PROPOSED NORTH PIERSON UNIT NO. 1

Application for Enhanced Oil Recovery Waterflood Project

Mission Canyon (Alida)

Mission Canyon 3A B Pool (43B)

Pierson, Manitoba

May 24th, 2013
Tundra Oil and Gas Partnership

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INTRODUCTION

The Pierson field, located in Township 3 Range 28 west of the prime meridian, first produced in November 1965 (Figure 1). The main production target in this area is the Mission Canyon (Alida) formation.

In the North Pierson field, potential exists for incremental production and reserves from a Waterflood EOR project in the Mission Canyon (Alida) oil reservoir. Attached is an application by Tundra Oil and Gas Partnership (Tundra, TOGP) to establish North Pierson Unit No. 1 (NPU No. 1) and implement a Secondary Waterflood EOR scheme within the Alida formation as outlined in Figure 2.

The proposed project area falls within the existing designated 07-43B Mission Canyon 3A B pool of the Pierson Oilfield (Figure 3).

SUMMARY

1. The proposed North Pierson Unit No. 1 will include 12 existing vertical wells and 14 horizontal wells that are producing from the Mission Canyon (Alida) formation.

2. The proposed unit will include 72 legal subdivisions (LSD), of which 50 have had wells drilled on them and 22 of which are still undeveloped. The boundary of the proposed unit is shown in Figure 2.

3. The original oil in place (OOIP) in the project area has been calculated to be 1,472.864 e^3m^3 (9,257.746 Mbbl).

4. Cumulative production current to February 28, 2013 from the proposed North Pierson Unit No. 1 project area was 372 e^3m^3 oil (2,342 Mbbl) and 496 e^3m^3 water (3,122 Mbbl), representing a 25% recovery factor (RF) of the total OOIP within the proposed boundary.

5. Estimated Ultimate Recovery (EUR) of Primary Proved Producing oil reserves in the proposed North Pierson Unit No. 1 project area has been calculated to be 434 e^3m^3 (2,730 Mbbl), with 61 e^3m^3 (388 Mbbl) remaining as of February 28, 2013.

6. Ultimate oil recovery of the proposed North Pierson Unit No. 1 OOIP, under the current Primary Production method, is forecasted to be 29%.

7. Figure 4 shows the production from the proposed area peaked in March 2007 at 74.7 m^3/d oil (470 bbl/d) from 20 wells. As of February 28, 2013, production was 21.4 m^3/d oil (135 bbl/d), 89.7 m^3/d of water (564.2 bbl/d) from 26 wells and 79% watercut.

8. In March 2007, production averaged 3.7 m^3/d oil (23.5 bbl/d) per well. As of February 2013, average per well production has declined to 0.8 m^3/d oil (5.2 bbl/d). Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately 13% in the project area. No natural water drive is apparent in the NE part of the pool.

9. Analog waterfloods indicate that a pattern waterflood would be successful in Pierson, resulting in an incremental recovery of 10%.

10. Estimated Ultimate Recovery (EUR) of oil reserves under Secondary WF EOR for the proposed North Pierson Unit No. 1 is estimated to be 3,656 Mbbl, with 1,314 Mbbl remaining. An incremental 147 e^3m^3 (926 Mbbl) of oil reserves, or 10%, are forecasted to be recovered under the proposed Unitization and Secondary EOR production vs the existing Primary Production method.

11. Total RF under Secondary WF in the proposed North Pierson No. 1 is estimated to be 39%.

DISCUSSION

The proposed North Pierson Unit No. 1 project area is located in Sections 15-21, Township 3, Range 28 W1 of the Pierson oil field. The proposed Pierson Unit currently consists of 12 producing vertical wells and 14 producing horizontal wells within an area covering four and a half sections (Figure 2). A project area well list complete with recent production statistics is attached as Table 3.

[Of note: The 14D-18-3-28WPM multilateral appears to be plotted incorrectly on all maps provided, as well as in AccuMap and GeoScout. As-drilled directional surveys for each of the three legs (Figure 10) were reviewed by Tundra to confirm the horizontal as otherwise shown is misplotted. Tundra also confirmed that production allocation factors assigned to the LSD's on the as-drilled survey appear to be calculated correctly. Tundra has requested that AccuMap and GeoScout update their systems to show the correct trajectories].

Geology

The Alida (MC-3 member) of the Mission Canyon Formation is a shallow marine carbonate of Mississippian age deposited in an inner shelf setting along the Northeast flank of the Williston Basin. It consists of interbedded limestones and dolomitic limestones. The MC-3 is the primary reservoir in the North Pierson field area. It is unconformably overlain by the Triassic Lower Amaranth Red Beds consisting of interbedded silts and shales which act as a top and lateral seal for the Pierson reservoir. It is underlain by the Tilston (MC-2) member of the Mission Canyon Formation which consists of shaly carbonates, evaporates and dolomitic limestones. The boundary between the MC-3 and MC-2 has a very distinctive spontaneous potential signature on petrophysical logs. In the proposed North Pierson Unit area the MC-2 has high water saturation and is non-productive. The upper portion of the MC-3 has been altered due to subaerial exposure diminishing porosity and permeability. This is informally called the altered dense cap and is non-productive.

Structural variations in the Pierson area are minimal, with regional dip trending Southwest at a low angle. Lateral variations in lithology, porosity, permeability and dense cap thickness define the edges of the pool. Up-dip the MC-3 erodes down to the MC-2 North and Northeast of the Pierson field. No distinctive oil/water contact within the MC-3 is present in the area of the proposed unitization.

The Mission Canyon (Alida) pay (reservoir within the zone that is capable of economic production) was determined and mapped (Appendix 4) using an 8% porosity (Phi) cutoff; roughly equivalent to a 0.5mD permeability (k). With recent development by competitors to the South, it was found that using a higher cutoff was too pessimistic and areas with potential reservoir would have been left undeveloped. The overall porosity average for the area using the cutoff is 11.8%; an average porosity map is shown in Appendix 5. Individual porosities were calculated on weighted average basis per well, using log and core analysis where available. The net pay (h) and storage capacity (phi * h) were then mapped (Appendix 6) thus allowing the assignment of average net pays and storage capacities to be used in the tract factor calculations on a per LSD basis. These values were then exported to an Excel spreadsheet to calculate OOIP on a per LSD basis (Table 6), and a hydrocarbon pore volume map is shown in Appendix 7.

After several iterations and consultations with an independent engineering firm, it was decided that an average initial water saturation (Swi) value be adopted for volumetric calculations. The independent engineering firm recommended an average Swi of 45% be used; Tundra's recommendation is that an average Swi of 46.3% be used, calculated by the taking the arithmetic mean of all water saturations over the identified net pay intervals as calculated by petrophysics. The Swi averages are within what is deemed to be an acceptable range of error for such a calculation.

NPU No. 1 does not show any apparent directional Alida permeability trends or anisotropy. Included in Appendix 8 is a map of Permeability * Net Pay, k * h or flow capacity. Areas of variable flow capacity can be seen.

An interpreted oil-water contact can be found at the 13-5-3-28 vertical well at approximately -525mSS. Tundra reviewed all available log information in the area to reveal this well. A subsequent review of the fractional flow of initial production in offset wells indicates several areas of clean oil production, with little to no water initially produced as the structural elevation increases and the structural elevation of the reservoir moves up from the contact and out of the interpreted transition zone. As all reservoir depths within the NPU No. 1 are above the oil-water contact, and because Tundra adopted an average Swi, the oil water contact has no bearing on volumetric calculations.

<u>OOIP Estimates</u>

Total volumetric OOIP for the Alida of the Mission Canyon formation, within the proposed North Pierson Unit No. 1 area, has been calculated to be 1,473 e^3m^3 (9,258 Mbbl) using Tundra internally created maps. Tabulated parameters for each LSD from the calculations can be found in Table 6.

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

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

where

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

OOIP values were calculated based on logs and core data using cutoffs described in the previous Geology section. The OOIP values were estimated by Bill Clow, P. Eng, Leonard Brooks, P. Geol., and Justin Robertson, P. Eng. The values were contoured and hand manipulated in Schlumberger's Petrel program. Petrel was used to export values of net pay and weighted average porosity by LSD, for calculations of OOIP to be carried out in Excel. The oil formation volume factor was adopted from a PVT taken from the A12-7-1-25W1 well. The OOIP calculations were carried out by Justin Robertson, P. Eng.

A listing of Mission Canyon (Alida) formation rock and fluid properties used to characterize the reservoir are provided in Table 1.

Historical Production

A historical group production history plot for the proposed North Pierson Unit No. 1 is shown as Figure 4. Oil production commenced from the proposed Unit area in November 1965. The pool produced from vertical wells until the early- to mid-2000's, at which time openhole unstimulated horizontals were drilled to delineate the northern extents of the pool using 3-dimensional seismic. Production peaked in March 2007 at 74.7 m^3/d oil (470 bbl/d) from 20 wells. As of February 28, 2013, production was 21.4 m^3/d oil (135 bbl/d), 89.7 m^3/d of water (564.2 bbl/d) from 26 wells and 79% watercut.

Oil production is declining at an annual rate of approximately 13% 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.

Reserves Recovery Profiles and Production Forecasts

The primary waterflood performance predictions for the proposed North Pierson Unit No. 1 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 current to February 28, 2013 from the proposed North Pierson Unit No. 1 project area was 372 e^3m^3 oil (2,342 Mbbl) and 496 e^3m^3 water (3,122 Mbbl), representing a 25% recovery factor (RF) of the total OOIP within the proposed boundary.

Based on decline analysis of the wells currently on production, coupled with the expected performance of the most recently drilled horizontal wells, the estimated ultimate recovery (EUR) for the proposed unit with no further development would be 434 e^3m^3 (2,730 Mbbl), with 61 e^3m^3 (388 Mbbl) remaining as of February 28, 2013. This represents a recovery factor of 29% of the total OOIP.

Primary production plots of the expected production decline and forecasted oil rate v. time and rate v. cumulative oil production are shown in Figures 5 and 6, respectively.

Secondary EOR Production Forecast

Based on the geological description, primary production decline rate and waterflood response in an analog waterflood implemented in the Storthoaks Alida pool (Sask), it is indicated that a pattern waterflood would be successful in Pierson, and could result in an incremental recovery of 10%.

Tundra supports the belief that the reservoir is laterally continuous in the proposed NPU No. 1, and as a result, decent areal sweep and efficiency will be attained under waterflood.

Secondary Waterflood plots of the expected oil production forecast over time and the expected oil production v. cumulative oil are plotted in Figures 5 and 6, respectively. Total Secondary EUR for the proposed North Pierson Unit No. 1 is estimated to be 3,656 Mbbl, with 1,314 Mbbl remaining representing a total secondary recovery factor of 39% for the proposed Unit area.

An incremental 147 e^3m^3 (926 Mbbl) of oil, or incremental 10% recovery factor, are forecasted to be recovered under the proposed Unitization.

Technical Studies

The waterflood performance predictions for the proposed North Pierson Unit No. 1, are based on recent geological and engineering analysis.

Internal reviews included analysis of available open-hole logs; core data; petrophysics; seismic; drilling information; completion information; and production information. These were used to develop a suite of geological maps and establish reservoir parameters to support the calculation of the proposed North Pierson Unit No. 1 OOIP (Table 6).

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP from the proposed project area by 10%. 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 North Pierson Unit No. 1 (NPU No. 1).

Unit Operator

Tundra Oil and Gas Partnership (Tundra) will be the Operator of record for North Pierson Unit No. 1.

Unitized Zone

The unitized zones to be waterflooded in the North Pierson Unit No. 1 will be the Mission Canyon (Alida).

Unit Wells

The wells to be included in the proposed North Pierson Unit No. 1 are outlined in Table 3 with their current status. A proposed development plan is included in Figure 7 with the timing of initial proposed injector conversions provided in Table 4.

Unit Lands

North Pierson Unit No. 1 will consist of four and a half sections as follows:

LSD 11-14 of Section 15 of Township 3, Range 28, W1M.
LSD 9-16 of Section 16 of Township 3, Range 28, W1M.
LSD 9-16 of Section 17 of Township 3, Range 28, W1M.
LSD 5-16 of Section 18 of Township 3, Range 28, W1M.
LSD 1-8 of Section 19 of Township 3, Range 28, W1M.
LSD 1-16 of Section 20 of Township 3, Range 28, W1M.
LSD 1-16 of Section 21 of Township 3, Range 28, W1M.

North Pierson Unit No. 1 will consist of 72 LSD's. The lands included in the 40 acre tracts are outlined in Table 5.

Tract Factors

The proposed North Pierson Unit No. 1 will consist of 72 tracts, based on the 40 acre LSD's containing the 12 existing vertical wells and 14 horizontal producing wells.

The 50% OOIP by LSD and 50% First 90 Days of Cumulative Production Method was used to allocate tract factors to individual LSD's.

Tract Factor calculations for all individual LSD's based on the above methodology are outlined within Table 5.

Working Interest Owners

Table 5 outlines the working interest (WI) for each recommended tract within the proposed North Pierson Unit No. 1. Tundra Oil and Gas Partnership holds a 99.583333% working interest ownership in the proposed tracts; Brandon Professional Investments owns the remaining 0.416667% working interest.

As such, Tundra Oil and Gas Partnership will have a 99.583333% WI in the proposed North Pierson Unit No. 1, and Brandon Professional Investments will have a 0.416667% WI.

WATERFLOOD EOR DEVELOPMENT

Primary production from the horizontal producing wells in the proposed North Pierson Unit No. 1 has declined significantly from peak rate to current rate, indicating a need for secondary pressure support. Through the process of developing other waterfloods in Manitoba, Tundra has measured a significant and ever increasing incidence of variation in reservoir pressure depletion by the existing primary vertical producing wells. Placing new horizontal wells immediately on water injection in areas without significant reservoir pressure depletion has been particularly problematic in similar low permeability formations. As a result, the following conditions have been observed 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
- Early water breakthrough issues

Tundra makes the case that, if future horizontals are to be drilled, they should be produced for a period of time (up to 12 months) to address the above issues.

Estimated Fracture Pressure

Completion data from the existing producing wells within the project area indicate a fracture pressure gradient of 18.0 kPa/m true vertical depth (TVD). Tundra does not intend to fracture stimulate wells in the area, as the reservoir is of sufficient quality to be effectively drained using unstimulated openhole laterals. However, Tundra's injection strategy will be implemented using an upper limit pressure gradient of approximately 15.0 kPa/m at the sandface, by taking 85% of the fracture gradient. This equates to a maximum operating wellhead pressure of 5.0 MPa.

Reservoir Pressure

It is estimated the initial reservoir pressure of the Mission Canyon (Alida) was approximately 9.8 MPa based on early DST's collected from the initial vertical wells drilled within the proposed Unit boundary. Subsequent DST's run with additional drilling indicates pressure depletion over time with fluid withdrawal. Recent gas measurements at the Tundra-operated 1-18-3-28 battery indicate a gas-oil ratio of 70 m^3/m^3 field-wide. Without gas measurements collected over the full life of the pool's production, it is difficult to ascertain with any degree of certainty whether the reservoir has dipped below bubble point or gas saturation pressures. A range is approximated for the average reservoir pressure of 2,000 – 5,000 kPa.

Although in general there is not much pressure information available in the recent history of the pool, static and fall-off pressures were collected on three horizontal wells drilled from 2007 to 2008. These are presented as Appendix 11. The wells are (15-18) Hz 8-19-3-28W1, (4-20) Hz 13-20-3-28W1, and (15-16) Hz 14-15-3-28W1. As can be seen from the fall-offs, pressures were still significantly declining at the time the recorders were pulled, indicating the amount of time was not sufficient to accurately extrapolate for an initial pressure.

Tundra drilled two vertical strat wells in the N/2 of Sec 20 in March 2013 to delineate this part of the field. The 16-20 strat was drilled, cored, logged and abandoned, having encountered zero net pay. The 14-20 strat was drilled, logged and subsequently cased, having encountered 2.5-3.0m of net pay. Prior to break-up, an Alida interval was perforated, and a bridge plug set above with pressure recorders hung to continuously monitor pressure. The gauges will be retrieved after break-up and the pressure signatures reviewed to shed insight on possible pressure communication in the reservoir with offset horizontal production. Once the pressure information becomes available, Tundra will submit it in the annual enhanced oil recovery report to the Manitoba Government.

On secondary, the plan is to increase the current reservoir pressure closer to the original pressure by maintaining an instantaneous voidage replacement ratio (VRR) of 1.25 to 2.0 until a cumulative VRR of 1.0 is reached, as long as sandface pressures stay below the maximum allowable wellhead pressures previously stated.

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 monthly Voidage Replacement Ratio (VRR) is expected to average approximately 1.25 to 2.00 within the pattern during the fill up period. As the cumulative VRR approaches 1.0, target reservoir operating pressure for waterflood operations will be 75 – 90% of original reservoir pressure.

Water Source and Injection Wells

Injection water for the proposed North Pierson Unit No. 1 will be supplied from the Mannville formation at the 100/3-18-3-28 well. Tundra will be submitting an application to convert the 100/3-18-3-28 well to supply water sourced from the Mannville. Mannville water will then be pumped from the 100/3-18 source well to the Pierson 1-18-3-28W1 battery, where it will be filtered and then pumped up to injection system pressure. A diagram of the Pierson water injection system and new pipeline connection to the project area injection wells is shown as Figure 8.

Produced water is not thought to be an ideal injection source in the proposed North Pierson Unit No. 1, as it could remove underlying reservoir energy over time if there is a limited extent to the aquifer. There are no current plans to use produced water as a source supply for North Pierson Unit No. 1. Oil carryover could also be considered as a potential concern.

A review of existing Alida floods in SE Saskatchewan and Manitoba yielded an extensive number of source water wells producing from the Mannville zone. On the macro scale, the Alida has been flooded successfully using Mannville water over many years. As such, Tundra collected an analogous Mannville source water sample with CNRL's permission from their operated 100/8-24-3-21W1 Mannville source water well with which to conduct compatibility testing with varying mixtures of Alida water. The testing was conducted by a highly qualified third party. 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. Tundra is considering a scale inhibitor application to be maintained into the source water stream out of the Pierson injection water facility. It is thought that the Mannville sourced from 3-18 will overall be compatible with Alida water. Review and monitoring of the source water scale inhibition system is also part of an existing routine maintenance program.

Water injection well conversions for the proposed North Pierson Unit No. 1 will be selected on the basis of maximizing oil recovery, sweep efficiency between wells, and learning. Wells currently being considered for conversion to downhole injection are depicted in Figure 7. Tundra’s plan is to target openhole, non-stimulated wells with access to good reservoir to obtain suitable injection rates, to reintroduce energy into the reservoir system. Tundra has also identified a number of areas in the proposed Unit that could be delineated with additional drilling. These areas are highlighted green in Figure 7. Tundra will evaluate these areas to determine whether additional drilling will increase the overall recovery of the pool. Tundra has extensive experience drilling in the area and elsewhere, and any new wells are rigorously programmed and monitored during execution. This helps ensure optimum placement of each lateral in zone, to prevent or minimize the potential for out-of-zone lateral placement that could otherwise increase the potential for future out-of-zone injection and oor flood conformance. Any changes to the development plan will be discussed in the annual enhanced oil recovery report submitted to the Manitoba Government.

New water injection wells will be placed on injection once approval to inject has been received. 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 will be surface equipped with injection volume metering and rate/pressure controls (Appendix 10). 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 Pierson Unit No. 1 horizontal water injection well rates are forecasted to average 200 - 300 bbls WPD based on expected reservoir conditions and fill-up volumes.

Schedule/Timing for Conversion of Wells to Water Injection

Tundra has designed the following well development schedule to allow for the most expeditious development of the waterflood within the proposed North Pierson Unit No. 1:

- Immediate Unitization of the project area provides a mechanism for primary production allocation during the pre-production period, regardless of oil rate or time on production
- Unitization allows the Unit Operator to convert existing wells to injection in the most expeditious and operationally efficient manner, and evaluate for possible additional drilling
- Calculate and/or obtain reservoir pressures and observe production rate profile characteristics on new wells and existing producing wells from 2013–2014
- Secondary oil rate response at producing wells is forecasted to begin within 12-24 months following conversion of wells to water injection service

Criteria for Conversion to Water Injection Well

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

- Measured reservoir build-up pressures measured by shutting in production
- Fluid production rates, cumulative volumes, and any changes in decline rate over time
- 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 Pierson Unit No. 1 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.

Waterflood Surveillance and Optimization

North Pierson Unit No. 1 EOR response and waterflood surveillance will consist of the following:

- Regular production well rate, WOR and WCT testing to monitor waterflood response, breakthrough or fingering
- Daily water injection rate and pressure monitoring v. target
- Evaluation of Hall plots to observe positive or negative skin indicating channeling or out of zone injection
- Gas measurement at individual wells to monitor changes to GOR with waterflood
- Water injection rate/pressure/time vs. cumulative injection plot
- Reservoir pressure surveys as required to establish pressure trends
- Instantaneous and cumulative VRR by pattern and in the overall Unit
- Potential use of chemical tracers to track water injector/producer responses
- Use of some or all: 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 Pierson Unit No. 1 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 North Pierson Unit No. 1.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed North Pierson Unit No. 1 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 Pierson Unit No. 1 waterflood operation will utilize the Tundra operated well 100/3-18-3-28W1, sourced from the Mannville, and water plant (WP) facilities located at the 1-18-3-28 W1M.

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Appendix 9. All surface facilities and wellheads will have cathodic protection to prevent corrosion. All injection flowlines will be made of fiberglass so corrosion will not be an issue. Injectors will have a packer set below the top of the MC3 (Alida) formation, and the annulus between the tubing and casing will be filled with inhibited fluid. Refer to Appendix 9 for additional corrosion control details.

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 North Pierson Unit No. 1. 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 Pierson Unit No. 1 Application.

Pierson No. 1 Unitization, and execution of the formal North Pierson Unit No. 1 Agreement by affected Mineral Owners, is expected before the end of June 2013. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the North Pierson Unit No. 1 Application.

Should the Petroleum Branch have further questions or require more information, please contact Justin Robertson, P. Eng. at 403.513.1024 or by email at Justin.Robertson@tundraoilandgas.com.

TUNDRA OIL & GAS PARTNERSHIP

Original Signed by Justin Robertson, P. Eng. May 24th, 2013

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