PROPOSED DALY UNIT NO. 14

APPLICATION FOR ENHANCED OIL RECOVERY WATERFLOOD PROJECT

BAKKEN FORMATION

DALY, MANITOBA

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Corex Resources Ltd.

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INTRODUCTION

The Daly portion of the Daly Sinclair Field is located in Townships 8 to 11 Ranges 27 to 29 W1M. The field was originally developed with vertical wells but recent exploitation has shifted to horizontal development. Corex Resources Ltd. drilled two horizontal wells on the lands at 100/05-25-009-29 W1M in October 2013 and 100/04-25-009-29 W1M in December 2013.

Corex is proposing a unit be created in Section 25 and NE/4 and S/2 Section 36 in Township 9 Range 29 W1M and believes the potential exists for incremental production and reserves from a waterflood Enhanced Oil Recovery (EOR) project in the Bakken formation. Currently, Corex is the operator of the lands within the proposed unit that contains 2 producing horizontal wells and 13 producing vertical wells. Corex plans to drill 10 additional horizontal producers. We anticipate converting existing and to be drilled horizontal wells to injection. Corex plans to produce any newly drilled wells for a year before converting them to injectors. Corex hereby submits an application to establish Daly Unit No. 14 and implement an Enhanced Oil Recovery Waterflood Project within the Bakken Formation (Figure 1).

The proposed Daly Unit No. 14 falls within the Daly Sinclair Bakken-Torquay B Pool (Figure 2).

SUMMARY

1. The proposed Daly Unit No. 14 is to include 13 vertical producers and 2 horizontal wells within the 28 legal subdivisions (LSD) that were completed in the Bakken formation (Figure 1).

2. The original oil in place (OOIP) for the Bakken formation in the proposed Daly Unit No. 14 is 1.80 $10^6 m^3$ (11.3 MMbbl) for an average of 64.2 $10^3 m^3$ (403.6 Mbbl) per LSD.

3. Cumulative production in the proposed Daly Unit No. 14 to the end of February 2015 is 45.5 $10^3 m^3$ (286.3 Mbbl) of oil. This represents a 2.5% recovery factor of the total OOIP.

4. Using decline analysis, the expected ultimate recovery (EUR) of oil on primary production within the proposed Daly Unit No. 14 is estimated at 62.0 $10^3 m^3$ (390 Mbbl) with 16.5 $10^3 m^3$ (104 Mbbl) remaining as of February 2015. The Expected Ultimate Recovery Factor (EURF) would be 3.5% of the OOIP.

5. Production from the proposed Daly Unit No. 14 peaked in March, 1995 at 3.6 m^3/d (20.5 b/d), or an average of 1.8 m^3/d (11.4 b/d) per well with a 75.6% watercut (Figure 3).

6. A section model was built to estimate the EUR from implementing a waterflood in the proposed Daly Unit No. 14. The modelled well configuration consisted of eight horizontal wells at 200 m spacing. Under primary depletion, the model would estimate a recovery factor of 10.9%. Implementing a waterflood with alternating producers and injectors, model results suggest a recovery factor of 15.7%. These results suggest that, by implementing a waterflood using horizontal wells at 200 m spacing, the EUR would be 283 $10^3 m^3$ (1,770 Mbbl).

7. The development plan includes drilling 10 additional horizontal producing wells. Six producing horizontal wells will be converted to injectors (Figure 4). All horizontal wells in the proposed Daly Unit No. 14 have been or will be completed using multi-stage hydraulic fracturing. Newly drilled horizontal wells will be put on production for one year prior to being converted to injectors.

GEOLOGY

Stratigraphy

The stratigraphy of the reservoir section for the proposed unit is shown on the structural cross section (Appendix I). The section runs north to south through the middle of the proposed unit. The producing sequence in descending order consists of the Upper Bakken Shale, Middle Bakken Siltstone, Lyleton A Upper Siltstone, Lyleton Shale Marker, Lyleton B Siltstone and the Lyleton C shale. The reservoir units within the unit area are the Middle Bakken and the Lyleton A Upper Siltstone. The Upper Bakken Shale is a black organic rich shale which forms the top seal for the underlying Middle Bakken/Lyleton reservoirs.

Sedimentology

The Middle Bakken reservoir consists of fine to coarse grained grey siltstone to very fine sandstone which can be subdivided into lithologic upper and lower units. The upper unit is one meter or less in thickness, is bioturbated and generally non-reservoir. These bioturbated beds often contain an impoverished fauna consisting of brachiopods and fossil hash of unknown origin suggesting deposition in a marginal marine environment. The lower unit which is one of the reservoirs in the proposed unit area is a very fine silty sand with flat laminations and rare bioturbation. This is a slightly higher energy marine environment. Within the proposed unit area it ranges from 3.7 to 4.6m thick (Appendix II) with permeabilities in the 1 to 2mD range.

The Lyleton A reservoir consists of tan silts to fine sandstone made up of quartz, feldspar and detrital dolomite with minor clays. The Upper part is bedded and has parallel laminations. The Lower part of the Lyleton A generally shows a greater proportion of the red-green fine-grained siltstone than the Upper part and is commonly brecciated. The Lower part of the Lyleton A is generally a poorer reservoir than the Upper. Within the area of the proposed unit, the Upper Lyleton A is between 3 to 4m thick. The Lower unit is not broken out of the Lyleton A reservoir unit within the proposed unit area. No net pay maps for the Lyleton A are included as the pays are generally less than 1m in thickness but the reservoir is oil stained in samples. The Lyleon Shale Marker consists of brick red dolomitic siltstone which is highly water soluble, it is non reservoir, and is generally 2 to 3m thick. The Lyleton B is similar to the Lower Lyleton A, but with thinner beds of siltstone interbedded with darker grey-green very fine grained siltstone. The siltstone beds display non reservoir quality within the proposed unit area. The Lyleton B is generally between 2 to 5m thick. The Lyleton C is simply a log marker pick. The underlying red very fine siltstone to mudstone Torquay Formation forms the basal seal of the reservoir sequence.

Structure

The structure within the proposed unit area consists of a gentle dip to the southwest (Appendix III). Structural variations in the area are interpreted as being caused by dissolution of the underlying Prairie Evaporites. Structural variations caused by dissolution 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. No direct evidence of natural faulting is noted from either proprietary seismic data or well/production data in the vicinity of the proposed unit area.

Reservoir

Porosity-thickness (phi-h) and net pay maps are provided in Appendices IV and V. These maps were generated using the open hole logs and core data. The net pay map (Appendix V) shows a maximum net pay thickness of 4.6 m in the north half of the unit. The phi-h map in Appendix IV demonstrates a slight increase in porosity and pay towards the north part of the proposed unit. Cutoffs for pay in the section were porosities greater than 10%. The one well with core within the unit boundaries, the 7-25-9-29W1 well, has permeabilities ranging from 0.03 to 3.85 mD, with a weighted average using no cutoffs of 1.1mD (Appendix VI).

RESERVIOR PROPERTIES AND TECHNICAL DISCUSSION

Original Oil in Place

The original-oil-in-place (OOIP) for the proposed Daly Unit No. 14 is 1.80 $10^6 m^3$ (11.3 MMbbl) for the Bakken formation. The OOIP was calculated in-house. Values of thickness and porosity for the Middle Bakken zone are used to calculate the OOIP for each LSD. Details of the calculations are summarized in Table 1.

Historical Production

Figure 3 shows the production history of the wells within the proposed Daly Unit No. 14. There are 13 vertical wells and 2 horizontal wells within the proposed unit area. Well 100/08-36-009-29W1/00 is used for water disposal. These wells are perforated in the Bakken formation. Eight of the vertical wells have commingled production from the Lodgepole formation.

To the end of February 2015, the proposed Daly Unit No. 14 has produced cumulative volumes of oil at 45.5 $10^3 m^3$ (286.3 Mbbl) and water at 193 $10^3 m^3$ (1,216 Mbbl). The current recovery factor is 2.5%.

In March 1995, the wells in the proposed Daly Unit No. 14 had a peak oil production rate of 3.6 m^3/d (20.5 b/d), along with 11.3 m^3/d (70.9 b/d) of water. The corresponding water cut is 75.6%.

Currently (February 2015), the proposed Daly Unit No. 14 is producing 11.5 m^3/d (72 b/d) of oil and 23.5 m^3/d (168 b/d) of water. These production rates correspond to rates on a per well basis of 1.3 m^3/d/well (8.0 b/d/well) of oil, and 2.6 m^3/d (16.4 b/d/well) of water.

Primary Recovery

Table 2 lists the wells within the proposed unit area, together with the cumulative oil production to the end of February 2015 and the expected ultimate recovery (EUR) estimated using decline analysis. The total EUR for the proposed Daly Unit No. 14 is 62.0 10^3m^3 (390 Mbbl), for a recovery factor of 3.5% of the total OOIP.

Secondary Recovery

A waterflood enhanced oil recovery project is expected to provide pressure support and sweep oil from the injectors towards the producers, thus increasing the ultimate recovery. A section model was built to assess the potential increase in the EUR. This section model was built using average reservoir properties and calibrated to type production profiles based on representative vertical and horizontal Bakken producers. Modeling results suggest the following recovery factors under various well configurations:

- For 16 vertical wells in a section (40 acre spacing) under primary depletion, model results indicate an EURF of 2.5%.
- With eight horizontal wells at 200 m spacing under primary depletion, the EURF is estimated at 10.9%.
- The implementation of a waterflood through converting four of the eight horizontal wells to injectors, the section model suggests that an EURF of 15.7%.

Additional details for the section model are given in Appendix VII.

UNITIZATION

The basis for unitization is to implement a waterflood to increase the ultimate recovery of the OOIP from the proposed project area.

Unit Name

Corex proposes that the name of the new unit shall be Daly Unit No. 14.

Unit Operator

Corex will be the Operator for Daly Unit No. 14.

Unitized Zones

The unitized zone to be waterflooded in the Daly Unit No. 14 will be the Bakken Formation.

Unit Wells

The 15 existing wells (2 horizontal and 13 vertical) and 9 horizontal locations in the proposed Daly Unit No. 14 are outlined in Figure 4. The projected timing of the new drills is expected to be in 2017 and 2018. New drills will be converted after one year of production.

Unit Lands

The Daly Unit No. 14 will consist of all 28 LSDs within Section 25 and the South half and Northeast quarter of Section 36, Township 9, Range 29W1. The lands included in the 40 acre tracts are outlined in Appendix VIII.

Tract Factors

The proposed Daly Unit No. 14 will consist of 28 tracts based on remaining OOIP using maps created internally by Corex per LSD, as of February 2015, with the production from the horizontal wells being divided according to the existing production allocation agreement. The calculation of the tract factors are outlined in Table 1.

Working Interest Owners

Appendix VIII outlines the working interest for each recommended tract within the proposed Daly Unit No. 14. Corex will have a 100% WI across all tracts.

WATERFLOOD DEVELOPMENT

The objective of implementing a waterflood is to improve recovery. The Bakken formation is relatively shallow, with saturated oil that has low solution gas-oil ratio. As such, there is not much drive energy within the system. Additional mechanism is required to improve the recovery. Waterflooding will enhance the recovery by providing pressure support as well as sweeping the oil from the injectors towards the producers.

The additional 10 horizontal locations will be drilled and placed on production in 2017 and 2018, with half of the wells in each year. There will be a total of six horizontal wells converted to injection after being produced for one year (Figure 4). After full development and the implementation of the waterflood, there will be 10 vertical producers, six horizontal producers, and six horizontal injectors.

Rock and Fluid Properties

Rock and fluid properties for the Bakken formation are summarized in Table 3. These properties were estimated using standard correlations in the literature. Core analysis is currently underway to determine the pertinent reservoir and fluid properties.

Using Corex's internal database on fracture treatments and step rate tests, the fracture gradient for the Bakken formation is estimated to be 20 kPa/m. The surface fracturing pressure is estimated to range between 8,150 kPa and 8,360 kPa. Step rate test will be conducted to confirm the fracturing pressure once the proposed injectors are converted.

Expected Recovery

A waterflood enhanced oil recovery project is expected to provide pressure support and sweep oil from the injectors towards the producers, thus increasing the ultimate recovery. A section model was built to assess the potential increase in the EUR. Model details are given in Appendix VII. Based on these results, the implementation of a waterflood using horizontal wells would lead to EUR estimated at 283 10^3m^3 (1,770 Mbbl).

Economic Limit

The economic limit will be when the net oil rate and net oil price revenue stream becomes less than the current producing operating costs. Based on current price forecasts, the economic limit for the project would be 1 m^3/d.

Source of Injection Water

Source of injection water will be from the Lodgepole formation. It is desired to reactivate the 100/03-32-009-28W1 well to supply Lodgepole source water for the waterflood. This well produced till July 2012 when it was shut-in due to an electrical strike at the 12-29-9-28W1 battery. Since then the well has not been on production. At last producing date it produced at 400 to 415 m^3/d (2500 to 2600 b/d) water, and 99.7% watercut. This will require a short tie-in from 12-29 to the 9-30 surface, and the group line from the 9-30 will be used as a source water line. Currently the 103/10-29-9-28W1 well is producing down this pipeline, it will be carried through to the source water system at the facility. The oil from these two wells will be skimmed off the water tanks and sent to the FWKO to be processed and sold. Carryover oil levels at the battery for source water will be kept to a minimum, and chemical will be used to treat the fluid to assist in separation as necessary. The 100/3-32 water will be sampled in 2015 to be analyzed for compatibility. Once this compatibility testing and the core analysis are completed, filters can then be sized accordingly to ensure pore throats will not be plugged and sweep efficiency is maintained.

A simplified process flow diagram of the system from the 15-25-9-29W1 to the injectors is located in Figure 5. The injector wells will be equipped with injection volume metering and rate/pressure control (Figures 6 and 7). Water injection volumes and balancing will be utilized to monitor the entire system measurement and integrity on a daily basis. The corrosion control program outlining the planned system design and operational practices to prevent corrosion is located in Figure 8.

Operating Strategy

The proposed well locations are depicted in Figure 4. Injection rates are expected to be in the range of 250 m^3/d to 500 m^3/d, subject to a maximum injection pressure of 7,400 kPa at the well head. This maximum pressure is based on a fracture pressure of 8,250 kPa and a safety factor of 90%. Initially, injection will target a monthly voidage replacement ratio (VRR) between 1.25 and 1.75. This over-injection will serve to replace the voidage that occurred during primary depletion within the proposed unit area. Once a cumulative VRR of one is attained, the injection rate will be scaled back to maintain the VRR at one, both on a monthly basis and a cumulative basis.

All producers will be maintained at pump-off condition. This will minimize the cross-flow between the Lodgepole and the Bakken formations, especially for the vertical producers that have commingled production from both zones.

Pressure

The initial pressure is estimated to be between 9,000 kPa and 9,500 kPa. This is based on the depth of the Middle Bakken zone and a static gradient ranging between 10.5 kPa/m and 10.8 kPa/m.

Waterflooding will help to re-pressurize and add energy to the reservoir. During the initial over-injection period, the reservoir pressure is expected to increase. Once the cumulative VRR reaches one, a monthly VRR of one will be maintained. At this stage, the reservoir pressure is expected to be around its initial value.

Waterflood Facilities

Within the project area, all of the producing wells are pipelined to the 15-25-009-29W1 Battery. The new horizontal wells will be tied in on a new pipeline system and kept separate from the old vertical producing wells.

In the winter of 2014, the 15-25 Battery underwent a major facility upgrade which included the install of a FWKO, injection pump, two 2000bbl water tanks, MCC and electrical upgrade, flare stack and associated piping. This was done to accommodate the development program for this area.

While installing new pipelines to the new horizontal wells and satellites, injection pipelines were installed in the common trench for future waterflood use. The field is able to be converted for injection fairly easily with lower capital cost. Corex plans to use nearby Lodgepole source water, filtered and treated, for injection fluid.

As the current disposal well located at 100/8-36-9-29W1 is injecting into the Crinoidal and lower Daly zones, it will be desired to drill a new disposal that will properly dispose the fluid to a separate non-hydrocarbon bearing formation below our target formation. The pipeline that runs to the 8-36 disposal is also a limiting factor as its MAWP is too low for proper disposal and operating at the facility. A new disposal would be drilled at the 15-25 facility.

Waterflood Surveillance

Waterflood response and performance within the proposed Daly Unit No. 14 will be closely monitored with the following:

- Regular production well testing to monitor fluid rate and water cut to watch for waterflood response
- Comparison of daily injection rates and pressure monitoring to targets
- Monitor monthly and cumulative voidage replacement ratio by pattern and overall unit
- Evaluation of Hall plots to assess any changes in injectivity
- New injection targets will be sent to the field on a regular basis

Project Schedule

Corex is planning to drill the new horizontal wells in 2017 and 2018, with about half of the wells in each year. Some of these newly drilled horizontal wells will be converted to injectors after one year of production. Along with these conversions, the necessary facilities will also be implemented. First water injection is expected in Q1 2018. Should the oil price recovers, the timing of drilling the horizontal wells and implementing the waterflood can be brought forward.

NOTIFICATIONS

Corex will notify all surface and mineral owners of the proposed EOR project and formation of the Daly Unit No. 14. Copies of the Notices, and proof of service, to all surface rights owners will be forwarded to the Petroleum Branch, when available, to complete the Daly Unit No. 14 Application.

Unitization and execution of the formal Daly Unit No. 14 agreement by affected mineral owners will occur once the Petroleum Branch has reviewed the tract factors. Copies of the agreement will be forwarded to the Petroleum Branch to complete the Daly Unit No. 14 application.

Please contact David McGuinness at 403-718-6345, by email at davidm@corexresources.ca or at Suite 3200, 700 – 2nd Street SW, Calgary, Alberta, T2P 2W2 for any other questions or clarification. Alternatively, please contact Stephen Wong at 587-390-0297, or by email at stephenw@corexresources.ca.

Corex Resources Ltd.

David McGuinness
Executive VP Land

Table 1 – Summary of Original Oil In Place and Tract Factor Calculations

Daly West
Bakken Unit

Tract	Tract	Total	1	2	3	4	5
LSD	Weighting		1-25-09-29W1	2-25-09-29W1	3-25-09-29W1	4-25-09-29W1	5-25-09-29W1
Tract Factor		100%	3.410362049%	3.408900054%	3.624284570%	3.625926838%	3.610469374%
Area (ac)	**0%**	**1,120**	**40**	**40**	**40**	**40**	**40**
h (m)			4.0	4.0	4.0	4.0	4.0
Vb (ac-ft)		14,947	525	525	525	525	525
phi			16.0%	16.0%	17.0%	17.0%	17.0%
Sw			40%	40%	40%	40%	40%
HCPV			0.384	0.384	0.408	0.408	0.408
OOIP (Mbbls)		11,641	391	391	415	415	415
Total OOIP (Mstb)	**0%**	**11,302**	**380**	**380**	**403**	**403**	**403**
Total OOIP (10^3m^3)		1,797	60	60	64	64	64
Cumulative Oil (Mstb)		286	3.9	4.1	4.1	3.9	5.6
OOIP-Cum Prd (Mstb)	**100%**	**11,015**	**376**	**376**	**399**	**399**	**398**

Comments: **Cumulative production to February 2015**
Bo **1.03**

Well 1			100/04-25-009-29W1/00	100/04-25-009-29W1/00	100/04-25-009-29W1/00	100/04-25-009-29W1/00	100/05-25-009-29W1/00
Factor			0.245334177	0.255477768	0.255291209	0.243896846	0.25
Cumulative Oil (Mstb)			15.9	15.9	15.9	15.9	22.3
Well 2							
Factor							
Cumulative Oil (Mstb)							

Daly West
Bakken Unit

Tract	Tract	Total	6	7	8	9	10
LSD	Weighting		6-25-09-29W1	7-25-09-29W1	8-25-09-29W1	9-25-09-29W1	10-25-09-29W1
Tract Factor		100%	3.610469374%	3.471386863%	3.395111747%	4.238722179%	3.386459958%
Area (ac)	**0%**	**1,120**	**40**	**40**	**40**	**40**	**40**
h (m)			4.0	4.1	4.0	4.1	4.0
Vb (ac-ft)		14,947	525	538	525	538	525
phi			17.0%	16.0%	16.0%	21.0%	16.0%
Sw			40%	40%	40%	40%	40%
HCPV			0.408	0.394	0.384	0.517	0.384
OOIP (Mbbls)		11,641	415	401	391	526	391
Total OOIP (Mstb)	**0%**	**11,302**	**403**	**389**	**380**	**511**	**380**
Total OOIP (10^3m^3)		1,797	64	62	60	81	60
Cumulative Oil (Mstb)		286	5.6	6.7	5.6	43.7	6.5
OOIP-Cum Prd (Mstb)	**100%**	**11,015**	**398**	**382**	**374**	**467**	**373**

Comments:
Bo

Well 1			100/05-25-009-29W1/00	100/05-25-009-29W1/00	100/05-25-009-29W1/00	100/09-25-009-29W1/02	100/10-25-009-29W1/02
Factor			0.25	0.25	0.25	1.0	1.0
Cumulative Oil (Mstb)			22.3	22.3	22.3	43.7	6.5
Well 2				100/07-25-009-29W1/00			
Factor				1.00			
Cumulative Oil (Mstb)				1.1			

Table 1 – Summary of Original Oil In Place and Tract Factor Calculations (cont'd)

Daly West
Bakken Unit

Tract	Tract Weighting	Total	11	12	13	14	15
LSD			11-25-09-29W1	12-25-09-29W1	13-25-09-29W1	14-25-09-29W1	15-25-09-29W1
Tract Factor		100%	3.261165351%	3.445722034%	3.012086067%	4.360013334%	3.613076897%
Area (ac)	**0%**	**1,120**	**40**	**40**	**40**	**40**	**40**
h (m)			4.3	4.0	3.9	4.6	3.8
Vb (ac-ft)		14,947	564	525	512	604	499
phi			16.0%	16.0%	16.0%	18.0%	18.0%
Sw			40%	40%	40%	40%	40%
HCPV			0.413	0.384	0.374	0.497	0.410
OOIP (Mbbls)		11,641	420	391	381	506	418
Total OOIP (Mstb)	**0%**	**11,302**	**408**	**380**	**370**	**491**	**406**
Total OOIP ($10^3 m^3$)		1,797	65	60	59	78	64
Cumulative Oil (Mstb)		286	48.8	0.0	38.3	10.8	7.7
OOIP-Cum Prd (Mstb)	**100%**	**11,015**	**359**	**380**	**332**	**480**	**398**

Comments:
Bo

Well 1			100/11-25-009-29W1/02		100/13-25-009-29W1/02	100/14-25-009-29W1/02	100/15-25-009-29W1/02
Factor			1.0		1.0	1.0	1.0
Cumulative Oil (Mstb)			48.8		38.3	6.9	7.7
Well 2						102/14-25-009-29W1/00	
Factor						1.00	
Cumulative Oil (Mstb)						3.8	

Daly West
Bakken Unit

Tract	Tract Weighting	Total	16	17	18	19	20
LSD			16-25-09-29W1	1-36-09-29W1	2-36-09-29W1	3-36-09-29W1	4-36-09-29W1
Tract Factor		100%	3.582673012%	3.565848802%	3.219434343%	3.573462337%	3.286895784%
Area (ac)	**0%**	**1,120**	**40**	**40**	**40**	**40**	**40**
h (m)			4.1	4.2	4.2	3.8	3.7
Vb (ac-ft)		14,947	538	551	551	499	486
phi			17.0%	16.5%	15.0%	18.5%	16.5%
Sw			40%	40%	40%	40%	40%
HCPV			0.418	0.416	0.378	0.422	0.366
OOIP (Mbbls)		11,641	426	423	385	429	373
Total OOIP (Mstb)	**0%**	**11,302**	**413**	**411**	**374**	**417**	**362**
Total OOIP ($10^3 m^3$)		1,797	66	65	59	66	58
Cumulative Oil (Mstb)		286	18.7	18.2	19.0	23.3	0.0
OOIP-Cum Prd (Mstb)	**100%**	**11,015**	**395**	**393**	**355**	**394**	**362**

Comments:
Bo

Well 1			100/16-25-009-29W1/02	100/01-36-009-29W1/02	100/02-36-009-29W1/02	100/03-36-009-29W1/02	
Factor			1.0	1.0	1.0	1.0	
Cumulative Oil (Mstb)			18.7	18.2	19.0	23.3	
Well 2							
Factor							
Cumulative Oil (Mstb)							

Table 1 – Summary of Original Oil In Place and Tract Factor Calculations (cont'd)

Daly West
Bakken Unit

Tract	Tract	Total	21	22	23	24	25
LSD	Weighting		5-36-09-29W1	6-36-09-29W1	7-36-09-29W1	8-36-09-29W1	9-36-09-29W1
Tract Factor		100%	3.286895784%	3.642235869%	3.445722034%	3.445722034%	3.935660636%
Area (ac)	**0%**	**1,120**	**40**	**40**	**40**	**40**	**40**
h (m)			3.7	4.1	4.0	4.0	4.3
Vb (ac-ft)		14,947	486	538	525	525	564
phi			16.5%	16.5%	16.0%	16.0%	17.0%
Sw			40%	40%	40%	40%	40%
HCPV			0.366	0.406	0.384	0.384	0.439
OOIP (Mbbls)		11,641	373	413	391	391	447
Total OOIP (Mstb)	**0%**	**11,302**	**362**	**401**	**380**	**380**	**434**
Total OOIP (10^3m^3)		1,797	58	64	60	60	69
Cumulative Oil (Mstb)		286	0.0	0.0	0.0	0.0	0.0
OOIP-Cum Prd (Mstb)	**100%**	**11,015**	**362**	**401**	**380**	**380**	**434**

Comments:
Bo

Well 1			100/05-36-009-29W1/02	100/06-36-009-29W1/02			
Factor			1.0	1.0			
Cumulative Oil (Mstb)			0.0	0.0			
Well 2							
Factor							
Cumulative Oil (Mstb)							

Daly West
Bakken Unit

Tract	Tract	Total	26	27	28
LSD	Weighting		10-36-09-29W1	15-36-09-29W1	16-36-09-29W1
Tract Factor		100%	3.962580339%	3.935660636%	3.643051699%
Area (ac)	**0%**	**1,120**	**40**	**40**	**40**
h (m)			4.6	4.3	4.1
Vb (ac-ft)		14,947	604	564	538
phi			16.0%	17.0%	17.0%
Sw			40%	40%	40%
HCPV			0.442	0.439	0.418
OOIP (Mbbls)		11,641	450	447	426
Total OOIP (Mstb)	**0%**	**11,302**	**436**	**434**	**413**
Total OOIP (10^3m^3)		1,797	69	69	66
Cumulative Oil (Mstb)		286	0.0	0.0	12.1
OOIP-Cum Prd (Mstb)	**100%**	**11,015**	**436**	**434**	**401**

Comments:
Bo

Well 1			100/10-36-009-29W1/02		100/16-36-009-29W1/02
Factor			1.0		1.0
Cumulative Oil (Mstb)			0.0		12.1
Well 2					
Factor					
Cumulative Oil (Mstb)					

Table 2 – Well List – Cumulative Oil Production and Expected Ultimate Recovery

Well	Type	Cumulative Oil Mbbl	Expected Ultimate Recovery Mbbl
100/04-25-009-29W1/0	Horizontal	15.877	41.01
100/05-25-009-29W1/0	Horizontal	22.300	64.84
100/07-25-009-29W1/0	Vertical	1.087	1.09
100/09-25-009-29W1/2	Vertical	43.715	53.59
100/10-25-009-29W1/2	Vertical	6.528	9.09
100/11-25-009-29W1/2	Vertical	48.797	50.72
100/13-25-009-29W1/2	Vertical	38.278	38.28
100/14-25-009-29W1/2	Vertical	6.942	6.94
102/14-25-009-29W1/0	Vertical	3.841	5.24
100/15-25-009-29W1/2	Vertical	7.660	9.82
100/16-25-009-29W1/2	Vertical	18.719	22.36
100/01-36-009-29W1/2	Vertical	18.210	21.86
100/02-36-009-29W1/2	Vertical	18.996	19.00
100/03-36-009-29W1/2	Vertical	23.292	33.78
100/16-36-009-29W1/2	Vertical	12.068	12.25

Table 3 – Middle Bakken – Summary of Rock and Fluid Properties

Proposed Daly Unit No. 14		
Rock and Fluid Properties		
Formation Pressure	kPa	9000
Oil Gravity	^{o}API	37
Solution Gas-Oil Ratio	m3/m^3	15
Oil Formation Volume Factor	Rm3/Sm^3	1.04
Average Porosity	fraction	0.167
Average Air Permeability	mD	0.5

Figure 1 – Outline of Proposed Daly Unit No. 14

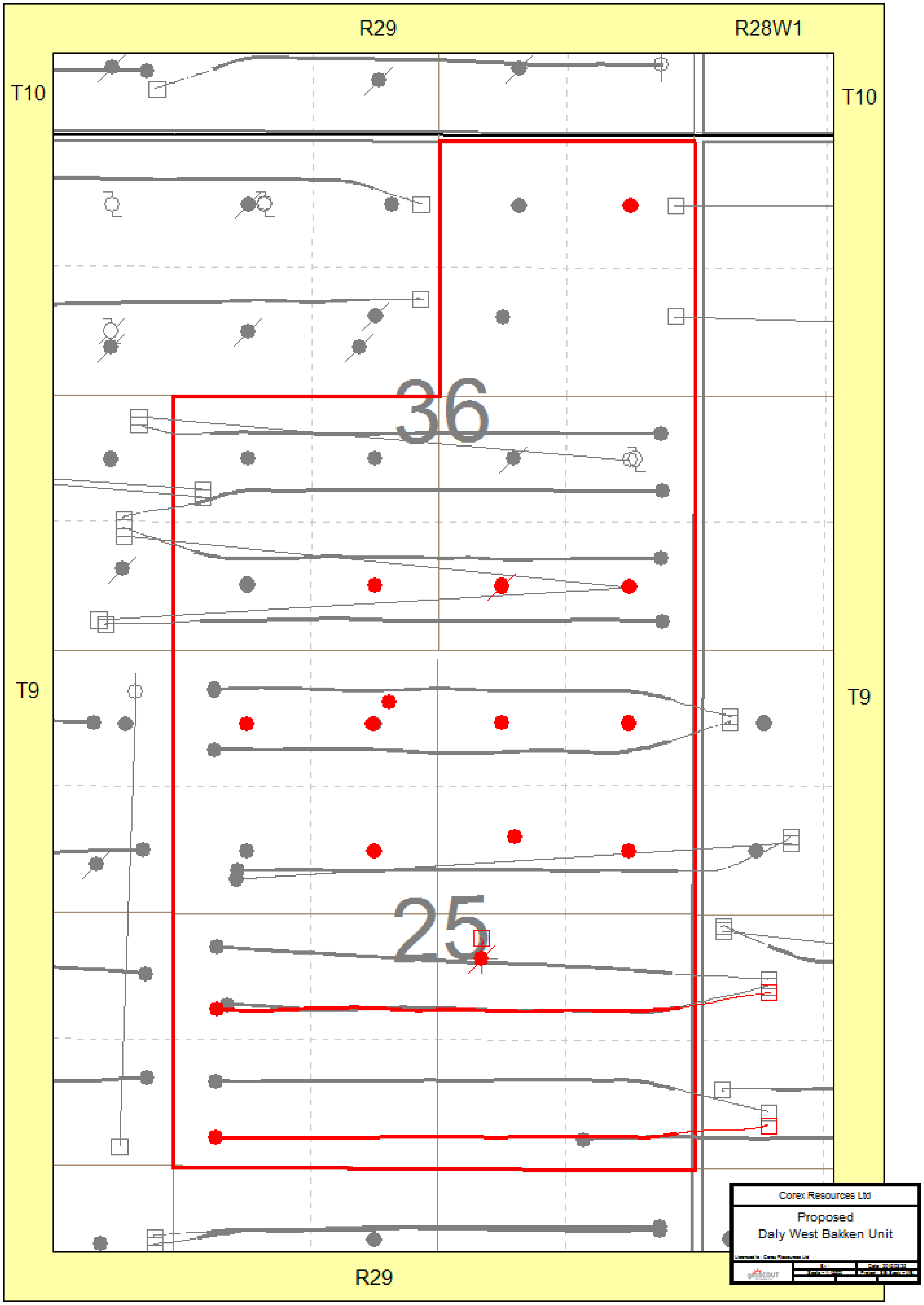


Figure 2 – Proposed Daly Unit No. 14 within Daly Sinclair Field

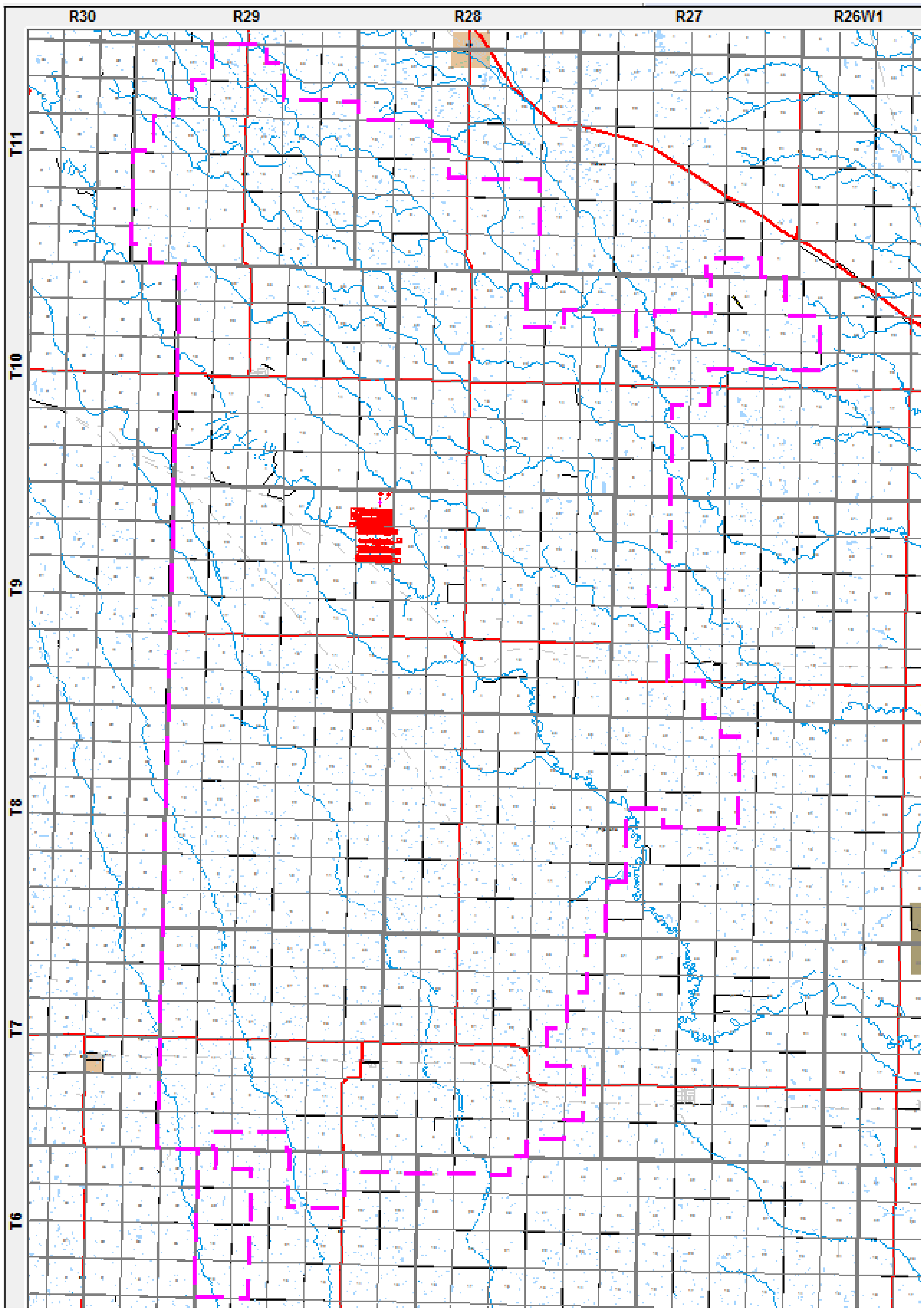


Figure 3 – Production History of Bakken Wells within Daly Unit No. 14

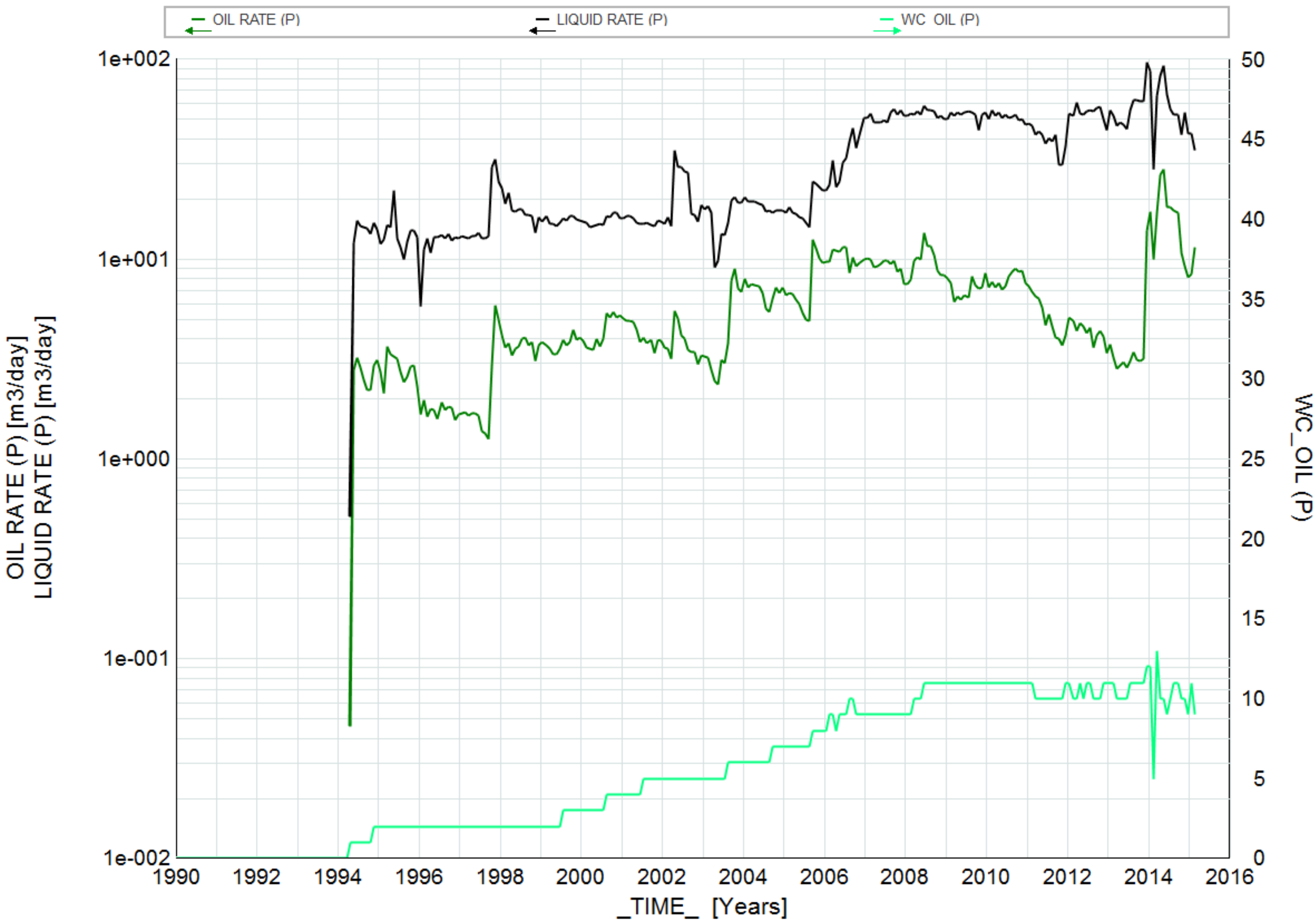


Figure 4 – Proposed Well Locations and Injector Conversions

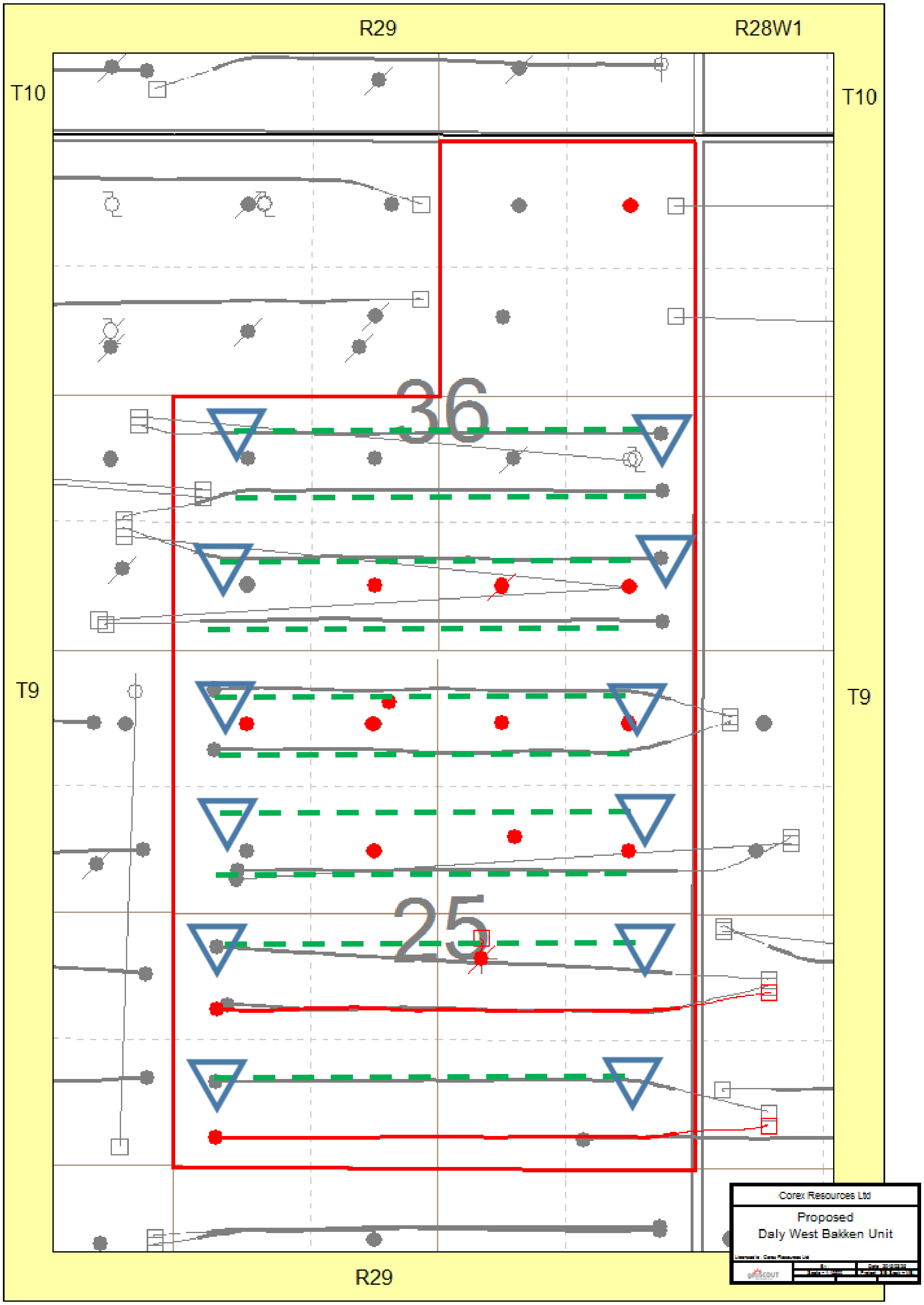


Figure 5 – Simplified Flow Diagram

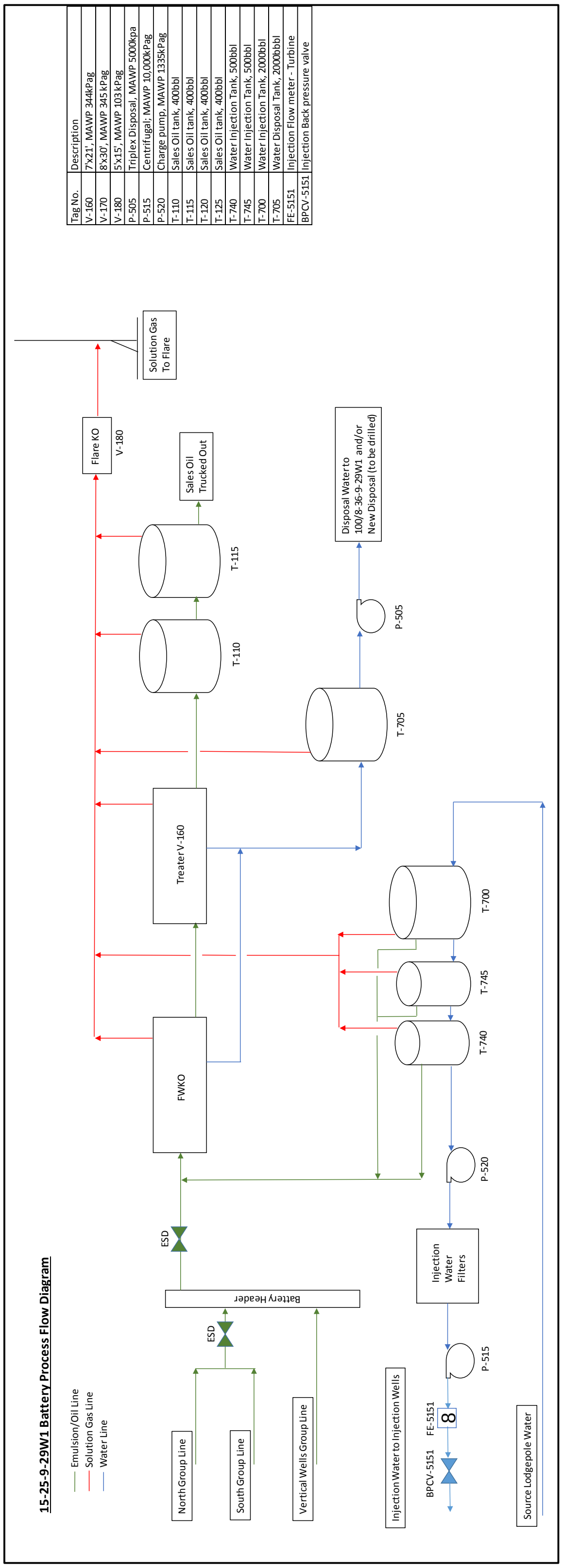
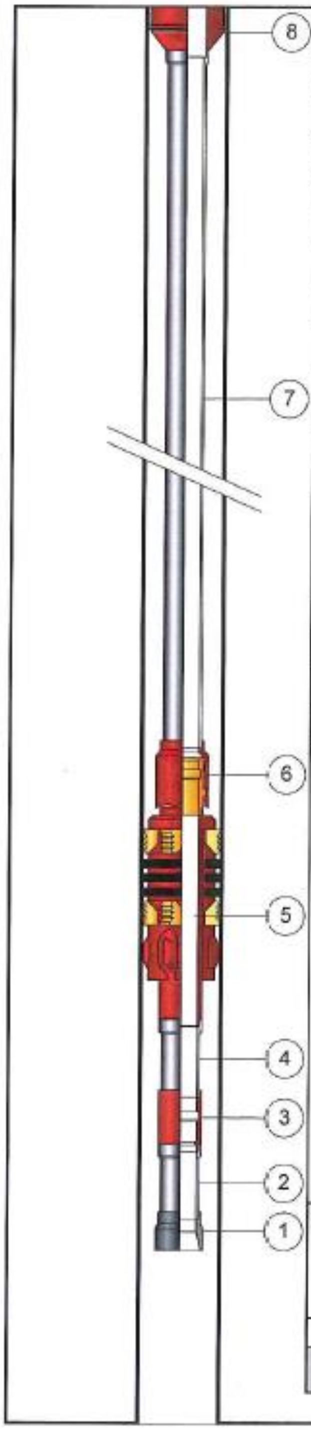


Figure 6 – Schematic Wellbore Diagram for Typical Injector

Weatherford

Corex Resources ~ 177.8mm x 88.9mm Arrowset 1-X Coated Injection Packers



Proposed Well Completion

Company	Corex Resources			Reference	CP13520
Prepared for	Michael Smith	Phone	403-693-7698	Location	Various
Prepared by	Patrick Browne	Sales Rep	Patrick Browne		
Service Centre	Estevan 1-866-844-0315	Drawn by	Patrick Browne	Date	12/18/2013 (Page 1)

TUBULAR	Size (mm)	Weight (kg/m)	Grade	Thread	Notes
Intermediate	177.8	34.23	N-80	LT&C	TBD
Injection String	88.9	13.84	TBD	EUE	TBD

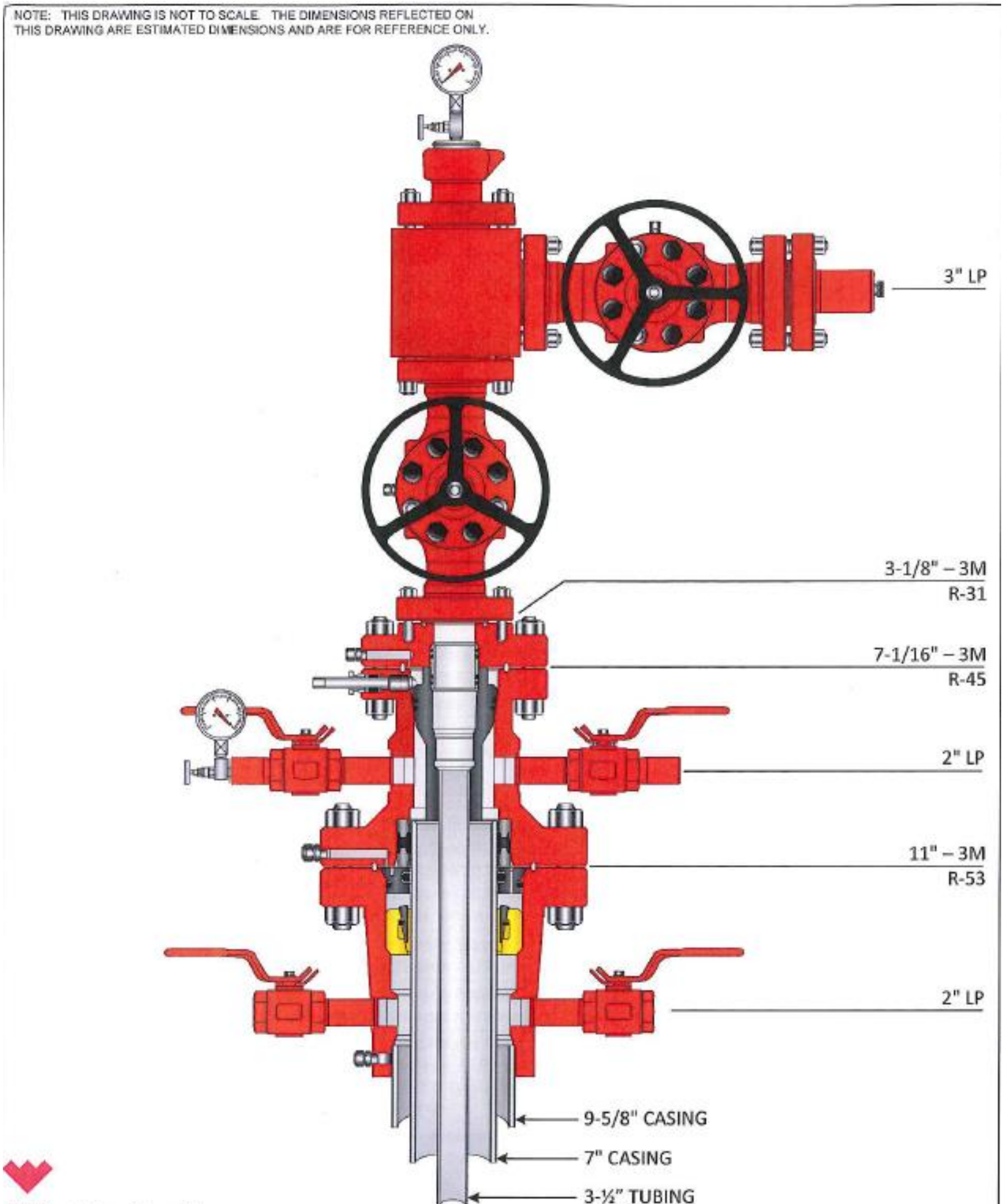
ITEM	DESCRIPTION
8.	Weatherford Tubing Hanger c/w TBD Coating
7.	88.9mm 13.84kg/m J-55 EUE (Polycore Lined) Tubing to Surface
6.	Weatherford ENC Coated 'NFT' On-Off Unit c/w 69.85mm (2.75") 'X' Profile Max OD: 149.2mm
5.	**Weatherford ENC Coated Arrowset 1-X Mechanical Set Double Grip Retrievable Packer** Max OD: 152.4mm Min ID: 76.2mm Differential Rating 42MPa
4.	88.9mm 13.84kg/m J-55 EUE (Polycore Lined) Tubing as Required
3.	88.9mm Weatherford ENC Coated 'NCN' Profile Nipple 69.85mm (2.75") c/w 66.93mm 2.63") No-Go
2.	88.9mm 13.84kg/m J-55 EUE (Polycore Lined) Tubing as Required
1.	Wireline Re-entry Guide ENC Coated

corex resources

NOTES

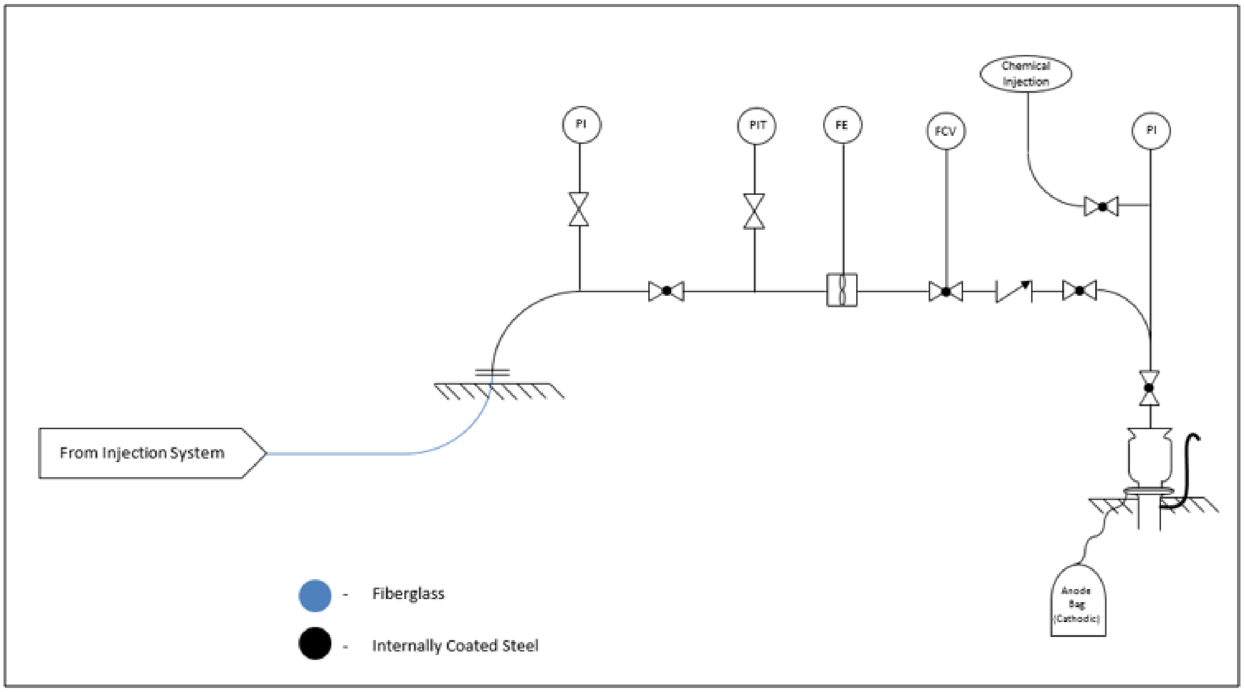
- Packer Differential Rating 42MPa

Figure 7 – Wellhead for Typical Injector



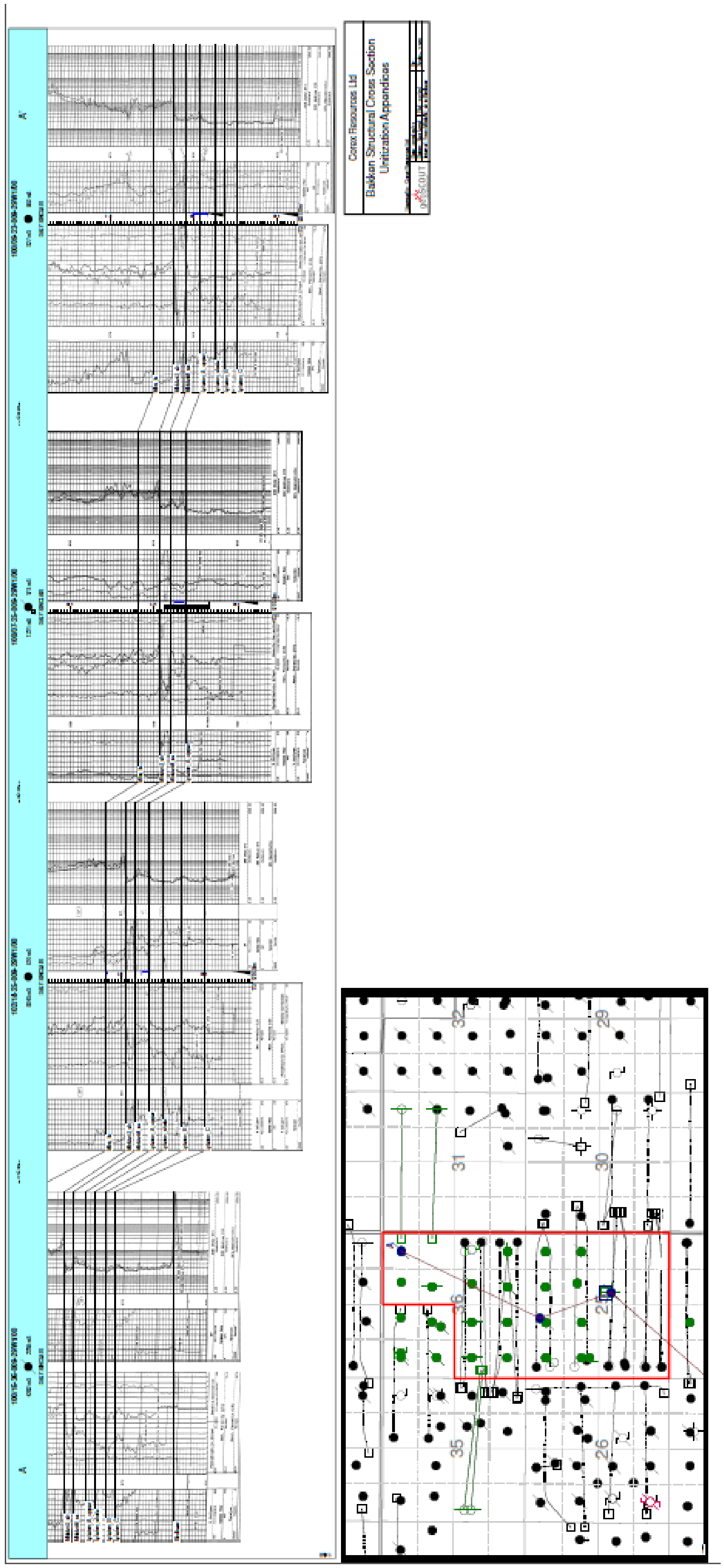
Customer:	COREX RESOURCES	DWG No:	CQD-7164V	Quote No.:	CW-131216-CR
Project Name:	3-½" - 3000 PSI INJECTOR WELLHEAD	Date:	12/18/2013	Drawn By:	M.GRAVELY

Figure 8 – System Plan for Corrosion Control

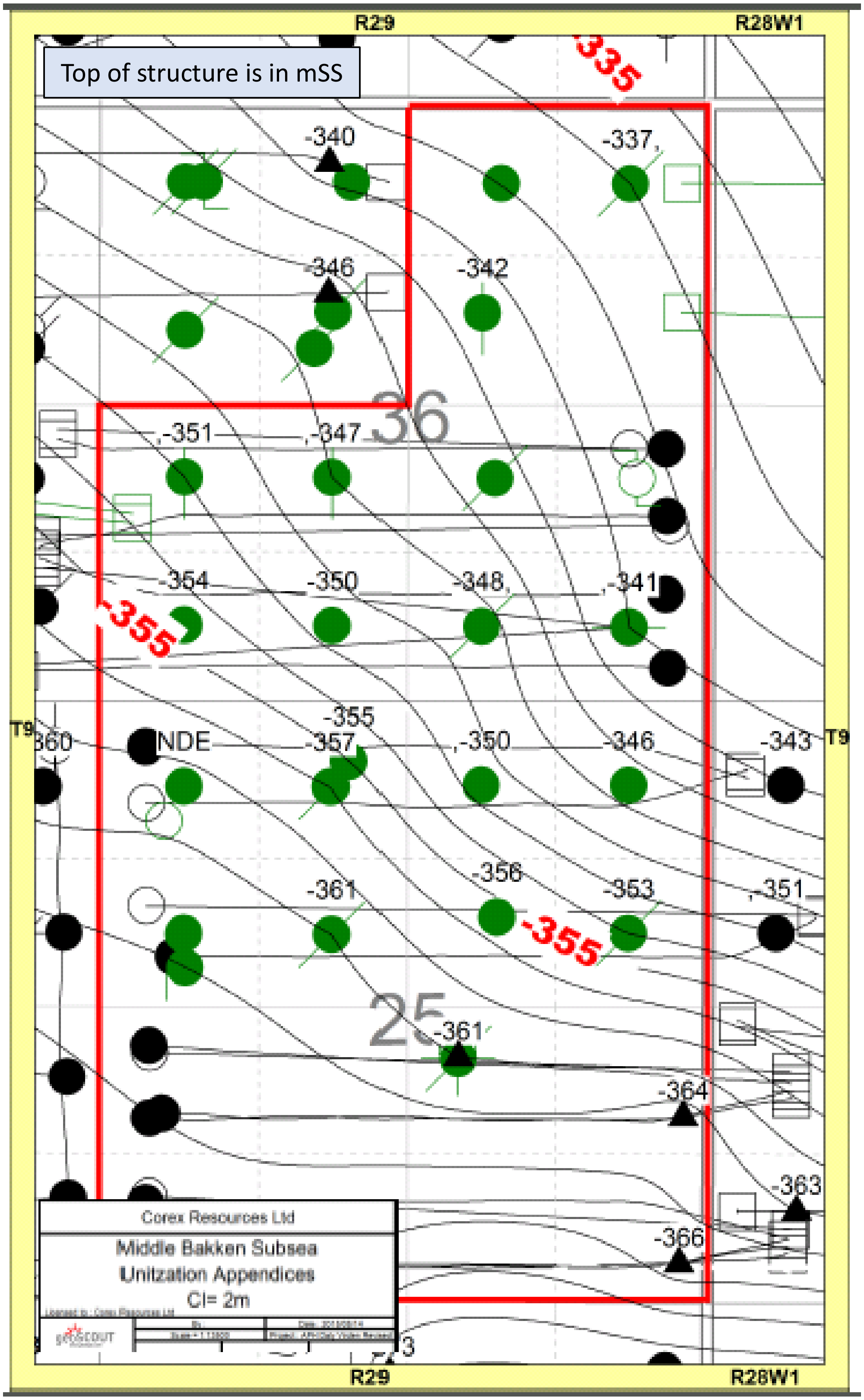


All injection pipelines will have corrosion inhibitor injected at the 15-25 facility, which will carry through to the wellhead for downhole corrosion control. Scale inhibitor will be injected in as well at the wellhead through continuous pumps. Both of these chemicals are also injected upstream at the producing source wells to protect the pipelines and the injection facilities at the battery.

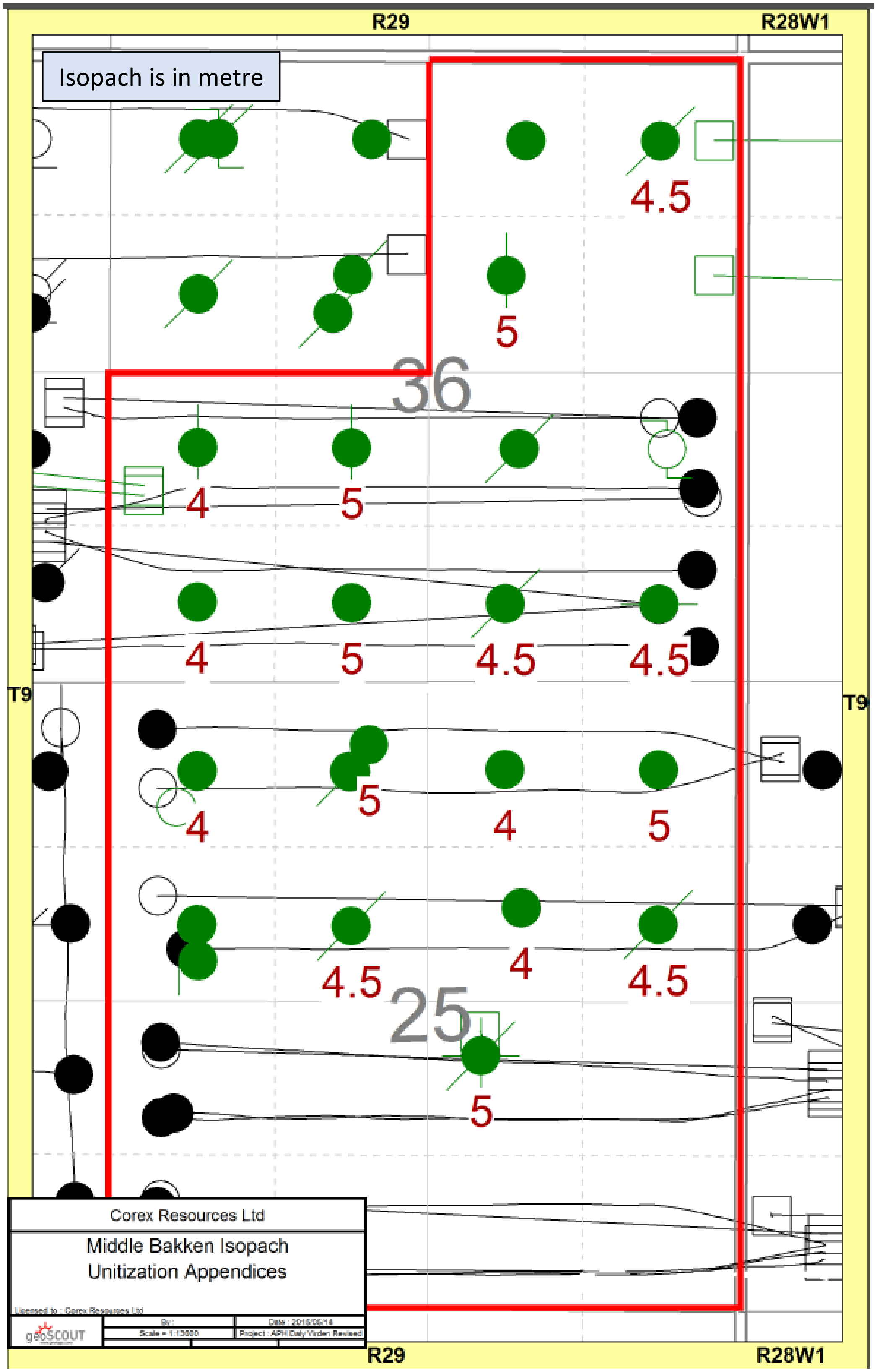
Appendix I – Middle Bakken – Stratigraphic Cross-Section



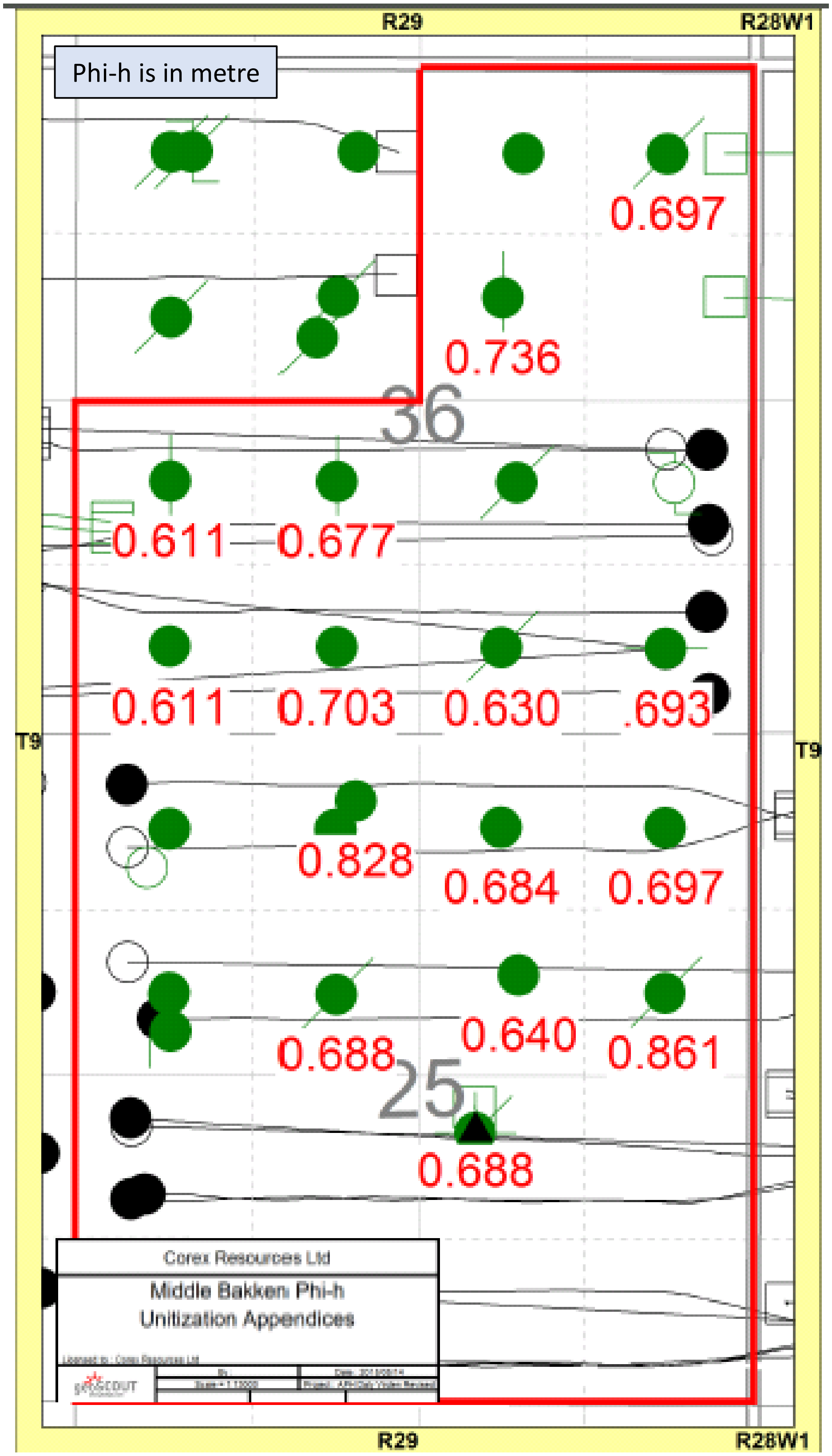
Appendix II – Middle Bakken – Top of Structure



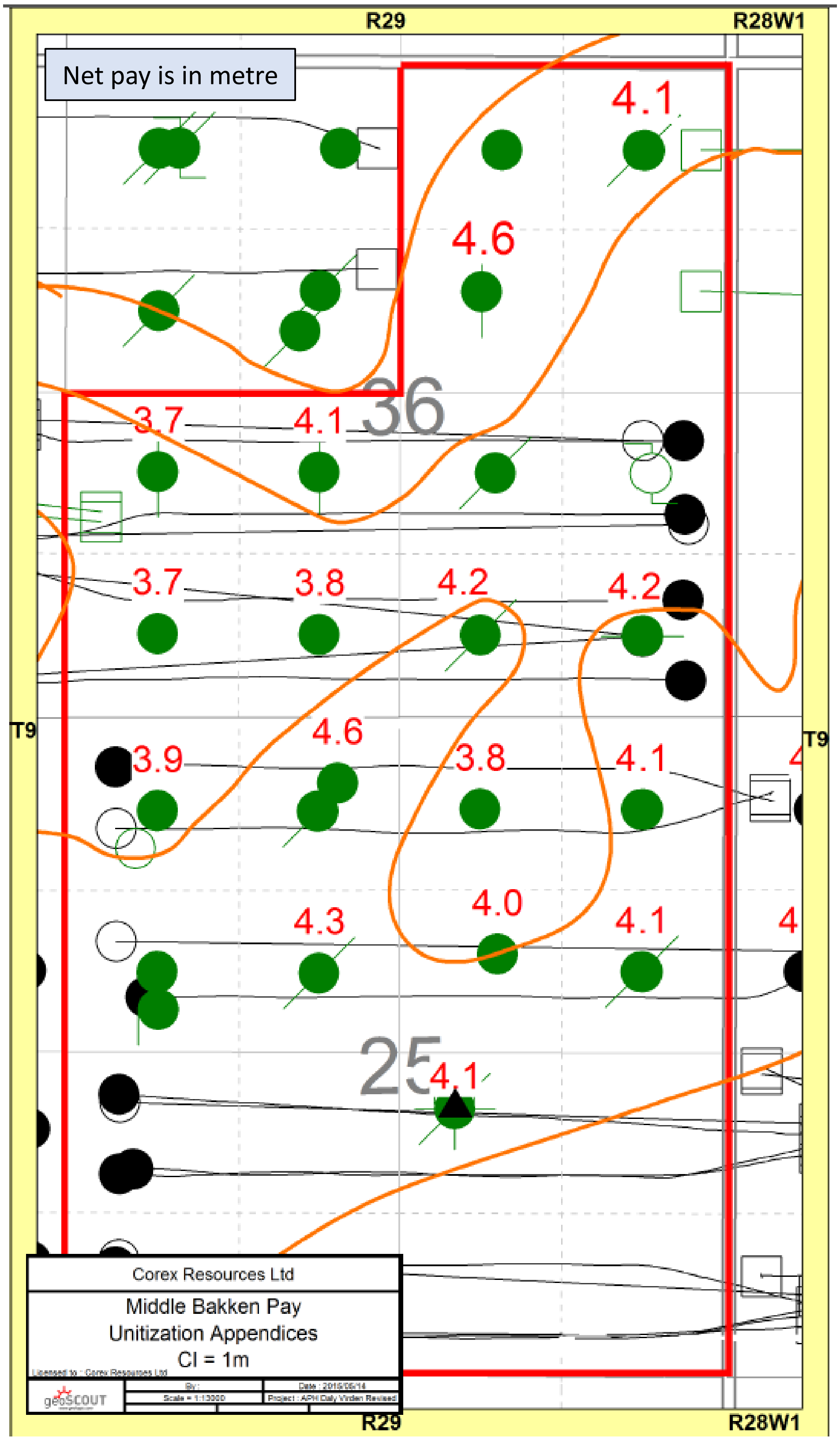
Appendix III – Middle Bakken – Isopach



Appendix IV – Middle Bakken – Porosity-Thickness



Appendix V – Middle Bakken – Net Pay



Appendix VI – Middle Bakken – Core Data

Core Data

Well Summary

Well ID:	100/07-25-009-29W1/02	Project:	APH Daly Virden Revised
Well Name:	RED RIVER DALY SINCLAIR DIR	Database Date:	2015/04/06
KB:	514.1 m	Field:	DALY SINCLAIR
Operator:	Red River Oil Inc	Pool:	
Orig Operator:		OS Area:	
		OS Dep:	

Analysis Summary

CA Number:	2629 (3 of 3)	CA Top:	777.00 m
File Number:	2629	CA Base:	787.40 m
Lab:	CORE LAB CANADA LTD.	CA Interval:	10.36 m
Analysis:	MB	Core Number:	001
Analysis Date:	2006/01/10	Core Interval:	878.00 m – 891.50 m

Statistical Summary

Mean Values

Analysis Output:

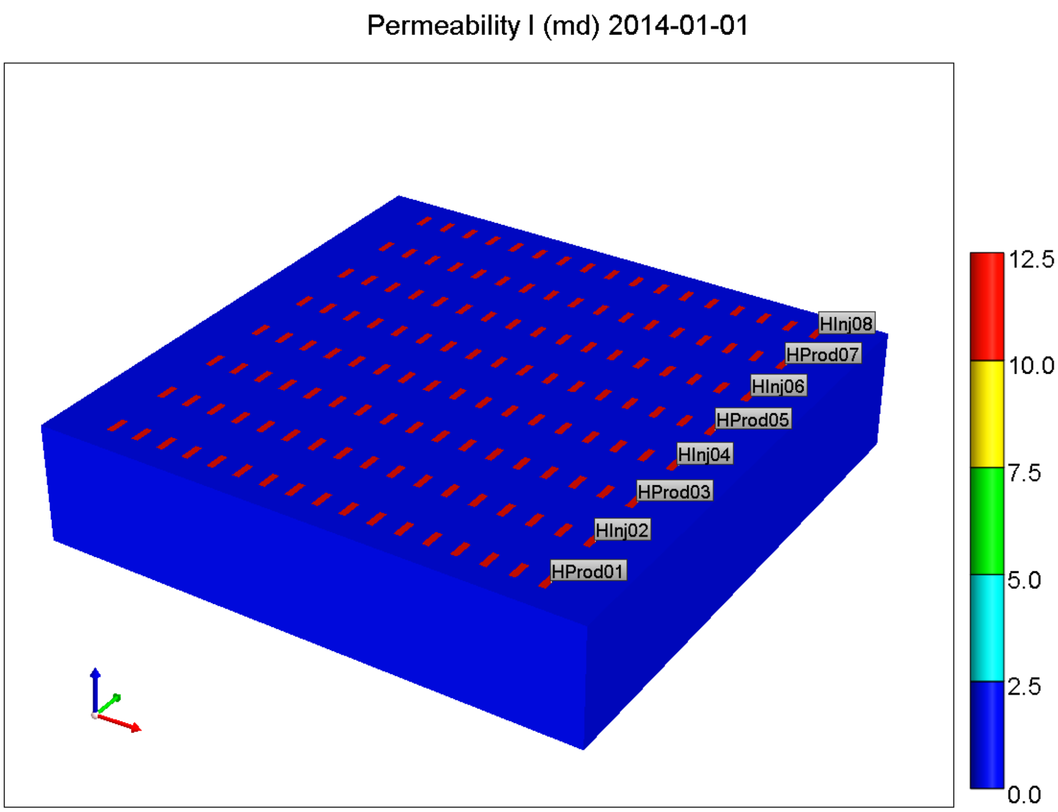
			Total Core: Ari	Geo	Har	Applied Cut-offs: Ari	Geo	Har
Interval Top:	0.00 m							
Interval Base:	0.00 m	Kmax(mD)	0.51	0.19	0.08	0.00	0.00	0.00
Net Thickness:	0.00 m	K90(mD)	0.58	0.45	0.37	0.00	0.00	0.00
phi-H:	0.00	Kvert(mD)	0.08	0.05	0.02	0.00	0.00	0.00
Kmax-H:	0.00 mD-m	Porosity(%)	13.40	12.93	12.17	0.00	0.00	0.00

Cut-offs Applied:

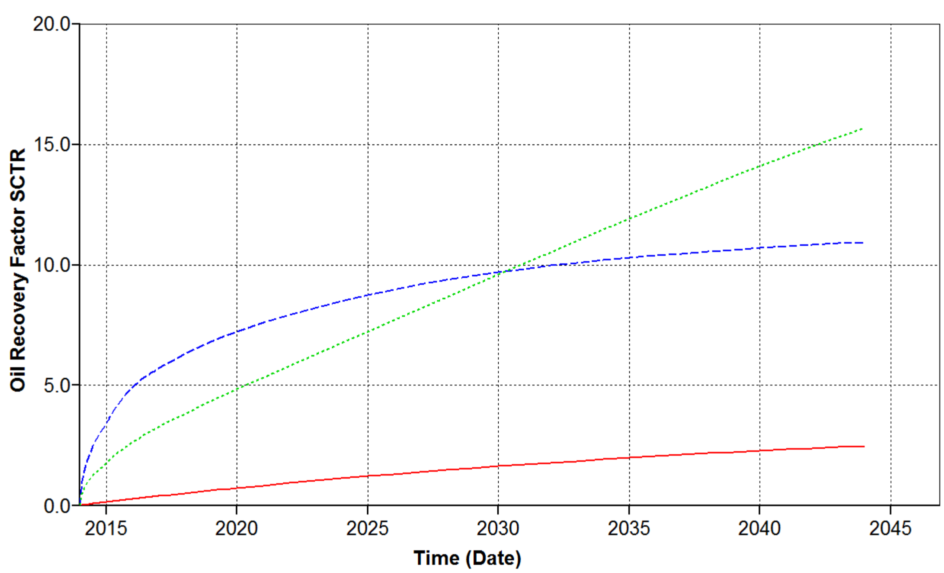
	Min	Max		Min	Max		Min	Max
Depth(m):			Grn Den(kg/m3):			BlkVol Wtr(frac):		
Porosity(frac):			Blk Den(kg/m3):			PorVol Wtr(frac):		
KMax(mD):			BlkMass Snd(frac):			BlkVol Wtr(frac):		
K90(mD):			BlkMass Wtr(frac):			PorVol Wtr(frac):		
KVert(mD):			GrnMass Wtr(frac):			BlkVol Oil(frac):		
Formation:			BlkMass Oil(frac):			PorVol Oil(frac):		
			GrnMass Oil(frac):			Core Gamma(API):		

Core	Depth m	Length m	K-Max mD	K-90 mD	K-Vert mD	Porosity frac	Grn Den kg/m3	Por Vol Oil frac	Por Vol Wtr frac	Lithology	Formation	Kmax-H	Phi-H	Blk Den kg/m3
1*	878.00	2.04								sh	MbkknU_sh			
1*	880.04	1.12								shy;sltst	MbkknM_ss			
1*	881.17	0.19	0.12			0.128	2770		0.880	anhy;ss;sshy	MbkknM_ss	0.02	0.02	2410
1*	881.36	0.23	1.18	1.12	0.01	0.116	2720	0.108	0.714	l;ls;ppv;sv	MbkknM_ss	0.27	0.03	2410
1*	881.59	0.18	0.32			0.119	2750	0.108	0.736	dol;l;ssdy;sshy	MbkknM_ss	0.06	0.02	2420
1*	881.77	0.21	0.11			0.133	2740	0.336	0.374	dol;l;ssdy;sshy	MbkknM_ss	0.02	0.03	2380
1*	881.98	0.32	0.47			0.147	2720		0.893	dol;l;ssdy;sshy	MbkknM_ss	0.15	0.05	2320
1*	882.30	0.34	0.24			0.138	2740		0.894	dol;l;lam;sdy;shy	MbkknM_ss	0.08	0.05	2360
1*	882.64	0.40	0.27	0.27	0.12	0.144	2730		0.880	l;lam;ls;sdy	MbkknM_ss	0.11	0.06	2340
1*	883.04	0.16	0.35			0.145	2750		0.882	lam;sh;ss;sshy	MbkknM_ss	0.06	0.02	2350
1*	883.20	0.19	1.04			0.140	2740	0.101	0.694	dol;l;ssdy;sshy	MbkknM_ss	0.20	0.03	2350
1*	883.39	0.35	0.14			0.090	2740	0.282	0.564	dol;l;lam;sdy	MbkknM_ss	0.05	0.03	2480
1*	883.74	0.23	3.85			0.162	2700	0.134	0.596	dol;l;lam;ssdy	MbkknM_ss	0.89	0.04	2270
1*	883.97	0.22	0.03			0.042	2770	0.170	0.510	anhy;dol;l;ssdy	MbkknM_ss	0.01	0.01	2650
1*	884.19	0.28	1.05			0.128	2720	0.149	0.532	dol;l;lam;ssdy	MbkknM_ss	0.29	0.04	2370
1*	884.47	1.07	0.03			0.159	2700		0.922	dol;l;shy;ssdy	MbkknM_ss	0.03	0.17	2270
1*	885.54	5.36								dol;shy	MbkknM_ss			
1*	890.90	0.60								lc	MbkknM_ss			

Appendix VII – Middle Bakken – Section Model



Section Model – Bakken – 3D View



Section Model – Bakken – Forecast – Oil Recovery Factor versus Time

Appendix VIII – Tract Description and Working Interest Owners

Tract	Land Description	Tract Factor	W.I. Owner	W.I. Percent	Mineral Owner
1	1-25-09-29W1	3.410362049%	Corex	100%	Heritage Royalty
2	2-25-09-29W1	3.408900054%	Corex	100%	Heritage Royalty
3	3-25-09-29W1	3.624284570%	Corex	100%	Heritage Royalty
4	4-25-09-29W1	3.625926838%	Corex	100%	Heritage Royalty
5	5-25-09-29W1	3.610469374%	Corex	100%	Heritage Royalty
6	6-25-09-29W1	3.610469374%	Corex	100%	Heritage Royalty
7	7-25-09-29W1	3.471386863%	Corex	100%	Heritage Royalty
8	8-25-09-29W1	3.395111747%	Corex	100%	Heritage Royalty
9	9-25-09-29W1	4.238722179%	Corex	100%	Harley/Kormylo (1)
10	10-25-09-29W1	3.386459958%	Corex	100%	Harley/Kormylo (1)
11	11-25-09-29W1	3.261165351%	Corex	100%	Harley/Kormylo (1)
12	12-25-09-29W1	3.445722034%	Corex	100%	Harley/Kormylo (1)
13	13-25-09-29W1	3.012086067%	Corex	100%	Harley/Kormylo (1)
14	14-25-09-29W1	4.360013334%	Corex	100%	Harley/Kormylo (1)
15	15-25-09-29W1	3.613076897%	Corex	100%	Harley/Kormylo (1)
16	16-25-09-29W1	3.582673012%	Corex	100%	Harley/Kormylo (1)
17	1-36-09-29W1	3.565848802%	Corex	100%	Jones et al (2)
18	2-36-09-29W1	3.219434343%	Corex	100%	Jones et al (2)
19	3-36-09-29W1	3.573462337%	Corex	100%	5206197/5188807 (3)
20	4-36-09-29W1	3.286895784%	Corex	100%	5206197/5188807 (3)
21	5-36-09-29W1	3.286895784%	Corex	100%	5206197/5188807 (3)
22	6-36-09-29W1	3.642235869%	Corex	100%	5206197/5188807 (3)
23	7-36-09-29W1	3.445722034%	Corex	100%	Jones et al (2)
24	8-36-09-29W1	3.445722034%	Corex	100%	Jones et al (2)
25	9-36-09-29W1	3.935660636%	Corex	100%	Computershare/69763 (4)
26	10-36-09-29W1	3.962580339%	Corex	100%	Computershare/69763 (4)
27	15-36-09-29W1	3.935660636%	Corex	100%	Computershare/69763 (4)
28	16-36-09-29W1	3.643051699%	Corex	100%	Computershare/69763 (4)
Total		**100.000000000%**			

Notes:

1. Don Harley Insurance Agency Ltd. (50%) and Joanne Kormylo (50%)
2. Clifford Jones (25%), Elizabeth Forsyth (12.5%), Jane Forsyth Payne (12.5%), Kool Resources Ltd. (25%), Computershare Trust Company of Canada (25%)
3. 5206197 Manitoba Ltd. (50%) and 5188807 Manitoba Ltd. (50%)
4. Computershare Trust Company of Canada (75%) and 69763 Manitoba Ltd. (25%)