October 25, 2013

SUBJECT

Bakken Formation

Daly Sinclair – Bakken-Three Forks B (01 62B)

Daly Sinclair Field, Manitoba

Proposed Unitization of Daly Unit No. 7 – S/2 22-9-29W1

Application for Enhanced Oil Recovery Waterflood Project - Daly Unit No. 7

INTRODUCTION

The Daly portion of the Daly Sinclair Oilfield is located in Townships 8, 9, 10 and 11, of Ranges 27, 28 & 29 WPM (Figure 1). Within the Daly oilfield, most Bakken reservoirs have been developed with vertical producing wells on Primary Production and 40 acre spacing. Horizontal producing wells have recently been drilled by Tundra Oil and Gas (Tundra) in the southern part of the Daly field. In addition, most vertical wells are commingled between the Lodgepole and Bakken zones.

Within the area, 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 Oil and Gas Partnership (Tundra) to establish Daly Unit No. 7 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 an existing designated 01-62B Bakken-Three Forks B Pool of the Daly Sinclair Oilfield (Figure 3).

CONCLUSIONS

1. The proposed Daly Unit No. 7 will include 7 producing wells within a ½ section of the Bakken producing reservoir. The project is located in the southern end of the Daly field in Section 22-9-29 W1 (Figure 1).

2. Total Original Oil in Place (OOIP) in the project area has been calculated to be **3,288,224** bbls (522,786 m^3) for an average of ~ 411,000 gross bbls OOIP per 40 acre LSD. OOIP values were calculated using a 12% limestone porosity and 0.1 mD permeability cutoff.

3. Cumulative production to the end of June 2013 from the 8 wells within the proposed Daly Unit No. 7 project area was 178,704 bbls (28,398 m^3) of oil and 142,158 bbls (22,590 m^3) of water, representing a **5.4%** Recovery Factor (RF) of the calculated gross OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary producing oil reserves in the proposed Daly Unit No. 7 project area has been estimated to be **228,000** bbls (36,249 m^3), with **49,296** bbls (7,837 m^3) remaining as of the end of June 2013.

5. Ultimate oil recovery of the proposed Daly Unit No. 7 gross OOIP, under the current Primary production method, is forecasted to be **6.9%**.

6. Figure 4 shows the production from the Daly Unit No. 7 area peaked during September 2003 at 103.98 bbls of oil per day (OPD) (16.52 m^3/d). As of June 2013, production was 20.96 bbls OPD (3.3 m^3/d), 97.73 bbls water per day (WPD) (15.53 m^3/d) and an 82.34% watercut (WCUT).

7. In September 2003, production averaged 14.85 bbls OPD per well in Daly Unit No. 7. As of June 2013, average per well production has declined to 3.49 bbls OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **14.2%** in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Daly Unit No. 7 has been estimated to be **328,000** bbls (52,148 m^3). An incremental **100,000** bbls (15,899 m^3) of proved oil reserves 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 Daly Unit No. 7 is estimated to be **10.0%**.

10. Based on waterflood response in the adjacent main portion of the Sinclair field, the Bakken formation in the proposed project area is believed to be suitable for WF EOR operations.

11. Proposed future horizontal injector, with multi-stage hydraulic fractures, will be drilled between existing vertical producing wells (Figure 5) within the proposed Daly Unit No. 7, to complete waterflood patterns with effective 20 acre spacing similar to that of Sinclair Unit No. 1.

12. The proposed Lodgepole Daly Unit No. 6 will be unitized commingled with the proposed Bakken Daly Unit No. 7. The production will 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 Daly Unit No. 7 project area is located entirely within Township 9, Range 29 W1 of the Daly oil field (Figure 1). The proposed Daly Unit No. 7 currently consists of 7 producing Bakken vertical wells within the south ½ of Section 22 (Figure 2). A project area well list is attached as Table 3.

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

Geology

Stratigraphy:

The stratigraphy of the reservoir section in Daly Unit No. 7 is shown in cross-sections A - A' and B - B' (attached as Appendix 1 and 2, respectively). Both cross-sections run from west to east. The producing sequence from youngest to oldest is: the Upper Bakken Shale, the Middle Bakken fine grained sand/siltstone, the Lyleton 'A' siltstone, the Lyleton (or 'Red') shale, the Lyleton 'B' siltstone, and the Lyleton 'C' silty shale. This sequence is unconformably overlain by the Mississippian Lodgepole Formation and unconformably underlain by the Devonian Birdbear Formation.

Within the sequence, the Mississippian Middle Bakken unconformably overlies the Devonian Three Forks Group (the Lyleton Shale, Lyleton 'B', and Lyleton 'C') and the Three Forks group thins towards the east. The Lyleton 'A' subcrops on the very eastern edge of the unit and the Lyleton Shale subcrops midway through Daly Unit No. 7 resulting in the Middle Bakken lying directly on top of the Lyleton 'B' on the eastern half of the unit (please refer to Appendix 3 – Three Forks Subcrop Edges Map*)*.

The main productive zone is considered to be the Middle Bakken, however the underlying Lyleton 'B' is also very productive in the area and should be considered in the total original oil-in-place (OOIP).

Sedimentology:

The Middle Bakken reservoir consists of fine to coarse grained siltstone to sandstone (often tan colored when oil stained). It can be divided into two units – the upper Middle Bakken and the lower Middle Bakken. The upper Middle Bakken is about 0.5 – 1m thick in the Daly Unit No. 7 area and is mainly considered non-reservoir. It is composed of heavily bioturbated grey siltstone with small brachiopod shells and the occasional crinoid and coral fragments. Pyrite nodules are common. The environmental interpretation of the upper Middle Bakken is an offshore transition/lower shoreface.

The lower Middle Bakken consists of finely laminated grey and tan colored siltstone and fine grained sandstone interbeds with occasional bioturbation. Where there is a higher sand content, bioturbation is rare. The environmental interpretation of the lower Middle Bakken is of a tidal bar. This is the main reservoir unit of the Middle Bakken and ranges from 1.7 to 3.0 meters thick in Daly Unit No. 7. West of Daly Unit No. 7 and past the Lyleton 'A' subcrop edge in the immediate area, the lower Middle Bakken thins to nothing.

The Lyleton Shale is composed of mainly reddish (sometimes green) dolomitic shale and is considered non-reservoir in the area.

The upper Lyleton 'B' reservoir unit is at the top and is composed of ripple-cross laminated dolo-siltstones increasingly interbedded with tight greenish/grey dolomitic shales with depth. The upper Lyleton 'B' is interpreted to have been deposited in a brackish bay type environment.

The Lyleton 'B' is difficult to define and characterized petro-physically, so it has been mapped by counting pay where the spontaneous potential logs and resistivity logs are greater than that of the underlying (and overlying when the Lyleton Shale is present) shale, and by comparing the logs to the closest cored Lyleton 'B' at 10-15-9-29W1. The upper Lyleton 'B' pay is considered to range from 1.3 to 2.5 meters in the Daly Unit No. 7 area.

The mid to lower Lyleton 'B' and underlying Lyleton 'C' of the Three Forks Group are often called the 'Torquay' Formation. They are generally brick red, light green, and light brown and are mainly composed of very fine dolomitic siltstones and shales and are considered non-reservoir. The lower Lyleton 'B' and 'C' are interpreted to have been deposited in a sabkha environment.

Structure:

Appendix 4 is a Top Middle Bakken Subsea structure map. No other structure maps are provided because the strata of the Upper Bakken Shale and underlying units basically layer cake over each other in the small area.

Structure generally rises towards the north – northeast and descends towards the south – southwest in the area. There is only 3m elevation change between the wells in the proposed unit.

Reservoir Continuity:

The geological cross-sections (Appendix 1 and 2), the Middle Bakken Net Pay map (Appendix 5*),* and the Lyleton 'B' Net Pay map (Appendix 7*)* indicate that there is likely fairly good lateral reservoir continuity in the Middle Bakken and Lyleton 'B'. Vertical continuity within and between the Middle Bakken and the Lyleton 'B' are unlikely due to their heterolithic depositional environments but may be enhanced due to the nature of horizontal drilling and possible fracturing later in the life cycle of the future horizontal wellbores in Daly Unit No 7. This is also supported in Appendix 9 (10-15-9-29W1 Core Analysis) where the horizontal permeability is much higher than the vertical permeability where tested.

Reservoir Quality:

While there are no cored wells within the proposed Daly Unit No. 7, the nearest cored wells at 10-15-9-29W1 and 11-28-9-29W1 appear to correlate very well on logs to the stratigraphy seen in the unit. Please refer to Appendices 8 – 10 for the cross-section and core analyses.

As such, the Middle Bakken likely has good reservoir and high flow capacity Kmax.h values between 14.3 and 35.7 mD.m throughout Daly Unit No. 7. The Lyleton 'B' similarly has good reservoir and high Kmax.h values between 3.8 and 5.0 mD.m. This is supported by the already high cumulative oil production from the two zones in the existing vertical wellbores within the unit.

Fluid Contacts:

The oil/water contact for the Middle Bakken and Lyleton reservoir is estimated from production in the area to be at about -525m subsea structure, with a transition zone (due to the tight nature of the reservoir) up to -490m subsea. Both of these contacts are far south and west of the area mapped for this application.

Gross OOIP Estimates

The total volumetric OOIP for the Middle Bakken and Lyleton B within the proposed Daly Unit No. 7 has been calculated to be 1708.1 MSTB and 1580.14 MSTB respectively.

The OOIP for the Middle Bakken was calculated with the following assumptions:

1) offset core analysis suggests the maximum limestone porosity value on logs approximates the average porosity
2) the Bakken net sand greater than 12% limestone porosity map approximates net pay because the area mapped is far updip from the regional oil/water contact. Regional nearby core shows that the Middle Bakken has over 12% porosity and permeability over 0.1mD with few exceptions in this area.

The OOIP for the Lyleton 'B' was calculated with the following assumptions:

1) the average porosity was extrapolated from the nearest core, and
2) the net pay was interpreted from log analysis integrating SP response, resistivity, PE, and regional knowledge.

A complete listing of Bakken formation rock and fluid properties used to characterize the reservoir and calculate the OOIP estimates are provided in Table 5.

Historical Production

A historical group production history plot for the proposed Daly Unit No. 7 is shown as Figure 4. Oil production commenced from the proposed Unit area in July 2001 and peaked during September 2003 at 103.98 bbls OPD. As of June 2013, production was 20.96 bbls OPD, 97.73 bbls water per day (WPD) and an 82.34% WCUT.

From peak production in September 2003 to date, oil production is declining at an annual rate of approximately **14.2%** under the current Primary Production method.

Reserves Recovery Profiles and Production Forecasts

The primary waterflood performance predictions for the proposed Daly Unit No. 7 are based on oil production decline curve analysis, and the secondary predictions are based on internal engineering analysis performed by the Tundra reservoir engineering group using Sinclair Unit No. 1 as an analogy because it is developed with a similar waterflood pattern design of a horizontal injector with offsetting vertical producers.

Based on the geological description, primary production decline rate, and waterflood response in the adjacent main portion of the Sinclair field, the Bakken formation in the project area is believed to be a suitable reservoir for WF EOR operations.

Primary Production (current)

Cumulative production in the Daly Unit No. 7 project area, to the end of June 2013, was 178,704 bbls of oil and 142,158 bbls of water for a recovery factor of **5.4%** of the calculated gross OOIP.

Remaining Producing Primary Reserves to the end of June 2013 has been estimated to be **49,296** bbls. The expected production decline and forecasted cumulative oil recovery under continued Primary Production is shown in Figure 8a and 8b.

Secondary EOR Production (proposed)

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 proposed Daly Unit No. 7 Secondary Waterflood oil production forecast over time is plotted on Figure 7a. Total Proved EOR recoverable reserves in the proposed Daly Unit No. 7 project under Secondary WF has been estimated at **328,000** bbls, resulting in a **10.0%** overall RF of calculated Net OOIP.

An incremental **100,000** bbls of oil reserves is forecasted, based on a recovery factor estimate using Sinclair Unit 1 as an analogy, to be recovered under the proposed Unitization and Secondary EOR production scheme vs. the existing Primary Production method.

Technical Studies

The waterflood performance predictions for the proposed Daly Unit No. 7 Bakken project are based on internal engineering assessments. Project area specific reservoir and geological parameters were utilized and then compared to Sinclair Unit No. 1 parameters, yielding the WF EOR response observed there to date.

As Tundra has a direct comparison of waterflood performance in Sinclair Unit 1, Tundra does not feel it is crucial to construct a simulation model for this area.

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP from the proposed project area. The basis for unitization is to develop the lands in an effective manner that will be conducive to waterflooding.

Unit Name

Tundra proposes that the official name of the new Unit shall be Daly Unit No. 7.

Unit Operator

Tundra Oil and Gas Partnership (Tundra) will be the Operator of record for Daly Unit No. 7.

Unitized Zone

The unitized zone(s) to be waterflooded in Daly Unit No. 7 will be the Bakken formation.

Unit Wells

The 7 wells to be included in the proposed Daly Unit No. 7 are outlined in Table 3.

Unit Lands

The Daly Unit No. 7 will consist of a ½ Section as follows:

South ½ of Section 22, of Township 9, Range 29, W1M

Daly Unit No. 7 will consist of 8 LSD's. The lands included in the 40 acre tracts are outlined in Table 1.

Tract Factors

The proposed Daly Unit No. 7 will consist of 8 Tracts, based on the 40 acre Legal Sub Divisions (LSD) within the south ½ of Section 22-9-29 W1.

The Tract Factor contribution for each of the LSD's within the proposed Daly Unit No. 7 was calculated as follows:

Total oil production from the first 90 operating days (2,160 hours) for each LSD/well, and the OOIP on an LSD basis, 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. The production from the abandoned producer at 100/01-22-009-29W1 was included in the tract factor and OOIP calculations.

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

Working Interest Owners

Table 1 outlines the working interest % (WI) for each recommended Tract within the proposed Daly Unit No. 7. 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 Daly Unit No. 7.

WATERFLOOD EOR DEVELOPMENT

A new horizontal injection well will be drilled between the existing vertical producing wells (Figure 5). Tundra proposes to drill only 1 new horizontal injection well and create one 20 acre waterflood pattern within Daly Unit No. 7. The very low reservoir permeability within the proposed Daly Unit No. 7 project area poses significant injection rate risks over time which may prove insufficient to replace production voidage. Such uncertainty around the WF EOR project success dictates an initially conservative 1 single pattern development approach.

Waterflood Operating Strategy

Water Source and Injection Wells

The injection water for the proposed Daly Unit No. 7 water will be supplied from the existing Sinclair Unit 1 source and injection water system. All Unit 1 injection water is obtained from the Lodgepole formation in the 102/16-32-7-29 W1 licensed water source well. Lodgepole water from the 102/16-32 source well is pumped to the main Unit 1 Water Plant at 3-4-8-29 W1, filtered, and pumped up to injection system pressure. A diagram of the existing high pressure injection system and required new pipeline to reach the project area is shown as Figure 9.

Tundra does not foresee any compatibility issues between the produced and injection waters based on previous testing.

The new future water injection well for the proposed Daly Unit No. 7 will be drilled, cleaned out, and configured downhole for injection as shown in Figure 10. The horizontal injection well will be stimulated by 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 and thereby limit the potential for future out-of-zone injection.

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

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

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

All new water injection wells will be surface equipped with injection volume metering and rate/pressure 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 Daly Unit No. 7 horizontal water injection well rate is forecasted to average 10 – 25 m^3 WPD, based on expected reservoir permeability and pressure.

Estimated Fracture Gradient

Completion data from the 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.

Reservoir Pressure

No representative initial pressure surveys are available for the proposed Daly Unit No. 7 project area in the Bakken formation because almost all the wells in the area are commingled with the Lodgepole zone. The 102/07-22-009-29W1/2 Bakken zone was shut-in from Feb 10th - Mar 10th, 2013 and was not able to obtain a stabilized pressure. The extremely long shut-in and build-up times required to obtain any possible representative surveys from the producing wells are economically prohibitive. The Lodgepole and Bakken zones in the 102/07-22-009-29W1 commingled well were segregated with a packer before the pressure survey was done. The 102/07-22-009-29W1/2 pressure survey is included as Appendix 11. Tundra will make all attempts to capture a reservoir pressure survey in the proposed horizontal injection well during the completion of the well and prior to injection or production.

Tundra expects to inject water for a minimum 2 – 4 year period to re-pressurize the reservoir due to cumulative primary production voidage and pressure depletion. Initial Voidage Replacement Ratio (VRR) is expected to be approximately 1.25 to 1.75 within the pattern during the fill up period. As the cumulative VRR approaches 1, target reservoir operating pressure for waterflood operations will be 75 – 90 % of original reservoir pressure.

Waterflood Surveillance and Optimization

Daly Unit No. 7 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 Daly Unit No. 7 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 Daly Unit No. 7.

Economic Justification

Due to the initial high capital investment and the uncertainty of the project's success, Tundra does not expect the project is economic. However, if successful, this project will enhance current recovery and open up a larger area for similar future EOR development.

Wells To Be Converted

No existing producer wells within the proposed Daly Unit No. 7 project are planned for conversion to water injection. One drilled-for-purpose new injection well is planned as described in Waterflood Development.

Water Injection Facilities

The Daly Unit No. 7 waterflood operation will utilize the existing Tundra operated source well supply and water plant (WP) facilities located at 3-4-8-29 W1M. The new injection well will be connected to the existing high pressure water pipeline system supplying Sinclair Unit 1.

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown on Appendix 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 Lodgepole zone (Daly Unit No. 6). Once Tundra is certain of a waterflood response from the Lodgepole, Tundra will then convert the newly drilled (proposed at this time) horizontal Daly (8-21) 8-22-9-29W1 Bakken well into a water injector. By not suspending or abandoning the Bakken zone in the vertical wells once injection in the Lodgepole zone commences, Tundra will ensure that the most optimum utilization of existing wellbores is achieved (reduced ground disturbance).

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 will plan an injection conversion schedule to allow for the most expeditious development of the waterflood within the proposed Daly Unit No. 7, while maximizing reservoir knowledge. Tundra plans to stagger the start of injection between the proposed Daly Unit No. 6 Lodgepole injector and Daly Unit No. 7 Bakken injector to ensure the waterflood response for each zone is distinct and observable (Table 7).

4. In order to minimize potential cross-flow between the Lodgepole and Bakken 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 will notify all mineral rights and surface rights owners of the proposed EOR project and formation of Daly Unit No. 7. 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 Daly Unit No. 7 Application.

Daly Unit No. 7 Unitization, and execution of the formal Daly Unit No. 7 Agreement by affected Mineral Owners, is expected during Q4 2013. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Daly Unit No. 7 Application.

TUNDRA OIL & GAS PARTNERSHIP

Calgary, AB