PROPOSED CROMER UNIT NO. 3

Application for Enhanced Oil Recovery Waterflood Project

Middle Bakken/Three Forks Formations

Bakken – Three Forks B Pool (01 62B)

Daly Sinclair Field, Manitoba

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Tundra Oil and Gas Partnership

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INTRODUCTION

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

In the eastern part of the Daly field, potential exists for incremental production and reserves from a Waterflood EOR project in the Three Forks and Middle Bakken oil reservoirs. The following represents an application by Tundra to rescind the current Cromer Unit No. 1 boundary and waterflood order and establish Cromer Unit No. 3 and implement a Secondary Waterflood EOR scheme within the Three Forks and Middle Bakken formations as outlined on Figure 2.

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

SUMMARY

1. The proposed Cromer Unit No. 3 currently includes 3 horizontal wells and 19 vertical wells (14 are commingled with the Lodgepole), within 38 Legal Sub Divisions (LSD) of the Middle Bakken/Three Forks producing reservoir. The project area is located north of Ewart Unit No. 5 and SE of the North Ebor Units No. 1 & 2 (Figure 2).

2. Total Net Original Oil in Place (OOIP) in Cromer Unit No. 3 has been calculated to be 748.6 e^3m^3 (4,709 Mbbl) for an average of 19.7 net e^3m^3 (123.9 Mbbl) OOIP per 40 acre LSD based on a 0.5 md cutoff for the Middle Bakken & Lyleton 'B'.

3. Cumulative production to the end of February 2015 from the 22 wells within the proposed Cromer Unit No. 3 project area was 85.0 e^3m^3 (534.7 Mbbl) of oil, and 111.5 e^3m^3 (701.9 Mbbl) of water, representing an 11.3% Recovery Factor (RF) of the Net OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary producing oil reserves in the proposed Cromer Unit No. 3 project area is estimated to be 124.8 e^3m^3 (785.0 Mbbl), with 39.8 e^3m^3 (250.3 Mbbl) remaining as of the end of February 2015.

5. Ultimate oil recovery of the proposed Cromer Unit No. 3 OOIP, under the current Primary Production method, is forecasted to be 16.7%.

6. Figure 4 shows the production from the Cromer Unit No. 3 peaked in January 2003 at 30.2 m^3 (OPD). As of February 2015, production was 12.7 m^3 OPD, 27.0 m^3 of water per day (WPD) and a 68.0% watercut (WCT).

7. In January 2003, production averaged 1.59 m^3 OPD per well in Cromer Unit No. 3. As of February 2015, average per well production has declined to 0.85 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately 27.6% in the project area.

8. EUR of oil under Secondary Waterflood EOR for the proposed Cromer Unit No. 3 is estimated to be 235.9 e^3m^3 (1,483.1 Mbbl), with 150.9 e^3m^3 remaining. An incremental 111.1 e^3m^3 (698.8 Mbbl) of proved reserves, or 14.8%, is forecasted to be recovered under the proposed Unitization and Secondary EOR production, versus the existing Primary production method.

9. Total RF under Secondary WF in the proposed Cromer Unit No. 3 is estimated to be 31.5%.

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

11. Future horizontal injectors, with multi-stage hydraulic fractures, will be been drilled between existing horizontal/vertical producing wells (Figure 5) within the proposed Cromer Unit No. 3, to complete line drive waterflood patterns with effective 20 acre spacing.

12. The proposed Lodgepole Cromer Unit No. 2 will be unitized commingled with the proposed Bakken Cromer Unit No. 3. The production well be allocated between the zones with an added emphasis on testing frequency and the generally accepted practice of sulfur content difference between the Lodgepole and Bakken oil.

RESERVOIR PROPERTIES AND TECHNICAL DISCUSSION

The proposed Cromer Unit No. 3 project area is located within Township 9, Range 28 W1 of the Daly Sinclair oil field. The proposed Cromer Unit No. 3 will include 3 horizontal wells and 19 vertical wells (14 are commingled with the Lodgepole), within an area covering 38 LSDs (Figure 2). The project area is located north of Ewart Unit No. 5 and SE of the North Ebor Units No. 1 & 2. A project area well list complete with recent production statistics is attached as Table 3.

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

Geology

Stratigraphy:

The stratigraphy of the reservoir section for the proposed unit is shown on the structural cross section attached as Appendix 1. The section runs NW to SE through the middle to Northern half of the proposed unit. 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, to a very limited extent, the Lyleton B Siltstones.

Sedimentology:

The Upper Bakken Shale is a black, organic rich, platy shale which forms the top seal for the underlying Middle Bakken/Lyleton B reservoirs (Appendix 3). The reservoir units in the proposed unit are analogous to the Bakken / Lyleton producing reservoirs that have been approved proximal to the proposed unit (Ewart Unit 3, Ewart Unit 5 and Ebor Unit 1 & 2) please see Appendix 2.

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. Within the proposed unit, the Middle Bakken ranges from about 4.5m to just over 5.0m in the West (Appendix 4).

The Lyleton B (Three Forks) reservoir consists of buff to tan very fine grained siltstone (occasionally 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 upper Lyleton B is generally well bedded and shows evidence of parallel lamination with occasional wind ripples. The coarser siltstones become interbedded with dark grey-green (occasionally red) very fine grained siltstone in the lower portion of the Lyleton B and is generally non-reservoir. The Lyleton B is between 0 and 2.0m thick within the proposed unit (Appendix 5). The upper Lyleton B has been partially to wholly eroded away in the proposed unit area.

The Torquay silty shale (Three Forks) forms the base of the reservoir sequence and is a brick red dolomitic fine to very fine siltstone (Appendix 6), similar to the Red Shale Marker found to the

Southwest in the Sinclair area units. This forms a good basal seal to the Middle Bakken / Lyleton B reservoir sequence.

Structure:

Structure contour maps are provided for the top of each major unit (Appendices 7 through 10). The structure within the proposed unit area generally consists of an overall Southwestward dip. Structural variations in the area are interpreted as being caused by dissolution of the underlying Prairie Evaporites (ex. Sec 19-09-28W1). Anomalous structural variations caused by dissolution are common in the Sinclair Daly area but do not appear to represent continuous barriers to lateral fluid flow within the reservoir as they do not appear to interrupt the lateral continuity of the reservoir beds. None of these features is found in the proposed unit area.

Reservoir Quality:

There are many existing vertical wells within the proposed unit area. Three cores were taken in the Bakken sequence in the proposed unit and there are several others proximal to the proposed unit boundaries, mainly to the South and East. Any available wells proximal to the unit have been used to infer the Permeability and Porosity for this unit application. The Middle Bakken reservoir is anticipated to have Fair to Good reservoir throughout the proposed unit.

Due to erosion of the upper portion of the Lyleton B formation there is limited to no pay reservoir in most LSDs in the proposed unit. There is unlikely to be any significant Lyleton B contribution to production or the overall recovery from this unit leaving the Middle Bakken as the primary reservoir.

Permeability (k-h in mD*m) and porosity (Phi-h in por*m) maps for the two reservoir units are provided (Appendices 11 through 14, point values on map posted at wells with core analysis). These maps are created using core data and are generated as follows. First the core is divided into the reservoir units present. This data is then subject to a permeability cutoff. Intervals that meet or exceed the cutoff are multiplied by the interval thickness and then summed to get the total value for the Phi-h or k-h for that particular reservoir unit. The value of the permeability cutoffs for each formation are the same values used by GLJ for third party reserve evaluations on Tundra's Sinclair properties. The permeability cutoffs applied are as follows:

- Middle Bakken = 0.5 md
- Lyleton B = 0.5 md

As can be noted from the Phi-h and k-h maps the bulk of the reservoir in the proposed unit is contained in the Middle Bakken formation. It is important to note that the 0.5 md cutoff effectively ignores pore volume with permeability between 0.2 and 0.5 md that may contain moveable oil. It should also be noted that due to the limited core data in the immediate area and interpolative methods were used to generate the mapping and OOIP numbers for the area.

Reservoir Continuity:

Lateral continuity of the reservoir units is an essential requirement of a successful waterflood. As demonstrated by the cross-section (Appendix 1) and the isopach maps, the lateral continuity of the reservoir within the proposed unit is very good.

Vertical reservoir continuity within the Middle Bakken and the underlying remaining upper Lyleton B is likely good but vertical continuity to the lower Lyleton B is probably limited due to the heterolithic depositional environment and the multiple thin shale interbeds found in the lower Lyleton B.

Fluid Contacts:

The oil/water contact for the Middle Bakken and Lyleton reservoir is estimated from production to be at about -525 m subsea. In tight reservoirs such as these the transition zone could be considerable and the top of the transition zone is estimated to be at about -490 m subsea based on production and simulation studies of the reservoir. The postulated oil/water contact at -525 m subsea is below the lowest contour on any of the attached structure contour maps.

<u>OOIP Estimates</u>

OOIP was calculated by Tundra Geologist Todd Neely. Todd holds a BSc. in Geology from the University of Manitoba, and has 15 years of industry experience, 4 of which are in the Williston Basin. Each vertical well within the unit was petrophysically analyzed by Gille Montsion, incorporating existing conventional core analysis data. Gille has over 20 years of experience as a Senior Petrophysicist with Canadian Hunter, ConocoPhillips, and Nexen.

Total volumetric OOIP for the Middle Bakken and Lyleton B within the proposed unit has been calculated to be 748.6 e^3m^3 using Tundra internally created maps. Maps used were generated from core data from 316 wells available in the Sinclair area (Appendix 15).

Net pay for each cored well is calculated using the formation specific permeability cut off discussed above. Representative intervals that had a measured permeability greater than the formation specific cutoff were considered pay. The weighted average porosity (phi) of all pay intervals for each formation was calculated for each cored well. The height of pay (h) was derived by summing the heights of each representative sample that met the permeability cut off. From these two parameters, a phi*h value was calculated for all four productive horizons in all wells with core over each respective formation.

The phi*h values for all cored wells were contoured using Golden Software's "Surfer 9" program using a 500 m grid node spacing. Phi*h values for each LSD were calculated off the associated Surfer 9 grid by determining the values at the center of each LSD.

Tabulated parameters for each LSD from the calculations can be found in Table 4. Average OOIP by individual LSD was determined to be 19.7 e^3m^3 for Cromer Unit No. 3.

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 a PVT taken from the 3-3-8-29 Sinclair Bakken well, thought to be representative of the fluid characteristics in the reservoir.

A complete listing of Middle Bakken/Three Forks formation rock and fluid properties used to characterize the reservoir are provided in Table 5.

Historical Production

A historical group production history plot for the proposed Cromer Unit No. 3 is shown as Figure 4. Oil production commenced from the proposed Unit area in July 1992 and peaked during January 2003 at 30.2 m^3 OPD. As of February 2015, production was 12.7 m^3 OPD, 27.0 m^3 of WPD and a 68.0% WCT.

From peak production in January 2003 to date, oil production is declining at an annual rate of approximately 27.6% under the current Primary Production method.

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

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP to 31.5%. 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 Cromer Unit No. 3.

Unit Operator

Tundra will be the Operator of record for Cromer Unit No. 3.

Unitized Zone

The Unitized zone(s) to be waterflooded in the Cromer Unit No. 3 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 3 horizontal wells and 19 vertical wells to be included in the proposed Cromer Unit No. 3 are outlined in Table 3.

Unit Lands

The Cromer Unit No. 3 will consist of 38 LSDs as follows:

NE ¼ of Section 11, Township 9, Range 28, W1M
NW ¼ of Section 13, Township 9, Range 28, W1M
LSDs 1-6, N/2 of Section 14 of Township 9, Range 28, W1M
Section 23, Township 9, Range 28, W1M

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

Tract Factors

The proposed Cromer Unit No. 3 will consist of 38 Tracts based on the 40 acre LSDs containing the existing 3 horizontal and 19 vertical wells.

The Tract Factor contribution for each of the LSD’s within the proposed Cromer 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 by LSD = the product of Remaining Gross OOIP by LSD as a % of total proposed Unit Remaining Gross OOIP

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

Working Interest Owners

Table 1 outlines the working interest (WI) for each recommended Tract within the proposed Cromer Unit No. 3. Tundra holds a 100% WI ownership in all the proposed Tracts. Tundra will have a 100% WI in the proposed Cromer Unit No. 3.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Cromer Unit No. 3 are based on internal engineering assessments. Internal reviews included analysis of available open-hole logs; core data; petro-physics; 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 Cromer Unit No. 3 OOIP (Table 6).

Unitizing the proposed Cromer Unit No. 3 will provide an extremely equitable means of maximizing ultimate oil recovery in the project area. This is being done to better understand the most effective water flood spacing for future development of the similar quality reservoir in other locations within the Daly area.

Pre-Production of New Horizontal Injection Wells

Primary production from the original vertical/horizontal producing wells in the proposed Cromer Unit No. 3 has declined significantly from peak rate indicating a need for secondary pressure support. It is projected that six new horizontal injection wells will be drilled between the existing vertical/horizontal producing wells as shown in Figure 5, but ultimately the final candidates for injection conversion will be chosen based on production performance post unit approval. This will result in effective 20 acre line drive waterflood patterns within Cromer Unit No. 3. Tundra believes an initial period of producing horizontal wells prior to placing them on permanent water injection is essential and all Unit mineral owners will benefit. Ultimately the timing of conversion will be based on production performance post unit approval. It is Tundra's desire to have the final injection conversion candidates on injection as soon as possible.

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

Reserves Recovery Profiles and Production Forecasts

The primary waterflood performance predictions for the proposed Cromer Unit No. 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.

Primary Production Forecast:

Cumulative production in the Cromer Unit No. 3 project area, to the end of February 2015 from 22 wells, was 85.0 e^3m^3 of oil and 111.5 e^3m^3 of water for a recovery factor of 11.3% of the calculated Net OOIP.

Ultimate Primary Proved Producing oil reserves recovery for Cromer Unit No. 3 has been estimated to be 124.8 e^3m^3, or a 16.7% RF of OOIP. Remaining Producing Primary Reserves has been estimated to be 39.8 e^3m^3 to the end of February 2015. The expected production decline and forecasted cumulative oil recovery under continued Primary Production is shown in Figure 7a.

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

Tundra will plan an injection conversion schedule to allow for the most expeditious development of the waterflood within the proposed Cromer Unit No. 3, while maximizing reservoir knowledge gained for further reservoir characterization.

Criteria for Conversion to Water Injection Well:

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

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

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

The above schedule allows for the proposed Cromer Unit No. 3 project to be developed equitably, efficiently, and moves to project to the best condition for the start of waterflood as quickly as possible. It also provides the Unit Operator flexibility to manage the reservoir conditions and response to help ensure maximum ultimate recovery of OOIP.

Secondary EOR Production Forecast:

The proposed project oil production profile under Secondary Waterflood has been developed based on the response observed to date in the Sinclair Unit 1 Pilot Waterflood (Figure 6).

Secondary waterflood plots of the expected oil production forecast over time and the expected oil production v. cumulative oil are plotted in Figures 8a and 8b, respectively. Total Secondary EUR for the proposed Cromer Unit No. 3 is estimated to be 235.9 e^3m^3 with 56.8 e^3m^3 remaining representing a total RF of 31.5% for the proposed Unit area. An incremental 38.7 e^3m^3 of oil, or incremental 14.8% Secondary RF, are forecasted to be recovered under the proposed Waterflood Unitization.

Estimated Fracture Gradient

Completion data from the producing wells within the project area indicate a fracture pressure gradient of 21.0 – 26.0 kPa/m true vertical depth (TVD). Tundra expects the fracture gradient encountered during completion of the proposed horizontal injection well will be somewhat lower than this value due to expected reservoir pressure depletion. The current Cromer Unit No. 1 Waterflood was approved for a maximum allowable wellhead injection pressure of 9.0 MPa at which water may be injected.

WATERFLOOD OPERATING STRATEGY

Water Source

The injection water for the proposed Cromer Unit No. 3 will be supplied from the existing Sinclair 3-4-8-29W1 Battery source and injection water system. All existing injection water is obtained from the Lodgepole formation in the 102/16-32-7-29W1 licensed water source well. Lodgepole water from the 102/16-32 source well is pumped to the main Sinclair Units Water Plant at 3-4-8-29W1, filtered, and pumped up to injection system pressure. A diagram of the Sinclair water injection system and new pipeline connection to the proposed Cromer Unit No. 3 project area is shown as Figure 9.

Produced water is not currently used for any water injection in the Tundra operated Sinclair Units and there are no current plans to use produced water as a source supply for Cromer Unit No. 3.

Since all producing Middle Bakken/Three Forks wells in the Daly Sinclair areas, whether vertical or horizontal, have been hydraulically fractured, produced waters from these wells are inherently a mixture of Three Forks and Bakken native sources. This mixture of produced waters has been extensively tested for compatibility with 102/16-32 source Lodgepole water, by a highly qualified third party, prior to implementation by Tundra in Sinclair Unit 1. All potential mixture ratios between the two waters, under a range of temperatures, have been simulated and evaluated for scaling and precipitate producing tendencies. Testing of multiple scale inhibitors has also been conducted and minimum inhibition concentration requirements for the source water volume determined. At present, continuous scale inhibitor application is maintained into the source water stream out of the Sinclair injection water facility. Review and monitoring of the source water scale inhibition system is also part of an existing routine maintenance program.

Injection Wells

There will be six 20 acre infill horizontal wells drilled as shown in Figure 5. The final design of the waterflood will be determined based on production results from the 20 acre infill horizontal wells but will likely consist of six horizontal injection conversions setting up a 20 acre line drive waterflood. All wells including the horizontal injection wells will be stimulated by multiple hydraulic fracture treatments in an openhole completion design (Figure 10). Tundra has extensive experience with horizontal fracturing in the area, and all jobs are rigorously programmed and monitored during execution. This helps ensure optimum placement of each fracture stage to prevent, or minimize, the potential for out-of-zone fracture growth and thereby limit the potential for future out-of-zone injection.

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

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

Tundra has a thorough understanding of area fracture gradients. A management program will be utilized to set and routinely review injection target rates and pressures vs. surface MOP and the known area formation fracture pressures.

All new water injection wells are surface equipped with injection volume metering and rate/pressure control. An operating procedure for monitoring water injection volumes and meter balancing will also be utilized to monitor the entire system measurement and integrity on a daily basis.

The proposed Cromer Unit No. 3 horizontal water injection well rate is forecasted to average 10 – 40 m^3 WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure Management during Waterflood

No representative initial pressure surveys are available for the proposed Cromer Unit No. 3 project area in the Bakken formation because almost all the wells in the area are commingled with the Lodgepole zone. The extremely long shut-in and build-up times required to obtain any possible representative surveys from the producing wells are economically prohibitive. Tundra will make all attempts to capture a reservoir pressure survey in the proposed horizontal injection wells during the completion of the wells and prior to injection or production.

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

Waterflood Surveillance and Optimization

Cromer Unit No. 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
- Sulfur content and oil density testing

The above surveillance methods will provide an ever increasing understanding of reservoir performance, and provide data to continually control and optimize the Cromer Unit No. 3 waterflood operation. Controlling the waterflood operation will significantly reduce or eliminate the potential for out-of-zone injection, undesired channeling or water breakthrough, or out-of-Unit migration. The monitoring and surveillance will also provide early indicators of any such issues so that waterflood operations may be altered to maximize ultimate secondary reserves recovery from the proposed Cromer Unit No. 3.

On Going Reservoir Pressure Surveys

For each openhole horizontal injection well, a measured reservoir pressure will be obtained prior to water injection. These pressures will be reported within the Annual Progress Reports for Cromer Unit No. 3 as per Section 73 of the Drilling and Production Regulation.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Cromer Unit No. 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 Cromer Unit No. 3 waterflood operation will utilize the existing Tundra operated source well supply and water plant facilities located at 3-4-8-29 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 in Figure 11.

OTHER CONSIDERATIONS

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

1. Tundra will start with waterflooding the Bakken zone (Cromer Unit No. 3). Once Tundra is certain of a waterflood response from the Bakken, Tundra will then begin waterflood development in the proposed Cromer Unit No. 2. By not suspending or abandoning the Lodgepole zone in the vertical wells once injection in the Bakken zone commences, Tundra will ensure that the most optimum utilization of existing wellbores is achieved and ground disturbance is reduced.

2. Tundra will also monitor the total fluid via fluid level in the vertical wells in order to manage the waterflood response. Once a waterflood response is observed, Tundra will ensure that sulfur content and oil density tests are done in order to accurately assign production for each zone. Table 6 summarizes Tundra's planned testing protocol.

3. Tundra plans to stagger the start of injection between the proposed Cromer Unit No. 3 Bakken development and Cromer Unit No. 2 Lodgepole development to ensure the waterflood response for each zone is distinct and observable.

4. In order to minimize potential cross-flow between the Bakken and Lodgepole zones, Tundra will continually monitor the fluid levels in the offsetting vertical wells and adjust the pump speed in order to maintain pump-off conditions in the wellbore. As this is an important project, Tundra will endeavor to service problems wells in an expedited manner so wells are never shut-in for prolonged periods of time. In the event one zone becomes uneconomic, it will be abandoned accordingly.

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra is in the process of notifying all mineral rights and surface rights owners of this proposed EOR project and formation of Cromer Unit No. 3. Copies of the notices and proof of service, to all surface and mineral rights owners will be forwarded to the Petroleum Branch when available to complete the Cromer Unit No. 3 Application.

Cromer Unit No. 3 Unitization, and execution of the formal Cromer Unit No. 3 Agreement by affected Mineral Owners, is expected during Q3 2015. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Cromer Unit No. 3 Application.

Should the Petroleum Branch have further questions or require more information, please contact Cary Reid at (403) 910-1669 or by email at cary.reid@tundraoilandgas.com.

TUNDRA OIL & GAS PARTNERSHIP

Original Signed by Cary Reid, P.L. (Eng.)