Manitoba

Energy and Mines

Petroleum and Energy Branch

1395 Ellice Avenue Suite 360
Winnipeg MB R3G 3P2
CANADA

PH: (204) 945-6577
PH: (204) 945-3760
FAX: (204) 945-0586

October 30, 1998

Mr. Brad Thiessen
Tundra Oil and Gas Ltd.
1111 - One Lombard Place
Winnipeg MB R3B 0X4

Dear Brad:

Re: Cromer Unit No. 1
Unit Agreement

The Branch is in receipt of a copy of the signed execution pages for each owner in Cromer Unit No. 1 and has registered the unit agreement. The effective date for Cromer Unit No. 1 is November 1, 1998.

Water injection into the unit may commence on November 1, 1998 in accordance with the conditions of Waterflood Order No. 6.

If you have any questions please don't hesitate to call the undersigned at 945-6574.

Yours truly,

John N. Fox, P.Eng.
Chief Petroleum Engineer

cc: Administration

Tundra oil and gas ltd.

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

October 28, 1998

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

Attention: John N. Fox, P. Eng.
Chief Petroleum Engineer

Dear John:

Re: Cromer Unit # 1

Please find enclosed one original copy of the Cromer Unit #1 Unit Agreement and a copy of the Unit Operating Agreement. We would ask that the Unit Agreement be registered prior to the end of the month to allow Tundra to commence Unit operations November 1, 1998.

Thank you.

Sincerely,

TUNDRA OIL AND GAS LTD.

Brad Thiessen

Brad Thiessen
Land Manager

BT/ps

Enclosure

Manitoba

Action/Route Slip

DATE:	May 29, 1998
TO:	Bob Dubreuil
FROM:	John Fox
Telephone:	945-6574

SUBJECT: Cromer Unit No. 1 – Waterflood Application

Notice of Tundra Oil and Gas Ltd.'s application for approval to conduct a waterflood in Cromer Unit No. 1 in the Daly Bakken I Pool was sent to all affected royalty and working interest owners and was advertised in the Virden Empire Advance. No objections or interventions were received.

Recommendations

It is recommended that:

(1) The Minister enter into the Cromer Unit No. 1 Unit Agreement on behalf of the Crown. Attached is a proposed memo to the Assistant Deputy Minister.

(2) Waterflood Order No. 6 be issued for Cromer Unit No. 1. A copy of the proposed order is attached.

Discussion

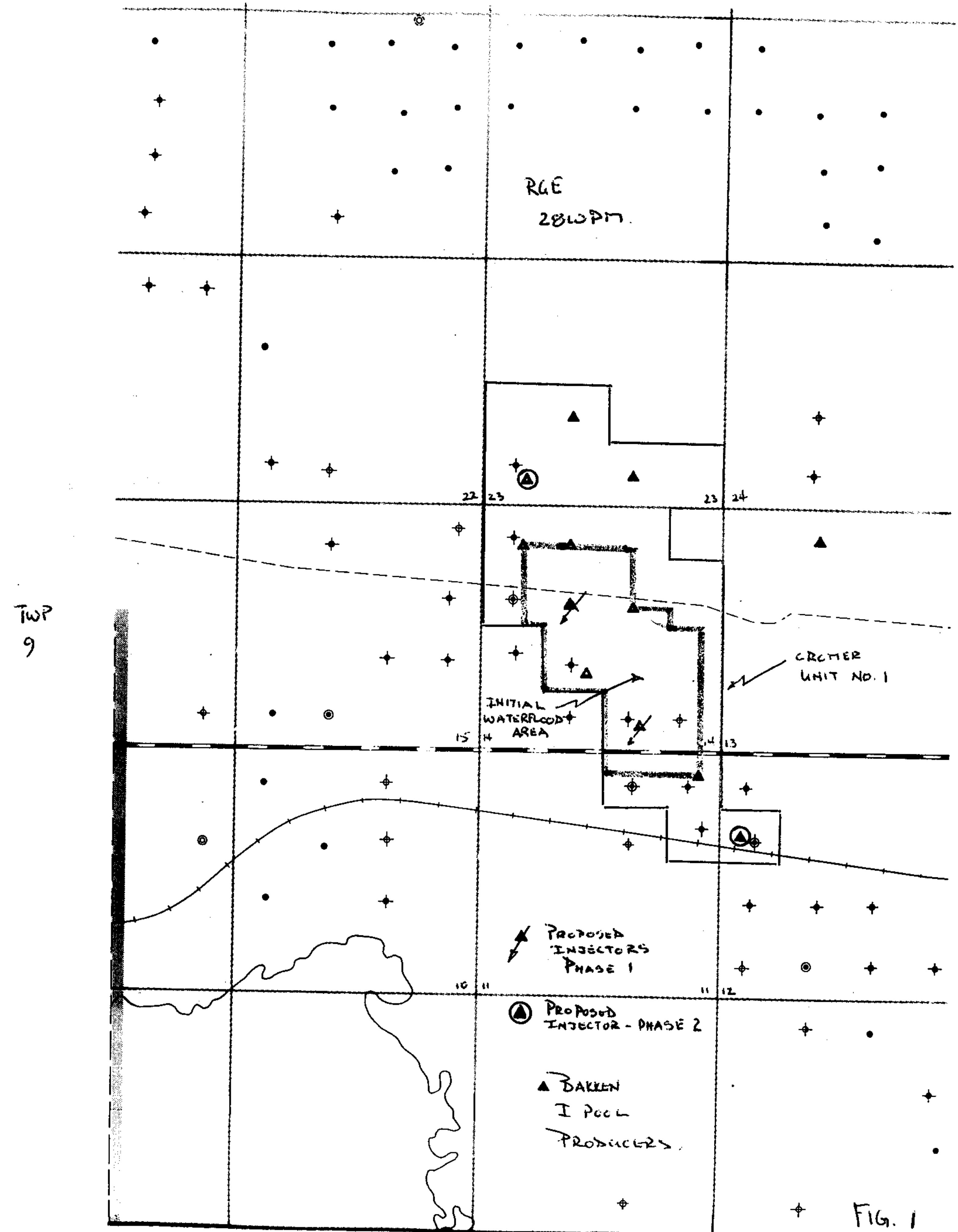
Tundra has submitted a copy of the Cromer Unit No. 1 Unit Agreement. The unit agreement contains the usual clauses with one exception. Clause 906 provides for the enlargement of the unit to include the currently undeveloped 7-14/8-14 tract, where the Crown is the royalty owner. Clause 906 provides for the 7-14/8-14 tract to become part of the unit six months after a well is drilled at 7-14 or 8-14-9-28. Clause 906 also sets out the tract participation formula for inclusion of the 7-14/8-14 tract in the unit. The Branch has reviewed the unit agreement and has no concerns. If a well is not drilled at 7-14 or 8-14 before May 5, 2003, the Crown lease will expire.

The Crown's share in the proposed unit is 73.79%. Tundra has proposed an effective date for the unit of July 1, 1998. Attached is a proposed memo to the Assistant Deputy

Minister recommending the Minister execute the Cromer Unit No. 1 Unit Agreement on behalf of the Crown as a royalty owner.

Also attached is proposed Waterflood Order No. 6 approving injection into the 2-14 and 11-14-9-28 wells as part of the first phase of the waterflood. Tundra has indicated that if Phase 1 is successful, the waterflood will be expanded with 12-12-9-28 and 4-23-9-28 being converted to injection (see Fig. 1). The recommended maximum injection pressure is 9000 kPa. Tundra will be advised that water injection cannot commence until all parties have executed the unit agreement and the Branch has registered the agreement.

John Fox



TWP
9
RGE
28W.PM.
22 23
23 24
15 14
14 13
10 11
11 12
CROMER
UNIT NO. 1
INITIAL
WATERFLOOD
AREA
PROPOSED
INJECTORS
PHASE 1
PROPOSED
INJECTOR - PHASE 2
BAKKEN
I POOL
PRODUCERS.

FIG. 1

Manitoba

Energy and Mines

Petroleum and Energy Branch

1395 Ellice Avenue Suite 360
Winnipeg MB R3G 3P2
CANADA

PH: (204) 945-6577
PH: (204) 945-3760
FAX: (204) 945-0586

June 3, 1998

Mr. George Czyzewski, P.Eng.
Sr. Reservoir Engineer
Tundra Oil and Gas Ltd.
1111 - One Lombard Place
Winnipeg MB R3B 0X4

Dear George:

Re: Cromer Unit No. 1
Waterflood Order No. 6

Your application to conduct waterflood operations in the Daly Bakken I Pool has been approved. Attached is Waterflood Order No. 6 outlining conditions for operation of the waterflood in Cromer Unit No. 1. Water injection into the unit may not commence until the unit agreement has been executed by all parties and registered by the Petroleum Branch.

If you have any questions please don't hesitate to call the undersigned at 945-6574.

Yours truly,

John N. Fox, P.Eng.
Chief Petroleum Engineer

MINISTERIAL ORDER
WATERFLOOD ORDER NO. 6

Pertaining to Waterflood Operations
in Cromer Unit No. 1

1.0 The Unit Operator shall conduct waterflood operations by injecting water into the Bakken Formation underlying Cromer Unit No. 1 ("the Unit") through the wells listed in Schedule A. The Director may approve the conversion of additional wells in the Unit to water injection.

1.1 Every injection well shall be completed as approved under Section 47 of the Drilling and Production Regulation.

1.2 The maximum wellhead pressure at which water may be injected is 9 000 kPa.

1.3 The Director may, from time to time, establish a maximum or minimum rate at which water may be injected into a well.

1.4 The annulus of each injection well shall be pressure tested in accordance with Section 50 of the Drilling and Production Regulation.

2.0 The Unit Operator shall conduct an annual survey to determine the level and distribution of reservoir pressure in the Unit. A summary of the results of any pressure surveys conducted during the year are to be included in the annual waterflood progress report required under Section 73 of the Drilling and Production Regulation.

2.1 The frequency of pressure surveys may be reduced where the Director is satisfied that more frequent surveys will not assist the Unit Operator in monitoring the effectiveness of the waterflood.

2.2 The Unit Operator is responsible for monitoring the effectiveness of the waterflood and for collecting such reservoir data and other information as is necessary to evaluate and optimize waterflood performance.

2.3 The Unit Operator is to advise the Petroleum Branch of the suspension of water injection at any well, any indication of channelling or breakthrough of injected water to a producing well or out of zone and any other detrimental effects that may be attributable to the waterflood operations.

3.0 The Unit Operator shall file a report of production or injection for each well in the Unit in accordance with Section 120 of the Drilling and Production Regulation.

4.0 The Unit Operator shall file an annual waterflood progress report in accordance with Section 73 of the Drilling and Production Regulation.

June 1, 1998
Date

Director of Petroleum for
Minister of Energy and Mines

Schedule A

Cromer Unit No. 1

Water Injection Wells

Cromer Unit No.1 WIW 2-14-9-28 (WPM)
Cromer Unit No.1 WIW 11-14-9-28 (WPM)

Manitoba

Action/Route Slip

DATE: May 29, 1998

TO: Bob Dubreuil

FROM: John Fox

Telephone: 945-6574

SUBJECT: Cromer Unit No. 1 – Waterflood Application

Notice of Tundra Oil and Gas Ltd.'s application for approval to conduct a waterflood in Cromer Unit No. 1 in the Daly Bakken I Pool was sent to all affected royalty and working interest owners and was advertised in the Virden Empire Advance. No objections or interventions were received.

Recommendations

It is recommended that:

(1) The Minister enter into the Cromer Unit No. 1 Unit Agreement on behalf of the Crown. Attached is a proposed memo to the Assistant Deputy Minister.

(2) Waterflood Order No. 6 be issued for Cromer Unit No. 1. A copy of the proposed order is attached.

Discussion

Tundra has submitted a copy of the Cromer Unit No. 1 Unit Agreement. The unit agreement contains the usual clauses with one exception. Clause 906 provides for the enlargement of the unit to include the currently undeveloped 7-14/8-14 tract, where the Crown is the royalty owner. Clause 906 provides for the 7-14/8-14 tract to become part of the unit six months after a well is drilled at 7-14 or 8-14-9-28. Clause 906 also sets out the tract participation formula for inclusion of the 7-14/8-14 tract in the unit. The Branch has reviewed the unit agreement and has no concerns. If a well is not drilled at 7-14 or 8-14 before May 5, 2003, the Crown lease will expire.

The Crown's share in the proposed unit is 73.79%. Tundra has proposed an effective date for the unit of July 1, 1998. Attached is a proposed memo to the Assistant Deputy

Minister recommending the Minister execute the Cromer Unit No. 1 Unit Agreement on behalf of the Crown as a royalty owner.

Also attached is proposed Waterflood Order No. 6 approving injection into the 2-14 and 11-14-9-28 wells as part of the first phase of the waterflood. Tundra has indicated that if Phase 1 is successful, the waterflood will be expanded with 12-12-9-28 and 4-23-9-28 being converted to injection (see Fig. 1). The recommended maximum injection pressure is 9000 kPa. Tundra will be advised that water injection cannot commence until all parties have executed the unit agreement and the Branch has registered the agreement.

John Fox

Manitoba

Memorandum

Date: May 29, 1998

To: Garry Barnes
A/Deputy Minister
Energy and Mines

From: L. R. Dubreuil
Director
Petroleum & Energy Branch

Telephone:

Subject: **Cromer Unit No. 1 Unit Agreement**

First | Fold

Tundra Oil and Gas Ltd. is proposing to unitize an area in the Daly Field, which includes eleven tracts. The proposed Cromer Unit No. 1 involves seven tracts for which the Crown is the royalty owner (i.e. mineral rights owner). Tundra has applied for approval to waterflood the unit area and has also submitted a copy of the proposed unit agreement for Cromer Unit No. 1 (attached) for execution by the Minister on behalf of the Crown as an affected royalty owner. Section 133 of The Oil and Gas Act provides for the Minister to enter such agreement on behalf of the Crown as a royalty owner.

Recommendation:

It is recommended that the Minister enter into the Cromer Unit No. 1 Unit Agreement on behalf of the Crown with respect to Lsd's 9, 15 & 16 of Section 11, Lsd 12 of Section 12, and Lsd's 1, 2, 9, 10 & 15 and the NW/4 of Section 14 in Township 9, Range 28 WPM by signing two copies of the attached execution page for the Cromer Unit No. 1 Unit Agreement.

Discussion:

The seven tracts in the proposed Cromer Unit No. 1 that contain Crown-owned mineral rights are highlighted in Attachment No. 1. Tundra Oil and Gas Ltd. holds all Crown leases. Currently the wells on the Crown tracts produce from the Daly Bakken I Pool at a combined rate of approximately 11 m^3/d.

It is anticipated that waterflood operations will significantly increase the amount of oil recovered from the unit area and consequently increase royalty and production tax revenue to the Crown.

The proposed unit area is currently developed with a mix of 16 ha and 32 ha locations. Proposed tract factors are based on current productivity (Sep-Dec 1997). Upon review, Branch staff has found the proposed tract factors to be reasonable. On this basis, it is recommended that the Minister enter into the proposed Unit Agreement on behalf of the Crown as a royalty owner.

L. R. Dubreuil

Tundra oil and gas ltd.

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

April 29, 1998

MANITOBA ENERGY & MINES
APR 29 1998
PETROLE... BRANCH

Manitoba Energy and Mines
Petroleum Branch
360 - 1395 Ellice Avenue
Winnipeg, MB R3G 0G3

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

Dear John,

RE: Cromer Unit No. 1
Pressure Maintenance Application

This letter is in reply to the Petroleum Branch's review of the referenced application. Tundra's position pertaining to the Petroleum Branch's questions is outlined as follows:

1) Development Drilling of 8-14-9-28

Tundra estimates that a location drilled at 8-14-9-28 would have an ultimate oil recovery of 3,975 m3 (25,000 STB). Based on a 1998 full cycle development cost of $300,000, this would result in a finding cost of $12 / barrel. This is clearly unacceptable according to both Tundra and industry standards. Historically, Tundra has developed Bakken oil on 80 acre tracts because of the large drainage areas characteristic of Bakken wells. Competitive drainage is quite likely occurring in tract 7-14/8-14 from offsetting wells 2-14 and 6-14. As a result, low oil recovery is estimated from a development well at 8-14-10-29.

2) Unit Waterflood Expansion

Tundra has stated that incremental oil recovery of 6,300 m3 is probable with further waterflood expansion. This would require further conversions at 12-12-9-28 and 4-23-9-28 (refer to Figure No. 1). Further waterflood expansion will also be dependent on good waterflood response in the Unit with 11-14-9-28 and 2-14-9-28 as initial injectors. Prevailing commodity prices will also have an impact on going ahead with further waterflood expansion. In summary, the incremental oil recovery of 6,300 m3 with further waterflood expansion can be classified at this time as probable reserves.

Tundra
oil and gas ltd.

3) **Production used in Tract Factor Determination**

Tundra has used oil production during the last 90 operating days as the method to determine the tract factors and equity interests in the Unit. The last 90 operating days was referenced to 97.12.31. This approach used 31 days during the month December, 1997, 30 days during the month of November, 1997, and only 30 of the 31 days were required during the month of October, 1997 to obtain a total of 90 operating days. As a result, the production stated in Table No. 7 for the month of October, 1997 has been adjusted to achieve the 90 operating days. Therefore, the production used in determining the tract factors is correct. As a further clarification, the production for the month of October, 1997 (full 31 days) for well 14-14-9-28 is 52.1 m3, not 51.2 m3 as stated in your letter.

4) **Commencement of Unit Operations**

Tundra would like the effective date of Unit operations to commence on July 1, 1998.

5) **Unit Agreements**

Tundra has drafted both the Unit and Unit Operating Agreements to date. Tundra will expedite the Unit agreements to all mineral owners after there is a resolution between Tundra and the Petroleum Branch pertaining to the questions addressed in your letter dated April 23, 1998.

6) **Unit Tract 7-14/8-14-9-28**

Tundra has proceeded with assigning a nominal production value of 1 m3 to the 7-14/8-14 tract, based on previous discussions (prior to formal submission of the application) with the Petroleum Branch. The Petroleum Branch was receptive with this approach as an interim method of including the 7-14/8-14 tract in the Unit. As previously stated, the reserves in tract 7-14/8-14 are quite likely being drained by offsetting wells 2-14 and 6-14-9-28. On this basis, a tract factor should be assigned to the 7-14/8-14 tract at this time. Although it is not economic at this time to drill a well in LSD 8-14, especially with prevailing oil prices, development of this tract will be revisited at a later date. As a result, Tundra would be agreeable to a redetermination of tract factors in the Unit with development of the 7-14/8-14 tract at a later date. Tundra would be receptive to the following approach in handling the 7-14/8-14 tract during the interim period:

a) The tract factors proposed in Table No. 8 (Cromer Unit No. 1 Pressure Maintenance Application) shall be adopted as the initial tract factors in Cromer Unit No. 1.

b) A deadline of May 5, 2003 will be set to develop the 7-14/8-14 tract, subject to attractive prevailing economic conditions. If business environment conditions are not economically attractive, a further extension will be granted by the Crown.

c) Subject to the development of tract 7-14/8-14, all Unit tract factors will be redetermined. The formula for redetermination will be as follows:

   i) Six (6) months of production will be required from tract 7-14/8-14 with the last 90 operating days used in the tract factor redetermination.

   ii) Similarly, the production during the last 90 days, referenced to the same time period as tract 7-14/8-14, will be used in the redetermination of tract factors in the unitized wells.

   iii) The tract factor assigned to the 7-14/8-14 tract will be calculated on the basis of the production (refer to 6ci) from the 7-14/8-14 tract as a percentage of the total Unit production during the same time period (last 90 operating days).

   iv) The remaining tract factors in the Unit will be adjusted in proportion to their percentage in the Unit prior to the development of tract 7-14/8-14, to reflect the change in tract 7-14/8-14.

Tundra would appreciate your feedback at the earliest convenience pertaining to the issues outlined in this letter. I can be reached at 934-5853 for further discussion.

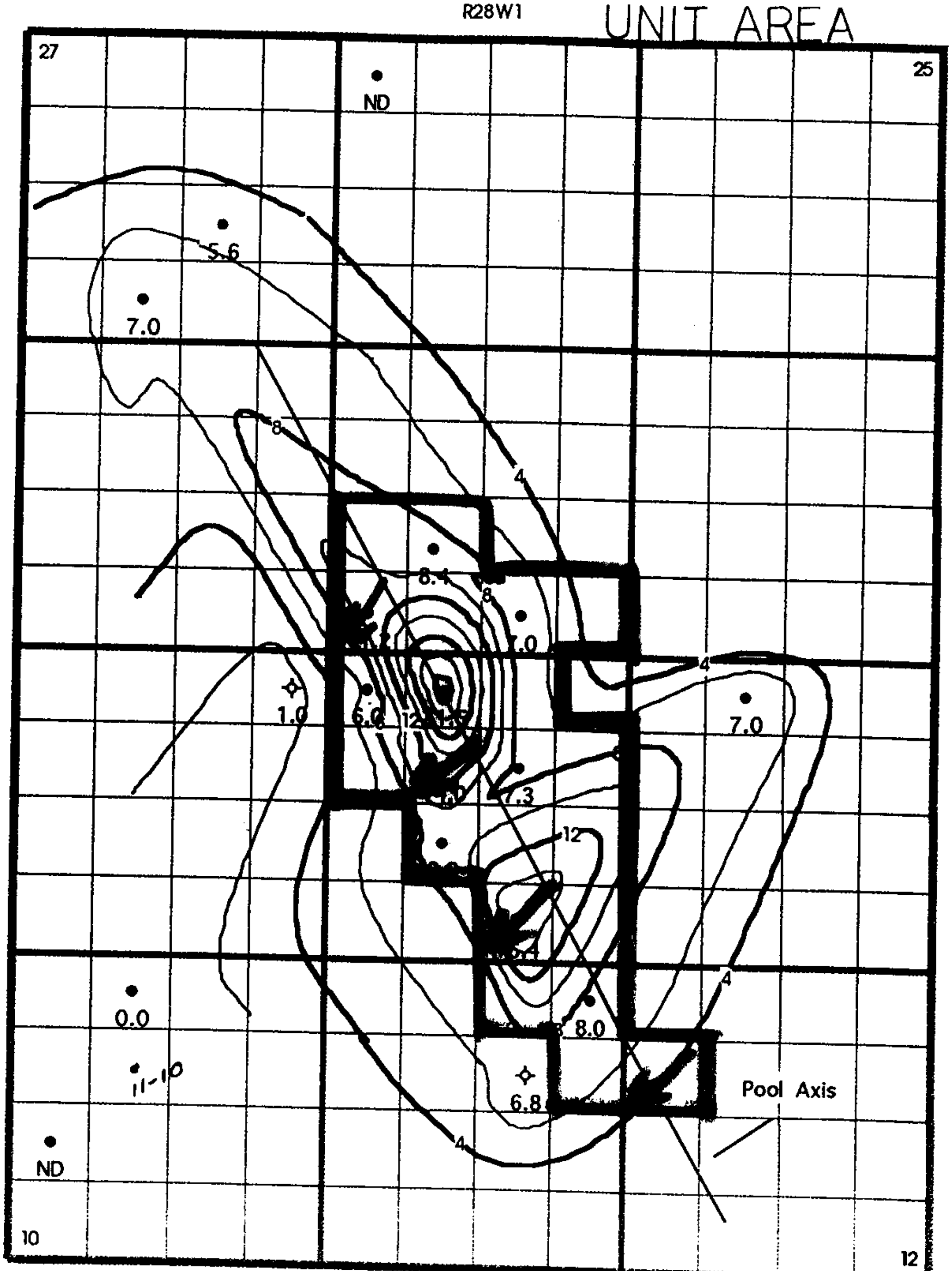
Sincerely,

TUNDRA OIL AND GAS LTD.

George Czyzewski, P.Eng.
General Manager

FIGURE NO. 1

UNIT AREA



UNIT OUTLINE

PROPOSED INJECTORS

TUNDRA OIL AND GAS LTD.	
Bakken I Pool PHI-H at 2.0 Intervals (1 km)	
M.B. DUPONT	
Date:6/16/97	33000

Manitoba

Action/Route Slip

DATE: April 23, 1998

TO: Bob Dubreuil

FROM: John Fox

Telephone: 945-6574

SUBJECT: Daly Bakken I Pool – Waterflood Application

Tundra Oil and Gas Ltd. has applied for approval to implement a waterflood in Cromer Unit No. 1 in the Daly Bakken I Pool.

Recommendations

It is recommended that:

(1) Notice of the application be sent to offsetting royalty owners, working interest owners in the I Pool and published in the Virden Empire Advance.

(2) Tundra submit plans for waterflood expansion in the unit.

(3) Tundra revise the tract factors using corrected production and assigning nil production to the 7-14 / 8-14 unit tract.

(4) Tundra submit two copies of Cromer Unit No. 1 Unit Agreement. The unit agreement should provide for determine of initial and final tract factors to accommodate the future drilling of a well at 7-14-9-28 or 8-14-9-28.

Discussion

Waterflood Project

Tundra proposes to unitize all the producing wells in the Daly Bakken I Pool, with the exception of the 14-13-9-28 well. The pool and proposed unit outline are shown on Figure 1.

There are 11 producing wells in the proposed Cromer Unit No. 1. Current production (December 1997) is 15 m^3/d with a WOR of 0.17 m^3/m^3. Cumulative production from the wells as of 31-Dec-97 totals 21,387 m^3. Tundra estimates ultimate primary recovery of 42,367 m^3. This represents a primary recovery factor of 24.3% OOIP. Figure 2 is a plot of the proposed unit production history.

Tundra plans to initially convert the 11-14-9-28 well to injection. If the waterflood responds favourably the 2-14-9-28 well will also be converted to injection. Figure 3 shows the initial waterflood area. Tundra estimates incremental waterflood recovery of 5% of the OOIP in the initial waterflood area or 3620 m^3. Tundra indicated expanding the waterflood to other areas of the unit would result in the recovery of an additional 6300 m^3, increasing the overall incremental waterflood recovery to 5.7% of the unit's OOIP. No specific waterflood expansion plans were provided in the application.

Based on waterflood performance of other Bakken pools in the Daly Field, Engineering supports Tundra's incremental waterflood recovery estimate for the I Pool. Notice of the application is required and will be sent to offsetting royalty owners, working interest owners in the I Pool and published in the Virden Empire Advance.

Cromer Unit No. 1

The proposed unit area is developed with a mix of 16 & 32 ha locations. Tundra has indicated that future development of undrilled 16 ha spacing units is uneconomic. To accommodate the mix of 16 & 32 ha development, Tundra in discussions with the Branch, has proposed a mix of 16 & 32 ha unit tracts, as outlined on Figure 4. The 32 ha unit tracts are oriented east west, and with the exception of the 9-11/12-12 and 14-14/15-14 tracts, consist of either the north-half or south-half of a quarter section. Unit tracts 9-11/12-12 and 14-14/15-14, which cross quarter section or section boundaries, are all Crown land under lease to Tundra. Engineering supports Tundra's use of a mix of 16 & 32 ha unit tracts. Though unorthodox, the proposed unit tracts, with the exception of the 7-14/8-14 tract, contain a producing well and cover the productive area of the pool as currently mapped (see Figure 5).

Tundra proposes to determine tract participation based on production from the wells for the last 90-days ending 31-Dec-97. The Crown is the royalty owner in 8 of the 12 unit tracts. Based on Tundra's proposed tract participation formula, the Crown's share in the unit is 73.9%. The tract participation formula is the same as used for Kola Unit No.'s 1 & 2. Engineering has reviewed alternate tract participation formulas (see Table 1) and tract participation based on the last 90-days production is reasonable as it preserves current revenue for royalty owners and is not subject to interpretation. It appears Tundra has used the wrong production values and the company will have to recalculate the tract factors.

One unit tract, 7-14/8-14, where the Crown is the royalty owner has not been drilled. Tundra has proposed assigning nominal production of 1 m^3 to the 7-14/8-14 unit tract. Tundra indicated it may drill a well at 8-14-9-28 in the future. Engineering is concerned that if the 7-14/8-14 tract is included in the unit and allocated production, Tundra can retain the lease without drilling a well. The 7-14/8-14 tract is the 3rd largest in terms of oil-in-place and should be developed to improve ultimate recovery from the pool. Engineering believes the following proposal for inclusion of the 7-14/8-14 tract in the unit is equitable to both Tundra and the Crown:

(1) The 7-14/8-14 unit tract is to be assigned nil production for the last 90-days ending 31-Dec-98 for the purpose of determining initial tract participation (See Table 1).

(2) If a well is drilled at 7-14-9-28 or 8-14-9-28, initial tract participation will be redetermined.

(3) Final tract participation for the 7-14/8-14 unit tract will be calculated using the last 90-days production from the 8-14* well, counted back from the last day of the 4th calendar month after the well goes on-production divided by total unit production over the same time period. Final tract participation for the remaining unit tracts will be determined by multiplying a tract's initial tract participation by the factor, (1- the final tract participation for the 7-14/8-14 unit tract). Table 2 shows a sample calculation of the final tract participation factors.

(4) If a well is not drilled at 7-14 or 8-14 before 05-May-2003, the Crown lease will be non-productive and will expire.

The Branch will request Tundra's comments on the above proposal which is designed to ensure that if a well is not drilled by Tundra at 7-14 or 8-14, the lands are returned to the Crown and are available for posting. Tundra has not submitted copies of the proposed Cromer Unit No. 1 Unit Agreement for review by the Branch.

11-14-9-28

MPP - 841 m.

WTR GRAD - 0.4 psi/ft

FRAC GRAD - 1.0 psi/ft

MWIP = 841×3.281 (1.0-0.4)

= 1655.6 psi

11 415 kPa.

SF=0.8

MWIP = 9132 kPa $\frac{486}{9000}$

John Fox

* For the purposes of this example, it has been assumed that a well is drilled at 8-14-9-28. The well could be drilled at either 8-14-9-28 or 7-14-9-28.

Table 1

Cromer Unit No. 1 - Initial Tract Factors

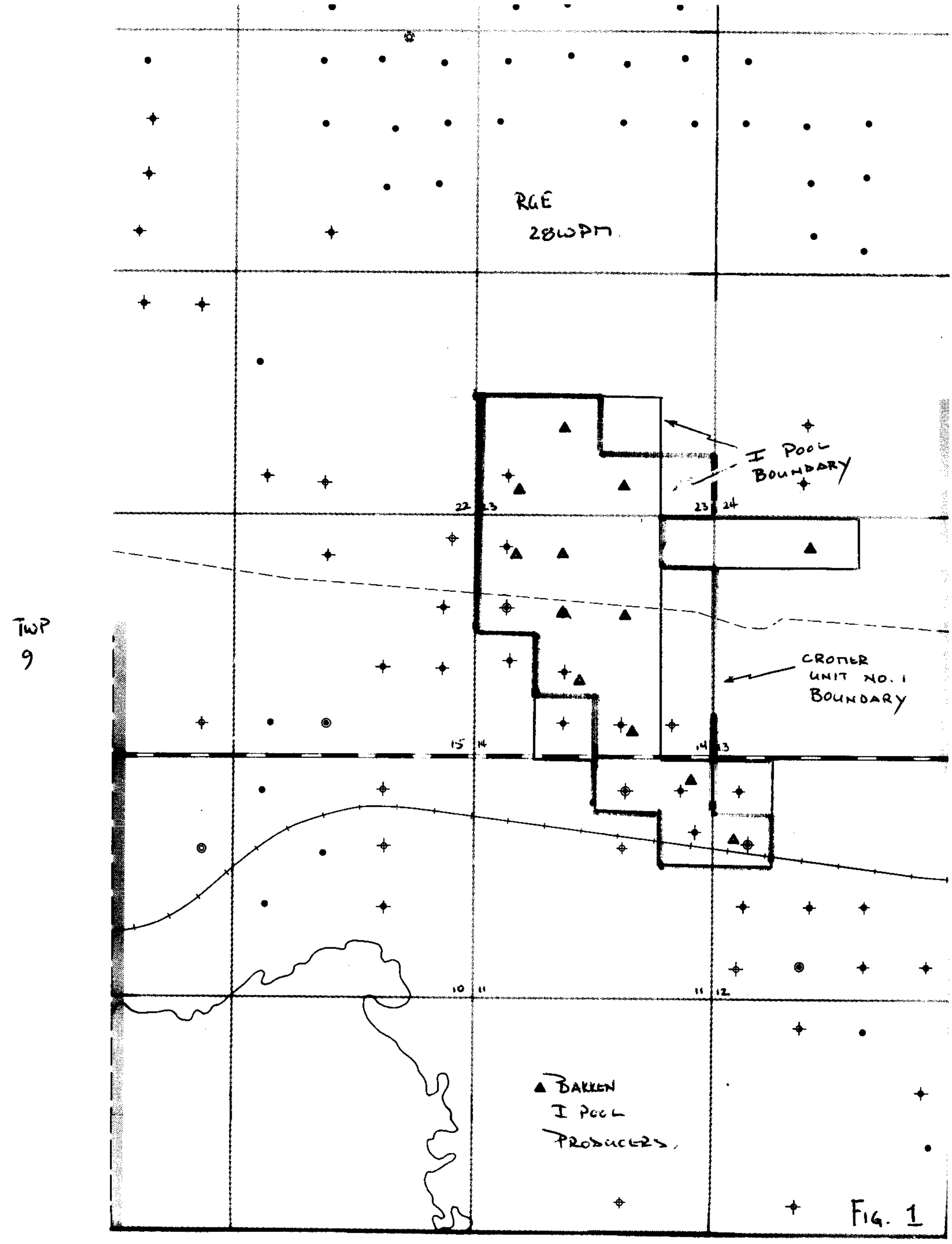
Tract	Royalty Owner	Last 90-days Production	Production Tract Factor	OOIP	OOIP Tract Factor	Recoverable Reserves	Reserves Tract Factor	Remaining Rec. Reserves	Rem. Rec. Res. Tract Factor
15-11 & 16-11	Crown	187.5	13.44086%	15510	8.89988%	4558	10.75837%	2906	13.85261%
9-11 & 12-12	Crown	199.4	14.29391%	8904	5.10925%	3279	7.73951%	2993	14.26733%
1-14 & 2-14	Crown	211	15.12545%	19183	11.00751%	7771	18.34211%	3693	17.60416%
6-14	Freehold	125.9	9.02509%	7632	4.37936%	3272	7.72299%	1675	7.98456%
9-14 & 10-14	Crown	98.2	7.03943%	15689	9.00259%	3025	7.13999%	1475	7.03118%
11-14 & 12-14	Crown	132.5	9.49821%	16113	9.24589%	5994	14.14780%	2229	10.62542%
13-14	Crown	47.1	3.37634%	7802	4.47691%	1841	4.34536%	390	1.85909%
14-14 & 15-14	Crown	155.2	11.12545%	20183	11.58132%	6379	15.05653%	2025	9.65297%
1-23 & 2-23	Freehold	22.2	1.59140%	9498	5.45010%	1618	3.81901%	295	1.40624%
3-23 & 4-23	Freehold	43.2	3.09677%	20099	11.53312%	1597	3.76944%	724	3.45123%
5-23 & 6-23	Freehold	172.8	12.38710%	13908	7.98063%	3033	7.15887%	2573	12.26523%
7-14 & 8-14	Crown	0	0.00000%	19751	11.33343%	0	0.00000%	0	0.00000%
	Total	1395.0	100%	174272.0	100%	42367.0	100%	20978.0	100%
Crown Unit Share			73.89964%		70.65679%		77.52968%		74.89274%

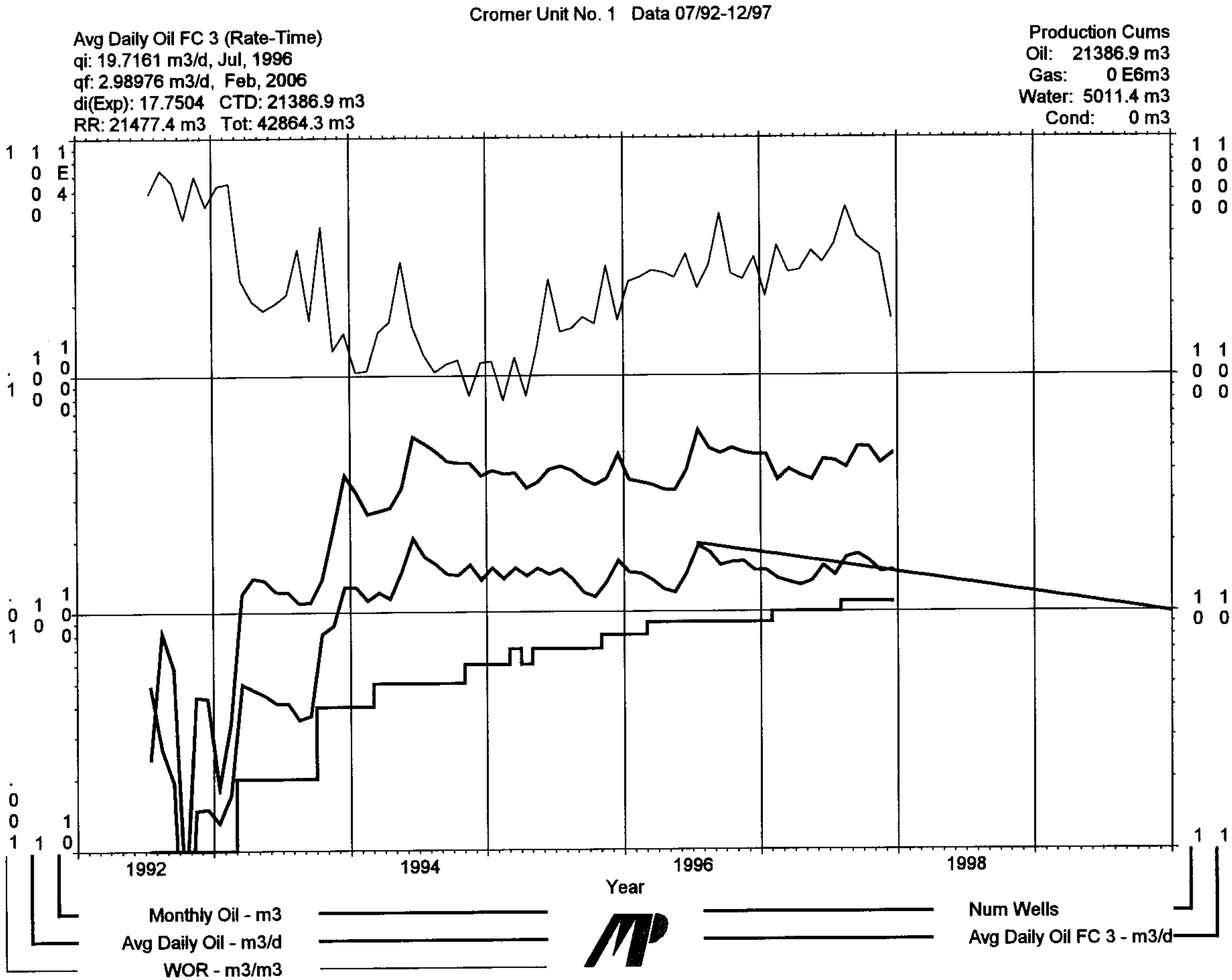
Table 2

Cromer Unit No. 1 - Sample Calculation Final Tract Participation

8-14-9-28 on production - November 18

Tract	Royalty Owner	Interim Tract Participation	Nov-98 PROD.	Nov-98 Days	Dec-98 PROD.	Dec-98 Days	Jan-99 PROD.	Jan-99 Days	Feb-99 PROD.	Feb-99 Days	Total PROD.	Total Days	Final Tract Participation
15-11 & 16-11	Crown	13.44086%	0	0	50.7	31	49.8	31	45.8	28	146.3	90	9.63617%
9-11 & 12-12	Crown	14.29391%	1.7	1	52.1	31	47.0	30	49	28	149.8	90	10.24775%
1-14 & 2-14	Crown	15.12545%	0	0	59.2	31	59.2	31	57.1	28	175.5	90	10.84391%
6-14	Freehold	9.02509%	1.4	1	42.1	31	43.2	31	43.2	27	129.9	90	6.47037%
9-14 & 10-14	Crown	7.03943%	2.3	2	34.5	30	34.5	31	32.6	27	103.9	90	5.04679%
11-14 & 12-14	Crown	9.49821%	0	0	0	0	0	0	0	0	0	0	6.80956%
13-14	Crown	3.37634%	0	0	11.7	31	12.0	31	11.2	28	34.9	90	2.42061%
14-14 & 15-14	Crown	11.12545%	1.7	1	49.8	30	50.2	31	48.3	28	150.0	90	7.97618%
1-23 & 2-23	Freehold	1.59140%	0.8	3	8.2	29	6.2	30	6.6	28	21.8	90	1.14092%
3-23 & 4-23	Freehold	3.09677%	0	0	14.2	31	14.0	31	13.3	28	41.5	90	2.22017%
5-23 & 6-23	Freehold	12.38710%	0	0	45.4	31	44.9	31	43.9	28	134.2	90	8.88070%
7-14 & 8-14	Crown	0.00000%	10.6	2	150.2	29	142.6	31	126.1	28	429.5	90	28.30686%
		100%									1517.3		100%


RGE
28WPM
TWP
9
I POOL
BOUNDARY
22
23
23
24
CROMER
UNIT NO. 1
BOUNDARY
15
14
14
13
10
11
11
12
▲ BAKKEN
I POOL
PRODUCERS.
FIG. 1



Cromer Unit No. 1 Data 07/92-12/97
Avg Daily Oil FC 3 (Rate-Time)
qi: 19.7161 m3/d, Jul, 1996
qf: 2.98976 m3/d, Feb, 2006
di(Exp): 17.7504 CTD: 21386.9 m3
RR: 21477.4 m3 Tot: 42864.3 m3
Production Cums
Oil: 21386.9 m3
Gas: 0 E6m3
Water: 5011.4 m3
Cond: 0 m3
1992
1994
1996
1998
Year
Monthly Oil - m3
Avg Daily Oil - m3/d
WOR - m3/m3
Num Wells
Avg Daily Oil FC 3 - m3/d

FIG. 2

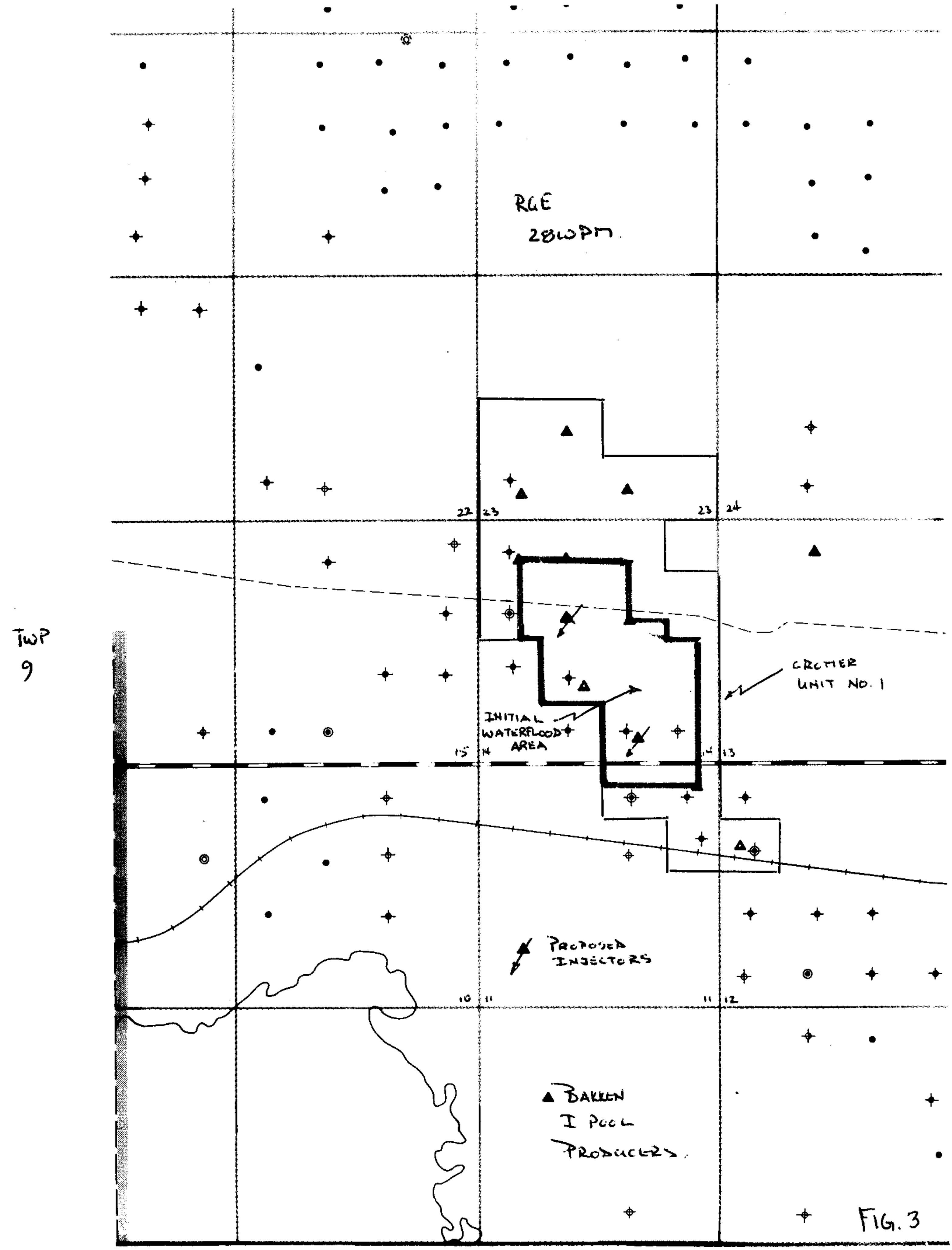
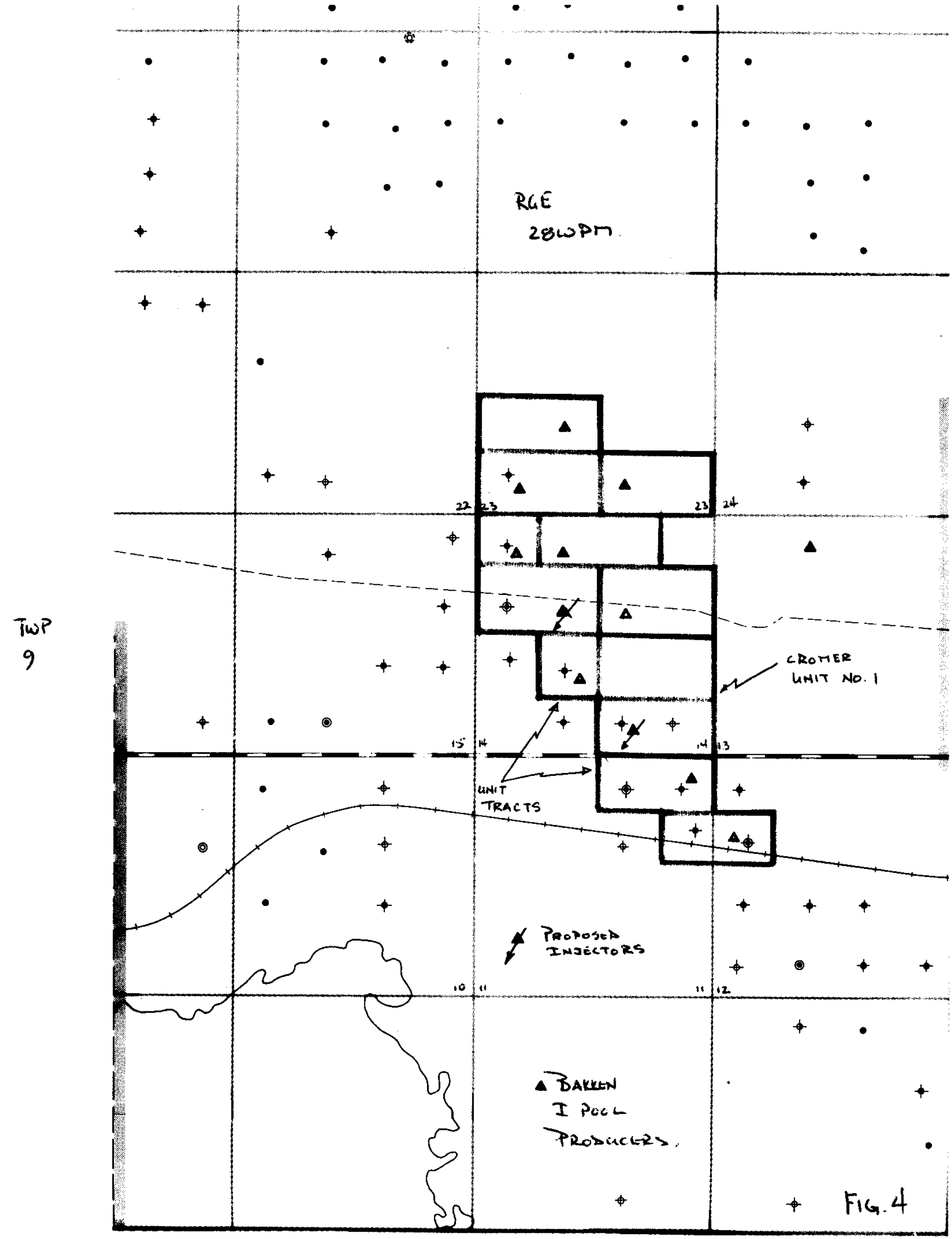
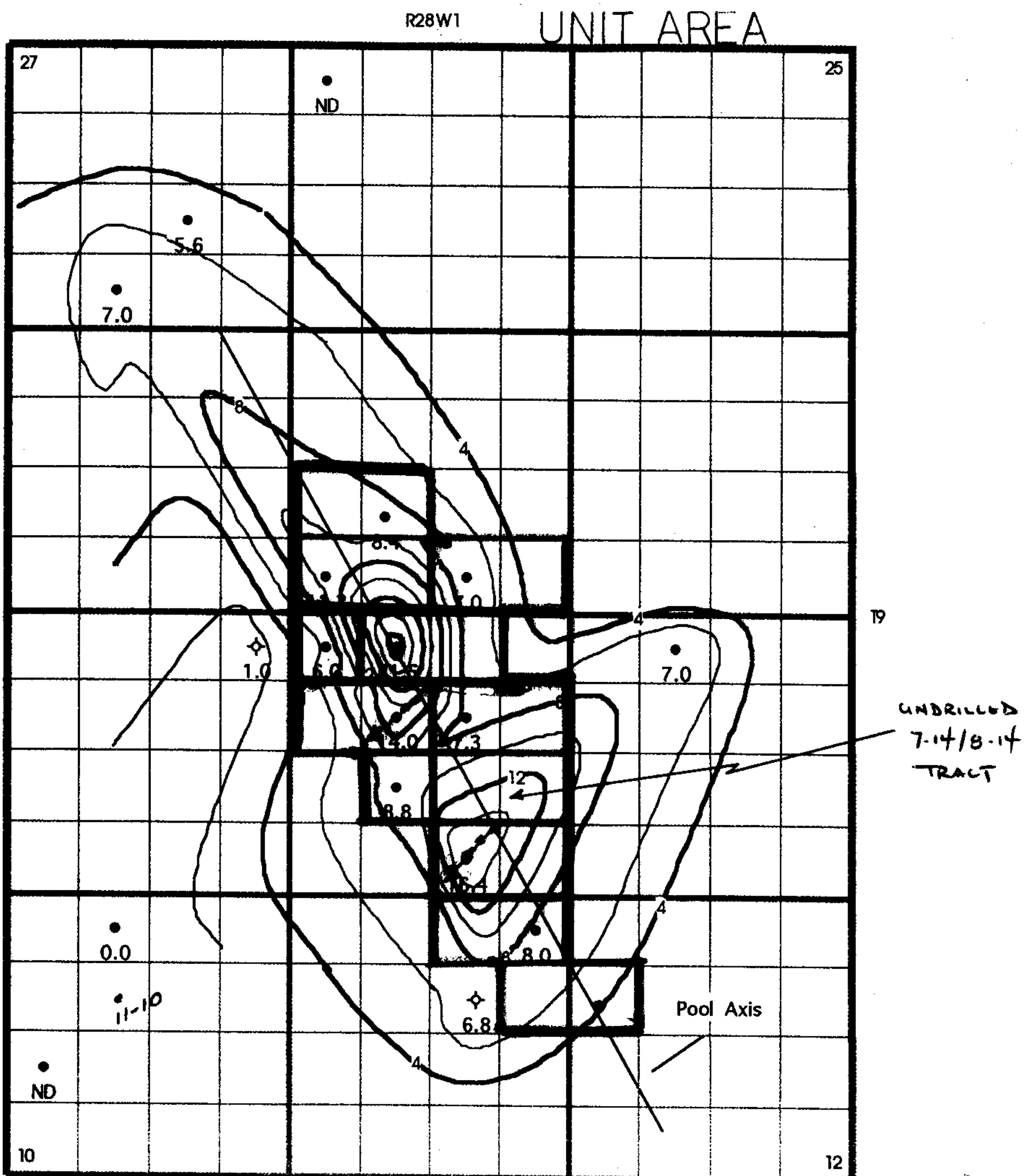

RGE
28WPM
TWP
9
22 23
23 24
CROMER
UNIT NO. 1
INITIAL
WATERFLOOD
AREA
15 14
14 13
PROPOSED
INJECTORS
10 11
11 12
BAKKEN
I POOL
PRODUCERS.

FIG. 3


RGE
28WPM
TWP
9
22
23
23
24
CROMER
UNIT NO. 1
15
14
14
13
UNIT
TRACTS
PROPOSED
INJECTORS
10
11
11
12
BAKKEN
I POOL
PRODUCERS.
FIG. 4



UNIT OUTLINE + UNIT TRACTS

PROPOSED INJECTORS

ECONOMIC PRODUCTIVITY LIMIT 0.8 phi·m

TUNDRA OIL AND GAS LTD.	
Bakken I Pool PHI-H at 2.0 Intervals (1 km)	
M.B. DUPONT	
Date:6/16/97	33000

FIG. 5

April 23, 1998

George Czyzewski, P.Eng.
General Manager
Tundra Oil and Gas Ltd.
1111 Lombard Place
Winnipeg, MB R3B 0X4

Dear Mr. Czyzewski:

Re: Cromer Unit No. 1 – Waterflood Application

The Branch has completed a preliminary review of your application to conduct a waterflood in the proposed Cromer Unit No. 1. Notice of the application will be distributed to offset royalty and working interest owners with a deadline for objections or interventions of 22-May-98.

Tundra indicated in its application that "development drilling at 8-14-9-28 would further increase recovery in the initial waterflood area" and "adding further injectors, could potentially provide further incremental oil recovery of 6300 m^3". Please provide the Branch with an estimate of the recoverable reserves for the 8-14 well and an outline of potential waterflood expansion plans in the unit.

The Branch has reviewed Tundra's tract participation calculations on Table 7 in the application. According to the Branch's records the production data for October 1997 for a number of wells is incorrect. The following are the correct production rates:

Well	Oct-97 Production (m^3)
2-14-9-28	77.5
11-14-9-28	49.5
13-14-9-28	18.0
14-14-9-28	51.2
2-23-9-28	8.0
4-23-9-28	15.3
6-23-9-28	62.2

One unit tract, 7-14/8-14, where the Crown is the royalty owner has not been drilled. Tundra has proposed assigning nominal production of 1 m^3 to the 7-14/8-14 unit tract. Tundra indicated it may drill a well at 8-14-9-28 in the future. The Branch is concerned that if the 7-14/8-14 tract is included in the unit and allocated production, Tundra can retain the lease without drilling a well. The 7-14/8-14 tract is the 3rd largest in terms of oil-in-place and should be developed to improve ultimate recovery from the pool. The Branch believes the following proposal for inclusion of the 7-14/8-14 tract in the unit is equitable to both Tundra and the Crown:

(1) The 7-14/8-14 unit tract is to be assigned zero production for the last 90-days ending 31-Dec-98 for the purpose of determining initial tract participation. The Branch has recalculated the initial tract participation using the corrected well production and zero production for the 7-14/8-14 unit tract (See Table 1).

(2) If a well is drilled at 7-14-9-28 or 8-14-9-28, initial tract participation will be redetermined.

(3) Final tract participation for the 7-14/8-14 unit tract will be calculated using the last 90-days production from the 7-14 or 8-14 well, counted back from the last day of the 4th calendar month after the well goes on-production divided by total unit production over the same time period. Final tract participation for the remaining unit tracts will be determined by multiplying a tract's initial tract participation by the factor, (1- the final tract participation for the 7-14/8-14 unit tract). Table 2 shows a sample calculation of the final tract participation factors.

(4) If a well is not drilled at 7-14 or 8-14 before 05-May-2003, the Crown lease will be non-productive and will expire.

Please provide the Branch with your comments on the proposed initial and final tract participation formulas.

The application indicates Tundra is in the process of notifying the owners within the proposed unit area of its plans to unitize. When does Tundra hope to complete unit negotiations and have the unit agreement executed by all unit owners? The Branch would like to review the proposed Cromer Unit No. 1 Unit Agreement as soon as possible so preparations can be made for the Minister to execute the agreement on behalf of the Crown.

If you have any questions in respect of this matter please contact the undersigned at 945-6574.

Yours truly,

ORIGINAL SIGNED BY

John N. Fox, P.Eng.
Chief Petroleum Engineer

Table 1

Cromer Unit No. 1 - Initial Tract Factors

Tract	Royalty Owner	Last 90-days Production	Production Tract Factor
15-11 & 16-11	Crown	187.5	13.44086%
9-11 & 12-12	Crown	199.4	14.29391%
1-14 & 2-14	Crown	211	15.12545%
6-14	Freehold	125.9	9.02509%
9-14 & 10-14	Crown	98.2	7.03943%
11-14 & 12-14	Crown	132.5	9.49821%
13-14	Crown	47.1	3.37634%
14-14 & 15-14	Crown	155.2	11.12545%
1-23 & 2-23	Freehold	22.2	1.59140%
3-23 & 4-23	Freehold	43.2	3.09677%
5-23 & 6-23	Freehold	172.8	12.38710%
7-14 & 8-14	Crown	0	0.00000%
	Total	1395.0	100%
Crown Unit Share			73.89964%

Table 2

Cromer Unit No. 1 - Sample Calculation Final Tract Participation

8-14-9-28 on production - November 18, 1998

Tract	Royalty Owner	Interim Tract Participation	Nov-98		Dec-98		Jan-99		Feb-99		Total		Final Tract Participation
			PROD.	Days	PROD.	Days	PROD.	Days	PROD.	Days	PROD.	Days	
15-11 & 16-11	Crown	13.44086%	0	0	50.7	31	49.8	31	45.8	28	146.3	90	9.63617%
9-11 & 12-12	Crown	14.29391%	1.7	1	52.1	31	47.0	30	49	28	149.8	90	10.24775%
1-14 & 2-14	Crown	15.12545%	0	0	59.2	31	59.2	31	57.1	28	175.5	90	10.84391%
6-14	Freehold	9.02509%	1.4	1	42.1	31	43.2	31	43.2	27	129.9	90	6.47037%
9-14 & 10-14	Crown	7.03943%	2.3	2	34.5	30	34.5	31	32.6	27	103.9	90	5.04679%
11-14 & 12-14	Crown	9.49821%	0	0	0	0	0	0	0	0	0	0	6.80956%
13-14	Crown	3.37634%	0	0	11.7	31	12.0	31	11.2	28	34.9	90	2.42061%
14-14 & 15-14	Crown	11.12545%	1.7	1	49.8	30	50.2	31	48.3	28	150.0	90	7.97618%
1-23 & 2-23	Freehold	1.59140%	0.8	3	8.2	29	6.2	30	6.6	28	21.8	90	1.14092%
3-23 & 4-23	Freehold	3.09677%	0	0	14.2	31	14.0	31	13.3	28	41.5	90	2.22017%
5-23 & 6-23	Freehold	12.38710%	0	0	45.4	31	44.9	31	43.9	28	134.2	90	8.88070%
7-14 & 8-14	Crown	0.00000%	10.6	2	150.2	29	142.6	31	126.1	28	429.5	90	28.30686%
		100%									1517.3		100%

Manitoba

Energy and Mines

Petroleum and Energy Branch

1395 Ellice Avenue Suite 360
Winnipeg MB R3G 3P2
CANADA

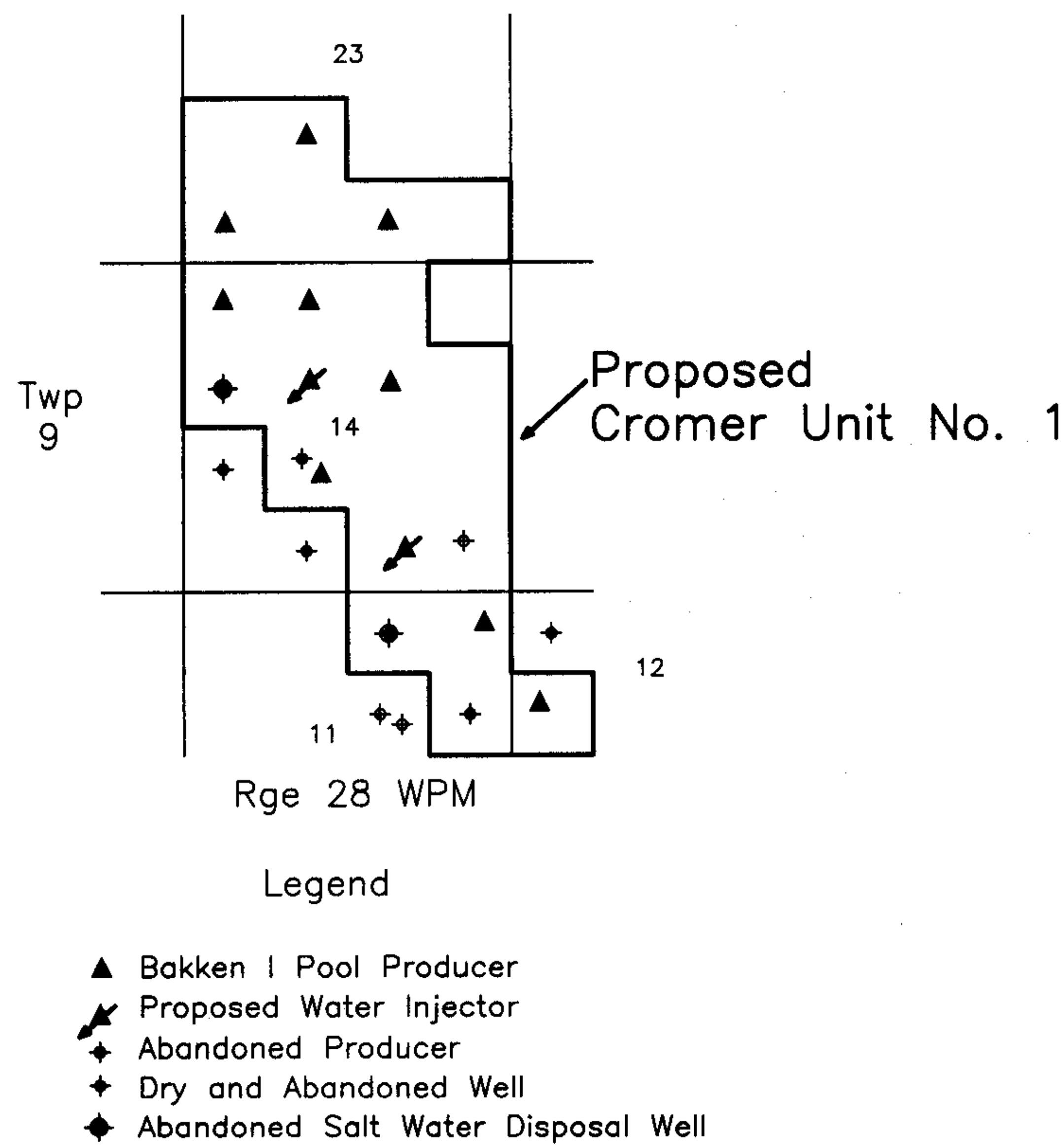
PH: (204) 945-6577
PH: (204) 945-3760
FAX: (204) 945-0586

NOTICE

UNDER THE OIL AND GAS ACT

DALY OIL FIELD

Tundra Oil and Gas Ltd. has made application under The Oil and Gas Act to conduct a waterflood in the Bakken Formation in that portion of the Daly Bakken I Pool referred to as Cromer Unit No. 1 and shown below.



It is proposed to convert the wells, Tundra Daly Prov. RE2-14-9-28 (WPM) and Tundra Daly Prov. 11-14-9-28 (WPM), to water injection.

If no valid objection or intervention is received in writing by the Department of Energy and Mines, Petroleum and Energy Branch, at Suite 360, 1395 Ellice Avenue, Winnipeg, Manitoba R3G 3P2 before May 22, 1998, the Director may approve the application.

Copies of the application can be obtained from:

George Czyzewski, P.Eng.
General Manager
Tundra Oil and Gas Ltd.
1111 Lombard Place
Winnipeg, MB R3B 0X4
(204) 934-5850

This application may be viewed at the offices of the Petroleum and Energy Branch:

Suite 360, 1395 Ellice Avenue
Winnipeg, MB R3G 3P2
(204) 945-6577

227 King Street West
Virden, MB R0M 2C0
(204) 748-1557

Dated at Winnipeg, this 23 rd day of April, 1998.

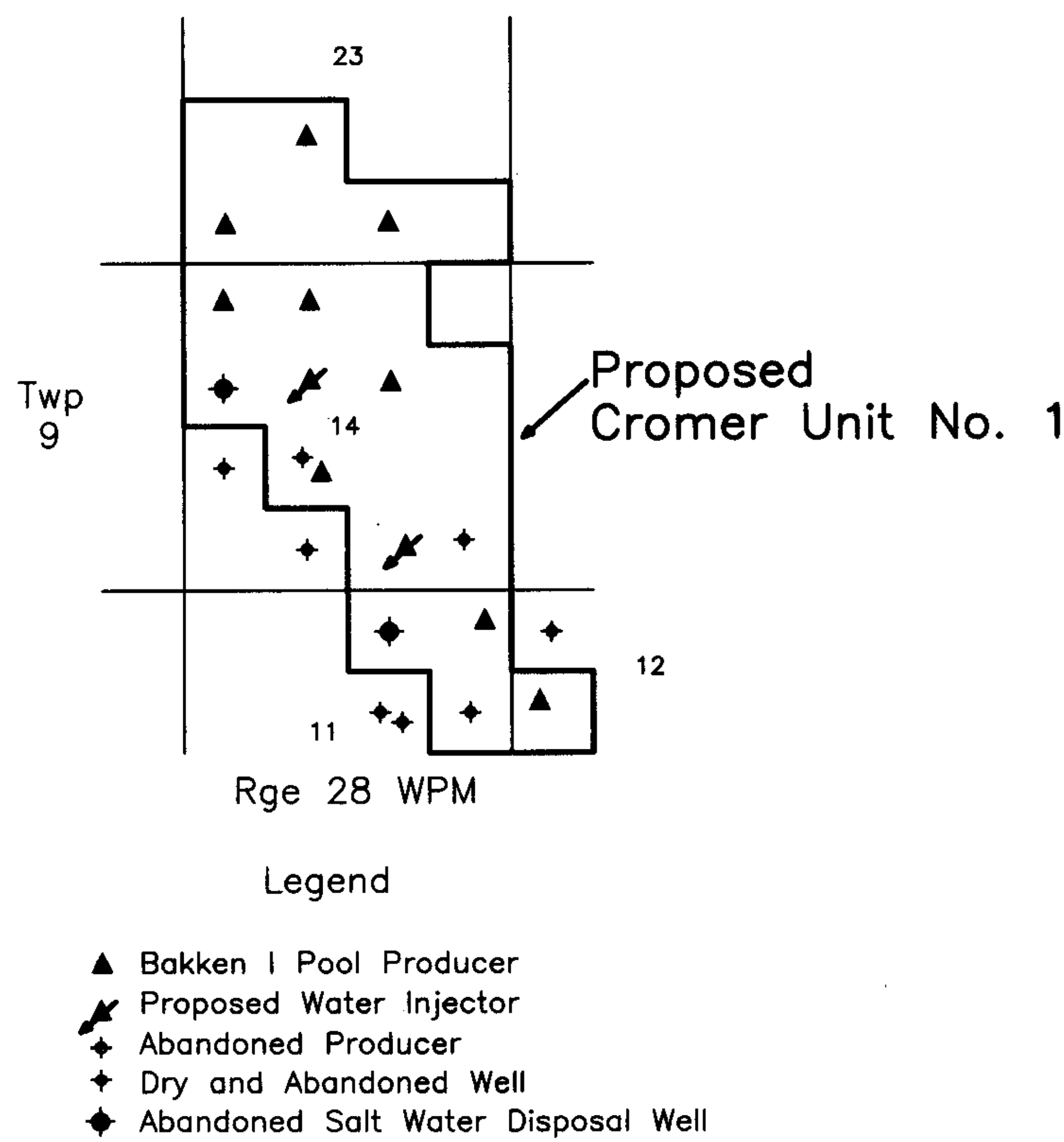
L.R. Dubreuil, Director
Petroleum and Energy Branch

NOTICE

UNDER THE OIL AND GAS ACT

DALY OIL FIELD

Tundra Oil and Gas Ltd. has made application under The Oil and Gas Act to conduct a waterflood in the Bakken Formation in that portion of the Daly Bakken I Pool referred to as Cromer Unit No. 1 and shown below.



Production Report

Group	:	Cromer Unit No. 1	Date	:	April 21, 1998 9:06:50 am
Well	:	Cromer Unit No. 1	User	:	Ludwig
	:	000000242			

Production Data from July, 1992 to June, 2003 (cont.)

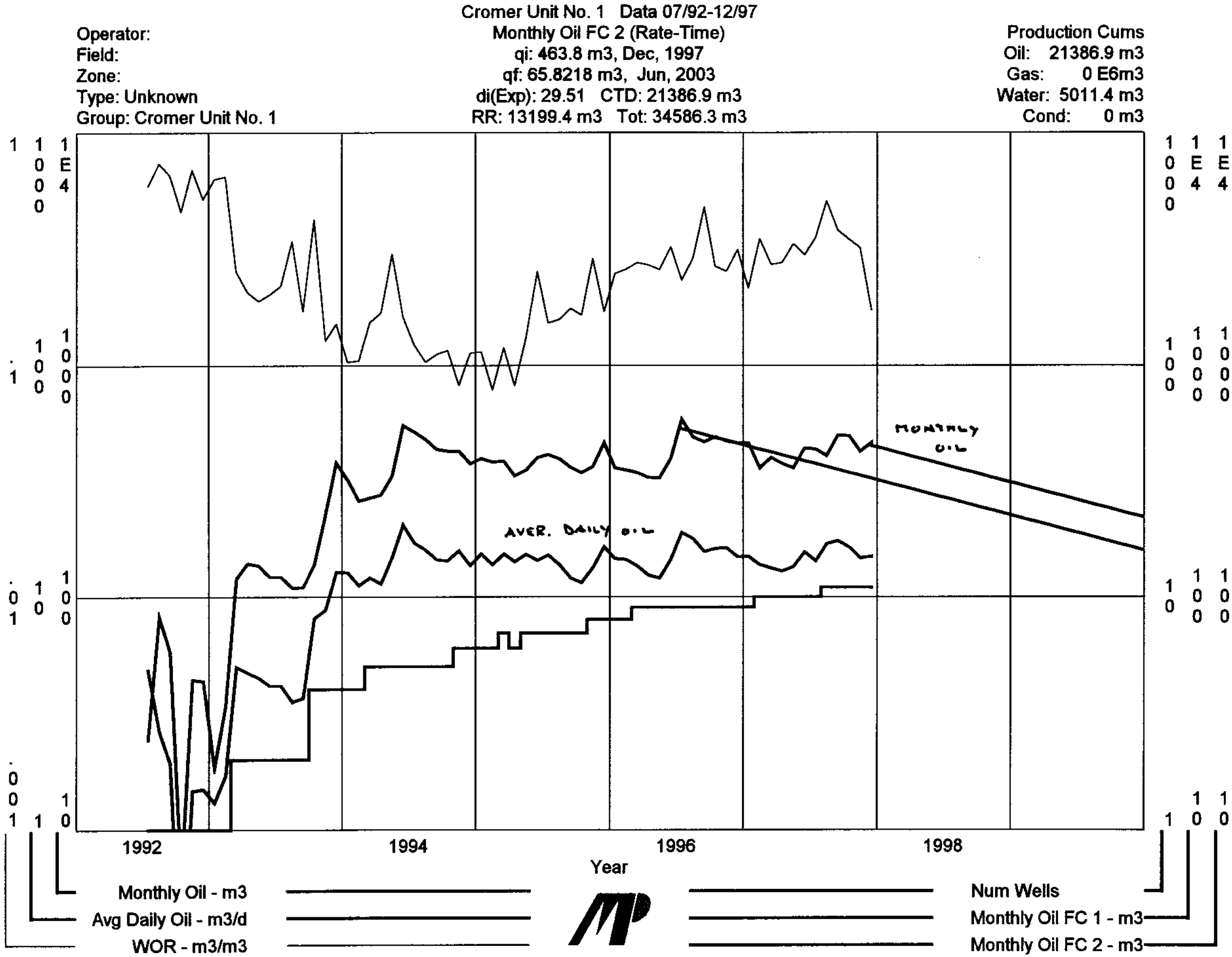
Year	Monthly Oil m3	Avg Daily Oil m3/d	WOR m3/m3	Num Wells	Num Wells
Mar., 1996	343.6	13.5632	0.277066	9	9
Apr., 1996	328.4	12.4315	0.271315	9	9
May., 1996	326.1	12.0406	0.259123	9	9
Jun., 1996	396.1	14.4915	0.324413	9	9
Jul., 1996	584.9	18.9441	0.233031	9	9
Aug., 1996	489.8	17.865	0.290527	9	9
Sep., 1996	467.7	15.6552	0.47894	9	9
Oct., 1996	493.4	16.155	0.268139	9	9
Nov., 1996	472.4	16.2897	0.254445	9	9
Dec., 1996	460.5	14.8548	0.315744	9	9
Jan., 1997	462.8	14.929	0.21586	9	9
Feb., 1997	360.9	13.7924	0.351898	10	10
Mar., 1997	400.8	13.2862	0.271956	10	10
Apr., 1997	376.4	12.9051	0.276833	10	10
May., 1997	360.2	13.4445	0.333704	10	10
Jun., 1997	440.2	15.6284	0.299409	10	10
Jul., 1997	435.2	14.2689	0.355699	10	10
Aug., 1997	407.7	16.9287	0.508707	11	11
Sep., 1997	499.8	17.4603	0.381353	11	11
Oct., 1997	497.1	16.3879	0.34822	11	11
Nov., 1997	425.8	14.6828	0.321512	11	11
Dec., 1997	463.8	14.9613	0.174213	11	11
Jan., 1998					
Feb., 1998					
Mar., 1998					
Apr., 1998					
May., 1998					
Jun., 1998					
Jul., 1998					
Aug., 1998					
Sep., 1998					
Oct., 1998					
Nov., 1998					
Dec., 1998					
Jan., 1999					
Feb., 1999					
Mar., 1999					
Apr., 1999					
May., 1999					
Jun., 1999					
Jul., 1999					
Aug., 1999					
Sep., 1999					
Oct., 1999					
Nov., 1999					
Dec., 1999					
Jan., 2000					
Feb., 2000					

Production Report

Group	:	Cromer Unit No. 1	Date	:	April 21, 1998 9:06:50 am
Well	:	Cromer Unit No. 1	User	:	Ludwig
	:	000000242			
Hist.Data	:	07/92-12/97	On Prod	:	02/09
Operator	:		Status	:	Unknown
Field	:		Zone	:	

Production Data from July, 1992 to June, 2003

Year	Monthly Oil m3	Avg Daily Oil m3/d	WOR m3/m3	Num Wells	Num Wells
Jul., 1992	24.2	4.84	0.590909	1	1
Aug., 1992	82	2.64516	0.740244	1	1
Sep., 1992	57.9	1.93	0.658031	1	1
Oct., 1992	6.1	0.203333	0.459016	1	1
Nov., 1992	44.1	1.47	0.696145	1	1
Dec., 1992	43.4	1.49655	0.518433	1	1
Jan., 1993	18.3	1.30714	0.63388	1	1
Feb., 1993	34.1	1.705	0.648094	1	1
Mar., 1993	119.8	4.99167	0.253756	2	2
Apr., 1993	139.4	4.72542	0.207317	2	2
May., 1993	136.3	4.46885	0.189288	2	2
Jun., 1993	122	4.13559	0.202459	2	2
Jul., 1993	122.2	4.14237	0.220131	2	2
Aug., 1993	109.4	3.52903	0.341865	2	2
Sep., 1993	110.2	3.67333	0.171506	2	2
Oct., 1993	137.8	8.10588	0.42598	4	4
Nov., 1993	225.9	8.77282	0.127933	4	4
Dec., 1993	380.6	12.7933	0.151603	4	4
Jan., 1994	321.2	12.7208	0.103674	4	4
Feb., 1994	260.1	11.1871	0.10496	4	4
Mar., 1994	267.7	12.0767	0.153157	5	5
Apr., 1994	275.7	11.4083	0.169024	5	5
May., 1994	334	14.7897	0.301796	5	5
Jun., 1994	550	20.5288	0.161273	5	5
Jul., 1994	515.6	17.0917	0.12277	5	5
Aug., 1994	480.2	15.9182	0.103499	5	5
Sep., 1994	433.7	14.4567	0.112059	5	5
Oct., 1994	427.2	14.3396	0.116339	5	5
Nov., 1994	426.4	15.7926	0.0823171	6	6
Dec., 1994	377.3	13.6373	0.113438	6	6
Jan., 1995	396.4	15.3445	0.114783	6	6
Feb., 1995	382.9	13.7569	0.0783494	6	6
Mar., 1995	387	15.3267	0.11938	7	7
Apr., 1995	333.1	14.1745	0.0819574	6	6
May., 1995	353.8	15.2995	0.131995	7	7
Jun., 1995	400.8	14.4	0.253992	7	7
Jul., 1995	411.8	15.1119	0.152987	7	7
Aug., 1995	395.3	13.7695	0.158108	7	7
Sep., 1995	361.9	12.0633	0.176015	7	7
Oct., 1995	344.5	11.5475	0.165167	7	7
Nov., 1995	364.9	13.3297	0.289394	8	8
Dec., 1995	464.2	16.4319	0.170832	8	8
Jan., 1996	360.3	14.6315	0.248682	8	8
Feb., 1996	353.6	14.5067	0.259615	8	8


Cromer Unit No. 1 Data 07/92-12/97
Monthly Oil FC 2 (Rate-Time)
qi: 463.8 m3, Dec, 1997
qf: 65.8218 m3, Jun, 2003
di(Exp): 29.51 CTD: 21386.9 m3
RR: 13199.4 m3 Tot: 34586.3 m3
Operator:
Field:
Zone:
Type: Unknown
Group: Cromer Unit No. 1
Production Cums
Oil: 21386.9 m3
Gas: 0 E6m3
Water: 5011.4 m3
Cond: 0 m3
MONTHLY OIL
AVER. DAILY OIL
1992
1994
1996
1998
Year
Monthly Oil - m3
Avg Daily Oil - m3/d
WOR - m3/m3
Num Wells
Monthly Oil FC 1 - m3
Monthly Oil FC 2 - m3

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:25:52 am
Well	:	Tundra Daly Prov. RE16-11-09-28W1	User	:	Ludwig
	:	00/16-11-009-28W1/2			
Hist.Data	:	03/96-12/97	On Prod	:	01/00
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60I

Production Data from March, 1996 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Mar., 1996	3.8	0.475	11.6234
Apr., 1996	13.3	1.10833	2.91846
May., 1996	10.7	1.52857	2.7261
Jun., 1996	16.6	1.84444	63.1827
Jul., 1996	176.5	5.69355	21.2683
Aug., 1996	145.6	4.85333	18.1497
Sep., 1996	117.6	4.05517	21.0665
Oct., 1996	115.4	3.72258	16.3708
Nov., 1996	100.1	3.45172	19.5915
Dec., 1996	90.5	2.91935	24.0691
Jan., 1997	86.6	2.79355	19.882
Feb., 1997	75.8	2.80741	18.136
Mar., 1997	84.9	2.73871	16.3487
Apr., 1997	67.1	2.23667	26.2552
May., 1997	71.3	2.37667	20.1497
Jun., 1997	69.7	2.58148	22.5479
Jul., 1997	72.3	2.41	28.8295
Aug., 1997	74.8	2.49333	21.5858
Sep., 1997	72.3	2.41	14.5335
Oct., 1997	70.1	2.33667	18.6708
Nov., 1997	55.9	1.92759	24.8574
Dec., 1997	61.5	1.98387	12.1382

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:54:49 am
Well	:	Tundra Daly Prov. RE R//E12-12-09-28W1	User	:	Ludwig
	:	00/12-12-009-28W1/2			
Hist.Data	:	08/97-12/97	On Prod	:	02/09
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60I

Production Data from August, 1997 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Aug., 1997	9.7	0.97	71.5453
Sep., 1997	84.6	4.02857	23.0831
Oct., 1997	68.7	2.45357	21.5679
Nov., 1997	60.4	2.08276	15.2818
Dec., 1997	62.2	2.00645	10.7562

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:25:07 am
Well	:	Tundra Daly Prov. RE02-14-09-28W1	User	:	Ludwig
	:	00/02-14-009-28W1/2			
Hist.Data	:	03/94-12/97	On Prod	:	01/00
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60I

Production Data from March, 1994 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Mar., 1994	2.1	2.1	
Apr., 1994	39.9	1.6625	19.8725
May., 1994	105.9	4.60435	19.8871
Jun., 1994	183.9	7.356	9.5832
Jul., 1994	172.2	5.55484	5.79628
Aug., 1994	156.2	5.03871	4.81212
Sep., 1994	146.3	4.87667	5.6714
Oct., 1994	141.6	4.88276	6.53196
Nov., 1994	133.8	4.46	7.08044
Dec., 1994	129.9	4.19032	5.38741
Jan., 1995	116.2	4.3037	7.77462
Feb., 1995	112	4	3.52994
Mar., 1995	102.8	3.31613	9.26373
Apr., 1995	100.2	3.45517	6.96094
May., 1995	103.2	3.32903	8.10002
Jun., 1995	92.9	3.09667	3.72899
Jul., 1995	88.6	2.95333	7.02755
Aug., 1995	83.6	3.0963	9.32383
Sep., 1995	78.7	2.62333	8.05749
Oct., 1995	74.3	2.47667	8.26826
Nov., 1995	63.6	2.12	11.5393
Dec., 1995	62.4	2.0129	3.99831
Jan., 1996	48.8	1.57419	12.54
Feb., 1996	38.2	1.36429	5.44328
Mar., 1996	38.1	1.22903	6.38557
Apr., 1996	30.7	1.02333	7.24779
May., 1996	32.3	1.1963	20.6316
Jun., 1996	109.5	3.65	12.3251
Jul., 1996	122.4	3.94839	8.92499
Aug., 1996	92.6	3.1931	10.6136
Sep., 1996	93.6	3.12	20.8718
Oct., 1996	100.3	3.23548	7.55453
Nov., 1996	96.7	3.33448	5.56409
Dec., 1996	89.7	2.89355	13.1605
Jan., 1997	82.3	2.65484	15.2363
Feb., 1997	77.8	2.88148	8.89573
Mar., 1997	76.8	2.47742	8.0207
Apr., 1997	76.5	2.55	11.2485
May., 1997	82.3	2.74333	8.45043
Jun., 1997	73.4	2.44667	14.347
Jul., 1997	74.3	2.39677	12.5834
Aug., 1997	67.3	2.32069	13.1563
Sep., 1997	72.8	2.42667	19.8168
Oct., 1997	77.5	2.5	13.2088

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:25:07 am
Well	:	Tundra Daly Prov. RE02-14-09-28W1	User	:	Ludwig
	:	00/02-14-009-28W1/2			

Production Data from March, 1994 to December, 1997 (cont.)

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Nov., 1997	63.1	2.17586	18.2577
Dec., 1997	70.4	2.27097	10.7689

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:24:10 am
Well	:	Tundra Daly COM A06-14-09-28W1	User	:	Ludwig
	:	02/06-14-009-28W1/2			
Hist.Data	:	11/95-12/97	On Prod	:	01/00
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60I

Production Data from November, 1995 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Nov., 1995	39.2	4.35556	53.8171
Dec., 1995	138.1	4.60333	25.5843
Jan., 1996	107.1	3.45484	32.0766
Feb., 1996	90.4	3.47692	31.0356
Mar., 1996	79.5	3.05769	38.266
Apr., 1996	61.1	2.03667	43.3102
May., 1996	59	1.96667	42.874
Jun., 1996	56.5	1.88333	41.8018
Jul., 1996	58.3	1.88065	36.6202
Aug., 1996	50.1	1.92692	42.6009
Sep., 1996	69.1	2.30333	53.9531
Oct., 1996	56.9	2.10741	51.2315
Nov., 1996	74.6	2.57241	40.1178
Dec., 1996	61.4	1.98065	50.9083
Jan., 1997	86.4	2.7871	25.4446
Feb., 1997	41.5	1.53704	59.4224
Mar., 1997	67.3	2.17097	36.6188
Apr., 1997	67.1	2.23667	30.1676
May., 1997	44.7	1.49	55.3783
Jun., 1997	39.6	1.36552	58.3051
Jul., 1997	38.9	1.29667	57.7526
Aug., 1997	37.9	1.3069	63.7219
Sep., 1997	44.3	1.47667	59.4958
Oct., 1997	44	1.46667	56.5109
Nov., 1997	37.6	1.29655	54.9052
Dec., 1997	44.3	1.42903	36.6135

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:26:58 am
Well	:	Tundra et al Daly Prov. COM 10-14-09-28W1	User	:	Ludwig
	:	00/10-14-009-28W1/0			
Hist.Data	:	03/95-12/97	On Prod	:	01/00
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60I

Production Data from March, 1995 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Mar., 1995	16.9	1.53636	14.2078
Apr., 1995	9.7	1.61667	2.99872
May., 1995	2.9	0.725	78.5111
Jun., 1995	88.9	5.22941	33.9426
Jul., 1995	113.7	3.79	17.781
Aug., 1995	94.7	3.15667	16.7777
Sep., 1995	77.2	2.57333	22.6376
Oct., 1995	70.1	2.41724	21.2286
Nov., 1995	64.3	2.14333	25.5703
Dec., 1995	68.8	2.21936	10.8766
Jan., 1996	45.9	2.295	19.3253
Feb., 1996	51.7	2.24783	22.8281
Mar., 1996	56.3	1.81613	19.7936
Apr., 1996	49.2	1.64	19.6009
May., 1996	52.9	1.76333	12.1216
Jun., 1996	44.6	1.48667	18.7547
Jul., 1996	44.2	1.42581	19.3362
Aug., 1996	26.8	1.34	44.5026
Sep., 1996	47.7	1.59	34.1061
Oct., 1996	49	1.58065	17.363
Nov., 1996	41.2	1.42069	13.6217
Dec., 1996	43.4	1.4	26.6806
Jan., 1997	43.8	1.4129	20.9313
Feb., 1997	34	1.25926	24.6038
Mar., 1997	34	1.17241	25.4302
Apr., 1997	34.3	1.14333	27.9323
May., 1997	31.9	1.06333	27.4912
Jun., 1997	34.9	1.16333	20.494
Jul., 1997	31.4	1.04667	25.4073
Aug., 1997	23	1.27778	30.5043
Sep., 1997	25.8	1.075	33.4953
Oct., 1997	31.7	1.0931	46.532
Nov., 1997	27.6	0.951724	31.3338
Dec., 1997	37.8	1.21935	12.8983

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:24:44 am
Well	:	Tundra Daly Prov. 11-14-09-28W1	User	:	Ludwig
	:	00/11-14-009-28W1/0			
Hist.Data	:	10/93-12/97	On Prod	:	01/00
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60I

Production Data from October, 1993 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Oct., 1993	17.1	2.44286	14.065
Nov., 1993	25.8	1.35789	10.4126
Dec., 1993	218.3	7.04194	14.6544
Jan., 1994	175.1	5.83667	10.7956
Feb., 1994	149.2	5.32857	10.0081
Mar., 1994	140.6	4.53548	13.4185
Apr., 1994	128.5	4.43103	9.75736
May., 1994	135.4	4.36774	3.14601
Jun., 1994	125.8	4.19333	6.67381
Jul., 1994	115.4	3.72258	8.26375
Aug., 1994	111	3.58065	5.60991
Sep., 1994	101.8	3.39333	3.32242
Oct., 1994	95.3	3.17667	9.6644
Nov., 1994	90.6	3.02	6.30557
Dec., 1994	84.9	2.73871	10.9086
Jan., 1995	88.8	2.96	5.62997
Feb., 1995	76.8	2.74286	7.24342
Mar., 1995	84.7	2.73226	9.01894
Apr., 1995	75	2.58621	7.51852
May., 1995	74.2	2.39355	9.61858
Jun., 1995	67	2.23333	15.2914
Jul., 1995	71.5	2.38333	8.32997
Aug., 1995	71.9	2.39667	12.098
Sep., 1995	64.5	2.15	9.15127
Oct., 1995	61.3	2.04333	11.2836
Nov., 1995	60.7	2.02333	8.3048
Dec., 1995	60.3	1.94516	4.1318
Jan., 1996	56.4	1.81936	9.46653
Feb., 1996	48.9	2.12609	6.85433
Mar., 1996	44.1	1.42258	7.92998
Apr., 1996	47.6	1.64138	11.355
May., 1996	44	1.46667	11.1068
Jun., 1996	50.6	1.87407	23.557
Jul., 1996	64.8	2.09032	20.0916
Aug., 1996	57.5	2.05357	26.8361
Sep., 1996	51.3	1.71	29.8129
Oct., 1996	58.6	1.89032	16.6369
Nov., 1996	54.7	1.88621	14.1234
Dec., 1996	58.9	1.9	8.10904
Jan., 1997	57.9	1.86774	7.05971
Feb., 1997	45	1.66667	18.4716
Mar., 1997	43.9	1.41613	26.58
Apr., 1997	43.2	1.44	19.5461
May., 1997	47	1.56667	15.0034

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:24:44 am
Well	:	Tundra Daly Prov. 11-14-09-28W1	User	:	Ludwig
	:	00/11-14-009-28W1/0			

Production Data from October, 1993 to December, 1997 (cont.)

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Jun., 1997	48.8	1.62667	12.54
Jul., 1997	50.9	1.64194	7.283
Aug., 1997	39.3	1.35517	31.2842
Sep., 1997	47.6	1.58667	19.3152
Oct., 1997	49.5	1.59677	12.6935
Nov., 1997	42.2	1.45517	16.5947
Dec., 1997	40.8	1.31613	8.51675

Production Report

Group	: Daly 60I	Date	: April 20, 1998 8:25:31 am
Well	: Tundra Daly Prov. RE13-14-09-28W1	User	: Ludwig
	: 00/13-14-009-28W1/3		
Hist.Data	: 10/93-12/97	On Prod	: 01/00
Operator	:	Status	: Unknown
Field	: 1	Zone	: 60I

Production Data from October, 1993 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Oct., 1993	13.4	6.7	73.2449
Nov., 1993	93.1	3.87917	12.5773
Dec., 1993	60.6	2.33077	5.60515
Jan., 1994	56	2.24	3.94344
Feb., 1994	26.7	2.225	4.98012
Mar., 1994	36.6	2.15294	18.66
Apr., 1994	25.2	2.52	29.4026
May., 1994	56.7	2.268	47.875
Jun., 1994	43.7	1.45667	38.6992
Jul., 1994	40.1	1.43214	36.0345
Aug., 1994	41.7	1.34516	26.3165
Sep., 1994	31.3	1.04333	40.7091
Oct., 1994	41.2	1.37333	23.2696
Nov., 1994	38.8	1.29333	17.0878
Dec., 1994	33.7	1.0871	27.6736
Jan., 1995	31.4	1.04667	27.1375
Feb., 1995	27.4	0.978571	27.6957
Mar., 1995	28.2	0.909678	32.0386
Apr., 1995	28.5	1.35714	14.9198
May., 1995	29.7	0.958065	24.2266
Jun., 1995	27.1	0.903333	23.4384
Jul., 1995	25.2	0.84	30.3774
Aug., 1995	25.4	0.846667	31.3419
Sep., 1995	25.1	0.836667	27.0262
Oct., 1995	26	0.866667	21.4427
Nov., 1995	27.2	0.906667	16.3017
Dec., 1995	26.1	1.18636	17.6592
Jan., 1996	19.2	0.914286	15.0386
Feb., 1996	23.5	0.903846	37.8203
Mar., 1996	24.3	0.783871	25.9062
Apr., 1996	21	1.23529	12.8581
May., 1996	30.7	1.02333	14.9528
Jun., 1996	24.9	0.83	16.4369
Jul., 1996	24.2	0.780645	16.5456
Aug., 1996	24.5	0.844828	19.401
Sep., 1996	22.2	0.74	17.7713
Oct., 1996	21.1	0.680645	23.8187
Nov., 1996	23.6	0.813793	17.7636
Dec., 1996	24	0.774194	23.3148
Jan., 1997	24.1	0.777419	9.73396
Feb., 1997	15.1	0.559259	27.0444
Mar., 1997	18.8	0.606452	18.608
Apr., 1997	17.5	0.583333	21.5172
May., 1997	17	0.607143	29.1576

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:25:31 am
Well	:	Tundra Daly Prov. RE13-14-09-28W1	User	:	Ludwig
	:	00/13-14-009-28W1/3			

Production Data from October, 1993 to December, 1997 (cont.)

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Jun., 1997	18.5	0.616667	21.9334
Jul., 1997	17.2	0.554839	24.221
Aug., 1997	14.3	0.680952	25.5125
Sep., 1997	12.1	0.403333	37.9384
Oct., 1997	18	0.580645	14.6864
Nov., 1997	16.8	0.57931	11.1068
Dec., 1997	12.3	0.396774	32.4079

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:27:19 am
Well	:	Tundra et al Daly Prov. COM 14-14-09-28W1	User	:	Ludwig
	:	00/14-14-009-28W1/0			
Hist.Data	:	03/93-12/97	On Prod	:	01/00
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60I

Production Data from March, 1993 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Mar., 1993	82.4	4.84706	3.51139
Apr., 1993	108.9	3.63	3.79698
May., 1993	102.6	3.42	1.34557
Jun., 1993	90.1	3.1069	0.770588
Jul., 1993	90.6	3.12414	4.22655
Aug., 1993	82	2.64516	13.4057
Sep., 1993	80.8	2.69333	0.246805
Oct., 1993	79.6	2.65333	3.27928
Nov., 1993	77.4	2.58	0.513914
Dec., 1993	74.4	2.4	1.58661
Jan., 1994	66.5	2.21667	2.20493
Feb., 1994	55.6	1.98571	1.06715
Mar., 1994	61.3	1.97742	1.44632
Apr., 1994	56.3	1.94138	3.09679
May., 1994	13.3	2.21667	41.656
Jun., 1994	179.8	6.2	11.2055
Jul., 1994	165.7	5.34516	4.1625
Aug., 1994	147.3	4.75161	4.41086
Sep., 1994	127.4	4.24667	6.25202
Oct., 1994	123	4.1	7.37651
Nov., 1994	103.8	3.57931	4.85589
Dec., 1994	46.4	4.21818	5.49669
Jan., 1995	89.2	5.94667	6.49628
Feb., 1995	106.1	3.78929	6.02054
Mar., 1995	106.9	3.44839	7.52289
Apr., 1995	90.9	3.36667	8.4558
May., 1995	94.6	3.05161	7.70419
Jun., 1995	90.4	3.01333	5.2389
Jul., 1995	82.4	2.74667	9.64528
Aug., 1995	72.3	2.33226	7.77745
Sep., 1995	76.5	2.55	9.03324
Oct., 1995	74.5	2.48333	8.69748
Nov., 1995	68.8	2.29333	11.9032
Dec., 1995	70.3	2.26774	8.1013
Jan., 1996	60.7	2.63913	8.58088
Feb., 1996	66.1	2.36071	13.0213
Mar., 1996	67	2.16129	11.2539
Apr., 1996	70.7	2.35667	5.479
May., 1996	63.9	2.13	8.31802
Jun., 1996	65.3	2.17667	6.84455
Jul., 1996	64.5	2.08065	6.51906
Aug., 1996	60.1	2.14643	10.2944
Sep., 1996	42.9	1.43	22.695
Oct., 1996	58.1	1.87419	7.62806

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:27:20 am
Well	:	Tundra et al Daly Prov. COM 14-14-09-28W1	User	:	Ludwig
	:	00/14-14-009-28W1/0			

Production Data from March, 1993 to December, 1997 (cont.)

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Nov., 1996	54.1	1.86552	7.98996
Dec., 1996	60.9	1.96452	5.57907
Jan., 1997	51.7	1.66774	9.13518
Feb., 1997	42.8	1.58519	15.5761
Mar., 1997	47.2	1.52258	11.2738
Apr., 1997	39.2	1.30667	17.6407
May., 1997	44.1	1.47	13.5243
Jun., 1997	47.7	1.59	11.3339
Jul., 1997	42.9	1.47931	12.2652
Aug., 1997	54	1.86207	19.5162
Sep., 1997	55.6	1.85333	9.29482
Oct., 1997	52.1	1.68065	10.6305
Nov., 1997	49	1.68966	10.2524
Dec., 1997	55	1.77419	6.45992

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:26:18 am
Well	:	Tundra et al Daly COM 02-23-09-28W1	User	:	Ludwig
	:	00/02-23-009-28W1/2			
Hist.Data	:	07/92-12/97	On Prod	:	01/00
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60I

Production Data from July, 1992 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Jul., 1992	24.2	4.84	37.1326
Aug., 1992	82	2.64516	42.526
Sep., 1992	57.9	1.93	39.677
Oct., 1992	6.1	0.203333	31.4512
Nov., 1992	44.1	1.47	41.0321
Dec., 1992	43.4	1.49655	34.1327
Jan., 1993	18.3	1.30714	38.7855
Feb., 1993	34.1	1.705	39.3133
Mar., 1993	37.4	1.20645	42.2732
Apr., 1993	30.5	1.05172	44.6352
May., 1993	33.7	1.0871	41.9858
Jun., 1993	31.9	1.06333	42.923
Jul., 1993	31.6	1.05333	42.0076
Aug., 1993	27.4	0.883871	47.3979
Sep., 1993	29.4	0.98	38.8669
Oct., 1993	27.7	0.955172	37.32
Nov., 1993	29.6	0.986667	29.0077
Dec., 1993	27.3	0.880645	36.0554
Jan., 1994	23.6	1.475	26.0103
Feb., 1994	28.6	1.144	23.3165
Mar., 1994	27.1	0.874194	26.7481
Apr., 1994	25.8	0.889655	28.9166
May., 1994	22.7	0.810714	27.2349
Jun., 1994	16.8	0.84	37.0684
Jul., 1994	22.2	0.74	36.0129
Aug., 1994	24	0.888889	35.9899
Sep., 1994	26.9	0.896667	18.9691
Oct., 1994	26.1	0.87	21.8488
Nov., 1994	26.5	0.883333	17.1812
Dec., 1994	21.8	0.703226	30.1189
Jan., 1995	18	0.782609	40.973
Feb., 1995	21.9	0.811111	10.6081
Mar., 1995	5.3	0.481818	32.0417
Apr., 1995			
May., 1995	15	5	10.1756
Jun., 1995	10.3	0.343333	72.4511
Jul., 1995	5.2	0.472727	50.9324
Aug., 1995	20.3	0.922727	26.1733
Sep., 1995	15.1	0.503333	41.6881
Oct., 1995	14.6	0.486667	38.9017
Nov., 1995	12.8	0.426667	42.3316
Dec., 1995	14.3	0.595833	30.9085
Jan., 1996	5.1	0.31875	54.0431
Feb., 1996	14.2	0.788889	28.9909

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:26:18 am
Well	:	Tundra et al Daly COM 02-23-09-28W1	User	:	Ludwig
	:	00/02-23-009-28W1/2			

Production Data from July, 1992 to December, 1997 (cont.)

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Mar., 1996	4.9	0.445455	62.2974
Apr., 1996	14.3	0.476667	49.989
May., 1996	16.2	0.54	31.636
Jun., 1996	13.5	0.45	38.3458
Jul., 1996	14.7	0.49	31.2989
Aug., 1996	16.8	0.6	27.5774
Sep., 1996	8	0.266667	74.1851
Oct., 1996	14.5	0.467742	36.3933
Nov., 1996	9.2	0.317241	61.6563
Dec., 1996	14.4	0.464516	34.2367
Jan., 1997	12.1	0.390323	45.9712
Feb., 1997	12.7	0.47037	35.5229
Mar., 1997	9.6	0.32	48.3761
Apr., 1997	13.6	0.453333	25.2664
May., 1997	13.5	0.45	26.221
Jun., 1997	9.8	0.326667	37.9643
Jul., 1997	8.4	0.270968	35.8677
Aug., 1997	6.8	0.34	29.8877
Sep., 1997	7.4	0.246667	39.8268
Oct., 1997	8	0.258065	33.8744
Nov., 1997	6.1	0.210345	46.9456
Dec., 1997	8.1	0.26129	30.7598

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:26:41 am
Well	:	Tundra et al Daly COM RE04-23-09-28W1	User	:	Ludwig
	:	00/04-23-009-28W1/3			
Hist.Data	:	11/94-12/97	On Prod	:	01/00
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60I

Production Data from November, 1994 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Nov., 1994	32.9	2.53077	
Dec., 1994	60.6	1.95484	
Jan., 1995	52.8	1.76	
Feb., 1995	38.7	1.38214	
Mar., 1995	42.2	1.36129	
Apr., 1995	28.8	0.993103	
May., 1995	34.2	1.10323	
Jun., 1995	24.2	0.864286	
Jul., 1995	25.2	0.84	
Aug., 1995	27.1	0.874194	
Sep., 1995	24.8	0.826667	
Oct., 1995	23.7	0.79	
Nov., 1995	28.3	0.943333	
Dec., 1995	23.9	0.919231	
Jan., 1996	17.1	0.7125	
Feb., 1996	20.6	0.895652	
Mar., 1996	25.6	0.914286	
Apr., 1996	20.5	0.683333	
May., 1996	16.4	0.546667	
Jun., 1996	14.6	0.486667	
Jul., 1996	15.3	0.493548	
Aug., 1996	15.8	0.544828	
Sep., 1996	15.3	0.51	
Oct., 1996	19.5	0.629032	
Nov., 1996	18.2	0.627586	
Dec., 1996	17.3	0.558064	
Jan., 1997	17.9	0.577419	
Feb., 1997	13.8	0.627273	
Mar., 1997	16.5	0.634615	
Apr., 1997	17.2	0.573333	
May., 1997	7.3	0.521429	
Jun., 1997	25	1.25	
Jul., 1997	13.7	0.441935	
Aug., 1997	15.3	0.728571	
Sep., 1997	19.1	0.636667	
Oct., 1997	15.3	0.493548	
Nov., 1997	11.8	0.406897	
Dec., 1997	16.1	0.519355	

Production Report

Group	:	Daly 60I	Date	:	April 20, 1998 8:54:14 am
Well	:	Tundra Daly COM 06-23-09-28W1	User	:	Ludwig
	:	00/06-23-009-28W1/2			
Hist.Data	:	02/97-12/97	On Prod	:	02/09
Operator	:		Status	:	Unknown
Field	:	1	Zone	:	60I

Production Data from February, 1997 to December, 1997

Year	Monthly Oil m3	Avg Daily Oil m3/d	Water Cut %
Feb., 1997	2.4	0.1	
Mar., 1997	1.8	0.0580645	
Apr., 1997	0.7	0.0318182	
May., 1997	1.1	0.06875	
Jun., 1997	72.8	2.8	12.6002
Jul., 1997	85.2	2.74839	26.4798
Aug., 1997	65.3	2.25172	35.9702
Sep., 1997	58.2	1.94	31.9998
Oct., 1997	62.2	2.00645	25.1421
Nov., 1997	55.3	1.9069	19.6151
Dec., 1997	55.3	1.78387	12.6334

Manitoba Energy and Mines
Well Production Record
1996

Report PPS1520

Field	1	Daly	Mineral Rights FREEHOLD
Pool	60I	Bakken I	
Unit	0		
Operator	103	Kiwi	
UWI	100.14-13-009-28W1.02		
Licence	3083		

Month	Days on Production	Oil Produced m^3	Water Produced m^3	Water Injection Disposed m^3
Cumulative Prior	.0	.0	.0	
Jan	.0	.0	.0	
Feb	.0	.0	.0	
Mar	.0	.0	.0	
Apr	.0	.0	.0	
May	.0	.0	.0	
Jun	.0	.0	.0	
Jul	.0	.0	.0	
Aug	.0	.0	.0	
Sep	30.0	5.2	104.5	
Oct	23.0	3.0	51.0	
Nov	27.0	10.0	60.6	
Dec	31.0	7.3	37.7	
Ytd	111.0	25.5	253.8	
Cum To Date	111.0	25.5	253.8	

Status Date	UWI Status
25-SEP-96	COOP

Manitoba Energy and Mines

Well Production Record

1997

Report PPS1520

Field	1	Daly
Pool	60I	Bakken I
Unit	0	
Operator	103	Kiwi
UWI	100.14-13-009-28W1.02	
Licence	3083	

Mineral Rights FREEHOLD

Month	Days on Production	Oil Produced m^3	Water Produced m^3	Water Injection Disposed m^3
Cumulative Prior	111.0	25.5	253.8	
Jan	31.0	10.5	29.6	
Feb	28.0	9.0	32.6	
Mar	31.0	10.2	28.7	
Apr	30.0	9.1	31.6	
May	31.0	9.2	30.8	
Jun	30.0	8.9	19.6	
Jul	20.0	2.6	12.9	
Aug	30.0	5.8	68.5	
Sep	28.0	11.7	27.5	
Oct	30.0	10.0	24.5	
Nov	30.0	10.4	19.8	
Dec	31.0	11.6	17.9	
Ytd	350.0	109.0	344.0	
Cum To Date	461.0	134.5	597.8	

Status Date	UWI Status
25-SEP-96	COOP

Manitoba Energy and Mines
Well Production Record
1996

Report PPS1520

Field	1	Daly
Pool	59B	Lodgepole B
Unit	0	
Operator	103	Kiwi
UWI	100.14-13-009-28W1.00	
Licence	3083	

Mineral Rights FREEHOLD

Month	Days on Production	Oil Produced m^3	Water Produced m^3	Water Injection Disposed m^3
Cumulative Prior	3713.0	2456.3	3759.2	
Jan	31.0	10.1	27.9	
Feb	29.0	14.5	27.5	
Mar	25.0	8.8	2.7	
Apr	30.0	13.3	59.3	
May	30.0	10.5	22.3	
Jun	28.0	12.9	50.9	
Jul	18.0	.7	67.5	
Aug	16.0	1.3	57.5	
Sep	.0	.0	.0	
Oct	.0	.0	.0	
Nov	.0	.0	.0	
Dec	.0	.0	.0	
Ytd	207.0	72.1	315.6	
Cum To Date	3920.0	2528.4	4074.8	

Status Date	UWI Status
06-JUL-96	ST
07-SEP-93	SUSP

Manitoba Energy and Mines
Well Production Record
1997

Report PPS1520

Field	1	Daly
Pool	59B	Lodgepole B
Unit	0	
Operator	103	Kiwi
UWI	100.14-13-009-28W1.00	
Licence	3083	

Mineral Rights FREEHOLD

Month	Days on Production	Oil Produced m 3	Water Produced m 3	Water Injection Disposed m 3
Cumulative Prior	3920.0	2528.4	4074.8	
Jan	.0	.0	.0	
Feb	.0	.0	.0	
Mar	.0	.0	.0	
Apr	.0	.0	.0	
May	.0	.0	.0	
Jun	.0	.0	.0	
Jul	.0	.0	.0	
Aug	.0	.0	.0	
Sep	.0	.0	.0	
Oct	.0	.0	.0	
Nov	.0	.0	.0	
Dec	.0	.0	.0	
Ytd	.0	.0	.0	
Cum To Date	3920.0	2528.4	4074.8	

Status Date	UWI Status
06-JUL-96	ST

1) Tundra has estimated ultimate oil recovery of 3975 m³ for a well at 8-14. This compares favourably with the estimated average well recovery for the I Pool of 3851 m³. ~~An above~~ review of the ~~primary recoverable reserves~~ perfor- for the wells 2-14, 6-14 & 10-14 indicate a primary recovery of ~~11068 m³~~ 26.7%. from the area 1-14, 2-14, 6-14, 7-14, 9-14 & 10-14 with an addition waterflood recovery of 5% OOIP or 2630 m³.

Based on Tundra's mapping Lsd 8-14 has original OOIP of 9659 m³. If it is assumed the 8-14 will competitively drain portions of 4-12, 5-12 & 12-12, the estimated OOIP in the 8-14 3/4 drainage area is 16443 m³. Using a primary recovery factor of 24.3% pool area and 26.7% average for, the estimated primary recoverable reserves for 8-14 are between 3995 - 4397 m³. Assuming an incremental waterflood recovery factor 5% and this time assuming the oil is swept from a portion of N/2 of 1-14 & the east/2 of 7-14 & 8-14, between 482 and 964 m³. Increasing ultimate WF recovery from the

5, ___

- TUNDRA ESTIMATES ULT REC. FROM 8-14
@ 3975 m^3

- COMPARES FAVOURABLY WITH AVER WELL
RECOVERY WITHIN THE POOL - 3851 m^3

- PRIMARY RECOVERY FROM 1-14, 2-14, 6-14, 7-14, 9-14, 10-14
REPRESENTATIVE OF THE AREA DRAINED BY THE
EXISTING WELLS @ 2-14, 6-14 & 10-14

OOIP : 52596 m^3
PRIM. REC. RES = 14068 m^3 RF = 26.74 % (POOL AVER RF = 24.3)
ΔWF REC. ~~RES~~. = 5% OOIP 2630 m^3

OOIP FOR 8-14 9659 m^3

- 8-14 will competitively drain portions 4-12, 5-12, 12-12
est OOIP 6784 m^3

- 8-14 should recover between 3995 - 4397 m^3
primary + incremental waterflood reserves of
482 - 964 (OOIP @ 8-14 + 1/2 OOIP 1-14 + 1/2 OOIP 7-14)
reducing finding costs to \$10.65 - 8.90/bbl

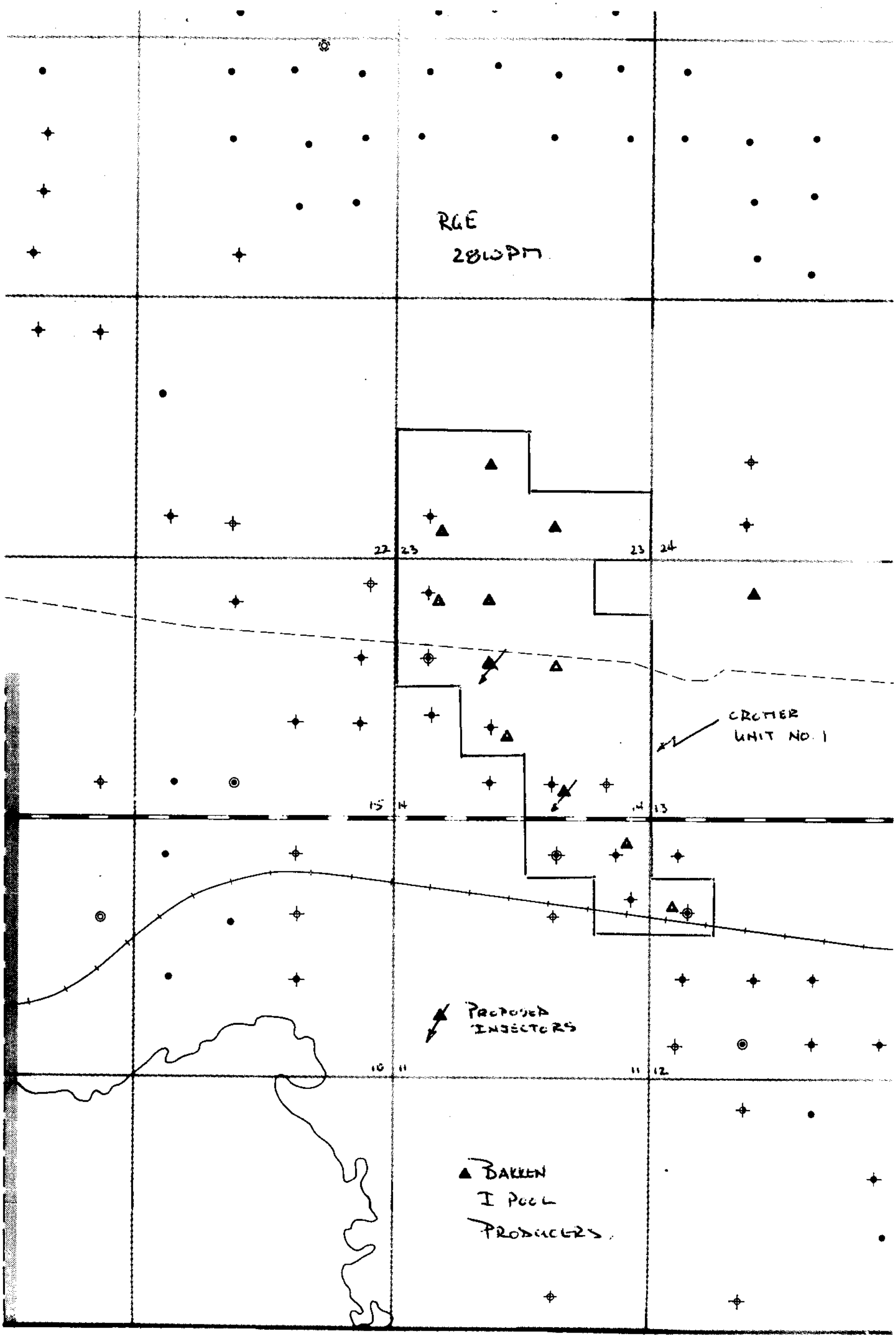
- assignment of 1 — 3 to the 7-14/6-14 tract allows Tundra to continue the lease with developing it which the Dep't does not view as equitable

- Branch feels a well is needed in the near future to recover oil ~~mobilized~~ mobilized by the waterflood & clearly not recoverable by the existing wells. Our further concern is that the Branch has no remedy to protect its interest in the event a well is drilled at 4-12 or 5-12.

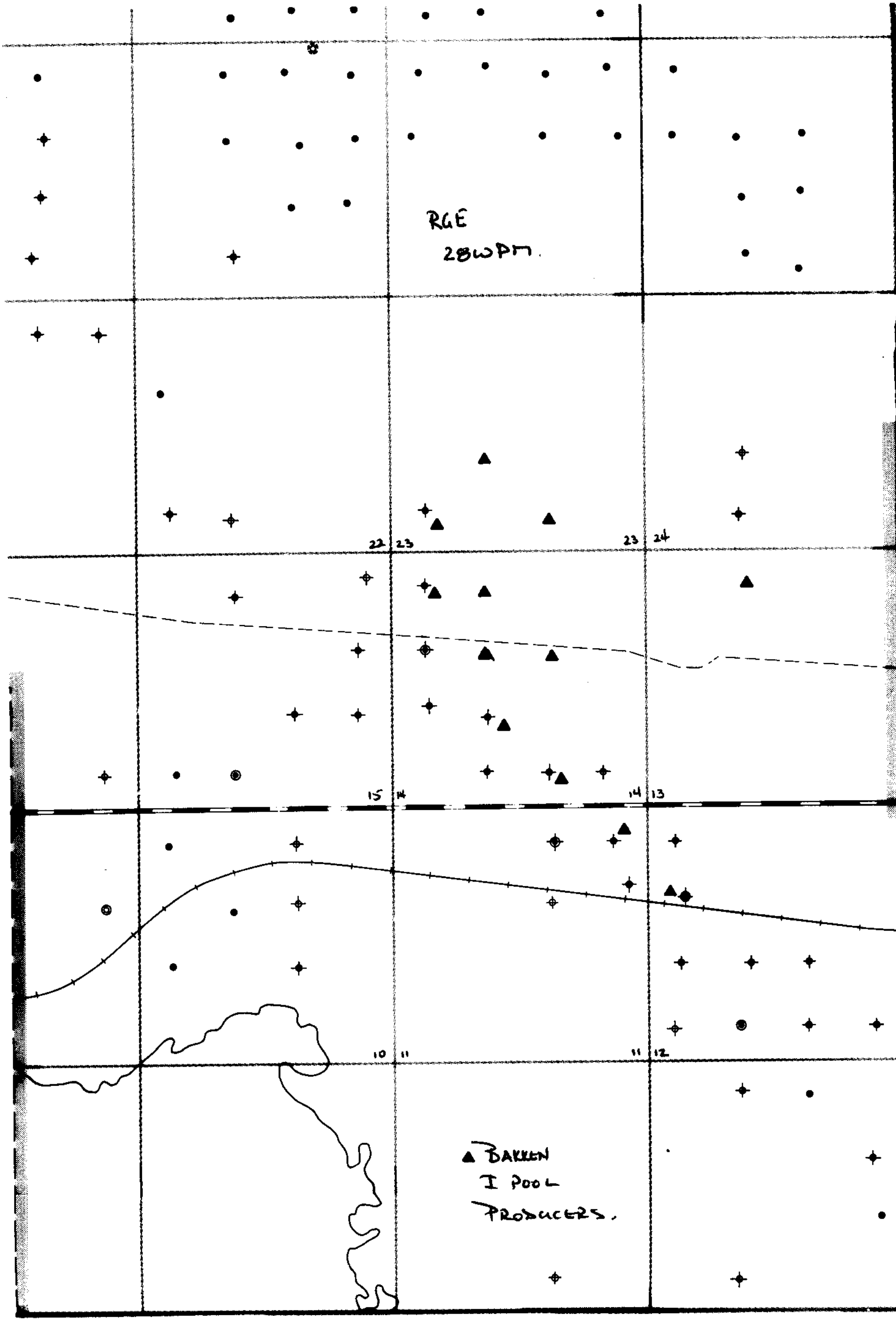
- continue the lease indefinitely which the Branch does not think is appropriate and eliminates the Branch's ability to call at offset.

- uphole hdqp. potential 6.14, 10-14, 14.14, 2.23, 4-23 & 6.23 (8) undeveloped 16 ha tracts. included in the unit

TWP
9


RGE
28WPM
22 23
23 24
CROMER
UNIT NO. 1
15 14
14 13
PROPOSED
INJECTORS
10 11
11 12
BAKKEN
I POOL
PRODUCERS

TWP
9


RGE
28WPM
22 23
23 24
15 14
14 13
10 11
11 12
▲ BAKKEN
I POOL
PRODUCERS.

A total of 109 volunteer hours were reported by those present.

Muriel Jones reported that the SAIL annual meeting was held April 29. Muriel Jones, Leona Joseph and Ron Heritage had attended the SAIL appreciation dinner in Virden.

The regional Auxiliary meeting was held May 4 at St. Paul's United Church in Virden.

The M.H.A. constitution is

"The List" by Steve Martin is the

In lieu of listing all the names of the people who do-nated prizes, the Elkhorn 4-H Club decided to make donation to the Elkhorn and Area Foundation.

Tundra
oil and gas ltd.

DATE: MARCH 12, 1998

PAGE 1 OF 3
(Including cover page)

TO:
ATTN: JOHN FOX

FAX ( )

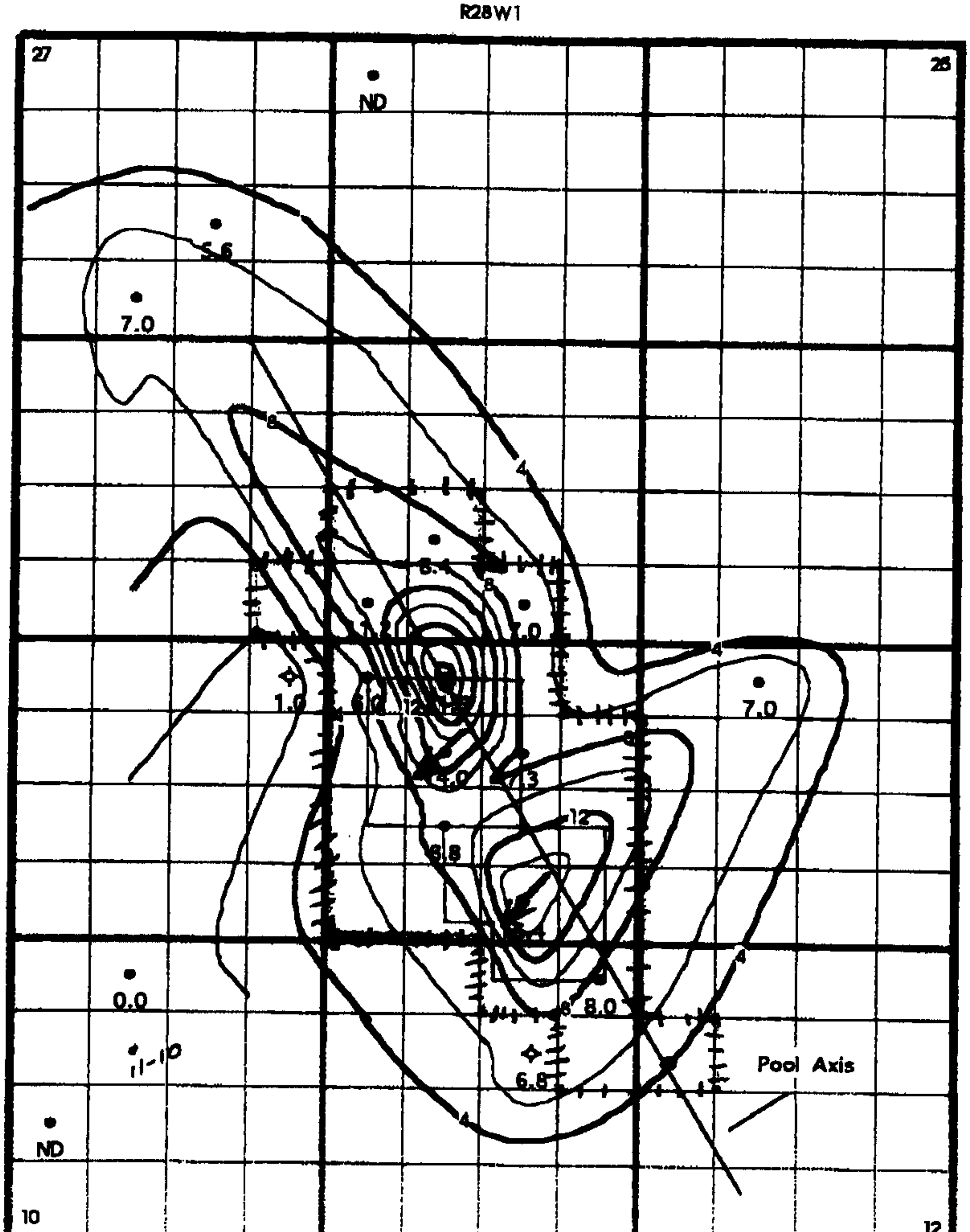
FROM: GEORGE CZYZEWSKI

FAX (204) 934-5820

Proposed Crown Unit #1 and tract factors.

PLEASE NOTE: If you do not receive all pages, please contact Paulette at (204) 934-5850.

FIGURE NO. 5



UNIT OUTLINE

INITIAL WATERFLOOD AREAS

TUNDRA OIL AND GAS LTD.	
Bakken I Pool PHI-H at 2.0 Intervals (1 km)	
M.B. DUPONT	
Date:6/16/97	33000

TRACTFAC.XLS

TABLE NO.8

CROMER UNIT NO.1

PROPOSED TRACT FACTORS

	Area	Well	Tundra W.I. in Well (%)	Total Operating Days	Total Production (m3)	Average Oil Rate Per Operating Day (m3/day)	Tract Factor Per LSD (%)	Tundra Tract Factor (%)
9&16-11	LSD 15-11 / 16-11	16-11-9-28	100	90	187.5	2.08	13.51839	13.51839
12&13-12	LSD 9-11 / 12-12	12-12-9-28	100	90	191.3	2.13	13.79236	13.79236
2&7-14	LSD 1-14 / 2-14	2-14-9-28	100	90	208.5	2.32	15.03244	15.03244
3&6-14	LSD 5-14 / 6-14	6-14-9-28	100	90	132.3	1.47	9.53857	9.53857
10&15-14	LSD 9-14 / 10-14	10-14-9-28	100	90	98.2	1.09	7.08003	7.08003
11&14-14	LSD 11-14 / 12-14	11-14-9-28	100	90	130.9	1.45	9.43764	9.43764
12&13-14	LSD 13-14	13-14-9-28	100	90	46.5	0.52	3.35256	3.35256
	LSD 14-14 / 15-14	14-14-9-28	100	90	154.4	1.72	11.13194	11.13194
2&7-23	LSD 2-23 / 3-23	2-23-9-28	100	90	21.9	0.24	1.57895	1.57895
4&5-23	LSD 1-22 / 4-23	4-23-9-28	100	90	42.7	0.47	3.07859	3.07859
3&6-23	LSD 5-23 / 6-23	6-23-9-28	100	90	170.8	1.90	12.31435	12.31435
	LSD 3-14 / 4-14	-	100 *	90	1	0.01	0.07210	0.07210
	LSD 7-14 / 8-14	* -	100	90	1	0.01	0.07210	0.07210
		Total			1,387.0	15.411111	100.00000	100.00000

* undeveloped, limited well control

* unleased royalty owner, may opt to be WIO

PROPOSED 80 AC SPACING

- P.B. reference is a regular grid of 80 ac spacing units contained within a quarter-section ie. lying down LSD 1 & 2
  LSD 7 & 8
  or standing up LSD 1 & 8
  LSD 2 & 7
  - easily described ie. LSD 1 & 2, south-half on the south-east quarter
  - allow for regular target areas ie. even vs odd Lsd.
  - eliminates pooling of different royalty owners to form SU.

- suggestion unitize slightly different area & stand-up 80 ac unit tracts can form the unit (W/exception of ~~with 16-11~~ 15-11 which Crown will throw-in (NO) exclude.)

- Crown perspective eliminate undeveloped 80 ac tracts from the unit

- disencourage/sterilize undeveloped Crown land around the edge of the unit, other companies may find economic to drill

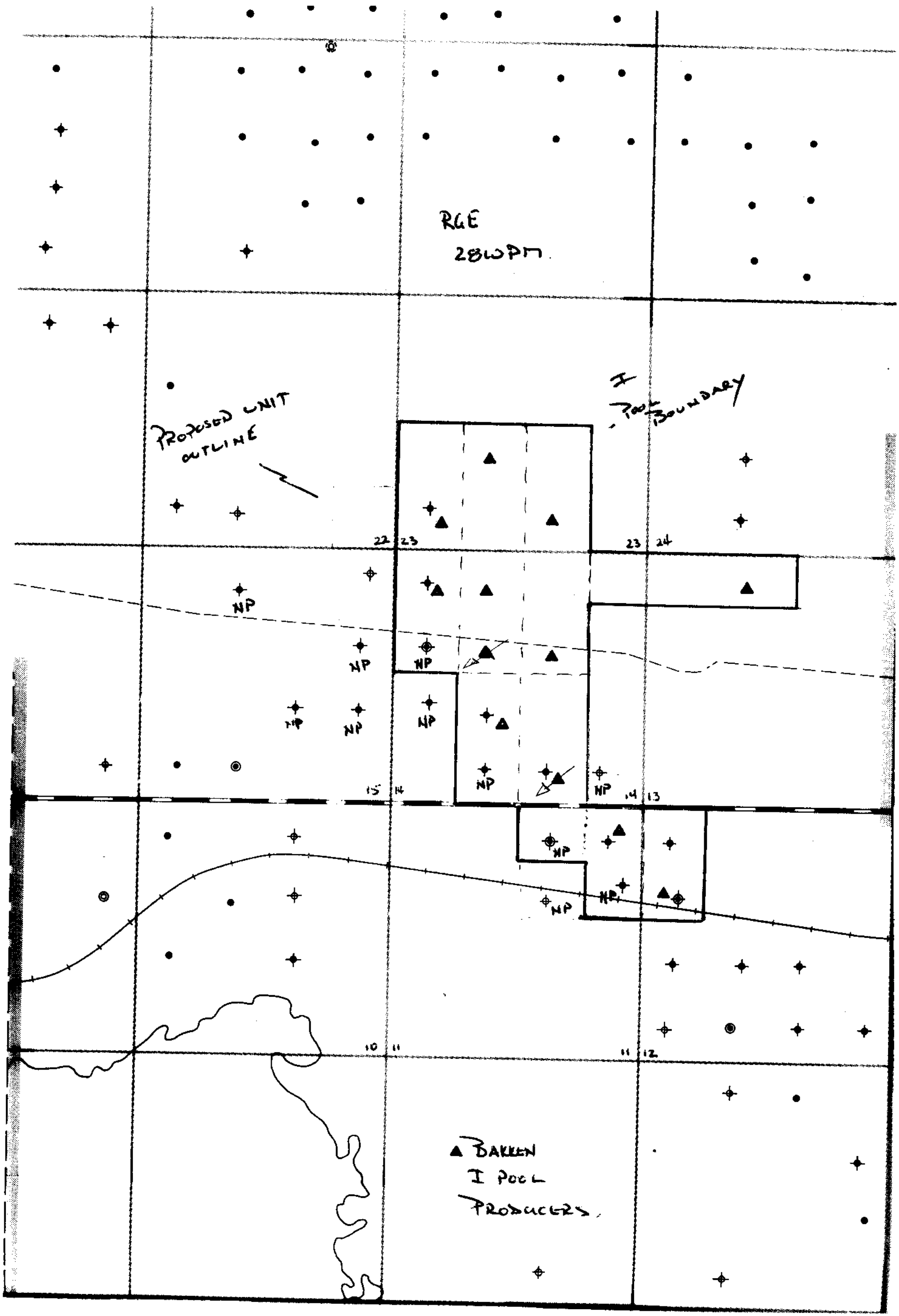
- all unit tracts have a productive well

- only potential objection unleased 25% royalty owner in SW/4 of Sec 14 (is also a potential WIO)

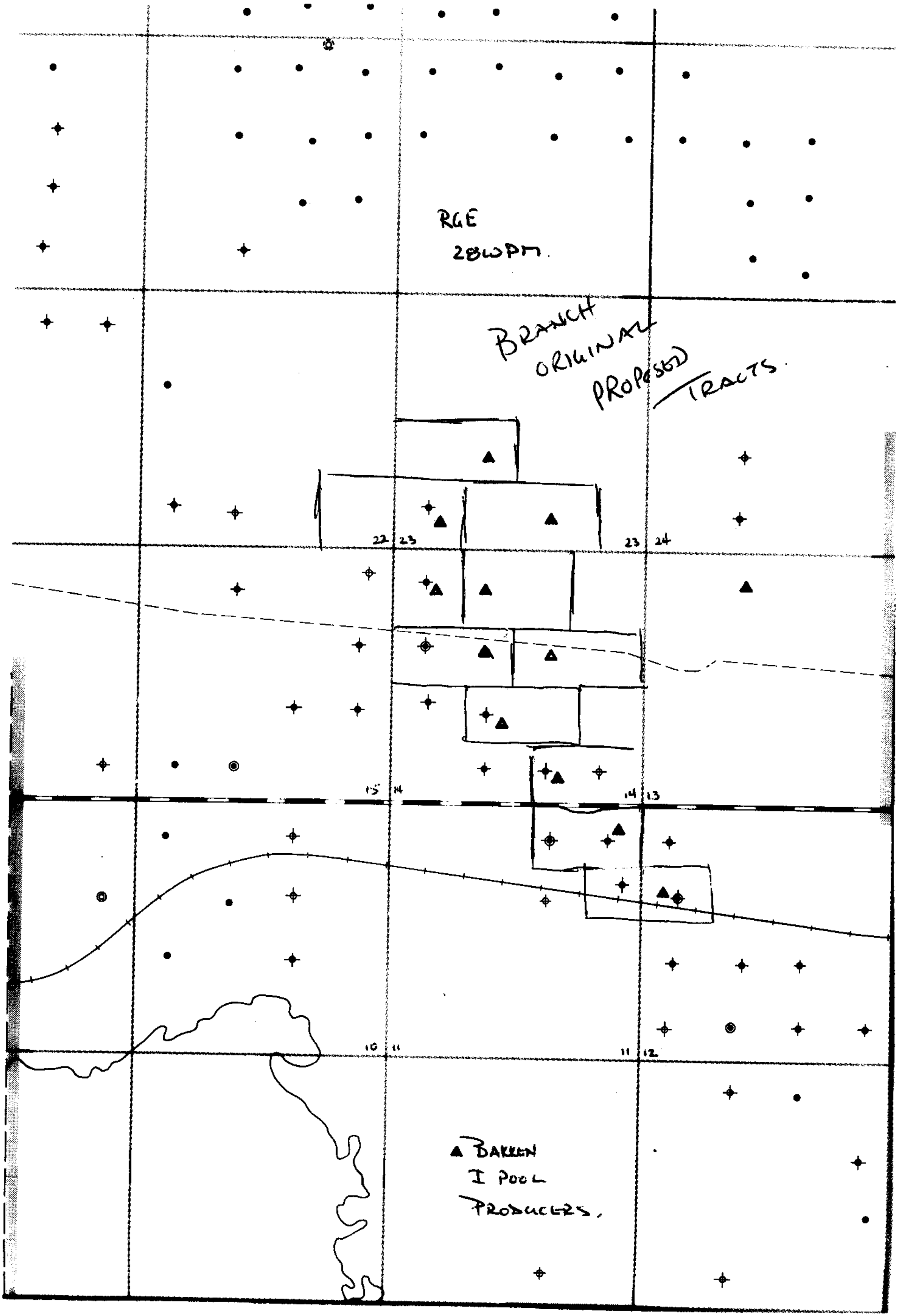
- Bu[illegible] would support the inclusion of 3-14 in the unit as oil under the tract would be swept to 6-14 (Tundra's argument that drilling on 40 ac is uneconomic)

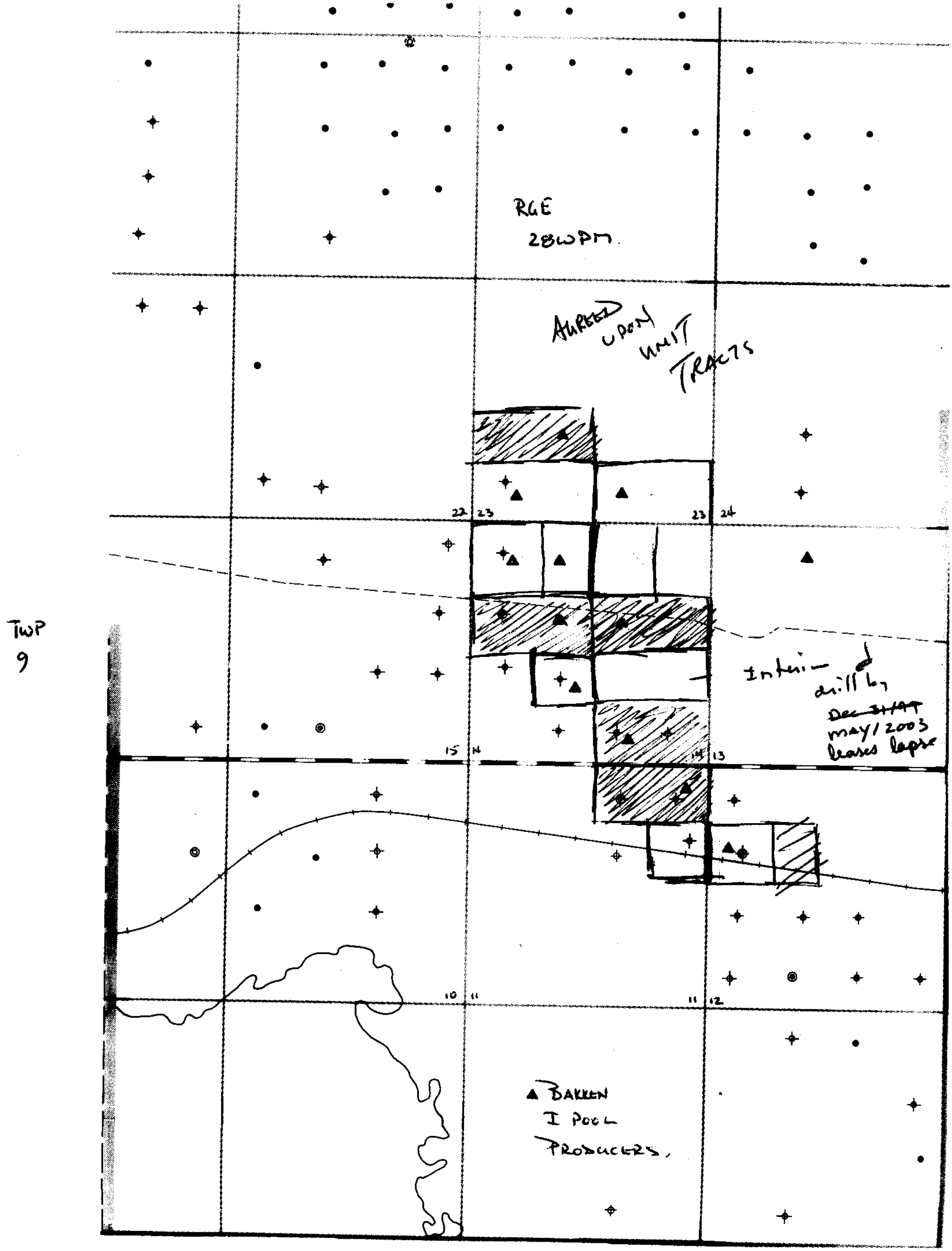
- while there is limited well control to suggest 5-14 is not an economic location

TWP
9


RGE
28WPM
PROPOSED UNIT
OUTLINE
I
POOL BOUNDARY
22 23
23 24
NP
15 14
14 13
10 11
11 12
BAKKEN
I POOL
PRODUCERS

TWP
9


RGE
28WPM.
BRANCH
ORIGINAL
PROPOSED TRACTS.
22 23
23 24
15 14
14 13
10 11
11 12
▲ BAKKEN
I POOL
PRODUCERS.



RGE
28WPM.
AGREED UPON UNIT TRACTS
22 23
23 24
TWP 9
Interim drill by ~~Dec 31/94~~ May/2003 leases lapse
15 14
14 13
10 11
11 12
▲ BAKKEN I POOL PRODUCERS.

MARCH 13/98

L931-1035 TUNDRA 100%

THEY WILL BE RENEWING ON MAY 5/98 AS "PRODUCTIVE QUARTER SECTION" FOR 5 YEARS. IF AFTER MAY 6/2003 THIS IS NOT A UNIT & THEY HAVE NOT DRILLED ANYMORE COOP WELLS THEN THEY WILL ONLY BE ABLE TO RENEW THE PRODUCTIVE SPACING UNITS WITH DEEPER RIGHTS SEVERED ON THE COOP WELLS.

L881-871 TUNDRA 50%
WESTMEAD 50%

THIS LEASE IS DUE APRIL 13, 1999 (SHOULD REALLY BE APRIL 13, 1998)

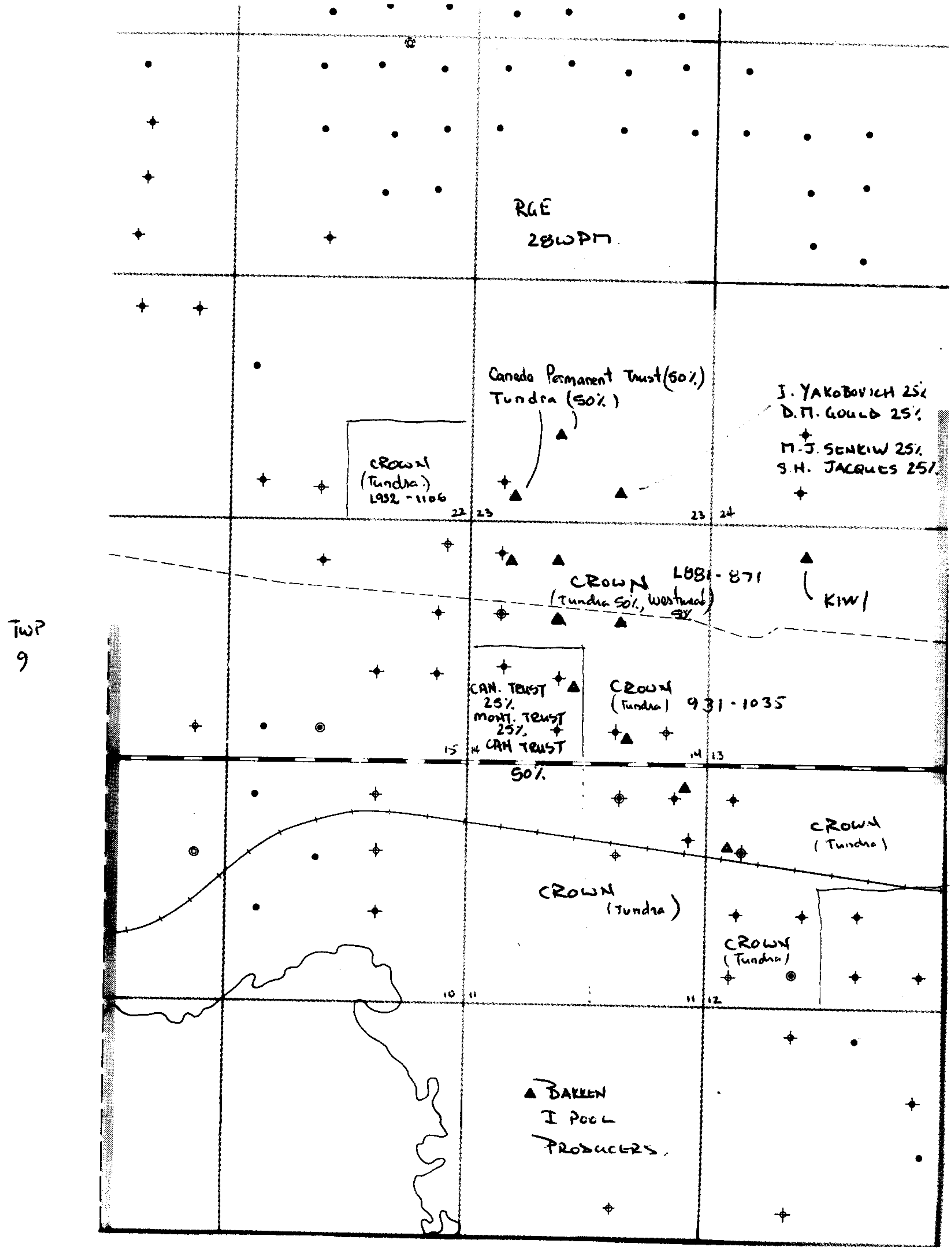
ORIGINAL THIS LEASE WAS MADE APRIL 13, 1988 MATURING APRIL 13, 1993. ON APRIL 13, 1993 AN EXTENSION FOR 1 YEAR WAS MADE, MATURING APRIL 13, 1994. ON APRIL 13, 1994 A FURTHER 1 YEAR EXTENSION WAS MADE, MATURING APRIL 13, 1995. IN 1995 A RENEW WAS ISSUED FOR "PRODUCTIVE QUARTER SECTION" MATURING ON APRIL 13, 1999. THIS DATE IS INCORRECT THE MATURING DATE SHOULD READ APRIL 13, 1998. IF THIS STAYS AS A NON-UNIT THEN ON MATURITY DATE OF APRIL 13, 1999(?) THEY WILL ONLY BE ABLE TO RENEW THE "PRODUCTIVE SPACING UNITS" WITH DEEPER RIGHTS SEVERED.

L932-1104 TUNDRA 100%.

THIS LEASE IS DUE NOVEMBER 3, 1998. IF NO WELLS ARE DRILLED BETWEEN TODAY & NOVEMBER 3, 1998, THIS LEASE WILL EXPIRE ON NOVEMBER 3, 1998.

L941-1206 TUNDRA 100% E½ 11-9-28 SW¼ & N½ 12-9-28

THIS LEASE IS DUE MAY 4, 1999
THEY WILL BE ABLE TO RENEW THIS FOR 5 YEARS "PRODUCTIVE QUARTER SECTION (AS OF TODAY RE 12-12-9-28 IS COOP.) IF THIS WELL STAYS COOP OR MORE PRODUCTIVE WELLS ARE DRILLED.


RGE
28WPM.
Canada Permanent Trust (50%)
Tundra (50%)
I. YAKOBOVICH 25%
D.M. GOULD 25%
M.J. SENKIW 25%
S.H. JACQUES 25%
CROWN
(Tundra)
L932 - 1106
22 23
23 24
CROWN L881 - 871
(Tundra 50%, Westwood 50%)
KIWI
TWP
9
CAN. TRUST
25%
MONT. TRUST
25%
CAN TRUST
50%
15 14
CROWN
(Tundra) 931 - 1035
14 13
CROWN
(Tundra)
CROWN
(Tundra)
CROWN
(Tundra)
10 11
11 12
▲ BAKKEN
I POOL
PRODUCERS.

Manitoba

Energy and Mines

Petroleum and Energy Branch

1395 Ellice Avenue Suite 360
Winnipeg MB R3G 3P2
CANADA

PH: (204) 945-6577
PH: (204) 945-3760
FAX: (204) 945-0586

April 29, 1998

Mr. George Czyzewski, P.Eng.
General Manager
Tundra Oil and Gas Ltd.
1111 Lombard Place
Winnipeg, MB R3B 0X4

Dear Mr. Czyzewski:

Re: Cromer Unit No. 1 - Waterflood Application

The Branch has received your letter dated April 29, 1998 and has the following comments.

1) 8-14-9-28 Recoverable Reserves Estimate

Tundra has estimated ultimate oil recovery of 3975 m^3 for a well at 8-14-9-28. The Branch believes a well at 8-14 has the potential to recover up to 5361 m^3 under waterflood.

Assuming the 2-14, 6-14 & 10-14 wells drain a larger area that includes 1-14, 2-14, 6-14, 7-14, 9-14 & 10-14, the average primary recovery is 26.7%. Tundra has estimated OOIP at 8-14 of 9659 m^3. In addition, the 8-14 well will competitively drains portions of Lsd's 4-12, 5-12 & 12-12-9-28, which based on Tundra's mapping, contain estimated OOIP of 6784 m^3. Based on a primary recovery factor of 24.3% (pool average) to 26.7%, the 8-14 well could been assigned primary recoverable reserves of 3995 to 4397 m^3. A well at 8-14 would complete the northern portion of the 2-14 injection pattern and should recover oil swept by the waterflood from Lsd's 1-14 & 7-14. Assuming an incremental waterflood recovery of 5% OOIP, the 8-14 well could be assigned probable incremental waterflood recoverable reserves of 482 to 964 m^3. In addition, possible recoverable reserves could be assigned to the Lodgepole, productive in both the 6-14 & 10-14 wells.

2. Unit Waterflood Expansion

The Branch supports Tundra proposed waterflood expansion plans. As the proposed future injectors are located near the unit boundary, application to convert the wells would require public notice.

3. Production Data

The Branch apologizes for the error in calculating the last 90-days production for the wells. The production numbers submitted by Tundra in the application are correct.

4. Commencement of Unit Operations

Provided Tundra is able to obtain the consent of all unit royalty owners, an effective date of July 1, 1998 for Cromer Unit No. 1 is acceptable to the Branch.

5. Unit Agreement

Please submit a draft copy of the Cromer Unit No.1 Unit Agreement to the Branch for review. Of particular interest to the Branch is the wording of the section related to establishment of initial and final tract factors.

6. Unit Tract 7-14/8-14

The Branch is prepared to include the undeveloped 7-14/8-14 tract in the unit. However if the 7-14/8-14 tract is allocated unit production, in accordance with the terms of the Crown Oil and Gas Lease, Tundra can continue the lease indefinitely without developing it, which the Branch does not view as in the best interests of the Crown. Tundra's current position is that it is uneconomic to drill at 8-14. The Branch in turns believes a well should eventually be drilled at 8-14 to recover oil mobilized by the waterflood, which clearly cannot be recovered by the existing wells. By allocating production to the 7-14/8-14 unit tract before a well is drilled, the Branch no longer has the ability to protect its interests. For example should a well be drilled adjacent to the unit on freehold land at 4-12 or 5-12, because the 7-14/8-14 tract is deemed productive, the Branch could not call an offset to protect against drainage. Though clearly not intended by Tundra, including the 7-14/8-14 tract in the unit with a nominal tract factor, does nothing more than protect Tundra's land position in the pool.

The Branch's proposal to include the 7-14/8-14 tract in the unit with an initial tract factor of zero is viewed as a win-win situation. The method of determining the final tract factors can be agreed upon and included in the unit agreement, so in the event a well is drilled at 7-14 or 8-14, the unit does not have to be formally enlarged. Tundra in turn has until May 5, 2003, or longer if a lease extension is granted, to make a decision on drilling a well at 7-14 or 8-14.

The Branch agrees with Tundra's proposal for determination of the final tract factors. The Branch proposes that the first six (6) months of production from a well at 7-14 or 8-14, be deemed to have been produced from the 7-14/8-14 unit tract only and as such will not be allocated to the other tracts in the unit. It is proposed that final tract factors take effect on the first day of the seventh (7th) calendar month after the on-production date of a well at 7-14 or 8-14.

Please call me at 945-6574 after you receive this letter and we can discuss and finalize these matters.

Yours truly,

John N. Fox, P.Eng.
Chief Petroleum Engineer

Tundra oil and gas ltd.

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

April 13, 1998

MANITOBA ENERGY & MINES

APR 16 1998

PETROLEUM & ENERGY BRANCH

Manitoba Energy and Mines
Petroleum Branch
360 - 1395 Ellice Avenue
Winnipeg, MB R3G 0G3

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

Dear John:

Re: Cromer Unit No. 1
Pressure Maintenance Application

Please find attached two (2) copies of the referenced application to unitize the Bakken "I" Pool at Cromer. Tundra would like to install waterflood operations in the proposed Cromer Unit No. 1 during the 2nd quarter of 1998, and any assistance that your office requires in processing the subject application, will be provided by Tundra.

Should you have any questions, I can be reached at 934-5853 for further discussion.

Sincerely,

TUNDRA OIL AND GAS LTD.

George Czyzewski, P. Eng.
General Manager

GC/ps

Enclosure

TUNDRA OIL AND GAS LTD.

CROMER UNIT NO. 1

PRESSURE MAINTENANCE APPLICATION

MARCH, 1998

Tundra
oil and gas ltd.

TABLE OF CONTENTS

Tundra oil and gas ltd.

TABLE OF CONTENTS (Continued)

FIGURES

TABLES

Tundra
oil and gas ltd.

TABLE OF CONTENTS (Continued)

ATTACHMENTS

Tundra oil and gas ltd.

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

March 23, 1998

Manitoba Energy and Mines
Petroleum Branch
1395 Ellice Avenue, Suite 360
Winnipeg, Manitoba
R3G OG3

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

Dear John,

RE: Cromer Field
Pressure Maintenance Application

Introduction

The Cromer Field is located in South Daly in Township 9, Range 28 WPM (refer to Attachment No.7). Oil production is obtained from 11 producing wells. The productive formations in the Cromer Field include both the Bakken and Lodgepole pools. Total oil production from the Bakken "I" Pool in this area at 97.12.31 was 15.8 m3/day at a watercut of 15%. The historical Bakken reservoir development strategy at Cromer included both 40 acre and 80 acre tracts. More recently, 80 acre tracts are considered the only economic option to develop the Bakken reservoir in this area. The purpose of this pressure maintenance application is to install waterflood operations to maximize oil recovery from the Bakken formation.

Conclusions

1. The Bakken "I" Pool is considered to be an acceptable reservoir for pressure maintenance operations when compared to other Bakken waterfloods in the Province of Manitoba.

2. Based on engineering studies and actual field performance, the ultimate primary and secondary recovery from the Bakken "I" Pool is estimated to be about 30% of the oil-in-place.

3. The wateflood program will be staged in the proposed Cromer Unit No.1. Initially, well 11-14-9-28 will be converted to water injection service. Pending acceptable waterflood response in the area around injector 11-14, well 2-14-9-28 will then be converted to injection service. Figure No.4 outlines the initial waterflood areas in the Cromer Unit No.1.

Tundra oil and gas ltd.

Discussion

The supporting documentation for the pressure maintenance application is summarized as follows:

UNIT NAME

Tundra proposes that that the official Unit name of the new pressure maintenance scheme in the Cromer area shall be Cromer Unit No.1.

OPERATORSHIP

Tundra Oil and Gas Ltd. will be the operator of record of the proposed Cromer Unit No.1.

UNIT WELLS

The wells to be included in the Unit are outlined in Table No.2.

UNIT LANDS

The Unit will consists of both 40 acre and 80 acre tracts. The 80 acre tracts will be lying down (east - west orientation). Specifically, the lands to be included in the Unit are outlined as follows (refer to Figure No.3):

80 Acre Tracts	40 Acre Tracts
LSD's 9-11 / 12-12-9-28 ✓	LSD 6-14-9-28 ✓
LSD's 15-11 / 16-11-9-28 ✓	LSD 13-14-9-28 ✓
LSD's 1-14 / 2-14-9-28 ✓	
LSD's 7-14 / 8-14-9-28 ✓	
LSD's 9-14 / 10-14-9-28 ✓	
LSD's 11-14 / 12-14-9-28 ✓	
LSD's 14-14 / 15-14-9-28 ✓	
LSD's 1-23 / 2-23-9-28 ✓	
LSD's 3-23 / 4-23-9-28 ✓	
LSD's 5-23 / 6-23-9-28 ✓	

Tundra oil and gas ltd.

Attachment No.1 outlines the surface and mineral owners in the proposed Unit area.

UNITIZED ZONE

The unitized zone in the proposed Cromer Unit No.1 will be the Bakken "I" Pool. Attachment No.2 outlines a representative log cross-section of a Bakken "I" Pool well.

TRACT FACTORS

As previously discussed, the Cromer Unit No.1 will consist of both 40 acre and 80 acre tracts. The tract factors proposed for the Unit lands are outlined in Table No.8. Tundra has used the same formula to determine the tract factors at Cromer Unit No.1 that was used at Kola Unit No.1 and Kola Unit No.2. Specifically, production during the last 90 operating days (referenced to December 31, 1997, refer to Table No.7) was used to determine the tract factors at the proposed Cromer Unit No.1. Since the 80 acre tract at 7-14/8-14-9-28 is undrilled at this time, a nominal tract factor was assigned to indicate that this area of the Unit has hydrocarbon development potential. If this undrilled 80 acre tract is developed in the future, the Unit tract factors would have to be redetermined to recognize the oil production from this area of the Unit. Production from the last 90 operating days from all the wells would be used in the redetermination of tract factors, as was done with the initial tract factor assignment.

WORKING INTEREST OWNERS

Tundra will be the only working interest owner in the proposed Cromer Unit No.1. As a result, Tundra Oil and Gas Ltd. will have a 100% working interest in the Unit.

TECHNICAL STUDIES

The waterflood performance predictions for the Bakken "I" Pool in the proposed Cromer Unit No.1 are based on several geological and engineering studies.

Geological work included a review of the available open-hole logs and core data to establish reservoir continuity and to develop an effective oil pore volume map. Figure No.3 outlines the pore volume map for the Unit area.

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Engineering reviews included reserve estimation, historical production assessment, and ultimate oil recovery predictions. A relative permeability study (refer to Attachment No.6) was also completed to increase the reliability of the reserves and to assess waterflood performance. Waterflood performance at Cromer Unit No.1 will be piston displacement as historically observed in other Bakken waterfloods in the Province of Manitoba. Piston waterflood displacement is characterized by low watercuts until water breakthrough. Once water breakthrough occurs, the majority of the oil will have been recovered with the current well orientation. Watercuts will increase rapidly after water breakthrough. The piston displacement process in the Bakken reservoir has been assessed as providing effective oil sweep and recovery.

HISTORICAL PRODUCTION

Figure No.1 outlines the Bakken production history of the proposed Cromer Unit No.1. The oil production profile peaked in 1994 and has been relatively flat since then due to development drilling, well re-entries, and workovers. Current oil production is about 16 m3/day (at 97.12.31). Cumulative oil production to 97.12.31 was 21,389 m3. Ultimate primary oil recovery is estimated at 42,367 m3 (refer to Figure No.2). This represents an ultimate primary oil recovery of 24.3% of oil-in-place based on log derived volumetrics. Table No.4 outlines the primary production forecast for the Unit. Table No.5 outlines the individual well production and recovery profiles. Attachment No.3 outlines the forecasts of the individual well ultimate recovery profiles.

RESERVES

The Bakken volumetric oil-in-place estimates for the proposed Unit are outlined in Table No.3. Total oil-in-place in the Unit is estimated at 174,273 m3. Table No.11 outlines a summary of the Unit reserves and recovery profiles estimated for primary and waterflood operations.

WATERFLOOD RECOVERY

Based on actual performance at similar Bakken waterflood operations in the Province of Manitoba, incremental waterflood oil recovery of 5% of the oil-in-place is estimated in the Unit. Figure No.4 outlines the areas of the Unit initially selected for waterflood operations. Figure No.5 and Table No.6. outline the Unit oil production forecast with initial waterflood operations as outlined in Figure No.5. Incremental oil recovery of 3,620 m3 is estimated from the initial area selected for waterflood operations, with the existing well complement. This estimate was derived by first estimating the oil-in-place in the initial waterflood area in the Unit (refer to Table No.9). The oil-in-place, current, and ultimate recovery factors were than adjusted according to the areas that would be impacted by waterflood operations with the initial injection wells (refer to Table No.10). Specifically, this included injectors 2-14 and 11-14-9-28 as outlined in Figure No.4. Based on the ultimate primary recovery estimated in Table No.10, further incremental oil recovery of 5% of oil-in-place is estimated with waterflood operations. Since there is an undrilled 80 acre tract at 7-14 / 8-14-9-28, development drilling at 8-14-9-28 would further increase oil recovery in the initial area of waterflood operations. Extending the pressure maintenance program to other areas of the Unit, by adding more injectors, could potentially provide further incremental oil recovery of 6,300 m3. Further expansion will be contingent on initial waterflood performance in the Unit, and the prevailing commodity price.

WATERFLOOD PATTERN

The waterflood pattern outlined in Figure No.4 is irregular and best approximates a line drive. Drilling further development wells beyond 8-14-9-28 is not economic. As a result, a traditional inverted 5-spot waterflood pattern is not economically feasible in the proposed Cromer Unit No.1. Initially, well 11-14-9-28 will be converted to injection service. Pending good waterflood response in the ofsetting oil producers, the next well proposed for water injection service will be 2-14-9-28.

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CONVERSION PROGRAM

The workover program to convert 11-14-9-28 to injection service is outlined in Attachment No.4. Similarly, the Manitoba EMR application form to reclassify the 11-14-9-28 well to injection service is outlined in Attachment No.5.

FACILITIES

The Cromer Unit No.1 will utilize battery facilities that are located at 11-10-9-28 WPM. The water injection pump will be located at injector 11-14-9-28 WPM. Make-up injection water will be procured that is compatible with produced Bakken water (produced water from 13-10-9-28). Figure No.6 outlines the location of the facilities, and existing flowlines in the proposed Unit.

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra is in the process of notifying all mineral rights and surface rights owners of the unitization of the Bakken zone at Cromer Unit No.1, and subsequent commencement of waterflood operations.

Respectfully Submitted,

TUNDRA OIL AND GAS LTD.

George Czyzewski, P.Eng.
General Manager

LIST OF FIGURES

FIGURE NO.1

CROMER UNIT NO.1 PRODUCTION HISTORY

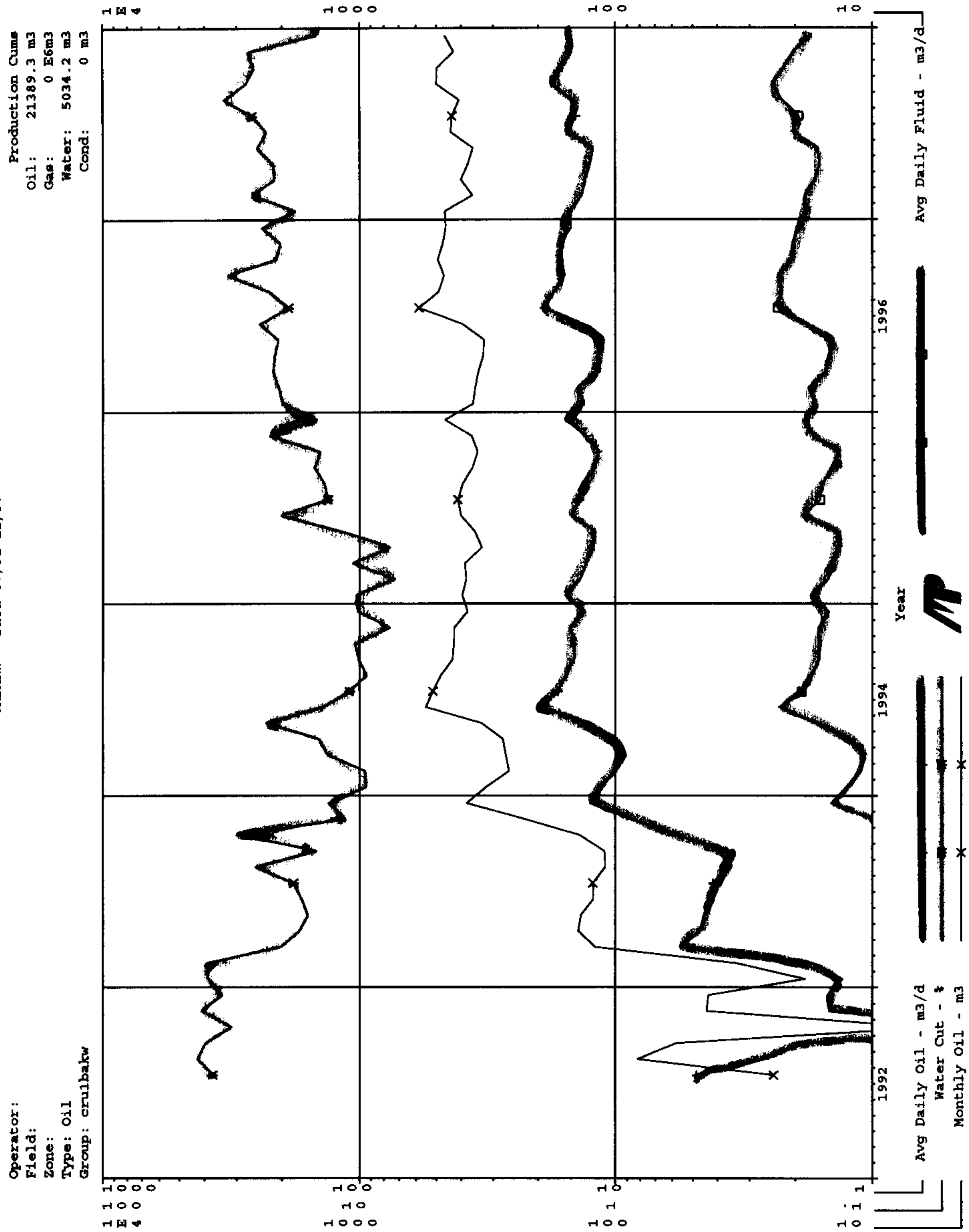


FIGURE NO. 2

CROMER UNIT NO.1 ULTIMATE PRIMARY RECOVERY PREDICTION

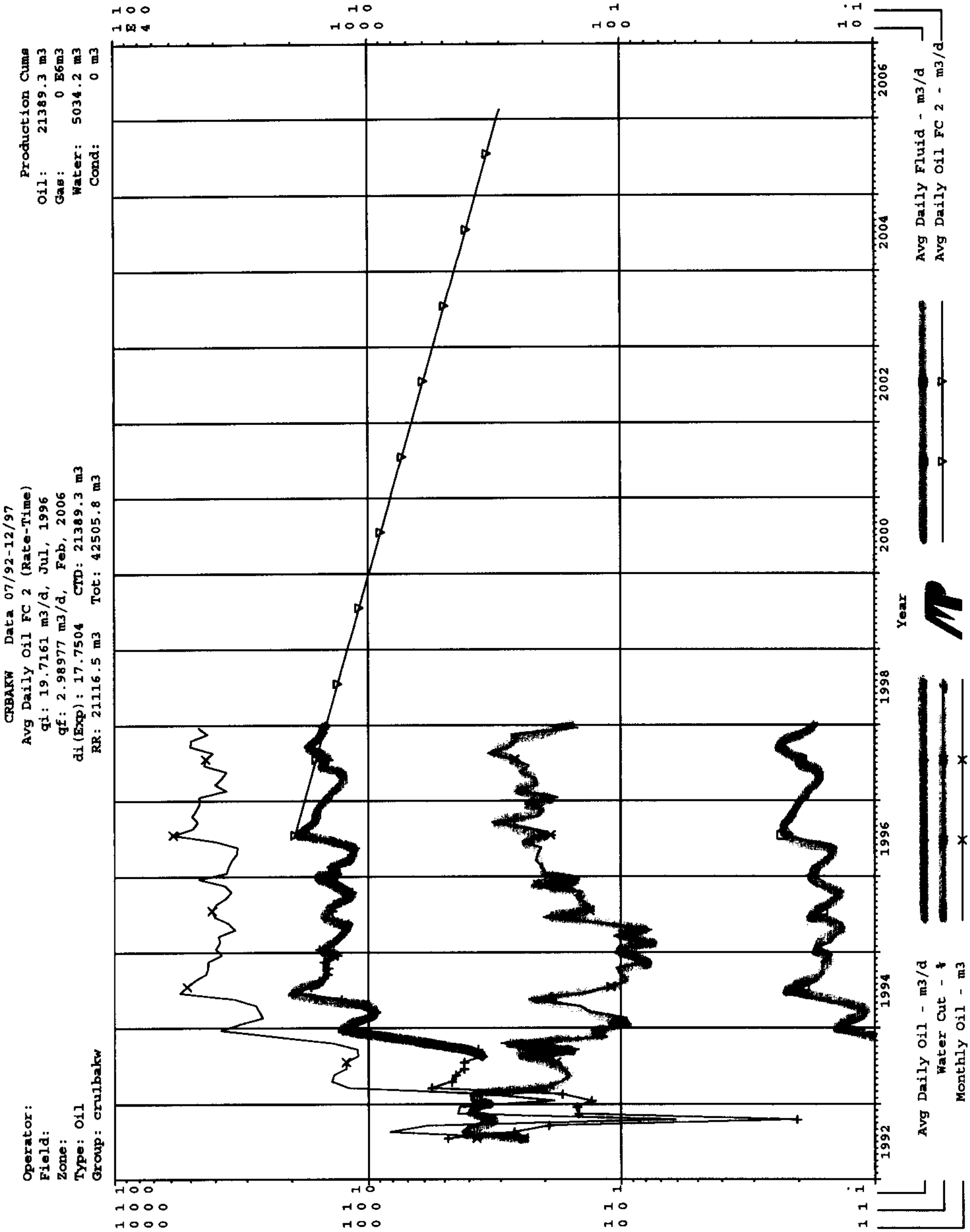
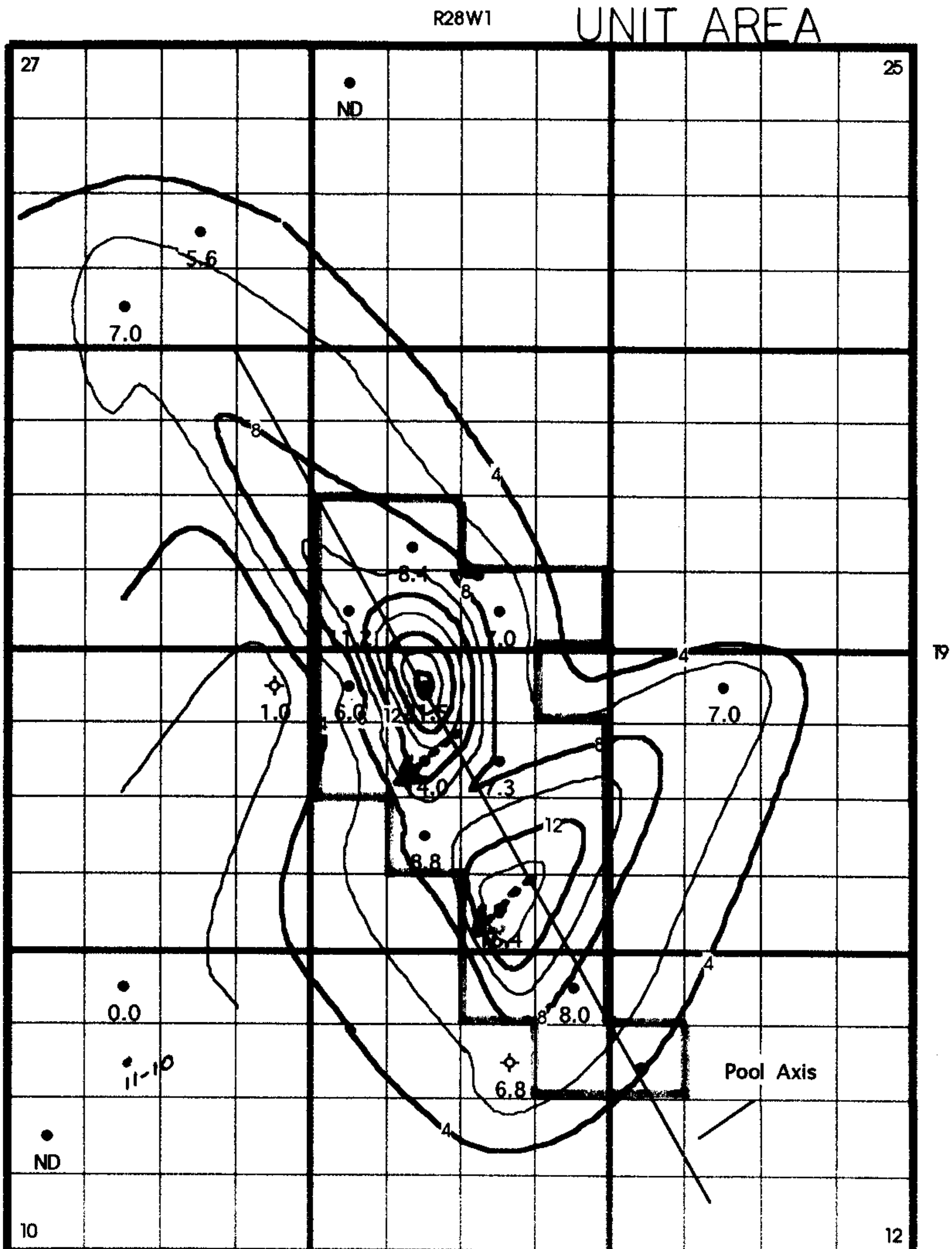


FIGURE NO.3

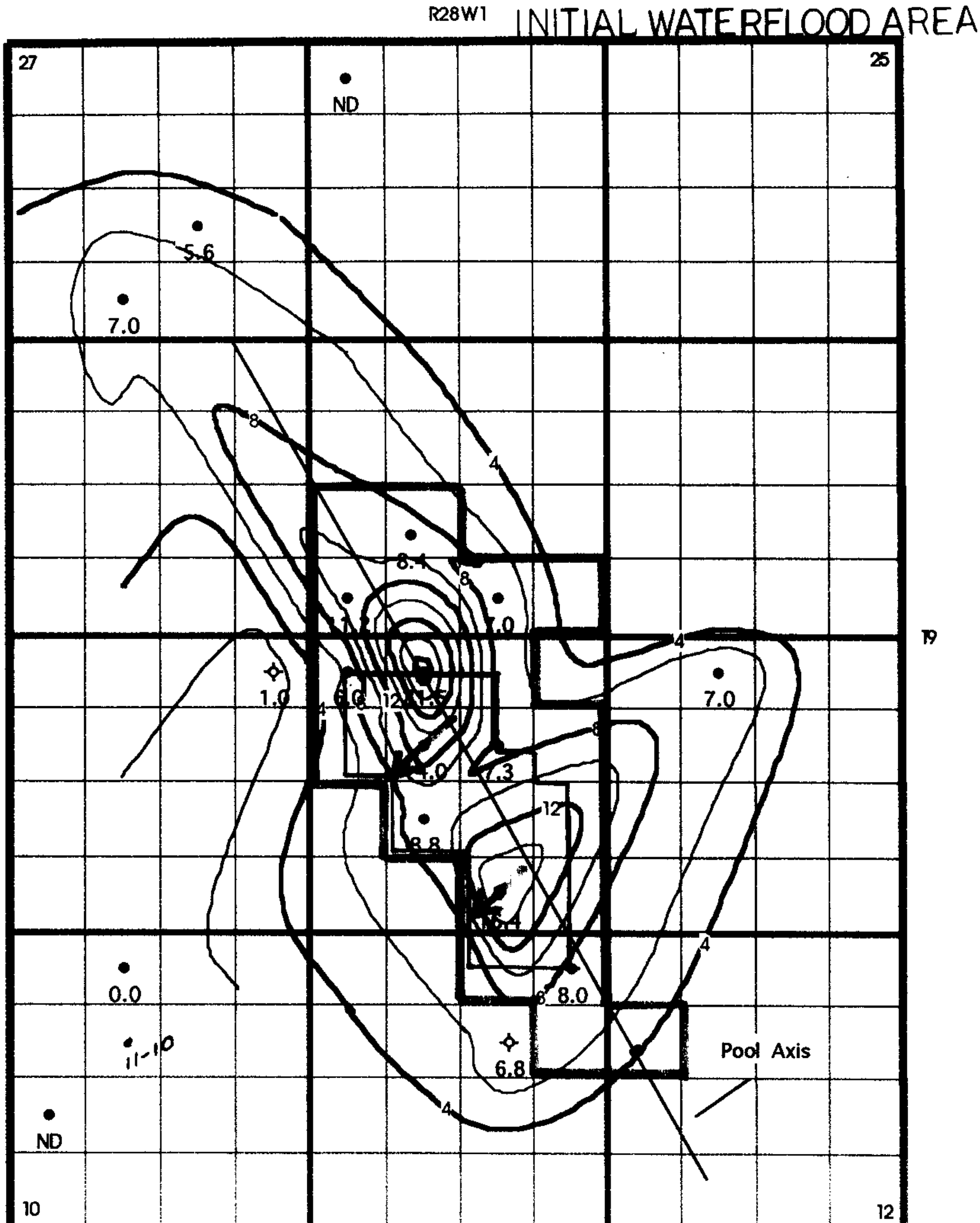


UNIT OUTLINE

PROPOSED INJECTORS

TUNDRA OIL AND GAS LTD.	
Bakken I Pool PHI-H at 2.0 Intervals (1 km)	
M.B. DUPONT	
Date:6/16/97	33000

FIGURE NO.4



UNIT OUTLINE

INITIAL WATERFLOOD AREA

TUNDRA OIL AND GAS LTD.	
Bakken I Pool PHI-H at 2.0 Intervals (1 km)	
M.B. DUPONT	
Date:6/16/97	33000

FIGURE NO.5

CROMER UNIT NO.1 PRIMARY AND WATERFLOOD FORECASTS

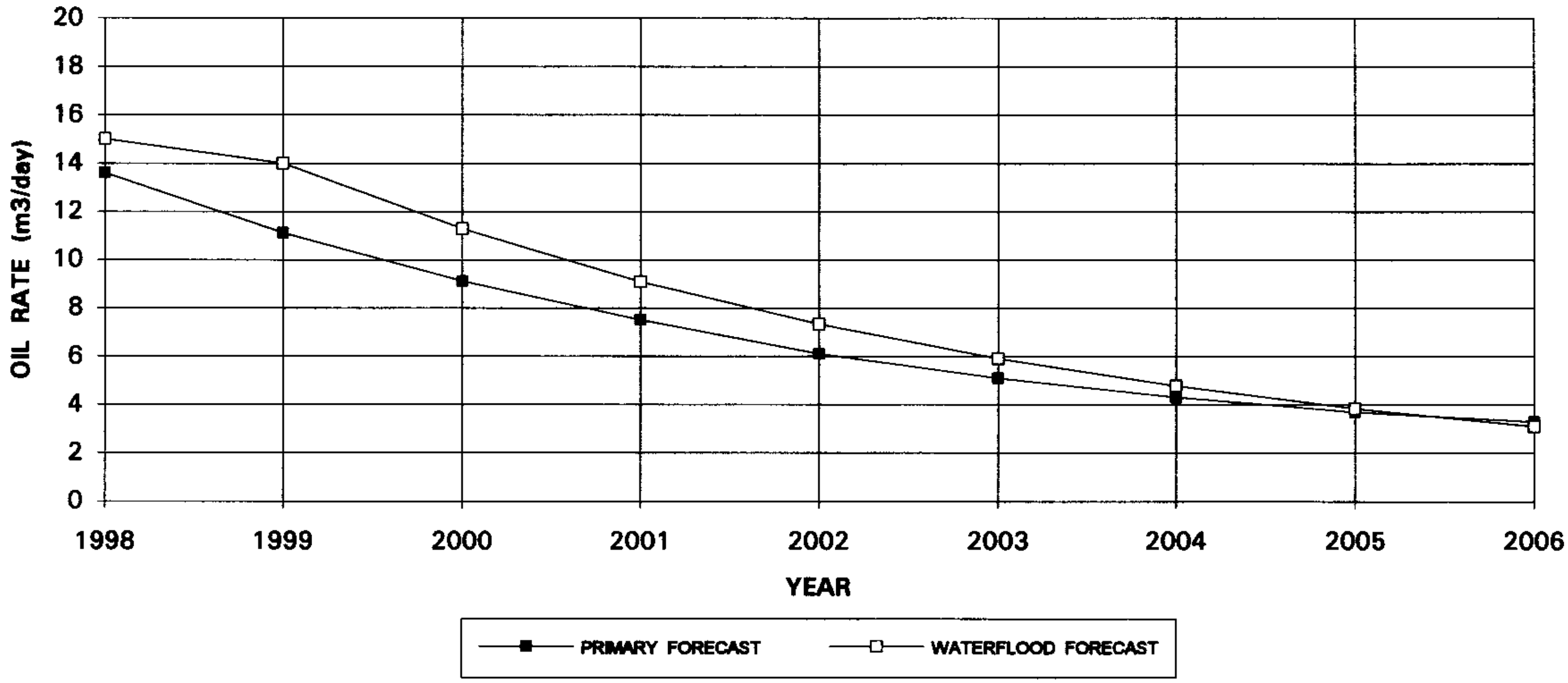
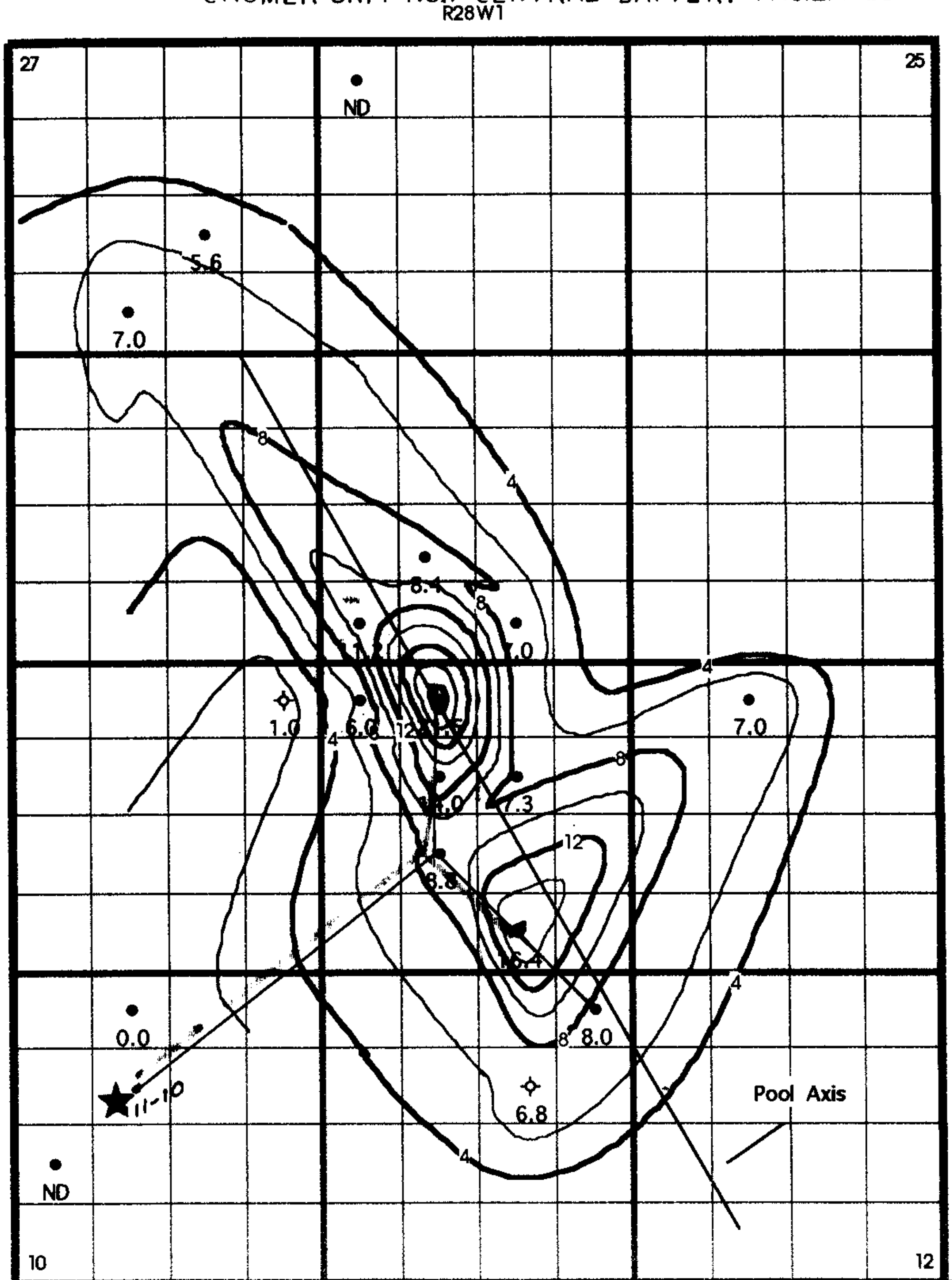


FIGURE NO.6

CROMER UNIT NO.1 CENTRAL BATTERY FACILITIES



WATER INJECTION LINES

EMULSION FLOWLINES

CENTRAL BATTERY

TUNDRA OIL AND GAS LTD.

Bakken I Pool

PHI-H at 2.0 Intervals

(1 km)

M.B. DUPONT

Date:6/16/97 | 33000

LIST OF TABLES

TABLE NO.1
BAKKEN 'I' POOL FLUID PARAMETERS

BAKKEN 'I' POOL	
Reservoir Temperature	31 deg. C
Bubble Point Pressure	2,101 kPag
Oil API	41 deg. API
Boi	1.063 Rm3/m3
Solution GOR	27 m3/m3
Oil Compressibility @ Pi	1.15 E-6 (1/kPa)
Water Compressibility	4.5 E-7 (1/kPa)
Rock Compressibility	5.8 e-7 (1/kPa)
Water Salinity	90,000 ppm

TABLE NO.2
CROMER UNIT NO.1

TOTAL UNIT WELLS

16-11-9-28 W1M

12-12-9-28 W1M

2-14-9-28 W1M

6-14-9-28 W1M

10-14-9-28 W1M

11-14-9-28 W1M

13-14-9-28 W1M

14-14-9-28W1M

2-23-9-29 W1M

4-23-9-28 W1M

6-23-9-28 W1M

CRU1OIP.XLS

TABLE NO.3

CROMER UNIT NO.1

VOLUMETRIC OIL-IN-PLACE ESTIMATES

BAKKEN 'I' POOL

LSD	Constant	Area (hectares)	Phi-h (% metres)	Sw (fraction)	(1-Sw) (fraction)	Boi (Rm3/m3)	OOIP (m3)	OOIP (STB)
9-11-9-28	10,000	16.19	6.1	0.45	0.55	1.05	5,173	32,539
15-11-9-28	10,000	16.19	9.5	0.45	0.55	1.05	8,056	50,675
16-11-9-28	10,000	16.19	8.79	0.45	0.55	1.05	7,454	46,888
12-12-9-28	10,000	16.19	4.4	0.45	0.55	1.05	3,731	23,471
1-14-9-28	10,000	16.19	10.82	0.45	0.55	1.05	9,176	57,716
2-14-9-28	10,000	16.19	11.8	0.45	0.55	1.05	10,007	62,944
6-14-9-28	10,000	16.19	9	0.45	0.55	1.05	7,632	48,008
7-14-9-28	10,000	16.19	11.9	0.45	0.55	1.05	10,092	63,477
8-14-9-28	10,000	16.19	11.39	0.45	0.55	1.05	9,659	60,757
9-14-9-28	10,000	16.19	8.6	0.45	0.55	1.05	7,293	45,874
10-14-9-28	10,000	16.19	9.9	0.45	0.55	1.05	8,396	52,809
11-14-9-28	10,000	16.19	11.7	0.45	0.55	1.05	9,922	62,410
12-14-9-28	10,000	16.19	7.3	0.45	0.55	1.05	6,191	38,940
13-14-9-28	10,000	16.19	9.2	0.45	0.55	1.05	7,802	49,075
14-14-9-28	10,000	16.19	14.3	0.45	0.55	1.05	12,127	76,279
15-14-9-28	10,000	16.19	9.5	0.45	0.55	1.05	8,056	50,675
1-23-9-28	10,000	16.19	3	0.45	0.55	1.05	2,544	16,003
2-23-9-28	10,000	16.19	8.2	0.45	0.55	1.05	6,954	43,741
3-23-9-28	10,000	16.19	13.3	0.45	0.55	1.05	11,279	70,945
4-23-9-28	10,000	16.19	10.4	0.45	0.55	1.05	8,820	55,476
5-23-9-28	10,000	16.19	9	0.45	0.55	1.05	7,632	48,008
6-23-9-28	10,000	16.19	7.4	0.45	0.55	1.05	6,276	39,473
TOTAL		356.18					174,274	1,096,182

NOTE: POROSITY CUT-OFF = 15%

8904
15510
19,183
19,751
15,689
16,113
20,183
9,498
20,099
13,908

TABLE NO.4

CROMER UNIT NO.1

PRIMARY PRODUCTION FORECAST

		TOTAL WELLS		
Year	Wells	Gross Daily Oil	Gross Annual Oil	Cum. Oil
		(m3/day)	(m3)	(m3)
97.12.31				21,389
1998	11	13.6	2,856	24,245
1999	11	11.1	3,996	28,241
2000	11	9.1	3,276	31,517
2001	8	7.5	2,700	34,217
2002	8	6.1	2,196	36,413
2003	8	5.1	1,836	38,249
2004	8	4.3	1,548	39,797
2005	8	3.7	1,332	41,129
2006	8	3.3	1,188	42,317

TABLE NO.5

CRU1RECP.XLS

CROMER UNIT NO.1

CURRENT RATES AND RECOVERY PROFILES

DEC 97 DAILY OIL	Well	LSD (undeveloped) ON PROD	Oil Rate (m3/day) 97.12.31	Water-cut (%) 97.12.31	Total Rate (m3/day) 97.12.31	Cum. Oil (m3) 97.12.31	OOIP (m3)	Ultimate Rec. (m3)	Rem. Oil (m3) 97.12.31	Cur. Rec. Fac. (% of OOIP) 97.12.31	Ult. Rec. Fac (% of OOIP)
1.98	16-11-9-28	MAR 96	2.1	12	2.4	1,652.4	7,454	4,558 ✓	2,906	22.2	61.1
2.01	12-12-9-28	AUG 97	2.1	11	2.4	285.6	3,731	3,279 ✓	2,993	7.7	87.9
2.27	2-14-9-28	MAR 94	2.4	11	2.7	4,077.7	10,007	7,771 ✓	3,693	40.7	77.7
1.43	6-14-9-28 C	NOV 95	1.5	37	2.4	1,597.3	7,632	3,272 ✓	1,675	20.9	42.9
1.22	10-14-9-28 C	MAR 95	1.3	13	1.5	1,550.3	8,396	3,025 ✓	1,475	18.5	36.0
1.32	11-14-9-28	OCT 93	1.4	9	1.5	3,765.0	9,922	5,994 ✓	2,229	37.9	60.4
0.40	13-14-9-28	OCT 93	0.4	32	0.6	1,451.0	7,802	1,841 ✓	390	18.6	23.6
1.77	14-14-9-28 C	MAR 93	1.9	6	2.0	4,353.7	12,127	6,379 ✓	2,025	35.9	52.6
0.26	2-23-9-28 C	JUL 92	0.3	31	0.4	1,323.4	6,954	1,618 ✓	295	19.0	23.3
0.52	4-23-9-28 C	NOV 94	0.5	0	0.5	872.6	8,820	1,597 ✓	724	9.9	18.1
1.78	6-23-9-28 C	FEB 97	1.9	13	2.2	460.3	6,276	3,033 ✓	2,573	7.3	48.3
		9-11-9-28					5,173				
		15-11-9-28					8,056				
		1-14-9-28					9,176				
		7-14-9-28					10,092				
		8-14-9-28					9,659				
		9-14-9-28					7,293				
		12-14-9-28					6,191				
		15-14-9-28					8,056				
		1-23-9-28					2,544				
		3-23-9-28					11,279				
		5-23-9-28					7,632				
	TOTALS		15.8	15.0	18.6	21,389	174,272	42,367	20,978	12.3	24.3

TABLE NO.6

CROMER UNIT NO.1

UNIT PRODUCTION FORECAST WITH INITIAL WATERFLOOD AREA

Year	Primary Oil	Waterflood	Annual	Cum. Oil	Rec. Factor
		Forecast	Production		
	(m3/day)	(m3/day)	(m3)	(m3)	(% OOIP)
				21,389	12.3
1998	13.6	15	3,150	24,539	14.1
1999	11.1	14	5,040	29,579	17.0
2000	9.1	11	4,062	33,641	19.3
2001	7.5	9	3,274	36,915	21.2
2002	6.1	7	2,639	39,554	22.7
2003	5.1	6	2,127	41,681	23.9
2004	4.3	5	1,714	43,396	24.9
2005	3.7	4	1,382	44,778	25.7
2006	3.3	3	1,114	45,891	26.3

LPROD90A.XLS

TABLE NO.7

CROMER UNIT NO.1

SEP/97 - DEC /97 OIL PRODUCTION

		Sep-97		Oct-97			Nov-97		Dec-97		Total	Last 90
WELL	W.I. IN LSD.	PROD.	DAYS	PROD.	DAYS		PROD.	DAYS	PROD.	DAYS	PROD.	DAYS
	(%)	(m3)		(m3)			(m3)		(m3)		(m3)	
16-11-9-28	100	-	0	70.1	30		55.9	29	61.5	31	187.5	90
12-12-9-28	100	8.1	2	68.7	28		60.4	29	62.2	31	191.3	90
2-14-9-28	100	-	0	75	30	77.5	63.1	29	70.4	31	208.5	90
6-14-9-28	100	-	0	44	30		37.6	29	44.3	31	125.9	90
10-14-9-28	100	1.1	1	31.7	29		27.6	29	37.8	31	98.2	90
11-14-9-28	100	-	0	47.9	30	49.5	42.2	29	40.8	31	130.9	90
13-14-9-28	100	-	0	17.4	30	18	16.8	29	12.3	31	46.5	90
14-14-9-28	100	-	0	50.4	30	51.2	49	29	55	31	154.4	90
2-23-9-28	100	-	0	7.7	30	8.0	6.1	29	8.1	31	21.9	90
4-23-9-28	100	-	0	14.8	30	15.3	11.8	29	16.1	31	42.7	90
6-23-9-28	100	-	0	60.2	30	62.2	55.3	29	55.3	31	170.8	90

TABLE NO.8

CROMER UNIT NO.1

PROPOSED TRACT FACTORS

	Area (80 Acre Tract)	Well	Tundra W.I. in Well (%)	Total Operating Days	Total Production (m3)	Average Oil Rate Per Operating Day (m3/day)	Interim Tract Factor in Unit (%)	Tundra Tract Factor (%)
CROWN	LSD 15-11 / 16-11	16-11-9-28	100	90	187.5	2.08	13.59090	13.59090
CROWN	LSD 9-11 / 12-12	12-12-9-28	100	90	191.3	2.13	13.86634	13.86634
CROWN	LSD 1-14 / 2-14	2-14-9-28	100	90	208.5	2.32	15.11308	15.11308
	LSD 6-14	6-14-9-28	100	90	125.9	1.40	9.12583	9.12583
CROWN	LSD 9-14 / 10-14	10-14-9-28	100	90	98.2	1.09	7.11801	7.11801
CROWN	LSD 11-14 / 12-14	11-14-9-28	100	90	130.9	1.45	9.48826	9.48826
CROWN	LSD 13-14	13-14-9-28	100	90	46.5	0.52	3.37054	3.37054
CROWN	LSD 14-14 / 15-14	14-14-9-28	100	90	154.4	1.72	11.19165	11.19165
	LSD 1-23 / 2-23	2-23-9-28	100	90	21.9	0.24	1.58742	1.58742
	LSD 3-23 / 4-23	4-23-9-28	100	90	42.7	0.47	3.09510	3.09510
	LSD 5-23 / 6-23	6-23-9-28	100	90	170.8	1.90	12.38040	12.38040
CROWN	LSD 7-14 / 8-14	-	100	90	1 (10)	0.01 (.11)	0.07248	0.07248
		Total			1,379.6	15.328889	100.00000	100.00000

TABLE NO. 9

BAKKEN "I" POOL

PROPOSED WATERFLOOD AREA

OIL-IN-PLACE ESTIMATES

LSD	Constant	Area (hectares)	Phi-H (%-metres)	Sw (fraction)	(1-Sw) (fraction)	Boi (Rm3/m3)	OOIP (m3)	OOIP (STB)	CUM. OIL 97.12.31 (m3)	Cur. Rec. Fac. 97.12.31 (% OOIP)	Ultimate Recovery (m3)	Ultimate Rec. Factor (% OOIP)
15-11-9-28	10,000	16.19	9.5	0.45	0.55	1.05	8,056	50,675				
16-11-9-28	10,000	16.19	8.79	0.45	0.55	1.05	7,454	46,888	1,652	22.2	4,558 ✓	61.1
1-14-9-28	10,000	16.19	10.82	0.45	0.55	1.05	9,176	57,716				
2-14-9-28	10,000	16.19	11.8	0.45	0.55	1.05	10,007	62,944	4,078		7,771	77.7
6-14-9-28	10,000	16.19	9	0.45	0.55	1.05	7,632	48,008	1,597	20.9	3,272	42.9
7-14-9-28	10,000	16.19	11.9	0.45	0.55	1.05	10,092	63,477	-	-	-	-
8-14-9-28	10,000	16.19	11.39	0.45	0.55	1.05	9,659	60,757	-	-	-	-
9-14-9-28	10,000	16.19	8.6	0.45	0.55	1.05	7,293	45,874	-	-	-	-
10-14-9-28	10,000	16.19	9.9	0.45	0.55	1.05	8,396	52,809	1,550	18.5	3,025	36.0
11-14-9-28	10,000	16.19	11.7	0.45	0.55	1.05	9,922	62,410	3,765	37.9	5,994	60.4
12-14-9-28	10,000	16.19	7.3	0.45	0.55	1.05	6,191	38,940	-	-	-	-
13-14-9-28	10,000	16.19	9.2	0.45	0.55	1.05	7,802	49,075	1,451	18.6	1,841	23.6
14-14-9-28	10,000	16.19	14.3	0.45	0.55	1.05	12,127	76,279	4,354	35.9	6,379	52.6
15-14-9-28	10,000	16.19	9.5	0.45	0.55	1.05	8,056	50,675	-	-	-	-
TOTAL							121,864	766,527	18,447	15.1	32,840	26.9

TABLE NO. 10

BAKKEN " I " POOL

PROPOSED WATERFLOOD AREA

PRIMARY RECOVERY PROFILES INITIAL WATERFLOOD AREA

Well	Waterflood Area	OOIP (m3)	OOIP Adj. Factor	OOIP Waterflood Area (m3)	Cum. Oil 97.12.31 (m3)	Prod. Adj. Factor	Waterflood Production Adj. Factor	Cum. Oil (adjusted) (m3)	Current Rec. Factor (% OOIP)	Ultimate Recovery (m3)	Adjusted Ult. Recovery (m3)	Ultimate Rec. Factor (% OOIP)
	15-11-9-28	8,056	0.50	4,028	-	0.5	0.5	413	10.3	-	1,140	28.3
16-11-9-28	16-11-9-28	7,454	0.25	1,864	1,652	0.5	0.25	207	11.1	4,558	570	-
	1-14-9-28	9,176	0.50	4,588		0.5	0.5	1,020	-	-	1,943	-
2-14-9-28	2-14-9-28	10,007	1.00	10,007	4,078	0.5	1	2,039	-	7,771	3,886	-
6-14-9-28	6-14-9-28	7,632	1.00	7,632	1,597	0.5	1	799	10.5	3,272	1,636	21.4
	7-14-9-28	10,092	1.00	10,092	-	0.5	1	799	7.9	-	1,636	16.2
	8-14-9-28	9,659	0.50	4,830	-	-	0.5	-	-	-	-	-
	9-14-10-29	7,293	0.00	0	-	0.5	-	-	-	-	-	-
10-14-9-28	10-14-9-28	8,396	0.75	6,297	1,550	0.5	0.75	581	9.2	3,025	1,134	18.0
11-14-9-28	11-14-9-28	9,922	1.00	9,922	3,765	0.5	1.0	1,883	19.0	5,994	2,997	30.2
	12-14-9-28	6,191	0.50	3,096	-	0.5	0.5	941	30.4	-	1,499	48.4
13-14-9-28	13-14-9-28	7,802	0.25	1,951	1,451	0.25	0.25	91	4.6	1,841	115	5.9
14-14-9-28	14-14-9-28	12,127	0.50	6,064	4,354	0.5	0.5	1,089	18.0	6,379	1,595	26.3
	15-14-9-28	8,056	0.25	2,014	-	0.5	0.25	544	27.0	-	797	39.6
TOTAL		**121,863**		**72,383**	**18,447**			**10,403**	**14.4**	**32,840**	**18,948**	**26.2**

TABLE NO.11
CROMER UNIT NO.1
RESERVE AND RECOVERY FACTOR SUMMARY

	UNIT	WATERFLOOD AREAS
RESERVES		
CUM.PROD.(97.12.31)	21,389 m3	10,403 m3
REMAINING PRIMARY	20,978 m3	8,545 m3
TOTAL PRIMARY	42,367 m3	18,948 m3
SECONDARY	9,935 m3	3,620 m3
TOTAL	52,302 m3	22,568 m3
RECOVERY FACTORS (% OOIP)		
CUM. PROD.(97.12.31)	12.3%	14.4%
REMAINING PRIMARY	12.0%	11.8%
TOTAL PRIMARY	24.3%	26%
SECONDARY	5.7%	5%
TOTAL	30%	31%

LIST OF ATTACHMENTS

- ATTACHMENT NO.1: SURFACE AND MINERAL OWNWERS
- ATTACHMENT NO.2: BAKKEN "I" POOL LOG CROSS-SECTION
- ATTACHMENT NO.3: INDIVIDUAL WELL RECOVERY PREDICTIONS
- ATTACHMENT NO.4: COMPLETION PROGRAM FOR INJECTOR 11-14-9-28 WPM
- ATTACHMENT NO.5: APPLICATION TO CONVERT 11-14-9-28 TO WATER INJECTION SERVICE
- ATTACHMENT NO.6: SPECIAL CORE STUDY BAKKEN "I" POOL
- ATTACHMENT NO.7: LOCATION MAP OF CROMER UNIT NO.1

ATTACHMENT NO. 1

SURFACE AND MINERAL OWNERS

BENT	Rosa Elizabeth Bentley Box 362 Kimberley, BC V1A 2Y9	SEMO	Morris John Senkiw General Delivery Virden, MB R0M 2C0
DEPT	Department of Energy & Mines	YAIR	Irene Anne Yakobovich 3406 Clover Place Regina, SK S4V 1J1
GODO	Doris Marie Gould 2119 Agincourt Crescent Burlington, ON L7P 1P3		
GREG	Ian Joseph Greggor 58 Wuskwatin Bay Thompson, MB		
IPLI	Interprovincial Pipe Line Inc. P.O. Box 398 Edmonton, AB T5J 2J9		
JASO	Sonia Helen Jacques P.O. Boix 1375 Virden, MB R0M 2C0		
JOBN	Nettie Jobko 207, 2344 Atkins Avenue Port Coquitlam, BC V3C 1Y8		
JOPJ	James Terrance Jopko P.O. Box 220 Bezanson, AB T0H 0G0		
JOPS	Stephen Jopko General Delivery Virden, MB R0M 2C0		
MCLA	Audrey Eugenie McLeod 60 Riverheights Drive Brandon, MB R7B 2Z9		
MOTR	Montreal Trust P.O. Box 369 Winnipeg, MB R3C 2J1		
PERM	Montreal Trust Company 600, 530 Eighth Avenue SW Calgary, AB T2P 3S8		
RPIP	Rural Municipality of Pipestone P.O. Box 99 Reston, MB R0M 1X0		

PERM 75% BENT 25%	TOGL 50% PERM 50%	RPIP 100%	DEPT 100%
DEPT 100%	TOGL 50% PERM 50%	GODO 25% JASO 25% SEMO 25% YAIR 25%	PERM 100%
MOTR 25% PERM 75%	DEPT 100%	DEPT 100%	GREG 75% PERM 25% IPLI Ptn.
MOTR 25% PERM 75%	PERM 75% MOTR 25%	DEPT 100%	JOBK 25% JOPJ 25% JOPS 25% MCLA 25%
DEPT 100%	DEPT 100%	DEPT 100%	DEPT 100%
	DEPT 100%	DEPT 100%	DEPT 100%

ATTACHMENT NO.2

BAKKEN "I" POOL LOG CROSS-SECTION

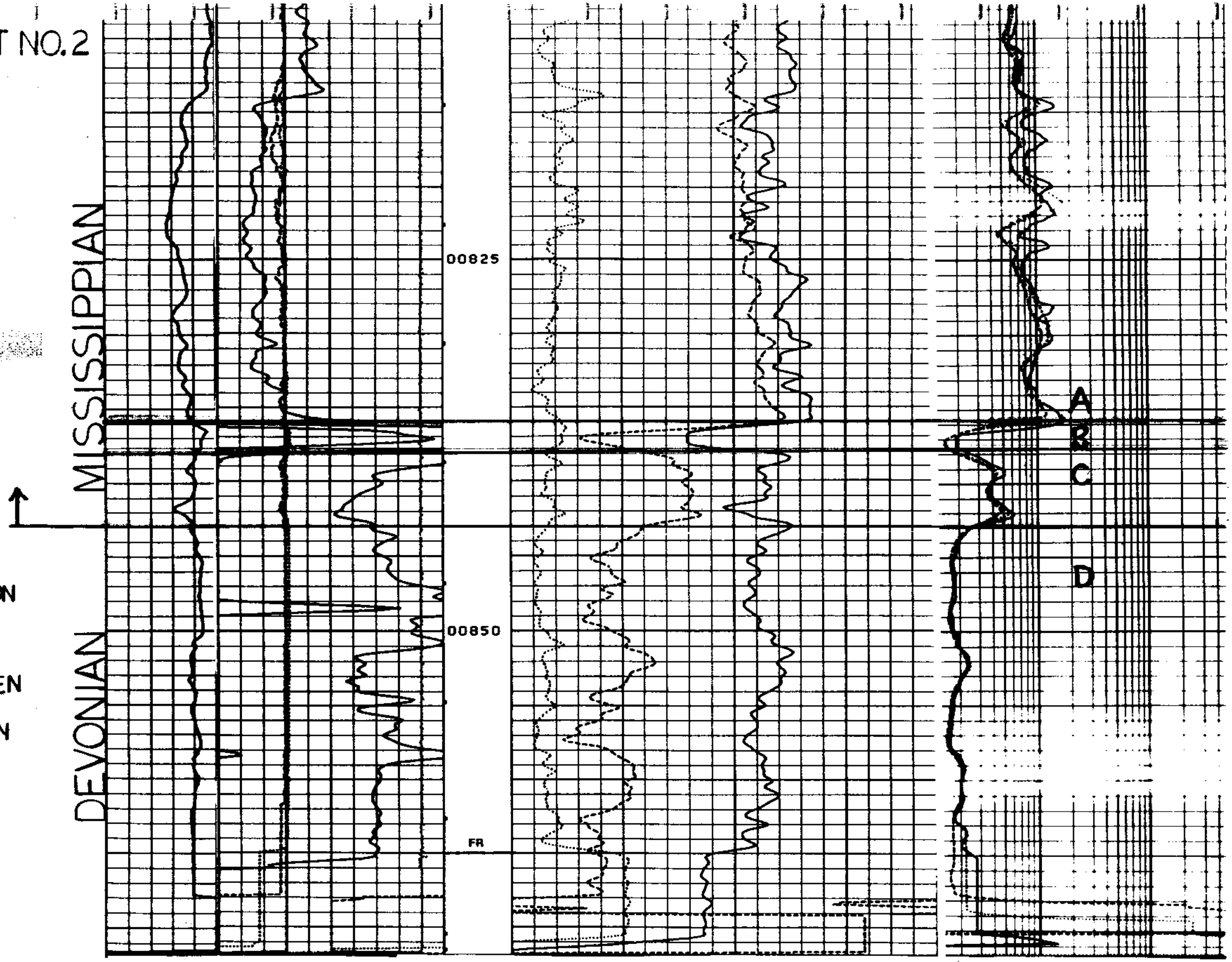
ATTACHMENT NO.2

A. LODGEPOLE FORMATION

B. UPPER MEMBER BAKKEN

C. MIDDLE MEMBER BAKKEN

D. LYLETON FORMATION



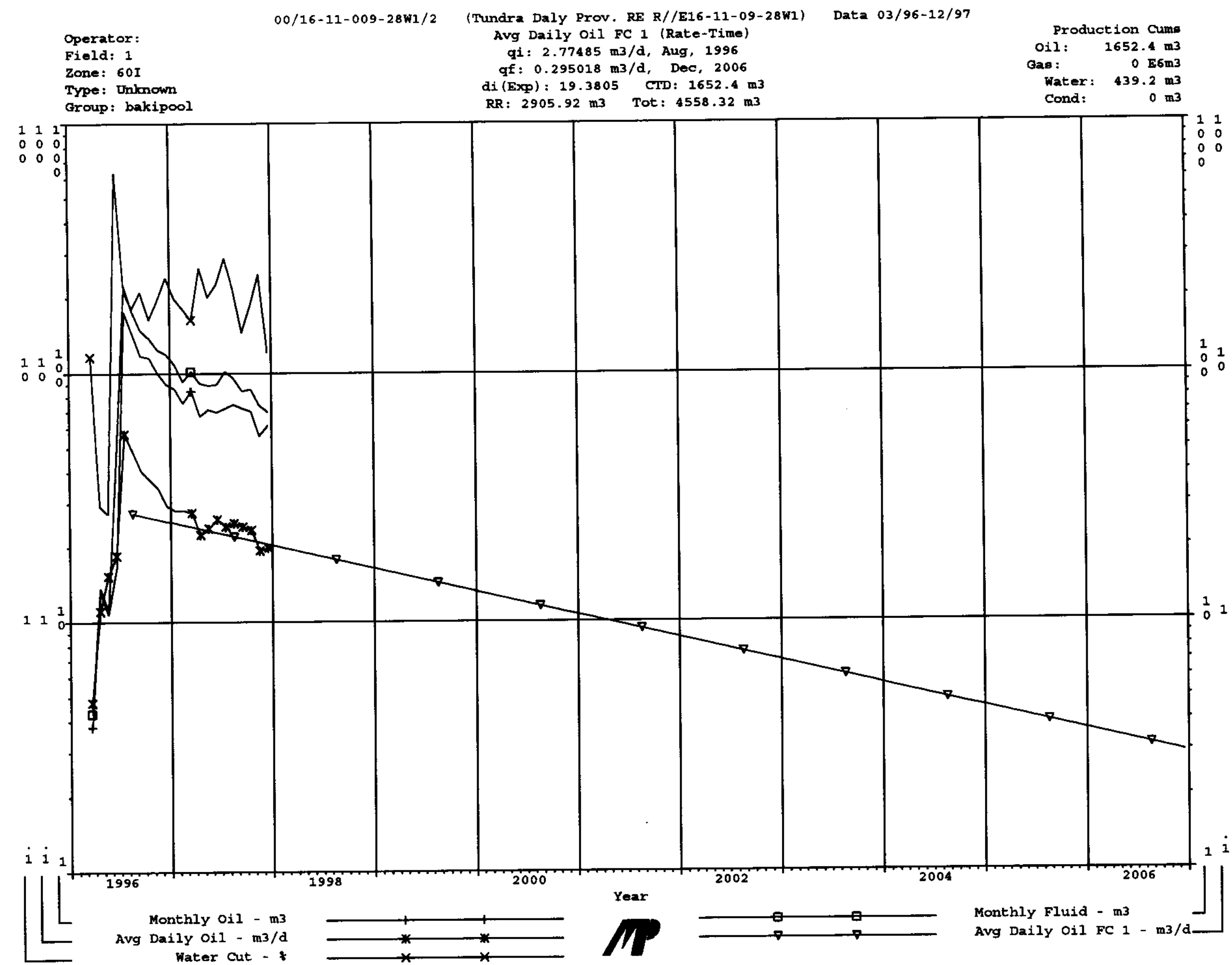
COMPOSITE LOG

TUNDRA 11-14-09-28

INDUCTION LOG / CNL-DENSITY LOG

ATTACHMENT NO. 3

INDIVIDUAL WELL RECOVERY PREDICTIONS



Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool
00/16-11-009-28W1/2 (Tundra Daly Prov. RE R//E16-11-09-28W1) Data 03/96-12/97
Avg Daily Oil FC 1 (Rate-Time)
qi: 2.77485 m3/d, Aug, 1996
qf: 0.295018 m3/d, Dec, 2006
di(Exp): 19.3805 CTD: 1652.4 m3
RR: 2905.92 m3 Tot: 4558.32 m3
Production Cums
Oil: 1652.4 m3
Gas: 0 E6m3
Water: 439.2 m3
Cond: 0 m3
1996
1998
2000
2002
2004
2006
Year
Monthly Oil - m3
Avg Daily Oil - m3/d
Water Cut - %
Monthly Fluid - m3
Avg Daily Oil FC 1 - m3/d

00/12-12-009-28W1/2 (Tundra Daly Prov. RE R//E12-12-09-28W1) Data 08/97-12/97

Avg Daily Oil FC 1 (Rate-Time)

qi: 2.02662 m3/d, Oct, 1997

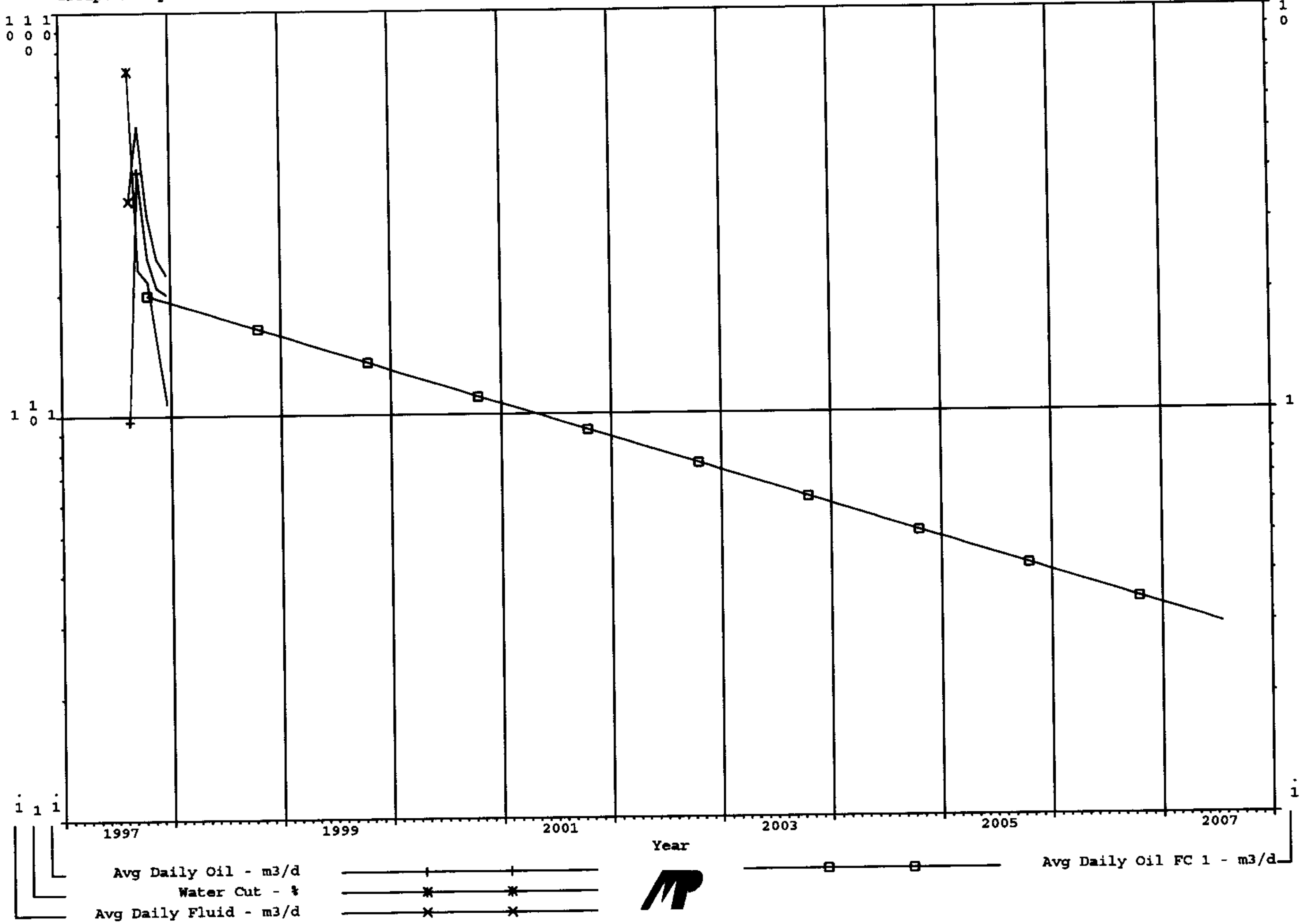
qf: 0.296339 m3/d, Jul, 2007

di(Exp): 17.7594 CTD: 285.6 m3

RR: 2992.97 m3 Tot: 3278.57 m3

Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool

Production Cums
Oil: 285.6 m3
Gas: 0 E6m3
Water: 87.1 m3
Cond: 0 m3

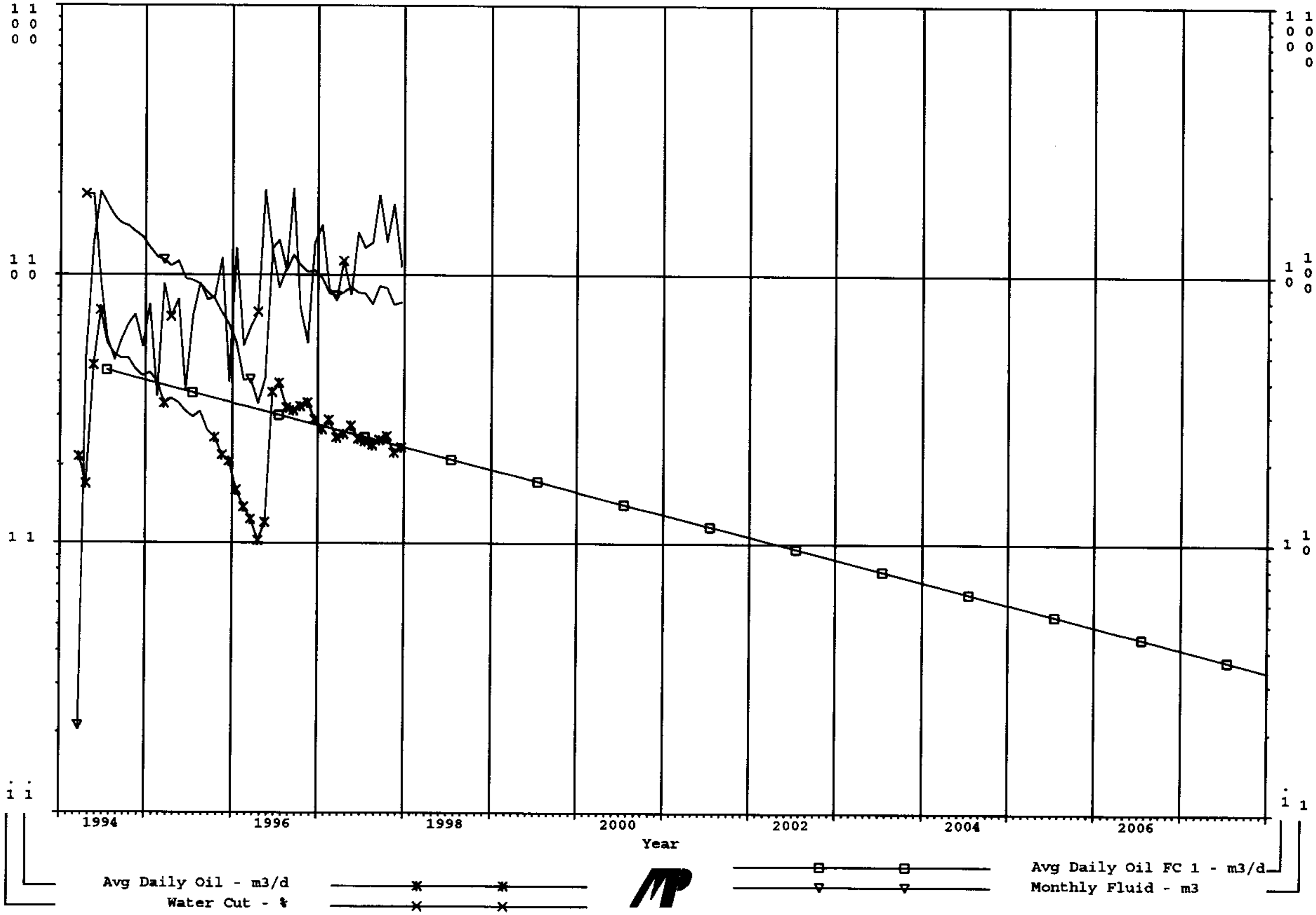


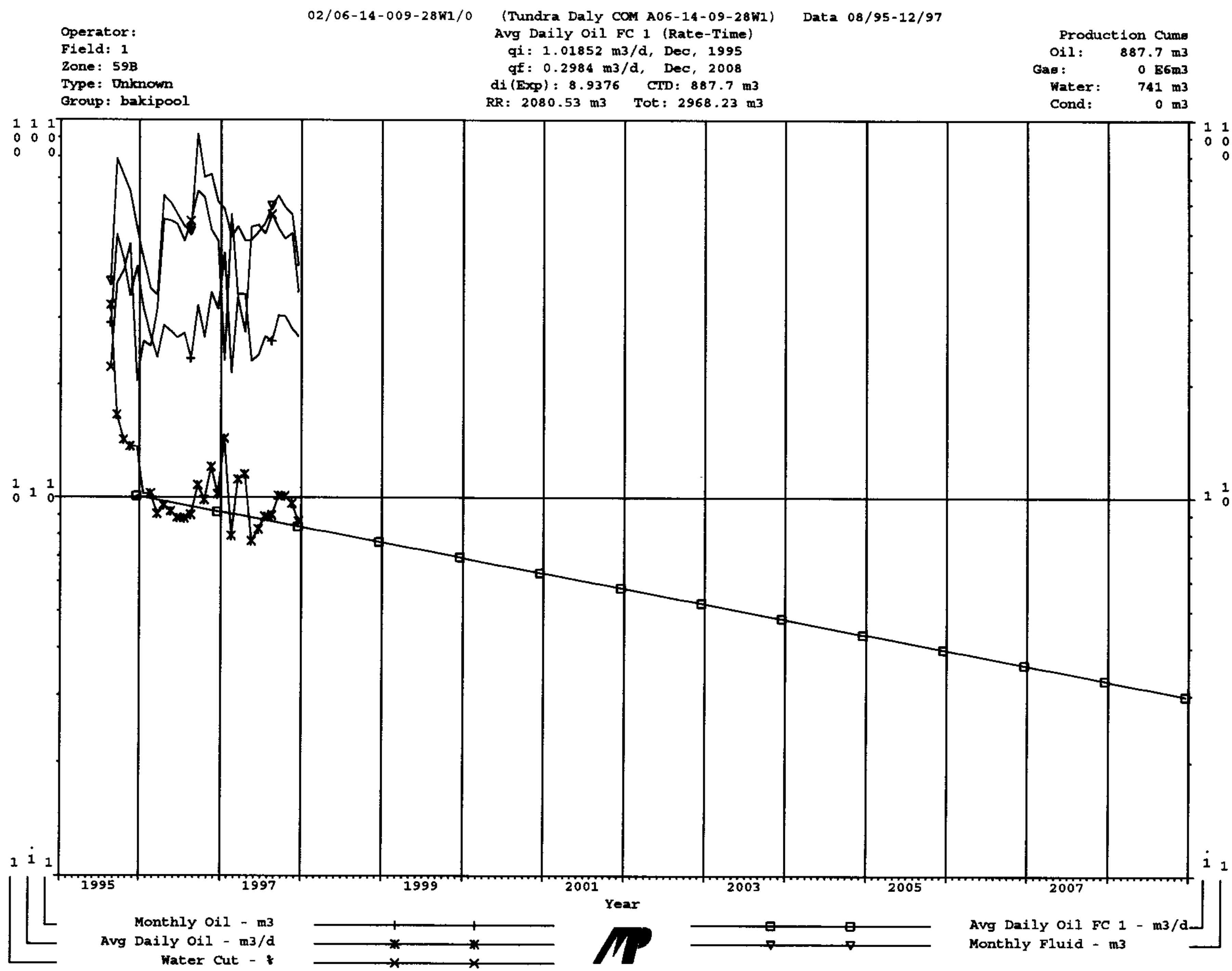
00/02-14-009-28W1/2 (Tundra Daly Prov. R//E02-14-09-28W1) Data 03/94-12/97

Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool

Avg Daily Oil FC 1 (Rate-Time)
qi: 4.46069 m3/d, Jul, 1994
qf: 0.29541 m3/d, Sep, 2008
di(Exp): 17.33 CTD: 4077.7 m3
RR: 3693.65 m3 Tot: 7771.35 m3

Production Cums
Oil: 4077.7 m3
Gas: 0 E6m3
Water: 440.1 m3
Cond: 0 m3





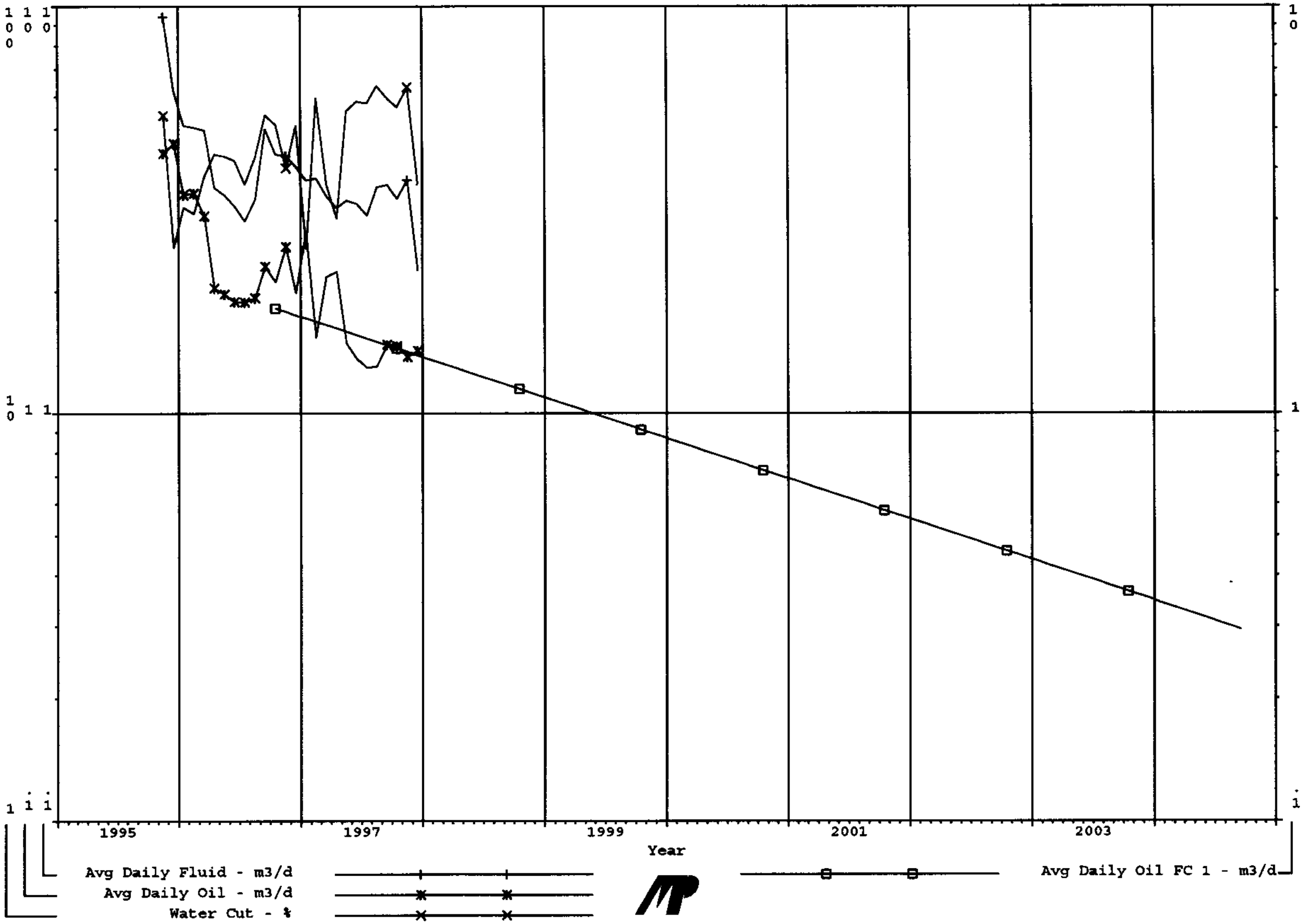
02/06-14-009-28W1/0
(Tundra Daly COM A06-14-09-28W1)
Data 08/95-12/97
Operator:
Field: 1
Zone: 59B
Type: Unknown
Group: bakipool
Avg Daily Oil FC 1 (Rate-Time)
qi: 1.01852 m3/d, Dec, 1995
qf: 0.2984 m3/d, Dec, 2008
di(Exp): 8.9376 CTD: 887.7 m3
RR: 2080.53 m3 Tot: 2968.23 m3
Production Cums
Oil: 887.7 m3
Gas: 0 E6m3
Water: 741 m3
Cond: 0 m3
1995
1997
1999
2001
2003
2005
2007
Year
Monthly Oil - m3
Avg Daily Oil - m3/d
Water Cut - %
Avg Daily Oil FC 1 - m3/d
Monthly Fluid - m3

02/06-14-009-28W1/2 (Tundra Daly COM A06-14-09-28W1) Data 11/95-12/97

Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool

Avg Daily Oil FC 1 (Rate-Time)
qi: 1.84898 m3/d, Oct, 1996
qf: 0.294454 m3/d, Sep, 2004
di(Exp): 20.5195 CTD: 1597.3 m3
RR: 1674.64 m3 Tot: 3271.94 m3

Production Cums
Oil: 1597.3 m3
Gas: 0 E6m3
Water: 1296.2 m3
Cond: 0 m3

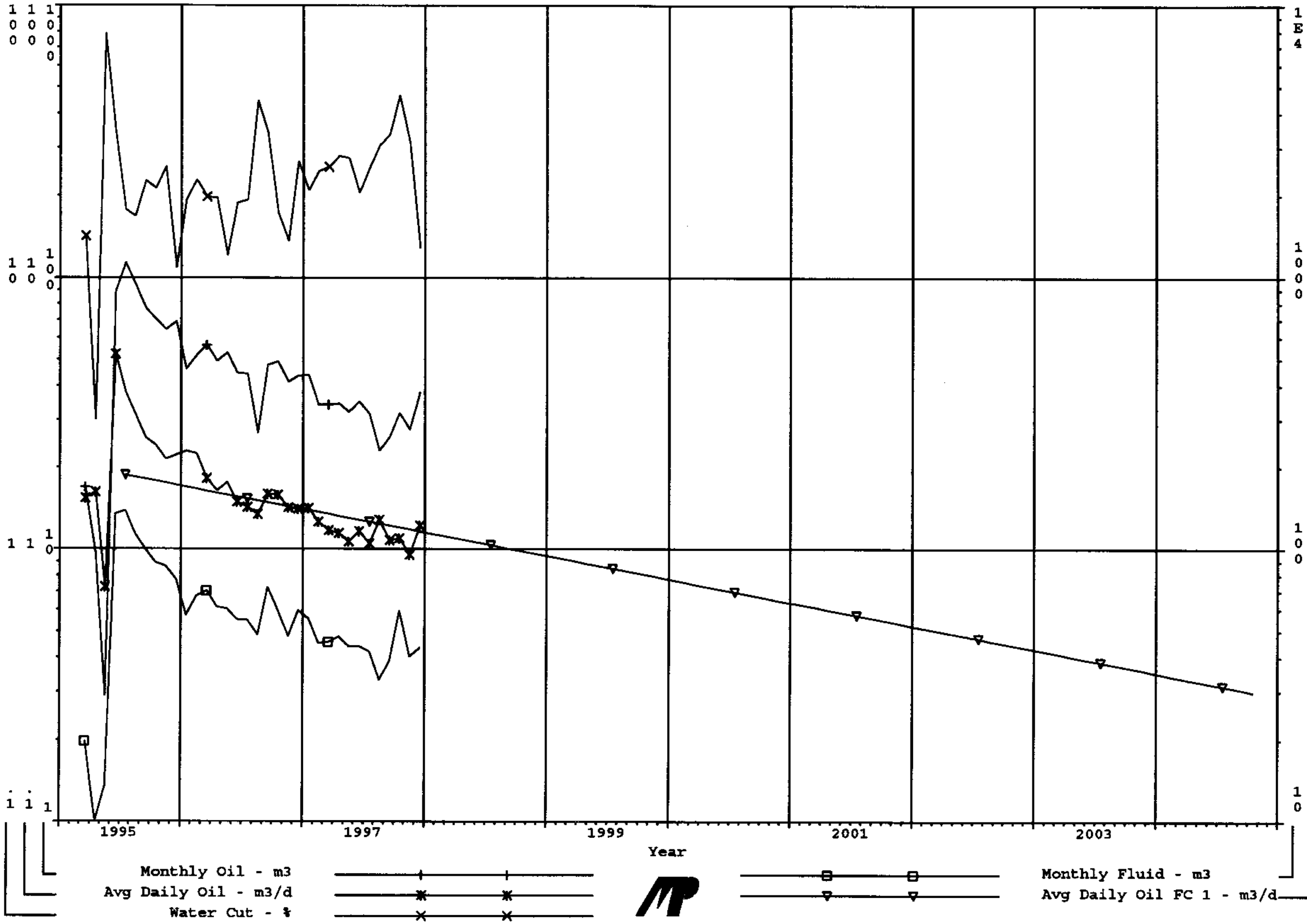


00/10-14-009-28W1/0 (Tundra et al Daly Prov. COM 10-14-09-28W1) Data 03/95-12/97

Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool

Avg Daily Oil FC 1 (Rate-Time)
qi: 1.90057 m3/d, Jul, 1995
qf: 0.298591 m3/d, Oct, 2004
di(Exp): 17.9639 CTD: 1550.3 m3
RR: 1474.8 m3 Tot: 3025.1 m3

Production Cums
Oil: 1550.3 m3
Gas: 0 E6m3
Water: 482.6 m3
Cond: 0 m3

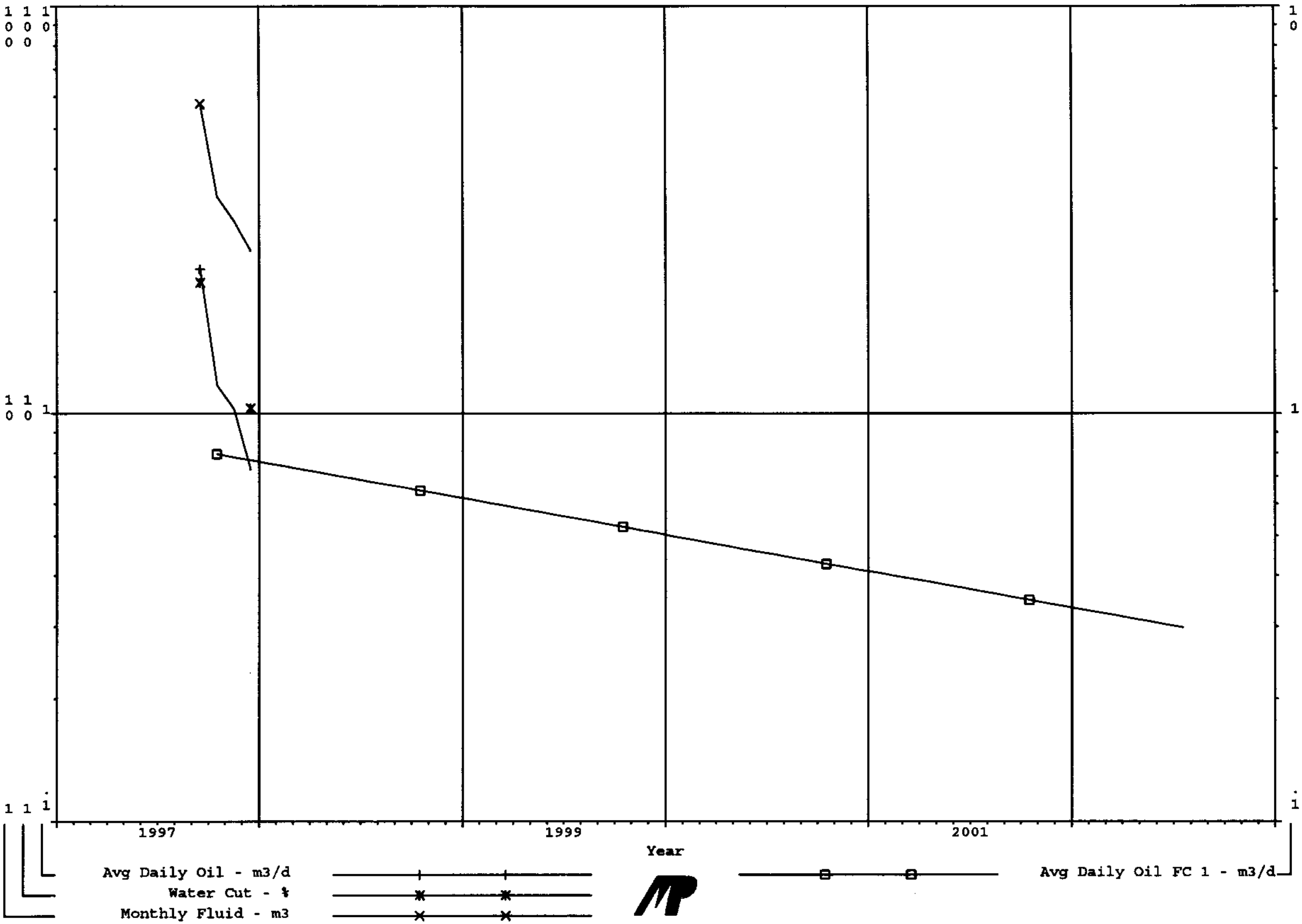


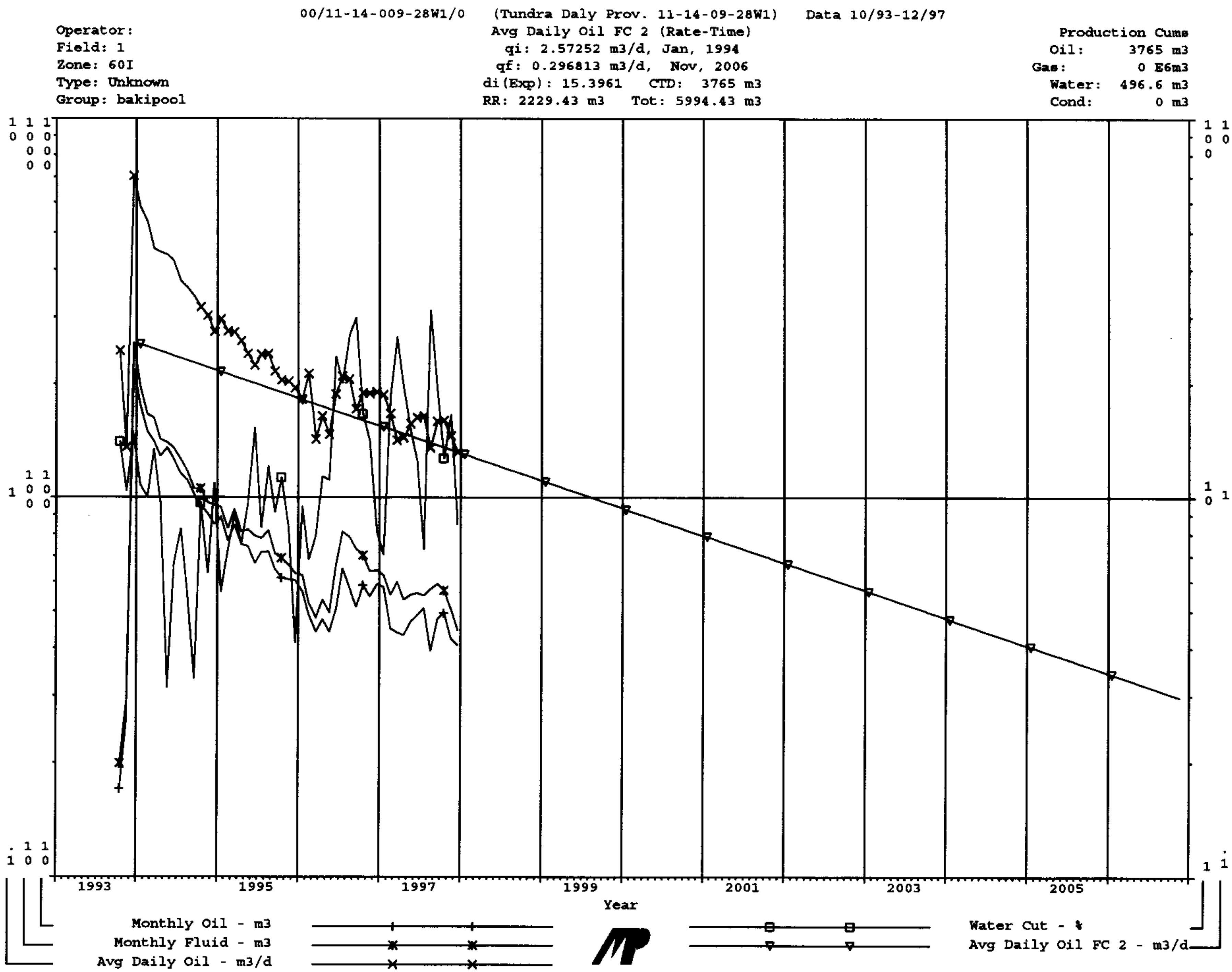
00/10-14-009-28W1/2 (Tundra et al Daly Prov. COM 10-14-09-28W1) Data 09/97-12/97

Operator:
Field: 1
Zone: 59B
Type: Unknown
Group: bakipool

Avg Daily Oil FC 1 (Rate-Time)
qi: 0.808966 m3/d, Oct, 1997
qf: 0.298171 m3/d, Jul, 2002
di(Exp): 18.6575 CTD: 131.9 m3
RR: 817.352 m3 Tot: 949.252 m3

Production Cums	
Oil:	131.9 m3
Gas:	0 E6m3
Water:	14.7 m3
Cond:	0 m3





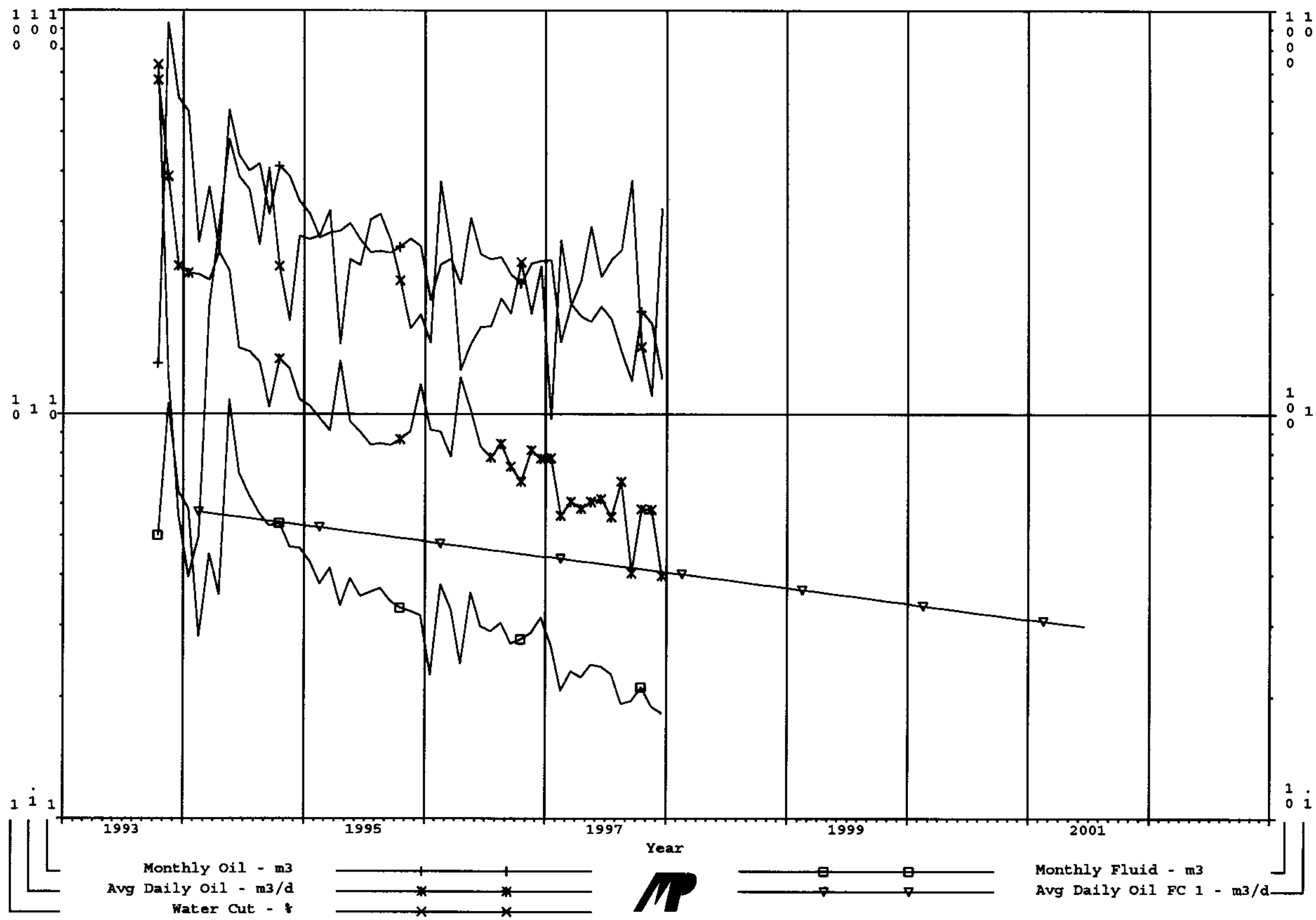
00/11-14-009-28W1/0
(Tundra Daly Prov. 11-14-09-28W1)
Data 10/93-12/97
Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool
Avg Daily Oil FC 2 (Rate-Time)
qi: 2.57252 m3/d, Jan, 1994
qf: 0.296813 m3/d, Nov, 2006
di(Exp): 15.3961 CTD: 3765 m3
RR: 2229.43 m3 Tot: 5994.43 m3
Production Cums
Oil: 3765 m3
Gas: 0 E6m3
Water: 496.6 m3
Cond: 0 m3
1993
1995
1997
1999
2001
2003
2005
Year
Monthly Oil - m3
Monthly Fluid - m3
Avg Daily Oil - m3/d
Water Cut - %
Avg Daily Oil FC 2 - m3/d

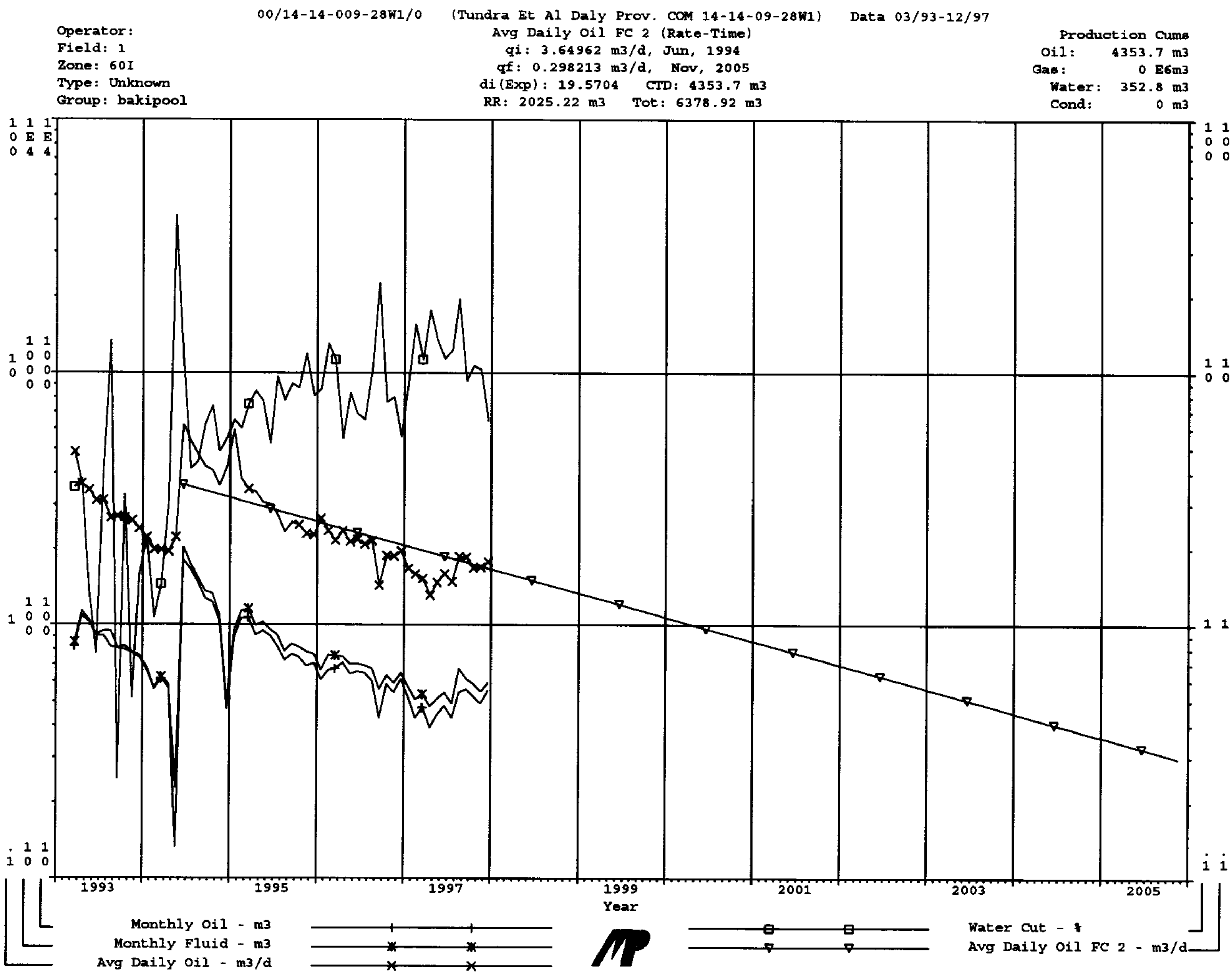
00/13-14-009-28W1/3 (Tundra Daly Prov. R//E13-14-09-28W1) Data 10/93-12/97

Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool

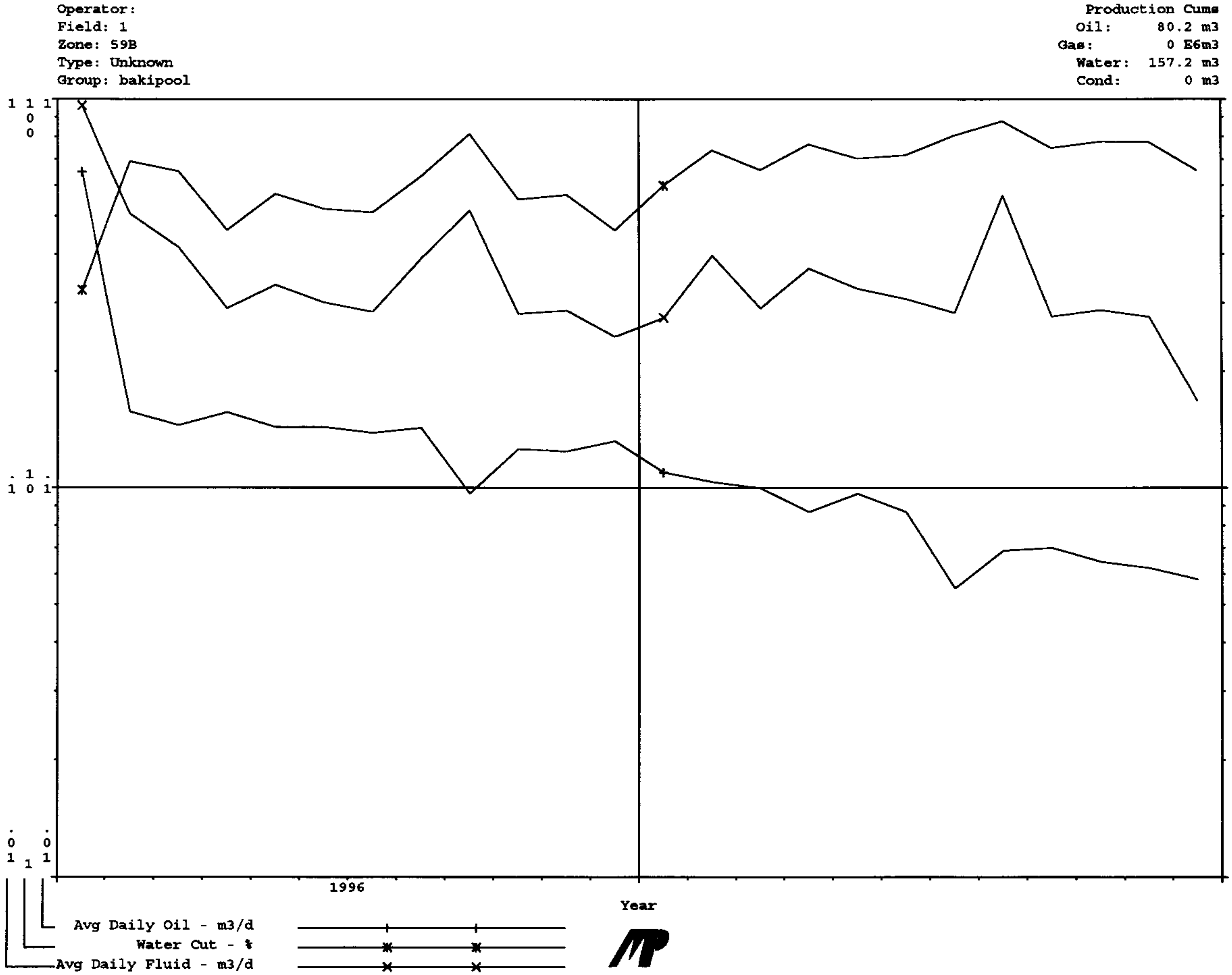
Avg Daily Oil FC 1 (Rate-Time)
qi: 0.575904 m3/d, Feb, 1994
qf: 0.298196 m3/d, Jun, 2001
di(Exp): 8.49212 CTD: 1451 m3
RR: 390.315 m3 Tot: 1841.32 m3

Production Cums
Oil: 1451 m3
Gas: 0 E6m3
Water: 489.1 m3
Cond: 0 m3




00/14-14-009-28W1/0 (Tundra Et Al Daly Prov. COM 14-14-09-28W1) Data 03/93-12/97
Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool
Avg Daily Oil FC 2 (Rate-Time)
qi: 3.64962 m3/d, Jun, 1994
qf: 0.298213 m3/d, Nov, 2005
di(Exp): 19.5704 CTD: 4353.7 m3
RR: 2025.22 m3 Tot: 6378.92 m3
Production Cums
Oil: 4353.7 m3
Gas: 0 E6m3
Water: 352.8 m3
Cond: 0 m3
1993
1995
1997
1999
2001
2003
2005
Year
Monthly Oil - m3
Monthly Fluid - m3
Avg Daily Oil - m3/d
Water Cut - %
Avg Daily Oil FC 2 - m3/d

00/14-14-009-28W1/2 (Tundra Et Al Daly Prov. COM 14-14-09-28W1) Data 01/96-12/97

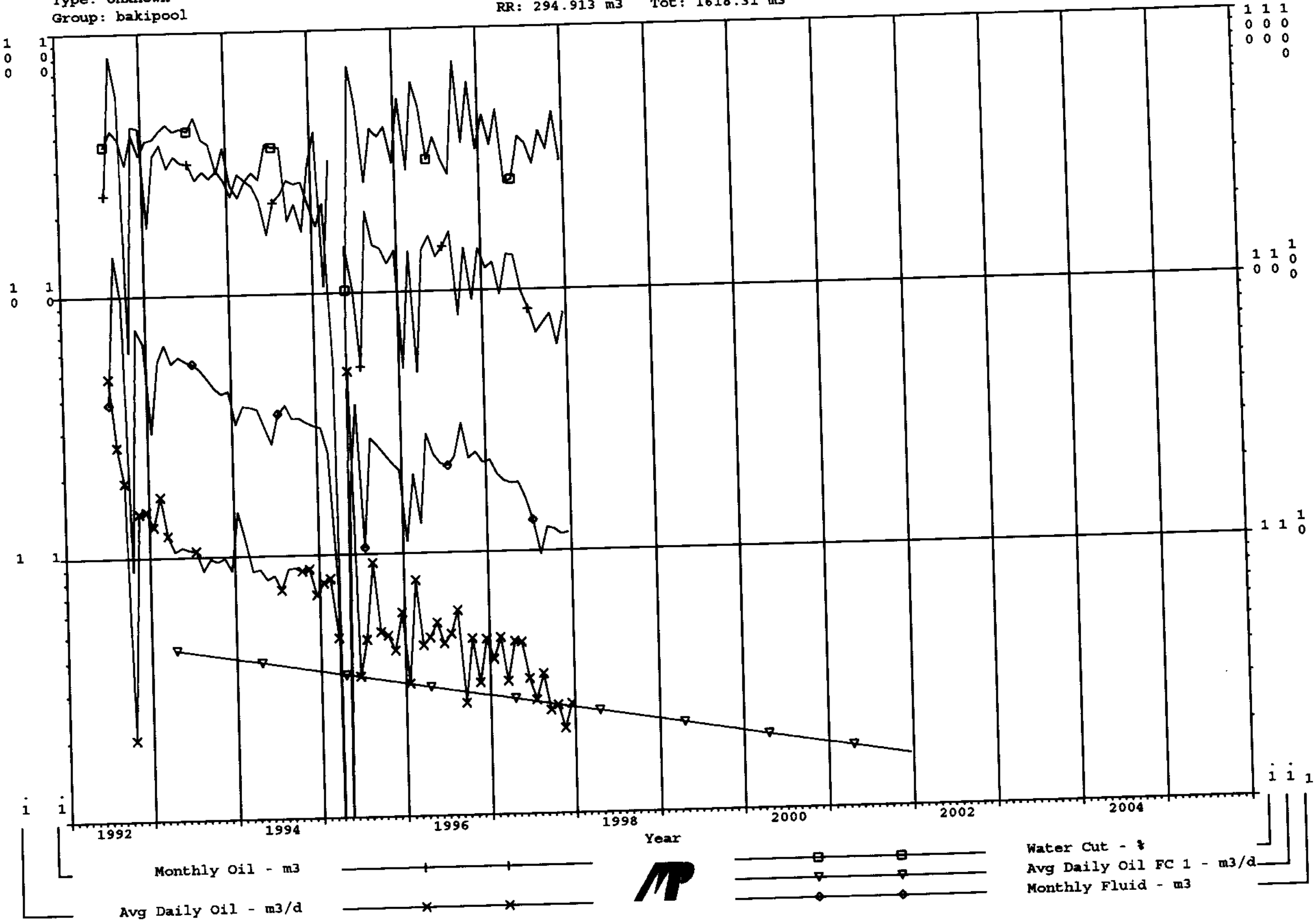


00/02-23-009-28W1/2 (Tundra Et Al Daly COM 02-23-09-28W1) Data 07/92-12/97

Avg Daily Oil FC 1 (Rate-Time)
qi: 0.446871 m3/d, Apr, 1993
qf: 0.15771 m3/d, Dec, 2001
di(Exp): 11.2219 CTD: 1323.4 m3
RR: 294.913 m3 Tot: 1618.31 m3

Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool

Production Cums
Oil: 1323.4 m3
Gas: 0 E6m3
Water: 802.8 m3
Cond: 0 m3

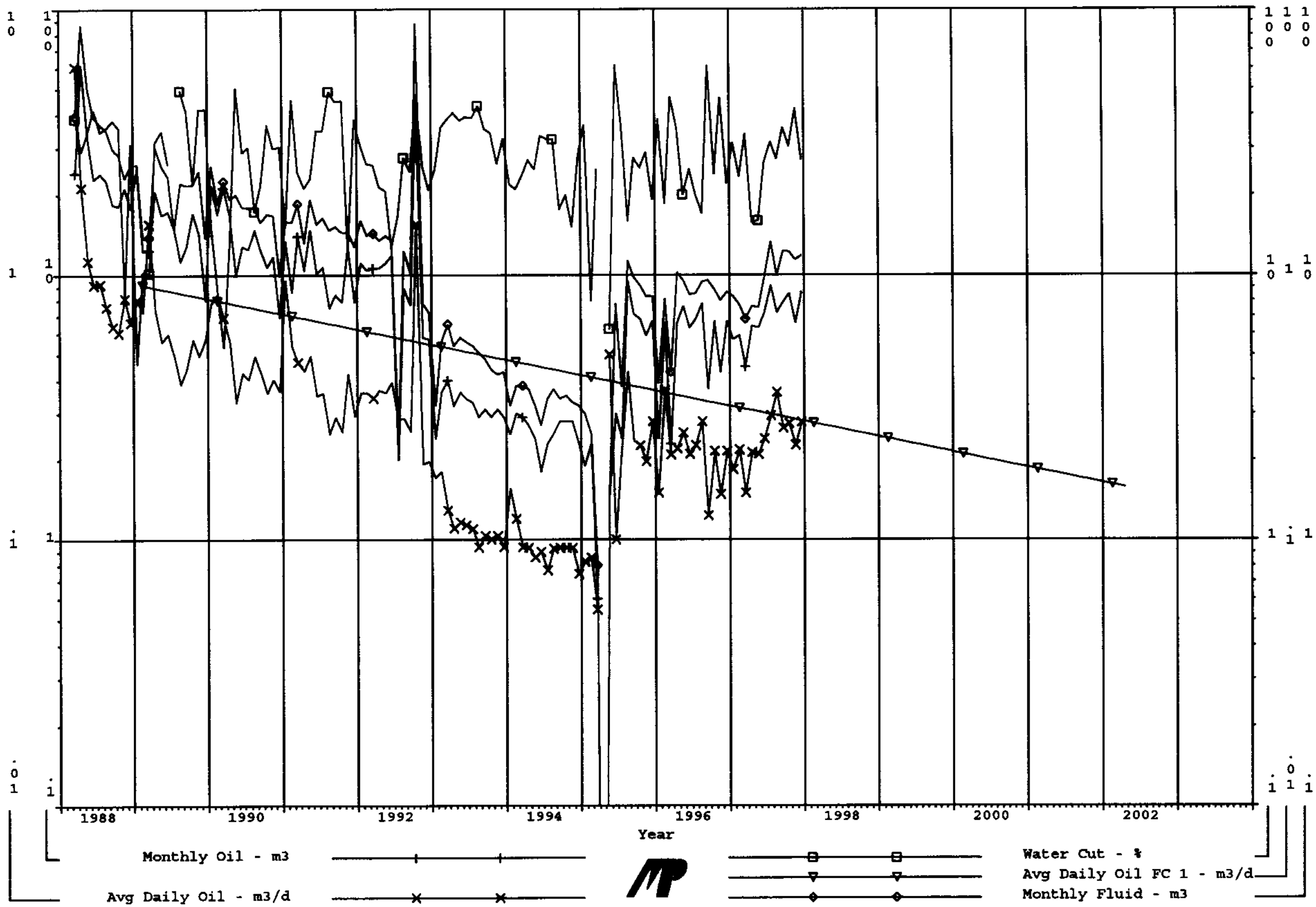


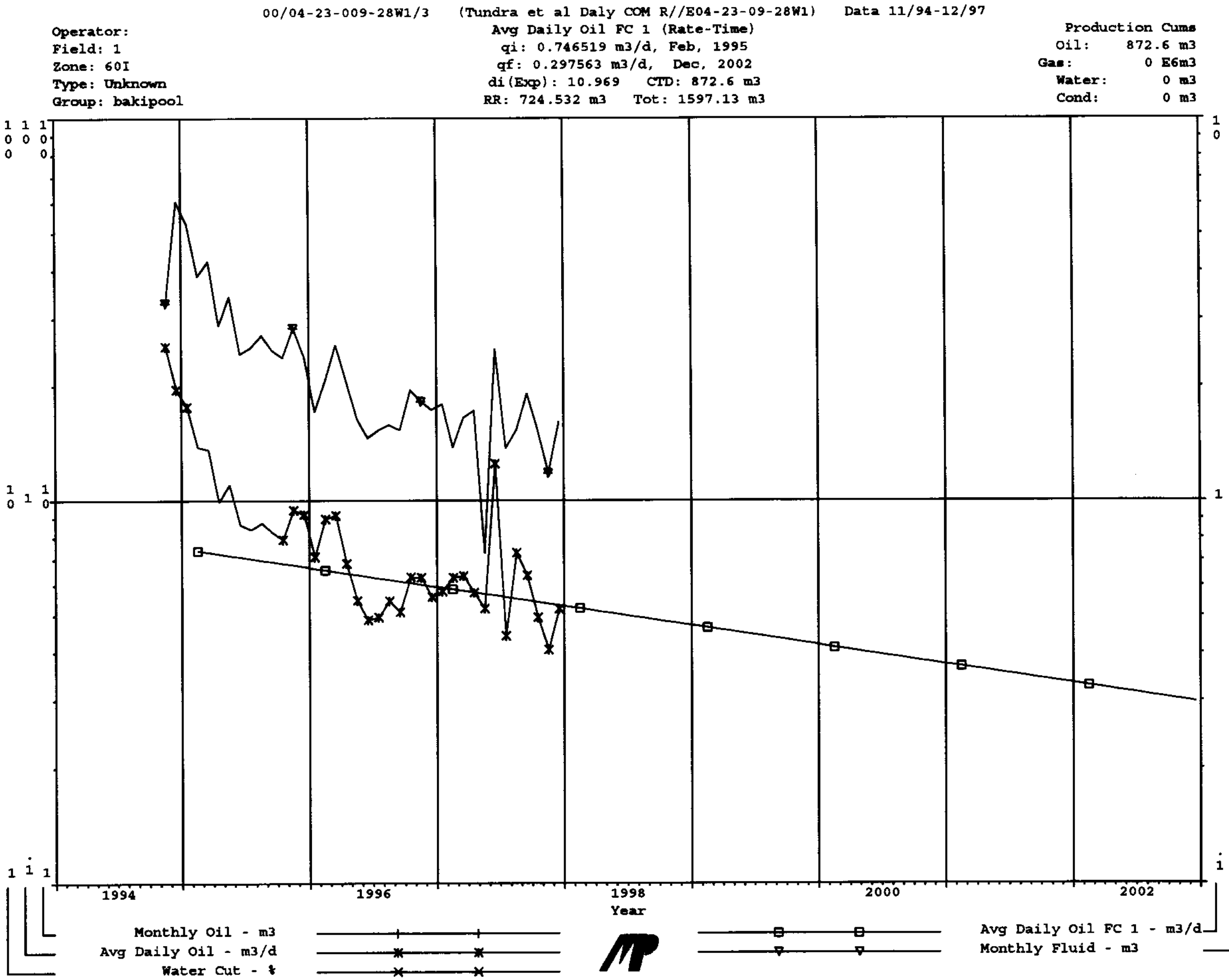
00/02-23-009-28W1/0 (Tundra Et Al Daly COM 02-23-09-28W1) Data 03/88-12/97

Operator:
Field: 1
Zone: 59B
Type: Unknown
Group: bakipool

Avg Daily Oil FC 1 (Rate-Time)
qi: 0.923968 m3/d, Feb, 1989
qf: 0.157995 m3/d, Apr, 2002
di(Exp): 12.4791 CTD: 1151.5 m3
RR: 289.01 m3 Tot: 1440.51 m3

Production Cums
Oil: 1151.5 m3
Gas: 0 E6m3
Water: 495.9 m3
Cond: 0 m3





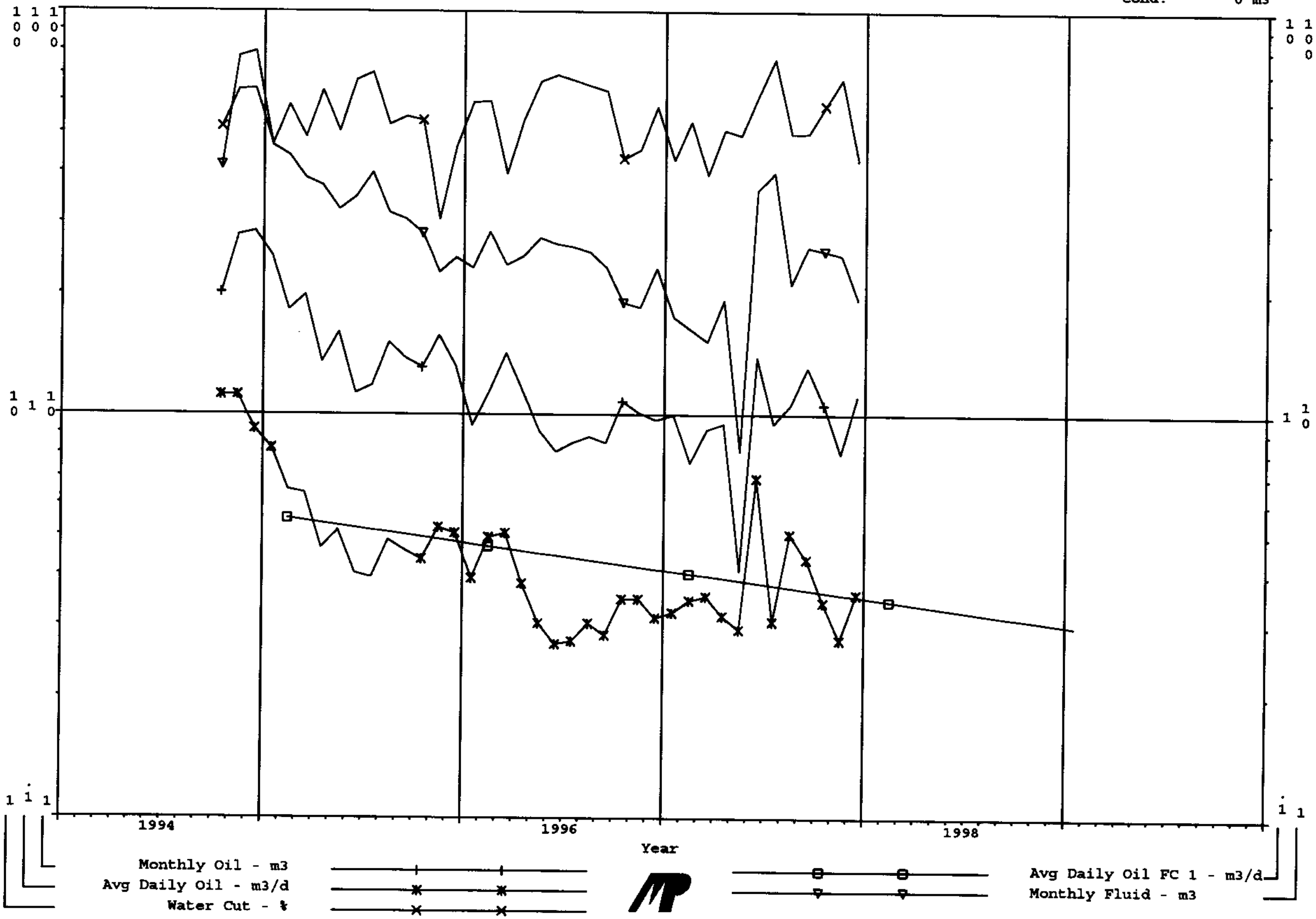
00/04-23-009-28W1/3 (Tundra et al Daly COM R//E04-23-09-28W1) Data 11/94-12/97
Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool
Avg Daily Oil FC 1 (Rate-Time)
qi: 0.746519 m3/d, Feb, 1995
qf: 0.297563 m3/d, Dec, 2002
di(Exp): 10.969 CTD: 872.6 m3
RR: 724.532 m3 Tot: 1597.13 m3
Production Cums
Oil: 872.6 m3
Gas: 0 E6m3
Water: 0 m3
Cond: 0 m3
1994
1996
1998
2000
2002
Year
Monthly Oil - m3
Avg Daily Oil - m3/d
Water Cut - %
Avg Daily Oil FC 1 - m3/d
Monthly Fluid - m3

00/04-23-009-28W1/2 (Tundra et al Daly COM R//E04-23-09-28W1) Data 10/94-12/97

Operator:
Field: 1
Zone: 59B
Type: Unknown
Group: bakipool

Avg Daily Oil FC 1 (Rate-Time)
qi: 0.558158 m3/d, Feb, 1995
qf: 0.298303 m3/d, Jan, 1999
di(Exp): 14.4984 CTD: 499.9 m3
RR: 126.537 m3 Tot: 626.437 m3

Production Cums
Oil: 499.9 m3
Gas: 0 E6m3
Water: 666.2 m3
Cond: 0 m3

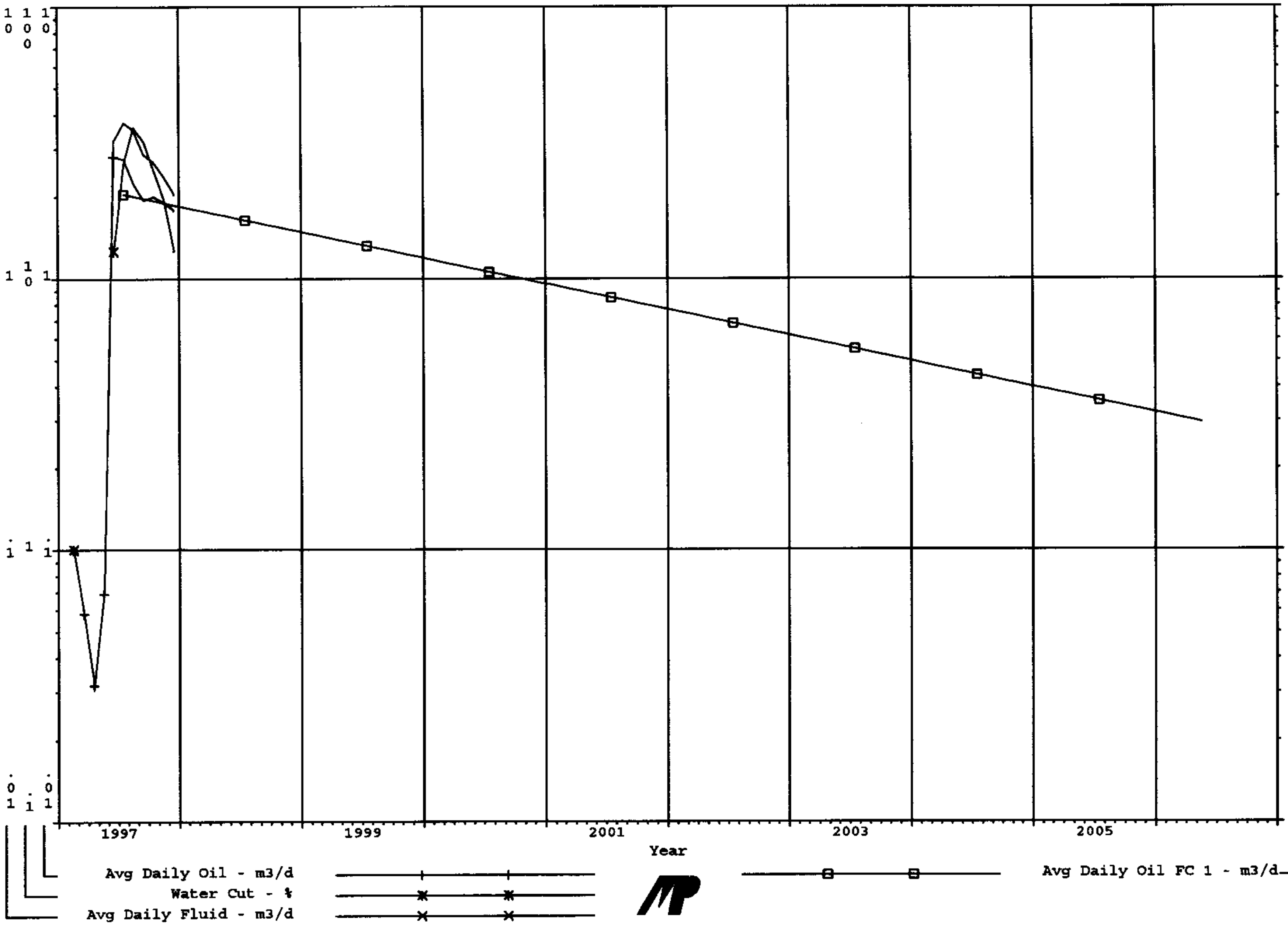


00/06-23-009-28W1/2 (Tundra Daly COM 06-23-09-28W1) Data 02/97-12/97

Operator:
Field: 1
Zone: 60I
Type: Unknown
Group: bakipool

Avg Daily Oil FC 1 (Rate-Time)
qi: 2.08317 m3/d, Jul, 1997
qf: 0.295283 m3/d, May, 2006
di(Exp): 19.6765 CTD: 460.3 m3
RR: 2573.02 m3 Tot: 3033.32 m3

Production Cums
Oil: 460.3 m3
Gas: 0 E6m3
Water: 147.7 m3
Cond: 0 m3



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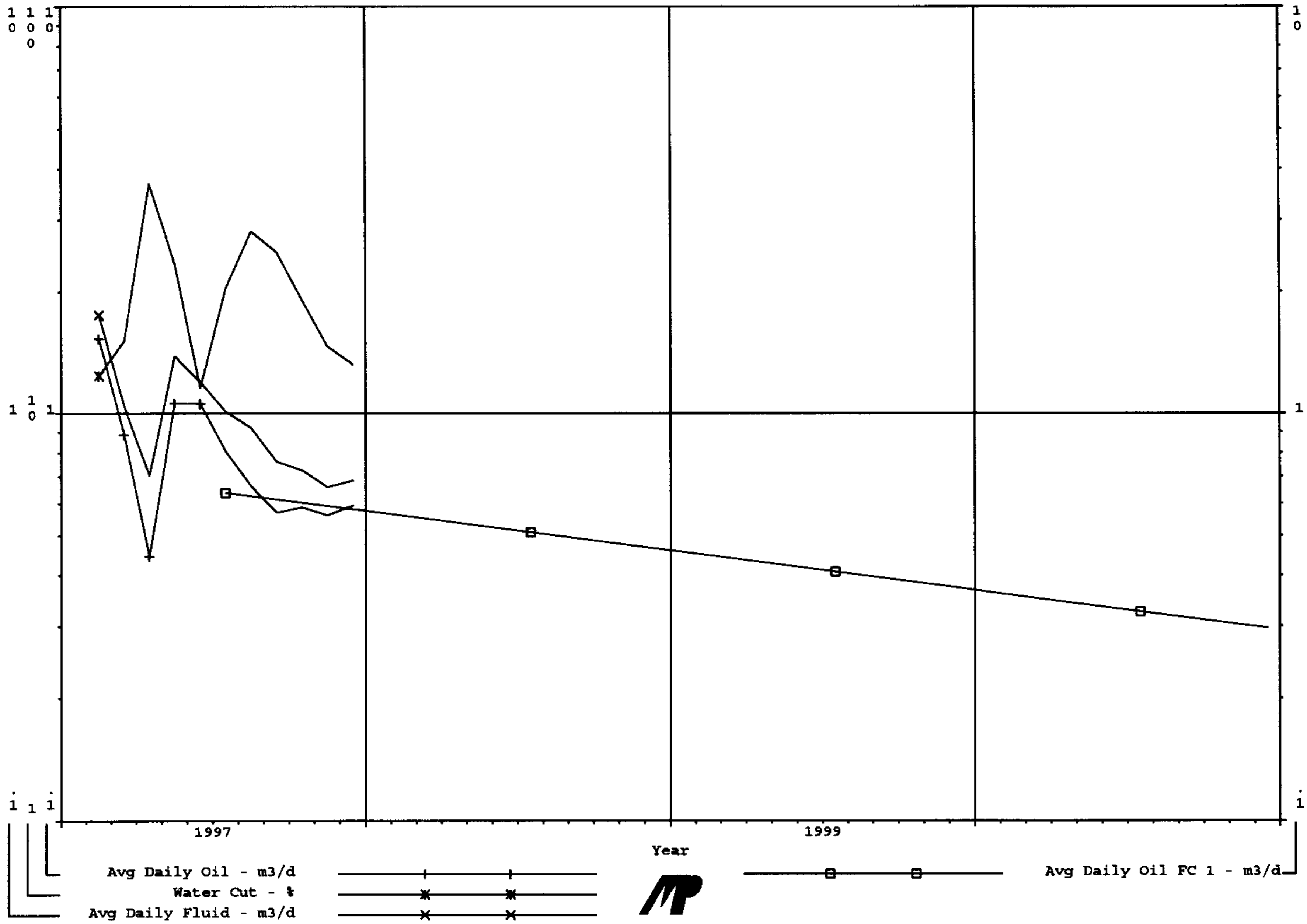
Operator:
Field: 1
Zone: 59B
Type: Unknown
Group: bakipool

Avg Daily Oil FC 1 (Rate-Time)
qi: 0.649754 m3/d, Jul, 1997
qf: 0.296431 m3/d, Dec, 2000
di(Exp): 20.0238 CTD: 232.7 m3
RR: 455.551 m3 Tot: 688.251 m3

Production Cums
Oil: 232.7 m3
Gas: 0 E6m3
Water: 54.1 m3
Cond: 0 m3

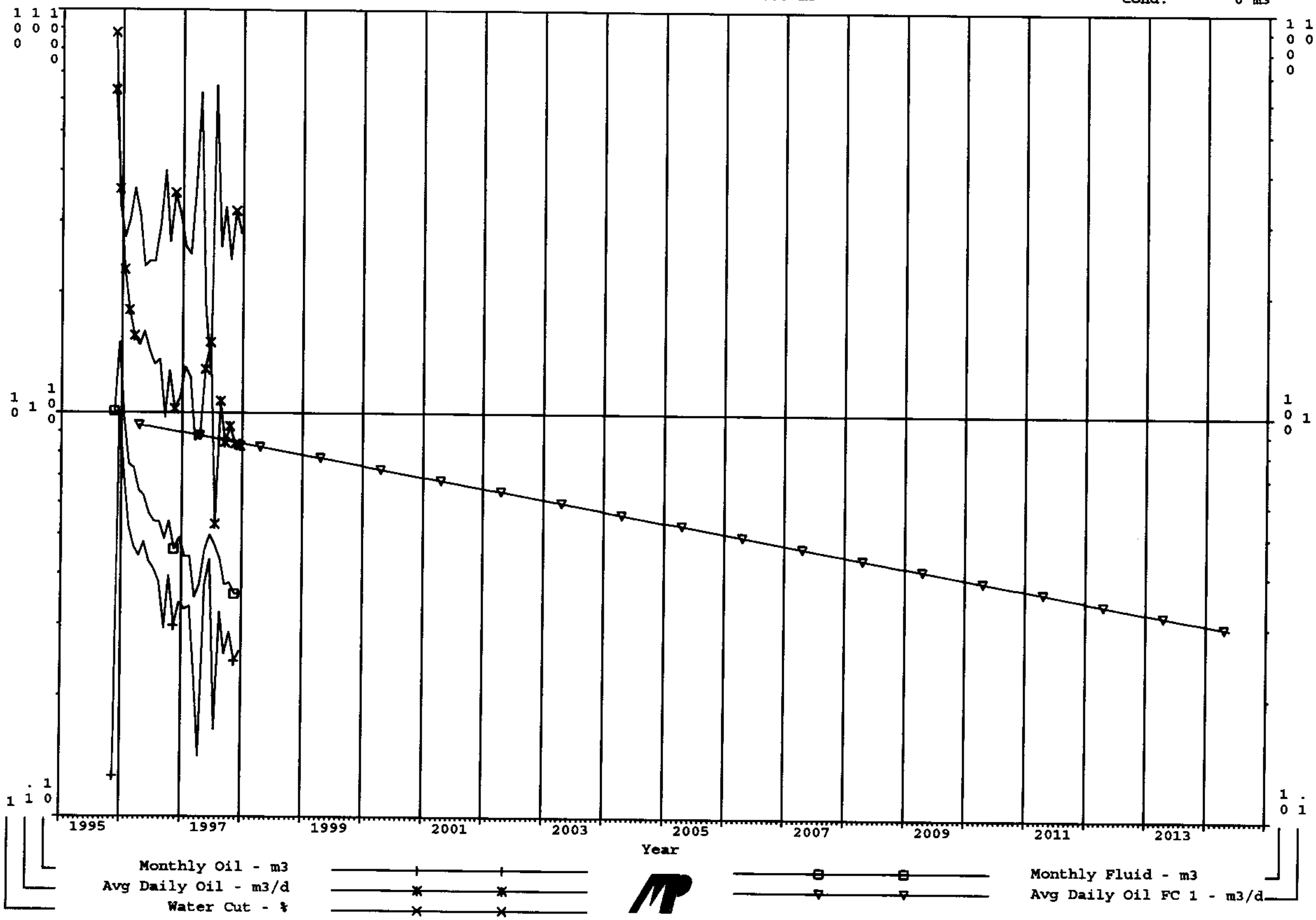


02/16-30-009-28W1/2 (Tundra Daly Prov. RE R//E16A-30-09-28W1) Data 11/95-12/97

Operator:
Field: 1
Zone: 60V
Type: Unknown
Group: bakipool

Avg Daily Oil FC 1 (Rate-Time)
qi: 0.937803 m3/d, Apr, 1996
qf: 0.298983 m3/d, May, 2014
di(Exp): 6.11283 CTD: 963.5 m3
RR: 2921.86 m3 Tot: 3885.36 m3

Production Cums
Oil: 963.5 m3
Gas: 0 E6m3
Water: 510.7 m3
Cond: 0 m3



ATTACHMENT NO.4

COMPLETION PROGRAM FOR INJECTOR 11-14-9-28 WPM

TUNDRA
OIL AND GAS LTD.

CONVERSION PROGRAM

TUNDRA DALY PROV 11-14-9-28 W1

KB-GL 4.17 M
219.1 csg @ 124.0 m
139.7 csg @ 865.0 m
PBTD 860.0 m
PERFS 839.0 - 843.0 Bakken
tubing landed at 846.95 m
pump LTV 1186 20-150-RWAC-10-3
rods 91-19mm plain, 16-19mm scrapered

1. Notify the local Department of Energy and Mines office at 748-1557 to inform them of the conversion.
2. Move in service rig complete with pump and tank and rig up. Review program with all rig crew members and ensure all applicable OH&S and E&M regulations are followed. Install and test rig anchors.
3. Pressure test tubing with produced water to 7000 kPa.
4. Pull out of hole and lay down pump and rods. (hot water if necessary to clean tubing and rods)
5. Install and pressure test BOP'S.
6. Tag plug back to check for fill and circulate clean if necessary. (conduct a feedrate with clean salt water, acidize with 1.0 m3 15% HCL if necessary)
7. Pull out of hole and lay down tubing. (Mark and discard tail joint)
8. Tally, visually inspect and run in the hole with the following:

    1-39.7 mm coated AD-1 tension packer
    1-coated ball seat nipple
    ~ 835 m - 60.3 mm internally coated TK-99 tubing
    1- teflon impregnated cross-over
    1- 14 MPa stainless ball valve

9. Land packer at approximately 835.0 mKB.
10. Reverse circulate the annulus over to fresh water containing .5 % packer/wellbore inhibitor. (50 l CRW0132 in 10.0 m3 fresh water)
11. Set packer in 5000 daN tension. Change out dognut for slips.
12. Pressure test annulus to 3500 kPa. Top off with diesel to prevent freezing.
13. Rig out and release service rig.

prepared by:
Jed Sanderson
Area Technologist
98/1/15
11-14CON.WPS

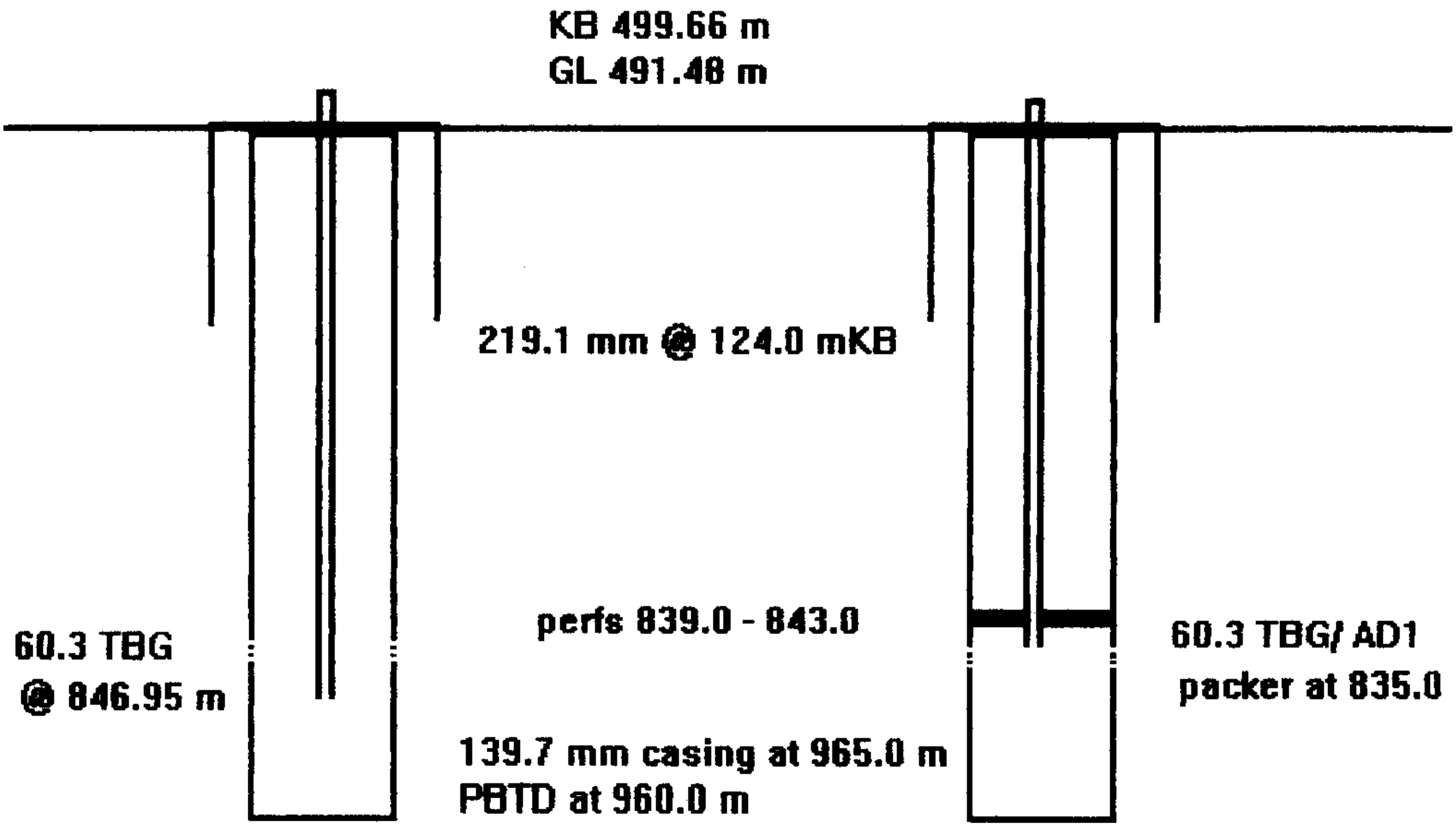
Tundra
oil and gas ltd.

Tundra Daly Prov. 11-14-9-28 w1

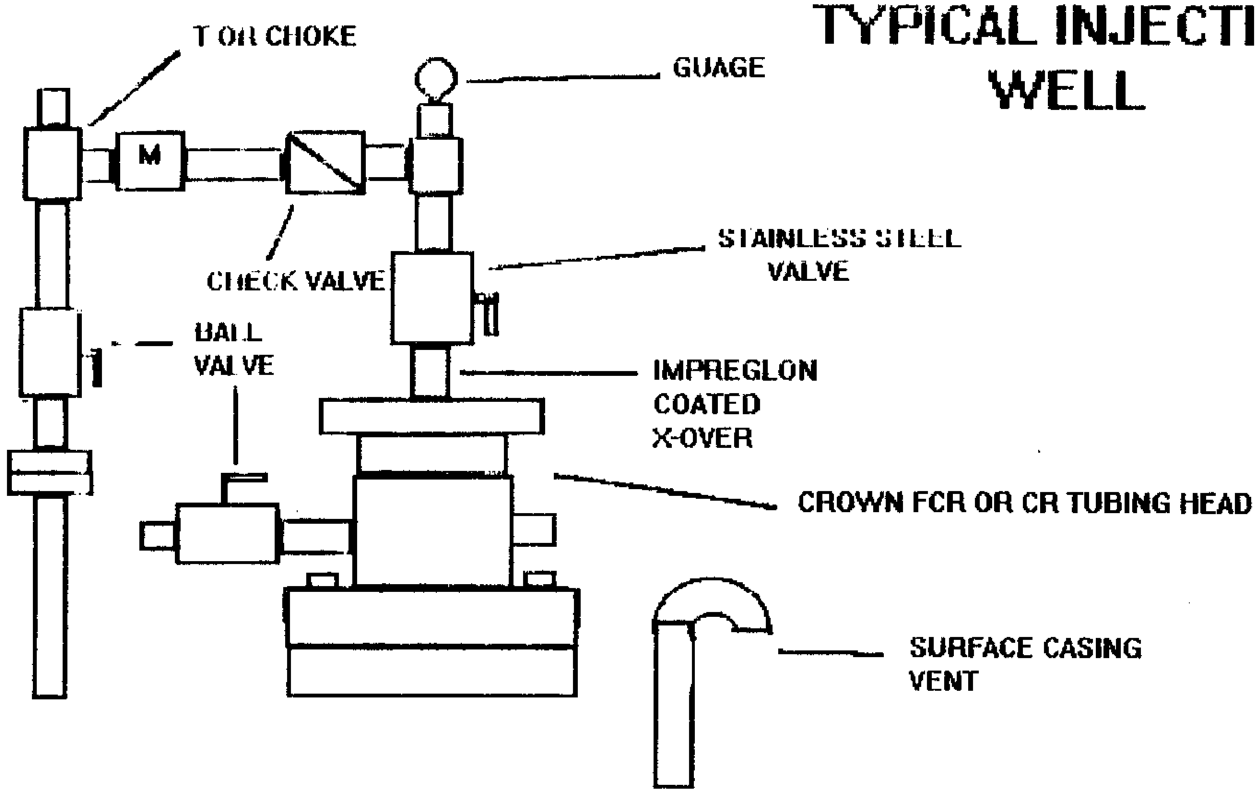
WELLBORE SCHEMATIC

EXISTING / PROPOSED

FOR SALT WATER INJECTION



TYPICAL INJECTION WELL



All equipment will be rated for 14 MPa.

ATTACHMENT NO.5

APPLICATION TO CONVERT 11-14-9-28 TO WATER INJECTION SERVICE

Manitoba

Energy and Mines **Petroleum**

APPLICATION FOR APPROVAL OF WELL OPERATIONS

In compliance with Section 47 of the Drilling and Production Regulation, application is hereby made for approval of the following operations:

PROPOSED WELL OPERATIONS (please check):

Suspend ___ Recomplete in another zone ___ Deepen ___ Remove Casing ___ Abandon ___

Convert to: Salt Water Disposal ___ Water Injection X

Other ______

Well name TUNDRA DALY PROV. 11-14-9-28 Licence No. 4386

Name of Licensee Tundra Oil and Gas Ltd.

Address of Licensee Box 1960, Virden, Manitoba ROM 2CO

Company Representative Jed Sanderson (204) 748-3095 *(telephone)* 748-1007 *(fax)*

GENERAL WELL INFORMATION

	Size (mm)	Weight (kg/m)	Depth (m)	Cemented to surface (yes or no)
Surface Casing:	219.1	35.72	124.0	Yes
Production Casing:	139.7	20.83	865.0	Yes

Total Depth 865.0 m Plugback Total Depth 860.0 m

Perforations 839 - 843 m ______ m Openhole Interval ______ m

CURRENT WELL STATUS (please check)

Capable of Oil Production X Salt Water Disposal ___ Water Injection ___ Other ___

Suspended ___ Expiry Date ______ (YY MM DD) Shut-in ___ Date Well Shut-in ______ (YY MM DD)

Final Production Rate: Oil: 1.62 m3/day Date of Last Production Test: 97 11 27 (YY MM DD)

Water: .25 m3/day

Reason for Proposed Operations: Well is required for saltwater injection for pressure maintenance.

Planned Commencement Date: 98 / 02 / 15 (YY MM DD)

Program of Proposed Operations:
(Complete below and attach detailed program):

Pull downhole equipment. Run a 139.7 coated packer on 60.3 mm coated tubing. Inhibit annulus with .5% CRW 0132 packer fluid. Set packer in tension at 835.0 mKB. Pressure test annulus to 3.5 Mpa.

98-01-15
(Date)

[signature]
(Signature of applicant)

For assistance in completing this form, contact Dan Surzyshyn, 204-945-8102 or Paulette Seymour, 204-945-6575.

For Department Use Only

ATTACHMENT NO.6

SPECIAL CORE STUDY BAKKEN "I" POOL

Hycal ENERGY RESEARCH LABORATORIES LTD.

TUNDRA - BAKKEN "I" POOL
RELATIVE PERMEABILITY STUDY

Prepared For

Tundra Oil & Gas Ltd.

Prepared By

Hycal Energy Research Laboratories Ltd.

December 9, 1997

97-035A(V)

1338A - 36th Avenue N.E., Calgary, Alberta, Canada T2E 6T6
Telephone (403) 250-5800 Fax: (403) 291-0481

TABLE 1
TUNDRA - BAKKEN I Pool
RELATIVE PERMEABILITY STUDY
ROUTINE CORE ANALYSIS

Sample No.	Depth (m)	Permeability (mD)	Porosity (fraction)	Grain Density (kg/m^3)
Tundra Daly Prov. 10-11-9-28 W1M				
5	853.82	0.33	0.154	2700
Tundra et al Daly 2-23-9-28 W1M				
3A	830.49	15.01	0.154	2750
3B	830.54	0.06	0.136	2750
U-A	Unknown	<0.01	0.141	2690
U-B	Unknown	<0.01	0.145	2680
13	832.69	<0.01	0.160	2660
1A	Unknown	0.25	0.082	2550
1B	Unknown	1.10	0.090	2580

TABLE 2
TUNDRA - BAKKEN I POOL
RELATIVE PERMEABILITY STUDY
CORE #3A - WATER-OIL RELATIVE PERMEABILITY
CORE AND TEST PARAMETERS

Core Stack Number	3A
Depth (m)	830.49
Field Name	Bakken I Pool
Well Location	2-23-9-28 W1M
Stack Length (cm)	6.22
Diameter (cm)	3.75
Effective Flow Area (cm^2)	11.04
Bulk Volume (cm^3)	68.70
Porosity (fraction)	0.154
Pore Volume (cm^3)	10.58
Test Temperature (°C)	34
Water Viscosity @ 34°C (mPa•s)	0.85
Oil Viscosity @ 34°C (mPa•s)	2.50
Displacement Rate (cc/hr)	10
Net Overburden Pressure (kPag)	10730

FIGURES

TABLE 3
TUNDRA - BAKKEN I POOL
RELATIVE PERMEABILITY STUDY
CORE #3A - WATER-OIL RELATIVE PERMEABILITY
SATURATION AND PERMEABILITY SUMMARY

Test Phase	So	Sw	Permeability (mD)	Relative Permeability
Absolute Liquid Permeability	0.000	1.000	14.0	1.000
Initial Oil Permeability (@ Sw_i)	0.550	0.450	6.03	0.431
Final Water Permeability (@ So_r)	0.161	0.839	0.52	0.037
Pore Volume Recovery				38.9%
Hydrocarbon Pore Volume Recovery				70.7%
Absolute permeability is determined by extrapolating the k_{ro} curve to 1.0 at Sw = 0.0				

97-035A

FIGURES

TABLE 4
TUNDRA - BAKKEN I POOL
RELATIVE PERMEABILITY STUDY
CORE #3A - WATER-OIL RELATIVE PERMEABILITY
DIFFERENTIAL PRESSURE & PRODUCTION

Cuml Injection (PV)	Cuml Production (PV)	Pressure (MPa)
0.145	0.145	0.20685
0.242	0.242	0.28959
0.290	0.290	0.31717
0.484	0.347	0.35165
0.967	0.380	0.33416
1.451	0.384	0.32407
2.418	0.389	0.29913
3.385	0.389	0.27406
4.352	0.389	0.25958
5.319	0.389	0.25236
6.286	0.389	0.24496
6.770	0.389	0.24408

TABLE 6
TUNDRA - BAKKEN I POOL
RELATIVE PERMEABILITY STUDY
Kro/Krw AND FORMATION WATER SATURATION DATA

K_{ro}	K_{rw}	K_{ro}/K_{rw}	S_w
0.4307	0.00001	4307.00	0.45
0.3706	0.00009	4117.7778	0.469
0.3164	0.00034	930.5882	0.489
0.2677	0.00075	356.9333	0.508
0.2243	0.00135	166.1481	0.528
0.1858	0.00212	87.6415	0.547
0.1520	0.00308	49.3506	0.567
0.1225	0.00423	28.9598	0.586
0.0971	0.00557	17.4399	0.606
0.0755	0.00710	10.6380	0.625
0.0574	0.00882	6.5068	0.644
0.0424	0.01074	3.9497	0.664
0.0303	0.01286	2.3585	0.683
0.0208	0.01518	1.3702	0.703
0.0135	0.01770	0.7644	0.722
0.0082	0.02042	0.4016	0.742
0.0046	0.02334	0.1954	0.761
0.0022	0.02647	0.0842	0.781
0.0009	0.02981	0.0305	0.800
0.0003	0.03335	0.0084	0.819
0.0000	0.03710	0.0003	0.839

FIGURE 2
TUNDRA - BAKKEN I POOL
CORE #3A - WATER-OIL RELATIVE PERMEABILITY
CUML PRODUCTION vs CUML INJECTION

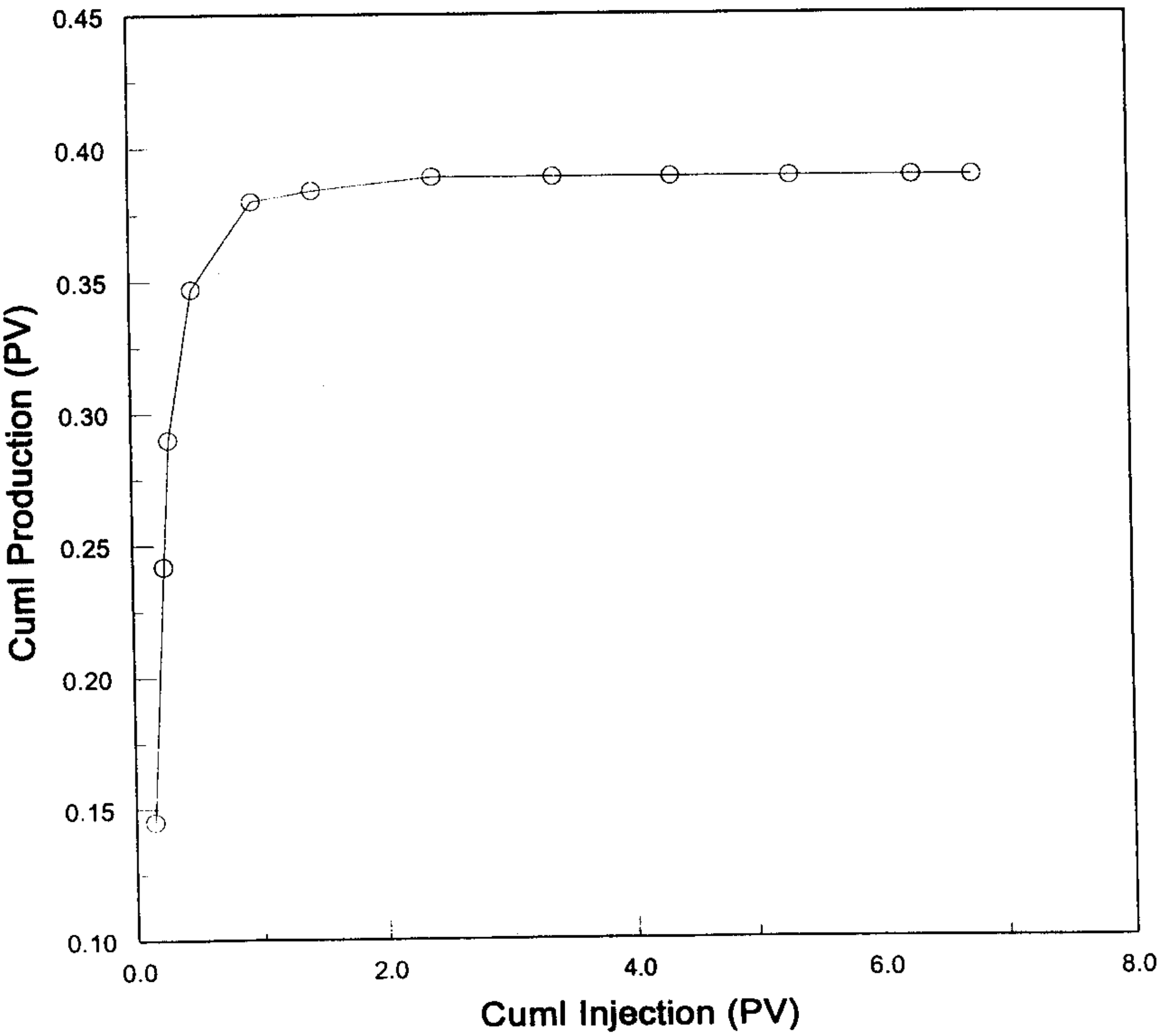


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FIGURE 3
TUNDRA - BAKKEN I POOL
CORE #3A - WATER-OIL RELATIVE PERMEABILITY
PRESSURE vs CUML INJECTION

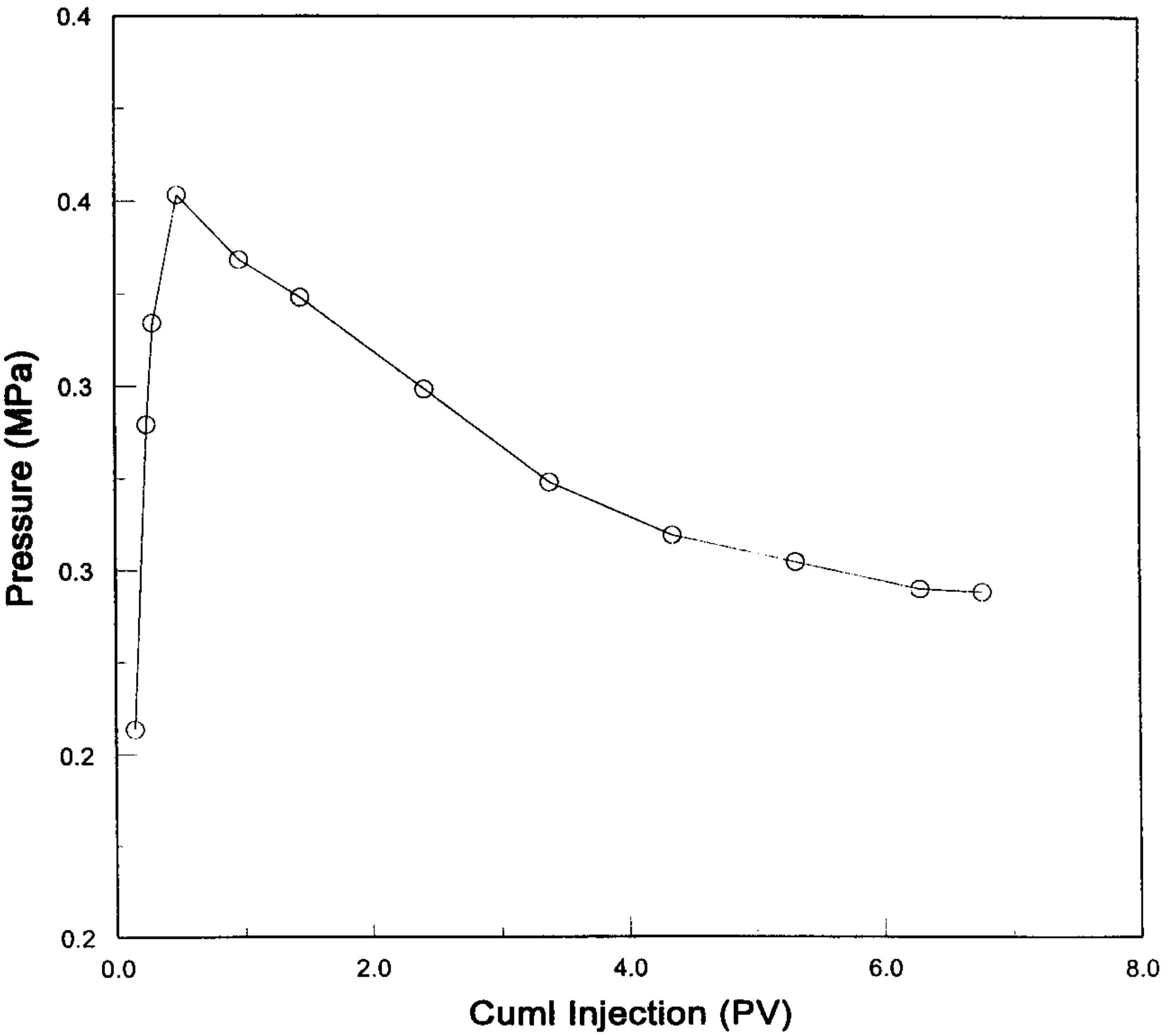

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FIGURE 4
TUNDRA - BAKKEN I POOL
RELATIVE PERMEABILITY STUDY
CORE #3A - WATER-OIL RELATIVE PERMEABILITY
RELATIVE PERMEABILITY vs WATER SATURATION

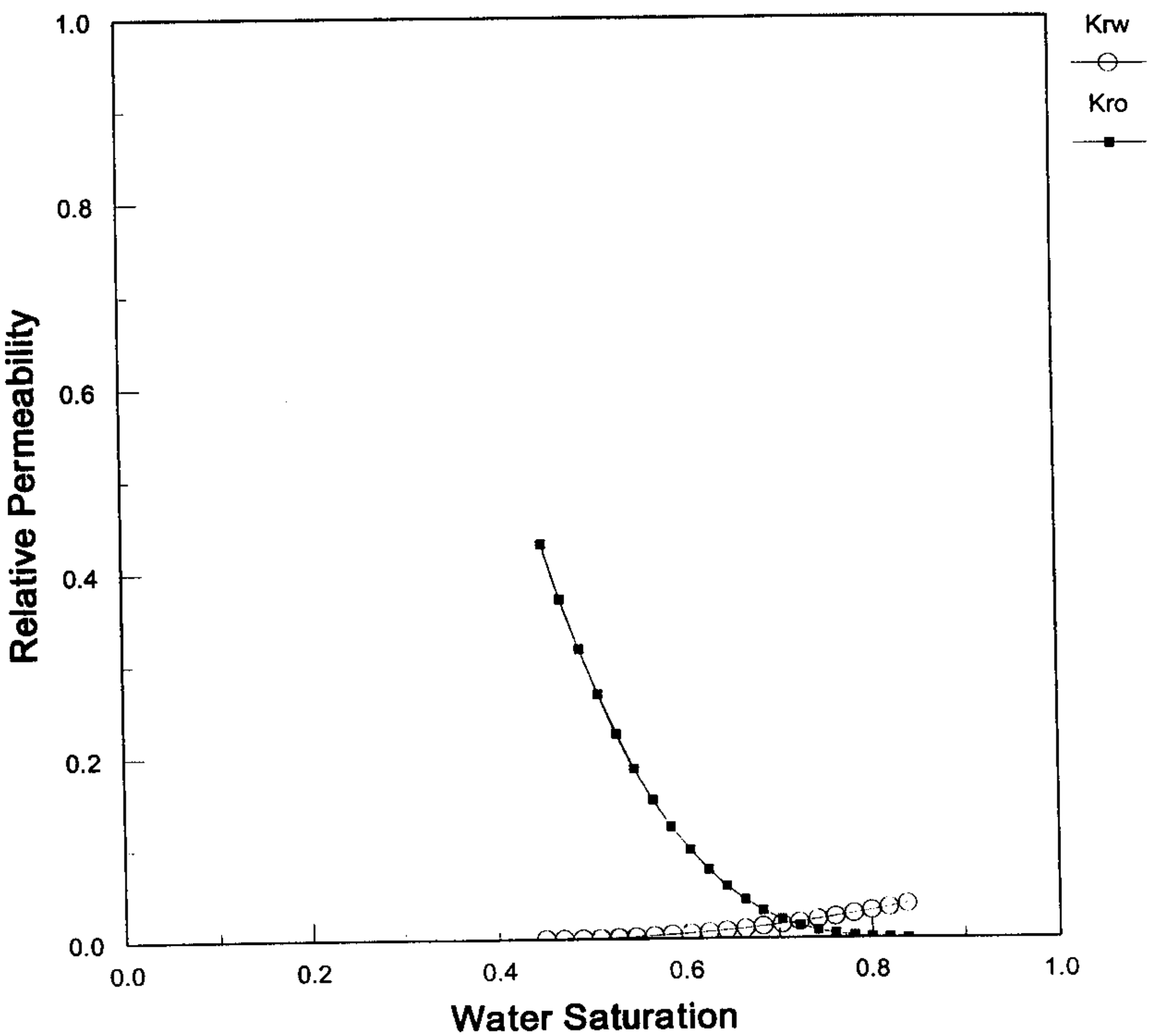
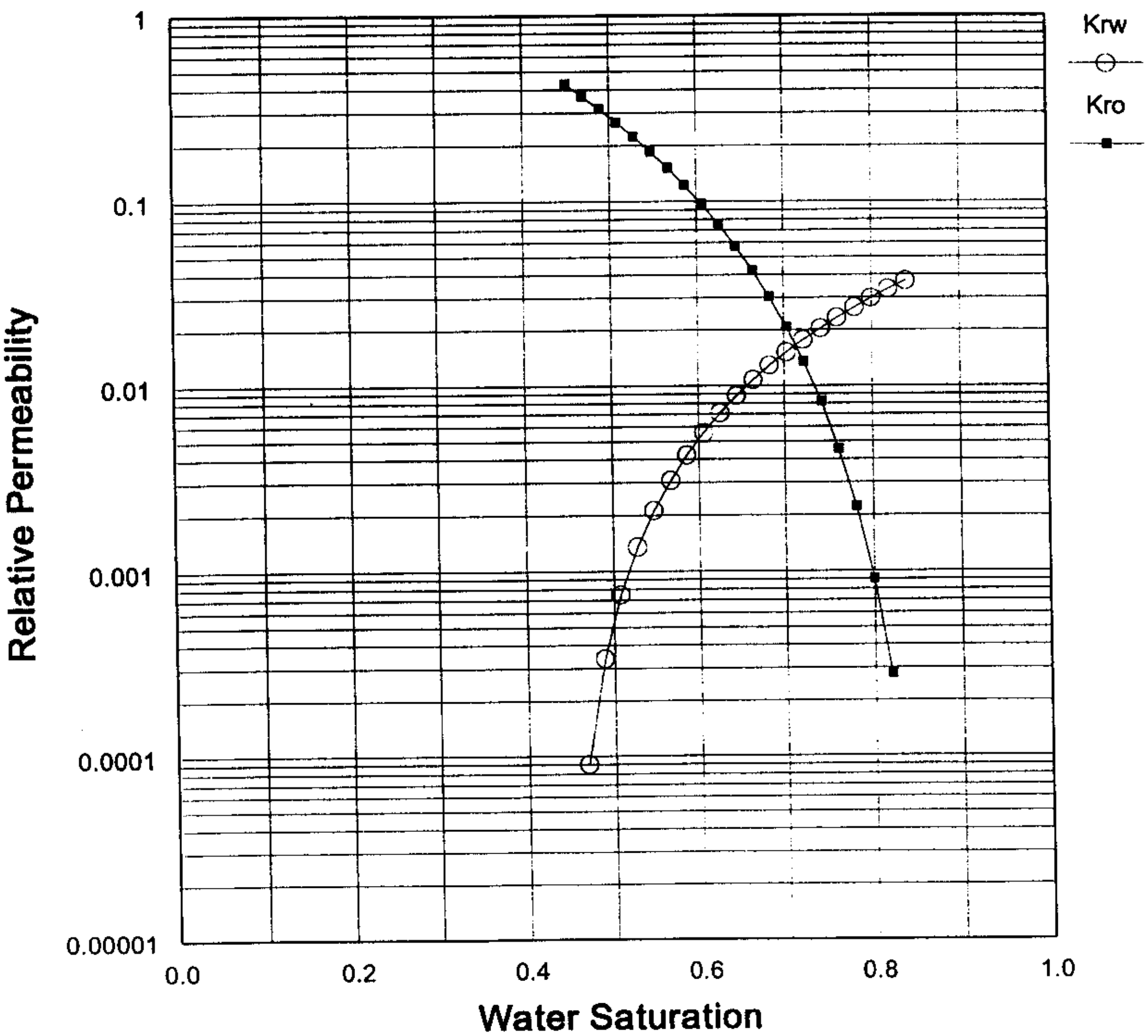


FIGURE 5
TUNDRA - BAKKEN I POOL
RELATIVE PERMEABILITY STUDY
CORE #3A - WATER-OIL RELATIVE PERMEABILITY
RELATIVE PERMEABILITY vs WATER SATURATION

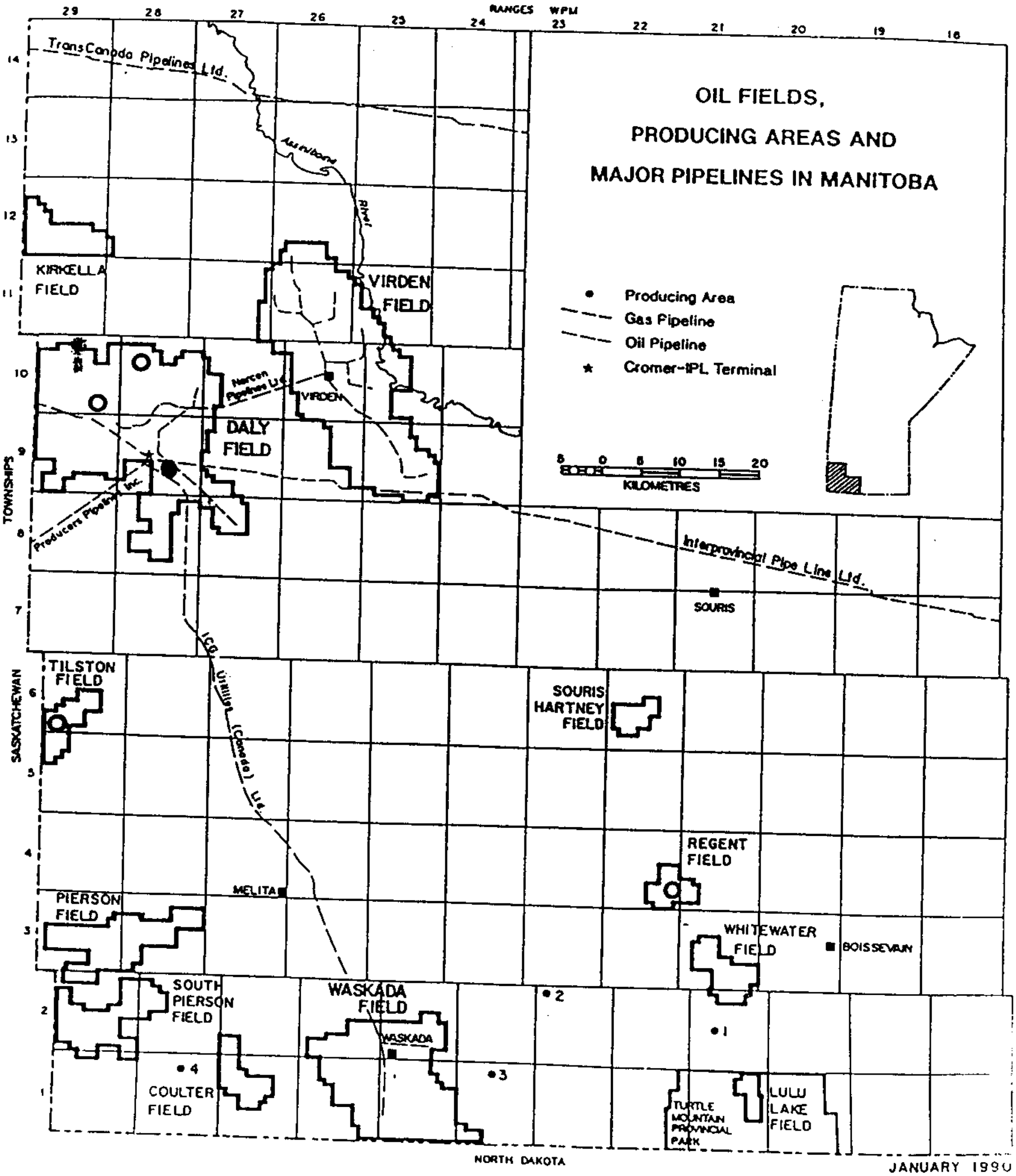


ATTACHMENT NO.7

LOCATION MAP OF CROMER UNIT NO.1

ATTACHMENT NO.7

LOCATION MAP OF CROMER FIELD



OTHER PRODUCING AREAS

1. Mountainside
2. Deloraine
3. Goodlands
4. Lyleton

• CROMER UNIT NO.1