotion and Recruitment Branch, Immigration and Multicultural Division, which states, and I'm quoting: We are temporarily suspending the employer application process and will not be accepting any additional employer applications until further notice.

There also was mention of a review that was going to be taking place. Now, we actually asked for, through a Freedom of Information request, asked for a copy of the review that was done. First of all, we were informed that there was no review, and then we were provided with a summary of a review, but this review had no date on it, nothing to indicate who did the review or when the review was done.

I really would like to know again why this program was suspended and what is the review. What was found out through this review that was necessary to put this application process on hold?

Ms. Allan: I would really like the MLA for Morris and the MLA for Inkster to sit down with the assistant deputy minister of Immigration and walk through this piece. I'd like you to really understand this, and I really don't think I can explain it to you. I am being really honest with both of you. I really don't think that we could write you letters until the cows come home.

But this is very complicated and you're confusing the employer with the worker, the Employer Direct stream with a process and, for some reason, no matter how hard I try to explain it, I can't explain it. So I would love it if you would sit down with the wonderfully talented Ben Rempel, the assistant deputy minister of Immigration, who, I'm sure, would love to talk about this because he loves to talk about immigration, and I am sure he could explain it to you. He would be more than happy to talk to you about the one-page review that we did that doesn't have a date on it. We can put a date on it, if you'd like, and explain it to you.

But at the end of the day, I can tell you that what was done in my department is going to be better for employers and better for workers because we're going to have an ethical recruitment process for temporary foreign workers, and we're going to have the Provincial Nominee Program. The two programs are going to run side-by-side and they're going to work really, really well.

Mr. Lamoureux: Mr. Chair, I thank the minister. It's always a good experience when I get the opportunity to meet with Mr. Rempel. I look forward to our next meeting, and we'll try to set something up in the next couple of weeks.

The essence of my understanding–and this way, Mr. Rempel can reflect on these words, but we'll maybe even broaden the discussion to include some of the other questions that we might have that we could, not necessarily have to put forward today, but we'll be able to include those discussions about the Provincial Nominee Program, the different streams and so forth.

Just so he knows where I'm going with the Employer Direct stream, my understanding of it is today, effective today, is that the employer application portion was on hold. It was on hold because of legislation that was passed by the Legislature, and until we felt comfortable with the regulations and so forth, it seemed to be content within the department to leave it on hold, whereas the employee, on the other hand, could still process through the Employer Direct stream. That's my understanding of it as of right now.

So then the question–and I say I look forward to the dialogue–is: Has all of that then been cleared up? Because Mr. Rempel would know, as I'm sure the minister does, in order for the employee to apply through the Employer Direct stream they have to have the okay from the employer. So, if the employer cannot put in for the application, it, in essence, freezes the employer stream. But, now, the minister is right. It can be fairly complicated. I look forward to having that dialogue, and we'll try to set something up in the next couple of weeks. I thank the minister.

Ms. Allan: But I can tell you, to give you a comfort level, that all systems are go. We're up and running. It was a very, very short–that one particular process in the big picture–it was short and sweet and things are up and running again.

Mrs. Taillieu: Mr. Chairperson, I just have still some questions though in regard to the review, the summary of the review that was provided to us. I'm just wondering, it appears that the employers were to be involved in the direct recruitment of employees but there was an increasing use of recruiters, and it does say in here: it became evident that some recruiters and/or employers misused the MPNP employer pre-approval application for several reasons, and it goes on to state some of them. But it also says: workers were charged, not only for immigration services, but also for the job offer, which is illegal in Manitoba.

So, if there was illegal activity going on, were there any charges laid?

Ms. Allan: Well, no, because we had no legislative authority. What we discovered when we started looking at this was we had no legislative authority because The Employment Services Act was a very weak piece of legislation and had not been reviewed for over 20 years. So that's one reason why we brought in the WRAPA legislation.

The other piece of this is the temporary foreign workers were totally unregulated. We didn't know who the worker was. We didn't know who they were working for. So, because of that, a total unregulation of that whole movement, that's why it was really–one of the reasons that we've been very, very fortunate here in Manitoba to develop this legislation is for the simple reason that we have the Employment Standards branch and the Immigration branch both in the same department. So we were able to figure this out from the point of view of providing newcomers with the basic minimum rights in the code, just like any other domestic worker would have.

***** (16:00)

Mrs. Taillieu: Mr. Chair, I note that this method of recruitment with hiring third-party recruiters was increasing starting in 2004, soon after this Employer Direct stream was created, all the way up through to 2008, but it wasn't until then that the legislation was proposed. So, if there was illegal activity going on for four years, what took so long to bring in the legislation?

Ms. Allan: Well, we are leading the country in this legislation. I just explained that the whole temporary foreign worker area is completely and totally unregulated. We didn't know who the employer was, we didn't know who the worker was and the recruiters weren't licensed. So the only way that we could find out if there was a problem was if the nanny, who was living with someone, had the guts to pick up the phone and call the Employment Standards branch and say, I've got a problem. Imagine how difficult that would be for someone who is living in the home of their employer and also somebody who comes from another country. Sometimes, you know, getting in touch with the government isn't always a positive experience. So we had absolutely no ability to control it or manage it.

I just want you to know, that what we're doing here in Manitoba is going to change the Canadian landscape, and it's going to end modern-day slavery, Mr. Chairperson. Two days ago, in the House, the Honourable Jason Kenney, the Minister of Citizenship, Immigration and Multiculturalism, said in the House: Mr. Speaker, we have launched consultations with live-in caregivers and those interested in this issue to seek ways we can better enforce regulations to protect the rights of caregivers. I encourage provincial ministers of Labour to do likewise, to follow the excellent lead of the government of Manitoba in this respect. So every jurisdiction in Canada right now, including the federal Tory Minister of Immigration, is looking at us and saying, way to go Manitoba, what you did is incredible.

I'd like to thank the officials in my department for this piece of legislation because it really is phenomenal, and it's going to end modern-day slavery in Canada, hopefully, some day.

Mrs. Taillieu: Mr. Chair, but I am looking before the legislation. I'm wondering, when did the minister first become aware that there was illegal activity going on?

Mr. Chairperson: Honourable Minister.

Ms. Allan: Did you say my name? Sorry, I'm waiting for you to say my name.

Well, it's a complaint-driven process, and we didn't have any complaints, and so what we did was we started to think about it. We knew what really broke it for us was two Septembers ago–or was it three–two Septembers ago, when Maple Leaf hired 200 workers from China. Those 200 workers were brought here by a recruitment agency in B.C. and they were charged $10,000 apiece. They were charged that illegally by the B.C. recruitment company–and they can still do it–and when the workers got here to Maple Leaf, Maple Leaf found out that those workers were living in Brandon, trying to send money home to their families, trying to pay rent and trying to pay an unscrupulous recruitment agency in British Columbia money.

I just got so angry and I was so disgusted, and we started talking about this. That's when we started to work on this legislation, and I bet you we're going find out there's lots more of this going on. We've already had lots of phone calls in my office from individuals in this province who have been brought over by unscrupulous recruitment agencies. It's really something that as people learn more and more about it here in Manitoba, they're going to stand up for their rights.

Mrs. Taillieu: Can the minister tell me what show money is?

Ms. Allan: It's a requirement under the federal legislation. If they're immigrating through the federal immigration stream, they have to provide information to the federal government that they have a certain ability and a certain financial strength to move to Canada.

Mrs. Taillieu: I'm still concerned about the summary of this review. I know that there must be another review because this is a summary of the review. I'm wondering if we can have a copy of the review.

Ms. Allan: This is the review.

Mrs. Taillieu: Well, thank you very much. As I indicated before, there's no date or anything on this review to indicate who did it or when it was done. Perhaps the minister could indicate that.

Ms. Allan: It was an internal review that was done by and signed off on by the assistant deputy minister of Immigration.

Mrs. Taillieu: Exactly what is the illegal activity referred to in this?

Ms. Allan: That people were charging for job offers.

Mrs. Taillieu: How many people were charging for job offers, and if that was known to the minister, why were there no charges laid against these people?

Ms. Allan: It's obvious that we knew anecdotally when we heard what went on in Maple Leaf, that there were problems. We knew there were problems. I mean, all you have to do is read the *Toronto Star* and know what's going on in Ontario, and you know there are problems.

It wasn't that we had individuals coming to our department, and employers. We had no legislative authority to lay charges. We had no legislation. We do now. You can't prosecute somebody without legislative authority to do that and now we have legislative authority. We knew about it anecdotally, and what we had to do is set up a legislative framework so that we could manage this issue.

***** (16:10)

Mrs. Taillieu: Can the minister indicate, within the last two years, how many people have left the Immigration Department not of their own volition?

Ms. Allan: No one.

Mrs. Taillieu: Can the minister indicate, within the last year, how many people have left the Immigration Department?

Ms. Allan: We can provide that information to the member.

Mrs. Taillieu: Well, thank you. Is the minister saying that she does not know, then, if people have left the Immigration Department?

Ms. Allan: People come and go all the time, and I am saying that we'll get that information to the member.

Mrs. Taillieu: Thank you very much. We have the assistant deputy minister of Immigration here, and I'm wondering if he might be able to provide that information in regard to the management staff at Immigration.

Ms. Allan: Well, the assistant deputy minister of Immigration is looking through his book and trying to find that information. When we have it, we'll provide it to you.

Mrs. Taillieu: I'm not going to dispute the fact that there may have been some unscrupulous recruiters. However, I think that there have been some recruiters that have done a decent job of bringing people into the province and now find themselves in a position where they feel that they're going to have to take their business elsewhere.

I'm not sure whether they will or not; how this will really impact them. But I'm wondering if the department has decided that the recruitment will all be done now by the department, and they will be the de facto recruiters now.

Ms. Allan: Well, recruitment can be done by any organization or any company, recruitment agency, that is registered with CSIC. The only problem is they cannot charge the worker for a job. They cannot do that. That is, no domestic worker is charged for a job.

So we cannot have two standards, one for domestic workers and one for newcomers, new immigrants.

So, if a recruiter had a business and their business model was to make money by charging foreign workers for the privilege of coming to Manitoba and paying money for a job, they're going to have to redesign their business model.

We are totally supported by CSIC on this. We are totally supported by the Honourable Jason Kenney. We're totally supported by the Honourable Minister Diane Findlay, the former Minister of Immigration, and the Canada Migration Institute.

Mrs. Taillieu: Well, again, when did the minister become aware of this illegal activity going on?

Mr. Chairperson: Just before recognizing the honourable minister, I'll just remind all members that technically, we're dealing with Estimates from the department, so questions should be phrased in that context or in relation to a piece of the Estimates.

Ministers can choose to answer whatever question they want, but there is latitude given to ministers when a question is asked which does fall outside of the Estimates process.

Ms. Allan: Well, the answer is exactly the same as the last time I answered the question. It became apparent to me when I found out what happened with 200 Chinese workers that came in through a recruiter in British Columbia. They were unscrupulously charged $10,000 per person, and I went, you know, I don't want that to happen in Manitoba.

So we need to look at this and figure out what we can do to stop unscrupulous recruiters from charging newcomers for the privilege of a job in our province. So we consulted with the federal government and the Employment Standards CEO, executive director Dave Dyson. Assistant Deputy Minister Rempel started to consult with a bevy of stakeholders about this legislation including the Canadian Border Services and the RCMP, and this legislation is supported by them as well.

Mrs. Taillieu: I believe that the Estimates process–we agreed to go about this in a global manner. I was referring to a letter that came from the Department of Labour and Immigration, Immigration branch, and also a FIPPA about a summary and a review of the employer application process, and I was asking questions identified in that summary letter provided to me which there–it talks about illegal activity.

The minister has said there has been illegal activity. I want to know when she first found out about it. When did she first discover there was illegal activity going on? When was it?

Mr. Chairperson: Again, just to clarify, and I appreciate the Member for Morris's statements. Nothing of what I said was in relation to the documents that she says she has. A global discussion just means that we're not going one section of the Estimates book after the other. It means that it's open for any discussion on any particular line item in the Estimates book, but it is the Estimates book and budgetary matters which should be the focus of questions.

When questions fall–you know, questions can be asked outside of the purview of the Estimates book, but members should recognize that under parliamentary practice ministers have discretion on whether to answer those questions or not because it falls outside of the purview of Estimates.

So the discussion that's going on is fine. I was just making sure that people knew that we're getting a little bit close, and the clerks have advised me of this, we're getting close to the area where we're technically outside of the specific area. There's nothing wrong with the questions. There's nothing wrong with the answers. I'm just pointing out that the questions can continue and the answers might not, and that that is okay.

***** (16:20)

Ms. Allan: Well, you know, I guess I don't know what to say anymore because I don't have an answer that's making my critic happy. I don't have a new answer. I've answered the question twice, honestly, as I would any question that I was asked, and I'm sorry, but I don't have an answer, obviously, for your question that you want to hear.

Mrs. Taillieu: I think we'll come back to that, then, tomorrow.

I want to just go on to the–I believe last year I talked about service purchase agreements with all the settlement services agencies, there are a number of them under the Immigration Department. I notice this year in the Estimates book, it's something new, it says: Establish contribution agreements with 200 service providers so that the delivery of a wide range of settlement, Adult EAL, and enhanced services through Manitoba Immigration.

I'm wondering then–I had asked for a package of information in regard to contribution agreements. We got into the issue of personal information and protection of privacy. I said I did not need any personal names or anything; I was looking for copies of the service purchase agreements or contribution agreements, didn't receive any of those, and now I see they're going to be established.

So can the minister indicate if these are done or they're just in the process of being done, and why haven't they been done to date, if not?

Ms. Allan: Well, no, it's nothing new in our department. Every year we have contribution agreements. We're actually bound, I believe, by federal government rules–*[interjection]*–guidelines, thank you. Not rules, guidelines. So we have very in-depth contribution agreements with our stakeholders, Mr. Chairperson. What happens is every year we review those contribution agreements and consult with the stakeholders and renew those contribution agreements with them in regard to the services they're providing. That's done on a yearly basis.

Mrs. Taillieu: How many actual agencies are there, then, that provide immigrant settlement services at the present time in Manitoba?

Ms. Allan: While Ben counts them, I'll give you the information you asked for in regard to the staff that left the department of the Immigration branch. In 2008-2009, a total of six staff left. One of them was Michael Scott. One of them was Mely Buenaventura, and the other one was Marsha Share, and they retired. Deb Fehr Barkman and Sophia Vong, left for another department. One of them resigned to move out of province and her name, or her name, is Chris McInnis.

The number of settlement providers we will fund is 200.

Mrs. Taillieu: Are there contribution agreements with all 200 of those?

Ms. Allan: Yes, there will be contribution agreements with all of them.

Mrs. Taillieu: The minister, I think, said will be. So there are some that aren't done yet?

Ms. Allan: It's early in the fiscal year, so we walk through those and we develop them as we go along.

Mrs. Taillieu: Just for clarification, I'd like to know how many are completed and how many are in progress.

Ms. Allan: We're not sure at this time, but I can just guarantee you that within the next few weeks, all 200 will be done.

Mrs. Taillieu: Perhaps then, in the next couple of weeks, the minister can provide a letter saying they have been completed.

Ms. Allan: Certainly.

Mrs. Taillieu: Thank you very much. I think there's quite a large amount of money that flows from the federal government to the Province for settlement services. I think it's something like $10 million or $12 million, and then that is distributed amongst the settlement service providers.

Are there criteria that the service providers must meet to be eligible for some of this funding?

Ms. Allan: We have funding criteria. They are that the service providers must demonstrate an effective service delivery model that will assist Manitoba immigrants and refugees towards economic and social integration, participatory citizenship and long-term residency in Manitoba. The proposal must give evidence that the services are needed and wanted. Unless otherwise agreed upon, funded services must be provided free of charge.

Mrs. Taillieu: I'm just trying to clarify here, but I believe that one of the important criteria for new immigrants to be accepted through the PNP program is that they have some competence in the English language. Is that correct?

Ms. Allan: It's one of the factors, depending on which stream they come through.

Mrs. Taillieu: I notice that a lot of the settlement and community supports are around assisting with English as an additional language. I'm wondering how that's measured. How do we know that the settlement service money is actually improving the English skills of new Manitobans. Is there a measurement how that works?

Ms. Allan: We have staff in the department that do assessments and they work, as well, with the service providers in regard to making sure that the delivery of services is making a difference in regard to newcomers' language abilities. We also have programs in place with employers. One of the gentlemen that I met last night is the head of Bison Transport, and Bison Transport does language training on site. There is specific language training for employers; it's called Benchmark training, and that's how we assess their language capability.

Mrs. Taillieu: I'm looking through a list that I have here of settlement and community supports. Some of them, I understand, show that there are clients served and some of them do not. There's a very wide range of people that are recipients of monies made available for settlement services, so I just want to pick a few, maybe, and ask if the minister could indicate–just give me a minute here, I'm looking just to pick one. Okay, Rural Municipality of Bifrost. I'm only using this, picking it out as an example. They received $26,000.

What would be the reason that they would be considered a settlement and community support? Can you give me just an example of what that would be for? I have no idea, so I'm just asking the question.

***** (16:30)

Ms. Allan: Ben Rempel has said that what he will do is he would have to look at the agreement. Of the 200 agreements, he doesn't have all of them in his head in regard to what the services are that are provided by each one of them.

Mrs. Taillieu: Well, I do appreciate it might be difficult to sort of go individually like that, but I'm just wondering if a municipality, any municipality, was to apply for a settlement and community supports and, yet, didn't indicate over the last three years that they had served any clients, what would be the basis for them to receive funding?

Ms. Allan: Well, a perfect example is Winkler. We gave them $600,000 for settlement supports. Obviously, some of it might be in language training. Some of the training that we provide is orientation to the job market. Sometimes they need help with resumes. Family members might. We started an entry program that's been very successful. Sometimes they want to just learn more about Canadian culture and learn more about what our systems are in regard to our education system and our health-care system. Sometimes those kinds of supports are important, as well, for newcomers who come from different cultures.

Mrs. Taillieu: I also note that there's a radio station, I don't know which one this is, CKUW, 95.5 FM received some money from Manitoba Immigrant Integration Program for settlement and community supports. What would a radio station need money for settlement and community supports for? Can you give me an example?

Ms. Flor Marcelino, Acting Chairperson, in the Chair

Ms. Allan: We've done language training through the radio for new immigrants. We're not sure that that's exactly what this one is, but we're going to check into it, and we'll get back to you.

Mrs. Taillieu: I also noticed that there is a financial institution in here, Assiniboine Credit Union, who also received some money from Manitoba Immigrant Integration program. Would this be the only–it's the only one I noticed anyway. Oh, no, I'm sorry, there was TD Canada Trust, I see.

I'm just wondering what criteria would they have to meet, then, to get money through Manitoba Immigrant Integration program?

Ms. Allan: Well, this one is probably one of my favourites. It's one of the most exciting programs that we fund. It is a program that was started by Christina Semaniuk, who actually was on our Manitoba Immigration Council.

It's a program to train newcomers in how to become customer service reps. It has become such a success that now the Royal Bank came on board–or, sorry, Toronto-Dominion. It's very exciting because the credit union system identified that as Manitoba's demographics change, because we will depend solely on immigration for population growth by the year 2014, that we better have people behind the counters that can relate to the new demographics of Manitoba. So it was an exciting program that was started by Christina, and it's to train newcomers.

I remember it was one of the first events that I went to shortly after becoming minister, and I met these incredible women that had all just been trained–and I think they were all women, actually, I don't recall if there were any men or not–and they had lived in Manitoba for quite some time, some of them. One woman said she'd been in Manitoba for five years, and she had not been able to find employment. They enrolled her in this program and it was very, very exciting because now she was working and participating in the economy and gainfully employed. It's really a neat program.

Mrs. Taillieu: What I understand from that, then, anybody that–anybody–in any field that wanted to hire new Manitobans and train them would be eligible to apply for this?

Ms. Allan: Well, there's an application process that they would have to go through, and it would have to meet the strategic objectives of our settlement services and our immigration strategy. So if someone had an idea like this, and they wanted to sit down with my department and consult with them in regard to whether or not this is something that would be of benefit, that is something certainly that we would entertain.

You should know that the federal government applauds Manitoba's settlement services strategy. There are only three jurisdictions in Canada that deliver settlement services, and they consistently tell us how, when I'm at FPT meetings, in regard to what a remarkable job we do here in Manitoba in delivering settlement services that really make a difference for our newcomers.

Mrs. Taillieu: Madam Chair, can the minister indicate what are the current wait times for all of the streams in the Provincial Nominee Program?

Ms. Allan: Well, we have–I have told–I wrote the MLA a letter, and I told her what the wait times were in regard to the streams. I can't recall what I said in that letter, but I don't believe that much has changed in regard to that. I can tell you that we take a holistic approach in regard to our immigration program. We believe that, you know, the due diligence has to be done in regard to our applications, and that sometimes it varies in regard to exactly what those wait times are because, quite often, what will occur is not all of the information is there in regard to the application.

But we're certainly pleased with our immigration program in regard to–when you look the success of the program, 70 percent of all of the provincial nominees that come to Canada come to Manitoba. We're particularly pleased with the fact that 34 percent of those that come to Manitoba come to rural Manitoba, which is very, very, very exciting, you know, because we can't have an immigration strategy that just benefits our urban centres. We also have a retention rate that we're very proud of, around 84 percent. So we believe our immigration strategy is working for Manitoba.

***** (16:40)

Mrs. Taillieu: The minister indicated that 70 percent of all newcomers to Canada come to Manitoba, and then she indicated a retention number. I'd asked through a Freedom of Information the number of Manitobans that had left within two years of settling here all years from 2000 to 2008. I was told that that record didn't exist. Is there, in fact, a record that exists to track the number of people that leave or stay in Manitoba every year–of the ones that come in through the PNP?

Mr. Chairperson in the Chair

Ms. Allan: No, we're just not set up to track those kinds of statistics. The actual retention rate statistic is from an independent study that was done by an independent body.

Mrs. Taillieu: But, Mr. Chair, according to the Canada-Manitoba Immigration Agreement, section 7, in order to aid in the evaluation of the Provincial Nominee Program, the Province will track provincial nominees for a minimum of three years from their date of entry as a basis for assessing the retention of provincial nominees.

So in light of that, I'd like to again ask what the retention rate is of provincial nominees in Manitoba. If they don't have that information, are they not complying with the Canada-Manitoba Immigration Agreement?

Ms. Allan: We actually are working with the federal government on an information-sharing agreement because no jurisdiction in Canada can do this because of the simple fact that we're not able to share information with the federal government in regard to those landings. So we're actually working with the federal government. I actually had Monty Solberg here last year, and we announced that we were going to be working with the federal government on this in regard to how to implement that.

Mrs. Taillieu: But there's an agreement between Canada and Manitoba which says that the Province will track provincial nominees for a minimum of three years from their date of entry as a basis for assessing the retention of provincial nominees.

Is the minister saying they are not doing this and therefore breaking that agreement?

Ms. Allan: Our agreement with the federal government is a bilateral agreement, and it's signed off on by the federal minister and the provincial minister. We are in consultations with the federal government in regard to how we can comply with what is in that agreement.

Mrs. Taillieu: From that answer, I take it that you're in violation of the agreement because you're not doing what the agreement says. So if you don't have the information, how can you measure the success of the program if people are coming to Manitoba and then you don't know where they're going? You really don't have a handle on how many people are staying or where they're going to. How can you measure the success of the program?

Ms. Allan: Well, what we do, we are in compliance with it. I know you'd just love to find something I wasn't in compliance with, but it's not going to happen.

What happens is we are in compliance because what we do is we provide the federal government with the newcomer's health registration number, and then they cross-reference it with their tax information. They're able to draw aggregate information from those two sets of data, and then that way, they can determine. That is the mechanism that we're using right now until we have an official information agreement with the federal government. So this process is in place for now until we have a better one.

I have the information for the member in regard to the radio station that received funding. CKUW was funded in 2007-2008 for $2,500 to run a day camp for immigrant children to learn about the radio broadcast business.

Mrs. Taillieu: Well, if the minister is saying that they are tracking this information, perhaps she can tell me then, what is the retention rate of immigrant medical personnel, doctors and nurses, that are retained in Manitoba, or how many actually leave the province?

Ms. Allan: It's aggregate data. We can't pull that information from aggregate data.

Mrs. Taillieu: Again, I'm just quoting from the agreement. In order to aid in the evaluation of the PNP, the Province will track the nominees for a minimum of three years. That doesn't sound like aggregate data. That sounds like it will track the people that come through the PNP to see whether they stay in Manitoba or they leave Manitoba. That doesn't appear to have been done.

The next section in this Canada-Manitoba agreement says that every five years, this annex, the whole annex, the whole agreement, will be reviewed, and I'm wondering if the Province has had discussions with the federal government in regard to this.

Ms. Allan: Well, we're actually in the process of negotiating a new bilateral agreement with the federal government, and we will be having discussions with the federal government about how we can better work together in regard to our immigration strategy.

Mrs. Taillieu: What is the nature of the new bilateral agreement?

Ms. Allan: Well, the old bilateral agreement was a five-year agreement, and that agreement is going to be up soon. We have been in negotiations with the federal government for six months on a new bilateral agreement.

The new bilateral agreement we have–without a bilateral agreement with the federal government, immigration is a federal responsibility. So, it is a shared jurisdiction. So, we have to have a bilateral agreement with the federal government for our immigration program.

I have the answers to your other question, the list of settlement services. We provide information referrals for community–and this is the Bifrost rural municipality–provide information referrals for community and regional supports in the areas of housing, health care and services, education, recreational activities, adult and family learning and literacy programs, instruction programs, finances, employment supports, support labour market preparations and entry for immigrants, organize and promote five community events to help immigrants feel more welcome.

Mrs. Taillieu: Well, thank you for that.

I'm just wondering, then, Mr. Chair, is this new bilateral agreement, is that going to replace the Canada-Manitoba Immigration Agreement or is it just a renegotiation of the same thing?

Ms. Allan: It is a renegotiation of the agreement that you're looking at right now. It will be a new agreement, and I will sign off on it with the new Minister of Immigration, Jason Kenney, if that's who's the minister when we sign off on it.

***** (16:50)

Mrs. Taillieu: Does the Department of Immigration advertise abroad the Provincial Nominee Program?

Ms. Allan: Well, we don't have to. We have the most successful Web site of any Web site in government. It gets about 1.6 million hits a year.

Mr. Lamoureux: Toward the minister, in terms of just the wording, talk about the overall numbers with the Provincial Nominee Program, we have seen an increase. I know we have a target of 20,000. I suspect that it wouldn't take that much effort to really achieve the 20,000. I suspect that the demand has actually been growing within the Provincial Nominee Program and I'm wondering if the minister can give an indication–I think she said that we're at 3,000 in the first three months. When does she anticipate at this stage that we'll hit that 20,000?

Ms. Allan: Well, the commitment was to hit 20,000 by 2016, and we just take it year by year.

Mr. Lamoureux: Generally speaking, individuals that will qualify for the Provincial Nominee Program put in an application, and I'm just guesstimating here, but I suspect that the numbers of individuals and their families that are actually applying probably exceed 20,000 today in terms of the number of applications that are being put in. Is the minister aware, or is the department aware of what sort of numbers that were actually applying to come through the program?

Ms. Allan: Well, we're not really as concerned about numbers as the MLA for Inkster is. Our approach to our immigration strategy is holistic. We're concerned about them succeeding. We want them to participate in our economy. We want them to get here without being taken advantage of by unscrupulous recruiters. We want them to get here and have settlement services and support services and we want them to feel welcome, and it's a challenge.

We have newcomers that come to Manitoba, not just through the Provincial Nominee Program but from the refugee stream and the family support stream and it really is a balancing act in regard to getting those folks here and getting them into the right organizations and getting them jobs. So I know that the MLA for Inkster would just like to open up the doors and have them all arrive tomorrow and tally ho, they'll all do well, but, you know, I think slow but steady is our approach to immigration and make sure that, you know, we have a lot to be proud of here, and, once again, 70 percent of all of the provincial nominees that come to Canada come to Manitoba. It's a very, very successful program, but one of the things that you can do when you have success sometimes is grow too fast, and we want to make sure that we don't make that mistake with this program that is so valuable to Manitoba and also valuable to the newcomers that want to live here and become Manitoba's newest citizens.

Mr. Lamoureux: You see, I would ultimately argue this is one of the greatest programs that the Province has, even if you go through all the many different departments, and that's why I think that we have to be thinking ahead in terms of how we're going to be able to meet those demands.

Does the minister have a graph that would show the number of applications that are coming into the PNP office for the last four years?

Ms. Allan: Well, you know, I would really ask the MLA for Inkster–I'm going to give you this data for 2008, but I don't want this to turn into a make-work project for my departmental staff, because every make-work project that I pull immigration staff onto means that less people are processing immigration applications and are providing services. So I think what you're asking me, and we have the numbers for 2008, the Provincial Nominee Program receives 6,922 skilled worker applications, 5,608 were accepted for assessment, 20 percent were complete and ready for assessment, and 60 percent were initially incomplete, and 1,314, 20 percent were returned as ineligible or incomplete. Now I think that's what you were asking me. Does that help?

Mr. Lamoureux: Yes, Madam Minister, that does help a lot. But, you see, if we just look at that 6,900, because the details in how the breakdown I'm not as much concerned about, at least for this particular argument or discussion, as that overall number. Let me explain. If it's 6,900 for 2008 and it was 6,000 for 2007, I suspect that we've been seeing year over year an increase, and that increase year over year will likely have an impact in terms of the number of arrivals that we would be getting at any given point in time of the year, the overall number on arrivals.

So what I'm concerned about is that we have the capability to be able to potentially, to the best of our abilities, meet the demand, which I believe is going to be increasing over the next number of years. I guess that's kind of like what I'm looking for, and that's why I think that there's some benefits in terms of understanding the increases that have been coming over the last few years. The last thing I would want to do is to tax the resources of the department, you know, to get them to do something when they could be helping out on case files.

Ms. Allan: Well, I totally agree with the MLA for Inkster in regard to the fact that, you know, we cannot do this work. We cannot make the mistake the federal government has made and not resource the Immigration branch, because this is a people business. This is all about applications and people. So, since 1999, the funding to the Immigration branch has increased by more than 260 percent and that's the settlements or that's funding, and the staffing levels have more than doubled to 77 FTEs.

We have made a consistent effort in my department to make sure that there are people and funding there to process applications, to do the assessments that are required to make sure that we're getting people in training and get them into jobs.

Mr. Lamoureux: I know. I've already written a note here that I'll pass on to Mr. Rempel before I leave in terms of suggesting some meeting times, and we'll get more into the processing times and so forth at that particular meeting.

The question that I would ask the minister–having said that, is that typically, and we'll talk about a family stream where all the paperwork is filled out correctly, there is no need to require additional information from the applicant. Let's just say they did a thorough good job in providing the paperwork. What could they expect to have to wait in order to go through the system in that situation?

Mr. Chairperson: The hour being 5 o'clock, committee rise.

An Honourable Member: Committee recess.

Mr. Chairperson: Oh, sorry. Committee recess, right. Sorry about that.

The time being 5 o'clock, I'm interrupting proceedings. The Committee of Supply will resume sitting tomorrow at 10 a.m.

SCIENCE, TECHNOLOGY, ENERGY AND MINES

***** (14:30)

Madam Chairperson (Bonnie Korzeniowski): This section of the Committee of Supply has been dealing with the Estimates of the Department of Science, Technology, Energy and Mines.

Would the minister's staff please enter the Chamber.

We are on page 148 of the Estimates book. As previously agreed, questioning for this department will proceed in a global manner.

The floor is now open for questions.

Mr. Blaine Pedersen (Carman): Through you to the minister, we've had various discussions over the last two years about low-speed vehicles, making regulations for them. I've offered Carman, the town of Carman, as a test case to set up regulations.

Can the minister advise me as to where his department is right now in co-ordination with the Ministry of Infrastructure and Transportation in terms of how soon these regulations will be developed?

Hon. Jim Rondeau (Minister of Science, Technology, Energy and Mines): The status of the low-speed vehicles, as far as that's concerned, the regulation is the responsibility of Manitoba Infrastructure and Transportation. But we worked with them, we co-ordinate and discuss the issue with them. We understand the drafting instructions for the regulations are nearing completion, but the regulations will not be available for comment for several more weeks.

There are some concerns, and we are trying to deal with other provinces regarding safety concerns, how to integrate with regular traffic, et cetera, and the whole roll out of these vehicles in a safe and cautious manner.

We would like to ensure that there are no concerns on cold weather or integration in regular traffic flow issues. So we are working with MIT on (a) how to roll this out in a safe process, (b) talking to other provinces on how their rolling it out and looking at their experience, and (c) we want to do it in a plan that makes sense and can be communicated to the public.

Mr. Pedersen: In the next couple of weeks when these draft regulations are written up, and realizing that they are just draft, and there may be things that need to be tweaked in it, does the public have a chance for input on this or what is the procedure here as you develop the regulations?

Mr. Rondeau: We're trying to work with the industry to roll out these regulations. As the regulations are developed, there will be discussions with industry and other concerned partners on the roll out of this, which may involve different industry players, such as Westward Industries or the company that's in your community, as well as other stakeholders which might be municipalities or other groups that may want to do a pilot project.

***** (14:40)

Mr. Pedersen: So when you have your regulations, and I guess all I can do is ask: Will you, either through myself or directly to Northland Machinery, perhaps to the town of Carman, give us a copy of these regulations, draft regulations, so that we do have input? I would hate to see this opportunity pass and us not have any chance for input to them.

Mr. Rondeau: Madam Chair, we will meet with Northland, go through what we're planning to do with them and make sure the communications are open.

Mr. Pedersen: Mr. Nussey, at Northland Machinery, will certainly be waiting with bated breath for that.

Mr. Rondeau: If the member would give us the contact information of the people, phone number and stuff like that, we'll make sure that we contact the right person.

Mr. Pedersen: Madam Chair, that's good. I will do that. I will go down and get the pamphlet and I'll leave it with your staff here today so you have the contacts. Very much appreciated. Thank you.

Mr. Cliff Cullen (Turtle Mountain): Just on the vehicle side of things. I know under the previous legislation, the minister had to set up a committee to investigate climate change as it relates to motor vehicles and that committee has put forward some recommendations. But the recommendations, to me, look like it's kind of a wait-and-see kind of an attitude. It looks to me like everybody's kind of waiting on what happens in California.

Is that where we're at? What's the next stage in the process here? I know there's some other–what they call complementary measures that are being recommended, but what's the role of this board going to be going forward? And then, what steps is the Province going to take from here on in based on these recommendations?

Mr. Rondeau: Thank you very much for the question. It's a good question because the board had a very important role, and I'd have to thank the board for completing it because it was a very tough job. They had a lot of public input. They went and did a job. They completed their role and I have received the report.

The report's very thorough and it was interesting because when I met first with the board, they sort of said, what's our role? Do you have any expectations? I said, well, I want you to look at the mandate and just do what you believe is appropriate.

The report is very thorough, it's very good, and they had a number of recommendations because they took a broad look at the subject and they looked at, you know, transit and looking at transit and they looked at other forms of alternative transportation. They looked at hybrid rebates and talking about maybe looking at how we can renew the fleet.

But one of the major things that they said was this is not just a Manitoba issue, Madam Chair. We need to work with others. Although we're working in the province on the new hydrogen buses that Flyer's developing for the Olympics, we're looking at hybrid buses which are using less fuel, although we're looking at integration of alternate vehicles or more fuel-efficient vehicles–those are all things we need to do–but one of the things they did say was that California is a huge market and we have to learn to work together in order to push demand or pull demand.

California has more people than Canada. We have about 0.03–less than one-third of 1 percent of the market for cars in North America, so we won't be driving the demand for cars. We have to work with others, California, other states, to sort of say, okay, here are the new rules, here's the reality, and have one standard that's understandable, that's acceptable for all North America, and it's one thing that all manufacturers can work towards. They said this well, and so that they said that if we can move towards a standard that's comprehensive, that's adopted by the vast majority of North America, that makes it much easier. That was another statement that they made.

I like the report. We're working towards addressing the issues and concerns–the recommendation report–and there will be future developments and, as the U.S. has said, they're moving towards things like this and they want to continue to move forward in that regard.

Mr. Cullen: I guess, specifically, there's reference to pre-1995 vehicles, and there's talk about those vehicles, I guess, that have been taken in by MPI. One of the recommendations is to use those vehicles for parts only. Is that something the government is going to be looking at? The other option, too, was there was some discussion about not being able to import into the province vehicles manufactured before 1995. Is the Province thinking of moving ahead on that as well?

Mr. Rondeau: There are two parts to this. First, we will look at all the recommendations this board made. We'll see what we can do as far as retirement programs, and that's basically older vehicles that could consume more fuel and create more greenhouse gases. As I understand it, as a vehicle gets older, it generally uses more fuel, and pre-1995, in general, and not specific, pollute a little bit more–in general, not in every specific case. So we want to look at the recommendation from the committee on that regard, but there's also the part of legislation we've already added.

Part of the legislation we did in the climate change was that we were moving forward with preventing pre-1995 being imported into the province for resale. Now, that meant retailers couldn't bring in pre-1995 vehicles and resell them. Individuals could bring in vintage or collectible cars or vehicles. We weren't going to prevent people who are bringing in a 1935 car or a car that has very good value in here. We want to make sure people are allowed to import individual cars, especially if they're collectors, so the legislation has that provision. But we want to look at all the recommendations of the board and make sure that we see what we can implement to make change.

Mr. Cullen: Well, it sounds like things are still pretty vague. I guess there's going to be more to follow, I guess, and we'll just have to wait and see how that materializes.

The Province did have a rebate on hybrid vehicles. My understanding is that is no longer available. Is there anything the minister is considering on that side?

Mr. Rondeau: Currently, the hybrid rebate is in existence and is being paid.

Mr. Cullen: I'm sorry, you said the program is still in existence?

Mr. Rondeau: Yes, it's currently still in existence.

***** (14:50)

Mr. Cullen: In reference to Bill 15 here, there was the–and maybe what the minister could do, I guess, first of all, is indicate–or at least some time in the near future, let me know which parts of The Climate Change and Emissions Reductions Act have been proclaimed or if there's anything in there that has not been proclaimed.

Mr. Rondeau: Sure, we'll get that to you with the package of materials.

Mr. Cullen: In the legislation there was, under coal phase out: after December 31, Manitoba Hydro must not use coal to generate power except to support emergency operations. Is that still on line as far as you're concerned?

The second part to that is there's no definition of emergency operation. So has your department put together a definition of emergency operations in respect to Manitoba Hydro?

Mr. Rondeau: Madam Chair, I'd like to inform the member opposite the process is unfolding as anticipated on schedule. We've been working with Manitoba Hydro to develop the regulations, the definitions and move this whole project forward.

Mr. Cullen: Okay. I appreciate the minister's response there.

The other issue that was discussed in the legislation was a coal tax, a tax on coal to try to limit the use. Has the Province implemented that or can you tell me if there's a time line for that potential coal tax to come into effect, and how much that particular tax would be?

Mr. Rondeau: The coal tax is anticipated to be $10 a tonne. It will be effective in 2010-2011. It's part of that budget, and the Department of Finance will bring forward the regulations and all that in due course. So you could ask the Minister of Finance (Mr. Selinger) next year on this.

Now, the purpose–we announced a 2010-11 tax last year, or this year, was because we wanted to make sure that people understood what was happening, and wanted to move forward on alternatives. So I can let the member know my department is working with people who currently use coal to come up with use of biomass or other sources. So what we're trying to do is look for alternatives. So we're trying to use green fuels. An example would be taking straw or flax sheaves, compressing them and being able to burn them instead of coal, which is a green fuel, and which would displace coal.

Just for the record, the tax would be effective in 2011. But we announced it early, and we announced it early so that people could take advantage of some of the incentives Hydro has put out there and, also, some of the things that we're trying to do so that people would be able to move off. It's hopeful that we don't collect any money on this tax. We're, hopefully, looking at people coming up with biomass and other options. I know that we've been working with companies to bring densifiers to the province, and to do experiments with flax and other material that we could use–called biomass–to displace coal.

Mr. Cullen: So the tax, then, as you see it, would be a fee up front, like a point of sale. I guess the question I have–I know a lot of our coal is imported from Saskatchewan, so how is the minister going to be able to tax that?

Mr. Rondeau: Finance will determine the process as it goes on. It's going to be part of the 2011 budget. What we wanted to do is make sure that we were fair to people, to sort of say this is what's coming. We're going to provide incentives now to use more green alternatives so people can get into biomass or other sources. This is an interesting process because usually you announce a tax as it comes in and, then, it just comes in. What we wanted to do is say, listen, we want to help support people with alternatives now, to convert now. What we would do is put this tax in the future and, hopefully, by announcing a tax this year, for 2011, people can make the changes necessary and we don't have to collect the tax. But the details of the tax will be worked out through Finance and will be presented to this House.

Mr. Cullen: Another point in this legislation was the plan to mitigate landfill emissions. I know the City of Brandon is working with or has had tenders from a number of companies that were interested in capturing emissions from the landfill there. I think it certainly can be a very worthwhile project. I know a number of the American states are doing it, and they're generating electricity from their landfill and it's proven to be very effective.

Also, what a lot of companies are able to do, or cities are able to do, is generate carbon credits through that process. I'm wondering if the minister is aware if that particular process is going to be available here in Manitoba, where, say for instance, the City of Brandon, by working with a private company, if that private company or the City of Brandon would be able to participate in the carbon credit trading.

Mr. Rondeau: I can inform the member opposite that we've been working with Brandon, the City of Winnipeg and other major landfill centres to discuss the capture of landfill gases. Landfill gases have a huge effect on the greenhouse gases. They're 16 times more potent than regular. It has to do with the methane gas. So what we want to do is work with the municipalities to capture and make sure that we're not letting this methane gas, which is 16 times more powerful than CO_2, actually get out into the atmosphere because it does make a big difference.

So, Madam Chair, we're working with Brandon, City of Winnipeg and other large landfills to do this. We want to capture entire credits. Because it's legislated, that's where we're going to go; we're going to capture, retire and meet our targets. After we've reached our targets, some companies, some groups, may look at ways of mitigating greenhouse gases and selling them. There will be a market in the future for some enterprises. I can't predict the future. I do know that as part of our strategy in the climate change bill, we want to move forward on capturing the greenhouse gases, retiring them, putting it against our target of three megatonnes. If we do this with Brandon, the City of Winnipeg, et cetera, on some of the major landfills, that's a huge component to our greenhouse gas reduction strategy.

***** (15:00)

Mr. Cullen: My question was specific about carbon credits. My question is, does the legislation that you have in place now regarding greenhouse gas emissions on landfills, does that legislation preclude a company from now trading those carbon credits that have been captured from landfills?

Mr. Rondeau: It's our plan to capture and retire those credits against our greenhouse gas reduction targets, against the government's greenhouse gas targets.

Mr. Cullen: Well, I don't want to put words in the minister's mouth, but what I think he is saying is that this legislation now precludes companies from trading those credits. Is that what the minister's saying?

Mr. Rondeau: To achieve our targets, we would have to capture the greenhouse gases from these disposal sites and retire them and not trade them, put them on the market.

Mr. Cullen: So I am hearing you say that no, you can't trade those carbon credits on the market. Is that what the minister's telling me?

Mr. Rondeau: I'd offer the member a briefing on how you can capture and retire the credits. It's part of our plan to take these credits that are being decreased from the greenhouse gases from the refuse sites. It's our plan to take those, capture them and retire the credits so that they're not part of the open market.

We also have got a Web site up and running which was developed by my branch, the Canadian Standards Association and other partners which is talking about how individuals can take action, where they can actually capture, record and then eventually maybe trade on the open market. It is the government's intention to capture the greenhouse gases from these sites and retire them against the climate change actions in our plan. Right now it's part of our plan to capture and retire them and not sell them on the open market.

Mr. Cullen: I will follow up directly with the minister on that just for clarification, but I think what he's done, or what the department has done with this legislation has precluded any private company that wants to come and do business in Manitoba the opportunity to do what's environmentally right, and, secondly of all, to actually generate some income from that by doing what's right. So by doing what's publicly perceived as doing the right thing in legislation, may not, in fact, in big picture, be helping the environment because we haven't seen any move on Brady Landfill in terms of catching gas. But if the opportunity was there to look at recovering some dollars with carbon credits, we know the carbon credits are going to increase in value. That's certainly the suggestion once everything comes into place. So I'm just wondering why the minister would preclude the opportunity for entrepreneurs to make money.

Mr. Rondeau: Madam Chair, one of the things we have is, we have a plan that is moving forward to reduce about three megatonnes. The things that are in our plan–it's a public document, it's on the Web site–it has lots of opportunity to reduce greenhouse gases.

There's a difference between the greenhouse gases that we're going to take. We're going to help work with different groups and put them and retire the credits and actually move forward and take the credits out because you don't want to take the credits and double count them. One of the things we found out is the whole greenhouse gas exchanges, we wanted to make sure that we have a process where we legitimately take, capture and retire three megatonnes. We don't want them to be double counted.

There are huge opportunities for entrepreneurs to come in and work in areas that we haven't prescribed in legislation or regulations, Madam Chair. There's huge opportunities for entrepreneurs to work in sites that the government doesn't have in its specific plan. We want to have entrepreneurs come to us and look at options. We're very open to work a new partnership with people who have ideas on how to reduce greenhouse gases and make some money and create jobs, because, as we mentioned before, we believe that being environmentally green can create economic activity. So if an entrepreneur comes to us with an idea on (a) moving forward with a project and (b) making money on it and (c) cutting greenhouse gases, we would definitely listen to him or her and we would also try to work with them.

However, if we have as part of our plan or part of our legislation, that we're going to retire certain credits, because if we legislate it or regulate it, then we cannot sell it; we have to retire it. So that's part of the WCI, that's part of the agreements that are being developed nationally, that if we regulate it, then we own the credits and we retire the credits.

If, and there will be lots of areas for entrepreneurs to work in, they want to go in and do other areas that we haven't regulated or we haven't legislated, not only are we welcoming them to do that, we encourage them to do that. We will actually help facilitate some of their actions. So that's where we want to go.

An example of where we could go are wind farms. They're very, very green, and in the case of the wind farms, Hydro is open to use the credits in any way to allow the best deal on power.

***** (15:10)

Another example is geothermal heat pumps. If I wanted to go and get all those people–in some cases, if they've gotten subsidies, they've sold the credits. In other cases, people have an opportunity to sell my credits. So, if I wanted to take the four tonnes of credit that I have in my house because of my geothermal heat pump and sell them on the open market, I could do that and get my $16 this year.

But these are all opportunities in the future. I wanted to let the member know that we'd encourage third party entrepreneurs to come into areas that we haven't regulated or legislated.

Mr. Cullen: Well, this isn't a thing of the future; it's happening now. Just read one report here, the Chicago trading index traded 69.2 million metric tonnes of CO_2 emissions. That was in 2008. That's increased 363 percent from 2007.

Now, we've got people and companies involved in signing up agriculture producers for carbon credits. Quite frankly, it can be pretty substantial. I just read an article where one company paid $20 million on contracts to 2,100 farmers between 2003 and 2006. So obviously those figures last year would certainly be more significant than that. Some of these farmers are Manitoba producers, and there's people out there now trying to sign up these producers for aggregators to turn around and do some carbon trading.

So, I think we, as a province certainly have to move this forward. I know we're involved with the Western Climate Initiative. How soon are we, as a group, going to be organized so that we can actually say, here's the process, here's the way we think it's going to work and Manitobans have a crystal clear market to go to?

Mr. Rondeau: I agree with the member opposite fully. I think that there's a huge opportunity for not only ag and forestry, but ag and forestry are two huge areas that they could get credits. There's others: energy efficiency. There's other companies, manufacturing companies that also may have huge opportunities here to produce offsets and be able to acquire credits and sell them.

Now, we've done one thing that's very, very interesting is because we know that this is an evolving industry. We know that at times, people weren't sure whether the credits were real, whether they were sold one time or 10 times. So, what we did is we worked with the Canadian Standards Association and other partners to develop a green registry. What this green registry does is it's–and I'd encourage the member opposite to go to it because it basically gives the person who has got this idea or what they want to do, they then can go to the Web site, sort of put in what they've done and get an example of how many tonnes of greenhouse gases they actually have.

It's the first step of understanding what you can do to mitigate your greenhouse gases. It's the first step that actually counts greenhouse gas reductions, verifies them and sort of says, okay, this is your number. This is how many greenhouse gases you are eliminating. Then, when you sell them, you're actually selling something that's counted and verified. Then, hopefully, down the road people will be able to aggregate these and sell them and these will have real value because it's no longer the wild, wild west.

We actually work with the Canadian Standards Association to make sure that these are real credits, they're sold once, they're counted once and they're verified. So, we've actually got that Web site up and running. I'd encourage you to go. If you have suggestions about it, we'd be happy to work with you on some of your suggestions.

But, yes, there will be huge opportunities to trade. The how and where and what and when is evolving. With Obama being the President of the United States, things have been moving very quickly. As part of the Western Climate Initiative, we've worked with a number of people, former governors, et cetera, that are moving forward on this file. So we believe that the rules on trading–we've been at the table for a few years, about five years now, and what we want to do is, we want to be there to talk about how the rules are established, what's counted, what can be retired, how they're retired. We've been there and we dealt with this. So we're happy that we've been at the table. We think it's a huge opportunity and I fully agree with the member opposite that this is a huge economic opportunity for Manitobans, because they get it. The first step is the green registry which is up and running and is available now.

Mr. Cullen: Okay, just so I'm kind of clear on where the minister is headed here, Manitobans will be signing up on the registry and this way the Province can monitor how many greenhouse gases are saved. Ultimately we're going to be able to put a figure on that, tonnage-wise. So then the Province will use that figure in terms of reducing–this is the amount of greenhouse gas that we've reduced as a province, and then will the Province take those numbers, whatever value that is, and then sell that on the market? Is that how this is going to work?

Mr. Rondeau: The registry is not meant to count what government's doing. We actually have a plan where we're going to actually take actions ourselves, capture greenhouse gases, like from landfills, and retire them. That's part of the government plan.

Separate from that, individuals can take actions. So what this Web site's done is it's allowing individuals to register, verify and sell on their own, their greenhouse gas reductions. Of course, it does affect the amount of greenhouse gases Manitoba emits but what we are going to do is we're going to reduce our greenhouse gases by 3.1 megatonnes to get down to Kyoto, which is 6 percent below 1990 levels, which we legislated.

Mr. Cullen: Bill 30, the bill that says we're not paying down our debt, part 14 of the bill relates to The Waste Reduction and Prevention Act and the wording is pretty vague here but maybe the minister can try to explain to me how he thinks this amendment to The Waste Reduction and Prevention Act is going to work so I have an understanding of–I understand we're going to be taxing garbage, if you will.

Could the minister fill me in on the process, how this is going to work and how it's going to improve the recycling in the province? I know we've got a long way to go in terms of improving our recycling here in the province. So if the minister can tell me how the process works and how it's going to improve–how it's going to get less garbage in the landfill, and how it may improve our recycling here in the province?

***** (15:20)

Mr. Rondeau: This part of the bill is adding garbage tax of $10 a tonne, details of which are being worked out through Finance and IGA, et cetera. It's the intention of this part of the bill to collect the tax and utilize or enhance recycling activities in the province, enhance waste recovery by using this fund to improve what's happening as far as recycling.

So we're going to charge tax on the garbage. The municipalities will continue to work with our government and my department and IGA to enhance recoveries. And so it's meant to help provide financial assistance to municipalities, to fund recycling activities and increase our numbers. Examples that we've done in the past are we want to continue to work with our partners as far as the e-waste recovery, and we did a very good job of collecting almost a million kilograms of e-waste in the last couple of years, getting more deposits, longer hours, et cetera. We just worked with our partners to do a phone and small electronics pick-up, but what we want to do is take this revenue and work to enhance recovery and thus have less unwanted items go into the landfill.

Mr. Cullen: Who's going to be paying the tax? Is it municipal corporations that are going to be paying the tax for how much garbage goes into their landfill? Is that how the system's going to work? The Province is going to bill the municipality for it and then collect the money and then turn around and give it back to the municipalities for a recycling program?

Mr. Rondeau: The departments of Finance and Intergovernmental Affairs are going to be working through the details with the municipalities, et cetera, to make it an effective system. As far as the usage of the revenue, we want to enhance the recyclable system and the amount that's recycled. Although we pay 80 percent of the bill for the recycling, which is the highest, I understand, in Canada, so our share is 80 percent, municipalities 20 percent, we think it's really important to divert unwanted products into the landfills, so we've gone out and worked previously on things like composting programs with the City of Winnipeg and others. We've worked on e-waste collection and other things, and we want to continue to enhance the recoveries.

I know that Conservation's been working on other printed paper and packaging regulations. That's part of their efforts. We want to continue to work on diverting waste into landfills, and we think by having this revenue source and working with the municipal governments, we can actually increase the amounts that are diverted from landfills.

Mr. Cullen: Well, I'm certainly interested to see how this is going to work. I guess time will tell how that plays itself out.

Just changing gears here, there's been very little discussion lately about wind farms in Manitoba, wind energy production. It sounds like it's kind of fallen off the radar, and I know the Province has made a commitment to increase wind energy production here in Manitoba, and, clearly, as the price of hydroelectricity goes up, I think the economics of wind farm production started looking better and better all the time. It was our understanding that there was going to be a wind farm in St. Joseph, but we haven't heard anything about that for several months. I just wonder if the minister can advise us where that particular wind farm development's at.

Mr. Rondeau: Madam Chair, the issues between Babcock & Brown and Hydro have been moving forward, and we have got the St. Leon wind farm up and running, the 99 meg wind farm. We have announced that Babcock & Brown and Hydro are working together to finalize all the issues.

One of the issues is a financial issue; trying to borrow money, move projects forward, and this economic time has been complex. It has been a large issue. But, so far, the project is on track for 2011 in-service date.

However, there are issues, as far as trying to get the project financed, move forward and get a very complex and, I understand, one of the largest wind farms in North America, up and running is an interesting complex issue.

I'd like to let the member know that our government is committed to wind, and we are committed to green energy projects. We will continue to build dams. I know that we believe in building dams. We believe in expanding hydro. We believe in wind farms. In fact, we just announced, just a little while ago, assistance for solar walls, and we have assistance for geothermal programs.

So, we do believe energy has a huge benefit, and we will continue to work with partners to try to develop all green energy sources that we can because we believe that it is truly a feather in our cap and a huge potential in the future.

Mr. Cullen: I know Obama is certainly making waves in the United States in terms of some of the announcements he's been making, Madam Chair. He seems to be keen on alternative fuel sources. I know he mentioned here, the last couple weeks, that wind power can generate 20 percent of the country's electricity needs by 2030 and would add 250,000 jobs. So he's certainly keen on the prospect of that.

Are the Province and Manitoba Hydro committed to the St. Joseph's project, or is there potential for another RFP process, or is that kind of where we're at right now?

Mr. Rondeau: I'll try to answer your question and refer the member to the standing committee for Hydro, if you have further questions.

But, I understand Babcock & Brown and Hydro are committed to the project and are working very much toward the 2011 in-service date. We've also made a commitment, public commitment, as a party, to 1,000 megs of wind, which would be about 20 percent of our current capacity.

The other thing I'm pleased is that President Obama is talking about green, meaning environment creating green, which is jobs. It was interesting, in his second speech, he talked about demand-energy projects, which is energy savings, as being a huge driver; like getting energy efficiency, insulation and home renovations. It was a wonderful speech. I was at the Y and I was cheering for him because I thought it was great, because he talked about ethanol and biodiesel being used as economic drivers and green things. He talked about demand-side energy efficiency. Again, the same thing. He talked about new energy sources. He mentioned wind. I believe he also mentioned geothermal.

***** (15:30)

I think that what he's doing is saying that by changing the economics, by changing green, you can create economic activity, and this government has been saying exactly the same thing for five years. It's interesting to note that some of the major names in the field have said that it's important to be early adopters, because if you're early adopters of technology, of green manufacturing, et cetera, like geothermal, then we can sell that production to the world.

By the way, we have two manufacturing plants. We have a training course. We have all that nailed, and we are exporting geothermal technology through many countries in the world. So, that's a perfect example. Now, we have a head start in the U.S., and we're working very hard to move some of these initiatives forward. I believe that it's the right strategy, and I'm glad that Obama is following Manitoba's lead.

Mr. Cullen: Madam Chair, I don't know if the minister has had any discussion with Elton Energy, a group just outside of Brandon. They were certainly interested in the concept of having community wind. I know they're certainly interested. I imagine they've had a proposal to the minister. They're looking at wind production on a relatively smaller scale, where the community can get involved and some of the profits could go back to the community. I'd just like to get the minister's comment on Elton Energy, in particular, and, I guess, in general terms, some of the other opportunities that might be there to generate power on a smaller community base.

Mr. Rondeau: Madam Chair, we've been in regular contact with Elton Energy and a number of other organizations or people who are interested in wind energy. The member might know that we–during the expression of interest, there were multiple people that expressed interest in participating in the wind RFP.

Not only that, but we've had many, many people and organizations contact my branch. They've been very busy in responding to different inquiries, and I anticipate because this is a growing industry, the inquiries will continue. Our dialogue will continue, and we'll try to roll out further wind projects with Hydro in due course.

What's nice about it is that people are excited about this industry, as I am, as the member opposite is, and I think what we want to do is help facilitate that. I'd like to compliment the staff at the branch because, although it's a smaller part of the branch, they're very, very active and very responsive to the inquiries.

Mr. Cullen: I think we have to view this energy development in broad terms. I don't think we have to think narrowly that it has to be a wind necessarily. I think there are other opportunities out there. I've visited some hog barns where they're doing some innovative things where they can generate electricity from the gas and clean up the waste water, if you will. It's very effective, and I just think we should be doing more to try to get those types operations off the ground.

I think, you know, if there's a will by government to get the job done and there's a willingness by Hydro to purchase that electricity at a reasonable rate, I think we should be looking at that. It's a tremendous economic opportunity for rural Manitoba.

Mr. Rondeau: I agree with the member opposite. There are all sorts of opportunities in different sectors. An example was the solar air heating potential. We just announced the GTEC, which is basically a tax credit to have solar heat used in hog barns. There are other options, and what we want to do is, as more and more options come around, as the technology changes, we want to work with companies to utilize the technology and utilize things like tax credits.

An example was the GTEC applicable to geothermal–which is a good industry in Manitoba and very well adopted. So now, we have expanded just recently, we were talking about the solar air heating. I was at, I think it was Assiniboine Credit Union, and they had a great little solar wall and it worked great. We talked about the importance of the return on investment and the GTEC on that Manitoba technology, Manitoba utilized and manufactured. Parts of those components, they were in process and they are now utilized or can utilize the tax credit, the green energy tax credit.

So I agree with the member. There are lots of things coming down. We're going to continue to work with industries and individuals who come up with ideas and there are lots of opportunities. We'll try things. We'll try to work forward to save energy and save money and reduce greenhouse gases.

Mr. Cullen: I appreciate where the minister's going here and I do know there are some tax credits for different things out there, but I think if the private sector is going to get involved in this, they would like to see some incentive financially besides just a tax credit. Like if they knew that they were going to generate electricity–by whatever means it is–and they knew they were going to get paid so much a kilowatt at the end of the day, it's pretty straightforward, pretty neat and tidy and clean. You just put it through the meter and the meter tells you how much electricity you're generating and, at the end of the day, here's your cheque for generating. Manitoba Hydro can take that electricity, turn around and sell it and hopefully everybody makes a little bit of money at the end of the day.

Mr. Rondeau: Actually, Hydro has a reverse metering policy, which means that people can eliminate their whole Hydro bill and actually get paid from Hydro if they have some projects that create electricity. That's in place now. It's in policy now. If a person wants to get a windmill, put it up on their farm, first they can eliminate their entire energy bill and then they get paid from Hydro.

There are some rules on connectivity, et cetera, but that policy is in place now and I would encourage people–I hope my neighbour doesn't put in a big wind tower, but beyond that, people can put in–they have to follow normal municipal by-laws; they have to follow normal practices. We hope that they work with others and Hydro to make sure that the connectivity is appropriate. What we want to do is encourage people to talk to our department and we will help facilitate these things with Hydro to see how they can integrate to the grid and get free electricity or maybe make some money.

Mr. Cullen: Other jurisdictions have gone so far as to implement feed-in tariffs so that there's an actual structure of what an individual or a company would get paid based on however they're producing it, so solar would be a certain rate, methane recovery could be a certain rate, wind energy would be a certain rate. Just wondering if the minister or the department has considered going so far as to establish a feed-in tariff and structure such as that.

Mr. Rondeau: If the member opposite would like to suggest one that the Conservative Party would adopt and like to suggest that we implement, I'd be open to receiving a written copy of what your policy would be. Right now, we have a policy of net metering which means you pay off the bill and then sell at a specific prescribed price to Manitoba Hydro.

***** (15:40)

Mr. Cullen: Well, talking about electricity, how about nuclear energy? We know there's certainly a demand for energy in Ontario and a growing demand in Saskatchewan. Those provinces are all talking about nuclear energy. It certainly sounds like Saskatchewan is really gung-ho and having some very positive discussions, I understand, looking at a fairly sizable facility somewhere in Saskatchewan.

So I just want to get the view from the minister. Is that an opportunity for us here in Manitoba or does he see that as a bit of a threat to Manitoba?

Mr. Rondeau: The member might know, right now, we're working on Keeyask, Conawapa and other dams, Wuskwatim. What we want to do is we want to develop those dams. Dams are very cost-effective because you build them. If the member has ever been to Norway House, I had the opportunity to live in Norway House for three years. You notice that these dams are rock, made of granite; they're miles long and they're there for a long time. So you make the investment; you get a huge return. So we believe in the hydro dams. We have three planned which, again, will be utilized for export sales, which is great revenue, which is wonderful.

We also have one wind farm. We're working on the second wind farm and others are going to be proceeding as time goes on, Madam Chair. We also have demand-side energy efficiency programs. So we are exporting a lot of electricity. We continue to build dams. We continue to work on wind farms. We want to do this. So that's where we want to go right now.

Other jurisdictions might not have the hydro potential we have. We have a huge hydro potential. I know when I talk to the energy ministers in Alberta and Saskatchewan, often, they comment on our huge potential and what we have. We're already exporting tonnes of electricity. Well, I guess it's not measured in tonnes. We export lots of electricity.

We believe that's a positive step. Already we are working to put strategic investments in that are paid back by export sales, that are paid back by consumers, generally, in other states or provinces. We're working with other states and provinces to improve connectivity and improve transmission lines. What we want to do is actually have it so that we have opportunities in the future.

Now we have chosen to go solar and wind and energy efficiency. That's our choice. Other governments might choose to do other things. We believe that we have a very green energy plan, and it seems to be resonating with a lot of people because they're saying that our plan makes sense. So that's where we're headed right now.

Mr. Cullen: Well, the minister made reference to a grid. Obviously, Bipole III is certainly the next one on the radar. Where do we have to go next in terms of a grid, though? If we're going to be exporting, what has to happen next? Are we looking at a line south, east, west? From your department's perspective, what has to happen next?

Mr. Rondeau: Although that's a question for Hydro, I can say that we're always looking at export opportunities wherever we can get good money, I understand, from hydro.

Mr. Cullen: Okay, I see we're not going to get too far down the line on this one. Mr. Obama just announced some pretty major undertakings in the ethanol side of things. He's certainly hanging his hat on ethanol and possibly new ways to produce ethanol. Where are we at here in terms of our mandate, and is there room for expansion here in the province in terms of the ethanol industry?

Mr. Rondeau: Madam Chair, the ethanol mandate has been 8.5 percent of the pool average that's been implemented. So, right now, 8.5 percent of the pool average is ethanol.

We're working towards a biodiesel mandate. We have been very active on both files to (a) create economic activity, (b) greenhouse gases, and (c) to make sure that we actually have people employed in Manitoba here. So we have been working on those.

Of course, there are always opportunities for expansion, depending on people's cost benefit analysis, what they want to do to invest, et cetera. Again, the department has been very proactive and responsive to people's concerns and interests in this area. It's an area that does get good greenhouse gas reductions and does reduce the dependency on fossil fuels.

Mr. Cullen: So you're saying that we are meeting our mandate? If so, is there a report that the department puts out on an annual basis, just so we know the facts and figures and the production and all that?

Mr. Rondeau: Madam Chair, I'd like to let the member know that we've been on 8.5 percent pool average for a while now. At first, it was just a 5 percent pool average working with the companies to implement it. We can get all the details together and send him the information on this, if you wish. Basically, we worked with the industry to do an 8.5 percent pool average because then it's easier for them to work with the mandate. As we put in the mandate, we wanted to make sure that we were working with the companies to do an achievable target and implement it in a very effective manner.

I'm pleased to say that the work of the staff with working with the companies did a very good implementation. In fact, it was so smooth no one took any notice of it, except we do have the report on how much ethanol is being used and we do have the 8.5 percent pool average now.

Mr. David Faurschou (Portage la Prairie): Madam Chairperson, I appreciate the opportunity to ask the minister a couple of questions as it pertains to recycling.

I know it was mentioned by the honourable minister that when I brought forward a private member's resolution regarding a deposit return system in Manitoba, being that Manitoba is the only jurisdiction in Canada that does not have that type of regime in place for beverage containers outside of that of beer bottles, and the minister's response said that it was coming and to just be patient. I'm wondering when that program is going to be coming forward and how the minister envisions the program working.

***** (15:50)

Mr. Rondeau: I'd like to thank the member for the question. I'd like to let the member know, through you, Madam Chair, that the multimaterial product stewardship initiative is moving forward. The regulations have been approved and moving forward. It's taken from the current government-funded central system to an industry-led program that has targets for recovery rates and the government will continue to work with the industry to ensure that we are achieving these targets and moving forward on the whole recovery.

Letting the member know that this is an interesting topic because just yesterday or the day before the Minister for Conservation (Mr. Struthers) was talking about an industry-led initiative to recycle and dispose of cellphones and BlackBerrys and other hand-held devices. So this is coming where more and more the industry is leading the retirement and the appropriate disposal of these commodities, whether it's bottles or whether it's cellphones or whatever. The printed paper and packaging regulations have been approved. They're moving out and discussions are happening with industry as we speak.

Mr. Faurschou: Well, then, is it the fact that the government is going to provide for enabling legislation whereby the industry can make a surcharge collection, if I'm using the correct terminology? There's an environmental levy currently collected by the government already on pop bottles. Is this money that is collected by government currently, is it going over to the industry organization that you speak of so that they can use those resources in order to facilitate the program of which he speaks?

Mr. Rondeau: Within the next six months the industry is building a business plan looking at the regulations that have been developed and published and are public now. The Minister of Conservation (Mr. Struthers) will review the business plan, work with the industry-led consortium on how the industry will fund it. There are some programs currently that don't have a fee. I just mentioned that there is the cellphone and personal electronic device, BlackBerry, et cetera, that is totally industry funded, so they have taken it upon themselves to be good stewards of the environment.

So they actually even have it where you can go to the Web site, which I did, and print off an address label that's prepaid that you can actually mail in at no cost and then your old cellphone gets disposed of appropriately and isn't landfilled. So there are a lot of models, but right now the industry-led consortium in each case will look after it, will develop a business plan, and develop a plan on how to dispose and collect these items, and then move it forward. They all have targets, and the Minister of Conservation will be dealing with the industry so he can go into more details with you on that.

Mr. Faurschou: Where I was going with this is just to have the minister's assurance that the monies collected by government currently that go into the Manitoba Product Stewardship Corporation at the present time, are they then still going to be collected and made available to the new entity? It's something that is always questionable with change as to whether or not the government's going to still keep collecting the money and it won't pass the monies on. So I'm looking for the minister's assurance that whatever resources that are being paid into the government and currently passed on to the Manitoba Product Stewardship Corporation will continue to do so.

Mr. Rondeau: These regulations will be moving forward. They have moved forward as far as the printed paper and packaging. They will supersede what's currently there, and the business plan that the industry will come up with will have financial arrangements and suggestions and comments and then financial decisions will be made from there.

Again, it's not my purview to talk about the levy. We in Green Manitoba are responsible for trying to enhance the collection and diversion of items out of the waste stream, so we'd be involved in the electronic waste pickups; we'd be involved in other activities, but we really wouldn't be involved in the regulation of the industry. That's the Minister of Conservation (Mr. Struthers) and I'd have to respectfully say the business plan's approved by the Minister of Conservation, not this department, although we are in dialogue with them because Green Manitoba is trying to divert waste from landfills. So we have that as part of our mandate. The regulation is with the Minister of Conservation and the business plans are approved by the Minister of Conservation. I don't approve them.

Mr. Faurschou: Well for me it's confusing insofar as you're responsible for the regulation, then he's responsible for the implementation, a colleague of his, and you keep on going around this merry-go-round and ultimately nothing happens.

So, anyway, I do want to, as a–pardon the pun–wrap-up question on recycling: Is the department looking at contingency plans to be able to wrap up the operations that are currently under way in recycling? This current situation, and I'm sure the minister is appreciative of, is very grave. Much of what is being collected in the blue box, green box programs throughout the province is going directly into storage, and if the minister is not aware of that, he could call up any recycling corporation that is active in the province and he'll be well informed by that call. So if the minister is wanting this program to go over to industry, and right now the government is responsible for current activity, it is incumbent upon government to make sure that they're going to pick up the mess that is currently in building, and I would like to ask the minister to give that assurance to the corporations engaged in recycling here in the province of Manitoba currently.

***** (16:00)

Mr. Rondeau: Madam Chair, I'd like to thank the member for the question. Here's the transition. The current program is under the purview of the Minister of Conservation (Mr. Struthers) and the Conservation Department. The transition to the new program and writing the regulations, the discussion on the regulations, is the purview of the Minister of Conservation.

The current program and the new program are under the Minister of Conservation so that's that minister's area of responsibility. The plan, the new programs, as they're transferred from the current to the new system will now, and the implementation and some of that, now goes to the department, Green Manitoba, et cetera. The current program, Conservation, the transition, Conservation, when it goes to an industry-led model, which we're moving towards, it's going to go more to this department. It will be an industry-led operation. It will have specific targets. It will have specific collections, but that doesn't mean that things like the blue box system are automatically wiped out. They might add to the blue box. They might utilize the blue box in Winnipeg in other areas. The interesting part is that there's already a tire stewardship program, there's already an oil program collecting used oil, motor oil, there's printed packaging and paper regulations that are out now, and there's others.

I explained the member the telephones, et cetera, the electronic waste we have been running because it's a program that we believe that's important to divert from landfill. So, we're running it, and a million kilograms is a lot that we collected in the last two years. Last year, it was about 660,000, about 700,000 kilograms. I might be off by a little bit because I'm using my memory, but basically we're moving from the two-cent levy on pop bottles to a new industry-led model that will come up with a business plan to the Minister of Conservation, the transition to the Minister of Conservation and the industry-led model that we then become involved in.

Mr. Cullen: Madam Chair, I want to just take the opportunity to thank the minister and his staff for the last couple of days and thanks for attempting to answer most of the questions. Thank you very much.

Ready to go line by line, Madam Chairperson.

Madam Chairperson: Is the committee ready to starting passing resolutions? *[Agreed]*

Resolution 18.2: RESOLVED that there be granted to Her Majesty a sum not exceeding $5,971,000 for Science, Technology, Energy and Mines, Energy, Climate Change and Green Strategy Initiatives, for the fiscal year ending March 31, 2010.

Resolution agreed to.

Resolution 18.3: RESOLVED that there be granted to Her Majesty a sum not exceeding $21,932,000 for Science, Technology, Energy and Mines, Science, Innovation and Business Development, for the fiscal year ending March 31, 2010.

Resolution agreed to.

Resolution 18.4: RESOLVED that there be granted to Her Majesty a sum not exceeding $33,286,000 for Science, Technology, Energy and Mines, Manitoba Information and Communication Technologies, for the fiscal year ending March 31, 2010.

Resolution agreed to.

Resolution 18.5: RESOLVED that there be granted to Her Majesty a sum not exceeding $12,055,000 for Science, Technology, Energy and Mines, Mineral Resources, for the fiscal year ending March 31, 2010.

Resolution agreed to.

Resolution 18.6: RESOLVED that there be granted to Her Majesty a sum not exceeding $8,555,000 for Science, Technology, Energy and Mines, Costs Related to Capital Assets, for the fiscal year ending March 31, 2010.

Resolution agreed to.

Resolution 18.7: RESOLVED that there be granted to Her Majesty a sum not exceeding $5,225,000 for Science, Technology, Energy and Mines, capital investment, for the fiscal year ending March 31, 2010.

Resolution agreed to.

The last item to be considered for the Estimates of the Department is item 1.(a) Minister's Salary, contained in Resolution 18.1.

The staff having left the Chamber, the floor is open for questions.

Resolution 18.1: RESOLVED that there be granted to Her Majesty a sum not exceeding $761,000 for Science, Technology, Energy and Mines, Administration and Finance, for the fiscal year ending March 31, 2010.

Resolution agreed to.

This concludes the Estimates for this Department. The next set of Estimates that will be considered by this section of the committee are the Estimates of Intergovernmental Affairs.

Shall we recess briefly to allow the minister and critic the opportunity to prepare for the commencement of the next set of Estimates? *[Agreed]*

Committee is in recess.

The committee recessed at 4:07 p.m.

The committee resumed at 4:15 p.m.

INTERGOVERNMENTAL AFFAIRS

Madam Chairperson (Bonnie Korzeniowski): Will the Committee of Supply please come to order. This section of the Committee of Supply will be considering the Estimates of the Department of Intergovernmental Affairs.

Does the honourable minister have an opening statement?

Hon. Steve Ashton (Minister of Intergovernmental Affairs): First of all, I want to indicate that during the consideration of Estimates we will obviously be dealing with issues related to the department and also to EMO, and what I wanted to suggest for consideration is that, if in fact we are in the Chamber and it's a bit difficult to circulate staff in and out, it might be appropriate if we can get some sort of indication in advance and make sure that the appropriate staff are available for the different components.

I do want to indicate that, in terms of Intergovernmental Affairs, I'm very proud of being minister of a department that probably has far greater impact on the lives of average Manitobans than most people realize. I'm very proud to be working with 198 municipalities in the province, have a very good partnership with those municipalities and with the Assembly of Manitoba Municipalities representing them.

I've always said that we are leaders in the country in many ways, and that's something that I know is echoed by our municipal leaders. We certainly have had a significant support to municipalities over the years. I have the numbers available if the critic is interested. I think it's been very noticeable, the increase, for example, to the City of Winnipeg; it's increased 66 percent since we came into government in 1999. We had a further 5.2 percent increase this past year, which is very significant. The 2009 provincial funding support will increase $4.5 million for other municipalities; that's 5.6 percent over 2008 levels.

The key element, of course, is the Building Manitoba Fund, the degree to which we share in growth revenues. I think that's been one of the most significant elements going back to the 1970s, the degree to which in Manitoba we do share with municipalities. That has had a very significant impact.

I do want to note the significance this past year of what we've been building on the last number of years in terms of transit funding. We reinstated the 50 percent share for transit funding for Winnipeg, Brandon, Thompson and Flin Flon. We also applied that both in legislation and in a direct funding announcement to rapid transit here in the city of Winnipeg. We consider that to be very significant.

We provide support for public safety, and I want to note this year the very significant new increase in funding for the Winnipeg ambulance services. I think it's important to note, by the way, that we are working toward the city's goal of having its share of EMS, cost 10 percent. I want to credit, by the way, the City of Winnipeg, also the firefighters. I met both with the fire chief, Jim Brennan, and with the firefighter union president, Alex Forrest, fairly early on in this, and met with Mayor Katz. They made a very compelling argument. I think it's important to note, by the way, the success of the combined fire-paramedic approach, which is providing excellent service to the city, and we are responding accordingly.

I want to note, by the way, the renewal of the Municipal Recreation Fund. We've already made a number of announcements in terms of municipal recreation and library facilities. That is extremely important, and we've worked with communities like Thompson, The Pas, Portage, Brandon and Arborg through the BMF funding.

We continue to focus in on infrastructure working with the Minister responsible for Infrastructure in the Department of MIT. I really want to say that we consider our investment in terms of municipal support to infrastructure to be very significant. There's almost $40 million in capital support that will flow to Winnipeg and, in fact, flowed early part of this year. We've accelerated funding for roads and bridges, part of our five-year, $125-million investment in transportation. That is very significant. If you combine that with a historic announcement of investment in rapid transit, you're seeing a tremendous commitment to infrastructure, and that's a commitment that's echoed throughout the province.

***** (16:20)

We're very proud of our work with communities across the province through Neighbourhoods Alive! It was expanded recently to Flin Flon, The Pas, Dauphin, Portage la Prairie and Selkirk. I want to indicate that we are having a tremendous amount of success in those communities, and we're already seeing some significant community-driven projects adding to the communities in Winnipeg and also in Brandon and Thompson that have been part of Neighbourhoods Alive! since 2000. We have been very much part of working towards economic development through the Winnipeg Partnership Agreement. I want to particularly note the excellent work that's been done in terms of the Aboriginal component. We're working with Brandon in terms of Renaissance Brandon, an excellent project that I think is visionary and one again that we support directly.

We are there in terms of the funding side, but we provide many other services. We're also focussed, obviously, on the tax affordability side. I want to note that we have seen a significant reduction in the net effect of property tax across the province. We've moved on the public education side, which I know members of the House will be aware of. We've increased our education property tax levy to $650 this year, and we'll be continuing to do that to $700. Very significantly, home-owners no longer play the ESL. We increased the Farmland School Tax Rebate this year, and we strengthened the tax incentive grant for school divisions. That's all important because obviously property taxes go to both municipal governments and to school boards, and we believe it's important to have a balanced approach.

We work with governments on their capacity. I want to note the excellent work that's been done by municipalities in terms of compliance with the PSAB, and I think it's very important to note the degree to which we are now working with municipalities on a review of provincial land use planning. We've seen some very significant challenges, but we think some significant progress in land use planning.

One of the key elements that we will be putting forward is redivision, particularly in rural and northern areas. I want to put on the record as minister that I believe that we have to ensure that our land use planning is helping ensure continued growth because there is growth in a number of areas in terms of rural population, but also to not only stop but to turn around the decline in other areas. So we have to make sure our land use policies are consistent with that.

We also have to ensure a sustainable land use planning. I want to note that there's been some significant progress there.

I just want to focus also very briefly on an area, and I'm sure that there'll be a number of questions during Estimates on, but obviously very much on people's minds, and that is in the EMO side. We did face some significant challenges this past year, particularly with the flooding that we have seen–I want to say, have seen–it's still receding in many parts of the province. We had a flood that was equivalent to the second highest in the last 100 years south of Winnipeg and north of Winnipeg. It was very much the flood of the century. I think it's important to note, by the way, that in 1950 a lesser flood resulted in a 107,000 Manitobans being evacuated and 10,000 homes being damaged. This year, much less damage, and it shows the value of our flood protection. We're going to be continuing to work on the flood protection at the recovery stage with the FA over the next period of time, and I would certainly welcome questions on that when we proceed to the question part of Estimates. Thank you.

Madam Chairperson: We thank the minister for those comments.

Does the official opposition critic, the honourable Member for Ste. Rose (Mr. Briese), have any opening statements?

Mr. Stuart Briese (Ste. Rose): Thank you, Madam Chairperson. Just a few opening comments. Obviously, from my background with municipalities and with the Association of Manitoba Municipalities, I have some understanding of how land use planning and any large number of the things that affect municipalities enter into this. I probably should do it at the end of the session, but I know the calibre of the staff that this minister has in his department and how good they are to work with over the years and still are. Even though I'm the critic here, I get very good co-operation out of them.

I heard the minister suggest that he would like somewhat of an indication of where we're going at certain times in this, and I would probably like to ask him what the breakdown is. That you want a separation of the EMO staff from the actual planning and municipal side of the staff, I presume, is what you're talking about, so I'll defer then. I know we're not going to have a great deal of time today, but EMO staff, then, I won't go with any questions on that today. Maybe at the end of the session we can take a look at where we may go with them. I do have a number of questions in that category. But, as for today, we won't touch on them. In fact, I think we'll only probably get through our openings.

I think that's all I need to say as an opening, so turn it back.

Madam Chairperson: We thank the critic for his remarks and, under Manitoba practice, debate on the minister's salary is traditionally the last item considered for a department in the Committee of Supply. Accordingly, we shall defer consideration of line item 1.(a) and proceed with consideration of the remaining items referenced in Resolution 1.

At this time, we invite the minister's staff to join us in the Chamber, and once they are seated, we will ask the minister to introduce the staff in attendance.

Mr. Ashton: Madam Chair, if I could introduce globally both the staff at the table and the staff that are available in the gallery and will be part of the Estimates consideration over the next whatever period of days. They are Linda McFadyen, Deputy Minister; Laurie Davidson, Assistant Deputy Minister, Provincial Municipal Support Services; Claudette Toupin, Assistant Deputy Minister, Community Planning and Development Division; Denise Carlyle, Executive Director, Municipal Finance and Advisory Services; Brian Johnston, Chief of Financial Services; Beverly Kachanoski, Manager, Human Resource Management Services; and Lee Spencer, Director of Recovery, Emergency Measures Organization.

Madam Chairperson: Does the committee wish to proceed through these Estimates in a chronological manner, or have a global discussion?

Mr. Ashton: I'm quite open to whatever suggestion the critic has, but we're certainly assuming that it will be global, with perhaps some separation between EMO and the department, just in terms of make sure we have the right staff available.

Mr. Briese: Yes, that's suitable for me.

Madam Chairperson: It is agreed to go global. The floor is now open for questions.

Mr. Briese: The first number of questions I'm going to ask are strictly, I think, basically internal questions and ones that we ask most years, I believe.

First off, I'd like to know how many staff actually work in the department and then, secondly, what your absence level is, like, what's the percentage of positions not filled?

Mr. Ashton: Full-time positions are 286.13, and in terms of current vacancies, that's if I could provide the information as of March 31–so as of March 31, 2009, the total vacancies were 18.3 FTs, that's a vacancy rate of 6.4 percent. Once again, the total FTs as of April 1, 2009, were 286.13 FTs. That includes regular and term, and if the member wishes a comparison, this compares total vacancies at March 31, 2008, of 19.2 regular FTs for a vacancy rate of 6.8 percent. So the vacancy rate is slightly lower than last year.

***** (16:30)

Mr. Briese: Can you give me a description of any positions that have been reclassified in the past year?

Mr. Ashton: Just to indicate there were eight positions reclassified in 2008-2009. That's six existing positions and two new positions that were actually classified, and there was a senior policy adviser, an administrative secretary in the deputy minister's office. I don't think the member wants the specific recalculations, but I'll maybe provide just a description of positions, and I can explain any of the details. Director of Recovery and director of emergency operations, the EMO office; policy planner in the Provincial Planning Services; administrative officer in the Municipal Board, and two neighbourhood planning project officers–these are two new positions in urban development. So, once again, there were a total of eight positions that were reclassified to varying, different levels in 2008-2009.

Mr. Briese: Have there been any positions relocated in the last year, for instance, from rural or northern Manitoba into Winnipeg or relocated in other directions, and why were they relocated?

Mr. Ashton: No.

Mr. Briese: Next question and this is on the minister's out-of-province travel. Has the minister taken part in any out-of-province trips in the last year, and what are the details on such trips?

Mr. Ashton: I attended the FCM back in 2008; that's May 29 to May 30. I also have been to Ottawa. Actually, I initially went to Ottawa in March to meet with Minister Van Loan in advance of the spring flooding that took place. I have since then met with Minister Van Loan, Minister Toews, and also met with Minister Strahl in Ottawa as a–I shouldn't say post-flood because we were still dealing with some flooding, but on flood recovery. Those are the three names over the past year.

Mr. Briese: Does the Intergovernmental Affairs Department have an annual advertising budget, and, if so, what is it?

Mr. Ashton: There is not a specific item in terms of advertising. Obviously, there would be–there are on occasion advertisements that are done. I can maybe undertake to try and pull that together, but there's not a specific line item for an advertising budget. Perhaps maybe by tomorrow at 10 o'clock, I'll certainly get a bit of a summary.

We do have AMM publications, probably the main aspect that's consistent on the advertising side, but if the member wishes, I can try and pull something together tomorrow with a bit more detail.

Mr. Briese: I'm a little more interested in possibly similar campaigns that maybe kind of run by the department–something like the budget ads that were run by the Department of Finance. If you do any of that in your department, or specifically, what kind of advertising do you do? I was aware you did the AMM, but whether there's more that comes through your department.

Mr. Ashton: We have done some public education through EMO, which is consistent with EMO's role not only in terms of response to disasters, but also in terms of public education. Again, I'll get some of that detail for the member tomorrow. Outside of AMM, we really–other than the occasional ads maybe related to specific meetings and processes that we have–don't have a specific advertising line item budget for the department per se.

Mr. Briese: I think I'll move on here. It appears to me that, when I go through the Estimates book, the budget for your department is down somewhat. I come up with about 11 percent. Is there a specific block of funding that was moved to another department, or am I accurate with that?

Mr. Ashton: The simple explanation is the fact that we advanced money to the City of Winnipeg as part of our funding commitment to the City of Winnipeg in the previous fiscal year. Of course, the City of Winnipeg has its own fiscal year, so whether it's transferred to the City in the previous or current fiscal year, it has the same net impact to the City and funding is up for the City. That was essentially the difference on the print over print, the degree to which we advanced funding to the City in the last fiscal year which will, of course, allow them to finance their activities through their fiscal year, which, I believe, is a different basis than ours.

Mr. Briese: So is that capital grants that are advanced, or what are the advances? What specifically are the advances?

Mr. Ashton: It was a mixture. Part of it was the roads funding, which is capital. There were some unconditional grants as well that were advanced to the City as well. Rapid transit was the other one again, which is capital, but it reflects accounting treatment that's similar to our 50 percent operating cost share that we have with the municipalities. So it was a combination of capital and regular grants that were cash-flowed to them. Of course, it won't impact their fiscal year, they have a different fiscal year. But that's the reason for the difference print over print. There's no actual difference in programming or level of support. It's just the year in which the support was spent, so it was actually advanced to the City in the previous fiscal year. That explains the difference in the print over print in the Estimates this year.

Mr. Briese: So that would translate, then, into the–financial assistance to municipalities appears to be down, but it's because of advances, then. Is that what I'm hearing?

Mr. Ashton: The total of advances to Winnipeg was $45 million, and that included 25 million. I'll give the specific numbers here for the member: for roads capital, 15 million unconditional; and 5 million for rapid transit. So the member's quite correct.

There's no reduction of program, no reduction in funding. What this simply reflects is our fiscal year in which the money was transferred to the City, and again–the member knows this from his municipal background–that fiscal years don't necessarily coincide between the Province and the municipalities. So that's really all it is. It's a cash flow from on our budget side; not only no reduction for the City, but the City actually is going to be receiving additional funding support this year, as I mentioned earlier, of 5.2 percent. I mentioned some of the specific components where we've actually increased funding. But this is simply a reflection of the cash flow.

Mr. Briese: Another thing I thought I picked up in here, in the Estimates book, was there appeared to be less funding for Provincial Planning Services. Is that true, and, if so, what is the reduction?

***** (16:40)

Mr. Ashton: Only difference year over year was a vacant position that was eliminated. The operating funding is the same. So there is no difference in actual provision of services; it really reflects a move on our part to indicate that vacant position was basically taken out of the FTE component. So nobody was laid off. There was no reduction in service, but that explains the difference.

Mr. Briese: I think I'm going to have to put in the earpiece here. I missed part of that answer.

It's a vacant position that's been cut. Is that what I was told?

Mr. Ashton: The dollar equivalent amount was taken out. The position was vacant to begin with. So that explains the difference in actual budgeted funding. It's a reflection of that vacant position that was basically eliminated.

Mr. Briese: Thank you for that answer. I have quite a number of questions I want to get in on the planning side, and I guess we'll probably start into some of them right now.

One of the curiosities I have is, how many of the municipal governments have actually filed their livestock operation policies?

Mr. Ashton: There are 28 that have been completed, and that means that they have livestock operation policies adopted in force. Under review, there are 38, and in that case that applies to municipalities that have drafted livestock operation policies. Some progress in another 27, but where the actual operating policy has not been drafted by the board or council. That's for a total of 93.

Mr. Briese: So I'm to understand that there are 93 that have either implemented or partially implemented their livestock policies in their development plans?

Mr. Ashton: I will just add the qualification that that's correct in case of the first 28 and 38 that I mentioned. I would probably describe the situation, the other 27 part of the 93, is that they've made some progress. Either they don't have a formal policy drafted or adopted. So 93 have made some progress or full progress.

Mr. Briese: There were extensions to the deadlines several times on that process, and I'm wondering why it still seems to be dragging along rather than being completed.

Mr. Ashton: Well, first of all, I want to stress that we're talking about the planning authority. So there are 93 planning authorities. It puts in context the degree to which you have, out of that number, already 66 that have a policy either drafted or a policy drafted and implemented. We did have the authority through the act to extend the deadline, and most municipalities and planning districts have formally requested that we give an extension to either June 30 of 2009 or January 1, 2010. That was, I think, appropriate given some of the complexities and some of the recent developments the last couple years. I would say that we are seeing significant progress. I wouldn't classify the extension of the deadlines as indicating anything other than the fact that we do understand the complexities of what we're dealing with here and the degree to which this is a policy that can have long-term and far-reaching implications in terms of the overall municipal planning.

So I would say we're making significant progress, even though there have been some extensions on the deadlines. We've had progress in all of planning authorities, and I fully anticipate that we will soon be in position where all of the nine authorities have a livestock-operation policy adopted and in force.

Mr. Briese: I thank the minister for the answer. One of my concerns–it looks to me like there's some provision in the proposed new waste-water regulations for that to have to be implemented into municipal development plans. We also have the provincial land-use policies under review, which once again will probably require fairly major changes to municipal planning.

I was chair of a planning district for probably 12 or 14 years–I'm not sure exactly how long–and I don't recall us ever having a series of major changes like we're seeing coming down the line now. It's very, very costly for the municipalities to implement and to do all the things necessary. I was involved in putting the livestock policy in place in our planning district; it took a lot of time and a lot of hearings and a lot of expense to get it into place. It almost seems like we're going to be in that kind of state of flux for quite some time coming where every time we get it rewritten, we're going to be opening up again and immediately rewriting it.

I'm wondering if the department is thinking of lending a little more assistance to planning districts with the major changes you're doing with legislation and with the provincial land-use policies or how–what's the expectation going to be on completion of all these additional things that are going to go in?

Mr. Ashton: I think it's important to know that, first of all, we already are providing assistance and we certainly recognize the many issues that municipalities are dealing with. Of course, it's important to note that many of the things the member was talking about are captured on the next review of the municipal plans. I think that's important notice.

I would actually argue that we–and the member, you know, I defer to his knowledge at the ground level, he has significant experience with a planning authority and his role and he's certainly seen some of the changes that are out there–but my concern as minister, quite frankly, and our concern as government is to ensure that we're not only developing state-of-the-art waste-water regulations–I think that's something that is a part of the overall vision of sustainable land-use planning–that we're not only dealing with state-of-the-art livestock operation policies, but that we're also dealing with some of the broader issues. That's where the review of provincial land-use policies is coming into place.

***** (16:50)

One of the concerns that I have raised is there are many areas of the province–and the member knows this directly from his own constituency–where farms are now measured in sections, not quarter sections, that population–you know, on three, four sections of land, there might have been six, seven, eight farm families; you're down to one. I really believe that we need to make sure our land-use policies are providing opportunities for both urban and rural municipalities to, yes, create sustainability; yes, to protect the integrity of agricultural land and green space–all the various factors that go into planning.

We also have to make sure, I believe, that we have a plan that is geared to recognizing that we do not want planning perversely to be accelerating depopulation in areas of the province where we're seeing some significant population reductions. I'm a great believer by the way, and I come from northern Manitoba, I really believe that one thing that northern and rural areas have to offer is a quality of life. I also recognize that in a lot of cases our planning principles often, while they may have been appropriate at a certain period of time, don't necessarily reflect what's happening now.

I can't stress enough how important the provincial land-use policy review is. I know the AMM has been very supportive of the review, and I think that is fairly critical. Now having said that, that's the broader vision, and I appreciate the member's also asking about the specific impact on the ground.

Under the community planning assistance grant program we have provided $1,114,945 over the last 10 years to the various municipalities and planning districts. That is, I believe, been a significant part of why we have had significant development. We've got 20 new planning districts with 77 member municipalities and 12 municipalities which are preparing and adopting new development plans. There are 38 planning districts, and municipalities have received assistance to review and update their development plans and zoning by-laws, including livestock operation policies that the member talked about earlier.

We are not only putting forward the broader vision on the planning side, I believe. We are also providing real assistance on the ground because we recognize there is work involved, not the least of which is the significant amount of community consultation. I do want to say that one thing that I think is unique in Manitoba is the degree to which our municipalities and our planning districts do have a significant amount of public input. I know the member knows that from, certainly, his experience with his planning district. I think it's, quite frankly, it's money and time that's well invested.

Yes, significant changes, but we are there to help municipalities, as well. We do recognize some of the costs.

Mr. Briese: Thank you for that answer. That's one of the places I was going to go is the recognition of local knowledge out there. I know when we were doing the work on our development plan and implementing the livestock policy, we had a great deal of difficulty with–actually one of the departments in government. It caused us a lot of grief. They refused to recognize what we had on the ground out there. By the way, Mr. Minister, it was not your department. I find your planning department and your planning staff just excellent to work with, and I have for many years. They're very willing to listen to what's going on out in the country, and I just wish some of the people elsewhere were as willing.

Back to the waste-water regulations that I mentioned before. I don't want to go into a debate on the waste-water regulations or necessarily even on the provincial land-use policies. It certainly appears to be a case where there's somewhat of a, for lack of a better word, a download onto municipal planning to police what the province wants for the waste-water policies. I know that's not unique. I know that we do that in a lot of cases, but it might not be as easily recognized by local authorities that waste-water regulation is in their jurisdiction, and that's somewhat of what I think I'm seeing coming through this.

Mr. Ashton: Well, first of all, clearly the provision of water and waste-water services is one of the prime roles and responsibilities of municipal government. I think there's been significant progress there, by the way, not just in compliance with new regulations and updated regulations, which I think is something that is absolutely necessary. I point to the fact, for example, in the city of Winnipeg, it wasn't really until the City of Winnipeg waste-water facilities were referred to the Clean Environment Commission in 2002, I believe it was, that we actually saw licensing of the City of Winnipeg waste-water treatment plant. I was Minister of Conservation at the time that the report was received, and I think it was long overdue, that indeed not only was there licensing but there was a licence requirement to upgrade the waste-water treatment facilities. That is something that's happening across the province.

I do want to note, by the way, that both water and waste-water facilities received a high priority in the announcements under the Building Canada Fund Communities Component this last Friday. I look at the largest grant in the announcement was to the City of Selkirk, more than $9 million. I believe the second-largest grant was to the City of Flin Flon, and it ranges all the way through to some significant funding that was provided to Northern Affairs communities including Nelson House and the Island Lake community council and many others, all of them providing either water treatment or waste-water treatment. I do want to note, by the way, the additional funding support for the R.M. of Gimli, which has provided a real model in terms of regional facilities.

I want to stress that there is the funding side as well through Infrastructure and as well as funding through the Water Services Board. I'm no longer the Minister responsible for the Water Services Board, but I know the member's more than aware of some of the things that have been happening in that particular case.

I also think, by the way, what's important to note is the degree to which we're working on a regional vision for water and waste water. I really want to credit the municipalities that have been taking a leadership role. I mentioned the R.M. of Gimli, for example, but there are examples throughout the province of either water treatment or waste-water treatment where we see regional realities. I look at Portage as probably a good example in recent years, where you've seen a real extension of the kind of vision you have.

So I believe–and without getting into a long discussion, debate on this, I don't think that's the member's intent here–I think that we are not only moving forward, we are providing additional supports. I think there's not a single municipal elected official that doesn't realize, as we do, that it's something the public is demanding. Whether it's post-Walkerton on the drinking-water side or North Battleford, or in terms of the environmental pressures we're under, I find that Manitobans are expecting us to do exactly what we're doing, which is to improve water and waste water, but do it in partnership and that's very much our approach on the funding side.

Mr. Briese: Thank you once again for that answer, Mr. Minister.

Trying not to get into a debate, but in the case of the waste-water management–and I know it doesn't even totally fall into your department but–I realize there's probably some problems in certain areas, probably in the capital region and some of the cottage country and some of the Red River Valley where it's a flood plain, but putting a blanket regulation across the province, I think, is counter-productive.

In my municipality, we have 800 people. There's probably–and I did the math–there's about four people per section, so there's about one per quarter section. I don't think waste water is a big problem out where I am. Now, there are some places where it would be a concern, you know, close to waterways and stuff like that, but we already have those setbacks in our development plans and in our zoning by-laws, so they are covered. The exceptions out there probably should be zone by zone or case by case, and that's where I think they should be covered off.

I see the Chairperson's right in the–put the hammer down, and it's about five seconds to go, so I'll cut it off there.

Madam Chairperson: The hour being 5 p.m., this section of the Supply will now recess and reconvene at 10 a.m. tomorrow (Friday).

LEGISLATIVE ASSEMBLY OF MANITOBA

Thursday, May 7, 2009

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Fourth Session - Thirty-Ninth Legislature

of the

Legislative Assembly of Manitoba

DEBATES
and
PROCEEDINGS

Official Report
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MANITOBA LEGISLATIVE ASSEMBLY
Thirty-Ninth Legislature

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Vacant	Concordia	

LEGISLATIVE ASSEMBLY OF MANITOBA

Tuesday, December 15, 2009

The House met at 1:30 p.m.

Mr. Speaker: O Eternal and Almighty God, from Whom all power and wisdom come, we are assembled here before Thee to frame such laws as may tend to the welfare and prosperity of our province. Grant, O merciful God, we pray Thee, that we may desire only that which is in accordance with Thy will, that we may seek it with wisdom, know it with certainty and accomplish it perfectly for the glory and honour of Thy name and for the welfare of all our people. Amen.

ROUTINE PROCEEDINGS

PETITIONS

PTH 15–Traffic Signals

Mr. Ron Schuler (Springfield): Mr, Speaker, I wish to present the following petition to the Legislative Assembly of Manitoba.

These are the reasons for this petition:

In August 2008, the Minister of Transportation stated that traffic volumes at the intersection of PTH 15 and Highway 206 in Dugald exceeded those needed to warrant the installation of traffic signals.

Every school day, up to a thousand students travel through this intersection in Dugald where the lack of traffic signals puts their safety at risk.

Thousands of vehicles travel daily through this intersection in Dugald where the lack of traffic signals puts at risk the safety of these citizens.

In 2008, there was a 300 percent increase in accidents at this intersection.

We petition the Legislative Assembly of Manitoba as follows:

To request that the Minister of Transportation (Mr. Ashton) consider the immediate installation of traffic signals at the intersection of PTH 15 and Highway 206 in Dugald.

To request that the Minister of Transportation recognize the values of the lives and well-being of the students and citizens of Manitoba.

Signed by Doug Raynard, Louise Bass, Juergen Hartmann and many, many other Manitobans.

Mr. Speaker: In accordance with our rule 132(6), when petitions are read they are deemed to be received by the House.

Ophthalmology Services–Swan River

Mrs. Myrna Driedger (Charleswood): Mr. Speaker, I wish to present the following petition to the Legislative Assembly.

These are the reasons for this petition:

The Swan Valley region has a high population of seniors and a very high incidence of diabetes. Every year, hundreds of patients from the Swan Valley region must travel to distant communities for cataract surgery and additional pre-operative and post-operative appointments.

These patients, many of whom are sent as far away as Saskatchewan, need to travel with an escort who must take time off work to drive the patient to his or her appointments without any compensation. Patients who cannot endure this expense and hardship are unable to have the necessary treatment

The community has located an ophthalmologist who would like to practise in Swan River. The local Lions Club has provided funds for the necessary equipment, and the Swan River Valley hospital has space to accommodate this service.

The Minister of Health (Ms. Oswald) has told the Town of Swan River that it has insufficient infrastructure and patient volumes to support a cataract surgery program; however, residents of the region strongly disagree.

We petition the Legislative Assembly of Manitoba as follows:

To urge the Minister of Health to consider rethinking her refusal to allow an ophthalmologist to practise in Swan River and to consider working with the community to provide this service without further delay.

And this is signed by Dori Driedger, Lily Grieger, Mary Ann Blythe and many, many others.

Manitoba Liquor Control Commission–Liquor Licences

Mr. Cliff Graydon (Emerson): Mr. Speaker, I wish to present the following petition to the Legislative Assembly and these are the reasons for this petition:

The Manitoba Liquor Control Commission has substantially raised the cost of annual liquor licences for restaurants, cocktail lounges and other Manitoba businesses.

The MLCC justifies this increase by stating that the cost of an annual licence is being increased to better reflect rising administration costs.

For some small business owners, the cost of annual liquor licences has more than doubled. These fee hikes are a significant burden for business owners.

The decision to increase the annual licence fee, while at the same time eliminating the 2 percent supplementary licence fee payable on the purchase of spirits, wine and coolers, has the effect of greatly disadvantaging smaller businesses. Small businesses which do not purchase liquor from the MLCC in large volumes will not receive the same benefit from the elimination of this supplementary fee. Instead, they are facing substantial increased costs simply to keep their doors open.

We petition the Legislative Assembly of Manitoba as follows:

To request the Minister responsible for the administration of The Liquor Control Act (Mr. Mackintosh) to consider working with MLCC to find alternate means of addressing rising administrative costs.

To request the Minister responsible for the administration of The Liquor Control Act to consider working with MLCC to revise the decision to implement a significant annual licence fee increase.

To urge the Minister responsible for the administration of The Liquor Control Act to consider ensuring that the unique challenges faced by small businesses are better taken into account in the future.

This petition is signed by Gord Hoffmann, Roxanne Greaves, Lindsay Kaartinen and many, many more fine Manitobans.

Education Funding

Mr. Rick Borotsik (Brandon West): I wish to present the following petition to the Legislative Assembly of Manitoba.

These are the reasons for this petition:

Historically, the Province of Manitoba has received funding for education by the assessment of property that generates taxes. This unfair tax is only applied to selected property owners in certain areas and confines, including, but not limited to, commercial property owners.

Property-based school tax is becoming an ever-increasing burden without acknowledging the commercial property owner's income or owner's ability to pay.

We petition the Legislative Assembly of Manitoba as follows:

To request the Minister of Education (Ms. Allan) consider removing education funding by school tax or education levies from all property in Manitoba, including commercial property.

To request that the Minister of Education consider finding a more equitable method of funding education, such as general revenue, following the constitutional funding of education by the Province of Manitoba.

This petition, Mr. Speaker, is signed by M. Malcolm, L. Brown, M. Harding and many, many other fine Manitobans.

Seven Oaks Hospital–Emergency Services

Mr. Kevin Lamoureux (Inkster): I wish to present the following petition to the Legislative Assembly of Manitoba.

The background to this petition is as follows:

The current Premier (Mr. Selinger) and NDP government are reducing emergency services at the Seven Oaks Hospital.

On October the 6th, 1995, the NDP introduced a matter of urgent public importance that stated that, quote, "the ordinary business of the House to be set aside to discuss a matter of urgent public importance, namely, the threat to the health-care system posed by this government's plans to limit emergency services in the city of Winnipeg community hospitals."

On December the 6th, 1995, when the then-PC government suggested it was going to reduce emergency services at the Seven Oaks Hospital, the NDP leader then asked Premier Gary Filmon to, quote, "reverse the horrible decisions of his government and his Minister of Health and reopen our community-based emergency wards."

The NDP gave Manitobans the impression that they supported Seven Oaks Hospital having full emergency services, seven days a week, 24 hours a day.

We petition the Legislative Assembly of Manitoba as follows:

To request the Premier of Manitoba to consider how important it is to have the Seven Oaks Hospital provide full emergency services, seven days a week, 24 hours a day.

Mr. Speaker, this is signed by A. Allard, V. Allard, L. Agapito and many, many other fine Manitobans. Thank you.

***** (13:40)

COMMITTEE REPORTS

Standing Committee on Public Accounts First Report

Mr. Leonard Derkach (Chairperson): Mr. Speaker, I wish to present the First Report of the Standing Committee on Public Accounts.

Madam Clerk (Patricia Chaychuk): Your Standing Committee on Public Accounts–

Some Honourable Members: Dispense.

Mr. Speaker: Dispense? Dispense.

Your Standing Committee on Public Accounts presents the following as its First Report.

Meetings

Your Committee met on December 14, 2009 in Room 255 of the Legislative Building.

Matters under Consideration

- *To consider the election of a new Vice-Chairperson*

Committee Membership

- *Mr. BOROTSIK*
- *Ms. BRAUN*
- *Ms. BRICK*
- *Mr. DERKACH (Chairperson)*
- *Mr. DEWAR*
- *Mr. JHA*
- *Mr. LAMOUREUX*
- *Mr. MAGUIRE*
- *Mr. MARTINDALE*
- *Mrs. STEFANSON*
- *Hon. Ms. WOWCHUK*

Your Committee elected Mr. DEWAR as the Vice-Chairperson.

Mr. Derkach: Mr. Speaker, I move, seconded by the honourable member for Springfield (Mr. Schuler), that the report of the committee be received.

Motion agreed to.

Standing Committee on Legislative Affairs First Report

Ms. Marilyn Brick (Vice-Chairperson): Mr. Speaker, on behalf of the honourable member for Kirkfield Park (Ms. Blady), I wish to present the First Report of the Standing Committee on Legislative Affairs.

Madam Clerk (Patricia Chaychuk): Your Standing Committee on Legislative Affairs presents the–

Some Honourable Members: Dispense.

Mr. Speaker: Dispense? Dispense.

Your Standing Committee on LEGISLATIVE AFFAIRS presents the following as its First Report.

Meetings

Your Committee met on December 14, 2009 at 4:00 p.m. in Room 255 of the Legislative Building.

Matters under Consideration

- *The appointment of the Conflict of Interest Commissioner*

Committee Membership

- *Ms. BLADY*
- *Ms. BRAUN*
- *Ms. BRICK*
- *Hon. Mr. CHOMIAK*
- *Mr. CULLEN*
- *Mr. GOERTZEN*
- *Mr. HAWRANIK*
- *Hon. Ms. HOWARD*
- *Mr. JENNISSEN*
- *Mr. PEDERSEN*
- *Mr. REID*

Your Committee elected Ms. BLADY as the Chairperson.

Your Committee elected Ms. BRICK as the Vice-Chairperson.

Motions

Your Committee agreed to the following motions:

- *THAT the Committee recommends to the Lieutenant-Governor-in-Council that Mr. Ron Perozzo be appointed as the Conflict of Interest Commissioner for a term not to exceed three years from date of commencement.*

Ms. Brick: Mr. Speaker, I move, seconded by the honourable member for Transcona (Mr. Reid), that the report of the committee be received.

Motion agreed to.

TABLING OF REPORTS

Hon. Diane McGifford (Minister of Advanced Education and Literacy): Mr. Speaker, I am pleased to table the following reports: Red River College's Annual Financial Report 2008-2009; and the Assiniboine Community College Annual Report 2008-2009. Thank you.

Introduction of Guests

Mr. Speaker: Order, please. Prior to oral questions, I'd like to draw the attention of honourable members to the public gallery where we have with us from River East Collegiate, we have 17 grade 10 to 12 students under the direction of Ms. Linda LaCoste. This school is located in the constituency of the honourable member for River East (Mrs. Mitchelson).

On behalf of all honourable members, I welcome you here today.

ORAL QUESTIONS

Provincial Debt Reduction Strategy

Mr. Hugh McFadyen (Leader of the Official Opposition): Mr. Speaker, since this is our last question period before the holidays, I think it's–I think it's important to acknowledge the remarkable generosity of Manitobans, as reported in today's *Free Press*, as the most generous people in Canada according to the Fraser Institute. That's something that we all–we're all proud of as Manitobans. It's one more reason why we have such a great province.

Mr. Speaker, one of the–one of the concerns that we have been raising in terms of the forecasts going forward in terms of the incomes and well-being of Manitobans is the rising level of public debt in the province of Manitoba. As the numbers show, Manitoba was the only province in western Canada that increased its debt over the last 10 years, at a time when other provinces were paying their debt down during good times.

Now, Mr. Speaker, this morning there are warnings coming from experts at both the Royal Bank and the Bank of Montreal predicting an increase–predicting an increase in interest rates starting as soon as July of 2010.

So as we see this record level of debt and predictions of rising interest rates, I wanna ask the minister: What is her plan to ensure that her government's NDP debt isn't gonna push down the incomes of Manitobans in the years to come?

Hon. Rosann Wowchuk (Minister of Finance): Mr. Speaker, indeed, the impacts of the recession are being felt around the world; Manitoba is not immune. However, Manitoba has ridden out the recession much better than many other provinces have and many other countries that have managed.

But, Mr. Speaker, the member opposite talks about the debt and debt repayment, and I can assure the member that our debt management strategy has many elements to it and we are committed to it. We have been paying down the debt. We have been paying down pension liabilities. We are funding our share of pensions, principal repayments and capital amortization, even though we are in difficult times. We have made a commitment that we will pay–make a payment on the debt this year, and I would say to the member–

Mr. Speaker: Order.

Mr. McFadyen: Well, Mr. Speaker, the patting of themselves in the back in terms of the economic performance is at odds with what her own–her own chairman of Manitoba Hydro wrote in June. Vic Schroeder wrote that, as the province established for 2007, we were last in dwelling starts; only two provinces have lower average weekly earnings; three have lower per capita retail sales and capital investment; and in none of the categories were we above average.

Mr. Schroeder, the chairman of Manitoba Hydro and former NDP Finance Minister, went on to say: To put it another way, assuming that we are in a race, even if we're moving faster than the others, when we are further back, running faster does not mean we're in the lead or even in the middle.

This is what–this is what her own Manitoba Hydro chairman, Mr. Schroeder, wrote in June, and I know that Manitobans are concerned with the rising level of public debt, now $21 billion, which represents $21,000 for every man, woman and child in Manitoba with the prospect of rising interest rates. What is she gonna do to protect the incomes of Manitoba families?

Ms. Wowchuk: Well, Mr. Speaker, as I said, we all recognize that we are in challenging times, and we have made a commitment to stand by the consumers and the people of this province. We will make a payment on the debt. We will invest in stimulus so that people continue to work, and we will continue to fund and support important services that our people rely on, whether that's health care, education or justice.

But, Mr. Speaker, the member talks about the net debt to GDP as a percentage, and I want to share with the member that since 1999 it has decreased from more than 25–it has decreased from 31.5 percent to 23 percent. The members opposite can't talk to us about how we should manage the debt. We have paid it down, but we are also very considerate of services important to people.

Mr. McFadyen: Well, we're well aware of the–of the profligate spending and their lack of regard for the impact of that spending on the next generation of Manitobans. The debt of the province has gone up from 13.5 billion to over 21 billion today under their watch at a time when other western provinces were paying the debt down during the good years. Mr. Speaker, when the sun is shining, this is the time to fix the roof and instead of fixing the roof they made the hole bigger in terms of Manitoba's debt.

Mr. Speaker, I wanna ask the minister if she will apologize for the mismanagement of the last 10 years and commit–commit today at a time when we're spending more than $2 million a day on debt servicing, a record high level: What is her plan to deal with Manitoba's debt? Rather than increasing it, what's she doing to protect the next generation?

Ms. Wowchuk: Well, I'm really pleased that the member opposite is interested in debt servicing because when he was chief of staff for the Conservatives when they were in power, the debt-servicing costs were much higher. They are down from 13.2 cents on a dollar to point–six cents on a dollar.

The member opposite refuses to accept that we are in a different accounting. He refuses to accept the fact that as well as having debt, we have much more assets, Mr. Speaker, because we have to account for those assets and we have made investments in assets, whether it be the Health science Centre, whether it be schools, whether it be hospitals.

I would stand beside our record of what we have invested into assets in this province anytime when they were in government.

***** (13:50)

**Provincial Debt
Servicing Costs**

Mr. Rick Borotsik (Brandon West): Mr. Speaker, I know that my warning about out-of-control debt has fallen on deaf ears.

The previous Finance Minister, now Premier (Mr. Selinger), and the current Finance Minister cannot control their credit card addiction. This fiscal year alone will mean an additional $1.8 billion of debt, taking us to an unheard of level of $23 billion.

Mr. Speaker, economists are now warning that higher interest rates and debt-servicing costs are just around the corner. They predict a 1 percent increase in rates in 2010, and they're predicting an additional 2 percent increase in rates in 2011.

Debt goes up; rates go up; debt-servicing costs go up: Program funding has to be affected.

What is the minister's long-term strategy for increased interest rates?

Hon. Rosann Wowchuk (Minister of Finance): Mr. Speaker, the member opposite is complaining about the amount of money we are spending on infrastructure.

Some Honourable Members: Oh, oh.

Ms. Wowchuk: Well, I–well, I wonder, Mr. Speaker, I wonder if he is complaining about the money we spent on the health–on the hospital in Brandon.

I'm wondering if he's complaining about the money that we spent on waste-water treatment–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Ms. Wowchuk: –in Brandon.

Some Honourable Members: Oh, oh.

Mr. Speaker: Order. Order.

Ms. Wowchuk: I wonder, Mr. Speaker–

Mr. Speaker: Order.

Ms. Wowchuk: I wonder, Mr. Speaker, if he's complaining about the bridges we spent in Brandon that he's trying to take credit for.

Mr. Speaker, you can't have it both ways. You can't ask for stimulus which we believe in and we have invested in because it keeps people working and then complain that there is money being spent.

Financial Statements
Tabling Request

Mr. Rick Borotsik (Brandon West): Well, Mr. Speaker, if the Finance Minister wants to play that game, I would suggest that I'm complaining about $640 million that's being wasted on the west-side hydro.

I'm gonna complain about $14 million that they're wasting on an enhanced ID.

I'm gonna complain, Mr. Speaker, about $250,000 that's been spent on advertising on *The Simpsons*. That's what I'm gonna complain about every day.

Every day, for the past two weeks, I have asked the Finance Minister for her to table the second-quarter financials. When I see her in the hall, Mr. Speaker, I ask her to table the financials.

Some Honourable Members: Oh, oh.

Mr. Speaker: Order.

Mr. Borotsik: Here in the Chamber, I ask her to table the financials. In question period, I ask her to table the financials, and what do I get? All I get is her thumbing her nose at me, Mr. Speaker.

I can tell by the number of pizza boxes outside the minister's office last night that she and her staff have been working on the NDP spin. Mr. Speaker, the pizza boxes were out. The lights were out. The minister wasn't home. Will she table the financials right now before we rise?

Hon. Rosann Wowchuk (Minister of Finance): Well, Mr. Speaker, the member–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order. Order. Order. Order. The honourable minister.

Ms. Wowchuk: You know, Mr. Speaker, the member opposite just complained about the money that would–being spent on Bipole III. The member opposite–

Some Honourable Members: Oh, oh.

Ms. Wowchuk: The members opposite would–just can't get it through their heads that building a line on the east side will not fly, Mr. Speaker.

And I want to table for the House a report that came out today that says the boreal forest is the world's richest carbon storage, and a spot in Manitoba–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order. Order.

Ms. Wowchuk: –a spot in Manitoba is the only place in the world that is identified as a pristine boreal forest, Mr. Speaker.

Mr. Speaker, I'll table this for the members opposite to see how far off target they are when they start talking about where the line should go.

Mr. Speaker: Order.

Manitoba Hydro
Bipole III West-Side Location

Mr. Cliff Cullen (Turtle Mountain): Well, Mr. Speaker, the minister already has a hydro line running through the boreal forest and now the NDP government's gonna build a road through the boreal forest.

Mr. Speaker, the Premier's (Mr. Selinger) been telling Manitobans that government must tighten its belt and reduce spending. Meanwhile he has instructed Manitoba Hydro to do exactly the opposite. Hundreds of millions of dollars will be wasted on their west-side route running over to the Saskatchewan border.

It's unfortunate that Manitoba Hydro employees won't speak up on the issue, but we know how this government treats whistle-blowers.

Mr. Speaker, one retired engineer from Manitoba Hydro with 30 years service did write to the NDP government, and he said: certainly a bad decision economically, technically and developmentally. He goes on to say that it will cost each of us as Manitobans $500 to $1,000 in addition to ongoing operating costs. Allowing politics to override sound and proven decision making is surely a mistake.

Will the minister now do the right thing for Manitobans, heed the advice of Bill Stephens and reverse this decision in the best interest of all Manitobans?

Hon. Rosann Wowchuk (Minister charged with the administration of The Manitoba Hydro Act): Mr. Speaker, as I said yesterday, I have a lot of respect for engineers. I have a brother who's an engineer, and I listen to him. But I would encourage the member also to look at what engineers do, and their job is to build lines. But I would ask him to–I'd ask those engineers to talk to the sales department, because it is the sales department that negotiates sales, and this government is not going to put at risk $20-billion worth of sales because of the members' opposite desire to have a shorter line. It may be shorter, but the price we pay will be much, much higher.

Mr. Speaker, it will never get built, and we will never get the benefits that are outlined for us by maintaining that boreal forest that benefits the whole world.

Mr. Cullen: Well, Mr. Speaker, Manitobans are looking for some leadership from government to stand up to the American environmentalists. What have we got from the NDP leadership? We've got hydro rates up 16 percent. We're looking at at least another 6 percent over the next two years. Manitoba Hydro's looking at 3.5 percent annually, long-term.

We no longer have the lowest rates in Canada, let alone the United States. Second-quarter reports show our export sales down 42 percent year-to-date. Long-range forecasts from Hydro show net income–net income dropping off dramatically. We've got independent consultants raising issues on this management at Hydro. We've got the Premier (Mr. Selinger) making jokes about it in public, and, meanwhile, Manitobans are on the financial hook from decisions made by this NDP government.

When will this government take the serious issues at Manitoba Hydro–when will they take those issues seriously?

Ms. Wowchuk: Mr. Speaker, we take all of these issues very seriously, and we take Manitoba Hydro's very seriously, very different from what the members opposite did. That was the mothball party with the– when the Conservatives were in power. We're building Manitoba Hydro. We're building dams and we have to–Hydro has to build a transmission line for reliability and also to ensure our sales.

Now, the member opposite talks about cost. He's willing–he's willing to take the chance on a–on a–on a line that will never be built but–and then give up $20-billion worth of sales, Mr. Speaker. That's an unacceptable position, and it's unacceptable for the member opposite to say we do not have the lowest rates in North America because we have the lowest rates.

Mr. Speaker: Order.

Court Orders Enforcement

Mr. Kelvin Goertzen (Steinbach): Mr. Speaker, today police charged an 18-year-old, high-risk, level 4 car thief with killing a 47-year-old father this past Friday. It is reported that this high-risk car thief had several court orders against him, which he clearly wasn't following.

Over and over, time and time again, car thieves and gang members and others who have court orders against them ignore those court orders and are responsible for violence and death in the city of Winnipeg. They are not being enforced. They take them as a joke because this minister takes them as a joke.

Why won't this minister acknowledge that his failure to enforce court orders is putting Winnipeggers and Manitobans at risk, Mr. Speaker?

Hon. Andrew Swan (Minister of Justice and Attorney General): Mr. Speaker, on behalf of all members of this House, I think we should congratulate the Winnipeg Police Service for making an arrest in this case. We're very pleased they've been able to do that.

I think the member opposite needs a little briefing and needs to understanding how criminal law works in this country, and at past federal-provincial meetings, my two predecessors have pushed strongly to make sure there are changes to the Youth Criminal Justice Act.

I don't believe the members opposite like the way the act works. We certainly don't and we have called upon the federal government to change the Youth Criminal Justice Act to make sure that deterrence is taken into account in sentencing. That hasn't happened yet. We hope to continue raising our voices, and I actually hope the member for Steinbach and his colleagues work with us to make changes to that act, because that would be a very good thing for safety in this country.

***** (14:00)

Mr. Goertzen: The minister either doesn't understand or chooses to ignore the fact that it's a provincial responsibility to enforce court orders when an individual is out, Mr. Speaker. It would save lives if those orders were enforced, yet this known car thief, this level 4 car thief, the worst of the worst, was out and clearly didn't have the enforcement of his orders, and a father died as a result.

These criminals know that those court orders are not going to be enforced under this NDP government. I will ask this minister: Mr. Minister, will you today finally do something to stand up for Manitobans, for the safety of Winnipeggers and Manitobans, and ensure that all of these court orders are strongly enforced so that there can be safety on the streets of Winnipeg, Mr. Speaker.

Mr. Swan: I'm not certain if the member opposite has heard of the Winnipeg Auto Theft Suppression Strategy. That strategy combines the efforts of our Winnipeg Police Service, who I know members on this side certainly respect. I thought the member for Steinbach did, but now I'm not so sure.

Certainly we work with Crown attorneys. We have excellent staff in Probations and Corrections to do their best to enforce those orders. And certainly we've been–we've been successful at reducing auto theft by some 70 percent since 2005. It's lower than it's been in any year since 1992 when auto theft became a major problem in this city and, frankly, there is more work to be done.

There are more tragedies that have happened and we will continue to work on that, but we are moving in the right direction, Mr. Speaker.

**Diagnostic Services of Manitoba
Review of Mismanagement Allegations**

Mrs. Myrna Driedger (Charleswood): Mr. Speaker, under this Minister of Health's watch there is a crisis brewing at Diagnostic Services Manitoba, yet she is calling a whistle-blower, a doctor, a liar and, once again, as she has done with the death of Brian Sinclair, she's covering up the facts.

One of the whistle-blower's allegations is that there is unsafe care going on in the labs, and yet this Minister of Health has been saying, and I quote: ". . . no patient harm was done." And on Friday, here in question period she said, and I quote: "There was a specific case in the allegations that was very concerning. That case was investigated immediately. Indeed, it was determined that the allegations did not match the actual facts and that, in fact, there was no negative impact on that patient's outcome."

Can the Minister of Health then tell us, if that was the case, why was a critical incident called on that case?

Hon. Theresa Oswald (Minister of Health): I want to be explicitly clear that the member across the way is the one who's using words like "liar" and so forth. I want to be very clear with her and with all members of this House that we are taking the allegations of this doctor very seriously. That's why there is an internal review. That's why there is an external review being led by Dr. Macdonald, a very well-respected doctor.

She, in turn, has sought the expertise of a pathologist from out of the province. There was a very specific case in the document that the doctor wrote that was investigated. I reiterate to the member that the facts did not match the allegations but, in fact, the review continues.

Indeed, we are taking the allegations of this doctor very seriously. That's why there is a review. It's actually the opposite of not believing him.

Mrs. Driedger: Mr. Speaker, this Minister of Health is trying to talk out of both sides of her mouth.

A critical incident is called when a patient is harmed, and yet this minister keeps saying that no harm was done. And when a critical incident occurs, the Minister of Health must be notified about the incident. So the minister would have known about this particular situation for many, many months and yet she keeps saying that no harm was done.

So can the Minister of Health please explain her misleading comments and tell us: Why is she trying to cover up the facts about this situation?

Ms. Oswald: I will say very clearly that this review is being done after allegations were brought forward. Patient safety is at the forefront of this investigation. There are other allegations that have been made concerning issues of remuneration, issues of administrative discord, of infighting. All of those are going to be investigated, Mr. Speaker.

I can say to the member opposite that we're taking these allegations very seriously. We will make the findings of this review public. There's absolutely nothing about this that's being covered up. No matter how many times the member opposite tries to use this particular smear campaign against me, it's not going to work. We're being open and transparent, Mr. Speaker.

Mrs. Driedger: Mr. Speaker, a minister with the track record she has on cover-ups has no credibility with her answers in this House.

Mr. Speaker, pathologists, lab technologists are all saying that there is bullying, intimidation and abusive behaviour happening in Manitoba labs. Because of this toxic environment, many in the labs are too afraid to come forward and speak to the review committee. In fact, on Friday, the lawyer on the review committee told pathologists that he can't guarantee that there will be no consequences for pathologists who speak out.

So, Mr. Speaker, I would like to ask the Minister of Health today to commit to ensure that all pathologists, technologists and other lab personnel who speak to the review committee will be guaranteed total and absolute anonymity, or is it her intent to have this whole review a whitewash?

Ms. Oswald: Well, again, Mr. Speaker, I made it clear, on the first day that I was asked this question, that these individuals are protected under the whistle-blower legislation.

And on the subject, Mr. Speaker, of credibility, as raised by the member opposite, when we received these allegations we immediately sought to review them and protect patient safety. When the member opposite received this document, she phoned a reporter, begged to get her picture in the paper, but didn't do a thing to help patients. It's a classic tactic by the member opposite. We care about patients. She cares about publicity. It's the same old, same old.

Thomas Lake Water Levels Flooding Concerns

Mr. Leonard Derkach (Russell): Mr. Speaker, last spring I asked the Minister of Water Stewardship (Ms. Melnick) to come to the aid of cottagers and home-owners along the Thomas Lake shores to help to alleviate the flooding that was occurring and to allow them to open up an outlet that had been silted over. The summer went by and nothing happened.

Mr. Speaker, today those same home-owners and cottage owners are facing flooding next spring when the melt waters come down, and, indeed, some of those cottages will be unusable, as will an access road and a connecting road.

I want to ask the government whether or not they are prepared to come to the aid of these cottage owners between now and spring so that, indeed, their cottages and their property will not be valued useless once the high waters hit the area.

Hon. Stan Struthers (Acting Minister of Water Stewardship): Mr. Speaker, I know the questions that the member for Russell asked of my colleague. I know of the content and I know that my colleague has undertaken to make sure that everybody who needs to be heard on the issue will be heard and that there is work being done towards finding a solution to this–to this unfortunate situation.

Mr. Derkach: Mr. Speaker, time has literally run out. When the cottage owners wanted the department to intervene, they were told that they had to get permission from landowners downstream before the outlet could be opened. That happened last June.

Mr. Speaker, the First Nations people have said they understood the problem and they were prepared to have the water go through their property and through the creek–or a river that runs through their property, but the department would not allow the outlet to be opened.

Mr. Speaker, today those cottagers are facing a devaluation of their property and perhaps unusable cottages because water will flood them in the spring. In addition, the main road will be flooded in the spring, as will connecting roads between the developments.

I ask the minister whether or not he's prepared to meet with these people and ensure that a solution is found before these waters start to impede the use of their property, Mr. Speaker.

Mr. Struthers: Certainly, the Minister of Water Stewardship (Ms. Melnick) is–has been working with the R.M. of Strathclair. My understanding–my understanding is–my understanding is is that the R.M. of Strathclair has promised the minister some information that she has requested, and when she receives that information from the R.M., she will be in a position to deal on a–on an ongoing basis with an issue that I know is frustrating for the member for Russell's constituents.

So I believe when the minister gets that information, she will be moving forward with it.

***** (14:10)

Mr. Derkach: Well, Mr. Speaker, perhaps the minister better get a better briefing on the whole issue than he has because the only thing that they received from this minister was a request that the municipality do a $50,000 environmental study before any action can be taken.

Mr. Speaker, there has been no consultation with either cottagers or the municipality, except for that one request. Since then, cottagers have been appealing to the department to get something done and nothing has been done.

Mr. Struthers: Mr. Speaker, if there is a holdup anywhere in the system, I would assume that the member for Russell wants to work its–work his way through that. And I would assume the member for Russell would want to be helpful in making sure that all the information that is needed to make decisions and to move forward to help his constituents–he'd be more than co-operative in trying to get the information that I have.

The most information–the most up-to-date information is that the Minister of Water Stewardship (Ms. Melnick) is waiting for some information from the R.M. of Strathclair so they can make some decisions. If that's–if that is the case, I would assume the member for Russell would want to help and be co-operative to help his constituents out. I'm sure he would.

Harmonized Sales Tax
Government Strategy

Hon. Jon Gerrard (River Heights): Mr. Speaker, the Minister of Finance has done a rather poor job of releasing a report on the harmonized sales tax. First of all, she says it's on the Web and we've tried with various computers in different ways to downlade it–download it and must conclude that the site's nonfunctional. We've gone to the minister's staff in her office and they say they don't have a hard copy and they have no idea where to get one. I ask the minister–in her short summary she says that they won't put an HST on in–with the global recession.

I ask the minister: Does this mean that the minister will consider imposing an HST next year after the recession is over?

Hon. Rosann Wowchuk (Minister of Finance): Mr. Speaker, the HST report that the member is referring to was released today. If he hasn't been able to get one, I can–I can assure him that I will provide him with one.

But the report that was released today indicates–and the review that people have done indicate to us clearly that this is not the time to implement the HST, in a time of recession. We've looked very closely at the numbers and this would, indeed, be a burden for our lowest-income people, to have these additional kind of costs put on them–on these.

Mr. Speaker, the member opposite says: Will we implement it at another time? Now is not the time to do it. Is it–if it is a time to review it at another date, certainly we would look at it.

Budget
Deficit Prediction

Hon. Jon Gerrard (River Heights): Mr. Speaker, you know, we know that the Minister of Finance has difficulty getting things done well and releasing financial reports and so on, but last year we note that the new debt of the–the debt of the government went up by $800 million or $900 million. In this year's budget, the government has released its budget plans for an $88-million deficit in the core operating budget.

I ask the Minister of Finance: We're now three-quarters of the way through the year. She must know, hopefully, where she's going in this respect. Can the minister tell us now what her current projection is? Is the deficit going to be more than 88 million or is it gonna be less than 88 million?

Hon. Rosann Wowchuk (Minister of Finance): Mr. Speaker, related to the–to the previous question, what I said was that although the federal government was trying to convince us to move towards the harmonization of GS–to HST we've conducted the review and the report just says that there are too many risks for Manitoba to–and Manitoba families in this time of recession to implement HST.

Mr. Speaker, with regard to–and I would report to the member that the HST report that he is looking for is on the Internet. It's the Finance Web site. It's there, but if he can't find a copy, we would be prepared to provide him with one.

Mr. Speaker, in regard to spending and debt, the member opposite has to remember that we've gone to summary financing, and he also has to look at our assets.

Boreal Forest Protection

Mr. Kevin Lamoureux (Inkster): Mr. Speaker, as we all witnessed, the Deputy Premier got fairly excited this afternoon as she jumped to want to table the boreal forest and how the NDP are protecting the boreal forest, you know.

And as she's doing that, I'm looking at this picture of the boreal forest with this big tractor and it's clearcutting 19 kilometres of the boreal forest. There seems to be a little bit of inconsistency. On the one hand, she's glowing about how wonderful she is in protecting the boreal forest; on the other hand, I'm looking at a tractor that's orange–it probably could have the label NDP labelled across it–that's clearcutting the boreal forest.

My question is to the Deputy Premier: Will she be as passionate in going to Manitoba Hydro and ask them why are they clearcutting the boreal forest in order to accommodate a few cottage owners, Mr. Speaker? Will she make that commitment and have that discussion with Manitoba Hydro?

Hon. Rosann Wowchuk (Minister charged with the administration of The Manitoba Hydro Act): Well, Mr. Speaker, I'm really pleased the member opposite has looked at the map that I have provided with him and shown where the one last pristine boreal forest is in the world and how it–important it is to climate change.

But I'm really disappointed in the member opposite. He tries to have it both ways, you know. Put the line on the west side, put the line on the east side, but don't give power to put in a small line from a main line for some cottagers.

The member opposite doesn't want to accept that there are people who have cottages who are trying to reduce their use of propane and diesel fuel and convert to electricity, Mr. Speaker. It's a local project. It is not a major line like the line that would have to go for Bipole III on the east side if he got his way.

Boreal Forest Protection

Mr. Drew Caldwell (Brandon East): Mr. Speaker, there is no government in North America as green as the New Democratic government in Manitoba.

The–our record has been–our record on the environment has been recognized by no less–

Some Honourable Members: Oh, oh.

Mr. Speaker: Order. Order. Order.

Mr. Caldwell: –of an authority–

Mr. Speaker: Order.

Mr. Caldwell: –than Dr. David Suzuki, Mr. Speaker.

Mr. Speaker, while the Premier (Mr. Selinger) and Minister of Conservation (Mr. Blaikie) are in Copenhagen this week acting on Manitoba's clean energy advantage and promoting our boreal forest protection as action to curb climate change, could the Acting Minister of Conservation please inform the House today if any new information has been released regarding Manitoba's east-side boreal forest?

Mr. Struthers (Acting Minister of Conservation): You know, Mr. Speaker, I'm reminded of the Tory position in the 1980s where they didn't have the courage to make the big decisions that are good for Manitobans, when they opposed the construction of Limestone. I'm reminded of the 1990s, when they bungled the Conawapa deal, another big project that they could have been the heroes on that they totally screwed up.

In the 21st century now, they're asking us–the Tories across the way are asking us to forgo the market in Wisconsin and in Minnesota, other U.S. markets, because of their concerns over the bipole.

Mr. Speaker, we're gonna make the big decisions on this side of the House that are good for all Manitobans, and there are people around the world who are cheering us on, including, today, the Boreal institute who said and released data and maps that showed the uniqueness, the uniqueness, Mr. Speaker, of the area that we're going to protect, the area that members opposite would bungle like they did in the '80s and in the '90s.

Pension Regulations Amendment Consideration

Mr. Cliff Graydon (Emerson): Mr. Speaker, when the members opposite attempt to justify cutting back services or their inability to budget, they're quick to reference the economic challenges that the global economy is facing.

However, they're not taking enough steps to protect Manitoba workers from the downturn. As we know, many pension funds have taken a hit over the last year. Some provinces have taken steps to reflect the downturn by amending their pension regulations.

Mr. Speaker, can the Minister of Labour and Immigration tell us that the Province of Manitoba is considering amending Manitoba's pension regulations to reflect what has happened in the markets?

Hon. Jennifer Howard (Minister of Labour and Immigration): I'm pleased to let the House know that those regulations are being examined right now by the Pension Commission and by the capable staff in my department.

We are looking at changes that are going to make the pension system in Manitoba one of the most progressive and, certainly, one of the best systems of protecting pensions for all Manitobans.

***** (14:20)

Mr. Graydon: Mr. Speaker, as far back as 2008, other provinces were addressing the pension issues they knew were coming, but the NDP government was cruising full speed ahead with a $4-billion transfer of money and immune to the recession, they said, that type of strategy, steady-as-she-goes downhill.

Mr. Speaker, the First Minister failed to protect the Crocus investors. He made off with taxpayers' dollars through rebate-gate. He failed workers at Tembec, and now the NDP government is failing pensioners.

Other provinces have taken real steps–already taken real steps to protect their pensioners. Alberta changed the way that the pension values were calculated to reflect changes in the market. As a result, pensioners aren't seeing decreases to their pension cheques.

Mr. Speaker, will the Minister of Labour and Immigration today tell us when these changes will take place in Manitoba?

Ms. Howard: Mr. Speaker, on the topic of pensions, I'm certainly proud to be part of a government that for the first time actually funded the pension plan for the civil servants, and we'll continue to move forward to look at modernizing and making sure that pensions are protected.

On the topic of the situation in Pine Falls, Mr. Speaker, I would like to let the House know that today we made an announcement with the federal government to fund the Winnipeg River Learning Centre, committed $600,000 to that initiative to help the people in Pine Falls and in that area get the training and education that they will need to compete in today's economy. Thank you.

Parkland Regional Health Authority
Ambulance Services

Mr. Stuart Briese (Ste. Rose): Mr. Speaker, I've raised the matter of ambulance services for Eddystone, Bacon Ridge and Ebb and Flow First Nations in this House many times. People in this area of the province are being ignored by this NDP government. The closest ambulance service is 45 minutes to an hour away.

When is the Minister of Health going to do the right thing and provide more timely emergency services to this area?

Hon. Theresa Oswald (Minister of Health): As the member knows, we work with our regional health authorities to ensure that we continue to provide the best emergency medical services that we can to Manitobans. We know that our investment in the Medical Transportation Co-ordination Centre in Brandon has enabled us to capture, to collect data on response times as we've never been able to do before in Manitoba, and that data helps inform regional health authorities about prioritizing where it is that they need to put EMS stations, and we'll continue to work with this community and the region to provide the best service that we can.

Mr. Briese: Mr. Speaker, there are approximately 2,500 people in the area and there are over 200 emergency calls per year. There are trained EMS providers at the Ebb and Flow First Nation, but they need an ambulance to provide their services.

When is this minister going to listen to the people and correct this dangerous situation by placing an ambulance in the Eddystone, Bacon Ridge and Ebb and Flow First Nation area of the province?

Ms. Oswald: And again, the MTCC allows data to be captured about response times. Regional health authorities work with the communities in their region to ensure that the response times are as expeditious as they can be. They monitor safety as being paramount in these situations. And, again, they'll continue to work as a group to provide the most responsive time with the best educated paramedics and emergency medical professionals that are–that are available in the area.

I will continue to work with the member on this issue, and we'll continue to keep growing the emergency medical system as we have done since 1999.

Mr. Speaker: Time for oral questions has expired.

Order. Order. Order.

* * *

Mr. Speaker: I'd like to ask the House to assist me in thanking Jean Speers, who works in *Hansard*, who will be retiring. She has given 20 years' service to the Assembly and has done a wonderful job in her time with *Hansard*, and I would like to ask all members to assist me in saying thank you, Jean, for a job well done.

[Applause]

And also I would like to remind the members that we'll be recessing today until the new year, and particularly because we will have Youth Parliament–will be meeting here in the Chamber later this month, I'm asking that all members empty the contents of their desk before leaving today. And I encourage members–*[interjection]* Order, please. Order, please.

I encourage members to use the blue bins here in the Chamber to recycle their *Hansards* and copies of the bills. Any other material you have to recycle should be placed in the larger blue bins in the two message rooms, and I thank all members for their co-operation on this matter.

MEMBERS' STATEMENTS

Bill 208–Government Support

Mrs. Bonnie Mitchelson (River East): Mr. Speaker, I rise today to express profound disappointment that this government's lack of support for legislation that will protect and enhance the well-being of Manitoba's most vulnerable.

For those neediest of government support, a cheque-cashing fee is often an added burden to an already tight budget. A $13 fee on a $500 cheque may seem like pocket change to the Minister of Family Services (Mr. Mackintosh) and this government, but for our most vulnerable it's significant.

Mr. Speaker, Larry Updike, spokesperson for Siloam Mission, understands the differences small amounts such as this one can make in strained budgets, and he recognizes the value of this bill. In support of this bill, he said, and I quote: It is one small step the Province can take toward helping our city's most vulnerable.

This minister's inability to recognize the unwarranted hardship these fees represent on Manitobans–on Manitoba's most vulnerable, and his refusal to see the value of passing this bill is shameful. Yesterday when I asked the minister if he would consider passing Bill 208, he answered, and I quote: It's very important that we not put in place legislation that will stop retailers from honouring these cheques.

But the truth is that this legislation would not stop retailers from honouring these cheques, as similar legislation exists for cheques from the federal government. Banks cannot charge fees on federal government support cheques.

Mr. Speaker, I strongly urge the government and this minister to support and pass Bill 208. It would be extremely disappointing if this government missed this opportunity to help those who need it most. This bill is a small step that would remove an unwarranted and unnecessary burden on Manitoba's most vulnerable at no cost to Manitoba's Treasury.

Thank you, Mr. Speaker.

Abby Constant-Bercier

Mr. Frank Whitehead (The Pas): Mr. Speaker, today I rise to recognize an inspirational young woman from Opaskwayak Cree Nation, Abby Constant-Bercier. Abby is an outstanding athlete and young scholar who is being recognized nationally for her considerable athletic abilities.

A talented hockey player, 13-year-old Abby was the assistant captain of the OCN Flin Flon Female Pee Wee Blues during the 2008-2009 season and played as the only female on her team, Norman Pee Wee development team, that competed against all other regions in Manitoba.

For the current 2009-2010 season, she is playing for the Aboriginal Team Manitoba Midget Girls, competing in the National Aboriginal Championships. She is the youngest female to ever make this team. She is also playing for Team Norman Midget AA Midget Girls competing in Manitoba Winter Games.

Abby is very committed to her Aboriginal heritage. She competes as well in winter and summer events such as the Trappers' Festival, Opaskwayak Indian Days, where she participates in competitions such as fire-starting, bannock baking, snowshoe races and other events.

She trained every day this summer with her grandpa to prepare for tryouts for these events. She worked very hard to keep up with her 15- and 16-year-old male cousins who were also training, and this helped her to make Team Manitoba.

***** (14:30)

Not only is Abby a gifted athlete, she is also an exceptional student. She has received an honours award for the last two years in junior high and currently boasts a 91 percent average in school.

Mr. Speaker, given the challenges that many northern communities face, we are fortunate that they can look to the leadership of people like Abby. I want to congratulate her on her numerous achievements and wish her luck in her future endeavours. I also want to recognize her parents, family members and the community that supports her because without them her dreams will–may never become reality.

Thank you.

Dairy Farmers of Manitoba Awards Banquet

Mr. Blaine Pedersen (Carman): Mr. Speaker, the dairy industry is very important in both Manitoba and, particularly, my constituency. A number of my– a number of my constituents were recognized for their contributions to the dairy industry at an awards banquet that was put on by the Dairy Farmers of Manitoba on Thursday, December 3rd.

While most people associate the black-and-white Holstein cow with the dairy industry, many producers are using Jersey cows for an increased butterfat quality in the milk.

Isidore Jerseys, which is operated by Henry and Meredith Delichte of St. Alphonse, won the award for the Highest Classified Jersey Herd in Manitoba at the awards banquet. The Delichte family operates a century farm in the picturesque hills surrounding St. Alphonse.

In the 2009 Top 10 Milk Quality Awards category over–for over 500,000 litres marketed, Michael and Darlene Carels of Bruxelles placed first, Daniel and Joann Van Deynze of Holland placed third, and Lakeshore Holsteins of Bruxelles placed fifth. Under the category of Top 10 Milk Quality Awards for under 500,000 litres marketed, Gabriel Fifi of Bruxelles placed first, Sandtree Farms of Haywood placed fourth, Maurice and Henry Delichte of St. Alphonse placed fifth. It should be noted, also, that Gabriel Fifi was also named the overall champion of Milk Quality Awards.

The dairy industry remains an integral part of the Carman constituency. All of us need to be mindful of the contribution, the hard work and the adherence to quality from our dairy farmers in Manitoba. We often take it for granted when milk shows up on our grocery shelves.

Congratulations to these producers, and to all dairy farmers of Manitoba, for their dedication in producing a home-grown, quality product for all of us to enjoy.

Mining Industry Initiatives

Mr. Gerard Jennissen (Flin Flon): Mr. Speaker, mining is vital to Manitoba. The global economic downturn has had a significant dampening effect on the mining industry. However, I am pleased to inform the House about two promising initiatives in northern Manitoba: Victory Nickel near Grand Rapids, and HudBay Mineral's Lalor site near Snow Lake.

Victory Nickel is continuing exploratory work and has plans to develop an open-pit mine and concentrator at Minago. Should Victory Nickel proceed, the mine would be one of the largest industrial undertakings in the province for many years, requiring more than 600 people in its construction and more than 400 employees in its operation.

HudBay Minerals has restarted operations at its Chisel North mine and concentrator near Snow Lake, Manitoba, with full production expected in the second quarter of 2010. The very exciting Lalor deposits will be accessed via ramp from Chisel North. Apart from excellent copper and zinc indicators at Lalor, the value of gold is estimated at between three and four billion dollars; $450 million are committed to completing all three phases at Chisel North and Lalor. The benefit to the entire region will be substantial because HudBay expects to employ up to 100 people at Lalor, once full production is achieved. This will also provide economic opportunities for those employees impacted by the anticipated copper smelter closure in 2010.

Mr. Speaker, these exciting new initiatives, as so many other mining exploration initiatives in Manitoba, were supported by the Mineral

Exploration Assistance Program, MEAP, available through the department of innovation, technology and mines. MEAP increases and stimulates exploration activities, leading to the development of new mines and industrial mineral deposits. The program has–the program has been wildly successful. Since 1999, 539 projects have been completed and approximately $19 million of assistant funds–assistance funds have been issued.

Congratulations to the department and to the northern mining sector for the two current initiatives that I have mentioned earlier, which will not only improve the economy and quality of life in northern Manitoba, but will also have a significant positive economic impact on all of Manitoba.

Thank you, Mr. Speaker.

Elton Sabres Girls Volleyball Team

Mrs. Leanne Rowat (Minnedosa): Mr. Speaker, I rise in the House today to recognize a team of female athletes from my constituency.

I had the honour of witnessing the Elton Sabre girls' volleyball team bring home the AA provincial championship for the first time in history this November in Lac du Bonnet.

Under the competent leadership of head coach Jeff Maxwell, the Sabres entered the tournament ranked third. After falling to the–to the No. 1-ranked Killarney Raiders in round-robin play before beating both Rivers and Souris, the Elton girls finished the tournament with a hard-fought win over the Niverville Panthers to take the gold.

Sabres Jenna Moffat and Stephanie Penner were named to the all-star team, and Brooke Hucaluk was distinguished as the championship MVP. Congratulations to these young women.

High school athletes from my constituency have been a dominant force in the province. Both the Souris and Elton male and female volleyball teams have consistently ranked in the top four provincially for the past many years. Rivers, Minnedosa and Wawanesa teams also make frequent appearances at provincial championships in sports, including fastball, soccer and hockey. The fact that rural athletes have taken a crucial role amongst Manitoba's best and brightest is simply undeniable.

Next year, the Elton Sabres will host–play host to the Manitoba High School Athletic Association's AA provincial championships. I look forward to the opportunity to play spectator to Manitoba's top young athletes in my own backyard.

So, again, congratulations to Jeff Maxwell and the ladies of the Elton Sabres. They have shown that our rural communities and small schools do produce talented and devoted student athletes. To all student athletes across the province, keep up the good work.

Thank you, Mr. Speaker.

ORDERS OF THE DAY

GOVERNMENT BUSINESS

THRONE SPEECH
(Eighth Day of Debate)

Mr. Speaker: Resume adjourned debate on the proposed motion of the honourable Member for The Pas (Mr. Whitehead) that the following address be presented to His Honour the Lieutenant-Governor: We the members of the Legislative Assembly of Manitoba thank Your Honour for the gracious speech addressed to us at this Fourth Session of the Thirty-Ninth Legislature of Manitoba, and the debate remains open and it should be on this side.

Ms. Erna Braun (Rossmere): Mr. Speaker, it's a privilege to rise today to speak in support of the Speech from the Throne for the Fourth Session of the Thirty-Ninth Legislature. I'm very pleased to be speaking in response to our government's blueprint for Manitoba's future, especially since this fourth session marks a new chapter for this government with a new leader and Premier (Mr. Selinger) and new additions to the Cabinet.

I wish to congratulate our new Premier and wish him well as he continues to move Manitoba forward with a strong vision and purpose and that this was recognized by Manitobans in a recent poll in today's *Free Press*. I also want to congratulate two members from our class of 2007, my colleagues from Fort Rouge and Wellington, on their appointments to Cabinet. I know they will bring great skill and ability to their new positions, and I wish them very well.

And I can't forget the member from Elmwood, one of our most recently elected members. What an asset he is. He brings his commitment to the environment, to his role as Minister of Conservation (Mr. Blaikie), and I wish him well in Copenhagen this week as he represents our duty to the environment to the UN conference, and, of course, his many years of experience at the federal level, which, I think, make him a natural choice as House leader.

Congratulations and best wishes to all my colleagues in Cabinet and the back bench as you embrace your new roles with the enthusiasm and dedication that I have seen over the past two years. This enthusiasm and energy that I see with my colleagues is the fuel that will continue to move Manitoba forward, and I guess this is a good time and an opportunity that I would like to take to say a few more thank-yous.

I also wish to thank our table officers. Their hard work and diligence keeps our House focussed and running smoothly. They keep us on track with rules, points of order and points of privilege and especially their work on committee. I would like to acknowledge that in particular. Their patience and guidance through sometimes rough seas is very appreciated and helps us get the work done, and the committee work also includes that of the *Hansard* folks, and I certainly want to extend my thank-yous to the work of the Clerks as well as *Hansard* through the many meetings and travel that we had through the province of Manitoba for our work on the Special Committee on Senate Reform. So I thank you very much for that. Also, to the pages, and I'm always so impressed with their hard work and their ability to quickly respond to our needs and our requests. So, thank you for your hard work and keep it up.

Mr. Rob Altemeyer, Acting Speaker, in the Chair

I obviously can't overlook an opportunity to say thank you to my constituents in Rossmere. Rossmere is such a delightful community to work in, and especially since it is the community that I was raised and grew up in and have spent the better portion of my life. It's an energetic community. Its citizens are dynamic and forward-thinking and have taken on a variety of initiatives that are always wonderful to watch.

***** (14:40)

I think one of the groups that, in particularly, absolutely astonishes me, is the group that works on the Northeast Pioneer Greenway and their good work continues, and they continue to embrace the community and tie Elmwood, North Kildonan and East Kildonan together.

Our road map for the future, outlined in our Throne Speech, will resonate well with my constituents in Rossmere. The themes of the Throne Speech focus on investing in the health and well-being of Manitobans and also bringing a stronger Manitoba.

On many occasions, the constituents of Rossmere have expressed to me how pleased they are with the direction this government has taken Manitoba, especially that our programs and measures have helped our province weather the economic storms that have battered many around the country and the world. They feel confident that we have a steady and even approach that will serve us well into the future.

Our Throne Speech continues that model of a sure hand on the province's rudder. Our theme of investing in the health and well-being of Manitobans is one that all Manitobans will benefit from and that lets every citizen know that we are continuing to move forward with their health and well-being in mind. We are investing not only in the social health of our people, but also the economic and environmental health of our province.

In spite of the recent economic challenges, Manitoba has one of the strongest economies in Canada. We are building on our economic health of our province through a variety of commitments. We have committed to invest $545 million in roads and bridges in 2010 as part of the Province's plan to stimulate the economy and create public assets with long-term benefits. So far the Manitoba government has invested in 1,500 stimulus projects, creating more than 12,000 direct and 10,000 indirect jobs.

In my community, the infrastructure project most closely to their hearts is obviously the Disraeli Bridge. This bridge is of great importance to East and North Kildonan residents. It is our northeast link to downtown. I can still remember how the only route to North Kildonan, when we first moved there, was over the Redwood Bridge, and what a boon the Disraeli Bridge has been to us. And with our investment, it will continue to flow traffic during the construction but, more importantly, it will also be constructed for a lifespan well beyond the initial 40 years that the City of Winnipeg had planned for.

Building cranes and heavy equipment can now also be seen in the Rossmere community. In fact, I could almost say that there's a hive of activity in and around our furniture park that's happening in Rossmere. The government's investment, by building an MPI claim centre on Gateway, is creating jobs not only in its construction, but with the ongoing enterprise that it has built.

Our economic plan also will eliminate both the corporation capital tax and the small business tax in 2010. I know this will be well received in my community, which is sprinkled with many businesses and industry of various sizes. When I drive through my neighbourhood, whether on Henderson Highway, Springfield or Gateway Road, I see shops of a variety: automotive, masonry companies, cabinet-makers, furniture manufacturers. I often think of Rossmere as being a one-stop shop for almost any of your household and family needs. *[interjection]* True. All of these enterprises will see benefits from the initiatives of this government.

We will build on our economic health by ensuring that Manitoba remains one of the most affordable places in Canada to live, work and raise a family. The northeast corner of Winnipeg has a wonderful selection of homes, both older and newer homes, homes which fit a wide variety of budgets.

One of the things which I find that has added a wonderful dimension to our communities are the building of homes through Habitat for Humanity. Over the years, Rossmere has seen its share of Habitat homes. But, just over the last number of months, a project of grander scale has been built in my neighbouring constituency of Concordia. I had the privilege of attending the groundbreaking with the previous MLA for Concordia back in the springtime, and I was recently invited again to attend the blessing of two homes on a street of 12 Habitat homes.

The opportunity for home ownership is very special, and meeting the two families that will be moving into these homes was quite an emotional experience. The look on the faces of the parents and of their children when they were handed the keys to their home and held these keys in their hands tells me how important it is that we work hard to make our province a place where families can afford to live and raise their children.

It is also interesting to note that the affordability for which Manitoba is known is now also attracting people back to our province. Friends of mine have commented on how members of their family are returning to work in Manitoba after years of living in other provinces because they see a better future here in Manitoba for themselves and their families.

And in talking with former colleagues in the teaching profession, they have also noticed a number of teachers who have returned from places like B.C. and Alberta because not only do they see Manitoba as being far more ahead of things in terms of education, but also, again, as a better place to move to and raise their children.

And another example of affordability that I took note of was an article I read in the *Free Press* not too long ago about our Winnipeg Symphony music director and how in Winnipeg he and his wife have finally been able to purchase a home. Having worked in many places around the world, it is here in our fair province that they have been able to realize their dream of home ownership.

Health care is obviously something that's very important to the constituents of Rossmere, and health care is a key priority for this government. From H1N1 to emergency care in rural areas, to helping people live longer through healthy living, we are committed to improving the physical health of Manitobans. And I guess one example, and my compliments to the Minister of Health (Ms. Oswald) with the H1N1 clinics around the province and in the city of Winnipeg, I have to state that the efficiency with which the clinics were held was quite astounding, and as I went for my H1N1 shot two weeks ago, I was so impressed with the–with the patience and respectfulness that the staff and the volunteers at the–at the clinic dealt with everyone who was there. At first I thought that it would be hours to get through because the parking lot was filled with cars, but everything was done so well and so efficiently that, within 45 minutes, I was in and out of the door.

Other commitments that we have made are building a new women's hospital at the Health Science Centre and the other is providing access centres to St. James and northwest Winnipeg, and I know that these communities in both areas of Winnipeg will be very well served by the access centres.

Our River East Access Centre certainly provides a whole host of services all within one facility. Many of my constituents have remarked to me on numerous occasions of the good quality service they receive, as well as the range of services. One, in particular, stands out for me, and that is the midwifery unit located at the River East Access Centre. And I've had a couple of new mums who have let me know how pleased they were that they were able to have their children arrive in the world with the support of a midwife.

Building these centres in St. James and northwest Winnipeg will certainly enhance access to medical centres for–services for our citizens in these areas.

So I've touched on but just a few things that this government is ensuring for the long-term health of Manitobans. We are being fiscally prudent as we build our rural and urban areas, our health care, our infrastructure, as well as justice, and we will continue to build on our strengths to ensure a prosperous future for all our citizens.

Thank you, Mr. Deputy Speaker.

Mr. Rick Borotsik (Brandon West): Mr. Deputy Speaker, thank you very much for allowing me the opportunity to rise and respond to a Throne Speech, but, before I do that, I, like others, would simply like to thank a number of people. Obviously, the first ones I would like to thank are my constituents, the constituents of Brandon West, who have allowed me to stand in this Chamber, who have allowed me to walk into the front doors of this Legislature, who have allowed me to represent them for many years, the last few years here in this Legislature, and I don't think any one of us should ever, at any point in time, take for granted the responsibility that we have with not only our constituents, but, obviously, the constituents for the whole province of Manitoba.

***** (14:50)

And I know that all members in this Legislature are honourable members, and they do come into this House recognizing the responsibility that they have to make sure that we, as Manitobans, have a much better quality of life, a much better opportunity for ourselves and for our children. And I say that, obviously, very open and honest with respect to both sides of this Legislature, Mr. Speaker.

I would like to thank the table officers who perhaps don't get as much recognition as they should but who certainly keep us, as members of this Legislature, on the straight and narrow with respect to the rules and regulations that we do follow on a regular basis.

Mr. Deputy Speaker, I'd like to thank our caucus staff, the PC caucus, and I know that I would also–I suggest that the members opposite would like to give their own caucus staff their thanks for the energy, the effort, the time that they put into their jobs here in this Legislature on behalf of not only us as members but certainly the constituents in Manitoba.

Others we talk about, the Speaker, earlier today, had congratulated a member of the *Hansard*, and what we don't recognize and what we sometimes take for granted is the effort that *Hansard* members put into this Legislature. And if you haven't seen the *Hansard* office in the bowels of this building, I would ask that each member go down there and just have a look to see how *Hansard* is produced on a very timely basis; how our every word is being transcribed by people who are very dedicated to make sure that what we do say is placed in a record for posterity's sake.

Mr. Speaker, I would like to thank those people who keep our offices clean, the security and the maintenance that we have in this building 'cause sometimes we don't appreciate the job that they do to make sure that our job is so much easier to perform. And, being that it's Christmas, I would also wish them a very merry Christmas going forward.

As for the Throne Speech, the–one of the members of the government–and I won't mention any names–one of the members of the government, after the Throne Speech, did in fact indicated that the Throne Speech was perhaps a little thin gruel. I would say that that was the case. Not only was it thin gruel, but it was perhaps somewhat mediocre, although this government does embrace mediocrity in all that it does. It certainly embraced mediocrity in this Throne Speech as well when they put it forward.

The fact that we're here, Mr. Speaker, Mr. Deputy Speaker, the fact that we're here two days after the Throne Speech session was supposed to be completed speaks to the inability and the mismanagement of the government not only in being able to control the operations of this Legislature and this House but the–but the operations and the mediocrity that they bring forward in managing the affairs of the Province of Manitoba.

A member from opposite said, what about the bells ringing? Well, Mr. Deputy Speaker, when one knows the rules of the House, one does not call a Throne Speech specifically for the number of days it is necessary to debate a Throne Speech.

The member that just spoke congratulated the member from Elmwood, the new–the new House leader. Well, I should say that the member from Elmwood did not, and perhaps does not understand the rules as he should understand the rules; otherwise, Mr. Deputy Speaker, we would not be here today speaking to the Throne Speech. We would've had an extended sitting of this Legislature and then the embarrassment that falls on the NDP's mismanagement of the Legislature and this House would not have been necessary.

So I would not congratulate the member from Elmwood. I would suggest that he should probably sit down and in fact learn the rules of this Legislature. I know the table officers would be happy to explain to him the rules of this Legislature.

The Throne Speech, Mr. Speaker, when I was asked to respond to it after the Throne Speech–and I didn't say thin gruel. I didn't say mediocrity. I didn't say mediocre. What I said was it was the opportunity of a new Premier to set the direction of his government. It was the opportunity of a new Premier to give a vision and a direction as to how he wanted his government to operate over the next two years. I saw none of that.

What I wanted to see was a Premier to stand up and say, I've had it with the same old, same old, steady as she goes. I want Manitoba to be a have province. That's my vision for the province of Manitoba. That's what I wanted him to say. I wanted him to say that agriculture in Manitoba is the economic backbone of our–of our economy. I wanted him to say that no longer are we gonna depend on others, handouts from Ottawa, and I don't want to depend on other policies coming from other provinces. I wanna make sure that Manitoba puts its own agricultural policy forward that's gonna support agriculture. I heard none of that, Mr. Speaker.

I wanted a Premier, a new Premier, to stand in this House and say in his Throne Speech, I want opportunities for rural Manitoba. I want opportunities beyond the Perimeter Highway. I want to have rural Manitobans represented in our economic vision going forward. I heard none of that, Mr. Speaker, from this Throne Speech.

I wanted a Premier to stand up and say, we are going to change the direction of our fiscal policy. We are not going to borrow our children and grandchildren into bankruptcy. What we're going to do is we're going to have a plan set out where, in fact, we're gonna pay back all of that debt that we now have so that we're gonna leave a legacy for our children and our grandchildren of no debt, not debt that they can drown in. I wanted a fiscal policy where the Premier stood up and said, for the people of Manitoba, we're gonna be competitive with respect to tax regime in this province. No longer are we gonna tax the men and women, the hard workers of this province to the point where we're the highest taxed in the country. I wanted the Premier (Mr. Selinger) to stand up and say, we're gonna change that policy. We're gonna become better than what we are right now.

But you know what, Mr. Speaker? I heard absolutely nothing that would say that we would do that.

Right now, Mr. Speaker, and I've heard all of the accolades, all of the platitudes that come from the other side of the House, the fact of the matter is there is a reality. The reality is in Manitoba we have some very, very serious financial issues–not dressed–not addressed by the Throne Speech in any way.

We have–and I talk about a have province, Mr. Speaker. Our province right now is dependent for 40 percent of its total budget on the federal government. That's like each and every one, as members of this Legislature, if we had to depend on our parents or our aunts or our uncles or someone else to fund our lifestyle by 40 percent, we would be dependent on those people. We cannot afford to be dependent on the federal government for 40 percent of our lifeline. We have to be dependent on our own resources.

Ms. Marilyn Brick, Deputy Speaker, in the Chair

And no where in the Throne Speech does it say, let's become much more reliant on ourselves, self-reliant. No where does it say that. It says, in fact, quite the opposite. We're going to continue to go and beg the federal government for more money so that we can squander it on wasteful mismanagement.

No where in this budget did it talk about tax cuts. It's talked about it before, Madam Deputy Speaker. It's talked about 'em before in budgets that have been put down. It's talked about trying to become a little bit more competitive with respect to our basic personal exemptions, a little bit more competitive with our tax rates, a little bit more competitive with our brackets. But no where does it talk about that. It's gonna maybe talk about it in the budget, but I doubt it because we've already got the foreshadowing from the Finance Minister that we are in some challenging times, and we are. Make no mistake about that. But they're challenging financial times of their own making.

Madam Deputy Speaker, I talk about the debt. I said it today in question period, no where in this Throne Speech did it talk about becoming much more reasonable with the debt loads that we have. If you look at the first-quarter financials, because we can't have the second-quarter financials 'cause that–that's not gonna happen until December the 24th.

An Honourable Member: Everything's changing. You don't understand. Everything's changing.

Mr. Borotsik: Everything's changing, but, unfortunately, they keep the same schedule. You see, I asked the Finance Minister if she wouldn't mind tabling the second-quarter financials, and she said, oh, no, no. We're just gonna do it the same we's–we've always done it. And that'll be, oh, 1 o'clock on December 24th. Well, Madam Deputy Speaker, there was no need for that, but if we go back to the first-quarter financials, it says right here that this budget year there's going to be new cash requirements of $1.8 billion. Those new cash requirements are borrowing debt of another $1.8 billion. It's gonna take our debt to $23 billion in this province. It's gonna take the debt to an unbearable level. And there's no blue sky; there's no light at the end of the tunnel. It's just going up and will continue to go up. And I'm very concerned. And there was no speech–no speaking to that in the Throne Speech.

***** (15:00)

Fiscal constraint–restraint. It was talked about that they're going to have some programming looked at to ratchet it back on programming. We know that there was a letter that was sent to all ministers and deputy ministers that said that they were going to change their operations the way they spend our money.

Well, we know there's wasteful spending. We know there's $14 million that we could save right off the bat by these enhanced identification cards, which are not being accepted by residents of the province of Manitoba and, quite frankly, the opposite. The people that I talk to that come into my office and who have tried to go through the process of the enhanced ID say, this is absolutely the most ridiculous program I've ever seen in the province of Manitoba, and I will get a passport. So we could've saved $14 million.

Madam Deputy Speaker, 370-odd million dollars that they want to spend–waste on nitrogen coming out of the effluent in the city of Winnipeg, 640 million that they want to spend or waste on a west-side–a west-side Hydro line, Bipole III, which I find there's not a logical individual in this province that can understand why they would continue to want to waste $640 million of our money for absolutely no reason at all.

But the one that I really enjoy, if you want to talk about wasteful spending mismanagement, is the new Minister of Justice (Mr. Swan), who's just spent a quarter of a million dollars. Now it doesn't sound like a lot of money, but a quarter of a million dollars, ladies and gentlemen, is a lot of taxpayers' dollars, borrowed dollars, because you're going out and borrowing $1.8 billion. Madam Deputy Speaker, $250,000 has gone into an advertising campaign to keep people out of gangs.

Now, we heard yesterday that the advertising is being placed on wonderful programs like *Ellen DeGeneres*. I don't even know the soap operas. What is it, *The Young and the Restless*? I would suspect that they would be better off putting the advertising during *The Simpsons*, Madam Deputy Speaker. At least, at that point in time, when they have *The Simpsons* advertising, that Homer could actually look at it, and say, d'oh. Now for *Hansard*, for *Hansard* that's d-o-h. Okay, that's d-o-h. *Hansard*, you can report it as that, because Homer Simpson says d'oh, and I'm going to say, d'oh, to $250,000 wasted, absolutely wasted on a stupid advertising program that is going to accomplish nothing. But that wasn't in the Throne Speech. That wasn't in the Throne Speech, that we would just simply waste money, as we always have and will continue to waste money.

I'm going to talk about my constituency. I told you at the very beginning of this that I am very, very thankful and somewhat humbled by having my constituents send me to this august place. I looked at the Throne Speech and I read the editorials after the Throne Speech, and I found that actually Brandon was short shrift. And I know you can stand up and talk about all those wonderful capital projects that are ongoing in Brandon, but I should also say, first of all, that those capital projects should have been done within the first 10 years of your mandate. And, quite frankly–quite frankly, you cannot continually take credit for projects that were done 10 years ago.

You've reannounced and announced and reannounced and announced so many times, the bridge construction, the hospital construction, the CancerCare construction. I'm even confused as to when and should and could've been built. Too many of the projects have already been started or completed but reannounced in a Throne Speech, which I find very ludicrous, Madam Deputy Speaker.

We talked about the ACC trade building. Well, I drive by First Street all the time, and it's almost complete, but it was mentioned in the Throne

Speech. I drive–I drive in Brandon, and I see the BU physical plant, which is completed now, but it was mentioned in the Throne Speech.

I don't know if there was anything new that was mentioned in the Throne Speech. Actually, there wasn't anything new that was mentioned–ah, that's not true, that's not true. There was one thing new about Brandon in the Throne Speech, and they talked about TIF, which is the tax incremental financing program that's suggested by this government, which really is simply another revenue centre taking money out of schools and property tax owners to put into their own pet projects. So let's get things straight here.

They did mention TIF for the Strand Theatre project, but it was gonna be funded by the school divisions and the municipality. Oh, isn't that wonderful. But that was mentioned in the Throne Speech. It was the only thing that was mentioned for Brandon.

One thing they didn't mention in Brandon, Madam Deputy Speaker, in the Throne Speech, was their absolute abysmal record when it comes to crime and crime prevention. I travel across the country on a fairly regular basis and I have to admit I fly the Manitoba flag. I believe strongly in this province. I believe we have great opportunity in this province. I believe in this province. It's been very good to me and I would like to, and I believe I have put back into the province as much as I possibly could. But, when I go and I travel across the country, I hear, and I think if they opened their ears they would hear as well, the comments that come from other jurisdictions.

They're now coming from Saskatchewan, Alberta, British Columbia, Ontario. I hear them and, unfortunately, they say, what's happening in Manitoba? Why is it that you're the murder capital of the country? Why is it that you're–why is it that you're the auto theft capital in the country? Why is it that every time we turn on a television set in the evening we hear about another serious assault or a serious incident in Winnipeg, Manitoba? And that hurts. That hurts because I depend on the government to put in place proper policies to solve those problems and this government has no idea, has no desire to be able to fix those problems.

I also, in talking to people from Saskatchewan, who now look down their nose at Manitoba, which, I find, when I was growing up in Manitoba, it was quite the opposite. We always thought perhaps Saskatchewan was the poor cousin. We're now looking at Manitoba as that black hole, that poor cousin. See, you see, Saskatchewan has now got–has now got the strongest economy in the country.

Saskatchewan now has less debt than they had when the recession started. Saskatchewan–Saskatchewan now has–now has, Madam Deputy Speaker, a have province status and they throw it in my face constantly. And you know what? These people across the way saying, oh, how's that working, oh, so they're a have–they're a have province now. Isn't that just wonderful. We can depend on the federal government for money that we can waste. We don't have to be a have province. Well, I wanna be a have province and that should've been reflected in the Throne Speech.

Madam Deputy Speaker, I was very happy to hear the Throne Speech to know exactly where this government stands, which, in my opinion, is nowhere. Mediocrity is their mantra. It's what they scream from the opposite sides of the benches. And we will vote against this Throne Speech and we should vote against this Throne Speech because the direction that was put in this has nowhere to go.

In fact it's the first Throne Speech that I know of that the Premier will not speak to and the Premier will not vote for. And I've always said if you're not gonna vote for it, then I would just assume at that point that you're opposed to it. So I would say I'm really apologetic for the NDP, why their own Premier will not support his own Throne Speech. Thank you, Madam Deputy Speaker.

Hon. Steve Ashton (Minister of Infrastructure and Transportation): Madam Deputy Speaker, I want to start by saying how great it is to be able to speak on the Throne Speech once again. I always say the Throne Speech can bring out the best in debate in this House because it gives us all an opportunity to talk about our vision for this great province of ours.

And I must admit, by the way, I have been–I won't say I've been keeping notes. I'm not sure there was a lot of noteworthy comments from members of the opposition but, you know, whether it was the Leader of the Opposition (Mr. McFadyen), or the member for Brandon West, what struck me is really how out of touch they are with what's going on in this province.

I mean, the quote of the day was from the member for Brandon West. He said it's, you know, the sun isn't shining in Manitoba. There's no light at the end of the tunnel. I don't know if he stepped outside of this building, but it's a classic cold winter day in Manitoba. The kind of cold winter day that defines this province that we want to save from climate change. And it's a bright sunny day out there but, you know, it's not just a bright sunny day in terms of the climate. We have seen in this province, in this past year, some of the most incredible developments we've seen in a long time.

***** (15:10)

We have the highest increase in population in this province since 1971, Madam Deputy Speaker, 1971. No mention of that from members opposite. You know, I want to put it into context. The increase in population year over year is greater than the size of the city of Thompson. That's the third largest city, and it's a result of the growing diversity of this province, the growing Aboriginal population, the increased number of immigrants. Again, something that didn't just happen. We have 14,000 immigrants coming to this province because of the success we made of the Provincial Nominee Program. By the way, we're the second youngest population in the country. Other jurisdictions throughout Canada and throughout the world are looking at what will make them develop in the future and we've got it.

So I don't want to just start off with anything other than a clear statement about the real sense that's out there. I want to also remark on something else that's quite noticeable and that is that we've been in government for 10 years. You know, I think probably one of the reasons as I've seen it is certainly we've seen over the last couple of weeks that the opposition, you know, basically has tactics in search of a strategy. They still haven't, Madam Deputy Speaker, most of their approach in this House hasn't changed in 10 years. Now, I'm not going to give them too much advice, but, you know, I found from previous experience they don't listen anyway.

But, you know, if you look at what happens when members opposite–I mean they're running out of letters in the alphabet to, you know, to point negative things that at the government in their amendments to Throne Speeches. They got to Q this year. You know, it's very difficult for them, I think, to actually get up and say one clear thing, and that is one of the reasons why this government continues to have the support from the people of Manitoba is that in many ways, this province is far better off than it was 10 years ago, far better off. That's the reality.

Now, I want to give you one quick example, one that I have some direct experience with, and it's newly appointed Minister of Industry and Transportation. One of the first things I wanted to do was double check and reference 10 years ago with today in terms of transportation. Now, what's interesting, by the way, some things haven't changed. The Leader of the Opposition (Mr. McFadyen) November 20th in the *Carman Valley Leader* is once again trying to divide and conquer, saying that too much is going to northern Manitoba. Well, I want to put on the record, since we came to government, something is going to northern Manitoba. There was not much in the 1990s. In fact, a significant investment's taking place in northern Manitoba.

We're extending the all-weather road network which is a significant development for those communities, but there's not a region of this province where we're not spending more on infrastructure, rural, in and around the city of Winnipeg and I've–you know, the member for Brandon West (Mr. Borotsik), I would suggest by the way, he go to the 18th Street Bridge, and he may want to stop there. Park on the side and look at it because it's the NDP that, again, is redeveloping Brandon in terms of infrastructure. You know, there's no tunnels in Brandon; there's bridges. He just has to open his eyes. He'll see it.

Now the real problem with this approach, though, is you notice they had little code words that they like to throw out. They don't get up and say if they were elected to government there would be major cuts in spending, but let me tell you what they did when they were in government before with infrastructure. They didn't increase it. At one time, it was less than $100 million, and I remember–I'll never forget the year they got money from the federal government, they deducted it from how much they were spending. What we've done is we've taken the infrastructure opportunity with a federal government that is talking about developing infrastructure, and we've partnered and I've been the first one to give credit where credit is due. We've accessed $100 million this year on highways alone under infrastructure funding and whether it be in terms of highways or recreational facilities or sewer and water, we are building, but you know what the code word is?

You know, they talk about debt. You know, I think the Leader of the Opposition talked about debt. I think the member for Brandon West talked about debt. You know, it's kind of stereophonic over there, the two of them, debt, debt, debt, debt, debt. But you know, what does that debt represent? It represents investment in our highways, $310 million in terms of education infrastructure. Major construction that's taking place in terms of *[inaudible]* and by the way, including our Justice facilities. Major construction in terms of health. Wherever you go in the province, we are seeing at a time of economic slowdown that Manitoba's leading the way in investing in our infrastructure. That's what they don't tell you because the real code word when they talk about debt is if they get into government, God forbid what they would start cutting first, but one of the things they would most definitely cut is their investment in the public sector.

Now, what's the other theme of this session, this pre-New Year session we're seeing from members opposite? You know, again, we see the whole approach in terms of tactics and strategy here. Well, you know, with all the bell ringing and all the rest of–the other issue they keep raising is Manitoba Hydro. They have not said a good word about Manitoba Hydro since the beginning of this session.

Now that should come as no surprise because they also talk about debt again. Now, what is the debt being invested in, in Manitoba Hydro? Well, right now it's being invested in a hydro dam, the Wuskwatim Dam, in partnership with Nisichawayasihk Cree Nation. And if they took the time to come to northern Manitoba, they would find out that we're seeing significant partnership between the community, many people from northern Manitoba working. Of course, it could always be a greater amount, but, you know, that investment is part of the future of Manitoba Hydro.

You know, they talk about some of the recent trends with Manitoba Hydro. I want to put on the record that, yes, energy prices in the U.S. have dropped; our export markets have been affected. There's cheap natural gas. But the bottom line when it comes to Manitoba Hydro, it's got a strong future. It's a major asset, a public asset that is gonna develop this economy, and not the least of which is because we do have the lowest hydro rates in North America–*[interjection]*

You know, they can't even get up and ask a question without attacking a simple fact, that we have the most affordable hydro rates in this country. And dare I say, with the discussions taking place in terms of climate change, it's clean energy, and we have proven that we are leaders in terms of clean energy, in terms of climate change. Now, that's the–that's the second theme.

Now, the third theme you'll run into–they like to recycle things, by the way. I'm not talking about environmentally. I loved when the Leader of the Opposition got up and talked about cutting the payroll tax. You know, they were in government for 11 years. They promised they were gonna cut it in five years, and, as a former premier once said, they just didn't say which five years they were gonna cut it in. You know, they–they've recycled pretty well every theme they had from the 1990s. Now, does anybody really wanna go back to that era? I don't believe so.

But I don't–I don't want to assume anything with the members opposite. I've always said they're stuck in the '90s. My view is it's probably the 1890s, in terms of their political philosophy. But at a time when the–when the world has responded to the recession in terms of stimulus, they are attacking the investment. And yes, yes, in some cases it involves debt that is invested, just like when you buy a house and you invest in the mortgage for the house, that's invested in the future productivity of the province.

Well, I wanna paint a very different picture because I can say that one of the strengths of this government, by the way, is the strengths of our team and our support throughout the province. We are the only political party that has support from all areas of this province. And I can tell you–*[interjection]*

Well, the member opposite talks about, you know, support in his area perhaps for a different political party. You know, they don't even try in northern Manitoba. There's been more sightings of the Sasquatch than there have of Tory MLAs, Madam Deputy Speaker. So they make no effort when it comes to huge parts of this province.

But, you know what? I want to–*[interjection]*

An Honourable Member: You say that every Throne Speech.

Mr. Ashton: Well, I know. Members opposite knows that I do talk about the Sasquatch many, many times. Go to Norway House, they've seen a lot more sightings of the Sasquatch there.

But you know, the reality is we've also, I think, shown something that's important the last couple of months, and that is that we are very much a party and a government that is team-based. And I know something about that; we went through a lively period a couple of months back in a leadership–*[interjection]*

An Honourable Member: How'd you do?

Mr. Ashton: And for the member–well, member opposite says how I did. I went for the gold, got the silver. But, you know, I can tell you one thing: This New Democratic Party and this New Democratic government, we're not like Tories in another way, and that is we are united. We have a transition, I think, that's demonstrated that, and the fact that I'm here today speaking on this Throne Speech, and all members of our caucus speaking support of this Throne Speech is indicative of the fact that we are a party that does work together, unlike members opposite.

And I wanna just conclude with this. You've got, really, two clear choices in terms of vision in this province. The members opposite are the dark cloud party, you know, nothing good is going on. In fact, I went through the Leader of the Opposition's speech, and I found maybe one paragraph that was positive. You know, the member for Brandon West (Mr. Borotsik), and member after member after member got up with negative comments. And I realize they've been in opposition for 10 years, and opposition is honourable, and I realize they may be getting somewhat downcast about their continuing ability to be an opposition party not ready for government.

***** (15:20)

These–you know, it's interesting, they talk about daytime TV. This–if they–if you're ever at a party that's not ready for prime time, it's the PC Party. I mean, you know, their Finance critic giving impressions of Homer Simpson, you know, obviously, he studied the part very well.

But, you know, we are a government, on the other hand, that has a positive vision for this province. We have dealt with some very difficult economic circumstances, but still are doing better than many areas of the country.

We're investing in our infrastructure, we're investing in our public services, and we represent all of Manitoba–by the way, an increasing Manitoba. And, in the end, I say to members opposite, and I say to the people of Manitoba, one of the reasons that I am supporting this Throne Speech is because it is an optimistic document that reflects what I always say is the quote of a great Manitoban that sums up where we are after 10 years in government; that is we've accomplished a lot. But, to quote Randy Bachman, you want to look at the future, Madam Deputy Speaker, you ain't seen nothin' yet.

Mr. Kelvin Goertzen (Steinbach): It's always a pleasure to follow my friend from Thompson with his Throne Speech who got a rousing support here in the House, but wasn't able to garner the same sort of support two months ago, Mr. Speaker, when he was entering the leadership race for the NDP.

And I know he quoted some statistics, and statistics can sometimes be deceiving, and 10 different people can quote him 10 different ways. I think he said he finished second in the race. Some would say he finished last in the race 'cause there was only two people who wanted to actually run for the leadership of the NDP. But we know that his position as the former future leader of the NDP is solid and entrenched in that party, Mr. Speaker.

It's always difficult to–it's always difficult to be one of the last speakers on the Throne Speech because, you know, you want to welcome everybody back and welcome everybody back for a new session, but it's been such a short session that's it's almost over. And so welcoming people back wouldn't make a lot of sense.

So, I will, though, say to the–to the Speaker and to the table officers and to those in *Hansard* and those working in the Legislature, I wanna wish you all a Merry Christmas, best of the season, a Happy Hanukkah as you celebrate with your–with your families in the days ahead.

But we still have some work to do and it was difficult to get this government to come back to work. You know, there was many who were trying to have the Legislature recalled earlier so we could debate the issues of the day and ensure that Manitobans were able to have their voice heard here. But over and over the government stalled and decided that they didn't want to come back to the Legislature. And I know that that probably left a number of Manitobans puzzled and wondering why the government was running from the democratic responsibility that all of us who were elected to uphold from our constituents.

And then we realized why when they came back, as they stumbled around trying to organize the House, and they made their mistakes. And the new House leader, the member for Elmwood (Mr. Blaikie), hadn't read the rule book or he read the wrong rule book, and they continued to get things wrong day after day and has led us to this point where we now are in the extended session. I don't ever remember a time when I've been called back three times to the Legislature within three weeks. But that's what's happened because of how badly the government has managed the House–*[interjection]*

Well, and I hear the new member for, I think Entrepreneurship, the new member–Minister for Entrepreneurship (Mr. Bjornson) trying to read the paper and talk at the same time. I know he had a difficult time doing even one thing right in his former portfolio. He needs to try to at least to hone in and to focus either to listen or to do something else and not to try to do too many things at the same time.

And I know, Madam Acting Speaker, that when we talk about the government wanting to stay out of the Legislature, try to avoid this place of democracy; we saw the reasons why. We hope that when we come back in the spring and maybe it'll be earlier–you know, there's–just because there's a rule or an agreement that we're gonna come back in the third week of March or something along those lines doesn't mean we couldn't come back earlier, you know. All of a sudden, if the Premier (Mr. Selinger) decides that he wants to work a little bit more here in the Legislature, he could call it back sooner. We could have a good, democratic debate. I would encourage him to do that. If his House leader gets through the rule book and feels that he has a grip and understanding of what's going on here, he absolutely should call it back sooner. We're always ready to come back here and to talk about the issues that are important to Manitobans and important to our constituents.

I noticed in the–in the Throne Speech, Mr. Speaker, that there was a number of things that just simply weren't mentioned. Even the member for Thompson (Mr. Ashton) refused to talk about crime in his–in his address to the Throne Speech, and that's the same member, when he was running for leadership, I remember him saying that crime was out of control, that it was skyrocketing. That's what he said when he was running for leadership, you know, so it was interesting. He talked about team and how there wasn't that division, that, finally, when the chains are off of some of those members who are trying to seek the leadership, we finally heard some of what they actually feel, and we heard it from the member for Thompson. He said crime was out of control, it was skyrocketing.

We heard for the now Minister of Justice (Mr. Swan) who said that we should look at building the Bipole III along the east side of the province instead of the west side of the province. Suddenly, everybody was unshackled, and they were saying what they actually felt and what they knew and what they know that Manitobans have been saying to them. But now they've sort of clustered back in and are trying again to toe the party line and put all of those concerns that Manitobans have brought to them aside and they don't want to have them addressed.

But I wish that they would've spoken more, that the member for Thompson would've spoken more about his feeling about how crime has got out of control, both in the city of Winnipeg and throughout Manitoba. He would've been wise to continue on his path during the leadership in recognizing that crime is out of control under this NDP government. Successive ministers, whether it was the member for St. Johns (Mr. Mackintosh) or whether it was the member for Kildonan (Mr. Chomiak) or now the member for Minto (Mr. Swan), have taken the approach that we're gonna be soft on crime and try to convince individuals that things are gonna get better, and the member for Thompson wanted to compare, you know, how things were in 1999 compared to how they are in 2009.

I wish you would've talked about crime and made that comparison, you know, and looked at how the growth of gangs has occurred in the city of Winnipeg, street-level gangs. We suspect that there are probably six to seven thousand known gang members in the city of Winnipeg in the province of Manitoba, but it's hard to quantify. It's hard to quantify, Madam Deputy Speaker, because of the fact–because of the fact that they unplugged the gang data base. You know, we had a system in place in the 1990s where there was about 1,500 known gang members and we were tracking them and we were using that information to try to see if things were getting better or things were getting worse when it came to crime, and what did the NDP do when they saw that their approach was causing gang activity to increase? Well, somebody ran into the back office and unplugged the database and said, we can't track it anymore. We're not gonna look at it anymore. Let's put our heads in the sand. Let's close our eyes and let's pretend the problem isn't there and maybe it'll go away.

And I know the member for Transcona (Mr. Reid)–I hear him making a couple of comments. I know that his constituents would be concerned. I've spoken to some of his constituents concerned about the level of crime in Winnipeg, and they might wonder why he is not standing up and saying what the member for Thompson (Mr. Ashton) did, that, under the NDP, crime has been skyrocketing. Maybe he'll have that opportunity in March or sooner if the Legislature comes back sooner. I'd encourage him to go to the Premier (Mr. Selinger) and say, we want to be here a little earlier to deal with some of these issues–if he has that influence. I can't remember which horse he backed in the race, so that may be difficult to have that influence, but I think that he should go–*[interjection]*

What's that? *[interjection]*

Well, you know, and I hear the member for Transcona making disparaging remarks when we talked about crime, when we talk about the concerns of his constituents, and I think that, ultimately, in the long run, that's an approach that will not serve him well as he goes back to them for support. But the issue of crime in unplugging the database is only one thing.

But, you know, we had–in fact, the new Minister of Justice (Mr. Swan) was making an issue about how he wasn't able to use a gang courthouse, and somehow he thought that that made him strengthen his hand; that Manitobans would somehow rally around him because he wasn't able to use a gang courthouse. Well, the reason he wasn't able to use the gang courthouse was he hasn't been able to get the gangs off the street, Madam Deputy Speaker. That's the reason he hasn't been able to use their courthouse. You don't need it if you're not going after the gangs. So, over and over we see these different failures when it comes to the issue of crime.

You know, it was sad. I think it was maybe not the saddest moment that I've seen in the Legislature, but one of the sadder moments when the Minister of Justice stood and said that–yesterday, when we were talking about the 47-year-old father who was killed as a result of a stolen vehicle on Friday–when he said that they were busy celebrating their achievements. You know, at a time when I think all of us should have our hearts going out to the family and redoubling our efforts and looking at what more could be done, he said that it was a time for celebration, and he was glad to be with the member for Kirkfield Park (Ms. Blady) to pat themselves on the back when it comes to auto theft.

***** (15:30)

And yet today we have the president of the Winnipeg Police Association, Mr. Mike Sutherland, saying that what's gonna be happening now, what they've already seen to some extent is, because of the immobilizer program, because of the focus of the government to put all of the onus on the victims, and instead of going after the criminal intent of those young people who are trying to steal cars, now there's going to be more carjackings because and, you know, this would be common sense and you don't have to be a lawyer, you don't have to be a criminologist, I think, to understand this, that if you don't go after the–if you don't go after the criminal intention of a person trying to steal a vehicle or commit some other crime, they're just gonna commit some other crime. And, if every car has an immobilizer, they may look at carjacking. They might be doing breaking and enters. There might be violent crime. And so you don't actually have less victims, you have just different kinds of crime.

And that's what this government has never understood. I mean, years ago they looked at a–at a seniors program and said, well, let's hand out deadbolts to the seniors 'cause they're concerned about crime–*[interjection]*

Well what–well, you know, I mean the member for Transcona (Mr. Reid) asked if one of the professors who's involved with the–with the program is wrong.

You know, I'm happy to stand by the police. If he wants to stand by every professor in the province of Manitoba, I'll stand beside every police officer in the province of Manitoba, and we'll have that debate. If he wants to ignore the police–if he wants to ignore what the police are saying on this issue, I'm more than happy to rent a hall, we'll bring in the police officers, he can bring in academia and we can have that debate about how to make our province safer.

But, you know, I think that most individuals would recognize that if you don't go after the criminal intention of an individual who wants to commit a crime, if you just put all of the onus on the victim, you know what's gonna happen. So they went to the seniors and they said, well, here are some deadbolts. Lock yourself in your homes. While the criminals are running outside, you lock yourself as a prisoner in your home, and that'll keep you safe.

Well what approach–what approach to crime is that, Madam Deputy Speaker? And what's the result gonna be? Well, it's clear what the result's gonna be. You're gonna have an increase of crime because individuals know that the government's gonna focus on the victims instead of focussing on them, and that's what happened. And we saw it, unfortunately, with the accused individual, who now has been charged with manslaughter, the 18-year-old individual, as a result of the death on Friday.

Here's an individual who was a level 4 car thief, and I think most members would know that that's the worst of the worst. That's the–you've been identified–if you're identified as a level 4 car thief, that means they know you're a repeat offender, you're likely to offend again and you have to have intense supervision. Well, you know, according to the initial reports, this individual obviously wasn't following his court orders that he had placed upon him. He didn't have electronic monitoring, he didn't have that supervision and we saw the deadly results, Madam Deputy Speaker. We didn't have that kind of intense supervision.

This wasn't somebody who never had a previous record, who you wouldn't expect would be committing a crime. This was a level 4 car thief who had already been identified as somebody who was likely to reoffend. But because this government refuses to crack down on those court orders, something that's fully in their ability to do, fully in their jurisdiction, in their purview, because they have decided that they're not going to enforce those court orders, we're gonna continue to have this type of violent crime where there's auto theft, gang activity or other kinds of crime and they know, you know.

And, you know, it's so sad because every time you hear of a horrific incident, whether it's a gang incident or some sort of other violent incident, you know that when the perpetrator is caught and charged, you know it's gonna be somebody who is breaching a court order. It's inevitable. We know that it's gonna be somebody who should've had some sort of a court order in force but this government refuses to enforce those court orders and we're gonna continue to have victims as a result.

So, look at their approach. You know the first thing–the first thing that the new Minister of Justice (Mr. Swan) did when he assumed office–and I had some hope, you know, I'd like to think that I'm a person who has hope and I believe I have an optimism, that things could change, Madam Deputy Speaker, so when the new Minister of Justice was sworn into office I said, well, let's give him the opportunity. Let's hope that this'll be different than the member for St. Johns (Mr. Mackintosh) was, and the member for Kildonan (Mr. Chomiak) was, the two individuals who announced eight gang strategies in 10 years. Let's hope that this would be something different.

But on one of the first days of office, the Minister of Justice announced his new strategy to take gangs off the streets, to wipe them away, to clean up the streets of Winnipeg was to launch an ad campaign on shows like *Ellen DeGeneres* and on soap operas like *The Young and the Restless*, and on *Canada AM* at seven in the morning, and hope that those gang members, instead of being addicted to selling drugs on the streets, were addicted to soap operas. That was his approach to trying to get gangs off of the streets of Winnipeg.

And you know we talk about the carrot and the stick approach, and I've heard the–I've heard the members opposite talk about how you need to have both the carrot and the stick approach. Well, you know, we don't disagree but, you know, there's more carrots over there than Bugs Bunny has and at some point, at some point, Madam Deputy Speaker, you have to bring out the stick, because there comes a point in time where these individual gang members are so entrenched and so hardened in that gang lifestyle, that there's going to be some consequences. You know, and it's not like there's no hope.

I've talked to individuals across North America about gang activity and how to–how to have an impact, and I met with some officials in the office of the mayor of Minneapolis recently. And, you know, Minneapolis is an interesting comparison, because they used to be called Murderapolis in the mid-1990s. That might ring a bell, of course, because of the challenges that we have in Winnipeg.

But they were able to go from one of the most violent cities in North America to one of the safest cities, not just because they extended a bunch of carrots, as the government would do, extended a bunch of carrots and hoped, and hoped that they would get them off the street because somebody was watching *Desperate Housewives*, or was watching a soap opera and decided, oh, look, apparently gangs are a dangerous lifestyle. Well, I've got news for you, you know, some of these young people actually know that gangs are a dangerous lifestyle.

But, when you talk to, you know, 14- or 15-year olds who are at risk or have been lured into that gang lifestyle, they'll tell you, on the one hand they're presented with a gang recruiter, with a gang recruiter who's saying, if you come into this gang, we're going to give you clothes, electronics, money. And, on the other hand, is a counterbalance, you have an ad running on *Ellen DeGeneres* that's saying, well, it's a dangerous lifestyle, maybe you shouldn't do it. Well, you know, if there's a young person who's watching *Canada AM* at seven in the morning, I suspect he's not at risk. I suspect that he's probably, you know, doing pretty well.

But this is what the government doesn't understand is you've got these gang recruiters out there offering all of these different things for these young people to get involved in gangs, and as a counterbalance, they throw out ads–and look, I mean, we all know why they did it. It was just to try to get those individuals who are watching the ads to try to believe, oh, maybe the government is trying to do something about gangs.

And I think it backfired. And I think it really backfired on the government because everybody that I've talked to about the ads, they've said, well, this is ridiculous. We know this isn't going to work. And I expect the member from Transcona and others, when they go back to their constituency, if they talk to those in their riding, they're probably getting the same comments. They're probably getting people who–*[interjection]* Well, the member for Transcona (Mr. Reid) says no. He's either living in a bubble or, you know, he's limiting his conversations to those who live within his household, and he needs to go a little bit beyond that, because people are saying this simply is not going to work because they're frustrated, they're frustrated, Madam Deputy Speaker, and I understand why they're frustrated.

Winnipeggers have had it. They're saying enough is enough. It's time that we take some serious action to try to bring order back to the streets of Winnipeg, because it's not that Winnipeg or that Manitoba that any of us remember growing up in. And yet what–you know, and so when the ads came on TV, the people that I've spoken to, from a variety of different ridings, have said this is ridiculous. This isn't going to keep gang members or get gang members out of gangs, and that's before they learnt, when they were running the ads during daytime talk shows and during soap operas. But that's the approach this government has always taken.

One of the first things the member for St. Johns (Mr. Mackintosh) did when this government was elected in 1999, actually, I think it was the second thing, first they took the safer communities act that the Filmon government had passed prior to the election and they copied that, put it on the photocopier, copied all the pages, re-introduced it and then claimed it as their own, and that worked. And so, you know, kudos to Gary Filmon and to Vic Toews.

So the second thing that the member for St. Johns did was to announce that they were going to have a Project Gang-Proof to drive gangs off of the street. And that was essentially pamphlets that were made up and distributed to parents and to youth.

But doesn't that sound familiar? Doesn't that sound familiar, Madam Deputy Speaker? Ten years later we've gone from distributing pamphlets and having ads on Project Gang-Proof to having ads on this new gang initiative. After a decade, we've come full circle. And all it is, is a media strategy by this government to try to convince people that they're going to get tough on gangs. And I think that most Manitobans recognize that this is not, this is not a party who really is going to ever ensure that there are tough measures placed on gang members. And I think that that's unfortunate, because as we continue along this path, there's going to be more and more crimes and more and more victims and more and more families who are mourning the loss of a loved one.

***** (15:40)

The one thing that was mentioned–*[interjection]*. Oh. I know, Mr.–Madam Acting–Madam Deputy Speaker, that my time is running short. My House leader, who I would like to commend for doing a tremendous job this session–I wouldn't want to say that my House leader could beat up their House leader, but certainly in a mind war, certainly in an intellectual debate, I'll put the member for Lac du Bonnet (Mr. Hawranik) up against the member for Elmwood (Mr. Blaikie) any time, and I think we saw that–we saw that this session.

But I would like to thank the residents of Steinbach, which include the town of Niverville, the R.M. of Hanover and the city of Steinbach, again, for their continuous support. Many of them have wished their good wishes to me and my wife and my son during this holiday season, and we have always appreciated the opportunity to represent I think one of the greatest constituencies in the province, and I look forward to continuing to serve them during the duration of this term.

Thank you very much, Madam Deputy Speaker.

Mr. Mohinder Saran (The Maples): Madam Deputy Speaker, I am pleased to stand in the House today and speak in support of this Speech from the Throne.

The Throne Speech shows that Manitobans have elected themselves the right government for these unsettling economic times. Just think back to what happened when a cold economic wind blew Manitoba's way in the 1990s. Yikes, the Tories said, and slashed funding for our universities, cancelled the bursary program, fired 1,000 nurses and cut medical post spots. Contrast those rash decisions with the steady performance of our government in education and health that the Throne Speech has described. My colleagues have already elaborated on our investments in these areas.

I would only like to add, as a footnote, about recent improvements in emergency services at our local Seven Oaks Hospital that benefit my constituents in particular. Recently, a $14-million expansion and redevelopment of the ER at Seven Oaks increased its capacity by 50 percent. Now, as part of budget 2009's province-wide improvements in emergency care, the ER will be staffed by additional nurses overnight. In addition, Seven Oaks has been part of a pilot project to add a new category of professionals to the ER team: physician assistants. They are qualified to perform a wide range of duties, including conducting physical exams, ordering diagnostics tests and prescribing medications and other treatment. This is yet another step towards strengthening the emergency team at Seven Oaks.

Manitoba was the first province to institute a children's fitness tax credit paralleling the federal credit introduced in 2007. Now Manitoba is showing the way for other provinces by phasing in a similar fitness tax credit for adults. This incentive to engage in physical activity is something that I have been advocating during my two years as an MLA. The health benefits of keeping fit are well known. Fit individuals are more likely to lead happier, healthier and longer lives. There is also a benefit to society as a whole. A fit population makes fewer demands on our health-care system. A report commissioned by the Fitness Industry Council of Canada estimated that Canadians would have saved $2.5 billion over the next 21 years if the federal fitness tax credit were extended to adults. The council claims that the foregone tax revenue would be matched by the health-care savings in only three years. The Canadian Diabetes Association estimates that, 2020 are nearly one in 10 Canadians will be living with the diabetes, at a cost of nearly $16.9 billion annually. Ninety percent of diabetics have type 2 diabetes, which is brought on by obesity, inactivity, poor diet and aging. Consider what an adult fitness tax credit might do to help Manitobans ward off the disease or keep it in check.

Madam Deputy Speaker, the Throne Speech commits the Province to working with the municipalities to encourage the construction of more secondary or granny suites, as they are called. These self-sufficient suites are added to or created within a single-family residence and provide the basic facilities for living, sleeping, cooking, and sanitation. At the urging of a number of my constituents, I met with the previous minister responsible for housing to propose this move.

Granny suites make good sense socially and economically. First of all, they are an excellent means of expanding the stock of affordable housing. The costs are minimal. Property owners who build granny suites to accommodate low-income seniors or adults with a disability are even eligible for forgivable loans from the Canada Mortgage and Housing Corporation in the range of $24,000 to $36,000.

Granny suites are also a plus environmentally. They create no sprawl and take less energy to heat and cool than independent residences. Best of all, they enable children, parents and grandparents to be mutually supportive while still affording an appropriate amount of independence and privacy. The older generation benefits from the companionship of their kids and grandkids. They receive assistance with the chores that would be beyond their capacity. There is always someone around to keep an eye on their health and well-being. And the younger generation benefits greatly from the presence of grandparents, particularly if both parents are working. Kids have someone to greet them when they come home from school. They have someone to monitor their activities and ensure that they don't fall in with a bad crowd.

The Throne Speech spoke of our government's desire to make Manitoba the most age-friendly province in Canada. By looking at how municipal planning and zoning regulations could make granny suites an option for more Manitobans, we are taking a step in the right direction.

My constituency, The Maples, is renowned for having the highest proportion of new Canadians in Manitoba. These newcomers in turn help attract more skilled workers to our province. They can also take a great deal of credit for encouraging these new workers to stay in Manitoba once they immigrate to Canada. In the last year for which we have statistics, over 84 percent of Manitoba's provincial applicants in the economic class who were over the age of 25 had post-secondary education in professional and technical fields; 84 percent. The comparable figure for Manitobans as a whole is around 57 percent. The 71,000 immigrants we have welcomed to our province over the last decade have been increasing our education edge as will the thousands more that will be coming each year as part of our immigration strategy.

I welcome the announcement in the Throne Speech that applications to our Provincial Nominee Program will be speeded up so that would-be immigrants will know within six months whether they have been accepted. Manitoba is also working with Ottawa to fast track the recognition of the credentials of foreign-trained professionals, and it is also good news that our government will be enabling successful applicants to start making work and living arrangements before they arrive in Manitoba.

Our government's continuing support for the smooth integration of newcomers from diverse nationalities into the Manitoban scene is key to their success. The recent budget provides for a respectable increase in funding for multiculturalism. Outreach to Manitoba's ethnocultural communities is not just about cultural diversity and the many benefits that such diversity brings to the fabric of our province. It is also about enabling newcomers who are keen to contribute their skills, knowledge, and experience to our economy to feel that they are included in and respected by mainstream society.

***** (15:50)

I would like, Madam Deputy Speaker, to tell a personal anecdote which illustrates this point. Back when I first came to Canada, I was desperately looking for employment. I was not having any luck. Time and again, however, I was told that it was next to impossible to get a job if you wore your hair in a turban as I did in accordance with my tradition. And so one day, I went into the bathroom with a pair of scissors. I cut my hair short, and I wept for betraying my Sikh culture by doing so. Then I composed myself, put on a brave smile and asked my roommates, how do you like my new look? Decades later, the recollection of this incident is still painful to me. But that was long ago. Now, thanks to the government's promotion of ethnocultural communities and educational campaigns, newcomers are much less likely to feel isolated and much less likely to feel pressure to conform in a way that violates their core beliefs.

Thank you, Madam Deputy Speaker.

Mr. Leonard Derkach (Russell): Madam Deputy Speaker, I rise today to put a few comments on the record with regard to the Throne Speech, and I begin by first of all congratulating the new Premier (Mr. Selinger) on being elected as the leader of his party and also the Premier of our province, and I want to wish him well. And I also want to say to the two runners-up, first of all the member from Thompson who I sat with in this House for a long time who came into the Chamber in 1981, I believe, and who has always been a very outspoken individual, who is charismatic and who is–I think carried the torch for the NDP over the years, and in fine fashion.

I only regret that throughout the campaign for leadership, the minister, in my view, did the honourable thing in trying to ensure that everybody had equal access and equal opportunity in the NDP party, but that was not so from the other candidates who were running for leadership. But that's sort of the history of the NDP party, and it's not surprising that they would conduct themselves in that manner.

And we also had the minister–current Minister of Justice (Mr. Swan) who got the second prize, but even though he quit. And I think we'll probably see more of him down the road, and we'll probably see more quitting down the road from his–from his side.

But, Madam Deputy Speaker, nevertheless we have a new face in the–in the form of the Premier of our province. We also have a new Minister of Finance (Ms. Wowchuk) in our province, but there is much more of the old style of governance from this government that we saw even under the leadership of Gary Doer.

Madam Deputy Speaker, I also want to take the opportunity today to comment and to thank the services that we are provided in this Chamber by the table officers, the staff in the Chamber and also the pages. And I want to say thank you to them for all of their efforts and for ensuring that our jobs are made as comfortable and as easy as possibly can be done in the Chamber. I know that they provide a great service to our Chamber, and I'm never one to complain about the cost of running this Chamber for a day, unlike the NDP, of course.

Madam Deputy Speaker, I also want to say thank you to the *Hansard* staff who record all of the transactions that occur in this House, because I know they work tirelessly and they work long hours and, to them, we wish them the very best. And I want to extend to all of the staff that serve us an extremely happy holiday season, a merry Christmas and also the best in the coming new year.

Madam Deputy Speaker, before I get into the meat of the–of the Throne Speech, I also want to send to my constituents the greetings of the Christmas season. May their Christmas be blessed and also wish them a happy new year and thank them for the support that they have given me over the last number of years. I think this is my 23rd year in the Chamber, and certainly I want to thank them for the support that they've given me over the years.

Madam Deputy Speaker, the Throne Speech that was delivered to us on November the 30th by His Honour the Lieutenant-Governor spoke about some of the things that the government would be doing, but there wasn't anything new in this Throne Speech. The Premier's (Mr. Selinger) comments were flat is now the order of the day, and expectations should be lowered by all Manitobans because we were–this province was starting to face its downturn in the economy. Well, if the NDP had protected what this province was blessed with over the course of the last 10 years, today we would be in a much better position to respond to the needs of Manitobans and to stimulate the economy in a much more positive way.

But, over the course of the last 10 years, Madam Deputy Speaker, we have seen an abundance of wasteful spending by this government, and I say wasteful because, if you look around and where the government's priorities have been, they weren't too concerned about ensuring that Manitoba's debt was maintained. They weren't too concerned about paying down that debt, and they weren't too concerned about the fact that two-thirds of our budgets were being supported by transfer payments from Ottawa.

And, you know, all of those signals out there should have said to them that in–when the sun is shining, let's, as my leader said, let's repair the roof, so that in times of rain we are protected, and that's not the attitude of this government, that's not what they did.

Madam Deputy Speaker, if you look at the sectors of the economy of this province that have generated the wealth of this province, we see that they have done very well in spite of our government because, if we compare ourselves to other jurisdictions, you will find that our tax rates are higher than they are in other jurisdictions. A family of four in Manitoba pays far more in taxes than they do in other parts of this province, almost in every part of this province and, yet, the government continues to spend money as though it were growing on trees.

Madam Deputy Speaker, when we have the tax regime that we have in our jurisdiction and we have the kind of transfer payments that we're receiving from Ottawa and a government that–it's got a spending habit, we have, indeed, a course for disaster down the road. And that's exactly what Manitoba is going to be facing over the course of the next few years, and we're seeing that the slide is starting to happen again.

You know, Madam Deputy Speaker, I go back to when Howard Pawley was the premier of this province, and when I went back that far, I was sitting in this Chamber at the time when the deficits of this province were roaring out of control and our debt-servicing costs–our debt-servicing costs during lean those years, were about a half a million dollars a day, increasing up to a million dollars a day towards the end of that regime.

And, Madam Deputy Speaker, when you look at where we are today, the Minister of Finance (Ms. Wowchuk) today was trying to defend this, but she couldn't, because today Manitoba's debt-servicing costs are 2 billion–or $2 million day. Now, that is very, very significant. It's very startling to begin with and I don't know where we're going to be down the road if we continue to support this kind of administration.

Madam Deputy Speaker, there's always somebody who comes up to clean up the mess that the NDP create. And I was told by one of the ministers of this government that it's okay, we know that sometimes we're going to have to lose government and the Tories will come in, and they'll clean up shop and then–and then we'll–they'll get booted out because they tend to focus on debt relief and on paying down their debts and then, all of a sudden, they–we can come back in and we can start spending money again. And that was told to me by one of the ministers of this current government.

An Honourable Member: Yeah, right.

Mr. Derkach: Yeah, that's right, and I don't want to name him, Madam Deputy Speaker but, indeed, he's a prominent member of the–of the current government and the NDP.

Madam Deputy Speaker, we talk about where we should be spending our money and the priorities that we should have. Today, I look at promises that were made to Manitobans, and I go specifically back to my own community of Russell where, since 1999, 1998 as a matter of fact, was when the first commitment was made for a dialysis unit in the Russell Hospital. At that time–and at that time, there was also another commitment made for a physical rehab clinic to be set up in the Russell Hospital as well.

Well, Mr.–well, Madam Deputy Speaker, we have been waiting for the dialysis now for the last 10 years and it hasn't happened. Four times now in throne speech and budget Addresses I have heard that Russell was going to be receiving a dialysis unit. It was also–it was also announced in this latest Throne Speech.

***** (16:00)

Madam Deputy Speaker, at AMM, the mayor of Russell asked the Minister of Health (Ms. Oswald) when this was going to happen. She said, imminently. I am awaiting that announcement, first of all but, secondly, the construction of it, because the people in that part of the province–it's not just what they want, it's what they need.

Madam Deputy Speaker, I have to say that the rehab unit was set up in Russell in 1999 while we were still in government. Two years after the NDP took over that was cancelled. Their excuse was that there weren't sufficient trained staff to be able to have that unit operating there. Well, the reality was the three people who worked in that lab had to go and find work elsewhere because they were dismissed as a result of that unit being cancelled in that community.

So, Madam Deputy Speaker, one has to ask where the priorities are. Are they just in NDP-held ridings? And that's the way that this government has been conducting itself. You know, my leader has been asking for a school in Fort Whyte for a long time. Not because he wants to see the government spend money, but the government is supposed to provide services where they are needed, and when you have a population the size of Fort Whyte that doesn't have a high school in it, then you have to question whether or not the government is really interested in serving all of Manitobans.

Well, Madam Deputy Speaker, just last week I heard an announcement that I could not believe. When we have–when we have people dying in hallways, dying in waiting rooms, dying in emergency wards, lying on a gurney for seven hours before they can be treated and then, unfortunately, because of complications, they die, and the minister and the government can't address those priorities, but they make announcements like a $31-million polar bear compound at the zoo. They make an announcement at Gordon Bell High School for a green area, which is fine, but don't–but don't go ahead and cancel projects that are needed in this province and make announcements because it's gonna look good in Copenhagen, or it's going to appease some people in the inner city or close to your–close to your election base, and that's how the NDP conduct their affairs as a government, and we have watched this over and over and over again.

Madam Deputy Speaker, all Manitobans deserve services, but I do have to credit the Minister of Health (Ms. Oswald) about some things, because she is somebody who I think has had a broader view of things, and I single her out because I've gone to her on several occasions with constituent issues that needed to be addressed and I have to say she has responded in a very forthright way, Not every demand that goes her way can be accomplished and can be satisfied, but at least, I have to say, to her credit, that she addressed the issue immediately and it was dealt with either positively or less positively. It didn't matter, for that matter, as long as there was good rationale and as long as somebody looked at the issue, and that's what I have to credit her with because she has been very open in that regard and she's been very approachable. That's not–that's not the norm for this government, unfortunately, and I wish that some of the members on that side of the House, some who've been sitting in their chairs for a long time perhaps could take a lesson from the way that this minister has been conducting herself.

Madam Deputy Speaker, the government has also talked a lot about the environmental issues. We have a Minister of Conservation past who now takes over the reins of the Department of Agriculture and, you know, when I heard that, I just about had to go to the washroom because I said to myself, now, that's about tantamount to appointing somebody off the street as the Minister of Justice for the province, because here is a guy who–what did he do for agriculture in the last 12 months? Well, I can recite a couple of things. Number 1, he killed the hog industry. He destroyed the hog industry in our province as Minister of Conservation. He said, he said this was good for farmers. He said what he was doing was good for farmers. It was putting a nail in the coffin of the hog producers of this province and he had the–and he had the audacity to say that this was good for farmers.

What else did he do? Well, let's take a look at the BSE issue. Together with the former minister of Agriculture they were going to build this elaborate killing plant in Dauphin. They went to the United States, bought a bunch of equipment, they were gonna set up a killing plant in Dauphin. Well, Madam Deputy Speaker, right in the minister's own backyard, that was fine; I didn't–we didn't care where it was as long as there was one there. But what happened, they left this equipment on a pile in Dauphin and today it sits rusting somewhere because it's not used. We don't have a cattle processing facility in Dauphin, and that's six years after BSE. What an embarrassment. What a let down to the producers of this province. Today we are seeing the cattle–the mother cow herd–in this province declining at a faster rate than it is anywhere else in Canada.

And why? Because this government has chosen to kill that industry as well. So the minister, now of Agriculture can put up on the wall that he helped to kill the hog industry in this province and, secondly, he's working towards that in the cattle industry as well. What other industry is he going to attack under his leadership as Minister of Agriculture?

I'm sure farmers in this province are going to be very confident in having him sit down at a negotiating table with the federal minister and other provincial ministers because he knows absolutely squat about what's happening in the field of agriculture.

Madam Deputy Speaker, I hate to be so unkind to him, but, really, one has to learn from the mistakes that he's made in the past, and I don't think he has.

What did he do with rural farm families with regard to effluent disposal in Manitoba? Twenty years ago or 22 years ago, I went to the Department of Agriculture and said we were putting in a new effluent system in our–in our–on our farm, and we wanted to know what the best system was so that it would be environmentally sustainable. We were told at the time, do not go to a field because a field will create a lock for all pathogens that cannot escape, and then you will contaminate whatever vegetation you have or whatever ground water you may have in that area. So they recommended that we put in one of two systems. One is a mound system. The other one was an ejector system for effluent, not for sewage, as this minister said. Madam Deputy Speaker, the sewage is hauled away with a–with a sewage truck to a lagoon. So the minister needs to, again, educate himself on what he is talking about.

Well, Madam Deputy Speaker, what did this minister do? He went and banned sewage ejectors. The very kinds of facilities that were promoted by the Department of Agriculture now were banned under his watch. Did he do any science? Did he do–did he apply any scientific facts to this? He did not.

Madam Deputy Speaker, so the minister doesn't have a very good track record when it comes to dealing with rural Manitobans and the issues that they face.

And I can go one step further. What did he do with the fishery in the Dauphin area? Finally, after the pressure from this side of the House, and the fact that we were going up there and visiting with the fishermen in the Dauphin area, he was dragged kicking and screaming to the table and offered some pathetic solutions to them, Madam Deputy Speaker. But the people of Dauphin know it–the people of Dauphin know it and they'll reward him accordingly down the road.

Madam Deputy Speaker, the Throne Speech in general sets a very low level or a low standard for this province. While other provinces are looking towards coming out of the recession, building their provinces, lowering their tax rates, improving the quality of life for their–for their inhabitants and their residents, this province is looking at our province slipping back from the growth that we should be projecting.

Our unemployment rates are starting to soar. Madam Deputy Speaker, when we take a look at what's happening with Tembec, when we look at what's happened with the call centre here in this province, those jobs are leaving. And why? Because this government doesn't have any creative insight in what it should do to assist Manitobans in not only long-term jobs, but keeping the jobs that are already here, and somebody has to stand up for 'em. A hundred days after the strike at Tembec, the Premier (Mr. Selinger) nor the minister who's responsible for it had ventured out there to talk to the workers and to see what solutions could be found. Instead, at the 11th hour, this government puts forward a million dollars and says, go play. Here's a million dollars, go play. In other words, shut down the industry. Find a new job. The town with a million dollars can find out what its destiny is going to be. Well, nobody is a fool, and a million dollars is never going to find a solution for a community that is losing its major industry like they did at Tembec. This Minister of Finance (Ms. Wowchuk) should be ashamed of what her government has done in this regard, and the lack of attention that they have paid to this very important industry in this province.

***** (16:10)

But, Madam Deputy Speaker, they talk with forked tongue. They talk about jobs and the importance of preserving them but at the same time they're losing them. They offer a million dollars for the community to go find a new destiny. It's the same thing that they're doing with the hydro line. They're talking about not cutting any of the boreal forest for the–for the hydro line, yet they're the same government that's gonna punch a road through the east side of the–of the lakes. They're the same government that's going to put in a road that they're slashing and burning boreal forest right now to a cottage development site. They're–and yet they–they're saying that they can't put a hydro line down that same corridor. It doesn't make any sense.

Yet on the west side of the province, where nobody wants the line, they're deciding that they're gonna spend another $650 million more for that project. Well, Madam Deputy Speaker, that, once again, is an example of what this government's lack of focus on priorities is. They have lost their focus in terms of where they should be but down the road Manitobans will reward them accordingly.

So, Madam Deputy Speaker, I know my time is up and I know the Minister of Finance wants to respond to some of the things I've said and I welcome that, but let me say that the amendment that was put forward by our leader was one that I was looking forward to perhaps the government even supporting, partially at least, but no, that wasn't to be. And it's unfortunate that we will not be able to support this Throne Speech because it lacks direction and it lacks any positive initiative for the good of this province. Thank you, Madam Deputy Speaker.

Hon. Rosann Wowchuk (Minister of Finance): Madam Deputy Speaker, I'm very, very pleased to have the opportunity to speak today on the Throne Speech, and I want to definitely comment on some of the comments made by the member for Russell.

But, Madam Deputy Speaker, when we–when we put this budget together under our new leader we looked at some very important issues. We looked at this budget, Throne Speech, I should say, to–with a couple of themes. One of them is investing in the health and well-being of Manitobans and then building a stronger Manitoba. Both of those themes are covered off very well and describe what it is we intend to do.

Madam Deputy Speaker, we know that we are facing challenging economical times. We're having a downturn in the economy but this government has made a commitment. This government has made a commitment that we will keep the economy going. We will invest in stimulus. We will invest, ensure that the services that are important to people of Manitoba, services like health care, education, safety, all of those issues and services to protect the most vulnerable people in our society. We will be there for those–for those people and we outlined our plan–we've outlined the plan that we have in our Throne Speech.

It's unfortunate that the members opposite want to take advantage and, in fact, make announcements about some of the infrastructure that we're proposing, and they lobby every day to have additional infrastructure in their constituency, but when the time comes to vote to support these they're nowhere to be seen. In fact, Madam Deputy Speaker, they vote against them. They vote against a commitment of $745 million in roads, investment in bridges, projects that will stimulate about 1,500 jobs, creating more than 1,500 stimulus projects that we have been in partnership with the national government, the national government. Their brothers and sisters recognize the importance of stimulus and they're prepared to put money in and the members opposite vote against it. And we New Democrats are working with the national government to stimulate our economy so that people will work, so that we have an infrastructure that will be there for many years to come. And through these 1,500 stimulus projects we are creating more than 12,000 direct jobs and 10,000 indirect jobs, but the members opposite don't seem to recognize that.

I heard the members opposite–the member opposite just talking about how bad things are in Manitoba and how the employment–unemployment is up and how the deficit is up and the economy is just not doing anything.

Well, let me quote a few. What did the Royal Bank say about the–Manitoba. The Royal Bank is forecasting that Manitoba's economy will lead Canada this year at 0.2 percent. In 2010, and it's forecasted that Manitoba's growth will be at 3 percent–third highest in Canada.

And so, despite what the members opposite are saying, although we are facing challenges, Mr. Speaker, our economy is growing and the vice-president and chief economic officer of the Royal Bank said, and I quote: Most of the indicators suggest Manitoba has endured the worst part of the economic storm while achieving a positive growth rate of 0.2 percent in 2009. Increased capital spending, agriculture activity and demands for provincial reproduced products and natural resources will result in a more significant economic growth going forward.

It's too bad the members opposite can't say something positive about the economy in this province. He also said, overall, the positive forces in the economy are expected to dominate the recent weakness in manufacturing and produce a positive growth in Manitoba–the only province to achieve this feat in 2009.

The member opposite also talked about our jobs. What does the Royal Bank say about Manitoba? It says, the province of Manitoba is one of only three projected to show an overall job gain in 2009. Manitoba's positive growth is 0.2 percent; New Brunswick, 0.1 percent; Saskatchewan, 1.5 percent.

So, Mr. Speaker, I wish, again, that the members opposite would just think a little bit more positively about what's happening in this province, because, indeed, we should be proud of our province. We are having a Homecoming next year. We should be encouraging people to come back home, and I can tell you that many people–many people that left this province, when the Tories were in power, are now recognizing the growth and the positive things in this province and they are coming back.

Madam Deputy Speaker, the members opposite, I want to–I just have to stray a little bit here. The member from Ste. Rose talked about Ranchers Choice. The member from Ste. Rose said the Province bought equipment, and I want to remind the member that it was not the Province that bought the equipment, it was producers who went out and bought the equipment. Real farmers went out and bought that equipment because they believed–*[interjection]*–that the real farmers bought the equipment. They came to–

Some Honourable Members: Oh, oh.

Madam Deputy Speaker: Order. Order. Order. Order. Order. Order. Order.

I'd like to remind all members that there are loges if they wish to have private conversations.

Ms. Wowchuk: Thank you, Madam Deputy Speaker.

You know, the members opposite said that the Province bought equipment. Well, Madam Deputy Speaker, that's wrong. I want them to know that it was producers that went and bought the equipment because they believed that they could add value and build a facility in Dauphin.

Unfortunately, we had members opposite–and I want to talk about the former member from Emerson who is on the record saying we didn't need slaughter capacity in this province, that we had enough slaughter capacity. I have to give credit to the present member from Emerson, because the present member from Emerson was one of the people who talked in a positive way about Ranchers Choice, one of the few Tories who thought that this could work.

But, you know, there–had there been a little bit more support, had they not been out there talking about how negative this would be, and had they not been trying to kill it, maybe it would have succeeded, maybe it would have. Maybe it wouldn't have, but the members opposite can–I just want to correct the record–it was we stood by the producers on that facility, and we will continue to stand by the producers who want to increase slaughter capacity and processing in this province, Mr. Speaker.

***** (16:20)

Mr. Speaker in the Chair

Because, Mr. Speaker, if we can add value to an agriculture product and create jobs, we should be very proud, and I would ask the member to look at the records of where, since this government has taken office, where value-added process was under their administration and where it is today. It has more than quadrupled, more than quadrupled in the food-processing area as to where they were and where we have taken the industry. Again, I've touched a sensitive nerve here, but the members opposite are wrong when they talk, as usual.

I should take a few minutes, Mr. Speaker, to talk about Hydro. You know, the members opposite just hate Hydro. And I honestly believe, if they had a chance, they would sell it, because if they aren't gonna sell it, they're gonna mothball it, just as they mothballed it in the past, and they just don't like the idea of having economic development in the north and having Aboriginal people part of the economic development, and they don't like the idea of clean energy. I really think they would much rather develop the tar sands and have Alberta make money on the tar sands despite the fact that it's the dirtiest energy that's there. They will not speak in a positive way about electricity and they will not talk about, in a positive way, about the sales, you know, and why we need another bipole.

The members opposite don't recognize that we need Bipole III for reliability. We need Bipole III to complete the sales that we–that we have. And the members opposite are bound and determined, despite the fact that on the east side of the province we have one of the jewels of the world, Mr. Speaker. We have, as I tabled in the House today, and many have seen on a world map, there's only one spot in the world where there is a pristine boreal forest, no place else in the world. We are taking steps to protect it, to try to get a UNESCO heritage designation for it, because the boreal forest is known for its ability to capture carbon and it's very important.

And as we are at–our Premier (Mr. Selinger) is in Kyoto–Copenhagen, pardon me, wrong, wrong agreement, continuation of Kyoto. But, of course, the members opposite hated Kyoto, Mr. Speaker, and they really don't want Canada to be in Copenhagen either to ensure that Canada can clean up their reputation. Right now, Manitoba–Canada does not have a very good reputation as it comes to addressing climate change. Our record here in Manitoba is something that we should be very proud of, and I'm very proud that our Premier and our Minister of Conservation (Mr. Blaikie) were invited to be part of the Canadian delegation to help influence–to help influence Canada's position and maybe help clean up Canada's reputation a little bit.

But, Mr. Speaker, the west-side line is very important to our sales and for our economic development and I wish that the members opposite would recognize that this will help us to–they talk about wanting to improve the economy of Manitoba, to have growth in this province, but they are very opposed to electrical clean energy which will help our economy, but, most importantly, is done in a new way, it's done in partnership with First Nations. The members opposite were critical of spending money to bring the Aboriginal community into the discussions, but we will see–we will see that project through.

And I, very much, am looking forward to seeing those dams built and our sales to the U.S. become a reality. And I'm very much hoping that we will, indeed, get a UNESCO designation for eastern Manitoba, and the members opposite should know that Ontario very much wants this designation as well because it is in their jurisdiction.

But I just had to talk about Hydro and how important it is–it is to our economy, Mr. Speaker, but I also want to talk about, as I said, what we have done, and the members opposite, in their, in their condemnation of Manitoba, talking about how negative it is, talk about how we haven't managed well, how we haven't saved. Well, I would remind the members opposite how much was in the rainy day fund when they were in power, and where is it now? They say we haven't managed, but, there is over $800 million in the rainy day fund.

Mr. Speaker, we have taken steps during some good years to put away funds to help us to ensure that we can provide services that are important to people, and, for me, that's one of the most important things we can think about as we go through this challenging time of a recession that is affecting the whole world. Challenging times, a recession that's affecting other provinces much more than Manitoba is being affected.

Manitoba is one of those provinces that is able to–may not have as many peaks, but they–we don't dip as low either, Mr. Speaker–and we've been able to ride this out well, and I want to give credit to where credit is due. I want to give credit to our Premier–previous premier and Cabinet. I want to give credit to the present Premier (Mr. Selinger) and Cabinet for–and I want to give credit to all of the staff in the departments who work with us on these important issues. And I want to give credit to the farmers because the farmers in this economy in this province do play a very important in the economy.

But, Mr. Speaker, I want to say that as challenging as these times are, we've committed in this budget that in 2009, business tax cuts will be in place and we will–in this business tax, we are going to save Manitoba companies $41 million a year. This is including the corporate tax rates of reducing from 13 to 12 percent and the reduction of small business tax from 12 percent to 1 percent. This the lowest–this is the lowest small business tax in Canada. We have to–we have to look at ways that we can address business issues, and I'm very proud of the steps that we have taken in reducing tax. I have to say that I'm very proud of the steps that we've taken to reduce education tax on farmland.

I'm very proud of the steps that we have been able to take to improve opportunities for our young people, whether it be in creating jobs or in training. It is my view that training is one of the key tools to help people get out of a recession, to get out of a downturn in the economy, and there's no doubt that steps we are taking to invest in education and training, whether it, whether it be in the north, whether it be here in the city, or whether it's working with immigrants, new immigrants who have come to this country, this province, Mr. Speaker, we are working with all of them.

And, Mr. Speaker, we will continue to work with the national government. We will continue to make investment in stimulus because it keeps people working and it provides the kind of, I guess, the legacy that you could have for working in the province during a time of downturn.

But, Mr. Speaker, we aren't through these challenges. They're–I'm hoping that we can come out of this very quickly, but the whole world is coming out of the recession much slower than they anticipated they would, so there's more to do, and that's why we, in 2010, in the Throne Speech, we announced that we will do an economic summit and it will be led by the business community, by the Premier, by labour, by Aboriginal people, and by local government leaders. These are real people that we will bring together and people who are working in the trades and look at ways that we can further stimulate the economy based on what we have started.

But, ultimately, Mr. Speaker, our goal to invest in education is important. Our goal to ensure that we maintain the health-care services that are very important are all what we are going to do. We will continue to build. We will continue to build a stronger, a healthier Manitoba, a strong–and one where people can work, one where we can provide services, whether it is in facilities in Russell like a dialysis unit or whether we can provide services in the Women's Health Centre or in Swan River or in Dauphin. This government has a record of investing across the province and bringing services closer to people.

This government–the opposition will not recognize the investments that we have made—

***** (16:30)

Mr. Speaker: Order. The hour being 4:30 p.m., pursuant to rule 45(5), I am interrupting proceedings in order to put the question on the motion of the honourable member for The Pas (Mr. Whitehead), that is, the motion for an address in reply to the Speech from the Throne.

Is it the pleasure of the House to adopt the motion?

Some Honourable Members: Agreed.

Some Honourable Members: No.

Voice Vote

Mr. Speaker: All those in favour of the motion, say aye.

Some Honourable Members: Aye.

Mr. Speaker: All those opposed to the motion, say nay.

Some Honourable Members: Nay.

Mr. Speaker: In my opinion the Ayes have it.

Formal Vote

Mr. Gerald Hawranik (Official Opposition House Leader): A recorded vote, Mr. Speaker.

Mr. Speaker: A recorded vote having been requested, call in the members.

Order. The question before the House is the motion of the honourable member for The Pas (Mr. Whitehead), that is, the motion for an address in reply to the Speech from the Throne.

Division

A RECORDED VOTE *was taken, the result being as follows:*

Yeas

Allan, Altemeyer, Ashton, Bjornson, Blady, Braun, Brick, Caldwell, Chomiak, Dewar, Howard, Irvin-Ross, Jennissen, Jha, Korzeniowski, Lemieux, Mackintosh, Marcelino, Martindale, McGifford, *Nevakshonoff, Oswald, Reid, Rondeau, Saran, Selby, Struthers, Swan, Whitehead, Wowchuk.*

Nays

Borotsik, Briese, Cullen, Derkach, Driedger, Eichler, Faurschou, Gerrard, Goertzen, Graydon, Hawranik, Lamoureux, Maguire, McFadyen, Mitchelson, Pedersen, Schuler, Stefanson.

Madam Clerk (Patricia Chaychuk): Yeas 30, Nays 18.

Mr. Speaker: I declare the motion carried.

* * *

Hon. Dave Chomiak (Deputy Government House Leader): I often wonder if all of us, because of our sometimes getting a little bit boaster should be–should be forced to do that roll call ourselves, and good job. I want to commend the good job done every time, and all of the people who make this place work, despite all of us and our best efforts. I mean, people work really hard. I want to congratulate them, and, on that note, wish everyone a very festive holiday season, sincerely to everyone, and perhaps might notice that the clock is 5 o'clock?

Mr. Speaker: Is it the will of the House to call it 5 o'clock? *[Agreed]*

Okay. The hour now being 5 p.m., this House is adjourned and stands adjourned until March 23, 2010, or at the call of the Speaker.

And I wish everyone a very merry Christmas and all the best in the New Years.

LEGISLATIVE ASSEMBLY OF MANITOBA

Tuesday, December 15, 2009

CONTENTS

The Legislative Assembly of Manitoba Debates and Proceedings
are also available on the Internet at the following address:

http://www.gov.mb.ca/legislature/hansard/index.html

Tab 139

Bipole III route best for Hydro's future

BR.S PpAD

AUG 13 2010

The NDP's commitment to providing clean, reliable and affordable power to Manitobans while building export relationships and protecting intact boreal forest is being met by the development of the transmission line Bipole III on the west side of Lake Manitoba.

Today, 75 per cent of our power is carried through the Interlake by Bipoles I and II; the probability of a power outage due to a tornado hitting Bipoles I and II is one in 16 years.

A western-routed Bipole III improves the probability of a three bipole outage to one in 3,650 years.

Bipole III is a financially sound project that will increase opportunities for hydro export sales, covering the cost of the project. With Bipole III and new generating stations operational, revenues from hydro exports are projected to exceed $20 billion over the next two decades.

After two years of consultations with west-side communities and residents, Manitoba Hydro has announced a preliminary preferred route for Bipole III.

The route runs closest to Lake Winnipegosis and Lake Manitoba, avoids all parks and has the least impact on agricultural lands. Manitoba Hydro will now begin a fourth round of consultations with local stakeholders and landowners along the preliminary route.

Hugh McFadyen and the provincial Conservatives play a dangerous game by pledging to reverse work on Bipole III and attempt to force it through the intact boreal forest on the east side of Lake Winnipeg.

Such a move would face local and international opposition that would delay and stall the critical project and damage Manitoba Hydro's reputation in export markets. The provincial government has received 40,000 emails and letters opposing projects like Bipole on the east side.

McFadyen has also been misleading the public by inflating the cost of a western-routed Bipole III. His figures are based on his reckless plan to cancel the converter stations at the start and the end of the line.

Manitoba Hydro has been clear; new converter stations are required, regardless of the route taken, to enhance reliability and to add capacity to carry power from new generating stations. McFadyen's approach would effectively cancel any future development of our hydro resources.

We will not roll the dice on Manitoba's future in this way. Our government is committed to moving Manitoba forward, and that includes investing in Bipole III to ensure clean energy and reliable hydro for generations to come.

ROSANN WOWCHUK
Manitoba Finance Minister

Manitoba Hydro

Tab 140

Manitoba Hydro
~~Manitoba~~ Dept of Finance

Project must proceed

BR.S

1 p. A6

FEB 01 2010

I read with interest your editorial on Jan. 24, with the headline Tenuous Logic In Bipole.

It's important for all Manitobans to understand the urgent need to get Bipole III built, and built on time as Manitoba Hydro needs to secure the reliability of Manitoba's power system.

Stalling or delaying the project in any way, as the leader of the opposition has demanded, would put $20 billion in power exports at risk.

Our government is committed to supporting east side first nations seeking to establish a UNESCO World Heritage Site on the east side of Lake Winnipeg. Recent events in Newfoundland and Labrador underscore that a hydro transmission line is incompatible with a UNESCO site.

Last September, Newfoundland's Conservative Premier Danny Williams announced he was scrapping a shorter, cheaper transmission route because it would threaten the Gros Morne UNESCO World Heritage Site. Instead he opted for a longer route around the UNESCO site even though it would cost at least $100 million more.

Work on Bipole III is already well underway, with three rounds of consultations with communities on the west side of Lake Winnipeg nearly complete. Following licensing approvals, construction of Bipole III will begin in 2012.

When complete in 2017, Manitoba will begin to benefit from billions of dollars in lucrative export sales. Reversing this work and delaying this project until 2020, as Conservative Leader Hugh McFadyen wants, would put the entire project and Hydro's exports at risk.

We will not roll the dice on Manitoba's future in this way.

ROSANN WOWCHUK
Minister Responsible for Hydro

Tab 141

McFadyen misses mark with Hydro comments

BR.S

VPpAll

SEP 23 2010

I would like to correct the misinformation that Mr. Hugh McFadyen and his Progressive Conservatives have been stating as fact.

Mr. McFadyen claims that Manitobans are paying three times as much as Americans for the same power. That is simply not true. Mr. McFadyen chose to compare Manitoba residential retail rates to some of the wholesale, bulk rates in the U.S.

The fact is, according to the U.S. Energy Information Administration, Wisconsin residential customers currently pay almost twice what Manitobans pay for the same power. The rate here is 6.38 cents/kWh. In Wisconsin, the rate varies from 9.6 to 13 cents. There's not a single state that pays below 7.58 cents.

Hydro sells its surplus power to the U.S. to generate profit. Much of that power is sold through long-term fixed rate contracts, and any extra power is sold based on short-term availability to generate additional profit.

There are two options for the extra power: sell the power for a profit or let the water flow through the dam and waste it. We sold it for profit; McFadyen wants to waste it.

These wholesale, bulk sales to the U.S. subsidize the low rates Manitobans pay, which continue to be one of lowest in the country.

The average Manitoba home pays $837 annually; families in Toronto paid $1,559, and in Regina, they paid $1,434.

Unfortunately, Hugh McFadyen has also misled Manitobans when talking about Hydro's future development. Every time he mentions Hydro's Bipole III line, he has a higher dollar figure for the cost. It's interesting how Mr. McFadyen continues to inflate the cost, despite the fact it has been corrected publicly and repeatedly (including in this paper) by the CEO of Hydro, Bob Brennan.

Mr. McFadyen ignores the fact that Bipole III built on the west side of the province will greatly increase opportunities for hydro export sales. With Bipole III and new generating stations operational, revenues from hydro exports are projected to exceed $22 billion over the next two decades. These export revenues show Bipole III is clearly a worthwhile investment as Manitoba Hydro estimates the cost of Bipole III to be $2.2 billion.

Our government is committed to developing a clean energy future to ensure that Manitoba families have reliable access to the energy they need and to power Manitoba's growing economy while maintaining the pristine boreal forest for generations to come.

ROSANN WOWCHUK
Minister Responsible for Manitoba Hydro

~~Progressive~~ Conservative Party of M
Manitoba Hydro
~~Manitoba.~~ Dept of Finance

13052

Tab 142

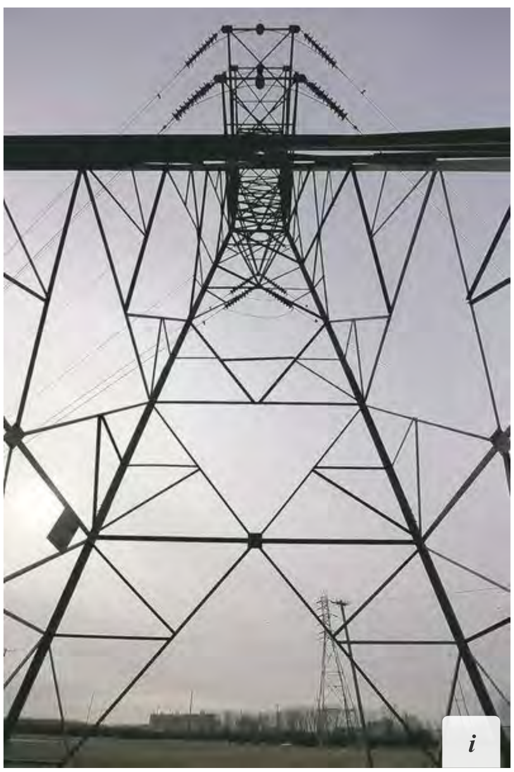
Hydro, gas hikes get go-ahead

BOARD APPROVES INCREASES TO HELP COVER CAPITAL COSTS

By: Bruce Owen
Posted: **04/27/2013 6:38 AM** | Last Modified: 04/27/2013 12:13 PM

Manitoba's Public Utilities Board brought some fresh pain to Manitobans Friday when it boosted hydro and natural gas rates -- the same day the Selinger New Democrats voted to boost the provincial sales tax to eight per cent July 1.

The NDP said despite the 3.5 per cent rate hike awarded to Manitoba Hydro -- and the prospect of similar hikes during the next few years -- Manitobans will stay pay less than their provincial neighbours.



TREVOR HAGAN / WINNIPEG FREE PRESS
Hydro must use 1.5 per cent of the rate increase to mitigate future increases when Bipole III comes into service in five years.

That's also despite the fact consumers will pay eight per cent more in electricity -- starting May 1 -- than they did a year ago, because of earlier interim rate increases.

"We'll still be the lowest, if not the second-lowest, in the country," Energy Minister Dave Chomiak said. "Everyone's rates are going up -- Saskatchewan's rates went up 4.9 per cent and Ontario's rates are higher.

"It's not a great time to be raising anything, but at the end of the day with Hydro, we've already signalled we will be asking for regular increases. We are guaranteeing that we will be the lowest and we will be held to that."

The PUB also awarded Centra Gas, a subsidiary of Hydro, an increase in natural gas rates -- the projected hit for a typical residential customer is approximately 5.6 per cent or $42 per year -- due to rising supply prices.

The Progressive Conservatives said the increases in energy rates are a symptom of a government that's going after a shrinking piece of the pie to pay for its spending and Hydro projects.

13054

"There's a little less money on the table for Manitobans and it adds up," PC Leader Brian Pallister said.

The PUB order for the Hydro rate increase outlines the challenges the Crown corporation faces due to a weak market for its surplus export power and the risk it faces under its 20-year, $33-billion development plan.

"The board is concerned about the deteriorating financial condition of Manitoba Hydro in the face of pending significant major capital expenditure," the PUB said.

The risk comes on several fronts, including a $6-billion decrease in forecast export revenues during the next 20 years and the steadily increasing cost of fixing and replacing aging Hydro generation and transmission systems, including the Pointe du Bois dam on the Winnipeg River that went into service in 1926. Hydro forecasts it will spend $2.4 billion on Pointe du Bois alone.

To soften that risk, the PUB told Hydro to use 1.5 per cent of the new rate increase to mitigate future increases when Bipole III comes into service in four or five years. The increase will generate $48 million in 2013-14.

Hydro's development plan includes building the Keeyask and Conawapa generating stations in Manitoba's north. The two mega-dams come with a combined price tag of $16.4 billion -- a cost that, in part, will see electricity rates more than double during the next 20 years at approximately twice the forecast level of inflation, the PUB said.

"Just because you have low prices now doesn't mean you should squander a Manitoba advantage by doing something that doesn't make sense in the longer term," Pallister said. "Clearly, at best, it will double our prices for Hydro."

Chomiak said Manitoba will continue to enjoy lower energy prices compared with the rest of the country as the two new generating stations will pay for themselves.

"We have (export) contacts that are firm, valued at $7 billion," he said. "We probably have another $20 billion that we're negotiating. We feel really confident about the future."

The board also said since a portion of the granted increase is to be dedicated to major capital, Hydro has to do more to control its operational, maintenance and administrative costs.

"Manitoba Hydro's cost-containment measures appear to be modest at best, and despite a hiring freeze, the utility's current projections still reflect a growth in staffing of 243 equivalent full-time positions from 2011-12 levels," the board said. "Since the economic downturn in 2007-08, levels have increased by 771, with total payroll increasing by $197 million, or 41 per cent, since that time."

It also said Hydro has to increase energy-conservation targets.

Hydro should expand its Lower Income Energy Efficiency Program as increasing energy prices will hurt low-income earners, the board said.

Interest rates are also a concern. The PUB said Hydro's long-term debt is expected to grow to $29 billion by 2027, from $9.4 billion in 2013, which will lead to a finance expense exceeding $1.6 billion in 2028; three times the current level. "The board sees a genuine risk that the capital cost for the major capital projects will escalate further and that interest rates will be higher than forecast," the PUB said.

bruce.owen@freepress.mb.ca

Ready to dig deeper?

WHAT the Public Utilities Board decision means to you:

It approved a 3.5 per cent increase in Manitoba Hydro customers' billed rates effective May 1;

The Crown utility was already granted a two per cent hike last April and another 2.5 per cent increase in September;

Hydro says the monthly cost of the latest increase for the typical residential customer, without electric space heat, using approximately 1,000 kilowatt-hours per month will be $2.60 or 3.4 per cent. A residential customer with electric space heat, consuming an average of 2,000 kilowatt-hours per month, will see an increase of $5.20 per month or 3.6 per cent;

The PUB granted Centra Gas, a subsidiary of Hydro, a hike, too. The approximate 5.6 per cent increase, or $42 per year to the average homeowner, is somewhat cushioned after almost five years of decreases due to low market supply prices for natural gas.

HISTORY

Updated on Saturday, April 27, 2013 at 12:13 PM CDT: kilowatt-hours

The Winnipeg Free Press invites you to share your opinion on this story in a letter to the editor. A selection of letters to the editor are **published daily**.

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• mail *Letters to the Editor, 1355 Mountain Avenue, Winnipeg, Manitoba, R2X 3B6*.

Letters must include the writer’s full name, address, and a daytime phone number. Letters are edited for length and clarity.

Tab 143

Halting hydro projects puts long-term prosperity at risk

Brian Pallister's recent letter asserting that Manitoba Hydro should halt the development of new generating and transmission projects is short-sighted at best. At worst, it's a dangerous gamble that would kill jobs while risking Manitoba's long-term economic prosperity and energy security.

Manitoba is growing and our demand for power is rising. In his letter, Mr. Pallister admits domestic demand is climbing at a pace that will require new power generation within a decade. What he fails to mention is that it takes well over a decade to plan and build a new generating station. We know this from our last project, Wuskwatim.

Cancelling our next hydro generation project now would not only leave us unable to meet our own energy needs in the coming years, it would also make it impossible to meet our export obligations. These signed contracts with customers beyond our borders are projected to generate $29 billion in export revenue over the next 30 years, which will help keep rates low for Manitoba families and businesses.

If we don't build now, we can't simply flip a switch when demand outstrips supply. The infrastructure must be there and that infrastructure takes time to plan and build.

But Mr. Pallister has stated he wouldn't stop at cancelling our new hydro generating projects; he also wants to cancel the next bipole transmission line. Even if we halted all hydro development as the Opposition has clearly stated they would do, a third bipole line is critical for the reliability of our system. Continuing to rely solely on the existing lines running through the Interlake is akin to keeping all our eggs in one basket.

To back his policy of cancelling the hydro capacity we are now building, Mr. Pallister claims the extensive review process for these projects is inadequate. Nothing could be further from the truth. Each project goes through extensive reviews where all information and detail is presented in a fully transparent manner to the public. Opportunities for Manitobans to raise questions and concerns exist throughout theses reviews which take several years to complete. Changes and amendments are made to ensure the best possible results for our province, as was the case with Wuskwatim.

Similarly, we have held extensive consultations and public hearings on the route of Bipole III. We have engaged in substantial public debate, had two provincial elections, and are currently consulting landowners and other stakeholders on the final route.

Manitobans know that hydro is our oil, only cleaner and greener. Mr. Pallister says we shouldn't develop our hydro power. That's like telling Alberta not to develop their oil.

Manitobans have told us they want a responsible long-term approach to hydro that keeps their rates affordable, not short-sighted proposals that ignore the realities of our growing province and increasing demand for energy.

Building Hydro for today and tomorrow will ensure we can meet our own energy needs while keeping our rates among the lowest in North America through export revenues.

DAVE CHOMIAK,
Minister responsible for Manitoba Hydro

Tab 144

November 2008

Manitoba Hydro

Integrated Financial Forecast (IFF08-1)

Financial Planning

Finance & Administration

2008/09 - 2018/19

Manitoba Hydro

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INTEGRATED FINANCIAL FORECAST (IFF08-1)

Section 1

KEY FINANCIAL RESULTS
(Dollars are in millions)

	Actual	IFF08-1 Forecast		
	2007/08	2008/09	2009/10	2010/11
PROJECTED RATE INCREASES - ELECTRIC - GAS (non-commodity)		 5.00% 1.00%	 4.00% 1.00%	 2.90% 1.00%
NET INCOME ($ Millions) - ELECTRIC - GAS	 $340 $6	 $308 $3	 $217 $3	 $177 $3
CAPITAL EXPENDITURES ($ Millions) - ELECTRIC - GAS	 $835 $34	 $1,013 $43	 $1,201 $47	 $1,086 $41
INTEREST COVERAGE RATIO	1.71	1.61	1.39	1.29
CAPITAL COVERAGE RATIO (excl. new major generation & transmission and new head office building)	1.60	1.76	1.07	1.15
DEBT/EQUITY RATIO	77:23	75:25	75:25	75:25

Note: In addition to the average rate increases projected for electric customers, General Consumers' Revenue also includes provisions for the new Energy Intensive Industrial Rate re-submitted to the Public Utilities Board in September, 2008.

1.0 OVERVIEW

1.1 INTRODUCTION

This Consolidated Integrated Financial Forecast (IFF08-1) projects Manitoba Hydro's financial results over the period 2008/09 to 2018/19 based on 2008 planning cycle assumptions regarding future energy demand and supply. Segmented forecasts prepared for the electricity (MH08-1) and natural gas (CGM08-1) operations are included. This forecast reflects the actual hydraulic conditions in the fall of 2008, new long term export sales agreements and the addition of the 630 MW Keeyask generating station for a targeted 2018/19 in-service date.

1.2 HIGHLIGHTS

- **Electricity Rates:** The base forecast includes the PUB-approved 5% rate increase effective July 1, 2008 and a further 4% conditional increase effective April 1, 2009 followed by projections of average rate increases of 2.9% per year beginning April 1, 2010 and every April 1 thereafter. Actual future rate applications to the PUB will be dependent upon the conditions of the day and subject to approval by the Board of Manitoba Hydro prior to filing.

- **Gas Rates:** The gas forecast includes the PUB-approved 1% average rate increase effective May 1, 2008, and general rate increases sufficient to generate net income of approximately $3 million in each of 2009/10 and 2010/11 (currently assumed to be 1% but will be dependent upon the cost of gas at the time of application). Thereafter, the forecast assumes 1% general rate increases effective April 1, of 2011, 2012, 2014 and 2018. The general rate increases projected for gas customers are intended to recover the distribution-related, non-commodity costs of operating the gas utility. As with electricity rate increases, these estimates are subject to future approvals.

- **Consolidated Net Income:** Consolidated net income is forecasted to reach $314 million in 2008/09, up $154 million from the $160 million forecasted in IFF07-1. The increase in net income is mainly attributable to higher export volumes due to current favourable water flow conditions and reductions to finance expense resulting from higher revenues and lower interest rates. Over the forecast period, net income is sufficiently improved to enable the debt/equity ratio to stay close to target even with substantial new capital investment.

- **Export Sales:** The forecast assumes new long term firm contracts with Minnesota Power and Wisconsin Public Service as well as a contract extension with Northern States Power.

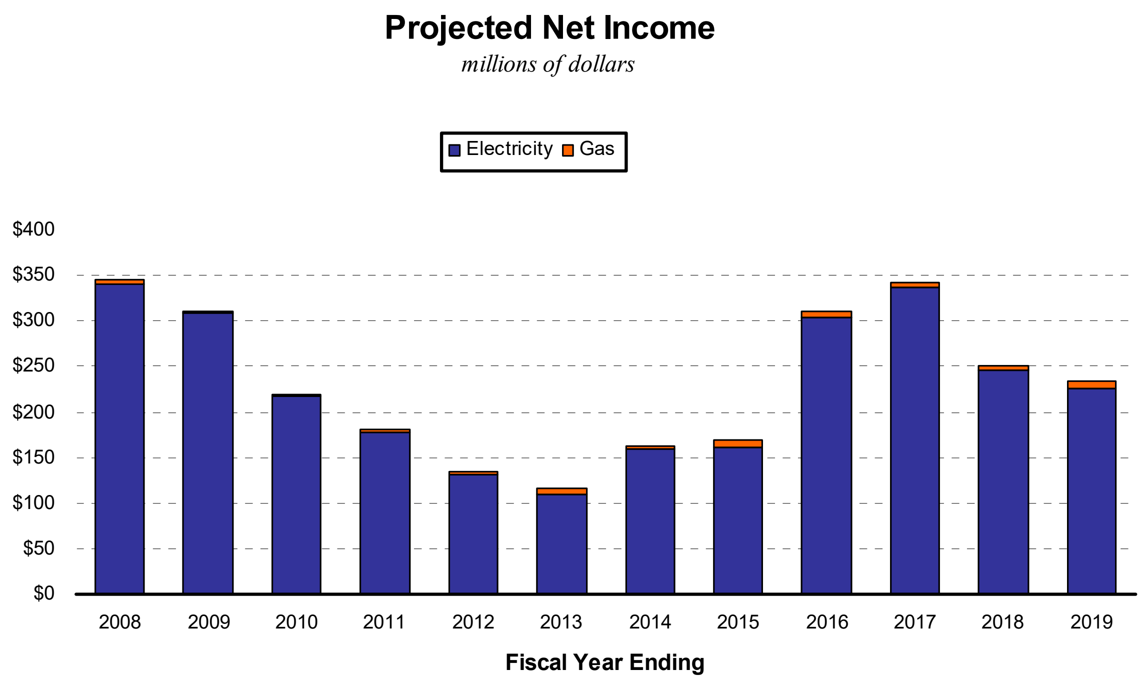
- **New Generation:** The Keeyask generating station (630 MW) is planned to come into service in 2018/19 in order to meet new export demands and domestic load growth. A draft partnership agreement, including equity ownership arrangements, has been submitted to the Tataskweyak, War Lake, Fox Lake and York Factory Cree Nations for community ratification over the next few months. Construction of the Wuskwatim generating station (200 MW) is proceeding, with the first unit planned to come into service in September, 2011. This forecast assumes that Nisichawayasihk Cree Nation will invest to acquire the maximum available 33% ownership interest in the generating station. Other assumptions related to hydraulic generation include the Conawapa generating station (1300 MW) first unit in-service in 2022/23 and the modernization of Pointe du Bois (from current 74 MW to 120 MW) by 2016/17.

- **New Major Transmission:** IFF08-1 assumes that the Bipole III HVDC line along with 2000 MW of converter capability at both north and south locations will be in service by 2017/18 for system reliability purposes and will accommodate future northern generation. A new 500 kV interconnection from Dorsey to the US border is planned for June, 2018 in order to meet the obligations of the new firm export sales.

- **The Capital Expenditure Forecast (CEF08-1):** The 2008 capital forecast, totalling $16.4 billion to 2018/19, is comprised of $11.5 billion of new major generation and transmission projects and $4.9

billion for other capital requirements including necessary system refurbishment and upgrades.

- **Projected net income for electricity and gas operations**: The following graph indicates projected levels of net earnings for Manitoba Hydro and the relative contributions made by each of the gas and electricity operations:



2.0 ASSUMPTIONS

2.1 ECONOMIC VARIABLES

The economic assumptions used in the forecast are based upon Manitoba Hydro's Spring 2008 Economic Outlook. Projected rates for key economic indicators are listed below with the previous projected rates in brackets.

	Manitoba Consumer Price Index	MH CDN New Short Term Debt Rate *	MH CDN New Long Term Debt Rate *	$US/$CDN Exchange Rate
2008/09	2.0% (2.0%)	3.50% (4.70%)	4.90% (5.60%)	1.02 (1.08)
2009/10	2.0% (2.0%)	4.05% (4.60%)	5.30% (5.75%)	1.06 (1.11)
2010/11	2.0% (2.0%)	4.60% (4.60%)	5.85% (5.95%)	1.06 (1.11)
2011/12	2.0% (2.0%)	4.60% (4.60%)	5.95% (6.10%)	1.07 (1.11)
2018/19	2.0% (2.0%)	4.60% (4.60%)	6.45% (6.45%)	1.10 (1.16)

*Excluding Provincial Guarantee Fee of 1.0%

Manitoba Hydro will be monitoring the global credit market crisis and how it may affect future interest rates, foreign exchange, load growth, capital and operating costs, and export market conditions.

2.2 IFRS - INTERNATIONAL FINANCIAL REPORTING STANDARDS

Manitoba Hydro will be required to produce IFRS compliant statements beginning with the 2011/12 fiscal year and provide comparative information for the 2010/11 fiscal year. While many aspects of IFRS are similar to Canadian Generally Accepted Accounting Principles, there are some areas that differ such as the capitalisation of overhead and the treatments of rate regulated assets. It is expected that the revised treatments will reduce the levels of expenditures that are deferred into future periods and will, therefore, cause an increase in current period costs which will, in turn, reduce net income and retained earnings over the short term. Manitoba Hydro is currently reviewing the accounting policy revisions necessary for the transition to these new standards and will be developing an implementation strategy over the next year. The forecast includes a provision for the adoption of the revised treatment of internally developed intangible assets, such as planning studies and DSM expenditures, effective April 1, 2009 as required under Canadian GAAP. For the years 2011/12 on, IFF08-1 includes provision for the more certain aspects of the conversion to IFRS in the amount of $25 million less offsets due to the corresponding reductions in depreciation and amortization expense. Areas which will require more detailed study will be reflected in subsequent forecasts.

2.3 US EXCHANGE EXPOSURE MANAGEMENT

Manitoba Hydro's Foreign Currency Exposure Management Program establishes an effective hedge between $US-denominated revenues and $US-denominated debt. Remaining $US inflows and outflows are valued at the market exchange rate. The exchange rate at year end is used for the balance sheet presentation of $US-denominated debt and investment instruments.

2.4 ELECTRICITY DEMAND AND SUPPLY

2.4.1 Manitoba Electricity Load Forecast

Relative to last year's forecast, the May 2008 Electric Load Forecast projects Manitoba electrical requirements to be 35 GW.h lower by 2017/18. Net total peak is forecast to be 1 MW higher. Significant growth is projected in the residential sector due to a higher population forecast and increased usage but this is largely offset by lower projected growth for general service customers.

Projected load growth in the general service class, (which represents 67% of all sales by volume) is lower even with higher growth in the primary metal sector. The reduction in overall growth is due to lower projected use in the chemical classifications and a reduced provision for potential large industrial loads.

General consumers' revenue includes the estimated impact of the proposed new marginal cost-based rate structure designed to encourage efficient use by new energy-intensive industrial loads which displace higher priced export sales. As this rate structure is related to actual marginal costs which change from time to time, it is not subject to projected general rate increases.

2.4.2 Extraprovincial Sales and Production Costs

Three new long term firm contracts have been included in this forecast (contracts under negotiation):

- Northern States Power contract extension (2015/16 to 2025/26) of 375 MW at 47.6% capacity factor, ramping up to 500 MW in 2022/23.
- Wisconsin Public Service (2018/19 to 2032/33) 66% capacity factor sale with capacity varying from 150 MW to 500 MW for various time periods.
- Minnesota Power (2022/23 to 2035/36) 250 MW at 66% capacity factor.

When combined with projected domestic load growth and existing export commitments, these new export agreements, which mostly occur outside of the IFF08-1 forecast period, necessitate the construction of the Keeyask and Conawapa generating stations and a 500 kV interconnection to the US.

Over the period to 2017/18, there is a projected increase in net export revenues of $508 million compared to the previous forecast. $242 million of this increase occurs in 2008/09 and 2009/10 and reflects current reservoir conditions and favourable market prices. The coal-fired Brandon unit #5 generation facility will be restricted in its operation throughout the forecast except during emergency conditions.

2.4.3 Demand Side Management

IFF08-1 includes DSM projections from the 2007 Power Smart Plan. Combined with savings achieved to date, the target for electrical savings is 807 MW / 2,759 GW.h by 2017/18. There is also a plan to achieve natural gas savings of 152 million cubic meters.

2.4.4 Electricity Supply

Manitoba Hydro's 2008 Power Resource Plan describes the Corporation's current expectations for new or enhanced major sources of electricity generation and HVDC transmission. The Power Resource Plan also provides projections of near-term retirement dates for existing facilities.

Major resource assumptions are shown in the table below. Keeyask is included in this forecast but was not in the plan for IFF07-1, while Conawapa is planned for one year later than in the previous forecast.

2008 Power Resource Plan			
	MW	**Dependable GW.h**	**In-Service Date**
Brandon #5 License Review	105	837	Restricted operation to 2018/19
Pointe du Bois	120	620	Rebuild by 2016/17
Wuskwatim	200	1,250	First power 2011
Keeyask	630	2,900	First power 2018
Conawapa	1300	4,550	First power 2022
Kelsey Re-runnering	77	-	All 7 units by 2011/12
Enhancements of Winnipeg River Plants	30	30	
HVDC Bipole III Line & 2000 MW of Converter Capability	89	243	2017/18
Northern AC Enhancements	45	-	
Demand Side Management Program			
Planned Additional	180	837	By 2017/18

2.4.5 Wuskwatim Partnership

The Wuskwatim Limited Partnership was established between Manitoba Hydro and Nisichawayasihk Cree Nation (NCN) to develop the Wuskwatim generating station. Construction of the infrastructure began in August 2006. The stage 1 cofferdam has been completed and significant progress has been made on excavation for the principal structures and channels. A number of major contracts have been awarded including the recent selection of a general civil contractor. Based on this bid, work is proceeding to achieve a nine month advancement of the first unit in-service to September, 2011. NCN may invest to acquire up to a 33% partnership interest in the generating station and finance up to 22% of project equity through loans from Manitoba Hydro.

Manitoba Hydro will purchase the output from the partnership under a power purchase agreement, and will construct, maintain and operate the Wuskwatim generating station and associated transmission. Manitoba Hydro's projected financial statements consolidate the partnership results, utilizing the non-controlling interest method of accounting for purposes of recording NCN's share of partnership net income. The partnership's net assets on the consolidated balance sheet are offset by an amount for NCN's non-controlling equity interest in the liability section of Manitoba Hydro's consolidated balance sheet. Manitoba Hydro's income statement reflects all of the revenues and costs related to the Wuskwatim partnership with NCN's share of the project net income shown as a deduction before net income.

3.0 NATURAL GAS DEMAND AND SUPPLY

The Corporation sells primary gas to Manitobans in a market which also includes a small number of brokers and marketers, and is the gas distribution utility for all customers in Manitoba. Currently, approximately 80% of customers representing approximately 60% of volumes purchase their primary gas requirements from Manitoba Hydro, with the balance using brokers and marketers through the Western Transportation Service.

The 2009 Natural Gas Volume Forecast is slightly higher than last year's forecast. The total natural gas sales volume forecast is up 13 million cubic meters (0.6%) in 2008/09 and up 20 million cubic meters (1.0%) in 2009/10. By 2017/18, the forecast is up 23 million cubic meters (1.1%). The Large General Service and Special Contract volume forecasts are expected to increase due to a combination of the increased usage experienced in 2007/08 and the use of a higher weather-adjusted base. The volume forecast increase is offset by lower consumption expectations of various manufacturing facilities in the Industrial sector.

The forecast incorporates the transportation and supplementary gas requirements, not only for Manitoba Hydro's customers but also for those consumers who purchase their primary gas from brokers and marketers.

There is no mark-up on primary gas but gas rates are structured to recover a portion of fixed costs through volume-based charges.

4.0 OPERATING & ADMINISTRATIVE EXPENSE

The operating forecast includes the necessary expenditures to provide for the safe and reliable operation and maintenance of the generation, transmission and gas and electric distribution systems.

Operating, Maintenance & Administrative (OM&A) Expenses in IFF08-1 are projected in total to be similar to those in the previous forecast with the addition of operating costs for the Keeyask generating station beginning in 2018/19. Overall, OM&A expenses are projected to increase by an average of 2.5% per year over the forecast period after including the projected requirements of both Wuskwatim and Keeyask. This rate of increase is lower than the combined total of projected inflation and customer load growth and will be achieved through continued productivity improvements.

5.0 CAPITAL EXPENDITURE FORECAST (CEF08-1)

CAPITAL EXPENDITURE FORECAST (CEF08-1) ($ in Millions)												
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Electric	1,013	1,201	1,086	851	818	1,159	1,827	2,227	2,146	1,753	1,900	15,981
Gas	43	47	41	41	41	37	36	36	36	37	38	433
Total	**1,056**	**1,248**	**1,127**	**891**	**858**	**1,196**	**1,864**	**2,263**	**2,183**	**1,790**	**1,938**	**16,414**

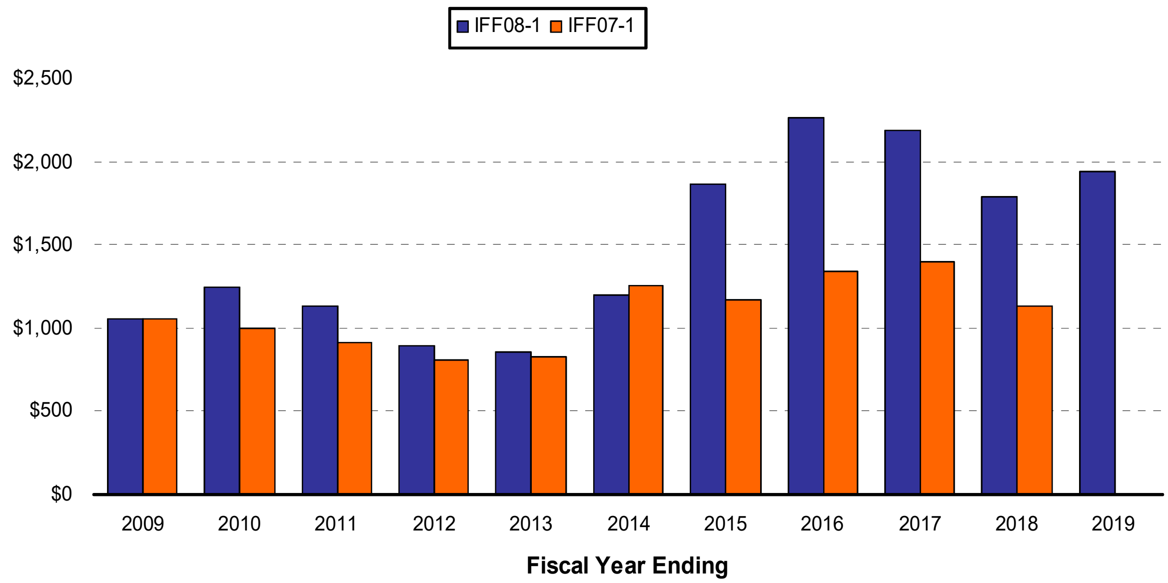
Projected capital expenditures for the period 2008/09 to 2018/19 total $16.4 billion. Over the first 10 years of the forecast, this is $3.6 billion higher than in CEF07-1 of which $2.9 billion relates to increases for major generation and transmission projects as referenced in the table below.

	10 Year Change in Forecast $ Millions	Total Project Cost $ Millions
Keeyask Generating Station	2,701	3,700*
Dorsey - US Border 500 kV T/L	201	205
Riel 230/500 kV Station	160	268
Dorsey 230 kV Relay Building	65	74
Kettle Transformer Overhauls	36	36
Power Supply Security Upgrades	26	36
New Head Office	25	278
Stanley 230-66 kV Transformer	21	21
Generation Townsite Infrastructure	20	52
Generation South Transformers	18	21
Wuskwatim Transmission	17	316
Slave Falls Rehabilitation	15	198
Conawapa Generating Station	(204)	4,978*
System refurbishment and other	477	
Total	**$3,578**	

* Under review

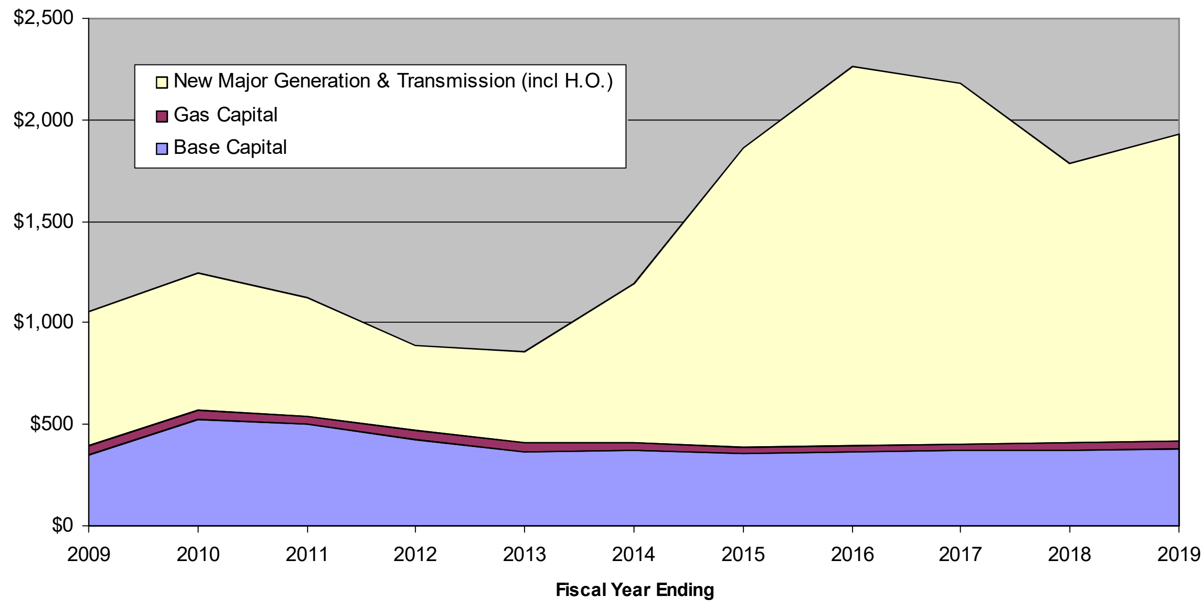
Projected Consolidated Capital Expenditures

millions of dollars



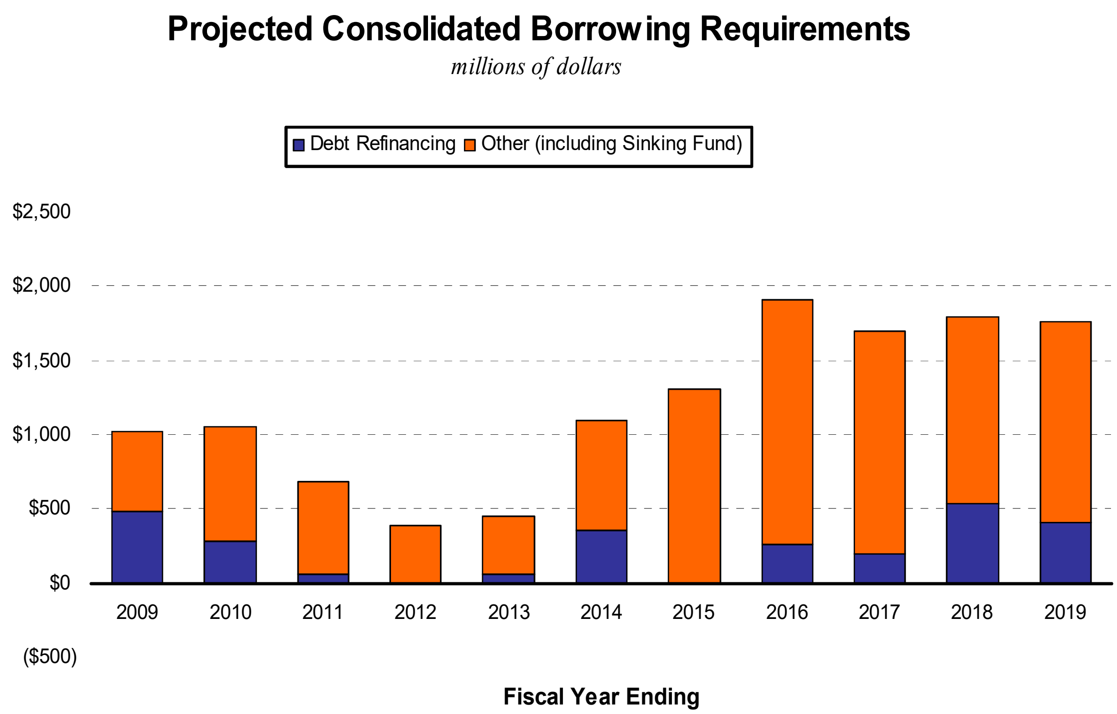
Projected Capital Expenditures
Major Categories

millions of dollars



6.0 BORROWING REQUIREMENTS

Manitoba Hydro's forecast borrowing requirements are portrayed in the following graph:



The Province of Manitoba issues long term debt directly on behalf of Manitoba Hydro. Both long and short-term borrowings are guaranteed by the Province. 15% to 25% of Manitoba Hydro's debt is held in floating rate instruments in order to minimize debt costs without undue interest rate exposure. Currently, about 21% of Manitoba Hydro's debt is in floating rate instruments.

7.0 FINANCIAL RATIOS

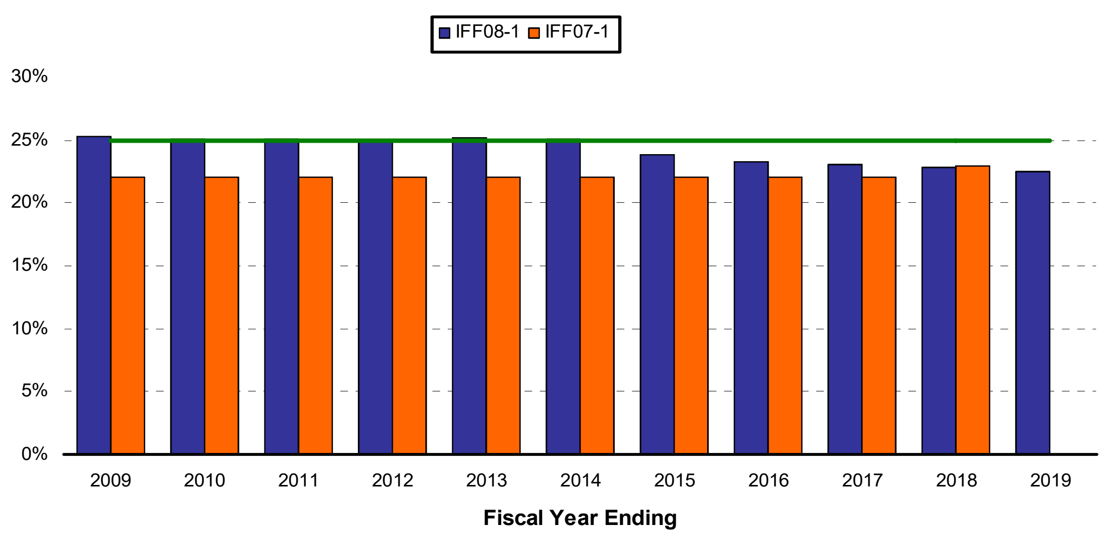
The following graphs depict the impact of IFF08-1, compared to IFF07-1, on Manitoba Hydro's financial targets.

Financial Targets	
Debt/Equity	Achieve a debt/equity ratio of 75:25 by 2011/12
Interest Coverage	Maintain a gross interest coverage ratio of at least 1.2
Capital Coverage	Maintain a capital coverage ratio greater than 1.0 (excluding new major generation and transmission & new head office building)

7.1 EQUITY RATIO

The equity ratio indicates the portion of Manitoba Hydro's capital structure that has been financed internally and not through debt financing. The current favourable water flow conditions are projected to result in the achievement of the Corporation's 75/25 debt equity ratio target by the end of 2008/09. Net income levels are projected to be sufficient to maintain this ratio at the target level until 2014/15 when capital expenditure levels begin to grow as a result of the construction of Keeyask, Conawapa and Bipole III.

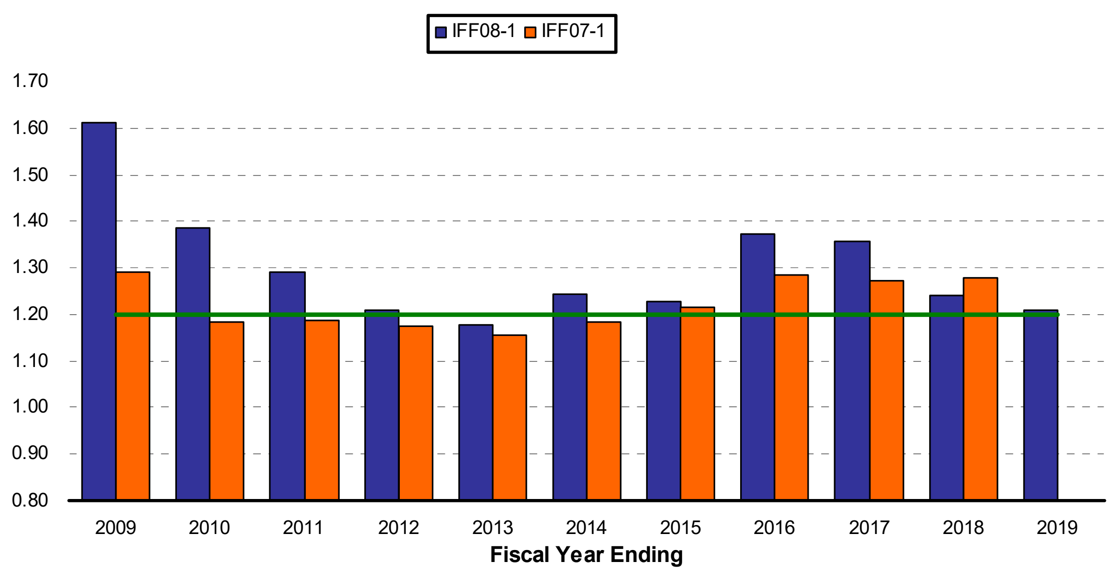
Projected Consolidated Equity Ratio



7.2 INTEREST COVERAGE RATIO

Interest coverage is measured by the ratio of the sum of gross finance expense plus net income to gross finance expense and provides an indication of the ability of the Corporation to meet interest payment obligations without the need for further borrowing. The effects of the current water flow conditions can be clearly seen in the level of interest coverage projected for 2008/09 with carryover effects into 2009/10. With the exception of a slight shortfall in 2012/13, the target level of 1.20 is projected to be met in all years of the forecast under assumed water flow conditions.

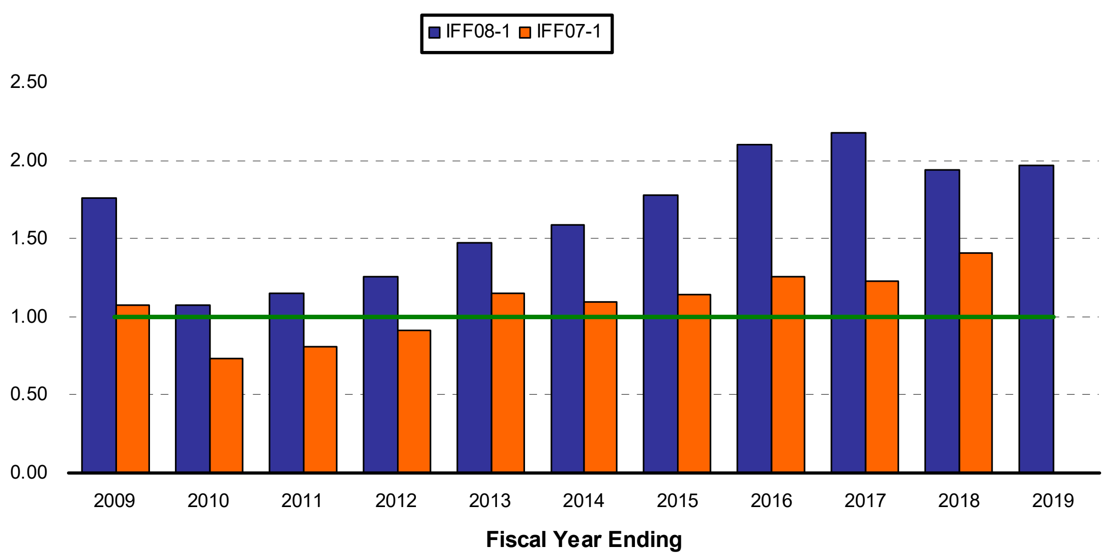
Projected Consolidated Interest Coverage Ratio



7.3 CAPITAL COVERAGE RATIO

Capital coverage measures the ability of current period internally generated funds to finance capital expenditures with the exception of major new generation, related transmission and the new head office. Projected net income levels are sufficient to enable this target to be met throughout the forecast period.

Projected Consolidated Capital Coverage Ratio



8.0 RISK ANALYSIS

Drought continues to be a risk of high significance in terms of both likelihood and consequence of occurrence. Manitoba Hydro typically derives over one third of its revenue from export sales and the potential loss of export revenue due to the adverse effects of a drought and/or other factors such as price declines, changes in regulation and increased domestic requirements is significant. Revenue losses are compounded by the additional costs to import power and operate thermal generation.

The impacts of export market and drought sensitivities, along with a number of other quantifiable risks and sensitivities, are shown in the table below. The table quantifies the resulting changes in retained earnings of the consolidated operations (IFF08-1) by the end of the forecast period 2018/19 assuming no change to rate increases from those in the base case and the annual rate increases/decreases relative to IFF08-1 necessary to offset the risks. Descriptions of the basis for the sensitivities follow.

	2010/11	2014/15	2018/19	Incremental Annual Rate Increase/(Decrease) *	
	Incremental Increase/(Decrease) in Retained Earnings (in millions of dollars)			Electric	Gas
IFF08-1 Baseline	**2,493**	**3,037**	**4,198**	**-**	**-**
+1% Interest Rates	32	27	(115)	0.18%	0.04%
-1% Interest Rates	(26)	13	214	-0.17%	-0.04%
Cdn $ down $0.10 US	53	126	258	-0.20%	N/A
Cdn $ up $0.10 US	(48)	(86)	(144)	0.20%	N/A
Low Export Prices	(64)	(408)	(936)	0.90%	N/A
High Export Prices	55	369	1,026	-1.18%	N/A
5 Year Drought	(485)	(2,651)	(3,488)	3.81%	N/A
+$100M & +$10M Capital Expenditures	(3)	(122)	(448)	0.54%	0.11%
Medium High Electric Load Forecast	(23)	(14)	(58)	0.13%	N/A

***NOTE** - the rate increases represent the additional identical annual percentage (incremental to the base case annual rate increases) required to achieve the same level of retained earnings in 2018/19 as in the base MH08-1 and CGM08-1.

Interest rates and foreign exchange

For the foreign exchange rate sensitivities, rates were adjusted beginning in fiscal year 2008/09. For the +/- 1% interest rate case and increase in capital spending scenarios, adjustments begin in 2009/10. In the +/- 1% interest rate case, the changes in rates were applied to all new long and short-term debt issues and to new sinking fund instruments For all other sensitivities, changes from MH08-1 and CGM08-1 begin in fiscal year 20010/11.

Export prices

Manitoba Hydro has developed an 'Expected' forecast of power prices for export which is assumed in the MH08-1 electricity forecast. In order to establish a reasonable set of bounds to cover the likely range of export prices, Low and High price forecasts have been developed based on industry research. Over the nine year period between 2010/11 and 2018/19, net export revenue would decline $746 million under the Low price forecast and increase $794 million under the High price forecast , before interest effects, compared to the Expected price forecast.

Manitoba load growth

The base load forecast used in MH08-1 represents the most likely future electricity requirements within the Province of Manitoba. Recent events suggest that load growth could be lower than forecast, but higher domestic load growth scenarios generally pose a greater financial risk to Manitoba Hydro. This is due to the reduction in high value export sales which are used to keep rates low, as well as the need to ensure that sufficient resources are available to meet the additional load requirements.

Increase in Capital Expenditures

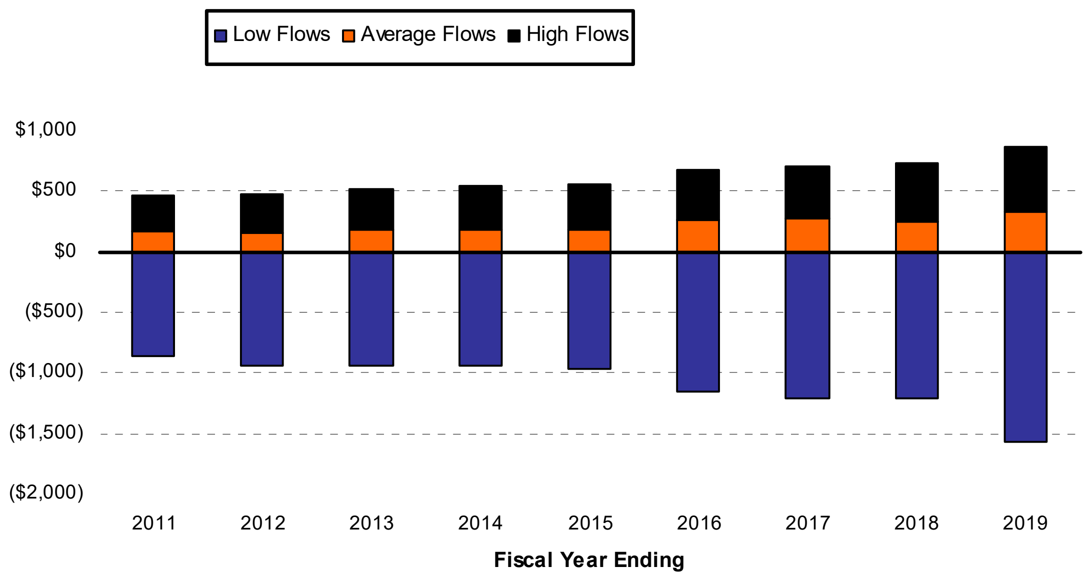
Sensitivities have been performed on capital spending for both gas and electricity operations to reflect the increased financial risk faced by the Corporation in the area of continued upward pressure on capital project construction costs, and/or additional expenditures to meet reliability, safety, regulatory or customer requirements. Increases in general infrastructure requirements of $100 million per year for electricity operations and $10 million per year for gas operations have been assumed for this sensitivity.

Water conditions

Historically, droughts of varying degrees of severity have occurred about once every ten years. The onsets of droughts are very unpredictable and their range in impact can vary significantly. A drought sensitivity has been prepared based on an assumed recurrence of the worst five year drought on record. This drought sensitivity replicates the water flows of the historic five year drought period between April 1987 and March 1992 beginning in the forecast year 2010/11 and extending to 2014/2015. The impacts of the drought on export revenues and thermal and import costs, assume expected market conditions. Over the five year drought period, net export revenue would be reduced by $2.2 billion compared to IFF08-1. The impact could be greater due to financing costs and will be dependent upon the timing and magnitude of the rate increases implemented to address the drought impacts. If a drought of this magnitude (or the even larger 1936 - 1943 drought) were to coincide with a period of high prices for thermal and import purchases the impact would be even greater.

The graph below shows the variability in net export revenues on an annual basis due to fluctuations in water flows. The asymmetry between the benefits of high flows and the costs of low flows is due to the fact that in high years, water is spilled as a result of system design constraints and to the requirements for thermally generated and imported energy under low water years.

Variability in Net Export Revenue
millions of dollars



From a financial perspective, Manitoba Hydro's best risk protection is achieved through adequate levels of equity (retained earnings). Equity provides a buffer to absorb adverse events so that compensating rate increases can be smoothed out over a period of time. The Corporation is exposed to a number of other uncertainties which must be managed including risks related to reliability of service, infrastructure loss, environmental, and regulatory/legal issues. The magnitude of their impact and relative probability of occurrence are outlined in Manitoba Hydro's Corporate Risk Management report.

Section 2

9.0 PROJECTED CONSOLIDATED FINANCIAL STATEMENTS (IFF08-1)

CONSOLIDATED PROJECTED OPERATING STATEMENT (IFF08-1)
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
REVENUES											
General Consumers Revenue	1,678	1,803	1,890	1,958	2,021	2,068	2,125	2,179	2,234	2,301	2,371
Extraprovincial	619	546	465	477	498	509	524	624	649	651	800
Other	32	25	26	27	27	28	28	29	29	30	30
	2,330	2,373	2,381	2,461	2,546	2,605	2,677	2,831	2,912	2,982	3,201
EXPENSES											
Finance Expense	434	461	470	517	579	553	568	541	553	629	733
Operating & Administrative	418	428	436	452	461	470	479	490	499	522	534
Depreciation & Amortization	377	404	424	470	500	508	526	533	535	566	607
Water Rentals & Assessments	121	112	107	110	113	114	114	115	116	116	121
Fuel & Power Purchased	149	198	199	213	210	226	240	252	267	291	354
Capital & Other Taxes	89	95	98	98	101	105	112	122	131	137	145
Cost of Gas Sold	427	450	463	463	461	460	459	457	456	455	454
	2,016	2,149	2,197	2,324	2,426	2,437	2,500	2,510	2,557	2,717	2,949
Noncontrolling Interest	0	0	0	2	2	(0)	(2)	(5)	(7)	(9)	(12)
Net Income	314	224	184	140	122	168	175	316	348	256	240
Additional General Consumers Revenue											
General electricity rate increases		4.00%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
General gas rate increases		1.00%	1.00%	1.00%	1.00%	0.00%	1.00%	0.00%	0.00%	0.00%	1.00%
Financial Ratios											
Debt	75%	75%	75%	75%	75%	75%	76%	77%	77%	77%	77%
Interest Coverage	1.61	1.39	1.29	1.21	1.18	1.24	1.23	1.37	1.36	1.24	1.21
Capital Coverage	1.76	1.07	1.15	1.26	1.47	1.59	1.78	2.10	2.17	1.94	1.96

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CONSOLIDATED PROJECTED BALANCE SHEET (IFF08-1)
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ASSETS											
Plant in Service	12,567	13,128	13,686	15,759	16,299	16,707	17,421	17,817	19,015	21,694	22,895
Accumulated Depreciation	(4,527)	(4,892)	(5,272)	(5,690)	(6,140)	(6,597)	(7,071)	(7,547)	(8,032)	(8,550)	(9,112)
Net Plant in Service	8,039	8,236	8,414	10,069	10,160	10,110	10,350	10,269	10,983	13,144	13,784
Construction in Progress	1,663	2,314	2,831	1,576	1,875	2,650	3,786	5,635	6,604	5,702	6,407
Current & Other Assets	2,509	2,368	2,311	2,410	2,499	2,250	2,429	2,737	2,910	3,210	3,058
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,319	13,024	13,663	14,163	14,641	15,117	16,672	18,748	20,605	22,163	23,357
LIABILITIES											
Long Term Debt	7,170	7,859	8,632	8,968	8,391	9,611	10,766	12,567	13,653	14,602	15,994
Current & Other Liabilities	2,356	2,269	1,947	2,045	2,978	2,099	2,344	2,321	2,762	3,127	2,689
Contributions in Aid of Construction	393	394	396	397	400	402	408	415	422	430	438
Retained Earnings	2,136	2,309	2,493	2,573	2,695	2,863	3,037	3,353	3,702	3,957	4,198
Accumulated Other Comprehensive Income	264	193	196	179	179	143	117	92	66	47	38
	12,319	13,024	13,663	14,163	14,641	15,117	16,672	18,748	20,605	22,163	23,357
Debt Ratio	75%	75%	75%	75%	75%	75%	76%	77%	77%	77%	77%

CONSOLIDATED PROJECTED CASH FLOW STATEMENT (IFF08-1)
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OPERATING ACTIVITIES											
Cash Receipts from Customers	2,427	2,462	2,469	2,550	2,630	2,689	2,761	2,915	2,996	3,065	3,285
Cash Paid to Suppliers and Employees	(1,262)	(1,387)	(1,383)	(1,437)	(1,447)	(1,472)	(1,503)	(1,534)	(1,569)	(1,623)	(1,712)
Interest Paid	(487)	(477)	(465)	(520)	(586)	(568)	(556)	(553)	(564)	(669)	(775)
Interest Received	29	30	20	11	14	13	2	13	24	34	37
	708	628	642	604	612	663	704	842	887	808	835
FINANCING ACTIVITIES											
Proceeds from Long Term Debt	800	990	800	400	320	1,200	1,400	2,000	1,600	1,800	1,800
Sinking Fund Withdrawals	251	262	238	29	85	486	0	6	0	0	440
Retirement of Long Term Debt	(735)	(541)	(302)	(29)	(147)	(839)	0	(262)	(201)	(530)	(853)
Other	(8)	(16)	(8)	26	(5)	(9)	(10)	(11)	(11)	(12)	(24)
	308	695	727	426	253	838	1,390	1,734	1,388	1,257	1,363
INVESTING ACTIVITIES											
Property, Plant & Equipment, net of contributions	(1,112)	(1,265)	(1,138)	(901)	(865)	(1,203)	(1,868)	(2,268)	(2,188)	(1,795)	(1,942)
Sinking Fund Payment	(103)	(102)	(99)	(98)	(113)	(171)	(108)	(194)	(154)	(234)	(193)
Other	(20)	(20)	(20)	(16)	(16)	(26)	(26)	(26)	(26)	(27)	(27)
	(1,235)	(1,387)	(1,257)	(1,014)	(994)	(1,400)	(2,002)	(2,488)	(2,368)	(2,055)	(2,162)
Net Increase (Decrease) in Cash	(219)	(65)	113	15	(130)	100	92	88	(92)	10	37
Cash at Beginning of Year	123	(96)	(161)	(48)	(32)	(162)	(62)	30	117	25	35
Cash at End of Year	(96)	(161)	(48)	(32)	(162)	(62)	30	117	25	35	72

10.0 CAPITAL EXPENDITURE FORECAST (CEF08-1)

PROPOSED CAPITAL EXPENDITURES FORECAST (CEF08-1)

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	11 Year Total
ELECTRIC													
MAJOR GENERATION & TRANSMISSION													
Wuskwatim Generation	1 274.6	200.6	326.9	256.4	126.8	20.8	-	-	-	-	-	-	931.5
Wuskwatim Transmission	315.5	117.4	52.5	32.2	15.5	0.9	-	-	-	-	-	-	218.6
Herblet Lake - The Pas 230 kV Transmission	93.2	16.1	39.3	29.0	4.2	-	-	-	-	-	-	-	88.6
Keeyask Generating Station	3 700.4	56.6	25.9	33.1	36.1	64.3	220.3	430.6	687.9	704.1	504.9	444.8	3 208.7
Conawapa Generating Station	4 978.4	58.9	60.5	60.7	57.7	62.3	67.7	261.8	356.3	330.7	609.4	1 044.6	2 970.5
Kelsey Generating Station Improvements & Upgrades	189.6	43.4	45.8	7.4	0.3	-	-	-	-	-	-	-	96.9
Kettle Generating Station Improvements & Upgrades	75.6	0.4	7.0	7.3	6.4	6.0	3.8	3.7	6.1	6.4	4.0	3.8	54.8
Pointe du Bois Rebuild	818.0	13.0	13.8	14.8	15.5	91.5	141.1	310.7	105.0	94.8	4.0	-	804.3
Pointe du Bois & Slave Falls Transmission	85.9	7.9	19.1	12.5	13.2	16.4	13.0	2.8	-	-	-	-	84.9
Planning Study Costs		5.7	5.9	4.7	-	-	-	-	-	-	-	-	16.3
Bipole 3 Western Route	2 247.8	9.2	16.6	21.4	36.7	113.4	266.5	420.2	627.7	557.9	168.6	-	2 238.3
Riel 230/ 500 kV Station	267.6	4.2	30.7	68.8	75.7	43.5	36.4	4.7	-	-	-	-	264.0
Firm Import Upgrades	4.8	0.1	0.4	2.1	2.1	-	-	-	-	-	-	-	4.8
Dorsey - US Border New 500kV Transmission Line	204.8	-	-	-	0.8	1.8	10.7	11.8	56.7	58.5	61.0	3.4	204.8
Demand Side Management - Electric		42.7	34.6	33.3	31.8	29.4	26.0	26.6	25.4	25.2	24.8	20.3	320.2
MAJOR GENERATION & TRANSMISSION TOTAL		**576.3**	**679.1**	**583.6**	**422.9**	**450.2**	**785.6**	**1 472.9**	**1 865.2**	**1 777.6**	**1 376.7**	**1 516.9**	**11 507.1**
NEW HEAD OFFICE													
New Head Office	**278.1**	**84.1**	-	-	-	-	-	-	-	-	-	-	**84.1**
CORPORATE RELATIONS													
Waterways Management Program		**5.2**	**5.3**	**5.5**	-	-	-	-	-	-	-	-	**16.0**

PROPOSED CAPITAL EXPENDITURES FORECAST (CEF08-1)

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	11 Year Total
POWER SUPPLY													
Converter Transformer Bushing Replacement	5.9	0.1	1.3	1.0	-	-	-	-	-	-	-	-	2.4
Bipole 1 & 2 Electrode Line Monitoring	1.7	0.1	1.5	0.1	-	-	-	-	-	-	-	-	1.7
HVDC Auxiliary Power Supply Upgrades	3.7	0.1	-	-	-	-	-	-	-	-	-	-	0.1
Dorsey Synchronous Condenser Refurbishment	32.3	2.7	4.5	2.8	3.8	2.6	2.7	3.4	-	-	-	-	22.4
Dorsey ASEA Synchronous Condenser Cooler Upgrade	3.5	0.5	-	-	-	-	-	-	-	-	-	-	0.5
HVDC Bipole 1 Roof Replacement	5.9	0.4	0.7	-	-	-	-	-	-	-	-	-	1.0
HVDC System Transformer & Reactor Fire Protection & Prevent	10.4	1.1	1.1	0.6	-	-	-	-	-	-	-	-	2.8
HVDC AC Filter PCB Capacitor Replacement	34.5	5.3	3.0	4.7	-	-	-	-	-	-	-	-	13.0
HVDC Transformer Replacement Program	105.7	0.8	4.5	10.0 -	0.2	0.3	-	-	-	-	-	-	15.3
Dorsey 230KV Relay Building Upgrade	73.8	0.6	2.8	3.5	1.7	15.8	32.9	12.2	3.6	-	-	-	73.0
HVDC Stations Ground Grid Refurbishment	4.3	0.9	0.4	0.3	0.4	0.5	-	-	-	-	-	-	2.4
HVDC Bipole 2 230 kV HLR Circuit Breaker Replacement	9.4	2.9	1.3	0.8	0.3	-	-	-	-	-	-	-	5.3
HVDC Bipole 1 Pole Differential Protection	3.3	-	3.3	-	-	-	-	-	-	-	-	-	3.3
HVDC Bipole 1 By-Pass Vacuum Switch Removal	20.4	0.2	4.7	5.4	4.4	5.8	-	-	-	-	-	-	20.4
HVDC Bipole 2 Refrigerant Condenser Replacement	11.0	-	-	2.9	7.2	0.9	-	-	-	-	-	-	11.0
HVDC Bipole 1 Smoothing Reactor Replacement	31.8	0.3	3.1	10.5	12.8	5.1	-	-	-	-	-	-	31.8
HVDC - BP1 Converter Station, P1 & P2 Battery Bank Separatic	3.2	0.0	0.0	1.0	2.2	-	-	-	-	-	-	-	3.2
HVDC Bipole 1 DCCT Transductor Replacement	11.7	0.8	2.5	1.2	3.5	1.3	1.8	0.7	-	-	-	-	11.7
HVDC BP1 & BP2 DC Converter Transformer Bushing Replacem	8.7	-	0.5	1.0	1.6	5.1	0.5	-	-	-	-	-	8.7
HVDC Bipole 2 Valve Wall Bushing Replacements	19.2	-	3.4	4.6	4.7	4.8	1.8	-	-	-	-	-	19.2
HVDC Bipole 1 CQ Disconnect Replacement	5.2	-	0.0	1.2	1.6	0.9	1.1	0.3	-	-	-	-	5.2
HVDC - Bipole 2 Thyristor Module Cooling Refurbishment	4.7	0.4	1.8	1.8	0.8	-	-	-	-	-	-	-	4.7
HVDC BP2 Smoothing Reactor Replacement	17.1	-	-	-	7.0	6.5	3.0	0.5	0.1	-	-	-	17.1
Great Falls Generating Station Rehabilitation	31.1	0.2	-	-	-	-	-	-	-	-	-	-	0.2
Pine Falls Generating Station Rehabilitation	56.2	2.3	4.6	24.5	5.2	3.8	3.2	5.9	0.7	-	-	-	50.3
Laurie River GS Phase 2 & 3 Rehabilitation	7.7	-	-	1.0	0.8	1.2	-	-	-	-	-	-	3.0
Jenpeg Generating Station Unit Overhauls	128.1	0.1	-	-	-	-	-	-	2.4	2.6	19.1	25.1	49.3
Power Supply Dam Safety Upgrades	34.0	2.1	3.5	1.2	1.2	1.2	1.3	1.3	1.9	-	-	-	13.7
Winnipeg River Control System	10.4	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Winnipeg River Riverbank Protection Program	19.7	1.3	1.1	1.2	1.2	1.2	1.2	1.3	1.3	1.5	-	-	11.3
Power Supply Hydraulic Controls	16.0	5.1	1.8	0.9	2.5	2.4	0.9	1.0	-	-	-	-	14.5
Slave Falls Rehabilitation	198.3	10.2	13.7	10.4	8.9	23.6	29.9	29.7	20.6	25.9	20.3	-	193.1
Generating Station Roof Replacements	9.2	3.9	-	-	-	-	-	-	-	-	-	-	3.9
Great Falls Unit 4 Overhaul	19.7	1.4	4.1	8.1	5.4	-	-	-	-	-	-	-	19.0
Great Falls 115 kV Indoor Station Safety Improvements	11.6	2.6	0.9	-	-	-	-	-	-	-	-	-	3.5
Generation South Transformer Refurbish & Spares	21.0	0.9	2.9	5.3	4.5	3.1	2.6	1.6	-	-	-	-	20.9
Water Licenses & Renewals	40.8	3.5	5.1	5.6	4.9	4.8	4.6	4.9	4.6	-	-	-	38.0
Generation South PCB Regulation Compliance	4.7	0.0	2.0	1.6	0.4	0.4	0.2	-	-	-	-	-	4.7
Kettle Transformer Overhaul Program	35.6	1.0	3.3	3.8	4.6	4.9	5.7	5.7	5.9	0.8	-	-	35.6
Generation South Breaker Replacements	9.4	1.6	2.5	0.9	2.8	1.6	-	-	-	-	-	-	9.4
Seven Sisters Generating Station Upgrades	9.5	1.3	3.5	2.5	1.2	1.0	-	-	-	-	-	-	9.5
Generation South Excitation Upgrades	18.3	-	-	2.0	3.2	3.9	3.3	3.2	2.7	0.1	-	-	18.3
Brandon Generating Station Unit 5 License Review	18.7	0.3	6.2	7.7	-	-	-	-	-	-	-	-	14.3
Selkirk Generating Station Enhancements	14.2	5.1	4.9	2.8	-	-	-	-	-	-	-	-	12.7
Fire Protection Projects - HVDC	5.2	2.0	2.5	-	-	-	-	-	-	-	-	-	4.5
Halon Replacement Project	42.5	11.0	19.2	11.0	0.4	-	-	-	-	-	-	-	41.6
Power Supply Fall Protection Program	13.5	2.6	-	-	-	-	-	-	-	-	-	-	2.6
Oil Containment - Power Supply	19.1	7.5	2.1	0.5	0.1	0.1	0.3	0.1	0.2	0.0	-	-	11.0
Generation Townsite Infrastructure	52.1	5.7	9.6	5.3	4.5	-	-	-	-	-	-	-	25.2
Site Remediation of Contaminated Corporate Facilities	30.9	1.4	0.7	0.5	0.4	0.3	-	-	-	-	-	-	3.4
High Voltage Laboratory	26.9	3.4	15.9	5.7	-	-	-	-	-	-	-	-	24.9
Power Supply Security Installations / Upgrades	36.3	6.1	21.4	7.4	-	-	-	-	-	-	-	-	35.0
Power Supply Sewer & Domestic Water System Instal / Upgr	15.1	6.2	4.1	1.6	1.3	-	-	-	-	-	-	-	13.2
Domestic Item - Power Supply		20.4	19.4	19.8	20.2	20.6	21.0	21.4	21.8	22.3	22.7	23.2	232.6
POWER SUPPLY TOTAL		**126.9**	**195.3**	**184.7**	**125.3**	**123.7**	**117.8**	**93.2**	**65.8**	**53.2**	**62.1**	**48.3**	**1 196.3**

PROPOSED CAPITAL EXPENDITURES FORECAST (CEF08-1)

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	11 Year Total
TRANSMISSION & DISTRIBUTION													
Winnipeg - Brandon Transmission Improvements	40.0	2.3	1.4	1.6	3.6	3.7	5.2	22.0	-	-	-	-	39.8
Transcona New 230 - 66 kV Station	31.0	0.7	8.6	11.9	9.4	-	-	-	-	-	-	-	30.7
Neepawa 230 - 66 kV Station	30.0	0.2	5.8	11.3	12.8	-	-	-	-	-	-	-	30.0
Pine Falls - Bloodvein 115 kV Transmission Line	34.1	-	-	0.3	0.9	4.5	21.2	7.1	-	-	-	-	34.1
Transmission Line Re-Rating	24.1	4.4	0.4	0.4	-	-	-	-	-	-	-	-	5.2
Dorsey 230 kV Bus Enhancement	24.0	0.7	-	-	-	-	-	-	-	-	-	-	0.7
St Vital-Steinbach 230kV Transmission	32.2	-	-	-	-	-	-	-	0.9	1.0	2.6	5.1	9.5
Rosser Station 230 - 115 kV Bank 3 Replacement	5.8	2.9	2.4	-	-	-	-	-	-	-	-	-	5.3
Rosser - Inkster 115kV Transmission	5.1	2.8	2.2	-	-	-	-	-	-	-	-	-	5.0
Transcona Station 66kV Breaker Replacement	6.0	0.1	1.0	2.9	1.7	0.3	0.0	-	-	-	-	-	6.0
Transcona & Ridgeway Station 66kV Bus Upgrade	2.8	1.0	1.5	0.3	-	-	-	-	-	-	-	-	2.8
Dorsey 500kV R502 Breaker Replacement	2.6	2.3	0.4	-	-	-	-	-	-	-	-	-	2.6
Birtle South-Rossburn 66kV Line	4.9	-	-	-	-	-	0.1	0.3	4.5	-	-	-	4.9
Perimeter South Station Distribution Supply Centre Installation	2.4	0.1	0.3	2.0	-	-	-	-	-	-	-	-	2.4
Winnipeg Central District 66 kV Breaker Replacement	6.1	0.4	-	-	-	-	-	-	-	-	-	-	0.4
Stanley Station 230-66 kV Transformer Addition	21.1	-	-	-	-	1.9	8.4	7.9	2.9	-	-	-	21.1
Stanley Station 230-66kV Hot Standby	6.2	1.5	3.8	0.8	0.1	-	-	-	-	-	-	-	6.2
Defective RINJ Cable Replacement	8.7	1.1	1.1	1.0	-	-	-	-	-	-	-	-	3.1
Brereton Lake Station Area	9.0	1.0	0.2	-	-	-	-	-	-	-	-	-	1.2
Stony Mountain New 115 - 12 kV Station	5.0	1.2	-	-	-	-	-	-	-	-	-	-	1.2
Mobile Transformer	3.5	0.0	-	-	-	-	-	-	-	-	-	-	0.0
Rover Substation Replace 4 kV Switchgear	12.7	0.2	5.9	1.1	0.4	-	-	-	-	-	-	-	7.5
Martin New Outdoor Station	20.2	0.1	12.6	9.0	5.4	-	-	-	-	-	-	-	27.1
Frobisher Station Upgrade	14.4	7.6	2.9	0.0	-	-	-	-	-	-	-	-	10.5
Burrows New 66 kV/ 12 kV Station	28.6	4.6	10.7	10.2	2.4	-	-	-	-	-	-	-	27.9
Winnipeg Central District Oil Switch Project	7.1	2.8	0.5	-	-	-	-	-	-	-	-	-	3.3
William New 66 kV/ 12 kV Station	10.3	0.0	2.8	3.9	3.3	-	-	-	-	-	-	-	10.1
Waverley West Sub Division Supply - Stage 1	6.5	3.2	1.4	-	-	-	-	-	-	-	-	-	4.6
St. James 24 kV System Refurbishment	65.9	0.7	19.1	11.1	22.5	12.5	-	-	-	-	-	-	65.9
Transcona Area Distribution Conversion	4.4	0.7	-	-	-	-	-	-	-	-	-	-	0.7
Shoal Lake New 33 - 12.47 kV DSC	3.6	0.2	3.2	-	-	-	-	-	-	-	-	-	3.4
York Station	4.0	0.2	1.1	2.7	-	-	-	-	-	-	-	-	4.0
Brandon Crocus Plains 115 - 25 kV Bank Addition	6.3	0.1	0.8	3.1	1.8	0.4	-	-	-	-	-	-	6.3
Winkler Market Feeder M25-13 Conversion	2.9	2.9	-	-	-	-	-	-	-	-	-	-	2.9
Neepawa N Feeder NN12-2 & Line 57 Rebuild	1.9	0.0	1.9	-	-	-	-	-	-	-	-	-	1.9
Interlake Digital Microwave Replacement	19.7	7.4	3.9	-	-	-	-	-	-	-	-	-	11.3
Communication System Southern MB (Great Plains)	21.9	4.0	1.6	-	-	-	-	-	-	-	-	-	5.6
Communications Upgrade Wpg Area	7.4	1.1	0.8	-	-	-	-	-	-	-	-	-	1.9
Pilot Wire Replacement	9.6	1.5	0.4	1.1	0.9	-	-	-	-	-	-	-	3.9
Trans Line Protection & Teleprotection Replacement	21.1	1.9	2.0	5.7	6.4	2.4	1.2	0.3	-	-	-	-	19.8
Winnipeg Central Protection Wireline Replacement	9.3	2.5	2.4	1.2	-	-	-	-	-	-	-	-	6.1
Mobile Radio System Modernization	30.7	0.1	0.5	13.9	16.2	-	-	-	-	-	-	-	30.7
Gas SCADA Replacement	4.6	0.4	1.1	3.1	-	-	-	-	-	-	-	-	4.6
Cyber Security Systems	10.1	4.0	2.8	0.6	-	-	-	-	-	-	-	-	7.4
Site Remediation	13.3	1.0	3.1	2.0	0.3	-	-	-	-	-	-	-	6.5
Oil Containment	7.4	1.8	1.3	-	-	-	-	-	-	-	-	-	3.1
Station Battery Bank Capacity & System Reliability Increase	46.5	4.9	6.9	7.0	6.7	6.7	3.9	3.6	-	-	-	-	39.6
Red River Floodway Expansion Project	1.8	0.5	-	-	-	-	-	-	-	-	-	-	0.5
Fleet	39.8	13.0	13.3	13.5	13.8	14.1	14.3	14.6	14.9	15.2	15.5	15.8	158.1
Domestic Item - Transmission & Distribution Electric		88.9	90.7	92.6	94.4	96.3	98.2	100.2	102.2	104.2	106.3	108.4	1 082.5
TRANSMISSION & DISTRIBUTION TOTAL		**178.9**	**222.8**	**214.2**	**203.0**	**142.7**	**152.6**	**155.9**	**125.3**	**120.4**	**124.5**	**129.4**	**1 769.8**

PROPOSED CAPITAL EXPENDITURES FORECAST (CEF08-1)

(In Millions of Dollars)

	Project Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	11 Year Total
CUSTOMER SERVICE & MARKETING													
Automatic Meter Reading	30.9	-	3.9	4.0	4.0	4.1	4.3	4.3	4.5	-	-	-	29.1
Distribution PCB Testing & Transformer Replacement	19.6	0.4	-	-	-	-	-	-	-	-	-	-	0.4
Winnipeg Distribution Infrastructure Requirements	14.9	2.0	1.8	-	-	-	-	-	-	-	-	-	3.8
Winnipeg Central District Underground Network Asbestos Removal	3.0	0.8	0.8	-	-	-	-	-	-	-	-	-	1.5
Domestic Item - Customer Service & Marketing - Electric		60.2	61.4	62.6	63.9	65.2	66.5	67.8	69.1	70.5	71.9	73.4	732.5
CUSTOMER SERVICE & MARKETING TOTAL		63.3	67.9	66.6	67.9	69.2	70.7	72.1	73.6	70.5	71.9	73.4	767.3
FINANCE & ADMINISTRATION													
Corporate Buildings	-	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	88.0
Enterprise GIS Project	21.9	0.4	-	-	-	-	-	-	-	-	-	-	0.4
Workforce Management (Phase 1 to 4)	11.3	6.7	-	-	-	-	-	-	-	-	-	-	6.7
WorkSmart	5.4	0.9	-	-	-	-	-	-	-	-	-	-	0.9
Domestic Item - Finance & Administration		22.3	22.7	23.2	-	24.1	24.6	25.1	25.6	26.1	26.6	27.2	271.2
FINANCE & ADMINISTRATION TOTAL		38.3	30.7	31.2	31.7	32.1	32.6	33.1	33.6	34.1	34.6	35.2	367.2
CAPITAL INCREASE PROVISION		-	-	-	-	-	-	-	63.1	90.4	82.8	97.3	333.6
ELECTRIC CAPITAL SUBTOTAL		1 073.2	1 201.2	1 085.8	850.7	817.9	1 159.4	1 827.2	2 226.6	2 146.2	1 752.7	1 900.4	16 041.4
GAS													
TRANSMISSION & DISTRIBUTION													
Southloop Capacity Upgrade - Winkler	4.3	3.6	-	-	-	-	-	-	-	-	-	-	3.6
Gas Riser Rehabilitation Program	16.5	2.0	-	-	-	-	-	-	-	-	-	-	2.0
Natural Gas Pipeline Replacement Red River at North Perimeter	1.7	1.6	-	-	-	-	-	-	-	-	-	-	1.6
Brandon Unodourised Pipeline Improvement	5.5	0.3	5.2	-	-	-	-	-	-	-	-	-	5.5
Domestic Item - Transmission & Distribution Gas		15.2	17.2	17.5	17.9	18.3	18.6	19.0	19.4	19.8	20.2	20.6	203.5
TRANSMISSION & TRANSMISSION TOTAL		22.8	22.4	17.5	17.9	18.3	18.6	19.0	19.4	19.8	20.2	20.6	216.3
CUSTOMER SERVICE & MARKETING													
Automatic Meter Reading - Gas	15.0	-	3.7	3.7	3.5	3.8	-	-	-	-	-	-	14.7
Demand Side Management - Gas		13.5	14.2	13.3	12.4	11.5	10.7	10.1	9.5	9.1	7.0	4.5	115.8
Domestic Item - Customer Service & Marketing Gas		6.7	6.9	6.7	6.8	7.0	7.1	7.3	7.4	7.6	7.7	7.9	79.0
CUSTOMER SERVICE & MARKETING TOTAL		20.2	24.7	23.7	22.8	22.3	17.8	17.4	16.9	16.7	14.7	12.4	209.5
CAPITAL INCREASE PROVISION		-	-	-	-	-	-	-	-	-	2.3	4.9	7.2
GAS CAPITAL SUBTOTAL		42.9	47.2	41.2	40.7	40.5	36.5	36.4	36.3	36.4	37.1	37.8	433.0
CONSOLIDATED CAPITAL SUBTOTAL		1 116.1	1 248.4	1 127.0	891.4	858.4	1 195.8	1 863.6	2 262.9	2 182.6	1 789.8	1 938.2	16 474.3
CONSOLIDATED CAPITAL COST FLOW ADJUSTMENT		(60.1)											(60.1)
CONSOLIDATED CORPORATE TOTAL		1 056.0	1 248.4	1 127.0	891.4	858.4	1 195.8	1 863.6	2 262.9	2 182.6	1 789.8	1 938.2	16 414.2

11.0 ELECTRIC OPERATIONS INTEGRATED FINANCIAL FORECAST (MH08-1)

ELECTRIC OPERATIONS (MH08-1)
PROJECTED OPERATING STATEMENT
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
REVENUES											
General Consumers Revenue											
at approved rates	1,110	1,159	1,190	1,214	1,233	1,241	1,250	1,259	1,269	1,286	1,299
additional *	0	45	82	120	160	202	245	290	337	388	440
Extraprovincial	619	546	465	477	498	509	524	624	649	651	800
Other	15	7	7	8	8	8	8	8	8	8	8
	1,744	1,756	1,744	1,819	1,899	1,959	2,026	2,181	2,263	2,333	2,547
EXPENSES											
Finance Expense	399	425	432	479	542	516	531	503	515	591	695
Operating & Administrative	349	358	365	379	386	394	402	410	418	439	450
Depreciation & Amortization	351	374	390	432	462	470	488	496	498	529	570
Water Rentals & Assessments	121	112	107	110	113	114	114	115	116	116	121
Fuel & Power Purchased	150	199	199	214	211	226	241	252	268	292	354
Capital & Other Taxes	65	71	74	74	76	80	87	96	105	111	119
	1,436	1,539	1,567	1,689	1,791	1,800	1,864	1,873	1,920	2,078	2,309
Noncontrolling Interest	0	0	0	2	2	(0)	(2)	(5)	(7)	(9)	(12)
Net Income	308	217	177	132	110	159	160	303	336	246	226
*Additional General Consumers Revenue											
Percent Increase		4.00%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
Cumulative Percent Increase		4.00%	7.02%	10.12%	13.31%	16.60%	19.98%	23.46%	27.04%	30.72%	34.52%

ELECTRIC OPERATIONS (MH08-1)
PROJECTED BALANCE SHEET
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ASSETS											
Plant in Service	12,018	12,545	13,078	15,128	15,642	16,025	16,714	17,090	18,263	20,913	22,082
Accumulated Depreciation	(4,406)	(4,755)	(5,117)	(5,522)	(5,954)	(6,394)	(6,849)	(7,312)	(7,777)	(8,276)	(8,816)
Net Plant in Service	7,612	7,790	7,960	9,607	9,687	9,632	9,866	9,778	10,486	12,638	13,266
Construction in Progress	1,658	2,312	2,829	1,574	1,873	2,648	3,784	5,633	6,602	5,700	6,406
Current & Other Assets	2,847	2,743	2,691	2,793	2,883	2,632	2,804	3,106	3,274	3,574	3,419
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,160	12,887	13,523	14,016	14,486	14,954	16,495	18,559	20,404	21,954	23,133
LIABILITIES											
Long Term Debt	7,153	7,842	8,615	8,951	8,374	9,594	10,749	12,550	13,636	14,585	15,976
Current & Other Liabilities	2,248	2,188	1,868	1,967	2,902	2,023	2,268	2,245	2,686	3,051	2,613
Contributions in Aid of Construction	392	394	396	399	402	405	412	419	427	435	445
Retained Earnings	2,102	2,270	2,447	2,521	2,631	2,789	2,949	3,253	3,589	3,835	4,061
Accumulated Other Comprehensive Income	264	193	196	179	179	143	117	92	66	47	38
	12,160	12,887	13,523	14,016	14,486	14,954	16,495	18,559	20,404	21,954	23,133

ELECTRIC OPERATIONS (MH08-1)
PROJECTED CASH FLOW STATEMENT
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OPERATING ACTIVITIES											
Cash Receipts from Customers	1,756	1,756	1,744	1,819	1,899	1,959	2,026	2,181	2,263	2,333	2,547
Cash Paid to Suppliers and Employees	(668)	(726)	(733)	(788)	(798)	(826)	(856)	(886)	(921)	(974)	(1,062)
Interest Paid	(463)	(452)	(437)	(491)	(558)	(540)	(528)	(525)	(537)	(641)	(747)
Interest Received	29	30	20	11	14	13	2	13	24	34	37
	655	608	594	550	557	607	643	783	830	752	775
FINANCING ACTIVITIES											
Proceeds from Long Term Debt	800	895	800	400	260	1,200	1,400	2,000	1,600	1,800	1,800
Sinking Fund Withdrawals	251	262	238	29	85	486	0	6	0	0	440
Retirement of Long Term Debt	(733)	(448)	(302)	(29)	(85)	(839)	0	(262)	(201)	(530)	(853)
Other	(8)	(15)	(7)	25	(5)	(9)	(11)	(11)	(11)	(12)	(24)
	310	694	728	425	255	838	1,389	1,734	1,388	1,257	1,363
INVESTING ACTIVITIES											
Property, Plant & Equipment, net of contributions	(1,067)	(1,217)	(1,096)	(859)	(824)	(1,166)	(1,831)	(2,231)	(2,151)	(1,757)	(1,904)
Sinking Fund Payment	(103)	(102)	(99)	(98)	(113)	(171)	(108)	(194)	(154)	(234)	(193)
Other	(20)	(20)	(20)	(16)	(16)	(26)	(26)	(26)	(26)	(27)	(27)
	(1,190)	(1,339)	(1,215)	(973)	(953)	(1,363)	(1,965)	(2,451)	(2,331)	(2,017)	(2,123)
Net Increase (Decrease) in Cash	(225)	(37)	107	3	(142)	81	68	66	(113)	(7)	16
Cash at Beginning of Year	130	(95)	(132)	(24)	(22)	(163)	(82)	(14)	51	(61)	(69)
Cash at End of Year	(95)	(132)	(24)	(22)	(163)	(82)	(14)	51	(61)	(69)	(53)

ELECTRIC OPERATIONS
COMPARISON OF MH08-1 TO MH07-1
INCREASE / (DECREASE)
(In millions of Dollars)

ACCOUNT	2009	CUMULATIVE 2009-2011	CUMULATIVE 2009-2018	VARIANCE EXPLANATION
REVENUES				
General Consumers Revenue Including Projected Rate Increases	(7)	21	205	5.0% July 1, 2008 and 4% April 1, 2009 rate increases, versus 2.9% April 1, 2008 & 2009 in previous forecast. Load growth lower in early years, higher in mid years. Lower projected Energy Intensive Industrial rate revenue.
Extraprovincial	151	329	169	Improved water flows in first two years. Higher export prices partially offset by strengthened Canadian dollar. Removal of 300 MW of new wind generation from forecast due to economic reasons.
Other	(7)	(37)	(153)	Revenue from subsidiaries now only included in consolidated operations. Increase in Joint Use revenue from MTS. Reduction in tenant revenue related to the new head office due to a reduction in downtown real estate lease rates.
Total Revenue	**136**	**313**	**221**	

ELECTRIC OPERATIONS
COMPARISON OF MH08-1 TO MH07-1
INCREASE / (DECREASE)
(In millions of Dollars)

ACCOUNT	2009	CUMULATIVE 2009-2011	CUMULATIVE 2009-2018	VARIANCE EXPLANATION
EXPENSES				
Finance Expense	(26)	(65)	(279)	Higher net income, lower interest rates in the early years of the forecast and strengthening of the Canadian dollar all reduce finance expense. Higher capital spending begins to offset finance expense in later years.
Operating & Administrative	(11)	(34)	(119)	O&A related to subsidiaries now reflected in consolidated operations
Depreciation & Amortization	4	39	310	DSM now amortized over 10 years rather than 15. Higher capital forecast. Inclusion of minimum IFRS provision.
Water Rentals & Assessments	9	13	6	Up in early years due to increased water flows.
Fuel & Power Purchased	7	23	(345)	Higher prices for thermal and import power purchases in early years. Reduction in power purchases due to the removal of 300 MW of wind from the forecast.
Capital & Other Taxes	2	11	66	Higher capital taxes and property tax assessments.
Total Expenses	**(15)**	**(13)**	**(362)**	
Non-controlling Interest	0	0	(46)	Higher export prices increase Wuskwatim net income and hence NCN's share.
Change in Net Income	**152**	**325**	**535**	

12.0 GAS OPERATIONS INTEGRATED FINANCIAL FORECAST (CGM08-1)

GAS OPERATIONS (CGM08-1)
PROJECTED OPERATING STATEMENT
(In millions of Dollars)

For year ending March 31:	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
REVENUES											
General Consumers Revenue											
at approved rates	570	594	607	606	605	604	602	601	600	599	598
additional revenue requirement *	0	6	12	18	23	23	29	29	29	29	35
	570	600	619	624	628	627	631	630	629	628	633
Cost of Sales	428	451	464	463	462	461	459	458	457	456	455
Gross Margin	142	149	155	161	166	166	172	172	172	172	178
Other Revenue	2	2	2	2	2	2	2	2	2	2	2
	144	151	157	163	168	168	174	174	174	174	180
EXPENSES											
Finance Expense	23	24	26	26	25	25	25	26	26	26	26
Operating & Administrative	58	59	60	62	63	64	65	67	68	69	71
Depreciation & Amortization	25	29	32	35	37	38	38	37	37	37	37
Capital & Other Taxes	23	24	24	24	24	25	25	25	25	26	26
Corporate Allocations	12	12	12	12	12	12	12	12	12	12	12
	141	148	154	159	161	164	165	167	168	170	172
Net Income	3	3	3	4	7	4	9	7	6	4	8
*Additional Revenue Requirement											
Percent Increase		1.00%	1.00%	1.00%	1.00%	0.00%	1.00%	0.00%	0.00%	0.00%	1.00%
Cumulative Percent Increase		1.00%	2.01%	3.03%	4.06%	4.06%	5.10%	5.10%	5.10%	5.10%	6.15%

GAS OPERATIONS (CGM08-1)
PROJECTED BALANCE SHEET
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
ASSETS											
Plant in Service	600	629	653	673	698	719	742	760	783	810	840
Accumulated Depreciation	(211)	(223)	(237)	(246)	(261)	(276)	(292)	(303)	(320)	(338)	(357)
Net Plant in Service	390	406	416	426	437	443	450	456	463	472	483
Construction in Progress	2	2	2	2	2	2	2	2	2	2	2
Current & Other Assets	248	253	255	252	248	243	238	234	230	225	219
	640	661	672	680	686	688	690	693	696	699	704
LIABILITIES											
Long Term Debt	143	238	238	175	235	235	235	235	235	235	235
Current & Other Liabilities	315	240	249	316	256	255	249	244	242	242	239
Contributions in Aid of Construction	30	30	29	28	27	26	26	25	24	24	23
Share Capital	121	121	121	121	121	121	121	121	121	121	121
Retained Earnings	30	33	36	40	46	51	59	67	73	77	86
	640	661	672	680	686	688	690	693	696	699	704

GAS OPERATIONS (CGM08-1)
PROJECTED CASH FLOW STATEMENT
(In millions of Dollars)

For year ending March 31:	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OPERATING ACTIVITIES											
Cash Receipts from Customers	656	690	709	714	713	712	717	715	714	713	718
Cash Paid to Suppliers and Employees	(583)	(649)	(638)	(637)	(636)	(633)	(634)	(634)	(635)	(635)	(636)
Interest Paid	(24)	(26)	(28)	(29)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
Interest Received	0	0	0	0	0	0	0	0	0	0	0
	49	15	43	48	49	50	55	53	52	50	54
FINANCING ACTIVITIES											
Proceeds from Long Term Debt	0	95	0	0	60	0	0	0	0	0	0
Retirement of Long Term Debt	(2)	(93)	0	0	(63)	0	0	0	0	0	0
Other	(0)	(1)	(1)	0	0	0	0	0	0	0	0
	(3)	1	(1)	0	(2)	0	0	0	0	0	0
INVESTING ACTIVITIES											
Property, Plant & Equipment, net of contributions	(43)	(48)	(42)	(41)	(41)	(37)	(37)	(37)	(37)	(38)	(38)
Other	0	0	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)
	(43)	(48)	(42)	(41)	(41)	(37)	(37)	(37)	(37)	(38)	(38)
Net Increase (Decrease) in Cash	3	(31)	1	7	6	14	18	16	15	12	15
Cash at Beginning of Year	(12)	(9)	(40)	(39)	(32)	(26)	(12)	6	22	37	48
Cash at End of Year	(9)	(40)	(39)	(32)	(26)	(12)	6	22	37	48	64

GAS OPERATIONS
COMPARISON OF CGM08-1 TO CGM07-1
INCREASE / (DECREASE)
(In millions of Dollars)

ACCOUNT	2009	CUMULATIVE 2009-2011	CUMULATIVE 2009-2018	VARIANCE EXPLANATION
REVENUES				
General Consumers Revenue Including Projected Rate Increases	14	112	509	Primarily due to higher gas prices. Slightly lower rate increases applied to higher base revenues.
Other	(0)	(1)	(4)	Lower late penalty charges as a result of the consolidation of customers' gas and electric bills.
Total Revenue	**14**	**111**	**505**	
EXPENSES				
Cost of Gas Sold	15	115	514	Primarily due to higher gas prices.
Finance Expense	(0)	2	(0)	Lower projected interest rates in the early part of the forecast. Partially offset by higher gas purchases and higher capital requirements.
Operating & Administrative	0	0	0	
Depreciation & Amortization	0	(1)	(4)	Lower due to a change in the treatment of the Furnace Replacement Program.
Capital & Other Taxes	0	1	4	Primarily due to higher property taxes.
Total Expenses	**15**	**117**	**514**	
Change in Net Income	**(1)**	**(6)**	**(9)**	

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Tab 145

20 YEAR FINANCIAL OUTLOOK

2009/10 – 2028/29

FINANCIAL PLANNING
CONTROLLER DIVISION
FINANCE & ADMINISTRATION

January, 2010

OVERVIEW

The 20 Year Financial Outlook is an extension to the Integrated Financial Forecast IFF09-1 which was approved by the Manitoba Hydro-Electric Board on November 19, 2009. The 20 Year Financial Outlook depicts the long-term financial direction of Manitoba Hydro based on current assumptions of future events.

The first decade of the 20 Year Financial Outlook (the decade of investment) shows the financial impacts of major investments in new generation and transmission. Financial ratios are projected to weaken slightly in the first decade but rebound strongly in the second decade (the decade of returns). Domestic rate increases are projected to range from 2.9% to 3.5% per year in the first decade, then drop to 2.0% per year for the entire second decade. Equity (retained earnings) is projected to remain strong throughout the period, rising from $2.2 billion at March 31, 2010 to $11.2 billion at the end of 20 years. Drought remains one of the major risks with a repeat of the worst 5 year drought on record projected to cost $2.4 billion (assuming drought commencing in 2011/12).

KEY ASSUMPTIONS

The key assumptions included in the 20 Year Financial Outlook reflect similar assumption as the 11 year IFF and include the following:

1) Domestic Load Growth

   Domestic electricity load will grow at an average of 1.5% per year for net firm energy to 2019/20 and then 1.3% per year to 2028/29. Net total peak demand grows at an average of 1.3% per year over the 20 Year Financial Outlook to 2028/29.

   Natural gas volumes are projected to decline approximately 0.2% per year over the 20 Year Financial Outlook to 2028/29.

2) Domestic Rate Increases

   Average electricity rate increases of 2.9% per year are projected in 2010/11 and 2011/12 followed by 3.5% per year to 2019/20. Average electricity rate increases then drop to 2%, consistent with long-term projected inflation, for the last 9 years of the 20 Year Financial Outlook.

   Natural gas rate increases are projected to be only the rates necessary to generate net income of approximately $3 to $6 million per year (rate increases average less than 1% per year).

3) Inflation

The Manitoba Consumers Price Index is projected to increase at an average 2% per year commencing in 2011/12.

4) Interest Rates

The very low current short and long-term interest rates are projected to rise over the next 12 to 18 months with long-term rates reaching 6.10% by 2013/14 (excluding the debt guarantee fee of 1.0%) and then remain constant to 2028/29.

5) Foreign Exchange Rates

The US-Canadian exchange rate is projected to rise from the current level of 1.03 ($1.00 US = $0.97 Cdn) to 1.07 in 2012/13, 1.14 in 2016/17 and 1.15 by 2023/24.

6) Export Sales Contracts

The term sheets negotiated for the 15 year 500 MW Wisconsin Public Service sale (commencing in 2018) and the 14 year 250 MW Minnesota Power sale (commencing in 2022) will be finalized into long-term contracts. The 10 year Northern States Power contract extension of 375MW to 500MW (commencing in 2015) will also be finalized.

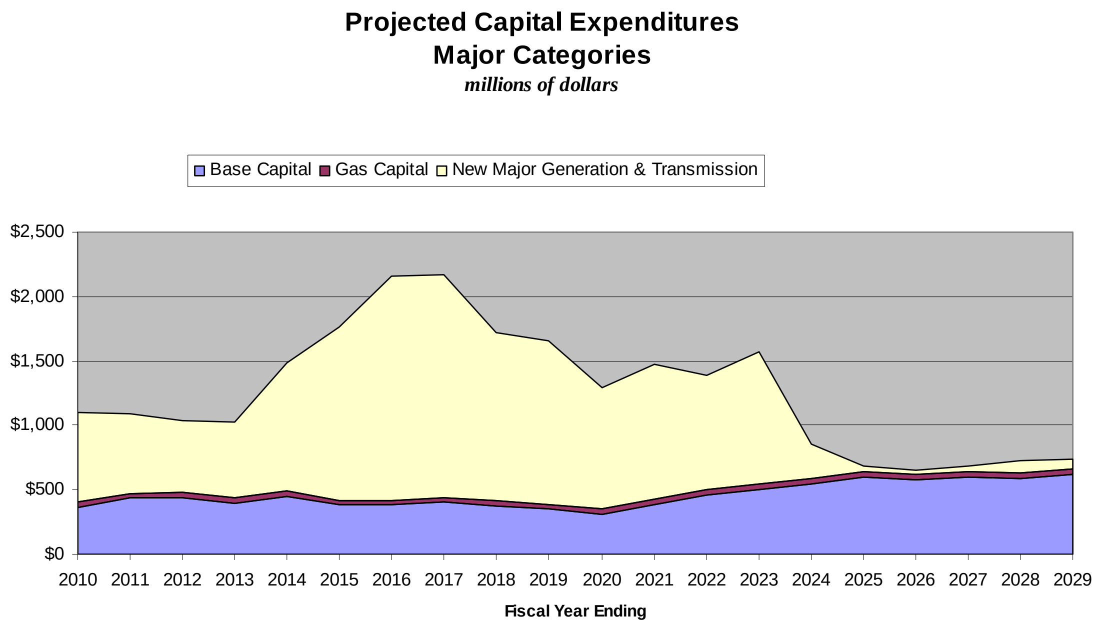
7) Carbon Pricing

Electricity export prices reflect anticipated greenhouse gas legislation and regulation which will likely impose significant constraints on emissions and will result in upward pressures on future market prices for electricity.

8) Capital Expenditures

Investments in new property, plant and equipment are projected to be significant during the first decade with major expenditures on Wuskwatim, Keeyask, Conawapa and Bipole 3 (total capital expenditures to 2019/20 projected to be $16.5 billion). The second decade will see the completion of Conawapa in 2022/23 plus the addition of new transmission to the US. No other new major generation and transmission projects are forecast in the second decade of the forecast. Figure 1 illustrates projected capital expenditures by major categories including new major generation & transmission, gas and other electric capital requirements including system refurbishment and upgrades necessitated by aging infrastructure.

Figure 1


Projected Capital Expenditures
Major Categories
millions of dollars
Base Capital
Gas Capital
New Major Generation & Transmission
$2,500
$2,000
$1,500
$1,000
$500
$0
2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029
Fiscal Year Ending

NET INCOME AND FINANCIAL TARGETS

Projected consolidated net income, equity ratios, interest coverage ratios, and capital coverage ratios for the 20 Year Financial Outlook are depicted in Table 1 and Figures 2 to 5.

Table 1
20 YEAR FINANCIAL OUTLOOK

			RATIOS		
Year Ending March 31	**NET INCOME** *(Millions)*	**RETAINED EARNINGS** *(Millions)*	**Debt/Equity**	**Interest Coverage**	**Capital Coverage**
2009 (actual)	$ 298	$2 120	75:25	1.58	1.81
2010	129	2 227	74:26	1.24	1.39
2011	88	2 315	75:25	1.15	1.09
2012	98	2 396	76:24	1.15	1.14
2013	83	2 479	76:24	1.12	1.28
2014	137	2 616	78:22	1.19	1.25
2015	122	2 738	79:21	1.15	1.52
2016	260	2 997	80:20	1.30	1.86
2017	271	3 268	80:20	1.27	1.83
2018	246	3 515	80:20	1.23	1.91
2019	257	3 772	80:20	1.22	2.14
2020	287	4 059	79:21	1.22	2.56
2021	307	4 366	79:21	1.24	2.23
2022	450	4 816	78:22	1.36	2.19
2023	554	5 369	76:24	1.44	2.25
2024	744	6 113	73:27	1.58	2.53
2025	805	6 918	70:30	1.65	2.45
2026	922	7 840	66:34	1.77	2.74
2027	1 019	8 859	61:39	1.88	2.85
2028	1 127	9 986	56:44	2.02	3.07
2029	1 237	11 223	51:49	2.18	3.09

Note: Assumes projected rate increases of 2.9% April 1, 2010; 2.9% April 1, 2011; 3.5% from 2013 to 2020; and 2.0% from 2021 to 2029.

Figure 2

Projected Consolidated Net Income

millions of dollars

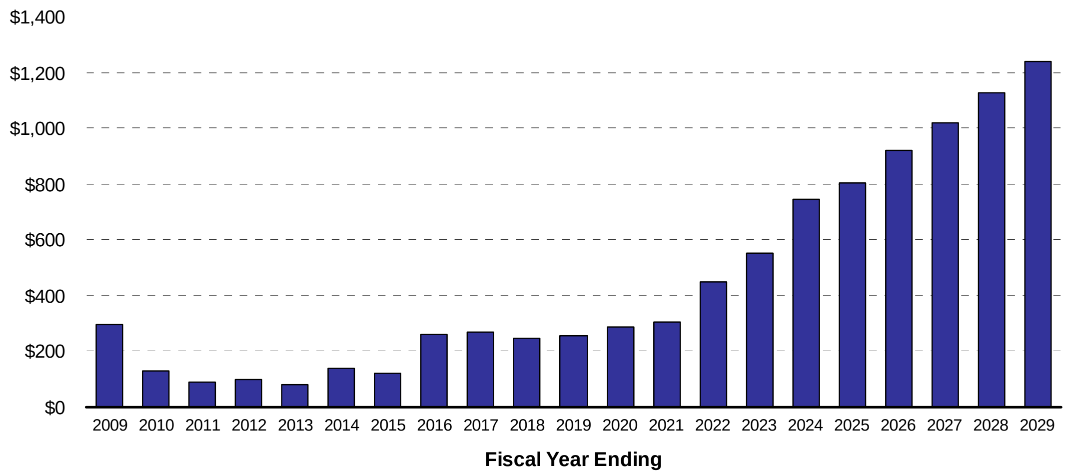


Figure 3

Projected Consolidated Equity Ratio

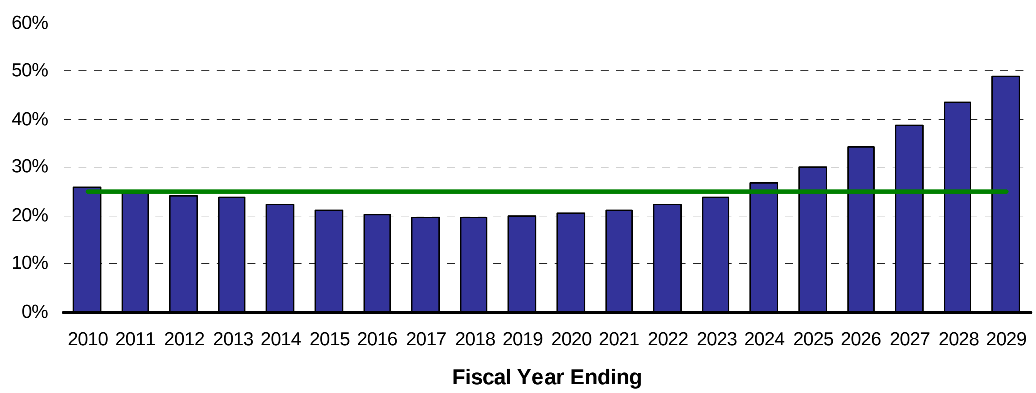


Figure 4

Projected Consolidated Interest Coverage Ratio

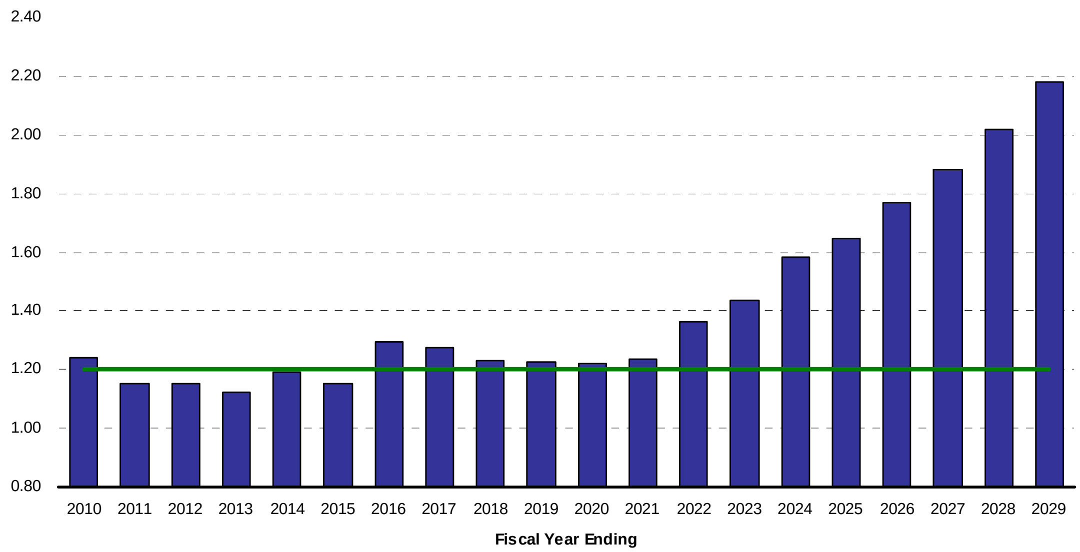
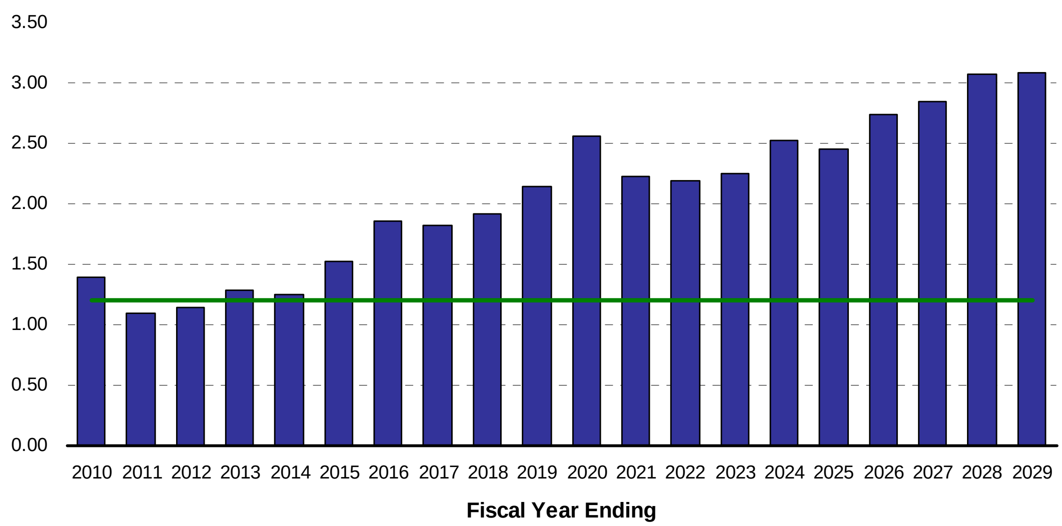


Figure 5

Projected Consolidated Capital Coverage Ratio



CONSOLIDATED PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
REVENUES											
General Consumers	1,652	1,670	1,739	1,808	1,869	1,953	2,028	2,101	2,178	2,256	2,336
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
	2,066	2,054	2,293	2,390	2,484	2,543	2,729	2,830	2,920	3,151	3,429
Cost of Gas Sold	351	332	340	346	342	349	350	351	352	353	352
	1,715	1,722	1,953	2,044	2,142	2,193	2,379	2,479	2,568	2,798	3,077
Other	28	29	31	32	32	33	34	34	35	36	36
	1,742	1,751	1,984	2,076	2,174	2,227	2,412	2,513	2,603	2,834	3,113
EXPENSES											
Operating and Administrative	446	456	482	492	501	512	522	532	555	568	589
Finance Expense	454	451	509	569	570	588	574	590	632	719	923
Depreciation and Amortization	394	415	438	469	481	502	513	519	540	573	607
Water Rentals and Assessments	120	110	111	113	114	114	115	115	115	115	124
Fuel and Power Purchased	103	131	248	249	259	268	296	341	362	440	418
Capital and Other Taxes	97	99	100	104	109	116	125	134	140	146	150
	1,613	1,663	1,888	1,995	2,035	2,100	2,144	2,231	2,344	2,562	2,812
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	129	88	98	83	137	122	260	271	246	257	287
Additional General Consumers Revenue											
General electricity rate increases		2.90%	2.90%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
General gas rate increases		0.00%	1.50%	0.00%	1.00%	0.00%	1.00%	0.00%	1.00%	1.00%	0.00%
Financial Ratios											
Equity	26%	25%	24%	24%	22%	21%	20%	20%	20%	20%	21%
Interest Coverage	1.24	1.15	1.15	1.12	1.19	1.15	1.30	1.27	1.23	1.22	1.22
Capital Coverage	1.39	1.09	1.14	1.28	1.25	1.52	1.86	1.83	1.91	2.14	2.56

CONSOLIDATED PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
REVENUES									
General Consumers	2,392	2,454	2,514	2,581	2,651	2,721	2,801	2,877	2,957
Extraprovincial	1,201	1,223	1,379	1,758	1,940	1,908	1,903	1,928	1,950
	3,593	3,677	3,892	4,338	4,591	4,630	4,704	4,805	4,907
Cost of Gas Sold	351	350	350	349	348	347	346	346	345
	3,242	3,327	3,543	3,990	4,243	4,283	4,358	4,459	4,562
Other	37	38	39	39	40	41	42	42	43
	3,279	3,364	3,581	4,029	4,283	4,324	4,399	4,502	4,605
EXPENSES									
Operating and Administrative	602	615	634	647	660	673	686	699	713
Finance Expense	1,004	897	937	1,118	1,214	1,174	1,142	1,086	1,029
Depreciation and Amortization	634	639	667	729	773	789	807	810	821
Water Rentals and Assessments	129	130	136	150	154	155	155	156	157
Fuel and Power Purchased	435	459	473	459	492	420	395	424	445
Capital and Other Taxes	143	147	153	154	155	156	157	158	159
	2,947	2,887	3,000	3,257	3,448	3,367	3,343	3,334	3,324
Non-controlling Interest	(25)	(27)	(28)	(29)	(30)	(34)	(38)	(41)	(43)
Net Income	307	450	554	744	805	922	1,019	1,127	1,237
Additional General Consumers Revenue									
General electricity rate increases	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
General gas rate increases	0.00%	1.00%	0.00%	1.00%	1.00%	0.00%	1.00%	0.00%	1.00%
Financial Ratios									
Equity	21%	22%	24%	27%	30%	34%	39%	44%	49%
Interest Coverage	1.24	1.36	1.44	1.58	1.65	1.77	1.88	2.02	2.18
Capital Coverage	2.23	2.19	2.25	2.53	2.45	2.74	2.85	3.07	3.09

CONSOLIDATED PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
ASSETS											
Plant in Service	13,097	13,626	15,691	16,213	16,654	17,387	17,844	18,579	21,071	22,401	25,835
Accumulated Depreciation	(4,800)	(5,171)	(5,562)	(5,985)	(6,414)	(6,864)	(7,320)	(7,787)	(8,275)	(8,799)	(9,357)
Net Plant in Service	8,297	8,455	10,129	10,228	10,240	10,523	10,524	10,792	12,796	13,602	16,478
Construction in Progress	1,949	2,460	1,343	1,820	2,840	3,856	5,534	6,950	6,161	6,448	4,170
Current and Other Assets	2,421	2,374	2,503	2,551	2,328	2,482	2,673	2,885	3,191	2,975	3,309
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,775	13,397	14,082	14,705	15,516	16,968	18,838	20,734	22,256	23,133	24,065
LIABILITIES AND EQUITY											
Long-Term Debt	7,816	8,613	9,071	8,786	10,366	11,522	13,140	14,429	15,363	16,446	14,164
Current and Other Liabilities	2,246	2,000	2,187	2,983	2,165	2,365	2,391	2,750	3,104	2,645	5,573
Contributions in Aid of Construction	293	291	285	280	276	273	272	270	268	267	267
Retained Earnings	2,227	2,315	2,396	2,479	2,616	2,738	2,997	3,268	3,515	3,772	4,059
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,775	13,397	14,082	14,705	15,516	16,968	18,838	20,734	22,256	23,133	24,065
Equity Ratio	26%	25%	24%	24%	22%	21%	20%	20%	20%	20%	21%

CONSOLIDATED PROJECTED BALANCE SHEET
(In Millions of Dollars)

For the year ended March 31	2021	2022	2023	2024	2025	2026	2027	2028	2029
ASSETS									
Plant in Service	26,935	27,406	31,328	34,430	35,739	36,567	37,186	37,941	38,573
Accumulated Depreciation	(9,943)	(10,538)	(11,165)	(11,855)	(12,595)	(13,354)	(14,132)	(14,916)	(15,711)
Net Plant in Service	16,991	16,868	20,164	22,575	23,144	23,213	23,054	23,025	22,861
Construction in Progress	4,525	5,456	3,114	879	273	121	210	207	340
Current and Other Assets	3,508	3,043	3,322	3,932	4,819	5,268	6,414	7,631	8,904
Goodwill	107	107	107	107	107	107	107	107	107
	25,132	25,474	26,706	27,493	28,343	28,710	29,784	30,971	32,213
LIABILITIES AND EQUITY									
Long-Term Debt	17,423	17,855	18,657	18,659	18,061	18,064	18,066	18,008	17,760
Current and Other Liabilities	3,075	2,536	2,413	2,453	3,095	2,537	2,587	2,702	2,951
Contributions in Aid of Construction	266	266	267	267	268	270	272	275	279
Retained Earnings	4,366	4,816	5,369	6,113	6,918	7,840	8,859	9,986	11,223
Accumulated Other Comprehensive Income	2	1	(0)	0	0	0	0	0	0
	25,132	25,474	26,706	27,493	28,343	28,710	29,784	30,971	32,213
Equity Ratio	21%	22%	24%	27%	30%	34%	39%	44%	49%

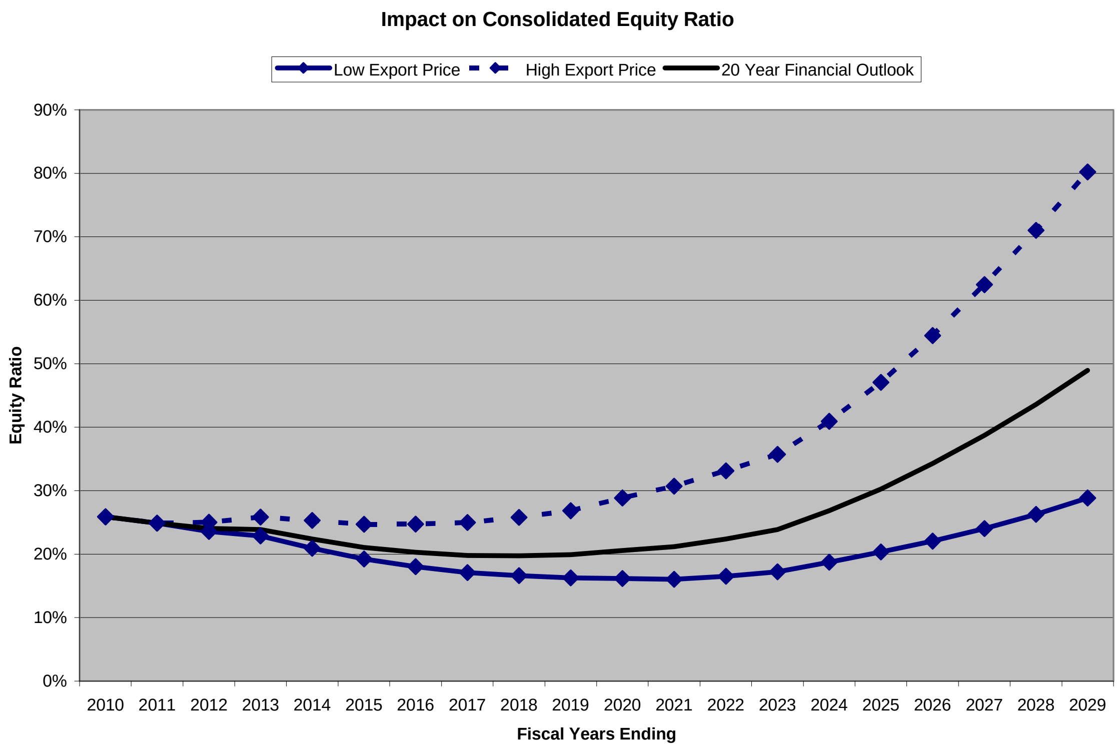
ALTERNATIVE SCENARIOS

IFF09 includes a section demonstrating the sensitivity of key assumptions in the base forecast. Scenarios with the greatest sensitivity, such as the Low and High Export Prices and Five Year Drought, have been developed under the 20 year timeframe to demonstrate the longer-term impacts. The drought scenario has been supplemented to include other flow related scenarios including median flows and periodic low flows. Additionally, an alternative development sequence required for Manitoba demand has been developed. These scenarios are further described below. Figures 6 to 9 show the impacts on the equity ratio for each scenario compared to the 20 Year Financial Outlook.

Low and High Export Prices

The 20 Year Financial Outlook assumes expected export prices. The Low Export Price scenario reflects the long-term impact on future energy prices due to a number of potential factors including low economic growth, aggressive energy conservation policies, low growth in energy demand, loss in momentum in the development of competitive electricity markets, lower natural gas and coal prices and lower premiums related to emissions costs. The High Export Price scenario is characterized by high economic and energy demand growth, higher capital costs, a move to fully competitive markets, higher natural gas and coal prices, stringent US environmental policies and higher environmental premiums relative to expected prices in the 20 Year Financial Outlook. Figure 6 below compares equity ratios under the Low and High Export Price scenarios and the 20 Year Financial Outlook.

Figure 6

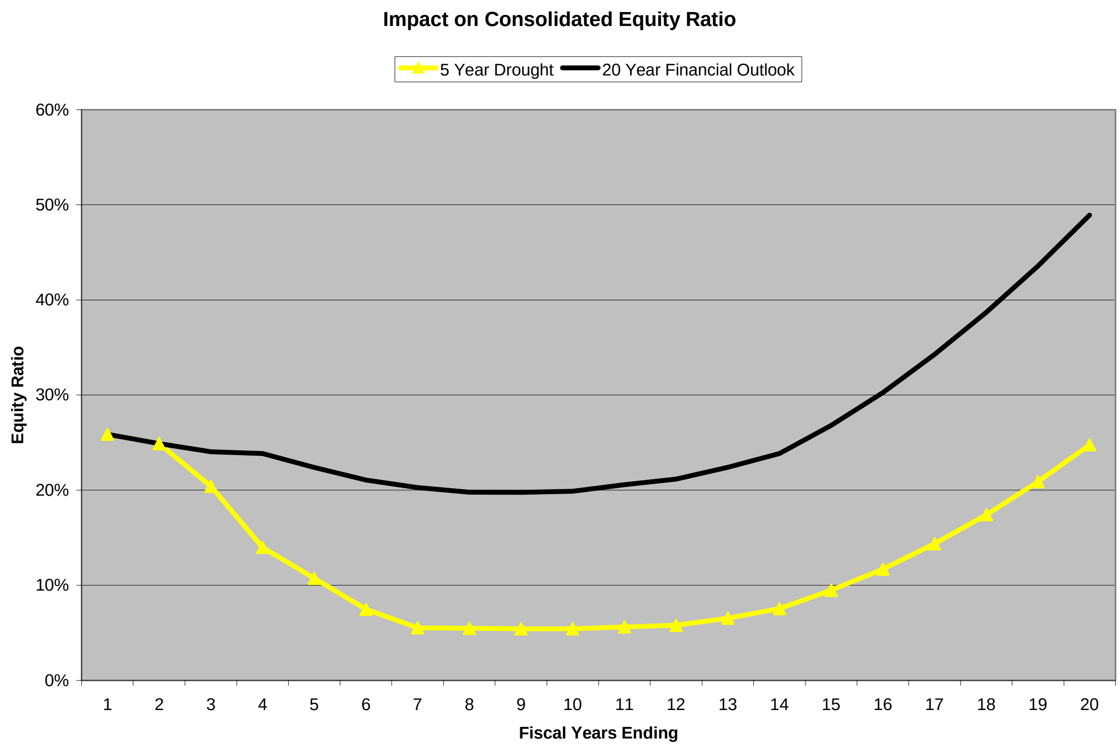


Impact on Consolidated Equity Ratio
Low Export Price
High Export Price
20 Year Financial Outlook
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Equity Ratio
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
Fiscal Years Ending

Five Year Drought

The five year drought scenario shown is identical to the scenario shown in IFF09-1 and assumes a recurrence of the worst five year drought on record commencing in 2011/12. Actual impacts could be smaller or return to normal sooner due to management actions that would mitigate the financial effects of extended low water flow conditions. Figure 7 below compares equity ratios under the 5 Year Drought scenario and the 20 Year Financial Outlook.

Figure 7



Median Flow Revenue Scenario

The base export revenue forecast assumed in IFF09-1 inherently incorporates the effects of drought and high water flows. The revenue forecast is developed by averaging the revenues corresponding to all 94 years of historic flow conditions on record in each year of the forecast. This method captures the asymmetric relationship between higher costs of low flows which are greater than the benefits of high flows. This produces a revenue forecast that is lower than would otherwise be calculated if the historic flows were simply averaged to then calculate revenue or was based on median flow conditions.

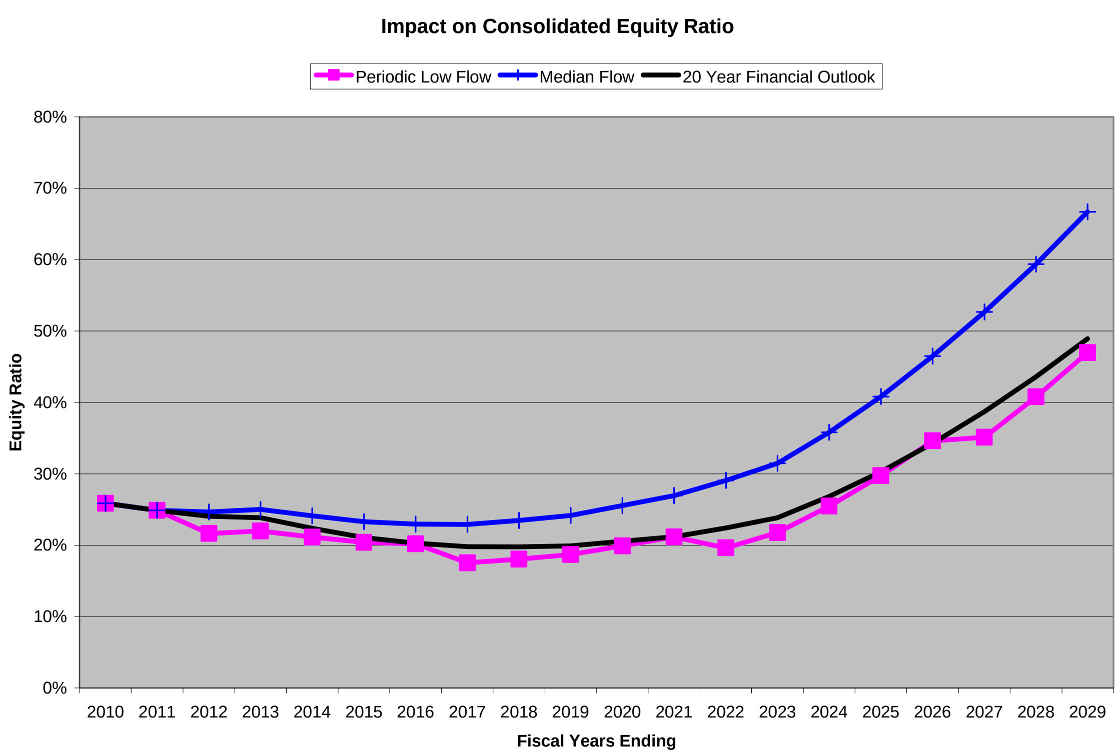
To remove the effects of low and high flows on the revenue forecast, a median flow scenario has been developed. An average of three median flow years (1921, 1926 and 1982) is used as the best representation of median flow conditions. Over the period to 2028/29, net export revenues, assuming median flows, are on average $145 million higher per year compared to the 20 Year Financial Outlook. However, it is more prudent planning to assume that low water flows (as well as high) are going to occur in the future and Manitoba Hydro employs a weighted average methodology for forecasting net export revenues as a result.

Periodic Low Water Flows

Low flow revenues are substituted one in every five years of the median flow forecast reflecting low flow conditions likely to occur in four out of twenty years. The median forecast is the base for the scenario (rather than the 20 Year Financial Outlook) in order to eliminate the duplication of low flows inherent in the 20 Year Financial Outlook. When compared to the IFF09, the Periodic Low Water Flow scenario shows no impact over the longer term compared to the 20 Year Financial Outlook demonstrating the effectiveness of the weighted average forecasting methodology for export revenues.

Figure 8 shows the equity ratios corresponding with the Median and Periodic Low Flow scenarios compared to the 20 Year Financial Outlook.

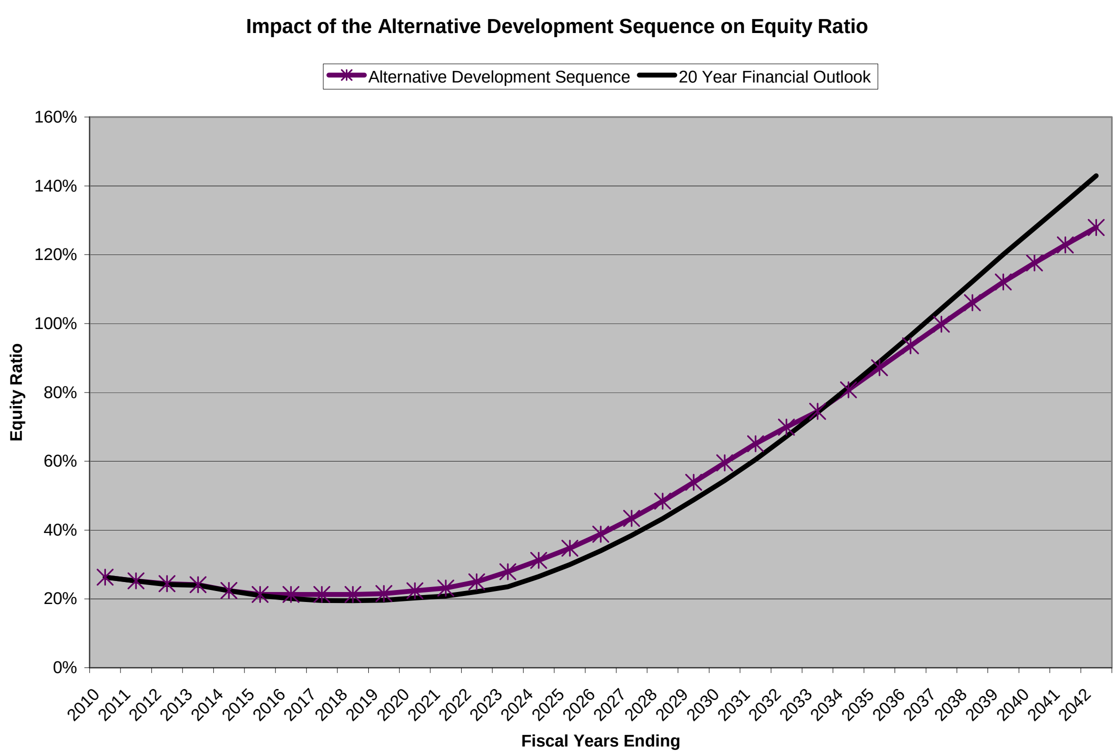
Figure 8



Alternative Development Sequence

The alternative power resource development plan for major infrastructure and resources to meet Manitoba requirements includes Conawapa in 2021/22 and a combined cycle gas turbine in 2033/34. This sequence excludes the sales related to the Wisconsin Public Service and Minnesota Power term sheets, the construction of Keeyask and the planned interconnection to the US. Although the equity ratio is slightly higher in the Alternative Development Sequence, the equity ratio under the 20 Year Financial Outlook crosses over by 2033/34 as the benefits of hydro development and additional tie-line capability are realized. Thereafter, the benefits are substantially positive for the entire life of the generation and transmission facilities. With respect to transmission, another benefit of the sale scenario is that counterparties in the US will be making large investments in new transmission which will enhance reliability and provide additional export sale opportunities. Figure 9 below compares the equity ratios under the Alternative Development Sequence and 20 Year Financial Outlook.

Figure 9



Tab 146

Hydro board slams handling of Bipole III, Keeyask dam projects — but says it's too late

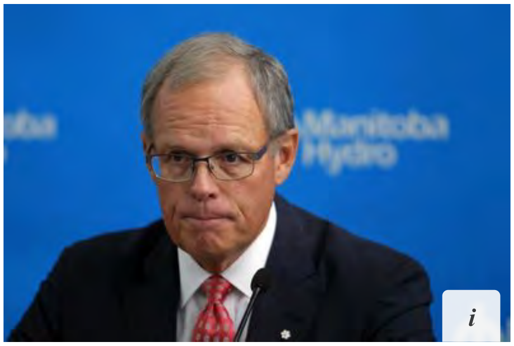
By: Nick Martin
Posted: **09/21/2016 2:16 PM**

The west side Bipole III line and the Keeyask dam projects are politically motivated mistakes that the NDP should not have built, Manitoba Hydro chair H. Sanford Riley charged Wednesday — but they're much too far along to pull the plug.

"This was an absolute no-brainer," Riley told a news conference in the atrium of the gleaming Hydro tower Wednesday morning.

Hydro's board said that 95 per cent of the initial cost of Bipole III has already been constructed or committed, and that Bipole III must be completed within the next couple of years to start generating revenue from the Keeyask dam project.

But as badly as the NDP mishandled those megaprojects, Riley said, they're a 'sideshow' to the enormous debt problems Manitoba faces — Hydro's debt will almost double to $25 billion within four years. And that will hit consumers on their monthly hydro bill.



BORIS MINKEVICH / WINNIPEG FREE PRESS
Manitoba Hydro-Electric Board Chairman H. Sanford Riley.

Previously predicted rate increases for consumers of four per cent a year for the next 20 years will only be the starting point, Riley said.

The review by American-based Boston Consulting Group told the new board — appointed this spring by Premier Brian Pallister — that Bipole III should have been built on the east side of Lake Winnipeg, and that Keeyask will not be needed for up to 15 years later than the NDP forecast, Riley said.

"If we had been the board at that time, we would not have proceeded," Riley said.

Both projects are behind schedule and will run close to $2 billion over budget, he said.

But so much work has been done and contracts signed and purchases made, he said, that cancelling the west side Bipole III and starting over on the east side would cost Manitobans more than $7 billion, Riley said.

Hydro plans a series of town hall meetings across Manitoba to explain its difficulties and challenges, and to hear from the public.

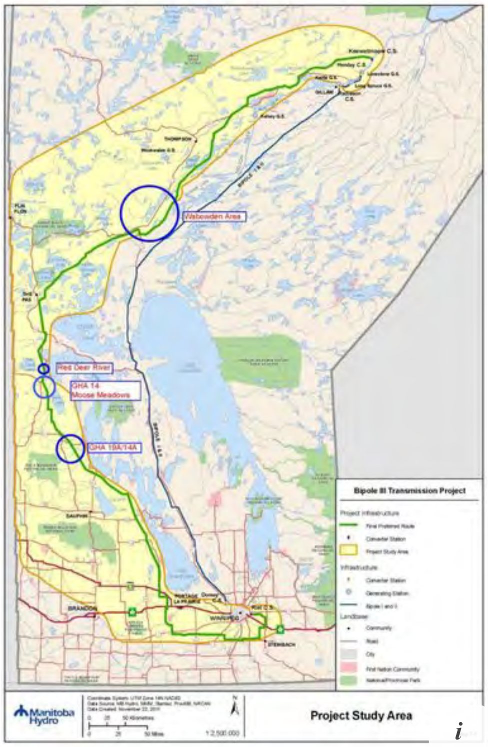
Finance Minister Cameron Friesen later told reporters that Manitoba could face a further downgrade to its credit rating, which means money intended for public services would have to go to servicing the debt.

"We know the NDP spent beyond their means," Friesen said. "The debt of Manitoba Hydro is the debt of all Manitobans."

But NDP crown services critic Ted Marcelino declared that finishing the west side line is the only logical choice. It's the most secure and reliable route, he said, and he challenged reporters to say why the cost matters if it saves the boreal forest on the east side. "History will judge us," Marcelino said.

BIPOLE III:

It cost $900 million more to build Bipole III down the considerably longer west side of Lake Winnipeg instead of the east side, Riley said. "It appears to be almost a $1 billion mistake."



Bipole III revised route 2012.

Hydro favoured the east side, but the NDP government was issuing the orders in 2007 without bothering to do any real analysis of the east side, Riley said, adding it was an imprudent decision.

Riley said Bipoles I and II now carry 70 per cent of the power Manitoba needs. Bipole III is for redundancy in case of catastrophe, and to carry power meant for export.

"The risk is some catastrophic event — I leave that to your imagination," Riley said, though the most likely is a weather event. The review refers to ice storms, a tornado, anything that could bring down a transmission line.

Hydro President and CEO Kelvin Shepherd said Bipole III is 12 to 15 months behind schedule, and its $4.65-billion price tag will likely hit $5 billion.

Pallister has been talking about scrapping the west side and starting from scratch on the east side, but, said Crown Services Minister Ron Schuler, "The Bipole III project is much further along than we were initially led to believe.

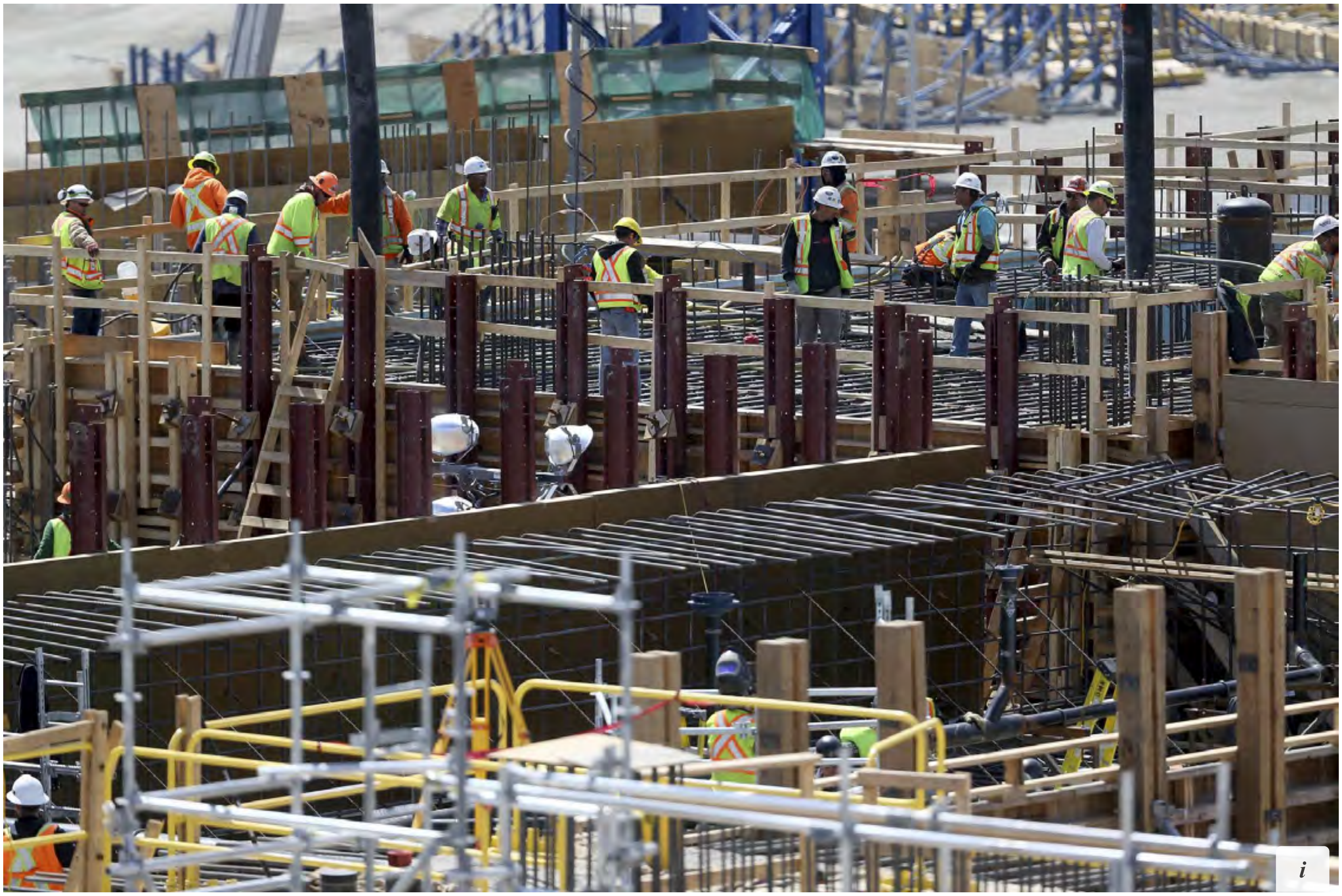
"Transformers are leaving Europe, four of them, as we speak, bought and paid for," Schuler said.

Schuler said it's all been mismanaged, but wouldn't say if the NDP or previous Hydro board had misled or outright lied about how far along the project had come — he'd just say the point of no return was before the April 19 election, but the Tories were unaware of that at the time.

Retorted Marcelino: "It will save our future."

13127

KEEYASK:



TREVOR HAGAN / WINNIPEG FREE PRESS
The Keeyask Dam project site near Gillam, Man.

Shepherd said the dam project is 21 to 31 months behind schedule, and will be as much as $1.3 billion over budget. "There were flaws in some of the strategic decision-making," he said.

Riley said Keeyask is too far along to stop now, an overall waste of $7 billion if scrapped, but the review indicated the NDP could have waited another 15 years to build it instead of adding to Hydro's debt load now before it's needed. "We all question why the decision was made to proceed with Keeyask when they did."

But if Hydro were to leave Keeyask uncompleted while starting over with a new Bipole III on the east side, "In effect, you'll have a white elephant up there," Riley said.

Under the former administration and NDP government, Riley said, "Hydro had a culture of building dams."

Big ones, he said.

In retrospect, Schuler said, it's obvious that the NDP inextricably linked Bipole III and Keeyask as one project, although the New Democrats passed them off as separate and distinct megaprojects.

Marcelino said the NDP were acting responsibly, knowing we lacked the oil that Alberta and Saskatchewan have. "It was a necessity on our part. The only resource we have is the development of our hydro," Marcelino said.

DEBT

NDP mismanagement on Bipole III and Keeyask leave Manitoba's finances in jeopardy, our debt rapidly approaching levels never seen here before, Riley warned. "That is an untenable risk for our utility."

Within four years, Manitoba Hydro's debt will almost double to $25 billion, he said, and that will further hurt the province's credit rating. The utility's debt to equity ratio is falling far below acceptable levels, he said, while public debt in Manitoba soars as a percentage of gross domestic product.

Meanwhile, the market price for exported surplus power is dropping.

"What can go wrong is water," Riley cautioned. "What we can't control is Mother Nature."

In 2004, Manitoba Hydro went from a $200 million profit to a $500 million loss because there wasn't enough water in the north to generate the power needed.

Friesen said that debt drives up the cost of borrowing and can lead to a downgrade in credit ratings, thus making it more expensive to borrow already higher amounts of money.

"While that threatens the bottom line of the province of Manitoba," he was not prepared to discuss Wednesday what could happen to provincial spending. Nevertheless, money going to servicing the debt is money not available for frontline services, said the finance minister.

WHAT IT MEANS TO YOU

It may be hard to get your head around billions of dollars — but your monthly hydro bill will be hard to ignore.

Riley said that getting Hydro's finances under control are the responsibility of the crown corporation and the province, and consumers. "There's no secret right now, ratepayers are going to be part of the solution. We have to fix Manitoba Hydro."

Under the NDP, expectations were that hydro rates would go up four per cent a year for 20 years, acknowledged Riley, who wouldn't speculate on numbers, but said, "That's a starting point.

"We have the lowest hydroelectric rates in North America, with the possible exception of Hydro Quebec. Probably, they've been maintained at too low a level."

And he took a shot at the public utilities board; interested only in getting rates as low as possible, the PUB "didn't pay a lot of attention to the overall health of Hydro," Riley charged.

nick.martin@freepress.mb.ca

Tab 147

NFAT Financial Panel

Darren Rainkie – Vice-President, Finance & Regulatory
Manny Schulz – Corporate Treasurer, Treasury Division
Greg Barnlund – Division Manager, Rates & Regulatory Affairs Division
Liz Carriere – Manager, Financial Planning Department

March 19, 2014

Presentation Summary

- Financial Profile
- Financial Outlook Update (IFF13)
- Rate Comparisons
- NFAT Financial and Rate Analysis
  - Impact on Rates
  - Uncertainty Analysis
  - Impact on Financial Position
  - Drought Analysis
- Financial Risk Management

Manitoba Hydro
Financial Profile

Consolidated Income Statement
(Condensed $ millions)

	For the nine months ended December 31	For the year ended March 31					
	2013	2013	2012	2011	2010	2009	2008
REVENUES							
Electric - Manitoba	990	1 380	1 219	1 218	1 156	1 148	1 087
Extraprovincial	338	353	363	398	427	623	625
Gas (Net)	99	147	132	143	138	149	142
	1 427	1 880	1 714	1 759	1 721	1 920	1 854
EXPENSES							
Operating and Administrative	405	533	481	463	440	429	381
Finance Expense	349	489	423	425	410	471	440
Depreciation and Amortization	334	423	381	393	384	368	349
Water Rentals and Assessments	95	118	119	120	121	123	124
Fuel and Power Purchased	105	133	146	106	104	176	134
Capital and Other Taxes	84	105	103	102	99	87	80
Non-controlling Interest	(17)	(13)	-	-	-	-	-
	1 355	1 788	1 653	1 609	1 558	1 654	1 508
Net Income	72	92	61	150	163	266	346
Net Extraprovincial Revenue	138	102	98	172	202	324	367
Interest Coverage Ratio*	1.33	1.15	1.10	1.27	1.32	1.49	1.69

*The interest coverage ratio provides an indication of the ability of the Corporation to meet interest payment obligations with the net income generated by the Corporation. Interest coverage ratio represents net income plus interest on debt divided by interest.

Consolidated Balance Sheet
(Condensed $ millions)

	As at December 31			As at March 31			
	2013	2013	2012	2011	2010	2009	1990
Property, Plant and Equipment (net)	10 665	10 541	8 647	8 215	8 076	7 944	2 677
Construction in Progress	2 658	1 967	3 150	2 739	2 052	1 438	1 206
	13 323	12 508	11 797	10 954	10 128	9 382	3 883
Current and Other Assets	1 898	1 682	1 622	1 646	1 487	1 499	812
Total Assets	15 221	14 190	13 419	12 600	11 615	10 881	4 695
Long-Term Debt (Net)	10 187	8 977	8 729	8 335	7 406	7 002	3 557
Current and Other Liabilities	1 803	1 937	1 495	1 127	1 328	1 637	924
Retained Earnings	2 613	2 542	2 450	2 389	2 239	2 076	117
Other Equity	618	734	745	749	642	166	97
Total Liabilities & Equity	15 221	14 190	13 419	12 600	11 615	10 881	4 695
Debt/Equity Ratio*	76:24	75:25	74:26	73:27	73:27	77:23	95:5

*The debt/equity ratio indicates the portion of Manitoba Hydro's assets that have been financed by internally generated funds rather than through debt. Debt-to-equity ratio represents debt (long-term debt plus notes payable minus sinking funds and temporary investments) divided by debt plus equity (retained earnings plus accumulated other comprehensive income plus contributions in aid of construction plus non-controlling interest).

Consolidated Cash Flow Statement

(Condensed $ millions)

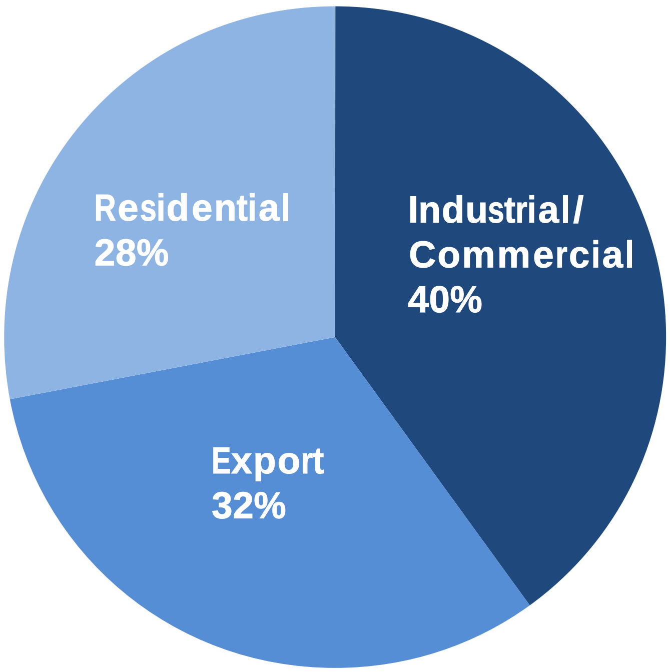
	For the nine months ended December 31	For the year ended March 31					
	2013	2013	2012	2011	2010	2009	2008
Cash provided by Operating Activities	452	589	567	595	589	688	633
Cash provided by Financing Activities	1 082	635	725	674	1 124	424	487
Cash used for Investing Activities	(1 289)	(1 242)	(1 312)	(1 373)	(1 698)	(1 086)	(988)
Capital Coverage Ratio*	1.41	1.25	1.13	1.25	1.34	1.77	1.62

*The capital coverage ratio measures the ability of current period internally generated funds to finance capital expenditures excluding major new generation and related transmission. Capital coverage ratio represents internally generated funds divided by base capital expenditures.

Electric Operations Income Statement
($ millions)

	For the nine months ended December 31	
	2013	2012
REVENUES		
Electric - Manitoba	975	899
Extraprovincial	338	280
	1 313	1 179
EXPENSES		
Operating and Administrative	350	334
Finance Expense	322	333
Depreciation and Amortization	311	293
Water Rentals and Assessments	95	87
Fuel and Power Purchased	105	96
Capital and Other Taxes	69	65
Corporate Allocation	7	7
Non-controlling Interest	(17)	(8)
	1 242	1 207
Net Income	71	(28)

Revenue Sources – Electricity
2003/04 – 2012/13



Industrial/Commercial	$6.5 billion
Export	$5.1 billion
Residential	$4.5 billion

13140

Financial Profile Summary

- With Retained Earnings of $2.6 billion, Manitoba Hydro is in the strongest financial position in its history.
- The Export Revenues associated with Manitoba Hydro's predominantly hydro system has been a key contributor to the Corporation's financial strength and affordable rates for customers.
- Manitoba Hydro is well positioned to make the necessary investments to meet the future energy needs of the Province.

Manitoba Hydro
Financial Outlook Update

(IFF13 February 2014)

Major Changes since IFF12 Approved in November 2012

- Load Forecast lower due to lower forecasted population growth. Gross firm energy is projected to be down 717 GW.h in 2022/23 and 1 159 GW.h in 2031/32 compared to IFF12.
- Conawapa in-service date deferred 1 year to 2026/27.
- Increased capital costs $1.6B due to Conawapa deferral, reinstatement of DSM costs into Capital Forecast and project estimate updates.
- 2013 Electric Export Price forecast projects on-peak prices to decrease on average 3% over the period 2014/15 to 2032/33.
- IFRS Implementation deferred 1 year to 2015/16 and assumption that rate-regulated accounting will continue over the forecast period.
- Forecast operating cost growth has been further constrained to 1% inflationary growth between 2016 and 2021.

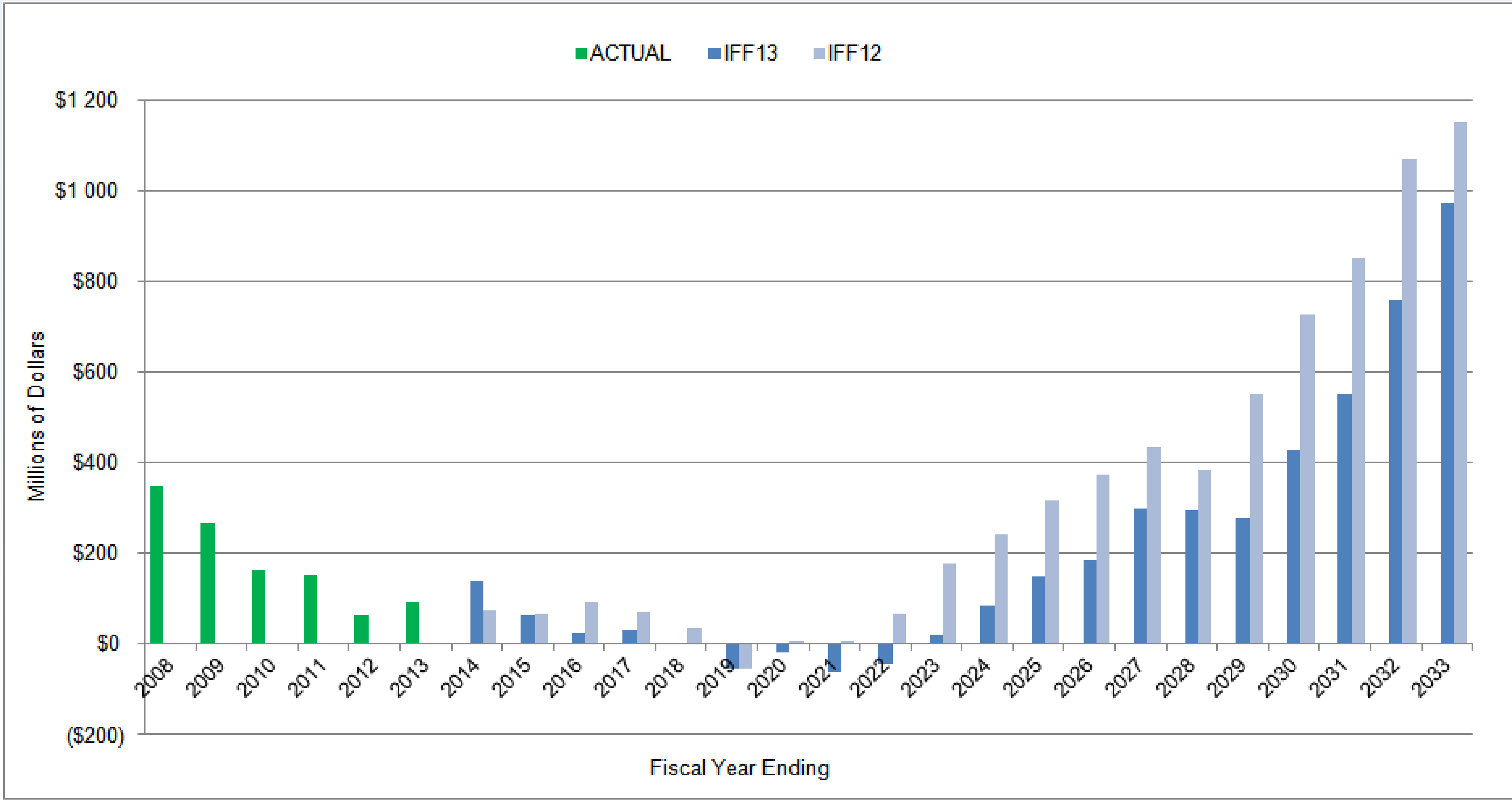
Comparison of IFF13 to IFF12 Consolidated Net Income ($ Millions)

Increases (Decreases)

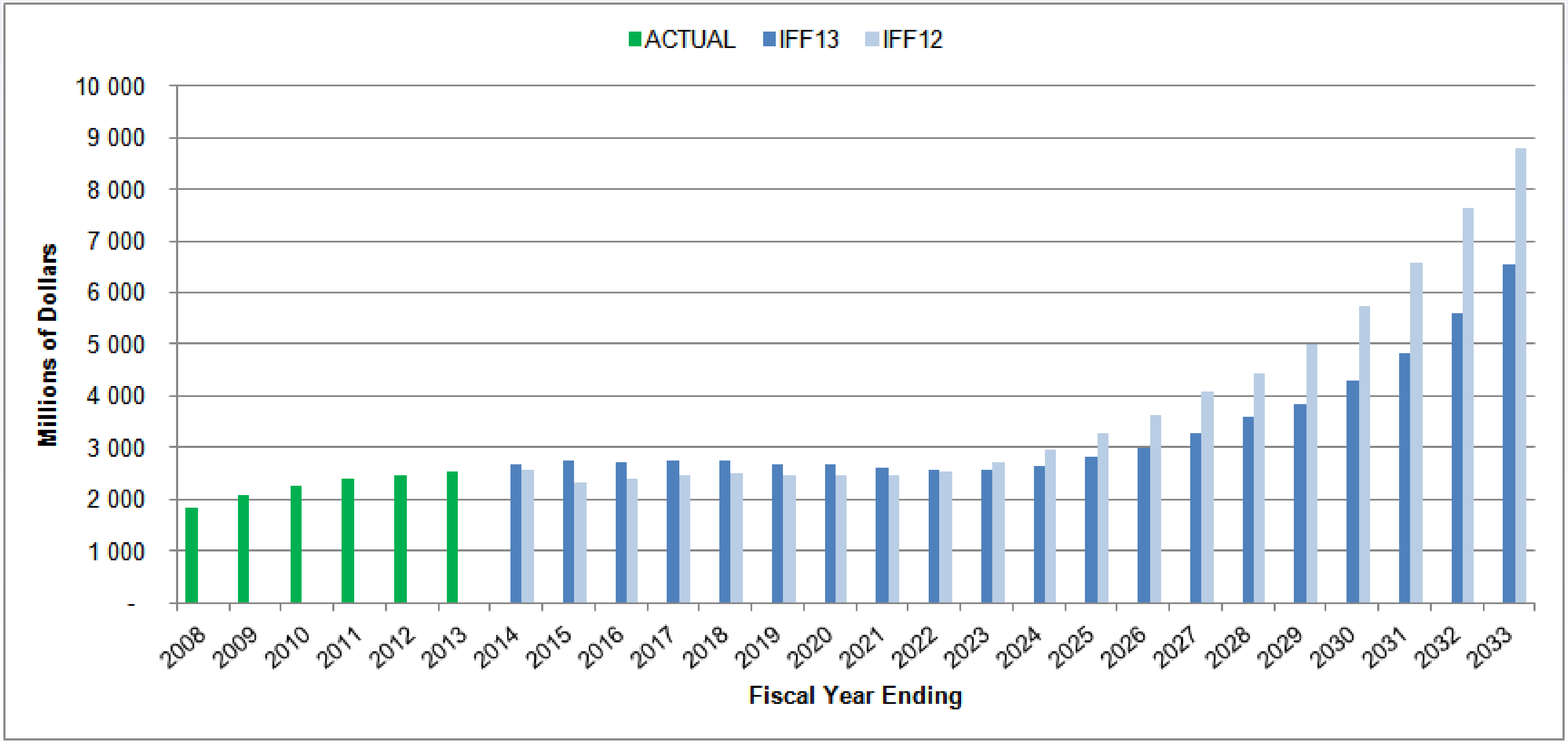
	2013/14	2014/15	2015/16	Cumulative to 2022/23	Cumulative to 2032/33
IFF12 Net Income	**72**	**66**	**90**	**529**	**6 621**
Manitoba Revenue (net of cost of gas)	(31)	(45)	(50)	(443)	(1 438)
Extraprovincial Revenue (net of water rentals and fuel & power purchases)	77	65	(1)	311	203
	46	20	(51)	(132)	(1 234)
Expenses	(17)	24	16	386	1 483
Change in Net Income @ IFF12 Rate Increases	63	(4)	(68)	(518)	(2 717)
Impacts of IFF13 Rate Increases	-	-	2	80	171
Total Change in Net Income from IFF12	63	(4)	(66)	(438)	(2 546)
IFF13 Net Income	**136**	**62**	**24**	**91**	**4 076**

Consolidated Net Income

($Millions)



Retained Earnings
($Millions)



13146

Financial Targets

Debt/Equity:

Maintain minimum debt/equity ratio of 75:25

Interest Coverage:

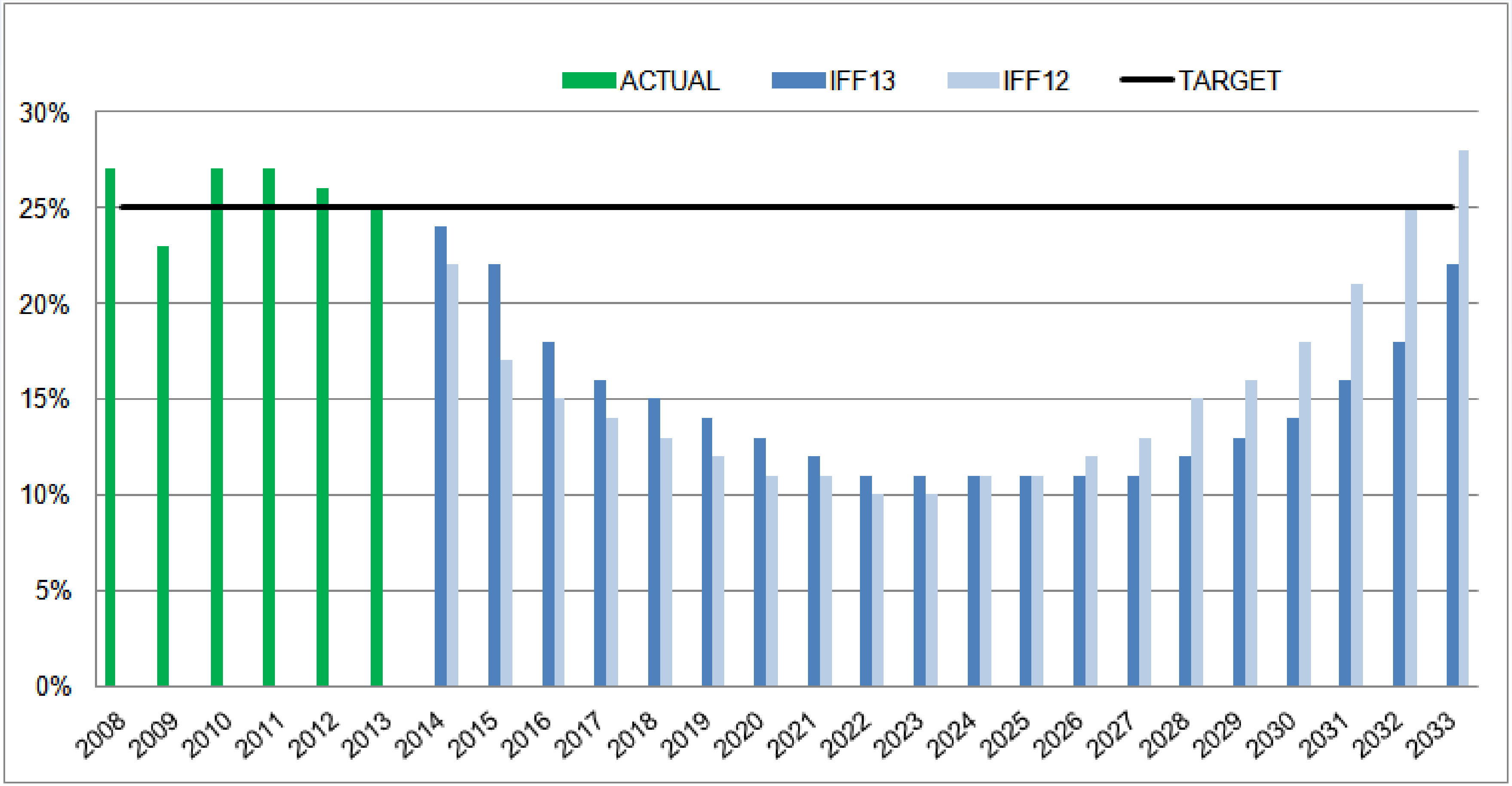
Maintain interest coverage ratio of > 1.20

Capital Coverage:

Maintain capital coverage ratio of >1.20

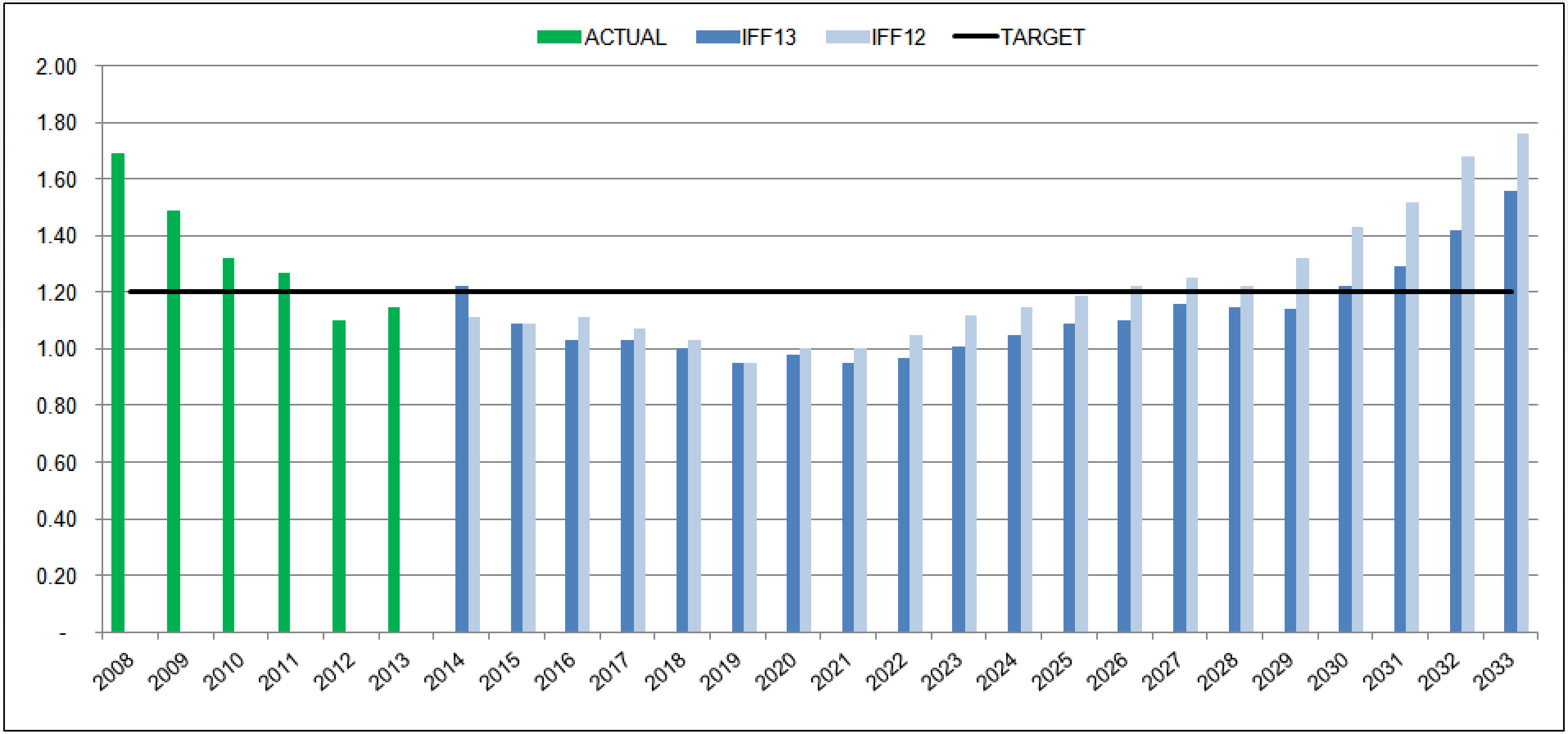
Note: Financial targets may not be maintained during years of major investment in the generation and transmission system.

Equity Ratio

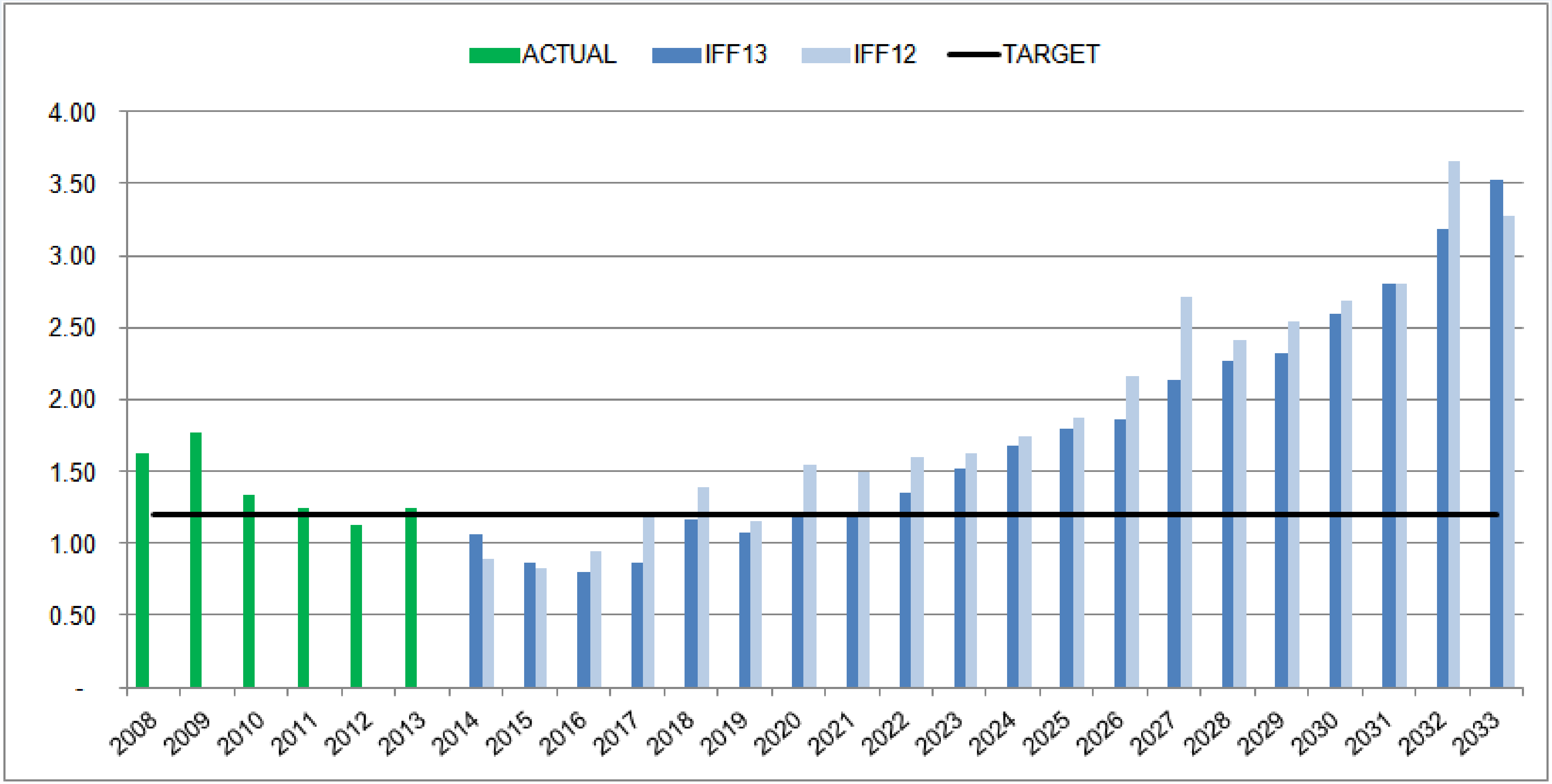


Note: 25% equity target attained in 2034 in IFF13

Interest Coverage Ratio



Capital Coverage Ratio



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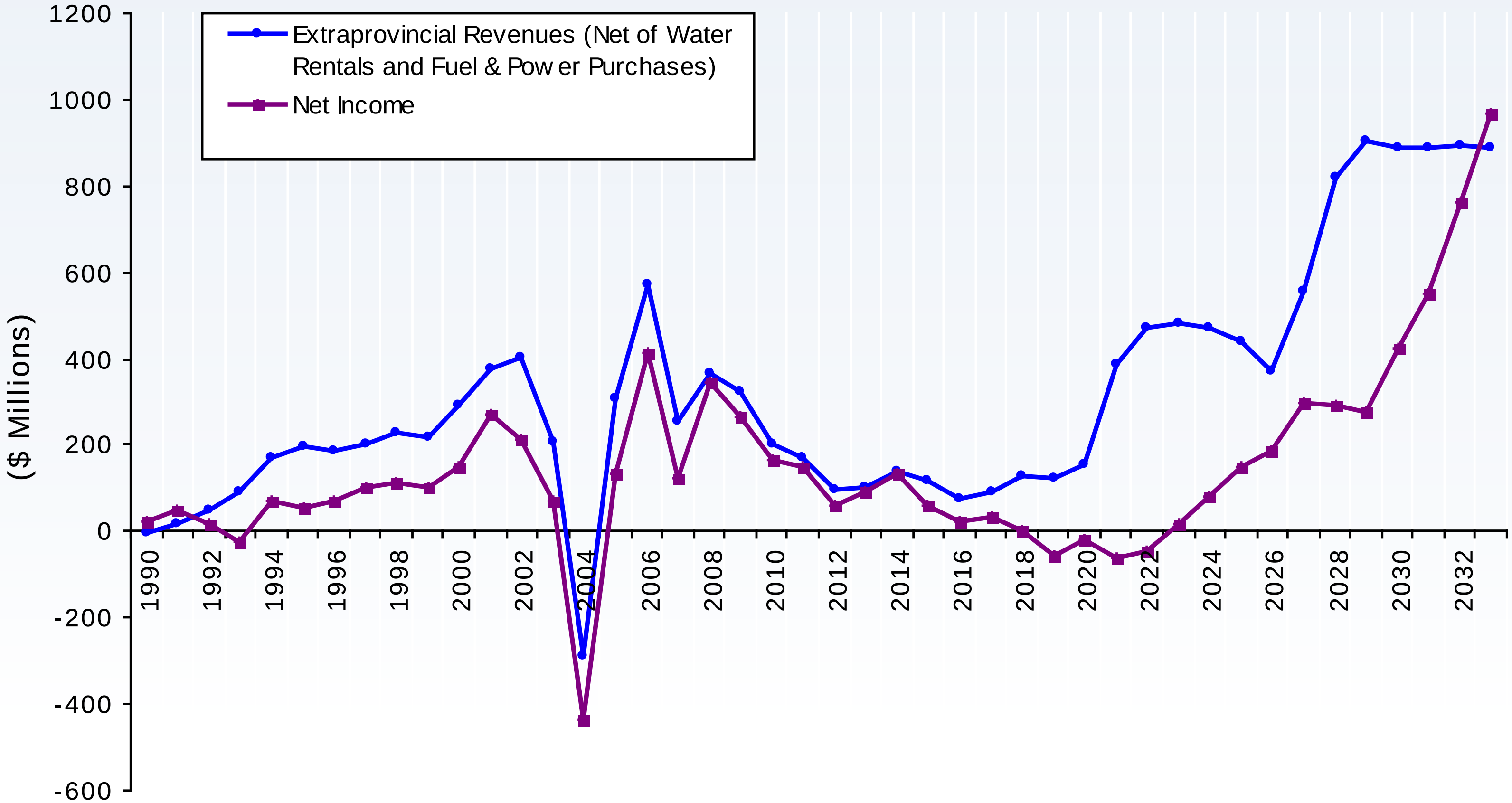
Consolidated Income Statement –
Comparison of Net Extraprovincial Revenues to Net Income



13151

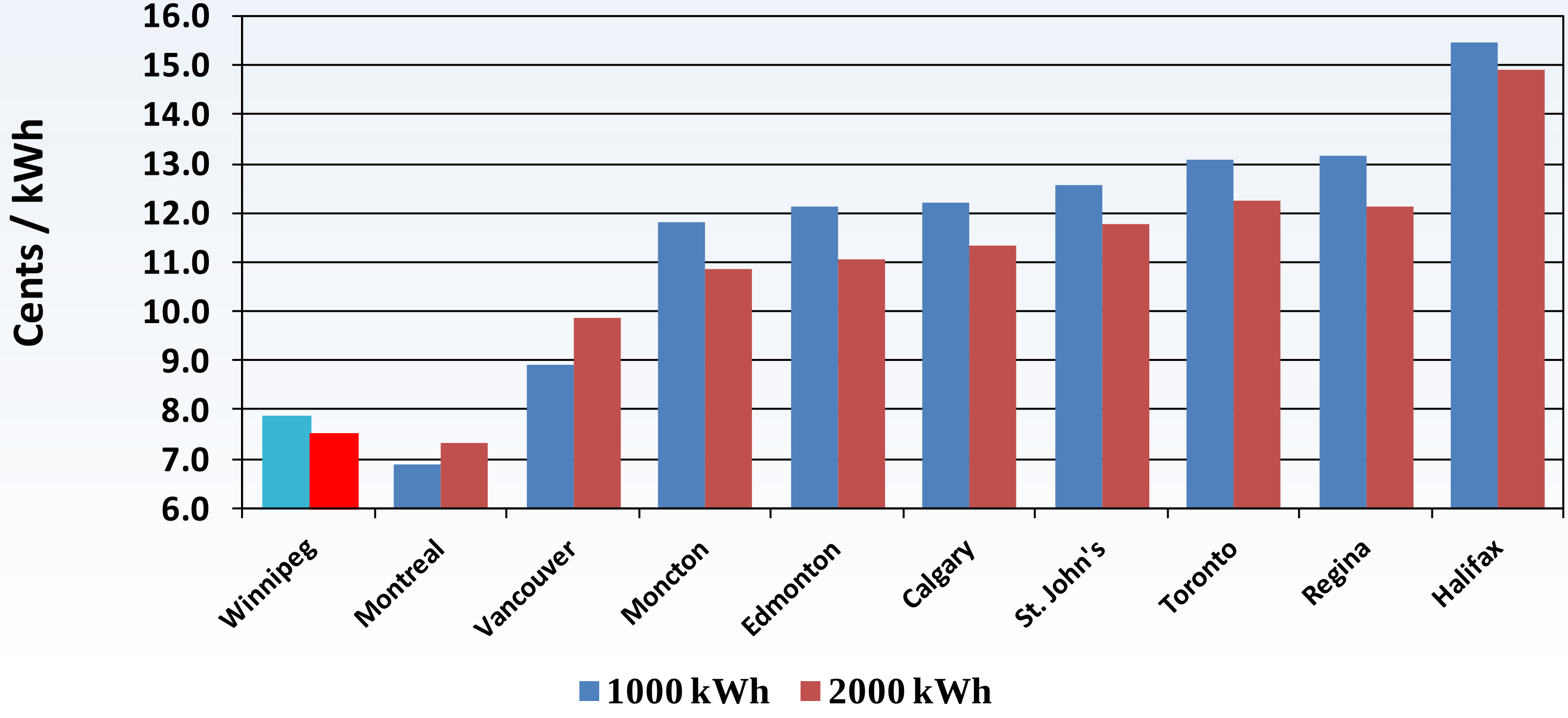
Financial Outlook Summary

- The required investments in existing infrastructure and new generation are expected to place pressure on Manitoba Hydro's key financial ratios in the next decade.
- Significantly higher rate increases than 3.95% would be required to maintain financial targets during the investment period.
- In setting financial targets, it has always been recognized that the targets may not be attained during periods major investments in the generation and transmission system.
- Credit rating agencies and other stakeholders are prepared to accept short-term weakness in financial ratios, as long as Manitoba Hydro can demonstrate progress to attaining the targets over the long-term.
- Financial ratios are expected to recover after the in-service of Keeyask and Conawapa generating stations and reach target levels within a forecast horizon of approximately 20 years.
- Export revenues will continue to play an important role in improving the Corporation's financial strength and keeping rates affordable for customers in the future.

Rate Comparisons

2013 Survey of Canadian Electricity Bills

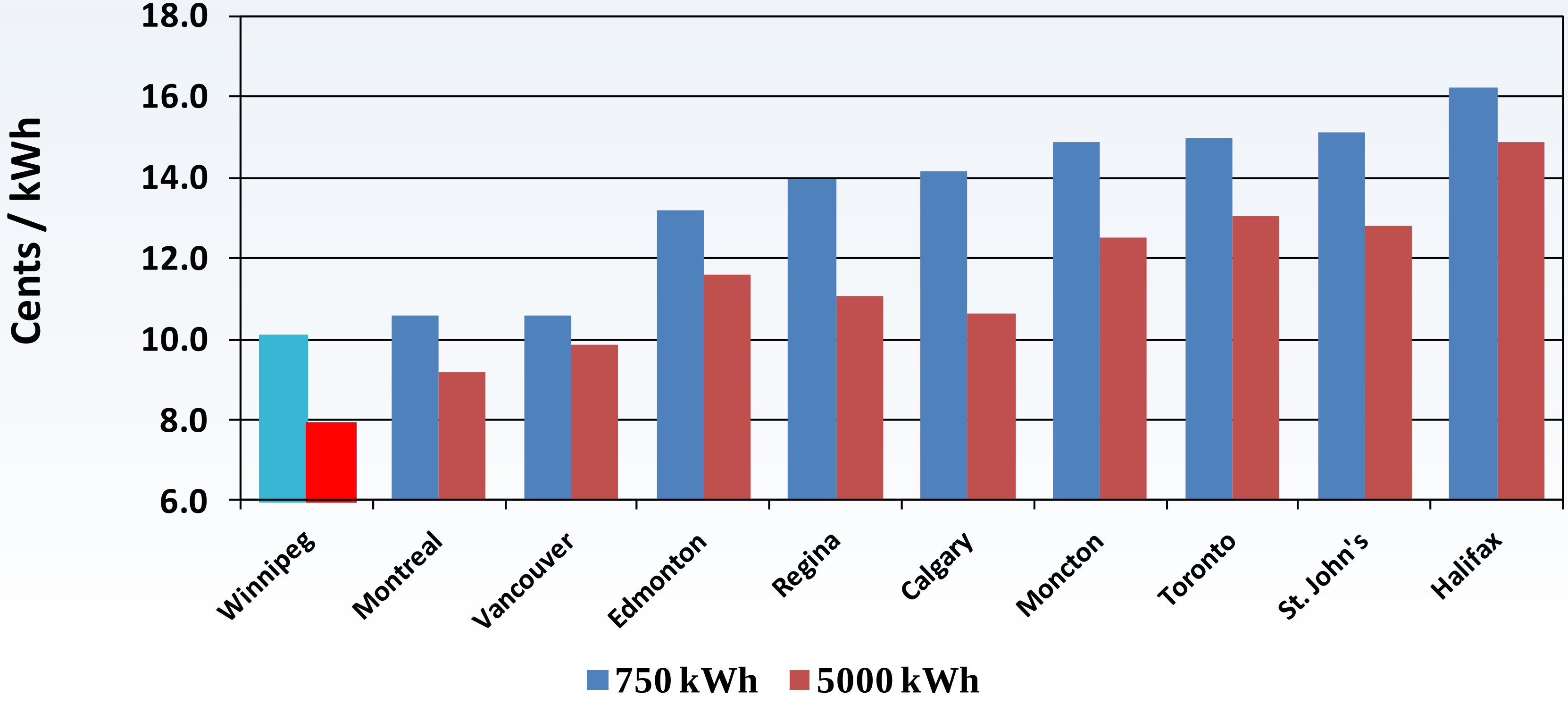
Residential Rate Comparison (Price per kWh)



13154

2013 Survey of Canadian Electricity Bills

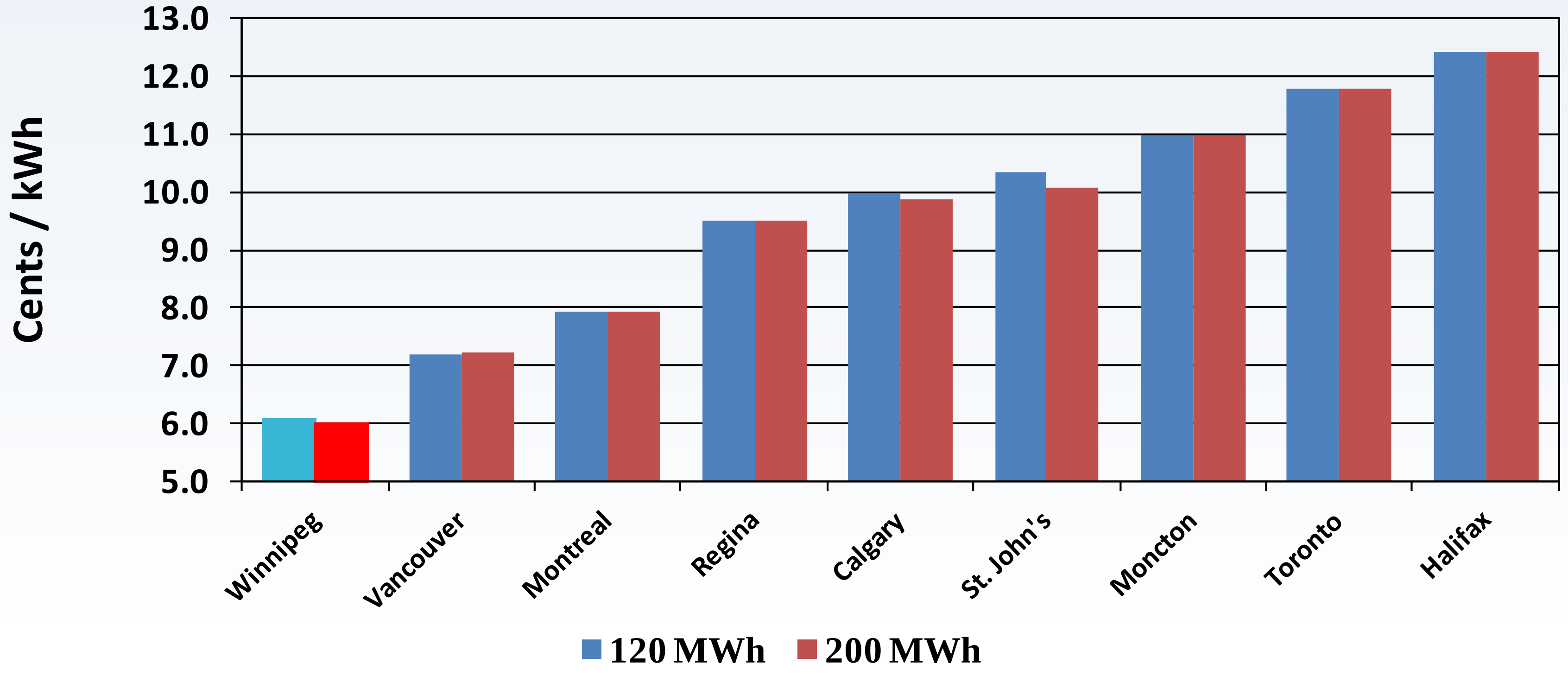
GS Small Rate Comparison (Price per kWh)



13155

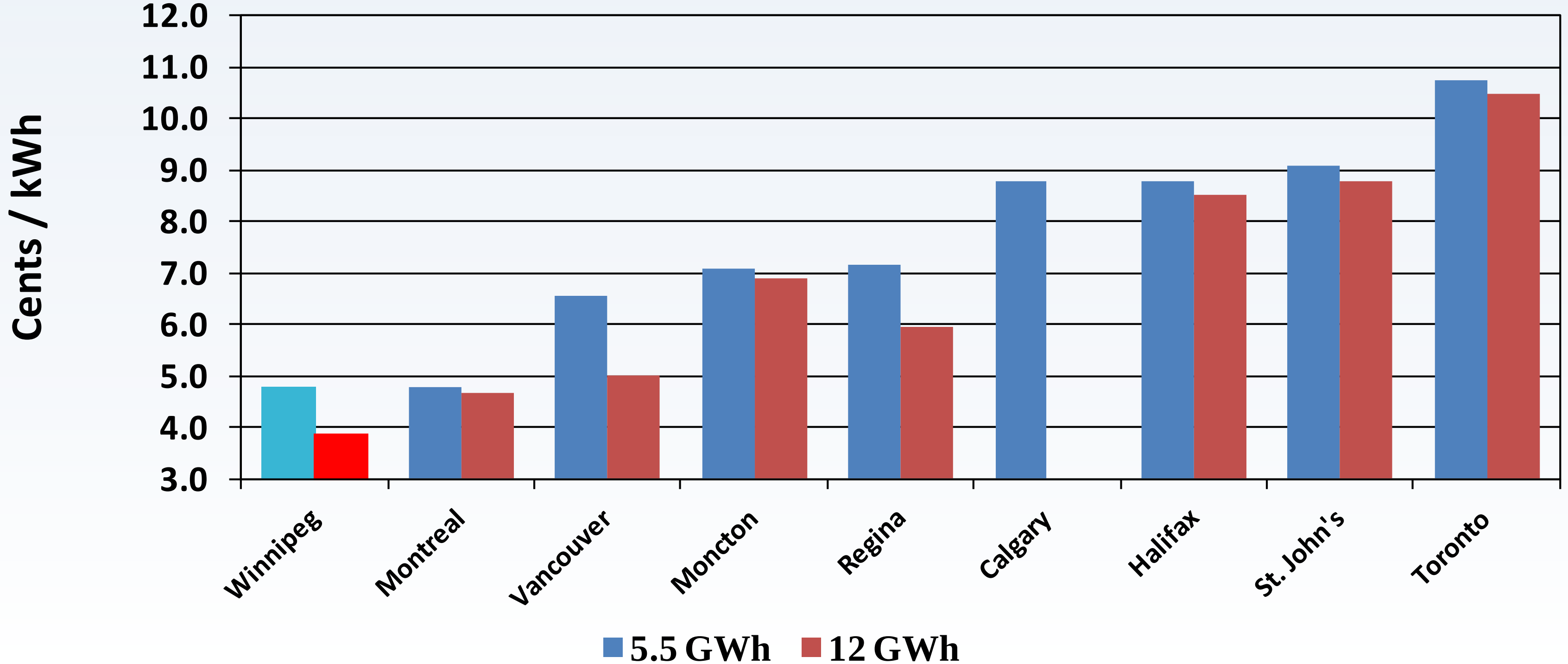
2013 Survey of Canadian Electricity Bills

GS Medium Rate Comparison (Price per kWh)



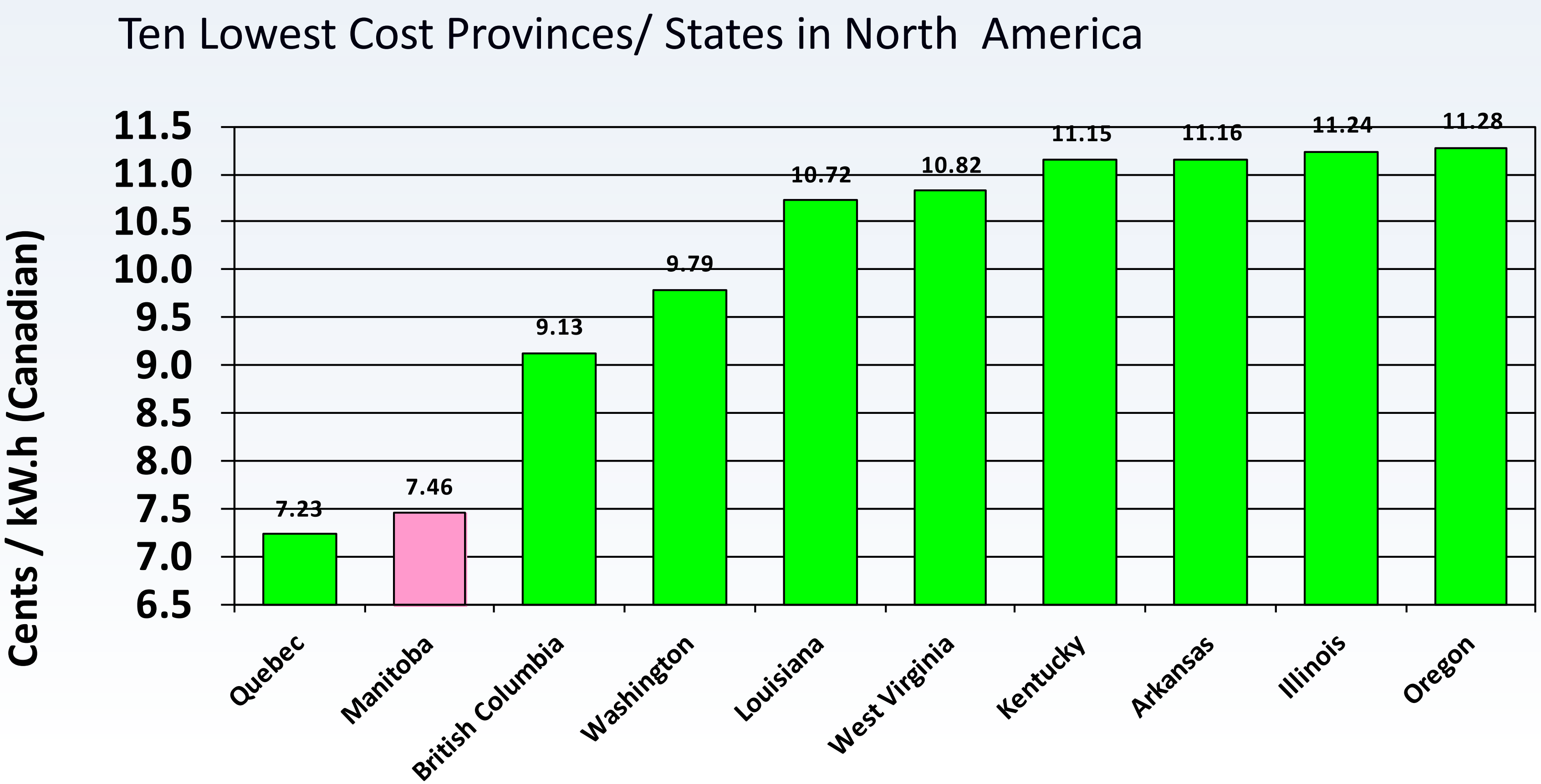
2013 Survey of Canadian Electricity Bills

GS Large Rate Comparison (Price per kWh)



13157

Average Residential Price of Electricity

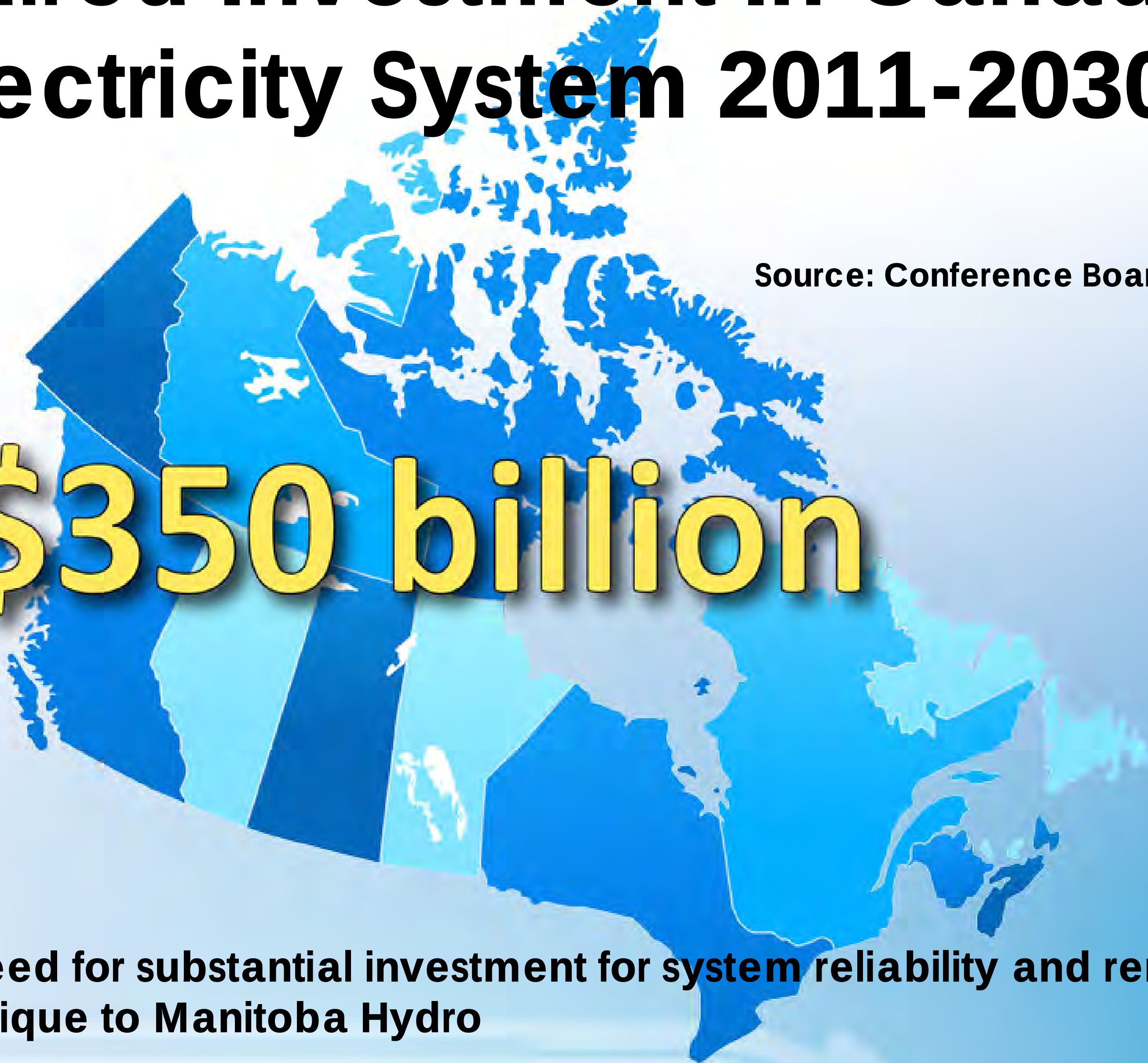


Source: US Dept of Energy (June 2013) & Edison Electric Survey (June 2013)
(Exchange rate as of Feb 20,2014: 1 US$ = 1.1104 Cdn)

13158

Required Investment In Canada's Electricity System 2011-2030

Source: Conference Board of Canada



$350 billion

- **The need for substantial investment for system reliability and renewal is not unique to Manitoba Hydro**
- **Utilities across Canada face the same challenges**

Recent Rate Increase Requests – Other Provinces

SaskPower seeks 15.5 per cent rate hike

CTV Regina
Published Friday, October 25, 2013 12:05PM CST

SaskPower has applied for a 15.5 per cent rate increase over three years.

The Crown corporation is asking for rate increases of 5.5 per cent next year, five per cent in 2015 and five per cent in 2016.

SaskPower says it needs to raise rates because demand for electricity is growing in Saskatchewan, while generation, transmission and distribution infrastructure is aging.

Ontario hydro bills to rise 42% in 5 years

604

BY ANTONELLA ARTUSO ,QUEEN'S PARK BUREAU CHIEF

FIRST POSTED: MONDAY, DECEMBER 02, 2013 01:43 PM EST | UPDATED: MONDAY, DECEMBER 02, 2013 03:47 PM EST

TORONTO - Ontario hydro bills are headed up, up, up.

The Liberal government's new long-term energy plan shows that the average monthly residential bill of $125 will rise to $178 within five years — a 42% increase.

Hydro bills are expected to dip slightly in 2019 to $177 a month, and then rise again until 2022 when they'll hit $193 a month.

A second decrease in prices is forecast for 2023-24 and then the trend for prices is onward and upward for the foreseeable future.

BC Hydro rates to increase 28 per cent over 5 years

"Our rates are still among the lowest in North America," says BC Hydro CEO Charles Reid

CBC News Posted: Nov 26, 2013 10:53 AM PT | Last Updated: Nov 26, 2013 7:54 PM PT

Energy Minister Bill Bennett and BC Hydro CEO Charles Reid announced a 28 per cent electricity rate hike over five years, with a nine per cent jump coming April 1, 2014.

In a press conference in Victoria this morning, Bennett and Reid said the rate hikes were part of a 10-year plan to keep rates as low as possible, while still allowing BC Hydro to invest in infrastructure and future power projects.

Hydro-Québec rates to rise by 4.3 per cent as of April 1

The 4.3 per cent increase is the biggest hike in the last 10 years

CBC News Posted: Mar 06, 2014 7:12 PM ET | Last Updated: Mar 06, 2014 7:12 PM ET

Quebecers will be paying more for electricity starting April 1.

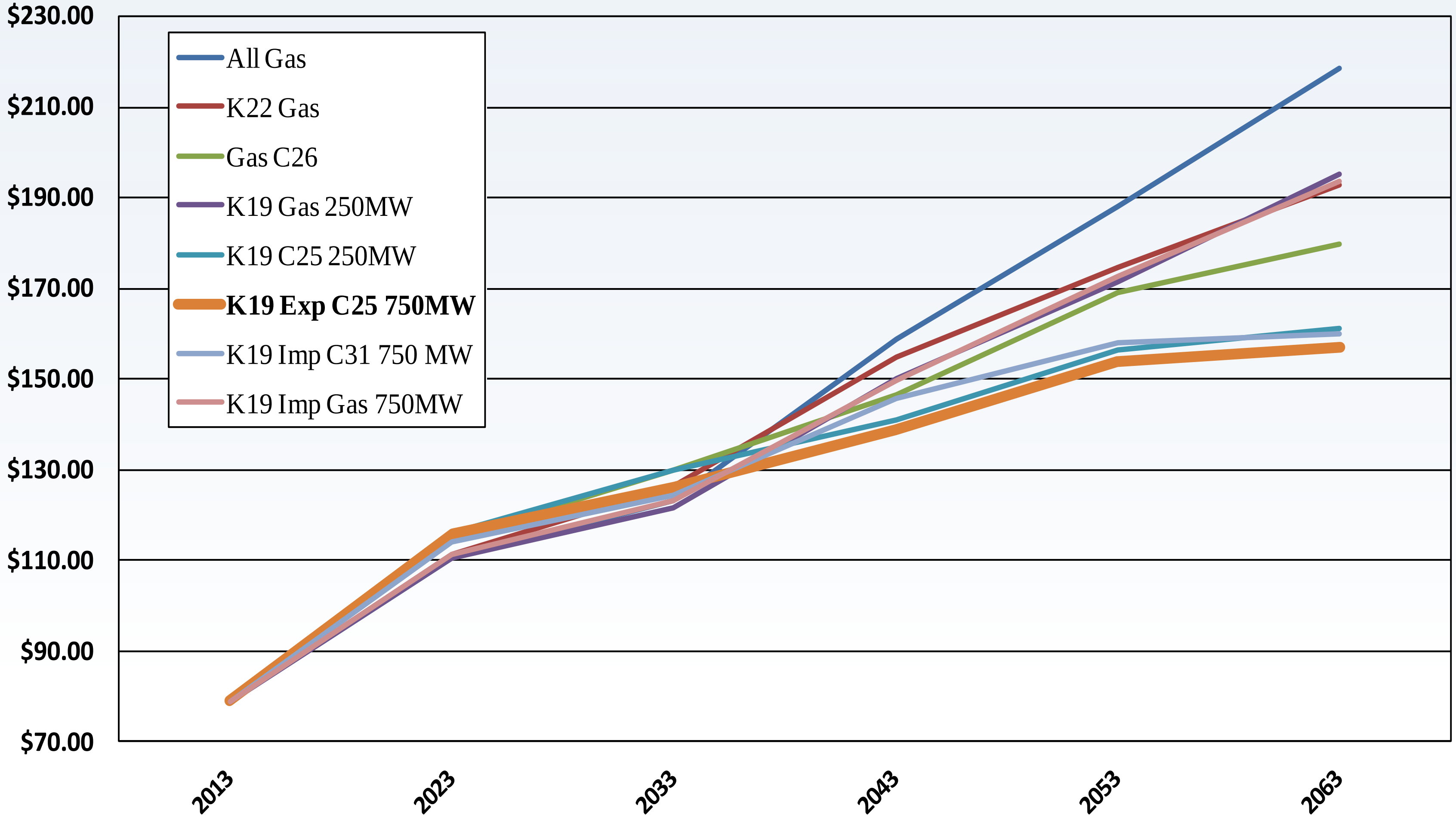
Quebec's energy board has approved a rate increase of 4.3 per cent.

This marks the highest increase since 2004.

Hydro-Quebec had requested a 5.8 per cent increase this year, but the energy board decided that was too high.

Last year, rates went up 2.4 per cent.

Projected Monthly Residential Bills
Based on 1000 kWh
CAC/MH I-140



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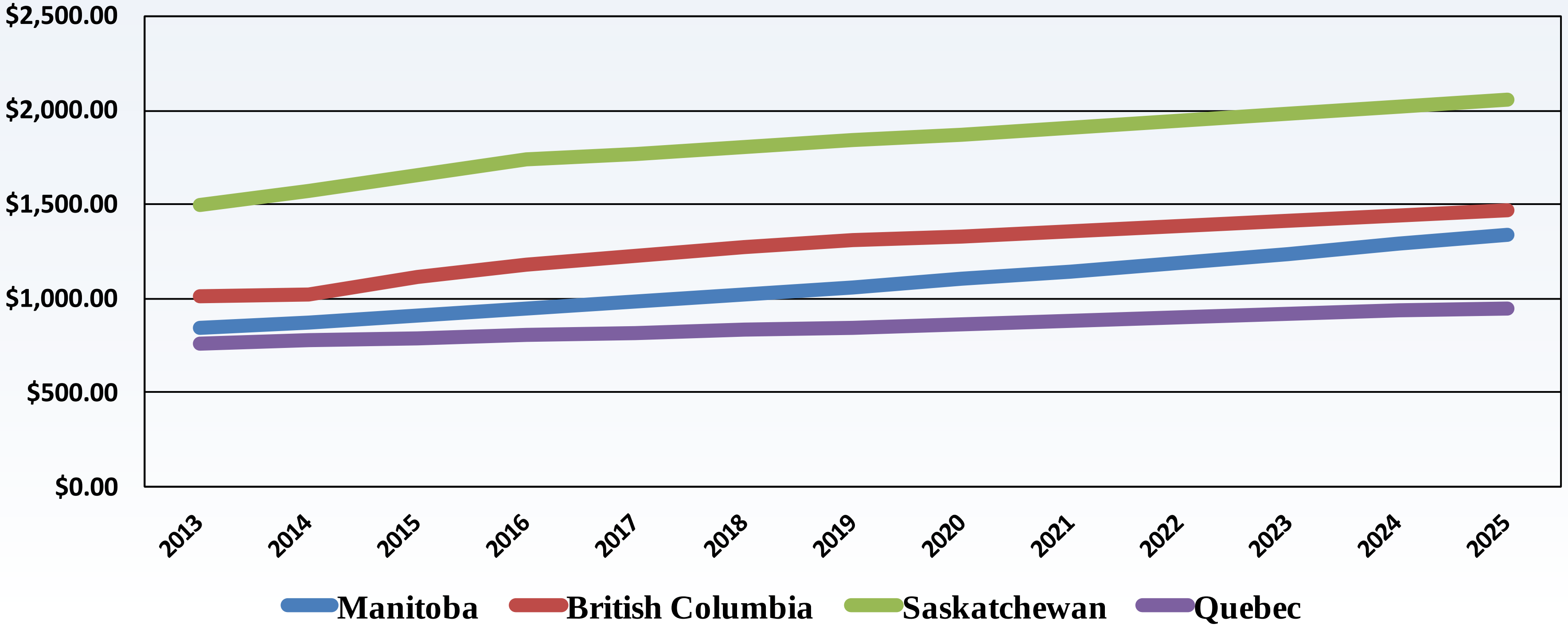
Residential Annual Bill Comparisons

CAC/MH II-134b (Assuming MH projected rate increases and BC, SK & PQ approved or proposed rate increases with GDP deflator* thereafter)



*The GDP deflator is considerably less than the average rate increases proposed in these jurisdictions and may not reflect the trend in future rates.

Rate Comparison Summary

- Manitoba Hydro electricity rates are among the lowest in North America.
- Electric utilities in other jurisdictions are facing the same increased costs of maintaining existing infrastructure and developing new resources.
- Electric utilities in other jurisdictions are requesting or implementing rate increases much higher than the rate of inflation and higher than Manitoba Hydro projected rate increases.
- Manitoba Hydro electricity rates will continue to be affordable and competitive with other jurisdictions.

NFAT Financial and Rate Analysis

Impact on Manitoba Hydro’s Customer Rates

Financial Evaluation Assumptions & Methodology

- Financial evaluation compares the year-by-year impacts of each of the development plans on Manitoba Hydro's projected financial statements and customer rates.
- Overlays development plan assumptions on the revenue and cost, balance sheet and cash flow projections for the entire electric operations, including existing infrastructure.
- Development plans are evaluated by extending IFF12 and modifying for preliminary 2013 forecast of electricity export prices
- IFF12 (adjusted) is modified for the generation costs and transmission associated with the type of facility and timing for each development plan

Financial Evaluation Assumptions & Methodology

- Capital costs are reflected in the balance sheet
  - Construction in progress until in-service
  - Property, plant & equipment following in-service
- Once in-service, capital costs are reflected on the income statement in depreciation on a straight-line basis over the useful life of the asset:
  - Hydro generation 20-125 years
  - Gas generation 30 years
  - Transmission substations 35 years
  - Transmission lines 50 years
- Incorporates the flow-related production costs and revenues associated with the facilities for each development plan
  - Production costs include import purchases, wind purchases, thermal fuel and direct operating costs of the facilities
  - Surplus energy, after serving domestic and firm exports, is assumed to be sold as firm (if available from dependable energy) and as opportunity (for any additional in excess of dependable).

Financial Evaluation Assumptions & Methodology

- Uses the same assumptions from economic evaluations converted from real to nominal dollars.
- General consumers revenue reflects sales to Manitoba customers, including load growth, at rates approved by the PUB
  - Does not change under differing development plans
- Annual borrowing requirements are calculated based on the cash flow surplus or deficit for each development plan based on both existing infrastructure and new generation and transmission associated with the specific development plan.
- Annual finance expense is calculated based on the existing debt portfolio plus the projected annual borrowing requirements.

Financial Evaluation Assumptions & Methodology

- General consumers revenue additional reflects the incremental revenue required to recover costs for both existing infrastructure and the development plan.

- Manitoba Hydro has a long-standing strategy of gradualism in its approach to developing rate proposals.

- Under cost of service regulation, cost recovery is smoothed out over time by absorbing some of the cost into retained earnings on a temporary basis, if prudent, allowing sufficient time for export revenue benefits to accrue.

- Due to the volume of projections evaluated, Manitoba Hydro applied a mechanical approach using a set of fixed parameters consistent with the Corporations financial targets to derive the annual rate adjustments – removes judgment and subjectivity.

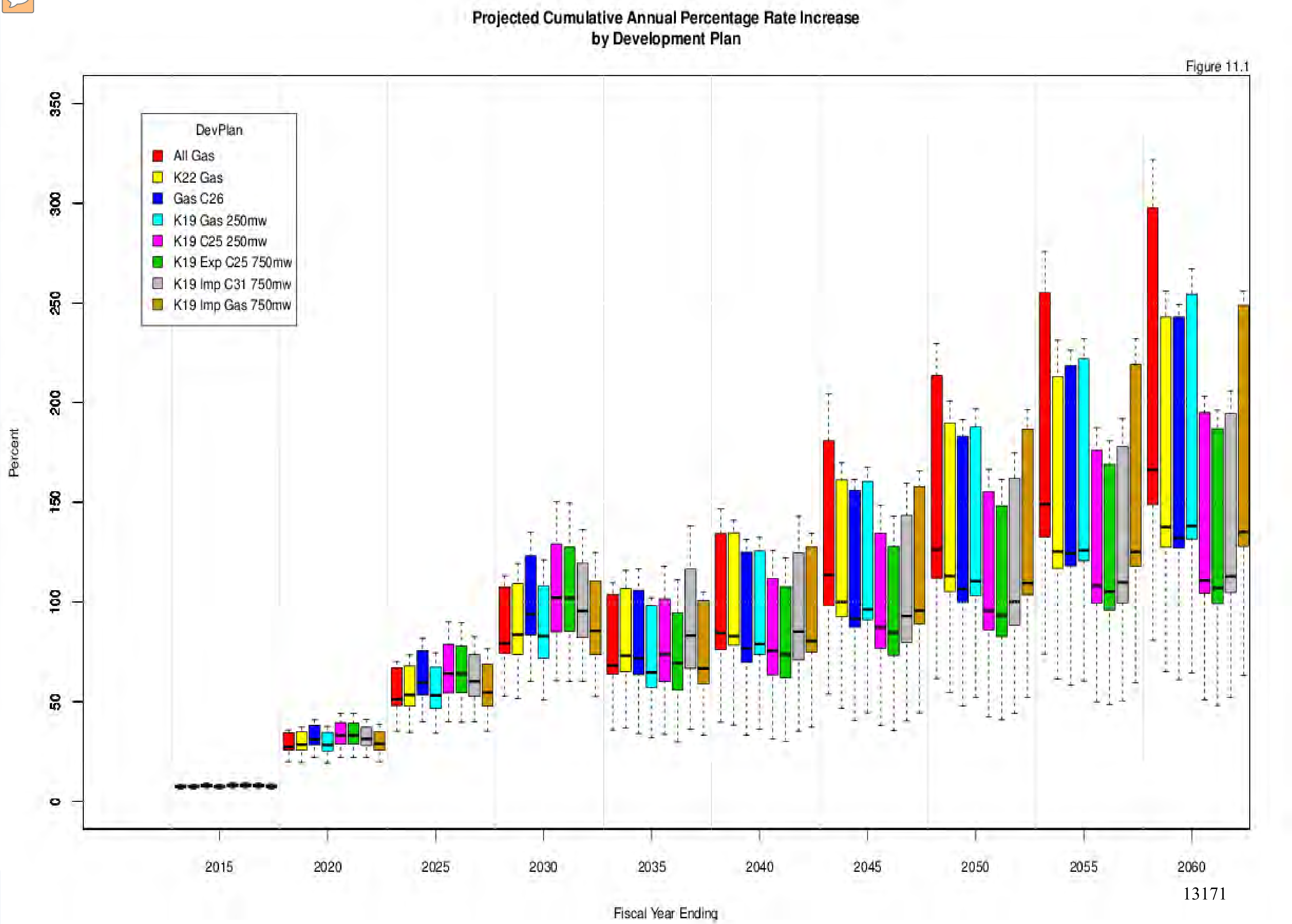
- Given that a timely return to the targeted 75:25 debt/equity ratio is prudent, the financial analysis assumes even-annual rate increases in order to achieve the targeted debt/equity ratio by the end of 2031/32, similar to the approach used in IFF12.

Financial Evaluation Assumptions & Methodology

- Once the debt/equity target is reached, the projected comparative annual rates for the remainder of the 50-year financial forecast period are derived based on the corporation's interest coverage ratio target of 1.20.
- Strictly adhering to the financial targets results in projected rate increases that are at times well above the rate of inflation and at other times result in rate reductions – in practice, these would be smoothed over a period of time.
- Rate increases are indicative for comparability purposes between plans
- Actual rate increases will vary from those projected in this analysis and will be dependent upon future revenue requirements
- Numerous factors, other than the choice of development plan, may influence the revenue requirement, such as changing water flow conditions, weather, costs to maintain the system, and economic variables.
- Future rate proposals will be subject to full justification as part of General Rate Applications before the Public Utilities Board.

Financial Evaluation Assumptions & Methodology

- Approximately $1.2 and $0.4 billion is projected to be incurred to June/14 in nominal dollars to protect the early in-service dates of Keeyask and Conawapa, respectively.
- For NFAT financial evaluation purposes, a simplifying assumption was made to expense all sunk costs over an 18-year amortization period.
- If CEC or NFAT regulatory approvals are not received or the Corporation defers one or both plants, costs deemed to no longer provide future benefit must be expensed.
- Manitoba Hydro would periodically analyze the nature of the costs to determine their future benefit – some costs have longer expected future benefits while others have shorter.


Projected Cumulative Annual Percentage Rate Increase
by Development Plan
Figure 11.1
DevPlan
All Gas
K22 Gas
Gas C26
K19 Gas 250mw
K19 C25 250mw
K19 Exp C25 750mw
K19 Imp C31 750mw
K19 Imp Gas 750mw
Percent
0
50
100
150
200
250
300
350
2015
2020
2025
2030
2035
2040
2045
2050
2055
2060
Fiscal Year Ending

Cumulative Rate Increases (Nominal) Reference Scenario

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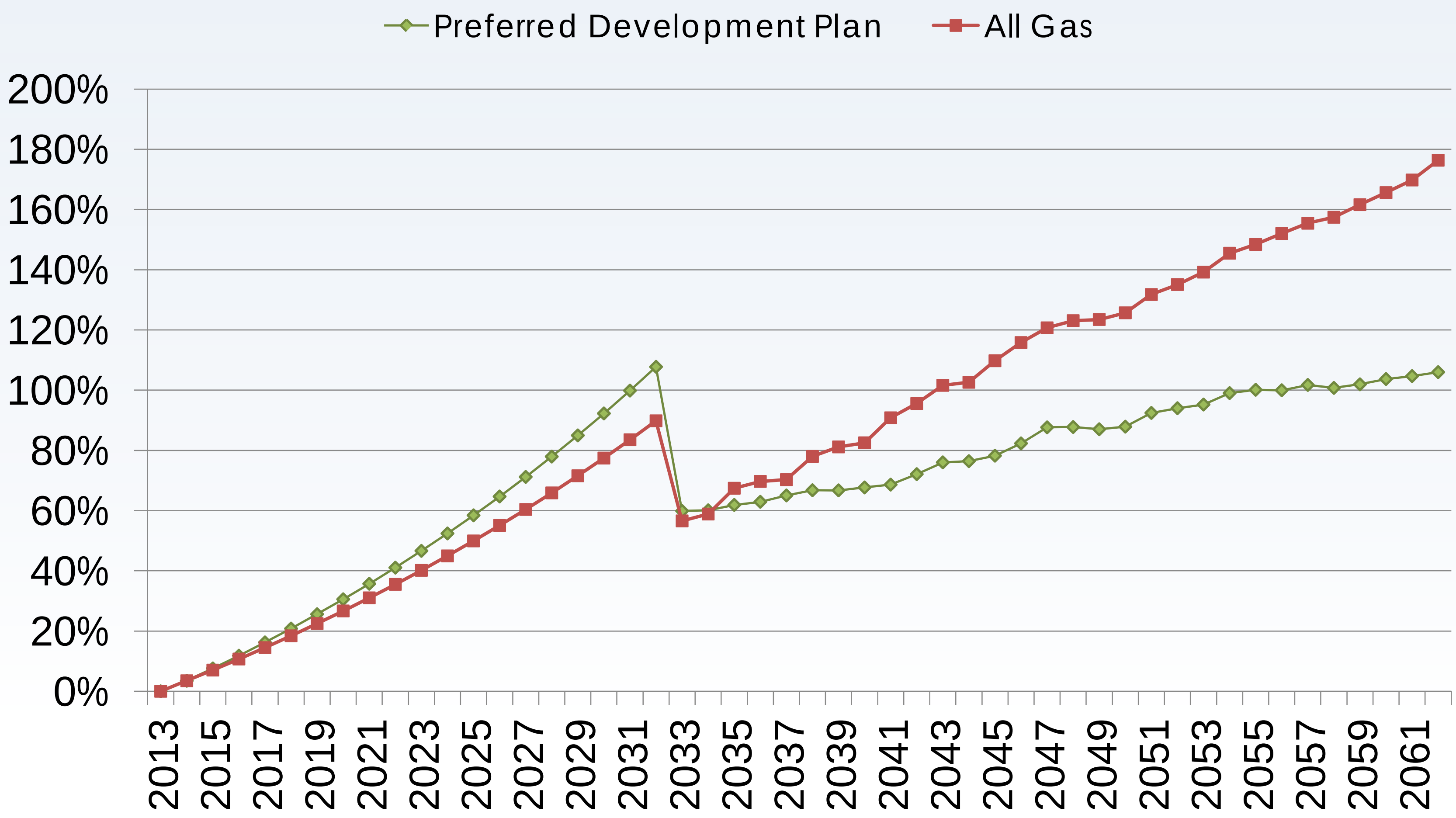
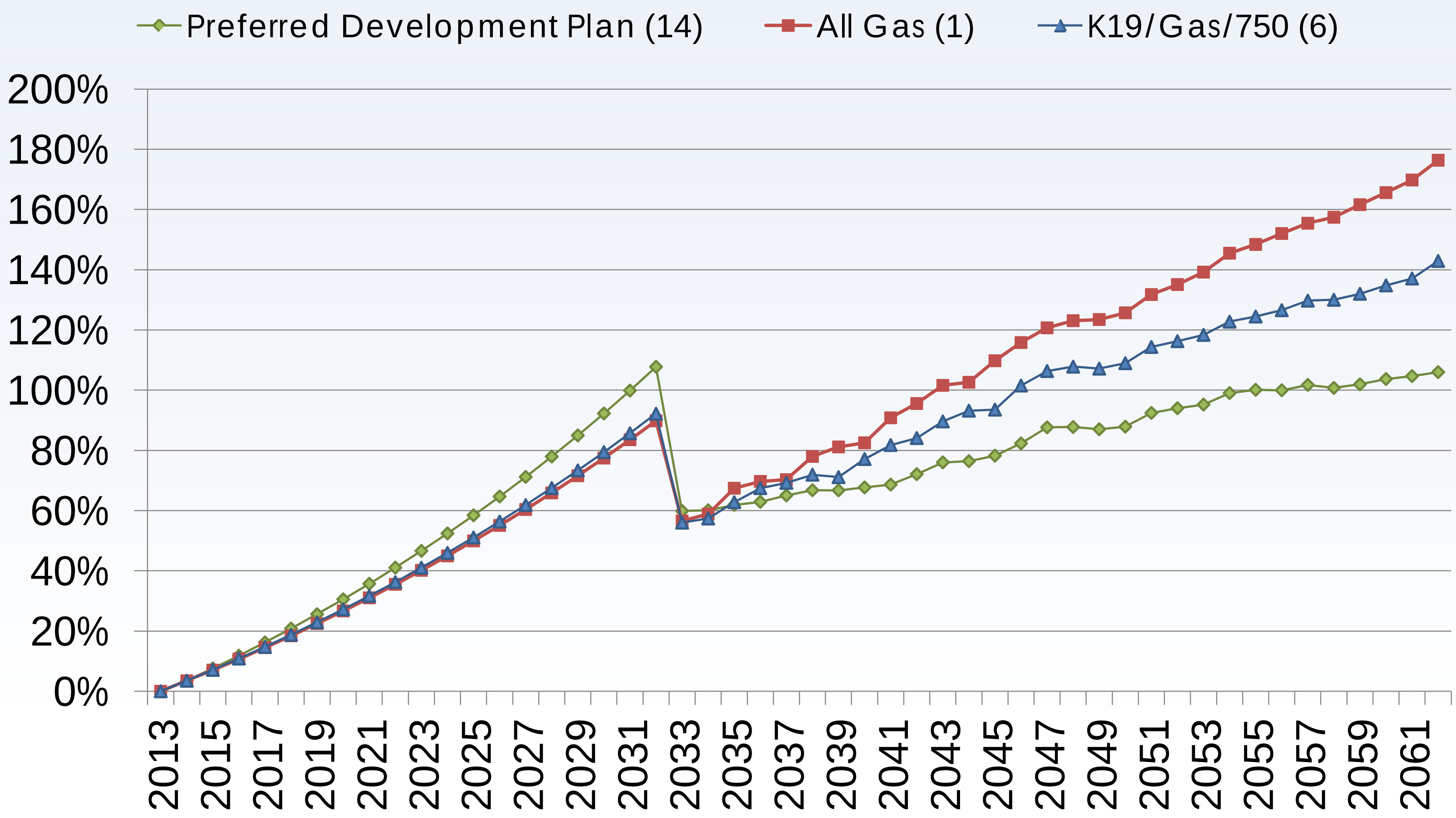
Cumulative Rate Increases (Nominal) Reference Scenario



13173

Cumulative Rate Increases (Nominal) Reference Scenario



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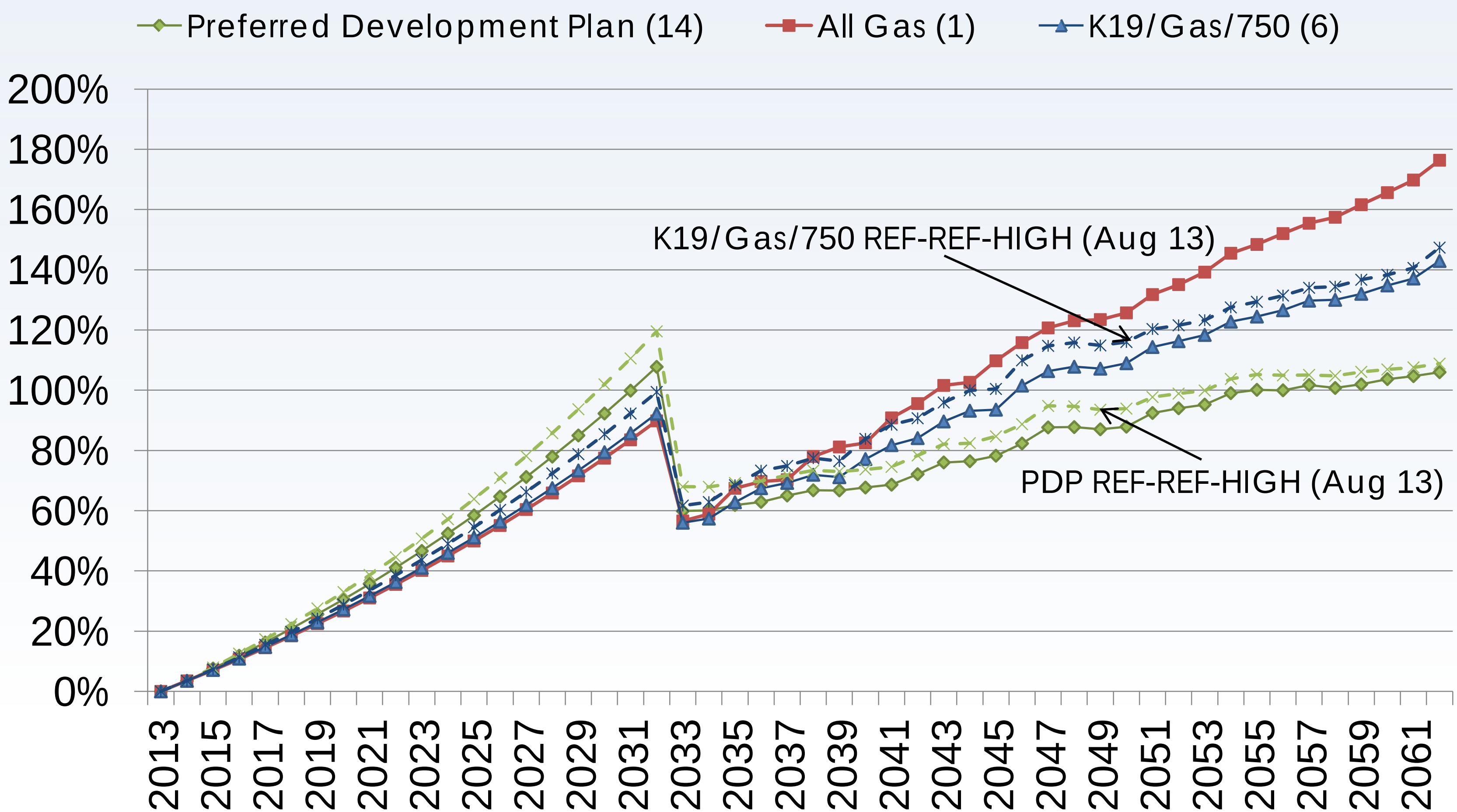
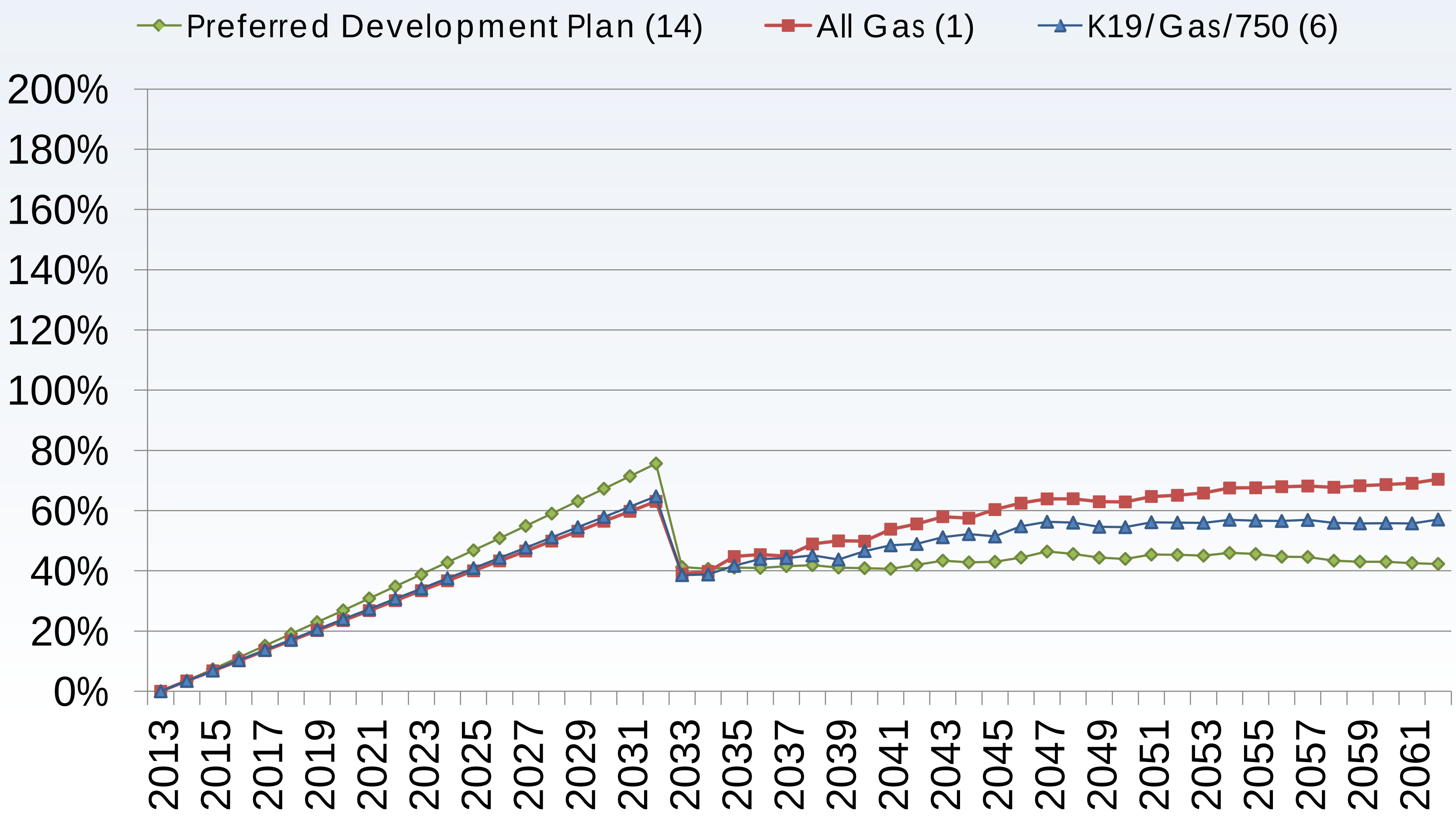
Cumulative Rate Increases (Nominal) Reference Scenario



13175

Cumulative Rate Increases (Real 2013 = 100) Reference Scenario

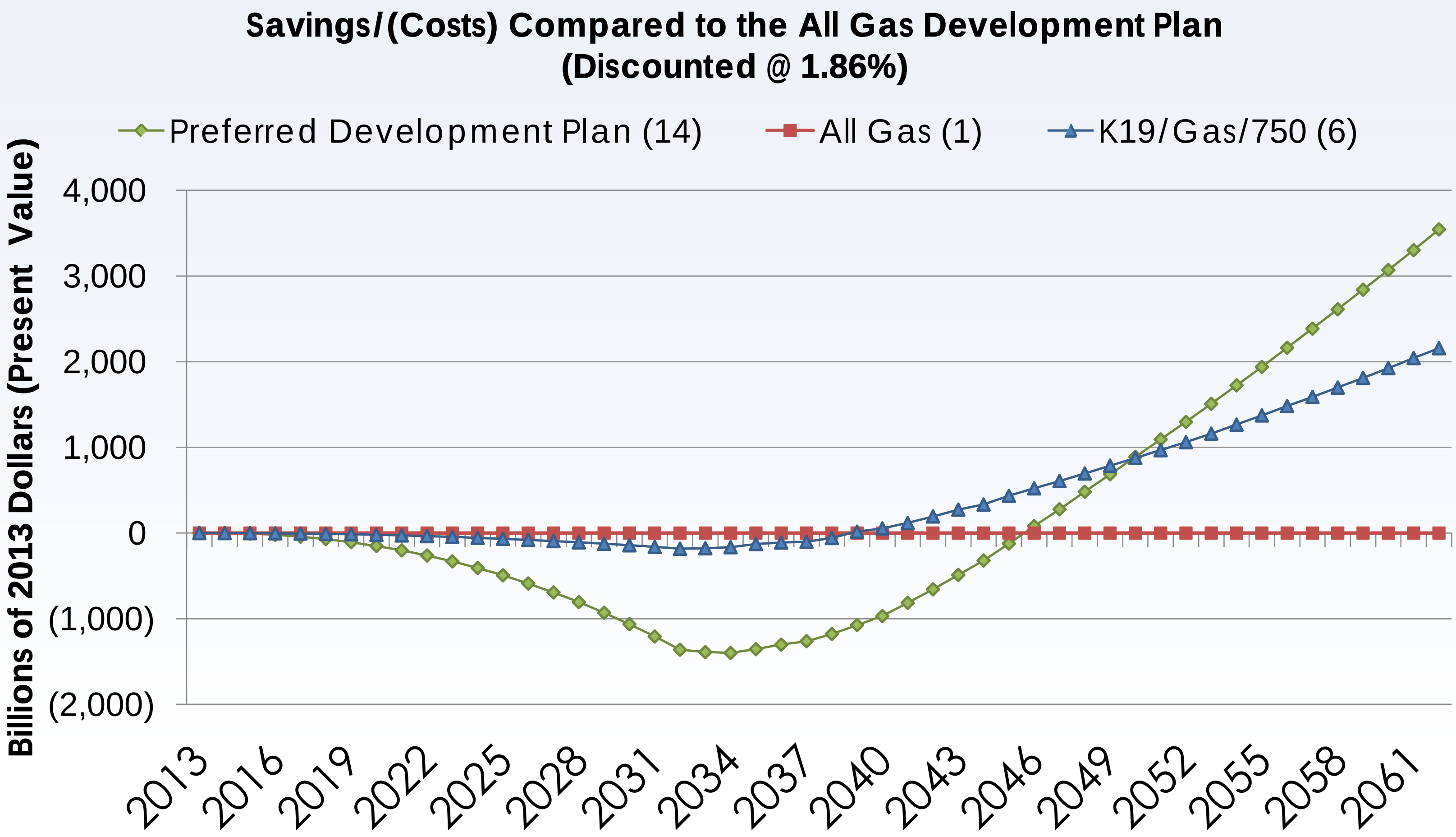


13176

Cumulative PV of Consumers Revenue

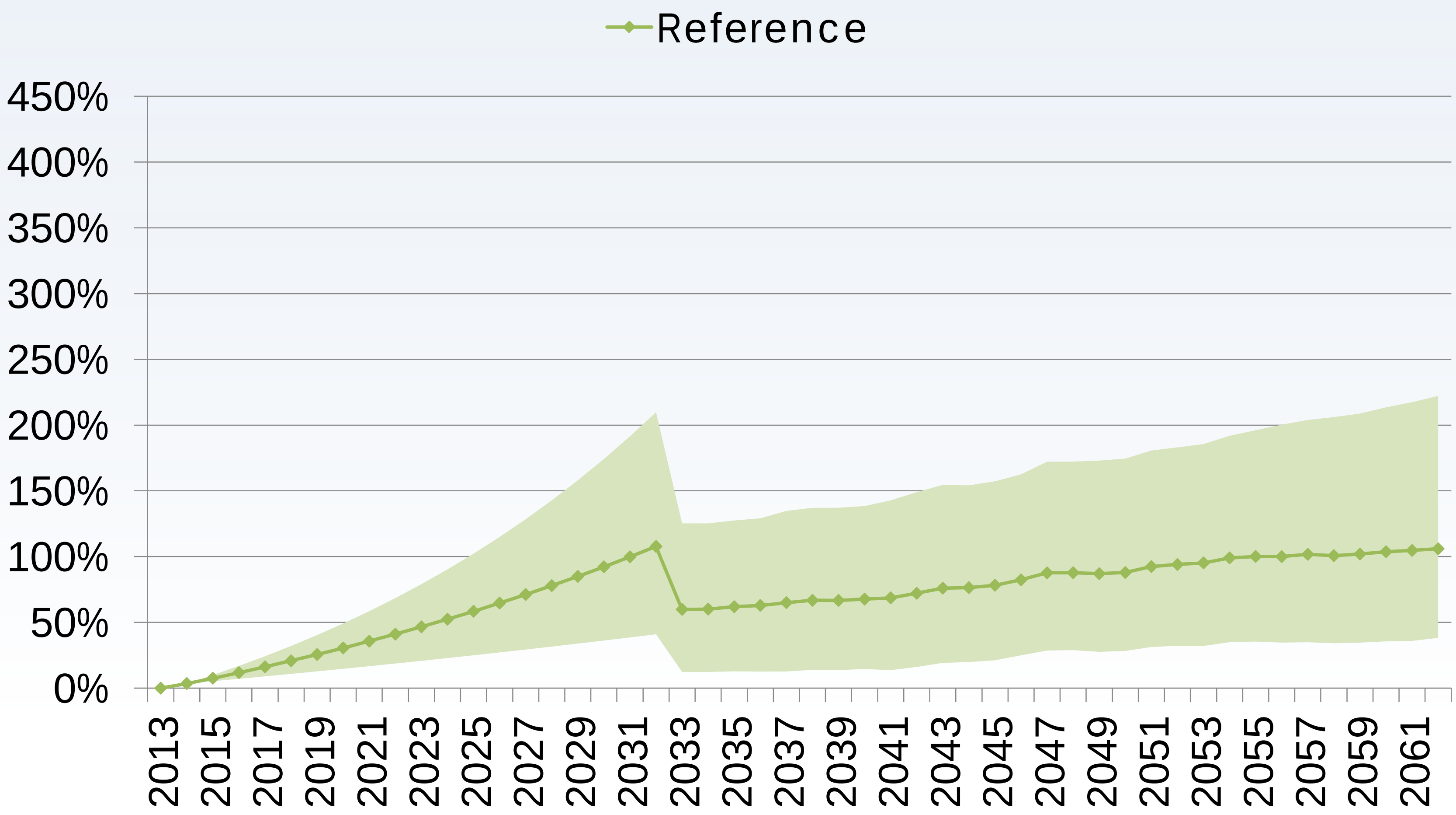
- Based on economic theory, discounted at the social time preference rate
- Addresses the relative patience or impatience for consumption and intergenerational equity
- 1.86% calculated based on projected real return on short term Canadian T-Bill, not adjusted for income taxes
- Reflects Manitoba Hydro's investment in province's public infrastructure – long-lived assets of 100 years or more
- Does not reflect WACC
  - Cost of Corporate debt and equity reflected in the consumers revenue
- Does not reflect high investment threshold for the private sector represented by cost of capital – this is in the economic analysis

Cumulative PV of Consumers Revenue Reference Scenario



Uncertainty Analysis

Cumulative Rate Increases (Nominal) Preferred Development Plan (14)



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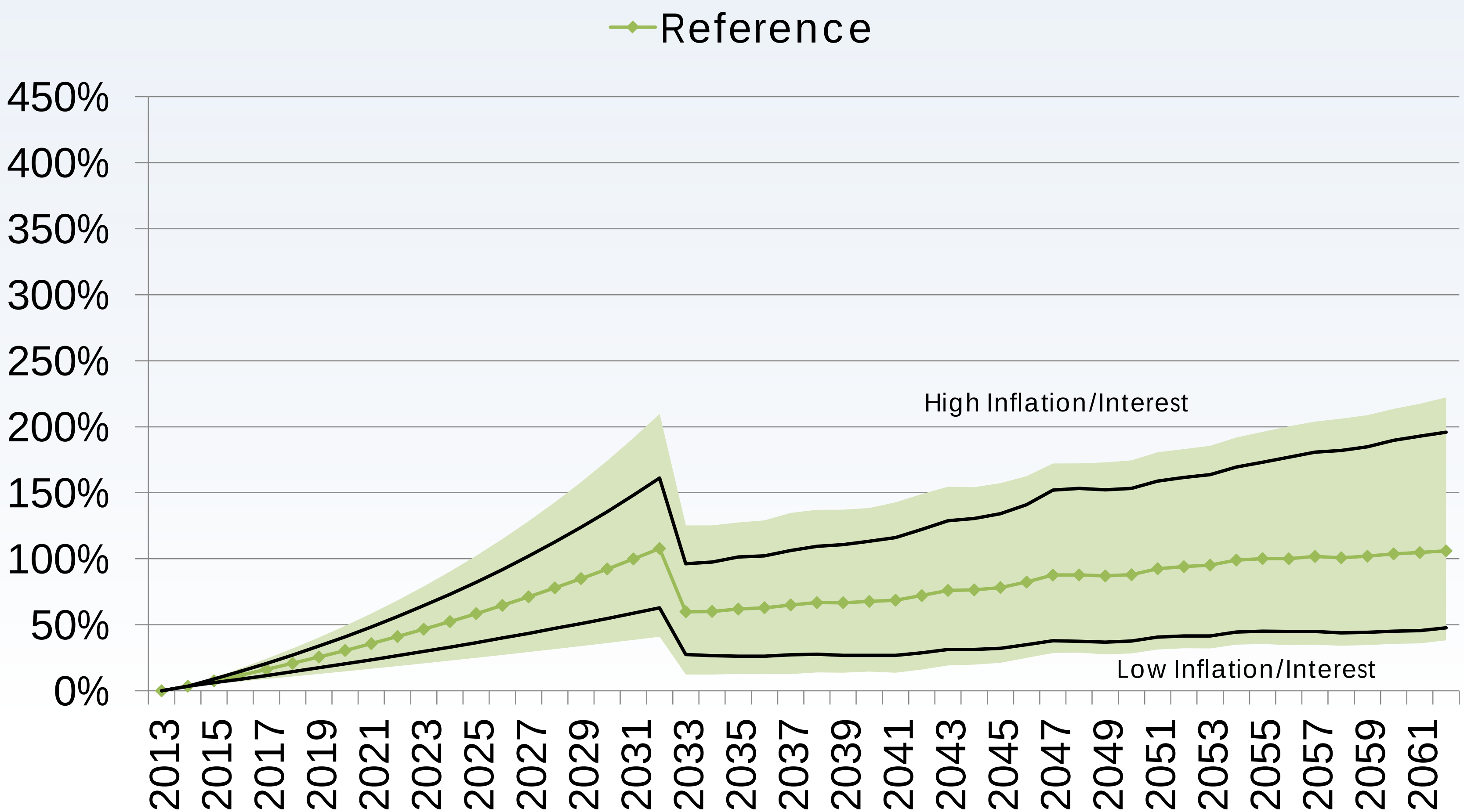
Cumulative Rate Increases (Nominal)
Preferred Development Plan (14)



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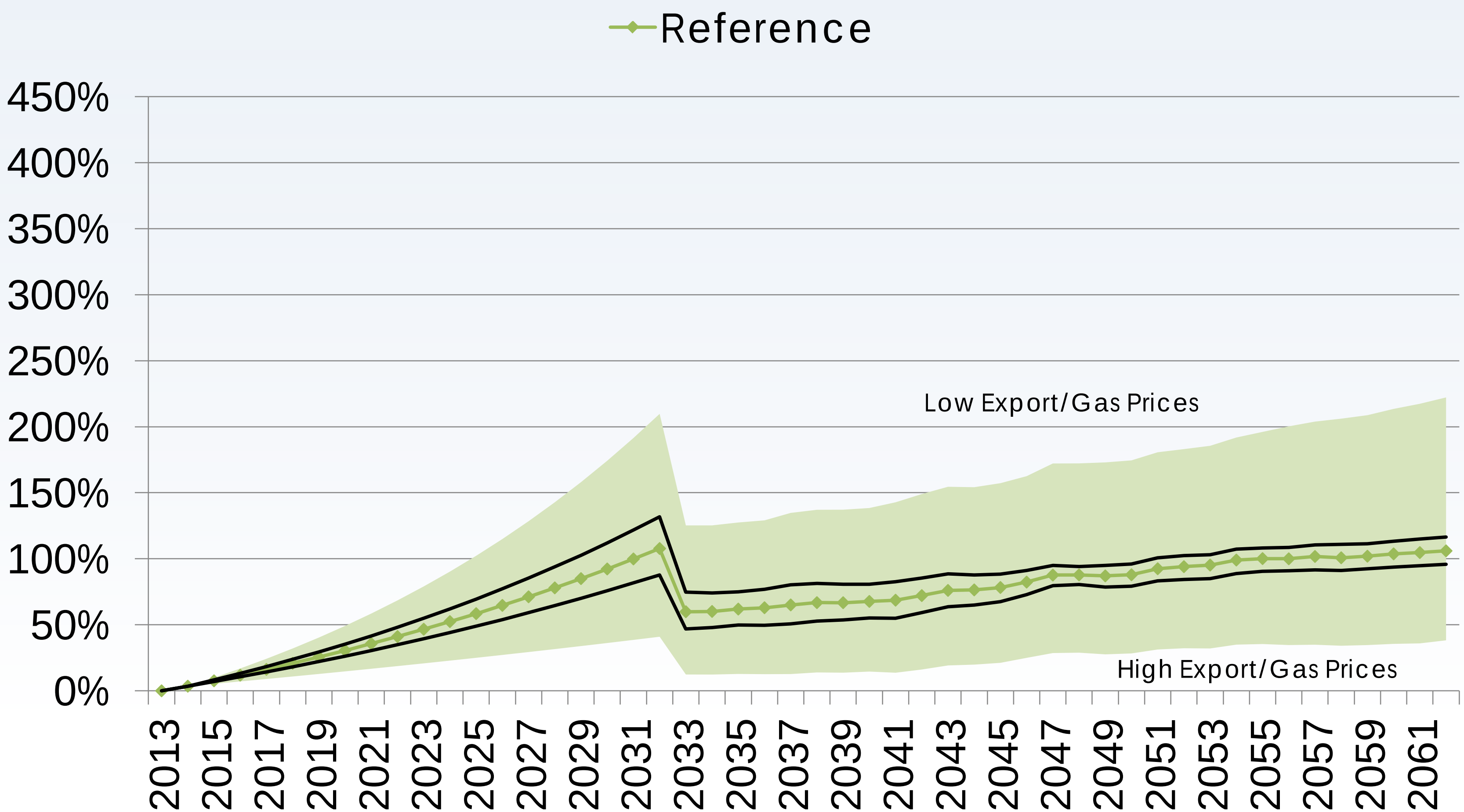
Cumulative Rate Increases (Nominal)
Preferred Development Plan (14)



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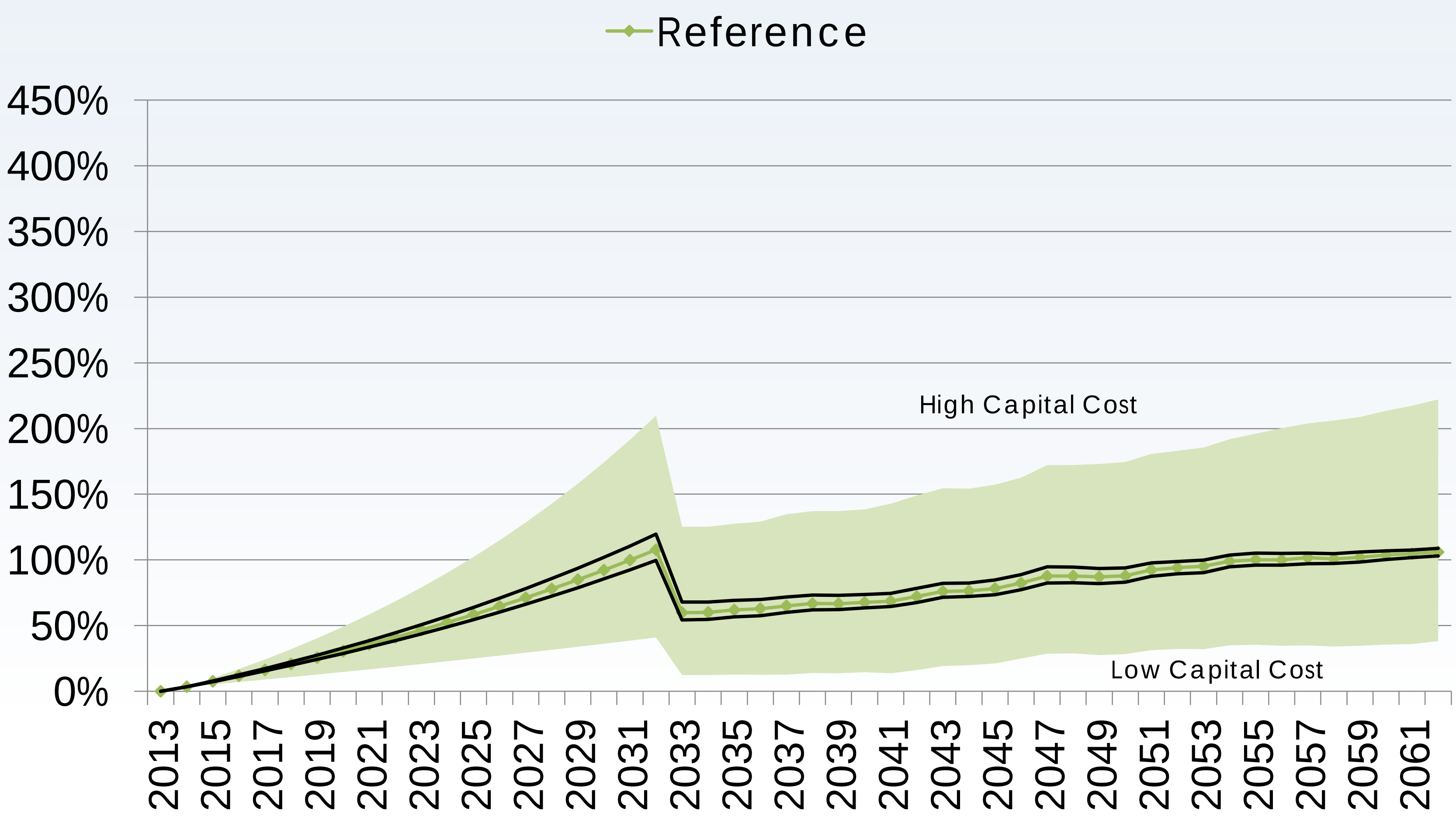
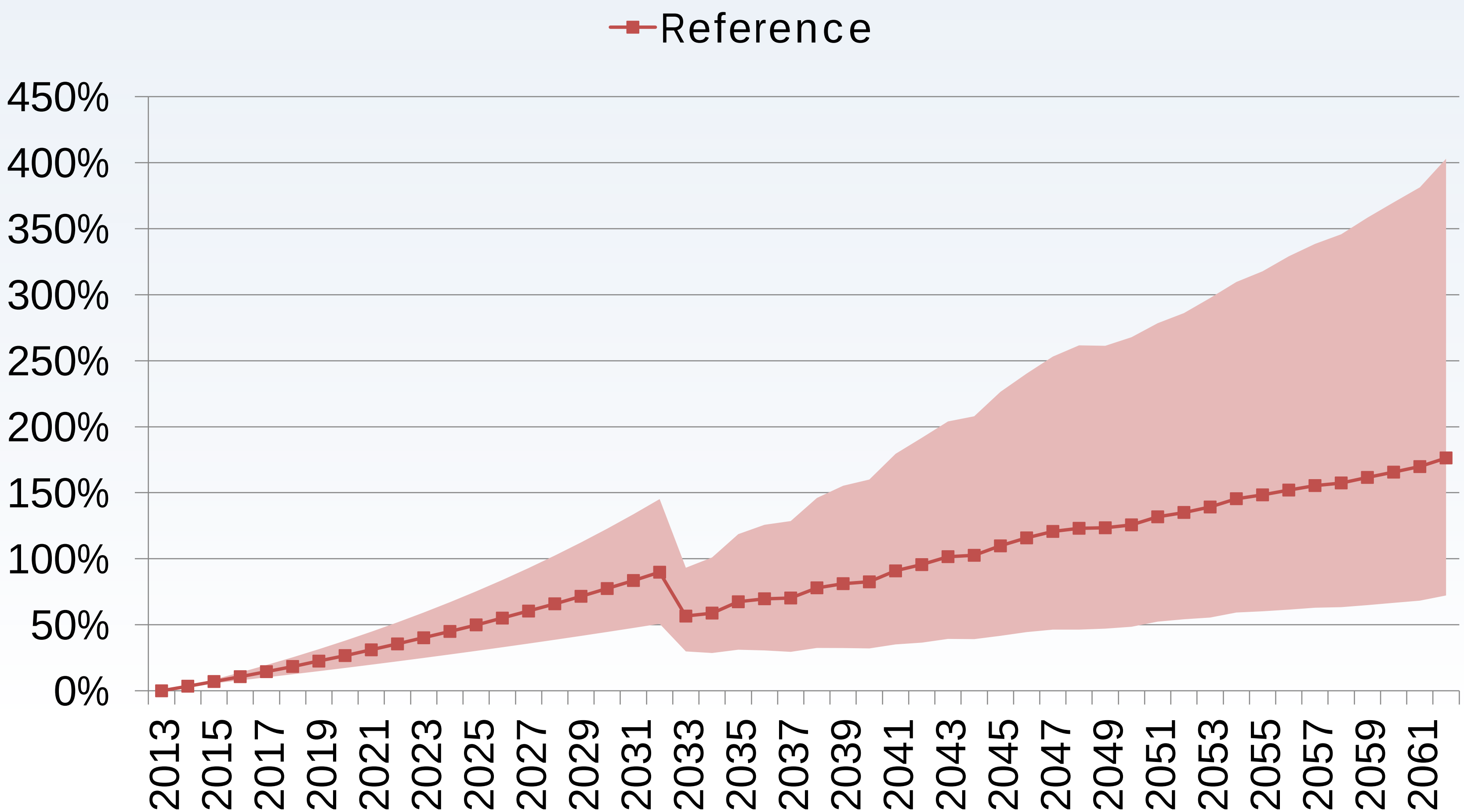
Cumulative Rate Increases (Nominal) Preferred Development Plan (14)



Cumulative Rate Increases (Nominal)
All Gas Development Plan (1)



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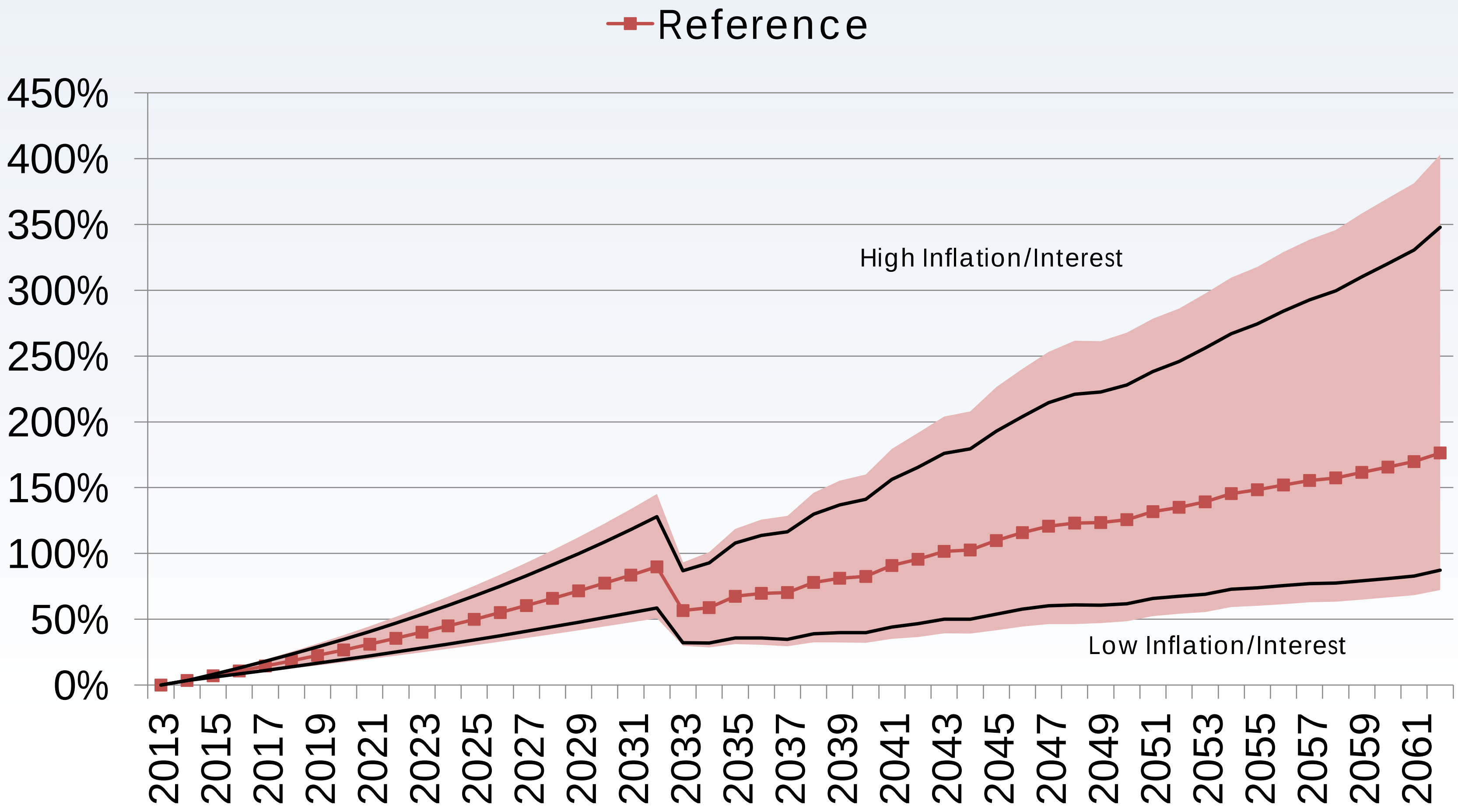
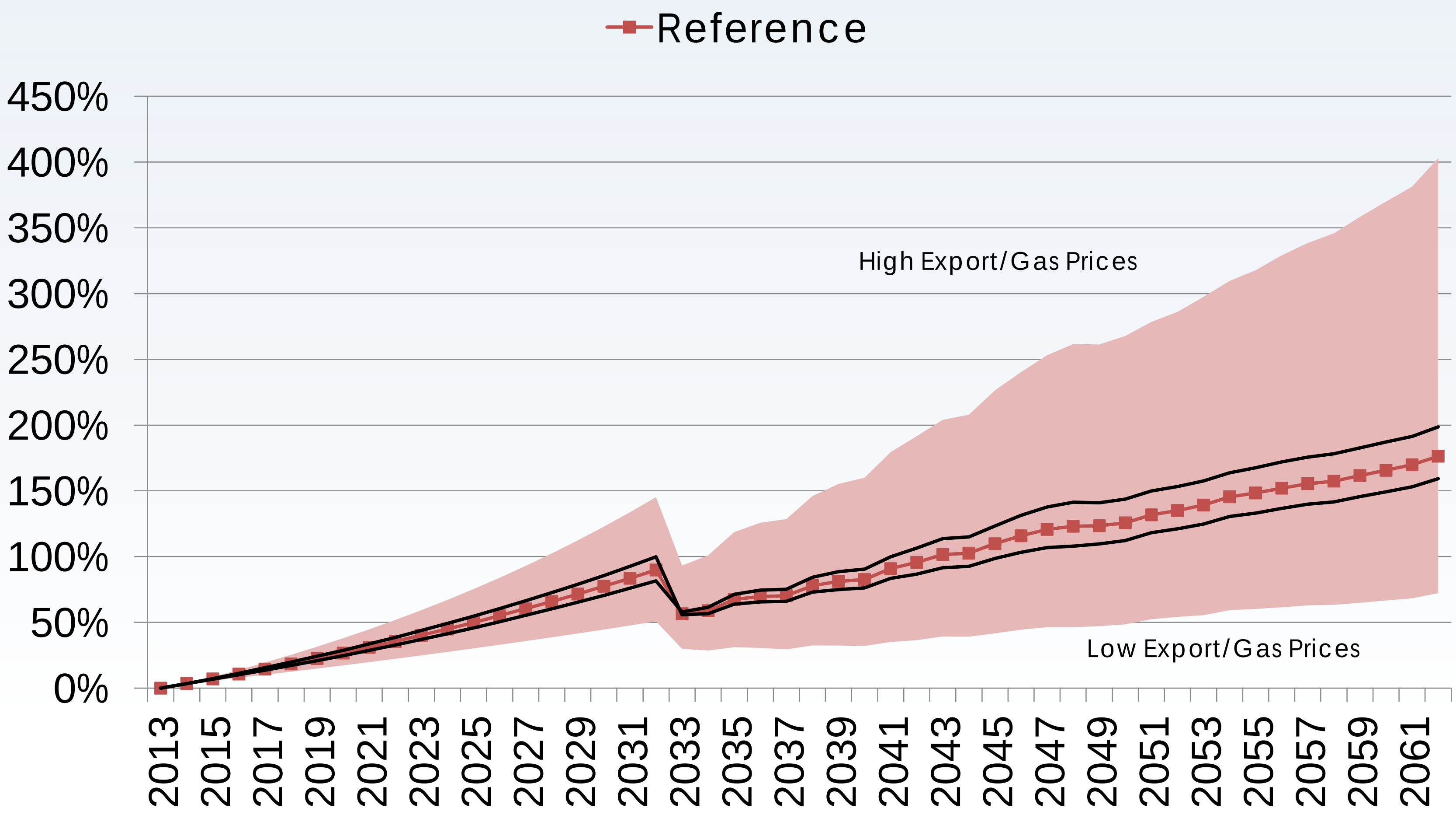
Cumulative Rate Increases (Nominal)
All Gas Development Plan (1)



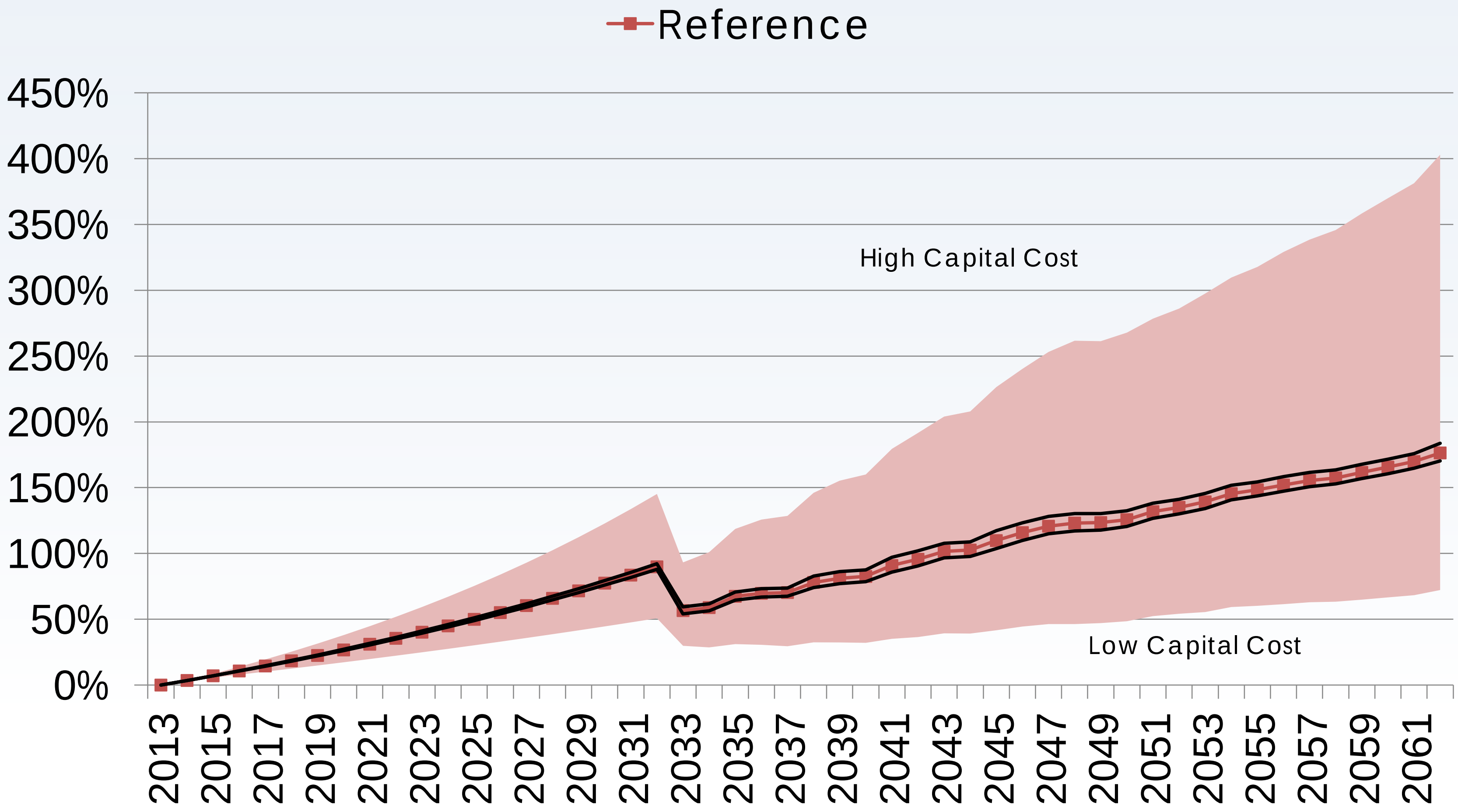
13185

Cumulative Rate Increases (Nominal)
All Gas Development Plan (1)



13186

Cumulative Rate Increases (Nominal)
All Gas Development Plan (1)



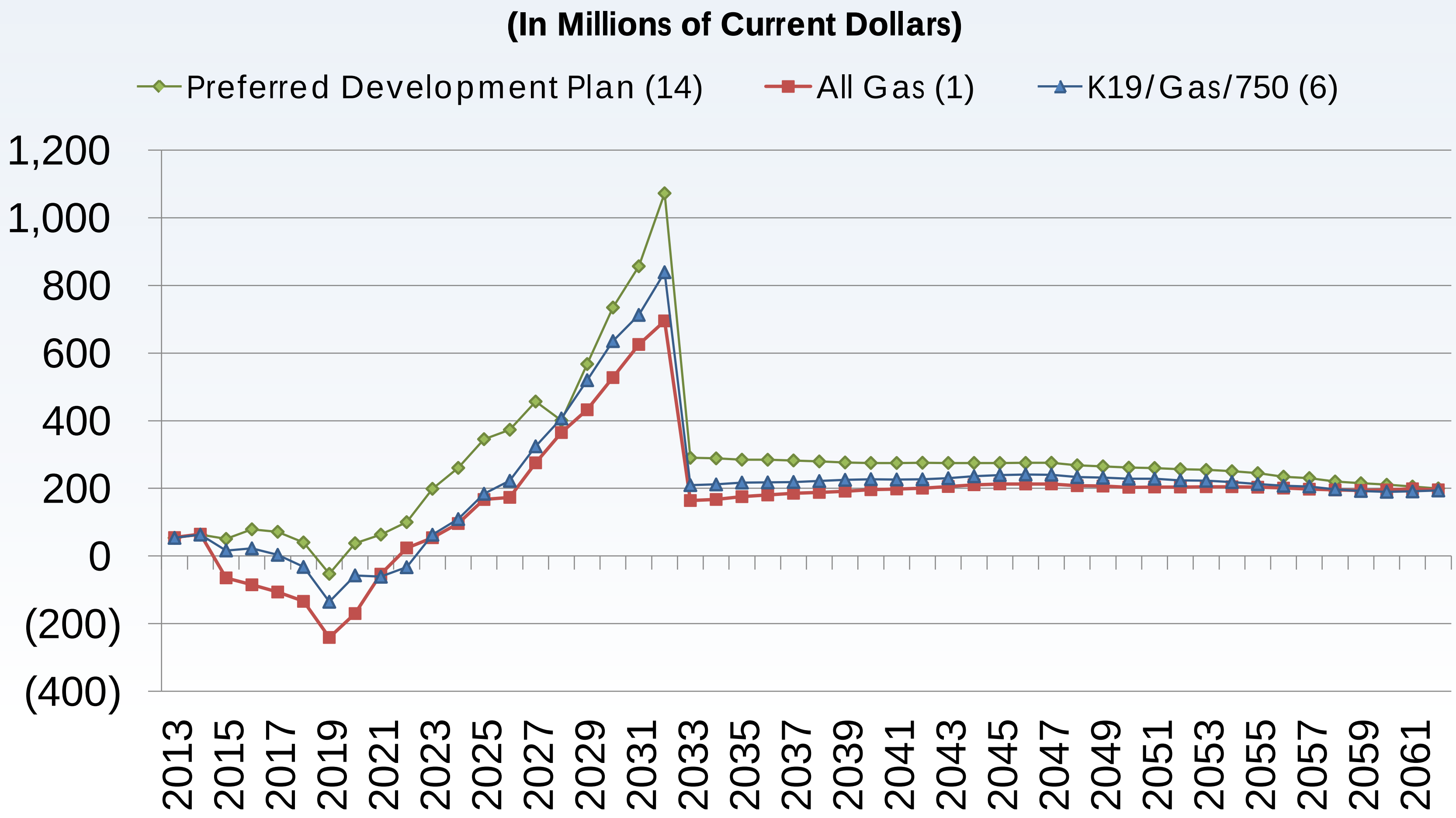
Customer Rates Summary

- Rate increases above the rate of inflation are required under all scenarios due to investments in existing infrastructure and reliability and reductions in non-firm export prices compared to those of a few years ago.
- Rate increases in the period to 2032 are moderately higher under the PDP than All Gas and Keeyask/Gas/750.
- Under the reference scenario, the PDP rates are lower than All Gas and Keeyask/Gas/750 by 2035.
- On a present value basis, the PDP consumers revenue is lower than All Gas by 2046 and lower than Keeyask/Gas/750 by 2050.
- Costs of the Preferred Development Plan do not directly affect Manitoba Hydro's electricity rates today.
  - Costs are deferred until in-service at which time they are included in net income and revenue requirement and amortized over the lives of the associated assets.
- Once in operation, the Preferred Development Plan is anticipated to assist in maintaining affordable and competitive Manitoba Hydro rates.
  - Costs are spread over a very long time matching when customers receive the benefits,
  - Carrying costs decline over time, and
  - Exports offset costs passed on to ratepayers.

NFAT Financial and Rate Analysis

Impact on Manitoba Hydro's Financial Position

Net Income
Reference Scenario



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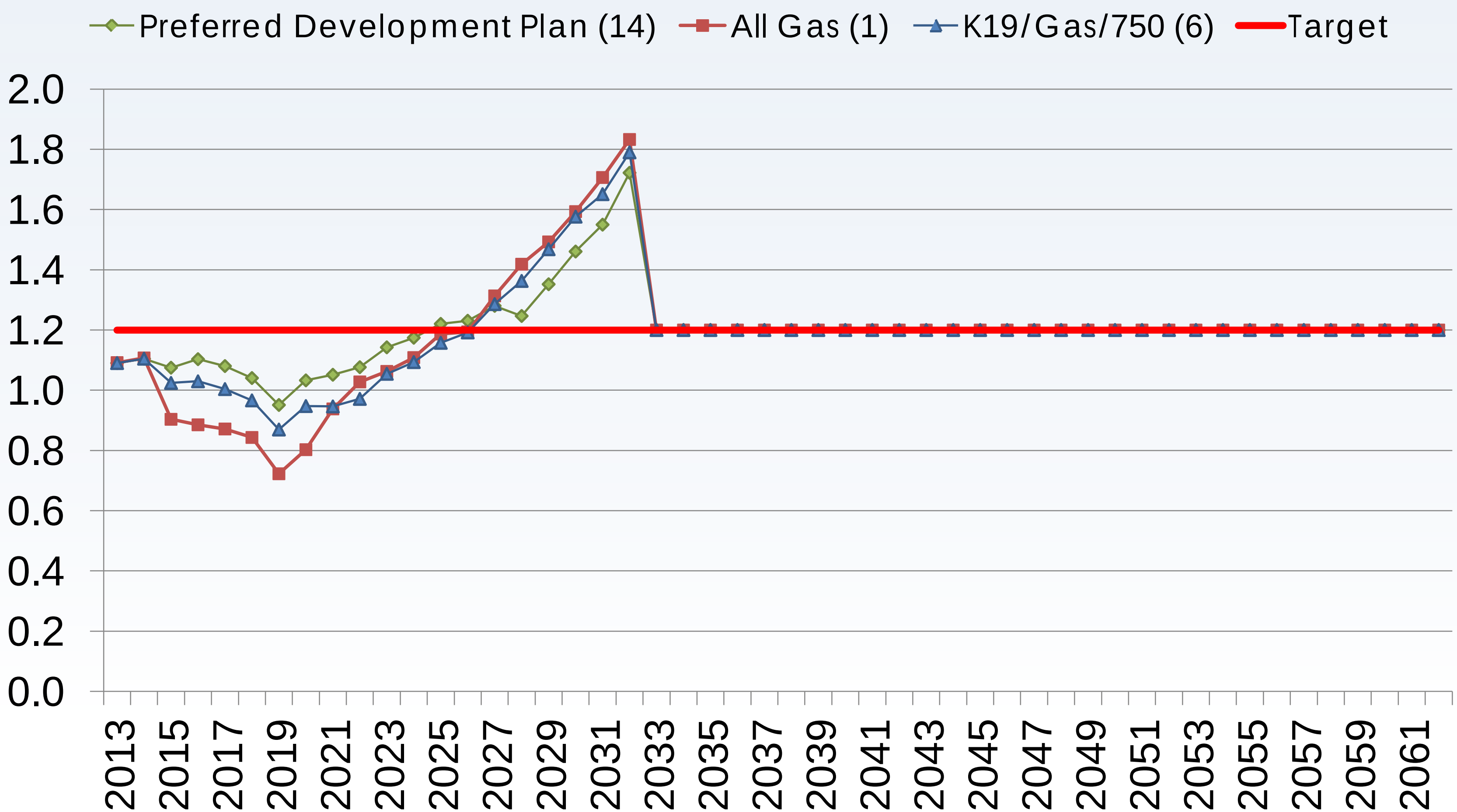
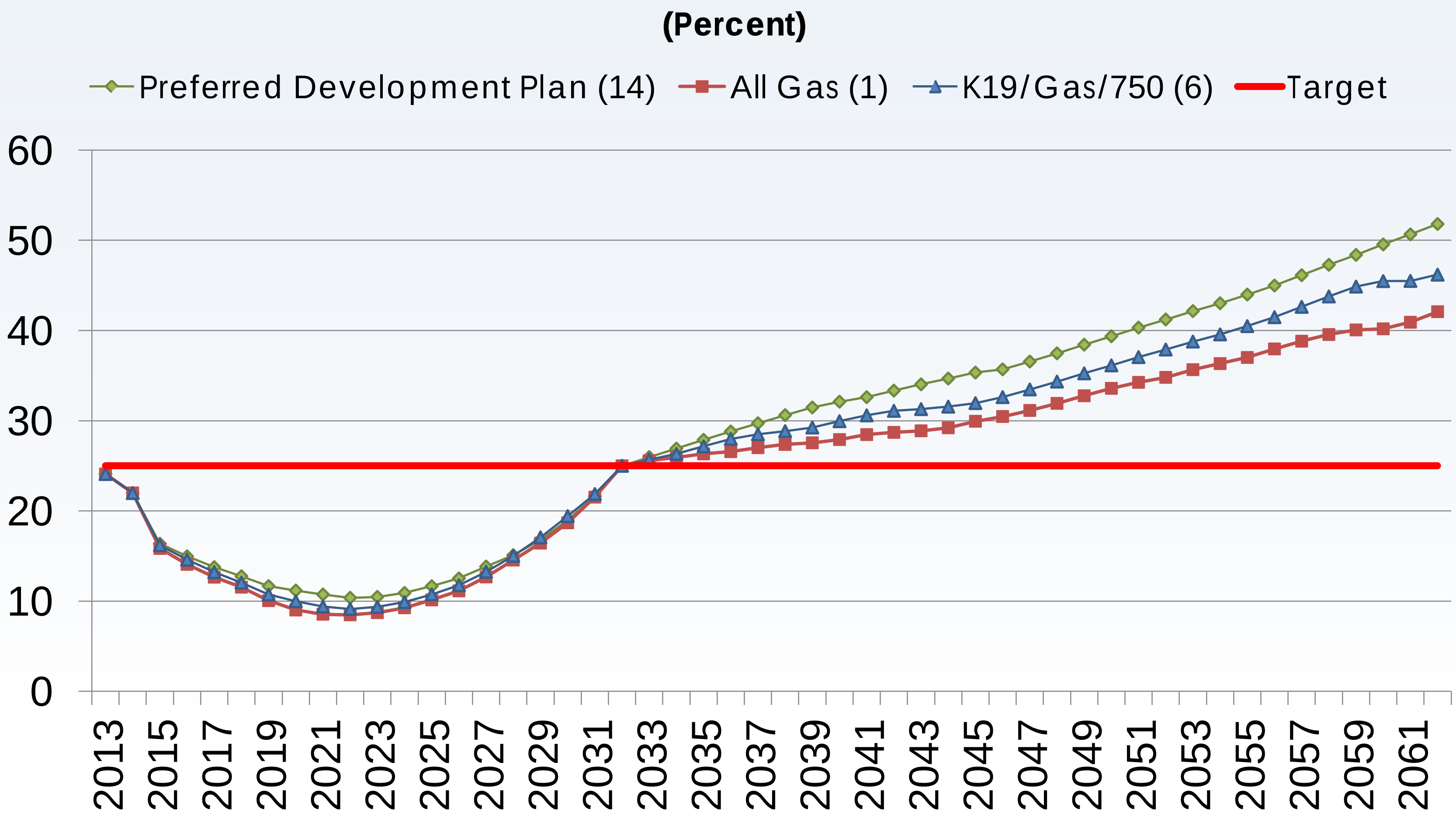
Interest Coverage Ratio
Reference Scenario

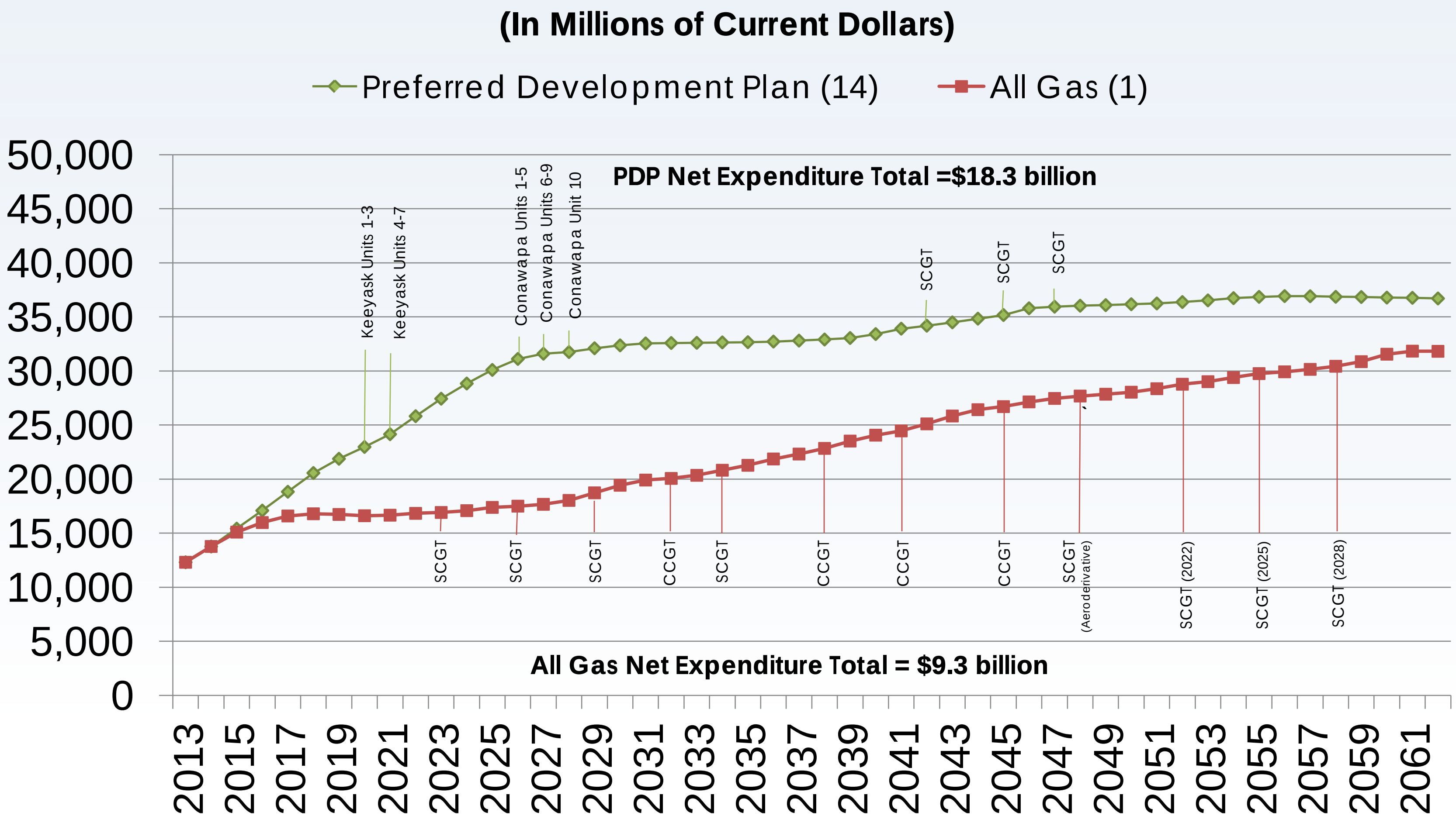


Equity Ratio
Reference Scenario



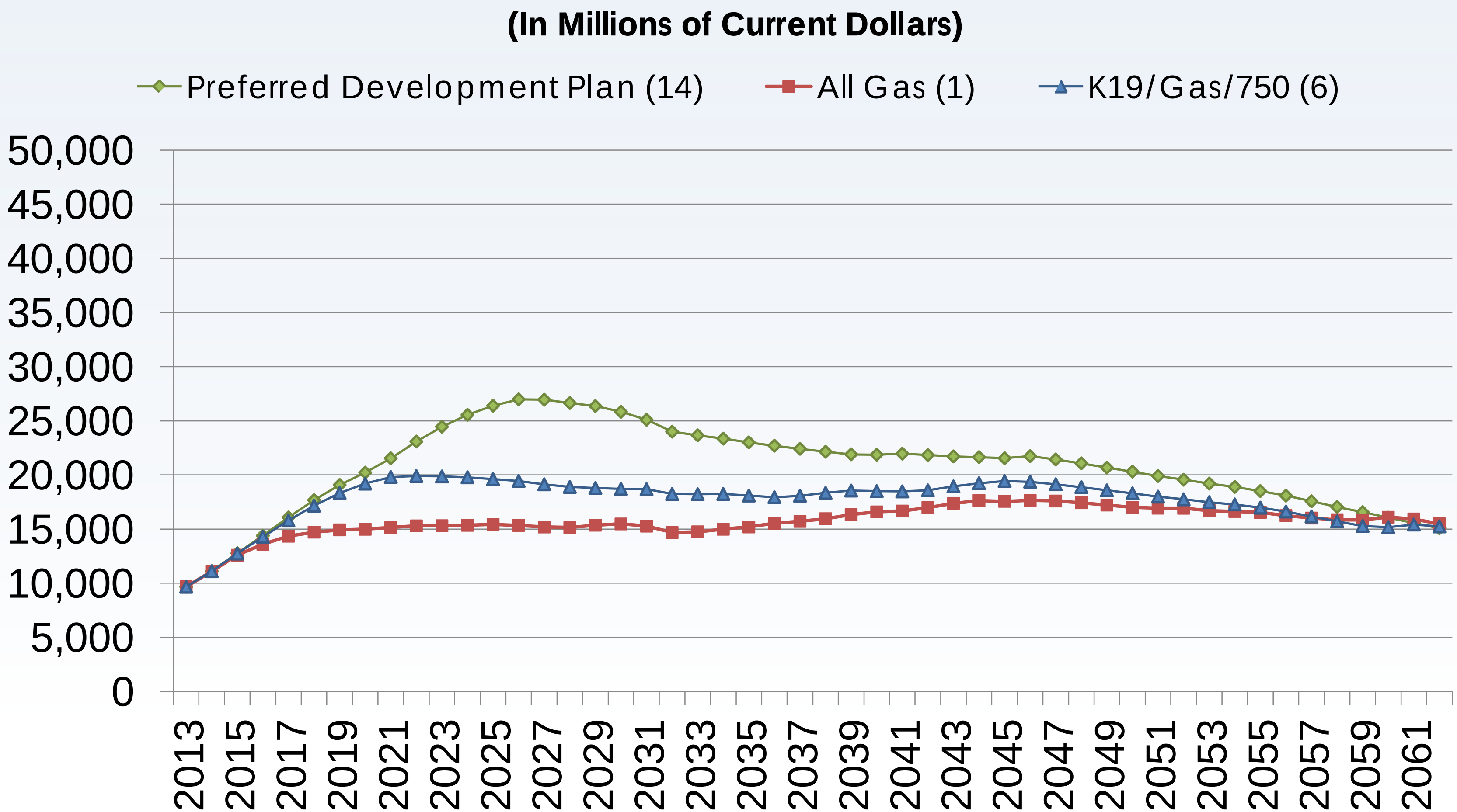
13192

Assets (PP&E and Construction in Progress) Reference Scenario



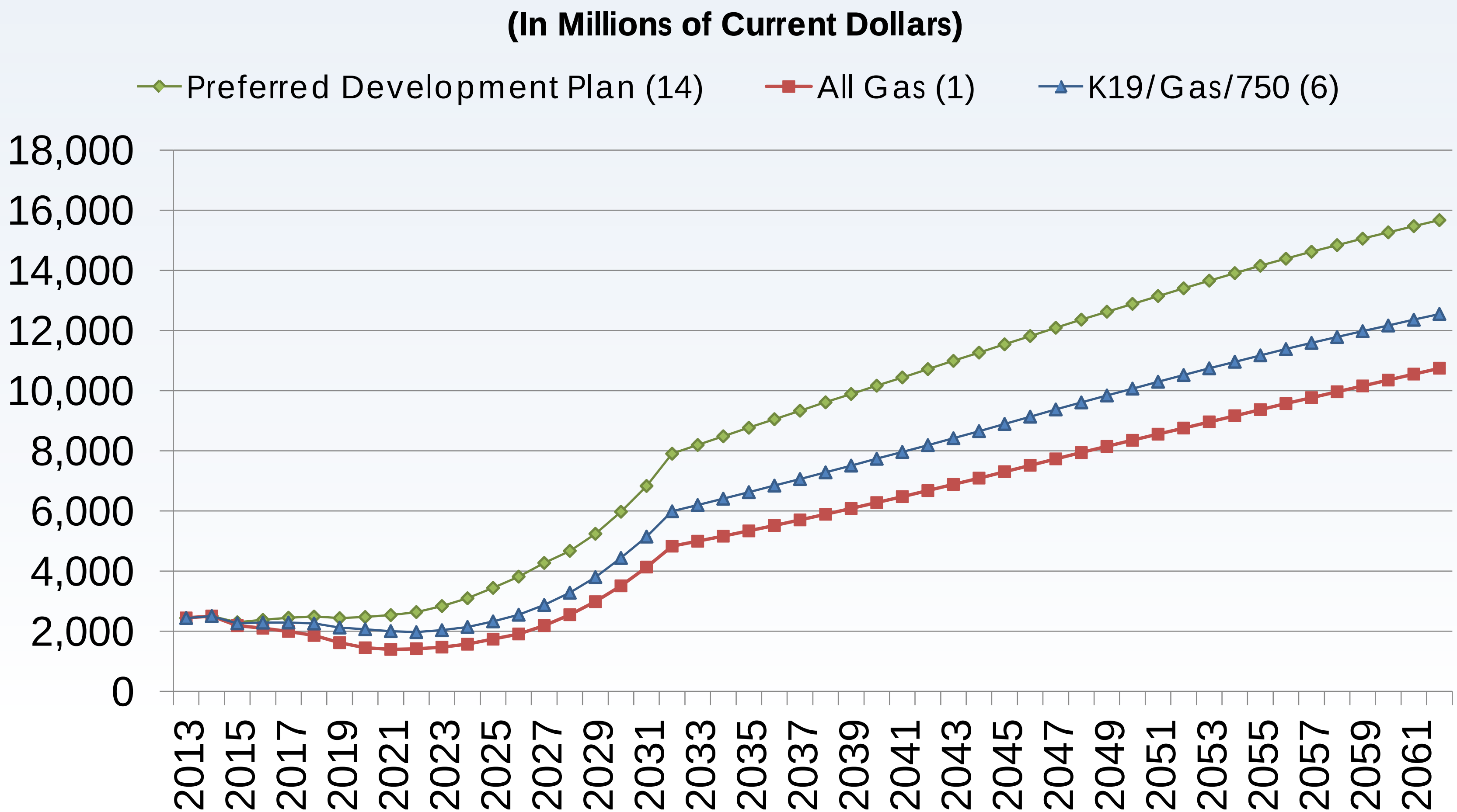
13193

Debt (Net of Sinking Fund and Investments)
Reference Scenario



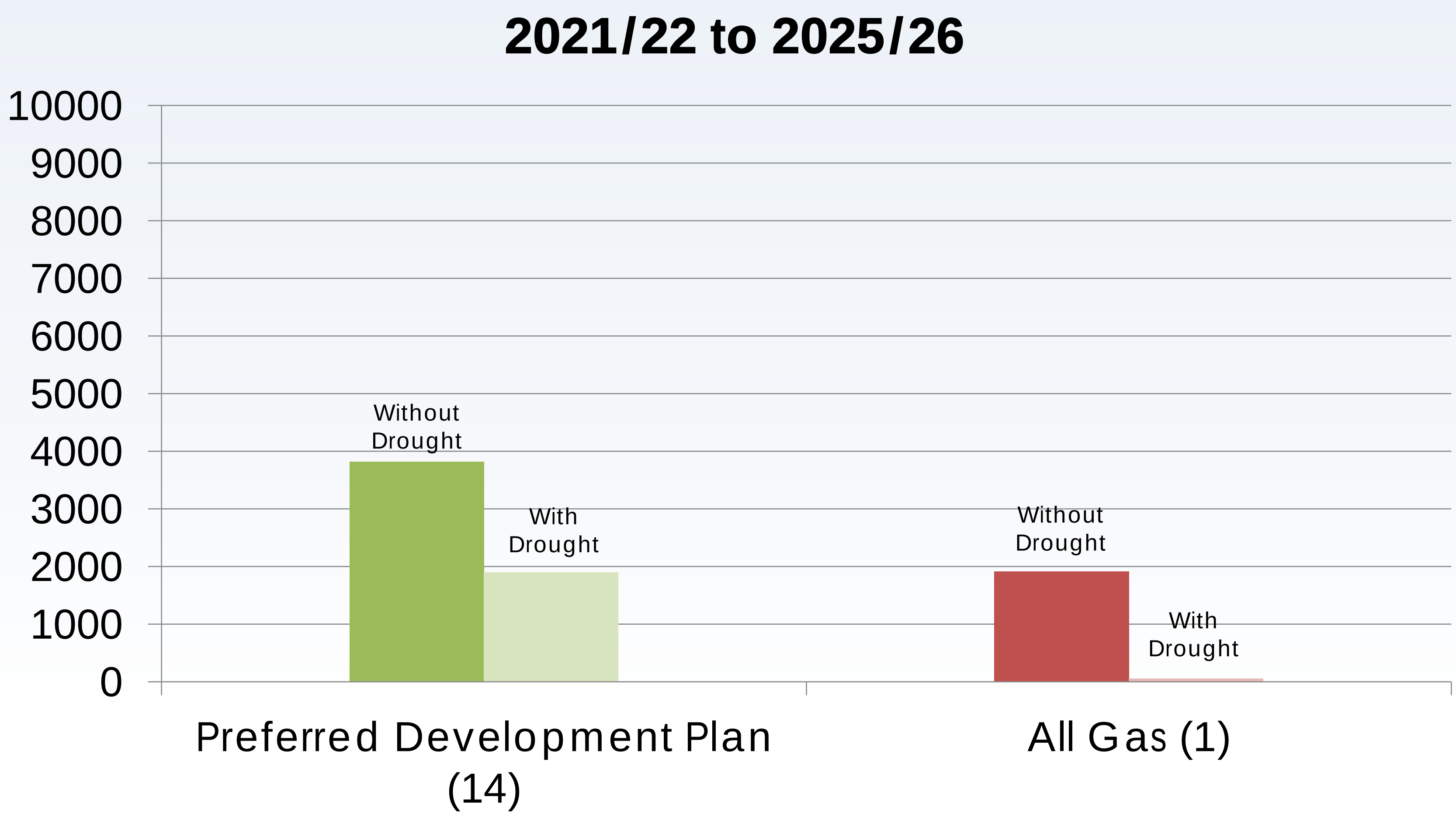
13194

Retained Earnings
Reference Scenario



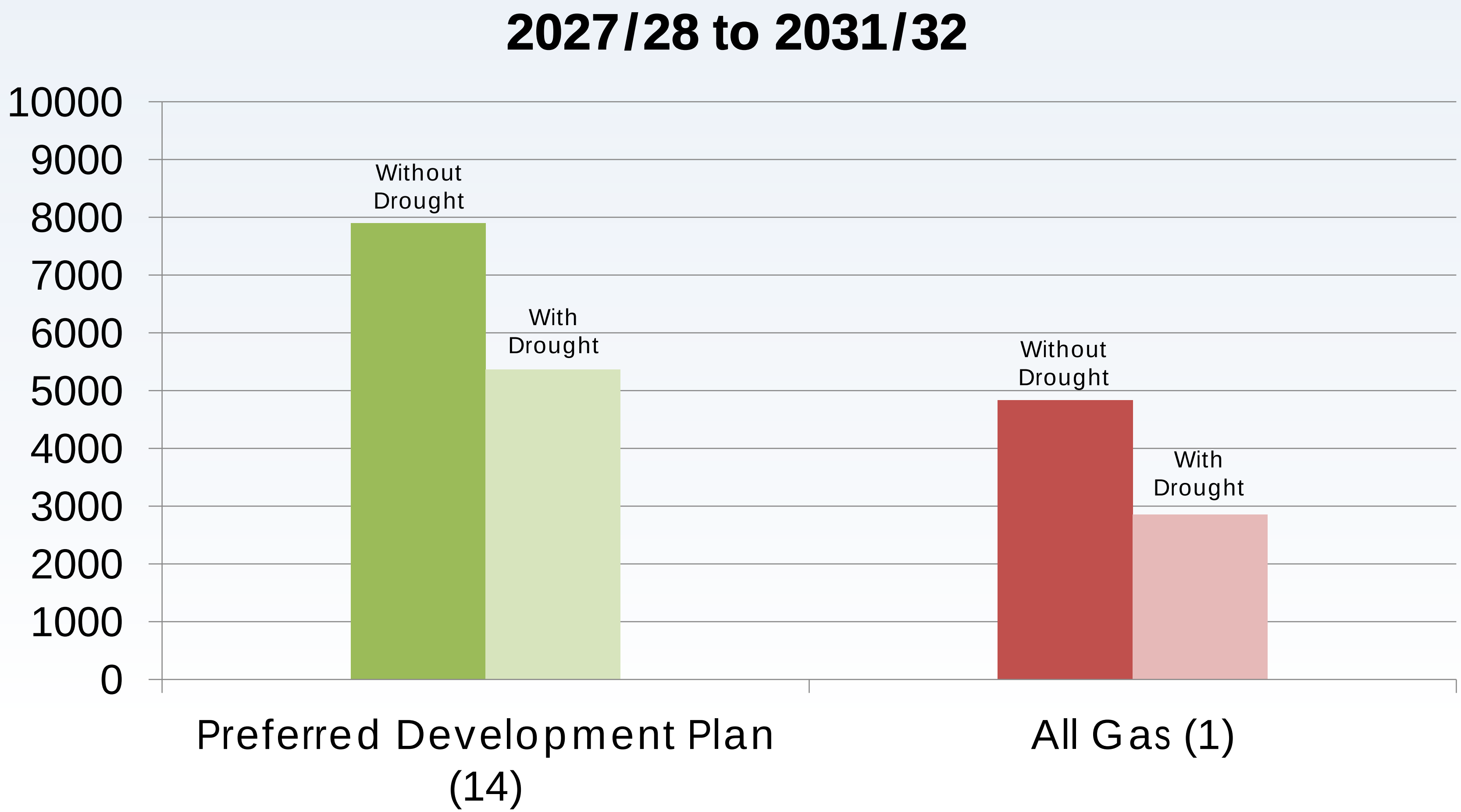
Drought Analysis

Retained Earnings (at End of Drought Year Five)



13197

Retained Earnings (at End of Drought Year Five)



13198

Retained Earnings (at End of Drought Year Five)

Financial Position Summary

- Net income, interest coverage ratio and debt/equity ratio weaken initially and then improve gradually to 2032 under all development plans.
- Net assets and retained earnings are highest under the PDP.
- Net assets under the All Gas grow steadily over the study period and are only $5 billion or 13% lower than the PDP by 2062 due to continuous investment in gas turbines over the study period.
- The PDP has the highest level of net debt throughout the study period but declines following hydro generation ISD’s.
- The All Gas has the lowest level of net debt initially but increases throughout the study period converging with the PDP net debt by 2062.
- The PDP results in the strongest projected balance sheet with the highest level of assets and retained earnings over the entire study period.
- The impact of drought is greater under the PDP; however, due to the higher net assets and retained earnings, the PDP is in a stronger financial position to absorb the adverse financial impacts of drought.

Financial Risk Management

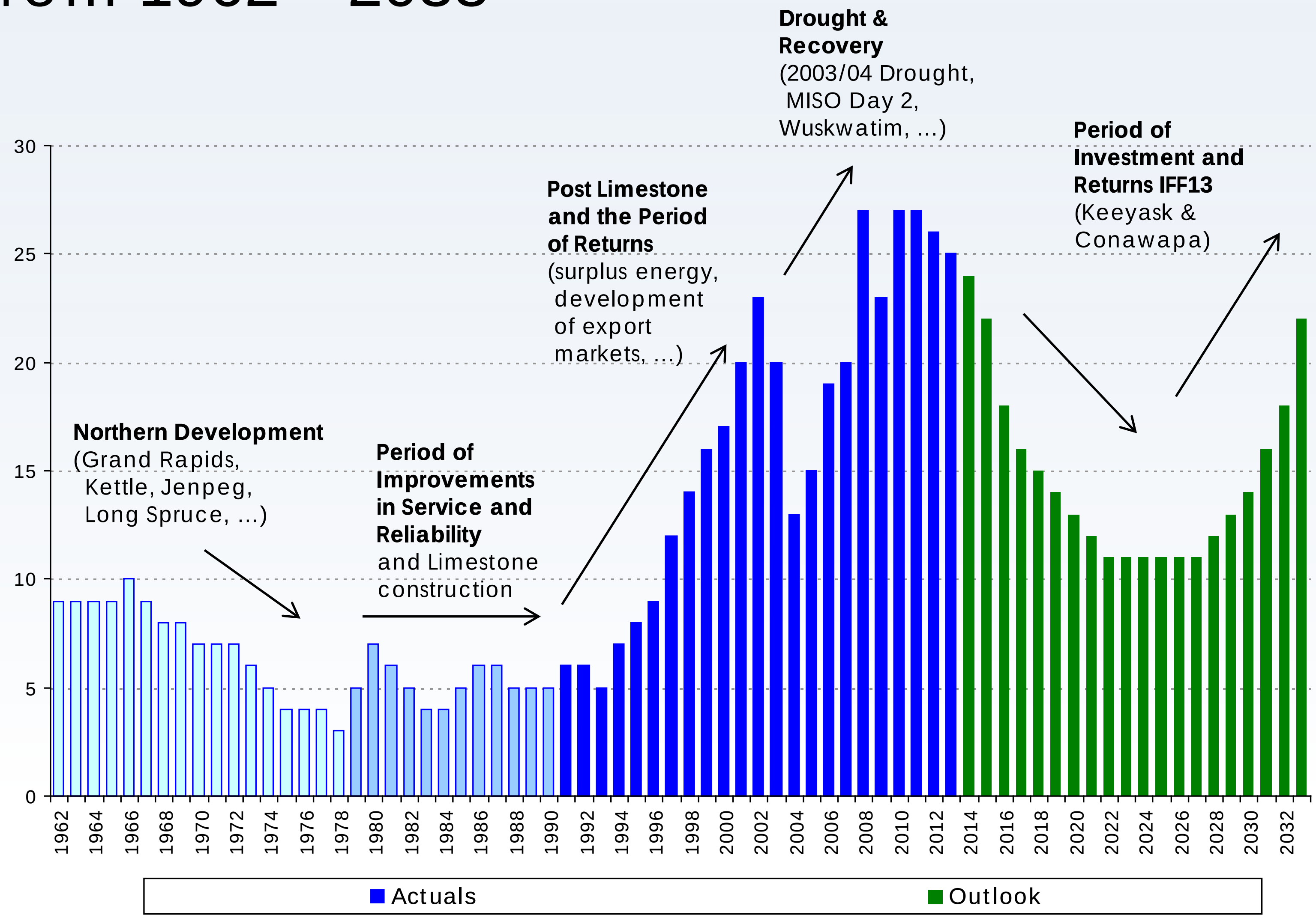
Risk Management is Integral to the NFAT Submission

- Manitoba Hydro considers **business risk as an integral aspect of its plans and operations**.
- Manitoba Hydro's financial risks, forecasts, ratios and evaluations have been extensively examined (eg. Chapter 11 and Appendix 11.4 with 216 distinct sets of pro-forma financial statements).
- The financial volatility of severe drought was also examined in the NFAT filing (eg. Section 11.4).
- The submission also includes flexible pathways to manage through future uncertainties.

Financial Risk is Manageable and Debt Self-Supporting

- Manitoba Hydro is embarking upon its development plans from a position of strength.
- As measured by the equity ratio, the Corporation is well situated to move forward with its upcoming capital investments.

Manitoba Hydro's Equity Ratio
from 1962 – 2033



13204

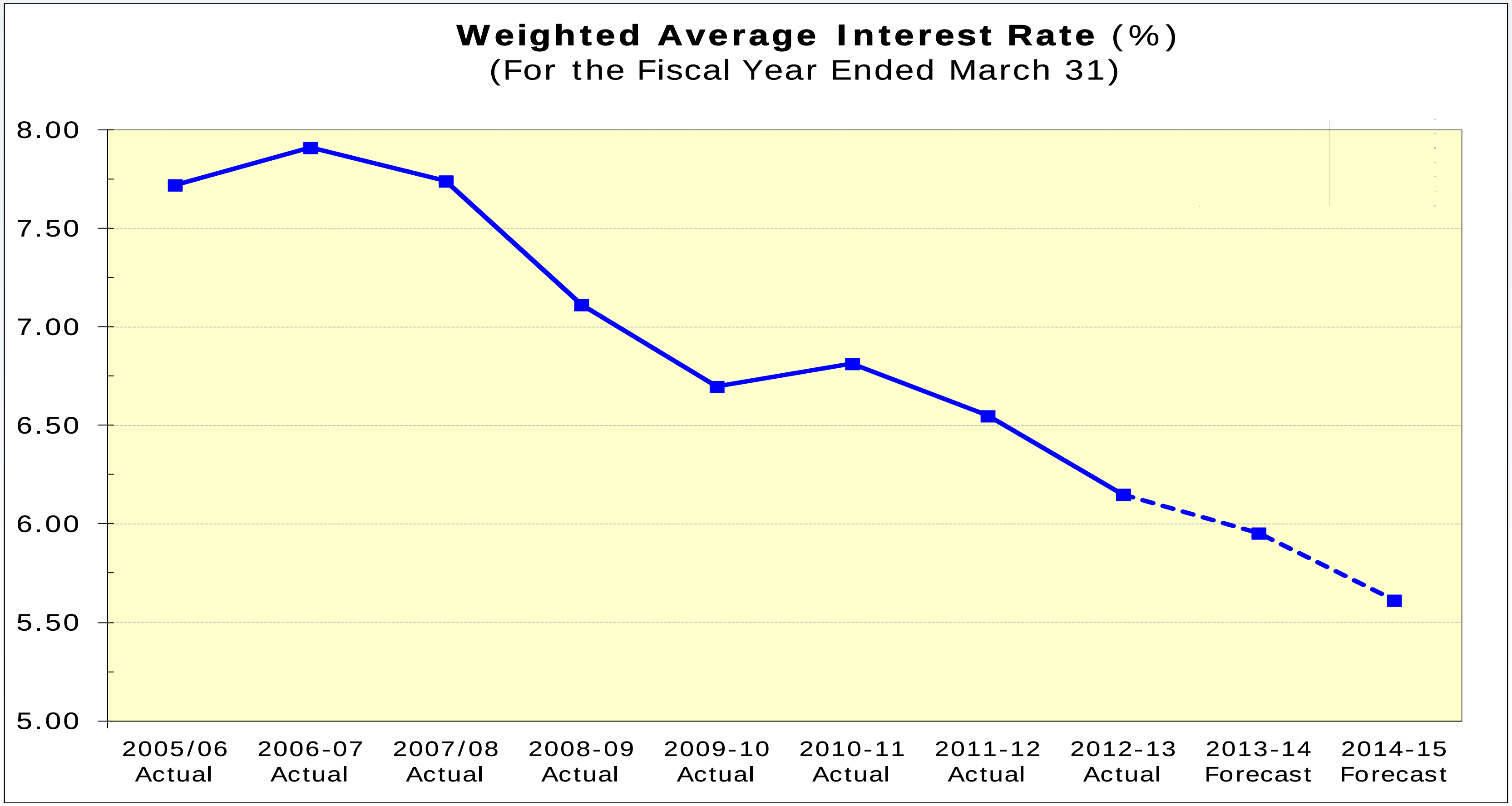
Financial Risk is Manageable and Debt Self-Supporting

- With respect to Manitoba Hydro's borrowings, the Corporation receives a flow through credit from the Province of Manitoba.
- In exchange for this flow through borrowing capability, Manitoba Hydro pays a provincial debt guarantee fee to the Province of Manitoba.
- As Manitoba Hydro makes interest and principal payments to bondholders on an uninterrupted basis, the debt is considered by the credit rating agencies to be self-supporting.
- Therefore, to the extent that Manitoba Hydro prudently manages its debt and maintains its self-supporting status, Manitoba Hydro's capital investment plans should have no significant impact on the Province of Manitoba's credit rating.

Debt Management Strategy

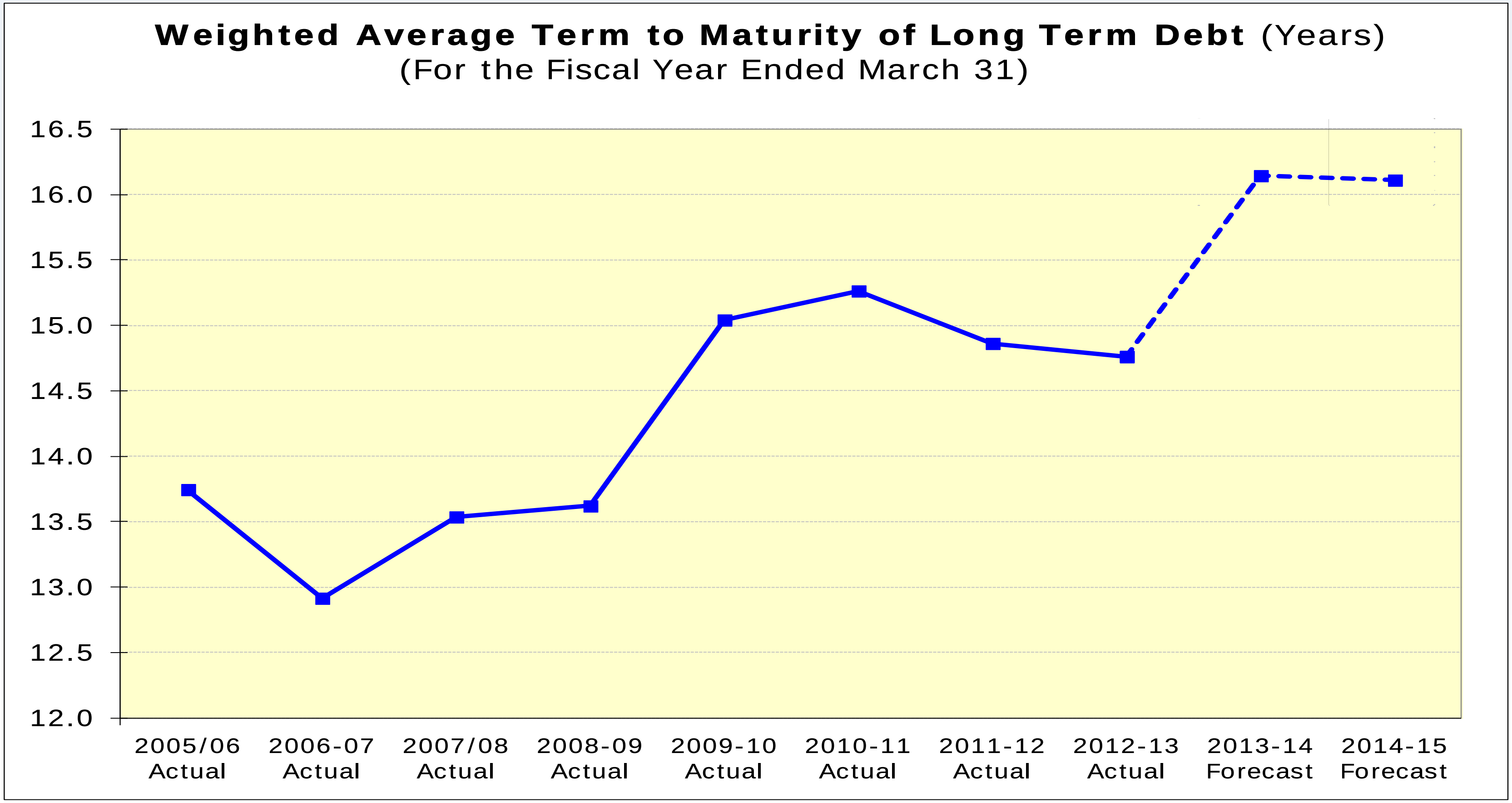
- Manitoba Hydro's fundamental debt management objective is to provide stable, low cost funding to meet the financial obligations and liquidity needs of the Corporation.
- Manitoba Hydro's actual long term financing includes debt issuance in various terms to maturity.
- In order to mitigate refinancing risk, Manitoba Hydro will:
  - Match long-lived assets with long term debt, and
  - Continue to favour long term fixed rate financings with maturities of 10 years+.

Debt Management Strategy – Low Cost



13207

Debt Management Strategy – Stability



13208

Foreign Currency Exchange Risk

- Manitoba Hydro's net income is largely inoculated from fluctuations in the movement of the USD/CAD exchange rate.
- Manitoba Hydro has significant export revenues and cash inflows denominated in US dollars.
- However, in order to manage the currency exchange risk on these revenues, Manitoba Hydro maintains a natural hedge with offsetting US dollar cash outflows, including finance expense on US denominated debt.

Liquidity Risk

- Liquidity risk refers to the risk that Manitoba Hydro will not have sufficient cash or cash equivalents to meet its financial obligations as they come due.
- Manitoba Hydro will meet its financial obligations when due through cash generated from operations, short term borrowings, long term borrowings, and where applicable, sinking fund withdrawals.
- Manitoba Hydro can issue short term borrowings in the name of the Manitoba Hydro-Electric Board up to a limit of $500 million.

Liquidity Risk

- During a severe prolonged drought Manitoba Hydro would provide sufficient cash flows for the continuity of business operations and Manitoba Hydro's self-supporting status.
- Liquidity measures include:

1. Cash conservation. Manitoba Hydro would curtail or delay operating and capital expenditures as required and appropriate. In severe circumstances, this may include exercising the optionality available within the development plan pathways.
2. Bridge financing. Manitoba Hydro could draw upon its $500 million short term borrowing program and/or access the capital markets for shorter dated debt financings that could be retired upon the resumption of positive cash flow from operations.
3. Increase cash inflows through rate increases. Should circumstances warrant, Manitoba Hydro could apply for higher rate increases in order to generate additional cash inflows.

View from the Credit Rating Agencies

(2) **Low-cost hydro-based generation.** Low-cost hydroelectric-based generating capacity results in one of the lowest variable cost structures in North America, which has enabled Manitoba Hydro to provide electricity to its domestic customers at one of the lowest rates on the continent. This gives the Utility the flexibility to increase rates in the future, especially in light of the substantially heightened future capital expenditure requirements.

From the **Dominion Bond Rating Service (DBRS)** credit rating report on the Manitoba Hydro-Electric Board dated September 16, 2013; page 2 (highlighting added). For the full report see PUB/MH I-85(b), Attachment 1]

View from the Credit Rating Agencies

Significant Borrowing for Manitoba Hydro, but Self-Supported

Roughly one third of the province's total direct and indirect debt is attributed to Manitoba Hydro (issued and on-lent by the province) and is considered to be self-supporting. This Crown Corporation's ability to meet its own financial obligations without recourse to provincial subsidies is a positive credit attribute for the province. In our view, the likelihood that the contingent liability represented by Manitoba Hydro's debt would materialize remains relatively remote.

[From the **Moody's** Investors Service credit rating report on the Province of Manitoba dated July 23, 2013; page 3 (highlighting added). For the full report, see PUB/MH I-85(b), Attachment 4].

View from the Credit Rating Agencies

FINANCIAL TARGETS TO BE CHALLENGED BY HIGHER CAPEX

As part of its debt management strategy, Manitoba Hydro targets certain financial metrics such as an interest coverage ratio greater than 1.2 and equity-to-capitalization greater than 25%. With new generation and transmission projects underway, such as Bipole III, Keeyask and Conawapa, total capital expenditures are forecasted to be $20.7 billion, or on average $2 billion per year from FY2014 to FY2023. About one third of the total planned capex will be funded by internally generated cash from operations, leaving the rest to debt financing. New debt financing will ramp up in FY2014 and peak in FY2018 and FY2022, at an annual average of approximately $1.7 billion. Given the uptick in capex and corresponding debt, financial metrics are predicted to fall below targets in the next three fiscal years. The equity ratio, in particular, will be challenged and not likely to return to target until FY2032. The weakening financial profile restricts financial flexibility and adds risk in case of unexpected events such as low water levels, cost overruns and construction delays, given the nature of a hydroelectric plant's long construction cycle before cash generating begins. However, we view Manitoba Hydro as being capable of prudently managing debt and mitigating such risks by seeking rate increases and curtailing capital spending to continue as a self-supporting corporation.

[From the **Moody's** Investors Service credit rating report on the Manitoba Hydro-Electric Board dated September 23, 2013; page 2 (highlighting added). For the full report, see PUB/MH I-85(b), Attachment 3].

Financial Risk Summary

1. Manitoba Hydro considers business risk as an integral aspect of its plans and operations.
2. Manitoba Hydro's financial risk is manageable.
3. Manitoba Hydro will continue to take appropriate actions to ensure its debt remains self-supporting.

Tab 148

2017/18 & 2018/19 ELECTRIC GENERAL RATE APPLICATION

Follow-Up Questions to Manitoba Hydro Undertaking Nos. 7 & 8 from Counsel for MIPUG (email dated December 21, 2017)

On December 21, 2017, MIPUG requested the following:

1. Please provide the data values, by year, used to generate Undertaking 8.

2. Add a line (scenario) to Undertaking 8 (the 1990 base scenario) that is based on an IFF as follows (please provide the underlying IFF 6 page financial forecast scenario as well):
   a) IFF16 Update with Interim assumptions, except where noted.
   b) 12 year WATM
   c) Overhead accruals at $20M continue throughout, amortized at 30 year rate (consistent with PUB/MH-I-1(e))
   d) Depreciation at ASL throughout, no amortization of difference with ELG.
   e) Rate increases as necessary consistent with the approach in Coalition-MH-II-19 (i.e., equal annual increases to target 75:25 by 2035/36)
   f) Make sure the graph goes out to 2035/36.
   g) Please also provide the summary data for this scenario as per Undertaking #9 page 2 (i.e., max net debt, etc.)

Response:

Notwithstanding the concerns outlined below, Manitoba Hydro is providing the data values included in Undertaking No. 8 and the projected financial statements, including data values, reflecting the December 21, 2017 MIPUG Scenario.

As noted in the responses to PUB/MH II-21 and PUB/MH II-28, Manitoba Hydro's financial plan reflects a goal to return to its target 25% equity to capitalization ratio in 10 years and believes limited value should be ascribed to forecasts a decade or more in the future. The potential for volatility in key assumptions, many of which are beyond Manitoba Hydro's ability to control, reduces the second half of a 20 year forecast to little more than a hypothetical modeling exercise.

Manitoba Hydro maintains all the same concerns outlined in PUB/MHI-1d) and e) related to items c) and d) of MIPUG's request. Furthermore, the 12 Year WATM in Manitoba Hydro's debt management strategy is justifiable only if there is a reasonable expectation of sufficient cash flow to retire the repositioned debt. The sufficient cash flow stems from the path of higher rate increases in MH16 Update with Interim and not from the rate path included in the scenario requested by MIPUG and presented below.

The table below outlines the accounting treatment in MH16 Update with Interim, and the assumptions in part c) and d), of the MIPUG scenario.

	MH16 Update with Interim	**MIPUG Scenario Dec 21/17**
Ineligible Overhead		
Ineligible Overhead Annual Provision	$20 million	$20 million
Ineligible Overhead Amortization Period	20 years	30 years
Ineligible Overhead Deferral Until	2022/23	Indefinite
Equal Life Group (ELG)/Average Service Life (ASL)		
ELG/ASL Amortization Period	20 years	None
ELG/ASL Deferred Until	2022/23	Indefinite

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MIPUG Scenario December 21, 2017
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	110	168	228	292	357	425	498	577	660
BPIII Reserve Account	(96)	(151)	3	79	79	79	79	26	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 178	2 251	2 443	2 642	2 791	2 816	2 891	2 845	2 949
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	749	831	907	1 159	1 205	1 213	1 211	1 226
Finance Income	(17)	(17)	(21)	(28)	(35)	(33)	(37)	(13)	(12)	(13)	(14)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	166	174	175	176	177	177
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 660	2 406	2 533	2 869	2 965	3 006	3 022	3 069
Net Income before Net Movement in Reg. Deferral	(46)	13	27	(409)	38	109	(78)	(149)	(115)	(177)	(120)
Net Movement in Regulatory Deferral	66	72	115	473	82	78	59	50	50	51	55
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	142	64	120	187	(19)	(99)	(66)	(126)	(65)
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	94	143	61	115	178	(29)	(111)	(69)	(128)	(68)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**94**	**143**	**61**	**115**	**178**	**(29)**	**(111)**	**(69)**	**(128)**	**(68)**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	142	64	120	187	(19)	(99)	(66)	(126)	(65)
* Additional Domestic Revenue											
Percent Increase		3.36%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
Cumulative Percent Increase		3.36%	7.05%	10.87%	14.82%	18.92%	23.16%	27.56%	32.11%	36.82%	41.70%
Financial Ratios											
Equity	16%	15%	14%	14%	13%	14%	13%	13%	12%	12%	12%
EBITDA Interest Coverage	1.51	1.54	1.64	1.58	1.62	1.69	1.58	1.52	1.57	1.53	1.58
Capital Coverage	1.53	1.40	1.35	1.18	1.41	1.64	1.33	1.27	1.24	1.12	1.20

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
MIPUG Scenario December 21, 2017
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	747	839	936	1 038	1 152	1 273	1 401	1 538	1 682
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 045	3 167	3 301	3 433	3 569	3 714	3 866	4 029	4 111
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 239	1 242	1 234	1 255	1 242	1 240	1 228	1 195	1 161
Finance Income	(16)	(21)	(19)	(15)	(16)	(17)	(22)	(23)	(25)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	179	180	181	183	184	186	188	189	196
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	3 111	3 142	3 170	3 231	3 232	3 265	3 286	3 296	3 288
Net Income before Net Movement in Reg. Deferral	(66)	25	131	202	337	449	580	733	823
Net Movement in Regulatory Deferral	57	61	67	69	72	75	76	76	75
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	(9)	86	197	271	409	525	655	809	899
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	(13)	81	190	261	398	512	641	793	883
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**(13)**	**81**	**190**	**261**	**398**	**512**	**641**	**793**	**883**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	(9)	86	197	271	409	525	655	809	899
* Additional Domestic Revenue									
Percent Increase	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%	3.57%
Cumulative Percent Increase	46.76%	52.00%	57.42%	63.04%	68.85%	74.88%	81.12%	87.58%	94.27%
Financial Ratios									
Equity	12%	12%	13%	14%	15%	17%	19%	22%	25%
EBITDA Interest Coverage	1.63	1.72	1.82	1.87	2.01	2.11	2.25	2.42	2.56
Capital Coverage	1.29	1.39	1.57	1.61	1.81	1.95	2.12	2.12	2.21

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MIPUG Scenario December 21, 2017
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 199	2 477	2 505	1 928	1 682	1 681	1 628	1 770	1 744
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 057	28 431	29 997	30 109	30 103	30 051	29 940	30 035	29 969
Regulatory Deferral Balance	462	534	649	1 121	1 204	1 281	1 340	1 390	1 440	1 491	1 546
	21 733	24 839	27 706	29 552	31 200	31 390	31 443	31 442	31 380	31 526	31 515
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 389	23 394	23 650	24 862	24 735	24 447	24 186	25 228
Current and Other Liabilities	3 204	3 643	3 047	3 816	4 359	4 147	3 027	3 184	3 468	3 993	2 998
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	344	265	185	106	26	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	2 986	3 047	3 162	3 340	3 311	3 200	3 132	3 003	2 935
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(437)	(339)	(338)	(337)	(337)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 657	29 504	31 152	31 341	31 395	31 393	31 331	31 477	31 466
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 706	29 552	31 200	31 390	31 443	31 442	31 380	31 526	31 515
Net Debt	15 427	18 473	20 813	22 628	23 759	24 424	24 666	24 702	24 765	24 891	24 963
Total Equity	2 856	3 163	3 443	3 558	3 698	3 881	3 549	3 532	3 478	3 363	3 309
Equity Ratio	16%	15%	14%	14%	13%	14%	13%	13%	12%	12%	12%

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
MIPUG Scenario December 21, 2017
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 012	2 450	2 194	2 054	2 443	2 521	3 066	3 434	4 183
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 192	30 601	30 294	30 127	30 480	30 519	31 020	31 407	32 175
Regulatory Deferral Balance	1 603	1 664	1 731	1 800	1 871	1 947	2 022	2 098	2 174
	31 795	32 265	32 025	31 927	32 351	32 465	33 043	33 505	34 349
LIABILITIES AND EQUITY									
Long-Term Debt	25 560	23 583	21 090	22 750	22 713	23 363	23 080	23 459	23 543
Current and Other Liabilities	2 949	5 307	7 361	5 332	5 386	4 329	4 539	3 819	3 685
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	2 922	3 002	3 192	3 453	3 851	4 363	5 004	5 798	6 680
Accumulated Other Comprehensive Income	(337)	(337)	(337)	(337)	(337)	(337)	(337)	(337)	(337)
Total Liabilities and Equity before Regulatory Deferral	31 747	32 216	31 976	31 878	32 302	32 417	32 994	33 456	34 300
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 795	32 265	32 025	31 927	32 351	32 465	33 043	33 505	34 349
Net Debt	24 971	24 899	24 713	24 476	24 091	23 592	22 950	22 221	21 403
Total Equity	3 310	3 396	3 594	3 863	4 269	4 789	5 439	6 242	7 134
Equity Ratio	12%	12%	13%	14%	15%	17%	19%	22%	25%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MIPUG Scenario December 21, 2017
(In Millions of Dollars)

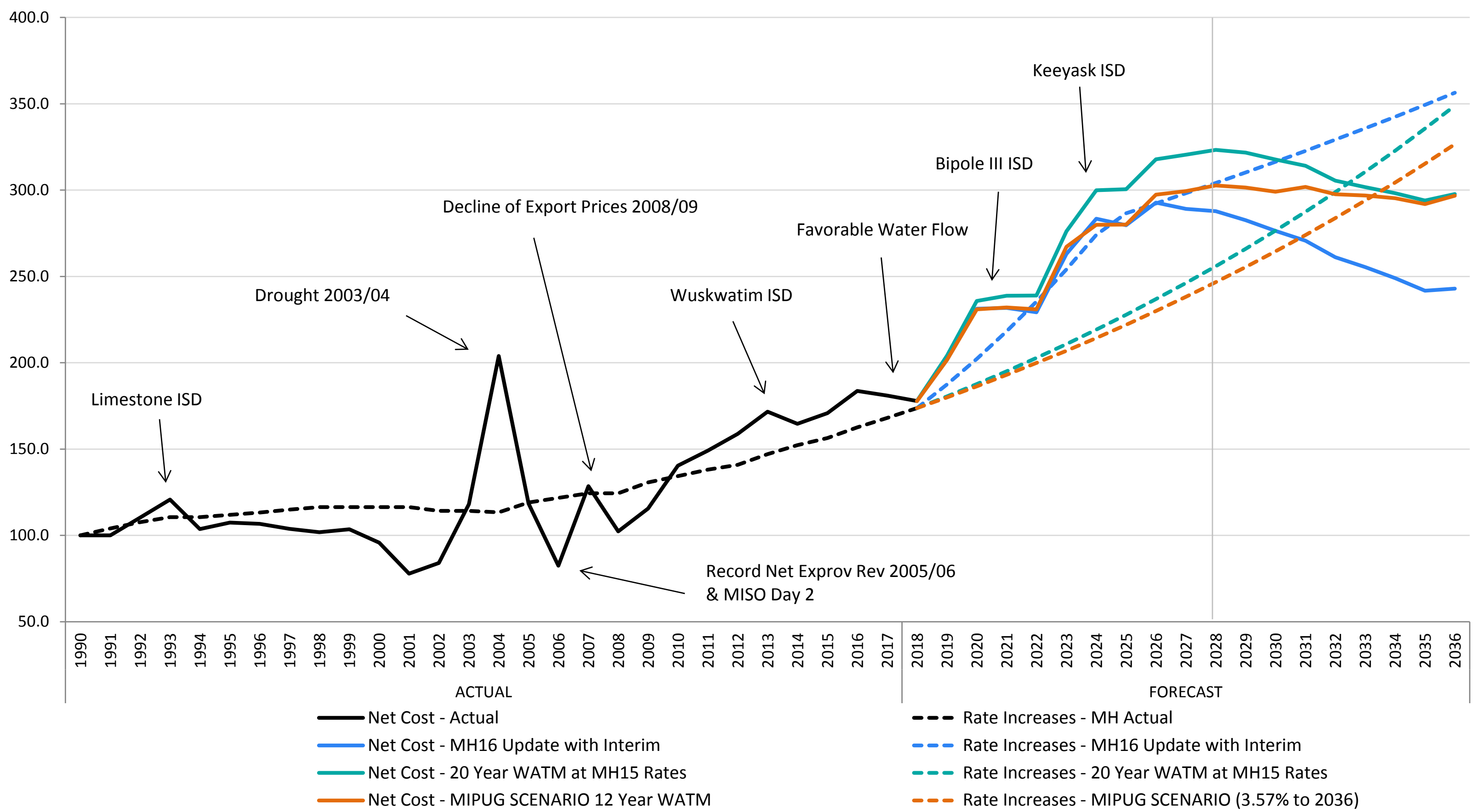
For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 164	2 160	2 352	2 550	2 699	2 777	2 878	2 833	2 936
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(916)	(934)	(934)	(948)
Interest Paid	(553)	(531)	(635)	(704)	(774)	(857)	(1 106)	(1 176)	(1 187)	(1 188)	(1 202)
Interest Received	17	5	11	22	26	19	6	4	6	5	7
	810	734	697	608	718	817	695	690	763	715	792
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 360	2 390	1 390	1 560	390	390	950	1 190
Sinking Fund Withdrawals	146	0	0	120	318	813	182	54	350	155	253
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(248)	(261)	(270)	(266)	(273)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 861	1 108	473	364	(111)	53	119	(13)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 659)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(720)	(724)	(752)	(776)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 748)	(3 059)	(2 437)	(1 850)	(1 477)	(997)	(816)	(820)	(834)	(858)
Net Increase (Decrease) in Cash	(309)	(146)	4	31	(23)	(187)	62	(237)	(3)	(0)	(78)
Cash at Beginning of Year	943	634	488	492	523	500	313	375	138	135	134
Cash at End of Year	634	488	492	523	500	313	375	138	135	134	56

Manitoba Hydro

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
MIPUG Scenario December 21, 2017
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 032	3 154	3 287	3 419	3 555	3 700	3 851	4 014	4 097
Cash Paid to Suppliers and Employees	(963)	(979)	(996)	(1 019)	(1 015)	(1 028)	(1 049)	(1 073)	(1 083)
Interest Paid	(1 216)	(1 232)	(1 239)	(1 246)	(1 226)	(1 237)	(1 224)	(1 210)	(1 175)
Interest Received	14	28	27	15	12	23	30	41	41
	867	972	1 079	1 169	1 326	1 458	1 609	1 773	1 880
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	390	390	1 970	3 990	2 350	1 940	1 160	1 100	570
Sinking Fund Withdrawals	150	60	510	540	0	230	51	10	463
Sinking Fund Payment	(274)	(282)	(291)	(278)	(266)	(276)	(274)	(282)	(289)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 373)	(2 390)	(1 284)	(1 487)	(665)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	111	103	(256)	(149)	(294)	(503)	(351)	(663)	74
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(787)	(818)	(813)	(852)	(860)	(877)	(890)	(968)	(986)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(867)	(893)	(884)	(925)	(933)	(948)	(960)	(1 036)	(1 053)
Net Increase (Decrease) in Cash	111	182	(62)	96	99	7	298	75	901
Cash at Beginning of Year	56	167	348	287	383	482	489	787	862
Cash at End of Year	167	348	287	383	482	489	787	862	1 763

MH16 Update with Interim Rate Increases and Net Cost/ Domestic Load



Manitoba Hydro

MH16 Update with Interim														
	Fiscal Year*	Rate Increase	Rate Increase Index	Total Expenses**	Winnipeg Hydro Revenue	Extra-Provincial	Other Revenue***	Non-Controlling Interest	Net Movement	Net Cost	Domestic Load (GWh)	Net Cost/MWh	Net Cost/MWh Yr over Yr Increase	Net Cost Index
				Millions of Dollars										
		A	B	C	D	E	F	G	H	I =C-D-E-F-G-H	J	K=I/J*1000	L	M
Actual	**1990**		**100**	$ 635	$ 47	$ 60	$ 2	$ -	$ -	$ 525	15 337	34		**100**
	1991	4.00%	**104**	650	50	67	4	-	-	529	15 447	34	0.1%	**100**
	1992	3.50%	**108**	735	54	97	3	-	-	582	15 397	38	10.2%	**110**
	1993	2.70%	**111**	843	53	143	3	-	-	644	15 577	41	9.5%	**121**
	1994	0.00%	**111**	851	53	232	3	-	-	564	15 870	36	-14.1%	**104**
	1995	1.20%	**112**	885	54	253	4	-	-	574	15 600	37	3.6%	**107**
	1996	1.20%	**113**	915	56	245	4	-	-	609	16 654	37	-0.7%	**107**
	1997	1.50%	**115**	922	50	268	5	-	-	599	16 851	36	-2.8%	**104**
	1998	1.30%	**116**	931	46	297	5	-	-	582	16 681	35	-1.8%	**102**
	1999	0.00%	**116**	982	48	326	7	-	-	600	16 929	35	1.6%	**104**
	2000	0.00%	**116**	976	42	376	11	-	-	547	16 696	33	-7.51%	**96**
	2001	0.00%	**116**	1 002	46	480	7	-	-	469	17 590	27	-18.7%	**78**
	2002	-1.92%	**114**	1 158	47	588	11	-	-	512	17 805	29	7.9%	**84**
	2003	0.00%	**114**	1 277	20	463	15	-	-	779	19 246	40	40.7%	**118**
	2004	-0.72%	**113**	1 715	-	351	18	-	-	1 346	19 280	70	72.6%	**204**
	2005	5.00%	**119**	1 370	-	554	15	-	-	801	19 735	41	-41.9%	**119**
	2006	2.25%	**122**	1 408	-	827	18	-	-	563	19 935	28	-30.4%	**83**
	2007	2.25%	**124**	1 511	-	592	16	-	-	902	20 510	44	55.7%	**128**
	2008	0.00%	**124**	1 370	-	625	8	-	-	738	21 061	35	-20.4%	**102**
	2009	5.00%	**131**	1 478	-	623	16	-	-	839	21 210	40	12.9%	**116**
	2010	2.84%	**134**	1 418	-	427	6	-	-	985	20 486	48	21.6%	**140**
	2011	2.80%	**138**	1 466	-	398	6	-	-	1 062	20 786	51	6.2%	**149**
	2012	2.00%	**141**	1 498	-	363	6	-	-	1 130	20 771	54	6.5%	**159**
	2013	4.40%	**147**	1 659	-	353	30	13	-	1 263	21 477	59	8.1%	**172**
	2014	3.50%	**152**	1 742	-	439	22	22	-	1 259	22 338	56	-4.1%	**165**
	2015	2.75%	**156**	1 779	-	384	30	11	41	1 313	22 458	58	3.7%	**171**
	2016	3.95%	**163**	1 892	-	415	31	10	74	1 362	21 654	63	7.5%	**184**
	2017	3.36%	**168**	1 952	-	460	48	12	66	1 365	22 025	62	-1.4%	**181**
Forecast	**2018**	3.36%	**174**	1 995	-	514	30	8	72	1 371	22 510	61	-1.8%	**178**
	2019	7.90%	**187**	2 150	-	469	31	1	114	1 535	22 224	69	13.4%	**202**
	2020	7.90%	**202**	2 655	-	420	31	(2)	464	1 741	21 977	79	14.7%	**231**
	2021	7.90%	**218**	2 392	-	567	33	(5)	71	1 726	21 750	79	0.2%	**232**
	2022	7.90%	**235**	2 507	-	693	33	(9)	64	1 725	21 971	79	-1.1%	**229**
	2023	7.90%	**254**	2 822	-	779	34	(10)	43	1 977	21 940	90	14.8%	**263**
	2024	7.90%	**274**	2 893	-	788	34	(11)	(48)	2 130	21 947	97	7.7%	**283**
	2025	4.54%	**287**	2 904	-	805	35	(3)	(50)	2 117	22 103	96	-1.3%	**280**
	2026	2.00%	**292**	2 887	-	667	35	(2)	(49)	2 236	22 303	100	4.6%	**293**
	2027	2.00%	**298**	2 889	-	671	36	(3)	(45)	2 231	22 531	99	-1.2%	**289**
	2028	2.00%	**304**	2 894	-	662	36	(4)	(44)	2 243	22 758	99	-0.5%	**288**
	2029	2.00%	**310**	2 892	-	677	37	(5)	(40)	2 223	22 976	97	-1.8%	**283**
	2030	2.00%	**316**	2 888	-	697	38	(8)	(35)	2 196	23 204	95	-2.2%	**276**
	2031	2.00%	**323**	2 878	-	709	38	(10)	(33)	2 173	23 443	93	-2.1%	**271**
	2032	2.00%	**329**	2 833	-	705	39	(11)	(31)	2 130	23 819	89	-3.5%	**261**
	2033	2.00%	**336**	2 818	-	701	40	(13)	(28)	2 118	24 216	87	-2.2%	**255**
	2034	2.00%	**342**	2 792	-	696	40	(14)	(28)	2 099	24 614	85	-2.5%	**249**
	2035	2.00%	**349**	2 762	-	694	40	(15)	(28)	2 071	25 024	83	-2.9%	**242**
	2036	2.00%	**356**	2 714	-	602	41	(16)	(30)	2 117	25 442	83	0.5%	**243**

* CGAAP 2000-2014, IFRS 2015-2027
** Includes Water Rentals & Assessments and Fuel and Power Purchased
***2017 includes $20 million non-recurring gain

Manitoba Hydro

MH16 Update with Interim with 20 Year WATM and MH15 Rates														
	Fiscal Year*	Rate Increase	Rate Increase Index	Total Expenses**	Winnipeg Hydro Revenue	Extra-Provincial	Other Revenue***	Non-Controlling Interest	Net Movement	Net Cost	Domestic Load (GWh)	Net Cost/MWh	Net Cost/MWh Yr over Yr Increase	Net Cost Index
				Millions of Dollars										
		A	B	C	D	E	F	G	H	I =C-D-E-F-G-H	J	K=I/J*1000	L	M
Actual	**1990**		**100**	$ 635	$ 47	$ 60	$ 2	$ -	$ -	$ 525	15 337	34		**100**
	1991	4.00%	**104**	650	50	67	4	-	-	529	15 447	34	0.1%	**100**
	1992	3.50%	**108**	735	54	97	3	-	-	582	15 397	38	10.2%	**110**
	1993	2.70%	**111**	843	53	143	3	-	-	644	15 577	41	9.5%	**121**
	1994	0.00%	**111**	851	53	232	3	-	-	564	15 870	36	-14.1%	**104**
	1995	1.20%	**112**	885	54	253	4	-	-	574	15 600	37	3.6%	**107**
	1996	1.20%	**113**	915	56	245	4	-	-	609	16 654	37	-0.7%	**107**
	1997	1.50%	**115**	922	50	268	5	-	-	599	16 851	36	-2.8%	**104**
	1998	1.30%	**116**	931	46	297	5	-	-	582	16 681	35	-1.8%	**102**
	1999	0.00%	**116**	982	48	326	7	-	-	600	16 929	35	1.6%	**104**
	2000	0.00%	**116**	976	42	376	11	-	-	547	16 696	33	-7.51%	**96**
	2001	0.00%	**116**	1 002	46	480	7	-	-	469	17 590	27	-18.7%	**78**
	2002	-1.92%	**114**	1 158	47	588	11	-	-	512	17 805	29	7.9%	**84**
	2003	0.00%	**114**	1 277	20	463	15	-	-	779	19 246	40	40.7%	**118**
	2004	-0.72%	**113**	1 715	-	351	18	-	-	1 346	19 280	70	72.6%	**204**
	2005	5.00%	**119**	1 370	-	554	15	-	-	801	19 735	41	-41.9%	**119**
	2006	2.25%	**122**	1 408	-	827	18	-	-	563	19 935	28	-30.4%	**83**
	2007	2.25%	**124**	1 511	-	592	16	-	-	902	20 510	44	55.7%	**128**
	2008	0.00%	**124**	1 370	-	625	8	-	-	738	21 061	35	-20.4%	**102**
	2009	5.00%	**131**	1 478	-	623	16	-	-	839	21 210	40	12.9%	**116**
	2010	2.84%	**134**	1 418	-	427	6	-	-	985	20 486	48	21.6%	**140**
	2011	2.80%	**138**	1 466	-	398	6	-	-	1 062	20 786	51	6.2%	**149**
	2012	2.00%	**141**	1 498	-	363	6	-	-	1 130	20 771	54	6.5%	**159**
	2013	4.40%	**147**	1 659	-	353	30	13	-	1 263	21 477	59	8.1%	**172**
	2014	3.50%	**152**	1 742	-	439	22	22	-	1 259	22 338	56	-4.1%	**165**
	2015	2.75%	**156**	1 779	-	384	30	11	41	1 313	22 458	58	3.7%	**171**
	2016	3.95%	**163**	1 892	-	415	31	10	74	1 362	21 654	63	7.5%	**184**
	2017	3.36%	**168**	1 952	-	460	48	12	66	1 365	22 025	62	-1.4%	**181**
Forecast	**2018**	3.36%	**174**	1 998	-	514	30	8	72	1 374	22 510	61	-1.8%	**178**
	2019	3.95%	**181**	2 171	-	469	31	1	114	1 556	22 224	70	14.7%	**204**
	2020	3.95%	**188**	2 692	-	420	31	(2)	464	1 778	21 977	81	15.6%	**236**
	2021	3.95%	**195**	2 449	-	567	33	(5)	71	1 783	21 750	82	1.3%	**239**
	2022	3.95%	**203**	2 584	-	693	33	(9)	64	1 802	21 971	82	0.0%	**239**
	2023	3.95%	**211**	2 925	-	779	34	(10)	43	2 080	21 940	95	15.6%	**276**
	2024	3.95%	**219**	3 022	-	788	34	(11)	(48)	2 259	21 947	103	8.6%	**300**
	2025	3.95%	**228**	3 067	-	805	35	(3)	(50)	2 280	22 103	103	0.2%	**301**
	2026	3.95%	**237**	3 085	-	667	35	(2)	(49)	2 433	22 303	109	5.8%	**318**
	2027	3.95%	**246**	3 136	-	671	36	(3)	(45)	2 478	22 531	110	0.8%	**320**
	2028	3.95%	**256**	3 176	-	662	36	(4)	(44)	2 525	22 758	111	0.9%	**323**
	2029	3.95%	**266**	3 206	-	677	37	(6)	(40)	2 537	22 976	110	-0.5%	**322**
	2030	3.95%	**277**	3 223	-	697	38	(8)	(35)	2 531	23 204	109	-1.2%	**318**
	2031	3.95%	**287**	3 232	-	709	38	(10)	(33)	2 527	23 443	108	-1.1%	**314**
	2032	3.95%	**299**	3 199	-	705	39	(11)	(31)	2 497	23 819	105	-2.8%	**305**
	2033	3.95%	**311**	3 207	-	701	40	(13)	(28)	2 507	24 216	104	-1.2%	**302**
	2034	3.95%	**323**	3 213	-	696	40	(14)	(28)	2 519	24 614	102	-1.1%	**298**
	2035	3.95%	**336**	3 214	-	694	40	(16)	(28)	2 524	25 024	101	-1.4%	**294**
	2036	3.95%	**349**	3 197	-	602	41	(16)	(30)	2 600	25 442	102	1.3%	**298**

* CGAAP 2000-2014, IFRS 2015-2027

** Includes Water Rentals & Assessments and Fuel and Power Purchased

***2017 includes $20 million non-recurring gain

Manitoba Hydro

MIPUG DECEMBER 21, 2017 SCENARIO

	Fiscal Year*	Rate Increase	Rate Increase Index	Total Expenses**	Winnipeg Hydro Revenue	Extra-Provincial	Other Revenue***	Non-Controlling Interest	Net Movement	Net Cost	Domestic Load (GWh)	Net Cost/MWh	Net Cost/MWh Yr over Yr Increase	Net Cost Index
				Millions of Dollars										
		A	B	C	D	E	F	G	H	I =C-D-E-F-G-H	J	K=I/J*1000	L	M
Actual	**1990**	0	**100**	$ 635	$ 47	$ 60	$ 2	$ -	$ -	$ 525	15 337	34	0.0%	**100**
	1991	4.00%	**104**	650	50	67	4	-	-	529	15 447	34	0.1%	**100**
	1992	3.50%	**108**	735	54	97	3	-	-	582	15 397	38	10.2%	**110**
	1993	2.70%	**111**	843	53	143	3	-	-	644	15 577	41	9.5%	**121**
	1994	0.00%	**111**	851	53	232	3	-	-	564	15 870	36	-14.1%	**104**
	1995	1.20%	**112**	885	54	253	4	-	-	574	15 600	37	3.6%	**107**
	1996	1.20%	**113**	915	56	245	4	-	-	609	16 654	37	-0.7%	**107**
	1997	1.50%	**115**	922	50	268	5	-	-	599	16 851	36	-2.8%	**104**
	1998	1.30%	**116**	931	46	297	5	-	-	582	16 681	35	-1.8%	**102**
	1999	0.00%	**116**	982	48	326	7	-	-	600	16 929	35	1.6%	**104**
	2000	0.00%	**116**	976	42	376	11	-	-	547	16 696	33	-7.51%	**96**
	2001	0.00%	**116**	1 002	46	480	7	-	-	469	17 590	27	-18.7%	**78**
	2002	-1.92%	**114**	1 158	47	588	11	-	-	512	17 805	29	7.9%	**84**
	2003	0.00%	**114**	1 277	20	463	15	-	-	779	19 246	40	40.7%	**118**
	2004	-0.72%	**113**	1 715	-	351	18	-	-	1 346	19 280	70	72.6%	**204**
	2005	5.00%	**119**	1 370	-	554	15	-	-	801	19 735	41	-41.9%	**119**
	2006	2.25%	**122**	1 408	-	827	18	-	-	563	19 935	28	-30.4%	**83**
	2007	2.25%	**124**	1 511	-	592	16	-	-	902	20 510	44	55.7%	**128**
	2008	0.00%	**124**	1 370	-	625	8	-	-	738	21 061	35	-20.4%	**102**
	2009	5.00%	**131**	1 478	-	623	16	-	-	839	21 210	40	12.9%	**116**
	2010	2.84%	**134**	1 418	-	427	6	-	-	985	20 486	48	21.6%	**140**
	2011	2.80%	**138**	1 466	-	398	6	-	-	1 062	20 786	51	6.2%	**149**
	2012	2.00%	**141**	1 498	-	363	6	-	-	1 130	20 771	54	6.5%	**159**
	2013	4.40%	**147**	1 659	-	353	30	13	-	1 263	21 477	59	8.1%	**172**
	2014	3.50%	**152**	1 742	-	439	22	22	-	1 259	22 338	56	-4.1%	**165**
	2015	2.75%	**156**	1 779	-	384	30	11	41	1 313	22 458	58	3.7%	**171**
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	2017	3.36%	**168**	1 952	-	460	48	12	66	1 365	22 025	62	-1.4%	**181**
Forecast	**2018**	3.36%	**174**	1 995	-	514	30	8	72	1 370	22 510	61	-1.8%	**178**
	2019	3.57%	**180**	2 150	-	469	31	1	115	1 534	22 224	69	13.4%	**202**
	2020	3.57%	**186**	2 660	-	420	31	(2)	473	1 738	21 977	79	14.5%	**231**
	2021	3.57%	**193**	2 406	-	567	33	(5)	82	1 729	21 750	79	0.5%	**232**
	2022	3.57%	**200**	2 533	-	693	33	(9)	78	1 738	21 971	79	-0.5%	**231**
	2023	3.57%	**207**	2 869	-	779	34	(10)	59	2 007	21 940	91	15.7%	**267**
	2024	3.57%	**214**	2 965	-	788	34	(11)	50	2 104	21 947	96	4.8%	**280**
	2025	3.57%	**222**	3 006	-	805	35	(3)	50	2 120	22 103	96	0.0%	**280**
	2026	3.57%	**230**	3 022	-	667	35	(2)	51	2 271	22 303	102	6.2%	**297**
	2027	3.57%	**238**	3 069	-	671	36	(3)	55	2 311	22 531	103	0.7%	**299**
	2028	3.57%	**247**	3 111	-	662	36	(4)	57	2 359	22 758	104	1.1%	**303**
	2029	3.57%	**255**	3 142	-	677	37	(5)	61	2 373	22 976	103	-0.4%	**302**
	2030	3.57%	**265**	3 170	-	697	38	(8)	67	2 376	23 204	102	-0.8%	**299**
	2031	3.57%	**274**	3 231	-	709	38	(10)	69	2 424	23 443	103	0.9%	**302**
	2032	3.57%	**284**	3 232	-	705	39	(11)	72	2 427	23 819	102	-1.4%	**298**
	2033	3.57%	**294**	3 265	-	701	40	(13)	75	2 462	24 216	102	-0.2%	**297**
	2034	3.57%	**304**	3 286	-	696	40	(14)	76	2 489	24 614	101	-0.5%	**295**
	2035	3.57%	**315**	3 296	-	694	40	(15)	76	2 501	25 024	100	-1.2%	**292**
	2036	3.57%	**327**	3 288	-	602	41	(16)	75	2 585	25 442	102	1.7%	**297**

* CGAAP 2000-2014, IFRS 2015-2027
** Includes Water Rentals & Assessments and Fuel and Power Purchased
***2017 includes $20 million non-recurring gain

To note, in Appendix 1.6 in Manitoba Hydro's Rebuttal Evidence, 3.95% rate increases to 2035/36 results in a 27% equity ratio in that year. Targeting a 25% equity ratio in 2035/36 would yield even annual rate increases of 3.88%. The table below breaks down the impacts of MIPUG's accounting and debt terming assumptions to arrive at 3.57%.

Assumption	**Scenario**	**Even Annual Rate Impact from 2018/19 - 2035/36**	**Even Annual Rate Increase from 2018/19 - 2035/36**
Targeting 25% Equity in 2035/36	MH16 Update with Interim with 20 Year Debt		3.88%
MIPUG's Accounting Changes	MH16 Update with Interim with 20 Year Debt and MIPUG Scenario Ineligible Overhead and ELG/ASL Assumptions	- (0.16%)	3.72%
Debt Terming	MH16 Update with Interim with 12 Year Debt and MIPUG Scenario Ineligible Overhead and ELG/ASL Assumptions	- (0.15%)	3.57%

As requested, the summary data for the December 21, 2017 MIPUG Scenario has been added to the table shown on page 2 of Undertaking #9. The updated table is provided below.

	Long Term Rate Increase	25% Equity Ratio	Maximum Long-Term Debt	Minimum Equity	Negative Net Income	Retained Earnings at 2033/34	Maximum Net Debt
NFAT Plan 5 - High Keeyask Level 2 DSM	3.95% in 2014/15; 3.99% 2015/16 to 2031/32	2031/32	$22.490 B in 2023/24	8% in 2021/22 - 2023/24	Total of $638 M in 8 years during 2015/16 - 2022/23	$6.659 B	$21.606 B in 2022/23
MH14	3.95% 2015/16 to 2030/31	2033/34	$24.476 B in 2028/29	10% in 2022/23 - 2026/27	Total of $977 M in 8 years during 2018/19 - 2025/26	$5.557 B	$23.227 B in 2024/25
MH15	3.95% 2016/17 to 2028/29	2031/32	$23.495 B in 2026/27	12% in 2021/22 - 2023/24	Total of $58 M in 3 years during 2018/19 - 2022/23	$7.402 B	$22.589 B in 2021/22
Coalition/MH II-19 (Based on MH16 Update with Interim)	3.36% in 2017/18; 4.14% 2018/19 to 2033/34	2033/34	$24.972 B in 2027/28	12% in 2025/26 - 2026/27	Total of $347 M in 4 years during 2023/24 - 2026/27	$6.385 B	$24.506 B in 2022/23
Coalition/MH II-19 20 Year WATM (Based on MH16 Update with Interim)	3.36% in 2017/18; 4.34% 2018/19 to 2033/34	2033/34	$25.315 B in 2028/29	11% in 2025/26 - 2026/27	Total of $507 M in 5 years during 2022/23 - 2026/27	$6.377 B	$24.692 B in 2025/26
MIPUG Scenario December 21, 2017	3.36% in 2017/18; 3.57% 2018/19 to 2035/36	2035/36	$25.560 B in 2027/28	12% in 2024/25 - 2028/29	Total of $418 M in 6 years during 2022/23 - 2026/27	$5.004 B	$24.971 B in 2027/28

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MANITOBA HYDRO
2019/20 ELECTRIC RATE APPLICATION

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MANITOBA HYDRO
2019/20 ELECTRIC RATE APPLICATION

1.0 OVERVIEW AND REASONS FOR THE REQUESTED RATE INCREASE

On May 5, 2017, Manitoba Hydro filed a comprehensive 2017/18 & 2018/19 General Rate Application ("GRA") with the Public Utilities Board of Manitoba ("PUB") and a lengthy and extensive review of Manitoba Hydro's operations, forecasts, financial plans, capital expenditures, and operating expenses was conducted over the course of nine months. Following its review, the PUB issued Order 59/18, dated May 1, 2018, which approved a 3.6% average electric rate increase effective June 1, 2018. Order 59/18 also contained a number of directives and recommendations requiring work to be undertaken and completed by Manitoba Hydro prior to filing its next GRA.

With the appointment of a new Manitoba Hydro-Electric Board ("MHEB"), a comprehensive review of Manitoba Hydro's operations, forecasts and financial plans is currently being undertaken to allow the MHEB to establish a long-term financial plan for the Corporation. As a result of the foregoing, and further to Manitoba Hydro's correspondence of November 12, 2018 and the PUB's correspondence of November 21, 2018, Manitoba Hydro is submitting to the PUB a one-year rate increase application for the 2019/20 fiscal year which is based on financial information currently approved by the MHEB for the 2018/19 and 2019/20 fiscal years as set forth in its letter of November 12, 2018. Upon the MHEB's development and approval of a long-term financial plan, Manitoba Hydro will submit a full GRA to the PUB, anticipated to be filed in late 2019. A fulsome review of Manitoba Hydro's responses to those directives contained in Order 59/18 which the PUB indicated in its November 21, 2018 correspondence would be deferred, will also be addressed as part of the next GRA.

In this Application, Manitoba Hydro is requesting an Order pursuant to section 25(1) of *The Crown Corporations Governance and Accountability Act* for final approval of a 3.5% rate increase for all customer classes to be effective April 1, 2019. As shown in Appendix 1, page 1, this increase is projected to generate additional revenues of $59 million and would result in a modest contribution to financial reserves (net income) of $31 million in 2019/20. Absent the proposed rate increase for 2019/20, Manitoba Hydro is projecting a net loss of $28 million from Electric operations based on current assumptions.

As noted by the PUB in Order 59/18 (page 173):

> *The Integrated Financial Forecast filed in the proceeding as Manitoba Hydro Exhibit 93 supports the Board's decision on the level of the overall rate increase. This financial scenario included: continued deferral of $20 million in ineligible overheads, amortized at a 30-year rate; Average Service Life depreciation methodology, without amortization of the difference with the Equal Life Group methodology; achievement of a 25% equity level over a longer period of time, specifically by 2035/36; and debt management based on a weighted average term to maturity of 12 years. In many respects, and as a departure from Manitoba Hydro's plan and Integrated Financial Forecast assumptions, Manitoba Hydro Exhibit 93 is therefore reflective of many of the Board's decisions in this Order.*

Considering the MHEB is undertaking a comprehensive review of Manitoba Hydro's operations, forecasts and financial plans to allow for the establishment of a long-term financial plan for the Corporation, for purposes of its rate request for the 2019/20 fiscal year, Manitoba Hydro has noted the PUB's comment regarding Manitoba Hydro Exhibit 93 from the 2017/18 & 2018/19 GRA ("Exhibit 93") and prepared the current Application utilizing a comparison to Exhibit 93.

Since Order 59/18 was issued, Manitoba Hydro's cumulative earnings (actual and projected) over the three year period 2017/18 to 2019/20 have deteriorated by nearly $200 million compared to Exhibit 93 as shown in the following Figure 1.1.

Figure 1.1: Comparison of Actual and Projected Net Income to Exhibit 93
(In Millions of Dollars)

	2017/18	2018/19	2019/20	Total
Actual & Projected Net Income	18 [1]	51 [2]	31 [3]	100
Exhibit 93 Net Income [4]	94	143	61	298
Increase/(Decrease)	(75)	(93)	(30)	(198)

[1] 2017/18 Actual net income (Section 2.1)
[2] 2018/19 Financial Outlook (Section 2.3)
[3] 2019/20 Interim Budget including 3.5% proposed rate increase (Section 2.4)
[4] Includes a projected 3.57% rate increase

Actual net income results for 2017/18 were lower than anticipated in Exhibit 93 mainly due to lower export prices, the impact of U.S. transmission outages which led to lower volumes and a higher proportion of off peak sales at lower prices, as well as higher net finance costs.

The outlook for 2018/19 net income is also much lower compared to Exhibit 93 which is primarily attributable to lower net export revenues as a result of below average water conditions impacting generation, as well as increases in depreciation and financing costs arising from the earlier than planned in-service of Bipole III, which went into service July 4, 2018 compared to a budgeted in-service date of July 31, 2018.

Exhibit 93 projected net income of $61 million for electric operations for the 2019/20 fiscal year. In comparison, the 2019/20 Interim Budget, which includes the proposed 3.5% rate increase requested in this application, projects net income of $31 million. The deterioration in projected net income for electric operations is mainly attributable to higher net financing costs. Exhibit 93 had assumed that Manitoba Hydro could take advantage of lower interest costs on debt issues with shorter terms to maturity. Since the 2017/18 & 2018/19 GRA, the interest rate yield curve has continued to flatten and the savings expected from shorter term borrowings are no longer available.

In the absence of the proposed 3.5% rate increase, a net loss of $28 million would be projected in 2019/20 under the same forecast assumptions, increasing the cumulative deterioration in earnings to approximately $260 million over the three year period from 2017/18 to 2019/20.

Exhibit 93, which assumed more favourable financial results and annual 3.57% rate increases, projected over $400 million in cumulative net financial losses over the six year period from 2022/23 to 2027/28 following the planned Keeyask in-service. Although Manitoba Hydro has not yet updated its longer term forecast, the lower than expected financial results in 2017/18 to 2019/20 compared to Exhibit 93 will exacerbate the losses projected in Exhibit 93. It follows that without the proposed 3.5% rate increase, the cumulative losses projected in Exhibit 93 following the Keeyask in-service will be even more significant.

Manitoba Hydro's net income has historically been extremely variable. Key drivers of net income such as water flow conditions, weather, interest rates and export prices are unpredictable and outside of Manitoba Hydro's control. Section 2.4.4 of this Application presents an analysis of the sensitivity of projected net income or losses for 2019/20 to key assumptions in the Interim Budget. Water flow conditions can vary projected net income for 2019/20 by as much as $360 million between the 10th and 90th percentile of net revenues under the 102 years of historic flow conditions. Colder or warmer winter weather can vary projected net income for 2019/20 by more than $60 million. With interest rates 1% above or below that forecasted, net income for the 2019/20 Interim Budget could vary by approximately $30 million. Export prices higher or lower than the reference forecast used in the 2019/20 Interim Budget can produce a variation of up to $50 million.

Without the proposed 3.5% rate increase, the likelihood of financial losses is greater given the variability of factors such as water, weather, interest rates and export prices. This potential annual variation in financial results and the deterioration in the Corporation's financial position relative to Exhibit 93 in the period leading up to the Keeyask in-service date also underscores the need for a reasonable rate increase in the 2019/20 fiscal year.

The requested 3.5% rate increase effective April 1, 2019 generates a modest level of net income under average water flow conditions that will assist in gradually building the revenue base and reduce the risk of the Corporation incurring a loss in 2019/20. The 3.5% requested rate increase is aligned with PUB-approved rate increases since 2015 and keeps Manitoba's customer rates and estimated bill impacts among the lowest in North America.

Section 2.0 of Manitoba Hydro's 2019/20 Electric Rate Application provides a summary of Manitoba Hydro's actual financial results for the 2017/18 fiscal year, its current financial position and financial outlook for 2018/19, as well as its Interim Budget and Planning Assumptions for the 2019/20 Test Year. Included in this discussion is an overview of Manitoba Hydro's current capital expenditure forecast and an update on the status of its Major New Generation and Transmission projects.

Section 3.0 provides updated rate schedules and customer bill impacts for the proposed rate increase, as well as a comparison of Manitoba Hydro's electricity rates to neighbouring jurisdictions. If approved, the April 1, 2019 rate increase would result in a \$3.30 increase in the monthly bill of a residential customer without electric space heat using 1,000 kilowatt-hours ("kWh") per month, and a \$6.30 increase in the monthly bill for a residential customer with electric space heat using 2,000 kWh per month.

Throughout this Application, Manitoba Hydro has also provided a brief update on certain directives and recommendations of the PUB as outlined in its Order 59/18. As noted above, further review of PUB directives will be addressed at the next full GRA filed by Manitoba Hydro.

2.0 MANITOBA HYDRO'S FINANCIAL POSITION AND OUTLOOK

Section 2.0 provides analyses of the actual and forecast revenues and expenses related to Manitoba Hydro's electric operations for 2017/18 to 2019/20.

Manitoba Hydro's Financial Outlook for 2018/19 and the 2019/20 Interim Budget form the basis of the current one-year rate application for a 3.5% average revenue increase effective April 1, 2019. Manitoba Hydro's financial results are prepared in accordance with International Financial Reporting Standards (IFRS).

2.1 2017/18 Actual Financial Results from Electric Operations

Section 2.1 compares 2017/18 actual financial results with Manitoba Hydro's 2017/18 Approved Budget. The 2017/18 Approved Budget, filed with the 2017/18 & 2018/19 GRA, was approved by the MHEB in March 2017 with MH16 for the purposes of financial reporting comparisons throughout the fiscal year and reflected a budgeted net income of $111 million.

Figure 2.1 below compares Manitoba Hydro's actual net income from Electric operations for the 2017/18 fiscal year of $18 million to the approved MH16 budget.

Figure 2.1: 2017/18 Actual Financial Results from Electric Operations Compared to the Approved Budget (MH16)

MANITOBA HYDRO
STATEMENT OF INCOME
For the Year Ended March 31, 2018
(In Millions of Dollars)

	ACTUAL	BUDGET	INCREASE (DECREASE)
Revenues			
Domestic revenue	$1 616	$1 657	($41)
BPIII Reserve Account	(152)	(119)	(33)
Extraprovincial	437	454	(17)
Other	30	30	-
	1 931	2 022	(91)
Expenses			
Operating and administrative	517	518	1
Net finance expense	578	558	(20)
Depreciation and amortization	402	396	(6)
Water rentals and assessments	126	124	(2)
Fuel and power purchased	130	135	5
Capital and other taxes	130	132	2
Other expenses	501	115	(386)
Corporate allocations	8	8	-
	2 393	1 987	(405)
Net income (loss) before net movement in regulatory balances	(462)	35	(496)
Net movement in regulatory balances	472	68	404
Net Income	**$10**	**$102**	**($92)**
Net income (loss) attributable to:			
Manitoba Hydro	**$18**	**$111**	**($93)**
Non-controlling interests	(8)	(9)	1
	$10	**$102**	**($92)**

Actual net income in 2017/18 was $93 million lower than budget primarily due to a 3.36% interim electric rate increase effective August 1, 2017 being granted as opposed to the 7.9% requested by Manitoba Hydro in its 2017/18 & 2018/19 GRA. The PUB directed that all revenues flowing from the 3.36% rate increase be added to the previously established Bipole III deferral account, to be recognized when Bipole III comes into service. Additionally, a continuation of weaker than forecast opportunity prices in the export market and higher financing costs also contributed to the lower than budgeted net income for 2017/18.

In addition to the impact of the lower than requested rate increase, actual domestic revenue was lower than budget as a result of the cooler summer weather which reduced air conditioning load, partially offset by higher customer usage (excluding weather impacts).

Actual extraprovincial revenues were lower than budget as export prices in the opportunity market did not reach forecasted levels. In addition, export volumes were lower than budget as a result of U.S. transmission outages leading to a higher proportion of off peak sales at lower prices.

The higher net finance expense reflects earlier than planned borrowings to take advantage of favourable market conditions, lower capitalized interest due to delayed capital spending as well as higher foreign exchange losses on U.S. cash balances resulting from the strengthening Canadian dollar. This was partially offset by higher interest income on pre-funded cash balances.

Actual other expenses were higher than budget primarily due to the transfer of the $379 million construction in progress balance related to the discontinuance of the Conawapa Generating Station project to a regulatory asset. The increase in other expenses, to a large degree, is offset in the net movement in regulatory balances (removed from the statement of income, deferred and subsequently amortized through net movement in regulatory balances). The regulatory asset will be amortized over 30 years as directed by the PUB in Order 59/18.

Exhibit 93 was filed as an update to MH16 for information purposes. Compared to the $111 million approved budget, the projected income for 2017/18 under Exhibit 93 was $94 million or $17 million lower due to the PUB's interim approval of the 3.36% rate increase compared to the 7.9% requested which was largely offset by a forecasted improvement in water flow conditions and weakening of the Canadian dollar resulting in higher forecast export revenues.

On an actual basis, 2017/18 net income was $75 million lower than forecast in Exhibit 93 as shown in Figure 2.2 below. The reduction in net income compared to Exhibit 93 was due to lower than forecast water flow conditions, as well as lower export prices and U.S. transmission outages described above, resulting in lower net export revenues.

Figure 2.2: 2017/18 Actual Financial Results from Electric Operations Compared to Exhibit 93

MANITOBA HYDRO
STATEMENT OF INCOME
For the Year Ended March 31, 2018
(In Millions of Dollars)

	ACTUAL	EXHIBIT 93	INCREASE (DECREASE)
Revenues			
Domestic revenue	$1,616	$1,615	$1
BPIII Reserve Account	(152)	(151)	(1)
Extraprovincial	437	514	(77)
Other	30	30	(0)
	1,931	2,008	(77)
Expenses			
Operating and administrative	517	518	1
Net finance expense	578	570	(8)
Depreciation and amortization	402	396	(6)
Water rentals and assessments	126	130	4
Fuel and power purchased	130	124	(6)
Capital and other taxes	130	132	2
Other expenses	501	116	(385)
Corporate allocations	8	8	0
	2,393	1,995	(397)
Net income (loss) before net movement in regulatory balances	(462)	13	(474)
Net movement in regulatory balances	472	72	400
Net Income	**$10**	**85**	**($74)**
Net income (loss) attributable to:			
Manitoba Hydro	**$18**	**$94**	**($75)**
Non-controlling interests	(8)	(8)	0
	$10	**$85**	**($74)**

The 67th Annual Report of the MHEB for the year ending March 31, 2018 can be found in Appendix 3.

Page 56 of the Annual Report provides Manitoba Hydro's Consolidated Statement of Cash Flows. As explained in Note 3(s) to the Financial Statements for the year ended March 31, 2018, the Corporation elected to present cash flows from operating activities using the indirect method as compared to the direct method used for the year ended March 31, 2017, which is consistent with other utilities in the electric industry and Manitoba Public Insurance. In addition, cash flows related to capitalized interest were reclassified from investing activities to operating activities. Both the indirect and direct cash flow methods and the reclassification of capitalized interest are acceptable under IFRS. In their Audit Findings report for the year ended March 31, 2018, Manitoba Hydro's independent external auditors (KPMG) concurred with the changes in presentation as noted above.

To assist with the comparison of the Consolidated Statement of Cash Flows for the year ended March 31, 2017, included in the 66th Annual Report of the MHEB filed as part of the 2017/18 & 2018/19 GRA, Manitoba Hydro has restated its Consolidated Statement of Cash Flows for the year ended March 31, 2018 under the Direct Method, and included it as Appendix 2 to this Application. As can be seen, regardless of whether the Indirect Method or Direct Method is used, the cash and cash equivalents at year end will remain the same.

2.2 2018/19 Actual Results to September 30, 2018 - Electric Operations

Manitoba Hydro's net loss from Electric operations for the first six months of the 2018/19 fiscal year was $32 million compared to a budgeted net loss of $37 million (which incorporated the 3.6% rate increase and accounting changes approved by the PUB effective June 1, 2018), as shown in the following Figure 2.3.

Figure 2.3: 2018/19 Actual Results to September 30, 2018 from Electric Operations

MANITOBA HYDRO
STATEMENT OF INCOME
For the Six Month Period Ended September 30, 2018
(In Millions of Dollars)

	ACTUAL	BUDGET	INCREASE (DECREASE)
Revenues			
Domestic revenue	$736	$707	$ 29
BPIII Reserve Account	(25)	(37)	12
Extraprovincial	249	250	(1)
Other	12	15	(3)
	972	935	37
Expenses			
Operating and administrative	249	249	-
Net finance expense	340	314	(26)
Depreciation and amortization	221	217	(4)
Water rentals and assessments	54	59	5
Fuel and power purchased	59	56	(3)
Capital and other taxes	71	71	-
Other expenses	46	36	(10)
Corporate allocations	4	4	-
	1 044	1 006	(38)
Net loss before net movement in regulatory balances	(72)	(71)	(1)
Net movement in regulatory balances	38	30	8
Net Loss	**($34)**	**($41)**	**$7**
Net loss attributable to:			
Manitoba Hydro	**($32)**	**($37)**	**$5**
Non-controlling interests	(2)	(4)	2
	($34)	**($41)**	**$7**

The net loss in the first six months of the 2018/19 fiscal year was lower than projected primarily due to favourable weather impacts partially offset by increased financing costs and depreciation expense associated with the earlier in-service date for Bipole III.

Actual domestic revenue was higher than budget primarily due to the impacts of weather, specifically warmer summer weather which increased air conditioning load and a cooler April and September which increased heating load. In addition, the earlier in-service date of Bipole III resulted in an increase in domestic revenue associated with the correspondingly earlier draw-down of the Bipole III deferral account into revenues.

Actual finance expense was higher than budget due to higher net interest on debt primarily as a result of Bipole III going into service earlier than projected as well as lower overall capital spending on the Bipole III project. In addition, there were unfavourable foreign exchange impacts resulting from the weakening Canadian dollar.

Actual depreciation and amortization expense reflect the impact of the earlier in-service date for Bipole III and therefore are higher than budget.

Actual fuel and power purchased was higher than budget due to a write off of coal inventory as a result of the Brandon Thermal Generating Station no longer being operational as a coal powered generator. This is partially offset by lower transmission charges due to redirecting transmission to lower cost nodes as well as lower purchased volumes.

Appendices 4 and 5 provide the MHEB Quarterly Reports for the three months ended June 30, 2018 and the six months ended September 30, 2018 respectively.

2.3 2018/19 Financial Outlook

As shown in Figure 2.4 below, Manitoba Hydro is projecting annual net income for Electric Operations of $51 million in the 2018/19 Financial Outlook compared to net income of $143 million projected in Exhibit 93. The 2018/19 Outlook incorporates actual financial results and water flow conditions to September 30, 2018 and assumes average water flow conditions and normal winter weather for the remainder of the year. The 2018/19 Outlook was reviewed and approved by the MHEB in late October for inclusion in this Application.

Figure 2.4: 2018/19 Financial Outlook Compared to Exhibit 93 for Electric Operations

MANITOBA HYDRO
STATEMENT OF INCOME
For the Year Ended March 31, 2019
(In Millions of Dollars)

	2018/19 OUTLOOK	EXHIBIT 93	INCREASE (DECREASE)
Revenues			
Domestic revenue	$1 701	$1 675	$ 26
BPIII Reserve Account	14	3	11
Extraprovincial	392	469	(77)
Other	30	31	(1)
	2 137	2 178	(41)
Expenses			
Operating and administrative	501	501	-
Net finance expense	708	656	(52)
Depreciation and amortization	473	471	(2)
Water rentals and assessments	113	120	7
Fuel and power purchased	138	140	2
Capital and other taxes	142	145	3
Other expenses	78	109	31
Corporate allocations	8	8	-
	2 161	2 150	(11)
Net income (loss) before net movement in regulatory balances	(24)	27	(52)
Net movement in regulatory balances	69	115	(46)
Net Income	**$45**	**$142**	**($98)**
Net income (loss) attributable to:			
Manitoba Hydro	**$51**	**$143**	**($93)**
Non-controlling interests	(6)	(1)	(5)
	$45	**$142**	**($98)**

The net income in the 2018/19 Outlook is $93 million lower compared to the net income from Exhibit 93 primarily due to lower net export revenues as well as an increase in financing costs partially offset by higher domestic revenue.

Domestic Revenue is $26 million higher than Exhibit 93 due to weather impacts (warmer summer weather which increased air conditioning load and a cooler April and September which increased heating load) as well as increased revenues associated with the earlier in-service date of Bipole III.

The decrease in Extraprovincial Revenue is primarily a result of below average water conditions impacting generation.

The increase of $52 million in Net Finance Expense is primarily attributable to higher forecasted interest rates. Subsequent to the filing of Exhibit 93 and during the course of the 2017/18 & 2018/19 GRA, the Bank of Canada interest rates rose such that the cost advantage to borrowing more shorter term maturities did not materialize. The yield curve continued to flatten such that there is now only a minimal difference between the all-in borrowing cost for a 5 year Province of Manitoba bond and a 30 year Province of Manitoba bond. As such, Manitoba Hydro reverted to a longer term borrowing strategy of targeting a 20 year weighted average term to maturity ("WATM") for new borrowings as opposed to the 12 year assumption in Exhibit 93. In addition, financing costs are higher due to the impacts of Bipole III going into service earlier than planned.

The Outlook for Other Expenses is $31 million lower compared to Exhibit 93, which is offset in net movement (the majority of other expenses are removed from the statement of income, deferred and subsequently amortized through net movement in regulatory balances). The remaining variance in net movement is primarily due to the annual amortization of the Conawapa deferral account which was not reflected in Exhibit 93 but was endorsed by the PUB in Order 59/18.

2.3.1 Water Conditions as of September 30, 2018

The total volume of water in reservoir storage was approximately 10% below average at the end of September. The water level on Lake Winnipeg, Manitoba Hydro's largest reservoir, was about one foot below historic average for the end of September period; this is approximately a 1 in 10 year low. This is in contrast to September 2017 when the water level on Lake Winnipeg was close to the historic average.

Following nine consecutive months of below average precipitation, water conditions began to improve in September particularly over the Winnipeg River and Lake Winnipeg local basins which were especially dry.

Manitoba Hydro expects water flows to be below average through the winter and overall hydraulic generation to be below average. In addition to inflow uncertainty, factors such as weather, export market prices and ice restrictions are drivers of revenue uncertainty for the remainder of the year.

Additional information on hydraulic generation, water conditions and extra-provincial energy exchange data is provided in Appendix 9.

2.3.2 Business Operations Capital – Recommendations of the PUB

At pages 110 and 111 of Order 59/18, the PUB concluded:

> *The Board finds that Business Operations Capital spending can be safely decreased by $160 million, based on Manitoba Hydro's evidence that it can defer $160 million of spending in the Test Year.*
>
> *…*
>
> *The Board recognizes that Order in Council 92/2017 does not give the Board authority to direct Manitoba Hydro to amend its planned Business Operations Capital spending. Rather the Board has factored into its rate decision the reduction in Business Operations Capital of $160 million. Manitoba Hydro can decide whether to accept the Board's findings and reduce its Test Year Business Operations Capital spending, or to incur additional debt in order to maintain spending at the proposed levels in CEF16.*
>
> *The reduction in spending on Business Operations Capital in no way diminishes Manitoba Hydro's responsibility and obligation to provide for an ongoing safe and reliable supply of energy to its customers in the most efficient and environmentally sensitive manner. The Board expects that Manitoba Hydro will appropriately assess, plan and prioritize Business Operations Capital spending in order to meet its obligations in this regard.*

The 2018/19 Financial Outlook includes the investment of $515 million for Business Operations Capital and represents the Corporation's best estimate of the expenses necessary to support the safe, sustainable and reliable operations in this period. To ensure sustainable, safe and reliable operation of the Manitoba Hydro system to the benefit of its customers, the projects identified in the 2018/19 Financial Outlook are projects which are active and cannot be cancelled without a cost to the safe and reliable services being provided. Manitoba Hydro will continue to assess active projects on an on-going basis which may impact timing, investments may be reduced accordingly.

2.3.3 Demand Side Management Deferral ("DSM") Account

In accordance with the PUB's direction in Orders 43/13 and 73/15, Manitoba Hydro established DSM deferral accounts for the years 2012/13 through to 2016/17 to capture the differences between planned and actual electric DSM spending. In Directive 23 of Order 59/18, the PUB directed Manitoba Hydro to discontinue the accounting practice of recognizing a DSM Deferral Account. As Order 59/18 was issued in advance of Manitoba Hydro finalizing its financial statements for the year ended March 31, 2018, for consistency with the PUB's direction in Order 59/18, Manitoba Hydro did not record the difference between its planned and actual DSM spending for the 2017/18 fiscal year to the deferral account.

As of March 31, 2018, $48.8 million had accrued to the DSM deferral account. Manitoba Hydro's 2018/19 Outlook assumes that the DSM deferred regulatory asset and corresponding credit will be written-off as of March 31, 2019. There will be no impact to net income as a result of the write-off as the deferred debit and credit accounts will completely offset each other. Manitoba Hydro has made a similar assumption with respect to its natural gas DSM Deferral Account, which will be reviewed by the PUB at Centra Gas Manitoba Inc.'s 2019/20 General Rate Application.

2.3.4 Regulatory Deferrals and Amortizations

Order 59/18 set out a number of directives for the following regulatory deferral accounts and related amortization periods: :

- Directive 17 - Manitoba Hydro continue to use its existing Average Service Life methodology for calculating depreciation rates for rate-setting purposes, without reversion to Equal Life Group in the financial forecast and not amortize the difference between Average Service Life and Equal Life Group for rate setting.

- Directive 19 - Manitoba Hydro to recognize the costs pertaining to the construction of the Conawapa Generating Station as a regulatory asset and amortize over a 30 year period.
- Directive 21 - Manitoba Hydro continue the annual deferral of $20 million in ineligible overhead. The regulatory account balance is to be amortized over 34 years.
- Directive 22 - Manitoba Hydro to begin recognizing the Bipole III Deferral Account in domestic revenues following the in-service date of Bipole III, amortized over a five-year period.

Manitoba Hydro has reflected the above-noted directives in the 2018/19 Financial Outlook and in the planning assumptions underlying the 2019/20 Interim Budget.

2.3.5 Demand Side Management Spending

Order 59/18 recommended that Manitoba Hydro reduce its demand side management programming and review it for cost effectiveness and cease or modify spending on programs that are no longer cost effective, except for programming targeted at lower-income and First Nations on-reserve customers.

In 2017, the Province of Manitoba tabled legislation, *The Efficiency Manitoba Act* ("The Efficiency Act") to create a new Crown Corporation to be known as Efficiency Manitoba which has a mandate to provide Demand Side Management programming. On January 24, 2018, excepting a few sections, The Efficiency Act was proclaimed and is now in effect. While Efficiency Manitoba is still in its formative stage, Manitoba Hydro continues to deliver Demand Side Management programs to meet the needs of Manitoba customers until the full transition occurs to Efficiency Manitoba. Until such time as the transition occurs and *The Energy Savings Act* has been repealed, the obligations of Manitoba Hydro to consult with the Minister to prepare a yearly energy efficiency plan remain in effect.

Manitoba Hydro's 2017/18 DSM plan filed with the PUB in response to PUB MFR 61 during the 2017/18 & 2018/19 GRA was the plan that Manitoba Hydro prepared in consultation with the Minister appointed to administer *The Energy Savings Act*. As the targets, programming and spending on energy efficiency and demand side management detailed in the reports filed with the PUB are set in consultation with the Government, these targets and spending cannot be unilaterally adjusted by Manitoba Hydro. As the 2018/19 Financial Outlook incorporates targets and spending assumptions set in consultation with Government, the PUB's recommendation to reduce DSM spending from its revenue requirement as a result of the new, lower marginal value has not been incorporated into the 2018/19 Financial Outlook.

2.4 2019/20 Interim Budget and Planning Assumptions

Manitoba Hydro's projected financial results and key financial and economic inputs underlying the 2019/20 Interim Budget are discussed in the following Sections.

2.4.1 2019/20 Interim Budget

Manitoba Hydro is projecting an annual net income for Electric Operations of $31 million for the 2019/20 fiscal year, inclusive of the 3.5% proposed rate increase, compared to net income of $61 million in Exhibit 93, as shown in the following Figure. The 2019/20 Interim Budget shown below in Figure 2.5 assumes average revenues and costs based on Manitoba Hydro's long term record of water and normal weather for the year.

Figure 2.5: Comparison of 2019/20 Interim Budget to Exhibit 93

	ELECTRIC OPERATIONS PROJECTED OPERATING STATEMENT (In Millions of Dollars)		
	Interim Budget	**Exhibit 93**	**Increase/ (Decrease)**
For the year ended March 31		**2020**	
REVENUES			
Domestic Revenue	1 737	1 720	17
BPIII Reserve Account	78	79	(1)
Extraprovincial	411	420	(9)
Other	29	31	(3)
	2 255	2 251	4
EXPENSES			
Operating and Administrative	511	511	(0)
Net Finance Expense	765	721	44
Depreciation and Amortization	508	515	(7)
Water Rentals and Assessments	111	110	1
Fuel and Power Purchased	160	158	2
Capital and Other Taxes	150	154	(4)
Other Expenses	111	481	(371)
Corporate Allocation	8	8	(0)
	2 325	2 660	(335)
Net Income before Net Movement in Reg. Deferral	(70)	(409)	339
Net Movement in Regulatory Deferral	103	473	(370)
Net Income	33	64	(30)
Net Income Attributable to:			
Manitoba Hydro	**31**	**61**	**(30)**
Non-controlling Interest	2	2	(1)
	33	64	(30)
Percent Increase	3.50%	3.57%	

The decrease in net income of $30 million is primarily attributable to higher finance expense partially offset by an increase in domestic revenue.

The increase in domestic revenue of $17 million reflects higher than anticipated load requirements in response to the PUB-approved 3.36% electricity rate increase in 2017/18 and lower forecast savings arising from program based DSM initiatives.

The increase of $44 million in net finance expense is primarily attributable to higher than forecasted interest rates. Exhibit 93 filed in the 2017/18 & 2018/19 GRA included savings of approximately $500 million due to lowering the WATM of new debt issuance from 20 years to 12 years in order to take advantage of borrowing rates in the short end of the yield curve. As discussed in Section 2.3, since Exhibit 93 was filed, the Bank of Canada has continued to raise interest rates. While yields have risen across all terms since the last forecasts were filed, the yield curve continued to flatten throughout 2018 and remains exceptionally flat. While the shape of the yield curve and interest rates themselves are subject to further change, the savings opportunity associated with shorter term borrowings continues to be substantially compromised.

The significant reduction in other expenses is offset in net movement and reflects the March 31, 2018 transfer of the $379 million construction in progress balance for the Conawapa Generating Station project compared to the planning assumption of April 1, 2019 in Exhibit 93.

2.4.2 2019/20 Planning Assumptions

The following provides a summary of the key financial and economic inputs underlying the 2019/20 Interim Budget including the Electric load forecast, forecast interest and foreign exchange rates, export prices and water flow conditions as well as assumptions with respect to Regulatory Deferrals.

<u>2019/20 General Consumer Sales (GW.h)</u>

General Consumer Sales includes the energy supplied to all of Manitoba Hydro's domestic customers. General Consumer Sales in the 2019/20 Interim Budget reflects the 2017 Electric Load Forecast adjusted for actual consumption experienced in 2017/18 and is compared to the 2017 Electric Load Forecast assumed in Exhibit 93. Manitoba Hydro is presently preparing the 2018 Electric Load Forecast which will be used in the preparation of MH19 and will be filed at the next General Rate

Application in late 2019. Planned additional savings are incorporated in the forecast of domestic revenue separately from the Load Forecast.

The future program based DSM savings incorporated in the 2019/20 Interim Budget are based on the 15-Year DSM Plan Supplement Report filed in Appendix 7.2 of the 2017/18 & 2018/19 GRA adjusted for actual DSM savings achieved in 2017/18 and the carry-forward effects of the changes made to the 2018/19 one-year DSM plan prepared in consultation with the Manitoba government. Manitoba Hydro is presently working in consultation with the Manitoba government to prepare the 2019/20 one-year DSM plan which will be incorporated into MH19 and filed as part of the next General Rate Application in late 2019. The 2019/20 DSM plan will incorporate the direction provided by Government.

Figure 2.6 below compares the forecast of General Consumer Sales between the Interim Budget and Exhibit 93.

Figure 2.6: Comparison of General Consumer Sales Volumes (GW.h)

GW.h	2019/20 Interim Budget	Exhibit 93	Increase/ (Decrease)
Residential	7,875	7,835	40
General Service	15,074	14,984	90
Area & Roadway Lighting	92	92	0
Sub-Total	**23,041**	**22,911**	**130**
Planned DSM Savings	(834)	(933)	99
Total	**22,207**	**21,977**	**230**

The actual domestic electric rate increase of 3.36% effective August 1, 2017 as opposed to the planned rate increase of 7.9%, which underpins the load forecast assumed in Exhibit 93, impacts the elasticity effect of prices such that load is expected to increase in 2019/20 for electricity in the residential sector by 40 GW.h and in the general service sector by 90 GW.h. The 99 GW.h decrease to the planned DSM savings are due to delays to the implementation of customer sited self-generation systems and the removal of the Fuel Choice initiative and Conservation Rates from the DSM plan.

2019/20 Interest Rates & Exchange Rates

Figure 2.7 below compares the interest rate and exchange rate assumptions underpinning the 2019/20 Interim Budget and Exhibit 93. The forecasted 20-year average interest rate listed under Exhibit 93 has been included for comparison purposes only as the 12-year average rate was used to derive the finance expense related to the issuances of new Canadian debt and is no longer being used in the 2019/20 Interim Budget.

Figure 2.7: Comparison of Interest Rates & Exchange Rates

	2019/20 Interim Budget Winter 2017	**Exhibit 93 Spring 2017**
MH Short Term Interest Rate*	2.20%	1.55%
MH Long Term Interest Rate*		
12 Year WATM	N/A	3.45%
20 Year WATM	4.00%	3.90%
U.S. – Cdn Exchange Rate	1.26	1.29

* Not including the 1% Provincial Guarantee Fee

Forecast interest rates are trending at about the same level as shown in Figure 2.7 . Section 2.4.4 provides a sensitivity analysis of the 2019/20 Interim Budget assuming interest rates at 1% higher or lower than the rates reflected in Figure 2.7 .

Although Figure 2.7 shows a slight strengthening of the Canadian dollar since Manitoba Hydro's 2017/18 & 2018/19 GRA, net income is generally not sensitive to changes in the U.S. exchange rate due to Manitoba Hydro's hedging policies and practices.

2019/20 Net Interchange Revenues and Generation Costs

The 2019/20 Interim Budget reflects Manitoba Hydro's reference electricity export price forecast and a simulation of the full historic flow record to derive the average net interchange revenues and generation costs. The reference electricity export prices from the 2017 Energy Price Forecast (Fall Update) for 2019/20 were approximately 6% to 7% lower than the prices from the 2017 Energy Price Forecast (Spring) assumed in Exhibit 93 and filed in the 2017/18 & 2018/19 GRA.

Hydraulic generation in 2019/20 is primarily driven by future precipitation which is impossible to forecast accurately beyond a one week period. As such, Manitoba Hydro uses its full historic flow record to project future net interchange revenues and generation costs beyond the 2018/19 fiscal year. Section 2.4.4 provides an analysis of the sensitivity of the 2019/20 Interim Budget to both electricity export prices and water flow conditions.

Manitoba Hydro has relatively small levels of unsold dependable energy and capacity in 2019/20. In forecasting the net interchange revenues and generation for both the 2019/20 Interim Budget and Exhibit 93, the Corporation has not projected incremental revenues associated with surplus dependable capacity. This is consistent with the PUB's finding on page 128 of Order 59/18:

> *Manitoba Hydro's change of methodology - to remove capacity values and dependability premiums from the substantial surplus dependable energy - **is reasonable in the near term**, but is not reasonable in the long term as it biases the export forecast to be low and is not consistent with third party forecasters nor with the needs in the Midcontinent Independent System Operator and Minnesota markets. (**emphasis added**)*

Regulatory Deferral Accounts and Accounting Assumptions

Manitoba Hydro's 2019/20 Interim Budget incorporates the PUB's direction in Order 59/18 for the regulatory deferral accounts listed in Figure 2.8, compared to Exhibit 93.

Figure 2.8: Accounting Treatment for Regulatory Deferral Accounts

	2019/20 Interim Budget	**Exhibit 93**
Ineligible Overhead		
Annual Provision	$20 million	$20 million
Amortization Period	34 years	30 years
Deferral	Indefinite	Indefinite
Equal Life Group (ELG)/Average Service Life (ASL)		
Amortization Period	None	None
Deferral	Indefinite	Indefinite
Costs Related to Conawapa		
Deferral Amount	$379 million	$379 million
Recorded in the Regulatory Deferral Account	Mar 31/18	Apr 1/19
Amortization Period	30 year	30 year

2.4.3 2019/20 Interim Budget with and without 3.5% Revenue Increase

Manitoba Hydro is requesting approval of a 3.5% rate increase to be effective April 1, 2019. This increase is projected to generate additional revenues of approximately $59 million and would result in a modest net income of $31 million in 2019/20. Absent the proposed rate increase for 2019/20, Manitoba Hydro is projecting a net loss of $28 million from Electric operations. Figure 2.9 compares the 2019/20 Interim Budget with and without the 3.5% revenue increase.

Figure 2.9: 2019/20 Interim Budget with and without the 3.5% Revenue Increase

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
(In Millions of Dollars)

	Interim Budget (3.50%)	Interim Budget (0.00%)	Increase/ (Decrease)
For the year ended March 31		**2020**	
REVENUES			
Domestic Revenue	1 737	1 678	59
BPIII Reserve Account	78	78	-
Extraprovincial	411	411	-
Other	29	29	-
	2 255	2 196	59
EXPENSES			
Operating and Administrative	511	511	-
Net Finance Expense	765	765	(1)
Depreciation and Amortization	508	508	-
Water Rentals and Assessments	111	111	-
Fuel and Power Purchased	160	160	-
Capital and Other Taxes	150	150	0
Other Expenses	111	111	-
Corporate Allocation	8	8	-
	2 325	2 325	(1)
Net Income before Net Movement in Reg. Deferral	(70)	(129)	59
Net Movement in Regulatory Deferral	103	103	-
Net Income	33	(26)	59
Net Income Attributable to:			
Manitoba Hydro	**31**	**(28)**	**59**
Non-controlling Interest	2	2	0
	33	(26)	59
Percent Increase	3.50%	0.00%	

2.4.4 2019/20 Sensitivity Analysis

This section provides an indication of the impact of changes in water flow conditions, weather, interest rates and export prices on the 2019/20 Interim Budget net income of $31 million.

The net income or loss resulting under each of the key changes in assumptions is shown below in Figure 2.10. Figure 2.10 also shows that the likelihood of a financial loss is greater without the proposed 3.5% rate increase under the range of sensitivities considered.

Figure 2.10: Key Variable Sensitivity Impacts on 2019/20 Interim Budget Net Income/ (Loss) With and Without the 3.5% Proposed Rate Increase

	Projected Net Income/(Loss)	
	3.5% Proposed Rate Increase	**No Rate Increase**
Interim 2019/20 Budget	$31 M	($28) M
Low Water Flow (10th percentile net interchange revenues and generation costs)	($169) M	($229) M
High Water Flow (90th percentile net interchange revenues and generation costs)	$194 M	$134 M
Colder than normal winter weather	$63 M	$4 M
Warmer than normal winter weather	($0) M	($60) M
+ 1% Interest Rates	$16 M	($43) M
- 1% Interest Rates	$45 M	($14) M
Low Export Price Case	($2) M	($61) M
High Export Price Case	$49 M	($10) M

The 2019/20 Interim Budget assumes average net interchange revenues and generation costs for the historic water flow record. The historic water flow record has a great deal of variability from the highest to the lowest flow which creates a dramatic range of the possible net interchange revenues and generation costs that could occur in a given year. The impact of low flows are greater than high flows due to the requirements for thermally generated and imported energy in low flow years and spilling of water beyond system constraints in high flow years. Due to this asymmetry, the average revenues and costs of the historic water flow record is the equivalent to approximately the 40th percentile or P40 and not the median or P50. To demonstrate the range of possible net interchange revenues and generation costs, the P10 and P90 sensitivities have been provided. Figure 2.10 shows that the projected income or loss for 2019/20 can vary by more than $360 million due to water flow conditions.

The 2019/20 Interim Budget assumes a weather adjusted forecast for General Consumer Sales. A record cold or warm winter will increase or decrease Manitoba's 2019/20 energy consumption by approximately 4%. An increase or decrease to domestic revenue due to a colder or warmer than normal winter will be partially offset by an associated decrease or increase to net interchange revenues and generation costs. Figure 2.10 shows that projected net income for 2019/20 can vary by more than $60 million due to colder or warmer winter weather.

Manitoba Hydro is planning to raise approximately $2.4 billion in new debt issuances in 2019/20. The interest rates affixed to new debt issuances have a lasting effect due to the perpetual nature of long-term debt (20-year WATM) which makes this a different risk than drought. The interest rate sensitivity demonstrates the financial impacts of interest rates one percent higher or lower than forecast on short-term, long-term and floating rate debt, as well as sinking funds. Figure 2.10 shows that the 2019/20 Interim Budget net income could vary by approximately $30 million with interest rates 1% above or below that forecasted.

The 2019/20 Interim Budget reflects Manitoba Hydro's reference electricity export price forecast derived from several independent price forecasts for the MISO region. There is uncertainty in each of these pricing factors, and particular uncertainty as to how future legislative and regulatory requirements may evolve. As such, Manitoba Hydro has developed high and low electricity export price forecasts as sensitivities around the reference case using information prepared by the U.S. Energy Information Administration (EIA). Figure 2.10 shows that projected net income from 2019/20 can vary by $50 million if export prices vary from the forecast reference export prices assumed in 2019/20 Interim Budget.

2.4.5 Information on Other Cash Payments

Directive 10 of Order 59/18 requested Manitoba Hydro to provide information about the Other Cash Payments included in its Cash Flow Statement. Manitoba Hydro has provided additional details on the Cash Flow Statement included in

Appendix 1. In addition to the further line item breakdown provided on the Cash Flow Statement, the “Other” category balance of $11 million in 2017/18 under Financing Activities represents the advance to Centra which is eliminated upon consolidation. The “Other” category of $3 million under Investing Activities is primarily investments in assets held for sale as well as payments associated with various obligations.

2.4.6 Operating & Administrative Costs

Consistent with Exhibit 93, Manitoba Hydro’s preliminary O&A target included in the 2019/20 Interim Budget is $511 million reflecting an inflationary increase of 2% over the $501 million of O&A expenses included in the 2018/19 Financial Outlook. The 2% increase is aligned with Manitoba CPI. Manitoba Hydro is committed to achieving this level of O&A expenditure and is in the process of developing detailed budgets for 2019/20 to support this commitment.

As discussed in the 2017/18 & 2018/19 GRA, the implementation of a significant work force reduction strategy resulted in cost reductions in both 2017/18 and 2018/19. As shown in Figure 2.11, O&A costs were $19 million lower in 2017/18 than the prior year and are projected to be further reduced by $16 million in 2018/19.

Figure 2.11: Year over Year Comparison of O&A Costs

(in millions of dollars)	2016/17 Actual	2017/18 Actual	2018/19 Budget	2019/20 Forecast
O&A Expenditures	$536	$517	$501	$511
Year over Year Inc / (Dec)		-3.5%	-3.1%	2.0%

The year over year decreases in 2017/18 and 2018/19 are primarily due to the impact of the Voluntary Departure Program (“VDP”) which was launched in April 2017 as a means to accomplish the Corporation’s workforce reduction target of 900 employees over a 3 year period ending March 31, 2020. A total of 821 employees were approved under the VDP with the majority of staff departing by March 2018. Manitoba Hydro’s headcount as of April 2017, excluding summer students and seasonal workers, was approximately 6150. The Corporation's projected headcount to March 2020 is approximately 5250.

Appendix 8 provides Manitoba Hydro's O&A Expenses Quarterly Report for the year ending March 31, 2018 as well as the quarters ending June 30th and September 30th 2018, filed in response to Directive 14 of Order 73/15. O&A performance to the end of September 2018 is closely aligned with budget. The September 30, 2018 report provides information for the 2018/19 annual budget by cost element.

2.4.7 Impacts of VDP on Pension

At March 31, 2018 Manitoba Hydro recognized a $30 million actuarial loss in Other Comprehensive Income (OCI) related to the VDP departures based on a December 2017 valuation of the pension liability. The loss is primarily a result of deviations in pension valuation assumptions. The pension valuation assumes age 59 as the average age of retirement and that pensioners will take a monthly pension payment. Individuals retiring as part of the VDP who were 55-58 years of age at retirement had a negative impact on the pension valuation as did individuals who withdrew the commuted value of their pension. Manitoba Hydro's actuary (Ellement Consulting) estimates that annual pension payments will increase by approximately $1 million per year once all the VDP individuals have retired and the current service rate is expected to decrease by 5% by 2019. Additional actuarial losses on the pension obligation of approximately $30 million and $7 million are projected for March 2019 and March 2020 respectively using fiscal 2017/18 VDP valuation impacts as a proxy.

2.5 Capital Expenditure Forecast (CEF18)

Appendix 6 contains a copy of Manitoba Hydro's Capital Expenditure Forecast (CEF18) from 2018/19 to 2027/28. CEF18 identifies all projects greater than $1 million in response to Directive 15 of Order 73/15. Projects greater than $15 million appear in the body of the report and projects less than $15 million are summarized in Appendix II of the report.

Figure 2.12 provides a comparison of CEF18 to CEF16 for Electric operations, which shows a decrease of $303.6 million over the 10 year period to 2027/28.

Figure 2.12: Comparison of CEF18 to CEF16

	2019	2020	2021	2022	2023	2019-2013 5 Year Total	2019-2028 10 Year Total
CEF16	$ 2,742.1	$ 1,884.2	$ 1,666.5	$ 1,332.5	$ 945.2	$ 8,570.5	$ 12,122.4
Inc (Dec)	(72.1)	(65.1)	(97.3)	64.2	(4.4)	(174.8)	(303.6)
CEF18	$ 2,670.0	$ 1,819.1	$ 1,569.2	$ 1,396.7	$ 940.8	$ 8,395.7	$ 11,818.8

Figure 2.13 provides a summary of the changes of $303.6 million over the 10 year period ending 2027/28.

Figure 2.13: Summary of CEF18 Forecast Changes

($ Millions)	10 Year Increase (Decrease)
MAJOR NEW GENERATION & TRANSMISSION	**(266.9)**
Keeyask - Generation	(133.8)
Bipole III Reliability	21.9
Manitoba-Minnesota Transmission Project	53.6
Birtle Transmission	4.4
Other Major New Generation & Transmission	(212.9)
Electric Business Operations Capital	**0.2**
Generation System	(65.3)
Transmission System	(123.7)
Distribution System	175.5
Corporate Infrastructure	6.4
Unallocated Target Adjustment	7.2
Electric DSM Program	**(36.9)**
ELECTRIC CAPITAL EXPENDITURE & DSM FORECAST TOTAL	**(303.6)**

Major New Generation and Transmission ("MNGT") capital expenditures over the 10-year period are forecast to be $5,391.2 million. Compared to CEF16, this is a reduction of $266.9 million primarily associated with Other MNGT projects included in CEF16. Several of these projects were completed in 2017/18 including: Wuskwatim–Generation, Pointe du Bois Spillway Replacement, Kelsey Improvements & Upgrades, Riel 230/500kV Station, Kettle Improvements & Upgrades and Pointe du Bois Transmission. The Grand Rapids Fish Hatchery Upgrade & Expansion project has been reclassified to Business Operations Capital and all future investment requirements related to the Gillam Redevelopment and Expansion Project will also be included as Business Operations Capital items. In addition, the Keeyask – Generation project cash flow reduced by $134 million over the 10 year period, however, the total project forecast remains unchanged at $8.7 billion. The Business Operations Capital (BOC) forecast did not materially change compared to CEF16.

2.5.1 Summary of MNGT Projects

A summary of capital expenditure requirements for each project within MNGT can be found in CEF18 on pages 10 through 12. Figure 2.14 summarizes by investment category the total project cost and forecast cash flow for each of the 4 projects.

Figure 2.14: Total Project Costs for Major New Generation & Transmission

MAJOR NEW GENERATION & TRANSMISSION ($ Millions)	Total Project Cost	2019	2020	2021	2022	2023	2019-2023 5 Year Total	2019-2028 10 Year Total
Capacity & Growth								
New Energy								
Keeyask - Generation	8,726.0	1,265.4	1,016.6	846.9	763.9	311.2	4,204.0	4,241.3
System Load Capacity								
Bipole III - Converter Stations	2,780.7	345.7	23.1	0.2	-	-	369.0	369.0
Bipole III - Transmission Line	1,957.6	290.2	10.2	2.4	-	-	302.8	302.8
Bipole III - Collector Lines	246.6	25.6	-	-	-	-	25.6	25.6
Bipole III - Community Development Initiative	56.6	1.1	-	-	-	-	1.1	1.1
System Load Capacity Total	**5,041.5**	**662.6**	**33.4**	**2.6**	**-**	**-**	**698.5**	**698.5**
Grid Interconnections - Import/ Export								
Manitoba-Minnesota Transmission Project	451.7	162.0	144.4	91.2	-	-	397.6	397.6
Birtle Transmission	56.5	2.5	20.0	18.2	13.0	-	53.8	53.8
Grid Interconnections - Import/ Export Total	**508.2**	**164.5**	**164.5**	**109.3**	**13.1**	**-**	**451.4**	**451.4**
Capacity & Growth Total	**14,275.7**	**2,092.5**	**1,214.4**	**958.9**	**777.0**	**311.2**	**5,353.9**	**5,391.2**

Directives 15 and 16 of Order 59/18 directed Manitoba Hydro to consider implementing recommendations made by the IEC's with respect to Keeyask, MMTP and GNTL, as well as filing detailed quarterly reports for all Major New Generation and Transmission projects currently under development. An update with respect to each of these directives is provided below.

<u>Directive 15 of Order 59/18</u>

Manitoba Hydro has implemented certain recommendations, and is in the process of considering implementation of other recommendations made by the IECs in the 2017/18 & 2018/19 GRA for those projects that are within its control in order to properly assess any projected cost savings and schedule impacts.

With respect to the Manitoba Minnesota Transmission Project, recommendations were mainly focused on schedule modifications such as breaking apart long duration activities and removing constraints. These recommendations have been addressed and a basis of estimate will be prepared when details of contractor pricing are received. Currently however, it does not appear that these changes have had a measurable impact to the project budget.

With respect to the Keeyask project, the recommendations proposed by MGF Project Services were primarily focused on improving outcomes of the General Civil Works Contractor ("GCC") with the goal of achieving the control budget of $8.7 billion and the control schedule first unit In-Service Date of August 2021.

In January 2018, during the 2017/18 & 2018/19 GRA, Manitoba Hydro laid out its approach on the closer collaboration between Manitoba Hydro and the GCC to improve performance and achieve the plan for the 2018 construction season and ultimately deliver the project within the revised control budget of $8.7B and related schedule. The intended approach aligned with the closer collaboration on execution planning and oversight of the GCC recommended by MGF as well as working with the GCC to develop an achievable plan in 2018 based on production experienced to date. Manitoba Hydro has increased the pressure on the GCC to perform, and has collaborated wherever possible to stimulate greater productivity.

By the end of November 2018, the GCC exceeded the concrete production goal of 105,000 m3 for the year representing a year-over-year improvement of more than 20% over last year's production. In total, more than 83% of the required volume of concrete to build the Keeyask Generating Station has now been placed. The GCC also met the planned quantities for earthworks for the year, achieving roughly double the volumes of production from last year. In addition to improving production rates, the work completed in 2018 was also completed more efficiently. Though significant project risks remain, the progress to date has been positive and the necessary improvements to achieve the control budget of $8.7B are being realized and the first unit In-Service Date (ISD) is currently trending ahead of the control schedule.

Directive 16 of Order 59/18

Manitoba Hydro has provided detailed quarterly reports on the following MNGT capital projects:

- Keeyask Generating Station – a 7 unit, 695-megawatt hydroelectric generating station under construction at Gull Rapids on the low Nelson River in northern Manitoba.
- Bipole III Transmission Reliability Project – a high voltage direct current transmission line that delivers renewable energy to southern Manitoba. Bipole III was brought into service on July 4, 2018.
- Manitoba–Minnesota Transmission Project – a new 500kV AC Transmission Line between Winnipeg and Duluth, Minnesota which will connect to the Minnesota Power's proposed Great Northern Transmission Line.
- Birtle Transmission Project – a new 230kV Transmission Line between Birtle, Manitoba and Tantallon, Saskatchewan.

Please see Appendix 7 for copies of Manitoba Hydro's Public MNGT Capital Reports for the quarter ended March 31, 2018, and the quarters ended June 30, 2018 and September 30, 2018.

3.0 PROPOSED RATE CHANGES & CUSTOMER IMPACTS BY CLASS

Manitoba Hydro's electric rates were last adjusted effective June 1, 2018 to reflect the 3.6% rate increase approved by the PUB in Order 59/18. Pursuant to Order 59/18, the rates that came into effect on June 1, 2018 reflected the following rate design considerations:

- the creation of a First Nation On Reserve Residential customer class, with no increase from August 1, 2017 rates;
- the application of no rate increase from August 1, 2017 rates to Residential Diesel class customers, and,
- the adjustment of class revenues to commence migration of customer classes toward the Zone of Reasonableness ("ZOR") of 95% to 105% over a ten year period.

Manitoba Hydro filed an Application to Review and Vary some of the directives in Order 59/18 including the directives related to the creation of a First Nation on Reserve Residential Customer Class. In its Order 90/18, dated July 13, 2018, the PUB denied Manitoba Hydro's application to Review and Vary these directives. On August 10, 2018, Manitoba Hydro filed a Motion with the Court of Appeal seeking Leave to Appeal portions of PUB Orders 59/18 and 90/18 with respect to the creation of a new customer class for First Nation on Reserve Customers. As of the filing of this Application, these issues remain before the Court of Appeal.

As part of its 2019/20 one-year electric rate application, Manitoba Hydro is requesting approval of a 3.5% rate increase, effective April 1, 2019, to be applied equally, across all customer classes.

In Order 59/18 the PUB directed for the 2018/19 test year rate, that Manitoba Hydro is to assume a 10-year timeframe to move all classes within the zone of reasonableness. The PUB further stated at page 199 of Order 59/18 that it would *"…examine the Revenue to Cost Coverage ratios arising from the Prospective Cost of Service Study filed with the next GRA and will consider adjustment to the differentiation of rates as necessary, including to consider the impact of Bipole III entering service".*

Manitoba Hydro intends to continue the migration of customer classes into the ZOR in its next full General Rate Application, anticipated to be filed in late 2019, based on the results of its next Prospective Cost of Service Study ("PCOSS") to be developed following approval by the MHEB of a new Integrated Financial Forecast. The next PCOSS will reflect Bipole III coming into service. As this is anticipated to have a significant impact on customer class costs, pausing further differentiation until Manitoba Hydro can assess which classes may remain outside the ZOR once the impacts of Bipole III have been reflected will limit potential over-corrections that may be unnecessary following Bipole III coming into service. The across-the-board increase proposed as part of this Application will not negatively impact the migration of class revenues that has been achieved to date following the implementation of differentiated rates approved by the PUB in Order 59/18.

In consideration of this one-year electric rate application and in absence of an updated PCOSS, Manitoba Hydro is proposing to apply the increase to all components of the rates (monthly basic charges, energy charges and demand charges) on an across-the-board basis for all customer classes, with the exception of Diesel General Service. For Diesel General Service customers Manitoba Hydro is proposing to increase the grid portion of the rate (Basic Charge and first 2,000 kWh per month for non-government customers) by 3.5% with the non-grid portion of the rate remaining unchanged.

Until the Court of Appeal rules on the issue of the creation of a First Nations On-Reserve Residential customer class, Manitoba Hydro proposes to apply the same rate increase to all residential customers (including the First Nations On-Reserve Residential and Diesel Residential customers) for the 2019/20 fiscal year.

The proposed 3.5% rate increase applied on an across-the-board basis generates additional revenue of $59 million for fiscal 2019/20.

On a class by class basis, the proposed increase in revenues is shown in Figure 3.1 below.

Figure 3.1: Additional Revenues by Customer Class

Customer Class	2019/20 Additional $(000s)
Residential	24,800
General Service (GS) Small*	11,900
GS Medium	7,400
GS Large	13,600
Area & Roadway Lighting	800
Miscellaneous	200
Total General Consumers Revenue	58,800

*includes revenues from General Service customers in Diesel Communities

A Proof of Revenue for the 2019/20 test year depicting the total revenue increase by customer class is provided in Appendix 10. Rate Schedules for proposed rates effective April 1, 2019 are provided in Appendix 11 and Bill Comparisons between current June 1, 2018 rates and proposed April 1, 2019 rates are provided in Appendix 12.

3.1 Rate Design and Cost of Service Directives

Order 59/18 set out a number of directives related to Manitoba Hydro's cost of service study and rate structures.

Directives 24 to 27

Manitoba Hydro has completed the modifications to the cost allocation model that will be used for future Cost of Service Studies to reflect these directives which direct non-tariffable transmission costs be excluded from the allocation of export revenues, the addition of a new subfuction to allocate the specified customer services costs to all classes other than GSL 30-100kV and GSL >100kV and export revenues be treated as a reduction to cost in the calculation of Revenue to Cost Coverage ratios. Manitoba Hydro is continuing to study the Service Drop allocator and Common Costs and intends to have the review completed in time for the next Prospective Cost of Service Study to be filed with the next full GRA.

Directive 28

Directive 28 requested information regarding the rationale for the declining block rate structure for the General Service customer classes and an evaluation of the block thresholds and charges. The declining block rate structure for the General Service Small, General Service Small Demand and General Service Medium customers is on account of class consolidation that began with rates implemented on July 1, 2008 and was necessary to recover the demand costs related to General Service Small customers that are not demand metered and to reflect the higher load factors of the General Service Small Demand and General Service Medium customers. There are no changes currently proposed to these customer classes as Manitoba Hydro intends to study whether consolidation of these classes continues to be appropriate.

<u>Directive 29</u>

Directive 29 directed filing of a time-of-use rate design proposal for general service large customers. Manitoba Hydro has invited customers in the General Service Large >100 class and representatives of the Manitoba Industrial Power Users Group to a kick off meeting on December 4, 2018 which will mark the beginning of the customer consultation phase. The consultation phase, originally anticipated to begin by the end of October 2018, was delayed to allow for additional internal review to analyze and study the key inputs and considerations underlying a time-of-use rates proposal in order to provide customers with updates that will allow for meaningful participation at the outset of the consultation process. Over the next several months, through group and individual consultations, Manitoba Hydro intends to solicit feedback and gather information from customers for the purposes of developing the new rate structure.

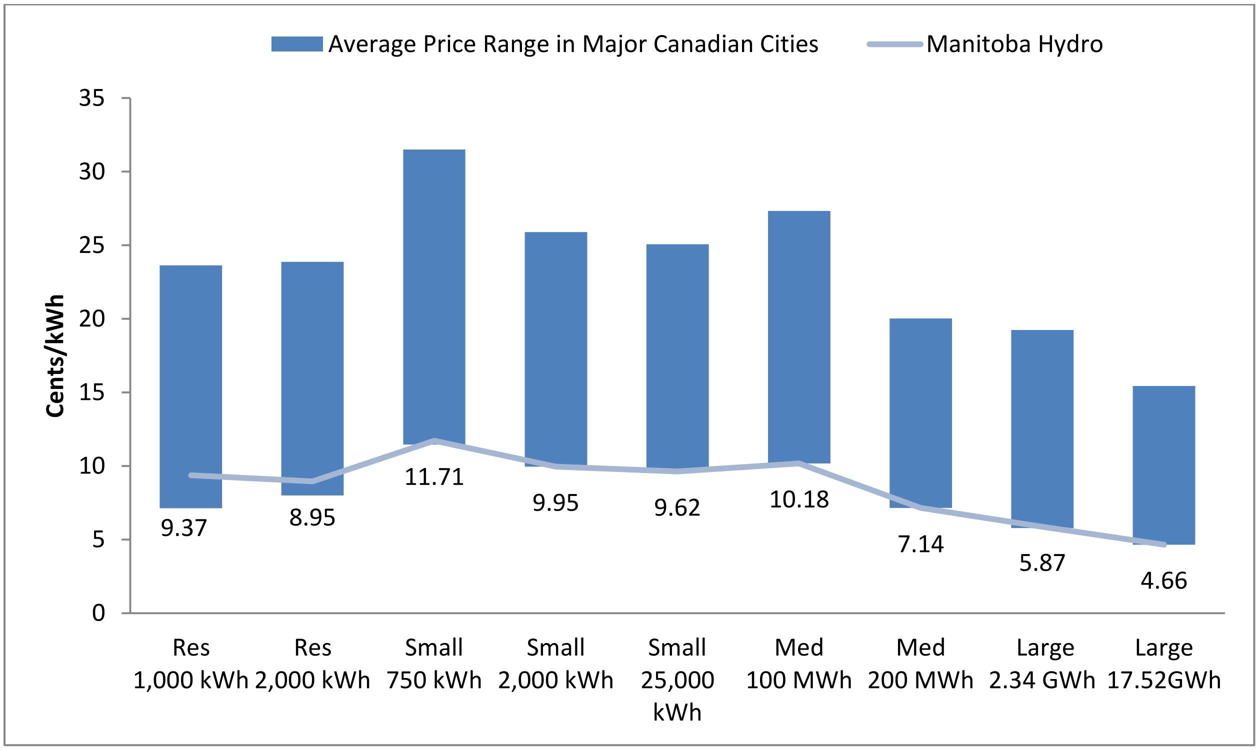
3.2 Comparison of Manitoba Hydro's Electricity rates to Neighbouring Jurisdictions

Manitoba Hydro has used Hydro Quebec's annual *"Comparison of Electricity Prices in Major North American Cities"*[1], to compare average rates for all major rate classes paid by Manitoba customers with those of other major Canadian utilities, as shown in Figure 3.2.

[1]http://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf

Figure 3.2: Comparison of Average Electricity Prices in Major Canadian Cities

Rates in effect April 1, 2018 (Price per kWh)



The 2018 Hydro Quebec survey demonstrates that the average price per kWh paid by Manitobans is amongst the lowest in large Canadian cities.

A summary of rate changes from utilities across Canada from 2007 to 2019 is provided in Figure 3.3 below.

1 **Figure 3.3: Utility Rate Changes 2007 to 2019**

Utility Rate Changes (%)															
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019*	Cumulative	Current Rate Index***
Manitoba Hydro	2.2	5.00	2.90	2.80	2.00	4.40	3.50	2.75	3.95	3.36	3.36	3.60	3.50	53.1	100
Hydro Quebec	1.90	2.90	1.20	0.35	-0.40	-0.50	2.41	4.30	2.90	0.70	0.70	0.30	0.80**	18.9	109
BC Hydro	2.10	0.83	9.28	7.29	7.77	7.07	1.44	9.00	6.00	4.00	3.50	3.00	3.00	86.4	142
SaskPower	4.20	0.00	8.50	4.50	0.00	0.00	4.90	5.50	5.00	5.00	3.50	3.50	0.00	54.4	159
NB Power	5.90	3.00	3.00	3.00	0.00	0.00	2.00	2.00	1.60	1.66	1.77	0.88	2.00	30.2	171
NS Power	3.80	0.00	9.30	0.00	6.05	8.70	3.00	3.00	0.00	-1.00	1.50	1.70	1.50	43.9	n/a
Toronto Hydro	-4.11	-0.99	4.95	10.84	-8.18	18.80	-7.52	18.93	-3.07	20.47	-2.52	-25.38	2.00	14.8	n/a

* Where published information on proposed increases is not available, Manitoba Hydro has assumed a 2% inflationary increase

** Hydro Quebec is proposing an overall 0.8% increase in 2019, but only 0.2% for industrial customers.

*** This index is based on the Edison Electric Institute Survey and compares the average price per kWh for the various utilities. Manitoba Hydro's average price is $0.0649/kWh in Canadian dollars based on 12 months data ending December 2017.

In addition to average prices, a comparison of monthly bills aids in providing context for what customers in each jurisdiction are paying on a monthly basis. The charts provided in Figures 3.4 to 3.8 compare projected monthly bills for major Canadian cities in 2019/20. Consistent with calculations in Figure 3.4, where published information on projected increases is not available, a simplifying and conservative assumption has been made that annual rate increases will be in line with inflation at 2% each year. Where information is available, projected rate increases have been reflected in the bill calculations.

Figure 3.4: Residential Monthly Bill Comparisons in 2019/20

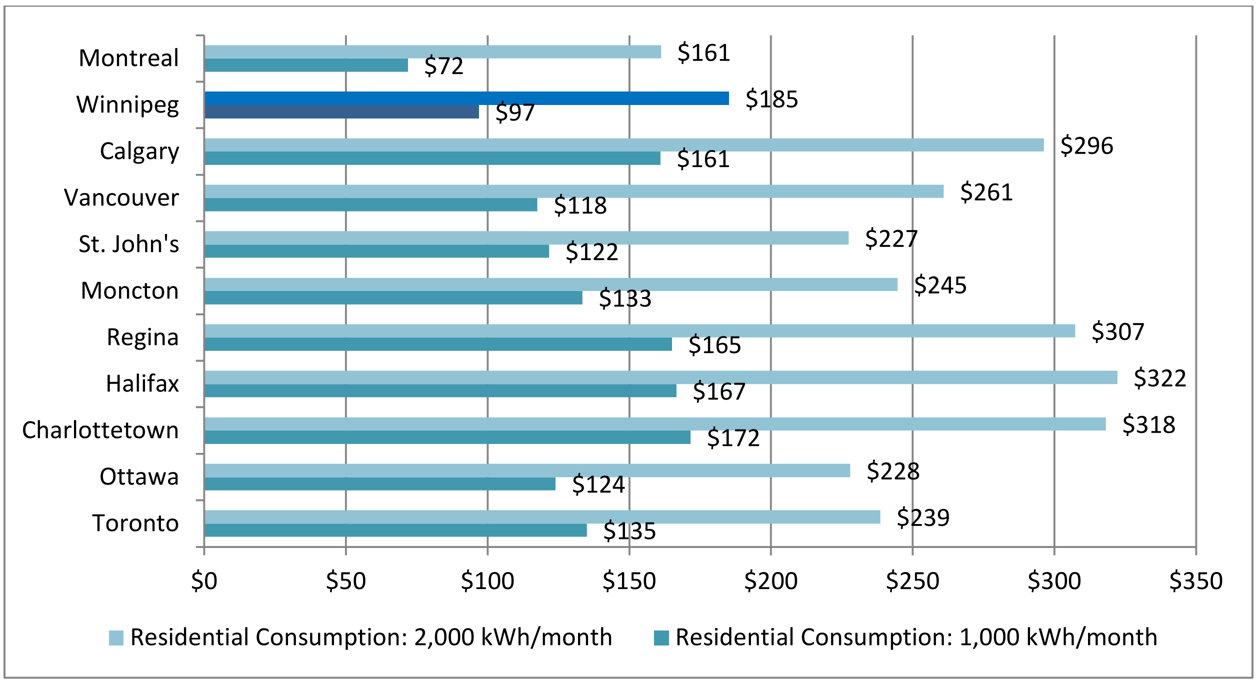


Figure 3.5: Small Power (10,000 kWh) Monthly Bill Comparisons in 2019/20

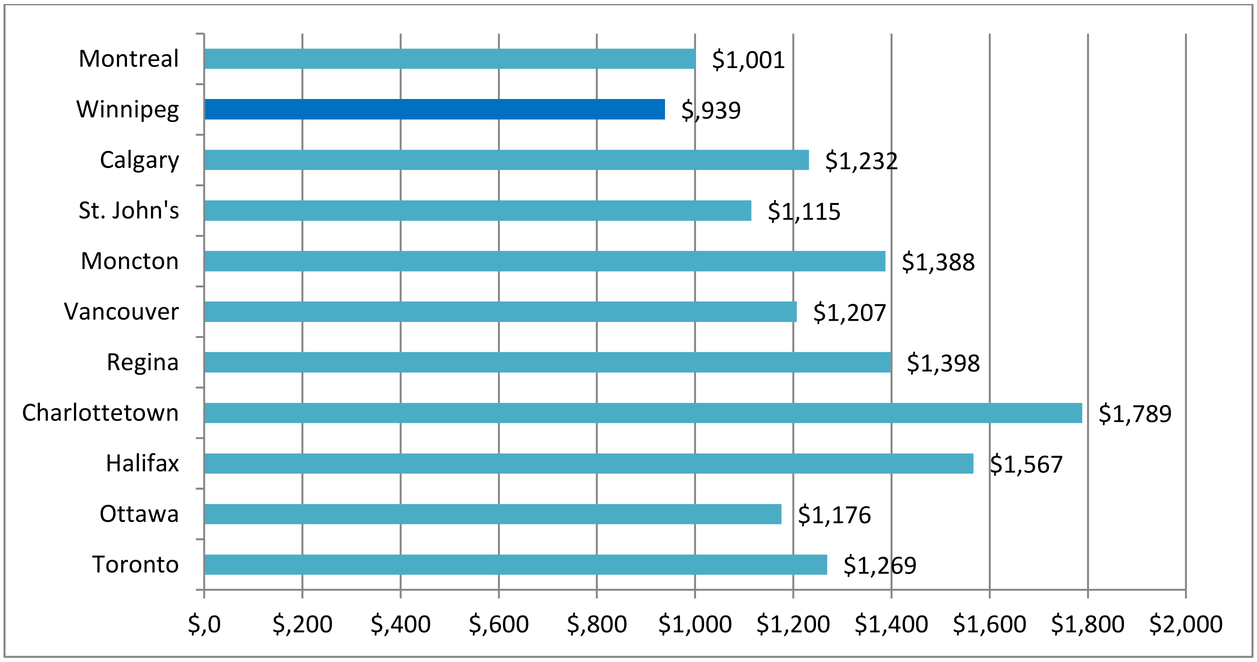


Figure 3.6: Medium Power (1,000 kW) Monthly Bill Comparisons in 2019/20

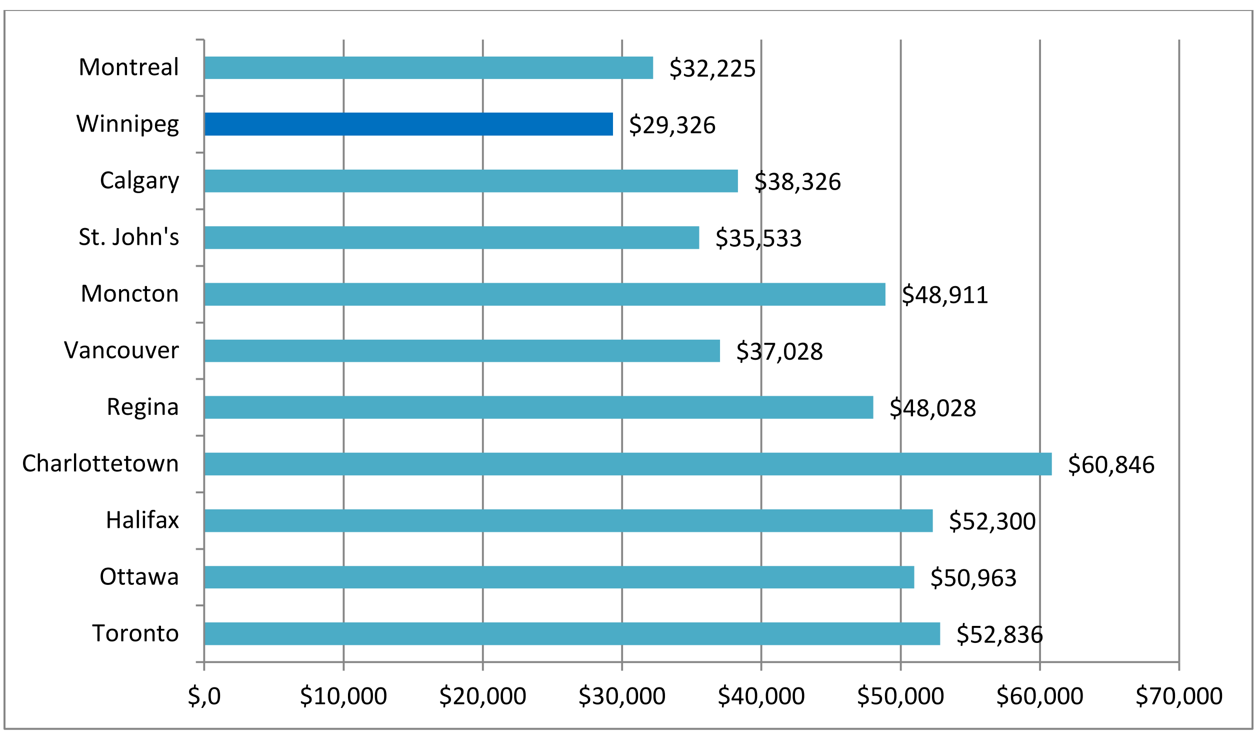


Figure 3.7: Large Power (5,000kW) Monthly Bill Comparisons in 2019/20

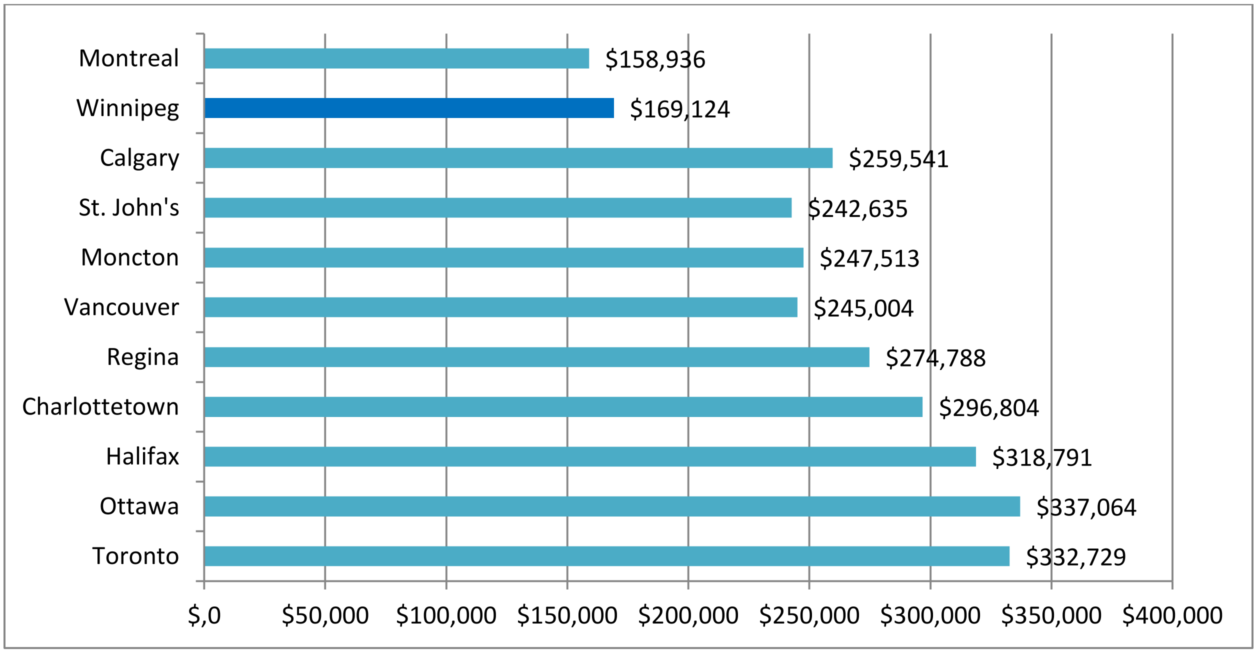
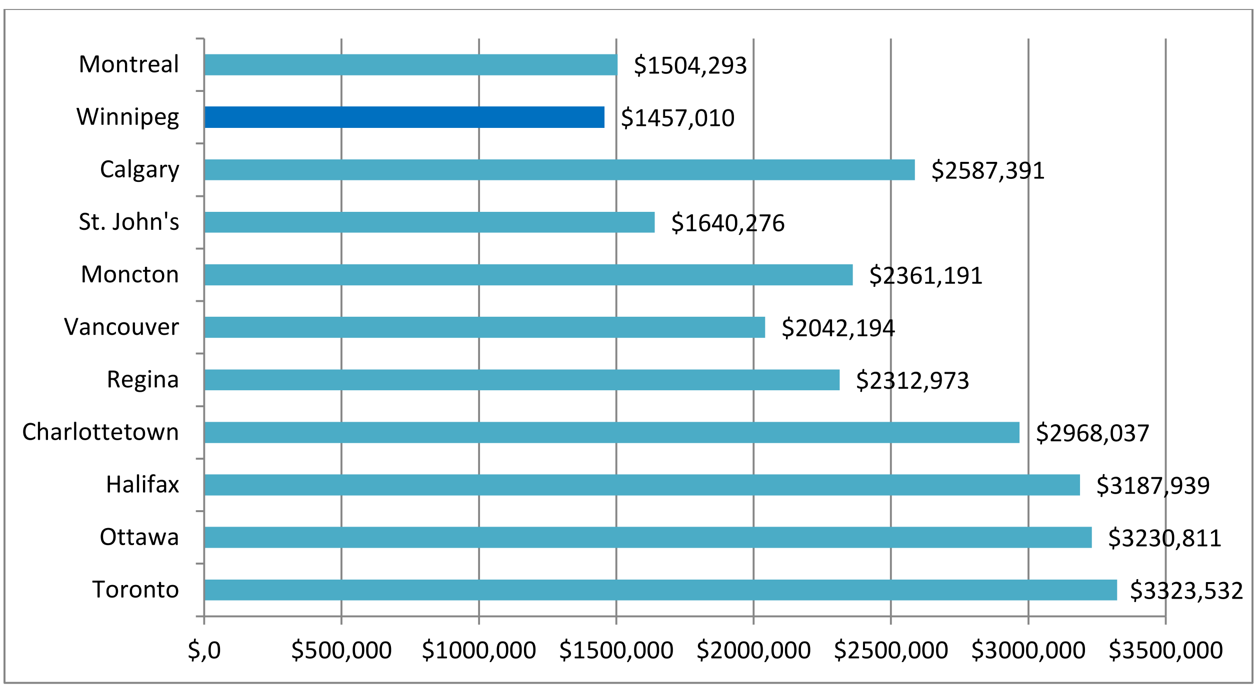


Figure 3.8: Large Power (50,000kW) Monthly Bill Comparisons in 2019/20



To measure its performance in the overall North American context, Manitoba Hydro uses the results of both the Edison Electric Institute ("EEI") survey as well as monthly statistics obtained from the United States Department of Energy ("DOE"). Unlike the EEI data that provides investor-owned utility comparisons, the DOE data provides comparisons by State which includes numerous utilities within each state. Figure 3.9 below provides the Total Retail Average Rate compared to other low-cost jurisdictions and neighboring utilities, including primary Mid-continent Independent System Operator states, based on the July 2018 DOE data and July 1, 2018 EEI data, using an exchange rate of 1 US $ =1.32154 Canadian as of July 3, 2018. The Average Retail Rate was determined by dividing the combined total revenue billed by the combined total kilowatt hours billed for the 12-month period ending June 30, 2018 for all customer classes (residential, commercial and industrial).

Figure 3.9: Average Retail Price

State / Province	Average Retail Price Cents per kWh
Manitoba Hydro	6.49*
Hydro Quebec	6.97
BC Hydro	9.22
SaskPower	10.67
North Dakota	11.00
South Dakota	13.09
Minnesota	12.36
Wisconsin	14.06

*Total revenue used in the calculation includes PUB-approved rate increases of 3.36% effective August 1, 2017 and the portion of 3.6% effective June 1 to June 30, 2018.

As demonstrated in the Figures above, Manitoba continues to maintain an advantage over most North American jurisdictions with respect to the average monthly customer bills and average prices for all customer classes.

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Report to the Manitoba PUB

Review of Manitoba Hydro Financial Targets and the 2017/18 and 2018/19 GRA

Prepared by
MPA Morrison Park Advisors Inc.

October 31, 2017

Contents

Appendices

Executive Summary

On May 5, 2017, Manitoba Hydro applied to the Manitoba Public Utilities Board for electricity rate increases of 7.9% for both 2017/18 and 2018/19.

In support of this application, Manitoba Hydro provided a substantial body of information on the company's financial performance, forecasts, and financial targets and goals. In particular, the application referenced that the Manitoba Hydro Electric Board has set a goal to achieve a target Debt to Equity Ratio of 75:25 by March 31, 2027. In order to achieve this goal, a series of substantial rate increases would be required over the coming years.

This Report addresses three critical issues:

- Why are financial targets relevant to rate-setting for Manitoba Hydro?
- Should the Debt : Equity Ratio be the primary financial target that is taken into account when setting rates for the future?
- Assuming the Debt : Equity Ratio is the primary target, should rates be set so as to achieve that target by March 31, 2027?

Manitoba Hydro's governing legislation does not specify a capital structure for the company. It is organized as a non-share capital corporation, to be operated at cost. However, the maintenance of reserves for various purposes are allowed, which gives the company flexibility in determining its capital structure. The Manitoba Public Utilities Board is free to take into account the need for reserves in its deliberations on rates, but is not required to approve of any specific level of reserves.

Manitoba Hydro is fairly unique as a government-owned, pure cost recovery electricity utility which is mandated to produce and sell electricity for export as well as for domestic purposes. This sets it apart from its peers in North America, none of whom have that exact combination of characteristics. While the experience of other utilities may be used as a guide, the particular nature of Manitoba Hydro means that there is no pattern that can simply be followed in determining how best to address the issues raised in the application. Regardless, government-owned utilities across North America exhibit a wide variety of financial profiles, lending support to the proposition that Manitoba has the flexibility to pursue its own course.

One of the principal reasons to carefully track and manage financial performance is to ensure continued access to the capital markets. Manitoba Hydro is a capital intensive business, and it is in the midst of a massive building program, for which it requires a significant amount of debt. While the company's debt is issued by the Province of Manitoba and on-lent to Manitoba Hydro, nonetheless the company must address itself to the capital markets to ensure that it does not weaken or harm the credit-worthiness of the Province of Manitoba.

The primary concern of lenders is the risk that a borrower will default on a loan. In order to gauge this risk, capital markets participants closely examine the financial history and circumstances of potential borrowers to determine their credit-worthiness. Manitoba Hydro, and the Province of Manitoba, are each regularly scrutinized and reported on by various credit rating agencies, and of course bond investors themselves monitor the behaviour and results of both the company and the Province in real time, as news and events instantly affect the bond trading market. It is apparent from reading various financial market reports that a primary focus is on the expected sufficiency of cash flows to satisfy debt obligations. While the capital structure of a prospective borrower like Manitoba Hydro is important, it appears to be a secondary issue for the capital markets. This raises questions about the centrality of the Debt to Equity Ratio in Manitoba Hydro's application: if the capital markets are focused on other financial metrics, then why not make those metrics central to rates, instead of the Debt to Equity Ratio?

Rates must be set prospectively, at a level that is expected to cover the costs of the utility. However, Manitoba Hydro's revenues depend very much on unpredictable water inflows to the hydroelectric facilities that the utility owns and operates. Other uncertainties include interest rates on the utility's outstanding debts, export prices for the power sold abroad, and the ultimate cost of the various construction projects currently underway. These risks mean that Manitoba Hydro must take a sophisticated approach to managing its finances. In addition, the variability of all of these factors raises questions about how the PUB should be setting Manitoba Hydro rates, and the degree of flexibility there should be in changing the level of those rates over time.

The Manitoba PUB must not only operate within the confines of its governing legislation and that of Manitoba Hydro, but it can and should call on the enormous body of practice and jurisprudence concerning regulated utilities that has been developed across North America over the past hundred years or more. A number of principles have emerged over the years which seek to clarify what may be considered "just and reasonable" in the setting of utility rates. An over-arching concern is to balance the needs of customers and the utilities themselves, so that services can be provided in a manner, and at a price, that is fair, economically efficient, prudent, predictable and stable.

Considering Manitoba Hydro's rate application in the light of regulatory principles, it becomes apparent that the urgency with which the utility wishes to achieve its targeted Debt to Equity Ratio makes it difficult to maintain a fair distribution of burden on ratepayers over time. The sharp increase in rates, designed ostensibly to protect ratepayers from undue financial risks and burdens in the future, instead appears to create significant burdens for ratepayers in the short term, with uncertain utility to ratepayers later. Alternative, more modest rate increases may be sufficient to satisfy the needs of the capital markets, while spreading burdens more equally across ratepayers over time. In the event that financial distress arises from the actualization of a risk, then rates could be increased further.

In short, the answers to the three questions posed above can be summarized in the following way:

- Financial targets are important for rate-setting, both because they indicate the general health of the utility, which must be a factor in rate-setting, and because they are critical to having access to capital markets.

- There appears to be significant doubt as to whether rate-setting should be driven by the Debt to Equity Ratio. This particular financial measure is of secondary importance to the capital markets, and the emphasis placed on it does not appear to lead to balanced, fair results for ratepayers.

- A goal to reach a financial target by a fixed date does not appear to take into account the ever-changing risks faced by the utility, and the need to balance those risks against the interests of ratepayers over time. It may be more advisable to focus on different financial metrics, and seek to achieve and maintain them on some form of rolling-forward basis, which might provide the Public Utilities Board with the flexibility it needs to find a fair and reasonable balance in the setting of rates.

Morrison Park Advisors

MPA is an independent, partner owned investment banking advisory firm. We primarily advise clients on mergers and acquisitions, equity and debt capital raises, divestitures and restructurings. In addition, we provide formal valuations, fairness opinions, contract negotiation services, advice to special committees of boards of directors, advice on initial credit ratings, expert testimony before courts and regulatory bodies, policy development, and market analysis. Our ability to deliver top tier financial advisory services is based on decades of combined experience and expertise developed at some of Canada's leading investment banks, while serving many of Canada's largest and most sophisticated corporate clients as well as federal, provincial and municipal governments and quasi-government entities.

Our areas of specialty include utilities, infrastructure and power; mining; real estate and technology. In the electricity sector, MPA has direct and recent experience on a number of transactions and other advisory assignments involving electricity assets and has detailed knowledge and experience with this market, its participants and how they operate.

Information on the team members contributing to this report, as well as the scope of our assignment is attached in Appendices F through J.

For more information on MPA, please visit our website at www.morrisonpark.com.

1. Manitoba Hydro Request

A. Original Request (May 5, 2017)

By way of formal application for electricity rates, Manitoba Hydro requested that the Manitoba Public Utilities Board ("PUB") approve:

- An across-the-board rate increase of 7.9% to be effective on August 1, 2017;
- An across-the-board rate increase of 7.9% to be effective on April 1, 2018; and
- A number of approvals relating to adjustment of specific rate classes, recovery of regulatory deferral accounts, amortization periods, and other technical matters.

Based on these requests, it could be expected that Manitoba Hydro would return to the PUB sometime in mid-to late-2018 with a request for new rates as of April 1, 2019.

B. Implicit Requests Inherent to the Application – Financial Targets and Goals

The request for rate increases reflects current assumptions about a range of expected revenue and cost drivers. Forecasts for domestic demand, export prices, operating expenses, interest costs and required capital expenditures were included in the application, as required, and are subject to scrutiny by the PUB to support the need for the requested rate increases.

Beyond forecasts of future operating and economic variables, however, the application provides substantial information about Manitoba Hydro's financial targets. Moreover, the application contends that the need to meet these targets within a specific period of time helps to justify the requested rate increases.

Manitoba Hydro focuses on three main tests for financial health:

- Debt to Equity Ratio, with a target level of 75:25;
- Interest Coverage Ratio, with a target level of 1.8x;[1] and
- Capital Coverage Ratio, with a target level of 1.2x.

[1] Note that historically Manitoba Hydro calculated its "interest coverage" using an EBIT-based formula. In 2015 Manitoba Hydro changed the formula, and began using a calculation that employs "EBITDA", instead of "EBIT". In its materials, the new ratio is sometimes referred to simply as the "Interest Coverage Ratio", and sometimes as the "EBITDA to Interest Coverage Ratio" in order to differentiate the new formula from the old formula (in documents from previous rate hearings, "interest coverage ratio" always referred to the "EBIT"-based calculation, hence the possible source of confusion). Please note that in this Report, all references to "Interest Coverage Ratio" refer to the new, post-2015 formulation. The older calculation is a different metric, and is not employed anywhere in this Report.

Debt to Equity Ratio

Manitoba Hydro calculates its Debt to Equity Ratio as follows:

$$\frac{\text{(Total Net Debt = Long-term Debt - Sinking Fund Balances + Short-term Debt - Short-Term Investments)}}{\text{(Retained Earnings + Unamortized Customer Contributions + Accumulated Other Comprehensive Income + Non-controlling Interest + Total Debt)}}$$

While most of the elements in the calculation are familiar, two notable elements are “Unamortized Customer Contributions” and “Accumulated Other Comprehensive Income”.

The former refers to contributions in aid of construction that were received from customers for capital projects, and that are being amortized in parallel to the depreciation of the capital items that they helped to pay for. In some jurisdictions, utilities remove contributions in aid of construction from the value of assets, and therefore also exclude these amounts from the liabilities/equities side of the balance sheet. Since Manitoba Hydro does not exclude contributions from the value of their assets, then there must be corresponding liabilities which are amortized over time, and Manitoba Hydro has reflected this in the Debt to Equity Ratio.

“Accumulated Other Comprehensive Income” has taken a more prominent role since Manitoba Hydro adopted the IFRS accounting standard in its fiscal year ending March 31, 2015. This balance sheet item includes transactions which are not part of the normal operations of the company, and often relate to unrealized gains or losses on such things as foreign exchange transactions, hedging arrangements and pension plans. Typically, such gains or losses are recorded because the fair value of a financial instrument has changed since it was first arranged, however that instrument is still outstanding as of the end of the financial year (hence the gains or losses are “unrealized”). Significantly, for Manitoba Hydro, the amounts in this item grew substantially (and became an accumulated loss instead of a gain) upon adoption of IFRS accounting standards, and have mounted since. The result is that the calculation of the Debt to Equity Ratio would be different if Manitoba Hydro were using CGAAP or USGAAP accounting standards, as opposed to IFRS. In any case, Manitoba Hydro has predicated all of its calculations and scenario-building on the continued use of IFRS accounting, so this treatment will be used.

The Manitoba Hydro Electric Board has taken the position that the company should strive to achieve the Debt to Equity Ratio target of 75-25 by the end of the fiscal year ending March 31, 2027. Based on the provided analysis and forecasts, and assuming the accuracy of all assumptions made in the application, the original application states that there is a 50% probability of achieving this goal, if domestic rates are increased by 7.9% per year for three additional years beyond the two increases for which Manitoba Hydro formally applied, followed by five years of 2% domestic rate increases.

This ten-year rate path, and its relationship to the Debt to Equity Ratio target, is critical to the application as a whole. If the Debt to Equity Ratio target were not 75-25, or if the goal was to achieve that target over a longer timeframe, then rate increases of 7.9% likely would not have been requested.

In addition, a ten-year rate path of 7.9% increases for five years followed by 2% increases for five years is not the only possible rate path that would result in the achievement of 75% debt target by March 31, 2027. Manitoba Hydro could have requested even annual rate increases over the entire period, or could have suggested more modest increases for the first several years of the period, followed by larger increases later, or any combination of various mathematical possibilities.

In the broader context facing Manitoba Hydro (which will be discussed further in Section 3), what does it mean to achieve a ratio of 75:25? In a literal sense, it means that the book value of the assets in the company are significantly greater than its outstanding debt. Manitoba Hydro has indicated that it believes this to be a sign of ample “financial strength”, and that if it has achieved that goal, it will have enhanced flexibility to issue more debt, if circumstances arise where that might be necessary.

Interest Coverage Ratio

Manitoba Hydro calculates its Interest Coverage Ratio as follows:

$$\frac{\text{Net Income + Depreciation Expense + Finance Expense + Capitalized Interest}}{\text{Finance Expense + Capitalized Interest}}$$

Manitoba Hydro sometimes refers to this calculation as an “EBITDA : Interest Coverage Ratio”, in order to distinguish it from an older calculation that was also called “Interest Coverage Ratio”, but which was calculated differently. The exact formulation that Manitoba Hydro is using now, described above, is not identical to what is commonly considered an EBITDA : Interest calculation (Earnings Before Interest, Depreciation and Amortization, as compared to Interest). In Manitoba Hydro’s formulation, it is important to note that Net Income includes a number of special items (such as recognition of deferred revenues and net movement of regulatory balances) which are not always included in the more common EBITDA calculation. This technicality can be ignored in practice, however.

The Interest Coverage Ratio, as calculated by Manitoba Hydro, is often considered an important metric when assessing the credit-worthiness of an enterprise, because it provides information about the sufficiency of cash flow to cover interest costs. However, it should be noted that customer revenue (and many other items) is recognized on an accrual basis (i.e., when billed) as opposed to on a cash basis (when payment is actually received). As a result, while this ratio serves as an indicator of the sufficiency of cash flow, it is an “accounting” measure and not a true “cash flow” measure of the results of the period for which the calculation is being made.

Capitalized interest represents the amount of interest accrued during the year which will ultimately be transferred to asset accounts associated with capital goods currently in construction.[2] When new capital goods take more than one year to construct, they must be financed through debt issuance (or equity contributions, in the case of utilities which have an equity provider who contributes capital). Since the costs associated with such construction projects should not be passed on to ratepayers until such time as they are in use (“used and useful”), the interest associated with that debt should not form part of the annual expenses of the regulated business.

Notably, according to the IFRS accounting rules that Manitoba Hydro relies on, the amount of capitalized interest is calculated not on the basis of the actual cash interest costs associated with the construction project (which might be the case if a project were undertaken by a special purpose entity that arranged construction financing, for example), but instead based on the average cost of debt for the corporation and the average cost of the construction projects outstanding for the year. Since the average cost of Manitoba Hydro debt is influenced by all of the debt issued in the past, and past debt issues were more expensive than debt incurred today, the average cost of debt for Manitoba Hydro is actually higher than the real cash cost of construction debt that would be required for projects currently in

[2] On the Consolidate Statement of Cash Flows, the amount of capitalized interest is buried in the Additions to Property, Plant and Equipment, and does not appear in the Cash Flow from Operating Activities line item.

progress. This means that more debt interest is being capitalized than was actually “caused by” the construction projects underway, strictly speaking. This serves to reduce finance expense in the current year, which increases net income now, while deferring more interest to be recovered from ratepayers in the future. Note, however, that if interest rates were to increase, such that past rates were lower than current rates, the opposite situation would obtain, so the relationship between current finance expense and capitalized interest is at least somewhat based on happenstance.

Despite the subtleties associated with capitalized interest, for the purposes of the Interest Coverage Ratio, the addition of finance expense and capitalized interest can be understood to approximate the net cash cost of debt interest for the year (note that Finance Expense is not just interest paid on long and short-term debt, but also includes offsets from interest income received from short-term investments, hence this is a “net” total).

What does it mean that the target is 1.8x? In this case, operating cash flows before interest charges would be greater than interest charges. The remaining 0.8x of funds after paying interest charges could be used to invest in new capital equipment, or to pay down debt principle (bonds that may be coming due). This measure alone does not clarify whether the company’s debt is increasing, since there is no information captured in this metric about the size of capital expenditures (if capital expenditures are greater than 0.8x Net Finance expense, then Manitoba Hydro will have to borrow additional funds, but if capital expenditures are less than 0.8x Net Finance Expense, then the corporation could actually retire some debt principal). By the same token, this ratio provides no information on whether the Debt : Equity Ratio is rising or falling. It would be necessary to know both the size of the annual capital investment and the size of depreciation in order to calculate the impact on the debt ratio. Nevertheless, if this ratio were at a 1.8x level, creditors would be comfortable that the business is producing enough cash flow to service outstanding debts.

It may also be instructive to note the limitations of this calculation with respect to cash flow. There are many possible measures of cash flow, and this is only a variant of one of them. Some measures, such as “Free Cash Flow” are focused on understanding more about the actual cash funds available from a company after all of its expenditures have been taken into account (including capital expenditures and non-cash items such as net working capital). Others, like “Discretionary Free Cash Flow” make some distinctions about which planned expenditures are absolutely required, versus those which are optional. Depending on the specific objective of an analysis, each different cash flow measure may be useful.

In the application, Manitoba Hydro does not emphasize this cash flow metric as much as it does the Debt : Equity Ratio, and does not address other variants of cash flow metrics and their uses.

Capital Coverage Ratio

Manitoba Hydro defines its Capital Coverage Ratio as follows:

$$\frac{\text{Cash Funds From Operations}}{\text{Capital Expenditures (excluding Major New Generation and Transmission Projects)}}$$

Notably, when calculated on a retrospective basis, “Cash Funds From Operations” is an actual measure of real cash flows, and not an approximation including non-cash items such as non-cash working capital, deferral accounts, regulatory accounts, accruals, etc. On a prospective basis, however, for the purposes of modeling, most such nuanced differences between cash and non-cash accounts are generally ignored, since modeling them would be an unnecessary and time consuming complication.

Excluding "Major New Generation and Transmission Projects" is an extremely important element of the calculation. In effect, this measure is indicating the sufficiency of actual cash flows from operations to pay for maintenance capital expenditures, and expenditures required to manage "normal" as opposed to "major" or "strategic" growth in the system. This distinction makes the calculation somewhat arbitrary, since Manitoba Hydro can redefine at any time, by an internal policy change, whether a given project is sufficiently "major" to be excluded.

This metric is not a typical part of financial analysis, and its value is somewhat obscure. Certain typical financial measures do take into account capital expenditures (such as "Free Cash Flow"), but determining whether funds from operations are sufficient to pay for capital expenditures does not in itself indicate much about the company. Knowing the amount of Cash Funds from Operations generated by a company is often useful when compared to interest charges or debt (in which case it becomes a cash flow metric), since debt providers often wish to understand whether a company has sufficient cash to make good on debt obligations. Since interest charges are paid before new capital expenditures, it is not clear what purpose is served by aiming for cash flows to be 0.2 times in excess of planned capital expenditures? Unless debt interest charges are very small, they will in all likelihood be greater than 0.2 times capital expenditures (especially in a large, capital intensive electricity business like Manitoba Hydro). Moreover, knowing that cash flows are slightly larger than planned capital expenditures does not provide any insight into the direction of the Debt : Equity Ratio or the Interest Coverage Ratio, because too many other values are missing from the calculation of the Capital Coverage Ratio. In short, this metric qualifies as information, but its usefulness is somewhat questionable.

In the application, Manitoba Hydro does not emphasize the Capital Coverage Ratio as a financial measure related to rate-making as much as it does the Debt : Equity ratio.

C. Revised Materials Based on the Interim Rate Decision

By Order 80/17, the PUB granted an interim rate increase of 3.36% to Manitoba Hydro, commencing on August 1, 2017. The PUB denied Manitoba Hydro's request for an increase of 7.9%.

As a result of this decision, Manitoba Hydro has now revised its application materials pertaining to its financial targets and its future rate path. In keeping with its apparently primary objective of achieving a Debt to Equity Ratio of 75-25 by March 31, 2027, it now asserts that an even more aggressive 10-year rate path will be required, as described in the chart below. It is notable that in making this adjustment to its forecast of the future, Manitoba Hydro does not reference its other two measures of financial health, but instead focuses almost exclusively on the need to meet its Debt : Equity target.

	Original Application	Revised Materials
1 August 2017 to 31 March 2018	7.9%	3.36%
1 April 2018 to 31 March 2019	7.9%	7.9%
1 April 2019 to 31 March 2020	7.9%	7.9%
1 April 2020 to 31 March 2021	7.9%	7.9%
1 April 2021 to 31 March 2022	7.9%	7.9%
1 April 2022 to 31 March 2023	2.0%	7.9%
1 April 2023 to 31 March 2024	2.0%	7.9%
1 April 2024 to 31 March 2025	2.0%	4.54%
1 April 2025 to 31 March 2026	2.0%	2.0%
1 April 2026 to 31 March 2027	2.0%	2.0%

Formal request: Interim Decision: Revised Projection:

It is important to note that despite the change in forward projections based on Manitoba Hydro's target Debt : Equity Ratio and timing goal, Manitoba Hydro has not requested that the PUB formally endorse or otherwise agree with either the target level or the timing goal. Nor is any certainty with respect to future rate increases actually being requested. In effect, the 10-year rate path is provided for illustrative purposes only, to support arguments justifying the formal rate request. Presumably, Manitoba Hydro will be returning to the PUB for new rates as of April 1, 2019, and such new application will be based on two additional years of operating history and a new set of assumptions (domestic demand, export prices, operating costs, etc., etc.). As a result, that future rate request and forward projections for rates could be entirely different, even if still based on a Debt : Equity Ratio target of 75:25, with a goal of March 31, 2027.

2. Issues Addressed in this Report

This report will attempt to shed light on a number of topics arising from Manitoba's Hydro's rate application, and in particular the reliance on financial targets and goals to support the particular level of the rate increase requested.

Manitoba Hydro's focus on financial targets, and in particular on the Debt : Equity Ratio, raises a number of questions.

- Why are financial targets relevant to rate-setting for Manitoba Hydro?
- Should the Debt : Equity Ratio be the primary financial target that is taken into account when setting rates for the future?
- Assuming the Debt : Equity Ratio is the primary target, should rates be set so as to achieve that target by March 31, 2027?

Section 3 of the report will examine the context for Manitoba Hydro's financial targets, in terms of the nature of the targets, the levels Manitoba has chosen to aim for, and the timeframe over which the targets will be achieved. The section will consider questions related to whether Manitoba Hydro's self-defined financial targets are appropriate targets to help guide ratemaking.

Section 3(a) will address the legislative framework under which Manitoba Hydro operates, and which supports the PUB's consideration of rate requests. Since the legislation requires Manitoba Hydro to apply to a utility regulator for rates, section 3(b) will summarize the general statements of the PUB with respect to the principles guiding its decisions. In addition to Manitoba legislation, the PUB is also guided by the body of regulatory principles and good practice that have been developed over the past hundred years across North America. As a result, this body of principles and practice will be outlined in section 3(c).

Manitoba Hydro is a public enterprise, in that it does not have private sector shareholders but is instead created by statute on behalf of the people of Manitoba. This places the company outside of the worldwide norm for utility companies, but is by no means a unique or exclusive condition. Section 3(d) will examine some of the ways in which Manitoba Hydro's circumstances differ from those of the traditional regulated utility model, particularly as they pertain to financial targets and performance.

There are many other utilities structured as public enterprises, even though a majority are not, and section 3(e) will provide information on a number of public enterprise electricity utilities from Canada and the United States for the purpose of comparison and contrast with Manitoba Hydro, particularly from the perspective of financial performance and targets.

Finally, in terms of context, the views and practices of the capital markets with respect to financial targets at public enterprise utilities like Manitoba Hydro will be addressed in section 3(f). This will provide some indication of the range of possible targets, levels and timing goals that the PUB may consider within its ratemaking deliberations while ensuring that Manitoba Hydro continues to have access to the capital markets.

In the application, Manitoba Hydro contends that robust financial targets are required in order to better manage risks that potentially threaten Manitoba ratepayers. As a result, section 4 attempts to assess the risks facing Manitoba

Hydro, understand how these risks might affect financial performance, and hence how the PUB may wish to address risk issues within its deliberation on Manitoba Hydro's application.

Section 4(a) outlines the risks faced by Manitoba Hydro in broad terms, and attempts to provide some boundaries on the frequency, severity and duration that should be expected for certain risk issues. Section 4(b) considers the mechanisms which could be used to financially manage these risks from a regulated utility perspective. In addition, the practical limitations on such mechanisms will be addressed so as to eliminate from consideration those that are not likely to be applicable in the future.

Section 4(c) focuses on the relationship between risks, financial targets, financial mechanisms to manage those risks, and the regulatory principles that should guide ratemaking decisions.

Section 5 addresses some of the practical issues that fall out of a determination about financial targets in a ratemaking context. In particular, section 5(a) considers the future ratemaking impact of a decision based on a particular set of financial targets and goals. Section 5(b) considers the regulator's ability, through its ratemaking decision, to affect the capital market's perception of Manitoba Hydro and its financial targets and behaviour. Finally, section 5(c) examines how a regulatory decision on financial targets and goals will affect the debt management strategy of Manitoba Hydro.

Section 6 summarizes the key observations on Manitoba Hydro's financial targets made in this report, and suggests possible paths forward for the PUB to pursue on these matters.

3. Context for Manitoba Hydro Financial Targets and Goals

The ultimate goal of regulatory rate-making is "just and reasonable rates", as well as ensuring "fair" and "equitable" treatment of all of the parties involved. However, these goals can only be met by reference to some set of principles and models which guide deliberation and decisions, as they are applied to specific circumstances. Without context and principles, "just", "reasonable", "fair" and "equitable" are just empty words.

A. Manitoba Hydro's Legislative Framework

[*Please see Appendix A for the text of the legislation referred to in this section of this report*]

Manitoba Hydro is a corporation created by statute of the Province of Manitoba, through the *Manitoba Hydro Act*. The *Act* specifies that the company is the sole provider of electricity to retail customers in Manitoba (s. 15.2), and has the power to require any electricity produced by anyone in the province to be supplied to Manitoba Hydro (s. 16(1)(c)). In effect, the Province of Manitoba is the exclusive territory of the utility from the perspective of electricity supply.

The corporation has two main purposes:

- To supply power "adequate for the needs of the province", and
- "to supply power to persons outside the province" (s. 2).

The Board of Directors of the corporation has the power to make most decisions about the conduct of the business of the corporation, and has the responsibility to ensure it is meeting its purposes (ss. 14 and 15). However, like most government-owned enterprises, the company may not sell its businesses or major assets without express government approval (s. 15.1).

From a financial perspective, four provisions are critical:

- The price of power must reflect the full cost of operating the electricity system (s. 39(1));
- The corporation has limited powers to raise debt for short-term purposes (up to $500 million);
- The corporation's long term debt may be supplied by the government of Manitoba
- The province will guarantee all outstanding debt of Manitoba Hydro (ss. 30 to 35)

Despite the broad powers of the corporation to manage the supply and delivery of power in the Province of Manitoba, the company does not have the right to set its own rates. The *Crown Corporations Governance and Accountability Act* requires that Manitoba Hydro apply to the Public Utilities Board of Manitoba for any change in rates (s. 25). The PUB has the authority to review Manitoba Hydro applications, and to set rates that are consistent with the provisions of the *Manitoba Hydro Act*. The *Public Utilities Board Act* specifies all of the procedural rules that the PUB follows in reviewing applications, which are brought into play by s. 25(3) of the CCGAA. However, much of the *PUB Act* is not applicable to Manitoba Hydro (according to s. 2(5)).

The *Manitoba Hydro Act* specifies what Manitoba Hydro can include in its calculation of the price of power (s. 39(1)):

a) the necessary operating expenses of the corporation, including the cost of generating, purchasing, distributing, and supplying power and of operating, maintaining, repairing, and insuring the property and works of the corporation, and its costs of administration;

> b) *all interest and debt service charges payable by the corporation upon, or in respect of, money advanced to or borrowed by, and all obligations assumed by, or the responsibility for the performance or implementation of which is an obligation of the corporation and used in or for the construction, purchase, acquisition, or operation, of the property and works of the corporation, including its working capital, less however the amount of any interest that it may collect on moneys owing to it;*
>
> c) *the sum that, in the opinion of the board, should be provided in each year for the reserves or funds to be established and maintained pursuant to subsection 40(1).*

The concept of "reserves" is critical to the finances of the corporation, since it provides the enterprise with a degree of flexibility in managing its finances, which might not otherwise be possible. Section 40(1) and s. 40(2) provide additional detail with respect to reserves:

> *40(1) The board shall establish and maintain, and may adjust as required, such reserves or funds of the corporation as are sufficient, in the opinion of the board, to provide*
>
> a) *for the amortization of the cost to the corporation of the property and works, (whether as a whole or in its component parts), of the corporation during the period, or remaining period, of the useful life thereof;*
> b) *insurance, for which provision is not otherwise made, against loss or damage to any property of the corporation, or to the persons or property of others, caused by or arising out of the works or operations of the corporation;*
> c) *for the stabilization by the board of rates or prices for power sold by the corporation, the meeting of extraordinary contingencies, and such other requirements or purposes as in the opinion of the board are proper.*
>
> *40(2) The reserves created pursuant to subsection (1) may be used or employed by the board*
>
> a) *towards the reservation and setting aside of the sinking fund established under section 41;*
> b) *towards the renewal, reconstruction, or replacement, or depreciated, damaged, or obsolescent property and works;*
> c) *towards restoration of any property lost or damaged, or the payment of any claims, in respect of which a reserve as insurance has been established;*
> d) *in such manner towards the stabilization of rates or prices for power, the meeting of extraordinary contingencies, and for such other requirements or purposes, as the board in its discretion deems proper; and*
> e) *subject to the approval of the Lieutenant Governor in Council, towards the cost of construction of new works and extensions, improvements, or additions, to any property and works of the corporation.*

Somewhat confusingly, however, the *Crown Corporations Governance and Accountability Act* provides a different description of what should be included in the PUB's consideration of proposed Manitoba Hydro rates:

> *25(4) In reaching a decision pursuant to this Part, The Public Utilities Board may*
>
> a) *take into consideration*
>
> (i) *the amount required to provide sufficient funds to cover operating, maintenance and administration expenses of the corporation,*

(ii) interest and expenses on debt incurred for the purposes of the corporation by the government,
(iii) interest on debt incurred by the corporation,
(iv) reserves for replacement, renewal and obsolescence of works of the corporation,
(v) any other reserves that are necessary for the maintenance, operation, and replacement of works of the corporation,
(vi) liabilities of the corporation for pension benefits and other employee benefit programs,
(vii) any other payments that are required to be made out of the revenue of the corporation,
(viii) any compelling policy considerations that the board considers relevant to the matter, and
(ix) any other factors that the Board considers relevant to the matter; and

b) hear submissions from any persons or groups or classes of persons or groups who, in the opinion of the Board, have an interest in the matter.

While the formulations of the requirements are somewhat different between the two Acts, it is clear that both Acts provide flexibility to include some amount of "reserves" in the calculation of rates charged by Manitoba Hydro. Moreover, both Acts make clear that recovery of all of Manitoba Hydro's necessary costs is required over time.

One notable issue is that while both Acts specifically allow for "reserves" to be maintained at Manitoba Hydro, and for the calculation of rates to take reserves into account, neither the legislation nor attendant regulations specify the size of those reserves, nor any other characteristics about them. Unlike in many other jurisdictions, where the capital structure of government-created utilities are specified by government, in Manitoba this matter has been left open.

B. Regulatory Principles and the Regulatory Model

While legislation spells out the broad outlines of what can and should be included in rates, the details and nuances of rate-setting are found in regulatory principles, policies and decisions. Over more than 100 years, a body of regulatory precedents and practice has developed which can be called upon to help make determinations about utility rate issues. This regulatory practice extends beyond Manitoba to the rest of Canada, the United States, the United Kingdom, and other countries with similar legal and government systems with respect to utilities.

In addition, there is also a substantial body of academic analysis from the perspective of economics and law which sheds light on regulated utility rates, and regulatory issues more broadly.

Manitoba PUB Regulatory Principles

The PUB has described its regulatory principles in the following way[3]:

> *There is no single authority that sets regulatory principles, and these principles may conflict or overlap, but it is the goal of the PUB to effectively balance the following principles and consistently take them into consideration when setting utility rates.*

[3] Please see Appendix B for the full text of the PUB's statement about regulatory principles, as drawn from the PUB's website.

- *Cost of service standard*
- *Intergenerational equity*
- *Matching Principle*
- *Rate stability and predictability*
- *Used or required to be used*
- *Prudence standard*
- *Why we do it*

Specifically with respect to its consideration of rate applications, in Board Order 98/14 the PUB summarized its duty as:[4]

- *Ensuring that forecasts are reasonably reliable;*
- *Ensuring that actual and projected costs incurred are necessary and prudent;*
- *Assessing the reasonable revenue needs of an applicant in the context of its overall general health;*
- *Determining an appropriate allocation of costs between classes; and*
- *Setting just and reasonable rates in accordance with statutory objective*

This summary reflects many of the concepts included in the PUB's principles, as described above.

Broader Regulatory Principles and Practice

As noted above, the PUB does not exist as a regulator in isolation, nor did it develop its principles and practices on its own. The PUB's principles and practices are drawn from, and broadly consistent with those of many other jurisdictions, with appropriate adjustments for the needs of Manitoba.

An enormous body of academic literature concerning utility regulation exists, which summarizes, analyses and critiques a multitude of the issues which may arise in any jurisdiction. One of the foundational texts for modern regulatory rate-making is James C. Bonbright's *Principles of Public Utility Rates* (1961), source of the famous "Bonbright Criteria" for regulatory rate-making.[5] Important additional texts include, for example, Alfred E. Khan, *The Economics of Regulation* (1970), and Charles F. Phillips, *The Regulation of Public Utilities* (1984). From these and many similar works, a summary list of general principles can be formed which capture what most regulators focus on.

Monopoly Utility Customer Service: Regulated rates should be set for services which can only be efficiently provided by a monopoly. If a service is amenable to market competition, then it should not be regulated, but rather should be opened to competition, to the benefit of customers. Assuming a territorial monopoly is the only reasonable arrangement for a service, then ensuring the actual delivery of high quality service to customers should be a priority of regulation.

Economic Efficiency, both Static and Dynamic: A monopoly utility should be regulated in such a way that its services are delivered as efficiently as possible, making best possible use of available resources, both at any given time and over time. Given that the potential for efficiency changes over time depending on labour markets,

[4] Board Order 98/14, page 28. Note that this was a Board Order in respect of the Manitoba Public Insurance Corporation. However, a substantially similar list appears in Board Order 5/12, pages 26 – 27, which was in respect of Manitoba Hydro.
[5] Please see Appendix C for the full text of the Bonbright Criteria.

available technology and economic conditions, regulators should ensure that utilities are not only delivering services using the most efficient tools and practices available at any given time, but are also appropriately planning and investing to perform their functions more efficiently in the future.

Cost Causality, both Between Customers and Over Time: Customers should pay the costs associated with the services they use, and rates should reflect that. This is a critical concept in allocating current costs between customer classes, but also with respect to allocating the cost of long-lived assets over time. This principle rests on the recognition that all customers are equally important, so fairness demands that no customers be forced to pay for costs caused by others.

Stability and Predictability: Customers' ability to properly plan their usage of the utility's products and services depends on knowledge about how much those services will cost or are likely to cost, and when and in what form they will be available. By the same token, the utility itself can only operate efficiently if it has appropriate foreknowledge of the standards and business practices that are going to be required of it.

Prudence: Utilities should operate in a manner which reasonably reflects the common understanding of risks applicable in their industry, and seek to appropriately manage those risks. This principle is both a standard for utility behaviour, and a defense for utilities against after-the-fact criticism of their decisions and behaviour in challenging circumstances.

Public Interest: Utilities should be required to operate in a manner that is cognizant of the externalities associated with their products and services, and as much as possible supports the economic and social development of their communities. As a matter of course, utilities should meet all public requirements and standards with respect to labour, environmental, health and safety practices.

Access to the Capital Markets: Utilities are capital intensive businesses, and as such should be regulated, organized and operated in a way which will be attractive to the capital markets as an investment opportunity. This will both facilitate ongoing investment, and ensure that the cost of capital applicable to the investment is as low as possible.

It is important to note that these principles cannot always be simultaneously accommodated in every regulatory situation. The essence of "fairness" or a "just and reasonable" determination is in fact typically associated with balancing and applying these principles to specific cases. For example, "cost causality" might imply that costs should be allocated on an individual customer basis, but concern with administrative efficiency demands customers be grouped into reasonably large classes to prevent undue administrative burden and keep costs down. Similarly, fixing prices for 10 years at a time might benefit customers by providing predictability, but the capital markets would object that limiting financial flexibility would create significant risks that would result in much higher costs of capital. Despite the impossibility of simultaneously satisfying all of the principles in every situation, it is still critical that the relationship between every regulatory decision and the principles upon which it rests are made clear.

The Typical Economic Model for Regulated Utilities

The broad regulatory principles outlined above were formulated in relation to an economic model for utilities. This model both expresses the application of these principles, and highlights their limitations.

Investor-owned: In the United States, where there has been the most development of both the economic literature and jurisprudence of regulated utilities, approximately 70% of electricity customers today are served by investor-owned utilities. While the remainder are served by a combination of rural electric cooperatives and government-owned utilities ("Public Power Utilities", as they are called in the United States), the starting point for utility analysis has traditionally been the investor-owned model. In an investor-owned utility, equity investors bear the primary risk of financial uncertainty and loss, in exchange for receiving a regulated return on the equity they contributed to the utility.

Ratebase Model: The capital base of the utility consists of the Property, Plant and Equipment (including "intangibles" that are necessary for the operation of the utility) that is currently in use ("used and useful"), plus some amount of Working Capital (the exact definition and calculation of which differs from jurisdiction to jurisdiction) necessary for the daily operation of the business.

Capital Structure Determined by the Regulator: Typically, regulators determine a maximum allowable amount of debt in the capital structure, with the remainder consisting of equity contributed by shareholders. The choice of the debt-equity ratio must balance efficiency, risk management and access to capital. A very significant literature exists specifically on the point of the restrictions regulators should put on equity providers to manipulate the capital structure for their own benefit.

Revenue Requirement Formula: Opex + Depreciation + Debt Interest + Return on Equity + Taxes
where:

- Operating Expenses (Opex) are consistent with prudent and efficient utility operations, and will be expected to be sufficient to deliver on customer requirements, while meeting all public interest standards;
- Depreciation is based on the total pool of depreciable assets employed in the business (as long as they are "used and useful"), and is typically calculated on a straight line basis (whether individual or group), in order to allocate the burden of the use of assets equally across time to the ratepayers that benefit from them;
- Debt Interest and Return on Equity are calculated based on the deemed Ratebase of the utility;
- Debt Interest is typically calculated using interest rates actually faced by the utility, to ensure that the cost of capital is both as efficient as possible, and reflective of the real cost of operating the utility;
- Return on Equity is based on a Rate of Return on Equity set by the regulator, at a level that is high enough to attract sufficient capital from the market, but not higher than necessary, so as to ensure that cost of capital for the utility is as efficient as possible;
- Taxes at prevailing rates, and calculated based on the expected Return on Equity.

Prospective Rates: The Revenue Requirement is calculated prospectively for a coming year, based on forecasts and assumptions. The Equity Provider is at risk for any variation between the forecasts and assumptions and reality as it may occur, within limits set by the regulator. If the utility is operated poorly, and earns less than the expected return on equity during the coming period, then investors will suffer. If weather events (such as heat waves or cold snaps) cause customers to use more than usual amounts of power, then investors may earn higher than normal returns. However, regulators sometimes provide full or partial relief against certain unusual risks, and/or may limit the allowed return on equity above a certain level (which reduces the financial risk associated with the equity while possibly also limiting the upside available to investors, and may make the total cost of the utility more efficient in the long run).

Capital Plans Approved by the Regulator: Since investors' return on equity is ultimately dependant on the capital used in the business, a primary concern of regulators is ensuring that capital equipment is only purchased if it is reasonably and prudently necessary for the proper operation of the utility (regulated utilities are one of the few classes of companies in the world where spending more money on capital equipment is a positive temptation).

This model, as refined over decades of experience, has been optimized to balance the various regulatory principles described above. Under theoretically ideal conditions (for example, stable inflation and interest rates, zero customer growth and equal amounts of capital expenditures required annually), customers would face a stable cost of power on an inflation-adjusted basis, which would represent a perfectly "fair" allocation of costs over time. However, since "ideal" conditions do not happen in reality, any number of challenging decisions are required to try and ensure "just and reasonable" rates. The widespread use of this model across North America means that most of these issues have been addressed many times in the past, and different solutions have been attempted, which provides all regulators with a rich body of experience upon which to draw.

C. Manitoba Hydro Differs from the Traditional Regulated Utility Model

Manitoba Hydro is not structured according to the typical regulated utility model, and differs in a number of important ways.

Non-share Capital Corporation: As noted above, Manitoba Hydro was created by statute, is an agent of the Government of Manitoba, has no equity investors at risk for its performance, and makes no payments to any equity investors (the government is not an equity investor itself). Theoretically, this means that 100% of the utility's capital could be debt. In addition, since there are no equity investors, and no equity capital at risk in the company, then any capital in the company other than debt is not really "equity" in the normal meaning of the word.[6]

Exports are an Objective: Unlike a typical monopoly utility whose obligation is to serve the customers in its territory as efficiently as possible, Manitoba Hydro is explicitly allowed by its governing legislation to seek to export power. This is a critical distinction, because the business model and risks associated with exports are fundamentally different from the business model and risks associated with a domestic monopoly utility business.

Debt Provided and Guaranteed by Government: The Government of Manitoba is the sole provider of long-term debt to Manitoba Hydro. In turn, the government raises debt capital from the capital markets, and on-lends the funds to Manitoba Hydro, with the addition of a debt guarantee fee. This means that Manitoba Hydro is not directly exposed to the capital markets. However, the regulatory principle of "Access to Capital" is still important, since Manitoba Hydro's performance could have important impacts on the government's access to capital. The relationship to capital markets is less direct than normal, but still relevant.

No Ratebase Model: Manitoba Hydro does not have a ratebase consisting of property and working capital, no deemed capital structure for ratemaking purposes, and no rate of return on equity. Instead, only actual costs of

[6] Note that some government-owned enterprises use various names for "non-debt" capital, while others share Manitoba Hydro's use of the term "equity". Please see the next section for a sampling of the terminology used.

debt incurred by the company are included in rates, effectively minimizing the cash cost of capital for the corporation.[7]

All Costs Are Recovered Over Time: Since no equity investors are at risk, there are no parties available to bear the risk of Manitoba Hydro's actual financial performance. Domestic ratepayers are ultimately responsible for all of the costs of the utility, <u>however and whenever incurred</u>. While rates are still set prospectively based on forecasts and assumptions, any divergence between those forecasts and reality as it ultimately occurs are simply captured in future rates.

Reserves are Required: Since Manitoba Hydro has no equity investors or equity capital at risk, and the corporation applies for rates based on estimates and forecasts of its expenses and cost of debt (rather than the larger deemed cost of debt and equity that would be calculated in a typical investor-owned utility model, which is based on a ratebase that includes some amount of working capital in addition to used and useful assets), the corporation must maintain reserves which allow it to manage divergences between forecasted and actual revenues and costs. This is an issue which will be examined in greater depth below.

Revenue Requirement Formula: Given the many differences from the typical regulated utility model, a different revenue requirement formula could be understood to apply to Manitoba Hydro, namely:
Opex + Depreciation + Debt Interest + Taxes +/- Planned Changes in Reserves
where:

- Opex, Depreciation, Debt Interest and Taxes have the same meaning as the typical regulatory model;
- Return on equity is conspicuously absent from the formula; and
- Planned changes in reserves can be positive or negative in any given year, depending on whether the corporation's reserves are more or less than required.

Government Approves Major Capital Spending: In the past, the Government of Manitoba has made decisions about major capital spending plans at Manitoba Hydro, and those plans were not contestable before the PUB. While "normal" capital spending could be reviewed as part of rate applications, very significant decisions related to the capital plan have been exempted from review. In the current rate application, the PUB has been directed by the government to review all capital spending plans as part of its determination of rates.[8]

Taken together, these various differences mean that Manitoba Hydro operates dramatically differently than a typical regulated utility, particularly in a financial sense.

The corporation's <u>cash</u> cost of capital is significantly lower than that of a typical utility, because Manitoba Hydro has access to government guaranteed debt, because it pays no returns on equity, and it charges customers only for its expected cash cost of debt interest rather than a deemed amount of debt interest based on a deemed ratebase. However, it is important to note that the <u>actual</u> cost of capital must include some accounting for the necessity and existence of reserves. The reserves represent a financial burden on the ratepayers that contributed the funds through their rates, and hence the capital cost of the reserves should be calculated at a discount rate appropriate for the full

[7] Note that there is an exception to "actual" costs of debt, which is the "deemed debt" that is capitalized in assets under construction, and which is calculated based on the average cost of debt in the utility, rather than an actual cost of "construction debt".
[8] Manitoba Order-in-Council 92/2017, issued on April 5, 2017.

body of Manitoba Hydro domestic customers.[9] Unlike equity providers in a typical regulated utility who freely choose to contribute capital based on expected returns, Manitoba Hydro customers involuntarily make contributions to reserves through their rates. The effectively hidden nature of this capital cost should increase the burden on Manitoba Hydro to demonstrate that its reserves are both required and properly managed.

This is complicated by the fact that the corporation's mission to pursue export opportunities creates strikingly different incentives, pressures and risks as compared to a typical regulated utility. There is no doubt that the existence within Manitoba of natural hydroelectric resources represents a significant opportunity for social and economic development on a provincial scale. However, developing those resources for export purposes rather than domestic consumption casts Manitoba Hydro in an entrepreneurial role, rather than the usual role of a regulated monopoly utility. Entrepreneurs fundamentally make a "risk/reward" decision when they choose to invest in a project: if their hopes bear out, they will make money, but if the project results are poor, they ultimately could lose their entire investment.

At Manitoba Hydro, investment decisions on export projects are made by the government based on analysis provided by Manitoba Hydro, yet the financial consequences of the decision are largely borne by domestic ratepayers, for good or ill. This disconnect in financial incentives is highly problematic, and not really amenable to analysis through the regulatory principles that arise from the typical regulated utility model. Regardless, the existence of these pressures in Manitoba Hydro means that the need for reserves are strongly impacted by the existence of export projects at any given time. Therefore, any consideration of the size and nature of reserves must take into account the risks inherent in export activities.

D. The Manitoba Hydro Peer Group

Manitoba Hydro is not a typical regulated utility, for all of the reasons described above. The primary difference is that it is an entity created by government statute, without equity investors. However, while this is not the way a majority of electricity utilities are structured, it is not a unique characteristic, as there are a number of government-created electricity utilities across North America, some of which share various characteristics with Manitoba Hydro.

Information on a number of such utilities has been gathered below.[10] A primary distinction between the two groups listed below is national identity: the first group consists of Canadian utilities, and the second consists of utilities from the United States.

A few observations may be considered notable:

Export Focus is Rare: Manitoba Hydro shares a mandate to pursue exports only with Hydro Quebec and Nalcor. BC Hydro conducts and profits from active trading with nearby jurisdictions, but that function depends more on the flexibility of that province's electricity system, rather than net exports (in many years the BC Hydro is a net importer of power, yet still profits handsomely from its trading activity). All other government-created utilities are

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[9] Note that reserves always are attributable to domestic ratepayers, even if Manitoba Hydro's exports happen to be profitable at any given time. The profits from exports in a cost-recovery entity like Manitoba Hydro should be used to reduce rates on domestic customers. If rates are not reduced because the export profits are necessary to increase reserves, then customers are making the contribution. Customers are in the same position as equity providers in a typical regulated utility, and bear the financial risk of the corporation.

[10] Please see Appendix D for additional information on these utilities.

mandated to seek to deliver low cost power to customers in their territories, and may engage in exports as an incidental by-product of having temporary excesses of supply.

Pure Cost Recovery Model More Common in the United States: Manitoba Hydro does not pay dividends to the Province of Manitoba.[11] This contrasts with most government-created utilities in Canada, which are required to pay dividends to provincial or municipal governments when financially feasible.[12] In several provinces, including in British Columbia, for example, the deemed debt to equity ratio is specified in legislation, and the regulator is required to include in rates a specific return on that equity. Comparison of financial targets between Manitoba and these provinces is therefore of limited use. In the United States, by contrast, a number of power authorities are explicitly structured as pure cost recovery enterprises, and pay no dividends to any government or other entity.

Use of the Term "Equity": Manitoba Hydro shares the use of the term "equity" with all other Canadian utilities. Given that virtually all Canadian utilities either do or have regularly paid dividends to their equity owner, this usage in cases other than Manitoba appears logical. However, in the United States where pure cost recovery models are more prevalent, a variety of different terms are used by utilities instead of the word "equity", which often provide a better description of the source of the capital in question. For example, the Bonneville Power Administration refers to "Accumulated Net Revenues", the New York Power Authority, Long Island Power Authority and Santee Cooper all refer to "Net Investment in Capital Assets", and the Tennessee Valley Authority uses the term "Proprietary Capital".

Debt to PPE Varies Dramatically: In the tables presented, recent information on long-term debt and on Property, Plant and Equipment is provided.[13] These two balance sheet line items were chosen deliberately because they tend to have stable definitions, even across various accounting standards and regulatory approaches. Calculating a ratio between these two figures provides insight into the degree of indebtedness of the entity.[14] In Canada, the range is from 27% for OPG to 102% for NB Power. In the United States, the range is from 22% for the New York Power Authority to 102% for the Long Island Power Authority. These dramatic differences depend both on policy choices, as well as coincidental characteristics of each utility.[15] Note that for comparison purposes, Manitoba Hydro's Debt : PPE ratio as of March 31, 2017 would be approximately 82%.

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[11] Note that special dividends have been paid in the past.

[12] Note that Nalcor, NB Power and SaskPower have not paid dividends in several years due to various financial challenges. Hydro Quebec and BC Hydro are required to make regular payments, while OPG's payments depend on performance. The municipal utilities all pay regular distributions to their owners.

[13] Note that for entities using IFRS accounting, "intangibles" were added to PPE. Also, the current portion of long-term debt has been added to reported long-term debt.

[14] Note that Debt/PPE is not a typical financial metric used by credit rating agencies or other analysts. Instead, an analyst will typically undertake a substantial process of "adjusting" reported financial results to standardize them and compare them to peers. For example, standard metrics for capitalization include Debt : Total Capital, and Debt : Equity. However, the use of GAAP vs. IFRS accounting affects the calculation of Total Capital, and some utilities use each of these accounting methods. Moreover, again depending on accounting standards and regulatory policy, non-cash items such as pension liabilities, post-retirement benefits liabilities and regulatory assets and liabilities may affect total capital in different ways. Focusing on the assets actually used in the utility business and verifiable long-term debt simplifies comparison and reduces the need for extensive explanations and caveats.

[15] For example, OPG has a massive non-debt liability on its balance sheet for nuclear retirement, which strongly affects its capital structure, and Santee Cooper has recently been forced to accept that it will have to write off several billion dollars of investment in a failed nuclear build, which has greatly increased its indebtedness.

Selected Government-Created Electricity Utilities in Canada

Name	Nalcor	NB Power	Hydro Quebec	Ontario Power Generation	Toronto Hydro	SaskPower	EPCOR	Enmax	BC Hydro
Created By	Government of Newfoundland and Labrador	Government of New Brunswick	Government of Quebec	Government of Ontario	City of Toronto	Government of Saskatchewan	City of Edmonton	City of Calgary	Government of British Columbia
Organization Type	Wholly owned Crown Corporation	Wholly owned Crown Corporation	Wholly owned Crown Corporation	Corporation with equity contributed by government	Wholly owned municipal company	Wholly owned Crown Corporation	Municipally owned commercial entity	Municipally owned utility	Wholly owned Crown Corporation
Regulated Market	Newfoundland and Labrador Generation and Transmission	New Brunswick Generation, Transmission and Distribution	Quebec and U.S. Northeastern regions (e.g. New England) Electricity Generation, Transmission and Distribution	Ontario Electricity Generation	Ontario Electricity Distribution	Saskatchewan Electricity Generation, Transmission and Distribution	Electricity Transmission and Distribution - British Columbia, Alberta, Saskatchewan	Calgary Electricity Generation, Transmission and Distribution and Natural Gas Distribution	British Columbia Electricity Generation, Transmission and Distribution
Other Markets	Electricity exports to Ontario, Quebec, Maritimes, US Northeast; also oil production and marketing	Maritimes, US Northeast	Ontario, Maritimes, US Northeast			Energy trading with Alberta, Manitoba, US Plains	Water and Wastewater in Alberta, BC, Saskatchewan, Arizona and New Mexico; Engineering services		Alberta, US Northwest
Export Mandate	Yes	No - surplus only	Yes	No	N/A	No - surplus only	N/A	N/A	Active Trading
Dividends Paid To	Government of Newfoundland and Labrador	Government of New Brunswick	Government of Quebec	Government of Ontario	City of Toronto	Government of Saskatchewan	City of Edmonton	City of Calgary	Government of British Columbia
Regulated By	Newfoundland and Labrador Board of Commissioners of Public Utilities	New Brunswick Energy and Utilities Board	Régie de l'énergie du Québec	Ontario Energy Board	Ontario Energy Board	Saskatchewan Rate Review Panel	Alberta Utility Commission	Alberta Utilities Commission	British Columbia Utilities Commission
2016 PPE (millions)	11,492	4,317	63,629	20,097	4,125	9,566	5,276	4,861	23,599
2016 Long-term Debt (millions)	6,015	4,427	45,616	5,520	2,085	5,559	1,920	1,647	20,024
Debt/PPE	52.3%	102.5%	71.7%	27.5%	50.5%	58.1%	36.4%	33.9%	84.9%
Company Credit Ratings					DBRS A S&P A		DBRS A low S&P A-	DBRS A low S&P BBB+	
Parent Credit Ratings (if applicable)	DBRS A low S&P A Moody's Aa3	DBRS A high S&P A+ Moody's Aa2	DBRS A high S&P AA- Moody's Aa2 Fitch AA-	DBRS AA low S&P A+ Moody's Aa2 Fitch AA-		DBRS AA S&P AA Moody's Aaa			DBRS AA high S&P AAA Moody's Aaa Fitch AAA

Selected Government-Created Electricity Utilities in the United States

Name	Bonneville Power Administration	Tennessee Valley Authority	New York Power Authority	Long Island Power Authority	Santee Cooper	Los Angeles Department of Water and Power	Basin Electric Power Cooperative
Created By	US Government	US Government	US Government	State of New York	State of South Carolina	City of Los Angeles	Member cooperatives
Organization Type	Self-funding Federal Power Marketing Administration	Self-funding Federally owned corporation	Self-funding State Authority	Co-funded municipal sub-division of the State of New York	State-owned electricity and water utility	Revenue-producing proprietary department	Not-for-profit electric cooperative under North Dakota law
Regulated Market	Northwestern USA Electricity Generation and Transmission	Midwestern USA Electricity Generation and Transmission	New York State Electricity Generation and Transmission	Long Island and Queens, NY Electricity Transmission and Distribution	State of South Carolina Electricity Generation, Transmission, Distribution	Los Angeles and surrounding communities Electricity Generation, Transmission and Distribution, and Water system management	Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota and Wyoming Electricity Generation and Transmission
Other Markets	Western Interconnection	Flood control, navigation and land management			Water systems		
Export Mandate	No - surplus only	No - surplus only	No	No	No	No	No
Dividends Paid To	None	None	New York State ("contributions to")	None	South Carolina	City of Los Angeles	None
Regulated By	FERC	Self-regulating for generation, FERC for transmission	Self-regulating for generation, FERC for transmission	Self-regulating with oversight by New York Department of Public Service	Self-regulating	Self-regulating	Self-regulating for generation, FERC for transmission
2016 PPE (US millions)	16,783	34,043	3,825	7,769	8,214	17,335	4,428
2016 Debt (US millions)	15,641	22,183	868	7,947	8,269	14,403	4,183
Debt/PPE	93.20%	65.16%	22.69%	102.29%	100.67%	83.09%	94.47%
Company Credit Ratings	Fitch AA Moody's Aa1 S&P AA-	Fitch AAA Moody's Aaa S&P AA+	Fitch AA Moody's Aa1 S&P AA	Fitch A- Moody's A3 S&P A-	Fitch A+ Moody's A1 S&P A+	Fitch AA- Moody's Aa2 S&P AA-	Fitch A Moody's A3 S&P A
Parent Credit Ratings (if applicable)							

Most But Not All Are Exclusive Monopolies in Their Territory: No other electricity company is allowed to operate in Manitoba. This is also true in most of the peer group jurisdictions, and it is a financial strength for all of the companies that share that characteristic. Some, like Ontario Power Generation, are not exclusive suppliers in their territory, and are subject to various forms of competition, making them less useful as a comparator for Manitoba Hydro.

Economic Model: BC Hydro, Nalcor, OPG and the three Canadian municipal utilities examined above explicitly use the traditional "ratebase" utility model to produce rate applications, again making comparison with Manitoba difficult and of limited use. Many of the US utilities examined set their own rates for all or part of their services. The Tennessee Valley Authority, which sets its own rates for power, describes its model as a "Debt-Service Coverage Methodology", which specifically focuses on the need to "cover its operating costs and to satisfy its obligations to pay principal and interest on debt".[16] The Bonneville Power Administration uses a cost recovery model to calculate its revenue requirement, but explicitly focuses on measurements of reserves, risk and liquidity in its calculations to ensure that it continues to be attractive to debt providers.[17] SaskPower, Santee Cooper, the Los Angeles Department of Water and Power and others target specific annual payments to their government parent entities, so their rates include their projected full costs, plus a payment to equity, which allows a financial "cushion" in rates in the event that forecasts prove to be inaccurate.

Investment Grade Debt: All of the utilities examined which have their own credit ratings (i.e., Canadian municipal utilities and all of the US utilities) boast investment grade debt (at least BBB+), regardless of their current levels of indebtedness (which in some cases are higher than Manitoba Hydro's). Every Canadian provincial utility is supported by provincial debt guarantees, or receives their debt funding directly through their provincial government, and all provincial governments in Canada are above investment grade.

This survey of government-created electricity utilities across North America serves to highlight that Manitoba Hydro is unique in important ways. It is the only utility which combines a full cost recovery model with an explicit mission to develop electricity resources for export purposes. Nalcor and Hydro Quebec both pursue exports, but neither operates based on a pure cost recovery model. Hydro Quebec shields its domestic ratepayers from the entrepreneurial risk associated with exports by designating a "heritage pool" of 165 TWh of energy for domestic use at fixed costs (rising annually by inflation). On the other hand, the results of export activities directly impact the government through the rise and fall of net income and dividends paid to the province. In essence, the government is taking the entrepreneurial risk associated with exports, not the ratepayer. Nalcor is pursuing a major export project (the Muskrat Falls generating station, and associated transmission infrastructure), but the government is directly contributing equity to that endeavour, and domestic rates continue to be based on a typical ratebase utility model. Similarly to Quebec, the Government of Newfoundland is at risk for its investment in export activities, while it earns a typical utility return on the portion of the investment serving domestic needs. In both of these cases, the risks facing domestic ratepayers are very different than in Manitoba, and the companies in question do not appear to be useful points of comparison with respect to financial targets for Manitoba Hydro.

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[16] Please see Tennessee Valley Authority, Form 10 K for 2016, page 12.

[17] Please see Bonneville Power Administration Overview for Investors, August 28, 2017, page 15, available at https://www.bpa.gov/news/Investor/Pages/default.aspx. In particular, please note the "Reserves Available for Risk" methodology and calculation, as well as "Days of Liquidity on Hand", which includes access to a short-term credit line.

Several major utilities in the United States operate on a pure cost recovery basis, but do not pursue exports out of their system, except as a means to manage temporarily surplus power. Again, a direct comparison with respect to Debt : Equity Ratio or other metrics may not be particularly useful. Having said that, their focus with respect to financial targets generally is not a specific capital structure, but rather on measures of cash flow sufficiency and interest coverage. As noted above, the Tennessee Valley Authority goes so far as to label their economic model a “debt service coverage” scheme. Bonneville Power Administration focuses on cash flow sufficiency, and the maintenance of liquidity sufficient to manage potential needs between rate reviews (which are every two years, in their case). Both utilities make clear that their ultimate recourse to ensure economic viability is to rate increases (in the case of TVA, they set their own rates, while for BPA they apply to FERC).

E. Capital Markets Environment

Manitoba Hydro has limited direct exposure to the Canadian capital markets, given that it receives almost all of its long-term debt resources through the Government of Manitoba. Nevertheless, the capital markets are the ultimate funders of Manitoba Hydro’s debt, so understanding market perspectives on Manitoba Hydro’s economic performance is extremely important.

Market for Manitoba Debt, and Manitoba Hydro’s Role

Manitoba Hydro does not issue long-term bonds to raise money.[18] Instead, the Province of Manitoba issues Manitoba bonds, and then on-lends the proceeds to Manitoba Hydro at identical terms (maturity date, interest rate, etc.). In addition, the Province adds a debt guarantee fee on all outstanding bonds, currently set at 1%.

From an investor’s point of view, they are never buying Manitoba Hydro debt, but rather are buying Province of Manitoba debt, which may be used to fund Manitoba Hydro projects, the projects of other Manitoba crown corporations, or the general obligations of the provincial government. Nevertheless, given the size of the Manitoba Hydro debt portfolio relative to the rest of the Government of Manitoba debt portfolio, information about Manitoba Hydro is critical to any potential bond buyer’s view of Manitoba bonds.

Issuance of provincial bonds or debt notes is typically an auction process. In grossly simplified terms:

- The issuer determines how much debt they are seeking, of what type (fixed rate, floating rate, etc.), and for what term;
- Potential investors are contacted by the banks acting as intermediaries for the bond sale and apprised of the details;
- On the day and time of the transaction, potential bond purchasers submit bids for the amount of bonds they are interested in purchasing, and at what price (sometimes investors are limited to a maximum bid, in order to ensure that bond issues are not overly concentrated into the hands of a small number of investors);

[18] In the past, Manitoba Hydro did issue “Hydrobonds”, but no longer does so. Outstanding bonds form a very small part of the existing pool of debt. In addition, Manitoba Hydro can issue short term debt in its own name. However, this source of capital is also dwarfed by outstanding long-term bonds.

- Bids are ranked from lowest to highest, and bids are accepted from the bottom up until the total desired amount of the bond issue is reached;
- The price of the highest bid to be accepted becomes the price of the entire debt issuance.

In order for potential investors to determine what interest rate they are willing to bid into the auction process, they must have an opinion on the risks associated with the transaction. All available information about the bond issuer and broader economic conditions factor into that understanding. Three layers of analysis are required, which are common to all financial investments:

- What currently is the risk associated with bonds vs. other types of available financial assets such as stocks, futures, options, or real estate? (i.e., asset class selection)
- What is the risk of the national jurisdiction of the issuer vs. other countries? (i.e., market selection)
- What is the relative risk of this particular issuer as compared to other issuers of that type of security in that country? (asset selection)

In concrete terms, the answers to the first two questions largely determine the interest rate associated with Government of Canada bonds. The global capital market determines the overall price of bonds versus stocks or other types of securities at any given time. The global capital market also determines the spread in bond prices between national governments, depending on real time collective global opinions about the expected performance of each national economy and government. Finally, information specific to Manitoba determines the spread between Manitoba bonds and Canada bonds.

Given that Manitoba Hydro debt represents such a large fraction of total Manitoba debt, information about Manitoba Hydro and its ability to make good on the terms and conditions of its bonds forms a very significant part of the story for all Manitoba bond issuances.

Who Buys the Bonds, and What Is the Role of Credit Rating Agencies?

For a typical Canadian dollar bond offering by a Canadian province, the list of potential buyers may consist of 150 to 200 institutions. Typically, these include pension funds, insurance companies, banks and other large financial institutions. Most are based in Canada, but some international institutions purchase Canadian dollar bonds as well. If a province chooses to issue bonds in a foreign currency, then the number and nature of likely players will very much depend on the currency chosen for the bond issue, and the terms of the offering.

Some institutions have large portfolios of government bond holdings. For example, according to its 2017 Annual Report, the Canadian Pension Plan Investment Board held over $80 billion in government bonds, from across Canada and globally. With over 1000 employees in its Toronto head office alone, and an entire group dedicated to the analysis and management of its bond portfolio, the fund can be considered an extremely sophisticated investor. Other potential investors are within the same class, while “smaller” institutional investors will still have large teams and significant research and analytical capabilities as they manage portfolios of government bonds measured in the billions of dollars.

All of these institutions make real time decisions about their bond purchases, trades and the management of their portfolios. There are numerous bond issues that occur every month, and furthermore government bonds are often traded after they are issued, as institutions constantly seek to adjust the size and duration of their bond portfolios, based on their own financial needs and priorities.

Conspicuously absent from this picture are credit rating agencies. These companies are independent analysts who review available information about debt issuers, and provide an opinion as to their credit-worthiness in exchange for fees. Agencies do not participate in the debt market themselves. There is no direct relationship between the opinions of credit rating agencies and the actions of bond purchasers or traders. Bond purchasers participating in the bond market make decisions in real time, and cannot wait for the opinions of external advisors.[19] Credit rating agency opinions are one more data point in an ongoing stream of information that is critical to debt market decision-making.

In fact, it is notable that the opinions of credit rating agencies are often inconsistent with each other, as each agency determines its views independently, according to its own criteria. Moreover, since credit rating agency reviews often follow from significant events and developments affecting a debt issuer (in the context of governments, that could be annual budgets, announcements of major new policies, or significant events in the local economy), it is often the case that the bond market reacts before credit rating agencies do. Changes in bond prices often will precede announcements of new opinions by credit rating agencies, rather than follow them.

Nevertheless, credit rating agency reports are useful:

- They consist of well written, high quality, thorough and sophisticated financial analysis that will mirror the kinds of analysis that institutional bond buyers will likely also pursue in-house;
- They are updated from time to time, to take into account recent conditions and expectations about the future for a particular issuer; and
- They are <u>publicly available</u> (usually for a price), unlike the views of actual bond market participants, who are naturally reticent to share their analyses and opinions lest their competitive position be affected.

As a result, reviewing the opinions of credit rating agencies should provide insight into the thinking process of the bond market as a whole, which is extremely useful when considering the broader context for Manitoba Hydro financial targets.

Credit Rating Agencies, Manitoba, and Manitoba Hydro

The key issue for a bond buyer is the risk that the debt issuer will not fulfill the terms of the bond: either by failing to make interest payments that are required periodically, or by failing to redeem the bond when it comes due. The greater this risk of default, the higher the interest rate that will be required to entice a bond buyer to purchase a particular bond. At some point, bond buyers will simply refuse to purchase the bonds at any price, if too much risk of default is perceived.

National governments have the ability to print money, and so, as long as they issued bonds in their own currency, they have an almost unlimited ability to avoid technical default. However, if a national government resorts to printing

[19] Note that if an issuer is issuing bonds for the first time, or if they are commencing a new series of bonds, they may contract with one or more credit rating agencies to issue reports in advance of an issue, as a service to investors who may not be fully familiar with the issuer. Principally, this is a means to give potential bond investors a starting point for their own analysis; it is not a substitute for bond buyers doing their own work to analyze opportunities.

money to fulfill its outstanding obligations, thereby debasing its currency, it will quickly find that investors will no longer buy any new issues of that country's debt securities, inevitably leading to financial crisis.

Sub-sovereign governments, like provinces in Canada, do not have the ability to print money. Nevertheless, provinces in Canada do have substantial capacity to raise funds through various forms of taxation. Their ability to actually do so, in sufficient quantity to fulfil financial obligations and potentially in the face of domestic political objections and resistance, is a critical part of the determination of credit-worthiness.

Manitoba is a special case among provinces, in that such a significant part of its debt is associated with its electricity crown corporation.[20] As a result, cash flows from electricity sales represent a significant part of its ability to service its debt, rather than just taxes.

Three credit rating agencies – DBRS, Moody's and S&P – provide opinions on the credit worthiness of Manitoba debt, and by extension also the credit-worthiness of Manitoba Hydro. Unfortunately, these agencies do not agree with each other on some important issues and conclusions. However, that very disagreement highlights the fact that credit rating agency opinions are independent conclusions of competing groups of analysts, each selling their analyses to purchasers in the capital markets. Each of the opinions is an important data point that may be useful to bond investors, but none of them appear to be directly determinative of capital markets behaviour.

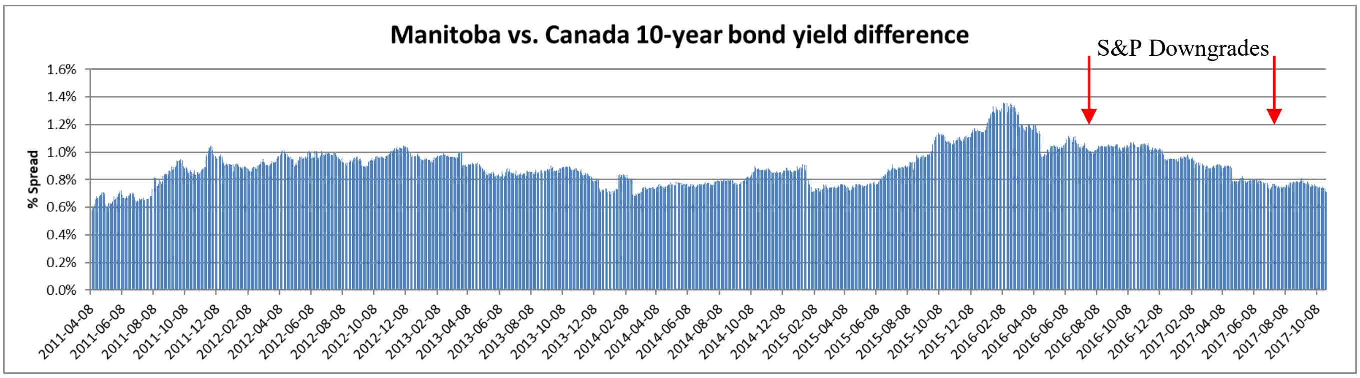
	DBRS	**Moody's**	**S&P**
Manitoba Credit Rating	A high	Aa2	A+
Relative Ranking	BC SK ON ***MB***, NB, QC NF	BC, SK ***MB***, NB, ON, QC NF	BC SK QC ***MB***, NB, ON NF
Manitoba Hydro is "self-supporting"	Yes	Yes	No

A critical issue in the three agencies' analysis of Manitoba finances is whether they consider Manitoba Hydro to be financially "self-supporting". Both DBRS and Moody's maintain that because Manitoba Hydro is expected to continue to service all of its debt through electricity revenues, Manitoba Hydro debt should not be included in the calculation of the provincial government's "tax-supported" indebtedness, and therefore does not affect consideration of the province's credit metrics and credit rating. S&P, on the other hand, has taken the position – only since July 2016 – that all of Manitoba Hydro's debt should be considered "tax supported". Simultaneously with it's release of an opinion reflecting this change, S&P also downgraded the province's credit rating from AA to AA-. A year later, in July 2017,

[20] As reported on page 57 of Appendix 4.5 by KPMG, Manitoba Hydro's net debt was the largest proportion of provincial net debt out of the provinces surveyed, including British Columbia, Quebec, New Brunswick and Newfoundland. Given Nalcor's planned expenditures on the Muskrat Falls hydroelectric project and BC Hydro's planned expenditures on the Site C hydroelectric facility, however, this status may change over the coming years.

S&P downgraded the province's rating further, from AA- to A+. Over this period, the other two agencies did not amend their credit ratings for Manitoba.

One way to shed some light on the relationship between credit ratings and the behaviour of actual bond investors is to examine the record of the spread in yields for Manitoba vs. Canada bonds. This spread represents the difference in perceived risk as between the Government of Canada (rated at the highest possible level by all three credit rating agencies) and the Government of Manitoba. Below is a chart showing the difference in yields for Manitoba 10-year bonds versus Canada 10-year bonds from April 2011 to October 2017. It is clear from even a cursory glance at this chart that the spread is constantly changing, due to a whole range of factors, but that rating actions do not appear to have much of an impact. The spread was actually lower in late 2016, after the S&P downgrade, than it was in early in 2016, when S&P still labeled Manitoba with a higher rating. Similarly, during July 2017 the spread was actually declining when S&P delivered its most recent downgrade. Canada's rating was stable throughout his period.



Source: Bloomberg

Nevertheless, the question of whether the debt of Manitoba Hydro is a financial burden to the Government of Manitoba is an extremely important one, and regardless of their conclusion on the matter, all three of the agencies do address this issue.

Under what circumstances would Manitoba Hydro be a financial burden to the Province of Manitoba? DBRS provided a clear explanation in its recent report on the Province of Manitoba: "DBRS fully expects the utility to recover its costs from the electricity rate base. As such, DBRS will continue to exclude the hydro-related debt from the calculation of tax-supported debt."[21] This recent statement reiterates a more comprehensive statement made in a November 2016 Rating Report on Manitoba Hydro:

> *DBRS continues to view Manitoba Hydro as self-supporting, as its earnings and cash flows continue to be sufficient to cover its operating expenses and to service its outstanding debt. However, DBRS could consider reclassifying a portion of the Utility's debt to be tax-supported should the financial health of the Utility deteriorate to the point where its expenses cannot be recovered through rates. If this were to occur, it could potentially put downward pressure on the Province's credit rating. Similarly, a large equity injection by the Province that materially increases tax-supported debt could also put downward pressure on the Province's credit profile. At this time, however, DBRS expects the Province's ratings to remain stable.*[22]

[21] DBRS, Province of Manitoba Rating Report, 12 July 2017, page 6.
[22] DBRS, Manitoba Hydro Electric Board Rating Report, 25 November 2016, page 2.

If DBRS were to come to the conclusion that Manitoba Hydro was not able to recover its costs from the electricity rate base for any extended period of time, then they would be forced to reconsider their exclusion of Manitoba Hydro debt from the Province's credit metrics.

Moody's echoes the position of DBRS: "Given its revenue stream that generates sufficient cash flow to support operations including interest payments, we view Manitoba Hydro as a self-supporting entity and therefore exclude the related debt from our debt metrics of the province."[23] However, Moody's goes on to clarify that "The anticipated increase in debt has put growing pressure on the province's rating since it raises the contingent liability of the province (anticipated to exceed 40% of the province's total debt by 2017-18) and has increased the risk that Manitoba Hydro could require a capital injection or other support from the province." Were Manitoba Hydro cash flows insufficient to satisfy its needs, or if Manitoba Hydro were to require some form of extraordinary support from the Province, then Moody's would reconsider its position.

In the case of both DBRS and Moody's, the determination of whether Manitoba Hydro's debt is a financial burden for the province is focused on cash flow. This emphasis on cash flow is consistent with typical definitions of insolvency (the inability to satisfy financial obligations), which is what bond investors are ultimately most worried about. Manitoba Hydro must continue to cover its costs, and in particular including its debt interest costs, without any external support from the Province. Failure to do so would call into question Manitoba Hydro's viability as a standalone entity, and result in at least some portion of its debt being determined to be "supported by the Province", to the potential detriment of the Province's credit rating.

S&P recently has taken a different position. In its December 21, 2015 rating report, S&P stated that "The province also borrows and on-lends to Manitoba Hydro, which we view as self-supporting."[24] No additional commentary was provided at that time clarifying why Manitoba Hydro was regarded as self-supporting, but this position had been consistent for many years. In its rating action six months later, however, S&P makes a statement about the "significant debt on-lent to the MHEB, which we no longer consider self-supporting mainly due to its high and rising leverage."[25] Apart from this statement, which is reiterated elsewhere in the report, there is no explanation given for the significant change in the S&P's position on the matter. One additional clue may be the statement that Manitoba Hydro "could produce considerable liabilities for the province. In our view, the government would be likely to support the utility in the event of financial distress. We believe that any such support would be limited to less than 10% of the province's consolidated operating revenues."[26] This statement points to the possibility that the *__risk__* of cash flow distress at Manitoba Hydro has caused S&P to reconsider its position on Manitoba Hydro being self-supporting, particularly given that increasing debt may increase the potential for financial distress. One additional consideration in the comparison of the two positions is that the "Primary Credit Analyst" for the Manitoba credit rating changed between the older and more recent reports. While S&P states that it follows a "committee" approach to making credit decisions, the possibility remains that a change in key personnel had some involvement in the changed position with respect to Manitoba Hydro's debt.

In any case, S&P's emphasis on "high and rising leverage" as a primary driver of a change of position with respect to self-supporting status is surprising, because it runs counter to S&P's own basic criteria for credit ratings. S&P emphasizes cash flow metrics as the basic determinant of financial risk, as opposed to capital structure metrics,

[23] Moody's, Province of Manitoba Update, 24 February 2017, page 4.
[24] S&P, Province of Manitoba, 21 December 2015, page 4.
[25] S&P, Province of Manitoba, Research Update, 14 July 2016, page 2.
[26] Ibid., page 4.

which are considered only as one factor among several which are used to refine ratings. This priority is clearly set out in the following excerpt from S&P's "General Corporate Methodology":[27]

> *11. The corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several factors so that Standard & Poor's considers all salient issues. First we analyze the company's business risk profile, then evaluate its financial risk profile, then combine those to determine an issuer's anchor. We then analyze six factors that could potentially modify our anchor conclusion.*

> *12. To determine the assessment for a corporate issuer's business risk profile, the criteria combine our assessments of industry risk, country risk, and competitive position. <u>Cash flow/leverage analysis determines a company's financial risk profile assessment</u>. The analysis then combines the corporate issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor. In general, the analysis weighs the business risk profile more heavily for investment-grade anchors, while the financial risk profile carries more weight for speculative-grade anchors.* [Note: <u>emphasis added</u>]

> *13. <u>After we determine the anchor, we use additional factors to modify the anchor</u>. These factors are: diversification/portfolio effect, <u>capital structure</u>, <u>financial policy</u>, <u>liquidity</u>, and management and governance. The assessment of each factor can raise or lower the anchor by one or more notches--or have no effect. These conclusions take the form of assessments and descriptors for each factor that determine the number of notches to apply to the anchor.* [Note: <u>emphasis added</u>]

> *14. The last analytical factor the criteria call for is comparable ratings analysis, which may raise or lower the anchor by one notch based on a holistic view of the company's credit characteristics.*

S&P further defines seven metrics that it focuses on with respect to cash flow (Note: the first two are the primary metrics, and the other five are secondary), the sheer number of which provides an illustration of the level of focus on cash flow in S&P's typical financial risk analysis. These are:[28]

- Funds From Operations (FFO) : Debt
- Debt : EBITDA
- Cash Flow From Operations (CFO) : Debt
- Free Operating Cash Flow (FOCF) : Debt
- Discretionary Cash Flow (DCF) : Debt
- FFO + Interest : Cash Interest
- EBITDA : Interest

Some of these measures rely on accrual accounting (from the Income Statement), and some are based in cash accounting (from the Cash Flow Statement), but all of them are designed to reveal whether an enterprise has the capacity to continue to meet its obligations.

[27] S&P, Criteria: General Corporate Methodology, published 19 November 2013.
[28] Ibid., paragraphs 101 to 103.

The emphasis that S&P normally places on cash flow metrics is consistent with the positions taken by Moody's and DBRS with respect to Manitoba Hydro's self-supporting status: Manitoba Hydro is self-supporting as long as its cash flows continue to be sufficient to covers its costs, including its debt costs.

Comparison to Other Pure Cost Recovery Electricity Providers

Manitoba Hydro's Canadian peer group does not include any utilities which are operated on a pure cost recovery basis. Each of them has shareholder equity and makes dividend payments to a parent, if financially feasible. Dividend payments represent a financial cushion which could be reduced or eliminated in times of financial distress (and in some cases this has occurred in the recent past). Manitoba Hydro does not share this ability.

Three of the United States utilities described above do share Manitoba Hydro's economic model of pure cost recovery, and each of these has an independent investment grade credit rating, despite the fact that two have Debt : PPE ratios which are higher than Manitoba Hydro's.[29] There are obviously many factors which contribute to the assessment of the credit worthiness of these companies, however a critical characteristic in all cases is a focus, both internally to them and among the rating agencies that review their credit-worthiness, on the sufficiency of cash flows to cover credit costs (i.e., Cash Flow : Interest metrics, or Debt : Cash Flow metrics), the ability to adjust cash flows in the face of financial distress, and the availability of sufficient liquidity to manage short term financial distress should it arise. Debt : Capital ratios are always included in ratings analysis, but they are not primary in the analysis, since the focus is always on cash flow sufficiency.

Appendix E contains copies of the following documents, which provide an illustration of these positions:

- Fitch credit rating criteria for US public power companies (highlights that cash flow sufficiency, and the ability to adjust customer rates to maintain that sufficiency, is critical to ratings)
- Fitch ratings summaries for Tennesee Valley Authority and Long Island Power Authority Bonds
- Moody's full credit rating report for Bonneville Power Administration
- Moody's rating summary for Tennesee Valley Authority
- S&P full credit rating report for Bonneville Power Administration

Priority of Capital Structure Ratio for Manitoba Hydro

This review of credit rating agency comments, both on Manitoba Hydro and on other pure cost recovery entities, raises questions about Manitoba Hydro's focus on Debt : Equity as the primary ratio of concern with respect to financial health. Throughout its application for new rates, Manitoba Hydro emphasizes the importance of ensuring the financial strength of the enterprise, principally as represented through the Debt : Equity ratio. However, this emphasis does not appear to be shared by analysts serving the capital markets, who appear to place a higher priority on cash flow metrics and the ability to adjust rates as required to match operational requirements. Certainly, the capital structure of a utility is important, and all analysts do recognize that, but few if any appear to make capital structure a centerpiece of their analysis in the way Manitoba Hydro does. This divergence between the narrative emphasized by

[29] Manitoba Hydro has a Debt:PPE ratio of 82%. For the Bonneville Power Administration, the ratio is 93%; for the Long Island Power Authority it is 102%, while for the Tennessee Valley Authority it is only 65%.

Manitoba Hydro and the narrative typically pursued by capital markets analysts is potentially troubling. If the Debt : Equity Ratio should not be the primary financial target of concern, then the setting of a goal for achieving a 75% ratio in 2027, and building rate proposals around that goal, is also cast into doubt.

4. Risks, Rates and Financial Plans

In its forecasts and plans, Manitoba Hydro has included "base case" or "reference" assumptions for all required variables. Under those assumptions, different rate paths will lead to specific financial outcomes. Conversely, defining a desired outcome (such as a 75:25 debt to equity ratio in 2027) allows for the calculation of the rate path required to achieve the outcome under base case assumptions.

However, since the world never operates according to forecasts, it is important to consider what might happen to financial outcomes as variables deviate from their base cases. How likely is it that the variables will deviate from the base case? How far might they deviate, in what time frame? Will financial outcomes that result from those deviations still be acceptable? If not, what can be done about it? Is it necessary to make provision in advance for these potential outcomes, or can they be addressed if or when they arise? Can regulatory principles help to guide these choices?

Potential deviation from a base case is, of course, just another way to describe a risk.

A. Nature, Magnitude and Expected Frequency of Manitoba Hydro Risks

As an electricity utility, the risks that Manitoba Hydro faces can be grouped into five broad categories:

Fuel Risk: The vast majority of electricity produced and delivered by Manitoba Hydro is hydroelectric in nature. The "fuel" for this output is water, and hence the primary fuel risk faced by Manitoba Hydro is the risk of persistent drought conditions. Even ignoring prolonged or severe droughts, the "normal" variability in water inflows into the Manitoba hydroelectric systems causes significant fluctuations in the corporation's annual financial results. Water is not the only fuel used in Manitoba, but all other resources, including wind, natural gas and imports, are minimal in comparison.

Operating Risk: This category encompasses the multitude of potential failures that could occur as part of the operation of an electric utility. Everything from storms damaging transmission infrastructure, to turbine or generator failure at major generation faculties, to labour disruption across the enterprise can be categorized as an operational risk.

Construction Risk: Manitoba Hydro is in the process of building two major projects (Keeyask and Bipole III) and a multitude of smaller undertakings. As has already occurred, construction projects face a range of possible ways in which their schedule or budget or both may be derailed, to the detriment to the corporation.

Market Risk: Manitoba Hydro must make forecasts and projections about its customers in order to understand and plan for delivery of its products and services in the future. In its particular case, Manitoba Hydro is heavily exposed to the growth rate in domestic demand for electricity, as well as both the demand and market price for exports. Manitoba Hydro does not face price risk in its domestic market, since rates are regulated on a full cost recovery basis.

Monetary Risk: As an enterprise which buys and constructs expensive equipment which will be operated over very long periods of time, Manitoba Hydro is particularly exposed to purely monetary variables, such as interest rates, inflation rates, and exchange rates.

Fuel Risk

Manitoba Hydro now has 104 years of data on water flows into the province's river systems. Using this data, the corporation can plot the likely physical output of its electricity generation facilities under a wide variety of conditions, and the financial consequences of each flow condition in a variety of different scenarios.

Water flows can vary enormously from year to year, with swings of up to 40%, as measured from the greater volume year. At the same time, flows can persist at above average or below average levels for significant periods. If a "severe drought" is defined as a period in which average water inflows for a five-year period are 85% of the historical average annual inflow, then such periods have occurred approximately 10% of the time over the past century. Put differently, and assuming both that water inflows are truly random on an annual basis and that the past 104 years is a representative sample of what will occur in the future,[30] then at the beginning of any given year, there is approximately a 10% chance that Manitoba is embarking on a five-year drought. This is a non-negligible risk.

The effects of water inflows are not financially symmetrical: in other words, high flows do not improve financial performance as much as low inflows harm it. This is because in times of exceptionally high inflows, water must be literally spilled out of reservoirs for a variety of safety and operational reasons. As a result, the mean financial case is actually associated with water inflows that are below the median. Manitoba Hydro has provided example scenarios for one specific year, 2017/18, for the operating income that results from the 104 water inflow cases under reference assumptions for domestic demand, interest rates, export prices, etc.[31] These illustrate the range of results that are possible, solely on the basis of alternative water flows. The chart on the next page is a graphical representation of the information provided.

The level of water inflows affects only three line items on the Manitoba Hydro Income Statement: Export Revenues, Water Rentals and Assessments Expenses, and Fuel and Purchased Power Expenses. Netting the three hydraulic line items provides a sense of the range of the impact that water availability can have on Manitoba Hydro's financial results (i.e., for each of the 104 water scenarios, the calculation Export Revenues – Water Rentals – Fuel and Purchased Power was completed. The result of each of those 104 calculations is a bar on the chart, which were then sorted in order from lowest to highest).

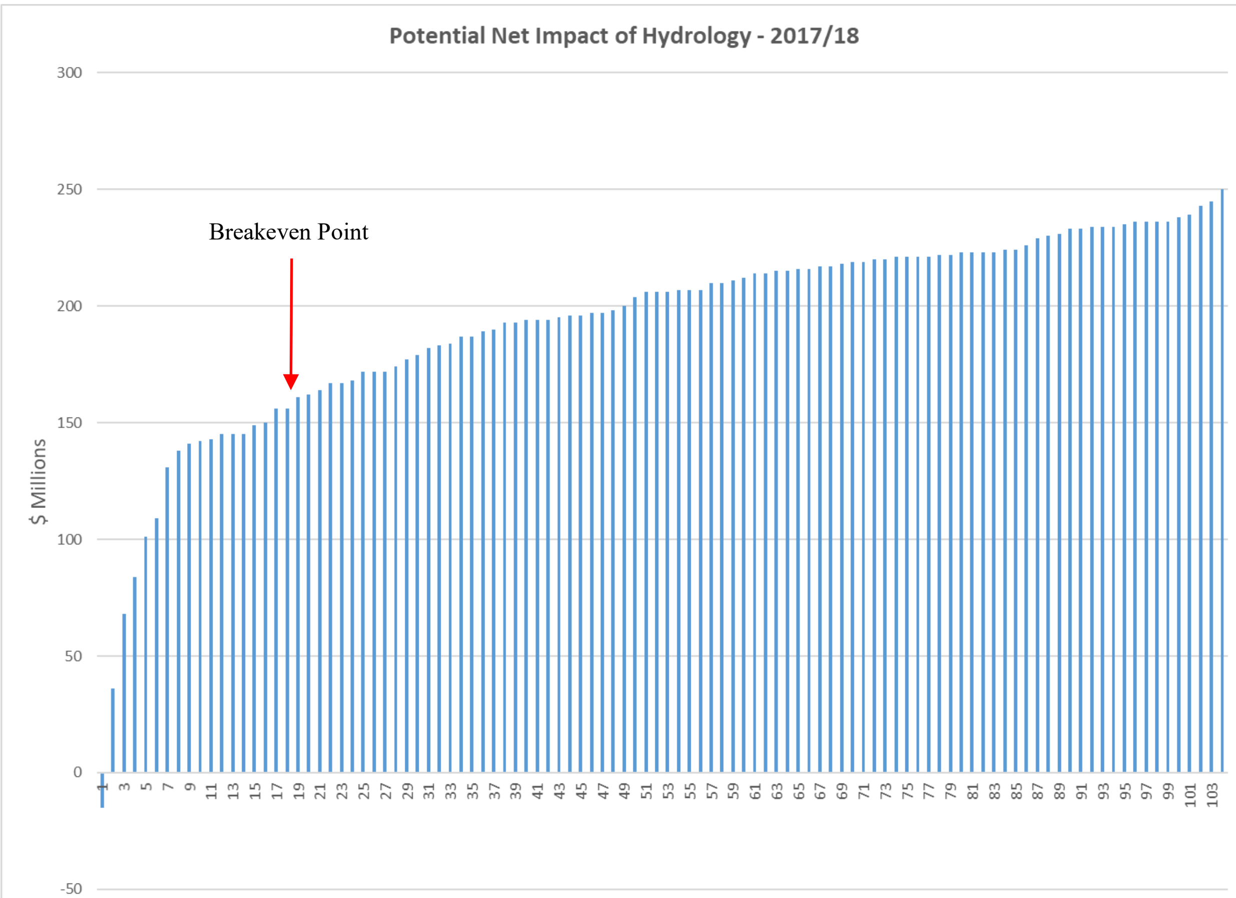
The mean of the financial results is $192 million of net revenue from these three line items. The best result is $250 million, but the worst result is a loss of $15 million. Bad water scenarios are very, very bad, but there are not many of them within the sample of 104 years. Only 6 water scenarios out of 104 result in net revenues of less than $130 million.

In each of the 104 scenarios, all of the line items on the financial statement are the same, except for the three water-related line items already identified. Keeping those three line items aside, if all of the remaining revenue and expense lines are netted out, the result is a net operating income of $795 million. However, Depreciation and Finance Expense are together $954 million. This means that before taking into account the three water-related line items (Export Revenues, Water Rentals, and Fuel), Manitoba Hydro would be suffering a net loss of $159 million.

[30] Note that these are VERY significant assumptions. For example, if water inflows are being affected by long-term changes in climactic conditions, such as climate change, then the past 104 years may not be a good sample of what will happen in the future.
[31] Please see the response to Coalition Round 2 IR-3(b) Attachment 1. This provides operating statement results for 104 different water scenarios for the 2017/18 financial year.

Of course, the three line items do need to be taken into account. Of the 104 water cases, only 18 result in net hydraulic revenues below $160 million, which means in only those 18 cases will Manitoba Hydro's net income be negative. Approximately 79% of the time, Manitoba Hydro will have a positive net income (before regulatory deferrals, non-controlling interests, etc.), at least in this example.

From the perspective of cash flows to cover interest costs, it is worthwhile to make two points. In this example, net operating finance expense is $558 million, and so it appears that EBITDA : Interest is always greater than 1, regardless of hydraulic outcomes. However, not included in finance expense information provided in the table is capitalized interest (which should be added to net operating finance expense), so cash flow metrics would be somewhat worse than they appear.



Recall that this chart is just an example of <u>one year</u>, the estimate for 2017/18, and that in this particular year, Manitoba Hydro has begun its analysis from the position of high water in reservoirs at the start of the year (because water levels were extremely high in 2016/17). If the assumption had been made that reservoirs were at historically average levels, then all figures would be lower, and the breakeven point would move to the right.

Unquestionably, fuel risk should be considered the most significant risk for Manitoba Hydro. In very low water years, operating income will fall significantly, which will result in poor cash flow ratios, potentially negative net income, and hence a deteriorating debt to equity ratio.

This inference is borne out by the analysis provided by Manitoba Hydro in Figure 4.4. of the Application, where a five-year drought has a more significant impact on retained earnings than any other variable examined, even though most other variables were examined over a ten-year period rather than just five.

Having said that, it is also true that over longer periods of time, a sustained water inflow below 85% of the average becomes less and less likely. While the financial consequences of drought can be intense, water inflows tend to revert to the mean over the longer term.

Operating Risk

All utilities rely on systems of built infrastructure to deliver goods and services. This makes them very susceptible to disruptions based on equipment not performing as intended, whether caused by weather events, operator error, or deliberate disruption. This can range from the normal randomized failure of equipment based on wear and tear, all the way up to province-wide ice storms that can wreck entire systems of overhead wires.

Operation and maintenance costs are a relatively small part of Manitoba Hydro's revenue requirement. In the year ending March 31, 2017, they amounted to slightly more than 25% of total expenses. Assuming that most operating risks, if they were to materialize, might affect the operating and maintenance costs in one year only, then the magnitude of these risks in terms of potential impacts on financial outcomes is not very large. For example, even if an ice storm caused significant damage to overhead distribution lines, requiring a substantially increased expenditure on repairs, the entire episode would be complete with one year, having few ongoing effects.

Manitoba Hydro did not examine the potential financial outcomes of this class of risk in its application, and given the typical magnitude of operating risks, this is reasonable. However, there is an exceptional case. One of the primary reasons that the Bipole III transmission line is being built at a cost of multiple billions of dollars is exactly to mitigate an operating risk of enormous magnitude. Without Bipole III, Manitoba is exposed to the risk of massive system failure in the event that an ice storm, tornado or other weather event destroys existing north-south high voltage transmission lines in the province. In this scenario, Manitoba Hydro's ability to serve its customer base is significantly impaired, potentially for a substantial period of time. However, assuming that Bipole III enters into service as scheduled, the most significant possible operational failure for Manitoba Hydro will have been mitigated, and all other potential events that fall into this category are likely to be less severe, both in terms of the extent of possible damage, and the speed of recovery that would be possible.

Construction Risk

Manitoba Hydro has already absorbed the news that both Keeyask and Bipole III are substantially behind schedule and over budget. These are two of the largest projects that Manitoba Hydro has ever undertaken (certainly in terms of current costs, if not physical size), and there are no plans to undertake anything remotely comparable for at least the next 15 years. The risk remains, however, that these projects, and in particular Keeyask, may not be completed according to the new schedule and timing included in the application as a base case assumption.

The financial consequences of being behind schedule or over budget can be significant. If the projects are over budget, then Manitoba Hydro will require additional debt above the assumed base case. This would in turn entail more debt interest, putting pressure on cash flow ratios, and would also put downward pressure on debt to equity ratios. If Keeyask were to be behind schedule, then construction interest costs would continue to accumulate, and the new revenues associated with Keeyask would be delayed further into the future. Again, cash flow ratios would deteriorate, as would debt to equity ratios.

Manitoba Hydro provided one sensitivity analysis in its application showing the impact of a $1 billion cost overrun above the current base case for the Keeyask plant. While the financial impact of this outcome would be significant, it would not be as damaging to Manitoba Hydro's financial outcomes as would be some other risks, and so additional information was not provided.

In response to PUB Round 2 IR 25, Manitoba Hydro provided financial analysis of a 32-month delay of the Keeyask Project. However, because of confidentiality concerns, this information was redacted. It is not clear whether the consequences of such a delay would be worse than, better than or equal to a $1 billion cost overrun.

Market Risk

Manitoba Hydro produces and sells electricity. This is a valuable business to be in only if there are customers who wish to buy that electricity, at prices high enough to cover the costs of production and delivery. Domestic customers have no choice with respect to the price of electricity, given its regulated nature. However, the volume of domestic demand can and does change over time. Other reports in this regulatory process examine the validity of the base case domestic demand forecast provided by Manitoba Hydro, and the appropriate magnitude of the upside and downside alternatives. For the purposes of financial risk, however, it is sufficient to point out that the low-growth case as Manitoba Hydro modelled it has very limited impact on financial outcomes, even with a fixed rate path. Domestic demand would have to be dramatically lower than the base case assumption in order to have a significantly negative impact on cash flow or capital structure ratios. This is theoretically conceivable over the longer term, especially given increasing technological change making conservation and demand management easier to implement, but the magnitude of the decline in domestic demand would have to be extremely significant before financial outcomes were strongly affected.

Manitoba Hydro exports its excess power, principally into the MISO market. That market is over ten times larger than the Manitoba electricity system, both in terms of instantaneous capacity requirement, and energy consumed per year. Manitoba Hydro is therefore a small player that should not be assumed to significantly affect that market. It is fair to assume that if Manitoba Hydro is willing to simply be a price taker in the MISO market (including $0 for power on some occasions), then Manitoba Hydro will be able to sell all of its surplus output. Effectively, there is no demand risk for Manitoba Hydro exports into the MISO market. However, from a price perspective, Manitoba Hydro is completely at risk.

In Manitoba Hydro's financial model, export prices are directly related to cash flow and net income. As a result, any deterioration in export prices below the base case causes cash flow and capital structure ratios to decline.

Other experts are commenting on Manitoba Hydro's base case export price forecast, and on the reasonableness of the high and low alternative forecasts. From a financial performance point of view, however, it is notable that Manitoba Hydro's own low alternative forecast caused significant deterioration in financial outcomes. Export prices are one of the three variables to which the financial model is most sensitive (along with drought risk and interest rate risk). If other experts conclude that export prices could be even lower than projected by Manitoba Hydro, then financial outcomes could suffer further.

Monetary Risk

Numerous monetary variables must be included in any modeling or forecasting exercise. The most obvious are interest rates, general inflation rates, and currency exchange rates. Greater refinement is possible by considering rates for specific subsectors of the economy (e.g., industrial goods inflation vs. consumer inflation, long-term vs. medium term vs. short-term interest rates, etc.).

Some of these rates are interlinked: for example, inflation rates and interest rates typically move together (though not always), and as a result if a scenario includes rising interest rates, some of that risk might also be reflected in higher inflation-based costs for labour, equipment and suppliers.

For Manitoba Hydro, inflation rates higher or lower than the base case would affect operating and maintenance costs (principally through higher labour costs), and the cost of capital goods. Manitoba Hydro did not provide any analysis of the financial impact of alternative inflation rates in the Application. This may be reasonable, because inflation rates have been relatively stable for the past decade, and the Bank of Canada remains committed to managing national monetary policy in such a way as to keep inflation rates stable within a target band.

Exchange rates varying from the base case would directly affect the value of electricity exports, but would also have an impact on the cost of equipment, supplies and capital goods, since many of these are purchased from abroad. These two pressures would be contradictory: a lower Canadian dollar would increase the value of exports, but would make supplies and capital goods more expensive, slightly mitigating the overall impact. Manitoba Hydro modeled a swing of CDN$0.10 above and below the base case assumption, and while the impact was measurable, it was substantially smaller than many other variables tested.

Interest rates are critical to Manitoba Hydro because of the overall debt burden that is resulting from the Keeyask and Bipole III projects. Historically, Canadian interest rates have been variable, changing with economic conditions, but for the past decade they have remained low and stable to an unprecedented degree. However, since Manitoba Hydro filed is application in May of this year, the Bank of Canada has increased its policy rate two times (for a total increase of 0.50%). This development was not anticipated in Manitoba Hydro's base case interest rate forecast, and raises the possibility that rates could move faster and higher than anticipated. Manitoba Hydro did examine the consequences of interest rates being 1% higher than anticipated in the base case, and this had a significant impact on financial outcomes, both for cash flows and capital structure.

Risk Modeling

Based on its sensitivity analysis, Manitoba Hydro selected three risks for further investigation: water risk, interest rate risk, and export price risk. Most other risks were much less significant from the perspective of affecting financial outcomes, as described above, and so justifiably were not examined further. However, construction risks associated with Keeyask were also significant, but unfortunately were not investigated.[32]

In Tab 4 of the application, Manitoba Hydro provided the results of 918 modeling runs for each of two rate paths. 102 water inflow scenarios were tested for each of three interest rate scenarios and each of three export price scenarios (102 * 3 * 3 = 918). The financial outcomes, in terms of financial results like net income and retained earnings, or ratios such as cash flow and debt to equity, for these modeling runs were recorded, and then summarized in the manner of "box and whisper" plots.

This method of presentation provides the range of annual outcomes for each metric that was examined (e.g., debt to equity ratio, interest coverage ratio, net income, etc.), but does not provide any information on how each of the 918 runs link from year to year. For example, in one year a run may produce the worst outcome in terms of a metric (e.g., net income), but in the next year the same run may have a much improved net income which is no longer at the bottom of the list. While it is valuable to know what the range of outcomes might be for a given variable in any given year, it would also be valuable to better understand the multi-year performance of Manitoba Hydro under different conditions.[33] Doing this type of analysis would require access to the full output of the 918 modeling runs, not just box and whisper plots. Unfortunately, the full output from these modeling runs could not be made available by Manitoba Hydro, so there was no opportunity to examine financial outcomes in detail.[34]

Some observations are nevertheless possible, based on the information made available by Manitoba Hydro.

Analysis Based on Original Application: The 918 modeling runs were based on the rate path and assumptions of the original application in May, and not the updated rate path presented after the PUB decision on interim rates in August. Nevertheless, the analysis is still useful in providing directional indications about risks and financial outcomes.

Only Two Rate Paths Contrasted: The 918 modeling runs were repeated twice, once with 7.9% rate increases, and once with 3.95% increases. It was assumed that no deviation from these paths was possible, regardless of the consequences. This assumption is clearly not realistic, but does help to simplify insights that can be made.

Interest Coverage Ratio and Capital Coverage Ratio: These box and whisper plots were not provided in Tab 4, however they were provided in response to IRs.[35] Given the importance of cash flow coverage ratios to credit rating agencies and the capital markets, these plots provide valuable information about the risks facing Manitoba Hydro.

Interest Coverage Remains Above Critical Throughout on the 3.95% Rate Path: At the P01 position of the EBITDA to Interest plot on the 3.95% rate path, the ratio is never below 1. It should be noted that a ratio of 1

[32] Assuming a linear relationship between cost overrun and impact on Manitoba Hydro financial outcomes, a $2 billion cost overrun from the base case budget of Keeyask would be approximately equivalent to a 1% across the board increase in interest rates. It may have been useful to investigate further this possibility, or the possibility of an additional delay in project completion.

[33] Another type of analysis which could usefully be performed given access to the raw data is to determine whether any single variable drives a majority of the worst outcomes. For example, in the worst water inflow years, does it matter what export prices or interest rates are? If the 9 worst outcomes are all the result of a particularly bad water year, then interest rates and export prices are simply much less important variables. This is particularly relevant to the question of what types of risks deserve to protected through "reserves".

[34] Please see the response to Coalition Round 2 IR-2.

[35] Please see the response to Coalition Round 2 IR-1.

means that operating income is just sufficient to cover finance expense costs. In the parlance of the Moody's and DBRS, as long as Manitoba Hydro is able to continue to cover all of its costs – including operating costs and interest – it will continue to be regarded as "self-supporting", and not a burden to the Province. Admittedly, the P01 position in the plot means that 9 model runs are actually below the numbers listed for each year, and it is not possible to know from the data if any runs actually resulted in interest coverage ratios below 1. However, it should be noted that it is unlikely that any given run remains at the low position for very long, and so the average capital coverage ratio for any single run (in other words, for any single future) should actually be comfortably higher. At the P50 position, the 1.8x target is exceeded in more than half of the years of the model, but not generally until later in the 2020s.

Interest Coverage is Very High on the 7.9% Rate Path: It is notable that on the 7.9% rate path the interest coverage ratio is comfortably above the 1.8x target for virtually the whole period at the P20 position. Even at the P01 position the 1.8x target is met in the later years of the model. At the P50 position, the 1.8x target is met and exceeded almost immediately, and is substantially exceeded in most years.

The 3.95% Rate Path Cannot Be Followed by 2% Increases: In the modeling presented, the 3.95% rate path includes increases at that level from 2017/18 until 2028/29, and then 2% per year thereafter. However, reducing the rate increases to 2% per year results in significant risk to the corporation after 2030. While the interest coverage ratio remains above critical levels throughout, net income actually becomes negative at the P20 position for more than half of the years of the model. The equity ratio becomes negative at the P01 position in 2030, and in the P05 position in it reaches 1% in 2032. It is not clear why annual rate increases were not kept at 3.95% for additional years beyond 2028/29, but based on this modeling, it would definitely be necessary.

On the 7.9% Path Rates Would Likely Fall After 2030: At the P50 position on the 7.9% rate path, the target equity ratio of 25% is reached as of March 2027. After that year, the equity ratio continues to rise at the P50 position, despite only 2% rate increases. This suggests that rates would either have to be frozen or reduced, to prevent an unnecessary build-up of equity.

The true value of the scenario modeling is to highlight what kind of situations could be problematic, in order to prepare for them. The limited nature of the data provided prevents a more thorough analysis of the individual runs that show the most significant downside risks for Manitoba Hydro financial outcomes, but even the limited data provided by Manitoba Hydro allows for the drawing of some useful inferences.

Assuming the downside cases of the examined variables are reasonable, the analysis shows that the 3.95% rate path is reasonably robust from a cash flow perspective for the first 10 years of the modeling period. After 2030, however, reducing the rate path down to 2% increases exposes the corporation to too much risk.

If a reasonably cautious standard to use is to choose an option which is feasible 95% of the time (which is the Bonneville Power Administration criteria), then the 3.95% percent option appears to qualify. There is no question that situations could arise which require further action beyond a 3.95% rate path, but they will be rare.

B. Options to Financially Manage Risks

The previous section demonstrated that combinations of factors can arise which undermine the best laid plans. Even in the 7.9% rate path, there are scenarios where interest coverage is insufficient. At 3.95% rate increases, more of this would be evident. However, in many scenarios distress does not arise. As noted above, cash flow is many times higher than necessary in a majority of the scenarios with the 7.9% rate path, and is adequate in most scenarios under the 3.95% rate path.

What are the available responses, knowing that such distress situations could arise? Several options appear to be available to Manitoba Hydro:

Build Up Cash Reserves in Advance: This is the "preventative medicine" approach. In effect, Manitoba Hydro would be building up its liquidity reserves in order to protect against relatively low likelihood combinations of challenges. Normally, liquidity reserves are limited and only intended to help manage the inevitable disconnect between accounts payable and accounts receivable, and other short term accounts, but Manitoba Hydro could choose to build up a "drought fund", for example, which could be called up on in the case of distress.

Pay Down Debt: Another form of preventative medicine, similar to the building of cash reserves. In this case, debt principle is repaid faster than the amortization of utility assets. This means that ratepayers must be charged rates that are higher than necessary for cost recovery purposes, but in the event of financially stressful situations, the corporation could simply borrow to cover its exceptional requirements. This is essentially the strategy being recommended by Manitoba Hydro in seeking a 7.9% rate increase to facilitate the goal of achieving a 25% Debt : Equity Ratio by 2027.

Cost-cutting: In the event of distress, be prepared to reduce costs significantly, in order to increase net cash flow from available revenues. A "wait and see" strategy, that depends on the willingness of the company to act decisively in the event of distress.

Increase Rates: If a significant risk materializes, then be prepared to raise rates on domestic customers to increase cash flows. Also a wait and see strategy.

Essentially, these are two strategies with two variants each. Practically speaking, one of each pair can be eliminated from consideration.

In the first pair, building up a cash reserve vs. paying down debt, the former represents a much more significant opportunity cost than the latter. All businesses require some amount of liquidity to manage unpredictable cash flows in the short term. However, maintaining liquidity is expensive because cash or "near cash" financial instruments earn very little return. Paying down debt, on the other hand, has the benefit of reducing interest payments, and therefore serves to improve cash flow metrics, as well as improving the debt to equity ratio of a company. Paying down debt is not a substitute for necessary liquidity, because issuing large amounts of debt takes time, and the essence of liquidity is the ability to respond to financial needs quickly. But liquid assets are not required to respond to a deeper challenge such as a multi-year drought: debt can serve that purpose well, and at less cost.

Cost-cutting and increasing rates are both initiatives that can be taken in response to distress, at the time the distress occurs. However, practically speaking, cost-cutting is limited by the need to continue to deliver utility services to customers: only so many costs can be cut while remaining in business. Moreover, utilities are under a general obligation to operate as efficiently as is reasonably possible. To assume that there is sufficient "fat" in a utility that would allow it to painlessly cut costs in the face of financial distress is equivalent to making the assumption that it is permanently inefficient, except when a crisis arises. Even if some amount of cost-cutting is feasible (as we see in the recently announced cost-cutting program from Manitoba Hydro), it is unlikely that cost-cutting alone would suffice to address the kinds of "P01" situations that were highlighted in the previous section, when multiple factors act simultaneously to create financial distress for a utility.

The four options to manage risk essentially collapse into two: paying down debt to create reserves that may be accessed when financial distress conditions rise, or responding to financial distress with rate increases. The next section will explore the pros and cons of managing risk in these two ways, through the lens of regulatory principles.

C. Regulatory Principles and Risk Management

As was described in the previous section, one version of a summary list of regulatory principles would be the following:

- Monopoly Utility Customer Service
- Economic Efficiency
- Cost Causality
- Stability and Predictability
- Prudence
- Public Interest
- Access to Capital Markets

Of these principles, the Customer Service and Prudence principles have the least bearing on the question at hand. Whether rates are raised now to generate funds to pay down debt, or rates are raised in the future if a financial distress situation arises, customer service is not affected either way. Admittedly, if severe cost-cutting were to be considered as an option, then the Customer Service principle would need to be considered, but for the reasons described above, cost-cutting is not considered relevant.

Prudence is often a catch-all term which is used ambiguously. However, in this case it is understood to have a procedural meaning, rather than a substantive meaning. The prudence principle requires that utilities consciously exercise good judgement through careful review and consideration of applicable risks before making decisions. In this case, a careful and deliberate choice between two methods of responding to potential future challenges is being considered, which is the essence of prudence. Prudence does not dictate the pros and cons of a choice, it only demands that the pros and cons be fairly and thoroughly considered.

The remaining five principles are all very much relevant to the choice of strategy to prepare for and potentially respond to future financial distress, and each will be considered in turn.

Economic Efficiency

Manitoba Hydro is proposing a rate path based on 7.9% rate increases, versus other options. This does not affect internal operations in any way, and so does not affect efficiency in an engineering or physical sense. However, Manitoba Hydro has claimed that paying down debt is an efficient use of ratepayer money, because it reduces interest costs in the long run, and protects against financial distress. In essence, the use of ratepayer capital beyond what is strictly required for the immediate operation of the utility in real time is an efficiency question.

The primary reason Manitoba is proposing an aggressive series of rate increases is to build up the reserves of the corporation (by paying down debt), and therefore reduce the likelihood that dramatic rate increases will be required in the future in response to a financial distress situation. This creates two possibilities that should be examined: a future where financial distress does not occur, and one where financial distress does test the company.

If reference assumptions were to actually persist for the next 19 years, then the financial outcomes for Manitoba Hydro might be consistent with the model presented in response to Coalition Round 2 IR 6 and IR 7. Manitoba Hydro calculated a future 7.9% rate path where a 75% debt ratio was achieved in 2027, and then domestic rates were adjusted annually to keep the debt ratio at 75% permanently. As a comparison, a different rate path was calculated under the same assumptions, with annual increases of 3.95% per year until a 75% debt ratio was achieved by March 2034, after which time rates were adjusted to maintain the 75% debt ratio.

These two financial projections highlight how differently rates and customer costs can turn out under a single set of financial assumptions, but maintaining all other things equal. Resulting rates are set in the tables on the next page.

If rates are increased by 7.9%, then by the end of 10 years, when the target 75:25 Debt : Equity Ratio is achieved, rates will have increased by approximately 77% in nominal dollar terms. In inflation-adjusted terms (assuming annual inflation of 2%), they will have increased by approximately 46%. If a ratepayer had purchased the same amount of power every year (1000 units), then the consumer will have spent 14,412 over that time period. In inflation-adjusted terms, the cumulative cost would be 12,816. However, in the next year, because the debt to equity ratio target had already been reached, rates could come down significantly, and in the 2030s price increases would be either modest or negative. By 2036, the last year of the model, nominal prices would be 44% higher than today, and would actually have fallen in inflation-adjusted terms.

Alternatively, if a 3.95% rate path were followed for the next ten years, rates would be lower, and cumulative costs would be lower, both in nominal dollar and inflation-adjusted dollars. However, the debt to equity ratio of the company would not be 75:25. In fact, rates would peak at 92% higher than today in 2034, when the debt target is achieved, and only then would rates come down somewhat. By 2036, prices in the two rate paths will have almost equalized, both in nominal and inflation-adjusted terms. However, the cumulative cost of power in the 3.95% rate path is actually slightly higher than for the 7.9% rate path, over the total 19-year period covered. In inflation-adjusted terms, the 3.95% rate path has lower cumulative costs until 2034, but then becomes slightly more expensive.

This comparison suggests that over a long period of time, under reference assumptions, the 7.9% rate path will actually be more economically efficient, in inflation-adjusted terms. This is the benefit that results from paying down debt early, rather than paying compounding interest costs over a long period of time.

This is far from a complete story, however. Nowhere in Manitoba Hydro's application has it considered the cost of capital that is applicable to its ratepayers. In the 7.9% rate path, ratepayers are paying more than in the 3.95% rate path for the same amount of electricity in years 2 through 10, and less in the next 9 years. In both cases the same amount of electricity is received, the only thing that changes is nominal price. This is a classic present value problem.

Rate path based on applied for 7.9% rate increase

			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Year Ending in March		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Change in Units																					
Annual Units Purchased		1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Price Increase			3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%	-19.75%	-3.12%	-1.11%	1.81%	-1.05%	0.57%	0.40%	0.72%	3.26%
Nominal Price		1	1.03	1.12	1.20	1.30	1.40	1.51	1.63	1.71	1.74	1.77	1.42	1.38	1.36	1.39	1.37	1.38	1.39	1.40	1.44
Inflation	2%	1	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46
Inflation-adjusted Price			1.01	1.07	1.13	1.20	1.27	1.34	1.42	1.46	1.46	1.46	1.15	1.09	1.05	1.05	1.02	1.01	0.99	0.98	0.99
Annual Nominal Cost of Power		1000	1,033.60	1,115.25	1,203.36	1,298.42	1,401.00	1,511.68	1,631.10	1,705.15	1,739.26	1,774.04	1,423.67	1,379.25	1,363.94	1,388.63	1,374.05	1,381.88	1,387.41	1,397.40	1,442.95
Cumulative Nominal Cost of Power			1,033.60	2,148.85	3,352.21	4,650.64	6,051.64	7,563.32	9,194.42	10,899.58	12,638.83	14,412.87	15,836.54	17,215.79	18,579.74	19,968.36	21,342.41	22,724.29	24,111.70	25,509.09	26,952.05
Annual Inflation-adjusted Cost			1,013.33	1,071.95	1,133.95	1,199.54	1,268.93	1,342.33	1,419.97	1,455.33	1,455.33	1,455.33	1,145.00	1,087.53	1,054.37	1,052.41	1,020.94	1,006.62	990.83	978.40	990.49
Cumulative Inflation-adjusted Cost			1,013.33	2,085.28	3,219.23	4,418.78	5,687.71	7,030.03	8,450.01	9,905.34	11,360.67	12,816.01	13,961.01	15,048.54	16,102.91	17,155.32	18,176.25	19,182.88	20,173.71	21,152.11	22,142.60

Rate path based on even annual rate increases of 3.95%

			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Year Ending in March		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Change in Units																					
Annual Units Purchased		1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000
Price Increase			3.36%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	-1.16%	-23.77%
Nominal Price		1	1.03	1.07	1.12	1.16	1.21	1.25	1.30	1.36	1.41	1.46	1.52	1.58	1.65	1.71	1.78	1.85	1.92	1.90	1.45
Inflation	2%	1	1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46
Inflation-adjusted Price			1.01	1.03	1.05	1.07	1.09	1.11	1.14	1.16	1.18	1.20	1.22	1.25	1.27	1.30	1.32	1.35	1.37	1.33	0.99
Annual Nominal Cost of Power		1000	1,033.60	1,074.43	1,116.87	1,160.98	1,206.84	1,254.51	1,304.07	1,355.58	1,409.12	1,464.78	1,522.64	1,582.79	1,645.31	1,710.29	1,777.85	1,848.08	1,921.08	1,898.79	1,447.45
Cumulative Nominal Cost of Power			1,033.60	2,108.03	3,224.89	4,385.88	5,592.72	6,847.23	8,151.30	9,506.87	10,916.00	12,380.78	13,903.42	15,486.20	17,131.51	18,841.80	20,619.65	22,467.73	24,388.81	26,287.60	27,735.04
Annual Inflation-adjusted Cost			1,013.33	1,032.71	1,052.45	1,072.57	1,093.07	1,113.97	1,135.27	1,156.97	1,179.09	1,201.63	1,224.60	1,248.02	1,271.87	1,296.19	1,320.97	1,346.22	1,371.96	1,329.46	993.57
Cumulative Inflation-adjusted Cost			1,013.33	2,046.04	3,098.49	4,171.06	5,264.13	6,378.10	7,513.37	8,670.34	9,849.43	11,051.06	12,275.67	13,523.68	14,795.56	16,091.75	17,412.71	18,758.94	20,130.90	21,460.35	22,453.93

Mathematical calculations on these scenarios give the result that a discount rate of 4.93% equalizes the discounted cumulative cost of power to ratepayers by 2036. However, customers in the 3.95% rate path will be paying less in cumulative discounted dollars throughout the entire period, until the final year. At discount rates lower than 4.93%, ratepayers in the 3.95% rate path will be better off for most of the period, but ratepayers in the 7.95% path will be better off towards the end. If the discount rate for customers is any higher than 4.93%, then ratepayers will always be better off in the 3.95% rate path.

This result makes sense, because there is a cost of capital (or time value of money) for everyone, ratepayers included. If a ratepayer pays less for their power today, then they will have more money available to pay down their own mortgage, or invest in a new business, or just buy something that they want. Manitoba Hydro cannot calculate the economic efficiency of proposed rate paths without taking into account the cost of capital to its ratepayers.

Some Manitoba Hydro ratepayers will have a higher cost of capital, while for others it will be lower. Given that Manitoba Hydro's ratepayers encompass almost all of the people in the province, it is arguable that a "social discount rate" should be used in this sort of calculation. There is an abundant academic literature around this subject, given its use in assessing long-term government programs (and conceptual problems like the cost of climate change). In Canada, recent government studies have landed on using a 3% real discount rate for many uses, consistent with recent decisions of the US government.[36] In the case of Manitoba Hydro, this would be a ratepayer cost of capital of 5%, given the assumed 2% inflation rate.

Applying a discount rate to the rate paths does not complete the review of economic efficiency issues, however. Manitoba Hydro's main purpose in applying for a 7.9% rate path is to strengthen the company's ability to withstand financial distress, without subsequently raising rates beyond the intended path. For example, as was suggested above in the review of hydrological risk, a severe drought could cause a series of years where cash flows are constrained, and all of the company's financial metrics deteriorate. If this were to occur in the context of the 7.9% rate path, the presumption would be that Manitoba Hydro would not ask for rate increases higher than already planned (debt would presumably no longer fall to 75% in 2027, but would instead only fall to 75% later, after the drought was over and financial results recovered). On the other hand, if the 3.95% rate path were pursued, then rates might have to be increased in the face of a severe drought. In this case, the 3.95% rate path would morph into something new, with different financial outcomes, and costs to ratepayers.

Suppose the drought began on April 1, 2024 (the year ending March 31, 2025, or year 8 in the tables above). At that point, rates in the 7.9% rate path would already be 71% higher than today, and Manitoba Hydro would have reached an equity ratio 19% (with an Interest Coverage ratio in the year ending March 31, 2024 of more than 2.0x). A ratepayer may have paid 9,194 for power over the previous seven years, which discounted at 5% would be 7,488. Alternatively, the same position on the 3.95% rate path would be rates that are 36% higher than today, with seven years of power purchases amounting to 8,151, discounted at 5% to 6,687. Manitoba Hydro would be at a 13% equity ratio (with a 1.55x Interest Coverage Ratio in the previous year).

In that situation, Manitoba Hydro ratepayers would be unequivocally economically better off in the 3.95% rate path when the drought begins. They will have paid lower prices over seven years, and used their own money as they saw fit. If, because of the drought, Manitoba Hydro's rates needed to be adjusted upwards, there would be room to do so.

[36] Please see the Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates (March 2016), available at http://ec.gc.ca/cc/default.asp?lang=En&n=BE705779-1 This document also provides references to recent work from the United States, as well as academic literature.

However, without knowing the severity and longevity of the drought, it would not be possible to calculate the point at which customers would no longer be better off. A whole range of scenario calculations would have to be done based on the probability associated with droughts, versus the discounted dollar impacts of the alternative rate paths, in order to calculate an optimal probability-weighted break even point. Manitoba Hydro did not address this issue in its application.

In effect, from an economic efficiency point of view, Manitoba Hydro assumed that ratepayers do not have a cost of capital, and considered financial issues only from the perspective of the corporation, not its ratepayers. Given the regulatory principle of economic efficiency, however, it may be valuable to consider ratepayer costs of capital in the formulation of rates.

Cost Causality

The principle of cost causality holds that ratepayers should pay only the cost of the services that they have received from a utility, and should not be required to pay costs that are attributable to others. This principle is important because it affirms that all ratepayers are equally valid and important, and should be treated equally well.

Given the long-lived and shared-use nature of utility assets, appropriately allocating the cost of developing and operating a utility system is necessarily approximate, both in terms of allocation between current customers, and allocating costs to customers over time. From a time perspective, depreciation is the critically important method of allocation, and straight line depreciation is a compromise that addresses the unknowability of exact wear and tear on long-lived assets over time. Appropriately allocating the cost of risks over time is conceptually challenging. As noted above, the frequency, duration and magnitude of negative outcomes is ultimately unknowable until they actually occur. Nevertheless, the utility must be prepared to meet these challenges should they occur, and ratepayers must pay for them. But which ratepayers?

Consider the example of a five-year drought. The historical record demonstrates that such droughts have occurred, and might do so again at any time. When they occur, droughts reduce revenues and raise costs, and the net impact must then be passed on to ratepayers, since Manitoba Hydro has no investors who are taking on any of that risk. When they occur, the costs of a drought could be charged to the ratepayers of the day through an immediate and severe rate increase, or could be spread forward in time to ratepayers of the future by delaying recovery of some of the costs until the drought is over and the utility financially recovers. Importantly, the costs of a drought cannot be spread backwards in time, to ratepayers of the utility before the drought occurrence, for obvious reasons

However, droughts are not “caused” by any ratepayers: neither the ratepayers of the day they occur, nor those before or afterward. There is no reason why any particular ratepayers across time should be required to bear the burden of drought, since all ratepayers are valued and respected equally. However, the creation of a “drought relief reserve”, to which all ratepayers must equally (in a real sense, adjusted for inflation) contribute over time, would be one way of notionally spreading costs “forward” from any future drought event, and “backward” at least to the point that the payments into the reserve were begun. This is essentially a form of insurance, with all of the pitfalls normally applicable to insurance, in terms of accurately estimating all of the probabilities and outcomes involved. Insurance schemes, for the purposes considered here, amount to a mechanism to fairly distribute the costs of infrequent negative occurrences over time, fulfilling the principle of cost causality (in the same way that straight line depreciation attempts to fairly distribute the costs of capital goods over time).

Another name for a "drought relief reserve fund" could be "equity". If all ratepayers were contributing the same amount (on an inflation- or discount rate-adjusted basis) to equity over time, then all ratepayers would be contributing equally to the management of infrequent but extremely negative events such as drought.[37]

There are a variety of practical problems associated with calculating a "contribution to reserve" that would be relatively stable and appropriate for all ratepayers over time. However, a primary issue concerns what types of events should be included in the list of occurrences that should be covered by the notional reserve. Certainly, droughts would qualify, as would significant operational challenges like major storm damage. However, two of the chief risks identified by Manitoba Hydro are interest rates and export prices. Arguably, these are not risks that should be subject to notional insurance or reserves. In normal ratemaking, regulators do not typically attempt to smooth the cost of interest over time. Instead, ratepayers are required to pay the interest cost at whatever level is extant at the time of ratemaking. Manitoba Hydro is consistent with this practice, since only the actual costs of debt are passed on to ratepayers, and Manitoba Hydro does not attempt to hedge or smooth its interest costs against some notional long-term estimate of what interest rates "should be".

Manitoba Hydro has not proposed that all ratepayers over time pay a certain amount above otherwise required rates in order to contribute to equity. Instead, they have proposed that ratepayers for a specific period of time pay much higher rates, in order to create a reserve fund to be used later, in the event of a drought, or other negative event. This proposed distribution of the burden is called into question by the principle of cost causality.

Stability and Predictability

Stability and predictability are important attributes that contribute to customer service, economic efficiency, capital market acceptance, and the public interest. Customers could make better decisions about their intended use of electricity if they knew that rates would remain stable, or at least knew that rates would follow a predetermined path for a reasonable period of time. Governments could better design policies relating to climate change, energy conservation, fuel switching, and other programs, and capital markets could make better decisions about credit-worthiness and provide interest rates at efficient levels.

According to the *Crown Corporations Governance and Accountability Act*, Manitoba Hydro is only allowed to apply for rates for up to a three-year period. This limits the absolute length of time over which there can be true predictability of rates. In fact, Manitoba Hydro has historically returned for rates more often than every three years.

As noted in Section 1 of this Report, Manitoba Hydro originally applied for two years of 7.9% rate increases. However, they emphasized a 10-year rate path in their application. The premise was that they would actually seek five years of 7.9% increases over time, before rate requests would be reduced to 2% per year. The theory presented was that these increases would have a 50% probability of resulting in a 75:25 Debt : Equity Ratio by March 31, 2027. However, when the PUB allowed an interim rate increase of only 3.36% instead of 7.9%, Manitoba Hydro returned with a revised application highlighting that the 10-year rate path would have to altered in order to maintain the 50% probability of achieving the Debt : Equity Ratio.

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[37] An explicit "contribution to reserves" could be included in the revenue requirement formula. The calculation of what this contribution should be over time would depend on the probability of negative events occurring, and their expected severity.

In other words, it appears that what is stable from the perspective of Manitoba Hydro is the need to aim for the targeted Debt : Equity Ratio by a specific date. If, over the next two years, economic and performance variables do not conform to reference assumptions, would Manitoba Hydro still return with a request for a rate increase of 7.9%, or would that figure be altered so that there continues to be a 50% probability of achieving the targeted Debt : Equity Ratio by the specified date?

From a ratepayer perspective, it is stable and predictable rates that are of value. From a capital markets perspective, it is apparent from the comments surveyed in Section 3 of this Report that stable and predictable cash flows are most helpful in achieving a higher rating. But stability and predictability in the capital structure does not necessarily assist in providing either of these things, since both rates and cash flows would have to be adjusted dramatically to hew closely to a specific Debt : Equity Ratio target on an annual basis.[38]

Public Interest

The public interest principle requires that the regulator of a utility take into account the broader impact of rates and utility operations on the economy and society in which it is situated.

On the question at hand, whether to pursue higher rates to build up equity or not, three public interest issues are apparent:

- The broader economic impact associated with higher rates;
- The risk to the Government of Manitoba credit rates arising from Manitoba Hydro financial outcomes; and
- Total payments to the Government of Manitoba under the two scenarios.

The first issue is addressed by economic experts in this process, and is outside the scope of this Report. Should it be found that raising rates to the 7.9% level will have a drag on the Manitoba economy, or should it be found that the competitiveness of certain economic sectors in the province will suffer, then this should be cause to carefully consider alternative options to the rate request. The second issue was addressed above in Section 3. It is evident that the capital markets would be very concerned if cash flows at Manitoba Hydro were insufficient to cover all costs, including interest on debt. Whatever rate path is ultimately chosen, protecting and preserving the credit of the Province must be a priority.

Total payments to the government by Manitoba Hydro consist of property taxes (or their equivalent), water rentals and assessments, the debt guarantee fee, and capital taxes. As noted in Appendix 4.5 of the application (page 60), these charges amounted to approximately $400 million, or 17% of Manitoba Hydro's total revenues in 2016/17. For the Province of Manitoba, which budgeted approximately $15.5 billion in total revenues in 2016/17, this amount represents approximately 2.5% of total annual budget revenues.

In considering two possible rate paths of 7.9% or 3.95%, it should be apparent that property taxes and water rental charges would not change in either case, since these charges are independent of rates. However, the debt guarantee fee is directly related to outstanding debt during each year, and the capital tax depends on the total of the

[38] As noted above in the examination of 7.9% rate path, in 2027/28 there could be a decline in rates of as much as 20%, with concomitant effects on cash flows.

debt and equity in the business. By following a 7.9% rate path and reducing debt more quickly than otherwise, Manitoba Hydro would actually be reducing its payments to the Government of Manitoba.

Given the very small portion of budget revenues represented by payments from Manitoba Hydro, and the fact that water rental charges and property taxes would not change in any case, the difference in total payments to the Province will be modest and have limited impact. However, it is a somewhat surprising result that under the 7.9% rate path, ratepayers would be paying more for their power, while the Government of Manitoba would actually be receiving less revenue from Manitoba Hydro.

Access to Capital Markets

Access to the capital markets is a critical requirement for regulated utilities, and must be a priority concern in the setting of rates.

The particular circumstances of Manitoba Hydro's access to capital were addressed in Section 3, above, and need not be repeated here in detail. The need to ensure that cash flows remain sufficient for Manitoba Hydro purposes is clear, in order to prevent indirect impacts on the Province's access to and cost of capital. However, Manitoba Hydro itself has automatic access to capital given its privileged relationship with the Province.

5. Practical Consequences of Financial Targets

A. Precedent for Future Ratemaking

The PUB, like all regulators, is not bound by precedent with respect to its ratemaking decisions. However, Manitoba Hydro's current application, given its focus on 10-year rate paths and longer term financial targets, presents an opportunity to set the agenda for a period of time into the future, which may be of benefit to all stakeholders.

Manitoba Hydro has not formally requested that the PUB adopt or endorse the financial targets that the Manitoba Hydro Electric Board has adopted. Nor is the PUB bound to do so in its duties as a regulator. The PUB is free to make its own determination about the amount of "any other reserves that are necessary for the maintenance, operation, and replacement of works of the corporation," per s. 25(4)(v) of the *Crown Corporations Governance and Accountability Act.* However, if the PUB chooses to clarify how it will approach the issue of reserves and rate stability in the future, it will simplify the process of ratemaking, both for Manitoba Hydro and for intervenors. With the settlement of these issues, and the adoption of a standardized methodology, the question of reserves and planned addition to reserves could become focused on mathematical and probabilistic calculation, rather than debate over principles and potential impacts.

B. Signals to the Capital Markets

A critical audience for PUB comments on reserves and rate stability in the future will be the capital markets. As discussed in Section 3, above, capital markets participants are very focused on cash flows at Manitoba Hydro, and the sufficiency of the same to meet all expenses, especially debt interest. They are quite aware of the potential for financial distress in the case of droughts, as well as the challenges potentially faced by Manitoba Hydro in the future with respect to interest rates, export prices, and the ongoing potential for budget or schedule slippage in the Keeyask project.

Explicit endorsement by the PUB of policies around reserves, cash flows, and rate increases will help all market participants understand what to expect. The lack of clarity about whether Manitoba Hydro is "self-supporting" could be at least partly addressed by a statement from the PUB about how it might consider approaching a hypothetical financial distress situation in the future. For example, adoption of a "debt service coverage" ratemaking formula in the style of the Tennessee Valley Authority would signal that rates will be adjusted above all to ensure sufficiency of cash flows (perhaps over some medium-term timeframe, such as a rolling five-year forward period, to aid in the smoothing of rates). Alternatively, use of some fixed or inflation-adjusted level of annual contribution to reserves, built into rates on an ongoing basis, would provide a means for observers to estimate the cash flows and financial resources of Manitoba Hydro under different circumstances.

Of course, endorsement of Manitoba Hydro's target for Debt : Equity of 75% would also be a strong signal, but this would then raise issues about how Manitoba Hydro and the PUB will each separately react to changing financial and operational conditions which will undermine the achievement or maintenance of that target. In many senses, Manitoba Hydro's preferred target and timing goal provides the least certainty to the markets about how rates will be managed in the future. Would rates continue to increase at 7.9% per year, regardless of outcomes, or would rates be adjusted, however dramatically might be necessary, in order to achieve that goal in 2027? Having achieved the goal, would it be strictly enforced thereafter, even if that meant rate decreases and increases from year to year?

Unambiguous signals to the capital markets are not without their potential pitfalls, however. If the PUB adopts policies around reserves and rates, then these will be understood as a new "baseline" by observers and analysts. Failure to be consistent with those policies in the future would undermine the credibility of the PUB and the financial soundness of Manitoba Hydro both. Given the very significant role of Manitoba Hydro debt in the finances of the Province, it is necessary to ensure that at no time there be any circumstance where financial stress at Manitoba Hydro becomes a "contagion" for the Province.

C. Manitoba Hydro Debt Management

In its original application, Manitoba Hydro stated that it had changed its internal treasury policies, and was now targeting an average term to maturity of 12 years for new debt. The meaning and import of this change was somewhat ambiguous. There appeared to be a suggestion that this policy was an argument in favour of adopting the 7.9% rate path, since it would facilitate the successful continuation of the debt maturity program.

In response to PUB Round 1 IR-28(c), Manitoba Hydro stated:

> *Should underlying forecast assumptions (including rate increases, cost savings, export prices, interest rates, in-service dates) not materialize as planned, Manitoba Hydro will re-evaluate and adjust its debt management strategy and the targeted weighted average term to maturity of new debt issuance as it deems necessary.*

This clarifies that the treasury function within Manitoba Hydro is creative and responsive to prevailing conditions, and is not in fact a driver of decision-making with respect to rates, reserves and other financial targets. In essence, treasury policies such as target term-to-maturity should be the result of ratemaking decisions, and not a cause.

6. Summary Observations

Why are financial targets relevant to rate-setting for Manitoba Hydro?

Financial targets are important in rate-setting because they help to define one aspect of the "overall general health" of Manitoba Hydro, which the PUB has said that it will take into account in its rate-setting. Ultimately, financial targets cannot be determinative of PUB decisions, and the PUB must balance a variety of principles of regulatory rate-making as it pursues each unique choice. However, many stakeholders, including especially the capital markets, are very focused on financial targets, both in historical terms, and with respect to intentions for the future.

The PUB may wish to give consideration to clarifying which financial measures it believes are important to rate-making, and how those measures will be incorporated into decisions, now and in the future. Doing so will provide clarity to the capital markets, reduce some of the ambiguity that currently clouds credit rating discussions about the Province of Manitoba, and set the stage for more efficient rate hearings in the future.

Should the Debt : Equity Ratio be the primary financial target that is taken into account when setting rates for the future?

Manitoba Hydro's application gives the Debt : Equity Ratio pride of place among financial measures, and implies that pursuit of the 75:25 target level by March 31, 2027 should drive rate-setting to an unprecedented degree. The revision of the proposed 10-year rate path after the PUB's decision on interim rates speaks volumes about the subsidiarity of all other considerations in the arguments of Manitoba Hydro.

This emphasis on capital structure does not appear to be shared by capital markets observers, who instead are more focused on measures of cash flow sufficiency to meet debt obligations, in keeping with their primary interest of protecting their debt investments. While capital structure is an important consideration, it is nevertheless secondary in credit analysis, and only indirectly sheds light on financial risk. This suggests that if preventing negative impacts on the credit rating of the Province of Manitoba is a concern, then pursuing a Debt : Equity Ratio is a secondary way of doing so. Instead, a more direct focus on ensuring cash flow sufficiency through rate-setting would be more likely to provide that support. However, lest the importance of stability and predictability be forgotten, the need to ensure the support of the capital markets for Manitoba Hydro should be balanced against the need to avoid wildly swinging rates. Cash flow sufficiency need not be an annual condition, but can rather be ensured on a rolling forward basis, which will help to manage both the predictability of rates, and the sufficiency of cash flows.

As a pure cost recovery, government-owned utility, it is not clear why "equity" should be a priority per se. From the perspective of the ratepayers who are the ultimate funders of all of the utility's operations, "equity" is essentially "dead money": it earns no return, but nevertheless has been taken out of the hands of the ratepayers who could otherwise use it. A review of rate paths through the lens of discounting at the social discount rate helps to stress the importance of making use of ratepayer funds in the most economical way.

If, per the language of the *Manitoba Hydro Act*, "equity" represents the reserves to be set aside "for the stabilization by the board of rates or prices for power sold by the corporation, the meeting of extraordinary contingencies, and such other requirements or purposes," then the term may be more effectively relabeled to better communicate its intentions to all concerned. In addition, if "equity" is properly to be understood as "reserves", then it should be clearly specified what those reserves are for, when they should be called upon (or not), and how exactly <u>all</u> ratepayers should be called upon to contribute equally to the reserves. Fairness as between ratepayers demands no less than an effort to apportion the costs of reserves over time and across customer classes. Estimating the necessary size of reserves should be founded upon an understanding of the risks faced by the corporation that should be borne by all ratepayers across time (as opposed to those risks that should be borne in real time, as they may or may not occur), and some form of careful calculation about the least size of reserves that will satisfy the need for the general financial health of the utility. This careful delineation does not appear to have been done; rather, all risks appear to have been accepted as included in the coverage by equity reserves, and no care taken to ensure that ratepayers over time are contributing an appropriate amount.

Assuming the Debt : Equity Ratio is the primary target, should rates be set so as to achieve that target by March 31, 2027, all other things being equal?

Given the observation that Debt : Equity Ratio should not be the primary financial focus for rate-making, this question is somewhat sidelined. However, if it is determined that Debt : Equity Ratio should be a primary focus, then the question arises whether the goal of meeting the target in 2027 is appropriate.

A glaring issue with this goal, even in a scenario where all reference assumptions were to prove miraculously accurate, is that in the year following the achievement of the target a very significant rate decrease would be warranted, otherwise the target would be substantially exceeded in short order. This casts into doubt the value of this timing goal from the perspective of rate stability and predictability, and also from the perspective of cash flow stability and predictability.

Manitoba Hydro stated in the risk assessment included in the original application that a 7.9% rate path would have a 50% probability of achieving the Debt target by 2027, in the face of a variety of uncertain variables. In the revised application, post interim rate decision, a revised and even more aggressive rate path was provided, which presumably continues to have approximately a 50% chance of successfully reaching that target by the same date. No clarity was provided about which variables would be allowed to undermine the reaching of that goal, and how they would relate to rate-making. For example, interest rates have already risen somewhat, presumably reducing the probability of reaching the goal: what should be the rate response, if any? Export prices between now and the next rate application for 2019 rates may be higher or lower than currently forecast; will that mean that the rates applied for will still be 7.9%, or will Manitoba Hydro simply accept that the probability of meeting the goal has changed? A fixed target for a specific date, which does not take into account changing variables and contexts, and is not adjustable and related to real drivers of rate-making policy, does not appear credible.

Appendix A – Relevant Manitoba Legislation

Manitoba Hydro Act

Purposes and objects of Act

2 The purposes and objects of this Act are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and, in addition, are

(a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and

(b) to market and supply power to persons outside the province on terms and conditions acceptable to the board.

General powers of board

14 The board on behalf of the corporation may perform, execute, and carry out, all the duties, powers, and functions imposed or conferred upon it or upon the corporation by this Act; and for that purpose the board may do all and any acts and things that are necessary for or incidental to the performance, execution, or carrying out, of any such duty, power, or function, including the passing of such by-laws and resolutions as the board may deem advisable.

Powers of board

15(1) The board, on behalf of the corporation, may

(a) make such by-laws, not contrary to law or this Act, as it deems necessary or advisable for the conduct of the affairs of the corporation, and, without limiting the generality of the foregoing, with respect to the time and place of the calling and holding of all meetings of the board, procedure in all things to be followed at such meetings, and generally with respect to the conduct in all other particulars of the affairs of the corporation, and may repeal, amend, or re-enact them;

(b) appoint and employ such officers and employees of the corporation as the board deems necessary for the transaction of the business of the corporation and prescribe the duties of any such officers and employees and fix their remuneration;

(c) obtain the services of such engineers, accountants, and other professional persons as the board deems necessary for the proper and convenient transaction of the business of the corporation, and fix their remuneration;

(d) make such inquiries and investigations into all or any matters, relating to the development, generation, transmission, distribution, supply, purchase, or use of power, actual or potential, at such times and places and in such manner as seems advisable to the board.

Corporation has powers of a natural person

15(1.1) In addition to the other powers set forth in this Act and subject to the limitations set forth in this Act, the corporation has the capacity, rights, powers and privileges of a natural person to carry out its purposes and objects and to carry on related business ventures, on such terms and conditions as the board deems proper.

Power to carry out purposes and objects of Act

15(1.2) Subject to subsection (1.3) and section 15.1, the corporation, or any subsidiary, may

(a) carry out the purposes and objects of this Act; or

(b) carry on related business ventures;

on behalf of the corporation, or the subsidiary, or, by way of a partnership, joint venture or any similar arrangement, with any other person, or by way of a company in which the corporation or a subsidiary owns shares or securities.

Approval of L.G. in C. required where aggregate value exceeds $5,000,000

15(1.3) The corporation or any subsidiary shall not, without the approval of the Lieutenant Governor in Council,

(a) carry out the purposes and objects of the Act; or

(b) carry on a related business venture;

by way of a partnership, joint venture or any similar arrangement, with any other person, or by way of a company in which the corporation or a subsidiary owns shares or securities, wherein the aggregate value of the investments of the corporation and any subsidiary in, and the obligations of the corporation and any subsidiary to, such partnership, joint venture, company or similar arrangement, with any other person, exceeds $5,000,000.

Powers of corporation

15(2) The corporation may, for temporary purposes, and with or without the consent of the owner, enter, remain upon, take possession of, and use, any property, real or personal, and erect, make, or place thereon any structure, installation, or excavation, and flood and overflow any land, and accumulate and store water thereon.

Compensation

15(3) Where the corporation exercises the powers conferred under subsection (2), if it causes damage to the property of, or loss to, any person, it shall pay compensation therefor as in a case to which subsection 24(2) applies.

Transmission access

15(4) The corporation may enter into agreements, or issue a tariff prescribing terms and conditions and a rate schedule, under which the corporation may provide access to the transmission facilities of the corporation to any person entitled under section 21 to purchase power for resale in Manitoba or to any person for sale or use outside Manitoba.

Definitions

15.1(1) In this section,

"joint enterprise" means

(a) a partnership, joint venture or similar arrangement, or

(b) a company, other than the corporation or a subsidiary,

in which the corporation or a subsidiary has an interest and which owns or operates a major facility or business; (« coentreprise »)

"major facility or business" means

(a) a major facility in Manitoba for generating, transmitting or distributing power, and

(b) the business of generating, transmitting or distributing power in Manitoba or of supplying fuel in Manitoba. (« installation ou entreprise importante »)

No sale by corporation or subsidiary

15.1(2) Neither the corporation nor a subsidiary shall

(a) sell, lease or otherwise dispose of, except to the corporation or a subsidiary, all or any part of its interest in a major facility or business;

(b) sell or otherwise dispose of, except to the corporation or a subsidiary, any of its shares of a subsidiary that owns or operates a major facility or business or has acquired an interest in a joint enterprise pursuant to subsection 15(1.2); or

(c) sell or otherwise dispose of all or a substantial part of an interest acquired in a joint enterprise pursuant to subsection 15(1.2).

No issue of shares by subsidiary

15.1(3) No subsidiary that owns or operates a major facility or business or has acquired an interest in a joint enterprise pursuant to subsection 15(1.2) shall issue, except to the corporation or another subsidiary, any shares of its capital stock.

No sale of major facility or business acquired under 1997 amendments

15.1(4) No joint enterprise in which the corporation or a subsidiary has acquired an interest pursuant to subsection 15(1.2) shall sell, lease or otherwise dispose of, except to the corporation or a subsidiary, all or a substantial part of its interest in a major facility or business.

No guarantee by corporation or subsidiary

15.1(5) Neither the corporation nor a subsidiary shall guarantee the borrowings or obligations of any person, except that the corporation or a subsidiary may, with the approval of the Lieutenant Governor in Council, guarantee the borrowings or obligations of a subsidiary.

Retail supply of power

15.2 No person other than the corporation shall engage in the retail supply of power in Manitoba.

No privatization without referendum

15.3(1) The government shall not present to the Legislative Assembly a bill to authorize or effect a privatization of the corporation unless the government first puts the question of the advisability of the privatization to the voters of Manitoba in a referendum, and the privatization is approved by a majority of the votes cast in the referendum.

Procedures for referendum

15.3(2) A referendum under this section shall be conducted and managed by the Chief Electoral Officer in the same manner, to the extent possible, as a general election under *The Elections Act*, and the provisions of that Act apply with necessary modifications to such a referendum.

Question to be put to voters

15.3(3) The question to be put to voters in a referendum under this section shall be determined by order of the Lieutenant Governor in Council at the commencement of the referendum process.

Regulations re procedures

15.3(4) The Lieutenant Governor in Council may make any regulations that the Lieutenant Governor in Council considers necessary respecting the referendum process to give effect to this section, including, without limitation, regulations

(a) governing the preparation of a voters list;

(b) governing the expenses that may be incurred and the contributions that may be made, and by whom, in connection with a referendum, including placing limits on such expenses and contributions and establishing registration and reporting requirements for persons or organizations who make such contributions or incur such expenses;

(c) where greater certainty is required, modifying to the extent necessary the provisions of *The Elections Act* to make them applicable to the requirements of a referendum.

Costs of referendum

15.3(5) The costs of conducting a referendum under this section shall be paid from the Consolidated Fund.

Capitalization of balance owing to City of Winnipeg

15.3.1 If the Legislative Assembly enacts a bill to authorize or effect a privatization of the corporation, the stream of annual payments comprising the unpaid balance of the purchase price for Winnipeg Hydro shall be capitalized and paid in the manner set out in the purchase agreement between The City of Winnipeg and the corporation dated June 26, 2002, or in any other manner agreed to by them and approved by the Lieutenant Governor in Council.

Amendment or repeal

15.4(1) Any bill introduced in the Legislative Assembly to amend, repeal, override or suspend the operation of this section or section 15.1 or 15.3 shall be referred at the committee stage to a standing committee of the Legislative Assembly which provides the opportunity for representations by members of the public.

Requirements re hearings

15.4(2) The standing committee referred to in subsection (1) shall not meet to review the bill until seven days after the later of

(a) the day the bill is distributed in the Legislative Assembly; and

(b) the day the public is given notice of the date, time and place of the meeting.

Powers of corporation with approval of L.G. in C.

16(1) With the approval of the Lieutenant Governor in Council the corporation may

(a) acquire by purchase, lease, licence, or otherwise

(i) any power project, power site, and power plant;

(ii) that part of the undertaking, property, and assets (including works) of any person, relating to, or used in, the generation, distribution, or supply of power;

(b) without the consent of the owner or persons interested therein, acquire, take, and expropriate land, including the right of entry to install, maintain and protect works and the right to impose restrictions on the use of any land, notwithstanding that the land which is subject to the restriction is not, or may not be, appurtenant or annexed to any land of the corporation;

(c) require any person generating, transmitting, distributing, or supplying power, to supply such power to the corporation as the board may from time to time require or designate;

(d) within such territorial or other limits as the Lieutenant Governor in Council may from time to time prescribe, control and regulate the development, generation, transmission, distribution, and supply, of power in Manitoba, and, for any of those purposes, control and regulate the flow of, and right to use for the generation of power, or any purpose connected therewith, the water in any lake, river, or watercourse, or other body of water in Manitoba, and the taking, diversion, storage, or pondage of any such water;

(e) acquire by purchase, lease, licence or otherwise

(i) any real property outside Manitoba and erect, construct, maintain and operate, upon the real property so acquired, any works, or

(ii) interconnection works and maintain and operate the interconnection works so acquired;

(f) enter into an agreement with Her Majesty in right of Canada or of any province, or with any commission or minister of the Government of Canada, or of any province, or with any state of the United States or any officer or representative thereof, or with any person interested in or affected by any interconnection works, as to the terms and conditions upon which the interconnection works and the works carried out thereon shall be carried on or exercised;

(g) acquire for use in Manitoba power generated outside Manitoba by the government of any other province, or of any state of the United States, or by any person in that other province or state;

(h) supply power generated in Manitoba to any other province or any state of the United States, or to any person in that other province or state;

(i) sell, lease or otherwise dispose of any property of the corporation to a subsidiary or make any other investment in, or incur any obligation to, a subsidiary, where the aggregate value of the property, investments and obligations to the subsidiary exceeds $5,000,000.;

(i.1) develop new power generation stations;

(j) enter into agreements and do all things proper or necessary for the due exercise of the powers mentioned in this section.

No approval required if less that $5,000,000

16(2) Notwithstanding subclause (1)(e)(i), the corporation shall not require the approval of the Lieutenant Governor in Council to acquire real property outside Manitoba if the purchase price of the real property is less than $5,000,000.

Subsidiaries

16.1(1) A subsidiary has the capacity, and subject to this Act and to the applicable laws of the jurisdictions in which the subsidiary carries on business, the rights, powers and privileges of a natural person.

L. G. in C. may limit rights, powers and obligations of subsidiaries

16.1(2) In the case of a subsidiary that carries on business outside Manitoba, the Lieutenant Governor in Council may, for the purposes of enabling the subsidiary to comply with the regulatory requirements of the jurisdiction in which it carries on business, specify the rights, powers and obligations of the corporation or a subsidiary set out in this Act which shall not apply to the subsidiary.

L.G. in C. to approve loans

16.1(3) A subsidiary shall not raise money by way of loan, on the credit of the subsidiary or otherwise, from any person other than the corporation, without the approval of the Lieutenant Governor in Council.

L.G. in C. approval required

16.1(4) A subsidiary shall not carry on an activity for which the corporation is required to obtain the approval of the Lieutenant Governor in Council without obtaining the approval of the Lieutenant Governor in Council.

Rights of board re subsidiaries

16.1(5) The board shall exercise all of the rights of a holder of shares or securities with respect to any subsidiary or any company of which it holds shares or securities, including the right to elect directors, as it deems proper.

Separation of functions

16.2 Any rules and procedures for the separation of functions which the board has established for the purposes of pursuing opportunities to purchase and sell power within and outside Manitoba may be adopted, by regulation, by the Lieutenant Governor in Council, and upon such adoption such rules and procedures shall have the force of law.

Adoption of codes and standards

16.3(1) For the purposes of pursuing opportunities to purchase and sell power within and outside Manitoba, the board may, subject to the approval of the Lieutenant Governor in Council,

(a) adopt, in whole or in part, any standards, rules, terms, conditions, guidelines or schedules, which are related to the planning, design or operation of generation or transmission facilities within an integrated regional power grid, established by an industry organization, regional transmission group, regulatory body or other association or group or any other person;

(b) prescribe variations in, additions to or deletions from any standards, rules, terms, conditions, guidelines or schedules adopted under clause (a);

notwithstanding that the adoption of such standards, rules, terms, conditions, guidelines or schedules may constitute the delegation of powers or duties of the corporation to carry out or carry on certain functions to any other person.

Effect of adoption

16.3(2) The adoption of any standards, rules, terms, conditions, guidelines or schedules under clause (1)(a), in whole or in part and either in existing form or as altered under clause (1)(b), is deemed, on the approval of the board, to be an adoption of

(a) any subsequent amendment made to the standards, rules, terms, conditions, guidelines or schedules; and

(b) any new standards, rules, terms, conditions, guidelines or schedules subsequently substituted by an industry organization, regional transmission group, regulatory body or other association or group or any other person, for the standards, rules, terms, conditions, guidelines or schedules, and any new standards, rules, terms, conditions, guidelines or schedules so substituted are deemed to be subject to such alterations, with such modifications as the circumstances require, as may have been made in the adopted standards, rules, terms, conditions, guidelines or schedules under clause (1)(b).

Authority for temporary borrowing

30(1) With the approval of the Lieutenant Governor in Council, the corporation may, from time to time, borrow or raise money for temporary purposes by way of overdraft, line of credit, or loan, or otherwise upon the credit of the corporation in such amounts, not exceeding in the aggregate the sum of $500,000,000. of principal outstanding at any one time, upon such terms, for such periods, and upon such other conditions, as the corporation may determine.

Guarantee

30(2) The government may, on such terms as may be approved by the Lieutenant Governor in Council, guarantee the payment of the principal and interest on any borrowings of the corporation under this section.

Minister of Finance's approval

30(3) Where the corporation borrows or raises money under this section, otherwise than

(a) by way of overdraft with a bank; or

(b) by sale of its short term notes to a bank in lieu of borrowing by overdraft;

it shall do so only with the prior approval of the Minister of Finance, who, at the request of the corporation, may act as its agent in that behalf.

Temporary advances by government

31 To the extent permitted by any Act of the Legislature the Lieutenant Governor in Council, on the recommendation of the Minister of Finance, may authorize the Minister of Finance to advance moneys to the corporation for its temporary purposes out of the Consolidated Fund; and every such advance shall be repaid by the corporation to the Minister of Finance at such times, and on such terms, as the Lieutenant Governor in Council may direct, together with interest thereon at such rate per annum as may be approved by the Lieutenant Governor in Council at the time of the making of the advance and from time to time.

Loans by government

32(1) To the extent permitted by any Act of the Legislature the Lieutenant Governor in Council may authorize the raising by way of loan, in the manner provided in *The Financial Administration Act* and *The Loans Act*, of such sums as the Lieutenant Governor in Council may deem requisite for any of the purposes of the corporation under this Act; and any such sums may be advanced to, and paid over by the Minister of Finance to, the corporation, and shall be repaid by it to the Minister of Finance at such times and on such terms as the Lieutenant Governor in Council may direct, together with interest thereon as provided in subsection (2).

Fixing of rate of interest

32(2) Where an advance is made to the corporation under subsection (1), the Lieutenant Governor in Council shall, by order in council at the time of making the advance, fix the rate of interest that shall be paid by the corporation on the sums so advanced, or on the balance thereof remaining from time to time outstanding and not repaid, during such period as is stated in the order; and after the expiry of that period the Minister of Finance shall, by an order in writing, fix, and alter from time to time, as may be required, the rate of interest that shall be paid by the corporation on the sums so advanced, or on the balance thereof as aforesaid, during any one or more subsequent periods that may be stated in any such order.

Power of corporation to borrow and to issue securities

33(1) Subject to the approval of the Lieutenant Governor in Council, and to subsection (2), the corporation may

(a) raise money by way of loan on the credit of the corporation;

(b) limit or increase the amount to be raised;

(c) issue notes, bonds, debentures, or other securities of the corporation;

for the purposes of the corporation or for any related business venture; and, through the Minister of Finance, who shall be its agent in that behalf, it may

(d) sell or otherwise dispose of the notes, bonds, debentures, or securities, for such sums, and at such prices, as are deemed expedient;

(e) raise money by way of loan on any such securities;

(f) pledge or hypothecate any such securities as collateral security; and

(g) do any of those things.

Limitation on borrowing powers

33(2) The powers conferred on the corporation under subsection (1) may be exercised only

(a) for the repayment of any expenditure made, or that may be made, by the government for the purposes provided for in this Act or for any related business venture, or for the repayment, refunding, or renewal, of the whole or part of any loan or advance made by the government to the corporation or of notes, bonds, debentures, or other securities issued by the corporation; or

(b) in cases to which clause (a) does not apply, only to the extent permitted by this Act or any other Act of the Legislature.

Reissue of pledged securities

33(3) Where securities have been pledged or hypothecated by the corporation as security for a loan and the loan has been paid off, the securities are not thereby extinguished, but are still alive, and may be reissued and sold or pledged as if the former pledging had not taken place.

Form of securities

33(4) The notes, bonds, debentures, and other securities the issue of which is authorized by subsection (1) shall be in such form, and shall bear such rates of interest, and shall be payable as to principal, interest, and premium, if any, at such times and places, in the currencies of such countries, in such amounts, and in such manner in all respects, as the Lieutenant Governor in Council may determine.

Form of securities

33(5) The notes, bonds, debentures, and other securities authorized by subsection (1) shall bear the seal of the corporation which may be impressed thereon or may be engraved, lithographed, printed, or otherwise mechanically reproduced thereon, and, together with any coupons attached thereto, shall bear the manual, engraved, lithographed, printed, or otherwise mechanically reproduced signatures of the chairman and of any one officer of the corporation appointed by the board for that purpose; and any such mechanically reproduced seal and signatures are, for all purposes, valid and binding upon the corporation if the note, bond, debenture, or other security bearing it, or to which the coupon bearing it is attached, is countersigned by an officer appointed by the corporation for that purpose, notwithstanding that the person whose signature is so reproduced may not have held office at the date of the notes, bonds, debentures, or other securities or at the date of the delivery thereof and notwithstanding that the person who holds any such office at the time when any such signature is affixed is not the person who holds that office at the date of the notes, bonds, debentures, or other securities or at the date of the delivery thereof.

Proof that issue of securities is necessary

33(6) A recital or declaration, in the resolution or minutes of the board authorizing the issue or sale of notes, bonds, debentures, or other securities, to the effect that the amount of notes, bonds, debentures, or other securities so authorized is necessary to realize the net sum authorized or required to be raised by way of loan, is conclusive evidence of that fact.

Power of government to guarantee

34(1) The government may, on such terms as may be approved by the Lieutenant Governor in Council, guarantee the payment of the principal, interest, and premium, if any, of any notes, bonds, debentures, and other securities issued by the corporation; and the form and manner of any such guarantee shall be such as the Lieutenant Governor in Council may approve.

Signing of guarantees

34(2) The guarantee shall be signed by the Minister of Finance, or such other officer or officers as may be designated by the Lieutenant Governor in Council; and, upon being signed, the government is liable for the payment of the principal, interest, and premium, if any, of the notes, bonds, debentures, and securities guaranteed, according to the tenor thereof.

Discharge of liability under guarantee

34(3) In a case to which subsections (1) and (2) apply, the Lieutenant Governor in Council may discharge the liability resulting from the guarantee out of the Consolidated Fund, or out of the proceeds of securities of the government issued and sold for the purpose; and, in the hands of a holder of any such notes, bonds, debentures, or securities of the corporation, a guarantee so signed is conclusive evidence that compliance has been made with this section.

Signature of Minister of Finance, etc.

34(4) The signature of the Minister of Finance or of any such officer or officers for which provision is made in subsection (2) may be engraved, lithographed, printed, or otherwise mechanically reproduced, and the mechanically reproduced signature of any such person shall be conclusively deemed, for all purposes, the signature of that person and is binding upon the Government of Manitoba notwithstanding that the person whose signature is so reproduced may not have held office at the date of the notes, bonds, debentures, or other securities or at the date of the delivery thereof and notwithstanding that the person who holds any such office at the time when any such signature is affixed is not the person who holds that office at the date of the notes, bonds, debentures, or other securities or at the date of the delivery thereof.

Authority to raise loans in other currencies or in units of monetary value

35 Where this Act, or any other Act, authorizes the corporation to borrow or raise by way of loan a specific or maximum number of dollars by the issue and sale of notes, bonds, debentures, or other securities, it authorizes the borrowing, or raising by way of loan in whole or in part, of the same number of dollars of the currency of the United States; and if the amount of the loan is raised, in whole or in part, by the issue and sale of notes, bonds, debentures, or other securities payable in the currency of any country other than Canada or the United States or in units of monetary value, the Act authorizes the raising of an equivalent amount in that other currency or in units of monetary value calculated in accordance with the nominal rate of exchange between the Canadian dollar or the unit of monetary value, as the case may be, and the currency concerned on the business day next preceding the day on which the corporation authorizes the issue of the notes, bonds, debentures, or other securities, as that nominal rate is determined by any bank in Canada.

Price of power requisitioned

38(1) The price to be paid by the corporation for power supplied to it on its requisition pursuant to clause 16(c) shall be computed by the board at the amount of the actual cost of producing it, including a reasonable allowance for employed capital; and the prices so paid shall not necessarily be the same as between different suppliers.

Review by P. U. Board

38(2) Any person required by the board to supply power to the corporation may apply to The Public Utilities Board to review the price computed under subsection (1) for power supplied to the corporation.

Price of power sold by corporation

39(1) The prices payable for power supplied by the corporation shall be such as to return to it in full the cost to the corporation, of supplying the power, including

(a) the necessary operating expenses of the corporation, including the cost of generating, purchasing, distributing, and supplying power and of operating, maintaining, repairing, and insuring the property and works of the corporation, and its costs of administration;

(b) all interest and debt service charges payable by the corporation upon, or in respect of, money advanced to or borrowed by, and all obligations assumed by, or the responsibility for the performance or implementation of which is an obligation of the corporation and used in or for the construction, purchase, acquisition, or operation, of the property and works of the corporation, including its working capital, less however the amount of any interest that it may collect on moneys owing to it;

(c) the sum that, in the opinion of the board, should be provided in each year for the reserves or funds to be established and maintained pursuant to subsection 40(1).

Fixing of price by corporation

39(2) Subject to Part 4 of *The Crown Corporations Governance and Accountability Act* and to subsection (2.1), the corporation may fix the prices to be charged for power supplied by the corporation.

Equalization of rates

39(2.1) The rates charged for power supplied to a class of grid customers within the province shall be the same throughout the province.

Interpretation

39(2.2) For the purpose of subsection (2.1),

(a) grid customers are those who obtain power from the corporation's main interconnected system for transmitting and distributing power in Manitoba; and

(b) customers shall not be classified based solely on the region of the province in which they are located or on the population density of the area in which they are located.

39(3) to (7) [Repealed] S.M. 1988-89, c. 23, s. 34.

Confining hearing

39(8) In any public hearing held under this section, The Public Utilities Board may define the status and rights of any intervener to the application and it may confine the public hearing by refusing to admit evidence or permit a submission that does not relate to matters that come within the scope of the public hearing as determined and prescribed by The Public Utilities Board.

39(9) [Repealed] S.M. 1988-89, c. 23, s. 34.

Material supplied by corporation

39(10) Where an application is made to The Public Utilities Board under this Act, the corporation, upon request of The Public Utilities Board, shall provide The Public Utilities Board with

(a) a statement showing the prices fixed or proposed to be fixed and the prices which were or are in effect prior to the new prices being fixed;

(b) a statement of the reasons for any changes in the prices fixed or proposed to be fixed including a statement of the facts supporting those reasons;

(c) a statement of the manner in which and a time at which the changes in the prices were or are proposed to be implemented; and

(d) such further information incidental thereto as The Public Utilities Board may reasonably require.

Recommendations by P. U. Board

39(11) After hearing evidence and submissions in respect of any application made to it under this Act, The Public Utilities Board shall make a report to the minister which shall include its recommendations as to the prices that should be charged for power supplied by the corporation or paid for power requisitioned by the corporation, as the case may be, and the reasons for its recommendations.

Action by L.G. in C.

39(12) Upon receiving the report of The Public Utilities Board under subsection (11), the minister shall refer the report for consideration to the Lieutenant Governor in Council, who shall thereafter direct the corporation as to the prices to be charged for power supplied by the corporation or paid for power requisitioned by the corporation, as the case may be, together with such other orders or directions incidental thereto as he deems appropriate, and the corporation shall comply with the orders and directions given by the Lieutenant Governor in Council for such period as may be prescribed by the Lieutenant Governor in Council.

Applications made under subsec. 38(2) or 50(4)

39(13) Where an application is made to The Public Utilities Board under subsection 38(2) to review a price computed under subsection 38(1) or an application is made to The Public Utilities Board under subsection 50(4) to review an assessment or apportionment made under subsection 50(3), subsections (8), (10), (11) and (12) apply with such modifications as the circumstances require to the application.

Establishment of reserves

40(1) The board shall establish and maintain, and may adjust as required, such reserves or funds of the corporation as are sufficient, in the opinion of the board, to provide

(a) for the amortization of the cost to the corporation of the property and works, (whether as a whole or in its component parts), of the corporation during the period, or remaining period, of the useful life thereof;

(b) insurance, for which provision is not otherwise made, against loss or damage to any property of the corporation, or to the persons or property of others, caused by or arising out of the works or operations of the corporation;

(c) for the stabilization by the board of rates or prices for power sold by the corporation, the meeting of extraordinary contingencies, and such other requirements or purposes as in the opinion of the board are proper.

Use of reserves

40(2) The reserves created pursuant to subsection (1) may be used or employed by the board

(a) towards the reservation and setting aside of the sinking fund established under section 41;

(b) towards the renewal, reconstruction, or replacement, or depreciated, damaged, or obsolescent property and works;

(c) towards restoration of any property lost or damaged, or the payment of any claims, in respect of which a reserve as insurance has been established;

(d) in such manner towards the stabilization of rates or prices for power, the meeting of extraordinary contingencies, and for such other requirements or purposes, as the board in its discretion deems proper; and

(e) subject to the approval of the Lieutenant Governor in Council, towards the cost of construction of new works and extensions, improvements, or additions, to any property and works of the corporation.

SINKING FUND

Establishment of sinking fund

41(1) The board shall reserve and set aside, out of the reserves or funds of the corporation established and maintained under section 40 and out of such other revenues and funds of the corporation as may be available for such purposes,

(a) such annual or other periodic amounts as may be required to be reserved and set aside as a sinking fund under any agreement or undertaking entered into, or assumed, by the corporation or the responsibility for the performance or implementation of which is an obligation of the corporation, relative to the repayment of moneys borrowed by the corporation and

(b) such additional annual or other periodic amounts as the Lieutenant Governor in Council may from time to time direct to be reserved and set aside as a sinking fund for the repayment of any other moneys borrowed by, or advanced to, the corporation and applied to the cost of acquisition or construction of property and works of the corporation, or indebtedness assumed by the corporation or the liability for the repayment of which is an obligation of the corporation, in respect of the cost of any property or works of the corporation, or otherwise.

Minimum annual amount for sinking fund

41(2) Subject to subsection (7), the aggregate of the amounts so reserved and set aside as a sinking fund in each fiscal year under subsection (1) shall not be less than

(a) 1% of the advances, borrowings, and assumptions of indebtedness or indebtedness for which the corporation is liable, mentioned in subsection (1) that are outstanding as at March 31 of the fiscal year next preceding the fiscal year in which the sinking fund payment is made; and

(b) an amount in each fiscal year equal to interest at the rate of 4% per annum on the total sinking fund balances as at March 31 in the next preceding fiscal year.

Payment to Minister of Finance

41(3) The moneys reserved and set aside in each fiscal year for sinking fund purposes under subsections (1) and (2) shall be paid to the Minister of Finance as trustee for the corporation before the end of that fiscal year.

Sinking fund trust account

41(4) The Minister of Finance shall continue to maintain appropriate sinking fund trust accounts, in which shall be included

(a) the moneys and investments made from the moneys reserved and set aside by the corporation, and from interest earnings thereon, held by the Minister of Finance at the time this Act comes into force; and

(b) the moneys paid to the Minister of Finance under subsection (3).

Investment by Minister of Finance

41(5) The Minister of Finance shall invest and keep invested the moneys and investments so held by the Minister of Finance, in securities authorized by *The Financial Administration Act* for the investment of funds, and shall apply them towards the repayment of advances made to, and moneys borrowed or assumed by, the corporation or liability for the repayment of which is an obligation of the corporation and to which reference is made in subsection (1), as they fall due; and the Minister of Finance shall pay to the corporation all interest earned from the investment of the moneys so reserved and set aside and paid to and held by the Minister of Finance.

Repayments to the government

41(6) The corporation in addition to the payments provided for under subsections (1) and (2), may pay to the Minister of Finance such money as it may have available for application on advances made by the government to the corporation or assumed by the corporation or liability for the repayment of which is an obligation of the corporation.

Authorization of omission or deferment of commencement of sinking fund payments

41(7) Subject to subsection (1) and notwithstanding subsection (2), the Lieutenant Governor in Council may direct that

(a) in respect of any moneys advanced to or borrowed by the corporation pursuant to sections 31 or 32, no amounts need be reserved or set aside as a sinking fund; and

(b) in respect of any moneys advanced to, or borrowed or assumed by, the corporation, or liability for the repayment of which is an obligation of the corporation, and that are applied to the cost of newly constructed works of the corporation, the payments to which reference is made in clauses (2)(a) and (b), shall begin with such fiscal year of the corporation as, in each case, the Lieutenant Governor in Council may direct.

Limitation respecting fiscal year that is to be fixed

41(8) The fiscal year to be directed by the Lieutenant Governor in Council under clause (7)(b) shall not be later than five years after the making of the respective advances to or borrowings by the corporation or, in the case of moneys assumed by the corporation or liability for the repayment of which is an obligation of the corporation, shall not be later than five years after the making of the respective advances or borrowings liability for repayment of which is an obligation of the corporation.

"Works" defined for purposes of subsection (7)

41(9) For the purposes of subsection (7), the expression **"works"**, in addition to the meaning given it in section 1, includes preliminary reports, surveys, investigations, engineering, accounting, or organization work or service, or any other work or service in connection with, or incidental to, any proposed development or construction.

APPLICATION OF REVENUES

Application of revenues of the corporation

42(1) The corporation shall apply its revenues toward payment of the operating expenses, interest, and other charges, to which reference is made in clauses 39(1)(a) and (b), and the establishment and maintenance of the reserves and funds established under section 40, and to the reservation and setting aside of the sinking fund established under section 41, and towards all other obligations of the corporation; and the corporation may pay the Minister of Finance, for investment for the corporation, such additional moneys as are available for that purpose and as are not immediately required for the purposes and objects of the corporation.

Funds to be held in trust

42(2) Additional moneys paid to the Minister of Finance for investment under subsection (1) shall form part of the Consolidated Fund; and interest earnings thereon shall be credited to the account of the corporation in the Consolidated Fund or shall be paid over to the corporation by the Minister of Finance.

Right of corporation to use of funds and securities

42(3) The moneys referred to in subsection (2), and any investment therefrom held for the corporation, may be used as required by the board for the purposes of the corporation.

TAXATION, CHARGES AND DISTRIBUTIONS

43(1) [Repealed] S.M. 1989-90, c. 24, s. 85.

Grant in lieu of cost of municipal and school services

43(2) The corporation, as an operating expense, shall make annually to any municipality in which land or personal property of the corporation are situated, or in which the corporation carries on business, such grant towards the cost of municipal and school services as the Lieutenant Governor in Council may approve.

Grants by subsidiaries

43(2.1) A subsidiary, as an operating expense, shall make annually to any municipality in which land or personal property of the subsidiary is situated, or in which the subsidiary carries on business, such grant towards the cost of municipal and school services as the Lieutenant Governor in Council may approve.

Exemption from municipal taxation

43(2.2) For greater certainty, and without limiting any exemption from municipal taxation under *The Municipal Assessment Act*, the corporation and its subsidiaries are exempt from all taxes levied by a municipality on the following property:

(a) conduits, poles, pipes, wires, transmission lines, plant, equipment and any similar property owned by the corporation or any of its subsidiaries or occupied or used by any of them in the generation, transformation, transmission or distribution of power; and

(b) any land on or under which such property is situated.

Limitation

43(2.3) Subsection (2.2) does not exempt the corporation or any of its subsidiaries from local improvement taxes levied against land used for an electric substation or an office building.

Funds of government and corporation not to be mixed

43(3) Except as specifically provided in this Act, the funds of the corporation shall not be employed for the purposes of the government or any agency of the government as that expression is defined in *The Civil Service Act*, other than the corporation, and the funds of the government shall not be employed for the purposes of the corporation except as advances to the corporation by the government by way of loan or as a result of a guarantee by the government of indebtedness of, or assumed by, the corporation or liability for the repayment of which is an obligation of the corporation.

Application of subsection (3)

43(4) Subsection (3) does not

(a) exempt the corporation from paying any tax that may be payable to the government under an Act of the Legislature; or

(b) apply to moneys that may be payable by the corporation

(i) under *The Water Power Act* in respect of water power leases, licences, or permits; or

(ii) as rentals or fees in respect of leases, licences, or permits, of transmission line rights-of-way; or

(iii) in respect of moneys advanced by the government to the corporation, or assumed by it or liability for the repayment of which is an obligation of the corporation, or guaranteed by the government, and interest thereon and any charge made in respect thereof; or

(iv) as a payment under subsection (5); or

(c) apply to moneys payable by the government or any agency of the government for power supplied to the government or the agency, as the case may be, by the corporation.

Distributions from retained earnings

43(5) The corporation shall pay a portion of its retained earnings to the government for its general purposes as follows:

(a) as soon as practicable after this subsection comes into force, an amount equal to the lesser of

(i) $150,000,000., and

(ii) 75% of the corporation's net income for the fiscal year that ended on March 31, 2002;

(b) in accordance with subsection (6), 75% of the corporation's net income for the year ending on March 31, 2003, or any lesser amount determined by the Lieutenant Governor in Council; and

(c) in accordance with subsection (6), 75% of the corporation's net income for the year ending on March 31, 2004, or any lesser amount determined by the Lieutenant Governor in Council.

But the total of the amounts paid under this subsection shall not exceed $288,000,000.

Timing of distributions

43(6) Amounts payable under clauses (5)(b) and (c) shall be estimated and remitted to the government before the end of the fiscal year to which they relate. As soon as practicable after the amount payable for the year is determined, the government shall refund any excess to the corporation and the corporation shall remit any shortfall to the government.

Order for interconnection of electrical systems

50(2) If authorized by the Lieutenant Governor in Council, the board may order any person engaged in Manitoba in the generation, transmission or distribution of power to make an interconnection of two or more electrical systems, or parts thereof, on such terms and conditions, including the provision of transmission access to the corporation or to any other person, and with such apportionment of costs, as the board may deem proper.

Enforcement of order

50(3) In default of such an order being carried out in the manner, and within the period therein specified, and without limiting any other remedy of the corporation, the corporation may carry out the order, or cause it to be carried out; and for that purpose the corporation may enter upon the property of any such person and do whatever is necessary to effect the interconnection ordered, and may assess to, and collect from, that person the cost of so doing or such portion thereof as the board may deem fit.

Review by P. U. Board

50(4) Any person against whom an assessment is made under subsection (3) may apply to The Public Utilities Board to review the assessment or the apportionment thereof.

Crown Corporations Governance and Accountability Act

PUBLIC UTILITIES BOARD REVIEW OF RATES

Hydro and MPIC rates review

25(1) Despite any other Act or law, rates for services provided by Manitoba Hydro and the Manitoba Public Insurance Corporation shall be reviewed by The Public Utilities Board under *The Public Utilities Board Act* and no change in rates for services shall be made and no new rates for services shall be introduced without the approval of The Public Utilities Board.

Definition: "rates for services"

25(2) For the purposes of this Part, **"rates for services"** means

(a) in the case of Manitoba Hydro, prices charged by that corporation with respect to the provision of power as defined in *The Manitoba Hydro Act*; and

(b) in the case of The Manitoba Public Insurance Corporation, rate bases and premiums charged with respect to compulsory driver and vehicle insurance provided by that corporation.

Application of Public Utilities Board Act

25(3) *The Public Utilities Board Act* applies with any necessary changes to a review pursuant to this Part of rates for services.

Factors to be considered, hearings

25(4) In reaching a decision pursuant to this Part, The Public Utilities Board may

(a) take into consideration

(i) the amount required to provide sufficient funds to cover operating, maintenance and administration expenses of the corporation,

(ii) interest and expenses on debt incurred for the purposes of the corporation by the government,

(iii) interest on debt incurred by the corporation,

(iv) reserves for replacement, renewal and obsolescence of works of the corporation,

(v) any other reserves that are necessary for the maintenance, operation, and replacement of works of the corporation,

(vi) liabilities of the corporation for pension benefits and other employee benefit programs,

(vii) any other payments that are required to be made out of the revenue of the corporation,

(viii) any compelling policy considerations that the board considers relevant to the matter, and

(ix) any other factors that the Board considers relevant to the matter; and

(b) hear submissions from any persons or groups or classes of persons or groups who, in the opinion of the Board, have an interest in the matter.

MPIC

25(5) In the case of a review pursuant to this Part of rates for services of the Manitoba Public Insurance Corporation, The Public Utilities Board may take into consideration, in addition to factors described in subsection (4), all elements of insurance coverage affecting insurance rates.

25(6) [Not yet proclaimed]

Multi-year approvals

26(1) A corporation may submit for the approval of The Public Utilities Board pursuant to this Part proposals regarding rates for services relating to a period of not more than three years and the Board shall identify in its order the change approved, if any, with respect to each year.

Increases not cumulative

26(2) No corporation shall increase rates for services by an amount in any year that exceeds the amount approved for that year by The Public Utilities Board or introduce new rates for services in any year other than new rates for services approved for introduction in that year by The Public Utilities Board.

Changed circumstances

26(3) Where The Public Utilities Board is satisfied that the circumstances of a corporation have changed substantially, The Public Utilities Board may, of its own motion or on the application of the corporation or an interested person, review an order made pursuant to this section and modify the order in any manner that The Public Utilities Board considers reasonable and justified in the circumstances.

Compensation or refunds

27 When a new rate for services or an increased rate is allowed pursuant to an interim order and a final order does not allow any changes or allows changes other than those permitted in the interim order, The Public Utilities Board may make any order to compensate for or to refund any excess amounts collected by the corporation that it considers necessary and appropriate in the circumstances.

Public Utilities Board Act

Application to Manitoba Hydro

2(5) Subject to Part 4 of *The Crown Corporations Governance and Accountability Act* and except for the purposes of conducting a public hearing in respect of an application made to the board under subsection 38(2) or 50(4) of *The Manitoba Hydro Act*, this Act, other than subsection 83(4) and the regulations under that subsection, does not apply to Manitoba Hydro and the board has no jurisdiction or authority over Manitoba Hydro.

Regulations respecting construction standards

83(4) The board may make and enforce regulations, not inconsistent with this Act, prescribing standards for the construction and erection of telephone, telegraph, and power transmission lines; and every such regulation made under and in accordance with the authority granted by this section, has the force of law; and any owner of a public utility who has constructed or erected such lines in accordance with such regulations, is relieved from all liability for damage arising out of the construction or erection of the lines.

Appendix B – Manitoba PUB Regulatory Principles

The following information was retrieved from the website of the Manitoba PUB, at http://www.pubmanitoba.ca/v1/about-pub/regulatoryprinciples.html.

Regulatory Principles

When considering a rate application, the Board must weigh all the available evidence. As such, the PUB operates on the basis of sound, established regulatory principles in order to come to decisions. There is no single authority that sets regulatory principles, and these principles may conflict or overlap, but it is the goal of the PUB to effectively balance the following principles and consistently take them into consideration when setting utility rates.

Cost of service standard

This principle is at the heart of rate regulation. Under this principle, a utility is permitted to set rates that allow it to recover its costs for regulated operations, including a fair rate of return on its investment devoted to those regulated operations—no more and no less. In most cases, rates are set in anticipation of future costs. If the regulated entity over-recovers those costs, it keeps the excess. If it under-recovers, it bears the cost of the deficiency of its projections.

Intergenerational Equity

Under this principle, customers in a given period should only pay the costs that are necessary to provide them with services in that period. They should not have to pay any costs incurred to provide services to customers in any other period. This principle is consistent with setting rates that are just and reasonable. For example, a regulated entity is usually not allowed to earn a return on projects under construction because any costs incurred are incurred in order to provide services to future customers. Instead, the costs are capitalized and recovered through depreciation over the period that the assets are used to provide the service.

Matching Principle

This principle requires that a regulated entity's costs be matched to the period that benefits from the costs being incurred, and should be recovered from customers in that period. In other words, the customers in each period should pay for the costs of providing them with service in that period. The matching principle follows from the cost of service standard and the principle of intergenerational equity. Consistent with the cost of service standard, all of a regulated entity's costs should be recovered from customers. Consistent with the principle of inter-generational equity, only customers in the period that benefit from the cost being incurred should pay for the cost.

Rate stability and predictability

This principle requires rates to remain stable and predictable, at least to the extent practical. Therefore, the principle may justify smoothing out increases to avoid any sharp rate climbs.
The principle of rate stability and predictability may require costs to be collected from customers in periods other than those for which the costs were incurred. Therefore, the principle is inconsistent with the principle of inter-generational equity. Despite that, it is justified because it recognizes the problems customers can face in adjusting to significant short-term rate fluctuations.

Used or required to be used

Under this principle, customers should only pay for the cost of those assets that are either used or required to be used to provide them with the service. An application of this principle is in the case of a diversified company with both regulated and non-regulated operations. The customers of the regulated operations should not be required to pay for assets used to supply non-regulated services.

Prudence standard
Under this principle, customers should be charged only for prudently incurred costs. This recognizes the fact that regulated entities have a responsibility to manage themselves in a prudent manner. This principle is central to the PUB hearing process and the wealth of evidence collected and examined by the Board in its proceedings.

Why we do it
Due to the capital intensive nature of the business, and the inherent difficulty of competition in such a closed market, utilities naturally tend toward monopoly formation, meaning the complete absence of market competition. The PUB regulates public utilities precisely because they constitute a so-called natural monopoly in the marketplace.
The industry demonstrates so-called "economies of scale," meaning that the costs for the utility in distribution and production decrease as demand increases. In short, the more customers, the cheaper it becomes to serve them. This means that one large firm can provide utility service at a lower cost than two or more firms.

In the absence of a competitive market, prices are not set based on supply and demand pressures but rather on a self-determined reasonable rate of return for the utility, coupled with some outside evidence of what consumers will reasonably pay. Without market competition there is a risk that consumers will pay exorbitant prices for utility service.

In Manitoba, these natural utility monopolies are largely controlled by the government, or the Crown, as state-owned enterprises or Crown Corporations Manitoba Hydro (which includes natural gas subsidiary Centra Gas) and Manitoba Public Insurance. These state-owned enterprises seek only to break-even in their operations.

But while state-owned monopolies do not seek to generate a profit, they may charge unfair or unjust rates in the absence of oversight. Regulation and rate setting is intended to ensure that rates are prudent, just and reasonable, that utility service is reliable and safe, and that a balance is achieved between customer needs and the revenue requirements of the utility and its creditors.

Appendix C – The Bonbright Criteria

This version is drawn from James C. Bonbright, *Principles of Public Utility Rates*, Second Edition, 1988.

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety
2. Revenue stability and predictability, with a minimum of unexpected changes that are seriously adverse to utility companies
3. Stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to utility customers and that are intended to provide historical continuity
4. Static efficiency, i.e., discouraging wasteful use of electricity in the aggregate as well as by time of use
5. Reflect all present and future private and social costs in the provision of electricity (i.e., the internalization of all externalities)
6. Fairness in the allocation of costs among customers so that equals are treated equally
7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (free of subsidies)
8. Dynamic efficiency in promoting innovation and responding to changing demand-supply patterns
9. Simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application
10. Freedom from controversies as to proper interpretation

Appendix D – Manitoba Hydro Peer Group

In the following pages, additional information has been gathered for:

<u>Canada</u>

BC Hydro
Enmax
Epcor
Hydro Quebec
Nalcor
New Brunswick Power
Ontario Power Generation
SaskPower
Toronto Hydro

<u>United States</u>

Basic Electric Power Cooperative
Bonneville Power Administration
Long Island Power Authority
Los Angeles Department of Water and Power
New York Power Authority
Santee Cooper
Tennessee Valley Authority

BC Hydro

Jurisdiction	British Columbia
Ownership	Government of British Columbia
Org. Type	- Vertically-integrated Crown Corporation - The board is appointed by the Lieutenant-Governor in Council - Pays dividends
Markets	Electricity generation, transmission and distribution
Mandate (in addition to primary purpose of providing listed services to customers)	From the annual *Mandate Letter:* “to provide reliable, affordable, clean electricity throughout British Columbia safely”
Regulation	- British Columbia Utilities Commission
Customers	Total customer accounts: 1,988,167 - Residential: 1,776,502 - Light industrial and commercial: 207,802 - Large industrial: 191 - Other: 3,467 - Trade: 204
Lines	- Distribution lines: 59,078 km - Transmission lines: 20,278 km
Sources of Production	- Hydroelectric and Thermal
Energy produced	Total: 79,319 GWh - Hydroelectric: 48,736 GWh - Thermal: 74 GWh
Imported Energy	
Exported Energy	- $675M in “Trade” representing 11.5% - arbitrage

In CAD millions							
	BC Hydro						
	2010	2011*	2012	2013	2014	2015	2016
Revenue	$4,016	$4,730	$4,898	$5,392	$5,748	$5,657	$5,874
Net income	$589	$588	$509	$549	$581	$655	$684
Total assets	$19,973	$21,900	$23,782	$25,711	$27,753	$30,034	$31,888
Property, plant and equipment	$15,019	$15,991	$17,226	$18,525	$19,933	$21,385	$22,998
Depreciation & Amortization	$533	$793	$953	$995	$1,205	$1,232	$1,241
Capital expenditure	$2,880	$1,703	$1,929	$2,036	$2,169	$2,306	$2,444
Long-term debt	$8,909	$10,062	$10,846	$11,610	$13,178	$15,837	$17,146
Pension Obligation	$298	$345	$1,182	$1,396	$1,173	$1,498	$1,657
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt Provisions							
Other Liabilities	$289	$1,423	$1,106	$1,196	$1,291	$1,583	$1,669
Total Liabilities	$9,496	$11,830	$13,134	$14,202	$15,642	$18,918	$20,472
Total Equity	$2,881	$3,219	$3,500	$3,865	$4,170	$4,500	$4,909
Liquidity and Capital Resources		Standard					
Most Recent Debt / Equity	81.0%	< 80%					
Most Recent Interest Coverage							
Most Recent Debt Service Coverage	N/A	N/A					

Epcor

Jurisdiction	Regulated in Alberta; also British Columbia, Saskatchewan, Arizona, New Mexico and Texas
Ownership	City of Edmonton
Org. Type	- Municipally-owned commercial entity - City of Edmonton appoints the Board
Markets	Electricity transmission and distribution, water and wastewater service and other engineering services
Mandate (in addition to primary purpose of providing listed services to customers)	Investor Presentation (2015) - Operate on commercial terms and fund investments independently without reliance on its Shareholder for capital
Regulation	- Alberta Utility Commission
Customers	Total customer accounts: 1,750,000
Lines	- Distribution lines: 5,500 km - Transmission lines: 260 km

In CAD millions							
	EPCOR Utilities						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$1,489	$1,833	$1,959	$1,955	$1,927	$2,018	$1,946
Net income	$105	$144	$19	$175	$191	$260	$309
Total assets	$4,932	$5,032	$5,424	$5,447	$5,738	$6,088	$6,161
Property, plant and equipment	$2,385	$2,658	$3,417	$3,776	$4,112	$4,568	$4,983
Depreciation & Amortization	$98	$105	$133	$145	$159	$178	$189
Capital expenditure	$245	$338	$360	$444	$385	$463	$502
Long-term debt	$1,453	$1,682	$1,956	$1,957	$1,963	$1,875	$1,905
Pension Obligation							
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt							
Provisions							
Other Liabilities	$532	$586	$741	$783	$847	$920	$1,016
Total Liabilities	$1,985	$2,268	$2,697	$2,740	$2,810	$2,795	$2,921
Total Equity	$2,342	$2,351	$2,222	$2,262	$2,340	$2,515	$2,672
Liquidity and Capital Resources		Standard					
Most Recent Debt / Equity	N/A	< 75%					
Most Recent Interest Coverage							
Most Recent Debt Service Coverage	N/A	N/A					

Enmax

Jurisdiction	Calgary; also other parts of Alberta
Ownership	City of Calgary
Org. Type	Vertically-integrated and municipally-owned utility - The City Council appoints the board - Pays dividends
Markets	Electricity generation, transmission and distribution, and natural gas generation and distribution
Mandate (in addition to primary purpose of providing listed services to customers)	2016 Annual report: "we power the potential of people, businesses and communities by safely and responsibly providing electricity and energy services"
Regulation	- Alberta Utilities Commission
Customers	- Residential: 540,000 - Business: 36,000
Lines	- Distribution lines: 8,500 km - Transmission lines: 326 km
Sources of Production	- Natural gas, wind and solar. Also uses district heating
Energy produced	- 2016 electricity sales: 19,145 GWh
Net Export (Import)	N/A

In CAD millions				Enmax			
	2010	2011	2012	2013	2014	2015	2016
Revenue	$2,404	$3,080	$3,160	$3,417	$3,457	$3,066	$2,801
Net income	$178	$185	$225	$353	$184	$49	$105
Total assets	$3,883	$4,328	$4,820	$4,566	$5,101	$5,198	$5,366
Property, plant and equipment	$2,274	$2,382	$2,695	$3,023	$3,840	$3,961	$4,071
Depreciation & Amortization	$165	$162	$164	$168	$178	$229	$215
Capital expenditure	$320	$342	$395	$299	$378	$338	$306
Long-term debt	$1,378	$1,469	$1,550	$1,375	$1,553	$1,652	$1,585
Pension Obligation					$56	$40	$55
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt Provisions							
Other Liabilities					$361	$395	$457
Total Liabilities	$1,378	$1,469	$1,550	$1,375	$1,970	$2,087	$2,097
Total Equity	$1,845	$1,944	$2,162	$2,460	$2,281	$2,299	$2,291
<u>Liquidity and Capital Resources</u>		<u>Standard</u>					
Most Recent Debt / Equity	N/A	< 63%					
Most Recent Interest Coverage							
Most Recent Debt Service Coverage	N/A	N/A					

Hydro Quebec

Jurisdiction	Quebec; also wholesale markets in northeastern regions in North America (e.g. Ontario, New England)
Ownership	Government of Quebec
Org. Type	Crown Corporation Pays dividends
Markets	Electricity generation, transmission and distribution
Mandate (in addition to primary purpose of providing listed services to customers)	From the *Hydro-Quebec Act:* "The objects of the Company are to supply power and to pursue endeavours in energy-related research and promotion, energy conversion and conservation, and any field connected with or related to power or energy"
Regulation	- Régie de l'énergie du Québec
Customers	Total customer accounts: 4,244,541 - Residential: 3,924,992 - Commercial, institutional and small industrial: 314,816 - Large industrial: 183 - Other: 4,550
Lines	- Distribution lines: 116,794 km - Transmission lines: 34,292 km
Sources of Production	- Hydroelectric and thermal
Energy produced	Total: 36,908 MW installed capacity - Hydroelectric: 36,366 MW (including Churchill fall) - Thermal: 542 MW Total electricity sales in 2016: 202 TWh Energy Purchased: $1.866 billion worth of energy and fuel purchases
Imported Energy	
Exported Energy	Net export of $1.568 billion for 32.6 TWh in electricity sales representing 16% of sales

In CAD millions							
	Hydro Quebec						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$12,484	$12,245	$12,136	$12,878	$13,652	$13,754	$13,339
Net income	$2,515	$2,611	$860	$2,942	$3,325	$3,147	$2,861
Total assets	$65,809	$69,637	$70,508	$73,110	$73,108	$75,199	$75,167
Property, plant and equipment	$55,537	$56,901	$57,174	$59,077	$60,413	$61,558	$62,691
Depreciation & Amortization	$2,732	$2,771	$2,715	$2,631	$2,740	$2,872	$2,770
Capital expenditure	$3,916	$3,508	$3,673	$4,055	$3,675	$3,340	$3,363
Long-term debt	$36,727	$41,025	$42,830	$43,320	$43,846	$43,924	$44,511
Pension Obligation							
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt							
Provisions							
Other Liabilities							
Total Liabilities	$36,727	$41,025	$42,830	$43,320	$43,846	$43,924	$44,511
Total Equity	$18,566	$18,834	$18,982	$19,394	$17,961	$19,475	$19,704
Liquidity and Capital Resources		Standard					
Most Recent Debt / Equity	69.5%	N/A					
Most Recent Interest Coverage							
Most Recent Debt Service Coverage	2.16 x	N/A					

Nalcor

Jurisdiction	Newfoundland and Labrador
Ownership	Government of Newfoundland and Labrador
Organization Type	Crown corporation Pays dividends
Markets	Electricity generation, transmission and distribution, off-shore Oil and Gas, fabrication site and energy marketing
Mandate (in addition to primary purpose of providing listed services to customers)	Among others, under the legislation under the Energy Corporation Act: - "Exploring for, developing, producing, refining, marketing and transporting hydrocarbons and products from hydrocarbons
Rate Regulation	Public Utilities Board
Customers	Total direct customer accounts: 38,000
Lines	Transmission line under construction: 4,861 km
Sources of Production	Hydroelectric, Thermal and Diesel
Energy produced	Total (2016): 40,025 GWh - Churchill falls (Hydro-electric): 33,806 GWh - Hydro: (4,380 GWh hydraulic, 1,740 GWh thermal and 66 GWh diesel) - Menihek (hydro-electric): 19 GWh - Purchased: 426 GWh
Imported Energy	
Exported Energy	29,622 GWh export (79% of total Electricity sales) – includes Churchill Falls

In CAD millions	Nalcor Energy						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$602	$714	$726	$785	$798	$811	$824
Net income	$78	$129	$93	$88	$116	($16)	$136
Total assets	$2,805	$3,042	$3,447	$9,524	$10,643	$12,322	$14,062
Property, plant and equipment	$2,096	$2,238	$2,414	$2,811	$3,743	$5,659	$8,325
Depreciation & Amortization	$55	$68	$85	$79	$89	$93	$159
Capital expenditure	$178	$196	$254	$477	$985	$1,774	$2,421
Long-term debt	$1,147	$1,141	$1,174	$1,208	$6,048	$6,241	$6,008
Pension Obligation	$60	$66	$74	$119	$145	$116	$117
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt							
Provisions							
Other Liabilities	$41	$33	$33	$547	$544	$1,053	$1,711
Total Liabilities	$1,248	$1,241	$1,281	$1,874	$6,736	$7,410	$7,836
Total Equity	$1,142	$1,265	$1,430	$1,565	$2,268	$2,974	$3,805
Liquidity and Capital Resources		Standard					
Most Recent Debt / Equity	68.0%	< 70%					
Most Recent Interest Coverage							
Most Recent Debt Service Coverage	Good	> 1.5 x					

New Brunswick Power

Jurisdiction	New Brunswick
Ownership	Government of New Brunswick
Organization Type	Crown Corporation Pays dividends
Markets	Electricity generation, transmission and distribution and energy trading
Mandate (in addition to primary purpose of providing listed services to customers)	From most recent 10-year strategic plan: "In addition, the Minister, by way of a Mandate Letter, has given NB Power the responsibility for delivery of the following: - Maintaining and creating jobs in the resource sector in an economically sustainable fashion - Working with the other Atlantic Provinces and neighbouring jurisdictions to improve regional cooperation - Working with the federal government in ongoing investment and energy-related issues - Meeting debt reduction targets as established in NB Power's 10-year plan - Protecting and improving our environment"
Rate Regulation	New Brunswick Energy and Utilities Board (EUB)
Customers	Total customers: 399,055 (of which 45,242 are indirect)
Lines	Distribution lines: 21,050 km Transmission lines: 6,830 km
Sources of Production	Thermal, Hydro, Nuclear and Combustion Turbine
Energy produced	2016-2017 (ending March 31st) – Total generation: 11,702 GWh: - Thermal: 3,992 GWh - Hydro: 2,848 GWh - Nuclear: 4,860 GWh - Combustion Turbine: 2 GWh - Purchases: 6,206 GWh
Imported Energy	
Exported Energy	2016-2017 export sales: G,360 MWh (20.5% of sales, but includes energy trading across New Brunswick)

In CAD millions				NB Power			
	2010	2011	2012	2013	2014	2015	2016
Revenue	$1,635	$1,616	$1,697	$1,328	$1,791	$1,791	$1,696
Net income	$67	$173	$65	$55	$73	$12	$27
Total assets	$5,632	$6,006	$6,689	$6,863	$6,811	$5,895	$5,959
Property, plant and equipment	$1,242	$1,530	$2,067	$4,072	$4,011	$4,237	$4,280
Depreciation & Amortization	$171	$187	$153	$198	$208	$226	$233
Capital expenditure	$238	$279	$296	$179	$264	$231	$278
Long-term debt	$3,417	$3,469	$4,370	$4,567	$4,025	$4,124	$4,007
Pension Obligation						$153	$137
Decommissioning and Used Fuel Mgmt						$866	$739
Generating Station Decommissioning and Used Fuel Mgmt	$471	$489	$549	$587	$635		
Provisions							
Other Liabilities							
Total Liabilities	$3,888	$3,958	$4,919	$5,154	$4,660	$5,143	$4,883
Total Equity	$306	$454	$277	$399	$325	$207	$320
Liquidity and Capital Resources		Standard					
Most Recent Debt / Equity	94.0%	< 80%					
Most Recent Interest Coverage							
Most Recent Debt Service Coverage	1.14 x	N/A					

Ontario Power Generation

Jurisdiction	Ontario
Ownership	Government of Ontario
Org. Type	Crown Corporation Pays dividends
Markets	Electricity generation
Mandate (in addition to primary purpose of providing listed services to customers)	- http://www.opg.com/about/management/open-and-accountable/Documents/memorandum.pdf - among others; - "OPG shall support the Province's economic development objectives where feasible, including generating financial benefits that remain within the Province of Ontario" - "OPG shall inform the Shareholder of any solar and wind developments or projects that the Corporation intends to undertake or assume, including the sources of the Corporation's financing, before undertaking or assuming such developments or projects" - "Where appropriate, OPG shall pursue prospective generation related developments with First Nations and Metis communities that can provide the basis for long-term mutually beneficial commercial arrangements"
Regulation	- Ontario Energy Board
Customers	-
Lines	-
Sources of Production	- Contracted Generation[1] , Hydroelectric, Nuclear and Other
Energy produced	Total 2016: 78.2 TWh - Contracted Generation[1] : 3.1 TWh - Hydroelectric: 29.5 TWh - Nuclear: 45.6 TWh

1. Includes OPG's thermal and hydroelectric generating stations that are under contracts, wind turbines and OPG's share of the Portland Energy Centre and Brighton Beach Generating Stations

In CAD millions							
	Ontario Power Generation						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$5,367	$4,964	$4,732	$4,863	$4,963	$5,476	$5,653
Net income	$649	$338	$367	$135	$804	$402	$436
Total assets	$29,577	$34,443	$37,601	$38,091	$41,653	$44,250	$44,372
Property, plant and equipment	$13,555	$14,633	$15,860	$16,738	$17,593	$20,595	$19,998
Depreciation & Amortization	$698	$694	$664	$963	$754	$1,100	$1,257
Capital expenditure	$978	$1,145	$1,427	$1,568	$1,545	$1,376	$1,704
Long-term debt	$3,843	$4,341	$5,109	$5,620	$5,227	$5,186	$4,417
Pension Obligation	$1,908	$5,463	$6,697	$5,369	$6,620	$5,682	$5,909
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt							
Provisions							
Other Liabilities							
Total Liabilities	$5,751	$9,804	$11,806	$10,989	$11,847	$10,868	$10,326
Total Equity	$8,085	$7,626	$7,904	$8,334	$9,467	$10,045	$10,508
Liquidity and Capital Resources		Standard					
Most Recent Debt / Equity	N/A	N/A					
Most Recent Interest Coverage							
Most Recent Debt Service Coverage	5.10 x	N/A					

SaskPower

Jurisdiction	Saskatchewan
Ownership	Government of Saskatchewan
Org. Type	Crown Corporation Pays dividends
Markets	Electricity generation, transmission and distribution and energy trading through NorthPoint energy
Mandate (in addition to primary purpose of providing listed services to customers)	Annual report: "Ensuring reliable, sustainable and cost-effective power for our customers and the communities we serve…"
Regulation	- Saskatchewan Rate Review Panel
Customers	Total customer accounts: 528,000
Lines	- Distribution lines: 144,339 km - Transmission lines: 14,384 km
Sources of Production	- Hydro, Coal, Natural Gas and Wind
Energy produced	Total (2016): 24,374 GWh - Coal: 10,759 GWh - Gas: 8,729 GWh - Hydro: 3,525 GWh - Wind: 740 GWh - Imports: 478 GWh - Other: 143 GWh Purchase: $661M worth
Imported Energy	475 GWh (2015)
Exported Energy	12 months (2016) 71 GWh ($8M representing 0.35% of sales)

In CAD millions	SaskPower						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$1,681	$1,827	$1,850	$2,042	$2,155	$2,296	$2,308
Net income	$204	$248	$135	$114	$60	$40	$21
Total assets	$5,699	$6,282	$6,969	$8,604	$9,674	$10,284	$10,434
Property, plant and equipment	$4,923	$5,387	$6,030	$7,641	$8,548	$9,071	$9,140
Depreciation & Amortization	$266	$290	$316	$355	$389	$452	$456
Capital expenditure	$517	$575	$922	$1,225	$1,194	$944	$900
Long-term debt	$2,708	$2,707	$2,980	$3,568	$4,350	$4,849	$5,025
Pension Obligation	$203	$315	$340	$153	$233	$231	$264
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt							
Provisions	$119	$145	$162	$158	$193	$198	$201
Other Liabilities	$409	$552	$430	$1,131	$1,130	$1,126	$1,122
Total Liabilities	$3,439	$3,719	$3,912	$5,010	$5,906	$6,404	$6,612
Total Equity	$1,758	$1,864	$1,858	$2,223	$2,178	$2,204	$2,146
<u>Liquidity and Capital Resources</u>		<u>Standard</u>					
Most Recent Debt / Equity	75.7%	N/A					
Most Recent Interest Coverage							
Most Recent Debt Service Coverage	2.16 x	N/A					

Toronto Hydro

Jurisdiction	Toronto
Ownership	City of Toronto
Org. Type	Holding Company Pays dividends
Markets	Electricity distribution
Mandate (in addition to primary purpose of providing listed services to customers)	
Regulation	- Ontario Energy Board
Customers	Total customer accounts: 761,000 - Residential: 679,717 - General service: 81,321 - Large users: 44
Lines	Total distribution lines: 28,600 km - Overhead wires: 15,570 km - Underground wires: 13,040
Sources of Production	-
Energy produced (or transmitted or distributed)	Total distribution: 25,373 GWh (2016) - Residential: 5,313 GWh - General service: 17,836 GWh - Large users: 2,225 GWh

In CAD millions							
	Toronto Hydro						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$2,612	$2,823	$2,852	$3,203	$3,273	$3,540	$4,030
Net income	$66	$96	$86	$121	$112	$127	$151
Total assets	$3,339	$3,528	$3,539	$3,798	$4,328	$4,687	$4,954
Property, plant and equipment	$2,129	$2,399	$2,527	$2,664	$3,250	$3,589	$3,907
Depreciation & Amortization	$169	$151	$142	$173	$185	$194	$212
Capital expenditure	$362	$384	$260	$359	$526	$551	$512
Long-term debt	$1,165	$1,470	$1,000	$1,449	$1,641	$1,885	$1,835
Pension Obligation	$170	$236	$244	$231	$287	$297	$281
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt Provisions							
Other Liabilities	$274	$215	$206	$183	$80	$107	$283
Total Liabilities	$1,609	$1,921	$1,450	$1,863	$2,009	$2,289	$2,398
Total Equity	$1,039	$1,102	$1,140	$1,219	$1,444	$1,513	$1,598
Liquidity and Capital Resources		Standard					
Most Recent Debt / Equity	N/A	< 75%					
Most Recent Interest Coverage							
Most Recent Debt Service Coverage	N/A	N/A					

Basin Electric Power Cooperative

Jurisdiction	Colorado, Iowa, Minnesota, Montana, Nebraska, New Mexico, North Dakota, South Dakota and Wyoming
Ownership	- Member cooperatives - Not-for-profit
Org. Type	Member cooperative
Markets	Electricity generation and transmission
Mandate (in addition to primary purpose of providing listed services to customers)	-
Regulation	- Federal Energy Regulatory Commission
Customers	-
Lines	- Transmission lines: 3,516 km
Sources of Production	- Coal, gas, oil, nuclear, distributed and renewable (including wind)
Energy produced	Total electricity sales (2016): 23 million MWh Total capacity as of 2017: 6,698 MW - Coal: 45% - Renewables: 21% (wind is 20%, remaining is recovered energy) - Hydro: 5% - Nuclear: 1% - Natural gas: 20% - Oil 3% - Unspecified: 5%
Imported Energy	
Exported Energy	- Non-member "others" of sales is 139,000,000 of $1.56 B in total revenue (approximately 8.9%)

In CAD millions	Basin Electric Power Cooperative						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$982	$1,026	$1,196	$2,082	$2,672	$2,716	$2,716
Net income	$9	$100	$120	$49	$58	$11	$73
Total assets	$5,254	$5,837	$6,031	$6,472	$9,863	$9,872	$9,872
Property, plant and equipment	$4,225	$4,554	$4,597	$5,062	$5,818	$7,615	$7,912
Depreciation & Amortization	$118	$132	$185	$211	$294	$246	$0
Capital expenditure	$908	$500	$341	$385	$870	$886	$886
Long-term debt	$2,537	$3,161	$3,614	$3,583	$5,564	$5,559	$5,559
Pension Obligation							
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt							
Provisions							
Other Liabilities	$394	$478	$609	$659	$596	$722	$624
Total Liabilities	$2,932	$3,639	$4,223	$4,242	$6,160	$6,281	$6,183
Total Equity	$924	$1,002	$1,098	$1,353	$1,514	$1,810	$1,808
<u>Liquidity and Capital Resources</u>							
Equity to asset ratio							24%
Equity to asset ratio target							18%

Bonneville Power Administration

Jurisdiction	Idaho, Oregon, Washington, western Montana and smaller parts of Eastern Montana, California, Nevada, Utah and Wyoming
Ownership	Part of U.S. Department of Energy
Org. Type	- Non-profit federal power marketing administration - No formal administrative authority or board of directors beyond its administrator and whatever oversight provided by the Department of Energy, FERC and Congress which reviews budget and power rates to ensure they are adequate to **cover the agency's expenditures**
Markets	Energy production and transmission
Mandate (in addition to primary purpose of providing listed services to customers)	Mission statement on website (among general duties: "Mitigation of the Federal Columbia River Power System's impacts on fish and wildlife"
Regulation	- Federal Energy Regulatory Commission
Customers	- Total:142 - Cooperatives: 54 - Municipalities: 42 - Public utility districts: 28 - Federal agencies: 7 - Investor-owned utilities: 6 - Direct-service industries: 2 - Port districts: 1 - Tribal utilities: 2
Lines	- Transmission lines: 24,523 km
Sources of Production	- Hydroelectric, combustion turbines, coal, cogeneration , nuclear and renewables
Energy produced	- Regional resources: 38,598 average MW (Hydro; 53%, combustion turbines; 18%, coal; 15%, cogeneration 7%, Nuclear; 3%; renewables; 0.4%) - Federal resources: 9,089 average (of which 7,919 MW came from Hydro generation)
Imported Energy	- Imported 3.1% of regional resources (1,197 MW)
Exported Energy	

In CAD millions	Bonneville Power Administration						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$3,055	$3,285	$3,318	$3,346	$3,600	$3,404	$3,433
Net income	($128)	$82	$87	($105)	$444	$405	$277
Total assets	$19,669	$23,175	$24,265	$24,272	$24,932	$25,549	$24,898
Property, plant and equipment	$10,220	$10,702	$11,364	$11,797	$12,281	$12,859	$13,278
Depreciation & Amortization	$368	$394	$389	$430	$441	$448	$471
Capital expenditure	$684	$787	$862	$779	$843	$965	$808
Long-term debt	$12,442	$12,846	$13,883	$14,259	$14,474	$15,055	$14,708
Total Liabilities	$12,442	$12,846	$13,883	$14,259	$14,474	$15,055	$14,708
Total Equity	$2,429	$2,510	$2,596	$2,432	$2,823	$3,176	$3,393
Liquidity and Capital Resources							
Debt service coverage ratio							5.1x
Standard							~1x

Long Island Power Authority

Jurisdiction	Nassau County, Long Island; Suffolk County, Long Island; Rockaway, Queens
Ownership	State of New York
Org. Type	Municipal sub-division of the State of New York - Board appointed by State of New York
Markets	Electricity transmission and distribution
Mandate (in addition to primary purpose of providing listed services to customers)	-
Regulation	- New York Department of Public Service
Customers	- Residential: 1,005,751 - Commercial: 115,033 - Street lighting: 5,479 - Other Public Authorities: 129
Lines	- Transmission lines: 2,198 km - Distribution lines: 22,072 km

In CAD millions	Long Island Power Authority						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$3,975	$3,645	$3,544	$3,869	$3,992	$4,484	$4,504
Net income	$57	$19	($65)	$50	$65	$67	($36)
Total assets	$11,528	$12,001	$12,111	$12,717	$15,327	$18,024	$17,621
Property, plant and equipment	$6,340	$6,662	$6,510	$7,009	$7,748	$10,459	$10,429
Depreciation & Amortization	$259	$265	$272	$288	$238	$301	$349
Capital expenditure	$256	$263	$330	$344	$487	$507	$705
Long-term debt	$6,327	$6,486	$6,440	$7,423	$8,772	$10,278	$10,433
Pension Obligation							
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt							
Provisions							
Other Liabilities							
Total Liabilities	$6,327	$6,486	$6,440	$7,423	$8,772	$10,278	$10,433
Total Equity	$375	$403	$330	$402	$503	$668	$611
Liquidity and Capital Resources							
Fixed charge coverage ratio							1.19x
Standard							1.15x

Los Angeles Department of Water and Power

Jurisdiction	Los Angeles and surrounding communities
Ownership	City of Los Angeles Pays contributions to Los Angeles' reserve fund
Org. Type	Municipal utility
Markets	Electricity generation, transmission and distribution and water system management
Regulation	- Self-regulated
Customers	Total power system customers: ~1,500,000 - Residential: 1,370,000 - Commercial and industrial: 123,000 - All other: ~7,000
Lines	N/A
Sources of Production	Department owned - Natural gas - Large Hydro - Renewables Jointly-owned - Coal - Natural Gas - Hydro - Nuclear - Renewables
Energy produced	- Total electricity sales in 2016 (GWh): 25,300 Capacity breakdown on department owned facilities - Natural gas: 42% - Large Hydro: 15% - Renewables: 4%

In CAD millions	Los Angeles Department of Power & Water						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$4,274	$3,889	$3,908	$4,223	$4,774	$5,184	$6,167
Net income	$411	$99	$196	$289	$307	$170	$437
Total assets	$18,231	$17,926	$19,139	$21,571	$25,607	$31,599	$34,172
Property, plant and equipment	$12,089	$11,711	$13,448	$14,772	$16,173	$20,522	$22,500
Depreciation & Amortization	$468	$515	$531	$534	$656	$766	$928
Capital expenditure	$1,217	$1,281	$1,528	$1,389	$1,872	$2,223	$2,048
Long-term debt	$8,941	$9,323	$9,727	$11,642	$12,855	$16,309	$18,308
Pension Obligation				$18	$51		
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt							
Provisions							
Other Liabilities							
Total Liabilities	$8,941	$9,323	$9,727	$11,661	$12,906	$16,309	$18,308
Total Equity	$7,662	$7,051	$7,648	$8,207	$8,653	$10,308	$11,145
<u>Liquidity and Capital Resources</u>							
Debt service coverage ratio							2.74x
Debt service coverage ratio target							2.25x
Debt to capitalizaiton							~62%

New York Power Authority

Jurisdiction	State of New York
Ownership	State of New York
Org. Type	- State Public Power Organization - Pays “contributions to New York State”
Markets	Electricity generation and transmission
Mandate (in addition to primary purpose of providing listed services to customers)	- To power the economic growth and competitiveness of New York State
Regulation	- Federal Energy Regulatory Commission
Customers	- Public entities: 100+ - Municipal electric systems: 47 - Rural electric cooperatives: 4 - Business and Industry: 800+ - Others: healthcare, education and cultural institutions, host communities, and electricity providers
Lines	- Transmission lines: 2253 km
Sources of Production	- Hydroelectricity and natural gas
Energy produced	Total generation in 2016: 29,000,000 MWh - Hydroelectricity: 75% - Remaining composed of natural gas and purchased - $514M of purchase power

In CAD millions	New York Power Authority						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$2,645	$2,627	$2,672	$3,121	$3,507	$3,208	$3,208
Net income	$180	$299	$174	$265	$315	$103	$30
Total assets	$7,578	$9,185	$9,074	$9,917	$11,062	$12,835	$12,835
Property, plant and equipment	$3,677	$4,992	$4,803	$5,069	$5,479	$6,629	$6,481
Depreciation & Amortization	$168	$192	$226	$235	$256	$306	$300
Capital expenditure	$82	$108	$145	$170	$242	$309	$283
Long-term debt	$1,488	$1,374	$1,132	$1,220	$1,225	$1,089	$1,089
Pension Obligation							
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt							
Provisions							
Other Liabilities							
Total Liabilities	$1,488	$1,374	$1,132	$1,220	$1,225	$1,089	$1,089
Total Equity	$2,985	$3,350	$3,459	$3,951	$4,622	$5,632	$5,482
Liquidity and Capital Resources							
Fixed charge coverage ratio							2.3x
Standard							1.75x

Santee Cooper

Jurisdiction	All 46 counties in the State of South Carolina
Ownership	South Carolina
Org. Type	- State-owned - Board is appointed by the governor a
Markets	- Electricity generation and operation of water systems
Mandate (in addition to primary purpose of providing listed services to customers)	-
Regulation	- Federal Energy Regulatory Commission
Customers	- Retail: 24% - Wholesale: 62% - Large Industrial: 14$
Lines	- Transmission lines: 8,135 km - Distribution lines: 4,604 km
Sources of Production	- Coal - Natural gas & oil - Nuclear - Other
Energy produced	2016 Total: 23,000 GWh - Coal: 48% - Natural gas & oil: 19% - Nuclear: 11% - Other:2%
Power Purchase Agreements	Purchased 20% of 2016 energy sources

In CAD millions	Santee Cooper						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$1,952	$1,894	$1,887	$1,871	$2,206	$2,404	$2,313
Net income	$99	$131	$85	$68	$142	$44	$117
Total assets	$7,917	$8,389	$9,713	$11,380	$13,018	$16,940	$16,826
Property, plant and equipment	$4,846	$5,177	$5,918	$6,775	$8,035	$10,384	$11,049
Depreciation & Amortization	$210	$203	$209	$203	$192	$225	$235
Capital expenditure	$227	$376	$488	$752	$801	$751	$1,492
Long-term debt	$4,728	$5,075	$5,386	$6,862	$7,433	$9,626	$10,305
Pension Obligation						$286	$325
Decommissioning and Used Fuel Mgmt							
Generating Station Decommissioning and Used Fuel Mgmt							
Provisions							
Other Liabilities							
Total Liabilities	$4,728	$5,075	$5,386	$6,862	$7,433	$9,912	$10,630
Total Equity	$1,747	$1,921	$1,965	$2,168	$2,519	$2,685	$2,731
Liquidity and Capital Resources							
Fixed charge coverage ratio							1.41x
Debt to capitalizaiton							79%
Both meeting standards							

Tennessee Valley Authority

Jurisdiction	Alabama, Georgia, Kentucky, Mississippi, North Carolina, Tennessee and Virginia
Ownership	United States Government
Org. Type	- Government-owned independent corporation (Corporate agency of the U.S.) – federal legislation - Board members are nominated by POTUS – no current politicians on the Board
Markets	Electricity generation and transmission, flood control, navigation and land management
Mandate (in addition to primary purpose of providing listed services to customers)	- Website: “Business and economic development, and creation of jobs” - Investor Presentation: “Leverage competitive rates to attract and retain good jobs and capital investment in the valley”
Regulation	- Federal Energy Regulatory Commission (only rates for interstate transmission lines) - No rate regulation for production / distribution
Customers	- 154 Local Power Companies - Serves 9 million people and 700,000 businesses across 7 states
Lines	- Transmission lines: ~26,070 km - Distribution lines:
Sources of Production	- Coal, Nuclear, hydroelectric and natural gas / oil
Energy produced	Total FY 2016: 155,855 GWh in power sales - Coal-fired: 34% - Nuclear: 39% - Hydroelectric: 9% - Natural gas / oil-fired: 18%
Exported Energy	Not “export” exactly, but electricity sales to “Federal agencies and other”: $134M (representing 1.3% of electricity sales)

In CAD millions	Tennessee Valley Authority						
	2010	2011	2012	2013	2014	2015	2016
Revenue	$11,320	$11,684	$11,304	$11,124	$12,057	$13,519	$14,072
Net income	$1,012	$160	$60	$275	$508	$1,365	$1,634
Total assets	$44,001	$48,244	$46,562	$47,471	$51,104	$65,309	$66,233
Property, plant and equipment	$28,643	$30,474	$29,242	$30,809	$34,016	$43,419	$44,654
Depreciation & Amortization	$2,168	$2,032	$2,228	$2,022	$2,346	$2,892	$2,875
Capital expenditure	$2,515	$2,598	$2,499	$2,374	$2,934	$3,932	$3,990
Long-term debt	$24,359	$24,556	$21,651	$25,038	$26,723	$32,674	$29,820
Pension Obligation	$4,729	$6,007	$6,279	$5,348	$5,839	$7,107	$6,929
Total Liabilities	$29,088	$30,563	$27,930	$30,386	$32,562	$39,781	$36,749
Total Equity	$5,287	$5,438	$5,239	$5,814	$6,841	$9,651	$11,045
<u>Liquidity and Capital Resources</u>							
Most Recent Debt / Equity							N/A
Most Recent Interest Coverage							N/A
Most Recent Debt Service Coverage							N/A

Appendix E – US Public Power Utilities; Credit Rating Information

The following documents are appended here:

- Fitch credit rating criteria for US public power companies (highlights that cash flow sufficiency and ratings flexibility to maintain that sufficiency is critical to ratings)
- Fitch ratings summaries for Tennesee Valley Authority and Long Island Power Authority Bonds
- Moody's full credit rating report for Bonneville Power Administration
- Moody's rating summary for Tennesee Valley Authority
- S&P full credit rating report for Bonneville Power Administration

FitchRatings **Public Finance**

Public Power / U.S.

U.S. Public Power Rating Criteria

Sector-Specific Criteria

This report was amended effective March 25, 2016 to include a section on Criteria Variations that provides additional clarity regarding the application of criteria in Fitch's rating committee process.

Inside This Report

This criteria report replaces the prior version of the same title, dated March 18, 2014. There have been no material changes to the report.

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Scope

This criteria report details Fitch Ratings' approach to rating U.S. public power utilities. It is a sector-specific extension of Fitch's global master criteria report, *Revenue-Supported Rating Criteria*. More specifically, the report elaborates on five key areas of operational and financial importance to the credit quality of municipal and cooperative power entities: governance and management strategy; assets and operations; cost and rate structure; customer profile and service area; and financial performance and legal provisions.

These key elements of Fitch's public power rating criteria remain largely consistent with its prior criteria reports. However, the importance of individual credit factors sometimes change as the industry evolves, particularly in response to new regulatory initiatives or as new market dynamics emerge. In addition, not all rating factors outlined in this report apply to each rating or rating action. Each specific rating action commentary or rating report discusses those factors most relevant to the individual rating decisions.

Key Rating Drivers

Rate Sufficiency and Flexibility: A public power utility's ability and willingness to maintain rates sufficient to meet all its financial obligations is of paramount importance. Fitch considers how a utility's rate structure affects its capacity for the full and timely recovery of costs, as well as its flexibility to raise additional revenue. Ratemaking autonomy and the process for adjusting rates factor into this analysis.

Comprehensive Strategic Planning and Risk Management: The extent of strategic planning and risk management performed by a utility is a key indicator of management's preparedness and sophistication, and an important rating factor. Fitch typically reviews prior strategic and financial plans versus actual outcomes, as well as newly adopted strategies, to gauge management effectiveness.

Resource Adequacy and Performance: Ensuring the adequacy of resources to meet current and projected demand is a fundamental planning requirement of public power utilities. Together with demonstrated operating efficiency, it is an important factor in providing low-cost, reliable energy supply. Fitch measures resource adequacy and performance against industry standards for cost and reliability.

Service Area Composition and Depth: Service area characteristics demonstrate the breadth, depth and stability of a utility's constituents, as well as their financial wherewithal. Fitch considers customer composition and concentration; income levels; and employment, population and sales growth trends in this assessment.

Financial Strength and Forecasting: The strength and stability of a utility's financial metrics reveal its ability to meet all financial obligations, and detailed financial forecasting provides an indication of future performance. Fitch reviews a broad array of historical and projected financial metrics in an assessment of a utility's financial strength, as well as a utility's adherence to adopted financial policies. Financial metrics focus principally on three core areas: cash flow, liquidity and capital structure.

Governance and Management Strategy

The strength of a utility's senior management and governing body is a key credit consideration in Fitch's analytical process and largely evaluated with qualitative observations. Interaction with utility management is key to this analysis.

Management's experience and ability to design and implement a comprehensive strategic plan is important to an issuer's rating, as is its ability to respond to unforeseen circumstances. A high degree of organizational understanding and support of a utility's business strategy and the issues facing the sector is also important.

Achieving Strategic Goals

Fitch typically reviews prior strategic and financial plans versus actual outcomes in an assessment of management and governance effectiveness. A stronger management team consistently meets or exceeds financial projections, and deals well with unexpected developments. Moreover, Fitch takes into account the reasonableness of key financial and operational planning assumptions relative to prevailing economic conditions and industry trends.

Comprehensive Resource Planning

Fitch analyzes a utility's integrated resource plan and its long-term strategies to provide reliable, high-quality, and low-cost service to its customers to determine if they are adequate and reasonable. Fitch monitors the implementation of those strategies and a utility's financial flexibility for responding to changing market conditions.

Major Components of a Comprehensive Strategic Plan
Forecasts of customer and load growth.
New generation, transmission or distribution requirements.
Plans to meet capital needs, including debt-financing forecasts.
Plans for rate increases.
Financial projections, including stress scenarios.
Risk management procedures and analysis.

Fitch discusses with management the purpose, amount and structure of planned debt issuances, and any debt-management policies in assessing a utility's capital needs and their effect on its future debt profile and financial performance. Fitch assesses the willingness and ability of a utility's management and governing body to increase rates to ensure the measured, timely and adequate recovery of total costs. Fitch also evaluates the likely effect of rate increases on a utility's financial performance relative to its peer group.

Related Research

U.S. Public Power Peer Study Addendum — February 2015 (February 2015)

2015 Outlook: U.S. Public Power and Electric Cooperative Sector (Steady as She Goes) (December 2014)

U.S. Public Power Peer Study — June 2014 (June 2014)

Related Criteria

Rating U.S. Public Finance Short-Term Debt (January 2015)

Criteria for Rating Prepaid Energy Transactions (July 2014)

Revenue-Supported Rating Criteria (June 2014)

Attributes: Governance and Management

Stronger	
	Tenured management team with extensive experience.
	An objective, engaged and independent board of directors.
	Transparency and strong communication between management, the board of directors and customers.
	Strong coordinated efforts among utility system membership and the governing body.
	Frequent analysis and updating of financial forecasts and resource-management plans.
	Success meeting results from prior financial forecasts.
	Well-developed and documented risk management policies and procedures.
	Documented succession planning.
Midrange	
	Generally stable and capable management team.
	A board of directors exhibiting solid local governance and modest turnover.
	Comprehensive strategic and resource plans, demand forecasts and risk management policies that generally reflect current economic, system and political conditions.
Weaker	
	Management team characterized by inexperience or frequent turnover.
	A detached, politically-appointed board of directors.
	Significant political pressure and influence observed throughout municipality or service area.
	Failure to maintain open communication between the utility and the board of directors, which may reveal itself in unexpected, significant rate increases.
	Poor history of meeting financial forecasts and/or limited financial forecasting and rate planning.
	Lack of adequate risk management policies and procedures.

Preparing for Uncertainties

The extent of risk management performed by a utility is a key indicator of management's sophistication. Fitch views favorably a management team that is able to recognize and discuss risks (and mitigating factors) that could affect a system, and in turn, bondholder security. Such risks include participation in the fuel and energy commodity markets; plans for managing a large generation unit or transmission outage; reliance on off-system counterparty credit quality; and the effect of regulatory or legislative changes.

Fitch believes the ability to manage unforeseen circumstances without causing material changes to a utility's financial or operating position is a good indication of management planning and preparedness.

Assets and Operations

Fitch analyzes the generation, transmission and distribution assets of public power and electric cooperative systems to determine if a utility's power supply mix and asset operating performance adequately meet existing and future demand requirements. This analysis may be informed through site visits, which are an important part of Fitch's review process, as well as quantitative measures.

Resource Portfolio Benchmarking

Fitch benchmarks a utility's resource portfolio to that of industry standards, the regional market in which the utility operates, and other utilities in the rating category. This allows for a comparative analysis of a utility's relative strengths and weaknesses. Fitch considers the following areas in its assessment of resources:

- Fuel mix;
- Plant availability and capacity factors;
- Load factor;

- Heat rate; and
- Environmental mandates or goals.

Integrated Resource Planning

Fitch analyzes how a utility's customer or load growth, expiring purchase power contracts, aging generation fleet and renewable mandates influence the demand for future power resources. Fitch considers the following areas in its assessment of a utility's integrated resource plan:

- The type of generation chosen and alternatives considered;
- The relative maturity of the proposed technology;
- The size and cost of the resource;
- The positioning of the resource within the utility's existing portfolio (baseload, intermediate or peaking);
- The availability of transmission and distribution resources; and
- Environmental factors.

Fitch does not have a systematic rating preference for owning assets versus purchasing power. On the contrary, Fitch's analysis considers the costs and benefits to individual utilities of both approaches.

Fuel Cost and Supply Management

The ability to manage fuel costs is a key credit concern, because fuel is often a utility's largest budgetary expense. Factors related to fuel cost and supply that Fitch considers include:

- Fuel mix diversity;
- Fuel agreement flexibility;
- Fuel transportation arrangements; and
- Alternative fuels, if primary sources are not available.

Fitch also reviews a utility's hedging techniques as part of its risk management assessment. The use of financial and physical forward markets can help mitigate the risk of price volatility or a longer term trend of increasing prices. Fitch views prudent and conservative fuel hedging programs favorably. However, these initiatives may expose a utility to counterparty risk or collateral posting requirements as fuel prices rise or fall.

Fitch considers all aspects of a utility's hedging program in its analysis, including the relevant terms of hedging agreements, counterparty credit quality and available liquidity to support rising prices or collateral requirements. Although the optimal fuel cost and supply strategy varies by utility and is driven by the diversity of generating resources, sufficiency of fuel sources and the ability to mitigate associated risks, Fitch views a power supply portfolio that exhibits a broadly diversified fuel mix as most supportive of long-term credit quality.

Environmental Considerations

Fitch conducts a review of a utility's compliance with current and proposed environmental standards to fully understand a system's future capital needs and operating expenses. Environmental retrofits can be costly on a capital basis and from an operating perspective, as increased captive consumption often results in lower plant output. Moreover, the cost to retrofit or improve older, smaller generating facilities may be high, rendering the generating facility uneconomic and subject to premature retirement. As such, the effect of more restrictive federal and state environmental policies can have significant operating and financial repercussions for a utility that require careful, advanced planning

Renewable Resources

Fitch reviews a utility's strategy for developing renewable or alternative power generation to gauge how a utility's resource mix will change, particularly when it must comply with a state renewable portfolio standard. Fitch also evaluates the capital and operational costs of the projects, and how they will ultimately affect financial metrics and customer rates.

Renewable energy projects are expected to have long-term environmental benefits. However, the intermittent nature of their generation and higher operating costs relative to traditional generating resources can pressure a utility's financial operations without adequate cost recovery. Fitch evaluates the availability and types of renewable resources, as well as transmission capacity, which vary by region.

Distribution and Transmission

Fitch's review of transmission and distribution assets includes an assessment of reliability, as measured by the frequency of outages, line losses, etc., and the extent and timeliness of necessary capital improvements. Fitch evaluates the level of historical and planned system investment to determine if customer growth will affect the operations of the existing utility relative to a peer group. Fitch also reviews a utility's business strategy regarding its transmission connection with a regional operator or other transmission system. Membership in a regional transmission organization can be the optimal method of providing reliable access to market power.

Cost and Rate Structure

Fitch analyzes a utility's cost structure and methods of adjusting rates to determine its rate-raising flexibility for the timely funding of financial operations and capital needs. The analysis is conducted bottom up, by looking at the costs to supply electricity to customers, and top down, by examining the structure of rates charged to users. A utility with overall rates below neighboring systems or systems with similar fuel mixes is generally viewed as having greater flexibility to use rates as a tool for funding. Strong service territory income measures typically enhance this flexibility.

Local Rate-Setting Authority

Fitch views the flexibility most municipal systems and electric cooperatives have to independently adjust rates as a positive credit factor and distinguishing characteristic from comparable investor-owned utilities. Most public power systems are not subject to regulation by state public service commissions. Instead, public power systems typically maintain local authority to adjust rates as needed, which contributes to the timely recovery of costs. This provides management with the ability to raise rates to maintain financial stability, build liquidity or pay for portions of a capital improvement plan. Conversely, rate regulation generally limits financial flexibility and may delay the timing or amount of necessary rate increases.

Attributes: Cost and Rate Structure

Stronger	
	Sole authority by an independent board to set rates and a demonstrated willingness to do so.
	Service rates that are typically below those of neighboring utilities and regionally competitive.
	Use of an automatic monthly fuel or purchased power adjustment for timely recovery of variable energy and fuel costs.
	Timely and measured rate increases implemented in anticipation of multiyear capital spending.
Midrange	
	Authority to set customer or member rates, subject to the approval of an elected city council.
	Comparable rates to neighboring utilities, and within range of regional averages.
	Use of a fuel or purchased power adjustment that requires board approval or adjusts less frequently than monthly.
	Well documented rate strategy for servicing capital spending and related debt obligations.
Weaker	
	Outside regulatory approval required for rate increases.
	Political pressure that might limit or postpone needed rate increases, which could ultimately affect a utility's financial metrics.
	Above average rates relative to a peer group, which reduces flexibility for managing unforeseen operating or other capital expenses.
	Lack of any fuel or purchased power adjustment factor.

Fitch also considers the use of automatic or interim rate adjustments, which further ensure timely cost recovery, in its assessment of a utility's rate structure. Interim adjustments that may be implemented by a utility's management team — without the involvement of a governing board — can help ensure the overall stability of financial operations.

Rate Competitiveness and Affordability

Fitch analyzes rate affordability with a mixture of qualitative and quantitative factors. Fitch's perception of high or volatile rates, lack of future rate flexibility or difficulty in obtaining timely rate relief may influence a utility's rating.

Fitch believes credit is due to those systems that consistently raise rates to preserve financial strength. However, Fitch believes these activities will be more sustainable when rate affordability is a focus of policymakers and cost containment is regularly employed. Fitch reviews a utility's rates relative to neighboring and comparable systems, and against service area income levels to gauge rate competitiveness and affordability.

Customer Profile and Service Area

Service area characteristics provide an indication of the stability of a constituency's load, and ultimately its ability to pay electric bills. Stronger electric utilities typically serve growing, well-diversified areas. However, the essential nature of electric service and the remedies available to most public power providers (e.g. shutoffs and liens) make payment delinquencies in the sector extremely low, regardless of wealth and other economic indicators.

Service Area Considerations

A utility's ability to maintain a sound operating position, despite changing service area characteristics, is an important rating consideration. Some of the factors Fitch considers in its assessment of a service area are shown in the table on page 7.

Fitch performs a more detailed analysis of an electric system's customer base to further evaluate the stability of the revenue source when there is industry or customer concentration. The latter is defined as one or a few large customers accounting for a material proportion of revenues (see table on page 7). Fitch conducts an analysis of all relevant member information

FitchRatings **Public Finance**

Key Service Area Metrics

Indicator	Source	Significance
Economic Factors	U.S. Bureau of Labor Statistics and U.S. Bureau of Economic Analysis	A diversified economy is typically better positioned to absorb cyclical changes than an economy concentrated in a certain sector, providing for greater stability of revenues.
Customer Profile (Breakdown of Residential, Commercial and Industrial Customers)	Utility or consultant	A higher percentage of residential energy sales (more than 40%) typically provides for greater financial stability. Residential customers each account for very small percentages of total sales. As such, the loss of any single customer does not disrupt a utility's revenue stream.
Top 10 Customers	Utility or consultant	As a percentage of the total, 5% of sales to the largest customer or 25% of sales to the 10 largest customers reveals concentration in the revenue base, which can be disruptive if a large customer(s) leaves the area.
Population	U.S. Census	A growing service area typically leads to additional energy sales, in support of revenues.
kWh Sales (Breakdown of Residential, Commercial and Industrial Sales)	Utility or consultant	The trend of kWh sales provides an indication of the health of the local economy, with steady annual increases demonstrating sound economic and population growth.
Unemployment Rate	U.S. Bureau of Labor Statistics	Provides an indication of the relative depth of a local employment base.
Income Levels	U.S. Census and U.S. Bureau of Economic Analysis	Provides an indication of the relative ability to pay.

when reviewing wholesale public power suppliers, as necessary, to the extent that information is available.

Financial Performance and Legal Provisions

The assessment of a utility's financial performance and policies, and the legal provisions underpinning specific debt issuances, are important considerations in Fitch's rating process. Fitch reviews five years of audited financial statements for an established utility to understand its historical trends and competitive position relative to a peer group. A utility's operating results, liquidity levels and capital structure are evaluated. Financial projections, including planning assumptions for load growth, rate increases and expenses, are likewise critical to the rating process.

Financial Performance

Fitch's analysis of financial metrics focuses principally on three core areas: cash flow, liquidity, and capital structure. No single financial ratio stands apart from the rest. On the contrary, the ratios are examined together, providing a context for a utility's financial position that informs a complete analysis.

Cash Flow

Cash flow indicators, particularly as they pertain to debt service coverage, provide a measure of financial cushion to meet obligations to bondholders. Fitch primarily considers two measures of debt service coverage to compare utilities that own generation versus purchase power. The standard debt service coverage ratio measuring funds available for debt service to total debt service applies to all utilities.

An adjusted measure of debt service coverage — coverage of full obligations — is primarily for systems that own little or no generation. This ratio treats a percentage (30%) of purchased power costs as a debt-like obligation. Thirty percent is an approximation based on historical experience for that portion of off-balance sheet obligations that might otherwise be a fixed expense. The ratio provides a more conservative estimate of financial margin and facilitates comparison with systems that own capital-intensive generating assets. This adjustment is particularly important for those arrangements where a wholesaler supplier has issued debt on behalf of obligated retail entities. See Appendices A and B.

Liquidity

Liquidity measures, such as days cash on hand and days liquidity on hand, provide an estimate of an issuer's ability to meet unplanned operating or other capital expenses. For the purpose of ratio calculation, cash typically includes unrestricted cash, cash equivalents and investments that can be converted to cash within a reasonable period of time. In some cases, restricted cash and investments may also be included if available for general system purposes, including the payment of debt service.

Key Financial Ratios

Ratio	Calculation	Significance
Cash Flow		
FADS ($)	Operating Revenues – Operating Expenses + Depreciation + Interest Income[a]	Provides a measure of cash flow from operations.
Debt Service Coverage (x)	FADS/Total Annual Debt Service	Indicates the margin available to meet current debt service requirements.
Coverage of Full Obligations (x)	(FADS + Fixed Charge – General Fund Transfer and/or PILOT)/ (Total Annual Debt Service + Fixed Charge)[b]	Indicates the margin available to meet all debt service and other fixed obligations.
Debt/FADS (x)	Total Debt/FADS	Indicates the size of debt compared to the margin available for debt service.
Liquidity		
Days Cash on Hand	Unrestricted Cash/(Operating Expenses – Depreciation) x 365	Indicates financial flexibility, specifically cash, cash equivalents and investments, relative to expenses.
Days Liquidity on Hand	(Unrestricted Cash + Available Lines of Credit and Commercial Paper Capacity)/(Operating Expenses – Depreciation) x 365	Indicates financial flexibility, including all available sources of cash and liquidity, relative to expenses.
Capital Structure		
Equity/Capitalization (%)	Total Equity/Capitalization	Provides a measure of cost recovery, leverage and additional debt capacity.
Debt Service/Cash Operating Expenses (%)	Total Annual Debt Service/(Operating Expenses + Total Annual Debt Service – Depreciation)	Provides an indication of debt burden relative to cash operating expenses.
Debt/Customer ($)	Total Debt/Total Customers	Provides a measure for relative comparison of leverage.
Variable-Rate Debt/Total Debt (%)	Variable-Rate Debt/Total Debt	Provides context for an issuer's short-term obligations.
Other		
Operating Margin (%)	Operating Margin/Operating Revenues	Provides a measure of operating stability and capacity to manage an increase in debt service.
Capex/Depreciation and Amortization (%)	Capex/(Depreciation + Amortization)	Indicates whether annual capital spending keeps pace with depreciation.
FCF/Capex ($)	(FADS – Total Annual Debt Service – General Fund Transfer and/or PILOT)/Capex	Indicates a utility's ability to internally fund capex.
Net Debt/Net Capital Assets (x)	(Total Debt – Cash and Reserve Funds)/Net Utility Plant	Provides a measure of leverage relative to the book value of physical assets.
General Fund Transfer/ Operating Revenues (%)	(General Fund Transfer + PILOT)/Operating Revenues	Indicates the degree to which a utility provides city or county general fund support.

[a]Operating revenues exclude deferrals to and transfers from a rate stabilization fund. [b]Fixed charge – 30% of purchased power expense, which is an approximation of the associated fixed expense. Note: Includes unrestricted cash, cash equivalents and investments plus restricted cash and investments (if available for general system purposes). FADS – Funds available for debt service. PILOT – Payment in lieu of taxes.

Certain utilities, including many cooperatives, rely heavily on committed bank revolvers or lines of credit and commercial paper programs for access to short-term capital. As such, days liquidity on hand, reflecting undrawn short-term borrowing arrangements and unused commercial paper capacity, is also an important measure of financial flexibility. Fitch assesses the diversity and credit quality of liquidity providers, the ability to extend and replace bank agreements, the adequacy and terms of the liquidity support, and a borrower's short-term market access.

Capital Structure

A utility's capital structure, which encompasses the strength of its balance sheet, presents another indication of financial flexibility. More specifically, the equity-to-capitalization ratio measures a utility's ability to grow equity over time.

A rising equity ratio is viewed favorably, as it typically suggests adequate cost recovery in rates, load growth and a component of internal funding of capital investments. In addition, a robust level of system equity can indicate a heightened capacity for issuing additional debt to fund future capital needs.

Debt Profile

Fitch's assessment of a utility's debt profile considers the purpose, amount and structure of its existing debt. Fitch also considers any off-balance sheet obligations such as take-or-pay contracts or interest rate swap agreements for a complete assessment of fixed-expense obligations. Future financing plans, including the funding of a long-term capital program, and the renewal and replacement of any bank liquidity facilities, are also important considerations, particularly as they affect financial metrics.

The amount of hedged or unhedged variable-rate debt an issuer can manage is a function of its operating risk profile; the strength, predictability and amount of its cash flows; the level of available funds; and its management of interest rate exposure and maturities. Fitch assesses the resiliency of an issuer's financial metrics relative to a peer group when evaluating its ability to manage variable-rate and short-term debt exposure. Issuers with robust cash balances, broad rate-setting authority, and widespread access to the capital markets are typically better able to take on a greater percentage of variable-rate debt, as compared with issuers lacking these characteristics.

Legal Provisions

Aspects of the Bond Indenture

The legal provisions of a bond indenture or resolution provide a framework for the establishment of funds and, ultimately, the repayment of a debt obligation. Consequently, Fitch analyzes indenture provisions, including security, revenue pledge, lien position, rate covenant, additional bonds test, debt service reserve fund and flow of funds to determine the relative strength of the security.

Bond covenants are important to overall bondholder protection, though the degree to which they influence a rating varies. These restrictive provisions take on greater importance the weaker the credit quality, as they are more likely to be tested.

Municipally Owned Systems

Pledge of Revenues

Fitch does not distinguish between a pledge of gross and net revenues for municipally owned systems, as all systems must fully cover annual operating expenses and debt service from total revenues. A weaker revenue pledge may allow for the inclusion of other available funds in the calculation of revenues.

Rate Covenant

The rate covenant provides a minimum level of protection and ensures a system reliably covers debt service by a certain margin. Fitch views it as an element of financial cushion. Rate covenants with only a 1.0x (sum sufficient) debt service coverage requirement, or those that allow inclusion of other funds in the calculation, are viewed as being weaker.

Additional Bonds Test

The terms of the additional bonds test often mimic the rate covenant. The strongest tests include both a historical and projected debt service coverage test and limit the period for calculating historical net revenues to the 12 months immediately preceding the issuance of additional debt.

Attributes: Select Indenture Provisions — Municipal Systems

Rate Covenant	Additional Bonds Test
Stronger	
Greater than 1.25x coverage of ADS by net revenues alone.	More than 1.25x coverage of MADS from net revenues. Typically, the test includes both a historical and projected revenue period; the test is met over a consecutive number of months.
Midrange	
Coverage of ADS between 1.10x and 1.25x by net revenues alone.	Coverage of MADS from net revenues of between 1.10x and 1.25x. Might only include a historical or projected net revenue coverage test; might allow inclusion of other available fund balances to meet the test.
Weaker	
Less than 1.10x coverage of ADS by net revenues plus available funds.	Less than 1.10x coverage of ADS from net revenues plus additional funds. Typically, a historical or projected test, with a looser interpretation of the revenue period (i.e. 12 consecutive months of the 24 months preceding the issuance of additional bonds).

ADS – Annual debt service. MADS – Maximum annual debt service.

Debt Service Reserve Fund

The incidence of relying on a debt service reserve fund to pay debt obligations is low, given the limited number of public power entities that Fitch rates below investment grade. However, maintaining additional legally restricted, cash-funded reserves is looked upon favorably, particularly for weaker credits. Fitch evaluates those instances where reserve funds have been funded with a surety from a financial guarantor on a case-by-case basis.

Flow of Funds

The flow of funds is fairly standardized for municipal utilities, providing for regular deposits to the debt service fund after the payment of operations and maintenance. As such, the flow of funds usually has little bearing on the rating, except in the uncommon instances when it deviates from the typical arrangement.

Cooperatively Owned Systems

Security

Unlike municipally owned utilities, cooperatives typically issue debt secured by a first lien on owned tangible and certain intangible assets, not net revenues. Pledged security for generation and transmission (G&T) cooperatives is also expected to include the power sales contracts with distribution members, which Fitch views as important.

Although Fitch believes a mortgage interest provides valuable bondholder support, it does not distinguish the ratings of a cooperative's senior secured and unsecured obligations. Fitch's public finance ratings consider an obligation's relative vulnerability to default; they do not consider the prospect of recovery post default. Therefore, the fact that an obligation may benefit from a higher recovery is not a basis for a higher rating.

Rate Covenant

Rate covenants provide a minimum level of protection and ensure a system reliably covers debt service by a certain margin. Cooperative rate covenants typically require cash flows sufficient to recover all costs and expenses, and to generate a minimum times interest earned or margins for interest ratio (e.g. 1.10x) for some measure of additional cushion.

Other than establishing minimum operating thresholds, these ratios provide marginal value in Fitch's analysis and are a limited rating factor, as most Fitch-rated cooperatives operate with stronger cash flows.

Limitations on Patronage Capital

Distributions of patronage capital — returns of excess capital — to member owners are typically limited under cooperative indentures until a specified ratio of equity to capitalization (generally 20%) has been achieved. These limitations provide a measure of balance sheet resource adequacy and some protection for bondholders vis-à-vis member owners.

Effects of Litigation

Fitch considers any litigation that might result in financial payments in its review of an issuer's legal framework. Any such payments that materially affect an issuer's balance sheet could result in a negative rating action.

Key Analytical Considerations

Governance and Management Strategy

- Type of governing body
- Management's experience and depth of industry knowledge
- Management's track record at achieving financial and strategic goals
- Business strategy and planning
- Extent of risk management

Assets and Operations

- Review of generation mix and comparison to the region
- Historical operating performance of generation facilities
- Relative load balance or shortfall, and plans for meeting additional power needs
- Fuel supply and hedging contracts
- Compliance with environmental and renewable mandates
- Distribution and transmission issues

Cost and Rate Structure

- State or federal regulatory oversight
- Process of adjusting rates to ensure timely and adequate cost recovery
- Structure and use of fuel or purchased power adjustment mechanism
- Rate-raising flexibility
- Cost and rate competitiveness

Customer Profile and Service Area

- Economic and demographic makeup and trends
- Customer composition, including a breakout of kWh sales and revenues
- Customer revenue or business sector concentration
- Service area profiles of member systems, for joint action agencies and cooperatives

Financial Performance and Legal Provisions

- Management's financial policies
- Historical five-year analysis of key cash flow, liquidity and leverage ratios
- Financial projections and reasonableness of key assumptions
- Existing debt characteristics and future financing needs
- Financial analyses of the largest member distribution systems, for joint action agencies and cooperatives
- Review of indenture provisions and bond security features
- Type, length and renewal terms of wholesale power contracts
- Any material pending litigation

Variations from Criteria

Fitch's criteria are designed to be used in conjunction with experienced analytical judgment exercised through a committee process. The combination of transparent criteria, analytical judgment applied on a transaction-by-transaction or issuer-by-issuer basis, and full disclosure via rating commentary strengthens Fitch's rating process while assisting market participants in understanding the analysis behind our ratings.

A rating committee may adjust the application of these criteria to reflect the risks of a specific transaction or entity. Such adjustments are called variations. All variations will be disclosed in the respective rating action commentaries, including their impact on the rating where appropriate.

A variation can be approved by a ratings committee where the risk, feature, or other factor relevant to the assignment of a rating and the methodology applied to it are both included within the scope of the criteria, but where the analysis described in the criteria requires modification to address factors specific to the particular transaction or entity.

Appendix A — Wholesale Public Power Suppliers

This criteria appendix provides additional guidelines for rating wholesale public power suppliers, a subset of the U.S. Public Power sector. Most of the key factors considered in rating public power entities are the same. However, different functional characteristics of the sector's participants sometimes result in credit considerations that are unique and financial metrics that are less comparable for a given rating level. This appendix will elaborate on those characteristics and how they influence Fitch's approach to rating wholesale suppliers.

Key Highlights

Power Supply Requirements Vary

Wholesale public power suppliers typically supply power to retail electric utilities. Most wholesale systems are organized by municipally owned retail power systems as joint action agencies (JAAs) or by cooperatively owned systems as G&T cooperatives to exclusively provide all or a portion of their members' power requirements. Other wholesale suppliers include state or federally owned entities.

Typically Member Governed

Most wholesale suppliers are governed by all or a subset of the members they serve, aligning the incentives of the contractual parties and strengthening the related obligations. All operating and financial decision making, including wholesale rate setting, typically resides with the representative board of directors.

Wholesale Contracts Dictate Obligations

Wholesale power system revenues are primarily derived from power sales contracts with participant or member retail systems. The terms, tenor and nature of the contract obligations (i.e. take-and-pay, take-or-pay) are a key factor when rating wholesale systems. Without such contracts, these wholesale suppliers are unlikely to be rated investment grade.

Purchaser Credit Quality Supports Rating

The credit quality of the purchasing utilities is an important rating factor for wholesale systems, as the corresponding payments enable issuers to meet their obligations on a timely basis. The degree to which the rating of a wholesale supplier is influenced by the credit quality of any individual purchaser (or subset of purchasers) is generally determined by the specific terms of the contract and the nature of the obligation.

Exceptional Operating Characteristics Could Enhance Rating

Exceptionally strong operating performance and/or resource economics could potentially enhance a wholesale power supplier's rating, particularly for single resource projects, above the level that the credit quality of the purchasers would otherwise indicate. However, such instances are rare.

Wholesale Metrics Comparably Weaker

Wholesale suppliers typically exhibit comparably weaker financial metrics to retail power systems. However, weaker debt service coverage, higher leverage and lower cash on hand are generally acceptable given the credit quality, liquidity and strong contractual obligations of the member systems.

Wholesale Public Power Ratings in Context

U.S. wholesale public power utilities are generally owned by the customers they serve and operate with a mission to provide essential, reliable and relatively low-cost power supply. Wholesale suppliers do not typically provide retail electric service. Fitch's average rating for wholesale public power systems in the sector is higher than the Issuer Default Ratings (IDRs) for independent power producers (IPPs).

Key credit characteristics supporting higher ratings for public wholesale utilities include their strong wholesale power supply contracts, self-rate regulating authority and lower consolidated enterprise risk relative to IPPs. Comprehensive supply contracts protect suppliers from operating risk and market price volatility, while self-rate regulating authority allows for the more timely recovery of costs through wholesale electric rates. These two factors provide for more stable energy sales and, in turn, more predictable financial operations. Efforts to diversify operations or compete in the competitive marketplace are rare in the public power sector.

Power Supply

The supply requirements of wholesale power entities typically vary and are generally characterized as all-requirements or partial-requirements. All-requirements arrangements obligate both the supplier to supply all of the purchasing entities energy and capacity needs, and the purchaser to purchase all of their requirements from the supplier. Partial requirements arrangements typically obligate the supplier to supply only a portion of a purchaser's needs. The amount supplied may be limited to the capacity and energy available from identified resources, or requirements in excess of other resources available to the purchaser.

Resources used to meet wholesale supply obligations also vary, ranging from broad, sizable asset portfolios to single-asset power projects. Fitch evaluates all power supply resources based in accordance with the criteria outlined in this report.

Governance

Most wholesale suppliers are governed by a board of directors composed of representatives from all or a subset of the members they serve. While it may not always ensure the adoption of robust financial policies and strong credit quality, Fitch believes member-governance aligns the incentives of the supplier and purchaser, thereby strengthening their related obligations. Wholesale suppliers governed by politically appointed boards of directors, including many state and federally owned suppliers, may be subject to greater political influence.

Fitch seeks to understand the dynamics among wholesale suppliers and their members, as well as those among the members, to determine whether the strategies and vision adopted by these entities are widely consistent and shared. Although occasional disagreement among members is anticipated by Fitch, organizational discord that detracts from strategic and financial planning is a concern.

Power Supply Contracts

Wholesale power systems derive most of their revenues from power sales contracts with their participants or member retail systems. These power contracts and the nature of the related obligations are significant drivers of wholesale public power supplier credit ratings. Absent acceptable long-term contracts — many of which are court validated to provide assurances they are enforceable — a wholesale supplier would be unlikely to obtain an investment-grade rating.

Fitch reviews relevant power sales contracts to understand the nature of the related obligations and to assess the terms. Contract obligations are typically characterized as take-and-pay or take-or-pay. The details of each contract and its implications are discussed below.

Although suppliers may sell excess power and energy to nonmembers or into organized markets to maximize operating margins and reduce net energy costs, a heavy reliance on off-system sales is viewed as a negative credit factor, as revenues tend to be more volatile.

Take-and-Pay Contracts

Under take-and-pay contracts, a purchaser's payment obligation is not unconditional, but contingent upon the delivery of electricity. Take-and-pay obligations are most often associated with all-requirements contracts, where participating retail electric systems are required to purchase all energy and capacity needs from the wholesale supplier. Power requirements are largely met through supplier-owned generation or long-term power purchase agreements. However, contract provisions typically provide that suppliers may procure power supply from alternative resources as necessary, mitigating operational and performance risk, as well as the risk of the take-and-pay obligation.

Fitch expects all requirements suppliers will be required to set rates sufficient to meet debt service requirements. Rates must therefore be adjusted to account for nonpayment by a member system or the failure of a major generating unit. This provides an implicit (or explicit) unlimited step-up requirement for participating systems, which Fitch views as strongly supportive of supplier credit quality.

Take-or-Pay Contracts

Take-or-pay contracts are typically used to finance individual power projects, which are expected to provide only a portion of the purchaser's power requirements. Under these contracts, purchasers are obligated to make specified payments to the supplier, whether or not energy is delivered by the project, thereby eliminating operating risk. Mandatory payment obligations are usually sized to adequately cover the supplier's debt service requirements.

Take-or-pay project participants are typically obligated to pay a fixed percentage of the project's costs, including debt service, which corresponds to their allocated ownership interest or percentage of output. A supplier's ability to meet its obligations, including debt service, therefore depends on each participant meeting its required payment.

As a means of mitigating nonpayment by weaker and smaller participants, most take-or-pay contracts include step-up provisions, which require participants to increase their payments by a specified percentage in the event of another participant default. Step-up requirements can range from 20% to more than 100% of a participant's initial obligation.

Although participant defaults are rare, the inclusion and size of required step-up provisions in power sales contracts provide meaningful bondholder protection and are an important rating factor.

In reviewing wholesale suppliers, Fitch also evaluates the expiration and renewal terms of power sales contracts relative to the final maturity of an issuer's outstanding bonds. Debt maturities beyond the terms of the agreements are considered a negative rating factor, given the uncertainty of sufficient revenue to meet debt service post expiration. In these cases, Fitch will evaluate the likelihood of contract renewal, as well as the viability of the assets or enterprise to generate alternative revenue sufficient to meet debt service. Resource economics and flexibility, and prevailing market conditions are important factors in this determination.

Purchaser Credit Quality

The credit quality of the purchasing utilities is an important consideration when rating wholesale power systems, because the corresponding payments enable the systems to meet their obligations on a full and timely basis. The ability and willingness of purchasers to make their required payments must therefore be considered.

The degree to which a supplier's rating is influenced by the credit quality of any individual purchaser (or subset of purchasers) is determined by the specific terms of the contract and the nature of the obligation. Ratings for all-requirements wholesale suppliers are generally less sensitive to the credit quality of individual purchasers. Instead, the ratings broadly reflect the credit quality of the pool, or its largest purchasers, given the default protection provided by unlimited step-up provisions.

By comparison, ratings for suppliers subject to take-or-pay contracts with limited step-up provisions are more sensitive to individual purchaser credit quality. Fitch evaluates structural and step-up provisions to determine the extent to which payments from each purchaser are required to meet a supplier's debt service. The rating for a take-or-pay supplier will generally reflect the credit quality of the weakest purchaser after factoring the applicable step-up provision.

Where a step-up provision is insufficient to cover an individual purchaser's obligations if it were to default, the supplier's rating may be capped by the credit quality of that purchaser. For example, if a supplier's step-up is limited to 25%, then that supplier's ability to meet debt service obligations would be highly reliant on payments from any purchaser with an allocated share higher than 20%. Stepping up the required payments from the remaining systems responsible for less than 80% of the project costs by 25% would likely result in a shortfall in revenue.

If a supplier is highly reliant on more than one purchaser (i.e. each purchaser has an allocated share of more than 20% in the case above), then the supplier's rating may be capped by the credit quality of the weakest of those purchasers.

Although reserve funds or funds received from the sale of output from a defaulting participant's share could be used to avert an immediate default on the supplier's debt obligations, the long-term rating reflects the likelihood of payment through final maturity.

Assessing Purchaser Credit Quality

Fitch seeks to assess the credit quality of purchasing or member utilities using all available information, including public and private disclosure. In the absence of a Fitch public rating of a purchasing system, Fitch may assign its own credit opinion, consider ratings of the local government or other related enterprises, refer to ratings from other nationally recognized credit rating agencies, or rely on comparative peer metric reviews in determining credit quality.

Project Operating Characteristics

In addition to the contract and purchaser evaluations described, Fitch evaluates project operating characteristics in accordance with the criteria outlined in this report when rating take-or-pay power projects. Although rare, exceptionally strong project operating performance and/or economics could potentially enhance the rating of a project above the level the purchaser evaluation would otherwise suggest. Any rating enhancement would likely be limited and would reflect Fitch's determination that the obligations of the weakest purchaser would likely be assumed upon a default, given the inherent value of the resource and the incentive of the remaining purchasers to preserve the project's credit quality.

Conversely, poor operating characteristics would not necessarily result in a project rating lower than purchaser credit quality would suggest. Fitch's analysis assumes valid and binding take-or-pay obligations will be paid as required and any financial strain related to a poor-performing project would be separately reflected in the credit quality of the purchasers.

Financial Metrics — Wholesale Systems

Wholesale suppliers exhibit financial metrics that are comparably weaker to retail power systems for a given rating level, particularly take-or-pay projects where debt service coverage averages 1.0x–1.1x and cash balances held by the issuer are very limited. Overall weaker debt service coverage, higher leverage, and lower cash on hand reflect the higher asset concentration and related leverage characteristic of wholesale suppliers and are generally acceptable, given the credit quality and strong contractual obligations of the member systems.

Fitch also considers a wholesale system's cost structure, rate adjustment and billing processes to assess the timeliness of cost recovery as part of its metric review. Wholesale suppliers typically pass through costs to members on a monthly basis, which enhances cash flow stability and further supports system metrics.

Attributes: Select Financial Metrics — Wholesale Systems

Debt Service Coverage (x)	Debt/FADS (x)	Days Cash on Hand	Equity/Capitalization (%)
Stronger			
Coverage of consistently more than 1.5x provides solid cash flow and bondholder protection.	Less than 7x debt to FADS indicates a favorable level of leverage relative to cash flow.	More than 120 days cash on hand indicates solid financial flexibility to meet unforeseen spending needs.	Strong equity levels of more than 30% indicate adequate cost recovery and ample debt capacity for future capital needs.
Midrange			
Many utilities target coverage in the 1.2x–1.4x range.	Ratios in the 7.0x–9.0x range indicate a generally balanced level of debt relative to cash flow.	Many wholesale systems target approximately 60–90 days operating cash.	Most wholesale systems maintain 20%–30% equity levels.
Weaker			
Consistently less than 1.1x coverage provides limited cushion for unexpected revenue shortfalls.	Greater than 10x debt without a suitable rationale can indicate a deficient rate structure.	Less than 60 days cash indicates less financial flexibility, but can be adequate if a system is subject to less cash flow volatility.	Less than 10% equity is relatively low for wholesale systems and may suggest limited capacity for additional debt.

FADS – Funds available for debt service. Note: Excludes take-or-pay projects. The debt and equity ratios above do not reflect off-balance sheet obligations. Fitch reviews adjusted financial ratios to take into account such obligations.

Appendix B — Retail Public Power Systems

This criteria appendix provides additional guidelines for rating municipally and cooperatively owned retail power systems, a subset of the U.S. Public Power sector. Most of the key factors considered in rating public power entities are the same. However, different functional characteristics of the sector's participants sometimes result in unique credit considerations and financial metrics that are less comparable for a given rating level. This appendix will elaborate on those characteristics and how they influence Fitch's approach to rating retail power systems.

Key Highlights

Retail Electric Services Provided

Retail public power systems provide electric supply and distribution services to end-user customers, and include both municipally and cooperatively owned systems.

Local Governance

Most retail systems are locally governed by an independent board of directors appointed or elected from among its end-user customers or member owners. All operating and financial decision making, including retail rate setting, typically resides with the representative board of directors.

Local Government Influence Assessed

Municipal systems sometimes operate as a component of the local government and may be governed by politically appointed boards or elected city councils. As part of its analysis, Fitch seeks to identify and assess the degree of political influence on utility operations and the degree to which utility credit quality could be influenced by local government decision making.

Power Supply Arrangements Vary

Retail systems meet their power supply requirements through a variety of arrangements. Some systems, typically larger entities, own and operate generating facilities to meet system power demands, while others receive all-requirements contractual power supply through membership in municipal JAAs or G&T cooperatives. Still others actively manage their power supplies through a combination of owned assets, take-or-pay projects, and bilateral contracts.

Financial Metrics Diverge with Asset Ownership

Financial metrics diverge widely with asset ownership and related borrowings. Fully integrated systems that generate their own power supply and have financed production facilities on-balance sheet typically report lower debt service coverage and higher leverage metrics than systems that contract for power supply.

Metrics Adjusted for Contractual Obligations

When rating retail public power systems, Fitch factors contractual debt obligations in its analysis, particularly those issued by JAAs and G&Ts on behalf of its member systems. Financial metrics are adjusted for off-balance sheet obligations as appropriate to facilitate peer comparison.

Retail Public Power Ratings in Context

U.S. retail public power systems include municipally or cooperatively owned enterprises that operate with a mission to provide essential, reliable and relatively low-cost electric service to end users. Fitch's ratings for retail public power systems are typically higher than the IDRs of investor-owned utilities.

Key credit characteristics supporting higher ratings for public systems include their self-rate regulating authority, predominantly residential customer bases and lower consolidated enterprise risk. Self-regulating authority allows for the more timely recovery of costs through electric rates, while higher proportions of residential customers provide for more stable energy sales and, in turn, more predictable financial operations. Efforts to diversify operations in the public power sector are rare.

Retail Services

Retail public power systems are distinguished by the transmission and delivery of electricity to end users, including residential, commercial and industrial customers. Municipal power systems are typically owned by the municipality the utility serves, and may operate as a stand-alone entity or as an enterprise fund of the local government. Moreover, municipal electric systems may be operated as part of a combined utility system providing other services, including natural gas, water and wastewater on a retail basis.

Electric distribution cooperatives provide electric distribution services to their end-user customers or owner members, typically within prescribed and largely rural territories. Alternative services may also be provided by distribution cooperatives, but instances are rare.

Fitch views the distribution function largely as a monopoly-type, stable business with limited business risk. Combined utility systems are viewed favorably — provided the individual systems are self-sustaining — given the diversity of revenue and economies of scale. However, retail systems that provide services subject to competitive pressures, including telecommunications and propane, may be exposed to a higher degree of operating and financial risk.

Governance

Most retail systems are locally governed by an independent board of directors appointed or elected from among its end-user customers or member owners. All operating and financial decision making, including retail rate setting, typically resides with the representative board of directors. Governing boards that include highly engaged directors with diverse and relevant professional experience, and operate free from political influence are viewed more favorably by Fitch.

Fitch seeks to identify and assess the degree of political influence on municipal utility operations and the degree to which utility credit quality could be influenced by local government decision making. Municipal systems governed by politically appointed boards or elected city councils that are unfamiliar with the utility sector introduce political interference into decision making or rate-setting policies are generally of greater concern to Fitch. The involvement of influential consumer councils in rate setting can further limit financial flexibility. Conversely, local governments with ambitious and well-funded economic development programs could be highly supportive of retail power systems.

Fitch reviews transfers by a utility to a corresponding municipality's general fund and other means of financial support, including in-kind services and borrowing arrangements, as part of its analysis. Transfer policies that are formulaic or subject to limitation are viewed positively; whereas subjective, open-ended policies that allow a local government to affect the liquidity levels of a utility generally increase credit risk. For electric cooperatives, policies related to the repatriation (or return) of patronage capital to members have similar importance.

Power Supply Arrangements

Some retail systems, typically larger entities, own and operate generating facilities to meet system power demands. Fitch's analysis of these vertically integrated systems includes an evaluation of all power supply resources and the related business risks in accordance with the criteria outlined in this report.

Most retail power systems receive all-requirements contractual power supply through membership in a JAA or G&T cooperative. Membership in these organizations is generally viewed positively by Fitch, particularly for smaller systems, as they provide greater economies of scale and diversification of resources vis-à-vis asset ownership.

Other retail systems choose to actively manage their power supplies through portfolios that may include owned assets, take-or-pay power supply arrangements and bilateral contracts. An organization's ability and sophistication to manage and effectively hedge the risks related to this strategy, either alone or with third-party experts, is a rating factor.

Financial Metrics — Retail Systems

Financial metrics diverge widely with asset ownership and associated borrowings. Fully integrated systems that generate their own power supply and have financed production facilities on-balance sheet will typically report lower debt service coverage and higher leverage metrics than systems that contract for power supply.

When rating retail public power systems, Fitch factors contractual debt obligations in its analysis, particularly those issued by JAAs and G&Ts on behalf of its member systems and supported by power sales contracts. Fitch reviews all relevant power sales contracts to understand the nature of the related obligations and to assess the terms.

Contract obligations are typically characterized as take-and-pay or take-or-pay. Although a purchaser's payment obligation is not unconditional under a take-and-pay contract, as it is under a take-or-pay contract, Fitch does not generally distinguish between the obligations, as take-and-pay contract provisions typically mitigate performance risk. See the *Power Supply Contracts* section in Appendix A.

In addition to calculating standard financial ratios for retail systems, adjusted ratios that take into account off-balance sheet obligations, including those related to purchased power, are also calculated to facilitate peer comparison between retail systems that own generation versus purchase power. Further adjustments are made to measure coverage of charges Fitch deems as fixed for retail systems, including general fund transfers. These adjusted ratios include coverage of full obligations and are discussed in greater detail on page 8 of this report.

FitchRatings Public Finance

Attributes: Select Financial Metrics — Retail Systems

Debt Service Coverage (x)	Coverage of Full Obligations (x)	Debt/FADS (x)	Days Cash on Hand	Equity/Capitalization (%)
Stronger				
Coverage of consistently more than 2.0x provides solid cash flow and bondholder protection.	Coverage of consistently more than 1.5x provides solid cash flow and bondholder protection.	Less than 6x debt to FADS indicates a favorable level of leverage relative to cash flow.	More than 120 days cash on hand indicates solid financial flexibility to meet unforeseen spending needs.	Strong equity levels of more than 50% indicate adequate cost recovery and ample debt capacity for future capital needs.
Midrange				
Many utilities target coverage in the 1.5x–2.0x range.	Many utilities target coverage in the 1.2x–1.5x range.	Ratios in the 6.0x–8.0x range indicate a generally balanced level of debt relative to cash flow.	Many retail systems target approximately 60–120 days operating cash.	Most retail systems maintain 30%–50% equity levels.
Weaker				
Consistently less than 1.5x coverage provides limited cushion for unexpected revenue shortfalls.	Consistently less than 1.2x coverage provides limited cushion for unexpected revenue shortfalls.	Greater than 8x debt without a suitable rationale can indicate a deficient rate structure.	Less than 60 days cash indicates less financial flexibility, but can be adequate if a system is subject to less cash flow volatility.	Less than 30% equity is relatively low for retail systems and may suggest limited capacity for additional debt.

FADS – Funds available for debt service. Note: The debt and equity ratios above do not reflect off-balance sheet obligations. Fitch reviews adjusted financial ratios including coverage of full obligations to take into account such obligations.

Fitch Rates Tennessee Valley Authority's Global Power Bonds 'AAA'; Outlook Stable

September 21, 2015 11:41 AM Eastern Daylight Time

NEW YORK--(BUSINESS WIRE)--Fitch Ratings has assigned an 'AAA' rating to the following Tennessee Valley Authority's (TVA) bonds:

--Approximately $1 billion global power bonds 2015 series A.

The 2015 series A bonds are expected to price on September 21. Proceeds will be used to refinance outstanding TVA debt and provide funds for ongoing capital investments.

The Rating Outlook is Stable.

SECURITY:

TVA's global power bonds are secured by net revenues of TVA's power system.

KEY RATING DRIVERS:

IMPLICIT GOVERNMENTAL SUPPORT: The 'AAA' rating assigned to TVA's outstanding global power bonds reflects its status as a wholly owned corporation of the U.S. Government and Fitch's expectation that repayment of the power bonds would ultimately receive the support of the U.S. Government in the event of fiscal distress.

COMPETITIVE WHOLESALE ELECTRIC SUPPLIER: TVA has an increasingly diverse resource portfolio, which provides competitively priced wholesale electricity to a population of more than nine million spanning an exceptionally large and diverse region.

RING-FENCED SERVICE TERRITORY: The Federal Energy Regulatory Commission (FERC) is prevented, pursuant to the Federal Power Act's anti-cherry-picking provision, from requiring TVA to provide open-access to its transmission lines for the purpose of serving TVA customers. This provision in essence significantly reduces TVA's risk of customer loss.

TIMELY COST RECOVERY: TVA is required, pursuant to the TVA Act of 1933 (the Act), to set rates sufficient to cover operating and maintenance costs and all other obligations, including debt service and payments to the U.S. Treasury. An automatic fuel cost adjustment made each month ensures the timely recapture of fuel costs.

SUBJECT TO DEBT LIMIT: Given the authority's sizeable capital needs, long-term borrowing capacity remains a credit concern as TVA continues to approach a $30 billion debt ceiling imposed by the Act. However, this concern continues to be partially mitigated by TVA's access to, and past use of, alternate financing that does not count against the limit.

RATING SENSITIVITIES

CHANGE IN U.S. SOVEREIGN RATING: Any change in the credit rating of the U.S. sovereign would likely result in a comparable change in the rating on Tennessee Valley's power revenue bonds.

CREDIT PROFILE:

LARGE REGIONAL WHOLESALE SYSTEM

TVA operates the nation's largest public power system, selling power on a wholesale basis to 155 municipal and cooperative distribution systems spanning an exceptionally large and diverse service area that includes portions of Tennessee, Alabama, Mississippi, Kentucky, Georgia, North Carolina and Virginia. TVA operates as a fully self-supporting enterprise fund supported entirely from the sale of electricity and power system financings.

SATISFACTORY FINANCIAL RESULTS

Energy sales decreased again in fiscal 2014, although the 2.4% decline was less pronounced than the nearly 5% decrease incorporated into TVA's originally adopted budget. The positive variance in sales relative to the budget coupled with a modest rate increase prompted a favorable increase in funds available for debt service (FADS). The stronger cash flow, together with significantly lower annual debt service costs, resulted in Fitch-calculated debt service coverage of 2.62x.

Available cash reserves remain low for the rating category, but the inclusion of multiple lines of credit provides sufficient resources relative to TVA's operating needs. Unrestricted cash and investments at fiscal year-end 2014 together with a $150 million credit facility with the U.S. Treasury and three long-term revolving credit facilities totaling $2.5 billion provide a robust 166 days liquidity on hand.

Year-to-date results through the first nine months of the current fiscal year are positive compared to the same period in the prior year. Operating income is reported as up $454 million, driven primarily by a 2.6% rate increase adopted at the outset of the current fiscal year and continued progress towards an initiative to reduce O&M costs by $500 million.

DEBT LIMITATION CURTAILS FLEXIBILITY

With nearly $24 billion of debt outstanding at the close of fiscal 2014, TVA remains close to its $30 billion debt limitation imposed under the Act. Consequently, various lease financings have been employed as a way to circumvent the current debt limitation while still continuing to finance the authority's ongoing capital program. Lease-purchase transactions are not subject to the Act's debt limitation.

The limitation placed on TVA's borrowing capacity remains a concern given its long-term capital needs exceed the remaining capacity under the debt limitation. Capital costs covering fiscals 2015-2017 are estimated at $7.5 billion, the majority of which could be financed with long-term borrowings.

WATTS BAR UNIT 2 CONSTRUCTION PROGRESSING

Fitch believes the near completion of TVA's Watts Bar Nuclear Plant's Unit 2 reactor remains a positive development. Project completion is slated for the latter part of 2015 with commercial operation expected in June 2016. The final cost remains unchanged, estimated to be within a range of $4 billion-$4.5 billion. Unit 2 appears likely to be granted an operating license in the near term by the Nuclear Regulatory Commission (NRC) following a recommendation by an advisory group to the NRC earlier this year. When online, the Unit will further diversify TVA's resource portfolio and provide 1,150 megawatts of carbon-free generating capacity.

Date of Relevant Committee: 22 April 2015

Additional information is available at 'www.fitchratings.com'.

Applicable Criteria

Revenue-Supported Rating Criteria (pub. 16 Jun 2014)

https://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=750012

U.S. Public Power Rating Criteria (pub. 18 May 2015)

https://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=864007

Additional Disclosures

Solicitation Status

https://www.fitchratings.com/gws/en/disclosure/solicitation?pr_id=991070

Endorsement Policy

https://www.fitchratings.com/jsp/creditdesk/PolicyRegulation.faces?context=2&detail=31

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Fitch Rates Long Island Power Authority Series 2016A/B Electric System Gen Revs 'A-'; Outlook Stable

August 24, 2016 11:22 AM Eastern Daylight Time

NEW YORK--(BUSINESS WIRE)--Fitch Ratings has assigned an 'A-' rating to the Long Island Power Authority's (LIPA) issuance of the following electric system general revenue bonds:

--$175 million, series 2016A (MMD FRN Rate);

--$414 million, series 2016B, fixed rate.

The series 2016A bonds are expected to be privately placed the week of Aug. 29, and proceeds will be used to repay the authority's outstanding series 2012C variable rate bonds. The series 2016B bonds are expected to be sold in September, and proceeds will be used primarily to fund capital improvements and refund certain fixed rate bonds.

Fitch has also affirmed the 'A-' ratings on the following LIPA debt and commercial paper bank notes:

--$4 billion, senior lien electric system revenue and refunding bonds;

--implied electric system revenue subordinate obligations;

--$200 million series 2014 CP-1A (federally taxable) and 1B;

--$100 million series 2014 CP-2A (federally taxable) and 2B.

The Rating Outlook is Stable.

SECURITY

The electric system general revenue bonds are senior lien obligations of LIPA secured by the net revenues of the electric system, after payment of operating and maintenance expenses. LIPA's subordinate lien general revenue obligations are also secured by the net revenues of the electric system, but are subordinate to payments on LIPA's outstanding senior lien electric revenue bonds and floating rate notes.

KEY RATING DRIVERS

SOLID UTILITY FUNDAMENTALS: LIPA is one of the nation's largest municipal electric distribution systems, serving 1.1 million retail customers. The authority benefits from sound utility fundamentals, including a flexible power supply mix, an affluent and well-diversified customer base and cost recovery mechanisms that stabilize cash flow. A series of comprehensive operating agreements with capable external service providers further support operations.

BUSINESS MODEL TRANSITION: The 2013 LIPA Reform Act, enacted in response to operating challenges following Superstorm Sandy, broadened the responsibilities of the utility's system operator (PSEGLI) and expanded the state's (Department of Public Service [DPS]) regulatory oversight of LIPA. Fitch views many of the legislated provisions as supportive of credit quality. However, added regulatory oversight could affect LIPA's financial and rate flexibility over time.

CONSTRUCTIVE REGULATORY RECOMMENDATIONS: The constructive recommendations submitted by the DPS following its initial review of LIPA's three-year rate plan, and adopted by the LIPA board, support LIPA's Stable Outlook. The authority implemented the first phase of a three-year rate increase on Jan. 1, 2016.

RATE PRESSURES PERSIST: Despite electric rates that have become more competitive regionally, political and consumer rate pressures persist as LIPA's average residential revenue per kilowatt hour (kwh) remains among the highest in the nation at approximately 19.4 cents/kwh.

HIGH DEBT LEVELS: LIPA's debt levels remain high, totaling $10.2 billion at Dec. 31, 2015 including capital lease and securitization obligations, or $9,337 per retail customer, well above the peer utility median of $3,318. Although Fitch recognizes the benefits of the separately secured $4.1 billion in securitized debt, the repayment profile remains an obligation and burden of current ratepayers. Positively, LIPA's three-year rate plan aims to reduce debt

financing of future capex to less than 64%, which should moderate future borrowings

SOUND LIQUIDITY: LIPA's liquidity was solid at 103 days of operating cash, and 202 days including available short-term notes and external bank facility at Dec. 31, 2015. Weaker metrics reported in recent years were affected by significant storm costs, but federal reimbursement of roughly 90% of the costs incurred is now complete.

RATING SENSITIVITIES

IMPROVED OPERATING STABILITY: Evidence of improved operating stability and financial performance at the Long Island Power Authority sufficient to offset persistent political and consumer-driven rate pressures could result in consideration of a positive rating action.

CREDIT PROFILE

LIPA owns one of the largest municipal electric distribution systems in the U.S., serving a population of about 3 million people located throughout Nassau and Suffolk counties, and the Rockaways section of New York City. The service area economy continues to exhibit well above average wealth and income levels. Unemployment in Nassau and Suffolk Counties (general obligations debt rated 'A'/Outlook Stable and 'A-'/Outlook Stable, respectively) is below that of the state and nation.

Operations and management services related to the LIPA transmission and distribution system, which had been provided by a subsidiary of National Grid plc, shifted to PSEG-LI, a subsidiary of Public Service Enterprise Group ([PSEG] Issuer Default Rating 'BBB+'/Stable) as of Jan. 1, 2014, for a 12-year term, pursuant to the operating services agreement (OSA). PSEG is paid a management fee and can earn performance incentives.

Effective Jan. 1, 2015, fuel management services shifted to an affiliate of PSEG - PSEG Energy Resources and Trade, LLC. The power supply and fuel management services are also provided pursuant to the OSA, which expires Dec. 31, 2025.

The power supply agreement remains with National Grid, plc, to provide capacity and energy from its oil and gas-fired generating units on Long Island. This agreement is in place through May 2028.

NEW ISSUE DETAILS

The series 2016A proceeds will be used to refinance LIPA's outstanding series 2012C variable rate demand bonds and should not expose LIPA or its bondholders to any meaningful new risks. The series 2016A bonds will initially bear interest at a variable rate based on prevailing AAA Municipal Market Data General Obligation Yield Curve plus an applicable spread and will have a final maturity of May 1, 2033

In addition to the bond issuance, LIPA is also expected to enter into a five year basis swap that will effectively convert the cost of the series 2016A bonds to 69.4% of one-month LIBOR plus an applicable spread. There is an additional requirement at the end of the basis swap agreement for LIPA to pay the counterparty 100% of any decrease in the market value of the series 2016A bond. However LIPA reserves the right to call or remarket the bond after five years, in which case the value of the basis swap would be $0.

The authority will continue to bear the interest rate risk associated with the series 2016A debt, but LIPA's overall variable rate exposure remained reasonable at 3.7% of total debt at year end 2015.

The series 2016 B bonds will bear interest at a fixed rate and have an expected final maturity of May 1, 2046.

For additional information on LIPA's long term ratings see the recent full rating report dated Feb. 18, 2016. The report and press release are available at 'www.fitchratings.com'.

Additional information is available at 'www.fitchratings.com'.

Applicable Criteria

Revenue-Supported Rating Criteria (pub. 16 Jun 2014)

https://www.fitchratings.com/site/re/750012

U.S. Public Power Rating Criteria (pub. 18 May 2015)

https://www.fitchratings.com/site/re/864007

Additional Disclosures

Dodd-Frank Rating Information Disclosure Form

https://www.fitchratings.com/creditdesk/press_releases/content/ridf_frame.cfm?pr_id=1010737

Solicitation Status

https://www.fitchratings.com/gws/en/disclosure/solicitation?pr_id=1010737

Endorsement Policy

https://www.fitchratings.com/jsp/creditdesk/PolicyRegulation.faces?context=2&detail=31

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U.S. PUBLIC FINANCE

MOODY'S INVESTORS SERVICE

CREDIT OPINION
30 March 2017

New Issue

Rate this Research

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Energy Northwest, WA

New Issue: Moody's assigns Aa1 to Energy NW's(WA) CGS, Project 1 and Project 3 bonds. BPA's Aa1 affirmed. Outlook stable

Summary Rating Rationale

Moody's Investors Service has assigned Aa1 ratings to Energy Northwest's (ENW) $242 million of Project 1 Electric Revenue Refunding Bonds, Series 2017-A; $194.4 million of Columbia Generating Station (CGS) Electric Revenue and Refunding Bonds, Series 2017-A; $159.7 million of Project 3 Electric Revenue Refunding Bonds, Series 2017-A; $525 thousand of Project 1 Electric Revenue Refunding Bonds, Series 2017-B (Taxable); $3.3 million of Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2017-B (Taxable); and $905 thousand of Project 3 Electric Revenue Refunding Bonds, Series 2017-B (Taxable). These bonds are supported by net billing agreements with Bonneville Power Administration (BPA, Aa1/stable) and thus are rated the same as BPA's other supported obligations. Moody's also affirmed BPA's Aa1 issuer rating and BPA supported debt obligations. The rating outlook is stable.

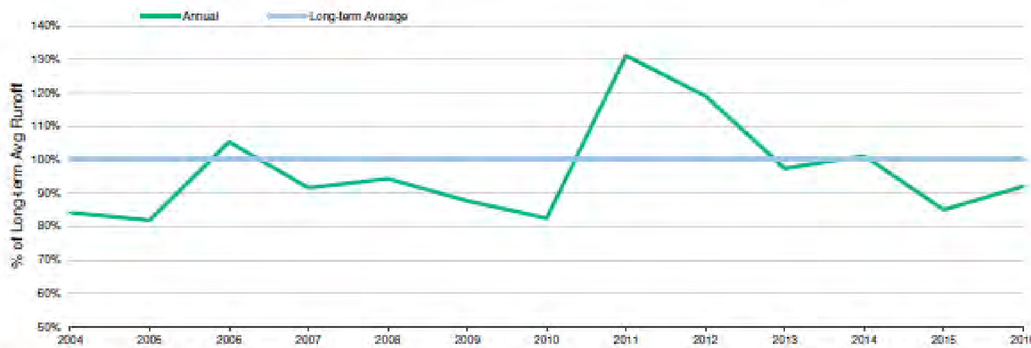
The Aa1 rating on Energy Northwest's (ENW) CGS, Project 1, and Project 3's revenue bonds reflect BPA's contractual obligation to pay including debt service under each project's net billing agreement, BPA's long history of meeting its contractual obligations, and BPA's Aa1 issuer rating.

BPA's Aa1 issuer rating reflects its credit strengths comprising of US Government (Aaa stable) support features, strong underlying hydro and transmission assets, very competitive power costs, and long-term power supply contracts with customers through 2028. Explicit US Government support features include borrowing authority with the US Treasury ($2.9 billion available as of September 30, 2016) and the legal ability to defer its annual US Treasury debt repayment if necessary. BPA's importance to the US Northwest region and its role as a US government agency represent drivers of implicit support. US federal government's strong explicit and implicit support features are key credit strengths that support BPA's Aa1 rating even though BPA faces weaknesses outlined below.

BPA's rating also considers long-term credit challenges such as hydrology and wholesale market price risk, 'regulated utility' like ratemaking process, environmental burdens, and forward-looking consolidated financial metrics that range in the 'Ba' to 'A' category per Moody's U.S. Public Power Electric Utilities with Generation Ownership Exposure methodology. Hydrology and wholesale market prices are the greatest volatility drivers of BPA's financial performance and have been the main driver of BPA's declining internal liquidity over the last ten years. These factors are likely to persist owing to the volatility associated with hydro resources along with the weak wholesale power that exists in the

Pacific Northwest. Additionally, BPA's accelerated repayment of federal appropriations debt and declining availability under the US Treasury line are continuing factors that diminish the US government's explicit support features over time and weakens BPA's positioning within its Aa1 rating. After the FY2018-2019 rate period, the combination of declining US Treasury line availability, declining internal reserves for risk, sustained weak wholesale power market and a reduction in the degree of federal debt subordination could lead to negative rating action.

Exhibit 1
Columbia River Runoff at Dalles



Source: Moody's Investors Service, BPA

Credit Strengths

- U.S. government support through US Treasury borrowing line and federal debt service deferral ability
- Regional importance as indirect power provider for 14 million people
- Access to 22 GW of low cost, federally owned hydro system
- Dominant electric transmission provider in the Pacific Northwest
- Highly competitive rates
- Long-term power sales contracts with creditworthy public power entities

Credit Challenges

- 'Regulated utility' like ratemaking process
- Significant exposure to hydrology risk and wholesale power markets
- 'Ba' to 'A' category forecasted financial metrics
- Federal debt subordination weakening
- Declining reserves for risk and availability under US Treasury Line
- Significant fish and wildlife environmental costs

Rating Outlook

The stable outlook on the CGS, Project 1, and Project 3 revenue bonds reflects BPA's stable outlook. BPA's stable outlook considers BPA's FY 2018-19 proposed rates and BPA's plan to maintain sufficient availability under the US Treasury line through FY2019.

Factors that Could Lead to an Upgrade

» Ratings on the CGS, Project 1 and Project 3 revenue bonds could be upgraded if BPA is upgraded.

» BPA's rating could improve over the long term if BPA is able to substantially mitigate hydrology and wholesale price risk and if BPA implements policies to ensure strong internal reserves for risk resulting in at least 250 days cash on hand on a sustainable basis.

Factors that Could Lead to a Downgrade

» Ratings on the CGS, Project 1 and Project 3 revenue bonds could be downgraded if BPA is downgraded or if the underlying net billing agreement is violated or weakened.

» BPA's ratings could be lowered if the US government's credit rating is downgraded, if we expect internal liquidity to fall below 60 days or availability under the US Treasury line declines below $1.5 billion on a sustained basis, or BPA experiences regulatory delays in receiving full recovery of costs. Other factors that could lead to a downgrade include any sign of waning federal government support or decline in the proportion of subordinated, deferrable debt owed to the US Treasury beyond actions currently planned.

Key Indicators

Exhibit 2

	2012	2013	2014	2015	2016
Total Sales (MWh)	94,774,440	87,547,440	89,325,720	81,599,400	84,463,920
Debt Outstanding ($' 000)	14,534,245	15,013,366	15,571,590	16,089,851	15,641,400
Debt ratio (%)	96.6%	95.7%	95.7%	94.5%	90.5%
Total Days Cash on Hand (days)	132	117	136	152	103
Total Debt Service Coverage Ratio (x) (Post Transfer/PILOTs - All Debt)	1.11	1.05	1.19	1.17	0.57
Non Federal Debt Service Coverage Ratio (x) (Post Transfers/PILOTs - Non-federal Debt)	2.07	1.70	3.46	4.34	3.77

Source: Moody's Investors Service, BPA

Recent Developments

In November 2016, BPA proposed rates for FY2018-2019, which would increase power rates by an average of 3.5% and transmission rates by 1.1% for the two year period. The BPA administrator will finalize the rates in July 2017 and final rates will go into effect on October 1st, 2017 subject to FERC approval.

As part of FY2018-2019 rates, BPA has proposed a reserves policy which targets 90 days cash on hand (based on reserves for risk) for each line of business with a minimum of 60 days cash on hand. If liquidity is below the minimum at the start of the year, a surcharge would trigger subject to a 3% cap. Liquidity above 120 days cash on hand would be credited back to customers, used to reduce debt or fund capex. Implementation of a reserve policy would be credit positive since BPA's reserves for risk have served as BPA's frontline cushion against underperformance and has dropped steeply since 2008. That said, we see the proposed policy as primarily seeking to maintain current reserve levels since BPA had around 100 days cash on hand at FY2016.

For FY 2016, BPA faced another year of below average hydrology conditions at around 92% of average. This was exacerbated by the need to refill reservoirs at the Canadian hydro dams in FY 2016. BPA previously drew down on available reservoir storage in FY2015 to offset low hydrology conditions. BPA's 'reserves for risk' serves as the primary buffer against any underperformance and it dropped to $602 million in FY 2016 ($845 million in FY 2015). For FY 2017, BPA reported in its Q1 quarterly business review that reserves for risk are forecasted to further drop to $395 million primarily due to lower power and transmission sales and higher than expected operating costs. BPA's rapid decline in its reserves for risk is a credit negative and an inability to ensure internal reserves at or near current levels could lead to a negative rating action.

Detailed Rating Considerations

Revenue Generating Base

Major Power and Transmission Provider to the Pacific Northwest

BPA derives its revenues from the sale of power and transmission services from its dominant hydroelectric generation and electric transmission assets in the Pacific Northwest. BPA has roughly 75% of the Pacific Northwest's bulk electric transmission consisting of 15,000 miles of high voltage transmission lines and 260 substations and other facilities located in BPA's service area. Additionally, BPA's power supply represents roughly one third of the total regional power supply and consists of 22 GW of mostly federally owned hydro plants, the 1.1 GW CGS nuclear plant, and market and contract purchases. The federal hydro projects also serve numerous purposes, including irrigation, navigation, recreation, municipal and industrial water supply, and fish and wildlife protection.

Power sales represent the largest portion at typically 75% of total revenue and the majority of these sales are made under long-term power sales contracts (Preference Contracts) maturing in 2028 with 133 municipally owned utilities, cooperatively owned utilities, and federal agencies. Sales to these customers totaled approximately $2 billion in FY 2016 and represent BPA's largest revenue segment at nearly 60% of total revenues. Snohomish County P.U.D. 1, WA Electric Ent. (Aa3/stable) is BPA's largest preference customer at 10% of power sales in FY 2016. Power rates charged by BPA are highly competitive and BPA's average tier 1 rate for FY 2016 was $35.63/MWh.

Electric transmission sales are BPA's second largest revenue source at $947 million in revenues in FY 2016. BPA's top transmission customer is Puget Sound Energy Inc (Baa1 stable) at 12% each of transmission revenue in FY 2016.

Exhibit 3

Power Customer Name	Type	Rating	% of Power Sales	Transmission Customer Name	Rating	% of Transmission Sales
Snohomish County P.U.D. 1, WA Electric Ent.	Preference	Aa3	10%	Puget Sound Energy, Inc.	Baa1	12%
Cowlitz County Public Utility District 1, WA	Preference	A1	7%	PacifiCorp	A3	11%
Seattle (City of) WA Electric Enterprise	Preference	Aa2	7%	Portland General Electric Company	A3	9%
Pacific Northwest Generating Coop	Preference	NR	6%	Powerex Corp.*	NR	7%
Tacoma Power, WA	Preference	Aa3	5%	Seattle (City of) WA Electric Enterprise	Aa2	5%
Clark County Public Utility District 1, WA	Preference	A1	4%	Iberdrola Renewables Inc.	Baa1	5%
Eugene Water & Electric Board, OR	Preference	Aa2	3%	Snohomish County P.U.D. 1, WA Electric Ent.	Aa3	4%
Benton County Public Utility District 1, WA	Preference	Aa3	2%	Pacific Northwest Generating Coop	NR	2%
Flathead Electric Cooperative, Inc.	Preference	NR	2%	Hermiston Power LLC	NR	2%
Central Lincoln Peoples Utility District, OR	Preference	NR	2%	Clark County Public Utility District 1, WA	A1	2%
Total			48%	Total		59%

*Subsidiary of British Columbia Hydro & Power Authority (Aaa)
Source: Moody's Investors Service, BPA

'Regulated Utility' Like Rate Making Process Could Delay Timely Recovery

Unlike a traditional public power utility, BPA's ratemaking procedure for power and transmission rates charged to its customers involves an extensive process that shares similarities with a rate regulated utility that often create complications and delays in timely and full recovery of BPA's costs. The Northwest Power Act contains specific ratemaking procedures for BPA, mandates justification and reasons in support of such rates, and requires a hearing. The BPA Administrator ultimately decides the power and transmission rates based on the hearing record including all information submitted. Rates established by BPA are subject to approval by FERC. Currently, BPA has rate cases every two years. In a stress situation, BPA could file an expedited rate with FERC and the whole process could take several months for an interim rate approval. We see BPA's rate setting process as materially weaker than peers such as Tennessee Valley Authority (Aaa stable) that have unfettered, self-regulated rate setting.

Notwithstanding the 'regulated utility' like ratemaking process that BPA operates under, we recognize that BPA has raised rates in difficult situations such as the power crisis of 2000-2001 when BPA raised rates by 46%. Additionally, within a rate period, BPA is able to charge up to an additional $300 million per year starting at the beginning of the fiscal year under the Cost Recovery Adjustment Clause (CRAC) if Power Service's accumulated net revenue is below a set level that is equivalent to reserves for risk at zero balance. A separate NFB Adjustment for certain environmental costs can raise the $300 million CRAC limit. While the CRAC mechanism adds some flexibility to BPA's two-year rate periods, the annual basis of the test and low trigger point limit the benefit of the CRAC mechanism.

A credit supportive rate setting tool is BPA's use of its treasury payment probability tool whereby BPA proposes rates at levels that it can meet its US Treasury payments at a 95% confidence level based on its cash flows and reserves. BPA's approach should ensure a high probability of near-term payments to the US Treasury and an extremely high probability of near-term timely payments on non-federal debt service, which is effectively senior to the debt owed to the US Treasury.

Regional Hydrology and Wholesale Price Risk Are BPA's Biggest Volatility Drivers

BPA's financial results can be materially impacted by hydrology in the Columbia River Basin and wholesale power prices since market based power sales can represent roughly 10-15% of total revenues. Since 2001, hydrology has been very volatile with high and low around 130% and 60%, respectively, of the long-term average. Similarly, power prices have also been volatile with a recent peak nearing $60/MWh in 2008 and a low below $20/MWh in 2012. These factors, which are outside of BPA's control, have contributed heavily to periods of underperformance and represent BPA's biggest driver of cash flow volatility since power sales under long-term contracts and transmission sales are much more stable and predictable. Moreover, wholesale power revenues have, in the past, provided a source of cash flow for funding capital expenditures at BPA. In light of the sustained weak power markets, BPA has been more reliant on the borrowing authority with the US Treasury (currently at $2.9 billion). The volatility of wholesale revenues emphasizes the importance of maintaining significant internal liquidity especially at BPA's rating level.

Operational and Financial Performance

Environmental Costs Are Material

BPA faces conflicting uses of the Columbia River and environmental regulations, such as the Endangered Species Act (ESA), that contributes significantly to BPA's costs and weighs heavily on BPA's cash flows. Biological opinions prepared by National Oceanic and Atmospheric Administration Fisheries Service and the US Fish and Wildlife Service mandate actions to protect fish species resulting in direct costs such as hatcheries and indirect loss of revenue from hydro dam operational changes. For FY2016, BPA estimates total fish and wildlife costs at approximately $622 million consisting of $495 million in direct costs and $127 million of indirect costs. BPA was able to recover the non-power related environmental costs totaling $77 million from the US Treasury in FY 2016. While BPA's fish and wildlife mitigation costs are considerable, BPA's federally and non-federally owned generation are emissions free since they consist of hydro and nuclear generation. As such, BPA remains insulated against new federal regulations including those for greenhouse gases and BPA could benefit if new emissions regulations increase the market price of power.

Financial Metrics Are Low for the Rating

On a fully consolidated basis including federal debt, BPA's financial metrics are commensurate with Ba to A category scoring on a historic basis. Total DSCR has averaged around 1.0x over the last three years, which is commensurate with a 'Ba' scoring, while BPA's debt ratio is high at an average of 95% which is commensurate with a 'Ba' scoring. Looking forward, BPA's sets rates to achieve around 1.0x DSCR; however, actual performance can deviate especially if hydrology and market prices are different than expectations. Separately, non-federal DSCR have risen to almost 3.8x since principal payments for CGS, Project 1, and Project 3 have been pushed out to the future resulting in an interest only coverage ratio for non-federal DSCR.

LIQUIDITY

For FY 2016, BPA had reserves for risk, a measure of internal liquidity, totaling $602 million (103 days cash on hand) , which is commensurate with the low end of the 'A' scoring. Below average hydrology, the need to replenish reservoirs, and lower than expected power prices were major drivers of the liquidity drop versus the $845 million (152 days cash on hand) at year-end FY 2015. For FY 2017, BPA expects its reserves for risk to decline to $395 million mainly due to lower power and transmission sales and higher operating costs.

As part of its current rate case, BPA proposed a reserve policy that targets 90 day cash on hand with a surcharge if reserves for risk drop below 60 days cash on hand. Implementation of a reserve policy would be credit positive since BPA's reserves for risk have served as BPA's frontline cushion when underperformance occurs and has dropped steeply since 2008. That said, we see the proposed policy as primarily seeking to maintain current reserve levels since BPA had little over 100 days cash on hand at FY2016.

Supplementing BPA's internal liquidity is a $750 million borrowing sublimit under the US Treasury line that can be used to fund operating expenses. This line of credit is renewed on an ongoing basis and any draw needs to be repaid within one year.

Debt and Other Liabilities

DEBT STRUCTURE

BPA's $15.6 billion in total debt consists of $8.5 billion of non-federal debt and $7.2 billion of federal debt, which is debt owed by BPA to the federal government. BPA's non-federal debt are debt like contractual obligations such as BPA's obligation to CGS, Project 1, and Project 3 under the net billing agreements. In addition to the net billing agreements, BPA has non-federal debt through leases, power prepay, and other take-or-pay contractual obligations. Since these obligations are treated as an operating expense of BPA, they have priority over BPA's direct debt obligation to the US Treasury and BPA can defer payments to US Treasury, if necessary. This deferral ability provides BPA a major source of financial flexibility under extreme situations though BPA has not deferred such payments since 1983 and any deferral is likely to have significant negative political ramifications. The significantly higher non-federal DSCR previously described above also highlights the substantial benefits of the federal debt's effective subordination to non-federal debt and these benefits are supportive of the Aa1 rating on CGS, Project 1, and Project 3.

We see BPA's Regional Cooperation Debt (RCD) program as undermining the benefits of the federal debt's subordination, since the program results in a substantial extension of non-federal debt in exchange for the accelerated repayment of federal appropriations debt. While we recognizes the cost savings benefits for this strategy, Energy Northwest's debt funding of interest and O&M expenses to accelerate repayment of federal appropriations debt further undermines the subordination and is credit negative.

DEBT-RELATED DERIVATIVES

BPA indirectly has interest rate derivative like exposure of around $1 billion mostly tied to its lease financed transmission assets. We understand there are no collateral posting requirements under any conditions for these derivatives.

PENSIONS AND OPEB

BPA employees are part of the US government's post-retirement benefit programs for all federal civil employees. The post-retirement benefits are overseen by the United States Office of Personnel Management (OPM), an independent agency that manages the civil service of the federal government. As such, BPA does not record any accumulated plan assets or liabilities related to the administration of a retirement plan.

Management and Governance

US Government Support is a Major Strength

While BPA's obligations do not benefit from the full faith and credit of the United States Government, BPA benefits from significant explicit and implicit support elements from the US Government. The key support elements consist of BPA's borrowing line ($2.9 billion available) with the US Treasury and ability to defer payments to the US Treasury. That said, BPA forecasts the US Treasury line availability shrinking over time which we see as weakening a key support element and could become a driver of future negative rating action.

A strong qualitative consideration for implicit support include BPA's role as a line agency of the US Department of Energy. As a line agency of the US DOE, the BPA Administrator reports to the US Secretary of Energy and BPA has numerous linkages with other federal agencies. For example, the US Army Corp of Engineers and the US Bureau of Reclamation own and operate the federal dams while BPA markets the power output and pays for all of the associated operating and capital costs.

Importance to the US Northwest region is another key qualitative factor. BPA is responsible for certain treaty responsibilities with Canada regarding the federally owned dams, significant regional environmental protection programs, and coordination of river operations. Northwest US representation on key US House and Senate committees that deal with energy legislation is a credit strength.

Overall, we see these explicit and implicit US support as providing a multi-notch lift to BPA's standalone credit quality and represent key considerations for BPA's Aa1 rating. In a major stress scenario, Moody's expects any US Government support to BPA is likely to be provided through the established US Treasury credit line or deferral of payments to the US Treasury.

Legal Security

CGS, Project 1, and Project 3's bonds are secured by a pledge of specific project revenues primarily sourced under substantially similar tri-party net billing agreements with BPA and project participants for each project. The Project 3's pledge is subordinate to $29.2 million of prior lien bonds. The revenues for each project are not cross collateralized. There are no debt service reserves.

The net billing agreements obligate the project participants, consisting of numerous municipal and cooperative electric utilities, to pay ENW their proportionate share of the project's annual costs, including debt service, irrespective of whether the project is operable or terminated. BPA, in turn, is obligated to pay (or credit) the participants identical amounts by reducing the amounts the participants owe for power and service purchased from BPA under their power-sales agreements. BPA has also agreed, in the event of any insufficient payment by a participant, to pay the amount due in cash directly to the project. In 2007, Energy Northwest and BPA adopted a new direct pay agreement whereby Energy Northwest participants directly pay all costs to BPA rather than through Energy Northwest. BPA has made a clear and tested commitment to support the payment under the net billing through more than more than 30 years of stressful circumstances including legal challenges in the early 1980s.

Use of Proceeds

Approximately $97 million of CGS's bond proceeds will be used to fund capital spending. Remaining funds for CGS, Project 1, and Project 3 will be used primarily to extend bond maturities per its Regional Cooperation Debt program. As part of the Regional Cooperation Debt program, BPA expects to accelerate repayment of defacto subordinated federal appropriations debt in conjunction with the CGS, Project 1, and Project 3 debt maturity extensions.

Obligor Profile

BPA was created in 1937 by an act of the US Congress and is one of four regional power marketing agencies within the US Department of Energy. BPA is primarily responsible for federally owned generation and electric transmission assets in the Pacific Northwest spanning all or parts of eight states. The Army Corps of Engineers and the Bureau of Reclamation own and operate the hydro projects. Many of the statutory authorities of BPA are vested with the Secretary of Energy, who appoints and acts through the BPA administrator. BPA's obligations are not backed by the full faith and credit of the US government and its cash payments are limited to funds available in the Bonneville Fund.

Other Considerations: Mapping to The Grid

Moody's evaluates BPA's issuer rating under the US Public Power Electric Utilities with Generation Ownership Exposure methodology, and the grid indicated rating is Aa2, which is lower than its Aa1 assigned rating. BPA's close linkages with the federal government as a federal agency are the supportive considerations for the Aa1 assigned rating as compared to the Aa2 indicated rating under the US Public Power with Generation Ownership methodology.

Moody's also evaluates CGS, Project 1, and Project 3 ratings under the US Municipal Joint Action Agencies methodology, and the grid indicated rating is Aa1 for CGS and Baa1 for Project 1 and Project 3. The Aa1 rating assigned to all three projects reflects BPA's contractual obligation to pay including debt service under each project's net billing agreement, BPA's long history of meeting its contractual obligations, and BPA's Aa1 issuer rating.

The grid is a reference tool that can be used to approximate credit profiles in the US public power industry in most cases. However, the grid is a summary that does not include every rating consideration. Please see U.S. Public Power Electric Utilities with Generation Ownership Exposure and US Municipal Joint Action Agencies for more information about the limitations inherent to grids.

Exhibit 4
BPA Methodology Scorecard

Factor	Subfactor	Score	Metric
1. Cost Recovery Framework Within Service Territory		Aa	
2. Willingness and Ability to Recover Costs with Sound Financial Metrics		A	
3. Generation and Power Procurement Risk Exposure		Aa	
4. Competitiveness	Rate Competitiveness	Aa	
5. Financial Strength and Liquidity	a) Adjusted days liquidity on hand (3-year avg) (days)	A	130
	b) Debt ratio (3-year avg) (%)	Ba	94%
	c) Adjusted Debt Service Coverage or Fixed Obligation Charge Coverage (3-year avg) (x)	Ba	1.0x
Preliminary Grid Indicated rating from Grid factors 1-5		**A2**	
		Notch	
6. Operational Considerations		1.0	
7. Debt Structure and Reserves		1.5	
8. Revenue Stability and Diversity		0.0	
Grid Indicated Rating:		**Aa2**	

Source: Moody's Investors Service

Exhibit 5

ENW CGS Methodology Scorecard

Factor	Subfactor Description	Score	Metric
1. Participant Credit Quality and Cost Recovery Framework	a) Participant credit quality. Cost recovery structure and governance	Aa1	
2. Asset Quality	a) Asset diversity, complexity and history	Baa	
3. Competitiveness	a) Cost competitiveness relative to market	Baa	
4. Financial Strength and Liquidity	a) Adjusted days liquidity on hand (3-year avg) (days)	Baa	49
	b) Debt ratio (3-year avg) (%)	Baa	130%
	c) Fixed obligation charge coverage ratio (3-year avg) (x)	Baa	1.06x
Material Asset Event Risk	Does agency have event risk?	No	
Notching Factors		**Notch**	
	1 - Contractual Structure and Legal Environment	0	
	2- Participant Diversity and Concentration	0	
	3 - Construction Risk	0	
	4 - Debt Service Reserve, Debt Structure and Financial Engineering	0	
	5 - Unmitigated Exposure to Wholesale Power Markets	0	
Scorecard Indicated Rating:		**Aa1**	

Source: Moody's Investors Service

Exhibit 6

ENW Project's 1 and 3 Methodology Scorecard

Factor	Subfactor Description	Score	Metric
1. Participant Credit Quality and Cost Recovery Framework	a) Participant credit quality, Cost recovery structure and governance	Aa1	
2. Asset Quality	a) Asset diversity, complexity and history	B	
3. Competitiveness	a) Cost competitiveness relative to market	B	
4. Financial Strength and Liquidity	a) Adjusted days liquidity on hand (3-year avg) (days)	Baa	
	b) Debt ratio (3-year avg) (%)	B	
	c) Fixed obligation charge coverage ratio (3-year avg) (x)	B	
Material Asset Event Risk	Does agency have event risk?	No	
Notching Factors		**Notch**	
	1 - Contractual Structure and Legal Environment	0	
	2- Participant Diversity and Concentration	0	
	3 - Construction Risk	0	
	4 - Debt Service Reserve, Debt Structure and Financial Engineering	0	
	5 - Unmitigated Exposure to Wholesale Power Markets	0	
Scorecard Indicated Rating:		**Baa1**	

Source: Moody's Investors Service

Methodology

The principal methodology used in this rating was US Public Power Electric Utilities With Generation Ownership Exposure published in March 2016. An additional methodology used in this rating was US Municipal Joint Action Agencies published in October 2016. Please see the Rating Methodologies page on www.moodys.com for a copy of these methodologies.

Ratings

Exhibit 10

Energy Northwest, WA

Issue	Rating
Project 3 Electric Revenue Refunding Bonds, Series 2017-A	Aa1
Rating Type	Underlying LT
Sale Amount	$159,705,000
Expected Sale Date	04/12/2017
Rating Description	Revenue: Government Enterprise
Project 3 Electric Revenue Refunding Bonds, Series 2017-B (Taxable)	Aa1
Rating Type	Underlying LT
Sale Amount	$905,000
Expected Sale Date	04/12/2017
Rating Description	Revenue: Government Enterprise
Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2017-A	Aa1
Rating Type	Underlying LT
Sale Amount	$194,360,000
Expected Sale Date	04/12/2017
Rating Description	Revenue: Government Enterprise
Columbia Generating Station Electric Revenue and Refunding Bonds, Series 2017-B (Taxable)	Aa1
Rating Type	Underlying LT
Sale Amount	$3,285,000
Expected Sale Date	04/12/2017
Rating Description	Revenue: Government Enterprise
Project 1 Electric Revenue Refunding Bonds, Series 2017-A	Aa1
Rating Type	Underlying LT
Sale Amount	$241,990,000
Expected Sale Date	04/12/2017
Rating Description	Revenue: Government Enterprise
Project 1 Electric Revenue Refunding Bonds, Series 2017-B (Taxable)	Aa1
Rating Type	Underlying LT
Sale Amount	$525,000
Expected Sale Date	04/12/2017
Rating Description	Revenue: Government Enterprise

Source: Moody's Investors Service

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Rating Action: Moody's assigns Aaa rating to TVA's $1 billion bond offering; stable outlook

Global Credit Research - 21 Sep 2015

New York, September 21, 2015 -- Moody's Investors Service today assigned an Aaa rating to Tennessee Valley Authority's (TVA) $1 billion Global Power Bonds 2015 Series A Due 2065. TVA's outlook is stable.

Proceeds from the bond offering will be used to pay down short-term debt and for general corporate purposes. TVA had approximately $2.6 billion in short-term debt outstanding as of June 30, 2015.

RATINGS RATIONALE

"TVA's Aaa senior unsecured rating considers several attributes unique to TVA, including federal ownership, legislation that provides protection from competition and the statutory authority of TVA's Board to set rates", said Scott Solomon, Moody's Senior Credit Officer. "These attributes, combined with TVA's size, scale, and economic importance within the Tennessee Valley, translate into a more predictable and stable financial profile relative to all other public power and investor owned utilities" added Solomon.

Challenges confronting TVA include a decline in electric demand and a significant capital spending program driven by the replacement of coal-fired generating capacity in an effort to increase the company's power supply from reduced emitting resources.

To that end, TVA's Board approved the retirement of coal units at three plant sites with more than 3,000 megawatts of combined generating capacity. In addition, TVA is constructing two new combined-cycle gas plants: the 1,000 megawatt Paradise plant, which is expected to achieve commercial operation in 2017 and the 1,046 megawatt Allen Plant (2018), at an estimated cost of $2.0 billion.

Combined with the anticipated commercial operation of Watts Bar Unit 2, a nuclear plant, in late 2015, TVA anticipates reducing the reliance on coal-fired generation from approximately 32% of total generation currently to approximately 22% by 2020 while increasing generation from gas-fired and nuclear generating assets to approximately 23% and 41% , respectively, from 19% and 35%, currently.

TVA's near-term projected capital expenditures is expected to exceed historical levels, which has averaged approximately $2.2 billion annually over the past three periods. Specifically, expenditures are anticipated at approximately $3.4 billion in fiscal year 2015 and $2.4 billion in each of 2016 and 2017, and require a modest amount of external funding.

TVA's Aaa credit rating could be downgraded if there are any limitations placed on the independence of TVA including its ability or willingness to set rates at sufficient levels to cover operating expenses and debt service requirements, or if there are any changes in law that negatively affect TVA's protected position in its service territory including permitting outside access through TVA's transmission lines. Also, the credit rating could be downgraded if TVA debt approaches its $30 billion debt ceiling. Moreover, pressure on the U.S. government's credit rating or a reduction or reconfiguration of federal ties could also place pressure on TVA's rating.

For additional information on TVA, refer to the Credit Opinion dated August 11, 2015 which can be found on moodys.com.

The principal methodology used in this rating was U.S. Public Power Electric Utilities with Generation Ownership Exposure published in November 2011. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

TVA is a wholly owned corporate agency and instrumentality of the United States, originally established by Congress in 1933 to develop the Tennessee Valley region. TVA is the largest public power system in the country, selling wholesale power to distributor customers including municipalities, cooperatives, and industrial customers in an 80,000 square mile region that covers most of the state of Tennessee, as well as parts of six other states.

REGULATORY DISCLOSURES

For ratings issued on a program, series or category/class of debt, this announcement provides certain regulatory disclosures in relation to each rating of a subsequently issued bond or note of the same series or category/class of debt or pursuant to a program for which the ratings are derived exclusively from existing ratings in accordance with Moody's rating practices. For ratings issued on a support provider, this announcement provides certain regulatory disclosures in relation to the rating action on the support provider and in relation to each particular rating action for securities that derive their credit ratings from the support provider's credit rating. For provisional ratings, this announcement provides certain regulatory disclosures in relation to the provisional rating assigned, and in relation to a definitive rating that may be assigned subsequent to the final issuance of the debt, in each case where the transaction structure and terms have not changed prior to the assignment of the definitive rating in a manner that would have affected the rating. For further information please see the ratings tab on the issuer/entity page for the respective issuer on www.moodys.com.

For any affected securities or rated entities receiving direct credit support from the primary entity(ies) of this rating action, and whose ratings may change as a result of this rating action, the associated regulatory disclosures will be those of the guarantor entity. Exceptions to this approach exist for the following disclosures, if applicable to jurisdiction: Ancillary Services, Disclosure to rated entity, Disclosure from rated entity.

Regulatory disclosures contained in this press release apply to the credit rating and, if applicable, the related rating outlook or rating review.

Please see www.moodys.com for any updates on changes to the lead rating analyst and to the Moody's legal entity that has issued the rating.

Please see the ratings tab on the issuer/entity page on www.moodys.com for additional regulatory disclosures for each credit rating.

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S&P Global
Ratings

RatingsDirect®

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Table Of Contents

Energy Northwest, Washington Bonneville Power Administration, Oregon; Wholesale Electric

Credit Profile		
US$236.775 mil proj 1 elec rev rfdg bnds ser 2017-A due 07/01/2028		
Long Term Rating	AA-/Stable	New
US$191.200 mil Columbia generating station elec rev and rfdg bnds ser 2017-A due 07/01/2034		
Long Term Rating	AA-/Stable	New
US$156.975 mil proj 3 elec rev rfdg bnds (Bonneville Pwr Admin) ser 2017-A due 07/01/2028		
Long Term Rating	AA-/Stable	New
US$3.790 mil Columbia generating station elec rev and rfdg bnds (Taxable) ser 2017-B due 07/01/2034		
Long Term Rating	AA-/Stable	New
US$1.660 mil proj 1 elec rev rfdg bnds (Bonneville Pwr Admin) (Taxable) ser 2017-B due 07/01/2028		
Long Term Rating	AA-/Stable	New
US$1.645 mil proj 3 elec rev rfdg bnds (Bonneville Pwr Admin) (Taxable) ser 2017-B due 07/01/2028		
Long Term Rating	AA-/Stable	New

Rationale

S&P Global Ratings has assigned its 'AA-' rating to six series of $592 million of proposed Energy Northwest (ENW), Wash., bonds. Bonneville Power Administration (BPA), Ore., will pay the bonds' debt service as operating expenses of its electric system.

The bonds include the following series:

- Project 1 electric revenue refunding bonds, series 2017-A;
- Columbia Generating Station (CGS) electric revenue and refunding bonds, series 2017-A;
- Project 3 electric revenue refunding bonds, series 2017-A;
- Project 1 electric revenue refunding bonds, series 2017-B (taxable);
- CGS electric revenue and refunding bonds, series 2017-B taxable) ; and
- Project 3 electric revenue refunding bonds, series 2017-B (taxable).

At the same time, S&P Global Ratings affirmed its 'AA-' ratings on existing parity and prior-lien ENW debt and additional nonfederal obligations that BPA pays as an operating expense of its electric system. The outlook is stable. S&P Global Ratings also affirmed its 'aa-' stand-alone credit profile on BPA.

Although the series project 3 bonds are subordinate ENW obligations, the utility covenanted to close its prior liens. The $29 million of project 3 prior-lien debt represents less than 1% of the $8 billion of nonfederal debt that BPA supports. In light of the modest amount of project 3 bonds, we do not view the subordinate-lien position as an additional exposure. ENW has retired its prior-lien CGS and project 1 debt.

CGS is ENW's only completed and operating nuclear unit. The incomplete nuclear units 1 and 3 have $1.9 billion of debt and the operating CGS nuclear unit has $3.4 billion.

ENW and BPA will use the bonds' proceeds to refund portions of ENW's existing debt and finance a portion of CGS's capital improvement needs. Bonneville has been using ENW refunding transactions to capture debt service savings and to defer portions of its ENW debt to free up funds to retire portions of higher interest federal appropriation debt more quickly and preserve Treasury borrowing capacity, which is subject to a cap.

At fiscal year-end 2016 (Sept. 30), Bonneville had $15.6 billion of debt obligations, consisting of $2.9 billion of federal appropriations, $4.8 billion of bonds issued to the U.S. Treasury, and $8.0 billion of nonfederal debt that the utility supports. BPA's financial statements include $2.1 billion of lease obligations and $285 million of customer power prepayments in its nonfederal debt. It pays nonfederal debt from net revenues before it services federal Treasury debt and appropriations.

Accelerating portions of high interest rate federal appropriations debt by using the cash flow that re-amortizing ENW debt through refunding transactions frees up should reduce interest expense. As federal debt is retired, funds that would have been applied to its principal will then be available to further accelerate portions of BPA's Treasury debt, which is critical to funding Bonneville's capital program. The utility operates under a congressionally imposed $7.7 billion ceiling on its Treasury borrowings. Although as of fiscal year-end 2016, $4.8 billion of Treasury bonds were outstanding, the utility's reports that capital spending needs could exhaust the remaining Treasury borrowing capacity by as soon as 2019. Debt extensions have reduced federal appropriations debt to $2.9 billion in 2016 from $4.3 billion in 2013 and Treasury debt rose modestly to $4.8 billion in 2016 up from $3.9 billion in 2013.

BPA expects that managing Treasury debt balances with the savings from ENW debt deferrals will alleviate its borrowing constraints and add years to its Treasury borrowing capacity. Bonneville labels its use of ENW debt extensions to reduce appropriations and Treasury debt, "Regional Cooperation Debt Refinancings." To further these plans, it expects more than $2 billion of additional transactions to extend debt beyond the approximately $1.2 billion of debt extensions since 2014.

The 'AA-' ratings on ENW's debt and the other nonfederal debt that BPA supports reflect Bonneville's contractual obligations to support the debt and the application of our government-related entities (GRE) criteria. We assess Bonneville's stand-alone credit profile to be 'aa-' and believe there is a moderately high likelihood that the U.S. government would provide extraordinary support to it in financial distress. We base the latter on our opinion of the strong link between the BPA and the federal government, as well as the important federal role the agency plays in the Pacific Northwest. However, after downgrading the U.S. to 'AA+' from 'AAA' in August 2011, we no longer view the U.S. government's sovereign credit profile as lifting the ratings of the nonfederal obligations that BPA supports above the utility's stand-alone credit profile.

The GRE rating reflects our view of:

- Bonneville's status as a federal agency;
- The ongoing financial support the federal government provides to the agency through long-term loans and credit lines;

- Legislation that allows BPA to defer repayments of federal obligations if in financial distress; and
- The utility's important contributions to the Pacific Northwest's economy, where it indirectly serves a population of about 12 million in eight states, provides low-cost power that is critical to the region's economic health, and operates key transmission resources.

Bonneville's stand-alone credit profile reflects our assessment of the following factors:

- The federal government provides ongoing support to BPA through loans and credit lines.
- Congress increased the agency's federal borrowing authority in 2009 to $7.70 billion, up $3.25 billion (or 73%). However, Bonneville projects that, by 2019, it could consume the headroom between its $4.8 billion of U.S. Treasury borrowings and $7.7 billion as it proceeds with capital spending.
- Nonfederal bondholders benefit from the legislative mechanism that allows BPA to pay nonfederal debt as an operating expense ahead of federal debt service and to defer repaying federal obligations if it lacks the financial resources to meet all of its operating and debt obligations.
- The utility's financial performance includes a track record of at least 1.8x nonfederal accrual debt service coverage (DSC) in fiscal years 2010-2016, tempered by accrual coverage of federal and nonfederal obligations of 1.0x in 2011 and 2013, 0.9x in 2012, and 0.7x in 2016. Coverage was 1.2x in 2014 and 1.3x in 2015. The years with low coverage reflect the influence of biennial rate cases without intraperiod adjustments and the utility's operational exposure to variable hydrology conditions that affect volumes of surplus power available for sale in competitive markets, prevailing market power prices when BPA makes surplus sales, and variations in renewable energy resources' output that affect market prices. In addition, the accelerated payment of appropriations debt heavily influenced 2016's DSC. Bonneville paid $1.04 billion of appropriations debt in 2016, compared with an average of less than $200 million in the prior five years.
- BPA exhibits robust liquidity, which tempers the sometimes substantial impacts of variable hydrology conditions on financial performance and mitigates credit risks inherent in biennial rate cases. For example, in 2016, unrestricted cash and investments dropped to $853 million from $1.3 billion in the preceding year, but remained at a level that, at four months' operating expenses, we consider strong.
- An exceptionally broad and diverse service territory supports the revenue stream.
- The strong, efficient, and economical operations of the federal hydroelectric Columbia River Power System translates into favorable wholesale power prices that foster strong demand for its output and ENW's nuclear production.
- Customers demonstrated their commitment to the agency's system by entering contracts with BPA that extend from 2008-2028. However, the contracts do not establish rates and the utility continues to rely on biennial rate proceedings.
- Tiered rates underlying the customer contracts help shield BPA from market volatility by assigning to customers the costs of their energy needs that exceed their allotments of capacity from the federal hydroelectric projects and CGS.

S&P Global Ratings also incorporates the following factors in its assessment:

- Financial performance hinges on hydrology conditions that can impair surplus power sales revenues and require replacement power purchases that add to expenses. The liquidity cushion is vulnerable to hydrology conditions, power market volatility, and accelerated debt reduction, as the nearly $500 million decline in 2016's unrestricted cash and investments relative to 2015 illustrated. Biennial rate proceedings and the high threshold for triggering the utility's cost recovery adjustment mechanism limit the flexibility to respond to pressures on liquidity and DSC.
- Highly politicized and protracted biennial rate proceedings can delay rate relief and constrain the benefits of autonomous ratemaking authority and financial flexibility. Nevertheless, the utility established electric rates for its municipal and electric cooperative customers for fiscals 2016-2017 that at $34 per megawatt-hour are 7.1% above

its 2014-2015 rates and transmission rates that were 4.4% higher. Rates during 2014-2015 that were 9% higher than the rates that went into effect in October 2013 and transmission rates were 11% higher. In addition, BPA is exploring rate increases for the 2018-2019 rate period.

- Bonneville and ENW project substantial capital needs that could add to both organizations' debt and consume BPA's Treasury borrowing authority. The utility reports it is exploring nonfederal financing arrangements, including leases and energy prepayments by its customers, to address expectations that it could soon exhaust its federal borrowing capacity. BPA's capital spending program is important to maintaining the integrity of its generation fleet and managing forced outage incidents.
- The $7.7 billion federal debt limit includes $750 million carved out as a credit line, which leaves about $2.15 billion of capacity based on $4.8 billion of existing Treasury debt.
- The success of the Regional Cooperation debt refinancings and the ability to extend the tenor of BPA's capacity to borrow from Treasury hinge on the economics of refinancing opportunities for reamortizing nonfederal debt, the willingness of ENW to serve as a conduit issuer, and the potential for accelerating portions of Bonneville's federal appropriations and Treasury debt.
- The Regional Cooperation debt refinancings will strengthen nonfederal DSC in the near term, but will likely erode DSC in later years because BPA and ENW are deferring nonfederal debt service.

Outlook

The stable outlook reflects our view that Bonneville's stand-alone credit profile can withstand a further downgrade on the U.S. Also, plans to increase rates for the 2018-2019 period could help support DSC and liquidity. At the same time, ENW's willingness to serve as a conduit to capital markets remains important to managing Treasury borrowing limits.

Upside scenario

We do not expect to raise the ratings in the next two years because of the size of the BPA and ENW capital programs and our view that improvements in nonfederal debt service coverage ratios reflect the deferral of debt amortization to later years to address the Treasury's cap on BPA's borrowings

Downside scenario

If, during our two-year outlook horizon, Bonneville's sound liquidity cushion erodes further whether due to hydrology conditions, capital needs, weak market for its surplus power, or debt acceleration that saps its liquidity, we could lower the stand-alone credit profile. Also, if BPA adds significant nonfederal leverage obligations because of its statutory debt ceiling, it could lead to negative implications for the stand-alone credit profile and the 'AA-' rating.

Bonneville's Nonfederal Debt Obligations

BPA's nonfederal rated obligations include:

- $5.3 billion of ENW revenue and refunding bonds: $3.4 billion relates to the operating CGS and the balance is for the incomplete units 1 and 3;
- $78.9 million of Public Utility District No. 1 of Lewis County, Wash., Cowlitz Falls Project bonds;
- $119.6 million of Northwest Infrastructure Financing Corp. (Schultz-Wautoma project) bonds; and
- $12.8 million of Northern Wasco Public Utility District, Ore. (McNary Dam Project) bonds.

Operations

Bonneville markets electricity generated at 31 federal hydroelectric projects, ENW's nonfederal nuclear CGS, and several nonfederal small power plants. It primarily markets these resources' output to the customers of 125 public power and electric cooperative utilities (88% of sales), federal agencies, direct service industries, and the residential and farm customers of six investor-owned utilities. BPA also operates an extensive transmission system that facilitates power marketing activities. Its transmission system represents about 75% of the Pacific Northwest's transmission capacity. Power sales accounted for 73% of 2016's operating revenues, compared to transmission's 27%.

ENW debt financed two partially completed nuclear reactors and one completed reactor, CGS, a 1,157 megawatt reactor. The nuclear assets' debt is the leading component of nonfederal obligations.

Capital Spending Forecast

Bonneville projects about $4.5 billion of 2017-2021 capital projects. In descending order, transmission projects, hydroelectric asset upkeep, facilities, IT, security, and fish and wildlife protection represent the largest segments of the capital program. We view investments in the hydroelectric assets as critical to cash flow, particularly because the generating assets have exhibited an above-average forced outage factor relative to the balance of the power industry.

ENW projects about $537 million of 2017-2021 capital projects.

Ratings Detail (As Of March 31, 2017)		
Energy Northwest, Washington		
Bonneville Pwr Admin, Oregon		
Energy Northwest proj 1 Columbia generating station & proj 3 elec rev rfdg bnds (Bonneville Pwr Admin)		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest proj 1, Columbia Generating Sta, & proj 3 elec rfdg		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest WHLELC		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest WHLELC		
Unenhanced Rating	AA-(SPUR)/Stable	Affirmed
Energy Northwest WHLELC		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest WHLELC		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest WHLELC		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest WHLELC		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest WHLELC		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest WHLELC		

Ratings Detail (As Of March 31, 2017) (cont.)		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest (Bonneville Pwr Admin) elec rev rfdg bnds (Proj 1)		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest (Bonneville Pwr Admin) Columbia generating station elec rev bnds		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest (Bonneville Pwr Admin) Columbia Generating Station elec rev & rfdg bnds (Bonneville Pwr Admin)		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest (Bonneville Pwr Admin) Sub Lien		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest (Bonneville Pwr Admin) (Nuclear Proj 1,2,3)		
Long Term Rating	AA-/Stable	Affirmed
Energy Northwest (Bonneville Pwr Admin) (1,Columbia,3)		
Long Term Rating	AA-/Stable	Affirmed
Bonneville Pwr Admin elec rev rfdg (Colu)		
Unenhanced Rating	AA-(SPUR)/Stable	Affirmed
Energy Northwest (Bonneville Pwr Admin)		
Unenhanced Rating	AA-(SPUR)/Stable	Affirmed
Energy Northwest (Bonneville Pwr Admin) (XL Capital Assurance Inc.)		
Unenhanced Rating	AA-(SPUR)/Stable	Affirmed
Washington Pub Pwr Supp Sys (Nuclear Proj #3) rfdg rev bnds ser 93C dtd 9/23/93 due 7/1/2013 2014 2015 2017(CUSIP #939830RW7 RY3 RX5 RZ0)		
Unenhanced Rating	AA-(SPUR)/Stable	Affirmed
Northern Wasco Cnty Peoples Util Dist, Oregon		
Bonneville Pwr Admin, Oregon		
Northern Wasco Cnty Peoples Util Dist (Bonneville Pwr Admin) rev rfdg bnds (Mcnary Dam Fishway Hydroelec Proj)		
Long Term Rating	AA-/Stable	Affirmed
Northern Wasco Cnty Peoples Util Dist (Bonneville Pwr Admin) (McNary Dam Fishway Hydroelec Proj)		
Long Term Rating	AA-/Stable	Affirmed
Northwest Infrastructure Financing Corp., New York		
Bonneville Pwr Admin, Oregon		
Northwest Infrastructure Financing Corp. (Bonneville Pwr Admin) TRANs		
Long Term Rating	AA-/Stable	Affirmed

Many issues are enhanced by bond insurance.

Appendix F – MPA Utilities Practice Overview

Morrison Park Advisors has deep experience in the utility sector, including electricity generation, transmission and distribution, as well as natural gas pipelines and distribution utilities. Both as a firm, and as individuals with prior experience, we have worked with many of the leading utilities in Canada helping them to understand and maximize the value of assets and opportunities, whether for the purpose of mergers and acquisitions, new development and construction, or balance sheet management. Given our expertise, we are often called upon to provide clients with advice in challenging situations that do not fit typical investment banking categories.

Morrison Park Advisors

- Independent, partner-owned investment banking firm established in 2005
- Co-founded by David Santangeli and Brent Walker, now ten professionals, with over one hundred successful assignments with public and private companies, governments and quasi-public entities
- Value proposition is a unique combination of Tier 1 investment banking capabilities, comprehensive scope of expertise, and excellent client value
- Integrated advisory practice, covering all facets of investment banking, capital markets and Mergers & Acquisition services

Utilities Services

- Mergers & Acquisitions
- Strategic advice on market consolidation; potential investors & partners
- Financial advice on balance sheet management, growth capital, dividend policies
- Valuation
- Regulatory reviews and expert witness testimony in legal disputes

Utilities Reference Assignments

- Manitoba Hydro Public Utilities Board: Consultant to the Board and Expert Witness on Manitoba Hydro's Needs For and Alternatives To Proposed Business Plan
- Nova Scotia Utilities Review Board: Consultant to the Board and Expert Witness on the review of the proposed Maritime Link transmission project to connect Nova Scotia with Newfoundland and Labrador Hydro
- Alberta Electric System Operator (AESO): capital markets view on Alberta electricity investing, interview of developers/owners/operators of electricity generation facilities, as well as capital providers and other capital markets participants
- Market Surveillance Administrator of Alberta: Analysis of electricity generation investment sustainability in Alberta based on market participant interviews and financial information
- Crown Investments Corporation of Saskatchewan: advice on the cost and commercial viability of a nuclear electricity generation plant in Saskatchewan.
- BC Hydro: strategic advice on market value and potential partnerships for new international and interprovincial transmission infrastructure
- City of London, Ontario: review of the value of and strategic opportunities for ownership of London Hydro
- PowerStream: financial advisor to PowerStream in its merger with Enersource Hydro and Horizon Utilities, with concurrent acquisition of Hydro One Brampton Networks, Inc., to create the new company Alectra Utilities
- City of Toronto: M&A advisor to the City of Toronto in the sale of its minority shareholding in Enwave, a district heating and cooling company in Toronto
- Altagas Utilities: independent valuation of distribution utilities for the special committee of the Board of Directors
- Oshawa PUC: advice to the Board with respect to potential merger, acquisition and sale opportunities
- Milton Hydro: advice to the Board and the special advisory committee to City Council with respect to the recapitalization of Milton Hydro, its dividend policy, and potential merger, acquisition and sale opportunities
- Enwin Utilities: strategic and financial advice on balance sheet management of electricity and water utility businesses, and advice on options available to the Board with respect to potential merger, acquisition and sales
- Haldimand Hydro: advice to the Board with respect to potential merger, acquisition and sale opportunities
- Woodstock Hydro: advice to the Board with respect to potential merger, acquisition and sale opportunities
- Hydro One: financial advisor for distribution industry consolidation from 2007 to 2009; completed valuations for more than 30 utilities; conducted negotiations; strategic advisory services in managing acquisition proposals

Sample Previous Experience of MPA Staff

- Hydro One: Directed acquisitions of Haldimand Hydro, Norfolk Power, Woodstock Hydro, and Terrace Bay Superior Wires, in addition to numerous discussions and negotiations with respect to potential transactions with electricity distributors across the province
- Province of Ontario: Development of provincial policies with respect to electricity distribution consolidation
- Province of Nova Scotia: Financial advisor to the Province on the sale of its interest in Nova Scotia Resources Limited
- Ontario Teachers, OMERS and SNC Lavalin: Advisor to consortium on the potential acquisition of 49% of Hydro One
- Fortis Inc.: M&A advisor on the $1.4 B acquisition of Alberta and BC electricity distribution assets formerly owned by Aquila Networks
- Newfoundland & Labrador Hydro: advisor on proposed privatization
- Advisor to a bidding consortium on the proposed acquisition of ENMAX, the electricity distributor of the City of Calgary

Appendix G – Summary of Relevant Experience

	Regulated Utility	Non-Regulated Utility	Generation	Transmission	Distribution	Sale Process	Fairness Opinion	Other	MPA Team Members
MPA Assignments									
City of London, Ontario: Review of London Hydro	X				X			X	Pelino Colaiacovo, Bill Meeker
PowerStream: Merger, Purchase and creation of Alectra	x				x	x	x		Pelino Colaiacovo
City of Toronto: Sale of Enwave		x				x	x		Pelino Colaiacovo
Altagas Utilities	x				x	x	x		Brent Walker
Oshawa Hydro	x				x			x	Pelino Colaiacovo, Brent Walker
Milton Hydro	x				x			x	Pelino Colaiacovo, Brent Walker
Enwin Utilities	x				x			x	Pelino Colaiacovo
Haldimand Hydro	x				x			x	Pelino Colaiacovo
Woodstock Hydro	x				x			x	Pelino Colaiacovo, Brent Walker
Hydro One	x				x			x	Pelino Colaiacovo, Brent Walker
Alberta Electric System Operator		x	x					x	Pelino Colaiacovo, Brent Walker
Manitoba Hydro	x		x	x			x		Pelino Colaiacovo, Ben Kinder
Nova Scotia Utilities and Review Board	x			x			x		Pelino Colaiacovo, Brent Walker, Ben Kinder
Market Surveillance Administrator of Alberta		x	x					x	Pelino Colaiacovo, Brent Walker
Crown Investments Corporation of Saskatchewan		x	x					x	Brent Walker
BC Hydro	x			x				x	Pelino Colaiacovo, Brent Walker
Prior Assignments of MPA Staff									
Hydro One acquisition of Haldimand, Norfolk, Woodstock distributors	x				x	x			Bill Meeker
Province of Ontario distribution consolidation policy	x				x			x	Pelino Colaiacovo
Province of Nova Scotia: sale of interest in Nova Scotia Resources		x				x	x		Brent Walker
Advisor to consortium for potential acquisition of Hydro One	x			x	x	x			Brent Walker
Fortis Inc. acquisition of Aquila Networks assets in BC and Alberta	x				x	x	x		Brent Walker
NALCOR: advisor on proposed privatization	x		x	x		x			Brent Walker
Advisor to consortium on proposed acquisition of ENMAX	x				x	x			Brent Walker

Appendix H – MPA Utilities Team

Pelino Colaiacovo

Pelino is a Managing Director at MPA. In this role he is responsible for origination and transaction execution, financial advisory and capital raising services. Since joining MPA Pelino has focused on advising clients in the energy, utilities, infrastructure and public sectors, and in addition assists clients in cleantech industry.

Utility clients have included Hydro One, BC Hydro, Enwin Utilities, Oakville Hydro, Woodstock Hydro, the Nova Scotia Utilities Review Board, the Alberta Market Surveillance Administrator, and numerous others, and more broadly in the energy sector Pelino has worked on a number of M&A and capital raising assignments for renewable energy and cleantech companies.

Prior to joining MPA in 2005, Pelino was Chief of Staff to the Ontario Minister of Energy from 2003 to 2005. During that time, he assisted in significant restructuring of the Ontario electricity sector, including the drafting and implementation of new legislation, the creation of the Ontario Power Authority, and significant procurements of new electricity generation capacity for the province.

Previously, Pelino spent more than 10 years in management, policy and communications consulting in Canada and the United States, advising clients across a wide range of sectors, including energy, transportation, telecommunications, and healthcare.

Pelino holds a B.A. and an L.Lb., both from the University of Toronto.

Bill Meeker

Bill is a Senior Advisor at Morrison Park Advisors. Since joining MPA in 2014, Bill has focused exclusively on the utility sector. Bill brings over thirty years of utility experience with Ontario Hydro, Ontario Hydro International and Hydro One Inc. to helping clients understand and meet the challenges of today's utility environment.

Bill's career has focused on transaction development in the electric distribution and transmission businesses – both internationally and in Ontario. He has led cross-functional teams in due diligence, valuation, execution and regulatory approvals. Bill's experience includes directing the acquisition of assets and shares, the sale of strategic investments, structuring complex cross-border partnerships, managing investment partnerships, and structuring merger arrangements.

Bill also led Hydro One's asset management function for electric distribution for two years from 2010 to 2012. From 2012 to 2014 Bill led Hydro One's acquisition of Norfolk Power, Haldimand County Hydro, and Woodstock Hydro.

Bill has a Bachelor of Business Administration (B.B.A.) and Master of Business Administration (M.B.A.) from York University's Schulich School of Business.

Brent Walker

Brent Walker is a Managing Director and co-founder of MPA. In this role he is responsible for transaction origination and execution, financial advisory and capital raising activities across a wide spectrum of industry segments, including energy, technology, government and quasi-government entities and a variety of other commercial sectors.

Utility clients have included BC Hydro, Altagas Utilities, Crown Investments Corporation, Hydro One, Market Surveillance Administrator of Alberta, the Nova Scotia Utilities Review Board, the Ontario Ministry of Energy and many others.

Prior to founding MPA in 2004, Brent spent over 10 years in the investment banking and financial industry. From 1996 to 2004, he was a managing director in Scotia Capital's mergers and acquisitions department, where he was the most senior M&A banker in a number of sectors including power and infrastructure, pipelines, energy midstream and real estate. During this period, he worked on the sale of the Province of Nova Scotia's interest in Nova Scotia Resources Limited, the acquisition of Aquila by Fortis, the proposed privatization of NALCOR and Enmax, and many other utility assignments.

Brent started his investment banking career at Lancaster Financial, Canada's foremost independent M&A boutique which was acquired by TD Bank in 1994.

Brent holds a B.Sc. from Dalhousie University and an MBA from McMaster University.

Benjamin Kinder

Benjamin Kinder is a Director at MPA. In this role he is responsible for transaction execution, financial advisory and capital raising services.

Since joining MPA in 2009, Ben has focused on advising clients in public and private mergers, acquisitions and divestiture transactions, and has acted as an expert witness.

Prior to joining MPA, Benjamin spent two years in Scotia Capital's investment banking and equity capital markets divisions. While there, he focused on the communications, media and technology sectors, advising clients on mergers and acquisitions, and capital markets transactions.

Benjamin holds a Bachelor of Business Administration (B.B.A.) from York University's Schulich School of Business, a Master of Arts (M.A. Cantab.) in law from the University of Cambridge.

John Park

John Park is an Analyst at MPA. In this role he is responsible for research, modeling, and assisting with transaction, execution services.

Prior to joining MPA, John served as an analyst in the business development department of a major Canadian corporation.

John holds an Bachelor of Business Administration (B.B.A,) from the Ivey School of Business at Western University.

Appendix I – Statement of Qualifications & CV of Pelino Colaiacovo

Pelino Colaiacovo – Statement of Qualifications

Pelino Colaiacovo has been a Managing Director at MPA Morrison Park Advisors Inc. since 2005. He focuses on the utility, electricity and infrastructure sectors, as well as Crown Corporations and green technology more broadly. He advises corporate, government and not-for-profit clients on mergers and acquisitions transactions, the raising of new capital, the valuation of corporations and major assets, and the financial fairness of proposed transactions or initiatives to various stakeholders. As part of this work, he has built hundreds of financial models and analyzed the financial impacts and sensitivities of scenarios too numerous to count. He tracks the view of the capital markets on initiatives and developments in the utilities, power and infrastructure sectors, and provides advice and assistance to clients that must interact with the capital markets. He regularly speaks at and participates in conferences, roundtables and industry associations with respect to energy policy development, and the likely financial impact on utility companies of new policies, technologies and financial developments. He has provided advice to several governments about energy policy.

Before joining MPA, he served as the Chief of Staff to the Ontario Minister of Energy, and was integrally involved in a large number of significant reforms to the electricity industry in that province. Prior to that he was a consultant to a wide variety of domestic and international companies and industry associations on energy and other policy issues.

Pelino appeared before the Manitoba PUB in 2014 as part of the NFAT process, and provided a view on the fairness of the NFAT to Manitoba ratepayers, and also commented on the financial viability of Manitoba Hydro's plan. He also appeared before the Nova Scotia Utilities and Review Board in 2013 on the fairness of the Maritime Link Project to ratepayers in that province (and is currently in the process of participating in the NSUARB review of the Maritime Link project to date).

PILC will rely on his expertise in financial modeling, capital markets, electricity planning and policy to comment on the financial and intergenerational consequences of Manitoba Hydro's GRA.

Pelino Colaiacovo, Managing Director

Professional Profile

- Well-known participant in the Ontario electricity sector
- Deep understanding of the Canadian utilities, energy, infrastructure and greentech sectors
- Over 20 years of experience in investment banking, government, corporate strategy, policy development, consulting

Professional Experience

August 2005 – Present Managing Director, MPA Morrison Park Advisors Inc.

- MPA is an employee-owned independent investment bank focusing on mergers & acquisitions, capital raising, and other strategic advisory services to public and private companies, as well as governments, crown corporations, regulators and not-for-profit enterprises (note that MPA's name pre-2007 was Energy Fundamentals Group)
- As Managing Director and Shareholder, responsibilities include marketing, client origination, transaction analysis, senior counsel, and transaction execution

October 2003 – August 2005 Chief of Staff, Office of the Ontario Minister of Energy

- Most senior advisor to the Minister
- Managed Minister's staff of 12

July 1993 – October 2003 Various Positions, GPC International

- Consulting firm providing policy analysis, government relations, public affairs, public relations, corporate communications and management consulting services
- Positions held in Toronto, Ottawa and Washington DC
- Progress from junior consultant to Vice President and Practice Leader
- As Practice Leader, managed both a permanent team, as well as flexible multidisciplinary teams for individual client campaigns

Education

1993 Bachelor of Laws, University of Toronto

1990 Honours Bachelor of Arts, University of Toronto (International Relations and Economics)

Detailed Experience

August 2005 – Present Managing Director, MPA Morrison Park Advisors Inc.

- Focus on utility and energy sector clients, and to a lesser extent on infrastructure projects, crown corporations, and greentech (MPA also covers mining, technology, real estate and public company M&A)
- Advisor to the Alberta Electric System Operator: Capital market consequences of transition to Coal Exit and Capacity Market
- Financial Advisor to PowerStream in its merger with Horizon Utilities, Enersource and Hydro One Brampton to create Alectra Utilities
- Expert Witness for and consultant to the Public Utilities Board of Manitoba: Commercial valuation of Manitoba Hydro's multi-billion dollar plan to build new hydroelectric facilities and export-focused transmission lines
- Expert Witness for and consultant to the Nova Scotia Public Utilities Board: Commercial valuation of the proposed Maritime Link interprovincial electricity transmission line
- Report to the Market Surveillance Administrator of Alberta on the commercial viability of new electricity generation facilities in the Alberta competitive electricity market
- Advisor to British Columbia Transmission Co (now part of BC Hydro) with respect to proposed new transmission lines to the United States and Alberta
- Financial Advisor to the City of Toronto with respect to the sale of the City's minority interest in Enwave
- Financial Advisor to the City of Toronto with respect to the proposed financing for and development of the Tower Renewal energy conservation program
- Numerous assignments as financial advisor to electricity distribution companies with respect to financial valuations, strategic reviews and mergers & acquisition opportunities (e.g., Milton Hydro, Oshawa PUC, Woodstock Hydro, Enwin Utilities, Oakville Hydro, Hydro One)
- Numerous assignments as financial advisor to buyers and sellers of renewable energy generation assets (wind, solar and hydroelectric) and district energy facilities
- Numerous assignments as financial advisor to project developers raising capital for new energy and infrastructure projects, and/or bidding into competitive procurement processes
- Energy policy and strategy advisor to the Ontario Energy Association
- Typically, clients are Boards of Directors of public companies, or senior management of private companies or government entities
- Numerous presentations before City Councils, utility regulators, and other public bodies
- Speeches and appearances at energy conferences and roundtables, guest lectures at university courses on energy policy and utility regulation, expert opinion resource for media

October 2003 – August 2005 Chief of Staff, Office of the Ontario Minister of Energy

- Principal political and policy advisor to the Minister
- Primary liaison with the Office of the Premier and with the public service
- Managed Minister's staff of 12

Final decision-maker for the Minister's public communication and stakeholder interaction

- Key accomplishments included:
  - Restructuring of the Ontario electricity sector through the passage of Bills 11 and 100
  - Development of a detailed plan to retire Ontario's coal-fired electricity generation fleet
  - Development of a smart metering strategy for Ontario
  - Creation of the Ontario Power Authority, selection of Board, appointment of CEO
  - New Board and senior management for Ontario Power Generation, new Board for the Independent Electricity System Operator
  - Review and approval of proposed refurbishment of Pickering A 1 nuclear unit
  - Negotiation of Bruce A nuclear refurbishment
  - Successful Requests For Proposals for new renewable energy facilities, and new gas-fired electricity generation plants

July 1993 – October 2003 Various Positions, GPC International

- Vice President and Corporate Practice Group Leader, Toronto
- Vice President responsible for integration of acquired offices in the United States, including Boston and Washington DC
- Senior Consultant, Ottawa
- Consultant, Toronto
- Focus on regulated sectors of the economy, including energy, transportation, media, healthcare and finance
- Leader of multi-disciplinary public affairs projects including policy development, government relations, media relations, stakeholder communications and polling
- Management consultant for large national and multi-national corporations with respect to public affairs

Appendix J – MPA Duties

The following duties were assigned to Morrison Park Advisors in the Manitoba Hydro 2017/18 and 2018/19 General Rate Application.

The Public Interest Law Centre on behalf of the Consumers Coalition, and the Manitoba Industrial Power Users Group (MIPUG), jointly retained the services of Morrison Park Advisors to assist with their participation in the Public Utilities Board review of Manitoba Hydro's Application on issues related to financial targets / capital structure, debt and debt management, and risk and uncertainty analysis.

Morrison Park Advisors' duties include:

- Reviewing the application, evidence and historical information;
- Modelling, on a very limited basis, the potential impact on Manitoba Hydro of further unplanned capital expenditures, and compare the same to other possible risks;
- Researching and benchmarking of alternatives;
- Researching and comparing the debt management strategies of comparable utilities, particularly with respect to the issue of shorter term maturity;
- Modelling; on a very limited basis, the varying impacts on customer rates over time of different financial targets, strategies, debt management plans and risks, including the use of different rate implementation strategies (i.e., higher earlier, steady increases use of “emergency” increases, etc.) and considering the impact of these various scenarios on access to capital and the Province of Manitoba;
- Preparing first and second rounds of Information Requests;
- Reviewing Information Request responses;
- Preparing a report to the Public Utilities Board;
- Responding to Information Requests, if necessary; and
- Preparing for and appearing before the Public Utilities Board, if necessary.

Morrison Park Advisors' retainer letter includes they are to provide evidence that:

- is fair, objective and non-partisan;
- is related only to matters that are within their area of expertise; and
- to provide such additional assistance as the Public Utilities Board may reasonably require to determine an issue.

Morrison Park Advisors' retainer letter also includes that their duty in providing assistance and giving evidence is to help the Public Utilities Board. This duty overrides any obligation to the Consumers Coalition and MIPUG.

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KPMG

Manitoba Hydro

Financial Targets Review

Supplementary Update

August 2017

KPMG LLP

Notice on Supplementary Update

KPMG LLP ("KPMG") has drafted this supplementary update ("Update") to the Financial Targets Review Report issued May 2015 (the "May 2015 Report"). This supplementary update and the May 2015 Report were prepared pursuant to our engagement to assist Manitoba Hydro-Electric Board ("Manitoba Hydro" or "MH") in its review of financial targets ("Financial Targets Review") in accordance with the terms of a services agreement dated December 5, 2014.

This Update has been prepared for Manitoba Hydro. Its contents may not be shared with or disclosed to anyone by the recipient without the express written consent of Manitoba Hydro and KPMG, unless Manitoba Hydro files the report or substantive components of the report for its regulatory purposes. KPMG does not accept any liability or responsibility to any third party who may use or place reliance on this Report.

Purpose of the Update

The purpose of this Update is to:

- Provide an update of the background information in the Financial Targets Review,
- Update data and information as at March 2017 for benchmarking and comparisons of government-owned power utilities in Canada; and
- Update the scenario analysis to include IFF16 filed by Manitoba Hydro in May 2017.

Basis of Information

The data and information included in this Update and the May 2015 Report were obtained primarily from secondary sources such as annual reports, financial statements and regulatory filings of MH and other power utilities, Decisions and Orders of the Public Utilities Board of Manitoba ("PUB") and of other regulatory agencies, credit agency reports, bank reports, and other sources of Canadian and international research and statistics. Financial forecasts were derived from MH's Integrated Financial Forecast and similar documents from other select power utilities. Scenario analyses were performed on KPMG's behalf by MH using its own in-house models.

This Update and the May 2015 Report relies on data and information from these secondary sources and KPMG makes no representations with respect to their accuracy or completeness.

The procedures performed do not constitute an audit, examination or review in accordance with standards established by the Chartered Professional Accountants of Canada, and we have not otherwise verified the information we obtained or presented in this Update or Report. KPMG expresses no opinion or any other form of assurance on the information presented in the Update and the May 2015 Report, and makes no representations concerning its accuracy or completeness.

Contents

1 Background

This chapter outlines the objectives, scope and process of the project.

1.1 Objective

In 2014, Manitoba Hydro-Electric Board ("Manitoba Hydro" or "MH") retained KPMG LLP ("KPMG") to undertake a review of its current financial targets (the "Financial Targets Review"). The specific objectives of this engagement were to:

- Provide recommendations with respect to appropriate financial targets for Manitoba Hydro that align with the mandate of Manitoba Hydro and the interests of its stakeholders considering its operating and business outlook and associated risks.
- The financial target recommendations should consider at a minimum the following:
  - The objective of maintaining rate stability for customers while at the same time maintaining safe and reliable service.
  - The period of significant capital investment and infrastructure renewal that Manitoba Hydro is entering into.
  - The maintenance of Manitoba Hydro's self-supporting status for credit rating purposes.
- Conduct scenario analysis to help address PUB's directive to Manitoba Hydro to review key operating and financial risks in order to assess the adequacy of financial reserves.

The results of this review culminated in a report dated May 2015 (the "May 2015 Report"). The analyses in the 2015 report were based, among other things, on MH's Integrated Financial Forecast ("IFF14"), dated December 2014.

The scope of the work did not involve review or comment on broader policy questions associated with Manitoba Hydro's overall structure, governance framework, and business strategy, including capital plans and IFF strategies and rate decisions.

1.2 Scope and Overview of Update Process

Given the passage of time, which has been accompanied by changes in the economic environment and by changes in Manitoba Hydro's financial outlook, Manitoba Hydro retained KPMG to undertake an update of certain analyses contained in the May 2015 Report. The results of this update process are summarized in this report.

The analysis in this update is intended to supplement that contained in the May 2015 Report. Hence, this "Supplementary Update" should be read in conjunction with the May 2015 Report and does not replace it. We have not updated all of the analyses of the earlier report, nor have we revisited all of discussions of conceptual issues contained in that report. Rather, the intent of this report is to address changes in the environment and to update key financial data and metrics. In particular, we reviewed recent developments at benchmark government-owned power utilities and we updated our financial comparisons with recent financial information.

As per our scope of work, the following Supplementary Update provides updated information for Chapters 3, 4, 5, 6 and 7 of the May 15 Report.

1.3 Summary of the May 2015 Report Recommendations

It should be noted that the updates contained herein have not changed the core recommendations of the May 2015 Report. For greater certainty, we still concur with the recommendations of the May 2015 Report.

The context for the recommendations in the May 2015 Report included the following:

- Relative to other Crown utilities with a significant base of hydro-electric generation, Manitoba Hydro faces a number of heightened risks:
  - Manitoba Hydro has a large capital investment program relative to its current installed asset base and its projected revenues going forward.
  - Manitoba Hydro faces relatively greater hydrology risks than other major utilities.
  - Manitoba Hydro relies on export markets for a significant proportion of its revenue.
  - Utility debt and utility assets in Manitoba are relatively high on a per capita basis compared to other jurisdictions. Manitoba Hydro thus has a relatively limited customer base over which to spread potential future cost overruns or business set-backs.
- As shown through benchmarking, Manitoba Hydro’s target equity ratio is at the low end of those maintained or forecast by other government-owned power utilities.
- Manitoba Hydro has limited ability to restrain a drop in financial ratios during adverse conditions, such as a drought. This highlights the risk of having an equity ratio that approaches 10%. For this reason, we believe that equity ratios of 15% or higher are the minimum that should be accepted even for short periods.
- Manitoba Hydro is dependent on an accumulation of retained earnings to build up its equity base. The Manitoba government does not expect to receive dividend income from the utility but nor does it make equity injections during periods of major capital expansion. As a consequence, Manitoba Hydro has few levers with which to adjust its financial position.
- Manitoba Hydro’s capital investment program is characterized by periodic “bumps” or “hills” of large magnitude. These fluctuations magnify the challenges associated with Manitoba Hydro’s limited levers for financial control.

As further context to this update, the recommendations of the May 2015 Report are repeated below:

Recommendation 1: debt/equity ratio target of 75/25 to 70/30

- Manitoba Hydro’s current debt/equity target of 75/25 is a reasonable long-term target. Notwithstanding this finding, we note that a target of 70/30 would provide additional financial strength to address the utility’s unique financial challenges and risks. Accordingly, our overall recommendation is that the debt/equity ratio should fall within the range of 75/25 to 70/30.
- Manitoba Hydro will need to depart from its equity target during major build programs: this reflects the utility’s limited financing tools and reliance on retained earnings as its dominant source of equity. Accordingly, the equity position should rise above 25% in advance of major build programs to mitigate the deviations from target that are observed.
- We have significant concerns that an 11% equity level, as forecast under IFF14, provides a less than desirable equity base to accommodate potential adverse developments. We suggest that Manitoba Hydro’s plans be adjusted to maintain an equity ratio no lower than 15% under forecast conditions during the peak periods of its major capital build program when equity ratios are at their lowest levels.
- In the long-term, with respect to deviations from any target, it would be desirable to limit decreases in the equity ratio to 5-10 percentage points.

- In the long-term, higher equity ratios need not translate into higher rates, because Manitoba Hydro has the option to seek lower rates of return on equity than investor-owned utilities.

Recommendation 2: minimum EBITDA interest coverage ratio target of 1.8 or greater

- As noted in the May 2015 Report, the debt/equity ratio should remain the primary measure of Manitoba Hydro's financial position. An interest coverage ratio is an important element of financial targets and indicator of trends. EBITDA is a widely accepted financial measure and is closer to a cash flow metric than EBIT, albeit with limitations since it does not incorporate capital expenditure requirements or working capital adjustments.
- Our recommendation is an EBITDA interest coverage ratio, at a minimum target level of 1.8 or greater.

Recommendation 3: maintain a minimum capital coverage ratio target of 1.2 or greater

- The capital coverage ratio is also an important financial target and a unique measure to Manitoba Hydro.
- The current minimum target of 1.2 or greater is reasonable in that the corporation should be able to fund its sustaining base capital from current operations without accessing external sources of financing. However, an inherent limitation of this ratio is that it does not reflect the financial challenges associated with major expansion programs. Hence it may be misunderstood or misinterpreted by stakeholders.

Recommendation 4: other metrics to continue to monitor

- Manitoba Hydro should maintain three Financial Targets.
- Manitoba Hydro should also continue to regularly monitor other financial metrics. These include but are not limited to: revenue growth, controllable operating costs, EBITDA, net income, cash flow from operations to net debt, net debt to assets, EBITDA to revenue, capital expenditures to fixed assets, average electricity prices across different customer groups.

In the context of this review, we note that the financial position of Manitoba Hydro has deteriorated in recent years, which increases risk to the corporation and to the Province of Manitoba. Benchmarking comparisons to peer government-owned power utilities show Manitoba Hydro in a relatively worse financial position than comparisons in the May 2015 Report. The Province of Manitoba has experienced credit downgrades from two credit rating agencies since the May 2015 Report. Thus, a return to minimum equity ratio targets, which is fundamental to the financial health of the corporation and the need for a sufficient equity cushion, has increased. With Manitoba Hydro's reliance on retained earnings for equity, the need for growth in sustainable positive cash flow and net income to increase equity has increased. Further, actions at other utilities confirm the importance of a robust equity ratio to support capital expansion and to provide protection against downside risks.

2 Update of Manitoba Hydro's Financial Outlook

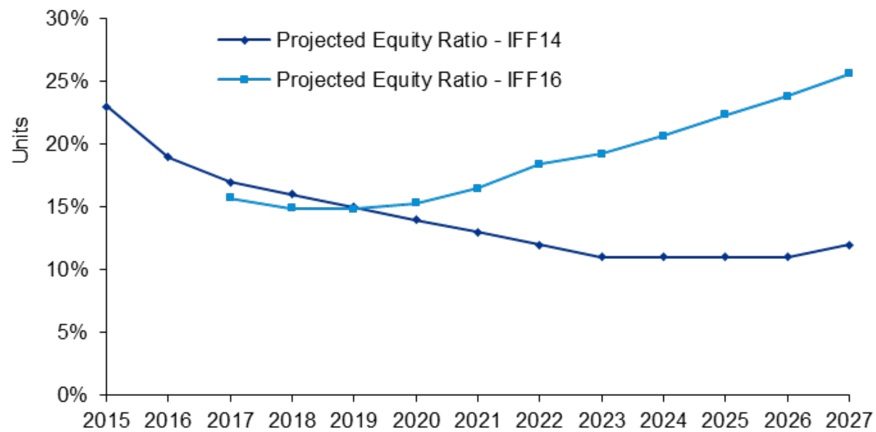
This chapter summarizes Manitoba Hydro's financial outlook under current plans as embodied in IFF16. This chapter updates some of the projections that were contained in Chapter 3 of the May 2015 Report.

2.1 Financial Metrics Forecast Over the Next 10 Years under IFF16

In this section, we compare key metrics for Manitoba Hydro under IFF16 versus IFF14. Manitoba Hydro's revised financial plan, IFF16, proposes annual rate increases in electricity rates of 7.90% for five years, 2017/18 to 2021/22, followed by inflationary increases of approximately 2.00% thereafter.

Figure 2-1 shows the projected equity ratio under the two forecasts. The projected equity ratio under IFF16 starts out from a lower position than under IFF14, but improves much more rapidly after 2020.

Figure 2-1: Projected Equity Ratio – IFF16 versus IFF14



In the short-term (through 2018), the equity ratio continues to fall under IFF16, remaining lower than under IFF14, even with projected 7.90% rate increases. This highlights the challenges related to financing large capital build programs. Given limited cash flows available from operations, Manitoba Hydro must rely significantly on debt to finance its capital expansion.

By definition, equity is a "stock" measure, and adjustments in the equity ratio over time require significant earnings flows to build up the retained earnings base and cash flows to reduce debt. If rate increases are not implemented, deficiencies in the earnings and in the cash flows available from operations could impair improvements in the utility's financial position.

Figure 2-2 below compares projected interest coverage ratios under the two forecasts (IFF16 and IFF14). Interest coverage ratios are consistently better under IFF16 after 2018 under the more recent projection, reflecting higher operating earnings.

Figure 2-2: Projected Interest Coverage Ratio – IFF16 versus IFF14

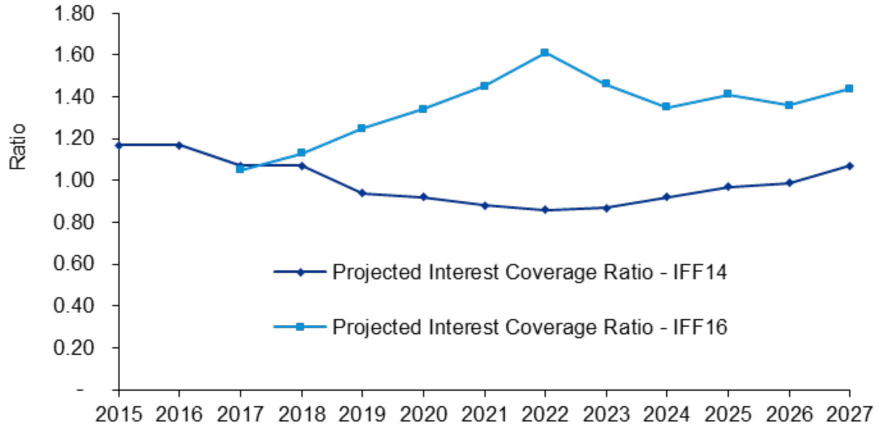


Figure 2-3 below compares projected EBITDA interest coverage ratios under the two forecasts (IFF16 and IFF14). EBITDA interest coverage starts from a slightly lower position in 2017 under IFF16, but then is consistently better than IFF14 for the remainder of the period.

Figure 2-3: Projected EBITDA Interest Coverage Ratio – IFF16 versus IFF14

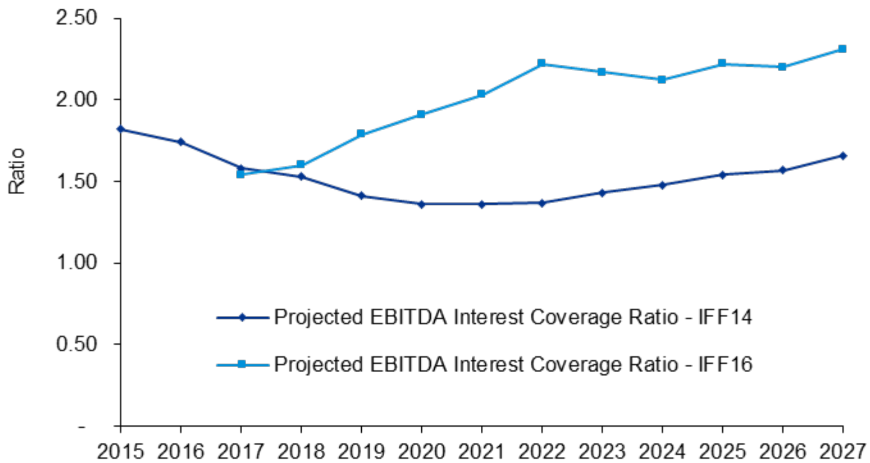
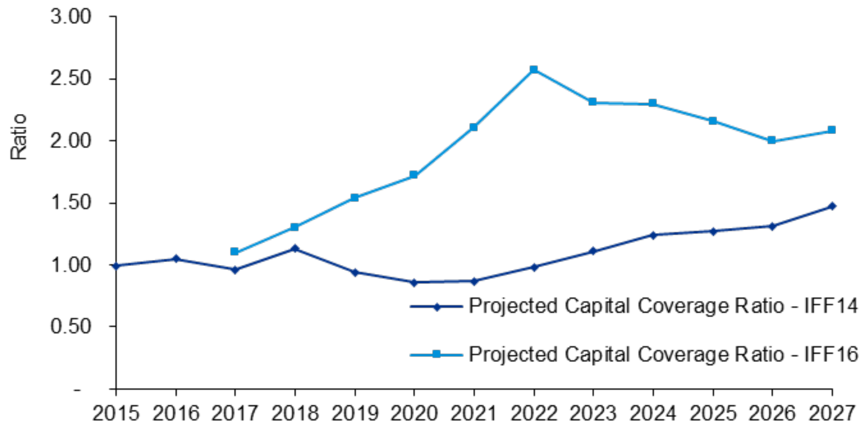


Figure 2-4 below compares projected capital coverage ratios under the two forecasts (IFF16 and IFF14). Capital coverage ratio is consistently better under IFF16. This reflects Manitoba Hydro's improved operating earnings.

Figure 2-4: Projected Capital Coverage Ratio – IFF16 versus IFF14



In evaluating projected trends in the capital coverage ratio, the limitations of this ratio need to be taken into account. As noted in the May 2015 Report, the capital coverage ratio does not take into account the financial impacts associated with major capital programs. Hence, it needs to be interpreted with caution. By definition, the ratio takes into account only base capital expenditures. It excludes projects categorized as Major New Generation and Transmission. It thus excludes:

- Capital expenditures related to large capacity expansions (such as Keeyask).
- Major reliability projects such as Bipole III.
- Some expenditures related purely to asset sustainment, such as the Pointe du Bois Spillway replacement, which are classified as Major New Generation and Transmission projects simply because of their size.

Projects such as Bipole III and major sustainment expenditures are particularly challenging from a financial perspective for Manitoba Hydro because they do not lead to material revenue increases that could help support their carrying costs once they are introduced into service. Bipole III has been built to reduce the risk of transmission outages and sustainment projects are built to ensure the continuation of existing revenue streams.

Furthermore, the capital coverage ratio excludes ongoing cash expenditures that Manitoba Hydro has to make to continue to operate as it currently does. Examples include deferred expenditures such as DSM and mitigation spending.

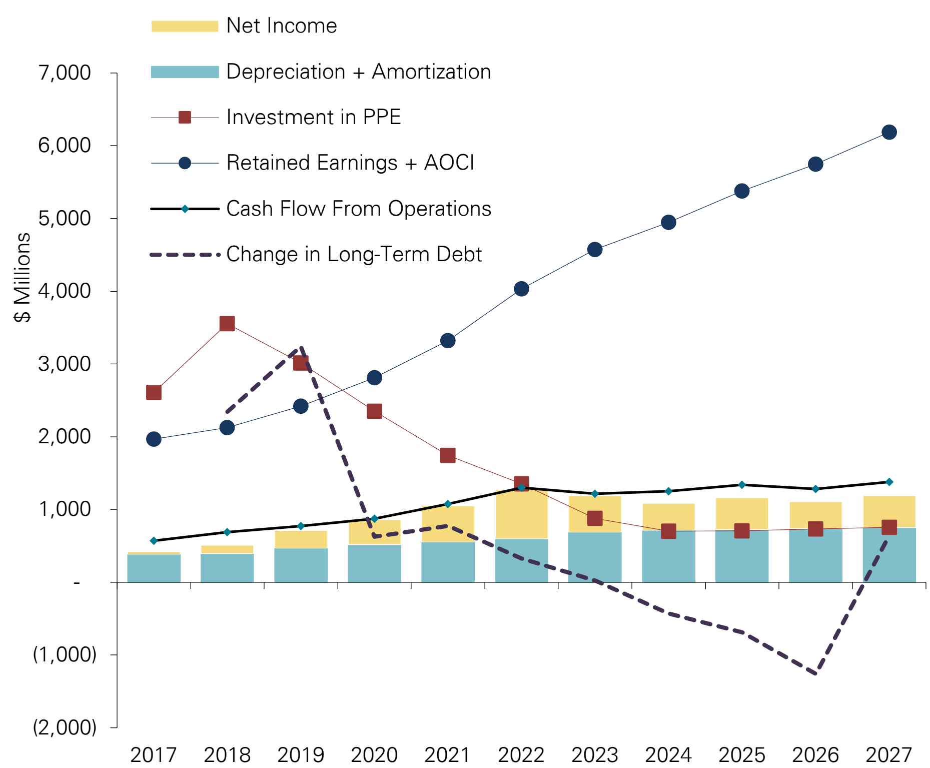
Also, the capital coverage ratio is based on cash flow from operations. This cash flow measure does not reflect the cash flow impact of interest payments that are capitalized for accounting purposes. Major capital projects result in a significant amount of such interest.

We note that Manitoba Hydro has developed an additional metric that examines adjusted cash flow to adjusted capital expenditures. This metric is intended to reflect overall cash flow impacts and related challenges in a more complete way during periods of major capital investment.

2.1.1 Integrated Assessment

Figure 2-5 shows the forecast evolution of Manitoba Hydro's financial position over the next 10 years based on projections in IFF16. This updates the data presented in Figure 3-10 of the May 2015 Report. All figures are shown in nominal dollars and are for Electric Operations alone, in contrast to Figures 2-1 through 2-4 above, which are for the overall corporation.

Figure 2-5: Forecast Evolution of Manitoba Hydro's Financial Position – IFF16



Source: IFF16 Projected Financial Statements for Electric Operations

A review of Figure 2-5 indicates the following:

- Projected capital expenditures in property plant and equipment ("PPE") are at very high levels in the near term, with a peak of $3.6 billion in Fiscal 2018. Thereafter they fall steadily to $700 million by Fiscal 2024 and then remain generally flat through to the end of the projection period. High capital expenditures in the near term reflect work associated with the construction of Keeyask and Bipole III. The capital expenditure profile is similar to that observed in IFF14, although peak spending in 2018 is higher (at $3.6 billion versus $3.2 billion). Overall spending is also higher due to increases in control budgets on the major projects.
- Depreciation and amortization expense is approximately $400 million in 2017, but increases gradually to $751 million by 2027. We note that depreciation expense has historically been significantly lower than actual annual investments in sustaining or business operations capital.
- Under IFF16 for electric operations, net income grows steadily over the period to 2022, from just $34 million in 2017 to $673 million in 2022. This provides support in reducing reliance on new debt to fund capital expenditures.

- Cash Flow from Operations tracks, but is slightly above, the sum of net income and of expenses for depreciation and amortization over the period.
- Given the limited cash flow available from net income and from depreciation and amortization, capital expenditures in the near term must largely be funded by debt. Thus, the annual change in debt during the years 2018 and 2019 is closely related to capital expenditures. The increase in debt highlights the major cash flow shortfall that Manitoba Hydro experiences during major capital projects. It also reflects that the costs of maintaining the existing Manitoba Hydro system have been $150 to $200 million more per year than what is being recognized through depreciation expense.
- Beyond 2022, net income falls again before recovering to $440 million in 2027. Over the same time period, projected capital expenditures are roughly equal to the cash flow available from depreciation and amortization expense. Because net income is retained rather than distributed as dividends, there is increasing growth in retained earnings in this period. Strong cash flow avoids the need to add new debt and, in many individual years, significant reductions in long-term debt balances occur.

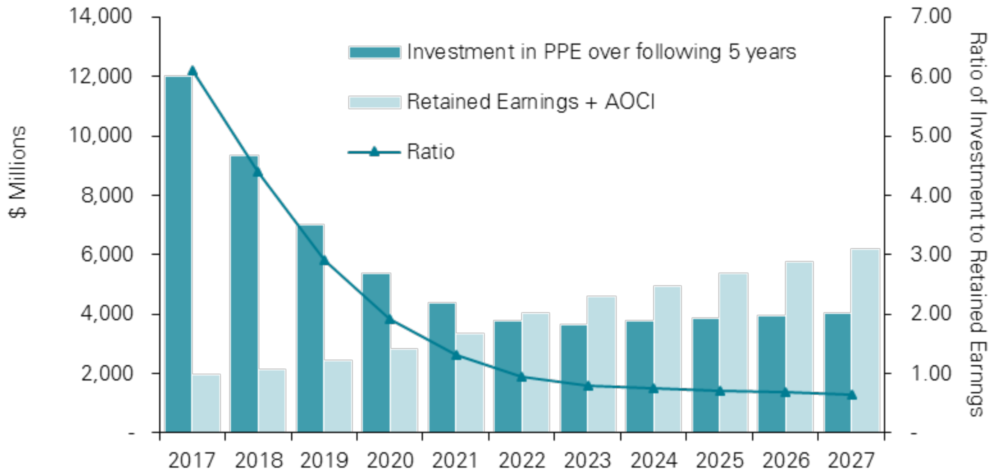
The following observations and conclusions are in order:

- Retained earnings are currently the only source of new equity for Manitoba Hydro, given that the Province has not made a practice of investing new equity into its operations.
- Because annual earnings are relatively modest in comparison to projected capital expenditures in the near term, the equity ratio declines slightly by 2019. As per IFF16, rate increases are assumed to be implemented, however, to avoid any significant reduction in the equity ratio below 15%.
- The increases in rates in the near term allow rate increases to fall to 2.0% annually beyond 2022. With moderate rate increases during this future period, the equity ratio recovers and reaches the minimum target of 25% by 2027.

Figure 2-6 provides an additional approach to examining Manitoba Hydro's financial position. This graph shows retained earnings (including AOCI) in each year as well as projected investments in PPE over the following 5 years.[1] The line shows the ratio between the two values. Higher ratios are indicative of higher capital cost risks, relative to the corporation's existing equity position, than lower ratios. Measured through this metric, capital cost risks are the highest in the first year of the outlook, in Fiscal 2016. The ratio falls rapidly over the period through 2022, as investments in Keeyask and Bipole III are completed. The ratio then continues to fall, although on a much more moderate trajectory.

[1] AOCI stands for Accumulated Other Comprehensive Income. It is a line item of the corporation's equity position.

Figure 2-6: Ratio of Projected Capital Investment to Retained Earnings



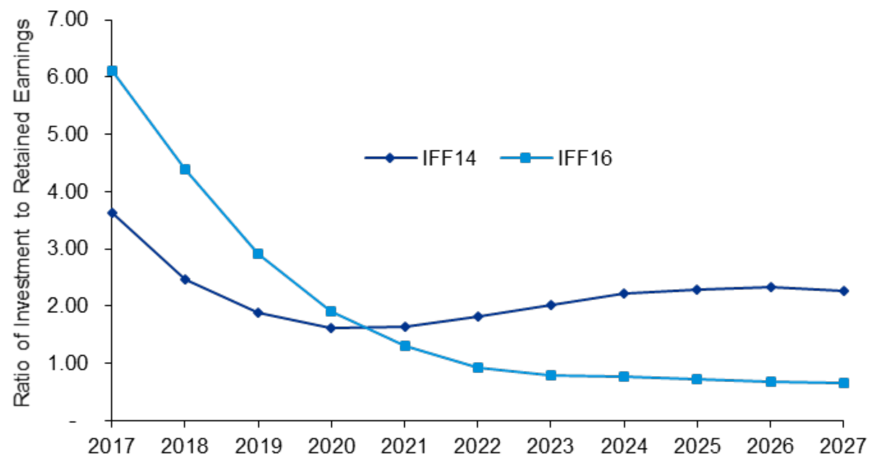
Source: IFF16 Projected Financial Statements for Electric Operations

Our observations with respect to Figure 2-6 are as follows:

- Relative to its equity base, Manitoba Hydro's risk with respect to capital costs is much higher in the next two or three years than it will be over the remaining projection horizon. There are large cash outflows in the near term without corresponding cash inflows until Keeyask is in-service.
- The decline in Manitoba Hydro's relative capital cost risk going forward is contingent on there being no new large capital projects after Keeyask. The introduction of Conawapa into the planned development sequence would result in a significant increase in capital cost risks in the future.
- As noted earlier in this Chapter, the projected equity position of the corporation is contingent on successive annual rate increases of 7.90% to 2022. Rate increases below this level would have a detrimental impact on relative capital cost risks.

Figure 2-7 below compares the ratio of near-term investment to retained earnings, as defined above for Figure 2-6, under IFF16 versus IFF14. The corporation's investment ratio improves more quickly, and more consistently, under IFF16 than under IFF14. This reflects the elimination of the extended period of negative net income that was observed under IFF14. However, the ratio starts from a higher starting point. Under IFF16, the ratio of near-term investment to retained earnings starts out at 6.1, relative to the value of only 3.6 projected for 2017 under IFF14. This indicates that relative investment risk is higher in 2017 than was forecast two years ago. This reflects, in part, delays in the construction of Keeyask, which has pushed some spending forward into the next few years. It is also a consequence of the combined $2.7 billion increase in capital budgets for Keeyask and Bipole III since IFF14.

Figure 2-7: Ratio of Projected Capital Investment to Retained Earnings



Source: IFF16 Projected Financial Statements for Electric Operations

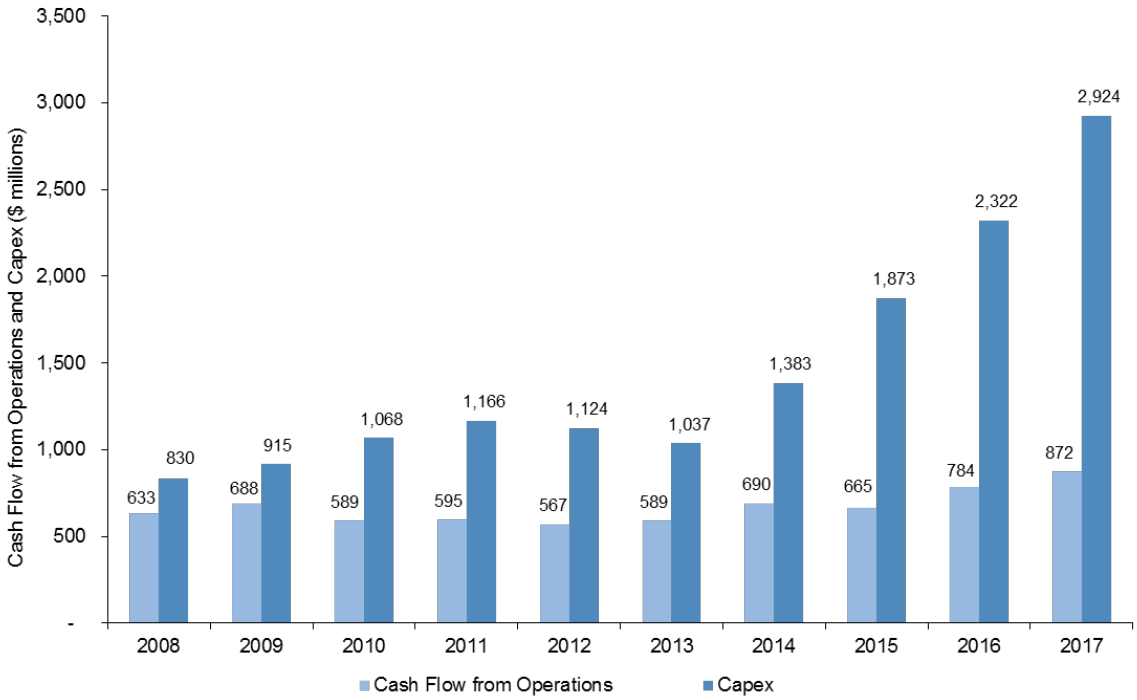
Figure 2-8 shows trends in cash flow from operations and capital expenditures over the past 10 years. Manitoba Hydro's cash flow from operations has grown to $872 million in 2016/17 and has averaged approximately $665 million from 2008 to 2017. A cautionary note with respect to recent growth is the understanding that the total cash flow from operations for the past two fiscal years are significantly higher due to increased payable balances driven by major capital projects. Manitoba Hydro noted in its annual reports for the years ending March 31, 2016 and 2017 that the increase in cash provided from operations largely reflects significantly higher payable balances primarily related to the construction of the Keeyask generation and transmission facilities and of the Bipole III project.[2]

Total capital expenditures have ramped up rapidly since 2008. This has resulted in an increasing gap between the two metrics, which is reflected in an increase in Manitoba Hydro's borrowing needs.

As shown in Figure 2-9, under IFF16, with 7.90% rate increases for the first five years, the gap between cash flow from operations and capex during the next five years is substantial.

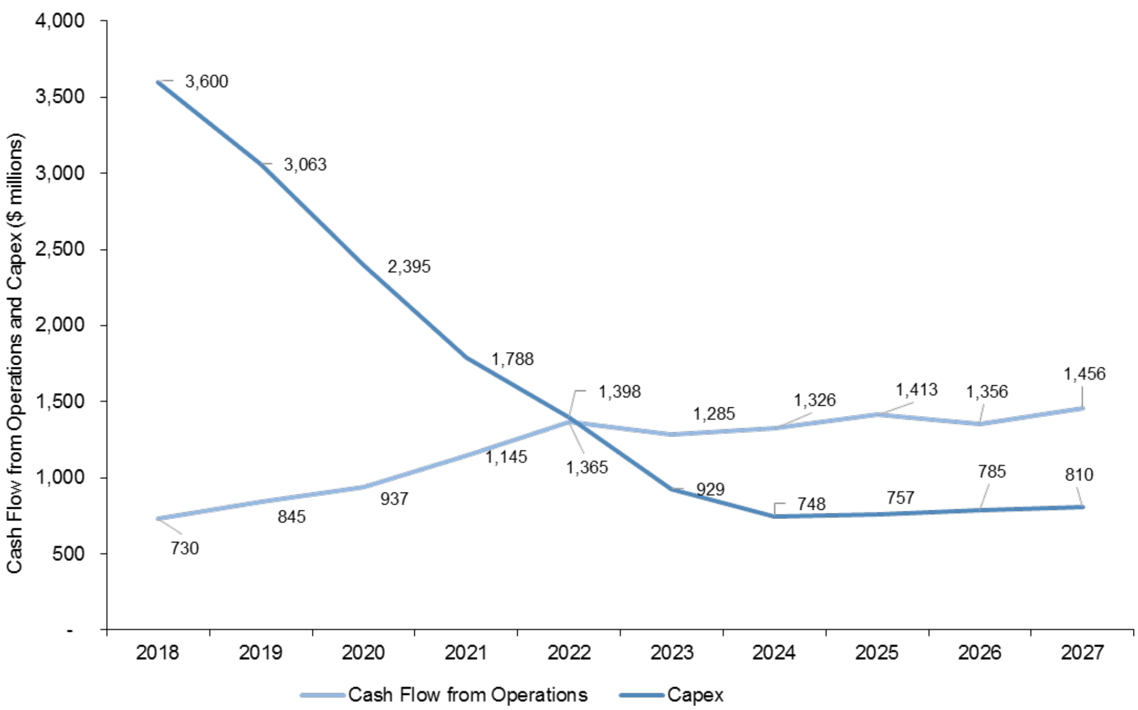
[2] See pages 25 and 31 of the 2016 and 2017 reports respectively.

Figure 2-8: Manitoba Hydro, Cash Flow from Operations and Capex, 2007/08 to 2016/17



Source: Derived from annual report and financial statements for the years ended March 31.

Figure 2-9: Manitoba Hydro, Cash Flow from Operations and Capex under IFF16, 2017/18 to 2026/27 Projections



Source: Derived from IFF16 projected consolidated financial statements.

3 Update of Developments and Issues Raised by Regulatory Bodies and Other Stakeholders in Canada

This Chapter updates the findings of the May 2015 Report with respect to regulatory developments at other utilities in Canada. The earlier findings were found in Chapter 4 of the May 2015 Report.

3.1 Structure of the Chapter

This Chapter reviews a number of recent developments at the following utilities:

- BC Hydro
- Hydro Quebec
- Nalcor
- NB Power.

Developments at these utilities are summarized, in turn, in the sections below.

3.2 BC Hydro

3.2.1 Overview

In the May 2015 Report, we noted that the BC government had put in place a 10-year plan in 2013 to improve the financial position of the utility while reducing rate increases that had been projected by the utility in an earlier rate application. With respect to the rate increases being proposed, the 10-year plan is still in effect and being followed.

On March 22, 2016, the British Columbia Utility Commission (BCUC) approved an interim rate increase of 4.0% effective April 1, 2016. The rate increase adheres to the rate trajectory laid out in the government's 2013 10-year plan. In approving the rate increase, BCUC noted that BC Hydro would actually need a rate increase of 9.7% to recover its forecast Fiscal 2017 revenue requirement during the rate year. The portion of the revenue requirement that will not be recovered as a result of the lower rate increase that was applied will be transferred to a regulatory deferral account for recovery in the future.

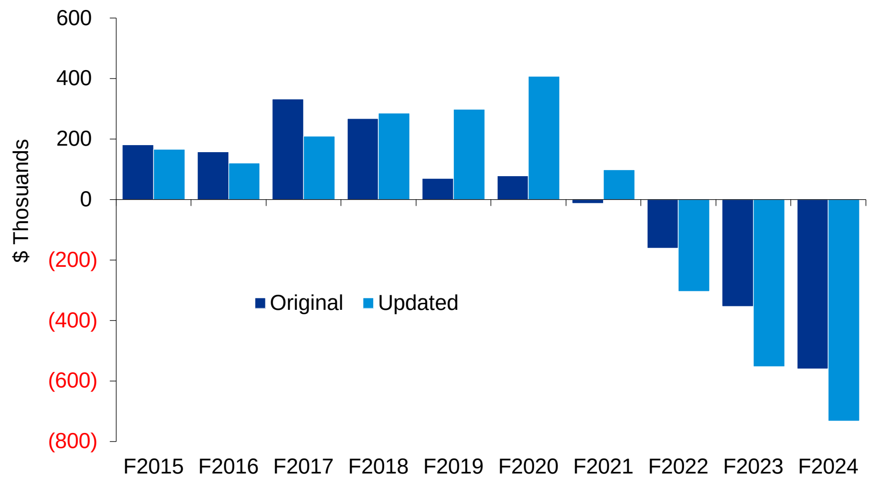
In its application for interim rates, dated February 2016, BC Hydro noted that there had been significant declines in the financial position of key commodity sectors in BC as well as delays in a decision to proceed with a Liquefied Natural Gas (LNG) project. These developments were expected to reduce load in the short term, putting additional upward pressure on rates. Accordingly, BC Hydro requested additional time to review its load and revenue forecast, in advance of submitting a full application that would seek approval of rates on a final basis.

BC Hydro submitted its full application on July 28th, 2016. It covers the 3-year period 2017 through 2019. This application maintains the request for a 3.5% effective rate increase for Fiscal 2017, consistent with the 10-year plan. While this application incorporates a lower load growth forecast in the short-term than earlier projections, BC Hydro is still projecting long-term growth across all three customer sectors (residential, light industrial/commercial, and large industrial).[3] Lower load growth in the short-term means that BC Hydro has had to take additional cost control measures to ensure that it can meet the

[3] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, July 28, 2016, p. 3-1.

targets set out in the 2013 10-year plan. [4] A particular concern is the need to recover all amounts that have been transferred to the regulatory deferral account for rate smoothing by 2024, thereby bringing balances down to zero by the end of that Fiscal Year. Deterioration in projected revenues relative to the original 10-year plan in the next few years mean that this regulatory deferral account will grow to a much larger amount than originally forecast. Figure 3-1 shows additions and withdrawals to the rate smoothing account in the original plan and as forecast in the rate application filed in 2016. Much greater withdraws from the rate smoothing deferral account will be required during the period Fiscal 2022 through 2024 than was originally forecast.

Figure 3-1: Additions / (Withdrawals) to Rate Smoothing Deferral Account

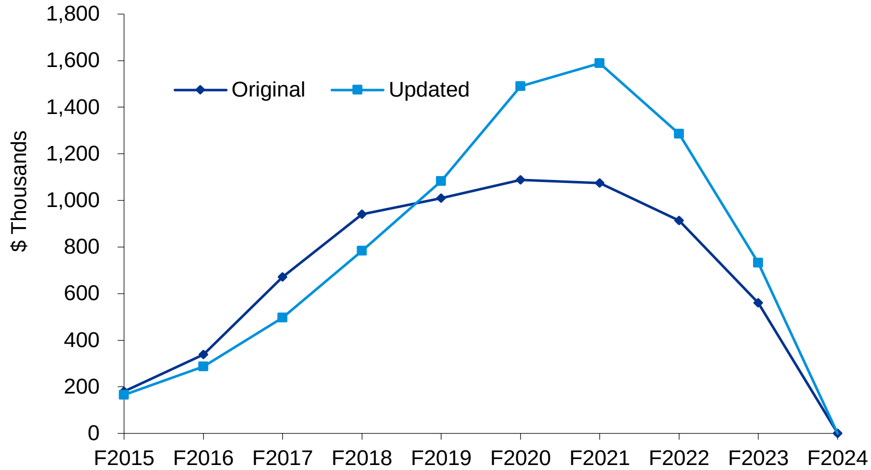


Source: derived from BC Hydro information.

Figure 3-2 shows cumulative balances in the rate smoothing account. Figure 3-2 shows that the cumulative balance grows to $1.59 billion, or almost 50% more than originally forecast. It should be noted that, although the rate smoothing account is projected to be brought down to zero by the end of Fiscal 2024, other regulatory accounts will remain in place. The balances in these other accounts are forecast to be at $3.609 billion at the end of Fiscal 2024, which is down slightly from the original forecast.

[4] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, July 28, 2016, p. 1-8.

Figure 3-2: Cumulative Balance - Rate Smoothing Deferral Account



Source: derived from BC Hydro information.

3.3 Hydro Quebec

3.3.1 Overview

Hydro Quebec issued a Strategic Plan for the period 2016-2020 on June 8, 2016. The Strategic Plan centres on four major objectives:

- Laying the groundwork to double the utility's revenue over the next 15 years, thereby increasing profits.
- Being a benchmark in customer service.
- Contributing to Quebec's economic development and energy transition to a low-carbon economy.
- Keeping rate increases lower than or equal to inflation.

Specific financial objectives include the following:

- Generating revenue of $27 billion by 2030 (versus $13.75 billion in 2015).
- Reaching net income of $3.2 billion in 2020 and $5.2 billion in 2030.
- Increasing net income by $300 million through new exports.

Reaching these financial targets will require significant business expansion. With only its current base of operations, Hydro Quebec expects that it would achieve nominal net income of just $2.850 billion in 2020 (versus $3.147 billion in 2015) and $4.0 billion by 2030. Projected nominal income of $4.0 billion for 2030 is equivalent to about $3.0 billion in 2015 dollars. [5] Hence, continuation of only its current base of business would result in a relatively steady-state outlook in real dollar terms.

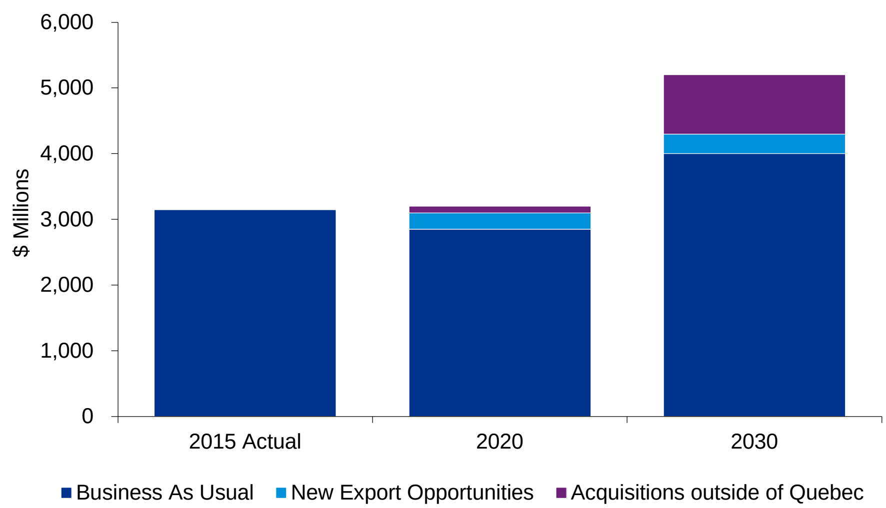
[5] Hydro Quebec, Strategic Plan 2016-2020, pp. 9-12.

To make up the difference between a 'business as usual' scenario and its long-term financial objectives, Hydro Quebec plans an increased focus on new export opportunities and on the acquisition of assets or business interests outside of Quebec. The bulk of growth will come from the acquisition of businesses and assets outside of the province of Quebec: of $1.2 billion in additional net income beyond a business as usual scenario, $900 million will come from out-of-province acquisitions.

The Strategic Plan does not specifically identify the size of investments that will be required to reach the targets for net income growth identified. Nor does it indicate if changes in dividend policy will be required to help fund this expansion through increased retention of utility earnings. Hydro Quebec has traditionally paid out 75% of its net income as dividends to the Province.

Figure 3-3 below shows the target composition of net income as outlined in the Strategic Plan.

Figure 3-3: Projected Sources of Net Income – Hydro Quebec



Source: derived from Hydro Quebec information.

In the Strategic Plan, the utility's forecast capital program over the period 2016 to 2020 is relatively stable, with annual spending of between $3.1 billion (in 2020) and $4.0 billion (in 2018). The capital program includes completion and commissioning of the last two units of the Romaine Dam complex:

- Romaine 3, with 395 MW, will come on-line in 2017, and
- Romaine 4, with 245 MW, will come on-line in 2020.

Over the 2016-2020 period, Hydro Quebec will also undertake preliminary studies to examine the feasibility of various other large-scale hydropower projects in the area of Plan Nord.[6] According to its Strategic Plan, Hydro Quebec will then be in a position to choose the next hydro-electric project, for implementation in the decade following.

[6] Plan Nord is the Province of Quebec's plan for development of Northern Quebec.

One observer has characterized the 2016-2020 years as a period of consolidation, rather than expansion, noting an increased focus on encouraging energy efficiency by customers, and on employee productivity and engagement.[7]

The Provincial government, in parallel, has introduced a new energy policy. This policy aims to make Quebec a North American leader in the fields of renewable energy and energy efficiency, thereby allowing Quebec to prosper in a low-carbon economy. Key elements of the plan:

- Enhancing energy efficiency by 15%.
- Reducing the consumption of petroleum products by 40%.
- Eliminating the use of thermal coal.
- Increasing overall renewable energy output by 25%.
- Increasing bioenergy production by 50%.[8]

Hydro Quebec Strategic Plan will support the broader provincial policy through:

- Support for the electrification of transportation, including through electric vehicle charging networks.
- Development and commercialization of innovative technologies, including battery materials and energy storage systems.
- Continued support to R&D.

3.3.2 Regulated transmission and distribution

As discussed in the May 2015 Report, only the business segments of transmission and distribution are regulated by the provincial utility regulator. The regulator approved a rate increase of 0.7% effective April 1, 2016 for residential customers and the majority of business customers, and also 0.7% for 2017. Industrial customers served under the large-power industrial rate will see no rate increase.[9] The capital structure assumed for the distributor remains unchanged, with a deemed debt/equity ratio of 65:35.

3.4 Nalcor

3.4.1 Overall Structure

On June 24, 2016, Nalcor Energy provided an update on its Muskrat Falls Project. This update indicated that there had been a material deterioration in the outlook for this project, with projected in-service costs escalating from $7.4 billion, as were forecast at project sanction in 2012, to $11.4 billion as projected at the time of the update. Excluding financing and other costs, projected construction costs alone have escalated from $6.2 billion as at project sanction to $9.1 billion currently. The completion date for the full project has also slipped from the second quarter of 2018 to the second quarter of 2020, a delay of about 2 years. These developments will put significant financial pressure on Nalcor and on the Province.

In parallel with the adverse developments noted above, the demand for power in Newfoundland has decreased as a result of the economic downturn and as a result of increased electricity costs. Annual energy deliveries on the island interconnected system are now not expected to reach levels initially forecast for 2020 until 2036.

[7] Erik Richer La Fleche, « Hydro-Quebec Strategic Plan 2016-2020 ». Blog entry posted on July 24, 2015. http://futureimperfect.ca/hydro-qubec-strategic-plan-2016-2020/

[8] Government of Quebec, "The 2030 Energy Policy: Energy in Quebec – A Source of Growth,

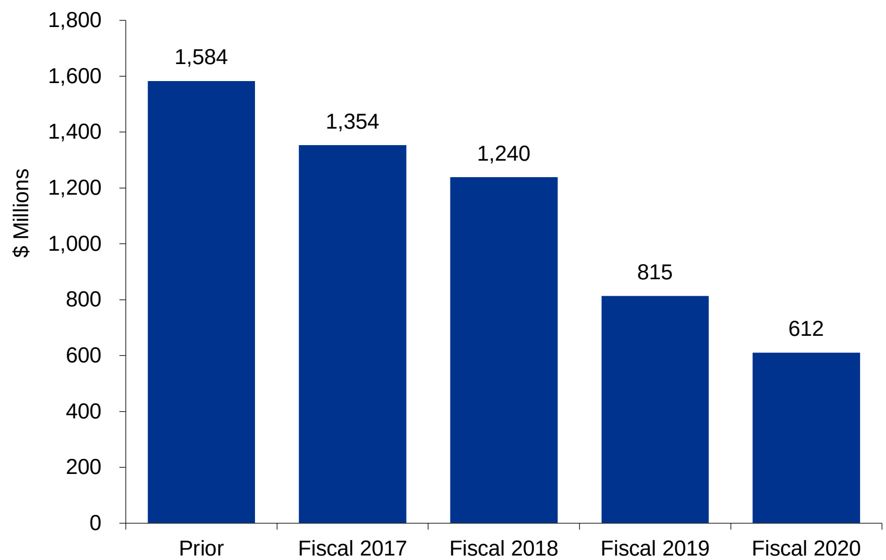
[9] Hydro Quebec press release: "2016-2071 Rate Application – An electricity rate increase below inflation", March 8, 2016.

As a result of the above developments, electricity rates for domestic customers are forecast to rise to 21.4 cents per kWh in 2021. This is about 6.3 cents per kWh more than the rates that were forecast when the Muskrat Falls project was initially approved. [10]

Although the economics of the project have deteriorated, Nalcor has indicated that it is no longer practical to cancel the project, given the amount of funds expended to date and contractual commitments for the delivery of power to Emera.

As a result of the cost overruns noted above, the Province will need to inject significant additional equity into Nalcor Energy. Total provincial equity requirements for the Muskrat Falls project are now $5.6 billion, with annual requirements summarized in Figure 3-4 below. [11]

Figure 3-4: Provincial Equity Requirements – Muskrat Falls Project



Source: derived from Nalcor information.

A DBRS rating report in November 2015 indicated that the Provincial equity commitment for the Lower Churchill Falls project was expected to be $3.2 billion, of which roughly 34% (or $1.09 billion) had already been extended. This forecast was based on then-estimated construction costs of $7.7 billion for the project.[12] As noted earlier, construction costs are now estimated at $9.1 billion, or $1.4 billion more.

Also as noted earlier, projected equity contributions are now estimated at $5.6 billion. Compared to the equity contributions noted in the November 2015 DBRS report (of $3.2 billion), equity contributions are thus now $2.4 billion higher. Increases in equity contributions reflect the increase in time to completion of the project as well as additional construction costs, both of which serve to increase project financing costs.

[10] Nalcor Energy press release: "Nalcor Energy provides update on Muskrat Falls Projects, June 24, 2016. The press release did not provide a definition of a domestic customer.

[11] Nalcor Presentation: "Muskrat Falls Project Update", June 24, 2016, p. 6.

[12] DBRS Rating Report, Province of Newfoundland and Labrador, November 19, 2015, p. 3.

In the May 2015 Report we noted that the Government had contributed $706 million in equity capital to Nalcor in 2013. This equity capital supported initial debt offerings to help fund the Muskrat Falls project. Given the figures presented above, this initial contribution will need to be followed by substantially greater contributions going forward. In the November 2015 report, DBRS had already noted that cost overruns during the construction phase could put pressure on Provincial credit metrics.

3.5 NB Power

3.5.1 Overview

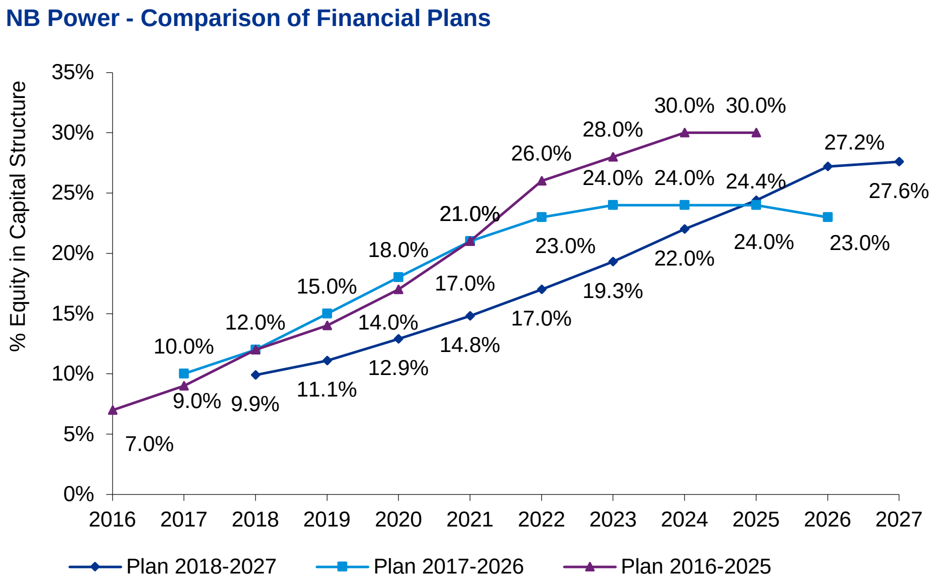
In the May 2015 Report, we noted that NB Power was operating under a long-term plan to significantly improve the utility's financial position. The key target of this plan is to achieve a capital structure with at least 20% equity. Under the plan, improvement of the utility's equity position was to be achieved through even annual rate increases of 2% over the period through 2022, with 1% rate increases thereafter. The approved rate for 2017 was 1.77%.

Since the May 2015 Report, NB Power has prepared two new 10-year plans in succession, covering Fiscal Years 2017 to 2026 and, subsequently, Fiscal Years 2018 to 2027. Under the latest plan, the achievement of at least a 20% equity position has been delayed to Fiscal 2024 from Fiscal 2021. The equity position continues to improve beyond that, to 27.6% by Fiscal 2027. However, this is still less than the 30% equity ratio projected for Fiscal 2024 and 2025 under the initial 2016-2025 plan.[13]

In both of the subsequent 10-year plans (2017-2026 and 2018-2027), rate increases of 2% extend only through to 2021, or one year earlier than under the 2016-2025 plan. Rate increases of 1% follow. The plan that was released for 2017-2026 roughly matched increases in equity shown to 2021 under the 2016-2025 plan but then showed a decline in equity growth thereafter. The most recent plan, for 2018-2027, shows strong increases in equity ratio throughout its planning horizon, although achievement of individual equity levels is considerably lagged. Overall, the deterioration in financial position relative to earlier plans appears largely related to decreases in load growth. Projected equity ratios under the various plans are shown in Figure 3-5 below.

[13] As a result of a typographical error, the May 2015 report stated at page 48 that NB Power would reach a 20% equity target by 2024 under its 10-Year Plan; the correct figure should have been 30%.

Figure 3-5: NB Power's Equity Ratio under Successive 10-Year Plans



Source: derived from NB Power information.

Over the medium to long-term, a key factor that bears on NB Power's financial position is projected spending for the Mactaquac project. Initially, NB Power expected to begin major spending on replacement or refurbishment of this dam in the early part of the next decade. NB Power has now concluded that it can extend the life of the existing facility beyond 2030 through a modified intensive maintenance program and replacement of aged equipment.[14] This has delayed the start of major expenditures to 2027 and should reduce overall total expenditures. Nevertheless, total spending of $2.7 billion for the Mactaquac project is forecast through to 2036. The delay noted above in the expenditure profile accounts for the fact that equity ratios continue to improve through 2027, rather than peaking a number of years earlier. (However, as noted earlier, improvements in the equity ratio are on a delayed trajectory.)

It is instructive to look at the rationale provided by NB Power for reaching a 20% equity target as outlined in its rate filings. In the 2016/17 General Rate Application filed December 28, 2015, NB Power noted the following:

> "The rationale for reaching the 20 per cent equity goal by fiscal year 2020/21 has not changed. First, NB Power recognizes that it requires an equity cushion as a risk management tool. The utility is subject to a variety of operational and financial risks, and an equity cushion will allow the utility to withstand negative contingencies without subjecting customers to sudden, unpredictable rate changes or the utility to financial losses."[15]

In the same application, NB Power went on to note:

> "The second justification for reaching the target of 20 per cent equity by 2021 relates to the timing of anticipated capital expenditures. NB Power needs to work towards reducing debt and improving its

[14] NB Power's 10-Year Plan, Fiscal Years 2018 to 2027. p. 18.

[15] New Brunswick Power Corporation, 2016/17 General Rate Application, December 28, 2015, p. 4.

capital structure due to the relatively low capital investments required in the next five years of the current 10-Year Plan. The current plan contemplates that the period of low capital investment will be followed by a number of years of very high investment, as the utility begins to incur costs associated with the decisions around Mactaquac. In order to prepare for that investment, and maintain stable rates as those costs are incurred, the 10-Year Plan continues to contemplate a series of smaller rate increases to build the necessary equity."[16]

While plans now call for a delay in reaching the 20% target, the underlying justification remains in place.

NB Power ultimately filed formal external evidence on an appropriate capital structure in GRA 2017/18. The evidence is in the form of a report by Elenchus Research Associates Inc.[17] The report does not provide much analysis or external data to support its conclusions but rather focuses on interpreting the government's intentions as laid out in the 2008 Electricity Act. Some highlights of this report are as follows:

- Planned rate increases should take into account the fact that events (e.g. low water-flows) could result in financial results being lower than forecast. Thus, the report notes: "Rates should be set to that there is steady progress toward the 20% target not only at the forecast level of net income but also if actual realized net income in the forecast year is at the lower end of the expected range."[18] This suggests that improvement in the equity position should occur even under adverse conditions.
- NB Power may require that the equity ratio be built up above the 20% minimum in advance of major capital programs. Thus, "projected rate projected rate increases should be high enough prior to the first year of the increased capital requirements so that the forecast equity ratio will not decline to less than 20% during the period when the high capital requirements cause the equity ratio to erode." [19]

While GRA 2017/18 included the external evidence as noted above, it did not then include any update to the 10-year financial plan provided with the GRA 2016/17. NB Power indicated that it would file a new 10-year plan only after its Board had made a decision on the option for replacement of Mactaquac. The 10-year plan for 2018-2027, summarized earlier in Figure 3-5, reflects the Board's subsequent decision to extend the service life of Mactaquac through intensive maintenance.

Based on the various sources of information summarized above, it can be observed that NB Power faces similar circumstances to Manitoba Hydro. Specifically:

- Cyclical patterns in the rate of investment in capital investment may require rate increases in advance of these investments to help bolster the utilities' financial positions.
- The shareholder does not contemplate making direct equity investments. Rather, equity is built up through retained earnings.

As part of its filing for GRA 2017/18, NB Power undertook a series of sensitivities that examined the impact of different rate trajectories over the 10-year plan, along with different scenarios for required capital spending. The different capital spending scenarios incorporated alternative estimates of the costs of Mactaquac refurbishment. As would be expected, these sensitivities showed that higher rate

[16] New Brunswick Power Corporation, 2016/17 General Rate Application, December 28, 2015, p. 5.

[17] Elenchus Research Associates Inc., "Consideration in Determining an Appropriate Long Term Capital Structure for New Brunswick Power", September 2016, filed as Appendix 06 of NB Power's 2017/18 General Rate Application, dated October 4th, 2016.

[18] Elenchus Research Associates Inc., p. 13.

[19] Elenchus Research Associates Inc., p. 14.

increases are required in individual years to maintain a target debt/equity ratio in the absence of strategies to smooth rate increases. Smoothing strategies include building up the equity ratio in advance of periods of high capital spending.[20]

In regard to these sensitivity analyses, NB Power noted in its rate filing:

> "It is NB Power's view that this analysis demonstrates the need for an overall two percent rate increase in the 2016/17 fiscal year, under any scenario in the sensitivity analysis. The need for the requested two per cent increase is enhanced if the Board ultimately approves a long-term capital structure which requires an equity component greater than 20 per cent." [21]

The request for sensitivities was prompted by a desire to see analysis of the impact of deferring achievement of the 20% equity target. The potential for deferral may have been prompted by observations that the equity ratio was projected to increase beyond 20% after the target was reached. In its 2015 Decision, the Board noted:

> "The 10-Year Plan projects that NB Power's equity ratio will increase from 21% in fiscal 2020-21 to 30% in 2024-25. Although this appears to provide NB Power with some degree of flexibility in its plans to improve its equity ratio, the Board did not receive any form of a sensitivity analysis to assess the impact of an extension scenario. A sensitivity analysis in future rate applications would provide the Board with a clear understanding of the impacts of deferring the achievement of the 20% equity goal beyond 2021."[22]

As highlighted in the above quote, the New Brunswick EUB specifically requested sensitivity analysis to better understand the potential impact of uncertainty and of different rate trajectories on achievement of the utility's financial targets. The desire for this type of scenario analysis also underlies Manitoba Hydro's decision to undertake uncertainty and sensitivity analysis with respect to future financial risks.

3.5.2 Costs of Carbon Taxes

In its most recent 10-year plan (for 2018-2027), NB Power has projected additional rate increases to incorporate the impact of federal and/or provincial actions to introduce carbon taxes. These increases will be over and above the 1% and 2% increases noted earlier to accommodate NB Power's own revenue requirement. As a utility that relies extensively on fossil-fueled generating facilities, NB Power will be significantly impacted by climate change initiatives and associated carbon taxes. In the current 10-year plan, total annual rate increases of 3.4% annually are now forecast beyond 2018. This incorporates 1.4% annual increases between 2019 and 2021, and 2.4% annual increases thereafter, to pay for carbon taxes or allowances. (These are added to base increases of 2.0% and 1.0% respectively for these same periods.) Thus, overall rate increases are projected to be much higher than in the initial 10-year plans.

3.6 Summary Observations

Each of the utilities summarized in this Chapter is facing developments that have or could put additional pressure on its financial position:

- BC Hydro has faced declines in demand relative to forecast, which has increased its need to rely on regulator deferral accounts to operate within the rate trajectory outlined in its 10-year plan.

[20] NB Power's 10 Year Plan: Fiscal Years 2017 to 2026, Appendix 2, prepared October 2015, pp. 1 - 4.

[21] New Brunswick Power Corporation, 2016/17 General Rate Application, December 28, 2015, pp. 5 - 6.

[22] New Brunswick Energy and Utilities Board, Reasons for Decision, Matter No. 272, October 28, 2015, p. 24.

- Hydro Quebec has ambitious targets for new business growth, which may require new equity investments to achieve the revenue targets as outlined.
- Nalcor has faced escalating capital costs on the Muskrat Falls project, resulting in the need for significant additional equity capital. The project will also put substantial upward pressure on electricity rates in Newfoundland and Labrador once these expenditures are put into the utility's Rate Base.
- NB Power has lowered its forecast of its equity ratio in the short- to medium-term, reflecting lower load growth and cost pressures. Delays in spending on Mactaquac refurbishment, however, have supported improvements in its projected equity ratio longer-term. NB Power is also forecasting significant additional rate increases as a result of the need to address federal and provincial climate change policies.

These various developments reinforce the need for utilities to have robust financial targets, to cushion against adverse developments in their financial outlook.

4 Comparison to Other Government-owned Power Utilities in Canada

This chapter summarizes the findings from benchmarking and review of the developments, targets and plans of government-owned power utilities in other jurisdictions. Financial data and information for government-owned power utilities are updated to the latest audited fiscal year, ending either December 31st, 2016 or March 31st, 2017. This reflects three additional years of financial data from the May 2015 Report in most cases.

4.1 Structure of the Chapter

This chapter is organized into the following sections:

- Section 4.2 provides an overview of government-owned power utilities in Canada, which have been selected as the peer benchmarking group, along with key operational metrics and comparisons on a per capita and per customer basis.
- Section 4.3 compares current debt/equity ratios and capital structures.
- Section 4.4 compares interest coverage ratios among the Canadian peer group.
- Section 4.5 looks at cash flow to capital expenditure comparisons among the Canadian peer group.
- Section 4.6 compares a number of other financial metrics among the Canadian peer group.
- Section 4.7 provides a comparison of recent electricity prices and analysis of trends in electricity prices in Canada over the next ten years based on various assumptions.
- Section 4.8 discusses financial targets and plans of other government-owned utilities in Canada.
- Section 4.9 outlines summary points of the benchmarking comparisons.

4.2 Overview of Government-owned Power Utilities in Canada

4.2.1 Overview of key operational metrics

Figure 4-1: Overview of Operating Information on Government-owned Power Utilities

Overview of Operating Information	Installed Capacity (MW)	Peak Demand (MW)	Total Electric System Deliveries (TWh)	% Hydro generation	Number of Electricity Customers
Manitoba Hydro	5,679	4,801	33.2	97%	573,438
BC Hydro	12,053	10,194	57.7	98%	1,988,167
Hydro Quebec	36,908	36,005	202.0	99%	4,244,541
Nalcor Energy	7,210	8,864	39.9	96%	> 38,000
Ontario Power Generation	16,177	n/a	78.2	40%	n/a
NB Power	3,513	3,000	16.7	25%	401,166

Source:
1. Manitoba Hydro Annual Report for the year ended March 31, 2017.
2. BC Hydro Annual Service Plan Report for the year ended March 31, 2017.
3. Hydro-Quebec Annual Report for the year ended December 31, 2016.
4. Nalcor Energy Annual Report for the year ended December 31, 2016. Note Churchill Falls represents installed capacity of 5,428 MW and its electricity is primarily exported to Hydro-Quebec. Number of customers is direct customers only, there are substantially more indirect customers through third party sales.
5. Ontario Power Generation Inc. Annual Report for the year ended December 31, 2016. All electricity generated is sold through Ontario's Independent Electricity System Operator.
6. NB Power Annual Report for the year ended March 31, 2017.

Government-owned power utilities with a significant reliance on hydroelectric generation are the most appropriate peer utilities in Canada for benchmarking the financial and operational position of Manitoba Hydro. These utilities are: BC Hydro, Hydro-Quebec, and Nalcor Energy (“Nalcor”).

In the analysis, NB Power and Ontario Power Generation (“OPG”) are also included, as both of these utilities have significant hydro assets and are Crown owned. NB Power is owned by the Province of New Brunswick and is the largest electric utility in Atlantic Canada. OPG is owned by the Province of Ontario, and operates a portfolio of hydroelectric, nuclear and other generating assets.

This group of six power utilities including Manitoba Hydro will represent the Canadian peer group for benchmarking and analysis in this Chapter.

To put into context the size of these power utilities in relation to their jurisdiction, the following is noted from comparisons in Figure 4-2:

- On a per capita basis, Manitoba Hydro has more installed generation capacity than BC Hydro, similar installed capacity as Hydro-Quebec and NB Power, and much higher capacity than OPG (although note that OPG is not the sole supplier in Ontario). It is lower only in comparison to Nalcor. (Figures for Nalcor, however, are distorted by the sale of power from Churchill Falls to Hydro-Quebec under long-term contract, which boosts its figures for capacity and sales per capita.)
- Manitoba Hydro's total power generation per capita is generally in line with per capita levels for Hydro-Quebec and NB Power, higher than BC Hydro, much higher than OPG, and much lower than Nalcor.
- Extra-provincial electricity sales represent 24% of total electricity sales, which is a very significant level and a higher share than for other power utilities. BC Hydro categorizes its extra-provincial activity as "trade" revenues and these represent approximately 11% of electricity revenues, a much smaller share than in the May 2015 Report (when the figure was 20%). Hydro-Quebec, the largest electricity exporter in Canada, also has a lower share with exports representing approximately 12% of its total sales.

Figure 4-2: Operational Metrics Per Capita and Value of Export Sales

Select Operational Metrics Per Capita	Provincial Population (2016)	Installed Capacity kW per capita	Electric System Deliveries thousands kWh per capita	Extraprovincial Electricity Sales ($ millions)	Extraprovincial / Trade Sales %electric sales
Manitoba Hydro	1,318,100	4.3	25.2	460	24%
BC Hydro	4,751,600	2.5	12.1	674	11%
Hydro-Quebec	8,326,100	4.4	24.3	1,626	12%
Nalcor	530,100	13.6	75.4	47	8%
Ontario Power Generation	13,983,000	1.2	5.6	n/a	n/a
NB Power	756,800	4.6	22.1	251	15%

Source:
1. Manitoba Hydro Annual Report for the year ended March 31, 2017.
2. BC Hydro Annual Service Plan Report for the year ended March 31, 2017. Extraprovincial exports reflects "trade" revenues.
3. Hydro-Quebec Annual Report for the year ended December 31, 2016.
4. Nalcor Annual Report for the year ended December 31, 2016. Extraprovincial sales from Churchill Falls and NLH's Energy Marketing.
5. Ontario Pow er Generation Inc. Annual Report for the year ended December 31, 2016.
6. NB Pow er Annual Report for the year ended March 31, 2017. Extraprovincial exports reflects "interconnection" revenues.
7. Populations from Statistics Canada as of July 1, 2016.

Figure 4-3 indicates the size of Manitoba Hydro, BC Hydro, Hydro-Quebec and NB Power in relation to the size of their domestic customer base. (Nalcor and OPG are not included in this figure as their customer bases are not comparable – Nalcor's customer base includes Hydro-Quebec and one major wholesale customer, Newfoundland Power Inc., and OPG is one of many suppliers to the broader Ontario market.) For the utilities that are included in Figure 4-3, note the following:

- As in the May 2015 Report, Manitoba Hydro has more installed capacity and electricity system deliveries per domestic customer than the other three electric utilities.
- Manitoba Hydro's domestic electricity revenues per customer is higher than BC Hydro, close to Hydro-Quebec and lower than NB Power.
- Manitoba Hydro has significantly more extra-provincial export revenues in relation to its domestic customer base than BC Hydro, Hydro-Quebec and NB Power.

Figure 4-3: Operational and Financial Information on a Per Customer Basis

Select Operational and Financial Information on a Per Customer Basis

	Electricity Customers	Installed Capacity kW per Customer	Electric System Deliveries thousands kWh per Customer	Electricity Revenues per Customer	Extraprovincial Electricity Sales per Customer
Manitoba Hydro	573,438	9.9	58.0	$3,360	$802
BC Hydro	1,988,167	6.1	29.0	$2,954	$339
Hydro-Quebec	4,244,541	8.7	47.6	$3,110	$383
NB Power	401,166	8.8	41.7	$4,038	$626

Source:
1. Manitoba Hydro Annual Report for the year ended March 31, 2017.
2. BC Hydro Annual Report for the year ended March 31, 2017.
3. Hydro-Quebec Annual Report for the year ended December 31, 2016.
4. NB Pow er Annual Report for the year ended March 31, 2017.

Figure 4-4 provides an overview of key financial metrics for the Canadian peer group for 2016/2017. (Appendix A provides, in addition, financial data for Manitoba Hydro and the other government-owned power utilities over the past seven fiscal years.)

Hydro-Quebec is considerably larger than the other utilities of the peer group, with annual revenues of over $13 billion, approximately 5.7 times that of Manitoba Hydro, and total assets of over $75 billion, approximately 3.4 times those of Manitoba Hydro. (The ratio of assets is down from the May 2015 Report, when it stood at 4.7, reflecting Manitoba Hydro relatively greater investments over the intervening period.) BC Hydro is the next largest. Manitoba Hydro is in the middle of the group, with revenues that are significantly larger than for NB Power and Nalcor. It should be noted, however, that Nalcor's revenues will grow with the completion of the Lower Churchill Project and Muskrat Falls.

Relative to utilities with fossil-fuel generation, the utilities based primarily on hydropower generally have significantly better operating margins and relatively higher EBITDA, EBIT and net income as a share of revenues. Hydro-Quebec's high levels of EBITDA, net income and cash flow relative to other utilities reflect its larger size and is partially due to the benefits of very low-cost electricity received under its long-term power contract with Churchill Falls in Newfoundland and Labrador.

Figure 4-4: Overview of Financial Information, Government-owned Power Utilities in Canada

Overview of Financial Information - Select Canadian Electric Power Utilities (CDN$ millions)					
($CDN millions)	Annual Revenues	EBITDA	EBIT	Depreciation & Amortization	Net Income
Manitoba Hydro	2,327	1,106	704	402	59
BC Hydro	5,874	2,521	1,289	1,232	684
Hydro Quebec	13,339	7,990	5,393	2,597	2,861
Nalcor Energy	824	343	208	135	136
Ontario Power Generation	5,653	1,998	741	1,257	453
NB Power	1,696	540	307	233	27

Overview of Financial Information - Select Canadian Electric Power Utilities (CDN$ millions)						
($CDN millions)	Total Assets	Net Debt	Interest on Debt	Retained Earnings & Other Equity	Cash Flow from Operations	Capex
Manitoba Hydro	22,338	15,792	711	2,360	872	2,924
BC Hydro	31,888	19,975	767	4,909	1,327	2,513
Hydro Quebec	75,167	44,673	2,510	19,704	5,504	3,363
Nalcor Energy	14,062	6,440	273	4,263	222	2,741
Ontario Power Generation	44,372	5,336	298	10,508	1,705	1,704
NB Power	6,968	4,900	207	320	253	278

Source:
1. Manitoba Hydro Annual Report for the year ended March 31, 2017.
2. BC Hydro Annual Report for the year ended March 31, 2017.
3. Hydro-Quebec Annual Report for the year ended December 31, 2016.
4. Nalcor Annual Report for the year ended December 31, 2016.
5. Ontario Pow er Generation Inc. Annual Report for the year ended December 31, 2016.
6. NB Pow er Annual Report for the year ended March 31, 2017.

Note: Retained earnings and other equity includes share capital or contributed capital, accumulated other comprehensive income and non-controlling interest. Net debt includes long-term debt, short-term borrow ings and current portion of long-term debt less sinking funding investments and cash and cash equivalents.

4.3 Capital Structure – Equity Ratio Comparisons

Manitoba Hydro's equity ratio was 16% as at March 31, 2017. This ratio is based on Manitoba Hydro's formula, which uses net debt in its calculation and includes contributions in aid of construction ("CIAOC") as part of equity, thus providing a debt/equity ratio of 84/16.

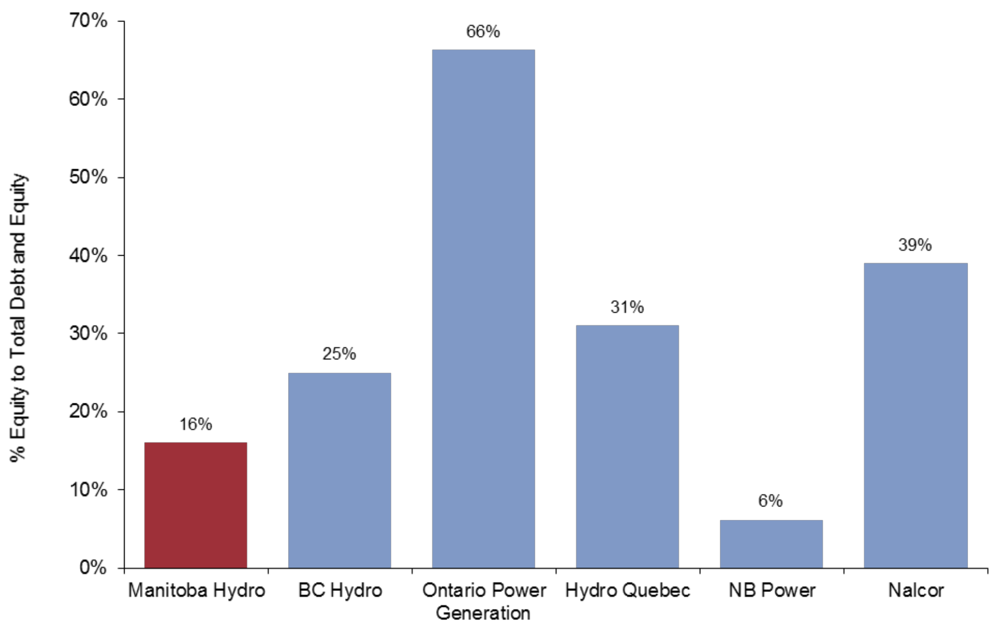
In comparing the equity ratios of government-owned electric power utilities in Canada, adjustments were made to reflect Manitoba Hydro's formula for calculating equity ratios. For example, BC Hydro's reported equity ratio has been 20% over the past five years. Making adjustments for Manitoba Hydro's definition of net debt and including CIAOC in equity, however, results in an equity ratio of 25%. Even with these adjustments, there are still some differences remaining in accounting and reporting frameworks among utilities. However, the adjustments that have been made enable better direct comparison.

Retained earnings represent the large majority of equity for most of the government-owned power utilities in Canada. Of the Canadian utilities in the benchmarking group, all include Accumulated Other

Comprehensive Income ("AOCI") as part of their equity. Like Manitoba Hydro, some utilities such as Hydro-Quebec, OPG and Nalcor have also included contributed capital as part of their equity. Manitoba Hydro also has a relatively small amount of non-controlling interest included in equity.

Investor-owned power utilities in Canada tend to have equity ratios of about 40%, but a more appropriate comparison for Manitoba Hydro is to government-owned utilities, particularly those with significant hydro-electric power. Manitoba Hydro's current equity ratio is at the lower end of those observed among government-owned power utilities. Only NB Power is lower, as NB Power has undergone considerable financial challenges and restructuring. Results are shown in Figure 4-5.

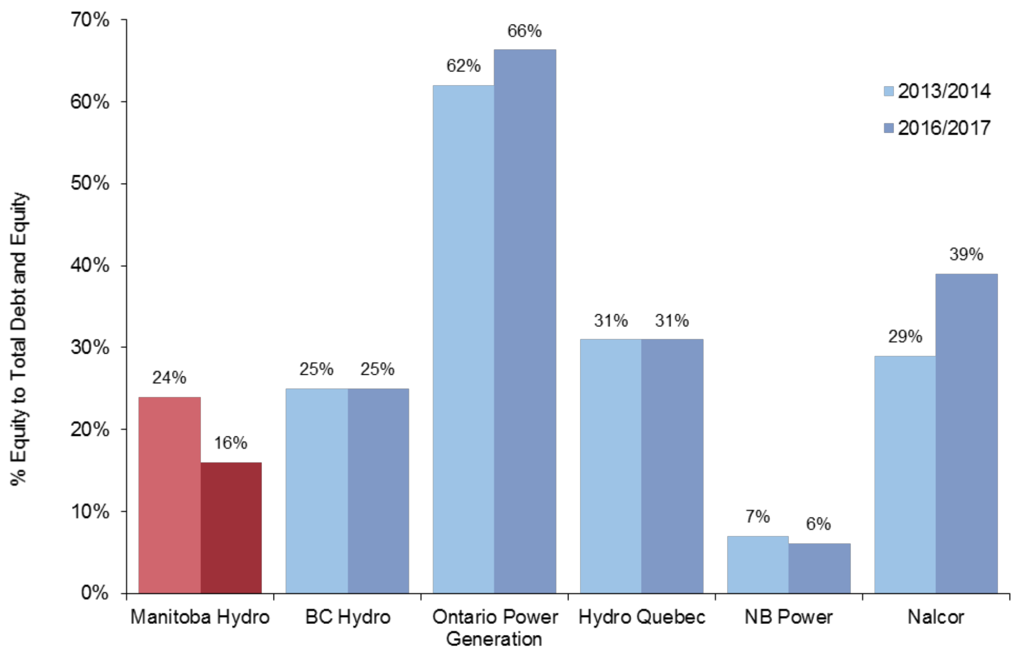
Figure 4-5: Comparison of Government-owned Power Utilities in Canada, Capital Structure – Equity Ratio, 2016/2017



Source: Derived from annual reports and financial statements for the year ended March 31, 2017 for Manitoba Hydro, BC Hydro and NB Power, and for the year ended December 31, 2016 for OPG, Hydro Quebec and Nalcor.. Subject to adjustments due to some differences in accounting and reporting. For direct comparison to Manitoba Hydro, equity includes contributions in aid of construction ("CIAOC"), and net debt includes long-term debt, current portion of long-term debt and other current borrowings less sinking fund investment and cash and cash equivalents. Note BC Hydro reports equity to debt at 20:80, but with CIAOC, equity ratio is 25%.

Figure 4-6 compares current ratios (in 2016/17) with those presented in the May 2015 Report, representing 2013/14 data. Manitoba Hydro's equity ratio has declined markedly, from 24% in 2013/14 to 16% in 2016/17. NB Power's equity ratio also significantly declined during this period, while those of BC Hydro and Hydro Quebec were relatively unchanged. Nalcor's equity ratio increased from 29% to 39%; this was due to its shareholder's contribution of \$734.6 million in 2015 and another \$656.1 million in 2016 in relation to Nalcor's capital expenditures.

Figure 4-6: Comparison of Government-owned Power Utilities in Canada, Capital Structure – Equity Ratio, 2013/2014 and 2016/2017

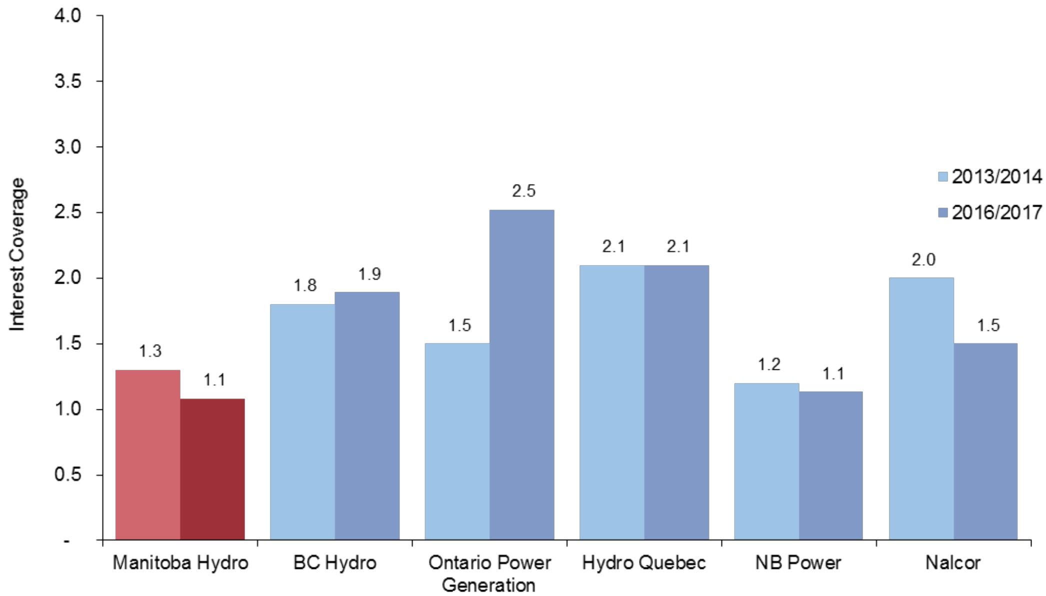


Source: Derived from annual reports and financial statements for the year ended March 31, 2017 and March 31, 2014 for Manitoba Hydro, BC Hydro and NB Power, and for the year ended December 31, 2016 and December 31, 2013 for OPG, Hydro Quebec and Nalcor. Subject to adjustments due to some differences in accounting and reporting. For direct comparison to Manitoba Hydro, equity includes contributions in aid of construction ("CIAOC"), and net debt includes long-term debt, current portion of long-term debt and other current borrowings less sinking fund investment and cash and cash equivalents. Note BC Hydro reports equity to debt at 20:80, but with CIAOC, equity ratio is 25%.

4.4 Interest Coverage Comparisons

For the year ending March 31, 2017, Manitoba Hydro was below its historical interest coverage target of greater than 1.20. Figure 4-7 provides a comparison of interest coverage ratios among government-owned power utilities in Canada as of the latest fiscal year as well as from the previous report (2013/2014). Nalcor experienced a substantial decline in its interest rate coverage ratio from 2.0 in 2013 to 1.5 in 2016. The ratio at OPG significantly improved. The other government-owned power utilities had ratios that were relatively unchanged in 2016/2017 compared to three fiscal years earlier.

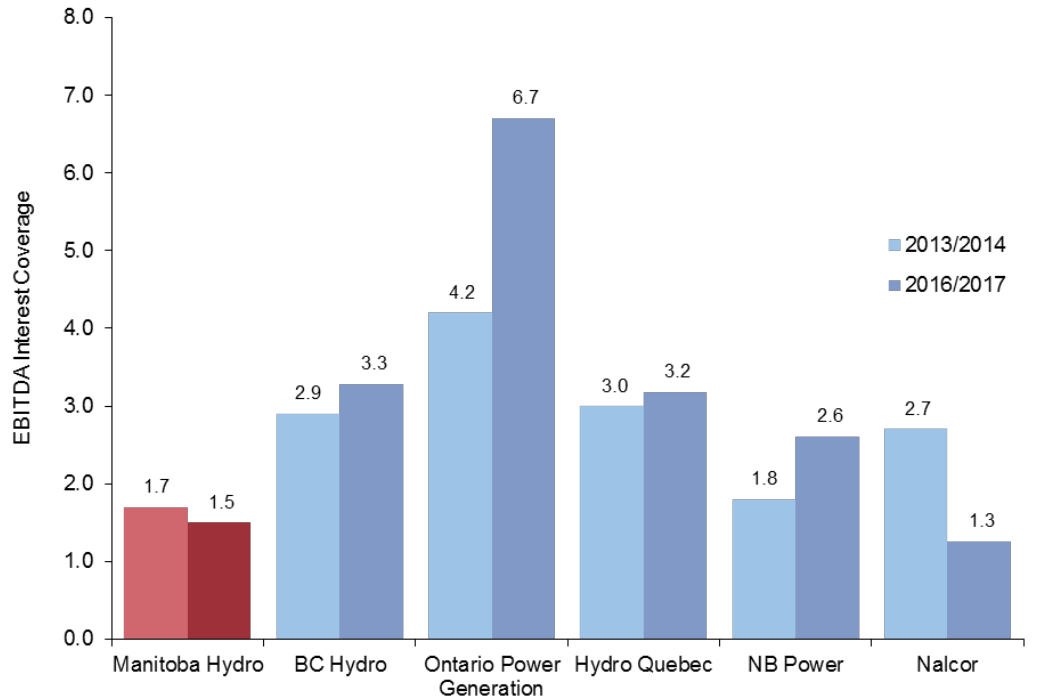
Figure 4-7: Comparison of Government-owned Power Utilities in Canada, Interest Coverage, 2013/2014 and 2016/2017



Source: Derived from annual reports and financial statements for the year ended March 31, 2017 and March 31, 2014 for Manitoba Hydro, BC Hydro and NB Power, and for the year ended December 31, 2016 and December 31, 2013 for OPG, Hydro Quebec and Nalcor. Subject to adjustments due to some differences in accounting and reporting. Interest coverage reflects total interest paid on debt and net income divided by total interest paid on debt.

Figure 4-8 provides a comparison of EBITDA interest coverage ratios among government-owned power utilities in Canada. Manitoba Hydro's EBITDA interest coverage was down (to 1.54) from the previous report. Most of the other government-owned power utilities experienced improvements in the EBITDA interest coverage ratios in 2016/2017 compared to the three years earlier in the previous report. The notable exception was Nalcor, which experienced a substantial deterioration in its EBITDA interest rate coverage from 2.7 in 2013 down to 1.3 in 2016.

Figure 4-8: Comparison of Government-owned Power Utilities in Canada, EBITDA Interest Coverage, 2013/2014 and 2016/2017



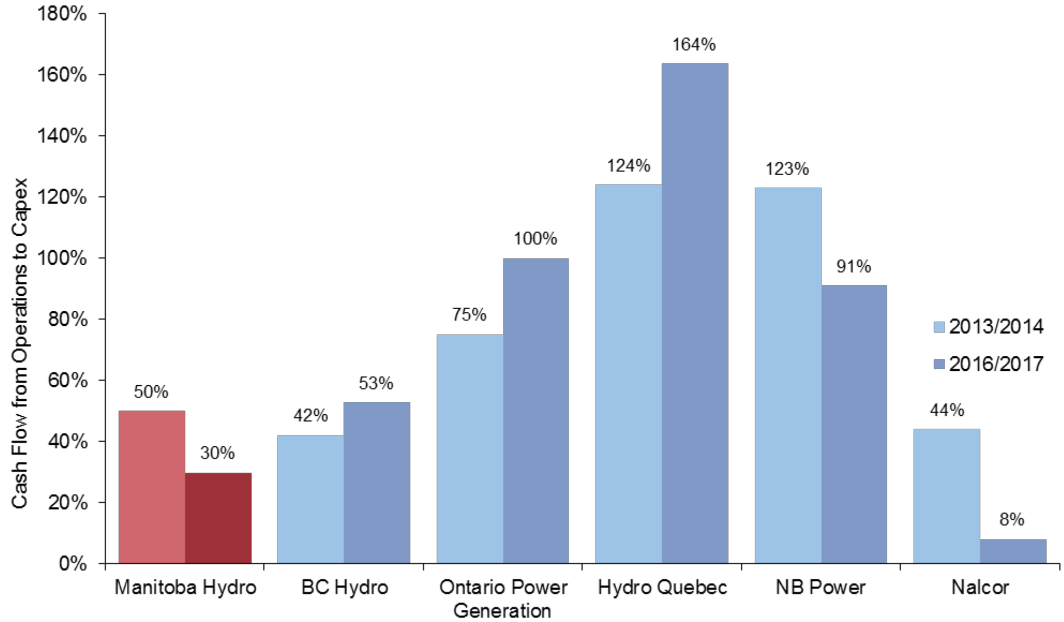
Source: Derived from annual reports and financial statements for the year ended March 31, 2017 and March 31, 2014 for Manitoba Hydro, BC Hydro and NB Power, and for the year ended December 31, 2016 and December 31, 2013 for OPG, Hydro Quebec and Nalcor. Subject to adjustments due to some differences in accounting and reporting. EBITDA (earnings before interest, taxes and depreciation and amortization) does not include capitalized interest. Property and capital taxes are operating expenses and are not added back to EBITDA calculations; only income taxes, if any, are part of the EBITDA calculations.

4.5 Capital Coverage or Cash Flow to Capex Comparisons

For Manitoba Hydro, the ratio of cash flow from operations to total capital expenditures dropped from 50% in 2013/14 to 30% in 2016/17. As shown in Figure 4-9, the 30% ratio was higher than at Nalcor, which is also in the process of completing major hydroelectric capital projects; Nalcor's cash flow position as measured through the capital coverage ratio substantially deteriorated between 2013 and 2016. In contrast to the other utilities, OPG and Hydro-Quebec had cash flows above their current capital expenditures in the latest available fiscal year.

Note that the ratio of cash flow to capex is subject to wide variation from year-to-year depending on the timing of major capital projects.

Figure 4-9: Comparison of Government-owned Power Utilities in Canada, Cash Flow from Operations to Capex, 2013/2014 and 2016/2017



Source: Derived from annual reports and financial statements for the year ended March 31, 2017 and March 31, 2014 for Manitoba Hydro, BC Hydro and NB Power, and for the year ended December 31, 2016 and December 31, 2013 for OPG, Hydro Quebec and Nalcor. Subject to adjustments due to some differences in accounting and reporting.

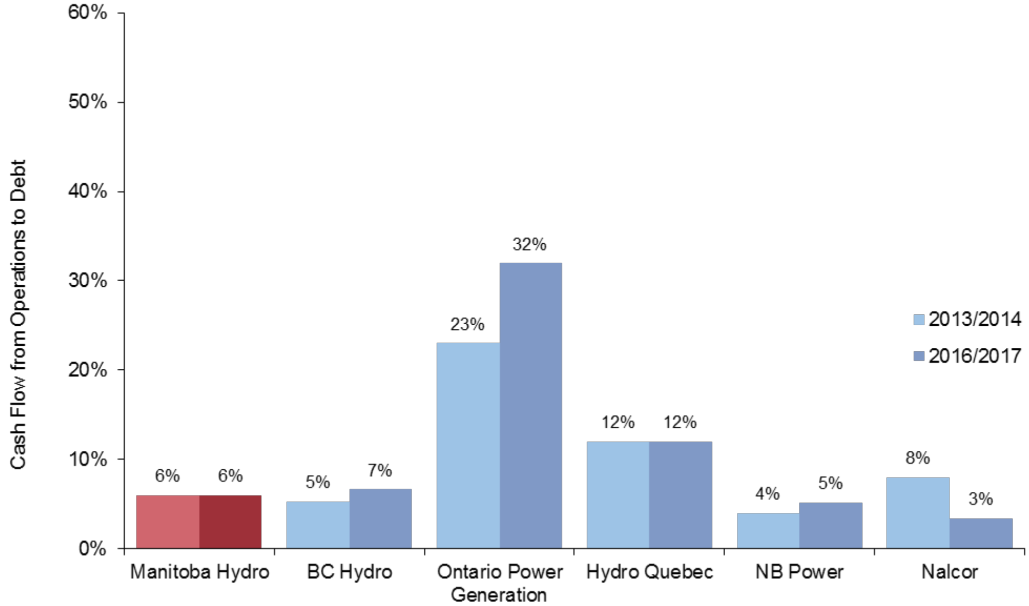
4.6 Other Financial Metrics Comparisons

The ratio of cash flow from operations to debt is one of the key measures monitored by credit rating agencies. Note that the figures for cash flow from operations shown in this section are as reported in audited cash flow statements; they have has not been adjusted for capitalized interest, which may be reported differently among utilities.

As noted earlier, Manitoba Hydro's increase in cash flow from operations grew significantly in 2016/17, reflecting significant growth in the balance of accounts payables primarily related to the construction of major capital projects. The understanding is that payables related to major capital projects will eventually reverse, which likely means that cash flow from operations for the reference year is overstated. Similarly, there may be other particular situations at other utilities that impact cash flow from operations in the reference year.

Figure 4-10 compares cash flow from operations to net debt. The ratio for Manitoba Hydro was approximately 6% as of March 31, 2017, higher than at Nalcor and NB Power, but considerably lower than Hydro-Quebec and OPG.

Figure 4-10: Comparison of Government-owned Power Utilities in Canada, Cash Flow from Operations to Net Debt, 2013/2014 and 2016/2017



Source: Derived from annual reports and financial statements for the year ended March 31, 2017 and March 31, 2014 for Manitoba Hydro, BC Hydro and NB Power, and for the year ended December 31, 2016 and December 31, 2013 for OPG, Hydro Quebec and Nalcor. Subject to adjustments due to some differences in accounting and reporting.

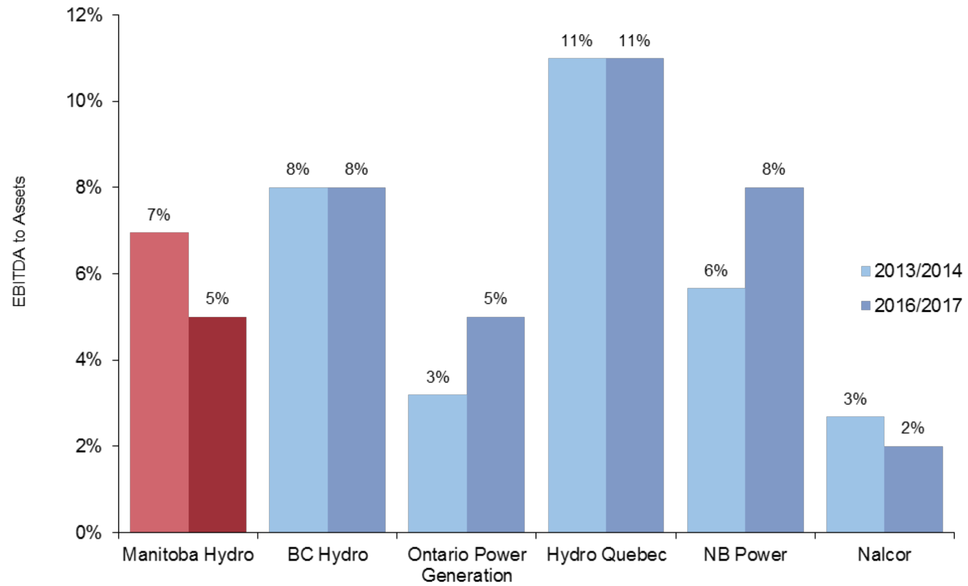
Figure 4-11 compares the ratio of EBITDA to total assets with significant growth in assets during a period of major construction. With significant growth in assets during this period of major construction, Manitoba's ratio of EBITDA to assets decreased from 7% in 2013/14 to 5% in 2016/17, with Nalcor lowest at 2% and Hydro Quebec highest at 11%.

Manitoba Hydro has consistently generated relatively strong EBITDA and net operating margins, reflecting its position as a power utility that is dominantly based on hydropower. Figure 4-12 compares EBITDA to total revenue. In 2016/17, Manitoba Hydro's EBITDA was approximately 47% of total revenues, among the highest ratios found among large power utilities in Canada. Of the group of government-owned power utilities, only Hydro Quebec had a higher level, at 60% EBITDA to total revenue.

Figure 4-13 compares net debt as a share of total assets. Manitoba Hydro is the highest in net debt to assets (at 71%) with NB Power second at 70%. Since the May 2015 Report, Manitoba Hydro and BC Hydro have had similar increases in this ratio. Nalcor experienced a significant decline in net debt to assets in the past three years related to significant shareholder contributions in 2015 and 2016.

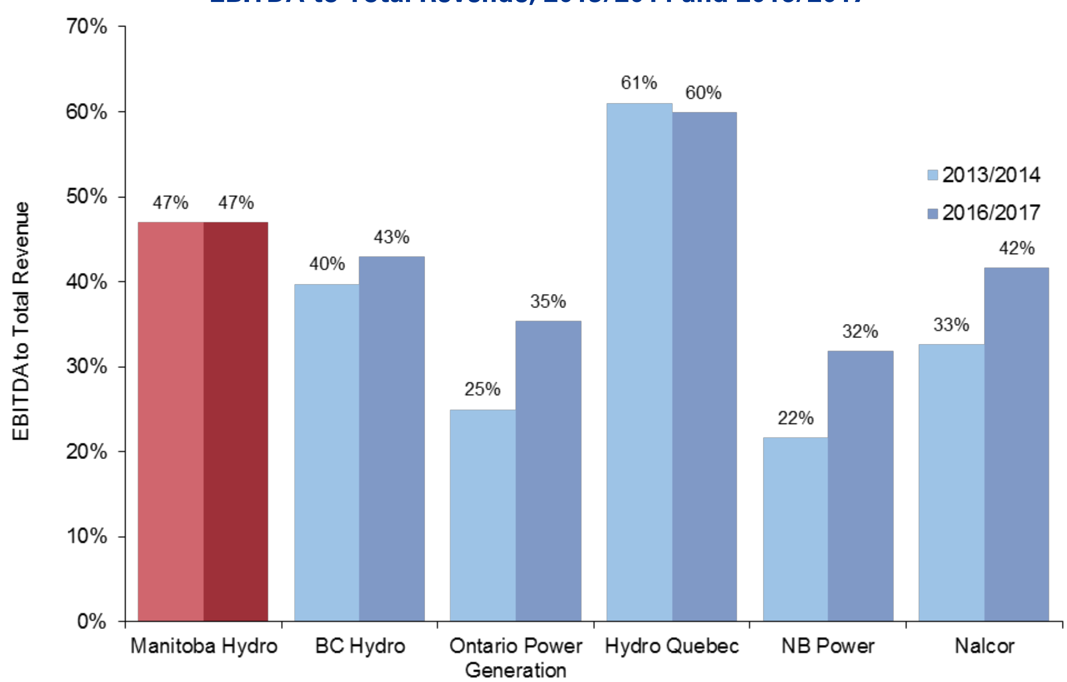
Figure 4-14 compares net debt to EBITDA which varies considerably, from 2.7 for OPG to 18.8 for Nalcor. Manitoba Hydro's ratio increased from 9.8 in 2013/14 to 14.3 in 2016/17.

Figure 4-11: Comparison of Government-owned Power Utilities in Canada, EBITDA to Assets, 2013/2014 and 2016/2017



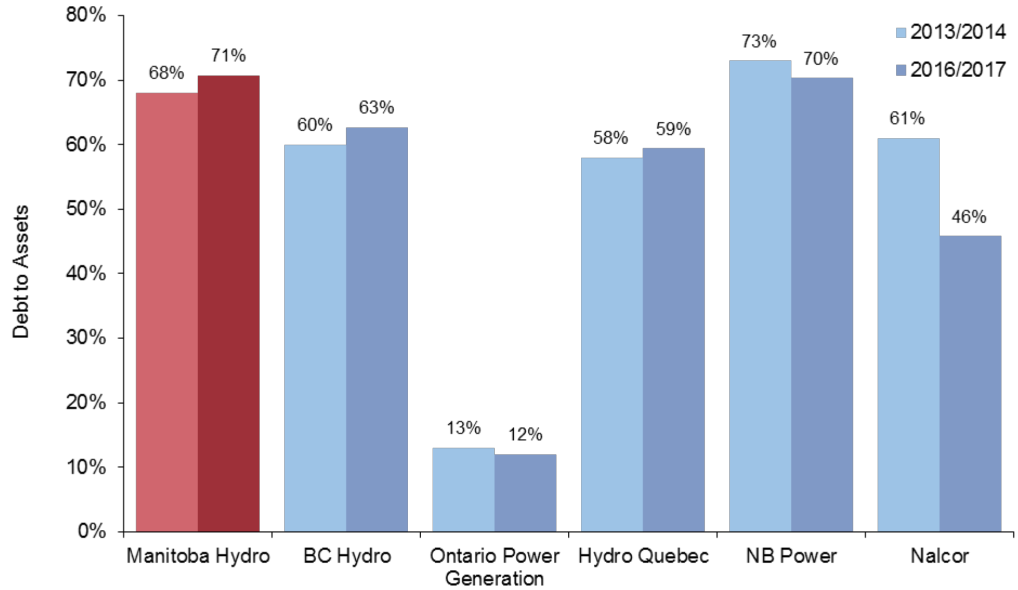
Source: Derived from annual reports and financial statements for the year ended March 31, 2017 and March 31, 2014 for Manitoba Hydro, BC Hydro and NB Power, and for the year ended December 31, 2016 and December 31, 2013 for OPG, Hydro Quebec and Nalcor. Subject to adjustments due to some differences in accounting and reporting.

Figure 4-12: Comparison of Government-owned Power Utilities in Canada, EBITDA to Total Revenue, 2013/2014 and 2016/2017



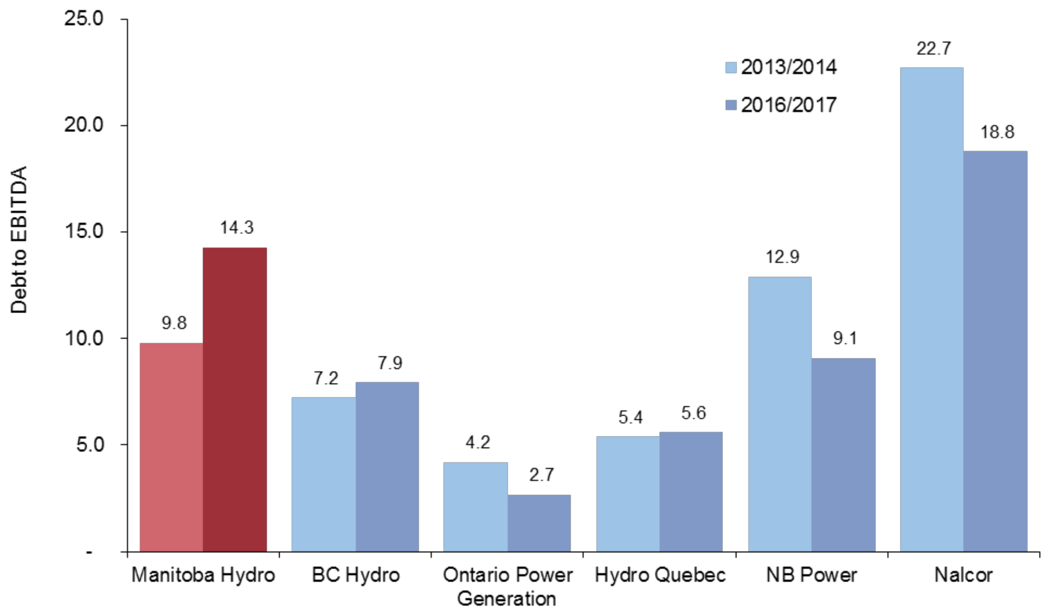
Source: Derived from annual reports and financial statements for the year ended March 31, 2017 and March 31, 2014 for Manitoba Hydro, BC Hydro and NB Power, and for the year ended December 31, 2016 and December 31, 2013 for OPG, Hydro Quebec and Nalcor. Subject to adjustments due to some differences in accounting and reporting.

Figure 4-13: Comparison of Government-owned Power Utilities in Canada, Net Debt to Assets, 2013/2014 and 2016/2017



Source: Derived from annual reports and financial statements for the year ended March 31, 2017 and March 31, 2014 for Manitoba Hydro, BC Hydro and NB Power, and for the year ended December 31, 2016 and December 31, 2013 for OPG, Hydro Quebec and Nalcor. Subject to adjustments due to some differences in accounting and reporting.

Figure 4-14: Comparison of Government-owned Power Utilities in Canada, Net Debt to EBITDA, 2013/2014 and 2016/2017



Source: Derived from annual reports and financial statements for the year ended March 31, 2017 and March 31, 2014 for Manitoba Hydro, BC Hydro and NB Power, and for the year ended December 31, 2016 and December 31, 2013 for OPG, Hydro Quebec and Nalcor. Subject to adjustments due to some differences in accounting and reporting.

4.7 Electricity Price Comparison

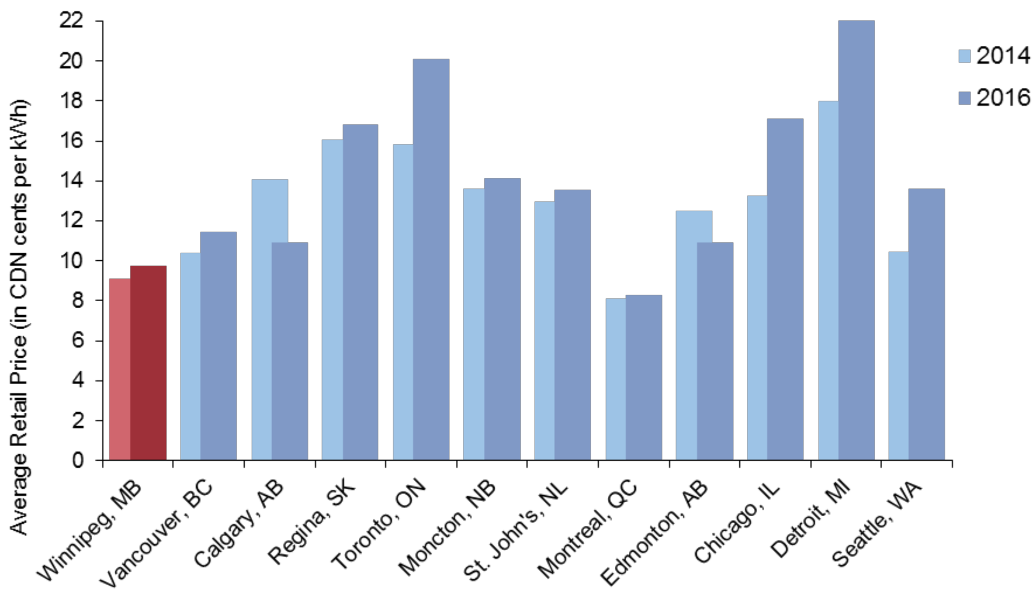
4.7.1 Manitoba Hydro's current competitive position

In this section, we have updated the comparison of retail electricity rates in Manitoba with those in a number of other North American jurisdictions. We present figures for 2016 as well as 2014, with figures for 2014 taken from the May 2015 Report. All figures are based on data from Hydro-Quebec's annual electricity price survey and are as at April 1 of the relevant year.

The analysis of electricity rates across jurisdictions can provide an indication of Manitoba's competitiveness with respect to energy costs. Manitoba Hydro has relatively low electricity rates, providing Manitoba Hydro with greater ability to raise rates in the future without causing undue adverse impact on Manitoba's attractiveness as a location for new business investment. Rate increases are necessary to ameliorate Manitoba Hydro's deteriorating equity position.

Figures 4-15, 4-16 and 4-17 below compare rates for residential, medium and large users. Figures for residential use assume monthly electricity consumption of 1,000 kWh, while those for medium and large assume monthly consumption of 400,000 and 30.5 million kWh respectively.

Figure 4-15: Comparison of Average Prices of Electricity, Residential, 2014 and 2016



Source: Hydro-Quebec. Comparison of Electricity Prices in Major North American Cities, Rates in effect April 1, 2016 and April 1, 2014 (including taxes). Residential assumption - power consumption 1,000 kWh. Hydro-Quebec study notes that these bills have been estimated by Hydro-Quebec and may differ from actual bills.

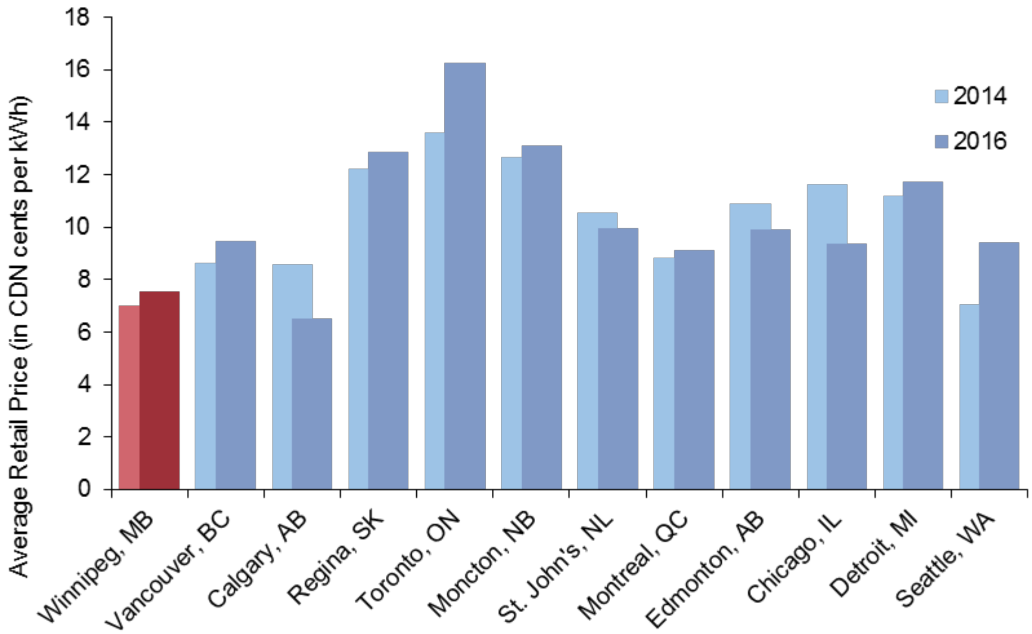
Based on Figure 4-15 we note the following:

- Manitoba currently has the second lowest electricity prices in the country for residential consumers (next to Quebec). The average price for residential customers in Winnipeg (including taxes) was 9.75 cents per kWh compared to an average of 14.1 cents per kWh among 12 Canadian cities in the survey. Manitoba prices are thus approximately 30% lower than the 12-city average.
- Residential rates in Manitoba increased somewhat between 2014 and 2016, as in many other jurisdictions, while rates in Toronto showed much larger increases (both in percentage and absolute terms). Rates in Calgary and Edmonton actually fell, reflecting lower electricity market prices in 2016. These were likely as a result of both low natural gas prices (which affect generation dispatch

costs) and a downturn in electricity market demand in the province. Both factors contributed to a decrease in prices in the competitive electricity market.

- Rates shown for US cities also increased sharply, although this may be largely attributable to changes in Canada / US exchange rates over the period.

Figure 4-16: Comparison of Average Prices of Electricity, Medium Power, 2014 and 2016

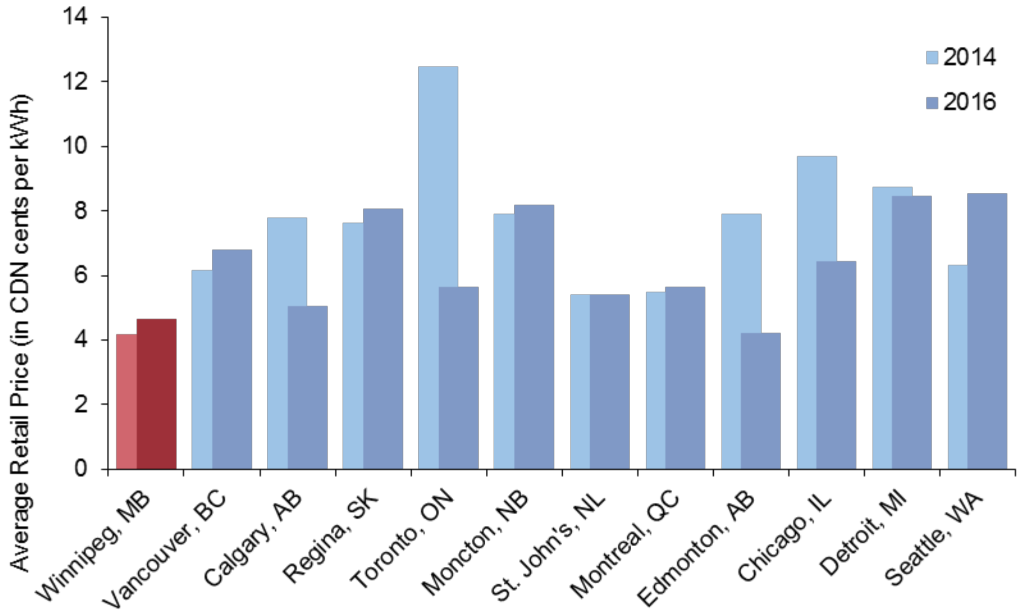


Source: Hydro-Quebec. Comparison of Electricity Prices in Major North American Cities, Rates in effect April 1, 2016 and April 1, 2014 (including taxes). Medium Power assumption - power demand 1,000 kW, power consumption 400,000 kWh, load factor 56%. Hydro-Quebec study notes that these bills have been estimated by Hydro-Quebec and may differ from actual bills.

Based on Figure 4-16 we note the following:

- Manitoba has the second lowest electricity prices for medium power consumers. The average price for "medium power" in Winnipeg (including taxes) was 7.5 cents per kWh compared to an average of 11.7 cents per kWh among 12 Canadian cities in the survey.
- As found in the residential rate comparison, retail prices for Toronto increased sharply, resulting in Toronto remaining the highest cost jurisdiction among those shown on the chart (and tied with Charlottetown, PEI, at 16.27 cents per kWh).
- Calgary had the lowest prices for 2016, representing a change in its relative position vis-à-vis 2014. Prices declined in both Calgary and Edmonton relative to 2014. This was driven by significant declines in the Alberta economy. Alberta is subject to relatively wide fluctuations in electricity prices.
- Rates for US jurisdictions showed both increases and decreases, showing that exchange rates were not the only factor affecting costs for medium power users in the US jurisdictions that were included.

Figure 4-17: Comparison of Average Prices of Electricity, Large Power, 2014 and 2016



Source: Hydro-Quebec. Comparison of Electricity Prices in Major North American Cities, Rates in effect April 1, 2016 and April 1, 2014 (including taxes). Large Power assumption - power demand 50,000 kW, power consumption 30,600,000 kWh, load factor 85%. Hydro-Quebec study notes that these bills have been estimated by Hydro-Quebec and may differ from actual bills.

Based on Figure 4-17 we note the following:

- Manitoba has the second lowest electricity prices for large power consumers. The average price for "large power" customers in Winnipeg (including taxes) was 4.7 cents per kWh compared to the 12-city average of 6.7 cents per kWh.
- Consistent with patterns observed for residential medium consumers, rates for large power users in Calgary and Edmonton fell between 2014 and 2016. Hydro Quebec reports that Edmonton is now the lowest cost jurisdiction for this class of users.
- Interestingly, the price shown for large power consumers in Ontario also fell sharply, in contrast to patterns observed for residential and medium power users (whose rates showed large increases). This fall may be attributable to the ability of large power users to avoid certain electricity costs in Ontario if they can reduce usage during system demand peaks.[23]

Overall, analysis of current price levels suggests that Manitoba remains a very low cost jurisdiction with respect to electricity rates. Accordingly, it should have relatively more ability to increase rates without jeopardizing the province's competitive position.

[23] Users classified as Class A can avoid costs associated with the "Global Adjustment" by reducing usage during the 5 hours of peak usage in the province in a year. Actual effective electricity costs can vary markedly based on usage profiles.

4.7.2 Manitoba Hydro's projected future competitive position

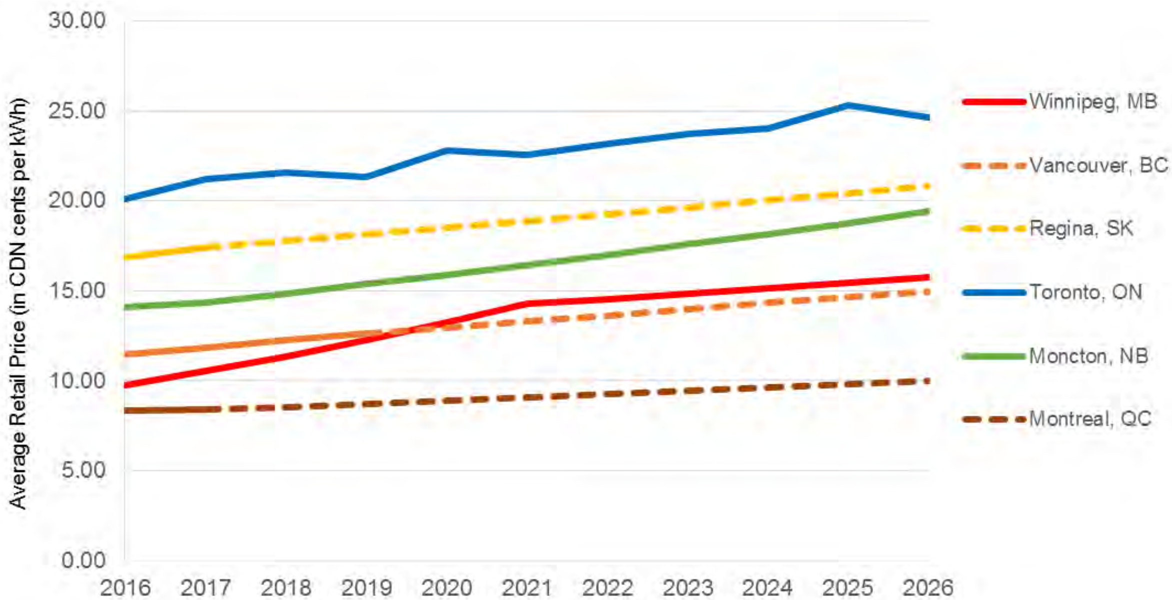
Figures 4-18, 4-19 and 4-20 indicate scenario forecasts of electricity prices over the next 10 years. These scenarios are based on public plans where available. The basis of these electricity price projections and assumptions is as follows:

- Manitoba electricity prices are based on proposed rate increases under Manitoba Hydro's IFF16.
- For BC Hydro, rate increases are based on the Province of British Columbia's 10 Year Plan, within which rate increases are prescribed for the next three years (applications for an increase of 4.0% in fiscal 2017, 3.5% in fiscal 2018 and 3.0% in fiscal 2019), and a target of 2.6% is identified for the next five years thereafter.
- For NB Power, rate increases are based on NB Power's 10 Year Plan, which outlines rate increases for the next ten years.
- For Ontario, rate increases are based on the projected increase in the unit cost of electricity as forecast by the Independent Electricity System Operator ("IESO"). Percentage increases are based on Outlook B contained in the IESO's Ontario Planning Outlook, dated September 1, 2016. As these figures reflect total system costs divided by total deliveries, they are not differentiated by customer class.
- Hydro-Quebec's rate increase is for 2016 and 2017 and SaskPower, rate increases are outlined for the next two years.
- For Nalcor, St. John's is excluded because the Muskrat Falls project is projected to lead to significant rate increases in the near and medium-term, however, there is no information at this time on projected rate increases.
- Where rate plans are not known, an assumption of 2% annually is applied.

Key findings from the review of Figures 4-18 through 4-20 are as follows:

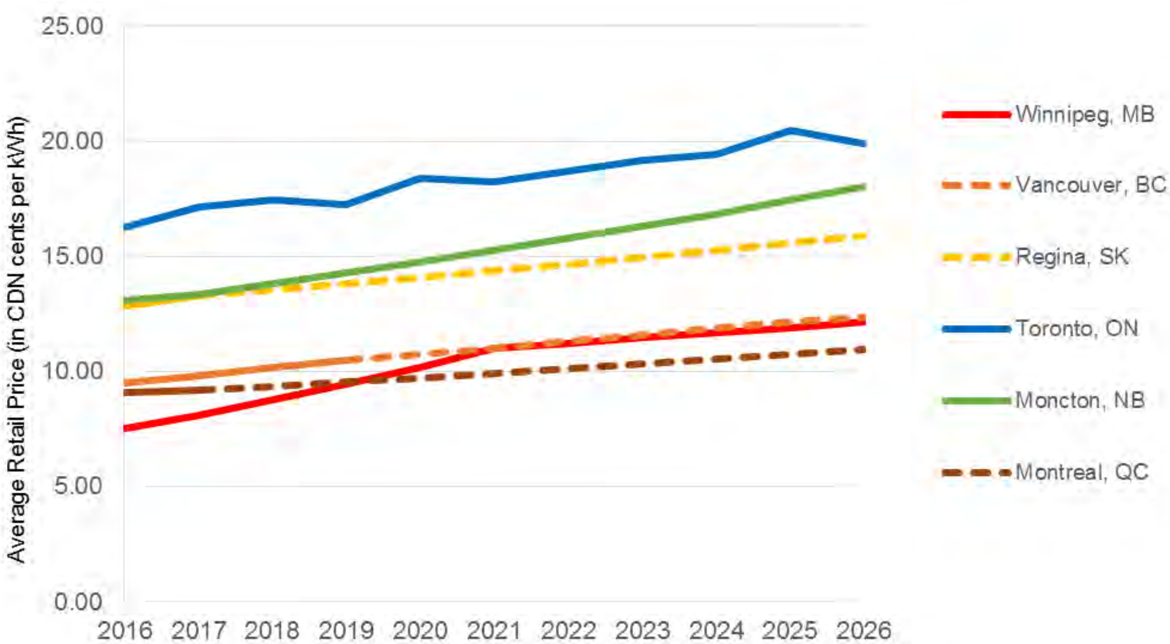
- Under 7.9% annual rate increases over the next five years, and 2.0% annual rate increases in the subsequent five years, these scenario graphs show Manitoba Hydro maintains its position as among the lowest electricity prices in Canada.

Figure 4-18: Comparison of Average Prices of Electricity in Canada, Scenario Projection 2016-2026, Residential



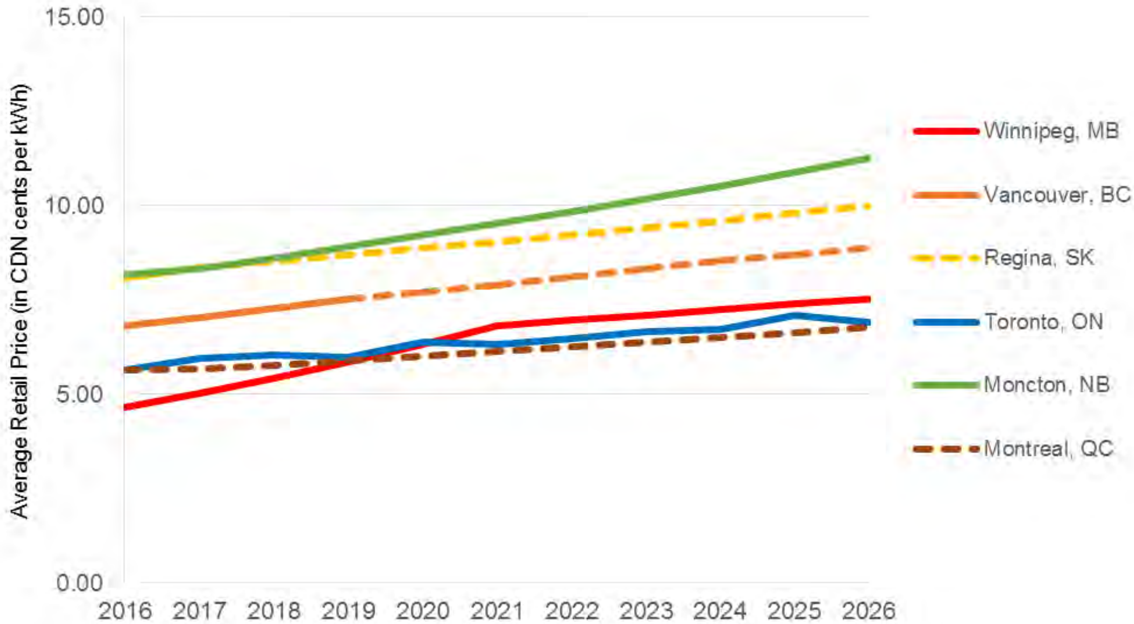
Source: 2016 base data from Hydro-Quebec Comparison of Electricity Prices in Major North American Cities, rates in effect April 1, 2016. Residential assumption - power consumption 1,000 kWh. Hydro-Quebec study notes that these bills have been estimated by Hydro-Quebec and may differ from actual bills. For jurisdictions, projected rate increases reflect projected plans and/or approved rates where available (see text for assumptions used). For all utilities and years where there is not a published plan, annual increases of 2% are used.

Figure 4-19: Comparison of Average Prices of Electricity in Canada, Scenario Projection, 2016-2026, Medium Power



Source: 2016 base data from Hydro-Quebec Comparison of Electricity Prices in Major North American Cities, rates in effect April 1, 2016. Medium Power assumption - power demand 1,000 kW, power consumption 400,000 kWh, load factor 56%. Hydro-Quebec study notes that these bills have been estimated by Hydro-Quebec and may differ from actual bills. For jurisdictions, projected rate increases reflect projected plans and/or approved rates where available (see text for assumptions used). For all utilities and years where there is not a published plan, annual increases of 2% are used.

Figure 4-20: Comparison of Average Prices of Electricity in Canada, Scenario Projection, 2016-2026, Large Power Users



Source: 2016 base data from Hydro-Quebec Comparison of Electricity Prices in Major North American Cities, rates in effect April 1, 2016. Large Power assumption - power demand 50,000 kW, power consumption 30,600,000 kWh, load factor 85%. Hydro-Quebec study notes that these bills have been estimated by Hydro-Quebec and may differ from actual bills. For jurisdictions, projected rate increases reflect projected plans and/or approved rates where available (see text for assumptions used). For all utilities and years where there is not a published plan, annual increases of 2% are used.

4.8 Financial Targets/Plans of Government-owned Power Utilities in Canada

Most of the government-owned power utilities in Canada include, as two of their primary financial metrics, one measure of capitalization (a debt to capital or debt/equity ratio) and one measure of interest coverage. Other metrics may be monitored in addition. Figure 4-21 indicates the financial targets/metrics highlighted in annual reports of select government-owned power utilities.

Figure 4-21: Key Financial Metrics or Targets of Government-owned Power Utilities in Canada

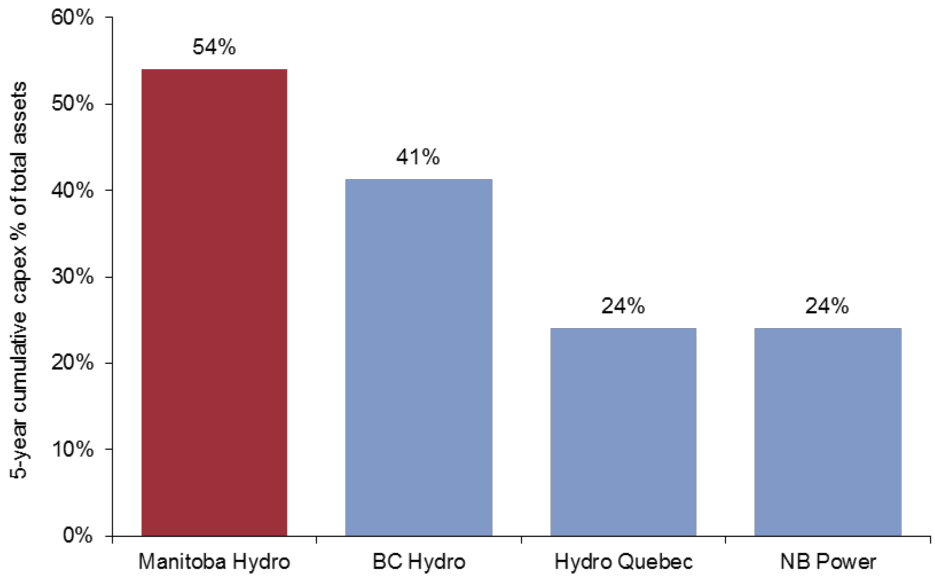
Key Financial Metrics or Targets of Government-Owned Power Utilities in Canada					
	Manitoba Hydro	**BC Hydro**	**Hydro-Quebec**	**Nalcor**	**NB Power**
Debt / Equity	• Long-term target of **75:25**, had been near target range from 2008 to 2014 • Forecast to deteriorate over the next decade due to major expansion	• Long-term target recently increased under new 10 Year Plan from **80:20** to **65:35** in 10 years • Target of 60:40 in the long-term	• Minimum requirement of **75:25**, practically has been steady in the range of **70:30** for several years • Expected to continue in the near term	• Minimum target of **70:30** for Nalcor and regulated hydro operations of NLH • Large increase in 2013 due to debt and equity for Lower Churchill Falls project	• Long-term target of **70:30** under new 10 Year Plan
Debt / Equity (as reported in latest annual report)	**84:16** (2016/17)	**80:20** (2016/17)	**69:31** (2016)	**61:39** (2016)	**96:04** (2016/17)
Interest Coverage	**> 1.8** EBITDA	target not stated	target not stated	**> 1.5** EBIT	target not stated
EBITDA interest coverage (as reported in latest annual report)	**1.54** (2016/17) • Has been significantly below target in recent years	**3.3** (2016/17) • Has averaged near 3x in recent years	**3.2** (2016) • Has averaged over 3x in recent years	**1.3** (2016) • Had averaged over 2x in recent years, but declined sharply in 2015 and 2016	**2.6** (2016/17) • Wide variance in recent years
Other financial metrics (highlighted in Annual Reports or Plans)	• Capital coverage of >1.2. **1.48** (2016/17) • Reflects cash flow to cover sustaining capital expenditures (excluding major generation and transmission expansion projects). Measure is challenged by the high amount of capitalized interest during high construction periods, and exclusion of certain capital, deferred and mitigation measures.	• Maintain rates in the first quartile. • Project Budget to Actual Cost within +5% to -5% of budget for five-year rolling data of generation, substation and transmission data.	• Return on equity from continuing operations 13.1% (2016), has ranged from 13-16% in recent years. • Profit margin from continuing operations 21.4% (2016), has ranged from 20-25% in recent years. • Self-financing, defined as cash flow from operations less dividends paid, divided by cash flows from investing activities, 58.8% (2016).	• Fixed rate debt as % of total debt, 91% (2016). • Return on capital employed (7.9% in 2016).	• Sets annual targets for net earnings, operating, management and administration costs, and net debt.

Source: Derived from annual reports, Manitoba Hydro, BC Hydro and N.B. Power for the year-ending March 31, 2017, Hydro-Quebec and Nalcor for the year-ending December 31, 2016. Also from latest published plans for various utilities.

Over the past decade, Manitoba Hydro's equity ratio climbed from 15% to be slightly over its long-term target of 25% in 2008 and 2010-2013. As Manitoba Hydro ramps up major generation and transmission projects, its equity ratio has significantly deteriorated and is forecast to deteriorate further. It will then recover after these new assets are in-service, and approach its long-term equity target. As of March 31, 2017, the equity ratio declined to 16%.

On a relative basis to assets, Manitoba Hydro's capital expansion program is larger than other government-owned power utilities in Canada. Projected capital expenditures over the next five year period are approximately 54% of the current asset base. Although this share is significantly lower than 83%, the number stated in the May 2015 Report (as significant capex is well underway now), it is still considerably higher than other government-owned utilities as shown in Figure 4-22.

Figure 4-22: Projected Capital Expenditures over the Next Five-Year Period Compared to Current Asset Base



Source: Derived from from annual reports and plans.

Hydro-Quebec

Hydro-Quebec has consistently maintained its equity ratio at slightly over 30% during the past decade, and this ratio is expected to remain near 30% over the next decade.

NB Power

NB Power has faced a number of financial challenges and this resulted in it having very low equity ratios over the past decade. Recognizing that its capital structure must improve, NB Power introduced a new 10 Year Plan, with the support of its owner, the Province of New Brunswick. The initial plan provided for a significant increase in its equity ratio over the next decade, with a target of 20% by 2021. NB Power's updated 10 Year Plan issued in 2017, indicates that various operating pressures and increased capital expenditure requirements results in a delay in meeting the internal capital structure target of 20% equity until 2024. However, recent results have continued to deteriorate, with the corporation having an equity ratio of only 6% in 2016/17.

BC Hydro

BC Hydro has maintained an equity ratio of 20% over the past decade. However, under the B.C. Government's recent 10-year plan for the utility, the Province directed that the utility move to a more robust capital structure. Under the Plan, BC Hydro targets to increase its equity ratio to 40% in the longer term (beyond the 10-year plan). The specific details of the 10-year plan, and the context for its development, are discussed in more detail in Chapter 4 of the May 2015 Report.

Nalcor

Nalcor is a holding company that holds the Government of Newfoundland and Labrador's interests in a number of energy companies, including Newfoundland and Labrador Hydro ("NLH"), which is a regulated utility whose activities encompass generation, transmission and electricity sales. Nalcor also holds entities created in the Lower Churchill Project and related investments. Nalcor's major new generation investment in the Lower Churchill Project is being undertaken outside of the regulated utility NLH. Its financial position has deteriorated in recent years, although its equity ratio was improved to 39% as a result of equity contributions in 2015 and again in 2016 from the Government of Newfoundland and Labrador.

4.9 Summary Observations – Benchmarking

Based on benchmarking and various comparisons of government-owned power utilities, particularly with hydro-based peer utilities in Canada, the following are summary observations:

- Manitoba Hydro has been and currently is at the low end of the peer group of government-owned power utilities in terms of key financial metrics including equity ratio, interest coverage ratio, cash flow comparison metrics, and other financial metrics. In benchmarking against government-owned power utilities in Canada, the gap in Manitoba Hydro's performance versus most other utilities has widened since the May 2015 Report.
- At a level of 25%, Manitoba Hydro's equity ratio target is below the current equity ratio observed at Hydro-Quebec and at Nalcor's regulated hydro operations. BC Hydro is currently near a 25% equity ratio, but plans to increase to 35% over the next decade, facilitated by a sharp drop in dividends paid to the Province of B.C. and by higher rate increases. Of the Canadian peer group, only NB Power has a lower equity ratio; however, NB Power has undergone financial challenges and its new plan is to ramp up to a minimum equity ratio of 20% over the next decade. Where government-owned power utilities have specified a plan to restore or achieve a target equity level, the planned time frame of ten years is consistent with that planned by Manitoba Hydro in IFF!6.
- Manitoba Hydro has a relatively high EBITDA to revenue ratio. The nature of the development of hydroelectric generation is that it entails very long development cycles, with very high capital expenditures during construction and relatively low operating costs and relatively strong operating margins once in service.
- Manitoba Hydro has very competitive electricity rates in Canada and North America, providing a significant advantage for ratepayers compared to other jurisdictions.
- Manitoba Hydro has relatively larger installed capacity and electric power generation per capita than most utilities, and extra-provincial electricity sales represent approximately 24% of total electricity sales, down somewhat in recent years, but a larger share than at other utilities and a very significant part of electricity operations.
- Manitoba Hydro's current capital expansion program is relatively much larger as a share of its existing asset base in comparison to other government-owned utilities in Canada (Figure 4-23).
- We note that the financial health of Manitoba Hydro has markedly deteriorated relative to forecast in the fiscal years that have passed since the May 2015 Report. For example, actual net income was significantly lower than forecast and retained earnings less AOCI dropped to $2.2 billion. These are concerning indicators for a utility in the midst of a large capital program. To be significantly off projection in the early years of a large capital program, further heightens risks and accelerates the need to return to better financial health.

Figure 4-23: Forecast under IFF14 versus Actual Results

IFF14 Projected versus Results ($ millions)	IFF14 Projected 2015/16	Actual 2015/16	% change	IFF14 Projected 2016/17	Actual 2016/17	% change
Revenues	2,337	2,258	-3%	2,387	2,327	-3%
Net income	126	39	-69%	67	59	-12%
Long-term debt	13,825	14,527	5%	16,698	16,438	-2%
Retained earnings less AOCI	2,502	2,052	-18%	2,559	2,190	-14%
Equity Ratio	19%	17%		17%	16%	

Source:
1. Manitoba Hydro Integrated Financial Forecast (IFF14).
2. Manitoba Hydro Annual Report for the year ended March 31, 2016 and for the year ended March 31, 2017.

5 Financial Targets in a Capital Markets Context

This chapter updates some of the credit rating perspectives as well as data on government-owned utilities in relation to their respective provincial economies and debt, from the May 2015 Report (in Chapter 6).

5.1 Overview of Credit Rating Reports on Manitoba and Manitoba Hydro

The Province of Manitoba has maintained a solid credit rating from three credit-rating agencies as indicated in the May 2015 Report (see Figure 5-1). However, since the May 2015 Report, Manitoba's credit rating from Moody's was downgraded in July 2015, and Standard and Poor's downgraded Manitoba's rating twice, in July 2016 and again in July 2017. The Moody's downgrade in July 2015 was Manitoba's first credit rating downgrade in nearly three decades.

Figure 5-1: Province of Manitoba Credit Rating

	Standard & Poor's	Moody's	DBRS
Rating	**A+**	**Aa1**	**A (High)**
Rating Outlook	Stable	Stable	Stable
Rating History	In July 2017, downgraded from AA-/Negative to A+/Stable. In July 2016, downgraded to AA-/Negative from AA/Stable Last upgrade was to AA/Stable from AA-/Positive in December 2007. Previous upgrade was in November 2006 to AA-/Positive from AA-/Stable since November 2002.	In July 2015, downgraded to Aa2 from Aa1. Outlook downgraded from Stable to Negative in August 2014. Last upgrade was November 2006, Aa2 to Aa1. Previously upgraded from Aa3 to Aa2 in January 2003, and after 13 years of A1 upgraded to Aa3 in September 1998.	Last upgrade was from A to A (High) in 2003 where it has remained since.

Source: Derived from information in credit agency rating reports – Standard and Poor's; Moody's; DBRS. Note: some credit agencies also issue a separate report on Manitoba Hydro, which reflect that Manitoba Hydro's debt is guaranteed by its owner, the Province of Manitoba.

Sovereign analysts from credit rating agencies review a number of factors in assigning ratings to governments including:

- Fiscal position and performance,
- Debt burden,
- Economy and economic fundamentals,
- Operating environment,
- Institutional framework,
- Contingent liabilities, and

- Other factors.

The Province of Manitoba's credit rating has typically been in the middle of those of Canadian provinces, lower than the Western provinces, and higher than the Atlantic Provinces and Quebec.

The credit rating agencies also issue separate analyses on Manitoba Hydro, although these reflect the fact that Manitoba Hydro's debt is guaranteed by the Province of Manitoba as its owner. Thus, Manitoba Hydro's credit rating is effectively a flow-through of the Province's credit rating. Most other government-owned utilities also receive the benefit of the credit rating of their provincial owner.

Comments from recent reports of individual credit ratings agencies are summarized in the sections below.

5.1.1 Standard and Poor's

In July 2017, Standard and Poor's lowered Manitoba's rating from "AA-" to "A+". Comments from the Standard and Poor's ratings report included:

> "Although Manitoba is taking clear steps to improve its fiscal sustainability in the long term, it faces large projected budget deficits and further growth in its already-high debt burden over the next two years. We are therefore lowering our long-term issuer credit and senior unsecured debt ratings on the Province of Manitoba to 'A+' from 'AA-'.
>
> Our assessment of the province's debt burden fully incorporates the debt on-lent to MHEB, which accounts for more than 40% of total tax-supported debt and for which the province expects to borrow heavily to finance capital projects over the next several years. We do not view MHEB as self-supporting due to its very high and rising leverage."[24]

One year earlier, in July 2016, Standard and Poor's[25] downgraded Manitoba's rating from "AA" to "AA-". Standard and Poor's commented:

> "The ratings on the Province of Manitoba reflect S&P Global Ratings' assessment of the significant rise in Manitoba's debt burden. This stems from the Province's ongoing fiscal shortfalls and significant debt on-lend to MHEB, which we no longer consider self-supporting mainly due to its high and rising leverage."[26]
>
> "Our assessment of the province's debt burden fully incorporates the debt on-lend to MHEB (nearly 40% of total tax-supported debt), whereas previously we had considered MHEB's status as a self-supporting entity to be a mitigating factor. We also expect Manitoba's interest expense will remain close to 6% of operating revenues over the next two years."[27]

The Standard and Poor's analysis outlined a number of key strengths for Manitoba including:

- Manitoba's very strong and diversified economy;
- Strong budgetary flexibility;
- Strong financial management;

[24] Standard and Poor's. Research Update: Province of Manitoba, July 21, 2017.

[25] Standard and Poor's. Supplemental Analysis: Province of Manitoba, July 29, 2016.

[26] Standard and Poor's. Supplemental Analysis: Province of Manitoba, July 29, 2016.

[27] Standard and Poor's. Supplemental Analysis: Province of Manitoba, July 29, 2016.

- Low contingent liabilities;
- Adequate liquidity;
- Canada's provincial-federal institution framework is very predictable and well-balanced.

5.1.2 Moody's

In August 2014, Moody's lowered its outlook on its rating for the Province of Manitoba from Aa1 stable to Aa1 negative. In July 2015, Moody's downgraded Manitoba's rating from Aa1 negative to Aa2 with a stable outlook.

> "The downgrade to Aa2 reflects the deterioration in Manitoba's financial metrics leading to an increased debt burden and our expectation that the province will face significant challenges in achieving fiscal balance by 2018-19." [28]

In its August 2016 rating report, Moody's[29] noted that Manitoba's ratings benefit from:

- Strong economic growth with a diversified economy;
- High debt affordability;
- Mature and supportive institutional framework and solid governance practices.

Moody's commented that the rating is challenged by the Province's elevated debt burden, substantial forecasted deficits over an extended time horizon, declining levels of liquidity, and contingent liability risk of Manitoba Hydro.

Moody's report noted the inherent risks related to increasing debt at Manitoba Hydro.

> "The province issues debt on behalf of its wholly-owned electric utility company Manitoba Hydro. Given its steady revenue stream that generates sufficient cash flow to support operations including interest payments, we view Manitoba Hydro as a self-supporting entity and therefore exclude the related debt from our debt metrics of the province.
>
> "We note, however, that Manitoba Hydro's total reported debt net of sinking of funds has risen considerably, doubling from CAD6.9 billion at March 31, 2008 to an estimated CAD14.2 billion as of March 31, 2016. We expect that its debt will continue to rise over the medium-term as the utility moves forward with construction projects, including the Keeyask hydroelectric station and the Bipole III transmission line, in anticipation of demand increases over the next few years and in order to boost electricity exports. The anticipated increase in debt continues to pressure the province's rating since it raises the contingent liability of the province.
>
> "Manitoba Hydro has flexibility to increase utility rates to ensure that its own revenues will continue to support its operations and debt payments. Political willingness to approve rate increases when Manitoba Hydro's credit metrics will reach their low point will be critical to recover expected capital expenditures and restore credit metrics." [30]

[28] Moody's Investors Service, Rating Action, July 10, 2015.

[29] Moody's Investors Service, Credit Opinion, Province of Manitoba, August 3, 2016, p.3.

[30] Moody's Investors Service, Credit Opinion, Province of Manitoba, August 3, 2016, p.4.

In its February 2017 update, Moody's confirmed its rating and Manitoba Hydro's self-supporting status, but noted the growing contingent liability risk of Manitoba Hydro:

> "Given its revenue stream that generates sufficient cash flow to support operations including interest payments, we view Manitoba Hydro as a self-supporting entity and therefore exclude the related debt from our debt metrics of the province.
>
> We note however that Manitoba Hydro's total reported debt net of sinking funds has risen considerably, doubling over the last eight years to CAD14.4 billion as of March 31, 2016, as the province moves ahead with several large capital projects. These include the Keeyask hydroelectric station and the Bipole III transmission line, which are being built to enhance reliability, meet anticipated demand increases over the next few years and boost electricity exports. We expect that the utility's debt may increase substantially by up to 70% over the medium-term from current levels just to complete these two projects, which are being hampered by significant delays and cost overrruns. The anticipated increase in debt has put growing pressure on the province's rating since it raises the contingent liability of the province (anticipated to exceed 40% of the province's total debt by 2017-18) and has increased the risk that Manitoba Hydro could require a capital injection or other support from the province."[31]

5.1.3 DBRS

In July 2017, DBRS confirmed the Province of Manitoba's "A (high)" rating with a trend of stable.[32] In its rating consideraitons, DBRS[33] outlined the following strengths and challenges:

Strengths

- Diversified and resilient economy,
- Favourable demographics,
- Prudent debt management practices,
- Abundant low-cost hydroelecricity.

Challenges

- Substantial deficits,
- Relatively high taxes,
- Moderate reliance on federal transfers,
- Below-average incomes and GDP per capita.

In July 2017, DBRS confirmed the rating of Manitoba Hydro obligations are a flow-through of the rating of the Province of Manitoba, as the Province unconditionally guarantees almost all of Manitoba Hydro's outstanding third-party debt.

> "DBRS fully expects the utility to recover its costs from the electricity rate base. As such, DBRS will continue to exclude the hydro-related debt from the calculation of tax-supported debt."[34]

[31] Moody's Investors Service, Credit Opinion, Province of Manitoba, February 24, 2017, p.4.

[32] DBRS Rating Report, Province of Manitoba, July 12, 2017.

[33] DBRS Rating Report, Province of Manitoba, July 12, 2017.

[34] DBRS Rating Report, Province of Manitoba, July 12, 2017, p.6.

DBRS notes the strengths of Manitoba Hydro including:

- Debt is a direct obligation of the Province,
- Low-cost hydro-based generation, and
- Access to favourable export markets.

Challenges of Manitoba Hydro noted by DBRS include:

- Hydrology risks,
- High leverage, and
- High level of planned capex.

The November 2016 DBRS report on Manitoba Hydro noted:

> "A new board appointed at Manitoba Hydro in 2016 intends to limit the deterioration in the Utility's balance sheet. As a result, the Utility has begun reviewing initiatives to help alleviate pressure on its key financial ratios, such as improving operating efficiencies, requesting annual rate increases higher than the previously planned 3.95%, as well as potential equity injection from the Province. DBRS sees these initiatives, if actualized, as positive to Manitoba Hydro's financial profile, as they will provide some financial flexibility for the Utility, especially in the event of adverse drought conditions or further cost overruns on the projects.
>
> DBRS continues to view Manitoba Hydro as self-supporting, as its earnings and cash flows continue to be sufficient to cover its operating expenses and to service its outstanding debt. However, DBRS could consider reclassifying a portion of the Utility's debt to be tax-supported should the financial health of the Utility deteriorate to the point where its expenses cannot be recovered through rates. If this were to occur, it could potentially put downward pressure on the Province's credit rating. Similarly, a large equity injection by the Province that materially increases tax-supported debt could also put downward pressure on the Province's credit profile. At this time, however, DBRS expects the Province's ratings to remain stable."[35]

5.2 Government-owned Power Utilities and Relation to Provincial Economies

5.2.1 Public power utilities in relation to provincial economies

As Government Business Entities and self-supporting entities, the assets and debt of Manitoba Hydro and other provincially-owned power utilities in Canada are not consolidated within the balance sheets of their respective provincial governments in Summary Financial Statements. Figure 6-6 illustrates the size of utility net debt in relation to provincial government net debt. It also shows the relative size of the combined net debt in relation to provincial population and GDP. Credit rating reports on governments in Canada focus their key debt metrics, such as net debt to GDP, on tax-supported debt, and do not include the self-supporting debt of Crown utilities. However, they do take utility debt into account and continue to monitor levels of debt. Rating agencies have generally commented that the combined debt burden is manageable for provinces.

In 2013/14, the utility net debt of Manitoba Hydro was approximately 38% of combined provincial net debt and utility net debt, slightly lower than the figure for Nalcor (39%), and higher than values for NB Power and BC Hydro (which are near 30%). As a share of GDP, combined provincial net debt and utility net debt is highest in Quebec (at 62%), followed by New Brunswick (at 51%), and then Manitoba (at 46%).

[35] DBRS Rating Report, The Manitoba Hydro-Electric Board, November 25, 2016, p.1-2.

Updated data to 2015/16 in Figure 5-2 incorporate general increases across the provinces in the past two years in combined provincial net debt and utility net debt. Data for 2015 and 2015/16 was utilized for direct comparison to audited financial statements of provinces as 2016/17 Public Accounts was not available as of August 2017 for Manitoba and most provinces.

In 2015/16, the utility net debt of Manitoba Hydro increased slightly to approximately 39% of combined provincial net debt and utility net debt, the highest share of the five provinces. As a share of GDP, combined provincial net debt and utility net debt is highest in Newfoundland at 63% (a sharp increase from 42% in 2013/14 as the province's GDP declined significantly), followed by Quebec at 60%, New Brunswick at 56% and Manitoba at 53% (up from 46% in 2013/14).

While audited financial statements were not available at this time for most provinces, we note that Manitoba Hydro net debt rose significantly to $15.8 billion in 2016/17, an increase of $2.2 billion from 2015/16 (see Figure 5-2). Provincial net debt for Manitoba is forecast at $23.1 billion for 2016/17 (from 2017 Manitoba Budget), an increase of $1.7 billion from 2015/16. Thus for 2016/17, combined provincial and utility net debt for Manitoba is estimated at $38.9 billion, which would be approximately 58% of provincial GDP.

Figure 5-2: Overview of Utility Asset and Net Debt Information and Relationship to Provincial Economy, 2015/2016

Overview of Utility Asset and Debt Information and Relationship to Provincial Economy

($CDN billions)	Provincially-Owned Utility	Utility Assets 2015/16	Utility Net Debt at Year End	Provincial Net Debt at Year End	Prov. Net Debt & Utility Net Debt	Utility Net Debt % of Combined Provincial & Utility Net Debt	Provincial Population 2015	Provincial GDP 2015	Provincial Net Debt and Utility Debt % of GDP
Manitoba	Manitoba Hydro	19.8	13.6	21.4	35.0	39%	1,296,000	65.9	53%
B.C.	B.C. Hydro	30.0	18.2	39.6	57.8	31%	4,693,000	250.0	23%
Quebec	Hydro Quebec	75.2	43.3	185.0	228.3	19%	8,259,500	381.0	60%
Newfoundland	Nalcor Energy	12.3	6.2	12.7	18.9	33%	528,700	30.1	63%
New Brunswick	New Brunswick Power	6.9	4.9	13.7	18.6	26%	754,300	33.1	56%

Source:
1. Manitoba Hydro Annual Report for the year ended March 31, 2016
2. B.C. Hydro Annual Report for the year ended March 31, 2016
3. Hydro-Quebec Annual Report for the year ended December 31, 2015
4. Nalcor Annual Report for the year ended December 31, 2015
5. New Brunswick Power Annual Report for the year ended March 31, 2016
6. Province of Manitoba Public Accounts, 2015/16
7. Province of B.C. Public Accounts, 2015/16
8. Province of Quebec Public Accounts, 2015/16
9. Province of Newfoundland and Labrador, 2015/16
10. Province of New Brunswick Public Accounts, 2015/16
11. Statistics Canada

Figure 5-3 indicates that Manitoba has a relatively high level of utility assets and net debt on a per capita basis, as Manitoba Hydro plays a significant role in its provincial economy.

Manitoba Hydro's net debt per capita is nearly $12,000, slightly below Nalcor, and substantially above other government-owned power utilities in Canada. Manitoba Hydro's net debt per capita increased by approximately 43% in only three years, from 2013/14 to 2016/17. This rate of growth in net debt and net debt per capita significantly exceeded that of the other government-owned power utilities.

Nalcor has the highest level of assets per capita of the government-owned power utilities in Canada, followed by Manitoba Hydro.

Manitoba Hydro's assets per capita increased from $12,359 per capita in 2013/14 to $16,947 per capita in 2016/17, an increase of approximately 37% over the past three years and a growth rate significantly higher than other government-owned power utilities except for Nalcor.

Figure 5-3: Overview of Utility Asset and Net Debt Information Per Capita, 2016/2017

Overview of Utility Asset and Debt Information Per Capita				
($CDN)	**Provincially-Owned Utility**	**Utility Net Debt Per Capita**	**Utility Assets Per Capita**	**Net Debt/ Assets**
Manitoba	Manitoba Hydro	11,981	16,947	70.7%
B.C.	B.C. Hydro	4,204	6,711	62.6%
Quebec	Hydro Quebec	5,365	9,028	59.4%
Newfoundland	Nalcor Energy	12,149	26,527	45.8%
New Brunswick	NB Power	6,475	9,207	70.3%

Source:
1. Manitoba Hydro Annual Report for the year ended March 31, 2017.
2. B.C. Hydro Annual Report for the year ended March 31, 2017.
3. Hydro-Quebec Annual Report for the year ended December 31, 2016.
4. Nalcor Annual Report for the year ended December 31, 2016.
5. New Brunsw ick Pow er Annual Report for the year ended March 31, 2017.
6. Statistics Canada

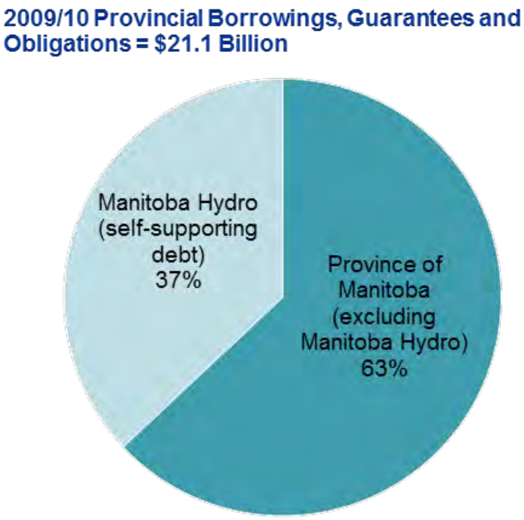
Figure 5-4 shows the level of Manitoba Hydro's self-supporting debt in conjunction with the Province of Manitoba's total borrowings, guarantees and obligations (net of sinking funds). From 2009/10 to 2013/14, this share had been relatively constant at approximately 37%.

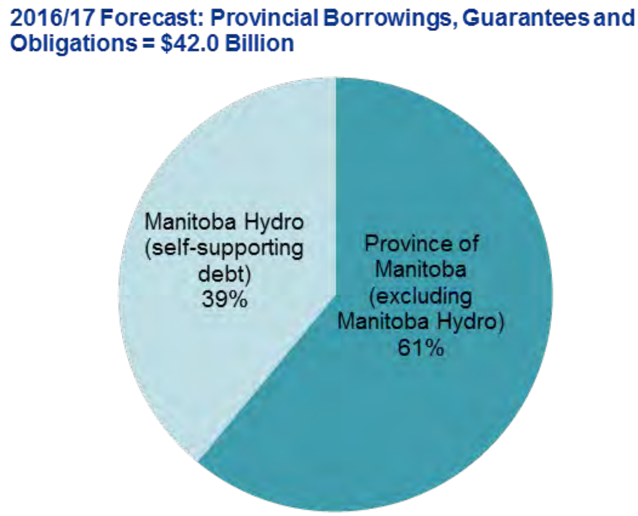
Debt advances to Manitoba Hydro are forecast in 2016/17 to be approximately 39% of total Provincial borrowings, guarantees and obligations, a marked increase in two years from 37% as Manitoba Hydro borrowings have increased from $12.5 billion in 2014/15 to a forecast level of $16.4 billion in 2016/17.

This share is expected to continue to increase in the medium term, depending upon the level of increase in the Province of Manitoba's tax-supported debt. Based on projections of Province of Manitoba borrowings outlined in the Manitoba Budget 2017, Manitoba Hydro's share is projected to significantly increase to 42.5% in 2017/18.[36] Based on Manitoba Hydro's projected debt under IFF16, self-supporting debt as a share of total Provincial borrowings, guarantees and obligations could increase to percentage range in the mid-40s by 2019/20, depending on the rate of increase of provincial tax-supported debt.

[36] Manitoba Budget 2017. Supplementary Financial Information, pg. B2.

Figure 5-4: Province of Manitoba Borrowings, Guarantees and Obligations, 2009/10 and 2016/17 Forecast





Source: 2009/10 from Province of Manitoba 2014 Budget Summary Financial Statistics. 2016/17 forecast from Province of Manitoba 2017 Budget Summary Financial Statistics. (Provincial borrowings, guarantees and obligations are net of sinking funds.)

5.2.2 Government contributions from public-owned power utilities in Canada

Figure 5-5 provides a breakdown of contributions paid to governments from Manitoba Hydro and four other government-owned power utilities in the peer group. Of these five government-owned power utilities, only BC Hydro and Hydro-Quebec currently pay a direct annual dividend to their provincial owner. In both cases, dividends are based on a formula and are capped to ensure that a minimum equity ratio is maintained.

Most government-owned utilities pay a debt guarantee fee based on a percentage of outstanding debt to their respective provincial owner.

- Manitoba Hydro pays a 1.0% fee on outstanding applicable debt, which is the highest percentage fee in the group. The Province of Manitoba's debt guarantee fee was increased from 0.5% to 0.65% effective April 1, 2000 and to 0.95% effective April 1, 2001. [37] The fee was subsequently increased to 1.0% during fiscal 2006/07.
- NB Power pays a 0.65% fee on outstanding debt.
- Hydro-Quebec pays guarantee fees to the Quebec government related to debt securities. In 2014, these fees were $205 million in 2014 which represents slightly under 0.5% on outstanding debt. [38]
- In 2008, the Government of Newfoundland and Labrador temporarily waived the guarantee fee paid by Nalcor until 2011. Upon reinstatement in 2011, the fee was reduced from 1.0% of outstanding debt to a fee of 0.5% on outstanding debt with a remaining term of over 10 years and 0.25% on outstanding debt with a remaining term of under 10 years. The new fee rates were designed to better reflect the value of the debt guarantee, and are based on a comparison of yields on bonds issued by the Province to bonds with similar maturities issued by a group of investment-grade

[37] PUB Board Order 7/03, p. 26.

[38] Hydro-Quebec 2014 Annual Report. Financial statements Note 6.

utilities comparable to Hydro. [39] NLH's recent rate application notes the cumulative impact of these fee initiatives to 2015 is $62.3 million.[40]

In fiscal 2016/17, Manitoba Hydro paid $136 million in debt guarantee fees to the Province of Manitoba, an amount that is expected to increase significantly over the next five years as borrowings ramp up to complete major generation and transmission projects.

Manitoba Hydro, BC Hydro and Hydro-Quebec pay annual water rental charges to their respective provinces. Manitoba Hydro's water rental charge is $3.34 per MW, which is a similar rate to Hydro-Quebec, and significantly lower than BC Hydro, which pays $6.896 per MW plus capacity charges. Under the *Water Power Act*, the Province of Manitoba approximately doubled water rental rates to its current level of $3.34 per MW effective April 1, 2001. Manitoba Hydro paid $131 million to the Province of Manitoba in water rental charges in 2016/17.

All utilities pay local property and related taxes in their respective jurisdictions. In addition to these taxes, Manitoba Hydro pays capital taxes to the Province of Manitoba ($84 million in 2016/17), and Hydro-Quebec pays a Provincial Public Utility Tax to the Government of Quebec.

Figure 5-5: Contributions Paid to Governments from Public-Owned Canadian Power Utilities (FY2016 or FY2016/17 in annual $ millions)

	Manitoba Hydro	BC Hydro	Hydro-Quebec	NB Power	Nalcor
Dividend (1)	n/a	$259	$2,146	n/a	n/a
Debt guarantee fee	$136		$218	$32	$4.5
Water rental charges	$131	$349	$673		$4.9
Property, capital & other taxes	$135	$234	$372	$43	not available
Total	$402	$842	$3,409	$75	$9.4
Total % revenues	17%	14%	26%	4%	1%
Per Capita (rounded dollars)	*$305*	*$177*	*$409*	*$99*	*$18*

Note: derived from annual reports and financial statements, for the year-ending March 31, 2017 for Manitoba Hydro, BC Hydro and NB Power and for the year-ending December 31, 2016 for Hydro-Quebec and Nalcor.

(1) No dividends are paid by Manitoba Hydro, NB Power and Nalcor. For Hydro-Quebec, dividend paid the Quebec government is 75% of net income; no dividend if it effectively reduced the cap rate/equity ratio to less than 25%. For BC Hydro, dividend is 85% of net income, subject to an 80:20 debt to equity cap. Dividend for the year ending March 31, 2016 and for the year ending March 31, 2017 is less than 85% due to the cap. Special Directives from the Province of BC define a minimum annual payment which was $259 million for the 2016/17 fiscal year. Note that BC Hydro's dividend payments to the Province of BC have been higher in previous years.

[39] Newfoundland and Labrador Hydro – 2013 General Rate Application, p. 3.31.

[40] Newfoundland and Labrador Hydro – 2013 General Rate Application, p. 3.32.

Based on information disclosed in annual financial statements, as noted in Figure 5-5, Manitoba Hydro's payments to government represent approximately 17% of total revenues. This is a similar share to BC Hydro (although BC Hydro's dividend payments to the Province of B.C. have been lower in recent years), a much higher proportion than government-owned utilities in Atlantic Canada, but significantly lower than Hydro-Quebec. Hydro-Quebec contributes approximately 26% of its total revenues to government, with nearly two-thirds of its government contributions in the form of dividends to its owner.

5.3 Summary Observations

Key conclusions from the analysis in this chapter are the following:

- Since the May 2015 Report, two credit rating agencies have issued a total of three credit downgrades for the Province of Manitoba. One credit rating agency no longer views Manitoba Hydro debt as self-supporting due to high and rising leverage. Two other credit rating agencies continue to view Manitoba Hydro as self-supporting.
- The combined debt of the Province of Manitoba and Manitoba Hydro has significantly increased in the past two fiscal years, and Manitoba Hydro's share of Provincial borrowings, guarantees and obligations now exceeds 40%.

6 Scenario Analysis and Testing

This chapter revisits some of the scenario analyses undertaken in the May 2015 Report (in Chapter 7) and reviews some additional scenario analyses that have been undertaken subsequently.

6.1 General Approach

In this Chapter, we have, in general, focused the analyses on differences between IFF14 and IFF16. This reflects the fact that the outlook for IFF14 was the basis of our prior analysis and that IFF16 is Manitoba Hydro's most current financial projection. In this context, figures for IFF15 are of secondary interest. Figures for IFF15 can shed light on changes in expectations over time but they are not as directly relevant to a discussion of how the environment and outlook have now changed or of the implications for Manitoba Hydro's financial targets.

6.2 Maintaining Profitability

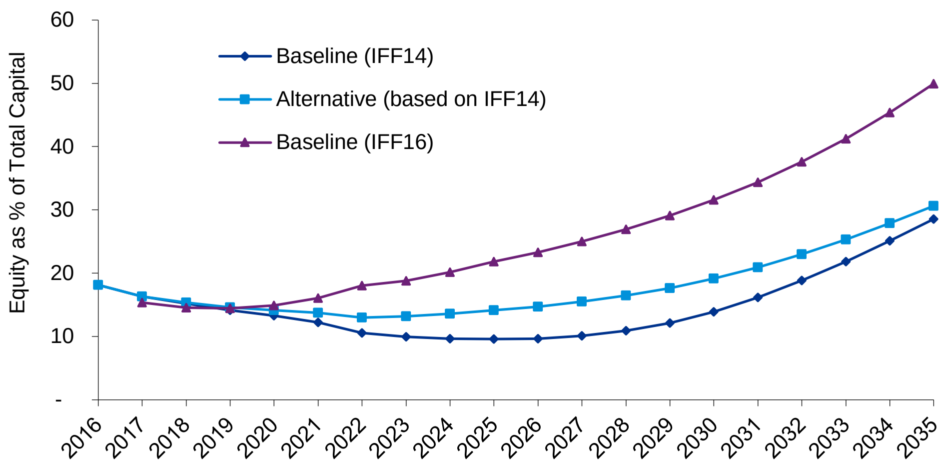
In the May 2015 Report, we noted that projections within IFF14 showed eight consecutive years of negative net income beginning in 2019. We then examined an alternative scenario with higher rate increases than under IFF14, with the rate increases set to restore profitability under expected conditions.

With IFF16, the projected outlook for Manitoba Hydro has substantially improved. The improvement relative to IFF14 is largely attributable to increases in rates, which have been used to bolster Manitoba Hydro's equity position and cash flow in parallel with large capital investments. IFF16 also reflects Manitoba Hydro's recently announced plans to reduce staff and operating costs. The improvement in outlook is also partly attributable to lower forecast interest rates, which reduce financing costs associated with Manitoba Hydro's ongoing capital program. Lower interest costs help offset reductions that are also projected in long term electricity export prices.

Figure 6-1 shows the new forecast compared to IFF14 and the alternative scenario presented in the May 2015 Report. This figure shows that IFF16 results in debt/equity ratios that improve more rapidly than before, even compared to our earlier alternative scenario, which also entailed higher rate increases than the IFF14 base scenario.

Beyond 2029, the rate of increase in equity position under IFF16 is similar to that under the IFF14 base scenario. This is the case even though IFF16 has rate increases of only 2.0% beyond 2023, while IFF14 had rate increases of 3.95% annually over the forecast horizon. This indicates the substantial benefit of restoring the equity position of the utility earlier rather than later.

Figure 6-1: Equity Ratio under IFF14, IFF16 and the IFF14 Alternative Scenario



6.3 Probabilistic Analysis

In the May 2015 Report, we summarized some scenario testing that Manitoba Hydro had undertaken based on examining potential variation in four input parameters. This scenario testing considered variation in:

- Interest rates (3 possible outcomes)
- Energy and Export prices (3 possible outcomes)
- Capital Expenditures (3 possible outcomes)
- Water Flow Sequence (99 possible scenarios).

By varying each of the inputs noted above, Manitoba Hydro obtained 2,763 distinct financial projections (calculated as 3 x 3 x 3 x 99).

As shown above, Manitoba Hydro examined just three individual scenarios for interest rates in its probabilistic analysis. These included a scenario with interest rates as forecast under IFF14, and scenarios with interest rates either one percentage point higher or lower.

6.3.1 Modelling of interest rate uncertainty

In the period since the 2015 report, Manitoba Hydro has explored a more sophisticated approach to modelling interest rate uncertainty. There has been a concern that the scenario testing undertaken in the context of IFF14, which examined interest rates just one percentage point higher or lower than forecast, did not adequately capture the actual uncertainty associated with interest rate movements. This concern arose from the observation that consensus forecasts, which are the basis of the reference case used for IFF purposes, tend to assume faster convergence of interest rates to their historical means than has been observed in practice in the past.

As an alternative to assuming a fixed adjustment above or below the reference case forecast for scenario testing, Manitoba Hydro has implemented a new approach based on using a stochastic interest rate generator. The generator is calibrated to produce outputs that are consistent with the interest rate uncertainty implied by futures market data.

As implemented for the purpose of scenario testing, the interest rate generator is used to prepare 50 interest rate trajectories. Each of these are assumed to be equally probable. The interest rate trajectories (or scenarios) are then combined with energy and export price scenarios (3 scenarios) and water flow sequences (102 scenarios) to produce a total of 15,300 outcomes.

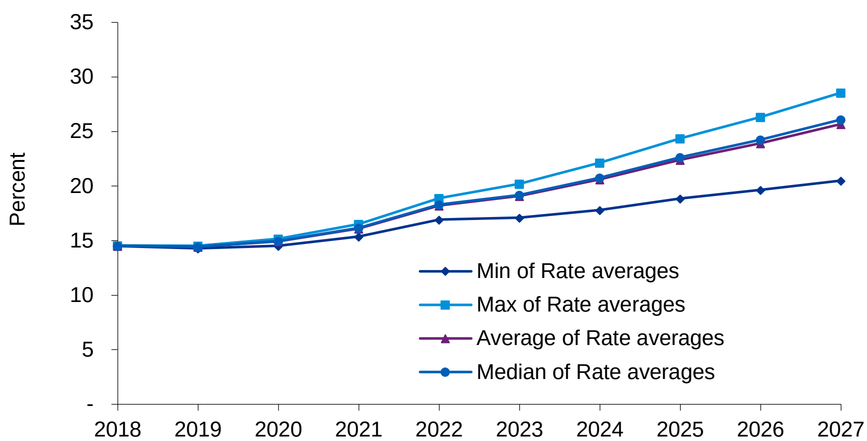
Figure 6-2 examines the impact of interest rate uncertainty on the outcomes observed. The figures presented in this chart require some explanation, and this is provided below.

As noted above, Manitoba Hydro has prepared a total of 15,300 runs, combining uncertainties in energy and export prices, water flows and interest rates. Each individual run is a combination of:

- One water flow sequence,
- One interest rate trajectory, and
- An assumption on energy and export prices (either Low, High or Reference Case).

To examine the impact of interest rates on overall outcomes, we examined, in turn, those runs associated with each individual interest rate trajectory. For each interest rate trajectory, there are 306 separate runs (which result from looking at the combination of 3 price scenarios combined with 102 water flow sequences). For each interest rate trajectory, we then calculated the average equity ratio in each year across the 306 runs and summarized these averages in a table. For these averages in each year, we then calculated the minimum, median, average, and maximum values observed across the 50 interest rate scenarios. These figures are presented in Figure 6-2 below.

Figure 6-2: Equity Ratio under Alternative Interest Rate Scenarios for IFF16



As noted in Figure 6-2 above, the minimum average equity ratio observed across the interest rate trajectories is about 14.3% in 2020. This means that the most unfavourable interest rate scenario in respect of the year 2020 showed an average equity ratio of 14.3% across the 306 runs associated with that interest rate input. Since this average is calculated across the combination of 102 water flow sequences with 3 energy and export price scenarios, the 14.3% is not the minimum observed across all runs. Rather, 14.3% is itself the average of a distribution produced by the 306 underlying runs associated with one interest rate trajectory.

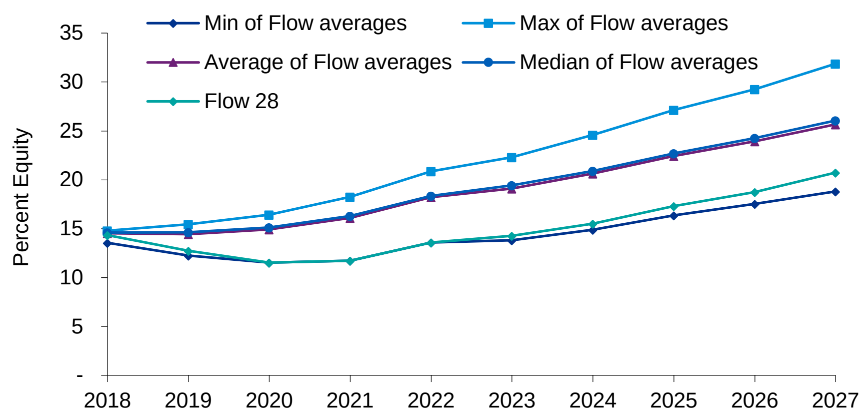
The rationale for looking at the distribution of the averages calculated for each interest rate trajectory is that it shows the contribution of the interest assumption to the variation in outcomes across the 15,300 individual projections. Variation in other assumptions is averaged out from the average calculated for individual groups of trajectories, when trajectories are grouped by interest rate assumption.

6.3.2 Impact of water flow uncertainty

In this sub-section, we focus on the impact of water flow uncertainty. In Figure 6-3 below we prepare an analysis of outcomes across the 102 water flow sequences. Our approach to the preparation of this graph was similar to that used for Figure 6-2 above, but involved grouping outcomes by water flow sequences.

For each water flow sequence, there are 150 associated runs. These result from the combination of 50 interest rate trajectories with 3 energy and export price scenarios. For each water flow sequence, we calculate the average equity ratio across these 150 runs and summarized the averages in a table. In Figure 6-3, we show the minimum, maximum, median and average value for these averages in each year.

Figure 6-3: Equity Ratio under Alternative Water Flow Scenarios for IFF16



From the results shown above, it can be observed that minimum average equity values of about 11.5 percent are observed in each of the years 2020 and 2021. As there are 102 water flow sequences, the minimum value observed could be considered to have about a 1 percent probability of being underachieved in practice (given that 1 divided by 102 equals about 0.01).

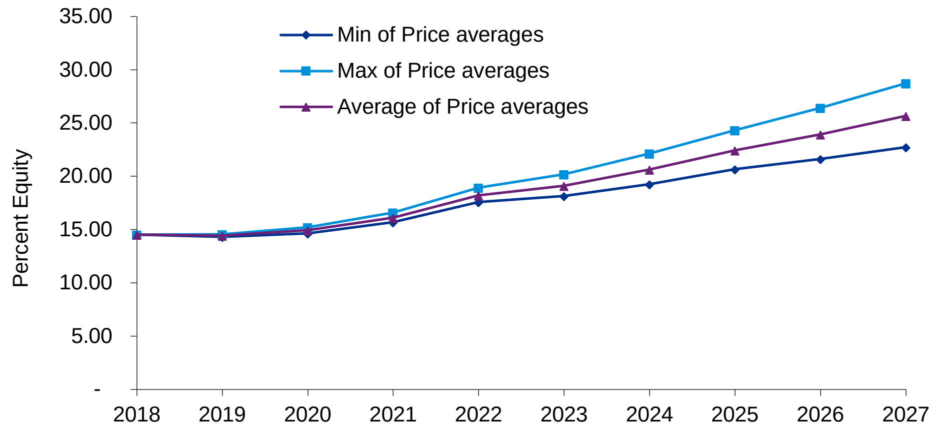
To provide greater insight on the circumstances that lead to the values shown, Figure 6-3 also shows the average equity values associated with water flow sequence 28 (labelled "Flow 28"). This line shows the average of equity values observed when water flow sequence 28 is selected, and interest rates and energy prices are varied. It can be seen Flow Run 28 accounts for the minimum average equity values observed in years 2020 and 2021. Although it does not account for the minimum values in other years, it provides values that are close to the minimum values. Accordingly, it can be seen that close to minimum values can persist for many years under certain hydrology scenarios.

6.3.3 Impact of energy and export price variation

In this sub-section, we focus on the uncertainty in energy and export prices. (Recall that energy and export price uncertainties are combined: for example, high energy prices are associated with high export prices.) In Figure 6-4 below we prepare an analysis of outcomes across the 3 scenarios ("High", "Low" and "Reference") for energy and export prices. Our approach to the preparation of this graph was similar to that used for Figures 6-2 and 6-3 above but involved grouping outcomes by price scenarios (instead of by interest rate trajectories or water flow sequences).

For each price scenario, there are 5,100 associated runs. These result from the combination of 50 interest rate trajectories with 102 water flow sequences. For price scenario, we calculate the average equity ratio across these 5,100 runs and summarized the averages in a table. In Figure 6-4, we show the minimum, maximum, median and average value for these averages in each year.

Figure 6-4: Equity Ratio under Alternative Energy and Export Price Scenarios for IFF16



From the results shown above, it can be seen that the spread in equity values produced by variation in energy and export prices is less than that associated with individual water flow sequences or with individual interest rate trajectories. In part, this can be attributed to the greater averaging of results when we look just at variation in price inputs. There are just 3 price scenarios and when we calculate average equity values for each such scenario, these are associated with 5,100 runs (the combination of 102 water flow sequences with 50 interest rate scenarios). In this analysis, it turns out that the minimum values are all accounted for by the low export price scenario. Similarly, and not unexpectedly, all of the maximum values are accounted for the high export price scenario.

6.3.4 Comparison of Impacts

In this section, we directly compare the minimum and maximum values observed under each of the analyses above. In other words, we first compare the minimum values observed in each of Figures 6-2, 6-3, and 6-4. We then compare maximum values observed in each of these figures. This presentation shows more directly the nature of variation observed when we examine differences resulting from variation in one input parameter (e.g. water flows), while averaging results across scenarios capturing variation in other parameters (e.g. interest rates and energy and export prices).

Figure 6-5 shows the minimum values taken from Figures 6-2, 6-3 and 6-4. We can see that the analysis for water flow variation results in the minimum values observed for all years.

Figure 6-5: Minimum Values for Alternative Scenario Sets under IFF16

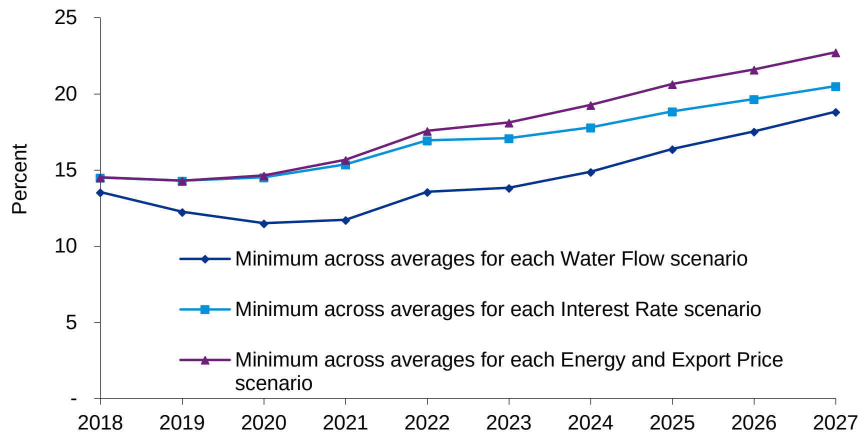
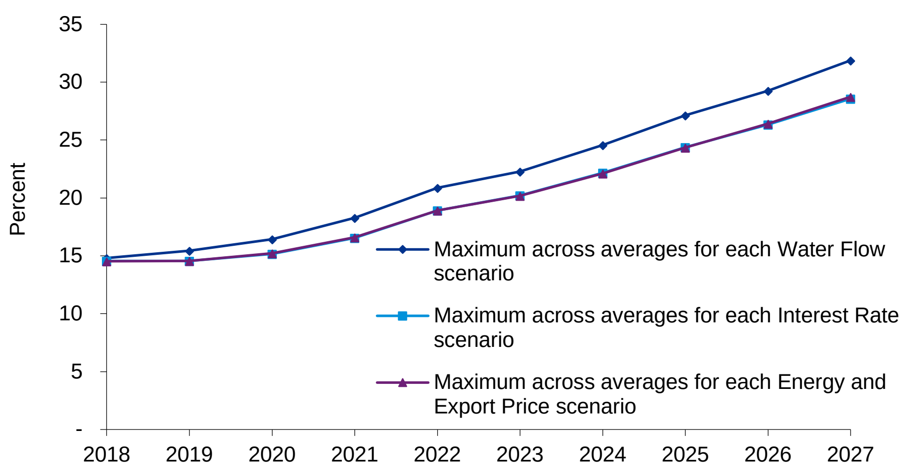


Figure 6-6 shows the minimum values taken from Figures 6-2, 6-3 and 6-4. We can see that the analysis for water flow variation results in the maximum values observed for all years for the averages found when grouping scenarios by particular input conditions. Taking into account both Figures 6-5 and 6-6, it is reasonable to conclude that water flow variation remains the biggest driver of uncertainty for Manitoba Hydro.

Figure 6-6: Maximum Values for Alternative Scenario Sets under IFF16



6.3.5 Contribution of different factors to overall variability

As an alternative approach to quantifying the relative impact of different factors on financial results, we looked at the impact on the full range of outcomes of adding different sources of uncertainty in turn. The approach is as follows:

- As a first step, we examine the range of outcomes when considering just water flow variability, Thus, financial results are forecast for each of the 102 water flow sequences, using Reference export prices and Reference interest rates. For each year, we then calculate the range of outcomes, or the difference between the minimum and maximum equity ratio observed across all runs.

- As a second step, we examine, in addition, the impact on variability by adding High and Low export prices to the set of financial runs. Compared to step one above, we then calculate the increase in the range of outcomes observed. (At the end of step two, we have 306 runs, obtained from 102 water flow sequences combined with 3 export price scenarios.)
- As the final step, we examine, in addition, the impact on variability by adding High and Low export prices to the set of financial outcomes obtained above. Comparing to step two above, we then calculate the increase in the range of outcomes observed. The range between the minimum and maximum equity values in each year is thus calculated based on 918 runs (102 water flow sequences, with 3 export price scenarios and 3 interest rate scenarios).

In this alternative analysis, we have examined interest rate uncertainty with 3 scenarios rather than 50 trajectories. Analysis by Manitoba Hydro shows that the 3 interest rate scenarios achieves similar outcomes to that obtained with the full 50 interest rate trajectories.

The range of outcomes observed at each of steps 1, 2 and 3 is shown in sequence in Figures 6-7 through 6-9 below.

Figure 6-7: Range of Outcomes from Water Flow Variability

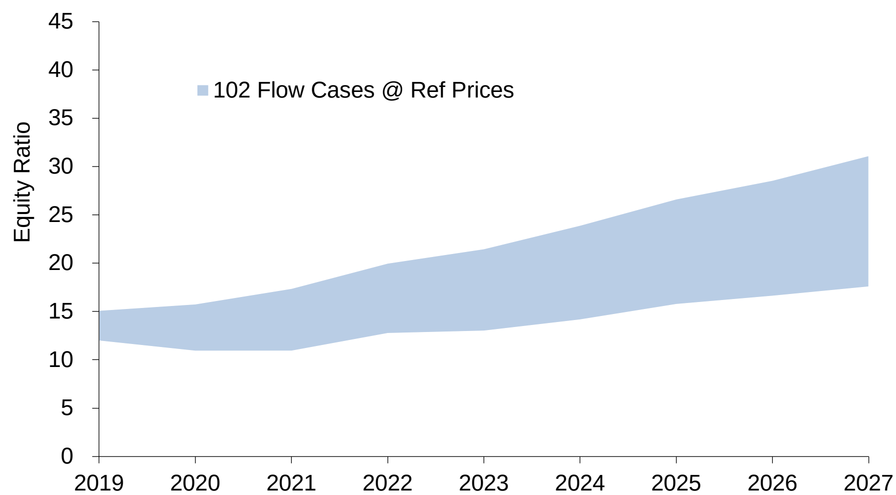


Figure 6-8: Range of Outcomes from Water Flow and Export Price Variability

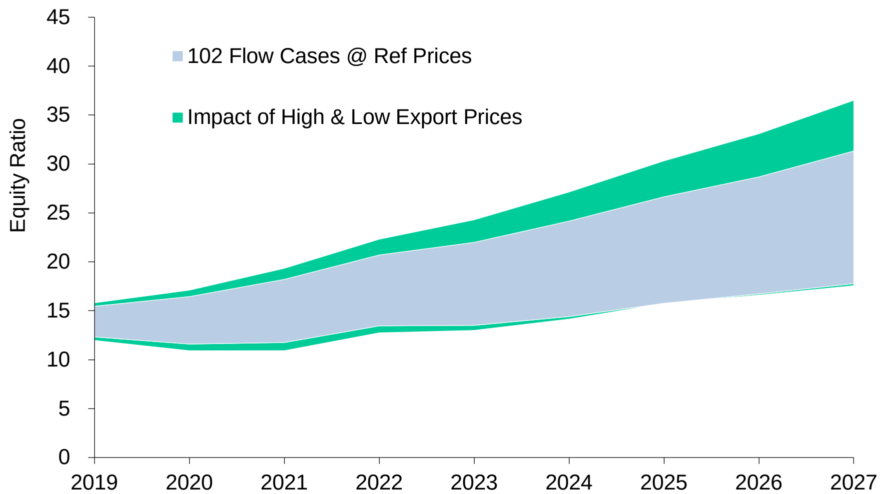


Figure 6-9: Range of Outcomes from Water Flow, Export Price and Interest Rate Variability

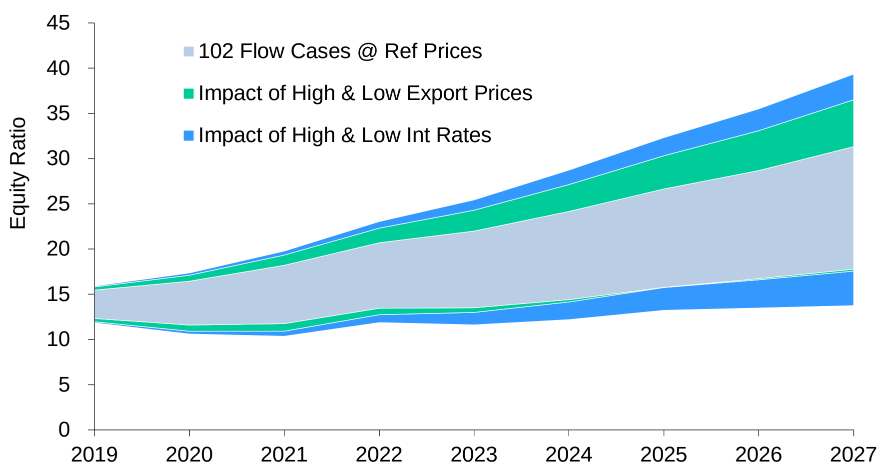


Figure 6-10 below summarizes the contribution that each factor made to total variability observed in each year. As expected, water flow remains the key contributor to the variability observed in each year through to the end of the projection period, accounting for over three-quarters of variability in 2019 and still over half in 2027. However, interest rates account for an increasing share of variability as time passes: interest rates account for 26% of variability in 2027 versus only 5% in 2019. This reflects the persistence of interest rate deviations in the modelling approach and the compounding effect that higher or lower interest rates can have on financial outcomes. Energy and export prices account for a relatively stable share of variability over the forecast period.

Figure 6-10: Factor Contribution to Total Variability

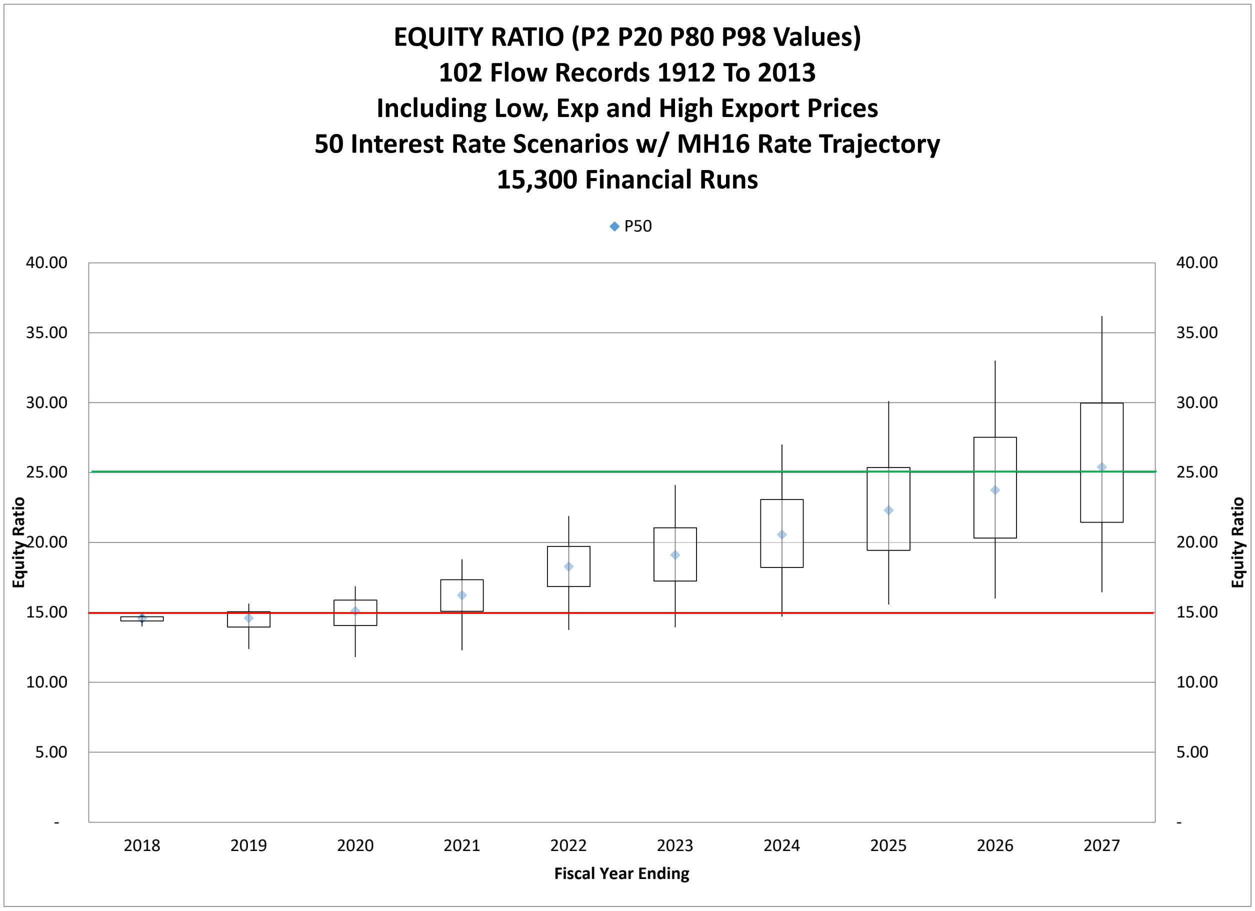
Percentage Contribution to Total Variability									
Year	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Factor									
Water Flow	77%	72%	68%	65%	61%	59%	57%	54%	53%
Energy and Export Prices	17%	20%	21%	21%	20%	20%	19%	21%	21%
Interest Rates	5%	8%	11%	14%	18%	21%	24%	25%	26%
	100%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

6.3.6 Combined impact

Figure 6-11 below shows the combined impact of variation across all three dimensions used in the scenario analyses (water flow, interest rate, and energy and export prices). This graph is in the form of a "box and whisker" chart. The box shows the range from the 20th to 80th percentile. The lines above and below show the range from the 2nd to 98th percentiles. The format of this graph is based on that currently used by Manitoba Hydro to present the results of its scenario analyses. We have changed the format to show values for 2nd to 98th percentiles, however, rather than for the 5th and 95th percentiles. For the consideration of financial risks, a broader distribution provides a more conservative perspective on potential variability.

In the near term, the lines below the boxes appear longer than the lines above, suggesting that the range of outcomes on the downside is wider than those on the upside. Figure 6-10 helps explain this result as water flow variation in early years has a far more profound impact on equity level than either of energy and export prices or interest rates. Moreover, as discussed earlier, water flow is an asymmetric risk for Manitoba Hydro – the negative financial impacts of low water flows are greater than the financial gains associated with high water flows. This reflects limitations in Manitoba Hydro's generating capacity and that high water flows tend to result in greater water spillage.

Figure 6-11: Combined Distribution from Uncertainty Modelling for IFF16



6.3.7 Review of a sample of runs

As an alternative approach to presenting the results, we examined about 13 individual runs, selected from across the 15,300 total runs undertaken in total. To select the 13, we plotted the 1st run out of the 15,300 total runs and then every 1,253th run thereafter. This fixed sampling approach captured results across a range of scenarios in combination.[41]

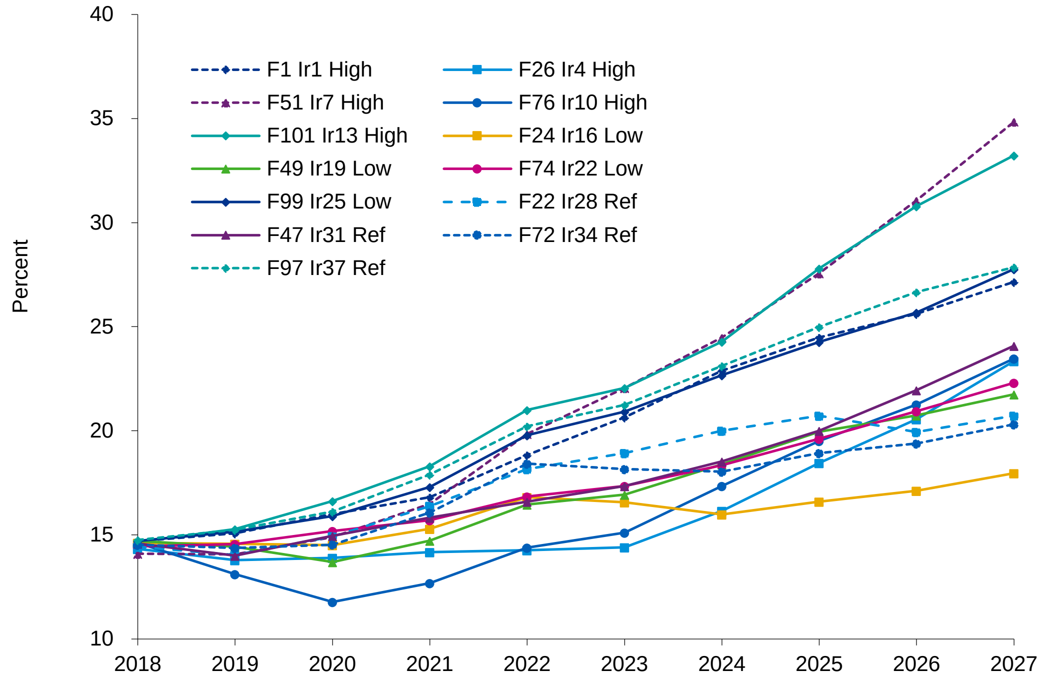
In labelling the various runs selected, the following approach is used:

- The first set of characters (with the prefix "F") indicates the water flow sequence.
- The second set of characters (with the prefix "Ir") indicates the interest rate trajectory.
- The third set of characters ("Low", "High", or "Ref") indicates the energy and export price scenario.

Figure 6-12 below shows the runs selected through this fixed sampling approach.

[41] Given the way that runs were constructed, we needed to avoid multiples of 3, 50 and 102 in setting the intervals, or periodicity, at which runs were selected for presentation. Otherwise, the scenarios presented would not show variation in the three input dimensions.

Figure 6-12: Selected Runs from Uncertainty Modelling for IFF16



The rationale for looking at individual runs is that it provides some additional insight on how various input conditions interact to produce an outcome within the overall distribution. In particular, an individual run shows how outcomes might evolve from year to year in response to a combination of input assumptions. For example, we note that the scenario defined by flow sequence 76, interest rate trajectory 10 and high energy and export prices (labelled "F76 Ir10 High") shows poor results in the initial years but improves rapidly after 2021. This trajectory is somewhat unusual amongst those plotted in that it moves from the bottom to the middle of the distribution over the forecast period. Many of the other runs plotted stay in about the same place relative to the broader group. For example, the run "F74 Ir22 Low" stays roughly in the middle of the group throughout the period. In a similar way, "F101 Ir3 High" remains at or near the top of the thirteen runs throughout. In other words, the runs selected tend to show little change over time in their relative positioning within the sample group.

6.4 Comparison of Probability Distributions

6.4.1 IFF16 versus IFF14

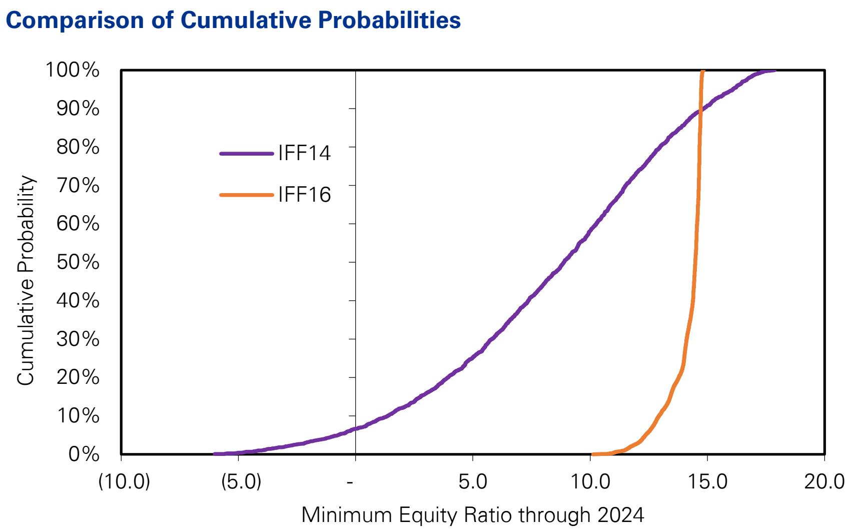
As noted at the beginning of this Chapter, the outcomes projected under IFF16 are significantly more favourable than under IFF14. One way of showing this is by comparing probability distributions for the minimum equity value observed during the period 2018 through 2024. Figures 7-7 and 7-11 of the May 2015 Report provided such distributions. Please note that the minimum equity values examined in this section are the minimum values observed over the full data set (all runs considered). They are not the minimums observed for averages calculated across groups of runs (which was the approach taken in Sections 6.3.3 and 6.3.4 earlier.)

As noted in the May 2015 Report, the interpretation of cumulative probability curves is as follows:

- For any given value on the "x" axis (representing, in this case, the minimum equity value observed through 2024), the line indicates a probability level on the "y" axis.
- The probability level observed above is the percentage of runs for which a lower equity value was observed than that corresponding to the "x" value.

In Figure 6-13 below compares the cumulative probability under IFF14 and IFF16 of various values for the minimum absolute equity ratio observed over the period to 2024. It can be seen that the line for IFF16 has been shifted considerably to the right relative to that for IFF14. There is now essentially no probability of having a minimum absolute equity value less than zero percent, versus a probability of about 7% under scenario modelling for IFF14.

Figure 6-13: Minimum Equity Value Observed 2018 through 2024 under Scenario Modelling



The dispersion of outcomes for the period 2018 through 2024 is much narrower under IFF16 than under IFF14. This reflects the following:

- Improved earnings under IFF16 as a result of higher rate increases reduce the risk of a fall in retained earnings relative to the forecast starting point.
- Because the base year (or starting point) for IFF16 is two years later than for IFF14, uncertainties have less time to evolve. For IFF16, the period 2018 to 2024 is closer to the base year from which the projection is made.
- The dispersion of input interest rates appears is narrower under IFF16 than IFF14.

6.4.2 Comparison of approaches to modelling uncertainty

As noted earlier in this Chapter, in Section 6.3, Manitoba Hydro moved to a new approach to modelling uncertainty when it presented results for IFF15 and now IFF16. The key differences are that Manitoba now uses a more sophisticated approach to representing interest rate uncertainty and it no longer accounts for construction cost variation. Because of changes in scenario modelling, some of the differences between the probability distributions for IFF14 and IFF16, as illustrated in Figure 6-13, reflect differences in the approach for modelling uncertainty rather than differences in the inherent risk associated with the baseline projections.

To help isolate differences in observed risk that are attributable to modelling approach, we asked Manitoba Hydro to model uncertainty under IFF16 using the same methodology as it had originally used for IFF14. This entailed considering uncertainty for IFF16 by taking into account 3 scenarios for each of:

- Interest rates (Reference Case, and +/- one percent point)
- Energy and Export prices (Reference Case, plus High and Low)
- Capital Expenditures (Reference Case, plus High and Low)

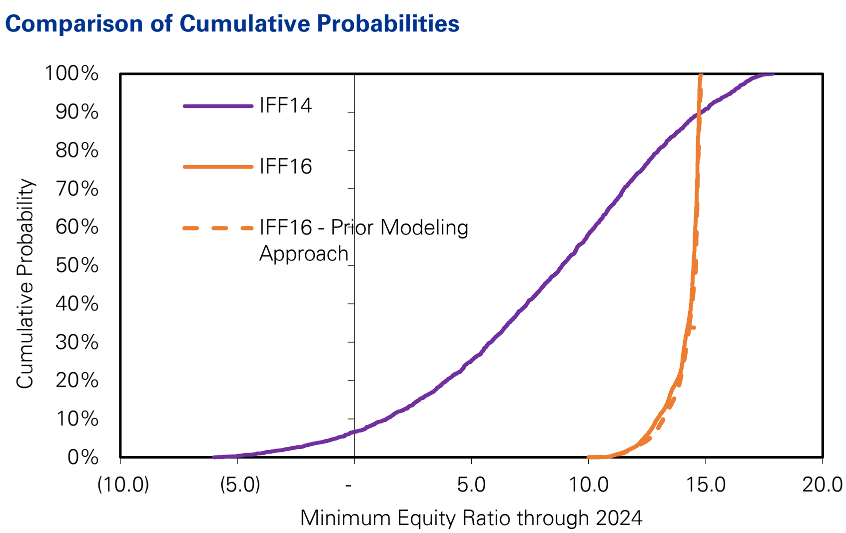
For IFF14, the combination of 27 scenarios thereby obtained was applied against 99 water flow sequences, for a total of 2673 runs.

In applying the above modelling approach to IFF16, Manitoba Hydro made a number of small changes to reflect issues of data availability:

- Capital expenditure uncertainty was modelled with annual expenditures adjusted up or down by $100 million, relative to the Reference Case, rather than by $50 million. A data set containing the higher level of cost variance ($100 million) was more readily available.
- Water flow uncertainty was modelling using 102 water flow sequences, reflecting the greater length of water flow data now available, rather than the 99 sequences used previously. This resulted in an output set of 2,754 runs rather than the 2,673 runs for the IFF14 stochastic analysis.

The probability distribution for this new set of runs has been added to the figure presented first in Figure 6-13 above. This is shown in Figure 6-14 below.

Figure 6-14: Minimum Equity Value Observed 2018 through 2024 – Alternative Scenarios



In Figure 6-14, the distribution of outcomes under IFF16 as estimated using the prior modelling approach (with adjustments as noted above) is shown with the dashed orange line. This line is virtually indistinguishable to the base analysis for IFF16 (the solid orange line), than to the outcomes shown for IFF14 (the solid purple line). This shows that the improvement in the distribution of forecast outcomes is related almost entirely related to improvement in underlying conditions, with very limited impact to results from changes in the approach for modelling uncertainty.

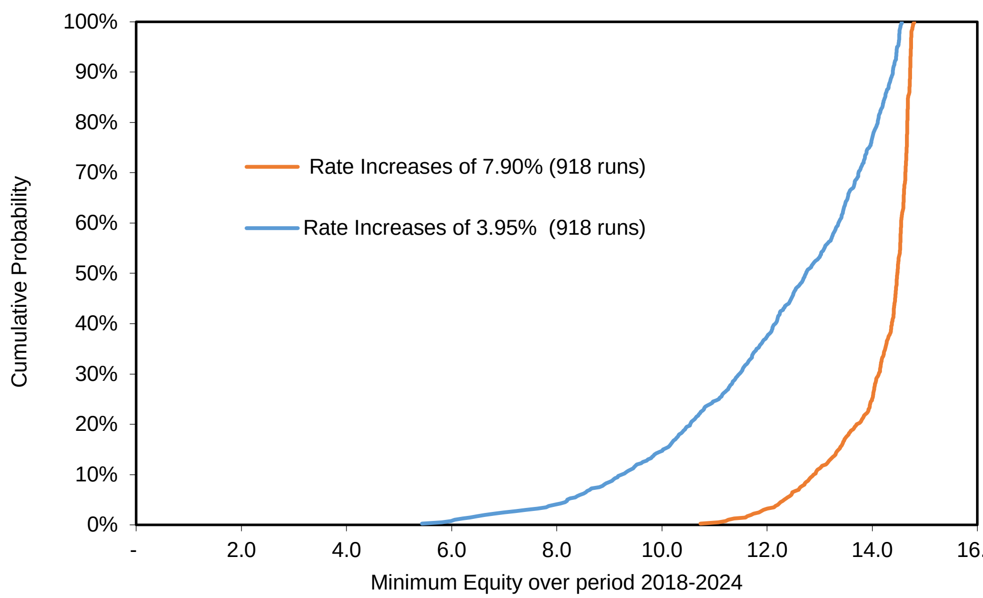
6.4.3 Impact of lower rate trajectory

As noted elsewhere in this report, IFF16 is based on the implementation of 7.90% rate increases for the first 5 years of the forecast, with increases thereafter to be in line with expected general price inflation (2.0%). Rate increases help to increase Manitoba Hydro's equity cushion. Manitoba Hydro, however, has also provided analyses of the impact of rate increases at a lower level, specifically at 3.95% over the entire projection period rather than at 7.90% in the initial years of the forecast. This lower rate trajectory follows that which had been assumed in IFF14 and IFF15.

To illustrate the impact of lower rate increases, we have prepared a cumulative probability chart that compares the two different rate trajectories in terms of the minimum equity values observed 2018 through 2024. Other assumptions are as for IFF16. Figure 6-15 shows that under the 3.95% trajectory, the risk that the equity ratio will fall below 10% is about 15%. In contrast, there is essentially no risk that the minimum equity ratio will fall below 10% under the 7.90% rate trajectory.

The probability distributions in this chart are based on an alternative scenario modelling approach than was used for earlier charts in this Chapter. For the runs summarized in Figure 6-15, Manitoba Hydro applied 102 water flow sequences against 3 energy price scenarios and 3 interest rate scenarios. This resulted in a total of 918 runs for each rate trajectory. Interest rate scenarios cover the consensus forecast, as well as plus/minus 1 percentage point. For the runs with a 7.90% rate trajectory, we confirmed that the distribution of outcomes is roughly similar to that for the same trajectory analyzed with the stochastic modelling approach with 15,300 runs as described earlier. Hence, the analysis with just 918 runs provides a reasonable assessment of the relative impacts of different rate trajectories on equity position.

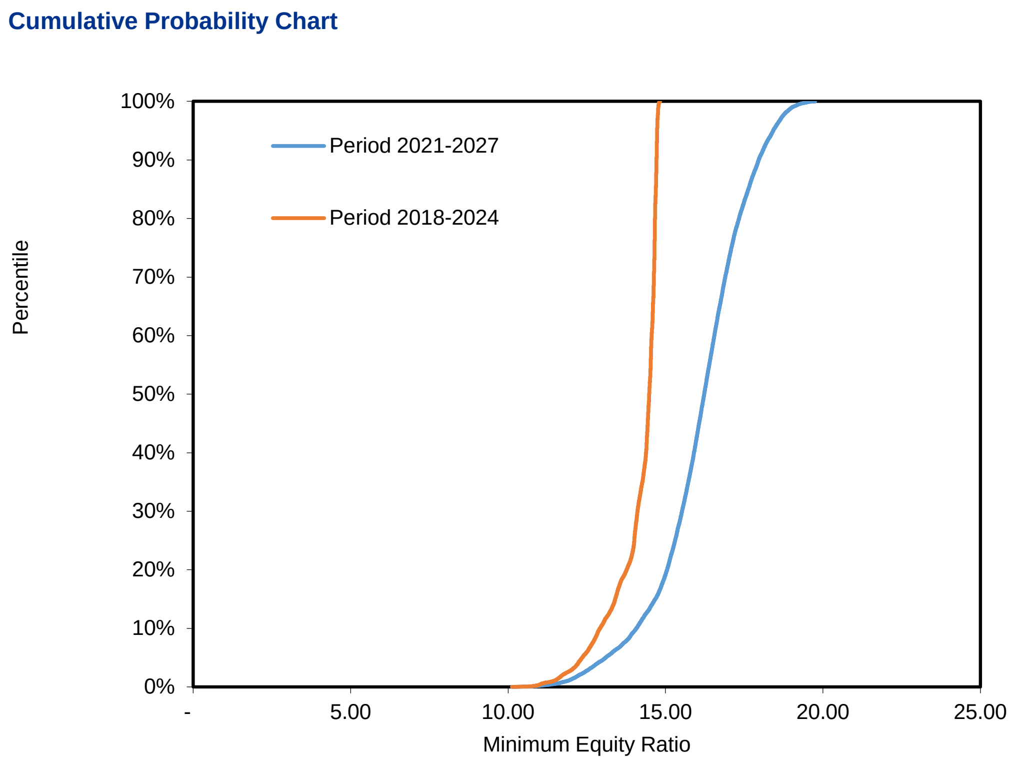
Figure 6-15: Minimum Equity Value Observed 2018 through 2024 – Alternative Scenarios for IFF16



6.4.4 Comparison of different time periods under IFF16

Figure 6-16 examines the minimum equity ratio observed over various periods for the IFF16 scenario modelling. The orange line is the same as in Figures 6-14 and 6-15 above. For the period 2021-2027, relative to 2018-2024, the distribution of minimum equity values broadens, covering a wide range of values, as indicated by the spread in values at the top and bottom of the distribution. This is not unexpected, given that the greater passage of time with a later summary period allows uncertainties to evolve and have greater impact on outcomes.

Figure 6-16: Minimum Equity Value Observed Under IFF16 Scenario Modelling – Alternative Time Periods



6.5 Changes in Equity

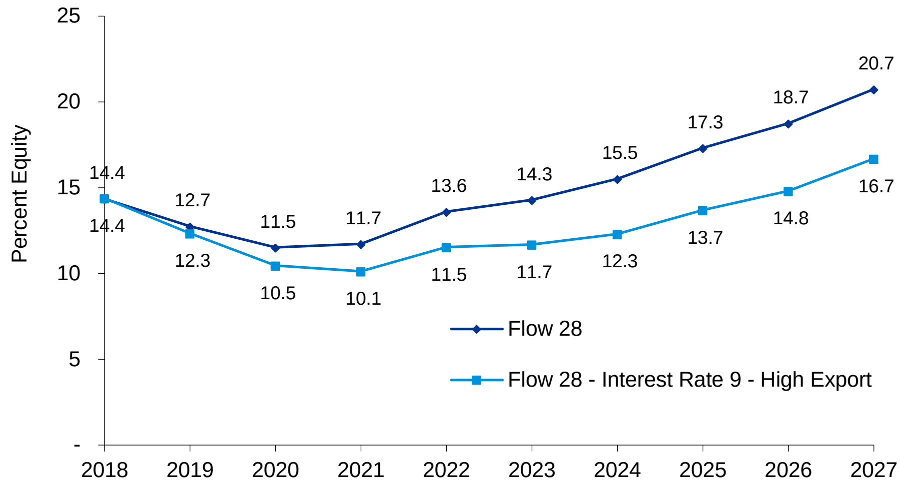
6.5.1 Analysis of selected scenarios

A particular concern for Manitoba Hydro is the potential for its equity position to deteriorate rapidly over a short time period as a result of adverse developments. Given the inherent variability in Manitoba Hydro's water flows, the potential for adverse developments is often closely associated with the potential for drought, particularly over a multi-year period. Other developments, however, such as increases in interest rates or a deterioration in export prices, can also contribute to a deterioration in financial position.

This potential for multiple factors to cause a deterioration in financial position is illustrated through Figure 6-17 below. Within this figure, we show two lines:

- Flow 28 shows the average results (in terms of equity ratio) for all runs associated with water flow sequence 28. This sequence was highlighted earlier in Figure 6–3 as contributing to the minimum average equity value observed in the years 2020 and 2021.
- The line labelled "F28 Ir9 High" shows an individual run from within the group of 150 runs associated with Flow 28. This line was highlighted because it shows a greater deterioration in equity ratios than the average. For the period 2018 through 2021, equity ratio declines by 4.3 percentage points even with the substantial rate increases proposed under IFF16; this drop is the largest decrease observed for this period amongst all 15,300 runs within the overall stochastic analysis. (The equity ratio falls from 14.4% to 10.1% over this period.)

Figure 6-17: Equity Ratio – Flow 28 Average and an Individual Run



Although the individual scenario "F28 Ir9 High" shows a notable fall, the following additional points should be noted:

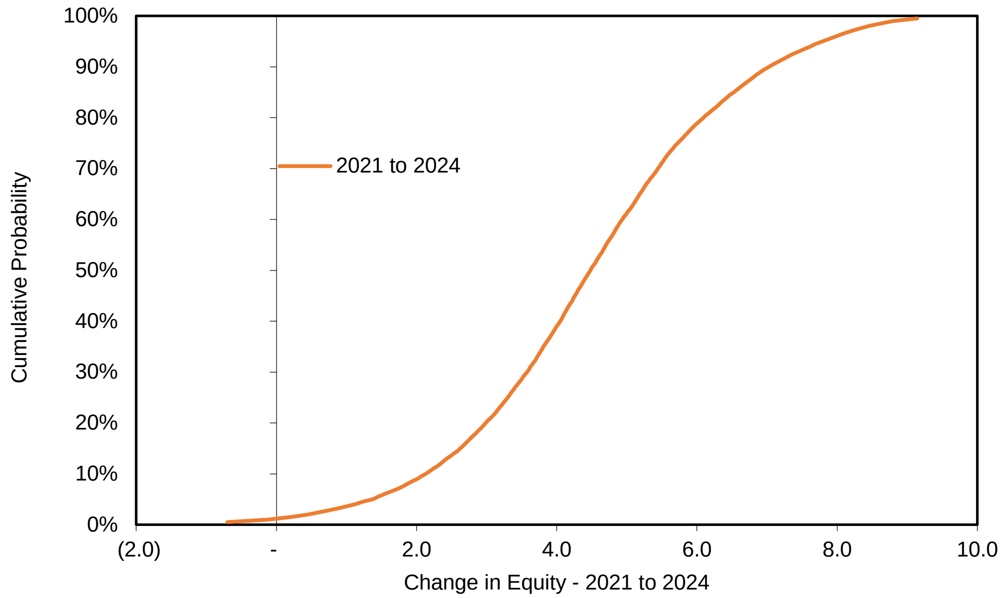
- Manitoba Hydro would likely seek to take corrective measures to ensure financial deterioration was minimized under any individual outcome.
- The scenario "F28 Ir9 High" can be assumed to be relatively improbable. It was selected because it had the worst equity drop in the period 2018 through 2021. Since it represents the maximum drop observed over 15,300 runs, it has a very small probability of occurring, assuming the various runs are equally probable and that input assumptions with respect to probability distributions are roughly accurate. (One individual run represents only 0.0065% of the total number of runs in the stochastic analysis; this number is calculated as 1 divided by 15,300).

Although any individual run may be relatively improbable, the example from Figure 6-13 highlights the fact that it may be useful to understand the probability distribution of changes in the equity ratio over multi-year periods. Events that put pressure on Manitoba Hydro's equity ratio over, say, a three to five year period, are a concern because of the difficulty that Manitoba Hydro has in bolstering its equity position through rate increases to compensate. It is difficult to raise rates quickly enough given lags in the regulatory process and general resistance to increases in rates that are above general price inflation. As a result and as noted in the May 2015 Report, the amount of additional equity that can, in practice, be made available through additional rate increases in the short term is small relative to the financial shocks that Manitoba Hydro can undergo. This was highlighted through the example provided in Section 7.9.1 of the May 2015 Report. Because we are interested in the probability of large reductions in Manitoba Hydro's equity position, we examine the probabilities of various reductions in the section below.

6.5.2 Analysis of overall results

To look at the overall distribution of equity ratio changes, we examined the change in equity ratio between 2021 and 2024 over the 15,300 runs included in the stochastic analysis. The cumulative probability distribution of the change in equity ratio is shown in Figure 6-18 below.

Figure 6-18: Change in Equity Value Observed 2021 to 2024



As noted above, the run with the largest decrease in equity ratio over this period had a fall in equity ratio of 2.81 percentage points. Over all runs, the "median" change in equity ratio was 4.48 percentage points, indicating that half of the runs showed an increase in equity of 4.48 percentage points or more. From a slightly different perspective, only 1.1% of runs had a decrease in equity. (This can be seen in Figure 6-18, where the line crosses the zero point on the "x" axis at a cumulative probability value of 1.1%.) Overall, the runs suggest that equity will likely increase over the period 2021 to 2024.

The line in Figure 6-18 was plotted using data for intervals of 0.5% probability, starting from a 0.5% cumulative probability level. As such the line does not capture or represent very small probability levels. Hence, the minimum value that appears on the graph is roughly (0.7) percentage points, rather than the true minimum value of (2.81) percentage points observed when examining the full data set. The approach of graphing values at 0.5% intervals was done for ease of graphical preparation and presentation.

Figure 6–19 takes the same approach as Figure 6–18, but looks at additional time periods. It adds data sets corresponding the change in equity value over the periods 2018 to 2021, and 2024 to 2027. Thus, it looks, in addition, at the 3-year periods before and after the 2021 to 2024 period used in Figure 6–18.

Figure 6-19: Change in Equity Value Observed – Alternative 3-Year Periods within IFF16

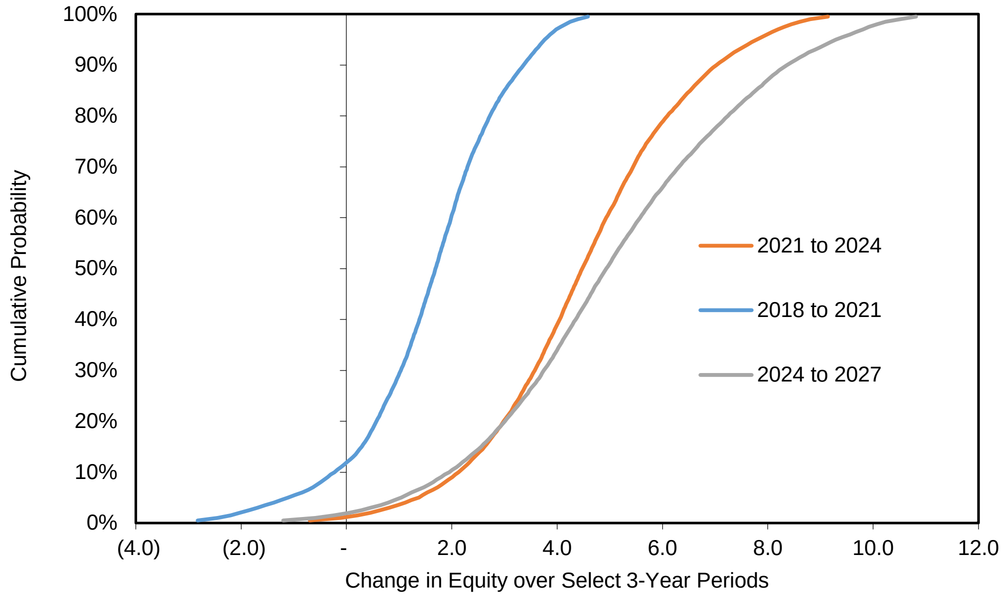
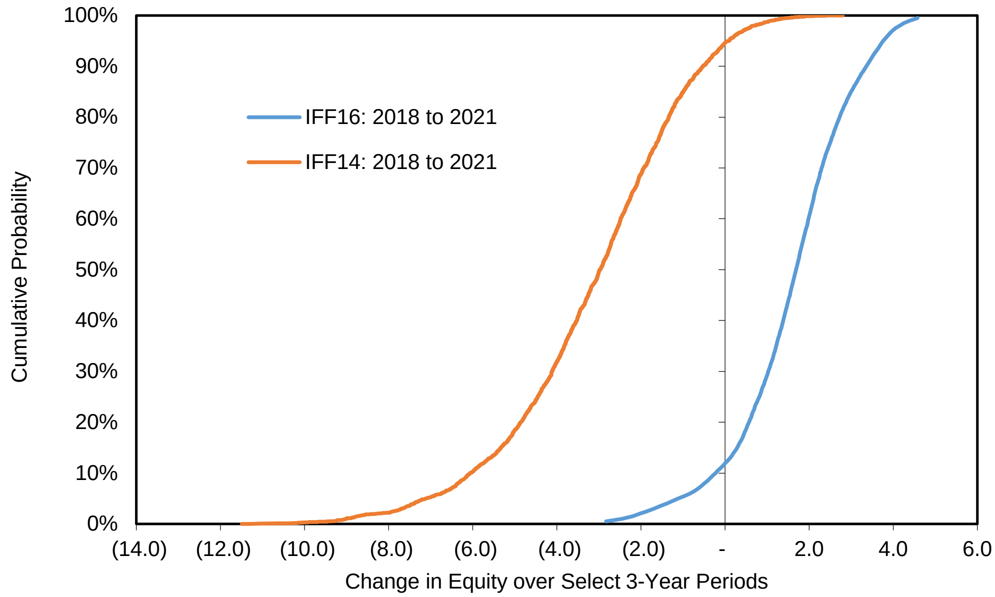


Figure 6-19 above shows that the probability of a decrease in equity ratio over a three-year lowers as you move farther out in time. About 12% of runs over the initial period from 2018 to 2021 showed a decrease in equity ratio. The share of runs with decreases in equity falls to less than 2% for the periods 2021 to 2024 and 2024 to 2027.

6.5.3 Comparison of IFF14 and IFF16

Figure 6-20 compares the probability distribution of changes in the equity ratio over the period 2018 through 2021 for IFF16 versus IFF14. It can be seen that the probability distribution shifts considerably to the right. Under IFF14, the median change in equity value (corresponding to the 50th percentile point on the orange curve) is about negative 3.0 percentage points. For IFF16, the same point is 1.66 percentage points (positive). The shape of the curves is roughly similar, although the distribution for IFF16 appears slightly steeper. This indicates that the spread in values for the change in equity is also smaller for IFF16 than for IFF14, suggesting relatively lower risk.

Figure 6-20: Change in Equity Value Observed – IFF16 versus IFF14



In summary:

- The shift in the distribution to the right indicates a much reduced risk of a fall in equity ratio over the period, consistent with the improved performance of IFF16 relative to IFF14 generally.
- The steeper curve for IFF16 implies that risks of deviating from expected values are also slightly smaller.

6.6 Summary Observations

Key conclusions to be drawn from the analysis in this chapter are the following:

- Forecast financial returns under IFF16 are better than those forecast under IFF14. This is mainly due to a financial plan that accelerates rate increases under IFF16 as compared to IFF14. As a result of this improvement in baseline financial condition, the risk of a fall in equity position to below zero, as observed in Manitoba Hydro's current scenario analysis, has been largely eliminated relative to the analysis for IFF14. This is consistent with a more robust financial condition.
- As expected, the dispersion observed in equity ratios under Manitoba Hydro's scenario analysis widens as you move farther into the future. (This can be seen from Figure 6-19.) The increase in dispersion simply reflects the fact that uncertainty is inherently greater as you move farther into the future.
- Water flow uncertainty remains the single largest risk factor with respect to results in the short term. This conclusion is based on examining the minimum average equity values observed when equity ratios under runs encompassing all interest rate and energy price scenarios are averaged for each water flow sequence, and the minimum value observed taken. (The results of this analysis are shown in Figure 6-3 and again in Figure 6-5.) Similar analysis for each interest rate scenario (averaging across water flows and energy price scenarios), and as summarized in Figure 6-2, shows higher minimum equity ratios throughout the forecast horizon. In addition, the analysis in Section 6.3.5 showed that water flow was the largest contributor to the range of outcomes, or difference between absolute high and low values observed.

7 Summary Observations

As noted in the background (section 1.3) to this supplementary update, KPMG reaffirms the recommendations in the May 2015 Report. These recommendations are that Manitoba Hydro should maintain the following:

- A long-term debt/equity target of 75/25 to 70/30, with a minimum of 85/15 during major capital programs.
- A minimum EBITDA interest coverage ratio target of 1.8 or greater.
- A minimum capital coverage ratio target of 1.2 or greater.

Manitoba Hydro relies on retained earnings as its sole source of equity. Thus, it requires sustained positive cash flow and net income to get back to its minimum equity target.

Further, as noted in the May 2015 Report, decreases in the equity ratio as a result of major capital expansions should be limited to 5 to 10 percentage points from the recommended target level of 25% to 30%. Implicit in these recommendations is that deviations from target should be for the minimum period of time possible.

Over the medium- to longer-term, we note that IFF16 provides for an improvement in Manitoba Hydro's financial outlook relative to that forecast in IFF14. However, this improvement is contingent on achievement of much higher rate increases under IFF16 than IFF14 in the near term (7.90% for five years versus 3.95% annually for 16 years in IFF14) and it takes into account current high reservoir levels, which help to increase forecast export earnings.

For 2017 and 2018, the projected equity ratio for Manitoba Hydro under IFF16 is actually below that originally forecast under IFF14. (See Chapter 2 of this update for a comparison of outlooks.) The EBITDA coverage ratio for 2017 is also lower for IFF16 versus IFF14. Relative investment risk, as measured by the ratio of projected investment to retained earnings, is also considerably higher now than forecast in IFF14. (See Figure 2-7.) Further, projected capital expenditures as a percent of the current asset base are significantly higher at Manitoba Hydro than at BC Hydro, Hydro Quebec and NB Power. (See Figure 4-22.)

Developments in other provinces illustrate the risks that can impede improvements in a utility's financial position, notwithstanding initial plans:

- At Nalcor, cost increases for the Lower Churchill Falls project have significantly increased the amount of equity capital that will be needed to support project completion.
- As outlined in its 2017-2018 Strategic Plan, NB Power is projecting a delay of three years in reaching its 20% equity target (to Fiscal 2024 from Fiscal 2021). This partly reflects decreases in load growth.
- As a result of reduced load growth, BC Hydro projects much larger growth in its rate smoothing deferral account (to $1.59 billion).

In comparing government-owned power utilities in Canada, we note that Manitoba Hydro remains at the low end of power utilities in terms of key financial metrics including equity ratio, interest coverage ratio, and cash flow comparison metrics. The gap in Manitoba Hydro's performance versus most other utilities has widened since the May 2015 Report.

Manitoba Hydro still has very competitive electricity rates compared to other Canadian and North American jurisdictions, giving the utility some flexibility in raising rates to respond to its current financial challenges.

Standard and Poor's downgraded the Province of Manitoba's debt rating in 2016 from "AA" to "AA-" and downgraded again in 2017 from "AA-" to "A+", citing fiscal deficits and significant debt loads at Manitoba Hydro. Most notably, Standard and Poor's indicated that it no longer considers Manitoba Hydro to be self-supporting. Moody's has also highlighted increasing debt loads at Manitoba Hydro as a concern and, although it continues to consider the utility to be self-supporting, it too has downgraded the Province of Manitoba's credit rating since the May 2015 Report.

DBRS, in November 2016, cited Manitoba Hydro's request for rate increases greater than 3.95%, "if actualized", as a positive factor for the utility's financial profile. While DBRS continues to view Manitoba Hydro as self-supporting, it noted that it could consider reclassifying a portion of Manitoba Hydro's debt to be tax-supported if the financial health of the utility deteriorates such that its expenses cannot be recovered in rates.

As noted in Chapter 5, the combined debt of the Province of Manitoba and Manitoba Hydro has significantly increased in the past two fiscal years, and Manitoba Hydro's share of Provincial borrowing, guarantees and obligations now exceeds 40%.

The scenario analysis in Chapter 6 suggests that Manitoba Hydro has an improved financial outlook under IFF16 than under IFF14. However, this improvement is largely contingent on higher rate increases. As shown in Figure 6-15, the distribution of minimum equity values observed over the period 2018 through 2024 is both wider and much lower if rate increases of only 3.95% are implemented. Even with 7.90% rate increases, uncertainty modelling shows that the median value for equity ratio begins to recover only after 2020.

All of these factors suggest that a continued focus on improving Manitoba Hydro's financial position is paramount to prudent risk management. Manitoba Hydro is in an environment of continued uncertainty and inherent business risk. In the near term, Manitoba Hydro remains particularly vulnerable to interest rates and drought as its debt leverage increases substantially to complete the Keeyask and Bipole III projects. In the longer term, water flow uncertainty will remain the paramount factor in evaluating appropriate financial targets. This and other fundamental business risks have not changed for Manitoba Hydro since the May 2015 Report, reinforcing the need to maintain its financial targets.

Appendices

Appendix A: Financial Information of Government-owned Power Utilities

(source: from audited financial statements)

Manitoba Hydro Financial Information, 2011 to 2017 ($ millions)							
For the year ended March 31	**2017**	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**
REVENUES							
Electric - Manitoba	1,419	1,399	1,424	1,405	1,341	1,219	1,218
Electric - extraprovincial	460	415	384	422	353	363	398
Other	106	91	81	70	69	-	-
Gas - commodity	342	353	274	252	182	197	261
Gas - distribution	-	-	153	163	147	132	143
Total Revenues	**2,327**	**2,258**	**2,316**	**2,312**	**2,092**	**1,911**	**2,020**
EXPENSES							
Cost of gas sold	183	181	266	252	182	197	261
Operating and administrative	608	614	614	558	533	481	463
Water rentals and assessments	131	126	125	125	118	119	120
Fuel and power purchased	132	117	129	160	133	146	106
Capital and other taxes	135	123	115	117	105	103	102
Finance expense	645	620	551	470	489	423	425
Depreciation and amortization	402	394	378	442	423	381	393
Other expenses	104	114	77	36	30	-	-
Finance income	(17)	(23)	(26)				
Total Expenses	**2,323**	**2,266**	**2,229**	**2,160**	**2,013**	**1,850**	**1,870**
Net income before net movement in regulatory changes	4	(8)	87	152	79	61	150
Net movement in regulatory balances	55	47	38				
NET INCOME	**59**	**39**	**125**	**152**	**79**	**61**	**150**
Net income attributable to Manitoba Hydro	71	49	136	174	92	61	150
Net loss attributable to non-controlling interest	12	10	11	22	13	-	-
Interest on debt	711	654	581	654	636	603	573
Interest capitalized	(248)	(177)	(145)	(142)	(141)	(170)	(138)
Other finance expenses / adjustments	182	143	115	(41)	(6)	(10)	(10)
Finance Expense	**645**	**620**	**551**	**471**	**489**	**423**	**425**
ASSETS							
Net plant in service	12,671	12,371	11,944	10,684	10,541	8,647	8,215
Construction in progress	7,086	4,837	3,278	2,943	1,967	3,150	2,739
Cash and cash equivalents	646	955	494	142	32	50	70
Other current assets	616	529	573	601	518	438	492
Goodwill and intangible assets	400	301	290	281	276	268	260
Regulated assets / deferral balance	566	486	410	360	306	310	309
Sinking fund investments	-	-	114	111	352	372	282
Other non-current assets	353	300	464	517	550	556	515
Total Assets	**22,338**	**19,779**	**17,567**	**15,639**	**14,542**	**13,791**	**12,882**
LIABILITIES AND EQUITY							
Long-term debt net of sinking fund investments	16,102	14,201	12,303	10,349	8,977	8,729	8,335
Current portion of long-term debt	336	326	377	408	656	281	30
Other current liabilities	1,284	906	719	661	500	465	431
Sinking fund investments shown as assets				111	352	372	282
Contributions in aid of construction	455	434	408	381	340	318	295
BiPole III contribution	196	100	49				
Employee future benefits	818	859	804				
Provisions	70	53	17				
Other liabilities	640	656	688	844	781	749	666
Total Liabilities	**19,901**	**17,535**	**15,365**	**12,754**	**11,606**	**10,914**	**10,039**
Retained earnings	2,899	2,828	2,779	2,716	2,542	2,450	2,389
Accumulated other comprehensive income	(709)	(776)	(720)	96	299	327	367
Non-controlling interest	170	140	120	73	95	100	87
Equity	**2,360**	**2,192**	**2,179**	**2,885**	**2,936**	**2,877**	**2,843**
Total liabilities and equity before regulatory deferral balance	22,261	19,727	17,544	15,639	14,542	13,791	12,882
Regulatory deferral balance	77	52	23				
Total Liabilities & Equity	**22,338**	**19,779**	**17,567**	**15,639**	**14,542**	**13,791**	**12,882**
Equity with CIAOC	**3,011**	**2,726**	**2,636**	**3,266**	**3,276**	**3,195**	**3,138**
Net Debt	**15,792**	**13,572**	**12,072**	**10,615**	**9,601**	**8,960**	**8,295**
Cash provided by operating activities	**872**	**784**	**665**	**690**	**589**	**567**	**595**
Cash provided by financing activities	**1,855**	**2,111**	**1,560**	**1,125**	**635**	**725**	**674**
Cash used for investing activities	**(3,036)**	**(2,434)**	**(1,873)**	**(1,706)**	**(1,242)**	**(1,312)**	**(1,373)**
Capex	**2,924**	**2,322**	**1,802**	**1,457**	**1,037**	**1,124**	**1,166**

BC Hydro Financial Information, 2011 to 2017
($ millions)

For the year ended March 31	2017	2016	2015	2014	2013	2012	2011
REVENUES							
Domestic	5,199	5,056	4,829	4,319	4,038	3,748	3,438
Trade	675	601	919	1,073	860	982	578
Total Revenues	**5,874**	**5,657**	**5,748**	**5,392**	**4,898**	**4,730**	**4,016**
EXPENSES							
Cost of energy	1,576	1,345	1,707	1,607	1,291	1,382	924
Water rentals	349	366	358	361	352	346	305
Transmission charges	169	141	138	178	163	148	186
Personnel expenses	541	527	534	538	527	521	541
Materials and external services	608	605	593	579	606	586	585
Grants and taxes	1,232	220	209	203	196	184	184
Finance charges	605	752	632	598	540	499	435
Depreciation and amortization	234	1,241	1,205	995	953	793	533
Other	55	8	15	28	20	(6)	4
Capitalized costs	(179)	(203)	(224)	(244)	(259)	(281)	(270)
Total Expenses	**5,190**	**5,002**	**5,167**	**4,843**	**4,389**	**4,172**	**3,427**
NET INCOME	**684**	**655**	**581**	**549**	**509**	**558**	**589**
Interest on long-term debt	767	771	685	731	647	612	549
Interest capitalized	(93)	(61)	(69)	(106)	(73)	(49)	(52)
Other finance expenses / adjustments	(69)	42	16	(27)	(34)	(64)	(62)
Finance Charges	**605**	**752**	**632**	**598**	**540**	**499**	**435**
ASSETS							
Cash and cash equivalents	49	44	39	107	60	12	27
Accounts receivable and accrued revenue	808	655	627	1,073	721	595	569
Inventories	185	155	122	114	173	142	128
Property, plant and equipment	22,998	21,385	19,933	18,525	17,226	15,991	15,211
Intangible assets	601	609	547	501	438	412	335
Regulatory assets	6,127	6,324	5,714	4,928	4,741	4,314	2,436
Sinking funds	-	-	-	129	112	105	97
Other assets	1,120	862	771	334	311	329	676
Total Assets	**31,888**	**30,034**	**27,753**	**25,711**	**23,782**	**21,900**	**19,479**
LIABILITIES AND EQUITY							
Accounts payable and accrued liabilities	1,190	1,725	1,708	1,886	1,544	1,423	1,515
Current portion of long-term debt	2,878	2,376	3,698	4,087	3,288	2,888	2,793
Long-term debt	17,146	15,837	13,178	11,610	10,846	10,062	8,851
Contributions in aid of construction	1,765	1,669	1,583	1,291	1,196	1,106	1,012
Other liabilities	4,000	3,927	3,416	2,972	3,408	3,202	2,428
Total Liabilities	**26,979**	**25,534**	**23,583**	**21,846**	**20,282**	**18,681**	**16,599**
Contributed surplus	60	60	60	60	60	60	60
Retained earnings	4,822	4,397	4,068	3,751	3,369	3,075	2,747
Accumulated other comprehensive income	27	43	42	54	71	84	73
Total Equity	**4,909**	**4,500**	**4,170**	**3,865**	**3,500**	**3,219**	**2,880**
Total Liabilities & Equity	**31,888**	**30,034**	**27,753**	**25,711**	**23,782**	**21,900**	**19,479**
Equity with CIAOC	**6,674**	**6,169**	**5,753**	**5,156**	**4,696**	**4,325**	**3,892**
Net Debt	**19,975**	**18,169**	**16,837**	**15,461**	**13,962**	**12,833**	**11,520**
Cash provided by operating activities	**1,327**	**1,060**	**1,018**	**788**	**888**	**816**	**668**
Cash provided by financing activities	**1,191**	**1,047**	**842**	**1,175**	**970**	**779**	**757**
Cash used for investing activities	**(2,513)**	**(2,102)**	**(1,928)**	**(1,916)**	**(1,810)**	**(1,610)**	**(1,407)**
Capex	**2,513**	**2,102**	**1,928**	**1,916**	**1,810**	**1,610**	**1,483**

Hydro-Quebec Financial Information, 2010 to 2016
($ millions)

For the year ended December 31	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**
REVENUES							
Electricity sales	13,339	13,754	13,652	12,878	12,136	12,245	12,019
Other							465
Total Revenues	**13,339**	**13,754**	**13,652**	**12,878**	**12,136**	**12,245**	**12,484**
EXPENSES							
Operations	2,438	2,527	2,366	2,460	2,364	2,410	2,579
Electricity and fuel purchases	1,866	1,938	1,968	1,568	1,183	1,154	1,390
Depreciation and amortization	2,597	2,713	2,593	2,483	2,415	2,603	2,565
Taxes	1,045	980	975	1,000	997	864	909
Finance expenses	2,532	2,449	2,425	2,429	2,441	2,528	2,526
Total Expenses	**10,478**	**10,607**	**10,327**	**9,940**	**9,400**	**9,559**	**9,969**
Result from discontinued operations				4	(1,876)	(75)	
NET INCOME	**2,861**	**3,147**	**3,325**	**2,942**	**860**	**2,611**	**2,515**
Interest on debt securities	2,510	2,552	2,594	2,584	2,576	2,662	2,495
Interest capitalized	(194)	(211)	(318)	(294)	(306)	(300)	(276)
Other finance expenses	216	108	149	139	171	166	307
Finance Expenses	**2,532**	**2,449**	**2,425**	**2,429**	**2,441**	**2,528**	**2,526**
ASSETS							
Cash and cash equivalents	1,243	2,648	1,271	1,695	2,183	1,377	80
Short-term investments (includes sinking fund)	2,184	1,895	1,664	1,689	609	1,102	1,230
Accounts receivable and other receivables	2,049	2,242	2,171	2,177	1,911	1,744	1,814
Derivative instruments	384	402	263	883	1,052	1,322	889
Regulatory assets	4,360	4,061	4,741	9	26	39	30
Materials, fuel and supplies	219	212	199	194	178	236	314
Property, plant and equipment	62,691	61,558	60,413	59,077	57,174	56,901	55,537
Intangible assets	938	1,014	1,062	2,323	2,241	2,187	2,083
Other assets	1,099	1,167	1,324	5,063	5,134	4,729	3,832
Total Assets	**75,167**	**75,199**	**73,108**	**73,110**	**70,508**	**69,637**	**65,809**
LIABILITIES AND EQUITY							
Borrowings	7	9	23	23	19	52	18
Accounts payable and accrued liabilities	2,199	2,278	2,257	2,229	2,069	2,099	1,987
Dividend payable	2,146	2,360	2,535	2,207	645	1,958	1,886
Accrued interest	894	913	907	890	835	862	909
Current portion of long-term debt	1,398	2,059	906	1,157	694	1,025	1,933
Long-term debt	44,218	43,613	43,579	43,067	42,555	40,744	36,439
Other liabilities	4,308	4,181	4,673	3,890	4,434	3,782	3,783
Perpetual debt	293	311	267	253	275	281	288
Total Liabilities	**55,463**	**55,724**	**55,147**	**53,716**	**51,526**	**50,803**	**47,243**
Share capital	4,374	4,374	4,374	4,374	4,374	4,374	4,374
Retained earnings	17,261	16,546	15,759	15,568	14,833	14,618	13,965
Accumulated other comprehensive income	(1,931)	(1,445)	(2,172)	(548)	(225)	(158)	227
Total Equity	**19,704**	**19,475**	**17,961**	**19,394**	**18,982**	**18,834**	**18,566**
Total Liabilities & Equity	**75,167**	**75,199**	**73,108**	**73,110**	**70,508**	**69,637**	**65,809**
Equity	**19,704**	**19,475**	**17,961**	**19,394**	**18,982**	**18,834**	**18,566**
Net Debt	**44,673**	**43,344**	**43,504**	**42,805**	**41,360**	**40,725**	**38,598**
Cash provided by operating activities	**5,504**	**6,235**	**5,873**	**5,017**	**4,768**	**5,161**	**4,639**
Cash provided by financing activities	**(3,200)**	**(1,276)**	**(2,286)**	**(127)**	**(639)**	**(185)**	**(1,725)**
Cash used for investing activities	**(3,693)**	**(3,644)**	**(3,755)**	**(5,386)**	**(3,321)**	**(3,683)**	**(3,302)**
Capex	**3,363**	**3,340**	**3,675**	**4,055**	**3,673**	**3,508**	**3,916**

Nalcor Energy Financial Information, 2010 to 2016 ($ millions)							
For the year ended December 31	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**
REVENUES							
Energy sales	779	761	756	785	726	700	589
Other revenue	45	50	42			14	31
Total Revenues	**824**	**811**	**798**	**785**	**726**	**714**	**620**
EXPENSES							
Fuels	168	193	268	191	182	155	140
Power purchased	61	61	68	63	61	53	44
Operating costs	207	244	249	212	207	200	182
Net finance expense	72	74	67	74	74	71	105
Depreciation, amortization and depletion	135	159	93	90	79	85	68
Other	46	38	4	11		(3)	3
Total Expenses	**689**	**768**	**749**	**640**	**603**	**561**	**543**
Regulatory adjustments	1	(58)	66	(57)	(30)	(24)	
NET INCOME	**136**	**(16)**	**116**	**88**	**93**	**129**	**77**
Interest on long-term debt	273	275	276	100	91	91	92
Interest capitalized during construction	(198)	(162)	(133)	(15)	(3)	(2)	(1)
Other finance income / expenses	(3)	(39)	(76)	(11)	(14)	(18)	15
Net Finance Expense	**72**	**74**	**67**	**74**	**74**	**71**	**105**
ASSETS							
Cash and cash equivalents	143	149	61	94	12	19	45
Accounts receivable	294	271	249	150	125	164	94
Inventory	93	78	97	75	62	64	63
Property, plant and equipment	11,417	8,325	5,659	3,743	2,435	2,110	1,969
Petroleum and natural gas properties	-	-	-		376	304	269
Regulatory deferrals	164	144	124	64	65	66	70
Other assets	1,951	3,356	4,453	5,398	372	316	296
Total Assets	**14,061**	**12,322**	**10,643**	**9,524**	**3,447**	**3,042**	**2,805**
LIABILITIES AND EQUITY							
Short-term borrowings	435	97	53	41	125	-	-
Accounts payable and accrued liabilities	1,162	997	672	412	198	156	152
Current portion of long-term debt	143	233	8	82	8	8	8
Current portion of regulatory liabilities	-	-	-	-	169	138	119
Limited partnership units	399	207	79	73	-	-	-
Long-term debt	5,873	6,008	6,241	6,048	1,126	1,132	1,137
Other liabilities	1,438	973	616	342	256	179	124
Total Liabilities	**9,449**	**8,516**	**7,669**	**6,997**	**1,882**	**1,612**	**1,539**
Share capital	123	123	123	123	123	123	123
Contributed capital	2,861	2,204	1,469	1,142	436	391	374
Accumulated other comprehensive income	-	-	-	-	44	46	27
Retained earnings	1,280	1,149	1,130	1,004	963	870	742
Total Equity	**4,263**	**3,475**	**2,722**	**2,268**	**1,565**	**1,430**	**1,265**
Regulatory deferrals	348	330	252	259			
Total Liabilities & Equity & Regulatory Deferrals	**14,060**	**12,322**	**10,643**	**9,524**	**3,447**	**3,042**	**2,805**
Contributions in aid of construction	11	11	15	11	44	26	121
Sinking funds	267	243	228	303	263	247	208
Equity with CIAOC	**4,274**	**3,486**	**2,737**	**2,279**	**1,609**	**1,455**	**1,387**
Net Debt	**6,440**	**6,155**	**6,092**	**5,847**	**984**	**874**	**892**
Cash provided by operating activities	**222**	**227**	**146**	**441**	**300**	**167**	**211**
Cash provided by financing activities	**1,397**	**186**	**(195)**	**5,159**	**204**	**63**	**11**
Cash used for investing activities	**(1,625)**	**(327)**	**16**	**(5,487)**	**(510)**	**(256)**	**(192)**
Capex	**2,741**	**2,421**	**1,774**	**985**	**449**	**254**	**196**

NB Power Financial Information, 2011 to 2017 ($ millions)							
For the year ended March 31	2017	2016	2015	2014	2013	2012	2011
REVENUES							
Sales of power							
In province	1,369	1,336	1,374	1,328	1,269	1,266	1,246
Out of province	251	370	346	391	254	225	250
Transmission revenue						90	91
Other	76	85	71	78	82	65	29
Total Revenues	**1,696**	**1,791**	**1,791**	**1,797**	**1,605**	**1,646**	**1,616**
EXPENSES							
Fuel and purchased power	702	830	825	834	807	742	874
Operations, maintenance and administration	483	450	419	437	449	409	416
Depreciation and Amortization	233	226	230	198	184	217	199
Property and other taxes	43	41	37	36	39	40	40
Finance costs	280	285	327	136	143	95	114
Other	(84)	(66)	(164)	101	(82)	(30)	(94)
Total Expenses	**1,657**	**1,766**	**1,674**	**1,742**	**1,540**	**1,473**	**1,549**
Net earnings before changes in regulatory balances	39	25	117	55	65	173	67
Net changes in regulatory balances	(12)	(13)	(17)				
NET INCOME	**27**	**12**	**100**	**55**	**65**	**173**	**67**
Interest expense	207	212	221	222	249	201	202
Interest capitalized	(4)	(5)	(6)	(53)	(99)	(113)	(97)
Other finance expenses / adjustments	77	78	112	(33)	(7)	7	9
Finance Charges	**280**	**285**	**327**	**136**	**143**	**95**	**114**
ASSETS							
Cash	1	2	3	3	1	4	10
Accounts receivable and prepaid expenses	255	235	269	313	265	278	275
Materials, supplies and fuel	168	204	148	211	206	221	252
Property, plant and equipment	4,280	4,237	4,382	4,072	4,072	3,909	3,773
Nuclear decommissioning & used nuclear fuel management funds	690	673	720	611	612	584	497
Long-term receivable	-	16	16	17	18	-	-
Derivative assets	4	1	6	157	25	-	18
Regulatory balances	1,009	1,021	1,034	1,052	1,072	943	728
Sinking funds receivable	503	464	471	404	376		
Other assets	58	63	113	23	42	67	79
Total Assets	**6,968**	**6,916**	**7,162**	**6,863**	**6,689**	**6,006**	**5,632**
LIABILITIES AND EQUITY							
Short-term indebtedness	977	855	784	858	687	583	483
Accounts payable and accruals	257	255	262	236	227	227	199
Accrued interest	40	41	47	46	50	37	38
Current portion of long-term debt	420	400	580	-	322	481	550
Current portion of derivative liabilities	14	95	73	13	60	77	27
Long-term debt	4,007	4,124	4,025	4,567	4,370	3,469	3,417
Other liabilities	933	939	1,055	744	696	678	612
Total Liabilities	**6,648**	**6,709**	**6,826**	**6,464**	**6,412**	**5,552**	**5,326**
Capital stock		-	-	-	-	140	140
Contributed surplus		-	-	-	-	187	187
Accumulated other comprehensive income	(127)	(213)	(72)	147	95	3	12
Retained earnings	447	420	408	252	182	124	(33)
Total Equity	**320**	**207**	**336**	**399**	**277**	**454**	**306**
Total Liabilities & Equity	**6,968**	**6,916**	**7,162**	**6,863**	**6,689**	**6,006**	**5,632**
Equity	**320**	**207**	**336**	**399**	**277**	**454**	**306**
Net Debt	**4,900**	**4,913**	**4,915**	**5,018**	**5,002**	**4,529**	**4,440**
Cash provided by operating activities	**253**	**183**	**365**	**223**	**104**	**191**	**1**
Cash provided by financing activities	**7**	**20**	**(83)**	**(42)**	**185**	**67**	**188**
Cash used for investing activities	**(261)**	**(204)**	**(282)**	**(179)**	**(294)**	**(264)**	**(183)**
Capex	**278**	**231**	**264**	**182**	**296**	**279**	**238**

Ontario Power Generation Financial Information, 2010 to 2016
($ millions)

For the year ended December 31	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**
REVENUES							
Revenues	5,653	5,476	4,963	4,863	4,732	4,964	5,367
Revenue limit rebate							
Total Revenues	**5,653**	**5,476**	**4,963**	**4,863**	**4,732**	**4,964**	**5,367**
Fuel expense	727	687	641	708	755	754	900
	4,926	**4,789**	**4,322**	**4,155**	**3,977**	**4,210**	**4,467**
EXPENSES							
Operations, maintenance and administration	2,747	2,783	2,615	2,747	2,648	2,781	2,913
Depreciation and amortization	1,257	1,100	754	963	664	694	688
Property taxes	46	45	32	53	47	50	77
Net interest expense	120	180	80	86	117	154	176
Income tax expense (recovery)	168	92	139	31	67	(27)	(60)
Other	135	172	134	140	67	220	24
Total Expenses	**4,473**	**4,372**	**3,754**	**4,020**	**3,610**	**3,872**	**3,818**
Extraordinary item			243				
NET INCOME	**453**	**417**	**811**	**135**	**367**	**338**	**649**
Interest on debt	298	293	300	289	267	258	260
Interest capitalized	(141)	(102)	(135)	(127)	(126)	(86)	(76)
Other finance expenses / adjustments	(37)	(11)	(85)	(76)	(24)	(18)	(8)
Net Interest Expense	**120**	**180**	**80**	**86**	**117**	**154**	**176**
ASSETS							
Cash and cash equivalents	186	464	610	562	413	630	280
Accounts receivables and prepaid expenses	915	843	618	550	567	526	312
Fuel inventory	310	344	334	390	505	655	734
Materials and supplies	445	433	432	425	445	462	485
Property, plant and equipment	19,998	20,595	17,593	16,738	15,860	14,633	13,555
Intangible assets	99	98	76	59	52	50	48
Nuclear fixed asset removal & nuclear waste management funds	15,984	15,121	14,354	13,471	12,690	11,878	11,246
Regulatory assets	5,855	5,868	7,191	5,400	6,478	5,017	1,559
Other assets	580	497	437	496	591	592	1,358
Total Assets	**44,372**	**44,263**	**41,645**	**38,091**	**37,601**	**34,443**	**29,577**
LIABILITIES AND EQUITY							
Accounts payable and accrued charges	1,164	1,199	1,151	1,026	891	825	762
Short-term debt	2	225	-	32	-	60	155
Long-term debt due within one year	1,103	273	503	5	5	403	385
Long-term debt	4,417	5,186	5,227	5,620	5,109	4,341	3,843
Fixed asset removal & nuclear waste management liabilities	19,484	20,169	17,028	16,257	15,522	14,392	12,704
Other liabilities	7,694	7,163	8,269	6,817	8,170	6,796	3,643
Total Liabilities	**33,864**	**34,215**	**32,178**	**29,757**	**29,697**	**26,817**	**21,492**
Common shares	5,126	5,126	5,126	5,126	5,126	5,126	5,126
Retained earnings	5,534	5,098	4,696	3,892	3,757	3,390	3,024
Accumulated other comprehensive income (loss)	(295)	(319)	(496)	(684)	(979)	(890)	(69)
Non-controlling interest	143	140	141				4
Total Equity	**10,508**	**10,045**	**9,467**	**8,334**	**7,904**	**7,626**	**8,085**
Total Liabilities & Equity	**44,372**	**44,260**	**41,645**	**38,091**	**37,601**	**34,443**	**29,577**
Equity	**10,508**	**10,045**	**9,467**	**8,334**	**7,904**	**7,626**	**8,085**
Net Debt	**5,336**	**5,220**	**5,120**	**5,095**	**4,701**	**4,174**	**4,103**
Cash provided by operating activities	**1,705**	**1,465**	**1,433**	**1,174**	**876**	**1,179**	**817**
Cash provided by financing activities	**(176)**	**(58)**	**160**	**543**	**310**	**320**	**337**
Cash used for investing activities	**(1,807)**	**(1,553)**	**(1,545)**	**(1,568)**	**(1,403)**	**(1,138)**	**(945)**
Capex	**1,704**	**1,376**	**1,545**	**1,568**	**1,427**	**1,145**	**978**

Tab 152

REFERENCE:

MFR 45 and 46

PREAMBLE TO IR (IF ANY):

QUESTION:

Quantify all payments to Government included in the forecast, by year, for Keeyask (by component) and for Bipole III (by component) and also as a percentage of MH's gross revenues.

RATIONALE FOR QUESTION:

RESPONSE:

The following tables quantify payments to the Government for the Keeyask and Bipole III projects. Please note the following assumptions:

- Water rental payments have been assigned based on the forecasted supply for the Keeyask Generating Station. No such payment is applicable to Bipole III.

- Manitoba Hydro issues debt based on the consolidated cash requirements of the Corporation and does not assign specific debt issues on a project-by-project basis. As such, the Provincial Guarantee Fee (PGF) attributable to a specific project is estimated for the purposes of this analysis by applying the 1% PGF to construction work in progress until the asset is in-service and the net book value (projected in-service cost net of accumulated depreciation) thereafter.

- Capital taxes are estimated by applying a fixed 0.5% capital tax rate to construction work in progress until the asset is in-service and the net book value thereafter. Similar to finance expense, the use of net book value as a proxy for paid up capital to estimate capital taxes may result in implied impacts to customers for each project that are not representative.

KEEYASK PROJECT - PAYMENTS MADE TO PROVINCE OF MANITOBA
MILLIONS OF DOLLARS

FISCAL YR ENDING	WATER RENTALS	PGF	CAPITAL TAX	TOTAL PMTS TO GOVT	TOTAL ELECTRIC DOMESTIC REVENUE	GOVT PMTS AS A % OF TOTAL DOMESTIC REVENUE
2017	-	33	16	49	1 419	3.5%
2018	-	44	22	65	1 464	4.5%
2019	-	56	28	85	1 746	4.8%
2020	-	68	34	101	1 946	5.2%
2021	-	76	38	114	2 075	5.5%
2022	4	83	42	129	2 243	5.7%
2023	14	85	43	142	2 410	5.9%
2024	15	85	42	142	2 541	5.6%
2025	18	84	42	143	2 647	5.4%
2026	18	82	41	141	2 724	5.2%
2027	18	81	41	139	2 807	5.0%
2028	18	80	40	138	2 893	4.8%
2029	18	79	39	136	2 979	4.6%
2030	18	77	39	134	3 069	4.4%
2031	18	76	38	133	3 163	4.2%
2032	18	75	38	131	3 277	4.0%
2033	19	74	37	129	3 397	3.8%
2034	19	73	36	128	3 521	3.6%
2035	19	71	36	126	3 651	3.5%
2036	19	70	35	124	3 785	3.3%

BIPOLE III PROJECT - PAYMENTS MADE TO PROVINCE OF MANITOBA
MILLIONS OF DOLLARS

FISCAL YR ENDING	PGF	CAPITAL TAX	TOTAL PMTS TO GOVT	TOTAL ELECTRIC DOMESTIC REVENUE	GOVT PMTS AS A % OF TOTAL DOMESTIC REVENUE
2017	32	16	48	1 419	3.4%
2018	43	22	65	1 464	4.4%
2019	49	25	74	1 746	4.2%
2020	49	25	74	1 946	3.8%
2021	49	24	73	2 075	3.5%
2022	48	24	73	2 243	3.2%
2023	48	24	72	2 410	3.0%
2024	47	24	71	2 541	2.8%
2025	46	23	69	2 647	2.6%
2026	45	23	68	2 724	2.5%
2027	44	22	66	2 807	2.3%
2028	43	21	64	2 893	2.2%
2029	42	21	63	2 979	2.1%
2030	41	20	61	3 069	2.0%
2031	40	20	60	3 163	1.9%
2032	39	19	58	3 277	1.8%
2033	38	19	56	3 397	1.7%
2034	37	18	55	3 521	1.6%
2035	35	18	53	3 651	1.5%
2036	34	17	52	3 785	1.4%

Tab 153

Undertaking #65 (Transcript pages 6459 - 6465)

MIPUG to provide a table similar to Board counsel book of documents Exhibit PUB-42-4, page 322, depicting one (1) to two (2) year water rentals paid for BC Hydro; as well as a table showing water rentals paid for Hydro Quebec, to include for the time period selected provincial payments as a percentage of gross revenue.

Response:

Government charges for crown-owned electric utilities compared to Manitoba Hydro (including Hydro Quebec, BC Hydro, Newfoundland Labrador Hydro, SaskPower and New Brunswick Power) are provided below in Table 1. Government charges as paid by these utilities are split by category including: water rentals, provincial guarantee fee, capital & other taxes and other government charges as applicable.

The information also separately shows dividend payments. The structure of dividend payments is in many cases (e.g., Hydro Quebec) not a typical "government charge" of the types noted above, but rather a payment to the government as investor tied to the risks and performance of the utility. Dividends can be specifically relevant in cases where (a) the government invested equity funds, (b) the government separately undertakes risks and rewards related to export sales, and/or (c) the government establishes rate directives whereby rates are established to fund returns on equity.

For comparison purposes gross electricity operations revenue and provincial payments as a percentage of gross revenue is provided, similar to the table in Exhibit PUB-42-4, page 322. For all but Hydro-Quebec the 2018/19 forecast year is provided[1]. Gross revenues provide one basis to compare these total government charge payments to government by different crown utilities; however, circumstances differ among these utilities. Charges on capital and debt are perhaps best compared based on debt or capital, rather than based only on revenues. Water rental overall charges reflect hydro generation levels, charge rates for use of water resources, and may also reflect the extent that utility hydro generation can earn attractive revenues in export markets. Overall, charge rates for water rentals, debt and capital may also vary depending on the whether assets are major new developments versus long-established facilities.

Attached to this response are relevant documents already on or previously on the record and therefore available to the Board on this topic, including:

[1] As Hydro-Quebec generation rates are not regulated, forecast government charges are not easily available. Therefore actual amounts from the most recent 2016 Annual Report are provided.

1. MH/MIPUG (Bowman) – 4 which includes background on utilities including BC Hydro, Newfoundland and Labrador Hydro and Hydro-Quebec regarding equity investment made by owner, dividend payments, debt guarantee fees, etc.
2. From Manitoba Hydro's Appendix 4.5, Updated Financial Target Review Report by KPMG, Section 5.2.2: Government Contributions from public-owned Power Utilities (pages 59-61), including Figure 5-5: Contributions Paid to Governments from Public-Owned Canadian Power Utilities
3. Exhibit MIPUG-26 in the NFAT Review (Response to Undertaking 144) with various examples of government support or intervention in projects to deal with rate pressures.

Table 1: Payments to Government ($ Millions)

($ Millions)	Manitoba Hydro (Forecast 2018/19)[i]	British Columbia Hydro (Forecast 2018/19) [ii]	Hydro-Quebec (2016 Actual, forecast not available)[iii]	Newfoundland Labrador Hydro (Forecast 2018/19)[iv]	SaskPower (Forecast 2018/19)[v]	New Brunswick Power (Forecast 2018/19)[vi]
Water Rentals	103	350.1	667	0	21	0
Debt Guarantee Fee	185	0	218	2.2	0	31.8
Capital & Other Taxes	145	238.7	284	0	50	45.1
Other	0	0	0	0	35	0
Payments to Gov't	**433**	**588.8**	**1,169**	**2.2**	**106**	**76.9**
Gross Operations Revenue	2,246	4,836.8	13,339	696.5	2,697.6	1,705.5
Payments to Gov't as Percentage of Gross Revenue	***19.3%***	***12.2%***	***8.8%***	***0.3%***	***3.9%***	***4.5%***
Dividends	0	70.8	2,146	0	21	0
Total Payments to Gov't (with dividend)	**433**	**659.6**	**3,315**	**127**	**76.9**	**76.9**
Total Payments to Gov't (with dividend) as Percentage of Gross Revenue	*19.3%*	*13.6%*	*24.9%*	*0.3%*	*4.7%*	*4.5%*

[i] PUB-MFR-44, Water rentals are $3.34/MW or 20.32/horse-power year, debt guarantee fee is 1% of outstanding debt (PUB-MFR-45 & PUB-MFR-46), Gross Operations Revenue updated per Appendix 3.8, MH16 Update with Interim
[ii] BC Hydro F2017 – F2019 Revenue Requirement Application, NOTE: prior to rate freeze for 2018/19 (i.e. reflects initial request for 3% rate increase for F2019). Water Rentals are $6.896/MW + capacity charges (per page 4-12 of application), dividend equal to 85% of net income,

subject to an 80:20 debt to equity cap, reduced for F2019 (Schedule 9.0), taxes per page 1-36, gross revenue per page 1-45. Available online: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf

[iii] Guarantee fee approx. 0.5% on debt securities (page 6 of annual report). Dividend (76% of net income – no dividend if equity ratio less than 26%), provincial public utility tax all per page 25 and 26 of 2016 Annual Report. Available online: http://www.hydroquebec.com/publications/en/docs/annual-report/annual-report-2016.pdf

[iv] Newfoundland Labrador Hydro 2017 GRA, 0.5% debt guarantee on outstanding debt over 10 years, 0.25% debt guarantee on outstanding debt under 10 year term remaining, debt guarantee fee Schedule 4-II page 8 of 9 (note: only $2.157 million debt guarantee fee allowed in rates, additional $4.127 million debt guarantee fee for forecast 2019 not in rates, i.e. disallowed portion), Total revenue, Schedule 4-II, page 1 of 9, no dividend payable. Available online: http://www.pub.nl.ca/applications/NLH2017GRA/applications/NLH%202017%20General%20Rate%20Application%20-%20Volume%201%20-%20Revision%203%20-%202017-10-27.PDF

[v] Water rentals, corporate capital tax, coal royalties (included under 'Other') and dividend per SRRP Q5 from the recent 2018 Rate Application. No debt guarantee fee. Available online: http://www.saskratereview.ca/docs/saskpower2017/saskpower-2018-rate-application-srrp-round-1-irs-q1-to-q148-public.pdf Total revenue from 2018 Rate Application, page 27 for fiscal 2018/19. Available online: http://www.saskratereview.ca/docs/saskpower2017/saskpower-2018-rate-application.pdf

[vi] New Brunswick Power 2018/19 Rate Case Application, Debt guarantee fee equals 0.65% debt portfolio management fee to Government (on total long-term debt and short-term indebtedness net of sinking funds) – page 19 (taxes), 99 and 100 (portfolio mgmt. fee), 22 (revenue with requested rate increase) - available online: http://www.nbeub.ca/opt/M/get_document.php?doc=NBP1.03.pdf&no=20980

Section:	**Section 3**	**Page No.:**	**3-2**
Topic:			
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

Mr. Bowman cites the price charged for electricity by BC Hydro, Yukon, Northwest Territories, Newfoundland and Labrador and Nova Scotia as being regulated based on a cost of service approach and indicates that Manitoba Hydro also fits into this category. Manitoba Hydro would like to understand the comparability of the cited utilities.

QUESTION:

a) For each of the utilities cited in the above reference, and for Hydro Quebec, please indicate:
   i. Ownership type (e.g. Crown, privately held shareholder, municipal)
   ii. Are equity investments made by the owner?
   iii. Is a rate of return charged on equity?
   iv. Are dividend payments made?
   v. Is the utility's debt guaranteed by government? If so, what is the guarantee fee?

RESPONSE:

(a)

The citation in question is referring to the model of regulation used by a jurisdiction, not necessarily a given utility within the jurisdiction.

In respect of the electrical utilities in the jurisdictions noted (British Columbia, Yukon, Northwest Territories, Newfoundland and Labrador and Nova Scotia), as well as Quebec:

i. Ownership type:

   a. British Columbia – mix of public, private and municipal.

   b. Yukon – mix of public and private.

c. Northwest Territories – mix of public and private.

d. Newfoundland and Labrador – mix of public and private.

e. Nova Scotia – understood to be a mix of private and municipal.

f. Quebec – understood to be a mix of public, municipal and cooperative.

ii. Equity investment made by the owner: This question is not meaningful in respect of private utilities, and information on municipal and cooperative utilities are often unavailable (plus these utilities are typically small and sometimes numerous). Focusing only on the publicly owned utilities:

a. The only example Mr. Bowman is aware of recently where an equity investment was made to a Crown Corporation per se is Newfoundland and Labrador Hydro, where the government of the day contributed $100 million in equity[1] along with waiving annual debt guarantee fee charges for a period. This was part of implementing recapitalization based on making Newfoundland Hydro equivalent to the profit-earning private utility in the jurisdiction (Newfoundland Power). The effect of this measure was to impose upward rate pressures on customers to ensure the utility earned a larger return on equity than has been the case in earlier rate proceedings through the 1990s and 2000s.

b. In the case of BC Hydro, while not an equity investment per se, Mr. Bowman is aware that the utility has in the past been prescribed to earn a large return on equity (equal to the fair return that a private sector utility would earn, plus the taxes that a private sector utility would pay despite the fact that BC Hydro is non-taxable) and pay a significant portion of that return on equity to the government in the form of a dividend. (as reviewed at Manitoba Hydro hearings over the years, notwithstanding that BC Hydro pays this dividend, it has traditionally paid a much smaller share of rate revenue to government than Manitoba Hydro since BC Hydro pays much lower charges in other areas like debt guarantee fees). The BC Government has foregone this entitlement to a dividend as part of addressing the capitalization of BC Hydro and rate relief, including as part of current efforts to address cost pressures related to Site C (per OIC 095-2014, dividends are to be suspended until BC Hydro reaches a debt:equity level of 60:40; as such, the equity increases are being funded by government foregone dividends). Although this is not an equity investment per se, it serves to function as a government support to major capital projects.

[1] http://www.releases.gov.nl.ca/releases/2009/nr/0617n04.htm.

iii. **Return on Equity:** In all cases Mr. Bowman is aware of, private sector utilities earn a rate of return on equity. Typically municipal utilities and cooperatives are not set up to enshrine a formal return on equity measure. In the case of publicly owned utilities, each of BC Hydro, Yukon Energy, Northwest Territories Power, and Newfoundland Hydro earn a return on equity but in each case because the respective provincial government has explicitly included a provision for such return in legislation or government policy. Mr. Bowman is not versed in the setting of rate for Hydro Quebec in respect of a return on equity.

iv. **Dividend payments:** In respect of private utilities, it would be understood that dividend payments are the norm. For municipal or cooperative utilities, Mr. Bowman cannot generalize, though there are examples Mr. Bowman is aware of that do earn positive financial returns for municipal governments. In respect of publicly owned utilities:

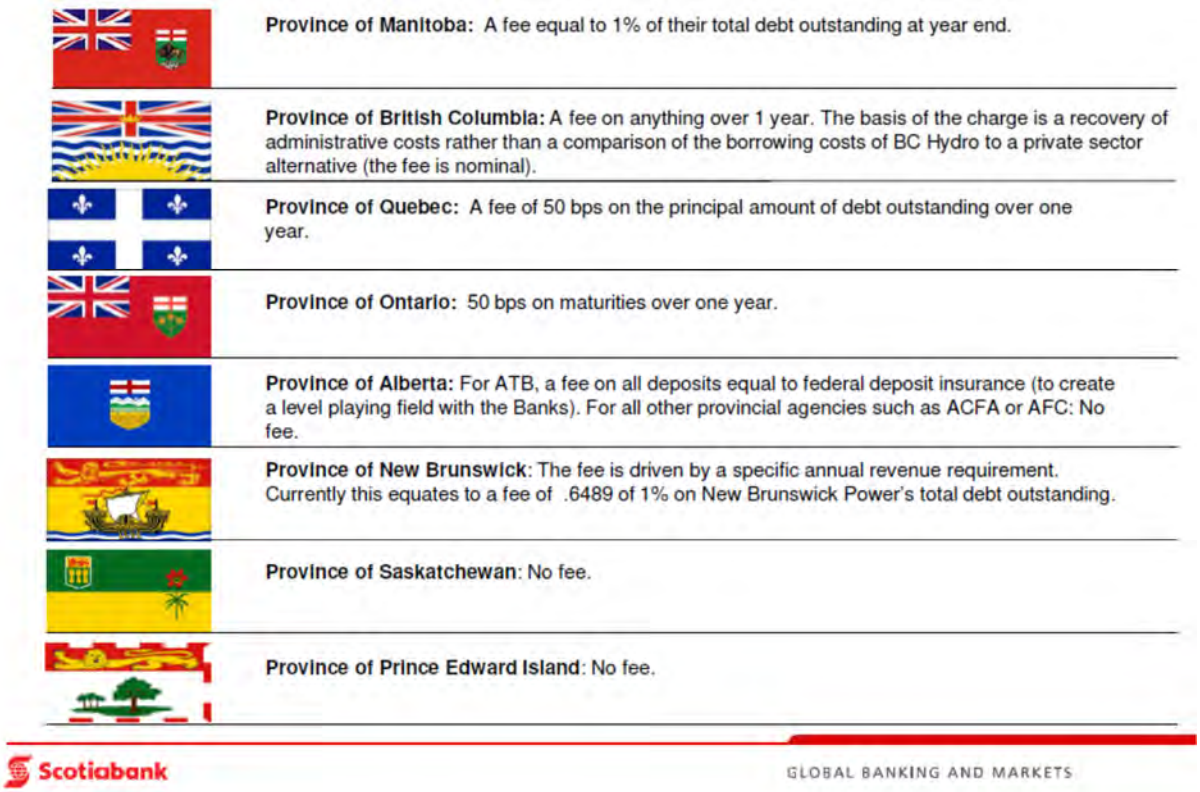
   a. the situation of BC Hydro is described above in item (ii).

   b. Hydro Quebec and Yukon Energy pay dividends to their respective shareholders. It is not known whether Hydro Quebec derives dividends from the regulated business or only from the non-regulated power generation functions.

   c. Northwest Territories Power and Newfoundland Hydro are not making dividend payments from the regulated businesses.

v. **Debt guaranteed by government and fee charged:** This question is assumed to only relate to publicly owned (provincial) utilities. The latest information available to Mr. Bowman on debt guarantees and guarantee fees is from a 2013 Newfoundland Hydro hearing,[2] summarizing the work of Scotiabank Government Finance as follows:

[2] http://www.pub.nf.ca/applications/NLH2013GRA/files/rfi/PUB-NLH-061.pdf.



Province of Manitoba: A fee equal to 1% of their total debt outstanding at year end.

Province of British Columbia: A fee on anything over 1 year. The basis of the charge is a recovery of administrative costs rather than a comparison of the borrowing costs of BC Hydro to a private sector alternative (the fee is nominal).

Province of Quebec: A fee of 50 bps on the principal amount of debt outstanding over one year.

Province of Ontario: 50 bps on maturities over one year.

Province of Alberta: For ATB, a fee on all deposits equal to federal deposit insurance (to create a level playing field with the Banks). For all other provincial agencies such as ACFA or AFC: No fee.

Province of New Brunswick: The fee is driven by a specific annual revenue requirement. Currently this equates to a fee of .6489 of 1% on New Brunswick Power's total debt outstanding.

Province of Saskatchewan: No fee.

Province of Prince Edward Island: No fee.

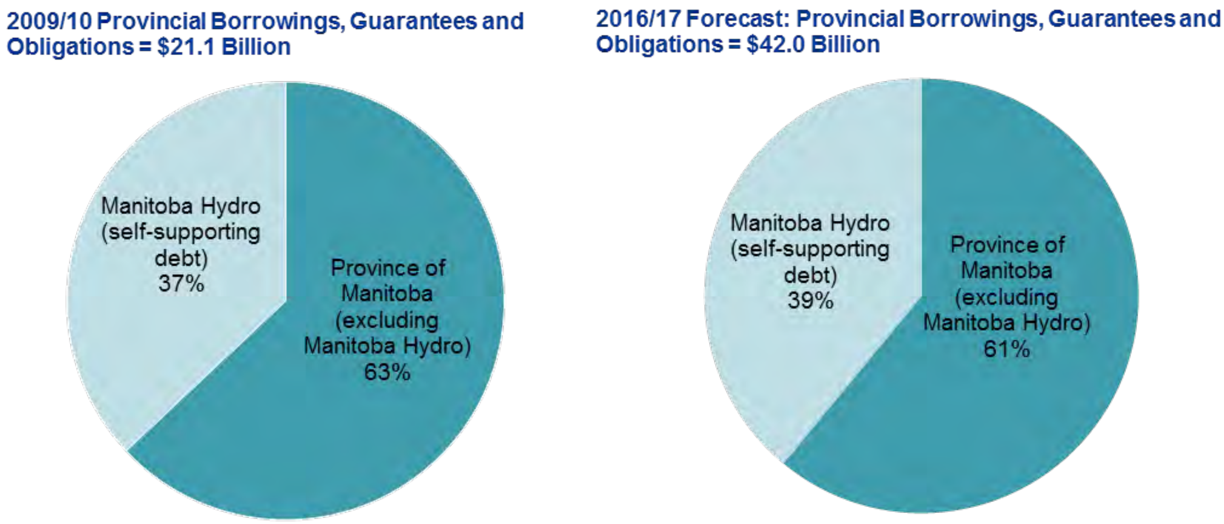
Scotiabank GLOBAL BANKING AND MARKETS

In respect of total amounts paid, Mr. Bowman's most current evidence is from the submission of KPMG in Appendix 4.4 (KPMG's Figure 5.5). This figure highlights the scope of payments made by each of the utilities, including as a percentage of the revenues charged and on a per capita basis.

Figure 5-5: Contributions Paid to Governments from Public-Owned Canadian Power Utilities (FY2016 or FY2016/17 in annual $ millions)

	Manitoba Hydro	BC Hydro	Hydro-Quebec	NB Power	Nalcor
Dividend (1)	n/a	$259	$2,146	n/a	n/a
Debt guarantee fee	$136		$218	$32	$4.5
Water rental charges	$131	$349	$673		$4.9
Property, capital & other taxes	$135	$234	$372	$43	not available
Total	$402	$842	$3,409	$75	$9.4
Total % revenues	17%	14%	26%	4%	1%
Per Capita (rounded dollars)	*$305*	*$177*	*$409*	*$99*	*$18*

Figure 5-4: Province of Manitoba Borrowings, Guarantees and Obligations, 2009/10 and 2016/17 Forecast



Source: 2009/10 from Province of Manitoba 2014 Budget Summary Financial Statistics. 2016/17 forecast from Province of Manitoba 2017 Budget Summary Financial Statistics. (Provincial borrowings, guarantees and obligations are net of sinking funds.)

5.2.2 Government contributions from public-owned power utilities in Canada

Figure 5-5 provides a breakdown of contributions paid to governments from Manitoba Hydro and four other government-owned power utilities in the peer group. Of these five government-owned power utilities, only BC Hydro and Hydro-Quebec currently pay a direct annual dividend to their provincial owner. In both cases, dividends are based on a formula and are capped to ensure that a minimum equity ratio is maintained.

Most government-owned utilities pay a debt guarantee fee based on a percentage of outstanding debt to their respective provincial owner.

- Manitoba Hydro pays a 1.0% fee on outstanding applicable debt, which is the highest percentage fee in the group. The Province of Manitoba's debt guarantee fee was increased from 0.5% to 0.65% effective April 1, 2000 and to 0.95% effective April 1, 2001. [37] The fee was subsequently increased to 1.0% during fiscal 2006/07.
- NB Power pays a 0.65% fee on outstanding debt.
- Hydro-Quebec pays guarantee fees to the Quebec government related to debt securities. In 2014, these fees were $205 million in 2014 which represents slightly under 0.5% on outstanding debt. [38]
- In 2008, the Government of Newfoundland and Labrador temporarily waived the guarantee fee paid by Nalcor until 2011. Upon reinstatement in 2011, the fee was reduced from 1.0% of outstanding debt to a fee of 0.5% on outstanding debt with a remaining term of over 10 years and 0.25% on outstanding debt with a remaining term of under 10 years. The new fee rates were designed to better reflect the value of the debt guarantee, and are based on a comparison of yields on bonds issued by the Province to bonds with similar maturities issued by a group of investment-grade

[37] PUB Board Order 7/03, p. 26.

[38] Hydro-Quebec 2014 Annual Report. Financial statements Note 6.

utilities comparable to Hydro.[39] NLH's recent rate application notes the cumulative impact of these fee initiatives to 2015 is $62.3 million.[40]

In fiscal 2016/17, Manitoba Hydro paid $136 million in debt guarantee fees to the Province of Manitoba, an amount that is expected to increase significantly over the next five years as borrowings ramp up to complete major generation and transmission projects.

Manitoba Hydro, BC Hydro and Hydro-Quebec pay annual water rental charges to their respective provinces. Manitoba Hydro's water rental charge is $3.34 per MW, which is a similar rate to Hydro-Quebec, and significantly lower than BC Hydro, which pays $6.896 per MW plus capacity charges. Under the *Water Power Act*, the Province of Manitoba approximately doubled water rental rates to its current level of $3.34 per MW effective April 1, 2001. Manitoba Hydro paid $131 million to the Province of Manitoba in water rental charges in 2016/17.

All utilities pay local property and related taxes in their respective jurisdictions. In addition to these taxes, Manitoba Hydro pays capital taxes to the Province of Manitoba ($84 million in 2016/17), and Hydro-Quebec pays a Provincial Public Utility Tax to the Government of Quebec.

Figure 5-5: Contributions Paid to Governments from Public-Owned Canadian Power Utilities (FY2016 or FY2016/17 in annual $ millions)

	Manitoba Hydro	BC Hydro	Hydro-Quebec	NB Power	Nalcor
Dividend (1)	n/a	$259	$2,146	n/a	n/a
Debt guarantee fee	$136		$218	$32	$4.5
Water rental charges	$131	$349	$673		$4.9
Property, capital & other taxes	$135	$234	$372	$43	not available
Total	$402	$842	$3,409	$75	$9.4
Total % revenues	17%	14%	26%	4%	1%
Per Capita (rounded dollars)	*$305*	*$177*	*$409*	*$99*	*$18*

Note: derived from annual reports and financial statements, for the year-ending March 31, 2017 for Manitoba Hydro, BC Hydro and NB Power and for the year-ending December 31, 2016 for Hydro-Quebec and Nalcor.

(1) No dividends are paid by Manitoba Hydro, NB Power and Nalcor. For Hydro-Quebec, dividend paid the Quebec government is 75% of net income; no dividend if it effectively reduced the cap rate/equity ratio to less than 25%. For BC Hydro, dividend is 85% of net income, subject to an 80:20 debt to equity cap. Dividend for the year ending March 31, 2016 and for the year ending March 31, 2017 is less than 85% due to the cap. Special Directives from the Province of BC define a minimum annual payment which was $259 million for the 2016/17 fiscal year. Note that BC Hydro's dividend payments to the Province of BC have been higher in previous years.

[39] Newfoundland and Labrador Hydro – 2013 General Rate Application, p. 3.31.

[40] Newfoundland and Labrador Hydro – 2013 General Rate Application, p. 3.32.

Based on information disclosed in annual financial statements, as noted in Figure 5-5, Manitoba Hydro's payments to government represent approximately 17% of total revenues. This is a similar share to BC Hydro (although BC Hydro's dividend payments to the Province of B.C. have been lower in recent years), a much higher proportion than government-owned utilities in Atlantic Canada, but significantly lower than Hydro-Quebec. Hydro-Quebec contributes approximately 26% of its total revenues to government, with nearly two-thirds of its government contributions in the form of dividends to its owner.

5.3 Summary Observations

Key conclusions from the analysis in this chapter are the following:

- Since the May 2015 Report, two credit rating agencies have issued a total of three credit downgrades for the Province of Manitoba. One credit rating agency no longer views Manitoba Hydro debt as self-supporting due to high and rising leverage. Two other credit rating agencies continue to view Manitoba Hydro as self-supporting.
- The combined debt of the Province of Manitoba and Manitoba Hydro has significantly increased in the past two fiscal years, and Manitoba Hydro's share of Provincial borrowings, guarantees and obligations now exceeds 40%.

REFERENCE: Undertaking #144, Transcript page 10,242

QUESTION:

a) MIPUG panel to provide brief summary of various examples of government support or intervention in projects to deal with rate pressures; also to look into examples of relief to ratepayers and, if available publicly, relief between government and other stakeholders, including First Nation government.

ANSWER:

(a)

As requested, Mr. Bowman has appended the information available to him at this time in regard to government support for energy developments, to address either (a) government protection for identified risks, (b) government support for projects that would otherwise have early-years upward pressure on rates, and (c) in some cases outright government subsidies of projects. Please note that Mr. Bowman did not identify any readily summarized examples (i.e., public information) for federal/provincial/territorial government relief for First Nation government investors in energy projects. The information is separated below by province.

Additional examples of government support on projects has been provided on the record in response to MH/MIPUG I-3.

PRINCE EDWARD ISLAND

PEI-New Brunswick Cable Interconnection

In the absence of indigenous resources for hydroelectric development, PEI connected to New Brunswick's electricity system through an underwater cable. The underwater cable was to be owned by the Province of Prince Edward Island and leased to the investor owned utility, Maritime Electric (ME). In 1977, the province took advantage of federal funding that was not available to ME in order to build the cable. The cost was approximately $36 million of which the federal government contributed $18 million and financed another $9 million at Crown corporation rates. The province financed the remaining $9 million. The debt was set up to be repaid in thirty equal annual instalments of principal and interest.

Maritime Electric built the cable under the Interconnection Lease Agreement whereby ME made annual payments to the provincial government equivalent to the financing charges. It was intended that once the debt was retired, ME will continue to lease the cable for $1 per year. The lease also provided that either ME or the province could propose any additions or alterations to the interconnection and the province had the option of financing these additions or let ME do so.

NEW BRUNSWICK

Point Lepreau Nuclear Station

The Government of Canada established a policy of co-financing any first application of Canada Deuterium Uranium (CANDU) nuclear technology in a Canadian province. In the case of the Point Lepreau, the initial agreement provided for federal loans at Crown corporation rates to cover 50 per cent of the capital costs of the plant. However, final costs exceeded the initial estimates by multiples and consequently the ceilings on federal loans were raised above the initially planned levels. The loans represented approximately 25 per cent of the final $1.4 billion total cost. In addition to the commercial aspects of this loan, the Government of Canada forgave interest payments on its loan for the first three years of operation up to a maximum of $102 million. The loans were repayable in equal annual instalments of principal and interest over 25 years. On April 1, 1993, New Brunswick Power repaid the full amount of the loans to Atomic Energy Canada Limited[1].

A more unique feature of the Point Lepreau arrangement was that Canada agreed to make performance loans to New Brunswick Power if the generating station operated below 75 per cent of capacity. This loan commitment is to a maximum of $49 million in any one year up to $130 million overall. These loans were to be repaid when the facility was operating at above 75 per cent capacity.

[1] NB Power 1993/1994 Annual Report.

<u>HVDC Interconnection with Quebec</u>

Through its agent Northern Canada Power Commission (NCPC), a federal Crown corporation, the federal government lent money to New Brunswick Power, at federal Crown corporation rates, to construct the HVDC transmission line from Quebec. The line was constructed in the early 1970s in conjunction with the world's largest converter station on the Eel River (bordering between New Brunswick and Quebec). The converter was designed to allow the Hydro-Quebec Power Commission and the New Brunswick Power Commission to exchange large amounts of power. The loans from the federal government were at rates varying from 4.5% to 8.5% and were to be repaid in equal principal and interest instalments to the year 2011.

NEWFOUNDLAND

<u>Bay d'Espoir</u>

The first major hydro development on the Island, Bay d'Espoir, was constructed in the mid-1960s. This project was funded $20 million (out of an estimated $90 million cost) by the federal government through the Atlantic Development Board.

<u>Roddickton</u>[2]

In 1981, the Roddickton small-scale hydroelectric generating plant (425 kW) was officially opened at White Bay, Newfoundland. The $1.2 million plant was largely funded by the federal government to show the potential of using indigenous energy sources to displace oil.

MANITOBA

<u>Hydro development on the Nelson River – Initial Investigations</u>

The Federal Government entered into a series of agreements to share equally with both the government of Manitoba and Manitoba Hydro the cost of investigating the hydroelectric potential along the Nelson River. Under this arrangement, the Nelson River Programming Board would be responsible for pre-feasibility support to assess the merits

[2] Natural Resources Canada: Canadian Energy Chronology: http://www2.nrcan.gc.ca/es/es/EnergyChronology/index_e.cfm, Viewed on May 8, 2007.

of and prepare a plan for developing hydro power on the Nelson. The initial study, conducted between 1963 and 1964 resulted in an in depth feasibility study, completed in 1968. The initial study under the cost-sharing agreement was $1.3 million, and the subsequent cost for further feasibility studies was an estimated $3 million[3][4].

<u>Nelson River Transmission</u>

In 1966, Manitoba and Canada signed an agreement (Canada-Manitoba Nelson Transmission Line Agreement) that enabled the development of Manitoba's hydro potential on the Nelson River. Canada, through its agent Atomic Energy of Canada, agreed to build an HVDC transmission line between Nelson River and Winnipeg as well as the converter stations and the related microwave communication system. Without this agreement Manitoba Hydro's next best alternative would have favoured thermal generation in southern Manitoba.

Atomic Energy of Canada owned the transmission line, and under the agreement it leased the line to Manitoba Hydro. From 1971, payments to Canada were based on a share of the revenue from sales of electricity over the line; however, the payments fell far short of the annual interest payments (interest rate of 5.625 per cent). In 1977 a repayment schedule was worked out that gradually increased from $2.5 million in 1977/78 to $22.5 million in 1988/89. Any balance remaining at that time was to be amortized over the next thirty years (to 2018/2019) at the original 5.625 per cent interest rate. Unpaid interest accrued to capital which increased from an initial sum of approximately $227 million to approximately $370 million as at 1987. This lease back arrangement enabled Manitoba Hydro to develop the Kettle Rapids hydroelectric generating station, which would not have been viable had the HVDC line been capitalized with the project.

Lease payments for the transmission line were structured to provide economic relief to ratepayers in the early years of development, with anticipated higher rates during the later years.

[3] Natural Resources Canada: Canadian Energy Chronology: http://www2.nrcan.gc.ca/es/es/EnergyChronology/index_e.cfm, Viewed on May 8, 2007.
[4] Manitoba Hydro: A History of Power in Manitoba: 1963. http://www.hydro.mb.ca/corporate/history/history_master.html Viewed on June 12, 2007.

In 1991-1992, Manitoba Hydro bought-out the lease agreement for $198.1 million, resulting in lower charges to operations in the future than had they continued with the arrangement[5].

<u>Nelson River Environmental Investigations</u>

Finally, to ensure that social, economic and environmental interests were fully explored during the development of the Nelson River projects, the federal and Manitoba governments initiated a $2 million study of the Lake Winnipeg Regulation, Churchill River Diversion that ultimately led to the Northern Flood Agreement with the affected northern Manitoba First Nations, and agreements with the cities of Thompson and Churchill[6].

<u>Development of Related Infrastructure</u>

Provincial Highway 280 (from Thompson to Gillam) was built by the Government of Manitoba to facilitate hydro development on the Nelson River system, as well as provide year-round road access to the community of Split Lake.

YUKON

<u>Canada Flexible Term Note – Whitehorse Hydro Facility Fourth Wheel</u>

In 1987, ownership of the Northern Canada Power Corporation (NCPC) was transferred from the Federal Government to the Yukon Energy Corporation (YEC), a wholly owned subsidiary of the Yukon Development Corporation (YDC).

At the time, one of the utility's major customers was a lead/zinc mine located at Faro. This mining operation was recognized as a major risk to the utility operations as the mine had recently been shut down (1982) due to metal market conditions.

In the mid-1980s, NCPC had developed a fourth turbine at the Whitehorse Hydro facility (called Whitehorse #4) to increase the installed capacity of the facility from 20 MW to 40 MW. The unit was added to displace diesel generation costs associated with the Faro

[5] Manitoba Hydro-Electric Board (1992) 41st Annual Review.
[6] Manitoba Hydro (1996) History and First Order Effects: Split Lake Cree Post Project Environmental Review, Vol 2.

Mine; however, the unit was of no value when the Faro mine was closed as the system had substantial surplus hydro and no export connections to sell the power.

Although the Faro Mine reopened during the period of the negotiations between Canada and Yukon to buy the NCPC Yukon-based assets, Yukon was reluctant to assume the full risks associated with Whitehorse #4 given that the mine could close again. The parties resolved a mechanism for a “Flexible Term Loan” from Canada to Yukon for $40 million. This loan provided that Canada would receive annual principal payments of $1 million and interest of 7% when the unit was fully required (the annual system sales were above 310 GW.h), and all interest was forgiven and principal deferred when the unit was not required (system sales below 200 GW.h). In the range of 200 and 310 GW.h, the interest and principal payments were adjusted on a linear sliding scale. All principal not paid would be deferred and all interest not paid in any year would be forgiven. As such, Canada retained all load-related risks associated with the unit.

<u>Mayo-Dawson Transmission Project – Yukon Development Corporation Financing</u>

Yukon Energy developed the Mayo-Dawson transmission line in 2001-2003 to allow otherwise surplus hydro at Mayo to be used to displace diesel generation at Dawson. The project received support from the Yukon Development Corporation (a Yukon Crown Corporation, and the sole shareholder of Yukon Energy) in two ways:

One-time contribution: Yukon Development Corporation (YDC) has provided $5.75 million in non-repayable contributions to Yukon Energy to offset project costs including $4 million for overall project costs, and $1.75 million for targeted items that could not otherwise be justified within the scope of the Mayo-Dawson project. YDC has also provided $50,000 for acquisition of additional land at the Calliston site that is not now repayable but will become repayable (without interest) should Yukon Energy decide to relocate the Dawson diesel plant to this location in the future.

Flexible financing: YDC provided $18 million in debt under a new “flexible financing” plan. Yukon Development receives principal repayments of $450,000 a year (1/40 of the principal). In addition, Yukon Development receives interest payments that are the lesser of 6.55% or the maximum Yukon Energy can afford to pay from the diesel savings – with the net result that the total cost to Yukon Energy for the project will in no year be above what it would have cost to serve Dawson using diesel generation power.

Tab 154

THE ENVIRONMENT ACT
LOI SUR L'ENVIRONNEMENT

Manitoba

LICENCE

Licence No. / Licence n° 3055

Issue Date / Date de délivrance August 14, 2013

In accordance with *The Environment Act* (C.C.S.M. c. E125) /
Conformément à la *Loi sur l'environnement* (C.P.L.M. c. E125)

Pursuant to Section 12(1) / Conformément au Paragraphe 12(1)

THIS LICENCE IS ISSUED TO: / CETTE LICENCE EST DONNÉE À:

MANITOBA HYDRO:
"the Licencee"

for the construction, operation and maintenance of the Development being the Bipole III Transmission Project, consisting of a new 500 kV HVdc transmission line connecting two new converter stations, one in the north near Gillam (Keewatinoow Converter Station) and one in the south near Winnipeg (Riel Converter Station), two new ground electrodes connected to each of the new converter stations, and new 230 kV ac transmission collector lines to connect the new northern converter station to existing northern converter stations, in accordance with the Proposal dated December 14, 2009, the Bipole III Transmission Project Environmental Impact Statement (EIS) filed under The Environment Act in December 2011, supporting information filed in association with the EIS dated June 22, July 31, August 8, September 17 and 20, October 2, 23, and 19, 2012, January 28, February 19, and 25, 2013, in consideration of the June 2013 Clean Environment Commission Report on Public Hearings, and subject to the following specifications, limits, terms and conditions:

DEFINITIONS

In this Licence:

"bog" means a peat-covered wetland in which the vegetation shows the effects of a high water table and a general lack of nutrients. The surface is often raised relative to the surrounding landscape and isolated from mineralized soil waters. At least 40 cm of peat are present. The plant community is dominated by cushion-forming Sphagnum mosses (peat mosses), ericaceous shrubs and black spruce trees;

"Director" means an employee referred to in this licence, so designated pursuant to *The Environment Act,* who is the Director of the Environmental Approvals Branch of the Department of Conservation and Water Stewardship (CWS), unless otherwise specified;

"Environment Officer" means an employee so designated pursuant to *The Environment Act;*

****A COPY OF THIS LICENCE MUST BE KEPT ON SITE AT THE DEVELOPMENT AT ALL TIMES****

"native habitat" means grasses, wildflowers, shrubs, trees, and other vegetation that occur naturally and support fauna indigenous to the area;

"Minister" means the Minister of Conservation and Water Stewardship;

"quarry" means a mine that is an open excavation from which quarry mineral is removed;

"quarry mineral" means a mineral, other than a diamond, ruby, sapphire or emerald, that is obtained from a quarry, and includes sand, gravel, clay, shale, kaolin, bentonite, gypsum, salt, peat, peat moss, coal and amber, and rock or stone that is used for a purpose other than as a source of metal, metalloid or asbestos;

"record drawings" means engineering drawings complete with all dimensions which indicate all features of the pipeline as it has actually been built;

"Region" means the geographic areas of the Province of Manitoba in which the Department of Conservation and Water Stewardship has been divided;

"Regional Director" means an employee so designated by the Department of Conservation and Water Stewardship;

"Regional Forester" means an employee so designated by the Department of Conservation and Water Stewardship;

"riparian area" means an area of land on the banks or in the vicinity of a waterbody, which due to the presence of water supports, or in the absence of human intervention would naturally support, an ecosystem that is distinctly different from that of adjacent upland areas (*The Water Protection Act* 2005);

"rutting" means a sunken track or groove made by the passage of vehicles;

"slash" means branches and other woody debris that result from forest clearing;

"transmission line right-of-way" means the corridor for the proposed 500 kV HVdc transmission line, as defined and described in the EIS;

"waterbody" means any body of flowing or standing water, whether naturally or artificially created, and whether the flow or presence of water is continuous, intermittent or occurs only during a flood, including but not limited to a lake, river, creek, stream, and wetland (slough, marsh, swamp, etc.), including ice on any of them (*The Water Protection Act* 2005); and

"wetland" means land that is saturated with water long enough to promote wetland or aquatic processes as indicated by poorly drained soils, hydrophytic vegetation, and various kinds of biological activity which are adapted to a wet environment. They are generally less than approximately 2 metres in depth (National Wetland Working Group 1997).

GENERAL TERMS AND CONDITIONS

This Section of the Licence contains requirements intended to provide guidance to the Licencee in implementing practices to ensure that the environment is maintained in such a manner as to sustain a high quality of life, including social and economic development, recreation and leisure for present and future Manitobans.

1. The Licencee shall, in addition to any of the following specifications, limits, terms and conditions specified in this Licence, upon the request of the Director:
   a) sample, monitor, analyse or investigate specific areas of concern regarding any segment, component or aspect of the Development for such duration and at such frequencies as may be specified;
   b) determine the environmental impact associated from the Development; and
   c) provide the Director, within such time as may be specified, with such reports, drawings, specifications, analytical data, descriptions of sampling and other information as may from time to time be requested.

2. The Licencee shall submit all information required to be provided to the Director under this Licence, in writing, in such form (including number of copies) and of such content as may be required by the Director and each submission shall be clearly labeled with the Licence Number and Client File Number associated with this Licence.

3. The Licence shall adhere to the commitments made in the EIS and supporting information filed in association with the EIS during construction and operation of the Development.

SPECIFICATIONS, LIMITS, TERMS AND CONDITIONS

Respecting Pre-Construction

4. The Licencee shall submit a complete Environmental Protection Plan (EPP) for approval of the Director prior to construction of the Development. The EPP shall describe the approach to be used by the Licencee to ensure that mitigative measures are applied systematically, and in a manner consistent with the commitments made in the EIS, including commitments for mitigation measures to address concerns raised by First Nations, Metis communities and local Aboriginal communities about potential adverse effects on the exercise of Aboriginal treaty rights as summarized in the EIS commitment table. If prior approval is given by the Director, separate EPPs may be submitted for the construction and operation phases, as well as for different reaches or components of the Development. Specifically, the EPP shall:
   a) describe the environmental management system and protocol for internal reporting on monitoring and compliance for the construction of the project;
   b) provide field construction personnel with clear instructions on the mitigation measures to be implemented and on the appropriate lines of communication and means of reporting to be followed throughout the full-life cycle of the project;
   c) summarize environmental sensitivities and mitigation actions and emergency response plans and reporting protocols;

d) provide specific information on waste management practices to be used during the construction phase of the project, including consideration of all liquid and solid wastes generated;
e) identify how Aboriginal Traditional Knowledge will be enhanced and used in activities addressed in the EPP; and
f) address issues and concerns identified by representatives of First Nations, Metis, and local Aboriginal communities relating to the environmental effects of the project as described above.

5. The Licencee shall, prior to construction of the Development in a Wildlife Management Area (WMA), obtain a WMA Use Permit from the Director of the Wildlife Branch of CWS.

6. The Licencee shall, prior to construction of the Development in agricultural areas, consult with agricultural land owners to determine the tower placement that would have the least impact on agricultural operations, and incorporate those changes into the final design of the Development unless there is compelling rationale to depart.

7. Where routing is along existing drains, the Licencee shall place towers for the Development in or immediately adjacent to the grass swales along the field side of drains, unless there is compelling reason to depart.

8. The Licencee shall follow the recommended routing changes cited in recommendation 9.3 in the Clean Environment Commission's report unless there is compelling reasons not to do so. Any proposed deviations from the route changes recommended by the Clean Environment Commission's recommendation 9.3 shall be provided to the Director, for approval prior to construction in those areas, providing compelling rationale for the final route preferred.

9. The Licencee shall, prior to construction of the Development in the areas cited in the Clean Environment Commission's recommendations 10.1, 10.2, and 10.3, incorporate the changes recommended in the transmission line route into the final design of the development for those specific locations.

10. The Licencee shall, prior to construction of the Development, submit maps of the final route to the Director with a description of any changes from the Final Preferred Route identified in the EIS. Maps may be submitted all at once for the entire route or in several separate submissions for portions of the route to accommodate construction schedules.

11. The Licencee shall prepare a plan for construction and maintenance associated with the Development within the area of the Lake Winnipegosis Salt Flats Ecological Reserve, the proposed expansion, and the source salt spring in consultation with the Parks and Natural Areas Branch and submit the plan for approval of the Director prior to initiating construction in this area.

12. The Licencee shall, for each region of CWS, re-establish any of the Forestry Branch's existing Permanent Sample Plots (PSPs) located within 200 m of the transmission line right-of-way with two new PSPs prior to construction in each applicable Region. Approval of the locations of the new PSPs shall be obtained from the Director of the Forestry Branch.

13. The Licencee shall, prior to construction in forested areas, consult with the responsible Regional Forester of the Forestry Branch to determine the disposition of timber cleared in association with the Development in those areas.

14. The Licencee shall, prior to construction, retain a qualified archaeological consultant to conduct a Heritage Resources Impact Assessment (HRIA) to identify and assess any heritage resources that may be negatively impacted by Development. Plans for the identification of and mitigation for Aboriginal sacred or ceremonial sites shall be included in the report. The HRIA shall be submitted to the Director for approval prior to construction.

15. The Licencee shall, prior to construction of the Development, submit access management plans for approval of the Director. The access management plans shall include, but not be limited to, the anticipated types and locations of roads, trails, and water crossings required to access the right-of way of the Development, and associated decommissioning plans. The plans may be submitted all at once for the entire route or in stages along the route as construction progresses.

16. The Licencee shall use terrain features and vegetation composition to limit access to and line-of-sight along the Development right-of-way.

17. The Licencee shall, prior to construction of the Development, submit a general plan for addressing any unanticipated adjustments to the transmission line right-of-way for approval of the Director. The plan shall describe the action and process that will be followed in the event an unanticipated adjustment is needed due to field conditions.

18. The Licencee shall prepare a report on monitoring programs to be undertaken in relation to the mitigation measures outlined in the EIS and supporting information. Monitoring of community socio-economic and cultural effects should be included in the report. The report shall be submitted prior to June 30, 2014, for the approval of the Director, and:
    a) provide a description of the proposed activities for monitoring effects to the physical, aquatic, and terrestrial environments arising from construction of the Development;
    b) describe the parameters to be measured, the methodology and frequency of measurement, references to establish thresholds and sustainability indicators, where appropriate, and the protocol for reporting the results of monitoring of the environmental conditions affected by the Development to CWS;
    c) in cooperation and consultation with the Wildlife Branch, monitor white-tailed deer distributions and prevalence of brainworm along the transmission line; and
    d) using methods approved by the Wildlife Branch, include descriptions of proposed programs:
        i) to continue monitoring the population status and movements of the woodland caribou herds specifically affected by the Development for 25 years, or less if approved otherwise by the Wildlife Branch. Collaring may be included over the timeframe as determined by the Wildlife Branch;
        ii) for the monitoring of black bear and timber wolf populations, distribution, and predation on woodland caribou in sensitive areas within the caribou ranges in the vicinity of the transmission line right-of-way;
        iii) to conduct periodic moose surveys for 25 years, or less if approved otherwise by the Wildlife Branch including, but not necessarily limited to, Game Hunting Areas 14, 14A and 19A; and

iv) to monitor the use of major points of access within the Development to sensitive wildlife areas by humans and animals using trail cameras, or other more effective techniques, for at least five years after clearing is completed.

19. The Licencee shall, prior to construction which may affect the Gillam area, conduct a community health assessment of the Gillam area to determine the potential impact that a large temporary influx of workers may have on personal, family and community life.

20. The Licencee shall consult the Wildlife Branch of CWS regarding the design and implementation of mitigation measures for the protection of moose and caribou in known sensitive ranges along the transmission line right-of-way. A mitigation plan for these ranges shall be submitted to the Director for approval prior to clearing of the transmission right-of-way in known sensitive areas.

21. The Licencee shall consult the Wildlife Branch and include in the plan required in Clause 18, regarding the design and implementation of mitigation measures and monitoring for impacts to birds of prey including the species at risk such as the peregrine falcon and ferruginous hawk.

22. The Licencee shall conduct clearing components of the Development between August 1 and April 30 of each construction year to avoid potential impacts to the nesting habitat for migratory birds and the calving and rearing habitat for woodland caribou. Should any transmission line clearing be required after April 30, the Licencee shall, prior to the construction activity, consult and reach an agreement with the Wildlife Branch regarding the location of any key wildlife habitats to be avoided including caribou calving areas and bird nesting and brooding areas.

23. The Licencee shall, prior to construction of the Development, provide a copy of this Licence to the contractor and subcontractor(s) involved in the Development.

24. The Licencee shall, prior to construction of the Development, arrange meetings with the construction project managers and the Northeast, Northwest, Western, and Central Regional Directors of Department of Conservation and Water Stewardship (CWS) to review construction related matters.

25. The Licencee shall not less than two weeks prior to beginning construction of the Development in each Region of CWS, notify the responsible Regional Directors of the intended start date of construction within a particular Region and the name of the contractor responsible for the construction.

26. The Licencee shall, prior to the commencement of construction on Crown land, apply for and obtain the appropriate land tenure allocations in accordance with ***the Crown Lands Act*** from the Crown Land and Property Agency.

27. The Licencee shall, prior to construction of the Development in each Region of CWS, obtain work permits and general land permits from the appropriate Regions and comply with the conditions of all permits.

Respecting Construction and Maintenance

28. The Licencee shall, during construction of the Development, employ qualified environmental inspectors to monitor the work on a daily basis to ensure that all the environmental practices outlined in the EIS, the EPPs, and supporting information are carried out.

29. The Licencee shall, during construction of the Development, arrange quarterly meetings with the responsible Regional Directors of CWS to discuss construction, environmental protection, and emergency response issues.

30. The Licencee shall expand and enhance the furbearer pilot study conducted on the Wuskwatim Transmission Project to include areas along the transmission line right-of-way.

31. The Licencee shall submit, to the Director for approval, a plan to accommodate the continuation of educational programs on community traplines that are affected by the Development.

32. The Licencee shall develop a policy, for submission to the Director, to manage documented losses to outfitters that are attributable to the Development and provide an option for disposition of payments in an annual format where compensation is deemed necessary.

33. The Licencee shall, prior to construction of the Development, develop a policy, for submission to the Director, to provide an option for disposition of payments in an annual format where compensation is paid in agricultural areas associated with the Development.

34. The Licencee shall design and decommission quarries in connection with the Development in accordance with the ***Quarry Minerals Regulation 65/92***. Reclamation of individual quarries shall occur as soon as they are no longer in use for the Development.

35. The Licencee shall submit annual plans for the harvest of timber on Crown Lands within the transmission right-of-way of the Development to the applicable Regional Forester in advance of clearing in those areas.

36. The Licencee shall, in consultation with the Forestry Branch, manage vegetation along the transmission right-of-way in coniferous dominated forest to retain the coniferous character.

37. The Licencee shall, during construction of the Development, dispose of all sewage and septage from on-site sanitary facilities in accordance with the ***Onsite Wastewater Management Systems Regulation 83/2003,*** or any future amendment thereof.

38. The Licencee shall dispose of non-reusable construction debris and solid waste from the construction and maintenance of the Development at a waste disposal ground operating under the authority of a permit issued under ***Waste Disposal Grounds Regulation 150/91***, or any future amendment thereof, or a licence issued pursuant to *The Environment Act*.

39. The Licencee shall, during construction and maintenance of the Development, adhere to the general recommendations on design, construction, and maintenance of stream crossings as specified in the Manitoba Department of Natural Resources guidelines titled ***Manitoba Stream Crossing Guidelines for the Protection of Fish and Fish Habitat, May 1996***, and the current versions of applicable federal Department of Fisheries and Oceans Operational Statements.

40. The Licencee shall establish any fuel storage areas required for the construction and maintenance of the Development:
    a) a minimum distance of 100 metres from any waterbody; and
    b) in compliance with the requirements of the ***Storage and Handling of Petroleum Products and Allied Products Regulation 188/2001,*** or any future amendment thereof**.**

41. The Licencee shall, during construction and maintenance of the Development, operate, maintain, and store all materials and equipment in a manner that prevents any deleterious substances including fuel, oil, grease, hydraulic fluid, coolant, and other similar substances from entering any waterbodies. An emergency spill kit for in-water use shall be readily available on site during construction.

42. The Licencee shall, in the case of physical or mechanical equipment breakdown or process upset where such breakdown or process upset results or may result in the release of a pollutant in an amount or concentration, or at a level or rate of release, that causes or may cause a significant adverse effect, immediately report the event by calling 204-944-4888 (toll-free 1-855-944-4888). The report shall indicate the nature of the event, the time and estimated duration of the event and the reason for the event.

43. The Licencee shall, following the reporting of an event pursuant to Clause 42:
    a) identify the repairs required to the mechanical equipment;
    b) undertake all repairs to minimize unauthorized discharges of a pollutant;
    c) complete the repairs in accordance with any written instructions of the Director; and
    d) submit a report to the Director about the causes of breakdown and measures taken, within one week of the repairs being done.

44. The Licencee shall minimize the burning of slash generated during clearing of the Development where smoke may affect residences. In these areas, the Licencee shall dispose of slash using environmentally suitable methods such as chipping and mulching where feasible.

45. The Licencee shall not use herbicides in association with construction of the Development.

46. The Licencee shall, during construction and maintenance of the Development, prevent the introduction and spread of foreign aquatic and terrestrial biota (e.g., weeds, non-native species) to surface waters and in native habitats and prevent invasive species to agricultural lands. To ensure this, all equipment used for the construction of the Development, including transport trucks and trailers, shall be cleaned prior to moving between areas of differing vegetation types (e.g., cultivated land to natural prairie, to forested, etc.).

47. To prevent rutting having the potential of mixing of soil layers, the Licencee shall implement mitigation measures as appropriate (e.g., avoiding excessively wet soils or other means).

48. The Licencee shall, during maintenance of the Development in Environmentally Sensitive Sites (ESSs) identified in the EPP related to traditional plant harvesting:
    a) clear vegetation using only low impact methods including hand clearing;
    b) not apply herbicides in the ESSs and within a buffer from the sites, unless a vegetation management agreement stating otherwise is developed with the First Nations, Metis communities and local Aboriginal communities that utilize the specific sites; and

c) post signs indicating herbicides have been applied in areas along the transmission line right-of-way when and where herbicides have been applied in the vicinity of the ESSs. The postings shall be left in place for one month after the application has occurred.

49. The Licencee shall, during construction and maintenance of the Development, clear only tower locations, danger trees, and trees in excess of 17 meters in height within the transmission line right-of-way along the approximately 8 kilometer long section of Game Hunting Area 19A, which is currently inaccessible by means of existing fence lines and trails.

50. The Licencee shall leave wildlife trees, where possible, throughout the Development right-of-way where they do not pose a hazard.

51. The Licencee shall, in consultation with Wildlife Branch, manage the Development right-of-way from Swan River northward to discourage population increase and distribution of white-tailed deer.

52. To ensure no net loss of wetlands, the Licencee shall, during construction and maintenance of the Development, maintain a minimum 30 meter riparian buffer zone immediately adjacent to wetlands and the shoreline of lakes, rivers, creeks, and streams. Within the riparian buffer zone:
a) trees that must be removed shall be cleared using only low impact methods including hand clearing;
b) all existing low growth vegetation such as grasses, shrubs, and willows shall be maintained;
c) the application of herbicides shall be prohibited; and
d) any affected wetland area will be restored, replaced or offset as approved by the Director to ensure no net loss of wetlands.

53. The Licencee shall, where native prairie habitat is disturbed during construction of the Development, retain a native prairie re-vegetation specialist to plan and oversee reclamation of these areas. Re-vegetation monitoring shall be conducted by the native prairie re-vegetation specialist for a minimum of three complete growing seasons. Follow-up monitoring, seeding, maintenance, and/or weed control shall be conducted until disturbed areas are re-vegetated to the satisfaction of the Director. Re-vegetation shall:
a) where conditions are ideal regarding topography, slope, moisture, time of year, and the condition of nearby prairie, allow for natural re-vegetation; or
b) where conditions are not ideal for natural recovery, re-vegetate areas exposed during the construction with native seed mixes approved by the Wildlife Branch of CWS.

54. The Licencee shall ensure access within the Development, where possible, to quarry mineral withdrawals by Manitoba Infrastructure and Transportation (MIT) in Townships 22-11W, 30-17W, 22-12W, 30-18W, 23-12W, 31-19W, 25-13W, 32-20W, 26-13W, 33-21W, 30-18W, 33-25W, 32-20W, 44-25W, 49-25W, and 45-25W.

55. The Licencee shall remove any temporary construction access routes and rehabilitate all disturbed areas within MIT's right-of-way and controlled area upon completion of construction of the Development in the locations identified in Clause 54 of this Licence.

56. The Licencee shall implement the monitoring programs approved pursuant to Clause 18 of this Licence.

57. The Licencee shall, during construction of the Development, submit annual reports to the Director on the success of the mitigation measures employed during construction, a description of the adaptive management measures undertaken to address issues, and recommendations for improvements of mitigation in future projects. The reports shall include a progressive assessment of the accuracy of predictions made in the EIS and supporting information, including those relating to domestic use of resources (including Aboriginal Traditional Knowledge) by First Nations, Metis communities and Local Aboriginal communities and the socio-economic and cultural impacts to those groups. The annual reports shall be submitted for five years after completion of construction or as otherwise approved by the Director.

Respecting Post-Construction

58. The Licencee shall provide the data and report annually to the Director, on the results of the monitoring programs approved pursuant to Clause 18 of this Licence.

59. The Licencee shall:
    a) prepare "record drawings" for the Development and shall label the drawings "record drawings"; and
    b) provide to the Director, within six months of the completion of construction of the Development, two sets of "record drawings" of the Development.

60. The Licencee shall, for approval of the Director, submit a vegetation control plan for line maintenance. The plan shall consider Integrated Pest Management (IPM) strategies and shall eliminate the use of herbicides during maintenance unless there are no other feasible means available. If herbicides are used, the Licencee shall adhere to the ***Pesticides Regulation 47/2004,*** or any future amendment thereof, for the storage, handling and application of pesticides in conjunction with the Development.

61. The Licencee shall not, during maintenance of the Development, use herbicides in Wildlife Management Areas, unless otherwise approved in the vegetation control plan referenced in Clause 60 above.

62. The Licencee shall not use herbicides in bog areas during maintenance of the Development.

63. The Licencee shall, upon completion of construction of the Development, undertake a third-party environmental audit to assess whether commitments they provided in their EIS and supporting information were met and to assess the accuracy of the assumptions and predictions in these documents. The audit shall be repeated after five years. Reports on the audits shall be submitted to the Director.

64. The Licencee shall, no later than December 31, 2013, develop and maintain an easily accessible project-related website to contain all of the information related to monitoring and assessing environmental mitigation and management committed to in the EIS and as noted in the CEC report. The website should contain minutes from community meetings related to the Development monitoring and mitigation management.

Respecting Alterations to the Development

65. The Licencee shall obtain approval from the Minister for any proposed alteration to the Development before proceeding with the alteration in accordance with *The Environment Act*.

REVIEW AND REVOCATION

66. If, in the opinion of the Minister, the Licencee has exceeded or is exceeding or has or is failing to meet the specifications, limits, terms, or conditions set out in this Licence, the Minister may, temporarily or permanently, revoke this Licence.

67. If the construction of the Development has not commenced within three years of the date of this Licence, the Licence is revoked.

68. If, in the opinion of the Minister, new evidence warrants a change in the specifications, limits, terms or conditions of this Licence, the Minister may require the filing of a new proposal pursuant to Section 12 of *The Environment Act.*

Originally signed by

Gord Mackintosh
Minister of Conservation and Water Stewardship

Client File No.: 5433.00

Tab 155

Conservation and Water Stewardship

Climate Change and Environmental Protection Division
Environmental Approvals Branch
123 Main Street, Suite 160, Winnipeg, Manitoba R3C 1A5
T 204 945-8321   **F** 204 945-5229
www.gov.mb.ca/conservation/eal

CLIENT FILE NO. : 5614.00

July 10, 2014

Shannon Johnson, Manager
Manitoba Hydro
820 Taylor (3)
Winnipeg MB R3C 0J1

Dear Ms. Johnson:

Enclosed is **Environment Act Licence No. 3106** dated July 10, 2014 issued to **Manitoba Hydro** for the construction, operation, maintenance and decommissioning of the Keeyask Transmission Project, to be located north of the proposed Keeyask Generation Station, in accordance with the Proposal filed under *The Environment Act*, dated November 5, 2012, and additional information dated April 26, 2013.

In addition to the enclosed Licence requirements, please be informed that all other applicable federal, provincial and municipal regulations and by-laws must be complied with. A Notice of Alteration must be filed with the Director for approval prior to any alteration to the Development as licensed.

For further information on the administration and application of the Licence, please feel free to contact Darrell Ouimet, Environment Officer at 204-803-1389.

Pursuant to Section 27 of *The Environment Act*, this licensing decision may be appealed by any person who is affected by the issuance of this Licence to the Minister of Conservation within 30 days of the date of the Licence.

Yours truly,

"original signed by"
Tracey Braun, M.Sc.
Director
Environment Act

c:	Don Labossiere, Director, Environmental Compliance and Enforcement
	Pierce Roberts, Northeastern Director: – **via email**
	Public Registries; Public Distribution List (see attached)

NOTE: **Confirmation of Receipt of this Licence No. 3106 *(by the Licencee only)* is required by the Director of Environmental Approvals. Please acknowledge receipt by signing in the space provided below and faxing a copy (letter only) to the Department by July 24, 2014.**

On behalf of Manitoba Hydro — **Date**

13565

****A COPY OF THE LICENCE MUST BE KEPT ON SITE AT THE DEVELOPMENT AT ALL TIMES****

Keeyask Transmission Project – Public Distribution List

Manitoba Wildlands
Peguis First Nation

THE ENVIRONMENT ACT
LOI SUR L'ENVIRONNEMENT

Manitoba

LICENCE

Licence No. / Licence n° **3106**

Issue Date / Date de délivrance **July 10, 2014**

In accordance with *The Environment Act* (C.C.S.M. c. E125) /
Conformément à *la Loi sur l'environnement* (C.P.L.M. c. E125)

Pursuant to Section 11(1) / Conformément au Paragraphe 11(1)

THIS LICENCE IS ISSUED TO : / CETTE LICENCE EST DONNÉE À :

MANITOBA HYDRO;
"the Licencee"

for the construction, operation, maintenance and decommissioning of the Keeyask Transmission Project, consisting of 22 km of a new 138 kV ac Construction Power transmission line, a new 138 kV ac to 12.47 kV ac Construction Power Station to be located north of the proposed Keeyask Generation Station, upgrades to the existing Radisson Converter Station, a new Keeyask Switching Station to be located south of the Nelson River, 4 km of four 138 kV ac Unit transmission lines that will transmit power from the proposed Keeyask Generation Station to the Keeyask Switching Station, and 38 km of three 138 kV ac Generation Outlet transmission lines that will transmit power from the new Keeyask Switching Station to the Radisson Converter Station, in accordance with the Proposal filed under *The Environment Act*, dated November 5, 2012, and additional information dated April 26, 2013, and subject to the following specifications, limits, terms and conditions:

DEFINITIONS

In this Licence:

"Director" means an employee so designated pursuant to *The Environment Act*;

"Environment Officer" means an employee so designated pursuant to *The Environment Act;*

****A COPY OF THIS LICENCE MUST BE KEPT ON SITE AT THE DEVELOPMENT AT ALL TIMES****

“riparian area” means an area of land on the banks or in the vicinity of a waterbody, which due to the presence of water supports, or in the absence of human intervention would naturally support, an ecosystem that is distinctly different from that of adjacent upland areas (*The Water Protection Act* 2005);

“waterbody” means any body of flowing or standing water, whether naturally or artificially created, and whether the flow or presence of water is continuous, intermittent or occurs only during a flood, including but not limited to a lake, river, creek, stream, and wetland (slough, marsh, swamp, etc.), including ice on any of them (*The Water Protection Act* 2005); and

“wetland” means land that is saturated with water long enough to promote wetland or aquatic processes as indicated by poorly drained soils, hydrophytic vegetation, and various kinds of biological activity which are adapted to a wet environment. They are generally less than approximately 2 metres in depth (National Wetland Working Group 1997).

GENERAL TERMS AND CONDITIONS

This Section of the Licence contains requirements intended to provide guidance to the Licencee in implementing practices to ensure that the environment is maintained in such a manner as to sustain a high quality of life, including social and economic development, recreation and leisure for present and future Manitobans.

Compliance

1. The Licencee shall adhere to the commitments made in the Proposal, supporting information filed in association with the Proposal, and plans submitted and approved pursuant to this licence during construction, maintenance, operation and decommissioning of the Development.

Additional Permits

2. The Licencee shall, prior to commencing construction of the Development, apply for and obtain all land tenure allocations and Work Permits as required from the appropriate Conservation and Water Stewardship district office and shall comply with the conditions of all permits.

Additional Reporting

3. The Licencee shall, in addition to any of the specifications, limits, terms and conditions specified in this Licence, upon the request of the Director:

a) sample, monitor, analyse or investigate specific areas of concern regarding any segment, component or aspect of the Development for such duration and at such frequencies as may be specified;
b) determine the environmental impact associated from the Development;
c) conduct specific investigations in response to the data gathered during environmental monitoring programs; or
d) provide the Director, within such time as may be specified, with such reports, drawings, specifications, analytical data, descriptions of sampling and other information as may from time to time be requested.

Environmental Inspection

4. The Licencee shall, during construction of the Development, employ qualified environmental inspectors to monitor the work on a daily basis to ensure that all the environmental practices outlined in the Proposal, supporting information, and the plans submitted pursuant to this Licence are carried out.

Reporting Format

5. The Licencee shall submit all information required to be provided to the Director or Environment Officer under this Licence, in writing, in such form (including number of copies) and of such content as may be required by the Director or Environment Officer, and each submission shall be clearly labelled with the Licence Number and Client File Number associated with this Licence.

SPECIFICATIONS, LIMITS, TERMS AND CONDITIONS

Notification

6. The Licencee shall, prior to beginning construction of the Development, provide notification to the Environment Officer responsible for the administration of this Licence of the intended start date of construction and the name of the contractor(s) responsible for the construction.

7. The Licencee shall, prior to construction, provide a copy of this Licence to the contractor(s) and subcontractor(s) involved in the Development.

Access Routes and Line of Sight

8. The Licencee shall not create or improve roads or short access routes for construction and/or maintenance of the Development without written approval from the Northeast Region Integrated Resource Management Team (IRMT) of Conservation and Water Stewardship.

9. The Licencee shall submit an access route inventory and decommissioning and rehabilitation plan for all access routes created or improved in association with the Development, upon completion of construction of the Development, as required by the Northeast Region IRMT.
10. The Licencee shall maintain existing vegetation screens at all points where the transmission right-of-way of the Development intersects an existing road or trail to limit the ability of humans to observe wildlife along the right-of-way.

11. The Licencee shall, during maintenance of the Development, to the extent possible without impeding maintenance activities, maintain natural re-growth of shrubs and other understory vegetation along the transmission line right-of-way to minimize the line of sight of hunters and predators.

Air Quality

12. The Licencee shall minimize the burning of slash generated during clearing of the Development where smoke may affect residences. In such cases, the Licencee shall dispose of slash using environmentally suitable methods such as mulching, where feasible.

Environmental Protection Plan

13. The Licencee shall submit an Environmental Protection Plan for the approval of the Director for the construction of the Development. This plan shall describe the approach to be used by the Licencee to ensure that mitigative measures are applied systematically, and in a manner consistent with the commitments made in the Proposal. Separate plans may be submitted for different components or phases of the Development. Specifically, the plan shall:
    a) describe the environmental management system;
    b) provide field construction personnel with clear instructions on the mitigation measures to be implemented and on the appropriate lines of communication and means of reporting to be followed throughout the life cycle of the project;
    c) summarize environmental sensitivities and mitigation actions and emergency response plans and reporting protocols.

Environmental Monitoring Plan

14. The Licencee shall prepare an Environmental Monitoring Plan to be undertaken in relation to the mitigation measures outlined in the Proposal and supporting information. The plan shall be submitted prior to November 30, 2014, for the approval of the Director, and:
    a) describe the protocol for reporting on compliance monitoring;
    b) describe the specific monitoring measures to be installed/undertaken;
    c) outline the communication and reporting protocol on implementation progress;

d) define the parameters to be measured and the methods to be used to evaluate the environmental effects of the Development to pre-Development baseline conditions;
e) describe how the performance and effectiveness of the recommended mitigation measures will be evaluated during implementation; and
f) describe how adverse effects will be adaptively managed.

15. The Licencee shall implement the plans approved pursuant to Clauses 13 and 14 of this Licence.

Annual Reporting

16. The Licencee shall, during construction, report annually, before June 15th, to the Director on the results of environmental monitoring plans, as approved pursuant to Clause 14 of this Licence and include sufficient detail that assessments can be made as to the accuracy of predictions, success of mitigation actions and commitment to future actions. These reports will provide assessments of any trends detected over the entire reporting period. The annual reports shall be submitted for five years after completion of construction or as otherwise approved by the Director.

Dangerous Goods Storage and Handling

17. The Licencee shall comply with all the applicable requirements of:
a) ***Manitoba Regulation 188/2001,*** or any future amendment thereof, respecting ***Storage and Handling of Petroleum Products and Allied Products.***
b) *The Dangerous Goods Handling and Transportation Act*, and regulations issued thereunder, respecting the handling, transport, storage and disposal of any dangerous goods brought onto or generated at the Development; and
c) The Office of the Fire Commissioner – Province of Manitoba.

18. The Licencee shall establish any fuel storage areas required for the construction and operation of the Development a minimum distance of 100 metres from any waterbody.

19. The Licencee shall, during construction and maintenance of the Development, operate, maintain, and store all materials and equipment in a manner that prevents any deleterious substances including fuel, oil, grease, hydraulic fluid, coolant, and other similar substances from entering any waterbody. An emergency spill kit for in-water use shall be readily available on site during construction.

Spill Response

20. The Licencee shall, in the case of physical or mechanical equipment breakdown or process upset where such breakdown or process upset results or may result in the

release of a pollutant in an amount or concentration, or at a level or rate of release, that causes or may cause a significant adverse effect, immediately report the event by calling 204-944-4888 (toll-free 1-855-944-4888). The report shall indicate the nature of the event, the time and estimated duration of the event and the reason for the event.

21. The Licencee shall, following the reporting of an event pursuant to Clause 20,
    a) identify the repairs required to the mechanical equipment;
    b) undertake all repairs to minimize unauthorized discharges of a pollutant;
    c) complete the repairs in accordance with any written instructions of the Director; and
    d) submit a report to the Director about the causes of breakdown and measures taken, within one week of the repairs being done.

22. The Licencee shall, in a manner approved by the Environment Officer, remove and dispose of all spilled dangerous goods.

23. The Licencee shall, following construction of the Development, verify that terrestrial contamination of the environment has not occurred in work areas of the Development. Any areas of contamination shall be remediated to the satisfaction of the Environment Officer.

Heritage Resources

24. The Licencee shall, during construction and operation of the Development, apply measures to protect heritage resources, as directed by the Historic Resources Branch of Manitoba Tourism, Culture, Heritage, Sport, and Consumer Protection.

Oil Containment Facilities

25. The Licencee shall, prior to commencement of construction activities for the oil containment facilities of the Development, submit to the Director the results of an Oil Containment Assessment. Oil containment plans and specifications, as recommended in the Oil Containment Assessment, shall be approved by the Director prior to the commencement of construction of the oil containment facilities of the Development.

26. The Licencee shall construct and install the oil containment equipment, as described in the Plans and Specifications approved by the Director, as required by Clause 25 of this Licence.

Onsite Wastewater Disposal

27. The Licencee shall, during construction of the Development, dispose of all wastewater from on-site sanitary facilities in accordance with ***Manitoba Regulation***

83/2001, or any future amendment thereof, respecting ***Onsite Wastewater Management Systems.***

Pesticide Application

28. The Licencee shall not use herbicides in association with the construction of transmission components of the Development unless there are no other feasible means available. If herbicides are used, the Licencee shall adhere to the ***Manitoba Regulation 47/2004,*** or any future amendment thereof, respecting ***Pesticides***.

Waste Disposal

29. The Licencee shall dispose of non-reusable construction debris and solid waste from the construction and maintenance of the Development at a waste disposal ground operating under the authority of a permit issued under ***Manitoba Regulation 150/91***, or any future amendment thereof, respecting ***Waste Disposal Grounds,*** or a licence issued pursuant to *The Environment Act*.

Water Crossings

30. The Licencee shall, during construction and maintenance of the Development, adhere to the general recommendations on design, construction, and maintenance of stream crossings as specified in the Manitoba Department of Natural Resources guidelines titled ***Manitoba Stream Crossing Guidelines for the Protection of Fish and Fish Habitat, May 1996***, and the current versions of applicable federal Department of Fisheries and Oceans Operational Statements.

Riparian Areas

31. The Licencee shall, during construction and maintenance of the Development within riparian areas associated with fish-bearing and potentially fish-bearing waterbody crossings:
    a) maintain all existing low growth vegetation such as grasses, shrubs, and willows;
    b) clear trees that must be removed using only low impact methods including hand clearing;
    c) prohibit the application of herbicides;
    d) where natural revegation methods will be insufficient to stabilize disturbed soils, biodegradable erosion control materials and a seed mix native to the area will be utilized.
    e) where possible, maintain 15 metres of riparian area from the high water mark of 1^{st} and 2^{nd} order creeks, and 30 metres from the high water mark of 3^{rd} order and higher streams and rivers;
    f) minimize in-stream construction time to reduce sedimentation;
    g) avoid use of organic soil, silt, or clay in temporary winter stream crossings; and

h) remove all materials used in the construction of ice bridges from the watercourse or water body prior to spring breakup.

Sedimentation and Erosion

32. The Licencee shall, during construction and maintenance of the Development, take all appropriate measures to prevent erosion and the deposition of sediment into any waterbodies. Construction adjacent to waterbodies shall not occur during high rainfall events if construction activities will result in increased erosion and sediment disposition in the adjacent waterbody.

Instream Works

33. The Licencee shall only conduct construction activities in connection with the Development in fish bearing waters or potentially fish bearing waters in accordance with applicable federal *Fisheries Act* Authorizations. The Licencee shall notify Conservation and Water Stewardship, Fisheries Branch, if an application is made to the federal Department of Fisheries and Oceans to work outside the prescribed in-stream work timing windows.

Wetlands

34. The Licencee shall not, during construction, clear, compact, grade or fill any wetlands or native upland habitat, which are not required for the construction of right-of-way of the Development.

Wildlife

35. The Licencee shall only conduct clearing components of the Development between August 1 and April 30 of each construction year to avoid potential impacts to the nesting habitat for migratory birds and the calving and rearing habitat for caribou. Should any transmission line clearing be required outside of this period, the Licencee shall, prior to the construction activity, consult and reach an agreement with the Wildlife Branch regarding the location of any key wildlife habitats to be avoided including bird nesting and brooding areas, and obtain approval of the Director.

36. The Licencee shall not remove, destroy or disturb species pursuant to ***Manitoba Regulation 25/98***, or any future amendment thereof, respecting ***Threatened, Endangered and Extirpated Species***, and in the federal *Species at Risk Act*.

37. The Licencee shall, during construction and maintenance of the Development, take measures to prevent the introduction and spread of foreign aquatic and terrestrial biota.

38. The Licencee shall not, unless otherwise approved by Environment Canada under the federal *Migratory Birds Convention Act*, disturb active migratory bird nests during construction and maintenance of the Development.

39. The Licencee shall avoid when possible, during construction and maintenance of the Development, operating helicopters at low level near calving habitat from May 1 to June 30.

Revegetation

40. The Licencee shall, when natural re-vegetation methods are insufficient to revegetate soil in areas of the Development exposed by construction, a mixture of native or introduced grasses or legumes will be utilized. Native species shall be used to revegetate areas where native species existed prior to construction. Exposed areas shall be revegetated as quickly as possible following construction to prevent soil erosion and the establishment of noxious weeds.

Decommissioning or Alteration

41. The Licencee shall, prior to decommissioning of the Development, submit for approval of the Director, a decommissioning plan for the Development.

42. The Licencee shall implement the decommissioning plan as approved pursuant to Clause 41 of this Licence.

43. The Licencee shall obtain approval from the Director for any proposed alteration to the Development before proceeding with the alteration.

REVIEW AND REVOCATION

44. If, in the opinion of the Director, the Licencee has exceeded or is exceeding or has or is failing to meet the specifications, limits, terms, or conditions set out in this Licence, the Director may, temporarily or permanently, revoke this Licence.

45. If construction of the development has not commenced within three years of the date of this Licence, the Licence is revoked.

46. If, in the opinion of the Director, new evidence warrants a change in the specifications, limits, terms or conditions of this Licence, the Director may require the filing of a new proposal pursuant to Section 11 of *The Environment Act.*

"original signed by"

Tracey Braun, M.Sc.
Director
Environment Act

File: 5614.00

Tab 156

A History of Electric Power Development in Manitoba

by Leonard Bateman
Bateman and Associates Ltd., Winnipeg, MB

Abstract

Today, with deregulation in the power industry occupying a good deal of public attention, this article presents the history of power development in Manitoba. Winnipeg was probably the only place in North America where competition between the private company and the municipal utility for customers was possible using the same power poles. This situation prevailed from 1912 to 1955. Manitoba is well endowed with rivers with significant hydroelectric power sites. The paper outlines the history of development up to and including the development of the Nelson River in the late 1960Õs.This involved the diversion of the Churchill River into the Nelson River and the regulation of Lake Winnipeg. The largest capital expansion program in the history of the utility was undertaken during this period and involved moving the power from the north using direct current transmission at +/-500 kV. The various stages of evolution and consolidation of the power industry are covered, with Manitoba Hydro ending up as the only utility in Manitoba serving all the citizens at a uniform rate.

Sommaire

De nos jours, avec la d”r”glementation de lÕindustrie”nerg”tique qui re“oit une bonne part de lÕattention du public, cet article pr”sente un historique du d”veloppement de lÕ”nergie au Manitoba. Winnipeg ”tait probablement le seul endroit en Am”rique du Nord oš la comp”tition entre des compagnies priv”es et les services publics municipaux utilisant les m’mes poteaux ”lectriques ”tait possible. CÕ”taitle cas de 1912 ‹ 1955. Le Manitoba regorge de complexes hydro”lectriques. Cet article dresse un historique du d”veloppement hydro”lectrique, des d”buts jusquÕauprojet de la rivi‘re Nelson ‹ la fin des ann”es 60. Durant ces ann”es-l‹, il y eut diversion de la rivi‘re Churchill vers la rivi‘re Nelson et la r”gularisation du Lac Winnipeg. Le plus grand programme dÕexpansion dans lÕhistoiredu service public a ”t” entrepris durant cette p”riode et a exig” le transport de lÕ”nergiedu Nord par des lignes de transmission de courant ‹ plus ou moins 500kV. Les diff”rentes ”tapes de lÕ”volutionet de la consolidation de lÕindustrie”nerg”tique sont discut”es, avec Manitoba Hydro devenant le seul service public au Manitoba offrant aux citoyens lÕ”lectricit” ‹ un taux uniforme.

1.0 Early History

Electric Arc Lamps were first seen in Winnipeg, Manitoba in March 1873, just three years after the Province of Manitoba was formed. This was six years before Edison invented the incandescent lamp. It was not long after this that a newly incorporated company received a contract to install arc lamps in the City. This was the beginning of several business ventures by a variety of new companies, and when electric trolley conveyance was demonstrated in 1891, it was the Winnipeg Electric Railway Company (WECO) that received the franchise from the City. This company built a thermal generating station on the banks of the Assiniboine River. It purchased its last competitor in the mid nineties. With a rapidly growing city and the demand for more uses of electricity, WECO looked to the Winnipeg River for hydroelectric development.

It was not the first company to develop a hydro plant in Manitoba. This was done by a company in Brandon some 120 miles west of the City of Winnipeg. They developed a plant on the Minnedosa River (now known as the Little Saskatchewan River) but the flow was such that the plant could only operate for a maximum of eight months of the year. The plant served the City of Brandon using an 11 kV wood pole line. The plant was dismantled in 1924.

2.0 Development of the Winnipeg River

At the beginning of the 20th century, WECO examined the possibility of a development on the Winnipeg River. The consultants that they engaged selected the Pinawa Channel, which is a channel parallel to the Winnipeg River, partially bypassing the Seven Sisters Falls site. It required the construction of a weir to divert the water into this channel with some enlargement of the intake. To build a hydroelectric plant in the wilderness with horses was a remarkable achievement. There were no roads or railways; access was by river or winter road. Construction started in 1902 and the first power was delivered using a 60 kV steel tower line to Winnipeg in 1906. The output of the plant was 22 MWs.

The WECO had a monopoly on the supply of electric power and was charging twenty cents per kWhr, which did not sit very well with some of the aldermen of the City. The company did lower its rate to 10 cents per kWhr when the Pinawa plant was completed. One alderman in particular, Alderman John Wesley Cockburn, managed to get the water rights for the Pointe du Bois site on the Winnipeg River and when the City Charter was amended to permit it to float a bond issue for the development of a hydroelectric site, he transferred the rights to this site to the City. The citizens of Winnipeg voted in favor of developing Pointe du Bois with the promise of power at 3 cents per kWhr. A railway was constructed from the nearest CPR line at Lac du Bonnet. This involved building bridges over the Winnipeg River and the Pinawa Channel. This site was developed into what is now the oldest plant still operating on the Winnipeg River. It has a 46-foot head and is rated at 78 MW. The first power was delivered in October 1911. The rate was set at 7 and cents per kWhr. This sparked a vehement protest from the citizens who had been promised 3 cents. The public outcry resulted in City Council lowering the rate for power to 3 and 1/3 cents per kWhr, which the private company met. This rate remained in use until 1968.

The delivery of power from the CityÕsplant caused a mad scramble to connect customers. It was not uncommon for the City to begin construction of a line on the opposite side of the street on a Saturday morning to supply an industrial customer on Monday morning. The multitude of lines eventually resulted in a judicial decision in 1912 to require both utilities to share the same poles. This arrangement continued until the power industry was rationalized in 1955.

3.0 Rural Electrification

The settlements in rural parts of the province also wanted to share in the benefits of this new form of energy. It spawned a multitude of entrepreneurs; all charging what they thought was reasonable. In order to rationalize this, the Government created the Manitoba Power Commission in 1919 and undertook to sell power to the municipalities, much the same as Ontario was doing, but by 1933, when the depression forced many municipalities into financial difficulties due to residents not paying their electric utility bills, they amended the legislation to permit the Commission to sell directly to the customer and do away with the so called middle man. The growth of consumption required Winnipeg to complete the second half of Pointe du Bois, a project they commenced in 1919 as they had a contract to supply the Commission with its requirements. The WECO also undertook to develop a new site at Great Falls on the Winnipeg River with a capacity of 132 MW. This was the first use of propeller type turbines and resulted in some interesting developments. The admission of air to the draft tube to reduce cavitation was first used at this plant and was soon to be the norm.

The growth in the twenties required the City and WECO to seek new sites for development on the Winnipeg River. The City received the license to develop Slave Falls [1], while WECO received the license to develop Seven Sisters, with a reservation of 35 MW for the Power Commission. The contract that the City had with the Government to supply the Commission was terminated in 1935 when the Company supplied the power from its Seven Sisters Plant. With the

Figure 1: Slave Falls Plant (Source: Manitoba Hydro)

simultaneous development of two sites, nobody foresaw the crash of 1929, and the result was rather catastrophic. The City actually ran its Slave Falls plant with only two units installed on a one-shift basis and incurred a deficit. Units three and four were installed by 1938. The Company shut the three units installed at Seven Sisters down and defaulted on the bond interest. In one respect it was provident that this surplus capacity was available when the 1939 war broke out. It made it possible for the Province to assist in the war effort. However, the growth in the war years required the City to develop a water heater control program, which shut the water heater load off at noon and again during the evening peak, using carrier current injected frequencies into the residential feeders. These were picked up by relays installed in each household. These measures to control the peak demand, along with the use of thermal generation from the Amy Street standby plant that was installed in 1924, resulted in the City meeting its firm load requirements. This thermal plant was built as a result of the loss of all transmission from the Pointe du Bois plant due to a very severe windstorm. It was combined with a central heating system to supply central heat to the downtown city area. Three electric boilers, in addition to the coal-fired boilers, were installed. The operator of these boilers had a recording totatalizer of the Winnipeg Hydro load at his workstation. His job was to utilize all the spare capacity in the system as load on the electric boilers with a resulting saving in coal for the central heating plant. This resulted in a very high load factor on the CityÕs two hydro plants.

The supply of some defense industry load during off peak hours, by arrangement with the WECO, further helped the City to meet its firm load requirements.

Even before the war ended, the City received permission from the Wartime Prices and Control Board to order the steel for the extension of the Slave Falls Plant, which was commenced in 1945. The plant with a total of eight units was completed in 1948. The transmission voltage was raised to138 kV - the first use of this voltage in Manitoba. Meanwhile the WECO undertook the completion of the Seven Sisters Plant to a capacity of 150 MW by raising the head and excavation in the tailrace. This utilized the full flow of the river. The retirement of the Pinawa Plant occurred in 1951.

The Government undertook a study of farm electrification in 1942 and with the completion of the war, commenced this program. The growth of the farm and rural load made it evident that someone had to add new capacity to meet these requirements. The private company would not invest in a new plant unless they received an agreement from the Province for a long-term commitment. The City was in a similar position. Without a guarantee, they were reluctant to commit the necessary funds for expansion of either of the two remaining hydro sites on the Winnipeg River.

4.0 Birth of The Manitoba Hydro Electric Board

This stalemate resulted in the Government creating the Manitoba Hydro Electric Board and the development of the Pine Falls site on the Winnipeg River. The City protected its position during the rather prolonged negotiations on how the power industry should be rationalized, by installing two thermal units of 15 and 25 MW capacity in the Amy Street thermal plant it built in 1924.

The plan for reorganization of the power industry, proposed by the Government, was turned down by the citizens of Winnipeg in a referendum. As a result, the Government forged ahead with its plans and bought the WECO and sold the load in the City, formerly supplied by the Company, to the City in exchange for the City load outside the City boundaries. It also agreed to leave the two City plants at Pointe du Bois [2] and Slave Falls with the City, but undertook to develop all future generation needs for the Province and entered into a cost sharing agreement with the City in 1955, based on the peak demand of the City load and the Provincial loads. The latter soon outdistanced the City load, due to the farm electrification program. Thus the competition for customers in Winnipeg by the two suppliers of power came to an end.

An interesting development occurred in January of 1957, when Manitoba Hydro Electric Board received a letter of intent from INCO to supply power for their new nickel mine being developed at Thompson Manitoba. This was a wilderness location, but the Hudson Bay Railway was some 50 miles away to the south. A hydro site on the Nelson River named Kelsey was available some 60 miles away and Manitoba Hydro undertook to develop this site on the Nelson. The schedule was very demanding, requiring power by 1960. This involved building a railway into the site, building dikes on perma-frost, and building the final earth and rock fill closure dam under a hoarding in the wintertime. The INCO estimated load required four units, but in anticipation of growth in the new town at Thompson, a fifth unit was added, and unit Number 7 was installed by 1972. This five-unit plant rated at 160 MW supplied an isolated load, including two arc furnaces rated at 18 MW each. Special governor characteristics were developed to handle the sudden loss of this furnace load, and governor development tests were run on the Pine Falls plant using electric boilers at the Paper Mill, close by, to simulate the condition of the loss of a furnace under load conditions. These tests were run with the help of Woodward Governor engineers to validate the anticipated governor performance. They are reported in a paper at the 1961 meeting of the AIEE and are recorded in the Transactions of the Institute. INCO placed limits on the amount of load that could be dropped; however very shortly after the tests, but before the instrumentation had been removed, an interruption of greater than one furnace occurred, and the governor performance for control of the machines was superb.

This first plant on the Nelson River was a good experience for future developments.

5.0 Formation of Manitoba Hydro

By 1961 the Government again moved to rationalize the power industry by an amalgamation of the Manitoba Power Commission and the Manitoba Hydro Electric Board. The new organization was called Manitoba Hydro.

With the growth of load in the fifties, the newly created Manitoba Hydro was struggling to stay ahead of the demand. It completed the last two sites on the Winnipeg River at Pine Falls and McArthur Falls and constructed a thermal generating station at Brandon, and another at Selkirk, while it studied its options for more hydro development on the Saskatchewan and Nelson rivers. The decision was made in 1960 to develop the Grand Rapids four-unit site with a capacity of 479 MW on

Figure 2: Pointe du Bois Plant (Source: Manitoba Hydro)

Figure 3: Kelsey Generating Station (Source: Manitoba Hydro)

the Saskatchewan River where it empties into Lake Winnipeg. This was, and still is, the largest head in Manitoba at 120 feet. The decision was made to use Kaplan units. The site was unique, in that it was built on a porous limestone foundation. This required extensive grouting, and became the largest grouting program ever encountered by any geophysical consultant. One sinkhole under the powerhouse location required approximately 6,000 cubic yards of grout.

6.0 Nelson River Sites

While this construction was progressing, studies were underway on future Nelson River sites. The Federal Government participated in these studies, which involved the future development of the northern Manitoba rivers for supplying the growing electrical load of the province. The outcome of these studies was an announcement in February 1966 of an agreement between the Federal Government and the Province of Manitoba to proceed to the Northern Sites for the future power requirements of the province. This agreement required Manitoba Hydro to build a 1272 MW power plant at the Kettle Rapids site [4] on the Nelson River, control Lake Winnipeg for storage for this and future Nelson River plants, and divert the Churchill River into the Nelson at a point above Kettle. The license from the Provincial Government to undertake these projects provided for four feet of storage on Lake Winnipeg and ten feet of storage on South Indian Lake, the reservoir for the Churchill River flow. The Federal Government agreed to lend the Province money, which the Federal Government would use to build a DC transmission line from the Nelson River Kettle site to a point near Winnipeg. Atomic Energy of Canada was the federal agency assigned to build the line. This loan was to be repaid by Manitoba Hydro when the load growth was sufficient to carry the financial burden of the line. In the meantime the interest was accumulating and being charged to the line capital account. This loan was discharged in 1992 when Manitoba Hydro bought the line and the accumulated debt.

To supply power to the construction site of the Kettle Plant, a 138 kV line was constructed from Kelsey [3] in 1966. In 1997, the Kelsey station was connected to the southern system by construction of a 230 kV line from Kelsey to Grand Rapids.

This present and future system expansion required additional revenue. As a consequence of this, the first rate increase in 57 years went into effect in July 1968.

7.0 Interconnection with the United States Utilities

This ambitious construction program with the many unknowns caused the Utility to look at alternatives to meet its load requirements in 1970. One option was the addition of another thermal unit at the Selkirk Plant, and an option on a shaft was actually bought. Another, which proved to be the preferred option, was to interconnect with the three utilities south of the border, namely Otter Tail Power, Northern States Power, and Minkota Power Cooperative Inc. and buy capacity for the winter of 1970. This alternative was pursued successfully and a 230 kV line was constructed after receiving approval from the National Energy Board. This line permitted the purchase of 90 MW of capacity for the winter of 1970. It also permitted the export sale of surplus energy, which proved to be very beneficial to all parties.

The first unit of the Kettle Plant [4] came on line in 1970, however the DC transmission terminal equipment was not ready. The two completed DC lines, approximately 900 km in length were used as a temporary 230 kV line with a reactor hung on at approximately the mid point at Grand Rapids to inject this power into the 230 kV system. It meant that Manitoba not only had the US utilities to support the Manitoba System, but the first unit at Kettle also improved the reserve and energy position. Long Spruce came on line in 1976 associated with the second bipole of the DC transmission Line. The converter station, named Henday was located at the site of the future Limestone plant to facilitate the conversion of this plant to DC. All Nelson River plants are interconnected with 230 kV transmission lines. The Limestone Plant came into service in 1990. There are still several sites on the Nelson and other rivers in the north to develop. Wuskwatim, on the Burntwood River, which carries the diverted Churchill River into the Nelson, is on the verge of being developed. The largest site in Manitoba is on the Nelson at Conawapa below Limestone and is being considered for a sale of power to Ontario Power Generation. A fourth interconnection, rated at 230 kV, has been added to the US system from the western part of the Manitoba system.

8.0 Interconnections

The first Interconnection from the Manitoba Hydro system was with Ontario HydroÕsisolated Northwest system in 1957. This was followed by an interconnection with Saskatchewan Power Corporation in 1960 between their Estevan Plant and Brandon. This was initially operated at 138 kV, but designed to be raised to 230 kV, which was accomplished in a few years. With the completion of the first 6 units of the 12 unit Kettle plant, Manitoba had a surplus of generation and negotiated a sale to Ontario Hydro commencing in 1972, but by this time the Northwest Region of Ontario Hydro was interconnected with their main system. This meant there would be a circulation of power around the Great Lakes unless phase shifting transformers were installed on this interconnection. Two 200 MVA phase shifting transformers with a 180 degree shift capability were installed to supply two new 230 kV lines to the Ontario System. This rather large angle was determined by test of an isolated machine on the tie line to Ontario and the Manitoba system tied to the US system.

A second 230 kV line was constructed between Saskatchewan and the Manitoba system in 1973.

The operation of the first tie to the US proved so successful that another utility, Minnesota Power and Light, negotiated a tie to their system near Duluth, which went into service in 1976. An agreement was reached with Northern States Power to interconnect their system with Manitoba Hydro at 500 kV. This was negotiated using seasonal diversity as one of the economic justifications for the line. It also provides the Manitoba system with a good backup in case of trouble on the DC system [5] from Northern Manitoba. The line came into service in 1980.

Figure 4: Kettle Plant (Source: Manitoba Hydro)

Figure 5: A view of the largest mercury arc rectifier ever built - this type of valve was originally used in the AC-DC conversion stations in the Nelson River DC transmission system. Most of these valves have now been replaced by thyristors. (Source: Manitoba Hydro).

The value of this 500 kV interconnection [6] with the US system was very vividly demonstrated in 1997, when a wind shear toppled 19 towers on the DC line. This occurred in the early morning hours, before daybreak. The Manitoba system went from an export mode to an import mode without any customer interruptions. The public and some large industrial customers were asked to conserve energy and capacity for the few days it took to build a temporary line around the downed towers. This 500 kV interconnection has had series compensation installed to increase its export capabilities. It has proven to be a valuable source of revenue as well as a source of energy during the 2002-03 years, when one of the worse droughts on record was experienced on the Prairies.

9.0 Winnipeg Hydro

The agreement between the Province and the City of Winnipeg in 1955, which provided for the City to retain its two generating stations and share in the cost of new generation, transmission, and interconnection revenue, was renegotiated each 10 years. The ratio of peak demand and energy use on the two systems had increased to approximately 90/10 and in 2002 Manitoba Hydro purchased the Utility, resulting in one utility supplying the entire province [7] with rates uniform throughout the system and one of the lowest rates in Canada.

Figure 6: 500 kV HVDC transmission line over the new 230 kV North Central transmission line from Kelsey Generating Station. (Source: Manitoba Hydro).

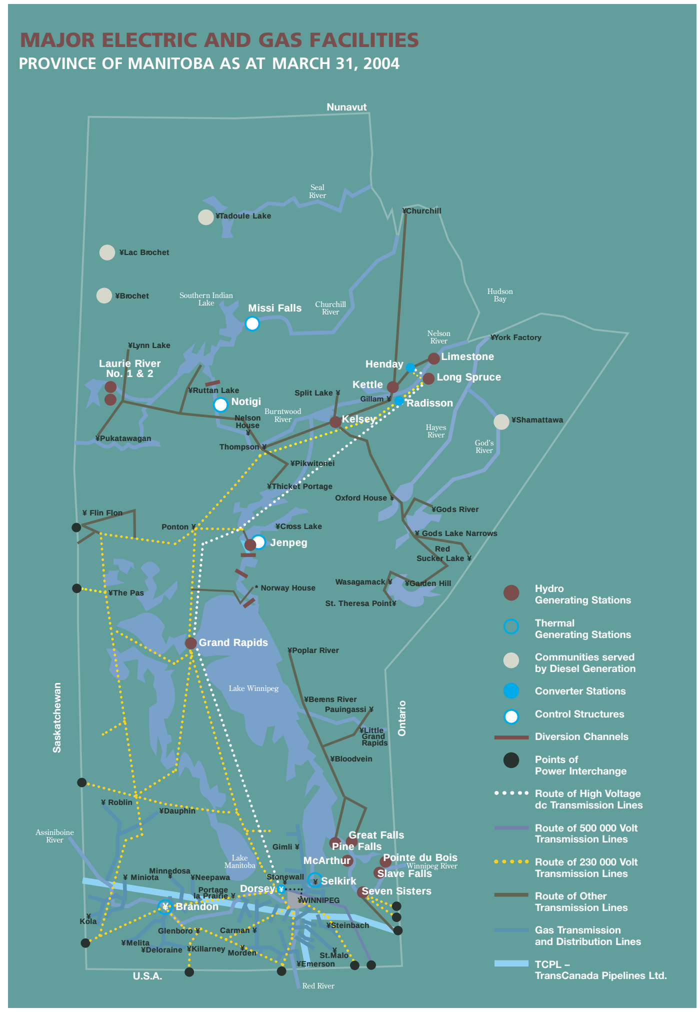


Figure 7: Major electric and gas facilities in the Province of Manitoba, as of March 31, 2004. (Source: Manitoba Hydro-Electric Board 53rd Annual Report).

About the author

Leonard A. Bateman is an electrical engineering graduate from the University of Manitoba with post-graduate qualifications in Engineering and Business Administration. His career spanned thirty-six years in the utilities of Manitoba. His last six years were spent as Chairman and CEO of Manitoba Hydro. He was the last person to hold both of these positions. He has served as President of the Canadian Electrical Association, The Association of Professional and Geophysical Engineers of the Province of Manitoba. He was the first and founding President of the Canadian Society for Senior Engineers. When he left Manitoba Hydro in 1979, he formed his own consulting company - Bateman and Associates Ltd., of which he is still President. As a consultant he has worked and presented papers in many countries of the world. He has received recognition by his peers in many organizations, and in 1994 received the Canadian EngineersÕGold Medal. In 2002 he was awarded the highest recognition that the Province of Manitoba bestows on its citizens - The Order of Manitoba. He is still interested in traveling as well as volunteering in seniorsÕorganizations, having served the two thousand members of Creative Retirement Manitoba as their President in the years 2001 and 2002.

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BUSINESS/ECONOMY

The shaping of Limestone

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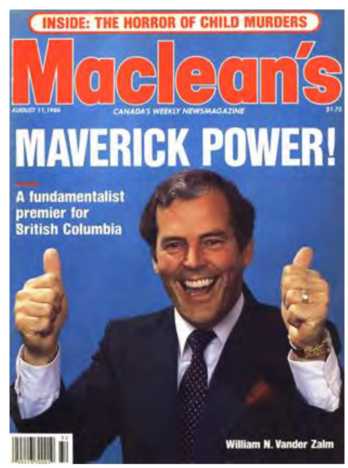

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BUSINESS/ECONOMY

The shaping of Limestone

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The shaping of Limestone

BUSINESS/ECONOMY

Towering above scrubby spruce trees in northern Manitoba's rugged landscape, the 70-mhigh, manmade hill is visible from two kilometres away. Around the sides of the heaped mass of more than 400,000 cubic metres of rock, huge trucks and bulldozers shift loads of granite that are being crushed to make concrete for the Limestone hydroelectric dam. When it is fully

completed in 1992, Limestone—located on the Nelson River 90 km from Hudson Bay—will be generating 1,280 megawatts of electricity annually, making it Canada's 10th-largest dam. But because declining oil prices have forced delays in other energy projects, Limestone holds a unique distinction: it is the largest construction job under way in Canada this year. And it is stirring excitement among workers from coast to coast. "Guys all across the country are dying to come here," said Barry Cozac, 35, an

CANADA/COVER

MAVERICK POWER!

ENTERTAINMENT

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INVADING THE NATION'S BEDROOMS

By FRED BRUNING

ironworker from Calgary. “There is nothing else like it.” Attracted by the prospect of big paycheques and steady work, by last week 1,300 workers had already settled into bunkhouses at the Limestone construction camp and in the company town of Sundance, ve kilometres away. They included carpenters fresh from the building of British Columbia’s $2-billion Revelstoke dam, ironworkers who reminisce about Calgary’s building boom and crane operators experienced in High Arctic oil exploration. Some, like Manitoba Hydro structures superintendent Dale Woods, who worked on the Long Spruce and Kettle dams built on the Nelson River in the 1970s, are returning to familiar territory—and

faces. Said Woods, who will likely spend the next six summers working at Limestone: “These are extremely challenging projects. I like the area, I like the way of life, I like the people.”

For the NDP government of Premier Howard Pawley, lagging activity in the construction industry has enabled Manitoba to win favorable terms from contractors. Three years ago Manitoba Hydro estimated that Limestone would cost $3 billion to build. But bids were so competitive that the price has fallen to $1.94 billion. The largest contract, for excavating the damsite and pouring concrete, was won last summer by joint-venture partners Bechtel Canada Ltd. and Japan’s giant Kumagai Gumi Co. Ltd. Their $236-million bid was the lowest of six o ers.

Roger Picard, project manager for Bechtel-Kumagai, said that the consortium's bid was low for the amount of work involved. But because there are so few heavy-construction projects under way in North America, the company has been able to hire hundreds of highly experienced workers. Efficiency, Picard added, is the only way to make money on a construction project in the 1980s. Added the 41-year-old native of Beauport, Que.: "We are bring-

ing in the most sophisticated, expensive equipment, and we have the very best men. All we can do now is make sure we get the best use out of both."

Premier Edward Schreyer's NDP government allowed Limestone's preliminary construction to begin in the mid-1970s, but Premier Sterling Lyon stopped it because of shrinking hydro demand when the Conservatives came to power in 1977. Construction started again last fall under the Pawley government, after the Manitoba Energy Authority signed a $3.2-billion, 12-year agreement to sell z up to 500 megawatts of Lime-

0 stone's output to the Minneapolis lis-based Northern States Pow? er Commission.

Still, Manitoba's opposition

1 Conservatives say that because 9 Limestone will begin generatE ing power in 1990—two years

before the contract takes effeet—Manitoba Hydro's cus-

But spokesmen for the Pawley government—which was re-elected in March, 1985, partly on the strength of its commitment to Limestone—say that the project will be profitable. Limestone will create 6,000 personyears of direct employment and another 17,000 person-years in support industries. And the power contract with Minnesota, officials say, will net a total profit of $1.7 billion.

pay year in interest charges on funds borrowed to build the dam. And some economists have criticized the policy of spending money to increase exports of energy—and indirectly create jobs in the United States—instead of developing Manitoba's industrial sector.

For Bechtel management and the workers on the Limestone site, there are more immediate concerns. They are hurrying to reach the current season's goal of pouring 190,000 cubic tons of concrete before the onset of winter in mid-October shuts down operations until next spring. According to Bechtel's Picard, work was slowed by a colder than usual spring. "But now everything is falling into place," he said.

At the same time, Manitoba Hydro has made determined efforts to create rst-class living and working conditions. At the main campsite, about 1,200 workers live in 40 prefab bunkhouses. The company town of Sundance has trailer-lot accommodation for about 280 married workers and their families. The two recreation centres at the main campsite—there is a third at Sundance—include television rooms, a library, weights, a billiard room, hockey and curling rinks and a baseball diamond. “This is a pretty damn good camp,” said William Liston, site representative for the Allied

Hydro Council, an association of trade unions involved in the building of Limestone. “When I went to my rst camp in 1953 up in Kitimat, B.C., we were living in tents. We have come a long way.” Added William Beaton, a crane operator from Winnipeg: “This is a fantastic job—the best camp I’ve ever been in.”

The buildup of the Limestone workforce, which is expected to climb to a total of 1,800 in the peak construction years of 1987-88, has reunited a special breed —engineers and skilled tradesmen who have labored together on previous dam projects in Canada. One veteran dam builder is Stephen Wight, a 71-year-old carpenter who will be at the site all summer designing and building the curved wooden forms used to cast the giant concrete draft tubes that will carry water from the dam’s turbines downstream into the Nelson River. Proud of his unusual skill, Wight said, “There are not many people who can do it.” He was also pleased when he discovered that Winnipeg’s Hugo Erhardt would be in charge of Limestone’s carpentry shop. “He’s about the best you’ll run into anywhere," said Wight. He added, "Pretty near half the force in the carpentry shop I've worked with elsewhere."

Because of the abbreviated 6V2month northern working season, the dam workers have been put on ninehour shifts that continue through the night under floodlights. At night the site resembles a vast movie set. Laborers and tradesmen work six days a week for 40 to 45 days before becoming eligible for a free flight from Gillam, Man.—50 km from the campsite—to their point of hire for six working days off.

But while the hours are long, the rewards can be considerable. Wages range from $13.40 an hour for heavyconstruction laborers to $17.88 an hour for ironworkers or $20.29 for pipe tters. Calgary's Barry Cozac calculates that with overtime he stands to earn as much as $1,100 a week. "If you're careful," said Cozac, "you can afford to never work again in winter for the rest of your life."

Camp life does have its inconveniences. Two months ago there were only ve pay telephones available for workers at the main campsite—now there are 10. And men and women— even if they are married—must stay in separate quarters if they live at the main camp. "There's too much segregation," said Michael Ontonovich, a bearded ironworker from Sault Ste. Marie, Ont. "If you get caught with a woman in your room, you are out of the camp." But others express satisfaction with the arrangements. Said

Bernard Potocki, a carpenter from British Columbia: “This is not Love Boat. It’s a production centre—but not for the next generation.”

To ensure that northern Manitoba native people share in Limestone’s rewards, the collective agreement between the unions, the contractors and the provincial government established hiring goals for various job categories. As many as 40 per cent of laborers, 60 per cent of apprentices and 30 per cent of some skilled categories must be natives. But last May Hydro chairman Marc Elieson caused a wave of complaints when he announced that with natives comprising about 35 per cent of Limestone’s unionized workforce, hiring goals in many job categories—including laborers and caterers—were being suspended for four months. Yvon Dumont, co-chairman of the Limestone Aboriginal Partnership Directorship Board, charged that Hydro was attempting to slip out of its commitment to native workers. The most recent gures show that as of June 30, natives made up 22 per cent of the workforce.

Still, the government has already improved on its record of the 1970s, when less than 10 per cent of the workforce on the province’s dam projects, such as Jenpeg and Kettle on the Nelson River, were natives. Preferential treatment for native entrepreneurs has resulted in the opening of a native-operated post office, grocery and liquor store in Sundance. At the main campsite, security guards wear distinctive badges depicting a yellow rising sun—the emblem of Wapun Security, a rm owned by ve northern Manitoba Indian bands in partnership with the Saskatchewan Indian and Native Peoples Corp.

To supply native workers with the needed skills, last summer the government set up a training camp at an abandoned Inco Ltd. strip mine at Pipe Lake, 30 km west of Thompson, Man. Nearly 1,000 natives have graduated from the camp with skills ranging from carpentry to machine maintenance. To instil the discipline needed to work at Limestone, life at the Pipe Lake camp is strictly regulated, with an 11.30 p.m. curfew and a total ban on alcohol.

The tough training appears to be effective, with both natives and non-natives praising its effectiveness. Native workers at Limestone, said Thomas Cummins, labor relations officer for Bechtel-Kumagai, seem “to have more staying power; they don’t seem to be dropping out of the workforce as much as in the past.” Les Cook, a Métis from Thompson, described the Limestone training program as nothing less than an opportunity to “join the human race, to join the flow of economic life.” Indeed, for many Canadian workers, a job at the Limestone dam in Manitoba’s inhospitable north is highly cherished.

DOUG SMITH

in Sundance

with

MARK NICHOLS

in Toronto

MORE FROM THIS ISSUE

Tab 158

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

2017/18 and 2018/19

GENERAL RATE APPLICATION

PUBLIC HEARING

Before Board Panel:

Robert Gabor	-	Board Chairperson
Marilyn Kapitany	-	Vice-Chairperson
Larry Ring, QC	-	Board Member
Shawn McCutcheon	-	Board Member
Sharon McKay	-	Board Member
Hugh Grant	-	Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

December 18, 2017

Pages 2031 to 2238

APPEARANCES

Bob Peters	)Board Counsel
Dayna Steinfeld	)
Patti Ramage	)Manitoba Hydro
Odette Fernandes (np)	)
Helga Van Iderstine (np)	)
Byron Williams (np)	)Consumers Coalition
Katrine Dilay	)
William Gange (np)	)GAC
Peter Miller (np)	)
Antoine Hacault	)MIPUG
George Orle	)MKO
Senwung Luk (np)	) Assembly of
Corey Shefman (np)	) Manitoba Chiefs
Kevin Williams	) Business Council
Douglas Finkbeiner	) of Manitoba
Daryl Ferguson (np)	) City of Winnipeg

LIST OF APPEARANCES (cont'd)

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William Haight William Gardner (np)	)Independent Expert)Witnesses

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--- Upon commencing at 9:01 a.m.

THE CHAIRPERSON: Good morning, everyone. I hope you had a nice weekend. Ms. Steinfeld...?

MS. DAYNA STEINFELD: Thank you, Mr. Chair. We're going to begin today with the Business Council of Manitoba. I understand they expect to be approximately fifteen (15) minutes, at which point in time GSS/GSM, in cap, will conduct their cross-examination. We also expect that requests will be made for a few parties to follow up on some undertakings that were filed in the last few days.

Before turning it back over, I'd just like to note, as well a reminder to the parties, that the Board no longer requires proposed expert witnesses to be qualified as an expert prior to their direct testimony. And the process that the Board has followed since the Cost of Service Study methodology review has been to have the party introducing the expert witness, briefly review the qualifications or CV of that expert to indicate to the Board and other parties the specific areas that the expert will be put forward to testify on. There will not be a void dire process where parties would have the opportunity to question the qualifications or expertise; rather, the witness will be allowed to provide their direct evidence, including opinion evidence. And on cross-examination, it is open to parties to question the expert witness as to qualifications and expertise, such that in closing submissions the party may request that the Board limit the weight that should be given to the expert witness' testimony.

We suggest that if any party has questions that they get in touch with Board counsel. Thank you, Mr. Chair.

THE CHAIRPERSON: Thank you. Mr. Williams...?

MR. KEVIN WILLIAMS: Thank you, Mr. Chairman. Thank you for accommodating my --

THE CHAIRPERSON: Excuse me. Ms. Ramage, did you --

MS. PATTI RAMAGE: I just wanted to interject, that we understand Mr. Williams has a date at the courthouse at 9:30 and will go first, but we had a matter we wanted to address and we'd ask that we'd -- after Mr. Williams is complete, we could -- we'll get on the mic to deal with that.

THE CHAIRPERSON: Certainly. Okay. Mr. Williams...?

MR. KEVIN WILLIAMS: Thank you. Thank you for accommodating my scheduling difficulties, Mr. Chairman.

CROSS-EXAMINATION BY MR. KEVIN WILLIAMS:

MR. KEVIN WILLIAMS: I just want to start with a few questions about the Manitoba Hydro Act itself, and I don't know who -- who they're best directed at, but I'll look across the room and see who responds and I'll follow it up from there, so.

Pursuant to Section 40 of the Manitoba Hydro Act, Manitoba Hydro is required to establish depreciation and stabilization reserves.

Is somebody familiar with that?

MR. JAMES MCCALLUM: Yeah, I -- I've read the act.

MR. KEVIN WILLIAMS: Okay. Can -- can you explain, in simple terms, what the purpose of the depreciation and stabilization reserves mandate by the Act is?

MR. JAMES MCCALLUM: Well I -- and I -- and I just --

MS. PATTI RAMAGE: May --

MR. KEVIN WILLIAMS: Section 40 of the Act, sorry.

MS. PATTI RAMAGE: Mr. McCallum can explain the need for reserves. I'm not sure that it's fair to ask him to explain the legislative part, but -- so it's -- it's a partial objection but I think he can proceed on the basis knowing that it's not a legal opinion.

THE CHAIRPERSON: Yes, well, let's -- let's see what the question is.

MR. JAMES MCCALLUM: Okay. So maybe we can pull -- was it Section 40?

CONTINUED BY MR. KEVIN WILLIAMS:

MR. KEVIN WILLIAMS: Forty.

MR. JAMES MCCALLUM: Forty.

(BRIEF PAUSE)

MR. KEVIN WILLIAMS: And -- and just so we're clear, I'm -- I'm not interested in what -- you speaking as to the legislative intent, I'm actually just asking you from Manitoba Hydro's perspective what their understanding is of -- of this is.

MR. JAMES MCCALLUM: And -- and it's best I don't speak to the legislative intent, but, you know, in my mind specifically as to I think your question was -- was on depreciation, but I believe and it might be a little further down in 40-2, but there's a provision or -- or a idea in the Act that reserves should be drawn from ratepayers and collected and maintained to allow for renewal and reconstruction of the fixed works to the -- of the Corporation.

MR. KEVIN WILLIAMS: And -- and have such reserves been establis -- been established by Manitoba Hydro?

MR. JAMES MCCALLUM: Well, I think our argument is that, you know, rates have been -- rate increases have been insufficient certainly over the last ten (10) years. If you recall back -- and I don't know that we need to pull it up, but -- but to our direct evidence of the policy panel I think it's Hydro Exhibit 64, page 66, you can -- you can see a chart that shows Manitoba Hydro's net income over the last nine (9) or ten (10) years. And you can see our net income goes from about $350 million a year to basically zero. While our fixed assets, our net plant in service go from 8 billion to 12 billion.

So I would -- and -- and then if you look forward from there, you know, a financial plan basis 3.95 percent rate increases will see the net plant in service doubling again to 25 billion while we've flipped to a significant net loss position.

And this is of great concern to Manitoba Hydro. We would argue that there are no reserves being -- being paid in rates to address significant infrastructure renewal needs and to address financial stability, rate stability and to provide for the unknown which is that we -- we obviously do our best to forecast but Manitoba Hydro is subject to significant volatility in its financial results owing to many things including weather, export prices, hydrology and interest rates.

So we would argue that, no, there's been extremely limited contribution to reserves over the last eight (8) or ten (10) years.

MR. KEVIN WILLIAMS: So -- so do I take it from that response that -- that -- that there aren't reserves reflected in the integrated financial that are before the Board?

MR. JAMES MCCALLUM: Well, it -- it -- you know, reserves I think is -- is a concept that you need to understand and in one (1) line of thinking reserves are -- is your equity position. I think that we would look at it and say that is, in part, true, equity is debt avoided. And that's really important to us.

However, equity -- book equity that is the accumulation of net income made since the Corporation was -- was began and hasn't been added to in the last, you know, number of years is really not that useful as a -- as a buffer. When you have no net income and things start going badly whether it's low water conditions or -- or something else that you haven't predicted, then you need to fund your business and the only way you do that is by borrowing more money or increasing rates.

You don't have -- equity is not a -- it's not a cash pile. It's -- at least not -- not the way we do it. It's not a cash pile that you -- you look to and draw from to help subsidize your business when you don't have the revenue you need to run it.

MR. KEVIN WILLIAMS: Thank you. Turning now briefly to Section 41 of the Act which is -- relates to the establishment of a sinking fund.

Are you familiar with that provision of the Act?

MR. JAMES MCCALLUM: I am. I'm fortunate that Ms. Stephen is beside me this morning. She can speak more directly to how the sinking fund provisions work.

MR. KEVIN WILLIAMS: I'm -- I don't really have specifics as to how they work. My questions are very general in nature so -- so has a sinking fund been established?

MS. SUSAN STEPHEN: We do have a legislated requirement to make a sinking fund contribution on an annual basis. As of late for probably the last two (2) or three (3) years we have made the minimum legislated requirement and we have withdrawn it for debt maturities in the same year.

MR. KEVIN WILLIAMS: And so I take it then, Ms. Stephen, as a consequence of that response that -- that the activity with respect to the sinking fund is reflected in the integrated financial forecasts that are before the Board as it relates to -- to the transaction that you just said how it was used; is that fair?

MS. SUSAN STEPHEN: That's correct.

MR. KEVIN WILLIAMS: Thank you. I want to turn now for a moment to reserves and regulatory deferrals. I looked at the testimony of Stephen, Ms. Bauerlein and Mr. McCallum and -- so someone who tried to be an accountant but failed, I would inarticulately refer to these deferrals and reserves as representative of timing differences between when the cash event occurs and when it's reflected in the Manitoba Hydro's income statement.

Is -- would you agree with that?

MS. SANDY BAUERLEIN: Good morning. I would characterize it as really timing differences between when costs are necessarily for financial reporting purposes versus when they're recognized for rate setting purposes.

MR. KEVIN WILLIAMS: So I -- I thought of them as revenue expense items that are not recognized in the income statement in the year that they occur from a cash flow perspective.

Is that -- is that fair?

MS. SANDY BAUERLEIN: Some accounting can be accrual based so it's not necessarily cash based but you can think of it that way. You can think of it as -- typically it's expenses that are incurred in one (1) year that we would recognize as a period expense for financial reporting purposes but for rate-setting purposes they're reflected over a longer -- or different timeframe.

MR. KEVIN WILLIAMS: It's becoming more apparent by the moment why I never became an accountant, I suppose.

Let me try to run it down to ground

with an example. So, Manitoba Hydro builds a generating station, and -- and -- for the most part all the cash outlays are incurred prior to that generating station -- station's in-service date.

Is that reasonable?

MS. SANDY BAUERLEIN: That is correct.

MR. KEVIN WILLIAMS: However, the expense associated with the outlay of that cash is reflected over a number of years through depreciation or amortization on the Corporation's income statements; isn't that correct?

MS. SANDY BAUERLEIN: That is correct.

MR. KEVIN WILLIAMS: As it relates to Bipole III, the reserve account represents cash that is coming in from rate increases that have been granted; isn't that correct?

MS. SANDY BAUERLEIN: The Bipole III reserve?

MR. KEVIN WILLIAMS: Yeah.

MS. SANDY BAUERLEIN: Yes, reflects cash that's been coming in that has been set aside for when Bipole is in service, correct.

MR. KEVIN WILLIAMS: Correct. And from an accounting perspective that reserve won't be utilized in the income statement until Bipole III goes

into service. Do I have that right?
MS. SANDY BAUERLEIN: And it won't be reflected in revenue, correct, until -- yes.
MR. KEVIN WILLIAMS: But the revenue's reflected on the income statement, right?
MS. SANDY BAUERLEIN: Correct.
MR. KEVIN WILLIAMS: Thanks, okay. But the cash receipts from the rate increases granted, which have been attributed to the Bipole III reserve account, have been consumed in -- in Manitoba Hydro's ongoing operations; correct?
MR. JAMES MCCALLUM: Yes, that's -- that's correct. If -- our net debt amount is reflective of having collected and I don't have the figure in front of me, but a couple hundred million dollars of -- of rates associated and allocated to the Bipole III reserve. It's not a cash -- we don't have that cash sitting on our --
MR. KEVIN WILLIAMS: I sta --
MR. JAMES MCCALLUM: -- a special account.
MR. KEVIN WILLIAMS: -- that's what my understanding was as well.
Now, from our test -- from your testimony, Mr McCallum, the other areas where

deferrals or reserves are utilized, you indicated were demand-side management expenditures, correct?

MR. JAMES MCCALLUM: That's one (1) area, yes.

MR. KEVIN WILLIAMS: Certain depreciation and amortization accounts, correct?

MR. JAMES MCCALLUM: I don't know that -- depreciation and amortization wouldn't flow through a regulatory deferral account, other than certain -- maybe Sandy should -- maybe Ms. Bauerlein should speak more. I think we're getting a few things kind of --

MS. SANDY BAUERLEIN: Well, you may be talking about the difference between depreciation methodologies. So for financial reporting purposes, we use the equal life group method of depreciation, compliant with IFRS. For rate-setting purposes we use the average service life methodology compliant with Canadian Generally Accepted Accounting Principles.

So the differential and depreciation between those (2) is captured in a regulatory deferral.

MR. KEVIN WILLIAMS: Okay. Thank you. And as it relates to certain site restoration costs are deferrals or reserves used for those?

MS. SANDY BAUERLEIN: Site restoration

costs are deferred, correct.

MR. KEVIN WILLIAMS: And certain -- certainly, some of the regulatory costs are as well?

MS. SANDY BAUERLEIN: Our regulatory costs are also deferred, yes, and amortized over a different timeframe. Typically those costs would be at a period expense.

MR. KEVIN WILLIAMS: And in each case the actual cash outlay or receipt in a particular year is not fully reflected in that year's financial statements due to the timing differences; is that fair?

MS. SANDY BAUERLEIN: It's not reflected in the statement of income but you would see your cash in your -- your cash flow statement.

MR. KEVIN WILLIAMS: Okay. So now I want to turn, for a moment, to Appendix -- Manitoba Hydro tab 3, Appendix 3.8, and I just want to run a couple of these concepts to ground for a moment.

So unfortunately they're all labeled page 1 of 6, but I'm looking at the first page 1 of 6. So, if we look at the Bipole III reserve account. This is the projected operation statement for Manitoba Hydro 16 updated with the interim rate grant. I see that -- that for 2017, 2018, the Bipole reserve account is reflected as a reduction of revenue for -- for those years totalling about $247,000.

Do I have that correct?

MR. JAMES MCCALLUM: I'm sorry, sir, where -- where do you see 200 -- these are all in millions.

MR. KEVIN WILLIAMS: Sorry, I misspoke, 96 million and 151 million total 247.

MR. JAMES MCCALLUM: They -- they -- yes, they do but in -- in fiscal 2018, we will be collecting roughly $151 million in customer rates and allocating that to the Bipole reserve. And last year we did the same to the extent of 96 million.

MR. KEVIN WILLIAMS: Yeah, I don't think we're saying anything different.

MR. JAMES MCCALLUM: Okay. Just the add -- the adding them I just wanted --

MR. KEVIN WILLIAMS: Right, yeah, but I guess what I then notice is as we move to 2019 to 2024, that timeframe.

MR. JAMES MCCALLUM: Yep.

MR. KEVIN WILLIAMS: We now see additions to revenues coming from the Bipole III reserve account.

MR. JAMES MCCALLUM: That's right.

We've -- we've made an assumption that we will amortize into our revenues this Bipole III reserve account over five (5) years after Bipole comes into service. And so that's a -- it's -- it's not cash, unfortunately. Cash has already been received but this is just the -- flowing it into your revenue as you spoke to a timing difference.

MR. KEVIN WILLIAMS: Right. And so -- so are you able to say -- like, when you add up the number of millions of dollars that are being reflected as additional revenue in the years 2019 to 2024, I noted that they added up to $348 million.

MR. JAMES MCCALLUM: It's more -- it's closer to 400 million in the first half of 2019 we're collecting. If you looked at our financial statements for -- for fiscal 2019, you'd see from March through August -- or April through August, you would see a deduction in allocation to the Bipole III reserve account.

MR. KEVIN WILLIAMS: Right.

MR. JAMES MCCALLUM: Which then reverses when you begin amortizing that account in the second half of the year when -- when Bipole is in service. So, the two (2) net off to that $1 million.

MR. KEVIN WILLIAMS: I see, okay.

MR. JAMES MCCALLUM: But the total amortization over five (5) years, subject to check, is 400 million.

MR. KEVIN WILLIAMS: Okay. Now if you look down to the -- still on that same statement to the net movement in the regulatory deferral. I -- I note that -- that it is positive through 2023, and then -- and then reverts to a negative position for the balance of the forecast.

Can you explain why it is that the -- that that happens?

MS. LIZ CARRIERE: Until 2023 we're capitalizing ineligible overhead to a regulatory deferral account, as well as the difference in depreciation methodology is also being capitalized to a deferral account to that date.

We stopped capitalizing it and then we're left with the amortization of it thereafter.

MR. JAMES MCCALLUM: Yeah, so -- so I guess, Mr. Williams, the way to look at it or the way that a non-accountant see it, is in the first five (5) or six (6) or seven (7) years of the forecast these regulatory deferral accounts are basically caused by differences between how the financial reporting standards tell us to -- you know, to -- to put the numbers together and then any differences that -- that a regulator wants to see.

So in -- in the first four (4) or five (5) years we're seeing the effect of -- of certain regulatory direction that causes certain expense items to be instead capitalized to a regulatory asset and then we see later in those years, later in the forecast, kind of a reversing effect as we see amortization of those deferrals eclipse additions.

MR. KEVIN WILLIAMS: Okay.

MS. SANDY BAUERLEIN: I just wanted to note that also in 2019/'20 you start seeing amortization of Conawapa.

MR. KEVIN WILLIAMS: Okay. Thank you. Now then if we move three (3) pages ahead in the same exhibit and we look at the operating statement, there's a regulatory deferral balance reflective on the asset side.

And once again we see it increasing to approximately 1.111 billion in -- sorry, 1.246 billion in --

MR. JAMES MCCALLUM: I think we need to go a page up.

MR. KEVIN WILLIAMS: Oh, sorry.

MR. JAMES MCCALLUM: Backwards. There

we go.

MR. KEVIN WILLIAMS: Okay, so it goes to 1.289 billion in 2023, and then starts -- starts reducing. And so -- so -- so are you able to explain exactly why it is that that's occurring?

MR. JAMES MCCALLUM: This is the -- sort of the impact of what we just spoke about on the statement of income. In the first few years we are capitalizing to -- to the regulatory asset a number of things to -- to -- which -- which has the effect of -- of increasing income, and so you see that balance build up.

A good chunk of that from 2019 to 2020 is -- is Conawapa but there are, you know, a number of other significant contributors. And then as you get out towards 2025 you start seeing the cumulative effect of depreciating these -- these -- and these are assumed -- we've made assumptions around, you know, depreciation or amortization periods that, you know, as part of this we're looking for some -- some direction from the Board on, but our assumptions are in there and you see that we start working down this -- this asset over time through amortization.

MR. KEVIN WILLIAMS: And -- and I take it then your responses would be the same as it relates to the Bipole III reserve account and the liability and equity side, as well as the regulatory deferral balance in terms of the -- the timing difference and -- and -- and what's happening as it relates to those various accounts?

MS. SANDY BAUERLEIN: Yes, it's just the collection of that money and then you're seeing the drawdown or amortization over the five (5) year period. Same on the asset side, again, that big increase in 1920 as you're adding the additional Conawapa and then you slowly start amortizing that under the assumption that we made of thirty (30) years.

MR. KEVIN WILLIAMS: How, if at all, do these regulatory deferral accounts impact on the need for the requested rate increase?

MR. JAMES MCCALLUM: Well, I would -- I would argue that have limited impact.

MR. KEVIN WILLIAMS: Are you able to explain briefly why that is?

MR. JAMES MCCALLUM: Well, I think the, you know, the heart of our -- our rate case here is that we need to come to terms with our debt balance and the growth in our debt balance and these are, you know, important tools by which to, you know, to provide for the recognition of income and expense.

But in the main, these are not really cash items and its cash that -- that we look to to kind of, in part, judge revenue rates sufficiency but, most importantly, as a means to come to terms with a -- with a debt that -- that isn't sustainable?

MR. KEVIN WILLIAMS: Okay, thank you, those are my questions.

THE CHAIRPERSON: Thank you, Mr. Williams. Ms. Ramage...?

MS. PATTI RAMAGE: Mr. Chair, thank you. What Manitoba Hydro wanted to do this morning was address a request from counsel for MGF to extend the deadline for the filing of MGF's answers.

THE CHAIRPERSON: Can I interrupt for a second. I was informed by counsel. This may take awhile. What -- what I would propose is that we finish the matters with this panel and then deal with it after, as a procedural motion. So that we -- we deal with Mr. Monnin. We have the cross-examinations, deal with the undertakings, have the -- we have the issue of the presentation on the question that I had asked before. Then deal with re-examination in then with the procedural motion at that time.

Because what I don't want to do is I

don't want to get into a situation where we're extending this panel sitting here on a procedural motion that may or may not relate to them but relates to the position of Manitoba Hydro.

MS. PATTI RAMAGE: That seems appropriate. Board counsel had asked all parties to put their position in writing, and I thought it was important that parties, before they do that, understand Manitoba Hydro's position and Manitoba Hydro's timelines but we can do that after the panels are done, but, if they're to put their submissions in writing this evening, we thought --

THE CHAIRPERSON: Well, let's -- let's see where we are at noon. I want to give parties an adequate -- adequate time but it's also a matter I think we need to set aside adequate time for and I don't want to see a situation where Mr. Monnin is sitting here for maybe an hour to two (2) hours or whatever. I'd like to get through the -- the cross-examination of this panel by the Intervenors first and then we'll --

MS. PATTI RAMAGE: That seems --

THE CHAIRPERSON: -- deal with it, okay.

MS. PATTI RAMAGE: -- reasonable. We

would just like to have time to speak to it before parties speak to --

THE CHAIRPERSON: You will absolutely have time to speak to it. Mr. Monnin...?

MR. CHRISTIAN MONNIN: Thank you, Mr. Chair, and if gives you any further comfort to Ms. Ramage, and I'm given a two (2) hour slot today. I don't expect to take up to two (2) hours. I'm quite confident I'll be done within the hour.

CROSS-EXAMINATION BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: Could you please proceed to Manitoba Hydro Exhibit 60, at slide 41 please. I'd like to start with some questions on OM&A. Thank you.

Now here at slide 41 of Exhibit 68 Manitoba Hydro states that:

> "A rate request is not meaningfully impacted by further reductions to OM&A expense and describes an illustrative exercise which arrived at 7.41 percent."

And I want to peremptorily apologize for two (2) things. I'm a little under weather so if I'm coughing into the microphone, I apologize and if my voice is a little hoarse again, to ask me to repeat the question. And on the issue of repeating questions, I've tried my level best going through the transcripts of this panel and hopefully I don't double-down and ask you a questions that's already been asked.

Is anyone on the board able to -- for clarification, provide an estimate of the incremental savings derived from a reduction of an additional 500 FTEs as identified in this slide?

MR. JAMES MCCALLUM: I assume your question -- you said "Board" but -- panel?

MR. CHRISTIAN MONNIN: Pardon me, panel, correct.

MR. JAMES MCCALLUM: Five hundred (500) operational staff would -- Ms. Bauerlein likely creating incremental savings in the order of $50 to $60 million?

MR. CHRISTIAN MONNIN: And can Manitoba Hydro speak to a breakdown position reductions performed in this analysis, as we see on slide 41?

MR. JAMES MCCALLUM: No, this was just illustrative using -- using five hundred (500) staff at -- at kind of an average, fully loaded cost.

MR. CHRISTIAN MONNIN: And when you were working through this analysis, you - being Manitoba Hydro -- I won't take you there but, for example, at PUB-Manitoba Hydro IR-13 (a) to (c), there's a table in the form of that -- that response identifying the breakdown on the projections, was that done with respect to the analysis that's found at -- at slide 41?

MS. SANDY BAUERLEIN: This was, again, as Mr. McCallum indicated an illustrated example. We took an average salary for employees, assuming that, again, there would have to be some type of a severance compensation if you were to reduce by a further five hundred (500) people and so it wasn't to which people would leave, it was just doing a -- a basic assumption as to the impacts on the rates.

But, as well, it's important to note that we feel that the further reductions to our staffing levels, again, we're going down to about thirty-two hundred (3200) operational employees as a result of the -- the VDP program, so, this would take us down a further five hundred (500) from that which we actually feel puts the -- the Corporation at risk. So, we're not looking at the full six thousand (6,000) employees, you're only looking at now starting at about thirty-two hundred (3200).

MR. CHRISTIAN MONNIN: And -- and when you say you -- you feel it puts the Corporation at risk, that is something that was determined by --by whom in particular at Hydro?

MR. JAMES MCCALLUM: It was determined by the -- the executive of Hydro and I think, you know, you would have heard or -- or seen in Mr. Shepherd and my's presentation that the -- our direct evidence at the policy panel that, you know, we -- we've taken all the steps that we think we can, and that if we thought we could cut more, we would have cut more.

It -- you know, these were the steps we took before formulating and concluding our financial plan where the last piece was the requisite rate increases. So, clearly, we've given a lot of thought and attention to -- to what can Hydro do on its own accord to mitigate rate inc -- increases and rate impacts to our -- our customers.

MR. CHRISTIAN MONNIN: And when Hydro here states just at slide 41 that the rate request is not meaningfully impacted about -- who are they referring to that -- who is it not meaningfully impacting; Hydro or the ratepayer?

MR. JAMES MCCALLUM: I think what we're saying is that five hundred (500) operational staff would be an extremely significant cut over and on top of the seven hundred (700) or so operational positions that will be out by the end of January of next year, and over and on top of the four hundred (400) plus operational positions that were reduced over the last several years, with the consequence of being able to reduce the -- the rate increase from 7.9 to 7.4 percent, which I think we would say in the context of 7.9 percent is not a material move.

We're not remotely suggesting that -- that, you know, any rate impact isn't -- isn't of -- of concern or challenge to our customers.

MR. CHRISTIAN MONNIN: So if I can take away from that -- and there's a whole lot to unpack in that answer, sir -- if I can take away from that, Hydro saying that it -- it -- the impact is not a meaningful impact on the rate request that it's putting forward going from seven point nine (7.9) to seven point forty-one (7.41), correct?

(BRIEF PAUSE)

MR. JAMES MCCALLUM: We -- the -- .5

percent on 7.9 percent, the -- the purpose of the -- the illustration, and again, it's an illustration, we can't do this. We can't do it. So the purpose of the illustration was to say even if we could -- and this is symptomatic of, really, all the offer -- all the -- all the -- the avenues you might want to go down around changing the model.

At the end of the day, nothing changes the big iceberg of $25 billion in debt. It drives everything. So as -- an infeasible operational headcount affects the rate increase by .5 percent.

MR. CHRISTIAN MONNIN: And perhaps I can view it from a different angle and put it this way to you, sir. Manitoba Hydro is not in a position to suggest in any way whether a .49 percent of a rate increase is meaningful to a ratepayer or not, correct?

MR. JAMES MCCALLUM: Correct.

MR. CHRISTIAN MONNIN: Thank you. If you can go to Appendix 5.1, please. That would be the UMS Group report. The UMS Group was engaged by Manitoba Hydro in September of 2016 to conduct a GAAP assessment of its assessment management capabilities.

Is that correct?

MR. JAMES MCCALLUM: That -- that's correct. I think we are probably in the process of alerting Mr. Wortley that he might be required here. We had not understood from your email last night you wanted to examine on UMS, which is fine, we just need to get the right personnel.

MR. CHRISTIAN MONNIN: Well, I'm sorry. My -- the email on Friday, I think, and I just sent two (2) orders across. And my understanding -- my take-away from Ms. Ramage last week was, Anything that's not on the record needs to be given a heads-up, which I did my level best to circulate to --

MR. JAMES MCCALLUM: I'm -- and it was Friday, for -- for the --

MR. CHRISTIAN MONNIN: And I'm not --

MR. JAMES MCCALLUM: -- and it wasn't criticism at all. I just -- we -- we hadn't been -- everything in our evidence is fair game. We -- we're not disputing that. It's just we didn't have the right people here.

MR. CHRISTIAN MONNIN: And -- and I took it like that, and please don't fret about criticism. I truck and trade in the misery of others, and I get criticized on a daily basis, so.

MR. JAMES MCCALLUM: Okay. Then I'll --

MR. CHRISTIAN MONNIN: No harm, no

foul. Thank you.

MS. PATTI RAMAGE: Mr. Wortley is on his way.

MR. CHRISTIAN MONNIN: I -- I apologize for -- for that gap. Perhaps if I can jump to something -- well, I...

MR. JAMES MCCALLUM: He'll be right up.

MR. CHRISTIAN MONNIN: Thank you.

(BRIEF PAUSE)

THE CHAIRPERSON: Nice to see you, Mr. Wortley.

MR. JOEL WORTLEY: Thank you. It's a pleasure to be here.

CONTINUED BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: Mr. Wortley, over here, good morning. I apologize. I'm the reason why you had to come to the panel on short notice.

I was asking some questions with respect to the UMS Group's report on asset management GAAP assessment, and as I'd stated earlier, my understanding was that UMS was engaged in September of

2016 to conduct a GAAP assessment of its asset management capabilities. Is that correct?

MR. JOEL WORTLEY: That's right. UMS was hired to come in and work with us to identify opportunities for improvement.

MR. CHRISTIAN MONNIN: And the scope of the assessment was to evaluate Manitoba Hydro's curs -- current asset management capabilities, and practices, and make recommendations for implementing a best practice asset management system; correct?

MR. JOEL WORTLEY: That sounds about right. I'd have to review the exact wording of their engagement, if that's what you're reading from.

MR. CHRISTIAN MONNIN: Kristen, if you can go down one (1) page, perhaps I will make a few -- a couple pages.

And a brief compris -- if I understand correctly, this report comprised a review of Manitoba Hydro's existing corporate business unit level asset management practices and comparisons to indusy -- industry best practices.

Are you able to educate me what asset management is at a very high-level?

MR. JOEL WORTLEY: So asset management, as we've talked about a little bit previously in this forum, often gets confused a little bit. There is -- there is making decisions about assets, which is usually termed as managing assets, and then there's asset management, which is how you run your asset-intensive business, and it's the alignment of all your activities to cert -- to your business objectives to realize value from your assets. And so in -- in the broadest sense, asset management is how you run your company.

MR. CHRISTIAN MONNIN: And Kristen, if you can go to page 4, please, of this report. Under the heading 'Strategic Value of Asset Management', among others, UMS report that benefits which can be achieved by Manitoba Hydro through the -- the maturation of its asset management system include -- and I'm looking at the fourth bullet -- fifth bullet down:

> "Improved effectiveness of expenditure dollars through focus on performance management and continuous improvement, and then optimizes use of human resource by matching the workforce in terms of size and composition to the work required, rather than creating work

"to keep the workforce busy."

Is that correct?

MR. JOEL WORTLEY: That's what it says, yes.

MR. CHRISTIAN MONNIN: And if you go to Tab -- sorry, page 7, please. In particular, after the stream of bullets, UMS identifies a number of gaps with Manitoba Hydro for which no current initiative is underway to close, and below is a summary of these key gaps, along with corresponding key recommendations.

And if you go to the next page over, please. And at page 8, some of the key recommend -- no, sorry. UMS noted that:

"Some of the key elements of an asset management system are missing from Hydro today. These include audits, controls, and performance metrics, which leadership can use to ensure to the stab -- the suitability, adequacy, and effective -- effectiveness of the system."

Is that correct?

MR. JOEL WORTLEY: That is what the report says, yes.

MR. CHRISTIAN MONNIN: And again:

"Different functions within each business unit have different roles in the asset life cycle leading to a situation where no one (1) group or function is responsible for optimizing total asset life cycle cost. In addition, most asset management efforts are focused on capital spending with minimal attention given to optimizing O&M, which is a key part of the asset life cycle."

Correct?

MR. JOEL WORTLEY: That's right. That's what it says.

MR. CHRISTIAN MONNIN: And under the heading 'Recommendations', namely, they recommend deci -- that Manitoba Hydro's decide on, declare, the operating model for asset management, roles, decision-making processes, goals, and key performance indicators, and the timetable for implementing these changes.

What has Manitoba Hydro done with these recommendations?

MR. JOEL WORTLEY: I -- as you noted,

the report was commissioned in 2016. Since then, a number of -- a number of initiatives have been put in place, first of all being our corporate asset management initiative to centralize asset management responsibility for the Company, which involved creating my own position, as the director of strategic business integration; involved creating the corporate asset management executive counsel, a group of vice-presidents responsible for ensuring -- or the stewardship of asset management within the Company; and a corporate asset management steering committee of directors responsible for deploying those asset management practices within their respective groups.

We've got a number of more technical initiatives underway to improve our asset health: indexing to create a corporate value framework to provide a common basis for valuing projects, and to roll out a computer foundation called C55 to allow portfolio management planning and the optimization of capital expenditures.

The next -- next on our list of things to do is to continue down our -- the development of our corporate asset management framework, phase 1 being this UMS report, where we looked for having UMS come in and identify opportunities for improvement.

Phase 2 is to develop asset management policy strategies and objectives, and phase 3 is a roadmap to close gaps and move us towards best practice.

MR. CHRISTIAN MONNIN: And so we're -- we're in phase 1, or we've started phase 2 now?

MR. JOEL WORTLEY: Phase 1 is complete. Phase 2 is next.

MR. CHRISTIAN MONNIN: And the -- at the foot of page 8, another recommendation is:

"Develop processes, implement tools to address operations and maintenance spend and the trade-off between O&M and capital in each business unit."

And that is comprised in phase 2?

MR. JOEL WORTLEY: No. If -- if you continue down the report towards the end, the -- UMS's recommendations are broken into four (4) steps. I think it's -- keep going.

(BRIEF PAUSE)

MR. JOEL WORTLEY: There, I believe, or one (1) page back. There we go.

And so what they're recommending is

that first, you need to create the right environment, then design the change the things that you want to accomplish, and then implement. And as you roll things out and they become adopted, then you work at achieving excellence.

MR. CHRISTIAN MONNIN: Okay, so when we were going through phase 1, 2, and 3, where do those fit in with these -- these four (4) steps?

MR. JOEL WORTLEY: So phase 1 and 2 would be -- phase 1 would be prior to these steps. Phase 1 was the -- the baseline. Phase 2, creating the right environment, is we're currently sitting, and phase 3, in terms of the roadmap, will be designing the change.

MR. CHRISTIAN MONNIN: And then the other two (2) implement the change?

MR. JOEL WORTLEY: That's right.

MR. CHRISTIAN MONNIN: That's the phase -- is that another phase, or?

MR. JOEL WORTLEY: We haven't named it a phase at this point. We'll have to see how we roll that out.

MR. CHRISTIAN MONNIN: And as -- as far as a roll-out for these phases, what's the timeline are we looking -- that we're looking at?

MR. JOEL WORTLEY: The -- there's no particular schedule being established right now. I expect that phase 2 will roll -- or will -- will be executed over the next year or so. The actual timing for phase 3, the roadmap and the execution really depends on what we're going to try to accomplish, and that -- that's subject to a cost/benefit analysis to see which -- which gap's first, and how long is it going to take, and what it's going to cost.

MR. CHRISTIAN MONNIN: Does Manitoba Hydro at this point have any notion or idea of this -- the cost savings or benefits that can be availed from proceeding with this -- these recommendations?

MR. JOEL WORTLEY: We haven't progressed far enough to be able to do a delta -- or a -- a cost analysis or a benefit analysis -- opportunity analysis for our own business. We know from other experience, we know from UMS themselves that other companies have achieved savings -- I believe UMS quotes 20 -- 20 percent, something like that. It -- it's in the early part of the report if you want to see it.

MR. CHRISTIAN MONNIN: No, that's fine. Thank you.

Ms. Bauerlein, I have some questions

for you still on -- on O&A. And as I understand matters in this GRA, Manitoba Hydro did not have the ability to prepare a detailed operating and administrative expense breakdown. Is that correct?

MS. SANDY BAUERLEIN: Correct.

MR. CHRISTIAN MONNIN: And the reason for that is -- is due to the fact that the full measure and impact of, for example, the voluntary departure program, and other directions are -- are still moving along. Is that correct? They're not come -- they're not finalized yet?

MS. SANDY BAUERLEIN: That's correct. To do a detailed budget, we have to understand exactly where every person is going to be and exactly what function they're going to be doing. With the people leaving, there's still a lot of transition happening across the Company.

MR. CHRISTIAN MONNIN: And my understanding on the evidence to date is that Manitoba Hydro has handled the voluntary departure program and the delimiting of positions internally. Is that correct?

MS. SANDY BAUERLEIN: That is correct. In some cases -- in many cases, the positions are delimited. In other cases, sometimes staff are redeployed to a position that a person may be leaving, but we feel that is a critical role, and that another subsequent follow-on position would be eliminated.

MR. CHRISTIAN MONNIN: And is Manitoba Hydro intending to hire any exterior -- external experts or consultants as it moves along with the workforce reduction plan and the optimizing of the O&M?

(BRIEF PAUSE)

MS. SANDY BAUERLEIN: On some areas may be looking to -- for assistance in trying to manage their specific functions. So while as -- as a company we haven't hired a consultant, there are certain areas that are looking for assistance to help refine some of their -- their processes.

MR. CHRISTIAN MONNIN: Kristen, if you could please go to Appendix 12 -- sorry, 10.12, and page 2 of 5. It's an operational cost and breakdown of benchmarking as prepared by the Boston Consulting Group.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: I'd said 2 of 5. I apologize, it's 4 of 7 on this -- this slide. If you scroll down a little bit, please. As a footnote number 1, it:

"...appears determined by size of global Hyd -- Hydro generation fleet."

Is Manitoba Hydro able to -- other than from that footnote, based on its dealings with Boston Consulting Group, are they -- is Manitoba Hydro able to describe the basis for selecting the utilities, and the numbers of utilities, and whether any of these selective comparatives are verily integrated to prepare this benchmarking study?

MS. SANDY BAUERLEIN: I'm not aware as to what -- how the section process was for the comparison that was done by BCG.

MR. CHRISTIAN MONNIN: And I understand that one (1) of the cost-saving measures that Hydro is looking for it pertains to supply change cost savings?

MS. SANDY BAUERLEIN: That is correct.

MR. CHRISTIAN MONNIN: Has Manitoba Hydro done anything to identify the streamlining and the savings that can flow from that?

MS. SANDY BAUERLEIN: Yes, it does. We have a supply chain initiative which, again, we have identified specific activities, similar to the capital asset management processes. We have different activities happening within different waves.

And as we discussed in the opening presentation, we expect to see -- or achieve savings of around -- a cumulative savings of around 150 million by -- I think it's 2021 -- 20 -- around that timeframe.

MR. CHRISTIAN MONNIN: Are -- are you familiar with what's referred to as a total factor productivity analysis?

MR. JAMES MCCALLUM: I have not heard that term.

MR. CHRISTIAN MONNIN: It represents a study -- the total quantity of outputs of a firm relative to the quantity of all the inputs of it -- that it employs. Is this something that -- anyone in Manitoba Hydro in the panel has -- has heard of in the past?

MS. SANDY BAUERLEIN: I have not.

MR. CHRISTIAN MONNIN: Thank you. I have now some questions with respect to Keeyask.

THE CHAIRPERSON: Sorry, Mr. Monnin,

can I just interrupt for a second? Can I just ask, on the GAAP assessment report, when was it actually ordered? When -- when was there a decision made to move forward with a gap assessment report?

MR. JAMES MCCALLUM: This is the UMS report, sir, on asset management?

THE CHAIRPERSON: Yeah.

MR. JAMES MCCALLUM: I -- I think we'll have to get back to you on that.

THE CHAIRPERSON: Okay. I -- I'm just wondering -- the -- the second question I had was: Who made the decision? Is this a management decision, or is this something that was reviewed with the Board? And you can get back to me on that one as well.

MR. JAMES MCCALLUM: Before my time. I'll have to --

THE CHAIRPERSON: Okay.

MR. JAMES MCCALLUM: -- endeavor to find out.

THE CHAIRPERSON: Thank you. Sorry, Mr. Monnin?

CONTINUED BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: Not a problem, Mr. Chair. Thank you.

I have some questions that I'd like to put to the panel with respect to Keeyask. Mr. McCallum, my take-away from your evidence on the policy panel was that Manitoba Hydro recognizes and anticipates that Keeyask will be a net detractor to its financial position for a considerable -- considerable period of time. Is that correct?

MR. JAMES MCCALLUM: Yes, that's correct. As we look at the future, here, we are seeing that domestic load growth is considerably slower than we had earlier anticipated, and we are -- which pushes out the -- the need for Keeyask in order to serve customers in the Province of Manitoba to a later date.

And then the capital cost has obviously increased significantly, and the export pricing on the opportunity market has -- has not recovered the way we had previously hoped and planned. And so as a result, you know, our -- and -- and this is in -- in Tab 2 of our application, albeit using some -- some dated and higher export pricing, but you can see that there is a material negative differential between the revenues we anticipate for Keeyask and the incremental carrying costs when the asset comes into service.

MR. CHRISTIAN MONNIN: And the take-away from that is based on the current outlook for its costs and the revenues that flow from it, that considerable period of time can feasibly be measured in decades. Is that correct?

MR. JAMES MCCALLUM: Yeah -- whether it's decades being 20 years, I'm -- I'm not sure. It depends a lot on the assumptions you look at, but clearly into the 2030s.

MR. CHRISTIAN MONNIN: And so safe to say that Manitoba Hydro reviews and would agree that Keeyask is a primary driver of the proposed rate increases?

MR. JAMES MCCALLUM: It's a significant driver of the rate increases, but so too are the limited contribution to reserves that's been made over the last several years, and, of course, in service of Bipole III reliability project next year.

MR. CHRISTIAN MONNIN: And Kristen, if you go to Tab 2, please, of the application, page 58 of 61.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: And I think this -- looking at lines 16, Mr. McCallum, I think

this ties into the evidence that you were just
providing, starting on line 16, going to the last
period on line 20:

"Since its last year rate application, Manitoba Hydro's experienced a further deterioration of its anticipated expert revenues, significant weakening in its forecast of domestic load, and sig -- significantly increased capital costs associated with its major new generation and transmission projects. In response to these challenging conditions, Manitoba Hydro is dramatically advancing the pace and scale of internal cost reductions."

Now, I'm -- I'm reading that not because -- I know everyone can read very well. I'm just reading that for the benefit of the record, and I thank you for your patience and allowing me to do that.

And so, in view of the changing environment, here's the question: In view of the changing environment, did Manitoba Hydro consider alternatives of scaling down, or modular versions of Keeyask in order to different portions of the capital costs?

(BRIEF PAUSE)

MR. JAMES MCCALLUM: I was just looking around to ensure that Mr. Miles was -- was with us. But, you know, at the heart of the Boston Consulting Group review of -- of the summer of 2016 was looking at, really, both major capital projects and the financial impact of -- of same, and to examine whether there were opportunities to -- to delay or halt the projects. And that analysis kind of came back with, you know, in a -- in a punchline, no choice but to move forward.

And as the Keeyask project, subsequently, we -- we reviewed and -- and updated the control budget in February or March of 2017, and -- and we -- and this is in our evidence -- refreshed, you know, a similar analysis to what BCG did of the Keeyask project and concluded that, again, the -- the best path forward for impacts on -- on ratepayers in the Company was to finish the project and get it in service.

MR. CHRISTIAN MONNIN: So I twigged to the use of the word -- or the -- in your response, sir, I twigged to you saying, In a punchline, BCG came back.

Was -- did BCG conduct an examination on the merit of such options and that would reduce the rates inquired -- the -- the rates that are now being required? More than a punchline, did it actually do an analysis of -- of scaling back or doing modular versions?

MR. JAMES MCCALLUM: I'll have to -- to let Mr. Miles speak to even the feasibility of any modular concept. Certainly in our -- our -- and -- and I wasn't here for the BCG work to speak to -- to rate impact analysis. We did do those analyses in February and March of this year to quantify and -- and similarly confirm that -- that the rate impacts were far worse by abandoning the project versus completing it.

MR. TERRY MILES: Maybe I -- Mr. Monnin, exactly what do you mean by modular options and different options? I'm not aware of any alternatives that -- that BCG would have looked at in terms of alternate structure makeup, but if you could provide a little more clarification as to what you mean by modular --

MR. CHRISTIAN MONNIN: Sure. Modular -- I believe Keeyask is -- is it seven (7) turbines? If you could scale that down, it would be modular. Looking -- if you could have two (2) going rather than the -- than the seven (7), then you can scale those out. That's what I would be referring to as modular.

And -- and in particular on that piece is I would -- would appreciate to know if -- if Boston Consulting Group conducted such an analysis to consider these alternatives and -- and where -- where that could be found.

MR. TERRY MILES: I -- I don't believe Boston Consultants considered those types of things. I think with a project like Keeyask, once it's at the state that it was at, about 75 to 80 percent of the actual cost is in the civil works, the main structures that are there. The mechanical turbines and that then ends up being incremental on top of those. And then typically, completing those and installing those resources actually helps to extract the value from that.

Once you've invested in the 75 to 80 percent of the civil -- civil works, the turbines and that actually help extract the value of it, and there's benefit in completing those at the time to do that, not -- the alternative is to not completing the turbines at the time. That would be my -- my understanding of that.

MR. CHRISTIAN MONNIN: So I appreciate it's qualified that depending -- it is qualified on -- based on the -- on the -- the point where Keeyask was -- was -- and what the situation was, and -- and the part of its development, it's -- with that qualification, is it safe to say that Boston Consulting Group did not conduct such an analysis?

MR. TERRY MILES: I'm -- I'm not aware of the analysis, and I'm not aware that they were asked -- asked to do that. I can't comment on that.

MR. JAMES MCCALLUM: Yeah, nor -- nor can I, but to -- to my awareness and knowledge, no.

MR. CHRISTIAN MONNIN: Okay. If you can go to Manitoba Hydro -- I believe it's MFR-72, page 1...

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: Yes, I'm sorry, and it really just -- and that -- I don't need to drag everyone there, but what I'm looking at is the -- I would draw your attention to the June 2nd, 2016 letter from BCG, to -- setting out the scope of work. And one (1) of the bullets is, "What viable alternatives exist to maximize value?"

And I think we've established that they haven't looked at alternatives. But my suggestion was -- would it -- being that under the scope of work, that would have been something they ought to have looked at?

MS. PATTI RAMAGE: If I could interject, Mr. Monnin?

MR. CHRISTIAN MONNIN: Please.

MS. PATTI RAMAGE: I don't think we've established what BCG did at all. We've established that this panel is not aware of -- of what that was.

MR. CHRISTIAN MONNIN: Well, then we'll leave it at that. Thank you, Ms. Ramage.

(BRIEF PAUSE)

CONTINUED BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: Is -- is -- and I -- I apologize. I'm asking this question because the pole's in front of me, and that's of my own making. I could have moved.

Is Mr. Cormie on the panel this

morning?

MR. JAMES MCCALLUM: No, he's not here this morning.

MR. CHRISTIAN MONNIN: Okay. I will ask the questions regardless that I were going to put to Mr. Cormie. If someone is able to respond to them, all the better; if not, then I will move on.

You may recall an exchange with my friend Mr. Peters. Mr. Cormie was put questions about the delay of Keeyask to thirty-two (32) months, and whether that would have any impact on Hydro's current contractual obligations. And Mr. Cormie's evidence was that they had -- that "they" being Manitoba Hydro had the resources to meet the obligations if the delay was extended to thirty-two (32) months.

As Mani -- can Manitoba Hydro provide -- anyone on the panel provide any -- is able to answer this question: What would happen if the delay was further than thirty-two (32) months, say an extra twelve (12) months? Would that affect Manitoba Hydro's abilities to meet its contractual obligation?

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: And Kristen, if

you could go to PUB book of documents, Exhibit 42, Tab 4, page 182, that'll set out the contracts, the obligations that I'm referring to.

(BRIEF PAUSE)

MR. JAMES MCCALLUM: I -- I think we'll need Mr. Cormie to speak specifically, but I -- I would just say that there -- there are important kind of pieces of calculus that go into a delay decision that go beyond Manitoba Hydro's ability to service the contract from -- from its excess dependable energy without Keeyask, which is, I think, where you're -- you're going, and those include the contractual terms of these export contracts that are specific to Keeyask.

But also not to be missed is we're building this -- this project in partnership with four (4) Cree nations who have -- Manitoba Hydro has made commitments to. And so there -- there is much more that goes into this analysis than simply whether we have the additional dependable power.

MR. CHRISTIAN MONNIN: That's fair. And I suppose this is something that Mr. Cormie would have to -- to respond to, but I appreciate the other factors in the consideration of meeting the obligations, but this was really specific to being able to meet the resource obligations. And Mr. Cormie's evidence was that, you know, with a thirty-two (32) month delay, if Manitoba Hydro had the resources, it could enter the market.

If -- if you could go to -- if thirty-two (32) months delay occurred, then I was just wondering whether the resources would be there if the delay was greater than thirty-two (32) months.

MR. JAMES MCCALLUM: We -- we will have to reserve on that. I -- I don't personally have the answer.

MR. CHRISTIAN MONNIN: That's fair.

(BRIEF PAUSE)

MS. PATTI RAMAGE: Mr. Monnin, would you like that by undertaking, or -- we have put out the call for Mr. Cormie, but --

MR. CHRISTIAN MONNIN: You know, whatever's easier for you folks over there. Frankly, I'm -- I'm fine either way.

MS. PATTI RAMAGE: Let -- let's take it by undertaking, and if Mr. Cormie -- I believe he's in meetings, but if we can pull him away, we'll get him back here and deal with it that way, if -- if this morning, we can get him here. And -- and we apologize. We weren't aware that --

THE CHAIRPERSON: Yeah. No.

MS. PATTI RAMAGE: -- Mr. Cormie was specifically required this morning.

THE CHAIRPERSON: Yeah. That's fine. We'll deal with it.

MS. PATTI RAMAGE: Gave him a pass.

--- UNDERTAKING NO. 13: Manitoba Hydro to provide whether they can continue to meet their contractual obligations if the delay of Keeyask is longer than thirty-two (32) months

CONTINUED BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: Kristen, if you can go to some of the IRs, GSS/GSM Manitoba Hydro 1-4, please.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: Thank you. Now, this might seem a little picayune, but here on the response we're referring to cancellation costs. And here we have 1.35 billion. And when I'm looking at the tab 2 application, it's 1.3 billion. And I say it's picayune because we're only looking at the difference being 1.3 and 1.35.

And I'm just wondering why there's that difference, and is it just because at the time of the application, vis-a-vis the time of response to the IR? Can anyone elucidate me on that over there?

(BRIEF PAUSE)

MR. TERRY MILES: Can you repeat the question, please, Mr. Monnin?

MR. CHRISTIAN MONNIN: Absolutely. In tab 2 of your application, Manitoba Hydro quantifies the additional cancellation costs of Keeyask at 1.3 billion, and in this IR it's quantified at 1.35 billion. And I said I appreciate it's picayune. It's very small, but I'm just wondering what the discrepancy is, and whether that's just because of the temporal issue of when the application was filed.

MR. JAMES MCCALLUM: No, I -- and I'll

let Mr. Miles overrule me. I -- I believe what's happened -- the -- the number I have in my head from February or March of this year when we -- when we, you know, refreshed our analysis of -- of whether to carry on with the Keeyask project in light of the new capital budget -- the number I have in my mind from then is 1.35 billion as being our estimate -- and it's important to emphasize estimate of -- of the cancellation costs and remediation costs. And so I -- I can't -- I don't know how that ended up being 1.3 billion in the -- in the application. It could well be just a typographical matter.

MR. CHRISTIAN MONNIN: And did -- did Hydro include the sunk costs in making a determination of whether or not to proceed with Keeyask?

MR. JAMES MCCALLUM: No, the sunk costs were taken as -- as just that, sunk costs. This was an analysis of paths forward, comparing the path of expending the additional capital to finish the project, obtaining the benefit of the export contracts, versus a path of halting construction, remediating the site, paying the breakage costs associated with the relationships that are contingent on the project. And then constructing the -- the comparison analysis was to construct a gas plant projected, you know, with a new projected need date for new resources.

MR. CHRISTIAN MONNIN: My Friend Mr. Williams referred to his failure in -- in going to accounting. My track record is even worse and it'll reflect in this question.

What's the difference between a sunk cost and actual costs incurred?

MR. JAMES MCCALLUM: Well, a -- a sunk cost is typically, at least in my mind, thought of as a cost that's in your rearview mirror. It's been expended. You can't do anything to recover it. And so really when you're -- when you're managing a business you're looking at the path forward and looking at the best decision you can make basis where you're at.

So when we -- when you -- you ask the question of, you know, is -- is Keeyask going to be -- effectively your question was: Is your -- is Keeyask going to be a net drag on Manitoba Hydro's income in the years after it comes into service. The question -- the answer that was -- is clearly yes.

But that doesn't mean that it is wrong choice to finish the project. What you're doing is you're -- you're saying, There's not much I can do about what's already been expended. But a -- a half built generating station is of no use to anyone. And so your path -- you're -- you're looking at alternate paths forward. Do I expend the remaining 4-odd billion dollars and finish the project? Or do I not do that -- expend in our estimate is 1.35 billion, forgo the export revenue tied to the project and have the ratepayers pay the interest cost on -- on 5 or $6 billion invested with no functioning asset to show for it? That's the analysis.

MR. CHRISTIAN MONNIN: I want to try -- try this again because -- and try to break it down even more simply because my brain only thinks in very simple ways.

And so I think my question was definition-wise, what's the difference between sunk costs vis-a-vis actual costs incurred? Are they the same, or are they a different animal?

MR. JAMES MCCALLUM: No, I'd regard them the -- as the same.

MR. CHRISTIAN MONNIN: All right. So here we have sunk costs at 2.8 billion, in this IR. And, Kristen, if you can go to the IR previous to that MH-1-3(a) to (c), page 3 of 3 is -- is fine. And again, this might just be because this is actual costs as April 3rd of 2017. We have -- and my understanding now from your evidence is sunk costs at 2.8 in the previous one (1) is the same as actual costs incurred. This is 3.348 billion. And I'm just trying to understand why there's a difference on these IRs for the sunk costs or the actual costs incurred.

MR. JAMES MCCALLUM: One (1) moment.

(BRIEF PAUSE)

MR. JAMES MCCALLUM: So I believe -- I believe the difference -- and we'll, subject to check -- it's an excellent question, Mr. Monnin. But -- but I believe if you look down to the --

MR. CHRISTIAN MONNIN: It might be my only one (1).

MR. JAMES MCCALLUM: If you look down to -- and, I'm sorry, I've lost the reference for which IR this is, but if you look -- just for the record's purposes -- if you look down at the bottom you'll see interest of 0.476. That's $476 million. That has been capitalized to the project, bringing the total from 2.8 billion to 3.348.

So I believe in the answer to the other IR that you referenced the 2.8 billion was without the

-- it was sort of the -- the sunk costs of -- you know, for buying nuts and bolts and widgets and concrete. And then you also need to consider the interest we've expended on the funds borrowed to progress the project to date. So that would be the difference.

MR. CHRISTIAN MONNIN: Thank you, Mr. McCallum. Kristen, if you can go to IR GSS/GSM 1-6, please.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: Oh, if you'd -- that's -- scroll up a little bit more. Thank you. Here -- a little bit more, please. Perfect. Here GSS/GSM puts one (1) statement from Hydro that's found at page 43 it's app -- of its application. And it speaks to:

"In examining the original decision BCG analyzed the NPV, net present value, of Keeyask and then Keeyask plus the US tie-line project against the base case of gas-fired generation, and concluded that the Keeyask 2019/'20 ISD with US tie-line provided the greatest benefit to both Manitoba Hydro and the province."

And Hydro was asked to reconcile that statement with BCG's statements below which read as follows:

"Conversely, a decision to build Keeyask and its associated infrastructure was an imprudent one (1) due to a failure to fully assess the risks associated with moving forward. And all three (3) projects, the Bipole III, Keeyask, and the associated tie-line should have been reviewed on an aggregate basis instead of individually to properly assess the collective risks of conducting all projects at once. While a Bipole III could have been pursued as a standalone project, the feasibility to Keeyask and the tie-line were both dependent on one another and on construction of the Bipole III as well."

Now with respect to the answers

provided, I just want to clarify a few points. Now, I've always been accused of having a firm grasp on the obvious, but the first response is as follows:

"Manitoba Hydro's interpretation of the above statements."

Is it safe to say that that's exactly what this is? It's a centre -- Manitoba Hydro's interpretation? It did not go back to Boston Consulting Group to confirm that?

MR. JAMES MCCALLUM: That's correct.

MR. CHRISTIAN MONNIN: And the next page over, Kristen. And the last paragraph:

"As to statement 2, Manitoba Hydro infers that BCG's conclusion is" --

And again, is it safe to say that Manitoba Hydro did not go back to BCG to confirm this -- what is being inferred?

MR. JAMES MCCALLUM: That -- that's right.

MR. CHRISTIAN MONNIN: Now, Mr. Chair, I had circulated some orders that I had some questions for on Friday. And they were really with respect to an exchange that My Friend Dr. Williams had with Mr. Barnlund. I appreciate he's not on the panel. I can defer these questions to the panel where Mr. Barnlund will be participating in. I have no problem with that. But I thought it prudent to have them ready, because the exchange occurred with respect to the revenue requirement panel.

MS. PATTI RAMAGE: Mr. Chairman, we can have Mr. Barnlund --

THE CHAIRPERSON: Ms. Ramage...?

MS. PATTI RAMAGE: -- here and I am also told Mr. Cormie is on his way, so.

THE CHAIRPERSON: I guess we'll keep going.

MS. PATTI RAMAGE: We might as well keep going.

THE CHAIRPERSON: Yeah, I'm just -- Mr. Monnin, do you have other questions besides those for Mr. Cormie or Mr. Barnlund?

MR. CHRISTIAN MONNIN: I -- I see that Mr. Cormie has just -- just entered. The ones that I have, the balance would just be for Mr. -- for Mr. Barnlund. And again, I --

THE CHAIRPERSON: Okay. Well --

MR. CHRISTIAN MONNIN: -- I have no problem delaying those to the next panel.

THE CHAIRPERSON: Well, no. But if Mr. Barnlund is on the way we might as well deal with it now. Mr. Cor -- if Mr. Cormie could be seated, and then we'll -- we can put his -- your questions to him. And then if Mr. Barnlund --

MR. JAMES MCCALLUM: Do you think you're finished with Mr. Wortley?

MR. CHRISTIAN MONNIN: I am. Thank you.

MR. JAMES MCCALLUM: Okay.

THE CHAIRPERSON: Thank you, Mr. Wortley. Mr. Cormie, good morning.

MR. DAVID CORMIE: Good morning, sir.

THE CHAIRPERSON: Mr. Monnin.

MR. CHRISTIAN MONNIN: Thank you, Mr. Chair.

CONTINUED BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: Good morning, Mr. Cormie.

MR. DAVID CORMIE: Good morning.

MR. CHRISTIAN MONNIN: And I -- I appreciate you being to attend this morning to answer a few -- the very few questions I have for you. Perhaps, Kristen, out of fairness it would be of benefit to putting up PUB book of documents at Exhibit 42-4, page 182.

Mr. Cormie, during cross-examination on this panel by My Friend Mr. Peters on behalf of the Board, there was an exchange between yourself and him with respect to Hydro's obliga -- ability to meet its obligations under contract, and -- that are found at page 182. And your answer on that at page 1278, no need to go there, but was:

> "Subject to check, Mr. Peters, I believe we do. We also have the ability to acquire resources in the short-term if that became necessary. We can enter the market, and if it was necessary acquire resources if -- if there were a thirty-two (32) month -- months for additional delay."

And do I understand that on the one (1) hand this answer, Mr. Cormie, is Manitoba Hydro can meet its obligations in two (2) ways: by going into market, or with the current resources it has.

MR. DAVID CORMIE: Well, clearly, Mr. Monnin, if we didn't have Keeyask, if it didn't come into service, that would be a significant strain on our system under the planning criteria. However, because we are also building a new 500 kV transmission line to the United States, we have access to additional resources that could be called upon from the market in the circumstances that things were delayed further than what we're planning. And -- and we would -- we would go to the market and use that firm transmission to pro -- to acquire those resources if necessary.

MR. CHRISTIAN MONNIN: And this exchange with Mr. Peters was in particular regard to a thirty-two (32) month delay.

What would occur in that scenario if the delay was greater than thirty-two (32) months?

MR. DAVID CORMIE: Well, we'd have to -- we'd have to -- we would be monitoring the progress of Keeyask. And -- and probably a year in advance of any deficiency that we would identify that put the company at risk, we would go to the market and acquire the resources.

MR. CHRISTIAN MONNIN: And are you able to say today whether -- if Keeyask was delayed for greater than thirty-two (32) months, whether Manitoba Hydro would be able to meet its obligations as set out on page 182 here?

MR. DAVID CORMIE: Which -- what -- 182 is that table of contracts? Mr. Monnin, if you remember, Manitoba Hydro supplies system power to all its con -- under all its contracts. It's from our portfolio of resources, including purchases. There are -- there are no contracts that are specifically tied to any specific resource. And so we would add a system resource, either a capacity purchase, or if -- if necessary, we would enter into a call option for energy. And that would become part of our portfolio, and it would be completely suitable for meeting any of our obligations either in -- to -- under our export sales or to our -- to our Manitoba customers.

MR. CHRISTIAN MONNIN: So to unpack that, the answer would be that Hydro would be able to meet its contractual obligations if the delay was greater than thirty-two (32) months; correct?

MR. DAVID CORMIE: Well, I'm -- I'm expecting that given our -- that the Great Northern transmission line and the Minnesota/Manitoba transmission line would be in service we can tolerate additional delays, yes.

MR. CHRISTIAN MONNIN: Thank you. Those are my questions. Mr. Chair, this might be an appropriate time to have the quick morning break. I see Mr. Barnlund has arrived.

THE CHAIRPERSON: I'm sorry. Sorry.

Mr. Monnin, how long do you think would be with Mr. Barnlund?

MR. CHRISTIAN MONNIN: I'd -- probably about ten (10), fifteen (15) minutes.

THE CHAIRPERSON: Well, why don't we do Mr. Barnlund now and then we can -- if we're done with him then Mr. Cormie, Mr. Barnlund can -- can leave unless they're required by -- well, I guess you're the last one (1) up, so. I'd just like to get through this and free up people so they don't have to sit here if they're not needed. So why don't we proceed, Mr. Monnin, and you can finish your cross.

MR. CHRISTIAN MONNIN: If I might just take thirty (30) seconds to refresh my glass of water, I'd...

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: My Friend has been kind enough to -- to take that on for me, so I'll -- and I'll just proceed.

THE CHAIRPERSON: Certainly.

CONTINUED BY MR. CHRISTIAN MONNIN:

MR. CHRISTIAN MONNIN: Thank you.

Good morning, Mr. Barnlund.

MR. GREG BARNLUND: Good morning.

MR. CHRISTIAN MONNIN: Mr. Barnlund, I understand that you're the person who has been identified by Manitoba Hydro as being responsible for responding to and dealing with Board Orders.

Is that correct?

MR. GREG BARNLUND: That's correct.

MR. CHRISTIAN MONNIN: And in that regard you are the appropriate person to respond to any questions relating to the Board Orders; correct?

MR. GREG BARNLUND: That's correct.

MR. CHRISTIAN MONNIN: Now, I'm mindful of what was -- the -- the concern was raised by My Friend Ms. Ramage last week ensuring sufficient time to receive and review documents that are not currently on the record for this GRA. I sent an email out on Friday, December 15th, copies of Board Order Number 101/04, and Board Order Number 34/05.

Did you receive copies of those Orders, sir?

MR. GREG BARNLUND: Yes, I did.

MR. CHRISTIAN MONNIN: And are you able to confirm that you had sufficient time to review those Board Orders?

MR. GREG BARNLUND: I gave them a -- a quick review. I'm -- I'm prepared to speak to them, yes.

MR. CHRISTIAN MONNIN: Okay. I'd like to take you back to an exchange that you had with My Friend Dr. Williams on December 12th, 2017. For the record, those can be found at pages 1469 and 1459 of the transcript. No need to take you there now.

Mr. Barnlund, you may recall you jumped in on an exchange between Dr. Williams and Mr. McCallum on the issue of rate shock. Do you recall that?

MR. GREG BARNLUND: Yes, I do.

MR. CHRISTIAN MONNIN: And do you recall your evidence that you advised that Manitoba Hydro did not consider that the 7.9 percent increase as being requested to meet the threshold of rate shock?

MR. GREG BARNLUND: That's correct.

MR. CHRISTIAN MONNIN: And you then advised that that was based on in 2004 the PUB looked at Manitoba Hydro's -- sorry, the PUB, the Board, the Public Utilities Board looked at Manitoba Hydro's application for an August 1 rate increase.

Is that correct?

MR. GREG BARNLUND: That was the one (1) I spoke to when I was exchanging with Mr. Williams -- with Dr. Williams. I might add, too, that there are some -- in other jurisdictions if you'd find the Ontario Energy Board and the Alberta Utilities Commission more clearly define a threshold for rate shock as being a 10 percent increase.

MR. CHRISTIAN MONNIN: Right. But in the evidence that you provided that day when you exchanged with Mr. Williams, you specifically referred to a 2004 Public Utilities Board of Manitoba's decision.

Is that correct?

MR. GREG BARNLUND: That's correct, yes.

MR. CHRISTIAN MONNIN: Okay. And I'm going to suggest to you that that decision is Order Number 101/04.

You have no reason to contest that?

MR. GREG BARNLUND: I believe that's correct.

MR. CHRISTIAN MONNIN: And based on the Board Order in 2004, the Board Order of the Public Utilities Board of Manitoba, your evidence was that as long as the increases were no more than 8 or 9 percent then they would not be considering those as rate shock.

That was your evidence?

MR. GREG BARNLUND: That was a finding -- and I'm just going to look it up here on which page of the Board Order it was.

MR. CHRISTIAN MONNIN: It's page 24 if you want to go there, and we'll take you there in -- in --

MR. GREG BARNLUND: Okay.

MR. CHRISTIAN MONNIN: -- in a bit, but I'm just more fixed -- I'm concentrated on your -- your evidence right now, sir.

MR. GREG BARNLUND: Okay.

MR. CHRISTIAN MONNIN: Do you recall give -- your -- your evidence of last week that was as long as the increases were no more than 8 or 9 percent, then they would not be considering those as rate shock? Was that your evidence, sir?

MR. GREG BARNLUND: That was what I read in the Board Order, yes.

MR. CHRISTIAN MONNIN: Pardon me? Can you repeat?

MR. GREG BARNLUND: That was what I read from the Board Order, yes.

MR. CHRISTIAN MONNIN: Okay.

MR. GREG BARNLUND: It's on page 27 of Order 101/04.

MR. CHRISTIAN MONNIN: And now, we'll get to the Board Order in just a moment, and also Board Order 34 -- 34.05. And when you said in your evidence last week that we don't considered it to be rate -- meeting the threshold of rate shock, and that rate shock threshold is 8 to 9 percent, when you mean "we," obviously you mean your evidence was on behalf of Manitoba Hydro?

MR. GREG BARNLUND: Well, to be clear I think that Manitoba Hydro's position is that a rate increase of 7.9 percent would not constitute rate shock. We would -- we do not have an official policy threshold in terms of what would be deemed as rate shock. However, we're cognizant of a level of 10 percent as being widely recognized in the utility industry as constituting a potential for rate shock.

MR. CHRISTIAN MONNIN: And we'll get to that in a bit. I'm just dealing with your evidence and dealing with what this Public Utilities Board of Manitoba has opined -- or has determined to be rate shock. And now, this decision that we're -- we're referring to, and we'll get to it, it sets a threshold of rate shock of 8 to 9 percent.

Is that correct?

MR. GREG BARNLUND: I wouldn't characterize it as it set a threshold of 8 to 9 percent. It determined that Manitoba Hydro's increase was not -- did not constitute rate shock. And it simply opined that other Intervenors had indicated a range of between 8 to 9 percent as being their definitions of constituting rate shock.

MR. CHRISTIAN MONNIN: So having this Board identify the threshold of rate shock -- and we can get -- that's page 27, as you quite said -- right -- right said, Mr. -- Mr. Barnlund. The last paragraph:

> "In coming to a decision on the rate increases, firm and conditional, the Board considered the issue of rate shock and opines that the rate increases for most customers would be within the thresholds put forth by the Intervenors, i.e., no more than 8 to 9 percent for any customers for the August 1, 2004 increase, and much less for most."

Are you able to advise whether Manitoba

Hydro's decision to put forward a 7.9 percent increase in this GRA was in light of the threshold here being 8 percent? Did that have any factor in -- in the rate that was being put forward?

MR. JAMES MCCALLUM: I -- I can answer that. The answer is no --

MR. CHRISTIAN MONNIN: Okay.

MR. JAMES MCCALLUM: -- because this is the first time that I've been made aware of this Board Order.

MR. CHRISTIAN MONNIN: The second, if you refer to last week's evidence of Mr. Barnlund. Now, Mr. Barnlund, in your exchange with Mr. -- Dr. Williams last week, you also provided further evidence that while the proposed rate increases in this GRA are difficult, and that's your evidence, they do not equate to rate shock because the rate shock also infers a sudden surprise on the customer.

Do you recall giving that evidence?

MR. GREG BARNLUND: Yes, I do.

MR. CHRISTIAN MONNIN: And you've added that Manitoba Hydro had been very clear in terms of its communications of its financial situation in indicating that there would be a need for continual rate increases of this order of magnitude; correct?

MR. GREG BARNLUND: Yes, that's correct.

MR. CHRISTIAN MONNIN: And based on this heads up, for lack of a better term, Manitoba Hydro would not necessarily consider this to be rate shock.

Is that correct?

MR. GREG BARNLUND: That's correct.

MR. CHRISTIAN MONNIN: And would you agree with me, sir, that -- just bear with me for a moment.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: Now, if you look at what this Board has said at page 27 here, and I'm suggesting to you that there's no reference on this -- in this paragraph or anywhere else in the order that the Board established that provided it was communicated properly, it wouldn't be rate shock.

Do you agree with that?

MR. GREG BARNLUND: I'm -- I'm not aware of any other clear, I think, policy distinction this Board has made. I might, I guess, maybe draw your attention though to some of the decisions that this Board has made with respect to the natural gas utility, Centra Gas Manitoba, which, of course, deals with a much more volatile cost structure due to the fact that a great deal of that cost as passed on to customers is a cost of gas that's procured in the wholesale market.

And there's been ten (10) at least -- or ten (10) occasions where this Utilities Board has approved increases to natural gas customers in excess of 10 percent. And a situation in 1999 and 2000 when wholesale commodity prices really increased at a -- at a very fast pace, the Utilities Board passed through an increase upwards of 25 percent on one (1) occasion.

MR. CHRISTIAN MONNIN: Okay. So that's -- I appreciate that. And we can maybe get to that at a later time. But this Order here, sir, is -- is a general rate application for Manitoba Hydro, the -- the PUB 101/04; correct?

MR. GREG BARNLUND: Yes. And -- and you were asking me about the surprise to customers. And certainly some of the gas rate increases that have been approved by this Board were driven by some surprising changes in the wholesale market where there is relatively little notice that was provided to customers of those changing conditions. And that was more of an issue of rate shock to be contended with than what we are certainly referring to here in this General Rate Application, sir.

MR. CHRISTIAN MONNIN: So I think it's best to take this in pieces in order to ensure that we move along in a timely fashion. So if you can go to page 24 of the decision. I just want to go through what the order -- what the -- what the PU -- Public Utilities Board said here.

MR. GREG BARNLUND: Yes, sir. I have that.

MR. CHRISTIAN MONNIN: Okay. So if you could scroll down a bit, please. Now, the last two (2) paragraphs, I think we can agree on -- on the penultimate paragraph that's before the last one (1):

> "The two (2) concerns of the Board when dealing with Manitoba Hydro applications, the interest of the Utility's ratepayers and the financial health of the Utility. Together, in the broadest interpretation, these interests represent the general public interest."

You take no issue with that, sir?

MR. GREG BARNLUND: Yes, sir.

MR. CHRISTIAN MONNIN: And here, the second paragraph, or the last paragraph, rather:

"In a sense, Manitoba and ratepayers are fortunate that the objective of avoiding rate shock plays a role in rate setting. In the case of other commodities, oil and gas, the market price changes ignore the concept."

Do you agree with that, sir?

MR. GREG BARNLUND: I see that statement, yes.

MR. CHRISTIAN MONNIN: We're dealing with a different beast here.

Do you agree with that, sir.

MR. GREG BARNLUND: Well, I would agree that certainly for -- for products or commodities that are transacted at a market price that -- that the potential for rate shock does exist for those particular commodities, yes.

MR. CHRISTIAN MONNIN: Now, I wasn't here in 2004. And -- and I wasn't here for Board Order 35 -- 34/05, which I also shared. But, Mr. Barnlund, were you here at that time?

MR. GREG BARNLUND: I was employed

with Manitoba Hydro, but I was not involved in those applications at that time.

MR. CHRISTIAN MONNIN: Okay. But you -- you familiarized yourself with these Orders?

MR. GREG BARNLUND: Yes, sir.

MR. CHRISTIAN MONNIN: Now, my understanding of that at this time frame, November -- Board Order 101/04 and Board Order 34/05, we were dealing with a significant -- an extremely significant financial impact of a drought; correct?

MR. GREG BARNLUND: That's correct, yes.

MR. CHRISTIAN MONNIN: And at page 28 of Board Order 101/04, the Board is referring to conditional and firm -- sorry, firm and conditional rate increases.

Do you agree with that?

MR. GREG BARNLUND: Yes.

MR. CHRISTIAN MONNIN: And -- and my understanding of that point, what they're referring to here is that the Board in this decision gave firm rate increases and conditional rate increase. A firm rate -- and the reason for that can be found -- bear with me again.

(BRIEF PAUSE)

MR. CHRISTIAN MONNIN: At page 22, last paragraph:

> "Accordingly, after careful consideration and realizing the additional burden that will be placed on the economy, the Board has determined to vary Manitoba Hydro rate -- rate increases."

And what the Board determined in this decision was to give a firm increase of 5 percent, and conditional increases of 2.5 percent in April and October of the following year, pending satisfactory information being filed by Manitoba Hydro to the Board, that those rate increases were set -- were -- were necessary.

Do you agree that's what occurred, sir?

MR. GREG BARNLUND: And I -- and I think what was occurring at the time and -- and part that was taken into consideration by the Utilities Board in arranging these increases on a firm and on a provisional basis, was that a number of things in addition to the significant loss that have been occurred -- that had been incurred, excuse me, in the year of the drought.

This Board also expressed a concern with the ability or the pace at which the Utility was approaching attaining its revenue -- or, sorry, attaining its equity targets. And it had concerns that -- that the Company was not on track to be able to do that appropriately. It was also concerned that in the face of looking at the construction of Wuskwatim, which was scheduled to occur within the next couple of years that this Board expressed a concern that -- that sufficient financial strength had to be -- had to be obtained by the Corporation in light of that major capital expenditure. And the Wuskwatim plant, at that point in time, was budgeted to be probably a eight hundred thousand (800,000) -- or a $800 million project.

MR. CHRISTIAN MONNIN: So you're not disputing that in Board Order 101/04, that after careful reflection realizing additional burden that would be placed on the economy, the Board varied the rate increases. It staggered them, for lack of a better term.

You don't dispute that at least, sir?

MR. GREG BARNLUND: It did -- it did more than stagger them. It actually awarded the

Utility more than it had requested.

MR. CHRISTIAN MONNIN: But, sir, you're not going to disagree that it gave a lesser increase, and then conditional increases where Manitoba Hydro was required to return before the Board to justify that these conditional increases were necessary.

Do you agree with that, sir?

MR. GREG BARNLUND: No, I think to make clear, the Utilities Board awarded Manitoba Hydro a larger increase for August 1 than it had initially requested, and then followed by requiring Manitoba Hydro to file, on a provisional basis, updated financial information prior to considering any -- or its next rate increase for April 1 of 2005.

MR. CHRISTIAN MONNIN: Is it safe to say, sir, that Manitoba Hydro views the issues of economic competitiveness and economic development as something that, while important, are mostly beyond its mandate and control?

MR. JAMES MCCALLUM: Sorry, Mr. Monnin, can you repeat the question?

MR. CHRISTIAN MONNIN: Is it safe to say that Manitoba Hydro views that the issues of economic competitiveness and economic development is something that, while important, are mostly beyond Manitoba Hydro's mandate or control?

MR. JAMES MCCALLUM: Well, I think clearly Manitoba Hydro has an interest in economic development. Economic development and -- and growth support Manitoba Hydro's business. I think our concern would be trying to use rate strategy in order to artificially deal with issues of economic competitiveness that go far beyond electricity rates.

MR. CHRISTIAN MONNIN: Is it safe to say that in preparing this application Manitoba Hydro did not turn its mind to the impact of the impending carbon tax and what that will have on -- on ratepayers' ability to absorb the proposed rate increases?

MR. JAMES MCCALLUM: Well, at the time we prepared our application we didn't have knowledge of the Province of Manitoba's choices around the carbon tax.

MR. CHRISTIAN MONNIN: You had knowledge that the federal government was imposing --

MR. JAMES MCCALLUM: Of course.

MR. CHRISTIAN MONNIN: -- which would apply to all provinces, unless a province has opted out and did their own; correct?

MR. JAMES MCCALLUM: That's my understanding.

MR. CHRISTIAN MONNIN: So there was a knowledge of a carbon tax of one (1) form, shape, or another at the time; correct?

MR. JAMES MCCALLUM: I would say that's correct.

MR. CHRISTIAN MONNIN: So is it safe to say that that didn't factor into Manitoba Hydro's analyses while preparing this application?

MR. JAMES MCCALLUM: I wouldn't -- yeah, I would agree with that directionally.

MR. CHRISTIAN MONNIN: And is it safe to say that in the same vein that Hydro has not attempted to identify the trade-offs between the impact of the rate increases on its financial health -- health on the one (1) hand, and that of the province and the ratepayers on the other hand in preparing its application.

Is that safe to say?

MR. JAMES MCCALLUM: Sorry, can you repeat your question?

MR. CHRISTIAN MONNIN: Sure. In the same vein, is it fair to say that Manitoba Hydro has not attempted to identify the trade-offs between the impact of the rate increases on its financial health, on the one (1) hand, that of the province and the ratepayers on the other hand?

MR. JAMES MCCALLUM: Oh, I don't think I'd agree with that. I think we had a tremendous amount of discussion around the executive and board around impacts of the rate increases on -- on the economy. I think, ultimately, our job is to look after the health of the Utility and I think what we put forward here we've said is what we believe is the minimum required to do so.

MR. CHRISTIAN MONNIN: And in those deliberations was an in-depth analysis done on behalf of Manitoba Hydro on the impacts that these rate increases would have on the one (1) hand, and on the benefits -- or on the impacts to the province and the ratepayers on the other hand?

MR. JAMES MCCALLUM: In-depth analysis -- no, when we relied on the judgement and experience of the executive team and its Board of Directors who are collectively a group of fairly experienced individuals.

MR. CHRISTIAN MONNIN: Mr. McCallum, members of the panel, members of the Board. Thank you. Those are my questions.

THE CHAIRPERSON: Thank you. We will break until 11:00. Ms. Ramage and Mr. Haight, I want to talk to the Panel about the issue of the motion. So we may revisit it immediately after we come back or we may wait till later. But they haven't had an opportunity to even know that there is a proposed motion, so. Okay. Thank you.

--- Upon recessing at 10:43 a.m.
--- Upon resuming at 11:05 a.m.

THE CHAIRPERSON: Okay, we're going to start. I guess -- our understanding is this matter relates to one (1) of our IACs. Mr. Haight's here, I'm just wondering, Ms. Ramage, if where to start would be for Mr. Haight to give us a background and then Manitoba Hydro could put forward your position.

MS. PATTI RAMAGE: That would make sense, it's Mr. Haight's request so.

MOTION BY MR. BILL HAIGHT:

MR. BILL HAIGHT: Thank you, Mr. Chair, I am here today just to speak to the issue of the deadline for MGF. One (1) of the IEC's that has been retained to give expert opinion evidence in this proceeding. To extend its deadline for provision of its IRs by two (2) days from January 3rd to January 5.

There are a couple things that I -- I want to advise of and -- and one (1) of them, in particular, is -- is the timing of this request and the request -- the timing of it being made at this juncture.

The -- when the schedule was announced and the IR deadlines were posted on the schedule, MGF immediately made known to me its concerns that there was a deadline for them to be provided with the IRs is this Friday, December 22nd, and that their IR responses are to be provided by January 3rd.

They made me know that their concern was -- was this: It was that MGF closes their office for Christmas; has done so for the last twenty (20) years, and the three (3) principals that are with the preparation of this report all, prior to the schedule being announced, had made plans to be out of town, and some out of the country.

And so when the made this known to me, we were also -- they were heavily involved in preparing their report which is significant and substantial as -- as I think everybody knows, it was actually just posted today, this morning, on PUB's website, having been with Manitoba Hydro and other -- Manitoba Hydro and PUB since Friday, December 8th for the purposes of redaction.

My advise to MGF at that time was, you know, work on the report. Get that report in. Once the parties can see its scope, its breath then perhaps there -- you'll be in a better position to ask for this brief extension. Some good can be engendered by providing that report, getting it in, so that the IRs can be dealt with. My thinking that it wouldn't be a significant ask for me to then appear and speak with Hydro, speak with your counsel about this short extension.

So the difficulty is -- is -- is that despite efforts by both Manitoba Hydro's counsel and I to try and work at some form of compromise that we could come to you with today, that has not been possible. We have not been able to agree on this extension.

I have sent around over the weekend a request to have the time extended to January 5. I have received responses from counsel for MIPUG, counsel for the Coalition that they are not opposed to -- to this request. It does but Hydro in a difficult spot and I'll let Ms. Ramage speak to that.

But, some of the things that were discussed is, all right, you've had the report since December 8th going through the redaction process, do you have IRs to identify -- that have come to light as a result of the redaction process; if you do, give them to us, we'll start working on them right now. And so that, therefore, the amount of IRs that would come in on the 5th would be significantly less and -- and that -- that efforts could be made by MGF to try and provide IR responses right away, this week.

Unfortunately, I'm told that that's not possible and -- and MGF remains prepared to do whatever it can this week to try to deal with that. These plans were made before the schedule was announced. They're plans that had been in place -- the travel plans of the principals and the closing of the office.

And so what I'm proposing is -- is that the deadline for MGF's response has been moved to the 5th; that we could provide Hydro with some more time to provide its IRs if -- and we could bump the 22nd to the 29th, and that would accommodate Hydro in some fashion in terms of providing it with some extra time in order to get the IRs to MGF.

And then, as you know, there is the

issue of the redactions to the IRs that have to be dealt with; that was to be dealt with on the 5th. I had proposed that we move that to the 9th and then provide Hydro effectively with that weekend to deal with Irs. I know that there is the week of the 8th to the 12th is going to be a busy week with Daymark appearing on that -- at that time in order to talk about load forecasts and export forecasts.

But, it is a very short time frame that we're seeking and there is a very reasonable explanation for the -- not only the request but the timing of the request and I would respectfully ask that Daymark might be accommodated and that Hydro be accommodated as well in order to get the process fully and completely before this -- the panel.

THE CHAIRPERSON: Mr. Haight, I'm just looking at the schedule. I'm trying to figure out, your proposal for Hydro would be to move the response from when to when?

MR. BILL HAIGHT: So firstly to move the -- the IRs that are to be provided by all parties, including Hydro from the 22nd to the 29th; that would accommodate not only Hydro, but all -- all Intervenors and -- but, as I've said, MIPUG and the Coalition have advised that they have -- do not have a concern or they're not opposed to the request that's being made by MGF. This is just my suggestion as to how all parties might be less inconvenienced by the request.

Then to move the IR responses for -- of MGF and Daymark on the Sask Power, we don't need to move Daymark's but to move the IR responses cleared for the public by Manitoba Hydro from January 5 to January 9.

Subject to any questions that any members may have, that's my submission.

THE CHAIRPERSON: Any questions from the Panel?

Ms. Ramage...?

SUBMISSIONS BY MS. PATTI RAMAGE:

MS. PATTI RAMAGE: Yes, Mr. Chairman, the basis for this request is MGF's offices closing for the holidays. We've heard from Mr. Haight that's been a practice of that firm for many, many years and it was known to them. It was known to them last summer. It was known to them in October when the schedule was developed. It was known to them when the schedule was issued. It was known to them in November when they asked for a second extension. It was known to them when -- in that second extension there was two

(2) options. One was just give it to Stanley (phonetic) or give it to both of us.

THE CHAIRPERSON: I'm sorry, just give it? I missed the word.

MS. PATTI RAMAGE: Stanley Consulting; their subconsultant.

THE CHAIRPERSON: Yes, okay.

MS. PATTI RAMAGE: That they were having issues with. It was known to them when they -- when they said, the Board has two (2) options, one, just give it to Stanley or give it to both of us. But they preferred that it be given to both of us.

And never during any of those -- that series of events was it raised that the schedule that was on the board had IRs due between December 19th and -- because December 19th was the October date, December 19th and January 3rd.

So, we went through that entire period, granted a number of ext -- this Board granted a number of extensions and that was never raised.

Manitoba Hydro, we simply don't understand why it's only being raised, the logic of that. But if I could deal with the request in two (2) parts:

First, there -- there was a discussion

regarding or a request that Manitoba Hydro -- that Manitoba Hydro file its Information Requests earlier this week. So of a as-it-goes type Information Request process. This isn't it possible. The report has been received one (1) week later than first expected. And Manitoba Hydro of -- that was on Friday, December 8th. We worked diligent -- diligently for the following week to get -- to extract the CSI from it and get it filed. And we filed it at Board counsel's request one (1) day earlier than the Board had asked.

The focus now shifts for our staff from that CSI review, which is a very important process, how they shift Information Requests and we are expecting there's going to be a high volume of IRs coming out of this report. It is lengthy. It covers four (4) major capital projects. And it contains a number of errors that Manitoba Hydro had attempted to address directly with MGF during that C -- as part of that CSI review process but MGF did not make those changes.

We don't know if the reason MGF did not make those changes was because it didn't have time or because it disagrees with Manitoba Hydro, but they're significant and we need to be able to focus our time on the Information Request process in order to address that.

Frankly, the report that -- the concerns we have, ultimately, would support our rate increase but that's not how to proceed with this. We have to get the best information in front of this Board so we need to address those concerns.

The project groups are already working under an extremely compressed timeline to develop their Information Requests and the Panel should understand that by necessity part of the process at Manitoba Hydro shop is that we have to review the report and those requests with our First Nation partners. The process can't be fast tracked. This is a two hundred and fifty-eight (258) page report, and it's a complex subject matter.

The October 5th schedule that we were all working with gave us eleven (11) days to file IRs. That was tight. And as a result of the extension granted to MGF in November, we were cut back to eight (8) days; that's razor thin.

Now, MGF -- or Mr. -- Mr. Haight has suggested that we bump the date from the 22nd to 29th. I want to be clear, Manitoba Hydro hasn't asked for that extension. It has planned all of its processes and all of its work for the 22nd date. We are dealing with people on the major projects here and they have significant responsibilities for those major projects. They can't, at a drop of a hat, re-organize all of their work processes.

We have a schedule and we have to stick to it. The projects are, by our own admission, still have risk, and we need our people's eye on the ball and they need to be able to count on schedules and they need to be able to plan accordingly.

I want to point out that also the request is for two (2) additional dates: January 3rd to January 5th. And that may not sound like a lot but there's two (2) issues at play here: First, following the November extension the deadline for Manitoba Hydro's rebuttal -- and I'm not sure why because it didn't -- was a part of their extension -- was cut by three (3) days. So we went from January 15th to January 12th; twelve (12) days to nine (9) days. Nine (9) days barely allows Manitoba Hydro enough time to file its rebuttal evidence by the revised deadline.

The entire schedule was already condensed to allow MGF to file its report late, and that greatly impacted Manitoba Hydro's ability to react and respond thoroughly, but we've adjusted all of our timelines to do that.

Now, following that November 28th request, Manitoba -- I want to be clear on this, Manitoba Hydro, in the juggle of days, lost eight (8) days of preparatory time for its IRs and for its rebuttal. MGF lost three (3).

And as it stands, staff are going to be working simultaneously on rebuttal, on drafting its presentation for direct, which comes to the Board on January 18th, and preparing for cross-examination, and all the while monitoring what's going on in this hearing, because there has been crossovers, as we've seen this morning. Now, some of those same staff are also working on redacting the Daymark report that's related to the Manitoba-Saskatchewan transmission line, so they have that added task.

So the suggestion that we move from January 5th to 9th, which is the first we've heard of that suggestion, but I can say right off the top of my head doesn't work, because our staff are already double-booked there with Daymark, and they can't do that next task.

So to take away any days from our ability to respond is extremely concerning. We have to present our direct on January 18th. The notion that we move our rebuttal to -- I'm seeing what the proposal is -- yeah. There is no change in the rebuttal, so that we would do our rebuttal, and then three (3) days later be testifying, it -- it's simply not possible. This is a topic on which Manitoba Hydro is seeing this just now, and our rebuttal is going to be our capital presentation, and there's going to be a lot of material to cover, and -- and it's just not possible.

And the other concern I have is, in terms of all of the changes that have been made to date, as I've said, it has impacted Hydro and we have responded, but in our view, the ability to use Manitoba Hydro staff that as the release valve has been completely exhausted now. The timelines are too tight. We can't get to it.

We -- the second concern, anyways, I had with the -- the January 2nd -- 3rd to 5th change is that we were told that the main principals will be away December 22nd to January 3rd, and our view is it's high -- we've been through this IR process many times, and we know based on the reports that there is going to be some substantial IRs coming, and it's highly unlikely that MGF would be able to complete its answers in such a short period of time. They're effectively saying they can turn around IRs in two (2) days.

So we are already anticipating a further request by MGF in the new year for a further delay, and that puts the entire hearing schedule at risk. So by changing anything right now, we have to keep our powder dry. We can't extend now for holidays knowing that there is a high risk of -- yet another risk -- another request coming down the pipe.

I -- Mr. Haight mentioned this morning that MIPUG and Coalition have not opposed this request. They have no skin in this game. This is about Hydro being able to respond to this report, and it's an important report, and there are gaps in the report that need to be addressed.

It -- it may be that MGF will agree with Manitoba Hydro, but it may be that they won't, and it's going to take time to deal with that. And to -- to use up that time now is unwise, because if our concerns manifest themself and they don't get it done by January 3rd, we're going to be looking at juggling the schedule.

And in that regard, we would simply ask now that we be consulted before making any of those kind of specific changes, because as I've indicated, Manitoba Hydro has planned all its activities around the current schedule, and we have a business to run, and our subject matter experts made commitments to other parties and to other work, and the huge proj -- these huge projects are ongoing, and we've got to be able to work with that schedule. We can't just flip these people around, or otherwise we're risking -- putting at risk what all of us want to protect.

We shouldn't be blindly changing the staff schedules at this point in order to accommodate what is -- I -- I was dumbfounded by this request on Saturday, that -- that -- and I think there's an obvious answer, and I think the obvious answer right now is we have to stick with the schedule we've all been working to.

And it's -- it's -- I don't want to be the Grinch and tell somebody that their Christmas is gone, but they were told back in October, and so for this to come in on Saturday morning to us was -- it's an understatement to say that we were surprised.

One moment.

(BRIEF PAUSE)

MS. PATTI RAMAGE: And I think maybe

to show the importance, Mr. McCallum wanted me to remind again that we just -- we're not in a position -- we -- we think there's going to be a lot of IRs. We think there's going to be a lot of material to address in rebuttal, and we just aren't in a position to shave that down any further.

And -- and I would repeat, we didn't ask for December 29th. We have work plans over the holidays, to be working on the rebuttal. We need to get the IRs done, get to our -- our next stage. There has to be some linear -- I -- I don't even know if it's a word, but we need to work in a linear fashion to be able to move this thing forward, and adding more and multiple layer of tasks is -- just doesn't work.

THE CHAIRPERSON: All right. Ms. Steinfeld...?

MS. DAYNA STEINFELD: Mr. Chair, can -- can we -- I would just ask that Ms. Ramage -- clarify and confirm her comments regarding the deadline for the Hydro rebuttal having changed at some point in this process.

It's my understanding that it was always scheduled to be filed for the rebuttal of Daymark, Sask Power and MGF on January 12th, so if we'd just ask her to check that and confirm. I'm looking now at the schedule that dated back to prior to the MGF request for an extension, so if that could be checked and confirmed for the purposes of the record.

It may also be helpful to clarify the timing between when Hydro first received the MGF report and the deadline of the responses. I think the calculation is being done by Ms. Ramage as between when the CSI redactions were completed, and when the IRs were due, but it may be helpful to put on the record the timing between when Hydro received the report in its unredacted form from MGF and the timing of the IR question deadline.

MS. PATTI RAMAGE: If you give me a moment, I can call that up right now.

THE CHAIRPERSON: Sure.

(BRIEF PAUSE)

MS. PATTI RAMAGE: Yes. With respect to the filing of Manitoba Hydro's rebuttal, I can confirm that, as indicated in the PUB's letter of October 5th, it indicated that Manitoba Hydro's rebuttal evidence on the MGF report would be filed on January 15th. That was changed, I believe, subject to check, on the November 28th report or letter from the Board, and that was changed to January 12th. So my comments stand on that aspect.

In terms of timing between CSI, again, I -- I don't think it's useful to do this on the mic, for me to check the dates. I will check them afterwards, but based on my review here, I don't have a reason to believe these dates are incorrect. What Ms. Steinfeld might be referring to is that we -- I referred to the date we have from the time we have CSI released to the time we have our IRs filed, and there may be a misconception that we start working on IRs when we get that report.

The task at hand is to get the CSI done, and while you may think of topics, IRs are not being developed. It's not -- it -- it's just not a process -- the process can't accommodate that. You -- you focus on the task at hand, get that done, and then you move to the next task of -- of answering IRs. But I will check, but I do believe the dates we've put on the record are correct.

THE CHAIRPERSON: Okay. Mr. Haight...?

REPLY MR. BILL HAIGHT:

MR. BILL HAIGHT: Thank you. A few brief comments in reply. You heard Ms. Ramage say that the report substantively supports Hydro's rate application, so I -- I wonder how something could be procedurally unfair when substantively, it's -- it's helping Hydro. So I -- I --

THE CHAIRPERSON: Well, here -- here's the -- sorry. Sorry to interrupt. Here's the problem.

MR. BILL HAIGHT: M-hm.

THE CHAIRPERSON: We haven't seen the report.

MR. BILL HAIGHT: M-hm.

THE CHAIRPERSON: We're not going to deal with the report. In terms of the substance, I -- I, you know, I -- I -- you made the comment -- as far as I'm concerned, I don't care. I'm -- we're dealing with the procedural motion, not with the substances, so I -- I think -- the substance of the report, you know, to talk about the substance of the report before we actually receive the report into evidence just -- just doesn't -- I don't think it's the appropriate way to deal with it.

So I -- I, you know, I -- I'm sorry to interrupt, but we -- we need to deal with the procedural issue and the dates, so.

MR. BILL HAIGHT: I -- I hear you, Mr. Chair, and -- and I only wanted to make that comment as well, because when you were -- when you are looking at the issue of procedural fairness, the fact that counsel to Manitoba Hydro indicated that on the record I think something that you want to --

THE CHAIRPERSON: Yes.

MR. BILL HAIGHT: -- keep in mind. And the other point is -- is Ms. Ramage spoke about beg -- you know, beg -- beginning to work on rebuttal, but you also said that their rebuttal is -- is essentially their capital project presentation. So Manitoba Hydro has known for some time -- if we want to talk about when people knew things -- Manitoba Hydro has known for a long time what its capital presentation is going to be. Of course, it has to fine-tune that, but it knows when it made the rate application.

And -- and it's had MGF's report since December 8th. So it's known, since it's reviewing that, and -- and the point is made that, Well, you're looking at CSI, and so therefore you have to -- if you just do that process, and then the next process, the substance of that report is clear, and when Manitoba

Hydro read -- reads that, and has been reading it since December 8th, it's known at that point in time what its rebuttal evidence is going to be. It's clear from the report.

So -- so to suggest and to confine timelines about the schedule of when CSI is done, when IRs are done, it really overlooks the fact that their capital presentation and their rebuttal are the same, and -- and that they have known for a long period of time what that case is that they have to meet, and that they've had the Daymark report since December 8th, so those are the only comments in -- in reply -- MGF, excuse me. Thank you.

THE CHAIRPERSON: Thank you. My understanding is that MIPUG's position is on the record on this issue. Is that correct?

MR. ANTOINE HACAULT: It -- it's not on the record in the sense of we haven't filed an exhibit, but I will put it on the record we did send an email confirming we're not opposed to this two (2) day extension. We can work with it, and I guess what I would encourage -- I see some discussion happening here while we might able to get with -- together with MGF and correct a lot of these things we might have to do through interrogatories.

We've always encouraged, as an Intervenor, open discussions and -- and trying to deal with things in a collegial way. I'm sure parties will try to do that, but there are ways to solve a two (2) day problem if people are talking to each other in answering IRs, and -- and -- and I'd ask the Board to consider and encourage the parties to continue to cooperate in these proceedings, as we have always tried to.

THE CHAIRPERSON: Ms. Dilay...?

MS. KATRINE DILAY: I can also confirm on behalf of the Coalition that we did not oppose the extension of time requested by MGF, and we would also echo MIPUG's comments on that.

THE CHAIRPERSON: Thank you. Mr. Monnin, I don't know if you want to take your position now, or file something in writing by the end of the day?

MR. CHRISTIAN MONNIN: You know, I'll -- I'll sit firmly on the fence on this one, Mr. Chair. I -- I am fine either way, whichever the Panel finds, we will -- we'll proceed, and that's about all I can say at this point, so.

THE CHAIRPERSON: Okay.

MS. PATTI RAMAGE: Mr. Chair, I should

correct something.

THE CHAIRPERSON: Go ahead --

MS. PATTI RAMAGE: I'm advised by --

THE CHAIRPERSON: -- Ms. Ramage.

MS. PATTI RAMAGE: -- Ms. Minier (phonetic) in the back row that I misspoke.

THE CHAIRPERSON: Okay.

MS. PATTI RAMAGE: In terms of Manitoba Hydro corrections. I said, "in CSI process." It has been an ongoing process in terms of those corrections, and Manitoba Hydro did not receive responses in terms of when it -- it -- when it submitted its response to MGF, because they provided...

(BRIEF PAUSE)

MS. PATTI RAMAGE: -- there was -- there was back-and-forth, but they -- those changes weren't incorporated and -- and I -- Manitoba Hydro can't respond to something it hasn't seen. So it's --

THE CHAIRPERSON: Yes.

MS. PATTI RAMAGE: -- it's nonsensical to suggest that we should respond before we can prepare our response to a report we haven't seen.

THE CHAIRPERSON: Yeah. Mr. Orle...?

MR. GEORGE ORLE: All that trouble for and take no position on the matter.

THE CHAIRPERSON: Thank you. As I understand it, counsel sent it to me and to all the Intervenors and gave me until the end of today. So we're -- the Board -- the Panel is not going to consider this until the time is elapsed in case any of the other Intervenors want to respond. And we will consider it in due course.

Mr. Hacault made the comment about the parties working together. Throughout this process we've tried to ensure all counsel knew what was going on. We've actually had a lot -- very good cooperation in terms of the schedule. This is a difficult matter to schedule. Our counsel spent an enormous amount of time and, quite frankly, this panel went through numerous schedules, so if there is an opportunity for counsel to try and come to some resolution of this they -- I guess they have today. Otherwise, the Panel will deal with this issue either at the end of today or sometime tomorrow and we will provide our decision to the parties.

Okay. On that note, I guess we are into the issue of the undertakings?

MS. PATTI RAMAGE: I have provided Mr. Simonsen with a number of undertakings. And does the Panel have them?

MR. KURT SIMONSEN: Not yet.

MS. PATTI RAMAGE: Okay.

(BRIEF PAUSE)

MS. PATTI RAMAGE: The first two (2) of the undertakings that are being distributed are Number 7 and Number 8. Mr. Simonsen had already assigned them Manitoba Hydro Exhibit 84 for Number 7, and Exhibit 85 for Number 8.

--- EXHIBIT NO. MH-84: Answer to Undertaking No. 7

--- EXHIBIT NO. MH-85: Answer to Undertaking No. 8

MS. PATTI RAMAGE: And I wanted to -- with respect to Number 7, the copy that was distributed electronically on which the paper copies provided have one (1) error in it that we wanted to correct. We will get a new electronic copy to Mr.

Simonsen, but rather than kill trees, on Undertaking Number 7, if you first look to the chart on the -- it's on page 3 of 5. We should delete the reference to gigawatt hours. The slash in gig -- the -- or the slash stays. Just "gigawatt hours" should come out. That's an incorrect reference.

And then similarly on page 4 that follows you'll see in the last two (2) columns of the right -- to the right, it should refer to not gigawatt hours but megawatt hours. And as I say, that correction will be made on the electronic copy, but we are hoping people could just do it by pen rather than reprinting all of these.

(BRIEF PAUSE)

MS. PATTI RAMAGE: Okay. The next --

BOARD MEMBER KAPITANY: Ms. Ramage, can I just ask on that table, page 4 of 5, is it all three (3) columns that we're meant to change gigawatt hours to megawatt hours, or just the second last column?

MS. PATTI RAMAGE: It was the two (2) last columns, net cost -- net cost, it's mega -- it said "gigawatt hour." It should be megawatt hours.

And net cost, megawatt hours year over year increase should change.

BOARD MEMBER KAPITANY: Okay. So the domestic load remains in gigawatt hours?

MS. PATTI RAMAGE: Yes, it does. Too many papers at once here. So the --

BOARD MEMBER KAPITANY: And then page 5 of 5 as well? Sorry.

MS. PATTI RAMAGE: Yes.

BOARD MEMBER KAPITANY: Okay. Thank you.

MS. PATTI RAMAGE: The next undertaking that we've provided is Manitoba Hydro Underna -- Undertaking Number 12. And that was producing the IFF runs that assume zero payments to government. That was provided to MKO at transcript page 1987. And that should now be given Manitoba Hydro 86.

Is that correct, Mr. Simonsen?

MR. KURT SIMONSEN: That's correct.

--- EXHIBIT NO. MH-86: Answer to Undertaking No. 12.

MS. PATTI RAMAGE: And then lastly we

have a revised IR. This is an IR that Mr. Miles was asked about by both the Coalition and PUB counsel. It's a revision to PUB/Manitoba Hydro 1st Round 131(b)(c), and that was -- actually it was in the IR itself, indicated that we would update values when they became available. And they are available. We have updated them.

Now, in this IR I should also explain that on page 3 of that IR, there is -- redactions have been made. Those redactions are exactly the same as in the original response with the same redaction code. So it's -- it's just an update to that information. So we will -- the CSI version will be with the Board and this is the public version.

MR. KURT SIMONSEN: Do you want that as an exhibit? That'll just be a -- a bolt on to the existing IR?

MS. PATTI RAMAGE: I think that's all we have to do with that one (1).

MR. KURT SIMONSEN: Thank you.

MS. PATTI RAMAGE: Mark it as revised.

(BRIEF PAUSE)

MS. PATTI RAMAGE: One (1) other point.

Undertaking 8. It's --

THE CHAIRPERSON: Sorry, which one (1), Ms. Ramage?

MS. PATTI RAMAGE: Undertaking 8. Oh, no, I'm sorry. It's Undertaking 7 is -- it's just the double-side of both pages.

THE CHAIRPERSON: Okay. Good. Thank you.

MS. PATTI RAMAGE: There is no further change.

(BRIEF PAUSE)

THE CHAIRPERSON: Mr. -- sorry. Ms. Ramage, are you done? What --

(BRIEF PAUSE)

MS. PATTI RAMAGE: Just to be clear, because I'm not sure I addressed it, I thought -- is in Undertaking 8, the second page also has a graph with gigawatt hours that should be crossed out. The 7 and 8.

THE CHAIRPERSON: Okay. That's the one (1) in the heading? Got it. Okay.

MS. PATTI RAMAGE: Correct.

THE CHAIRPERSON: That's it?

MS. PATTI RAMAGE: Yes, it is.

THE CHAIRPERSON: Mr. Hacault...?

MR. ANTOINE HACAULT: Thank you, Mr. Chairman. Manitoba Industrial Power Users Group thanks Manitoba Hydro for having put this information together. As you will note in -- in the response to Undertaking Number 7, provided last night, most of the references are to materials which are not on the record.

And some of the information unfortunately isn't necessarily readily available on, I'm going to say, the electronic record. Some of the references to evidence which supports this graph dates back to applications and General Rate Applications which were only done in a paper format. So I think we're actively trying to pull some of those from InterGroup's archives.

And in the circumstances I'm unable to advise whether or not we have any questions. We'll do our best to deal with it as soon as we can and advise the Board as soon as we can. But as I said, unfortunately, this graph and information was not largely based on the current records. So we didn't have a chance to ask IRs on it. And we've got to dig out some material to determine whether or not we would need to do that.

THE CHAIRPERSON: Okay.

MS. PATTI RAMAGE: Mr. Chair --

THE CHAIRPERSON: Sorry.

MS. PATTI RAMAGE: -- Mr. Hacault is correct --

THE CHAIRPERSON: Okay.

MS. PATTI RAMAGE: -- that it was not based on IRs, but it was in response to --

THE CHAIRPERSON: Right.

MS. PATTI RAMAGE: -- MIPUG's evidence. Therefore, there wouldn't have been an IR process for that, but...

THE CHAIRPERSON: Mr. Hacault, do you have any --

MS. PATTI RAMAGE: We will attempt to assist --

THE CHAIRPERSON: I'm sorry, Ms. Ramage?

MS. PATTI RAMAGE: I -- I said we can assist MIPUG as required.

THE CHAIRPERSON: Yeah. Do you have any idea what sort of time frame we're talking about?

We're talking this week or are we talking after Christmas?

MR. ANTOINE HACAULT: I would expect this week. To the extent we don't have ready access to the archives, Ms. Ramage has kindly indicated that she'll assist. So we'll do our best to advise this week whether we have any questions.

THE CHAIRPERSON: And if you -- right. And if you could, if you do have questions, if you could determine which witnesses on this panel you would need to ask questions, so that we don't have to bring back everybody if they're not needed.

MR. ANTOINE HACAULT: Yes, Mr. Chairman, we will do that. And prior to the previous questioning, we had an exchange with Ms. Ramage as to which people we needed on the panel. And I am grateful for the good cooperation we've received in making those people available. And I'm sure that'll continue.

THE CHAIRPERSON: Thank you. We have -- sure, go ahead.

VICE-CHAIRPERSON KAPITANY: Ms. Ramage, can you just clarify now, on this graph page 3 of 5, what is the units on the y-axis, the y-axis of the graph? What are the units?

(BRIEF PAUSE)

MS. LIZ CARRIERE: It's -- it's an index of net costs.

VICE-CHAIRPERSON KAPITANY: Thank you.

MS. LIZ CARRIERE: And revenue, sorry.

(BRIEF PAUSE)

MR. JAMES MCCALLUM: Sorry. Madam Vice Chair, if, if it's helpful the graph is an indexed graph trying to show the relationship and the changing relationship between net unit costs and -- and customer rates taken from the 2000 starting point through to 2017, and then -- and then going forward. And so it's indexed to one hundred (100) as to say at that point how have they changed relative to each other since then.

MS. LIZ CARRIERE: Thank you. Sorry I missed the nineteen (19) -- ninety-nine (99,000) equals a hundred. Thank you.

THE CHAIRPERSON: Okay. I believe the -- the remaining piece prior to re-examination, Ms. Ramage, would be the -- the issue that was raised before about the presentation on the decision-making process for the business operations capital budget. And I had spoken to -- to Board counsel and asked him to prepare questions if there are follow-up. I'm just -- I don't expect it's going to take very long.

I'm -- I'm thinking that what we should do is break for lunch now, and then we can do that right after lunch and then finish with your -- with your re-examination. And I think that probably will conclude the matters before this panel, subject to the -- you know, to Mr. Hacault's possible questions of this panel later on. Okay.

MS. PATTI RAMAGE: Yeah, that sounds fine.

THE CHAIRPERSON: Okay. So we'll break for -- we'll -- we'll break till one o'clock. Thank you.

--- Upon recessing at 11:50 a.m.

--- Upon resuming at 1:05 p.m.

THE CHAIRPERSON: Ms. Ramage...? Did you want to put that on the record?

MS. PATTI RAMAGE: Yes. This undertaking is Manitoba Hydro's -- took this undertaking under advisement and that was with respect to getting permission, and providing details and analysis to support a request for an equity injection and as indicated in the response to the undertaking, Manitoba Hydro respectfully declines to provide the information.

In discussions with Mr. Peters he requested Manitoba Hydro put its position in writing. So we have provided our position in the response to the undertaking and as you will note and we can address it in further detail, if required, and if parties take issue but Manitoba Hydro has declined on the basis of relevance and on the basis of public interest privilege.

And if I could comment under the relevance because, Mr. Chair, you made this comment on Friday with respect to a similar topic. We include in our comments regarding relevance the concept of making recommendations on matters which are not strictly within the PUB's mandate and we address that issue in this indicating that these types of recommendations have arose out of evidence produced in the context of the normal review of rates and we think that is quite different from embarking down a path of inquiry for the sole purpose of making a recommendation on matters that are beyond this Board's mandate.

So, I will file that and await further directions, if any, on how we'll deal with that.

THE CHAIRPERSON: Okay, thank you.

MS. PATTI RAMAGE: And if I didn't say it, I think it's Exhibit 87.

THE CHAIRPERSON: Exhibit 87, yes, I was just going to say that. Okay. Exhibit 87.

--- EXHIBIT NO. MH-87: Manitoba Hydro's written response to undertaking given under advisement.

THE CHAIRPERSON: I guess the next matter was the issue of your presentation or Hydro's presentation on this issue of the decision-making for the business operations capital budget, and we have had evidence before about the way it was done for distribution, transmission and generation, and whether there are priorities set on -- on a corporate basis.

There was a suggestion, I guess there's testimony, that it wasn't done on a corporate basis, it was done with the different groupings and I had asked if you could explain to us what the decision-making process is, and I believe Mr. Wortley had said that there's -- there's a view of moving -- and I guess it was a three (3) to five (5) year period toward something on more of a corporate basis.

And I'd just be interested in knowing how you decide how to budget for it when you may be in a position not to have enough money for the requests of -- of all of your divisions which, quite frankly, has always been my experience.

So if somebody wants to go through that.

MS. PATTI RAMAGE: Yes and Mr. Wortley and Ms. Bauerlein have prepared some brief comments for the Board.

THE CHAIRPERSON: Thank you.

MS. SANDY BAUERLEIN: Good afternoon. I thought if we could just bring up IR -- it's PUB-MH-1-64(b). It actually has a schematic diagram of sort of how the current process works today and how we set targets and allocate our targets to each of the different groups. So, if we could bring that up I'd thought then I would just -- we'd walk through that, Mr. Wortley and myself, and talk a little bit about where we're at today and -- and where we see ourselves going in the future.

So, it kind of starts on the far left

side. So, you'll see there's a box that talks about executive committee establishes business operations capital targets. So, again, we're not a new company so those are really the targets -- each CEF you're taking a look at what was approved in that - in the prior CEF.

And so when looking at that early in the development of the capital expenditure forecast the -- the four (4) vice-presidents responsible for generation, transmission, distribution assets, as well as assets such as like our buildings and IT meet with finance and -- and now it would be Mr. McCallum and we discuss some sort of what has changed or what might be different in terms of what was approved previously.

So if I kind of give an example, back in 2012/'13 the overall target for business operations capital was around 430 million. In 2016/'17, it's 530 million. And in that five (5) year window there's been a lot of discussions at the vice-president level talking about -- we have a capacity -- there's been a problem in some capacity in certain geographic areas of the province, which I think we've talked about throughout this hearing or at times in this hearing.

So, these were sort of raised by both the vice-president of transmission and the vice-president of distribution at the time. So, you know, there was evidence pointing towards we had some issues along areas like Lake Winnipeg East in the southern Steinbach area. Within the City of Winnipeg we have some substation issues.

And so while it's not a sort of precise calculation, it's looking at, here is some of the issues here is what we think it's going to cost, here's some of the resource constraints, you know, we have financial constraints from the perspective of we typically in the past have looked towards the capital coverage ratio as an indicator of, you know, whether or not that was a reasonable ability for us to -- to spend, and we looked at, you know, people availability, as well as availability of -- of perhaps contracting out that work.

So while it wasn't anything exact, it did help us establish sort of the allocation for what that pot of money should look like and you can see that over the five (5) years we have increased that allocation.

It's important to note when we do this, though, we kind of look a lot -- and I think Mr. Wortley has talked about this and -- and perhaps can elaborate a little further, is we do look a lot at the short -- the -- the next couple years, next one (1) to three (3) year timeframe.

Really, the targets beyond that are right now currently sort of set just based on historical spend and anything that we might sort of know of in the future. But again, they're -- they're fairly preliminary and as those years become closer, we refine them.

So in each year even when we look at the allocation of the target to each of the areas, again, we're looking at where the specific requirements are. So, for example, if you compare the capital expenditure forecast from CEF15 to CEF16, you'll see again that there was a -- based on a review of where some of the risks were and the requirements, there was a -- a reallocation of -- of actually a change in the overall target, as well as a reallocation of that target funds from the generation portfolio to, you know, some in the transmission and distribution portfolio is based on -- on the understanding of the risk and the needs and the requirements.

So that's sort of at the highest level how the targets are established and it's an iterative process. Those targets are then finalized by approval of the capital expenditure forecast by executive committee as the sort of input into the integrated financial forecast, and then they are also now finalized by the MHEB capital -- capital committee, so it's a subcommittee of the Manitoba Hydro Electric Board.

So I'll let Mr. Wortley add to that a little bit in terms of where we now take the target and how we, you know, prioritize the investments within those targets.

MR. JOEL WORTLEY: So the first thing it's really important to understand that all -- albeit it's one (1) supply chain and one (1) company, the -- the role of generation versus transmission versus distribution, there's -- it's very different.

And so if we think about that first when you're planning your investments, the first thing to come off the table are the really big things. You're going to make sure that you've got the security of your dams locked down because a cascading failure of, say, the lower Nelson River is just completely unacceptable. So when you're talking about planning investments, those things have already been taking care of, and you've also secured the things that would say -- insure you against a -- a provincewide blackout because that's -- that's not acceptable either. When you're getting into really the -- the marginal planning in terms of optimization, you're into the marginal risks and the marginal benefits.

And the marginal risks and benefits are very different from generation to transmission to distribution. Because in generation any excess energy is sold on the export market. It's simply a revenue question. If you decide not to invest in a generating unit and it comes off-line, you lose the revenue that you have gotten by exporting that energy on the export market.

In transmission, it's a question of bulk grid reliability and revenue to a certain extent if you're dealing with a -- a tie-line or an export line. And so, as you decide whether to invest or not, again, the premise being that your big risks and your -- your customer connections, your capacity issues have come first, you're into that -- that marginal area of: Can I afford to be without this particular element from a reliability perspective? And if you -- if you've -- if you've done your job well you won't -- the difference is hard to see. If you've done your job poorly, you have big problems with rolling blackouts or brownouts, and grid reliability issues.

And so in generations its revenue; in transmission it's reliability; and distribution, it's direct impact to the customer in terms of outage and -- and not having the energy when they want it.

And so when you -- when you line those three (3) things up, and you say what -- what's the level of risk tolerance that I should apply across the board with these things, they're very difficult to compare to each other. You can't say that this much reliability is worth that much outage time for -- from a customer they're different units.

And so what happens in our current practice is that each of those groups is responsible for planning their capital such that they reduce those risks, the risk to their particular portion of the business to an acceptable level.

As we go forward and what we're doing is we're moving from that individual portfolio perspective to a common basis evaluation for the Company. And what that means is we've developed something called the corporate value framework. And the corporate value framework works in five (5) categories to use twenty-eight (28) different value measures to assess how much risk am I buying down or how much benefit am I achieving from this particular investment.

And it will give you a score on a common basis, a common denominator, whether it's in generation, transmission or distribution such that you've got a -- a means of comparing them to each other.

The ele -- elements of common risk: environment, safety, corporate citizenship are all done on a -- on a common consequence scale, but the -- the revenue -- well, revenue is revenue it's easy, it's dollars, but the -- the reliability and the customer reliability need to be levelled against the other, each other.

And so we've done that in this corporate value framework, and -- and it -- it brings that leveling of risks and benefits such that you do get a common denominator evaluation of all your investments, which is cal -- you can calibrate it. You can change it such that if you -- if you're finding that the output is not supporting your corporate objectives, it can be re-leveled and -- and you can carry on.

On the basis of that corporate value framework, we are in the process of and -- and the three (3) to five (5) year time frame was mentioned, the corporate value framework exists today. It's being piloted. It's been rolled out. We will be using it in the next little while to optimize each of our investment portfolios. So you'll have an optimized portfolio in generation, an optimized portfolio in transmission, and an optimized portfolio in distribution.

You can then take that and compare them to each other because they're on -- they're on a common point system to say, well, the last dollar that went into generation bought his many points and the last dollar that went into distribution bought that many points. Maybe, you know, if they're not the same, if they're out of whack, would give you the opportunity to -- to -- to adjust.

And that's exactly what we're working on. That's our -- our objective of optimizing or executing portfolios and would be the information that we would use to adjust targets as we go forward.

The other piece of information is the longer-term outlook and so the same tools and the same monitoring of asset condition, forecasting, and degradation, and therefore forecasting of end-of-life of assets will be used to say, well, how much money are we going to need longer-term to keep the assets functioning, to keep the system safe and reliable and to make sure that we don't get into a situation where we're -- we're suddenly surprised or overwhelmed by a -- a bulge in asset replacements.

And so that -- that -- that is not an easy thing to do. Forecasting anything is fraught with uncertainty. Forecasting then an asset is going to expire and what you might think you might want to do about it when it does expire, cause you may not be a straight replacement, you might want to intervene some other way, whether it's life extension, or some operating mitigation. Trying to understand what it might cost you in ten (10) years to -- to deal with that asset has a lot of uncertainty in it.

And so, we want to make sure as we approach that that we're not burying a lot of time and expense in forecasting -- you know, trying to fine-tune a forecast number that doesn't really change anything. It's got to be meaningful and so that -- those are steps ahead of us to see how -- how good are these forecasts; do they drive decisions; and then if they do, it's worth it. If -- if they don't well that's a lot of engineering and a lot of -- a lot of time spent producing forecasts that isn't worthwhile.

THE CHAIRPERSON: Mr. Wortley, when

you -- you moved to this system where you're going to be, sort of establishing common measurements, how to you actually test against it? What do you do, for example, let's say you've moved -- you're now using this -- this new system and you're at the end of year one, how are you testing whether you're actually achieving the kind of results you were hoping for versus just, you know, creating a more complicated system that's difficult to evaluate?

MR. JOEL WORTLEY: So the -- the testing of the output comes in a number of different forms; mostly to do with release, running scenarios, sensitivity analyses, looking at, if I -- say if I -- if I subtract 10 percent of my capital what -- what happens if I add 10 percent more. Do I actually get more value?

And so there's that portfolio level of questioning my output but then within a project there's a -- there's another level of questioning or testing that goes on, which is that, if are you using the system to its full capability instead of having one (1) project, one (1) solution in the system, you've got one (1) project with three (3) or four (4) different options that you're considering for that particular issue.

And so when you run the optimizer you're allowing the computer to look at -- the computer understands how the asset is going to degrade over time. It understands -- you've told it potentially that your costs may go up, your costs to -- to mitigate may go up over time as degradation carries on it. It -- it understands the difference between you're A, B and C options and -- and will allow trade-offs.

And so if it chooses, say, option B you've got the opportunity to look at that and say, hmm, it chose B over A, which had a cost difference of whatever it happens to be, Does -- does that make sense? Does that make sense from a risk tolerance perspectives? Does that make sense from a value perspective? Did I get enough value? Did I feel like I -- I got what I paid for.

And so you can see it at the project level. You can see it at the portfolio level. You can -- you can run scenarios and -- and test the output to say: Does this risk -- level of risk tolerance that's coming out here, does the place where the dollars are being programmed make sense.

And fundamentally that's the test you've got to come back to. Because at the end of the day, generation knows its business and knows where -- where the revenue is at stake. Transmission knows where reliability is at risk and distribution knows where the customers are at risk.

And if we got something out in a black box type scenario that didn't make any sense at all, then we're definitely doing it wrong and that's not the case at all. It's -- it's not black box. It's very transparent. You can see this mon -- this money buys down these risks. So you've got the opportunity to -- to question. You don't have to accept what comes out. It is just a decision support tool, not a decision tool.

THE CHAIRPERSON: Do you have any questions. Mr. Peters...?

RE-CROSS-EXAMINATION BY MR. BOB PETERS:

MR. BOB PETERS: Yes, thank you. I would like to follow-up on -- on just a couple of areas if I could, Mr. Chair, and Mr. Wortley, and Ms. Bauerlein.

Would it be correct that the capital budgets are not currently based on the quantified and objective processes that Manitoba Hydro intends to use after phase 3 of its capital asset management program is implemented?

MR. JOEL WORTLEY: You've almost got it right there in that the -- the -- phase 3 is not -- not directly related to the capital asset management practices or, sorry, the capital planning practices that we're implanting.

The plans to deploy our capital asset planning tools are already in motion. They're not waiting for phase 3. Phase 3 of our corporate asset management framework is the larger endeavour about aligning the Company's activities. The capital planning processes and tools are being deployed currently and by the end of this year they'll all be in place and what needs to happen before the -- the three (3) to five (5) year timeframe comes from building the data sets, getting good at the processes and challenging the -- the outputs such that we get to a place where we are confident that we're -- that we're getting what we need out of these systems.

MR. BOB PETERS: Mr. Wortley, does that suggest to the Panel that the phase 3 is going to take place sometime after the next three (3) to five (5) years that you've spoken about?

MR. JOEL WORTLEY: Not necessarily. These things -- it's -- it's a journey and it's a journey that happens in different phases, and it happens very broadly across the organization. And so the challenge is to foster the changes you want to see in a coordinated and efficient fashion without overloading areas. If you -- if you try to move too quickly, undoubtedly people check out.

So no, phase 3 does not have to wait for the completion of the capital planning tools. It will happen when the Company's ready.

MR. BOB PETERS: And you're not able to put time estimate on when the Company will be ready for that?

MR. JOEL WORTLEY: I could estimate right now that it -- it -- we would likely start phase 3 towards the end of the coming year, but at this point that's uncertain.

MR. BOB PETERS: In the Manitoba Hydro rebuttal evidence which was Manitoba Hydro, I think it's, Exhibit 52, and specifically on page 49, which is on the monitors in front of us, at the end of the second paragraph there is a sentence that says:

"Past practice has been to assume that past renewal investment requirements are indicative of future mid and long-term renewal investment requirements."

Do you see that?

MR. JOEL WORTLEY: I do.

MR. BOB PETERS: Does that suggest that that is no longer the practice or is that still the practice as we sit here today?

MR. JOEL WORTLEY: With respect to CEF16, that is the practice. I'd say we are in transition. It will not be the future practice.

MR. BOB PETERS: So what you're telling the Board is that instead of using that -- the new science and the computer assistance that you just mentioned in a previous answer from your asset management techniques, for the two (2) test years that Hydro is -- has before this Board, Manitoba Hydro is relying on the trends, and assuming that things will be the same as they have been in the past?

MR. JOEL WORTLEY: Not quite. This sentence refers to mid- and long-term investment requirements. So, these are outside of the test years.

The test year investments are programed based on current issues, current condition of the assets and the need to ensure the safe, reliable operation of the system.

MR. BOB PETERS: All right. Well,
let's -- let's stay with that thought in terms of the test year and we may have to go back to -- well, let me ask the question and we'll see if we need the schematic back up again.

But, would the Board be correct in understanding, Mr. Wortley, that the current and the test years and the capital budgets that Manitoba Hydro has in those test years would -- would be coming down in front of the senior executives to the management?

MR. JOEL WORTLEY: They begin with the senior executive, yes. It's -- it's sort of a top-down/bottom-up meet-in-the-middle type process where the -- the needs identified in the operating areas are -- are brought up, and the -- the need for constraints and limiting spending are brought down from the upp -- executive of the Corporation with a bit of a negotiation in-between.

MR. BOB PETERS: All right. Maybe we could go back then just to show the Panel that Schematic. Thank you.

We see in the top left-hand area of the screen, and this is PUB first round interrogatory 64 (a) and (b) that the executive committee will establish the budget, the capital targets; correct?

MS. SANDY BAUERLEIN: As I said, those are really the establishment from, you know, prior CEF. Again, we're not starting at square 1. So that's really saying today if I was looking at CEF16, I would be starting with what had been approved in CEF15 for those years.

MR. BOB PETERS: But there can be adjustments to what was approved previously, and you've told the Board about that this afternoon; correct?

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: But I also see Mr. Wortley's point, I think, that the capital expenditure forecast inputs comes from the bottom-up is what I think I understood Mr. Wortley to say and then as well as from the top down.

Is that practically what happens, Mr. Wortley?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: So in that particular instance, the executives know how much was approved in the prior year, and they're getting feedback from the vice-presidents as to how much they want for the current year, and they're going to meet somewhere in the middle?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: I wonder if we could also go to, hopefully not forgotten, PUB Exhibit 42-4 of the fourth book of PUB counsel documents and I think we'll go to page 578. And I think we can look at the bottom of the page, the last paragraph. It's not highlighted, but it relates to a point that Ms. Bauerlein and Mr. Wortley that you just talked to the Chairman about, and I'm looking at the end of the paragraph, starting in the middle. I'll read it for the record.

> "On this basis approved capital targets are reviewed at the vice-president level to assess whether re-allocation of funds is required in order to balance operational priorities and optimize overall corporate value considering changes in business, financial and economic assumptions, as well as operational risk factors. Any proposed target adjustments are reviewed and approved by all impacted vice-presidents to balance operational priorities and risks."

Do you see that portion I read?

MR. JOEL WORTLEY: I do.

MR. BOB PETERS: Now, does that suggest that currently as amongst the vice-presidents, they will have to make trade-offs as between who gets how much based on how they assess the risks?

MR. JOEL WORTLEY: That's correct.

MR. BOB PETERS: And you've already indicated that different divisions and I'm thinking of the generation as a division, the transmission as a division, and the distribution as a division, they may have different measuring sticks as to what their risks are; correct?

MR. JOEL WORTLEY: Yes, they have different risks, that's right.

MR. BOB PETERS: They have different risks and they -- and therefore measure them differently as well.

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: And so if the vice-presidents are supposed to decide who gets how much of the capital budget, how meaningful can that be if -- if they are all using different risk definitions and assessments of risk?

MR. JOEL WORTLEY: This is the

challenge. And it -- and it's not an easy one to overcome. In this particular case with this practice. the vice-presidents are -- are the operating vice-presidents. They understand their operations and they understand where -- they define what is a tolerable level of risk to carry with respect to their operation. And so this -- look at the -- at the -- at their targets and the unfunded -- the work they can't fit into their targets is a look at what risks are there to my business at this level of funding.

And teaching in -- in the perspective of their own operating context: Is this tolerable or not? And if it's -- if they deem it to be intolerable, then it's up to them to bring that -- that perspective forward, make their case to the other vice-presidents to say -- to demonstrate that it's not tolerable.

MS. SANDY BAUERLEIN: Which is really what they've done over the last number of years with respect to some of the issues around some of the capacity constraints. So, they've been bringing those risk assessments forward for discussion.

MR. BOB PETERS: And, Ms. Bauerlein, what you're telling the Panel is that the capacity constraints -- do I assume that's mostly transmission?

MS. SANDY BAUERLEIN: And distribution, a lot of substations. So again, it's in certain geographic parts of -- of the province and -- and even parts of -- of the City of Winnipeg.

MR. BOB PETERS: So would it be accurate then to suggest that the -- the vice-presidents of transmission and distribution have to convince the vice-president of generation that their risks are of a higher priority than what perhaps the VP generation has on -- on that VP's risk register?

MR. JOEL WORTLEY: It's about a discussion for what's -- what's best for the Company, what's best for the customer.

MR. BOB PETERS: And is it correct then that under this corporate value framework that you're -- you're migrating to, Mr. Wortley, Manitoba Hydro's executive has not yet sat down and established corporate wide risk measures and acceptable levels?

MR. JOEL WORTLEY: The corporate value framework is -- embeds those risk tolerances, those risk levels in terms of how the consequences are rated. And so within the corporate value framework, there are fourteen (14) identified consequence categories, each with nine (9) levels of impact.

And so how you -- how you balance those

defines your risk tolerance. And so the corporate value framework, as it exists today, has been developed based on existing practice. So it's essentially a documentation of our current risk tolerance. It gives us the opportunity now, as we go forward, to change it. To say we want to take more risk in this area, or we see that we need to reduce our risk in this area and actually target those outcomes.

MR. BOB PETERS: And so you're telling the Panel that going forward you'll be making use of this corporate value framework by looking at each of those fourteen (14) risk areas and the nine (9) different risk levels for each of the operating units?

MR. JOEL WORTLEY: The corporate value framework is applied on an investment -- at an investment level. You can then use it to roll up aggregate, how much risk is -- what is the risk level under a particular consequent -- or sorry, under a particular category or how much risk am I buying down on a particular portfolio.

So it becomes the basis for communicating those -- those elements, as well as making decisions as to the acceptability.

MR. BOB PETERS: Just so the panel

understands that answer, Mr. Wortley, doesn't this corporate value framework mathematically give the information that still, then, has to be subjectively analyzed by -- by the vice-presidents?

MR. JOEL WORTLEY: Absolutely. You -- you'll never get to a place where you take the human factor, the -- the judgment out of the decision. The -- the corporate value framework provides a quantification for consideration by the decision-makers.

MR. BOB PETERS: And -- and -- so how long until that corporate value framework is fully populated by all of the units?

MR. JOEL WORTLEY: So the -- it's being -- it was rolled out this year to all operating groups, and they're starting to use it. It will take some time, which is why we've given this three (3) to five (5) year window for -- for getting fully up and running with -- with the tool, and that there are a number -- dozens and dozens of projects already existing in the system, and so to -- to score them all, and to score them all rel -- reliably and repeatably is going to take some time.

And so we want to work our way into it and make sure that we're getting solid -- solid data, solid, repeatable outcomes before we -- we -- walk before we run, in a sense. And so I would anticipate that all new projects in the coming year will be put through the -- the screening through the corporate value framework, or certainly most of them. And then in -- in time, the older projects that were not screened will be completed and -- and weeded out of the system such that you'll arrive at a place where all projects have a -- a common basis scoring.

MR. BOB PETERS: I don't want to go over matters that we've previously talked about, but an example that I believe was given by yourself to this Board was when Pointe du Bois was reevaluated, changing from one (1) Capital Expenditure Forecast to another, there was an economic decision made that the export revenues wouldn't be sufficient to justify proceeding on Pointe du Bois. Is that correct?

MR. JOEL WORTLEY: That is correct.

MR. BOB PETERS: Was that decision not to proceed on Pointe du Bois as a result of the corporate value framework, or was that as a result of -- of the vice presidents just looking at the economics of the project?

MR. JOEL WORTLEY: It was primarily the economics of the project, which obviously would be available without the corporate value framework. What the corporate value framework allows you to do is -- is to take that evaluation a step further and to say, Pointe du Bois is a hundred year old powerhouse with some safety issues associated to it. And so by deciding to -- if I have two (2) options, to continue operating in its current mode, I'm taking safety risks every day by having staff working in that environment, as well as foregoing the potential for additional revenue if I -- I re-power the units.

So we're re-powering the units, it may bring financial benefit, but it may also bring a safety benefit, and it may even bring an environmental benefit, depending on -- on your particular scenario. The corporate value framework allows you to consider all of those things in one (1) scoring rather than simply the financial payback of that investment.

(BRIEF PAUSE)

MR. BOB PETERS: So, Mr. Wortley, when -- when Pointe du Bois was on the Capital Expenditure Forecast, some money had to be found from other divisions to support the increased spending on that generation station. Would that be correct?

(BRIEF PAUSE)

MR. JOEL WORTLEY: In -- in essence, anytime there's a spending in the program or in the -- in the CEF, it's -- you're committing dollars somewhere that you can't go somewhere else. So in that sense, yes, by committing money to Pointe du Bois, it's money that was not available to go somewhere else. The -- when Pointe du Bois was added to the forecast, I can't tell you if something was specifically displaced to make room for it.

MR. BOB PETERS: Mr. Chair, I was looking at page 568 of Board counsels' fourth book of documents just to orient myself back to the discussion that we had previously.

And -- and Mr. Wortley, let's not spend much time on this, but the comparison between the Capital Expenditure 15 and 16, we already saw that under the generation line items at the top of the page, that there was $140 million of savings found over the next ten (10) years, correct?

MR. JOEL WORTLEY: That's correct.

MR. BOB PETERS: And I think it's common ground that that savings is almost all attributable to the Pointe du Bois decisions to -- to not proceed with the -- I'm going to call it the powerhouse and the station to --

MR. JOEL WORTLEY: That's correct.

MR. BOB PETERS: -- to upgrade it. So now that that $140 million comes off, does that allow transmission and distribution increase budget to -- to fill the gap based on their needs as opposed to a corporate rebalancing of the risk?

MR. JOEL WORTLEY: So in this particular case, the needs at the time were to add some spending in transmission and on the distribution system to account for some capacity issues, but overall, not all the money was required, and so the target overall was reduced. And so you can see in the bottom row that over the ten (10) years, we see a fifteen (15) to sixteen (16), the total went down by $240 million.

MR. BOB PETERS: But Mr. Wortley, if we stay on the 2018 column, and we go down just past generation and wholesale, we'll see that transmission increased -- it looks like 7 million, and the marketing and customer, which we now understand to be distribution, has increased by about 8 million, correct?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: And so when generation has gone down, it looks like transmission and distribution have been increased to help fill that gap, and I'm wondering was that based on a risk assessment, or was that just based on there being available cash or capital?

MR. JOEL WORTLEY: The additional money in transmission and distribution, beginning in 2018, reflects the capacity demand due to regional load growth. So it's not a question of pushing money around. It's a question of funding the risks it needed.

MR. BOB PETERS: Mr. Wortley or Ms. Bauerlein, can you indicate to the panel how the executive team ensures that the decisions being made provide a net benefit to the ratepayer?

MR. JOEL WORTLEY: As we've discussed, I think quite a bit here, the -- it's about that balance of cost performance and risk that's going to deliver for the customer. It's the customer, ultimately, who is subject to that balance of cost -- cost performance and risk, and essentially, the -- the safe, reliable operation of the system is deemed to be what's best for the customer. And so these are the dollars are required to protect that safe and reliable operation and make sure that the customer -- we're there when the customer needs us.

MR. BOB PETERS: And in three (3) to five (5) years, Manitoba Hydro hopes to have a numerical basis on which to assess and quantify that risk to make that judgement that it's now making?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: Because presently, it's making that value judgement without the empirical data?

MR. JOEL WORTLEY: It's making that value judgement essentially on the assumption that we want to continue the -- the level of performance and -- and balance of risks that we've had to date. And so the -- the indicators are -- are positive in terms of the customer experience, are positive in terms of the assets, in terms of how long the assets are living, positive in terms of the amount of reinvestment required. And so the -- the tacit assumption is that by carrying on, we're -- we're doing at least what's -- what, at face value, is the right thing for the customer.

(BRIEF PAUSE)

MR. BOB PETERS: But at this point in time, Mr. Wortley, I thought we covered it, that the -- Manitoba Hydro doesn't have a mandate from its ratepayers as to how much more they want to spend on -- on the system upgrades. Is that correct?

MR. JOEL WORTLEY: It would be fair to say that we don't have a mandate from the customer as to how much more they want to spend, nor do we have a mandate from the customer as to how much less reliability they like, so that -- that, yes. You're correct.

MR. BOB PETERS: All right. Okay. I'd like to, Mr. Chair, just turn to a matter that I -- I mentioned to my friend Ms. Ramage that I was going to start with Mr. Wortley, and see if this was something that was on this panel and not the capital panel.

And I wanted to start with an IR that might make it to Board counsels' fifth book of documents, but it's not presently compiled, and that's an undertake -- sorry, an Information Request PUB Manitoba Hydro First Round 62.

And this one has a chart. I'm not going to review the chart in any detail, but Mr. Wortley, you're familiar with these progression of

Capital Expenditure Forecast numbers?

MR. JOEL WORTLEY: I've seen before. I haven't studied them ad -- ad nauseam.

MR. BOB PETERS: All right. And I wouldn't expect you to, sir, in fairness, but one (1) of the concerns is that when a project makes it to the Capital Expenditure Forecast list, that means it has to go up the channels and make it to the vice presidents, and then to the executive of Manitoba Hydro. Would that be correct?

MR. JOEL WORTLEY: The approval process is such that depending on the dollar value, it goes to an appropriate level of management for -- for approval, and then the plan itself does go up to executive to be approved. So there's an individual approval of the project, and then there's an approval of the plan.

MR. BOB PETERS: And --

MR. JAMES MCCALLUM: And just to jump in, the plan is all the CEF, or Capital Expenditure Forecast, is approved by the Board of Directors.

MR. BOB PETERS: Thank you, Mr. McCallum. That means it's gone through the executive committee at Manitoba Hydro?

MR. JAMES MCCALLUM: That's right.

MR. BOB PETERS: Would it be correct that when an item makes it to the Capital Expenditure Forecasts, that item includes what are the expected in-service costs, Mr. Wortley? Like, that is for Ms. Bauerlein, those are the costs that the Corporation expects it will have incurred up until the date that that item becomes in service and of use to the ratepayers?

MS. SANDY BAUERLEIN: Not necessarily when the item is first placed in the CEF. The -- and Mr. Wortley can expand a little bit further, but that may be sort of a -- which is why we've now sort of redefined sort of the look and feel of our report, to give a better perspective on when things are here, as we think there's a potential investment, and we've done some from preliminary work to assess at a high level, and then there's, of course, further refinement as to what the overall scope, and overall requirements, and therefore, in-service costs of the project will be as it progresses through that -- that analysis.

Mr. Wortley, do you want to add to that?

MR. JOEL WORTLEY: The practice has -- had been that to begin any sort of work on project, an approval -- a -- budget had be raised and -- and approved to -- to do any sort of work on the project, including defining its scope to any real extent. As a result, what often happened was that a -- a very, very rough budget was put into the system long before there was any clear understanding of the scope of the project, which inevitably turned out to be wrong, way wrong, because it was produced at a time when there was no clear understanding of what was actually trying to be accomplished or what the scope of work was going to be.

And so we -- we've discontinued that practice now in favour of a practice that allows some money to be spent on some preliminary engineering to define the scope, schedule the project, and therefore, firm up the budget before it's approved. But what you'll see here in many instances, I'm sure, if we look, is a situation where that initial budget, which was a bit of a guess, turns out to be very different from the final number.

MR. BOB PETERS: All right, Mr. Wortley and Ms. Bauerlein, I am going to give you a chance to explain to the panel the current system. So we'll -- we'll come to that with the aid of, I think, one (1) of the Information Requests.

But Mr. Wortley, is the process the same on this Capital Expenditure Forecast for business operations capital items, as it is for the major new generation items?

MR. JOEL WORTLEY: It is insofar as that anytime the -- the budget can only reflect what you know what you know about the project. So if you're very early in the project life cycle, you don't know a lot about it. Your -- your budget is inevitably uncertain. As the project progresses, the scope is defined, the design is completed, the projects -- contracts are let, ground is broken, you learn more as you go, you gain more confidence, more certainty in the actual cost.

And so if you're very early in the project, whether it's a major new gen and transmission, or whether it's business operations capital, inevitably, you don't know a lot about what it's going to cost, but as you progress into the project, and it -- its scope matures, you gain more confidence.

MR. BOB PETERS: Okay. Well, let's follow that through, and I'll ask that your -- Manitoba Hydro's rebuttal evidence, Manitoba Hydro Exhibit 52 be brought up again, and specifically, page

53 of that document, 53 of 78, if that's available, and I believe what we have here is -- is what -- what I think will help the Board understand.

I want to start with -- the premise of this is Manitoba Hydro's rebuttal to METSCO, one (1) of the experts that was engaged by the Consumers Coalition, correct?

MR. JOEL WORTLEY: Correct.

MR. BOB PETERS: And one (1) of the observations that METSCO made was -- and Mr. Wortley, in fairness, I think you made the same one, is it appears that Manitoba Hydro's capital costs are materially underestimated relative to what actually becomes the capital cost, correct?

MR. JOEL WORTLEY: That's correct.

MR. BOB PETERS: And so you took -- Manitoba Hydro took the time to explain in this rebuttal -- and I'm now looking at line 13 -- at the time these projects were conceived, and -- and Mr. Wortley, let's assume these projects are either business operations capital, or major new generation, it really doesn't matter. Are you okay with that?

MR. JOEL WORTLEY: Yeah, I think that's fair.

MR. BOB PETERS: All right. So when

these projects are conceived, and that means that -- and I don't -- you know, somebody's come up with the idea that you need a new substation, you need a new generating station, you need a new transmission line. Somebody's come up with that idea?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: And -- and I'm not -- and I'm not belittling the work that it takes to get to that decision, but somebody's come up with the idea, then at the time they come up with the idea, they're also supposed to put a -- a project budget estimate forward for that idea. Is that correct?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: And so what you're telling the panel is if you need a new substation, a new transmission line, a new generating station, the Manitoba Hydro folks who conceived the idea should also put a price tag on it?

MR. JOEL WORTLEY: Yes. Again, this is the -- the past practice where the transmission line is a great example, where you may have a starting point and an end point to that transmission line, but not a route. And so if you put an estimate on that transmission line on day 1, without knowing what route it -- the line needs to follow, inevitably, that estimate is not going to be very good.

MR. BOB PETERS: Mr. Wortley, you told the Board that -- and -- and I want to stick with it -- this is the historic way Manitoba Hydro used to do things?

MR. JOEL WORTLEY: That's right. In our current practice --

MR. BOB PETERS: And -- and -- well, I -- I'm going to let you get there, but you've got to -- you've got to trust me on that, and your counsel will make sure I do, but when you say it's historically how you did it, when did Manitoba Hydro have the about-face, or the change in methodology?

MR. JOEL WORTLEY: It -- it's happened a little bit over time in that -- in the last -- in the last year or so, we've -- we've adopted a formal process by which the groups can now raise what's called a -- a capital investment concept to get a little bit of money to do some preliminary engineering, but in -- in years prior to that, there was some opportunity to rai -- raise some preliminary engineering money that some groups were taking advantage of. So it -- it's a little bit inconsistent on when it happened in which groups.

MR. BOB PETERS: Okay. So it's

relatively new with -- we'll say within the last year, and you're trying to get to a common platform?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: And you're not quite there yet?

MR. JOEL WORTLEY: I -- I would think we're -- I would say we're -- we're there in terms of -- we're there in terms of when projects are raised today, the approval on the -- the approval on the project justification is not proposed until there's a firm definition of the scope, schedule, and budget. You need that in order to value -- there's no point in scoring the value the of the project if you -- if you don't really know what it costs, because the -- the value is obviously not going to be correct either.

However, projects last a long time at Manitoba Hydro. A lot of our -- our big jobs have been over many years, and so you can have many projects in the system that were still started under the old process that will be there for many years to come. So it -- it will appear, even though the -- the practices in place today to avoid the situation, the hangover is still there from the past practice and will be for many years.

MS. SANDY BAUERLEIN: So I did want to

add, in the last CEF, we actually tried to, from a presentation perspective, make it a little clearer by defining executing projects, so these are projects that are underway, versus one (1) that we were calling potential investments. So this is really where you know you're going to build a transmission line, but again, we're not sure exactly what the route is. So we were trying to make it a little clearer in even our presentation of the Capital Expenditure Forecast, the difference.

MR. BOB PETERS: So does Capital Expenditure Forecast 16 contain the new methodology, Ms. Bauerlein?

MS. SANDY BAUERLEIN: It -- it contains the new presentation, and Mr. Wortley said, the transition of some of the -- the new methodology where we're trying to actually have now scope approved separate from actual project costs.

MR. BOB PETERS: All right, and we'll come to that. I promised again. So CEF17 will be the first time the Board will be able to see the Capital Expenditure Forecast using the new methodology that Manitoba Hydro has migrated to?

(BRIEF PAUSE)

MR. JOEL WORTLEY: For new projects, that will be the case. Year 1 in the CEF is a mixture of projects in flight and new starts. So the new starts, that -- that will be the case.

I guess maybe I should add one (1) more clarification, which is that there are instances where a project was first conceived many years ago, and then followed in time, and -- and deferred, because it wasn't needed right away, that's still -- still waiting to be actioned. And so when that one comes up to be executed in year 1, it will still have somewhere on the books an initial project justification that was done under the old -- under the old process.

MR. BOB PETERS: All right. I -- I want to complete the old process as quickly as I can, and I'm still on Manitoba Hydro's Exhibit 52, page 53 of 78, and I was still up on lines 13 and 14.

And so you've told us that under the old methodology, which we have seen on the progression of Capital Expenditure Forecasts that we've just had on the monitor, this old process had the project budget estimated and approved prior to ending -- engineering or planning being done to define the project scope, correct?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: And so who approved that? Who -- under the old system, who was approving this capital expenditure if it hadn't gone yet to engineering or planning to define the scope?

MR. JOEL WORTLEY: Again, depending on the level of spend, the appropriate level of management, as per the policy, would be required to improve the investment.

MR. BOB PETERS: Okay. So remind the panel, in terms of the level of spend, is there a dollar amount that has to make it to the executive committee and the vice president level?

MR. JOEL WORTLEY: Yes.

MR. BOB PETERS: And what's that dollar amount?

(BRIEF PAUSE)

MR. JOEL WORTLEY: It -- it's changed a little over time, which makes them -- I don't want to give you a half hour long answer. At -- at one time, it was anything over 2 million was going to EC, executive committee.

MR. BOB PETERS: And -- and is that your best understanding as to what was used at the time CEF16 was prepared?

MR. JOEL WORTLEY: CEF16 was approved under our new process, and our new process has multiple -- new process and new policy has multiple approval levels. I think 25 million?

MS. SANDY BAUERLEIN: Current -- under the new approval policy, 25 million goes -- anything greater goes to executive committee. Anything greater than fifteen (15) goes to our corporate asset management executive counsel.

MR. BOB PETERS: And anything lower than fifteen (15) goes to the director level?

MS. SANDY BAUERLEIN: Vice-president is --

MR. JAMES MCCALLUM: An individual will get the director level, an individual vice-president can approve up to a fifteen (15), $15 million project. The corporate asset management executive counsel, which is the four (4) operating group. That's marketing and customer service, transmission, generation, and then human resources and corporate services, those four (4) and me as the chief financial officer are on that committee. I chair it, and that approves projects between 15 and $25 million. Above $25 million goes to the full executive committee, which includes any remaining vice-presidents, plus the president, of course, and then above 50 million, a project goes to the Board of Directors of Manitoba Hydro.

MR. BOB PETERS: Okay. I think I've got the -- the latter, there, and I thank you, Mr. McCallum.

I would like to complete on this item in front of us on the screen, this page 53 of the rebuttal.

(BRIEF PAUSE)

MR. BOB PETERS: What you're showing the Board on lines 18 to 21 is that this original estimate that may have made its way to the original Capital Expenditure Forecast was, by Manitoba Hydro's expectations, expected to be wrong in a significant way, because no engineering or planning had been done for that?

MR. JOEL WORTLEY: It was the best information at hand at the time.

MR. BOB PETERS: But Manitoba Hydro chose not to get better information which was available at the time. Would that be true?

MR. JOEL WORTLEY: Better information was not at hand at the time, it would have had to have been studied and -- and the engineering advanced to get better information.

MR. BOB PETERS: And Manitoba Hydro chose not to do that, at that -- at the initial stage?

MR. JOEL WORTLEY: You know, it's the life cycle of a project. And so at that time the project was relatively immature. As it progressed that level of maturity increased and a better definition of scope, schedule and budget would have -- would have resulted. So it wasn't so much a choice not to get it, it just hadn't been gotten yet.

(BRIEF PAUSE)

MR. BOB PETERS: I'd like to -- was there anything further? Thank you. I'd like to turn to tab 5, page 4 of 28 of Manitoba Hydro's application. And I believe Ms. Bauerlein and Mr. Wortley, this will make good on my promise to you to get to a current state.

Under this, what is described on lines 7 to 13 is the current state that Manitoba Hydro talked about, and that was depicted in the capital expenditure forecast narrative. Correct?

And I'm sorry on the screen, I would ask for page 4 of 28 of Manitoba Hydro's tab 5 and there it is at 5.1.2. That's correct.

But one (1) of the things that's said, Mr. Wortley, on line 9 is that certainty in the capital plan is the highest in the year one (1).

Do you see that?

MR. JOEL WORTLEY: I do.

MR. BOB PETERS: That -- that doesn't intuitively follow to me that -- that certainty is available in year one (1) because the scope is defined, the schedule and the budget is all known.

I thought you were telling us that longer-term projects, you didn't have that certainty and you expected that the number would change over time, and likely grow over time?

MR. JOEL WORTLEY: This -- what's being referenced here is that in year one (1) of the forecast is the one that you know the most about. And so it's the ones -- the projects that you're committing to begin, the ones that have already been committed and are in flight. Every year beyond that has a growing level of uncertainty as to actually what work you're going to perform, as in which projects are going to be in the plan and which ones are out.

And so year one (1) is the one that has the most mature projects 'cause they're ready to begin execution, as well as the ones that are already in flight that are even further more mature than the ones you're about to begin and, therefore, the ones you know the most about.

MR. BOB PETERS: All right. I didn't understand it to mean that it was the year of the capital expenditure forecast in which you had most certainty, I thought it was year one (1) of a project is the year in which you have the most certainty, and that's certainly not the case?

MR. JOEL WORTLEY: No. This -- this refers to year one (1) of the forecast.

MR. BOB PETERS: Mr. Wortley, if Manitoba Hydro chose, they could assign resources to a project and engineers to a project and accountants to a project to -- to, essentially, study it and scope it to a pretty finite number very early in the planning cycle.

Would that be true?

MR. JOEL WORTLEY: The very act of advancing the studies you're describing is -- is to mature it through the planning cycle. So no, you can't do it early in the planning cycle, because what you're doing is advancing the planning cycle by -- by doing those studies.

MR. BOB PETERS: Okay, you're going to have help me understand that or explain it so that I -- how is it that you can't study a project initially and know exactly what it's going to cost you in three (3) years to bring this project in using the assumptions as to interest rate assumptions as to escalation.

Why can't Manitoba Hydro determine that before the shovel goes in the ground?

MR. JOEL WORTLEY: You can advance your planning, you can advance your definition, and you can advance -- for instance, take your design right through to contract ready, we'll say, ready to be bid. What I was trying to say was that by doing so you are not at the beginning of your planning process anymore. Within your project you are some ways into your planning of that project.

MR. BOB PETERS: All right. And so Manitoba Hydro's current methodology is Manitoba Hydro doesn't study the details of the project until it's advanced through various years of -- of process?

MR. JOEL WORTLEY: The two (2) are

synonymous in that as you -- as you start from an -- an idea, we think we want to do this, that's the first step in your -- your planning process for that project. From there you may identify different alternatives, different concepts, what's the right solution to this particular problem. And those as -- as your planning progresses may be developed, flushed out, to the point where you have some understanding of their relative merits.

A particular option at some point is chosen to be further advanced in terms of flushing out the scope, the design, coming to a place where more of the details are known and the budget is -- is more mature.

MR. BOB PETERS: The last sen -- the last sentence, Mr. Wortley, on page 4 of 28 of Manitoba Hydro's tab 5 reads:

"Long-term planning investments have only a notional definition of scope, schedule, and budget."

Do you see that?

MR. JOEL WORTLEY: I do.

MR. BOB PETERS: What would be a long-term planning investment? Would that be a generating station, as an example?

MR. JOEL WORTLEY: No, in this sense long-term means things that been identified as one day going to need to be invested in. And so, for instance, we will know how many transformers we've got on the system. We will know that eventually some of those transformers are going to need to be replaced and, therefore, a long-term planning investment may be to put some -- flag some money for re-investment in those transformers.

And so the -- the scope is transformers, the schedule is sometime in the future, and the budget is rough. In time, as those long-term planning investments come in -- into the nearer term, which transformer gets identified. The one that's in rather -- relatively poor shape may be identified as going to be the one that might be next. Its particular size, where it is, what work is going to have be done to -- to address the degradation. Is it just the transformer? Are there other works that will need to be done around it.

Those -- all those things are considered and built to -- into a project plan such that now you have some definition of -- of scope, schedule, and budget. And so what's being differentiated here is that long-term outlook to say, we know there's been a need to be money spent versus we have a particular potential investment that we're considering.

MR. BOB PETERS: I'd like to turn to page 5 of 28, the next page on -- on Manitoba Hydro's document and -- and conclude my questioning in this area.

This is a -- an attempt to conceptualize Manitoba Hydro's current capital planning model, Ms. Bauerlein?

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: Now the axis are not identified with any scale other than that time runs out on the right and capital increases on the left. Correct?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: And when we see the word "target" on this capital planning model, that's a target that has been set by the executive level as to where the executive currently feels the capital budget is best set?

MR. JOEL WORTLEY: That's right.

MR. BOB PETERS: And, Ms Bauerlein, you were cleared to show the Board that executing projects is a new terminology meaning these are projects that are already underway and were developed prior to the new methodology.

MS. SANDY BAUERLEIN: Already underway or about to begin in that next -- that year one (1) as Mr. Wortley was talking about. So they're about -- so you're looking at year one (1), and you're looking at projects that are in flight or projects that are -- that are going to begin.

MR. BOB PETERS: And that could be either business operations capital, or that could be major new generation and transmission assets.

MS. SANDY BAUERLEIN: That is correct.

MR. BOB PETERS: And so, the Board would understand that in the first year of the CEF when the most certainty is there, the certainty is really only as to the target level of money that's available?

MR. JOEL WORTLEY: What -- what's trying to be depicted here is that if you stood in year zero (0), as we are today, and you look forward, you would see that in year one (1) of the CEF you've got some program spending, which is the -- the base of the diagram here, and that's -- that's money being spent on common assets, a certain number of run-to-fail assets that you know are going to need to be replaced annually. And so there's money flagged there, but it's not broken up into individual projects.

Up from that in the executing projects triangle, there are a collection of projects and you can think of them is as -- as layers, horizontal layers. Where up near the top of the triangle they're just endings so they don't have a lot of spending in the -- in the current year or they only run just beyond the current year.

And down on the bottom of the executing projects triangle maybe are ones that are just beginning and are going to run for several years.

The top portion up there is that little wedge of scope development, are the projects that have been -- or the potential investments that have been identified that need flushing out in terms of their scope, schedule and budget. So a little bit of money is identified to advance the engineering, firm up the scope, firm up the schedule, and the budget for those.

Beyond that, in the potential investments are specific projects, so, specific assets, specific projects with a preliminary scope, schedule and budget that are being considered. They -- they're -- they're not tied to a particular time frame yet, but they're out there and are being considered potentially to be advanced execution next year, the year after, as required.

And then out -- even in -- further into the future, the long-term planning investments that we talked about a minute ago, where through watching the degradation of the assets, monitoring the asset health, you know that there is going to be money that will need to be spent on certain assets, but you haven't flushed them out into how much money, when to do what.

And so in time those long-term planning investments are developed into potential investments, and in time, their scope is developed to give them a firm budget and schedule and they arrive at the first year of the CEF to be actioned or to put a shovel in the ground. And so --

MR. BOB PETERS: I'm sorry.

MR. JOEL WORTLEY: And that -- that is the life cycle or the -- the development of -- of projects from those long-term planning to executing.

MR. BOB PETERS: Why is it that the scope development item stays stagnant where it is and lets the calendar elapse to bring all of the long-term planning investments closer to it, ra -- instead of having the scope development moved out further or having monies allocated further out so that you can study the long-term planning much earlier than currently done?

MR. JOEL WORTLEY: So what's trying to be depicted here is that year one (1) is the only year that you can actually do things in. Everything -- beyond that is things you can see but you -- you can't do work in year five (5) until year five (5) becomes year one (1). If that makes any sense.

This is a -- this is a look forward. And so it's not what you're going to do in year five (5), it's what you know about year five (5) or year ten (10) or -- or the outlook.

The choices you make are all about year one (1). What am I going to start this year? How much engineering am I going to do? How much construction am I going to do?

By doing some scope development work on a particular potential investment, you then gain the information to know whether you want to put it in as an executing project next year, or maybe you find out it's going to be significantly more expensive than you originally thought and it gets deferred.

MR. BOB PETERS: Thank you. I believe

I have your points. Last question to you, Mr. McCallum, you told us the ladder of approval levels and the dollars amount that went with it.

I -- I neglected to ask, and I will now: At what level does Manitoba Hydro seek approval from the province of Manitoba for any of these projects, if at all?

MR. JAMES MCCALLUM: I -- I -- the answer to that is there's no dollar level upon which, that I'm aware, that we go to the province of Manitoba, although -- and perhaps Ms. Bauerlein or Ms. Ramage can jump in, my understanding was that certain classes of project, for example, a new generating station require a provincial approval, amongst others.

MR. BOB PETERS: Is that approval as a result of environmental issues? Is that what you're referring to?

MR. JAMES MCCALLUM: Yeah, I -- I can't speak to that. I think obviously The Clean Environment Commission is one. I think there's layers of approval for including federal for extra-provincial transmission lines.

Yeah, I can't speak to the specific for the approval of a new generating station, for example, certainly requires environmental licensing but I'm not aware of if there's other provincial approvals for other reasons.

MR. BOB PETERS: All right. Thank you. Mr. Chair, I want to thank the Panel again. Those are the questions that I have.

MR. CHAIRPERSON: Thank you. Ms. Ramage, re-examination, do you have any? And if so do you want a break? Or do you want to go straight into it?

MS. PATTI RAMAGE: We would like a break please.

MR. CHAIRPERSON: Okay. And how long would you like?

MS. PATTI RAMAGE: Ten (10) minutes.

MR. CHAIRPERSON: Sure, fifteen (15).

MS. PATTI RAMAGE: Okay. If we're bargaining.

MR. CHAIRPERSON: I like even -- even numbers. I'm not very -- you know, if we say ten (10) minutes we'll be back in fifteen (15) anyway, so. Okay, thank you.

--- Upon recessing at 2:14 p.m.

--- Upon resuming at 2:36 p.m.

THE CHAIRPERSON: Ms. Ramage...?

RE-DIRECT EXAMINATION BY MS. PATTI RAMAGE:

MS. PATTI RAMAGE: Yes, we have a couple of matters for redirect. The first I would like to put to Mr. Wortley, and it relates to questions I believe posed by you, Mr. Chairman, that we will respond to in redirect is the easiest way of doing it.

And Mr. Wortley, with respect to the Corporation's asset management journey, could you tell us how and when the decision was made to perform a GAAP assessment?

MR. JOEL WORTLEY: As -- as we've discussed a little bit, asset management is still relatively new in North America. It's come out of Europe and -- and Australia in the last decades, and so the -- the North American -- the ISO standard was written in 2014, and in 2015 a number of individual efforts were started at Manitoba Hydro in different parts of the Corporation to improve their asset management practices such that in -- in late '15/early '16, the executive committee directed that a more concerted, more coordinated effort be undertaken by the Corporation to manage its asset management practices.

And at that time in January 2016, the corporate asset management executive council and steering committees were -- were created with membership from the operating groups and it was under this -- under the governance of these committees that the GAAP assessment was first -- was first proposed, as well as the -- as part of the -- the three-phase framework development that we've talked about several times.

And so in -- in April '16, the RFP was released to perform the GAAP assessment. It was wrapped up by December of '16, and in response to the findings of the GAAP assessment, a little bit of reorganization took place at Manitoba Hydro to which the -- the hybrid model referred to in the UMS report was created by -- by forming a -- a central seat for asset management, which is my own position under Mr. McCallum and the -- the nature of the corporate asset management executive councils and steering committees was -- was shifted to have a central role and a central authority as in Mr. McCallum took over chairing the corporate asset management steering committee, I took over -- sorry, the corporate asset management executive council. I took over chairing the corporate asset management steering committee, and that's the basis on which we've moved forward.

MS. PATTI RAMAGE: Thank you, Mr. Wortley, and now to you, Mr. McCallum. Over the past couple of weeks you've been asked a number of times questions regarding your knowledge of the regulatory text principles of public utility rates by James Bonbright. You've been called upon to read a number of chapters of Bonbright and the Coalition included a number of excerpts of that text in its book of documents.

Your discussions with Mr. Williams were, however, fairly abbreviated. Given you were directed to Bonbright and certain excerpts have been placed on the record, do you have any additional observations regarding Bonbright's views on the used and useful concept that was -- the discussion was cut off at transcript page 1515 but do you have any additional observations to add to the discussion?

MR. JAMES MCCALLUM: Yes, I do. During the first week of the hearing each of Mr. Monnin, Mr. Hacault and Dr. Williams made an -- an effort to make clear that I'm not steeped in complex theology of regulatory principles.

I can report I'm still not, but I did

take the time to go read parts of Dr. Bonbright. And I wouldn't claim to be any more expert than two (2) weeks ago but when I listened to Dr. Williams and reading the evidence that -- that he asked us to look at, I expected to find pretty strong statements that would be a great affront to the Bonbright doctrine for a utility that for when adding new -- major new works, you can't do anything other than capitalize the interest costs and wait until the asset was in-service and not a moment sooner to begin recovering from your customers, you know, those costs through the recovery of depreciation expense and interest.

And so the issue here is the idea of quote "used and useful," unquote, a fundamental regulatory principle. This is the notion that it would be a breach of principle to charge today's ratepayers for Keeyask and Bipole III before those assets are in-service. So here we find a regulatory principle that has been put forward in what I would regard as an incomplete and misleading way as a justification for putting off coming to terms with our -- what we regard as our unsustainable debt load.

So when I look to Bonbright on the issue of capitalization of interest during construction, I found this quote: [quote]

"As long as this withholding
practice exists, as I think it
should, at least in times of rapid
plant expansion there arises a need
for some rate making provision where
the company may eventually receive
an adequate compensation for its
advanced commitment of capital. The
standard provision of this nature,
and the one that I believe most
satisfactory is that of a compound
allowance for interest during
construction. An allowance not
restricted to the contract interest
that the company may pay on loans
designed to finance the construction
work." [closed quote]

Bonbright goes on to say that any practical rule of rate control by appeal to general principles of accounting is unconvincing to him but, instead, the funda -- fundamental question is whether the provisions for compensation on capital that has been tied up in work under construction should take the form of a rate-based enhancement or rate of return based enhancement. Dr. Bonbright favours the latter.

It is not that the Utility should not be paid for tying up capital, but that it should be paid through the determination of its rate of return. But Manitoba is not a rate-based rate of return jurisdiction. I'm aware of that. I'm aware of that much.

I'm not remotely suggesting anything should be different; that's not in the scope of this application, and lies in the hands of government, in any event. But because we are not a rate-based rate of return environment, we have to really know what we're doing when we apply these regulatory principles.

The fair rate of return principle is the one that I have not heard the Intervenors talk about. I don't think they want to talk about it because it's the unifying principle, near as I can tell, that enables all of these other principles that can otherwise be put forward as the basis for putting off problems on tomorrow's customer.

The fair rate of return is the means by which a Utility can be regulating -- regulated using all of these principles without becoming financially unstable. So used and useful is a principle that sounds great in theory but can fail in the absence of a fair rate of return.

Turning back to Dr. Bonbright, do we

find great opposition? No, again, we find a scholar who is actually quite okay with the notion of the utility shareholder expecting to get paid for the value of tying up capital for years building large assets before they can be completed and brought into service.

Again, his solution is to deal with it in the rate of return. Instead of capitalizing just the interest on borrowed funds, Bonbright supports capitalizing to the project to reflect a rate of return as well.

So the issue is the timing and method of recovery, not the notion that the Utility should not be paid for tying up its capital for many years. With that promise, the Utility is able to attract capital, equity capital, which is another Bonbright principle we need to be aware of; that is to say, that regulation must allow the Utility to attract the capital it needs to keep it financially stable while it invests in step-change levels of plant investment.

So rigidly following the Bonbright principles fails in the absence of a rate of return. We have to find another way. And as I discussed while being cross-examined we're skipping over the most important regulatory principle which is that the public interest is the primary goal of ratemaking. The public interest trumps all. Bonbright says this. The PUB says this in Order 73/15, wherein they speak to the compelling policy interest to phase in the required rate increase over a number of years in advance of the in-service dates of the new major capital projects; as we done with Bipole and the Bipole III reserve.

In keeping Manitoba Hydro financially stable is, as the Manitoba Court of Appeal has said, a key component of the public interest. We are midflight on a doubling of our asset base. It is not in the public interest to wait for these assets to be in-service. There's numerous examples in both constating legislation and regulatory practice throughout North America to supersede the used and useful principle to ensure that the Utility is financially stable and can support the timely and cost-effective addition of major assets.

MS. PATTI RAMAGE: Thank you. And you had a discussion with Mr. Hacault beginning at transcript page 1708, where he had you acknowledge that Manitoba Hydro's assets have long lives and their costs will be covered in depreciation.

Did those discussions serve to present

the full picture of this situation of the issues facing Manitoba Hydro?

MR. JAMES MCCALLUM: No, I don't believe it. And I'm going to, again, veer into a discussion of regulatory principle again, and the importance of this rate of return concept.

Mr. Hacault asked the revenue requirement panel questions regarding our business operations' capital; that's the ongoing regular expenditures we make to sustain our assets, maintain safe and reliable service, expand capacity to meet, you know, generally localized needs, and accommodate service extension to our new customers.

When you look historically over the last few years and prospectively, Manitoba Hydro's expenditures in this regard are actually fairly steady in and around the $500 million a year mark and that's as we continue to try to manage investments related to continuously aging infrastructure. So Manitoba Hydro provided evidence at tab 2, pages 15 through 18, that has a material ongoing cash shortfall and this was the genesis of Mr. Hacault's questioning around our business operations capital. Cash shortfall at present electricity rates due in part to a substantial difference roughly $250 million a year between what we recover in revenue requirement through annual depreciation charges and what we must expend annually to maintain, replace and enhance existing infrastructure in the normal course.

The issue is that depreciation expense is determined based on the historical cost of assets when they're first installed. Manitoba Hydro's reality is at the cost of replacing these assets, as they expire, is an ongoing cash need that comes in the form of today's costs, which due to the age of our infrastructure and the inflation and construction costs and otherwise, bears almost no relation to historical cost.

As can be seen in the transcript, Mr. Hacault has Manitoba Hydro acknowledge that the replacement assets we build have long useful lives and at the cost of these -- buildings assets will serve today's and future ratepayers, and be recovered from the same in future depreciation. In other words, the assets will be paid for overtime and, therefore, there is no problem. Certainly not one that today's ratepayer should be asked to do anything about.

But there's a big problem and I think it's important that the Board get a complete picture on this point and -- and -- and I'll do so in tying it, in due course here, to -- to -- to some of these Bonbright principles that we rely on and look to.

I -- I want to start with a simple example just to illustrate the issue and why it's critical we look at cash flow and cash flow deficiency. So imagine if we could produce, and this is a very simple example but bear with me, all of Manitoba Hydro's system to one (1) asset. And let's say the asset we acquired it in 1974 for $250 million. And let's further assume that the asset has a fifty (50) year life. So that means, for accounting purposes, we'll depreciate that asset to the tune of $5 million a year, and following the concepts here, we will -- we will recover from our ratepayers $5 million a year on account of that -- that asset.

So the ratepayers of 1974 and 1975, they're paying $5 million a year, which basically represents, you know, a then present day fair price for the one-fiftieth of the asset's usable life they are consuming each year. But as we know, inflation, whether modest like now or high like at other times, has been a fact of life for over almost any period in history. But the ratepayer keeps paying $5 million per year regardless. B 2017 the ratepayer's still paying $5 million per year, based on 1974 prices, but, using 2017 money; that's a bargain.

Adjusted for inflation, 5 million in 1974 is the same as 24 million today. So it becomes a bargain that the Utility struggles to afford, absent another approach. So that's play the very simplified example out further.

In 2024 we reached the end of our fifty (50) year life of the asset. It has to be replaced. Remember, we paid 250 million for it in 1974. Adjusting for inflation, by 2024 that asset will cost us $1.4 billion to replace.

Let's assume it too is expected to last fifty (50) years. So now our depreciation charge, and following the model, the cost assigned to our ratepayers each year is $28 million a year, up from five (5). So 2024, the ratepayer goes from paying 5 million per year, to complete the final use and depletion of the old asset, wakes up the next day, has no change in service, but now must pay $28 million a year; 450 percent more.

That's what happens if we dogmatically follow accounting policy as our means of assigning costs across the generations. It's actually worse. Our asset costs have not followed the basic consumer price index. I'll take Kettle Generating Station, for example. We built it for $250 million in 1974. Total coincidence. That works out to 1.2 billion today. The plant cost 1 million per megawatt of capacity in today's dollars.

We built Limestone Generating Station in around 1992 for 1.43 billion. That's 2.3 billion in today's money, or roughly 1.7 million per megawatt. So in today's dollars, Limestone was 70 percent more expensive per unit of capacity than Kettle.

While Keeyask is a different project, as each of them are, I'll just point out that at 8.7 billion for 695 megawatts, Keeyask will be about $12 million per megawatt, better than twelve (12) times Kettle and six (6) times Limestone, both using today's dollars.

And we can show examples like this throughout our asset fleet, from wood poles to -- to Bipoles. Costs have gone up both for inflation, but also for changes in construction standards and techniques.

So the example I gave, the one that results in a 450 percent rate increase when we finally deplete this one (1) fifty (50) year old asset that once cost 250 million, start using our shiny new one that costs 1.4 billion due to inflation, probably understates the cost increase and consequent rate impact. If we just used the escalation from Kettle to Limestone as our example, 70 percent, we would complete the depletion of a $250 million asset and immediately replace it with a $2.4 billion asset. Rates would need to increase tenfold, and it doesn't speak to the debt issue.

On that day in 2024, when we switched from the old asset to the new asset, we go from paying interest on whatever's left of the original 250 million in debt, presumably almost nothing, to paying interest on the new debt, which may be ten (10) times greater in value.

So to recap, ratepayers, in an instant, go from paying 5 million of depreciation and virtually nothing in interest to paying 47 million in depreciation and $118 million in interest, using a 5 percent interest rate as an assumption. So rates must actually go up over thirty (3) fold. And would this be in the public interest?

Obviously, it's a grossly simplified example. Manitoba Hydro's system is a compilation of thousands of assets in varying vintages with varying degrees of inflation impacts when you look to replacement value, and this smooths out and obscures the very real issue we face of having failed to fund asset replacement in a way that doesn't compromise our balance sheet.

The example is -- illustrates a signif -- significant issue of relentlessly -- relentlessly hewing to this notion or principle of cost causality. Current rate -- ratepayers are enjoying quite a break paying 1950s, 60s, and 70s prices, to consume and deplete a system where a lot of the major components were put in place ages ago, but that now need to be replaced in 2017 dollars.

It results in a huge buildup of debt pressure, rate pressure, and rate volatility if we don't find a way to charge today's ratepayers for the reality of what it cost to continue maintaining and enhancing the system they use and rely on every day. And to put the problem off, to allow our debt to expand and expand at a rate much faster than the underlying customer base and load is growing, and it -- to explain and enable it under the guise of intergenerational fairness is frankly hypocritical.

So how other utilities manage this issue, because we all have this issue in front of us -- it's not unique to Manitoba Hydro, it's not particularly unique to the present day. So again, I turned as I was told to, to Bonbright, expecting to find pretty strong statements that it would be a violation of doctrine for there to be any recognition in customer rates for the fact that new assets are going to cost a lot more than the assets they replace.

What I found is quite interesting. Dr. Bonbright's chapter 11 is called "The Rate Base: Cost or Value?" He starts -- unquote. He starts the discussion of whether the rate base should be set at historical cost less depreciation, or at some proxy for replacement value by saying this debate is,

> "The most widely disputed legal issue in the history of American public utility regulation."

Reading further, Bonbright, at least to me, doesn't take the position that replacement value-based rate -- rate regulation is intellectually indefensible by any stretch. He appears to favour historical cost basis for the simple reason that it's significantly more practical and efficient from a regulatory standpoint, what he called superior administrative flexibility. In other words, he felt the confusion and unpredictability witnessed in trying to establish "fair value" was not worth the effort. It would be just too hard to get right as opposed historical costs, which are known facts. They're non-negotiable.

So he agrees the Utility must receive credit for replacement cost and cost escalation, but to deal with it through the determination and setting of a fair rate of return. So how does that work? Well, it means that the owners of a Utility know that when they put up new capital to build new assets, they will receive a rate of return, and per Bonbright, that rate will include an allocation for inflation, such that they protect against a diminution of the purchasing power of their capital.

This promise of a fair return enables the Utility to attract equity capital, as I mentioned, a critical Bonbright principle, which allows the Utility to fund the renewal of its system at actual costs that were compromising its credit-worthiness or capital stability.

In other words, the promise of a rate of return enables the Utility to not 100 percent debt fund replacement costs and avoid the risk of doing what Manitoba Hydro is doing, which is increasing debt at a much higher rate than the underlying customer base is growing.

So if we don't have fair rate of return

in our model, what do we do? Well, the first thing we have to do is be aware of the difference between what we're recovering in our existing rates from historical costs, base depreciation, and we -- what we are having to reinvest in the system and -- to keep it reliable and safe.

We have to identify, as Manitoba Hydro has, that all else being equal, 100 percent of this difference is being added to our debt. We have to recognize that particularly in a fairly low-growth environment, this has and will continue to contribute to a destabilization of our balance sheet, and therefore, we have to find another way.

It's convenient to argue that we should simply be paid back over the fifty (50) or seventy (70) years, but that ignores the fact that we need the cash today, and that this issue is and will be presenting every year. So we are, each year, stacking and stacking again more debt without really increasing the number of customers who are around to help us pay for it. This is in part how debt gets out of all historical proportion to the size of our business, which I think we've amply demonstrated has occurred.

So Manitoba Hydro's proposed solution is simple. We need to start listening to what the

Manitoba Hydro Act says. At Section 40, part 2, clause (b), and we spoke about this a bit this morning with Mr. Williams from Business Council, where it says:

> "The Board shall establish, maintain, and adjust reserves such that they be used amongst other things, towards the renewal, reconstruction, and replacement of depreciated property and works."

Morrison Park Associates points to the need for reserves since there are no equity investors who have capital at risk. If we don't have a rate of return and a ready source of equity to provide for financial stability, then we have to turn to reserves. Reserves have to mean an annual charge on the customers, just as surely as customers are charged for interest, and operating costs, and everything else, and we've not been charging enough for reserves in today's rates. In fact, we haven't been charging at all. We have slowly but surely depleted the annual conterburtion -- contribution to reserves embedded in our rates at the same time as we have been dramatically growing our business.

Going forward. If we follow the 3.95

percent rate path, our net income will be negative over ten (10) years while our plant and service more than doubles. In 2017, we made thirty (30) million on the operations, and that's what we expect to make in fiscal 2018. These aren't contributions to reserves on a business that is twenty (20) billion and heading to thirty (30) billion in size of its assets.

In fact, Mr. Monnin pointed us this morning to Board Order 101/'04, wherein at page 13 the Public Utilities Board says:

"A net income of forty (40) million is minimal for a corporation with assets of then ten (10) billion."

So it -- a net income of negative two hundred (200) million is consequently more minimal for assets --

MR. CHAIRPERSON: Sorry, can I interrupt for a second. This isn't even close to redirecting, you know, Ms. Ramage. This isn't redirect, this is final argument. You know, and I expect -- I didn't want to interrupt, I was prepared to allow Mr. McCallum to do this but this is inappropriate.

If you have redirect -- you know what redirect is, you're seasoned counsel. If you have redirect, ask in redirect. This isn't a time to give a -- to read a written speech. I've got Bonbright in my office, I can read Bonbright.

So if there's proper redirect put the questions to him. In my opening comments I asked that questions and answers be clear and concise. You know, there may be very well a good argument but it's for -- for the argument phase, not for redirect because I don't want to get the next panel when you -- when you're asked for redirect, where you get to summarize your entire case and put it in an argument form.

MS. PATTI RAMAGE: Thank you, Mr. Chair, and I understand and I apologize. I will say, however, that because chapters of Bonbright were put to the witness this is where we were going to explain how it fits into the system. But we will --

MR. CHAIRPERSON: Yeah, but come on, Ms. Ramage, I mean, you could put questions to him, specific questions to him. I mean, redirect's intended for something not anticipated. I can understand putting a Bonbright question to him. And Mr. McCallum is reading very eloquently from written comments which are normally done by counsel at the end of the case.

This is -- I -- I don't know if this is

going to be included in your argument at the end of the case, but it may very well be, but it's just not appropriate for -- for redirect.

MS. PATTI RAMAGE: We will -- if I can have a moment with Mr. McCallum to...

(BRIEF PAUSE)

MS. PATTI RAMAGE: In light of your comments, Mr. Chair, we'll just -- we'll come -- we'll open Mr. McCallum up to any questions that he has on his comments.

MR. CHAIRPERSON: Does Panel have any questions?

(BRIEF PAUSE)

MR. CHAIRPERSON: Nope. I think we're fine.

BOARD MEMBER MCKAY: Can I make one (1) comment?

THE CHAIRPERSON: Sorry, Ms. McKay, yes.

BOARD MEMBER MCKAY: It's nice to know that the position has changed from the opening answer

-- the -- last week from Mr. McCallum and not knowing what Bonbright -- what I thought -- since he was dead by the time that second edition came out. So, it's good that you read the book.

MR. JAMES MCCALLUM: Just for the record, I didn't read all of it.

MR. CHAIRPERSON: Well, Mr. McCallum, if you wanted I have it and God bless you if you can -- it's a -- it's a well-written book in a few pages at a time.

Anyways, if we're -- we're done. We will adjourn and reconvene at 9:00 a.m. with panel 3 tomorrow. Thank you.

--- Adjourned at 3:04 p.m.

Certified Correct,

____

Sean Coleman, Mr.

Tab 159

PUB MFR 122 (Revised)
Keeyask

Provide a description outlining the reasons for the increased Keeyask budget of $8.7 billion and explain what Manitoba Hydro is doing to ensure the project is completed according to the revised budget and schedule.

It was announced in February, 2017 that the Keeyask control budget was increased to $8.7 billion and the first unit in-service date has been revised to August 2021. The revised control budget reflects a detailed review by Manitoba Hydro that considered the current state of project's progress and costs incurred to date, including the results of the first full year of structural concrete work in 2016.

At the end of the 2016 construction season, concrete placement was only at approximately 40% of plan while earthworks were only at approximately 60% of plan. The full impact of these challenges were only realized at the end of the 2016 construction season. Manitoba Hydro and the General Civil Contractor assessed the underlying causes of the challenges experienced with the Keeyask Project. The main contributing factors to the underperformance included:

- BBE's bid was based upon labour productivity rates that proved to be unachievable in the current market,
- Slower than planned progress in ramp-up on site, and,
- Actual experience with geotechnical and geological conditions.

Generally speaking, all other components of the project remain on track but have now been affected due to a longer schedule and increased workforce to accommodate a recovery plan.

Figure 1 below provides a summary of the cost increases.

Figure 1. Keeyask Budget Summary

Keeyask Budget Summary (in Billions $)				
Item #	**Item**	**Previously Approved Budget (2014$)**	**Current Approved Budget(2016$)**	**Variance**
1.1	Generating Station	4.046	5.948	1.902
1.2	Generation Outlet Transmission (GOT)	0.164	0.202	0.038
1.3	Escalation @ CPI	0.244	0.249	0.005
1.4	Interest (including Interest on Equity)	1.343	1.749	0.406
1.5	Contingency	0.307	0.578	0.271
1.6	Labour Management Reserve	0.304	0.000	-0.304
1.7	Escalation Management Reserve	0.088	0.000	-0.088
1.8	**Total**	**6.496 B**	**8.726**	**2.230**
1.9	First in-service Date	Nov-2019	Aug-2021	21 months.

To ensure that cost increases and schedule delays are minimized, Manitoba Hydro developed a recovery plan which incorporates a number of features. The recovery efforts include understanding the root causes of underperformance and defining actions that can lead to positive change. Implementation of these changes began in the fall of 2016 and continues into the 2017 construction season. The primary activities in recovery planning include:

- An amended contract between Manitoba Hydro and the General Civil Contractor to align interests and provide incentives for meeting performance objectives (completed);
- Implementing revisions to the General Civil Contractor organization structure to increase supervision and improve the management of work processes (in progress);
- Implementing an improved cost and schedule control system (completed);
- Development and deployment of an issues management system (completed);

- Development of refined processes, systems, and tools based upon the findings of the root cause analysis (in progress);
- Implementation of a change management program to enable a culture shift within the project team (in progress);
- Development of key performance indicators to report on all deliverables (in progress);
- Management of respectful workplace concerns (in progress); and
- Continued implementation of the PR280/290 task force to work with Partners, stakeholders and Manitoba Infrastructure (in progress).

Please find attached the Keeyask Capital Project Justification Addendum 5 attached to this response.

APPROVED BY MHEB
MINUTE # 875.01

DATE: 2017 02 15
Financial Planning

APPROVED BY EXECUTIVE COMMITTEE
MINUTE # 1610.02

DATE: 2017 02 14
Financial Planning

CAPITAL PROJECT JUSTIFICATION ADDENDUM FOR

Keeyask Generation Station

Addendum Number #5

REVIEWED BY:
(Requesting Dept Manager)

NOTED BY:
(if applicable)

Responsible Division: 2017.03.20

Constructing Division:

Financial Department:
(if over $1 million) 2017-03-20

RECOMMENDED FOR IMPLEMENTATION:

Requesting Div. Manager: 2017.03.20

Business Unit V.P.: 2017.03.21.

PRIMARY JUSTIFICATION:
Indicate key project driver(s):

- ☐ Safety
- ☒ System Supply
- ☐ System Reliability
- ☐ Customer Service
- ☐ Efficiency
- ☐ Environmental

NERC COMPLIANCE*: ☒ **YES** ☐ **NO**

*Determine if the project requires compliance with North American Electric Reliability Corporation (NERC) CIP Cyber Security Standards.

PREV. APPROVED BUDGET $:	$6,496,061,000
REVISED BUDGET $:	$8,726,026,000
START DATE:	2002 04
PREV. APPROVED ISD:	2020 12
REVISED ISD:	2022 08
RISK MATRIX/ BUSINESS CASE TIER: (Optional)	n/a
INVESTMENT REASONS: (Optional)	CL04 Future Power Generation

REQUESTING DIVISION:	Keeyask Project Division
I.M. NODE NUMBER:	1.5.1.6
W.B.S. NUMBERs:	P:05866/P:14539/P:14621/P:14622/P:14625/P:14703/P:15264/P:15955/P:16020/P:16023/P:16024/P:16892/P:16895/P:16897/P:17448/P:18568/P:21087/P:21089/P:25183/P:25188/P:25484/P:25638/P:25639/P:25662/P:25719/P:26472/P:26688
MAJOR ITEM ☒	**DOMESTIC ITEM** ☐
PREPARED BY:	J.D. Bowen
DATE PREPARED:	2017 02 15
REPORT NUMBER:	
FILE NUMBER (Optional):	

5	2017 02 15	Revision to budget and schedule	J.D. Bowen	Board Minute #875.01 (a)
4	2014 03 20	Revision to budget	J.D. Bowen	E.C. Minute 1505.07
3	2012 09 06	Sensitivity Analysis Review	G.P.F. Schick	E.C. Minute 1418.04
2	2010 09 15	Re-estimate	G.P.F. Schick	E.C. Minute 1324.05
1	2009 03 06	Revision to budget	C. Michaluk/D. Magnusson	Board Minute # 797-09 06
	2008 10 15	Capital Project Justification (CPJ)	C. Michaluk	Board Minute # 796-08 04
ADDENDUM NUMBER	**DATE** (yyyy mm dd)	**REVISION**	**REVISED BY**	**APPROVED BY**

MANITOBA HYDRO
CAPITAL PROJECT JUSTIFICATION ADDENDUM

Project Name

Keeyask Generating Station

Recommendation

That the project estimate be increased by $2,230 million to a revised total of $8,726 million.

Project Scope

A new control budget of $8.7 billion and revised first unit in-service date of August 2021 have been established for the Keeyask Generating Station, currently under construction on the Nelson River in northern Manitoba. This is an increase from the previously approved control budget of $6.5 billion and a delay of 21 months from the previous in-service date of November 2019.

Background

The potential for the increased cost estimate was first identified in the Manitoba Hydro-Electric Board's review of the capital projects completed in the fall of 2016. That analysis, conducted by the Boston Consulting Group, identified costs for Keeyask were expected to rise from the 2014 control budget of $6.5 billion up to a possible $7.8 billion, along with a potential delay in completion of up to 31 months.

The revised control budget of $8.7 billion reflects a more detailed review conducted by Manitoba Hydro. The revised control budget considers the current state of the project's progress including actual results of the first full year of concrete construction (2016), and allows for $900 million in contingency to account for risks that still remain on the project.

At the conclusion of 2016, the first full year of concrete construction of the principle structures and permanent earthworks, progress of the concrete structures was roughly 40 percent and progress of the earthworks was roughly 60 percent of the plan for the year. As a result, a recovery plan was developed and implemented for the General Civil Works contract and the overall Keeyask project. The recovery plan includes a comprehensive amendment to the General Civil contract, a re-organization of the project execution team and the development of a Step Change Program that is tasked with increasing production rates.

Justification

Manitoba load is growing. Updated electric growth forecasts indicate the province is going to need a new source of generation to meet domestic load by approximately 2033. Keeyask will provide a reliable, renewable source of energy to meet that demand then and into the future. Completing Keeyask will also allow Manitoba Hydro to fulfill export contracts worth approximately $4.5 billion, offsetting some of the costs of the project.

ANALYSIS OF ALTERNATIVES:

Economic Analysis		
Discount Rate	%	

Recommended Option	**NPV Benefits/(Costs)**
Despite the increased cost to complete construction of the Keeyask Project, stopping now is not an economically viable option as the significant costs of cancellation - together with lost revenues - more than offset any potential savings.	

Other Alternatives Considered	**NPV Benefits/(Costs)**
Cancellation of the Keeyask Project	

Risk Analysis

The new control budget includes contingency of an additional $900 million in funds to help address potential cost and schedule risks still present in the project such as:

- the ability to successfully achieve and improve upon General Civil Works production rates;
- the potential for delays caused by interface hand-offs between the General Civil Works and other contractors;
- delays arising during the turbine and generator installation, balance of plant and commissioning;
- delays caused by geotechnical conditions in the south dam and south dyke (two areas that have not yet been excavated);

The new control budget does not include allowances for the following risks:

- the potential for capitalized interest rate changes where a one percentage increase in interest rates equates to approximately $215 million;
- severe event risk that has a high impact but low likelihood of occurrence - examples of severe events include a loss of site access (ie. extended blockade), severe weather event (fire or flood), and severe safety/environmental incident that would cause a work stoppage of up to a year.

Labour:

No labour reserve has been carried forward.

Total Budget

The impact on annual budget requirements is as follows (in thousands of dollars):

Fiscal Year	Prev. Approved CPJ/Addendum	Proposed CPJ Addendum	Increase (Decrease)
Prev. Actuals	$ 1,693,518	$ 1,693,518	$ -
2015/16	$ 676,333	$ 665,675	$ (10,658)
2016/17	$ 962,189	$ 914,219	$ (47,971)
2017/18	$ 1,351,297	$ 1,077,483	$ (273,814)
2018/19	$ 927,908	$ 1,290,484	$ 362,576
2019/20	$ 616,472	$ 1,116,741	$ 500,269
2020/21	$ 208,578	$ 867,942	$ 659,364
2021/22	$ 55,193	$ 707,069	$ 651,876
2022/23	$ 4,470	$ 329,896	$ 325,426
2023/24	$ 103	$ 58,189	$ 58,086
2024/25	$ -	$ 2,382	$ 2,382
2025/26	$ -	$ 1,509	$ 1,509
2026/27	$ -	$ 920	$ 920
Total	$ 6,496,061	$ 8,726,026	$ 2,229,965

Proposed Schedule

The first unit in-service date was November 2019 in CPJA #4, and is revised to August 2021. The last unit in-service date was December 2020 in CPJA #4, and is revised to August 2022.

Related Projects

Grand Rapids Fish Hatchery Expansion of which 50% was previously included in the budget for Keeyask.

Reference Documents

2014 Public Utilities Board Report on the Needs for and Alternatives To
K-C NFAT Submission – Original NFAT submission
March 2014 Update - Presentation & Undertakings
2013/14 Power Resource Plan
CPJ dated October 15, 2008 - Keeyask Generating Station
CPJ Addendum #1 dated March 6, 2009
CPJ Addendum #2 dated September 9, 2010
CPJ Addendum #3 dated September 6, 2012
CPJ Addendum #4 dated November 4, 2014