January 8, 2010

<u>SUBJECT</u>

Middle Bakken Formation / Three Forks Formation

Daly Bakken – Three Forks Pool (01 62B)

Daly Field, Manitoba

Proposed Unitization of Ebor Unit No. 2

Application for Enhanced Oil Recovery Waterflood Project
Ebor Unit No. 2

INTRODUCTION

The Daly oilfield is located in Townships 8, 9, 10 and 11, of Ranges 27, 28 & 29 WPM (see Figure 1). Within the Daly oilfield, most Middle Bakken / Three Forks reservoir has been developed with vertical producing wells on Primary Production and 40 acre spacing. Horizontal producing wells have recently been constructed by Tundra Oil and Gas (Tundra) in the southern part of the Daly field (circled in Figure 2).

Within the area, potential exists for incremental production and reserves from a WF EOR project in the Middle Bakken and/or Three Forks oil reservoirs. The following represents an application by Tundra to establish Ebor Unit No. 2 and attempt a Secondary Waterflood EOR scheme within Middle Bakken / Three Forks formations.

A portion of the proposed project area falls within an existing designated Middle Bakken / Three Forks oil pool 01-62B (Figure 3).

CONCLUSIONS

1. The proposed Ebor Unit No. 2 will include 3 producing wells within a ½ section of the Middle Bakken / Three Forks producing reservoir. The project is located in the southern end of the Daly field in section 11-9-29 W1, NE of Sinclair (Figure 4).

2. Total Original Oil in Place (OOIP) in the project area has been calculated to be 3,598,960 Barrels (bbls) for an average of ~ 450,000 gross bbls OOIP per 40 acre LSD. OOIP values are gross bbls with no net pay cutoffs applied.

3. Cumulative production to end August 2009 from the 3 wells within in the proposed Ebor Unit No. 2 project area was 35,415 bbls of oil, representing a 0.98 % Recovery Factor (RF) of the calculated gross OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary producing oil reserves in the proposed Unit 2 project area has been calculated to be 84,283 bbls, with 48,868 bbls remaining as of the end of August 2009.

5. Ultimate oil recovery of the proposed Unit 2 gross OOIP, under the current Primary production method, is forecasted to be 2.3 %.

6. Production from the proposed area peaked during January 2009 at 111 bbls of oil per day (OPD). As of August 2009, production was 46 bbls OPD, and 70 bbls water per day (WPD), at a relatively stable 60 % watercut (Figure 5).

7. In August 2009, production at the 4-11-9-29 vertical well was 10 bbls OPD (Figure 6), while 3-11 and 5-11-9-29 horizontal wells produced 21 and 14 bbls OPD respectively (Figures 7 & 8).

8. Decline analysis of group primary production data forecasts current total oil declining at an initial annual rate of approx. 35 % in the project area (Figure 9).

9. Although no recent Middle Bakken reservoir pressure surveys are available in the project area, production declines indicate significant primary pressure depletion.

10. Middle Bakken and/or Three Forks Formations in the project area may be potentially acceptable reservoirs for WF EOR operations.

11. Estimated Ultimate Recovery (EUR) of oil reserves under Secondary WF EOR for the proposed Unit 2 has been calculated to be 264,231 bbls, with 228,816 bbls remaining.

12. Ultimate Secondary Waterflood Recovery Factor in the proposed Unit 2 is forecasted to be 7.3 %, or an incremental 5.0 % of gross OOIP over primary production.

13. An incremental 179,948 bbls of oil reserves are forecasted to be recovered under the proposed Unitization and Secondary EOR production vs the existing Primary Production method.

14. A horizontal injector, with multi-stage hydraulic fractures, will be constructed between existing vertical and horizontal producing wells, within the proposed Unit 2, to complete a waterflood pattern with an effective 20 acre spacing (Figure 10).

DISCUSSION

RESOURCE POTENTIAL IN PROPOSED EBOR UNIT 2

The proposed Ebor Unit No. 2 project area is located entirely within Township 9, Range 29 W1 of the Daly oil field (Figure 1). The proposed Unit 2 contains 1 producing vertical well and 2 producing horizontal wells within the south ½ of section 11 (Figure 4).

Within the proposed Unit, potential exists for incremental production and reserves from a WF EOR project the Middle Bakken and/or Three Forks oil reservoirs.

Geology

A stratigraphic cross-section of the Sinclair Middle Bakken formation, and Lyleton B member of the Three Forks formation has been plotted through Section 11 just north of the proposed Unit 2 and is attached as Appendix 1. The cross section provides the evidence of interwell reservoir continuity essential for successful waterflood operations.

Structure maps for the project area based on the top of Middle Bakken, and the top of the Lyleton B member of the Three Forks formation are attached as Appendices 2 and 3 respectively.

Porosity (Phi-h in por*m) and Permeability (k-h in mD*m) maps for the Middle Bakken are included as Appendices 4 and 5. Lyleton B member of the Three Forks formation Porosity (Phi-h in por*m) and Permeability (k-h in mD*m) maps for the project area are also included as Appendices 6 and 7.

Gross OOIP Estimates

Total volumetric OOIP for the Middle Bakken, and Lyleton B member of the Three Forks formation, within the proposed Ebor Unit No. 2 area, has been estimated at 3,598,960 bbls. Appendix 8 outlines the Unit 2 gross volumetric OOIP estimates on an individual LSD basis with no net pay cutoffs applied. Average OOIP by individual LSD was determined to be 450,000 bbls.

A complete listing of Middle Bakken / Three Forks formation rock and fluid properties used to characterize the reservoir and calculate the OOIP estimates are provided in Table 1.

The gross OOIP values presented in Appendix 8 were determined internally by Tundra.

Historical Production

A historical group production history plot for the proposed Ebor Unit No. 2 is shown as Figure 5. Oil production commenced from the proposed Unit area in August 2007 and peaked during January 2009 at 111 bbls OPD. As of August 2009, production was 46 bbls OPD and 69.5 bbls WPD, at a relatively stable 60 % watercut (WCT).

Individual history plots for the 3 project producing wells at 4-11, 3-11, and 5-11-9-29 W1 are shown as Figures 6, 7, and 8 respectively.

From peak production in January 2009 to date, oil production is declining at annual rate of approx. 35 % under the current Primary Production method.

Unit 2 Reserves Recovery Profiles and Production Forecasts

Primary Production (current)

Cumulative production in the Ebor Unit No. 2 project area, to end August 2009, was 35,417 bbls of oil, and 45,755 bbls of water for a recovery factor of 0.98 % of the gross OOIP.

An incremental 179,948 bbls of oil reserves are forecasted 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 7.3 % of the gross calculated OOIP. Incremental EUR oil reserves recovery for Unit 2 has been estimated to be 5.0 % Recovery Factor (RF) of OOIP (Table 2).

Remaining Producing Primary Reserves to end August 2009 has been estimated to be 48,868 bbls. The expected production rate and decline under continued Primary Production is shown as the 1 ry Forecast on Figure 9.

Secondary EOR Production (proposed)

The estimated project production rate profile under Secondary WF EOR over time is shown as the 2 ry Forecast on Figure 9.

Total EUR reserves in the proposed Unit 2 project under Secondary WF has been estimated at 264,231 bbls (Table 2), resulting in a 7.3 % RF of gross OOIP. Remaining Secondary Reserves as of end August 2009 has been estimated at 228,816 bbls.

The initial production decline rate is forecasted to be 16 % after peak production.

All reserves recovery estimates were generated internally by Tundra.

Technical Studies

The waterflood performance predictions for the proposed Unit 2 Middle Bakken / Three Forks project are based on internal engineering assessments. Project area specific reservoir and geological parameters were utilized and then compared to Sinclair Unit 1 parameters, yielding the WF EOR response observed there to date.

A numerical reservoir simulation model for the project area is currently being constructed. Tundra anticipates model completion and history matching through the end of Q1 2010. Predictive runs of future production rates from the EOR project are expected by the end of Q3 2010 for comparison to the initial engineering assessments presented.

UNITIZATION and EOR DEVELOPMENT

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 shall be Ebor Unit No. 2.

Unit Operator

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

Unitized Zone

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

Unit Wells

The 3 wells to be included in the proposed Ebor Unit No. 2 are outlined in Table 3.

Unit Lands

The Ebor Unit No. 2 will consist of a ½ Section as follows:

South ½ of Section 11, of Township 9, Range 29, W1M

Ebor Unit No. 2 will consist of 8 LSD's. The lands included in the 40 acre tracts are outlined in Appendix 9.

Tract Factors

The proposed Ebor Unit No. 2 will consist of 8 Tracts, based on the 40 acre Legal Sub Divisions (LSD) within the south ½ of section 11-9-29 W1.

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

- Gross OOIP by LSD, minus cumulative production to date for the LSD as distributed by the LSD specific Production Allocation (PA) % in the applicable producing horizontal or vertical well (to yield Remaining Gross OOIP)
- Tract Factor by LSD = the product of Remaining Gross OOIP by LSD as a % of total proposed Unit Remaining Gross OOIP

Tract Factor calculations for all individual LSD's based on the above methodology are outlined within Appendix 10.

Working Interest Owners

Appendix 9 also outlines the working interest % (WI) for each recommended Tract within the proposed Ebor 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 Ebor Unit No. 2.

Waterflood Development

A new horizontal injection well will be constructed between the existing vertical and horizontal producing wells (Figure 10). However, Tundra proposes to construct only 1 new horizontal injection well and create one 20 ac waterflood pattern within Unit 2. The very low reservoir permeability within the proposed Ebor Unit No. 2 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 Ebor Unit 2 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 11.

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

A new water injection well for the proposed Ebor Unit 2 will be drilled, cleaned out, and configured downhole for injection as shown in Figure 12. 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 Application 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 Unit 2 horizontal water injection well rate is forecasted to average 10 – 25 m3 WPD based on expected reservoir permeability and pressure.

<u>Reservoir Pressure</u>

No recent or representative pressure surveys are currently available for the proposed Unit 2 project area. The extremely long shut in and build up times required to obtain any possible representative surveys from the vertical producing well are economically prohibitive. Proposed Unit 2 project area reservoir pressure has been estimated to range between 3500 – 6000 kPa. A reservoir pressure survey will be recorded in the proposed horizontal injection well prior to completion and injection.

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.

<u>Waterflood Surveillance and Optimization</u>

Unit 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 Unit 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 Unit 2.

Wells to be Converted

No existing producer wells within the proposed Unit 2 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 Ebor 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. 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 Figure 13.

Notification of Mineral and Surface Rights Owners

Tundra is in the process of notifying all mineral rights and surface rights owners of the proposed EOR project and formation of Ebor 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 Unit 2 Application.

Ebor No. 2 Unitization, and execution of the formal Unit 2 Agreement by affected Mineral Owners, is expected during Q1 2010. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Unit 2 Application.

TUNDRA OIL & GAS PARTNERSHIP

Calgary, AB