October 3, 2014

SUBJECT

Middle Bakken/Three Forks Formations

Bakken – Three Forks B Pool (01 62B)

Daly Sinclair Field, Manitoba

Proposed Unitization of Ewart Unit No. 7

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

INTRODUCTION

The Sinclair portion of the Daly Sinclair Oil Field is located in Ranges 28 and 29 W1 in Townships 7 and 8. Since discovery in 2004, the main oilfield area was developed with vertical 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, 8, 10 and 11 and Ewart Units 1, 2, 3 and 4 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. 7 (N/2 9-8-28W1) 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 B pool of the Daly Sinclair Oilfield (Figure 3).

CONCLUSIONS

1. The proposed Ewart Unit No. 7 will include 6 producing vertical wells within 8 Legal Sub Divisions (LSD) of the Middle Bakken/Three Forks producing reservoir. The project is located east of Sinclair Unit No. 3 and Sinclair Unit No. 5 (Figure 2).

2. Total Net Original Oil in Place (OOIP) in the project area has been calculated to be **285.4** E^3m^3 (1795.1 Mbbl) for an average of **35.7** net E^3m^3 OOIP per 40 acre LSD.

3. Cumulative production to the end June 2014 from the 6 vertical wells within the proposed Ewart Unit No. 7 project area was **20.8** E^3m^3 of oil, and **9.3** E^3m^3 of water, representing a **7.3%** Recovery Factor (RF) of the Net OOIP.

4. Estimated Ultimate Recovery (EUR) of Primary Proved Developed Producing oil reserves in the proposed Ewart Unit No. 7 project area has been calculated to be **30.9** E^3m^3 (194.3 Mbbl), with **10.1** E^3m^3 (63.5 Mbbl) remaining as of the end of June 2014. There are 2 undrilled LSDs (9 and 16) within the proposed unit boundary for which 2 vertical wells are planned for in the development plan of the area. The two wells are estimated to add an additional **8.8** E^3m^3 of oil reserves from primary production increasing the total EUR of Primary Proved Reserves within the unit to **39.7** E^3m^3.

5. Ultimate oil recovery based on the existing wells of the proposed Ewart Unit No. 7 OOIP, under the current Primary Production method, is forecasted to be **10.8%**. The addition of 2 vertical wells in the undrilled LSDs (9 and 16) will increase the recovery to **13.9%.**

6. Figure 4 shows the production from the Ewart Unit No. 7 which peaked in September 2006 at 19.7 m^3 of oil per day (OPD). As of June 2014, production was 3.4 m^3 OPD, 1.5 m^3 of water per day (WPD) and a 30.7% watercut.

7. In September 2006, production averaged 4.9 m^3 OPD per well in Ewart Unit No. 7. As of June 2014, average per well production has declined to 0.56 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately **11.2%** in the project area.

8. Estimated Ultimate Recovery (EUR) of proved oil reserves under Secondary WF EOR for the proposed Ewart Unit No. 7 has been calculated to be **71.4** E^3m^3 (449.4 Mbbl), with **50.6** E^3m^3 (318.6 Mbbl) remaining. An incremental **31.7** E^3m^3 (255.1 Mbbl) of proved oil reserves, or **11.1%**, are forecasted to be recovered under the proposed Unitization and Secondary EOR production vs the Primary Production forecast.

9. Total RF under Secondary WF in the proposed Ewart Unit No. 7 is estimated to be **25.0%**.

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. Tundra intends to drill a horizontal injector, with multi-stage hydraulic fractures, as well as two (2) vertical producers, as shown in Figure 5, to complete a waterflood pattern with effective 20 acre spacing similar to that of Sinclair Units No. 1, 2, 3, 6, 7, 8 and Ewart Unit 1.

DISCUSSION

RESOURCE POTENTIAL IN PROPOSED EWART UNIT NO. 7

The proposed Ewart Unit No. 7 project area is located within Township 8, Range 28 W1 of the Daly Sinclair oil field. The proposed Ewart Unit No. 7 currently consists of 6 existing producing vertical wells within an area covering the north half of Section 09-008-28W1 (Figure 2). A project area well list complete with recent production statistics is attached as Table 3.

Tundra believes that the waterflood response in the adjacent main portion of the Sinclair field 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 producing section in Ewart Unit No. 7 is shown on the structural cross section attached as Appendix 1. The line of section runs West to East through the top row of LSDs in Ewart Unit No. 7. The producing section in Ewart Unit No. 7 consists of the Upper Bakken Shale, the Middle Bakken Siltstone, the Lyleton B Siltstone and the Torquay silty shale. The reservoir units are represented by the Middle Bakken, 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 and Lyleton reservoirs. The Torquay (Three Forks) shale forms the base seal for the Middle Bakken and Lyleton B reservoirs.

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 abraded 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 to moderate bioturbation. Reservoir quality is highly variable within the Unit area. Within Ewart Unit No. 7 the Middle Bakken is generally 3.5m to 4.0 m thick (Appendix 3).

The Lyleton B in Ewart Unit No. 7 consists of thinly interbedded tan colored reservoir siltstone and grey-green very fine grained non-reservoir siltstone. The Lyleton B reservoir beds also display variable reservoir quality similar to the Middle Bakken reservoir. The Lyleton B is between 2.5m to 4.3m thick in Ewart Unit No. 7. It shows slight erosional thinning toward the East (Appendix 4).

Structure:

Structure contour maps are provided for the top of both major reservoir unit and for the non-reservoir Torquay (Three Forks) Formation (Appendices 5-7). The structure within the area of

Ewart Unit No. 7 generally consists of a gentle dip to the SE. Structural features such as the low, shown on the Middle Bakken Structure map (Appendix 5) in Section 8, are likely the result of post-Upper Bakken dissolution of the underlying Prairie Evaporites. The low is shifted on the Lyleton B structure map (Appendix 6) suggesting the locus of salt dissolution shifted slightly through time. The apparent lack of such features on the Torquay structure map (Appendix 7) is the result of less structure control. The structure maps are drawn on data from both the vertical and horizontal wells, however, the horizontal wells only infrequently contact the Torquay as they are generally placed in the lower part of the Middle Bakken or upper part of the Lyleton B. Solution lows such as this represent potential hazards when drilling and later completing horizontal injectors 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 (see cross-section Appendix 1).

Reservoir Continuity:

Lateral continuity of the reservoir units is an essential requirement of a successful water flood and as demonstrated by the cross-section (Appendix 1) and the isopach maps, the lateral continuity of the reservoirs in Ewart Unit No. 7 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 upper part of the Lyleton B reservoir. Vertical continuity between the Middle Bakken and underlying Lyleton B reservoir is also good as there is no evidence of an intervening aquitard between these units. In fact it is often difficult on logs to pick the unconformity surface between these units. In the Sinclair units located West of Ewart Unit No. 7 there is a Red Shale interval that intervenes between the MBKKN/Lyleton A reservoir sequence and the Lyleton B reservoir. This aquitard has been removed by pre-Middle Bakken erosion and is absent in the area of Ewart Unit No. 7. The erosional edge of the Red Shale is shown on the Area Cored Wells map for reference (Appendix 12). The Red Shale Marker is present south, southwest and west of the brick red line.

Reservoir Quality:

Permeability (k-h in mD*m) and porosity (phi-h in *por**m) maps for the two main reservoir units are provided. 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 0.5mD cutoff on the permeability and intervals that meet or exceed this criteria are multiplied by the interval thickness and then summed to get the total value for the phi-h or k-h for that particular reservoir unit. This cutoff is similar to the cutoff used to generate the OOIP, but doesn't utilize the 12 percent porosity cutoff since for core data the 0.5mD cutoff effectively removes any porosity less than 12 percent.

It is important to note however that the 0.5mD cutoff effectively ignores a considerable pore volume with permeability between 0.2 and 0.49 md that may contain moveable oil based on NMR log analysis. Maps of k-h and phi-h for the Middle Bakken are included as Appendices 8 and 9, and Lyleton B maps for the Unit area as Appendices 10 and 11.

Fluid Contacts:

The oil/water contact for the Middle Bakken and Lyleton B reservoir is estimated from production to be at about -525m 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 -490m subsea based on production and simulation studies of the reservoir. As mapped these contacts are too far down dip to appear on any of the maps in this application as the minimum structure displayed on the Middle Bakken structure map is about -434m subsea.

OOIP Estimates

OOIP was calculated by Tundra Geologists Barry Larson and Todd Neely. Barry holds a BSc. in Geology from the U of S and has 35 years of industry experience, 19 of which are in the Williston Basin. Todd Neely holds a BSc. in Geology from the University of Manitoba, and has 15 years of industry experience, 4 of which are in the Williston Basin. The dataset used to determine the OOIP values for Ewart Unit No. 7 was originally compiled by Barry Larson. It consists of conventional core analysis of all available core in the Sinclair area. Todd took over Barry's dataset in 2012. Ultimately, OOIP values for Ewart Unit No. 7 were generated by Todd, using Barry's original dataset.

Total volumetric OOIP for the Middle Bakken and Lyleton B within the proposed unit has been calculated to be **285.4 E^3m^3** (1795.1 Mbbl) using Tundra internally created maps. Maps used were generated from core data from 316 wells available in the greater Sinclair area (Appendix 12)

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

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

Tabulated parameters for each LSD from the calculations can be found in Table 4.

OOIP values were calculated using the following volumetric equation:

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

or

$$OOIP(m3) = \frac{A * h * \emptyset * (1 - Sw)}{Bo} * \frac{10{,}000m2}{ha}$$

or

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

where

OOIP	= Original Oil in Place by LSD (Mbbl, or m3)
A	= Area (40acres, or 16.187 hectares, per LSD)
h * Ø	= Net Pay * Porosity, or Phi * h (ft, or m)
Bo	= Formation Volume Factor of Oil (stb/rb, or sm3/rm3)
Sw	= Water Saturation (decimal)

The initial oil formation volume factor was adopted from a PVT taken from the 3-3-8-29 Sinclair Bakken well. The value is a suitable representative to use for the proposed unit because the oil sampled and analyzed from 3-3-8-29 is from the same pool as the Bakken formation within the proposed boundary.

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

Historical Production

A historical group production history plot for the proposed Ewart Unit No. 7 is shown as Figure 4. Oil production commenced from the proposed Unit area in November 2005 and peaked during September 2006 at 19.7 m^3 OPD.

As of June 2014, production was 3.4 m^3 OPD, 1.5 m^3 WPD and had a 30.7% watercut. Oil production is declining at an annual rate of approximately **11.2%** under the current Primary Production method. The field's production rate indicates the need for pressure restoration and maintenance, and waterflooding is deemed to be the most efficient means of re-introducing energy back into the reservoir system and to provide areal sweep between wells.

UNITIZATION

Unitization and implementation of a Waterflood EOR project is forecasted to increase overall recovery of OOIP from the current development by **11.1%**. The basis for unitization is to develop the lands in an effective manner that will be conducive to waterflooding. Unitizing will enable the reservoir to have the greatest recovery possible by allowing the development of additional drilling and injector conversions over time, in order to maintain reservoir pressure and increase oil production.

Unit Name

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

Unit Operator

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

Unitized Zone

The Unitized zone(s) to be waterflooded in the Ewart Unit No. 7 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 6 vertical wells to be included in the proposed Ewart Unit No. 7 are outlined in Table 3.

Unit Lands

Ewart Unit No. 7 will consist of 8 LSDs as follows:

LSD's 9-16 of Section 9 of Township 8, Range 28, W1M.

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

Tract Factors

The proposed Ewart Unit No. 7 will consist of 8 Tracts based on the 40 acre LSD's containing the existing 6 vertical producing wells.

The Tract Factor contribution for each of the LSD's within the proposed Ewart Unit No. 7 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 Table 2.

Working Interest Owners

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

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Ewart 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.

Pre-Production of New Horizontal Injection Wells

Primary production from the vertical producing wells in the proposed Ewart Unit No. 7 has declined significantly from peak rate indicating a need for secondary pressure support. A new horizontal injection well will be drilled between the existing vertical producing wells which will result in an effective 20 acre line drive waterflood pattern within Ewart Unit No. 7 (Figure 5).

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, and has a negative impact on the ultimate total recovery factor of OOIP.

Considering the expected reservoir pressures and reservoir lithology described, Tundra believes an initial period of producing all new horizontal wells prior to placing them on permanent water injection is essential and all Unit mineral owners will benefit.

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

Reserves Recovery Profiles and Production Forecasts

The primary waterflood performance predictions for the proposed Ewart 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.

Primary Production Forecast

Cumulative production to the end of June 2014 from the 6 wells within the proposed Ewart Unit No. 7 project area was **20.8** E^3m^3 of oil, and **9.3** E^3m^3 of water, representing an **7.3%** Recovery Factor (RF) of the calculated Net OOIP.

Ultimate Primary Proved Producing oil reserves recovery for Ewart Unit No. 7 has been estimated to be **30.9** E^3m^3, or a **10.8**% Recovery Factor (RF) of OOIP. Remaining Producing

Primary Reserves has been estimated to be **10.1** E^3m^3 to the end of June 2014. The expected production decline and forecasted cumulative oil recovery under continued Primary Production is shown in Figures 7 and 8.

There are 2 LSDs which currently do not have wells. Tundra plans to drill 2 vertical wells in the undrilled LSDs as shown in Figure 5. Tundra estimates that the 2 new drills should add **8.8** E^3m^3 of reserves from primary production methods thus increasing the total Ultimate Primary oil reserves from the lands within the proposed unit boundary to **39.7** E^3m^3, or a **13.9%** Primary Recovery Factor of OOIP.

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

Tundra will plan an injection conversion schedule to allow for the most expeditious development of the waterflood within the proposed Ewart Unit No. 7, while maximizing reservoir knowledge (Table 6).

<u>Criteria for Conversion to Water Injection Well</u>

One (1) water injection well is required for this proposed unit as shown in Figure 5.

Tundra will monitor the following parameters to assess the best timing for converting 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. 7 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.

<u>Secondary EOR Production Forecast</u>

Secondary Waterflood plots of the expected oil production forecast over time and the expected oil production v. cumulative oil are plotted in Figures 9 and 10, respectively. Total Secondary EUR for the proposed Ewart Unit No. 7 is estimated to be **71.4** E^3m^3 with **50.6** E^3m^3 remaining representing a total secondary recovery factor of **25.0%** for the proposed Unit area. An incremental **31.7** E^3m^3 of oil, or an incremental **11.1%** recovery factor, are forecasted to be recovered under the proposed Unitization and Secondary EOR production scheme vs. primary production at 40 acre spacing.

Estimated Fracture Pressure

Completion data from the existing producing wells within the project area indicate a fracture pressure gradient range of 18.0 to 22.0 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

The injection water for the proposed Ewart Unit No. 7 will be supplied from the existing Sinclair 3-4-8-29W1 Battery source and injection water system. All existing injection water is obtained from the Lodgepole formation in the 102/16-32-7-29W1 licensed water source well. Lodgepole water from the 102/16-32 source well is pumped to the main Sinclair Units Water Plant at 3-4-8-29W1, filtered, and pumped up to injection system pressure. A diagram of the Sinclair water injection system and new pipeline connection to the proposed Ewart Unit No. 7 project area injection wells is shown as Figure 12 and 13.

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. 7.

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

Injection Wells

The new injection well for the proposed Ewart Unit No. 7 will be drilled, cleaned out, produced and then configured for downhole injection after approval for waterflood has been received (Figure 11). The horizontal injection well will be stimulated by multiple hydraulic fracture treatments to obtain suitable injection. 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:

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

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

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

The proposed Ewart Unit No. 7 horizontal water injection well rate is forecasted to average **10 - 25 m^3** WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure

No recent or representative initial pressure surveys are available for the proposed Ewart Unit No. 7 project area in the Bakken formation. 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.

Reservoir Pressure Management during Waterflood

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

Waterflood Surveillance and Optimization

Ewart 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

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. 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 Ewart Unit No. 7.

On Going Reservoir Pressure Surveys

For each openhole horizontal injection well, a measured reservoir pressure will be obtained prior to water injection. Tundra expects useful reservoir pressure data may be obtained from existing vertical wells within the project area after WF start up. These pressures will be reported within the Annual Progress Reports for Ewart Unit No. 7 as per Section 73 of the Drilling and Production Regulation.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Ewart Unit No. 7 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. 7 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 14.

NOTIFICATION OF MINERAL AND SURFACE RIGHTS OWNERS

Tundra is in the process of notifying all mineral rights and surface rights owners of this proposed EOR project and formation of Ewart Unit No. 7. Copies of the notices and proof of service, to all surface and mineral rights owners will be forwarded to the Petroleum Branch when available to complete the Ewart Unit No. 7 Application.

Ewart Unit No. 7 Unitization, and execution of the formal Ewart Unit No. 7 Agreement by affected Mineral Owners, is expected during Q3 2014. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Ewart Unit No. 7 Application.

Should the Petroleum Branch have further questions or require more information, please contact Abhy Pandey at 403.767.1247 or by email at abhy.pandey@tundraoilandgas.com.

TUNDRA OIL & GAS PARTNERSHIP

Original Signed by Abhy Pandey, Exploitation Engineer, October 3, 2014

Proposed Ewart Unit No. 7

Application for Enhanced Oil Recovery Waterflood Project

List of Figures

Figure 1	Daly Field Area Map
Figure 2	Ewart Unit No. 7 Proposed Boundary
Figure 3	Bakken-Three Forks A Pool
Figure 4	Ewart Unit No. 7 Historical Production
Figure 5	Ewart Unit No. 7 Development Plan
Figure 6	Sinclair Pilot Waterflood Section 4 Production Profile
Figure 7	Ewart Unit No. 7 Primary Recovery – Rate v. Time
Figure 8	Ewart Unit No. 7 Primary Recovery – Rate v. Cumulative Oil
Figure 9	Ewart Unit No. 7 Primary + Secondary Recovery – Rate v. Time
Figure 10	Ewart Unit No. 7 Primary + Secondary Recovery – Rate v. Cumulative Oil
Figure 11	Typical Openhole Water Injection Well Downhole Diagram
Figure 12	Sinclair Water Injection System
Figure 13	Typical Water Injection Surface Wellhead Piping Diagram
Figure 14	Planned Corrosion Program

Proposed Ewart Unit No. 7

Application for Enhanced Oil Recovery Waterflood Project

List of Tables

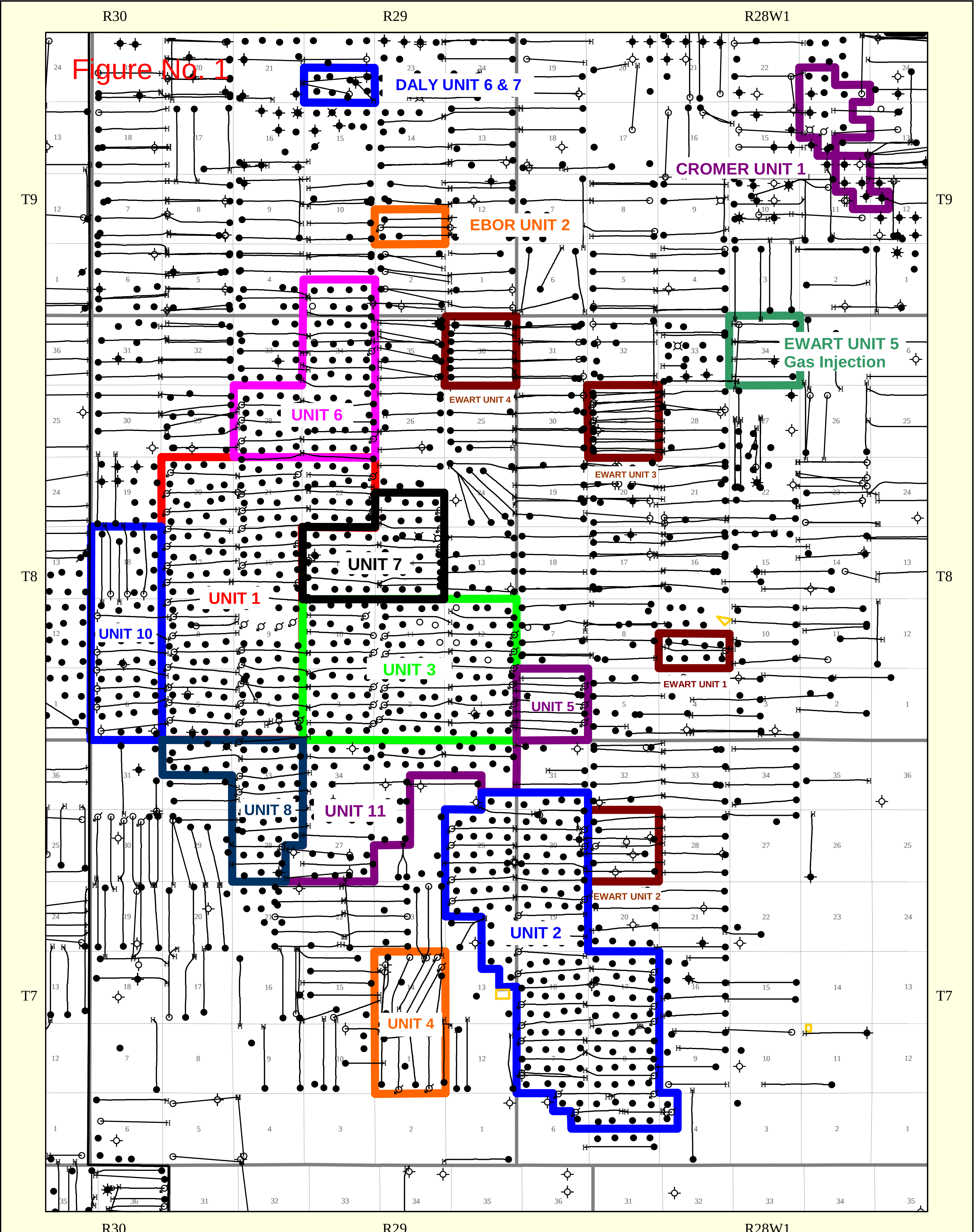
Table 1	Tract Participation
Table 2	Tract Factor Calculation
Table 3	Current Well List and Status
Table 4	Original Oil in Place and Recovery Factors
Table 5	Reservoir and Fluid Properties
Table 6	Ewart Unit No. 7 – Project Schedule

Proposed Ewart Unit No. 7

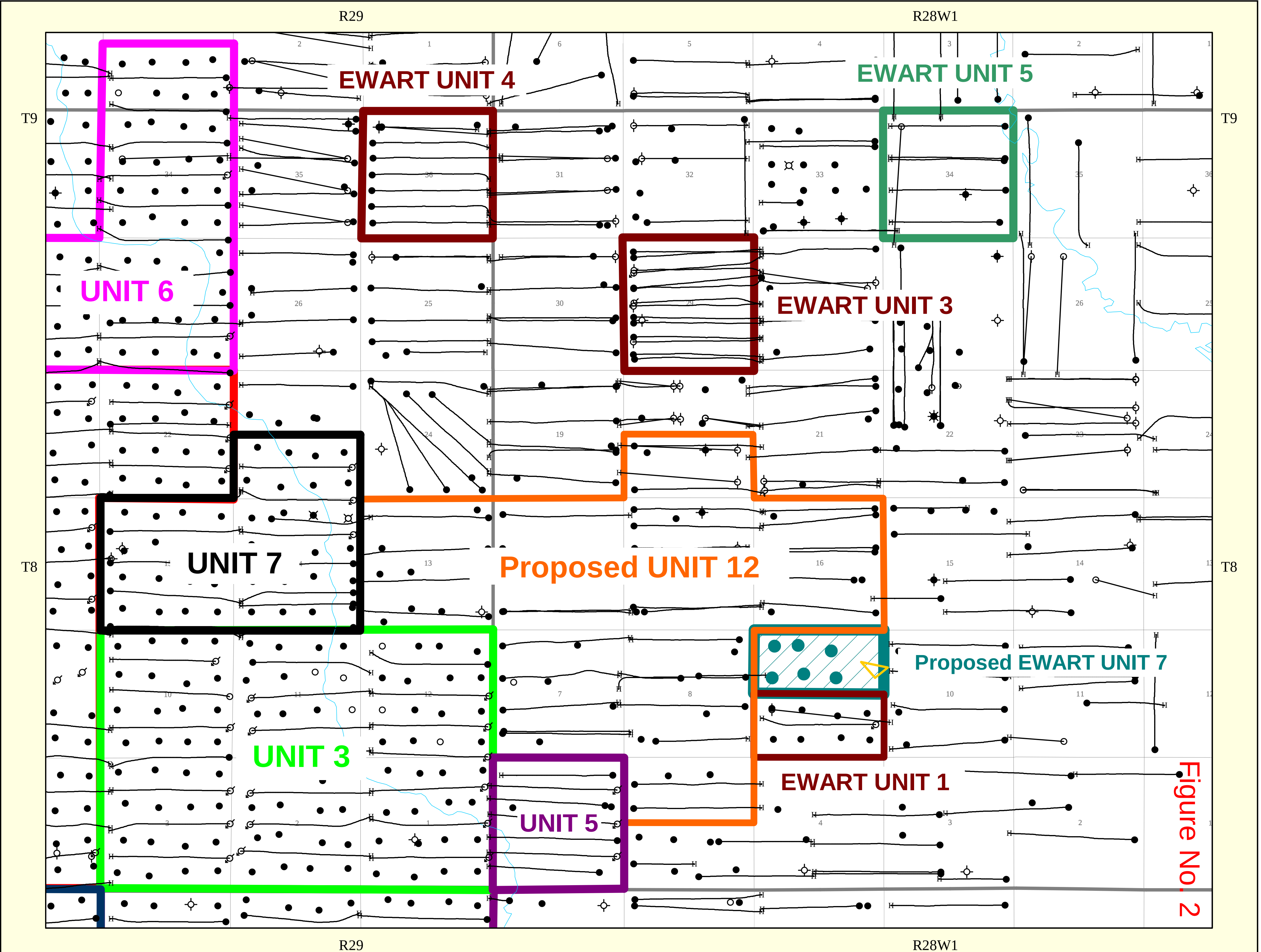
Application for Enhanced Oil Recovery Waterflood Project

List of Appendices

Appendix 1	Structural Cross-Section
Appendix 2	Map of Offsetting Units
Appendix 3	Middle Bakken Isopach
Appendix 4	Lyleton B Isopach
Appendix 5	Middle Bakken Structure
Appendix 6	Lyleton B Structure
Appendix 7	Torquay Structure
Appendix 8	Middle Bakken k*h @ 0.5 mD CO
Appendix 9	Lyleton B k*h @ 0.5 mD CO
Appendix 10	Middle Bakken phi*h @ 0.5 mD CO
Appendix 11	Lyleton B phi*h @ 0.5 mD CO
Appendix 12	Area Cored Wells



File: Tundra Approved Unit Map.MAP Datum: NAD27 Projection: Stereographic Center: N49.64577 W101.29059 Created in AccuMap™, a product of IHS



File: Ewart Unit 7.MAP Datum: NAD27 Projection: Stereographic Center: N49.66760 W101.25724 Created in AccuMap™, a product of IHS

Figure No. 3

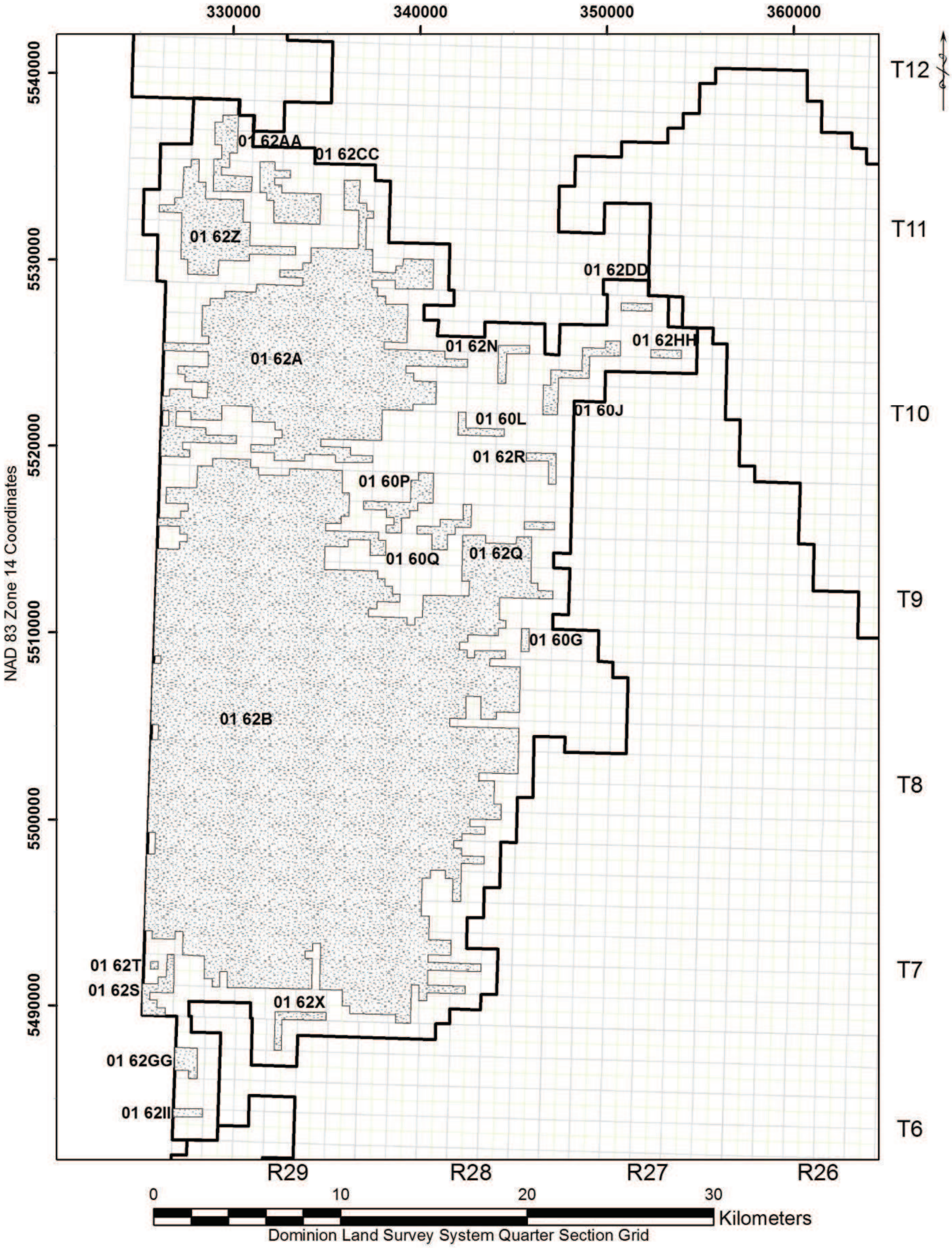


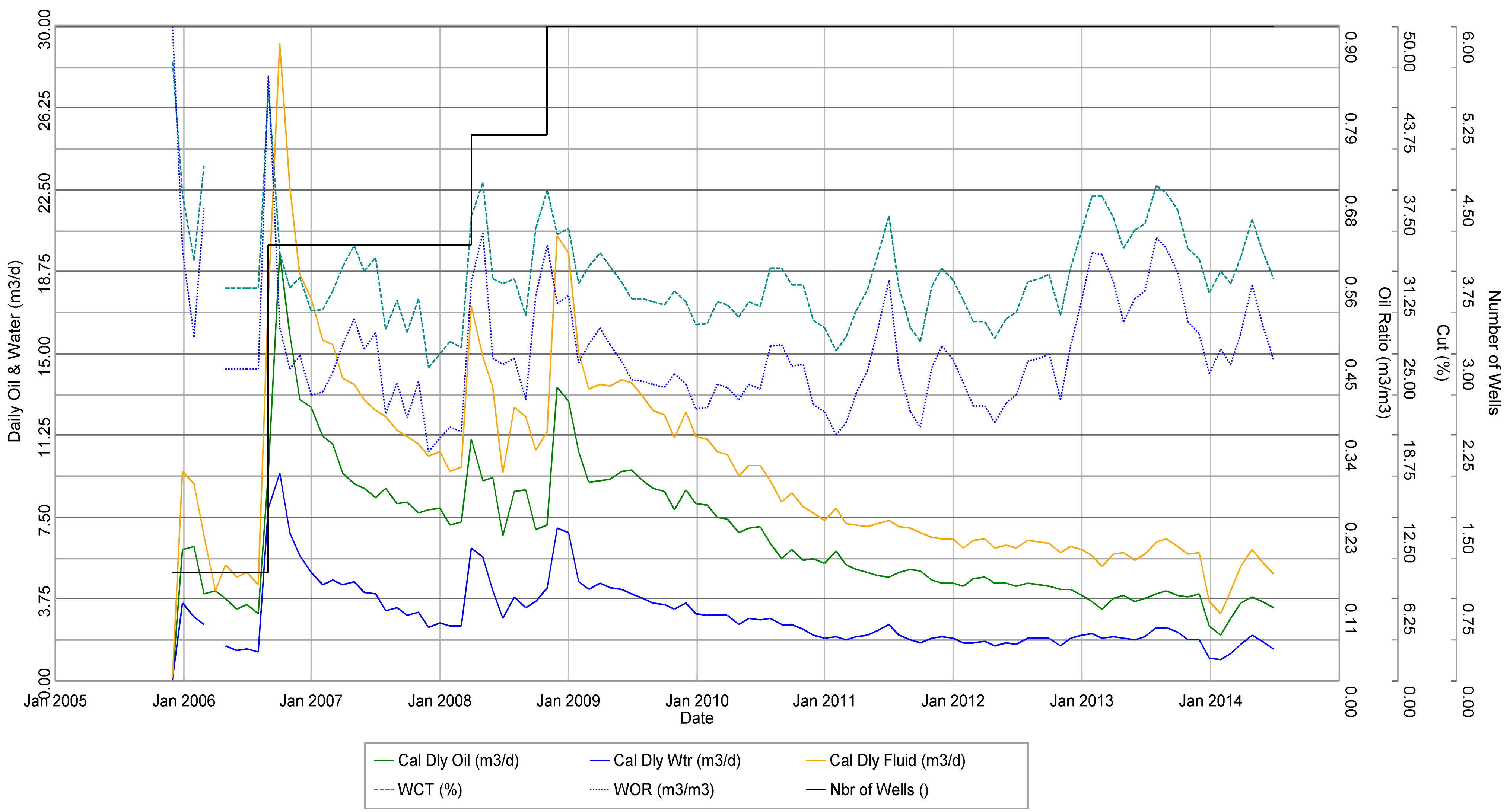
Figure 13 - Daly Sinclair Bakken & Bakken-Three Forks Pools (01 60A - 01 60BB & 01 62A – 01 62II)

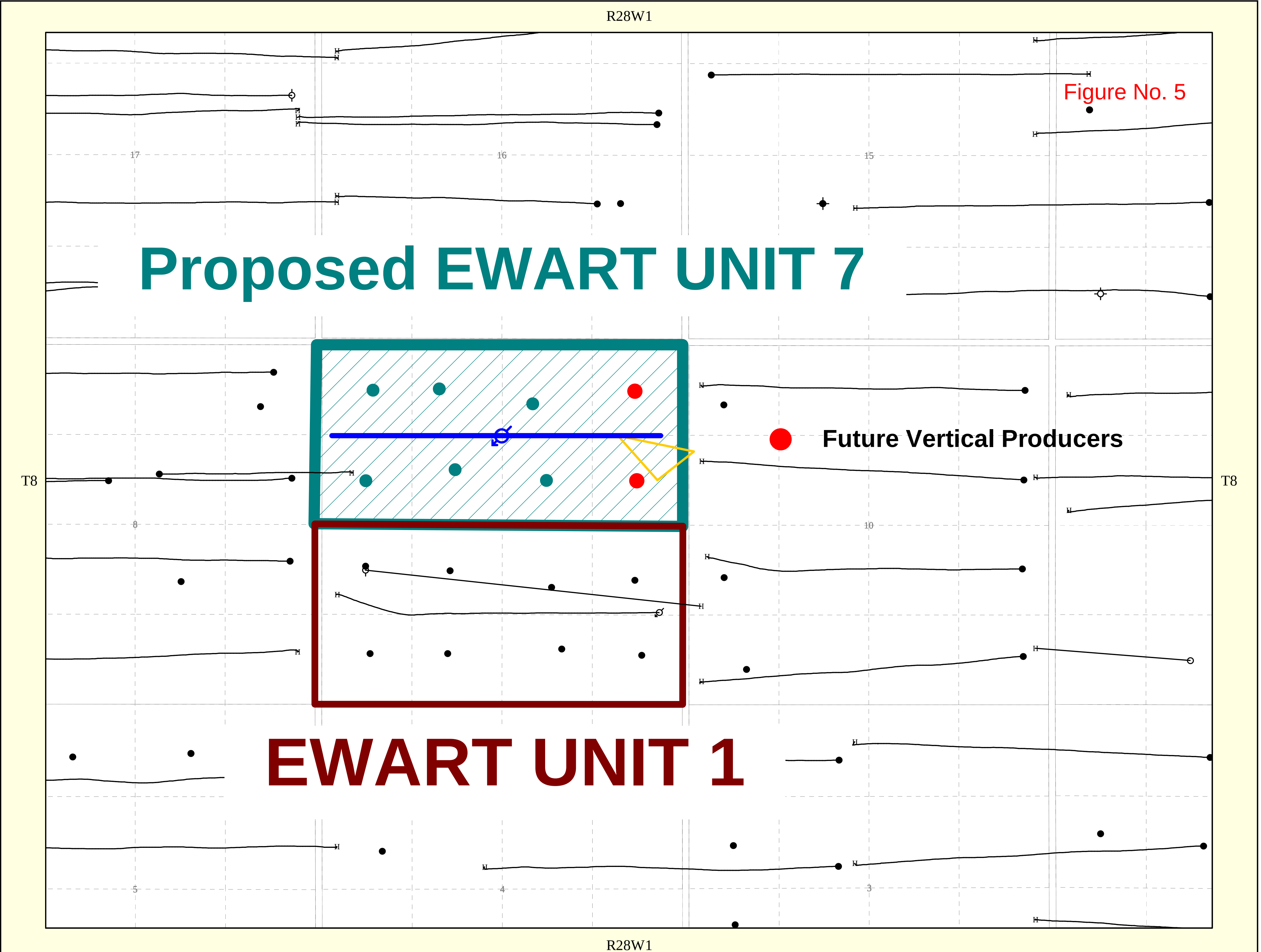
Well Information as of 9/5/2014 - Group Well Report

Figure No. 4

Production Graph

# of Wells:	6	Prod Zone:	BAKKEN; THREEFK	On Prod:	2005-11 to 2014-06
		Field:	DALY (1)	Cum Oil:	20783.4 m3
Fluid:	Oil	Pool Code:	62B	Cum Gas:	0.0 E3m3
Mode:	Producing	Unit Code:	162B01	Cum Wtr:	9291.0 m3





File: Ewart Unit 7 Proposed Injector Datum: NAD27 Projection: Stereographic Center: N49.64518 W101.21602 Created in AccuMap™, a product of IHS

Well Information as of 4/16/2014 - Group Well Report

Sinclair Unit No. 1 Analog

Figure No. 6

Production Graph

# of Wells:	16	Prod Zone:	BAKKEN; TORQUAY	On Prod:	2004-12 to 2014-02
		Field:	DALY (1)	Cum Oil:	145249.5 m3
Fluid:	Oil; Water Injection	Pool Code:	62B	Cum Gas:	0.0 E3m3
Mode:	Producing; Injection	Unit Code:	162B01	Cum Wtr:	22626.7 m3

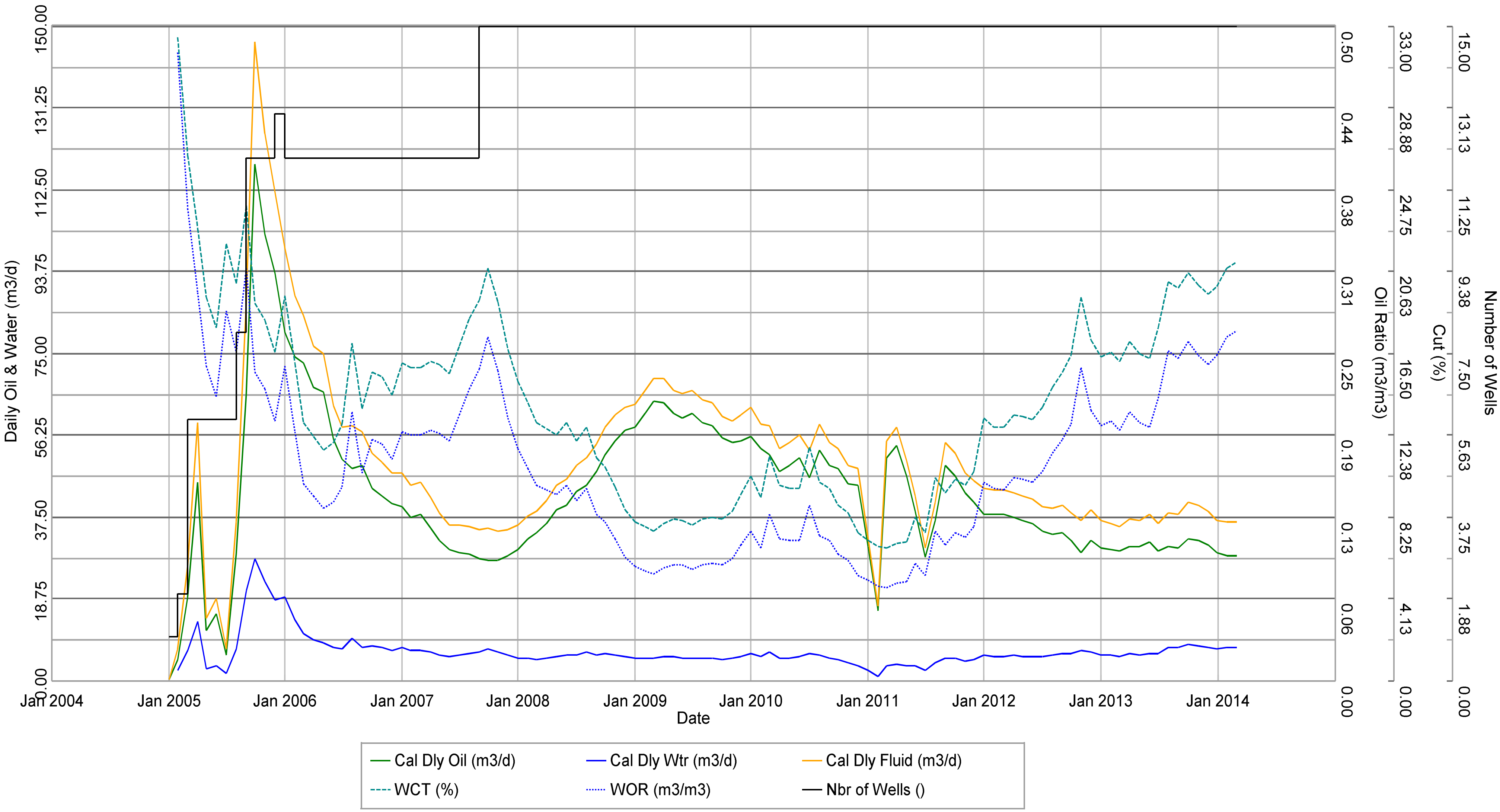
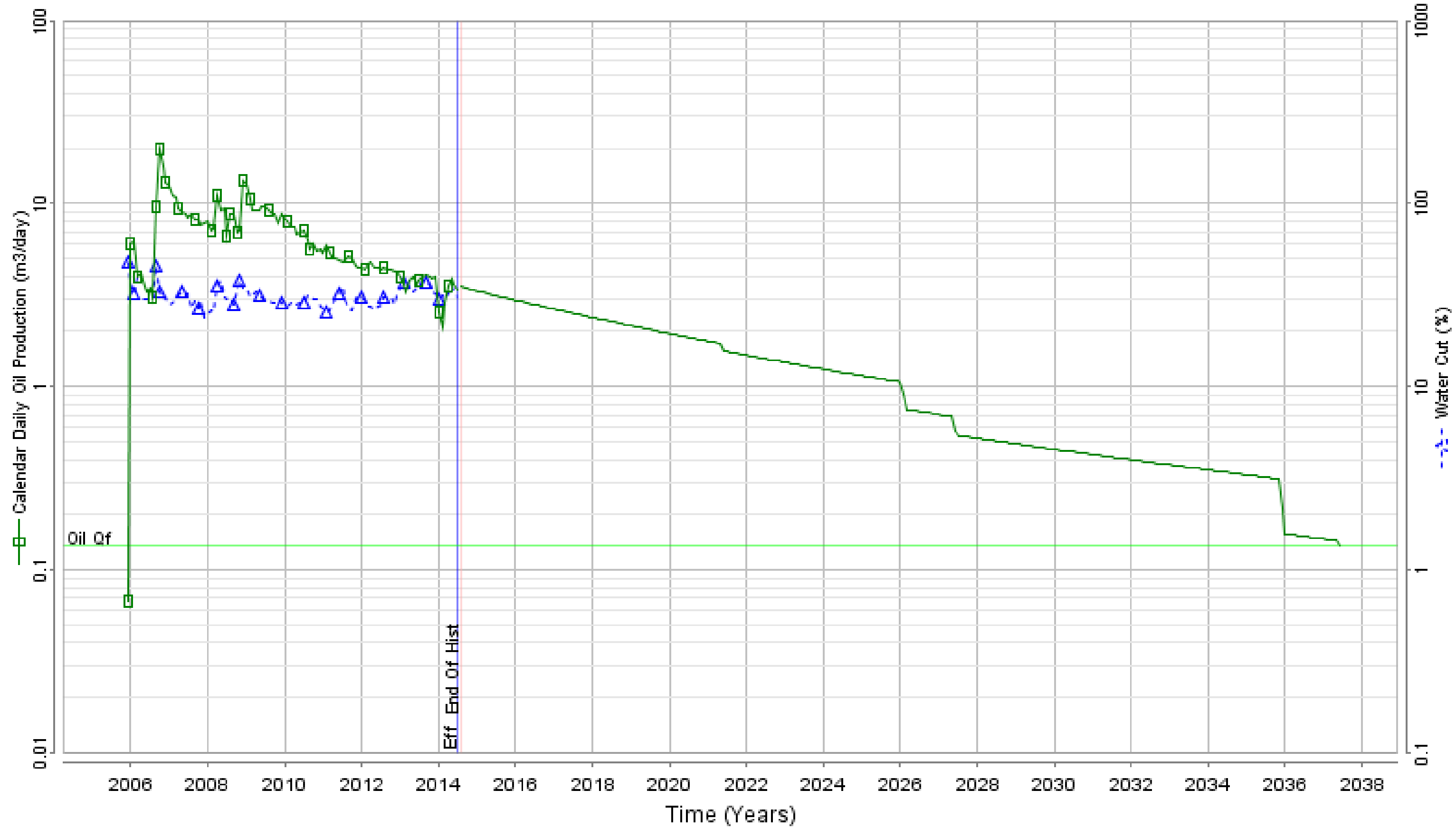


Figure No. 7

Province:	Manitoba
Field:	DALY SINCLAIR
Pool:	BAKKEN-THREE FORKS B
Unit:	multi zone (6)
Status:	n/a
Operator:	Tundra O&G Prtnshp

Proposed Ewart Unit 7
Ewart 7 for Unit App
Base

Primary Recovery



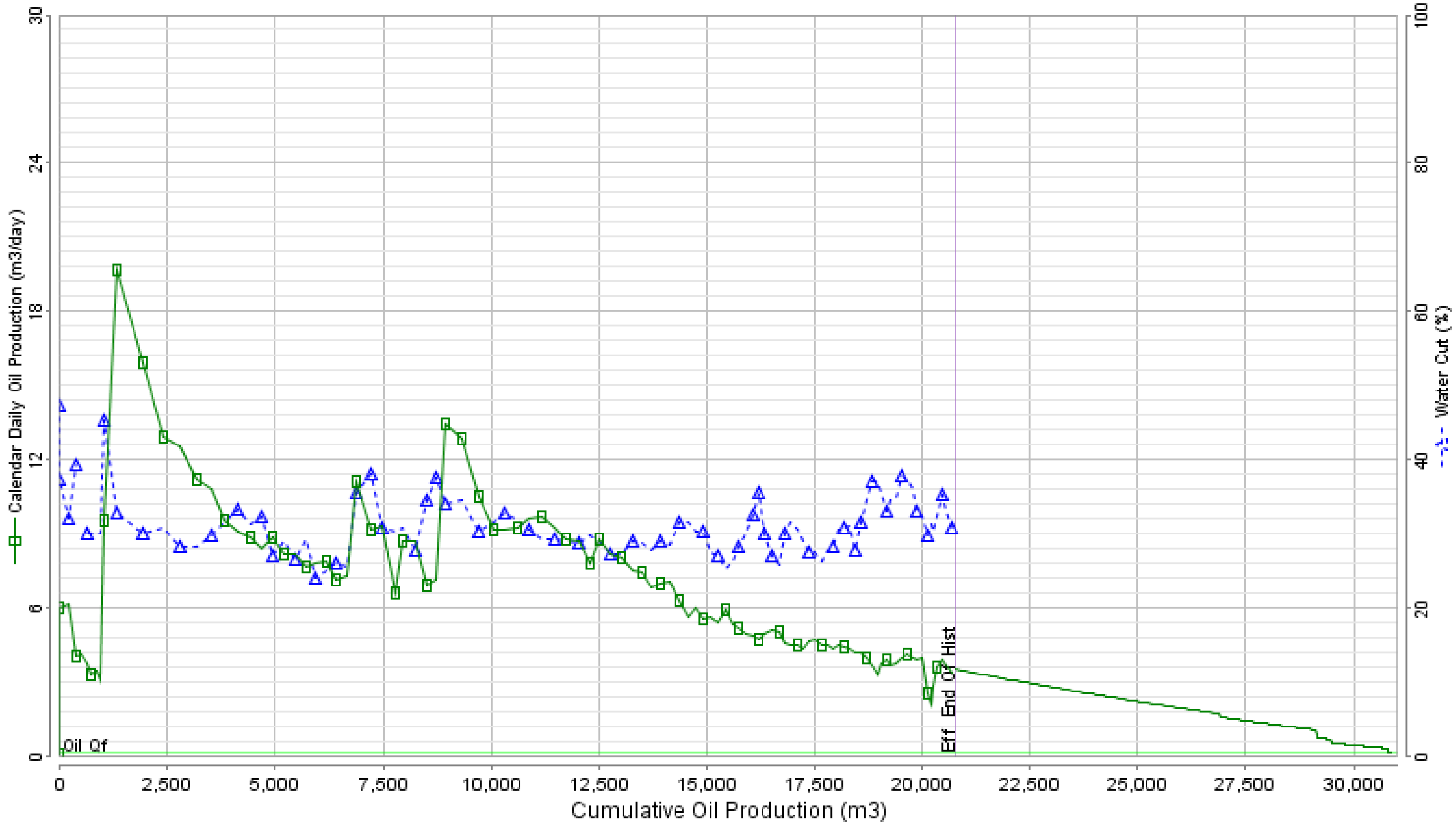
Cum Oil(m3):	20,783	Cum Gas(E3m3):	0	Cum Water(m3):	9,291	Cum Cond(m3):	0
Forecast Start:	07/01/2014	Calculation Type:	Undefined	Est. Cum Prod (m3):	20,783	Decline Exponent:	0.000
Forecast End:	05/31/2037	OVIP (m3):	0	Remaining (m3):	10,088	Initial Decline (%/yr):	0.0
Initial Rate (m3):	3.5	Recovery Factor:	0.000				
Final Rate (m3):	0.1	Ult. Recoverable (m3):	30,872				

Figure No. 8

Province:	Manitoba		
Field:	DALY SINCLAIR		
Pool:	BAKKEN-THREE FORKS B		
Unit:	multi zone (6)		
Status:	n/a		
Operator:	Tundra O&G Prtnshp		

Proposed Ewart Unit 7
Ewart 7 for Unit App
Base

Primary Recovery



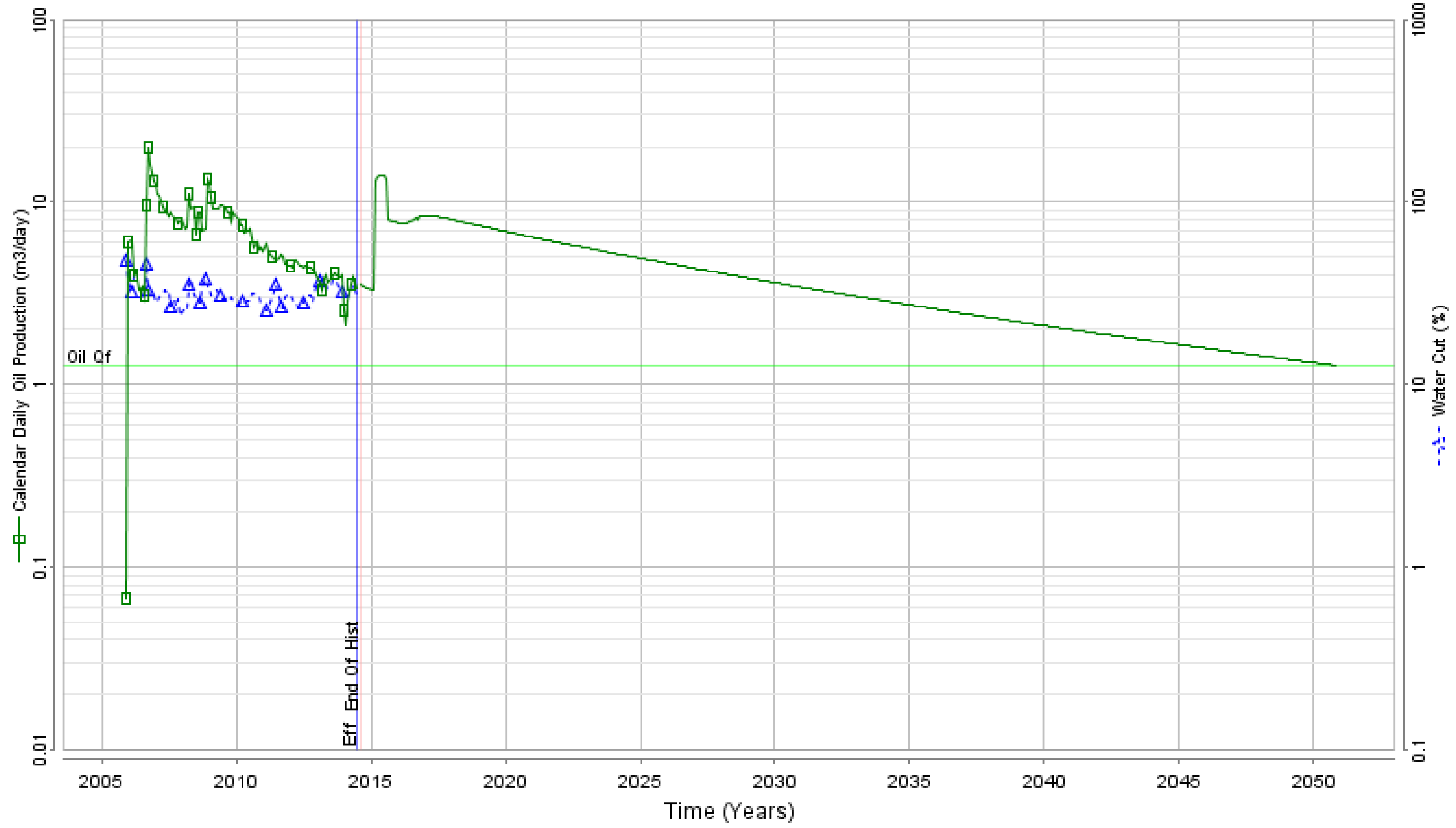
Cum Oil(m3):	20,783	Cum Gas(E3m3):	0	Cum Water(m3):	9,291	Cum Cond(m3):	0
Forecast Start:	07/01/2014	Calculation Type:	Undefined	Est. Cum Prod (m3):	20,783	Decline Exponent:	0.000
Forecast End:	05/31/2037	OVIP (m3):	0	Remaining (m3):	10,088	Initial Decline (%/yr):	0.0
Initial Rate (m3):	3.5	Recovery Factor:	0.000				
Final Rate (m3):	0.1	Ult. Recoverable (m3):	30,872				

Figure No. 9

Province:	Manitoba
Field:	DALY SINCLAIR
Pool:	BAKKEN-THREE FORKS B
Unit:	multi zone (6)
Status:	n/a
Operator:	Tundra O&G Prtnshp

Primary + Secondary Recovery

Proposed Ewart Unit 7
Ewart 7 for Unit App
Base+G1+G2



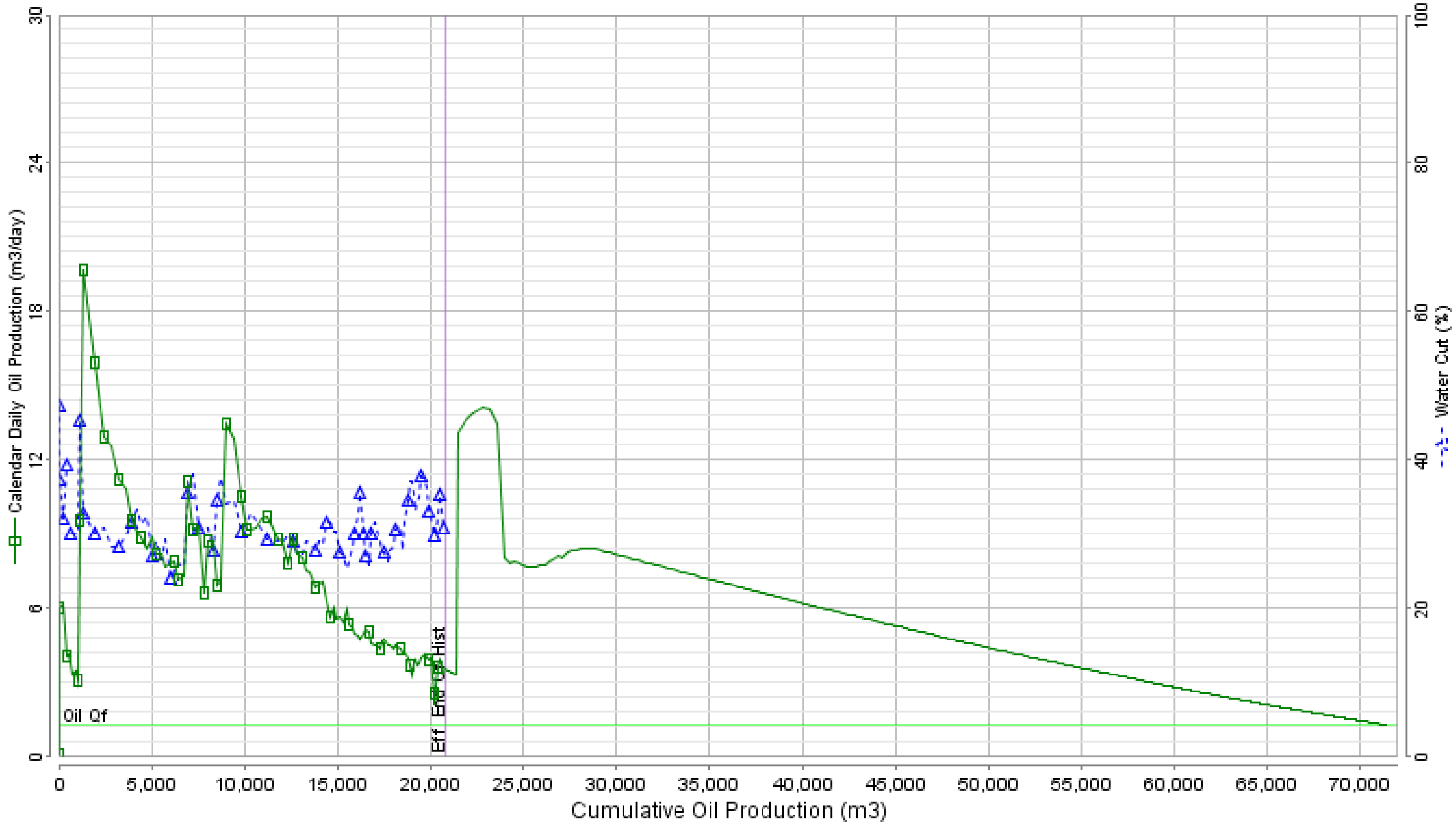
Cum Oil(m3):	20,783	Cum Gas(E3m3):	0	Cum Water(m3):	9,291	Cum Cond(m3):	0
Forecast Start:	07/01/2014	Calculation Type:	Undefined	Est. Cum Prod (m3):	20,783	Decline Exponent:	0.000
Forecast End:	10/29/2050	OMP (m3):	0	Remaining (m3):	50,627	Initial Decline (%/yr):	0.0
Initial Rate (m3):	3.5	Recovery Factor:	0.000				
Final Rate (m3):	1.3	Ult. Recoverable (m3):	71,411				

Figure No. 10

Province:	Manitoba
Field:	DALY SINCLAIR
Pool:	BAKKEN-THREE FORKS B
Unit:	multi zone (6)
Status:	n/a
Operator:	Tundra O&G Prtnshp

Proposed Ewart Unit 7
Ewart 7 for Unit App
Base+G1+G2

Primary + Secondary Recovery

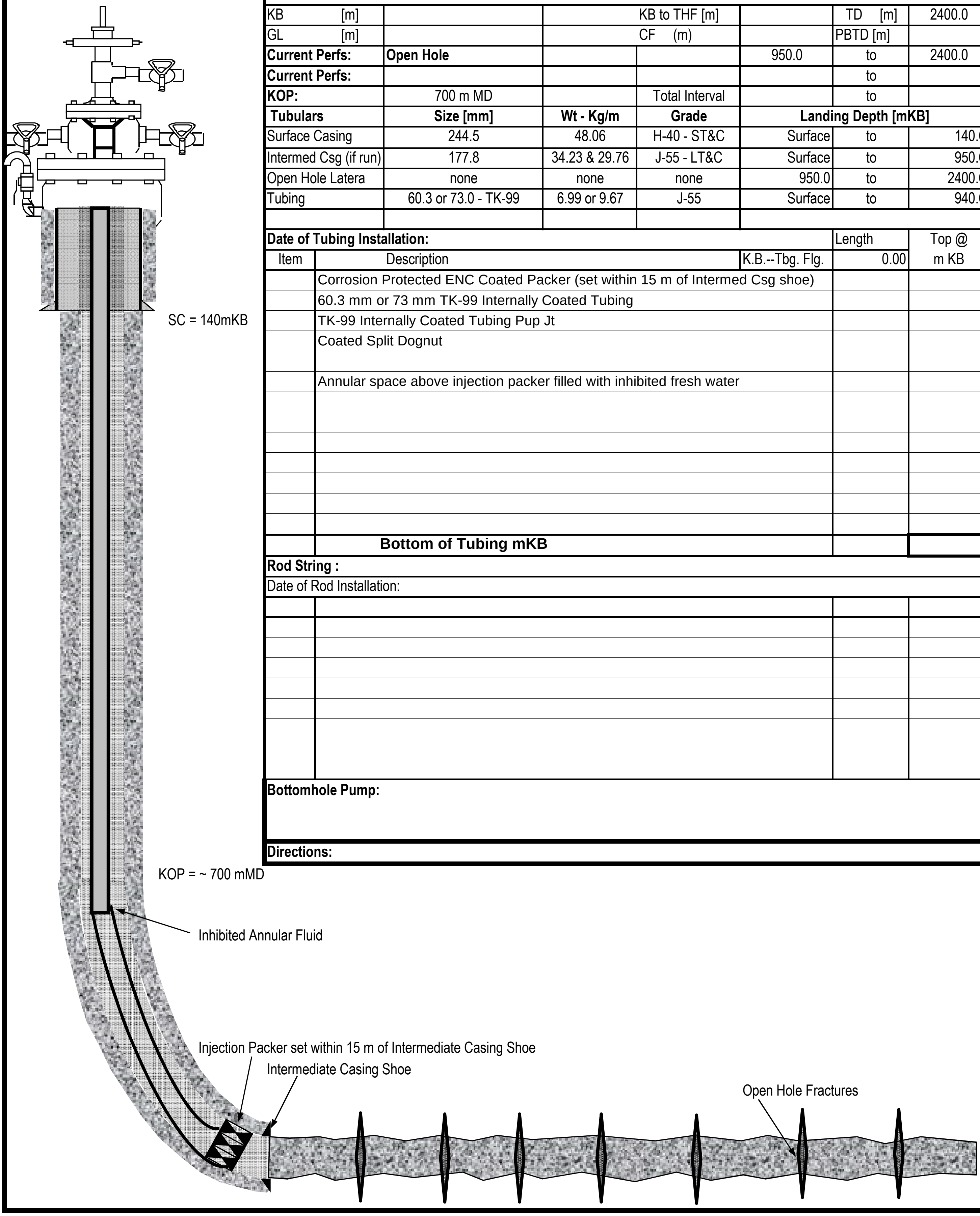


Cum Oil(m3):	20,783	Cum Gas(E3m3):	0	Cum Water(m3):	9,291	Cum Cond(m3):	0
Forecast Start:	07/01/2014	Calculation Type:	Undefined	Est. Cum Prod (m3):	20,783	Decline Exponent:	0.000
Forecast End:	10/29/2050	OVIP (m3):	0	Remaining (m3):	50,627	Initial Decline (%/yr):	0.0
Initial Rate (m3):	3.5	Recovery Factor:	0.000				
Final Rate (m3):	1.3	Ult. Recoverable (m3):	71,411				

Tundra Oil And Gas Partnership

Figure No. 11

TYPICAL OPEN HOLE WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM



WELL NAME:	Tundra Ewart Unit 7 HZNTL Open Hole WIW			**WELL LICENCE:**		
Prepared by	WRJ	(average depths)		Date:	2012	
Elevations :						
KB [m]			KB to THF [m]		TD [m]	2400.0
GL [m]			CF (m)		PBTD [m]	
Current Perfs:	**Open Hole**			950.0	to	2400.0
Current Perfs:					to	
KOP:	700 m MD		Total Interval		to	
Tubulars	**Size [mm]**	**Wt - Kg/m**	**Grade**	**Landing Depth [mKB]**		
Surface Casing	244.5	48.06	H-40 - ST&C	Surface	to	140.0
Intermed Csg (if run)	177.8	34.23 & 29.76	J-55 - LT&C	Surface	to	950.0
Open Hole Latera	none	none	none	950.0	to	2400.0
Tubing	60.3 or 73.0 - TK-99	6.99 or 9.67	J-55	Surface	to	940.0

Date of Tubing Installation:

Item	Description	Length	Top @ m KB
	K.B.--Tbg. Flg.	0.00	
	Corrosion Protected ENC Coated Packer (set within 15 m of Intermed Csg shoe)		
	60.3 mm or 73 mm TK-99 Internally Coated Tubing		
	TK-99 Internally Coated Tubing Pup Jt		
	Coated Split Dognut		
	Annular space above injection packer filled with inhibited fresh water		
	Bottom of Tubing mKB		

Rod String :

Date of Rod Installation:

Bottomhole Pump:

Directions:

FIGURE NO. 12

Sinclair Water Injection System

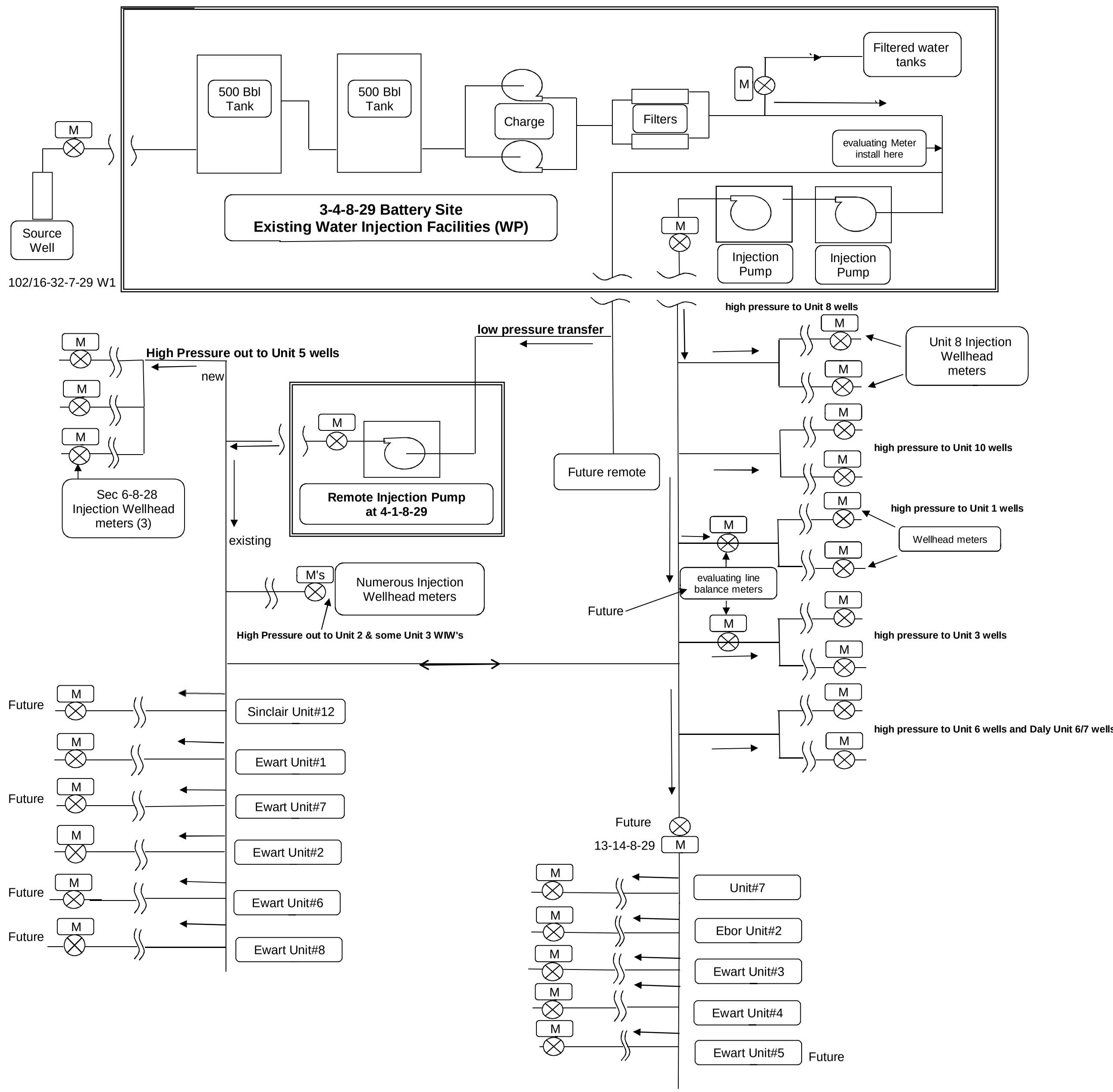
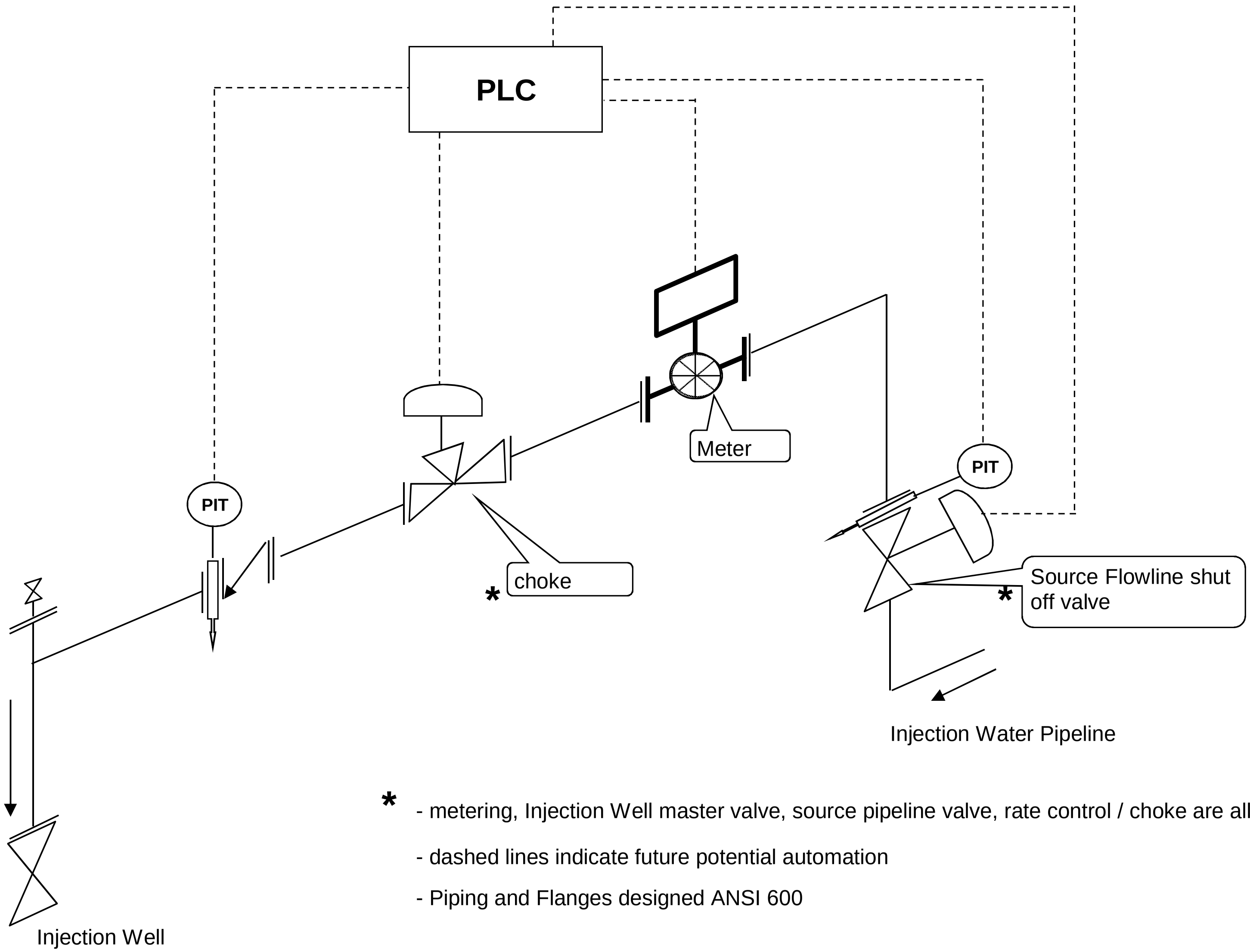


FIGURE NO. 13

Ewart Unit No. 7

Proposed Injection Well Surface Piping P&ID



* - metering, Injection Well master valve, source pipeline valve, rate control / choke are all standard

- dashed lines indicate future potential automation

- Piping and Flanges designed ANSI 600

Ewart Unit No. 7

EOR Waterflood Project

Planned Corrosion Control Program **

Source Well
- Continuous downhole corrosion inhibition
- Continuous surface corrosion inhibitor injection
- Downhole scale inhibitor injection
- Corrosion resistant valves and internally coated surface piping

Pipelines
- Source well to 3-4-8-29 Water Plant – Fiberglass
- New High Pressure Pipeline to Unit 9 injection wells – 2000 psi high pressure Fiberglass

Facilities
- 3-4-8-29 Water Plant and New Injection Pump Station
    - Plant piping – 600 ANSI schedule 80 pipe, Fiberglass or Internally coated
    - Filtration – Stainless steel bodies and PVC piping
    - Pumping – Ceramic plungers, stainless steel disc valves
    - Tanks – Fiberglass shell, corrosion resistant valves

Injection Wellhead / Surface Piping
- Corrosion resistant valves and stainless steel and/or internally coated steel surface piping

Injection Well
- Casing cathodic protection where required
- Wetted surfaces coated downhole packer
- Corrosion inhibited water in the annulus between tubing / casing
- Internally coated tubing surface to packer
- Surface freeze protection of annular fluid
- Corrosion resistant master valve
- Corrosion resistant pipeline valve

Producing Wells
- Casing cathodic protection where required
- Downhole batch corrosion inhibition as required
- Downhole scale inhibitor injection as required

Figure 14

** subject to final design and engineering

EXHIBIT 'A': TRACT PARTICIPATION

Table 1

Proposed EWART UNIT NO. 7

Attached to and made part of an Agreement Entitled
Ewart Unit No. 7 - Unit Agreement

Working Interest				Royalty Interest		Tract Participation %
Tract No.	Land Description	Owner	Share (%)	Owner	Share (%)	
1	LSD 9-09-8-28 WPM	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA Ewart Oil Ltd. Archibald Chisholm Estate 1093105 Ontario Inc. 5301807 Manitoba Ltd. Cenovus Energy Inc.	45.50% 15.73% 32.17% 0.08% 0.60% 5.92%	13.072280545
2	LSD 10-09-8-28 WPM	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA Archibald Chisholm Estate	92.96% 7.04%	10.100411250
3	LSD 11-09-8-28 WPM	Tundra Oil & Gas Partnership	100%	Freehold Royalties Partnership	100%	10.009393971
4	LSD 12-09-8-28 WPM	Tundra Oil & Gas Partnership	100%	Freehold Royalties Partnership	100%	12.638358738
5	LSD 13-09-8-28 WPM	Tundra Oil & Gas Partnership	100%	Freehold Royalties Partnership	100%	15.105387404
6	LSD 14-09-8-28 WPM	Tundra Oil & Gas Partnership	100%	Freehold Royalties Partnership	100%	13.037537076
7	LSD 15-09-8-28 WPM	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA Archibald Chisholm Estate 1093105 Ontario Inc.	47.06% 16.75% 36.19%	12.105535242
8	LSD 16-09-8-28 WPM	Tundra Oil & Gas Partnership	100%	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF MANITOBA Archibald Chisholm Estate 1093105 Ontario Inc. Cenovus Energy Inc.	17.12% 0.16% 82.36% 0.36%	13.931095775
						100.000000000

TABLE NO. 2: TRACT FACTOR CALCULATIONS

TRACT FACTORS BASED ON OIL-IN-PLACE (OOIP) LESS CUMULATIVE OIL PRODUCED METHOD

PROPOSED EWART UNIT NO. 7						
LSD-SEC	**TWP-RGE**	***UWI***	***OOIP (m3)***	***Vertical Cum Prodn June 2014 (m3)***	***OOIP Minus Cum Oil Prodn (m3)***	***Tract Factor (%)***
09-09	008-28W1	100/09-09-008-28W1/0	34586	0	34586	13.072280545
10-09	008-28W1	100/10-09-008-28W1/0	29548	2825	26723	10.100411250
11-09	008-28W1	100/11-09-008-28W1/0	30505	4023	26482	10.009393971
12-09	008-28W1	100/12-09-008-28W1/0	37750	4312	33438	12.638358738
13-09	008-28W1	100/13-09-008-28W1/0	43536	3571	39965	15.105387404
14-09	008-28W1	100/14-09-008-28W1/0	37789	3295	34494	13.037537076
15-09	008-28W1	100/15-09-008-28W1/0	34786	2758	32028	12.105535242
16-09	008-28W1	100/16-09-008-28W1/0	36858	0	36858	13.931095775
TOTAL			**285358**	**20783**	**264575**	**100.000000000**

TABLE NO. 3

Proposed Ewart Unit 7 Well List

UWI	*License Number*	*Type*	*Pool Name*	*Producing Zone*	*Mode*	*On Prod Date*	*Prod Date*	*Cal Dly Oil (m3/d)*	*Monthly Oil (m3)*	*Cum Prd Oil (m3)*	*Cal Dly Water (m3/d)*	*Monthly Water (m3)*	*Cum Prd Water (m3)*	*WCT (%)*
100/10-09-008-28W1/0	006559	Vertical	BAKKEN-THREE FORKS B	BAKKEN,THREEFK	Producing	10/1/2008	Jun-2014	0.8	22.9	2825.0	0.2	6.0	1459.7	20.76
100/11-09-008-28W1/0	005984	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	8/1/2006	Jun-2014	0.6	19.4	4022.6	0.1	4.3	1185.8	18.14
100/12-09-008-28W1/0	005678	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	11/1/2005	Jun-2014	0.5	15.4	4312.2	0.2	6.0	1910.9	28.04
100/13-09-008-28W1/0	005985	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	8/1/2006	Jun-2014	0.5	14.7	3571.1	0.3	8.7	1570.9	37.18
100/14-09-008-28W1/0	005986	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	8/1/2006	Jun-2014	0.4	13.1	3295.0	0.3	9.0	1852.0	40.72
100/15-09-008-28W1/0	006560	Vertical	BAKKEN-THREE FORKS B	BAKKEN	Producing	3/1/2008	Jun-2014	0.5	16.2	2757.5	0.4	11.0	1311.7	40.44
										20783.4			**9291.0**	

TABLE NO. 4: OOIP Calculation

UWI	MBKKN OOIP 0.5 md (m3)	Lyleton UA OOIP 1.0 md (m3)	Lyleton LA OOIP 1.0 md (m3)	Lyleton B OOIP 0.5 md (m3)	TOTAL OOIP GLJ Cut-Offs (m3)	MB Phih 0.5 md	UA Phih 1.0 md	LA Phih 1.0 md	LB Phih 0.5 md
09-09-008-28W1M	17828	0	0	16758	34586	0.204220176	0	0	0.175506330
10-09-008-28W1M	16616	0	0	12932	29548	0.187886083	0	0	0.135443189
11-09-008-28W1M	18004	0	0	12501	30505	0.201266265	0	0	0.130929907
12-09-008-28W1M	19598	0	0	18152	37750	0.228451343	0	0	0.190110431
13-09-008-28W1M	22167	0	0	21369	43536	0.250004007	0	0	0.223808127
14-09-008-28W1M	20654	0	0	17136	37789	0.229560905	0	0	0.179464727
15-09-008-28W1M	18824	0	0	15961	34786	0.213550628	0	0	0.167167300
16-09-008-28W1M	18836	0	0	18022	36858	0.215112181	0	0	0.188748222
					285,358				
					1,794,850	**BBL**			

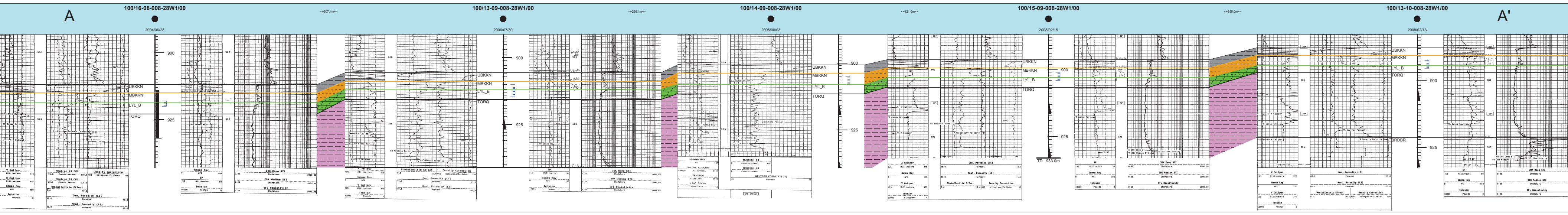
TABLE NO. 5

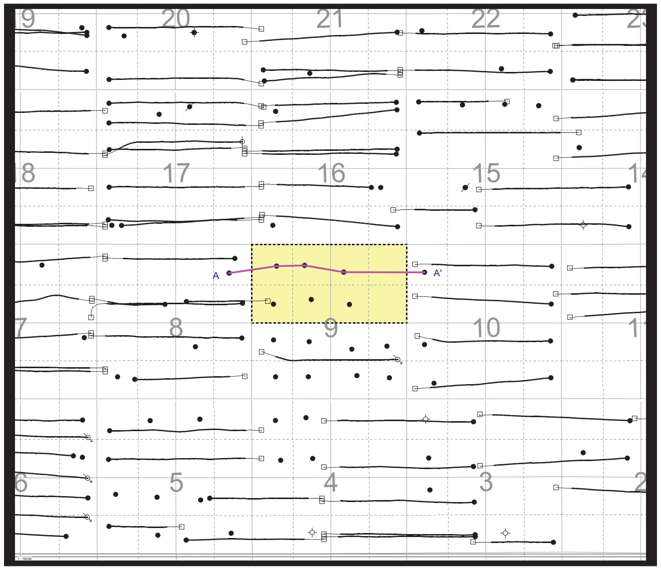
Ewart Unit No. 7 - N/2 9-008-28W1M
Middle Bakken/Three Forks Fm (Lyleton) Rock and Fluid Properties

Formation Pressure		9200 kPa	Initial Average Reservoir Pressure
Formation Temperature		30^{o}C	
Saturation Pressure		2034 kPa	Bubble Point
GOR		6-10 m^3/m^3	Gas-Oil Ratio
API Oil Gravity		40	
Swi (fraction)		0.4	Intial Water Saturation
Produced Water Sp. Gr.		1.08	
Produced Water pH		7.1-7.3	
Produced Water TDS (mg/L)		125,000	
Wettability		Moderately oil-wet	
Average Air Permeability	Middle Bakken Lyleton B	1.50 mD 0.6 mD	
Average Porosity (Fraction)	Middle Bakken Lyleton B	0.16 0.16	

Table No. 6: Ewart Unit 7 Schedule

	Injectors		Producers
Timing	Drilled	Conversion	Drilled
Q3 2014			
Q4 2014			
Q1 2015	1		2
Q2 2015			
Q3 2015		1	
Q4 2015			
Q1 2016			
Q3 2016			
Q4 2016			



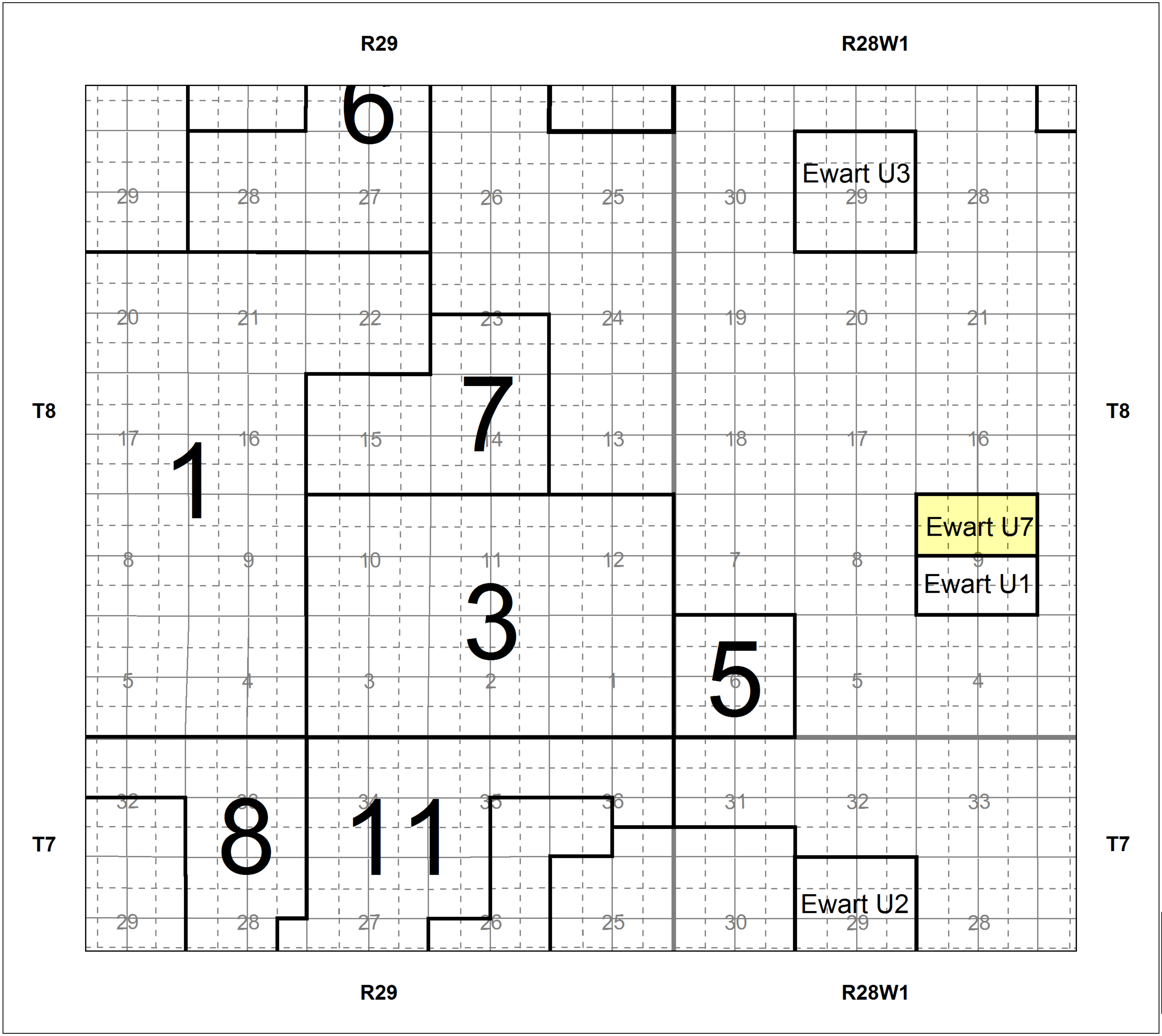


Tundra Oil & Gas Partnership

Structural X-Section A - A'
Proposed Ewart Unit 7
APPENDIX 1

Licensed to : Tundra Oil and Gas Ltd

geoSCOUT	Date : 2014/06/20		By : Hackert
	Datum : Sea Level	Ref : 0.0 (m)	Scale = 1:480
	Interval : From UBKKN to BRDBR		



Tundra Oil & Gas Partnership

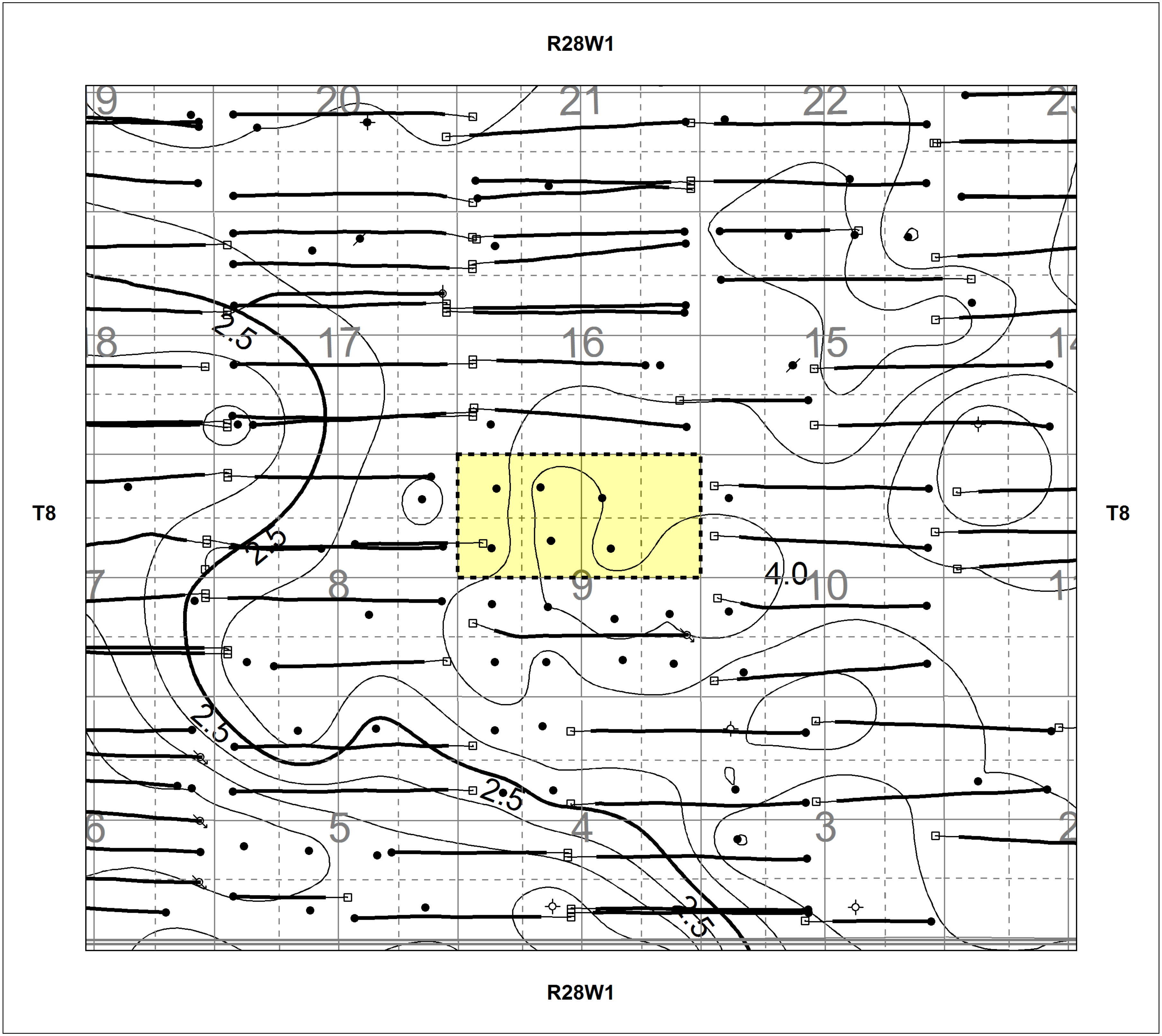
EWART UNIT No. 7
Offsetting Units
APPENDIX 2

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT

www.geologic.com

By : Hackert	Date : 2014/06/20
Scale = 1:65649	Project : Sinclair - Daly

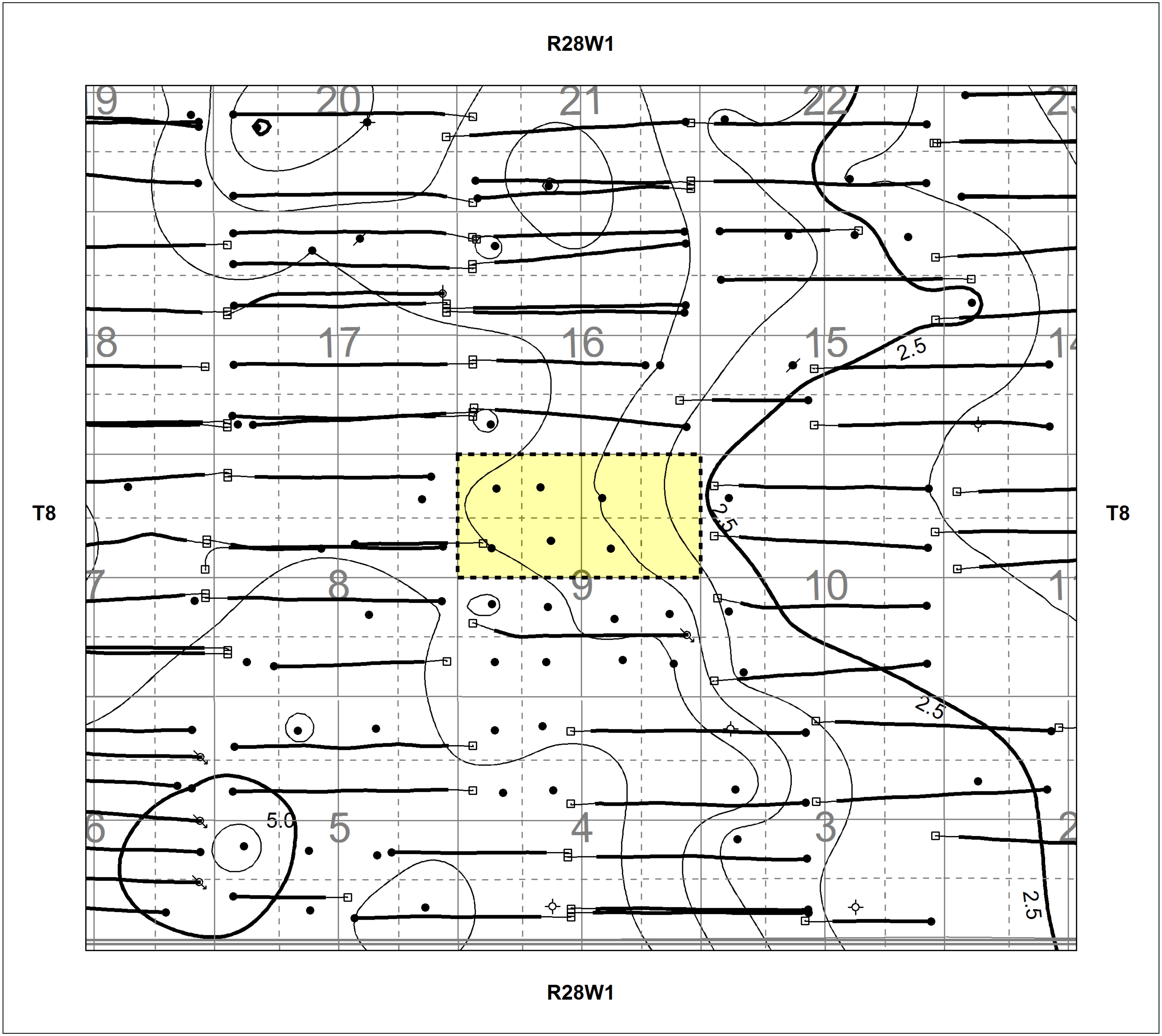


Tundra Oil & Gas Partnership

EWART UNIT No. 7
Middle Bakken Isopach CI=0.5m
APPENDIX 3

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT	By : Hackert	Date : 2014/06/20
	Scale = 1:32788	Project : Sinclair - Daly



Tundra Oil & Gas Partnership

EWART UNIT No. 7

Lyleton B Isopach CI=0.5m

APPENDIX 4

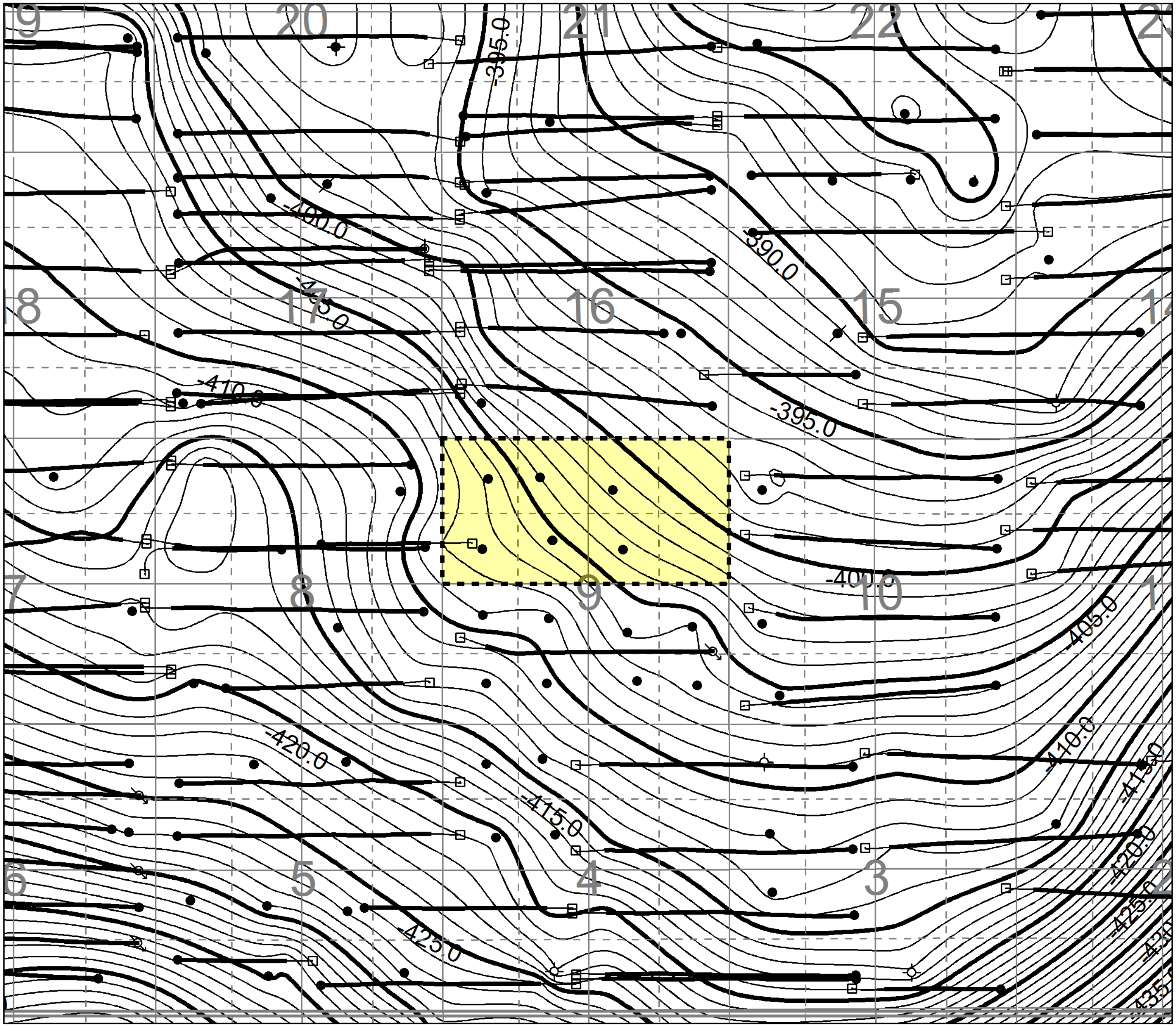
Licensed to : Tundra Oil & Gas Partnership

By : Hackert | Date : 2014/06/20

Scale = 1:32788 | Project : Sinclair - Daly

R28W1

T8



T8

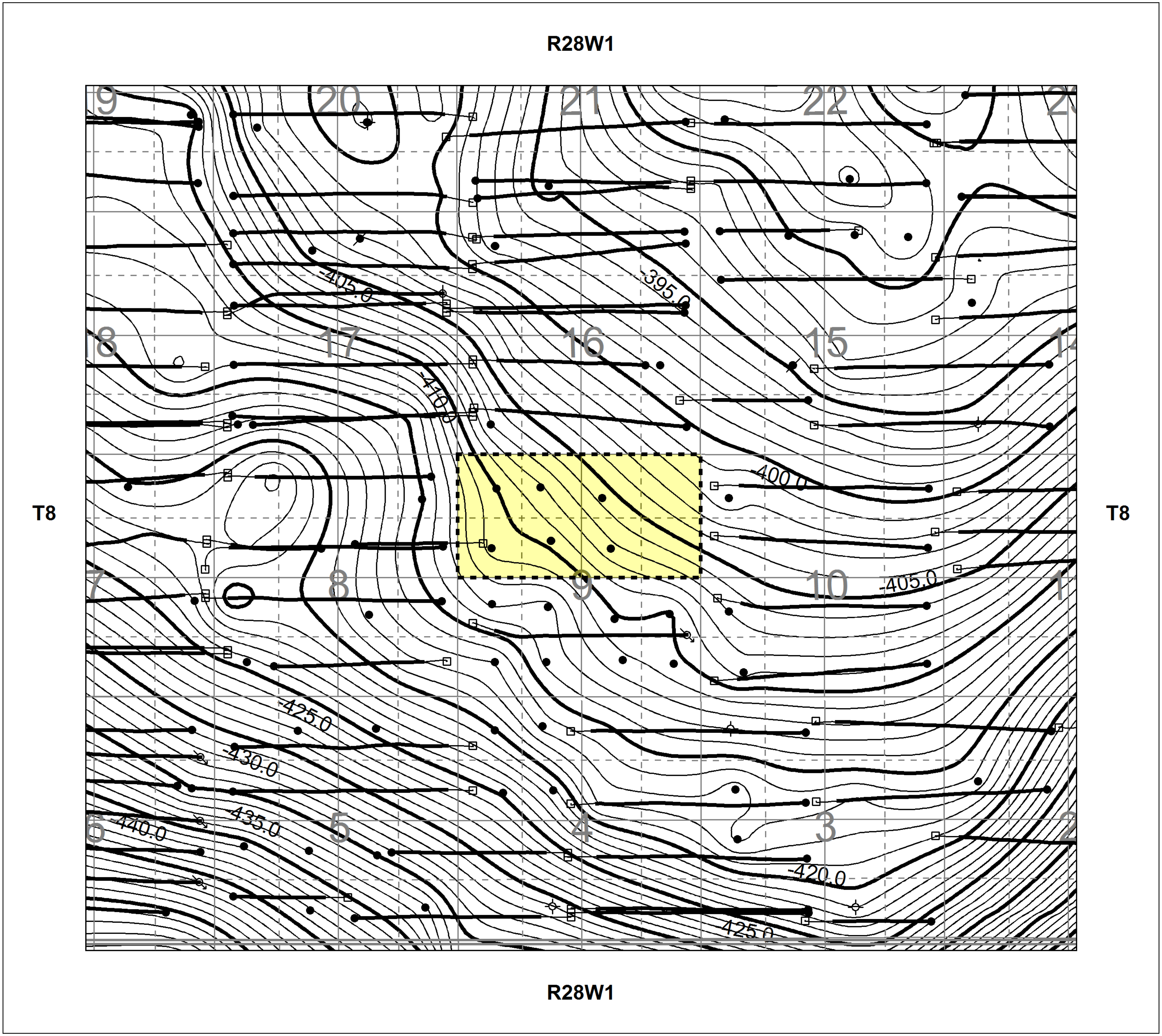
R28W1

Tundra Oil & Gas Partnership

EWART UNIT No. 7
Middle Bakken Structure CI=1.0m
APPENDIX 5

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT	By : Hackert	Date : 2014/06/20
	Scale = 1:32788	Project : Sinclair - Daly

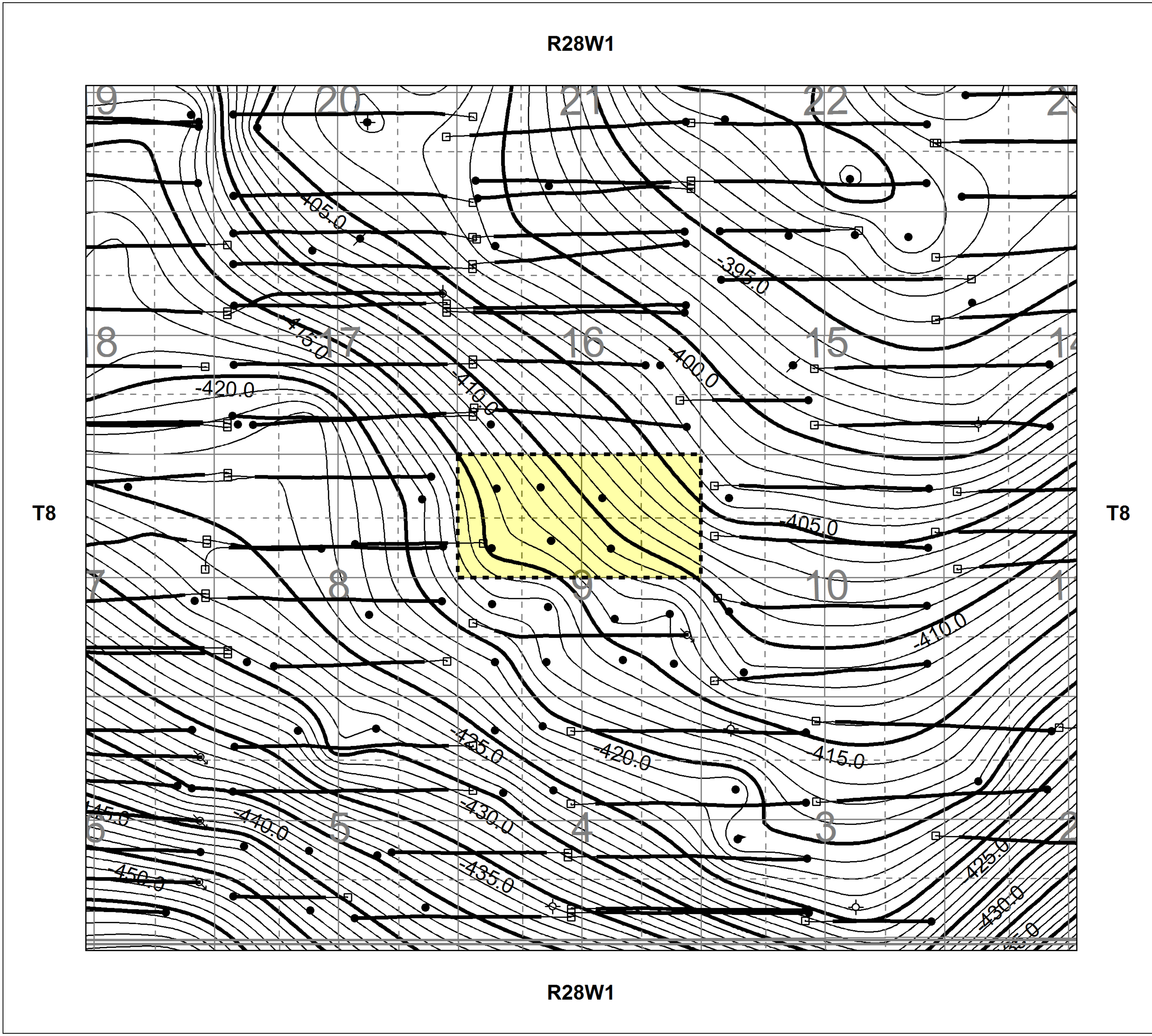


Tundra Oil & Gas Partnership

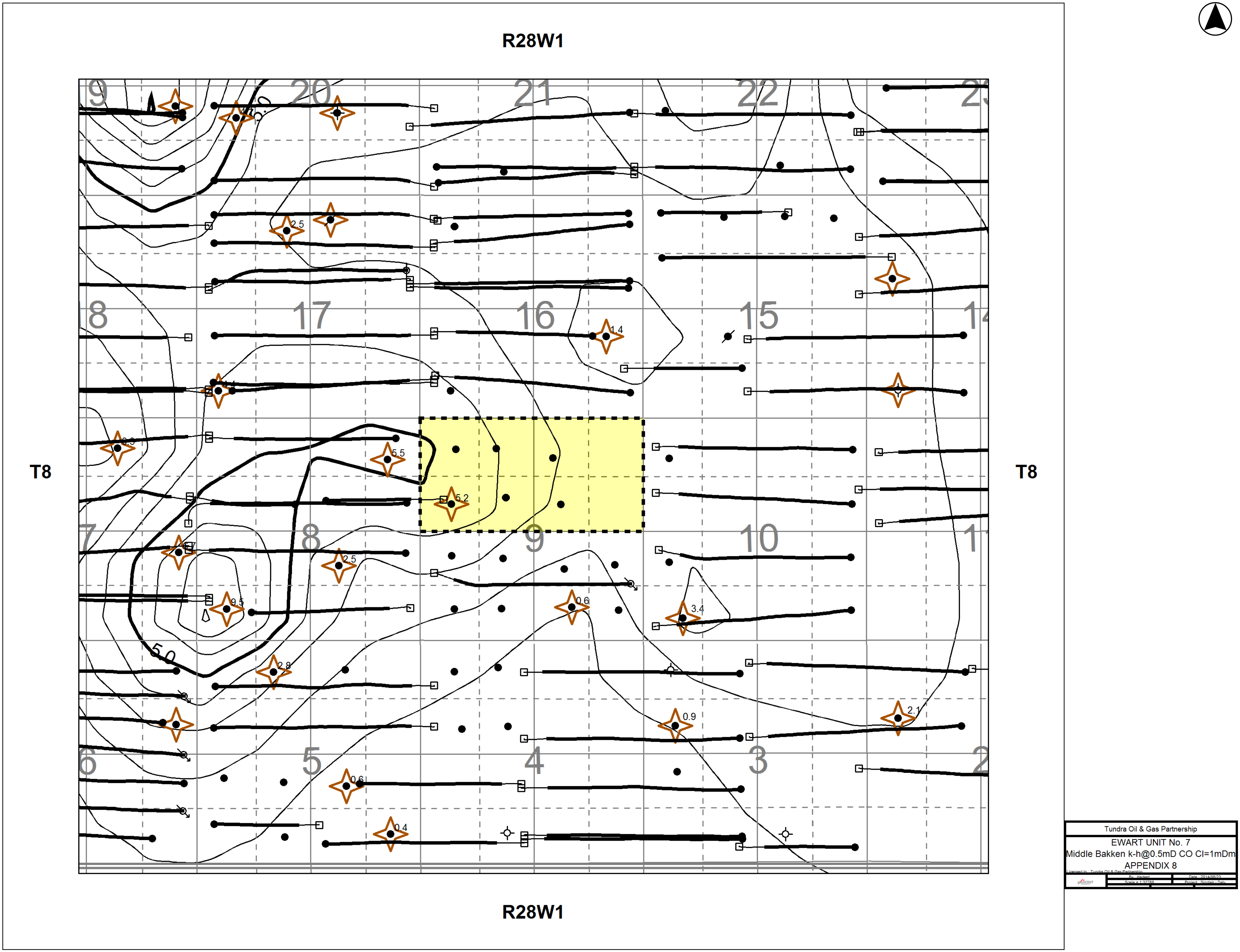
EWART UNIT No. 7
Lyleton B Structure CI=1.0m
APPENDIX 6

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT	By : Hackert	Date : 2014/06/20
	Scale = 1:32788	Project : Sinclair - Daly



Tundra Oil & Gas Partnership	
EWART UNIT No. 7 Torquay Shale Structure CI=1.0m APPENDIX 7	
Licensed to : Tundra Oil & Gas Partnership	
By : Hackert	Date : 2014/06/20
Scale = 1:32788	Project : Sinclair - Daly



Tundra Oil & Gas Partnership

EWART UNIT No. 7
Middle Bakken k-h@0.5mD CO CI=1mDm
APPENDIX 8

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT

By : Hackert

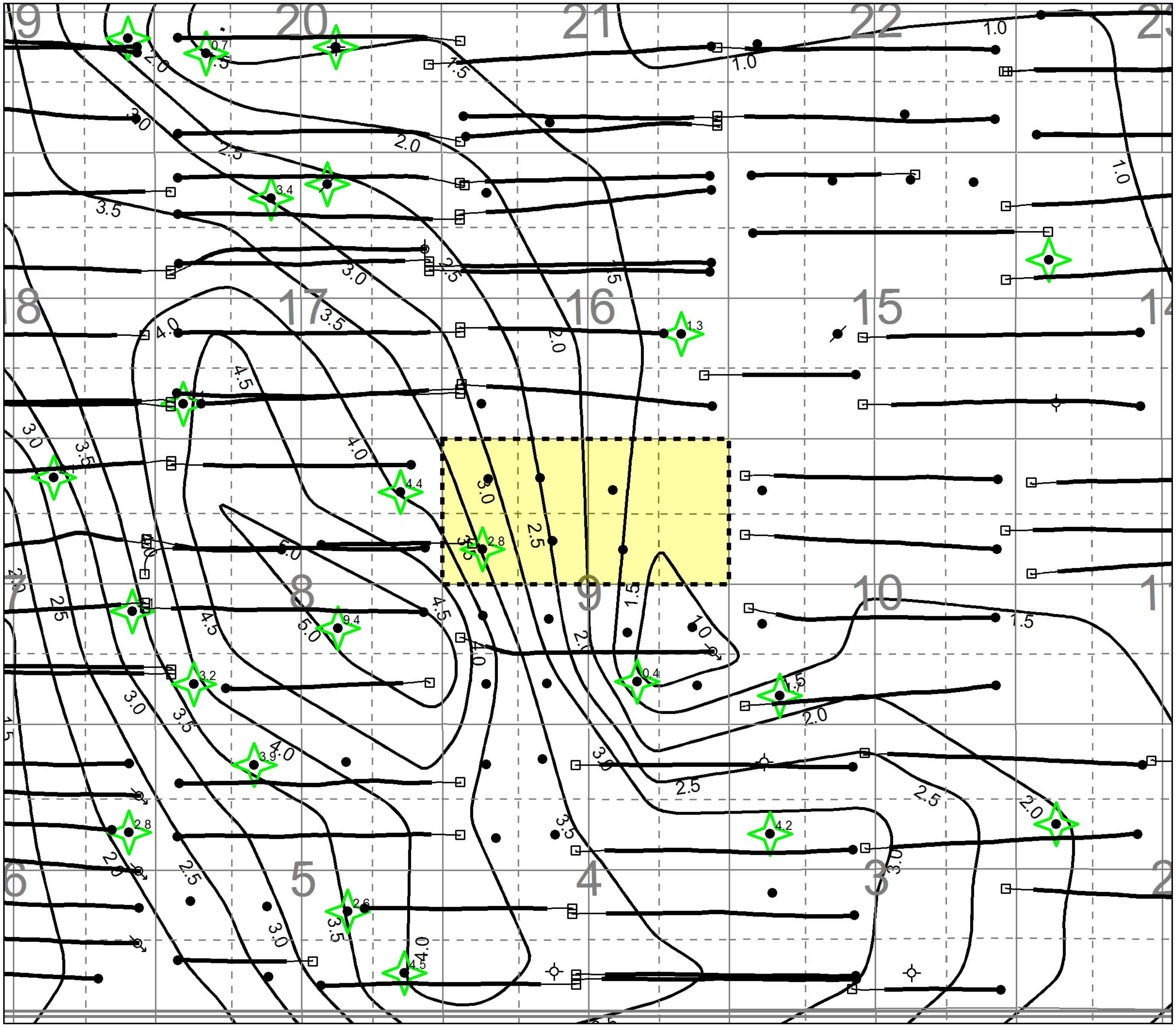
Date : 2014/06/23

Scale = 1:32788

Project : Sinclair - Daly

R28W1

T8



T8

R28W1

Tundra Oil & Gas Partnership

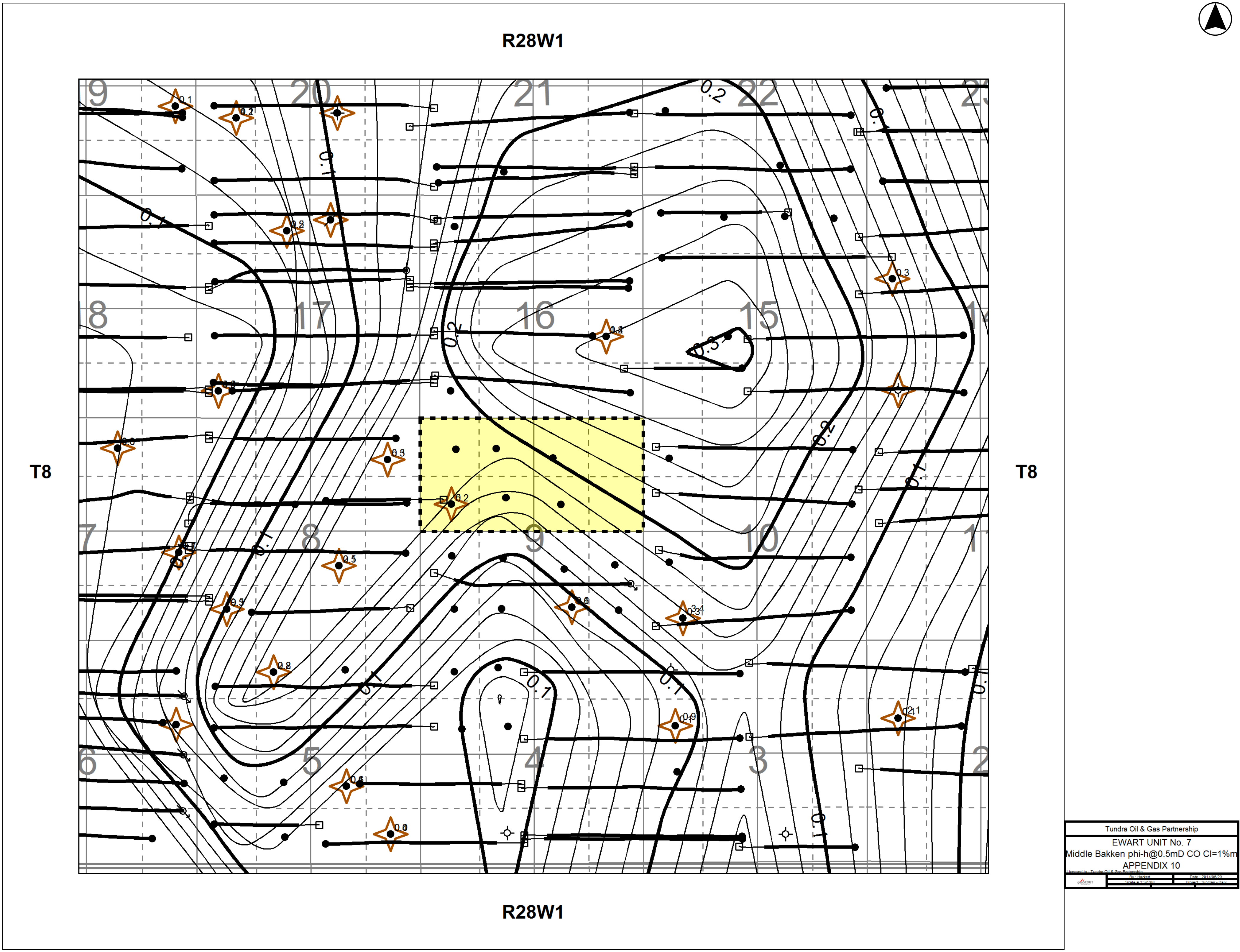
EWART UNIT No. 7

Lyleton B k-h@0.5mD CO CI=1mDm

APPENDIX 9

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT	By : Hackert	Date : 2014/06/23
	Scale = 1:32788	Project : Sinclair - Daly



Tundra Oil & Gas Partnership

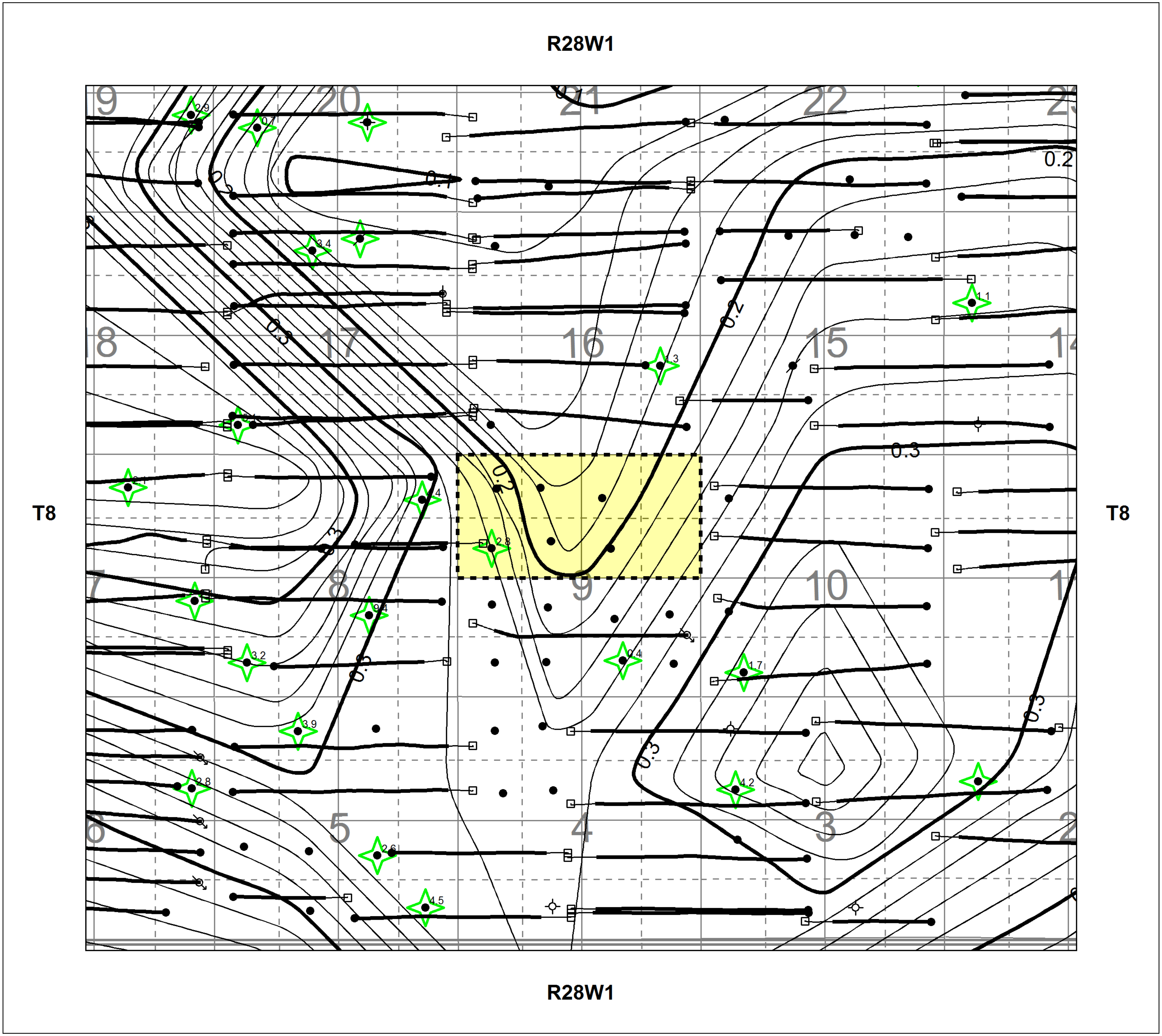
EWART UNIT No. 7

Middle Bakken phi-h@0.5mD CO CI=1%m

APPENDIX 10

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT	By : Hackert	Date : 2014/06/23
	Scale = 1:32788	Project : Sinclair - Daly



Tundra Oil & Gas Partnership

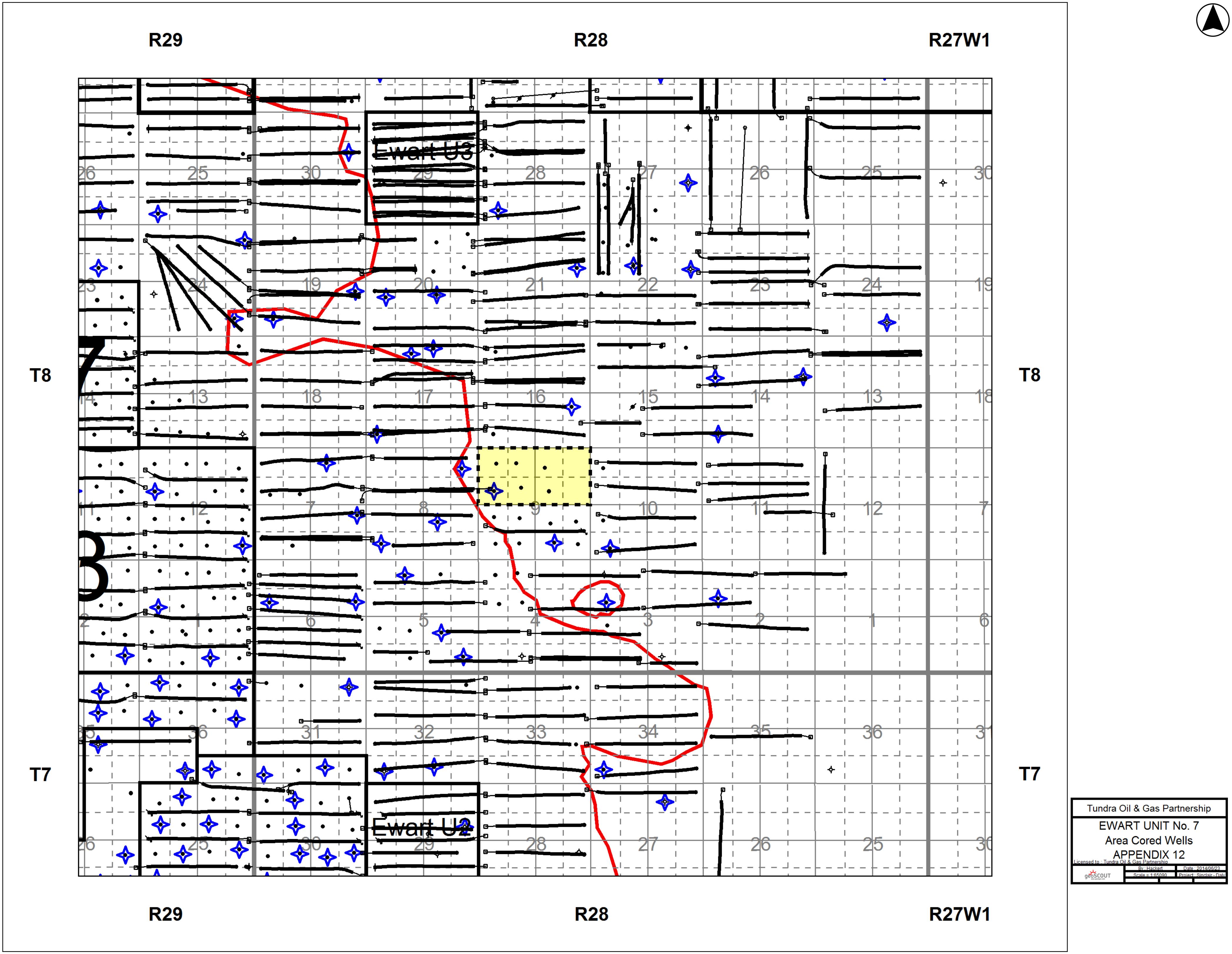
EWART UNIT No. 7

Lyleton B phi-h@0.5mD CO CI=1%m

APPENDIX 11

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT	By : Hackert	Date : 2014/06/23
	Scale = 1:32788	Project : Sinclair - Daly



R29
R28
R27W1
T8
T7
Ewart U3
Ewart U2
Tundra Oil & Gas Partnership
EWART UNIT No. 7
Area Cored Wells
APPENDIX 12