PROPOSED DALY UNIT NO. 19

Application for Enhanced Oil Recovery Waterflood Project

Bakken Formation

Bakken-Three Forks A Pool (01 62A)

Daly, Manitoba

September 21, 2018
Tundra Oil and Gas Limited

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INTRODUCTION

The Daly portion of the Daly Sinclair Oilfield is located in Townships 8, 9, 10 and 11, of Ranges 27, 28 & 29 WPM (Figure 1). Within the Daly Oilfield, Bakken reservoirs have been developed with horizontal and vertical producing wells on Primary Production and 40 acre spacing. Horizontal producing wells on 20 acre spacing have been drilled by Tundra Oil and Gas Limited (Tundra) in parts of the Daly field.

Within the area, 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 Oil and Gas Limited (Tundra) to establish Daly Unit No. 19 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 an existing designated 01-62A Bakken-Three Forks A Pool of the Daly Sinclair Oilfield (Figure 3).

CONCLUSIONS

1. The proposed Daly Unit No. 19 will include 8 producing horizontal wells and 1 abandoned vertical location within 32 Legal Subdivisions (LSD) of the Bakken producing reservoir. The project is located west of Daly Unit No. 10 and east of Daly Unit No. 9 (Figure 2).

2. Total Original Oil in Place (OOIP) in the project area has been calculated to be **1,067** e^3m^3 (6,713 Mbbl) for an average of 33.4 net e^3m^3 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 May 2018 from the 8 Horizontal wells and 1 Vertical well within the proposed Daly Unit No. 19 project area was 92.0 e^3m^3 (578 Mbbl) of oil and 292.0 e^3m^3 (1,838 Mbbl) of water, representing an **8.6%** Recovery Factor (RF) of the calculated gross OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary producing oil reserves in the proposed Daly Unit No. 19 project area is estimated to be 110.8 e^3m^3 (697 Mbbl), with 18.8 e^3m^3 (119 Mbbl) remaining as of the end of May 2018.

5. Ultimate oil recovery of the proposed Daly Unit No. 19 gross OOIP, under the current Primary production method, is forecasted to be **10.4%**.

6. Figure 4 shows the production from the Daly Unit No. 19 area peaked during March 2013 at 90.6 m^3 of oil per day (OPD). As of May 2018, production was 13.9 m^3 OPD, 64.1 m^3 of water per day (WPD) and an 82.1% watercut (WCUT).

7. In March 2013, production averaged 11.3 m^3 OPD per well in Daly Unit No. 19. As of May 2018, average per well production has declined to 1.7 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **16%** in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Daly Unit No. 19 has been estimated to be 208 e^3m^3. An incremental 97.3 e^3m^3 of proved oil reserves are forecasted to be recovered under the proposed Unitization and Secondary EOR production vs the existing Primary Production method.

9. Total RF under Secondary WF in the proposed Daly Unit No. 19 is estimated to be **19.5%**.

10. Based on waterflood response in the adjacent portion of the Daly field, the Three Forks and Middle Bakken Formations in the proposed project area is believed to be suitable for WF EOR operations.

11. Proposed future horizontal openhole produce first injectors, with multi-stage hydraulic fractures, will be drilled between existing horizontal producing wells (Figure 5) within the proposed Daly Unit No. 19, to complete waterflood patterns with effective 200m horizontal to horizontal spacing.

DISCUSSION

The proposed Daly Unit No. 19 project area is located in Township 10 Range 29 W1 of the Daly Sinclair Oil Field (Figure 1). The proposed Daly Unit No. 19 currently consists of 8 producing horizontal wells and 1 abandoned vertical well within an area covering Section 25-010-29W1 and Section 36-010-29W1 (Figure 2). A project area well list with recent production statistics is attached as Table 3.

Within the proposed Unit, potential exists for incremental production and reserves from a Waterflood EOR project in the 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 SW to NE 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 (Daly Unit 8, Daly Unit 10, Daly Unit 11 and Daly Unit 9) 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 from just under 4m to 5.4m (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 isopach is between 1m to over 3m 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 similar to the Red Shale Marker and it forms a good basal seal to the Lyleton B reservoir.

Structure:

The structure within the proposed unit area approaches the top of the paleo high over the Daly Field. Toward the North and South boundaries of the proposed unit structure drops off quite steeply (Appendix 3). The total structural drop over the unit area is roughly 23m. This structural change is not expected to negatively impact flood efficiency or interrupt the lateral continuity of the reservoir beds (see cross-section Appendix 1).

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, all reservoir formations, the Middle Bakken, and Lyleton B, are continuous throughout the proposed unit area. Vertical continuity between the reservoir formations is also unbroken within the unit area.

Gross OOIP Estimates

Total volumetric OOIP for the Middle Bakken and Lyleton B within the proposed unit has been calculated to be **1,067** e^3m^3 (**6,713** Mbbl) using Tundra internally created maps. Maps used were generated from core data from wells available in the greater Sinclair area (Appendix 6).

An average net to gross ratio was calculated for the reservoir 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 calculated in the same way, using an average 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 100/02-17-009-29W1 and 100/13-19-009-28W1 Bakken wells and is thought to be representative of the fluid characteristics in the reservoir.

Historical Production

A historical group production history plot for the proposed Daly Unit No. 19 is shown as Figure 4. Oil production commenced from the proposed Unit area in November 1987 and peaked during March 2013 at 90.6 m^3 OPD. As of May 2018, production was 13.9 m^3 OPD, 64.1 m^3 WPD and an 82.1% WCUT.

Oil production is currently declining at an average annual rate of approximately **16%** 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 from the proposed project area to **19.5%**. 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 Daly Unit No. 19.

Unit Operator

Tundra Oil and Gas Limited (Tundra) will be the Operator of record for Daly Unit No. 19.

Unitized Zone

The unitized zone(s) to be waterflooded in Daly Unit No. 19 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 8 horizontal wells and 1 vertical well to be included in the proposed Daly Unit No. 19 are outlined in Table 3.

Unit Lands

The Daly Unit No. 19 will consist of 32 LSDs as follows:

Section 25 of Township 10, Range 29, W1M
Section 36 of Township 10, Range 29, W1M

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

Tract Factors

The proposed Daly Unit No. 19 will consist of 32 Tracts, based on the 40 acre Legal Sub Divisions (LSD) containing the existing 8 horizontal wells and 1 vertical well.

The Tract Factor contribution for each of the LSD's within the proposed Daly Unit No. 19 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 Daly Unit No. 19. Tundra Oil and Gas Limited holds a 100% WI ownership in all the proposed Tracts.

Tundra Oil and Gas Limited will have a 100% working interest in the proposed Daly Unit No. 19.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Daly Unit No. 19 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 Daly Unit No. 19 OOIP (Table 4).

Pre-Production of New Horizontal Injection Wells

It is likely that future horizontal injection wells will be drilled between the existing horizontal producing wells, as shown in Figure 5, completing an effective 20 acre horizontal to horizontal line drive waterflood pattern within Daly Unit No. 19.

Primary production from the existing horizontal producing wells in the proposed Daly Unit No. 19 has declined significantly from peak rate indicating a need for secondary pressure support. Through the process of developing similar waterfloods, Tundra has measured a significant variation in reservoir pressure depletion by the existing primary producing wells. Placing new horizontal wells immediately on water injection in areas without significant reservoir pressure depletion has been problematic in similar low permeability formations. The following conditions have been observed, without injector conditioning, which Tundra believes negatively impact the ultimate total recovery factor of OOIP:

- Lower initial and peak water injection rates
- Rapid increases in injection wellhead pressures to the maximum allowable
- Lower sustained water injection rates at maximum allowable pressure
- Lower monthly instantaneous and cumulative voidage replacement ratio
- Delayed secondary oil production response
- Secondary oil production response of lower magnitude

As a result, Tundra has chosen to produce these future injectors to condition the reservoir for optimal waterflood.

Ultimately the final candidates for injection conversion will be chosen based on production performance post unit approval. This will result in an effective 20 acre line drive waterflood pattern within Daly Unit No. 19.

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

Reserves Recovery Profiles and Production Forecasts

The primary performance predictions for the proposed Daly Unit No. 19 are based on oil production decline curve analysis, and the secondary waterflood predictions are based on internal engineering analysis performed by the Tundra reservoir engineering group.

Based on the geological description, primary production decline rate, and waterflood response in Daly Unit No. 8, the Bakken formation in the project area is believed to be a suitable reservoir for WF EOR operations.

Primary Production Forecast

Cumulative production to the end of May 2018 from the 8 horizontal wells and 1 vertical well within the proposed Daly Unit No. 19 project area was **92.0** e^3m^3 of oil, and **292.0** e^3m^3 of water, representing an **8.6%** Recovery Factor (RF) of the calculated Net OOIP.

Based on decline analysis of the wells currently on production, the estimated ultimate recovery (EUR) for the proposed unit with no further development would be **110.8** e^3m^3, with **18.8** e^3m^3 remaining as of the end May 2018. This represents a recovery factor of **10.4%** of the total OOIP.

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

Seven horizontal injection wells are required for this proposed Unit. They will be placed on production followed by permanent water injection service as shown in Figure 5.

Tundra will monitor the following parameters to assess the best timing for converting 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 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 Daly Unit No. 19 project to be developed equitably, efficiently, and moves the 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 Daly Unit No. 19 is estimated to be **208.1** e^3m^3 with **116.1** e^3m^3 remaining representing a total secondary recovery factor of **19.5%** for the proposed Unit area. An incremental **97.4** e^3m^3 of oil, or an incremental **9.1%** recovery factor, are forecasted to be recovered under the proposed Unitization.

WATERFLOOD OPERATING STRATEGY

Water Source

Injection water for the proposed Daly Unit No. 19 will be supplied from the Jurassic source water well at 100/02-25-010-29W1 (2-25). Tundra received approval from the Petroleum Branch in March 2013 to use the 2-25 well as a source water well for waterflood operations. Jurassic-sourced water will be pumped from the 2-25 source well to the Daly 12-24-10-29 battery, where it will be filtered and then pumped up to injection system pressure. A diagram of the Daly 12-24 water injection system and new pipeline connection to the project area injection wells is shown as Figure 10.

Produced water is not currently used for any water injection in the Tundra operated Daly Units and there are no current plans to use produced water as a source supply for Daly Unit No. 19. Tundra does not foresee any compatibility issues between the produced and injection waters based on previous compatibility testing performed by a third party, Baker Hughes.

Injection Wells

Seven horizontal injection wells are required for this proposed Unit, as shown in Figure 5. The planned injection wells will be drilled and put on production after unit approval. 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. These planned injectors will be openhole horizontals and 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 well(s) 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:

1. The area specific known and calculated fracture gradient, or
2. 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 will be surface equipped with injection volume metering and rate/pressure programmable logic control (PLC). 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 Daly Unit No. 19 horizontal water injection well rate is forecasted to average 10 – 25 m^3 WPD, based on expected reservoir permeability and pressure.

Estimated Fracture Gradient

Completion data from the producing wells within the project area indicate an actual fracture pressure gradient range of 16 to 18 kPa/m true vertical depth (TVD). Tundra expects the fracture gradient encountered during completion of the proposed horizontal injection well will be lower than these values due to expected reservoir pressure depletion.

Reservoir Pressure

No representative initial pressure surveys are available for the proposed Daly Unit No. 19 project area in the Bakken. Tundra will make all attempts to capture a reservoir pressure survey in the proposed horizontal injection well during the completion of the well 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 8,400 kPa.

Reservoir Pressure Management During Waterflood

Tundra expects to inject water for a minimum 2 – 4 year period to re-pressurize the reservoir due to cumulative primary production voidage and pressure depletion. Initial Voidage Replacement Ratio (VRR) is expected to be approximately 1.25 to 1.75 within the pattern 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

Daly Unit No. 19 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

The above surveillance methods will provide an increased understanding of reservoir performance, and provide data to continually control and optimize the Daly Unit No. 19 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 Daly Unit No. 19.

On Going Reservoir Pressure Surveys

For each proposed 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 Daly Unit No. 19 as per Section 73 of the Drilling and Production Regulation.

Economic Justification

Under the current Primary recovery method, existing wells within the proposed Daly Unit No. 19 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 Daly Unit No. 19 waterflood operation will utilize the Tundra operated well 100/02-25-10-29W1, sourced from the Jurassic, and water plant (WP) facilities located at the Daly 12-24-10-29W1 battery (Figure 10).

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Figure 12. Surface facilities and wellheads will have cathodic protection to prevent corrosion, where required. All injection flowlines will be made of fiberglass so corrosion will not be an issue. Injectors will have a packer set above the Middle Bakken and Three Forks formations, and the annulus between the tubing and casing will be filled with inhibited fluid.

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra will notify all mineral rights and surface rights owners of the proposed EOR project and formation of Daly Unit No. 19. Copies of the Notices, and proof of service, to all surface rights owners will be forwarded to the Petroleum Branch, when available, to complete the Daly Unit No. 19 Application.

Daly Unit No. 19 Unitization, and execution of the formal Daly Unit No. 19 Agreement by affected Mineral Owners, is expected during Q4 2018. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Daly Unit No. 19 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, September 21, 2018

Proposed Daly Unit No. 19

Application for Enhanced Oil Recovery Waterflood Project

List of Figures

Figure 1

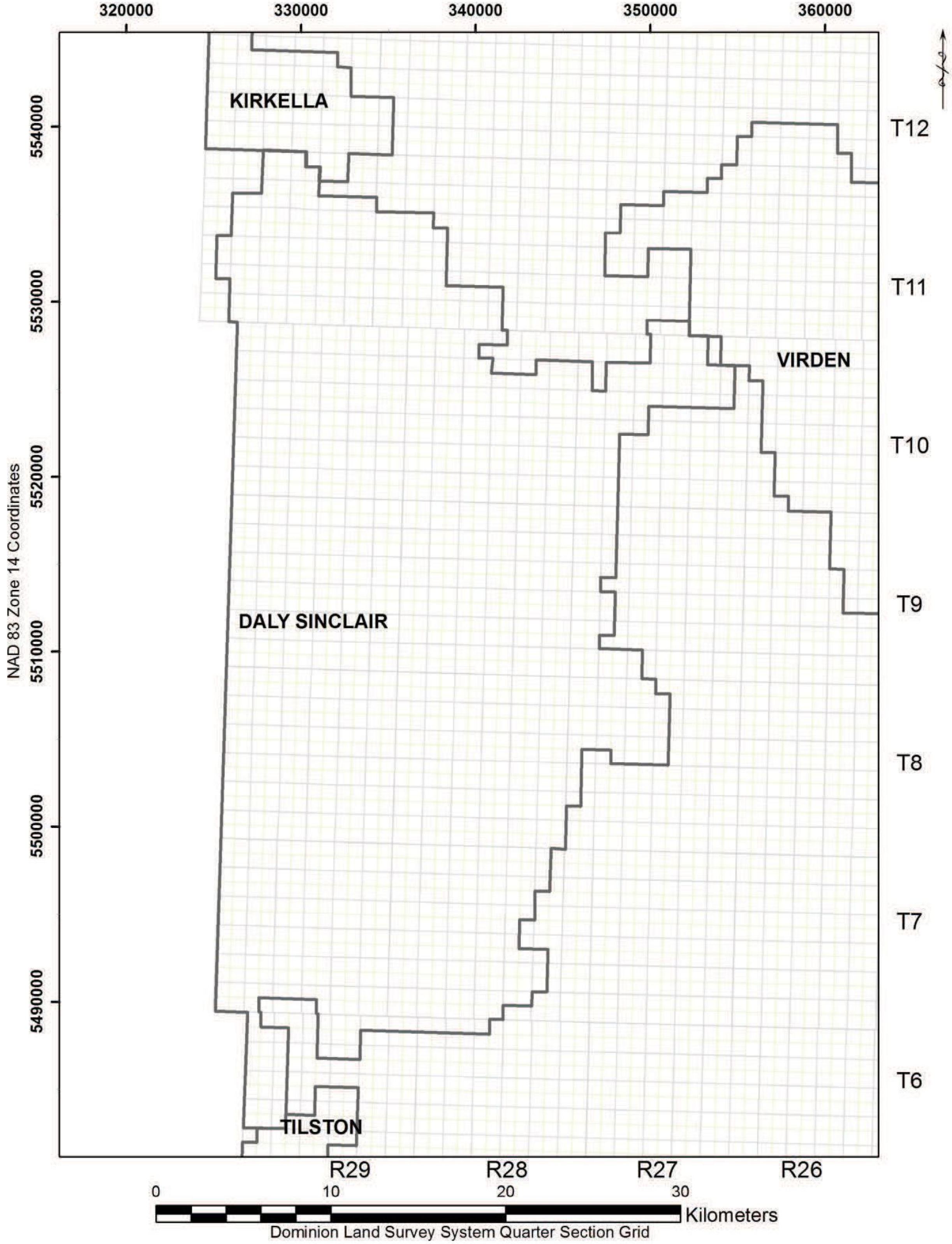

Figure 2 - Daly Sinclair Field (01)

Figure No. 2

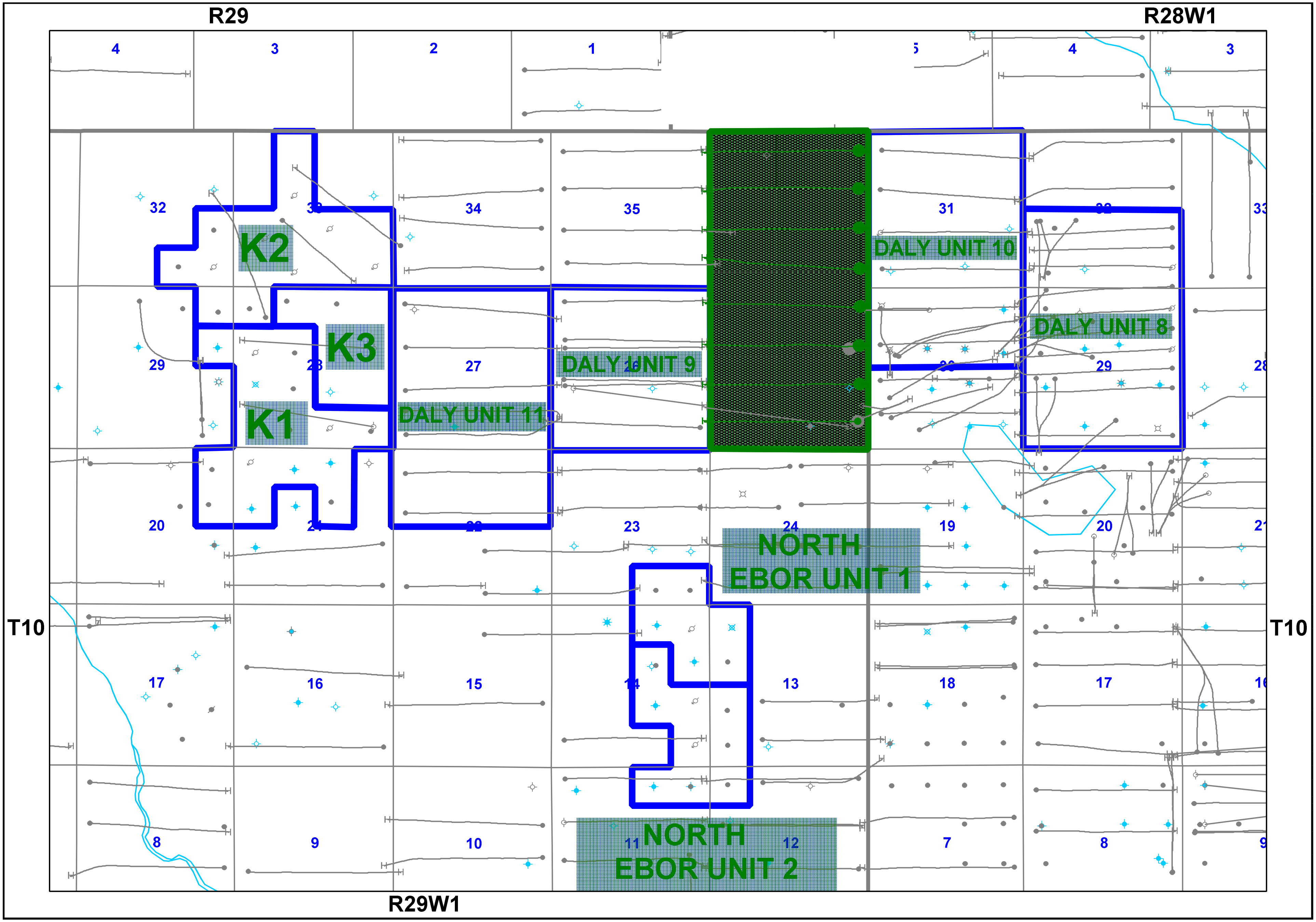
R29
R28W1
T10
T10
R29W1
K1
K2
K3
DALY UNIT 8
DALY UNIT 9
DALY UNIT 10
DALY UNIT 11
NORTH EBOR UNIT 1
NORTH EBOR UNIT 2
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Figure No. 3

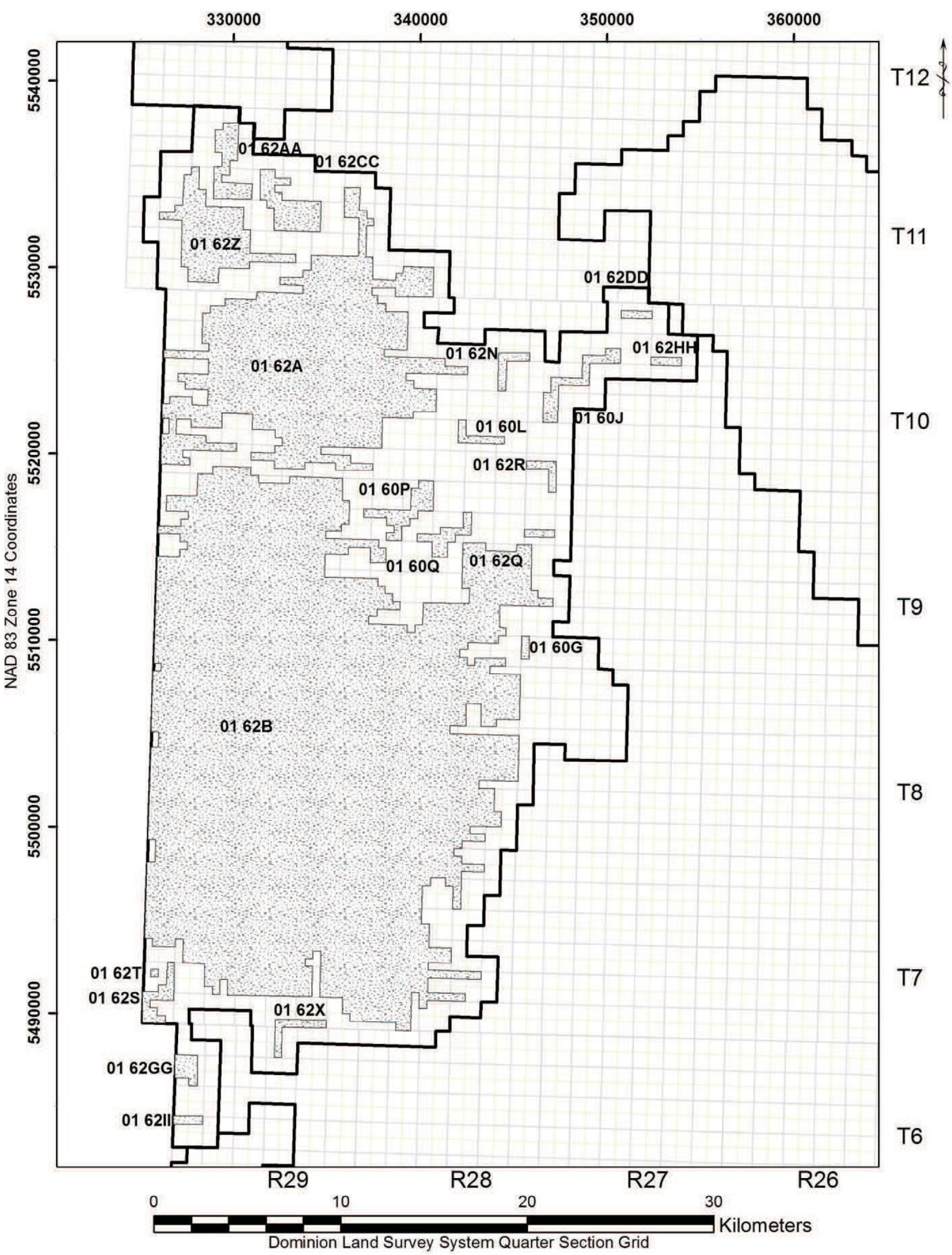


Figure 13 - Daly Sinclair Bakken & Bakken-Three Forks Pools (01 60A - 01 60BB & 01 62A – 01 62II)

Well Information as of 8/8/2018 - Group Well Report

Figure 4

Production Graph

Group:	daly unit 19 well list.lwell	**On Prod:**	1987-11 to 2018-05	**Cum Oil:**	91971.2 m3
# of Wells:	9	**Prod Form:**	BAKKENM; BAKKEN	**Cum Gas:**	0.0 E3m3
Fluid:	Oil	**Field:**	DALY (MB1)	**Cum Wtr:**	292037.0 m3
Mode:	Producing; Abandoned	**Pool Code:**	MB000162A	**Cum Inj Oil:**	0.0 m3
		Unit Code:		**Cum Inj Gas:**	0.0 E3m3
				Cum Inj Wtr:	0.0 m3

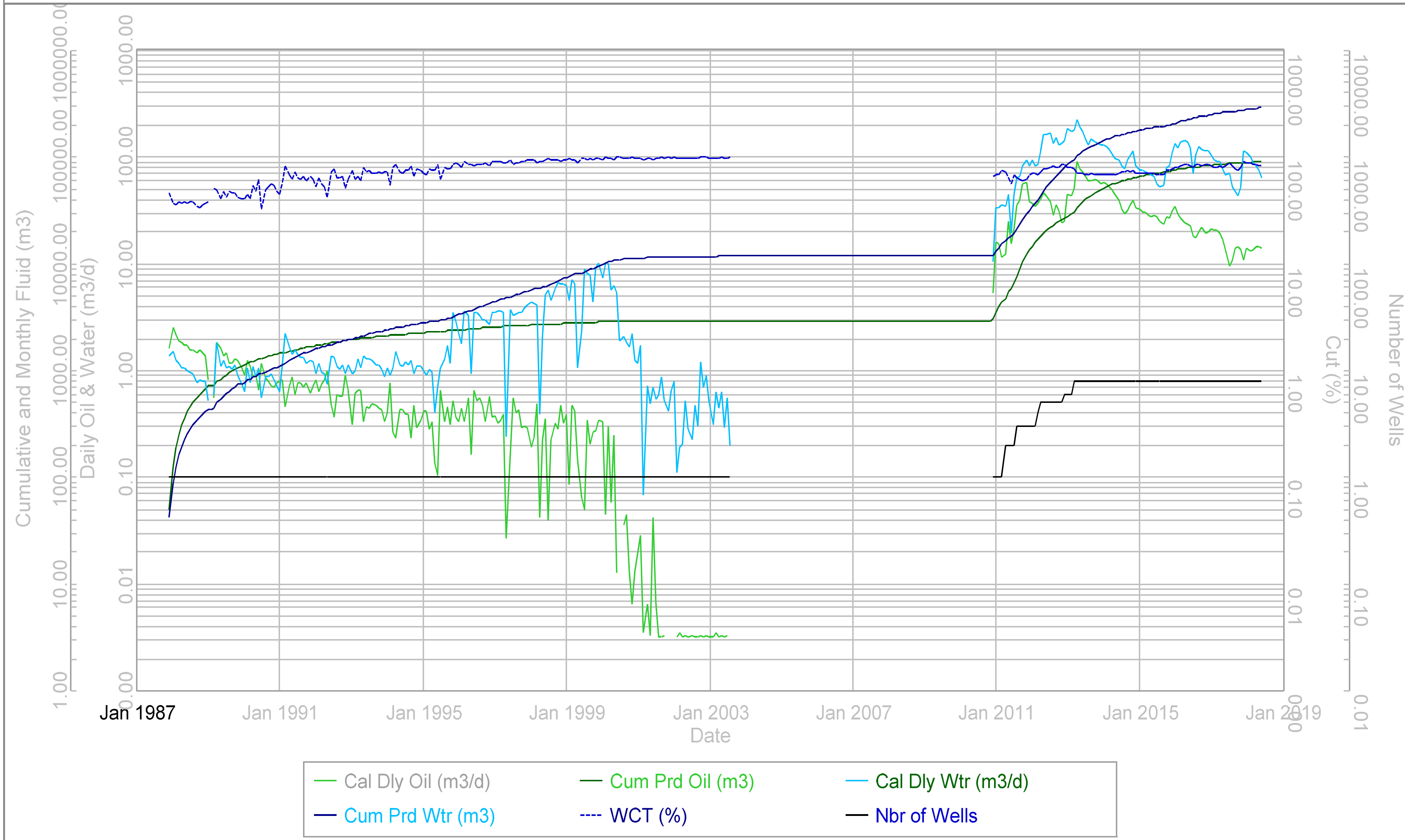


Figure 5.

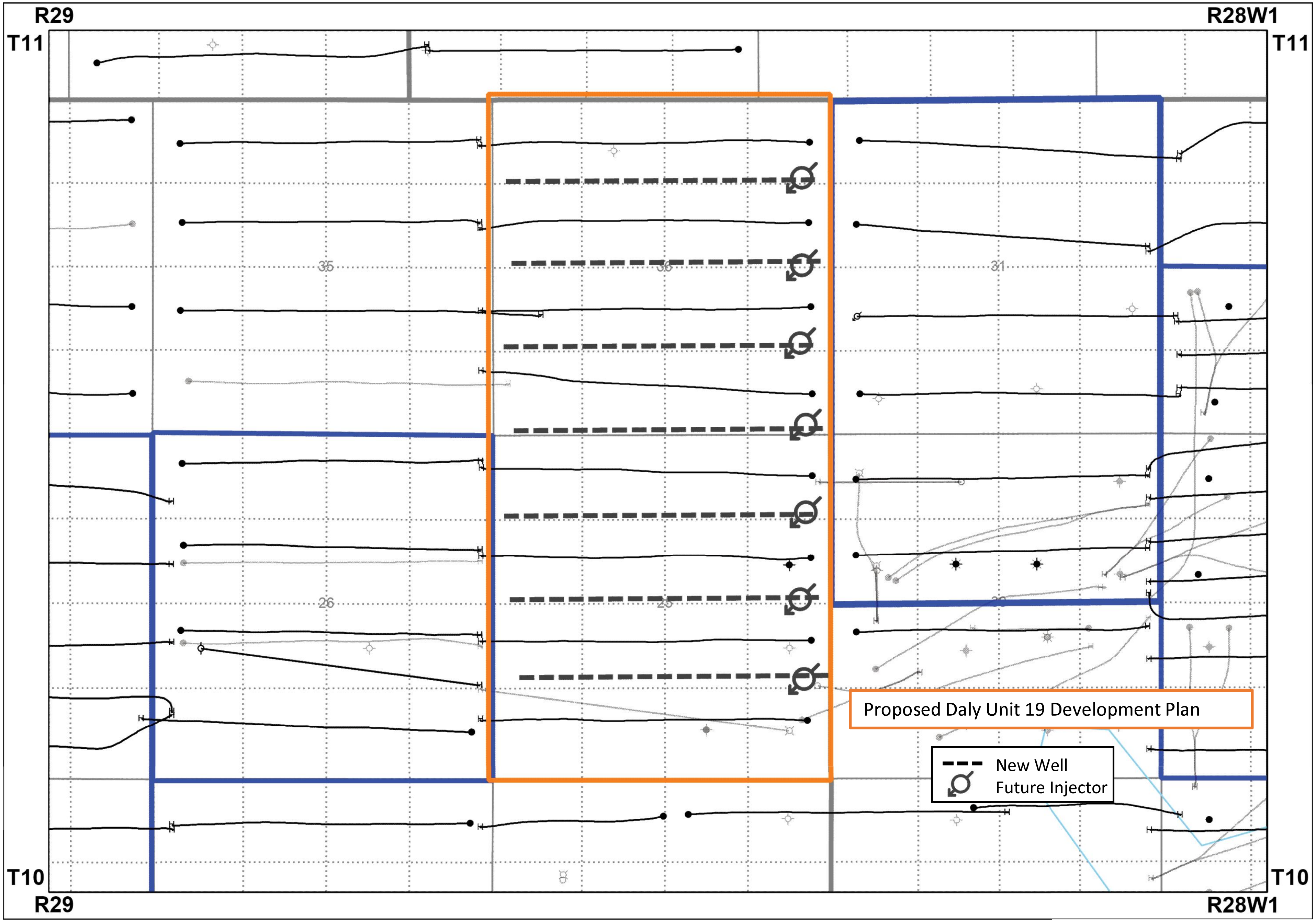

R29
T11
R28W1
T11
35
36
31
26
25
Proposed Daly Unit 19 Development Plan
New Well
Future Injector
T10
R29
T10
R28W1

Figure 6. Primary Production – Rate vs Time

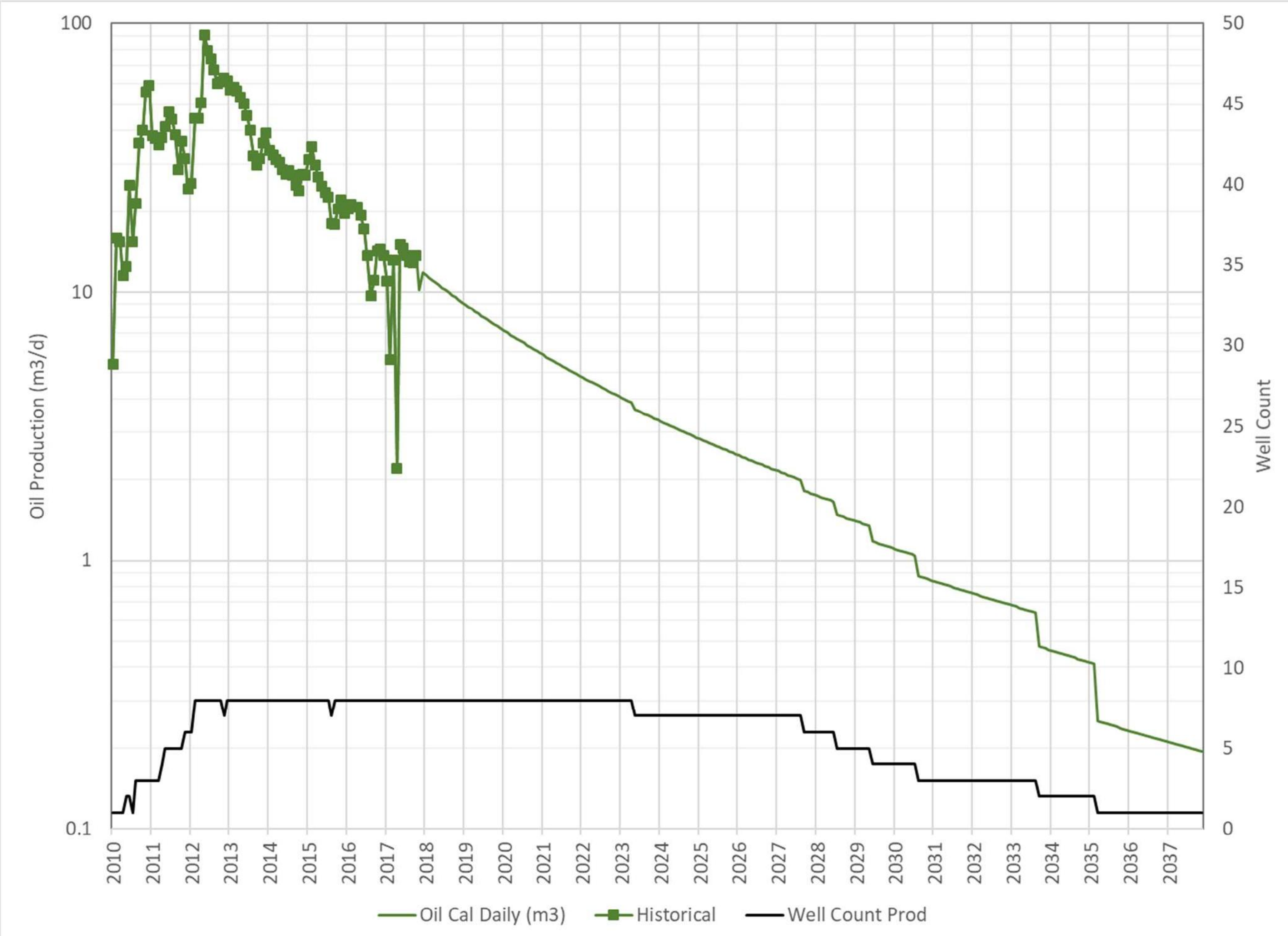


Figure 7. Primary Production – Rate vs Cumulative

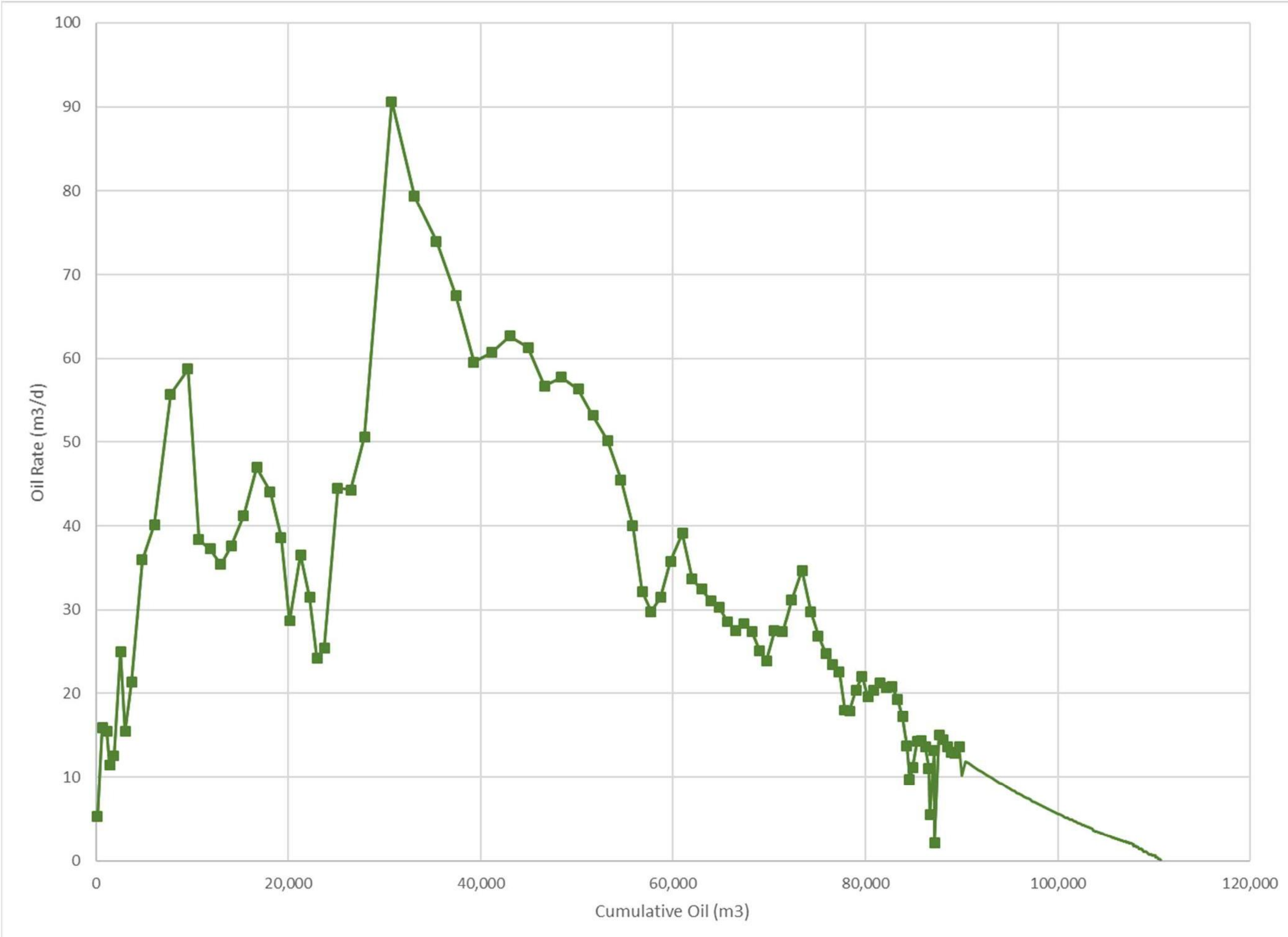


Figure 8. Waterflood Production – Rate vs Time

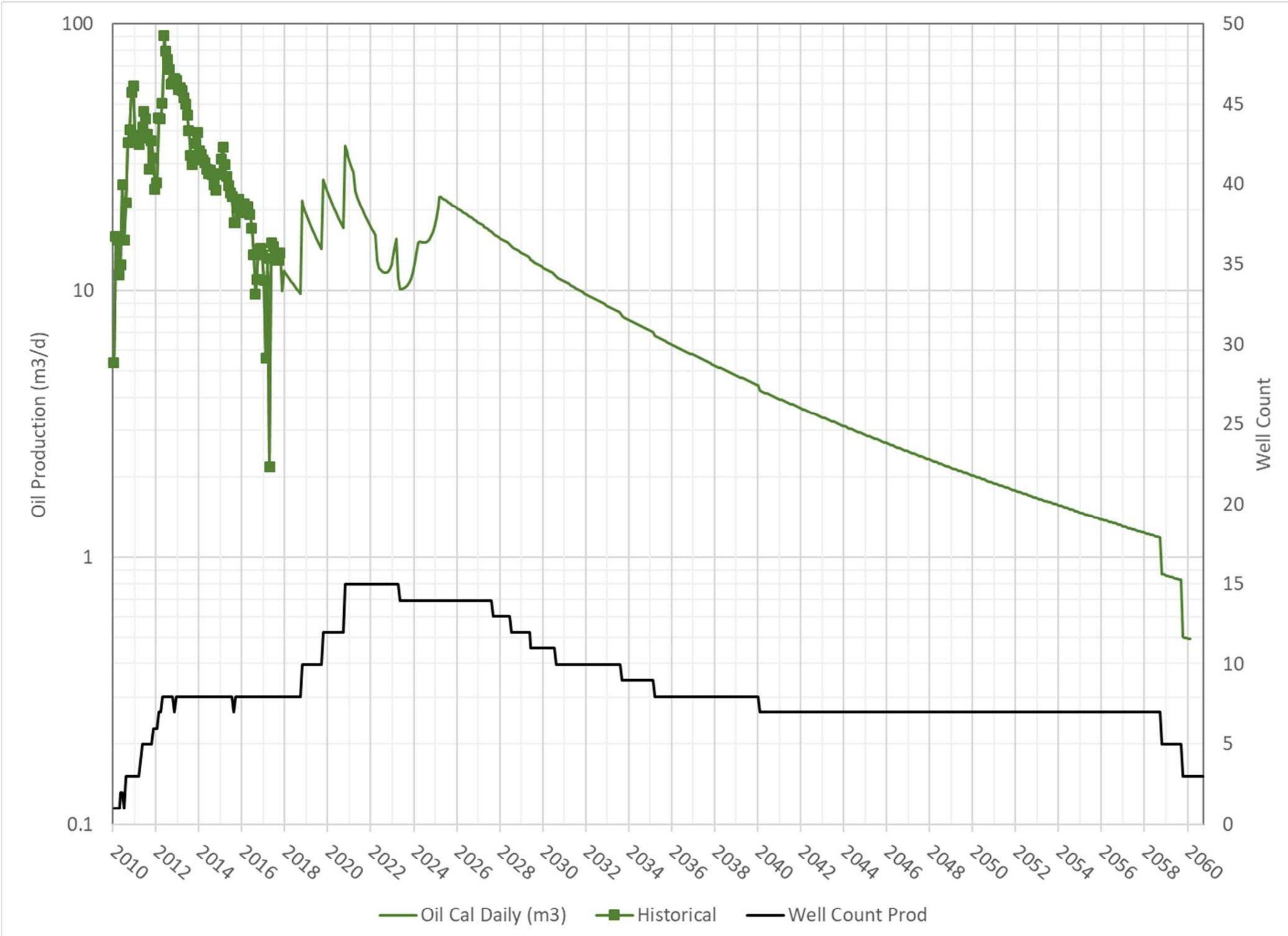
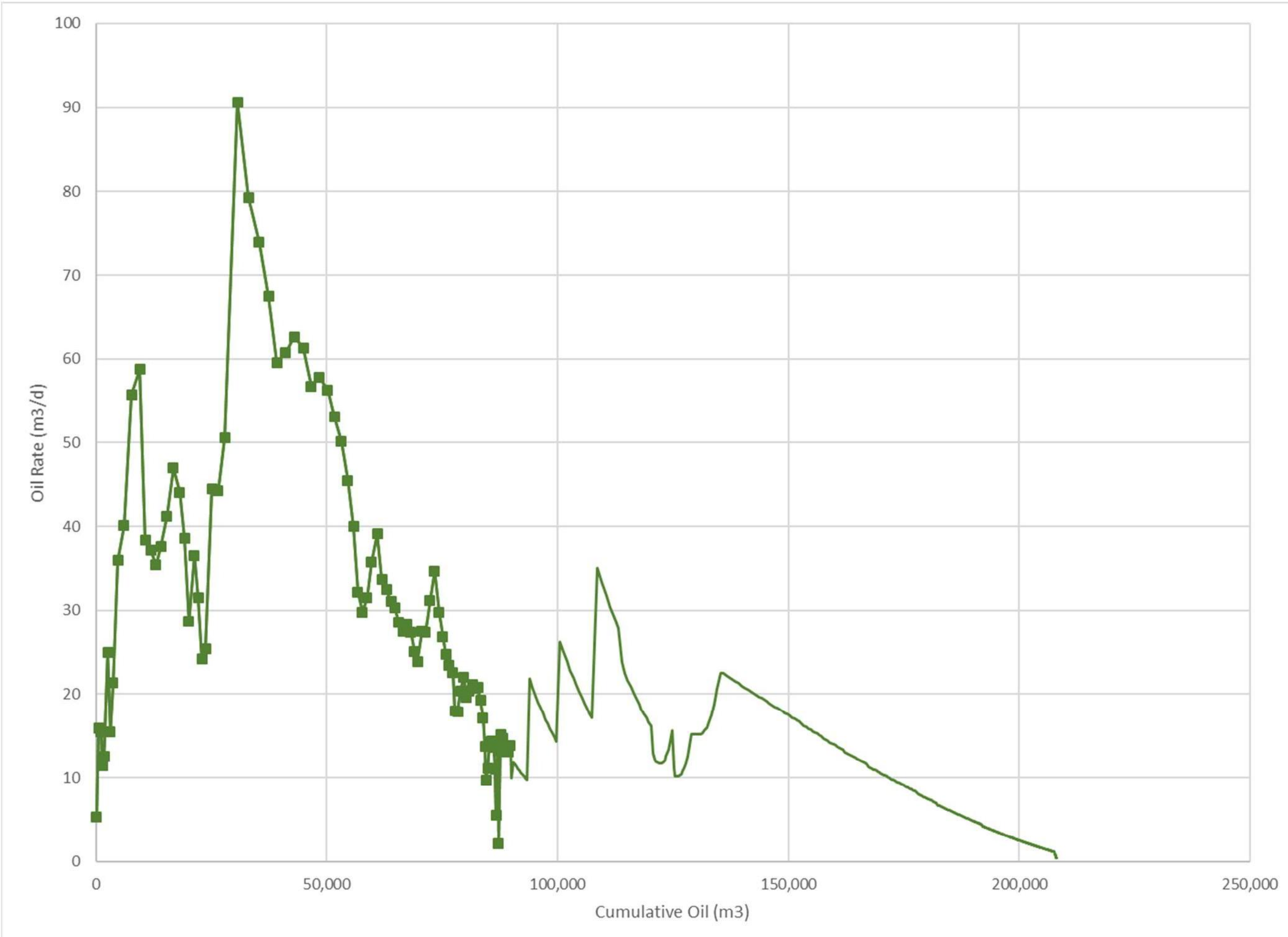
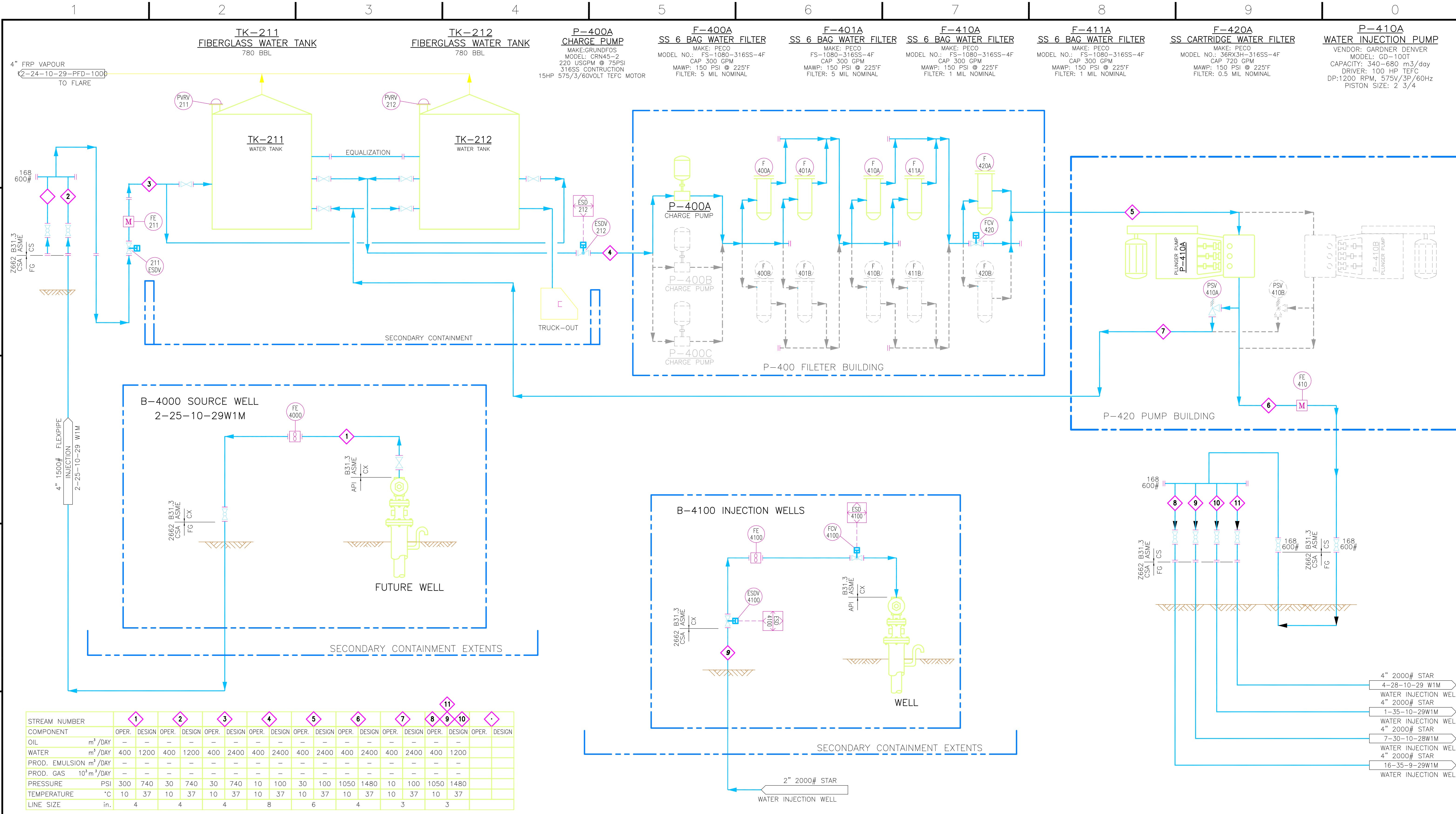


Figure 9. Waterflood Production – Rate vs Cumulative





STREAM NUMBER	1		2		3		4		5		6		7		8 9 10 11		·	
COMPONENT	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	ISSUED FOR CONSTRUCTION	JC	30MAY2013	BE	–

REFERENCE DRAWING: –

NOTES:

Figure No. 10

TUNDRA OIL & GAS PARTNERSHIP

PROCESS FLOW DIAGRAM
12-24-10-29W1M

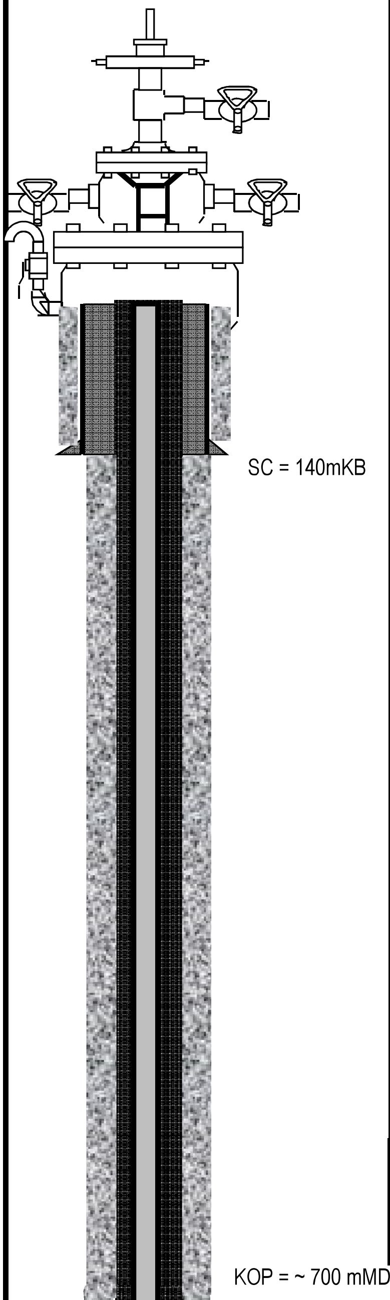
PROCESS FLOW DIAGRAM 4 OF 4
INJECTION SYSTEM

DRAWN BY:	SCALE:	AFE:	DRAWING NUMBER:	REV NO:
RM	NTS		12-24-10-29-PFD-1400	0

Tundra Oil And Gas Partnership

Figure No. 11

TYPICAL OPEN HOLE WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM



WELL NAME:	Tundra Daly Unit No. 19 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]	
Current Perfs:	**Open Hole**			950.0	to	2400.0
Current Perfs:					to	
KOP:	700 m MD		Total Interval		to	
Tubulars	Size [mm]	Wt - Kg/m	Grade	Landing Depth [mKB]		
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	[illegible]	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:

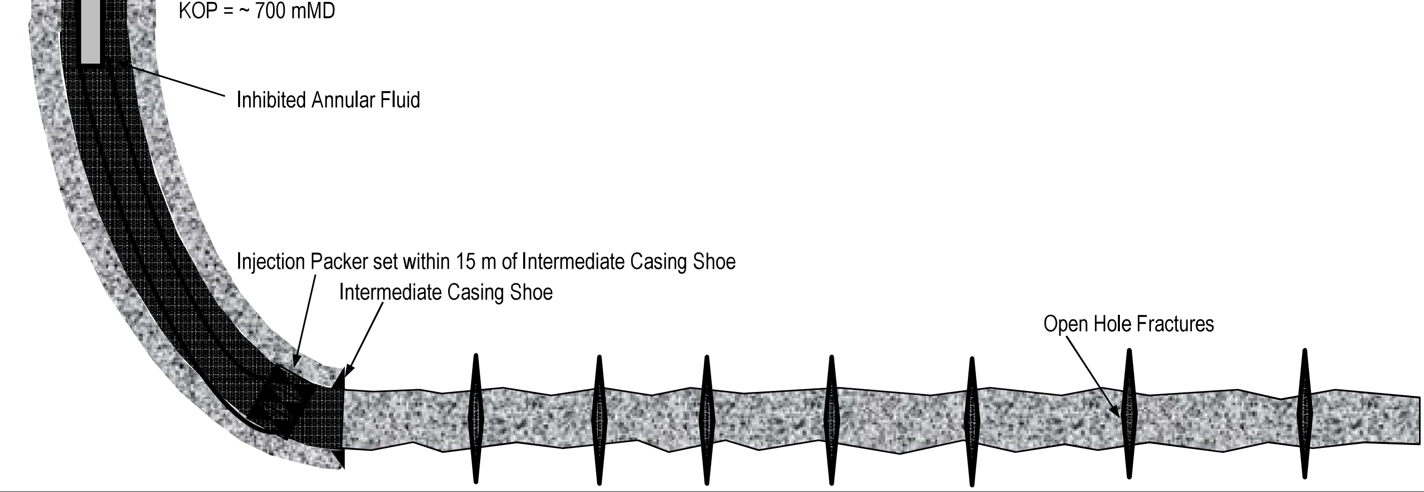


Figure 12 – Corrosion Controls

Source Well

- Located at 02-25-010-29
- Continuous downhole corrosion inhibition
- Downhole scale inhibitor injection
- Corrosion resistant valves and internally coated surface piping
- Biocide injected at source well for entire system

Pipelines

- The water source line will be composite from source well to 12-24-10-29 water plant.
- Injection lines will be a mix of 2000psi high pressure fiberglass and composite pipe.
- Producing lines existing as per original flowline licenses.

Facilities

12-24-10-29 Water Plant

- Plant piping – 600 ANSI stainless steel schedule 80 pipe, fiberglass or internally coated
- Filtration – Stainless steel bodies, PVC piping or stainless steel piping
- Pumping – Ceramic plungers, stainless 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 Wells

- 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
- Scale inhibition (pellets & injected post pump at battery)

Producing Wells

- Downhole corrosion inhibitor, either batch or daily injection, as needed.
- Scale inhibitor treatment daily injection as required for horizontal wells.
- Casing cathodic protection where required.

Proposed Daly Unit No. 19

Application for Enhanced Oil Recovery Waterflood Project

List of Tables

TABLE NO. 2: TRACT FACTOR CALCULATIONS FOR DALY BAKKEN UNIT NO. 19 APPLICATION

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

Tract	*OOIP (m3)*	*Hz Cum Allocated Prodn (m3)*	*Vertical Cum Oil Prodn (m3)*	*OOIP Minus Cum Oil Prodn (m3)*	*OOIP - Cum Prod Tract Factor (%)*	Last 12 Mth Alloc Prod	% of Last 12 Mth Prod	*50% of OOIP - Cum TF + 50% Last 12 Mth Prodn TF*
01-25-010-29W1M	35206	2546.1	0.0	32660	3.348543882	118.2	2.460130321	2.904337101%
02-25-010-29W1M	33614	2802.5	0.0	30812	3.159074370	130.2	2.707880851	2.933477610%
03-25-010-29W1M	34577	2804.8	0.0	31772	3.257581029	130.3	2.710078892	2.983829960%
04-25-010-29W1M	36629	2679.2	0.0	33949	3.480801971	124.4	2.588768006	3.034784989%
05-25-010-29W1M	35649	1945.6	0.0	33704	3.455601345	89.5	1.862071846	2.658836596%
06-25-010-29W1M	32093	2034.5	0.0	30059	3.081892430	93.6	1.947175270	2.514533850%
07-25-010-29W1M	29615	2036.6	0.0	27579	2.827605808	93.7	1.949116369	2.388361088%
08-25-010-29W1M	27675	1948.1	0.0	25727	2.637774157	89.6	1.864488427	2.251131292%
09-25-010-29W1M	27715	1875.5	2903.2	22937	2.351663853	177.5	3.692965010	3.022314432%
10-25-010-29W1M	29714	1979.5	0.0	27735	2.843622543	187.4	3.897810895	3.370716720%
11-25-010-29W1M	32208	1978.9	0.0	30229	3.099341170	187.3	3.896538750	3.497939960%
12-25-010-29W1M	35208	1892.9	0.0	33315	3.415785770	179.2	3.727182079	3.571483925%
13-25-010-29W1M	35232	3755.1	0.0	31477	3.227311131	173.4	3.607165148	3.417238140%
14-25-010-29W1M	32733	3931.9	0.0	28801	2.952975554	181.5	3.777035743	3.365005648%
15-25-010-29W1M	30737	3930.4	0.0	26806	2.748434731	181.5	3.775558607	3.261996669%
16-25-010-29W1M	29242	3759.7	0.0	25482	2.612623897	173.6	3.611596555	3.112110226%
01-36-010-29W1M	29114	3914.3	0.0	25200	2.583732763	285.2	5.933200183	4.258466473%
02-36-010-29W1M	30570	4095.2	0.0	26475	2.714456113	298.4	6.207373195	4.460914654%
03-36-010-29W1M	32512	4092.0	0.0	28420	2.913917030	298.1	6.202563142	4.558240086%
04-36-010-29W1M	33968	3765.1	0.0	30203	3.096654928	274.3	5.707127699	4.401891313%
05-36-010-29W1M	34426	3315.8	0.0	31110	3.189702849	145.8	3.032646418	3.111174633%
06-36-010-29W1M	33457	3600.5	0.0	29856	3.061131647	158.3	3.292956428	3.177044038%
07-36-010-29W1M	32002	3601.1	0.0	28400	2.911865476	158.3	3.293524236	3.102694856%
08-36-010-29W1M	30062	3422.3	0.0	26640	2.731325651	150.4	3.130009522	2.930667586%
09-36-010-29W1M	33984	2278.0	0.0	31706	3.250781320	98.5	2.048753646	2.649767483%
10-36-010-29W1M	36136	2459.0	0.0	33677	3.452882720	106.3	2.211584337	2.832233528%
11-36-010-29W1M	37761	2458.3	0.0	35303	3.619526601	106.3	2.210953337	2.915239970%
12-36-010-29W1M	37793	2342.2	0.0	35450	3.634695587	101.3	2.106497554	2.870596570%
13-36-010-29W1M	38291	1901.6	0.0	36390	3.731014593	76.5	1.591434554	2.661224574%
14-36-010-29W1M	38259	2010.5	0.0	36249	3.716534638	80.9	1.682611799	2.699573218%
15-36-010-29W1M	36637	2011.8	0.0	34625	3.550067495	80.9	1.683636980	2.616852237%
16-36-010-29W1M	34486	1899.3	0.0	32587	3.341076948	76.4	1.589564202	2.465320575%
	1067306	**89068.0**	**2903.2**	**975335**	**100.000000000**	**4806.6**	**100.000000000**	**100.000000000%**

Table 3 - Proposed Daly Unit No. 19 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 (%)
102/01-25-010-29W1/0	007896	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Producing	3/30/2011	May-2018	1.32	40.80	10832.50	11.01	341.20	32697.50	89.32
103/08-25-010-29W1/0	007961	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	2/29/2012	May-2018	1.42	43.90	7964.80	11.01	341.20	33299.00	88.60
100/09-25-010-29W1/2	003883	Vertical	BAKKEN-THREE FORKS A	BAKKEN	Abandoned	11/16/1987	Jul-2003	0.00	0.00	2903.20	0.20	6.20	11878.10	100.00
102/09-25-010-29W1/0	007897	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	3/20/2012	May-2018	2.12	65.80	7726.70	19.01	589.20	83225.00	89.95
100/16-25-010-29W1/0	007907	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	7/31/2011	May-2018	2.22	68.90	15377.10	5.30	164.20	29540.70	70.44
100/01-36-010-29W1/0	007539	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	11/25/2010	May-2018	3.57	110.60	15866.60	12.17	377.40	50073.70	77.34
100/08-36-010-29W1/0	008671	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	2/22/2013	May-2018	1.00	30.90	13939.70	1.41	43.80	23143.10	58.63
100/09-36-010-29W1/0	008965	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	2/28/2013	May-2018	1.38	42.90	9537.40	1.60	49.50	13235.00	53.57
100/16-36-010-29W1/0	008952	Horizontal	BAKKEN-THREE FORKS A	BAKKEN	Producing	11/20/2012	May-2018	0.91	28.20	7823.20	2.60	80.50	14944.90	74.06
										91971.2				

Table No. 4: OOIP Calculation

Polygon Name	Total Area (MTR x MTR)	Isopach (m)	OOIP (m3)	OOIP (bbl)
1-25-10-29W1	161,719.47	7.0	35206	221436
2-25-10-29W1	161,322.35	6.7	33614	211426
3-25-10-29W1	161,134.27	6.9	34577	217483
4-25-10-29W1	161,341.89	7.3	36629	230387
5-25-10-29W1	161,451.19	7.1	35649	224227
6-25-10-29W1	161,243.82	6.4	32093	201860
7-25-10-29W1	161,402.80	5.9	29615	186274
8-25-10-29W1	161,799.71	5.5	27675	174072
9-25-10-29W1	162,033.66	5.5	27715	174324
10-25-10-29W1	161,943.30	5.9	29714	186897
11-25-10-29W1	161,819.21	6.4	32208	202581
12-25-10-29W1	161,731.49	7.0	35208	221453
13-25-10-29W1	161,841.62	7.0	35232	221603
14-25-10-29W1	161,929.33	6.5	32733	205886
15-25-10-29W1	162,023.49	6.1	30737	193329
16-25-10-29W1	162,114.14	5.8	29242	183923
1-36-10-29W1	156,028.67	6.0	29114	183123
2-36-10-29W1	156,029.45	6.3	30570	192281
3-36-10-29W1	156,035.56	6.7	32512	204497
4-36-10-29W1	156,034.06	7.0	33968	213651
5-36-10-29W1	155,911.67	7.1	34426	216534
6-36-10-29W1	155,913.39	6.9	33457	210436
7-36-10-29W1	155,910.55	6.6	32002	201283
8-36-10-29W1	155,909.69	6.2	30062	189083
9-36-10-29W1	170,742.92	6.4	33984	213752
10-36-10-29W1	170,876.34	6.8	36136	227289
11-36-10-29W1	171,013.98	7.1	37761	237508
12-36-10-29W1	171,158.03	7.1	37793	237708
13-36-10-29W1	171,008.72	7.2	38291	240846
14-36-10-29W1	170,864.55	7.2	38259	240643
15-36-10-29W1	170,732.88	6.9	36637	230438
16-36-10-29W1	170,599.85	6.5	34486	216910
		Sum:	**1067306**	**6713143**

N/G:	0.334
Por:	0.158
Sw:	0.35
Boi	1.1

UWI	0.5 md CO N/G	Porosity (.5md CO)
04-06-11-28	0.13	0.16
12-24-10-29	0.23	0.14
02-25-10-29	0.16	0.16
10-30-10-28	0.32	0.16
12-29-10-28	0.65	0.17
11-29-10-28	0.52	0.16
10-29-10-28	0.41	0.15
07-20-10-28	0.25	0.16
Average	**0.334**	**0.158**

Table 5 - Daly Unit No. 19: Reservoir and Fluid Properties

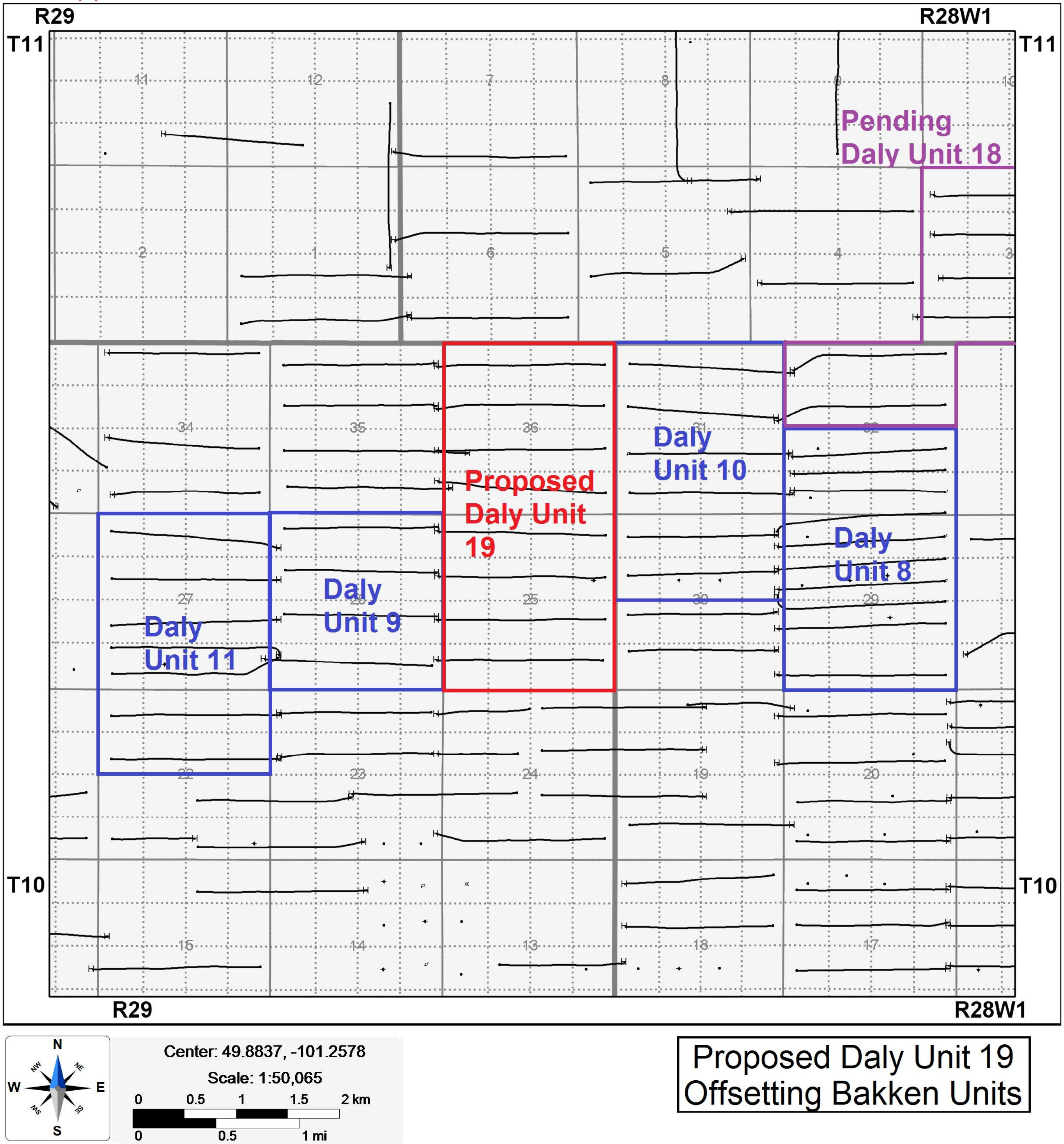
	Units	Bakken	
Depth	m	820	
Initial Reservoir Pressure	kPa	8,400	estimated
Formation Temperature	^{o}C	30	
Saturation Pressure	kPa	1,675	
Solution GOR	m3/m3	5	
Oil Gravity (dead oil)	^{o}API	42	
Bo @ Psat	m3/m3	1.10	
Initial Water Saturation	dec	0.35	
Wettability		neutral	
Average Porosity	%	0.158	
Average Permeability	mD	5	
Water Salinity	mg/L	113,000	

Proposed Daly Unit No. 19

Application for Enhanced Oil Recovery Waterflood Project

LIST OF APPENDICES

Appendix 1



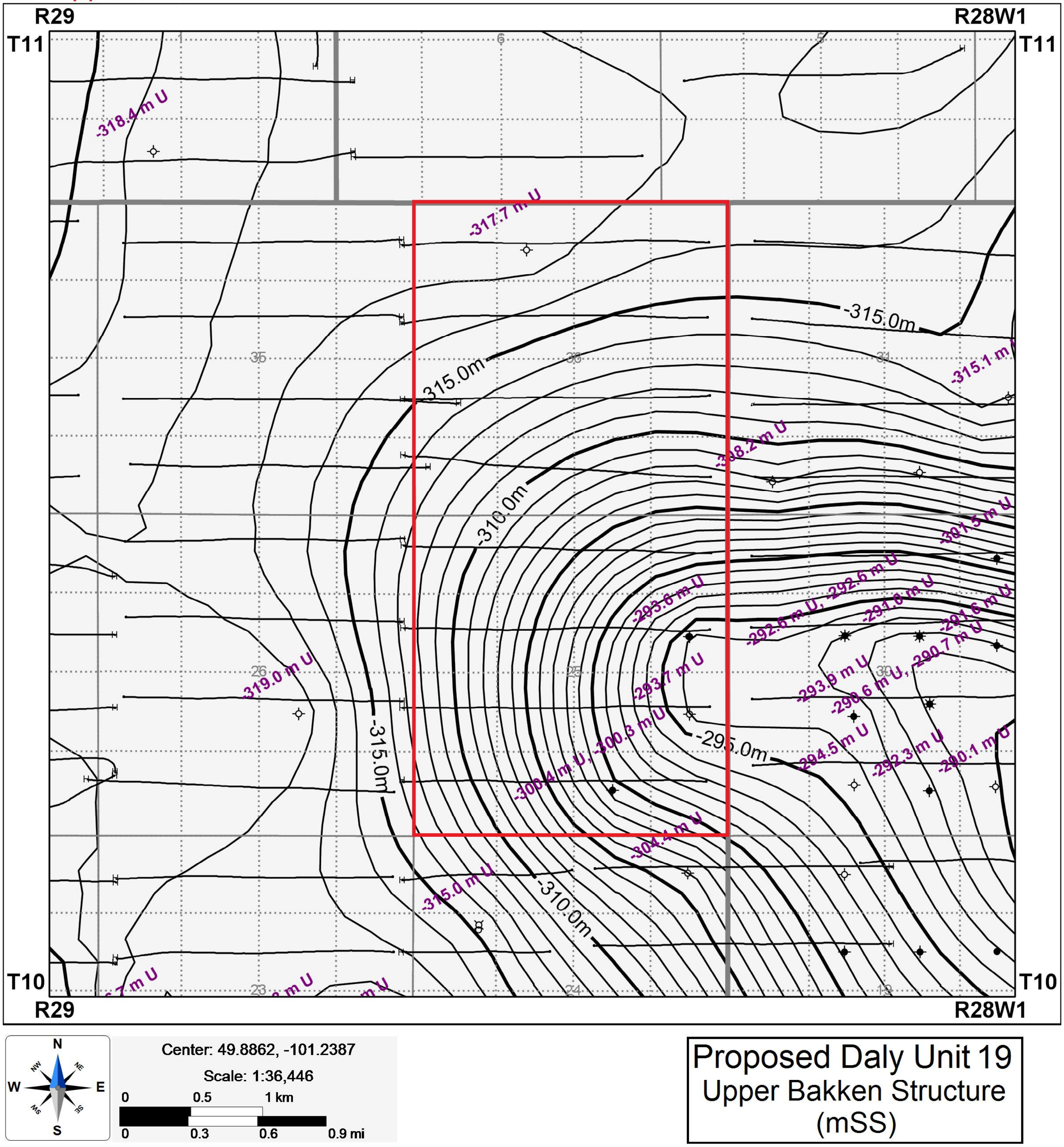
Proposed Daly Unit 19
Offsetting Bakken Units

Appendix 2

A	00/02-25-010-29W1/0 KB: 524.9 m RR: 1986-06-29 TD: 850.0 m [TVD] FormTD: TORQUAY Mode: Abnd Fluid: Oil PEREGRINE ET AL DALY 2-25-10-29 893.2m to next well >	00/09-25-010-29W1/0 KB: 522.7 m RR: 1986-07-04 TD: 848.0 m [TVD] FormTD: TORQUAY Mode: Abnd Fluid: Oil PEREGRINE ET AL DALY 9-25-10-29 < 893.2m to previous well 2178.9m to next well >	00/14-36-010-29W1/0 KB: 524.9 m RR: 1997-02-20 TD: 903.0 m [TVD] FormTD: BIRDBER Mode: Abnd Fluid: N/A NORTHROCK ETAL DALY PROV 14-36-10-29 < 2178.9m to previous well	A'

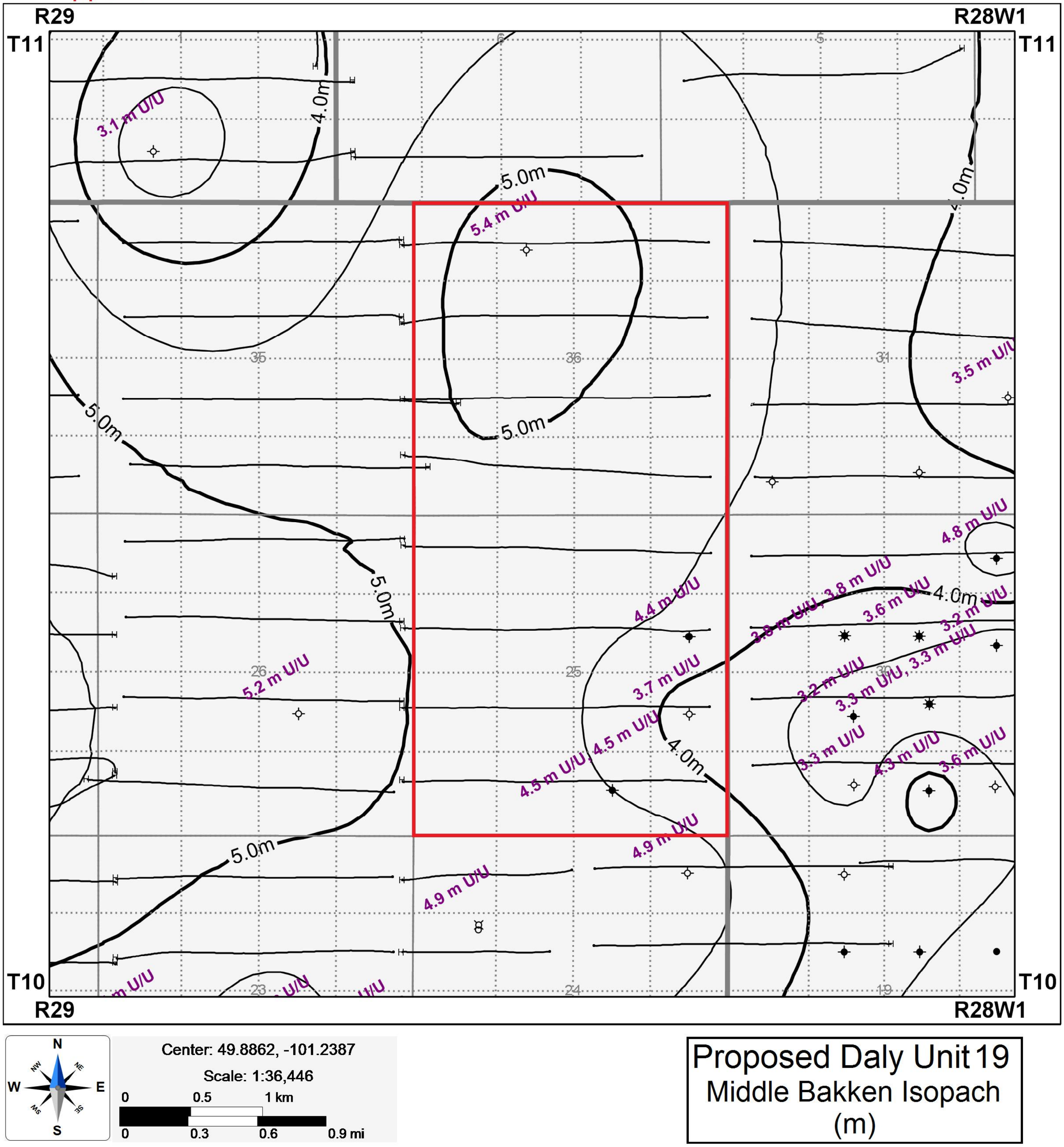
Proposed Daly Unit 19
Structural Cross Section
-South to North-
Through Proposed Unit Area

Appendix 3



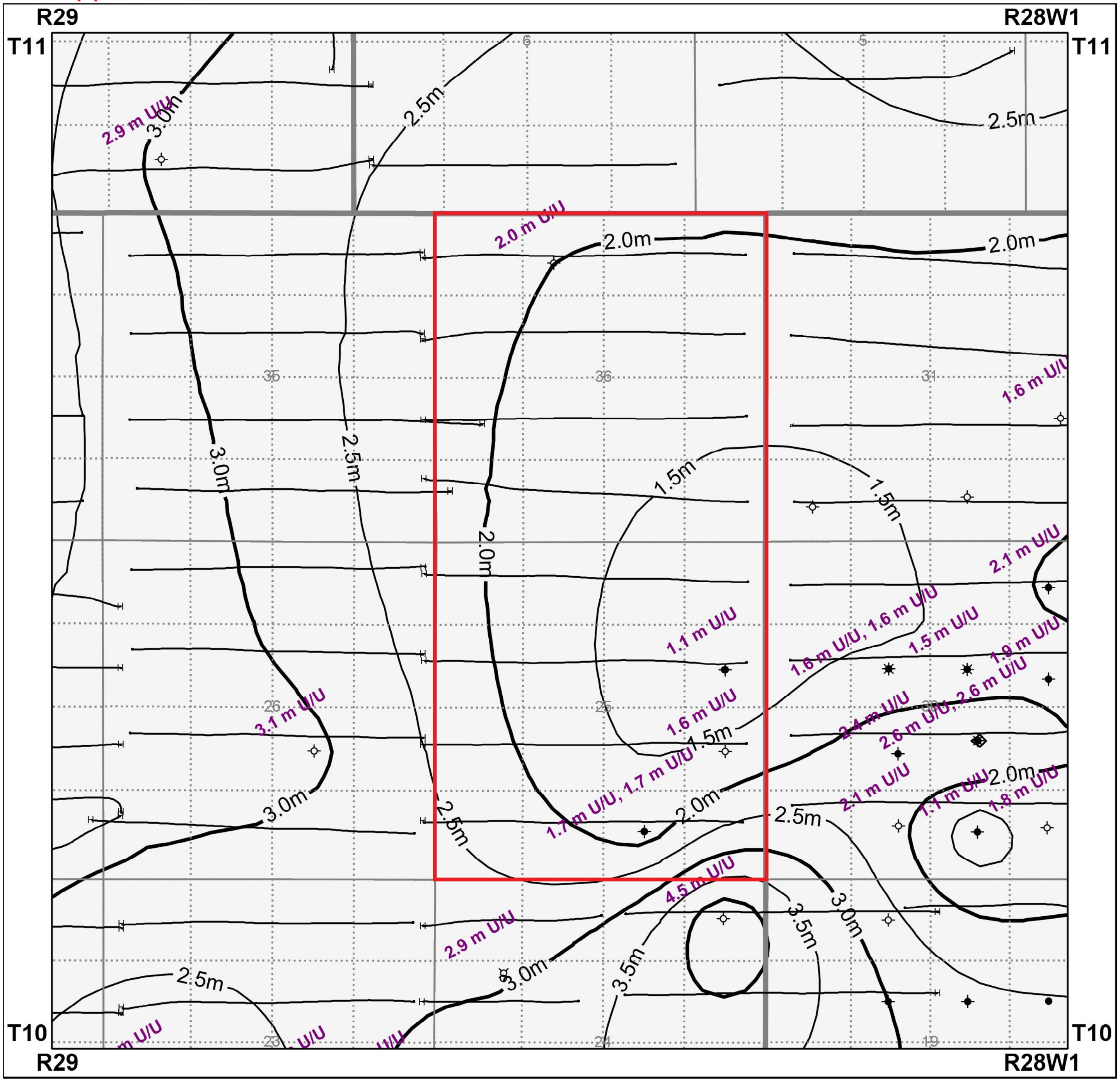
Proposed Daly Unit 19
Upper Bakken Structure
(mSS)

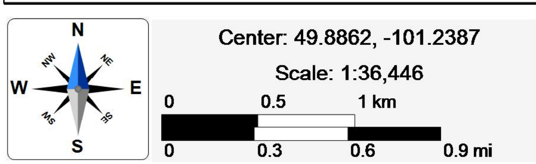
Appendix 4



Proposed Daly Unit 19
Middle Bakken Isopach
(m)

Appendix 5



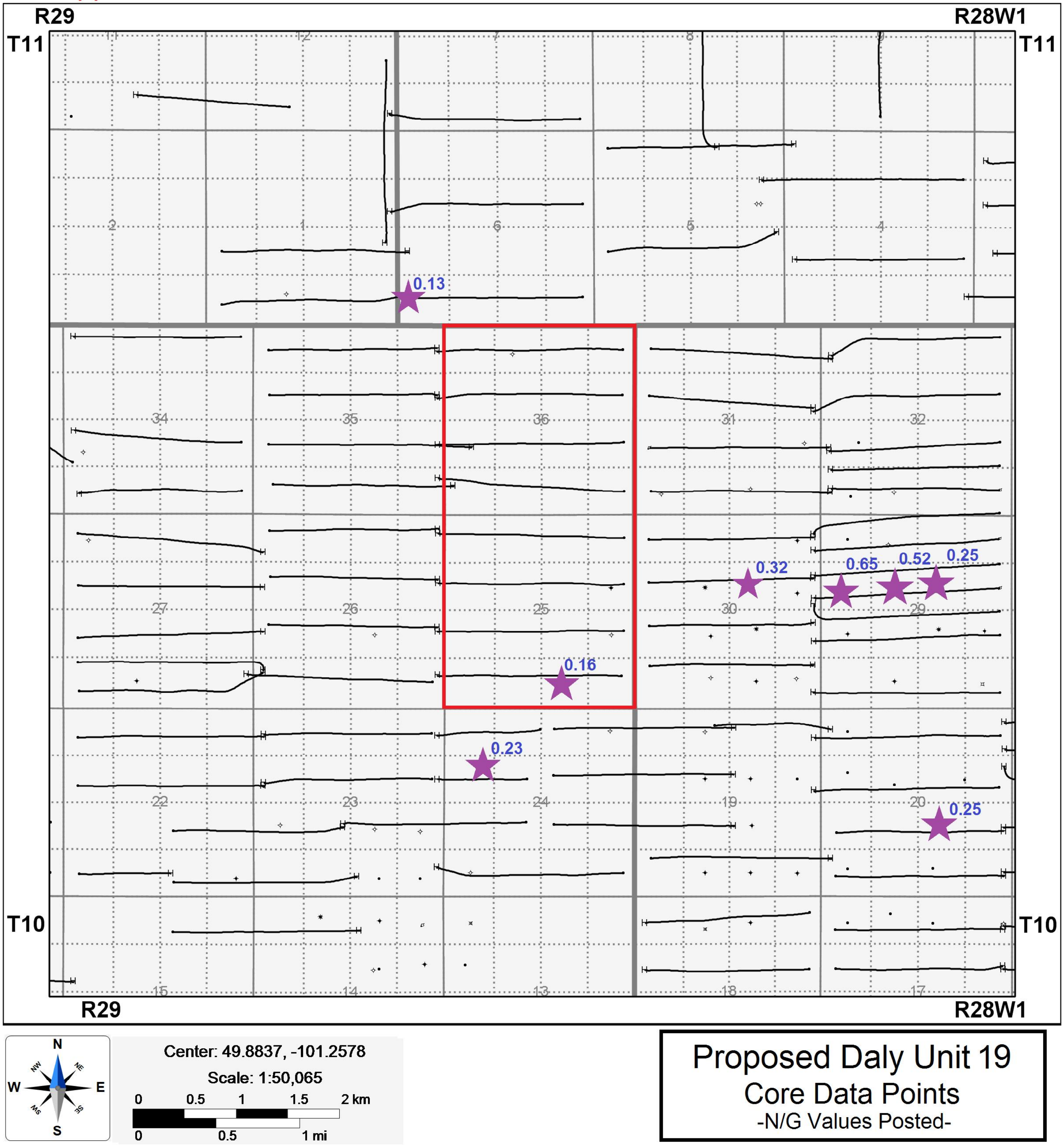


Proposed Daly Unit 19

Lyleton B Isopach

(m)

Appendix 6



R29
R28W1
T11
T11
T10
T10
R29
R28W1
0.13
0.32
0.65
0.52
0.25
0.16
0.23
0.25
34
35
36
31
32
27
26
25
30
29
22
23
24
19
20
N
W
E
S
Center: 49.8837, -101.2578
Scale: 1:50,065
0 0.5 1 1.5 2 km
0 0.5 1 mi
Proposed Daly Unit 19
Core Data Points
-N/G Values Posted-