PROPOSED DALY UNIT NO. 11

Application for Enhanced Oil Recovery Waterflood Project

Bakken Formation

Bakken-Three Forks A Pool (01 62A)

Daly, Manitoba

April 29th, 2015
Tundra Oil and Gas Partnership

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INTRODUCTION

The Daly portion of the Daly Sinclair Oilfield is located in Townships 8-11 Ranges 27-29 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 Partnership (Tundra) in the Daly field.

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 to establish Daly Unit No. 11 (N ½ of Section 30-010-28W1 & all of section 31-10-28W1) 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 Pool of the Daly Sinclair Oilfield (Figure 3).

SUMMARY

1. The proposed Daly Unit No. 11 will include 6 producing horizontal wells, and one abandoned vertical wells, within 24 Legal Sub Divisions (LSD) of the Middle Bakken/Three Forks producing reservoir. The project is located west of Daly Unit No. 8 and east of the Kola Units 1 & 2 (Figure 2).

2. Total Net Original Oil in Place (OOIP) in Daly Unit No. 11 has been calculated to be 837.6 E^3m^3 (5268.6 Mbbl) for an average of 34.9 net E^3m^3 OOIP per 40 acre LSD. After petro physical analysis OOIP values were determined using a permeability cutoff of 0.5 mD.

3. Cumulative production to the end of December 2014 from the 7 wells within the proposed Daly Unit No. 11 project area was 46.9 E^3m^3 (294.8 Mbbl) of oil, and 174.2 E^3m^3 (1095.6 Mbbl) of water, representing a 5.6% Recovery Factor (RF) of the Net OOIP.

4. Estimated Ultimate Recovery (EUR) of producing oil reserves in the proposed Daly Unit No. 11 project area has been calculated to be 66.2E^3m^3 (416.2 Mbbl), with 19.3 E^3m^3 (121.4 Mbbl) remaining as of the end of December 2014.

5. Ultimate oil recovery of the proposed Daly Unit No. 11 OOIP, under the current Primary Production method, is forecasted to be 7.9%.

6. Figure 4 shows the production from the Daly Unit No. 11 which peaked in May 2012 at 91.9 m^3 of oil per day (OPD). As of December 2014, production was 15.4 m^3 OPD, 67.7 m^3 of water per day (WPD) and an 81.5% watercut.

7. In May 2012, production averaged 15.3 m^3 OPD per well in Daly Unit 11. As of December 2014, average per well production has declined to 2.6 m^3 OPD. Decline analysis of the group primary production data forecasts total oil to continue declining at an annual rate of approximately 23.0% in the project area.

8. The EUR of oil reserves under Secondary WF EOR for the proposed Daly Unit No. 11 has been calculated to be 85.6 E^3m^3 (538.6 Mbbl), with 38.7 E^3m^3 (243.4 Mbbl) remaining. An incremental 19.4 E^3m^3 (122.0 Mbbl) in oil reserves, or 2.3%, 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. 11 is estimated to be 10.2%.

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. Existing cemented liner horizontal wells with multi-stage hydraulic fractures (Figure 13) will be converted to injection wells within the proposed Daly Unit No. 11 setting up a 40 acre line drive waterflood. Daly Unit No. 11 will be the first horizontal to horizontal line drive at 40 acre spacing in the Daly portion of the Daly Sinclair Field.

RESERVOIR PROPERTIES AND TECHNICAL DISCUSSION

The proposed Daly Unit No. 11 project area is located within Township 10, Range 29 W1 of the Daly Sinclair oil field. The proposed Daly Unit No. 11 currently consists of 6 producing horizontal wells and 1 abandoned vertical well within an area covering the N ½ of Section 22-010-29W1 and all of Section 27-010-29W1 (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 Daly Sinclair field demonstrates potential for incremental production and reserves from a WF EOR project in the subject Middle Bakken and/or Three Forks oil reservoirs.

Geology

Stratigraphy:

The stratigraphy of the reservoir section for the proposed unit is shown on the structural cross section attached as Appendix 1. The section runs W to E through the middle of the proposed unit. The producing sequence in descending order consists of the Upper Bakken Shale, Middle Bakken Siltstone, Lyleton B Siltstone and the Torquay silty shale. The reservoir units are represented by the Middle Bakken and Lyleton B Siltstones.

Sedimentology:

The Upper Bakken Shale is a black, organic rich, platy shale which forms the top seal for the underlying Middle Bakken/Lyleton B reservoirs. The reservoir units in the proposed unit are analogous to the Bakken / Lyleton producing reservoirs that have been approved proximal to the proposed unit (Daly Unit 8, North Ebor Unit 1 and Kola Unit 3) please see Appendix 2.

The Middle Bakken reservoir consists of fine to coarse grained grey siltstone to fine sandstone which may be subdivided on the basis of lithologic characteristics into upper and lower units. The upper portion is very often heavily bioturbated and is generally non-reservoir. These bioturbated beds often contain an impoverished fauna consisting of well-worn brachiopod, coral and occasional crinoid fragments suggesting deposition in a marginal marine environment. The lower part of the Middle Bakken is generally finely laminated with alternating light and dark laminations with occasional bioturbation. Within the proposed unit, the Middle Bakken ranges from about 4.5m to just over 5.0m in the West (Appendix 3).

The Lyleton B reservoir consists of buff to tan very fine grained siltstone (occasionally fine siltstone) made up of quartz, feldspar and detrital dolomite with minor mica and clay mostly in the form of clay clasts or chips. The upper Lyleton B is generally well bedded and shows evidence of parallel lamination with occasional wind ripples. The coarser siltstones become interbedded with dark grey-green (occasionally red) very fine grained siltstone in the lower portion of the Lyleton B and is generally non-reservoir. The Lyleton B is approximately 4.0 m thick within the proposed unit (Appendix 4). The upper Lyleton B has been partly eroded away in the proposed unit area.

The Torquay silty shale (Three Forks) forms the base of the reservoir sequence and is a brick red dolomitic fine to very fine siltstone (Appendix 5), similar to the Red Shale Marker found in the Western parts of Kola Units 1 & 2 to the West. This forms a good basal seal to the Middle Bakken / Lyleton B reservoir sequence.

Structure:

Structure contour maps are provided for the top of each major unit (Appendices 6 through 8). The structure within the proposed unit area generally consists of an overall Southwestward dip. Structural variations in the area are interpreted as being caused by dissolution of the underlying Prairie Evaporites (ex. Sec 17-10-29W1). Anomalous structural variations caused by dissolution are common in the Sinclair Daly area 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). None of these features is found in the proposed unit area.

Reservoir Quality:

There is only 1 existing vertical well (100/03-27-10-29W1) within the proposed unit area. No core was taken in the Bakken sequence in this well. There are several wells with Bakken core analysis to the West within the Kola Units however wells with analyzed core data to the Northeast, East and South are few and not proximal. Any available wells proximal to the unit have been used to infer the Permeability and Porosity for this unit application. The Middle Bakken reservoir is anticipated to have Fair to Good reservoir throughout the proposed unit. Horizontal production further supports this expectation with 3 of the 6 wells producing over 5000m^3.

Due to some partial erosion of the upper portion of the Lyleton B formation there may be limited pay reservoir. This will likely have some contribution the overall recovery from this Unit leaving the MBKKN as the primary reservoir.

Permeability (k-h in mD*m) and porosity (Phi-h in por*m) maps for the two reservoir units are provided (Appendices 9 through 12), **point values on map posted at wells with core analysis**). These maps are created 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 permeability cutoff. Intervals that meet or exceed the cutoff 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. The value of the permeability cutoffs for each formation are the same values used by GLJ for third party reserve evaluations on Tundra's Sinclair properties. The permeability cutoffs applied are as follows:

- Middle Bakken = 0.5 md
- Lyleton B = 0.5 md

As can be noted from the Phi-h and k-h maps the bulk of the reservoir in the proposed unit is contained in the Middle Bakken formation. It is important to note that the 0.5 md cutoff effectively ignores pore volume with permeability between 0.2 and 0.49 md that may contain moveable oil. It should also be noted that due to the limited core data in the immediate area and interpolative methods were used to generate the mapping and OOIP numbers for the area.

Reservoir Continuity:

Lateral continuity of the reservoir units is an essential requirement of a successful waterflood. As demonstrated by the cross section (Appendix 1) and the isopach maps, the lateral continuity of the reservoir within the proposed unit is very good.

Vertical reservoir continuity within the Middle Bakken and the underlying remaining upper Lyleton B is likely good but vertical continuity to the lower Lyleton B is probably limited due to the heterolithic depositional environment and the multiple thin shale interbeds found in the lower Lyleton B.

Fluid Contacts:

The oil/water contact for the Middle Bakken and Lyleton reservoir is estimated from production to be at about -525 m subsea. In tight reservoirs such as these the transition zone could be considerable and the top of the transition zone is estimated to be at about -490 m subsea based on production and simulation studies of the reservoir. The postulated oil/water contact at -525 m subsea is below the lowest contour on any of the attached structure contour maps.

OOIP Estimates

OOIP were calculated by Tundra Chief Geologist Barry Larson. 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. The dataset used to determine the OOIP values for the Unit was originally compiled by Barry Larson. It consists of conventional core analysis of all available core in the Daly Sinclair area.A listing of Middle Bakken formation rock and fluid properties used to characterize the reservoir are provided in

Total volumetric OOIP for the Middle Bakken and Lyleton B within the proposed unit has been calculated to be 837.6 E^3m^3 (5,268.6 MSTB) using Tundra internally created maps. Maps used were generated from core data from 316 wells available in the Sinclair area (Appendix 13).

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, thought to be representative of the fluid characteristics in the reservoir.

Historical Production

A historical group production history plot for the proposed Daly Unit No. 11 is shown as Figure 4. Oil production commenced from the proposed Unit area in September 1996 and peaked during May 2012 at 91.9 m^3 OPD. As of December 2014, production was 15.4 m^3 of OPD, 67.7 m^3 of WPD and an 81.5% watercut.

Oil production is currently declining at an annual rate of approximately 23% 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 to 10.2%. 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 covering the N ½ of Section 22-010-29W1 and all of section 27-010-29W1 shall be Daly Unit No. 11.

Unit Operator

Tundra will be the Operator of record for Daly Unit No.11.

Unitized Zone

The Unitized zone(s) to be waterflooded in the Daly Unit No. 11 will be the Middle Bakken and Three Forks formations.

Unit Wells

The 6 horizontal wells and 1 vertical well to be included in the proposed Daly Unit No. 11 are outlined in Table 3.

Unit Lands

Daly Unit No. 11 will consist of 24 LSD as follows:

N ½ of Section 22 of Township 10, Range 29, W1M
All of Section 27 of Township 10, Range 29, W1M

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

Tract Factors

The proposed Daly Unit No. 11 will consist of 24 Tracts based on the 40 acre LSD's containing the existing 6 horizontal producing wells and 1 abandoned vertical well.

The Tract Factor contribution for each of the LSD's within the proposed Daly Unit No. 11 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 in Table 2.

Working Interest Owners

Table 1 outlines the working interest (WI) for each recommended Tract within the proposed Daly Unit No. 11. Tundra holds a 100% WI ownership in all the proposed Tracts. Tundra will have a 100% WI in the proposed Daly Unit No. 11.

WATERFLOOD EOR DEVELOPMENT

Technical Studies

The waterflood performance predictions for the proposed Daly Unit No. 11 are based on internal engineering assessments. Internal reviews included analysis of available open-hole logs; core data; petro-physics; seismic; drilling information; completion information; and production information. These parameters were reviewed to develop a suite of geological maps and establish reservoir parameters to support the calculation of the proposed Daly Unit No. 11 OOIP (Table 4).

Unitizing the proposed Daly Unit No. 11 will provide an extremely equitable means of maximizing ultimate oil recovery in the project area. This is being done to better understand the most effective water flood spacing for future development of the similar quality over a large portion of the Daly area.

Pre-Production of New Horizontal Injection Wells

Primary production from the horizontal producing wells in the proposed Daly Unit No. 11 has declined significantly from peak rate indicating a need for secondary pressure support. It is likely two of the existing producing horizontal wells will be converted to injection wells upon approval as shown in Figure 5, but ultimately the final candidates for injection conversion will be chosen based on production performance post unit approval. This will result in an effective 40 acre line drive waterflood pattern within Daly Unit No. 11. Since the proposed horizontal injection wells have already been on production for a period of time there not necessarily a need for an additional pre-production period within this unit, but again the timing of conversion will be based on production performance post unit approval. It is tundra's desire to have the final injection conversion candidates on injection as soon as possible.

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

Reserves Recovery Profiles and Production Forecasts

The waterflood performance predictions for the proposed Daly Unit No. 11 are based on oil production decline curve analysis, and the secondary waterflood predictions are based on internal engineering analysis performed by the Tundra reservoir engineering group.

Primary Production Forecast:

Cumulative production to the end December 2014 from the 7 wells within the proposed Daly Unit No. 11 project area was 46.9 E^3m^3 of oil, and 174.2 E^3m^3 of water, representing a 5.6% Recovery Factor (RF) of the calculated Net OOIP.

Ultimate Primary Proved Producing oil reserves recovery for Daly Unit No. 11 has been estimated to be 66.2 E^3m^3, or a 7.9% RF of OOIP. Remaining Producing Primary Reserves has been estimated to be 19.3 E^3m^3 to the end of December 2014. The expected production decline and forecasted cumulative oil recovery under continued Primary Production is shown in Figures 7 and 8.

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

Tundra will plan an injection conversion schedule to allow for the most expeditious development of the waterflood within the proposed Daly Unit No. 11 while maximizing knowledge gained for further reservoir characterization (Table 6).

Criteria for Conversion to Water Injection Well:

Two water injection wells are likely required for this proposed unit as shown in Figure 5.

Tundra will monitor the following parameters to assess the best timing for each individual horizontal well to be converted from primary production to water injection service.

- Measured reservoir pressures at start of and/or through primary production
- Fluid production rates and any changes in decline rate
- Any observed production interference effects with adjacent vertical and horizontal wells
- Pattern mass balance and/or oil recovery factor estimates
- Reservoir pressure relative to bubble point pressure

The above schedule allows for the proposed Daly Unit No. 11 to be developed equitably, efficiently, and moves the 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.

Secondary EOR Production Forecast:

Daly Unit No. 11 will be the second horizontal line drive at 40 acre spacing in the Daly portion of the Daly Sinclair Field. The proposed project oil production profile under secondary recovery has been developed based on predictions derived from conventional internal engineering analysis performed by the Tundra reservoir engineering group and therefore Tundra does not believe a 40 acres WF simulation is necessary for the project area.

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 Daly Unit No. 11 is estimated to be 85.6 E^3m^3 with 38.7 E^3m^3 remaining representing a total recovery factor of 10.2% for the proposed Unit area. An incremental 19.4 E^3m^3 of oil, or an incremental 2.3% secondary recovery factor, are forecasted to be recovered under the proposed Unitization and water flood scheme vs. the existing Primary Production method.

Estimated Fracture Gradient

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

Injection water for the proposed Daly Unit No. 11 will be supplied from the Jurassic source water well at 100/02-25-010-29W1 (2-25). Tundra received approval from the Petroleum Branch in March 2013 to use the 2-25 well as a source water well for waterflood operations. Jurassic-sourced water will be pumped from the 2-25 source well to the Daly 12-24-10-29 battery, where it will be filtered and then distributed to the injection system. A diagram of the Daly 12-24 water injection system and new pipeline connection to the project area injection wells is shown as Figure 11.

Produced water is not currently used for any water injection in the Tundra operated Daly Units and there are no current plans to use produced water as a source supply for Daly Unit No. 11. Tundra does not foresee any compatibility issues between the produced and injection waters based on previous compatibility testing performed by a third party, Nalco Champion.

Injection Wells

The water injection wells for the proposed Daly unit No. 11 have been drilled, are currently producing and plans are in progress to re-configure the wells for downhole injection after approval for waterflood has been received (Figure 12). The horizontal injection wells will have been stimulated by multiple hydraulic fracture treatments in a Hybrid Monobore completion design (Figure 13). 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 water injection wells will be placed on injection after the approval to inject has been received from the Petroleum Branch. 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 Operating 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 programmable logic control (PLC). 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. 11 horizontal water injection well rate is forecasted to average 10 – 40 m3 WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure Management during Waterflood

No recent or representative initial pressure surveys are currently available for the vertical producing wells within the proposed Daly Unit No. 11 project area in the Bakken formation. The extremely long shut-in and build-up times required to obtain any possible representative surveys from the producing wells are economically prohibitive. Tundra will make all attempts to capture a reservoir pressure survey in the proposed horizontal injection wells during the completion of the wells and prior to injection or production.

Tundra expects 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 1.2 to 2.0 within the unit during the fill up period. As the cumulative VRR approaches 1.0, target reservoir operating pressure for waterflood operations will be 75-90% of original reservoir pressure.

Waterflood Surveillance and Optimization

Daly Unit No. 11 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 Daly Unit No. 11 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. 11.

On Going Reservoir Pressure Surveys

For each cemented liner horizontal injection well, a measured reservoir pressure will be obtained prior to water injection. These pressures will be reported within the Annual Progress Reports for Daly Unit No. 11 as per Section 73 of the Drilling and Production Regulation.

Economic Limits

Under the current Primary recovery method, existing wells within the proposed Daly Unit No. 11 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 cutoff 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 Daly Unit No. 11 waterflood operation will utilize the Tundra operated well 100/02-25-10-29W1, sourced from the Jurassic, and water plant (WP) facilities located at the Daly 12-24-10-29W1 battery (Figure 11).

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Figure 14. All surface facilities and wellheads will have cathodic protection to prevent corrosion. All injection flowlines will be made of fiberglass so corrosion will not be an issue. Injectors will have a packer set above the Middle Bakken and Three Forks formations, and the annulus between the tubing and casing will be filled with inhibited fluid.

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 Daly Unit No. 11. 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 Daly Unit No. 11 Application.

Daly Unit No. 11 Unitization, and execution of the formal Daly Unit No. 11 Agreement by affected Mineral Owners, is expected during Q4 2015. Copies of same will be forwarded to the Petroleum Branch, when available, to complete the Daly Unit No. 11 Application.

Should the Petroleum Branch have further questions or require more information, please contact Cary Reid at (403) 536-0787 or by email at cary.reid@tundraoilandgas.com

TUNDRA OIL & GAS PARTNERSHIP

Original Signed by Cary Reid, P.L. (Eng.)

Proposed Daly Unit No. 11

Application for Enhanced Oil Recovery Waterflood Project

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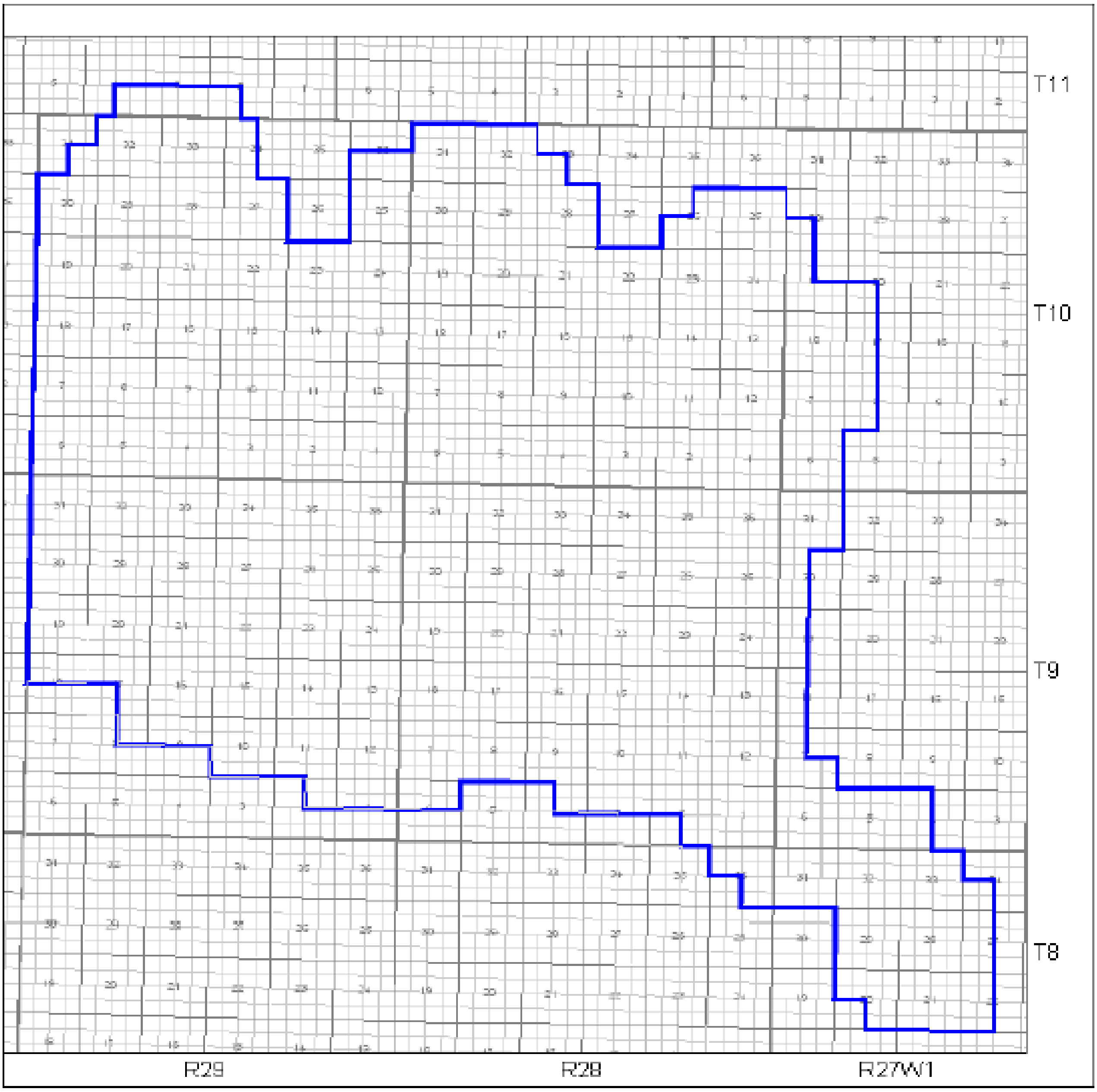

Daly Field

Daly Field Boundary

Source: Manitoba Petroleum Branch Designated Fields and Pools – 2009

Figure 1

Figure No. 2

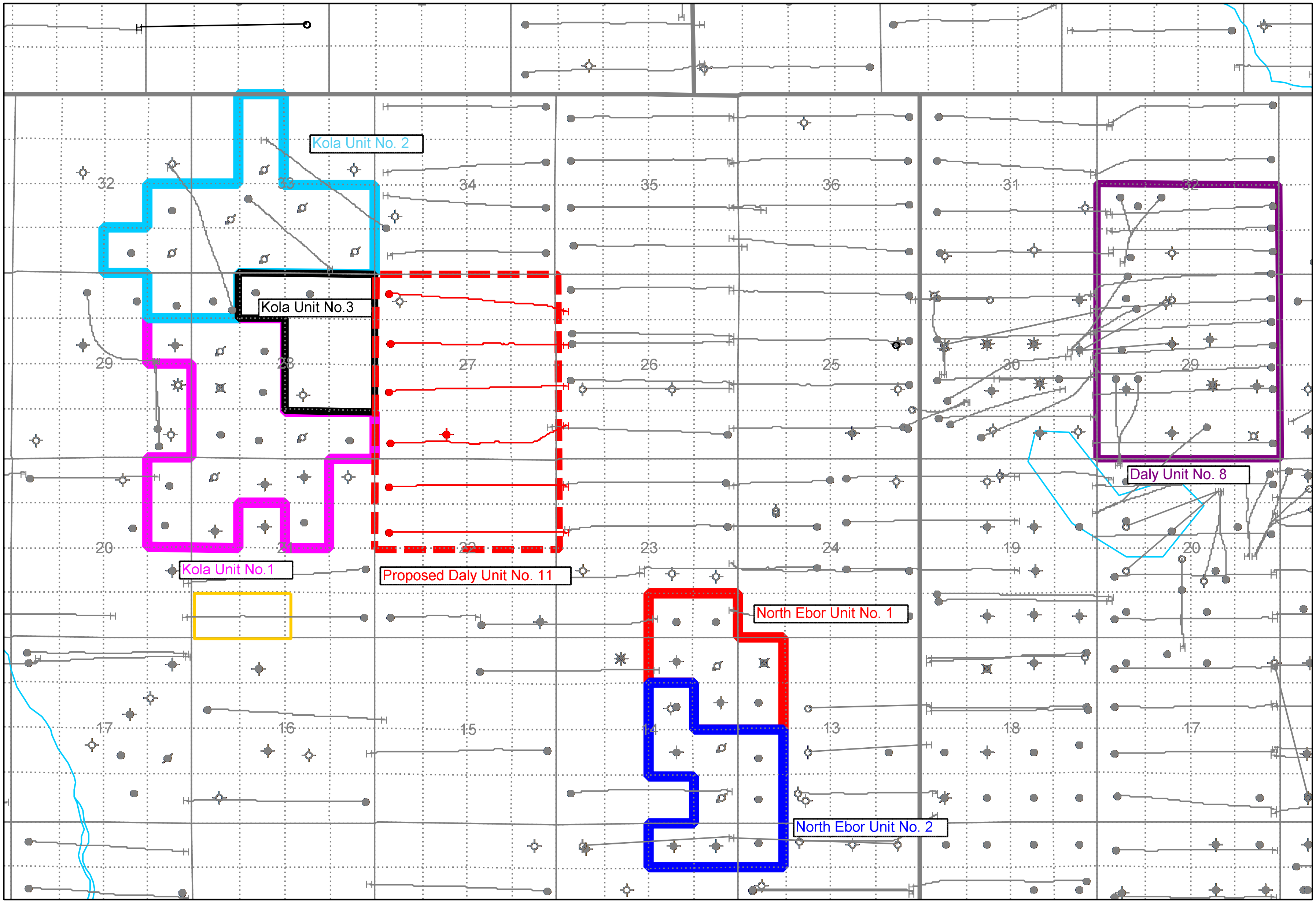

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Figure No. 3

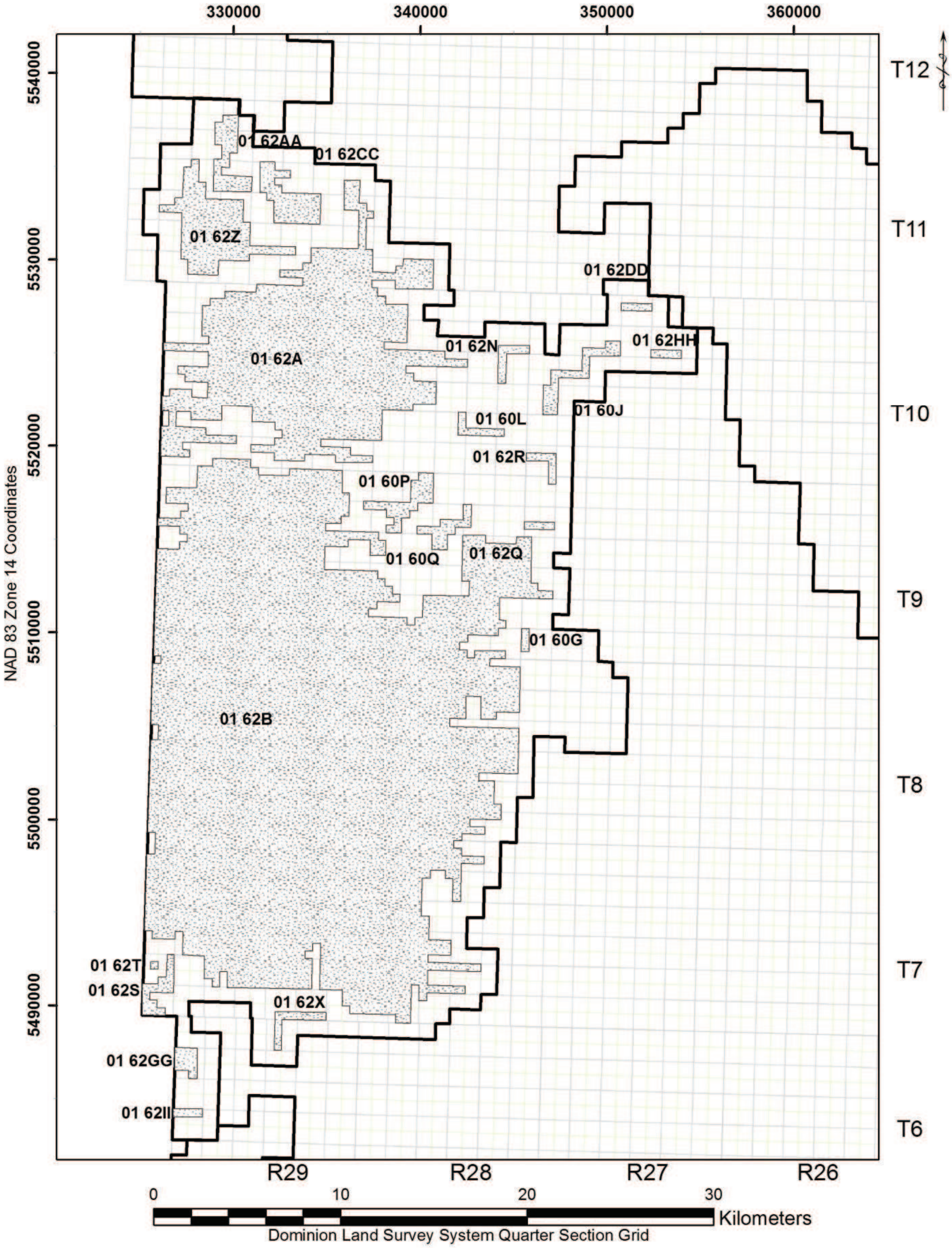


Figure 13 - Daly Sinclair Bakken & Bakken-Three Forks Pools (01 60A - 01 60BB & 01 62A – 01 62II)

Figure No. 4

Well Information as of 3/18/2015 - Group Well Report

Production Graph

Group:	daly unit no. 11.lwell	**Prod Form:**	THREEFK; BAKKEN	**On Prod:**	1996-09 to 2014-12
# of Wells:	7	**Field:**	DALY (1)	**Cum Oil:**	46863.4 m3
Fluid:	Oil	**Pool Code:**	62A	**Cum Gas:**	0.0 E3m3
Mode:	Abandoned; Producing	**Unit Code:**		**Cum Wtr:**	174188.4 m3

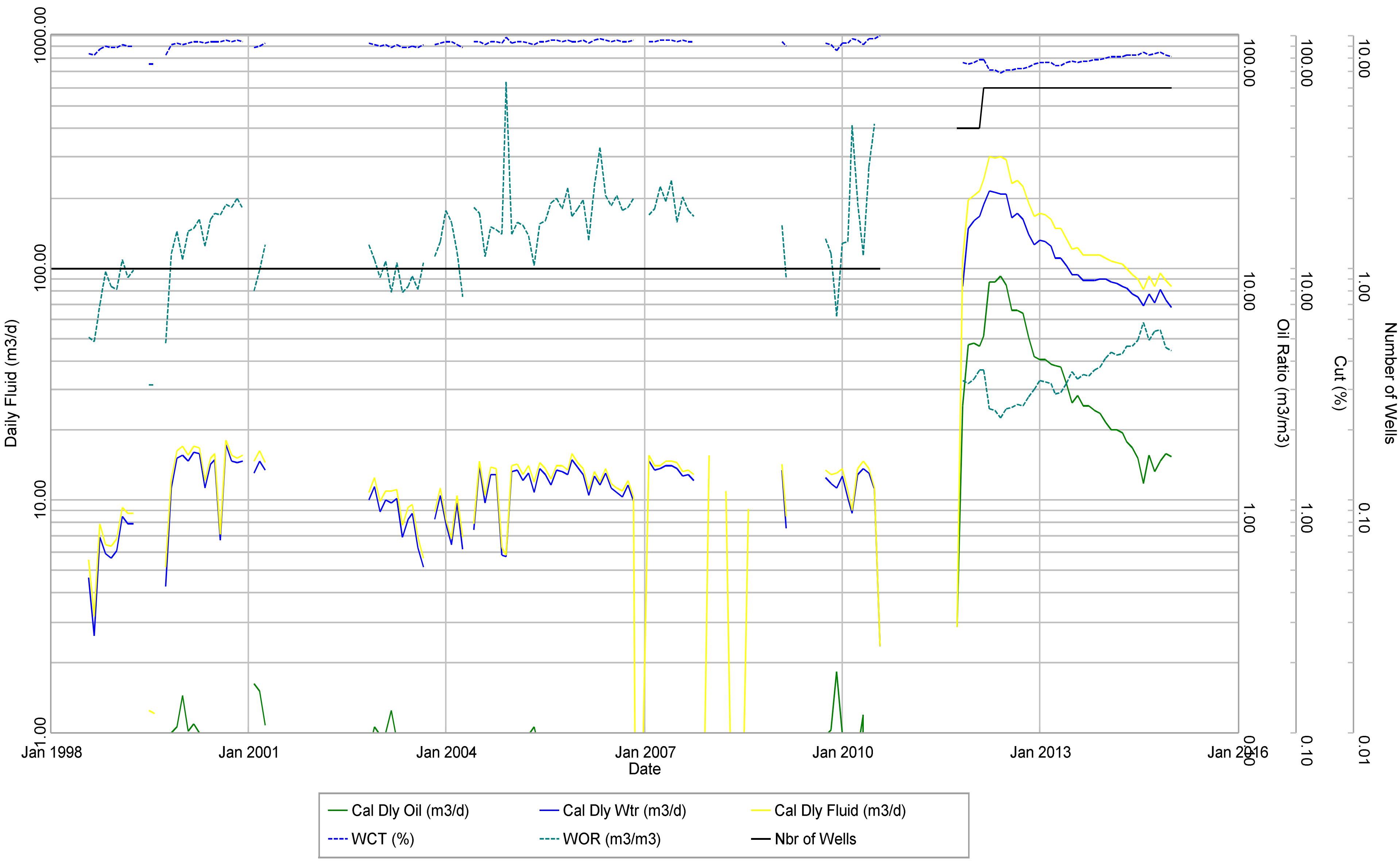
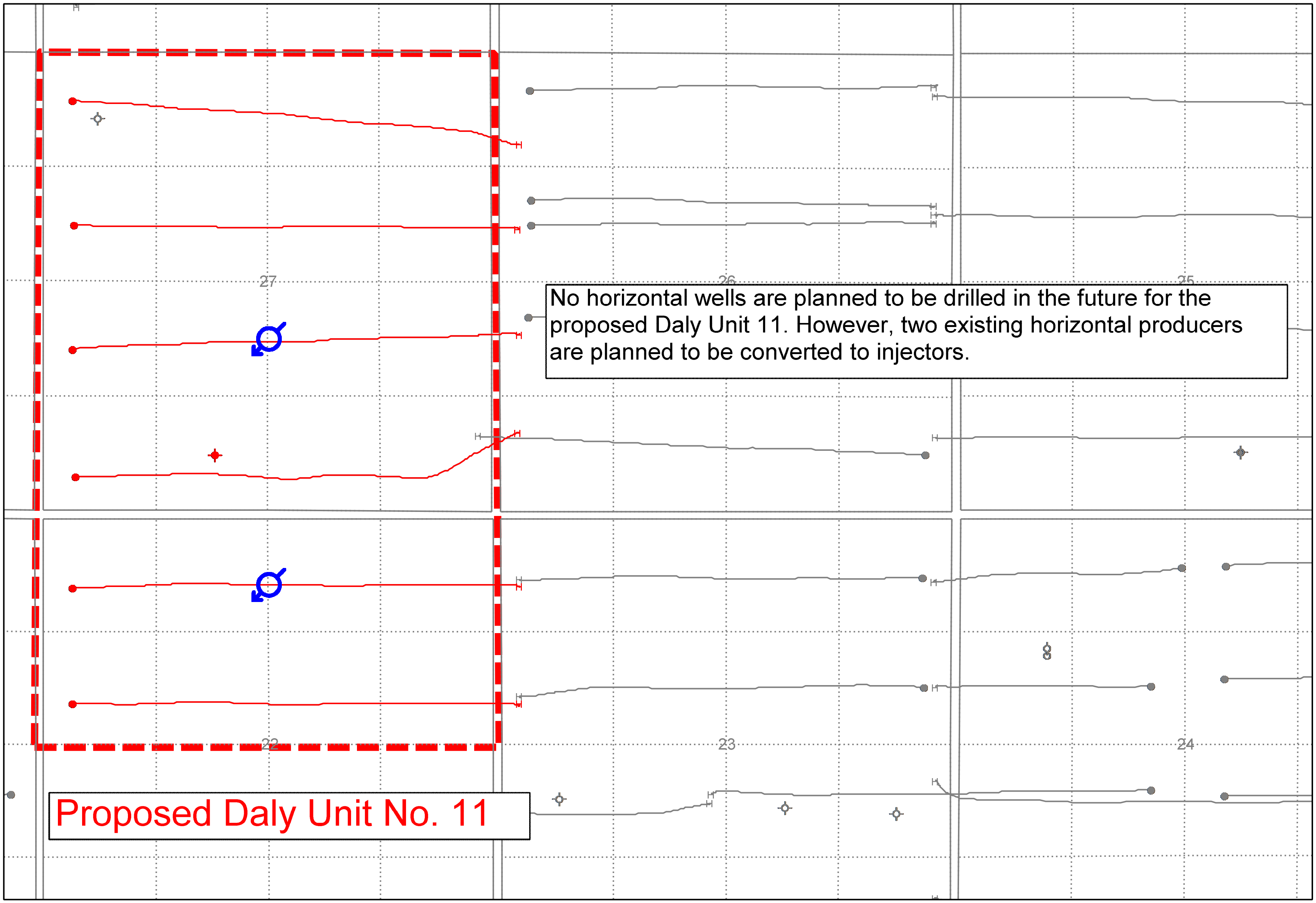


Figure No. 5



Datum: NAD27 Projection: Stereographic DLS Version AB: ATS 2.6, BC: PRB 2.0, SK: STS 2.5, MB: MLI07

Production Graph

Figure No. 6

Group:	sinclair unit no. 1 section 4 well list.wls	**Prod Form:**	BAKKEN; TORQUAY	**On Prod:**	2004-12 to 2014-11
# of Wells:	16	**Field:**	DALY (1)	**Cum Oil:**	962915.4 bbl
Fluid:	Water Injection; Oil	**Pool Code:**	62B	**Cum Gas:**	0.0 mcf
Mode:	Injection; Producing	**Unit Code:**	162B01	**Cum Wtr:**	156271.5 bbl

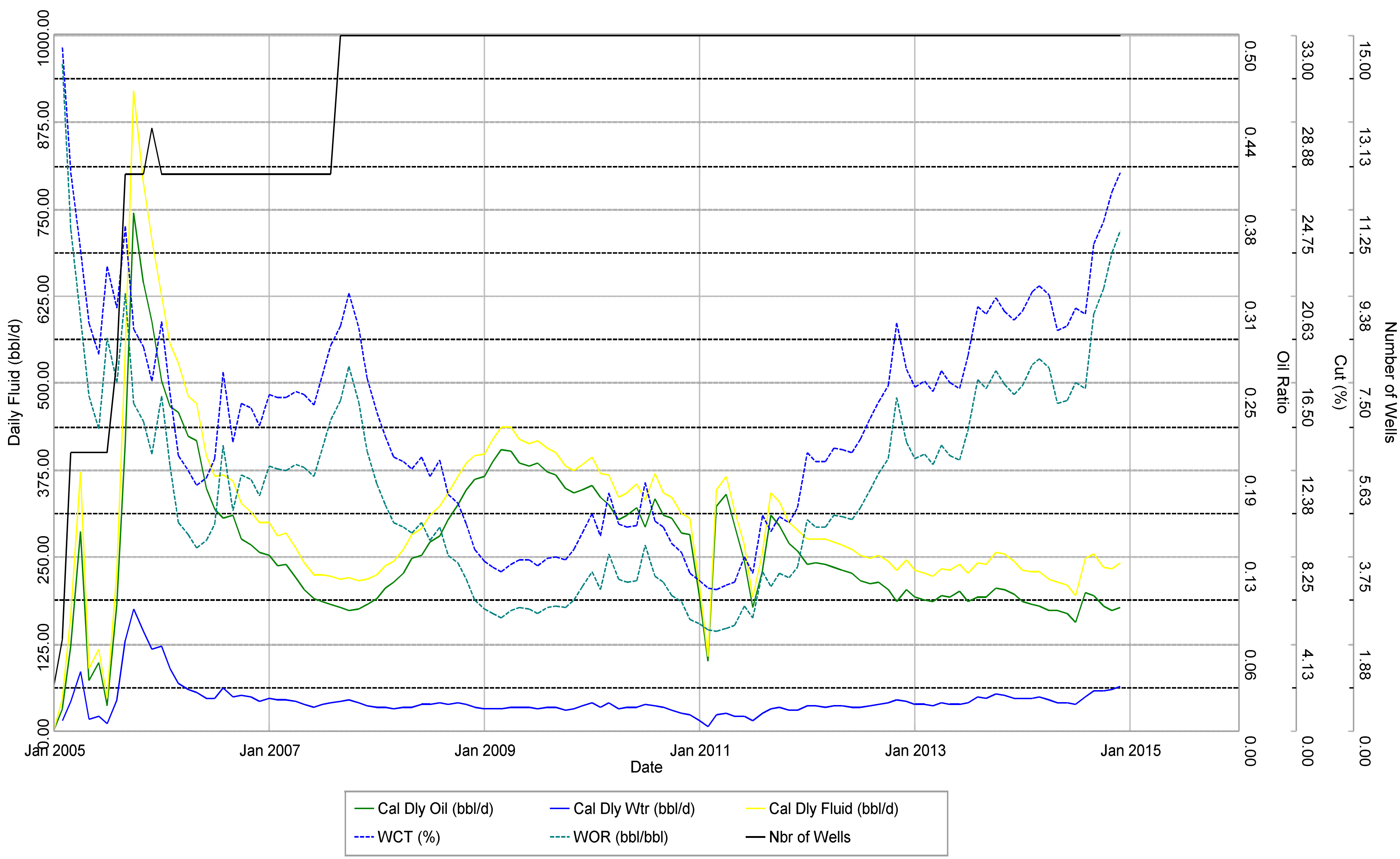


Figure No. 7 - Base Forecast - Oil Rate vs Time

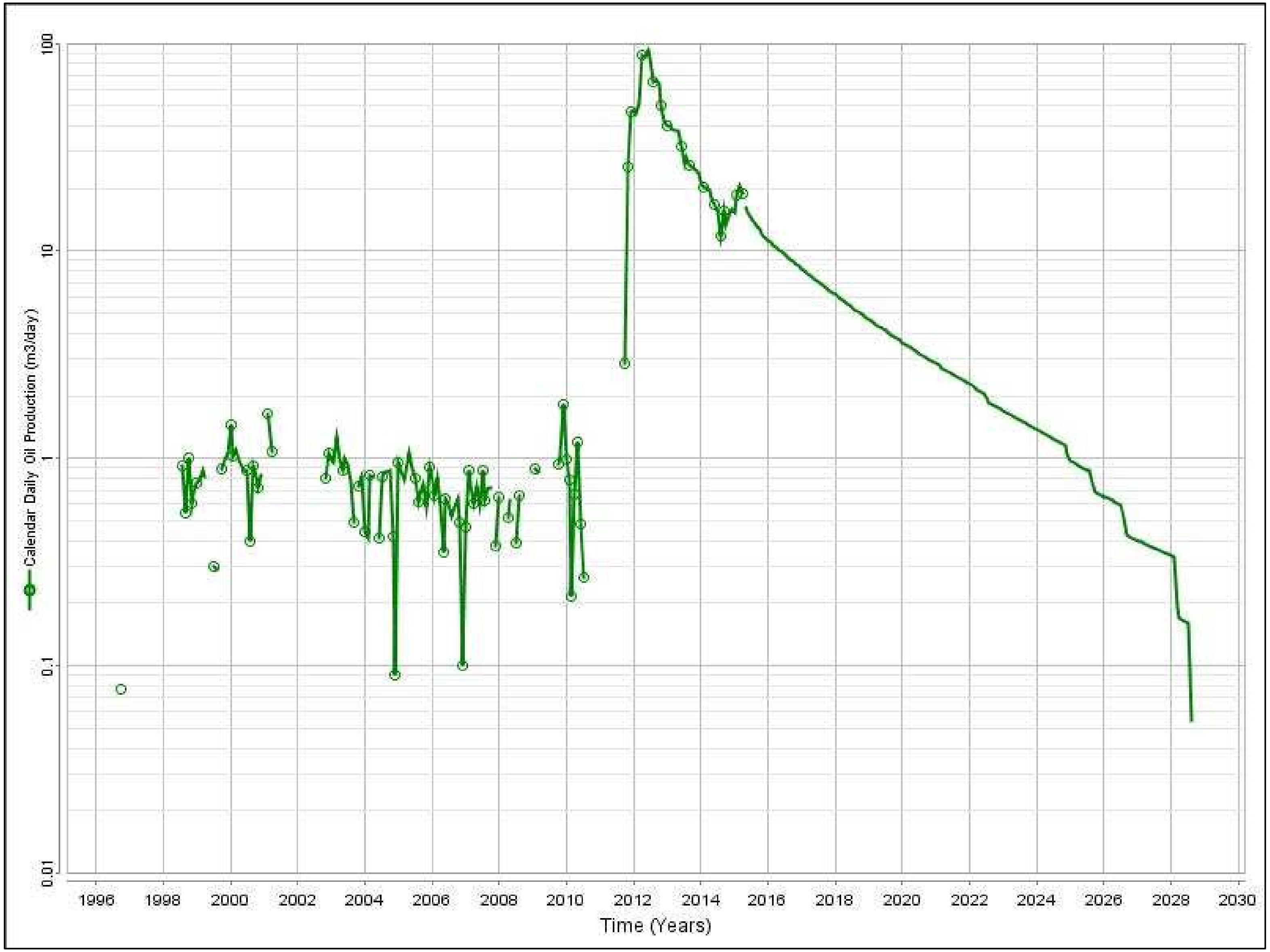


Figure No. 8 - Base Forecast - Oil Rate vs. Cumulative Oil

Figure No. 9 - Base + Growth Forecast - Oil Rate vs Time

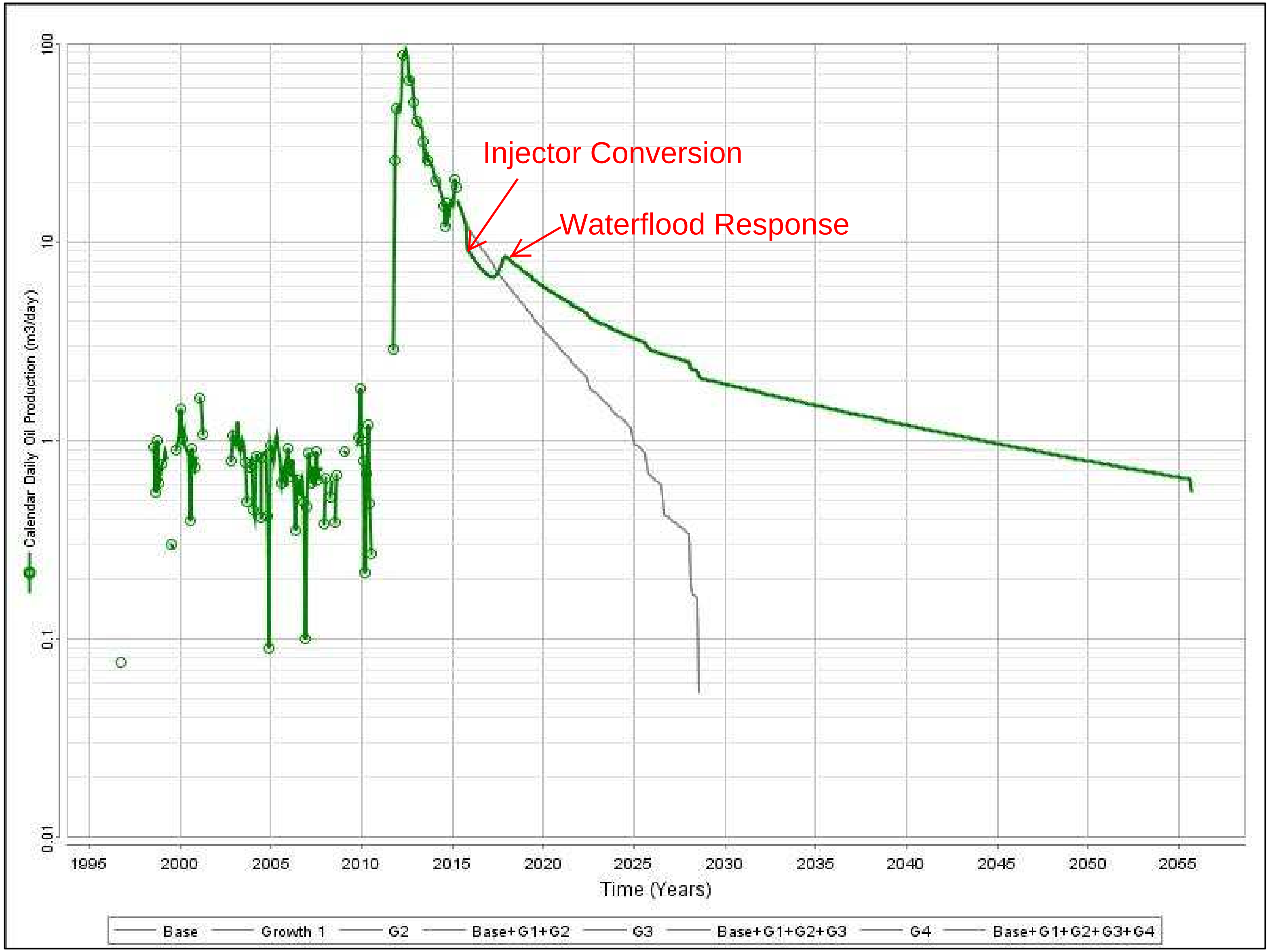
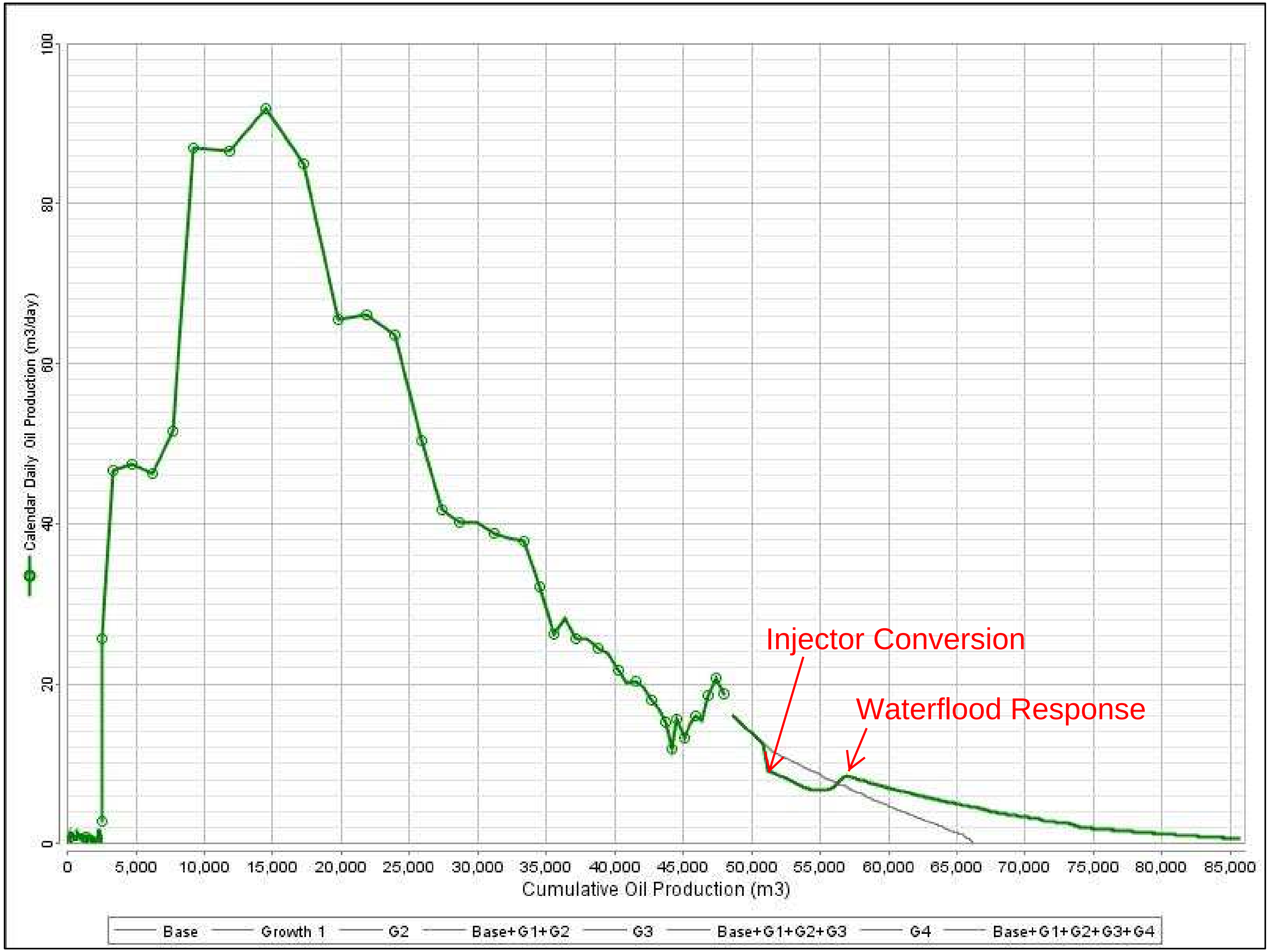
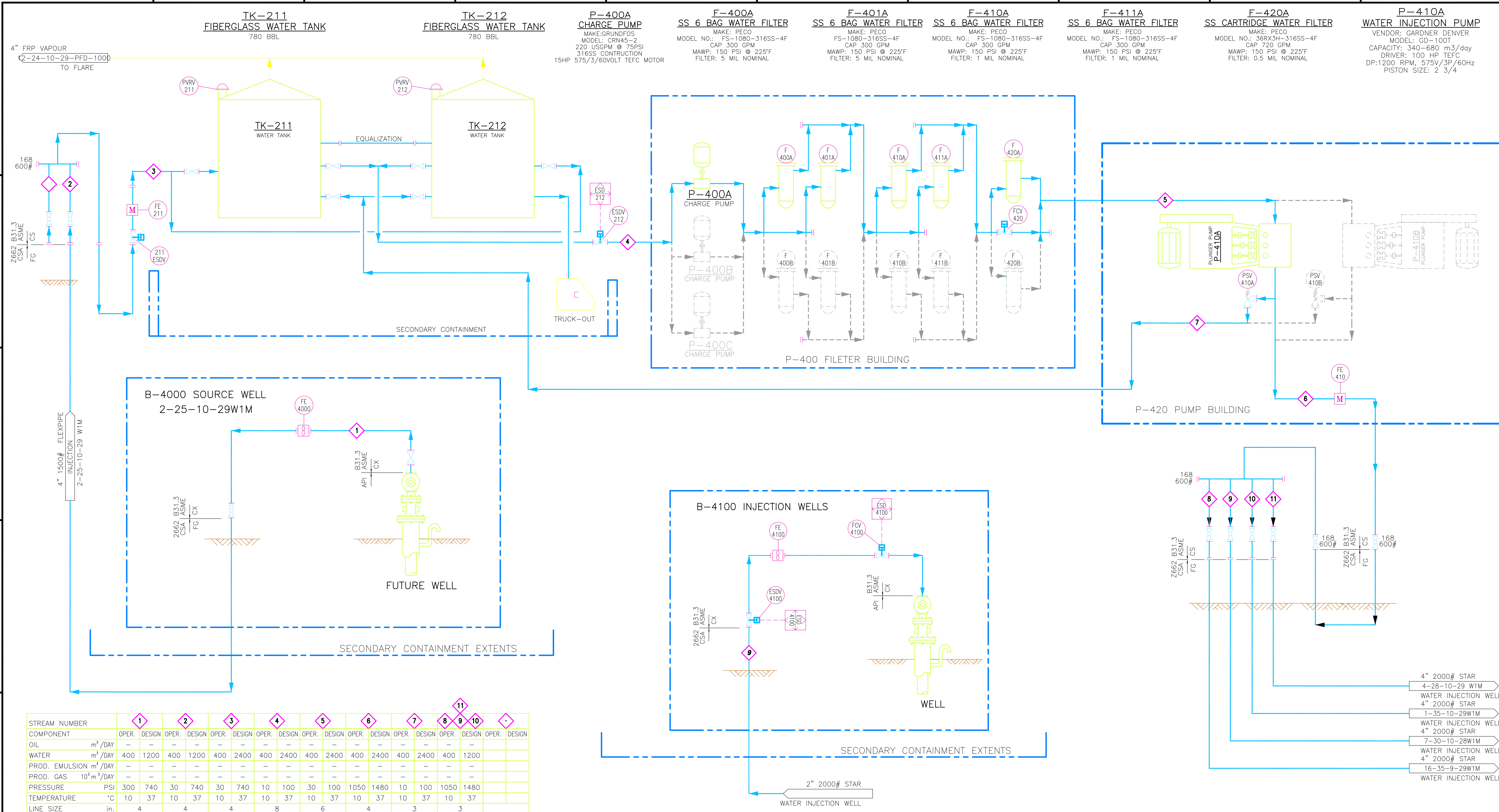


Figure No. 10 - Base + Growth - Oil Rate vs Cumulative Oil





STREAM NUMBER	1		2		3		4		5		6		7		8 / 9 / 10 / 11		·	
COMPONENT	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN
OIL m³/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		
WATER m³/DAY	400	1200	400	1200	400	2400	400	2400	400	2400	400	2400	400	2400	400	1200		
PROD. EMULSION m³/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		
PROD. GAS 10³m³/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		
PRESSURE PSI	300	740	30	740	30	740	10	100	30	100	1050	1480	10	100	1050	1480		
TEMPERATURE °C	10	37	10	37	10	37	10	37	10	37	10	37	10	37	10	37		
LINE SIZE in.	4		4		4		8		6		4		3		3			

REV	DESCRIPTION	BY	DATE	CHK	APP
0	ISSUED FOR CONSTRUCTION	JC	30MAY2013	BE	–

REFERENCE DRAWING

–

NOTES:

Figure No. 11

TUNDRA OIL & GAS PARTNERSHIP

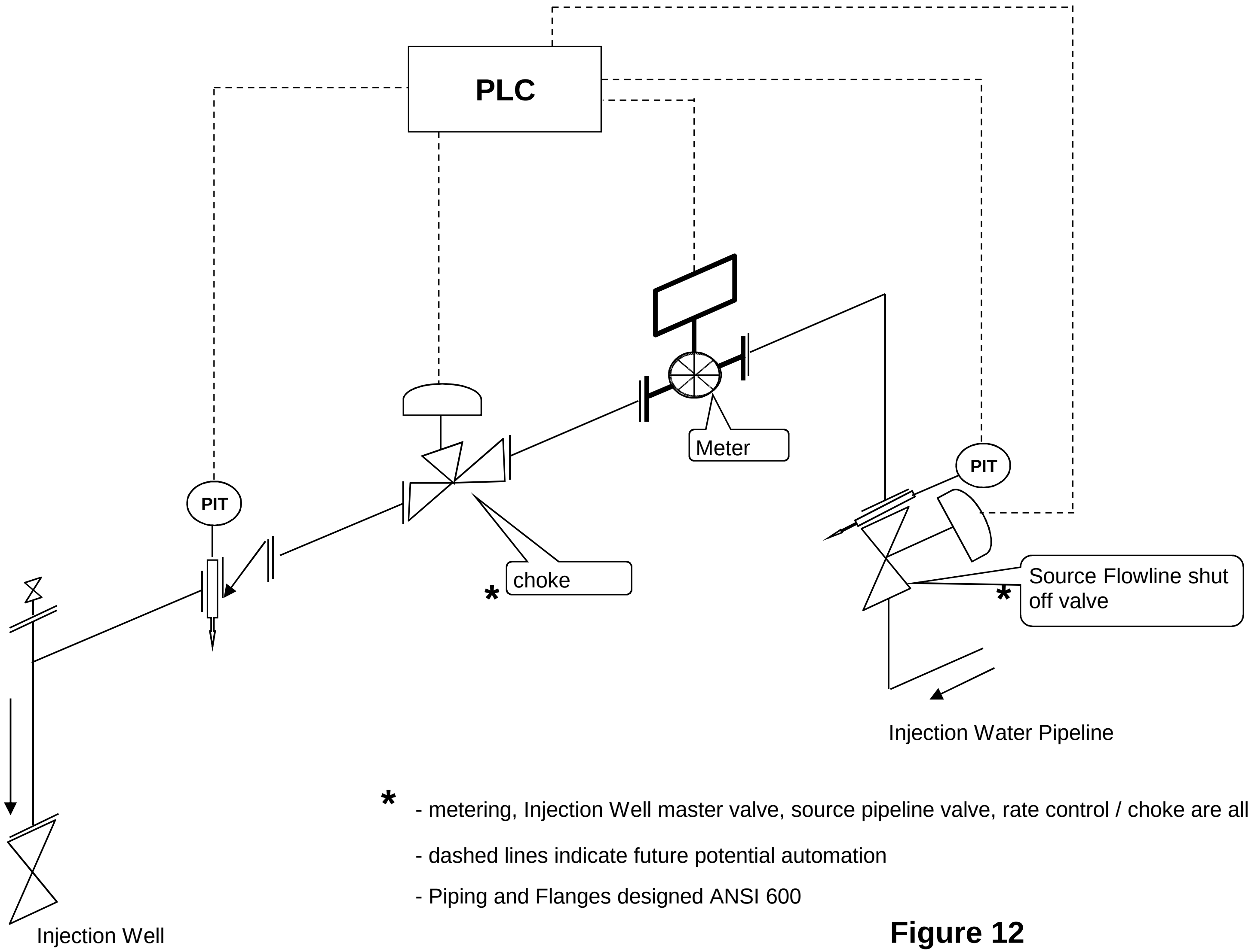
PROCESS FLOW DIAGRAM
12-24-10-29W1M

PROCESS FLOW DIAGRAM 4 OF 4
INJECTION SYSTEM

DRAWN BY:	SCALE:	AFE:	DRAWING NUMBER:	REV NO:
RM	NTS		12-24-10-29-PFD-1400	0

Daly Unit No. 11

Proposed Injection Well Surface Piping P&ID



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

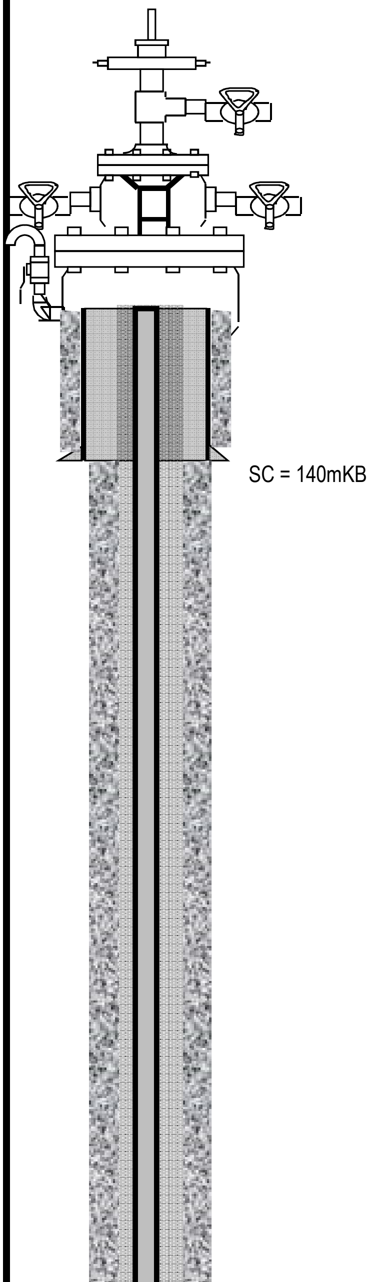
- dashed lines indicate future potential automation

- Piping and Flanges designed ANSI 600

Figure 12

Tundra Oil And Gas Partnership

TYPICAL CEMENTED LINER WATER INJECTION WELL (WIW) DOWNHOLE DIAGRAM



WELL NAME:	Tundra Daly Unit No. 11 HZNTL Cemented Liner 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:	**Cemented Casing / Liner**			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
Production Liner	114.3	17.26	L-80	Surf or from Intermed Csg 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:		Length	Top @
Item	Description	K.B.--Tbg. Flg. 0.00	m KB
	Corrosion Protected ENC Coated Packer (set inside 114.3 mm Casing / Liner)		
	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:

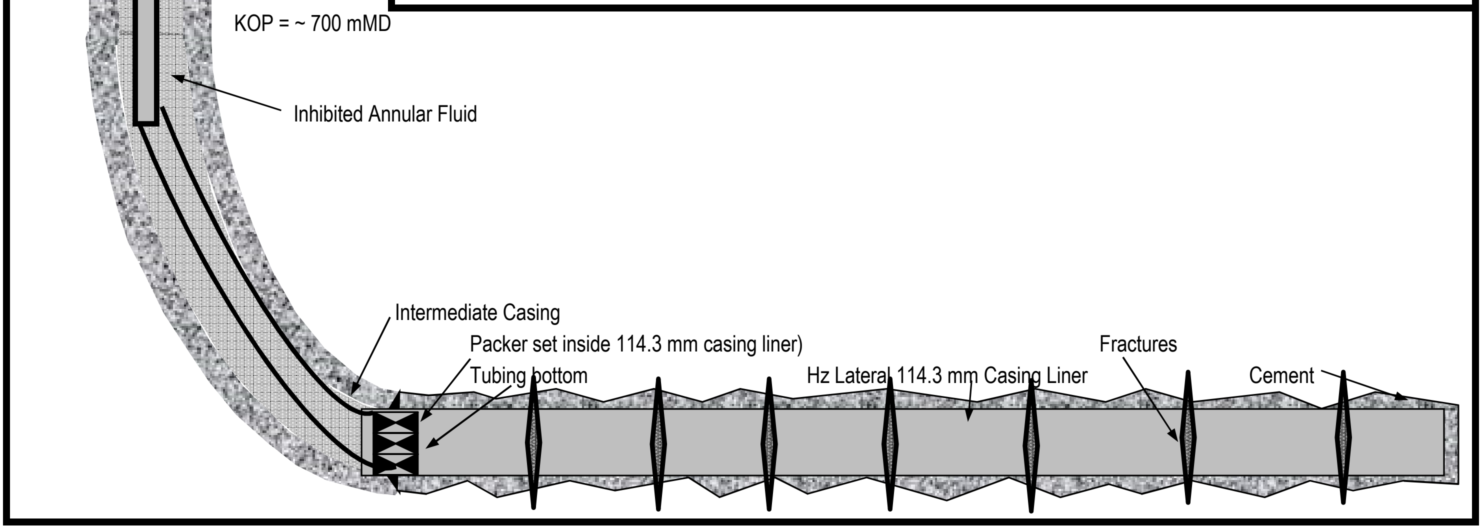


Figure 14 – Corrosion Controls

Injection Wells

- Corrosion inhibitor in the annulus between tubing and casing.
- Surface freeze protection of annular fluids near surface.
- Corrosion-resistant valves on wellhead and flowline.
- Corrosion-resistant flowline equipment.
- Installation of cathodic protection to protect casing.
- Scale inhibitor protection as needed.
- Bacteria control chemical treatments when needed.
- Water injector packer will be coated for corrosion resistance.

Producing Wells

- Downhole corrosion inhibitor, either batch or daily injection, as needed.
- Scale inhibitor treatment daily injection as required for horizontal wells.
- Paraffin treatment daily injection if needed.
- Casing cathodic protection where required.

Pipelines

- The water source line will be Flexcord 2000# pipe.
- Injection lines will be a mix of Flexpipe 601 pipe and Centron 2000# pipe.
- Producing lines existing as per original flowline licenses.
-

Facilities

12-24-10-29 Water Plant

- Plant piping – internally coated, fiberglass or stainless steel.
- Filtration – stainless steel.
- Pumps – ceramic plungers, stainless steel disc valves.
- Tanks – fiberglass with stainless steel valves.

Proposed Daly Unit No. 11

Application for Enhanced Oil Recovery Waterflood Project

List of Tables

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TABLE NO. 1: TRACT PARTICIPATION FOR PROPOSED DALY UNIT NO. 11

Working Interest				Royalty Interest		Tract Participation
Tract No.	**Land Description**	**Owner**	**Share (%)**	**Owner**	**Share (%)**	
1	09-22-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	2.967250880%
2	10-22-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	3.364373197%
3	11-22-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	3.822912212%
4	12-22-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	4.297368111%
5	13-22-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	4.815270898%
6	14-22-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	4.166976170%
7	15-22-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	3.705841781%
8	16-22-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	3.388054334%
9	01-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	3.561038741%
10	02-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	4.019091943%
11	03-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	4.176182578%
12	04-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	5.061967226%
13	05-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	5.234179747%
14	06-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	4.812505884%
15	07-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	4.190404132%
16	08-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Tundra Oil & Gas Partnership 6320040 Manitoba Ltd.	50% 50%	3.816745406%
17	09-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	3.652120627%
18	10-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	4.071205754%
19	11-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	4.587607170%
20	12-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	5.075662114%
21	13-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	5.141919085%
22	14-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	4.682931810%
23	15-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	3.962260778%
24	16-27-010-29W1M	Tundra Oil & Gas Partnership	100%	Bank of Nova Scotia Trust Company	100%	3.426129419%
						100.000000000%

TABLE NO. 2: TRACT FACTOR CALCULATIONS FOR DALY UNIT NO. 11

TRACT FACTORS BASED ON OIL-IN-PLACE (OOIP) MINUS CUMULATIVE PRODUCTION TO DECEMBER 2014

LS-SE	Tract	*OOIP (m3)*	HZ Wells Alloc Prod (m3)	Vert Wells Cum Prodn (m3)	Sum Hz + Vert Alloc Cum Prodn	OOIP - Cum Prodn	Tract Factor	Tract
09-22	09-22-010-29W1M	24,688	1,224.2	0.0	1,224.2	23,464	2.967250880%	09-22-010-29W1M
10-22	10-22-010-29W1M	27,956	1,351.5	0.0	1,351.5	26,604	3.364373197%	10-22-010-29W1M
11-22	11-22-010-29W1M	31,580	1,350.0	0.0	1,350.0	30,230	3.822912212%	11-22-010-29W1M
12-22	12-22-010-29W1M	35,270	1,288.2	0.0	1,288.2	33,982	4.297368111%	12-22-010-29W1M
13-22	13-22-010-29W1M	39,742	1,665.0	0.0	1,665.0	38,077	4.815270898%	13-22-010-29W1M
14-22	14-22-010-29W1M	34,688	1,737.1	0.0	1,737.1	32,951	4.166976170%	14-22-010-29W1M
15-22	15-22-010-29W1M	31,042	1,737.7	0.0	1,737.7	29,304	3.705841781%	15-22-010-29W1M
16-22	16-22-010-29W1M	28,347	1,555.6	0.0	1,555.6	26,791	3.388054334%	16-22-010-29W1M
01-27	01-27-010-29W1M	29,516	1,357.0	0.0	1,357.0	28,159	3.561038741%	01-27-010-29W1M
02-27	02-27-010-29W1M	33,262	1,480.2	0.0	1,480.2	31,781	4.019091943%	02-27-010-29W1M
03-27	03-27-010-29W1M	36,963	1,477.9	2,461.2	3,939.1	33,024	4.176182578%	03-27-010-29W1M
04-27	04-27-010-29W1M	41,396	1,368.3	0.0	1,368.3	40,028	5.061967226%	04-27-010-29W1M
05-27	05-27-010-29W1M	42,723	1,333.0	0.0	1,333.0	41,390	5.234179747%	05-27-010-29W1M
06-27	06-27-010-29W1M	39,488	1,432.7	0.0	1,432.7	38,055	4.812505884%	06-27-010-29W1M
07-27	07-27-010-29W1M	34,570	1,433.6	0.0	1,433.6	33,136	4.190404132%	07-27-010-29W1M
08-27	08-27-010-29W1M	31,544	1,363.0	0.0	1,363.0	30,181	3.816745406%	08-27-010-29W1M
09-27	09-27-010-29W1M	31,303	2,423.1	0.0	2,423.1	28,880	3.652120627%	09-27-010-29W1M
10-27	10-27-010-29W1M	34,825	2,631.4	0.0	2,631.4	32,194	4.071205754%	10-27-010-29W1M
11-27	11-27-010-29W1M	38,908	2,631.4	0.0	2,631.4	36,277	4.587607170%	11-27-010-29W1M
12-27	12-27-010-29W1M	42,617	2,480.4	0.0	2,480.4	40,136	5.075662114%	12-27-010-29W1M
13-27	13-27-010-29W1M	43,374	2,713.5	0.0	2,713.5	40,660	5.141919085%	13-27-010-29W1M
14-27	14-27-010-29W1M	39,867	2,836.0	0.0	2,836.0	37,031	4.682931810%	14-27-010-29W1M
15-27	15-27-010-29W1M	34,177	2,844.5	0.0	2,844.5	31,332	3.962260778%	15-27-010-29W1M
16-27	16-27-010-29W1M	29,779	2,686.9	0.0	2,686.9	27,092	3.426129419%	16-27-010-29W1M
	m3	**837,624**				**790,761**	**100.000000000%**	
	Mbbl	**5,268**						

TABLE NO. 3: DALY UNIT NO. 11 WELL LIST

UWI	*License Number*	*Type*	*Pool Name*	*Producing Zone*	*Mode*	*On Prod Date*	*Last 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 (%)**
100/12-22-010-29W1/0	008121	HORIZONTAL	BAKKEN-THREE FORKS A	BAKKEN	Producing	9/1/2011	12/31/2014	1.4	43.8	5213.9	10.3	317.8	19558.9	87.89
100/13-22-010-29W1/0	008122	HORIZONTAL	BAKKEN-THREE FORKS A	BAKKEN	Producing	9/1/2011	12/31/2014	1.6	49.7	6695.4	14.5	448.1	30048.9	90.02
100/03-27-010-29W1/2	003835	VERTICAL	BAKKEN-THREE FORKS A	THREEFK,BAKKEN	Abandoned	9/1/1996	7/31/2010	0.0	0.0	2461.2	2.4	73.0	33369.4	100.00
100/04-27-010-29W1/0	008116	HORIZONTAL	BAKKEN-THREE FORKS A	BAKKEN	Producing	9/1/2011	12/31/2014	1.6	49.6	5683.4	28.8	894.1	51896.1	94.74
100/05-27-010-29W1/0	008090	HORIZONTAL	BAKKEN-THREE FORKS A	BAKKEN	Producing	9/1/2011	12/31/2014	0.2	7.1	5562.3	5.4	167.2	14912.9	95.93
100/12-27-010-29W1/0	008444	HORIZONTAL	BAKKEN-THREE FORKS A	BAKKEN	Producing	2/1/2012	12/31/2014	4.7	145.7	10166.3	5.3	165.8	12649.8	53.23
102/13-27-010-29W1/0	008445	HORIZONTAL	BAKKEN-THREE FORKS A	BAKKEN	Producing	2/1/2012	12/31/2014	5.8	181.0	11080.9	3.4	105.2	11752.4	36.76
										46,863.4			174,188.4	

TABLE NO. 4: OOIP FOR DALY UNIT NO.11

UWI	MBKKN	Lyleton B	Total OOIP GLJ cut offs (m3)	MB Phi-h	LB Phi-h	SW MBKKN	SW Lyleton UA	SW Lyleton LA	SW Lyleton B
	0.5 md	0.5 md	0.5 md	0.5 md	0.5 md				
09-22-010-29W1M	24,688	0	24,688	0.26329	0.11886	0.45	0.45	0.45	0.45
10-22-010-29W1M	27,956	0	27,956	0.31133	0.14400	0.45	0.45	0.45	0.45
11-22-010-29W1M	31,580	0	31,580	0.36343	0.17199	0.45	0.45	0.45	0.45
12-22-010-29W1M	35,270	0	35,270	0.41997	0.20613	0.45	0.45	0.45	0.45
13-22-010-29W1M	39,742	0	39,742	0.46194	0.18807	0.45	0.45	0.45	0.45
14-22-010-29W1M	34,688	0	34,688	0.40241	0.16096	0.45	0.45	0.45	0.45
15-22-010-29W1M	31,042	0	31,042	0.34732	0.13650	0.45	0.45	0.45	0.45
16-22-010-29W1M	28,347	0	28,347	0.29809	0.11585	0.45	0.45	0.45	0.45
01-27-010-29W1M	29,516	0	29,516	0.18979	0.03256	0.45	0.45	0.45	0.45
02-27-010-29W1M	33,262	0	33,262	0.19364	0.03570	0.45	0.45	0.45	0.45
03-27-010-29W1M	36,963	0	36,963	0.19999	0.03898	0.45	0.45	0.45	0.45
04-27-010-29W1M	41,396	0	41,396	0.20831	0.04219	0.45	0.45	0.45	0.45
05-27-010-29W1M	42,723	0	42,723	0.21691	0.04238	0.45	0.45	0.45	0.45
06-27-010-29W1M	39,488	0	39,488	0.20662	0.03816	0.45	0.45	0.45	0.45
07-27-010-29W1M	34,570	0	34,570	0.19953	0.03468	0.45	0.45	0.45	0.45
08-27-010-29W1M	31,544	0	31,544	0.19494	0.03122	0.45	0.45	0.45	0.45
09-27-010-29W1M	31,303	0	31,303	0.19785	0.00000	0.45	0.45	0.45	0.45
10-27-010-29W1M	34,825	0	34,825	0.20227	0.03290	0.45	0.45	0.45	0.45
11-27-010-29W1M	38,908	0	38,908	0.20973	0.03676	0.45	0.45	0.45	0.45
12-27-010-29W1M	42,617	0	42,617	0.21825	0.04071	0.45	0.45	0.45	0.45
13-27-010-29W1M	43,374	0	43,374	0.21699	0.00000	0.45	0.45	0.45	0.45
14-27-010-29W1M	39,867	0	39,867	0.20946	0.00000	0.45	0.45	0.45	0.45
15-27-010-29W1M	34,177	0	34,177	0.20400	0.00000	0.45	0.45	0.45	0.45
16-27-010-29W1M	29,779	0	29,779	0.19880	0.00000	0.45	0.45	0.45	0.45
			837,624	**m3**					
			5,268	**Mbbl**					

Table 5 - Daly Unit No. 11: Reservoir and Fluid Properties

	Units	Bakken
Depth	m	825
Initial Reservoir Pressure	kPa	8,200
Formation Temperature	^{o}C	30
Saturation Pressure	kPa	1,675
Fracture Pressure	kPa	14,500
Solution GOR	m3/m3	5
Oil Gravity (dead oil)	^{o}API	42
Bo @ Psat	m3/m3	1.03
Initial Water Saturation	dec	0.55
Wettability		neutral
Average Porosity	%	16.2
Average Permeability	mD	30
Water Salinity	mg/L	113,000

Table No. 6: Daly Unit No. 11 Project Schedule

Timing	Infill Drilling	Injector Conversions
Q1 2015	-	-
Q2 2015	-	-
Q3 2015	-	-
Q4 2015	-	2

Proposed Daly Unit No. 11

Application for Enhanced Oil Recovery Waterflood Project

List of Appendices

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Appendix 7	Lyleton B Structure
Appendix 8	Torquay Structure
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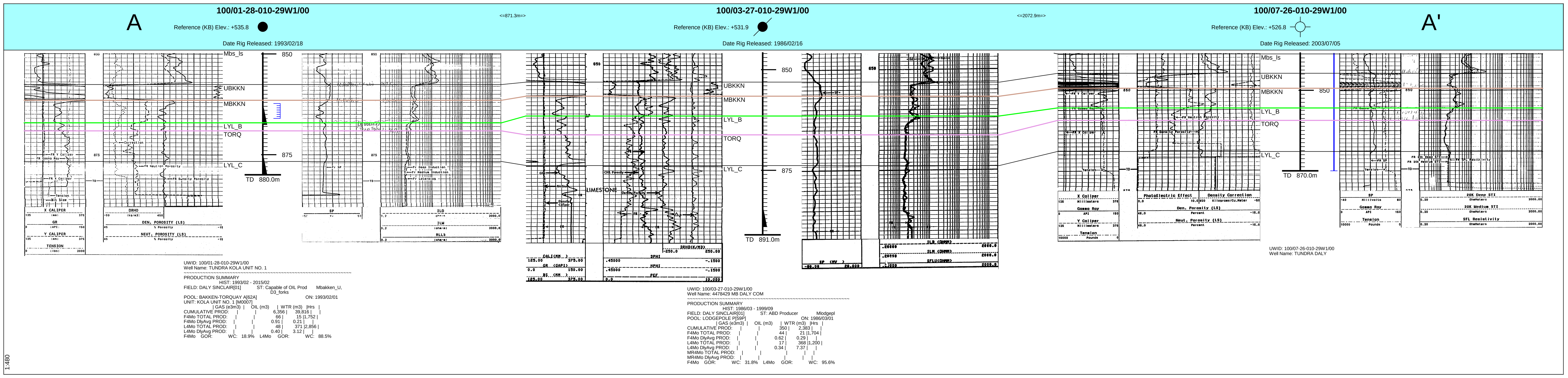
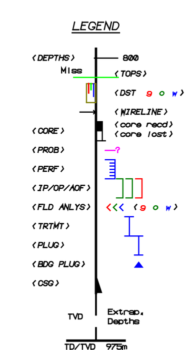
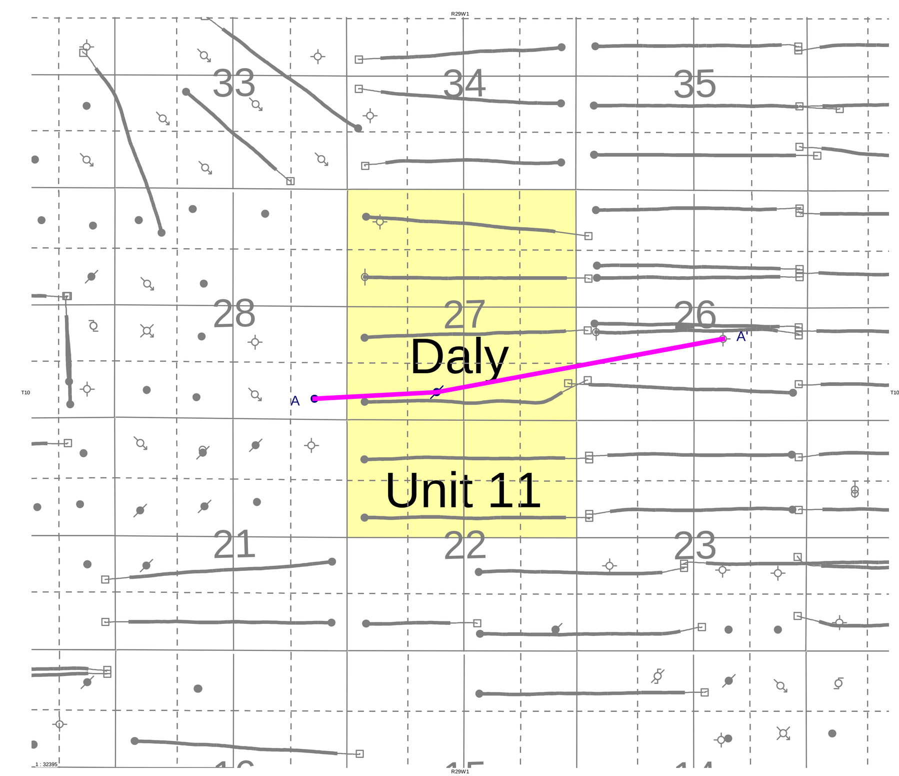
Appendix 10	Middle Bakken phi*h @ 0.5 mD CO
Appendix 11	Lyleton B k*h @ 0.5 mD CO
Appendix 12	Lyleton B phi*h @ 0.5 mD CO
Appendix 13	Area Cored Wells



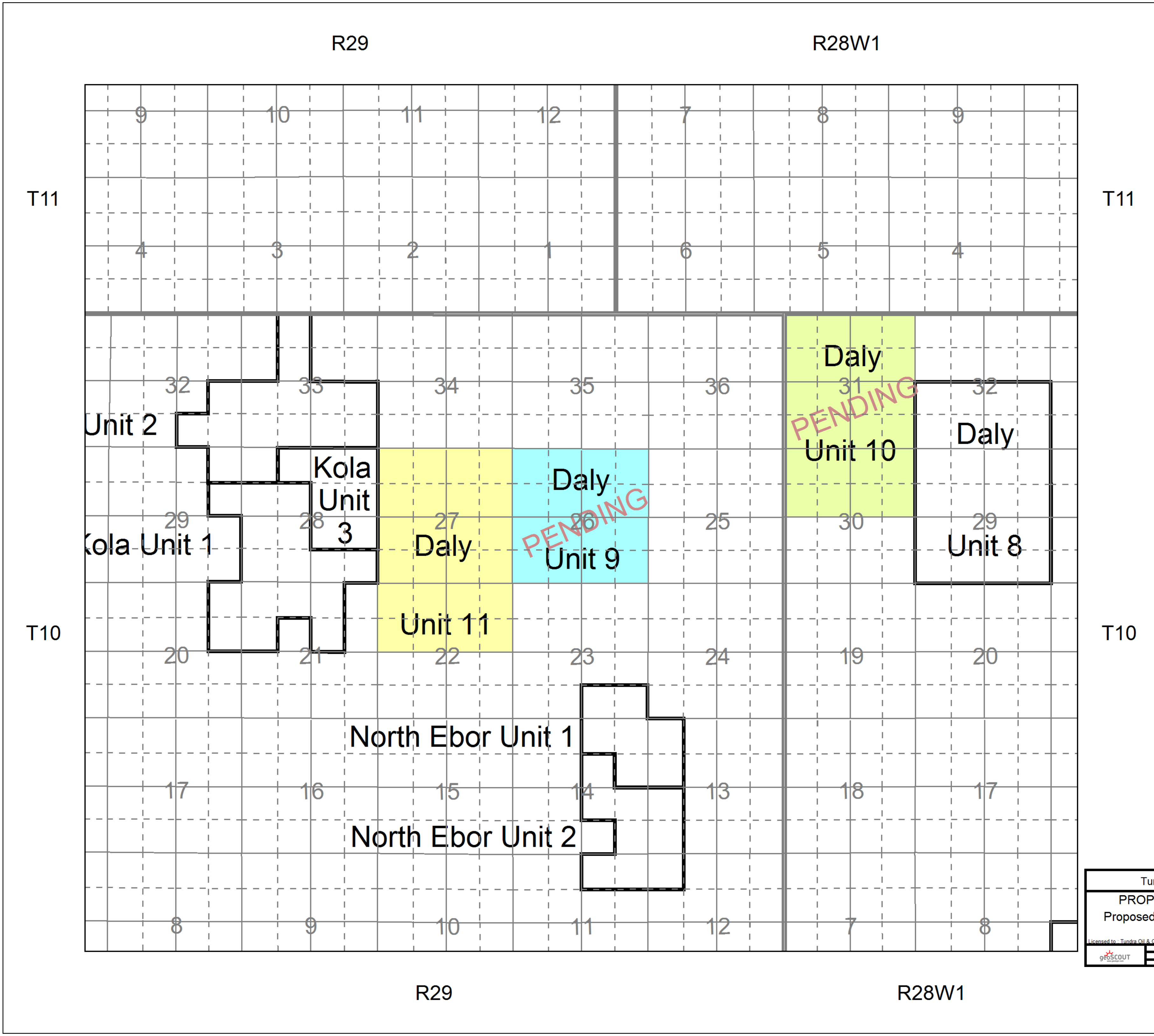




Appendix No. 1

Tundra Oil & Gas Partnership		
Structural Cross Section A - A' Proposed Daly Unit 11		
Licensed to : Tundra Oil and Gas Ltd		
Date : 2015/04/22		By : Hackert
Datum : Sea Level	Ref : 0.0 (m)	Scale = 1:480
Interval : From UBKKN to T.D.		

geoSCOUT www.geologic.com



Appendix No. 2

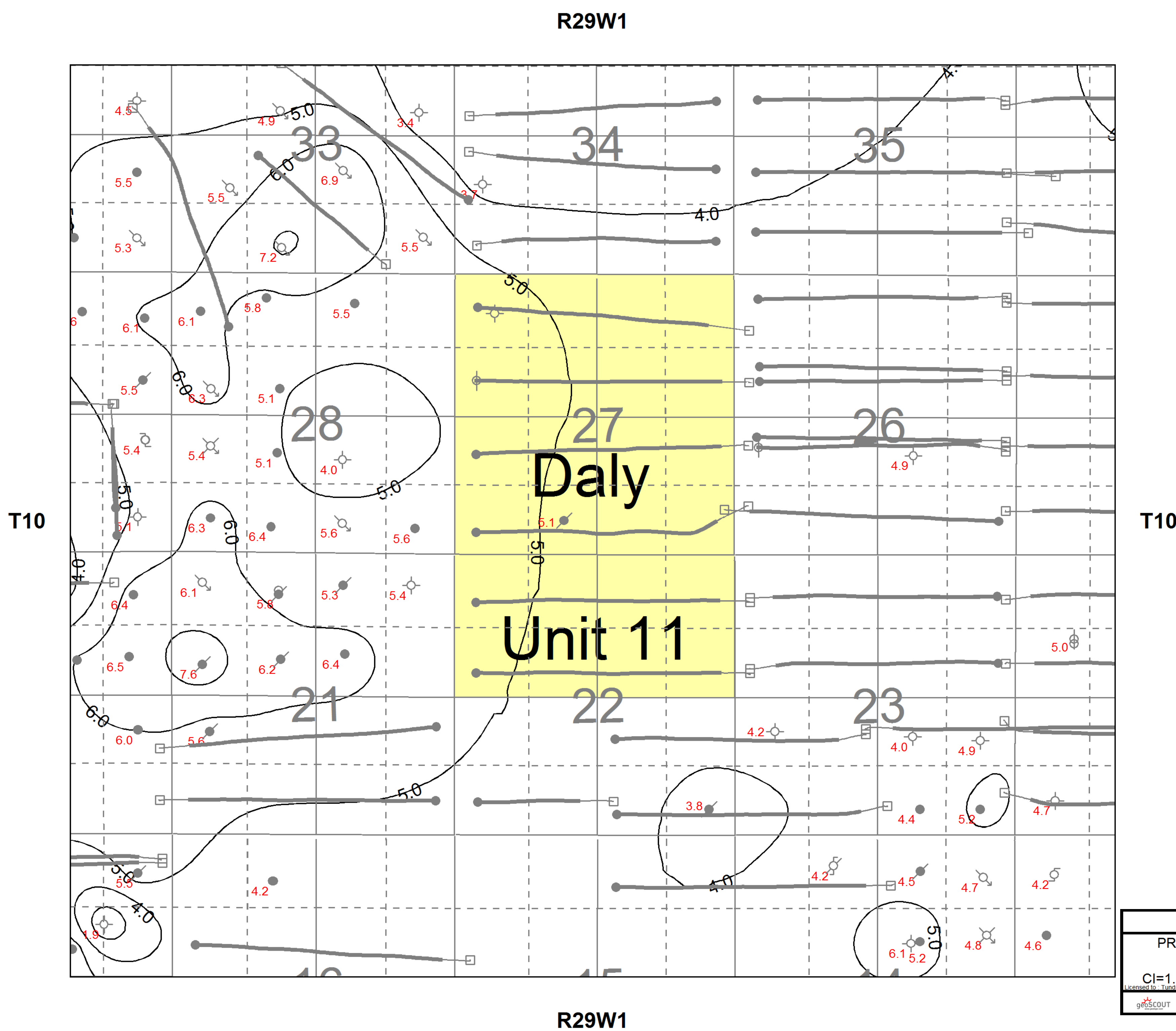
Tundra Oil & Gas Partnership

PROPOSED DALY UNIT No. 11
Proposed Units and Surrounding Units

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT

By : Hackert | Date : 2015/04/22
Scale = 1:58353 | Project : Sinclair Daly 2015 Expansion



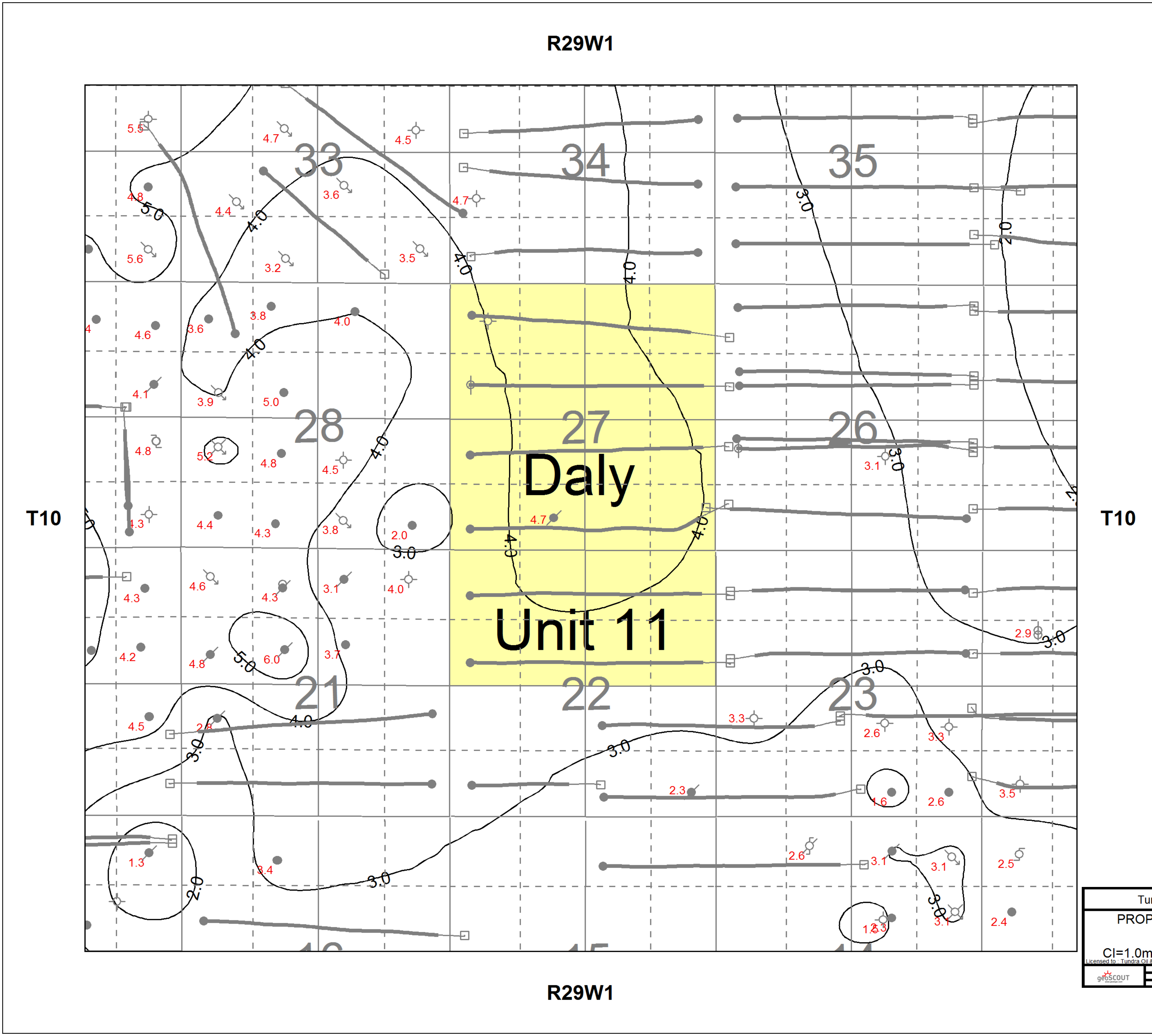
Appendix No. 3

Tundra Oil & Gas Partnership

PROPOSED DALY UNIT No. 11
Middle Bakken Isopach
CI=1.0m, Well Isopach Values in Red

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT	By : Hackert	Date : 2015/04/22
	Scale = 1:29722	Project : Sinclair Daly 2015 Expansion



Appendix No. 4

Tundra Oil & Gas Partnership

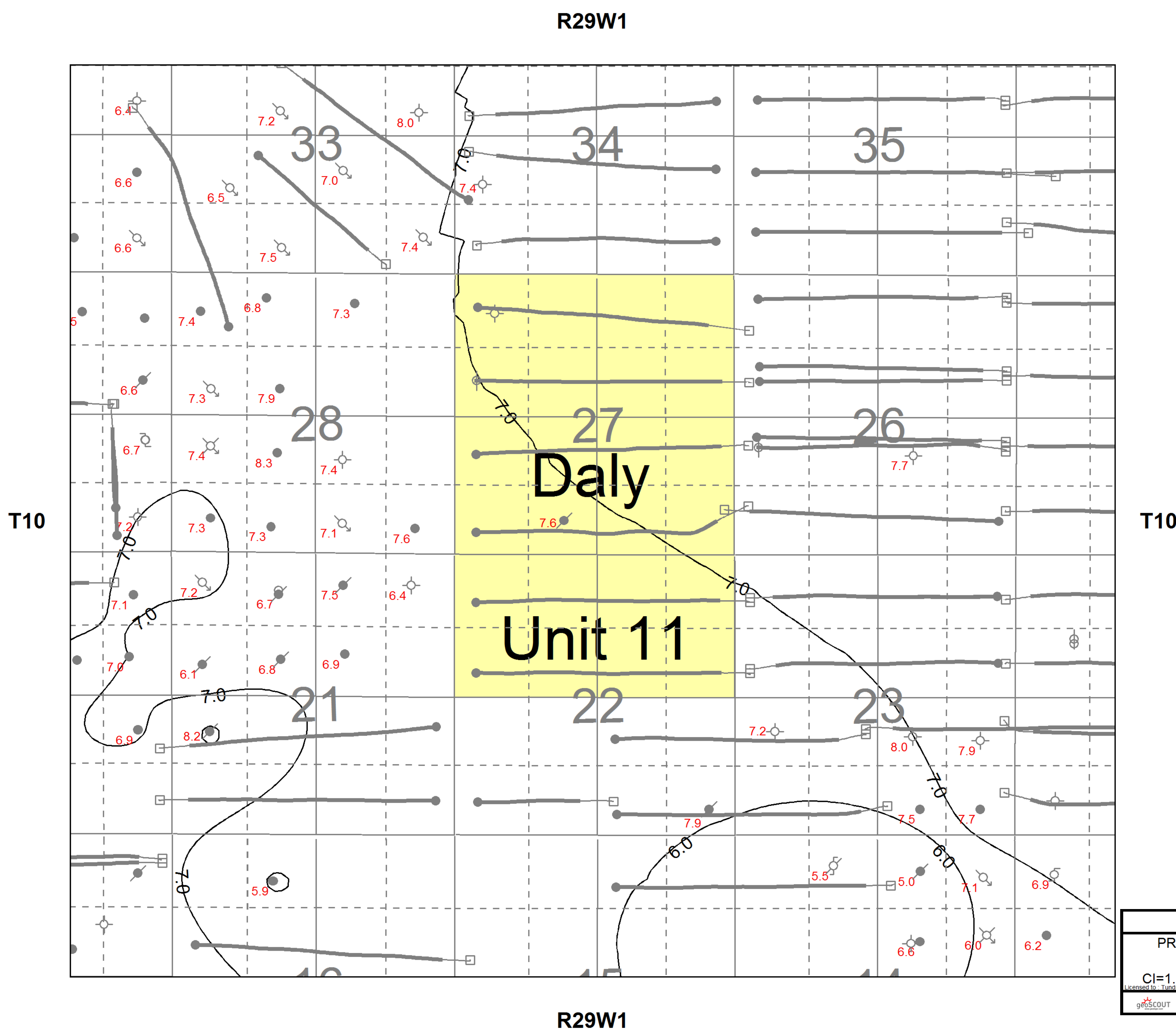
PROPOSED DALY UNIT No. 11

Lyleton B Isopach

CI=1.0m, Well Isopach Values in Red

Licensed to : Tundra Oil & Gas Partnership

By : Hackert	Date : 2015/04/22
Scale = 1:29722	Project : Sinclair Daly 2015 Expansion



Appendix No. 5

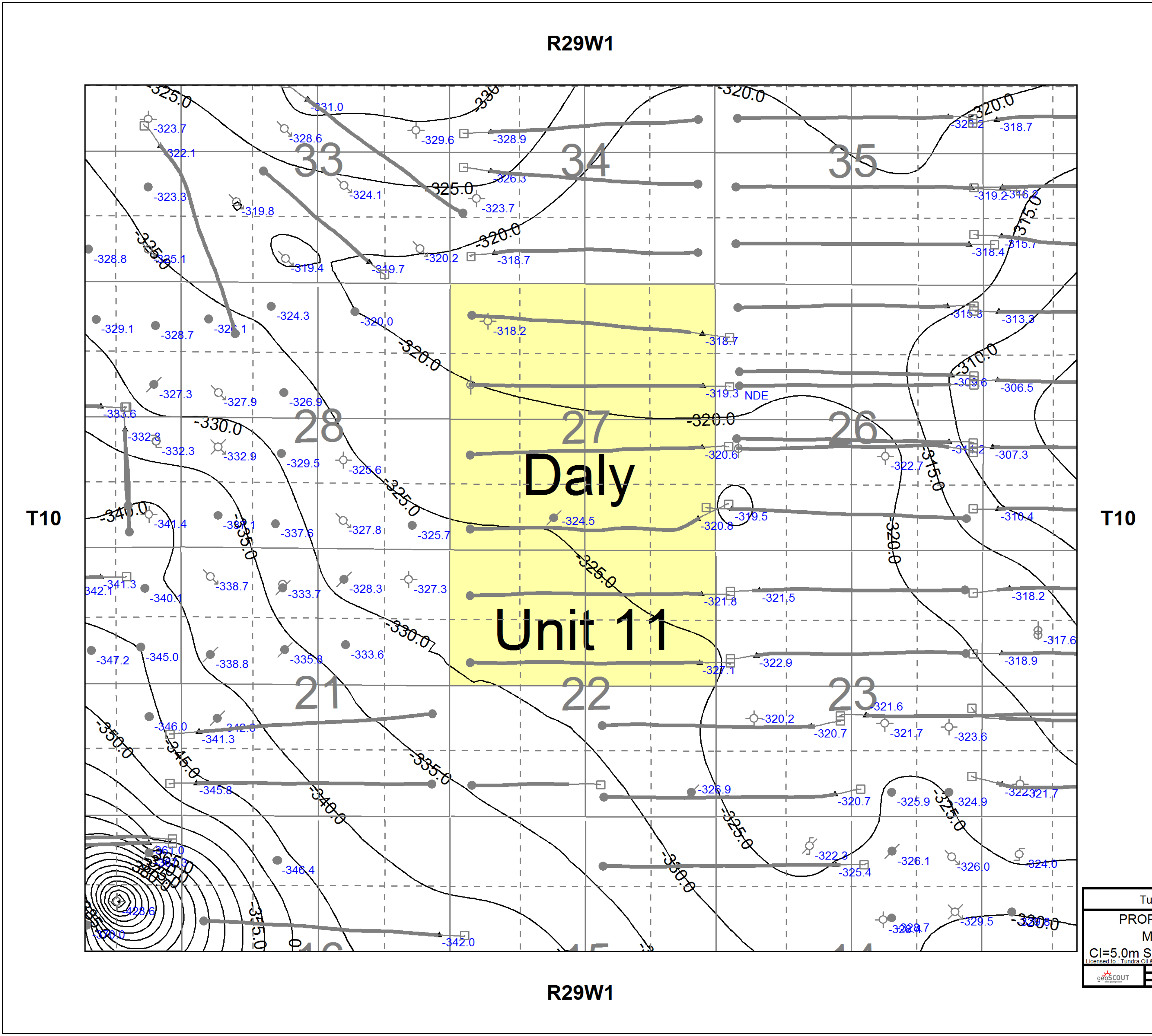
Tundra Oil & Gas Partnership

PROPOSED DALY UNIT No. 11
Toruqay Shale Isopach
CI=1.0m, Well Isopach Values in Red

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT	By : Hackert	Date : 2015/04/22
	Scale = 1:29722	Project : Sinclair Daly 2015 Expansion

Appendix No. 6



Tundra Oil & Gas Partnership

PROPOSED DALY UNIT No. 11

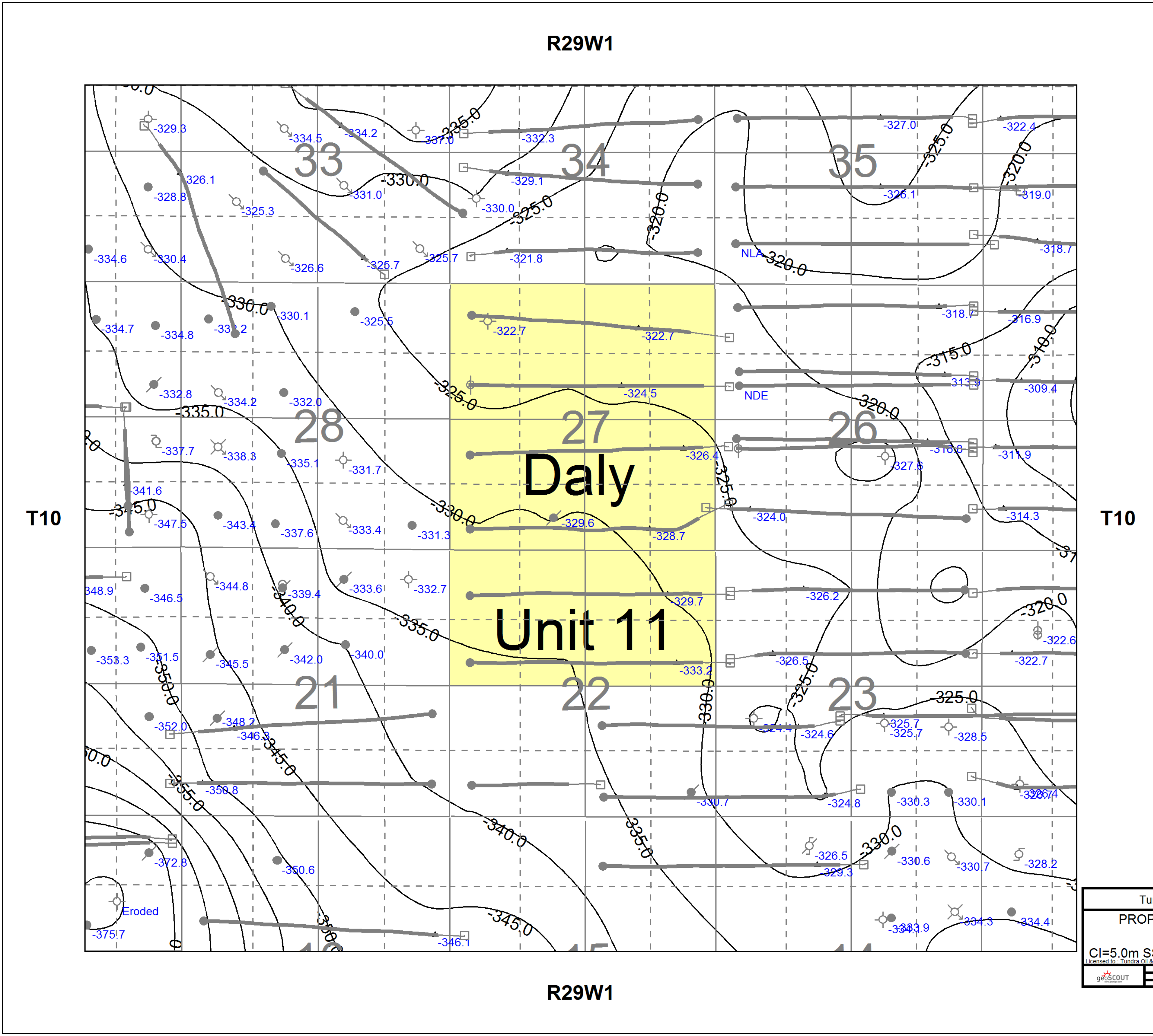
Middle Bakken Structure

CI=5.0m SS, Well Elevation Values in Blue

Licensed to : Tundra Oil & Gas Partnership

By : Hackert | Date : 2015/04/22

Scale = 1:29722 | Project : Sinclair Daly 2015 Expansion



Appendix No. 7

Tundra Oil & Gas Partnership

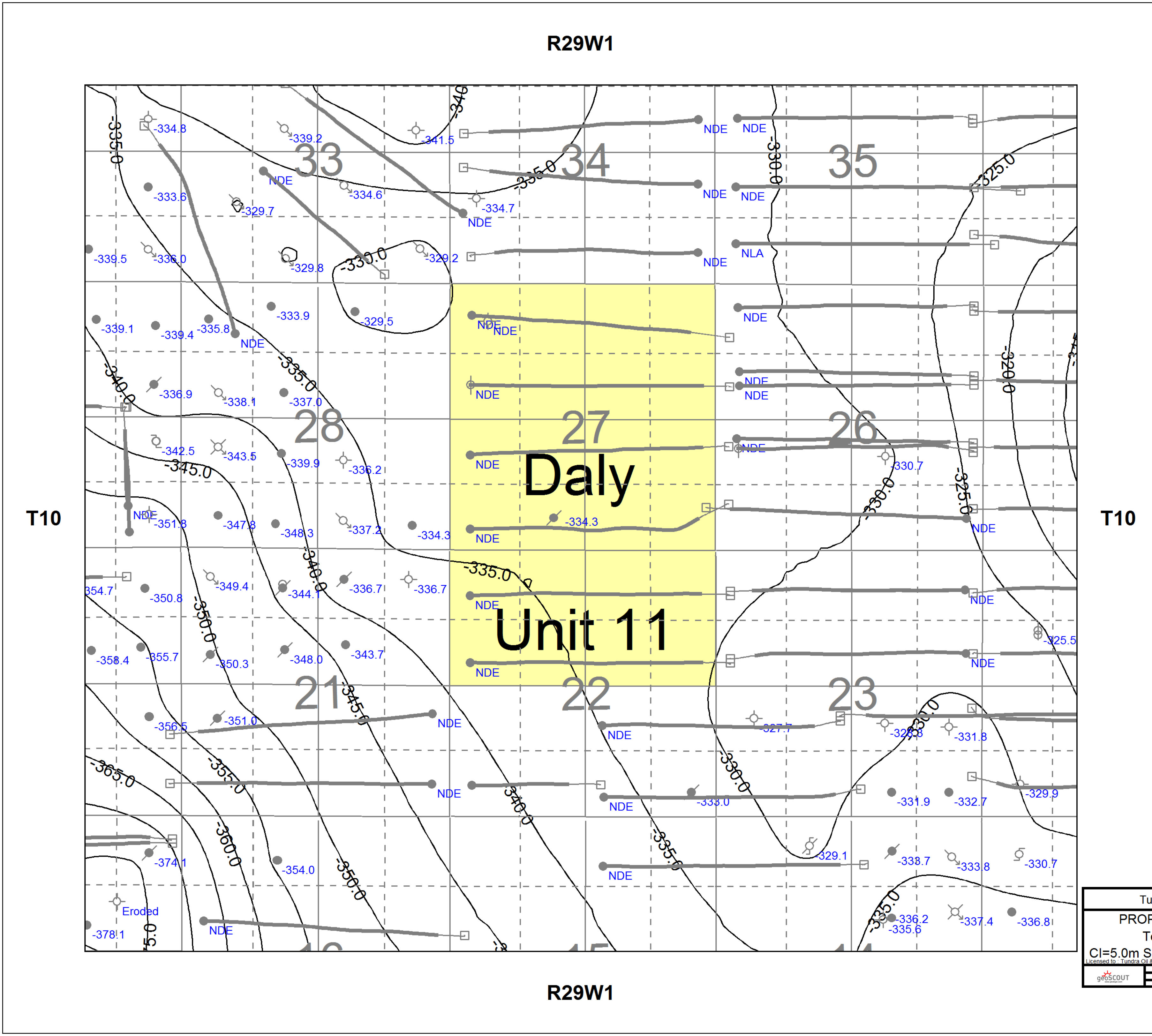
PROPOSED DALY UNIT No. 11

Lyleton B Structure

CI=5.0m SS, Well Elevation Values in Blue

Licensed to : Tundra Oil & Gas Partnership

By : Hackert	Date : 2015/04/22
Scale = 1:29722	Project : Sinclair Daly 2015 Expansion



Appendix No. 8

Tundra Oil & Gas Partnership

PROPOSED DALY UNIT No. 11

Toruqay Shale Structure

CI=5.0m SS, Well Elevation Values in Blue

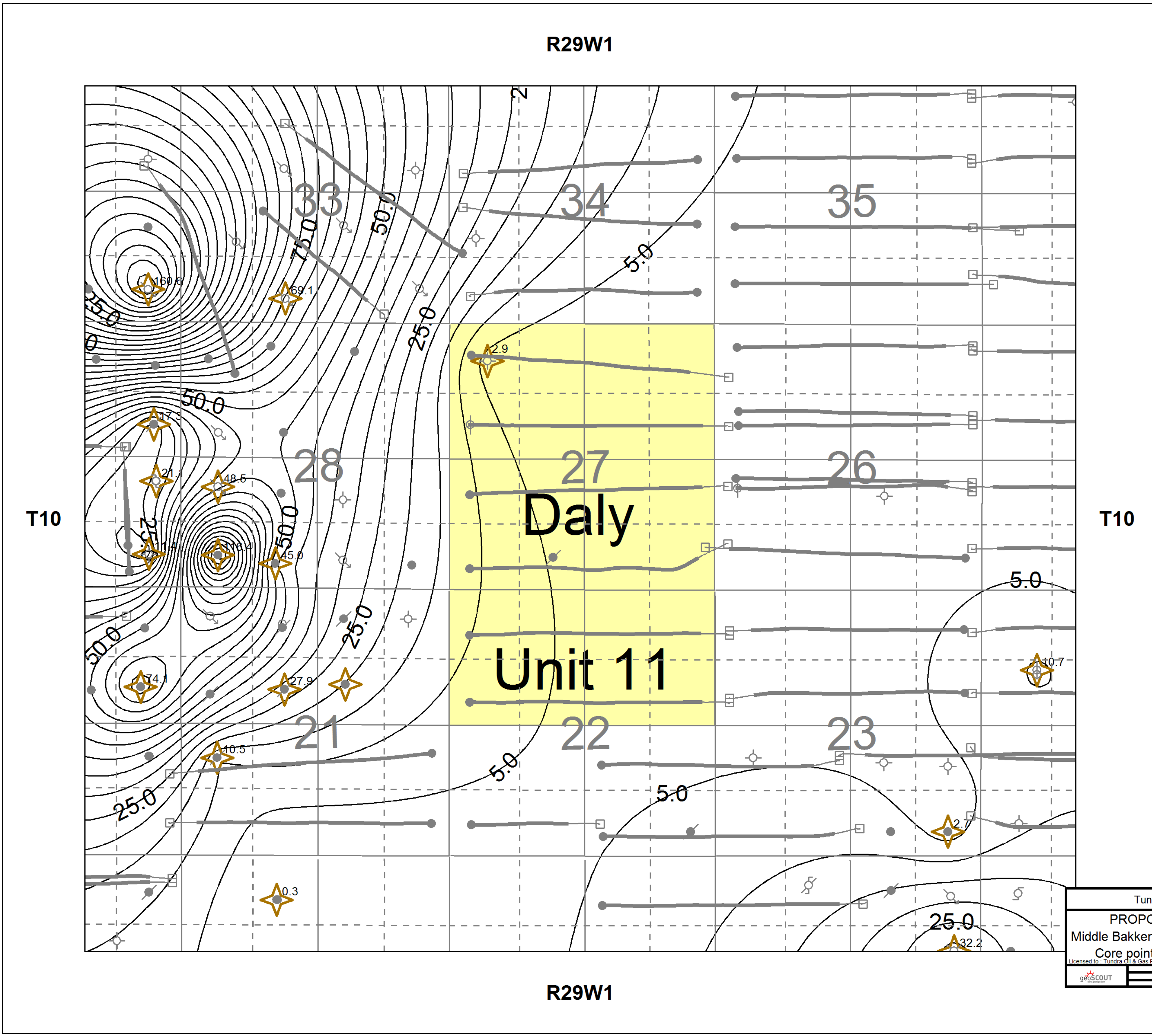
Licensed to : Tundra Oil & Gas Partnership

By : Hacker

Date : 2015/04/22

Scale = 1:29722

Project : Sinclair Daly 2015 Expansion



Appendix No. 9

Tundra Oil & Gas Partnership

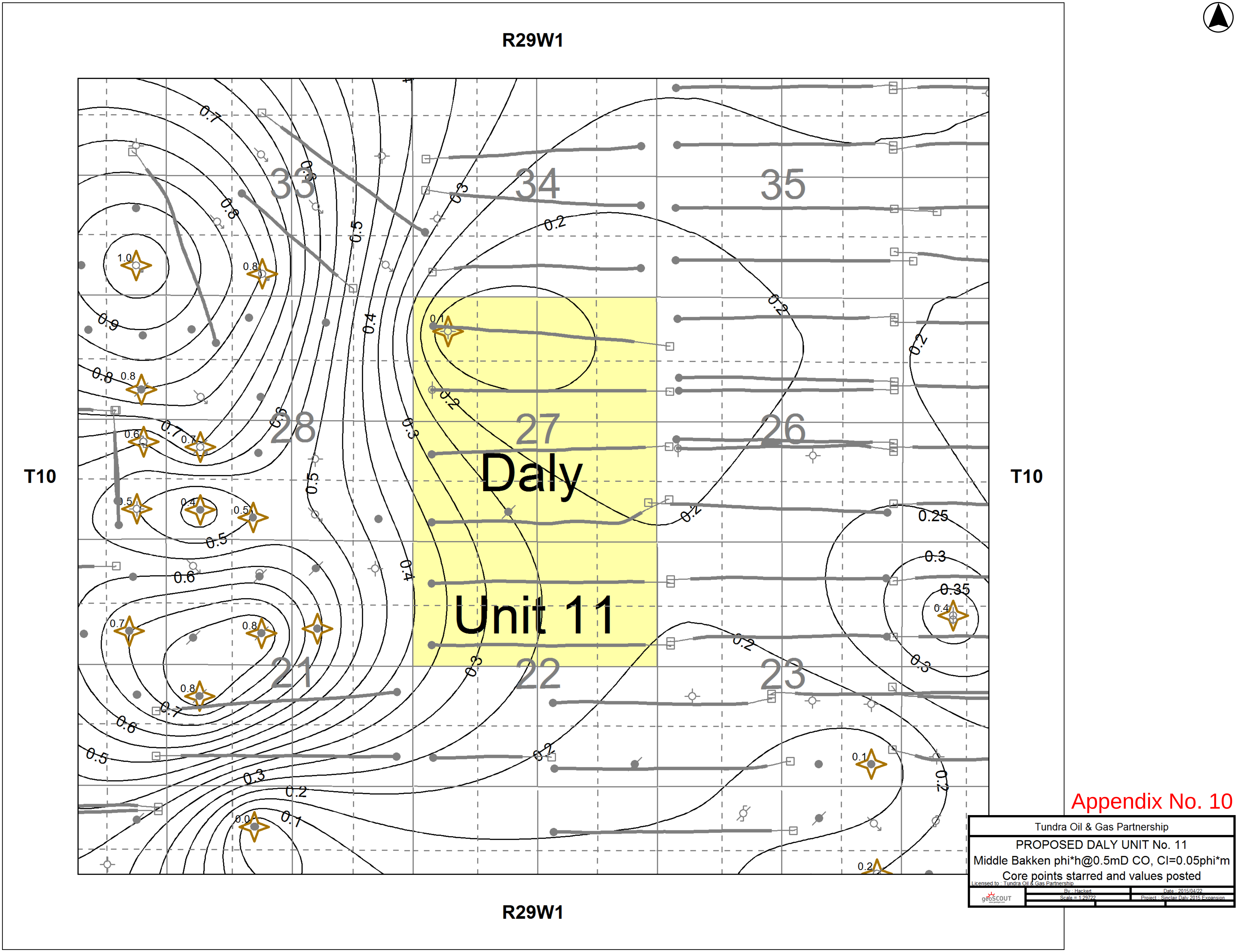
PROPOSED DALY UNIT No. 11

Middle Bakken k*h@0.5mD CO, CI=5.0mD*m

Core points starred and values posted

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT	By : Hackert	Date : 2015/04/22
	Scale = 1:29722	Project : Sinclair Daly 2015 Expansion

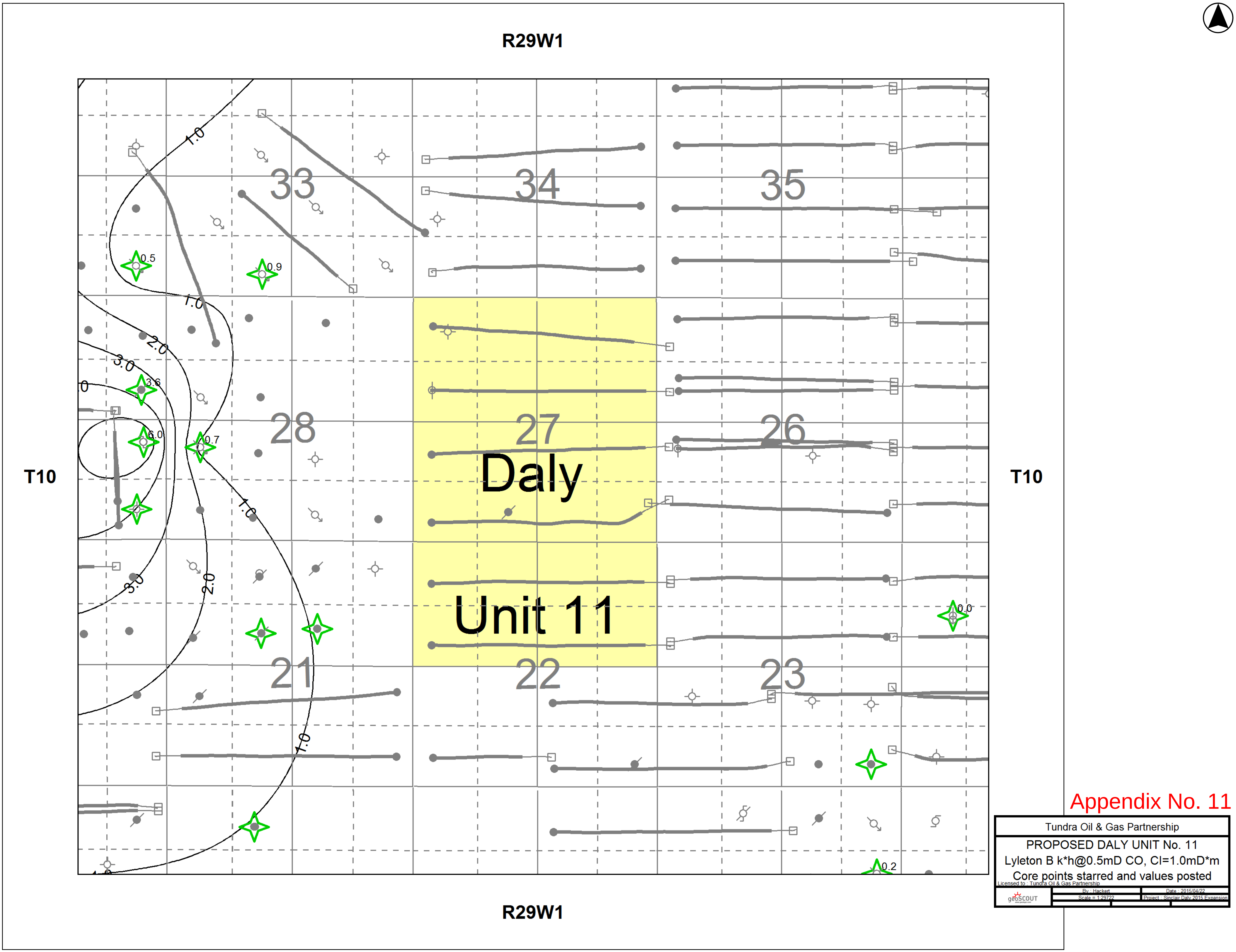


Appendix No. 10

Tundra Oil & Gas Partnership

PROPOSED DALY UNIT No. 11
Middle Bakken phi*h@0.5mD CO, CI=0.05phi*m
Core points starred and values posted

geoSCOUT | By : Hackert | Date : 2015/04/22 | Scale = 1:29722 | Project : Sinclair Daly 2016 Expansion



Appendix No. 11

Tundra Oil & Gas Partnership

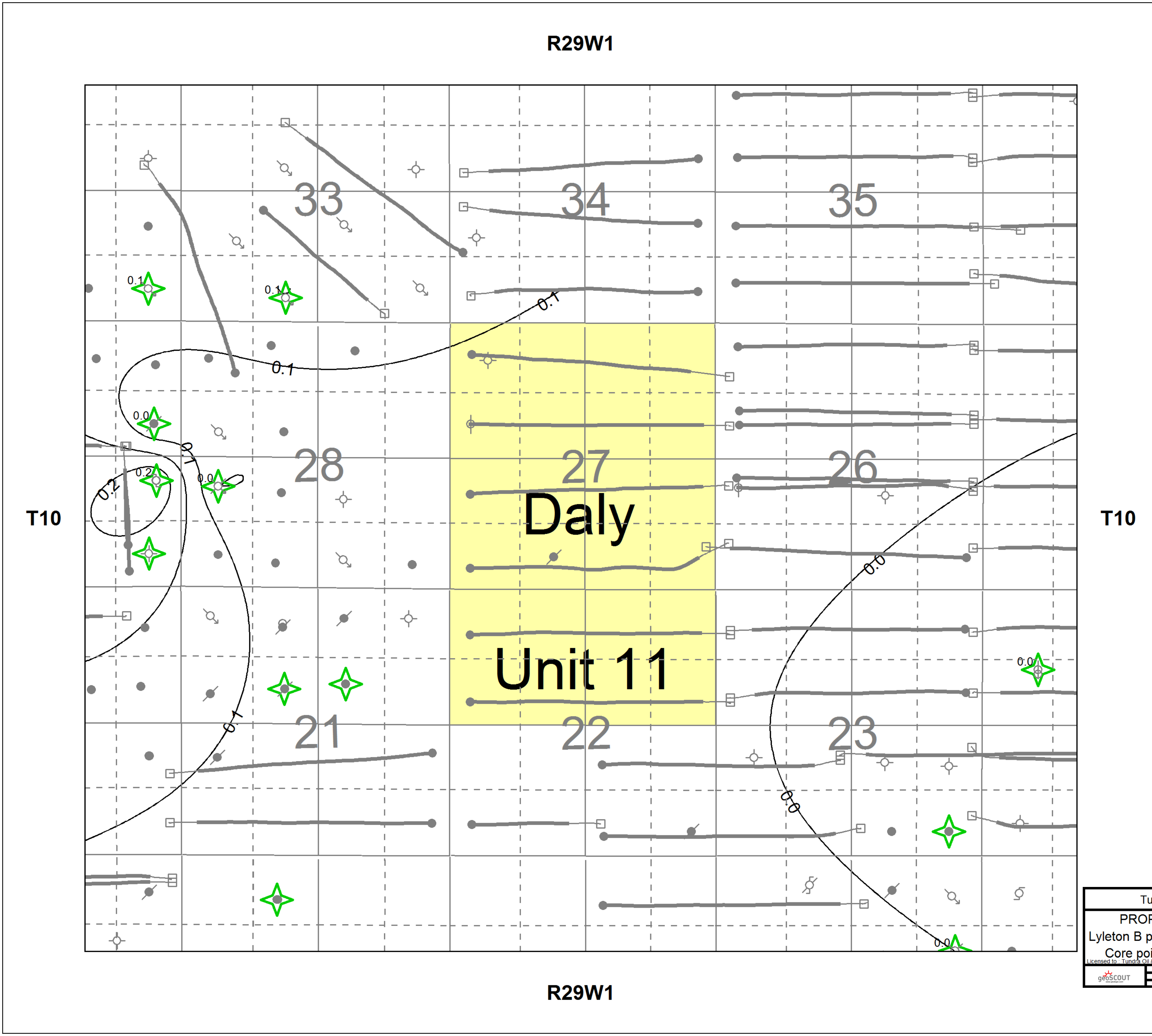
PROPOSED DALY UNIT No. 11

Lyleton B k*h@0.5mD CO, CI=1.0mD*m

Core points starred and values posted

Licensed to : Tundra Oil & Gas Partnership

By : Hackert	Date : 2015/04/22
Scale = 1:29722	Project : Sinclair Daly 2015 Expansion



Appendix No. 12

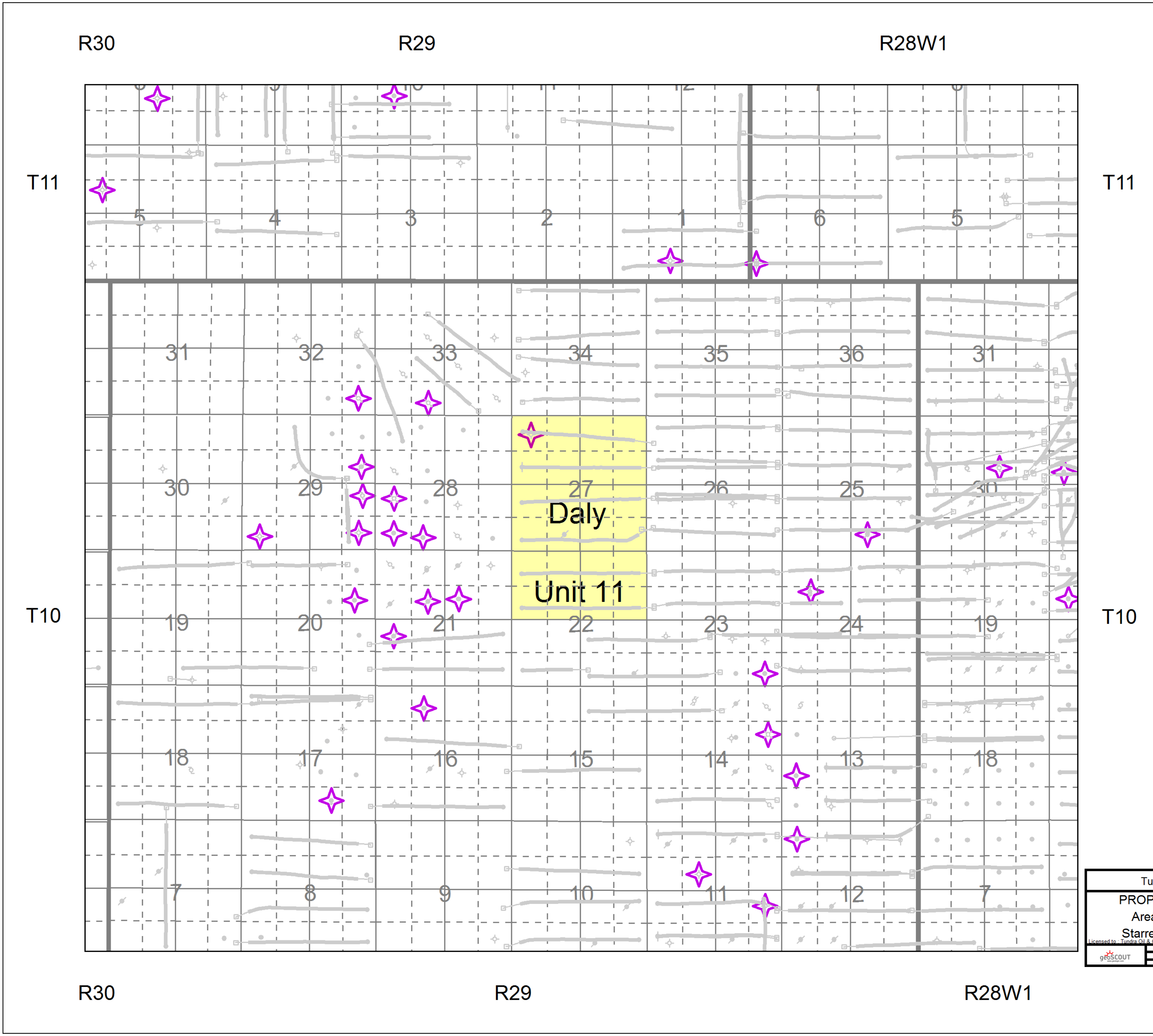
Tundra Oil & Gas Partnership

PROPOSED DALY UNIT No. 11
Lyleton B phi*h@0.5mD CO, CI=0.05phi*m
Core points starred and values posted

Licensed to : Tundra Oil & Gas Partnership

By : Hackert | Date : 2015/04/22
Scale = 1:29722 | Project : Sinclair Daly 2015 Expansion

Appendix No. 13



Tundra Oil & Gas Partnership

PROPOSED DALY UNIT No. 11
Area Wells and Cored Wells
Starred wells have Bakken Core

Licensed to : Tundra Oil & Gas Partnership

geoSCOUT	By : Hackert	Date : 2015/04/22
	Scale = 1:58353	Project : Sinclair Daly 2015 Expansion