April 15, 2013

SUBJECT

Middle Bakken/Three Forks Formations

Bakken – Three Forks B Pool (01 62B)

Daly Sinclair Field, Manitoba

Proposed Unitization of Sec 29-7-28W1

Application for Enhanced Oil Recovery Waterflood Project

INTRODUCTION

The Sinclair portion of the Daly Sinclair Oil Field is located in Ranges 28 and 29 W1 in both Townships 7 and 8. Since discovery in 2004, the main oilfield area was developed with vertical and horizontal wells at 40 acre spacing on Primary Production. Since early 2009, a significant portion of the main oilfield has been Unitized and placed on Secondary Waterflood (WF) Enhanced Oil Recovery (EOR) Production, mainly from the Lyleton A & B members of the Three Forks Formation. Tundra Oil and Gas (Tundra) currently operates and continues to develop Sinclair Units 1, 2, 3, 5, 6, 7 and 8 as shown on Figure 1.

In the eastern part of the Sinclair 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 establish Ewart Unit No. 2 (Sec 29-7-28) 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).

CONCLUSIONS

1. The proposed Ewart Unit No. 2 will include 7 existing producing horizontal wells and 1 vertical observation well, within 16 Legal Sub Divisions (LSD) of the Middle Bakken/Three Forks producing reservoir. The project is located east of the existing Sinclair Unit No. 1 (Figure 2).

2. Total Net Original Oil in Place (OOIP) in Ewart Unit No. 2 has been calculated to be **1817.1** thousand barrels (Mbbl) for an average of **113.5** net Mbbl OOIP per 40 acre LSD.

3. Cumulative production to the end December 2012 from the 7 wells within the proposed Ewart Unit No. 2 project area was 165.6 Mbbl of oil, and 265.4 Mbbl of water, representing an **9.1%** Recovery Factor (RF) of the Net OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary Proved Producing oil reserves in the proposed Ewart Unit No. 2 project area has been calculated to be **260.4** Mbbl, with **94.8** Mbbl remaining as of the end of December 2012.

5. Ultimate oil recovery of the proposed Ewart Unit No. 2 OOIP, under the current Primary Production method, is forecasted to be **14.3%**.

6. Figure 4 shows the production from the Ewart Unit No. 2 which peaked in April 2009 at 260 bbl of oil per day (OPD). As of December 2012, production was 120 bbl OPD, 224 bbl of water per day (WPD) and a 65.1% watercut.

7. In April 2009, production averaged 37.1 bbl OPD per well in Ewart Unit No. 2. As of December 2012, average per well production has declined to 17.1 bbl OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **16.5%** in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Ewart Unit No. 2 has been calculated to be **493.2** Mbbl, with **327.6** Mbbl remaining. An incremental **232.8** Mbbl of proved oil reserves, or **12.8%**, are forecasted to be recovered under the proposed Unitization and Secondary EOR production vs the existing Primary Production method.

9. Total RF under Secondary WF in the proposed Ewart Unit No. 2 is estimated to be **27.1%**.

10. Based on waterflood response in the adjacent main portion of the Sinclair field, 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, have been drilled between existing horizontal producing wells (Figure 5) within the proposed Ewart Unit No. 2, to complete waterflood patterns with effective 20 acre spacing similar to that of Sinclair Unit No. 5.

DISCUSSION

RESOURCE POTENTIAL IN PROPOSED EWART UNIT NO. 2

The proposed Ewart Unit No. 2 project area is located within Township 7, Range 28 W1 of the Daly Sinclair oil field. The proposed Ewart Unit No. 2 currently consists of 7 producing horizontal wells and 1 vertical observation well, within an area covering section 29-7-28W1 (Figure 2). A project area well list complete with recent production statistics is attached as Appendix 19.

Tundra believes that the waterflood response in the adjacent main portion of the Sinclair field 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 in proposed Ewart Unit No. 2 is shown on the type log attached as Appendix 1. The producing sequence in descending order consists of the Upper Bakken Shale, Middle Bakken Siltstone, Lyleton A Siltstone, the Red Shale Marker, Lyleton B Siltstone and the Torquay silty shale. The reservoir units are represented by the Middle Bakken, Lyleton A and Lyleton B Siltstones. The Upper Bakken Shale is a black, organic rich, platy shale which forms the top seal for the underlying Middle Bakken/Lyleton reservoirs. The Red Shale Marker is a very fine grained, dolomitic siltstone which effectively forms an aquitard between the Lyleton A and B reservoirs. A structural cross-section showing the stratigraphy of Ewart Unit No. 2 as it relates to the surrounding area is attached as Appendix 2. This line of section is shown on each of the maps attached as appendices and runs East-West approximately through the mid-point of the proposed Ewart Unit No. 2. The most easterly wells on the section, 10-30-007-28W1M and 09-30-007-28W1M are located in Sinclair Unit 2. Correlation of these wells with the wells in the proposed Ewart Unit No. 2 show that the same reservoir units are present in both units and are continuous and correlative between Sinclair Unit 2 and the proposed Ewart Unit No. 2 but the Lyleton A is thinned by erosion in Ewart Unit No. 2.

Sedimentology:

The Middle Bakken reservoir consists of fine to coarse grained grey siltstone to fine sandstone which may be subdivided on the basis of lithologic characteristics into upper and lower units. The upper portion is very often heavily bioturbated and is generally non-reservoir. These bioturbated beds often contain an impoverished fauna consisting of well worn brachiopod, coral and occasional crinoid fragments suggesting deposition in a marginal marine environment. The lower part of the Middle Bakken is generally finely laminated with alternating light and dark laminations with occasional bioturbation. Reservoir quality is highly variable within the Unit area. Over most of the area of proposed Ewart Unit No. 2, the Middle Bakken is generally about 1-3 m thick, thickening up to greater than 4 m towards the SE of corner of Ewart Unit No. 2 where the underlying Lyleton A is thinned by erosion (Appendix 3).

The Lyleton A reservoir within the area of proposed Ewart Unit No. 2 consists of buff to tan medium to coarse siltstone (occasionally fine sandstone) made up of quartz, feldspar and detrital dolomite with minor mica and clay mostly in the form of clay clasts or chips. Clays do not generally occur as pore filling material, but rather as discrete grains within the siltstone. In the area of proposed Ewart Unit No. 2 the upper part of the Lyleton A is removed by pre-Middle Bakken erosion. The preserved lower part of the Lyleton A generally shows a greater proportion of the grey-green fine-grained siltstone than the Upper and is generally a poorer reservoir. It also tends to exhibit greater amounts of haloturbation which produces a pseudobreccia composed of siltstone clasts in a finer grained grey-green very fine grained siltstone matrix. Because of the fine grained matrix in this pseudobreccia the connectivity between the clasts is much lower than the bedded siltstone and the Lower part of the Lyleton A is generally a poorer reservoir than the Upper part of the Lyleton A. Within the area of proposed Ewart Unit No. 2, the Lyleton A is generally between 1 and 3 m thick (Appendix 4).

The Red Shale Marker forms an aquitard between the Lyleton A and B reservoirs and consists of brick red dolomitic siltstones which are highly water soluble. The Red Shale Marker is generally between 3 and 4 m thick with the area of Unit 2 (Appendix 5).

The Lyleton B in proposed Ewart Unit No. 2 is similar to the Lyleton A, but with thinner beds of siltstone interbedded with darker grey-green very fine grained siltstone which is generally non-reservoir. The siltstone beds display variable reservoir quality, but the quality is generally less than that in the Lyleton A. The Lyleton B is generally between 4.5 and 6 m thick in proposed Ewart Unit No. 2 and shows no evidence of erosional thinning within the Unit area (Appendix 6).

The Torquay (Three Forks) forms the base of the proposed Ewart Unit No. 2 reservoir sequence and is a brick red dolomitic fine to very fine siltstone similar to the Red Shale Marker and forms a good basal seal to the Lyleton B reservoir.

Structure:

Structure contour maps are provided for the top of each major reservoir and non-reservoir unit. The structure on the top of the Upper Bakken shale within the area of proposed Ewart Unit No. 2 shows a structural low along the eastern side of Section 29 (Appendix 7). This low is most likely the result of post Upper Bakken dissolution of the underlying Prairie Evaporites. Solution lows such as this are common in the Sinclair-Daly area and represent potential hazards when drilling and completing horizontal injector wells 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 in any significant way (see cross-section Appendix 1). This low is also evident on the Middle Bakken, Lyleton A, Red Shale Marker, Lyleton B and Torquay (Three Forks) structure maps (Appendices 8 – 12) showing that the structural low post-dates all of the stratigraphic units in proposed Ewart Unit No. 2.

No direct evidence of natural faulting is noted from either proprietary seismic data or well/production data in the vicinity of the proposed Ewart Unit No. 2 area, although the presence of such faults/fractures may be interpreted by the presence of salt dissolution lows. Whether or not such fracture systems provide conduits for vertical flow across the vertical flow barriers such as the Red Shale Marker is also indeterminate, although if such flow were possible it is highly likely the overlying Upper Bakken shale would have been compromised and the Sinclair hydrocarbon system would have been breached before the emplacement of the hydrocarbon charge which occurred much later than the salt dissolution. Any breaches in the Upper Bakken top seal must have been effectively sealed before this event and it is likely that any breaches in the Red Shale Marker would also have been sealed as well as there are hydrocarbons trapped in the Lyleton B reservoir at least as far downdip as in the Lyleton A and Middle Bakken reservoirs.

Reservoir Continuity:

Lateral continuity of the reservoir units is an essential requirement of a successful waterflood and as demonstrated by the cross-section (Appendix 2) and the isopach maps, the lateral continuity of the reservoir units within proposed Ewart Unit No. 2 is very good. None of the major reservoir units can be shown to be depositionally thin laterally and where thinning does occur it can be demonstrated to be by pre-Middle Bakken erosion removing the underlying sequences from the top down. Vertical continuity between the Middle Bakken and underlying Lyleton A reservoir is also good as there is no evidence of an intervening aquitard between these units. In fact it is often difficult even in core to pick the unconformity surface between these units. The vertical continuity between the Lyleton A and Lyleton B reservoirs is obviously non-existent due to the presence of the Red Shale Marker which represents an effective barrier to vertical flow (Appendix 1 and 2).

Observation well 10-29-7-28W1

An observation well drilled at 10-29-7-28W1 was drilled (rig released Nov 30, 2011) and cored to provide reservoir characterization information. It was left openhole and has been equipped with continuous pressure and temperature monitoring. Gauges are set in the Lower Lodgepole, Middle Bakken and Lyleton B reservoirs, separated by open-hole packers. Unfortunately the upper two gauges did not achieve pressure isolation from each other and the resulting data is not reliable. Pressure isolation was achieved for the Lyleton B zone and virgin or close to virgin pressure was initially measured (Appendix 25). The adjacent horizontal injector well 02/05-29 was put on production July 2012, and since then until contact with the bottomhole gauge was lost on December 18, 2012, no significant change in pressure in 10-29-7-28W1 has been observed. Given the fracture stimulated completion on 02/09-29, the closest producer this may suggest that less vertical conductivity may have been established in the area of the induced fractures. Continued observation of the pressure at the 10-29 will be warranted to help with ongoing reservoir surveillance. However unfortunately gauge connectivity will likely not be re-established until July 2013. Pressure depletion may have now occurred from drainage at 02/09-29, but that is as yet unknown.

Reservoir Quality:

Porosity (Phi-h in por*m) and permeability (k-h in mD*m) maps for the three reservoir units are provided (Appendices 13-15, 18). These maps are generated 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 1.0 md permeability cutoff for the Lyleton “A” zone and a 0.5 millidarcy (mD) permeability cutoff for the Lyleton “B” and Mid-Bakken zones. This method was used by GLJ Petroleum Consultants (GLJ) to calculate the OOIP. It should be noted that GLJ has historically used a 1.0 millidarcy cutoff for the Lyleton “B” and Mid-Bakken zones, however, production performance and corresponding recovery factors determined for Section 29-7-28W1 under primary depletion necessitated the use of a 0.5 millidarcy cutoff. A 12% porosity cutoff was used for net pay values for the Lyleton “A” zone only.

Comparison of the porosity and permeability data from Sinclair Units 1 and 3 to Ewart Unit No. 2 (Appendix 16) show the reservoir quality is very comparable between the two areas within the units preserved. The slightly lower permeability in Ewart Unit No. 2 is due solely to the removal of the upper part of the Lyleton A reservoir by pre-Middle Bakken erosion.

As can be noted from the Phi-h maps, the bulk of the reservoir in proposed Ewart Unit No. 2 is contained in the Middle Bakken and Lyleton A. Maps of Phi-h and k-h for the Middle Bakken are included as Appendix 18 – Map 4 and Appendix 13, Lyleton A maps as Appendix 18 – Map 2 and Appendix 14, and Lyleton B maps for the Ewart Unit No. 2 area as Appendix 18 – Map 3 and Appendix 15.

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 top of transition and the oil/water contacts are below the lowest contour on any of the attached structure contour maps.

OOIP Estimates

Total volumetric OOIP for the Middle Bakken, Lyleton A, and Lyleton B members of the Three Forks formation, within the proposed Ewart Unit No. 2, has been calculated to be **1817.1** Mbbl. Table 2 within Appendix 18 outlines the proposed Ewart Unit No. 2 volumetric OOIP estimates on an individual LSD basis by formation. Average OOIP by individual LSD was determined to be **113.5** Mbbl for Ewart Unit No. 2. OOIP values were calculated with a 1.0 millidarcy (mD) permeability cutoff for the Lyleton "A" zone and a 0.5 millidarcy (mD) permeability cutoff for the Lyleton "B" and Mid-Bakken zones and a 12% porosity net pay cutoff.

The OOIP values were determined independently by GLJ Petroleum Consultants of Calgary, and a copy of the report is included in Appendix 18.

A listing of Middle Bakken/Three Forks formation rock and fluid properties used to characterize the reservoir are provided in Appendix 17.

Historical Production

A historical group production history plot for the proposed Ewart Unit No. 2 is shown as Figure 4. Oil production commenced from the proposed Unit area in August 2008 and peaked during April 2009 at 260 bbl OPD.

As of December 2012, production was 120 bbl OPD, 224 bbl WPD and a 65.1% watercut.

From peak production in April 2009 to date, oil production is declining at an annual rate of approximately 16.5% under the current Primary Production method.

Proposed Ewart Unit No. 2 Reserves Recovery Profiles and Production Forecasts

The primary waterflood performance predictions for the proposed Ewart Unit No. 2 are based on a recent external evaluation by GLJ Petroleum Consultants (GLJ) and the secondary predictions are based on internal engineering studies performed by the Tundra reservoir engineering group, using Sinclair Unit 1 Section 4-8-28W1 as an analog (Figure 6).

Based on the geological description, primary production decline rate, and waterflood response in the adjacent main portion of the Sinclair field, the Three Forks and Middle Bakken Formations in the project area are believed to be suitable reservoirs for WF EOR operations.

Primary Production Forecast

Cumulative production in the Ewart Unit No. 2 project area, to the end of December 2012, was 165.6 Mbbl of oil, and 265.4 Mbbl of water for a recovery factor of 9.1% of the calculated Net OOIP.

The forecasted primary oil production for the Ewart Unit No. 2 project area is plotted as Figure 7.

All the proposed injection wells are drilled and have been producing since August 2012. These wells are expected to produce for a period of approximately 1 year and then be converted to injectors after unitization approval.

Ultimate Primary Proved Producing oil reserves recovery for Ewart Unit No. 2 has been estimated to be **260.4** Mbbl, or a **14.3**% Recovery Factor (RF) of OOIP. Remaining Producing Primary Reserves has been estimated to be **94.8** Mbbl. The expected production decline and forecasted cumulative oil recovery under continued Primary Production is shown in Figure 8.

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 Pilot WF (Figure 6).

The secondary initial response forecast for the proposed unit was calculated by analogy to Sinclair Units 1-3. These units have shown a response from flooding within 3 months of start of injection. It is forecasted that a peak response, as shown in Figure 7, of approximately 100 bbl OPD occurs in March 2015.

The proposed Ewart Unit No. 2 Secondary Waterflood oil production forecast over time is plotted on Figure 7. Total Proved EOR recoverable reserves in the proposed Ewart Unit No. 2 project under Secondary WF has been estimated at **493.2** Mbbl (Figure 8), resulting in a **27.1%** overall RF of calculated Net OOIP.

An incremental **232.8** Mbbl of oil reserves is forecasted, based on a recovery factor estimate using Sinclair Units 1-3 analogy, to be recovered under the proposed Unitization and Secondary EOR production scheme vs. the existing Primary Production method. Incremental Secondary RF is forecasted to be **12.8%** of the calculated OOIP.

Technical Studies

The waterflood performance predictions for the proposed Ewart Unit No. 2, is based on recent geological and engineering studies.

Geological work included internal Tundra and Independent reviews of the available open-hole logs, core data, seismic, and completion information. These were used to develop a suite of geological maps and establish reservoir parameters to support the independent review and calculation of the proposed Ewart Unit No. 2 OOIP (Appendices 1 – 17).

A project area specific Independent Geological review was conducted by GLJ Petroleum Consultants of Calgary and a discussion of the geological considerations and Original Oil-In-Place estimates methodology is described within Appendix 18.

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP from the proposed project area.

Unit Name

Tundra proposes that the official name of the new Unit covering Sec 29-7-28W1 shall be Ewart Unit No. 2.

Unit Operator

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

Unitized Zone

The Unitized zone(s) to be waterflooded in the Ewart Unit No. 2 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 7 horizontal wells and 1 vertical observation well are to be included in the proposed Ewart Unit No. 2 are outlined in Appendix 19.

Unit Lands

The Ewart Unit No. 2 will consist of 1 Section as follows:

Section 29 of Township 7, Range 28, W1M

Ewart Unit No. 2 will consist of 16 LSD. The lands included in the 40 acre tracts are outlined in Appendix 20.

Tract Factors

The proposed Ewart Unit No. 2 will consist of 16 Tracts based on the 40 acre LSD's containing the existing 7 horizontal producing wells.

Total oil production from the first 90 operating days (2,160 hours) for each LSD/well, and the OOIP by LSD/well, were used to determine the proposed Unit tract factors. Both 90 day production volume and OOIP each received an equal 50% weighting in calculating overall individual Tract Factors.

Tract Factor calculations for all individual LSD's based on the above methodology are outlined within Appendix 21.

Working Interest Owners

Appendix 20 also outlines the working interest (WI) for each recommended Tract within the proposed Ewart Unit No. 2. Tundra Oil and Gas Partnership holds a 100% WI ownership in all the proposed Tracts. The Crown is the lessor.

Tundra Oil and Gas Partnership will have a 100% WI in the proposed Ewart Unit No. 2.

WATERFLOOD EOR DEVELOPMENT

Three (3) future horizontal injection wells have been drilled between the existing horizontal producing wells as shown in Figure 5, completing an effective 20 acre line drive waterflood pattern within Ewart Unit No. 2.

Primary production from the original horizontal producing wells in the proposed Ewart Unit No. 2 has declined significantly from peak rate indicating a need for secondary pressure support. However, through the process of developing similar waterfloods, Tundra has measured a significant variation in reservoir pressure depletion by the existing primary producing wells. Placing new horizontal wells immediately on water injection in areas without significant reservoir pressure depletion has been problematic in similar low permeability formations. The following conditions have been observed , without injector conditioning, which Tundra believes negatively impact the ultimate total recovery factor of OOIP:

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

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

Estimated Fracture Pressure

Completion data from the existing producing wells within the project area indicate an actual fracture pressure gradient range of 18.0 to 21.0 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 these values due to expected reservoir pressure depletion.

Waterflood Operating Strategy

Water Source and Injection Wells

The injection water for the proposed Ewart Unit No. 2 will be supplied from the existing Sinclair Units 1-8 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 Ewart Unit No. 2 project area injection wells is shown as Figure 12.

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 Ewart Unit No. 2.

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.

The water injection wells for the proposed Ewart Unit No. 2 have been drilled, are currently producing and plans are in progress to re-configure the wells for downhole injection after approval for waterflood has been received. The horizontal injection wells have been stimulated by multiple hydraulic fracture treatments to obtain suitable injection rates in either an open-hole (Figure 9a) or cemented liner (Figure 9b) completion. 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 (Figure 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 Ewart Unit No. 2 horizontal water injection well rates are estimated in Appendix 25.

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 Ewart Unit No. 2, while maximizing reservoir knowledge. As a result one injector will be converted on approval with the others following on a staggered basis (similar to the conversion schedule of Sinclair Unit No. 5).

Criteria for Conversion to Water Injection Well

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 Ewart Unit No. 2 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.

Reservoir Pressure

The current estimated reservoir pressure for proposed Ewart Unit No. 2 is in the range of 2,000 – 5,000 kPa. Pressures measured in the newly drilled wells are detailed in Appendix 25. All measured pressures are within the Middle Bakken, Lyleton A zones.

Waterflood Surveillance and Optimization

Ewart 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 vs target
- Water injection rate/pressure/time vs. cumulative injection plot
- Reservoir pressure surveys as required to establish pressure trends
- Pattern VRR
- Potential use of chemical tracers to track water injector/producer responses

- Use of some or all of: Water Oil Ratio (WOR) trends, Log WOR vs Cum Oil, Hydrocarbon Pore Volumes Injected, Conformance Plots

The above surveillance methods will provide an ever increasing understanding of reservoir performance, and provide data to continually control and optimize the Ewart 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 Ewart Unit No. 2.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Ewart Unit No. 2 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 Ewart Unit No. 2 waterflood operation will utilize the existing Tundra operated source well supply and water plant (WP) facilities located at 3-4-8-29 W1M which supplies the existing Sinclair Units.

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Figure 11.

Notification of Mineral and Surface Rights Owners

Tundra sent out notification letters to all mineral rights and surface rights owners of this proposed EOR project and formation of Ewart Unit No. 2 on March 20, 2013. Copies of the notices and proof of service, to all surface and mineral rights owners are attached as Appendices 22-24.

Ewart Unit No. 2 Unitization, and execution of the formal Ewart Unit No. 2 Agreement by affected Mineral Owners, is expected during Q2. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Ewart Unit No. 2 Application.

TUNDRA OIL & GAS PARTNERSHIP

Calgary, AB