PROPOSED NORTH VIRDEN SCALLION UNIT NO. 3

Application for Enhanced Oil Recovery Waterflood Project

Lodgepole Formation

Lodgepole A (05 59A)

Virden Field, Manitoba

July 31, 2018
Tundra Oil and Gas

Contents

INTRODUCTION

The Virden Oilfield is located in Townships 9-11, of Ranges 26-27 WPM (Figure 1). Within the Virden Oilfield, most Lodgepole reservoirs have been developed with vertical producing wells on Primary Production and 40 acre spacing.

Within the area, potential exists for incremental production and reserves from a Waterflood Enhanced Oil Recovery (EOR) project in the Lodgepole oil reservoir. The following represents an application by Tundra Oil and Gas Partnership (Tundra) to establish North Virden Scallion Unit No. 3 (LSDs 3-5, 7, 10, 15-29-011-26W1, LSDs 1-3, 6-8, 11, 14-30-011-26W1) and implement a Secondary Waterflood EOR scheme within the Lodgepole formation as outlined on Figure 2.

The proposed project area falls within the existing designated Lodgepole A Pool of the Virden Oilfield (Figure 3).

SUMMARY

1. The proposed North Virden Scallion Unit No. 3 will include 14 vertical wells (10 abandoned, 4 producing) and 9 horizontal Lodgepole wells (7 producing, 1 standing, 1 drainage). The area of the proposed North Virden Scallion Unit No. 3 comprises 14 Legal Sub Divisions (LSD), and is located south of North Virden Scallion Unit No. 2 (Figure 2).

2. Total Original Oil in Place (OOIP) in the project area is estimated to be **1,600** e^3m^3 (10,061 Mbbl) for an average of **114.0** e^3m^3 (719.0 Mbbl) OOIP per 40 acre LSD.

3. Cumulative production to the end of April 2018 from the 11 producing Lodgepole wells within the proposed North Virden Scallion Unit No. 3 project area is 269.1 e^3m^3 (1,692 Mbbl) of oil and 684.1 e^3m^3 (4,303 Mbbl) of water, representing a 16.8% Recovery Factor (RF) of the OOIP.

4. Figure 4 shows the production from the proposed area peaked in June 1969 at 32.35 m^3/d oil (203.55 bbl/d) from 9 wells. As of April 2018, production was 8.75 m^3/d oil (55.1 bbl/d), 110.2 m^3/d water (693.5 bbl/d) from 8 wells and 92.6% watercut.

5. In June 1969, production averaged 3.59 m^3/d oil (22.6 bbl/d) per well. As of April 2018, average per well production has declined to 1.09 m^3/d oil (6.9 bbl/d). Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately 12% in the project area.

6. Estimated Ultimate Recovery (EUR) of Primary producing oil reserves in the proposed North Virden Scallion Unit No. 3 project area is estimated to be 306.7 e^3m^3 (1,929.2 Mbbl), with 37.5 e^3m^3 (236.0 Mbbl) remaining as of the end of April 2018.

7. Ultimate oil recovery of the proposed North Virden Scallion Unit No. 3 OOIP, under the current Primary production method, is forecasted to be **19.2%**. Tundra plans to drill an additional 5 wells in 2018 and 2019, which would add an estimated 63.8 e^3m^3 (401.0 Mbbl) of Primary recovery, or **4.0%** of the Unit OOIP. Total Primary recovery for the Unit would be **23.2%**.

8. Estimated Ultimate Recovery (EUR) of oil under Secondary Waterflood EOR for the proposed North Virden Scallion Unit No. 3 is estimated to be 518.6 e^3m^3 (3,261.7 Mbbl). An incremental 148.1 e^3m^3 (931.5 Mbbl) of oil is forecasted to be recovered under the proposed Unitization and Secondary EOR production, versus the existing and future Primary production method.

9. Total RF under Secondary WF in the proposed North Virden Scallion Unit No. 3 is estimated to be **32.4%**.

10. Based on waterflood response in the analogs in the North Virden Scallion Units 1 & 2, the Scallion Lodgepole formation in the proposed project area are believed to be suitable reservoirs for WF EOR operations.

11. Future open-hole horizontal injectors will be drilled between existing horizontal/vertical producing wells (Figure 5) within the proposed North Virden Scallion Unit No. 3.

DISCUSSION

The proposed North Virden Scallion Unit No. 3 project area is located within Township 11, Range 26 W1 of the Virden Oilfield (Figure 1). The proposed North Virden Scallion Unit No. 3 currently consists of 14 vertical and 9 horizontal wells within an area covering 14 LSDs (Figure 2). A project area well list complete 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 Lodgepole oil reservoir.

Geology

Stratigraphy:

The Scallion Member is part of the Mississippian aged Lodgepole Formation as seen on the type log 102/01-30-011-26W1/0 from 630-659m in Appendix 1. In the proposed unit area the Lodgepole Formation consists, in descending order, of the Upper Whitewater Lake, Virden and Scallion Members. All of these members have a conformable relationship and in turn are unconformably overlain by the Jurassic aged Amaranth Formation refer to Appendix 2, cross-section A-A'. The Lodgepole Formation conformably over lies the dark shales of the Bakken Formation.

Sedimentology:

The Scallion Member in the proposed North Virden Scallion Unit No. 3 is comprised of white to pink, variably oil stained cherty limestones generally consisting of bioclastic skeletal mudstones to packstones. Crinoid fragments make up the bulk of the skeletal material with rare brachiopod shells and solitary rugose corals. Occasionally the rock becomes moderately oolitic in texture. White chert nodules are common as is chalky white limestone, generally deeper in the section. The Scallion is divided into upper and lower porosity units with the best reservoir developed in the upper, consisting of finely crystalline bioclastic cherty limestones. The lower porosity unit is generally less porous and more finely crystalline with a more chalky appearance. Porosity in the upper unit is developed where the rock has been re-crystalized and moderately leached creating secondary porosity. The Scallion Member is interpreted to have been deposited on a gently sloping carbonate shelf dipping to the south west. Trapping is stratigraphically controlled by alteration of the limestone to non-porous dolomites in the up dip direction.

Structure:

The Scallion Structure Map (Appendix 3) of the area proximal to the proposed unit shows a general drop in structure from east (-161.2m) to west (-182.6m) with structure dropping dramatically along the east side which is controlled by collapse feature caused by salt dissolution of a portion of the underlying Devonian aged Prairie Evaporites. In addition there are a number of more subtle structural features in the area. This includes two structural highs, one in the north portion of North Virden Scallion Unit No. 2 and the other along the southern edge of the proposed unit, separated by a saddle approximately 2 LSD's wide. The structure drop in the saddle is approximately 8m and is controlled by minor salt dissolution in the Prairie Evaporite Formation. This feature is associated with a major north to south trending salt collapse feature along the east side of the area. As mentioned previously, the eastern portion of the proposed unit has dramatic structural relief on the top of the Scallion from approximately -175m along the west edge of the collapse feature to -195m in the centre of the feature. Over the western portion of the proposed unit there is approximately 12m of relief on the top of the Scallion from a low of -182 to a high of -170m.

Reservoir:

The Scallion reservoir within the proposed North Virden Scallion Unit No. 3 is estimated to be of excellent quality in the upper unit and fair to good in the lower. All of the existing vertical wells and horizontal wells within to proposed unit have been completed in the upper porosity with a number of wells having accumulated production of greater than 100m BBLs which supports the reservoir quality estimation.

Tundra used log data from 4 wells drilled in the proposed unit area with modern log suites to determine net pay values. The porosity cutoff was set at 9% using the limestone density scale above an oil water contact of -192m. These values were then used to create net pay maps for the upper and lower porosity units over the proposed unit. The differentiation between the upper and lower porosity can be seen on the type log at 102/01-30-011-26W1m with the upper porosity is observed where the density porosity increases from 637.6m to the base at 647m. The lower porosity is less clearly defined but still can be seen where the density porosity increases from 647m to the base at 660.5m. The average porosity in the upper unit is 16.3% compared to an average porosity in the lower of 12.3% from the logs used in the calculation. The calculated average Sw in the upper unit is 34.2% compared to an average Sw of 44.9% in the lower unit. Water saturations were calculated using the Buckles equation with calculated porosity from logs and Buckles constant of 550 derived from an oil based core from North Virden Scallion Unit No. 1 at 9-23-11-26W1. These average values were used to calculate OOIP in the upper and lower porosity units. The calculated OOIP is higher in the upper porosity than in the lower unit due to the higher average porosity and lower average Sw. There is limited core data from wells in the area but the data that is available indicates that in the more porous rock Kmax values range from the single digit (1-9 mda) to mid to high double digit (40-95 mda) with occasional thin streaks of greater than 100 mda noted. Appendix 4 includes two net pay maps for the Scallion, one for the upper porosity and one for the lower porosity.

OOIP Estimates

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)

For the purposes of this unit application, Bo was held constant at 1.045. The initial oil formation volume factor was obtained from the original reservoir study done by Chevron Canada Resources Limited on a portion of the Virden Lodgepole "A" pool which became the North Virden Scallion Unit No. 1.

Historical Production

A historical group production plot for the proposed North Virden Scallion Unit No. 3 is shown as Figure 4. Oil production commenced from the proposed unit area in August 1957. Production peaked in June 1969 at 32.35 m^3/d oil from 9 wells. As of April 2018, production was 8.75 m^3/d oil, 110.2 m^3/d of water from 8 wells and 92.6% watercut.

From peak production in June 1969, oil production is declining at an annual rate of **approximately 12%** 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 secondary recovery to introduce energy back into the system and provide areal sweep between wells.

UNITIZATION

The basis for unitization is to develop the lands in an effective manner that will be conducive to waterflooding. In addition, Unitizing will facilitate a pressure maintenance scheme, which will increase oil production over time. Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP from the proposed project area **by 9.2% of RF (from a recovery factor of 23.2% to 32.4%).**

Unit Name

Tundra proposes that the official name of the new Unit shall be North Virden Scallion Unit No. 3.

Unit Operator

Tundra Oil and Gas (Tundra) will be the Operator of record for North Virden Scallion Unit No. 3.

Unitized Zone

The unitized zone(s) to be waterflooded in North Virden Scallion Unit No. 3 will be the Lodgepole formation.

Unit Wells

The 14 vertical and 9 horizontal wells to be included in the proposed North Virden Scallion Unit No. 3 are outlined in Table 3.

Unit Lands

The North Virden Scallion Unit No. 3 will consist of 14 LSDs as follows:

> LSDs 3-5, 7, 10, 15 of Section 29, of Township 11, Range 26, W1M
> LSDs 1-3, 6-8, 11, 14 of Section 30, of Township 11, Range 26, W1M

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

Tract Factors

The Tract Factor contribution for each of the LSD's within the proposed North Virden Scallion Unit No. 3 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)

Tract Factor calculations for all individual LSD's based on the above methodology are outlined within Table 2.

Working Interest Owners

Table 1 outlines the working interest % (WI) for each recommended Tract within the proposed North Virden Scallion Unit No. 3.

Tundra Oil and Gas will have a 100% working interest in the proposed North Virden Scallion Unit No. 3.

WATERFLOOD EOR DEVELOPMENT

The waterflood performance predictions for the proposed North Virden Scallion Unit No. 3 Lodgepole project 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 information; 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 North Virden Scallion Unit No. 3 OOIP (Table 2).

Unitizing the proposed North Virden Scallion Unit No. 3 will provide an equitable means of maximizing ultimate oil recovery in the project area, which is otherwise not currently achievable given the constraints of drilling full-length horizontals.

Pre-Production of New Horizontal Injection Wells

Three (3) future horizontal wells (2 in North Virden Scallion Unit No. 2 and 1 in the proposed North Virden Scallion Unit No. 3) will be converted to horizontal injection wells as shown in Figure 5. Placing new horizontal wells immediately on water injection in areas without significant reservoir pressure depletion has been problematic in similar low permeability formations, and has a negative impact on the ultimate total recovery factor of OOIP.

Considering the expected reservoir pressures and reservoir lithology described, Tundra believes an initial period of producing the proposed horizontal wells prior to placing them on permanent water injection is essential and all Unit mineral owners will benefit.

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

Reserves Recovery Profiles and Production Forecasts

The primary waterflood performance predictions for the proposed North Virden Scallion Unit No. 3 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 using numerical simulation in combination with analogue studies of successful waterfloods in the Lodgepole Scallion formation.

Primary Production Forecast

Cumulative production to the end of April 2018 from the 11 producing Lodgepole wells within the proposed North Virden Scallion Unit No. 3 project area is 269.1 e^3m^3 of oil and 684.1 e^3m^3 of water for a recovery factor of 16.8% of the total OOIP.

Based on decline curve analysis of the wells currently on production, the estimated ultimate recovery (EUR) for the proposed Unit with no further development is estimated to be 306.7 e^3m^3, representing a recovery factor of 19.2% of the total OOIP.

Production plots of the forecasted oil rate v. time and oil rate v. cumulative oil produced are shown in Figures 6 & 7, respectively.

Tundra plans to drill an additional 5 wells in 2018 and 2019, which would add an estimated 63.8 e3m3 of Primary recovery, or 4.0% of the Unit OOIP. Total Primary recovery for the Unit would be 23.2%.

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

Tundra proposes to implement an initial waterflood phase which will consist of converting 3 wells to injection in 2019-2020, subject to specific production criteria. Subsequent wells will be converted in the unit as required, in accordance with the development plan set out in Figure 5.

Criteria for Conversion to Water Injection Well

Three (3) water injection wells are 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 wells
- Pattern mass balance and/or oil recovery factor estimates
- Reservoir pressure relative to bubble point pressure

The above schedule allows for the proposed North Virden Scallion Unit No. 3 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

The proposed North Virden Scallion Unit No. 3 Secondary Waterflood oil production forecasts over time and over cumulative oil are plotted on Figures 8 and 9. Total EOR recoverable volumes in the proposed North Virden Scallion Unit No. 3 project under Secondary WF has been estimated at 518.6 e^3m^3, resulting in a 32.4% overall RF of calculated Net OOIP.

An incremental 148.1 e^3m^3 of oil is forecast to be recovered under the proposed Unitization and Secondary EOR production scheme vs. the existing Primary Production method. This relates to an incremental 9.2% recovery factor as a result of secondary EOR implementation.

Estimated Fracture Pressure

The estimated fracture gradient for the Lodgepole Scallion is 24 kPa/m based on breakdown pressure data in the area. Tundra expects that this gradient has lowered due to pressure depletion in the proposed area.

WATERFLOOD OPERATING STRATEGY

Water Source

Source water is not currently being used for any water injection in the North Virden Scallion units. Tundra plans to re-inject produced water back into the formation after adequate filtration. Produced water will be filtered at the 8-19-11-26, and pumped to the injection wells, where it will be further filtered via polishing filters at the injection wellheads (Figure 12). Since Tundra will use produced water, compatibility is not a concern.

Injection Wells

New water injection wells for the proposed North Virden Scallion Unit No. 3 will be drilled, cleaned out, and configured downhole for injection as shown in Figure 10.

The new water injection well 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 implemented 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 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 North Virden Scallion Unit No. 3 horizontal water injection well rate is estimated to average 25– 40 m^3 WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure

An initial reservoir pressure build-up test was conducted on 02/01-29-011-26W1/0 at the time of drilling in 2014. The results of this test can be seen in the table below.

UWI	Depth (mTVD)	Pressure (kPa)	Temperature (°C)
102/01-29-011-26W1/0	628.1	4278.3	28.94

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

North Virden Scallion Unit No. 3 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 ever increasing understanding of reservoir performance, and provide data to continually control and optimize the North Virden Scallion Unit No. 3 waterflood operation. Controlling the waterflood operation will significantly reduce or eliminate the potential for out-of-zone injection, undesired channeling, 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 North Virden Scallion Unit No. 3.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed North Virden Scallion Unit No. 3 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 North Virden Scallion Unit No. 3 waterflood operation will utilize the existing Tundra operated water plant (WP) facilities located at 8-19-11-26 W1M 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 on Figure 11.

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 North Virden Scallion Unit No. 3. 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 North Virden Scallion Unit No. 3 Application.

North Virden Scallion Unit No. 3 Unitization, and execution of the formal North Virden Scallion Unit No. 3 Agreement by affected Mineral Owners, is expected during Q3 2018. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the North Virden Scallion Unit No. 3 Application.

Should the Petroleum Branch have further questions or require more information, please contact Robert Prefontaine at 403.767.1248 or by email at robert.prefontaine@tundraoilandgas.com.

TUNDRA OIL & GAS

Original Signed by Robert Prefontaine, July 31st, 2018, in Calgary, AB

Proposed North Virden Scallion Unit No. 3

Application for Enhanced Oil Recovery Waterflood Project

List of Figures

Figure 1 - Virden Field

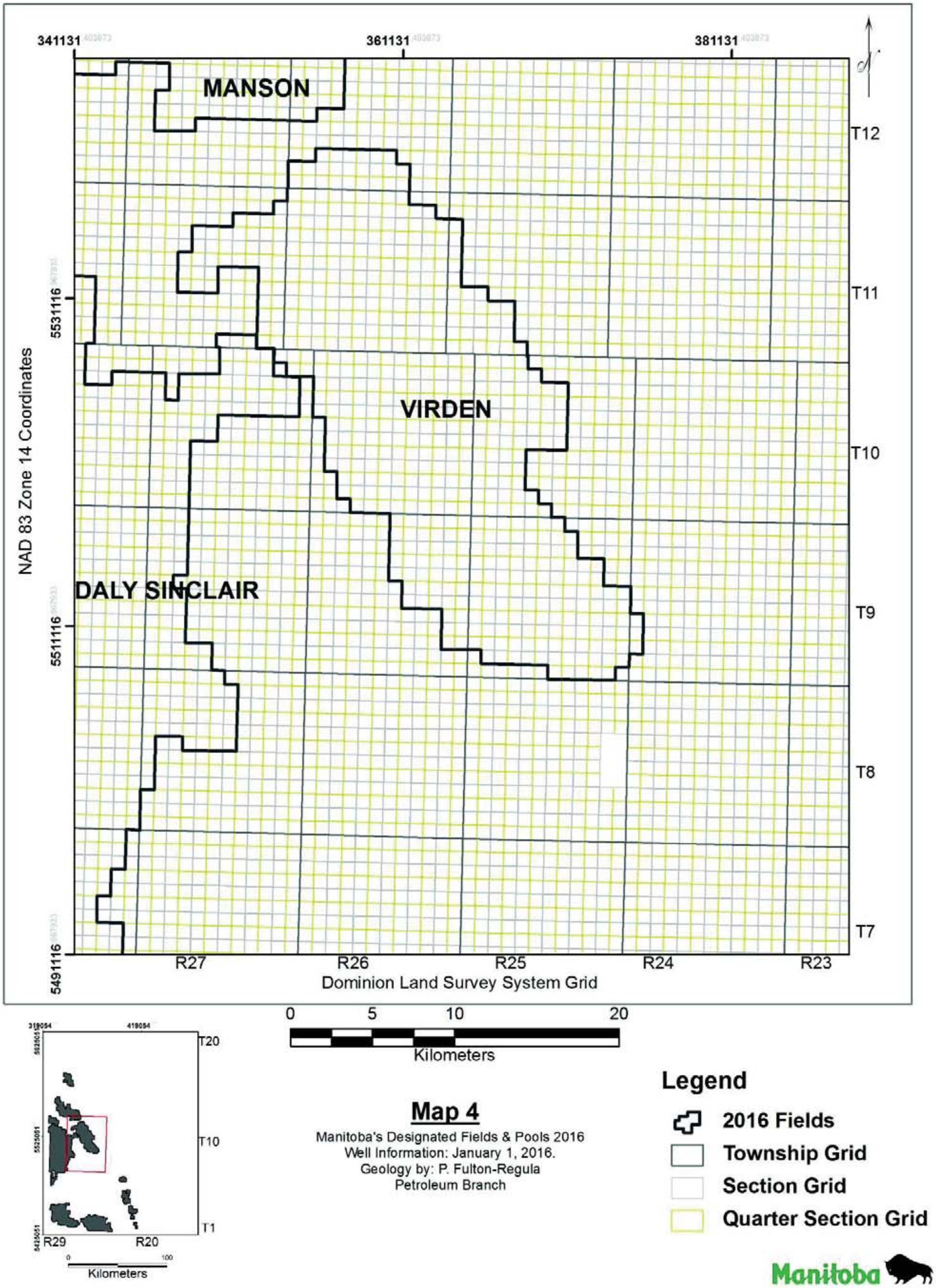
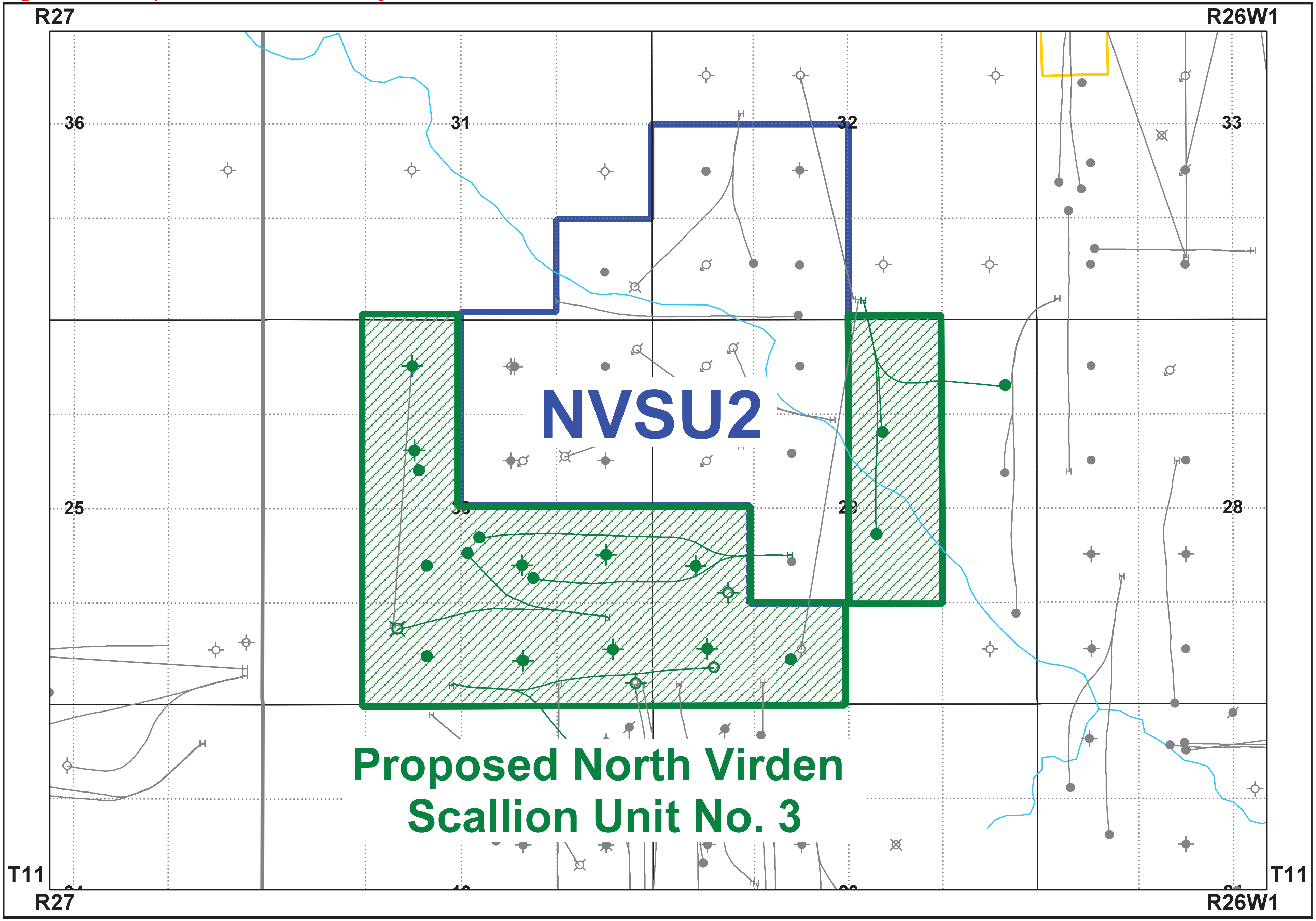


Figure 6 - Map 4 Manson, Daly Sinclair & Virden Fields

Figure 2 - Proposed Unit Boundary



PROPOSED UNIT AREA

Figure 3 - Lodgepole Pool Boundaries

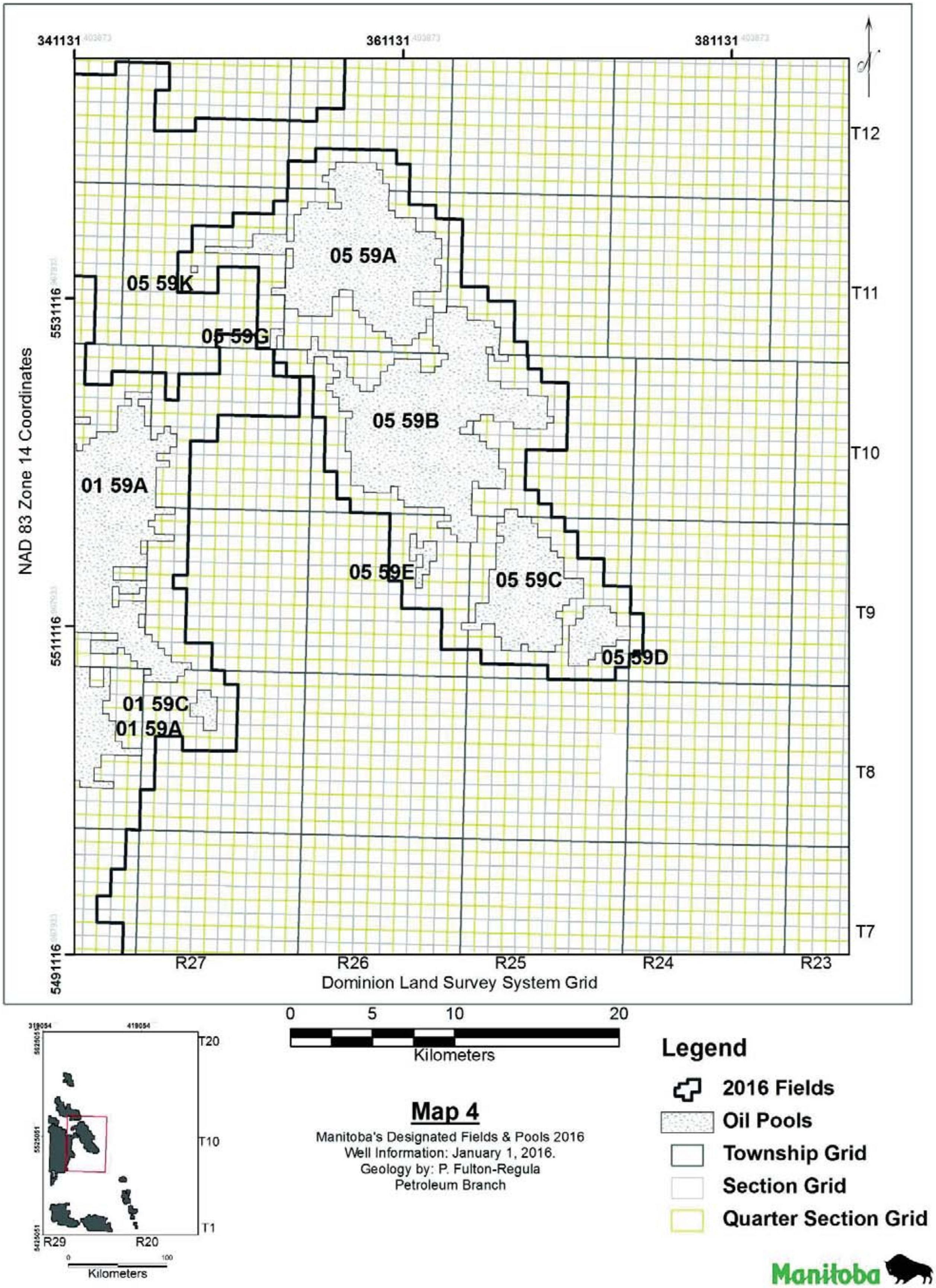


Figure 25 - Map 4 Lodgepole Undifferentiated Pools (59)

Production Graph

Figure 4 - Historical Production

Group:	north virden scallion unit no. 3.lwell	**On Prod:**	1957-08 to 2018-03	**Cum Oil:**	268795.1 m3
# of Wells:	23	**Prod Form:**	LODGEPOL	**Cum Gas:**	0.0 E3m3
Fluid:	Oil	**Field:**	VIRDEN (MB5)	**Cum Wtr:**	680826.6 m3
Mode:	Producing; Abandoned; Potential; Abandoned Zone; Drain...	**Pool Code:**	MB000559A	**Cum Inj Oil:**	0.0 m3
		Unit Code:		**Cum Inj Gas:**	0.0 E3m3
				Cum Inj Wtr:	179596.6 m3

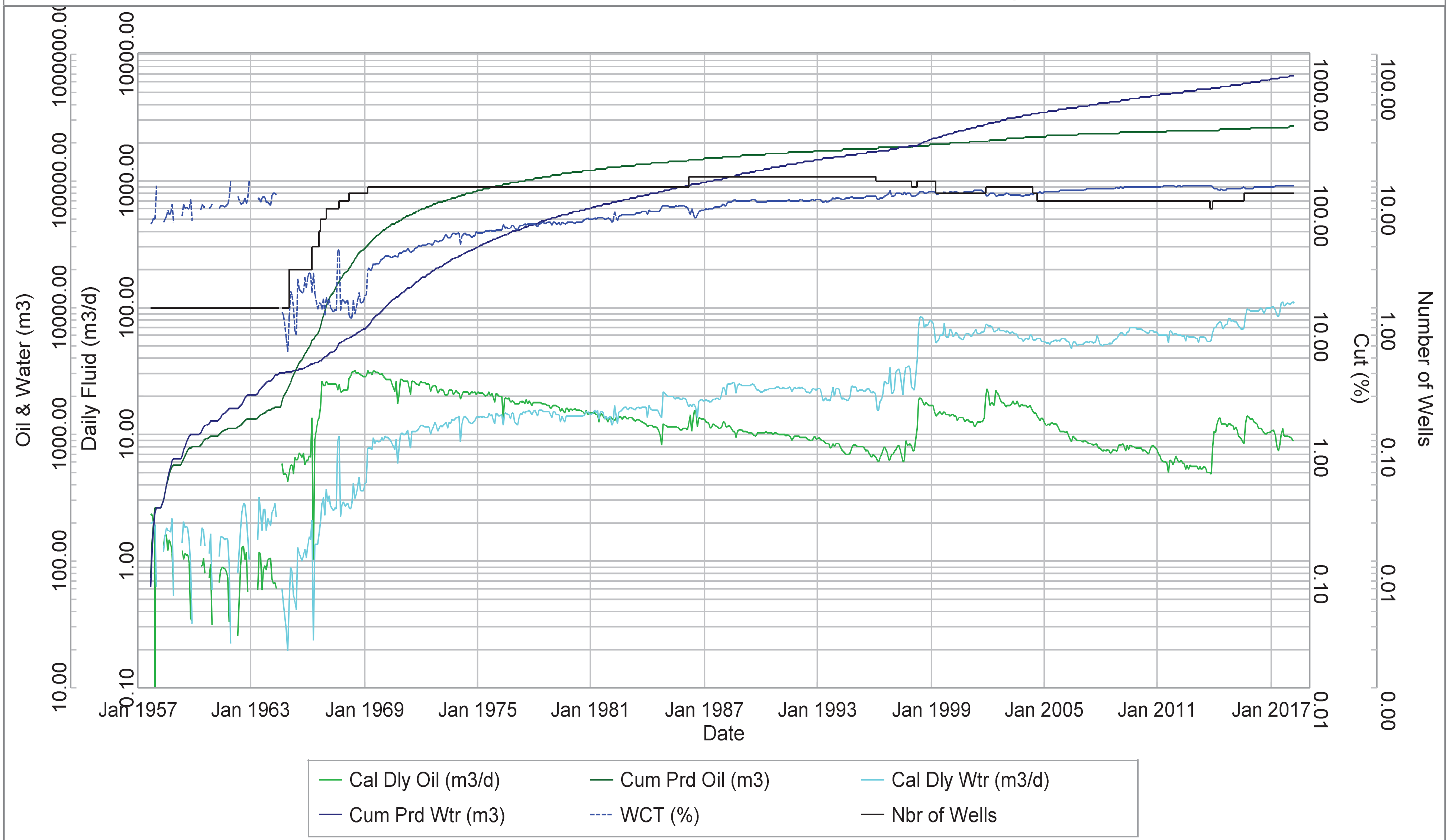
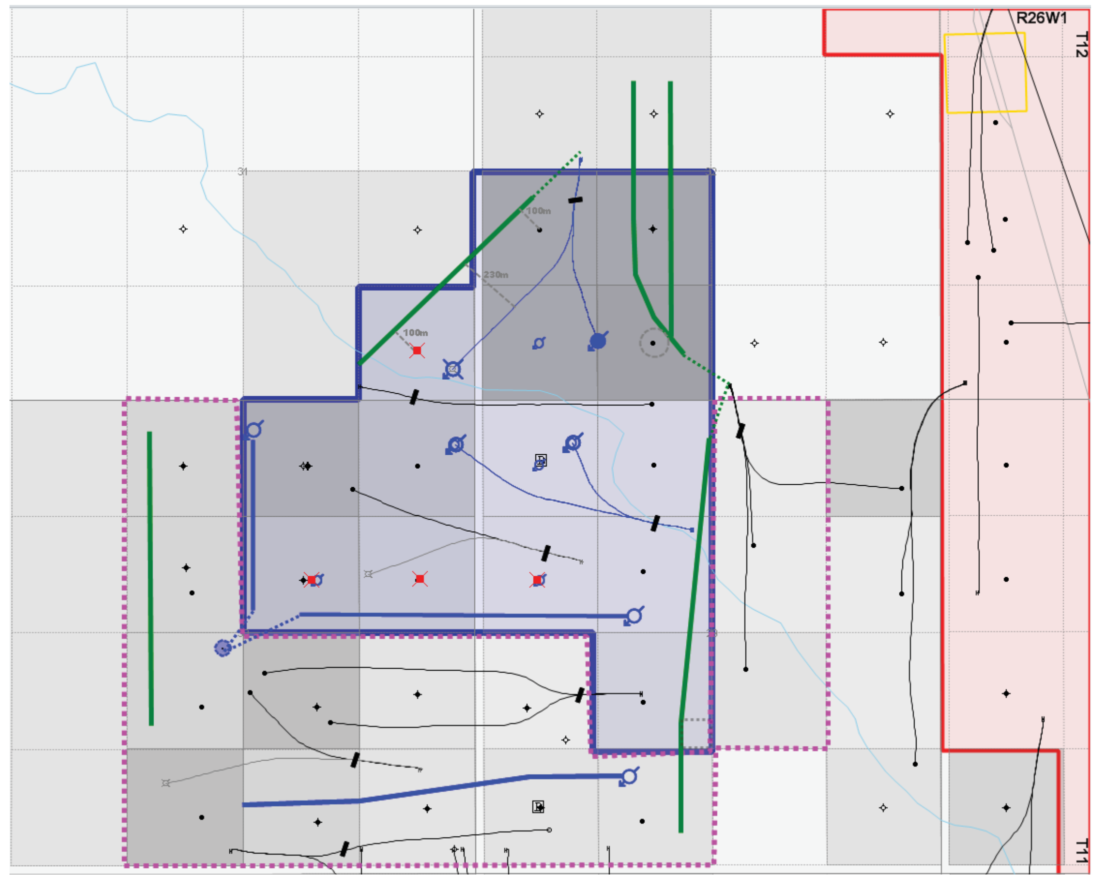


Figure 5 - Future Waterflood Development

NVSU3 Development

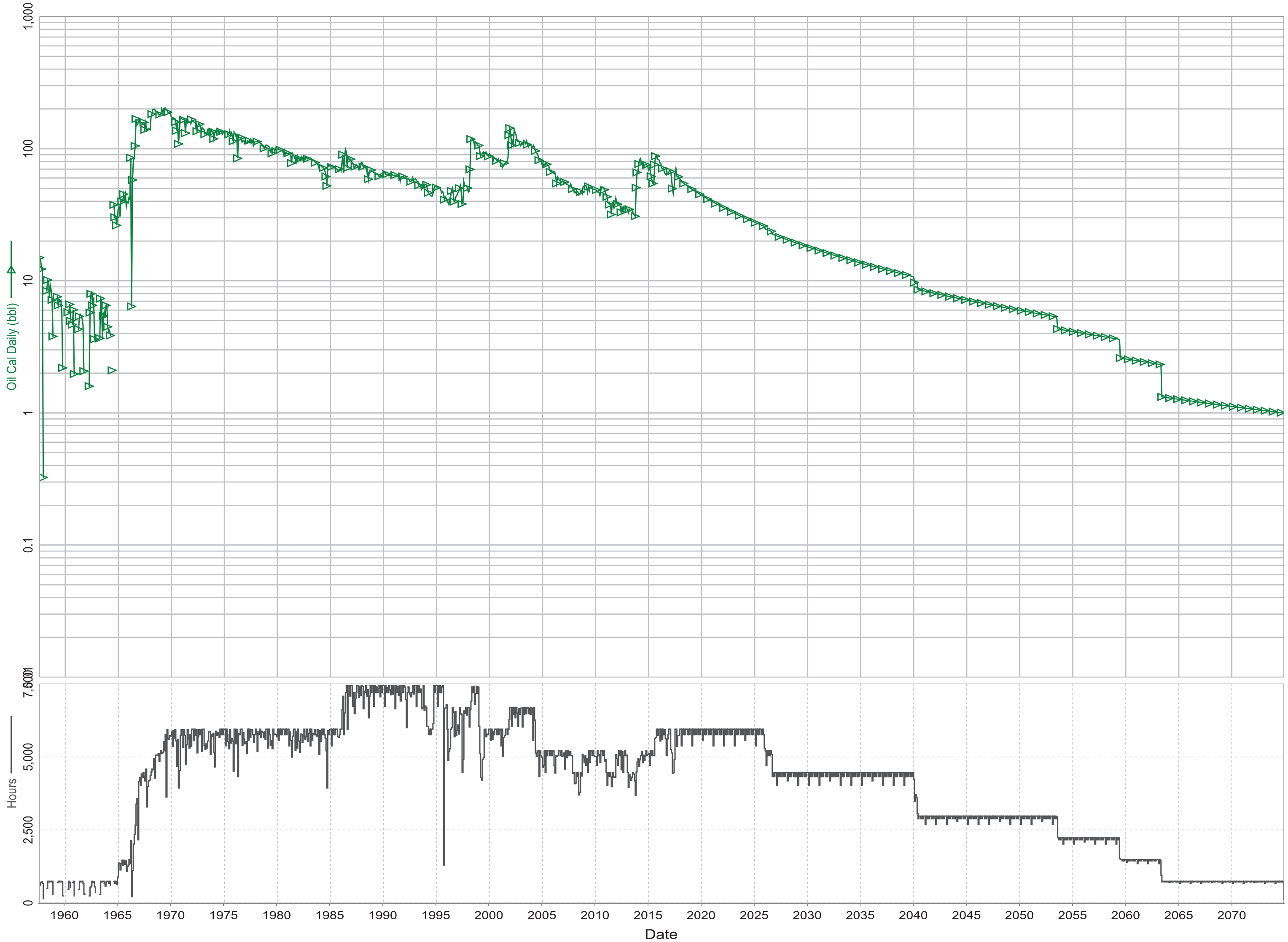
- **3 Future Produce-First Injectors (1 inside Unit, 2 between proposed Unit and NVSU2).**
- **2 Future Horizontal Producers.**



Tundra Oil and Gas
VOLUME FORECAST
Evaluation WB List

Effective May 01, 2018

Figure 6 - Base Forecast - Rate vs Time



Selection:	Evaluation WB List
Volume:	Oil Production
Category:	Base
Aggregation	Sum
Normalization	None

Volume Summary

Oil	Cum (bbl)	1,693,147
	Rem Rec (bbl)	236,016
	Ult Rec (bbl)	1,929,163
Gas	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0
Water	Cum (bbl)	4,303,215
	Rem Rec (bbl)	8,805,145
	Ult Rec (bbl)	13,108,360
Field	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0
NGL	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0

Forecast and Indicators @ Eff Date

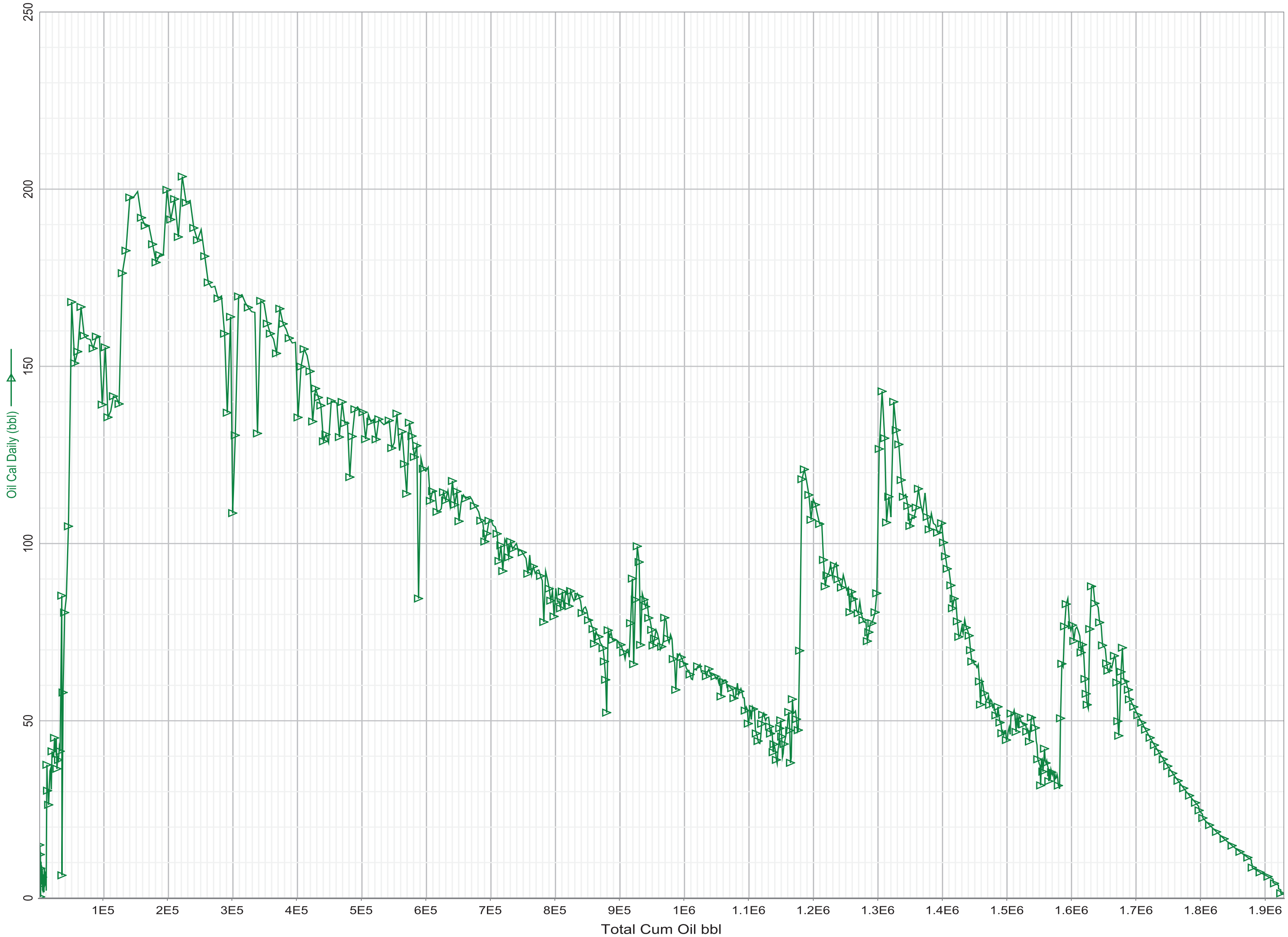
Product	Oil
Forecast Start	2018/05/01
Forecast End	2074/12/01
Presentation	Oil - Group
Initial Rate (bbl)	54.51
Final Rate (bbl)	1.01
Ult Rec (bbl)	1,929,162.85
Cum (bbl)	1,693,146.65
Rem Rec (bbl)	236,016.20
Res Life (yrs)	56.59
RLI Full Year (yrs)	12.58
Res Half Life (yrs)	70.12

Report Time: Tue, 31 Jul 2018 14:46
Economic Case: Unit Apps /
Hierarchy: Reserves
DB: WORKING_AD : Mosaic10 Version: 2017.6.1

Tundra Oil and Gas
VOLUME FORECAST
Evaluation WB List

Effective May 01, 2018

Figure 7 - Base Forecast - Rate vs Cumulative Oil



Selection:	Evaluation WB List
Volume:	Oil Production
Category:	Base
Aggregation	Sum
Normalization	None

Volume Summary		
Oil	Cum (bbl)	1,693,147
	Rem Rec (bbl)	236,016
	Ult Rec (bbl)	1,929,163
Gas	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0
Water	Cum (bbl)	4,303,215
	Rem Rec (bbl)	8,805,145
	Ult Rec (bbl)	13,108,360
Field	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0
NGL	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0

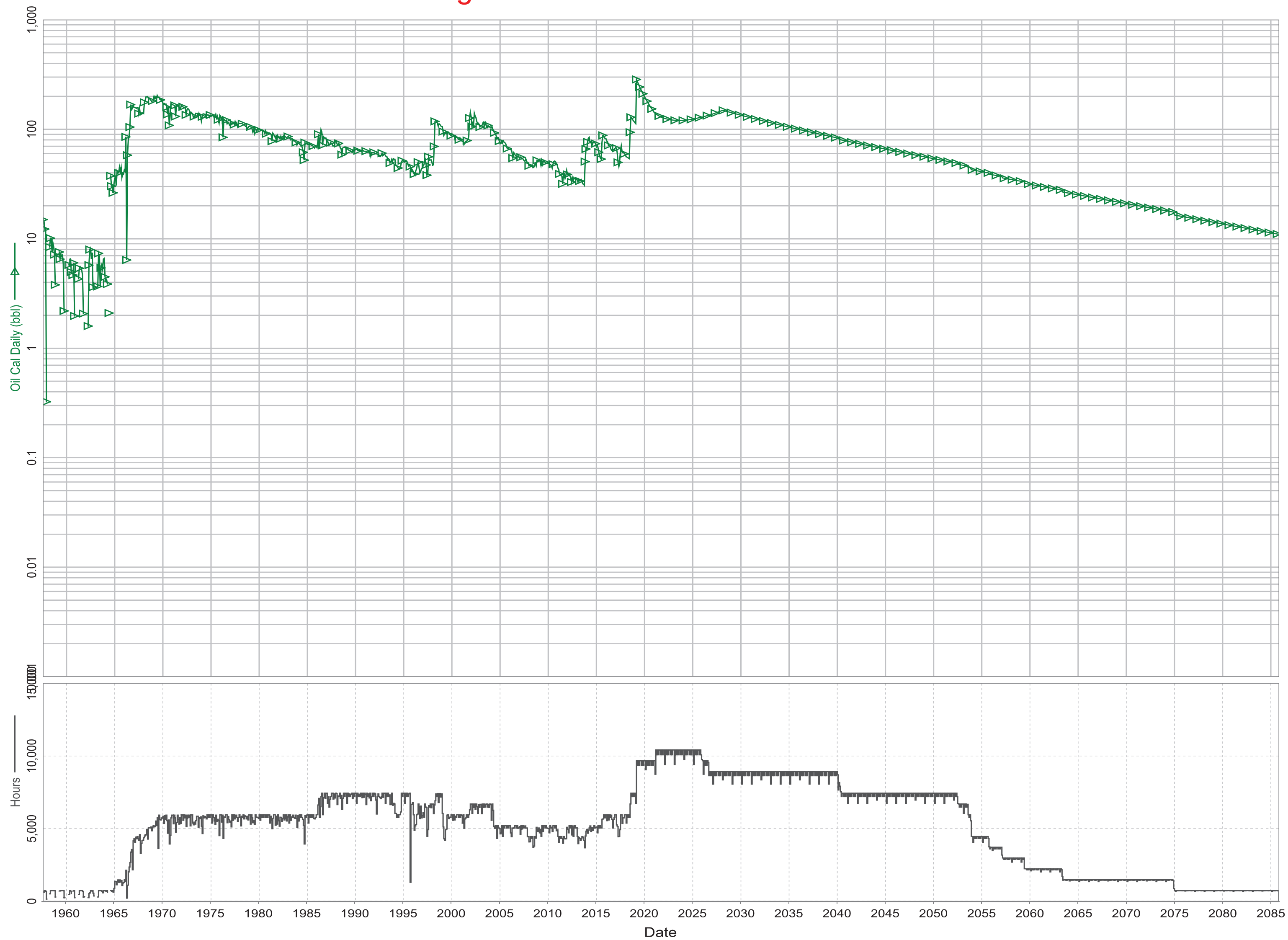
Forecast and Indicators @ Eff Date	
Product	Oil
Forecast Start	2018/05/01
Forecast End	2074/12/01
Presentation	Oil - Group
Initial Rate (bbl)	54.51
Final Rate (bbl)	1.01
Ult Rec (bbl)	1,929,162.85
Cum (bbl)	1,693,146.65
Rem Rec (bbl)	236,016.20
Res Life (yrs)	56.59
RLI Full Year (yrs)	12.58
Res Half Life (yrs)	70.12

Report Time: Tue, 31 Jul 2018 14:46
Economic Case: Unit Apps /
Hierarchy: Reserves
DB: WORKING_AD : Mosaic10 Version: 2017.6.1

Sample Oil and Gas
VOLUME FORECAST
Evaluation WB List

Effective May 01, 2018

Figure 8 - Base + Growth Forecast - Rate vs. Time



Selection:	Evaluation WB List
Volume:	Oil Production
Category:	All
Aggregation	Sum
Normalization	None

Volume Summary		
Oil	Cum (bbl)	1,693,147
	Rem Rec (bbl)	1,568,595
	Ult Rec (bbl)	3,261,742
Gas	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0
Water	Cum (bbl)	4,303,215
	Rem Rec (bbl)	8,805,145
	Ult Rec (bbl)	13,108,360
Field	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0
NGL	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0

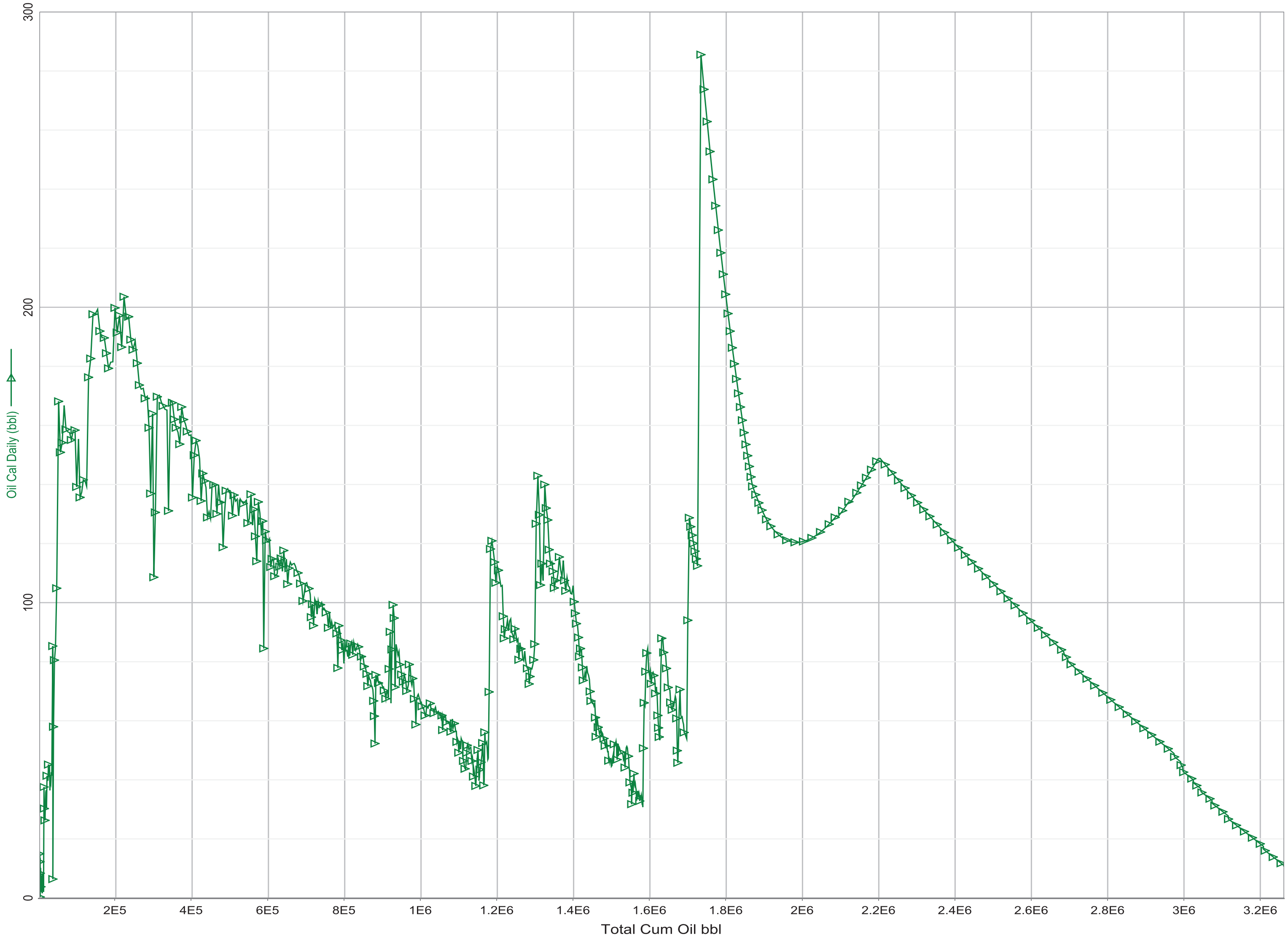
Forecast and Indicators @ Eff Date	
Product	Oil
Forecast Start	2018/05/01
Forecast End	2085/11/01
Presentation	Oil - Group
Initial Rate (bbl)	54.51
Final Rate (bbl)	10.80
Ult Rec (bbl)	3,261,741.60
Cum (bbl)	1,693,146.65
Rem Rec (bbl)	1,568,594.95
Res Life (yrs)	67.50
RLI Full Year (yrs)	32.14
Res Half Life (yrs)	76.56

Report Time: Fri, 10 Aug 2018 08:43
Economic Case: Unit Apps /
Hierarchy: Reserves
DB: WORKING_AD : Mosaic10 Version: 2017.6.1

Sample Oil and Gas
VOLUME FORECAST
Evaluation WB List

Effective May 01, 2018

Figure 9 - Base + Growth Forecast - Rate vs. Cum



Selection:	Evaluation WB List
Volume:	Oil Production
Category:	All
Aggregation	Sum
Normalization	None

Volume Summary		
Oil	Cum (bbl)	1,693,147
	Rem Rec (bbl)	1,568,595
	Ult Rec (bbl)	3,261,742
Gas	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0
Water	Cum (bbl)	4,303,215
	Rem Rec (bbl)	8,805,145
	Ult Rec (bbl)	13,108,360
Field	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0
NGL	Cum (bbl)	0
	Rem Rec (bbl)	0
	Ult Rec (bbl)	0

Forecast and Indicators @ Eff Date	
Product	Oil
Forecast Start	2018/05/01
Forecast End	2085/11/01
Presentation	Oil - Group
Initial Rate (bbl)	54.51
Final Rate (bbl)	10.80
Ult Rec (bbl)	3,261,741.60
Cum (bbl)	1,693,146.65
Rem Rec (bbl)	1,568,594.95
Res Life (yrs)	67.50
RLI Full Year (yrs)	32.14
Res Half Life (yrs)	76.56

Report Time: Fri, 10 Aug 2018 08:43
Economic Case: Unit Apps /
Hierarchy: Reserves
DB: WORKING_AD : Mosaic10 Version: 2017.6.1

Tundra Oil And Gas

FIGURE 10 - TYPICAL OPEN HOLE WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM

WELL NAME:	North Virden Scallion Unit 3 HZNTL Open Hole WIW				WELL LICENCE:	
Prepared by	BH	(average depths)		Date:	2018	
Elevations :						
KB [m]			KB to THF [m]		TD [m]	2000.0
GL [m]			CF (m)		PBTD [m]	
Current Perfs:	Open Hole			750.0	to	2000.0
Current Perfs:					to	
KOP:	625 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	750.0
Open Hole Latera	none	none	none	750.0	to	2000.0
Tubing	60.3 or 73.0 - TK-99	6.99 or 9.67	J-55	Surface	to	750.0

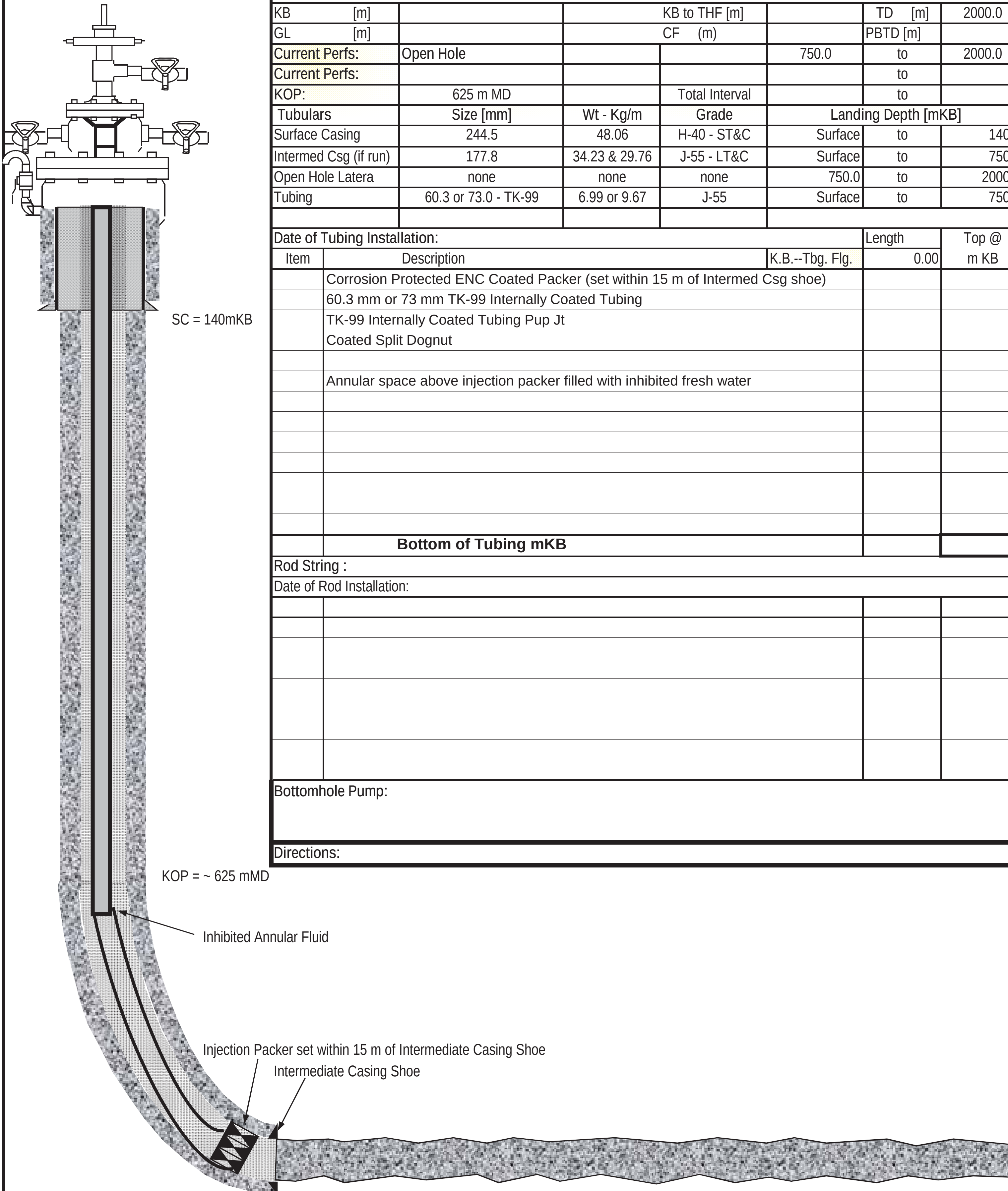
Date of Tubing Installation:			Length	Top @
Item	Description	K.B.--Tbg. Flg.	0.00	m KB
	Corrosion Protected ENC Coated Packer (set within 15 m of Intermed Csg shoe)			
	60.3 mm or 73 mm TK-99 Internally Coated Tubing			
	TK-99 Internally Coated Tubing Pup Jt			
	Coated Split Dognut			
	Annular space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

Rod String :

Date of Rod Installation:

Bottomhole Pump:

Directions:



North Virden Scallion Unit No. 3

EOR Waterflood Project

Planned Corrosion Control Program **

Pipelines
- New High Pressure Pipeline to injection well – 2000 psi high pressure Fiberglass

Facilities
- 8-19-11-26 Water Plant and New Injection Pump Station
    - Plant piping – 600 ANSI schedule 80 pipe, Fiberglass or Internally coated
    - Filtration – Stainless steel, HDPE Poly, fiberglass materials
    - Pumping – Ceramic plungers, stainless steel disc valves
    - Tanks – Fiberglass shell, corrosion resistant valves

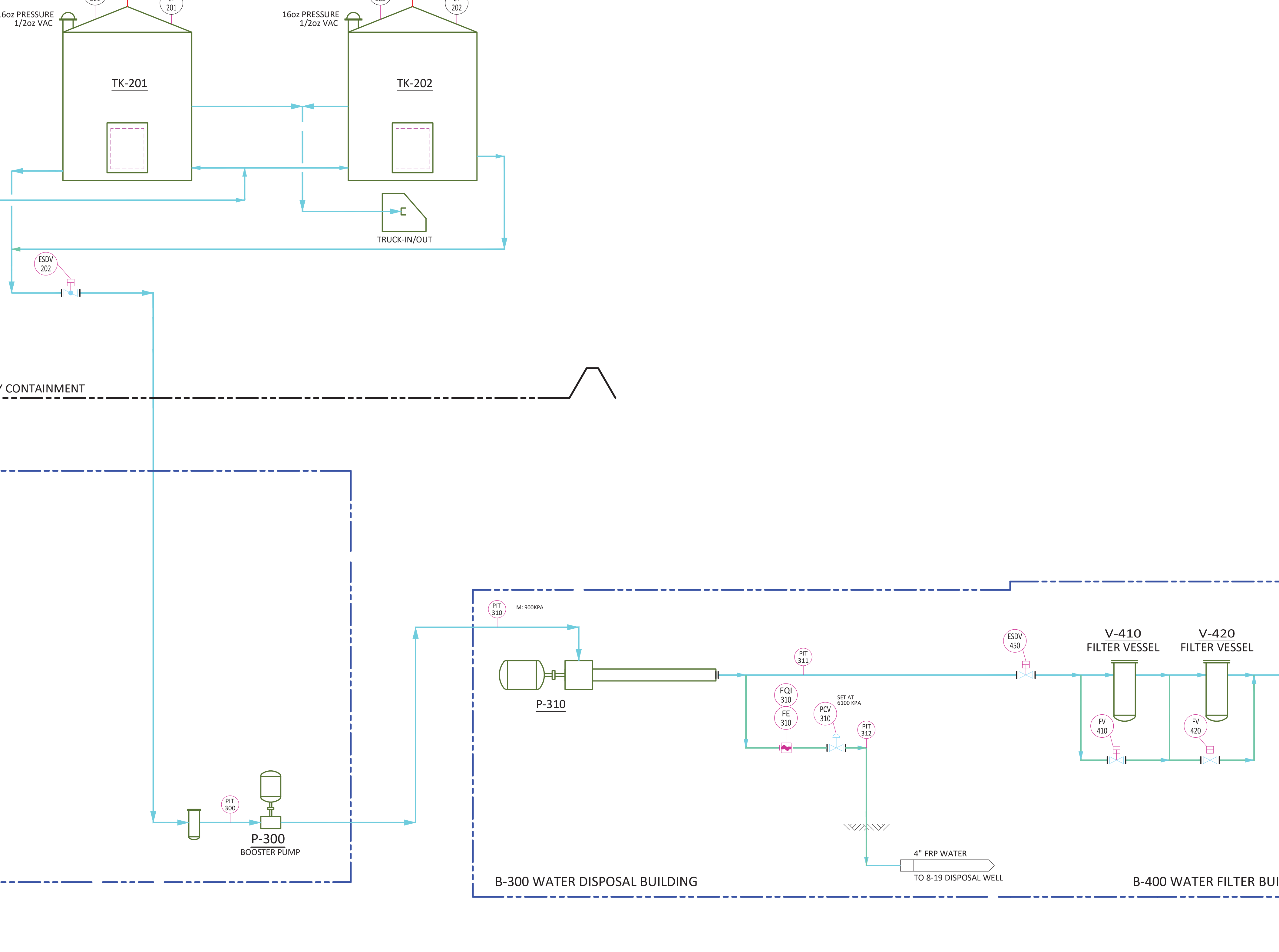
Injection Wellhead / Surface Piping
- Corrosion resistant valves and internally coated surface piping

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 11

** subject to final design and engineering



16oz PRESSURE
1/2oz VAC
201
TK-201
16oz PRESSURE
1/2oz VAC
202
TK-202
TRUCK-IN/OUT
ESDV
202
CONTAINMENT
PIT
300
P-300
BOOSTER PUMP
PIT
310
M: 900KPA
P-310
PIT
311
FQI
310
FE
310
PCV
310
SET AT
6100 KPA
PIT
312
4" FRP WATER
TO 8-19 DISPOSAL WELL
ESDV
450
V-410
FILTER VESSEL
FV
410
V-420
FILTER VESSEL
FV
420
B-300 WATER DISPOSAL BUILDING
B-400 WATER FILTER BUI

Proposed North Virden Scallion Unit No. 3

Application for Enhanced Oil Recovery Waterflood Project

List of Tables

TABLE NO. 2: TRACT FACTOR CALCULATIONS

TRACT FACTORS BASED ON OIL-IN-PLACE (OOIP) LESS CUMULATIVE OIL PRODUCED METHOD

PROPOSED NORTH VIRDEN SCALLION UNIT NO. 3

LSD-SEC	*TWP-RGE*	*UWI*	*OOIP (m3)*	*Hz Allocated Cum Prodn April 2018 (m3)*	*Vertical Cum Prodn April 2018 (m3)*	*OOIP - Cum Oil Prodn (m3)*	*OOIP - Cum Tract Factor (%)*
03-29	011-26W1M	100/03-29-011-26W1M	41,538	0.0	18220.6	23,318	1.734895506
04-29	011-26W1M	100/04-29-011-26W1M	135,781	7901.5	24854.8	103,025	7.665298405
05-29	011-26W1M	100/05-29-011-26W1M	157,854	1125.6	14420.7	142,308	10.588040016
07-29	011-26W1M	100/07-29-011-26W1M	9,060	778.8	0.0	8,281	0.616140924
10-29	011-26W1M	100/10-29-011-26W1M	32,066	1674.6	0.0	30,392	2.261203694
15-29	011-26W1M	100/15-29-011-26W1M	55,342	2247.7	0.0	53,094	3.950300952
01-30	011-26W1M	100/01-30-011-26W1M	182,216	11610.1	39675.9	130,930	9.741489954
02-30	011-26W1M	100/02-30-011-26W1M	155,878	10222.3	38284.5	107,371	7.988656132
03-30	011-26W1M	100/03-30-011-26W1M	114,135	4254.4	26437.2	83,444	6.208417143
06-30	011-26W1M	100/06-30-011-26W1M	131,897	1332.0	22178.9	108,386	8.064207141
07-30	011-26W1M	100/07-30-011-26W1M	160,098	5407.9	10324.7	144,366	10.741160529
08-30	011-26W1M	100/08-30-011-26W1M	172,640	1907.8	967.3	169,765	12.630916168
11-30	011-26W1M	100/11-30-011-26W1M	131,171	0.0	9751.4	121,420	9.033917005
14-30	011-26W1M	100/14-30-011-26W1M	119,956	0.0	2011.0	117,945	8.775356431
			1,599,633	**48,462.9**	**207,127.0**	**1,344,044**	**100.000000000**

TABLE NO. 3

Proposed North Virden Scallion Unit 3 Well List

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 (%)*	*UWI*
103/16-19-011-26W1/0	004791	Horizontal	LODGEPOLE A	LODGEPOL	Producing	3/21/1998	Apr-2018	0.81	24.40	37091.50	43.25	1297.50	275833.70	98.15	103/16-19-011-26W1/0
100/03-29-011-26W1/0	002211	Vertical	LODGEPOLE A	LODGEPOL	Producing	8/5/1967	Apr-2018	0.24	7.10	18220.60	1.15	34.40	14714.40	82.89	100/03-29-011-26W1/0
100/04-29-011-26W1/0	001968	Vertical	LODGEPOLE A	LODGEPOL	Abandoned	8/1/1964	Feb-1999	0.28	7.80	24854.80	1.23	34.40	21950.90	81.52	100/04-29-011-26W1/0
102/04-29-011-26W1/2	004791	Horizontal			Potential	N/A									102/04-29-011-26W1/2
100/05-29-011-26W1/0	002025	Vertical	LODGEPOLE A	LODGEPOL	Abandoned	12/26/1964	Feb-1999	0.28	7.70	14420.70	1.96	54.90	25285.40	87.70	100/05-29-011-26W1/0
102/05-29-011-26W1/0	005367	Vertical			Abandoned	N/A									102/05-29-011-26W1/0
100/07-29-011-26W1/0	009536	Horizontal	LODGEPOLE A	LODGEPOL	Producing	11/11/2013	Apr-2018	1.38	41.30	6111.50	18.93	568.00	24925.30	93.22	100/07-29-011-26W1/0
100/10-29-011-26W1/3	009536	Horizontal			Producing	N/A									100/10-29-011-26W1/3
100/16-29-011-26W1/2	009536	Horizontal			Producing	N/A									100/16-29-011-26W1/2
100/01-30-011-26W1/0	002118	Vertical	LODGEPOLE A	LODGEPOL	Abandoned	3/5/1966	Apr-2004	0.21	6.40	39675.90	2.25	67.60	21992.90	91.35	100/01-30-011-26W1/0
102/01-30-011-26W1/0	009074	Vertical			Abandoned	N/A									102/01-30-011-26W1/0
100/02-30-011-26W1/0	002159	Vertical	LODGEPOLE A	LODGEPOL	Abandoned Zone	8/23/1966	Aug-2013	0.01	0.30	38284.50	0.02	0.70	27310.40	70.00	100/02-30-011-26W1/0
100/03-30-011-26W1/0	002280	Vertical	LODGEPOLE A	LODGEPOL	Producing	2/12/1968	Apr-2018	0.46	13.80	26437.20	1.30	39.10	28854.80	73.91	100/03-30-011-26W1/0
102/03-30-011-26W1/2	005027	Horizontal	LODGEPOLE A		Drain	N/A									102/03-30-011-26W1/2
100/06-30-011-26W1/0	002340	Vertical	LODGEPOLE A	LODGEPOL	Producing	2/8/1969	Apr-2018	0.63	18.90	22178.90	4.32	129.60	87947.00	87.27	100/06-30-011-26W1/0
100/07-30-011-26W1/0	002182	Vertical	LODGEPOLE A	LODGEPOL	Abandoned Zone	12/11/1966	Jul-2004	0.00	0.00	10324.70	0.48	15.00	9471.30	100.00	100/07-30-011-26W1/0
102/07-30-011-26W1/0	005027	Horizontal	LODGEPOLE A	LODGEPOL	Pumping	11/8/2001	Apr-2018	1.17	35.10	14956.30	12.33	369.90	85118.60	91.33	102/07-30-011-26W1/0
103/07-30-011-26W1/0	010387	Horizontal	LODGEPOLE A	LODGEPOL	Producing	7/31/2015	Apr-2018	3.13	93.90	3771.30	21.11	633.20	21672.50	87.09	103/07-30-011-26W1/0
103/07-30-011-26W1/2	010387	Horizontal	LODGEPOLE A		Producing	N/A									103/07-30-011-26W1/2
100/08-30-011-26W1/0	002137	Vertical	LODGEPOLE A	LODGEPOL	Abandoned	7/18/1966	Nov-1997	0.00	0.00	967.30	0.00	0.00	572.20	0.00	100/08-30-011-26W1/0
100/11-30-011-26W1/0	001526	Vertical	LODGEPOLE A	LODGEPOL	Abandoned	8/7/1957	Jun-1964	0.33	10.00	1669.50	1.97	59.00	3040.30	85.51	100/11-30-011-26W1/0
102/11-30-011-26W1/0	003771	Vertical	LODGEPOLE A	LODGEPOL	Pumping	2/3/1986	Apr-2018	0.93	28.00	8081.90	7.81	234.40	33631.70	89.33	102/11-30-011-26W1/0
100/14-30-011-26W1/0	003772	Vertical	LODGEPOLE A	LODGEPOL	Abandoned	2/3/1986	Dec-1995	0.12	3.60	2011.00	0.26	8.00	1811.30	68.97	100/14-30-011-26W1/0
										269057.60			**684132.7**		
										1692321 BBL			**4303065 BBL**		

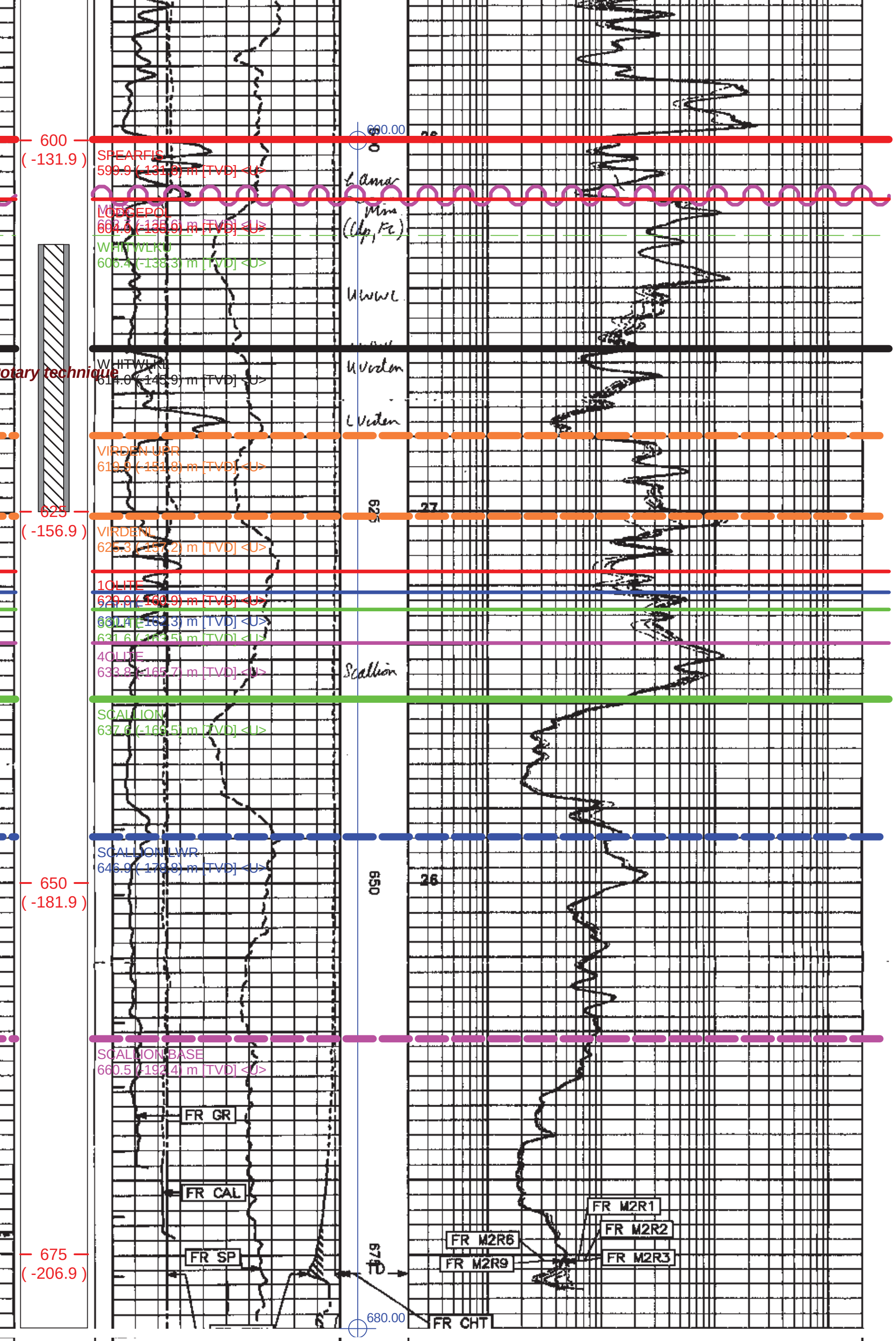
TABLE NO. 4: OOIP Calculation

LSD	UPR_SCAL OOIP (m3)	UPR_SCAL OOIP (bbls)	LWR_SCAL OOIP (m3)	LWR_SCAL OOIP (bbls)	TOTAL OOIP (m3)	TOTAL OOIP (bbls)
100/03-29-011-26W1M	27,416	172,444	14,122	88,824	41,538	261,268
100/04-29-011-26W1M	85,729	539,220	50,052	314,819	135,781	854,039
100/05-29-011-26W1M	100,634	632,969	57,220	359,903	157,854	992,873
100/07-29-011-26W1M	4,563	28,702	4,497	28,284	9,060	56,986
100/10-29-011-26W1M	13,849	87,111	18,217	114,579	32,066	201,690
100/15-29-011-26W1M	26,973	169,656	28,368	178,432	55,342	348,088
100/01-30-011-26W1M	101,630	639,231	80,586	506,872	182,216	1,146,103
100/02-30-011-26W1M	84,185	529,507	71,693	450,935	155,878	980,442
100/03-30-011-26W1M	68,090	428,273	46,045	289,617	114,135	717,890
100/06-30-011-26W1M	78,100	491,234	53,797	338,375	131,897	829,610
100/07-30-011-26W1M	88,748	558,208	71,351	448,781	160,098	1,006,989
100/08-30-011-26W1M	96,306	605,746	76,334	480,127	172,640	1,085,874
100/11-30-011-26W1M	79,405	499,444	51,766	325,598	131,171	825,042
100/14-30-011-26W1M	76,394	480,504	43,562	273,994	119,956	754,498
	932,023		**667,610**		**1,599,633**	**10,061,392**

Proposed North Virden Scallion Unit No. 3

Application for Enhanced Oil Recovery Waterflood Project

List of Appendices



GR BACKUP

TOOL STICKING

CAL < BIT

METERS

0	GAMMA RAY [gr] (gAPI)	150
150	CALIPER [cal] (mm)	450
150	BIT SIZE (mm)	450
0	SP [sp] (mV)	150
1000	DIFF. TENSION [ten] (kgf)	-100
5000	CH-TENSION [cht] (kgf)	0

MINUTE MARK

2FT. Matched Resolution Resistivity

0.2	10 in. DOI [m2r1] (ohm.m)	2000
0.2	20 in. DOI [m2r2] (ohm.m)	2000
0.2	30 in. DOI [m2r3] (ohm.m)	2000
0.2	60 in. DOI [m2r6] (ohm.m)	2000
0.2	90 in. DOI [m2r9] (ohm.m)	2000

BHT
(degC)

GR BACKUP

TOOL STICKING

CAL < BIT

GAMMA RAY [gr] 150
(gAPI)
CALIPER [cal] 450
(mm)
BIT SIZE 450
(mm)
SP [sp] 150
(mV)
DIFF. TENSION [ten] 1800 -100
(kgf)
CH-TENSION [cht] 5000 0
(kgf)

MARK

METERS

2FT. Matched Resolution Resistivity

0.2 10 in. DOI [m2r1] 2000
(ohm.m)
0.2 20 in. DOI [m2r2] 2000
(ohm.m)
0.2 30 in. DOI [m2r3] 2000
(ohm.m)
0.2 60 in. DOI [m2r6] 2000
(ohm.m)
0.2 90 in. DOI [m2r9] 2000
(ohm.m)

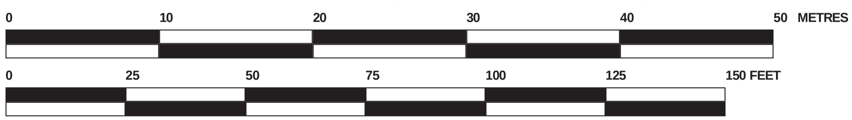
BHT
(degC)

Prod	Oil (STB)	Gas (Mscf)	Water (STB)
Cum	249675.3	0.0	138398.5
Daily	18.5	0.0	10.3

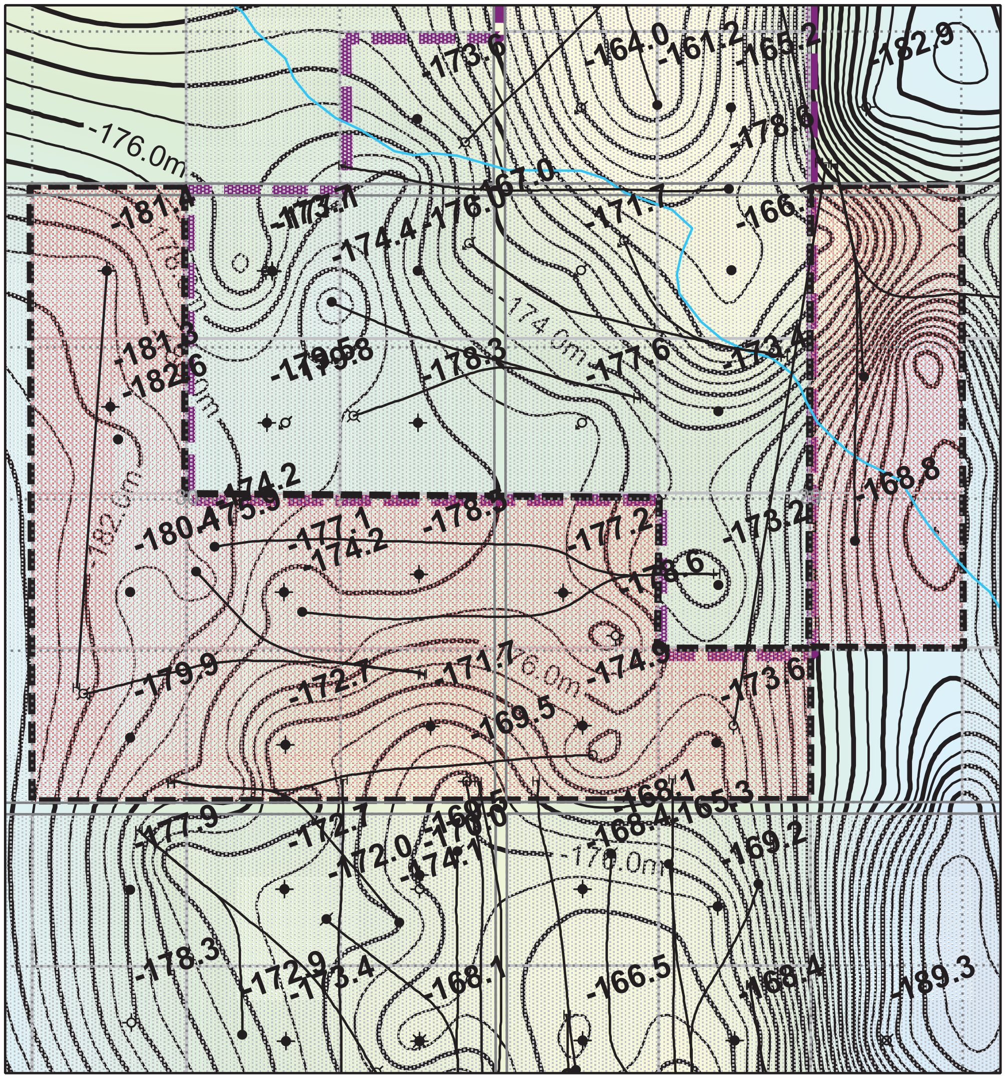
3. 2107.9[TVD]
Type: IP -
VO: 0.0/0.0
FP: 0.0/0.0
SIP: 0.0/0.
HP: 0.0/0.0
"MAX OIL TO

Prod	Oil (S
Cum	15640
Daily	1

Depth Scale (actual scale 1: 480)



Appendix 3 - Lodgepole Scallion Structure Map



North Virden

Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07

Center: 49.9521, -101.0109

Scale: 1:20,000

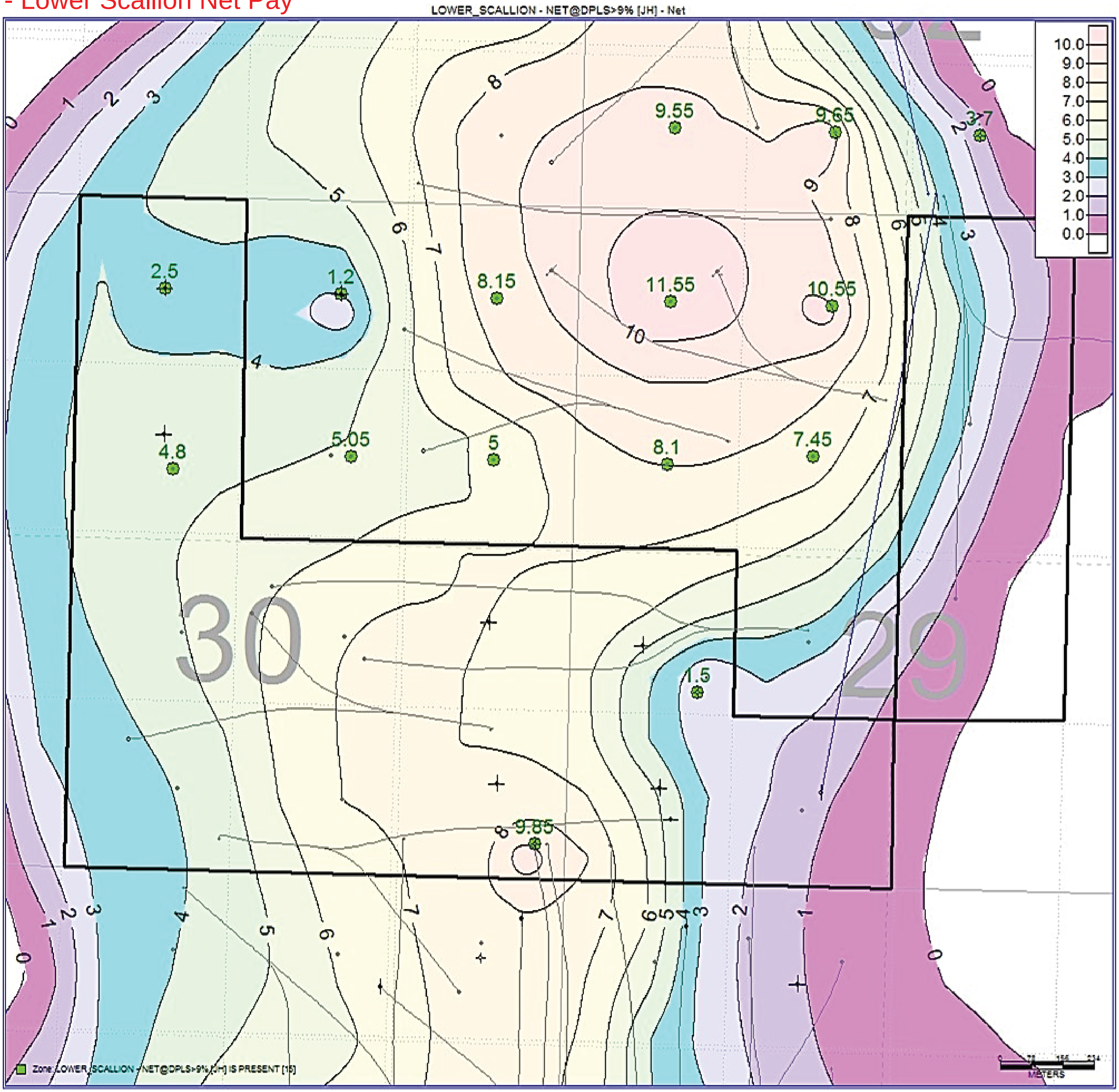
0 0.1 0.8 km

0 0.1 0.2 0.3 0.4 0.5 mi

N E S W

North Virden
Scallion Structure
June 18, 2018
\\FS02\AccuMapData$\Norman.Hopkins\New_AccuMap\NVS 2017 Scallion Net Pay DST.accumap

Appendix 4a - Lower Scallion Net Pay



Appendix 4b - Upper Scallion Net Pay