PROPOSED CROMER UNIT No. 2

Application for an Enhanced Oil Recovery (EOR) Waterflood Project

Lodgepole Formation

Daly Sinclair – Lodgepole B (01 59B)

Daly Sinclair Field, Manitoba

June 18th, 2015

Tundra Oil and Gas Partnership

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

INTRODUCTION

The Daly portion of the Daly Sinclair Oilfield is located in Townships 8, 9, 10 and 11, Ranges 27, 28 & 29 WPM (Figure 1). Figure 2 shows the outline of the proposed Cromer Unit No. 2 boundary within the Daly oilfield targeting the Lodgepole formation.

Within the proposed Cromer boundary, potential exists for incremental production and reserves from a Waterflood Enhanced Oil Recovery (EOR) project in the Lodgepole B oil reservoir. The following is an application by Tundra to establish Cromer Unit No. 2 and implement a Secondary Waterflood EOR scheme.

The proposed project area falls within an existing designated Lodgepole B (01-59B) Pool of the Daly Sinclair Oilfield (Figure 3).

SUMMARY

1. The proposed Cromer Unit No. 2 consists of 26 vertical Lodgepole wells. Of the 26 wells, 15 are currently producing (14 have been commingled with the Bakken) and the remainder are either abandoned or suspended. The area of the proposed Cromer Unit No. 2 comprises 38 Legal Sub Divisions (LSD's).

2. Total Original Oil in Place (OOIP) in the project area is estimated to be 7,763.9 e^3m^3 (48,833 Mbbl) for an average of 204.3 e^3m^3 (1,285 Mbbl) OOIP per 40 acre LSD. OOIP values were estimated by contouring phi*h values and applying volumetric methods using permeability cutoffs by zone.

3. Cumulative production to the end of February 2015 from the 26 Lodgepole wells within the proposed Cromer Unit No. 2 project area is 87.8 e^3m^3 (553 Mbbl) of oil and 750.0 e^3m^3 (4,720 Mbbl) of water, representing a 1.1% Recovery Factor (RF) of the OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary producing oil reserves in the proposed Cromer Unit No. 2 project area is estimated to be 102.2 e^3m^3 (643 Mbbl), with 14.4 e^3m^3 (90 Mbbl) remaining as of the end of February 2015.

5. Ultimate oil recovery of the proposed Cromer Unit No. 2 OOIP, under the current Primary production method, is forecasted to be 1.3%.

6. Figure 4 shows that the oil production rate in the proposed Cromer Unit No. 2 peaked during July 1955 at 45.3 m^3 (285.0 bbl) of oil per day (OPD). As of February 2015, production was 2.66 m^3 (16.8 bbl) OPD, 53.19 m^3 (334.7 bbl) water per day (WPD) and a 95.2% water cut (WCUT).

7. In July 1955, production averaged 5.0 m^3 (31.7 bbl) OPD per well in the proposed Cromer Unit No. 2. As of February 2015, average per well production has declined to 0.22 m^3 (1.4 bbl) OPD. Decline analysis of the Primary production data forecasts the oil rate to continue declining at an annual rate of approximately 5.6% in the project area.

8. Estimated Ultimate Recovery (EUR) of oil under Secondary Waterflood EOR for the proposed Cromer Unit No. 2 is estimated to be 215.0 e^3m^3 (1,352 Mbbl). An incremental 112.8 e^3m^3 (710 Mbbl) of oil is forecasted to be recovered under the proposed Unitization and Secondary EOR production, versus the existing Primary production method (Figures 8 & 9).

9. Total RF under Secondary WF in the proposed Cromer Unit No. 2 is estimated to be 2.8%.

10. Based on waterflood response in the adjacent Daly Unit Nos. 1, 3, & 4, the Lodgepole formation in the proposed project area is thought to be suitable reservoir for successful EOR operations.

11. Proposed future horizontal injectors with multi-stage hydraulic fractures will be drilled between existing vertical producing wells (Figure 5) within the proposed Cromer Unit No. 2 area, to complete waterflood patterns with an 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.

DISCUSSION

The proposed Cromer Unit No. 2 project area is located in Township 9, Range 28 W1 within the Daly Sinclair Field Boundary (Figure 1) and is comprised of 38 LSD's (Figure 2). The proposed Cromer Unit No. 2 consists of 26 vertical wells (14 have been commingled with the Bakken), 15 of the Lodgepole wells are currently producing, and the remainder are either suspended or abandoned. A project area well list with current well status and well type is attached in Table 3.

Within the proposed Unit, potential exists for incremental production and reserves from a Waterflood EOR project in the Lodgepole oil reservoir.

GEOLOGY

Geology Introduction

The proposed Cromer Unit No. 2 (Appendix 1) is located on the carbonate slope of the Mississippian Lodgepole Formation on the eastern edge of the Williston Basin (Appendix 2). It has produced oil on a primary recovery scheme since the 1950's, with the first well spud at 100/12-14-009-28W1 on August 30th, 1954. The Lodgepole lies conformably on top of the Bakken Formation. In the Cromer area, it is unconformably overlain by the Lower Member of the Jurassic Formation which consists of evaporites and red beds. This geology section focuses on the methodology and data gathered to define the thickness of net reservoir, porosity and water saturation to estimate the OOIP's provided for this Unitization application. The reader is referred to the literature (Appendix 22) for a more detailed review of the stratigraphy, sedimentology and diagenesis of the Mississippian Lodgepole Formation (McCabe, 1963; Young and Rosenthal, 1991; Klassen, 1996; Nicola, 2008; Nicola and Barchyn, 2008).

Reservoir Geology

The Lodgepole Formation in the Cromer area occurs between 717 and 851 mTVD in the subsurface, and is subdivided into seven members (as shown in Appendices 4A to 4B). In descending stratigraphic order, these are:

1. Unnamed
2. Upper Daly
3. Middle Daly
4. Cruickshank Shale
5. Cruickshank Crinoidal
6. Cromer Shale
7. Basal Limestone

Of the above seven members, the first five are productive and correlatable on logs and in cores across the study area, as shown in a set of north-south and northwest-southeast cross-sections (Appendices 4A to 4B). The Cromer Shale is comprised of tight argillaceous mudstones, and appears as a higher Gamma Ray unit on logs compared to the overlying Cruickshank Crinoidal and the underlying Basal Limestone members. It is considered to act as the bottom seal for the overlying Lodgepole hydrocarbon-bearing reservoir zone.

The first occurrence of hydrocarbon-bearing Lodgepole reservoir occurs in the Unnamed, and the last occurrence is encountered in the Cruickshank Crinoidal, both of which define the top and bottom of hydrocarbon-bearing Lodgepole reservoir respectively. This is referred to as the “Lodgepole Reservoir Section” (Appendices 3, 4 & 5) in this Application. The Basal Limestone commonly contains reservoir quality rock, but is observed to be wet. In contrast, the Lodgepole reservoir above the Cromer is observed to be oil-stained in cores across the Cromer area, and is oil producing. Dolostone predominates close to the Mississippian-Jurassic unconformity, and is typically observed down to the base of the Unnamed, with a few instances where it extends further down into the Middle Daly. The rest of the Lodgepole Reservoir Section is commonly limestone with high chert content in the Middle Daly. Key papers listed in the references (Appendix 22) provide further details on the stratigraphy, sedimentology and diagenesis of the Lodgepole Formation.

A combination of micro- (pin-point, intercrystalline, inter and intra-particle) and macro- (moldic and vuggy) pore types characterize the Cruickshank Crinoidal, the Cruickshank Shale and the Middle Daly. Moving up stratigraphically, the Upper Daly and Unnamed mark a change to a unimodal micro-dominated pore system, with common intercrystalline and fine pin-point porosity. These differences in pore types and pore distributions justified applying different cut-offs to different stratigraphic members, as explained in the following section.

Geological Mapping Input

a. Data Control and Quality

32 wells have been drilled with the proposed Cromer Unit No. 2 boundary (Appendix 1). 29 wells are vertical, and of these, 26 have been completed in the Lodgepole. Production has been mostly from the Upper Daly, Middle Daly and Cruickshank Crinoidal members. 15 of these Lodgepole producers are still active. 11 wells were drilled between 1954 and 1964; consequently, log quality for this group is rather poor, as can be seen by the logs from the 09-11 well in Appendix 4B. However, 11 wells provide some core coverage, and these cores were examined in detail to estimate net reservoir thickness and to confirm porosity cutoffs used in the Cromer Unit No. 2 application for each reservoir member in the Lodgepole Reservoir Section. The remainder of wells were drilled post-1975 and provide a more modern log suite from which to conduct petrophysics. In total, 17 wells within the proposed Unit boundary provide a control point down to the base of the Lodgepole Reservoir Section, providing for estimates of phi-h (Appendices 12 & 13). The remainder either are not deep enough, or the data quality is too poor to be of use. Core

and log information from an additional 18 peripheral wells to the Unit were considered to constrain mapping contours.

b. Phi-h Estimation and Petrophysical Evaluation

By necessity, pay thickness and porosity were estimated using a number of techniques. In wells with old neutron and resistivity logs, net pay and porosity were estimated by examining the cores where available. A first batch of 20 vintage wells (1951 – 1974) with core analyses were selected and described (both inside and outside of the Cromer Unit). Porosity and permeability data were integrated with the core descriptions, and were used to calibrate visual identification of reservoir and non-reservoir rocks using a 0.5 mD permeability (k) cut-off. Subsequently, cores from older wells with no analyses were examined to visually estimate net pay thickness and average porosity. For wells drilled post-1975, petrophysical evaluation was incorporated to estimate net reservoir thickness, porosity and water saturation (Appendix 5). Three post-1980 wells outside the proposed Unit boundary provide excellent vertical core control in the Lodgepole: 102/15-27-009-28W1/00, 100/03-34-009-28W1/00 and 100/06-34-009-28W1/00. Data from these wells were examined in detail to calibrate core descriptions to petrophysical log evaluations. Nine wells within the proposed Unit boundary, and in close proximity to it, provide excellent vertical core coverage with porosity and permeability data. These were used to build porosity and permeability cross-plots for each key hydrocarbon-bearing Lodgepole reservoir members (Appendices 6A to 6F). Data points suspected to be affected by localized fractures were removed. Many of these core analyses give only one permeability value, or Kmax, and so porosity cutoffs equivalent to a Kmax of 0.5 mD are deemed most appropriate.

Overall, the relationship between core porosity and permeability is poor (Appendices 6A to 6F), highlighting the high level of heterogeneity within each reservoir member. However, general trends can be established and used to determine porosity cutoffs equivalent to a Kmax of 0.5 mD. Using this method, the following porosity cut-offs were derived for a Kmax of 0.5 mD (Appendices 6A to 6F):

- Unnamed Dolostone: 9%
- Unnamed Limestone 10%
- Upper Daly: 10%
- Middle Daly: 7%
- Cruickshank Shale: 7.5% (assumed porosity cutoff)
- Cruickshank Crinoidal: 6%

A cut-off of 7.5% was assumed for the Cruickshank Shale due to the significantly high scatter in the porosity-permeability data, which did not allow for a high value regression on the porosity-permeability relationship. This 7.5% assumption was based on qualitatively relating observations in cores with log data.

Appendix 5 provides an example of the petrophysics evaluated for wells with post-1975 data within the proposed Cromer Unit No. 2. Using cut-offs for each stratigraphic members as listed above, a summation of effective net reservoir (h) and weighted average porosity (phi) was calculated on logs for the Lodgepole Reservoir Section (from Unnamed to the top of the Cromer Shale). Weighted average water saturation (Sw) was also estimated for each well. To calculate Sw, salinity data from the Lodgepole Formation was examined in the Cromer area (Appendix 17). Data suspected to be contaminated by drilling or completion fluids was excluded. Salinity data from a total of 3 wells were examined and compiled to calculate an average salinity of 100,691 ppm for the Cromer Unit No. 2 area.

Appendix 7 was used to derive a formation water resistivity of 0.065 ohm-m at reservoir conditions, based on the 100,691 ppm salinity averaged for the Lodgepole wells in the Unit area. Archie's formula was then used to calculate Sw, assuming a=1, m=2 and n=2:

$$Sw = \sqrt[n]{\frac{a * Rw}{\emptyset^m * Rt}}$$

Where:

Rw	= Formation Water Resistivity (ohm-m) = 0.053 (Appendix 7)
Rt	= True Formation Resistivity (ohm-m)
Ø	= Log Porosity (v/v)
a	= Tortuosity Factor
m	= Cementation Exponent
n	= Saturation Exponent

Sw was derived for the 17 wells with modern logs. An average Sw of 49% was then calculated for wells within the proposed Cromer Unit (Appendix 18), and applied as a constant in the volumetrics to be discussed further in this application.

c. k-h Estimates

An attempt was made to establish a permeability-porosity relationship using the 100/06-34-009-28W1/00 well which has both Profile Permeameter data (PDPK KLIQ) and Routine Core Analysis (RCA KMAX). Appendix 8A is a crossplot of PDPK KLIQ v. Porosity for this well, and shows the computed best fit trend in red. As one can see, the regression is low as is the case with most carbonate reservoirs. Appendix 8B is a crossplot of RCA KMAX v. Porosity for all cored wells, with the same best fit trend plotted as Appendix 8A. Both plots show a similar scatter of data. This was as close a relationship that could be achieved given the variability in reservoir quality and heterogeneity in the Lodgepole Reservoir Section. Geometric average permeability values as described above were then calculated to estimate k-h values where available.

d. Maps / Observations

Lodgepole isopach, structure, net reservoir thickness and phi-h were mapped, showing control points on net reservoir distribution and/or depositional character of the Lodgepole (Appendices 9 to 15). A localized thickening of the Lodgepole to Cromer isopach is observed in Section 23-009-28W1 and towards the south of the proposed Unit boundary (e.g. 100/10-23-009-28W1 and 102/10-11-009-28W1, Appendix 9). These correspond with a structural high in Section 23-009-28W1 and a structural low offsetting the south side of the proposed Unit boundary (Appendix 10), and is captured on the isopach and phi-h maps (Appendices 9, 12 & 14). Top Lodgepole structure, coincident with bottom Lodgepole reservoir structure, gradually increases toward the NE (Appendices 10, 11 & 16). Appendix 15 highlights variations in k-h across the unit, ranging from 4.8 to 65.4 mD-m and averaging 30.8 mD-m.

Thicker occurrences of net reservoir in each stratigraphic member result in thicker total net reservoir and higher phi-h values in Section 23-009-28W1 and the southern portion of the proposed unit (Appendices 12 & 14). The porosity map indicates relatively uniform weighted average porosity across the Unit (Appendix 13). Hence, variation in phi-h is controlled predominantly by changes in net reservoir thickness (Appendices 12 & 14).

e. Fluid Contacts

As part of the review undertaken for this application, cores from 20 Lodgepole wells were examined (blue wells in Appendix 1), several of which penetrate the Cromer Shale. Where the Cruickshank Crinoidal is cored, good to excellent oil staining is observed down to its base. Isolated lenses of oil-stained coarser porous debris occurs in Cromer shale cores. Appendix 20 provides an example of moderate to good oil staining observed in cores down to the top of the Cromer Shale member. This was used to define an “oil down to” value of -285.5mSS at the base of the Cruickshank Crinoidal in the 100/06-14-009-28W1 well that has produced roughly 14,000 bbl oil and 192,000 bbl water from the Lodgepole formation. The high water production is attributed to disposal from the nearby 100/12-14-009-28W1 well. Similarly, Appendix 21 shows an example further downdip of excellent oil staining down to the base of the Cruickshank Crinoidal at the 100/04-15-009-28W1 well. This corresponds to an “oil down to” value of -298.0 mSS at the 04-15 location. The 100/04-15 well is located structurally downdip of the proposed Cromer Unit and has produced roughly 8,000 bbl oil and 450,000 bbl water. The high water production is attributed to disposal from the nearby 100/03-15-009-28W1 well.

Appendix 18 highlights that there is some variation in water saturation across the Unit, however it does not indicate an increase in water saturation downdip. As there are no wells within the Unit boundary that produced only water volumes, and there are no logs that definitively indicate an oil-water contact, it is suggested that the Lodgepole is located in a transition zone, and any oil-water contact that may exist is beyond the Cromer Unit No. 2 boundary. A similar observation can be made on the producing water cut map (Appendix 19).

Based on the information above, the Lodgepole Reservoir Section appears to be hydrocarbon-bearing down to the bottom seal (top of Cromer Shale Member) within the proposed Cromer Unit boundary. High water production over time in several downdip wells suggests the Lodgepole Reservoir Section is in a transition zone; or proximity of a fracture network accessing an aquifer of moderate to strong drive. In either case, an oil-water contact cannot be observed via logs, core or production within the Unit boundary.

OOIP ESTIMATES

Total volumetric OOIP for the Lodgepole formation within the proposed Cromer Unit No. 2 area is calculated to be 7,764.9 e^3m^3 (48,833 Mbbl). Table 4 provides volumetric OOIP estimates on both an individual LSD and total Unit basis. The OOIP values were estimated using Tundra internally created maps. Average OOIP by individual LSD was determined to be 204.3 e^3m^3 (1,285 Mbbl).

OOIP values were calculated using the following volumetric equation:

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

or

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

where:

OOIP	= Original Oil in Place by LSD (sm3, stb)
A	= Area by LSD (m2, acre)
h * ϕ	= Net Pay * Porosity, or Phi * h (m, ft)
Sw	= Water Saturation (dec)
Boi	= Initial Oil Formation Volume Factor (rm3/sm3, rb/stb)

OOIP values were calculated by compiling log and core data as described in the previous Geology section. Gille Montsion provided petro-physical expertise and performed advanced petro-physical analysis on every well in the Unit boundary. Gille has over 20 years of experience as a senior petro-physicist with Canadian Hunter, ConocoPhillips, and Nexen. OOIP values were estimated and vetted by Kerri McNeil, P. Geol., and Justin Robertson, P. Eng., two senior professionals in good standing who have over 25 years of industry experience combined in the WCSB. Phi*h values were hand-contoured on maps from petro-physical input, digitized and imported into Petra. Average phi-h values by drilling spacing unit or LSD were then exported into Excel for calculations of OOIP to be carried out. Water saturation was treated as a constant value, as outlined previously in the geology section of this application. The oil formation volume factor was estimated to be 1.11rm3/sm3 and treated equally for all OOIP calculations by tract. The OOIP calculations were carried out in Excel by Justin Robertson, P. Eng.

A listing of the Lodgepole formation rock and fluid properties used to characterize the reservoir are provided in Table 5.

The following maps provided support for OOIP estimation by LSD:

- Top Lodgepole to Top Cromer Shale Isopach (m), Appendix 9.
- Top Lodgepole Reservoir Structure (subsea TVD, m), Appendix 10.
- Bottom Lodgepole Reservoir Structure (subsea TVD, m), Appendix 11.
- Lodgepole Net Reservoir Isopach (m), Appendix 12.
- Lodgepole Reservoir Phi Map (m), Appendix 13.
- Lodgepole Phi-h, Appendix 14.
- Lodgepole K-h, Appendix 15.
- Top Lodgepole Structural Map (subsea TVD, m), Appendix 16.
- Lodgepole Salinity Map (ppm), Appendix 17.
- Water Saturation Map, Appendix 18.
- Water Cut Map, Lodgepole Formation, data averaged over the first 12 months of production, Appendix 19.

<u>Historical Production</u>

A group production history plot for the proposed Cromer Unit No. 2 is shown in Figure 4. Oil production commenced in the proposed Unit area in September 1954 and peaked during July 1955 at 45.3 m^3 (285.0 bbl) of oil per day (OPD). As of February 2015, production was 2.66 m^3 (16.8 bbl) OPD, 53.19 m^3 (334.7 bbl) water per day (WPD) and a 95.2% water cut (WCUT).

Oil production is currently declining at an annual rate of approximately 5.6% under the current Primary Production method.

The remainder of the field's production and decline rates indicate the need for pressure restoration and maintenance. Waterflooding is deemed to be the most efficient means of secondary recovery to introduce energy back into the system and to provide areal sweep between wells.

Reserves Recovery Profiles and Production Forecasts

Primary performance forecasts for the proposed Cromer Unit No. 2 are based on oil production decline curve analysis, and secondary waterflood predictions are based on internal engineering analysis performed by the Tundra reservoir engineering group.

Based on the geological descriptions, primary production decline rate, and positive Lodgepole waterflood response in the adjacent analog Daly Unit Nos. 1, 3, and 4, the Lodgepole formation in the project area is deemed to be a suitable target for waterflood EOR operations.

Primary Production Forecast

Cumulative production to the end of February 2015 from the 26 Lodgepole wells within the proposed Cromer Unit No. 2 project area is 87.8 e^3m^3 (553 Mbbl) of oil and 750.0 e^3m^3 (4,720 Mbbl) of water, representing a 1.1% Recovery Factor (RF) of the 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 102.2 e^3m^3 (643 Mbbl), representing a recovery factor of 1.3% 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.

Secondary EOR Production

The proposed project oil production profile under Secondary Waterflood has been developed based on the response observed to date in the analog offset Daly Unit Nos. 1, 3, & 4.

Based on log cross-sections and core data, the Lodgepole Reservoir Section is laterally continuous in the proposed Cromer area. As a result, it is thought that decent areal sweep and efficiency will be attained under waterflood.

The proposed Cromer Unit No. 2 Secondary Waterflood oil production forecast over time is plotted on Figure 8. Total recoverable oil associated with the project under secondary waterflood is estimated to be 215.0 e^3m^3 (1,352 Mbbl), resulting in a 2.8% overall recovery factor of total OOIP.

An incremental 112.8 e^3m^3 (710 Mbbl) 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 1.5% recovery factor as a result of secondary EOR implementation.

Technical Studies

The waterflood performance predictions for the proposed Cromer Unit No. 2 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. Historical performance of heritage waterfloods in Daly Unit Nos. 1, 3 & 4 also provided an upper bound for potential.

Internal reviews included detailed analysis of all available open-hole logs; core data; petrophysics; seismic; drilling information; completion information; and production information. Including the data methodology as described in the geology section, the above data was then used to develop a suite of maps and establish reservoir parameters to support the calculation of Cromer Unit No. 2 OOIP (Table 4).

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecast to increase the recovery factor to 2.8% from 1.3%, or approximately double the recovery factor of the primary depletion case. The basis for unitization is to develop the lands in an effective and responsible manner that will be conducive to waterflooding. Unitizing will enable the reservoir to have a higher recovery of oil by allowing the development of additional drilling and injector conversions over time. In addition, Unitizing will facilitate a pressure maintenance scheme, and overall will increase oil production over time.

Unit Name

Tundra proposes that the official name of the Lodgepole Unit shall be Cromer Unit No. 2.

Unit Operator

Tundra Oil and Gas Partnership (Tundra) will be the Operator of record for the Cromer Unit No. 2.

Unitized Zone

The unitized zone to be waterflooded in Cromer Unit No. 2 will be the Lodgepole formation.

Unit Wells

The wells to be included in the proposed Cromer Unit No. 2 are outlined in Table 3 with a listing of their current status.

Unit Lands

The Cromer Unit No. 2 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. 2 will consist of 38 Tracts, based on the 40 acre Legal Sub Divisions (LSD) within the proposed Unit boundary.

The Tract Factor contribution for each of the LSD's within the proposed Cromer Unit No. 2 was calculated as follows:

- 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 OOIP by LSD.
- Tract Factor by LSD is the percentage of Remaining OOIP by LSD as it relates to the total proposed Unit Remaining OOIP.

Tract Factor calculations for 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 Cromer Unit No. 2. Tundra Oil and Gas Partnership holds a 100% WI ownership in all the proposed Tracts.

Tundra Oil and Gas Partnership will have a 100% working interest in the proposed Cromer Unit No. 2.

WATERFLOOD EOR DEVELOPMENT

Waterflood development plans include the drilling of areas not already drilled to a spacing of 40 acres, as well as the drilling of 20 acre horizontal infills. The plan is to produce the infill horizontals for a period of approximately 2-3 years, then convert them to water injection service to provide pressure maintenance and areal sweep to the offset vertical producers. A map of the development plan is included in Figure 5.

WATERFLOOD OPERATING STRATEGY

Water Source

The injection water for the proposed Cromer Unit No. 2 will be supplied from the existing source and injection water system at the Sinclair 3-4-8-29 Battery. All existing injection water is obtained from the Lodgepole formation in the 102/16-32-007-29W1 licensed water source well. Lodgepole water from the 102/16-32 source well is pumped to the main Water Plant at 3-4-8-29W1, filtered, and pumped up to injection system pressure. A diagram of the Daly Sinclair water injection system and new pipeline connection to the proposed Cromer Unit No. 2 project area is shown as Figure 10.

Produced water is not currently used for any water injection in the Tundra-operated Daly Sinclair Units and there are no current plans to use produced water as a source supply for Cromer Unit No. 2.

Injection Wells

Primary production from the original vertical/horizontal producing wells in the proposed Cromer Unit No. 2 has declined significantly from peak rate indicating a need for secondary pressure support.

The new future water injection wells for the proposed Cromer Unit No. 2 will be drilled, cleaned out, and configured downhole for injection as shown in Figure 11. Plans are for the injection wells to be cemented liner horizontals, stimulated via multiple hydraulic fracture treatments to obtain suitable injection rates. 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 thereby limiting the potential for future out-of-zone injection.

The new water injection wells will be placed on injection after a 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 controls. 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. 2 horizontal water injection well rate is forecasted to average 10 – 30 m^3 WPD, based on expected reservoir permeability and pressure and primary performance.

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

Tundra plans an injection conversion schedule to allow for the most expeditious development of the waterflood within the proposed Cromer Unit No. 2, while maximizing reservoir knowledge.

Criteria for Conversion to Water Injection Well

As shown in Figure 5, six water injection wells are required for this proposed unit.

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. 2 project to be developed equitably and efficiently. It also provides the Unit Operator flexibility to manage the reservoir conditions and response to help ensure maximum ultimate recovery of OOIP.

Estimated Fracture Pressure

The fracture pressure for the Lodgepole reservoir is estimated to be 23.9 MPa based on average fracture diagnostic information from a recently completed Lodgepole horizontal.

Reservoir Pressure

No representative initial pressure surveys are available for the proposed Cromer Unit No. 2 project area in the Lodgepole producing zone because almost all of the wells in the area are commingled with the Bakken zone. 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 to inject water for a minimum 2 to 4 year period to re-pressurize the reservoir due to cumulative primary production voidage and pressure depletion to date. The Instantaneous Voidage Replacement Ratio (IVRR) is expected to be approximately 1.25 to 1.75 within the pattern during the fill-up period. As the cumulative voidage replacement ratio (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. 2 EOR response and waterflood surveillance will consist of the following:

- Regular production well rate and WCT testing
- Daily water injection rate and pressure monitoring v. target
- Water injection rate / pressure / time vs cumulative injection plot
- Reservoir pressure surveys as required to establish pressure trends
- Pattern IVRR and 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. 2 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. 2.

Economic Limit / Justification

Due to the initial high capital investment, Tundra does not expect the project to be economic in the short-term using current oil price decks. However, if technically successful, this project will enhance the oil recovery and help prove up the area for EOR developments in the Lodgepole reservoir.

WATER INJECTION FACILITIES

The Cromer Unit No. 2 waterflood operation will utilize the existing Tundra-operated source well supply and water plant (WP) facilities located at the 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 12.

OTHER CONSIDERATIONS

Tundra is requesting approval to continue to produce the vertical wells commingled between the Bakken and Lodgepole zones. The current practice of splitting production between Bakken and Lodgepole using the sulfur content difference will continue to be used. 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 7 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 isolated and abandoned accordingly.

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 Cromer Unit No. 2. 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 Cromer Unit No. 2 Application.

Cromer Unit No. 2 Unitization, and execution of the formal Cromer Unit No. 2 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. 2 Application.

Should the Petroleum Branch have any further questions or require additional information, please contact Justin Robertson at 403.513.1024 or by email at justin.robertson@tundraoilandgas.com.

TUNDRA OIL & GAS PARTNERSHIP

Original Signed by Justin Robertson, P. Eng on June 18th, 2015, in Calgary, AB

Proposed Cromer Unit No. 2

Application for an Enhanced Oil Recovery Waterflood Project

List of Figures

Proposed Cromer Unit No. 2

Application for an Enhanced Oil Recovery Waterflood Project

List of Tables

Proposed Cromer Unit No. 2

Application for an Enhanced Oil Recovery Waterflood Project

List of Appendices

Appendix 1	Cromer Unit No. 2 – Geological Base Map
Appendix 2	Lodgepole Formation Regional Geological Setting Diagram
Appendix 3	Mississippian Lodgepole Stratigraphic Column
Appendix 4A - 4C	Cromer Unit No. 2 A-A’, B-B’, C-C’ Structural Cross-Sections
Appendix 5	Cromer Unit No. 2 Example Petro-physical Evaluation
Appendix 6A - 6E	Cromer Unit No. 2 Permeability-Porosity Crossplots by Member
Appendix 7	Salinity – Temperature – Water Resistivity Plot for Rw Conversion
Appendix 8A - 8B	Permeability-Porosity Crossplots for k-h Estimation
Appendix 9	Cromer Unit No. 2 Lodgepole-Cromer Isopach Map
Appendix 10	Cromer Unit No. 2 Top Lodgepole Reservoir Structure Map
Appendix 11	Cromer Unit No. 2 Bottom Lodgepole Reservoir Structure Map
Appendix 12	Cromer Unit No. 2 Net Lodgepole Reservoir Isopach Map
Appendix 13	Cromer Unit No. 2 Lodgepole Weighted Average Porosity Map
Appendix 14	Cromer Unit No. 2 Lodgepole Reservoir Phi-h Map
Appendix 15	Cromer Unit No. 2 Lodgepole Reservoir k-h Map
Appendix 16	Cromer Unit No. 2 Top Lodgepole Formation Structure

Appendix 17	Cromer Unit No. 2 Lodgepole Salinity Map
Appendix 18	Cromer Unit No. 2 Lodgepole Water Saturation Map
Appendix 19	Cromer Unit No. 2 Average First 12 Months Water Cut Map
Appendix 20	Core Photo Composite of 06-14-009-28W1
Appendix 21	Core Photo and Log Comparison of 04-15-009-28W1
Appendix 22	List of Geology References