PROPOSED CROMER UNIT NO. 5

Application for Enhanced Oil Recovery Waterflood Project

Middle Bakken/Three Forks Formations

Bakken – Three Forks B Pool (01 62B)

Daly Sinclair Field, Manitoba

April 23, 2018
Tundra Oil and Gas Limited

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INTRODUCTION

The Daly portion of the Daly Sinclair Oilfield is located in Townships 8-11 Ranges 27-29 WPM (Figure 1). Since discovery in 2004, the main oilfield area was developed with vertical and horizontal wells at 40 acre spacing on Primary Production. In addition, most vertical wells are commingled between the Lodgepole and Bakken zones.

In the eastern part of the Daly field, potential exists for incremental production and reserves from a Waterflood EOR project in the Three Forks and Middle Bakken oil reservoirs. The following represents an application by Tundra to establish Cromer Unit No. 5 (N/2 Section 22, Sections 26, 27, 28, S/2 33 and S/2 34-009-28W1) and implement a Secondary Waterflood EOR scheme within the Three Forks and Middle Bakken formations as outlined on Figure 2.

The proposed project area falls within the existing designated 01-62B Bakken-Three Forks Pool of the Daly Sinclair Oilfield (Figure 3).

SUMMARY

1. The proposed Cromer Unit No. 5 currently includes 15 horizontal wells and 12 vertical wells (4 are commingled with the Lodgepole), within 72 Legal Sub Divisions (LSD) of the Middle Bakken/Three Forks producing reservoir. The project area is located north of Cromer Unit No. 3 (Figure 2).

2. Total Net Original Oil in Place (OOIP) in Cromer Unit No. 5 has been calculated to be 1,087 e^3m^3 (6,835 Mbbl) for an average of 15.1 net e^3m^3 (94.9 Mbbl) OOIP per 40 acre LSD based on a 0.5 md cutoff for the Middle Bakken & Lyleton 'B'.

3. Cumulative production to the end of January 2018 from the 27 wells within the proposed Cromer Unit No. 5 project area was 80.8 e^3m^3 (508.0 Mbbl) of oil, and 256.1 e^3m^3 (1,611 Mbbl) of water, representing a 7.4% Recovery Factor (RF) of the Net OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary producing oil reserves in the proposed Cromer Unit No. 5 project area is estimated to be 163.8 e^3m^3 (1,030 Mbbl), with 83.0 e^3m^3 (522.1 Mbbl) remaining as of the end of January 2018.

5. Ultimate oil recovery of the proposed Cromer Unit No. 5 OOIP, under the current Primary Production method, is forecasted to be 15%.

6. Figure 4 shows the production from the Cromer Unit No. 5 peaked in March 2014 at 95.7 m^3 (OPD). As of January 2018, production was 24.1 m^3 OPD, 82.4 m^3 of water per day (WPD) and a 77.3% watercut (WCT).

7. In March 2014, production averaged 5.63 m^3 OPD per well in Cromer Unit No. 5. As of January 2018, average per well production has declined to 1.15 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately 20.8% in the project area.

8. EUR of oil under Secondary Waterflood EOR for the proposed Cromer Unit No. 5 is estimated to be 278.0 e^3m^3 (1,748.8 Mbbl), with 197.2 e^3m^3 remaining. An incremental 114.2e^3m^3 (718.5 Mbbl) of proved reserves, or 11%, is forecasted to be recovered under the proposed Unitization and Secondary EOR production, versus the existing Primary production method.

9. Total RF under Secondary WF in the proposed Cromer Unit No. 5 is estimated to be 26%.

10. Based on waterflood response in the adjacent main portion of the Sinclair field and the North Ebor Units No. 1 & 2, the Three Forks and Middle Bakken Formations in the proposed project area are believed to be suitable reservoirs for WF EOR operations.

11. Future horizontal injectors, with multi-stage hydraulic fractures, will be drilled between existing horizontal/vertical producing wells (Figure 5) within the proposed Cromer Unit No. 5, to complete line drive waterflood patterns with effective 20 acre spacing.

RESERVOIR PROPERTIES AND TECHNICAL DISCUSSION

The proposed Cromer Unit No. 5 project area is located within Township 9, Range 28 W1 of the Daly Sinclair oil field. The proposed Cromer Unit No. 5 will include 15 horizontal wells and 12 vertical wells (4 are commingled with the Lodgepole), within an area covering 72 LSDs (Figure 2). The project area is located north of Cromer Unit No. 3. A project area well list complete with recent production statistics is attached as Table 3.

Tundra believes that the waterflood response in the adjacent main portion of the Sinclair field and North Ebor Units No. 1 & 2 demonstrates potential for incremental production and reserves from a WF EOR project in the subject Middle Bakken and/or Three Forks oil reservoirs.

Geology

Stratigraphy:

The stratigraphy of the reservoir section for the proposed unit is shown on the structural cross-section attached as Appendix 2. The section runs SE to NW through the proposed Unit area. The producing sequence in descending order consists of the Upper Bakken Shale, Middle Bakken Siltstone, Lyleton B Siltstone and the Torquay Silty Shale. The reservoir units are represented by the Middle Bakken and Lyleton B Siltstones. The Upper Bakken Shale is a black, organic rich, platy shale which forms the top seal for the underlying Middle Bakken and Lyleton reservoirs. The reservoir units in the proposed unit are analogous to the Bakken / Lyleton producing reservoirs that have been approved adjacent to the proposed unit as noted on the Offsetting Units Map at Appendix 1.

Sedimentology:

The Middle Bakken reservoir consists of fine to coarse grained grey siltstone to fine sandstone which may be subdivided on the basis of lithologic characteristics into upper and lower units. The upper portion is very often heavily bioturbated and is generally non-reservoir. These bioturbated beds often contain an impoverished fauna consisting of well-worn brachiopod, coral and occasional crinoid fragments suggesting deposition in a marginal marine environment. The lower part of the Middle Bakken is generally finely laminated with alternating light and dark laminations with occasional bioturbation. Reservoir quality is highly variable within the Unit area. Within the proposed unit, the Middle Bakken thickness ranges between 2.5m to 4m (Appendix 4).

The Lyleton B reservoir consists of buff to tan fine grained siltstone (occasionally very fine siltstone) made up of quartz, feldspar and detrital dolomite with minor mica and clay mostly in the form of clay clasts or chips. The Lyleton B is generally well bedded and shows evidence of parallel lamination with occasional wind ripples. The coarser siltstones are interbedded with dark grey-green or red very fine grained siltstone which is generally non-reservoir. The Lyleton B thickness ranges between just under 1.5m to almost 4m thick within the proposed unit (Appendix 5).

The Torquay (Three Forks) forms the base of the reservoir sequence and is a brick red or mint green dolomitic very fine siltstone. It forms a good basal seal to the Lyleton B reservoir.

Structure:

The structure within the proposed unit area is relatively consistent, dipping primarily to the South West (Appendix 3). To the East of the unit, the dip shifts to an Eastward direction. This is due to the regional SW dip, and the edge of a large paleo high associated with the Sinclair Daly field to the East.

Reservoir Continuity:

Lateral continuity of the reservoir units is an essential requirement of a successful waterflood. As demonstrated by the cross section and the isopach maps, both reservoir formations, the Middle Bakken, and Lyleton B, are continuous throughout the proposed unit area.

Vertical continuity between the Middle Bakken and underlying Lyleton B reservoir exists throughout the proposed unit as they are in direct contact.

Fluid Contacts:

There is no oil/water contacts proximal to the proposed unit area.

Gross OOIP Estimates

Total volumetric OOIP for the Middle Bakken Lyleton A and Lyleton B within the proposed unit has been calculated to be **1,087** e^3m^3 (**6,835** Mbbl) using Tundra internally created maps. Maps used were generated from core data available in the greater Sinclair area (Appendix 6).

An average net to gross ratio was calculated for each reservoir formation using pressure decay profile permeameter data (PDPK) with a cut off of 0.5mD on surrounding cored wells. To determine net pay these ratios are then applied to each formation thickness from isopach maps based on logs. Porosity is also calculated using an average for each formation from surrounding core data after a 0.5mD cutoff.

Tabulated parameters for each LSD from the calculations can be found in Table 4.

OOIP values were calculated using the following volumetric equation:

$$OOIP = \frac{Area * Net\ Pay * \ Porosity * (1 - Water\ Saturation)}{Initial\ Formation\ Volume\ Factor\ of\ Oil}$$

or

$$OOIP(m3) = \frac{A * h * \emptyset * (1 - Sw)}{Bo} * \frac{10{,}000m2}{ha}$$

or

$$OOIP(Mbbl) = \frac{A * h * \emptyset * (1 - Sw)}{Bo} * 3.28084\frac{ft}{m} * 7{,}758.367\frac{bbl}{acre * ft} * \frac{1Mbbl}{1{,}000bbl}$$

where

OOIP	= Original Oil in Place by LSD (Mbbl, or m3)
A	= Area (40acres, or 16.187 hectares, per LSD)
h * Ø	= Net Pay * Porosity, or Phi * h (ft, or m)
Bo	= Formation Volume Factor of Oil (stb/rb, or sm3/rm3)
Sw	= Water Saturation (decimal)

The initial oil formation volume factor was adopted from PVT information taken from the Bakken Intervals of 100/02-17-009-29W1 and 100/13-19-009-28W1 which are representative of the fluid characteristics in the reservoir.

Historical Production

A historical group production history plot for the proposed Cromer Unit No. 5 is shown as Figure 4. Oil production commenced from the proposed Unit area in October 1994 and peaked during March 2014 at 95.7 m^3 OPD. As of January 2018, production was 24.1 m^3 OPD, 82.4 m^3 of WPD and a 77.3% WCT.

From peak production in March 2014 to date, oil production is declining at an annual rate of approximately 20.8% under the current Primary Production method.

The field’s production rate indicates the need for pressure restoration and maintenance, and waterflooding is deemed to be the most efficient means of re-introducing energy back into the reservoir system and to provide areal sweep between wells.

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP to 26%. The basis for unitization is to develop the lands in an effective manner that will be conducive to waterflooding. Unitizing will enable the reservoir to have the greatest recovery possible by allowing the development of additional drilling and injector conversions over time, in order to maintain reservoir pressure and increase oil production.

Unit Name

Tundra proposes that the official name of the new Unit shall be Cromer Unit No. 5.

Unit Operator

Tundra will be the Operator of record for Cromer Unit No. 5.

Unitized Zone

The Unitized zone(s) to be waterflooded in Cromer Unit No. 5 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 15 horizontal wells and 12 vertical wells to be included in the proposed Cromer Unit No. 5 are outlined in Table 3.

Unit Lands

The Cromer Unit No. 5 will consist of 72 LSDs as follows:

> N/2 Section 22, Township 9, Range 28, W1M
> Section 26, Township 9, Range 28, W1M
> Section 27, Township 9, Range 28, W1M
> Section 28, Township 9, Range 28, W1M
> S/2 of Section 33 of Township 9, Range 28, W1M
> S/2 of Section 34 of Township 9, Range 28, W1M

The lands included in the 40 acre tracts are outlined in Table 1.

Tract Factors

The proposed Cromer Unit No. 5 will consist of 72 Tracts based on the 40 acre LSDs containing the existing 15 horizontal and 12 vertical wells.

The Tract Factor contribution for each of the LSD's within the proposed Cromer Unit No. 5 was calculated as follows:

- Gross OOIP by LSD, minus cumulative production to date for the LSD as distributed by the LSD specific Production Allocation (PA) % in the applicable producing horizontal or vertical well (to yield Remaining Gross OOIP)
- Last twelve (12) months production to date for the LSD as distributed by the LSD specific PA % in the applicable producing horizontal or vertical well.
- Tract Factor by LSD = Fifty percent (50%) of the product of Remaining Gross OOIP by LSD as a % of total proposed Unit Remaining Gross OOIP, and fifty percent (50%) of the product of the Last 12 Months Production as a % of total proposed Unit Last 12 Months Production.

Tract Factor calculations for all individual LSD's based on the above methodology are outlined within Table 2. Tundra believes that the above given method provides the most equitable assignment of tract participation factors to all mineral owners, given the geological and reservoir risks associated with waterflooding horizontal to horizontal wellbores in the Bakken formation.

Working Interest Owners

Table 1 outlines the working interest (WI) for each recommended Tract within the proposed Cromer Unit No. 5. Tundra holds a 100% WI ownership in all the proposed Tracts. Tundra will have a 100% WI in the proposed Cromer Unit No. 5.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Cromer Unit No. 5 are based on internal engineering assessments. Project area specific reservoir and geological parameters were used to guide the overall Secondary Waterflood recovery factor. Internal reviews included analysis of available open-hole logs, core data, petrophysics, seismic, drilling and completion information, and production information. These parameters were reviewed to develop a suite of geological maps and establish reservoir parameters to support the calculation of the proposed Cromer Unit No. 5 OOIP (Table 4).

Unitizing the proposed Cromer Unit No. 5 will provide an equitable means of maximizing ultimate oil recovery in the project area.

Pre-Production of New Horizontal Injection Wells

Primary production from the original vertical/horizontal producing wells in the proposed Cromer Unit No. 5 has declined significantly from peak rate indicating a need for secondary pressure support. It is projected that 4 new horizontal producers & 15 new horizontal injection wells will be drilled between the existing vertical/horizontal producing wells as shown in Figure 5. This will result in effective 20 acre line drive waterflood patterns within Cromer Unit No. 5. Tundra believes an initial period of producing horizontal wells prior to placing them on permanent water injection is essential and all Unit mineral owners will benefit. Ultimately the timing of conversion will be based on production performance post unit approval. It is Tundra's desire to have the final injection conversion candidates on injection as soon as possible.

Tundra monitors reservoir pressure, fluid production and decline rates in each pattern to determine when the well will be converted to water injection.

Reserves Recovery Profiles and Production Forecasts

The primary waterflood performance predictions for the proposed Cromer Unit No. 5 are based on oil production decline curve analysis, and the secondary predictions are based on internal engineering analysis performed by the Tundra reservoir engineering group.

Primary Production Forecast:

Cumulative production in the Cromer Unit No. 5 project area, to the end of January 2018 from 27 wells, was 80.8 e^3m^3 of oil and 256.1 e^3m^3 of water for a recovery factor of 7.4% of the calculated Net OOIP.

Ultimate Primary Producing oil reserves recovery for Cromer Unit No. 5 has been estimated to be 163.8 e^3m^3, or a 15% RF of OOIP. Remaining Producing Primary Reserves has been estimated to be 83.0 e^3m^3 to the end of January 2018.

The expected production decline and forecasted cumulative oil recovery under continued Primary Production is shown in Figures 6 and 7.

Pre-Production Schedule / Timing for Conversion of Horizontal Wells to Water Injection:

The injection wells will be drilled after unit approval has been received. Tundra will produce these future injectors to condition the reservoir for optimal waterflood. Timing for injection conversion will be chosen based on production performance post unit approval.

Criteria for Conversion to Water Injection Well:

Fifteen water injection wells are likely required for this proposed unit as shown in Figure 5.

Tundra will monitor the following parameters to assess the best timing for each individual horizontal well to be converted from primary production to water injection service.

- Measured reservoir pressures at start of and/or through primary production
- Fluid production rates and any changes in decline rate
- Any observed production interference effects with adjacent vertical and horizontal wells
- Pattern mass balance and/or oil recovery factor estimates
- Reservoir pressure relative to bubble point pressure

The above schedule allows for the proposed Cromer Unit No. 5 project to be developed equitably, efficiently, and moves to project to the best condition for the start of waterflood as quickly as possible. It also provides the Unit Operator flexibility to manage the reservoir conditions and response to help ensure maximum ultimate recovery of OOIP.

Secondary EOR Production Forecast:

Secondary waterflood plots of the expected oil production forecast over time and the expected oil production v. cumulative oil are plotted in Figures 8 and 9, respectively. Total Secondary EUR for the proposed Cromer Unit No. 5 is estimated to be 278.0 e^3m^3 with 197.2 e^3m^3 remaining representing a total RF of 26% for the proposed Unit area. An incremental 114 e^3m^3 of oil, or incremental 11% Secondary RF, are forecasted to be recovered under the proposed Waterflood Unitization.

Estimated Fracture Gradient

Completion data from the producing wells within the project area indicate a fracture pressure gradient of 21.0 – 26.0 kPa/m true vertical depth (TVD). Tundra expects the fracture gradient encountered during completion of the proposed horizontal injection well will be somewhat lower than this value due to expected reservoir pressure depletion. The current Cromer Unit No. 3 Waterflood was approved for a maximum allowable wellhead injection pressure of 9.0 MPa at which water may be injected.

WATERFLOOD OPERATING STRATEGY

Water Source

The injection water for the proposed Cromer Unit No. 5 will be supplied from the existing Sinclair 4-1-8-29W1 Battery source and injection water system. All existing injection water is obtained from the Mannville formation in the 100/14-30-7-28W1 licensed water source well. Mannville water from the 100/14-30 source well is pumped to the main Sinclair Units Water Plant at 4-1-8-29W1, filtered, and pumped up to injection system pressure. A diagram of the Sinclair water injection system and new pipeline connection to the proposed Cromer Unit No. 5 project area is shown as Figure 10.

Produced water is not currently used for any water injection in the Tundra operated Sinclair Units and there are no current plans to use produced water as a source supply for Cromer Unit No. 5.

Since all producing Middle Bakken/Three Forks wells in the Daly Sinclair areas, whether vertical or horizontal, have been hydraulically fractured, produced waters from these wells are inherently a mixture of Three Forks and Bakken native sources. This mixture of produced waters has been extensively tested for compatibility with 100/14-30 source Mannville water, by a highly qualified third party, prior to implementation by Tundra. All potential mixture ratios between the two waters, under a range of temperatures, have been simulated and evaluated for scaling and precipitate producing tendencies. Testing of multiple scale inhibitors has also been conducted and minimum inhibition concentration requirements for the source water volume determined. At present, continuous scale inhibitor application is maintained into the source water stream out of the Sinclair injection water facility. Review and monitoring of the source water scale inhibition system is also part of an existing routine maintenance program.

Injection Wells

The injection wells will be drilled after unit approval has been received. The horizontal injection wells will be stimulated by multiple hydraulic fracture treatments to obtain suitable injection rates in an openhole completion (Figure 11). Tundra has extensive experience with horizontal fracturing in the area, and all jobs are rigorously programmed and monitored during execution. This helps ensure optimum placement of each fracture stage to prevent, or minimize, the potential for out-of-zone fracture growth and thereby limit the potential for future out-of-zone injection.

The new water injection wells will be placed on injection after the pre-production period and approval to inject. Wellhead injection pressures will be maintained below the least value of either:

- the area specific known and calculated fracture gradient, or
- the licensed surface injection Maximum Allowable Pressure (MOP)

Tundra has a thorough understanding of area fracture gradients. A management program will be utilized to set and routinely review injection target rates and pressures vs. surface MOP and the known area formation fracture pressures. All new water injection wells are surface equipped with injection volume metering and rate/pressure control. An operating procedure for monitoring water injection volumes and meter balancing will also be utilized to monitor the entire system measurement and integrity on a daily basis.

The proposed Cromer Unit No. 5 horizontal water injection well rate is forecasted to average 10 – 25 m^3 WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure Management during Waterflood

No representative initial pressure surveys are available for the proposed Cromer Unit No. 5 project area in the Bakken formation because almost all the wells in the area are commingled with the Lodgepole zone. The extremely long shut-in and build-up times required to obtain any possible representative surveys from the producing wells are economically prohibitive. Tundra will make all attempts to capture a reservoir pressure survey in the proposed horizontal injection wells during the completion of the wells and prior to injection or production. Based on a normally pressured reservoir, it is believed the initial reservoir pressure in this area was on average 8,300kPa.

Tundra expects it will take 2-4 years to re-pressurize the reservoir due to cumulative primary production voidage and pressure depletion. Initial monthly Voidage Replacement Ratio (VRR) is expected to be approximately 1.25 to 2.00 within the patterns during the fill up period. As the cumulative VRR approaches 1, target reservoir operating pressure for waterflood operations will be 75-90% of original reservoir pressure.

Waterflood Surveillance and Optimization

Cromer Unit No. 5 EOR response and waterflood surveillance will consist of the following:

- Regular production well rate and WCT testing
- Daily water injection rate and pressure monitoring vs target
- Water injection rate/pressure/time vs. cumulative injection plot
- Reservoir pressure surveys as required to establish pressure trends
- Pattern VRR
- Potential use of chemical tracers to track water injector/producer responses
- Use of some or all of: Water Oil Ratio (WOR) trends, Log WOR vs Cum Oil, Hydrocarbon Pore Volumes Injected, Conformance Plots
- Sulfur content and oil density testing

The above surveillance methods will provide an ever increasing understanding of reservoir performance, and provide data to continually control and optimize the Cromer Unit No. 5 waterflood operation. Controlling the waterflood operation will significantly reduce or eliminate the potential for out-of-zone injection, undesired channeling or water breakthrough, or out-of-Unit migration. The monitoring and surveillance will also provide early indicators of any such issues so that waterflood operations may be altered to maximize ultimate secondary reserves recovery from the proposed Cromer Unit No. 5.

On Going Reservoir Pressure Surveys

For each openhole horizontal injection well, a measured reservoir pressure will be obtained prior to water injection. These pressures will be reported within the Annual Progress Reports for Cromer Unit No. 5 as per Section 73 of the Drilling and Production Regulation.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Cromer Unit No. 5 will be deemed uneconomic when the net oil rate and net oil price revenue stream becomes less than the current producing operating costs. With any positive oil production response under the proposed Secondary recovery method, the economic limit will be significantly pushed out into the future. The actual economic cut off point will then again be a function of net oil price, the magnitude and duration of production rate response to the waterflood, and then current operating costs. Waterflood projects generally become uneconomic to operate when Water Oil Ratios (WOR's) exceed 100.

WATER INJECTION FACILITIES

The Cromer Unit No. 5 waterflood operation will utilize the existing Tundra operated source well supply and water plant facilities located at 4-1-8-29W1 Battery. Injection wells will be connected to the existing high pressure water pipeline system supplying other Tundra-operated Waterflood Units.

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Figure 12.

OTHER CONSIDERATIONS

Tundra is requesting approval to continue to produce the vertical wells commingled between the Bakken and Lodgepole zones. The current practice of splitting production between Bakken and Lodgepole using the sulfur content difference will continue to be used.

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra is in the process of notifying all mineral rights and surface rights owners of this proposed EOR project and formation of Cromer Unit No. 5. Copies of the notices and proof of service, to all surface and mineral rights owners will be forwarded to the Petroleum Branch when available to complete the Cromer Unit No. 5 Application.

Cromer Unit No. 5 Unitization, and execution of the formal Cromer Unit No. 5 Agreement by affected Mineral Owners, is expected during Q2 2018. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Cromer Unit No. 5 Application.

Should the Petroleum Branch have further questions or require more information, please contact Lindsey Snyder at (403) 910-1665 or by email at lindsey.snyder@tundraoilandgas.com.

TUNDRA OIL & GAS LIMITED

Original Signed by Lindsey Snyder, Exploitation Engineer, April 23, 2018

Proposed Cromer Unit No. 5

Application for Enhanced Oil Recovery Waterflood Project

List of Figures

Figure 1

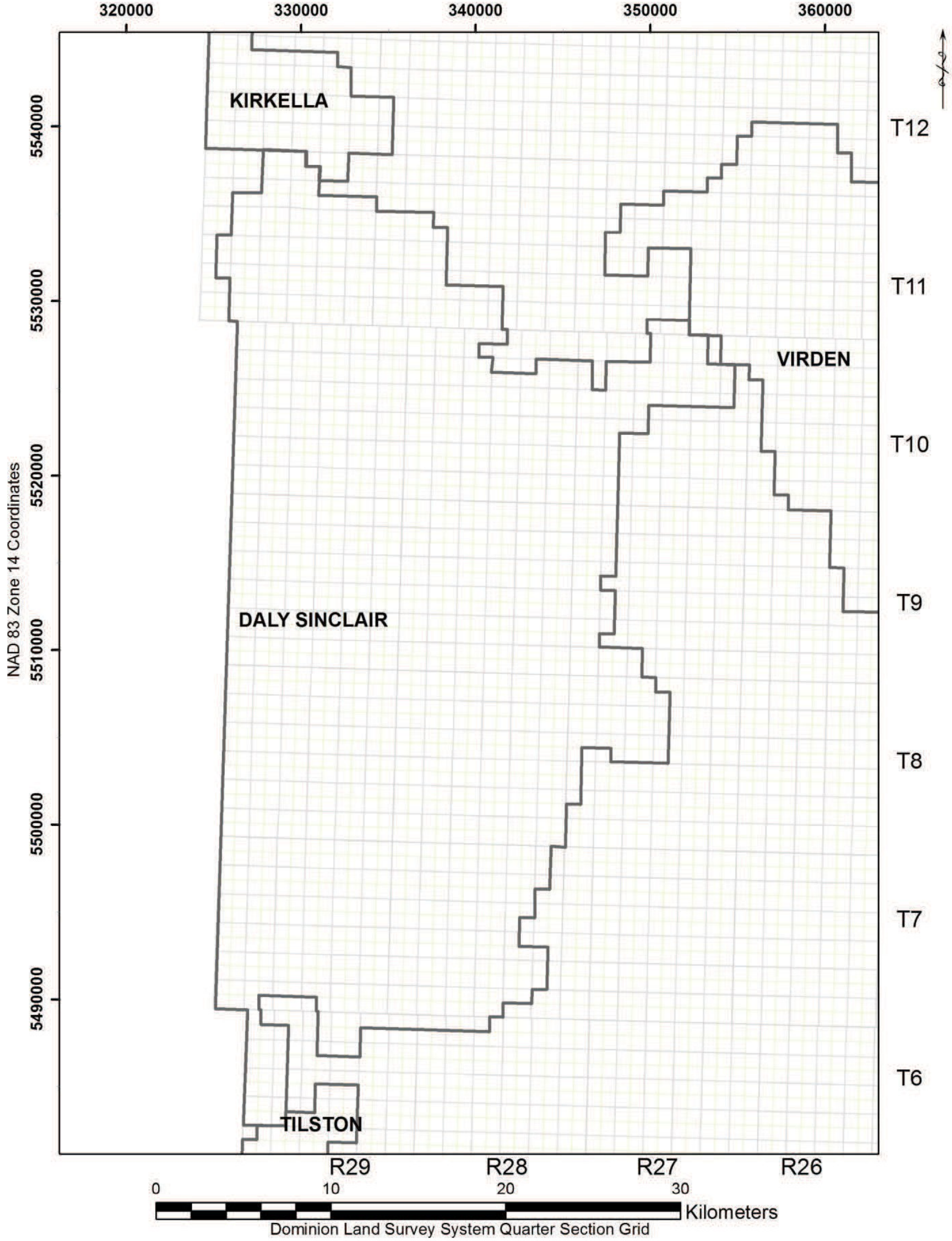
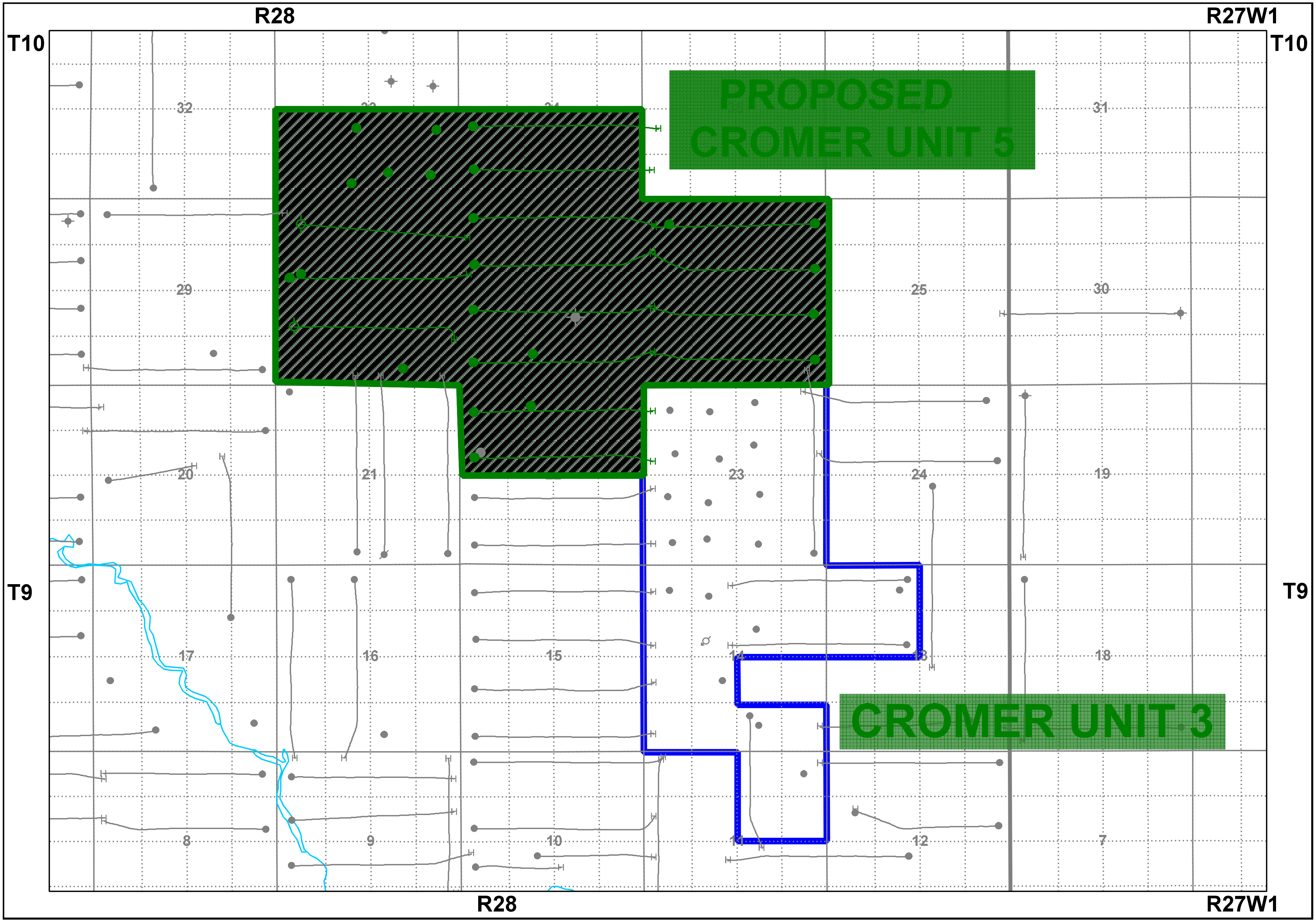


Figure 2 - Daly Sinclair Field (01)

Figure No. 2


R28
R27W1
T10
T10
PROPOSED
CROMER UNIT 5
32
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T9
T9
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CROMER UNIT 3
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R28
R27W1

Figure No. 3

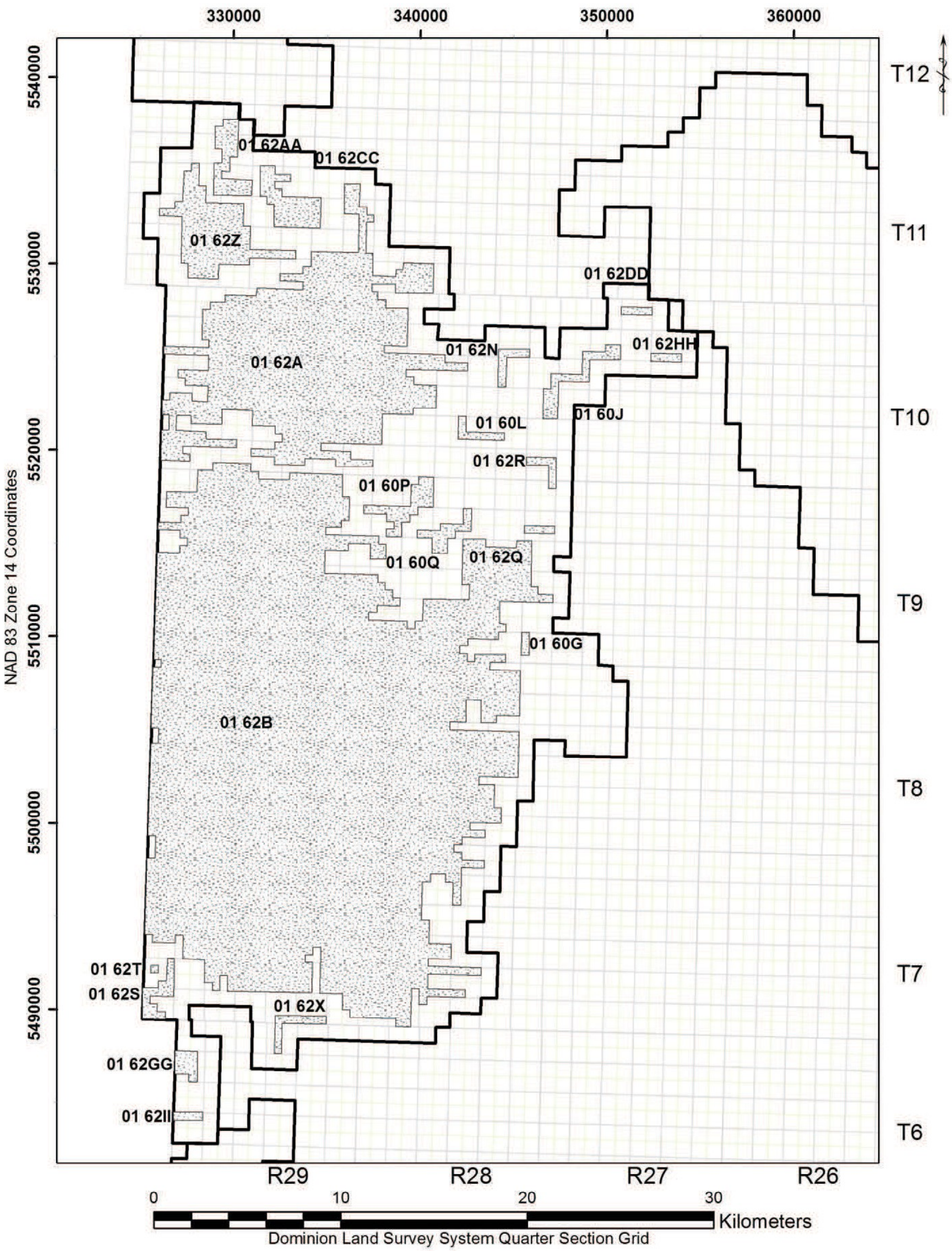


Figure 13 - Daly Sinclair Bakken & Bakken-Three Forks Pools (01 60A - 01 60BB & 01 62A – 01 62II)

Well Information as of 4/6/2018 - Group Well Report

Production Graph

Group:	cromer unit no. 5.lwell	**On Prod:**	1994-10 to 2018-01	**Cum Oil:**	80774.5 m3
# of Wells:	27	**Prod Form:**	BAKKEN; TORQUAY; BAKKENM; BAKKENU; THREEFK	**Cum Gas:**	0.0 E3m3
Fluid:	Oil	**Field:**	DALY (MB1)	**Cum Wtr:**	256127.4 m3
Mode:	Producing; Commingled; Pumping; Abandoned Zone	**Pool Code:**	MB000162A	**Cum Inj Oil:**	0.0 m3
		Unit Code:		**Cum Inj Gas:**	0.0 E3m3
				Cum Inj Wtr:	0.0 m3

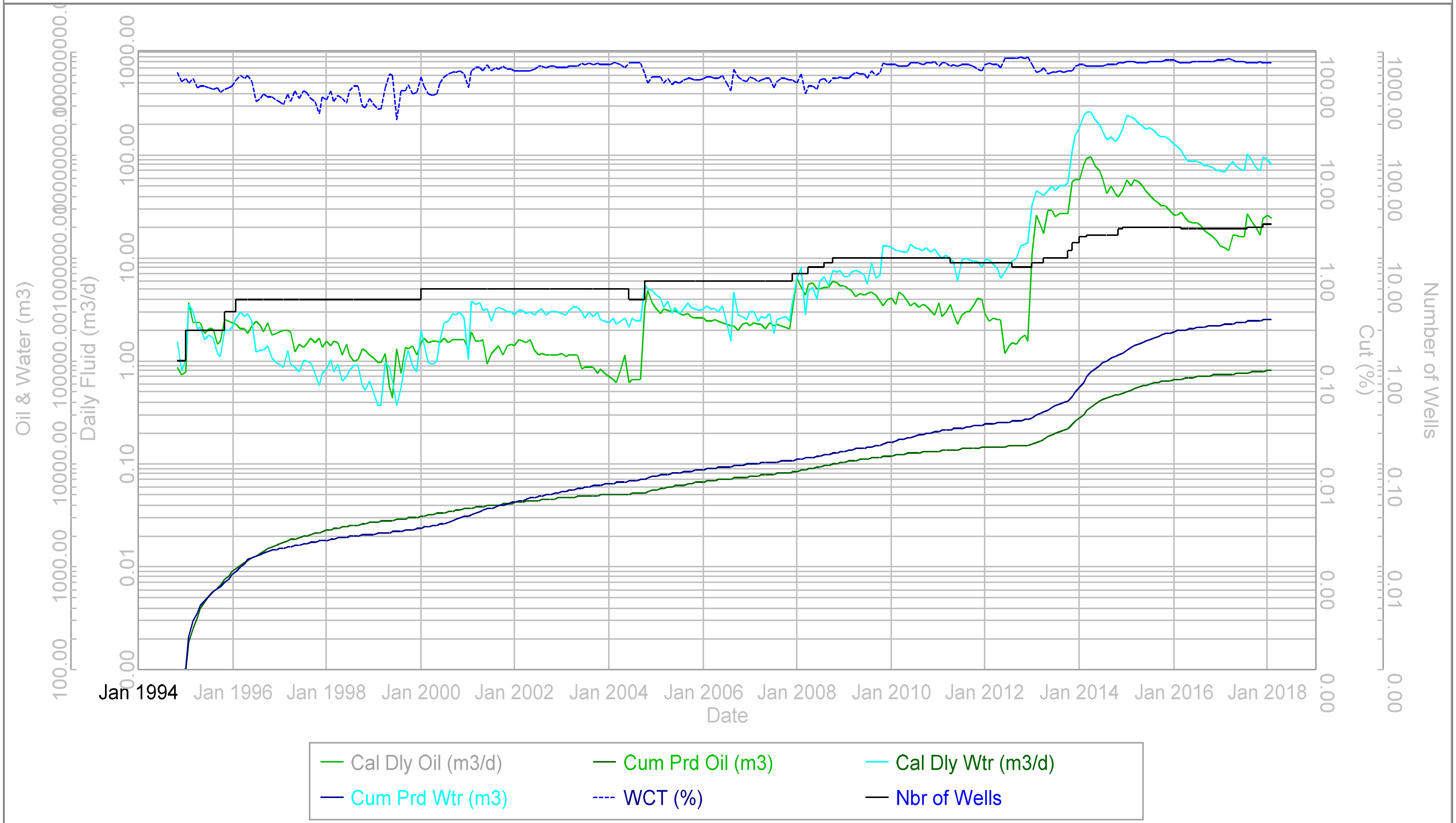
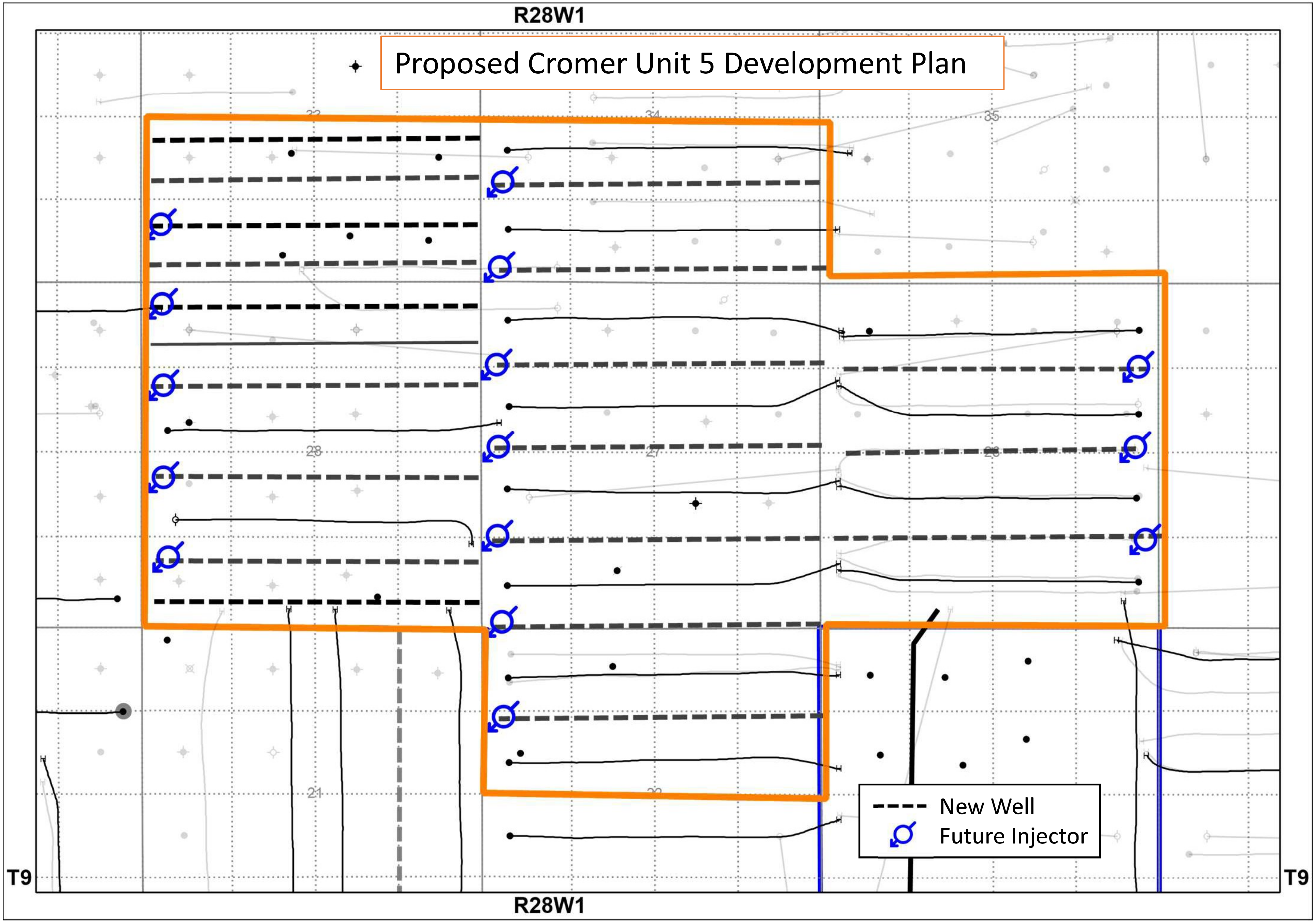


Figure 5.



R28W1
Proposed Cromer Unit 5 Development Plan
T9
T9
R28W1
New Well
Future Injector

Figure 6. Rate vs Time - Primary

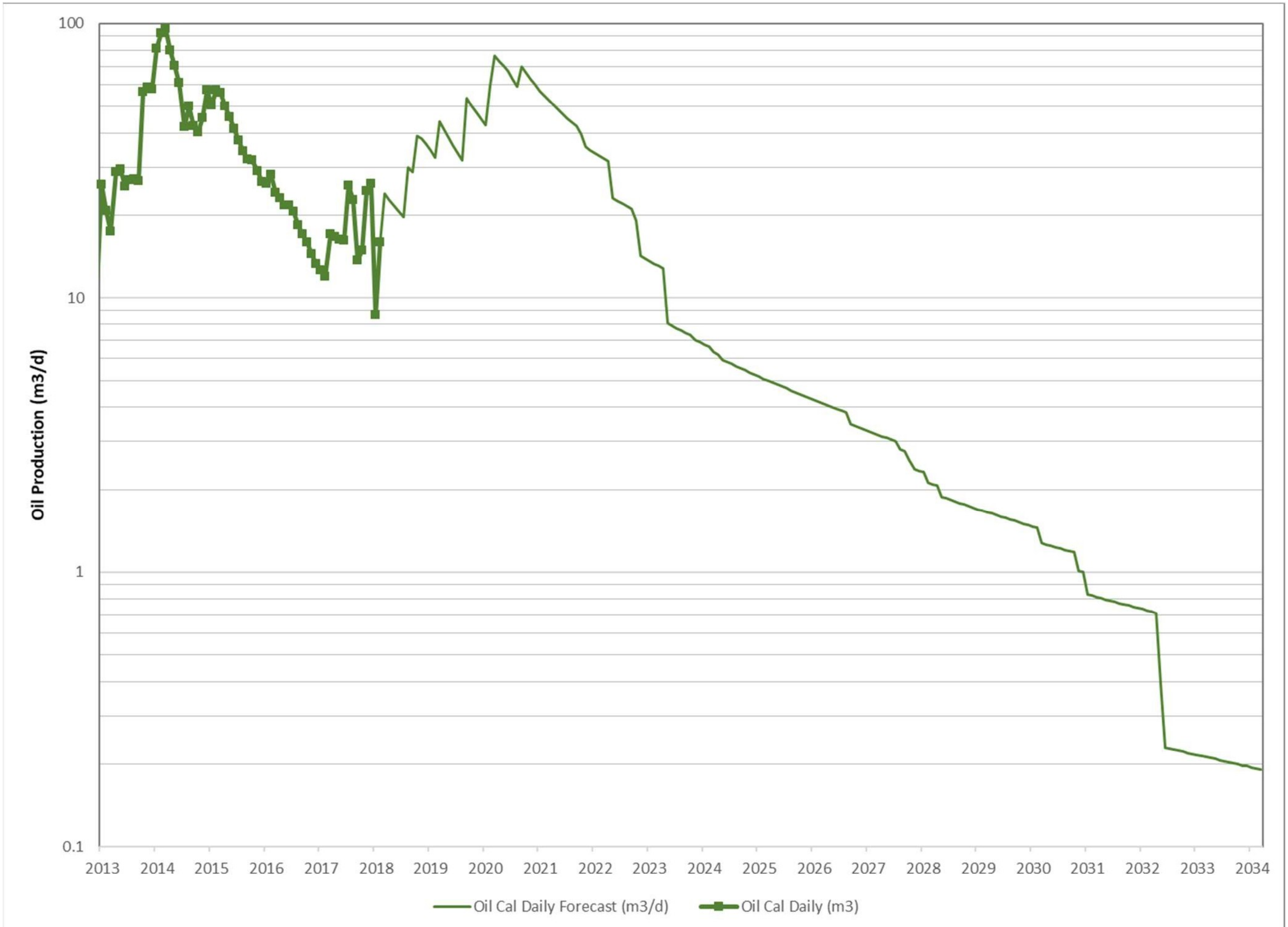


Figure 7. Rate vs Cumulative - Primary

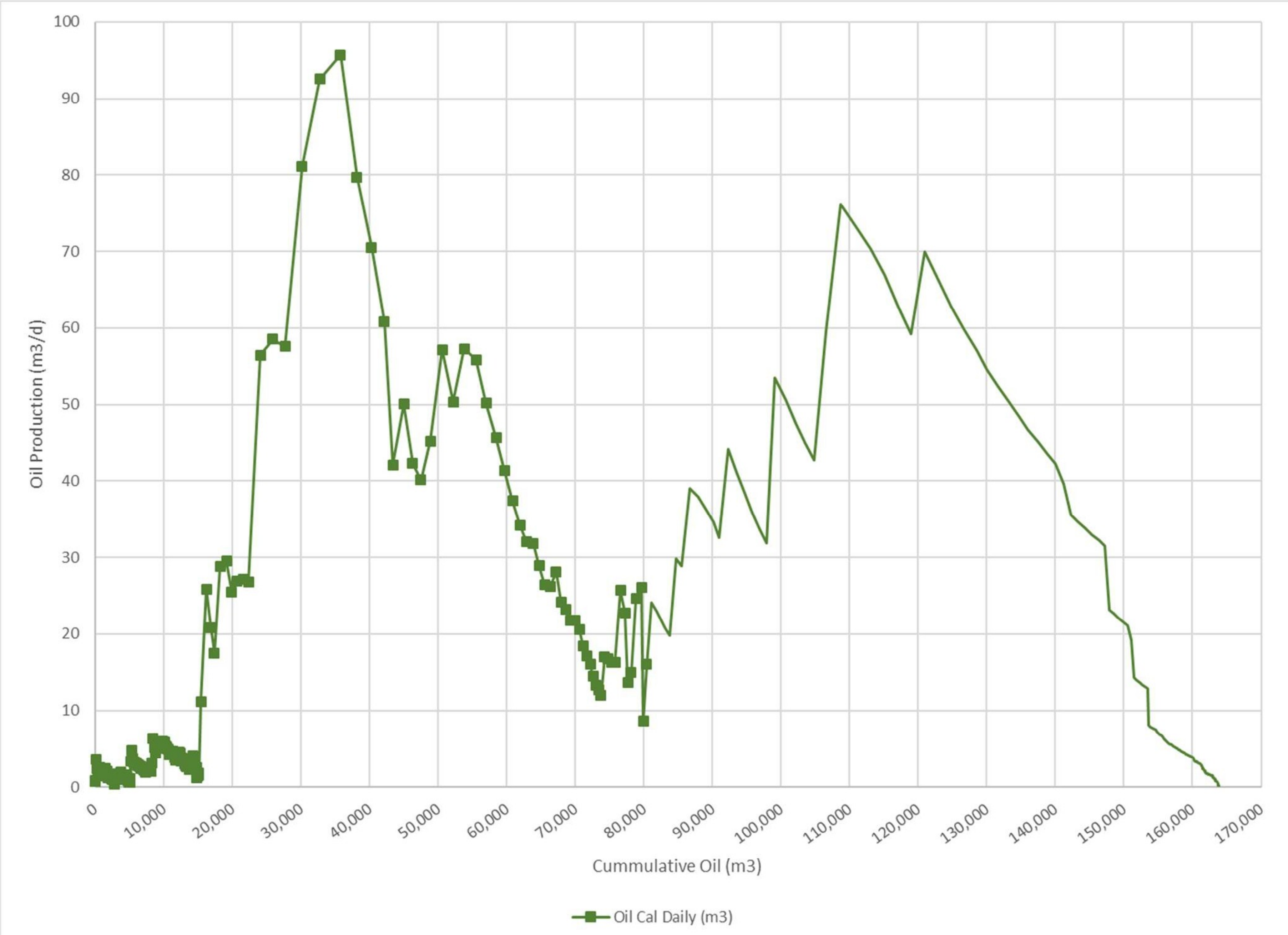


Figure 8. Rate vs Time - Waterflood

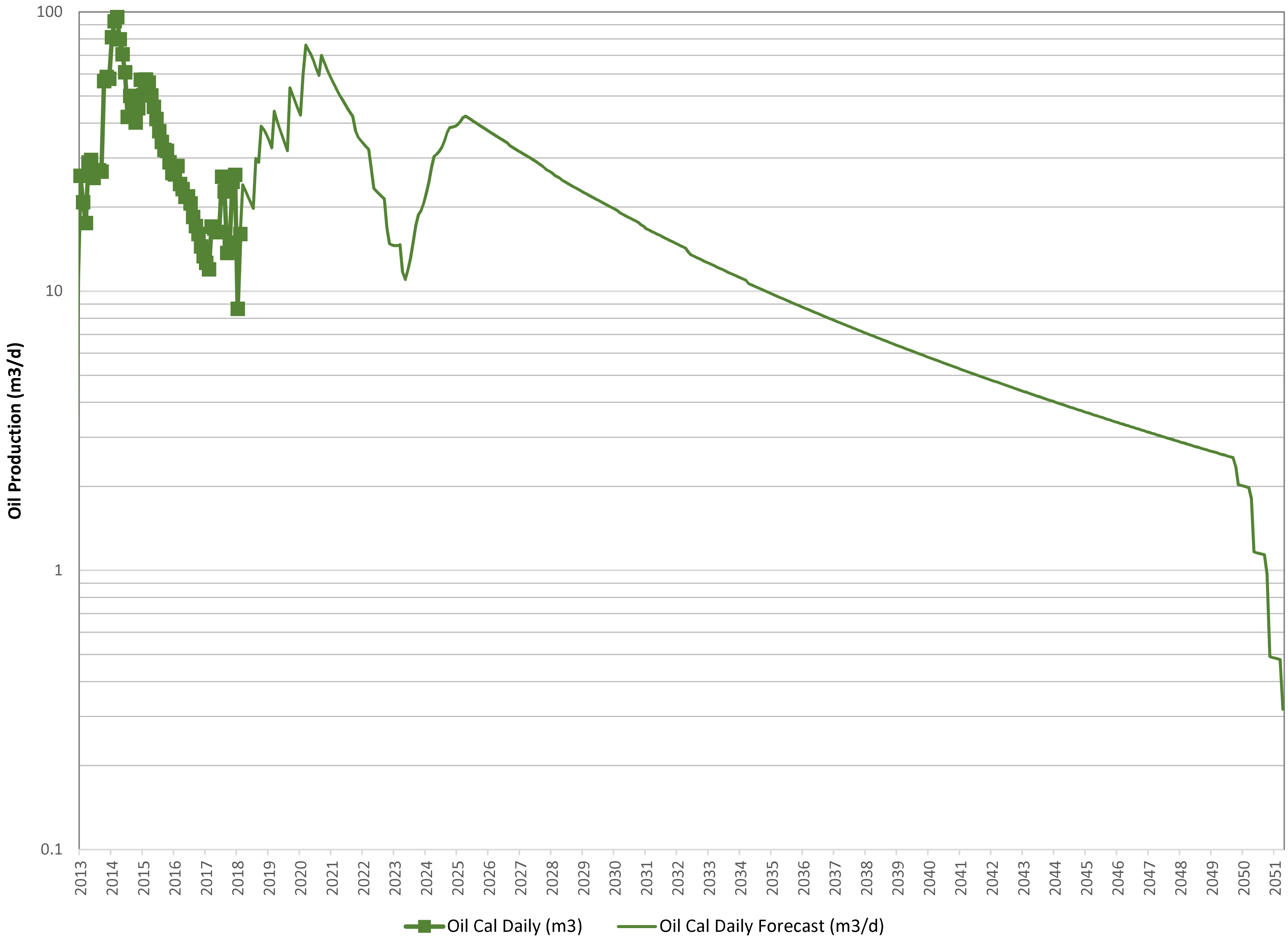
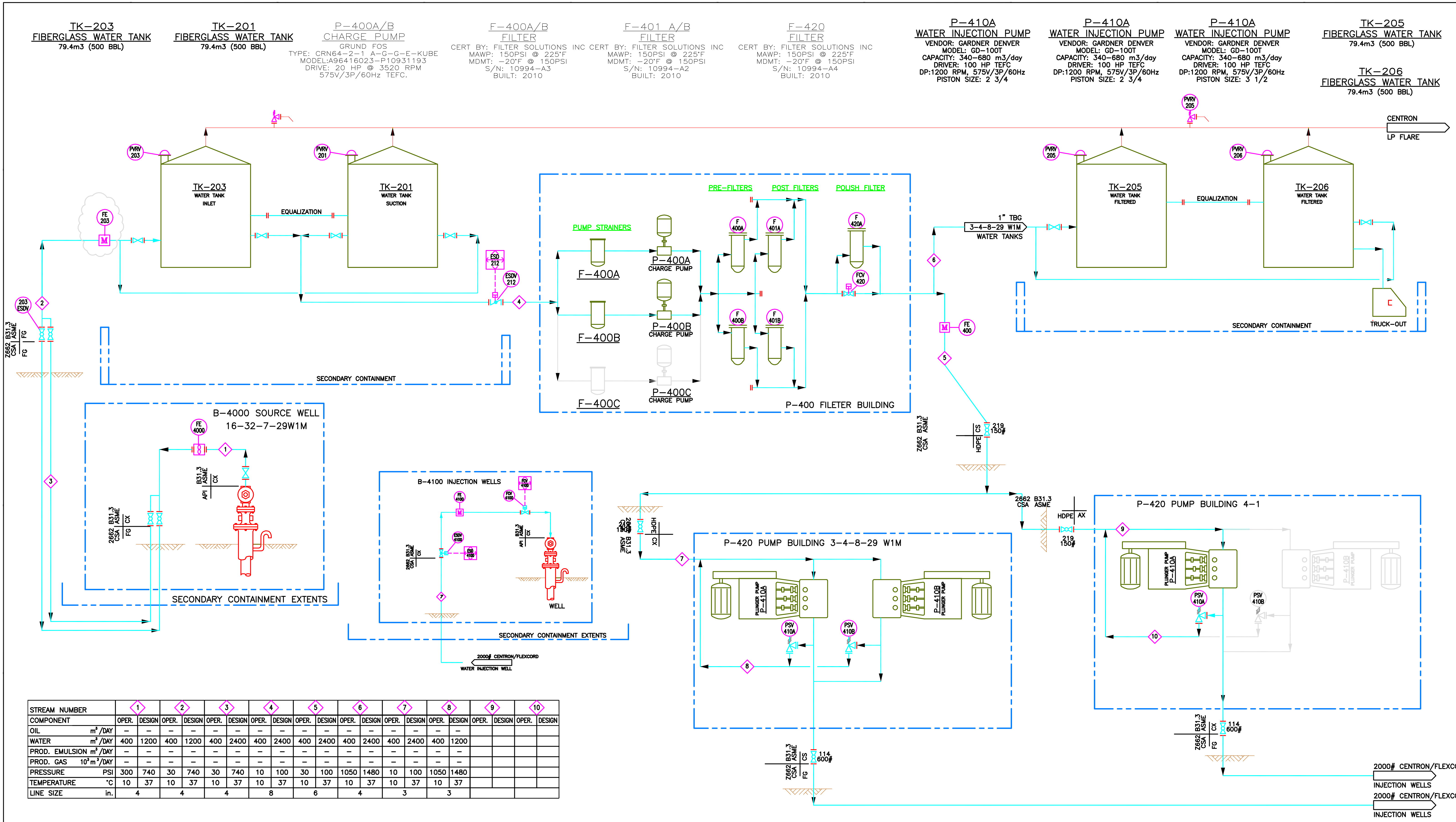


Figure 9. Rate vs Cumulative - Waterflood



STREAM NUMBER	1		2		3		4		5		6		7		8		9		10	
COMPONENT	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN
OIL m^3/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–				
WATER m^3/DAY	400	1200	400	1200	400	2400	400	2400	400	2400	400	2400	400	2400	400	1200				
PROD. EMULSION m^3/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–				
PROD. GAS $10^3 m^3$/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–				
PRESSURE PSI	300	740	30	740	30	740	10	100	30	100	1050	1480	10	100	1050	1480				
TEMPERATURE °C	10	37	10	37	10	37	10	37	10	37	10	37	10	37	10	37				
LINE SIZE in.	4		4		4		8		6		4		3		3					

REV	DESCRIPTION	BY	DATE	CHK	APP
0	AS-BUILT	RM	30-JUNE 2014	LF	JC

REFERENCE DRAWING

NOTES:

Figure 10

TUNDRA OIL & GAS PARTNERSHIP

SINCLAIR
03-04-008-29/13-10-009-28 W1M

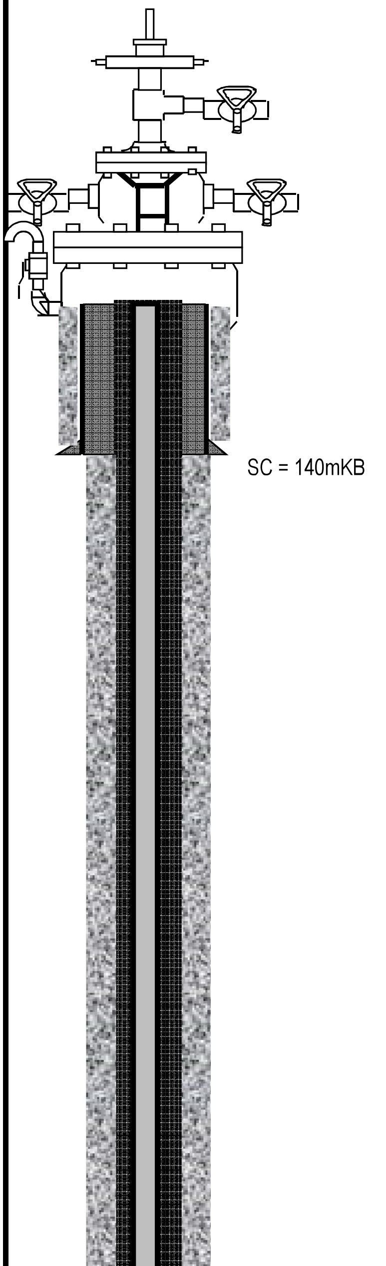
WATER INJECTION
PROCESS FLOW DIAGRAM

DRAWN BY:	SCALE:	AFE:	DRAWING NUMBER:	REV NO:
RM	NTS	TBA	FAIRWAY UNIT INJECTIONN PFD	1

Tundra Oil And Gas Partnership

Figure No. 11

TYPICAL OPEN HOLE WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM



WELL NAME:	**Tundra Cromer Unit No. 5 HZNTL Open Hole WIW**			**WELL LICENCE:**		
Prepared by	WRJ	(average depths)		Date:	2012	
Elevations :						
KB [m]		KB to THF [m]			TD [m]	2400.0
GL [m]		CF (m)			PBTD [m]	
[redacted]	**Open Hole**			950.0	to	2400.0
[redacted]					to	
[redacted]	700 m MD		Total Interval		to	
[redacted]						
Surface Casing	244.5	48.06	H-40 - ST&C	Surface	to	140.0
Intermed Csg (if run)	177.8	34.23 & 29.76	J-55 - LT&C	Surface	to	950.0
Open Hole Latera	none	none	none	950.0	to	2400.0
Tubing	60.3 or 73.0 - TK-99	6.99 or 9.67	J-55	Surface	to	940.0

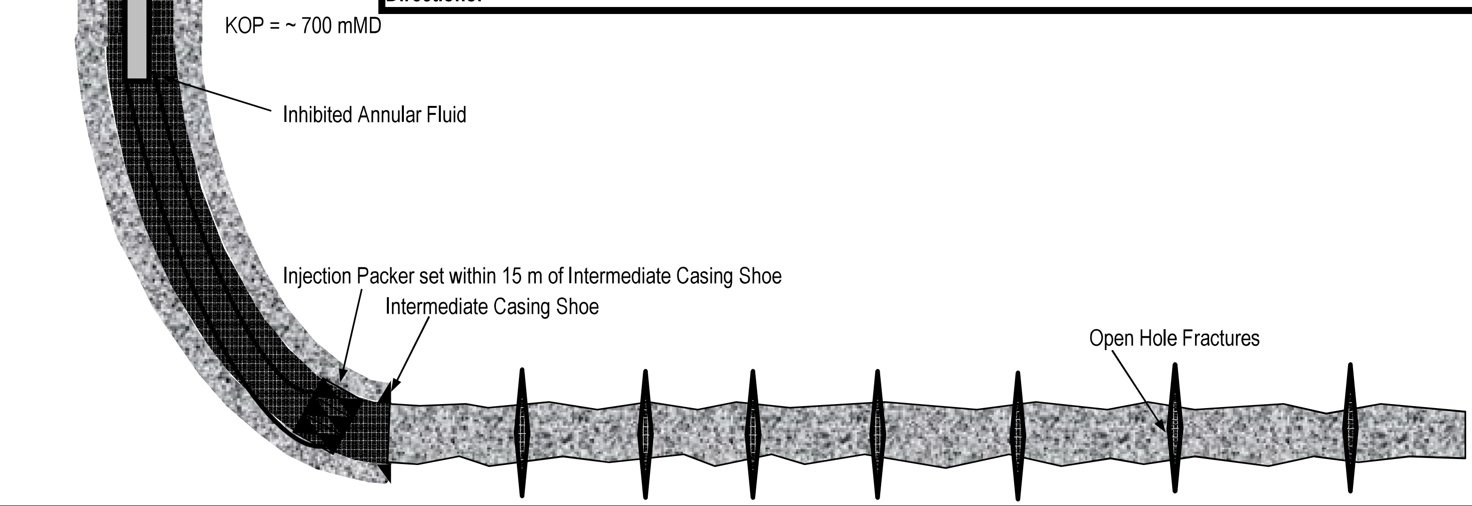
Date of Tubing Installation:		Length	Top @
Item	Description [redacted]	0.00	m KB
	Corrosion Protected ENC Coated Packer (set within 15 m of Intermed Csg shoe)		
	60.3 mm or 73 mm TK-99 Internally Coated Tubing		
	TK-99 Internally Coated Tubing Pup Jt		
	Coated Split Dognut		
	Annular space above injection packer filled with inhibited fresh water		
	Bottom of Tubing mKB		

Rod String :

Date of Rod Installation:

Bottomhole Pump:

Directions:



Cromer Unit No. 5

EOR Waterflood Project

Planned Corrosion Control Program **

Source Well
- Continuous downhole corrosion inhibition
- Continuous surface corrosion inhibitor injection
- Downhole scale inhibitor injection
- Corrosion resistant valves and internally coated surface piping

Pipelines
- Source well to 3-4-8-29 Water Plant – Fiberglass
- New High Pressure Pipeline to Unit 9 injection wells – 2000 psi high pressure Fiberglass

Facilities
- 3-4-8-29 Water Plant and New Injection Pump Station
    - Plant piping – 600 ANSI schedule 80 pipe, Fiberglass or Internally coated
    - Filtration – Stainless steel bodies and PVC piping
    - Pumping – Ceramic plungers, stainless steel disc valves
    - Tanks – Fiberglass shell, corrosion resistant valves

Injection Wellhead / Surface Piping
- Corrosion resistant valves and stainless steel and/or internally coated steel surface piping

Injection Well
- Casing cathodic protection where required
- Wetted surfaces coated downhole packer
- Corrosion inhibited water in the annulus between tubing / casing
- Internally coated tubing surface to packer
- Surface freeze protection of annular fluid
- Corrosion resistant master valve
- Corrosion resistant pipeline valve

Producing Wells
- Casing cathodic protection where required
- Downhole batch corrosion inhibition as required
- Downhole scale inhibitor injection as required

Figure 12

** subject to final design and engineering

Proposed Cromer Unit No. 5

Application for Enhanced Oil Recovery Waterflood Project

List of Tables

TABLE NO. 2: TRACT FACTOR CALCULATIONS FOR CROMER BAKKEN UNIT NO. 5 APPLICATION

TRACT FACTORS BASED ON OIL-IN-PLACE (OOIP) - CUMULATIVE PRODUCTION TO JANUARY 2018

LSD-SEC	Tract	OOIP (m3)	HZ Wells Alloc Cum Prodn (m3)	Vert Wells Cum Prodn (m3)	Sum Hz + Vert Alloc Cum Prodn	OOIP - Cum	OOIP - Cum Tract Factor (%)	Last 12 Mth Alloc Hz Prodn	Last 12 Mth Vert Prodn	Sum Hz + Vert Alloc Last 12 Mth Prodn	% of Last 12 Mth Prodn	50% of OOIP - Cum TF + 50% Last 12 Mth Prod TF	Tract
09-22	09-22-009-28W1M	14,141	758.4	0.0	758.4	13,383	1.330432188%	35.4	0.0	35.4	0.482090029%	0.906261108%	09-22-009-28W1M
10-22	10-22-009-28W1M	14,920	802.6	0.0	802.6	14,117	1.403467906%	37.5	0.0	37.5	0.510228290%	0.956848098%	10-22-009-28W1M
11-22	11-22-009-28W1M	15,440	801.9	0.0	801.9	14,638	1.455199404%	37.4	0.0	37.4	0.509769999%	0.982484701%	11-22-009-28W1M
12-22	12-22-009-28W1M	15,433	755.0	1,211.4	1,966.4	13,467	1.338798277%	35.2	13.3	48.5	0.661163644%	0.999980961%	12-22-009-28W1M
13-22	13-22-009-28W1M	16,205	1,075.5	0.0	1,075.5	15,129	1.504049890%	57.1	0.0	57.1	0.777595151%	1.140822520%	13-22-009-28W1M
14-22	14-22-009-28W1M	16,473	1,132.3	711.3	1,843.6	14,629	1.454339296%	60.1	11.3	71.4	0.972624551%	1.213481924%	14-22-009-28W1M
15-22	15-22-009-28W1M	15,169	1,132.7	0.0	1,132.7	14,037	1.395426950%	60.1	0.0	60.1	0.818940126%	1.107183538%	15-22-009-28W1M
16-22	16-22-009-28W1M	13,868	1,077.8	0.0	1,077.8	12,790	1.271501584%	57.2	0.0	57.2	0.779249065%	1.025375324%	16-22-009-28W1M
01-26	01-26-009-28W1M	12,819	2,628.1	0.0	2,628.1	10,191	1.013083828%	351.8	0.0	351.8	4.792120434%	2.902602131%	01-26-009-28W1M
02-26	02-26-009-28W1M	12,818	2,747.3	0.0	2,747.3	10,071	1.001195878%	367.7	0.0	367.7	5.009487450%	3.005341664%	02-26-009-28W1M
03-26	03-26-009-28W1M	12,820	2,747.8	0.0	2,747.8	10,073	1.001351250%	367.8	0.0	367.8	5.010504704%	3.005927977%	03-26-009-28W1M
04-26	04-26-009-28W1M	13,085	1,538.0	0.0	1,538.0	11,547	1.147934534%	205.9	0.0	205.9	2.804495957%	1.976215245%	04-26-009-28W1M
05-26	05-26-009-28W1M	13,870	770.2	0.0	770.2	13,100	1.302339829%	44.9	0.0	44.9	0.611920783%	0.957130306%	05-26-009-28W1M
06-26	06-26-009-28W1M	13,605	1,319.9	0.0	1,319.9	12,286	1.221362715%	77.0	0.0	77.0	1.048681168%	1.135021941%	06-26-009-28W1M
07-26	07-26-009-28W1M	13,342	1,319.6	0.0	1,319.6	12,022	1.195164007%	77.0	0.0	77.0	1.048434085%	1.121799046%	07-26-009-28W1M
08-26	08-26-009-28W1M	13,342	1,228.2	0.0	1,228.2	12,114	1.204283475%	71.6	0.0	71.6	0.975848446%	1.090065960%	08-26-009-28W1M
09-26	09-26-009-28W1M	13,605	882.3	0.0	882.3	12,723	1.264810683%	128.1	0.0	128.1	1.744641727%	1.504726205%	09-26-009-28W1M
10-26	10-26-009-28W1M	13,869	922.4	0.0	922.4	12,946	1.287028894%	133.9	0.0	133.9	1.823804978%	1.555416936%	10-26-009-28W1M
11-26	11-26-009-28W1M	14,394	922.2	0.0	922.2	13,472	1.339312197%	133.9	0.0	133.9	1.823569136%	1.581440666%	11-26-009-28W1M
12-26	12-26-009-28W1M	14,657	599.3	0.0	599.3	14,058	1.397554649%	87.0	0.0	87.0	1.184924002%	1.291239325%	12-26-009-28W1M
13-26	13-26-009-28W1M	15,443	327.9	788.5	1,116.4	14,326	1.424227462%	25.0	0.0	25.0	0.340530161%	0.882378812%	13-26-009-28W1M
14-26	14-26-009-28W1M	14,918	588.7	0.0	588.7	14,329	1.424525383%	44.9	0.0	44.9	0.611442964%	1.017984174%	14-26-009-28W1M
15-26	15-26-009-28W1M	14,392	588.6	0.0	588.6	13,803	1.372254130%	44.9	0.0	44.9	0.611361086%	0.991807608%	15-26-009-28W1M
16-26	16-26-009-28W1M	14,128	567.1	0.0	567.1	13,561	1.348185655%	43.2	0.0	43.2	0.589019753%	0.968602705%	16-26-009-28W1M
01-27	01-27-009-28W1M	13,878	1,370.1	0.0	1,370.1	12,508	1.243506898%	71.9	0.0	71.9	0.979547520%	1.111527209%	01-27-009-28W1M
02-27	02-27-009-28W1M	15,207	1,411.4	0.0	1,411.4	13,796	1.371528747%	74.1	0.0	74.1	1.009078558%	1.190303652%	02-27-009-28W1M
03-27	03-27-009-28W1M	16,515	1,411.4	3,857.1	5,268.5	11,247	1.118097239%	74.1	48.6	122.7	1.671171742%	1.394634491%	03-27-009-28W1M
04-27	04-27-009-28W1M	16,536	1,351.7	0.0	1,351.7	15,184	1.509544049%	70.9	0.0	70.9	0.966400955%	1.237972502%	04-27-009-28W1M
05-27	05-27-009-28W1M	16,235	1,198.0	0.0	1,198.0	15,037	1.494865992%	66.5	0.0	66.5	0.906551689%	1.200708840%	05-27-009-28W1M
06-27	06-27-009-28W1M	15,691	1,255.1	0.0	1,255.1	14,436	1.435162676%	69.7	0.0	69.7	0.949759685%	1.192461180%	06-27-009-28W1M
07-27	07-27-009-28W1M	14,690	1,254.9	1,161.8	2,416.7	12,273	1.220125277%	69.7	0.0	69.7	0.949628562%	1.084876919%	07-27-009-28W1M
08-27	08-27-009-28W1M	14,147	1,202.9	0.0	1,202.9	12,944	1.286805503%	66.8	0.0	66.8	0.910276285%	1.098540894%	08-27-009-28W1M
09-27	09-27-009-28W1M	14,932	1,766.0	0.0	1,766.0	13,166	1.308892422%	122.2	0.0	122.2	1.665287781%	1.487090101%	09-27-009-28W1M
10-27	10-27-009-28W1M	15,198	1,847.2	0.0	1,847.2	13,351	1.327241779%	127.9	0.0	127.9	1.741869011%	1.534555395%	10-27-009-28W1M
11-27	11-27-009-28W1M	15,369	1,847.5	0.0	1,847.5	13,521	1.344184515%	127.9	0.0	127.9	1.742106958%	1.543145737%	11-27-009-28W1M
12-27	12-27-009-28W1M	15,926	1,725.0	0.0	1,725.0	14,201	1.411742317%	119.4	0.0	119.4	1.626564498%	1.519153408%	12-27-009-28W1M
13-27	13-27-009-28W1M	15,627	1,003.2	0.0	1,003.2	14,624	1.453801616%	55.8	0.0	55.8	0.760283720%	1.107042668%	13-27-009-28W1M
14-27	14-27-009-28W1M	15,332	1,054.3	0.0	1,054.3	14,277	1.419366147%	58.7	0.0	58.7	0.798980279%	1.109173213%	14-27-009-28W1M
15-27	15-27-009-28W1M	15,205	1,054.6	0.0	1,054.6	14,150	1.406734770%	58.7	0.0	58.7	0.799239464%	1.102987117%	15-27-009-28W1M
16-27	16-27-009-28W1M	14,939	1,024.0	0.0	1,024.0	13,915	1.383346083%	57.0	0.0	57.0	0.776032283%	1.079689183%	16-27-009-28W1M
01-28	01-28-009-28W1M	16,408	13.9	0.0	13.9	16,394	1.629833542%	13.9	0.0	13.9	0.188850636%	0.909342089%	01-28-009-28W1M
02-28	02-28-009-28W1M	16,124	31.6	6.9	38.5	16,086	1.599163387%	31.6	0.0	31.6	0.430946813%	1.015055100%	02-28-009-28W1M
03-28	03-28-009-28W1M	15,843	13.6	0.0	13.6	15,829	1.573627892%	13.6	0.0	13.6	0.184898116%	0.879263004%	03-28-009-28W1M
04-28	04-28-009-28W1M	16,088	10.0	0.0	10.0	16,078	1.598389912%	10.0	0.0	10.0	0.136272172%	0.867331042%	04-28-009-28W1M
05-28	05-28-009-28W1M	15,309	331.8	0.0	331.8	14,978	1.488982086%	331.8	0.0	331.8	4.520261153%	3.004621620%	05-28-009-28W1M
06-28	06-28-009-28W1M	15,327	381.8	0.0	381.8	14,945	1.485767463%	381.8	0.0	381.8	5.201522146%	3.343644804%	06-28-009-28W1M
07-28	07-28-009-28W1M	15,873	363.7	0.0	363.7	15,509	1.541799985%	363.7	0.0	363.7	4.953862416%	3.247831200%	07-28-009-28W1M
08-28	08-28-009-28W1M	16,156	221.1	0.0	221.1	15,935	1.584176011%	221.1	0.0	221.1	3.012146356%	2.298161184%	08-28-009-28W1M
09-28	09-28-009-28W1M	16,169	1,035.8	0.0	1,035.8	15,133	1.504452012%	125.7	0.0	125.7	1.711911286%	1.608181649%	09-28-009-28W1M
10-28	10-28-009-28W1M	15,885	1,173.9	0.0	1,173.9	14,711	1.462504394%	142.4	0.0	142.4	1.940093717%	1.701299055%	10-28-009-28W1M
11-28	11-28-009-28W1M	15,075	1,176.9	0.0	1,176.9	13,898	1.381693034%	142.8	0.0	142.8	1.945092111%	1.663392573%	11-28-009-28W1M
12-28	12-28-009-28W1M	14,001	1,127.0	966.5	2,093.5	11,908	1.183793683%	136.7	0.0	136.7	1.862580306%	1.523186994%	12-28-009-28W1M
13-28	13-28-009-28W1M	14,541	179.9	0.0	179.9	14,361	1.427730558%	179.9	0.0	179.9	2.450650055%	1.939190306%	13-28-009-28W1M

LSD-SEC	Tract	OOIP (m3)	HZ Wells Alloc Cum Prodn (m3)	Vert Wells Cum Prodn (m3)	Sum Hz + Vert Alloc Cum Prodn	OOIP - Cum	OOIP - Cum Tract Factor (%)	Last 12 Mth Alloc Hz Prodn	Last 12 Mth Vert Prodn	Sum Hz + Vert Alloc Last 12 Mth Prodn	% of Last 12 Mth Prodn	50% of OOIP - Cum TF + 50% Last 12 Mth Prod TF	Tract
14-28	14-28-009-28W1M	15,352	188.2	0.0	188.2	15,164	1.507516210%	188.2	0.0	188.2	2.563840648%	2.035678429%	14-28-009-28W1M
15-28	15-28-009-28W1M	16,162	187.4	0.0	187.4	15,975	1.588152527%	187.4	0.0	187.4	2.552355914%	2.070254221%	15-28-009-28W1M
16-28	16-28-009-28W1M	16,182	168.4	0.0	168.4	16,013	1.591939685%	168.4	0.0	168.4	2.294476400%	1.943208043%	16-28-009-28W1M
01-33	01-33-009-28W1M	16,067	0.0	3,211.9	3,211.9	12,855	1.277953154%	0.0	14.4	14.4	0.196163906%	0.737058530%	01-33-009-28W1M
02-33	02-33-009-28W1M	16,605	0.0	663.5	663.5	15,941	1.584778583%	0.0	12.8	12.8	0.174367916%	0.879573250%	02-33-009-28W1M
03-33	03-33-009-28W1M	15,840	0.0	3,002.8	3,002.8	12,837	1.276201511%	0.0	0.0	0.0	0.000000000%	0.638100755%	03-33-009-28W1M
04-33	04-33-009-28W1M	14,793	0.0	0.0	0.0	14,793	1.470681601%	0.0	0.0	0.0	0.000000000%	0.735340801%	04-33-009-28W1M
05-33	05-33-009-28W1M	14,765	0.0	0.0	0.0	14,765	1.467861120%	0.0	0.0	0.0	0.000000000%	0.733930561%	05-33-009-28W1M
06-33	06-33-009-28W1M	15,283	0.0	13.0	13.0	15,270	1.518018113%	0.0	0.0	0.0	0.000000000%	0.759009056%	06-33-009-28W1M
07-33	07-33-009-28W1M	16,287	0.0	0.0	0.0	16,287	1.619127224%	0.0	0.0	0.0	0.000000000%	0.809563612%	07-33-009-28W1M
08-33	08-33-009-28W1M	16,538	0.0	700.8	700.8	15,837	1.574463729%	0.0	2.3	2.3	0.031331735%	0.802897732%	08-33-009-28W1M
01-34	01-34-009-28W1M	15,485	950.8	0.0	950.8	14,534	1.444922967%	74.8	0.0	74.8	1.019435897%	1.232179432%	01-34-009-28W1M
02-34	02-34-009-28W1M	15,229	1,069.8	0.0	1,069.8	14,159	1.407599080%	84.2	0.0	84.2	1.147036604%	1.277317842%	02-34-009-28W1M
03-34	03-34-009-28W1M	15,341	1,068.9	0.0	1,068.9	14,272	1.418848482%	84.1	0.0	84.1	1.146044850%	1.282446666%	03-34-009-28W1M
04-34	04-34-009-28W1M	15,575	1,004.2	0.0	1,004.2	14,571	1.448590904%	79.0	0.0	79.0	1.076650042%	1.262620473%	04-34-009-28W1M
05-34	05-34-009-28W1M	15,116	1,161.7	0.0	1,161.7	13,954	1.387274455%	97.7	0.0	97.7	1.330922039%	1.359098247%	05-34-009-28W1M
06-34	06-34-009-28W1M	14,880	1,222.9	0.0	1,222.9	13,657	1.357694295%	102.9	0.0	102.9	1.401075177%	1.379384736%	06-34-009-28W1M
07-34	07-34-009-28W1M	14,964	1,221.7	0.0	1,221.7	13,742	1.366171145%	102.7	0.0	102.7	1.399691942%	1.382931544%	07-34-009-28W1M
08-34	08-34-009-28W1M	15,220	1,162.9	0.0	1,162.9	14,058	1.397515163%	97.8	0.0	97.8	1.332292969%	1.364904066%	08-34-009-28W1M
		1,086,668	**64,479.0**	**16,295.5**	**80,774.5**	**1,005,893**	**100.000000000%**	**7238.1**	**102.7**	**7340.8**	**100.000000000%**	**100.000000000%**	

Table No. 3 - Well List and Status

UWI	License Number	Type	Pool Name	Producing Zone	Mode	On Production Date	Prod Date	Cal Dly Oil (m3/d)	Monthly Oil (m3)	Cum Prd Oil (m3)	Cal Dly Water (m3/d)	Monthly Water (m3)	Cum Prd Water (m3)	WCT (%)
100/12-22-009-28W1/2	003511	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Producing	12/27/1999	Jan-2018	0.00	0.00	1211.40	1.96	60.70	12866.70	100.00
102/12-22-009-28W1/C	010083	Horizontal	BAKKEN-THREE FORKS A	TORQUAY	Producing	11/28/2014	Jan-2018	0.25	7.80	3117.90	1.50	46.60	9622.10	85.66
100/13-22-009-28W1/C	009681	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	2/14/2014	Jan-2018	0.54	16.80	4418.20	2.27	70.40	10845.10	80.73
100/14-22-009-28W1/2	006419	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Commingled	7/13/2008	Jan-2018	0.03	1.00	711.30	0.08	2.60	1784.80	72.22
100/01-26-009-28W1/C	008905	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	12/16/2012	Jan-2018	2.74	84.80	9661.20	7.18	222.70	16894.30	72.42
100/08-26-009-28W1/C	008955	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	9/30/2013	Jan-2018	0.35	10.90	4637.80	3.65	113.10	13090.40	91.21
102/09-26-009-28W1/C	010069	Horizontal	BAKKEN-THREE FORKS A	BAKKENM,TORQUAY	Producing	10/31/2014	Jan-2018	1.05	32.50	3326.20	7.59	235.30	17909.40	87.86
100/13-26-009-28W1/2	003796	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Commingled	1/1/1996	Oct-2008	0.13	3.90	788.50	0.09	2.80	567.50	41.79
102/16-26-009-28W1/C	010068	Horizontal	BAKKEN-THREE FORKS A	BAKKENU,THREEFK	Producing	10/31/2014	Jan-2018	0.33	10.30	2072.30	6.09	188.80	23770.90	94.83
100/03-27-009-28W1/2	004512	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Pumping	12/29/1994	Jan-2018	0.11	3.50	3857.10	0.23	7.20	2961.90	67.29
100/04-27-009-28W1/C	009294	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	3/31/2013	Jan-2018	0.68	21.00	5544.60	1.39	43.20	9614.00	67.29
100/05-27-009-28W1/C	009172	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	9/30/2013	Jan-2018	0.57	17.80	4911.00	1.81	56.10	8176.90	75.91
100/07-27-009-28W1/2	004561	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned Zone	10/18/1995	Apr-2004	0.35	10.50	1161.80	0.36	10.80	877.90	50.70
100/12-27-009-28W1/C	009597	Horizontal	BAKKEN-THREE FORKS A	THREEFK,BAKKEN	Producing	12/27/2013	Jan-2018	1.14	35.40	7185.70	6.34	196.40	16696.70	84.73
100/13-27-009-28W1/C	009598	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	12/31/2013	Jan-2018	0.51	15.90	4136.20	4.48	138.90	20382.80	89.73
102/02-28-009-28W1/2	006577	Vertical	BAKKEN-THREE FORKS A	BAKKEN,THREEFK	Producing	3/1/2008	Feb-2011	0.00	0.00	6.90	0.50	14.00	1677.50	100.00
102/05-28-009-28W1/C	010660	Horizontal	BAKKEN-THREE FORKS A	BAKKENU,THREEFK	Producing	7/1/2017	Jan-2018	3.50	108.50	1367.50	9.00	279.00	3544.50	72.00
100/12-28-009-28W1/2	004504	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Pumping	10/18/1994	Jan-2015	0.00	0.00	966.50	1.02	31.50	937.50	100.00
102/12-28-009-28W1/C	010129	Horizontal	BAKKEN-THREE FORKS A	TORQUAY	Producing	2/12/2015	Jan-2018	1.09	33.90	4513.60	3.02	93.60	10211.20	73.41
102/13-28-009-28W1/C	010740	Horizontal	BAKKEN-THREE FORKS A	THREEFK,BAKKEN	Producing	11/3/2017	Jan-2018	7.89	244.70	723.90	18.51	573.80	1915.00	70.10
100/01-33-009-28W1/2	005275	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Producing	9/12/2004	Jan-2018	0.11	3.40	3211.90	0.50	15.50	1886.80	82.01
100/02-33-009-28W1/2	006725	Vertical	BAKKEN-THREE FORKS A	BAKKEN,THREEFK	Commingled	9/13/2008	Jan-2018	0.06	1.80	663.50	0.44	13.70	1284.30	88.39
100/03-33-009-28W1/2	006400	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Producing	11/17/2007	Jan-2016	0.01	0.40	3002.80	4.74	146.80	20084.80	99.73
102/06-33-009-28W1/2	006813	Vertical	BAKKEN-THREE FORKS A	BAKKEN,THREEFK	Commingled	11/27/2008	Jun-2012	0.00	0.00	13.00	0.00	0.10	6.00	100.00
100/08-33-009-28W1/2	005276	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Producing	9/24/2004	Jan-2018	0.03	0.80	700.80	0.28	8.80	348.20	91.67
100/04-34-009-28W1/C	009280	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	10/31/2013	Jan-2018	1.50	46.50	4093.80	1.76	54.60	18341.70	54.01
100/05-34-009-28W1/C	009566	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	10/31/2013	Jan-2018	1.66	51.50	4769.10	4.32	133.90	29828.50	72.22

UWI	12 Mth Prod Feb2017-Jan2018
100/12-22-009-28W1/2	13.3
102/12-22-009-28W1/C	145.5
100/13-22-009-28W1/C	234.5
100/14-22-009-28W1/2	11.3
100/01-26-009-28W1/C	1293.2
100/08-26-009-28W1/C	270.5
102/09-26-009-28W1/C	482.8
100/13-26-009-28W1/2	
102/16-26-009-28W1/C	158.0
100/03-27-009-28W1/2	48.6
100/04-27-009-28W1/C	291.0
100/05-27-009-28W1/C	272.8
100/07-27-009-28W1/2	
100/12-27-009-28W1/C	497.4
100/13-27-009-28W1/C	230.1
102/02-28-009-28W1/2	
102/05-28-009-28W1/C	1367.5
100/12-28-009-28W1/2	
102/12-28-009-28W1/C	547.6
102/13-28-009-28W1/C	723.9
100/01-33-009-28W1/2	14.4
100/02-33-009-28W1/2	12.8
100/03-33-009-28W1/2	
102/06-33-009-28W1/2	
100/08-33-009-28W1/2	2.3
100/04-34-009-28W1/C	322.2
100/05-34-009-28W1/C	401.1

Table No. 4 - OOIP Calculation

UWI	Isopach (m)	Area (m2)	OOIP (m3)	OOIP (bbls)
9-22-9-28W1	5.4	161731	14,141	88,945
10-22-9-28W1	5.7	161659	14,920	93,844
11-22-9-28W1	5.9	161618	15,440	97,112
12-22-9-28W1	5.9	161552	15,433	97,073
13-22-9-28W1	6.2	161418	16,205	101,924
14-22-9-28W1	6.3	161484	16,473	103,610
15-22-9-28W1	5.8	161524	15,169	95,411
16-22-9-28W1	5.3	161597	13,868	87,225
1-26-9-28W1	4.9	161566	12,819	80,626
2-26-9-28W1	4.9	161561	12,818	80,624
3-26-9-28W1	4.9	161588	12,820	80,637
4-26-9-28W1	5.0	161625	13,085	82,302
5-26-9-28W1	5.3	161627	13,870	87,241
6-26-9-28W1	5.2	161590	13,605	85,576
7-26-9-28W1	5.1	161564	13,342	83,916
8-26-9-28W1	5.1	161568	13,342	83,919
9-26-9-28W1	5.2	161584	13,605	85,573
10-26-9-28W1	5.3	161606	13,869	87,230
11-26-9-28W1	5.5	161634	14,394	90,537
12-26-9-28W1	5.6	161647	14,657	92,191
13-26-9-28W1	5.9	161649	15,443	97,131
14-26-9-28W1	5.7	161636	14,918	93,831
15-26-9-28W1	5.5	161608	14,392	90,523
16-26-9-28W1	5.4	161586	14,128	88,865
1-27-9-28W1	5.3	161722	13,878	87,293
2-27-9-28W1	5.8	161933	15,207	95,652
3-27-9-28W1	6.3	161902	16,515	103,879
4-27-9-28W1	6.3	162105	16,536	104,009
5-27-9-28W1	6.2	161718	16,235	102,113
6-27-9-28W1	6.0	161515	15,691	98,695
7-27-9-28W1	5.6	162008	14,690	92,397
8-27-9-28W1	5.4	161797	14,147	88,981
9-27-9-28W1	5.7	161789	14,932	93,920
10-27-9-28W1	5.8	161830	15,198	95,592
11-27-9-28W1	5.9	160874	15,369	96,665
12-27-9-28W1	6.1	161239	15,926	100,169
13-27-9-28W1	6.0	160852	15,627	98,290
14-27-9-28W1	5.9	160487	15,332	96,433
15-27-9-28W1	5.8	161905	15,205	95,636
16-27-9-28W1	5.7	161864	14,939	93,963
1-28-9-28W1	6.2	163446	16,408	103,205
2-28-9-28W1	6.1	163252	16,124	101,419
3-28-9-28W1	6.0	163072	15,843	99,647
4-28-9-28W1	6.1	162884	16,088	101,191
5-28-9-28W1	5.8	163018	15,309	96,293
6-28-9-28W1	5.8	163206	15,327	96,404
7-28-9-28W1	6.0	163380	15,873	99,835
8-28-9-28W1	6.1	163574	16,156	101,619
9-28-9-28W1	6.1	163704	16,169	101,700
10-28-9-28W1	6.0	163510	15,885	99,914
11-28-9-28W1	5.7	163341	15,075	94,820
12-28-9-28W1	5.3	163152	14,001	88,065
13-28-9-28W1	5.5	163285	14,541	91,462
14-28-9-28W1	5.8	163474	15,352	96,562
15-28-9-28W1	6.1	163638	16,162	101,659
16-28-9-28W1	6.1	163832	16,182	101,779
1-33-9-28W1	6.1	162668	16,067	101,057
2-33-9-28W1	6.3	162778	16,605	104,440
3-33-9-28W1	6.0	163046	15,840	99,631
4-33-9-28W1	5.6	163150	14,793	93,048
5-33-9-28W1	5.6	162837	14,765	92,870
6-33-9-28W1	5.8	162733	15,283	96,125

N/G:	0.180
Por:	0.152
Sw:	0.35
Boi	1.1

UWI	0.5 md CO N/G	Porosity (.5md CO)
01-30-09-28	0.251	0.158
02-23-09-28	0.094	0.149
13-16-09-28	0.207	0.141
10-11-09-28	0.104	0.140
16-01-09-28	0.243	0.174
Average	**0.180**	**0.152**

UWI	Isopach (m)	Area (m2)	OOIP (m3)	OOIP (bbls)
7-33-9-28W1	6.2	162235	16,287	102,440
8-33-9-28W1	6.3	162126	16,538	104,022
1-34-9-28W1	5.9	162095	15,485	97,399
2-34-9-28W1	5.8	162159	15,229	95,786
3-34-9-28W1	5.9	160586	15,341	96,492
4-34-9-28W1	6.0	160323	15,575	97,967
5-34-9-28W1	5.8	160960	15,116	95,078
6-34-9-28W1	5.7	161223	14,880	93,591
7-34-9-28W1	5.7	162134	14,964	94,120
8-34-9-28W1	5.8	162070	15,220	95,733
			1,086,668	

Table No. 5

Proposed Cromer Unit No. 5

LYLETON / THREE FORKS FORMATION ROCK & FLUID PARAMETERS

Formation Pressure		8300 kPa	Estimated Initial Average Reservoir Pressure
Formation Temperature		31°C	
Saturation Pressure		2,034 Kpa	Bubble Point
GOR		6 - 10 m3/m3	Gas Oil Ratio
API Oil Gravity		40	
Swi (fraction)		0.40	Initial Water Saturation
Produced Water Specific Gravity		1.08	
Produced Water pH		7.1 - 7.3	
Produced Water TDS		125,000	
Wettability		Moderately oil-wet	
Average Air Permeability*	Middle Bakken	2.12 mD	Wt. Average Core Data
	Lyleton Upper A	*	* no data
	Lyleton Lower A	*	* no data
	Lyleton B	1.23 mD	Wt. Average Core Data
Average Porosity (fraction)*	Middle Bakken	0.150	Wt. Average Core Data
	Lyleton Upper A	*	* no data
	Lyleton Lower A	*	* no data
	Lyleton B	0.170	Wt. Average Core Data

* Wt ave from MBKKN/Lyleton cores in 10-11, 1-13, 13-14 and 2-23-9-28W1.

Proposed Cromer Unit No. 5

Application for Enhanced Oil Recovery Waterflood Project

List of Appendices

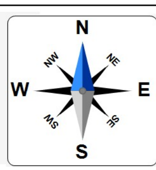
APPENDIX 1

Center: 49.7730, -101.1980

Scale: 1:63,487

0 0.5 1 1.5 2 km

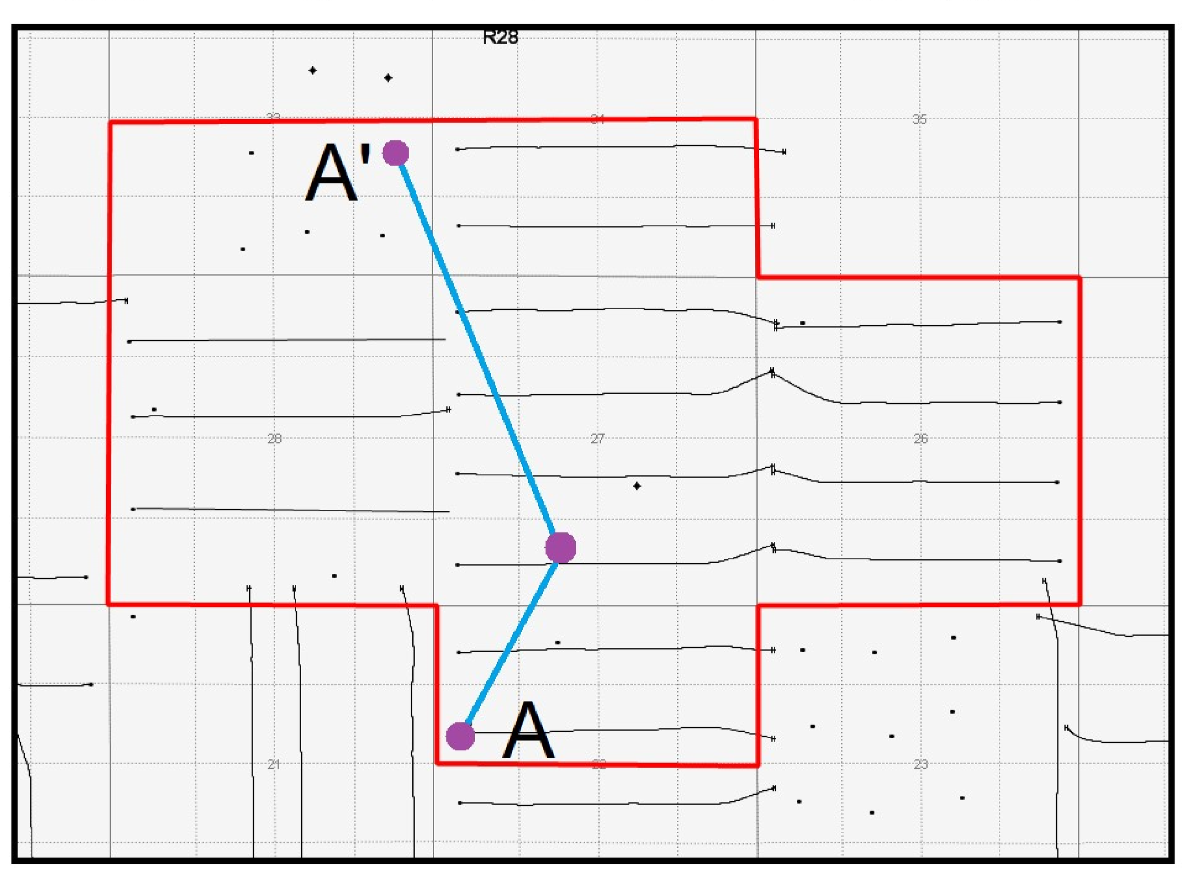
0 0.5 1 mi



Proposed Cromer Unit 5
Offsetting Units

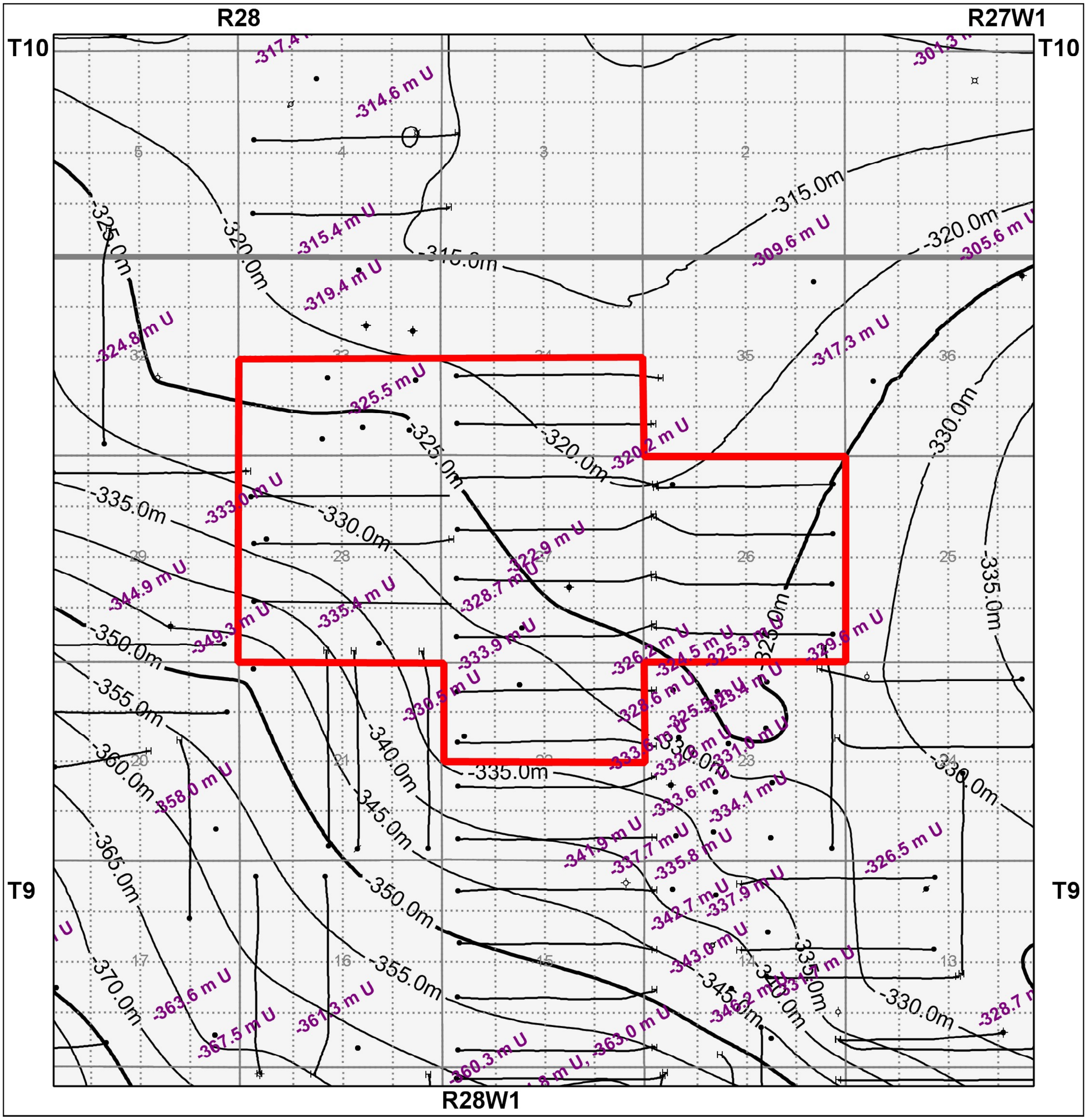
APPENDIX 2

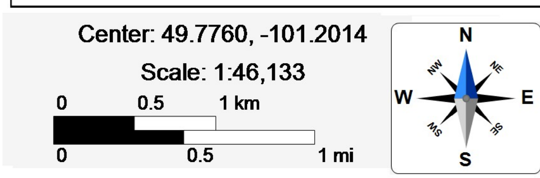
A	00/12-22-009-28W1/2	02/02-28-009-28W1/2	00/08-33-009-28W1/0	A'
	KB: 504.5 m RR: 1985-03-14	KB: 509.8 m RR: 2008-02-04	KB: 511.8 m RR: 2004-07-13	
	TD: 862.0 m [TVD] FormTD: TORQUAY	TD: 868.0 m [TVD] FormTD: BAKKEN	TD: 874.0 m [TVD] FormTD: BIRDBER	
	Mode: Prod Fluid: Oil	Mode: Prod Fluid: Oil	Mode: Prod Fluid: Oil	
	TUNDRA DALY SINCLAIR COM 12-22-9-28(WPM)	COREX DALY SINCLAIR COM A2-28-9-28(WPM)	TUNDRA DALY SINCLAIR COM 8-33-9-28(WPM)	
	1024.0m to next well >	< 1024.0m to previous well 2151.0m to next well >	< 2151.0m to previous well	



Proposed Cromer Unit 5
Structural Cross Section
South to North Through Proposed Unit Area

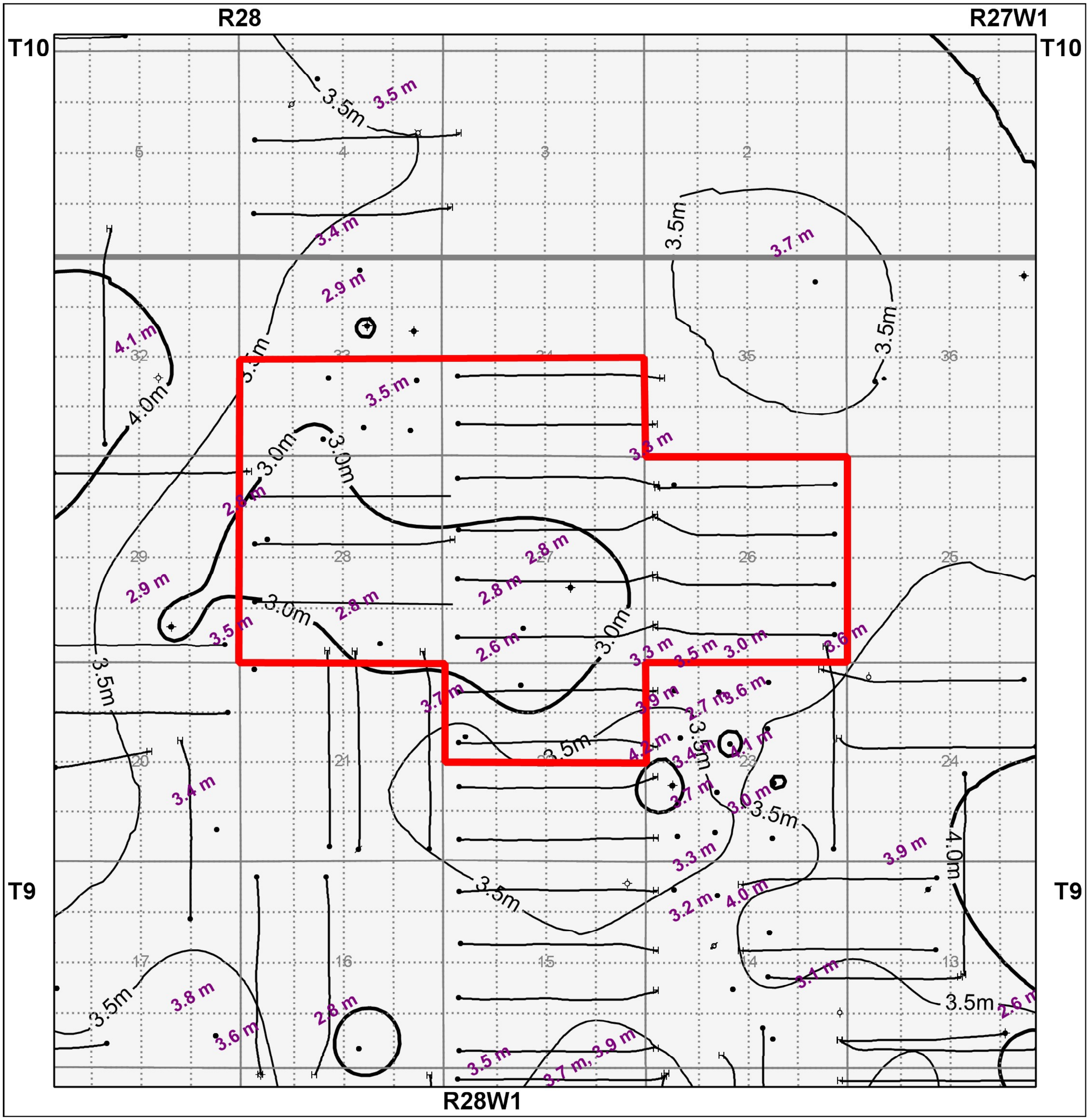
APPENDIX 3





Proposed Cromer Unit 5
Middle Bakken Structure
(mSS)

APPENDIX 4



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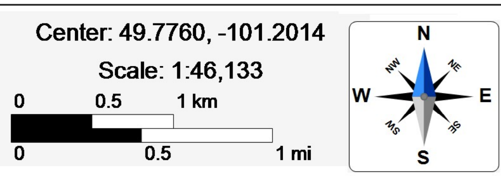
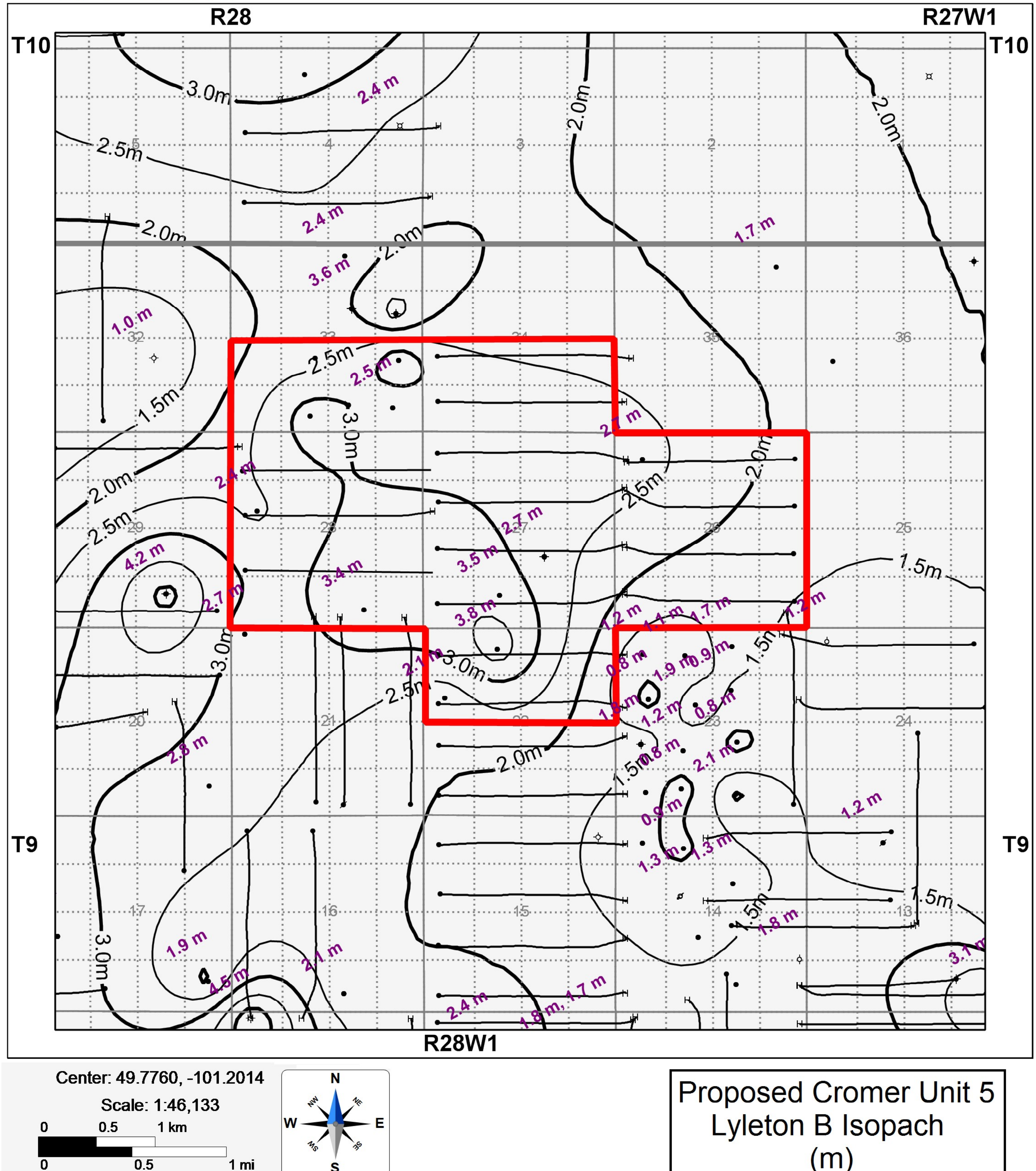
Scale: 1:46,133



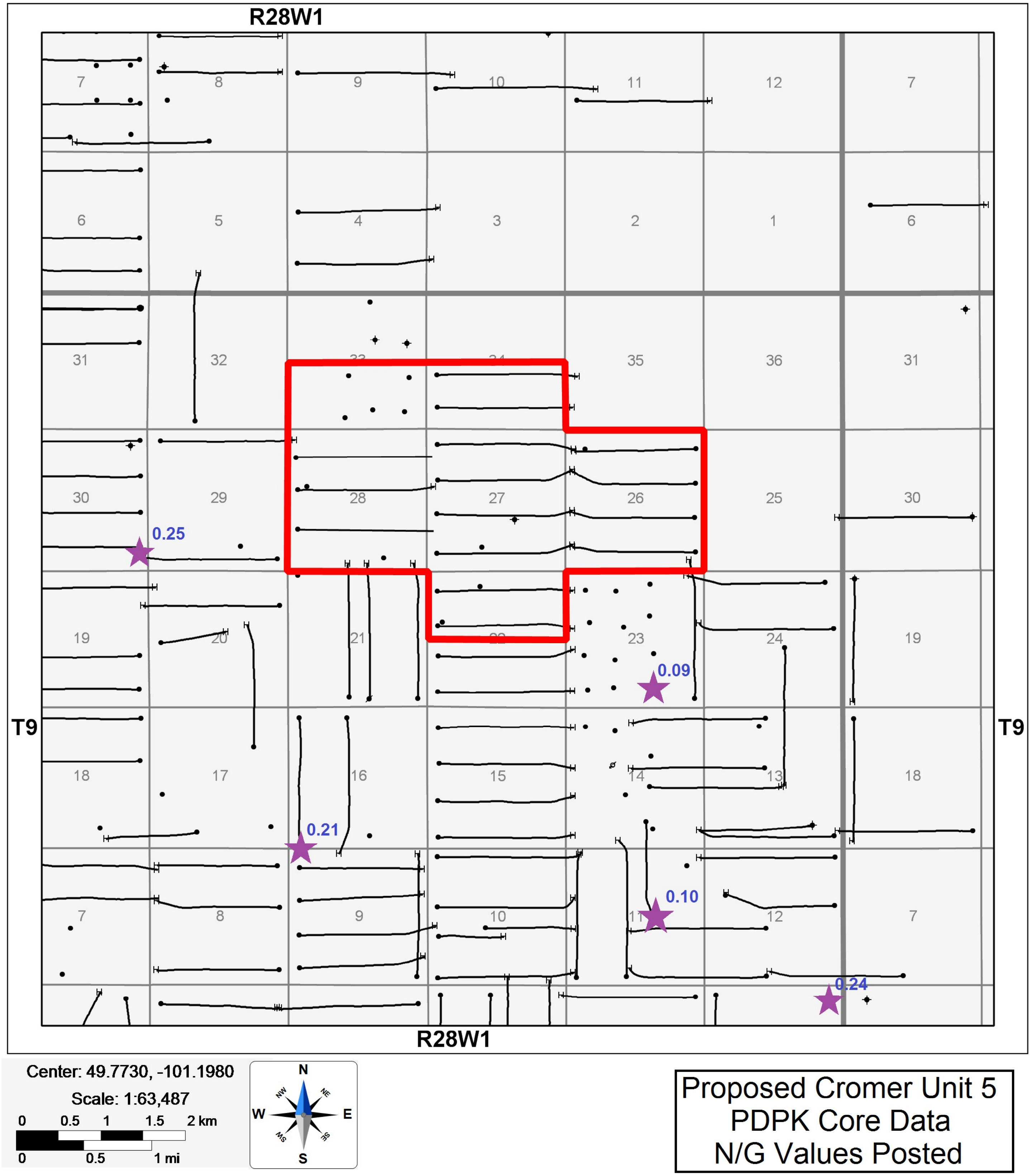
Proposed Cromer Unit 5
Middle Bakken Isopach
(m)

APPENDIX 5



Proposed Cromer Unit 5
Lyleton B Isopach
(m)

APPENDIX 6



Proposed Cromer Unit 5
PDPK Core Data
N/G Values Posted