File: Field/Pool
NVSU #2
Pressure Surveys.

Tundra oil and gas ltd.

1111 One Lombard Place, Winnipeg, Manitoba R3B 0X4 TEL: (204) 934-5850 FAX: (204) 934-5820

February 2, 1998

Manitoba Energy and Mines
Petroleum Branch
1395 Ellice Avenue
Suite 360
Winnipeg, Manitoba
R3G 3P2

Attention: **Mr. John Fox, P.Eng.**
Chief Petroleum Engineer

Dear John,

RE: Mountcliff NVS Unit No.2 16-30-11-26 WPM
Well Licence Conditions

In reply to your letter dated 98.02.02, Tundra encloses the information requested in support of our position that the Petroleum Branch waive Condition 6 of the well licence application for the 16-30 horizontal. The information package includes pressure surveys completed in 1994 and 1995, voidage replacement calculations for the North Virden Scallion Unit No.2 from 1994 to 1997.09.30., and pressure fall-off tests completed in 1997. Since the Unit has a low cumulative voidage replacement ratio of 0.38, and pressure fall-off tests with bleed-off conditions to reservoir pressures conditions of 6,500 kPag in less than 3 days, it is unlikely that the Upper Cherty is over pressured in the area proposed for horizontal drilling. In our opinion, there has been minimal reservoir pressure change since the pressure maintenance scheme was initiated in 1989. As a result, it is unlikely that over pressuring from waterflood operations will impact drilling operations. To mitigate any potential effects from the pressure maintenance scheme, Tundra will shut-in injection wells 12-29 and 4-32-11-26 WPM during drilling operations.

Should you have any questions, please contact me at 934-5853.

Sincerely,

TUNDRA OIL AND GAS LTD.

George Czyzewski, P.Eng.
General Manager

cc: T. Howell

NORTH VIRDEN SCALLION UNIT NO.2

VOIDAGE CALCULATIONS

FROM JAN 1,1994 TO DEC. 31, 1994

OIL FORMATION VOLUME FACTOR = 1.05 Rm3

MONTH	OIL PRODUCTION	WATER PRODUCTION	OIL VOIDAGE	TOTAL VOIDAGE	TOTAL INJECTION	NET VOIDAGE	VOIDAGE REPLACEMENT RATIO
	m3	m3	Rm3	Rm3	Rm3	Rm3	VRR (Rm3/Rm3)
JAN.	397.9	512.0	417.8	929.8	545.9	383.9	0.59
FEB.	363.1	474.9	381.3	856.2	512.8	343.4	0.60
MAR.	387.9	524.1	407.3	931.4	563.2	368.2	0.60
APRIL	368.9	505.1	387.3	892.4	543.6	348.8	0.61
MAY	381.6	580.4	400.7	981.1	625.5	355.6	0.64
JUNE	371.4	575.1	390.0	965.1	600.9	364.2	0.62
JULY	378.2	576.7	397.1	973.8	688.7	285.1	0.71
AUG.	363.7	622.8	381.9	1,004.7	758.1	246.6	0.75
SEPT.	343.3	628.7	360.5	989.2	638.8	350.4	0.65
OCT.	320.1	680.4	336.1	1,016.5	635.1	381.4	0.62
NOV.	381.1	765.5	400.2	1,165.7	654.0	511.7	0.56
DEC.	368.0	754.2	386.4	1,140.6	671.7	468.9	0.59
TOTAL	4,425.2	7,200	4,646	11,846	7,438	4,408	0.63

CUM. POOL VOIDAGE (94.12.31) =	131,910.2	Rm3
CUM. POOL INJECTION (94.12.31) =	41,872.4	Rm3
CUM. NET VOIDAGE (94.12.31) =	90,037.8	Rm3
CUM. VRR (94.12.31) =	0.32	Rm3 / Rm3

NORTH VIRDEN SCALLION UNIT NO.2

VOIDAGE CALCULATIONS

FROM JAN 1,1995 TO DEC. 31, 1995

OIL FORMATION VOLUME FACTOR = 1.05 Rm3

MONTH	OIL PRODUCTION m3	WATER PRODUCTION m3	OIL VOIDAGE Rm3	TOTAL VOIDAGE Rm3	TOTAL INJECTION Rm3	NET VOIDAGE Rm3	VOIDAGE REPLACEMENT RATIO VRR (Rm3/Rm3)
JAN.	387.9	704.7	407.3	1,112.0	629.9	482.1	0.57
FEB.	353.2	685.1	370.9	1,056.0	540.4	515.6	0.51
MAR.	376.3	760.8	395.1	1,155.9	583.2	572.7	0.50
APRIL	370.7	683.8	389.2	1,073.0	525.7	547.3	0.49
MAY	363.2	600.8	381.4	982.2	508.4	473.8	0.52
JUNE	365.6	590.5	383.9	974.4	412.6	561.8	0.42
JULY	370.9	579.9	389.4	969.3	515.3	454.0	0.53
AUG.	372.2	585.5	390.8	976.3	672.8	303.5	0.69
SEPT.	377.3	583.0	396.2	979.2	553.0	426.2	0.56
OCT.	398.2	617.7	418.1	1,035.8	698.7	337.1	0.67
NOV.	383.3	577.6	402.5	980.1	651.3	328.8	0.66
DEC.	372.2	513.6	390.8	904.4	516.1	388.3	0.57
TOTAL	4,491.0	7,483	4,716	12,199	6,807	5,391	0.56

CUM. POOL VOIDAGE (94.12.31) =	131,910.2	Rm3
CUM. POOL INJECTION (94.12.31) =	41,872.4	Rm3
CUM. POOL VOIDAGE (95.12.31) =	144,108.7	Rm3
CUM. POOL INJECTION (95.12.31) =	48,679.8	Rm3
CUM. NET VOIDAGE (95.12.31) =	95,428.9	Rm3
CUM. VRR (95.12.31) =	0.34	Rm3 / Rm3

NORTH VIRDEN SCALLION UNIT NO.2

VOIDAGE CALCULATIONS

FROM JAN 1,1996 TO DEC. 31, 1996

OIL FORMATION VOLUME FACTOR = 1.05 Rm3

MONTH	OIL PRODUCTION	WATER PRODUCTION	OIL VOIDAGE	TOTAL VOIDAGE	TOTAL INJECTION	NET VOIDAGE	VOIDAGE REPLACEMENT RATIO
	m3	m3	Rm3	Rm3	Rm3	Rm3	VRR (Rm3/Rm3)
JAN.	366.8	520.6	385.1	905.7	520.3	385.4	0.57
FEB.	332.4	484.2	349.0	833.2	486.1	347.1	0.58
MAR.	361.7	636.1	379.8	1,015.9	589.4	426.5	0.58
APRIL	377.6	587.0	396.5	983.5	613.0	370.5	0.62
MAY	380.9	584.3	399.9	984.2	624.9	359.3	0.63
JUNE	362.0	593.0	380.1	973.1	647.1	326.0	0.66
JULY	374.9	924.4	393.6	1,318.0	908.9	409.1	0.69
AUG.	369.7	1,143.2	388.2	1,531.4	970.0	561.4	0.63
SEPT.	360.7	840.4	378.7	1,219.1	713.5	505.6	0.59
OCT.	359.5	705.3	377.5	1,082.8	843.6	239.2	0.78
NOV.	361.9	726.9	380.0	1,106.9	640.3	466.6	0.58
DEC.	367.9	596.1	386.3	982.4	583.3	399.1	0.59
TOTAL	4,376.0	8,342	4,595	12,936	8,140	4,796	0.63

CUM. POOL VOIDAGE (95.12.31) =	144,108.7	Rm3
CUM. POOL INJECTION (95.12.31) =	48,679.8	Rm3
CUM. POOL VOIDAGE (96.12.31) =	157,045.0	Rm3
CUM. POOL INJECTION (96.12.31) =	56,820.2	Rm3
CUM. NET VOIDAGE (96.12.31) =	100,224.8	Rm3
CUM. VRR (96.12.31) =	0.36	Rm3 / Rm3

NORTH VIRDEN SCALLION UNIT NO.2

VOIDAGE CALCULATIONS

FROM JAN 1,1997 TO SEPT. 30, 1997

OIL FORMATION VOLUME FACTOR = 1.05 Rm3

MONTH	OIL PRODUCTION	WATER PRODUCTION	OIL VOIDAGE	TOTAL VOIDAGE	TOTAL INJECTION	NET VOIDAGE	VOIDAGE REPLACEMENT RATIO
	m3	m3	Rm3	Rm3	Rm3	Rm3	VRR (Rm3/Rm3)
JAN.	361.1	598.8	379.2	978.0	464.1	513.9	0.47
FEB.	321.8	617.1	337.9	956.0	600.0	355.0	0.63
MAR.	334.2	659.9	350.9	1,010.8	663.4	347.4	0.66
APRIL	320.5	642.7	336.5	979.2	684.6	294.6	0.70
MAY	344.8	681.5	362.0	1,043.5	688.1	355.4	0.66
JUNE	325.7	608.8	342.0	950.8	639.7	311.1	0.67
JULY	374.9	334.5	611.6	946.1	428.7	517.4	0.45
AUG.	331.4	686.6	348.0	1,034.6	707.6	327.0	0.68
SEPT.	317.8	677.2	333.7	1,010.9	672.0	338.9	0.66
OCT.	0.0	0.0	0.0	0.0	0.0	0.0	0.00
NOV.	0.0	0.0	0.0	0.0	0.0	0.0	0.00
DEC.	0.0	0.0	0.0	0.0	0.0	0.0	0.00
TOTAL	3,032.2	5,507	3,402	8,909	5,548	3,361	0.62

CUM. POOL VOIDAGE (96.12.31) =	157,045.0	Rm3
CUM. POOL INJECTION (96.12.31) =	56,820.2	Rm3
CUM. POOL VOIDAGE (97.09.30) =	165,953.9	Rm3
CUM. POOL INJECTION (97.09.30) =	62,368.4	Rm3
CUM. NET VOIDAGE (97.09.30) =	103,585.5	Rm3
CUM. VRR (97.09.30) =	0.38	Rm3 / Rm3

FEB-02-1998 11:26 TUNDRA OIL & GAS P.02

George

Scallion 12-29-11-28 WIW Fall Off Test
Feb / 1997

Delta T Hours	Pressure Psi
0	340
1	300
2	200
3	160
4	140
5	120
6	112
7	102
8	92
9	85
10	78
11	70
12	65
13	60
14	58
15	54
20	38
25	25
30	16
35	10
40	2

Scallion 4-32-11-28 WIW Fal
Feb / 1997

Delta T Hours	Pressure Psi
0	400
1	355
2	330
3	310
4	294
5	280
6	270
7	260
8	252
9	242
10	235
11	227
12	220
13	215
14	210
15	203
16	198
17	194
18	190
19	184
20	180
25	162
30	150
35	138
40	127
45	119
50	114
55	104
60	98
65	92
70	90
75	82
80	77
85	72
90	65
95	62

TOTAL P.02

Tp = ((7,108) / 1.6) * 24 = 106,620 hrs

NORTH VIRDEN SCALLION UNIT NO.2

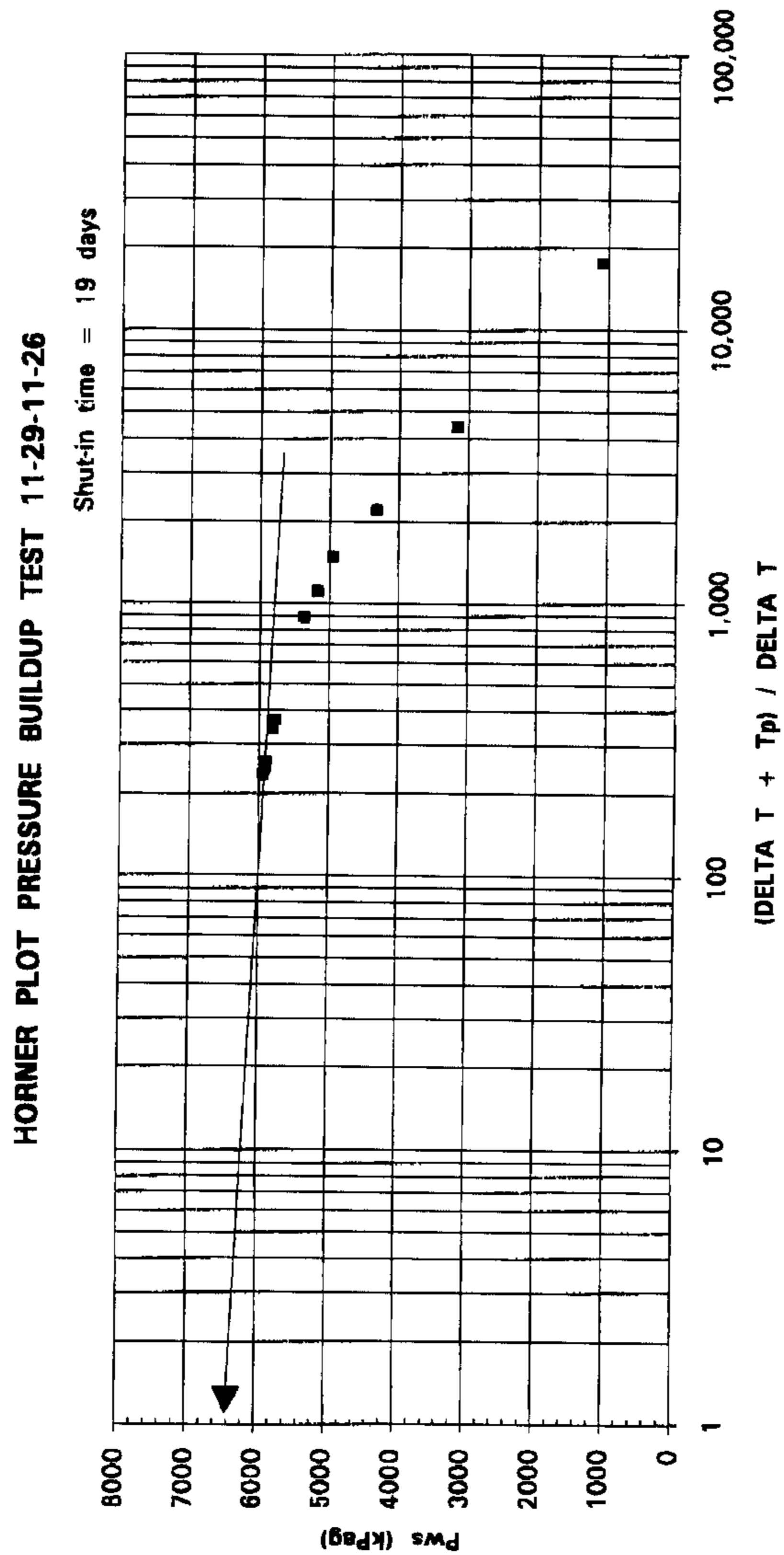
WELL 11-29-11-26

PRESSURE BUILDUP DATA

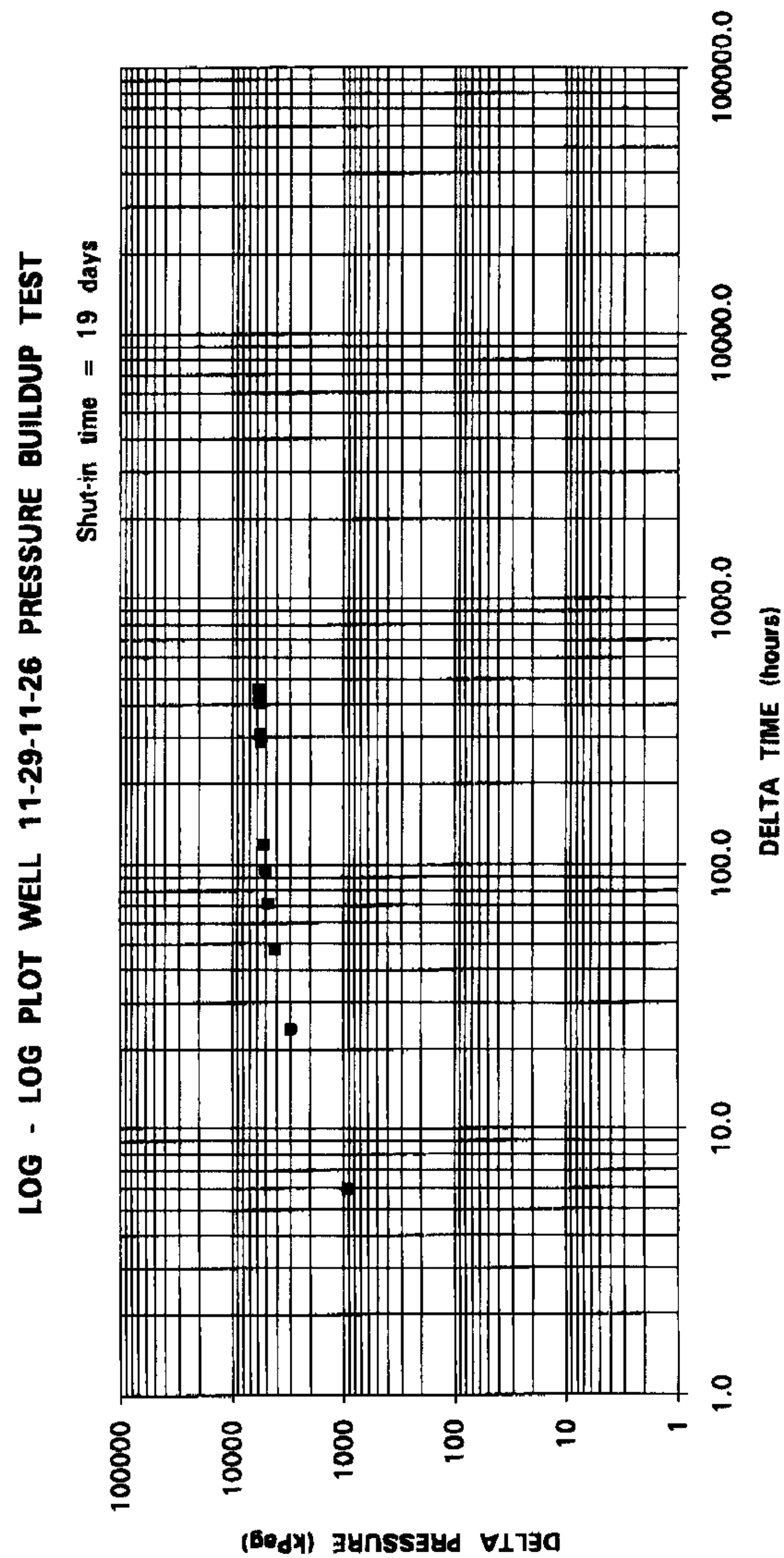
HORNER PLOT

DATE	TIME (hours)	DELTA TIME (hours)	TIME (days)	(DELTA T + Tp) / DELTA T	JOINTS TO FLUID	FLUID LEVEL (m)	FLUID PRESSURE (kPa)	CASING PRESSURE (kPa)	ADJ. CASING PRESSURE (kPa)	TOTAL PRESSURE (kPa)	TOTAL PRESSURE (psig)
May 20/95	9:00 AM	0	0.0	-	67	637	0	172	180	180	26
	3:00 PM	6	0.25	17,771	58	651	841	241	250	1091	158
May 21/95	9:00 AM	24	1.0	4,444	36.5	347	2740	414	424	3164	459
May 22/95	9:00 AM	48	2.0	2,222	25.5	242	3711	607	617	4328	628
May 23/95	9:00 AM	72	3.0	1,482	20	190	4197	745	755	4951	718
May 24/95	9:00 AM	96	4.0	1,112	17.5	166	4417	745	753	5171	750
May 25/95	9:00 AM	120	5.0	890	15.5	147	4594	758	766	5360	777
June 1/95	9:00 AM	288	12.0	371	13.5	128	4771	986	995	5766	836
June 2/95	9:00 AM	312	13.0	343	13	124	4815	993	1001	5816	844
June 6/95	9:00 AM	408	17.0	262	12.5	119	4859	1034	1042	5901	856
June 7/95	9:00 AM	432	18.0	248	12.33	117	4874	1041	1049	5923	859
June 8/95	9:00 AM	456	19.0	235	12.25	116	4881	1048	1056	5937	861

CHP1129.XLC


HORNER PLOT PRESSURE BUILDUP TEST 11-29-11-26
Shut-in time = 19 days
Pws (kPag)
8000
7000
6000
5000
4000
3000
2000
1000
0
1
10
100
1,000
10,000
100,000
(DELTA T + Tp) / DELTA T

LGLG1129.XLC



Tp = ((4,444) / 0.8) * 24 = 133,320 hrs

NORTH VIRDEN SCALLION UNIT NO.2

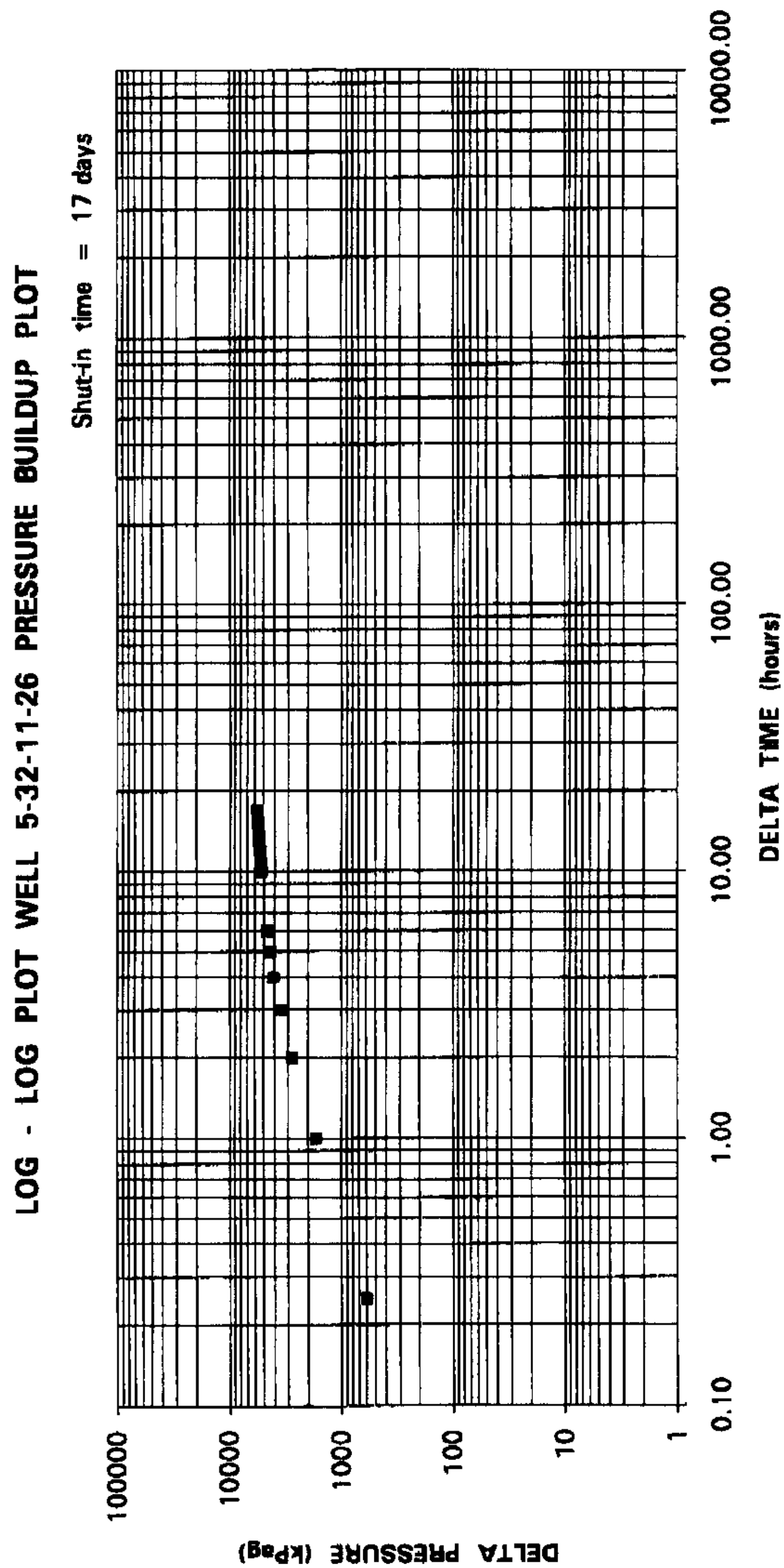
WELL 5-32-11-26

PRESSURE BUILDUP DATA

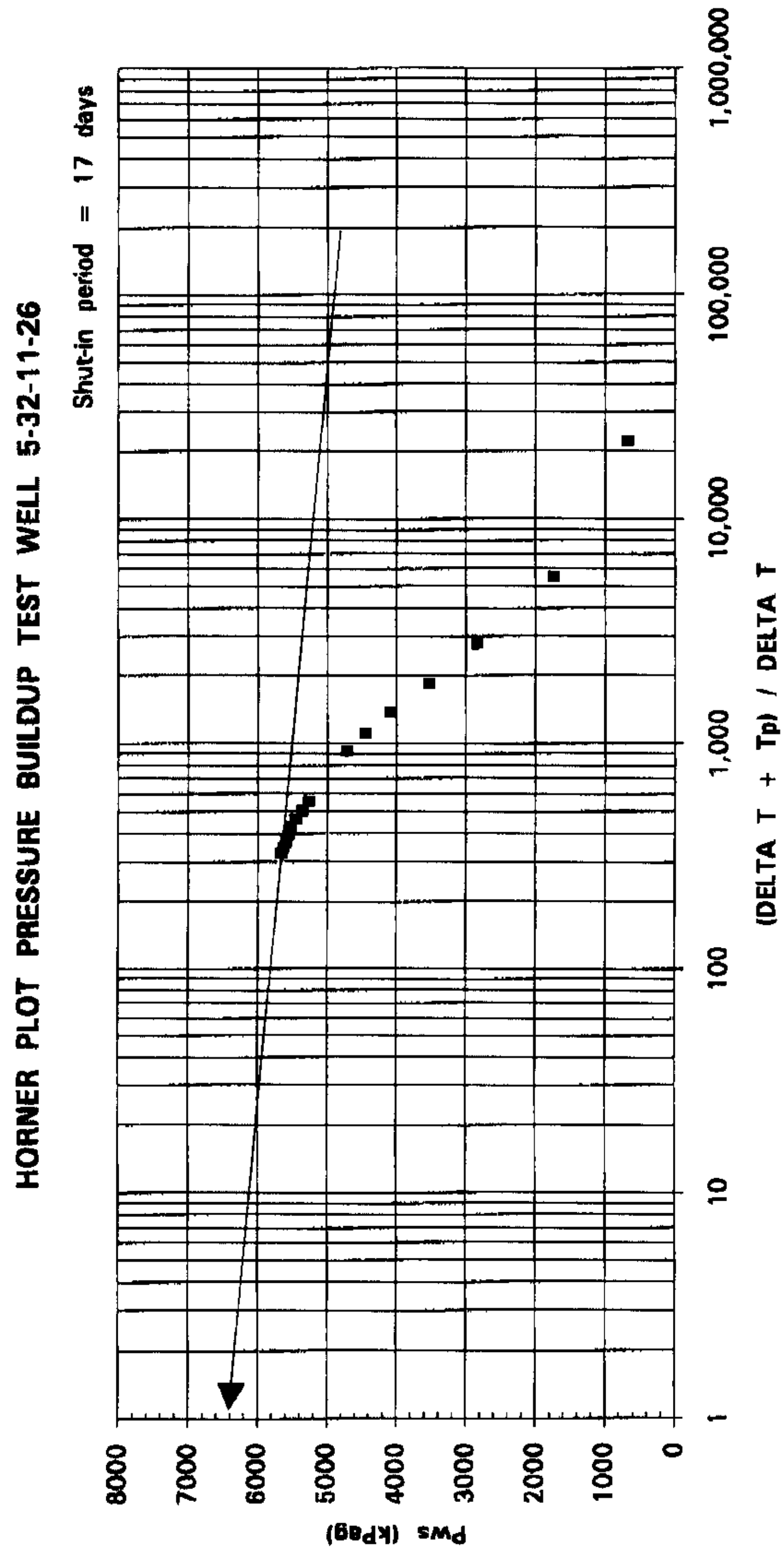
HORNER PLOT

DATE	TIME (hours)	DELTA TIME (hours)	TIME (days)	(DELTA T + Tp) DELTA T	JOINTS TO FLUID	FLUID LEVEL (m)	FLUID PRESSURE (kPa)	CASING PRESSURE (kPa)	ADJ. CASING PRESSURE (kPa)	TOTAL PRESSURE (kPa)	TOTAL PRESSURE (psig)
Mar. 18 / 95	9:00 AM	0	0.0	-	67	637	0	69	72	72	10
	3:00 PM	6	0.25	22,221	60	570	559	103	107	667	97
Mar. 19 / 95	9:00 AM	24	1.0	5,556	48.5	461	1549	179	185	1734	252
Mar. 20 / 95	9:00 AM	48	2.0	2,779	36.75	349	2561	262	268	2829	410
Mar. 21 /95	9:00 AM	72	3.0	1,853	29.5	280	3185	345	351	3536	513
Mar. 22 / 95	9:00 AM	96	4.0	1,390	24	228	3658	421	427	4085	592
Mar. 23 / 95	9:00 AM	120	5.0	1,112	20.5	195	3959	483	489	4448	645
Mar. 24 / 95	9:00 AM	144	6.0	927	18.25	173	4153	552	558	4711	683
Mar. 28 / 95	9:00 AM	240	10.0	557	13.75	131	4540	717	723	5264	763
Mar. 29 / 95	9:00 AM	264	11.0	506	13	124	4605	745	751	5358	777
Mar. 30 / 95	9:00 AM	288	12.0	464	12.25	116	4669	772	778	5448	790
Mar. 31 / 95	9:00 AM	312	13.0	428	11.75	112	4712	800	806	5518	800
Apr. 1 / 95	9:00 AM	336	14.0	398	11.5	109	4734	814	820	5554	805
Apr. 2 / 95	9:00 AM	360	15.0	371	11.25	107	4756	827	833	5589	811
Apr. 3 / 95	9:00 AM	384	16.0	348	11	105	4777	841	847	5624	816
Apr. 4 / 95	9:00 AM	408	17.0	328	10.75	102	4798	855	861	5659	821

LGLG532.XLC


LOG - LOG PLOT WELL 5-32-11-26 PRESSURE BUILDUP PLOT
Shut-in time = 17 days
DELTA PRESSURE (kPag)
100000
10000
1000
100
10
1
DELTA TIME (hours)
0.10
1.00
10.00
100.00
1000.00
10000.00

CHP532.XLC


HORNER PLOT PRESSURE BUILDUP TEST WELL 5-32-11-26
Shut-in period = 17 days
(DELTA T + Tp) / DELTA T
Pws (kPag)
8000
7000
6000
5000
4000
3000
2000
1000
0
1
10
100
1,000
10,000
100,000
1,000,000

Tp = {(7,680) / 1.7} * 24 = 108,424 hrs

NORTH VIRDEN SCALLION UNIT NO.2

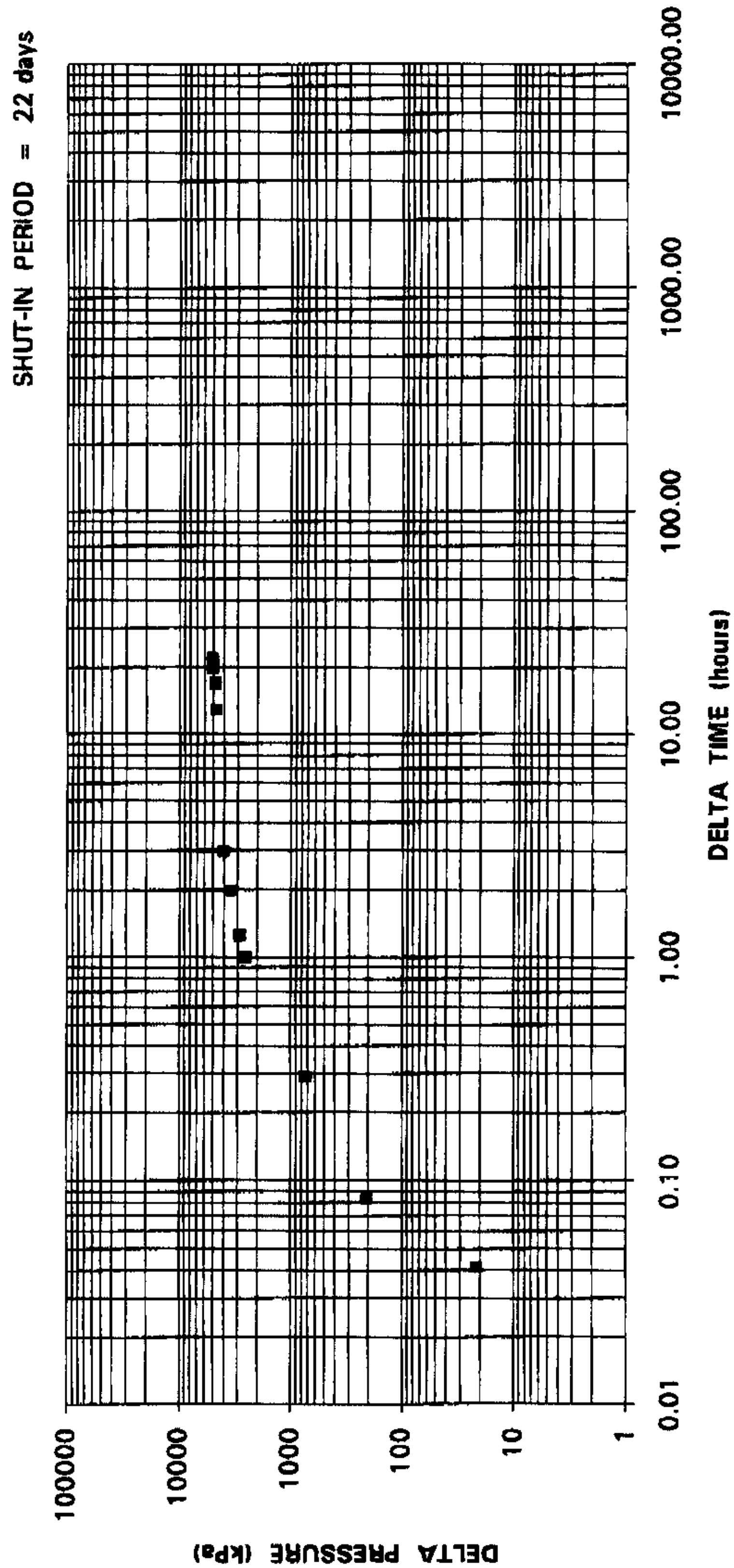
WELL 16-30-11-26

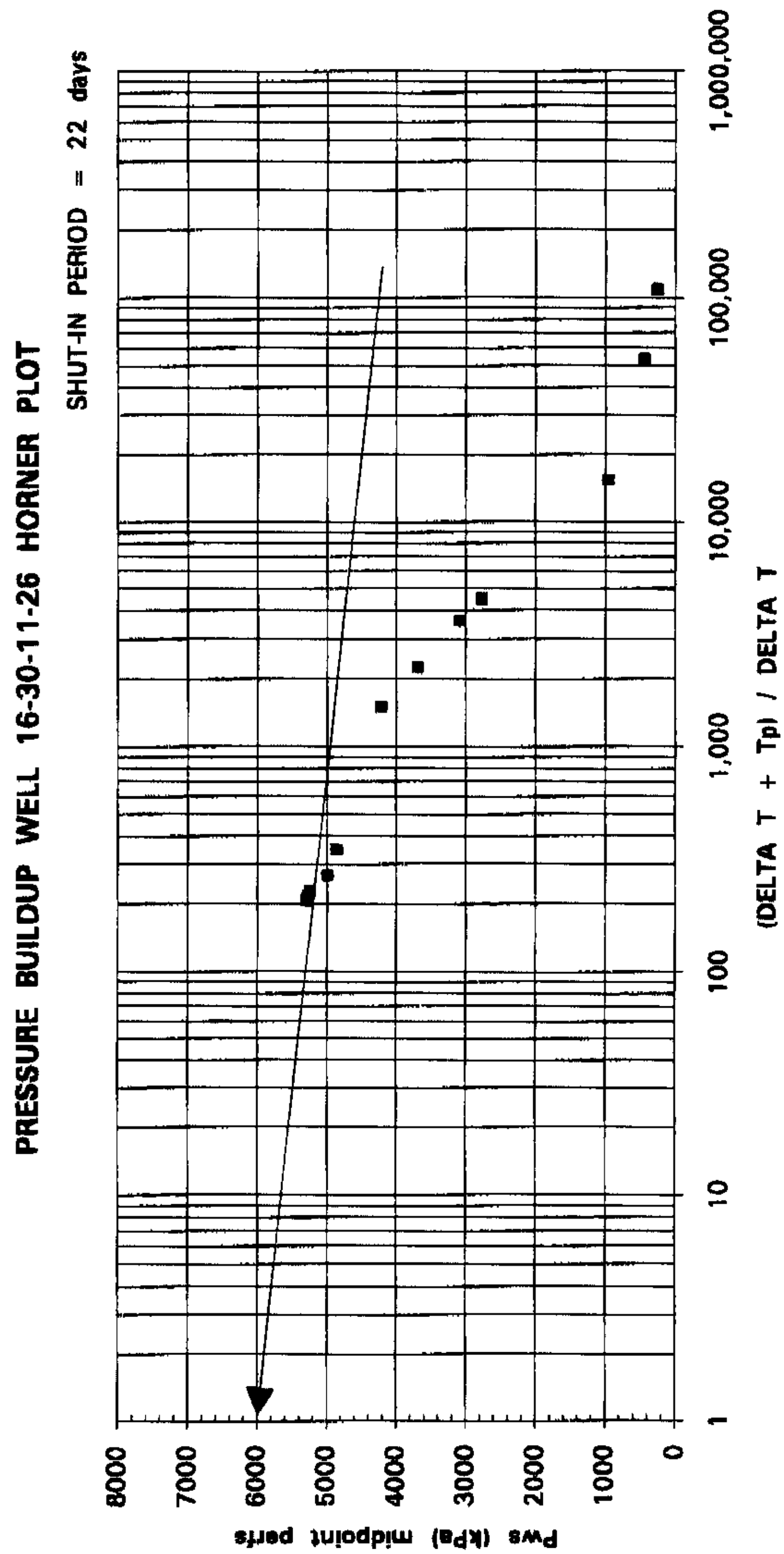
PRESSURE BUILDUP DATA

HORNER PLOT

DATE	TIME (hours)	DELTA TIME (hours)	TIME (days)	(DELTA T + Tp) DELTA T	JOINTS TO FLUID	FLUID LEVEL (m)	FLUID PRESSURE (kPa)	CASING PRESSURE (kPa)	ADJ. CASING PRESSURE (kPa)	TOTAL PRESSURE (kPa)	TOTAL PRESSURE (psig)
Nov. 25/94	9:00 AM	0	0.0	-	68	646	11	207	216	228	33
	10:00 AM	1	0.04	108,425	68	646	11	229	238	250	36
	11:00 AM	2	0.1	54,213	66	627	183	241	252	435	63
	4:00 PM	7	0.3	15,490	60	570	699	248	258	957	139
Nov. 26/94	9:00 AM	24	1.0	4,519	40	380	2419	345	354	2773	402
	3:00 PM	30	1.3	3,616	36	342	2763	310	317	3080	447
Nov. 27/94	9:00 AM	48	2.0	2,260	27.75	263.625	3472	207	211	3683	534
Nov. 28/94	9:00 AM	72	3.0	1,507	19.5	185.25	4181	34	34	4216	611
Dec. 6/94	9:00 AM	312	13.0	349	12	114	4826	34	34	4860	705
Dec. 12/94	9:00 AM	408	17.0	267	10.5	99.75	4955	34	34	4989	724
Dec. 15/94	9:00 AM	480	20.0	227	7.5	71.25	5213	34	34	5247	761
Dec. 16/94	9:00 AM	504	21.0	216	7.25	68.875	5234	34	34	5268	764
Dec. 17/94	9:00 AM	528	22.0	206	7	66.5	5256	34	34	5290	767

LOG - LOG PLOT 16-30-11-26




PRESSURE BUILDUP WELL 16-30-11-26 HORNER PLOT
SHUT-IN PERIOD = 22 days
1,000,000
100,000
10,000
1,000
100
10
1
(DELTA T + Tp) / DELTA T
8000
7000
6000
5000
4000
3000
2000
1000
0
Pws (kPa) midpoint perfs

Manitoba

Action / Route Slip

Date: January 10, 1992

To: H. Clare Moster
Deputy Chairman

From: John N. Fox

Telephone:

☐ Take Action ☐ Per Your Request ☐ Circulate, Initial and Return ☐ For Approval and Signature ☐ Make ____ Copies

☐ May We Discuss ☐ For Your Information ☐ Return With Comments or Revisions ☐ Draft Reply for Signature ☐ Please File

Comments: Ranchmen's continued objection to Saskoil's application to revise Section 8 of Board Order No. PM 59 has been reviewed. The Branch recommends Saskoil's application be approved as Ranchmen's equity concerns can be resolved by an enlargement of the unit either voluntary or Board ordered. The attached letter to Saskoil addressed the Board's concerns regarding the waterflood in NVSU No. 2. The attached letter to Ranchmen's addresses the concerns raised in the company's objections.

MG-1298 PS-f-182

January 10, 1992

Mr. K.J. Majoram, P. Eng.
Operations Engineer
Ranchmen's Resources Ltd.
Suite 1000, 333-11th Avenue S.W.
Calgary, Alberta
T2R 1L9

Dear Mr. Majoram:

RE: North Virden Scallion Unit No. 2
Application to Amend Board Order No. PM 59

The Board has completed its review of Saskoil's application to amend the provisions of Section 8 of Board Order No. PM 59 and Ranchmen's objections to the subject application. The Board has approved Saskoil's application effective January 1, 1992. A copy of the Board's letter of approval is attached.

In response to the concerns raised by Ranchmen's in its letter of December 20, 1991, the Board offers the following comments:

1. Unit Expansion

   The Board encourages Ranchmen's to continue its negotiations with Saskoil to expand NVSU No. 2 to include all or a portion of Ranchmen's wells in Section 30-11-26 (WPM). If the negotiations are unsuccessful, Ranchmen's may file an application with the Board under Section 79 of The Mines Act for an order to enlarge the unit.

   An application to enlarge the unit to include all Ranchmen's wells in Section 30-11-26 (WPM) should be accompanied by an application for enhanced recovery operations under Section 126 of The Petroleum Drilling and Production Regulation.

   The Petroleum Branch has indicated it is prepared to offer administrative and technical assistance to both parties in this matter.

2. Waterflood Implementation and Injection Distribution

   The Board recognizes that there is a problem with low injectivity and injection distribution in NVSU No. 2. However, since water injection commenced the voidage-replacement ratio (VRR) in NVSU No. 2 has been 0.99. Though less than the target VRR of 1.10 - 1.15, water injection has reduced the unit production decline to 8% /year, from a pre-flood decline rate of 13% /year.

The original Clause 8(b) of Board Order No. PM 59 limited injection at A10-30 to a VRR of 1.15. In calculating the VRR for the A10-30 injection pattern, the Board has used all the wells in the N/2 of Section 30 with appropriate tract factors, including a tract factor of 1.0 for the A11-30 and 14-30 wells. Since waterflood start-up the VRR for the A10-30 injection pattern has been 1.09, not 1.72 as suggested by Ranchmen's (refer to Table 1).

The Board recognizes approval of this application will not solve the low injectivity and injection distribution problems in NVSU No. 2. However, increased injection of approximately 3.0 m^3 /d at A10-30 will provide additional pressure support to the 9-30 and 16-30 wells which are common to the other patterns. Together these wells account for 26% of the unit's voidage.

3. Premature Water Breakthrough and Potential Loss in Recovery at A11-30 and 14-30

As stated in the Board's letter of November 20, 1991, to date, the performance of A11-30 and 14-30 has not been adversely effected by injection at A10-30. Figure 1 which is a combined production plot for both wells suggests that production may have benefitted from injection.

The Board in its letter of November 20, 1991 did not state that there will be a loss in recovery at A11-30 and 14-30 as a result of premature water breakthrough. Rather, the Board indicated this is a potential concern. The Board, in approving Saskoil's application over Ranchmen's objection, was satisfied that the provisions for a Board ordered unit enlargement under The Mines Act, should negotiations fail, provides an appropriate mechanism for resolving any equity issues related to this matter.

If you have any questions in respect of this approval, please contact the undersigned at (204) 945-1111.

Yours respectfully,

ORIGINAL SIGNED BY
H. CLARE MOSTER

H. Clare Moster
Deputy Chairman

cc: Mr. G. Yeryk
Pasqua Resources Ltd.

TABLE 1

VOIDAGE-REPLACEMENT A10-30 INJECTION PATTERN

Well	Tract Factor	Reservoir* Voidage (rm^3)	Reservoir* Replacement (rm^3)
9-30	0.5	1462.2	--
15-30	1.0	546.8	--
16-30	0.33	584.1	--
A10-30	1.0	--	5812.6
A11-30	1.0	2023.7	--
14-30	1.0	728.4	--
		5345.2	5812.6

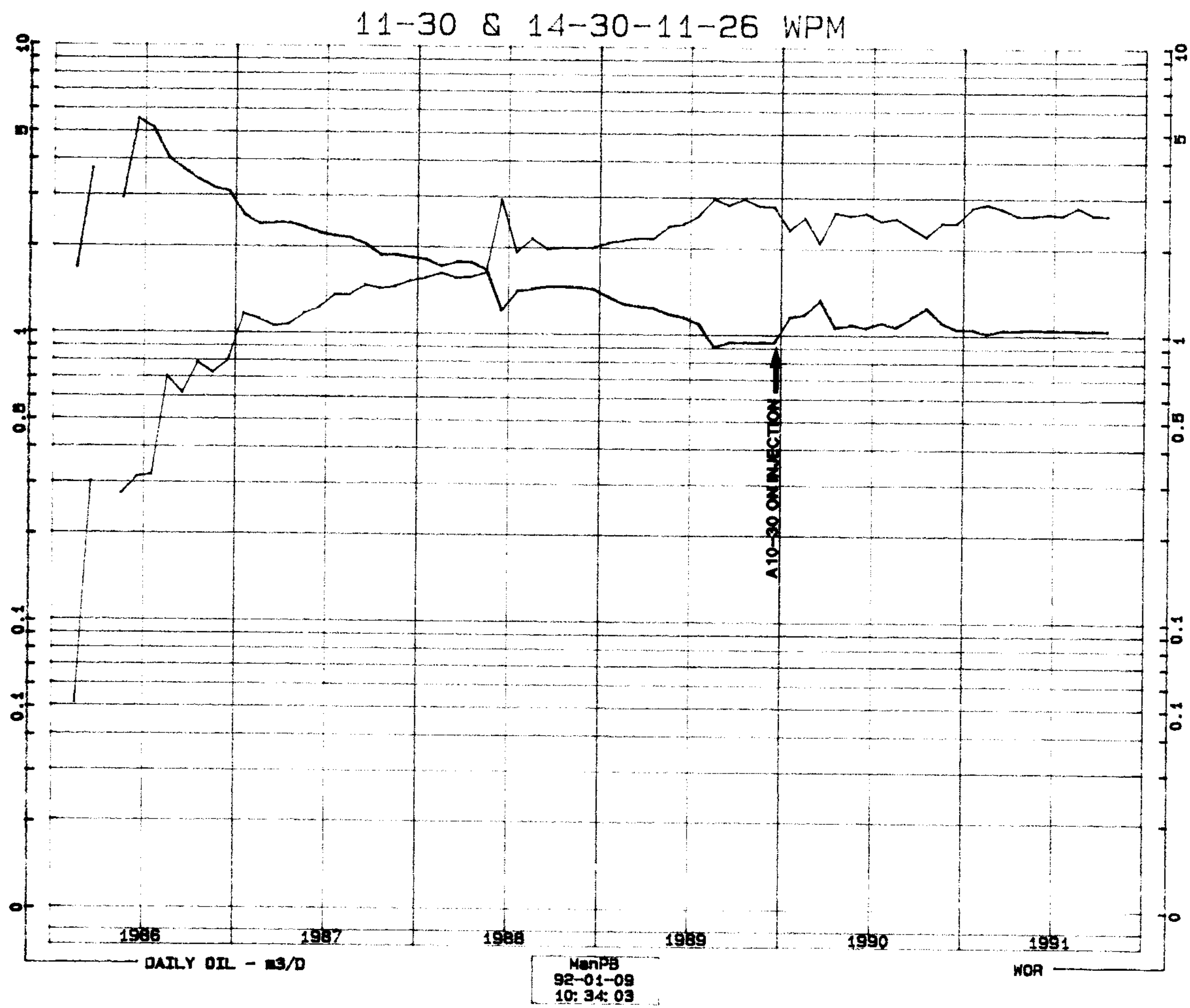
A10-30 injection pattern voidage-replacement ratio = 1.09

* Voidage and replacement calculated from December 1, 1989 to October 31, 1991

Boi = 1.045 rm^3/m^3

Bw = 1.0 rm^3/m^3

FIGURE 1


11-30 & 14-30-11-26 WPM
10
5
1
0.5
0.1
0.1
0
1986
1987
1988
1989
1990
1991
A10-30 ON INJECTION
DAILY OIL - m3/D
WOR
ManPB
92-01-09
10:34:03

January 10, 1992

Mr. Glen Yeryk
Pasqua Resources Ltd.
1777 Victoria Avenue
P.O. Box 1550
Regina, Saskatchewan
S4P 3C4

Dear Mr. Yeryk:

RE: North Virden Scallion Unit No. 2
Application to Amend Board Order No. PM 59

The Board has completed its review of the subject application and the comments and concerns filed by Ranchmen's Resources Ltd. The Board hereby approves Saskoil's application and Section 8 of Board Order No. PM 59 is amended, effective January 1, 1992, as follows:

8. Unless otherwise provided by the Board in writing, the ratio of water injected in the well, ICGR et al Virden WIW A10-30-11-26 (WPM) to reservoir withdrawals from the wells producing in the N/2 of Section 30 in Township 11, Range 26 (WPM) shall not exceed 1.5 on a semi-annual basis. The following factors will be applied to the wells' production to calculate reservoir withdrawals: 9-30 = 0.5, A11-30 = 1.0, 14-30 = 1.0, A15-30 = 1.0 and 16-30 = 0.25.

ICG Resources Ltd. in its original pressure maintenance application (September, 1988) suggested that under certain circumstances Ranchmen's wells, A11-30 and 14-30-11-26 (WPM), would be considered for inclusion in North Virden Scallion Unit No. 2 (NVSU No. 2). Ranchmen's, in its objection to the current application, suggested that the pressure maintenance scheme in NVSU No. 2 be expanded to include all its wells in Section 30-11-26 (WPM). The Board encourages both parties to continue negotiations to expand the unit. The Petroleum Branch has indicated it is prepared to offer administrative and technical assistance to both parties in this matter. If negotiations are unsuccessful, the Board has advised Ranchmen's that it has the option of applying under Section 79 of The Mines Act for an order to enlarge the unit.

During 1991, the voidage-replacement ratio (VRR) for NVSU No. 2 was only 0.79. The 4-32 injection pattern which contained approximately 45% of the original oil-in-place (OOIP) in the unit, had a VRR of 0.42 in 1991. The Board, like Saskoil, is concerned with the low injectivity and poor injection distribution in NVSU No. 2.

ICG Resources Ltd. in its original pressure maintenance application predicted a significant production response to the waterflood within 2 years of commencement of injection and an increase in recovery from 7% to 27.3% OOIP. To date this has not materialized. In light of the injectivity problems and significant deviation from the predicted waterflood performance, the Board requests Saskoil provide the following information by April 1, 1992.

1. A revised water injection schedule, production forecast and ultimate recovery estimate for NVSU No. 2.

2. Comments on the technical and economic feasibility of converting additional wells to injection as a means of optimizing waterflood performance in NVSU No. 2.

3. An update on the progress of unit enlargement negotiations with Ranchmen's.

If you have any questions in respect of this matter, please contact L.R. (Bob) Dubreuil, Director of Petroleum or John N. Fox, Chief Petroleum Engineer at (204) 945-6573 and 945-6574, respectively.

Yours respectfully,

ORIGINAL SIGNED BY
H. CLARE MOSTER

H. Clare Moster
Deputy Chairman

cc: Mr. K.J. Majoram, P. Eng.
Ranchmen's Resources Ltd.

bcc: Roland Massinon

File: NVSU No. 2 PM Application

December 20, 1991

L.R. DUBREUIL/JOHN FOX

RE: BOARD ORDER No. PM 59

Attached is Ranchmen's fax which I agreed would be considered by the Board if received on or before this date.

Please review Ranchmen's arguments and advise the Board of Branch's comments and recommendations.

Thanks.

R. Meyers
for H. C. Moster

Attachment

Ranchmen's Resources Ltd.

December 20, 1991

Manitoba Energy and Mines
The Oil and Natural Gas Conservation Board
Room 309 - Legislative Building
Winnipeg, Manitoba
R3C 0V8

Attention: H. Clare Moster
Deputy Chairman

Dear Sir:

Re: Ranchmen's Concerns Regarding
Manitoba Oil and Natural Gas Conservation Board's Decision
Board Order No. PM 59

Ranchmen's Resources Ltd. hereby responds to the Board's proposed decision of 1991-11-20 concerning the Board Order No. PM 59. We apologize for being a few days late in getting our response to you and appreciate the extension of the response date to 1991-12-20.

Ranchmen's offers the following comments in defense and elaboration of our previous concerns;

1. Unit Expansion

Ranchmen's feels that of all the existing wells in the pool should be used in the design of a unified waterflood design that will supply adequate injectivity to provide the necessary pressure support and sweeping of the reservoir to maximize hydrocarbon recovery. Trying to inject all of the water in one or two central wells should be avoided; where as, converting other carefully selected existing wells into water injectors will create a uniform sweeping between the wells.

The most porous and permeable zone in the two wells (A11-30 and 14-30) adjacent to the injection well A10-30 are structurally situated down dip. Core analysis from these two wells show vuggy and fracture porosity. For these reasons an increase in water volumes injected into the A10-30 well will a have greater tendency to create finger channels and cause premature water breakthrough.

TOTAL

Suite 1000, 333 Eleventh Avenue S.W., Calgary, Alberta, Canada T2R 1L9
Tel: (403) 267-9400 / Fax: (403) 267-9455 / Toll Free in Canada: 1-800-661-6742

2. Water Flood Implementation and Injection Distribution

Ranchmen's finds it difficult to understand how the Board is satisfied with how Saskoil is implementing the waterflood. It appears from our gathered information that Saskoil is injecting 75% of the water to support pressure in the southern half of the pool, while only 25% is being used for the north half. Injecting all this water (both Ranchmen's and Saskoil volumes) into the south part of the pool will not effectively support any pressure in the north half of the pool (VRR on the north part of the pool is only 0.38). A water flood scheme should support the entire pool in order to maximize pool recovery. Could you please comment on why the Board is satisfied with the over-all performance of the waterflood on the entire pool especially in light of the poor performance to date?

The existing voidage replacement ratio (VRR) immediately surrounding the A10-30 well is already 1.72, which is above the typically over-injected VRR of 1.2 - 1.4 and is significantly over the previously licensed allowable of 1.15 (please see the attached sketch). Ranchmen's also has four wells compared to Saskoil's three in this vicinity, and are at much greater risk. Three of the four Ranchmen's producers involved are down-dip to the Saskoil injector, and would very likely be the ones to be effected by excess injectivity. Increasing the injection volumes in the A10-30 well will increase slightly the VRR value, where as the conversion of one or two wells to water injectors in the NE portion of the pool would help immensely the over-all pool VRR. In doing so, the potential risk to Ranchmen's production in the SW portion of the pool will be reduced.

It must be pointed out that the 8-30 well's injection volumes are higher than A10-30, but this is contributed to the well being fracture stimulated down into the underlying aquifer. The well was a good oil producer with some fracture porosity shown on the core. When it was stimulated the fracture created opened up into the aquifer and immediately produced 100% water. This well creates pressure support in the aquifer, but has no risk of effecting offsetting wells.

In one paragraph the Board considers... *"the limited injectivity in NVSU No. 2 to be the greatest impediment to the success of the waterflood"* and in the next paragraph you... *"do not see the distribution of the injection as an issue."* Both these statements are of the utmost importance and interrelated wherein one coincides with the other. Please explain how the incremental increase in injection volumes in one well can be the real concern?

If the two injector in the east part of the unit cannot support the production voidage the producing wells immediately offsetting, how does Saskoil and the Board expect pressure support from water injected into A10-30, especially when it is so far removed from the producers in question.

3. Premature Water Breakthrough and Loss in Recovery at A11-30 and 14-30 Wells.

Ranchmen's is pleased to see you agree there will be a loss in recoverable reserves resulting from premature water breakthrough attributed to implementation of the water flood scheme by the North Virden Scallion Unit No. 2. As stated in your comments, expected lost production may be in the 1000 m^3 range; however, based on the success other operators have had in the area with Versine stimulation treatments these estimates may be low by a factor of 2 or 3. This will result in lost revenues to Ranchmen's and the freehold mineral owners in excess of $150,000 to $500,000, based on this months oil price.

It appears the performance of the waterflood has not met expectations envisioned by ICG in their initial waterflood application. Factors such as reduced injectivity and plan of implementation must be considered when determining a new value for incremental waterflood oil recovery. A re-evaluation should be performed to determine the true expectations of waterflooding this tight reservoir based on reduced water injectivity and recent production increases due to the Versine stimulation treatments.

In conclusion, Ranchmen's finds the position the Board has taken very disturbing in supporting inequalities in an equity issue. The Board's stance should be without bias to ensure an equitable resolution wherein both parties benefit. Ranchmen's vigorously opposes the proposed changes to the Board Order No. PM 59 at this time due to the inequalities shown between the two operating companies.

Ranchmen's is looking forward to your response and we trust our points will be considered. If you have any questions or require additional information please contact me at (403) 267-9452.

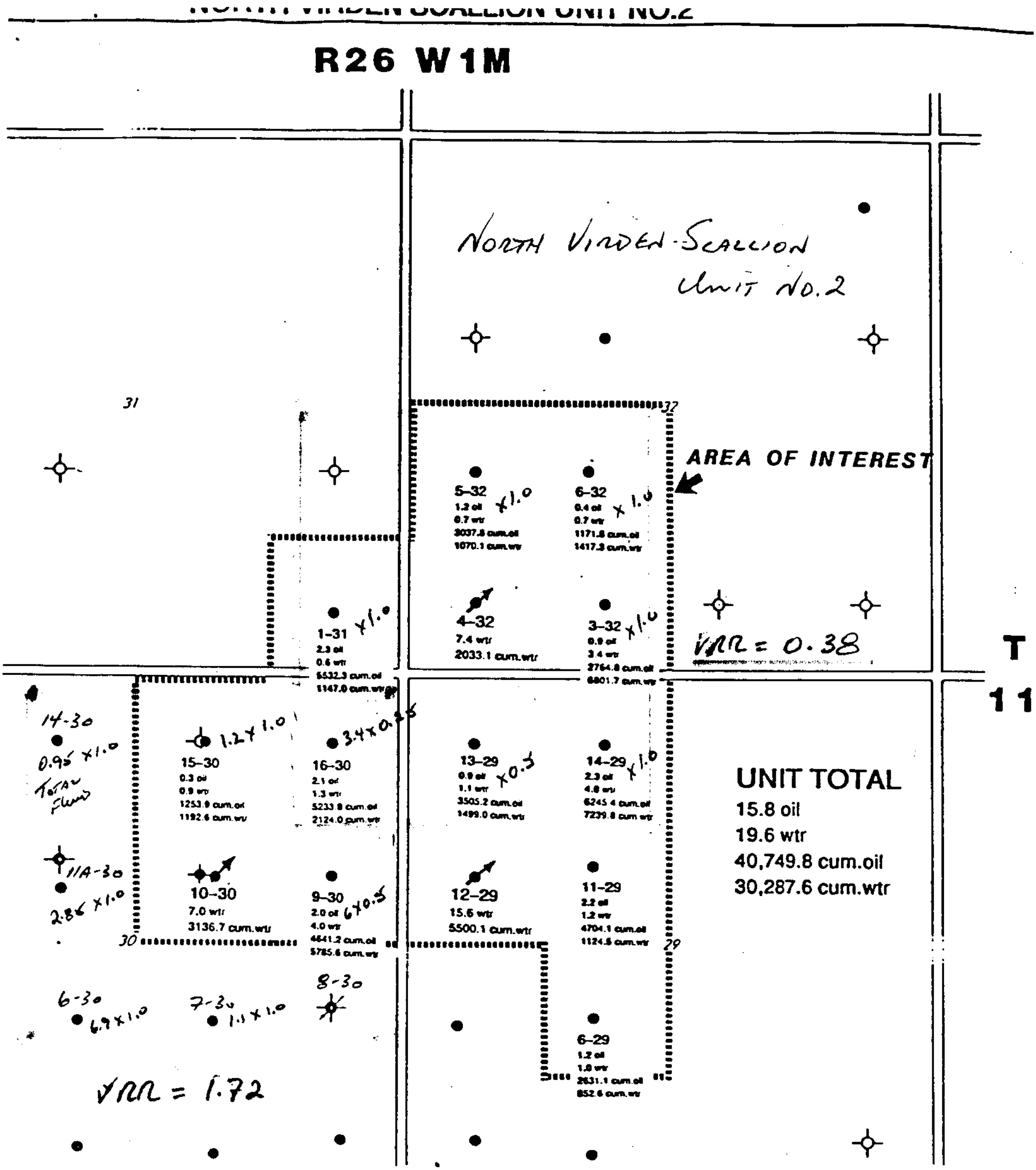
Yours very truly,

RANCHMEN'S RESOURCES LTD.

KJ Marjoram

K.J. Marjoram, P. Eng.
Operations Engineer

KJM:yp



R26 W1M
NORTH VIRDEN-SCALLION
Unit No. 2
31
32
AREA OF INTEREST
5–32
1.2 oil
0.7 wtr
3037.8 cum.oil
1070.1 cum.wtr
x1.0
6–32
0.4 oil
0.7 wtr
1171.8 cum.oil
1417.3 cum.wtr
x 1.0
4–32
7.4 wtr
2033.1 cum.wtr
3–32
0.9 oil
3.4 wtr
2764.8 cum.oil
6801.7 cum.wtr
x1.0
1–31
2.3 oil
0.6 wtr
5532.3 cum.oil
1147.0 cum.wtr
x1.0
VRR = 0.38
T
11
14-30
0.95 x1.0
Total Fluid
15–30
0.3 oil
0.9 wtr
1253.9 cum.oil
1192.6 cum.wtr
1.2 x 1.0
16–30
2.1 oil
1.3 wtr
5233.9 cum.oil
2124.0 cum.wtr
3.4 x 0.5
13–29
0.9 oil
1.1 wtr
3505.2 cum.oil
1499.0 cum.wtr
x0.5
14–29
2.3 oil
4.8 wtr
6245.4 cum.oil
7239.8 cum.wtr
x1.0
UNIT TOTAL
15.8 oil
19.6 wtr
40,749.8 cum.oil
30,287.6 cum.wtr
11A-30
2.86 x1.0
10–30
7.0 wtr
3136.7 cum.wtr
9–30
2.0 oil
4.0 wtr
4641.2 cum.oil
5785.6 cum.wtr
6 x 0.5
12–29
15.6 wtr
5500.1 cum.wtr
11–29
2.2 oil
1.2 wtr
4704.1 cum.oil
1124.5 cum.wtr
30
29
8-30
6-30
6.9 x 1.0
7-30
1.1 x 1.0
6–29
1.2 oil
1.0 wtr
2631.1 cum.oil
852.6 cum.wtr
VRR = 1.72

WELL	PRE-UNIT OIL PRODUCTION	PRE-UNIT WTR PRODUCTION	OIL PROD 91-10-31	WTR PROD 91-10-31	TRACT FACTOR	A10-30 INJ PATTERN VOIDAGE
9-30	4240.6	4997.8	5160.9	6960.5	0.5	1462.206
15-30	1148.7	1017	1316.9	1388	1	546.769
16-30	4696.1	1895.8	5800.6	2511.7	0.33	584.1338
A11-30	1551.7	2722.2	1996.9	4280.7	1	2023.734
14-30	1299.7	818.6	1616	1216.5	1	728.4335
						5345.277 TOTAL VOIDAGE

A10-30 INJECTION =5812.6

VRR= 1.0874225956

OIL / WATER	Cum. Prod. Dec. 31/90 m³	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	OCT. Daily m³	1991 Y.T.D. m³	Cum. Total m³
CHEVRON CANADA RESOURCES LIMITED (Cont.)																
16-05-12-26	10 488.3	5.9	5.3	5.9	5.6	5.9	5.8	6.0	7.2	27.0	27.4			0.88	102.0	10 590.3
	22 149.6	78.7	74.0	81.8	80.5	84.3	73.4	76.2	26.1	480.2	511.7				1 566.9	23 716.5
PREVIOUS	775 144.7															775 144.7
PRODUCERS	840 827.1															840 827.1
N.V.S.	9 238 749.9		9 549.2		9 896.4		9 756.7		10 141.5		10 095.4					9 339 237.9
UNIT #01	16 731 798.7		85 127.9		89 594.8		80 392.9		80 101.8		87 249.6					17 601 579.9
TOTAL OIL		10 517.3		10 474.3		10 004.6		10 211.1		9 841.5					100 488.0	
TOTAL WATER		94 453.9		91 818.0		91 254.2		89 397.9		80 390.2					869 781.2	

4-32 VOIDAGE = 2113.9 + 2529.6
= 4643.5
REPL. = 1973.1
VRR = 1973/4643

N.V.S. UNIT #02 (Effective August 1, 1989)

OIL / WATER	Cum. Prod. Dec. 31/90 m³	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	OCT. Daily m³	1991 Y.T.D. m³	Cum. Total m³
ICG RESOURCES LTD.																
06-29-11-26	2 631.1	39.3	35.4	42.7	40.5	42.1	40.4	41.3	40.8	37.4	33.5			1.08	393.4	3 024.5
Prow.	852.6	28.1	23.8	23.9	23.0	24.4	23.4	24.2	23.7	22.6	19.3				236.4	1 089.0
11-29-11-26	4 704.1	66.6	57.2	61.0	60.7	63.1	59.1	59.0	58.3	55.2	47.9			1.55	588.1	5 292.2
Prow.	1 124.5	37.4	36.9	38.9	37.5	36.6	34.3	36.1	35.5	35.0	28.9		TF		357.1	1 481.6
13-29-11-26	3 505.2	33.3	29.9	33.6	28.9	30.1	28.9	29.5	29.2	27.6	23.9		0.5	0.77	294.9	3 800.1
Prow.	1 499.0	31.2	26.4	29.9	28.8	30.4	29.2	30.3	29.6	29.1	24.1				289.0	1 788.0
14-29-11-26	6 245.4	84.6	70.8	79.3	75.3	84.2	80.9	82.6	81.6	74.9	119.7		0.5	3.86	833.9	7 079.3
Prow.	7 239.8	143.5	124.3	140.7	135.3	134.0	128.7	133.1	130.2	124.2	197.6				1 391.6	8 631.4
09-30-11-26	4 641.2	54.5	54.4	58.0	55.0	54.1	52.0	53.1	52.5	45.4	40.7			1.31	519.7	5 160.9
	5 785.6	118.6	111.1	119.8	120.9	124.8	119.9	124.1	121.3	115.6	98.8				1 174.9	6 960.5
15-30-11-26	1 253.9	6.1	5.4	9.2	8.7	6.0	5.8	5.9	5.8	5.3	4.8			0.15	63.0	1 316.9
	1 192.6	15.6	18.5	20.9	20.1	21.3	20.5	21.2	20.7	19.7	16.9				195.4	1 388.0
16-30-11-26	5 233.8	34.8	59.9	67.1	60.8	63.1	60.7	59.0	58.3	55.2	47.9		0.33	1.55	566.8	5 800.6
	2 124.0	24.0	39.7	41.9	40.3	42.6	40.9	42.4	41.4	40.8	33.7				387.7	2 511.7
01-31-11-26	5 532.3	69.6	62.6	73.2	69.5	69.2	66.4	67.8	67.1	61.4	55.1		1.0	1.78	661.9	6 194.2
	1 147.0	18.7	15.9	18.1	14.4	18.3	17.5	18.2	17.8	16.9	14.5				170.3	1 317.3
03-32-11-26	2 764.8	27.2	24.5	24.4	23.2	24.1	23.1	23.6	23.3	21.4	19.2		1.0	0.62	234.0	2 998.8
	6 801.7	115.4	92.6	104.7	97.8	103.5	96.5	99.9	97.6	93.1	79.5				980.6	7 782.3
05-32-11-26	3 037.8	33.3	29.9	33.6	31.8	32.2	31.8	32.4	32.1	30.4	26.3		1.0	0.85	313.8	3 351.6
	1 070.1	21.8	18.5	20.9	20.1	20.7	20.5	21.2	20.7	20.4	16.9				201.7	1 271.8
06-32-11-26	1 171.8	9.1	5.4	6.1	5.8	6.0	5.8	5.9	5.8	5.3	4.8		1.0	0.15	60.0	1 231.8
	1 417.3	25.0	21.2	20.9	20.1	21.3	20.5	21.2	20.7	19.7	16.9				207.5	1 624.8
PREVIOUS	8 766.1															8 766.1
PRODUCERS	4 505.6															4 505.6
N.V.S.	49 487.5		435.4		460.2		454.9		454.8	13.7 m³/d	423.8					54 017.0
UNIT #02	34 759.8		528.9		558.3		551.9		559.2		547.1					40 352.0
TOTAL OIL		458.4		488.2		474.2		460.1		419.5					4 529.5	
TOTAL WATER		579.3		580.6		577.9		571.9		537.1					5 592.2	

1991 VOIDAGE
4529.5×1.045 + 5592.2
10325.5 rm3
INJECTION 8167.2 rm3

VRR = 8167.2 / 10325.5 = 0.79

OIL / WATER	Cum. Prod. Dec. 31/90 m³	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	OCT. Daily m³	1991 Y.T.D. m³	Cum. Total m³
AMOCO CANADA PETROLEUM COMPANY LTD.																
04-29-11-26	21 961.8	39.3	35.7	38.9	37.3	39.2	37.4	38.7	37.0	38.1	38.6			1.25	380.2	22 342.0
Prow.	14 760.8	79.1	70.3	78.6	76.1	79.0	75.4	79.0	78.4	82.4	81.6				779.9	15 540.7
05-29-11-26	12 493.1	31.9	29.0	31.7	30.3	31.8	30.0	31.5	16.5	29.3	31.2			1.01	293.2	12 786.3
Prow	15 586.9	134.5	120.3	133.7	129.6	135.3	129.1	135.1	89.6	133.6	138.4				1 279.2	16 866.1
	34 454.9		64.7		67.6		67.4		53.5		69.8					35 128.3
	30 347.7		190.6		205.7		204.5		168.0		220.0					32 406.8
TOTAL OIL		71.2		70.6		71.0		70.2		67.4					673.4	
TOTAL WATER		213.6		212.3		214.3		214.1		216.0					2 059.1	
CENTOBA OILS LTD.																
15-03-11-26	127.8	3.2	8.7	8.1	7.8	9.2	8.9	8.6	10.1	13.3	13.4			0.43	91.3	219.1
	1 247.1	59.0	73.0	82.5	23.5	91.0	37.0	67.5	80.0	107.5	108.0				729.0	1 976.1
16-03-11-26	2 252.3	40.1	56.6	44.3	42.7	51.1	55.6	42.0	52.9	53.1	48.0			1.55	486.4	2 738.7
	19 617.3	376.0	465.5	425.5	378.5	477.0	478.0	434.5	415.5	416.0	352.5				4 219.0	23 836.3

LODGEPOLE A POOL
05 59A

VIRDEN FIELD

KIWI RESOURCES LTD. (Cont.)

OIL / WATER	Cum. Prod. Dec. 31/90 m³	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	OCT. Daily m³	1991 Y.T.D. m³	Cum. Total m³
TOTAL OIL	70 750.2	300.0	248.1	246.5	205.7	274.5	239.6	257.1	252.5	268.1	249.2				2 541.3	73 291.5
TOTAL WATER	1 496 087.7	8 783.1	8 013.6	7 830.6	7 210.9	9 190.7	10 617.9	10 762.3	11 038.8	10 940.9	10 355.6				94 744.4	1 590 832.1

RANCHMEN'S RESOURCES LTD.

OIL / WATER	Cum. Prod. Dec. 31/90 m³	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	OCT. Daily m³	1991 Y.T.D. m³	Cum. Total m³
14-19-11-26	16 650.7	27.6	27.8	30.7	29.4	30.8	27.7	30.1	29.3	29.4	29.5			0.95	292.3	16 943.0
	43 425.1	157.3	167.2	172.5	170.9	181.8	172.3	184.7	176.3	173.6	173.4				1 730.0	45 155.1
14-20-11-26	25 048.7	30.4	26.2	29.7	28.0	29.8	27.8	29.7	27.0	27.5	29.0			0.94	285.1	25 333.8
	5 015.2	22.6	19.9	22.4	22.5	24.0	23.2	24.0	23.0	23.1	24.0				228.7	5 243.9
03-29-11-26	13 661.0	20.4	17.3	19.8	18.4	19.6	18.0	19.4	17.9	17.9	19.2			0.62	187.9	13 848.9
Prov.	3 977.9	20.3	19.1	20.7	21.4	22.4	21.4	22.4	21.1	21.6	22.1				212.5	4 190.4
01-30-11-26	34 420.7	60.4	55.2	59.9	57.3	60.2	57.0	59.1	56.9	57.1	58.0			1.87	581.1	35 001.8
	9 915.5	65.3	59.5	61.3	60.7	64.6	67.6	65.8	62.9	61.9	61.9				631.5	10 547.0
02-30-11-26	33 229.7	41.1	37.6	40.7	38.8	38.4	38.7	39.8	38.8	38.7	39.2			1.26	391.8	33 621.5
	16 288.1	74.1	67.3	68.4	68.1	68.3	77.3	74.8	71.4	69.8	69.1				708.6	16 996.7
03-30-11-26	20 702.5	34.7	32.7	35.6	33.9	35.8	32.0	35.1	33.5	34.0	34.1			1.10	341.4	21 043.9
	15 303.7	55.6	54.0	55.6	55.0	58.8	55.6	59.4	56.7	55.7	55.8				562.2	15 865.9
06-30-11-26	14 537.8	32.5	30.4	33.2	32.0	33.6	30.4	33.2	32.2	32.0	32.2			1.04	321.7	14 859.5
	40 845.8	177.5	172.7	178.2	176.6	187.6	178.3	190.9	182.3	179.7	179.4				1 803.2	42 649.0
07-30-11-26	8 609.5	16.4	14.7	15.9	15.1	15.9	14.9	15.3	14.9	14.9	15.4			0.50	153.4	8 762.9
	5 477.9	19.2	17.6	18.0	18.0	19.3	20.1	19.6	18.5	18.1	18.2				186.6	5 664.5
11-30-11-26	1 805.6	19.6	17.7	19.5	18.9	19.5	18.9	19.5	19.5	18.7	19.5			0.63	191.3	1 996.9
	3 590.8	74.8	65.0	69.1	66.9	69.1	67.5	69.1	72.6	66.7	69.1				689.9	4 280.7
14-30-11-26	1 489.3	13.1	10.7	13.0	12.6	13.2	12.6	13.0	12.9	12.6	13.0			0.42	126.7	1 616.0
	1 048.3	16.2	16.7	20.6	15.6	16.3	16.4	16.2	18.5	15.6	16.1				168.2	1 216.5
TOTAL OIL	170 155.5	296.2	270.3	298.0	284.4	296.8	278.0	294.2	282.9	282.8	289.1				2 872.7	173 028.2
TOTAL WATER	144 888.3	682.9	659.0	686.8	675.7	712.2	699.7	726.9	703.3	685.8	689.1				6 921.4	151 809.7

SHANNON OILS LIMITED

OIL / WATER	Cum. Prod. Dec. 31/90 m³	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	OCT. Daily m³	1991 Y.T.D. m³	Cum. Total m³
11-18-11-26	4 473.5	7.0	5.4	1.4	—	—	12.0	18.3	12.7	11.0	11.0			0.35	78.8	4 552.3
	136 848.7	242.3	224.0	40.0	—	—	336.0	800.0	950.0	851.0	896.0				4 339.3	141 188.0
12-18-11-26	1 897.5	—	—	—	—	—	—	—	—	—	—				—	1 897.5
	18 685.5	—	—	—	—	—	—	—	—	—	—				—	18 685.5
02-13-11-27	34 840.4	46.1	38.8	0.5	—	—	37.5	56.0	48.0	41.0	40.4			1.30	308.3	35 148.7
	103 124.2	461.0	412.0	6.0	—	—	160.0	465.0	510.6	450.0	465.0				2 929.6	106 053.8
TOTAL OIL	41 211.4	53.1	44.2	1.9	—	—	49.5	74.3	60.7	52.0	51.4				387.1	41 598.5
TOTAL WATER	258 658.4	703.3	636.0	46.0	—	—	496.0	1 265.0	1 460.6	1 301.0	1 361.0				7 268.9	265 927.3

TUNDRA OIL AND GAS LTD.

OIL / WATER	Cum. Prod. Dec. 31/90 m³	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	OCT. Daily m³	1991 Y.T.D. m³	Cum. Total m³
15-26-11-26	10 427.1	43.2	28.0	51.2	34.8	17.1	34.6	33.7	51.7	37.9	42.5			1.47	374.7	10 801.8
	22 232.6	106.6	104.8	99.4	85.4	40.9	111.7	118.0	112.8	148.0	118.7				1 046.3	23 278.9

UPTON RESOURCES INC.

OIL / WATER	Cum. Prod. Dec. 31/90 m³	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	OCT. Daily m³	1991 Y.T.D. m³	Cum. Total m³
01-20-11-26	25 084.3	15.5	15.6	17.0	10.1	17.3	17.7	18.0	19.4	20.9	15.5			0.50	167.0	25 251.3
	140 049.7	481.8	437.3	500.3	311.3	501.0	466.6	470.1	421.1	338.5	363.5				4 291.5	144 341.2

WATER INJECTION/SALT WATER DISPOSAL
N.V.S. UNIT #01 (Cont.)

LODGEPOLE A POOL
05 59A

VIRDEN FIELD

	Cum. Dis./Inj. Dec. 31/90 m³	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	1991 Y.T.D. m³	Cum. Total m³
CHEVRON CANADA RESOURCES LIMITED (Cont.)															
08-33-11-26	164 228.5	1229.2	2093.0	924.0	973.0	942.8	976.8	1115.1	1159.7	1005.5	1334.7			11 753.8	175 982.3
14-33-11-26	320 409.6	1158.5	1006.8	1121.7	1182.1	1212.3	1170.2	679.2	1528.6	1217.0	1277.8			11 554.2	331 963.8
16-33-11-26	297 750.7	332.1	383.3	456.5	386.1	491.5	456.1	389.2	450.1	387.2	573.9			4 306.0	302 056.7
06-34-11-26	261 632.5	716.4	826.6	947.0	991.0	902.7	778.7	556.3	594.7	237.3	829.5			7 380.2	269 012.7
04-03-12-26	328 015.8	2008.4	1717.4	1914.4	1904.1	2018.6	1934.0	1972.2	1784.7	1885.8	2097.0			19 236.6	347 252.4
02-04-12-26	175 343.6	168.4	154.2	170.8	212.0	196.8	229.6	159.4	162.0	129.2	552.1			2 134.5	177 478.1
04-04-12-26	240 180.0	1123.1	1181.6	1147.9	764.5	915.0	812.9	574.1	783.2	771.3	935.0			9 008.6	249 188.6
06-04-12-26	147 624.4	860.4	739.1	842.2	838.2	875.0	800.4	789.6	688.7	747.0	766.5			7 947.1	155 571.5
10-04-12-26	358 821.6	2152.5	1863.1	2091.4	2057.1	2136.8	1875.6	1893.7	1576.2	2064.8	2204.7			19 915.9	378 737.5
12-04-12-26	351 156.7	1084.3	722.7	850.7	802.2	790.5	838.9	2656.3	587.2	653.2	932.6			9 918.6	361 075.3
N.V.S. UNIT #01 TOTAL	22 541 124.7	94 942.9	85 723.8	92 234.1	90 181.8	90 660.1	80 648.0	89 074.1	80 476.2	80 451.2	87 369.3			871 761.5	23 412 886.2

N.V.S. UNIT #02 (Effective August 1, 1989)

	Cum. Dis./Inj. Dec. 31/90 m³	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	1991 Y.T.D. m³	Cum. Total m³
ICG RESOURCES LTD.															
12-29-11-26 Prov.	5 500.1	538.8	411.3	443.7	391.8	395.9	350.1	312.9	261.1	221.8	190.8			3 518.2	9 018.3
10-30-11-26	3 136.7	220.5	189.6	218.1	215.1	299.5	297.7	307.2	312.2	302.0	314.0			2 675.9	5 812.6
04-32-11-26	2 126.5	144.7	219.2	220.3	199.0	206.1	193.9	197.7	189.1	203.9	199.2			1 973.1	4 099.6
N.V.S. UNIT #02 TOTAL	10 763.3	904.0	820.1	882.1	805.9	901.5	841.7	817.8	762.4	727.7	704.0			8 167.2	18 930.5
CHEVRON CANADA RESOURCES LIMITED															
06-16-11-26	2 403 945.7	10802.9	8067.5	8924.4	7686.3	7600.7	7835.7	12027.6	11871.6	8671.6	11208.6			94 696.9	2 498 642.6
ESSO RESOURCES CANADA															
07-19-11-26	1 027 930.9	3884.9	3999.3	4514.9	4479.5	3820.0	3588.0	3647.8	3593.1	3564.7	3649.8			38 742.0	1 066 672.9

- Board requests Saskoil [illegible] [illegible] [illegible] by Ranchmen's
- Board suggests the parties meet together with Petroleum Branch Staff

RANCHMEN'S CONCERNS

A UNIT EXPANSION

1. All existing wells in pool should be included in a unified waterflood. → competitive waterflooding is acceptable alternative

2. Avoid concentrating injection into 1 or 2 wells
consider injector conversions NE portion of pool (reduce [illegible] risk to Ranchmen's production) - request Saskoil address the technical & economic feasibility of additional conversions in NVSU No. 2

3. 8-30 & 4-30 pay zone vuggy, fractured porosity
concern channelling & premature breakthrough
IN NVSU No.2 & RANCHMEN'S WELLS IN SEC. 30
OBVIOUS INFLUX FROM WATER LEG IN SCALLION

B WATERFLOOD IMPLEMENTATION

- [illegible] pressures distribution & voidage distribution in NVSU No.2
- 75% / 25% → N/S split in injection volumes
- Ranchmen's calculation N/2 Pool VRR = 0.38
- Ranchmen's calculates VRR A10-30 1.2 to 1.4
with existing VRR = 1.72

- Concerned 3 downdip producers

- 8-30 injection into underlying aquifer as a result of a frac job

Ranchmen's questions [illegible] Board's "[illegible] injectivity greatest impairment" vs. injection distribution.
- [illegible] how increased injection volume @ A10-30 [illegible] [illegible] [illegible].

How does Board expect pressure support @ A10-30 to benefit producing wells in E/2 of unit?

3. PREMATURE WATER BREAKTHROUGH

- may be vs will be a loss in recovery
  may be an increase in recovery

- Ramsden's suggestion [illegible] [illegible] of other [illegible] [illegible] with versene treatments loss recovery [illegible] 2000 To 3000 m^3 [illegible] [illegible] to $500000

appears NUSU # 2
- waterflood has not met expectations, suggested revised waterflood performance [illegible]

- [illegible] believes Board [illegible] [illegible] [illegible] [illegible] [illegible] equity [illegible]

INJECTION DISTRIBUTION

8-30 DISPOSAL WELL

NOTE: A11-30 penetrates west of the Cherty zone 22 m thick underlying water

COMPLETION HISTORY PERFS 2120 - 2135

MAY/67 PRODUCTION 15 BOPD WC 7/17

JUNE/67 WELL FRAC'D sanded off after 1500# (acidized)

POST-FRAC PRODUCTION 60 BWPD

AUG/67 SI CUMUL. PROD 6087 bbl oil
3599 bbl wtr

Cherty - vertical fractures observed 1-30 & 2-30

- low between high to south @ 9-19 &
high to north @ 15-30

CONVERTED TO INJECTION JUN/73

NVSU No. 2 Participation Formula (File)
55% Øh + 45% Productivity

A11-30 6-4-30 drilled by TransCanada Resources Ltd. in 1986

NVSU No. 2 WF Study (TCG Resources Aug 1988)

Ultimate waterflood recovery prediction - 27.3% OOIP (primary recovery - 7%) OOIP - 5678 MSTB Prim Rec - 397 MSTB
Sec. Rec 1548 MSTB

1) P_R = 6274 kPa (910 psig) Res Pr 5958-6712 kPa
Feb 1/91 fall off test results 4-32 4267 kPa 16-30 6462 kPa 5900 kPa (Aug/89)
3) VRR target 1st 3 yrs 1.1-1.15 m^3/m^3, then 1.05-1.0

4) recognized that oil @ edge of pool will not be swept by waterflood

5) Production forecast - peak 2 year after waterflooding commenced @ 47.7 m^3/d (300 BOPD), over 2 times primary production rate @ commencement of the flood

6) Forecast Injection target Year
1 40 - 80 m^3WPD
2 80 - 100 m^3WPD
3 onward 100 m^3WPD

ORIGINAL OIL IN PLACE

WELL	ϕh porosity·m	OOIP ($10^3 m^3$)	CUMULATIVE PRODUCTION Oct 31/91 (m^3)	CURRENT RECOVERY (%)	ULTIMATE * RECOVERY $10^3 m^3$	REMAINING REC. RES. $10^3 m^3$
A11 - 30	0.57	57.0	1996.9	3.5	8.5 - 16.5	5 - 13.0
14-30	0.14	14.0	1616.0	11.6	2.1 - 4.1	0.5 - 2.5
					TOTAL	5.5 - 15.5

* PRIMARY RECOVERY no aquifer pressure support - 15%
* PRIMARY RECOVERY (use recovery avg. from S/2·30) - 29 %

ESTIMATE ULTIMATE RECOVERY USING PRODUCTION HISTORY FROM A11-30 & 14-30, WELLS IN S/2 of SEC 30. & NVSU No. 2

S/2 - 30 decline rate 5% / yr. prior to 2-30 disposal 9%/yr
NVSU No. 2 primary decline rate 13%
A11-30 & 14-30 decline rate 8% /yr.

A11-30 & 14-30 combined production Oct/91 1.05
economic limit 0.2 m³/d /well Remaining Rec Res - 2966 m³ - 4745 m³

OTHER PM REVIEWS (1983)

DOME, CDN RESERVE, TRANS-CANADA RESOURCES - WF not feasible
SW/4-29 E/2-19 S/2-30

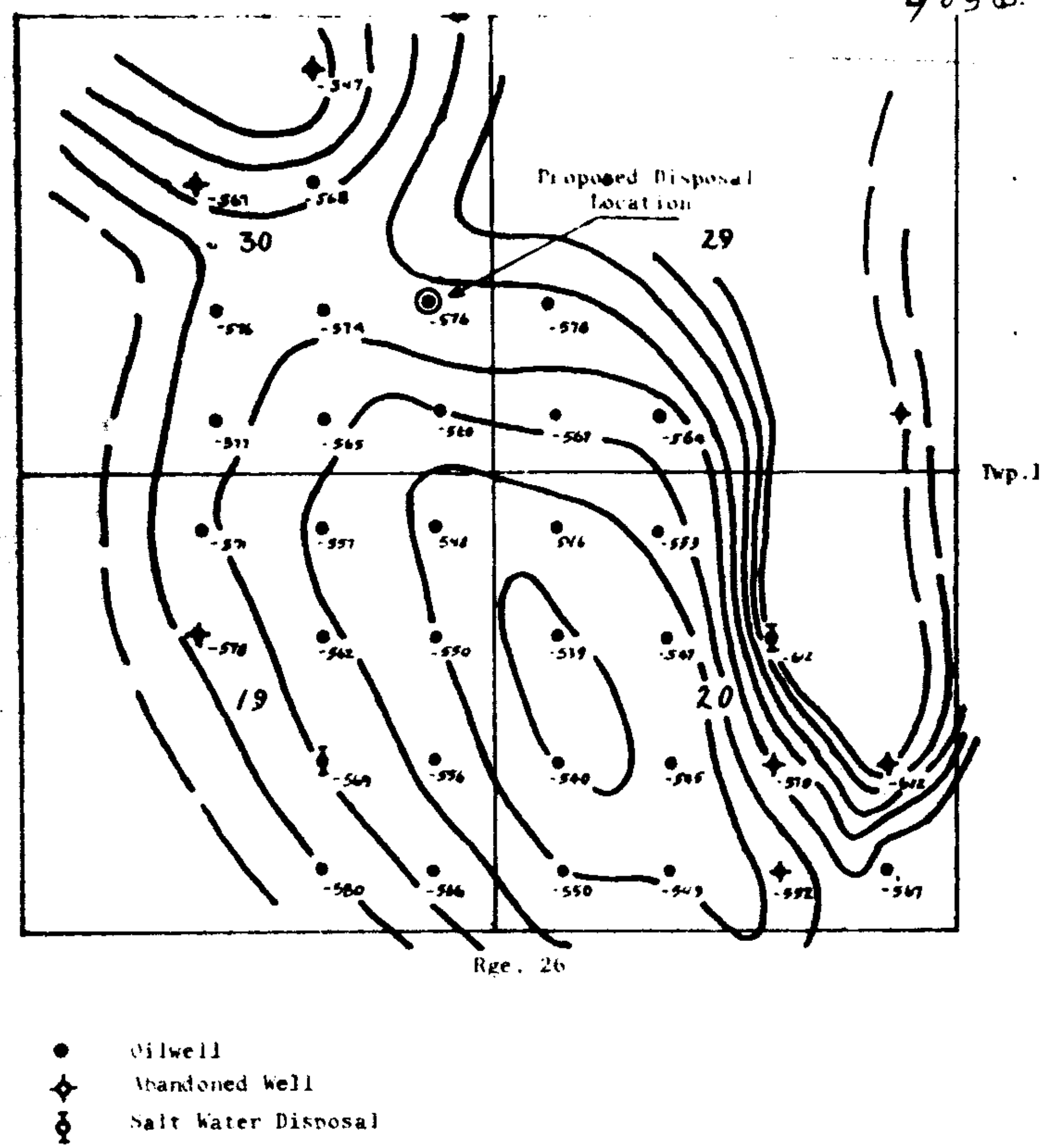
- injection @ 2-30 & [illegible] aquifer pressure support adequate for Dome's wells @ 4-5-29 - [illegible] total fluid production
- primary recovery est 15%

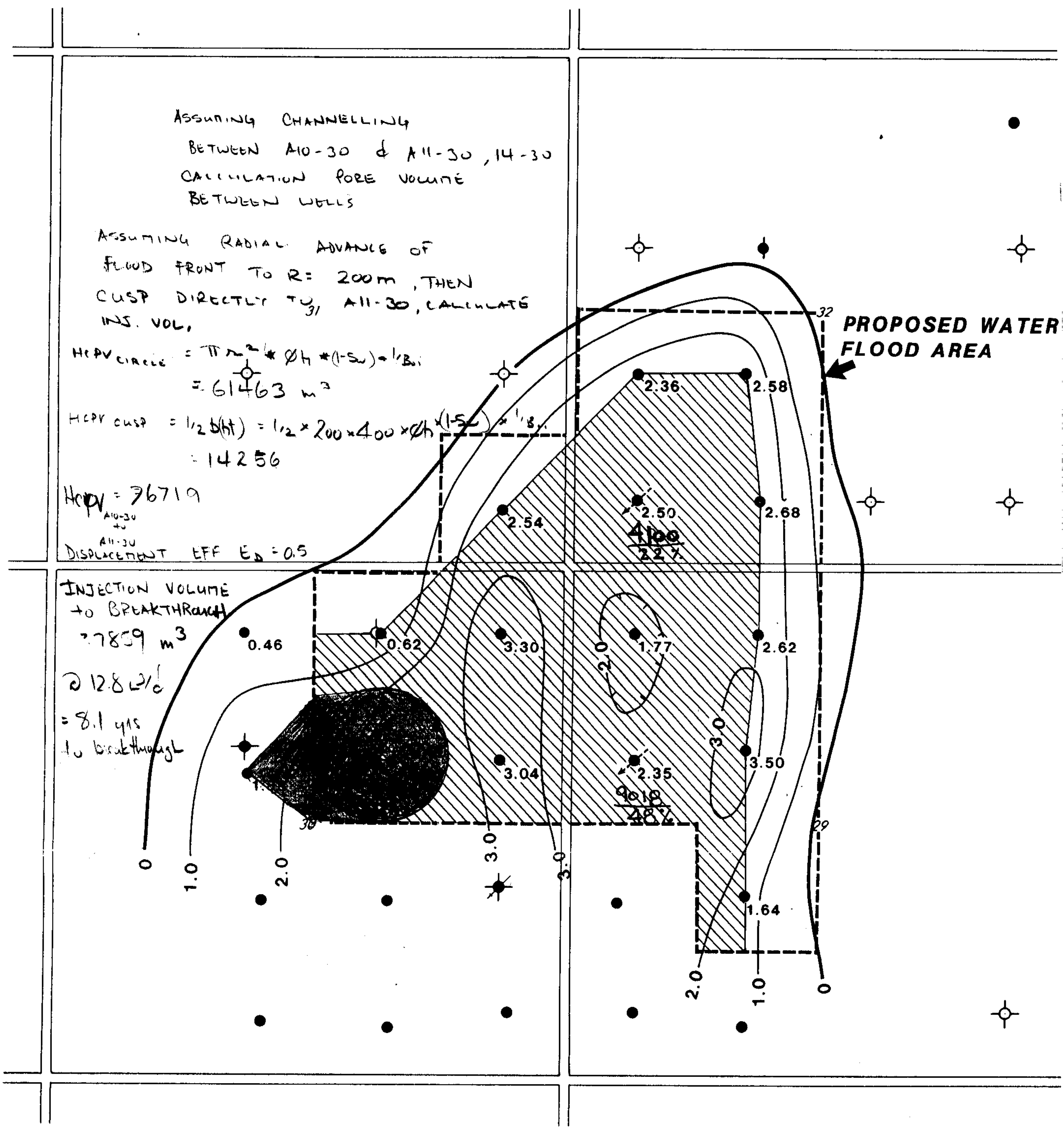
SUNCOR - WF not feasible
Sec 20

- Prim Rec - 19% wide variation
- poor WF response due to low k
  $\bar{P}_R$: 6330 kPa
- water disposal [illegible] provide pressure support
- O/W contact @ -172.8 m SS (-597' SS) between N-S/2 of Sec 30

STRUCTURE
TOP OF CHERT

905B.





SEC	HCPV $10^3 m^3$
NE/4-30	289.3
1-31	77.0
NW/4-29	301.6
6-29	49.7
SW/4-32	307.0
TOTAL	1024.6 $10^3 m^3$

INJ PATTERN	HCPV
A10-3	176.5
12-29	373.2
4-32	484.0

PROPOSED WATER INJECTION WELL

WATERFLOOD SWEPT AREA

ICG RESOUR

NORTH VIRDEN
LODGEPOLE 'A'

PORE VOLUME
Porosity Fee

GEOLOGY BY. D. Bates | DRAF

November 18, 1991

The Oil and Natural Gas Conservation Board
- Ian Haugh, Chairman
- H. Clare Moster, Deputy Chairman
- Wm. McDonald, Member

John N. Fox
Chief Petroleum Engineer
Petroleum Branch

RE: North Virden Scallion Unit No. 2
Application to Amend Board Order No. PM 59

Saskatchewan Oil and Gas Corporation (Saskoil), the operator of North Virden Scallion Unit No. 2 (NVSU No. 2) has made application to amend Section 8 of Board Order No. PM 59 covering pressure maintenance operations in the unit. Ranchmen's, the operator of wells adjacent to NVSU NO. 2 objected to the application.

Recommendations

It is recommended that the Board advise Ranchmen's that it is prepared to approve the application. The proposed Board letter to Ranchmen's (attached) addresses the concerns raised in their objection, lists the reasons for the Board's decision and requests Ranchmen's provide the Board with its comments, additional questions or concerns by December 16, 1991.

The letter also advises Ranchmen's that in the event continued unit enlargement negotiations fail, the company can apply to the Board under Section 79 of The Mines Act for an order to enlarge the unit.

Discussion

Ranchmen's objected to ICG Resources' (now Saskoil) application to conduct a waterflood in NVSU No. 2 (September, 1988). Ranchmen's was concerned that injection at A10-30 may have an adverse effect on its wells at A11-30 and 14-30-11-26 (Figure 1).

Discussions at that time between ICG, Ranchmen's and the Branch resulted in the inclusion of injection restrictions for A10-30 in Section 8 of Board Order No. PM 59.

Clause 8(a) limited injection at A10-30 to less than 1/3 of the total unit injection on a quarterly basis. Clause 8(b) limited the voidage-replacement (VRR) ratio for the A10-30 injection pattern to 1.15 or less on a quarterly basis. Clause 8(c) required Saskoil and Ranchmen's submit a joint report on the feasibility of unit expansion, 6 months after injection commenced in NVSU No. 2. The deadline for the joint report was extended from August, 1990 to May 1, 1991 by the Board at the request of both companies.

Instead of submitting a joint feasibility study May 1, 1991, Saskoil submitted a waterflood progress report and an application requesting Clause 8(a) be removed and Clause 8(b) be increased to a VRR of 1.5. Ranchmen's objected to the application with the following concerns:

(1) NVSU No. 2 should be expanded to include all Ranchmen's wells in Section 30-11-26; and

(2) Injection restrictions for A10-30 should continue

  (a) until evidence of successful implementation of the waterflood is available,

  (b) to ensure injection is evenly distributed within NVSU No. 2 and the S/2 of Section 30, and

  (c) to prevent premature water breakthrough and loss in recovery at A11-30 and 14-30.

At issue here is Saskoil's desire to accelerate waterflood response in NVSU No. 2 and recover its investment in the waterflood and Ranchmen's desire to protect itself against possible financial loss. The Branch in its review of the subject application will review the validity of each parties concerns and the options available to the parties.

NVSU No. 2 Waterflood Performance

Water injection in NVSU No. 2 commenced in December, 1989 at A10-30-11-26 and in February, 1990 at 12-29-11-26 and 4-32-11-26. Cumulative injection to July 31, 1991 totalled 16 736.4 m^3, resulting in a VRR of 0.99 since waterflood start-up and a cumulative VRR of 0.18. Pattern VRR's are shown in Table 1.

Saskoil has complied with Clause 8(a). Injection into A10-30 as of July 31, 1991 totalled 29.2% of the cumulative unit injection. Clause 8(b) is difficult to interpret:

> "8(b) The ratio of water injection to reservoir withdrawals in the nine spot injection pattern surrounding the A10-30 well shall not exceed 1.15 on a quarterly basis,".

A nine-spot injection pattern surrounding A10-30 would include Ranchmen's disposal well at 8-30 (Figure 1). Daily injection at 8-30 is 1.6 times A10-30, 15.6 m^3/d compared to 9.9 m^3/d. If one quarter of this volume is attributed to the A10-30 pattern (corner well), the injection volume is still equivalent to 60% of reservoir withdrawals for the nine spot injection pattern. This effectively reduces injection at A10-30 to 55% of reservoir withdrawals to meet the requirements of Clause 8(b). I don't believe this is what was intended under Clause 8(b). Saskoil has included production from 9-30, A15-30 and 16-30 in NVSU No. 2 with appropriate tract factors and production from Ranchmen's wells, A11-30 and 14-30 to determine reservoir withdrawals for compliance under Clause 8(b). The Branch agrees with Saskoil's interpretation of Clause 8(b). The VRR for the A10-30 injection pattern since waterflooding commenced in accordance with the proposed interpretation of Clause 8(b) is 1.06, less than the maximum of 1.15.

The production history of NVSU No. 2 is shown in Figure 2. To July 31, 1991 the only response to water injection appears to be a lessening of both the production decline and the trend of increasing WOR. The dramatic jump in production in September, 1990 was a result of successful versene treatments on the producing wells. It would be premature at this time to attempt to predict incremental recovery resulting from waterflooding.

Saskoil is concerned injection restrictions in Section 8 of Board Order No. PM 59 are unnecessarily delaying waterflood response. The 4-32 well has low injectivity. During 1991, the average injectivity has been 6.5 m^3/d, only 42% of reservoir withdrawals. Saskoil's injection target for the 4-32 well is 24 m^3/d (VRR = 1.5). The 12-29 well cannot make up for the shortfall in injection at 4-32. The injectivity at 12-29 is only 10.1 m^3/d (July, 1991) or 73% of its pattern voidage. Because of the low injectivity of 4-32, application of Clause 8(a); limiting injection into A10-30 to less than 1/3 of the total unit injection, unreasonably restricts injection at A10-30. It is recommended that this clause be deleted and injection limitations established using only a maximum VRR as in Clause 8(b).

Saskoil has requested the VRR limitations in Clause 8(b) be increased to 1.5, effectively increasing injection at A10-30 from a maximum of 9.8 to 12.8 m^3/d.

Ranchmen's is concerned that increased injection at A10-30 will result in premature water breakthrough and loss in recovery at its downdip A11-30 and 14-30 wells. The combined production history of A11-30 and 14-30 is shown in Figure 3. Combined the wells produce slightly more than 1.0 m^3/d. Since injection commenced at A10-30 in December, 1989 combined production from the two wells has increased slightly. The increase may or may not be related to injection at A10-30.

The Branch is of the opinion that injection at A10-30 will eventually effect production at A11-30 and 14-30 and increased injection will accelerate the response. Experience also indicates that for waterfloods to be successful, water injection volumes must exceed reservoir withdrawals. In Lodgepole waterfloods in the Virden Field VRR's are typically 1.2 - 1.4. Injection above a VRR of 1.0 is recommended as it accelerates fill-up, enhances volumetric sweep efficiency and counteracts limited out of zone injection.

The Branch offers no opinion on whether a modest increase in injection at A10-30 will have a positive or negative effect on ultimate recovery at A11-30 and 14-30. However, the downside loss in recovery from the wells if premature water breakthrough occurs will be less than 1000 m^3. By comparison, ICG in its original waterflood application predicted incremental waterflood recovery for NVSU No. 2 of 183 x $10^3 m^3$. Reduced injection volumes and delayed waterflood response may adversely effect ultimate recovery in NVSU No. 2.

The Branch suggests the benefits of accelerating waterflood response in NVSU No. 2 outweigh the possibility of lost recovery at A11-30 and 14-30. Therefore, it is recommended that Clauses 8(a) and (c) be deleted and Section 8 be revised as follows:

8. Unless otherwise provided by the Board in writing, the ratio of water injected in the well, ICGR et al Virden WIW A10-30-11-26 (WPM) to reservoir withdrawals from the wells producing in the N/2 of Section 30 in Township 11, Range 26 (WPM) shall not exceed 1.5 on a semi-annual basis. The following factors shall be applied to the wells' production to calculate reservoir withdrawals; 9-30 - 0.5, A11-30 - 1.0, 14-30 - 1.0, 15-30 - 1.0 and 16-30 - 0.25.

The revised restrictions allow injection into A10-30 to be increased from 9.8 m^3/d to 12.8 m^3/d.

Ranchmen's Objection

In its objection Ranchmen's was concerned with unit expansion, waterflood implementation, injection distribution and loss in ultimate recovery of A11-30 and 14-30 (previously discussed).

Unit Expansion

Ranchmen's position that NVSU No. 2 should be expanded to include all its wells in Section 30-11-26 is questionable. ICG in its original application indicated wells south of NVSU No. 2 were excluded due to their advanced stage of depletion. Ranchmen's wells in the S/2 of Section 30 were drilled in 1966-69. Current recovery for the wells averages 29% OOIP compared to a current recovery of 5% OOIP for wells in NVSU No. 2. In addition, ICG postulated the structural low between the N/2 and S/2 of Section 30 (Figure 4) may effectively separate NVSU No. 2 from Ranchmen's wells in the S/2 of Section 30. In addition, Ranchmen's has been essentially operating a pressure maintenance scheme in the S/2 of Section 30 using the 8-30-11-26 disposal well (refer to following discussion). The Branch is of the opinion that unit enlargement to include wells in the S/2 of Section 30 is unnecessary and unwarranted.

ICG in its original pressure maintenance application indicated Ranchmen's wells at A11-30 and 14-30 were of questionable value to NVSU No. 2 because of their low productivity and high WOR. ICG also stated that if a positive response to the waterflood was observed at A11-30 and 14-30, the wells should be considered for inclusion in NVSU No. 2 after one year.

The Branch suggests Ranchmen's be reminded that if further attempts to negotiate a unit enlargement to include A11-30 and 14-30 in NVSU No. 2 fail, the company may apply to the Board under Section 79 of The Mines Act for an order to enlarge the unit.

Waterflood Implementation and Injection Distribution

The Branch is satisfied with Saskoil's implementation of the waterflood in NVSU No. 2. What concerns the Branch and Saskoil is the limited injectivity of wells in the unit. A problem that will be partially corrected by increasing injection volumes in A10-30.

The Branch finds it odd that Ranchmen's is concerned with injection distribution. Since 1973 when 8-30-11-26 was converted to water disposal, a total of 129.8 x 10^3m^3 water (7.8 times the cumulative injection in NVSU No. 2) has been injected into the Virden Lodgepole A Pool, a volume equivalent to 62% of cumulative reservoir withdrawals in the S/2 of Section 30.

The 8-30 disposal well is completed in the same zone, downdip of offset producers in the S/2 of Section 30. A review of the production history of Ranchmen's wells in the S/2 of Section 30 shows disposal at 8-30 has resulted in a decrease in the decline rate from 10% /year (1969-74) to 5% /year (1974-91). Figure 5 shows the production history of wells in the S/2 of Section 30 from 1979-91. A similar response as that observed in NVSU No. 2 to date.

Current recoveries for wells in the S/2 of Section 30 are estimated to average 29% OOIP (based on a 16 ha drainage area). The ultimate recovery from the S/2 of Section 30 is predicted to be 36% OOIP. Both the current and ultimate recovery estimates are similar to recovery estimates for existing waterflood projects in the Virden Field.

The Branch is satisfied that the proposed injection distribution in NVSU No. 2 and disposal at 8-30 will continue to have a beneficial effect on production from NVSU No. 2 and Ranchmen's wells in Section 30.

ORIGINAL SIGNED BY
JOHN N. FOX

John N. Fox

Approved: ______________________________
L.R. Dubreuil, Director

TABLE 1

NVSU NO. 2 PATTERN VRR'S

INJECTION PATTERN	DAILY INJECTION (91-07)	VRR (91-07)	TARGET INJECTION	TARGET VRR	VRR SINCE WATERFLOOD START-UP	CUMULATIVE VRR
12-29	10.9	0.73	17	1.2	1.25	0.25
A10-30*	9.9	1.13	12.8	1.5	1.06	0.19
4-32	6.4	0.42	24	1.5	0.44	0.08
				TOTAL	0.87*	0.16*

* Includes voidage from A11-30 and 14-30.

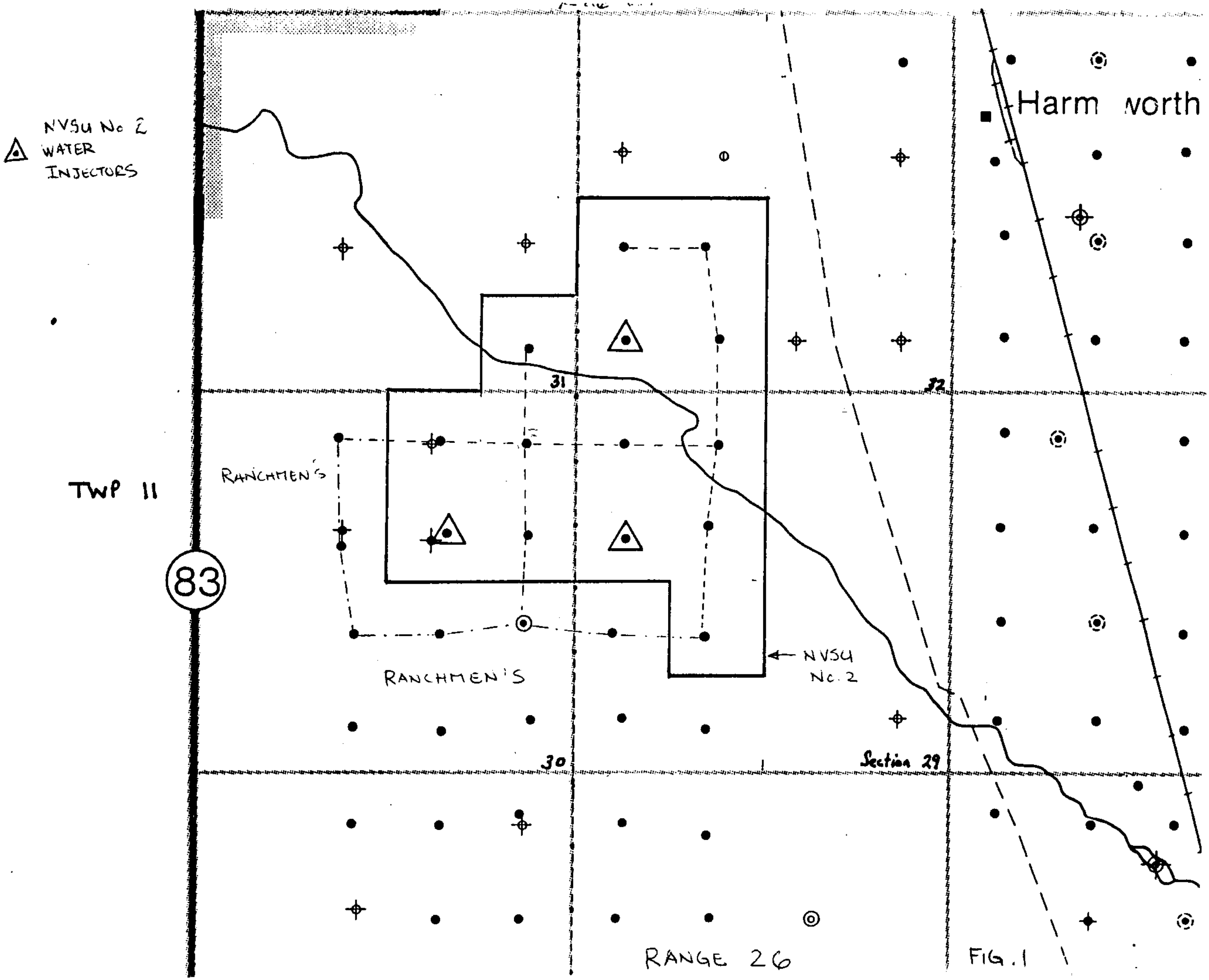

NVSU No 2
WATER
INJECTORS
Harm north
TWP 11
83
31
32
30
Section 29
RANCHMEN'S
RANCHMEN'S
NVSU
No. 2
RANGE 26

FIG. 1

NVSU NO. 2 PRODUCTION HISTORY

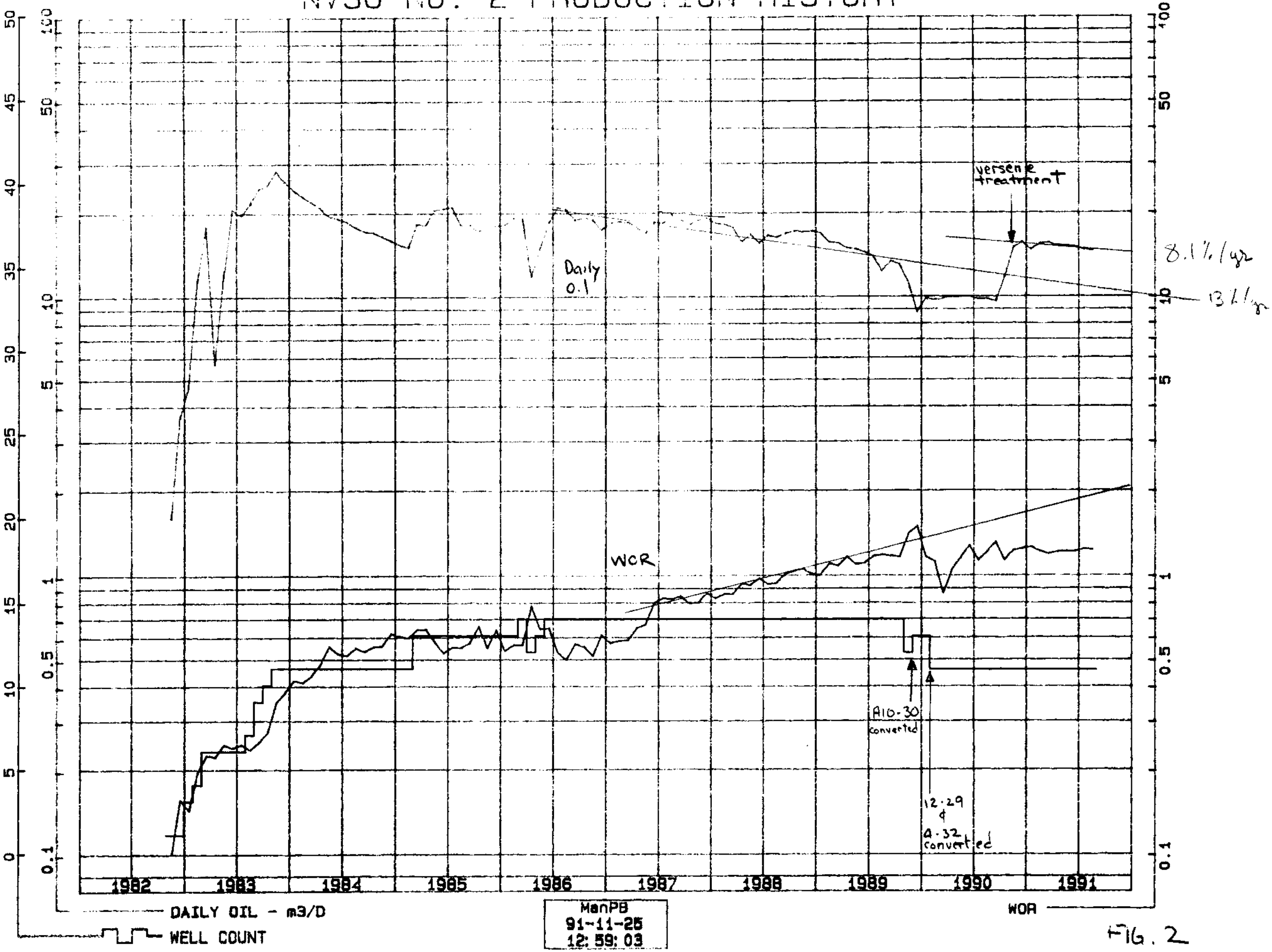


FIG. 2

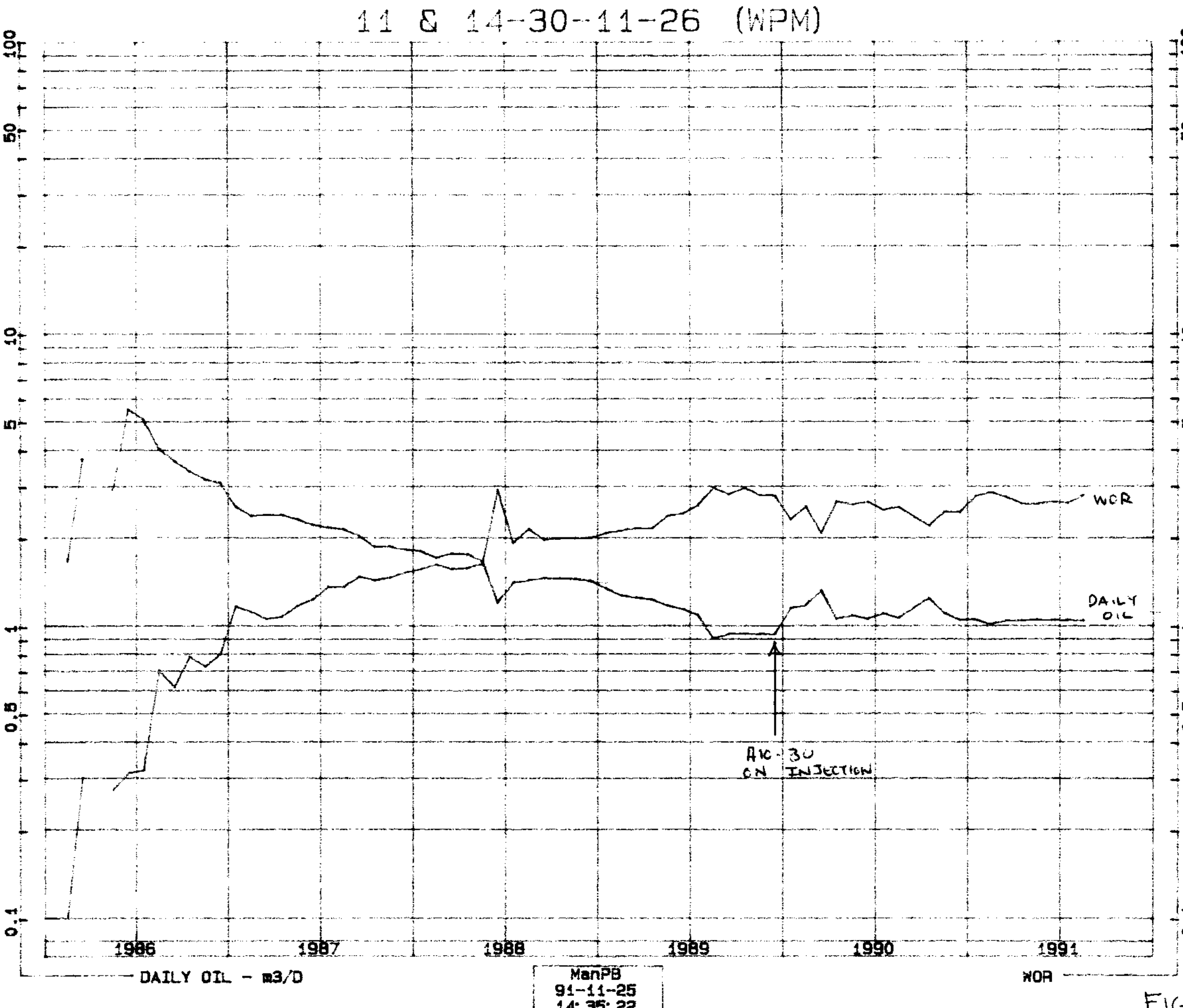
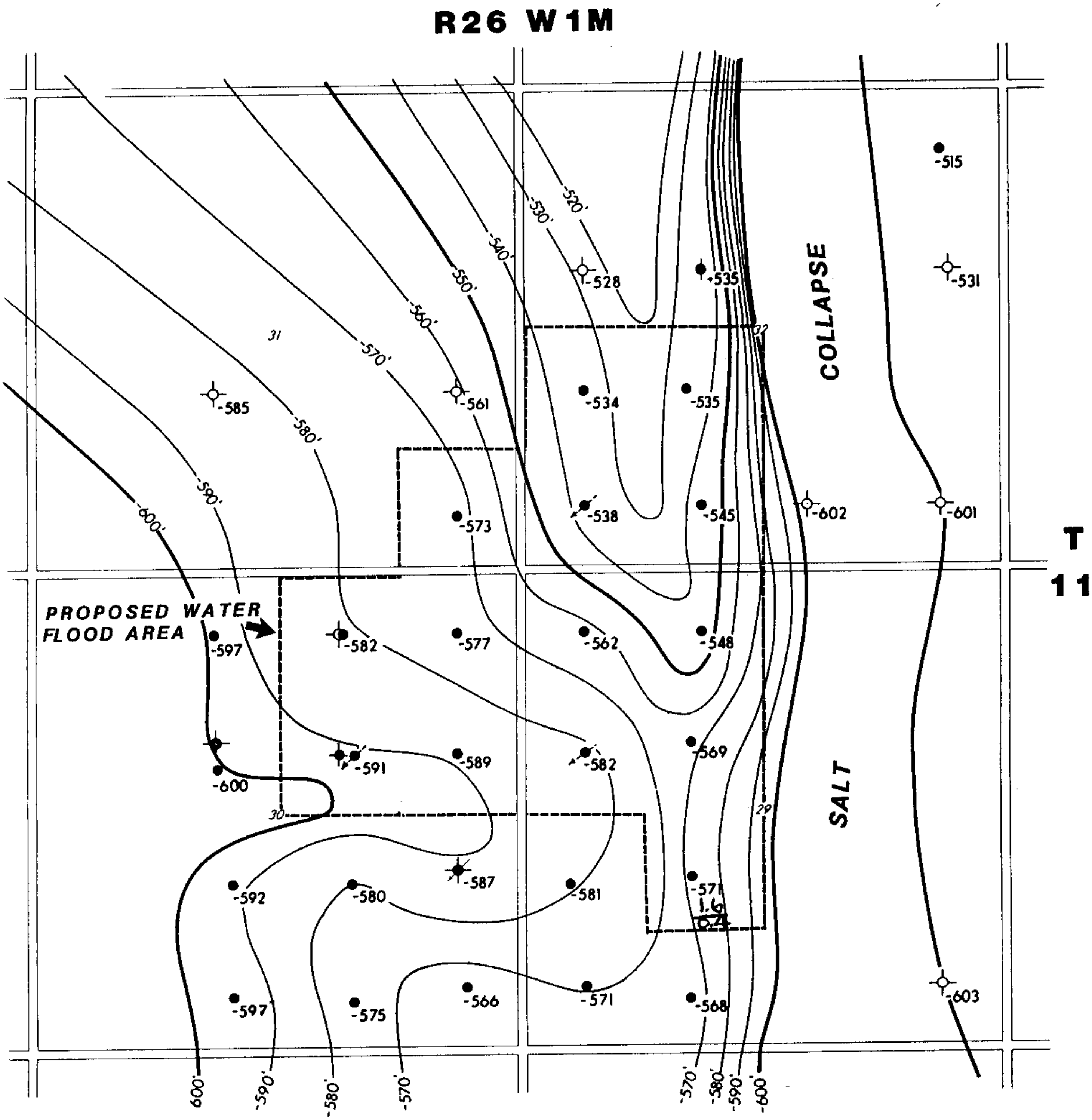

11 & 14-30-11-26 (WPM)
100
50
10
5
1
0.5
0.1
1986
1987
1988
1989
1990
1991
WOR
DAILY OIL
A10-30
ON INJECTION
DAILY OIL - m3/D
ManPB
91-11-25
14:35:22
WOR

FIG. 3



PROPOSED WATER INJECTION WELL

ICG RESOURCES LTD

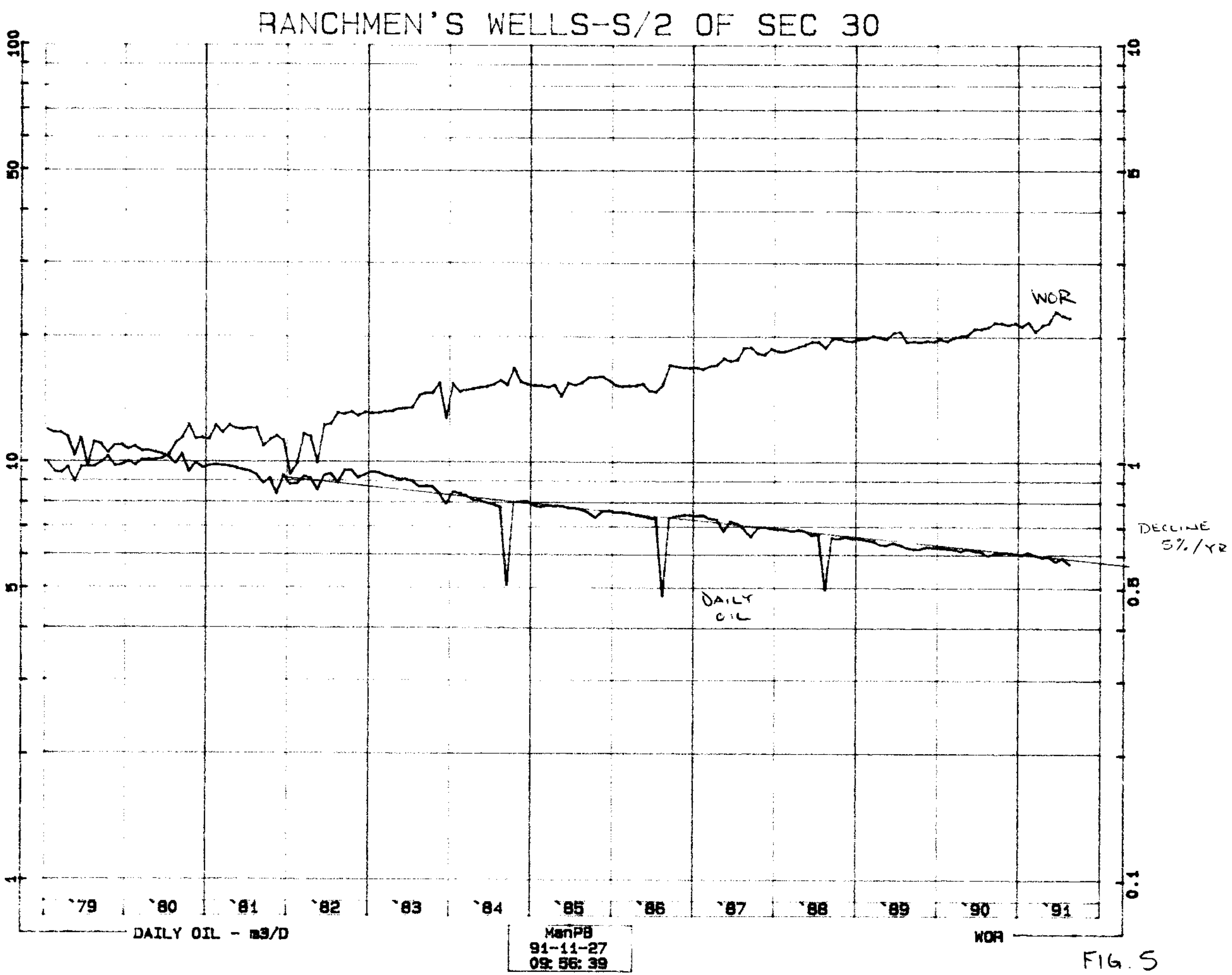
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL

STRUCTURE CONTOUR MAP

C.I.=10'

Fig. 4

GEOLOGY BY M.Gabriel	DRAFTING BY F.F.
SCALE 1: 12,500	DATE 1988-08-30



RANCHMEN'S WELLS-S/2 OF SEC 30
100
50
10
5
1
10
5
1
0.5
0.1
WOR
DECLINE 5%/YR.
DAILY OIL
`79
`80
`81
`82
`83
`84
`85
`86
`87
`88
`89
`90
`91
DAILY OIL - m3/D
WOR
ManPB
91-11-27
09:56:39

FIG. 5

Manitoba

The Oil and Natural Gas
Conservation Board

Room 309
Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

(204) 945-3130

November 20, 1991

Mr. K.J. Marjoram, P. Eng.
Operations Engineer
Ranchmen's Resources Ltd.
Suite 1000, 333-11th Avenue S.W.
Calgary, Alberta
T2R 1L9

Dear Mr. Marjoram:

RE: North Virden Scallion Unit No. 2
Application to Amend Board Order No. PM 59

The Board has completed its preliminary review of Saskoil's application to amend Section 8 of Board Order No. PM 59 and Ranchmen's objection to the application. This letter is to advise you that the Board is prepared to amend Section 8 of Board Order No. PM 59, as follows:

> 8. Unless otherwise provided by the Board in writing, the ratio of water injected in the well, ICGR et al Virden WIW A10-30-11-26 (WPM) to reservoir withdrawals from the wells producing in the N/2 of Section 30 in Township 11, Range 26 (WPM) shall not exceed 1.5 on a semi-annual basis. The following factors will be applied to the wells' production to calculate reservoir withdrawals: 9-30 = 0.5, A11-30 = 1.0, 14-30 = 1.0, A15-30 = 1.0 and 16-30 = 0.25.

The revised injection restrictions will allow current maximum injection at A10-30 to be increased from approximately 9.8 m^3/d to 12.8 m^3/d.

Ranchmen's, in its objection to the application, expressed the following concerns:

(1) North Virden Scallion Unit No. 2 (NVSU No. 2) should be expanded to include all the wells in Section 30-11-26 (WPM); and

(2) Injection restrictions for A10-30 should continue

(a) until evidence of successful implementation of the waterflood is available,

(b) to ensure injection is evenly distributed within NVSU No. 2 and Section 30, and

(c) to prevent premature water breakthrough and loss in recovery at A11-30 and 14-30.

The Board offers the following comments with respect to the concerns raised by Ranchmen's:

1. **Unit Expansion**

   Enlargement of NVSU No. 2 to include the S/2 of Section 30 does not appear as much at issue as enlargement of the Unit to include the A11-30 and 14-30 wells.

   It appears to the Board that disposal at 8-30-11-26 has been effective in providing pressure support in the S/2 of Section 30 and that a structural low may separate NVSU No. 2 from the wells in the S/2 of Section 30.

   ICG Resources in its original pressure maintenance application (September, 1988) suggested under certain circumstances the A11-30 and 14-30 wells would be considered for inclusion in the unit. The Board encourages continuation of negotiations for unit enlargement to include these wells. If Ranchmen's is not satisfied with the progress of unit negotiations, an application may be filed with the Board under Section 79 of The Mines Act for an order to enlarge the unit.

2. Waterflood Implementation and Injection Distribution

   The Board is satisfied with Saskoil's implementation of the waterflood in NVSU No. 2. What concerns the Board and Saskoil is the limited injectivity of wells in the unit. In successful waterfloods in the Lodgepole Formation in the Virden Field, water is typically over-injected at a voidage-replacement ratio (VRR) between 1.2 - 1.4. Injection at a VRR in excess of 1.0 accelerates fill-up, enhances volumetric sweep efficiency and counteracts limited out of zone injection.

   The Board considers the limited injectivity in NVSU No. 2 to be the greatest impediment to the success of the waterflood. Increased injection at A10-30 will assist in alleviating this problem.

   The Board does not see the distribution of injection within NVSU No. 2 as an issue but considers the maximum injection volume permitted for the A10-30 well to be the real concern.

3. Premature Water Breakthrough and Loss in Recovery at A11-30 and 14-30

   The Board has reviewed the performance of the A11-30 and 14-30 wells. Combined the wells produce slightly more than 1.0 m^3/d. Since injection commenced at A10-30 in December, 1989, production from the two wells has increased slightly. The Board is not in a position to determine if the increase is related to injection at A10-30.

Assuming an economic limit of 0.2 m^3/d/well, the Board estimates the potential loss in recoverable reserves resulting from premature water breakthrough at A11-30 and 14-30 will be less than 1 000 m^3. In comparison, ICG in its original waterflood application predicted incremental waterflood recovery for NVSU No. 2 of 183 x $10^3 m^3$.

The Board in conducting its review of the application has attempted to balance Saskoil's desire to accelerate and enhance waterflood response in NVSU No. 2 to recover its waterflood investment and Ranchmen's desire to protect itself against financial loss. The Board in reaching its current conclusion to ease the injection restrictions at A10-30 has also taken into account the remedy available to Ranchmen's under Section 79 of The Mines Act. The Board is prepared to entertain further comments, questions and concerns from Ranchmen's on this matter before December 16, 1991 before making its final decision.

Yours respectfully,

H. Clare Moster
Deputy Chairman

cc: Mr. Robert Kehring, P. Eng.
Saskatchewan Oil and Gas Corporation

Ranchmen's Resources Ltd.

SUITE 1000
333 Eleventh Avenue S.W.
CALGARY, Alberta T2R 1L9

TELEPHONE (403) 267-9400
10th Floor Fax (403) 267-9455
9th Floor Fax (403) 267-9444

June 17, 1991

Manitoba Energy and Mines
The Oil and Natural Gas Conservation Board
Room 309 - Legislative Building
Winnipeg, Manitoba
R3C 0V8

Attention: Mr. John N. Fox
Chief Petroleum Engineer

Dear Sir:

Re: Ranchmen's Concerns With Saskoil's Application
Board Order No. PM 59

Ranchmen's Resources Ltd. hereby responds to Saskoil's Application Letter of May 1, 1991, concerning the Board Order No. PM 59. As per the initial Board Order request Ranchmen's and Saskoil met on 1991-01-18 to discuss the submittance of a detailed joint report and the expansion of the Unit. Ranchmen's stated at that time and still do feel that expansion of the unit to include all our wells in Section 30 (1-30, 2-30, 3-30, 6-30, 7-30 8-30 SWD, 11-30 and 14-30) would benefit everyone by working together on the waterflood of the Virden Lodgepool "A" Pool to maximize hydrocarbon recovery.

Ranchmen's is still in strong disagreement of removing or changing any of the water injection restrictions in Clauses 8(a) and 8(b). Voidage replacement calculations for the pool show water injection replacement is very uneven through out the pool. Voidage Replacement Ratios (VRR's) including Ranchmen's wells for the south portion of the pool are as high as 2.16 while the ratio for the north-east section of the pool is as low as 0.40. Ranchmen's has not seen results of any subsurface pressure surveys recommended in Clause 3 of the Board Order PM 59 justifying the excessive water injection volumes in the south end of the pool. The initial Board Order PM 59 should remain as written until satisfactory evidence is obtained showing a successful implementation of the waterflood pressure maintenance scheme.

Ranchmen's does not consider having no early breakthrough of water reason to increase injection volumes in the south half of the pool, as once breakthrough is obtained well life is reduced substantially. The injection restrictions should be maintained in order that total pool injections are more evenly distributed as injection ratios in the north end of the pool should be increased.

Ranchmen's is looking forward to working with the Manitoba Oil and Natural Gas Conservation Board and Saskoil in maximizing the effectiveness of the waterflood program. If you have any questions, require additional information or would like to set a meeting please contact me at 403-267-9452.

Yours very truly,

RANCHMEN'S RESOURCES LTD.

KJ Marjoram

K.J. Marjoram, P. Eng.
Operations Engineer

KJM:yp

cc: Saskoil
1777 Victoria Avenue
P.O. Box 1550
Regina, Saskatchewan
S4P 3C4
Fax (306) 781-8364
Attention: Mr. Robert Kehrig

Manitoba

Memorandum

Date May 22, 1991

To The Oil and Natural Gas Conservation Board
- Ian Haugh, Chairman
- H. Clare Moster, Deputy Chairman
- Wm. McDonald, Member

From John N. Fox
Chief Petroleum Engineer
Petroleum Branch

Telephone

Subject

Re: North Virden Scallion Unit No. 2
<u>Application to Amend Board Order No. PM 59</u>

First | Fold

Saskatchewan Oil and Gas Corporation, the operator of North Virden Scallion Unit No. 2 (NVSU No. 2) has made application to amend Clauses 8(a) and 8(b) of Board Order No. PM 59. The application and a waterflood progress report were submitted by Saskoil in lieu of a detailed joint report by Saskoil and Ranchmen's on the feasibility and desirability of expanding the unit area as required by Clause 8(c) of the Order. Figure 1 shows the unit area and Ranchmen's lands.

<u>Recommendation</u>

It is recommended that Ranchmen's be requested by the Board to provide its comments on the application and its position of expansion of NVSU No. 2. A copy of the proposed Board letter is attached.

John N. Fox
Chief Petroleum Engineer

JNF/sml

Attachment

Recommended for Approval: ______________
L. R. Dubreuil, Director

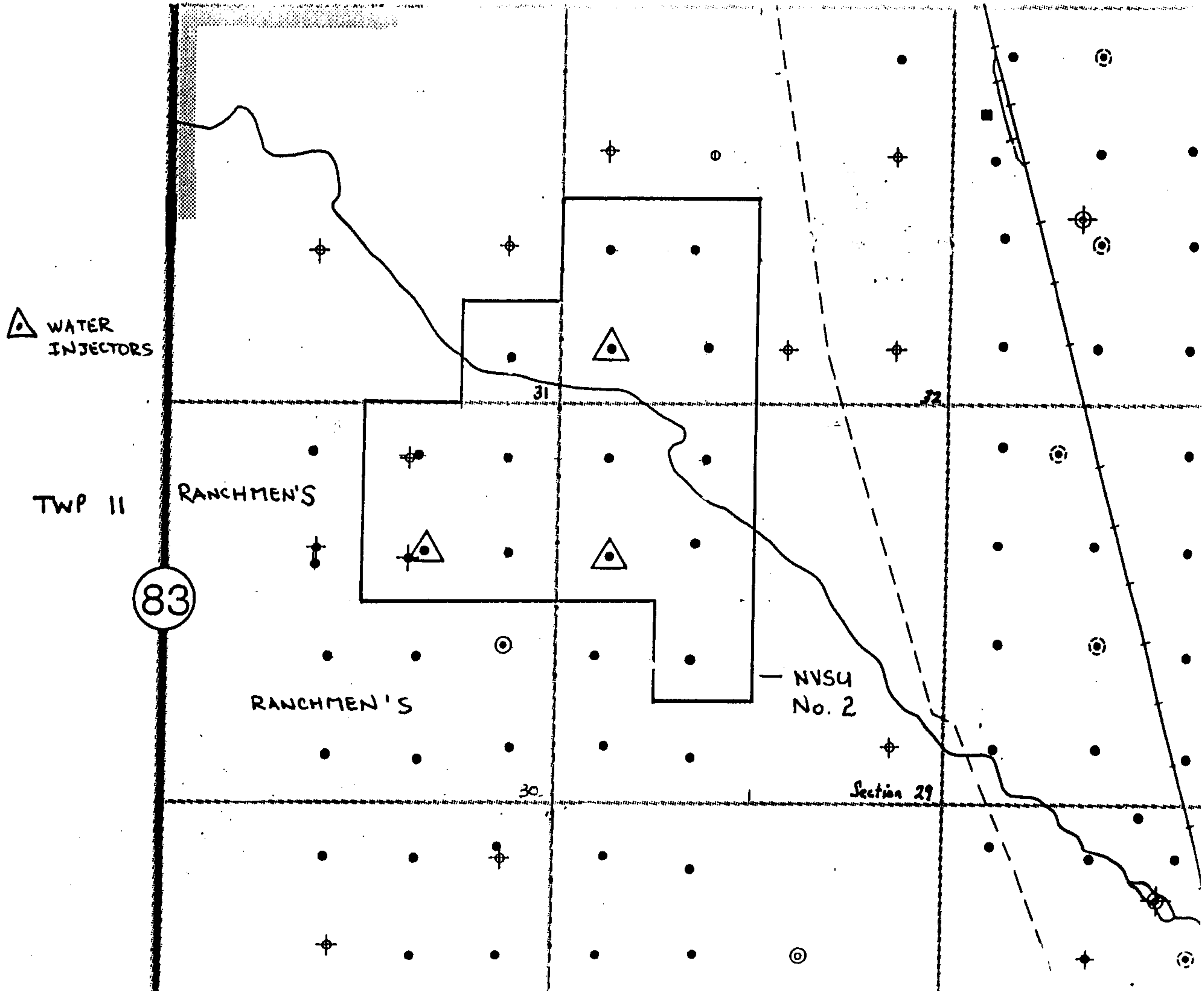

WATER INJECTORS
TWP 11
83
RANCHMEN'S
RANCHMEN'S
31
32
30
Section 29
NVSU No. 2
RGE 26

FIGURE 1

Manitoba

The Oil and Natural Gas Conservation Board

Room 309
Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

(204) 945-3130

May 22, 1991

Mr. P. G. Maguire
Operations Engineer
Ranchmen's Resources Ltd.
Suite 1000
333 - 11th Avenue S.W.
Calgary, Alberta
T2R 1L9

Dear Mr. Maguire:

Re: North Virden Scallion Unit No. 2
<u>Board Order No. PM 59</u>

Clause 8(c) of Board Order No. PM 59 ("the Order") required Ranchmen's and Saskoil to submit a detailed joint report on the feasibility and desirability of expanding the unit area. In lieu of a joint report, the Board has received a waterflood progress report for North Virden Scallion Unit No. 2 (NVSU No. 2) and application for relief from the restrictions of Clauses 8(a) and 8(b) of the Order from Saskoil. It is the Board's understanding that Saskoil has forwarded a copy of the application to Ranchmen's.

Ranchmen's is requested to provide the Board before June 17, 1991, with its comments and concerns regarding Saskoil's application and its position on expansion of NVSU No. 2.

If you have any questions in respect of this matter, please contact L. R. Dubreuil, Director of Petroleum or John N. Fox, Chief Petroleum Engineer at (204) 945-6573 or 945-6574, respectively.

Yours respectfully,

ORIGINAL SIGNED BY
H. CLARE MOSTER

H. Clare Moster
Deputy Minister

JOHN

saskoil

1-May-91

Mr. J.N. Fox
Chief Petroleum Engineer
Manitoba Oil and Gas Conservation Board
Room 39, Legislative Building
Winnipeg, Manitoba
R3C 0V8

Dear Mr. Fox:

RE: North Virden Scallion Unit No. 2
Board Order No. PM59

Saskatchewan Oil and Gas Corporation (Saskoil), would like to present a waterflood operations report in lieu of a joint waterflood study as described in Clause 8(c) of Board Order No. PM59. Saskoil, at the same time, seeks some relief regarding Clauses 8(a) and 8(b) of Board Order No. PM59.

Saskoil requested, and was granted, an extension of the submission of the detailed joint study until May 1, 1991. Since the beginning of the waterflood, Saskoil has stayed within the injection limits imposed by Clauses 8(a) and 8(b), as shown in Tables 1 and 2. The voidage replacement calculations in Table 2 do not take Ranchmen's Resources two subject wells into account; when included, the voidage replacement ratio is below the prescribed limit of 1.15, as per Clause 8(b). The voidage calculations also do not include the water disposal well at 8-30-11-26 WPM, which has been injecting to the Lodgepole "A" pool for a long time, with no adverse effects on the surrounding producers.

As per part of Clause 8(c) regarding the feasibility and desirability of enlarging the unit, Saskoil does not wish to include the two additional Ranchmen's wells in the unit. Ranchmen's Resources has already had a pressure maintenance scheme in Section 30 with 8-30-11-26 WPM as a disposal well.

Regarding Clauses 8(a) and 8(b), no early breakthrough of water has occurred in the unit, as well as in the non-unit wells in the area. The watercuts of oil-producing wells surrounding the 8-30-11-26 WPM disposal well have also been in line with those of unit wells. We would therefore ask the Board to consider

1777 Victoria Avenue
P.O. Box 1550
Regina, Saskatchewan
S4P 3C4 (306) 781-8200 Fax (306) 781-8364

removal of Clause 8(a) regarding the limit of volume injected to A10-30-11-26 WPM and raising the ratio of water injection to reservoir withdrawals to 1.5 from the current 1.15 in Clause 8(b).

We hope this will be satisfactory to the Board, and consideration will be given to our request for relaxation of the limits prescribed in Clauses 8(a) and 8(b).

We would also like to mention that future correspondence regarding the above be sent to the attention of Mr. Glen Yeryk, Pasqua Resources Ltd., a subsidiary of Saskatchewan Oil and Gas Corporation (at the address listed on the previous page). Any questions about this report, however, can be directed to Mr. Kadri Kaleli (306) 781-8367, or Mr. Don Gallant (306) 781-8522, both of our Saskoil Regina office.

Yours truly,

Robert Kehrig

Robert Kehrig, P.Eng.
Supervisor, Development Engineering
Southern Saskatchewan

rak/KK/ljg
Attach.
xc: G. Yeryk
R. Kehrig/K. Kaleli
D. Gallant/R. Batt/R. Gladysz
Ranchmen's Resources
Working Interest Owners
Unit File

TABLE I

NORTH VIRDEN SCALLION UNIT No.2

- Waterflood Injection History -

INJECTOR		TARGETS	12/89	1/90	2/90	3/90	4/90	5/90	6/90	7/90	8/90	9/90	10/90	11/90	12/90	1/91	2/91	3/91	CUM.TO DATE	% of CUM.INJ.
12-29-11-26W1M	m3/mth				503.5	550.1	528.2	500.1	508.8	508.1	488.5	477.8	480.2	472.0	482.8	538.8	411.3	443.7	6,893.9	51.9%
	m3/d	14 - 17			18.0	17.7	17.6	16.1	17.0	17.1	15.8	15.9	15.5	15.7	15.6	17.4	14.7	14.3		
	kPa				5998	5998	5998	5998	5998	5998	5998	5998	5998	5998	5998	5998	5998	5998		
10-30-11-26W1M	m3/mth		275.3	341.5	284.0	211.0	204.9	219.3	200.1	220.1	219.1	233.2	222.4	209.4	296.4	220.5	189.6	218.1	3,764.9	28.4%
	m3/d	5 - 7	8.9	11.0	10.1	6.8	6.8	7.1	6.7	7.4	7.1	7.8	7.2	7.0	9.6	7.1	6.8	7.0		
	kPa		5516	5861	5929	3447	3861	3447	3241	3964	3309	3309	3654	3033	3033/5998	3102	3102	3102		
04-32-11-26W1M	m3/mth				132.6	136.1	160.4	165.9	166.6	208.3	201.1	199.0	211.5	221.0	230.6	144.7	219.2	220.3	2,617.3	19.7%
	m3/d	18 - 24			4.7	4.4	5.3	5.4	5.6	7.0	6.5	6.6	6.8	7.4	7.4	7.6	7.8	7.1		
	kPa				5998	5998	5998	5998	5998	5998	5998	5998	5998	5998	5998	5998	5998	5998		
TOTAL	m3/mth		275.3	341.5	920.1	897.2	893.5	885.3	875.5	936.5	908.7	910.0	914.1	902.4	1009.8	904.0	820.1	882.1	13,276.1	
	m3/d	37 - 48	8.9	11.0	32.9	28.9	29.8	28.6	29.2	31.5	29.3	30.3	29.5	30.1	32.6	32.1	29.3	28.5		

NOTE : Max. injection pressure limited to 6000 kPa as per MEM.
10-30 injection rate is limited to 33% of total volume due to offsetting Ranchmen wells.

TABLE II

NORTH VIRDEN SCALLION UNIT NO.2

PRODUCTION DATA AND TARGET INJECTION RATES

PATTERN	WELL LOCATION (W1M)	WELL TYPE	FACTOR APPLIED	CUM OIL to 91/03 (M3)	CUM WATER to 91/03 (M3)	CUM FLUID (M3)	DLY FLD RATE (M3/DAY)	CUM FLUID (M3/PAT)	DLY FLD RATE (M3/DAY)	EXISTING INJ RATE (M3/DAY)	TARGET INJ RATE (M3/DAY)
1	13-29-11-26	OIL	0.50	3602.0	1586.5	5368.6	2.0				
	14-29-11-26	OIL	0.50	6480.1	7648.3	14452.4	7.1				
	16-30-11-26	OIL	0.33	5395.6	2229.6	7895.0	3.5				
	01-31-11-26	OIL	1.00	5737.7	1199.7	7224.3	2.9				
	03-32-11-26	OIL	1.00	2840.9	7114.4	10097.3	4.2				
	05-32-11-26	OIL	1.00	3134.6	1131.3	4422.6	1.8				
	06-32-11-26	OIL	1.00	1192.4	1484.4	2736.4	0.9	42371.7	15.5	7.4	24
	04-32-11-26	INJ	1.00	3745.1	1442.8	5375.2					
2	09-30-11-26	OIL	0.50	4808.1	6135.1	11183.6	5.7				
	15-30-11-26	OIL	1.00	1274.6	1247.6	2585.9	1.0				
	16-30-11-26	OIL	0.33	5395.6	2229.6	7895.0	3.5	15541.7	5.0	7.0	7
	10-30-11-26	INJ	1.00	28[illegible].7	1725.5	4758.6					
3	06-29-11-26	OIL	1.00	2748.5	928.4	3814.3	2.1				
	11-29-11-26	OIL	1.00	4888.9	1237.7	6371.0	3.2				
	13-29-11-26	OIL	0.50	3602.0	1586.5	5368.6	2.0				
	14-29-11-26	OIL	0.50	6480.1	7648.3	14452.4	7.1				
	09-30-11-26	OIL	0.50	4808.1	6135.1	11183.6	5.7				
	16-30-11-26	OIL	0.33	5395.6	2229.6	7895.0	3.5	37461.5	14.0	15.6	17
	12-29-11-26	INJ	1.00	2132.3	1337.3	3576.2					

Boi = 1.05

NORTH VIRDEN SCALLION UNIT NO. 2

1990 OPERATIONS REPORT

JANUARY 1, 1990 - DECEMBER 31, 1990

SASKATCHEWAN OIL AND GAS CORPORATION
PRODUCTION DEPARTMENT

January, 1991

NORTH VIRDEN SCALLION UNIT NO. 2

INDEX

TABLES

FIGURES

INTRODUCTION

The following report summarizes the operations performance of the North Virden Scallion Unit No. 2 for the reporting period January 1, 1990 to December 31, 1990.

The subject Unit is operated by Saskoil and is located in Sections 29, 30, 31, 32, Township 11, Range 26, W1M in Manitoba. Saskoil became operator in November, 1989.

The effective start date for the Unit was August 1, 1989, with water injection commencing on February 1, 1990.

I. PRODUCTION PERFORMANCE

The Unit production for the reporting year is summarized as follows:

		1990	1989
OIL PRODUCTION:	Daily (m3)	11.2	15.8
	Monthly (m3)	334.0	474.2
	Year (m3)	4,007.7	5,689.8
WATER PROD.:	Daily (m3)	13.1	18.9
	Monthly (m3)	388.1	567.6
	Year (m3)	4,657.0	6,811.3

Daily oil production averaged 11.2 m^3/d in 1990. Successful versene treatments carried out in September and October have increased daily production by 58%. The current oil production rate in the Unit is 15.8 m^3/day. The 1989 data includes an additional three producers which were later converted to injectors (late 1989). Refer to Tables I and II and Figures I - III for production details.

II. WATER INJECTION

Water is injected into the base of the Lodgepole "A" at three locations:

12-29-11-26 W1M
10-30-11-26 W1M
04-32-11-26 W1M

	12-29-11-26	10-30-11-26	4-32-11-26
1990 WATER INJECTED (M3)	5,500.1	2,861.4	2,033.1
PERCENT OF TOTAL WATER INJECTED	52.9%	27.5%	19.6%
AVERAGE WATER INJECTION RATE (M3/D)	15.6	7.0	7.4

(Refer to Table IV for Injection History Details)

III. WELL STATUS

During the reporting period, the North Virden Scallion Unit No. 2 active well count list remained constant. As of December 31, 1990 the well status in the Unit is as follows:

		DEC. 31, 1990	DEC. 31, 1989
OIL WELLS:	Active:	11	11
	Suspended:	0	0
WATER INJECTORS:	Active:	3	1
	Suspended:	0	2
TOTAL		**14**	**14**

NOTE: Water injection wells 12-29 and 4-32 were being converted in late 1989 and only 10-30 was on injection in December, 1989.

IV. BATTERY

The annual treater maintenance and battery inspection took place in June, 1990.

V. OPERATING EXPENSES

The gross operating expenses for the reported year were approximately $221,838. Since this was the first year of operation, an operating budget was developed part way through the year using actual costs for the first six (6) months of operations. An outlook of $157,095 for the year was presented to partners at an Operating Committee Meeting on 90-08-15. This forecast to year-end did not include approximately $23,800 for property taxes, $20,000 for the battery and waterplant turnaround repairs, and $27,500 for versene treatments (ie. a total of $71,300) which would have adjusted the estimate of $157,095 to $228,300.

A breakdown of the expenses are as follows:

BATTERY	\$35,038.00
WATER INJECTION	\$25,161.00
WELL OPERATING	\$158,639.00
TOTAL GROSS	**\$221,838.00**

VI. WELL WORKOVERS/SERVICE

WELL	DESCRIPTION	COST (\$)
4-32-11-26 W1 Injector	PERFORATE LOWER IN CHERTY AND ACIDIZE	\$17,000
11 wells	VERSENE (EDTA) TREATMENTS	\$27,500

The 4-32 workover increased injection capability from 4.5 m^3/day to 7.4 m^3/d. The versene treatments increased oil production from 10.0 m^3/d to 15.8 m^3/d (ie. 58%).

VII. CHEMICALS

Production from the North Virden Scallion Unit No. 2 is chemically treated to break the oil/water emulsion and to prevent scale build-up in production equipment. The total cost for chemicals for the reported year is \$10,433.00.

NORTH VIRDEN SCALLION UNIT NO.2

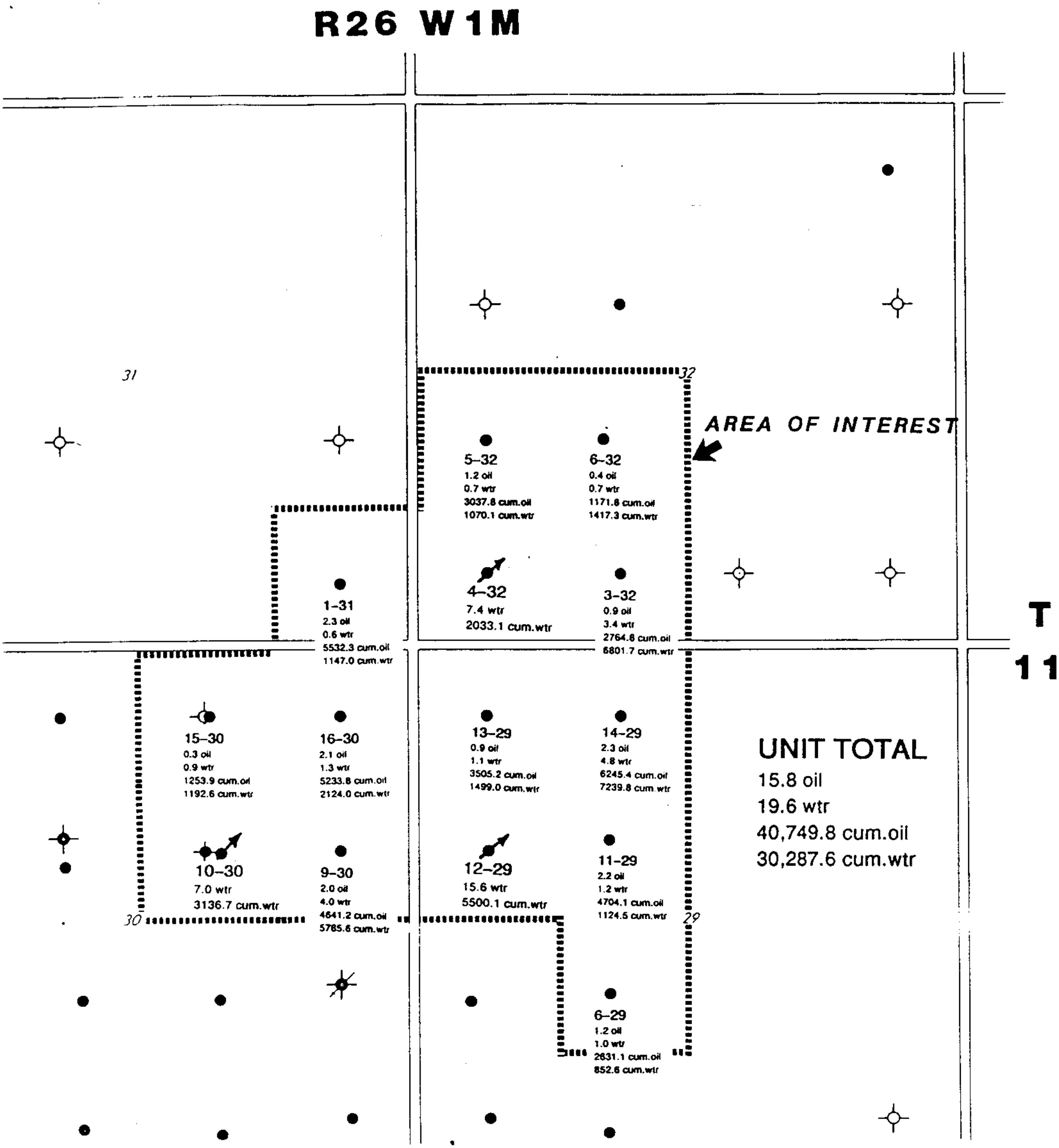


TABLE 1

NORTH VIRDEN SCALLION UNIT NO.2
1990 MONTHLY PRODUCTION RESULTS

MONTH	DAILY OIL PRODUCTION (m3)	MONTHLY OIL PRODUCTION (m3)	CUMMULATIVE OIL (m3)	DAILY WATER PRODUCTION (m3)	M'THLY WATER PRODUCTION (m3)	CUMMULATIVE WATER (m3)
		PRIOR CUM.->	36,742.1		PRIOR CUM.->	25,630.6
JANUARY	9.0	307.5	37,049.6	10.4	357.0	25,987.6
FEBRUARY	9.8	273.9	37,323.5	10.9	306.1	26,293.7
MARCH	9.9	306.9	37,630.4	8.5	264.5	26,558.2
APRIL	10.1	301.6	37,932.0	10.6	316.7	26,874.9
MAY	10.0	310.3	38,242.3	11.6	359.3	27,234.2
JUNE	10.1	302.3	38,544.6	12.9	386.1	27,620.3
JULY	9.8	304.4	38,849.0	11.1	343.3	27,963.6
AUGUST	9.9	305.9	39,154.9	12.0	370.9	28,334.5
SEPTEMBER	10.5	288.7	39,443.6	13.3	378.9	28,713.4
OCTOBER	12.6	365.4	39,809.0	14.0	412.2	29,125.6
NOVEMBER	16.3	450.9	40,259.9	21.7	553.0	29,678.6
DECEMBER	15.8	489.9	40,749.8	19.6	609.0	30,287.6
TOTALS	11.2	4,007.7		13.1	4,657.0	

TABLE II

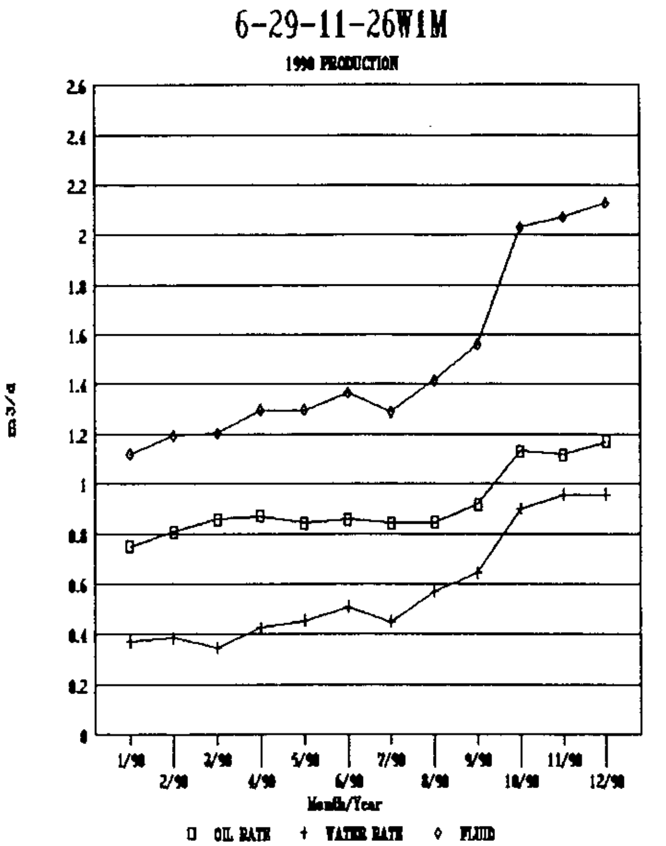
NORTH VIRDEN SCALLION UNIT NO.2

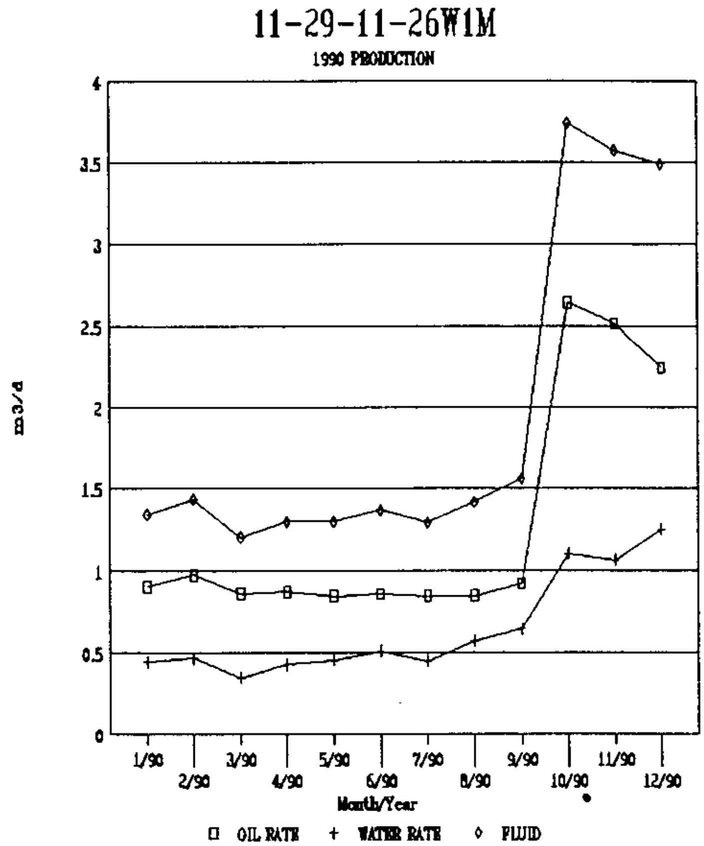
PRODUCTION HISTORY – January'90 to December'90

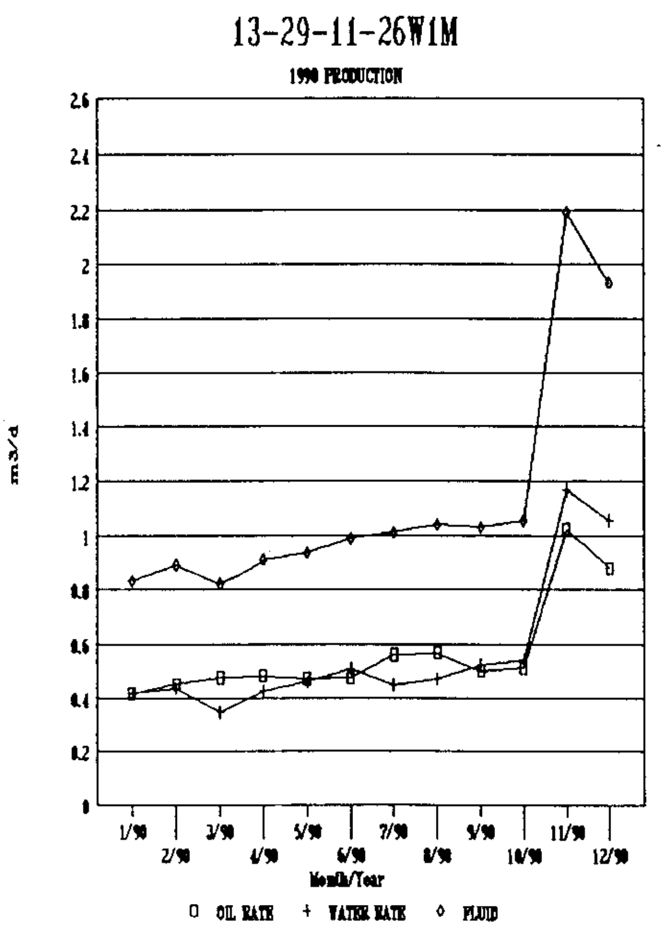
Well		1/90	2/90	3/90	4/90	5/90	6/90	7/90	8/90	9/90	10/90	11/90	12/90
06-29-11-26w1m	Oil m3/d	0.7	0.8	0.9	0.9	0.8	0.9	0.8	0.8	0.9	1.1	1.1	1.2
	Water m3/d	0.4	0.4	0.3	0.4	0.5	0.5	0.4	0.6	0.6	0.9	1.0	1.0
	Fluid m3/d	1.1	1.2	1.2	1.3	1.3	1.4	1.3	1.4	1.6	2.0	2.1	2.1
11-29	Oil m3/d	0.9	1.0	0.9	0.9	0.8	0.9	0.8	0.8	0.9	2.6	2.5	2.2
	Water m3/d	0.4	0.5	0.3	0.4	0.5	0.5	0.4	0.6	0.6	1.1	1.1	1.2
	Fluid m3/d	1.3	1.4	1.2	1.3	1.3	1.4	1.3	1.4	1.6	3.7	3.6	3.5
13-29	Oil m3/d	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.5	0.5	1.0	0.9
	Water m3/d	0.4	0.4	0.3	0.4	0.5	0.5	0.4	0.5	0.5	0.5	1.2	1.1
	Fluid m3/d	0.8	0.9	0.8	0.9	0.9	1.0	1.0	1.0	1.0	1.1	2.2	1.9
14-29	Oil m3/d	1.9	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.4	2.7	2.3
	Water m3/d	3.5	3.7	2.9	3.6	3.9	4.3	3.8	4.0	4.4	3.7	5.1	4.8
	Fluid m3/d	5.4	5.7	5.1	5.8	6.0	6.5	5.9	6.1	6.7	6.1	7.8	7.1
09-30	Oil m3/d	0.8	0.8	0.9	0.9	1.0	1.0	0.8	0.8	0.9	0.9	1.9	2.0
	Water m3/d	1.4	1.5	1.2	1.4	1.7	1.9	1.5	1.6	1.8	1.8	4.6	4.0
	Fluid m3/d	2.2	2.3	2.0	2.3	2.8	3.0	2.4	2.5	2.7	2.7	6.5	6.0
15-30	Oil m3/d	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.3
	Water m3/d	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.5	1.0	0.9
	Fluid m3/d	0.6	0.6	0.6	0.6	0.7	0.7	0.6	0.7	0.7	0.7	1.2	1.2
16-30	Oil m3/d	1.2	1.3	1.2	1.3	1.2	1.2	1.2	1.2	1.3	1.8	1.9	2.1
	Water m3/d	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	1.2	1.6	1.3
	Fluid m3/d	1.5	1.6	1.5	1.6	1.6	1.6	1.6	1.6	1.7	3.0	3.4	3.5
03-32	Oil m3/d	0.8	0.9	1.0	1.0	0.9	1.0	0.9	0.9	1.0	0.9	0.9	0.9
	Water m3/d	2.6	2.7	2.1	2.6	2.9	3.2	2.7	2.9	3.3	3.1	4.2	3.4
	Fluid m3/d	3.4	3.6	3.1	3.6	3.8	4.1	3.7	3.9	4.3	4.0	5.1	4.3
05-32	Oil m3/d	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	1.3	1.2
	Water m3/d	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.7	0.7
	Fluid m3/d	0.9	1.0	0.9	1.0	1.0	1.1	1.0	1.0	1.1	1.1	2.0	1.8
06-32	Oil m3/d	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
	Water m3/d	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.7	0.7
	Fluid m3/d	0.6	0.6	0.6	0.6	0.7	0.7	0.6	0.7	0.7	0.7	1.1	1.1
01-31	Oil m3/d	1.2	1.3	1.2	1.3	1.2	1.2	1.2	1.2	1.3	1.2	2.3	2.3
	Water m3/d	0.4	0.4	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.6
	Fluid m3/d	1.6	1.7	1.4	1.5	1.5	1.5	1.5	1.5	1.6	1.5	2.9	2.9
TOTALS	Oil m3/d	9.0	9.8	9.9	10.1	10.0	10.1	9.8	9.9	10.5	12.6	16.3	15.8
	Water m3/d	10.4	10.9	8.5	10.6	11.6	12.9	11.1	12.0	13.3	14.0	21.7	19.6
	Fluid m3/d	19.4	20.7	18.4	20.6	21.6	22.9	20.9	21.9	23.8	26.6	38.0	35.4
INJECTION	Fluid m3/d	11.0	32.9	28.9	29.8	28.6	29.2	31.5	29.3	30.3	29.5	30.1	32.6

FIGURE I

NORTH VIRDEN SCALLION UNIT NO.2







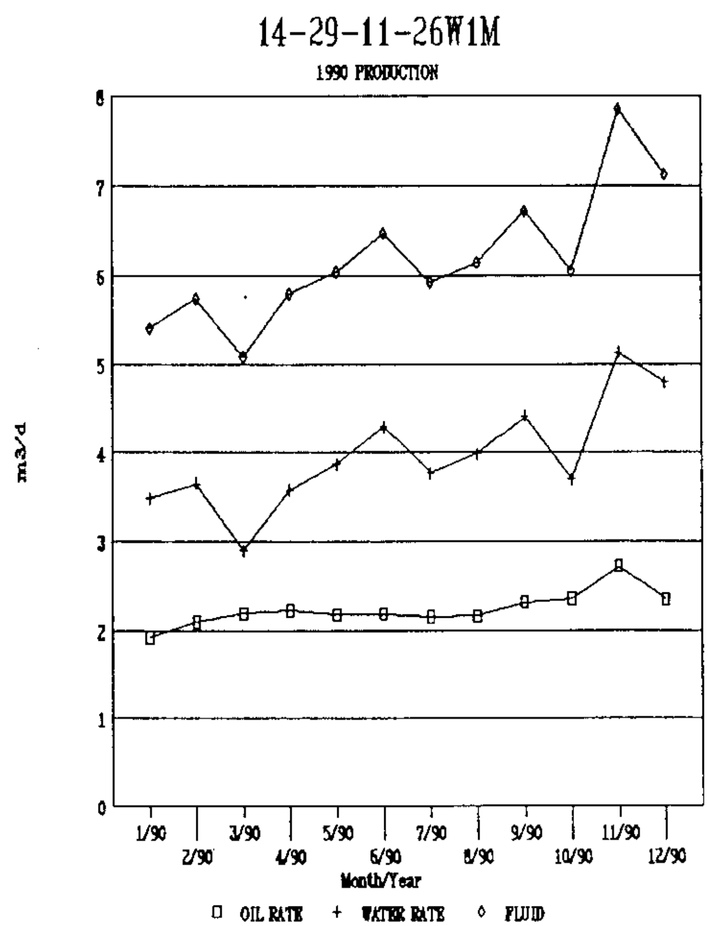
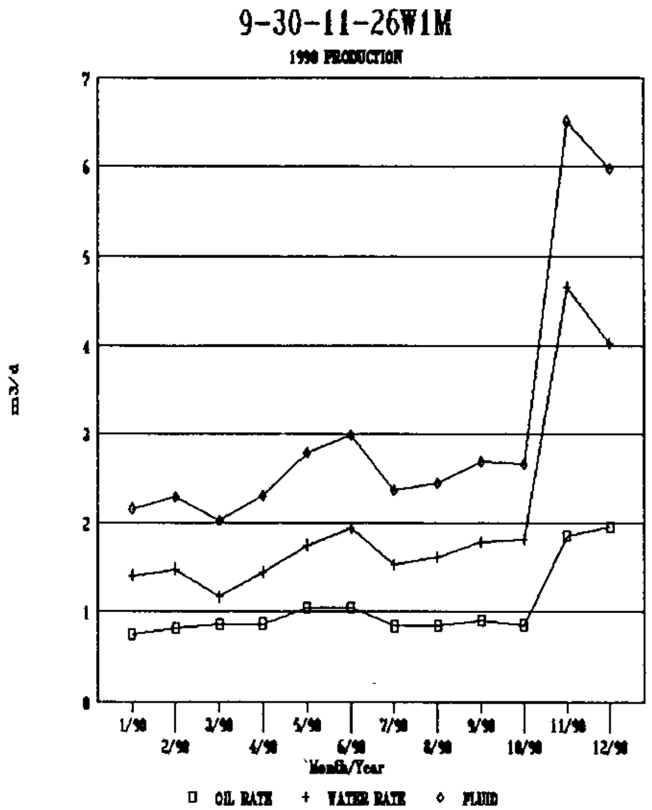
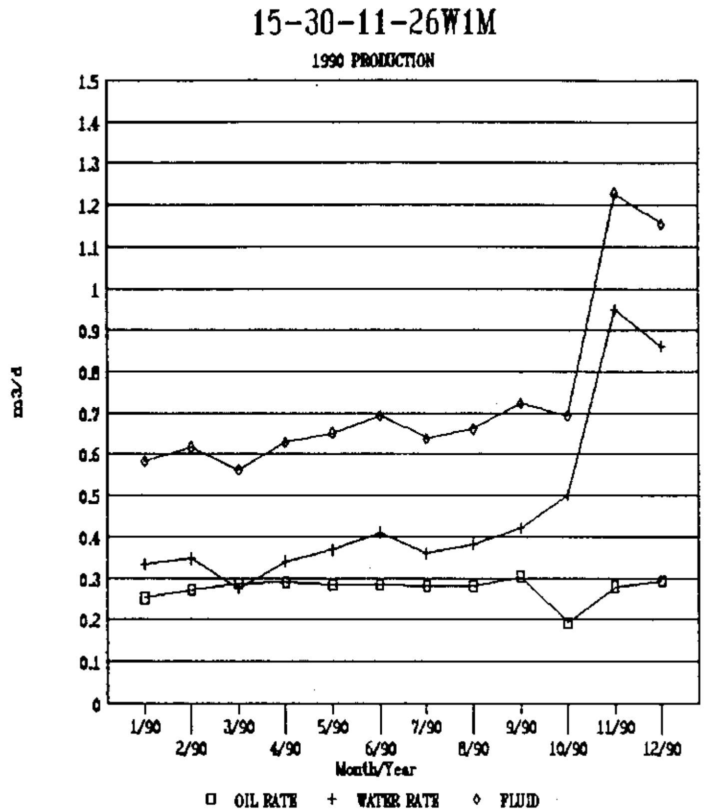
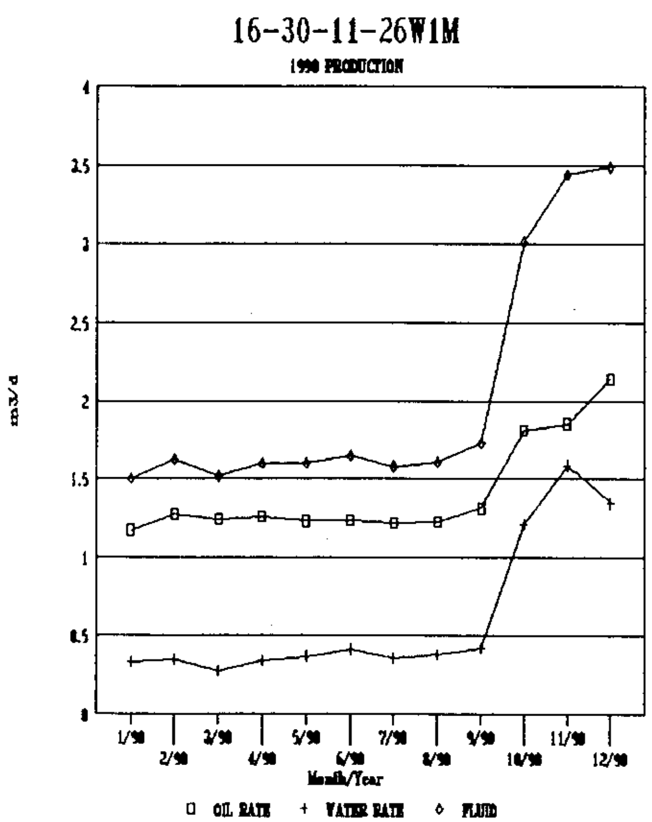


FIGURE II

NORTH VIRDEN SCALLION UNIT NO.2







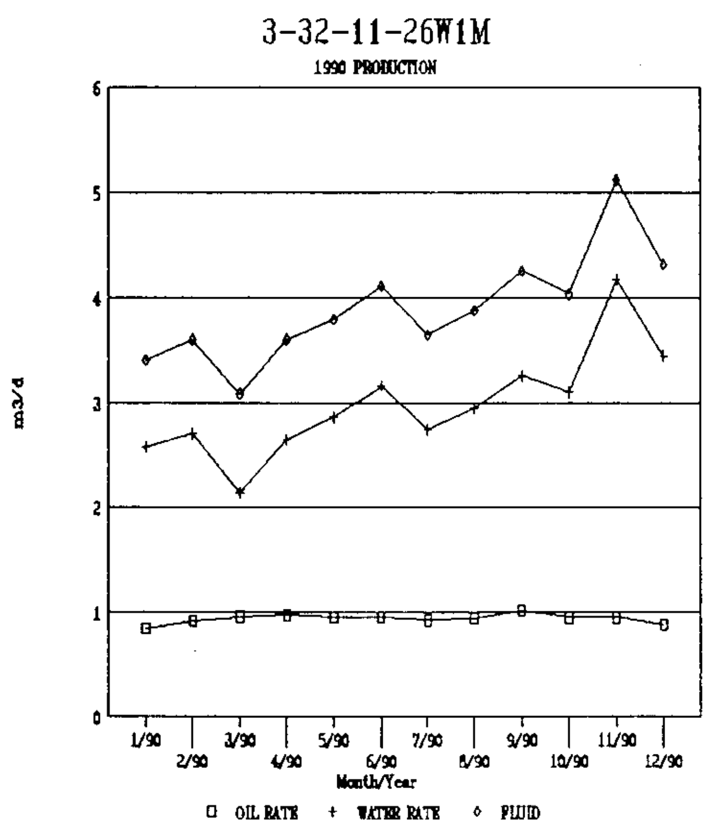
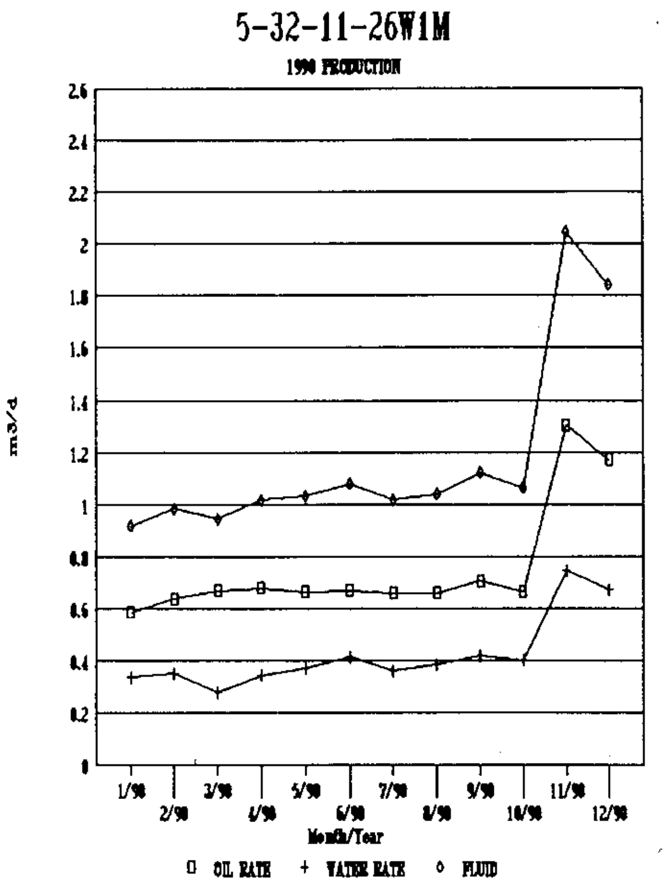
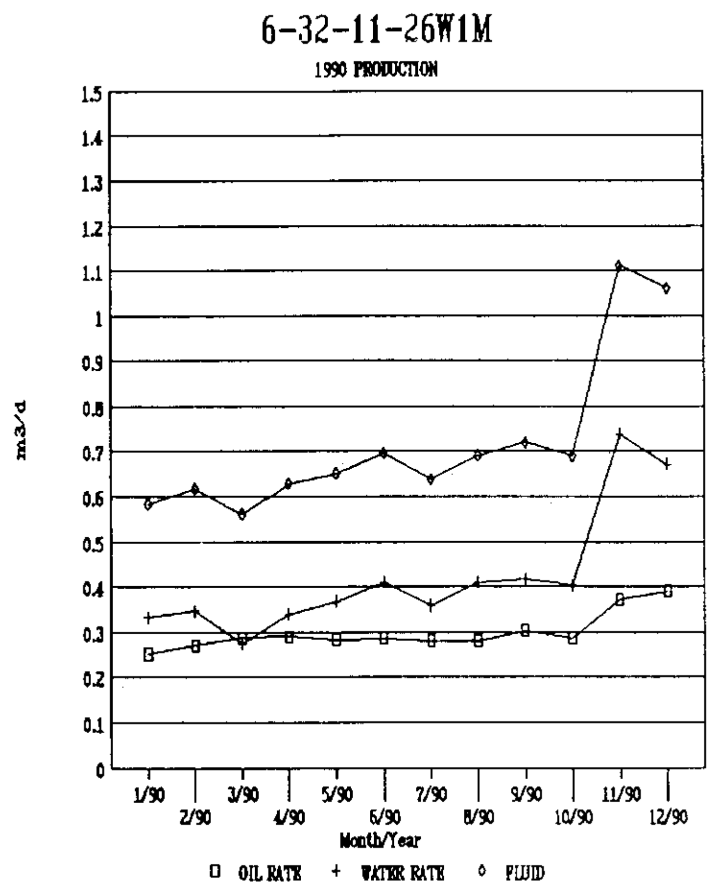
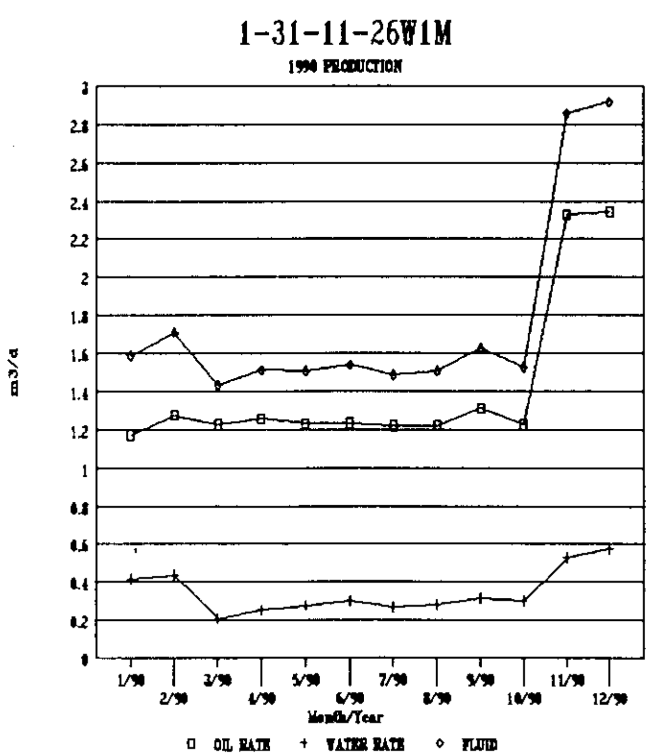


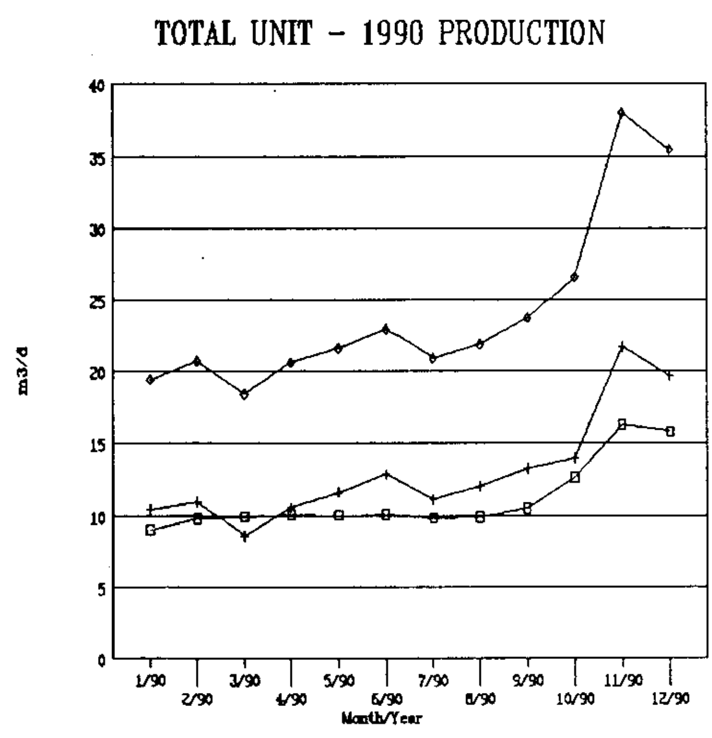
FIGURE III

NORTH VIRDEN SCALLION UNIT NO.2









B. F. May 1/91

October 25, 1990

Mr. G.A. Yeryk
Manager, Resource Recovery
Saskatchewan Oil and Gas Corporation
Saskoil Tower
1945 Hamilton Street
P.O. Box 1550
Regina, Saskatchewan
S4P 3C4

Dear Mr. Yeryk:

RE: North Virden Scallion Unit No. 2
Board Order No. PM 59

The Board has received letters from Saskoil and Ranchmen's requesting a six month extension on the submission of the joint report on the feasibility and desirability of expanding the unit to include Lsd's 11 and 14 in Section 30-11-26 (WPM).

The Board has approved your request for a six month extension. The joint report required pursuant to Clause 8(c) of Board Order No. PM 59 is now to be submitted by May 1, 1991.

If you have any questions in respect of this matter, please contact John N. Fox, Chief Petroleum Engineer, at (204) 945-6574.

Yours respectfully,

H. Clare Moster
Deputy Chairman

B. F. May 1/91

October 25, 1990

Mr. P.G. Maguire
Operations Engineer
Ranchmen's Resources Ltd.
Suite 1000
333 Eleventh Avenue S.W.
Calgary, Alberta
T2R 1L9

Dear Mr. Maguire:

RE: North Virden Scallion Unit No. 2
Board Order No. PM 59

The Board has received letters from Saskoil and Ranchmen's requesting a six month extension on the submission of the joint report on the feasibility and desirability of expanding the unit to include Lsd's 11 and 14 in Section 30-11-26 (WPM).

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If you have any questions in respect of this matter, please contact John N. Fox, Chief Petroleum Engineer, at (204) 945-6574.

Yours respectfully,

H. Clare Moster
Deputy Chairman

BOARD ORDER NO. PM 59 - CLAUSE 8(a)

A10-30 INJECTION < 1/3 total injection / quarter

1990	A10-30 INJ. VOL.	TOTAL INJ	% of Total Inj.
1st Qu	1111.8 *	2434.1	
2nd Qu	624.3	2654.3	24%
3rd Qu	672.4	2755.2	24%
4th Qu	728.2	2919.7	25%
1990 TOTAL	3136.7	10763.3	29 %
1991			
1st Qu	628.2	2606.2	24 %
2nd Qu	600.1	2549.1	23.5%
TOTAL TO 91-07-31	4884.4	16736.4	29.2 %

* A10-30 on INJ DEC/89, 12-29 & 4-32 on inj. Feb/90

VOIDAGE - REPLACEMENT - CLAUSE 8(b) A10-30 INJ. PATTERN VRRCLIS

1990	NUSU #2 WELLS 9-30, 15-30, 16-30 VOIDAGE	REPLACEMENT	VRR	ADDITIONAL VOIDAGE 11-30 & 14-30	TOTAL VRR
1st Qu		1111.8			
2nd Qu.		624.3			
3rd Qu.		672.4			
4th Qu		728.2			
1990 Total		3136.7			
1st Qu/91	430.2	628.2	1.46	360.2	0.79
2nd Qu	394.9	600.1	1.52	351.8	0.80
[illegible]	2190	4884.4	2.23	2393	1.07

CUMULATIVE VOIDAGE - REPLACEMENT A10-30 INJ PATTERN
TO 91-07-31

VOIDAGE 9-30, A10-30, 15-30+16-30 ⇒ 16133.91 m^3

REPLACEMENT 4884.4

CUM VRR = 0.3

A-32 INJ. PATTERN VOIDAGE - REPLACEMENT JAN 1 to July 31/91

VOIDAGE = 3292.2

REPLACEMENT = 1380.9

VRR = 0.42

12-29 INJ. PATTERN VOIDAGE - REPLACEMENT JAN 1 TO JUL 31/91

VOIDAGE = 2995.5

REPLACEMENT = 2844.5

VRR = 0.95

VOIDAGE

PATTERN	PRE-WATERFLOOD (m3)	SINCE WATERFLOOD (NOV 30/89) (L3)	INJECTION m3
4-32	36252.2	8019.1	3507.4
A10-30	20517.3	4590.7	4884.4
12-29	26924.5	6691.4	8344.6
	83694.	19301.2	16736.4

8-30-11-26 SWD

CUMULATIVE DISPOSAL TO JUL 31/91 - 129760 m^3

8-30 PV h = 20' ϕ = 20% A = 16 ha

PV: 137600 m^3

INJ VOL (91-07-31) = .94 PV

Assuming 8-30 injection for 9-spot injection pattern, calculate 1991 and cumulative VRR

1991 VRR = 2.3

CUMULATIVE VRR (91-07-31) = 1.75

RANCHMEN'S WELLS VOIDAGE S/2 of Sec 30

	VOIDAGE
1-30	46757.4
2-30	51798.5
3-30	37582.4
6-30	57534
7-30	14718
	208389

PATTERN	INJECTION TO 91-07-31	VOIDAGE Dec 1/89 to July 31/91
12-29	8344.6	
A10-30	4884.4	
4-32	3507.4	
TOTAL	16736.4	

NVSU No. 2

PRE WATERFLOOD PRODUCTION (NOV. 30/89)

WELL	OIL	WATER	VOIDAGE DEC 1/89 to JULY 31/91 OIL	WATER
TWP 11-26				
6-29 ✓	2285.9	634.6	626.9	388.8
11-29 ✓	4223.0	880.7	907.8	501.5
12 29* ✓	2107.9	1304.3	24.4	33.0
13-29 ✓	3285.9	1277.4	433.5	427.8
14-29	5402	5713.0	1401.1	2466.4
9-30 ✓	4240.6	4997.8	781.7	1627.0
A10-30 ✓	2889.7	1725.5	—	—
15 30 ✓	1148.7	1017.0	152.3	313.7
16-30 ✓	4696.1	1895.8	943.1	500
1-31 ✓	4990.5	1008.1	1020.1	260
3-32 ✓	2412.0	5670.9	522.9	1841.2
4-32* ✓	3715.8	1404.3	29.3	38.5
5-32 ✓	2751.1	907.9	511.7	305.9
6-32 ✓	1057.8	1255.8	158.1	312.1
TOTAL	45206	29692.7	7512.9	9015.9
A11-30 ✓	1551.7	2722.2	387.5	1350.1
14-30 ✓	1299.7	818.6	277.8	347.7

* CUMULATIVE PRODUCTION PRIOR TO CONVERSION

12-29 2132.3 m3 oil
1337.3 m3 wh

4-32 ✓ 3745.1 m3 oil
1012.8 wh

	1972 OIL	73	74	75	76	77	78
1-30	10080	10357	10611	10106	9358	9482	9058
2-30	13096	10373	9921	9593	8624	7053	7161
3-30	9552	6634	5681	5192	4697	5061	5051
6-30	4771	4164	4722	5130	4570	4822	4583
7-30	1927	3625	3542	3402	2557	1851	1920
TOTAL	39426	35093	34477	33423	29806	28269	27377

	1969	1970	1971
[illegible]	11498	10308	10860
[illegible]	15656	13120	14199
[illegible]	13496	10316	10940
[illegible]	9968	[illegible]	[illegible]
7-30	[illegible]	[illegible]	[illegible]
	53867	43790	44207

DECLINE
1969-74 · 9%/yr.
1973-91 - 5%/yr.

Estimate OOIP

ϕ = 15-20%

[illegible] = [illegible]

B_o - [illegible]

A - 16 ha

WELL	OOIP ($10^3 m^3$)	CUMULATIVE PRODUCTION 91-07-31 ($10^3 m^3$)	CURRENT RECOVERY
1-30	[illegible] 97	34.8	36-41
2-30	[illegible]-73	[illegible]	46-6[illegible]
	36-49	[illegible].9	[illegible]
6-30	27-36	[illegible]2	[illegible]
7-30	55-[illegible]3	[illegible].7	12-[illegible]
All 30	57	[illegible].9	[illegible]
[illegible]	14	[illegible]	[illegible]
	[illegible] 294 USE	116.2	29.1 - 36.[illegible] USE

CURRENT RECOVERY NVSU No. 2

[illegible] - 1046 × $10^3 m^3$

CUM PROD (91-07-31) 52 719 m^3

CURRENT RECOVERY = 5%

ULT. REC S/2 of Sec 30

$$Q_t = 365\frac{(q_i - q_t)}{D} + Q_{91\text{-}07\text{-}31}$$

Q_t = 145.4 $10^3 m^3$

q_i = 6 m^3/d

q_t: 0.4 m^3/d/well • 5 wells [illegible]

$Q_{91\text{-}07\text{-}31}$ 116.2 × $10^3 m^3$

D: 5%/yr

NO - DO NOT USE

REVISED VOIDAGE CALCULATION A10-30

1991

	OIL	WATER
9-30	381.1	839.2
A11-30	133.6	421.5
14-30	86.2	118
15-30	47.1	138.1
16-30	405.4	271.8
1-31	[illegible]	[illegible]
	975.4	1848.6

DAILY VOIDAGE - 13.5 m³/d proposed new Sec. 8

CLAUSE 8(b) - 9.8 m³/d

Saskoil's request - 12.8 m³/d

- WF Upper Charity Zone - 001P 5678 MSTB (903 10³m³)
Some wells have a Lower Charity zone present 143 10³m³
TOTAL 1046 10³m³

- incremental recoverable reserves 183 ×10³ m³
(increase in recovery from 7% to 27% OOIP)

- Ranchmens wells @ A11-30 & 14-30 low
productivity & high WOR

B_{oi} = 1.045 RB/STB

- target VRR = 1.0 - 1.15 (higher initially)
650 b/d (105 m³/d)
- wells south of the Unit excluded due to
their advanced stage of depletion

- ICG in its original application A11-30 & 14-30 of
questionable value to WF project as high WOR
but if they WF response observed wells
should be considered for inclusion into the Unit
after 1 yr.

Ranchmen wells in S/2 of Sec 30 on production 1966 69
8-30 commenced disposal Dec / 80

- N.I. No 2 $\phi_{N\text{-}D\ cut\text{-}off} = 13\%$

PORE VOLUME ϕ . ft $S_w = 35\%$ $B_{oi} = 1.045$ rb/stb

11A - 30	1.88
14 - 30	0.46
8 - 30	2.8

(h = 14' $\phi = 0.20$)

→ 8 - 30 PV

$$1000 \times 16 \times 4.3 \times 0.2 = 137600 \ m^3$$

cumulative injection to Mar 1/91 - 126680 m³ ([illegible] PV)

FEB 28/91

PATTERN	VOIDAGE FEB/91 m³/mon	VOIDAGE CUM	REPLACEMENT MONTHLY TARGET	REPLACEMENT MONTHLY ACTUAL	CUMULATIVE	VRR SINCE WF COMMENCED	VRR CUMUL.
12 - 29	404	27793 [illegible]	465 - 516	411 - 474	6450		
A10 - 30	143	1062[illegible] [illegible]	164 - 213	190 - 213	3547		
4 - 32	439	36435 4-32	504 - 730	219 - 225	2490		

WELL PATTERN VOIDAGE SINCE WF COMMENCED

12-29

A10-30

4-32

S/2 of SEC 30 VOIDAGE - 205481 m^3

SE/4 of SEC 29 (EXCLUDING 6-29) VOIDAGE - 85232 m^3

A11-30 5656 m^3 cumulative voidage, monthly voidage 83 m^3/mo

14-30 2662 m^3 cumulative voidage, monthly voidage 28 m^3/mo

- injectivity @ 10-30 restricted by Clause 8( )
due to low injectivity @ 4-32 , m3/d 1ST Qu/91
vs. injection target 18-24 m3/d

- 4-32 pattern voidage 1ST Qu/91 m3/d

- water injection in NVSU #2 commenced in
Dec/89 @ 10-30 and @ 12-29 & 4-32 in
FEB/90

- production plot

- cumulative oil, cumulative WOR maps, current
daily oil & wtr maps

→ well workover to increase inj - additional perforations
in 4-32 increased injectivity 4.5 to 7.4 m3/d

- versene treatment (Sep & Oct/90) increase oil
production from 10 to 15.8 m3/d

[illegible] 8-30, 9-30, 10-30, 11-30

TABLE II

NORTH VIRDEN SCALLION UNIT NO.2

PRODUCTION DATA AND TARGET INJECTION RATES

PATTERN	WELL LOCATION (W1M)	WELL TYPE	FACTOR APPLIED	CUM OIL to 91/07 (M3)	CUM WATER to 91/07 (M3)	CUM FLUID (M3)	DLY FLD RATE (M3/DAY)	CUM FLUID (M3/PAT)	DLY FLD RATE (M3/DAY)	EXISTING INJ RATE (M3/DAY)	TARGET INJ RATE (M3/DAY)
							VOIDAGE			REPLACEMENT	
1	13-29-11-26	OIL	0.50	226.5	~~194.4~~	213.9	7932.4				
	14-29-11-26	OIL	0.50	732.1	1233.2						
	16-30-11-26	OIL	0.33	328.5	166.7						
	01-31-11-26	OIL	1.00	1066	260						
	03-32-11-26	OIL	1.00	546.4	1841.2						
	05-32-11-26	OIL	1.00	534.7	305.9						
	06-32-11-26	OIL	1.00	165.2	312.1						
	04-32-11-26	INJ	1.00	–	–						
2	09-30-11-26	OIL	0.50	408.4	813.5		2190.0				
	15-30-11-26	OIL	1.00	~~1066~~ 159.2	~~260~~	313.7					
	16-30-11-26	OIL	0.33	328.5	166.7						
	10-30-11-26	INJ	1.00	–	–						
3	06-29-11-26	OIL	1.00	655.1	388.8		6616.9				
	11-29-11-26	OIL	1.00	948.7	501.5						
	13-29-11-26	OIL	0.50	226.5	~~194.4~~	213.9					
	14-29-11-26	OIL	0.50	732.1	1233.2						
	09-30-11-26	OIL	0.50	408.4	813.5						
	16-30-11-26	OIL	0.33	328.5	166.7						
	12-29-11-26	INJ	1.00	–	–						

Boi = 1.05

(d) the static reservoir pressure data obtained from the survey corrected to the pool datum depth, and;
(e) a discussion of the survey results and pressure distribution within the unit area.

4 The unit operator shall immediately report to the Board any indication of channelling or break-through of injected water to producing wells or any indication of other detrimental effects that may be attributable to the pressure maintenance operations.

5 The maximum wellhead pressure at which water is injected into the wells referred to in subsection 1(1) shall not exceed 6 000 kPa or such other maximum pressure as the Board may prescribe and the Board may, from time to time, prescribe a maximum or minimum rate at which water shall be injected into any well in the unit area.

6(1) The unit operator shall, not later than the last day of each month, file with the Petroleum Branch, a report of the quantity, source and pressure of water injected during the preceding month into each well referred to in subsection 1(1).

6(2) The unit operator shall, not later than the last day of each month, file with the Petroleum Branch a summary report of production and injection operations during the preceding month, which report shall include:

(a) a tabulation of total oil, total water and total gas produced;
(b) a tabulation of the number of producing wells and injection wells which were active;
(c) the results of at least one twenty-four hour production test on each producing well in the unit area including volumes of oil, gas and water produced during the test; and
(d) a summary of any remedial operations carried out on any well in the unit area.

7 The unit operator, shall, within 60 days of the end of each calendar year, file with the Petroleum Branch a report of the pressure maintenance program, setting out graphically such interpretive information necessary to evaluate the efficacy of the waterflood.

8 Unless otherwise provided by the Board in writing, the following special conditions shall apply:

(a) The amount of water injected in any calendar quarter into the well ICGR et al Virden WIW A10-30-11-26 (WPM) ("the A10-30 well") shall not exceed one third of the total water injected in the unit area during the same calendar quarter,
(b) The ratio of water injection to reservoir withdrawls in the nine spot injection pattern surrounding the A10-30 well shall not exceed 1.15 on a quarterly basis, and;
(c) The unit operator and Ranchmen's shall submit to the Board within six months of the commencement of injection in the unit area a detailed joint report including recommendations on the feasibility and desireability of expanding the unit area to include wells operated by Ranchmen's located in legal Subdivisions 11 and 14 of Section 30, Township 11, Range 26, West of the Principal Meridan.

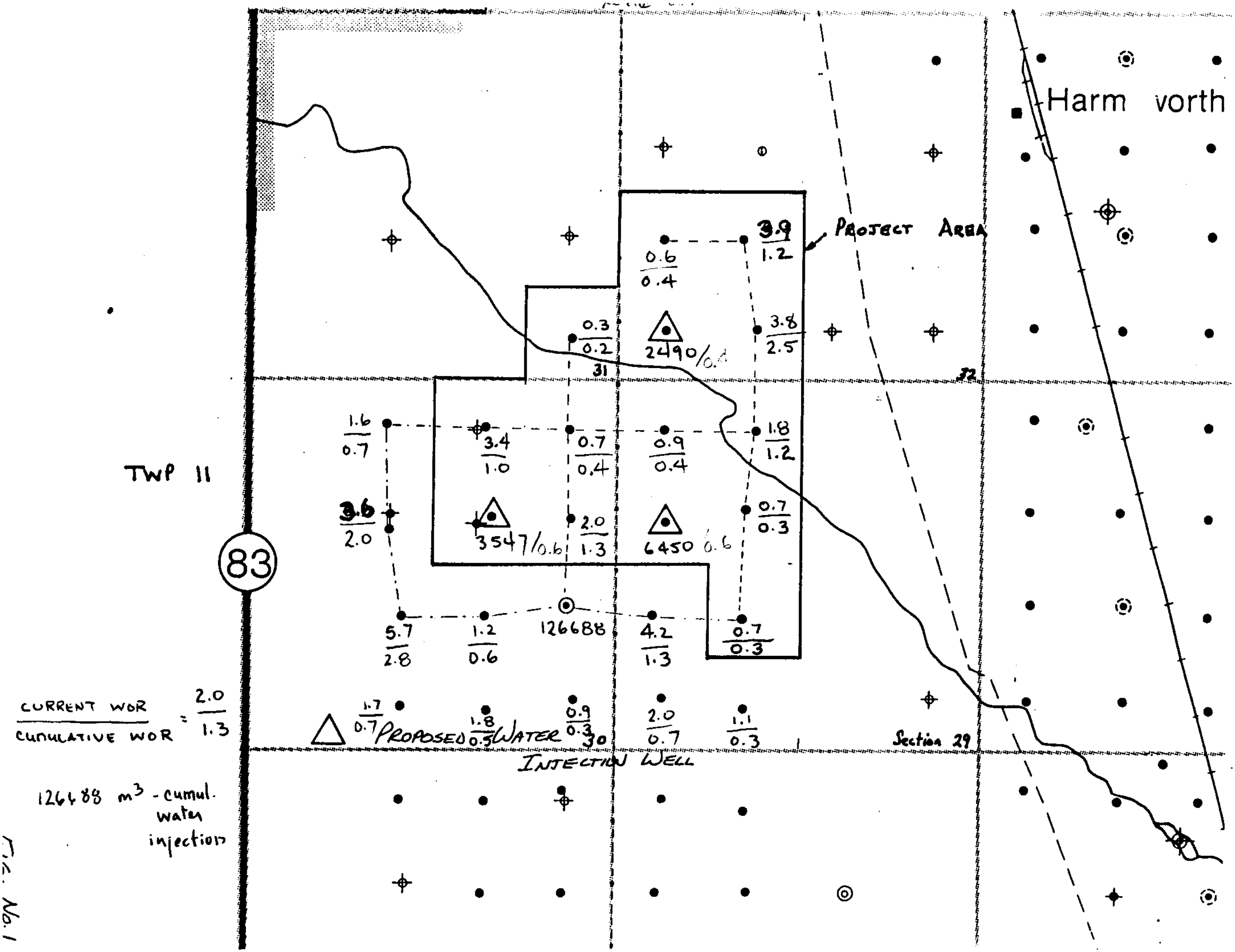
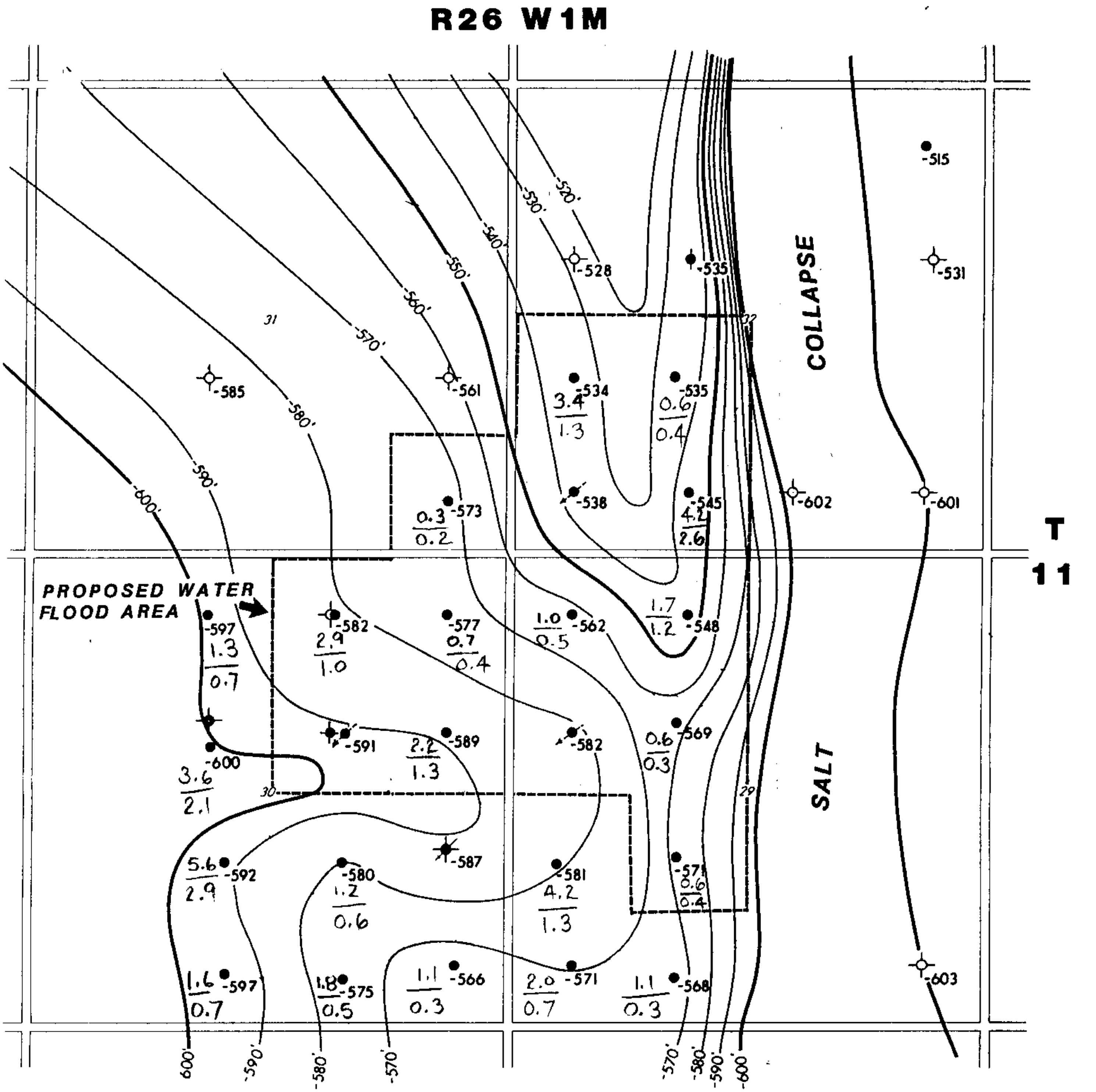

Harm vorth
PROJECT AREA
31
32
30
Section 29
TWP 11
83
2490/0.4
3547/0.6
6450 0.6
126688
PROPOSED WATER INJECTION WELL
CURRENT WOR / CUMULATIVE WOR = 2.0 / 1.3
126488 m³ - cumul. water injection

Fig. No. 1



PROPOSED WATER INJECTION WELL

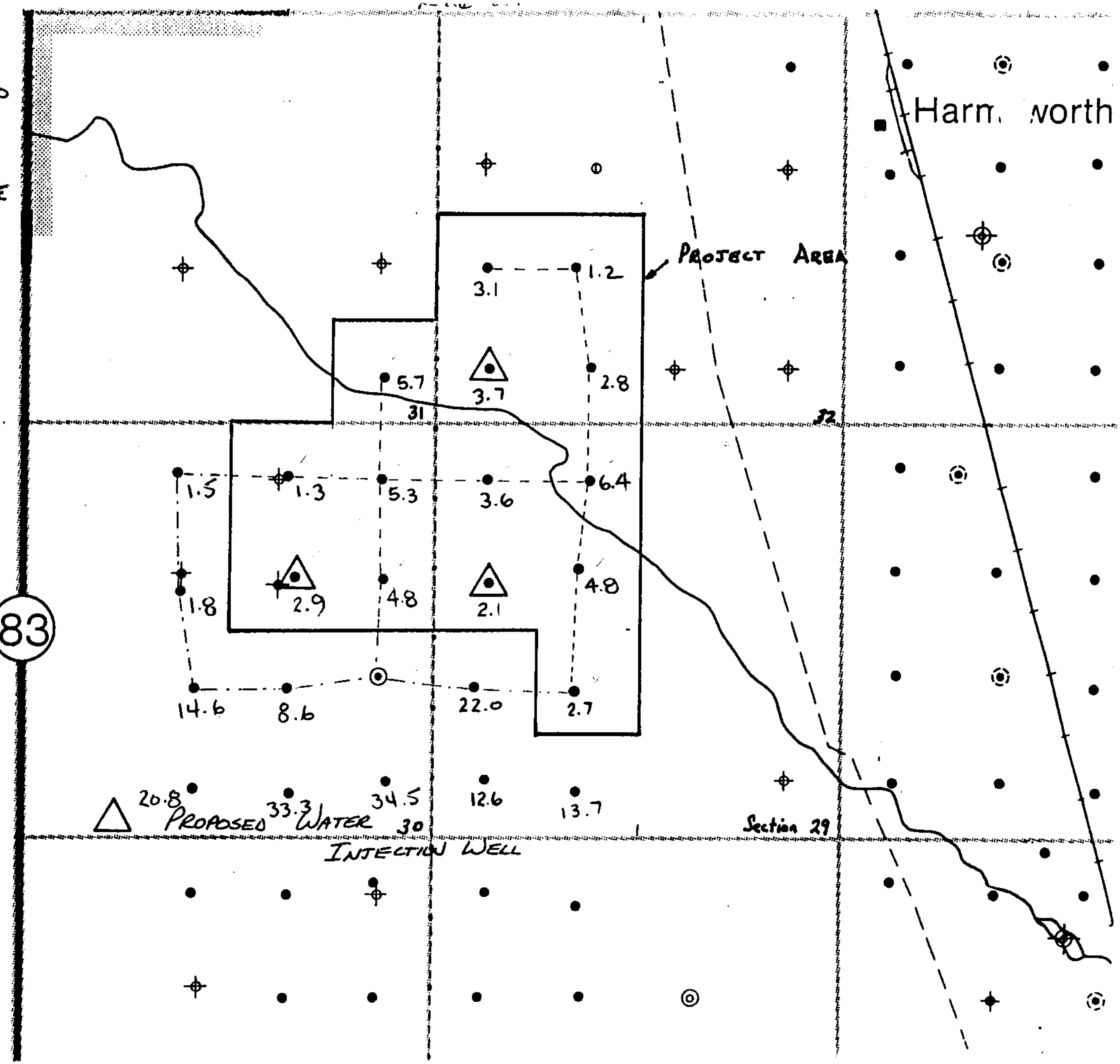
ICG RESOURCES LTD.

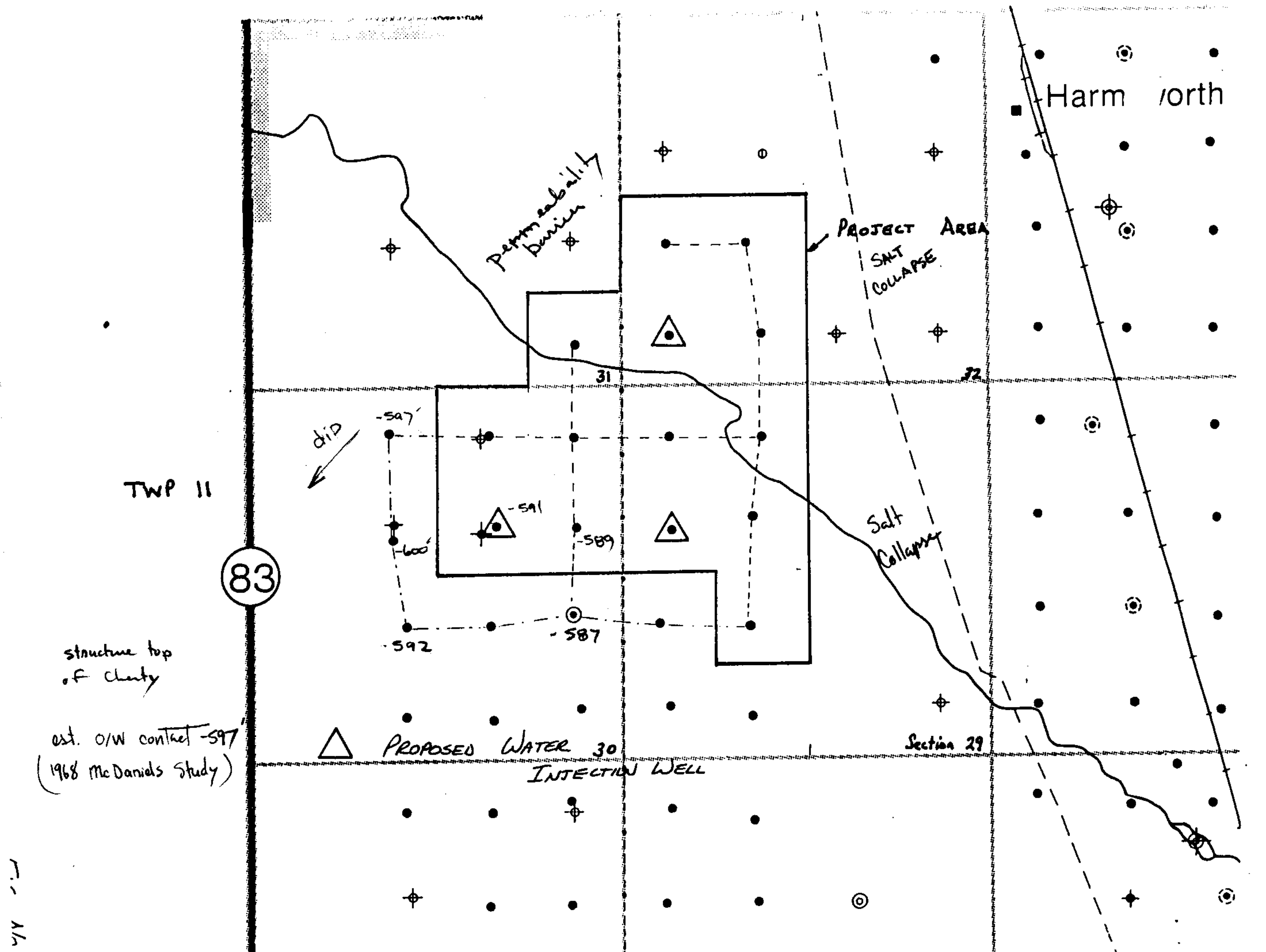
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL

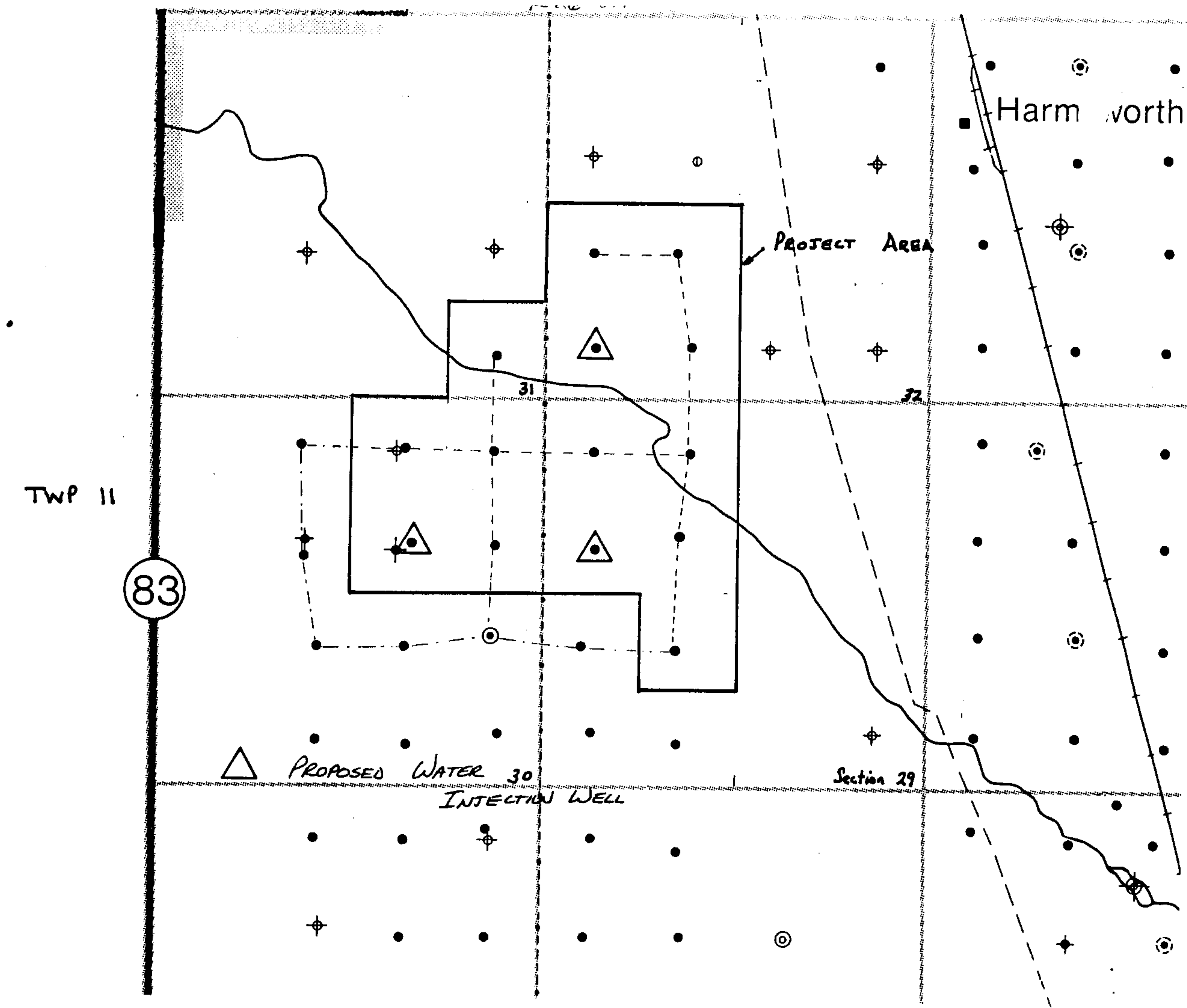
STRUCTURE
CONTOUR MAP
C.I.=10'

Fig. 2

GEOLOGY BY M.Gobrial	DRAFTING BY F.F.
SCALE 1: 12,500	DATE 1988-08-30


3-29 - Ranchmen's
S/2 & NW/4 of Sec. 30
Ranchmen's
LSD's 4 & 5-29 - Done
TWP 11
83
2.7 Cumulative
oil $10^3 m^3$
Proposed Water
Injection Well
Project Area
Harm. worth
Section 29
30
31
32
3.1
1.2
3.7
2.8
5.7
1.5
1.3
5.3
3.6
6.4
1.8
2.9
4.8
2.1
4.8
14.6
8.6
22.0
2.7
20.8
33.3
34.5
12.6
13.7
Fig. No. 1


Harm /orth
PROJECT AREA
SALT COLLAPSE
Permeability barrier
31
32
-597'
dip
TWP 11
-591
-589
-600'
Salt Collapse
83
-592
-587
structure top of Cherty
est. O/W contact -597' (1968 McDaniels Study)
PROPOSED WATER INJECTION WELL
30
Section 29



Harm vorth
PROJECT AREA
31
32
TWP 11
83
PROPOSED WATER INJECTION WELL
30
Section 29

FIG. No. 1

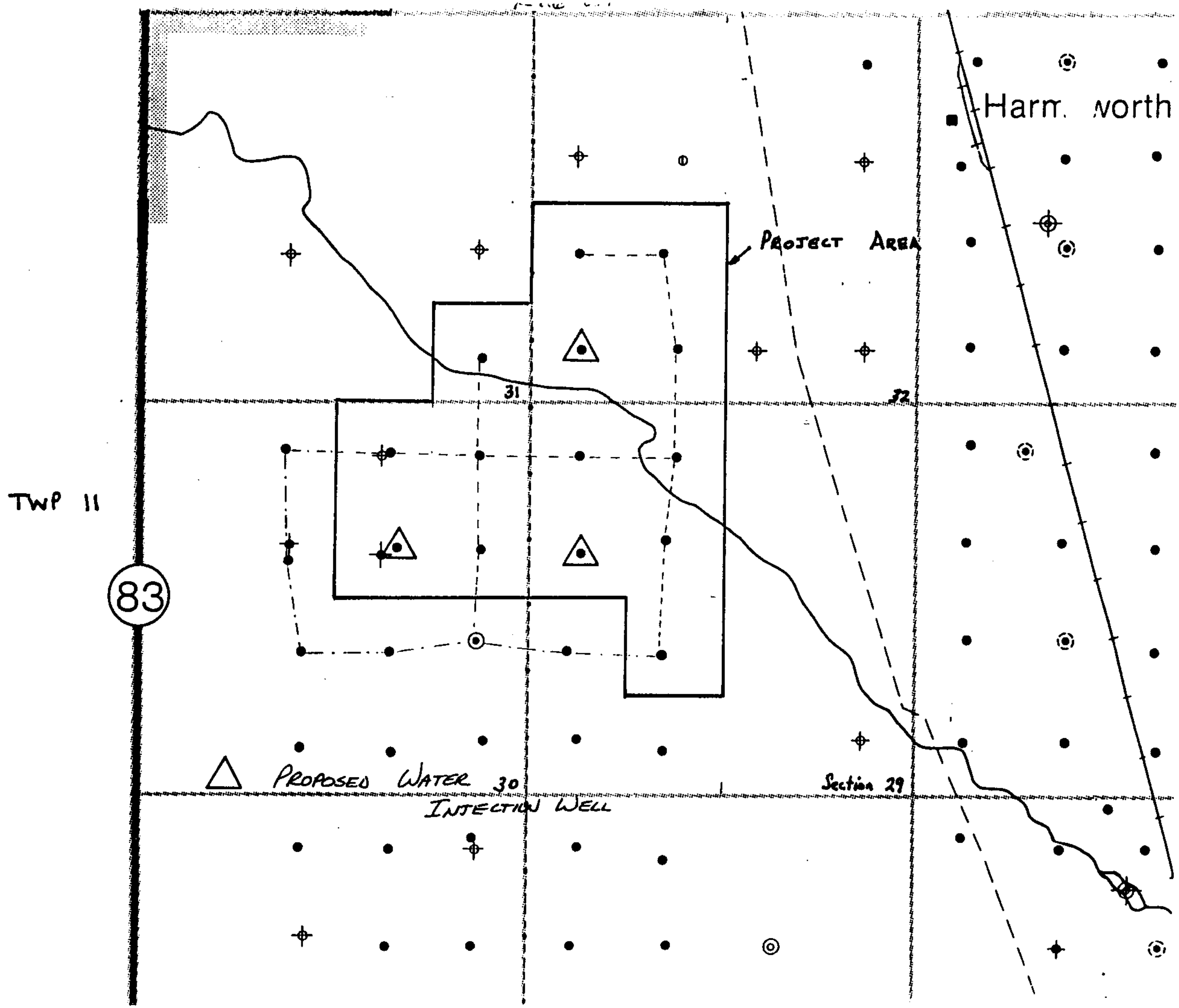
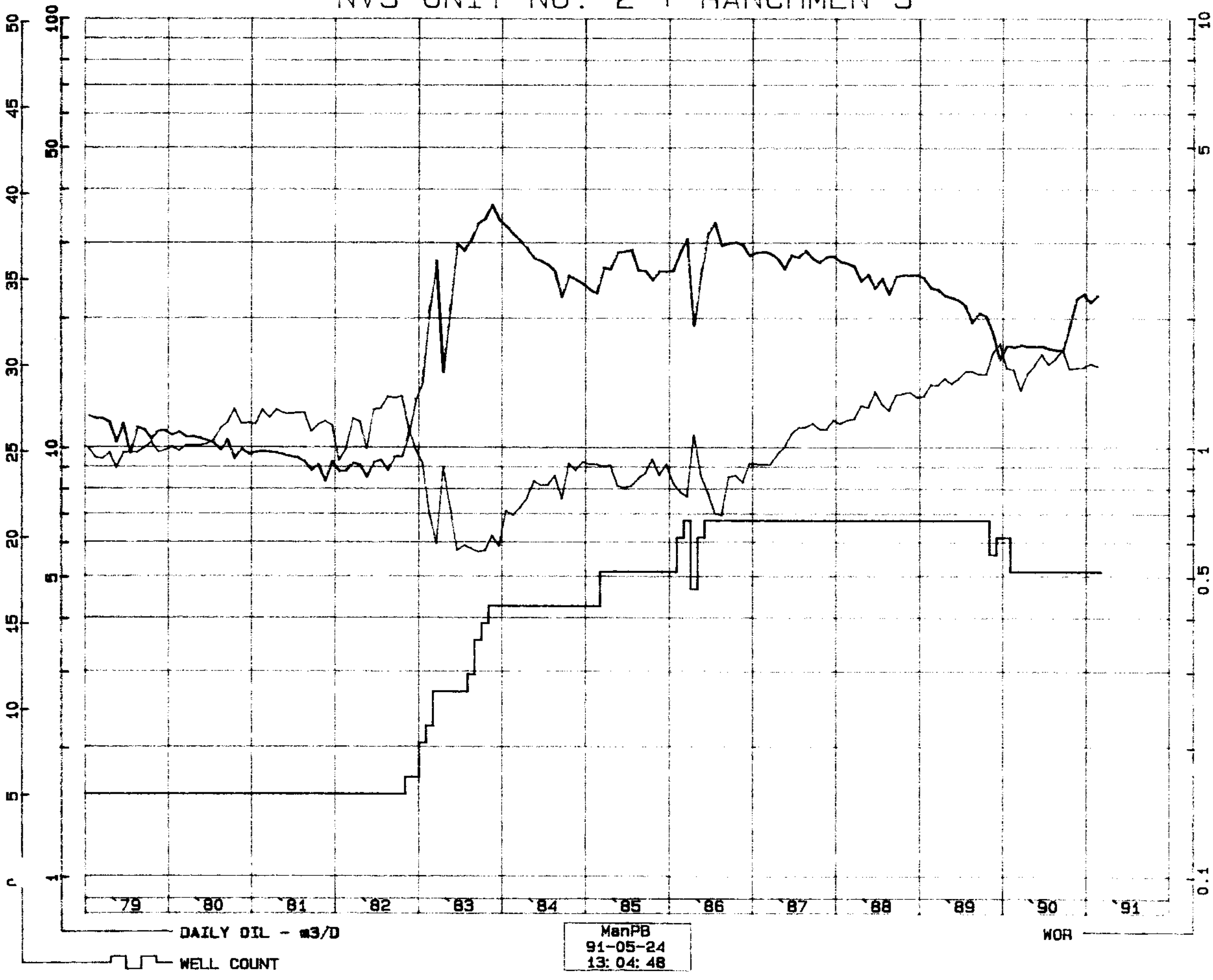
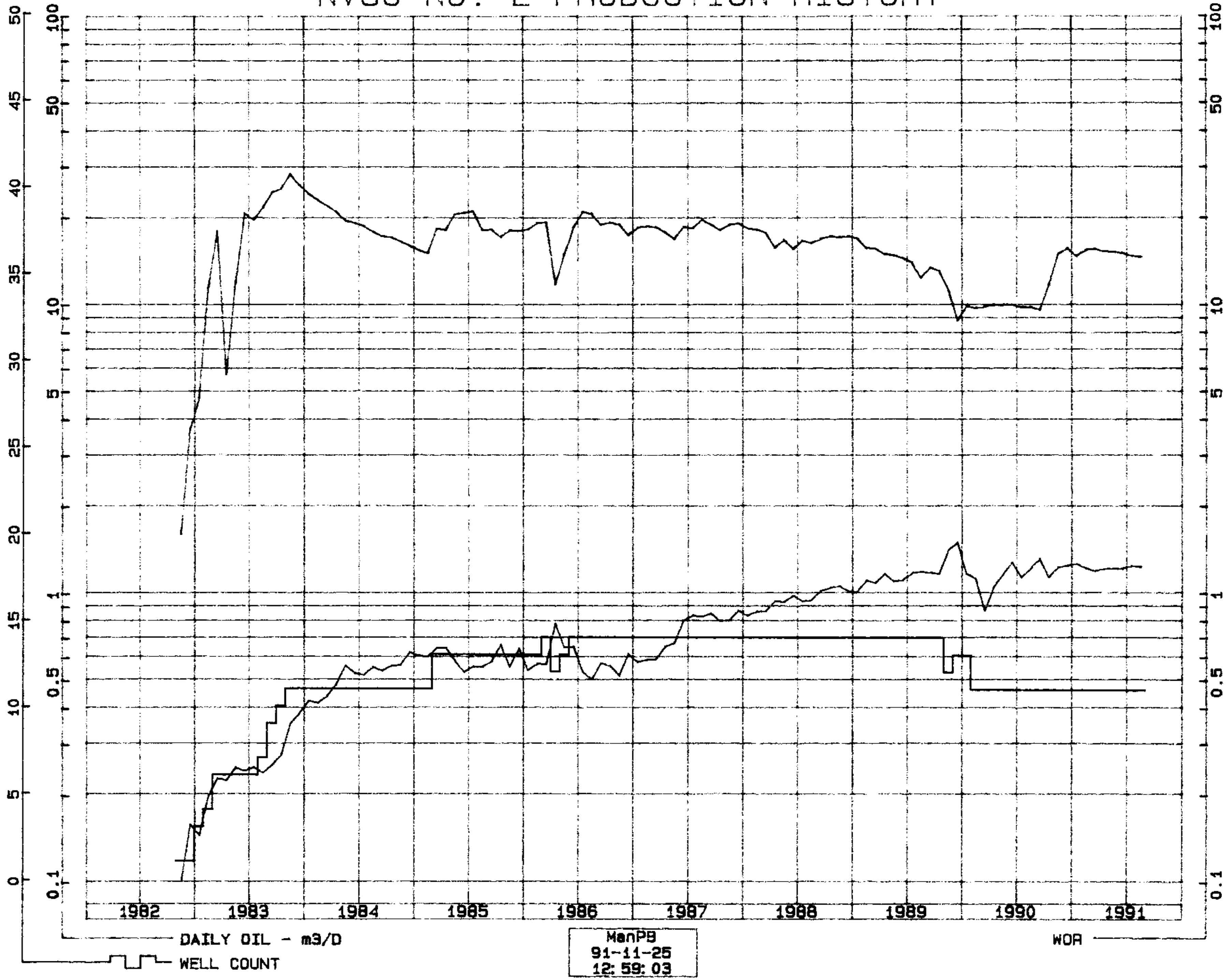

Harm. north
PROJECT AREA
31
32
TWP 11
83
PROPOSED WATER INJECTION WELL
30
Section 29

Fig. No. 1

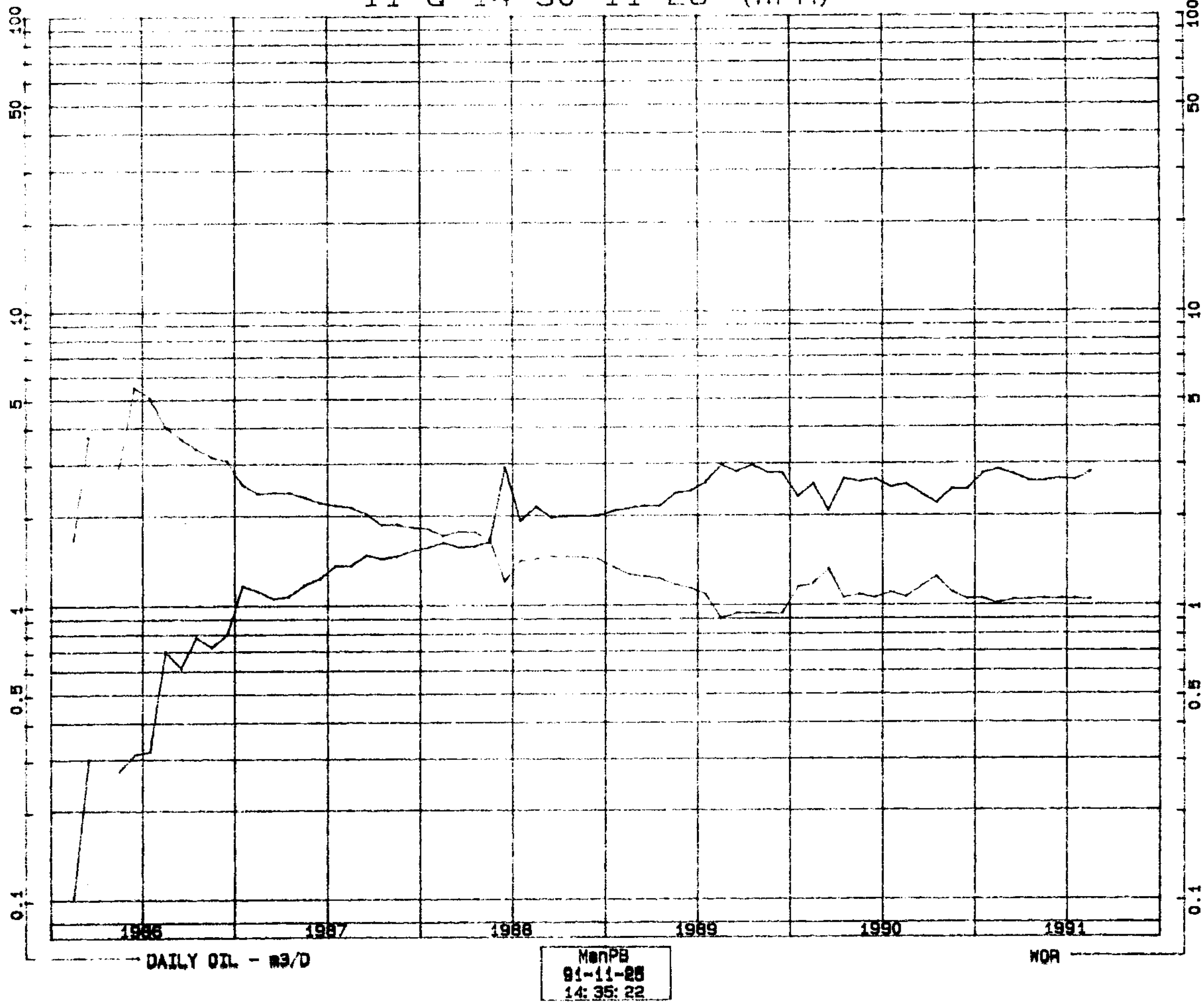
NVS UNIT NO. 2 + RANCHMEN'S



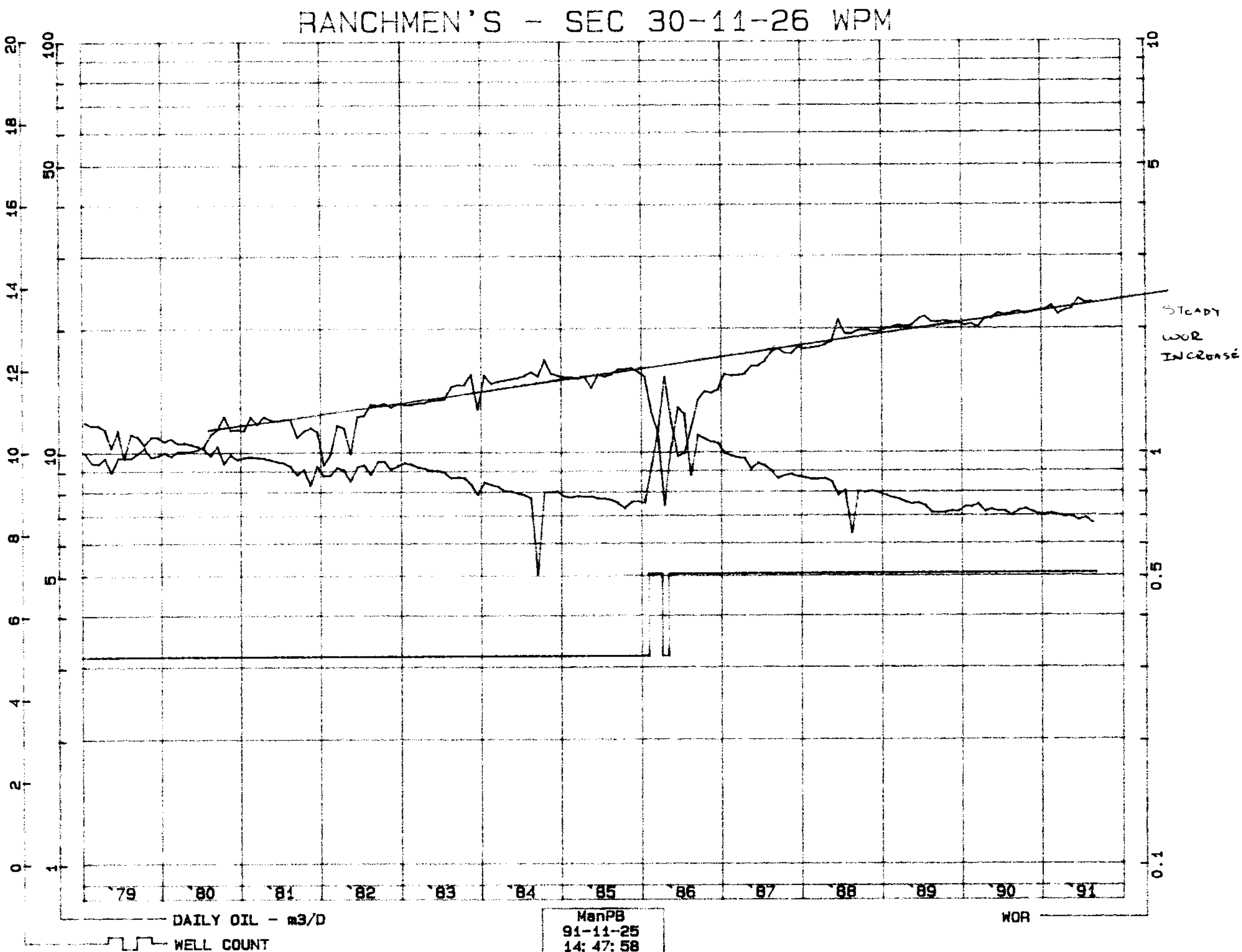
NVSU NO. 2 PRODUCTION HISTORY

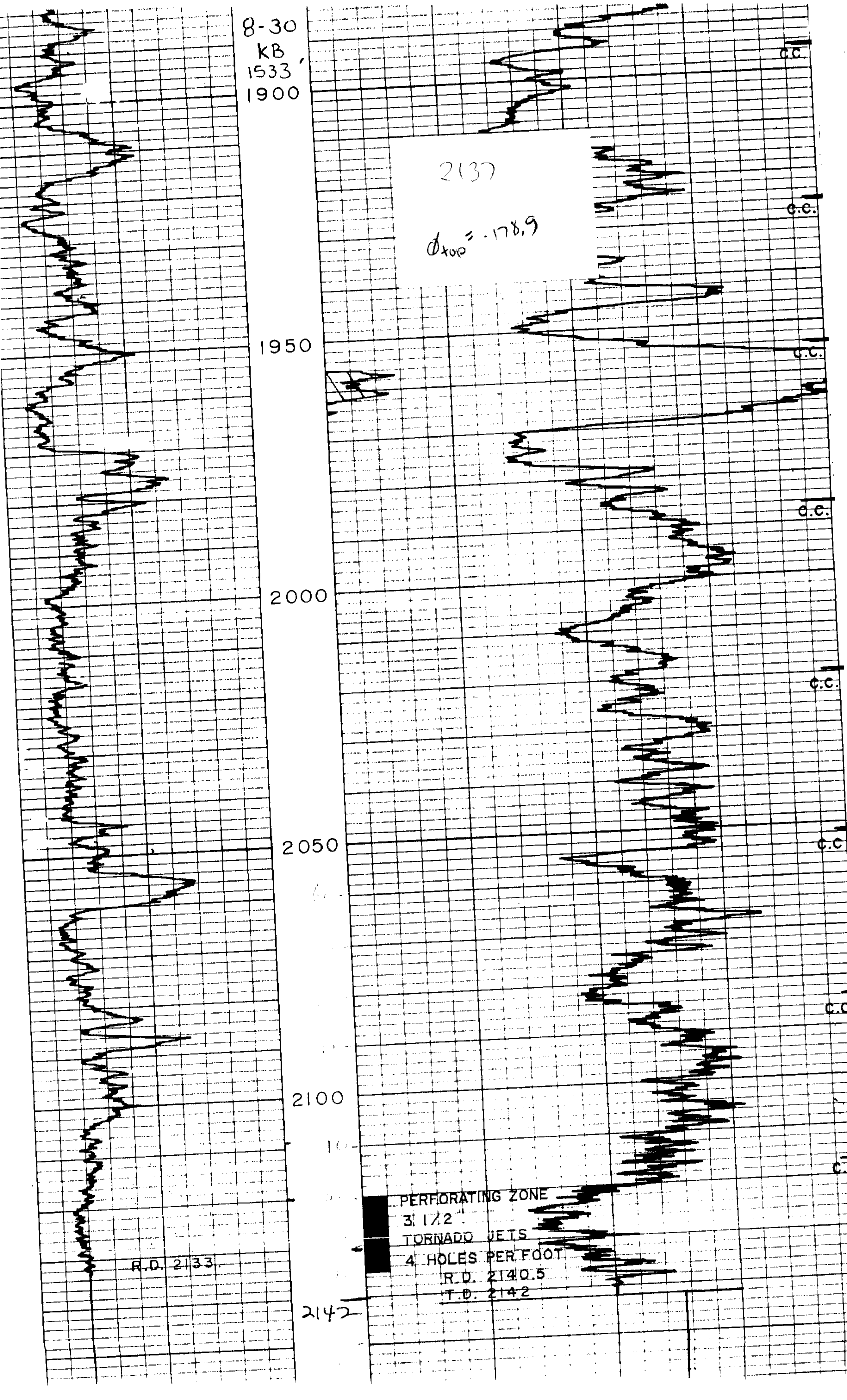


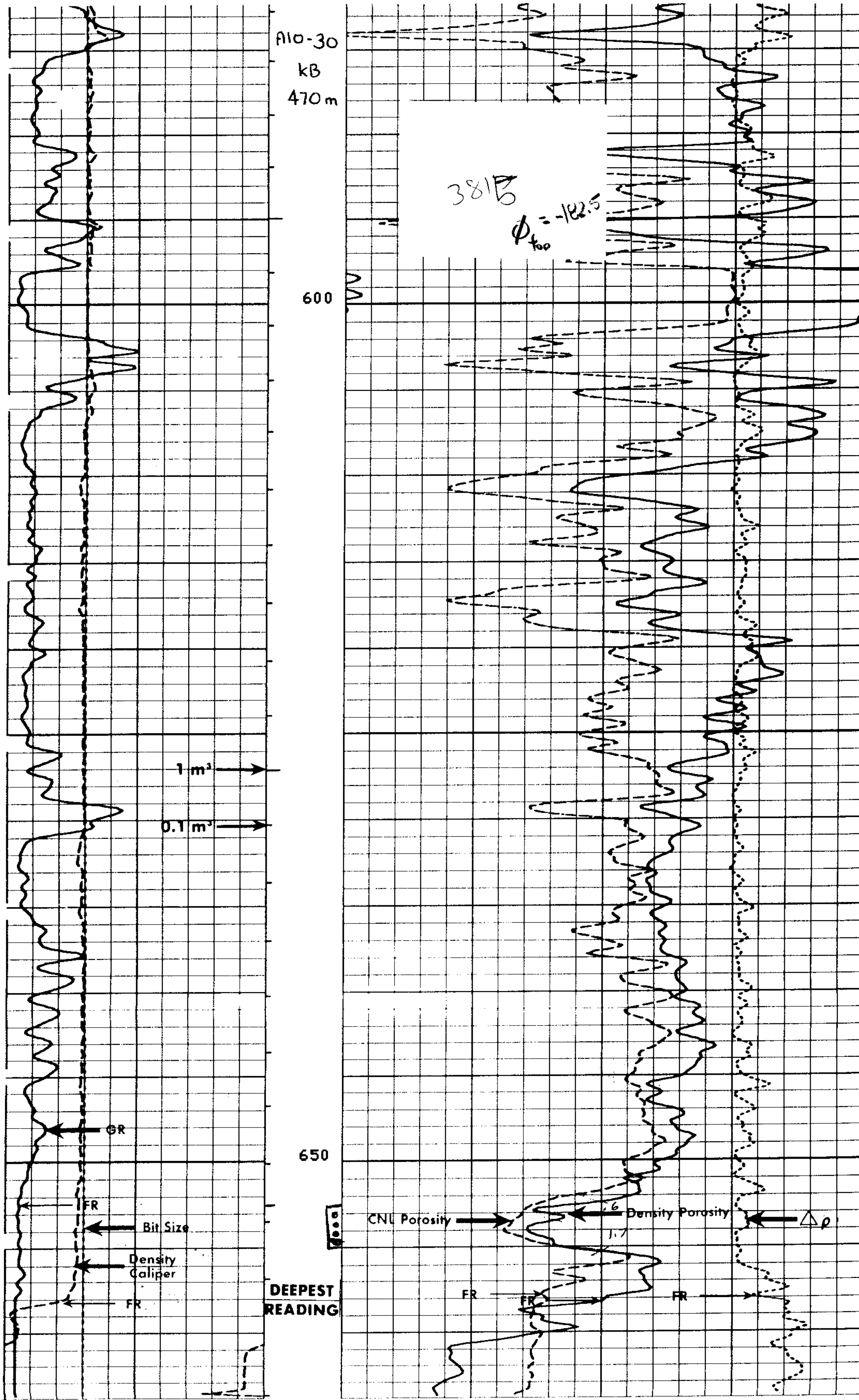
11 & 14-30-11-26 (WPM)



DELETE AH-30 & IN-30




8-30
KB
1533'
1900
2137
ϕ_{top} = -178.9
1950
2000
2050
2100
c.c.
c.c.
c.c.
c.c.
c.c.
c.c.
PERFORATING ZONE
3 1/2
TORNADO JETS
4 HOLES PER FOOT
R.D. 2140.5
T.D. 2142
R.D. 2133
2142

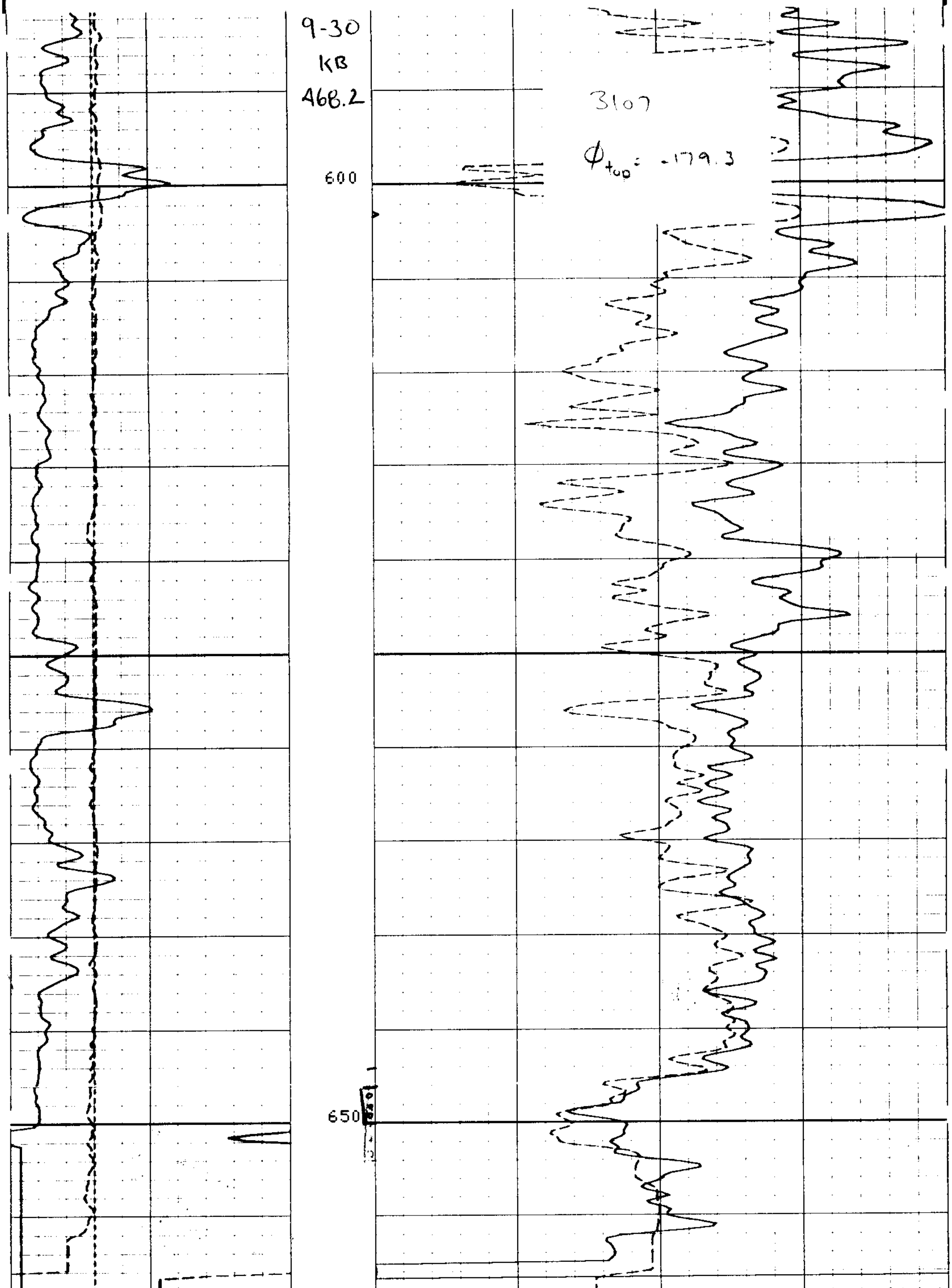

A10-30
kB
470 m
600
1 m³
0.1 m³
650
GR
FR
Bit Size
Density
Caliper
FR
DEEPEST
READING
CNL Porosity
Density Porosity
Δρ
FR
FR
FR

CALI(MM)		DPHI( )	
125.00	375.00	0.4500	-0.150
GR (GAPI)		NPHI( )	
0.0	150.00	0.4500	-0.150

FILE

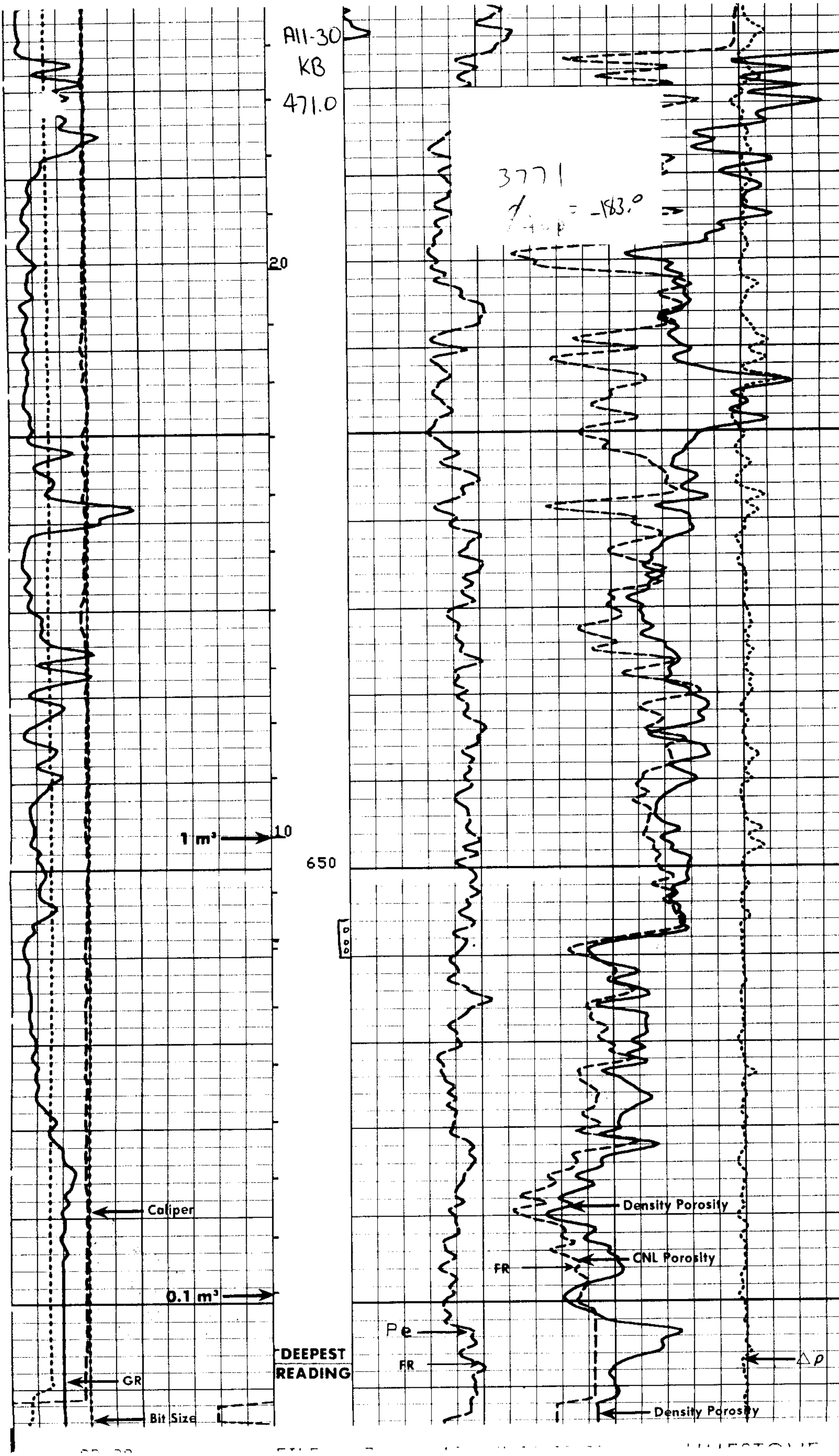
7

REPEAT SECTION



FILE

7


A11-30
KB
471.0
3771
20
10
1 m³
650
0.1 m³
DEEPEST
READING
Caliper
GR
Bit Size
Density Porosity
CNL Porosity
FR
Pe
FR
Δρ
Density Porosity

NVSU #2 91-03-08

- special provisions of PM Order designed to minimize the effect of operations on Ranchmen's offsetting wells.

(a) A10-30 < 1/3 of total unit injection each calendar quarter

b) VRR = 1.15 (quarterly basis) A10-30 inj. pattern < 9 spot pattern > on only unit wells in pattern

(c) joint feasibility study

- SASKOIL MAY APPLY TO BOARD FOR WITHDRAWAL OF CONDITIONS OF SECTION 8 OF PM 59

RANCHMEN'S CONCERNS

① "-ve" impact on 11-30 & 14-30

- LRD suggested Ranchmen's well in longer run will probably be effected by NVSU #2 WF operations

ICG - WF Applⁿ two zones in Cherty - Main (upper) & Lower

- Dome wells in SE/4-30

- Ranchmen wells A11-30, 14-30 - down dip, high WOR west edge of pool

OOIP - NVSU #2 Main Zone 5678 MSTB
Total - 6578 MSTB

ϕ cut-off ϕ_{N-D} = 13% equates core cut-offs ϕ = 10%
Crossplot K = 0.1 md

Sw = 35% (estimated) Boi = 1.045 rb/STB

AVER PROD '90 m^3/d WOR '90

A11-30 $\phi H = 1.88$
14-30 $\phi H = 0.46$

- jt. feasibility study due May/91

- check for compliance with conditions of Board order

	TOTAL INJ m^3	INJ 10-30 m^3	10-30 % of total inj.
2^{ND} Qu/90	2654.3	624.3	24%
3^{RD} Qu./90	2755.2	672.4	24%
4^{th} Qu/90	2919.7	728.2	25%
		2861.4	
1^{ST} Qu/91	2606.2	628.2	24%

A10-30 Pattern Withdrawals 1990

WELL	TRACT FACTOR	OIL*	WTR	VOIDAGE** 1990	CUM. VOIDAGE 90-12-31
NVSU #2					
9-30	1/2	377.6	732.1	1126.7	10635.7
15-30	1.0	98.3	163.9	266.6	2502.9
16-30	1/4	505.6	216.5	744.8	7593.3
			TOTAL PATTERN VOIDAGE(1990)	1016.2	

NVSU #2 VRR wells only $= \frac{2861.4}{1016.2} = 2.82$

WELL	TRACT FACTOR	OIL*	WTR	VOIDAGE** 1990	CUM. VOIDAGE 90-12-31
Ranchmen's 11-30	1.0	239.4	804.9	1055.1	5478
14-30	1.0	174.9	205.9	388.7	2604
			[NVSU #2 + Ranchmen's] VRR 1990	2460	

VRR $= \frac{2861.4}{2460} = 1.16$

** tract factor not applied
* Boi = 1.045 rb/stb

WF response observed NOV/90 NVSU #2 wells
no response Ranchmens wells

Remaining Ranchman's wells in SE/4-30

WELLS	OIL	WTR	INJ	VOIDAGE	CUM VOIDAGE
6-30	396.2	2154.1		2568.1	56037.8
7-30	193.0	216.4		418.1	14474.8
8-30			7175.1	- 125508 →	

Manitoba

Energy and Mines

Petroleum

555 — 330 Graham Avenue
Winnipeg, Manitoba, CANADA
R3C 4E3

(204) 945-6577

November 17, 1988

ICG Resources Ltd.
2700, 140 - 4th Avenue S.W.
CALGARY, Alberta T2P 3S3

Attention: D.R. Bates, P. Eng.
Engineering Manager

Re: Board Order No. PM59
Virden Lodgepole A Pool

Dear Doug:

Enclosed is Board Order No. PM59 authorizing pressure maintenance operations in the Virden Lodgepole A Pool. Please note that pressure maintenance operations should not commence prior to the Board's approval of the Unit Agreement for North Virden Scallion Unit No. 2.

Please note special provisions of the Order (Pressure Maintenance Rule No. 8) designed to minimize the effect of your operations on offsetting wells operated by Ranchmen's Resources Ltd. and if feasible to lead to eventual inclusion of the Ranchmen's wells in the Unit.

Prior to commencing injection, you are required to obtain Petroleum Branch approval of your proposed conversion program (using Form MG 416) for each proposed injector.

If you have any questions, please call me at (204) 945-6574.

Yours sincerely,

Original Signed By
L. R. DUBREUIL

L.R. Dubreuil
Chief Petroleum Engineer

LRD:dah

encl

cc: Ranchmen's Resources Ltd. (J. Shand)

Manitoba

The Oil and Natural Gas
Conservation Board

Room 309
Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

(204) 945-3130

Order No. PM 59

An Order Pertaining to Pressure Maintenance by Water Flooding
Virden Lodgepole A Pool

WHEREAS, subsection (9)(d) of Section 62 of "The Mines Act", Cap. M160, of the Revised Statutes of Manitoba, provides as follows:

> "62(9) Without restricting the generality of subsection (8) the board, with the approval of the minister, may make orders
>
> (d) requiring the repressuring, recycling, or pressure maintenance, of any pool or portion thereof where it is economical so to do, and for that purpose where necessary requiring the introduction or injection into any pool or portion thereof of gas, air, water or other substance;"

AND WHEREAS, the Board received an application dated August 30, 1988 from ICG Resources Ltd. for approval of a project to inject water into the Virden Lodgepole A Pool ("the pool") in the proposed North Virden Scallion Unit No. 2 area in Manitoba.

AND WHEREAS, notice of the application was published in the Manitoba Gazette on September 24, 1988 and the Virden Empire Advance on September 21, 1988.

AND WHEREAS, the Board has received an objection to the application from Ranchmen's Resources Ltd. ("Ranchmen's").

AND WHEREAS, after discussions between ICG Resources Ltd., Ranchmen's and the Department of Energy and Mines, Ranchmen's has agreed to withdraw its objection subject to certain conditions.

AND WHEREAS, ICG Resources Ltd. is the unit operator of the proposed North Virden Scallion Unit No. 2 ("the unit area").

NOW THEREFORE, the Board orders that:

1. The unit operator shall conduct pressure maintenance operations by the injection of water into the pool underlying the unit area.

2. The pressure maintenance operation shall be in accordance with, and subject to, the following rules:

PRESSURE MAINTENANCE RULES

1(1)
Water shall be injected into the pool through the wells:

ICGR et al Virden Prov. WIW 12-29-11-26 (WPM)
ICGR et al Virden WIW A10-30-11-26 (WPM)
ICGR et al Virden WIW 4-32-11-26 (WPM)

and such other wells in the unit area as the Board may approve.

1(2) After the commencement of injection, the unit operator shall, subject to any remedial work required to be performed on the wells referred to in subsection (1), endeavour to maintain continuous injection.

1(3) Notwithstanding the provisions of subsection (2), the Board may, upon application by the unit operator, approve the suspension of water injection into any well or wells, provided that the Board is satisfied that pressure maintenance operations in the unit area will not be adversely affected.

1(4) The completion of the wells referred to in subsection (1) will be as prescribed by the Director of Petroleum.

2 The unit operator, upon the request of the Board, shall satisfy the Board as to the source, suitability and method of treatment of the water to be injected.

3(1) Before injection of water is commenced, the unit operator shall submit, to the Board, results of a survey conducted to determine the static reservoir pressure in a minimum of two wells in the unit area.

3(2) The unit operator shall, not less than six months nor more than 12 months after the commencement of injection, and at yearly intervals thereafter, conduct a survey to determine the static reservoir pressure in a minimum of two wells in the unit area.

3(3) The Board may, at any time, require the unit operator to carry out such additional reservoir pressure surveys as it deems necessary.

3(4) Within 30 days of the completion of the surveys described in subsections (1), (2) and (3) the unit operator shall submit the details of the surveys including:

(a) a list of wells surveyed,
(b) the measurement technique used,
(c) the shut in period for each well,

(d) the static reservoir pressure data obtained from the survey corrected to the pool datum depth, and;
(e) a discussion of the survey results and pressure distribution within the unit area.

4 The unit operator shall immediately report to the Board any indication of channelling or break-through of injected water to producing wells or any indication of other detrimental effects that may be attributable to the pressure maintenance operations.

5 The maximum wellhead pressure at which water is injected into the wells referred to in subsection 1(1) shall not exceed 6 000 kPa or such other maximum pressure as the Board may prescribe and the Board may, from time to time, prescribe a maximum or minimum rate at which water shall be injected into any well in the unit area.

6(1) The unit operator shall, not later than the last day of each month, file with the Petroleum Branch, a report of the quantity, source and pressure of water injected during the preceding month into each well referred to in subsection 1(1).

6(2) The unit operator shall,,not later than the last day of each month, file with the Petroleum Branch a summary report of production and injection operations during the preceding month, which report shall include:

(a) a tabulation of total oil, total water and total gas produced;
(b) a tabulation of the number of producing wells and injection wells which were active;
(c) the results of at least one twenty-four hour production test on each producing well in the unit area including volumes of oil, gas and water produced during the test; and
(d) a summary of any remedial operations carried out on any well in the unit area.

7 The unit operator, shall, within 60 days of the end of each calendar year, file with the Petroleum Branch a report of the pressure maintenance program, setting out graphically such interpretive information necessary to evaluate the efficacy of the waterflood.

8 Unless otherwise provided by the Board in writing, the following special conditions shall apply:

(a) The amount of water injected in any calendar quarter into the well ICGR et al Virden WIW A10-30-11-26 (WPM) ("the A10-30 well") shall not exceed one third of the total water injected in the unit area during the same calendar quarter,
(b) The ratio of water injection to reservoir withdrawls in the nine spot injection pattern surrounding the A10-30 well shall not exceed 1.15 on a quarterly basis, and;
(c) The unit operator and Ranchmen's shall submit to the Board within six months of the commencement of injection in the unit area a detailed joint report including recommendations on the feasibility and desireability of expanding the unit area to include wells operated by Ranchmen's located in legal Subdivisions 11 and 14 of Section 30, Township 11, Range 26, West of the Principal Meridan.

Wm. McDonald
Deputy Chairman

Charles S. Kang
Chairman

OIL AND NATURAL GAS CONSERVATION BOARD ORDER NO. PM 59 APPROVED THIS 14th DAY OF November A.D., 1988 AT THE CITY OF WINNIPEG.

APPROVED:

H. Neufeld
Minister of Energy and Mines

PS-f-25

Manitoba

Memorandum

Date November 2, 1988

To The Oil and Natural Gas Conservation Board

Charles S. Kang - Chairman
Wm. McDonald - Deputy Chairman

From L. R. Dubreuil
Chief Petroleum Engineer
Petroleum Branch

Subject

Telephone

Re: **North Virden Scallion Unit No. 2**
Pressure Maintenance Operations

ICG Resources Ltd. has made application to initiate a pressure maintenance by waterflood project in the proposed North Virden Scallion Unit No. 2. Notice of the application was published in The Manitoba Gazette (Sept. 24, 1988) and The Virden Empire Advance (Sept. 21, 1988). Copies of the notice were also sent to all affected working interest owners.

Ranchmen's Resources Ltd., operator of several wells adjoining the project filed an intervention in the application. A copy of this letter is included as Attachment No. 1. As a result of discussions between ICG, Ranchmen's and the Petroleum Branch, Ranchmen's has agreed to withdraw its intervention under certain conditions (see Attachment No. 2).

Recommendation:

It is recommended that the application be approved and that Board Order No. PM 59 be issued. A copy of the proposed Board Order is attached.

Discussion:

In its intervention, Ranchmen's indicated its concern that it had not been notified of the planned project until it received the Board's notice. Further, concern was expressed that the proposed project may have a negative effect on its wells, particularly those located in Lsd 11 and 14 of Section 30-11-26 (WPM).

In its application, ICG suggests that the Ranchmen's wells could be brought into the Unit if they exhibited waterflood response. If negative (or no) response was indicated, Ranchmen's would not be approached to join the Unit. Ranchmen's sees this proposal as benefitting only the Unit and not providing any protection to Ranchmen's production revenue.

In withdrawing its objection, Ranchmen's recognize the desire of the proposed Unit's working interest owners to proceed with the project before freeze up. The conditions suggested by Ranchmen's (controlling the volume of injected water adjacent to its wells) are designed to minimize possible negative effects of the project on its wells. The conditions appear reasonable. ICG has indicated it is prepared to accept the conditions.

Withdrawl of the intervention will permit the project to proceed this fall. In the longer term, as the Ranchmen's wells are likely to be affected by injection, their inclusion in the Unit would be preferable. Therefore, in addition to the conditions suggested by Ranchmen's a provision requiring submission, within 6 months of commencement of injection, of a detailed joint review (by ICG and Ranchmen's) of inclusion of the Ranchmen's wells in the Unit is included in the Board Order.

Upon initial processing of ICG's applications, several deficiencies, mostly in the area of facilities design were noted. ICG, in its letter of October 25, 1988, has addressed these deficiencies in a satisfactory manner.

Board Order No. PM 59 (attached) contains normal provisions for an order of this type as well as the special conditions noted above. A provision to limit well head injection pressure to 6 000 kPa (below the estimated fracture pressure) is also included.

Upon approval of the Board Order, it is proposed to forward copies to both ICG and Ranchmen's with appropriate cover letters.

L R Dubreuil

L. R. Dubreuil

LRD/sml

Attachments

Original Signed by H. C. Moster

Recommended for Approval________________________

H. Clare Moster

Well	MPP'(kB)		P_{fsp} @0.85 psi/ft	P_{SURF}	kPa
2932 12 - 29	646.5	2121	1803	884	5973
381~~7~~5 A 10 - 30	653.5	2144	1822	894	6163
2952 3 - 32	633.5	2078	1767	856	<u>5901</u>

ICG RESOURCES LTD
DIVISION OF INTER-CITY GAS CORPORATION
2700-140 FOURTH AVENUE S.W.
CALGARY ALBERTA CANADA
T2P 3S3
(403) 231-9000

1988 10 25

The Oil and Natural Gas Conservation Board
Room 309
Legislative Building
Winnipeg, Manitoba
R3C 0V8

Attention: Mr. Charles S. Kang,
Chairman

Gentlemen:

Re: Proposed Pressure Maintenance
Operations - Virden Lodgepole A Pool

Further to your letter of September 6, 1988, please find below and attached the mentioned deficiencies in our application for our waterflood scheme in the Virden Lodgepole A Pool.

1. Attached find a schematic cross section showing the typical injection well configuration we intend to use in the subject project. Our configuration of downhole equipment shows a 114.3 mm tension packer run on 60.3 mm tubing and set in the 114.3 mm casing at approximately 8 m above the perforations. Prior to setting the packer, the hole will be circulated over to inhibited fresh water so as to have inhibited water left in the annulus when the packer is set. All three injection wells will be set up the same way. Note: Prior to running in with the injection string, a casing scraper trip followed by a diesel surfactant and acid squeeze will be done on the well for change-over from oil producer to water injector.

2. Attached is a schematic drawing of surface facilities. Surface facilities will be built at our battery facilities at 13-29-11-26 WPM. These facilities will consist of:

   (a) pressure pump with electric motor, pulsation dampner, pop valve and filter element;

   (b) header (3) each with needle valve for flow control, strainer, volume meter, check valve, pressure gauge and shutoff valve;

   (c) electrical pressure control and switching valves;

   (d) all HP fittings to tie in will be 2000 psi WOG;

   (e) utilization of existing 79.5 m^3 water storage tank.

   The bulk of the water will come to us from the high pressure water tie-in line from Chevron Canada Resources. This tie-in will be from a high pressure salt water tie-in at 14-28-11-26. ICG's line from this point to our battery will be built of either cement lined, composite or fiberglass high pressure pipe. ICG's contract with Chevron will be to supply us with up to 80 m^3 per day of 5-6000 kPa pressure salt water. Produced salt water at battery 13-29 is 15-16 m^3 per day and this water will also be reinjected. Electrical switching control valves will automatically turn off HP water line when water tank is at high level and pump water from the storage tank. After pump out of tank auto-switching will revert back to Chevron's HP water line. Flow injection control will be regulated by means of a needle choke valve. Electrical safety HP/LP shutdowns will protect all lines and equipment.

3. (a) Corrosion control downhole will be controlled by plastic lined tubing, packer and inhibited annulus. If injection drops below needed rates, some type of acid stimulation treatment will be designed to cleanout perforations.

.../3

(b) Flowline Corrosion Control

High pressure supply line will be internally and externally coated. Wells to be used for injection are 10A-30, 12-29 and 4-32-11-26 WPM. The 10A-30 well already has a cemented lined and yellow jacket flowline. The wells 12-29 and 4-32 which are externally yellow jacket steel pipe will be pressure tested to a new MOP x 1.25 and then a plastic liner will be pulled through them.

All subsurface (including any extentions) flowlines and high pressure supply line will be internally and externally coated. Cathodic Protection is in place on all our flowline systems.

(c) <u>Other Equipment Corrosion Control</u>

Tank for produced water is internally coated. Pump fluid end will be protected by non-corrosive alloy metals and first out of ground valve(s) will be made of a non-corrosive alloy.

4. There is no planned treatment of injection water. We will, however, monitor the water(s) to see if any chemical additives for chemical and bacterial control are required.

5. The anticipated total injection rate in all three wells is 80 m^3 per day. These rates will be controlled on each well by means of a choke. The amount of water injected in any one well will depend on the voidage replacement ratio of that particular well (area). Anticipated injection pressure is 4850 kPa but could possibly go as high as 7600 kPa during some phase of the project.

6. In conjunction with the installation of this waterflood facilities, a test treater will be installed at the battery. The existing water tank (which is coated) will still be used for produced water but will be moved so as to be alongside of the water plant.

7. All surface landowners in the project area have been or will be verbally or letter informed of our plans to proceed with this waterflood project before any construction begins.

.../4

Trusting that we have supplied you with all the requested information so that you can proceed with the processing of our application for the waterflood scheme in the Virden Lodgepole A Pool in twp 11 range 26 WPM. If you should require additional information, please contact the writer at (403) 231-9035.

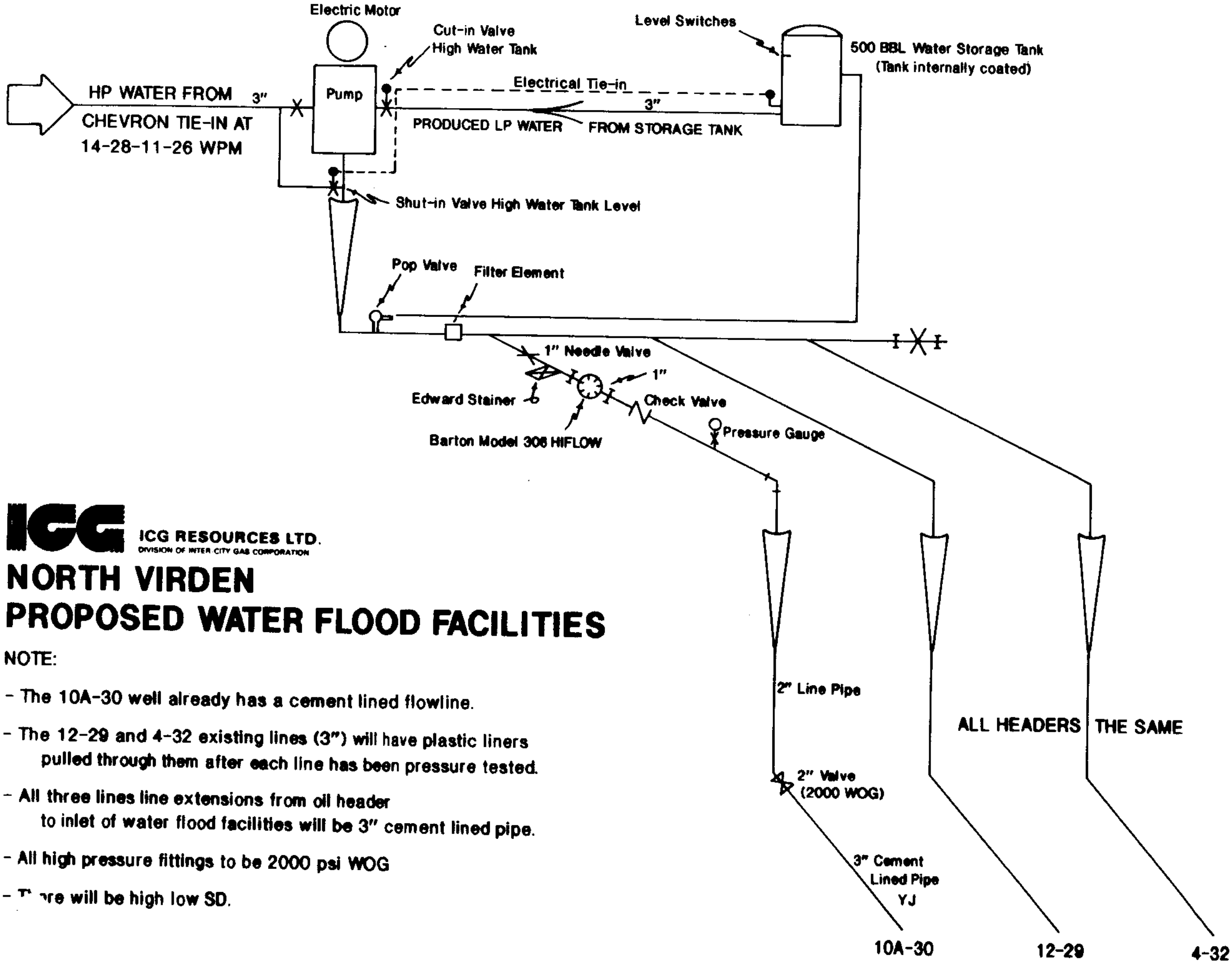
Yours truly,

ICG RESOURCES LTD.

D.J. Bull

D.J. Bull,
Construction Co-ordinator

DJB/hjm
Encl.
cc: L.R. Dubreuil, Chief Petroleum Engineer
Petroleum Branch, Energy and Mines
555, 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3



ICG RESOURCES LTD.
DIVISION OF INTER-CITY GAS CORPORATION

NORTH VIRDEN
PROPOSED WATER FLOOD FACILITIES

NOTE:

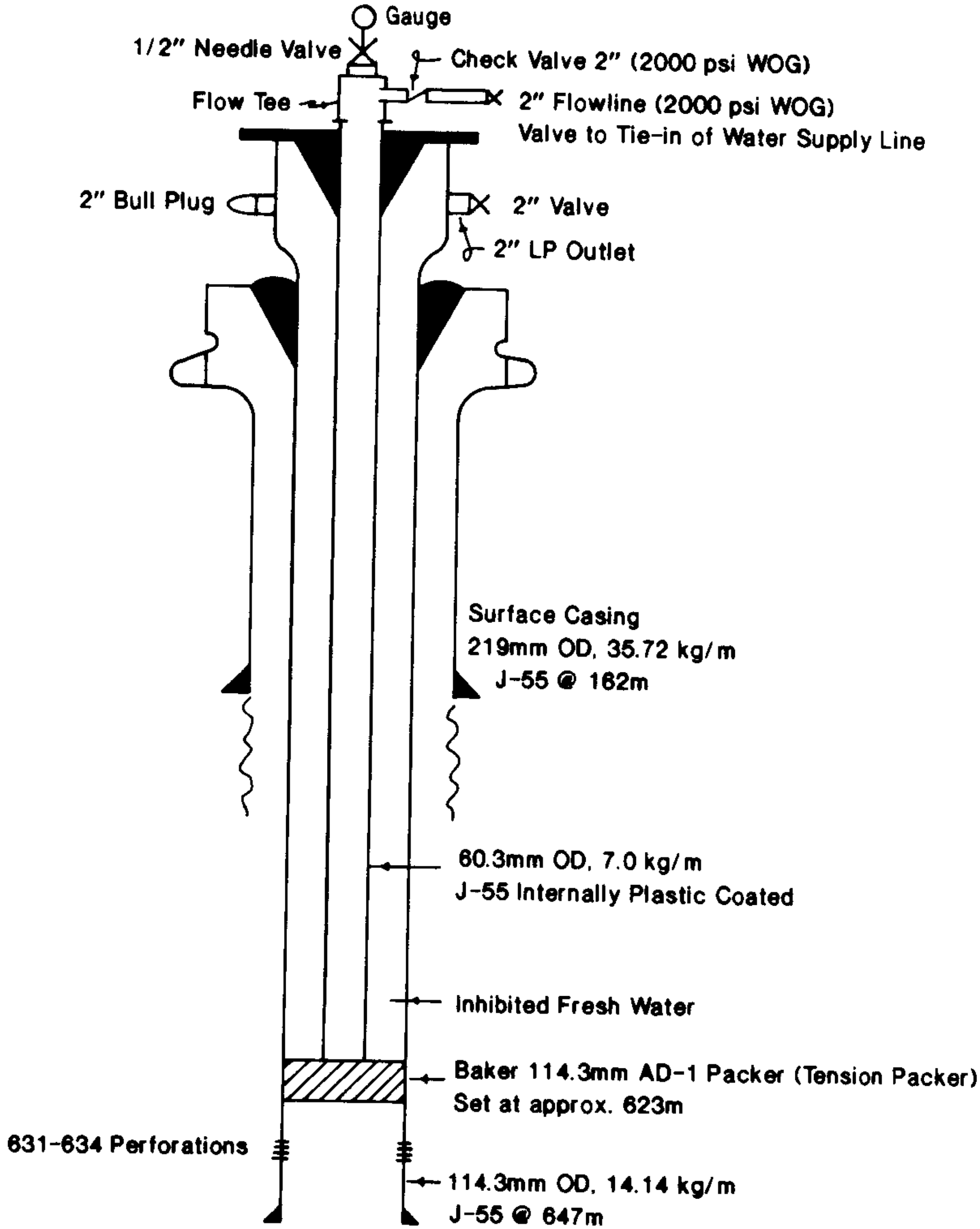
- The 10A-30 well already has a cement lined flowline.
- The 12-29 and 4-32 existing lines (3") will have plastic liners pulled through them after each line has been pressure tested.
- All three lines line extensions from oil header to inlet of water flood facilities will be 3" cement lined pipe.
- All high pressure fittings to be 2000 psi WOG
- T' ›re will be high low SD.

21 October 1988

ICG RESOURCES LTD.
DIVISION OF INTER-CITY GAS CORPORATION

NORTH VIRDEN
PROPOSED WATER INJECTION WELL

4-32-11-26 WPM (TYPICAL OF ALL THREE WELLS)



21 October 1988

Attachment No. 2

Ranchmen's Resources Ltd.

Suite 800, SunLife Plaza III
112 - 4th Avenue, S.W.
Calgary, Alberta T2P 0H3

Telephone: (403) 265-0262
Telecopier: (403) 237-0393
Telex: 03-821172 CGY

DEPARTMENT OF ENERGY AND MINES
OCT 18 1988
PETROLEUM BRANCH

1988-10-12

Manitoba Oil & Gas Conservation Board
Room 309, Legislative Building
Winnipeg, Manitoba
R3C 0V8

Attention: Mr. L. R. Dubreuil
Chief Petroleum Engineer
Petroleum Division

Re: ICG Resources Ltd. Application For Enhanced Recovery In Part of the Virden Lodge Pole "A" Pool

Further to our letter dated 1988-09-21 regarding the subject application, Ranchmen's Resources Ltd. hereby withdraws our objection subject to the following conditions:

1. Volumes injected into well A 10-30-11-26 WPM be limited to a maximum of one-third (1/3) of the total volume injected on a monthly basis.

2. The voidage replacement ratio for the partial inverted 9 - spot pattern surrounding well A 10-30-11-26 WPM not exceed 1.15 on a monthly basis.

Should you have any questions, please contact the undersigned at 265-0262.

Yours very truly,

RANCHMEN'S RESOURCES LTD.

John Shand

G. John Shand
Production Superintendent

GJS/lmf

cc. ICG Resources Ltd.
Attention: Mr. Doug Bates

Attachment No. 1

Ranchmen's Resources Ltd.

Suite 800, SunLife Plaza III
112 - 4th Avenue, S.W.
Calgary, Alberta T2P 0H3

Telephone: (403) 265-0262
Telecopier: (403) 237-0393
Telex: 03-821172 CGY

DEPARTMENT OF ENERGY AND MINES
SEP 23 1988
PETROLEUM BRANCH

1988-09-21

Manitoba Oil & Gas Conservation Board
Room 309, Legislative Building
Winnipeg, Manitoba
R3C 0V8

Attention: Mr. L.R. Dubreuil
Chief Petroleum Engineer
Petroleum Division

Re: ICG Resources Ltd. Application for Enhanced Recovery In part of the Virden Lodge Pole "A" Pool

In response to your notice dated September 12, 1988, regarding the subject application, Ranchmen's Resources Ltd., as operator and on behalf of the working interest owners in the SW, SE, and NE quarters of section 30-11-26 WPM and LSD. 3 of section 29-11-26 WPM hereby objects to approval of the subject application.

The Notice from the Manitoba Oil & Gas Conservation Board is Ranchmen's first notification that a waterflood and unitization are proposed for offsetting lands.

ICG Resources Ltd. application implies that they are uncertain of the effect to off-setting production and that they are not prepared to allow Ranchmen's operated properties into the unit at this time.

Ranchmen's proposes to conduct a reservoir study to determine the impact of the project on our production and to disscuss the matter with ICG Resources Ltd.

Should you have any questions, please contact the undersigned at 265-0262.

Yours very truly,

RANCHMEN'S RESOURCES LTD.

G. John Shand

G. John Shand
Production Superintendent

GJS:yj

cc: ICG Resources Ltd.

DEPARTMENT OF ENERGY AND MINES
Deputy Minister's Office
SEP 22 1988

UNDER THE MINES ACT

NOTICE
VIRDEN OIL FIELD

ICG Resources Ltd. has made application under The Mines Act to conduct a waterflood pressure maintenance project in that part of the Virden Lodgepole A Pool outlined below. ICG proposes to convert the following wells to water injection.

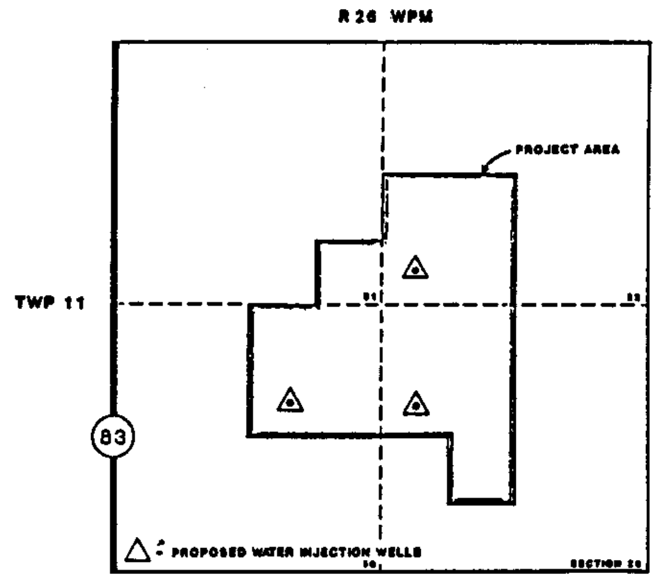
ICGR et al Scallion Prov. 12-29-11-26 (WPM)
ICGR et al Virden A10-30-11-26 (WPM)
ICGR et al Scallion 4-32-11-26 (WPM)

If no objection or intervention in writing is received by the Board at Room 309, Legislative Building, Winnipeg, Manitoba, R3C 0V8, within 14 days of the publication of this notice, the Board may approve the application.

Dated at Winnipeg, this 12th day of September, 1988.

CHARLES S. KANG,
Chairman.

14694—39



...ict director

Toupin has been appointed ... of the Winnipeg District ... Veterans Affairs Canada, ... August 1, 1988.

...ing the announcement, Di... ...neral Bill Shead of the De... ...t's Prairie Region in... ...hat Ms. Toupin will be re... ...e for providing a wide ... benefits and services to ... and their dependents.

Toupin has been with Vet... ...fairs Canada since 1983. ... that, she worked for the ...nal Service of Canada. She ...ster of Social Work degree ...ng taught at the University ...oba, she subsequently de... ...n interest in geriatric so... ... She is a member of the ... Association on Gerontology.

The Winnipeg District Office is located at 101 - 180 Main Street.

Social and Personal

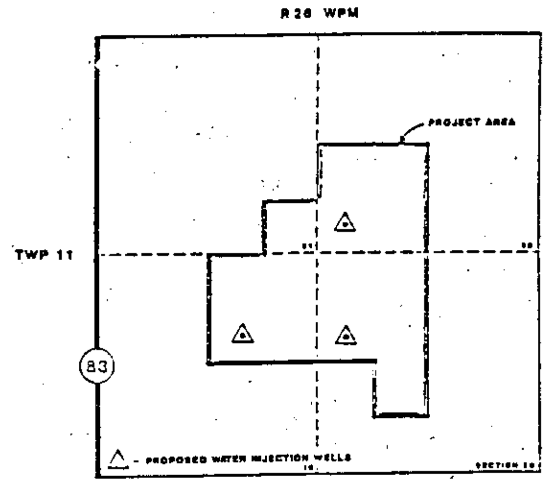
Mrs. Lorraine Austin has returned home after a seven-week holiday in England visiting family. She visited with Mr. and Mrs. Pete Lambourne and family (formerly of Virden) of Cheshire while in England, and also visited with friends in Holland.

NOTICE

VIRDEN OIL FIELD

ICG Resources Ltd. has made application under The Mines Act to conduct a waterflood pressure maintenance project in that part of the Virden Lodgepole A Pool outlined below. ICG proposes to convert the following wells to water injection.

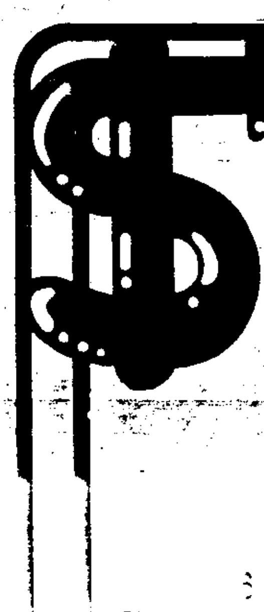
ICGR et al Scallion Prov. 12-29-11-26 (WPM)
ICGR et al Virden A10-30-11-26 (WPM)
ICGR et al Scallion 4-32-11-26 (WPM)



If no objection or intervention in writing is received by the Board at Room 309, Legislative Building, Winnipeg, Manitoba R3C 0V8, within 14 days of the publication of this notice, the Board may approve the application.

DATED at Winnipeg, this 12th day of September, 1988.

Charles S. Kang
Chairman



Manitoba

The Oil and Natural Gas Conservation Board

Room 309
Legislative Building
Winnipeg, Manitoba, CANADA
R3C 0V8

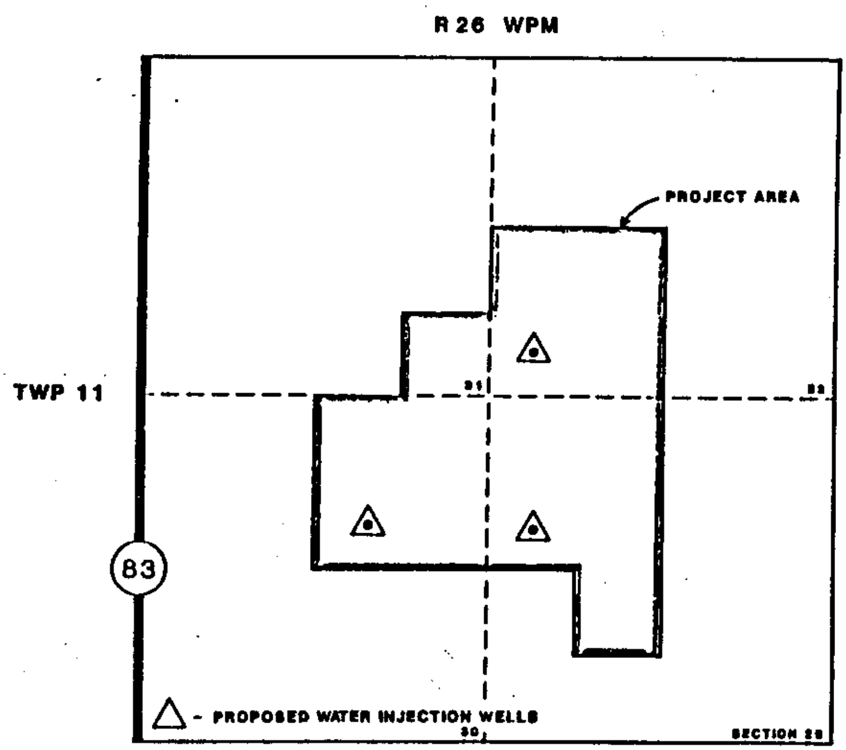
(204) 945-3130

NOTICE

VIRDEN OIL FIELD

ICG Resources Ltd. has made application under The Mines Act to conduct a waterflood pressure maintenance project in that part of the Virden Lodgepole A Pool outlined below. ICG proposes to convert the following wells to water injection.

ICGR et al Scallion Prov. 12-29-11-26 (WPM)
ICGR et al Virden A10-30-11-26 (WPM)
ICGR et al Scallion 4-32-11-26 (WPM)



If no objection or intervention in writing is received by the Board at Room 309, Legislative Building, Winnipeg, Manitoba, R3C 0V8, within 14 days of the publication of this notice, the Board may approve the application.

DATED at Winnipeg, this 12th day of Sept ,1988

Charles S. Kang
Chairman

Manitoba

Memorandum

Date September 8, 1988

To The Oil and Natural Gas Conservation Board

Charles S. Kang - Chairman
Wm. McDonald - Deputy Chairman
R. Bruce Ball - Member

From L. R. Dubreuil
Chief Petroleum Engineer
Petroleum Branch

Subject

Telephone

First | Fold

Re: Pressure Maintenance Operations
Virden Lodgepole A Pool

ICG Resources Ltd. as operator of the proposed North Virden Scallion Unit No. 2 has made application for approval to conduct a waterflood pressure maintenance project in the north western part of the subject Pool.

Recommendations:

It is recommended that notice of the application be published in the Manitoba Gazette and the Virden Empire Advance. It is also recommended that copies of the notice be sent to all working interest owners within one kilometre of the proposed scheme area. (see Table No. 1). A copy of the proposed notice is attached.

Discussion:

During the period from late 1982 to early 1985, ICG Resources Ltd. (with partners) and Tundra Oil and Gas Ltd. (with partners) developed a productive area on the north west edge of the Virden Lodgepole A Pool (see Fig. No. 1) Initial well productivities were favourable (about 3 m^3/d/well with very low WOR's), however, continued production resulted in a significant production decline (see Fig. No. 2). The production decline was also reflected by a decline in total fluids production.

This production performance indicated a low energy reservoir regime with little aquifer support. Primary recovery in this situation is likely to be very limited, however, ultimate recovery can generally be substantially increased by pressure maintenance. With this in mind, the Petroleum Branch requested in May 1983 that operators in this part of the field undertake a waterflood feasibility study. As a result of this request a study, sponsored by operators of older wells to the south was submitted recommending waterflooding not be proceeded with due to the near depletion of the wells involved. ICG indicated in April 1984, however, that a waterflood project would be economical in its area of operation and committed to a reservoir study. After numerous and lengthy delays, ICG submitted a study in October, 1985 indicating its internal commitment to implementing a waterflood project. Subsequent to this, further delays resulted from the inability of working interest owners in the area to agree upon a tract participation formula. In its current application, ICG has indicated that the tract participation formula has been resolved in principle and that the working interest owners desire to implement the waterflood prior to freeze up this fall.

It is proposed to convert three wells to water injection to result in a partial inverted nine spot injection pattern (see Fig. No. 1). It is estimated that implementation of this proposal will result in an increase in recoverable reserves from 7 to 27 percent of the original oil in place or an incremental recovery of approximately 185,000 m^3. The proposed injection pattern is similar to that successfully used in North Virden Scallion Unit No. 1. Estimated waterflood performance is also based on production performance of North Virden Scallion Unit No. 1. Both the proposed pattern and the predicted performance appear reasonable.

The proposed project area does not include adjacent wells operated by Dome Petroleum Limited and Ranchmen's Resources Ltd. to the south and by Ranchmen's to the west. The wells to the south of the project area were drilled in the mid 1960's and are currently in an advanced stage of depletion. Due to the large varience in degree of depletion, inclusion of these wells would make it very difficult to derive an equitable tract participation and would probably result in further delay of implementation of the project. Combined production of two recently drilled wells operated by Ranchmen's is shown on Fig. No. 3. The relatively high water production and declining oil rates of these wells reflecting their downdip position brings into question their value to the project. ICG's proposal to exclude these wells but monitor them for possible waterflood response is acceptable in the interest of expediting unitization. Inclusion of these wells should be given serious consideration in the future.

ICG's application is deficient in a number of aspects, primarily involving details of the physical facilities involved with the project. These deficiencies have been brought to ICG's attention. Approval of the scheme should be withheld until the deficient items have been provided.

The proposed project area is offset by a number of producing wells and one active salt water disposal well. As it is probable that injection in the project area will affect some of these wells, the application must be advertised for objections or interventions. Table 1 shows a list of all working interest owners within the project area and within one kilometre of the project area. It is recommended that the application be forwarded to all parties on this list as well as be published in the Manitoba Gazette and the Virden Empire Advance. A proposed notice is attached.

Origin[illegible]
L. R. Du[illegible]

L. R. Dubreuil

LRD/sml

Attachment

Recommended for Approval: Original signed by H. C. Moster
H. Clare Moster

Table No. 1

Working Interest Ownership Within
and Adjacent to Proposed
North Virden Scallion Unit No. 2

Working Interest Owner	Lands
ICG Resources Ltd.	Lsd's 12, 13 & 14 of Section 29-11-26 (WPM) Lsd's 9, 10, 15 & 16 of Section 30-11-26 (WPM) SE 1/4 of Section 31-11-26 (WPM) SW 1/4 of Section 32-11-26 (WPM)
Dome Petroleum Limited Canpar Holdings Ltd.	Lsd's 4, 5, 12, 13 and 14 of Section 29-11-26 (WPM) Lsd's 9 & 16 of Section 30-11-26 (WPM)
Tundra Oil and Gas Manitoba Oil and Gas Corporation	Lsd's 6 & 11 of Section 29-11-26 (WPM)
Mountcliff Resources Ltd.	Lsd's 12, 13 & 14 of Section 29-11-26 (WPM) Lsd's 9, 10, 15 & 16 of Section 30-11-26 (WPM) SE 1/4 of Section 31-11-26 (WPM) SW 1/4 of Section 32-11-26 (WPM)
Shell Canada Limited	N 1/2 of Section 32-11-26 (WPM)
Saskatchewan Oil and Gas Corporation	Lsd 3 of Section 29-11-26 (WPM)
Ranchmen's Resources Ltd.	Lsd 3 of Section 29-11-26 (WPM) S 1/2 & NW 1/4 of Section 30-11-26 (WPM)
O'Sullivan Resources Ltd.	Lsd 3 of Section 29-11-26 (WPM)

N. VIRDEN SCALLION UNIT NO. 2

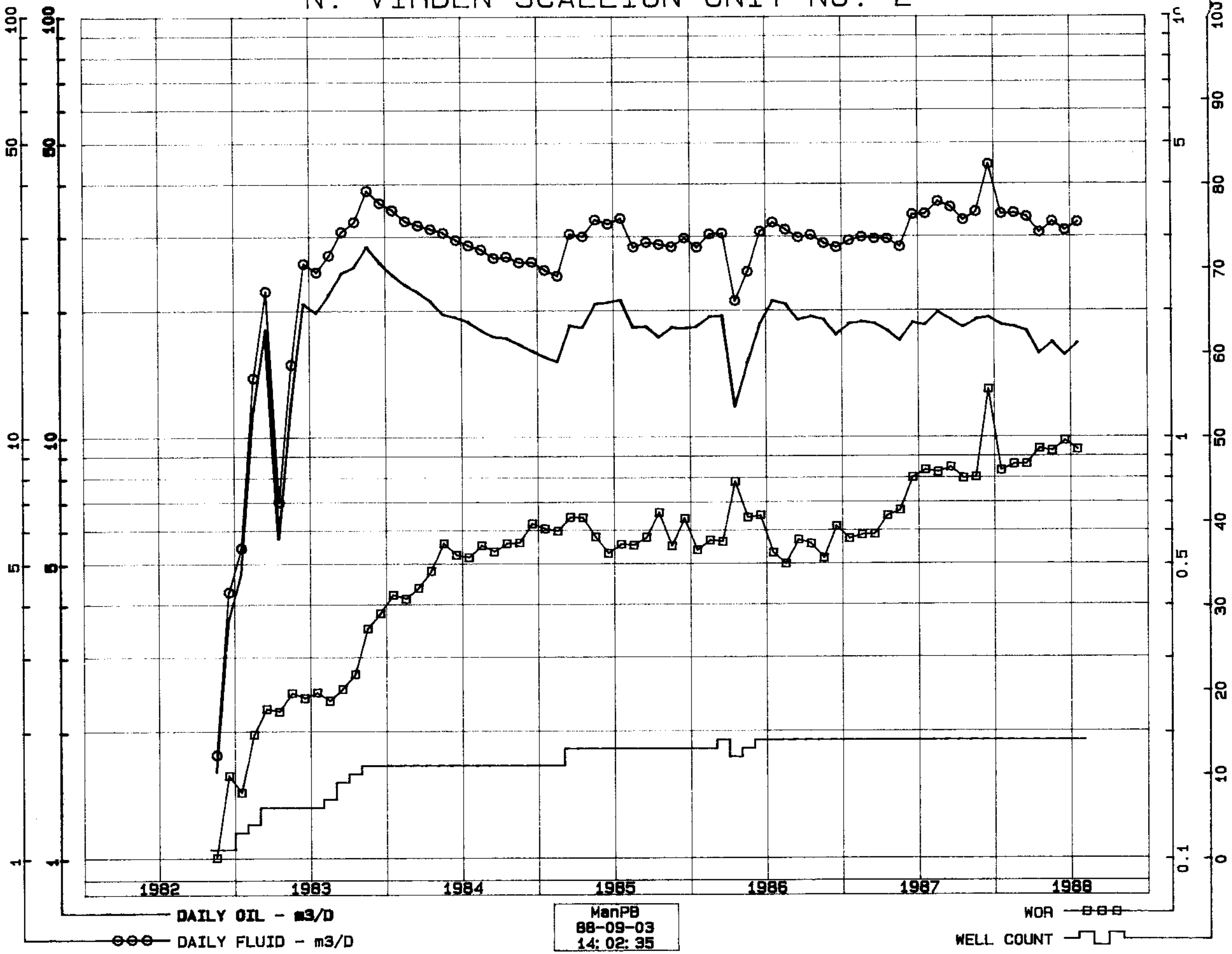


FIG No. 2

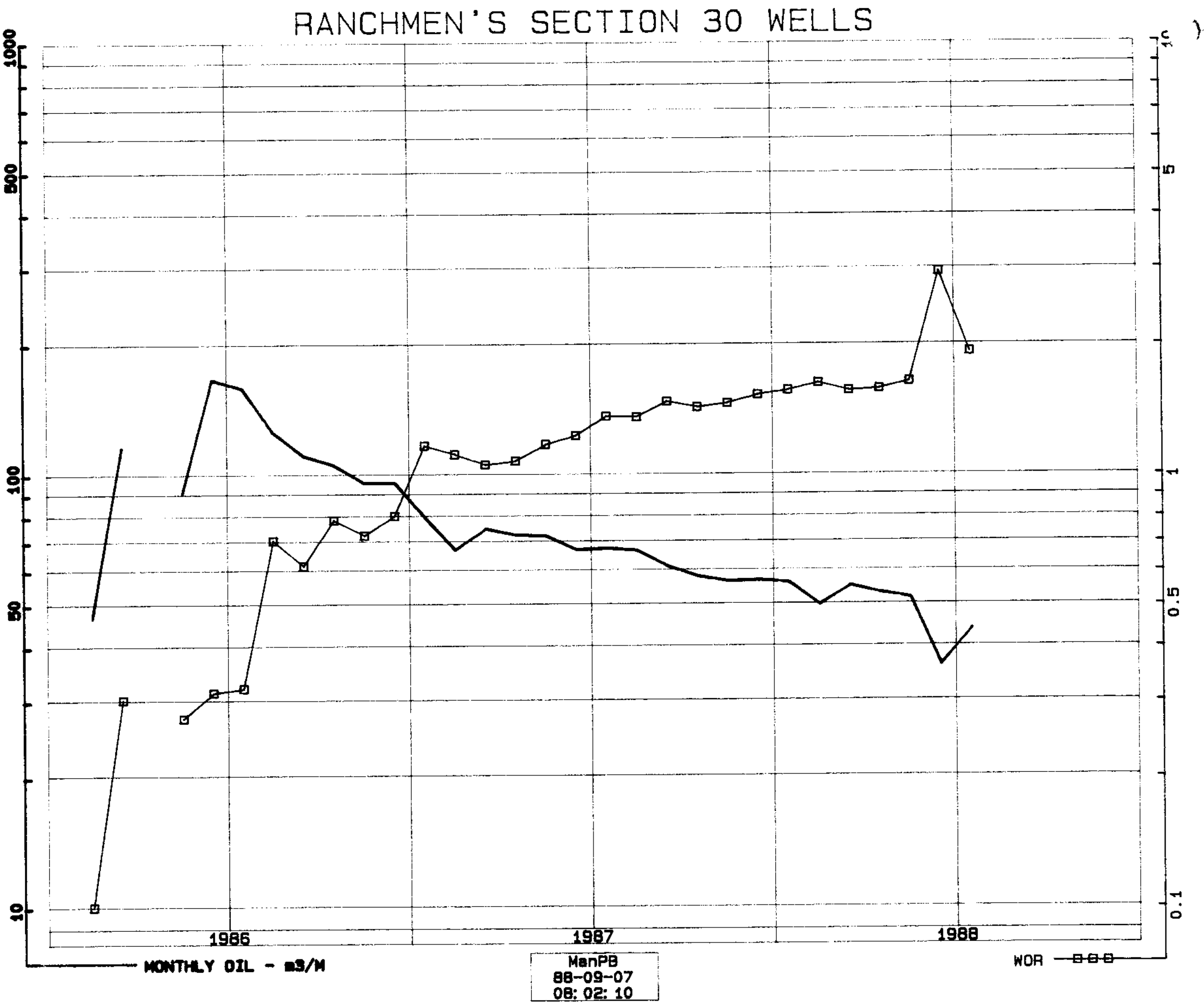
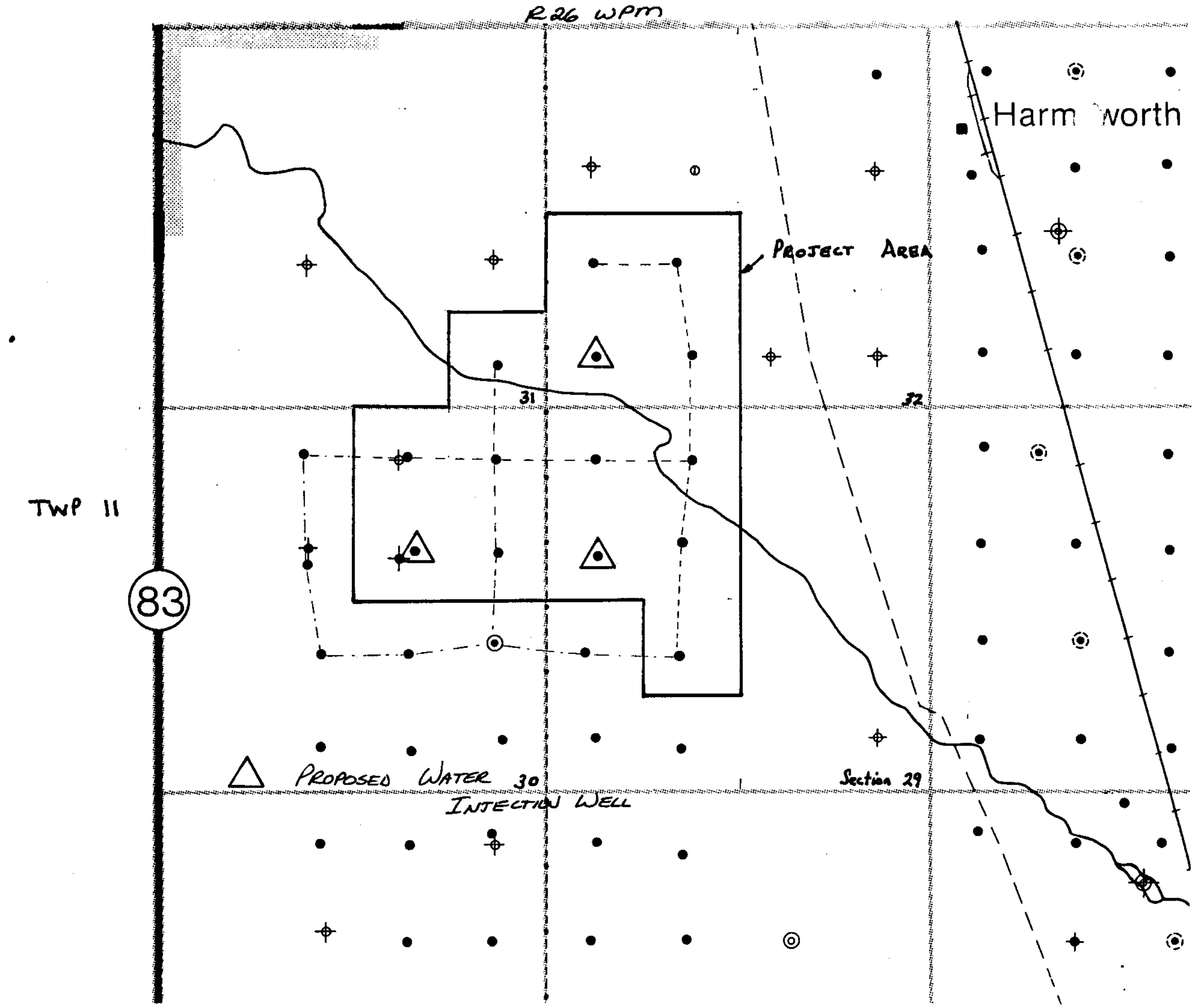

RANCHMEN'S SECTION 30 WELLS
1000
500
100
50
10
10
5
1
0.5
0.1
1986
1987
1988
MONTHLY OIL - m3/M
ManPB
88-09-07
08: 02: 10
WOR

FIG No. 3



R26 WPM
Harm worth
Project Area
31
32
TWP 11
83
30
Section 29
Proposed Water Injection Well

FIG. No. 1

PROPOSED NORTH VIRDEN SCALLION UNIT NO. 2

MINERAL AND SURFACE OWNERSHIP

Ds O'Sullivan Res 2350 - 10060 Jasper Ave ~~[illegible]~~ Edmonton Alta T5J 3R8

LAND DESCRIPTION	MINERAL OWNER LESSOR	LESSEE	SURFACE OWNER
Sec 29-11-26 WPM			
NE 1/4	Crown	-	B. Van V
SE 1/4	Crown	-	K. Kerr
LSD 3	Crown	Trans Canada/Saskoil/O'Sullivan	55810 Manitoba Ltd.
LSD's 4 and 5	Crown	Dome/Canpar	55810 Manitoba Ltd.
LSD's 6 and 11	Crown	MOGC/Tundra	55810 Manitoba Ltd.
LSD's 12, 13 and 14	Crown	Dome/Canpar/ICG/Mountcliff	55810 Manitoba Ltd.
Sec 30-11-29 WPM			
LSD's 9 and 16	J. Nichol/K. Younge	Dome/Canpar/ICG/Mountcliff	55810 Manitoba Ltd.
LSD's 10 and [illegible]	J. Nichol/K. Younge	ICG/Mountcliff	55810 Manitoba Ltd.
SE 1/4	J. Nichol/K. Younge	Trans Canada et al	55810 Manitoba Ltd.
SW 1/4		Bridger Homes et al	55810 Manitoba Ltd.
NW 1/4		Bridger Homes et al	55810 Manitoba Ltd.
Sec 31-11-29 WPM			
NE 1/4	Toronto General Trusts Corp	-	Unavailable
SE 1/4	C. Chappell	ICG/Mountcliff	W. Meahan
SW 1/4	Toronto General Trusts Corp	-	Unavailable
NW 1/4	L. Graham	Canadian Landmasters	Unavailable
Sec 32-11-26 WPM			
N 1/2	Toronto General Trusts Corp/ J. Ross/P. Baker		L. DeClerpe
SE 1/4	Toronto General Trusts Corp C. Forster/D. Forster/N. [illegible]	-	Unavailable
SW 1/4	Canada Permanent Trust/ N. Mearns/L. Mearns	ICG/Mountcliff	N. Mearns

Manitoba

Energy and Mines Petroleum

555 — 330 Graham Avenue
Winnipeg, Manitoba, CANADA
R3C 4E3

(204) 945-6577

September 6, 1988

ICG Resources Ltd.
2700 - 140 - Fourth Avenue S.W.
Calgary, Alberta
T2P 3S3

Attention: Douglas R. Bates, P. Eng.
Engineering Manager

Dear Sir:

Re: Proposed Pressure Maintenance Operations
Virden Lodgepole A Pool

Your application, dated August 30, 1988, for approval of a pressure maintenance by waterflood scheme in the Virden Lodgepole A Pool is acknowledged. Upon review, it is noted your application is deficient in several areas. You are requested to submit the following supplementary information to permit processing of the application:

1. A map showing mineral rights ownership (working and royalty interests) in and adjoining the project area. ✓rec'd

2. A schematic cross section showing the proposed injection well completion configuration.

3. Evidence that surface owners in the project area have been informed of your plans to proceed with a waterflood project.

4. A summary of surface facilities related to the project including a schematic flow diagram and a plot plan.

5. A discussion of the proposed methods of corrosion control in the wellbores, flow lines and surface facilities.

6. A discussion of any planned treatment of the injection water.

7. The anticipated injection rates and wellhead pressures.

Upon submission of the above information, your application will be complete (per Section 126 of the Petroleum Drilling and Production Regulation) and can be processed. It is suggested that you provide the map of mineral rights ownership as soon as possible as this will allow advertisement of the application for objections.

Please note that all future correspondence in this matter should be addressed as follows:

Charles S. Kang, Chairman
The Oil and Natural Gas Conservation Board
Room 309
Legislative Building
Winnipeg, Manitoba
R3C 0V8

with a carbon copy to:

L. R. Dubreuil
Chief Petroleum Engineer
Petroleum Branch
Energy and Mines
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Yours sincerely,

L. R. Dubreuil
Chief Petroleum Engineer

cc: Oil and Natural Gas
Conservation Board

LRD/sml

ICG RESOURCES LTD
DIVISION OF INTER-CITY GAS CORPORATION
2700-140 FOURTH AVENUE S.W.
CALGARY ALBERTA CANADA
T2P 3S3
(403) 231-9000

1988-08-30

Manitoba Energy and Mines
Petroleum Branch
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Attention: Mr. L. R. Dubreuil
Chief Petroleum Engineer
Petroleum Division

Dear Sir:

Re: Application for Enchanced Recovery by Waterflood in a Portion of the Virden Lodgepole "A" Pool, The Proposed North Virden Scallion Unit No. 2

ICG Resources Ltd., as operator of the proposed North Virden Scallion Unit No. 2, and on behalf of the working interest owners in the proposed Unit, hereby applies under Section 64 of the Manitoba Petroleum Drilling and Production Regulations pursuant to Clause 62 (9) (d) of the Mines Act of Manitoba, for approval to inject water, as an enhanced recovery operation, into a portion of the Virden Lodgepole "A" Pool, shown on Figure 1 of the attached waterflood study.

The working interest owners have been negotiating on the formation of a unit since 1985 and have reached agreement on the unit's participation formula. The partners recognize the value of waterflooding this portion of the Virden Lodgepole "A" Pool and wish to proceed with water injection by November 1, 1988, prior to freeze up. The Unit Agreement, itself, is not yet in place but should be in the near future.

As is more fully described in the attached waterflood study, enhanced recovery is anticipated to recover an additional 183 10^3m^3 (1150 MSTB) of oil in this area of the pool, an overall recovery factor, primary plus enhanced, of about 27%. Three of the fourteen wells in the project will be converted to water injection, 12-29, 10A-30, and 4-32-11-26 WPM, forming three partial inverted 9-spot waterflood patterns which should effectively sweep the reservoir area. Wells 10A-30 and 4-32-11-26 WPM will inject only through their existing

.../2

perforated intervals in the Cherty zone but 12-29-11-26 WPM will have additional perforations added in a Lower Cherty member, which is also present in three wells in the project area, to allow effective recovery from both the main Upper Cherty and the limited Lower Cherty members.

It is not intended to include the older Dome wells adjacent to and south of the project area, due to the advanced stage of depletion. At this time, the two wells west of and adjacent to the project area, A11-30 and 14-30-11-26 WPM operated by Ranchmen's Resources Ltd. will not be included in the waterflood project or unit. High producing water-oil ratios are being exhibited by these wells on the structurally down dip edge of the pool and the value of these wells to the unit, at this stage, is undefinable. Water will be injected into the 10A-30-11-26 WPM well offsetting these wells and the unit owners have chosen to monitor flood response at Ranchmen's wells during the first year of water injection. With favourable flood response, the Ranchmen's wells could be considered for inclusion in both the unit and the waterflood project through enlargement procedures.

Injection water for the project will be obtained from Chevron Canada Resources Limited, the operator of North Virden Scallion Unit No. 1. Chevron has sufficient produced water from their waterflood project to satisfy make up water injection requirements. Because of this water source, water compatibility will not be a concern.

ICG Resources Ltd. is aware that this waterflood project will qualify for a crown royalty reduction under the Petroleum Crown Royalty and Incentives Regulations and also a freehold tax reduction under the Oil and Natural Gas Tax Act because of the enhanced oil recovery project.

All pertinent information regarding this waterflood application is enclosed in the attached waterflood study. ICG Resources Ltd. requests that this application be processed as soon as possible to allow implementation prior to winter freeze-up. Any questions regarding this application should be addressed to the undersigned at (403) 231-9057.

Yours very truly,

ICG RESOURCES LTD.

Douglas R. Bates, P. Eng.
Engineering Manager

DRB/ma
Enc.
cc: Working Interest Owners

PROPOSED NORTH VIRDEN SCALLION UNIT NO. 2

VIRDEN LODGEPOLE "A" POOL

WATERFLOOD STUDY

AUGUST 1988

D. R. Bates, P. Eng.
ICG RESOURCES LTD.

VIRDEN LODGEPOOL "A" POOL
PROPOSED WATERFLOOD

Introduction

ICG Resources Ltd. has evaluated a portion of the Virden Lodgepole "A" Pool for a potential enhanced recovery scheme by waterflood. The area investigated which has been drilled since 1983, is shown on Figure 1 and is currently operated by ICG Resources Ltd. and Tundra Oil & Gas. The study has indicated that it is technically and economically feasible to waterflood this northwest extension of the Virden Lodgepole "A" Pool. The proposed waterflood area, however, must be unitized to protect the interests of the working interest and mineral owners. Negotiations with the working interest owners have proceeded such that the unitization parameters have been agreed upon. Wells drilled to the west of and adjacent to the unit area, operated by Ranchmen's Resources Ltd., have not been included in the proposed unit and waterflood project area, at this time, due to water production concerns but could be reviewed at a later time and included by enlargement procedures.

Recommendations

1. Submit an application to the Manitoba Department of Energy and Mines, Petroleum Branch requesting approval of the proposed waterflood scheme.

2. Complete unitization of the proposed waterflood area.

3. Commence waterflooding activities prior to fall 1988 freeze-up upon approval by the Manitoba Government and the completion of unitization proceedings.

4. Monitor production in the Ranchmen's Resources Ltd. wells to the west for potential project and unit enlargement.

Conclusions

1. The original oil in place in the proposed waterflood area, Upper Cherty zone only, of the Virden Lodgepole "A" pool is 5678 MSTB.

2. Primary recovery from the proposed waterflood area is estimated by decline curve analysis to be 397 MSTB, a primary recovery factor of 7.0%.

3. Waterflooding the proposed area with a partial inverted 9-spot waterflood pattern by converting wells 12-29-11-26 WPM, 10A-30-11-26 WPM and 4-32-11-26 WPM to water injection is the best waterflood configuration for the Pool and is forecast to result in an ultimate recovery (primary plus enhanced) of 1548 MSTB, a recovery factor of 27.3%. Some volumes of oil will also be recovered from the Lower Cherty zone in 14-29 and 3-32-11-26 WPM by injection into that zone in 12-29-11-26 WPM but waterfloodable volumes have not been rigorously analysed.

4. Cumulative oil recovery to 1988-05-31 is 231.6 MSTB for the proposed waterflood area. Approximately 1316 MSTB is yet to be recovered under the waterflooding scheme.

RESERVOIR STUDY
Virden Lodgepole "A" Area
Proposed Waterflood Area

History

Development of the northwest extenstion of the Virden Lodgepole "A" Pool by ICG Resources Ltd. began with the drilling of well 12-29-11-26 WPM in November, 1982. Since that time, ICG drilled 11 successful wells and 4 dry holes which have defined the limit of the productive area in this portion of the Lodgepole "A" Pool. In March, 1985, Tundra Oil & Gas drilled wells 6-29 and 11-29-11-26 WPM on the east edge of this area and in January, 1986 TransCanada Resources Limited drilled wells A11-30 and 14-30-11-26 WPM on the west edge of this area which completed current drilling activity.

Reservoir Geology

The North Virden pool is an extension to the northwest of the main Virden pool and it lies west of the Salt Collapse feature which occupies the east half of Section 29 and east half of Section 32, Twp 11, Rge 26 WPM. The Salt Collapse is due to solution of the underlying Devonian salt formations mainly of the Prairie Evaporites. The pool is basically a stratigraphic trap in the Mississippian and the limits are controlled by both structural nosing and a permeability barrier to the north and west where the Cherty Zone leached limestone has been dolomitized. This low permeability "halo" or barrier has variable production characteristics but is marked by higher interstitial water saturation, hence it produces mainly water. Wells in which the Lodgepole formation is structurally high generally show the effect of post-Lodgepole movement which resulted in a fracture system that might be filled with anhydrite in some places.

The main producing zone is the Cherty Zone of the Scallion Member which is predominantly a finely crystalline Cherty limestone. This zone has been leached over the entire pool increasing the permeability and porosity and destroying much of the structural and textural features of the original rock. The leaching by ground waters, during an erosion period, has taken place regionally over much of the Lodgepole Formation, but the most noticeable effect is in the Cherty Zone of the Virden Scallion Field.

Overlying the Cherty Zone is the Lower Virden Member which consists mainly of oolitic limestone interbedded with argillaceous limestone or calcareous shales. These oolite lenses are cyclic in nature. The lower oolitic or fragmental zone generally blends into the Cherty Zone and within this study has been included as part of the pay zone if it meets the porosity and resistivity cut offs. Overlying the Lower Virden Member is the Upper Virden bioclastic limestone with Crinoidal debris forming the Crinoidal Zone.

The Cherty Zone itself, in some parts of the project area, has both an upper and lower productive interval, however, the Upper Cherty zone is the major zone and is present in all project area wells. Wells 12-29, 14-29 and 3-32-11-26 WPM do have the Lower Cherty zone present as well, and it is producing in wells 14-29 and 3-32-11-26 WPM.

Reservoir Characteristics

The reservoir structure on top of the Cherty zone porosity is shown in Figure 2. The reservoir dips to the southwest and becomes water-bearing in that direction.

Figure 3 is a net oil pay map for the Upper Cherty zone which is the main zone of interest in this study. Net pay was determined utilizing a computer generated (Logmate) crossplot analysis of the neutron and density wellbore logs using a 13% crossplot porosity cutoff. The pays calculated by this procedure most closely compared to pays generated using a 10% porosity cutoff and a 0.1 md permeability cutoff on the two cored wells in the project, 6-29 and 3-32-11-26 WPM.

An average water saturation of 35% has been used in the determination of reserves in place. Water saturation calculations from logs are suspect due to the inability of the resistivity logs to read the available lithologies and saturations due to the thin bedded nature of the rock types within the induction spacing. The value of 35% chosen compares with values used by Chevron in the North Virden Scallion Unit No. 1 to the east obtained from oil based cores.

Recoverable Reserves

The orginial oil in place in the proposed waterflood area of 6578 MSTB was determined by planimetering the pore volume map, Figure 4, using an average water saturation of 35%, and using an initial formation volume factor of 1.045 Reservoir BBL/STB. The formation volume factor was obtained from the original reservor study the Chevron Canada Resources Limited performed on the portion of the Virden Lodgepole "A" Pool which became the North Virden Scallion Unit No. 1.

Primary recovery is expected to be in the order of 7 percent by declining current production trends, or 297 MSTB. Appendix 1 shows the historical production characteristics of the 14 wells in the proposed waterflood area. Cumulative production to May 31, 1988 was 231.6 MSTB. The rapid initial decline of the wells productivity under primary depletion is typical of the Lodgepole "A" Pool and indicative of a declining reservoir pressure. Only DST pressures are available from the proposed waterflood area wells, but pressures on wells drilled late in 1983 show shut-in pressures as low as 850 psig compared to the original pressure of about 910 psig.

The study of an enchanced recovery scheme for this northwest extension area was based upon the original work done by Chevron in the North Virden Scallion Unit No. 1 in a reservoir study dated August 1961. The area chosen for the proposed waterflood is limited to the area which has been developed since late 1982 excluding the Ranchmen's well A11-30 and 14-30-11-67 WPM to the west. Twelve of these wells were drilled by ICG Resources Ltd. and two were drilled in 1985 by Tundra Oil & Gas.

It will be necessary to convert three of the fourteen wells to water injectors to maintain voidage and achieve an effective sweep of the proposed waterflood area. Wells 12-29-11-26 WPM, 10A-30-11-26 WPM and 4-32-11-26 WPM have been chosen as the wells to be converted for water injection which will result in

Recoverable Reserves (continued)

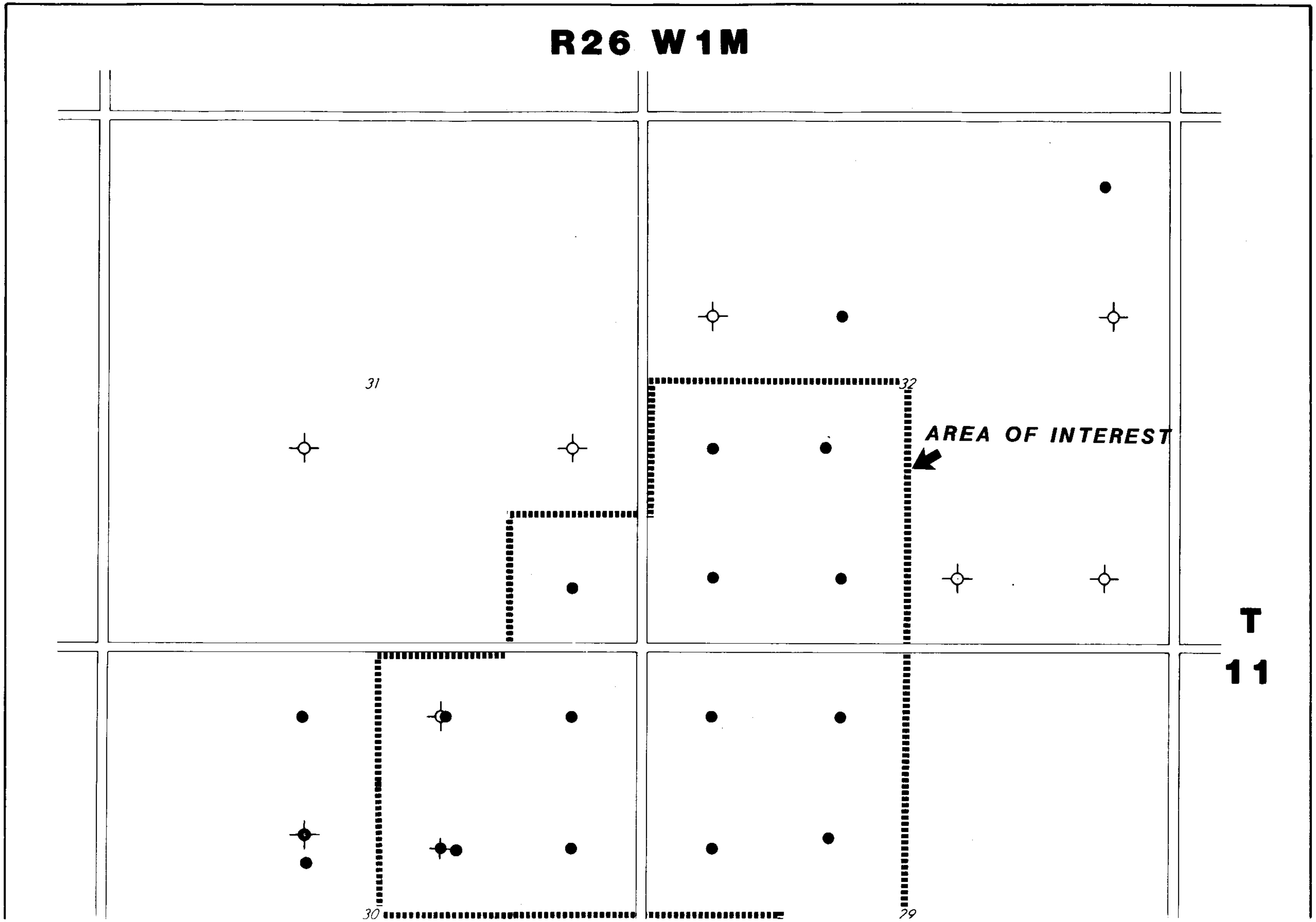
three partial inverted 9-spot patterns, similar to the pattern configuration of the Unit No. 1 flood scheme. The current production perforated intervals would be utilized in wells 10A-30 and 4-32-11-26 WPM for water injection purposes. Perforations, however, would be added to the Lower Cherty zone in 12-29-11-26 WPM to also effectively sweep the hydrocarbon reserves in that zone to the producing wells 14-29 and 3-32-11-26 WPM. It is planned to overinject for the first three years at a voidage replacement rate of about 1.10 - 1.15 and then replace voidage for the rest of the waterflood at a ratio of 1.05 - 1.10.

The wells to the south of the project area, operated by Dome Petroleum Limited, have not been included into the flood scheme due to the advanced stage of depletion exhibited by those wells which have been producing since the early to mid-1960's. The Ranchmen's Resources Ltd. wells A11-30 and 14-30-11-26 WPM were drilled in early 1986 but are on the downdip edge of the reservior. As can be seen from their production plots in Appendix 1, the producing water-oil-ratio of A11-30-11-26 WPM is currently at 3 BBL/BBL and that of 14-30-11-26 WPM is over 1 BBL/BBL. It is questionable what value these wells would have in the waterflood project, but well 10A-30-11-26 WPM, offsetting these wells may result in positive flood response. If that is the case, it is recommended that these wells be considered for inclusion into the waterflood project and unit a year after water injection commences.

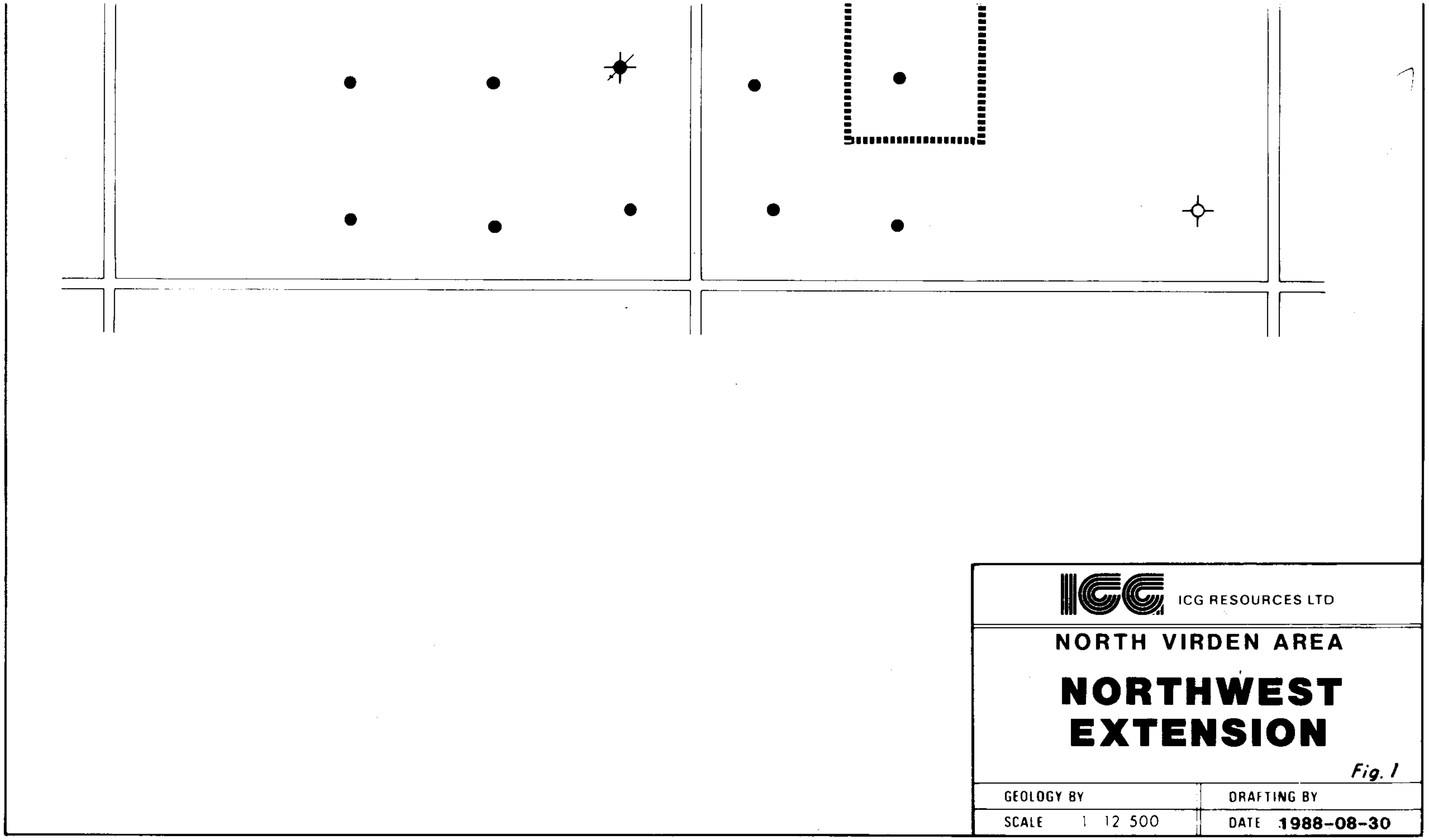
The waterflood is forecast to recover 33 percent (total primary plus waterflood) of the original oil in place of the sweepable enclosed area. Because the injection patterns are not totally enclosed, oil on the pool edges is not swept by the waterflood. It was assumed that the recoverable reserves from these edges would be based on a primary recovery factor of 7 percent. Figure 4 shows the area that will be effectively waterflooded.

With these assumptions, the overall primary plus waterflood recovery factor for the proposed waterflood area in the Upper Cherty zone only, is 27.3 percent of the original oil in place. This is a total recoverable reserve of 1548 MSTB. The Chevron study estimated an overall recovery factor of 28.4 percent for the Unit No. 1 waterflood. An analysis of the Unit's production history indicates that the ultimate recovery should be above 33 percent so the recovery factor being used in this evaluation are felt to be realistic.

Figure 5 shows a forecast of the proposed waterflood's production performance. This assumes an on injection date of January 1, 1989. Peak production rates of 300 BOPD are forecast in 1990. Figure 6 shows the water injection forecast. Injection rates commence at 300 BWPD and should be a maximum of almost 650 BWPD in 1991. The maximum make-up water required is forecast to be 350 BWPD. Chevron Canada Resources Limited has indicated that they have sufficient produced water from the Scallion Member in the North Virden Scallion Unit No. 1 to satisfy our flood requirements.



R26 W1M
31
32
AREA OF INTEREST
T
11
30
29



ICG RESOURCES LTD

NORTH VIRDEN AREA

NORTHWEST EXTENSION

Fig. 1

GEOLOGY BY	DRAFTING BY
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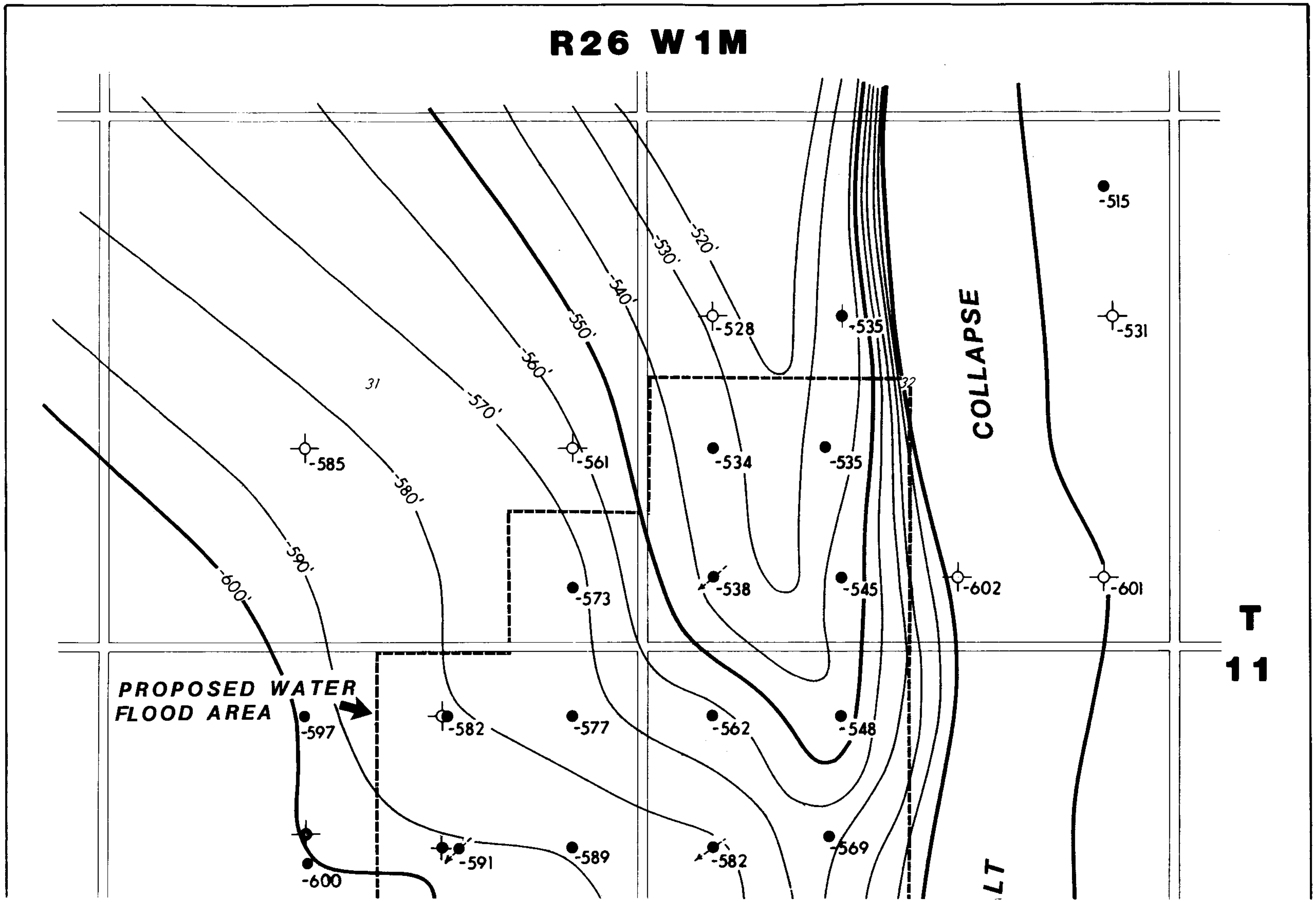
R26 W1M
T
11
COLLAPSE
LT
PROPOSED WATER
FLOOD AREA
-520'
-530'
-540'
-550'
-560'
-570'
-580'
-590'
-600'
31
32
-515
-531
-528
-535
-534
-535
-585
-561
-538
-545
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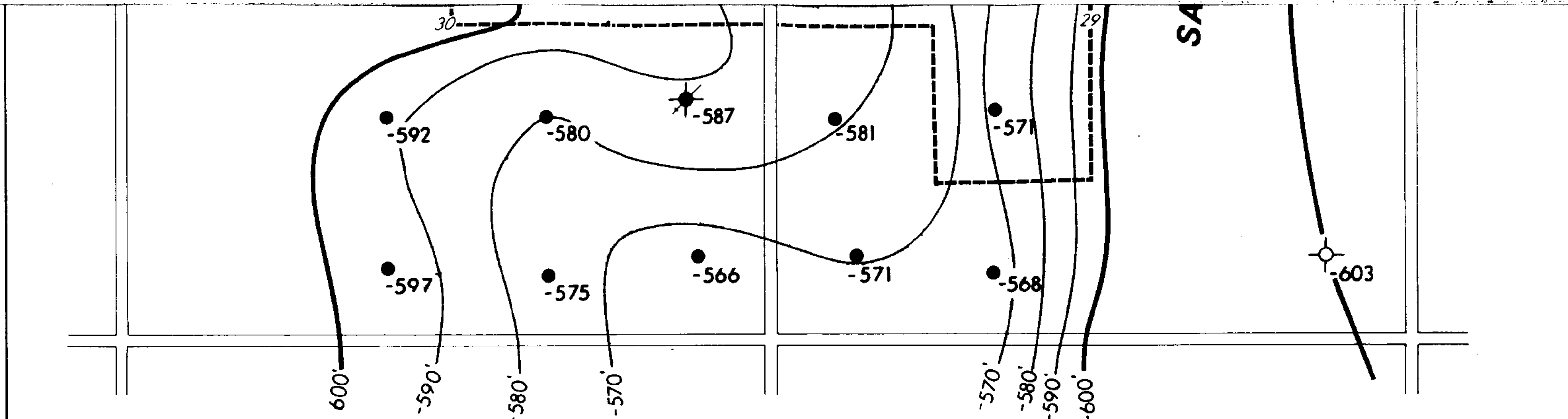
-589
-582
-569



PROPOSED WATER INJECTION WELL

ICG RESOURCES LTD.

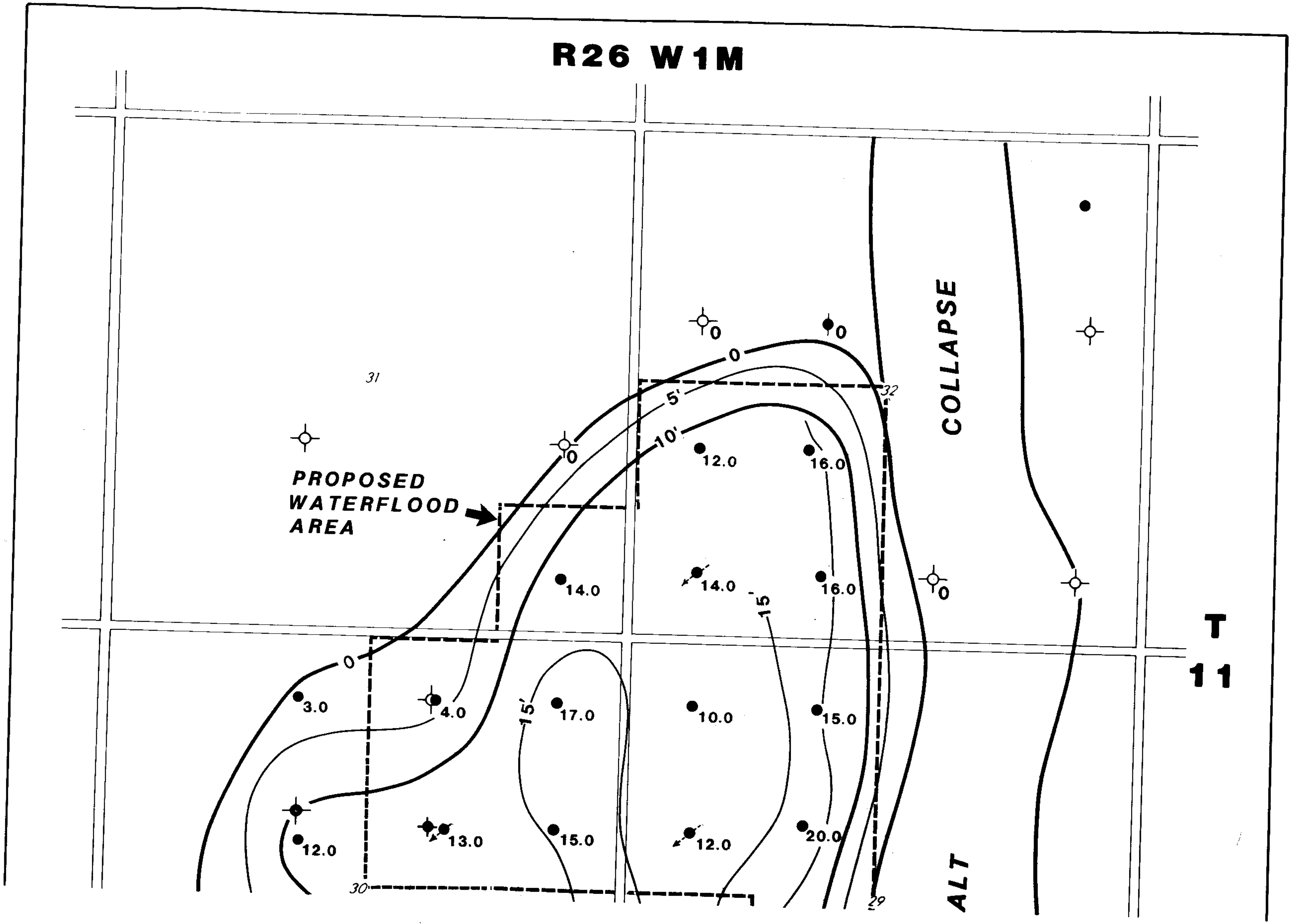
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL

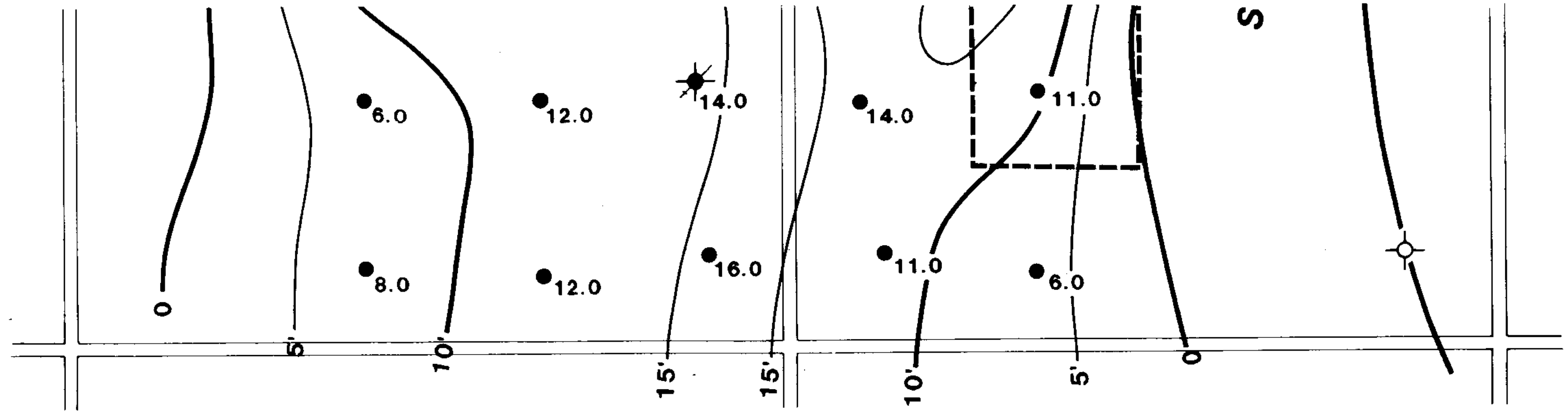
STRUCTURE CONTOUR MAP

C.I.=10'

Fig. 2

GEOLOGY BY M.Gobrial	DRAFTING BY F.F.
SCALE 1: 12,500	DATE 1988-08-30


R26 W1M
T 11
COLLAPSE
ALT
PROPOSED WATERFLOOD AREA
31
32
29
30
0
5'
10'
15'
12.0
16.0
14.0
3.0
4.0
17.0
10.0
15.0
13.0
20.0



PROPOSED WATER INJECTION WELL

ICG RESOURCES LTD.

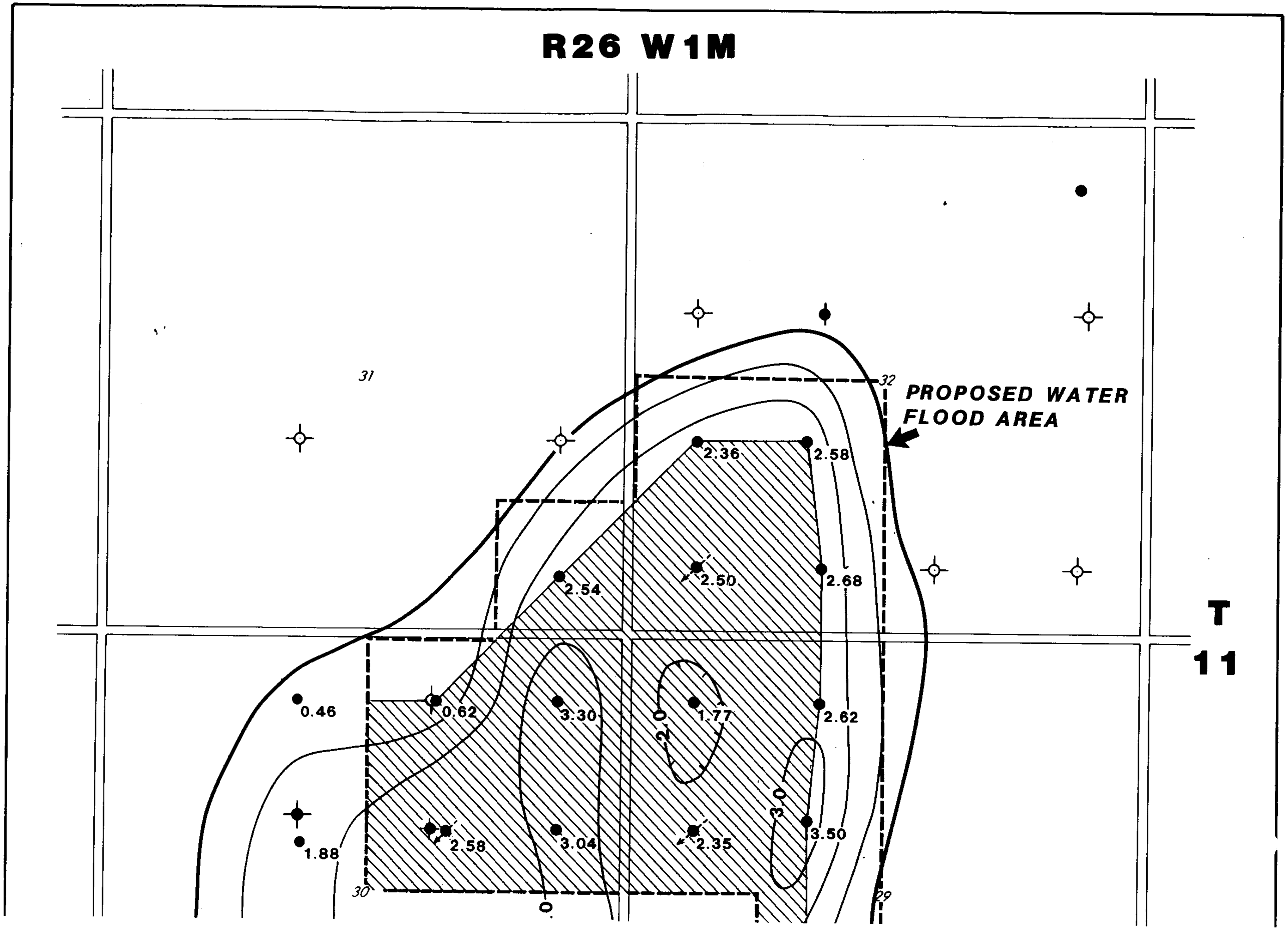
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL

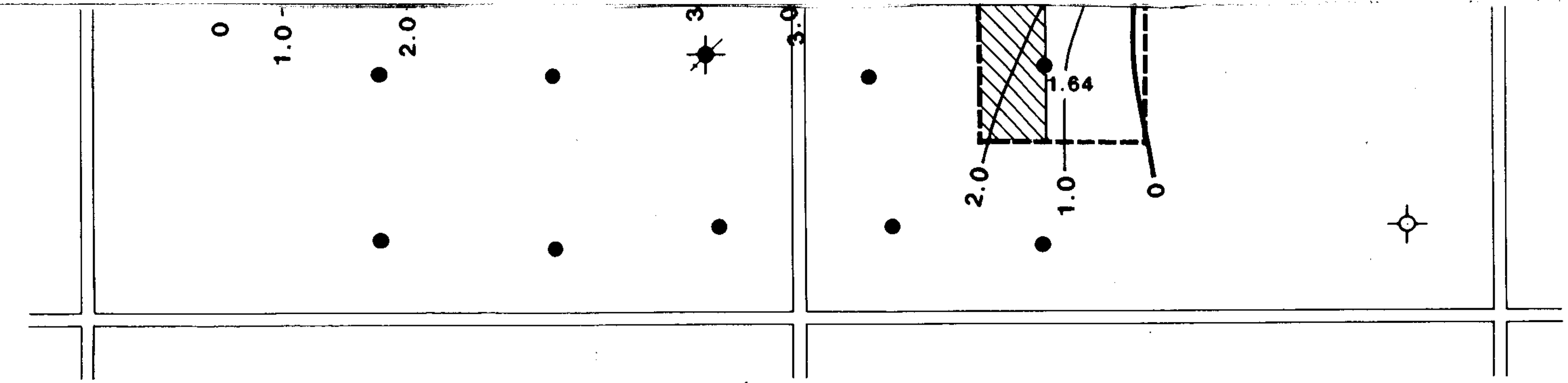
NET OIL PAY ISOPACH MAP

C.I.=5'

Fig. 3

GEOLOGY BY D. Bates	DRAFTING BY F.F
SCALE 1:12,500	DATE 1988-08-23


R26 W1M
T
11
PROPOSED WATER
FLOOD AREA
31
32
30
29
2.36
2.58
2.50
2.68
2.54
0.46
0.62
3.30
1.77
2.62
2.0
3.0
1.88
2.58
3.04
2.35
3.50
0



PROPOSED WATER INJECTION WELL

WATERFLOOD SWEPT AREA

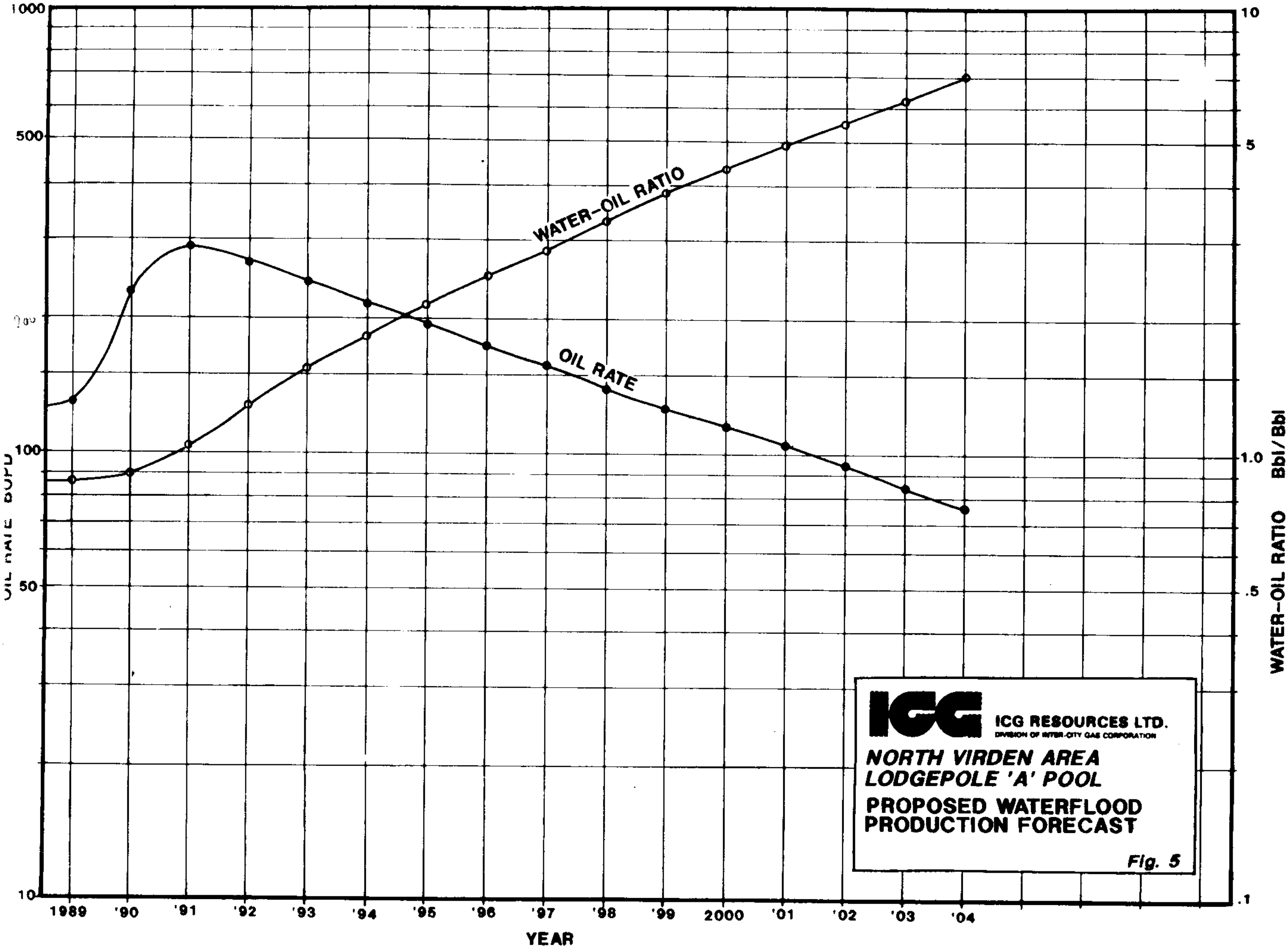
ICG RESOURCES LTD.
DIVISION OF INTER-CITY GAS CORPORATION

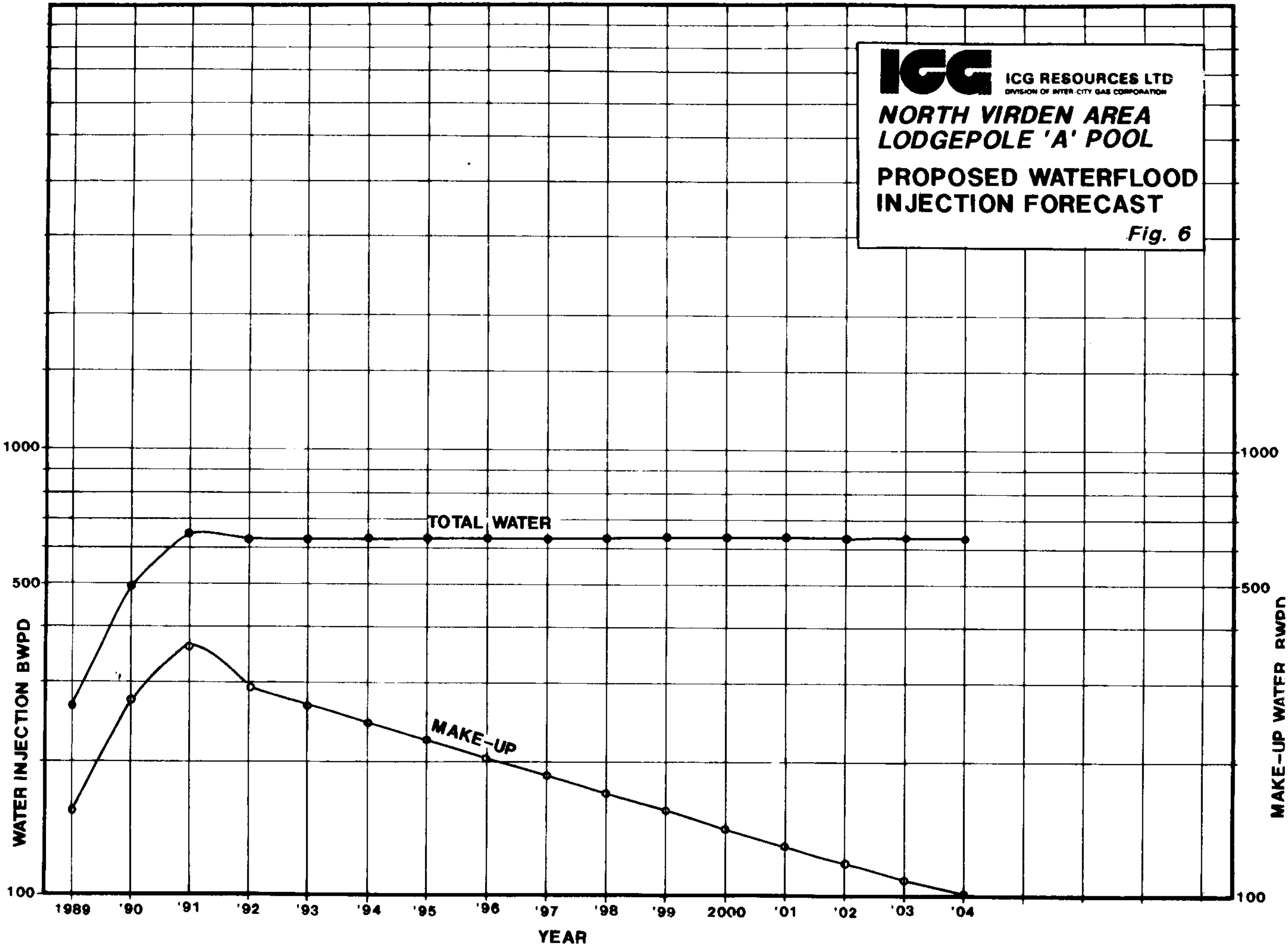
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL

PORE VOLUME MAP
Porosity Feet

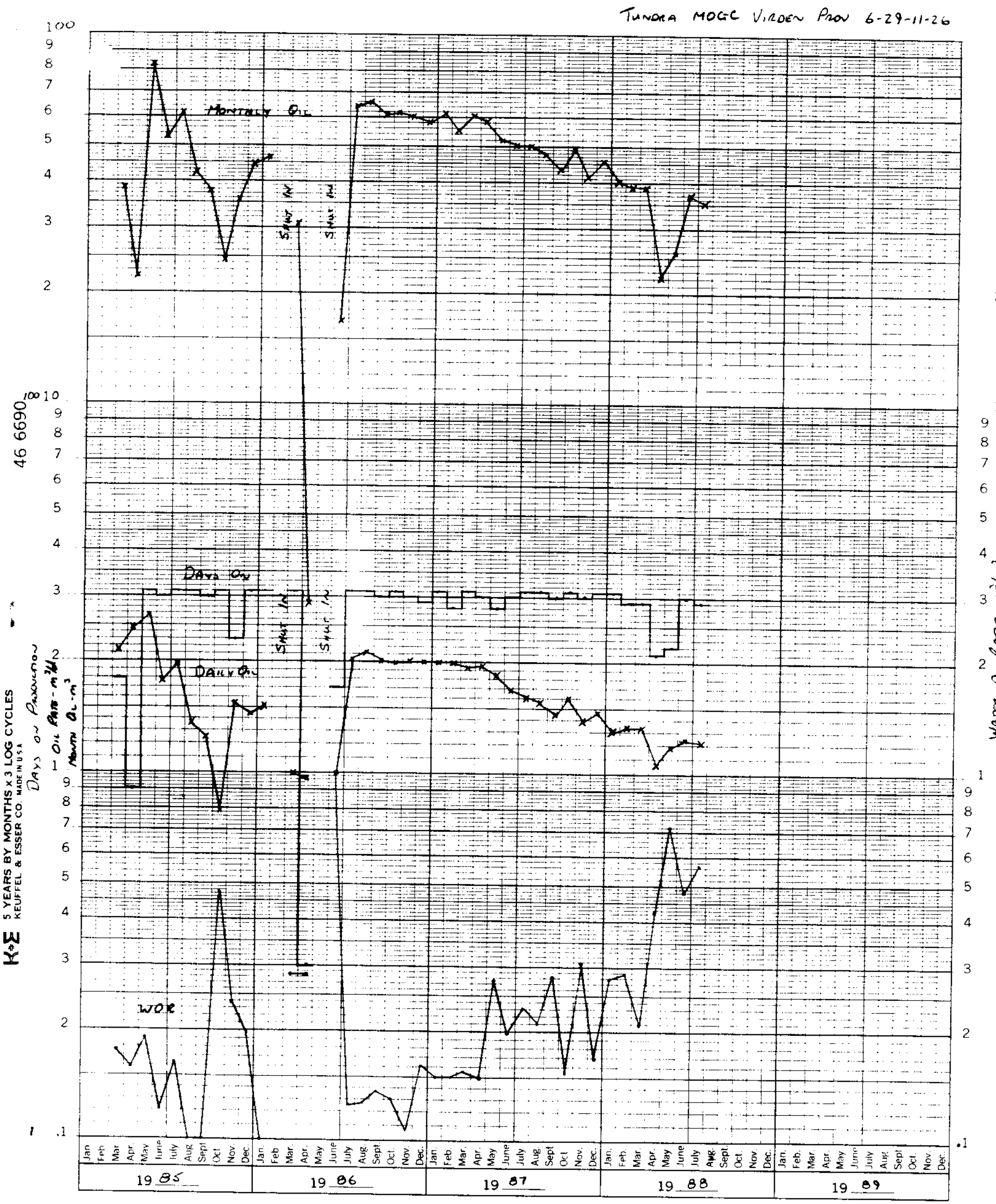
Fig. 4

GEOLOGY BY. D. Bates	DRAFTING BY. F.F.
SCALE. 1:12,500	DATE. 1988-08-23


OIL RATE BOPD
1000
500
200
100
50
10
WATER-OIL RATIO Bbl/Bbl
10
5
1.0
.5
.1
WATER-OIL RATIO
OIL RATE
1989
'90
'91
'92
'93
'94
'95
'96
'97
'98
'99
2000
'01
'02
'03
'04
YEAR
ICG RESOURCES LTD.
DIVISION OF INTER-CITY GAS CORPORATION
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL
PROPOSED WATERFLOOD
PRODUCTION FORECAST
Fig. 5

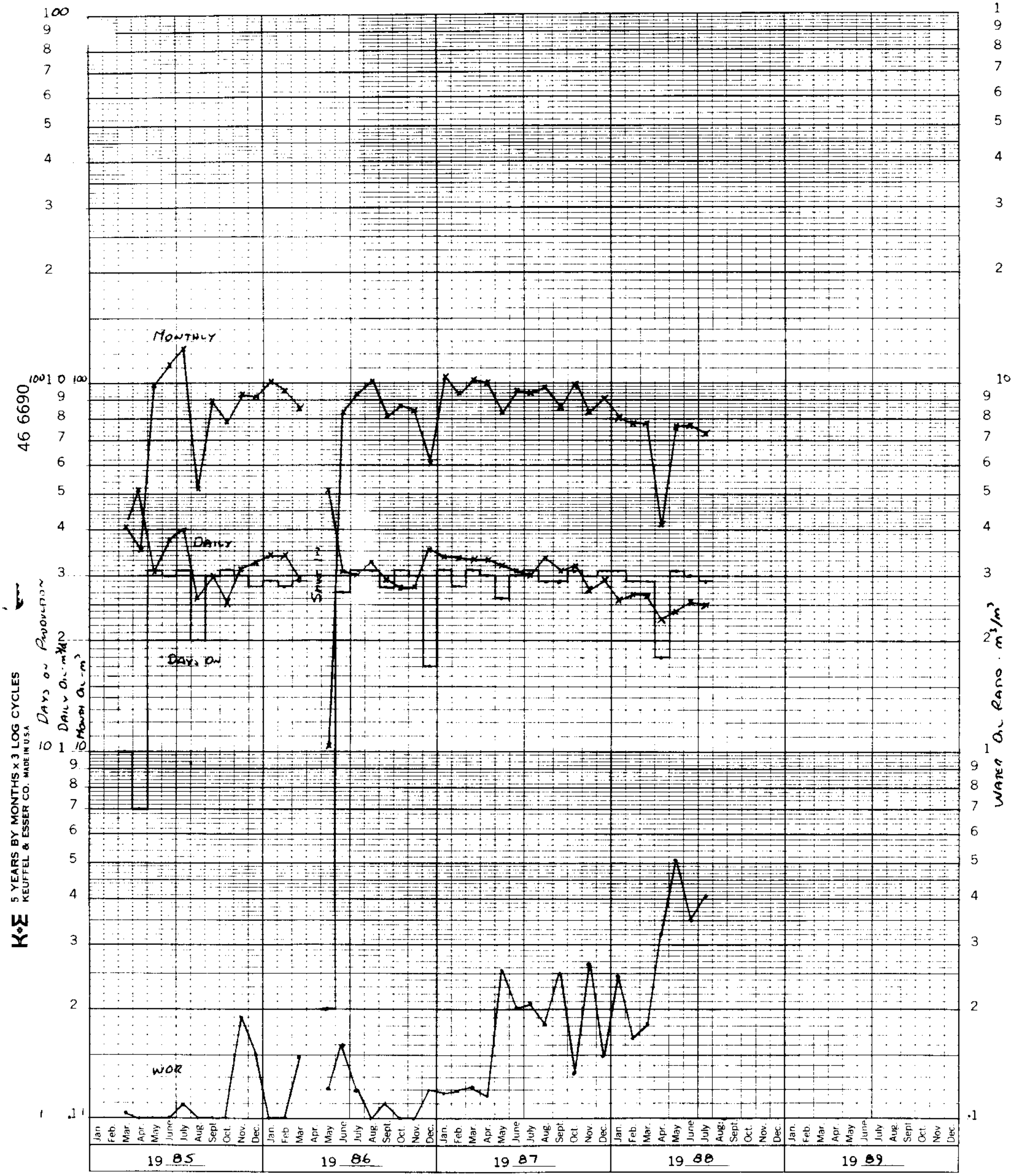

ICG
ICG RESOURCES LTD
DIVISION OF INTER-CITY GAS CORPORATION
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL
PROPOSED WATERFLOOD
INJECTION FORECAST
Fig. 6
TOTAL WATER
MAKE-UP
WATER INJECTION BWPD
MAKE-UP WATER BWPD
1000
500
100
1989
'90
'91
'92
'93
'94
'95
'96
'97
'98
'99
2000
'01
'02
'03
'04
YEAR

APPENDIX 1



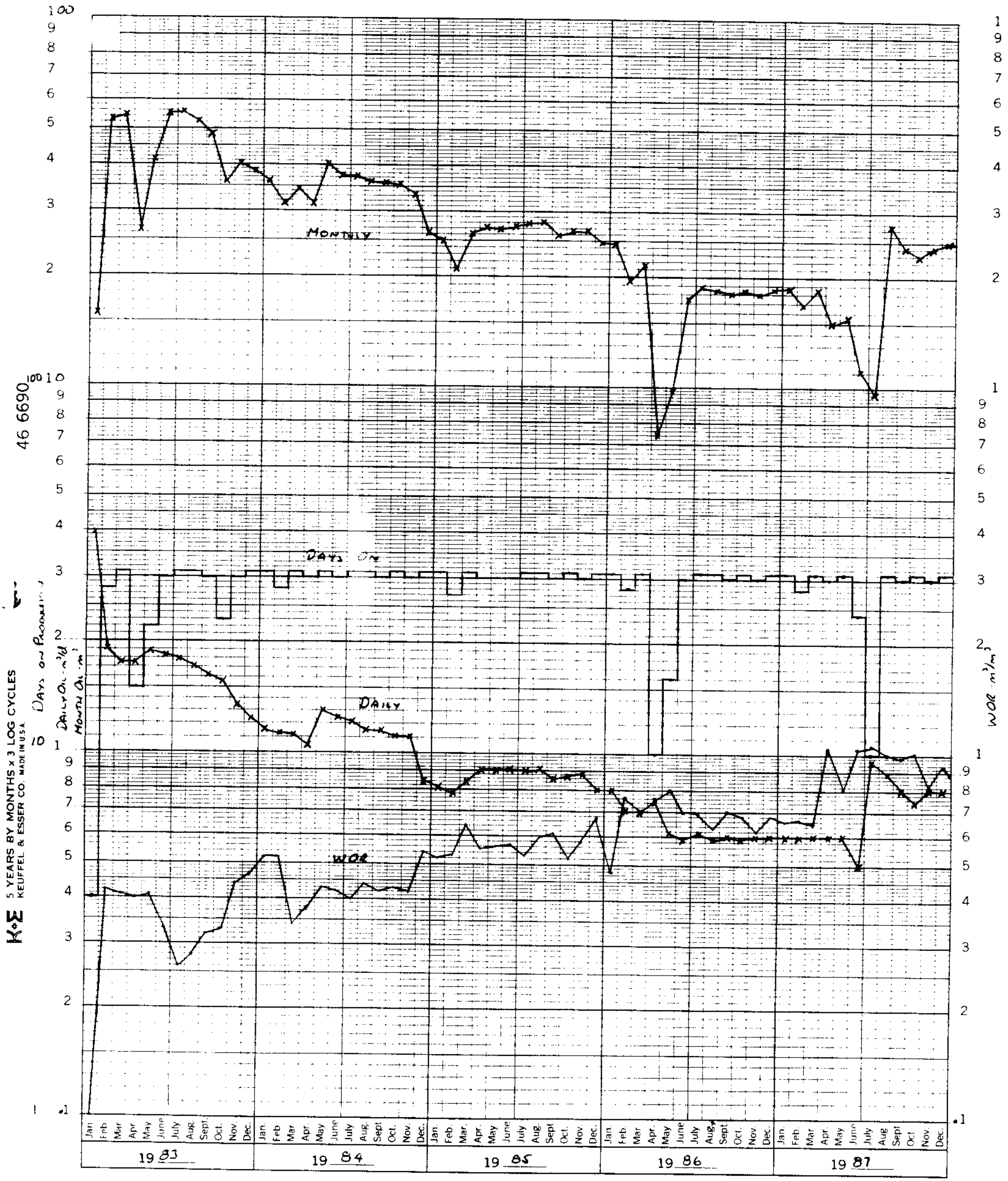
TUNDRA MOGC VIRDEN PROV 6-29-11-26
MONTHLY OIL
SHUT IN
SHUT IN
DAYS ON
DAILY OIL
WOR
DAYS ON PRODUCTION
OIL RATE - m3/d
MONTH OIL - m3
WATER - OIL RATIO m3/m3
46 6690
K&E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.
Jan. Feb. Mar. Apr. May June July Aug. Sept. Oct. Nov. Dec.
19 85
19 86
19 87
19 88
19 89

TUNDRA MOGC VIRDEN PROV 11-29-11-26



1

ICGR et al Scallion Prov 12-29-11-26



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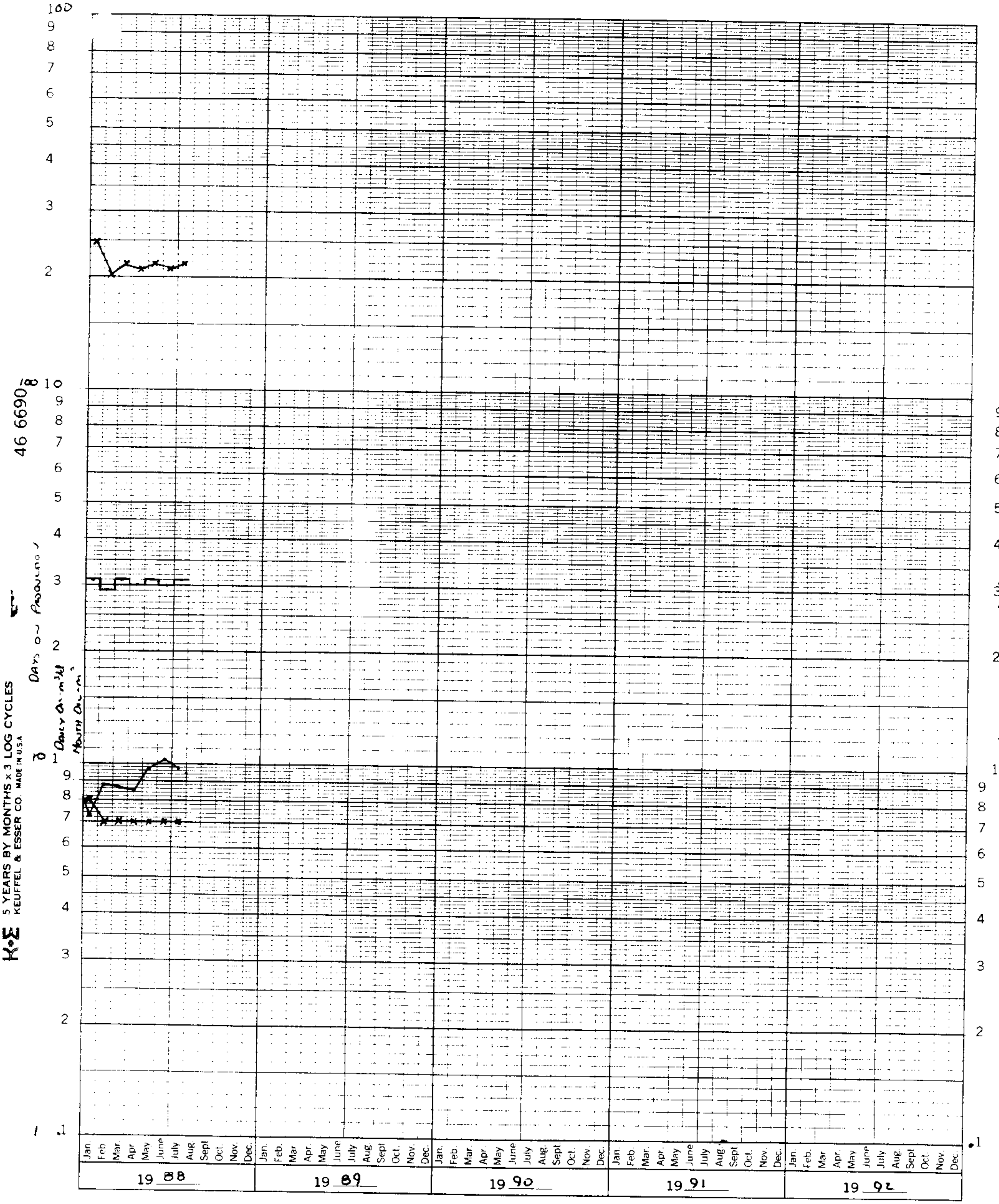
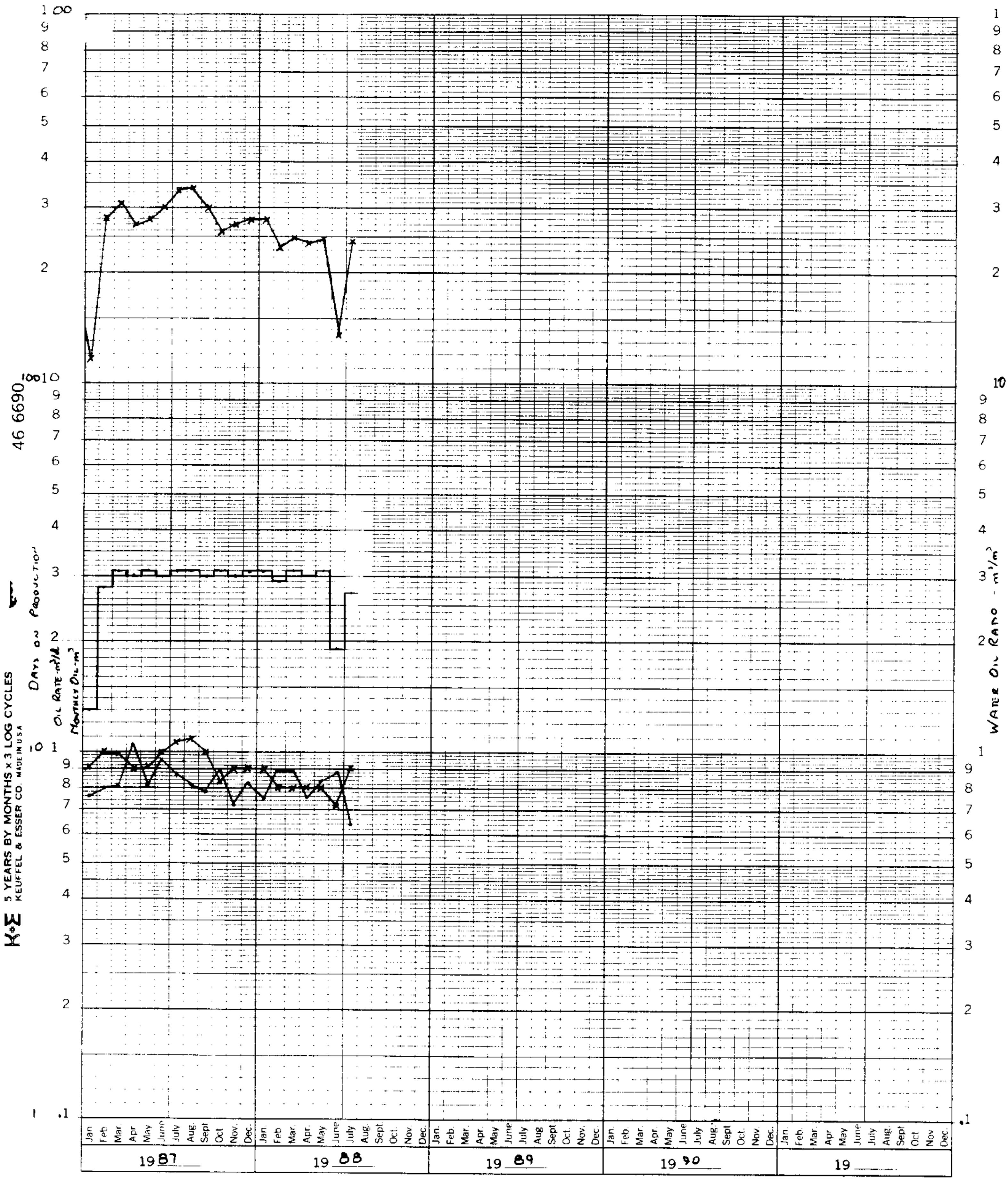


ICGR et al Scallion Prov 13-29-1

ICGR et al Scallion Prov
13-29-11-26

②



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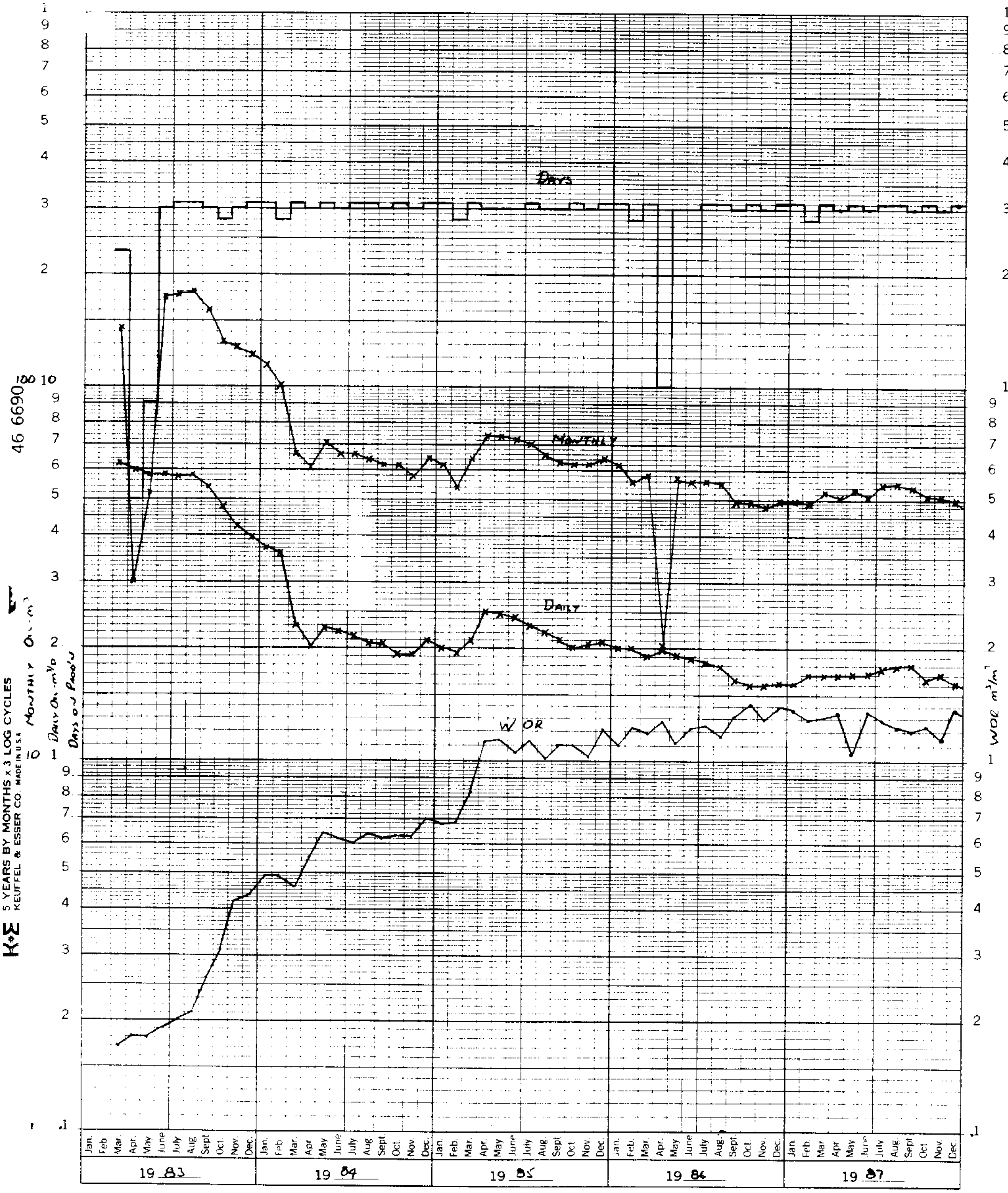

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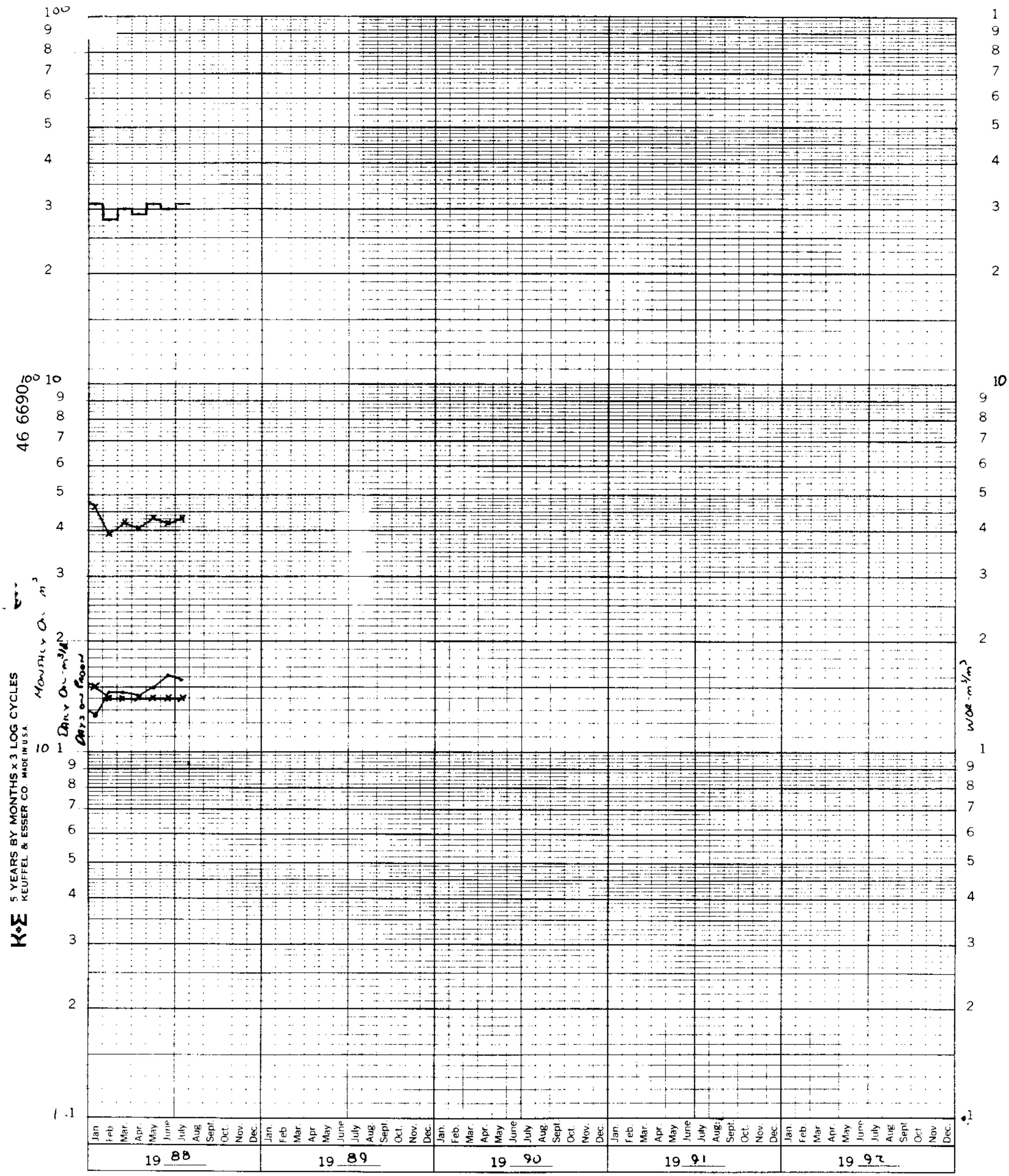

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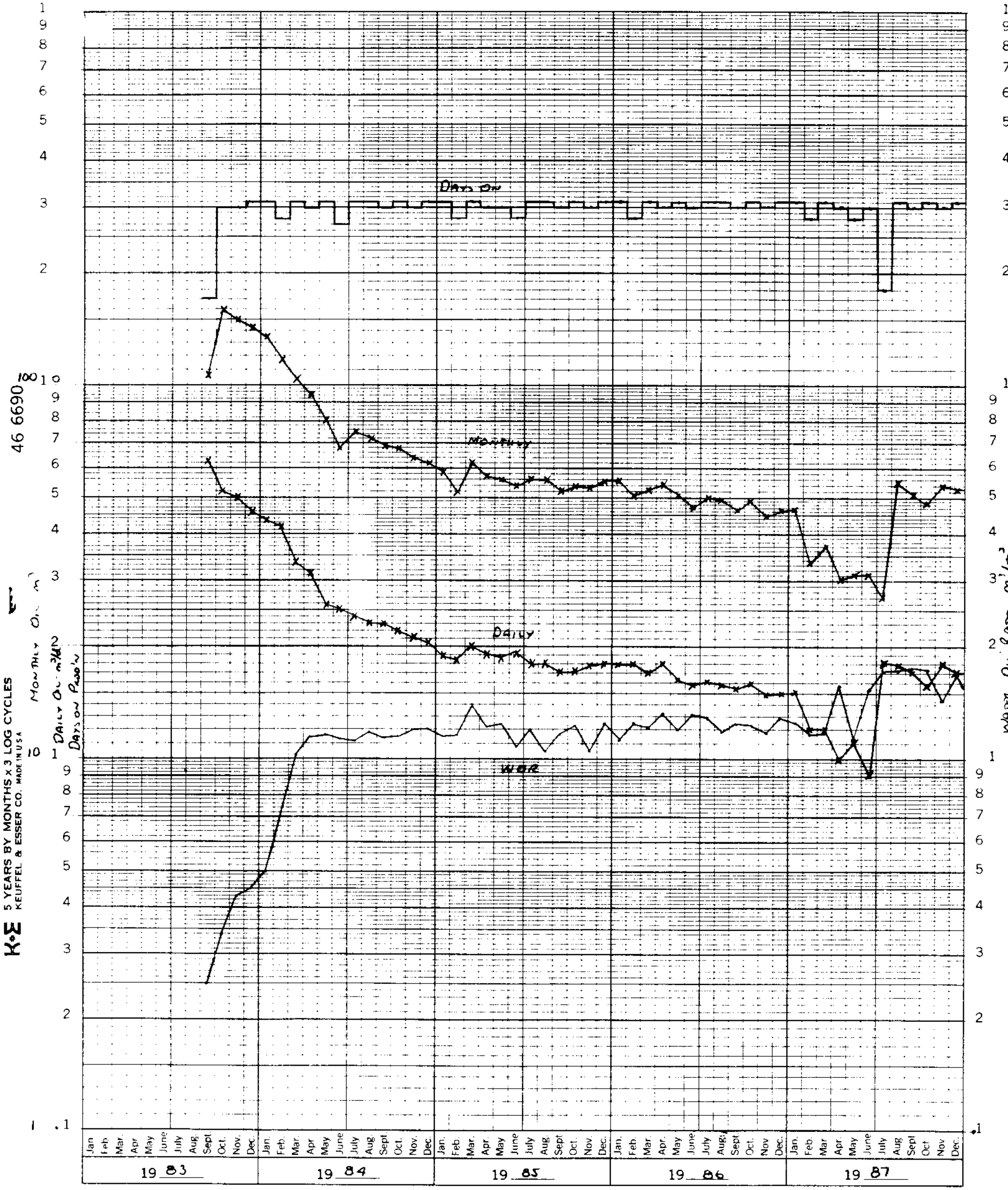
ICGR et al VIRDEN 9-30-11-26



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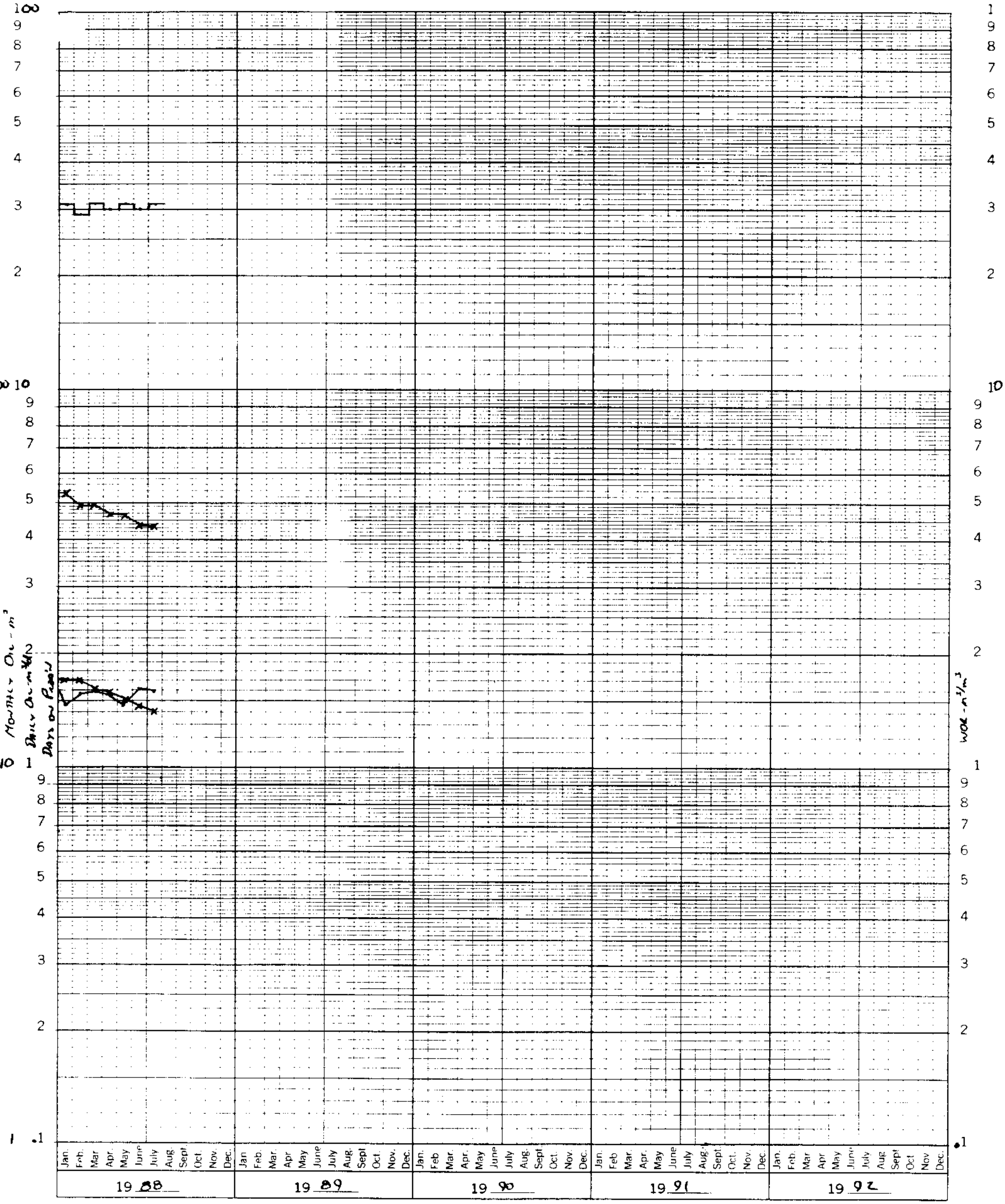
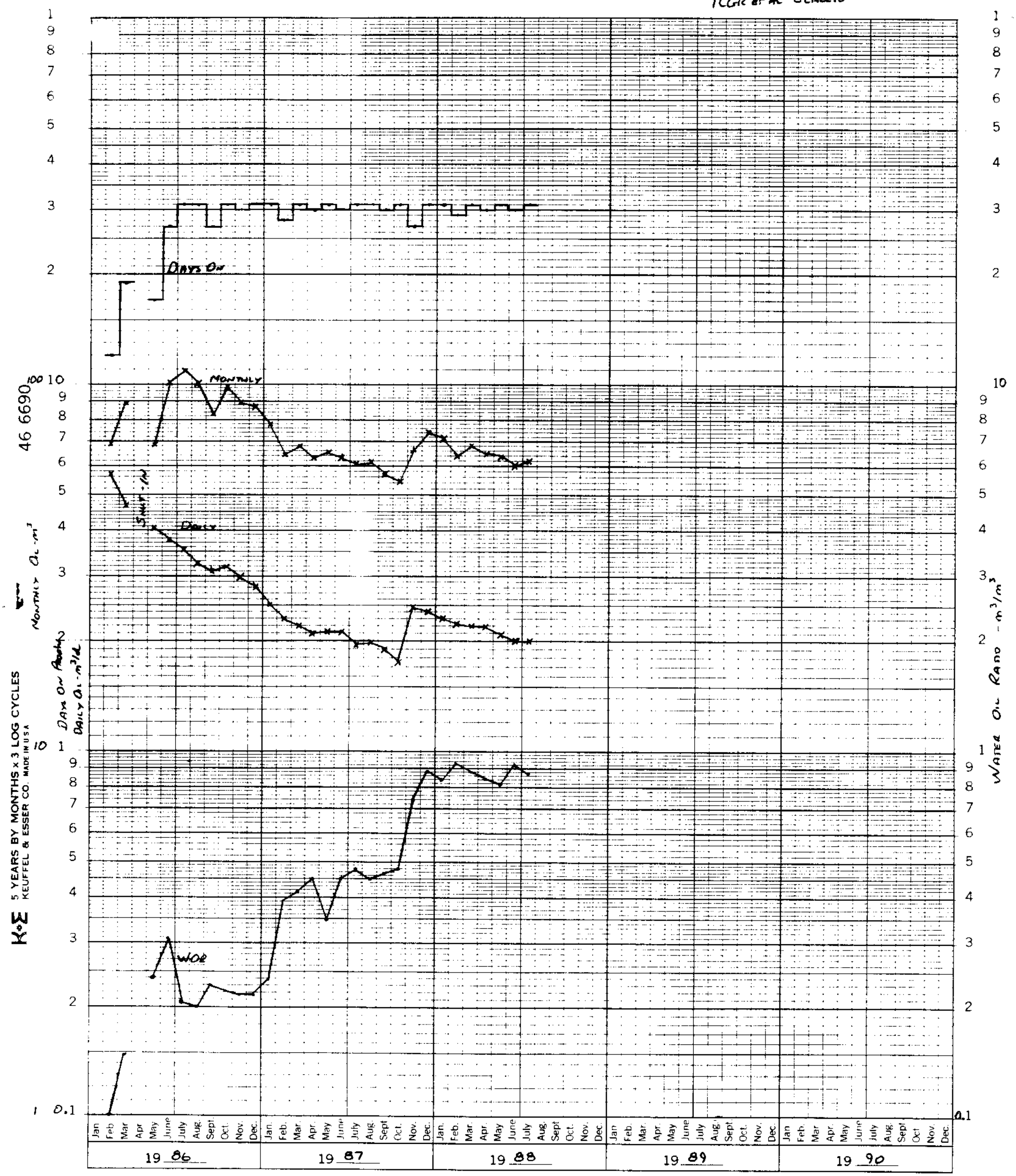
ICG R et al Virden 9-30-11-26

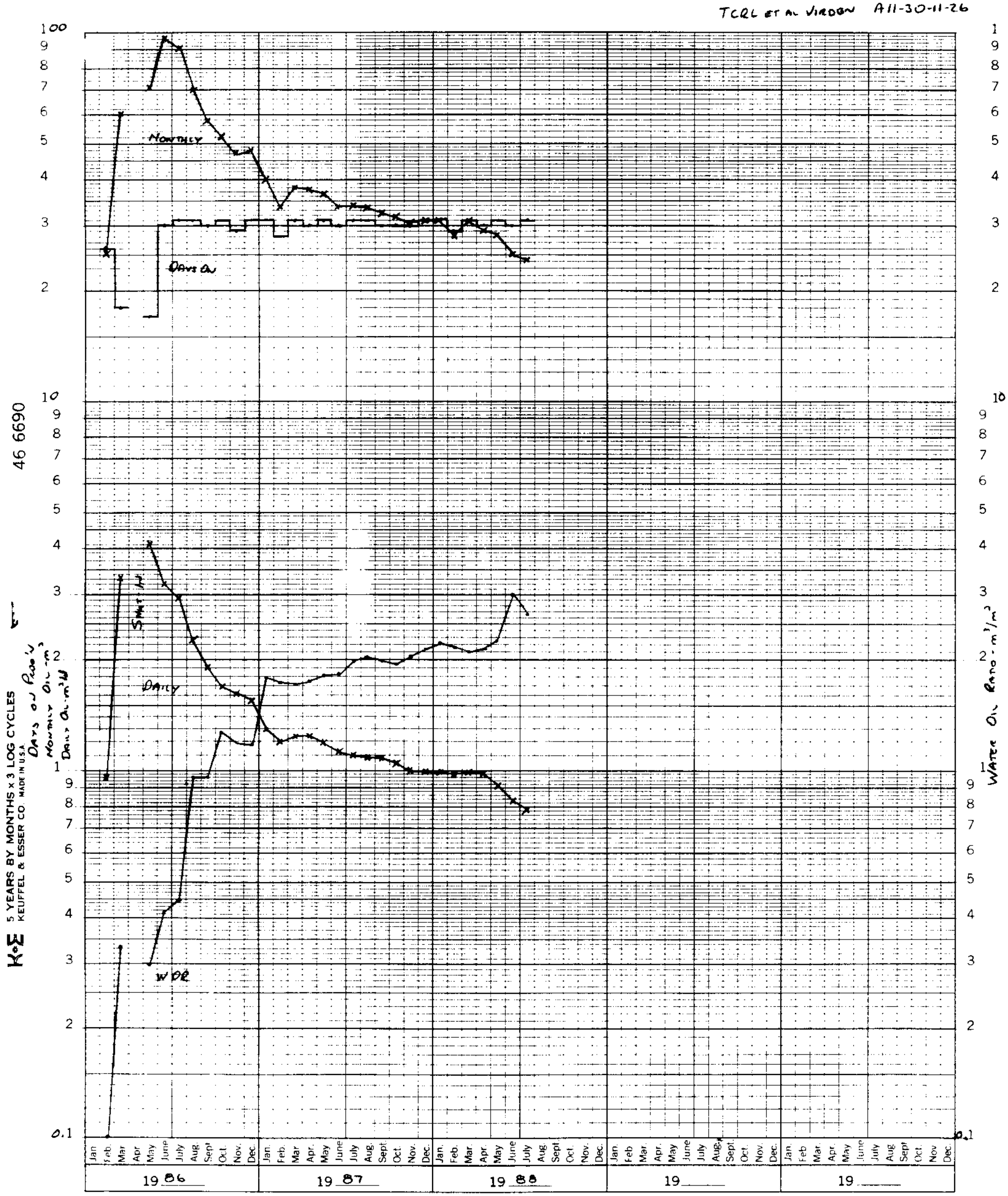


K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN USA

46 6690

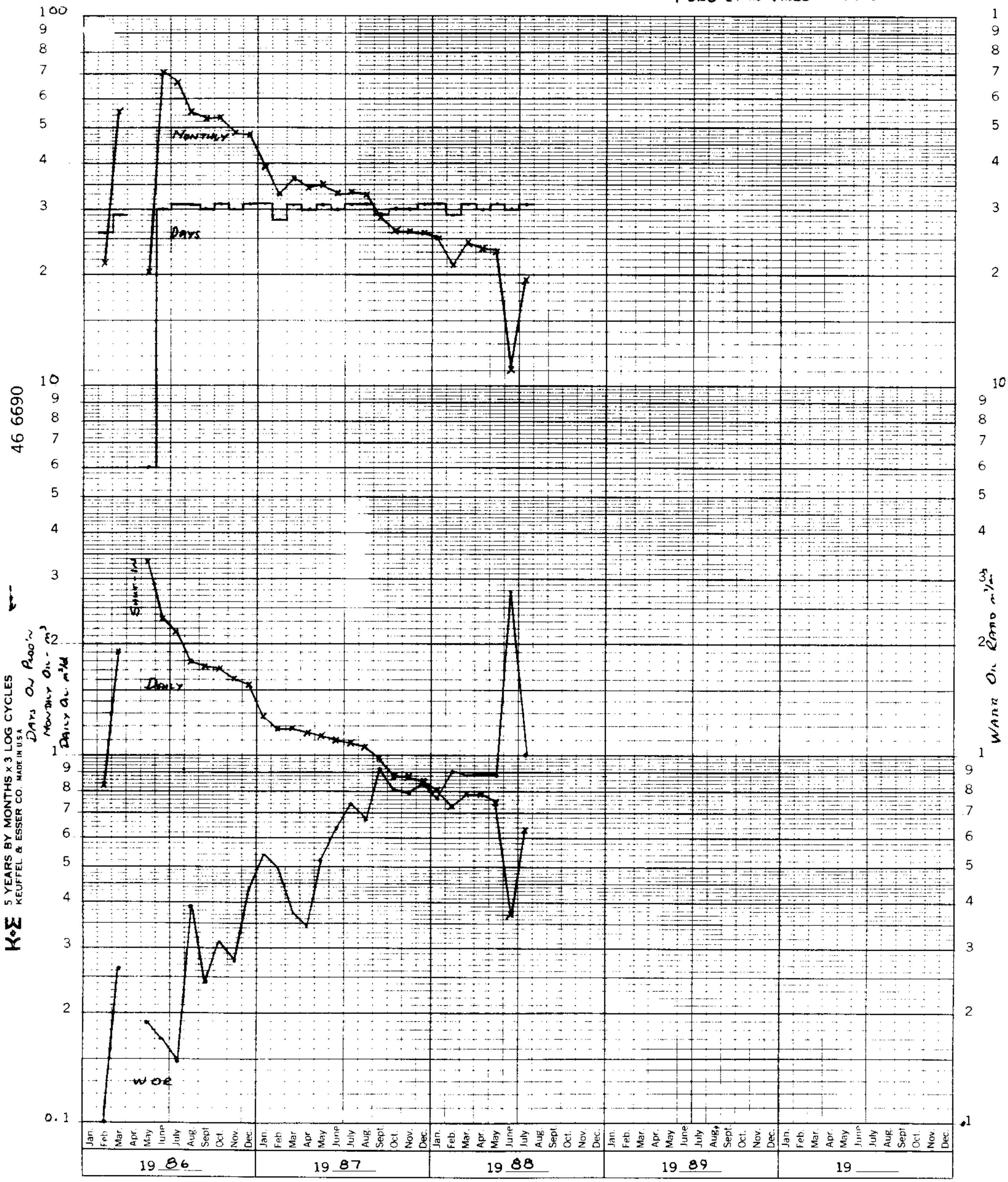
ICGR et al Scallion 10A-30-11-26





TCRL ET AL VIRDEN A11-30-11-26
MONTHLY
DAYS ON
DAILY
WOR
SHUT IN
DAYS ON PROD'N
MONTHLY OIL-m³
DAILY OIL-m³/d
WATER OIL RATIO - m³/m³
46 6690
K+E 5 YEARS BY MONTHS x 3 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.
1986
1987
1988
19
19

TCRL ET AL VIRDEN 14-30-11-26



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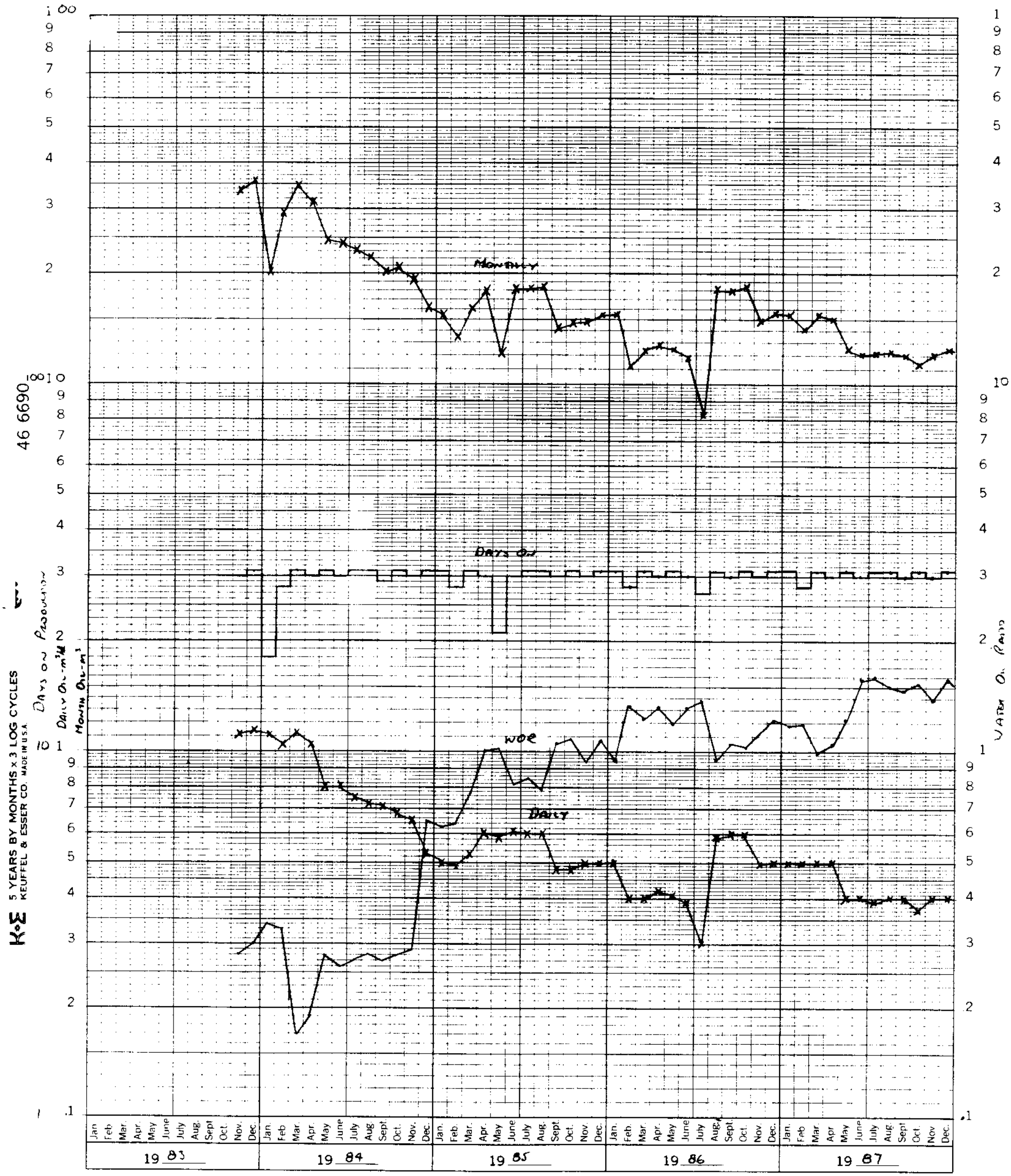
ICGR et al Virden A 15-30-11-26



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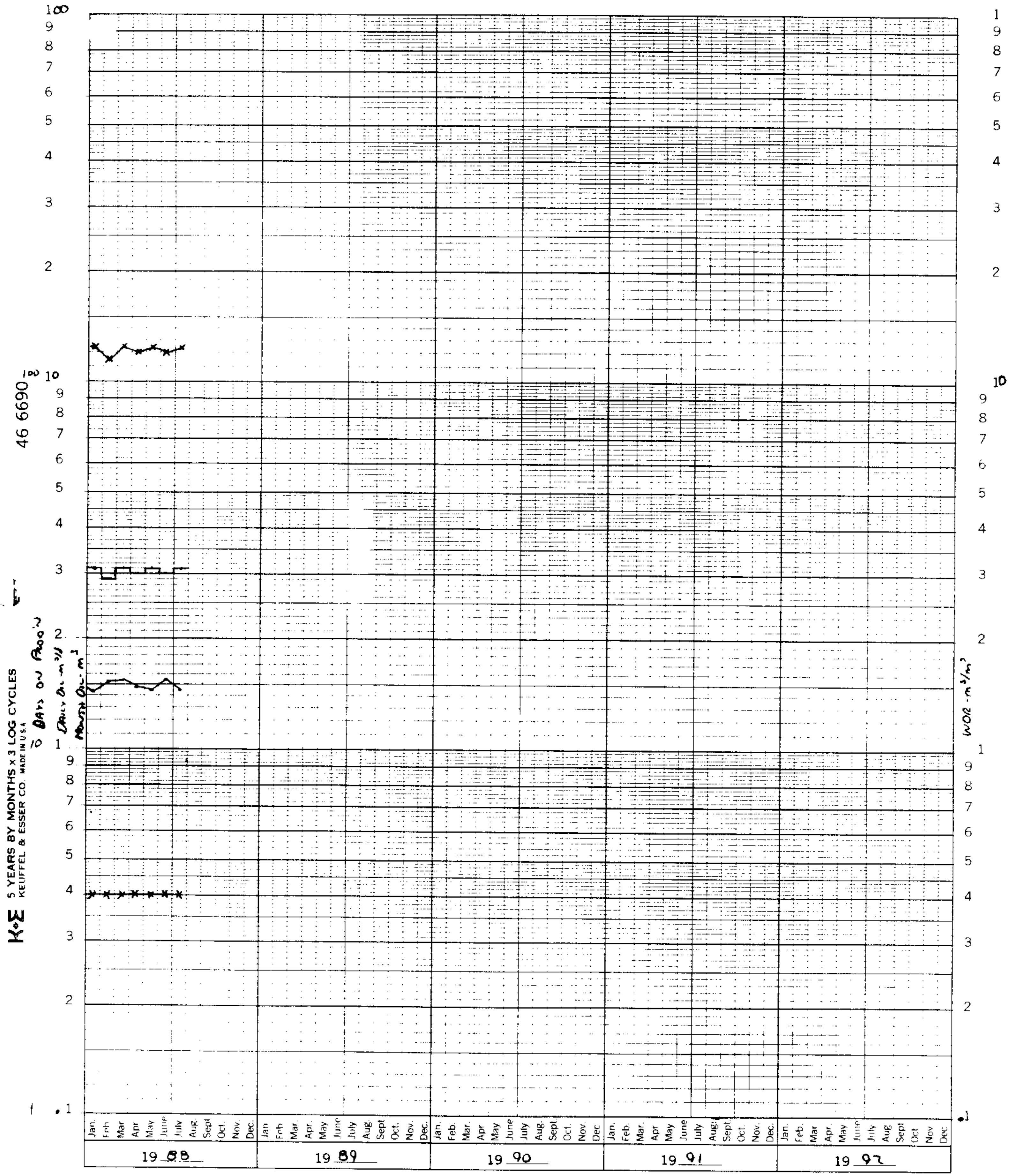
ICGR et al Virden A 15-30-11-26



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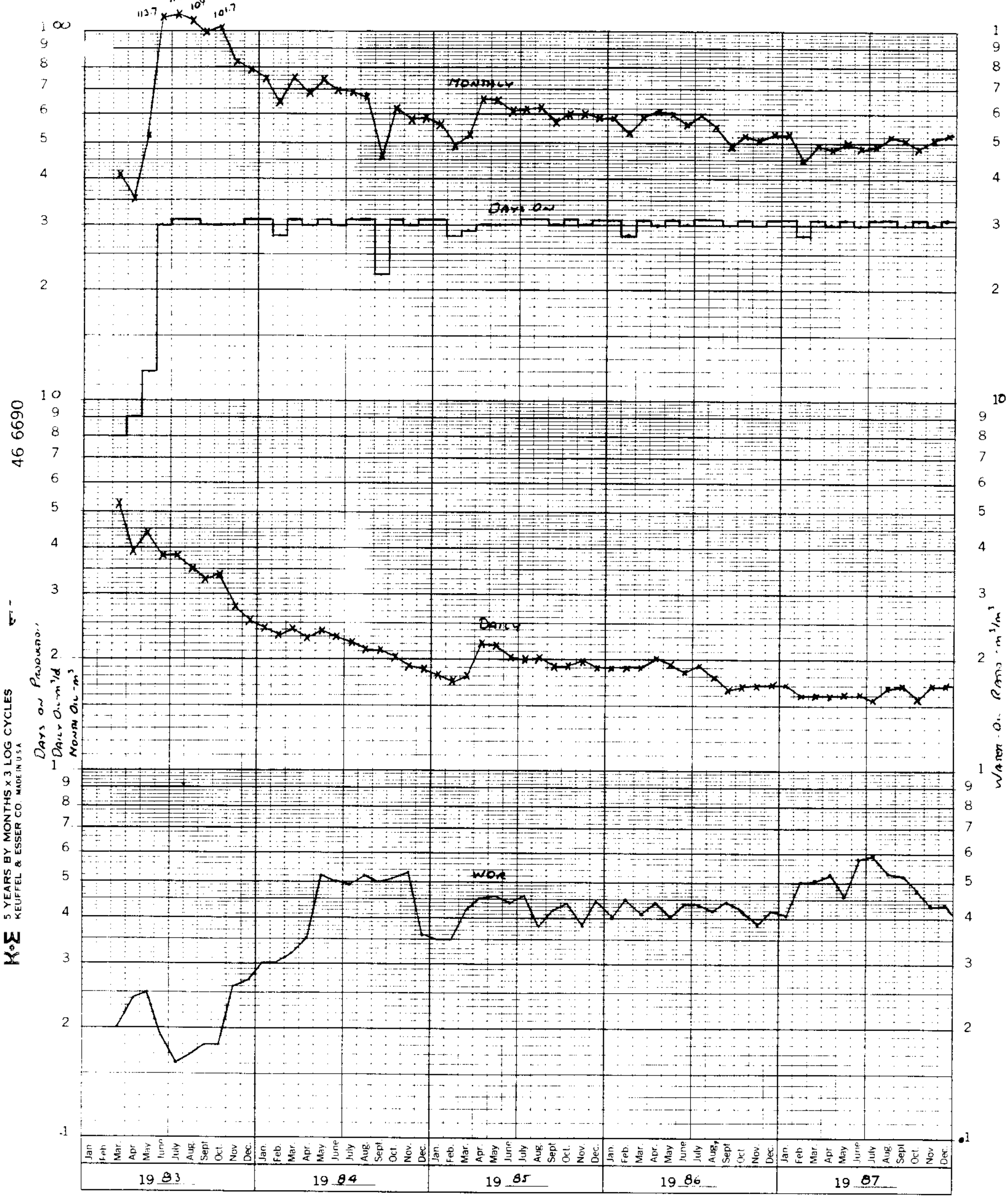
ICGR et al Scallion 16-30-11-26



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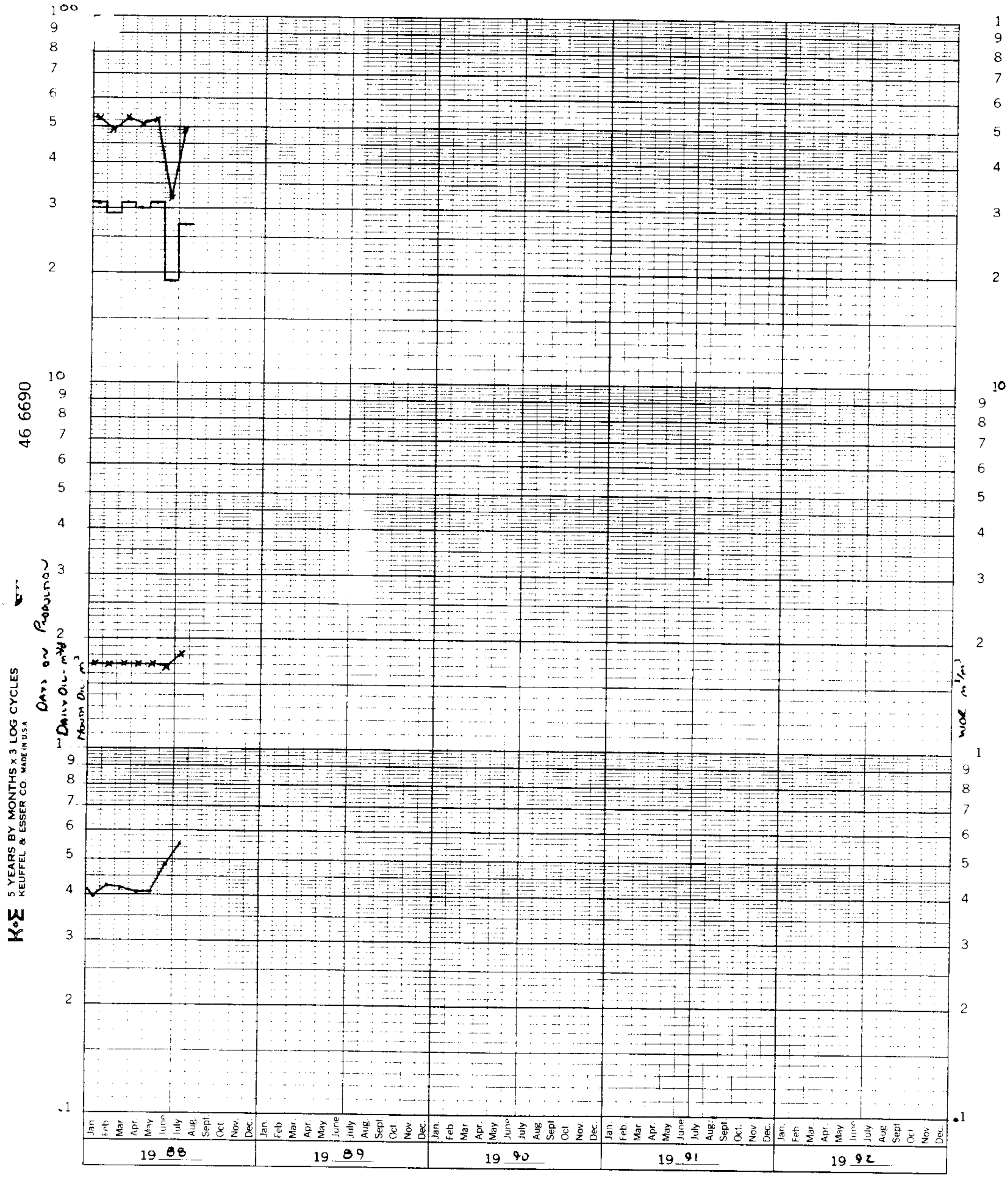
ICG R et al Scallion 16-30-11-26



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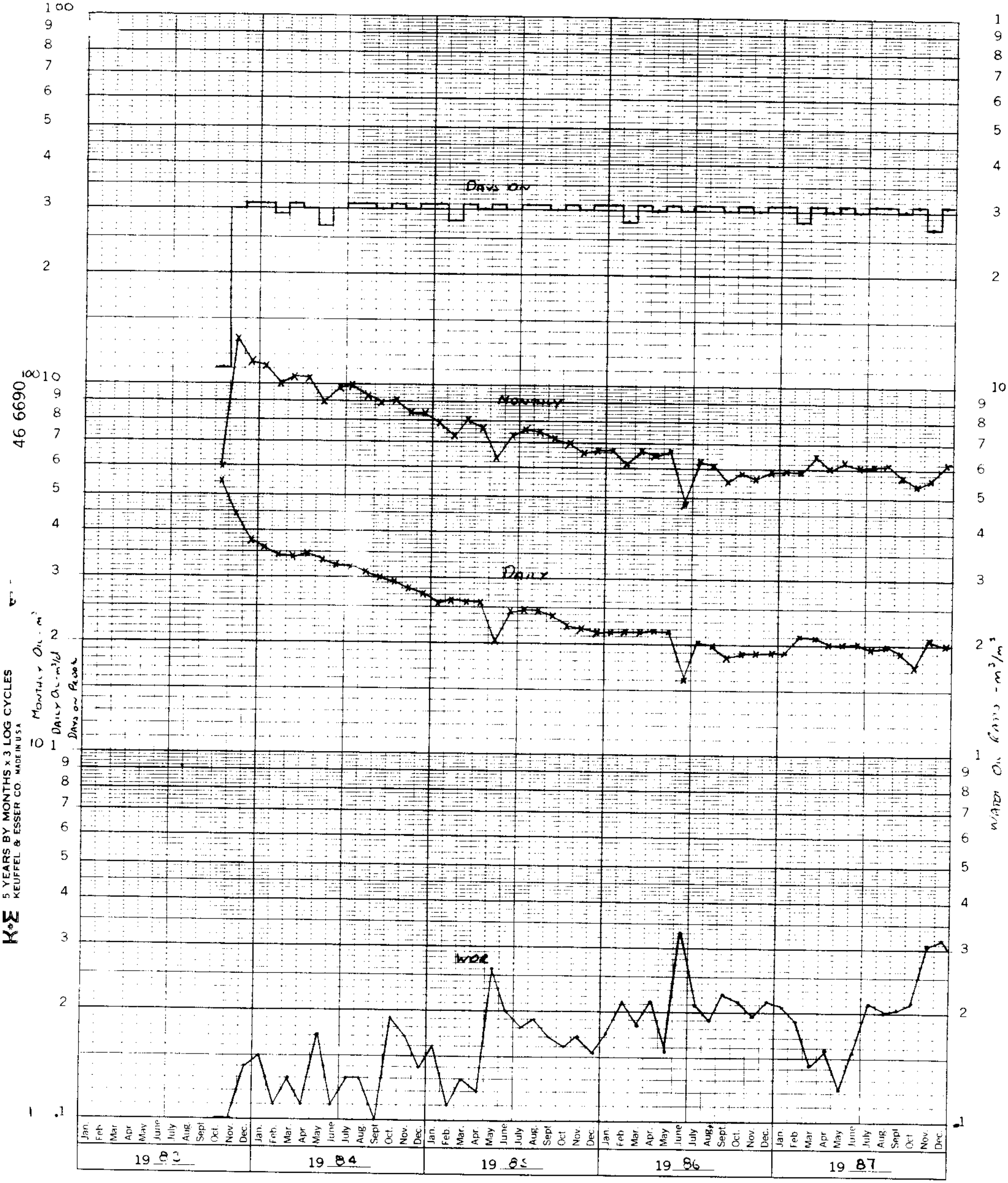

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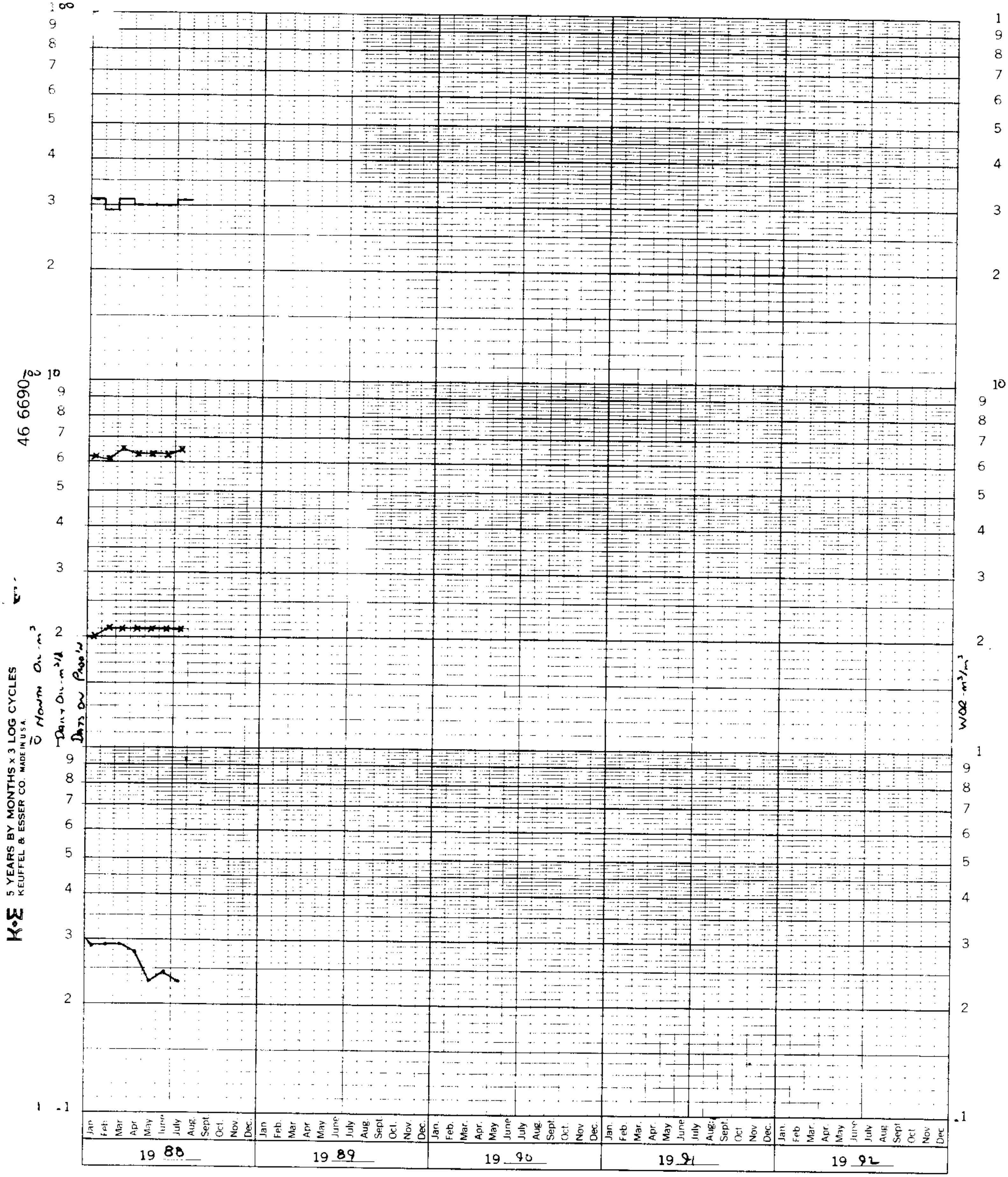

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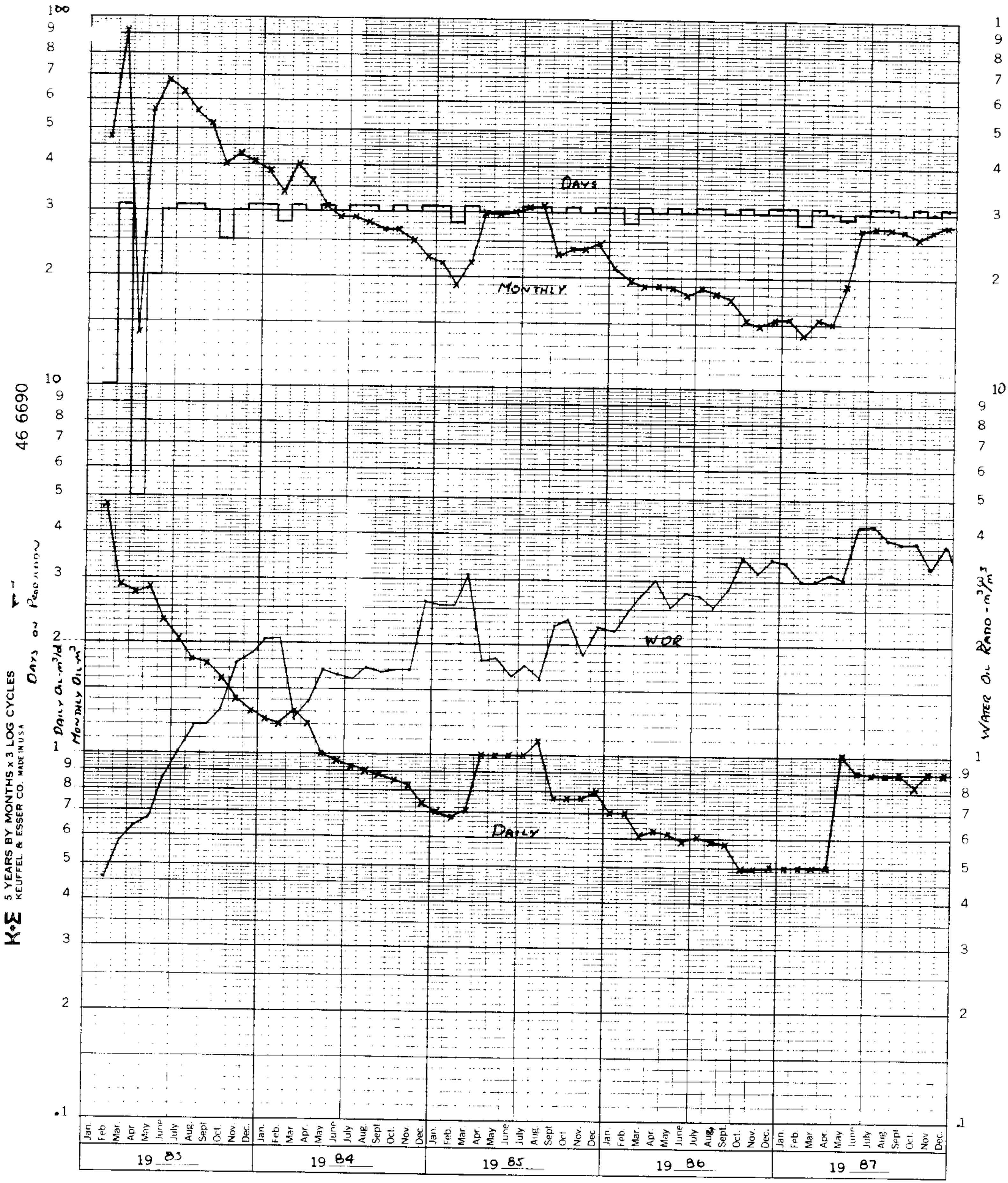
ICGR et al Scallion 3-32-11-26



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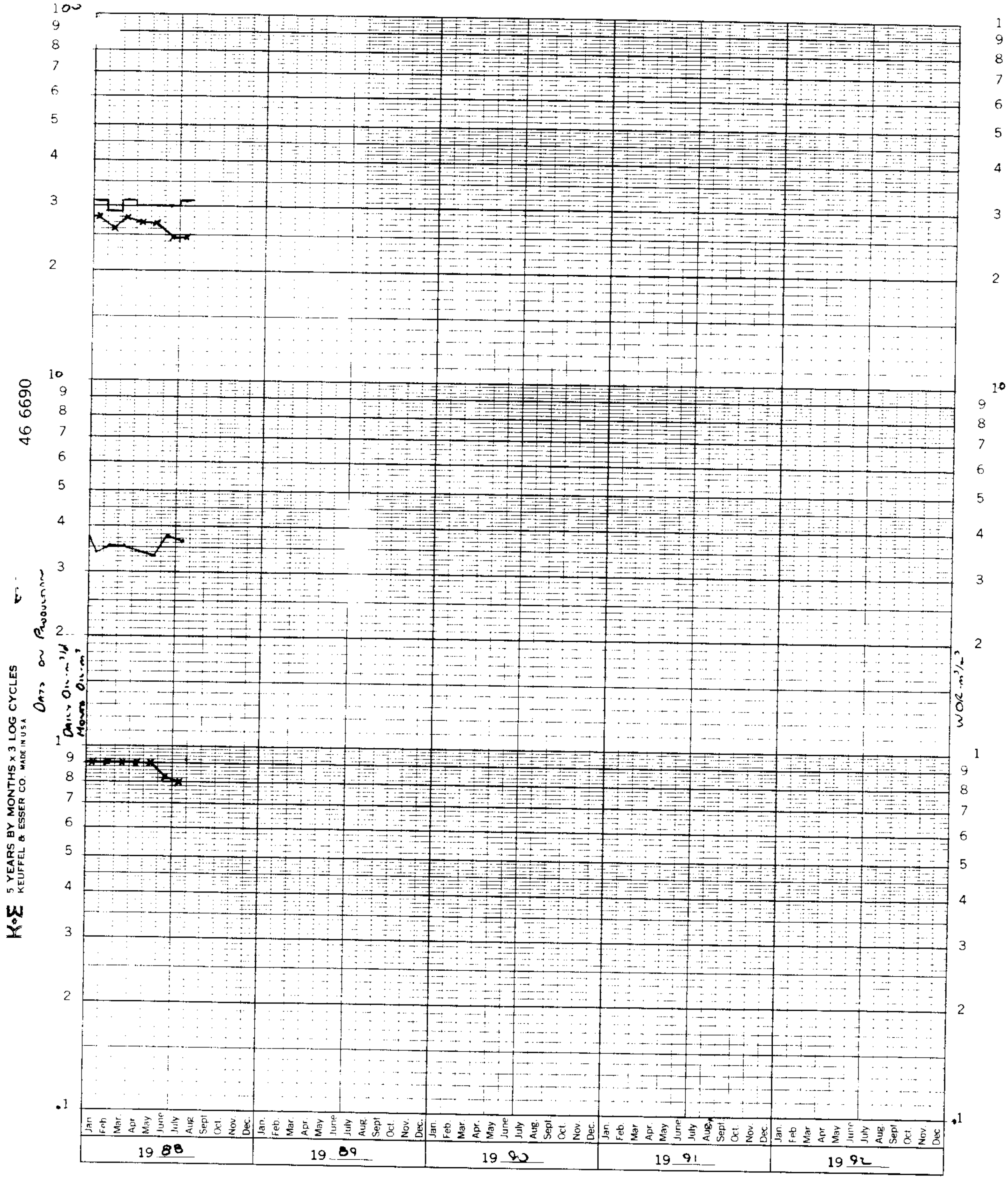

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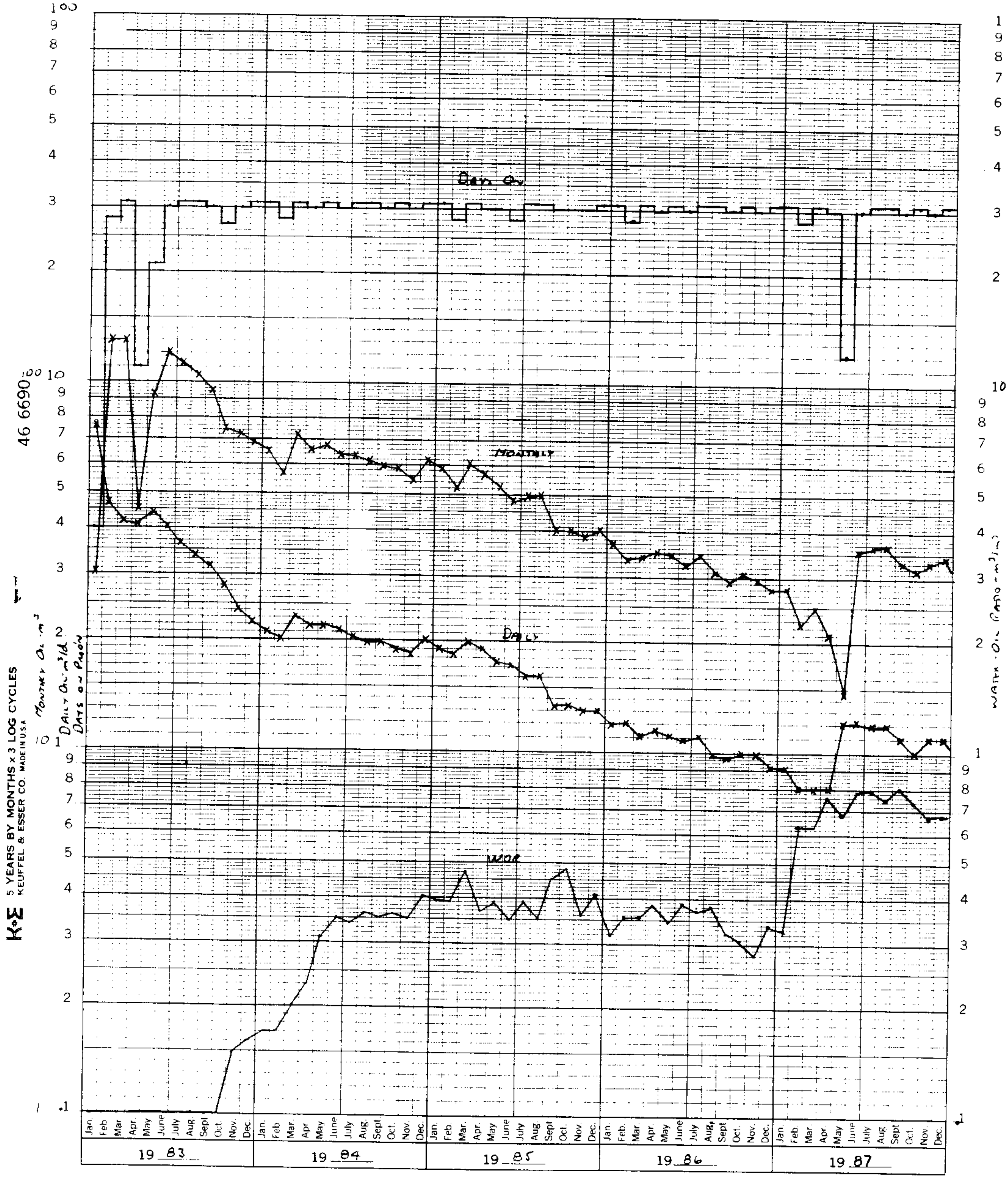
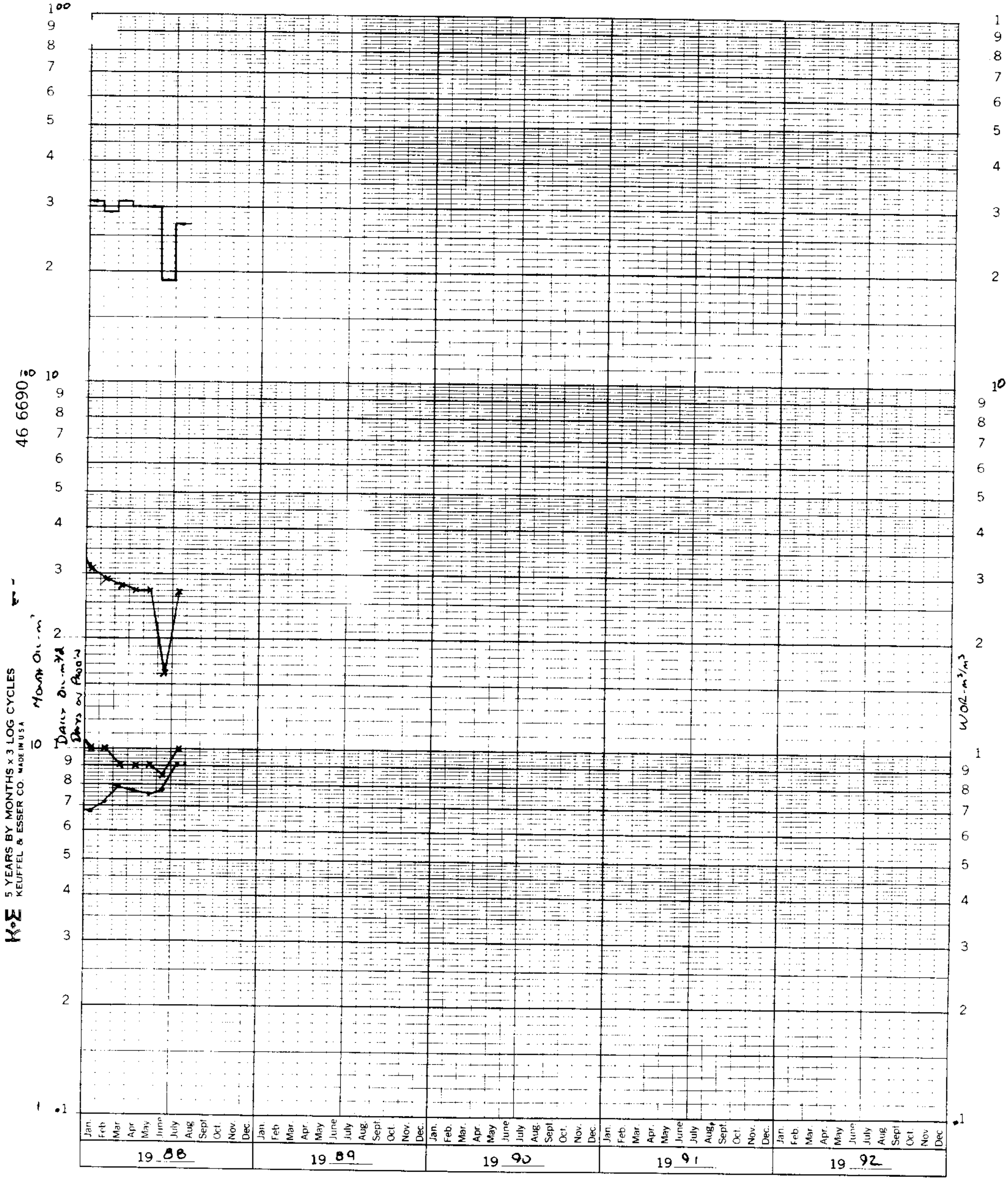


② ICGR et al Scallion 4-32-1-26



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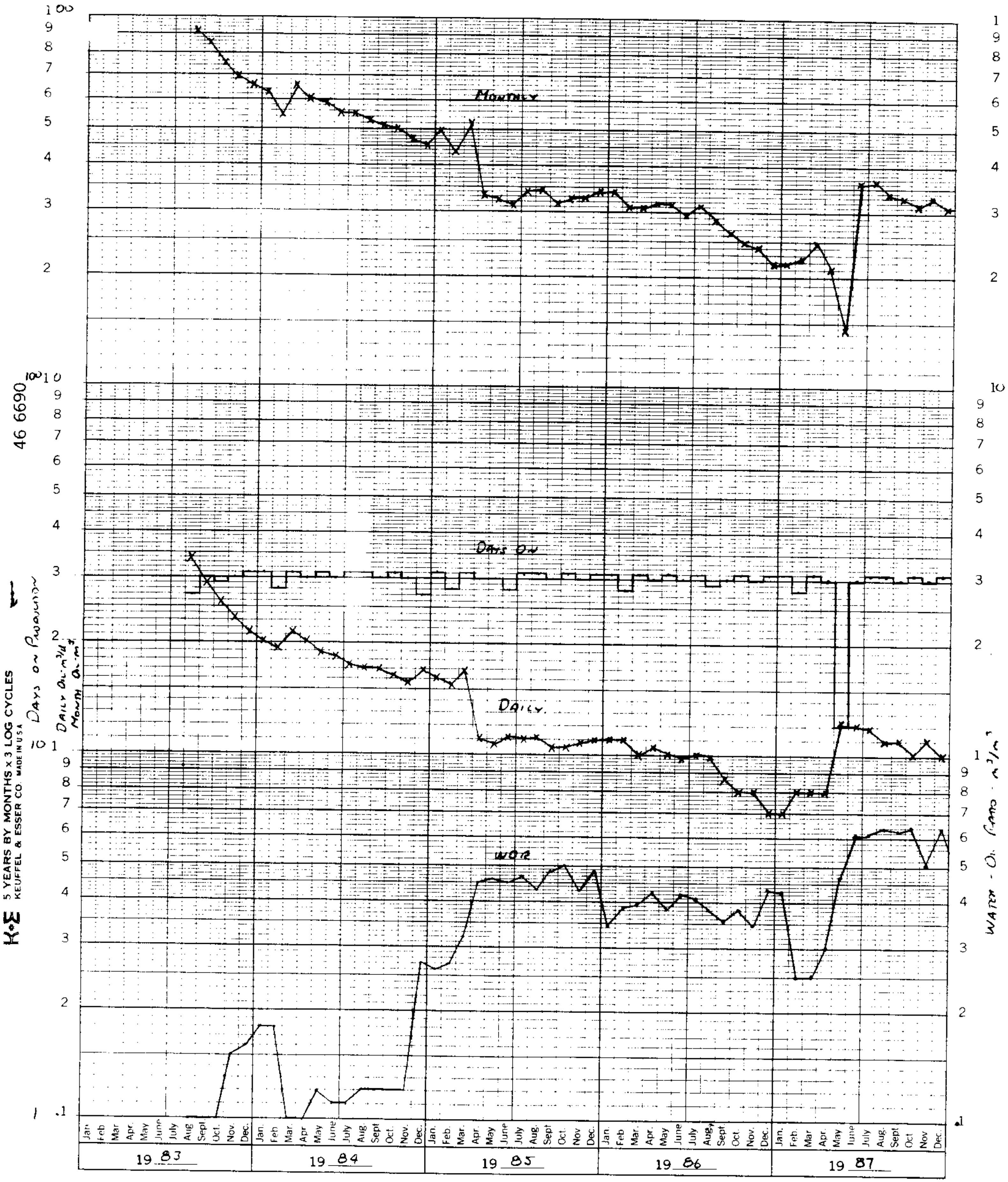
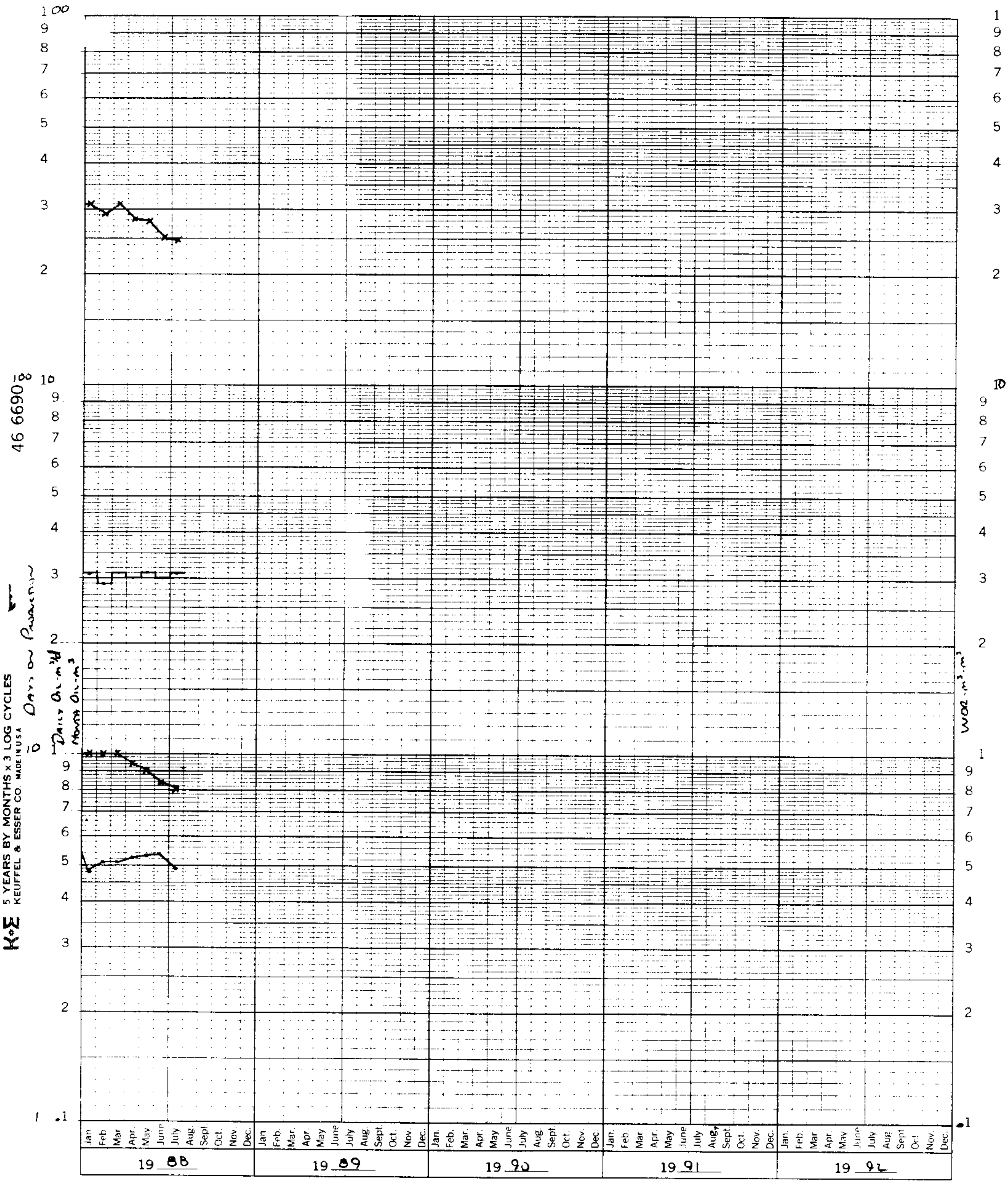
ICGR et al VIRDEN 5-32-11-26



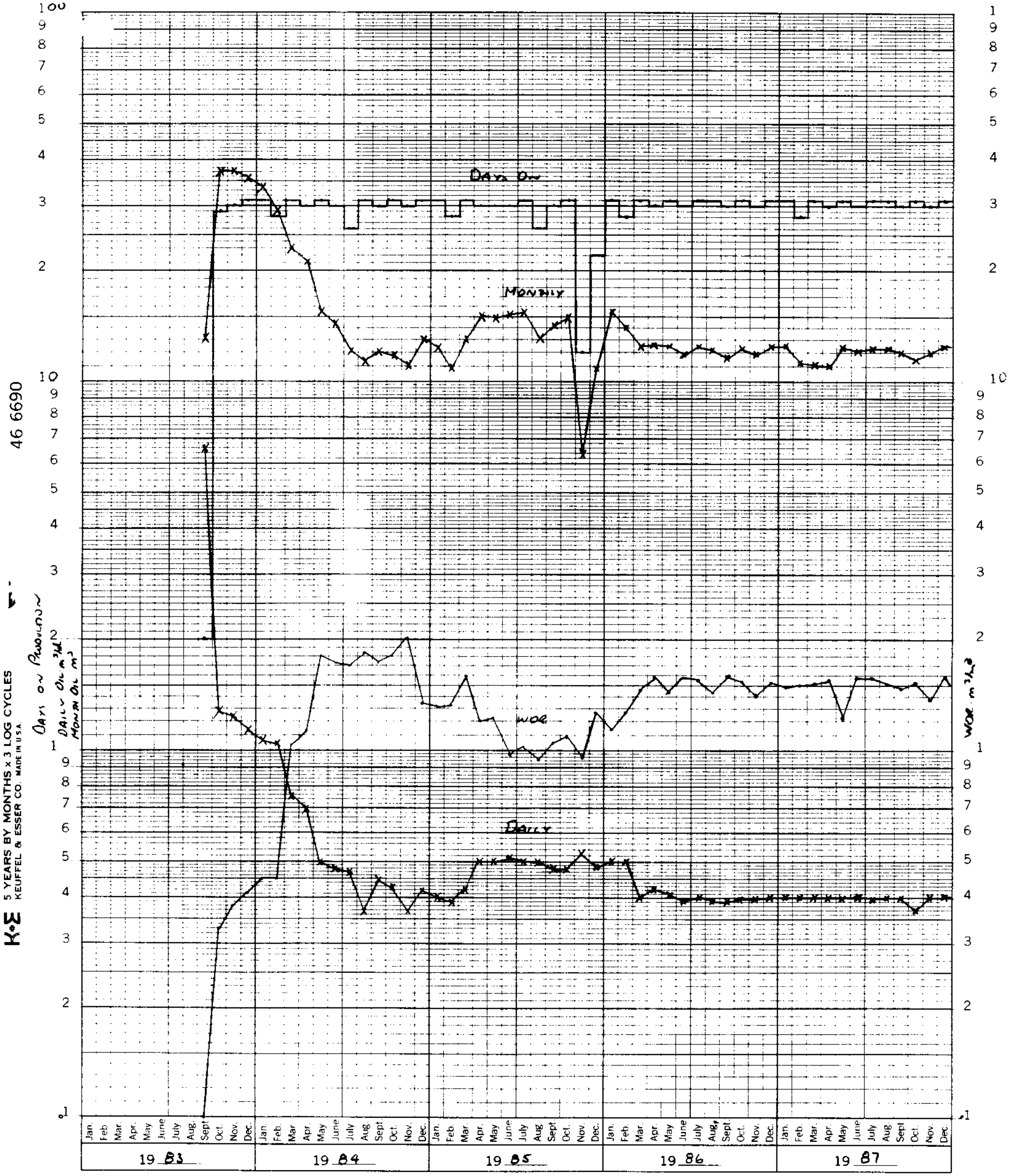
②

ICGR et al Virden 5-32-11-26



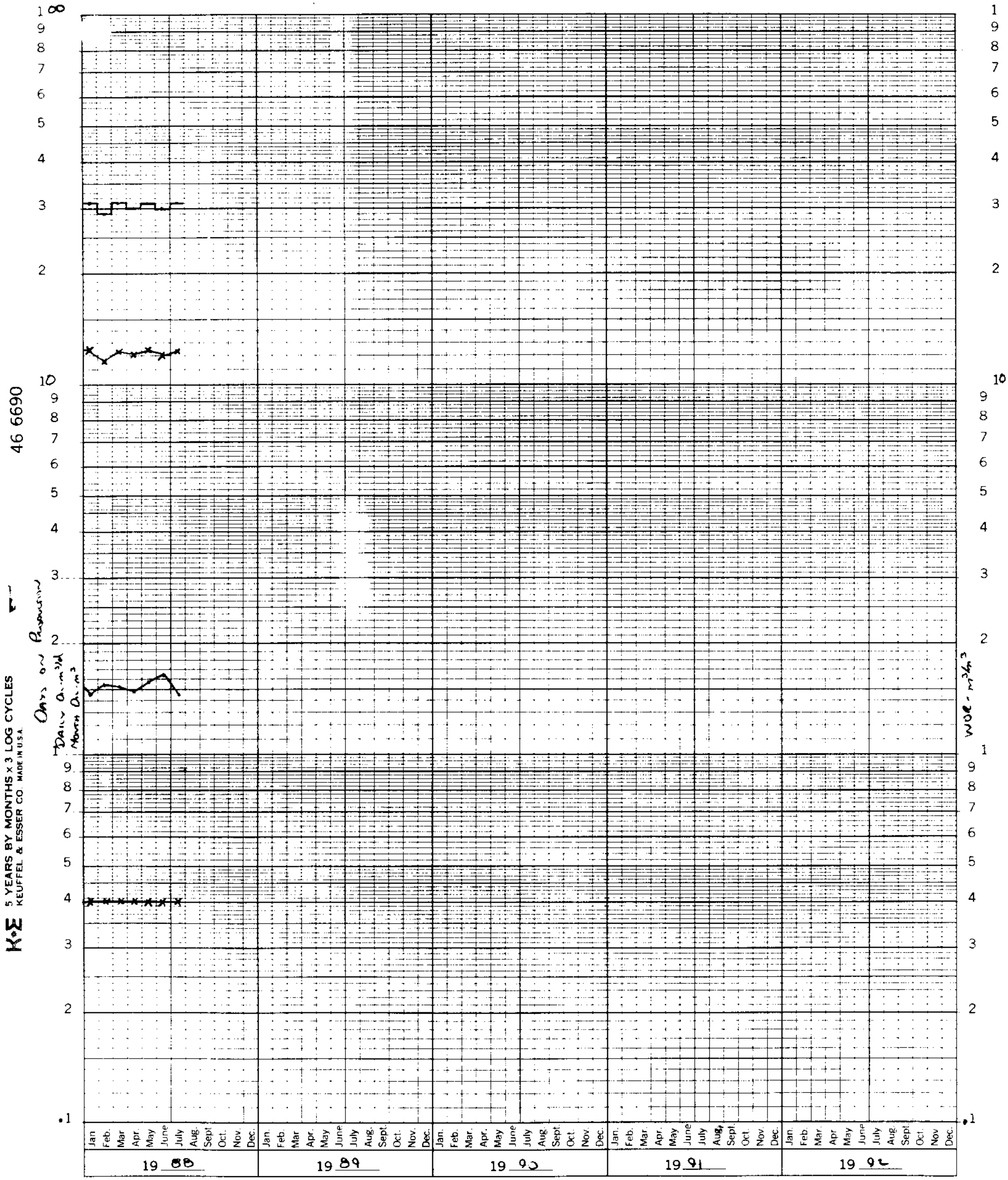
①

ICGR et al Virden 6-32-11-26



⑥

ICGR et al Virgen 6-32-11-26



NORTHWEST EXTENSION

VIRDEN LODGEPOLE 'A' POOL

PROPOSED WATERFLOOD

OCTOBER 1985

D.R. Bates, P.Eng.
Senior Reservoir Engineer
ICG RESOURCES LTD.

VIRDEN LODGEPOLE 'A' POOL
PROPOSED WATERFLOOD

Introduction

ICG Resources Ltd. has evaluated a portion of the Virden Lodgepole 'A' Pool for a potential enhanced recovery scheme by waterflood. The area investigated which has been drilled since 1983 is shown on Figure 1 and is currently operated by ICG Resources Ltd. and Tundra Oil & Gas. The study has indicated that it is technically and economically feasible to waterflood this northwest extension of the Virden Lodgepole 'A' Pool. The proposed waterflood area, however, must be unitized to protect the interests of the working interest and mineral owners.

Recommendations

1. Submit an application to the Manitoba Department of Energy and Mines, Petroleum Branch requesting approval of the proposed waterflood scheme.

2. Unitize the proposed waterflood area.

3. Commence waterflooding activities as soon as possible upon approval by the Manitoba Government and the completion of unitization procedings.

Conclusions

1. The original oil in place in the proposed waterflood area of the Virden Lodgepole 'A' Pool is 5209 MSTB.

2. Primary recovery from the proposed waterflood area is estimated by decline curve analysis to be 365 MSTB, a primary recovery factor of 7.0%.

3. Waterflooding the proposed area, by drilling well 10-30-11-26 W1M as a water injection and by converting wells 12-29-11-26 W1M and 4-32-11-26 W1M to water injection, is forecast to result in an ultimate recovery (primary plus enhanced) of 1282 MSTB, a recovery factor of 24.6%.

4. Cumulative oil recovery to 1985-04-30 is 100.6 MSTB for the proposed waterflood area. Approximately 1181 MSTB is yet to be recovered under the waterflooding scheme.

RESERVOIR STUDY
Virden Lodgepole 'A' Pool
Proposed Waterflood Area

History

Development of the northwest extension of the Virden Lodgepole 'A' Pool by ICG Resources Ltd. began with the drilling of well 12-29-11-26 W1M in November, 1982. Since that time, ICG drilled 10 successful wells and 4 dry holes which have defined the limit of the productive area in this portion of the Lodgepole 'A' Pool. ICG completed its drilling in October, 1983. In March, 1985 Tundra Oil & Gas drilled wells 6-29 and 11-29-11-26 W1M which completed current drilling in this area.

Reservoir Geology

The North Virden pool is an extension to the northwest of the main Virden pool and it lies west of the Salt Collapse feature which occupies the east half of Section 29 and east half of Section 32, Twp 11, Rge 26 WPM. The Salt Collapse is due to solution of the underlying Devonian salt formations mainly of the Prairie Evaporites. The pool is basically a stratigraphic trap in the Mississippian and the limits are controlled by both structural nosing and a permeability barrier to the north and west where the Cherty Zone leached limestone has been dolomitized. This low permeability "halo" or barrier has variable production characteristics but is marked by higher interstitial water saturation, hence it produces mainly water. Wells in which the Lodgepole Formation is structurally high generally show the effect of post-Lodgepole movement which resulted in a fracture system that might be filled with anhydrite in some places.

The main producing zone is the Cherty Zone of the Scallion Member which is predominantly a finely crystalline Cherty limestone. This zone has been leached over the entire pool increasing the permeability and porosity and destroying much of the structural and textural features of the original rock. The leaching by ground waters, during an erosion period, has taken place regionally over much of the Lodgepole Formation, but the most noticable effect is in the Cherty Zone of the Virden Scallion Field.

Overlying the Cherty Zone is the Lower Virden Member which consists mainly of oolitic limestone interbedded with argillaceous limestone or calcareous shales. These oolite lands are cyclic in nature. The lower oolitic or fragmental zone generally blends into the Cherty Zone and within this study has been included as part of the pay zone if it meets the porosity and resistivity cut offs. Overlying the Lower Virden Member is the Upper Virden bioclastic limestone with Crinoidal debris forming the Crinoidal Zone.

Reservoir Characteristics

The servoir structure on top of the Cherty zone porosity is shown in Figure 2. The reservoir dips to the southeast and becomes water-bearing in that direction.

Figure 3 is a net oil pay map for the Cherty zone which is the zone of interest in this study. Net pay was determined by using a porosity cutoff of 10% on the density porosity curve of the density-neutron log and a resistivity cutoff of 2.5 ohm from the dual induction log. Only one well had a core over a portion of the pay in the Cherty zone, 3-32-11-26 W1M. The core and log density porosities compared farvourably in this well. Table 1 shows the individual well petrophysical parameters.

Figure 4 is a hydrocarbon pore volume map of the area. Water saturation was calculated using a formation water resistivity of 0.02 ohm at a reservoir temperature of 82^{o}F.

Recoverable Reserves

The original oil in place in the proposed waterflood area of 5209 MSTB was determined by planimetering the hydrocarbon pore volume map, Figure 4, and using an initial formation volume factor of 1.045 Reservoir BBL/STB. The formation volume factor was obtained from the original reservoir study that Chevron Canada Resources Limited performed on the portion of the Virden Lodgepole 'A' Pool which became the North Virden Scallion Unit No. 1.

Primary recovery is expected to be in the order of 7 percent by declining current production trends, or 365 MSTB. Figure 5 shows the historical production characteristics of the 14 wells in the proposed waterflood area. Cumulative production to April 30, 1985 was 100.6 MSTB. The rapid initial decline of the wells productivity under primary depletion is typical of the Lodgepole 'A' Pool and indicative of a declining reservoir pressure. Only DST pressures are available from the proposed waterflood area wells, but pressures on wells drilled late in 1983 show shut-in pressures as low as 850 psig compared to the original pressure of about 910 psig.

The study of an enhanced recovery scheme for this northwest extension area was based upon the original work done by Chevron in the North Virden Scallion Unit No. 1 in a reservoir study dated August 1961. The area chosen for the proposed waterflood is limited to the area which has been developed since late 1982. Eleven of these wells were drilled by ICG Resources Ltd. and two were drilled in 1985 by Tundra Oil & Gas. The fourteenth tract, 10-30-11-26 W1M, has a suspended well but it is expected a new well will have to be drilled.

It will be necessary to convert two of the thirteen wells to water injectors and to drill one additional water injector to maintain voidage and achieve an effective sweep of the proposed waterflood area. Wells 12-29-11-26 W1M and 4-32-11-26 W1M have been chosen as the wells to be converted for water injection and well 10-30-11-26 W1M will be drilled which will result in three partial inverted 9-spot patterns, similar to the pattern configuration of the Unit No. 1 flood scheme. It is planned to overinject for the first three years at a voidage replacement rate of about 1.25 and then replace voidage for the rest of the waterflood with a 10 percent overplacement.

The waterflood is forecast to recover 30 percent (total primary plus waterflood) of the original oil in place of the sweepable enclosed area. Because the injection patterns are not totally enclosed, oil on the pool edges is not swept by the waterflood. It was assumed that the recoverable reserves from these edges would be based on a primary recovery factor of 7 percent. Figure 6 shows the area that will be effectively waterflooded.

With these assumptions, the overall primary plus waterflood recovery factor for the prop- ed waterflood area is 24.6 percent of the original oil in place. This is a total reco. :able reserve of 1282 MSTB. The Chevron study estimated an overall recovery factor of 28.4 percent for the Unit No. 1 waterflood. An analysis of the Unit's production history indicates that the ultimate recovery should be about 33 percent so the recovery factors being used in this evaluation are felt to be realistic.

Figure 7 shows a forecast of the proposed waterflood's production performance. This assumes an on injection date of January 1, 1986. Peak production rates of 300 BOPD are forecast in 1989. Figure 8 show the water injection forecast. Injection rates commence at 300 BWPD and should be a maximum of almost 600 BWPD in 1989. The maximum make-up water required is forecast to be 350 BWPD. Other operators south of the area have been approached for their Lodgepole 'A' Pool produced water. Initial indications are that there will be enough water available for make up requirements. If not, source water wells may be required.

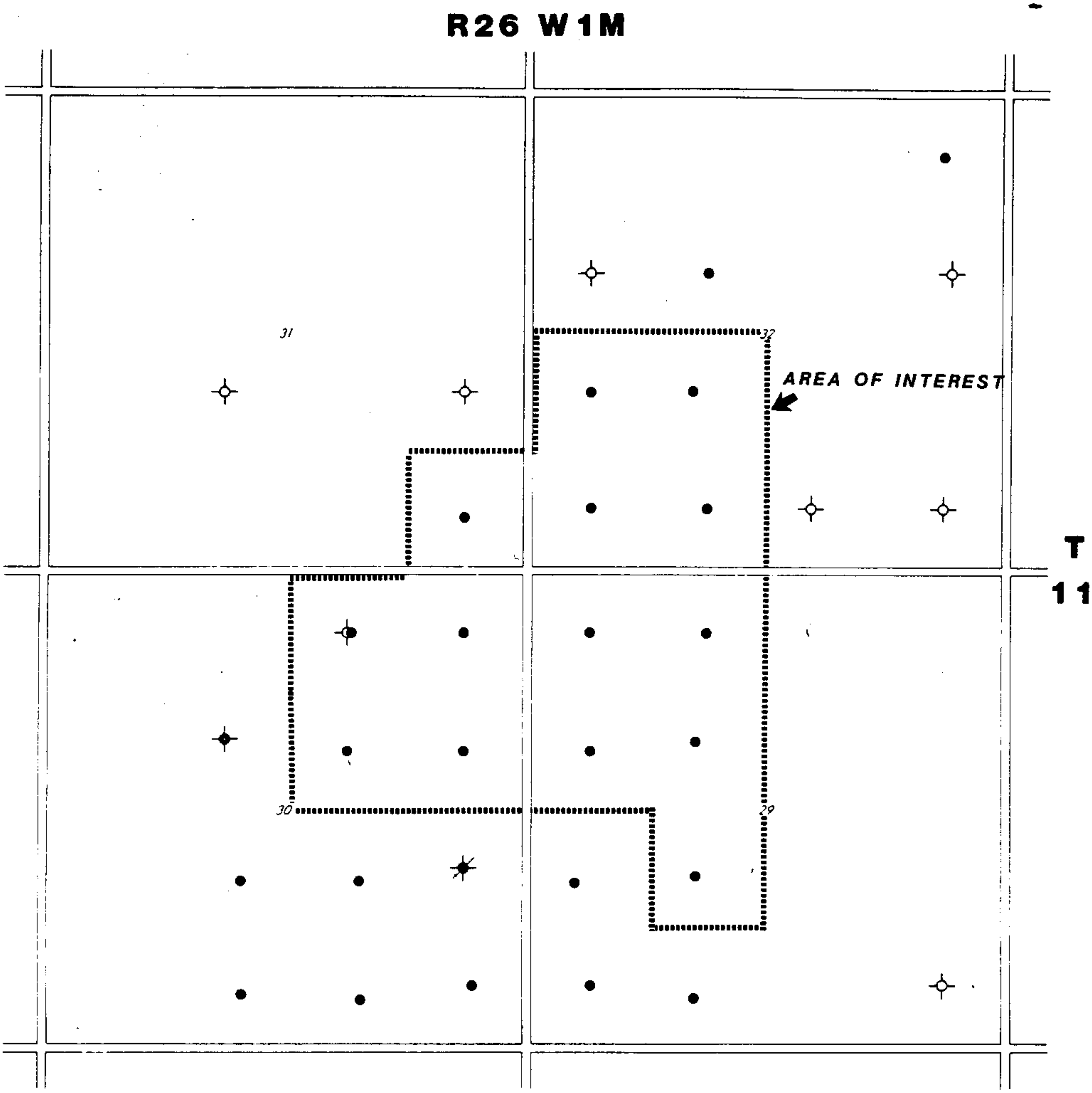
TABLE 1
VIRDEN LODGEPOLE 'A' POOL
PROPOSED WATERFLOOD AREA
RESERVOIR PARAMETERS

Well Name	Net Pay (h) (ft)	ϕ (decimal)	(1-SW) (decimal)	HCPV
14-29-11-26 W1	14	.17	.63	1.5
13-29-11-26 W1	12	.16	.68	1.31
12-29-11-26 W1	11.5	.16	.64	1.18
11-29-11-26 W1	16	.19	.69	2.10
6-29-11-26 W1	13	.19	.72	1.78
16-30-11-26 W1	14	.20	.60	1.68
15A-30-11-26 W1	4	.14	.63	.35
10-30-11-26 W1	6	.22	.68	.90
9-30-11-26 W1	11	.22	.66	1.59
1-31-11-26 W1	12	.24	.68	1.96
6-32-11-26 W1	7	.17	.62	.74
5-32-11-26 W1	11	.19	.68	1.42
4-32-11-26 W1	14	.19	.70	1.86
3-32-11-26 W1	8	.18	.65	.94

$\phi_{AVG} = 19\%$

VIRDEN LODGEPOLE 'A' POOL
PROPOSED WATERFLOOD

LIST OF FIGURES



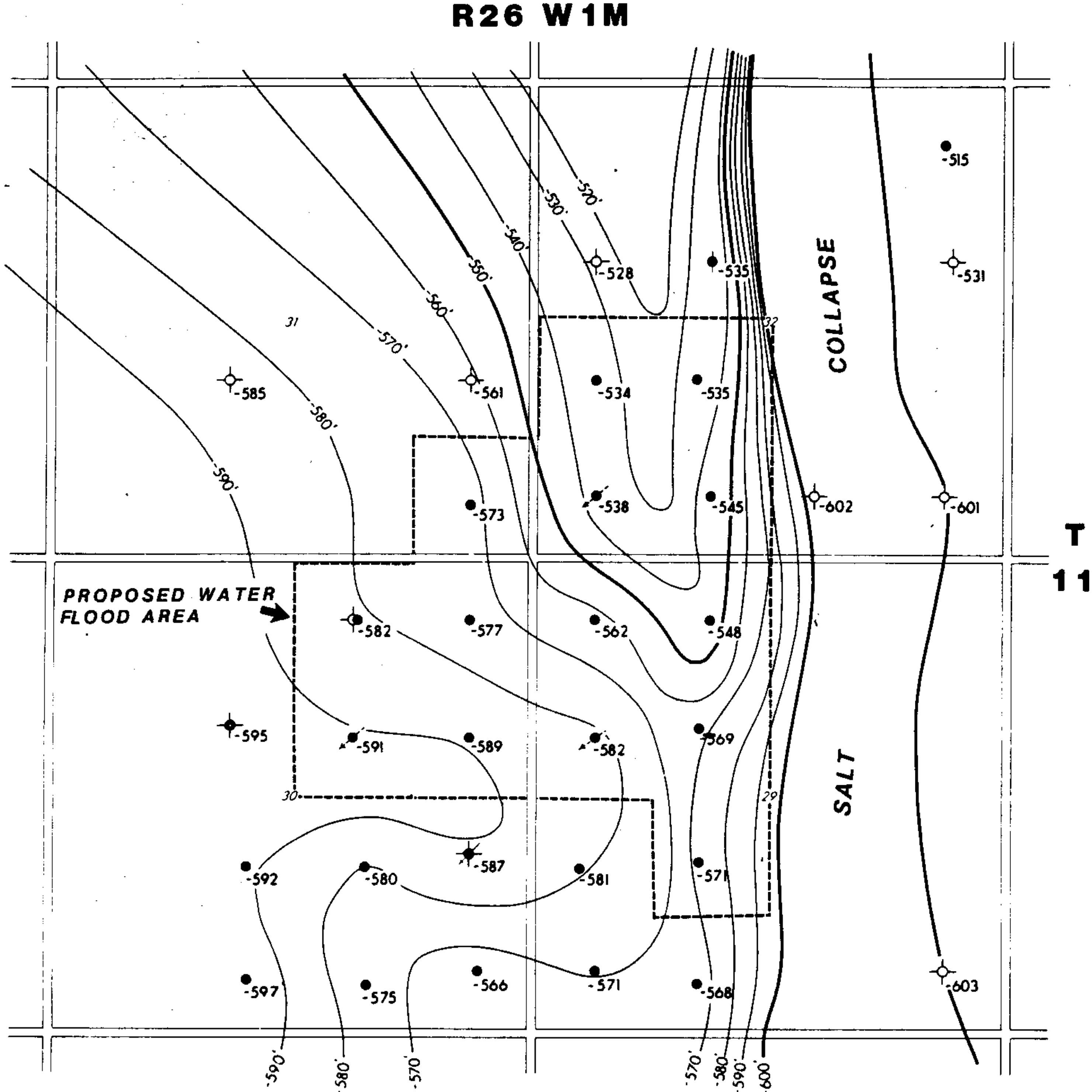
ICG RESOURCES LTD

NORTH VIRDEN AREA

NORTHWEST EXTENSION

Fig. 1

GEOLOGY BY	DRAFTING BY
SCALE	DATE



PROPOSED WATER INJECTION WELL

ICG RESOURCES LTD

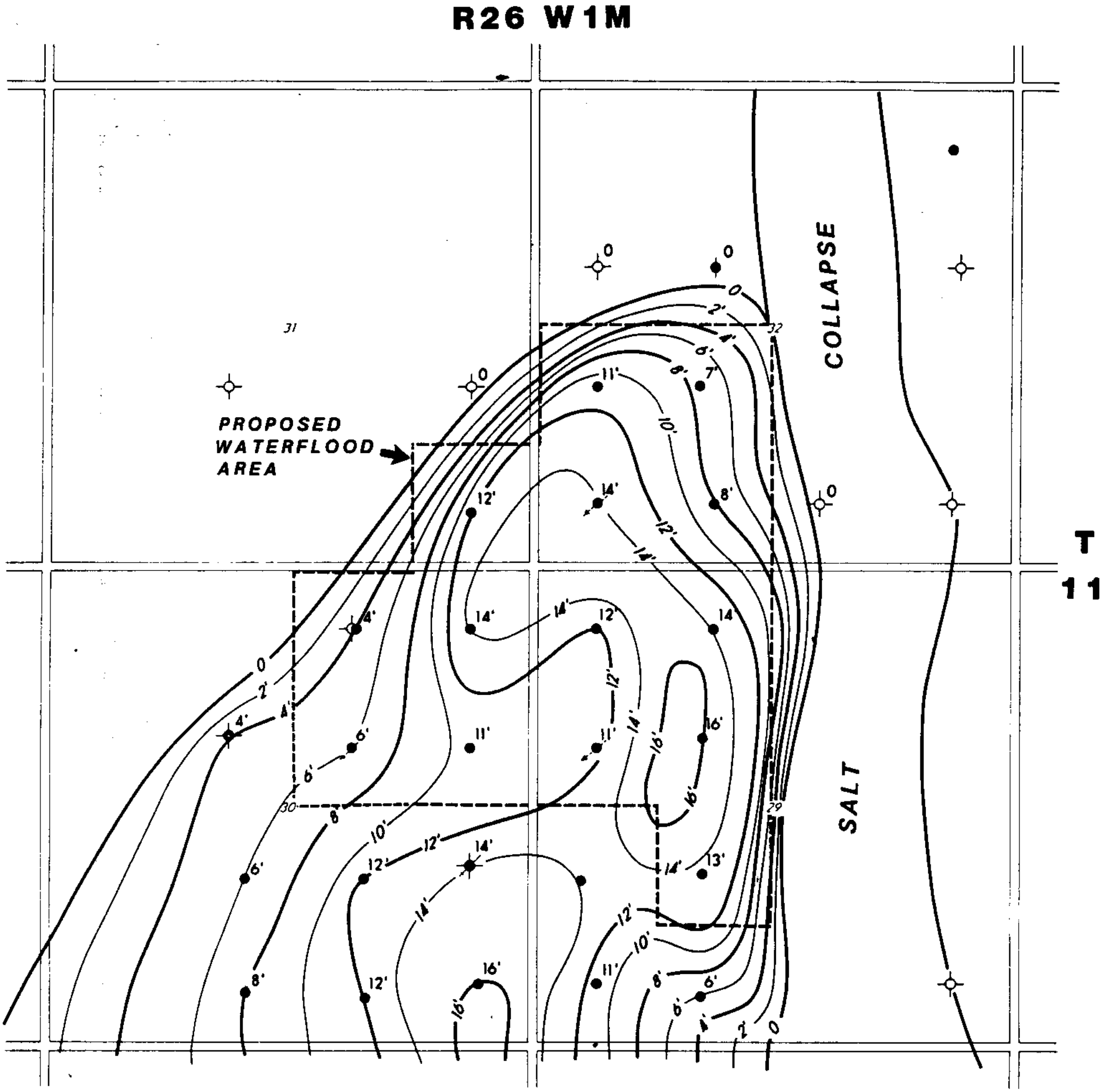
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL

STRUCTURE CONTOUR MAP

C.I.=10'

Fig. 2

GEOLOGY BY M.Gabrial	DRAFTING BY F.F.
SCALE	DATE 1985-10-07



PROPOSED WATER INJECTION WELL

ICG RESOURCES LTD

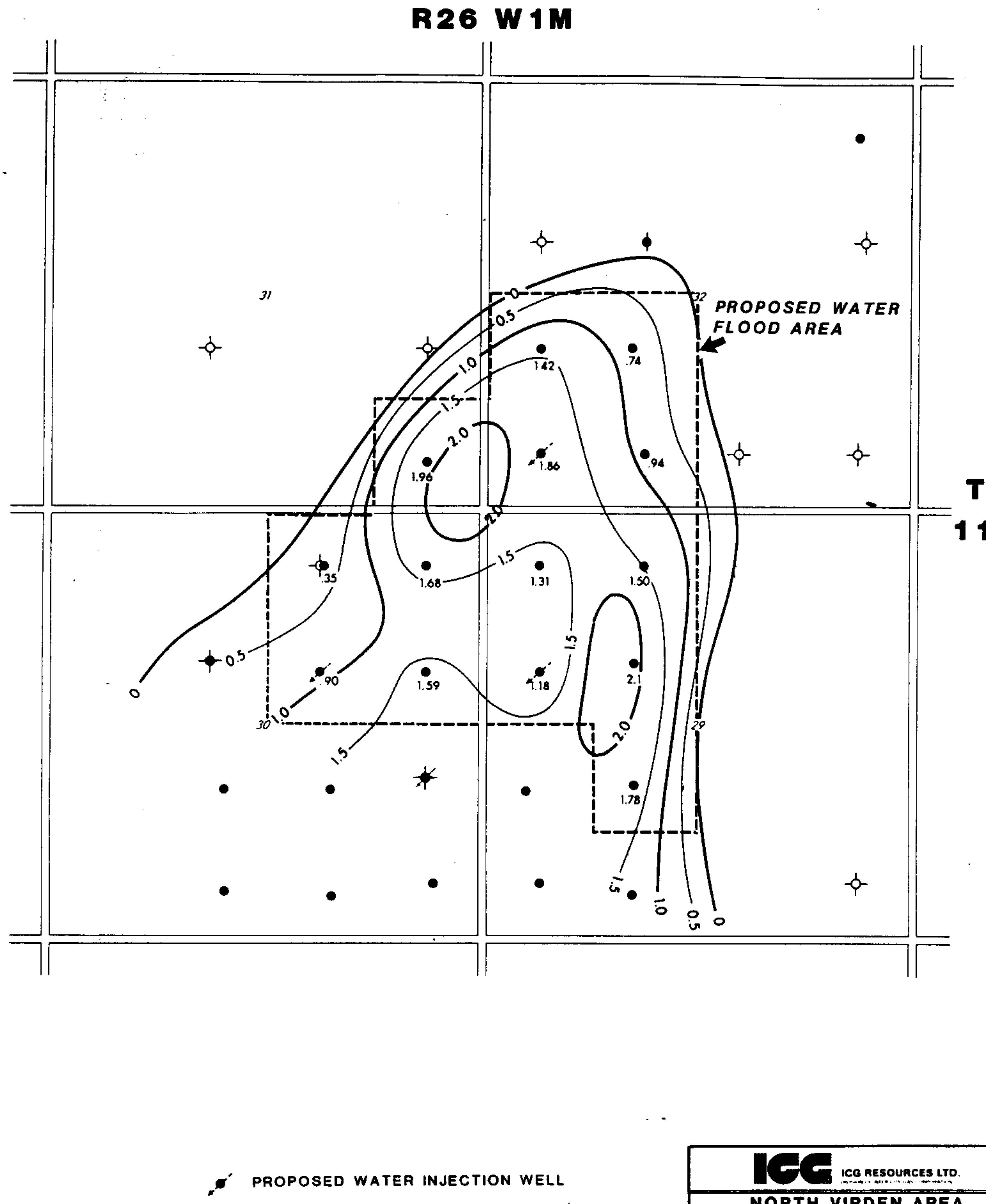
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL

NET OIL PAY ISOPACH MAP

C.I. 2 FT.

Fig.3

GEOLOGY BY M. Gabriel	DRAFTING BY F.F.
SCALE	DATE 1985-10-01



ICG RESOURCES LTD.

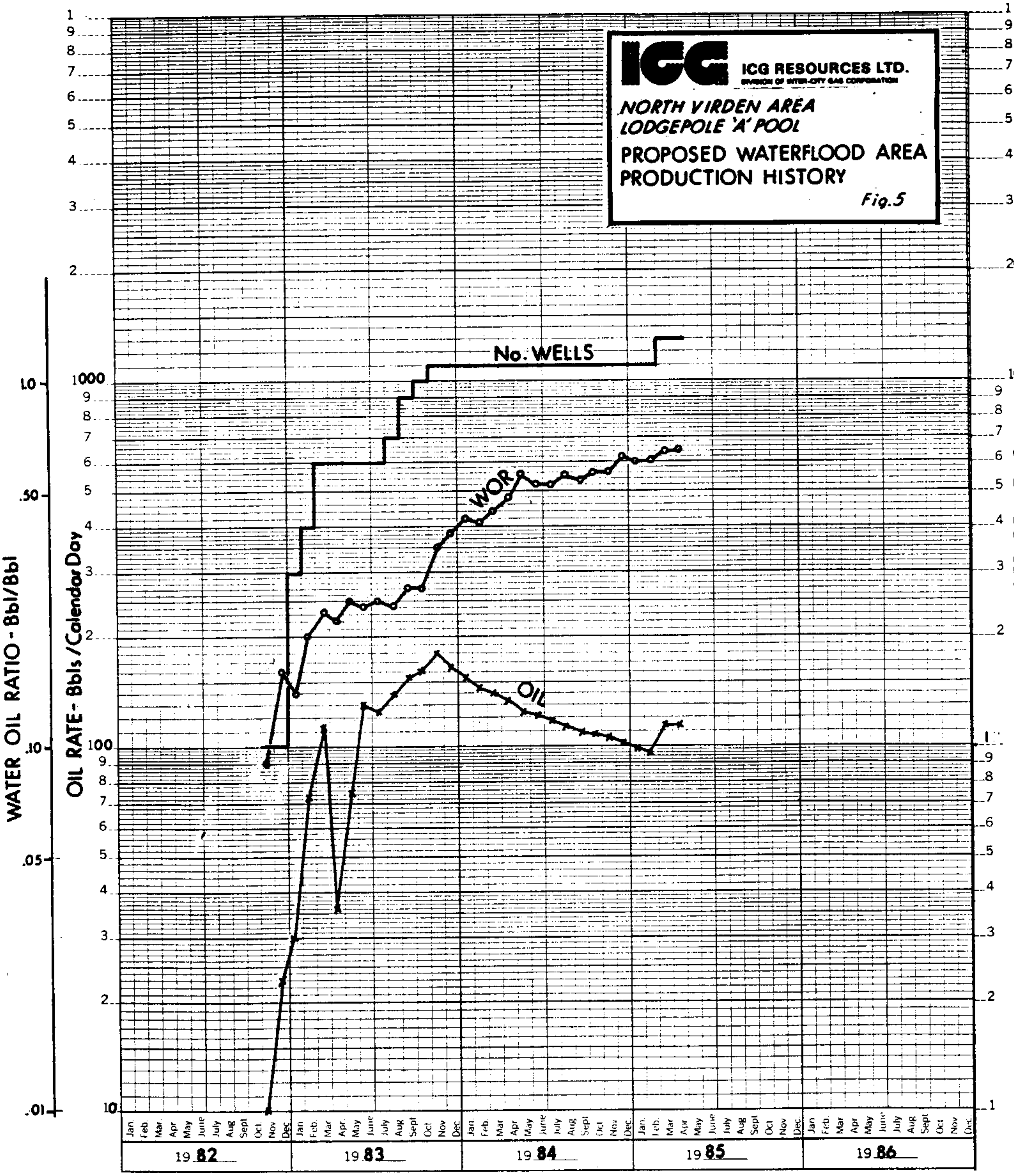
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL

HCPV MAP

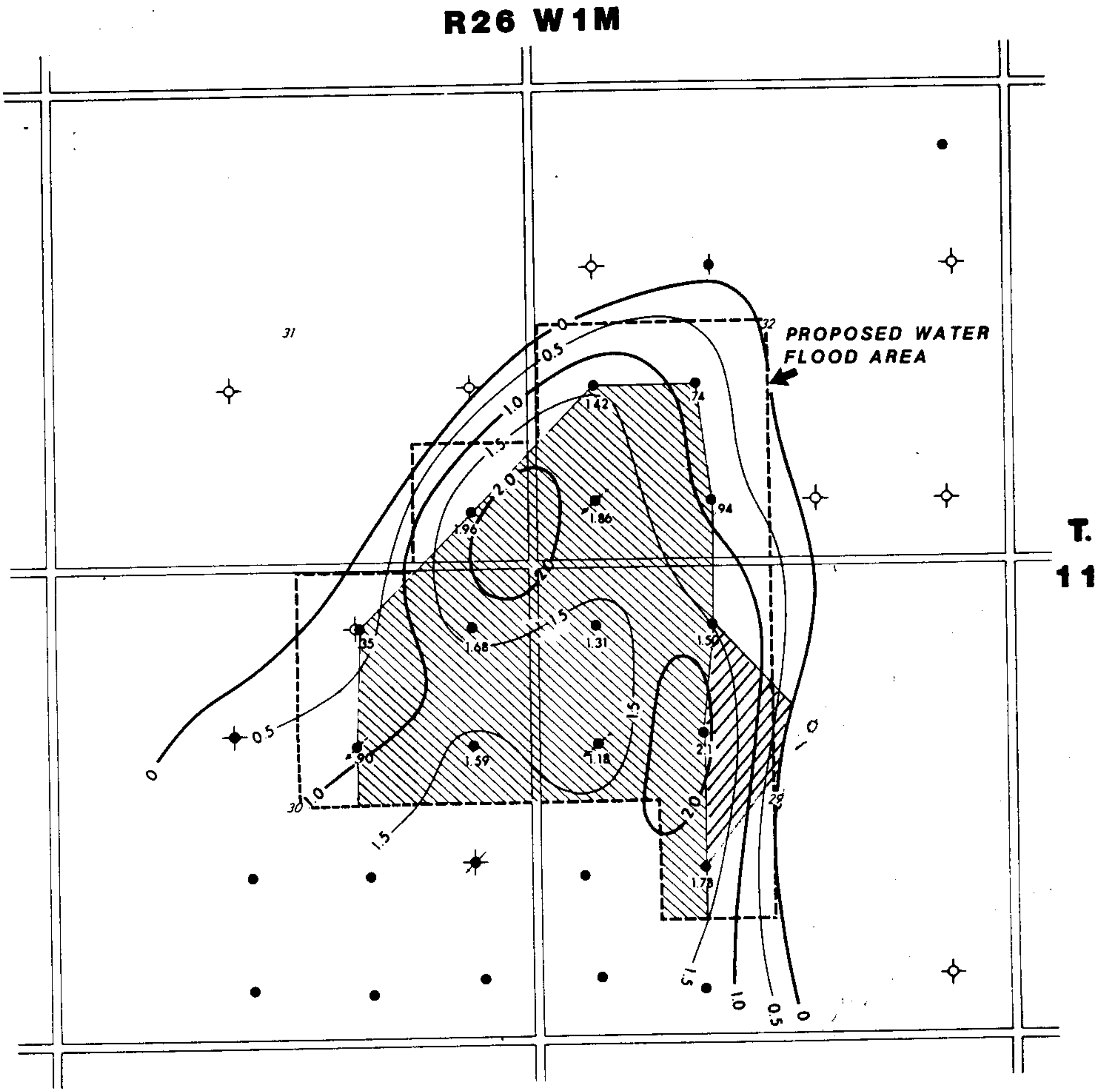
Øh (1-SW)

Fig. 4

GEOLOGY BY M.P. Gobrial	DRAFTING BY F.F.
SCALE	DATE 1985-09-24



ICG RESOURCES LTD.
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL
PROPOSED WATERFLOOD AREA
PRODUCTION HISTORY
Fig.5
No. WELLS
WOR
OIL
WATER OIL RATIO - Bbl/Bbl
OIL RATE - Bbls /Calendar Day
NUMBER OF WELLS
1982
1983
1984
1985
1986



PROPOSED WATER INJECTION WELL

WATERFLOOD SWEPT AREA

ICG RESOURCES LTD.

NORTH VIRDEN AREA
LODGEPOLE 'A' POOL

HCPV MAP

Øh (1-SW)

Fig. 6

GEOLOGY BY M.P. Gabriel	DRAFTING BY F.F.
SCALE	DATE 1985-09-24

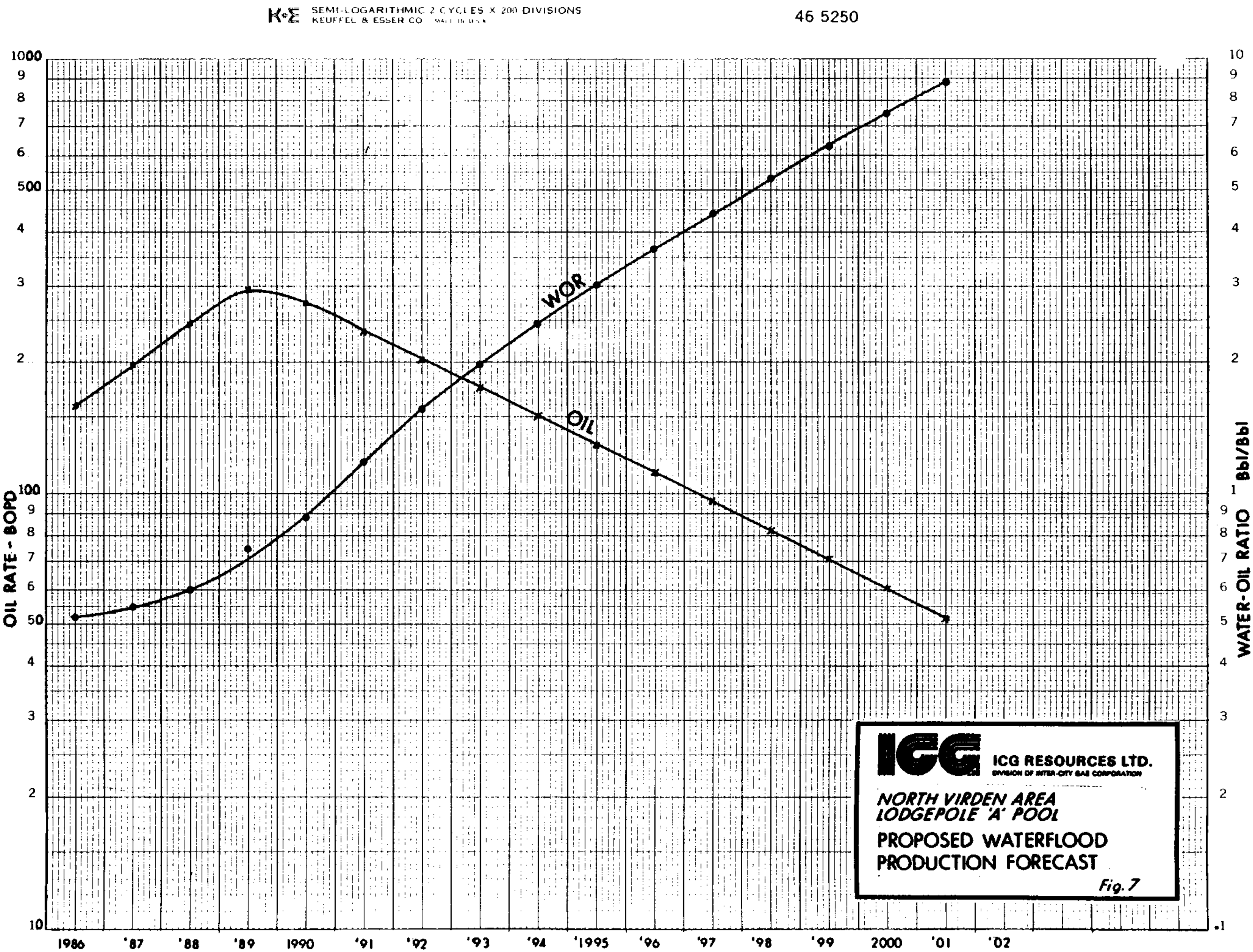
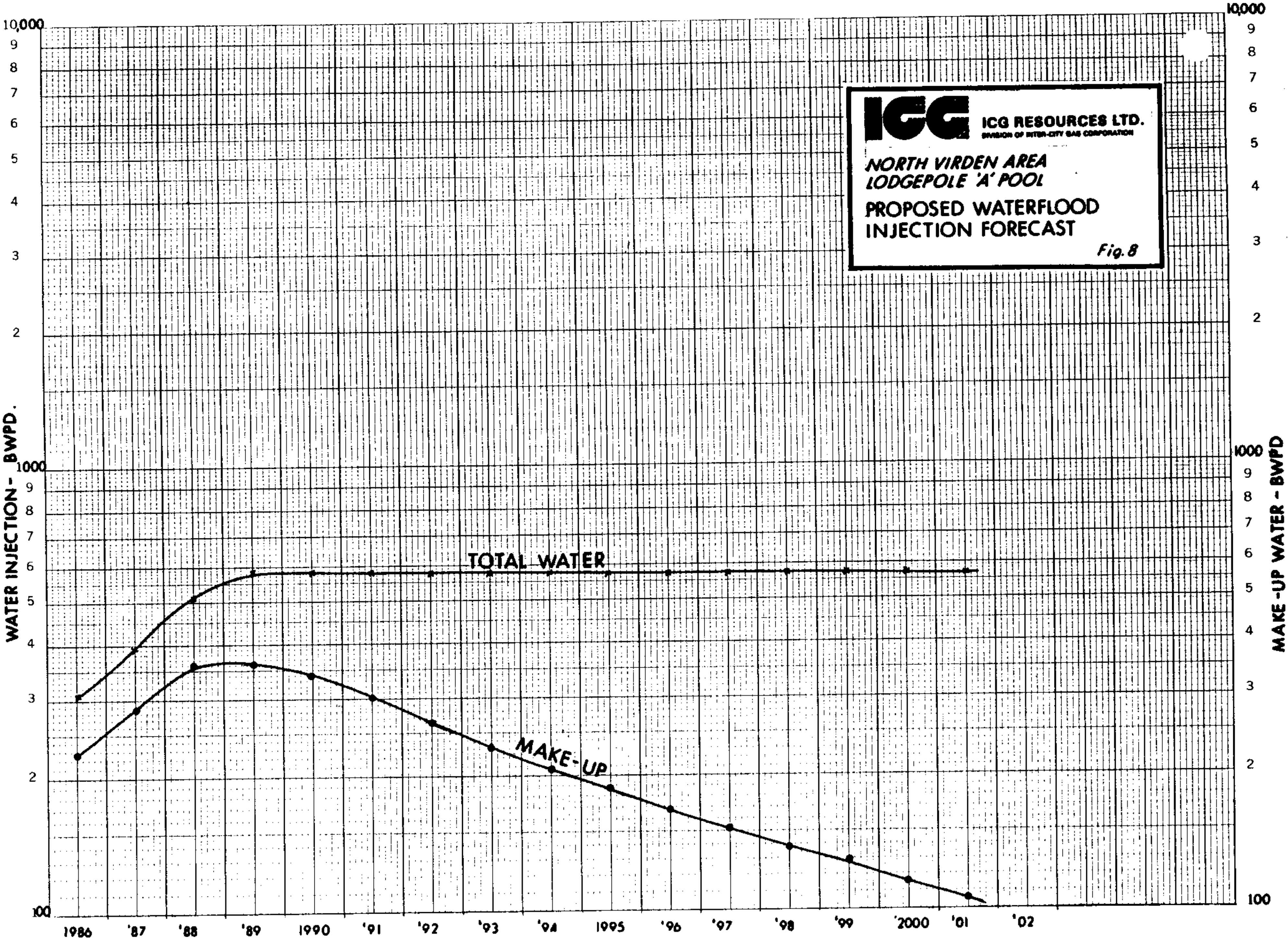

K•E SEMI-LOGARITHMIC 2 CYCLES X 200 DIVISIONS
KEUFFEL & ESSER CO.
46 5250
OIL RATE - BOPD
WATER-OIL RATIO _ Bbl/Bbl
1000
500
100
50
10
WOR
OIL
1986
'87
'88
'89
1990
'91
'92
'93
'94
1995
'96
'97
'98
'99
2000
'01
'02
ICG RESOURCES LTD.
DIVISION OF INTER-CITY GAS CORPORATION
NORTH VIRDEN AREA
LODGEPOLE 'A' POOL
PROPOSED WATERFLOOD
PRODUCTION FORECAST

Fig. 7

K·E SEMI-LOGARITHMIC 2 CYCLES X 200 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 5250



August 7, 1985

ICG Resources Ltd.
2700 - 140 Fourth Avenue S.W.
Calgary, Alberta
T2P 3S3

Attention: Mr. P. Krenkel, P. Eng.
Engineering Manager

Dear Sirs:

Re: Virden Lodgepole A Pool - Northwest Extension

Further to your letter of April 26, 1985, we have not yet received the results of your feasibility study of pressure maintenance operations in the subject area.

Please submit the results of these studies along with your recommendations to ensure maximum economic recovery from the area to The Oil and Natural Gas Conservation Board as soon as possible but not later than October 1, 1985.

Yours sincerely,

Original Signed by H. C. Moster

H. Clare Moster, P. Eng.
Director, Petroleum Branch

LRD/lk

c.c. C. Kang, Chairman
The Oil and Natural Gas
Conservation Board

→ Bob

ICG RESOURCES LTD
DIVISION OF INTER-CITY GAS CORPORATION

2700-140 FOURTH AVENUE S.W.
CALGARY ALBERTA CANADA
T2P 3S3
(403) 231-9000

1985 04 26

Manitoba Department of Energy and Mines
Eaton Place
555 - 330 Graham Avenue
Winnipeg, Manitoba
R3C 4E3

Attention: Mr. H. Clare Moster, P.Eng.
Director Petroleum Branch

Gentlemen:

Re: Virden Lodgepole 'A' Pool
Northwest Extension

This is in reply to your letter of March 6, 1985, requesting that we review the production performance of the above Area to determine if a secondary recovery scheme is required to maximize oil recoveries in the Area.

We have been closely monitoring the production rates on ICG's 11 wells in the above Area and have recently conducted three workovers in an attempt to improve production rates. We are currently conducting a detailed evaluation of the reservoir in the area and our preliminary indications are that a secondary recovery scheme (probably waterflood) will be economical. Until this study is complete, I can not provide you with specific details in regards to which well(s) will be converted to water injection and the proposed injection rates. I will review with you the recommendations of our study which will be completed by June 1, 1985.

.../2

Simultaneous to this reservoir study, we will commence unitization discussions in accordance with the Manitoba regulations.

I would be pleased to discuss the matter with you at any time. My telephone number is (403) 231-9036.

Yours truly,

ICG RESOURCES LTD.

P. Krenkel, P.Eng.
Engineering Manager

PK/hjm

Manitoba

Energy and Mines Petroleum

555 — 330 Graham Avenue
Winnipeg, Manitoba, CANADA
R3C 4E3

(204) 945-6577

March 6, 1985

ICG Resources Ltd.
2700, 140 - 4th Avenue S.W.
Calgary, Alberta
T2P 3S3

Attention: Mr. G. A. Henshel, P. Eng.
Reservoir Engineer

Dear Sirs:

Re: Virden Lodgepole A Pool - North West Extension

Please refer to our letter (copy attached) of February 15, 1984 regarding the need for and feasibility of pressure maintenance operations in the northwest extension of the subject Pool developed by ICGR in 1982 and 1983. In the subject letter, we requested that you provide, prior to March 1, 1985, a preliminary analysis of the need for pressure maintenance. To date, we have not received the requested analysis.

The Branch has reviewed the production performance of the wells in this area, and based on this preliminary review, is of the opinion that some form of pressure maintenance will be necessary to ensure maximum oil recovery in the area.

Summarized below are the results of this analysis:

1. Figure No. 1 is a plot of normalized production for ICGR's 13 producing wells. Average oil rate and total fluids rate are plotted. Note that both curves are monotonically decreasing and represent decline rates in the order of 50% per year.

2. Figure No. 2 is a plot of historical production. Note that upon completion of development drilling in November 1983, oil production has declined at a rate of about 43%/year while water production volumes have remained quite constant indicating only partial aquifer support.

3. Figure No. 3 presents the results of extrapolation of the historical decline curve to different abandonment rates. Using cumulative production to December 31, 1984 and an abandonment rate of 0.3 m^3/d/well, an ultimate per well recovery of only 2 000 m^3 is estimated. A review of production reports indicates that only 8 of 239 active wells (excludes ICGR's wells) in the Pool, or 3.3 percent, had failed to achieve this level of production by year end 1983.

You are requested to submit your plans as soon as possible but not later than May 1, 1985, to implement necessary pressure maintenance or other operations to ensure maximum oil recovery from the area. An application for approval to conduct pressure maintenance or enhanced oil recovery operations should be made to The Oil and Natural Gas Conservation Board in accordance with the provisions of Sections 64 and 126 of The Petroleum Drilling and Production Regulations, 1984. Also note that pursuant to Section 74 of The Mines Act, a unitization agreement must also be approved by the Board before it takes effect.

If you have any questions or comments on the foregoing, please contact L. R. Dubreuil at 204-945-6574, or the undersigned at 204-945-6573

Yours sincerely,

Original Signed by H. C. Moster

H. Clare Moster, P. Eng.
Director, Petroleum Branch
LRD/lk

c.c. The Oil and Natural Gas
Conservation Board

Wm. McDonald, Deputy Chairman

FIG. No. 1

NORMALIZED PRODUCTION CURVE

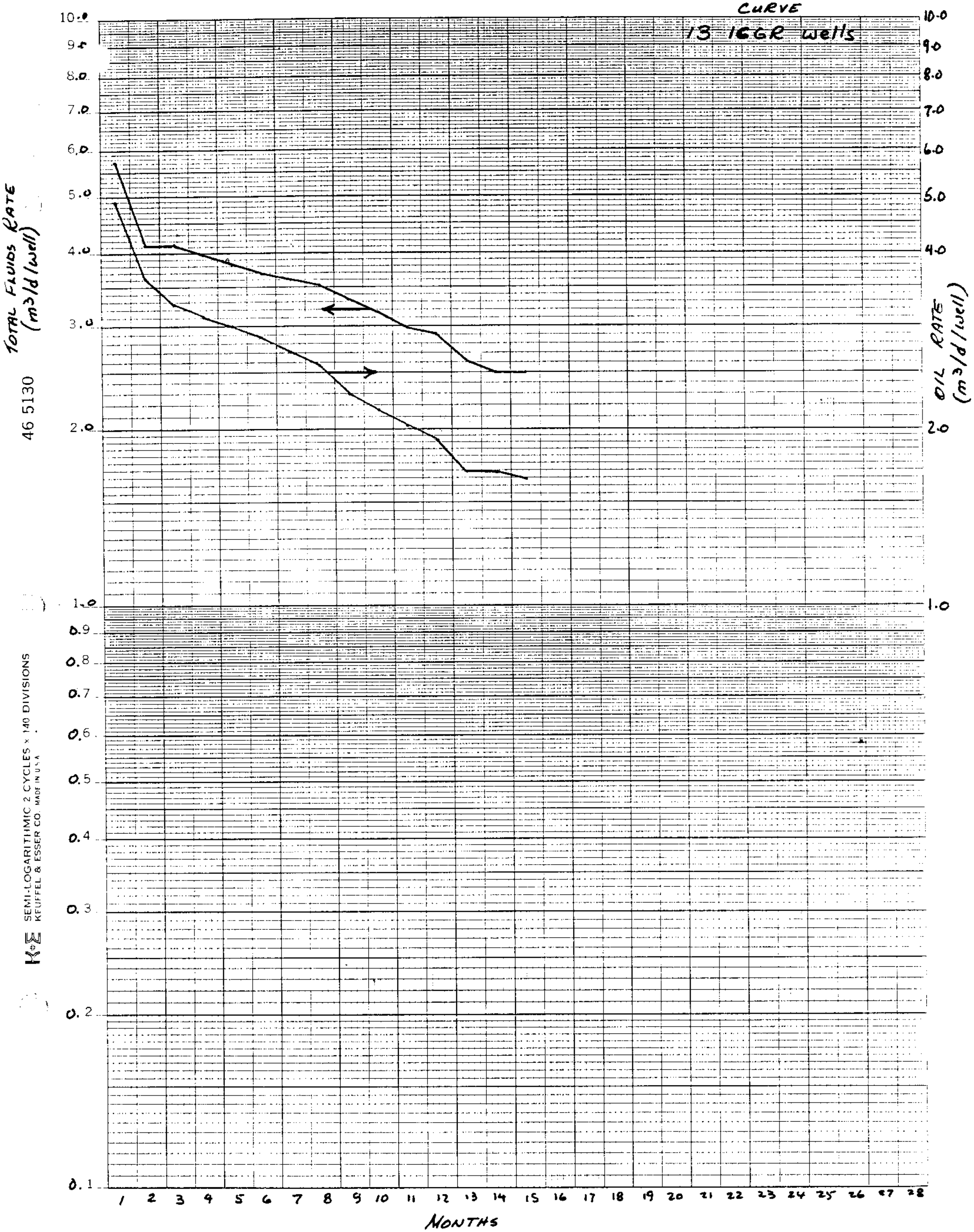
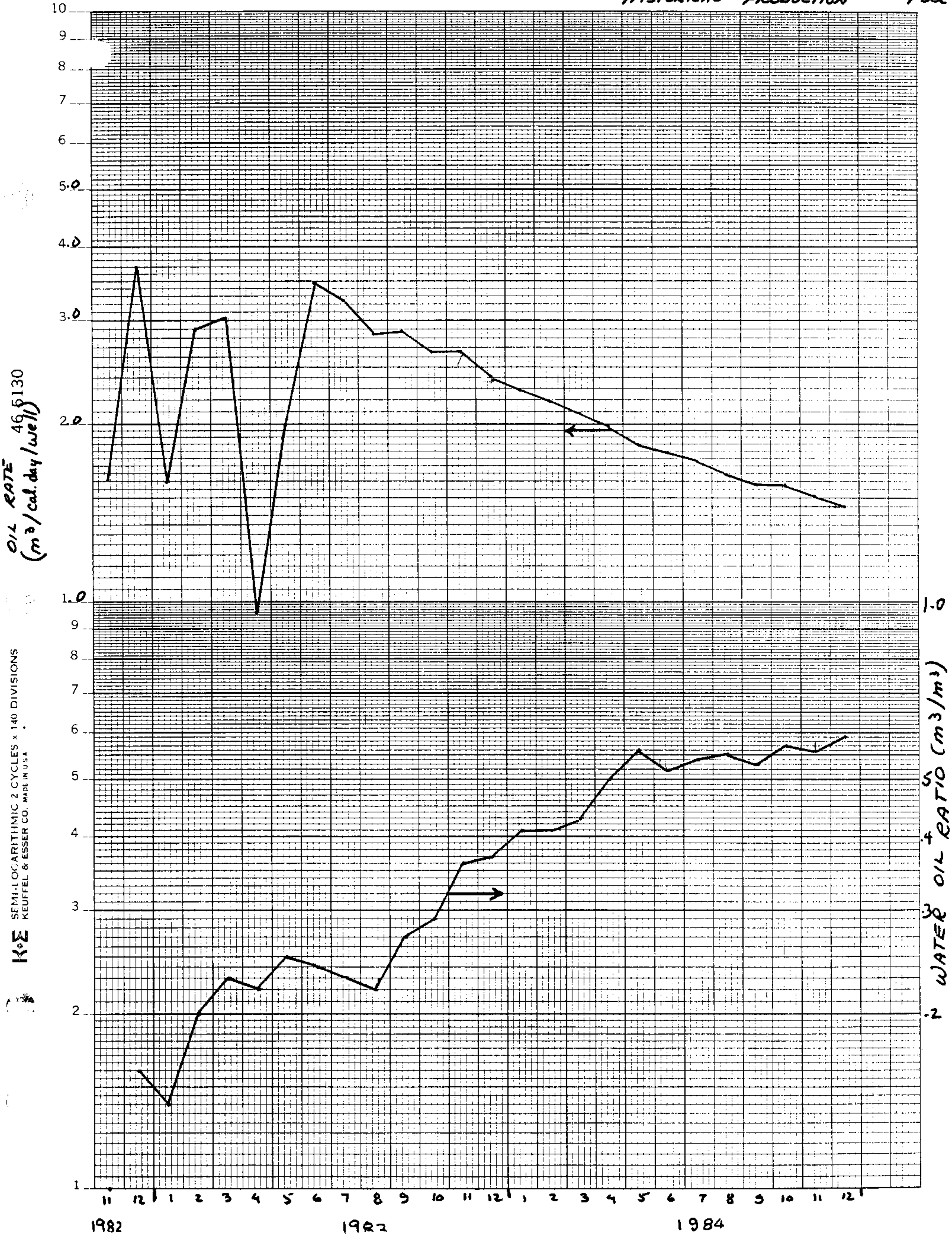


FIG. No. 2

NW EXTENSION VIRDEN LODGEPOLE A POOL

HISTORICAL PRODUCTION



February 15, 1984

ICG Resources Ltd.
2700, 140 - 4th Avenue S.W.
Calgary, Alberta
T2P 3S3

Attention: Mr. G. A. Henschel, P. Eng.
Reservoir Engineer

Dear Sirs:

Re: Virden Lodgepole A Pool - North West Extension

Your letter of January 25, 1984 regarding the feasibility of pressure maintenance operations in the northwest part of the Virden Lodgepole A Pool is acknowledged.

We concur that limited production history in the area makes it difficult to comprehensively evaluate the need for pressure maintenance. However, we question whether "several years" of production history are needed to properly evaluate this need. Further, it is suggested that other reservoir data, such as static reservoir pressures designed to quantify the amount of aquifer support would be of substantial assistance.

In light of the above, we request that you provide a preliminary analysis of the need for pressure maintenance in the subject area prior to March 1, 1985. This review should include an analysis of production trends and the results and evaluation of a reservoir pressure survey.

Yours sincerely,

Original Signed by H. C. Moster

H. Clare Moster, P. Eng.
Director, Petroleum Branch

LRD/lk

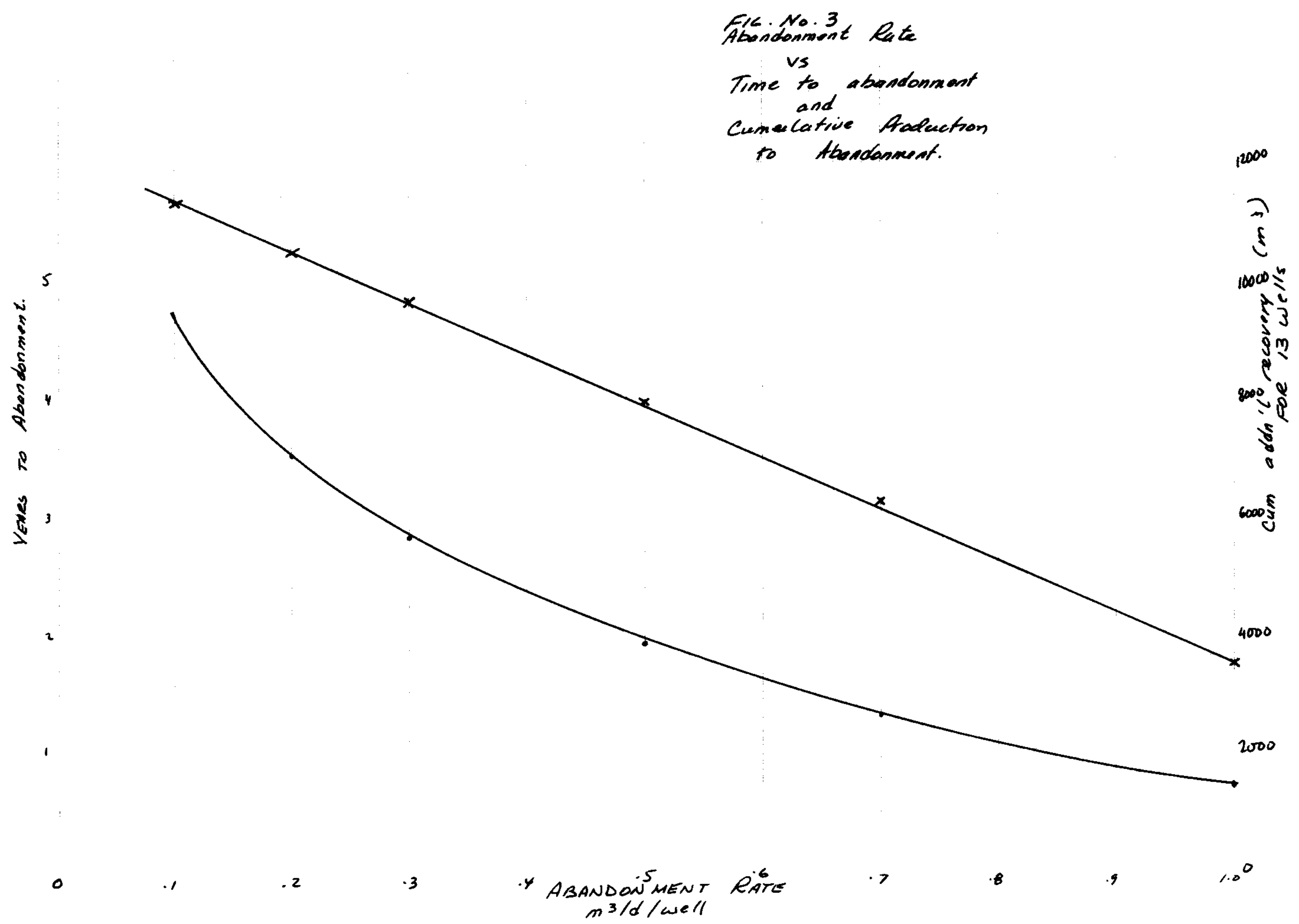
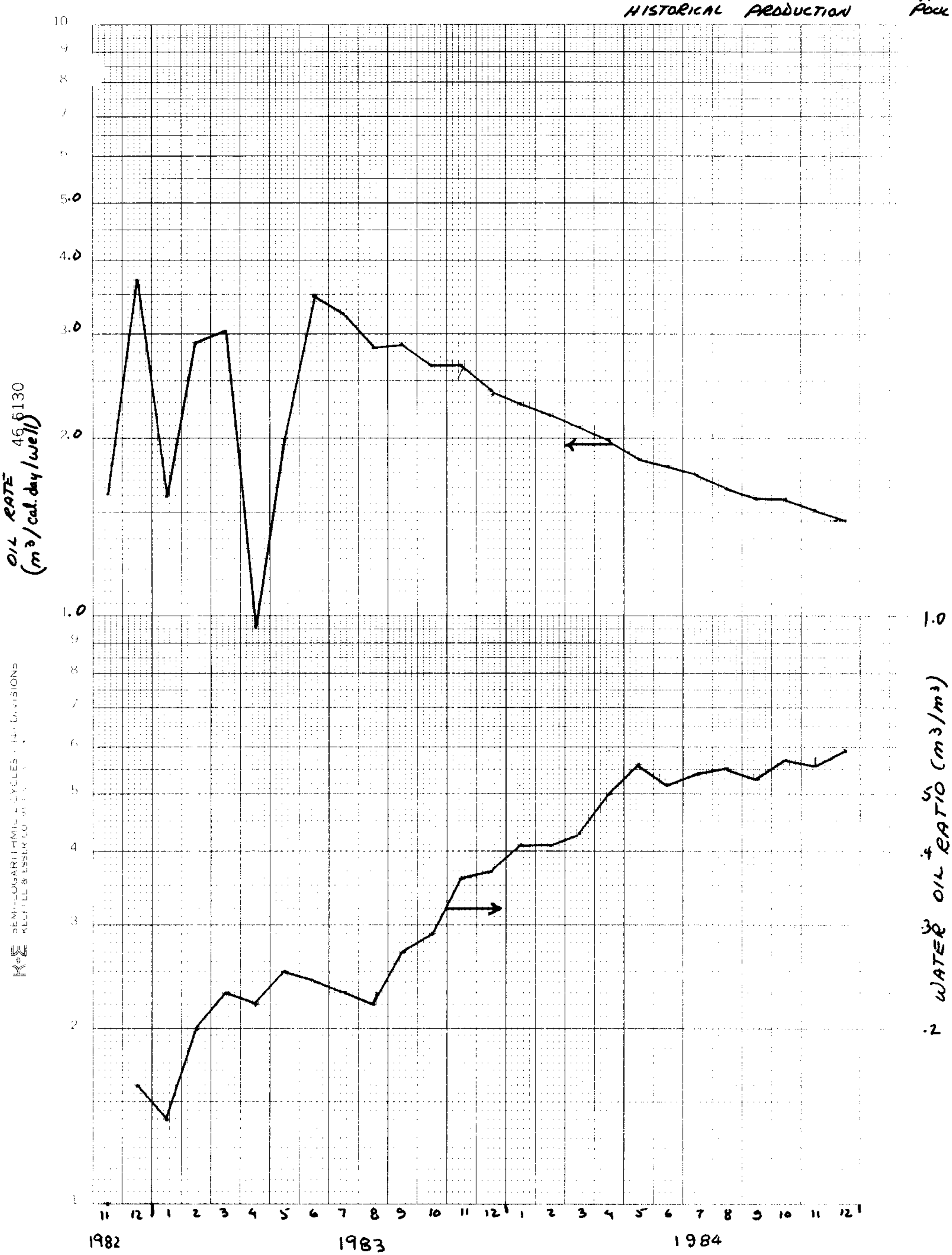
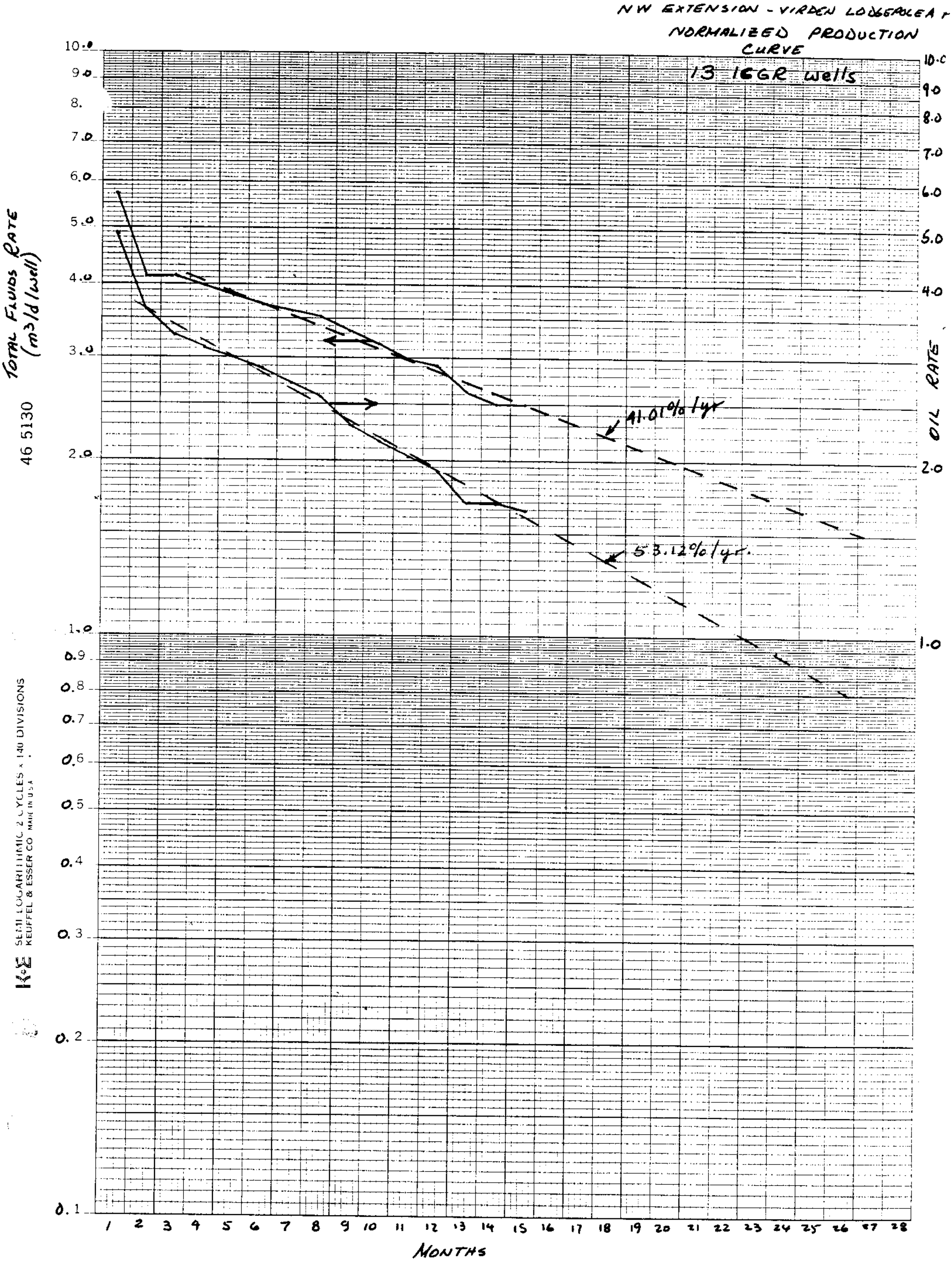


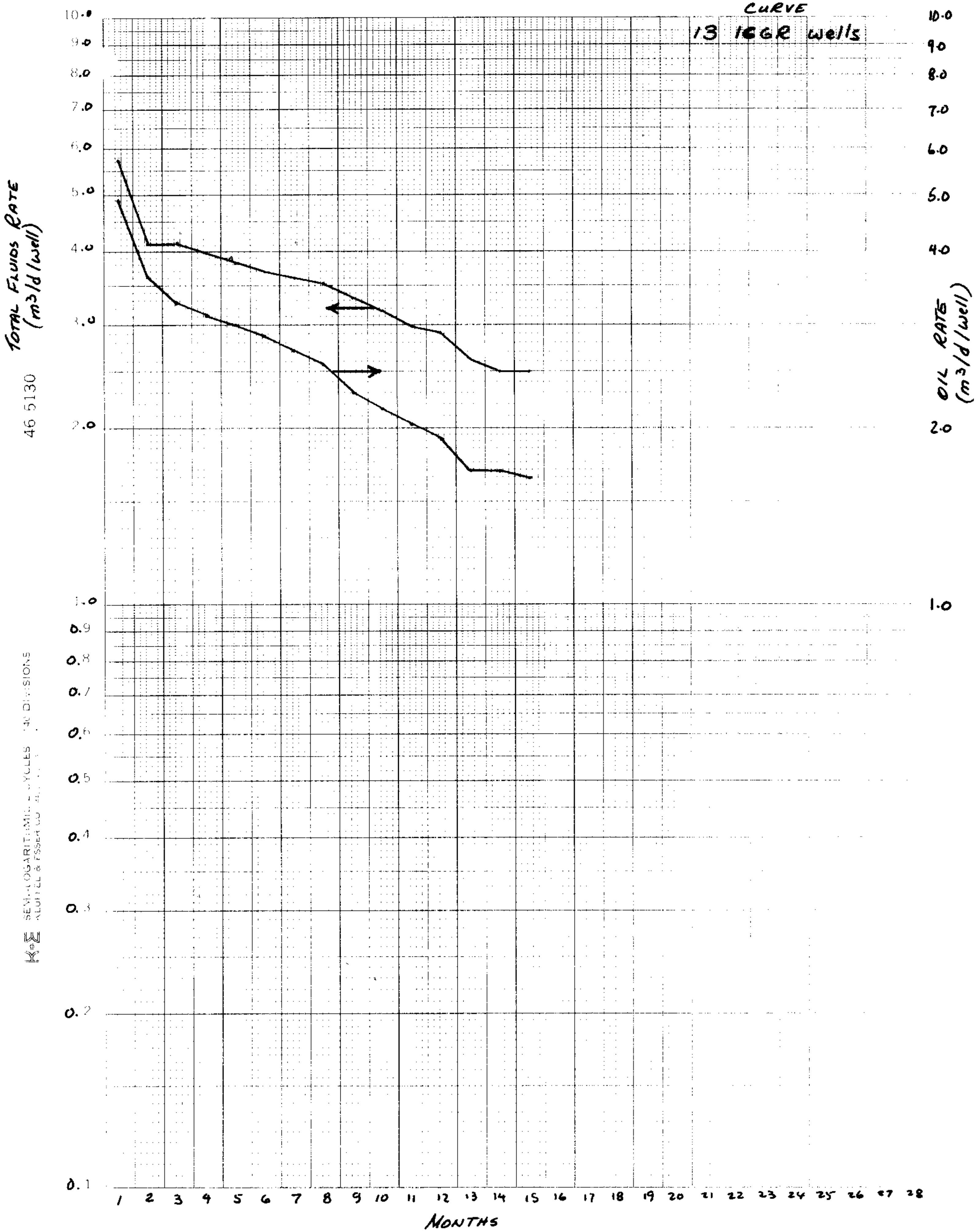
Fig. No. 3
Abandonment Rate
vs
Time to abandonment
and
Cumulative Production
to Abandonment.
Years to Abandonment.
1
2
3
4
5
Cum add'l recovery (m³)
FOR 13 wells
0
2000
4000
6000
8000
10000
12000
0
.1
.2
.3
.4
.5
.6
.7
.8
.9
1.0
ABANDONMENT RATE
m3/d/well

N W EXTENSION VIRDEN LODGEPOLE A POOL
HISTORICAL PRODUCTION




NW EXTENSION - VIRDEN LODGEPOLE A
NORMALIZED PRODUCTION CURVE
13 16GR wells
TOTAL FLUIDS RATE (m3/d/well)
OIL RATE
41.01%/yr
53.12%/yr.
MONTHS
46 5130
K+E SEMI-LOGARITHMIC 2 CYCLES x 140 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.

NW EXTENSION - VIRDEN LODGEPOLE A POOL
NORMALIZED PRODUCTION CURVE



Month # 1

Well	Oil	Water	Tot. Fluid	Days	Oil/Day	Fluid/Day
13-21	90.8	7.3	98.1	24	3.78	4.09
4-28	12.0	2.8	14.8	2	6.00	7.40
12-29	15.9	4.0	19.9	4	3.98	4.98
13-29	48.2	4.4	52.6	15	3.21	3.51
14-29	144.7	24.2	168.9	23	6.29	7.34
9-30	106.3	26.2	132.5	17	6.25	7.79
A15-30	33.8	9.6	43.4	30	1.13	1.45
12-30	42.2	8.5	50.7	8	5.28	6.34
1-31	60.0	4.5	64.5	11	5.45	5.86
3-32	47.9	22.0	69.9	10	4.79	6.99
4-32	30.2	1.6	31.8	4	7.55	7.95
5-32	91.8	2.7	94.5	27	3.40	3.50
6-32	13.2	1.1	14.3	2	6.60	7.15
					63.71	74.35
					4.90	5.72

13 wells

Month # 2

Well	Oil	Water	Tot. Fluid	Days	Oil/Day	Fluid/Day
13-21	101.0	10.2	111.2	31	3.26	3.71
4-28	121.1	58.0	179.1	30	4.04	5.97
~~12-29~~	~~53.5~~	~~22.5~~	~~76.0~~	~~28~~	~~1.91~~	~~2.71~~
13-29	114.7	16.0	132.7	31	3.70	4.28
14-29	30.2	5.3	35.5	5	6.04	7.10
9-30	158.9	53.9	212.8	30	5.30	7.09
A15-30	35.8	10.8	46.6	31	1.15	1.50
16-30	35.4	8.4	43.8	9	3.93	4.87
1-31	133.1	12.6	145.7	30	4.86	4.44
3-32	91.8	53.7	145.5	31	4.69	2.96
4-32	130.0	6.9	136.9	31	4.19	4.42
5-32	85.9	3.0	88.9	30	2.86	2.96
6-32	37.6	12.3	49.9	29	1.30	1.72
					47.23	53.73
					13 wells	
					3.63	4.13

MONTH # 3

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	91.3	11.7	1030	30	3.04	3.43
4-28	108.9	55.3	164.2	31	3.51	5.30
12-29	54.8	22.3	77.1	31	1.77	2.49
13-29	101.5	15.5	1170	31	3.27	3.77
14-29	52.5	9.2	61.7	9	5.83	6.85
9-30	150.1	64.2	214.3	30	5.00	7.14
A-5-30	20.2	6.8	27.0	18	~~1.50~~ 1.12	1.50
16-30	52.8	13.2	66.0	12	4.40	5.50
1-31	116.2	15.9	132.1	31	3.75	4.26
3-32	13.8	8.9	22.7	5	2.76	4.54
4-32	130.0	6.9	136.9	31	4.19	4.42
5-32	75.2	5.0	80.2	29	2.59	2.76
6-32	37.5	14.2	51.7	30	1.25	1.72
					42.48	53.68
					13 wells	
					3.27	4.13

MONTH # 4

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	85.0	12.4	97.4	31	2.74	3.14
4-28	99.4	60.0	159.4	30	3.31	5.31
18-24	26.6	10.7	37.3	15	1.77	2.49
13-29	89.7	11.8	101.5	28	3.20	3.62
14-24	176.0	33.5	209.5	30	5.87	6.98
9-30	143.0	65.0	208.0	31	4.61	6.71
A15-30	29.4	9.8	39.2	28	1.05	1.40
16-30	113.7	21.7	135.4	30	3.79	4.51
1-31	111.9	16.4	128.3	31	3.61	4.14
3-32	57.4	38.6	96.0	20	2.87	4.80
4-32	45.2	2.7	47.9	11	4.11	4.35
5-32	69.7	10.7	80.4	30	2.32	2.68
6-32	35.8	14.5	50.3	31	1.15	1.62
					40.40	51.75
					13 wells	"
					3.11	3.98

MONTH # 5

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	78.6	16.7	95.3	30	2.62	3.18
4-28	89.6	37.6	127.2	31	2.89	4.10
~~[illegible]~~	~~41.3~~	~~16.8~~	~~58.1~~	~~22~~	~~1.88~~	~~2.64~~
13-29	98.4	11.5	109.9	31	3.17	3.54
14-31	178.1	35.4	213.5	31	5.75	6.89
9-30	135.7	68.2	203.9	31	4.38	6.58
A15-30	34.7	5.9	40.6	31	1.12	1.31
16-30	118.1	19.4	137.5	31	3.81	4.44
1-31	100.1	10.8	110.9	29	3.45	3.82
3-32	69.4	60.2	129.6	30	2.31	4.32
4-32	93.2	5.1	98.3	21	4.44	4.68
5-32	66.4	10.8	77.2	31	2.14	2.49
6-32	33.9	15.2	49.1	31	1.09	1.58
					39.05	49.57
					13 wells	
					3.00	3.81

MONTH # 6

Well	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-29	74.9	13.9	88.8	31	2.42	2.86
4-28	92.5	50.7	143.2	31	2.98	4.62
12-29	54.9	18.0	72.9	30	1.83	2.43
13-29	20.7	2.3	23.0	7	2.96	3.28
14-29	182.4	38.6	221.0	31	5.88	7.13
9-30	117.7	59.1	176.8	28	4.20	6.31
A15-30	31.6	6.0	37.6	30	1.05	1.25
16-30	109.0	18.1	127.1	31	3.52	4.10
1-31	105.3	14.1	119.4	31	3.40	3.85
3-32	63.6	65.5	129.1	31	2.05	4.16
4-32	121.0	6.1	127.1	30	4.03	4.24
5-32	63.0	11.4	74.4	31	2.03	2.40
6-32	29.4	13.1	42.5	28	1.05	1.52
					37.4	48.15

13 wells

2.87 3.70

MONTH # 7

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	76.5	5.1	81.6	31	2.47	2.63
4-28	85.8	44.3	130.1	29	2.96	4.49
13-29	55.5	14.2	69.7	31	1.79	2.25
13-29	72.4	8.3	80.7	22	3.29	3.67
14-29	161.9	41.8	203.7	30	5.40	6.79
4-30	104.0	106.4	210.4	31	3.35	6.79
A15-30	24.7	7.0	31.7	31	0.80	1.02
16-30	99.0	17.5	116.5	30	3.30	3.88
1-31	103.9	11.6	115.5	30	3.46	3.85
3-32	56.4	67.2	123.6	31	1.82	3.99
4-32	113.4	5.8	119.2	31	3.66	3.84
5-32	54.6	5.9	60.5	28	2.15	2.16
6-32	23.1	23.7	46.8	31	0.75	1.51
					35.20	46.67

13 wells

2.71 3.60

MONTH # 8

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	69.3	14.8	84.1	29	2.39	2.90
4-28	81.8	42.8	124.6	29	2.82	4.30
12-29	52.6	14.7	67.3	31	1.70	2.17
13-29	90.9	10.6	101.5	30	3.03	3.38
14-29	135.0	41.8	176.8	28	4.82	6.31
9-30	94.7	108.5	203.2	30	3.16	6.77
A15-30	24.2	6.3	30.5	30	0.81	1.02
16-30	101.7	18.2	119.9	30	3.39	4.00
1-31	89.8	9.6	99.4	27	3.33	3.68
3-32	52.3	62.9	115.2	30	1.74	3.84
4-32	105.5	6.2	111.7	31	3.40	3.60
5-32	66.5	5.9	72.4	31	2.15	2.34
6-32	21.1	24.1	45.2	30	0.70	1.51
					33.44	45.82
					13 wells	3.52
					2.57	

MONTH # 9

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	72.8	19.6	92.4	31	2.35	2.98
4-28	69.6	66.3	135.9	30	2.32	4.53
12-29	48.3	15.4	63.7	30	1.61	2.12
13-29	84.2	11.3	95.5	31	2.72	3.08
14-29	128.6	53.5	182.1	30	4.29	6.07
9-30	80.3	93.8	174.1	31	2.59	5.62
A15-30	23.2	6.2	29.4	31	0.75	0.95
16-30	83.1	21.4	104.5	30	2.77	3.48
1-31	97.5	11.1	108.6	30	3.25	3.62
3-32	39.9	52.4	92.3	25	1.60	3.69
4-32	95.4	7.7	103.1	30	3.18	3.44
5-32	60.5	6.0	66.5	30	2.02	2.22
6-32	15.4	27.8	43.2	31	0.50	1.39
					29.95	43.19
					13 wells	
					2.30	3.32

MONTH # 10

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	68.0	14.8	82.8	30	2.27	2.76
4-28	66.7	60.2	126.9	31	2.15	4.09
12-29	35.9	11.9	47.8	23	1.56	2.08
13-29	80.6	12.8	93.4	31	2.60	3.01
4-29	122.7	54.2	176.9	31	3.96	5.71
9-30	67.8	76.9	144.7	27	2.51	5.36
15-30	22.2	6.3	28.5	31	0.72	0.92
16-30	79.2	21.7	100.9	31	2.55	3.25
1-31	99.3	13.0	112.3	31	3.20	3.62
3-32	42.9	74.9	117.8	30	1.43	3.93
4-32	75.2	7.7	82.9	27	2.79	3.07
5-32	58.7	7.0	65.7	31	1.89	2.12
6-32	14.5	25.3	39.8	30	0.48	1.33
					28.11	41.25

13 wells

2.16	3.17

MONTH # 11

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	64.8	15.9	80.7	31	2.09	2.60
4-28	58.6	44.5	103.1	30	1.95	3.44
12-29	40.2	17.8	58.0	30	1.34	1.93
13-29	76.1	10.5	86.6	30	2.54	2.89
14-29	116.3	56.8	173.1	31	3.75	5.58
9-30	75.1	83.1	158.2	31	2.42	5.10
A15-30	20.2	5.7	25.9	29	0.71	0.89
16-30	75.1	22.7	97.8	31	2.42	3.15
1-31	93.3	11.9	105.2	31	3.10	3.39
3-32	40.9	75.9	116.8	31	1.32	3.77
4-32	72.4	10.7	83.1	30	2.41	2.77
5-32	55.1	6.3	61.4	30	1.84	2.05
6-32	12.1	20.6	32.7	26	0.47	1.26
					26.36	38.82
					13 wells	
					2.03	2.99

MONTH # 12

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	60.3	13.9	74.2	30	2.01	2.47
4-28	54.5	56.4	110.9	31	1.76	3.58
12-29	38.3	18.1	56.4	31	1.24	1.82
13-29	72.0	8.7	80.7	29	2.48	2.78
14-29	100.9	49.1	150.0	28	3.60	5.38
9-30	72.0	85.2	157.2	31	2.32	5.07
A15-30	20.7	5.9	26.6	31	0.68	0.86
6-30	65.[illegible]	19.7	84.8	28	2.33	3.03
1-31	89.8	8.7	98.5	30	2.99	3.28
3-32	38.8	79.6	118.4	31	1.25	3.82
4-32	69.0	10.8	79.8	31	2.23	2.57
5-32	55.0	6.2	61.2	31	1.77	1.97
6-32	11.6	21.2	32.8	31	0.37	1.06
					25.03	37.69

13 wells

192 2.90

MONTH # 13

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	59.4	19.6	79.0	31	1.92	2.55
4-28	50.5	39.1	89.6	31	1.63	2.89
2-29	36.4	18.9	55.3	31	1.17	1.78
13-29	64.3	10.7	75.0	30	2.14	2.50
14-29	40.5	50.3	90.8	31	1.31	2.93
9-30	68.7	79.0	147.7	30	2.31	4.92
15-30	19.4	5.6	25.0	30	0.65	0.83
16-30	75.1	23.7	98.8	31	2.42	3.18
1-31	90.5	16.9	107.4	31	2.92	3.46
3-32	33.6	68.9	102.5	28	1.20	3.66
4-32	65.4	11.4	76.8	31	2.11	2.48
5-32	52.7	6.3	59.0	31	1.70	1.90
6-32	12.0	23.4	35.4	30	0.45	1.18
					21.93	34.26

13 wells

1.69 2.63

MONTH # 14

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-21	54.9	17.0	71.9	31	1.77	2.32
4-28	44.3	36.0	80.3	30	1.48	2.68
12-29	31.5	16.4	47.9	28	1.13	1.71
13-29	61.3	10.8	72.1	31	1.98	2.32
14-29	36.8	51.2	88.0	30	1.23	2.93
9-30	67.9	79.8	147.7	31	2.21	4.76
15-30	16.3	10.6	26.9	3	0.53	0.87
16-30	68.4	24.1	92.5	30	2.28	3.08
1-31	84.4	14.4	98.8	30	2.81	3.29
3-32	66.5	32.5	99.0	31	2.30	3.19
4-32	56.7	9.8	66.5	28	2.03	2.38
5-32	50.8	5.8	56.6	30	1.69	1.89
6-32	11.8	23.7	35.5	31	0.43	1.1[illegible]
					21.87	32.56

13

1.68	2.50

MONTH # 15

WELL	OIL	WATER	TOT. FLUID	DAYS	OIL/DAY	FLUID/DAY
13-31	53.4	15.0	68.4	30	1.78	2.28
4-25	44.1	42.1	86.2	31	1.42	2.78
[illegible]-29	34.7	[illegible]8	46.5	31	[illegible]2	1.50
13-29	58.2	11.4	69.6	31	1.88	2.24
[illegible]-29	30.9	52.1	83.0	31	[illegible].00	2.67
9-32	63.6	75.5	139.1	30	2.12	4.64
15-32	15.6	9.8	25.4	31	0.50	0.82
16-32	74.1	38.2	112.3	31	2.39	3.62
[illegible]-32	84.2	11.8	96.0	31	2.72	3.10
3-32	60.5	33.2	93.7	30	2.02	3.12
4-32	72.3	14.8	87.1	31	2.33	2.81
5-32	50.2	5.9	56.1	31	1.62	1.81
6-32	11.[illegible]	22.3	33.4	30	0.37	1.[illegible]
					21.27	32.50

13 wells 2.50

1.64

Recovery of other wells in Virden Lodgepole A Pool.
random sample - (every 11th well)

8-15-11-26	84 203.5
9-16-11-26	98 492.4
14-21-11-26	31 143.1
11-22-11-26	154 144.6
11-23-11-26	17992.8
14-24-11-26	41919.6
10-26-11-26	32630.4
9-27-11-26	67074.4
3-28-11-26	64082.6
2-33-11-26	464509
3-34-11-26	51120.8
1-4-12-26	39174.1
7-5-12-28	3339.0
2-19-11-26	8822.5
13-17-11-26	20558.2
6-8-11-26	1776.2
1-20-11-26	24358.8
3-29-11-26	11416.1

Current rate 1.45 m³/d.

Abandonment Rate	Time (yrs)	Np (m³)		
1	0.7 yr	289	×13	3757
0.7	1.3	482	×13	6266
0.5	1.9	611	×13	7943
0.3	2.8	739	×13	9607
0.2	3.5	803	×13	10439
0.1	4.7	868	×13	11284

Recovery Calculation

Cum Rec to 12-31-84 = 16,381.7

AT ECONOMICALLY LIMITING RATE OF $0.3\ m^3/d/well$

Remaining reserves = 9607

ULTIMATE Recovery = 25,988.7 or 1999 ⇒ $2000\ m^3/well$

OIL IN PLACE CALCULATION. - USE 5-32 (average well)

$h = 4.2\ m$ = 13.8 FT

ϕ = 19% $1/B_{oi}$ = 0.94

S_w = 65%

A = 40

Recovery $2000\ m^3$

< 2% of OOIP.

$N = 7758 \times 13.8 \times 40 \times 0.19 \times (1-0.65) \times 0.94 =$ 1,408,914 bbl

$= 223,992\ m^3$

ICG PRODUCTION

Month	OIL	WATER	wells	m^3/cd/well	WOR
11-82	48.2	4.4	1	~~1.55~~ 1.61	0.09
12-82	114.7	18.0	1	3.70	0.16
1-83	147.6	21.1	3	1.59	0.14
2	~~471.0~~ 323.4	63.6	4	2.89	0.20
3	561.9	127.1	6	3.02	0.23
4	171.9	38.3	6	0.96	0.22
5	369.6	91.2	6	1.99	0.25
6	625.9	150.1	6	3.48	0.24
7	703.7	158.9	7	3.24	0.23
8	791.3	173.3	9	2.84	0.22
9	950.8	255.8	11	2.88	0.27
10	985.3	284.1	12	2.65	0.29
11	1033.7	377.0	13	2.65	0.36
12	973.1	360.0	13	2.41	0.37
1-84	923.9	374.6	13	2.29	0.41
2	824.6	335.4	13	2.19	0.41
3	840.9	363.3	13	2.09	0.43
4	770.4	385.1	13	1.98	0.50
5	740.1	415.9	13	1.84	0.56
6	697.6	361.8	13	1.79	0.52
7	696.7	377.5	13	1.73	0.54
8	662.4	363.8	13	1.64	0.55
9	618.1	328.8	13	1.58	0.53
10	631.7	361.4	13	1.57	0.57
11	588.8	328.4	13	1.51	0.56
12	585.4	348.0	13	1.45	0.59

→ Bob
B/F

February 15, 1984

ICG Resources Ltd.
2700, 140 - 4th Avenue S.W.
Calgary, Alberta
T2P 3S3

Attention: Mr. G. A. Henschel, P. Eng.
Reservoir Engineer

Dear Sirs:

Re: Virden Lodgepole A Pool - North West Extension

Your letter of January 25, 1984 regarding the feasibility of pressure maintenance operations in the northwest part of the Virden Lodgepole A Pool is acknowledged.

We concur that limited production history in the area makes it difficult to comprehensively evaluate the need for pressure maintenance. However, we question whether "several years" of production history are needed to properly evaluate this need. Further, it is suggested that other reservoir data, such as static reservoir pressures designed to quantify the amount of aquifer support would be of substantial assistance.

In light of the above, we request that you provide a preliminary analysis of the need for pressure maintenance in the subject area prior to March 1, 1985. This review should include an analysis of production trends and the results and evaluation of a reservoir pressure survey.

Yours sincerely,

Original Signed by H. C. Moster

H. Clare Moster, P. Eng.
Director, Petroleum Branch

LRD/lk

→ Bob—
draft reply

ICG RESOURCES LTD
DIVISION OF INTER-CITY GAS CORPORATION

2700-140 FOURTH AVENUE S.W.
CALGARY ALBERTA CANADA
T2P 3S3
(403) 231-9000

DEPARTMENT OF ENERGY AND MINES
JAN 27 1984
PETROLEUM BRANCH

1984 01 25

Manitoba Government
Department of Energy and Mines
Mineral Resources Division
Petroleum Branch
975 Century Street
Winnipeg, Manitoba
R3H 0W4

Attention: H. Clare Moster, P. Eng.
Director

Dear Sir:

This is in reply to your letter of December 14, 1983, regarding enhanced recovery considerations for our lands in the Scallion - North Virden area.

ICG has drilled 18 wells, with 14 producing, 1 suspended and 3 D&A. Our Exploration Department is looking at several locations in order to find the northeastern limit of the Lodgepole A reservoir. A large majority of our wells have been on production for only 4-6 months and this does not allow enough production data to confidently evaluate the pool, including the drive mechanism. We need several years of stabilized data to realistically perform any type of competent reservoir engineering study.

We feel that after our drilling has been completed in the area, and after we have some characteristic production data, we will then be able to fully evaluate the possibility of secondary production. We are cognizant of the potential that a waterflood/pressure maintenance program has in terms of increasing the production rate and the ultimate recovery.

Yours sincerely,

ICG RESOURCES LTD.

G.A. Henschel

G.A. Henschel, P. Eng.
Reservoir Engineer

GAH/nb

Bob

December 14, 1983

ICG Resources Limited
2700, 140 - 4th Avenue S.W.
Calgary, Alberta
T2P 3S3

Attention: Mr. G. A. Henshel, P. Eng.
Reservoir Engineer

Dear Sirs:

Re: Virden Lodgepole A Pool

Further to your letter of August 16, 1983 regarding enhanced recovery considerations for your lands in the northwest part of the subject pool, we request that you provide an update of your evaluations. Please submit prior to January 31, 1984 a preliminary study of the feasibility of enhanced recovery operations for your wells. This study should include an indication of incremental reserves and a review of the economics for the possible schemes under consideration.

Yours sincerely,

Original Signed by H. C. Moster

H. Clare Moster, P. Eng.
Director, Petroleum Branch

LRD/1k

——> R&E

ICG RESOURCES LTD
DIVISION OF INTER-CITY GAS CORPORATION

2700-140 FOURTH AVENUE S.W.
CALGARY ALBERTA CANADA
T2P 3S3
(403) 231-9000

DEPARTMENT OF ENERGY AND MINES
AUG 19 1983
PETROLEUM BRANCH

1983 08 16

Manitoba Government
Department of Energy and Mines
Mineral Resources Division
Petroleum Branch
975 Century Street
Winnipeg, Manitoba
R3H 0W4

Attention: H. Clare Moster, P. Eng.
Director

Dear Sir:

ICG Resources has studied and reviewed the geology and production performance of the wells in the northwest part of the Virden Lodgepole Pool, as indicated by the Petroleum Branch in its letter dated May 18, 1983.

ICG's Geological and Reservoir Engineering personnel have been examining this reservoir with great detail, as we have just drilled 6 producing oil wells in the last year and other locations are pending.

Because of the long production history and the recovery to date of the wells on the southern portion of the area, ICG feels that it would be advantageous to set up our own project on the northern half of this area.

We have met with the other operators in this field and they agreed that it would be extremely difficult to assess the value of each well, since a majority of the wells have been producing for 20-25 years and ICG's wells have been producing for just a couple of months.

...2/

ICG feels that after our drilling has been completed in that area, we will then be evaluating the possible methods of a secondary production scheme. We are very cognizant of the possible potential that a waterflood/pressure maintenance program has in terms of increasing the production rate and the ultimate recovery.

Yours sincerely,

ICG RESOURCES LTD.

GHenschel.

G.A. Henschel, P. Eng.
Reservoir Engineer

GAH/nb
cc: P. Krenkel
W.J. Smart

→ Bob

December 14, 1983

Dome Petroleum Limited
Box 200
Calgary, Alberta
T2P 2H8

Attention: Mr. W. E. Froehlich, CET,
Enhanced Recovery and Special Studies

Dear Sirs:

Re: Virden Lodgepole A Pool

Your letter of December 5, 1983 regarding your review of waterflood feasibility in the northwest part of the subject pool is acknowledged.

While your review indicates that benefits to be derived from waterflooding in the mature portions of the pool may be marginal, we will continue to monitor production and field developments including secondary recovery proposals or operations of other operators in the area. Should such developments include implementation or consideration of waterflooding (or other enhanced recovery technique), further review and consideration from Dome and other operators in the area may be required.

Yours sincerely,

Original Signed by H. C. Moster

H. Clare Moster, P. Eng.
Director, Petroleum Branch

LRD/lk

DOME PETROLEUM LIMITED
BOX 200
CALGARY, ALBERTA, CANADA
T2P 2H8
(403) 231-3000

DEC 8 1983

1983 12 05

Department of Energy and Mines
Mineral Resources Division
Petroleum Branch
975 Century Street
WINNIPEG, Manitoba
R3H 0W4

Attention H. Clare Moster, P.Eng.
Director, Petroleum Branch

Dear Sir

RE: WATERFLOOD FEASIBILITY REVIEW
VIRDEN LODGEPOLE A POOL - WESTERN LEG

Pursuant to the Department's letter of 1983 05 18, Dome undertook in co-operation with Trans Canada Resources and Canadian Reserve Oil & Gas Ltd. to evaluate the feasibility of waterflooding the study area. An examination of the general area and specifically, data for the two Dome wells, indicated that additional water injection would be of marginal benefit to the mature portion of the study area.

In response to your request for pressure information, no bottom hole pressure surveys have been taken at the Dome wells. Telephone discussion with Canadian Reserve and Trans Canada yielded no additional historic pressure information. To the pressure data submitted by Suncor in their response of 1983 08 24, can be added the DST pressures for the ICG Resources Ltd. wells available through the Petroleum Information Exchange Ltd. card system.

ICG drilled an initial direct offset at 12-29-11-26 WPM to the Dome well 5-29-11-26 WPM during December 1982. The shut-in DST pressures listed are 6584 and 6034 kPa (955 and 874 psi). Subsequent drilling by ICG confirmed the above pressure with a sample range of 5958 to 6713 kPa (868 to 974 psi).

....2

Another indication of pressure maintenance in this area is the lack of significant decline in the total fluid production rates. The average total fluid production rate in the last 4 months of 1968 was 4.2 m^3/D for 4-29 and 1.7 m^3/D for 5-29. Average fluid rates during the first 5 months of 1983 were 3.9 m^3/D for 4-29 and 4.0 m^3/D for 5-29.

Oil production has declined at 2% per year at the 5-29 well during the last 15 years. At 4-29 the decline rate was 4% from 1968 to 1978 but has since increased to 10%. This increase in decline is being investigated for mechanical or well bore causes.

The low production decline rates combined with the low WOR indicate that substantial reserves remain to be recovered with the current mechanism. Cumulative production to year end 1982 represents 16.3% recovery for 4-29 based on 7.9 m of pay with 13.1% porosity. The 5-29 well with 5.5 m of pay had produced 12.6% of the OOIP.

The recoveries for the above wells compare favourably with other wells in the area when consideration is given to the initial productivity, the length of time on production, structural location and proximity to the water zone. In general the expected recovery factors for wells in the area will be within the range of the 14.9% primary and 25% flood recoveries projected by the November 28, 1968 study by McDaniel Consultants (1965) Ltd. for Ensign Oil Limited.

In conclusion, Dome on behalf of Trans Canada and Canadian Reserve submits that the combination of peripheral down dip injection plus water influx is providing a high degree of pressure support to the study area. Increasing the number of injectors would not add appreciable reserves but may place current production from offsetting wells at risk. For these reasons, the current method of operation is the most appropriate.

Yours very truly

Dome Petroleum Limited

W. E. Froehlich

W. E. Froehlich, CET
Enhanced Recovery &
Special Studies

WEF/gs

cc: Canadian Reserve Oil & Gas Ltd.
Suncor
Trans Canada Resources

→ BOB

CANADIAN RESERVE OIL AND GAS LTD.
1600,639-5th Avenue S.W. Calgary Alberta T2P 0M9 • (403)260-0800

DEPARTMENT OF ENERGY AND MINES
NOV 3 1983
PETROLEUM BRANCH
m

1983-11-01

Department of Energy and Mines
Mineral Resources Division
Petroleum Branch
975 Century Street
Winnipeg, Manitoba
R3H 0W4

Attention: H. Clare Moster, P. Eng.
Director, Petroleum Branch

Dear Sir:

Re: Waterflood Feasibility Review
Virden Lodgepole A Pool

Further to the Department's 1983-05-18 letter regarding waterflood feasibility in the Virden Lodgepole A Pool, Canadian Reserve would like to update the Department with regard to the current status of the review.

1. Canadian Reserve's investigation indicated that on a stand alone basis a waterflood scheme on this Company's operated lands is not economically feasible given current production performance, ultimate recoverable reserves, and location on the structure.

2. Several area working interest owners met 1983-08-28 to discuss the merits of a joint waterflood study. Canadian Reserve, Suncor, Dome, ICG and TransCanada Resources were in attendance at that meeting. ICG advised the meeting that they were planning on submitting to the Department a separate report. Suncor later informed the remaining participants that rather than participate in a joint study they would submit a separate report which concluded that waterflooding was not feasible (1983-08-24).

3. Dome, TransCanada and Canadian Reserve agreed to pool their effort towards investigating the feasibility of a joint technical study. It was agreed that Dome would first scope the need for the study and set up the criteria and parameters for an in-depth review. It is now this Company's understanding that Dome's review has also indicated that a waterflood would not be feasible. Further, Dome will be submitting to the Department a letter summarizing their investigation.

. . ./Page 2

If there are any questions on this matter, our contact is P. D. (Peter) Sametz at (403) 260-0800.

Yours truly,

CANADIAN RESERVE OIL AND GAS LTD.

G. S. Boon
Manager, Engineering

PDS/jr

cc: Dome Petroleum Limited
Attention: Craig Ladkin

TransCanada Resources
Attention: Domenic Galati

Suncor Inc.
Resources Group
Production Division

1983-08-24

Department of Energy & Mines
Mineral Resources Division
Petroleum Branch
975 Century St.
Winnipeg, Manitoba
R3H 0W4

DEPARTMENT OF ENERGY AND MINES
AUG 29 1983
PETROLEUM BRANCH

Dear Sir:

Waterflood Feasibility Review
Virden Lodgepole "A" Pool

Suncor has completed a review of the reservoir performance and considered the feasibility of initiating a water injection scheme in Suncor's non-unitized western flank area of the Lodgepole "A" pool. We believe waterflooding of our acreage is unwarranted as study results indicate little or no incremental oil recovery.

This review was undertaken in response to your request that the feasibility of a water injection scheme be considered. Your review of geology and production performance indicated a structural high in the proposed unit and coupled with the relatively low degree of water production, suggested that this area is somewhat remote from the acquifer.

Suncor's evaluation consisted of studying production performance and using decline forecasting techniques to predict remaining reserves and the ultimate recovery factor for our acreage. Individual well forecasts were made to determine the contribution of each and highlight the variation in recovery factors.

Suncor's western flank acreage has eight oil wells capable of economic production (1 near abandonment) and two water injection wells presently being used for salt water disposal. The oil wells are producing at rates of 0.2 - 3.2 m^3/d with an average watercut of 98 percent, with the exception of wells 6-20 and 11-20. These wells produce substantially less water and are believed to be realizing somewhat less benefit from the acquifer.

An ultimate recovery of 19 percent of the calculated original oil-in-place (OOIP) is expected from Suncor's wells. Seventeen percent of the OOIP was recovered as of 31 December 1982.

..../2

P.O. Box 38, 500 - 4th Avenue S.W. Calgary, Alberta T2P 2V5 Telephone (403) 269-8100

There is tremendous variation in the individual well recovery factors ranging between 1 and 40 percent. The majority of Suncor's wells with low recovery factors are in edge positions along the western flank rim of the pool, where permeabilities are less continuous and the effects of the acquifer are limited. These wells are adjacent to the 10-20 injector yet the WOR is low. Considering the reduced reservoir quality and the previous observation, it is unlikely any incremental oil would be swept by injecting additional water. The recovery factor for these wells is around 1 percent. The remaining wells recovery factors are between 11 - 40 percent. When compared to more likely recovery factors of 18-20 percent, the effects of pressure maintenance by the acquifer and the salt water disposal scheme are evident. The average producing water-oil ratio of 44 m^3/m^3 also indicates the presence of an active acquifer under Suncor lands. It is noted that those wells to the north and northwest of our property do have relatively low WOR's as you indicated, and are possible candidates for waterflooding.

However, results of pressure surveys, although few, indicate the acquifer is active in providing pressure maintenance to our wells. The original pressure in the flank area of the pool was 918 psia in 1955. Subsequent drilling in 1968, north and west of Suncor's acreage, indicated pressures in the order of 865 psia. A pressure survey conducted in June 1968 on well 12-20-11-26 W1 indicated a reservoir pressure of 835 psia and a pressure buildup survey done in 1972 on well 13-20 indicated an extrapolated pressure of approximately 900 psia.

Copies of the last two surveys are found in Attachment 10 and 11. Recent quality pressure information is not available, however, a survey performed by Chevron in 1979 on a well located immediately to the south reported a pressure of approximately 800 psia. Assuming this pressure is representative of pressures in Suncor's adjacent wells, it would appear the acquifer and SWD scheme are adequately maintaining pressure in our portion of the pool.

A salt water disposal system has been in service since April, 1958 to date with the exception of a period between 1975 and 1979. In 1979 the SWD system was re-activated. During this time water has been injected into wells 2-20, 8-20, 10-20, and 5-21 although not concurrently. Both the Crinoidal and Cherty zones were flooded with this produced water. Oil production from wells 1-20, 3-20, 6-20, and 4-21 will exceed the primary recoverable reserves estimated for each spacing unit. The estimates of ultimate recovery factors for Suncor's wells are shown in Attachment 9. It is believed the incremental oil is a

..../3

result of water injection in wells 10-20, 8-20, 2A-20, and 5-21 combined with the pressure maintenance afforded by the acquifer.

As pertains to the proposed water injection scheme, five Suncor wells are involved as shown in Attachment #1. Of these five, one is currently an injector, one is suspended (13-20), and one is near abandonment (11-20), producing 0.2 m^3/d. This leaves two potential producers with a total oil productivity of less than 2 m^3/d and combined water production of approximately 46 m^3/d. Both these wells appear to be responding to the acquifer and SWD system, as the estimated ultimate recovery for 6-20 is approximately 31 percent, and a 22 percent recovery factor is estimated for 12-20, which currently has a WOR of 45 m^3/m^3.

As a note of interest, the suspended well 13-20 has no potential as a producer but would certainly be a good candidate for water injection in any future water injection scheme formed to the north of our property. It appears this well is located in the most northernly portion of the advancing acquifer. Both the wellbore and casing are in reasonable condition and amenable to water injection.

As a result of this review, Suncor concludes that little or no additional incremental oil recovery is expected by implementing further water injection into the Lodgepole "A" pool in our properties.

Therefore, Suncor feels additional waterflooding is unwarranted in Suncor lands. We propose to continue operating according to the current depletion strategy - which includes water injection.

Yours truly,

R.J. Waraksa
Manager, Reservoir Eng.

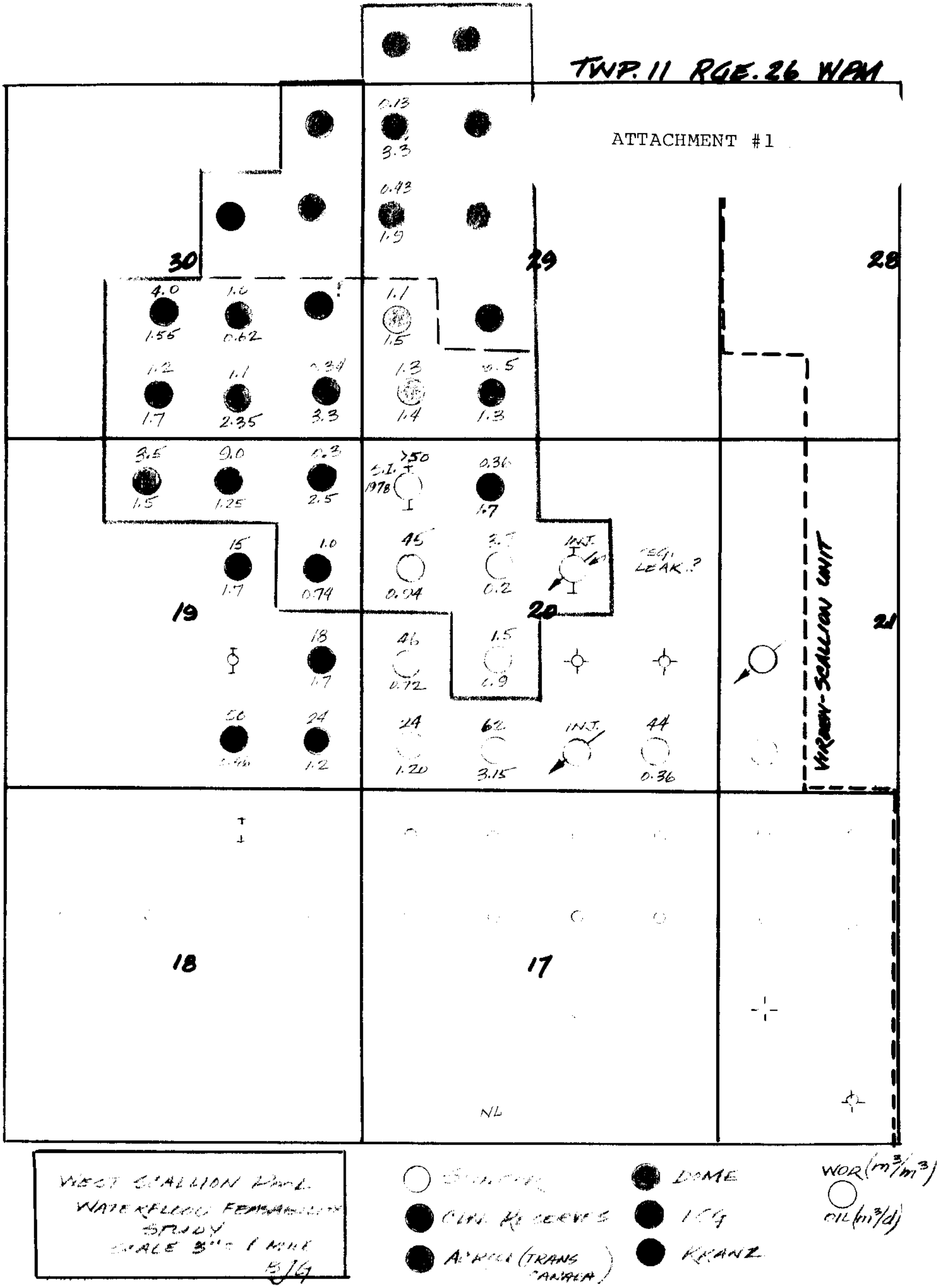
GB/sc
c.c. Canadian Reserve Oil & Gas Ltd.
Dome Petroleum Ltd.
Trans Canada Resources

LIST OF ATTACHMENTS

Virden Scallion Review

1. Map Showing Suncor Acreage
2. Original Oil in Place Calculations
3. Structure - Cherty Zone
4. Net Pay - Cherty Zone
5. Structure - Crinoidal Zone
6. Net Pay - Crinoidal Zone
7. Decline Curve Analysis
8. (a-j)
   Rate vs. Time Plots
9. Reserves - Drainage Unit Basis
10. BHP Survey 1968
11. BHP Survey 1972
12. Current Cash Flow Calculation.

ATTACHMENT #1



West Scallion Pool
Waterflood Feasibility Study
Scale 3" = 1 mile
BJG

ATTACHMENT 2

Oil-In-Place Calculations

North Virden Scallion Area

*N.B. Taken From 1979 Study by B. Schlacter

Crinodal Zone

Reservoir Parameters	Source
$\phi = 10.4\%$	Core Analysis
$S_{wi} = 52\%$	Oil Base Core
$B_{oi} = 1.046$ RB/STB	PVT Analysis

$$\text{Yield} = 7758 \times \phi \times (1 - S_{wi})/B_{oi}$$

$$= 370.25 \text{ BBL/AC.FT.}$$

$$(477.2 \text{ m}^3/\text{ha.m})$$

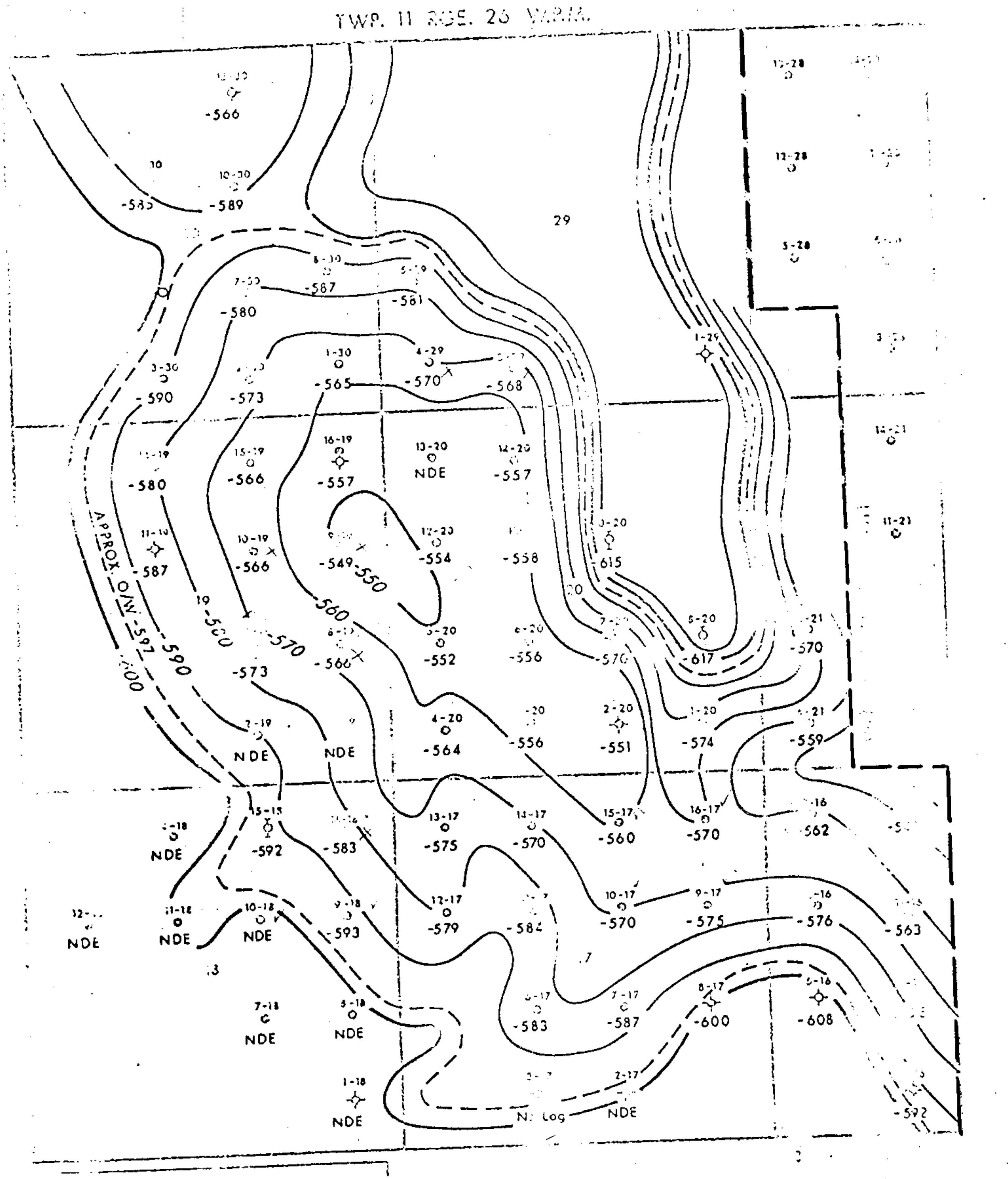
Cherty Zone

Reservoir Parameters	Source
$\phi = 15.2\%$	Core Analysis
$S_{wi} = 30\%$	Oil Base Core
$B_{oi} = 1.046$	PVT Analysis

$$\text{Yield} = 7758 \times \phi \times (1-S_{wi})/B_{oi}$$

$$= 789.15 \text{ BBL./AC. FT.}$$

$$(1017.1 \text{ m}^3/\text{ha.m})$$

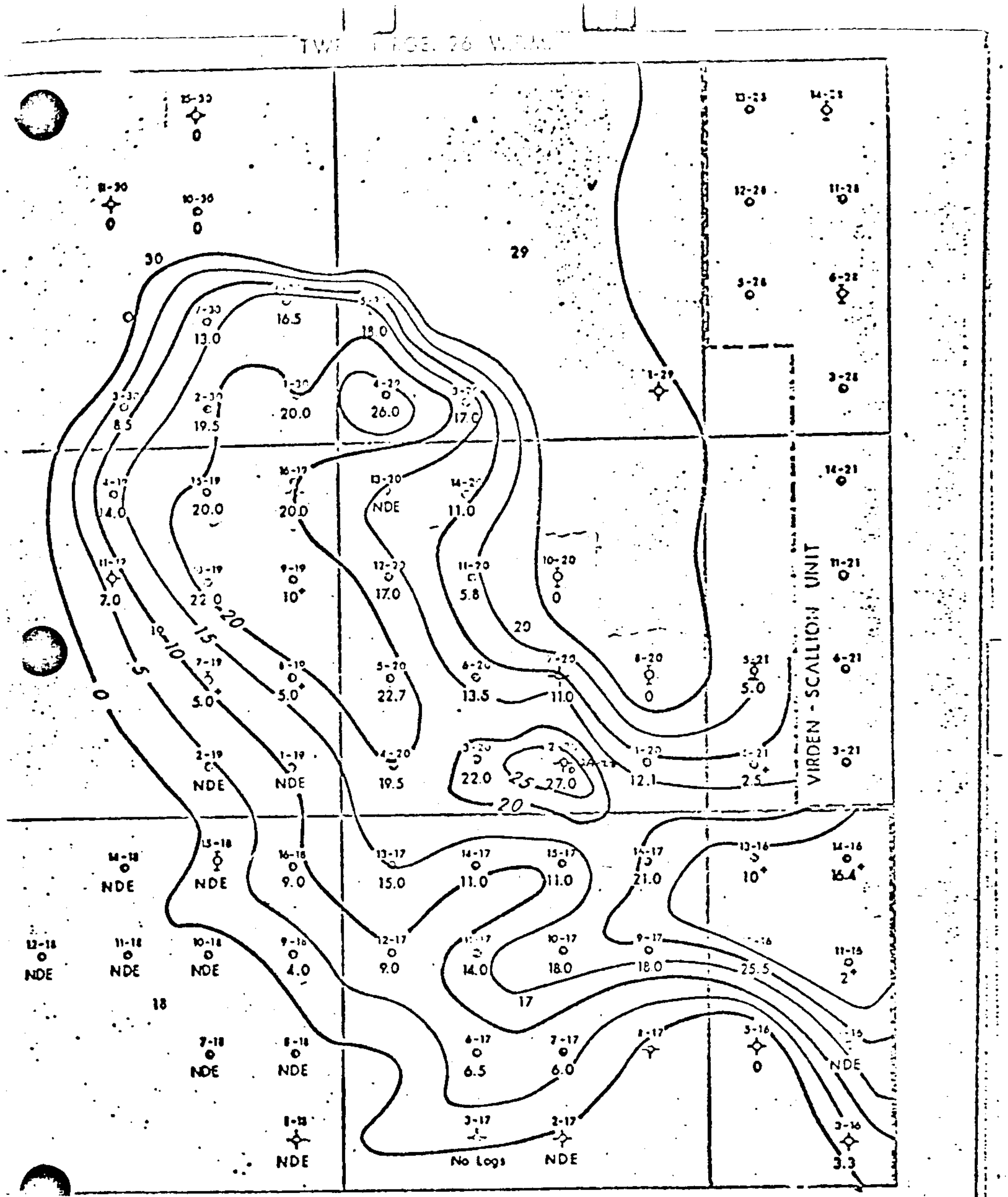


WEST SCALLION POOL
ENGINEERING AND
UNITIZATION STUDY
SCALE. 3" = 1 MILE   C.I. = 10 FT. SS.
(FROM McDANIEL'S STUDY 1968)

STRUCTURE

TOP OF CHERTY ZONE

ATTACHMENT #3

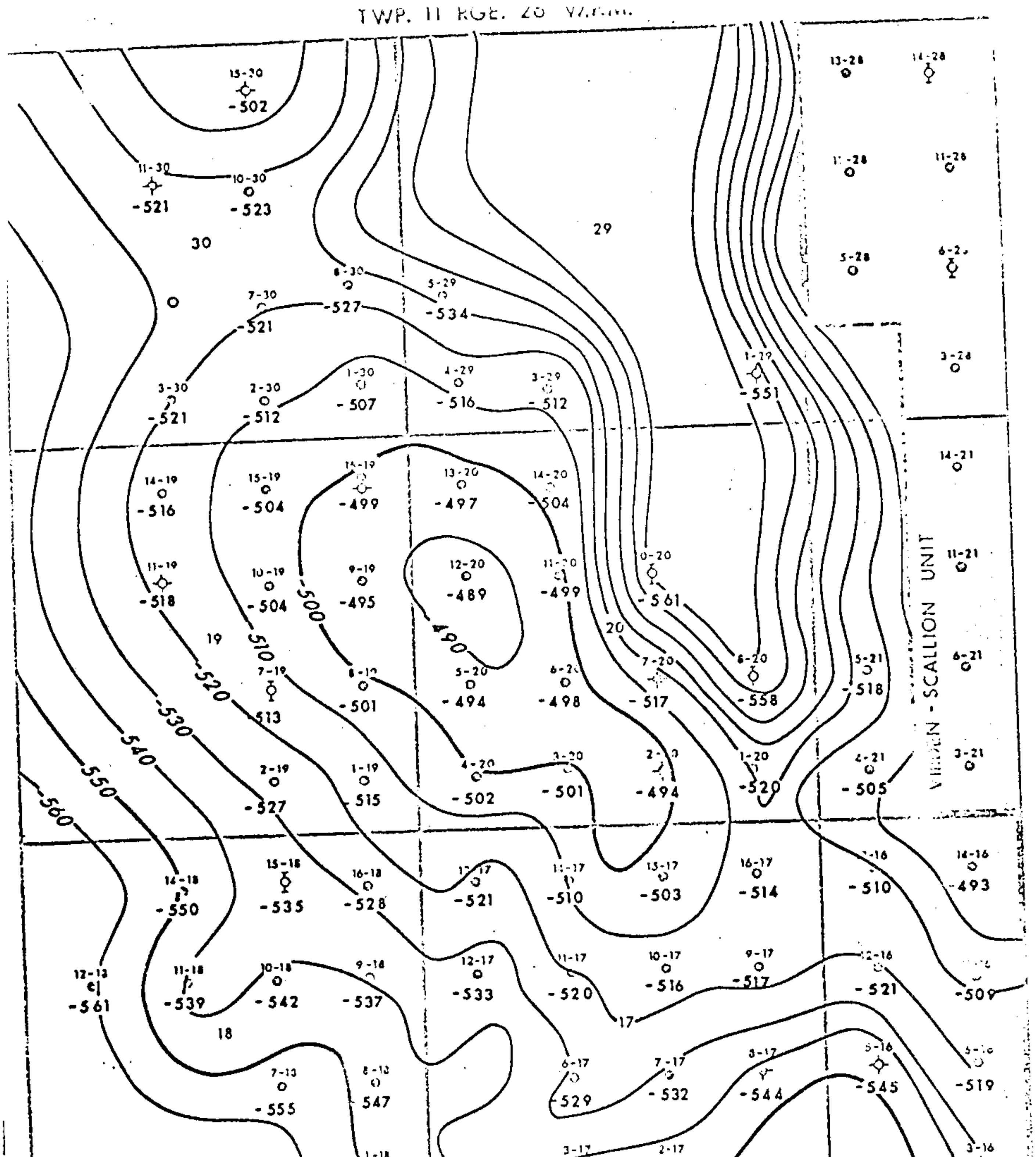


WEST SCALLION POOL
ENGINEERING AND
UNITIZATION STUDY
SCALE: 3" = 1 MILE C.I. = 5 FT.
(FROM McDANIEL'S STUDY 1968)

NET PAY

CHERTY ZONE

ATTACHMENT #4



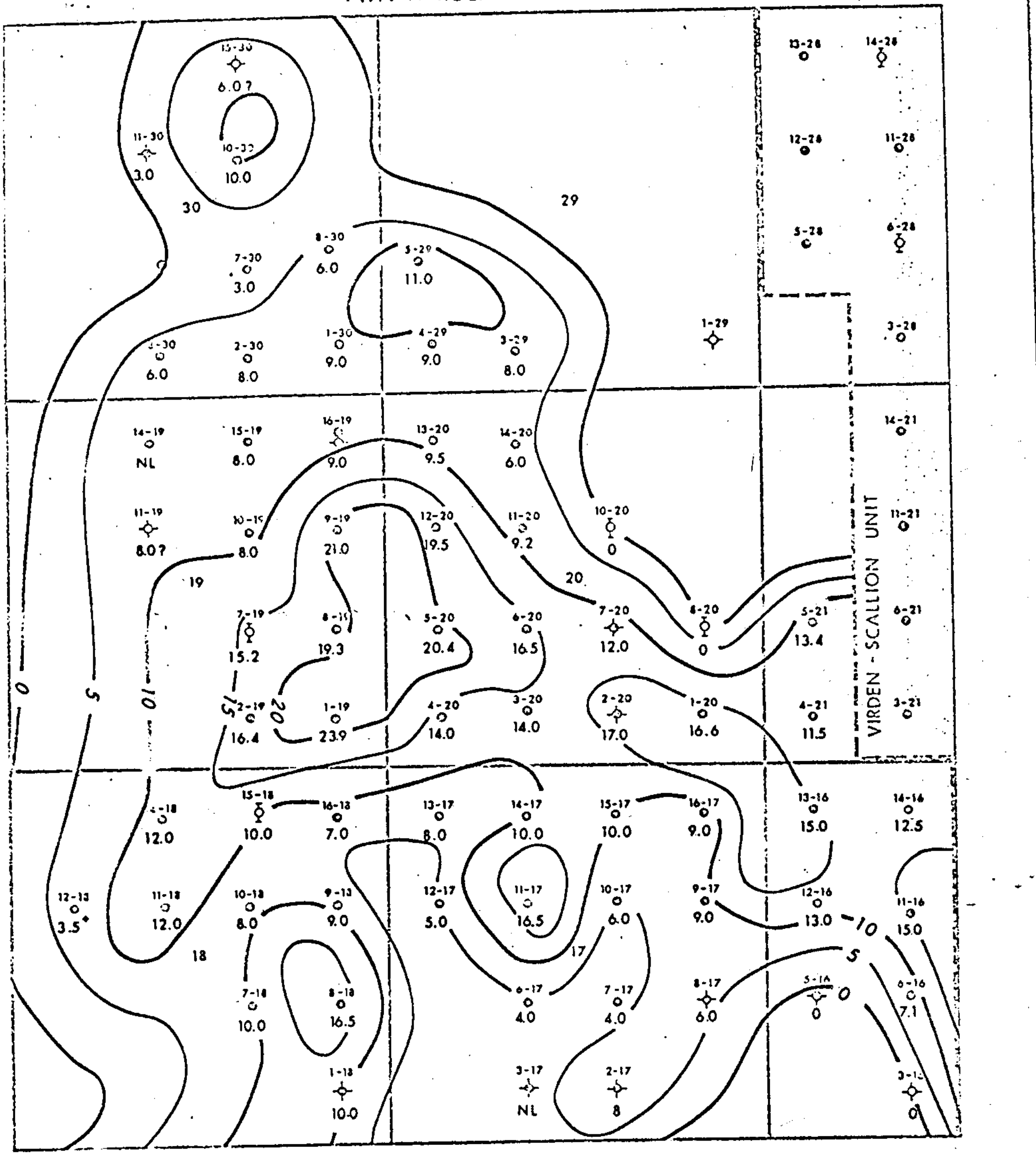
WEST SCALLION POOL
ENGINEERING AND
UNITIZATION STUDY
SCALE: 3" = 1 MILE C.I. = 10 FT. SS.
(FROM McDANIEL'S STUDY 1968)

STRUCTURE

TOP OF CRINOIDAL ZONE

ATTACHMENT #5

TWP. 11 RGE. 26 W.P.M.



WEST SCALLION POOL
ENGINEERING AND
UNITIZATION STUDY
SCALE: 3" = 1 MILE   C.I. : 5 FT.
(FROM McDANIEL'S STUDY 1968)

NET PAY
CRINOIDAL ZONE

ATTACHMENT #6

ATTACHMENT #7

Decline Curve Analysis
North Virden Scallion Area

q_i = 8.3 m^3/d

q_f = 2.0 m^3/d (From $\frac{\text{Yrly. Operating Costs}}{\text{Oil Price}} = \frac{\$118\ 358/\text{yr.}}{\$184.53/m^3}$)

decline = 13 percent exponential per year

Remaining Recoverable Reserves = $\frac{(q_i - q_f)365}{D}$

R.R.R. = $\frac{(8.3 - 2.0)365}{0.13}$

R.R.R. = $\underline{\underline{17\ 688}}$ m^3

Actual Cumulative to 1982.12.31:	189 338.6
Actual 1983 Production to 1983.03.31:	668.1 m^3
Remaining (From Decline Analysis):	17 688.0 m^3
Ultimate Total :	207 695.2 m^3
O.O.I.P. (Suncor 100% W.I. - Crinoidal + Cherty)	1 103 000 m^3

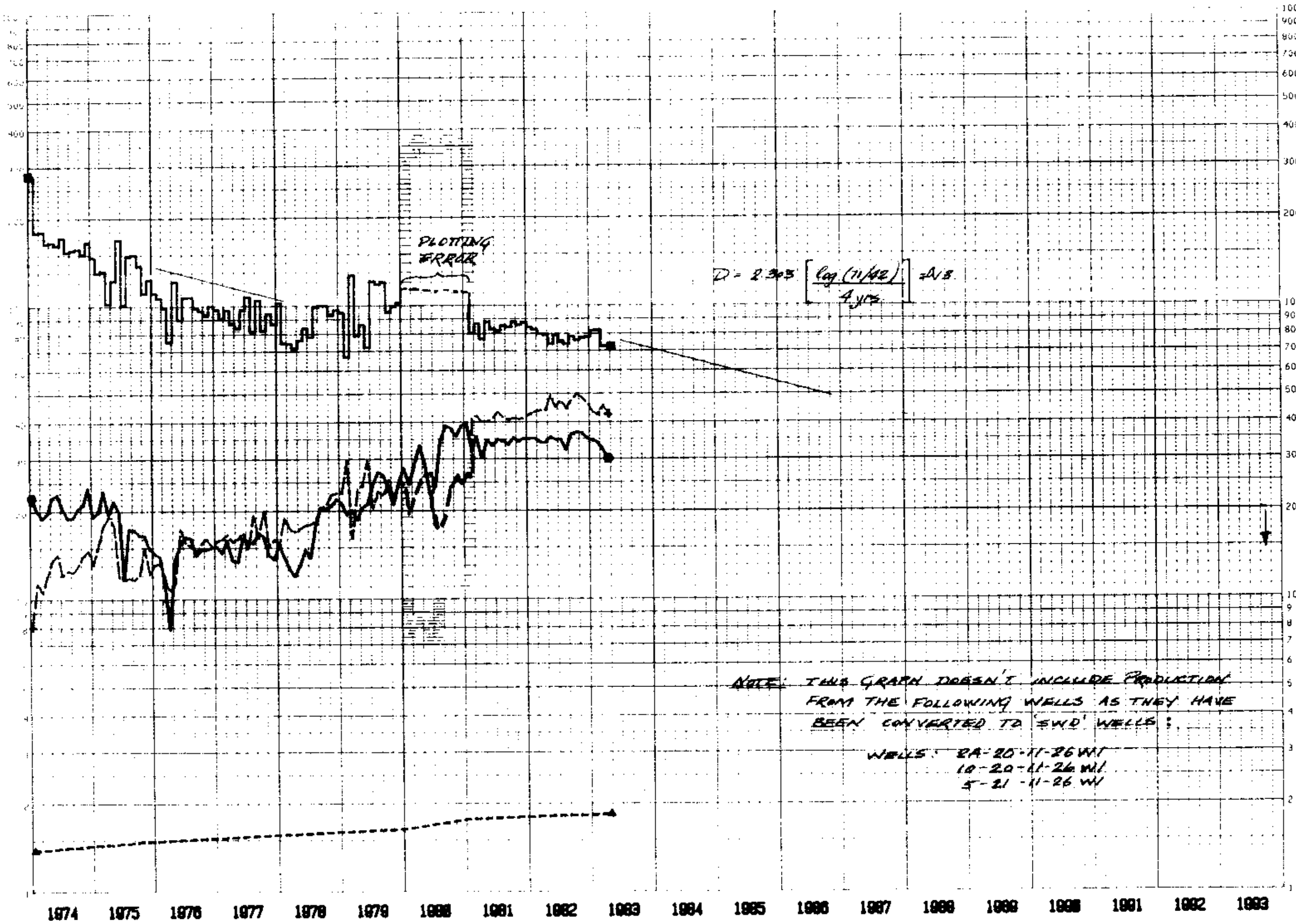
Current Recovery Factor = 17.2%

Ultimate Recovery Factor = 18.8%

PROP SUM : VIR .PRO

VIRDEN SCALLION WELLS

VIRDEN SCALLION WELLS



FINAL PRODUCTION VALUES

CUM OIL	100327.30	m3
CUM GAS	0.00	E3m3
CUM WATER	1324137.00	m3

ATTACHMENT #8a

DLY OIL	m3/DAY	(□)	X .1
DLY WTR	m3/DAY	(⊙)	X 10.
CUM OIL	m3	(▲)	X 100000.
WATER/OIL	m3/m3	(+)	X 1.

DATALINE INC.

21465

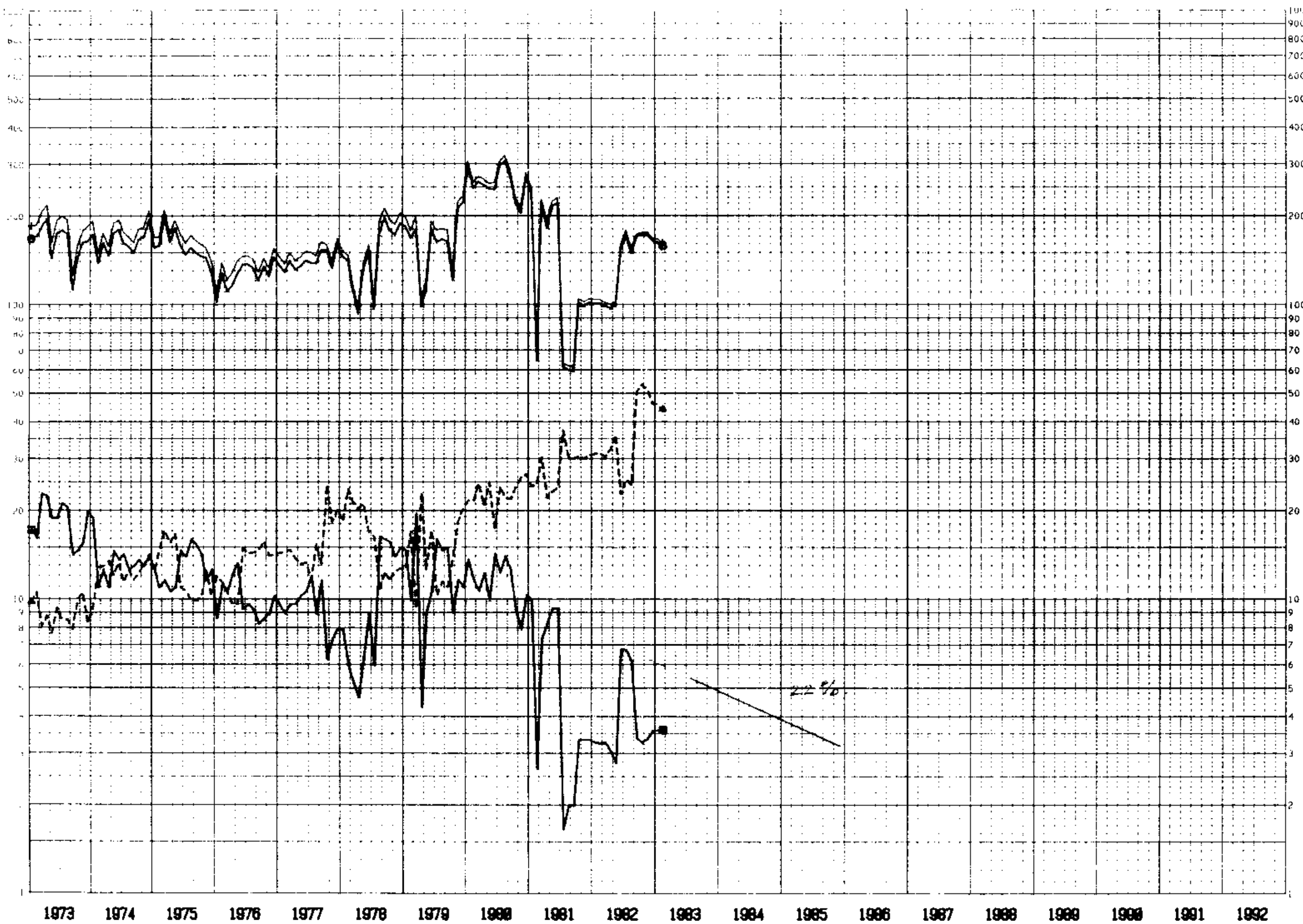
00/01-20-011-26W1/0

FIELD : 6 NORTH VIRDEN SCALLIO

VIRDEN UNIT

SUNCOR W. SCALLION 1-20-11-26

POOL : 0



FINAL PRODUCTION VALUE.

CUM OIL	24295.50	M3
CUM WATER	112565.10	M3
CUM FLD	136860.60	M3

ATTACHMENT #8b

DLY OIL	M3/DAY	(□)	X .1
DLY WTR	M3/DAY	(○)	X .1
WATER/OIL	M3/M3	(△)	X 1.
DLY FLD	M3/DAY	(+)	X .1

DATALINE INC. 3C100L

19706

00/03-20-011-26W1/0

FIELD : 6 NORTH VIRDEN SCALLIO

VIRDEN UNIT

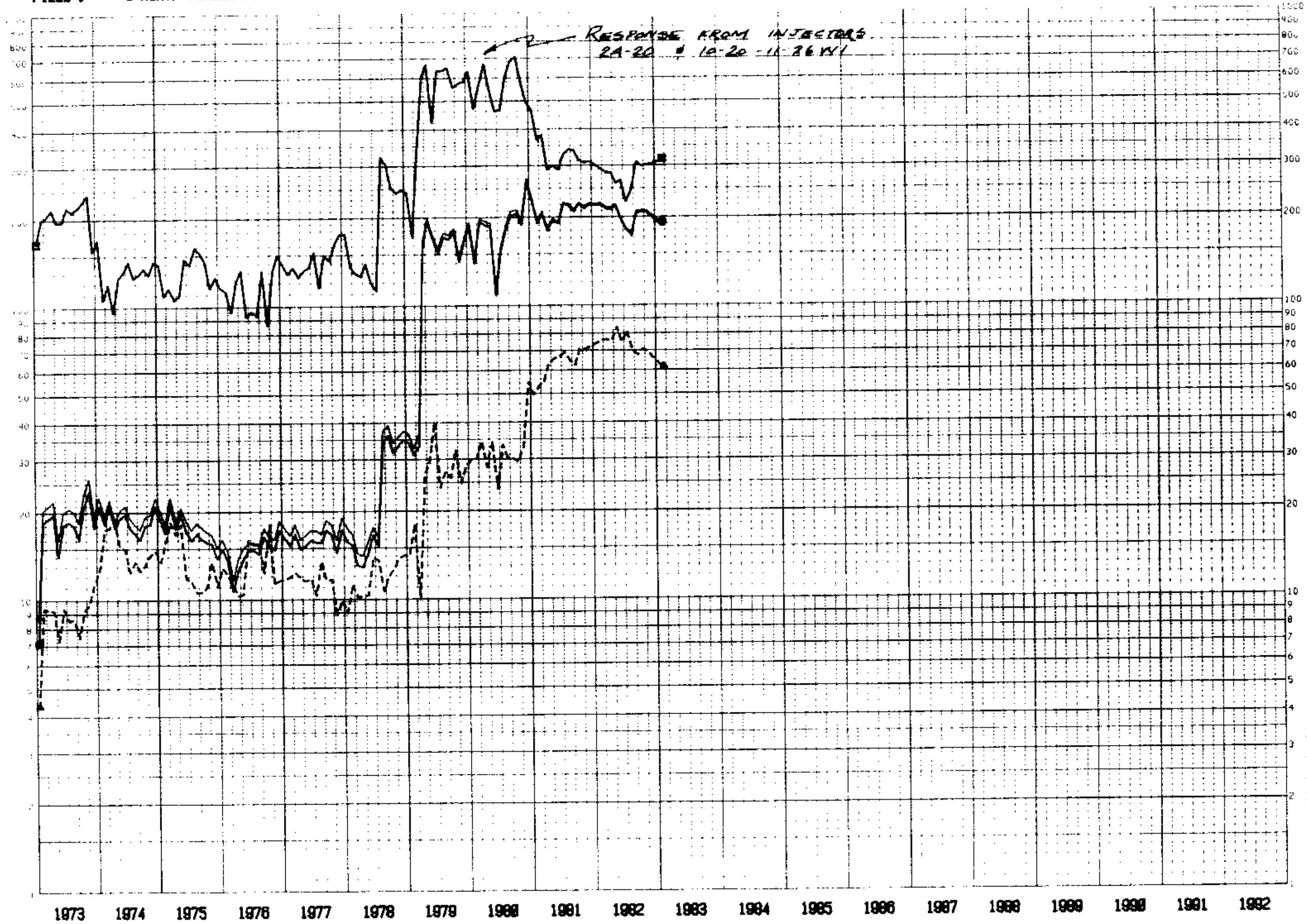
SUNCOR W. SCALLION 3-20-11-26

POOL : 0

FINAL PRODUCTION VALUE

CUM OIL	25368.00	M3
CUM WATER	381461.90	M3
CUM FLD	406829.90	M3

ATTACHMENT #8c



DLY OIL	M3/DAY	(□)	X .01
DLY WTR	M3/DAY	(○)	X 1.
WATER/OIL	M3/M3	(△)	X 1.
DLY FLD	M3/DAY	(+)	X 1.

DATALINE INC. 3C100L

19707

00/04-20-011-26W1/0

FIELD : 6 NORTH VIRDEN SCALLIO VIRDEN UNIT

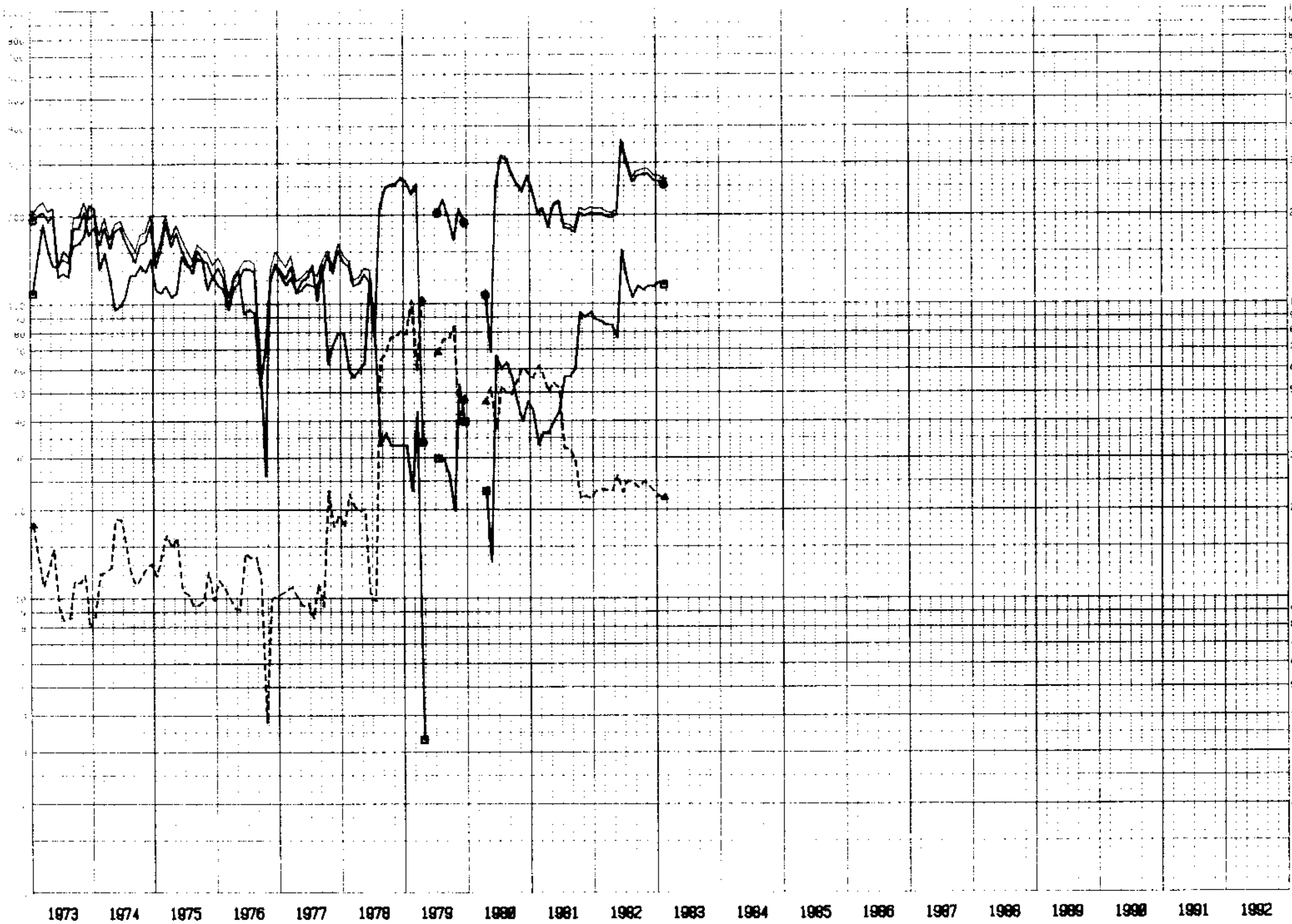
SUNCOR W. SCALLION 4-20-11-26

POOL : 0

FINAL PRODUCTION VALUES

CUM OIL 19649.40 M3
CUM WATER 121488.80 M3
CUM FLD 141138.20 M3

ATTACHMENT #8d



DLY OIL M3/DAY (□) X .01
DLY WTR M3/DAY (O) X .1
WATER/OIL M3/M3 (△) X 1.
DLY FLD M3/DAY (+) X .1

DATALINE INC. 3C100L

19700

00/05-20-011-26W1/0
FIELD : 6 NORTH VIRDEN SCALLIO

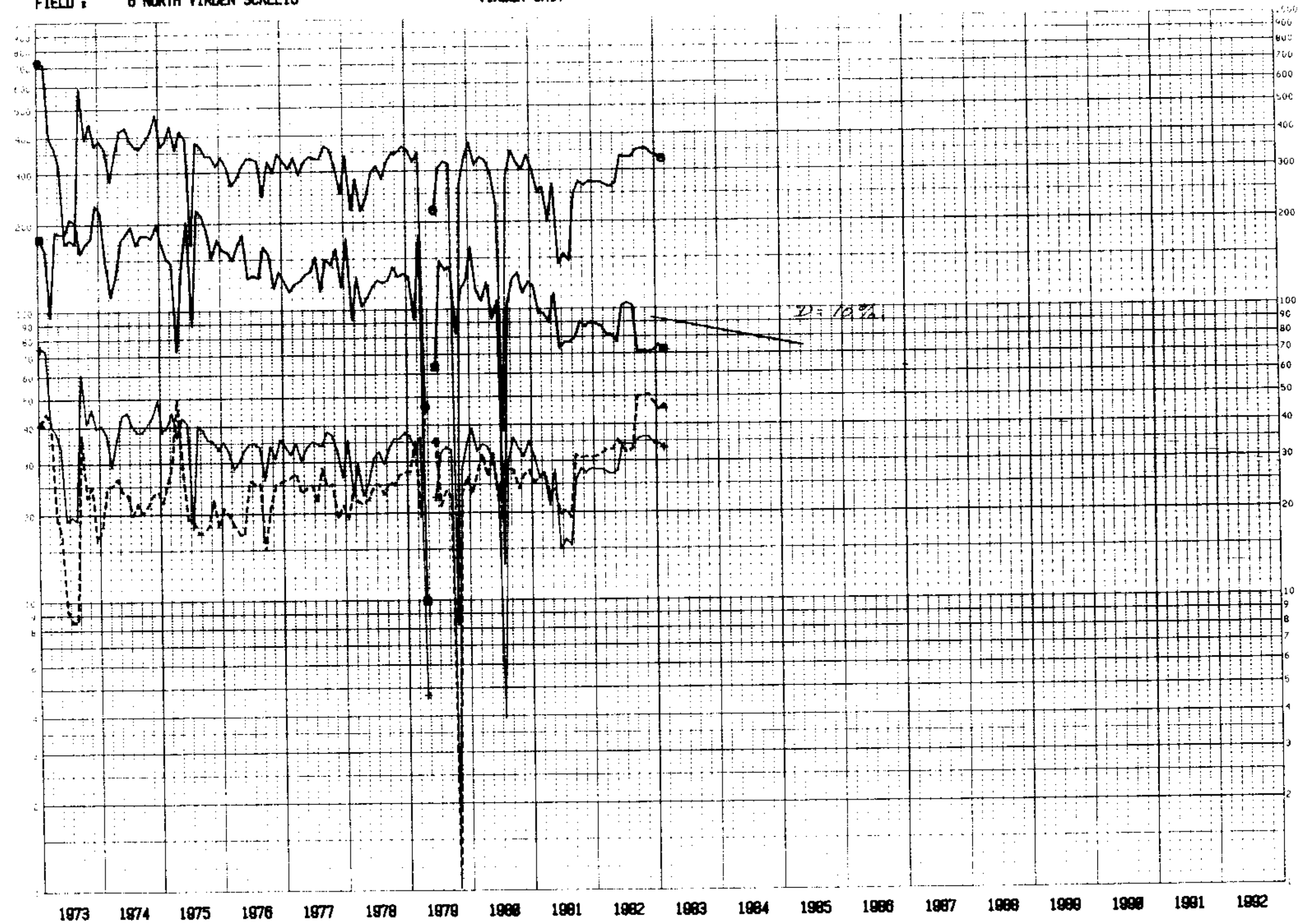
VIRDEN UNIT

SUNCOR W. SCALLION 5-20-11-26
POOL : 0

FINAL PRODUCTION VALUES

CUM OIL	11680.10	M3
CUM WATER	187177.40	M3
CUM FLD	198857.50	M3

ATTACHMENT #8e



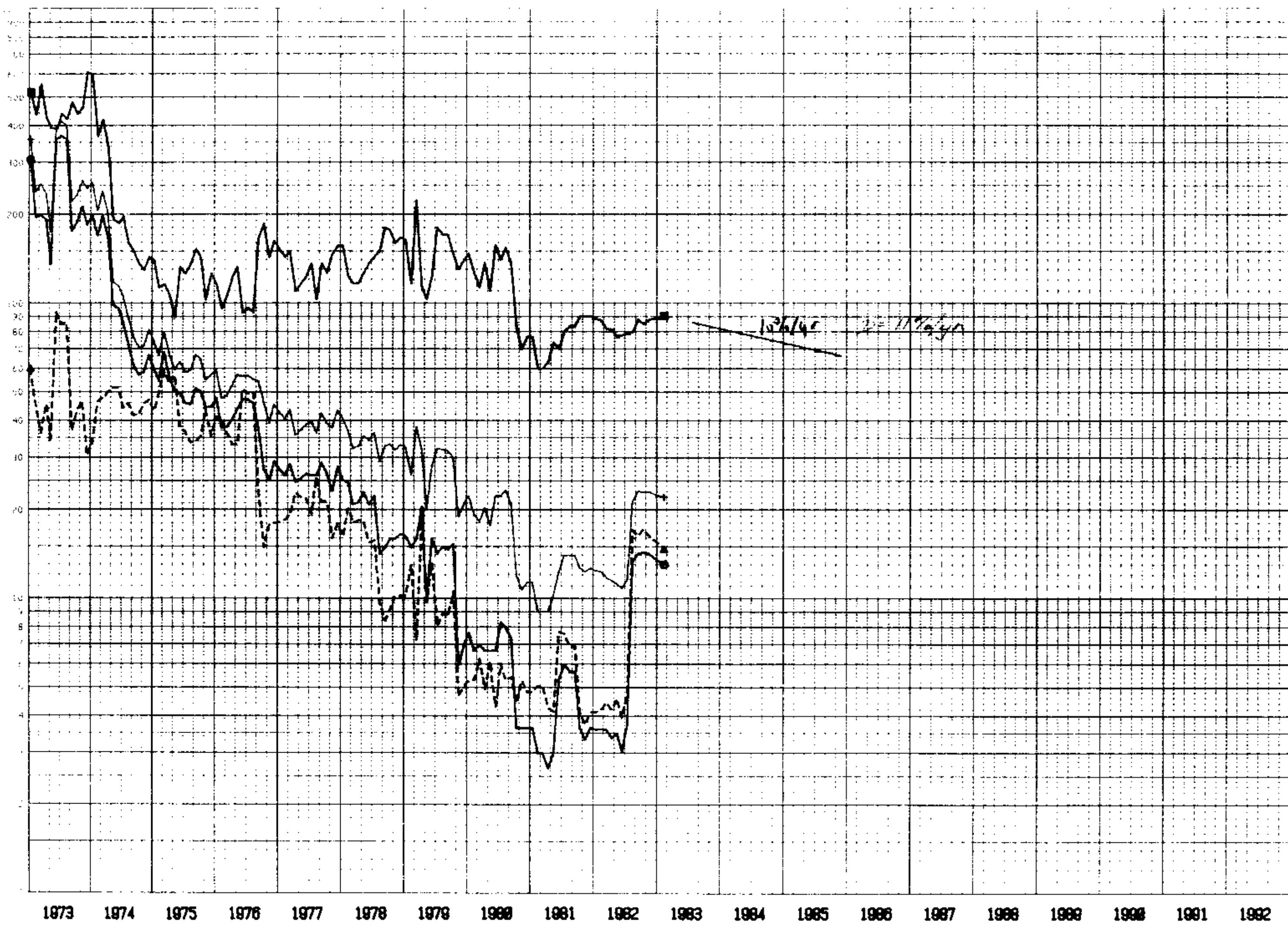
DLY OIL	M3/DAY	(□)	X .01
DLY WTR	M3/DAY	(O)	X .1
WATER/OIL	M3/M3	(△)	X 1.
DLY FLD	M3/DAY	(+)	X 1.

DATALINE INC. 3C100L

19700

00/06-20-011-26W1/0 SUNCOR W. SCALLION 6-20-11-26

FIELD : 6 NORTH VIRDEN SCALLIO VIRDEN UNIT POOL : 0



FINAL PRODUCTION VALUES

CUM OIL	22927.30	M3
CUM WATER	75407.10	M3
CUM FLD	98334.40	M3

ATTACHMENT #8f

DLY OIL	M3/DAY	(⊡)	X .01
DLY WTR	M3/DAY	(⊙)	X .1
WATER/OIL	M3/M3	(▲)	X .1
DLY FLD	M3/DAY	(+)	X .1

DATALINE INC. 3C100L

19710

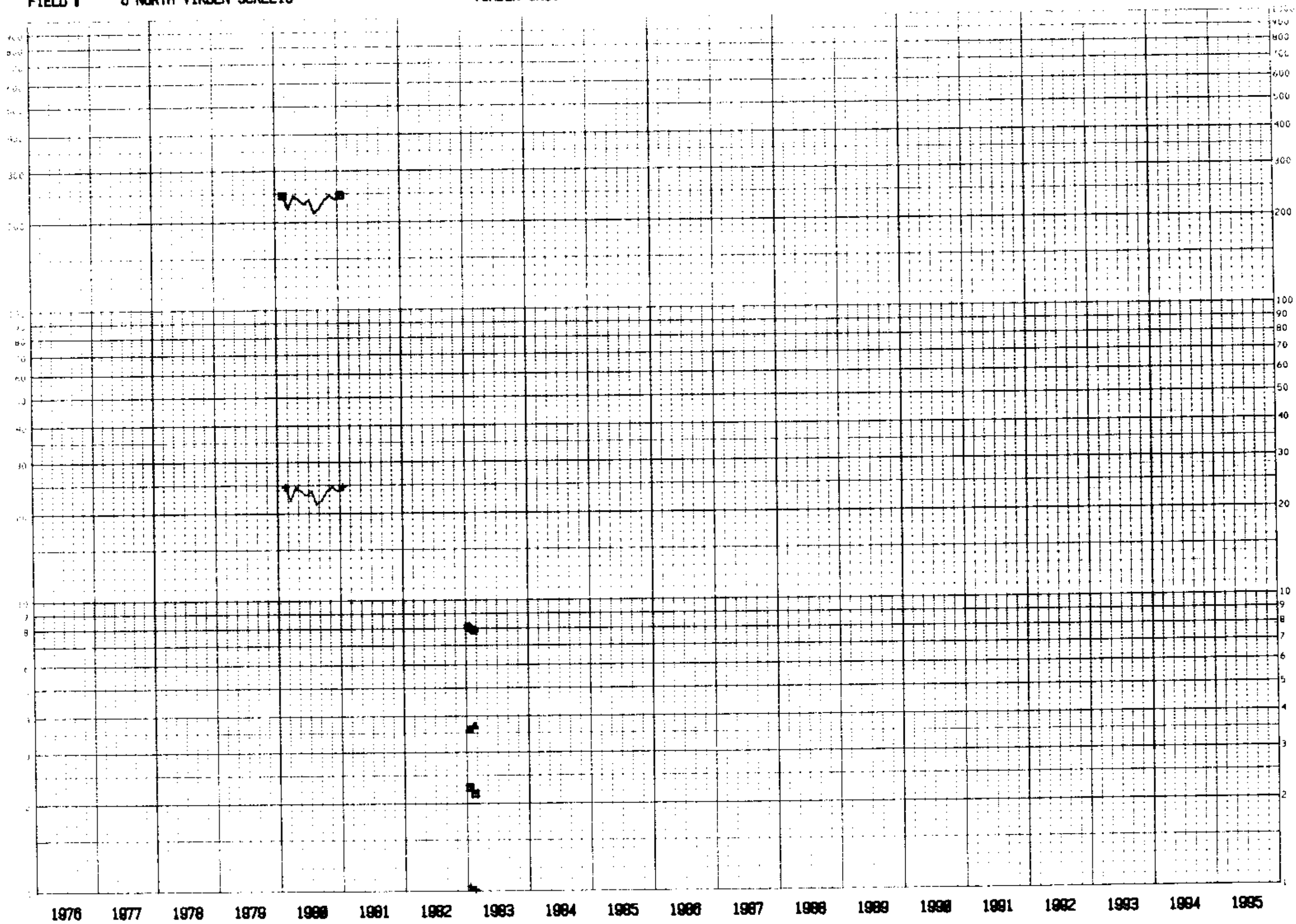
00/11-20-011-26W1/0 SUNCOR W. SCALLION 11-20-11-26

FIELD : 8 NORTH VIRDEN SCALLIO VIRDEN UNIT POOL : 0

FINAL PRODUCTION VALU

CUM OIL	4955.00	M3
CUM WATER	6274.30	M3
CUM FLD	19142.70	M3

ATTACHMENT #8g



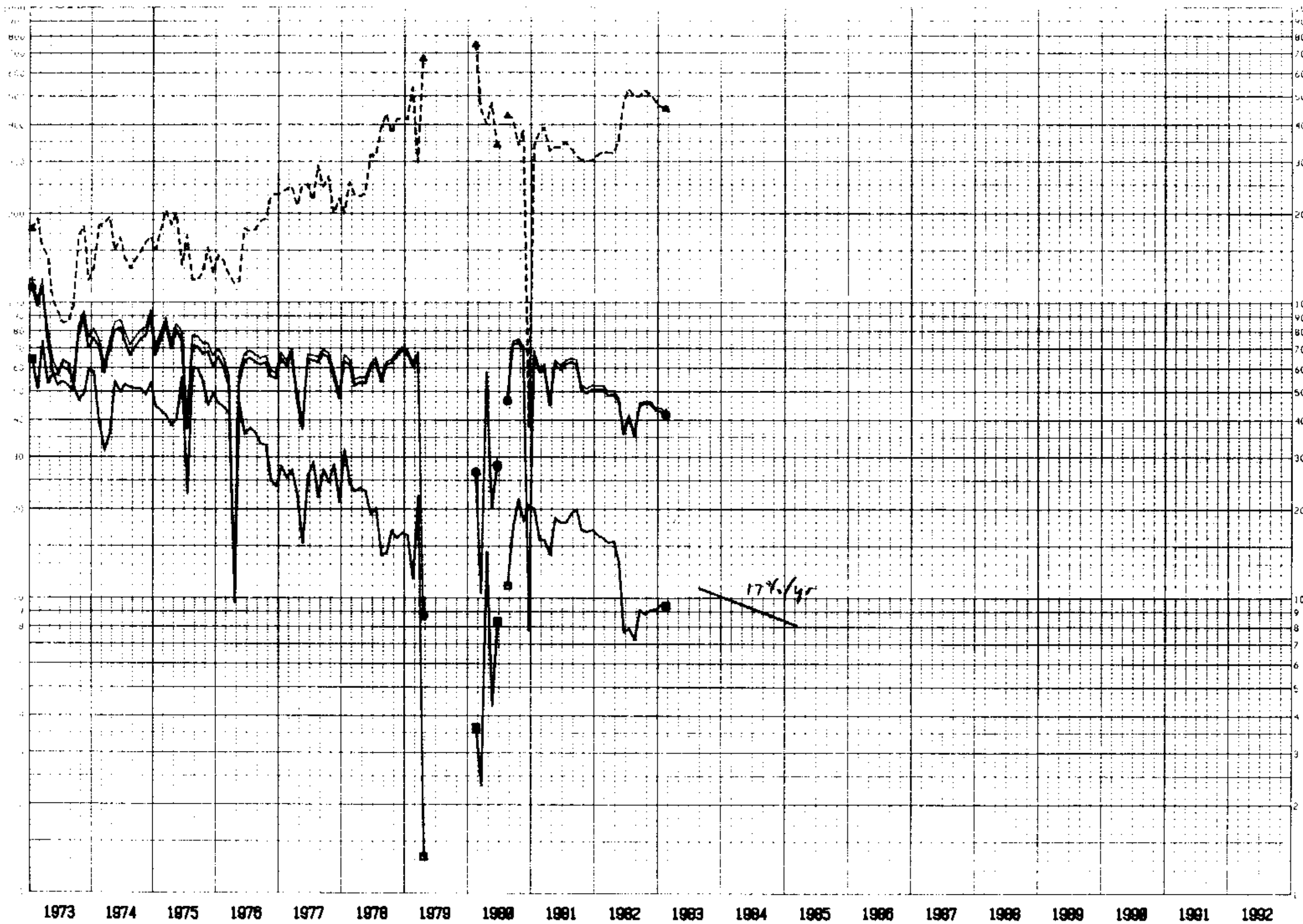
DLY OIL	M3/DAY	(□)	X .1
DLY WTR	M3/DAY	(○)	X .1
WATER/OIL	M3/M3	(△)	X 1.
DLY FLD	M3/DAY	(+)	X 1.

DATALINE INC. 3C100L

19711

00/12-20-011-26W1/0 SUNCOR W. SCALLION 12-20-11-26

FIELD : 6 NORTH VIRDEN SCALLIO VIRDEN UNIT POOL : 0



FINAL PRODUCTION VALUES

CUM OIL	26103.00	M3
CUM WATER	262409.30	M3
CUM FLD	288512.30	M3

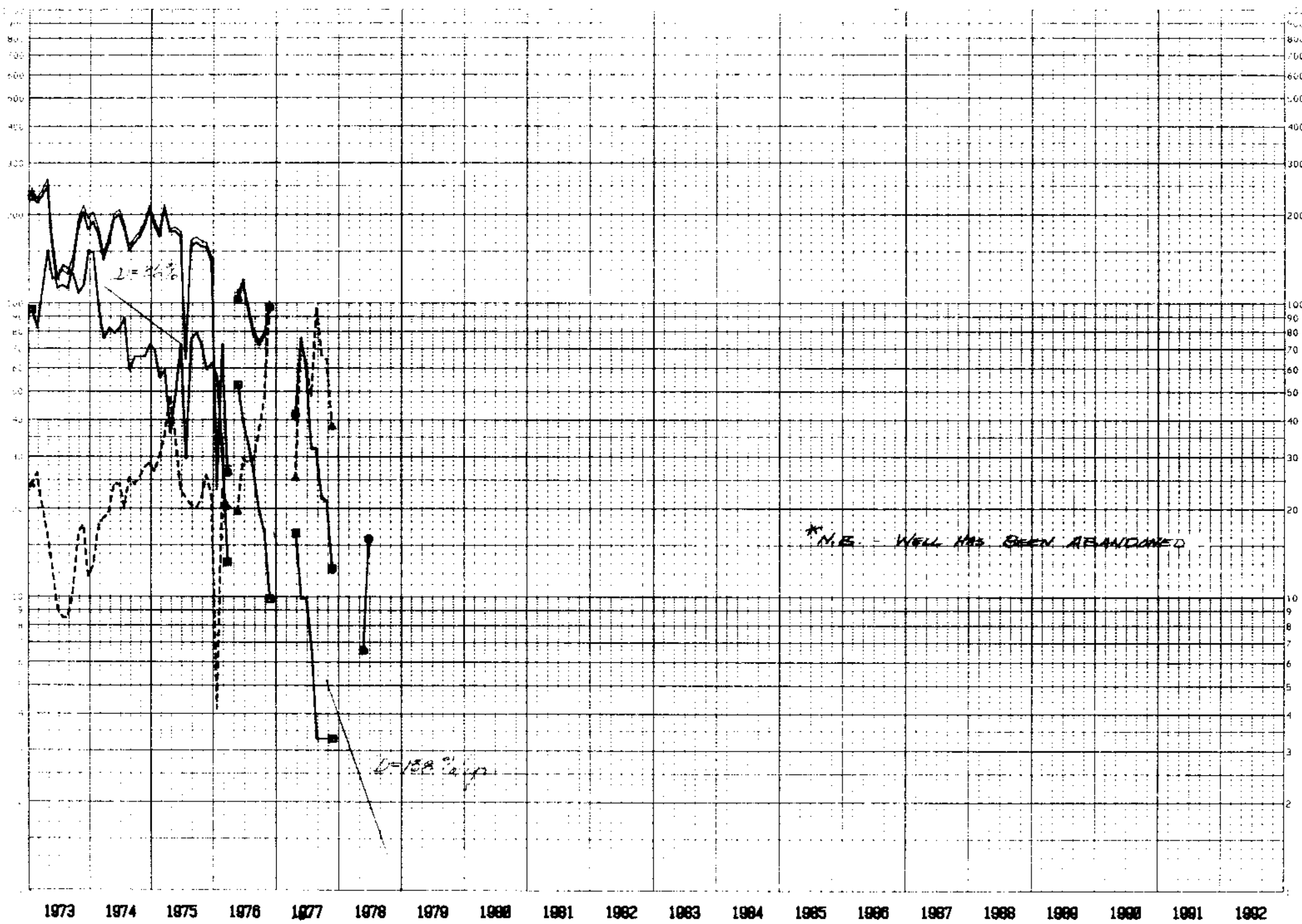
ATTACHMENT #8h

DLY OIL	M3/DAY	(⊡)	X .1
DLY WTR	M3/DAY	(⊙)	X 1.
WATER/OIL	M3/M3	(▲)	X .1
DLY FLD	M3/DAY	(+)	X 1.

DATALINE INC. 3C100

19712

00/13-20-011-26W1/0
FIELD : 6 NORTH VIRDEN SCALLIO   VIRDEN UNIT   SUNCOR W. SCALLION 13-20-11-26
POOL : 0



FINAL PRODUCTION VALUES

CUM OIL	5904.00	M3
CUM WATER	47410.00	M3
CUM FLD	53314.00	M3

ATTACHMENT #8i

DLY OIL	M3/DAY	(□)	X .01
DLY WTR	M3/DAY	(O)	X .1
WATER/OIL	M3/M3	(▲)	X 1.
DLY FLD	M3/DAY	(+)	X .1

DATALINE INC. 3C100L

19713

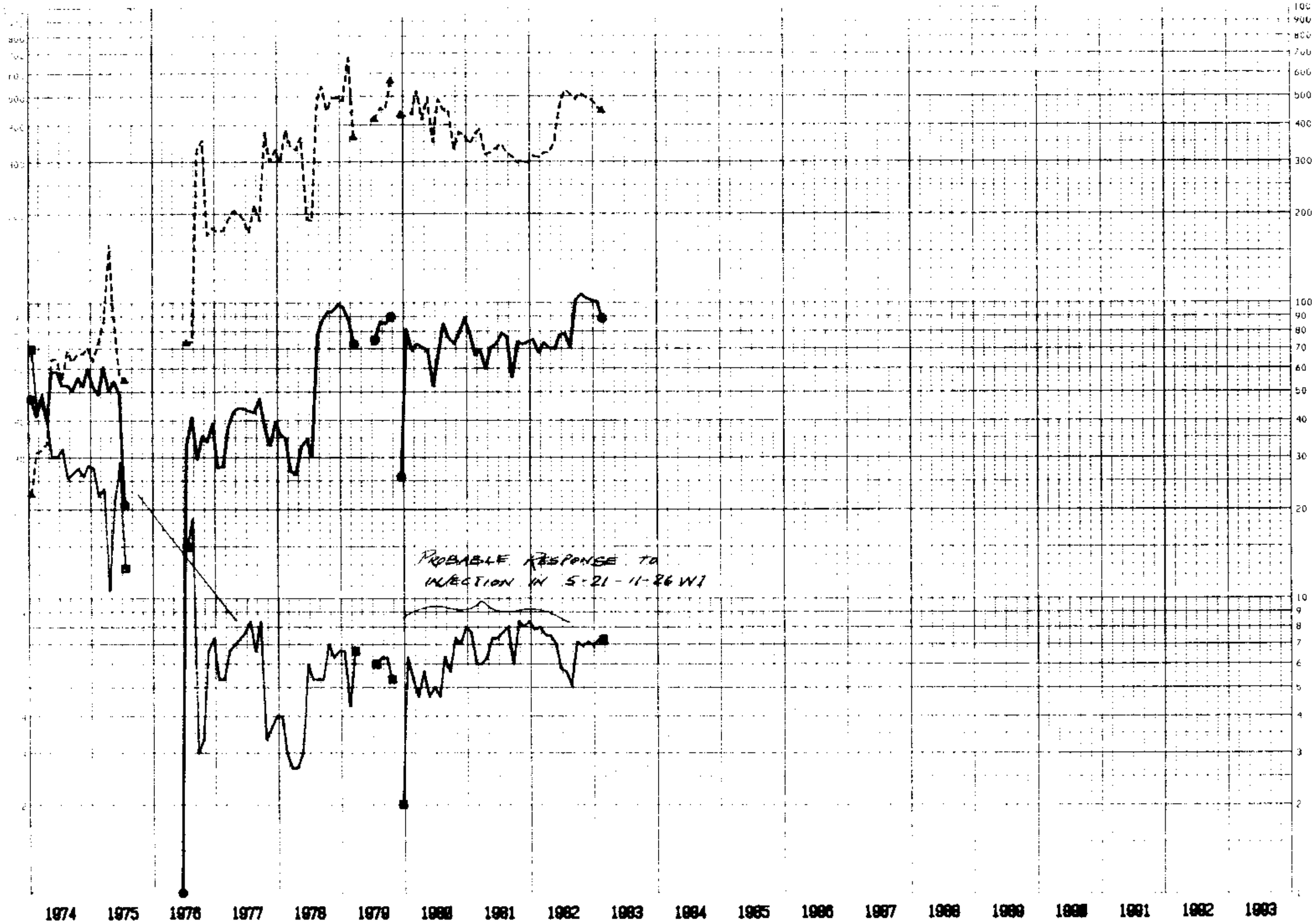
00/04-21-011-26W1/0

SUNCOR W. SCALLION 4-21-11-26

FIELD : 6 NORTH VIRDEN SCALLIO

VIDEN SCALLION

POOL : 0



FINAL PRODUCTION VALUES

CUM OIL	31101.00	M3
CUM WATER	111353.10	M3

ATTACHMENT #8j

DLY OIL	M3/DAY	(□)	X .1
WATER PROD	M3	(○)	X 10
WATER/OIL	M3/M3	(▲)	X .1

DATALINE INC.

21320

ATTACHMENT #9

*RESERVES - DRAINAGE UNIT BASIS

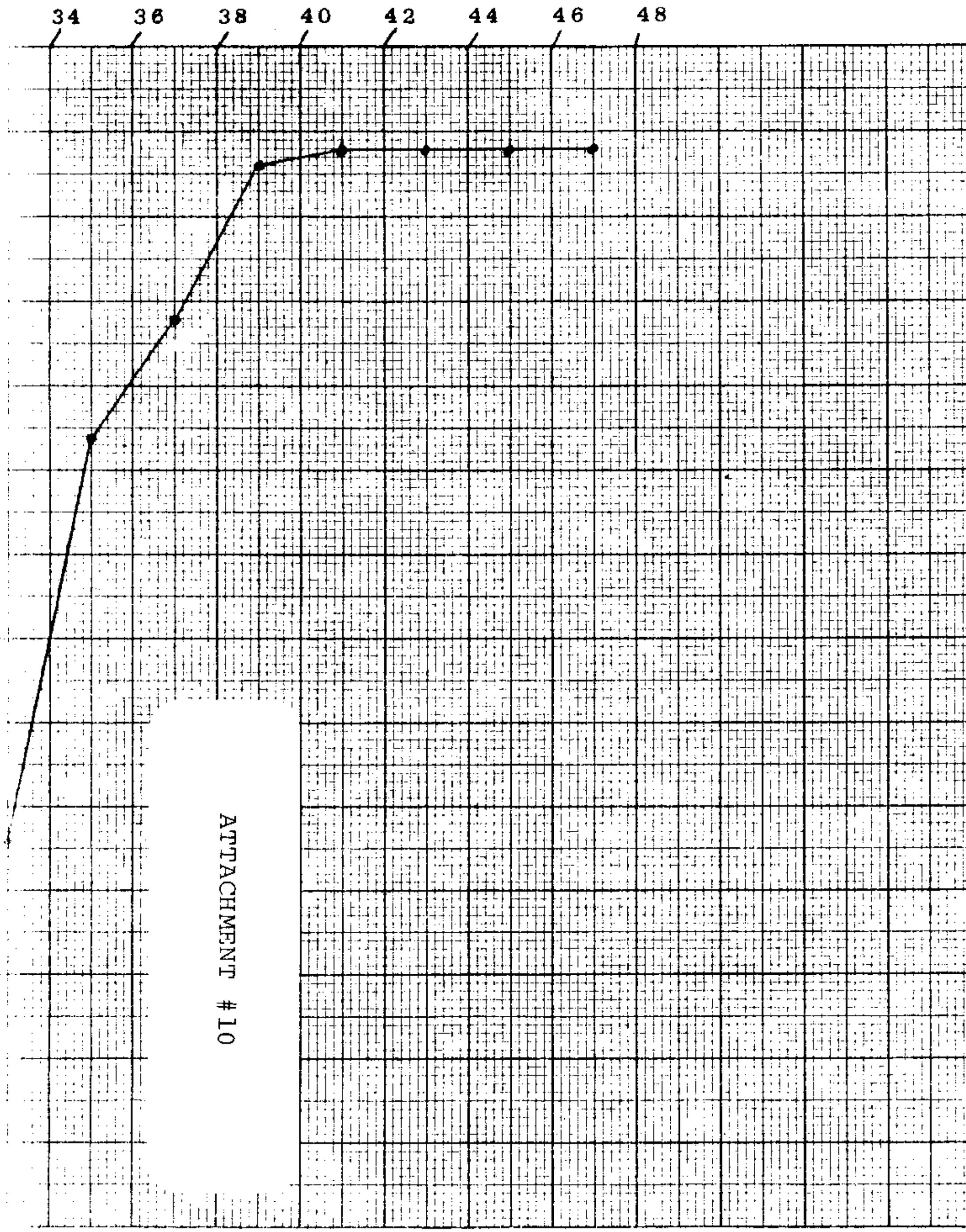
North Virden Scallion Area

Section 20	OOIP (mstb)			Cum. to	Ultimate	
Lsd.	Crinoidal	Cherty	Total	79.12.30	(mstb)	R.F.
1	222.2	347.2	569.4	147.6	156.7	28
2	222.2	631.3	853.5	17.3	17.3	0
3	177.7	568.2	745.9	129.4	184.2	25
4	207.3	505.1	712.4	118.7	127.8	18
5	296.2	568.2	864.4	64.8	92.1	11
6	237.0	252.5	489.5	134.7	153.0	31
7	148.1	189.4	337.5	25.9	25.9	1
8	-	-	-	-	-	-
9	-	-	-	-	-	-
10	-	-	-	-	11.0	
11	133.3	189.4	322.7	29.0	34.9	1
12	251.8	536.6	788.4	156.1	174.3	22
13	103.7	378.8	482.5	37.2	43.1	1
15	-	-	-	-	-	
16	-	-	-	-	-	
Section 21:						
4	148.1	347.2	495.3	190.8	198.1	40
5	118.5	157.8	276.3	50.0	50	18
	2266	4672	6938		1268	

* Obtained from 1979 Study

7 U 8671B REV.3

BUILD-UP PRESSURE



SUN OIL COMPANY
OPERATING DEPARTMENT

WELL NAME: C.Nichol 12-20 LOC 12-20-11-26W1
COMPANY: Sun Oil Company
FIELD: North Virden POOL: Cherty
ELEV. K.B. 1531.6, C.F. 1521, M.V.
DEPTH MEASURED FROM: Csg. Flange
DATUM: -545 DATUM DEPTH: 2066 RUN DEPTH: 2080
PERF. INTERVAL: 2088'-2100'
CUMUL. OIL 66,866 BBLS, GAS ____ MCF; WATER 176,000 BBLS.
RESERVOIR GRAD.: ____ PSI/FT

Amerada PRESSURE ELEMENT, SERIAL NO. 13727
RANGE: 0-2500 TEMP. RESPONSE: sensitive
BASE LINE TEMP. 63 °F; BOTTOM HOLE TEMP. 85 °F
CALIB. EQUATION P= 1289.57D -5.44 DATE: June 18/68

TEST DATA

SHUT-IN: DATE June 4, 1968 ; TIME 8:00 AM AM/PM

DATE	TIME	S.I. HOURS	DEFLECTION INCHES	CORR. PRESS (RUN DEPTH) PSIG	FLUID GRADIENT PSI / FT	DATUM PRESS PSIG
June 5	5:34 PM	33	0.4794	615	0.296	
June 5	7:34 PM	35	0.5743	736	0.354	
"	9:34 PM	37	0.6003	770	0.370	
"	11:34 PM	39	0.6342	813	0.391	
June 6	1:34 AM	41	0.6392	820	0.394	
"	3:34 AM	43	0.6392	820	0.394	
"	5:34 AM	45	0.6392	820	0.394	
"	7:34 AM	47	"	"	"	

Run depth to mid perfs: +14'
Extrapolate mid perf to run depth=14(0.394
=+5.5psi
Mid perfs to datum - 28'
Extrapolation=14(0.394)-28 (Reser. Grad.)

RUN BY: G.R.M. CHECK: ____ APPROVED: ____

Form 0-8678

Sun Oil Company
Operating Department
BOTTOM HOLE PRESSURE SURVEY CALCULATIONS

Type of Survey Bottom Hole Pressure **Date of Test** June 6,1968 **Date S.I.** June 4,1968 **Time S.I.** 8:00 AM

Well **Name** C. Nichol 12-20 **Location** 12-20-11-26-W1M **Field** North Virden **Pool** Cherty

Well **K.B.** 1531.6 **C.F.** 1520.6 **M.V.** ______ **Datum** -545 **Datum Depth** 2066CF **Run Depth** 2080CF **Perf.Int.** 2088-2100'

Cumulative **Production** May 31/68 66,866 **(bbls.) Gas** ______ **(Mcf) Water** May 31/68 176,007 **(bbls.) Stabilized Rate** ______ **B.O.P.H.**

Amerada **Gauge Type** R.P.G. -3 **Range** 0-2500 **(psi) Serial No.** 13727 **Clock** 24 **(hrs.)**

Gauge **Pressure (Tbg/Csg)** 20/nil **(psig) Base Line Temp.** 63 **°F. Bottom Hole Temp.** 85 **°F. Bottom** June 5 5:34PM to June 6 7:34AM

Bomb **Equation:** $P = mD + a = 1289.57\ D\ -5.44$

Remarks Cumulative Production is from the Crinoidal Zone.
Cherty zone perforated June 4, 1968

Time	Depth (ft.)	Read Deflection (ins.)	Bomb Temp. (°F.)	Diff. from 80°F. (°F.)	Bomb Temp. Correction (ins.)	Base Temp. Correction (ins.)	Corrected Deflection (ins.)	Total Correction (ins.)	Calculated Press. (psig)	Non-Linear Correction (psig)	Correct B.H.P. (psig)	$\frac{\Delta P}{\Delta ft}$ Gradient (psig/ft)	Miscellaneous
June 5 :34PM	CF 2080	0.~~480~~ .4813	+85	-5	-.0006	nil	-.0006	0.4794	612.78	+1.9	614.68	0.296	Run depth
:34PM	"	0.~~575~~ .5721	+85	-5	-.0007	nil	-.0007	0.5743	735.16	+1.2	736.36	0.354	" "
9:34PM	"	0.~~601~~ .6038	+85	-5	-.0007	"	-.0007	0.6003	768.69	+1.0	769.69	0.370	" "
11:34PM	"	0.~~636~~ .6378	+85	-5	-.0008	"	-.0008	0.6342	812.41	+0.8	813.21	0.391	" "
June 6 1:34AM	"	0.~~640~~ .6410	+85	-5	-.0008	"	-.0008	0.6392	818.85	+0.7	819.55	0.394	" "
3:34AM	"	0.~~640~~ .6421	+85	-5	-.0008	"	-.0008	0.6392	818.85	+0.7	819.55	0.394	" "
5:34AM	"	0.~~640~~ .6418	+85	-5	-.0008	"	-.0008	0.6392	818.85	+0.7	819.55	0.394	" "
:34AM	"	0.~~640~~ .6466	+85	-5	-.0008	Nil	-.0008	0.6392	818.85	+0.7	819.55	0.394	" "

1972 TEST - WELL 13-20

Pressure Build Up Test 13-20-11-26 W1

ATTACHMENT #11

1. Shut in well. Circulated hole to clean oil. Hole volume 31 BBL. Pump 40 BBL down annulus and up tubing.
2. Shut casing valve and flow line. Recorded pressure build up on casing.
3. Clean oil gravity 33.4° API @ 54° F
→ 33.8° API @ 60° F.

Bottom hole temp ~ 80° F 32.4° API → SG = .8623 avg SG → .8592
Surface temp ~ 60° F → 33.8° API → SG = .8560
Gradient = .8592 × .433 = .372 psi/ft.

Open hole in Cherty: 2078 - 2110 avg depth 2094 KB.
top tbg to KB = 8' → 2086 ft. fluid.
Fluid head = 2086 × .372 = 776 psi.

4. Cumulative Production to end June/72 : for June 2578 w, 314 oil, 2892 BFPM
To end 1971: 127458 water + 27141 oil
1972 prod to end June: 15942 water + 1775 oil
Total fluid: 143400 + 28916 = 172316 BBL.
+ 2½ month @ 2892 → 7250 7250
179566

Last test prior to build up: 11 BBL oil + 94 BBL water = 105 BFPD.

Pseudo Life: T = 180000/105 = 1710 days = 41000 hrs.

5.

Time	ΔT min	ΔT hr.	Casing Pressure psig	Bottom Hole Pressure psig	ΔT/T (T=41000) ($\times 10^{-4}$)	T/ΔT $\times 10^4$
12:10 PM	0	0	48	824	0	∞
12:20	10	.167	42	818	.0407	24.6
12:25	15	.250	39	815	.0610	16.4
12:30	20	.333	36	812	.0813	12.3
12:35	25	.417	34½	810½	.101	9.91
12:40	30	.500	33	809	.122	8.20
12:55	45	.750	32	808	.182	5.50
1:15	65	1.083	31	807	.261	3.83
1:30	80	1.333	32	808	.325	3.08

5.

Time	ΔT		Casing Press.	Btm. Hole Press.	ΔT/T ($\times 10^{-4}$)	T/ΔT ($\times 10^{4}$)
	min	hr.	psig	psig	(T = 41000 hrs)	
1:45	95	1.58	33	809	.385	2.60
2:00	110	1.83	33	809	.446	2.24
2:10	120	2.00	34	810	.487	2.06
4:15	245	4.08	39	815	.995	1.01
6:15	365	6.08	42	818	1.48	.677
8:10	480	8.00	44	820	1.95	.513
10:10	600	10.00	45	821	2.44	.415
12:35 AM	745	12.40	46.5	822.5	3.02	.331
4:30 AM	980	16.30	49	825	3.97	.252
8:25 AM	1215	20.20	49.5	825.5	4.92	.203
4:45 PM	1715	28.60	52	828	6.98	.143

6. Above data was plotted: BHP vs. $\log(T/\Delta T)$

$$\left\{ \begin{array}{l} m = 15.25 \text{ psi/decade} \\ p^* = 891 \text{ psia} \end{array} \right\}$$

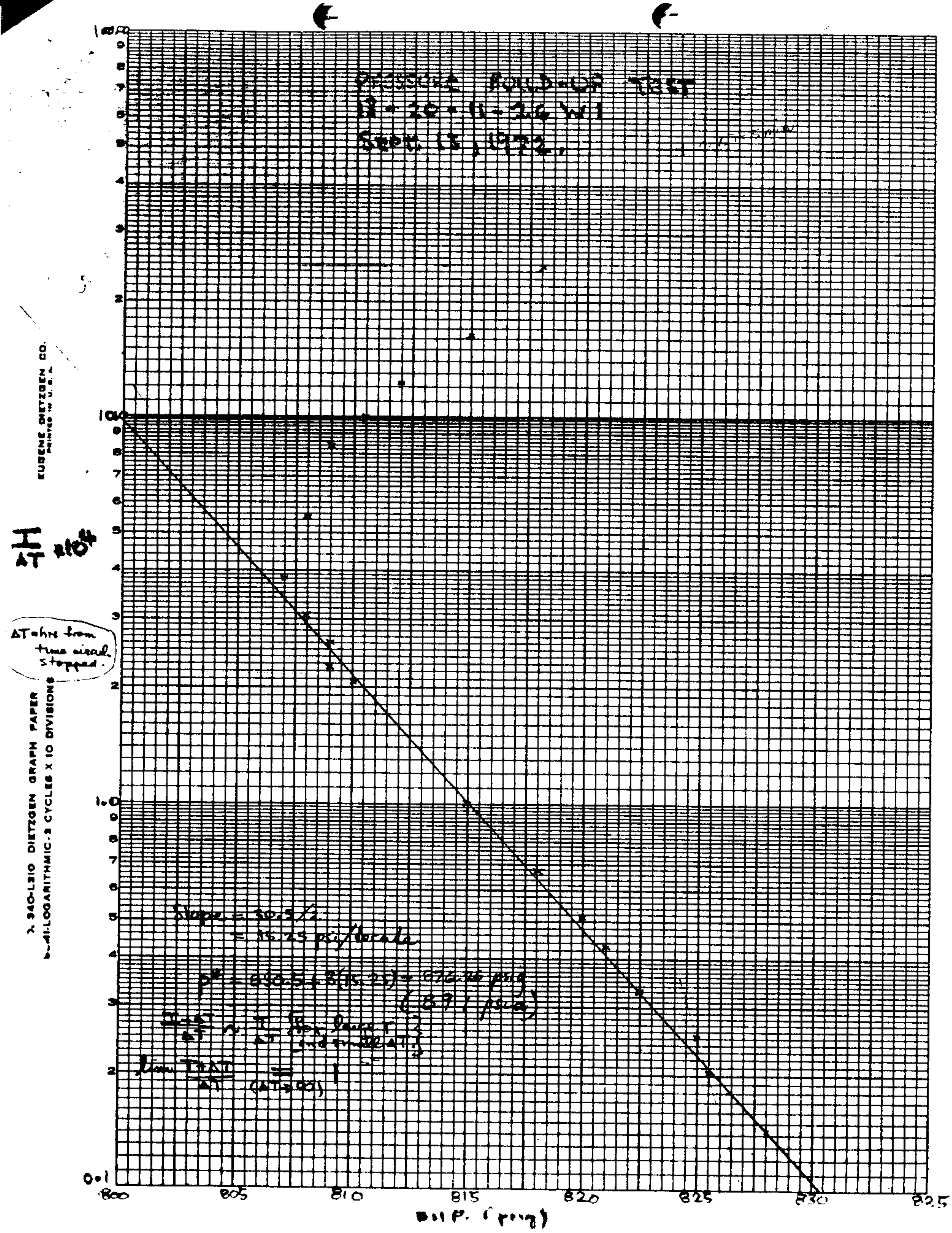
7. Correction made to account for time used to circulate hole. Took 1 hr. to circulate hole to clean oil. Shut in time ΔT in previous table should be increased by 1 hour.

ΔT	BHP	ΔT/T ($\times 10^{-4}$)	T/ΔT ($\times 10^{4}$)
2.083	807	.505	1.98
2.333	808	.569	1.76
2.58	809	.629	1.59
2.83	809	.690	1.45
3.00	810	.731	1.37
5.08	815	1.439	.695
7.08	818	1.72	.582
9.00	820	2.19	.456
11.00	821	2.68	.373
13.40	822.5	3.26	.303
17.30	825	4.21	.238
21.20	825.5	5.16	.194
29.60	828	7.22	.138

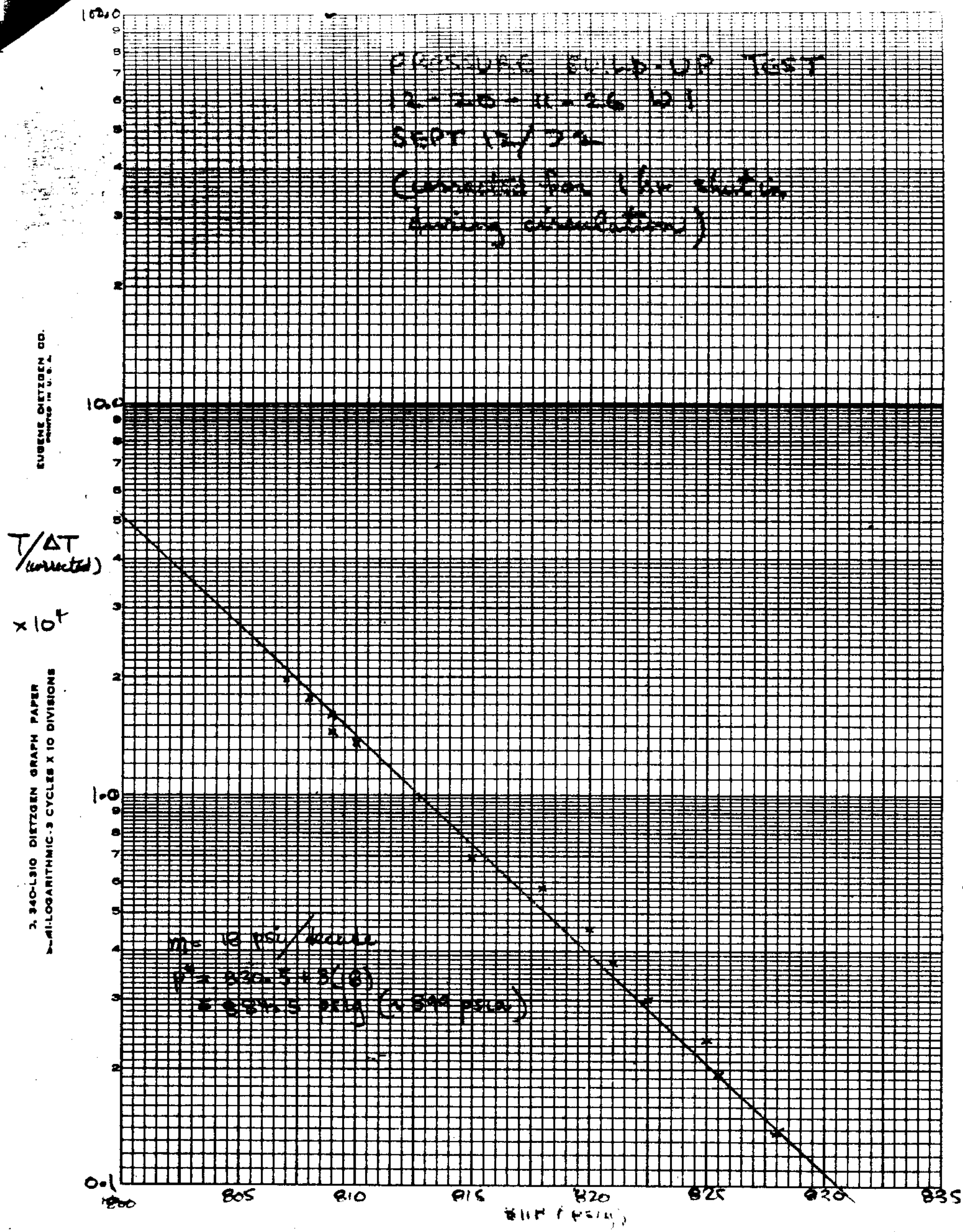
8. Corrected data plotted → $m = 18$ psi/decade
$p^* = 884.5$ psig (899 psia)

9. Plot using Muscat method. $\log(p_e - p_w)$ vs Δt

ΔT	(p_w) BHP	$p_e = 850$ ($p_e - p_w$)	$p_e = 900$ ($p_e - p_w$)	$p_e = 950$ ($p_e - p_w$)
2.08	807	43	93	143
2.33	808	42	92	142
2.58	809	41	91	141
2.83	809	41	91	141
3.00	810	40	90	140
5.08	815	35	85	135
7.08	818	32	82	132
9.00	820	30	80	130
11.00	821	29	79	129
13.40	822.5	27.5	77.5	127.5
17.30	825	25	75	125
21.20	825.5	24.5	74.5	124.5
25.60	828	22	72	122



PRESSURE BUILD-UP TEST
11-20-11-24 W1
Sept. 13, 1972.
EUGENE DIETZGEN CO.
PRINTED IN U.S.A.
NO. 340-L310 DIETZGEN GRAPH PAPER
SEMI-LOGARITHMIC 3 CYCLES X 10 DIVISIONS
T/ΔT x10^4
ΔT = hrs from time circul. stopped.
Slope = 30.5/2
= 15.25 psi/decade
(891 psia)
800
805
810
815
820
825
830
835


PRESSURE BUILD-UP TEST
12-20-11-26 W1
SEPT 12/72
(corrected for 6 hr shut-in during circulation)
m = 18 psi/decade
p* = 830.5 + 3(18)
= 884.5 psig (≈ 844 psia)
T/ΔT (corrected)
× 10⁴
100.0
10.0
1.0
0.1
800
805
810
815
820
825
830
835
EUGENE DIETZGEN CO. PRINTED IN U.S.A.
NO. 340-L310 DIETZGEN GRAPH PAPER
SEMI-LOGARITHMIC 3 CYCLES X 10 DIVISIONS

ATTACHMENT 12

VIRDEN SCALLION - 1982 CASH FLOW

83-08-15

Net Revenue Before Royalty $	Crown Royalty $	Operating Expense $	PGRT $	Net Operating Income $	Net Cash Flow B.I.T. $
378 179	45 734	118 358	31 178	182 909	182 909

Income for Resource Allowance $	Resource Allowance $
228 643	57 160

Net Income For Depletion $	Federal Income Tax $	Provincial Income Tax $	Cash Flow A.I.T. $
171 483	63 277	15 148	104 484

w/8 Producers; A.I.T. Cash Flow = $1088/well/month

N.B. This is not representative of Suncor's wells included in the proposed unit. The cash flow for those wells would be less.

September 14, 1983

Dome Petroleum Limited
Box 200
Calgary, Alberta
T2P 2H8

Attention: Mr. C. Ladkin
Exploitation Engineer

Dear Sir:

Re: Virden Lodgepole A Pool Reservoir Study

Your letter of September 8, 1983 regarding the Virden Lodgepole A Pool reservoir study is hereby acknowledged.

We ask that you keep us informed on a regular basis, regarding the progress and outcome of any studies undertaken, and also that you indicate the approximate timing of your response to our request regarding waterflood feasibility in this area.

Yours sincerely,

Original Signed
L. R. DUBREUIL

L. R. Dubreuil
Chief Petroleum Engineer
Petroleum Branch

LRD/sb

→ Rub
draft a reply t

DOME PETROLEUM LIMITED

J.R. MOORE
Vice-President, Exploitation

BOX 200
CALGARY, ALBERTA, CANADA
T2P 2H8

(403) 260-5100

September 8, 1983

Manitoba Department of Energy and Mines
Mineral Resources Division
975 Century Street
WINNIPEG, Manitoba
R3H 0W4

DEPARTMENT OF ENERGY AND MINES
SEP 13 1983
PETROLEUM BRANCH

ATTENTION: H. Clare Moster
Director, Petroleum Branch

Dear Sir:

RE: Virden Lodgepole A Pool Reservoir Study

In response to your request to review the above pool with respect to waterflood feasibility and unitization, I wish to confirm that a study will be forthcoming at a later date, due to certain delays in organizing the area operators. Dome called a meeting of operators of the proposed study area on July 28, 1983 that was intended to authorize and commission an independent study on behalf of all operators. At that time, ICG Resources Ltd. indicated they had no intention of participating on a joint study or future unitization, due to their ongoing NORP development. Suncor had agreed to co-ordinate future meetings and the study, but later informed the remaining partners that after further review, they were no longer interested in participating in or co-ordinating such a study. I believe you have received correspondence from the above parties to this effect.

At this point in time, Dome is acting as co-ordinator for a joint study on behalf of Dome, Trans Canada Resources Ltd., and Canadian Reserve Oil and Gas Ltd. Dome is presently assembling data to prepare a request for bids from several consultants.

When a consultant is selected, I will inform the Petroleum Branch of the expected completion date, and of any further changes in this study.

Please contact me at 403, 231-3019 if there are any further questions.

Yours truly,

DOME PETROLEUM LIMITED

Craig Ladkin

Craig Ladkin
Exploitation Engineer

CKL/jo

3002

Jane 17, 1983

ICG Resources Ltd.
700 Three Calgary Place
355 - Fourth Avenue S.W.
Calgary, Alberta
T2P 0J1

Attention: Mr. Grant Henschel, Reservoir Engineer

Dear Sir:

Enclosed, as per your request, is a copy of some of the technical and descriptive material pertaining to the North Virden Scallion Unit No. 1 waterflood project. Also included is an invoice for copying charges.

We also have available relative permeability, capillary pressure and PVT data which can be supplied at your request.

If you have any further questions or comments, please don't hesitate to call.

Yours sincerely,

L. R. Dubreuil
Chief Petroleum Engineer
Petroleum Branch

LRD/sb
Encls.

PS-1-25

MANITOBA

Inter-Departmental Memo

Date: May 25, 1983

To: Oil & Natural Gas Conservation Board

Marc Eliesen
Dr. I. Haugh
J. F. Redgwell

From: H. Clare Moster, Director
Petroleum Branch
975 Century St.

Telephone

Subject: Feasibility Study - N. W. Virden Lodgepole A Pool

The attached letter was sent to the Operators (see Attachment No. 1) on May 18th, 1983.

First | Fold

H. Clare Moster

H. Clare Moster

MANITOBA

DEPARTMENT OF ENERGY AND MINES
Mineral Resources Division
Petroleum Branch
Telephone: (204) 633-9543
975 Century Street
Winnipeg, Manitoba
R3H 0W4

A review of the geology and production performance of certain wells in the north west part of the Virden Lodgepole A Pool (see Fig. 1 for area of study), indicates that the feasibility of a water injection scheme in the area should be reviewed.

The presence of a structural high in this area coupled with the relatively low degree of water production suggest that this area is somewhat remote from the aquifer and may therefore not be receiving the benefits of an active water drive. In addition, the effectiveness of water injection as a means of increasing production rate and ultimate recovery has been clearly demonstrated in other parts of the Virden Field, notably within the Lodgepole A Pool (North Virden Scallion Unit No. 1).

You are, therefore, requested to submit to the Petroleum Branch, not later than September 1, 1983, a review of the feasibility, both from the ultimate recovery and economic viewpoints, of water flood (or other enhanced recovery) operations in this area. You may wish to submit an individual study or to collaborate with other operators in the area (see Attachment No. 1) to develop a combined submission. The study should examine at least the following aspects:

1) Any reservoir pressure data available.

2) Determination of production forecasts and remaining ultimate reserves under continued primary depletion and under at least two different waterflood schemes.

. . Cont'd . .

3) A review of the economics of waterflooding in the area in comparison to primary depletion.

4) Unitization considerations.

Yours sincerely,

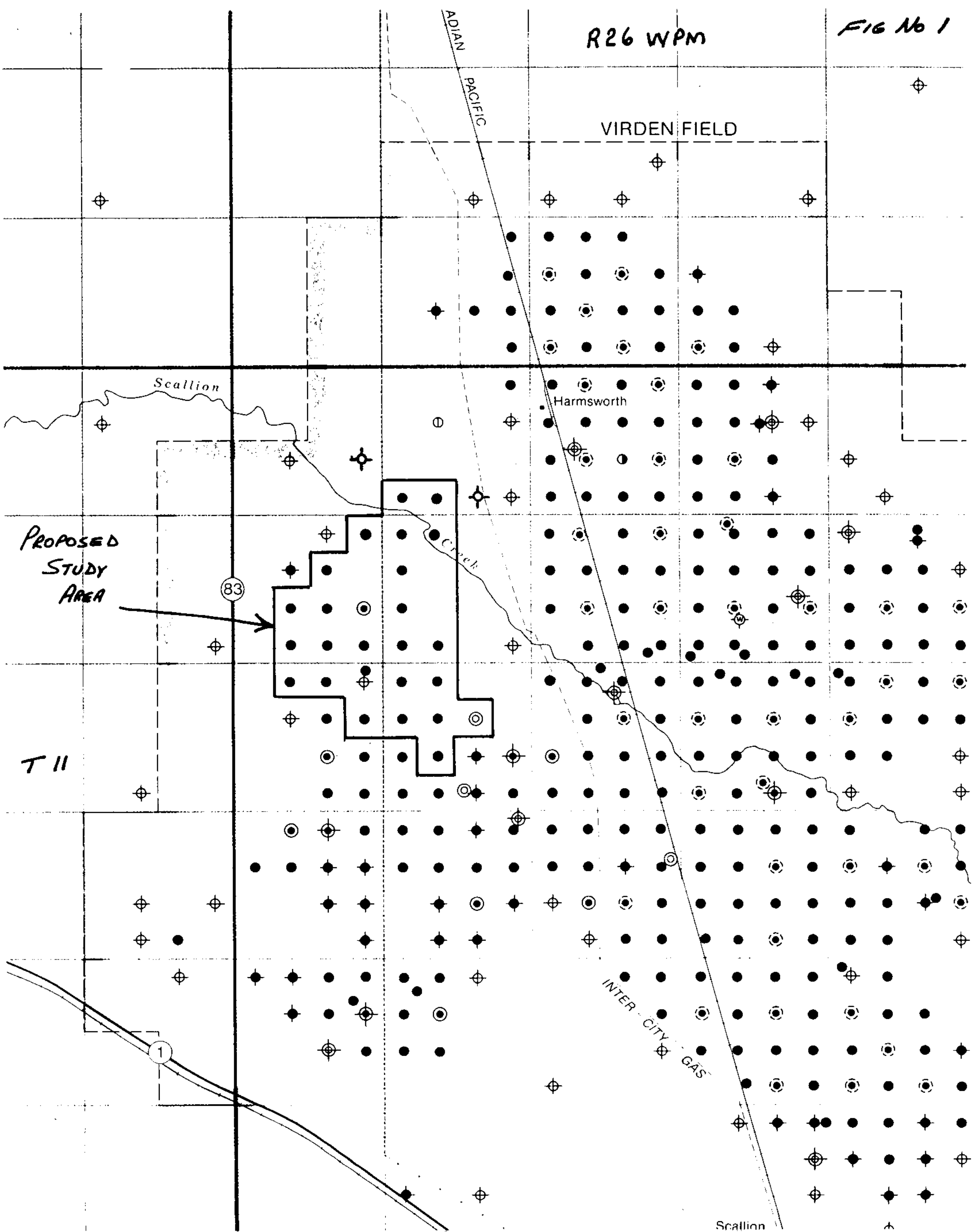
H. Clare Moster, P. Eng.,
Director
Petroleum Branch

cc: - Oil and Natural Gas
Conservation Board

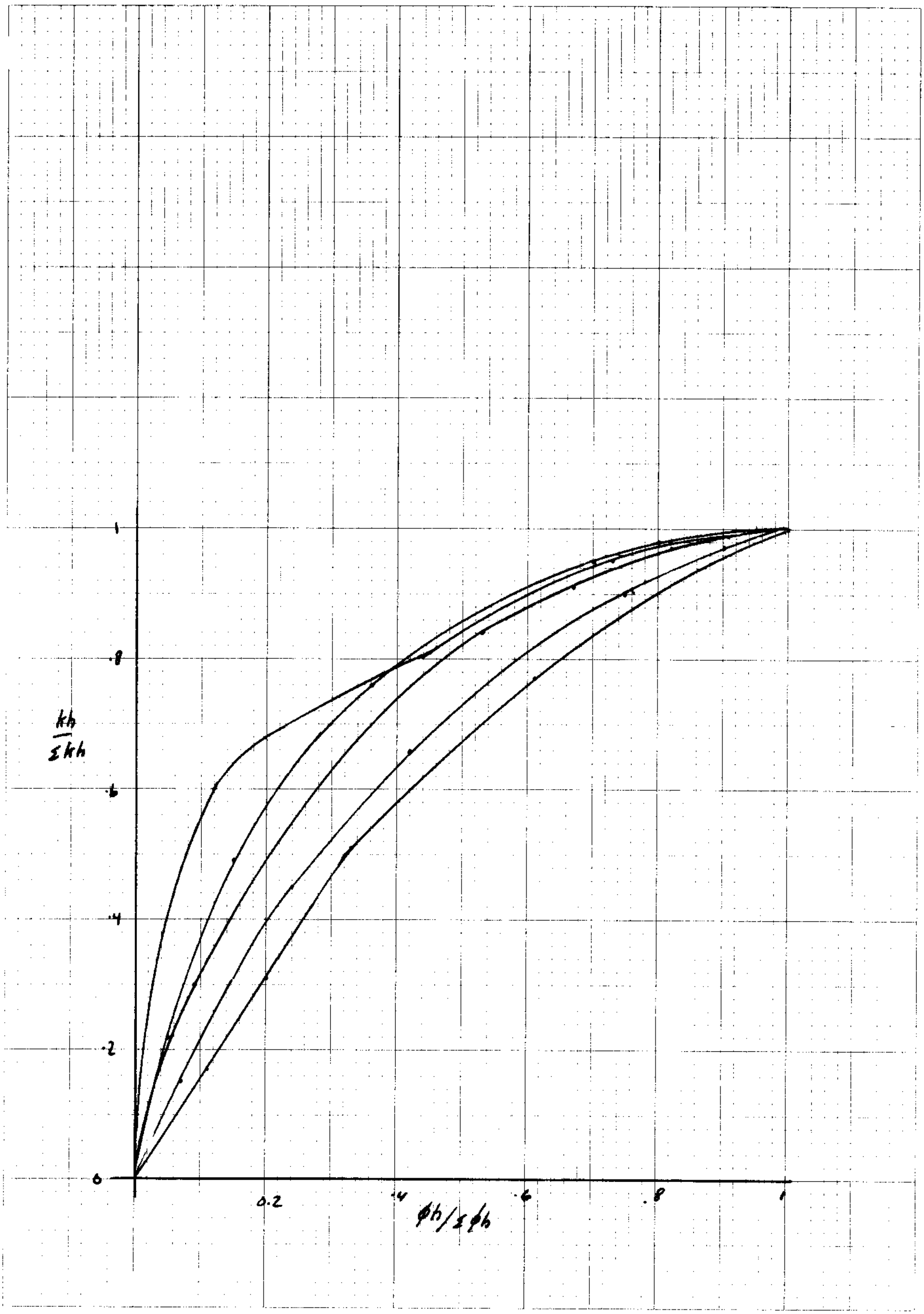
Attachment No. 1

LIST OF OPERATORS

Acroll Petroleums Ltd. 200 - 708 - 11th Ave. S.W. Calgary, Alberta T2R 0E4	-	Mr. P. G. Schmaltz Production Technologist
Canadian Reserve Oil & Gas Ltd. 1600 - 639 - 5th Ave. S.W. Calgary, Alberta T2P 0M9	-	Mr. A. L. Brynland, P. Eng., Senior Production Engineer
Dome Petroleum Ltd. P. O. Box 200 Calgary, Alberta T2P 2H8	-	D. L. Peterson
ICG Resources Ltd. 700 Three Calgary Place 355 - Fourth Ave. S.W. Calgary, Alberta T2P 0J1	-	Peter Krenkel Engineering Manager
Suncor Inc. Resources Group P. O. Box 38 500 - 4th Ave. S.W. Calgary, Alberta T2P 2V5	-	Mr. W. H. Hogue Engineering Technician



R26 WPM
FIG No 1
VIRDEN FIELD
ADIAN PACIFIC
Scallion
Harmsworth
Creek
PROPOSED STUDY AREA
83
T 11
1
INTER - CITY - GAS
Scallion


1
.8
.6
.4
.2
0
$\frac{kh}{\Sigma kh}$
0.2
.4
.6
.8
1
$\phi h/\Sigma\phi h$

Wells in Proposed STUDY Area.

Well		LOGS ~~STATUS~~	CORE
1) 6-20.		GRN	×
2) 10-20 ØSWD		E LOG	
3) 11-20		E LOG	×
4) 12-20		GRN	×
5) 13-20		GRN	×
6) 14-20		GRN	
7) 9-19		ELOG GRN	×
8) 14-19		GRN	×
9) 15-19		GRN	
10) 16A-19		GRN	
11) 3-29		GRN	
12) 4-29	Dome	GRN	
13) 5-29		CRN	
14) 12-29		CNL FDC DIL	
15) 13-29		CNL FDC DIL	
16) 14-29		CNL FDC DIL	
17) 1-30		GRN	×
18) 2-30		GRN	
19) 3-30		GRN	
20) 6-30		GRN	
21) 7-30		GRN	×
22) 8-30 ØSWD		GRN	×
23) 10-30		ELOG	
24) 16-30		CNL FDC DIL	×
25) 3-32		CNL FDC DIL	
26) 4-32		CNL FDC DIL	

	CRIN	OOL	CHERTY	KB	TΦ in Cherty o/w
9-19	2032	2060	2079	1535	2084
14-19	2054	2083 ~~2077~~	2103	1538	2109
15-19	2039	2067	2089	1536	2102
16A-19	2029	2058	2080	1532	2090
6-20	2027	2054	2083	1528	2084
10-20	2083	2113	2135	1522	2160
11-20	2025	2056	2089	1527	
12-20	2021	2050	2089	1532	2080
13-20	2022	2052		1526	
14-20	2028	2054	2075	1522	2077
3-29	2036	2065	2083	1524	2092
4-29	2045	2074	2091	1529	2101
5-29	2060	2087	2104	1527	2110
12-29	2062	2080	2104	1534	2116
13-29	2039	2066	2084	1530	2093
14-29	2020	2051	2068	1529	2076
1-30	2039	2067	2092	1532	2098
2-30	2049	—	-	1545	2113
3-30	2056			1536	2128
6-30	2058			1540	2132
7-30	2055			1535	2115
8-30	2060			1533	2120
10-30	2062			1539	2135
16-30	2055			1535	2112
3-32	2020			1532	2072
4-32	2016			1532	2070

Core Analysis in Study Area

13-20-11-26 2021-2071

use 1.0 md cutoff.

1.0 - 1.5		1.51 - 2.0		2.01 - 3.0		3.01 - 4.0		4+	
ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh
.0861	0.98	.1107	1.62	.0679	1.75	.1085 ~~.155~~	2.73	.1424	3.36
.1352	0.96	.0992	1.36	.0984	2.08				
.0678	0.60	.0650	1.00						
.0896	0.98	.0850	1.12						
.1120	0.96								
.4907	4.48	.3599	5.10	.1663	3.83	.1085	2.73	.1424	3.36

Σ kh 19.50 Σ ϕh 1.2678

Σh = 9.0

$\bar{\phi}$ = 14.09%

$\bar{k}$ = 2.17 md.

$\phi h / \Sigma \phi h$	$kh / \Sigma kh$
0.39	0.23
0.67	0.49
0.80	0.69
0.89	0.83
1.00	1.00

14-20-11-26

0-5		5.01-10		10.01-20		20.01-50		50-100		100+	
0213	.93	0696	5.20	.1224	10.82	0880	25.60	0880	26.00	0945	71.00
0208	.70	.1120	6.50	.1720	11.20	1450	48.00				
0324	1.23	0684	3.88			1211	14.70				
0375	0.85	0550	2.95			0627	14.40				
0534	1.92					.1068	12.40				
0726	1.92					0699	10.20				
0775	1.45					0759	13.20				
0290	1.55					0975	21.00				
0406	2.59					.1398	18.00				
3851	12.84	.3050	18.53	2944	22.02	.9067	177.50	.0880	26.00	.0945	71.00

$\Sigma\,\phi h$ 2.0737

$\Sigma\, kh$ 327.89

$\phi h / \Sigma \phi h$	$kh / \Sigma kh$
.05	.22
.09	.30
.53	.84
.67	.91
.82	.97

14-19-11-26

2085-2145

0-5.		5.01 - 10		10.1 - 20		20.1 - 50		50.1 - 200		200+	
ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh
.0561	3.08	.0360	1.20	.0679	9.1	.0500	15.2	.0800	30.0	.1002	130.8
		.0976	4.56	.0564	6.0	.0700	17.6	.1430	61.0	.0581	158.2
		.0258	2.16	.0690	9.6	.1104	18.4	.2241	67.5	.0252	233.6
				.0968	6.8	.0496	10.4	.2584	52.0	.0712	87.6
				.0957	5.4	.1140	16.2				
						.1072	38.4				
						.0384	14.4				
						.0560	15.6				
.0561	3.08	.1594 ~~1.594~~	7.92	.3858 ~~3.858~~	36.9	.5956	146.2	.7055	210.5	.2547	610.2

$\Sigma \phi h =$ 2.1571 ~~[illegible]~~ $\Sigma kh =$ 1014.8

$\phi h / \Sigma \phi h$	$kh / \Sigma kh$
0.12	0.60
0.45	0.81
0.73	0.95
0.91	0.99

8-31-11-26 636.75 - 652.0

0 - 2		2.01 - 5		5.01 - 10		10.01 - 20		20.01 - 30		30+	
ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh
~~[illegible]~~	~~[illegible]~~	.017	.525	.021	.90	.035	2.60	.016	2.90	.045	6.80
.015	0.255	.027	.540	.056	3.76	.049	3.25	.054	5.50		
.009	0.300	.018	.720	.025	1.38	.034	4.00	.046	5.50		
.011	0.520	0.041	1.53	.034	1.30						
0.036	0.425			.057	2.52						
				.027	1.275						
0.071	1.50	0.103	3.315	.220	11.14	.118	9.85	.116	13.90	045	6.80

$\Sigma \phi h = 0.673\ \phi m$ kh = 46.51 md-m.   h = 5.05

ϕ = 13.3%   k = 9.21 md.

$\phi h / \Sigma \phi h$	$kh / \Sigma kh$
.07	0.15
.24	0.45
.42	0.66
.75	0.90
.90	0.97

15-19-11-26 2075-2125

0 - ~~10.0~~ 5.0		~~10~~ 5.01 - 10.0		10.01 - 20.0		20.01 - 50.0		50.01 - 100		100+	
ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh	ϕh	kh
.0781	1.32	.1062	5.49			.0925	15.00	.1630	68.00	.~~1800~~	~~120.0~~
.1080	3.60	.0492	4.44			.0612	7.80	.1800	120.0	.1485	176.4
.0675	3.33	.0384	8.00			.0936	30.00	.1570	93.0	.1518	237.6
.0455	1.61	.0532	5.74			.1264	19.20	.1498	70.7	.2552	261.8
.0738	0.78	.0400	3.68			.1463	25.30	.1308	41.4		
.0495	1.10	.0365	3.05			.1560	22.40				
.0462	1.14	.0474	5.28			.0882	21.70				
.0518	1.54					.1357	26.40				
.0918	2.16					.1416	32.0				
.0539	1.05					.0678	18.6				
.0765	0.90					.1386	40.7				
.7426	18.53	.3709	35.68			1.2519	259.1	.7806	393.1	.5555	675.8

$\Sigma_1' \phi h : 3.7015$ $\Sigma_1' kh = 1382.21$

$\phi h / \Sigma \phi h$	$kh / \Sigma kh$
.150	0.49
.36	0.76
.70	0.95
.80	0.98
'	'

$\Sigma h = 29.1$

$\bar{\phi} = 12.72$

$\bar{k} = 47.5$ md.

GROSS PAY vs NET PAY CORE ANALYSIS

WELL	CORED (CHERTY)	GROSS PAY	1 md NET PAY	RATIO
2-20 ✓	2080 - 2127	47	44.7	.95
4-20 ✓	2095 - 2138	43	22.6	.53
8-20	2140 - 2156.5	16.5	8.4	.51
6-20 ✓	2086 - 2135	49	26.4	.54
12-20 ✓	2080.4 2103	22.6	19.3	.85
8-30 ✓	2120.1 2139.0	18.9	16.9	.89
10-30 ✓	2134.8 2160	25.2	7.4	.29
3-32	633- 648	15.0	10.5	.70
10-19 ✓	2117.7 2134.2	16.5	15.2	.92
2-30 ✓	2113.1 2130.0	16.9	15.6	.92
14-20 ✓	2079.9 - 2100.4	20.5	14.4	.70
15-19	2101.7 2125	23.3	21.7	.93
14-19 ✓	2118.4 2138.2	19.8	13.1	.66

	CRIN	TOP ø in Cherty.	KB.
8-19	~~8-19~~ 2036	2101	1532
10-19	2048	2118	1545
11-19	2054	2128	1536
2-19	2064	-	1537
1-19	2041	2095	1537
2-20	2019	2080	[illegible] 1526
3-20	2030	2085	1529
4-20	2034	2095	1530
5-20	2028	2086	1532
7-20	2038	2090	1521
8-20	2076	2140	1524
1-29	2075	2130.	1523
11-30	2069	2144	1547
15-30	2040	2119	1539
1-32	2074	2127	1526
2-32	2073	2128	1527
16-17	2034	2090	1523
15-17	2027	2086	1523
14-17	2041	2103	1530
13-17	2054	2110	1533
12-17	2064	?	1531
11-17	2051	2116	1530
10-17	2041	2098	1526
9-17	2037	2100	1520
8-17	2062	2119	1518
7-17	2065	-	1523
3-17	2068	2124	1529
10-18	2082		1540
15-18	2072		1537
16-18	2062		1534

DRILL STEM TEST DATA.

3-17	~~2098~~-2111	20' SCM		
7-17	2106-2121	90' OCM 330' GMO 90' SW.		
	2123-2147	90' OCM 1620' OCSW		
8-17	2120-32	540' OCM & M.O. 180' OSW.		
11-17	2124-34	270' GOCM 360' GMCO 90' SW.		
12-17	2124-2115	110' OCM 10' SW		
13-17	2130-2140	60' M 240' OCM 420' MCO 120' SW		
14-17	2085-2110	630' SMCO 30' OCGM		
16-17	2085-2100	280' GOCM & M.O.		
	2100-2116	390' GOCM & MCO & 30' SW.		
1-18	2076-2100	75' OCM		
	2112-2126	35' OCM		
	2122-2132	270' GOCM		
7-18	2087-2105	240' GOCM		
8-18	2015-2100	160' GOCM		
9-18	2125-45	480' C.O. 180' GMO		
11-18	2094-2107	105' HOCM		
12-18	2110-2120	125' OFM		
14-18	2089-98	60' OFM		
	2091-2108	45' OCM		
16-18	2107-25	90' GOCM 90' GMO		
	2125-45	230' M.O 90' OCM 10' SW	2144	(610)
1-19	2090-2110	135' GOCM		
2-19	2112-2121	90' GOCM		
7-19	2105-2120	180' OCM		
8-19	2081-2105	203' OGCM		
9-19	2074-2095	55' GM 65' OGCM		
11-19	2085-2124	125' DM		
	2120-2180	200' OCM 600' SW.	2135	(599)
14-19	2113-2145	680' C.O. 60' OCM		

16-19	2083-2111	180' GOCM	
10-20	2135-2155	120' GOCM	
14-20	2075-2115	120' OCM 400' M.O.	
1-29	2088-2148	300' MG SW.	
3-29	2075-2130	210' OCM 90' GMO&OCM 22' OCMW.	
4-29	2102-2136	270' HOCM	
12-29	643-650	31m gocm 78m gmco, 36m m.w.	
13-29	635-650	76m gmco 34m s.w.	
1-30	2085-2130	90' ocm 210' ghocm 90' m.o.	
3-30	2123-2148	90' OCGM 250' m.o.	
6-30	2151-2170	90' GOCM 180' GSW	
10-30	2128-2147	328' GOM 30' GMCO	
11-30	2135-47	210' GOCM	
	2147-57	170' OCM & 10' MSW.	2156 (609)
15-30	2105-87	420' GMO 330' OFWM.	
	2166-79	150' SW 10' C.O.	2167 (628) ~~2178 (639)~~
	2128-55	300' GMO 90' MSW, 60' M.	
	2128-43	30' OFM 15' OFWM	
1-32	2126-47	480' SW.	600

LOWEST DEPTH RECOVERING NO WATER 10-20 (-633)

BASED ON TESTS WHERE OIL & WATER RECOVERED
AVE OWC ≈ - -612

∴ ASSUME OWC average at -600.

N. V. Scallion

Well	PERFS	Zone	TOP OF CHERTY
9-17	2097-2103	Cherty	2100
10-17	2097 - 2103	Cherty	2098
11-17	2099 - 2113	Cherty	2116
14-17	2093 - 2096	Cherty	2103
15-17	2080 - 2086	cherty	2086
16-17	[2093 - 2098 2039 - 2042]	cherty (CRINOIDAL	2090
1-20	2056 - 2064	CRINOIDAL	
2A - 20 (SWD)	(2114 - 2115.6) 644.5 - 645.0	Cherty	2080
3-20	2089 - 94	Cherty	2085
6-20	[2030 - 34 2043 - 49]	CRINC	2083
5-20	[2031 - 36 2044 - 48]	CRINC	2086
4-20	[2036 - 41 2048 - 53]	CRINC	2095
4-21	[2081 - 82 2041 - 47]	CRINC	
13-17	[2099.5 - 2103]	Cherty	2110
12-17	[2066 - 69]	CRINC	
7-17	[2057 - 60]	CRINC	
13-16	[2062 - 78 2097 - 2106]	OOL & CHERTY	
12-16	[2076 - 2078 2097 - 2106]	OOL + CHERTY	

x logs available

Lodgepole A - Pool   05-59A   N.V. Scallion

Suncor.
6-20 x
11-20
12-20 x
13-20 x

Dome
4-29
5-29

Acroll.
14-20 x
14-19 x
3-29
1-30
2-30 x
3-30
6-30
7-30

Krantz Oil
10-30 x

Canadian Reserve oil & gas
9-19
15-19
16A-19

12-33
13-33
15-33
3-34
4-34
5-34
7-34
11-34
12-34
13-34
14-34

× logs Available.

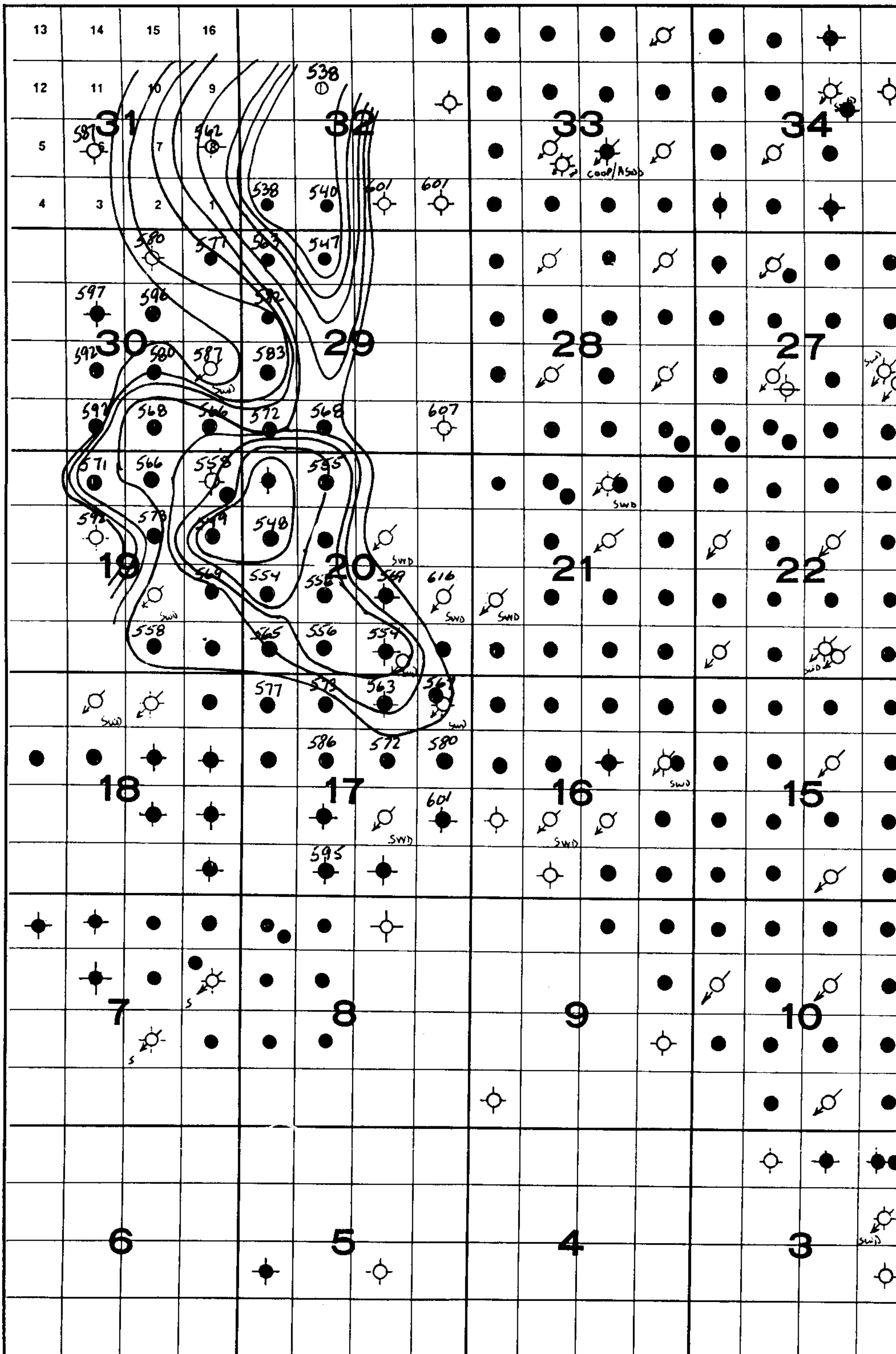
North Virden Scallion - Lodgepole 'A' Pool
- 05 59A

TWP 11, RGE. 26

	CHERTY ZONE		K cut off 1 mD	
	NET PAY (CORE)	ØFt.	Porosity	Ø Logs
• 6-20 (2086 / 2135)	26.7	396.65	14.85	
× 4-20 (2095 / 2138)	22.6	454.9	20.1	
× 2-20 (2080 / 2127)	43.9	503.49	11.46	
15-19× (2101.7 / 2125.0)	21.7			
14-19× (2118.4 / 2138.2)	13.1	210.92	16.1	
10-19× (2117.7 / 2134.2)	16.8	298.4	17.74	
10-30× (2134.8 / 2160.0)	7.5	167.8	22.3	
8-30× (2120.1 / 2139.0)	16.1	255.52	15.87	
2-30 (2113.1 / 2130.0)	16.3	264.45	16.2	
14-30 (2079.9 / 2100.4)	14.5	164	11.3	
13-20× (2024.8 / 2040.6)	10.4	146.34	14.1	
12-20 × (2080.4 / 2103.0)	19.1	367.84	19.2	
× 8-20 (2140.0 / 2156.5)	8.4	164.75	19.6	
8-28 ( )				
3-22 ( )				

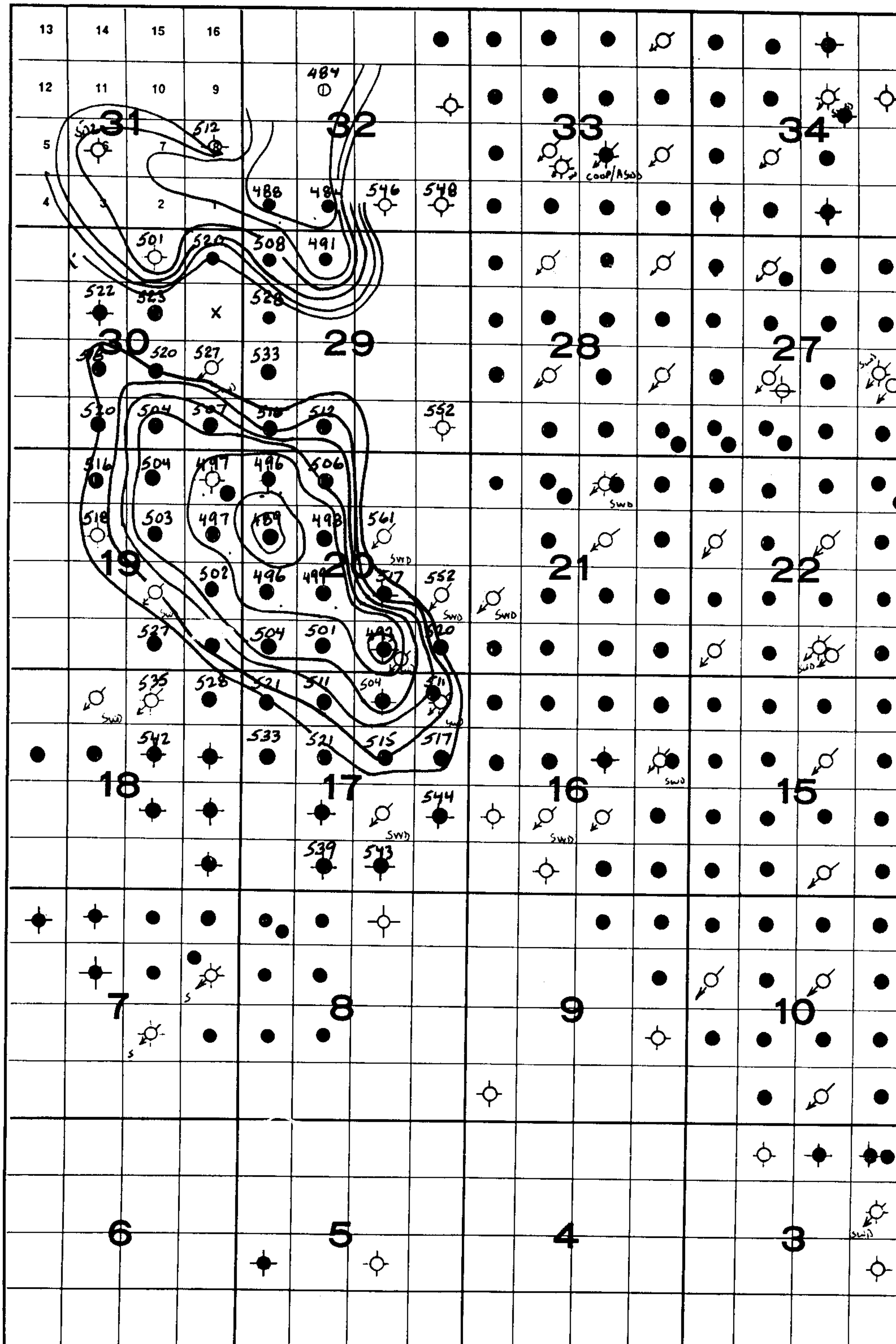
STRUCTURE TOP OF CHERTY φ

Tp. 11 Rge. 26



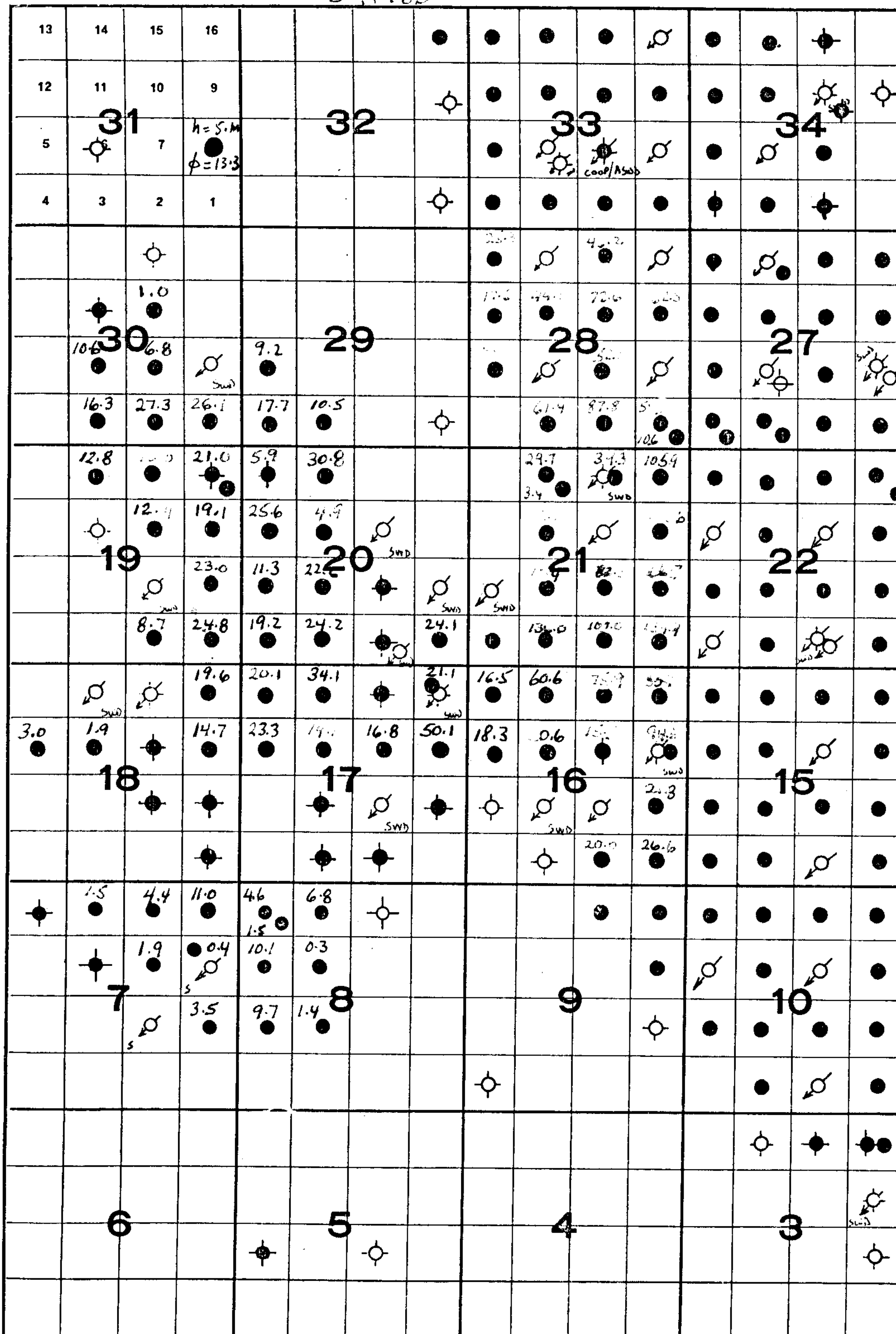
STRUCTURE ON TOP OF CRINOIDAL FT S.S.

Tp. 11 **Rge.** 26



Cum Oil Production **Tp.** 11 **Rge.** 26

m3 - TO DEC 31, 1982

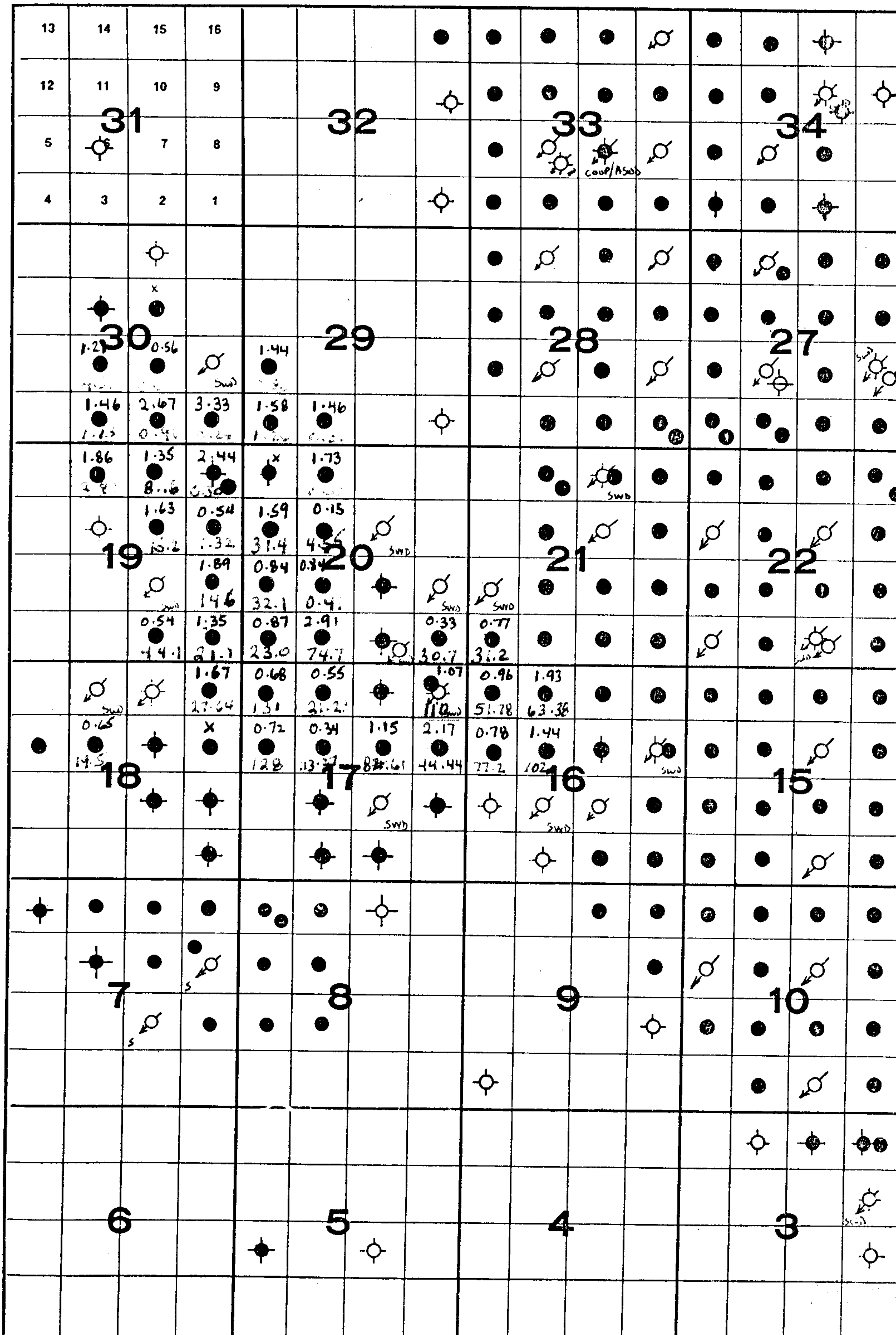


Cp > 60000 — 20000 > Cp > 10000

50000 > Cp > 20000 — Cp < 10000

Feb 82 Production Data 0.56 - OIL RATE m3/d

Tp. 11 Rge. 26



WOR > 50 20>WOR>2

50>WOR>20 WOR<2

GROSS
PAY
(ERTY

Tp. 11 Rge. 26