Manitoba

The Oil and Natural Gas
Conservation Board

555 — 330 Graham Avenue
Winnipeg MB R3C 4E3
CANADA

(204) 945-1111
FAX: (204) 945-0586

December 10, 1993

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

Dear Mr. Czyzewski:

Re: Application to Convert to Water Injection
Tundra N. Ebor Unit No. 1 WIW 9-14-10-29 (WPM)

Your application to convert the subject well to water injection in North Ebor Unit No. 1 is hereby approved. Water injection at 9-14-10-29 is subject to the terms and conditions of Board Order No. PM 62. The maximum wellhead injection pressure is not to exceed 9000 kPa. Attached is a copy of the well operations form approved by the Petroleum Branch.

If you have any questions please contact John N. Fox, Chief Petroleum Engineer at 945-6574.

Yours respectfully,

H. Clare Moster
Deputy Chairman

cc. Well File
Virden District Office

Manitoba

The Oil and Natural Gas
Conservation Board

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CANADA

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NOTICE

UNDER THE MINES ACT

DALY OIL FIELD

Tundra Oil and Gas Ltd., the operator of North Ebor Unit No. 1 has made application to convert the well, Tundra Daly 9-14-10-29 to water injection in accordance with the provisions of Board Order No. PM 62.

If no valid objection or intervention in writing is received by The Oil and Natural Gas Conservation Board at 555-330 Graham Avenue, Winnipeg, Manitoba, R3C 4E3 before December 8, 1993, the Board may approve the application.

Copies of the application can be obtained from:

Tundra Oil and Gas Ltd.
1111 One Lombard Place
Winnipeg MB R3B 0X4

(204) 934- 5850

The application may be viewed at the offices of the Petroleum Branch:

555-330 Graham Avenue
Winnipeg MB R3C 4E3

(204) 945-6577

227 King Street
Virden MB ROM 2C0

(204) 748-1557

Dated at Winnipeg, this 18th day of NOVEMBER, 1993.

H. Clare Moster
Deputy Chairman

Manitoba

Memorandum

Date November 16, 1993

To The Oil and Gas Conservation Board
David Tomasson, Chairman
H. Clare Moster, Deputy Chairman

From Roland Massinon
Petroleum Engineer

Telephone

Subject **Daly Bakken D Pool**
North Ebor Unit No. 1 - Application to Convert 9-14-10-29

Tundra Oil and Gas Ltd. has made application to convert Tundra Daly 9-14-10-29 (WPM) to water injection (see Figure 1).

First | Fold

Recommendations:

It is recommended that a notice be sent to all working interest owners and royalty owners within the adjoining North Ebor Unit No. 2. If no objections are received, approval of the application is recommended.

Geology:

The Bakken formation is a thin clastic unit which is conformably overlain by limestone of the Mississippian Lodgepole formation. It is underlain by the dolomitic shales and siltstones of the Upper Devonian (Three Forks) formation.

Reservoir Pressure::

Production from North Ebor Unit No. 1 commenced in late 1987. The primary recovery mechanism for the Daly Bakken D Pool is fluid expansion drive. Reservoir pressure dropped from an initial value of 8,600 kPa to below 5,000 kPa in 1990 prior to initiating the waterflood in June of 1990. Since that time the reservoir pressure has risen to above 8,000 kPa (see Figure 2).

Oil Recovery (Primary):

Tundra predicted that primary oil recovery from the unit would be 41,564 m^3 or 35.8% of the original-oil-in-place (OOIP) based on Tundra's OOIP estimate of 116 x 10^3 m^3. It appears that Tundra's primary recovery figures may be high (see Figure 3). The Branch's more conservative estimate is 24,000 m^3 (see Figure 3, Branch primary decline curve) or 21% of Tundra's OOIP. It should be noted that the Branch's volumetric estimate of OOIP in the unit is substantially higher, 192.2 x 10^3 m^3, yielding a primary recovery of 12.5% OOIP.

Oil Recovery (Current Waterflood):

Under the current inverted nine-spot waterflood (injection into 16-14-10-29 only), Tundra calculated recovery at 49,000 m^3 or 42.2% of OOIP. This indicates incremental recovery of 21.2% when compared to the Branch's primary recovery.

After the initiation of waterflood there was a 30% increase in oil productivity for the unit. Figure 4 shows current production data for the entire Bakken D Pool.

The current voidage replacement ratio (VRR) in the unit as shown on Table 1 is 1.8 and the cumulative voidage replacement ratio (CVRR) is 0.7. When calculating the VRR 100% of production from 13-13, 15-14, 1-23 and 2-23 was used to calculate voidage. Because 12-13, 9-14 and 10-14 are also supported by the injector 8-14 only 50% of the production for those wells was used in calculating voidage. Although the CVRR is still below 1.0, the reservoir pressure at 1-23 indicates that the reservoir pressure is near the original discovery pressure. This can partially be explained by the fact that not all the withdrawals from the producing wells are from within the 16-14 waterflood pattern.

Oil Recovery (Proposed Waterflood):

As Tundra indicated in their application, conversion of 9-14-10-29 should increase the areal sweep efficiency for producing wells in North Ebor Unit No. 1 and North Ebor Unit No. 2. In light of the fact that the existing waterflood has performed well, the conversion of 9-14-10-29 is expected to increase the ultimate recovery of the pool. Tundra has estimated an ultimate recovery for the proposed scheme of 45.0% which is an incremental gain of 2.8% over the current waterflood scheme projected recovery of 42.2%. It should be noted that benefits from the conversion should also be seen in North Ebor Unit No. 2.

The injection pressure at the current injection well has increased from the commencement of injection to approximately 9,000 kPa in 1993. The conversion of 9-14-10-29 will result in lower injection pressure which in turn reduces the possibility of out of zone injection and channelling of injected water ultimately resulting in better areal sweep of the reservoir.

Future Waterflood Development:

Although not addressed in the subject application, Tundra has indicated that they expect to also modify the waterflood scheme for North Ebor Unit No. 2. Because the pool is only three legal subdivisions wide it does not lend itself to development as a five-spot pattern because a number of "edge" wells would be injectors and there would be potential for lost recovery at the pool boundaries.

For this reason the implementation of a line drive appears to be the most appropriate for the pool. The injectors would be located in the center of the pool and the oil would be swept to the producing wells located on the edge of the pool while minimizing the possibility of oil being left unrecovered at the edge of the pool.

The conversion of 9-14-10-29 is the first step in the implementation of a line drive waterflood. Tundra has indicated it will evaluate the North Ebor Unit No. 2 waterflood and the possibility of converting 1-14-10-29 to water injection.

ORIGINAL SIGNED BY
JOHN N. FOX

for Roland M. Massinon

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

/rmm
Attached.

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Tundra Oil and Gas Ltd.
1111 One Lombard Place
Winnipeg MB R3B 0X4

(204) 934- 5850

The application may be viewed at the offices of the Petroleum Branch:

555-330 Graham Avenue Winnipeg MB R3C 4E3	227 King Street Virden MB ROM 2C0
(204) 945-6577	(204) 748-1557

Dated at Winnipeg, this day of , 1993.

H. Clare Moster
Deputy Chairman

Table I

North Ebor Unit No. 1

Voidage Replacement Ratios

August/1993 Production & Injection

	DAILY PRODUCTION			CUMULATIVE PRODUCTION					
	OIL (m3/day)	WATER (m3/day)	TOTAL (m3/day)	OIL (m3)	WATER (m3)	FLUID (m3)	PATTERN FACTOR	DAILY VOIDAGE	CUMULA' VOIDAGE
12–13	2.4	0.5	2.9	4,473	658	5,131	0.5	1.4	2,566
13–13	0.1	0.9	1.0	2,877	664	3,541	1.0	1.0	3,541
9–14	0.5	1.6	2.1	5,828	1,277	7,105	0.5	1.0	3,553
10–14	0.4	1.9	2.3	1,414	984	2,398	0.5	1.2	1,199
15–14	0.5	1.2	1.7	4,674	1,621	6,295	1.0	1.7	6,295
16–14	0.0	0.0	0.0	2,888	318	3,206	1.0	0.0	3,206
1–23	2.5	0.2	2.7	5,629	446	6,075	1.0	2.7	6,075
2–23	1.8	0.3	2.0	4,268	345	4,613	1.0	2.0	4,613
TOTAL:	8.2	6.5	14.7	32,051	6,313	38,364		11.1	31,047
							TOTAL VRR	1.79	0.67

16–14: DAILY INJECTION: 19.8 CUMULATIVE INJECTION: 20,859

ATTACHMENT NO.3

NORTH EBOR UNIT NO.1 REMAINING PROVED PRODUCING RESERVES

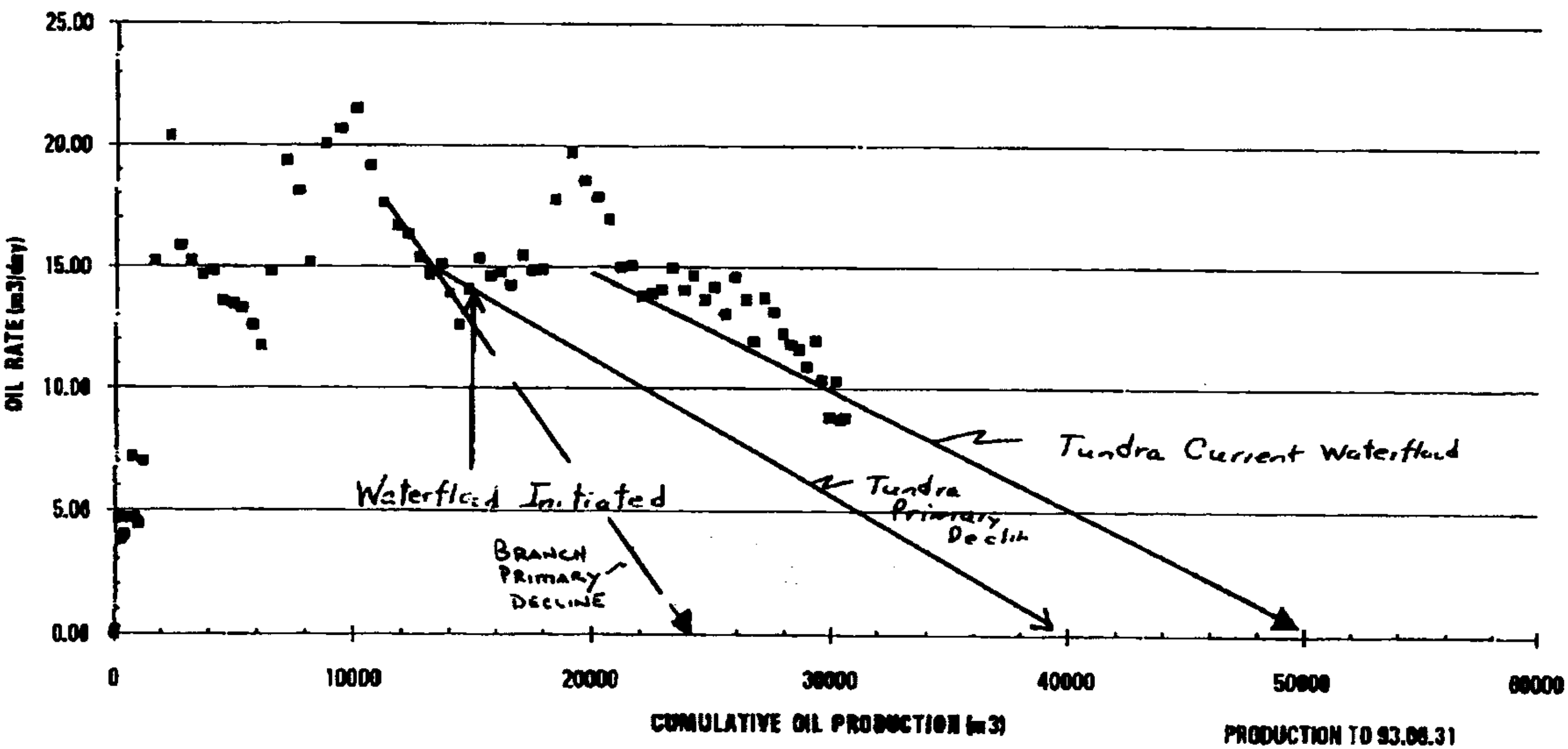
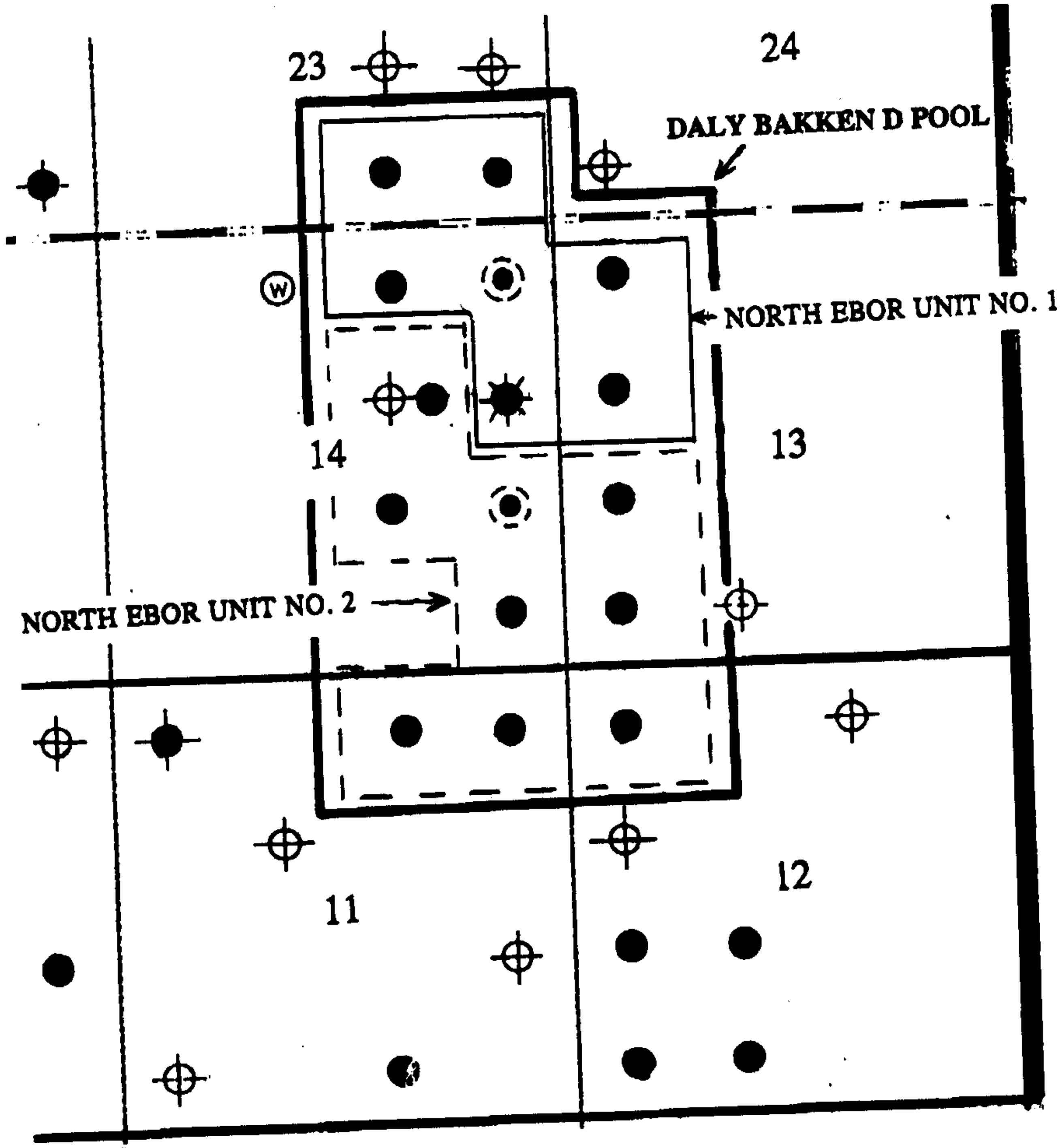


Figure 3

North Ebor Unit No. 1



OIL WELL
DRY AND ABANDONED
WATER INJECTION WELL (FORMER PRODUCER)
WATER SUPPLY WELL
PROPOSED WATER INJECTION WELL

Figure 1

North Ebor Unit No. 1

Reservoir Pressure Data

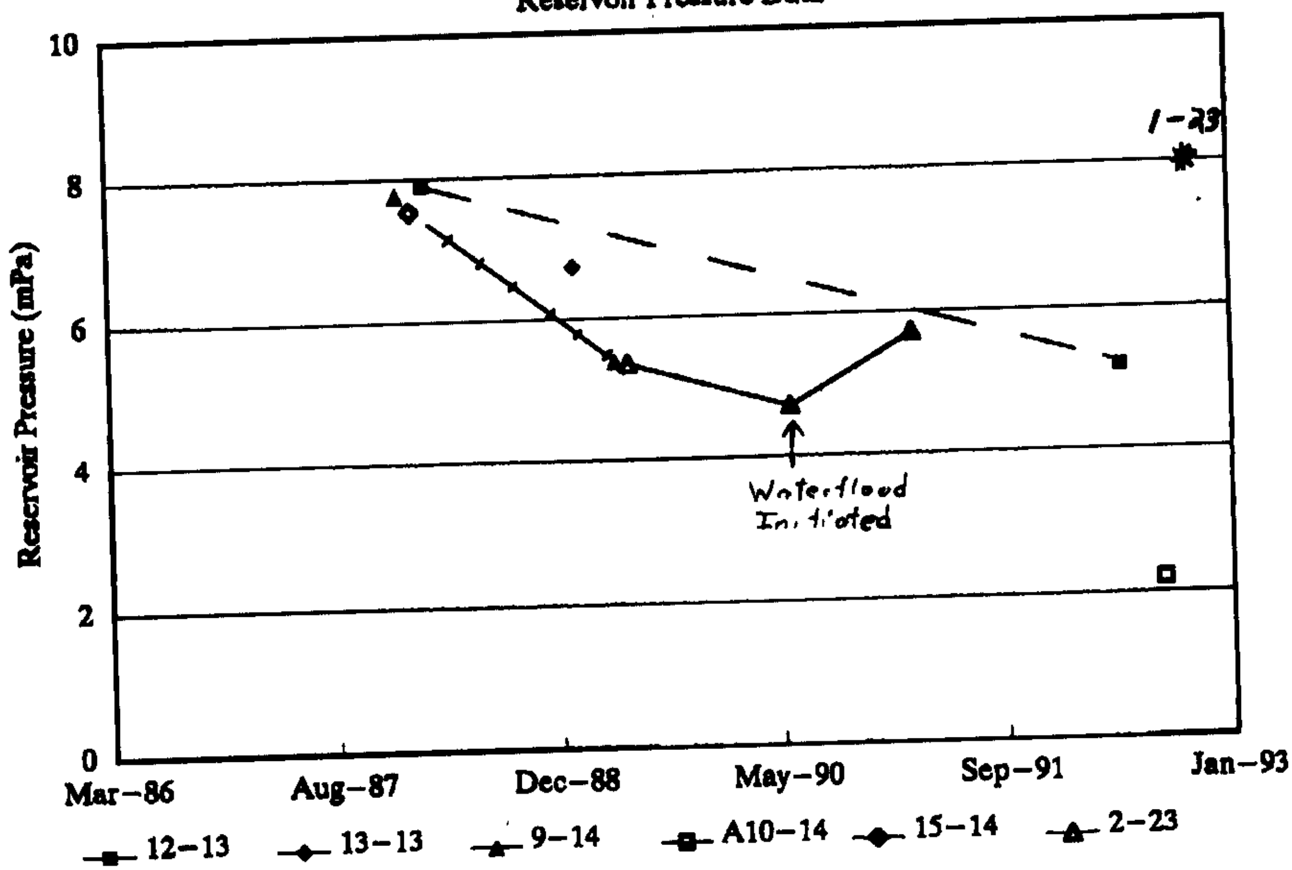


Figure 2

North Ebor Unit No. 1

Production Data

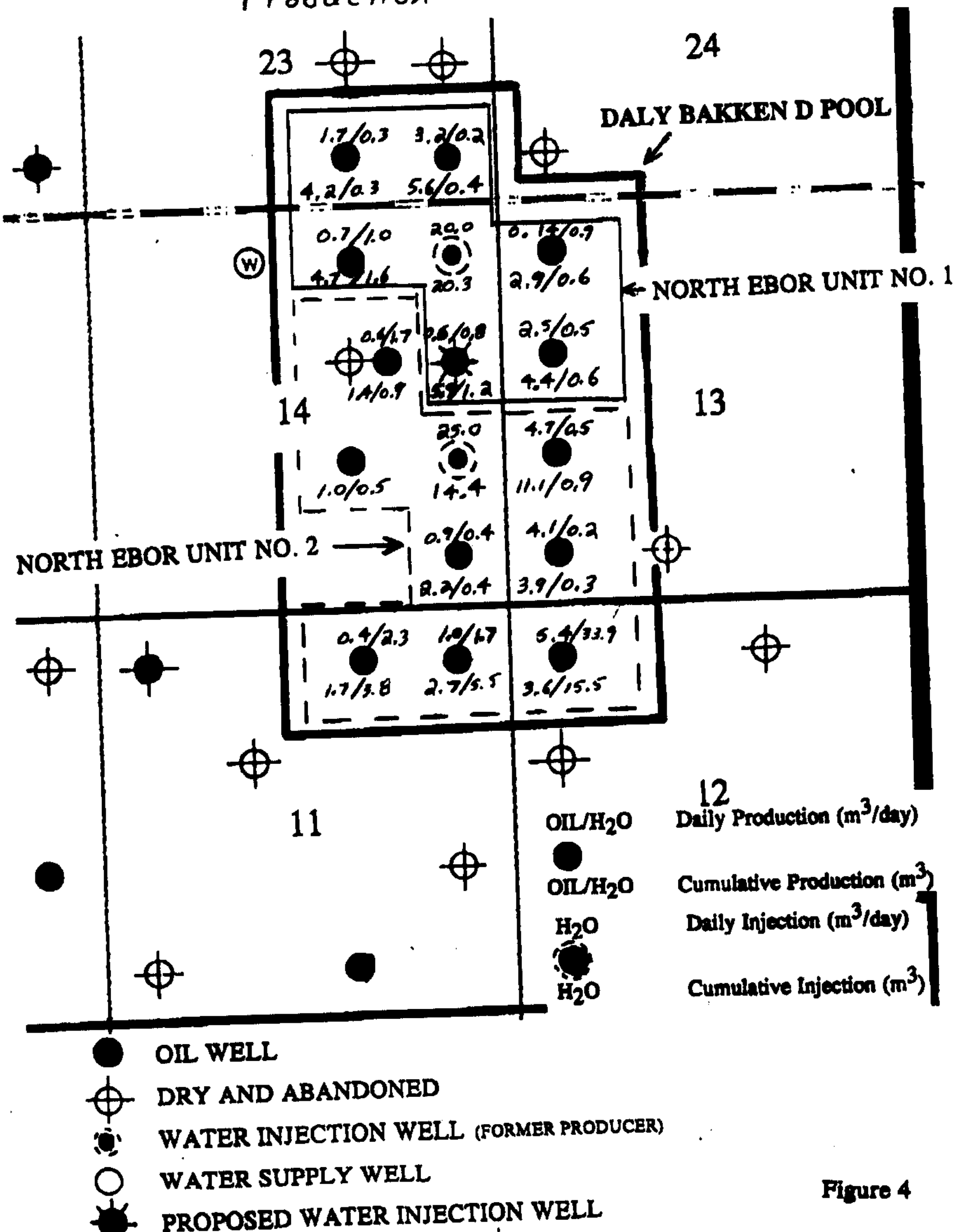


Figure 4

Table II

North Ebor Unit No. 1

Voidage Replacement Ratios

August/1993 Production & Injection

	DAILY PRODUCTION OIL (m3/day)	DAILY PRODUCTION WATER (m3/day)	DAILY PRODUCTION TOTAL (m3/day)	CUMULATIVE PRODUCTION OIL (m3)	CUMULATIVE PRODUCTION WATER (m3)	CUMULATIVE PRODUCTION FLUID (m3)	PATTERN FACTOR	DAILY VOIDAGE	CUMULA' VOIDAGE
12-13	2.4	0.5	2.9	4,473	658	5,131	0.5	1.4	2,566
13-13	0.1	0.9	1.0	2,877	664	3,541	1.0	1.0	3,541
9-14	0.5	1.6	2.1	5,828	1,277	7,105	0.5	1.0	3,553
10-14	0.4	1.9	2.3	1,414	984	2,398	0.5	1.2	1,199
15-14	0.5	1.2	1.7	4,674	1,621	6,295	1.0	1.7	6,295
16-14	0.0	0.0	0.0	2,888	318	3,206	1.0	0.0	3,206
1-23	2.5	0.2	2.7	5,629	446	6,075	1.0	2.7	6,075
2-23	1.8	0.3	2.0	4,268	345	4,613	1.0	2.0	4,613
TOTAL:	8.2	6.5	14.7	32,051	6,313	38,364		11.1	31,047
							TOTAL VRR	1.79	0.67

16-14: DAILY INJECTION: 19.8 CUMULATIVE INJECTION: 20,859

APPENDIX C: DALY BAKKEN D POOL – RESERVOIR PRESSURES

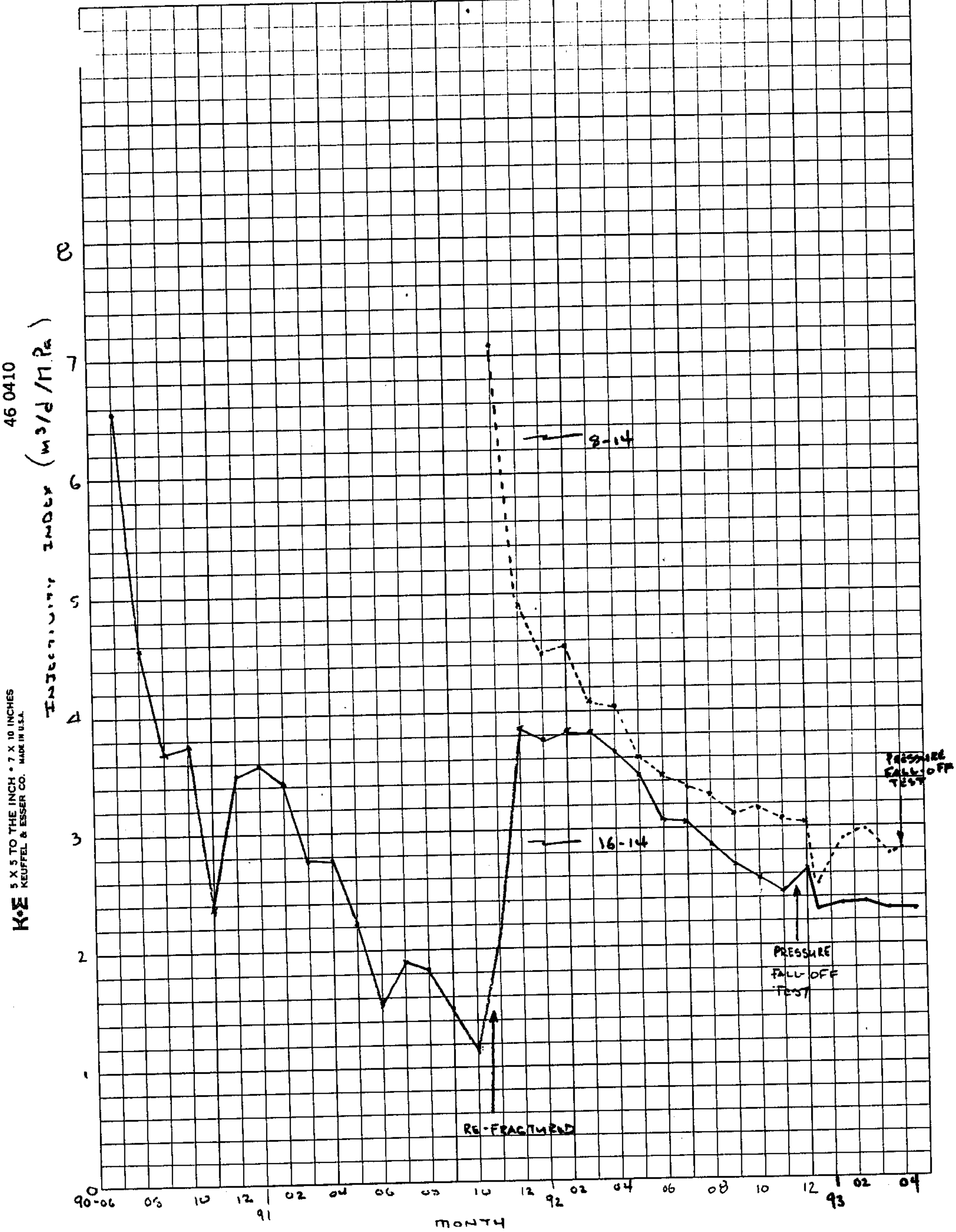
Well	Date	Type of Test	Pressure (Kpa)
7-14-10-29	Feb./87	DST	8,591
9-14-10-29	Jan./88	DST	7,763
15-14-10-29	Feb./88	DST	7,537
12-13-10-29	Mar./88	DST	7,914
13-13-10-29	Feb./89	DST	6,719
5-13-10-29	Feb./89	DST	7,426
9-14-10-29	May/89	Fluid Level	5,392
2-23-10-29	June/89	DST	5,353
2-23-10-29	June/90	Fluid Level	4,480 – 4,960
4-13-10-29	Feb./91	DST	4,355
A10-14-10-29	Mar./91	DST	5,710
13-12-10-29	Mar./91	DST	6,230
5-13-10-29	OCT/91	FLUID LEVEL	1112
5-13-10-29	MAY/92	FLUID LEVEL	1600
12-13-10-29	JUN/92	" "	5200
1-14-10-29	AUG/92	BUILD-UP (3 MON)	5000
10-14-10-29	SEP/92	FLUID LEVEL	2200

HISTORY OF MAX INJ. PRESS. APP.

JUN/90	6000 KPa
DEC/90	7000 KPa
JUL/92	8500 KPa
93	9000 KPa

DALY BARREN D POOL

FIGURE 5 - INJECTIVITY INDEX



K+E 5 X 5 TO THE INCH • 7 X 10 INCHES KEUFFEL & ESSER CO. MADE IN U.S.A. 46 0410

Tundra oil and gas ltd.

October 14, 1993

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

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

Dear Mr. Fox:

RE: North Ebor Unit No.1
Application to Convert 9-14-10-29 W1M to Injection Service and Suspend Production at 13-13-10-29 W1M

INTRODUCTION

Waterflood operations were initiated in the North Ebor Unit No.1 in June, 1990. Oil recovery to August 31, 1993 is estimated at 26.4% of the total original oil-in-place. The total average daily oil production in the Unit during August , 1993 was 8.8 m3/day at a watercut of 37.2% (refer to Attachment No.1). Currently three wells, 13-13, 9-14, and 15-14-10-29 have indicated water breakthrough. Well 13-13-10-29 has been shut-in , since it is no longer economic to operate.

The objectives of the program to convert 9-14-10-29 to injection service are as follows:

1. Improve recovery of bypassed oil in LSD 9-14-10-29 and in the surrounding LSD's.

2. Improve cumulative voidage replacement in the entire Unit.

3. Reduce the injection pressure load on the existing injection well at 16-14-10-29.

Tundra Oil and Gas Ltd. also requests that suspended well status be granted for oil well 13-13-10-29. The waterflood front has broken through at this location, and the 13-13 well is no longer economic to produce. The September, 1993 production test rate was 0.06 m3/day of oil at a watercut of 91%. The 13-13-10-29 wellbore will be used as an observation well.

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

Tundra oil and gas ltd.

LAND

Attachment No.2 outlines the proposed new injection location and observation well in the North Ebor Unit No.1. The new injection well will border the north half of North Ebor Unit No.2.

GEOLOGY

A reservoir fence diagram was prepared to determine the connectivity between wells in the Bakken 'D' Pool. Tundra's analysis indicates that proposed injection well 9-14-10-29 is more attractive than either 13-13 or 15-14-10-29 to improve waterflood recovery in the Unit. Injection well 9-14-10-29 has greater reservoir sweep exposure, and on this basis, better opportunity to improve recovery in the offset producers than does 13-13 or 15-14-10-29. Appendix A outlines the reservoir fence diagram for the Bakken 'D' Pool.

PRODUCTION PERFORMANCE

The production histories for wells 13-13-10-29, 9-14-10-29, and 15-14-10-29 are outlined in Figures No.1, No.2, and No.3, respectively. Cumulative oil production in wells 13-13, 9-14, and 15-14 to 93.08.31 was 2877.0 m3, 5828.1 m3, and 4674.1 m3, respectively. The average daily oil rate for 9-14 during August, 1993 was 0.5 m3/day at a watercut of 75%. The average daily oil rate for 15-14 during August, 1993 was 0.5 m3/day at a watercut of 71%. Figures No.2 and No.3 indicate that water breakthrough has occurred at both 9-14 and 15-14 from injection well 16-14-10-29. As previously mentioned, well 13-13 has watered out. Remaining proved producing reserves at 9-14 and 15-14 are estimated at 572 m3 and 525 m3, respectively. Figures No.4, No.5, and No.6 outline the remaining reserves for 13-13, 9-14, and 15-14, respectively. Remaining proved producing reserves for the other Unit wells are presented in Figures No.7 to No.9.

A review of the waterflood production performance in the Unit indicates that the movement of water in the reservoir is quite likely radial (movement in all directions), but there also seems to be a preferential permeability trend in an east - west direction. This conclusion is based on water breakthrough being observed first in 13-13 and 15-14, prior to breakthrough at 9-14-10-29. A recent pressure buildup at 1-23-10-29 also indicates that pressure support is also being provided to the north by injector 16-14-10-29.

Tundra oil and gas ltd.

RESERVES

Tables No.1 and No.2 outline the volumetric reserve estimates for the Bakken 'D' Pool lower and upper zones, respectively. Total original oil-in-place is estimated at 116,150 m3 (730,000 STB) in the North Ebor Unit No.1.

RECOVERY PROFILES

Table No.3 outlines the current recovery profiles for the Unit to 93.08.31. Current total Unit recovery is estimated at 26.4% of the total original oil-in-place. Total remaining proved producing oil is estimated at 115,000 STB.

The ultimate recoverable reserves in the Unit were volumetrically estimated to be 308,000 STB. This estimate was derived by assigning an ultimate recovery of 53% of the original oil-in-place to the lower zone in the Bakken 'D' Pool (based on recent relative permeability testing in a similar reservoir in the area) with waterflooding. An ultimate recovery of 18% of the original oil-in-place was assigned to the upper zone with waterflooding. The ultimate recovery in the upper zone is considered speculative, since no information is available at this time to support moveable hydrocarbon with reservoir permeabilities of less than 1 md. As a final check, the ultimate recoverable reserves predicted from volumetric analysis were compared to actual production performance. Attachment No.3 outlines the ultimate recoverable oil reserves from the North Ebor Unit No.1. From actual production performance, 49,000 m3 (308,000 STB) are estimated as ultimate recoverable oil reserves with the current depletion program. On this basis, there is a good match between the volumetric prediction and actual production performance. As a result, the recovery profiles are considered to be reliable within the scope of the aforementioned analysis.

Continuing with this methodology, recovery for 13-13 is estimated at 22.4% of the original oil-in-place(OOIP) to 93.08.31. Similarly current recovery(93.08.31) for 15-14 is estimated at 36.3% OOIP. The waterflood sweep efficiency at both 13-13 and 15-14 is estimated at best to be 50% of the reservoir area. Sweep efficiency was estimated by comparing cumulative production(including migration of oil from 16-14) to 93.08.31 to estimated ultimate recoverable reserves. Since there is marginal reservoir development to the west of LSD 15-14 and to the east of LSD 13-13, no further development drilling is economically feasible to install injectors in these locations to maximize sweep on the east side of LSD 13-13, and the west side of LSD 15-14.

Recovery for well 9-14-10-29 to 93.08.31 is estimated at 23.1% of the original oil-in-place. The sweep efficiency at 9-14 is greater than at 13-13 and 15-14, since the 9-14 well is bounded by injectors to the north and to the south. A review of the production history at 9-14 indicates that injection support has been provided at this location by 16-14-10-29 in the North Ebor Unit No.1 and by 8-14-10-29 from the North Ebor Unit No.2. Current sweep efficiency at 9-14 is estimated at 60% of the reservoir area.

INJECTOR SELECTION PROCESS

The following criteria (ranked in decending order of importance) were used to screen existing producing wells as injector candidates:

1. Good reservoir connectivity with offset producers (refer to Appendix A)

2. Bypassed oil remaining in watered out producer or where water breakthrough has occurred.

3. Minimization of oil migration out of the Unit where there are no producers to capture the bypassed oil or there being no further opportunity to drill additional wells (adjacent to unswept area) because of marginal reservoir development.

In our analysis, a good injection well had to satisfy all of the above conditions.

The current waterflood pattern in the North Ebor Unit No.1 is an inverted 9-spot. The next logical step is to consider installing an inverted 5-spot in the Unit. An inverted 5-spot grid was developed for the entire Bakken 'D' Pool as is outlined in Attachment No.4. The only wells in the North Ebor Unit No.1 that would satisfy this configuration as a 5-spot injector are 12-13 and 2-23-10-29. Since both 12-13 and 2-23 are still producing at high oil rates with low watercuts (no breakthrough at this time), these wells were not considered as attractive injection candidates. In addition, from the reservoir fence diagram in Appendix A, well 2-23 would only provide limited waterflood sweep at 1-23 and 15-14. Similarly well 12-13 would only provide waterflood support for 9-14 (North Ebor Unit No.1) and 5-13 (North Ebor Unit No.2).

The next step was to evaluate the producing wells that have indicated water breakthrough. Well 13-13 would only provide limited waterflood support at 12-13 and 9-14. However, well 13-13 has attractive remaining reserves and may be a potential injection location in the future. Well

15-14 has good reservoir connectivity with wells 9-14, 10-14, 1-23, and 2-23. However, well 15-14 like 13-13 is a Unit edge well and may sweep oil reserves out of the Unit. The remaining well offering injection potential was 9-14-10-29. Well 9-14 has good reservoir connectivity in the North Ebor Unit No.1 with 12-13, 13-13, and 15-14. There is also good reservoir connectivity between 9-14 and three additional wells in the North Ebor Unit No.2 (5-13, 7-14, and 10-14-10-29). Well 9-14 has the highest remaining bypassed oil reserves (refer to Table No.3) of the three wells with water breakthrough in the North Ebor Unit No.1. Finally, well 9-14 is surrounded by offset producing wells which will minimize oil migration out of the Unit with 9-14 in injection service. As a result, Tundra considers 9-14-10-29 at this time to be the best location for installing another injector in the Unit to capture bypassed oil reserves.

INCREMENTAL OIL RESERVES

Incremental oil recovery of 20,000 STB is estimated in the offset producers by converting 9-14-10-29 to injection service (refer to Table No.3; incremental recovery at 9-14 = ultimate volumetric recoverable oil - cum. production).

WELL 13-13-10-29

Suspended well status is requested for well 13-13-10-29. The 13-13 location will be used as an observation well for annual reservoir pressure surveys. Since well 13-13-10-29 has attractive bypassed reserves, it may be converted to an injector in the future or put back on production if there is an indication of significant pressure support from proposed injection well 9-14-10-29.

WATER INJECTION SERVICE COMPLETION

Attachment No.5 outlines the proposed down-hole configuration for placing 9-14-10-29 into injection service.

Tundra Oil and Gas Ltd. would prefer to begin converting 9-14-10-29 to injection service by mid November, 1993, prior to winter freeze-up, and any further assistance that Tundra can provide to expedite approval of this application will be made available from our office. Should you have any questions, I can be reached at 934-5853.

Respectfully submitted,

Tundra Oil and Gas Ltd.

G. Czyzewski

George Czyzewski, P.Eng.
Senior Reservoir Engineer

FIGURE NO.1

WELL 13-13-10-29 PRODUCTION HISTORY

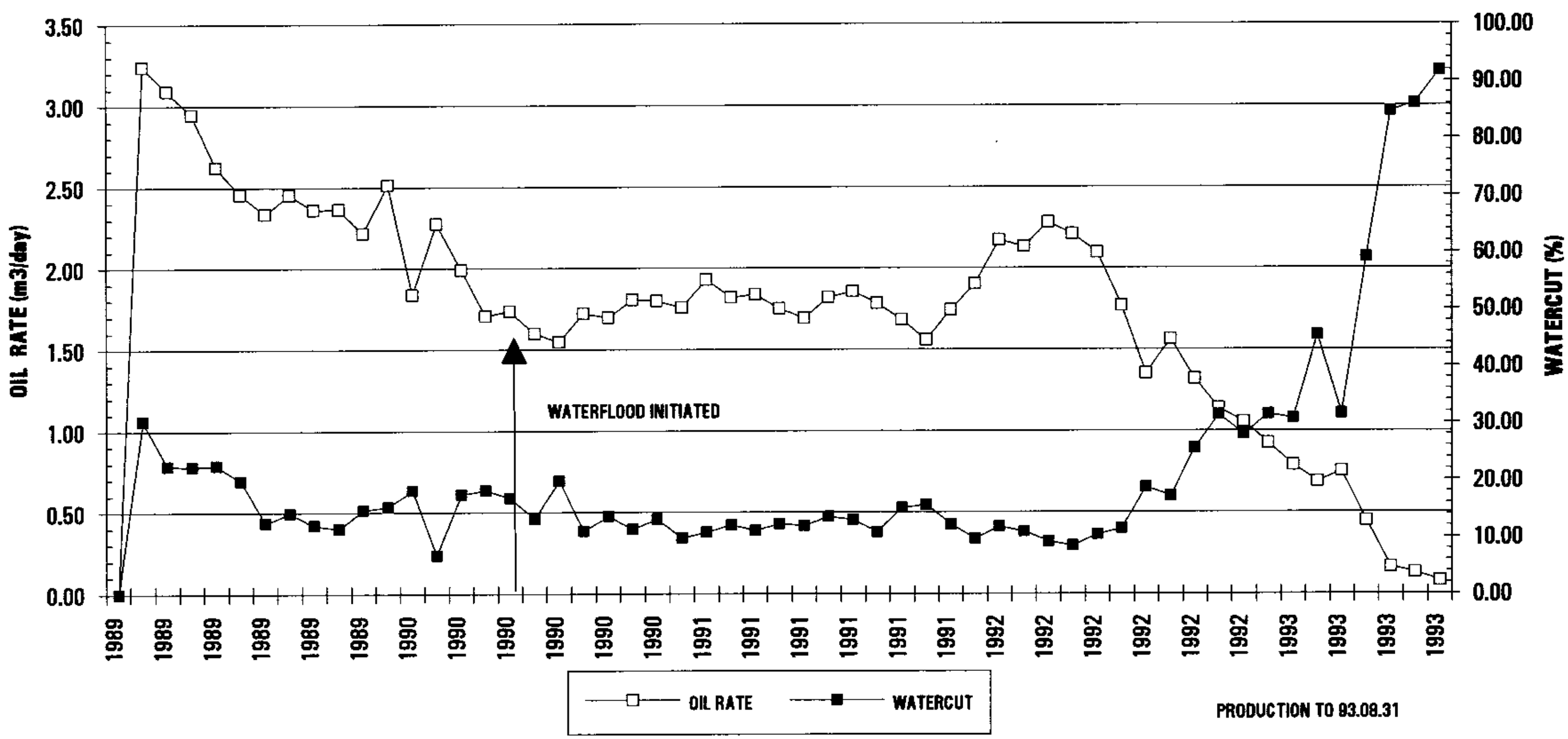


FIGURE NO.2

WELL 9-14-10-29 PRODUCTION HISTORY

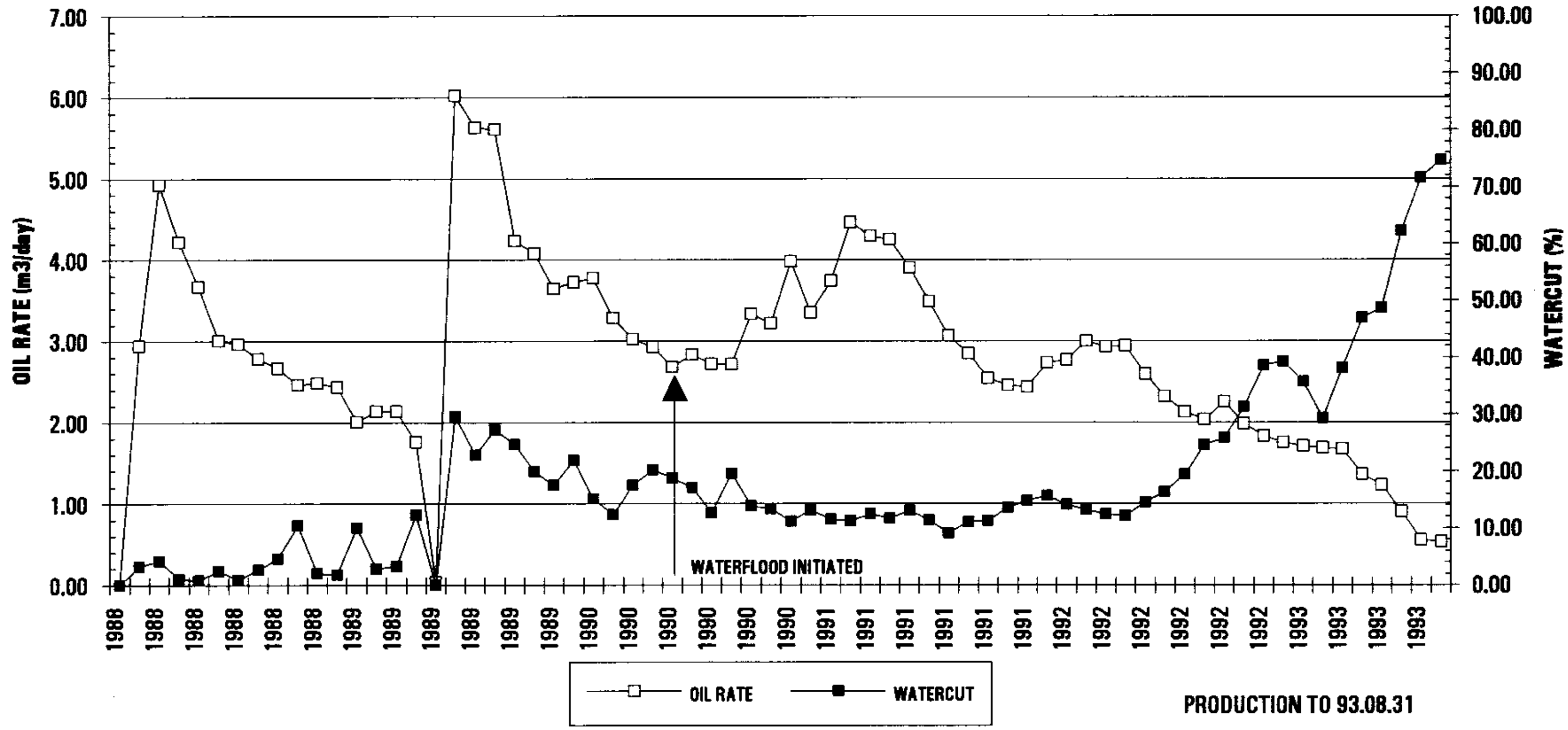


FIGURE NO.3

WELL 15-14-10-29 PRODUCTION HISTORY

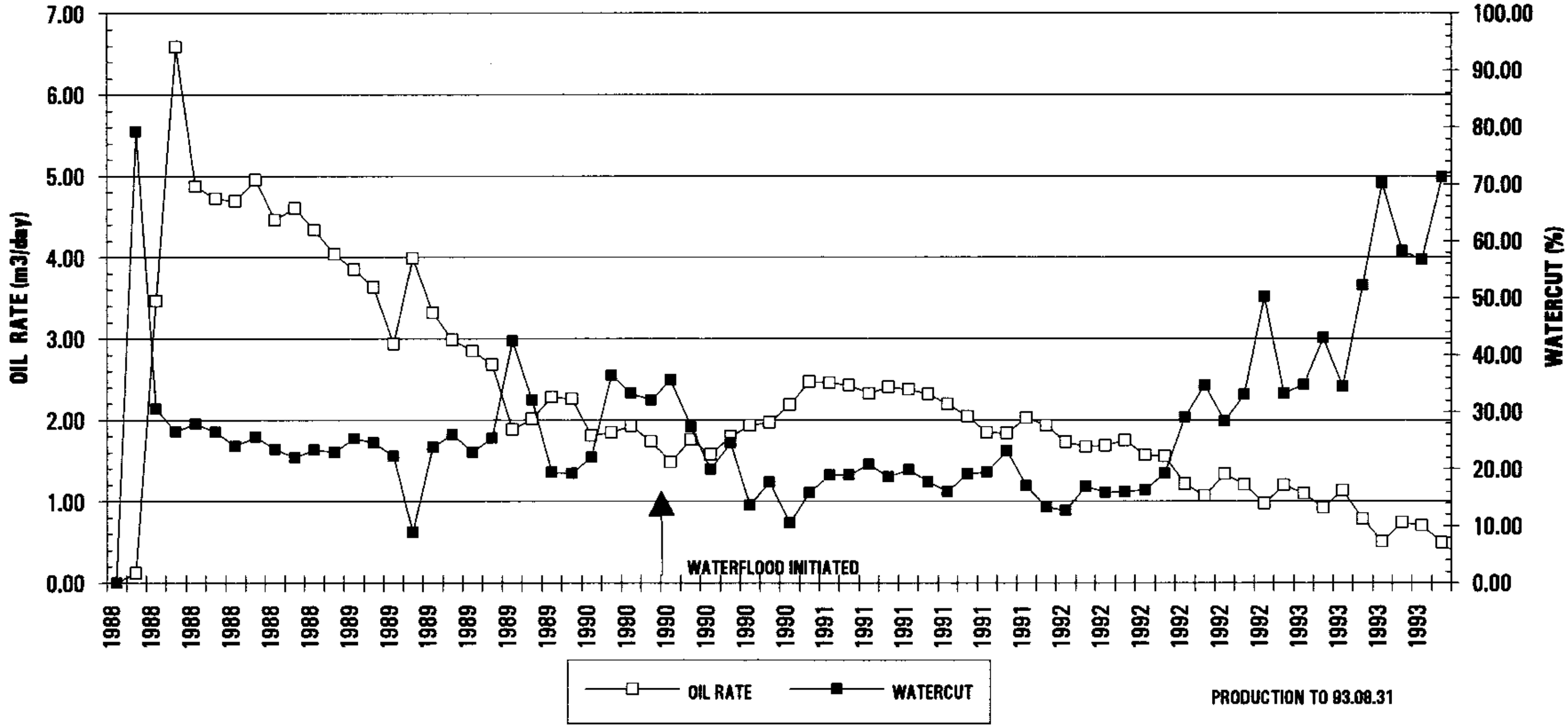


FIGURE NO.4

WELL 13-13-10-29 REMAINING PROVED RESERVES

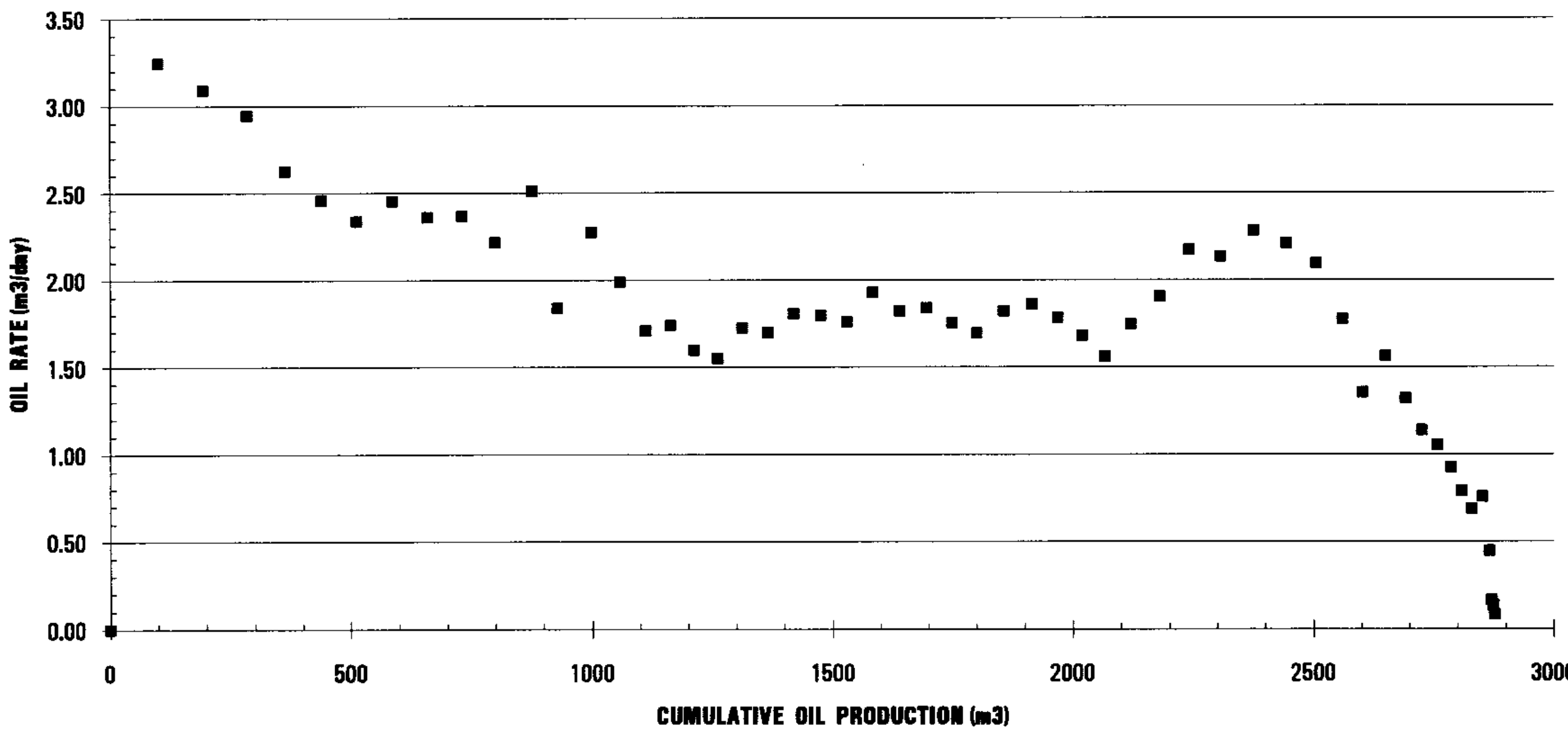


FIGURE NO.5

WELL 9-14-10-29 REMAINING PROVED PRODUCING RESERVES

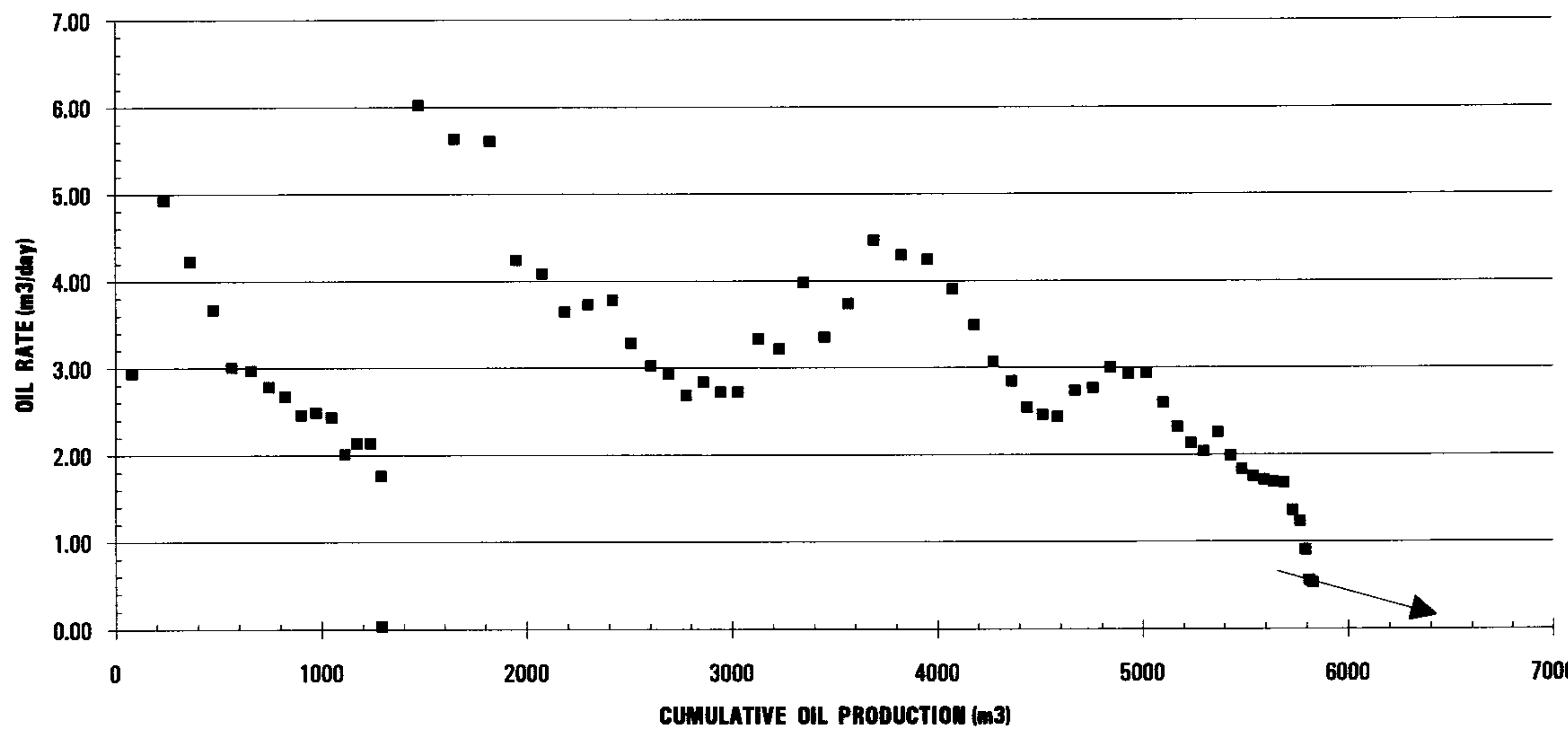


FIGURE NO.6

WELL 15-14-10-29 REMAINING PROVED PRODUCING RESERVES

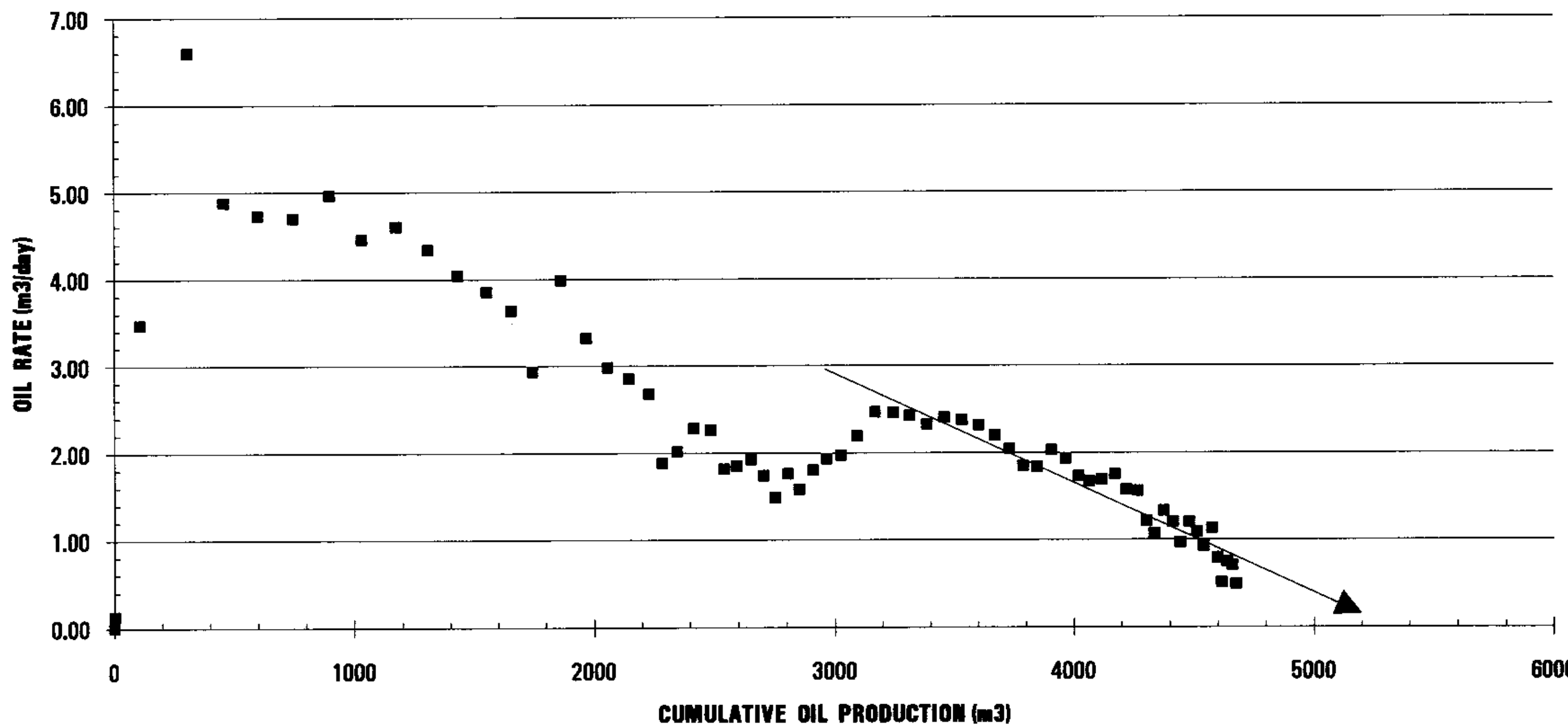


FIGURE NO.7

WELL 1-23-10-29 REMAINING PROVED PRODUCING RESERVES

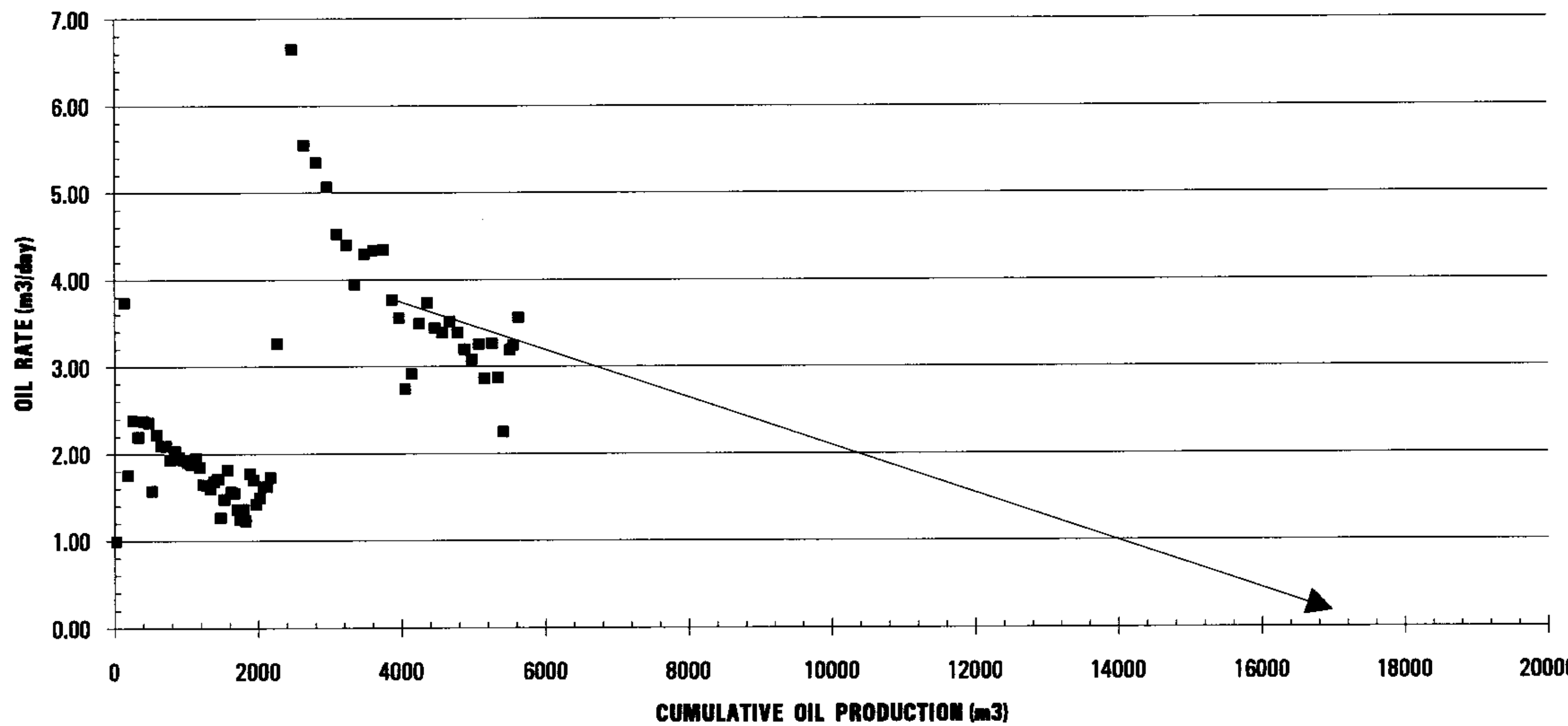


FIGURE NO.8

WELL 2-23-10-29 REMAINING PROVED RESERVES

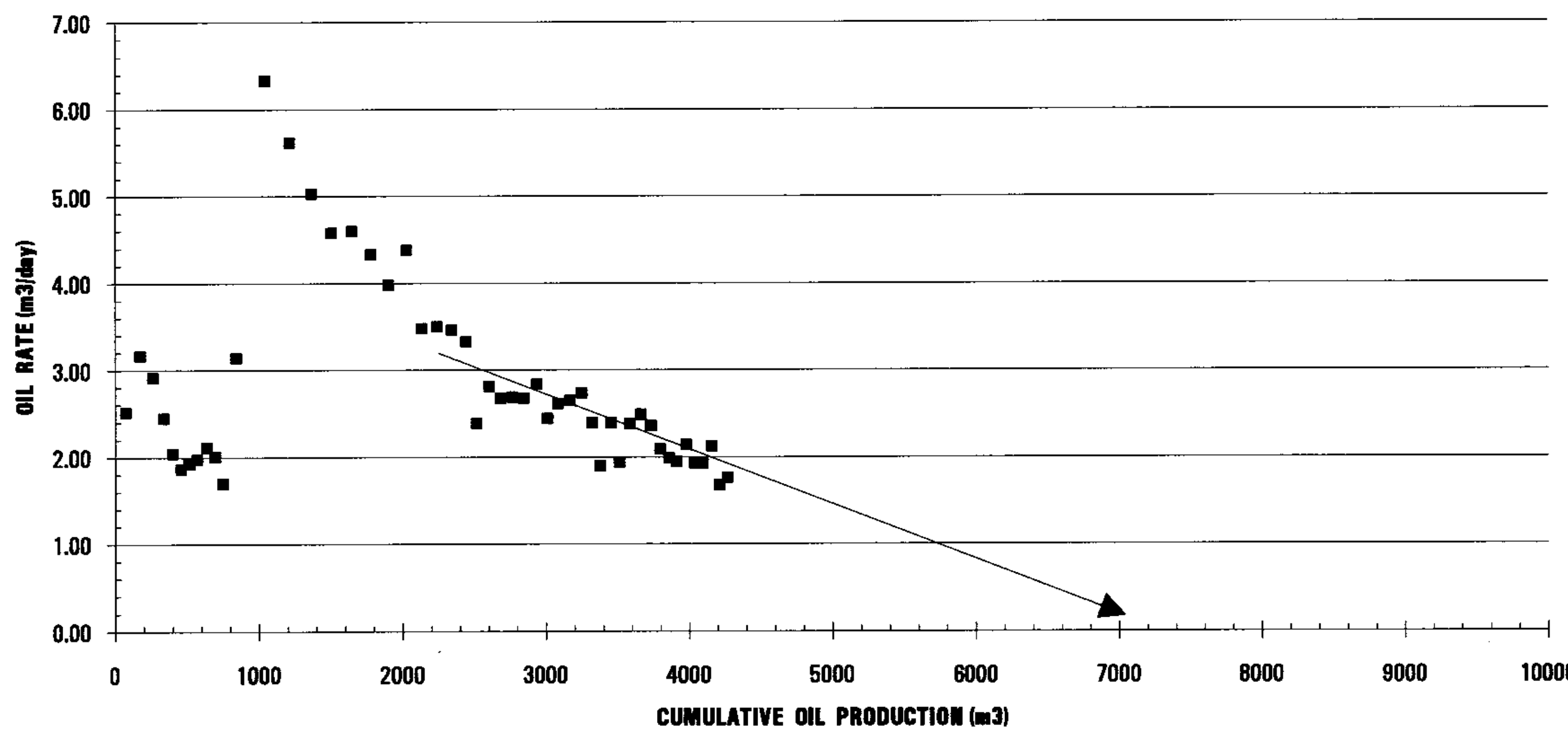


FIGURE NO.9

WELL 12-13-10-29 REMAININING PROVED PRODUCING RESERVES

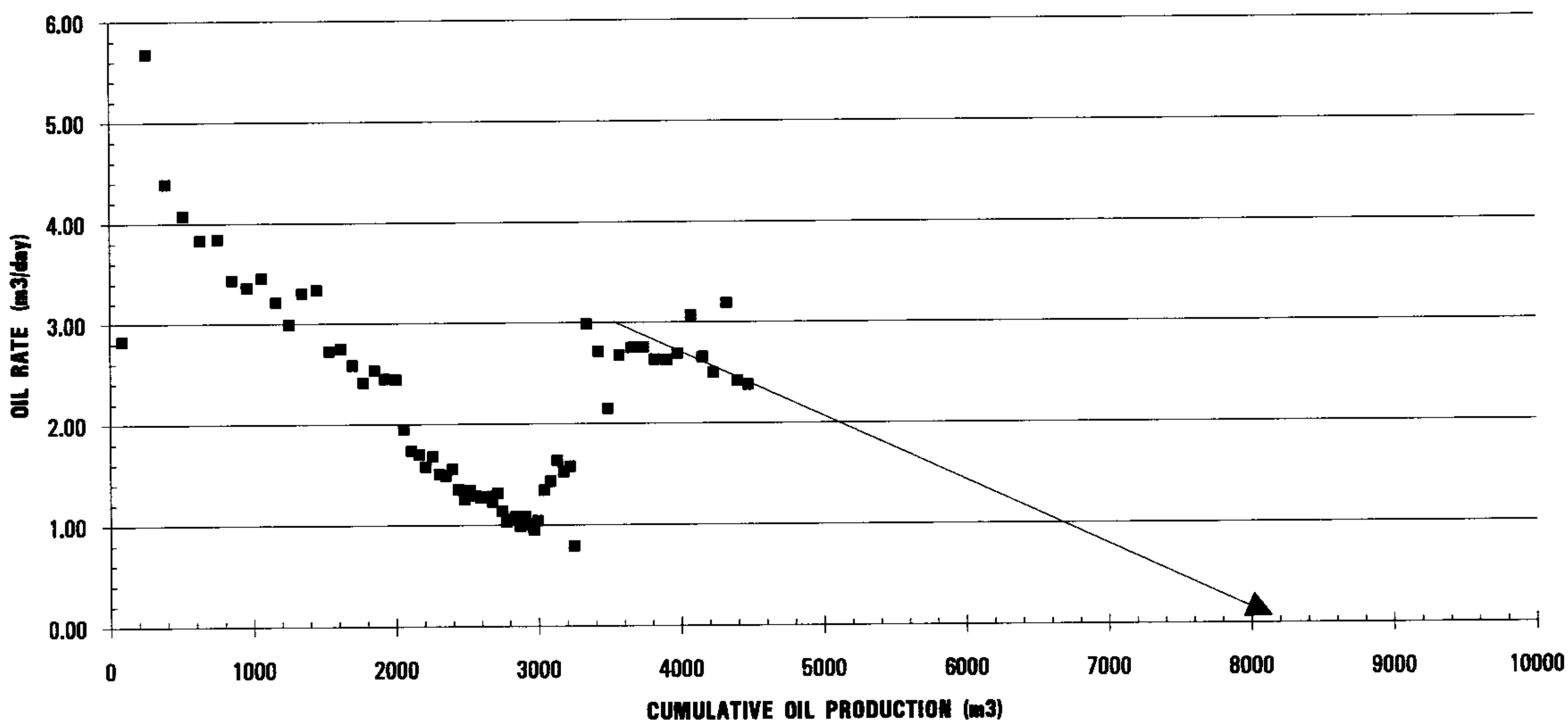


TABLE NO.1

NORTH EBOR UNIT NO.1

ORIGINAL OIL-IN-PLACE ESTIMATES

Lower Zone

Well	Constant	Area (hectares)	Net Pay (m)	Porosity (fraction)	Sw (fraction)	(1-Sw) (fraction)	Boi (Rm3/m3)	OOIP (m3)	OOIP (STB)
12-13-10-29	10,000.00	16.19	0.80	0.16	0.420	0.580	1.063	11,307	71,122
13-13-10-29	10,000.00	16.19	0.80	0.15	0.481	0.519	1.063	9,486	59,664
9-14-10-29	10,000.00	16.19	1.20	0.20	0.607	0.393	1.063	14,365	90,358
15-14-10-29	10,000.00	16.19	1.00	0.17	0.562	0.438	1.063	11,341	71,332
16-14-10-29	10,000.00	16.19	0.90	0.17	0.450	0.550	1.063	12,816	80,615
1-23-10-29	10,000.00	16.19	0.70	0.16	0.432	0.568	1.063	9,689	60,944
2-23-10-29	10,000.00	16.19	0.80	0.16	0.418	0.582	1.063	11,346	71,367
Totals								80,350	505,403

TABLE NO.2

NORTH EBOR UNIT NO.1

ORIGINAL OIL-IN-PLACE ESTIMATES

Upper Zone

Well	Constant	Area (hectares)	Net Pay (m)	Porosity (fraction)	Sw (fraction)	(1-Sw) (fraction)	Boi (Rm3/m3)	OOIP (m3)	OOIP (STB)
12-13-10-29	10,000.00	16.19	1.40	0.13	0.578	0.422	1.063	11,698	73,578
13-13-10-29	10,000.00	16.19	0.40	0.13	0.578	0.422	1.063	3,342	21,022
9-14-10-29	10,000.00	16.19	1.30	0.13	0.578	0.422	1.063	10,862	68,322
15-14-10-29	10,000.00	16.19	0.20	0.12	0.578	0.422	1.063	1,543	9,703
16-14-10-29	10,000.00	16.19	1.00	0.13	0.578	0.422	1.063	8,355	52,556
1-23-10-29	10,000.00	16.19	0.00	0.00	0.578	0.422	1.063	0	0
2-23-10-29	10,000.00	16.19	0.00	0.00	0.578	0.422	1.063	0	0
Totals								35,800	225,181

TABLE NO.3

North Ebor Unit No.1

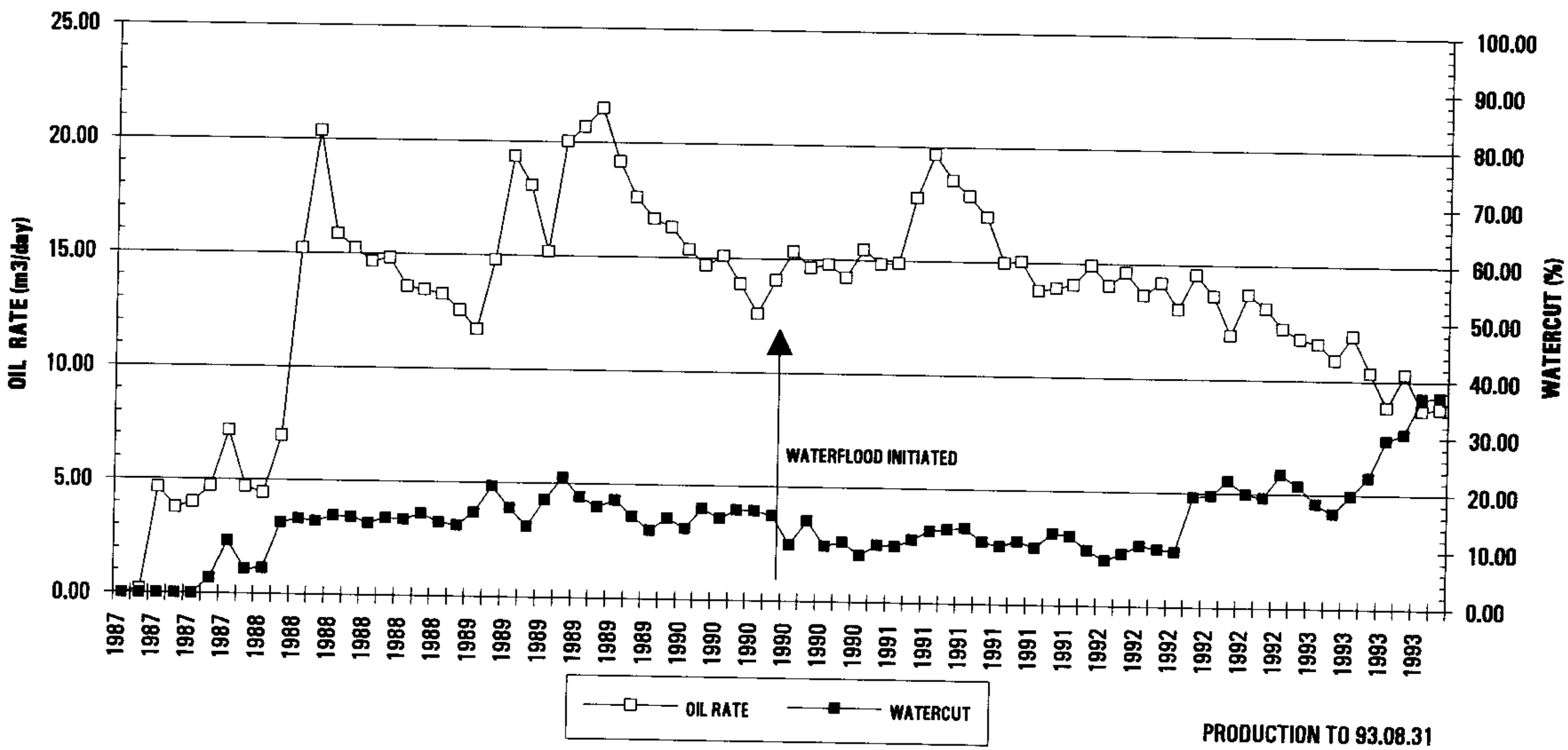
Recovery Profiles

Well	Cum. Prod. to Aug.31/93 (m3)	Cum. Prod. to Aug.31/93 (STB)	Lower Zone OOIP (STB)	Upper Zone OOIP (STB)	Total OOIP (STB)	Ultimate Volumetric Recoverable Oil (STB)	Remaining Proved Producing Oil (STB)	Current Recovery Factor Lower Zone Only (%)	Current Rec. Fac. Lower & Upper Zone (%)
12-13-10-29	4,472.5	28,132.0	71,122	73,578	144,700	50,939	22,807	39.6	19.4
13-13-10-29	2,877.0	18,096.3	59,664	21,022	80,686	35,406	0	30.3	22.4
9-14-10-29	5,828.1	36,658.7	90,358	68,322	158,681	60,188	3,598	40.6	23.1
15-14-10-29	4,674.1	29,400.1	71,332	9,703	81,035	39,553	3,302	41.2	36.3
16-14-10-29	2,888.1	18,166.1	80,615	52,556	133,171	52,186	0	-	-
1-23-10-29	5,629.4	35,408.9	60,944	0	60,944	32,300	69,657	58.1	58.1
2-23-10-29	4,268.3	26,847.6	71,367	0	71,367	37,824	16,322	37.6	37.6
Totals	30,637.5	192,709.9	505,403	225,181	730,584	308,396	115,685	38.1	26.4

Remaining proved producing reserves have been estimated from decline analysis

ATTACHMENT NO.1

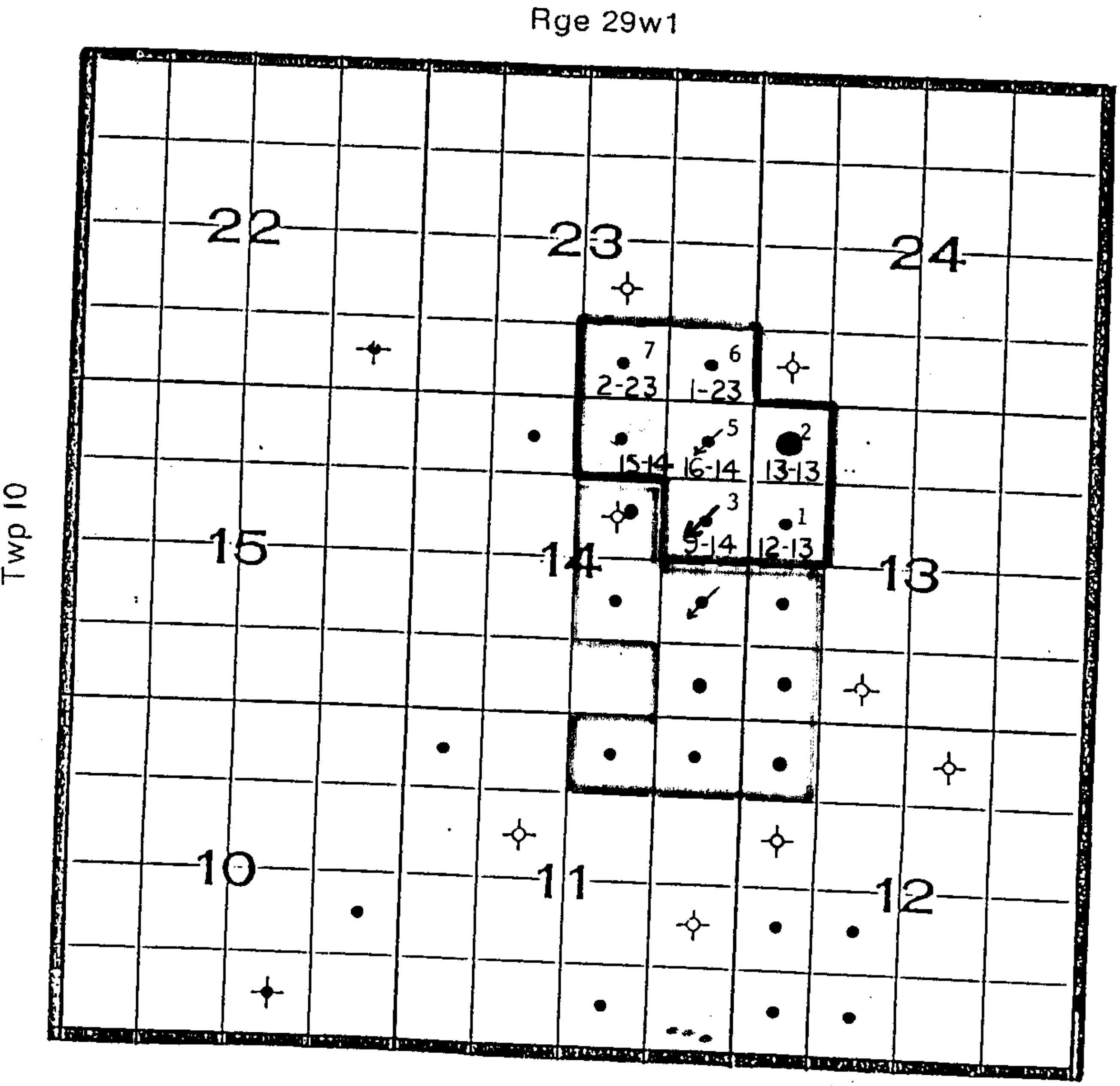
NORTH EBOR UNIT NO.1



PRODUCTION TO 93.08.31

ATTACHMENT NO.2

NORTH EBOR UNIT NO. 1



Unit Outline, NORTH EBOR UNIT NO.1

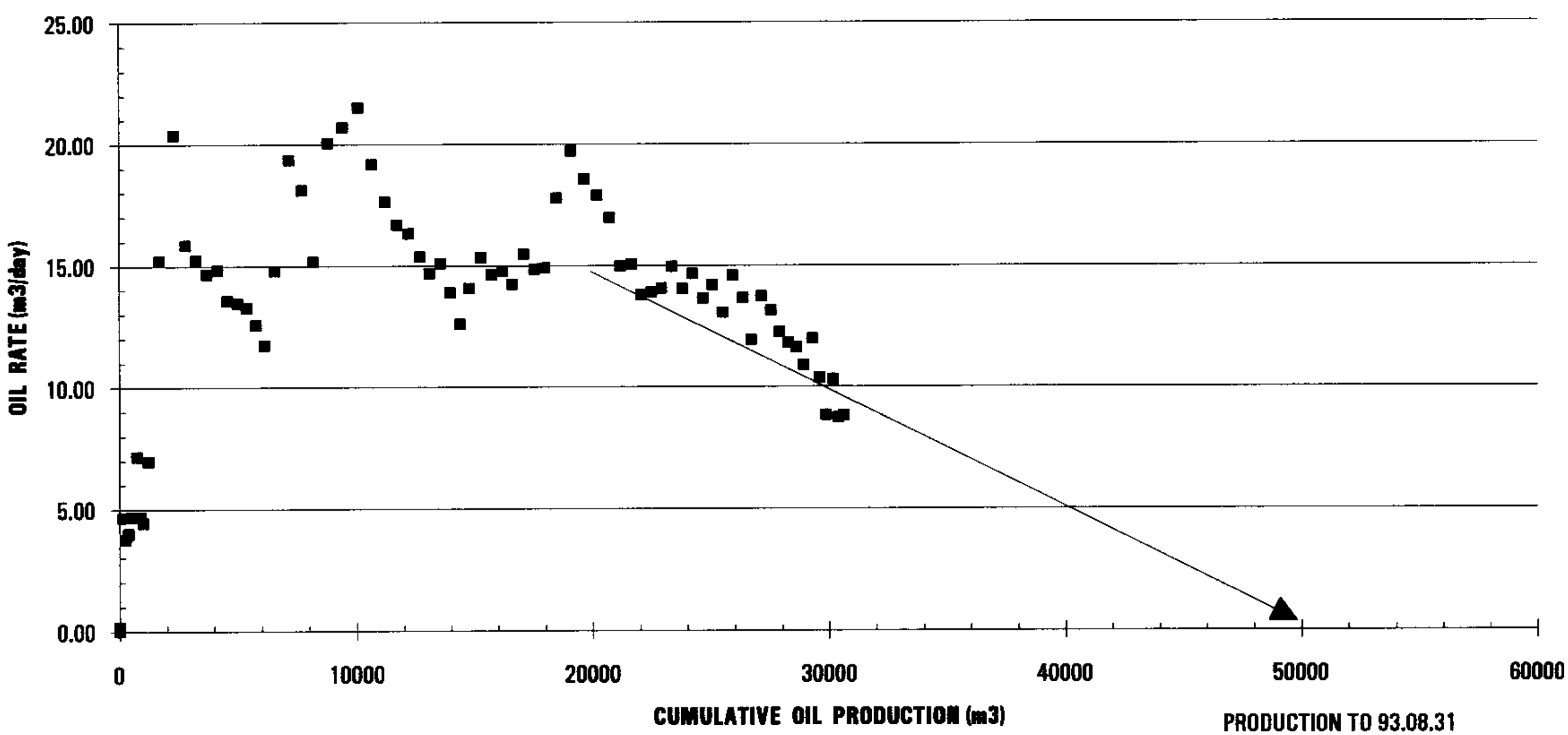
PROPOSED 9-14 INJECTION LOCATION

PROPOSED OBSERVATION WELL

NORTH EBOR UNIT NO.2 OUTLINE

ATTACHMENT NO.3

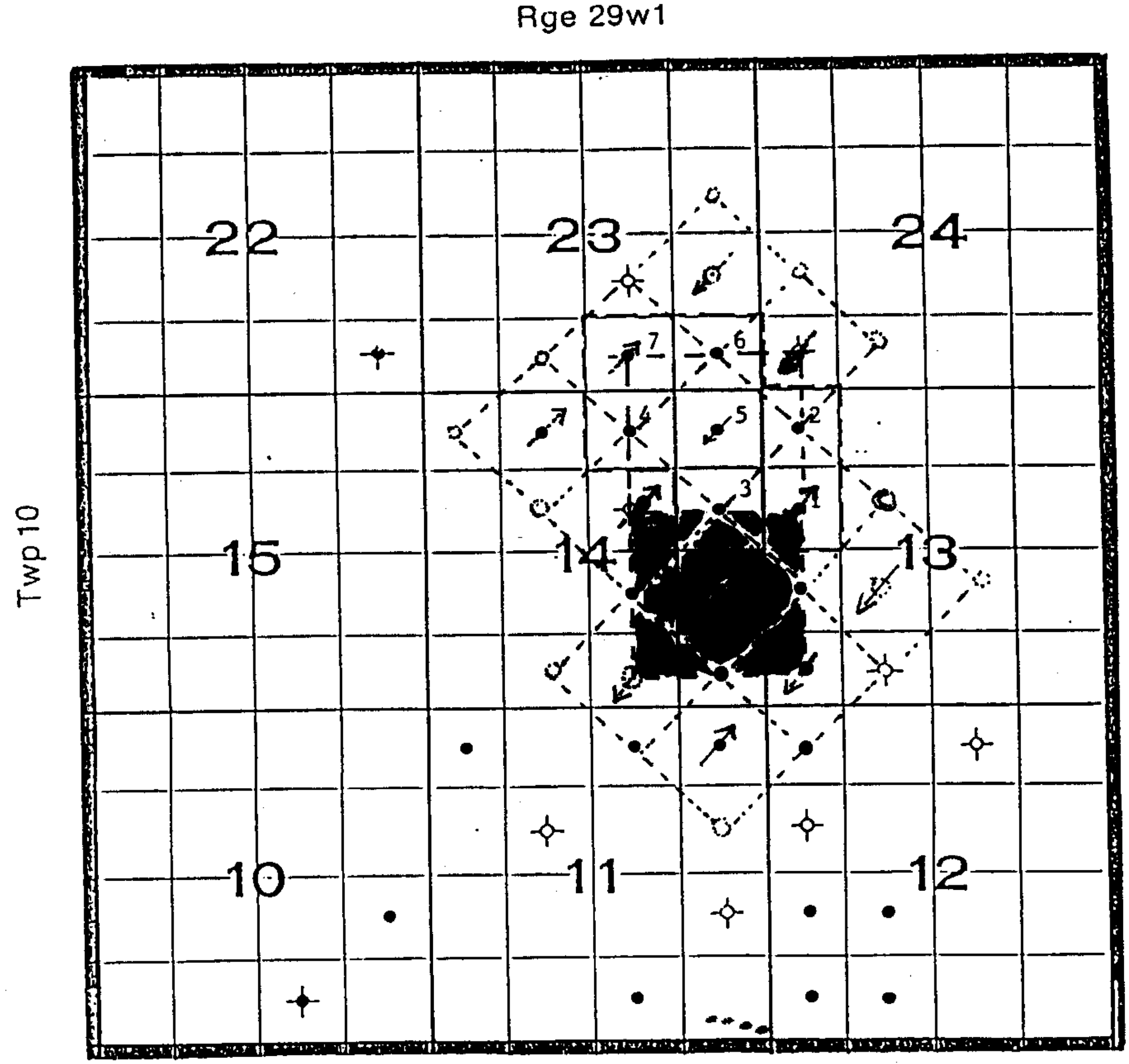
NORTH EBOR UNIT NO.1 REMAINING PROVED PRODUCING RESERVES



ATTACHMENT NO.4

NORTH EBOR UNIT NO. 1

INVERTED 5-SPOT FLOOD PATTERN



- - Unit Outline

NORTH EBOR UNIT NO.1

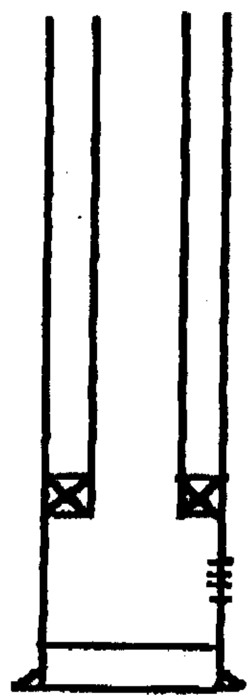
NORTH EBOR UNIT NO.2

ATTACHMENT NO. 5

DOWNHOLE CONFIGURATION

INJECTION WELL 9-14-10-29

PROPOSED CONVERSION TO WATER INJECTION
TUNDRA DALY 9-14-10-29 WPM



INTERNALLY COATED 60.3 MM TBG

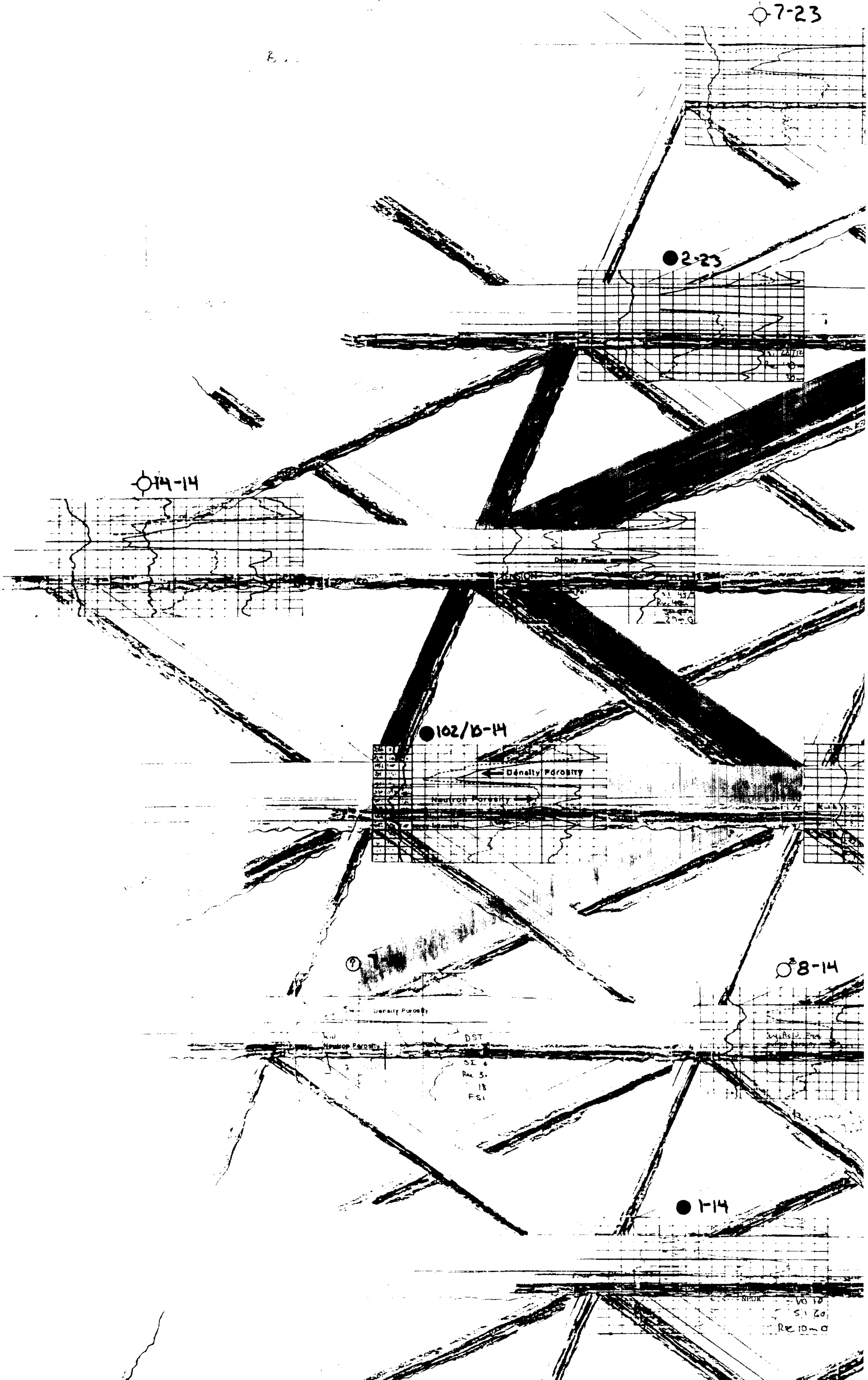
COATED AD-1 TENSION PACKER
SET AT 854 m

BAKKEN PERFORATIONS
856.5 - 860.5 m

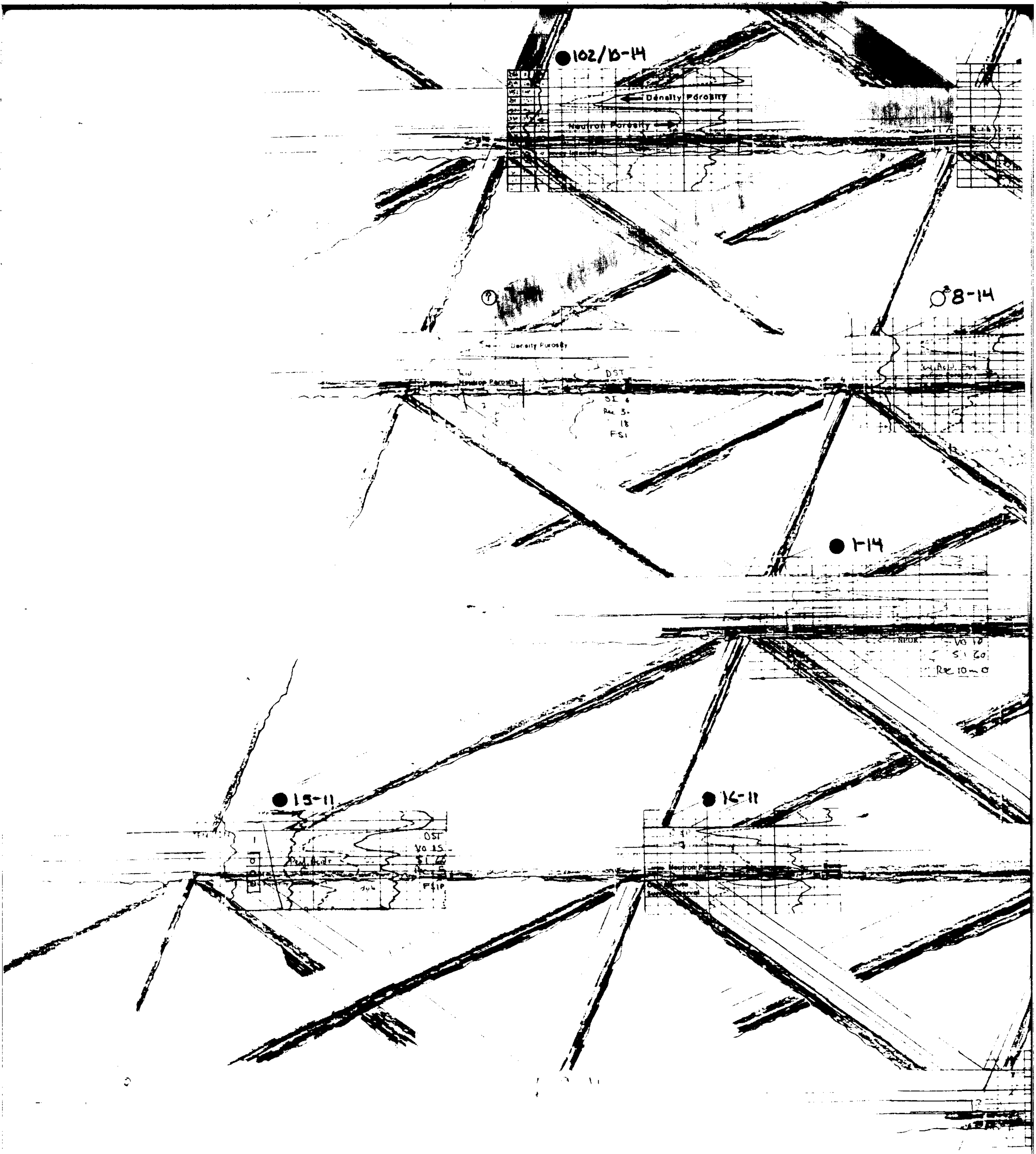
P.B.T.D. 862.5 m

APPENDIX A

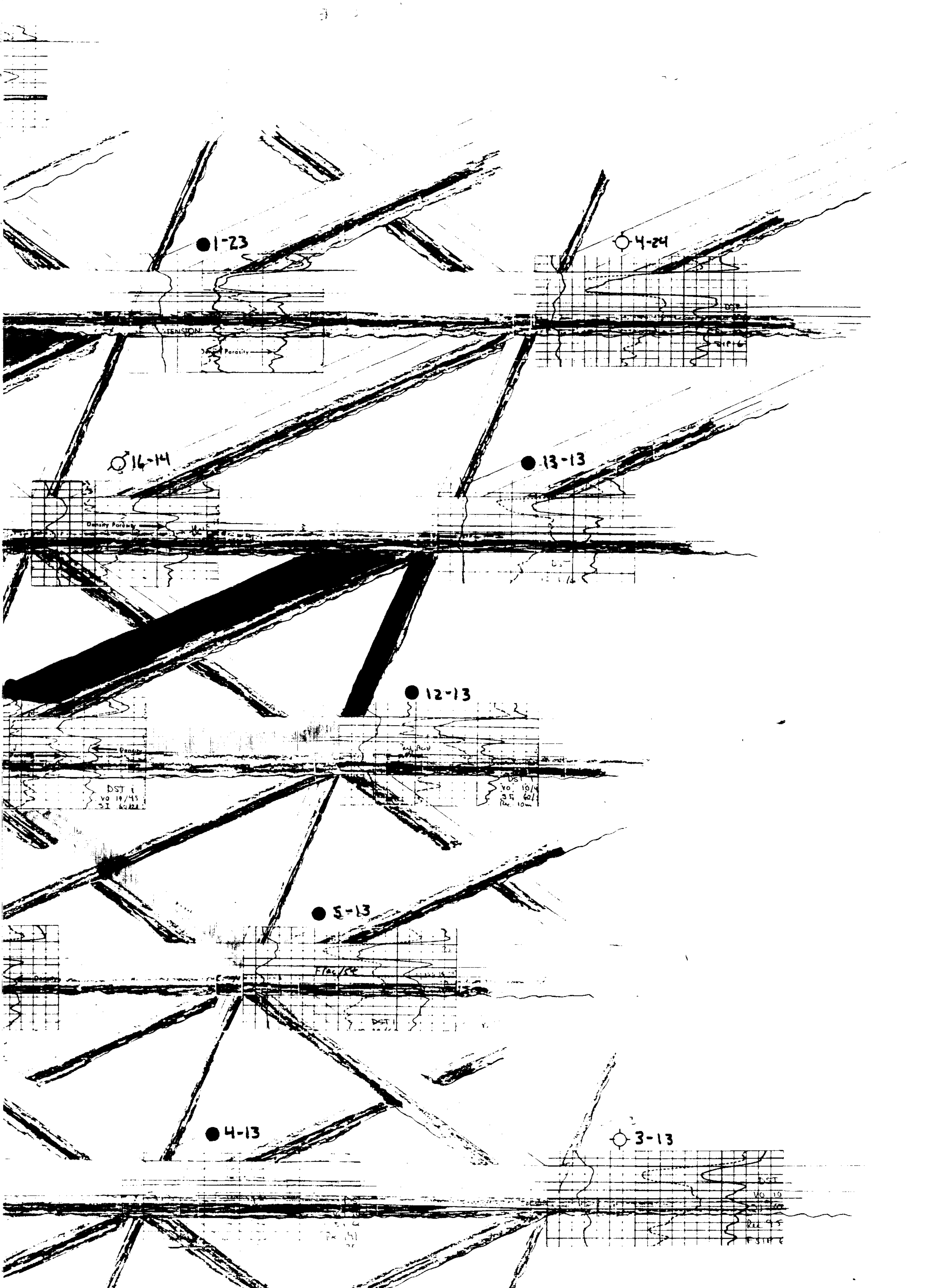
BAKKEN 'D' POOL RESERVOIR FENCE DIAGRAM



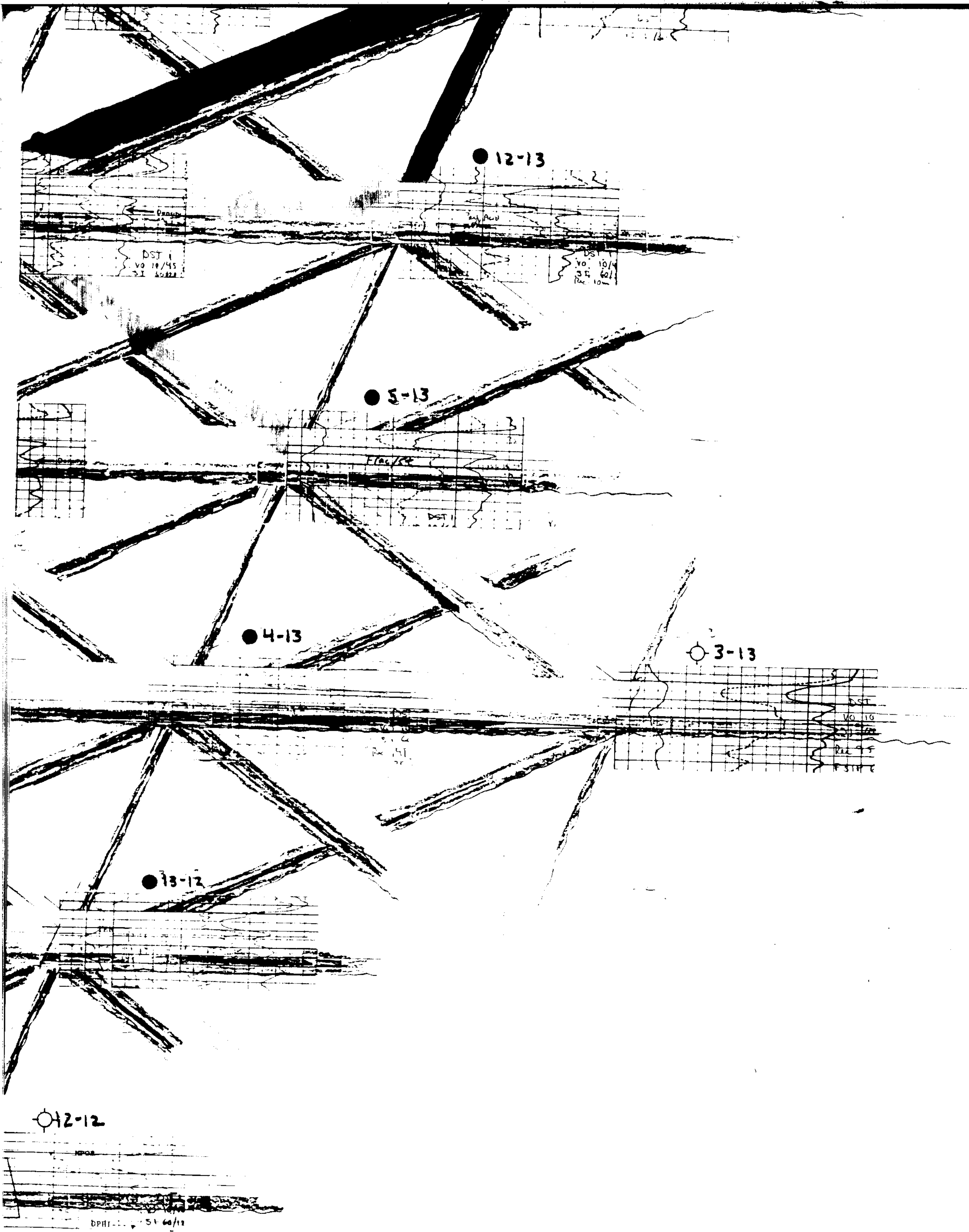
7-23
2-23
14-14
Density Porosity
102/13-14
Density Porosity
Neutron Porosity
8-14
Density Porosity
Neutron Porosity
DST
1-14


102/13-14
Density Porosity
Neutron Porosity
Density Porosity
DST
8-14
1-14
15-11
DST
16-11
Neutron Porosity

BAKKEN 'D' PO



1-23
4-24
TENSION
Sand Porosity
16-14
13-13
Density Porosity
12-13
Density
DST 1
5-13
DST 1
4-13
3-13
DST



L RESERVOIR FENCE DIAGRAM