Husky Oil Operations Limited

Tucker Thermal Project

Commercial Scheme No. 9835

Annual Performance Presentation

Alberta Energy Regulator

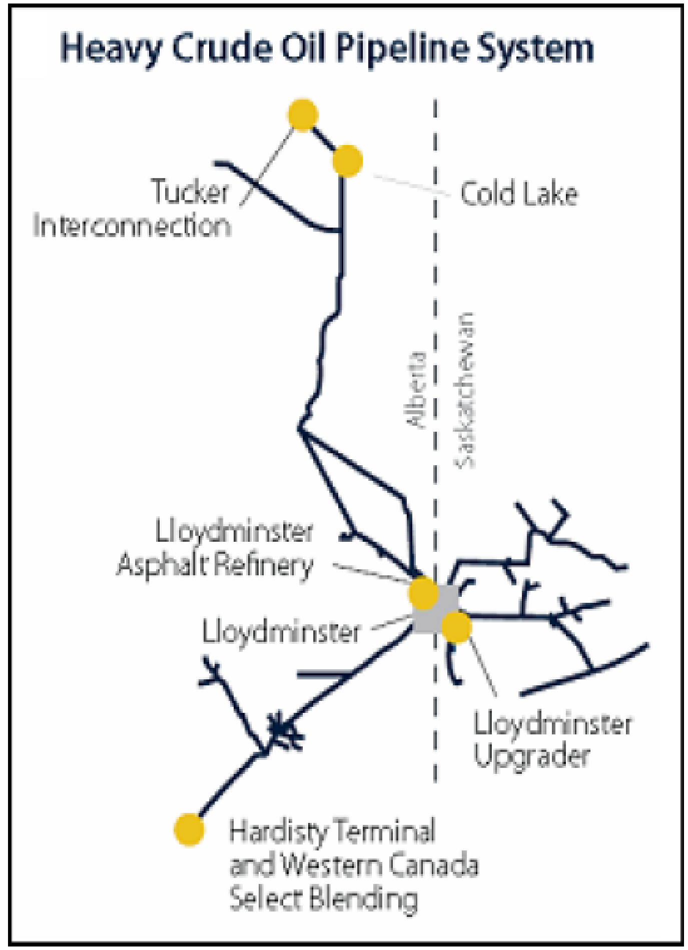
September 13, 2017

3.1.1. Subsurface – Table of Contents

1. Brief Background

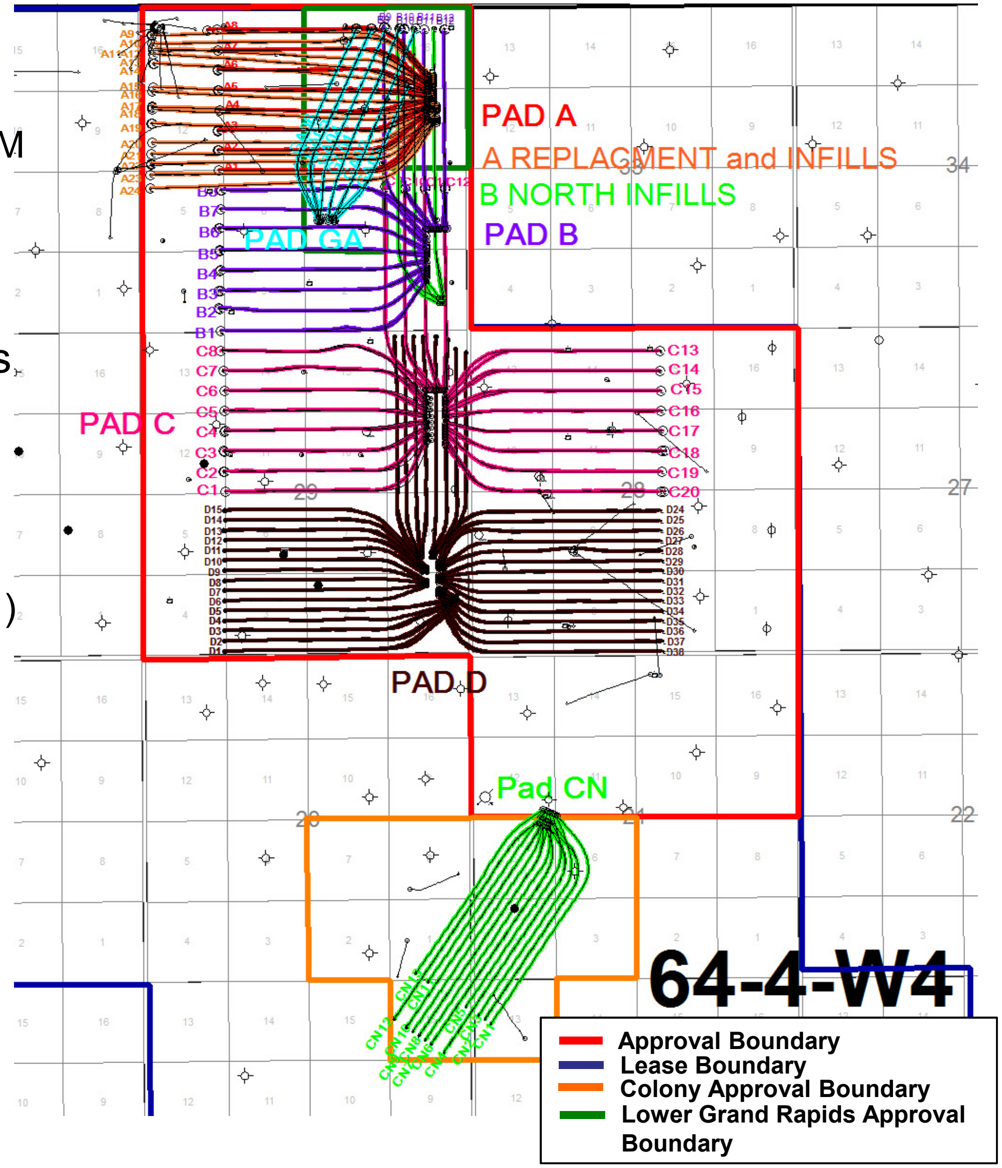
Project Overview

- AER Commercial Scheme Approval No. 9835
- 30,000 BOPD SAGD Project
- Clearwater and Grand Rapids Reservoirs
- 9-10º API Bitumen
- Integrated with Husky Pipeline & Upgrader
- Project completed in 24 months
- First Steam August 20, 2006
- First Production November 29, 2006



Project Development Area

- Approval Area:
  - Sections 28, 29, 32 & N/2 of 21 in 064-04 W4M
  - SE ¼ Section 23, SW ¼ Section 21, Section 17 LSD 16 & Section 16 LSD 13
- 35 Year Project Life
- 109 Horizontal Well Pairs & 7 Infill Producers
  - 32 original well pairs (Pads A, B, C)
  - Well pairs added:
    - Pad C East 2007 - 8 well pairs
    - Pad B Infill 2009-2010 - 3 well pairs
    - Pad A Infill & Replacements (2010/2011) - 16 well pairs
    - Pad Lower Grand Rapids (GA) 2011 - 1 well pair; 2012-2013 – 5 well pairs
    - Pad D East 2014 - 15 well pairs
    - Pad Colony (CN) 2015 - 6 well pairs & 7 infill producers
    - Pad D North 2016 - 8 well pairs
    - Pad C West Replacement 2016 – 8 injectors
    - Pad D West 2017 - 15 well pairs



Site Overview

- Field Facilities – six well pads, infield pipelines and central pump station
- Central Plant:
  - Emulsion treating
  - Water Treatment – 120,000 bbl/day
  - Steam Generation – 99,000 bbl/day CWE
  - Utilities and Off sites
- Water Source & Disposal Wells
- Metering and Export Pipelines to Cold Lake Terminal

2. Geology / Geosciences

Average Reservoir Characteristics and OBIP

CLEARWATER	OBIP ($X10^6$ m^3)	Thickness (m)	Φ	So	Original Pressure (kPa)	Original Temperature (°C)	Depth (m)	Vertical Permeability (mD)	Horizontal Permeability (mD)
Approval area	72	45	0.31	0.57	3,200	16	440	1,800	3,000
Operating portion	36.7	46	0.32	0.57	3,200	16	440	1,800	3,000

LOWER GRAND RAPIDS	OBIP ($X10^6$ m^3)	Thickness (m)	Φ	So	Original Pressure (kPa)	Original Temperature (°C)	Depth (m)	Vertical Permeability (mD)	Horizontal Permeability (mD)
GA Approval Area	3.7	33	0.29	0.55	2,600	14	370	1,300	1,800

COLONY	OBIP ($X10^6$ m^3)	Thickness (m)	Φ	So	Original Pressure (kPa)	Original Temperature (°C)	Depth (m)	Vertical Permeability (mD)	Horizontal Permeability (mD)
CN Approval Area	2.8	10	0.3	0.79	2,500	12	305	2,400	4,000

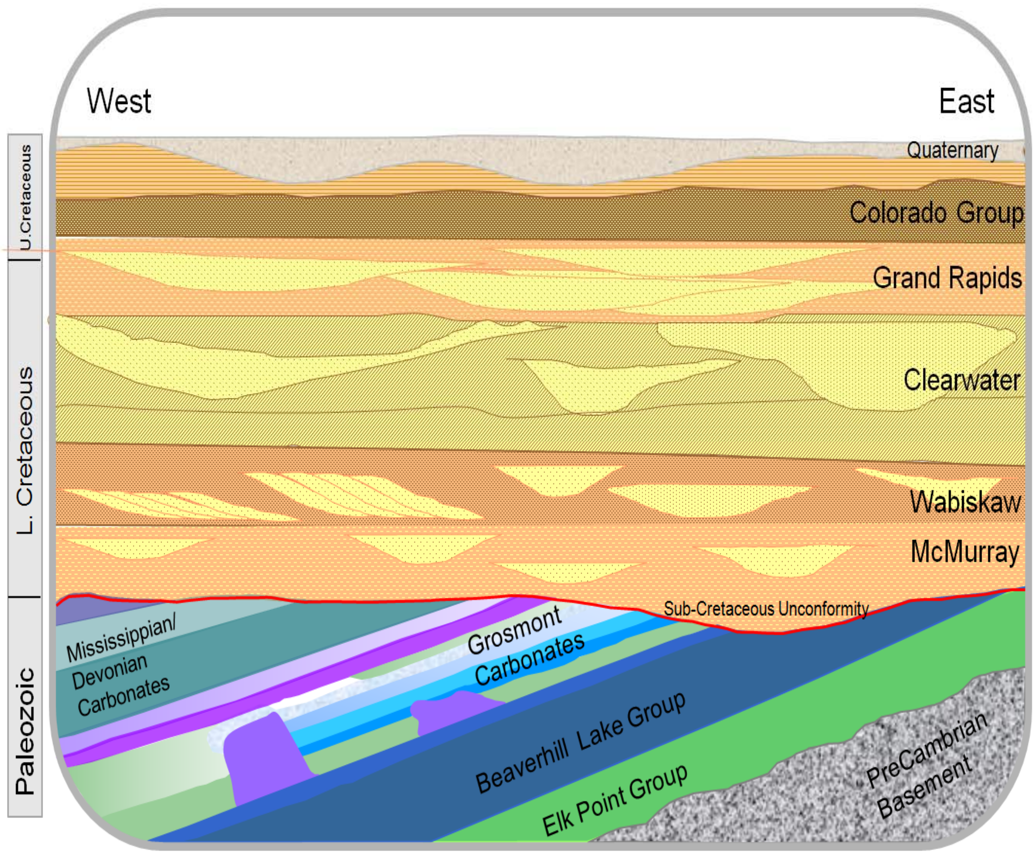
Notes:

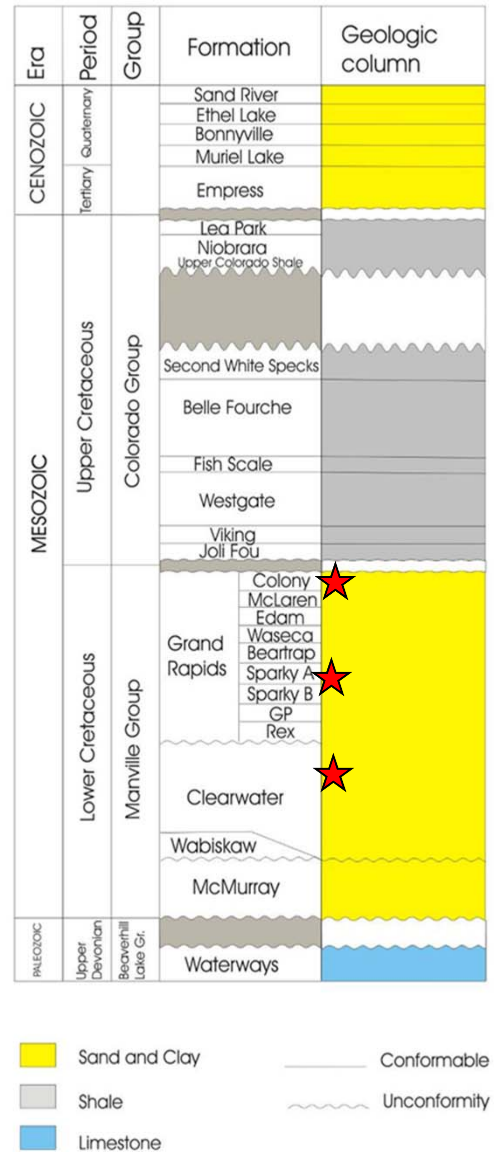
Calculation: OBIP interval: Top of Formation → oil water contact

OBIP = Area x Thickness x Φ x S_o

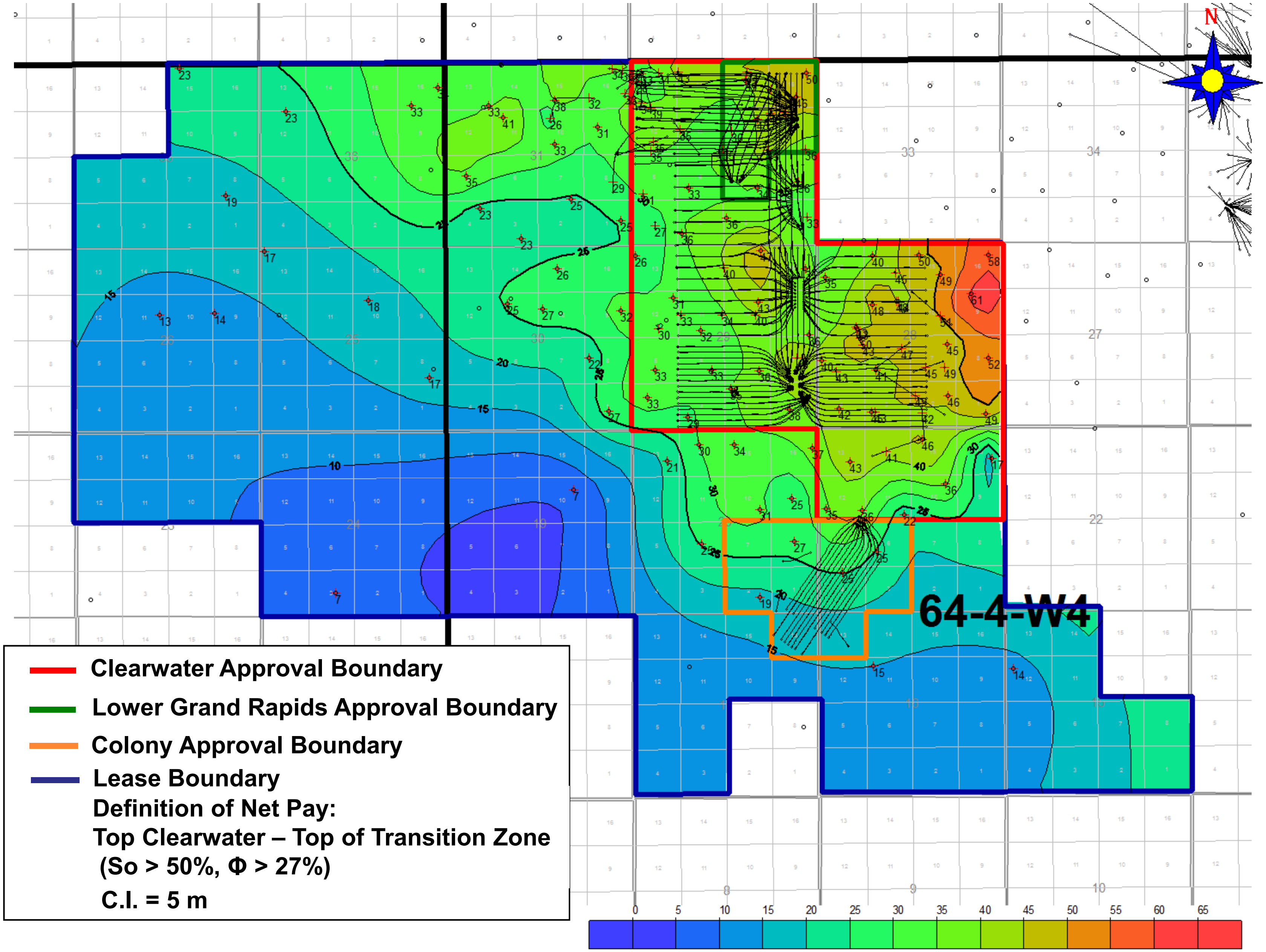
Regional Stratigraphy

- Marginal marine deposits consisting of stacked incised valley and shoreface deposits





Isopach Map of Clearwater SAGD Net Pay



Clearwater Approval Boundary

Lower Grand Rapids Approval Boundary

Colony Approval Boundary

Lease Boundary

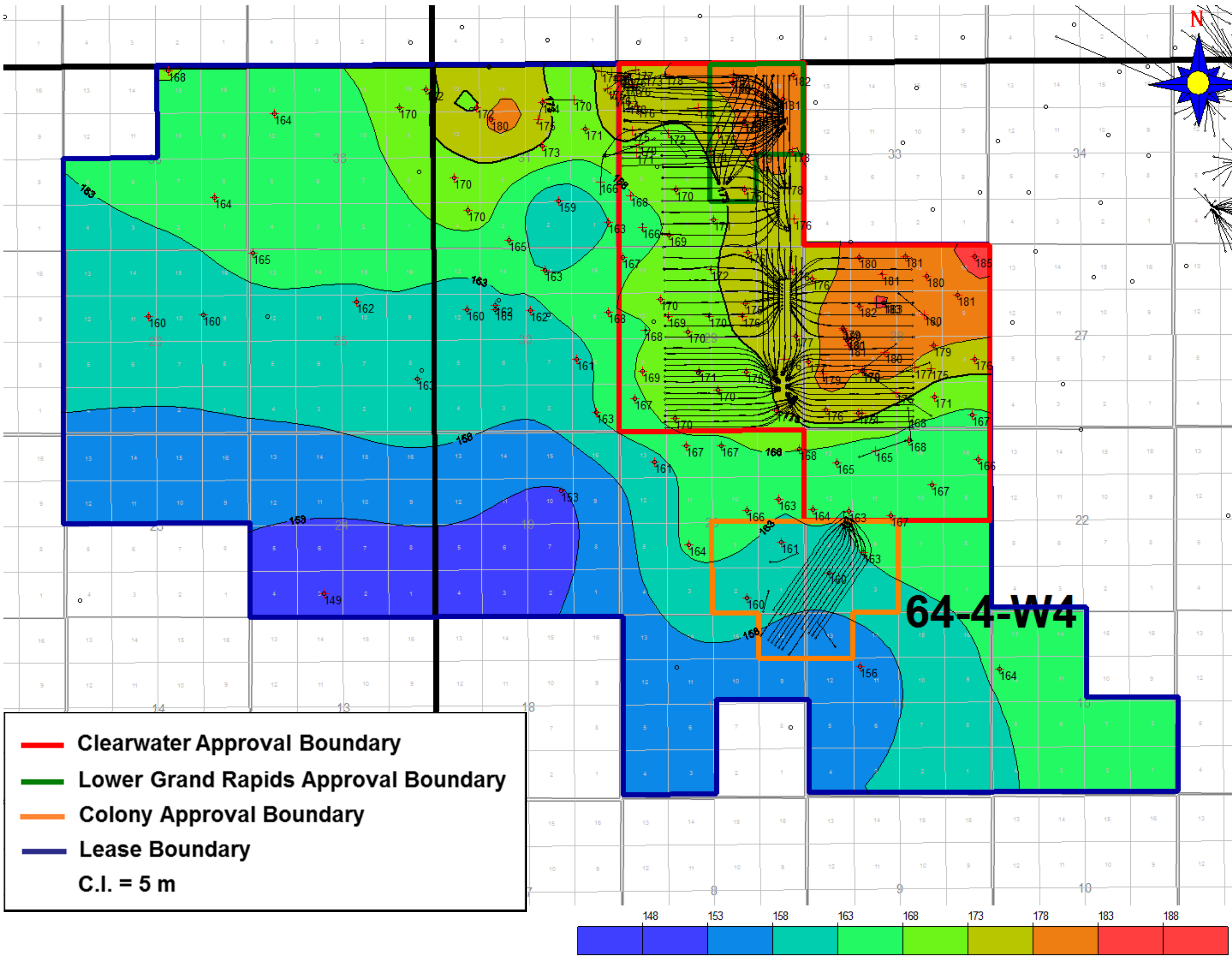
Definition of Net Pay:

Top Clearwater – Top of Transition Zone

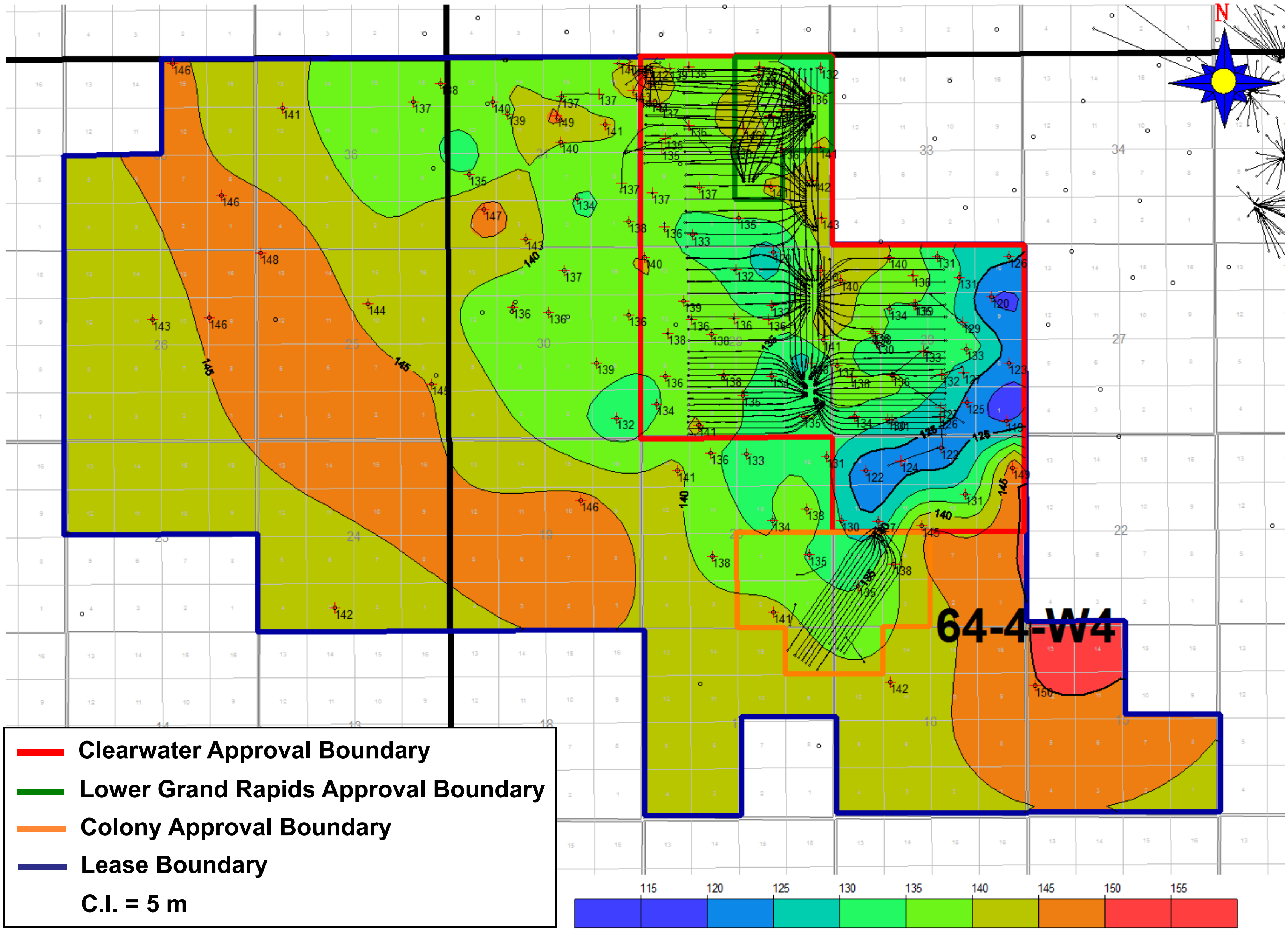
(So > 50%, Φ > 27%)

C.I. = 5 m

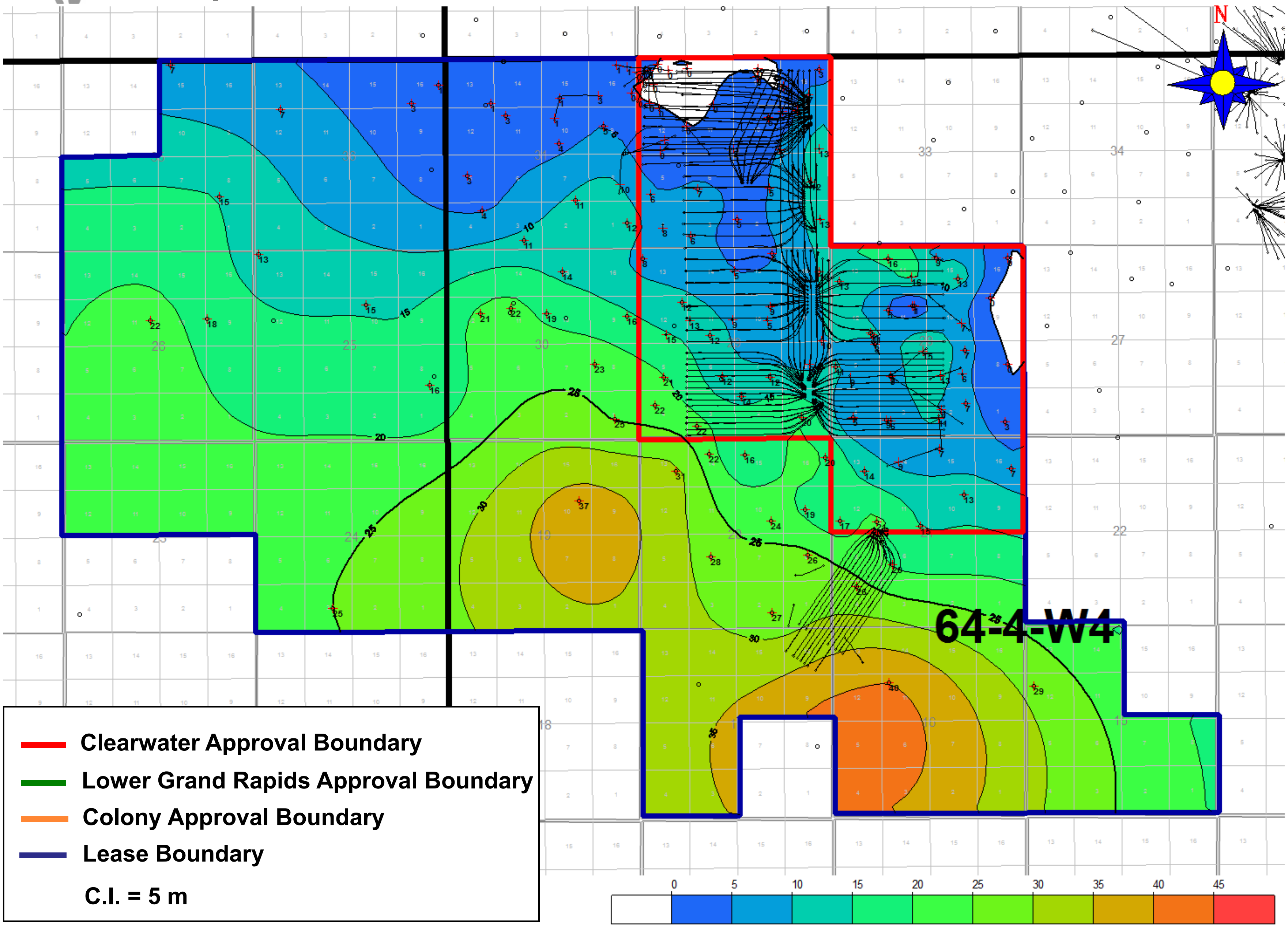
Structure Map of the Clearwater Top of Net Pay



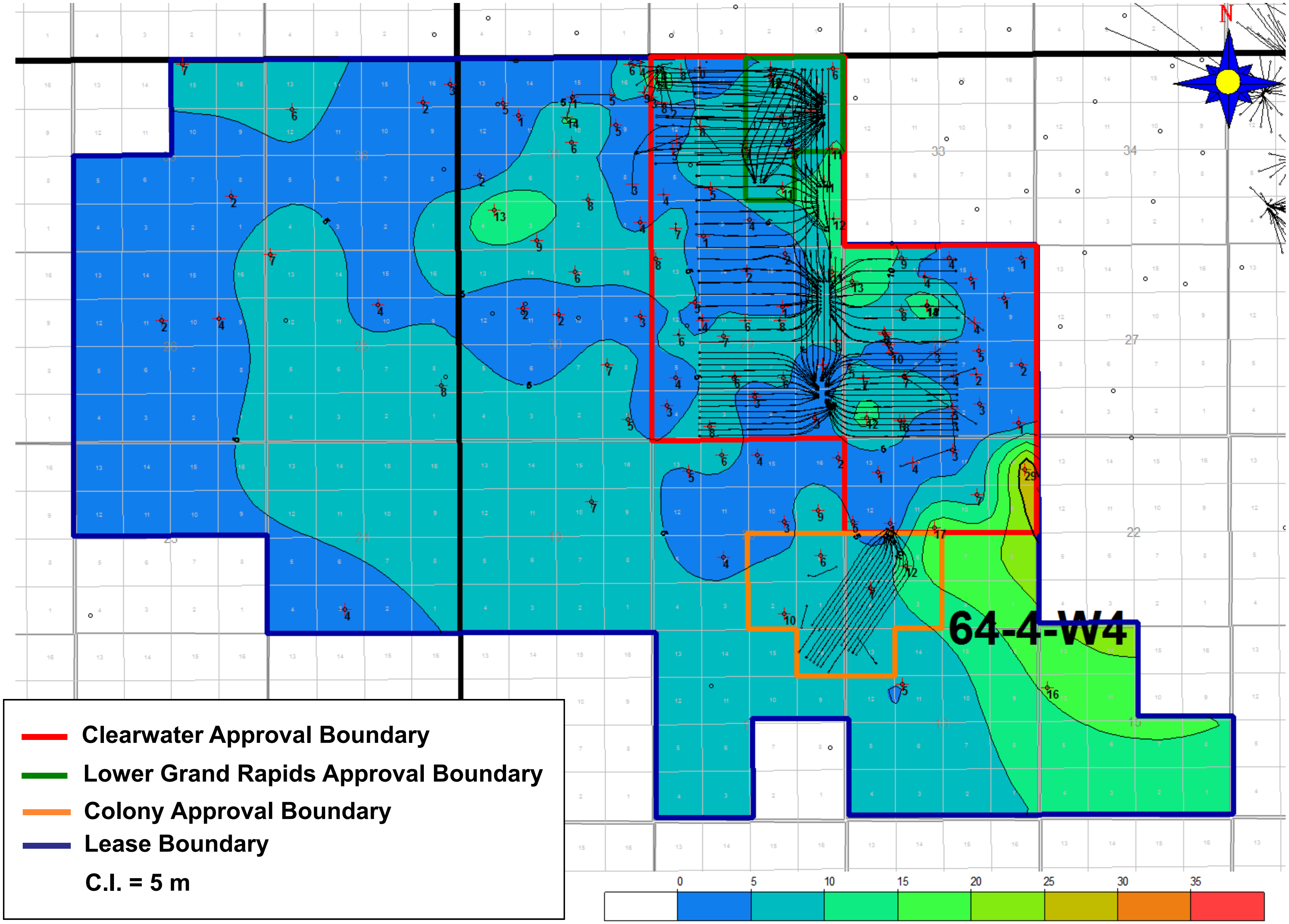
Structure Map of the Clearwater Base of Net Pay



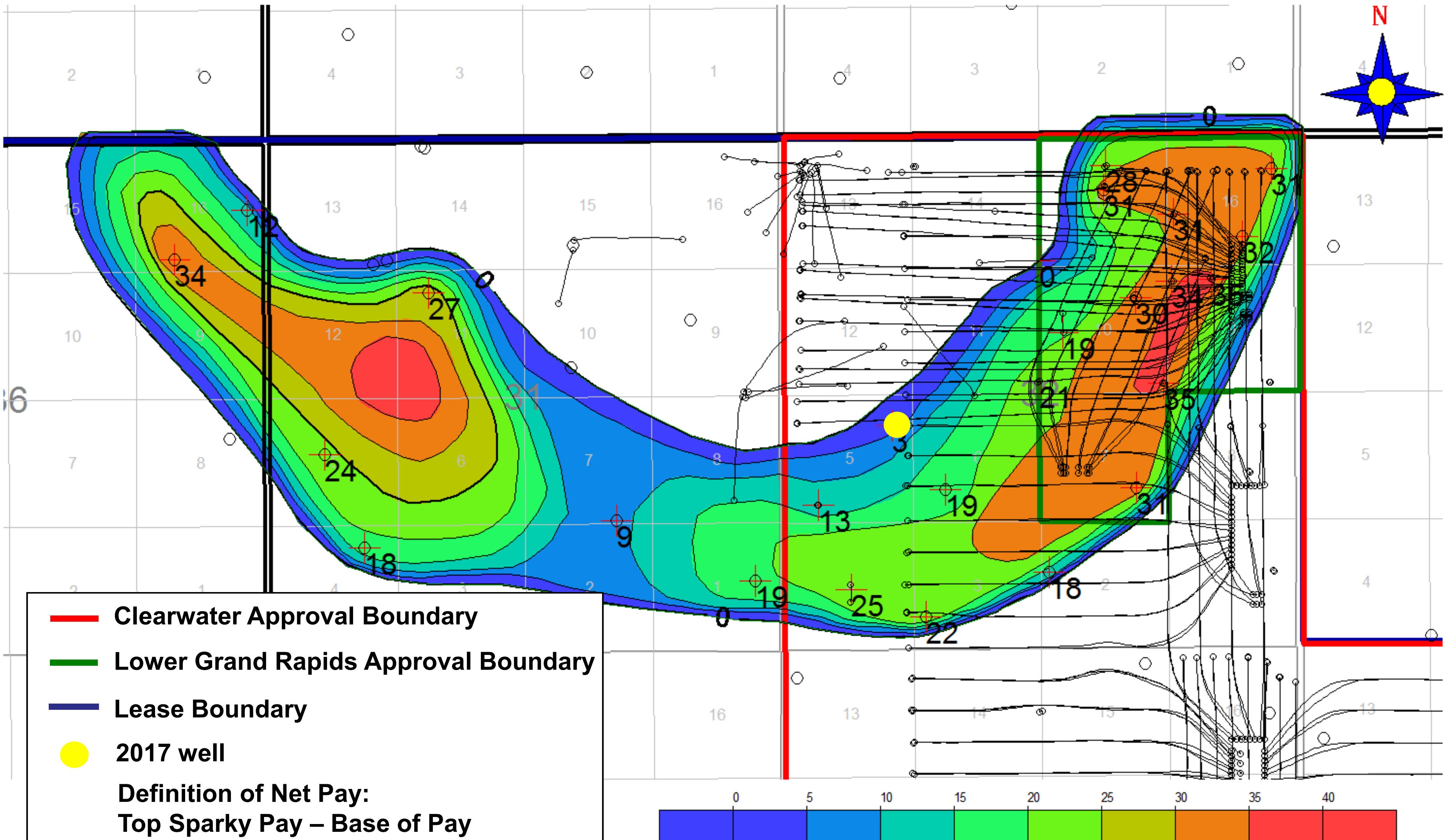
Isopach of Clearwater Bottom Water



Isopach of Clearwater Transition Zone



Isopach Map of Lower Grand Rapids SAGD Net Pay



Clearwater Approval Boundary

Lower Grand Rapids Approval Boundary

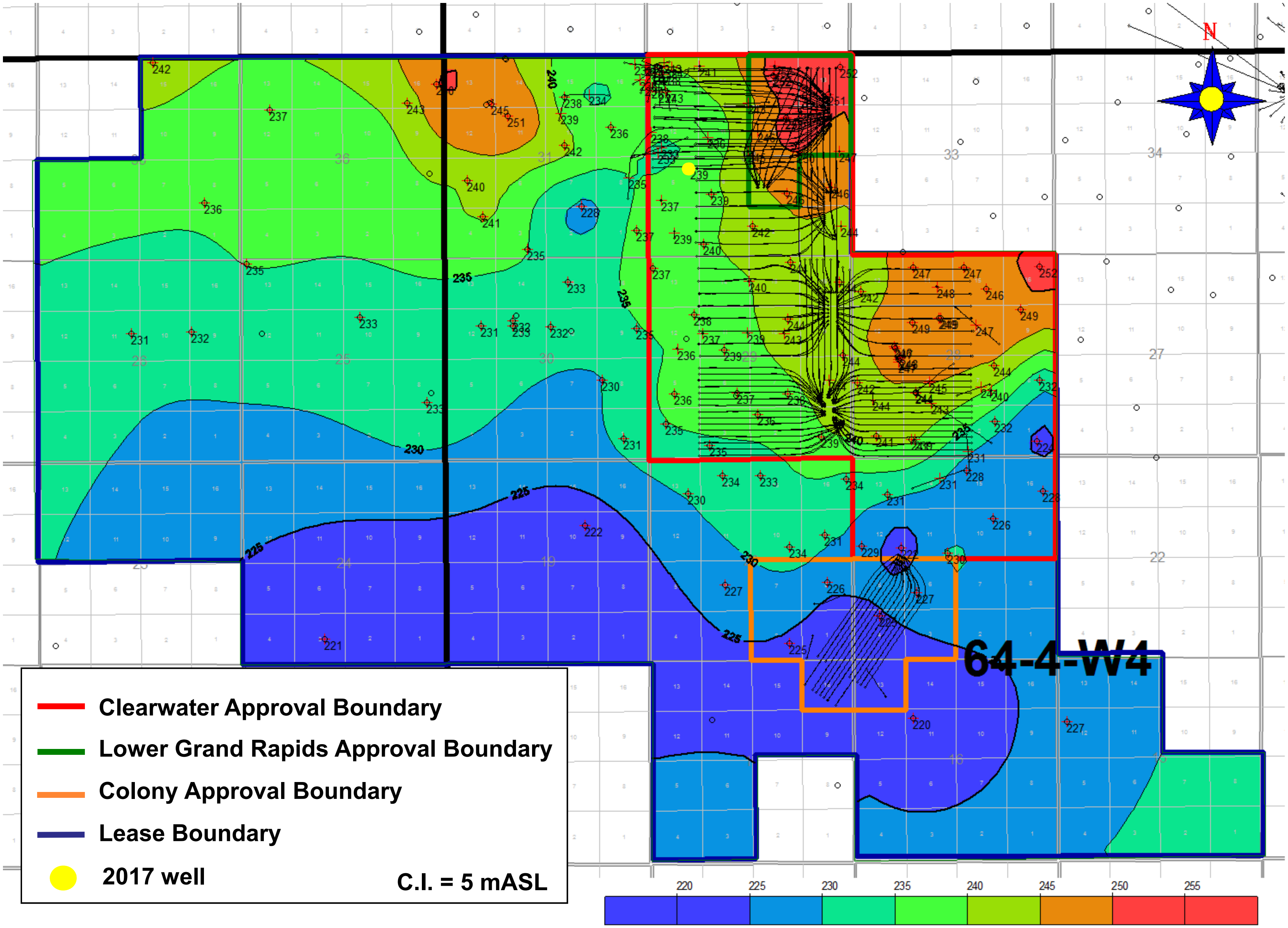
Lease Boundary

2017 well

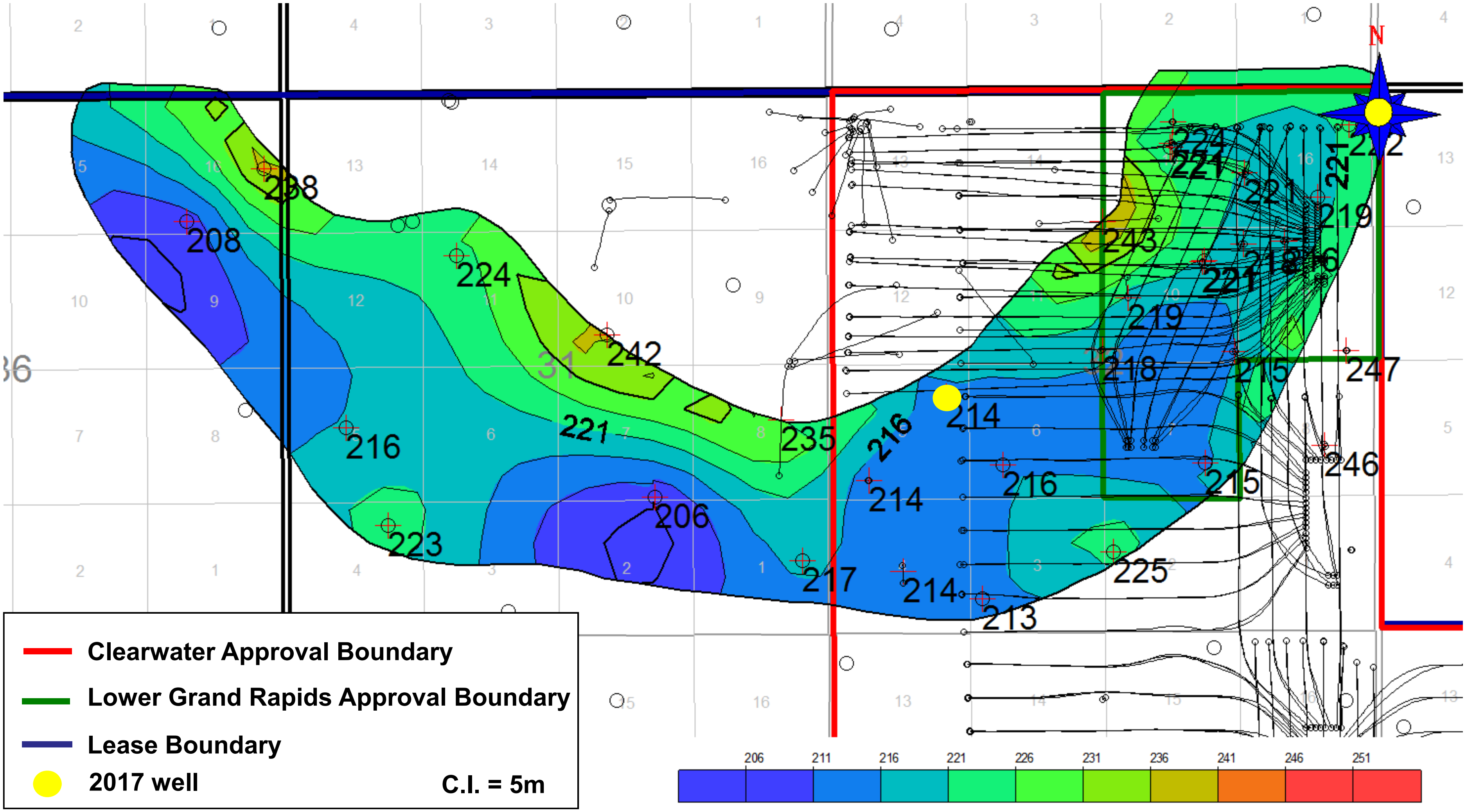
Definition of Net Pay:
Top Sparky Pay – Base of Pay
(So >50%, Φ >27%)

C.I. = 5m

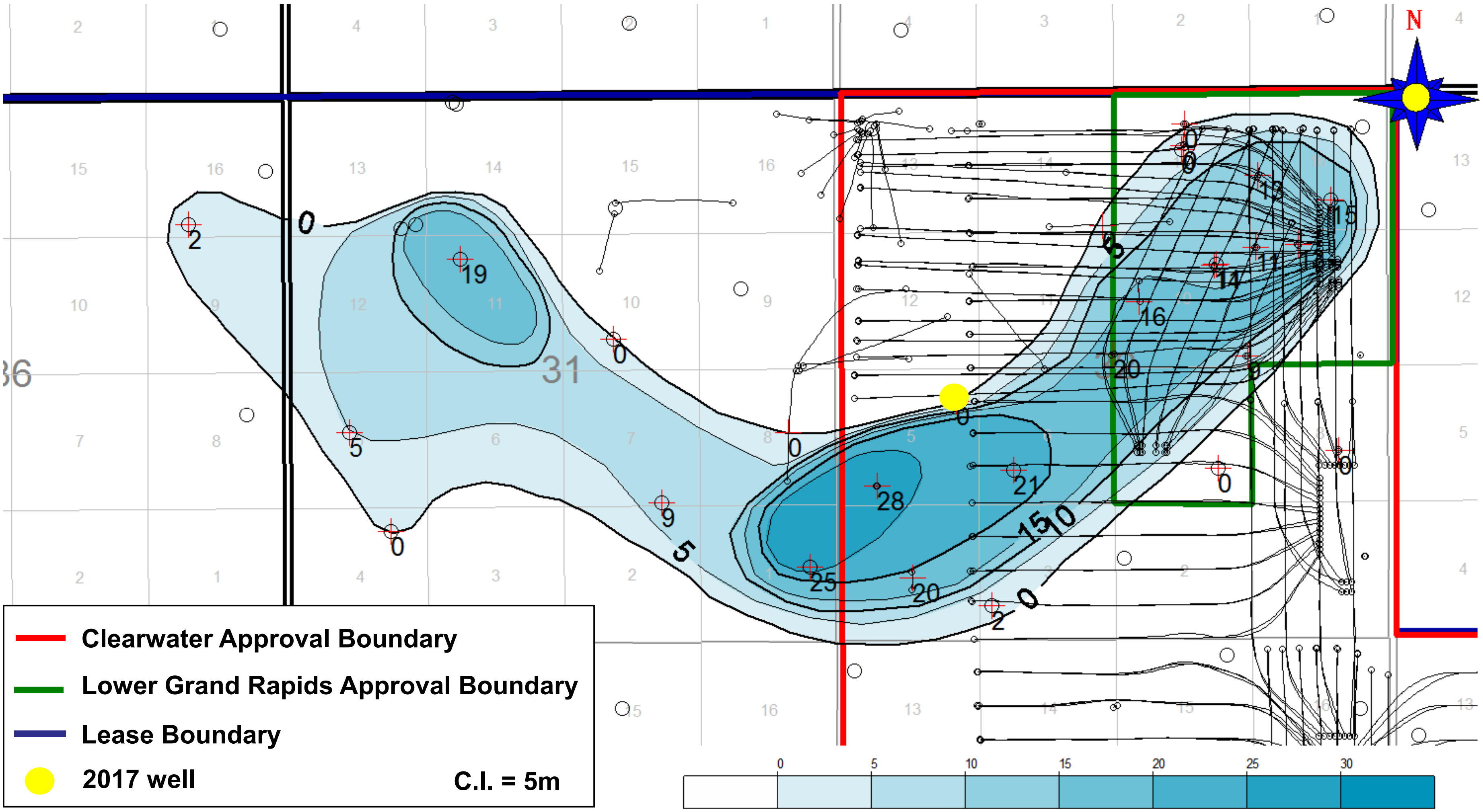
Structure Map of the Lower Grand Rapids



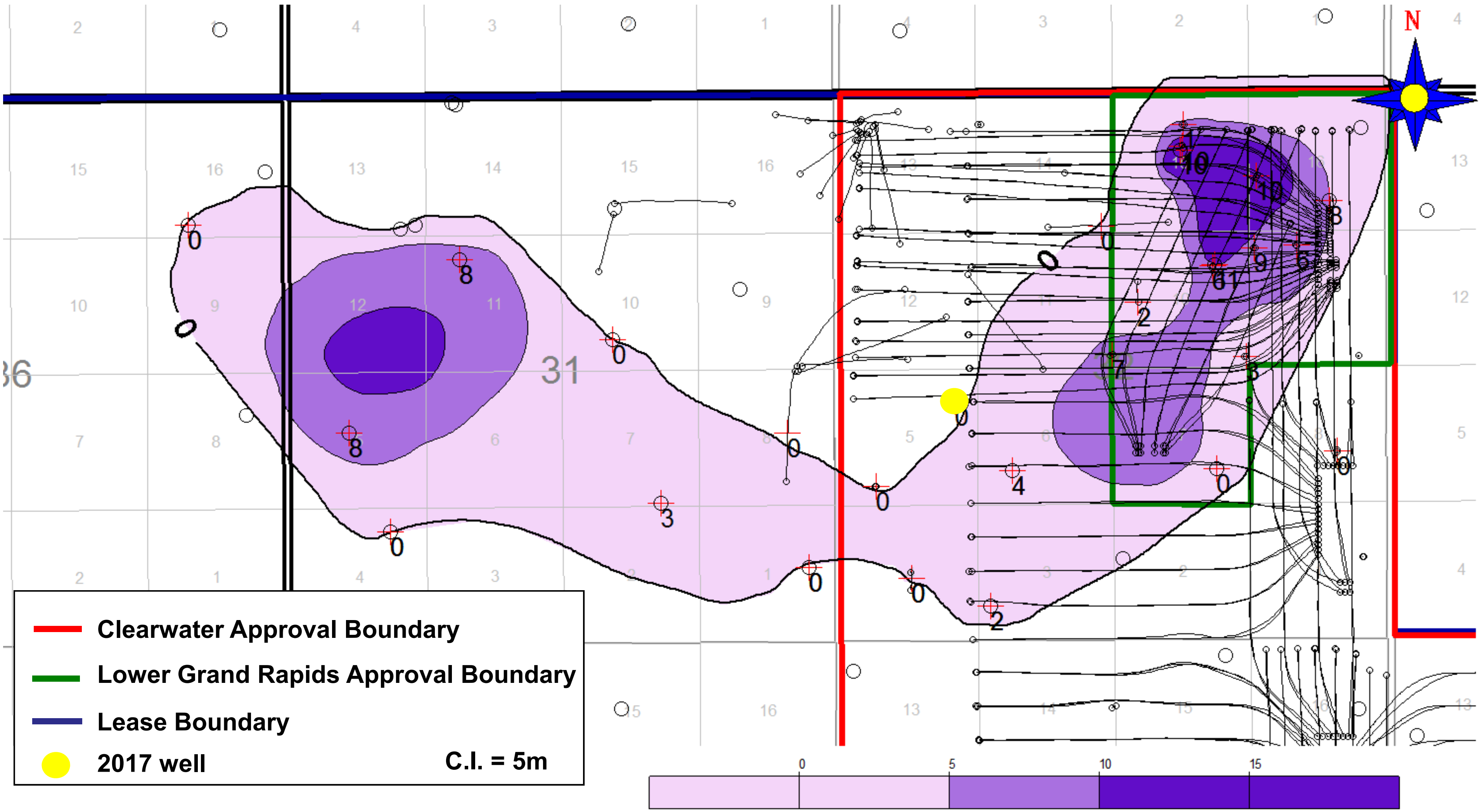
Structure Map of the Lower Grand Rapids Base of Net Pay



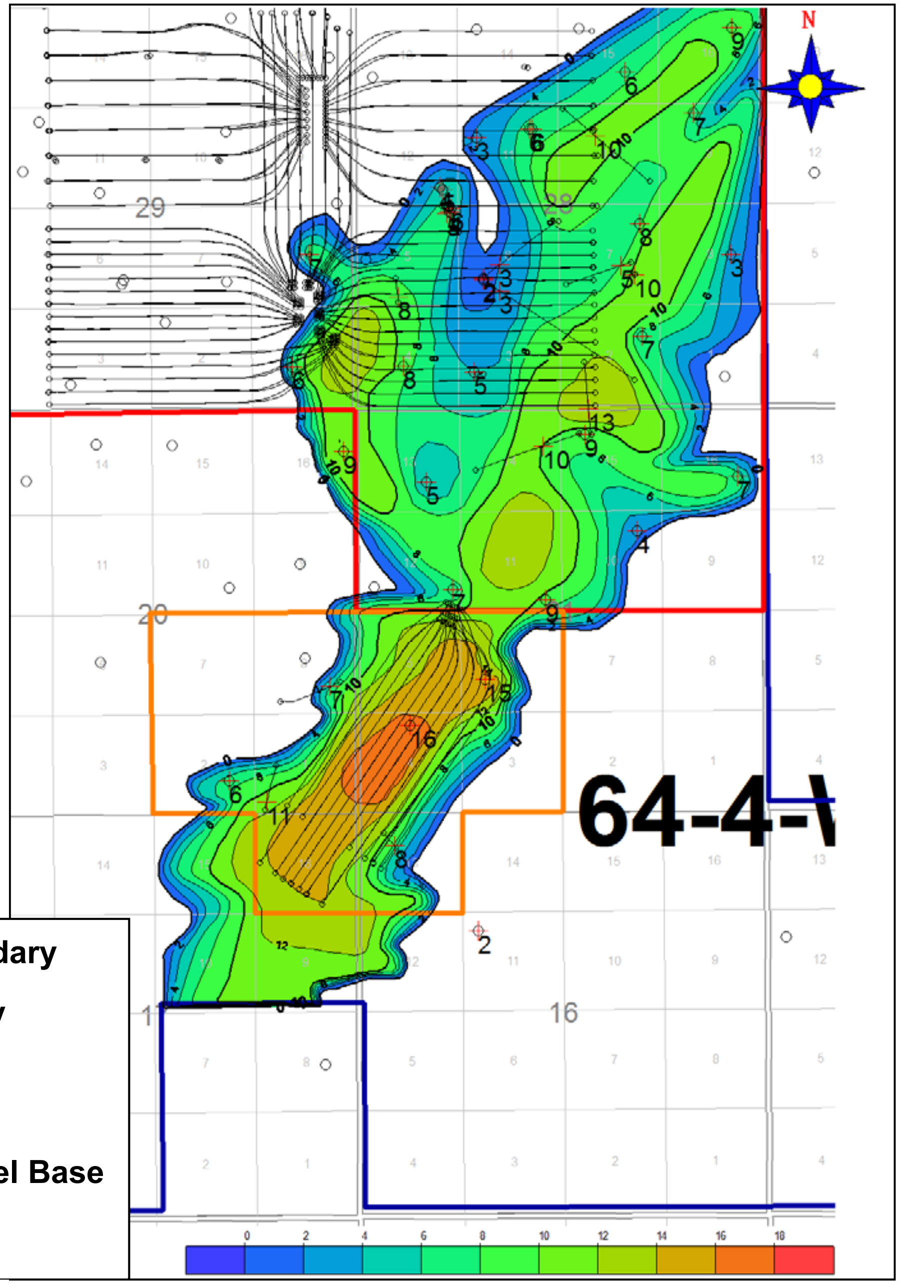
Isopach Lower Grand Rapids Bottom Water



Isopach Lower Grand Rapids Transition Zone



Isopach Map of Colony SAGD Net Pay



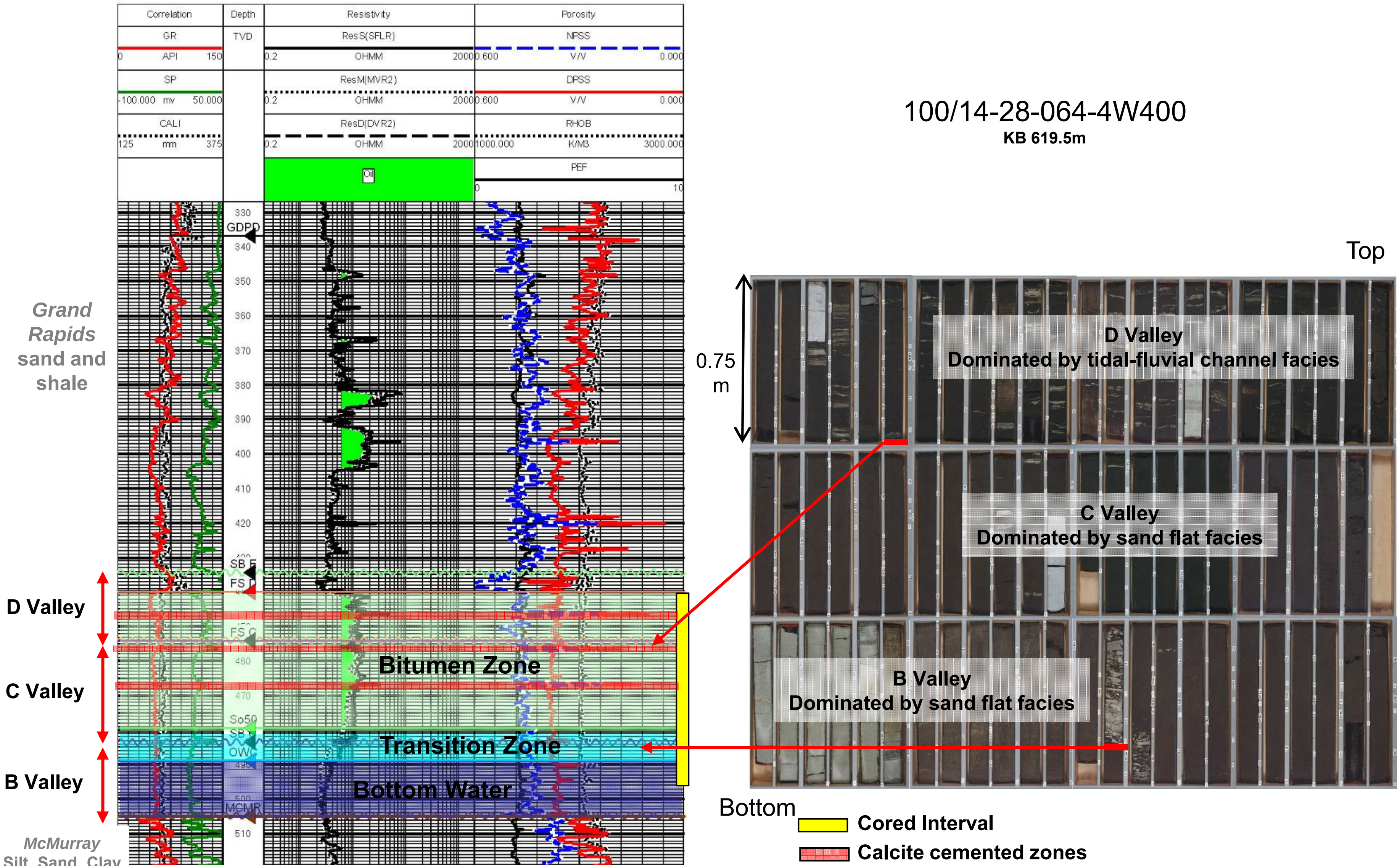
Clearwater Approval Boundary

Colony Approval Boundary

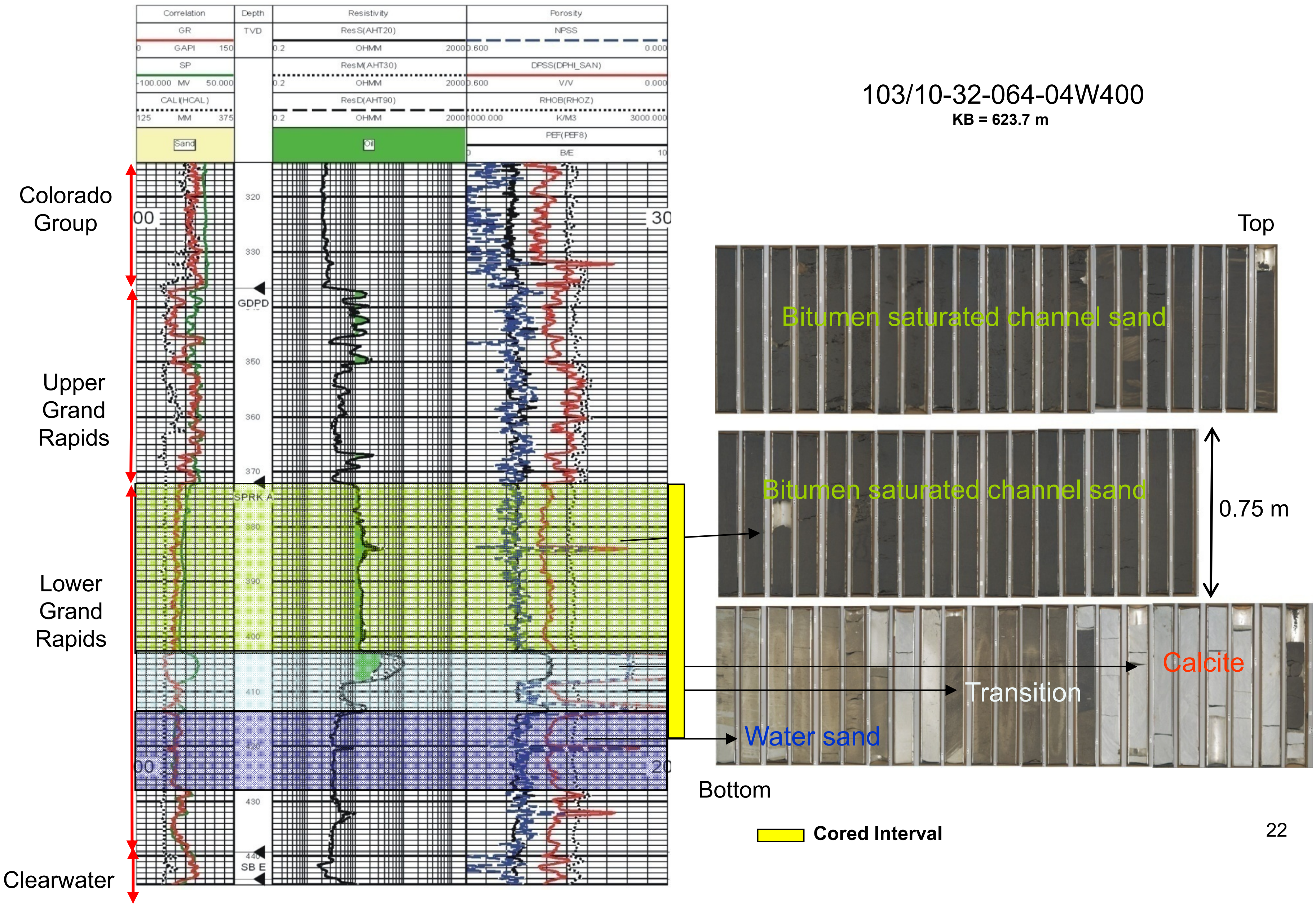
Lease Boundary

Definition of Net Pay:
Colony Top Pay– Colony Channel Base Pay (So >50%, Φ>27%)
C.I. = 2 m

Clearwater Formation Type Log



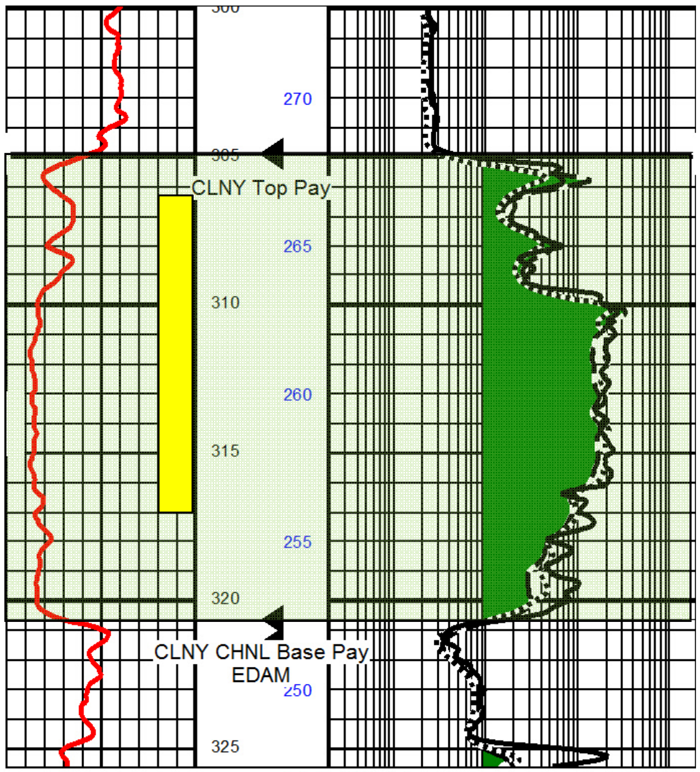
Sparky Formation Type Log



Colony Formation Type Log

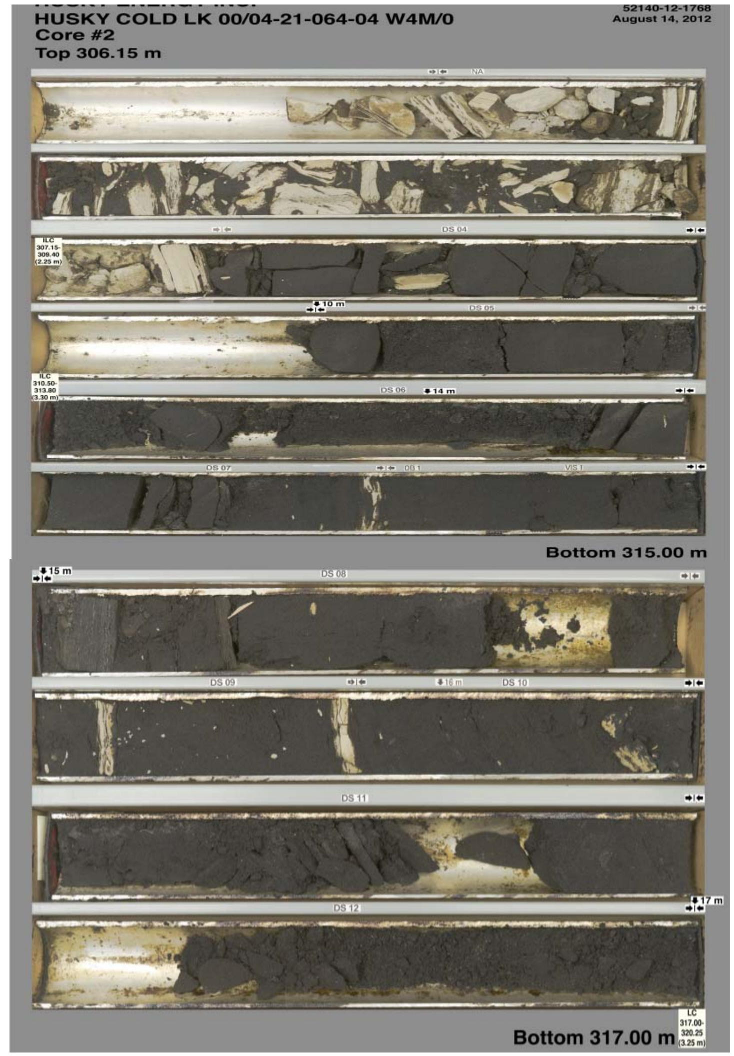
100/04-21-064-04W00

16 m



Cored Interval

Top



Bottom

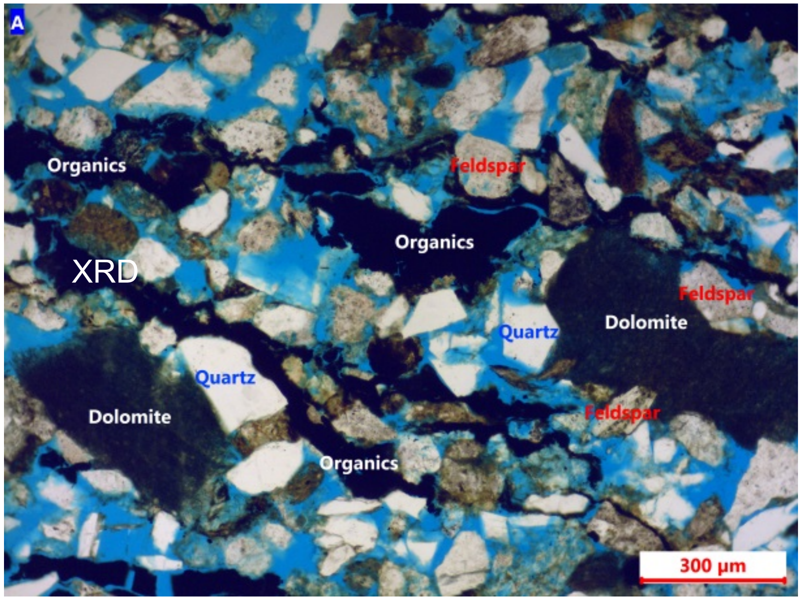
0.75 m

Cored Wells and Special Core Analysis

- Sparky Petrography

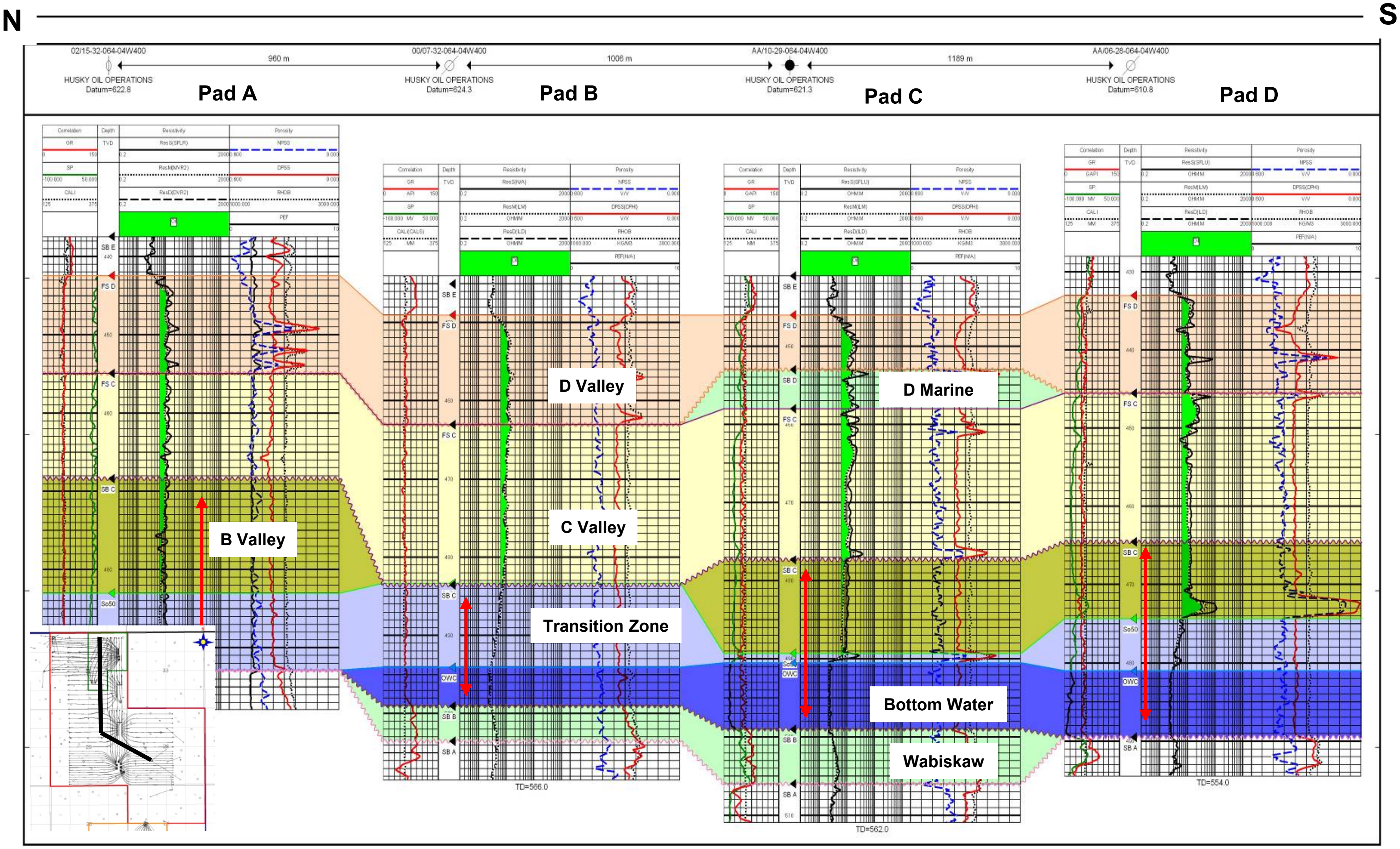
- Moderately well sorted sand, dominantly upper very fine grained
- Feldspar-rich (up to 28 wt % XRD) and lithic unconsolidated sandstone
- Monocrystalline quartz grains make up the majority of the detrital clasts (up to 60 wt% XRD)
- Lithic clasts: include chert, volcanics, organics, minor dolomite, and detrital clay (up to 23 wt. % XRD)

well 116/05-32-064-04W400

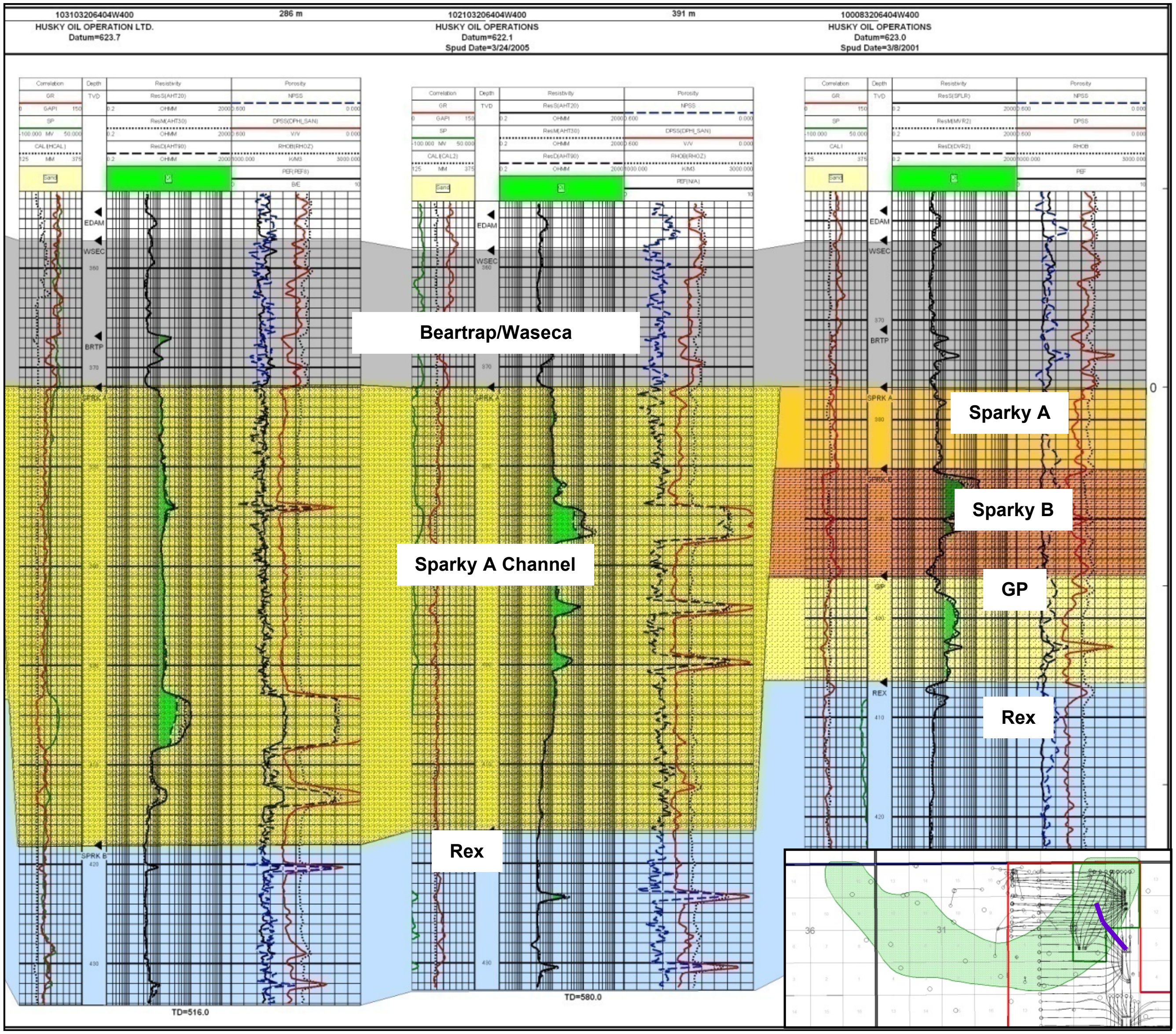


- Viscosity @ 20°C varies between 313,000 cp to more than 1,000,000 cp

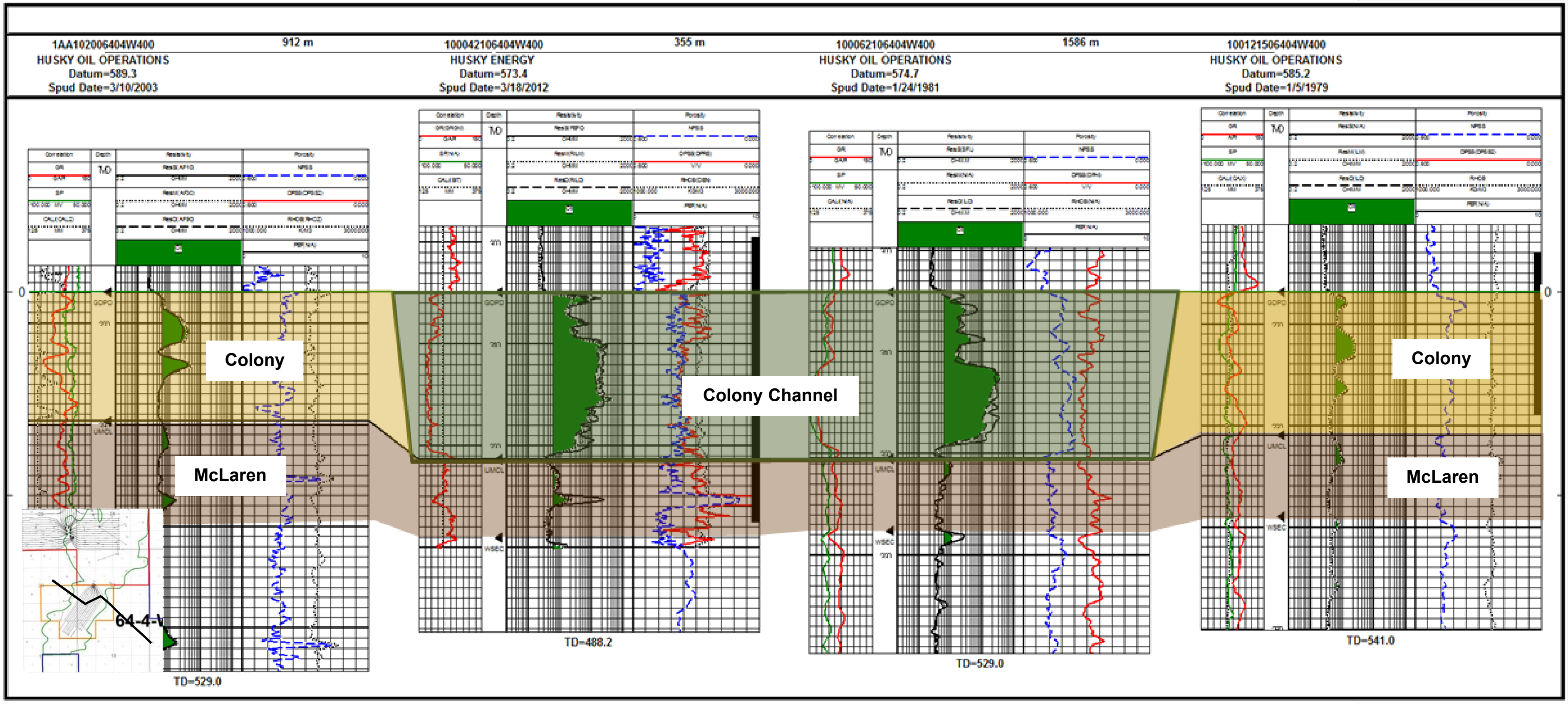
Representative Structural N-S Cross-section through the Approval Area



Representative Strike Cross-section through the Sparky Channel



Representative Strike Cross-section through the Colony Channel



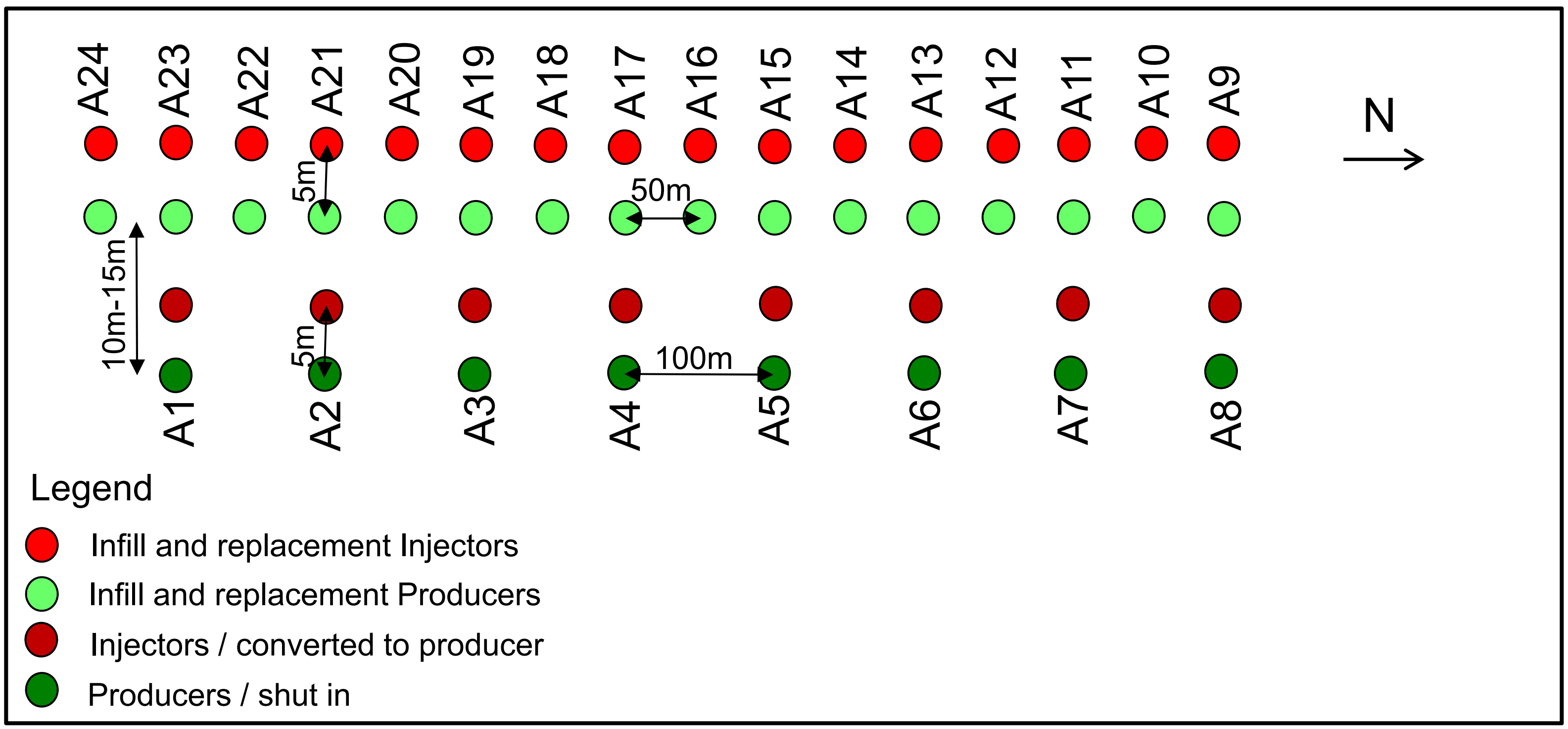
Surface/Subsurface Geomechanical Data/Analysis

Capping Shale Properties						
Well Pad	Capping Shale Issues to date	Capping shale Fracture Pressure Exceeded	Shale Depth (m)	Measured Fracture Gradient (kPa/m)	Measured Fracture Pressure (kPa)	Fracture Regime
CN	No	No	305	20.0	6,100	Horizontal
GA	No	No	357	19.9	7,120	Horizontal
Clearwater	No	No	426	21.8	9,280	Horizontal

Sand Properties				
Well Pad	Sand Depth (m)	Measured Fracture Gradient (kPa/m)	Measured Fracture Pressure (kPa)	Fracture Regime
GA	375	17.0	6,360	Vertical
Clearwater	446	16.0	7,140	Vertical

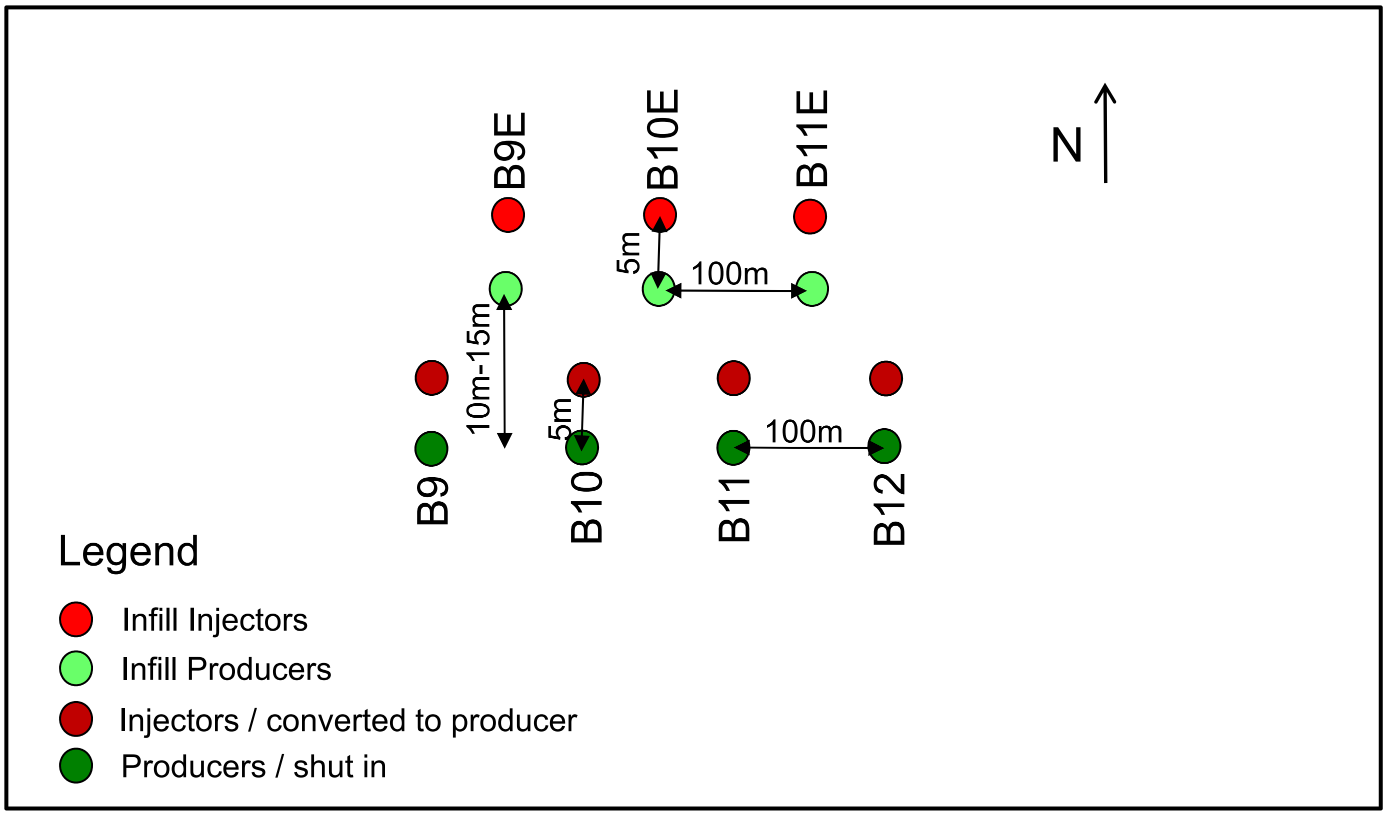
Pad A Well Spacing Schematic

- Pad A original (A1 – A8 drilled 2005) injectors were converted into producers in 2015
- Pad A replacement producers (A9 – A24 drilled 2010/2011) are 10m - 15m directly above Pad A original producers
- Pad A infill producers are 10m - 15m above and mid distance from Pad A original producers



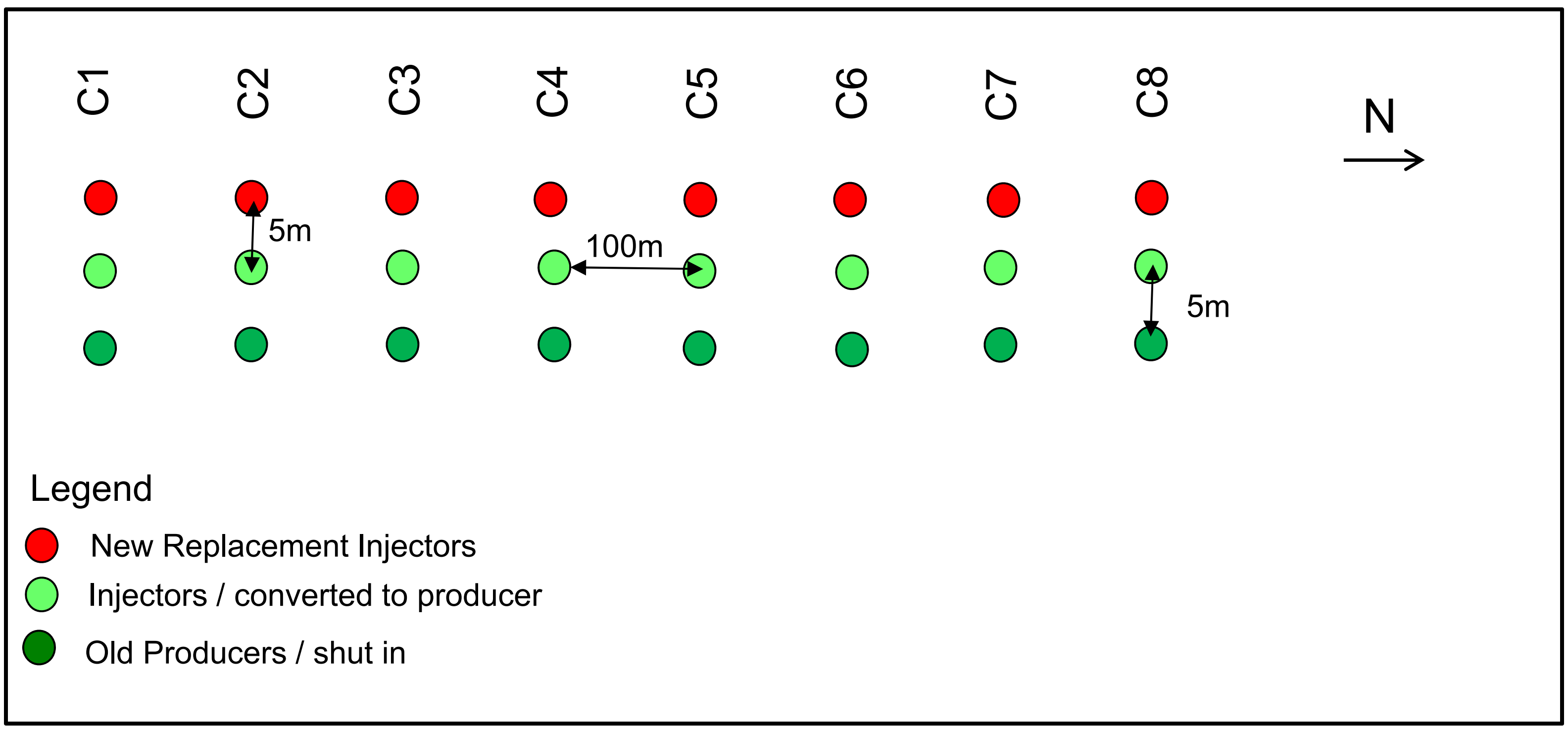
Pad B North Well Spacing Schematic

- Pad B North injectors (B9 – B12 drilled 2005/2006) converted into producers in 2014
- Pad B North infill producers (B9 – B11 drilled 2009/2010) are 10m - 15m above and mid distance from Pad B North



Pad C West Schematic

- Pad C West (C1 – C8 drilled 2005)
- Pad C West replacement injectors (C1R – C8R drilled 2016) are 5m directly above injectors



Pad Inter-well Spacing

Well Pad	Inter-well Spacing (m)
A Original	100
A Infill and Replacements	50
B West	100
B North	100
B North Infill	100
C North	100
C West	100
C East	100
D East	50
D North	50
D West	50
GA (LGR)	75
CN (SAGD)	75
CN Infill	37.5*

* Spacing to SAGD producer

Surface Heave Monitoring Programs

- No surface heave monitoring programs have been conducted
- Operating near reservoir pressure, therefore unlikely to be any surface heave
- Husky is committed to further investigate the possible extent of surface heave if a change in operating conditions warrant

3D Seismic Data

- No new Seismic data run or interpreted during the reporting period

3. Drilling and Completions

Drilling Results

Pad C West:

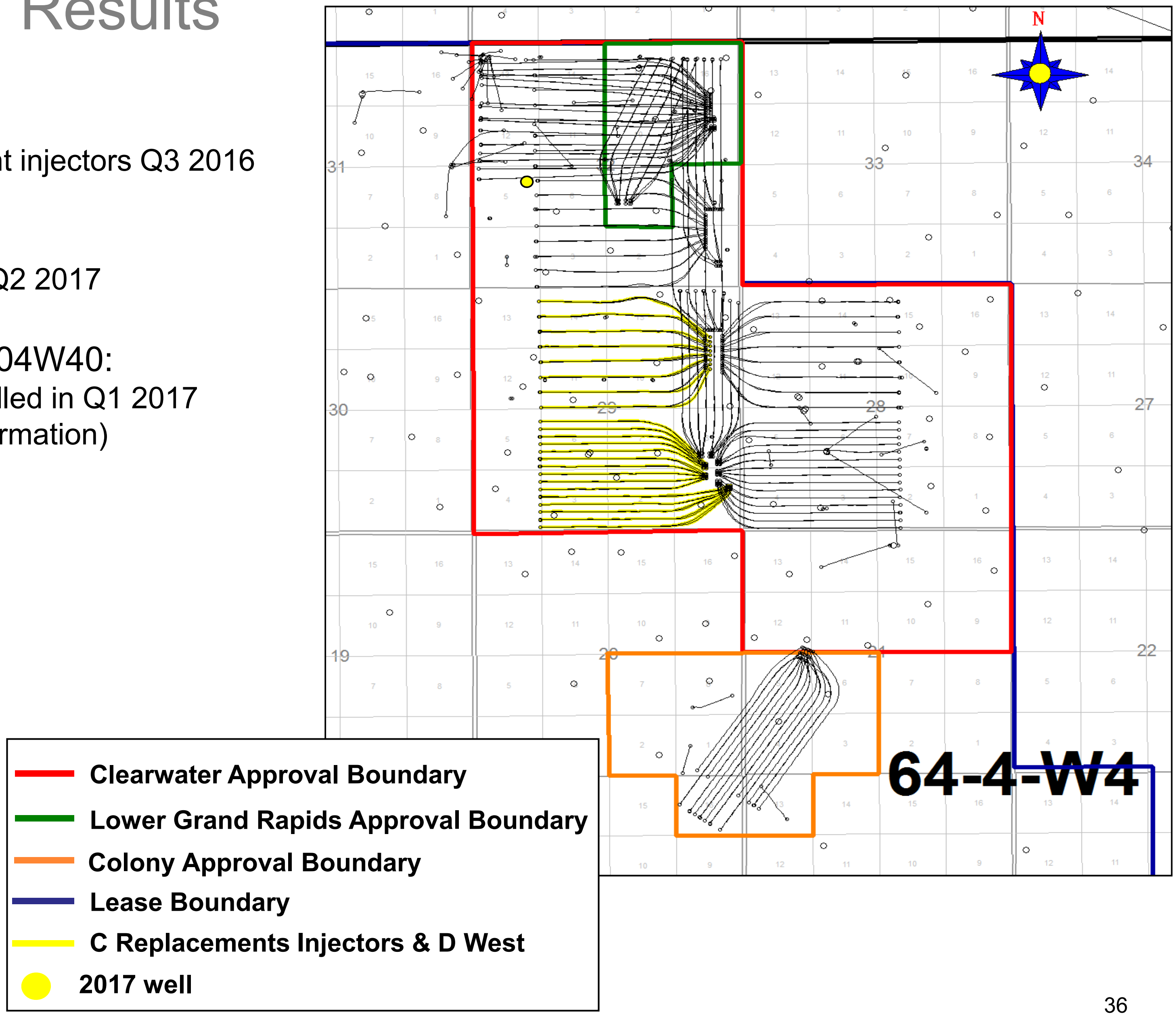
- 8 replacement injectors Q3 2016

Pad D West:

- 15 well pairs Q2 2017

116/05-32-064-04W40:

- 1 strat well drilled in Q1 2017 (TD in Rex Formation)



Summary of Well Completions

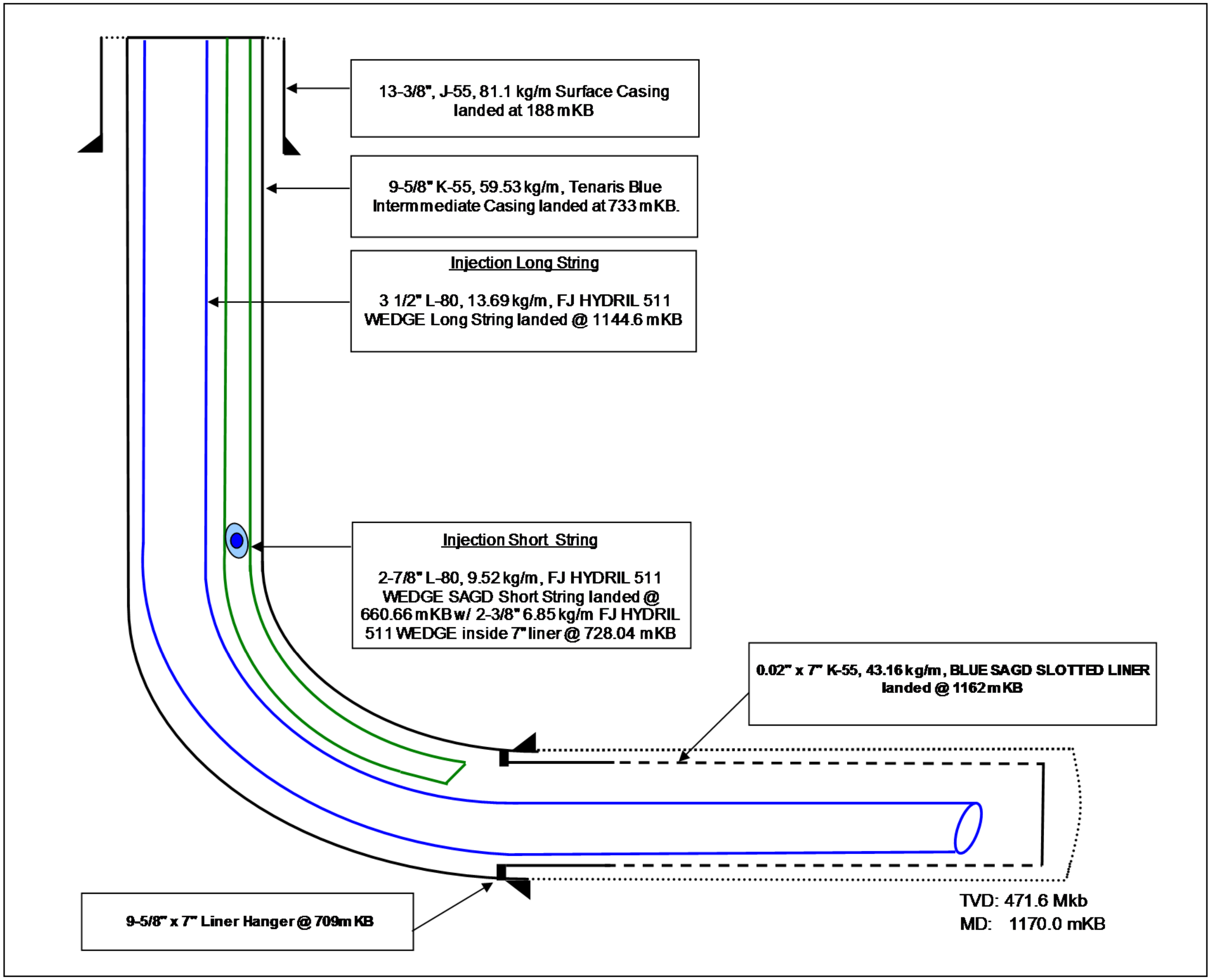
Injectors (109 SAGD Injectors):

- All injectors completed with Slotted Liner: 109 (includes Pad D West)
- Injectors completed with Vacuum Insulated Tubing (VIT): 31
  - Pad C: 2
  - Pad D: 23 (does not include Pad D West yet)
  - Pad CN: 6
- Injectors completed with Steam Splitters: 36
  - Pad B: 7
  - Pad D: 23 (does not include Pad D West yet)
  - Pad CN: 6

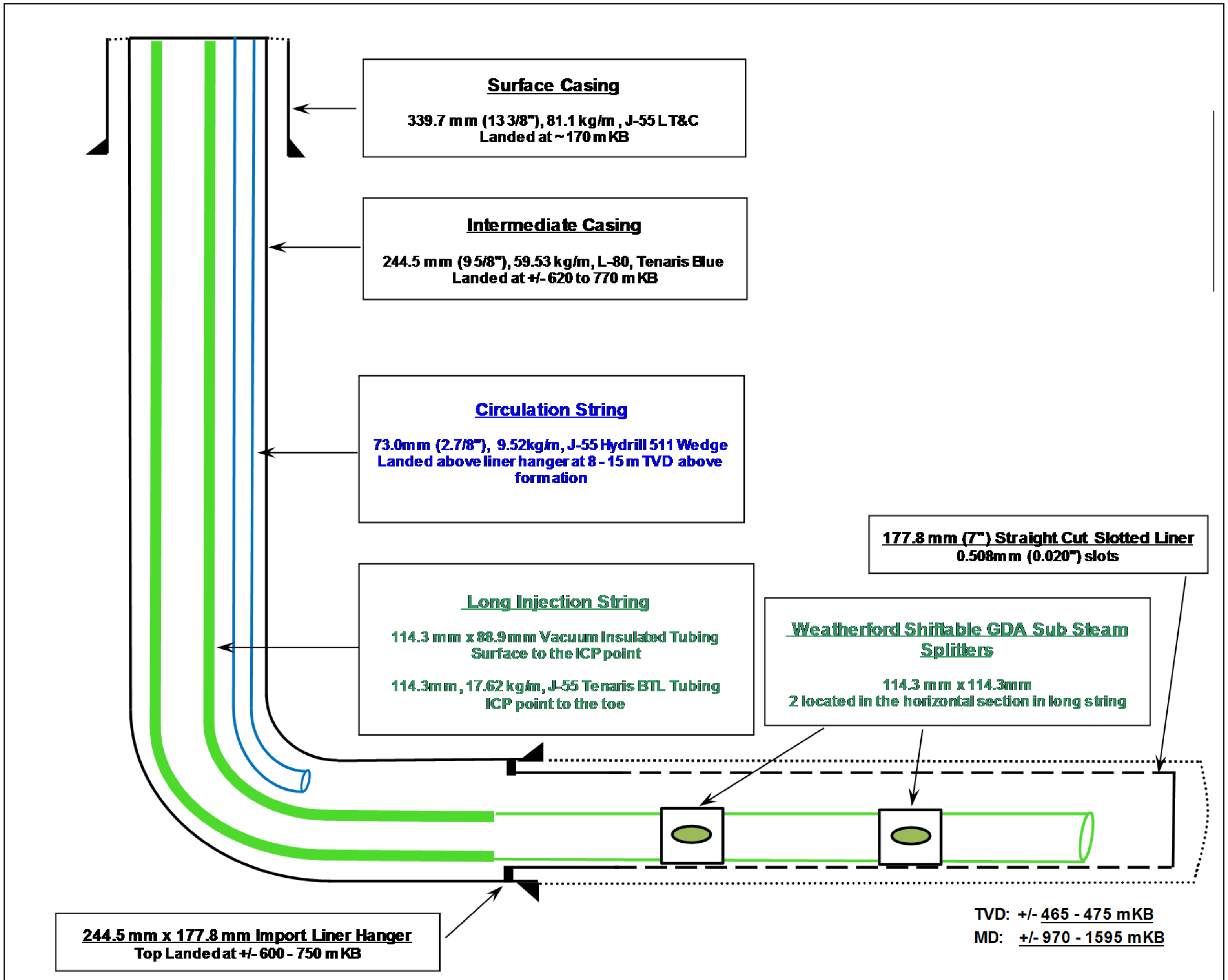
Producers (116 Producers: 109 SAGD Producers and 7 Infill Producers):

- Producers completed with Slotted Liner: 38
  - Pad A: 8
  - Pad B: 12
  - Pad C: 18
- Producers completed with Wire Wrap Screen (WWS) : 78
  - Pad A: 16
  - Pad B: 3
  - Pad C: 2
  - Pad D: 38 (includes Pad D West)
  - Pad GA: 6
  - Pad CN: 13

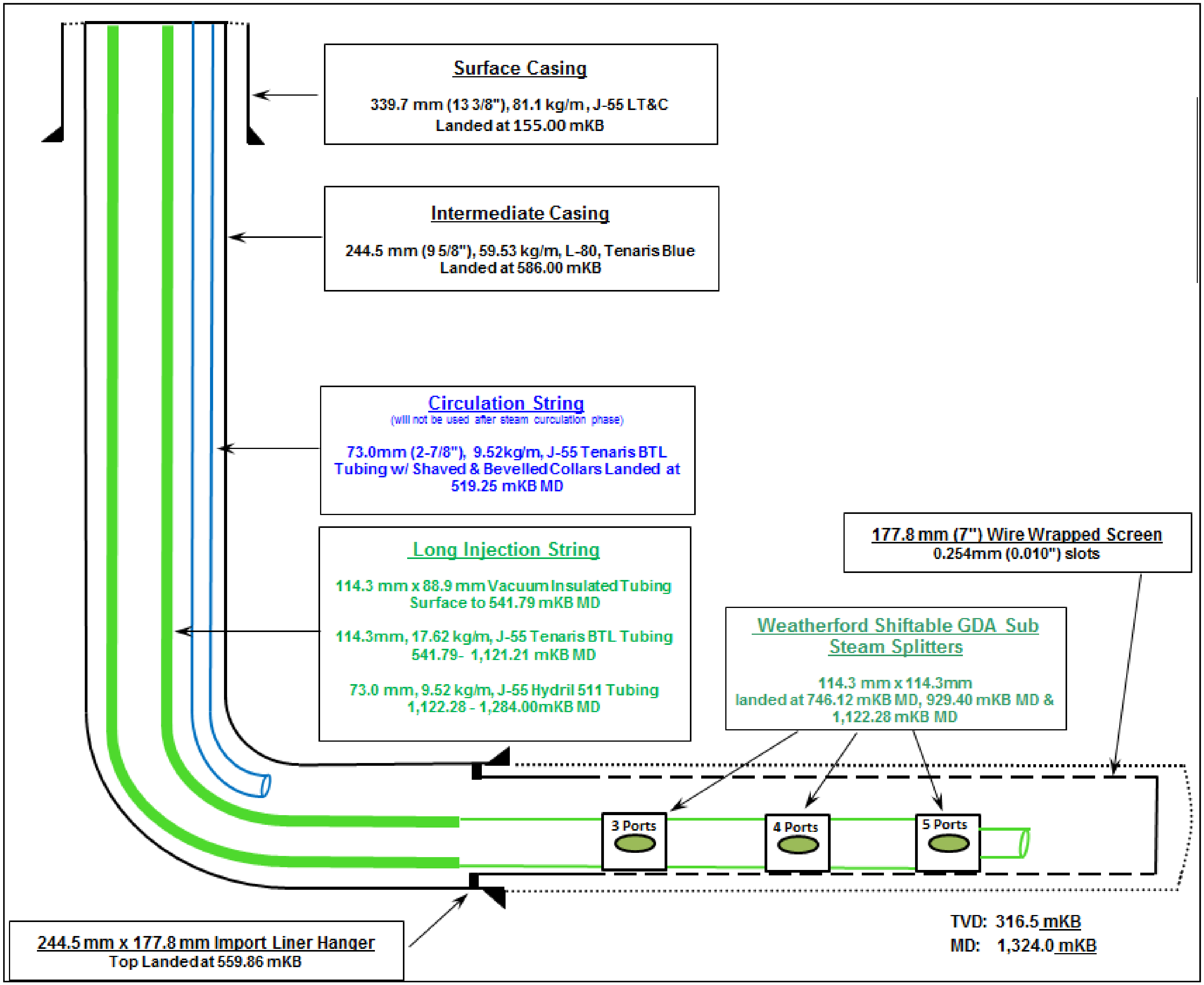
SAGD Well - Injector without VIT



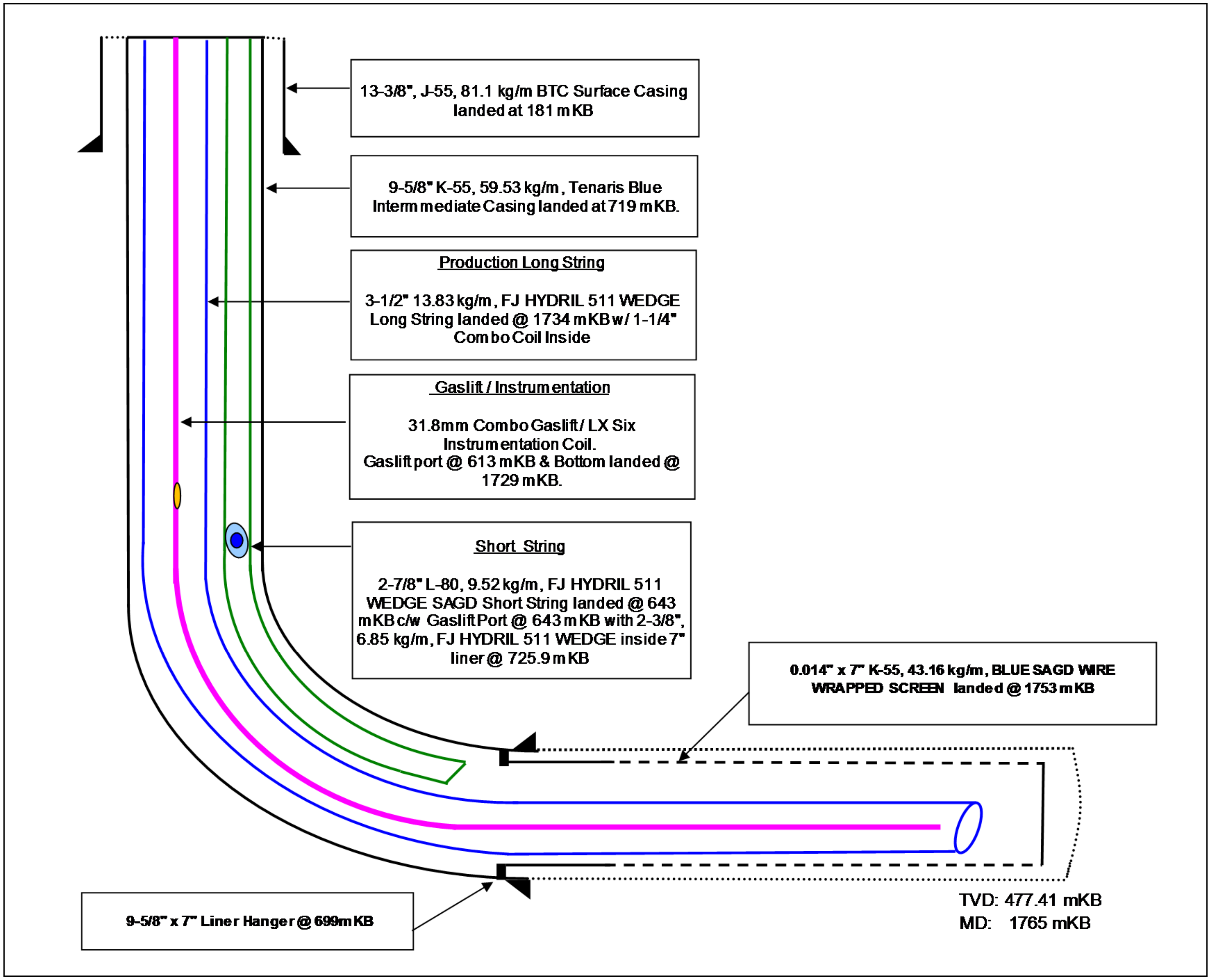
SAGD Well - Injector with VIT



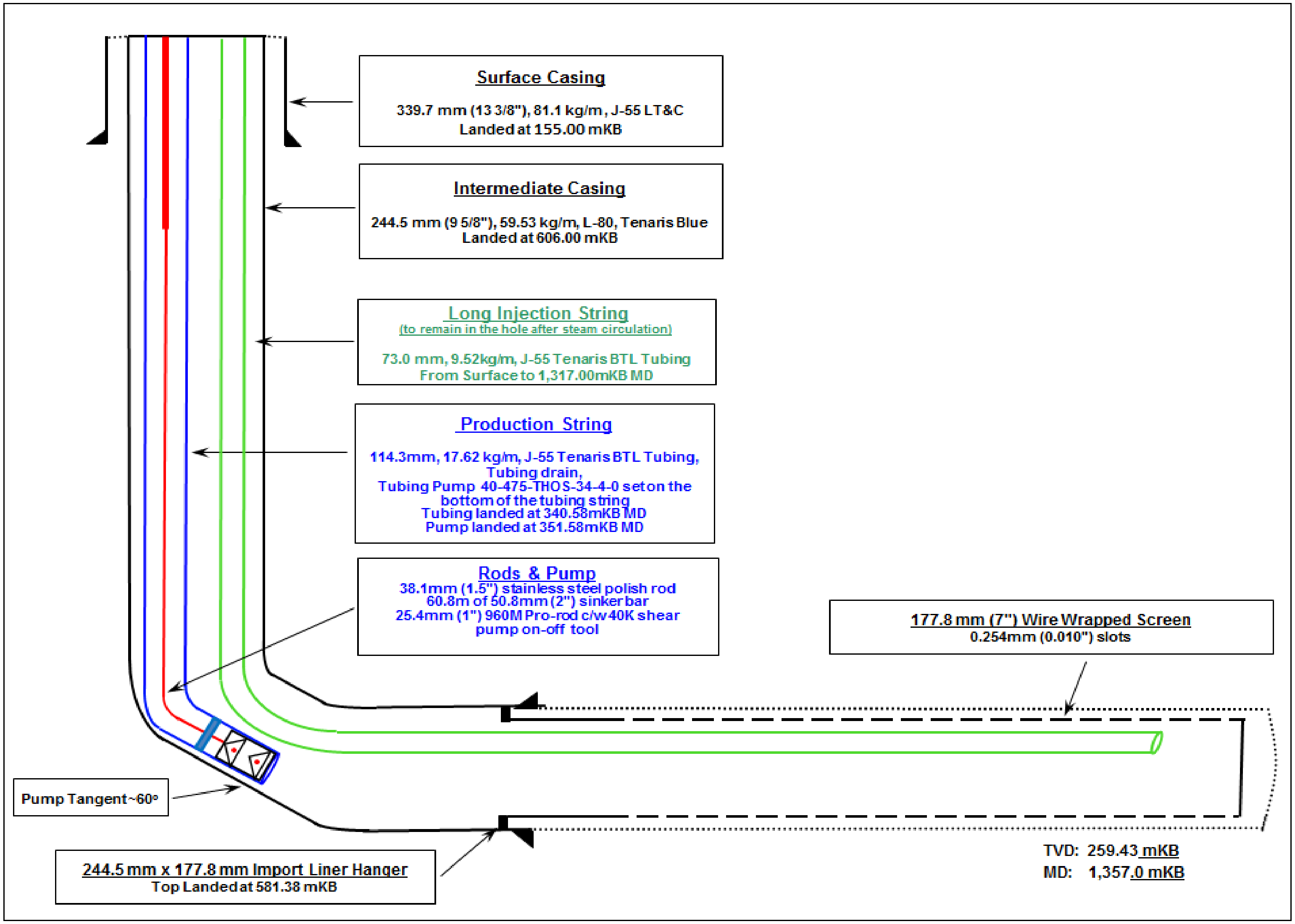
SAGD Well Pad CN - Injector with VIT



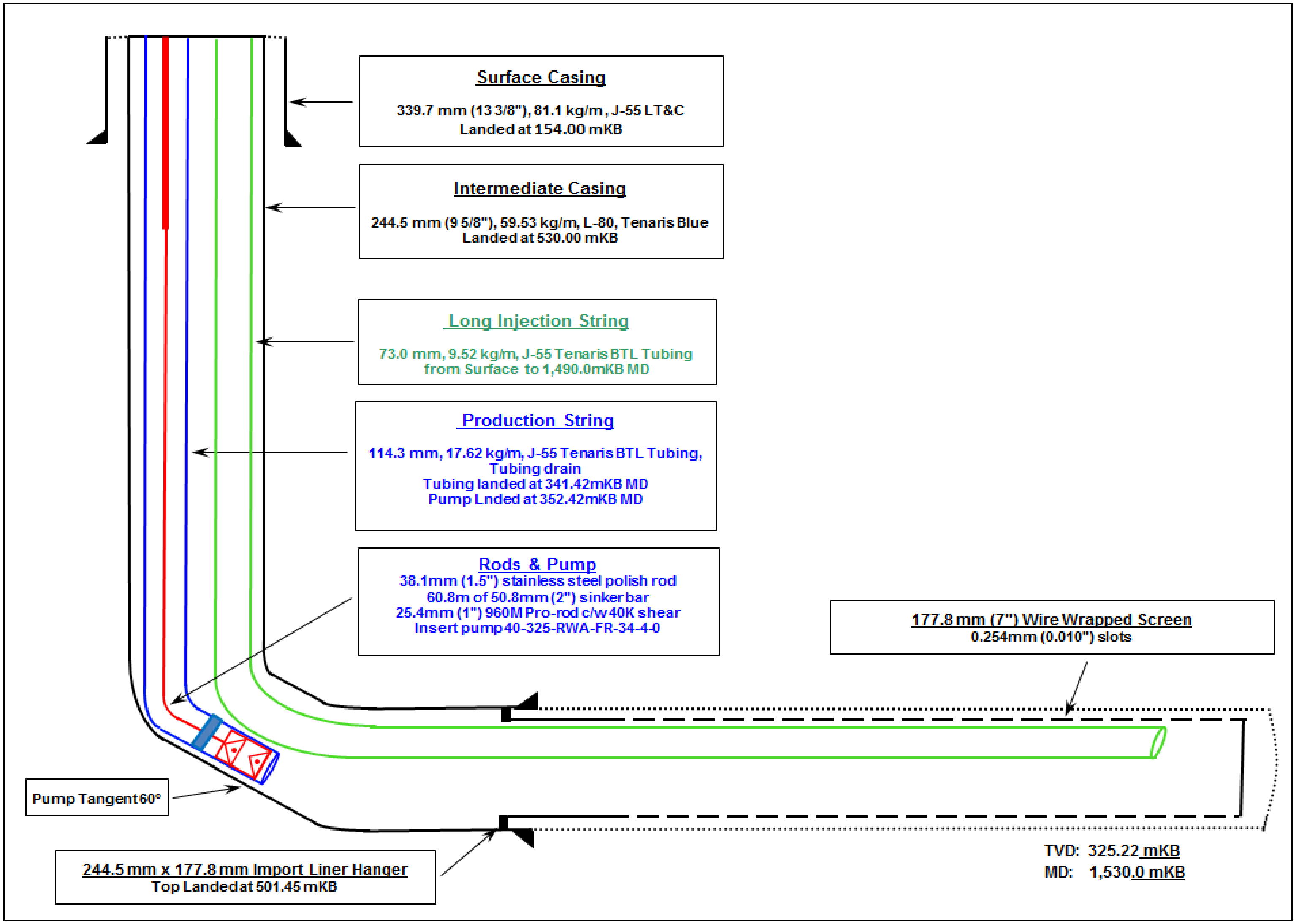
SAGD Well - Producer with Gas-Lift



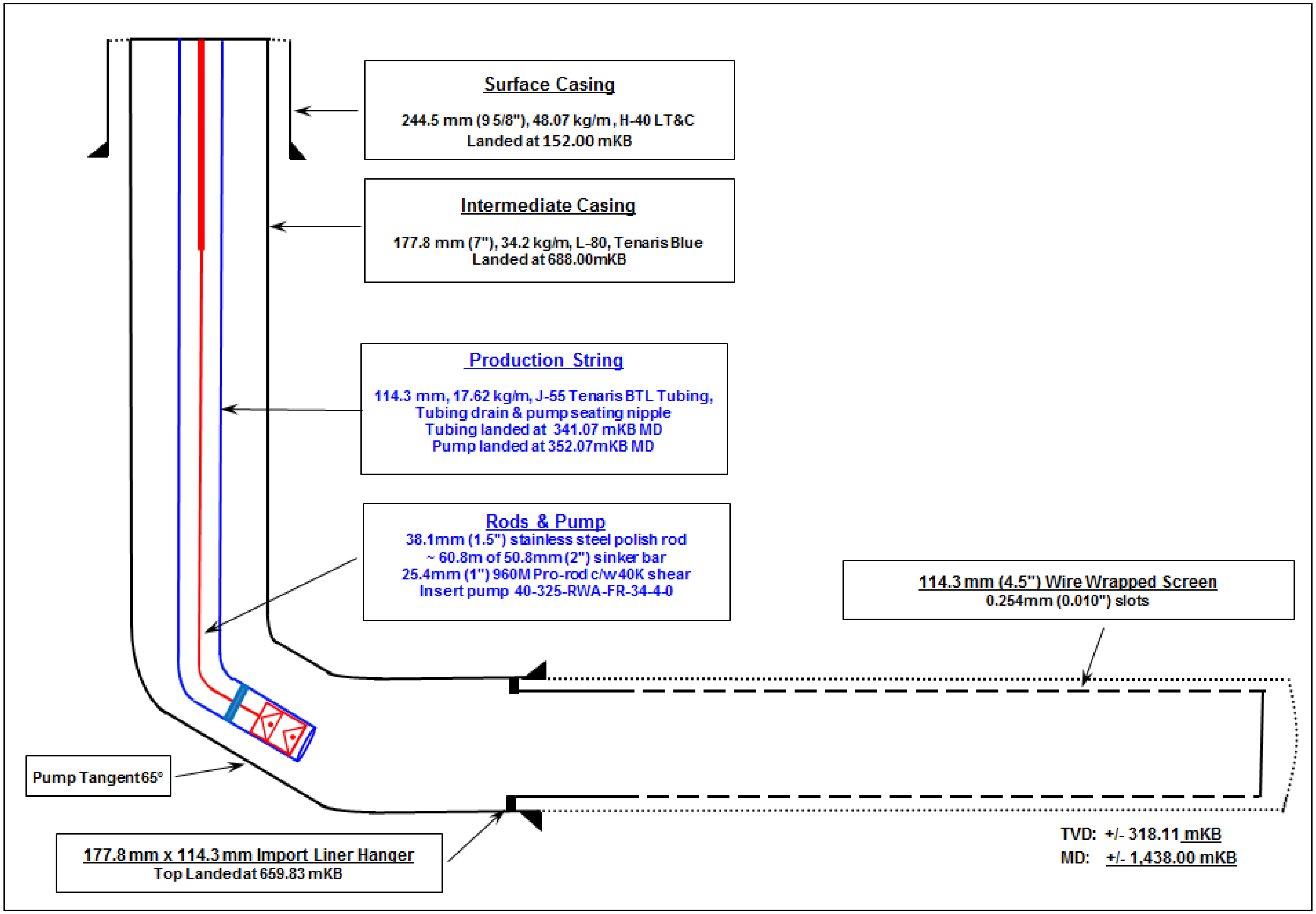
SAGD Well Pad CN - Producer with Rod-Pump



Intermittent Steam Stimulation Well Pad CN - Producer with Rod-Pump



Infill Well Pad CN - Producer with Rod-Pump



Completions - Key Learnings

Production - Slotted Liners vs Wire Wrap Screens (WWS):

- Slotted liner scaling has been a chronic problem:
  - Short term solution - Acidization
  - Long term solution - perforated liners
- WWS, which increase the open area, used in producers drilled since 2009:
  - No scaling issues observed in these wells
- Current plan is to complete future producers with WWS

Injection - Vacuum Insulated Tubing (VIT) and Steam Splitters:

- VIT:
  - Improve the wellbore integrity by slowing heat transfer through tubing
  - Deliver high quality steam downhole and improve production
- Steam Splitters:
  - Shift-able steam splitters enable proper circulation and allow steam distribution adjustments
- VIT combined with Steam Splitters:
  - Improve steam quality and distribution into the reservoir

4. Artificial Lift

Artificial Lift

Rod-pump: 13 (Pad CN only)

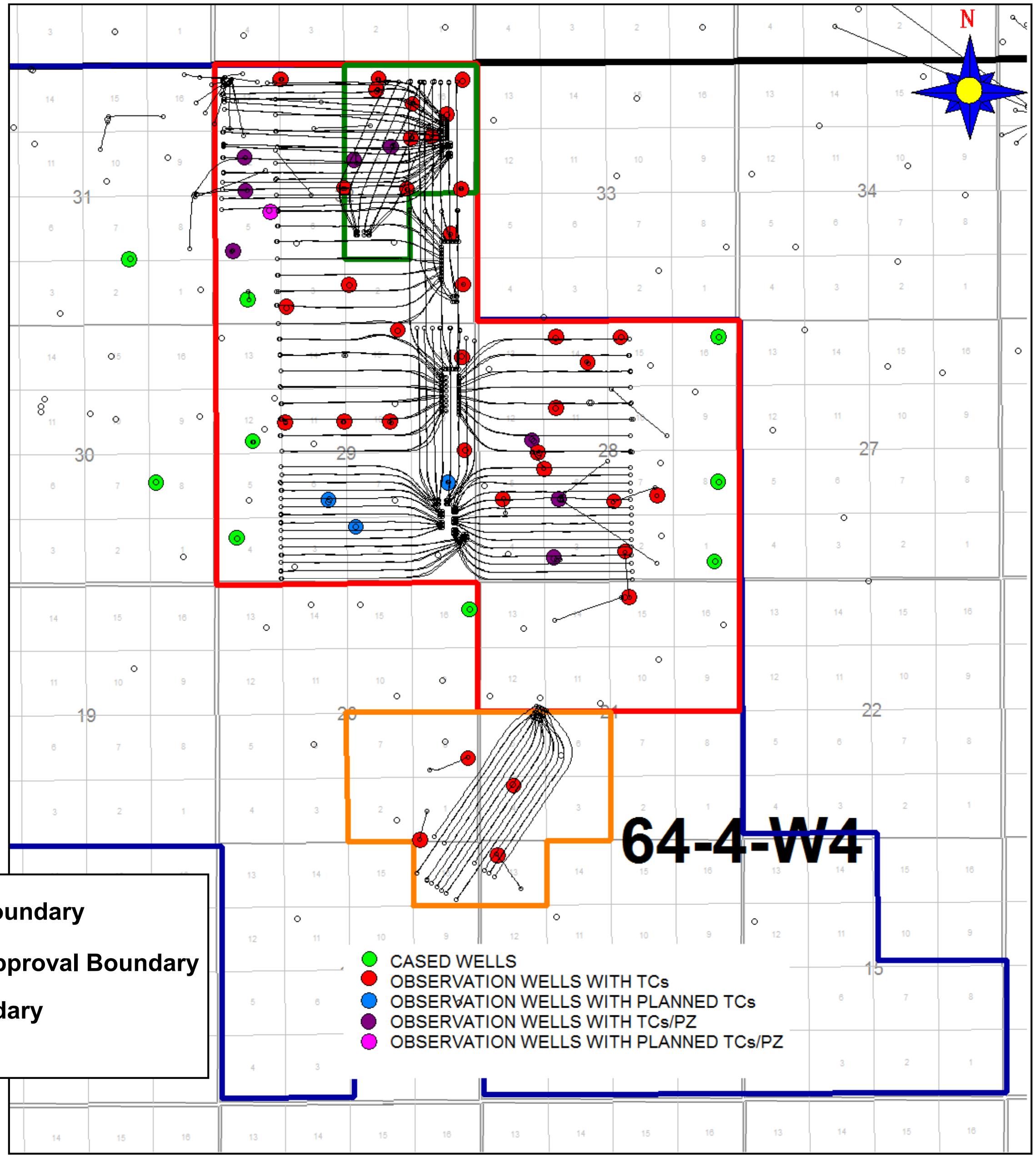
- 6 SAGD producers (Tubing liner pump)
- 2 ISS producers (Insert pump)
- 5 Infill producers (Insert pump)
- Rod-pump operational parameters:
  - Pressure: 1,500 – 2,500 kPa
  - Bottom hole temperature: 130 – 180 ºC
  - Fluid production range: 65 – 420 m^3/day

Gas-lift: 88, all producers except Pad CN

- 88 SAGD producers (does not include Pad D West)
- Gas-lift operational parameters:
  - Pressure: 2,400 kPa – 4,000 kPa
  - Bottom hole temperature: 200 – 240 ºC
  - Gas injection rate: 1,200 – 10,800 m^3/day

5. Instrumentation in Wells

Instrumentation – Observation Wells Map



Clearwater Approval Boundary

Lower Grand Rapids Approval Boundary

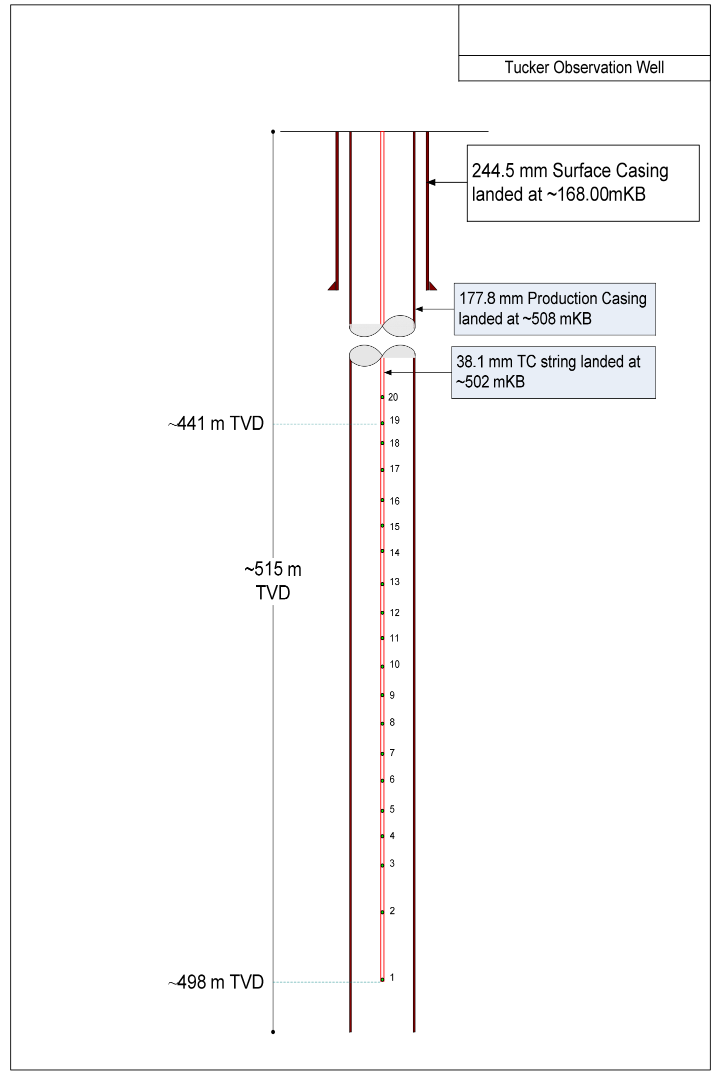
Colony Approval Boundary

Lease Boundary

Instrumentation in OBS and SAGD Wells

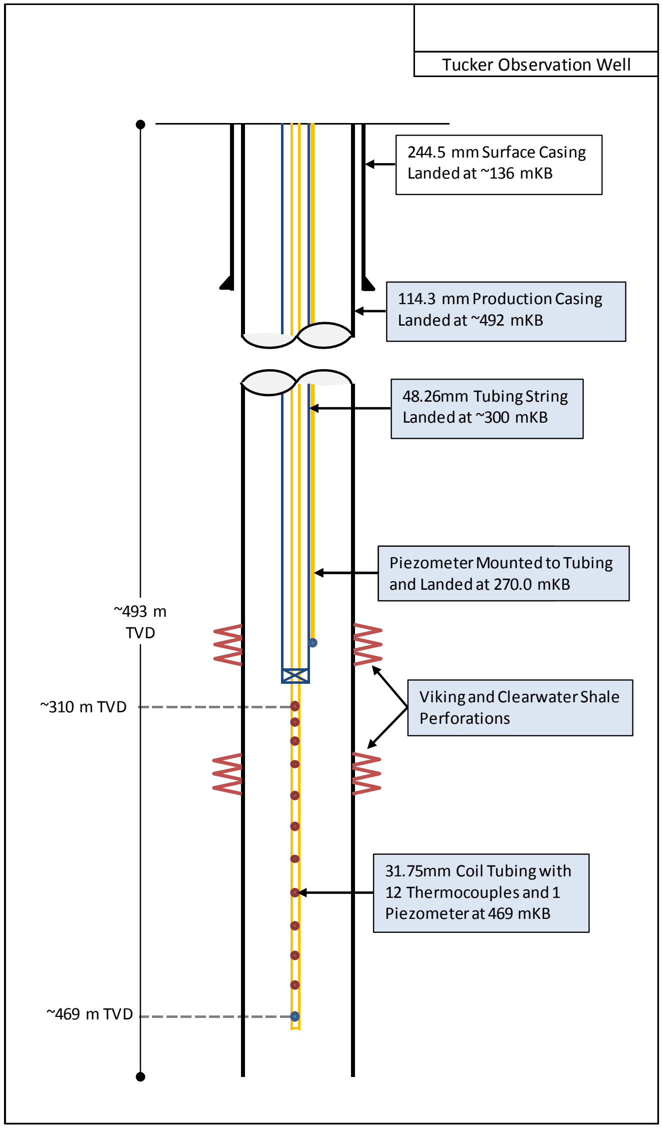
- 44 OBS Wells with Instrumentation:
  - 36 wells: thermocouple only
  - 8 wells: both thermocouple & piezometer
- 4 Planned OBS Wells (convert existing wells):
  - 3 wells for Pad D West: thermocouple only
  - 1 well (Pad GB thermocouple and piezometers)
- SAGD Injectors – wells use blanket gas to measure pressure and for insulation
- SAGD Producers – equipped with combo instrumentation coil (gas lift & thermocouple or fiber)
  - Combo coil installed in the long production string delivers lift-gas for the long string and provides temperature measurement in the horizontal section
  - Pressure at the heel of producers is estimated from the gas pressure of the lift-gas injected into the annulus (annulus injection provides lift-gas for the short production string)

Thermocouple only OBS well

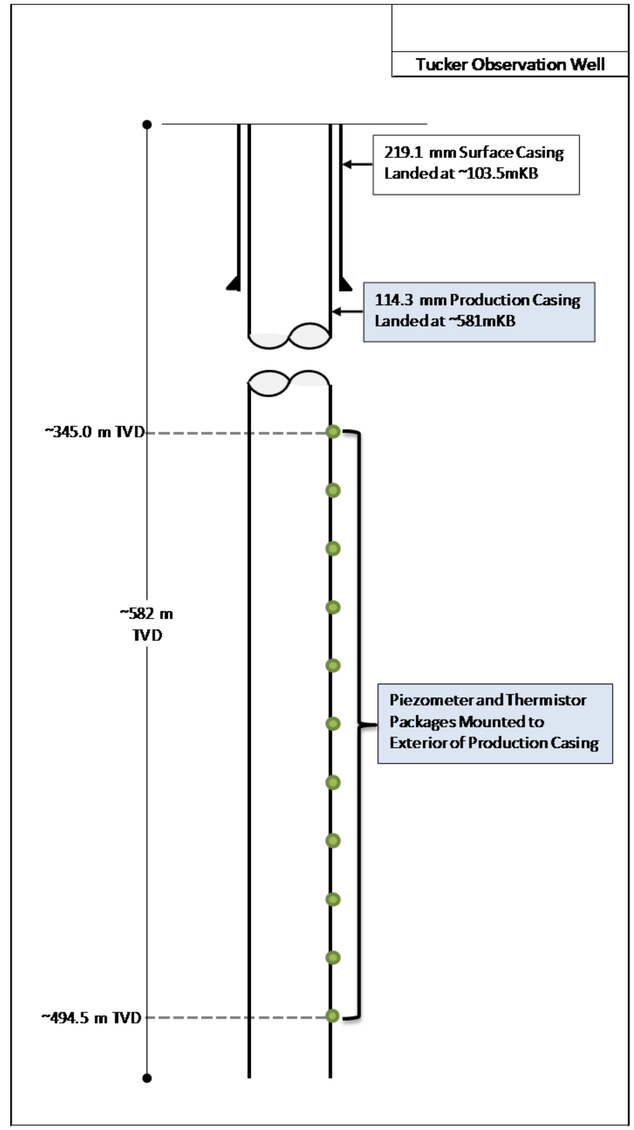


Thermocouple and Piezometer OBS Wells

Type 1 – Instrumentation Inside Tubing



Type 2 – Instrumentation Outside of Casing



6. 4D Seismic

4D Seismic

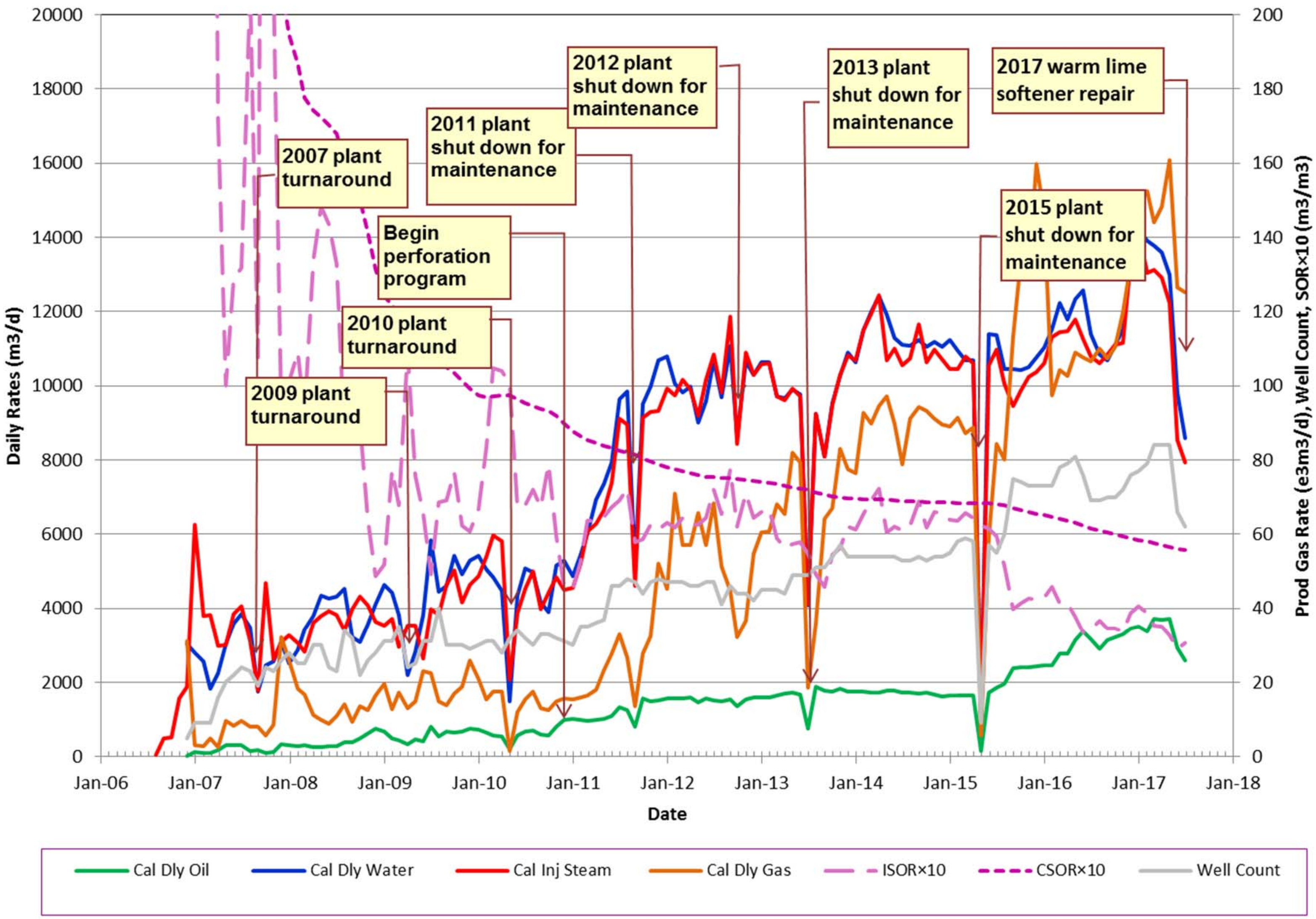
- No new Seismic data run or interpreted during the reporting period

7. Scheme Performance

Scheme Performance Prediction Methodology

- Current performance prediction based on:
  - Updated geological model supplemented with simulation and analytical models
  - Observation of actual performance
  - Analysis of analogous SAGD projects

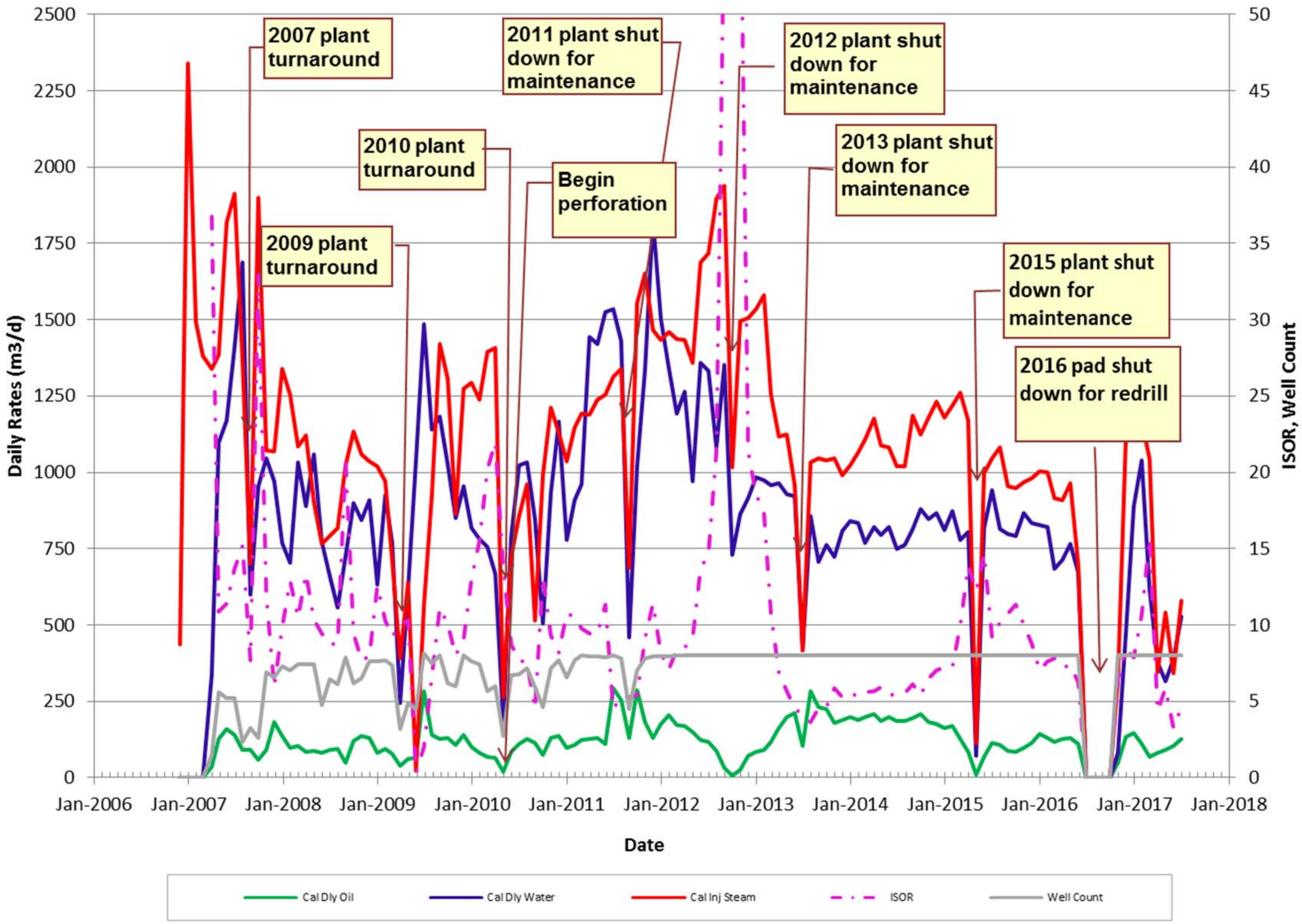
Production and Injection History



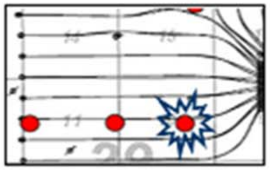
Production vs. Approval Capacity Variance

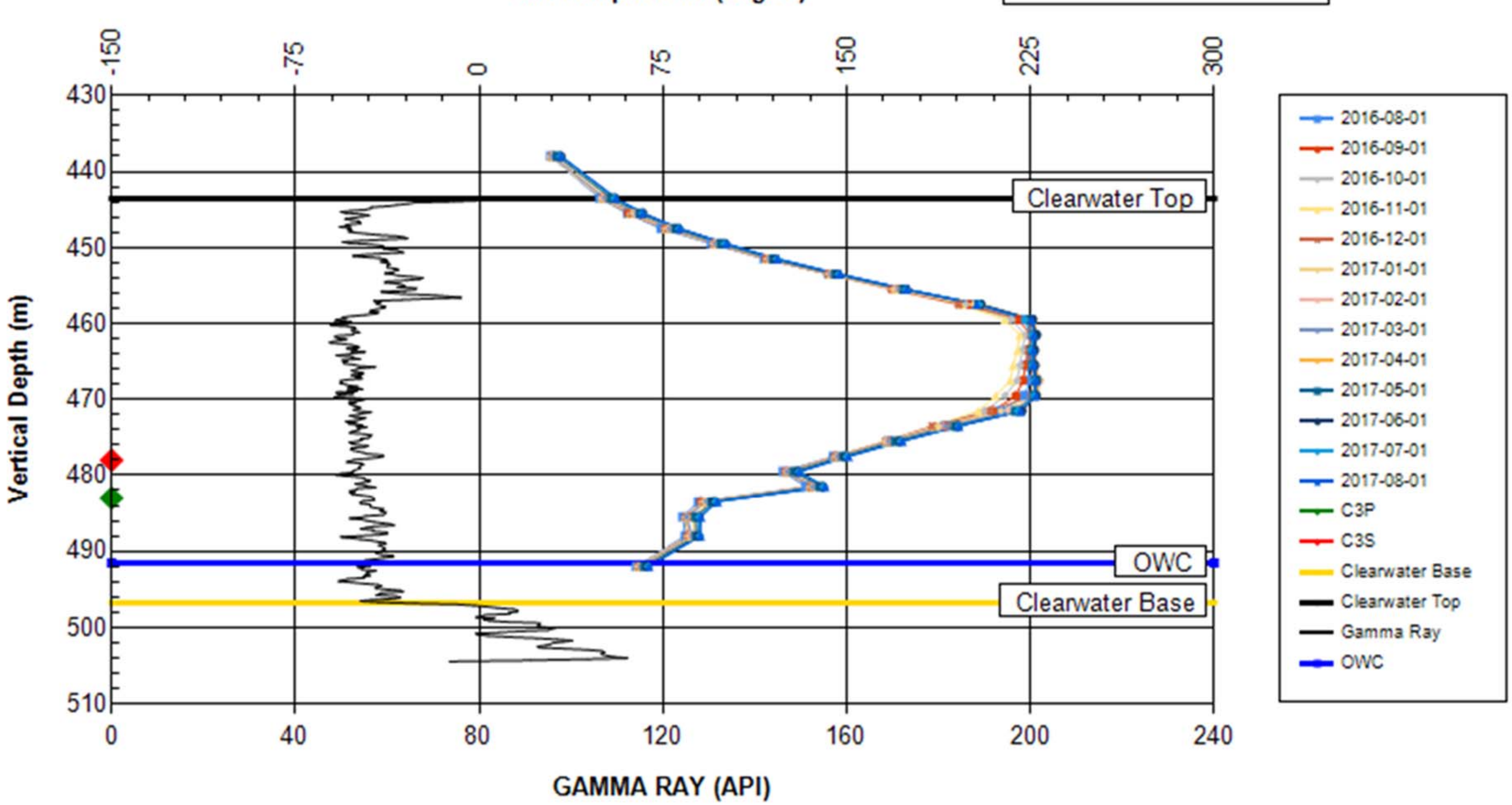
- 32 original well pairs had poor performance due to:
  - Placement in the transition zone where oil saturation is low
  - Poor start-up strategy (bull-heading); currently use circulation
- Since 2008 all well pairs drilled to the base of SAGD net pay
- Revised completion of new wells
  - Dual string completions in both injector and producer
  - Injectors completed with VITs and steam splitters for Pads D East, D North and CN
  - Wire Wrapped Screens for all new producers to increase open area
  - Blanket gas installed on all wells to provide
    - Insulation
    - Casing protection
    - Down hole pressure measurement

Pad C West Performance - Low Recovery Example

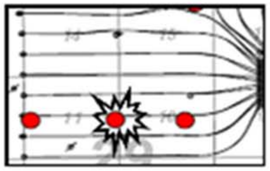


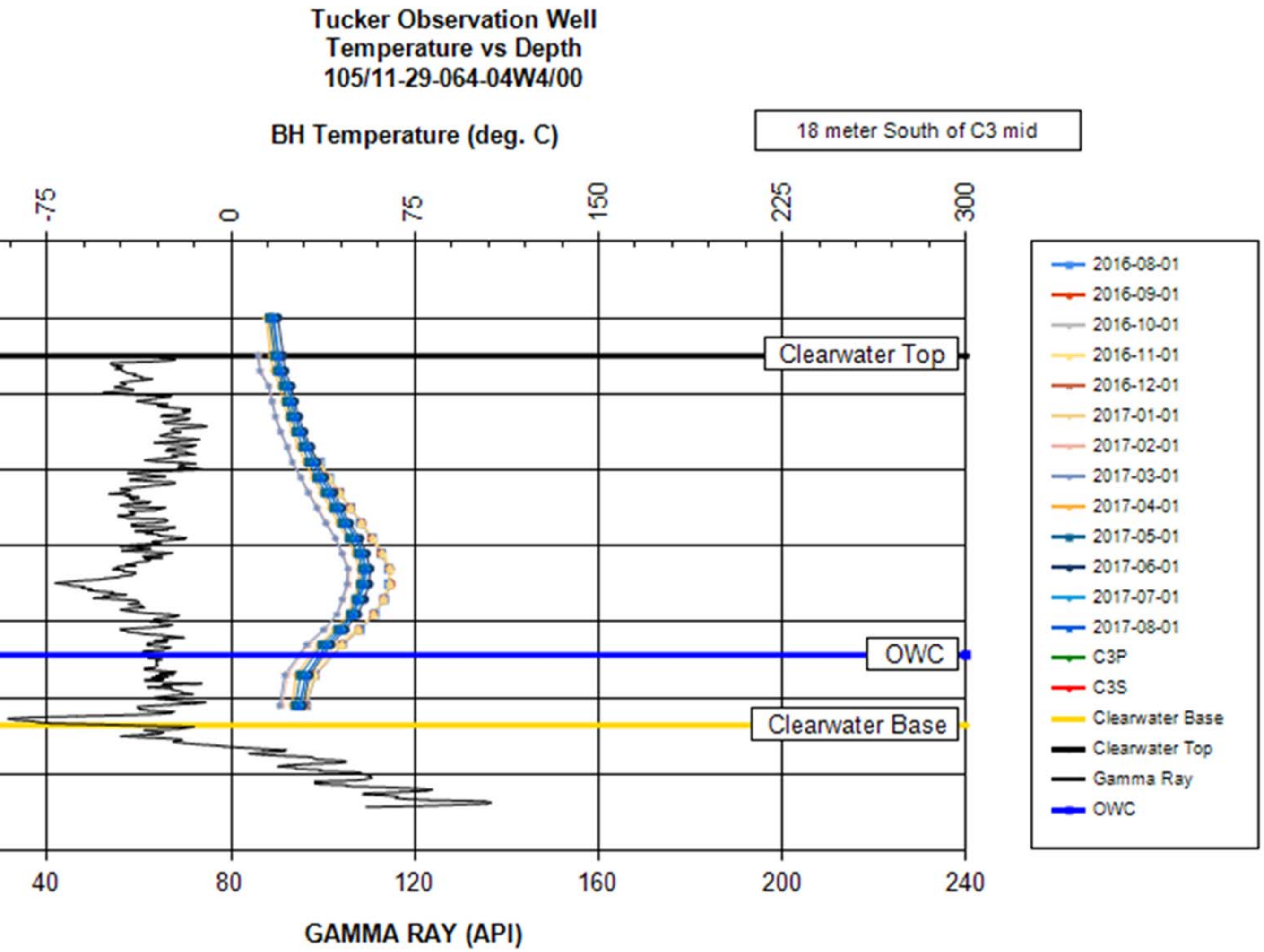
Pad C West Heel Observation Well



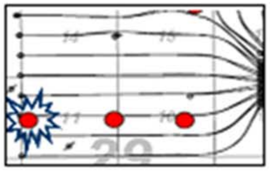


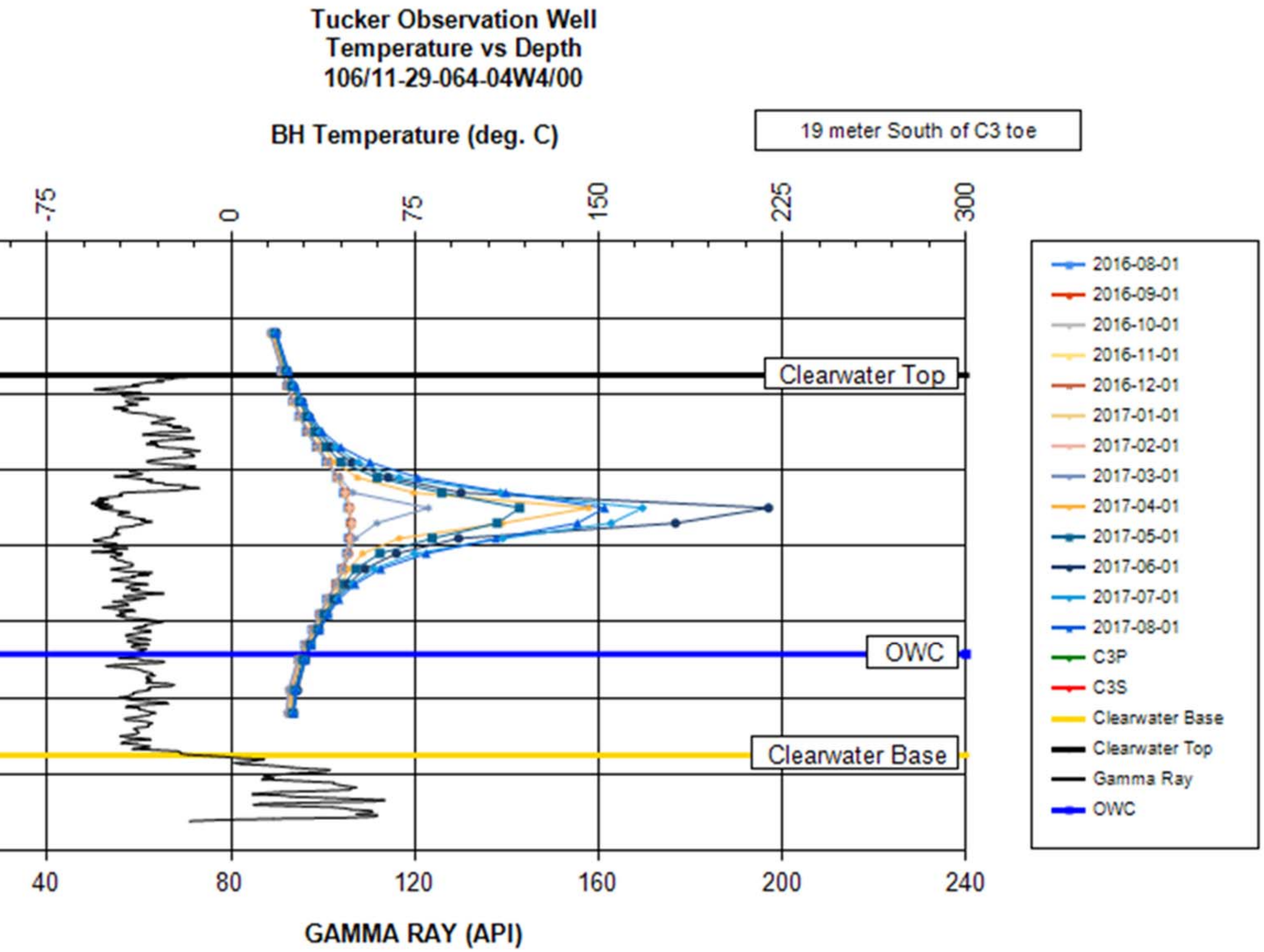
Pad C West Mid Observation Well





Pad C West Toe Observation Well

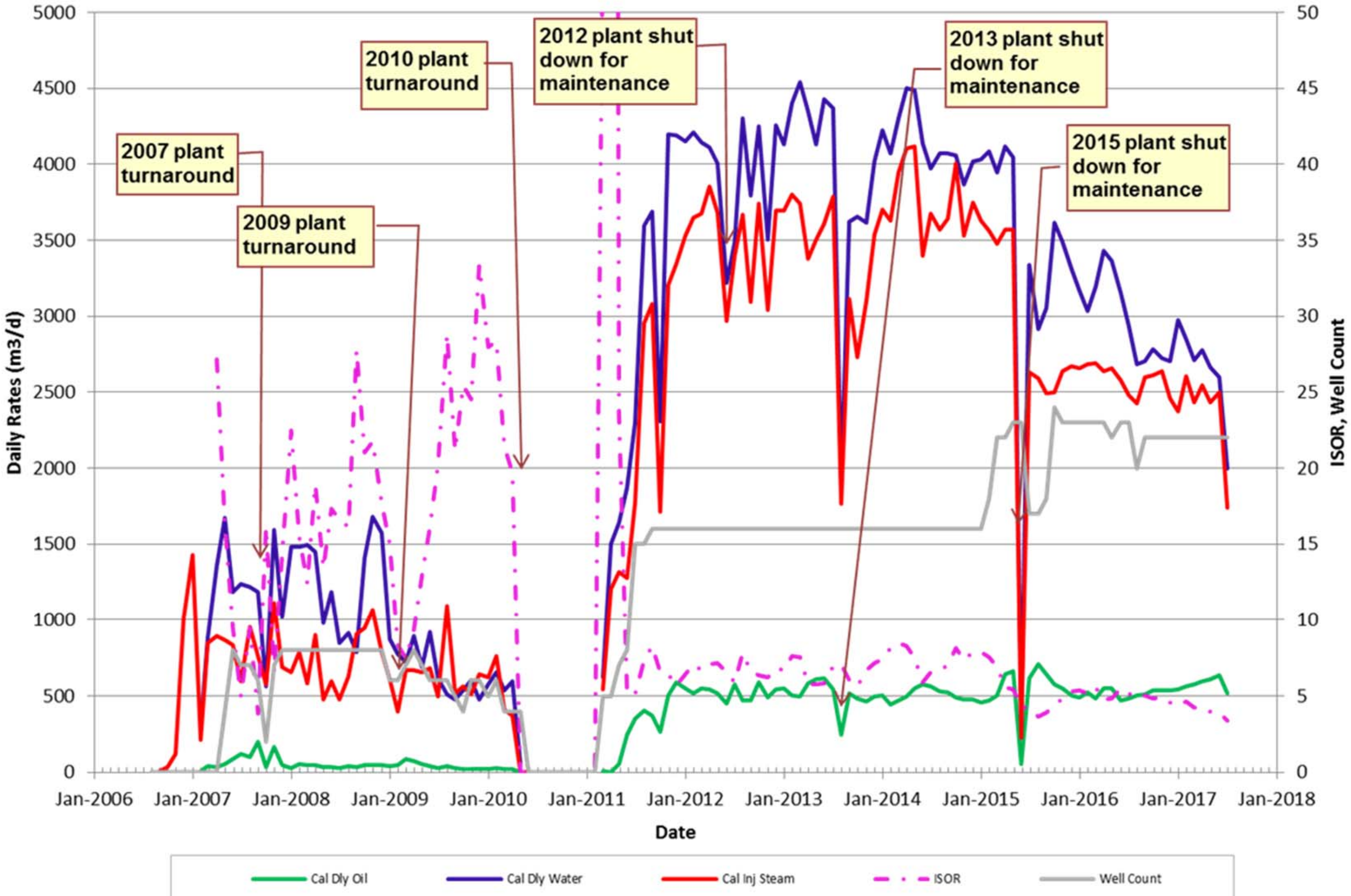




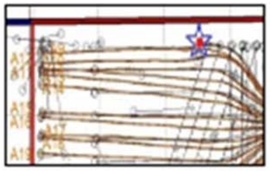
Discussion of Pad C West Performance

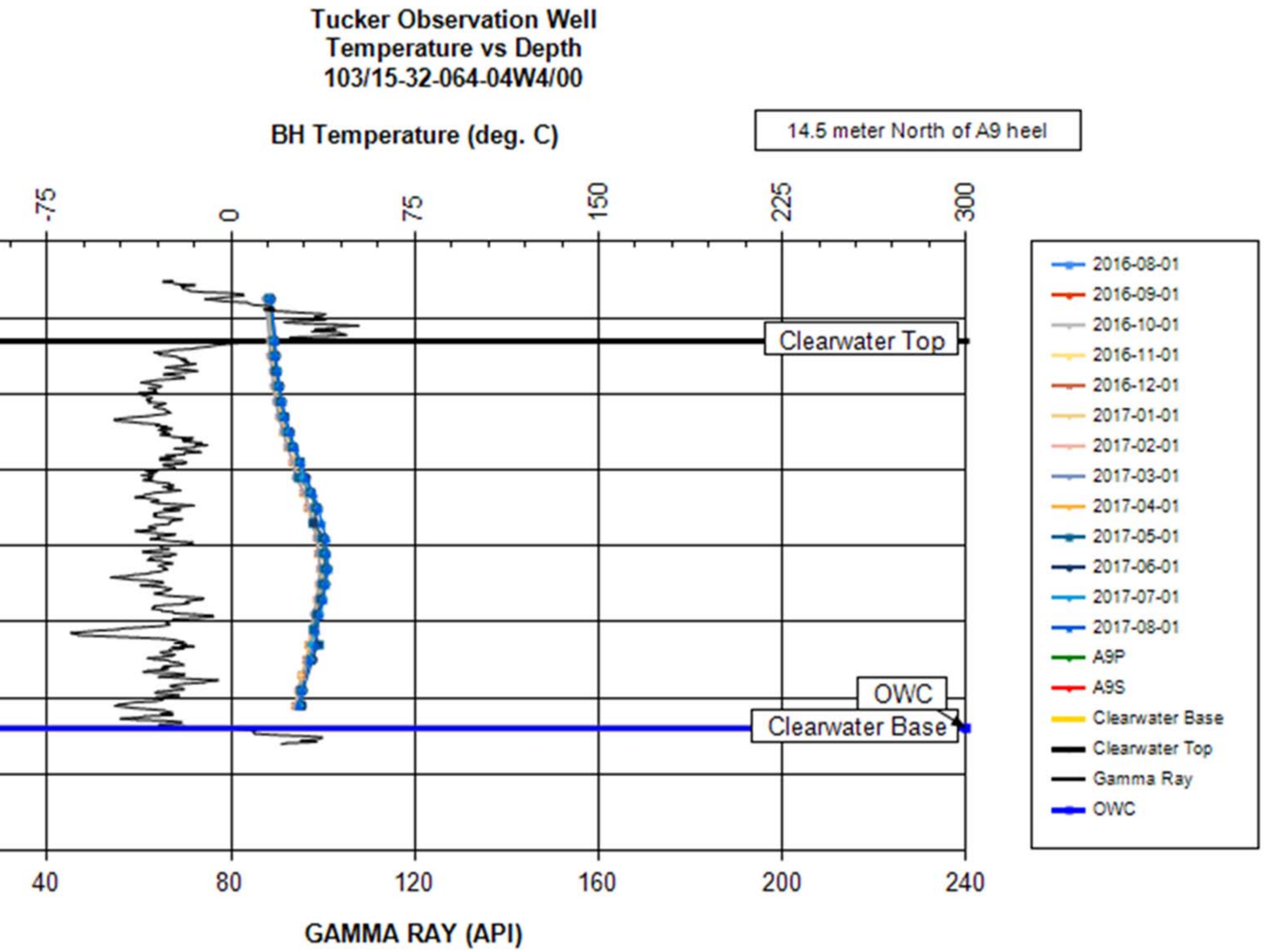
- The OBS wells along C3 show non-uniform steam chamber development
- To improve production from this pad, new injectors 5 m above exiting injectors were drilled and existing injectors were converted to producers
- Pad C West performance indicators as of July 31, 2017:
  - Cum. Oil: 462,734 m^3
  - Cum. Steam Injected: 4,155,958 m^3
  - Cum. Water Produced: 3,232,458 m^3
  - CSOR: 9.0
- Pad C West performance for the reporting period:
  - Cum. Oil: 27,601 m^3
  - Oil Rate per well: 12.6 m^3/day
  - SOR: 7.3

Pad A Performance - Medium Recovery Example

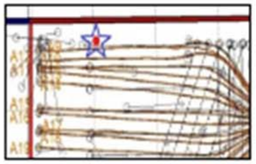


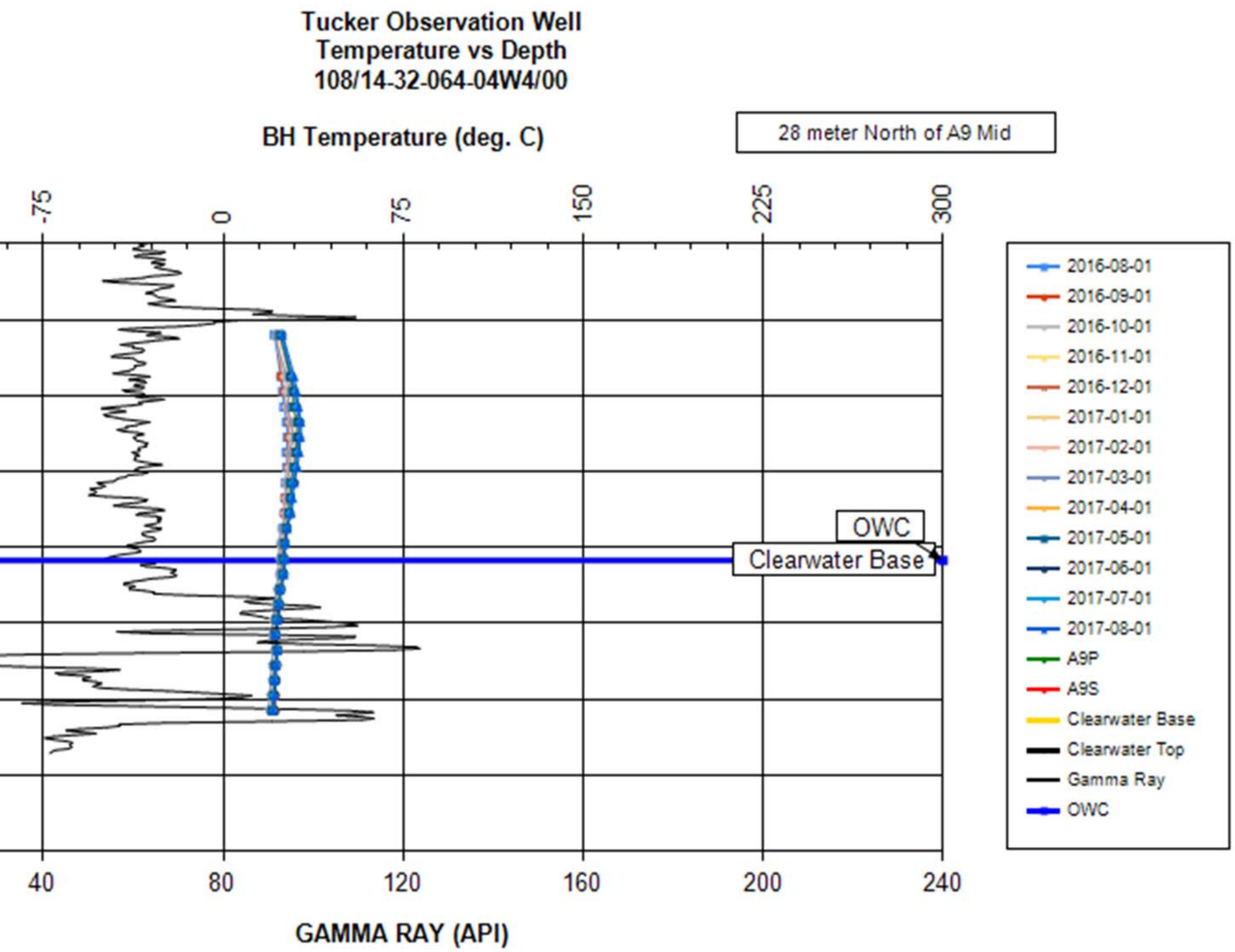
Pad A Wells Heel Observation Well





Pad A Wells Mid Observation Well

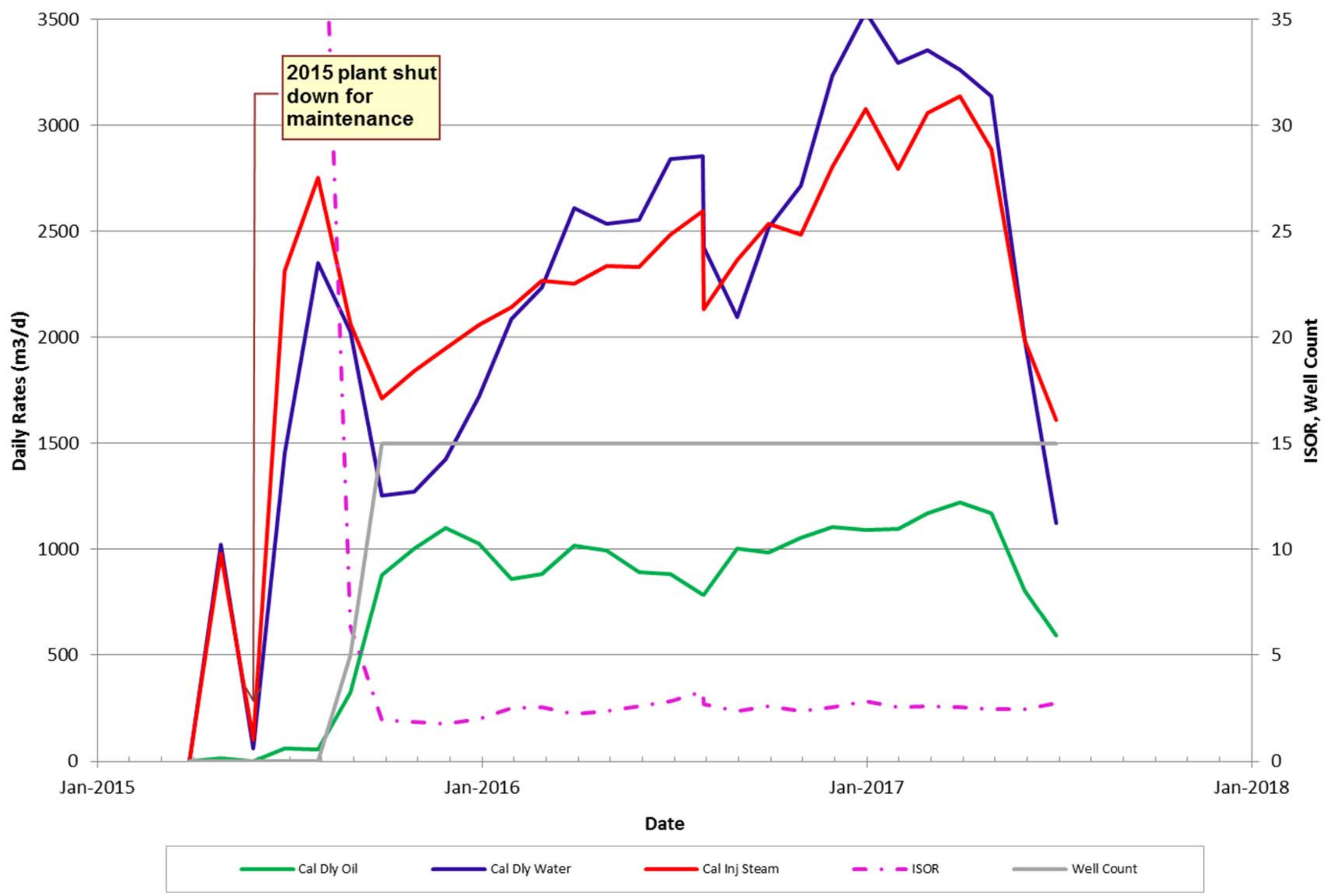




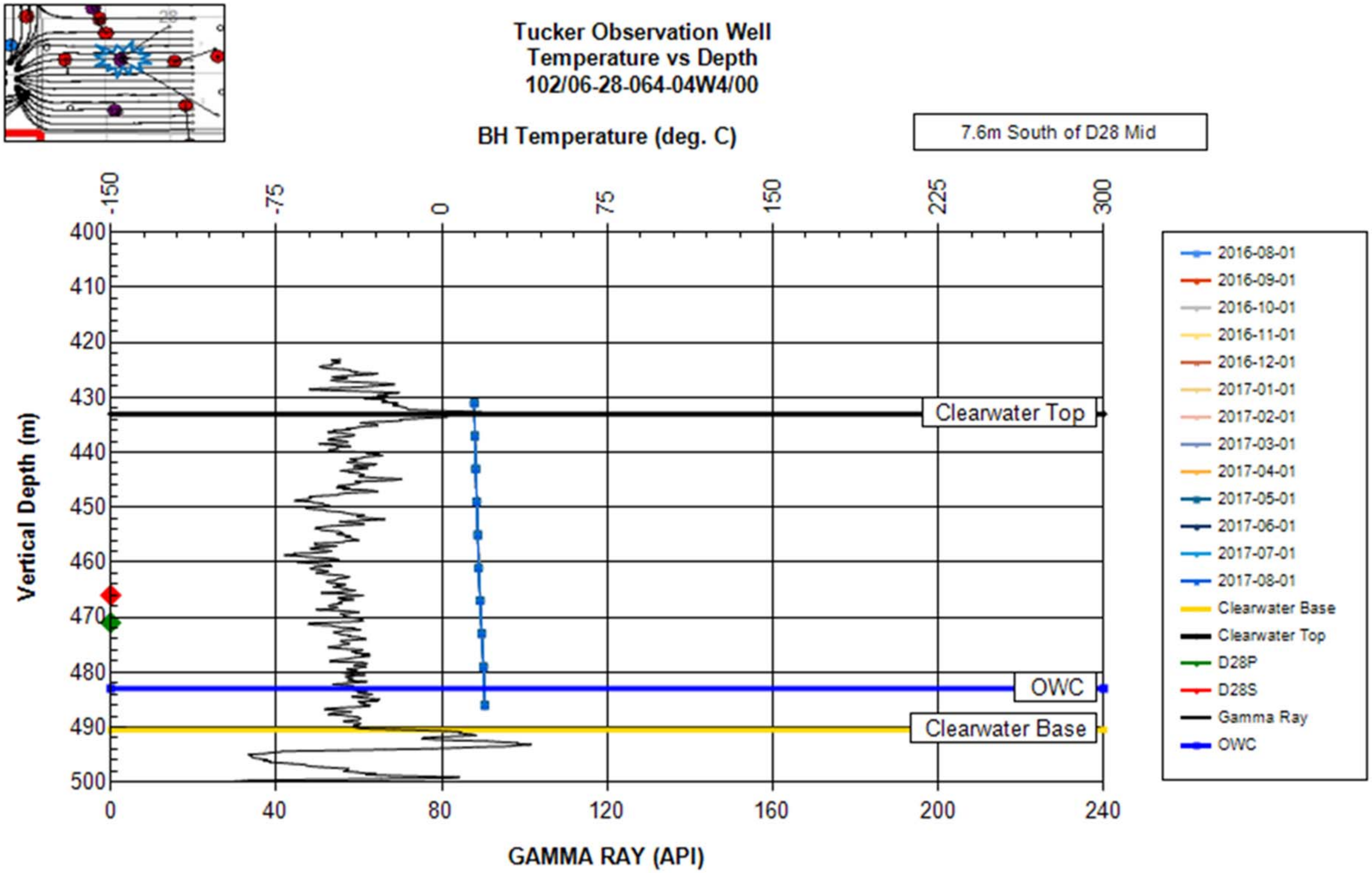
Discussion of Pad A Wells Performance

- The OBS wells near A9 showing minimal steam chamber development
- Pad A performance indicators as of July 31, 2017:
    - Cum. Oil: 1,227,520 m^3
    - Cum. Steam Injected: 7,899,493 m^3
    - Cum. Water Produced: 9,162,368 m^3
    - CSOR: 6.4
- Pad A performance for the reporting period:
    - Cum. Oil: 202,759 m^3
    - Oil Rate per well: 25.2 m^3/day
    - SOR: 4.3

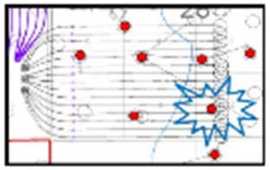
Pad D East Performance – High Recovery Example

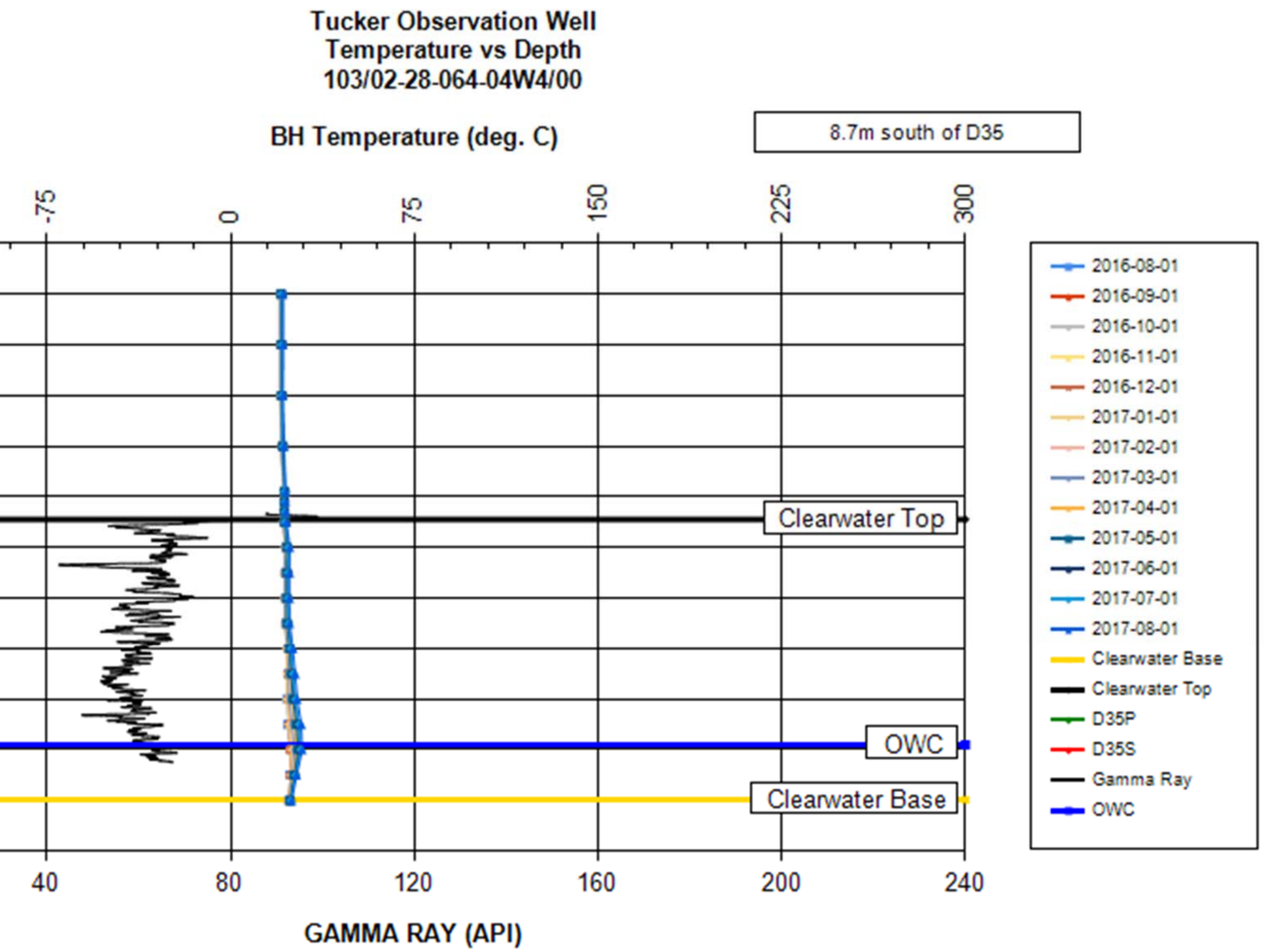


Pad D East Mid Observation Well



Pad D East Toe Observation Well





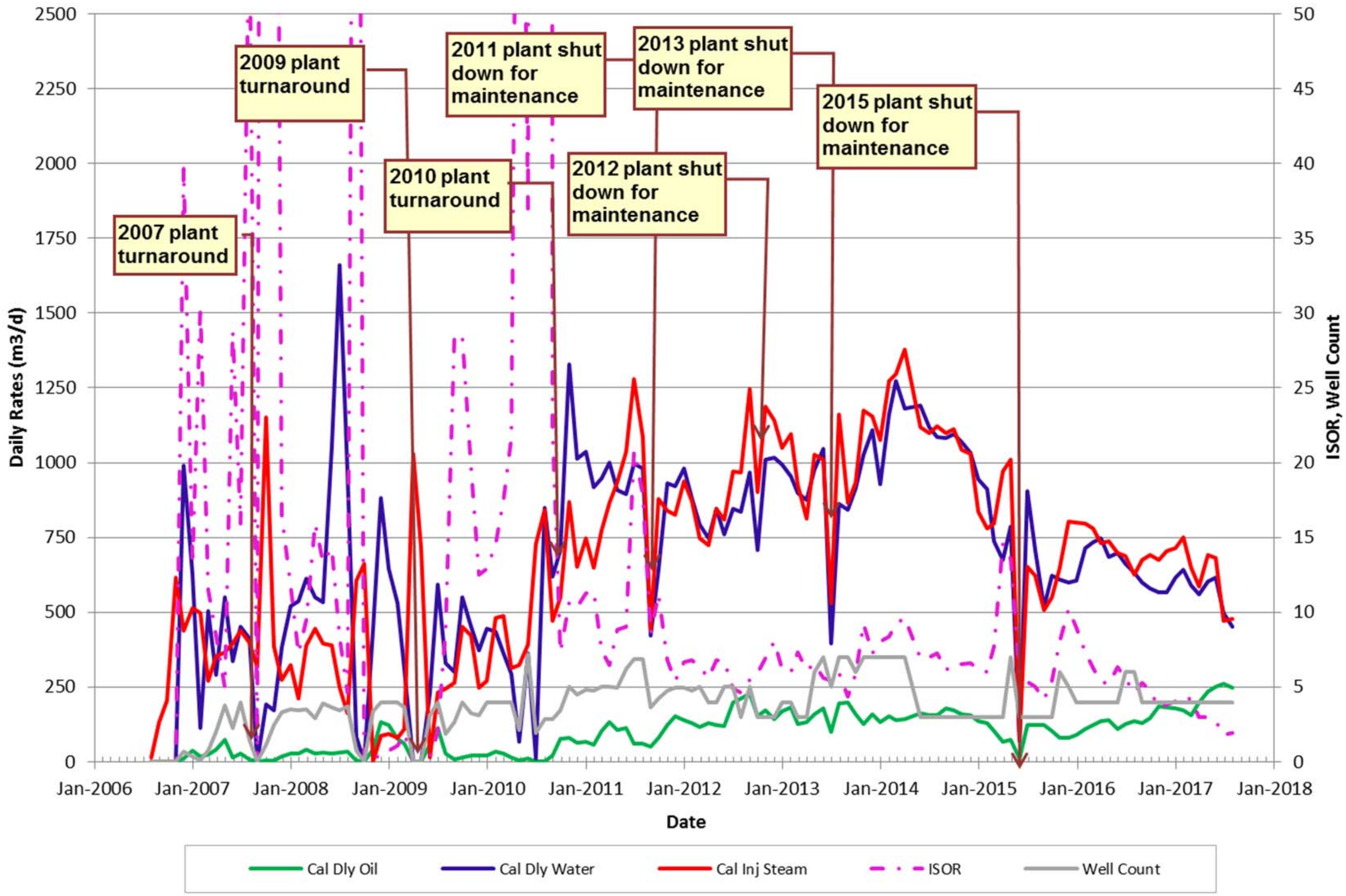
Discussion of Pad D East Performance

- Since steam commenced in Q2 2015, high temperature has not been observed at the OBS wells

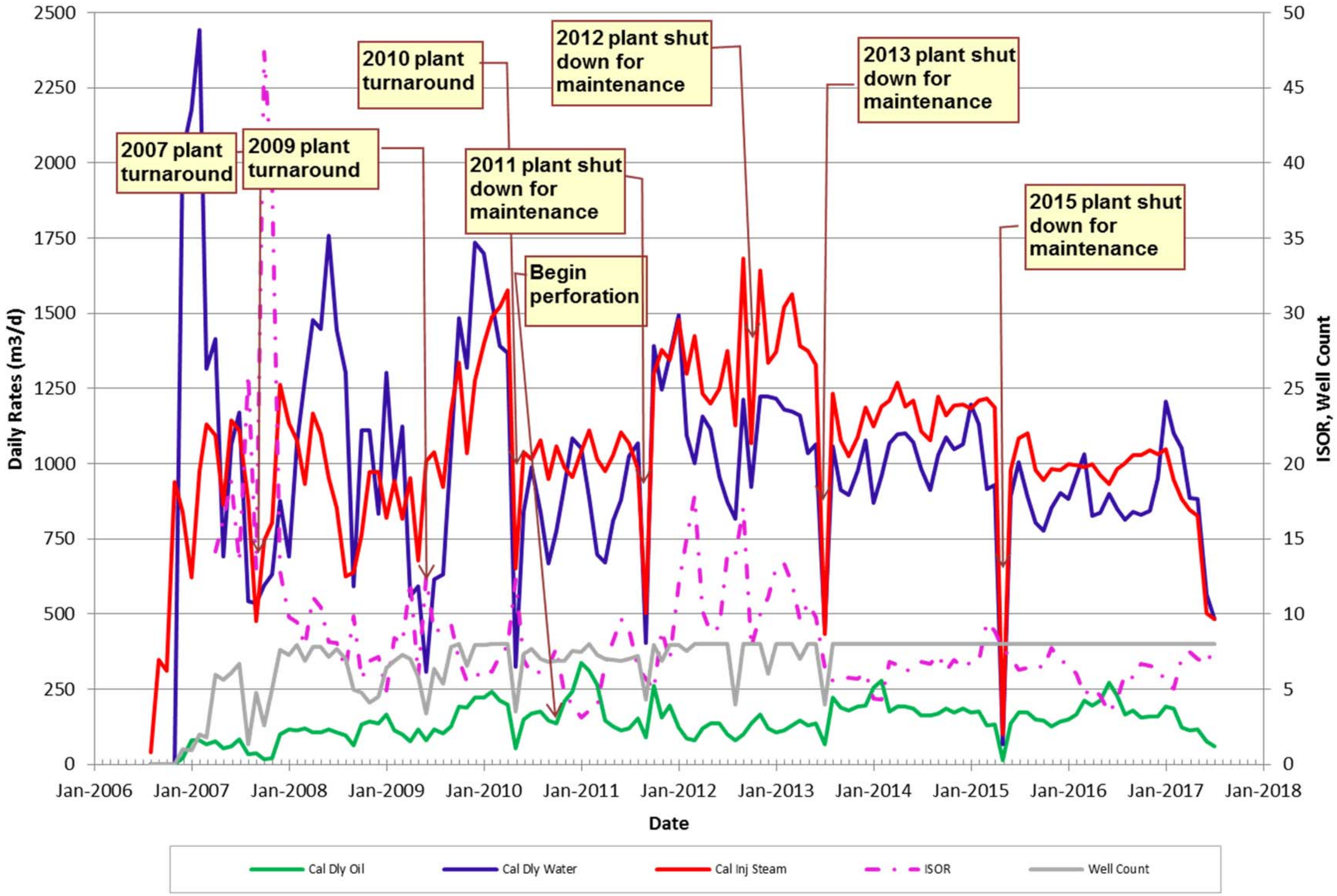
- Pad D East performance indicators as of July 31, 2017:
  - Cum. Oil: 696,316 m^3
  - Cum. Steam Injected: 1,919,170 m^3
  - Cum. Water Produced: 1,916,785 m^3
  - CSOR: 2.8

- Pad D East performance for the reporting period:
  - Cum. Oil: 367,935 m^3
  - Oil Rate per well: 67.2 m^3/day
  - SOR: 2.6

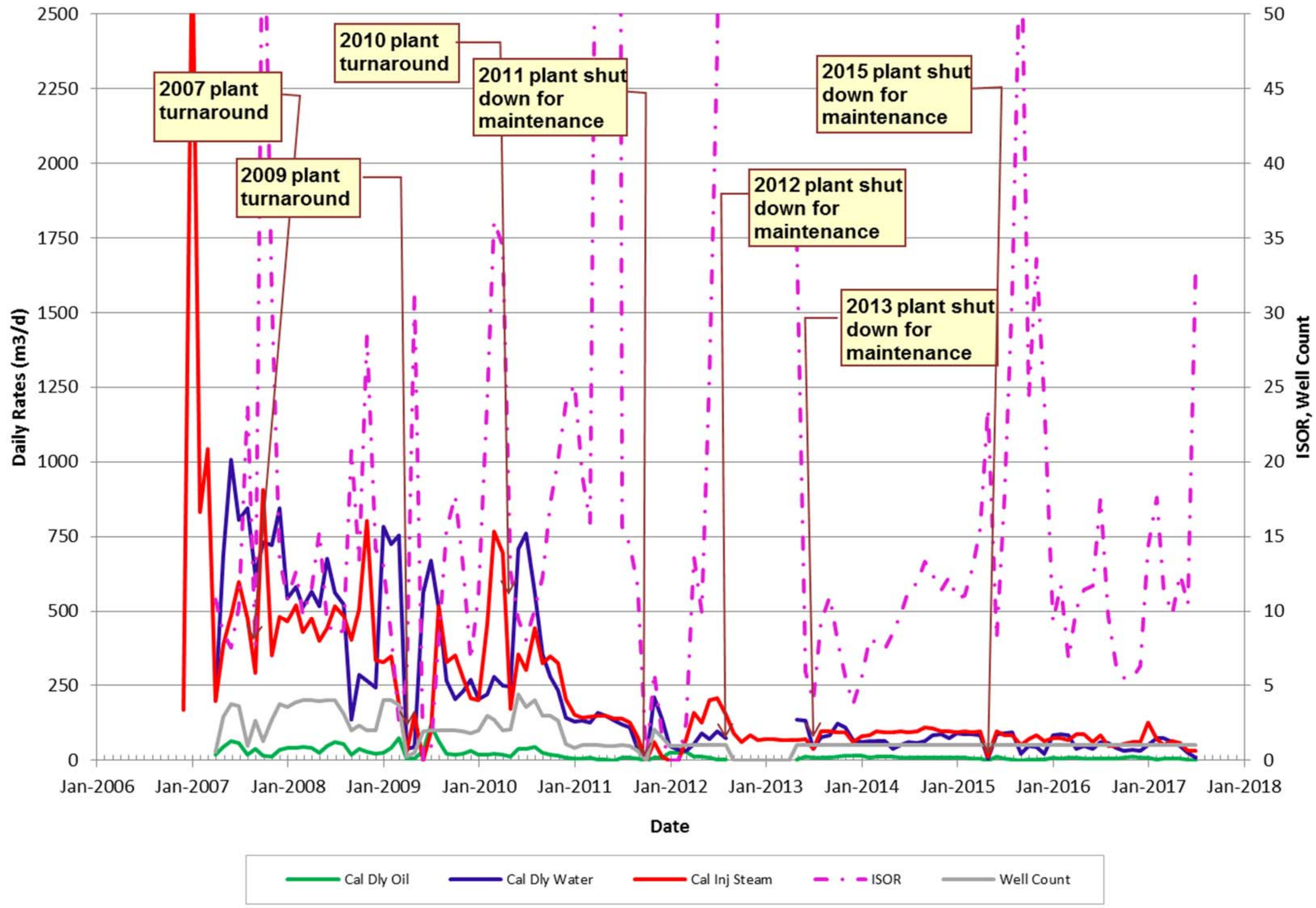
Pad B North Performance



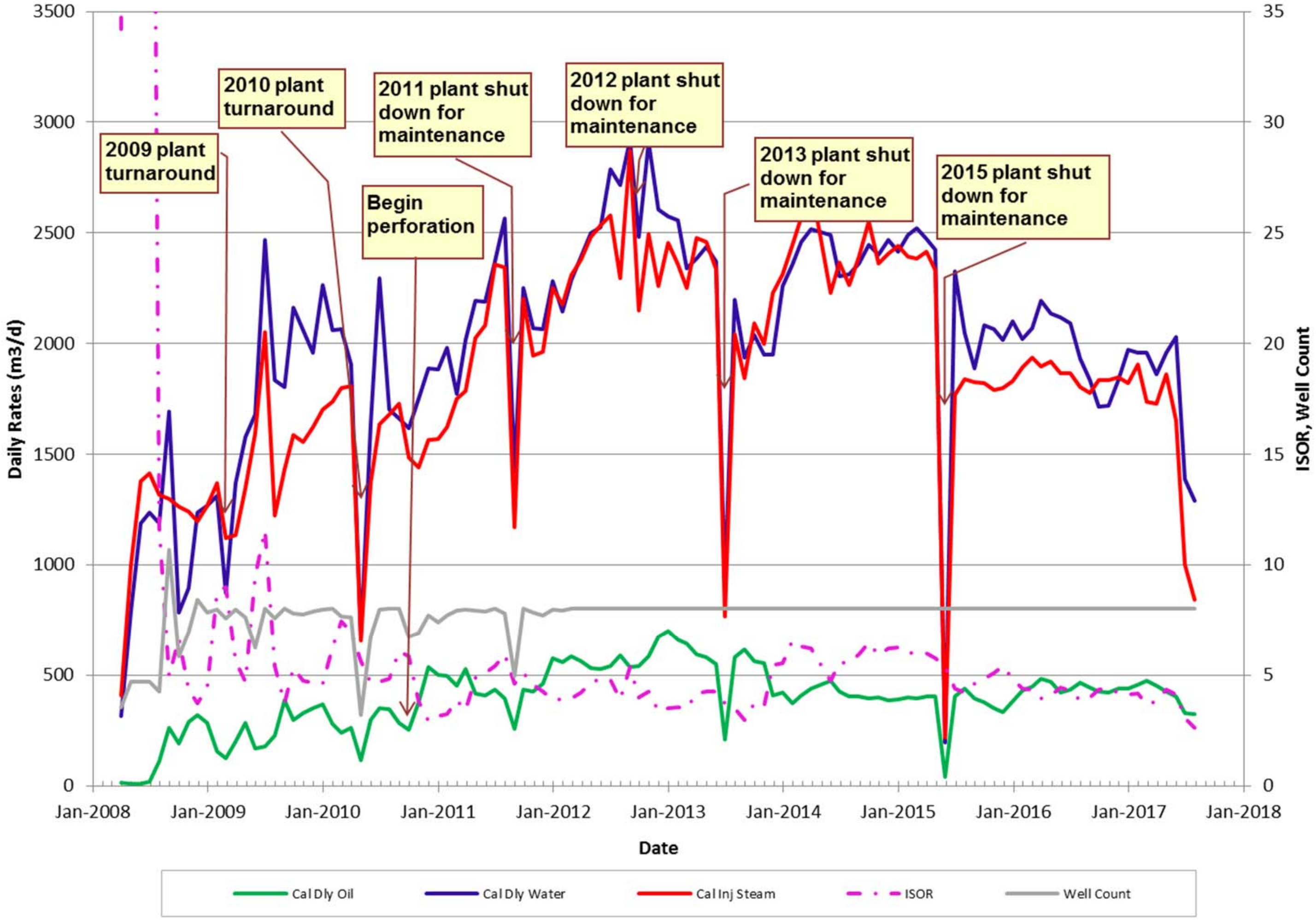
Pad B West Performance



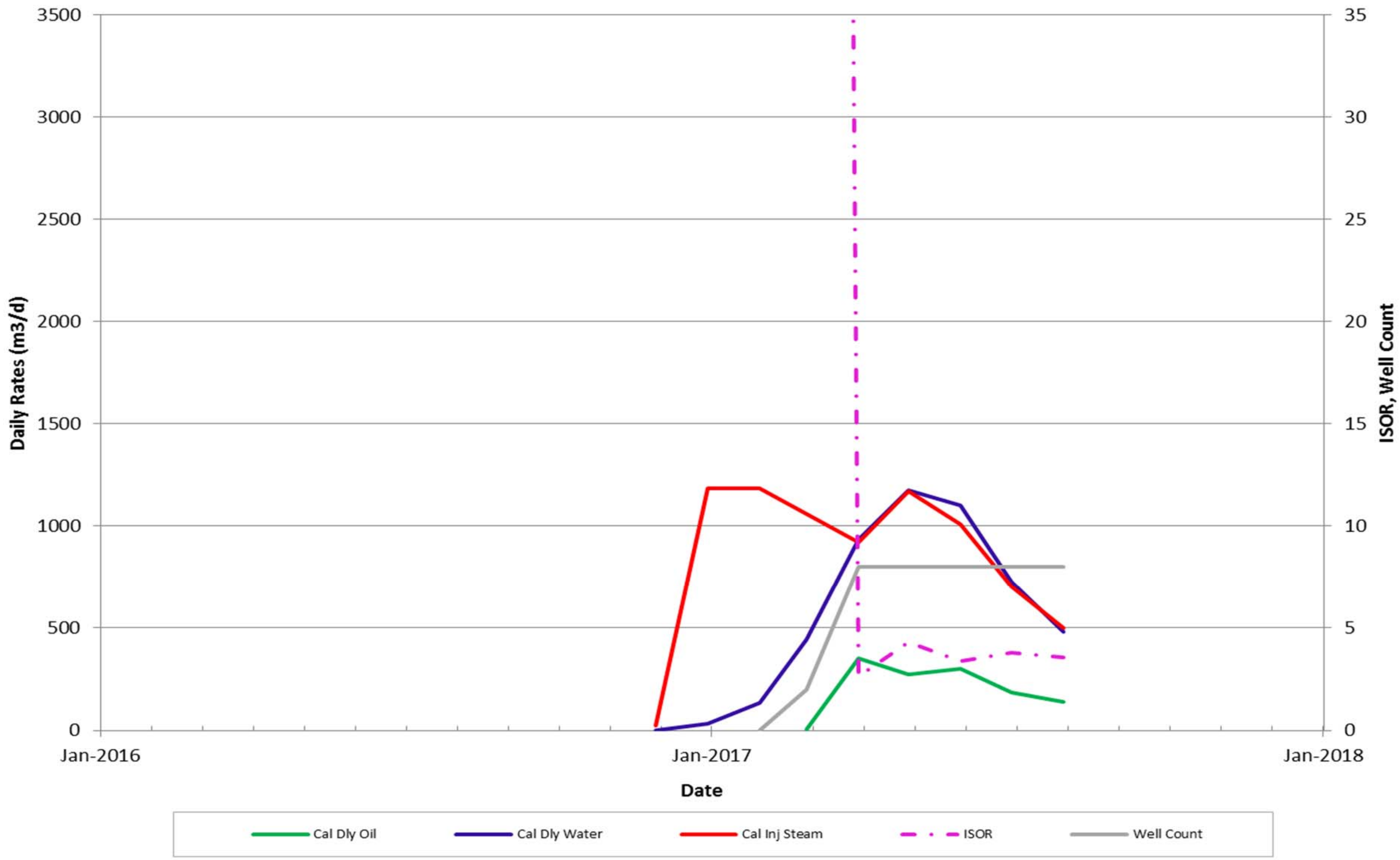
Pad C North Performance



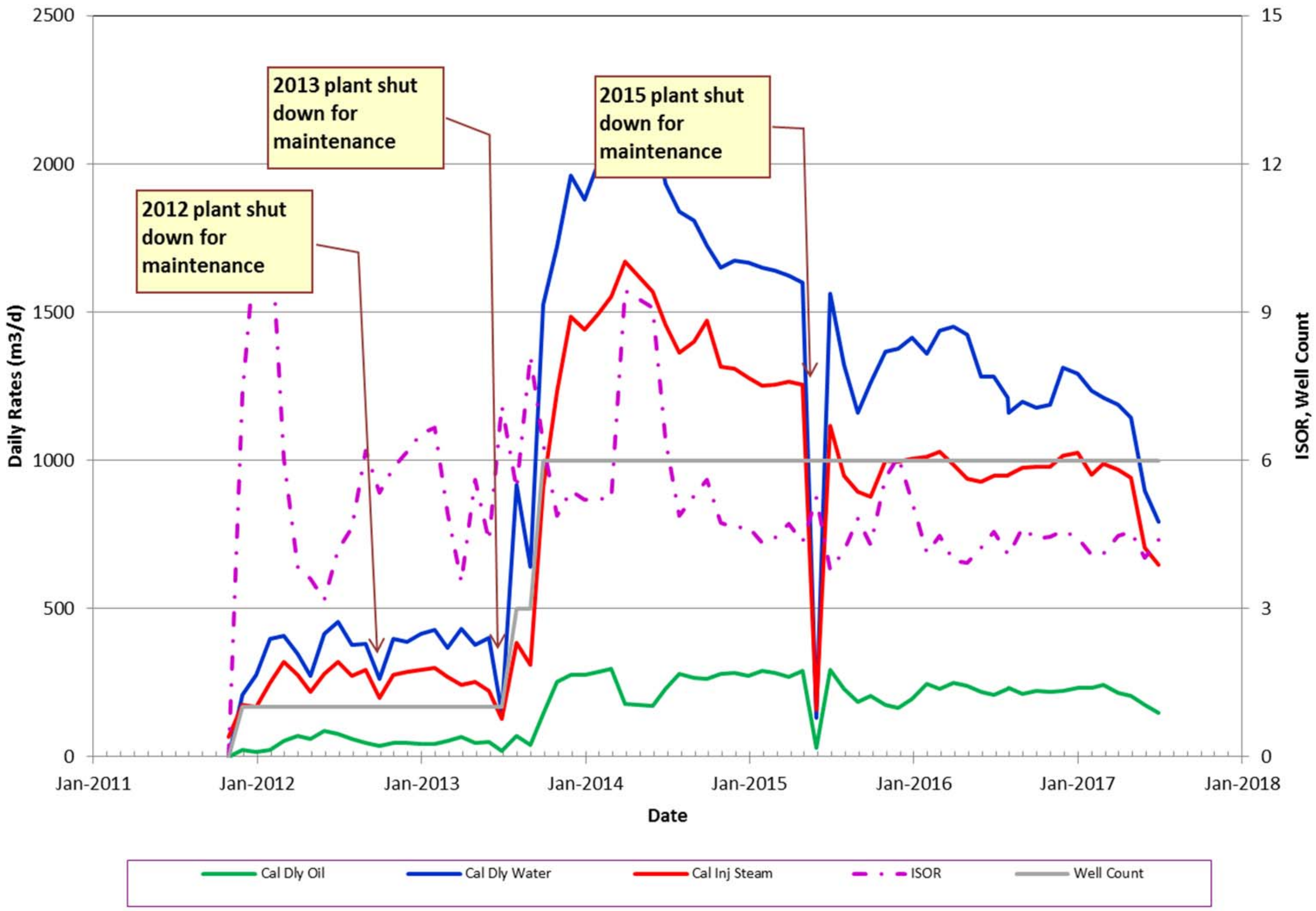
Pad C East Performance



Pad D North Performance



Pad Lower Grand Rapids (GA) Performance



- Water-steam-ratio is high due to the presence of bottom water and high water mobility in the reservoir
- Operating pressure at or slightly below the bottom water pressure to optimize steam efficiency
- Steam injection rates are optimized on a weekly basis based on well performance and total water produced from each well pair

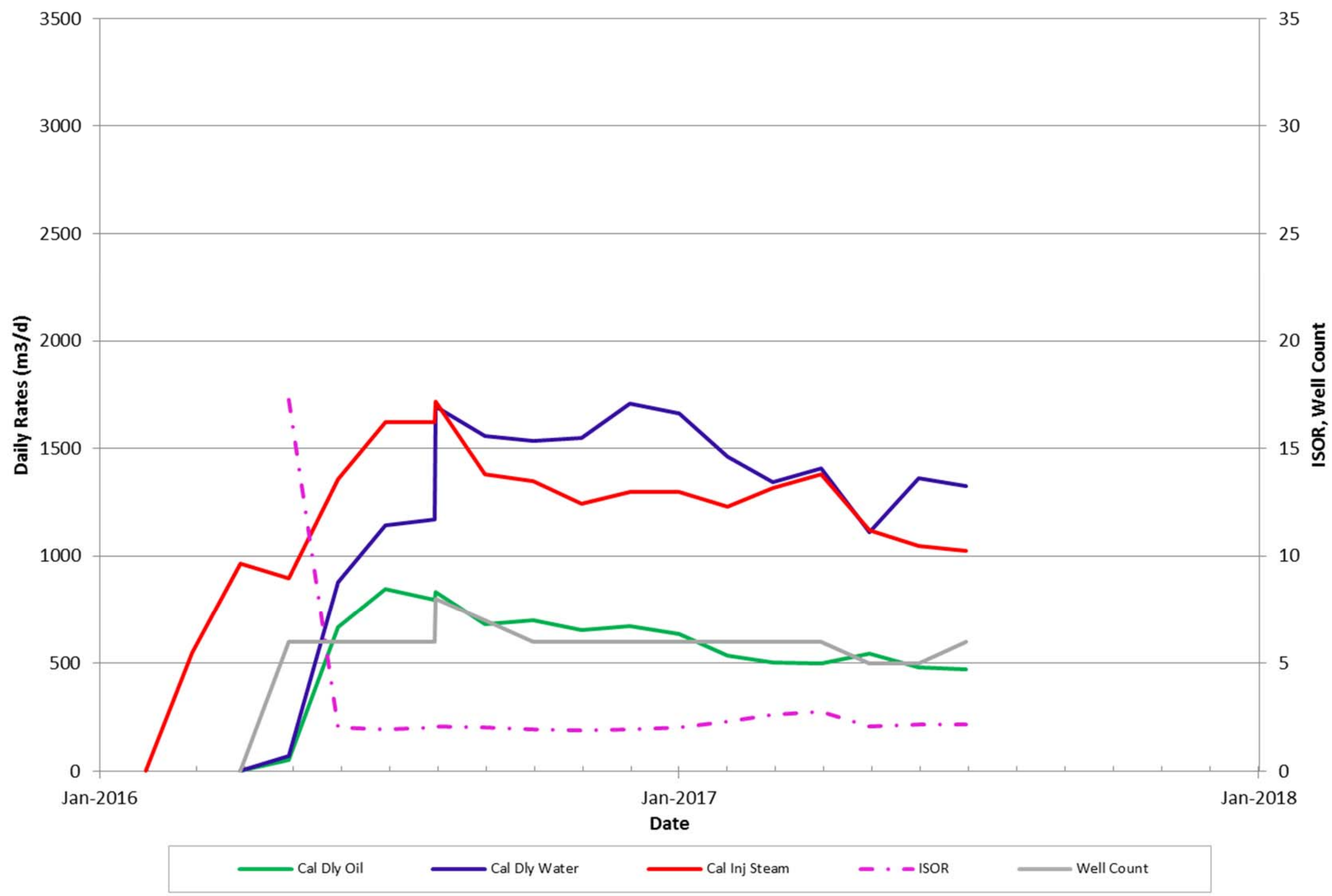
Discussion of Pad GA Performance

- Pilot well started in September 2011
- Remaining 5 well pairs started by September 2013

- Pad GA performance indicators as of July 31, 2017:
  - Cum. Oil: 353,744 m^3
  - Cum. Steam Injected: 1,725,549 m^3
  - Cum. Water Produced: 2,311,070 m^3
  - CSOR: 4.9

- Pad GA performance for the reporting period:
  - Cum. Oil: 77,847 m^3
  - Oil Rate per well: 35.5 m^3/day
  - SOR: 4.4

Pad Colony (CN) Performance



Discussion of Pad CN Performance

- First steam in February 2016
- 6 SAGD pairs and 7 infill wells

- Pad CN performance indicators as of July 31, 2017:
  - Cum. Oil: 291,311 m^3
  - Cum. Steam Injected: 682,217 m^3
  - Cum. Water Produced: 638,727 m^3
  - CSOR: 2.3

- Pad CN performance for the reporting period:
  - Cum. Oil: 219,439 m^3
  - Oil Rate per well: 98.8 m^3/day
  - SOR: 2.1

New Development: Pad D West

- Pad D West (15 SAGD well pairs):
  - 8 injectors will be equipped with VIT and steam splitters
  - 7 injectors will be equipped with bare tubing and steam splitters
  - All producers will be completed with dual string
  - Drilling completed Q2 2017

OBIP and Recoveries by Pad

- OBIP for each pad is calculated from the formula:

$$OBIP = L \times W \times H \times (1-S_w) \times \Phi \times 1/B_o$$

Where

L = Effective Average Length of wells
W = Lateral Width covered by the wells
H = Thickness from the top of pay to the producer elevation
Φ = Average Porosity in the Pay zone
S_w = Average Water Saturation in the Pay zone
B_o = Oil Volume factor/Shrinkage factor (taken as 1)

OBIP and Recoveries by Well Pad

Well PAD		Thickness (m)	Area ($10^3 m^2$)	Pad Volume[1] ($10^6 m^3$)	So	PhiE	OBIP ($10^6 m^3$)	Recovery to Date 7/31/2017 ($10^3 m^3$)	Recovery Factor to Date (%)	Estimated Ultimate Recovery ($10^6 m^3$)	Ultimate Recovery Factor (%)
A Pad	A Infills and Replacement (16 well pairs)	30	880	30.6	0.56	0.32	5.5	1228	23	3.1	57
	A original (8 well pairs)	7	640								
B Pad	B West (8 well pairs)	37	640	39.8	0.57	0.32	7.3	943	13	3	42
	B North (4 well pairs)	8	320								
	B North Infills (3 well pairs)	40	345								
C Pad	C West (8 well pairs)	36	640	53.8	0.6	0.32	10.3	1865	18	5.1	50
	C North (4 well pairs)	10	320								
	C East (8 well pairs)	43	640								
D East (15 well pairs)		43	660	28.1	0.61	0.32	5.5	696	13	3.2	60
D North (8 well pairs)		36	330	11.8	0.61	0.33	2.4	38	2	1.4	60
GA Pad (6 well pairs)		30	355	10.6	0.62	0.3	2.0	354	18	1.2	60
CN Pad (6 well pairs + 7 infill)		13	502	6.5	0.82	0.29	1.5	292	18	1	60

Note:
[1] Due to rounding of values, the calculated values may not equal the individual values presented in the table.

5-Year Outlook of Expected Pad Abandonment

- No pad abandonment anticipated in the next 5 years

Temperature, Pressure and Quality of Steam

- High pressure steam separator delivers steam at a 100% quality
- Steam quality losses are experienced during transportation to the pads
- Steam quality at the wellhead is estimated to be 95%

Composition of Other Injected/Produced Fluids

- Not applicable

Summary of Key Learnings

- Well placement is a critical factor for well performance
- Circulation is the optimum startup procedure for establishing thermal communication in a SAGD process
- Wire-wrapped screens are better for avoiding scaling problem of the production liner
- Steady operating conditions are key to obtaining good steam chamber conformance
- To maintain steady operations and prevent water inflow the operating pressure needs to be constant and close to bottom water pressure

8. Future Plans

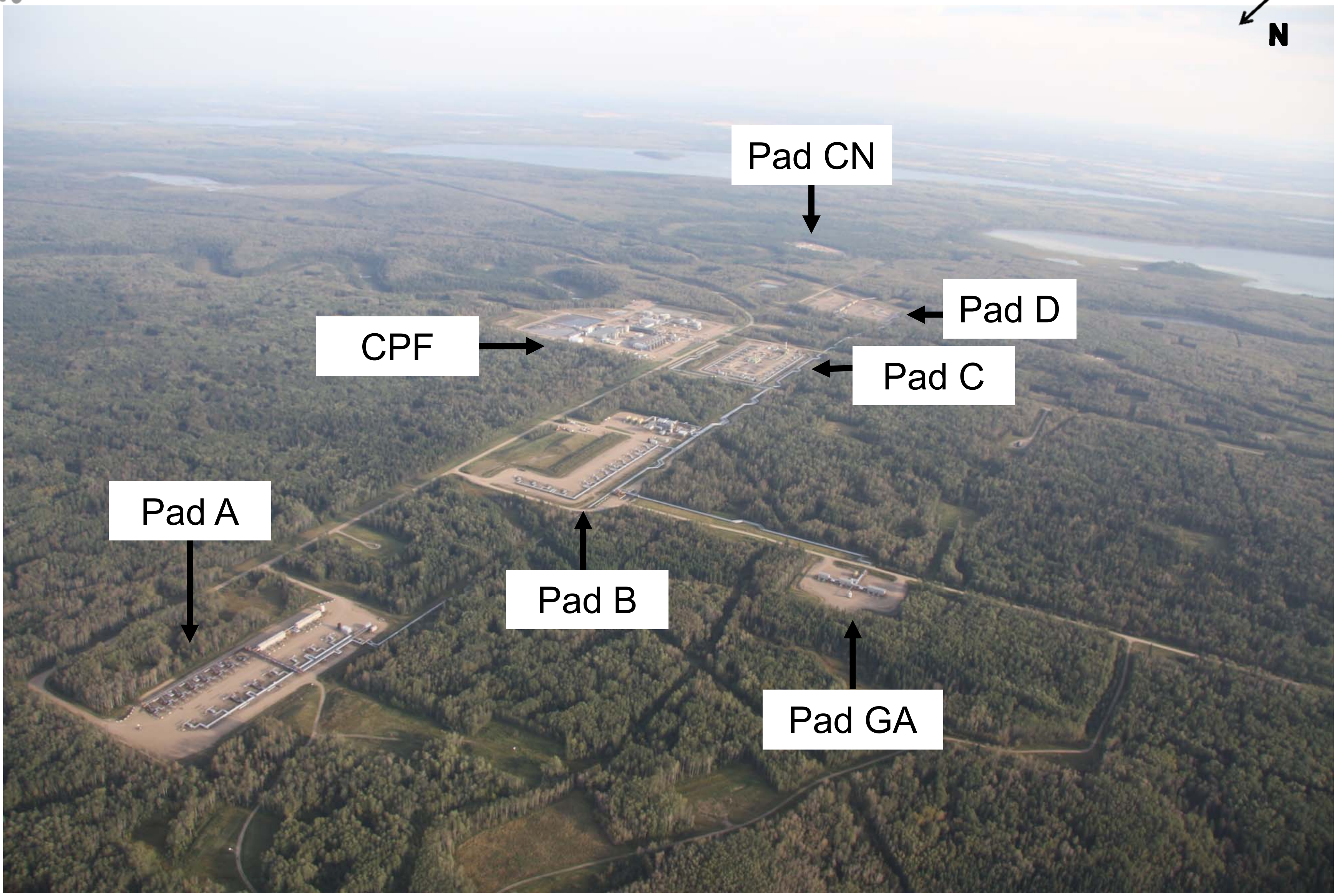
Future Plans (2017/2018)

- Pad D West Development:
  - Finish construction, commission & start-up facilities (Q4 2017/Q1 2018)
  - Complete 15 SAGD well pairs, circulate/start-up SAGD operations (Q4 2017/ Q1 2018)
- Pad B West Replacement Wells:
  - Based upon performance of Pad C West Replacement wells (2018)
- Pad C North Future Development:
  - Evaluate and propose a development strategy for optimizing the resource recovery

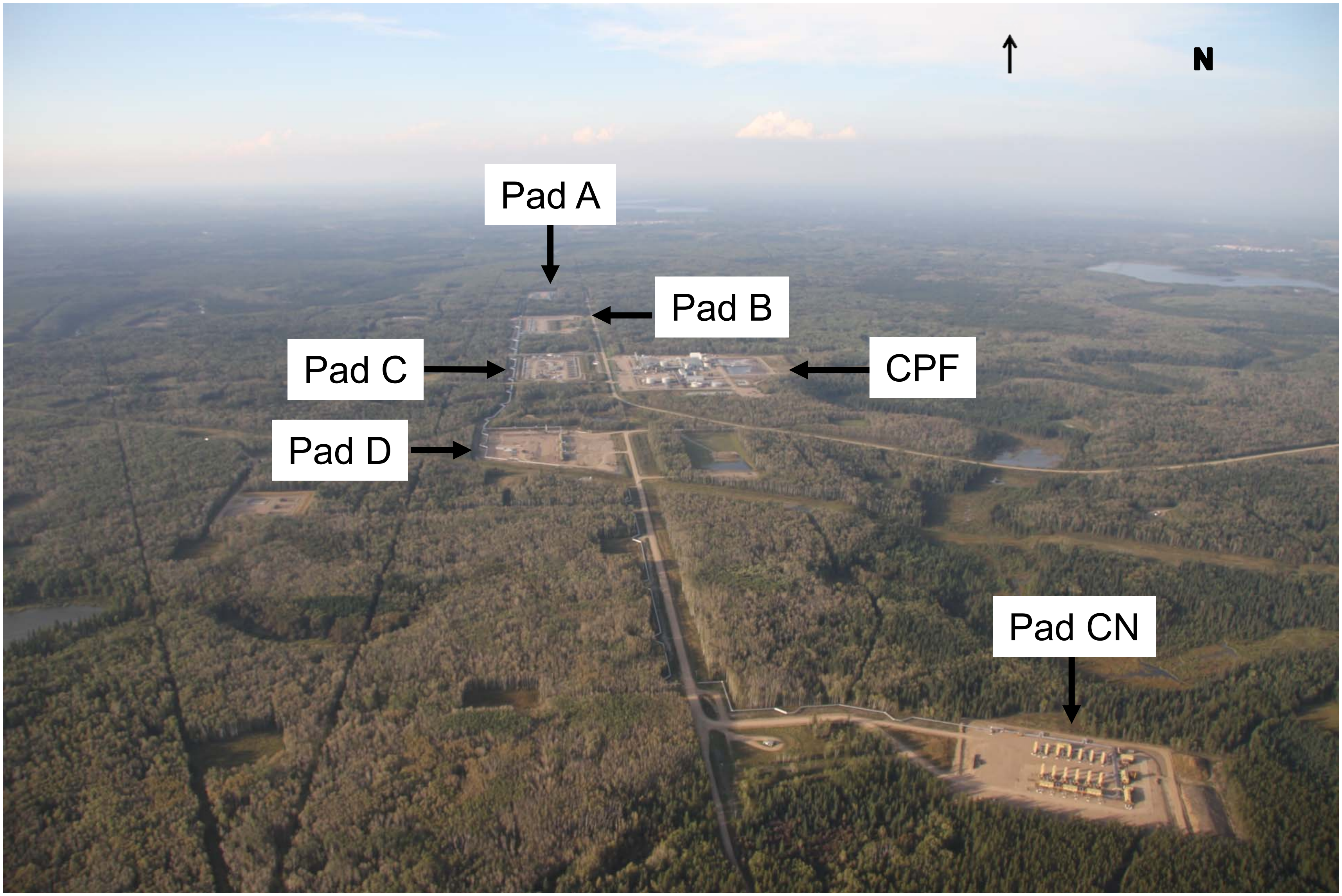
3.1.2. Surface - Table of Contents

1. Facilities

Layout (Looking Southeast)



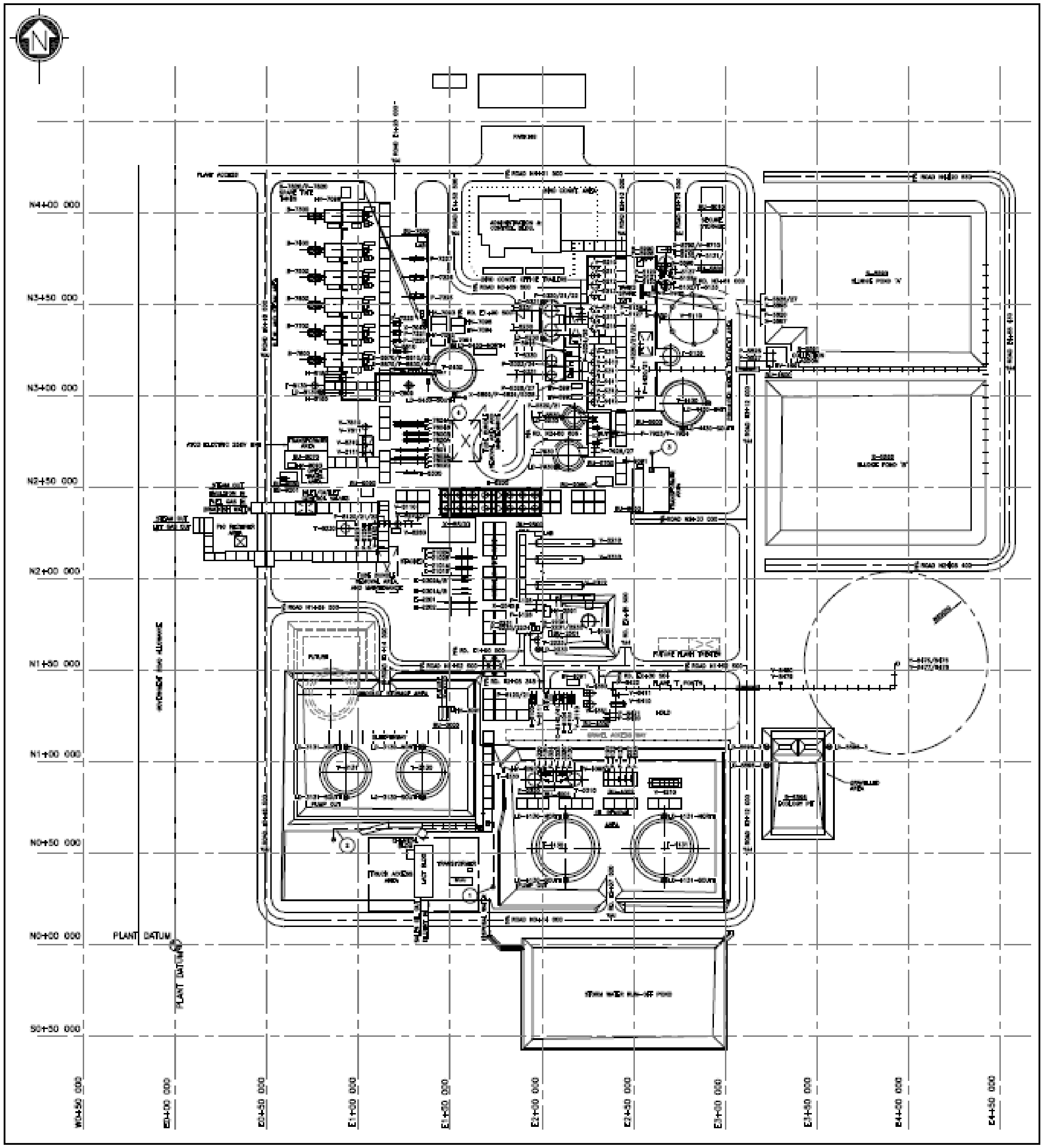
Layout (Looking North)



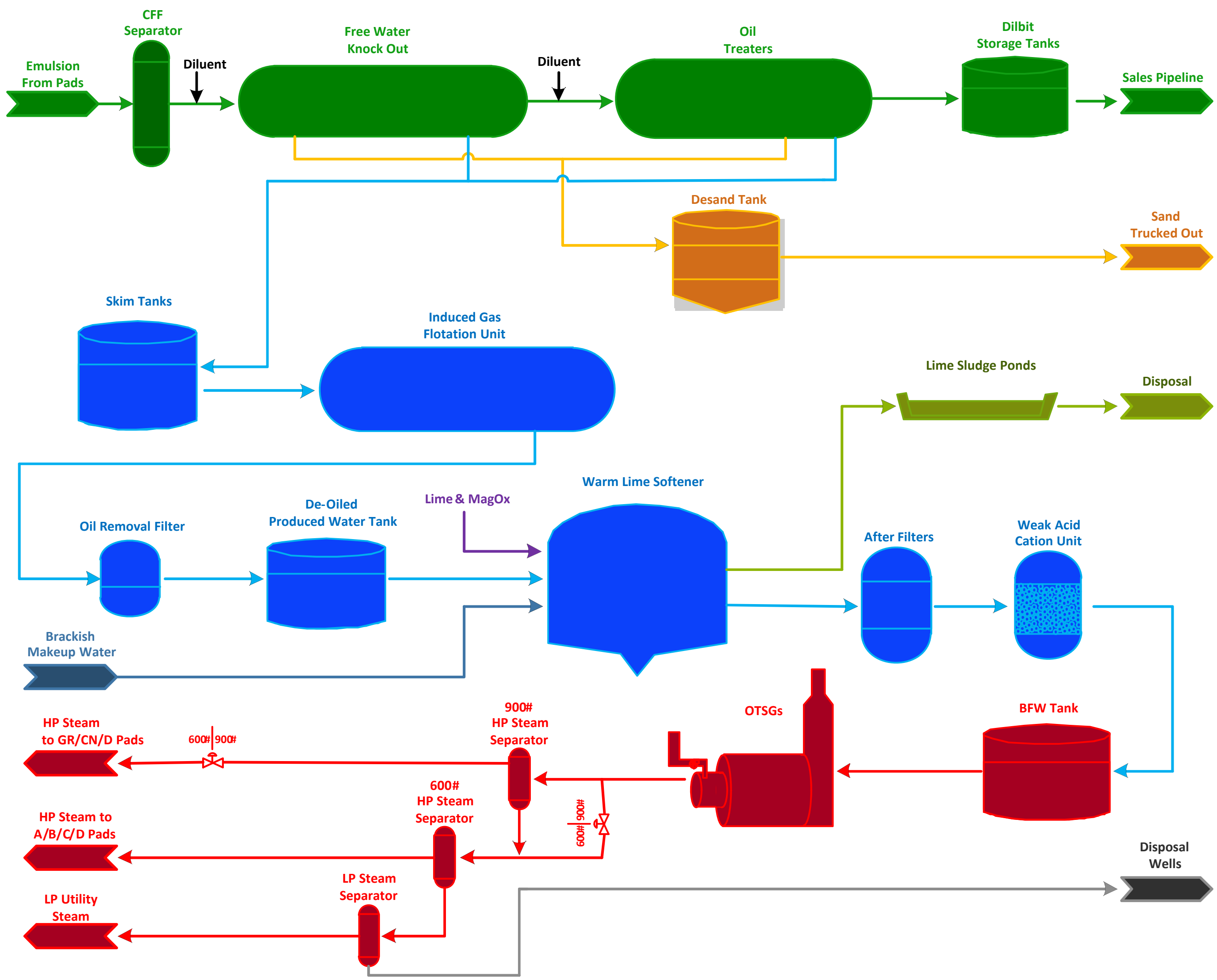
Central Processing Facility (CPF)

Central Field Facility (CFF - Located at Pad B)

Central Process Facility (CPF) Plot Plan



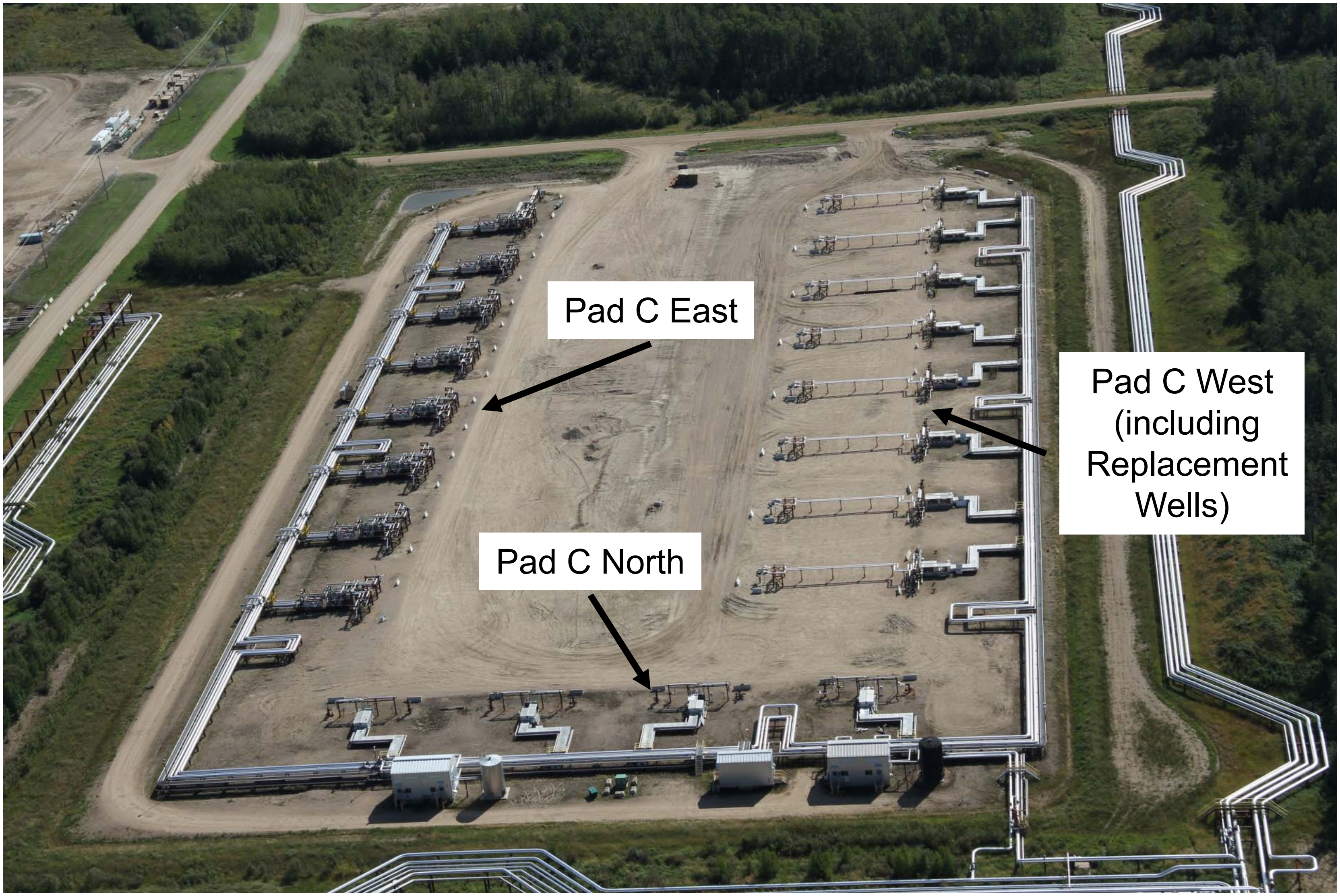
Facility Schematic



Facility Modifications

- Pad C West Replacement Well Commissioning:
  - Commissioned new injectors and original injectors converted to producers in Q4 2016
- Pad D North Commissioning:
  - Surface facility construction & commissioning completed in Q4 2016
- Pad D West Drilling and Construction:
  - Drilling completed Q2 2017
  - Surface facility construction on-going with completion expected in Q4 2017/Q1 2018

Pad C West Replacement Wells



Pads D North and D West

2. Facilities Performance

Operating Issues

Operating issues:

- The de-oiled storage tank had the roof replaced due to corrosion under insulation (CUI)

- Warm Lime Softener (WLS):
  - The WLS scrapper rake failed due to a broken shaft; repaired
  - Found holes in the floor of the WLS while repairing the broken shaft; repaired
  - Root cause analysis is currently ongoing

Operating Limitations

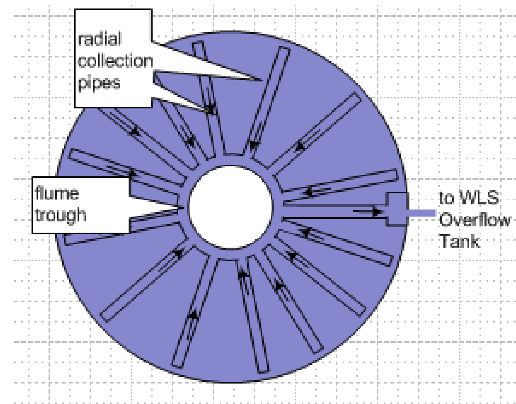
- The WLS rake shaft failure resulted in one month of reduced production (~ 12k bbl/day)

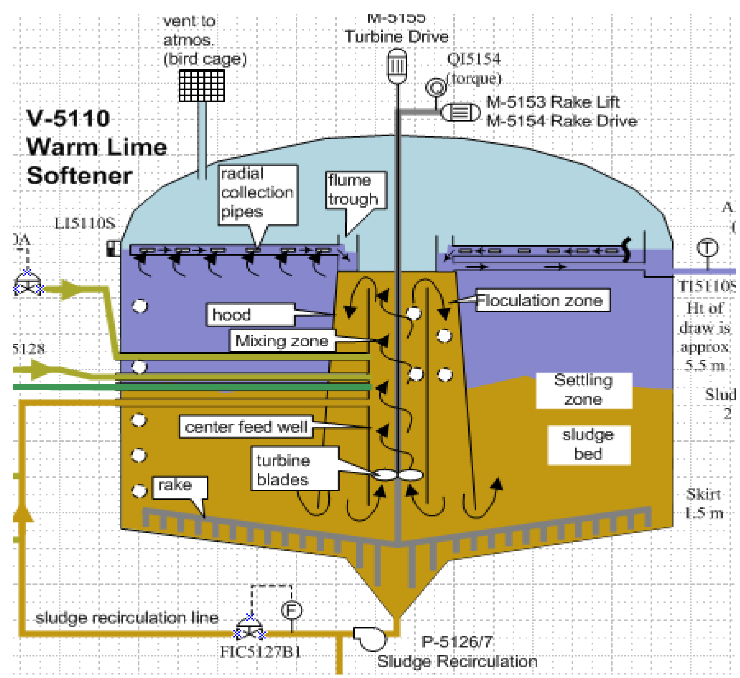
Process Water De-Oiling

- The de-oiling process consists of 2 Skim Tanks (in series), IGF and 2 Oil Removal Filters
- The performance of the de-oiling equipment has been close to specifications; performing well
- De-Oiling KPI's are:
  - FWKO – 1,000 ppm (average 307 ppm)
  - IGF Inlet – 100 ppm (average 129 ppm)
  - IGF Out – 40 ppm (average 90 ppm)
  - ORF Outlet – 20 ppm (average 40 ppm)

Warm Lime Softener (WLS)

- Primary water treatment to produce boiler feedwater
- Feed sources:
  1. De-oiled produced water
  2. Brackish water make-up
  3. Sludge pond water
- Reduces water contaminants:
  1. Hardness - primarily Calcium and Magnesium
  2. Silica - main contaminant due to thermal recovery process
  3. Turbidity - suspended solids
- Produces sludge as waste product - stored in ponds
- Mechanical turbine, rake drives
- Main zones: Mixing, Reaction, Settling
- Produces water effluent with hardness ~20 ppm and silica ~50 ppm





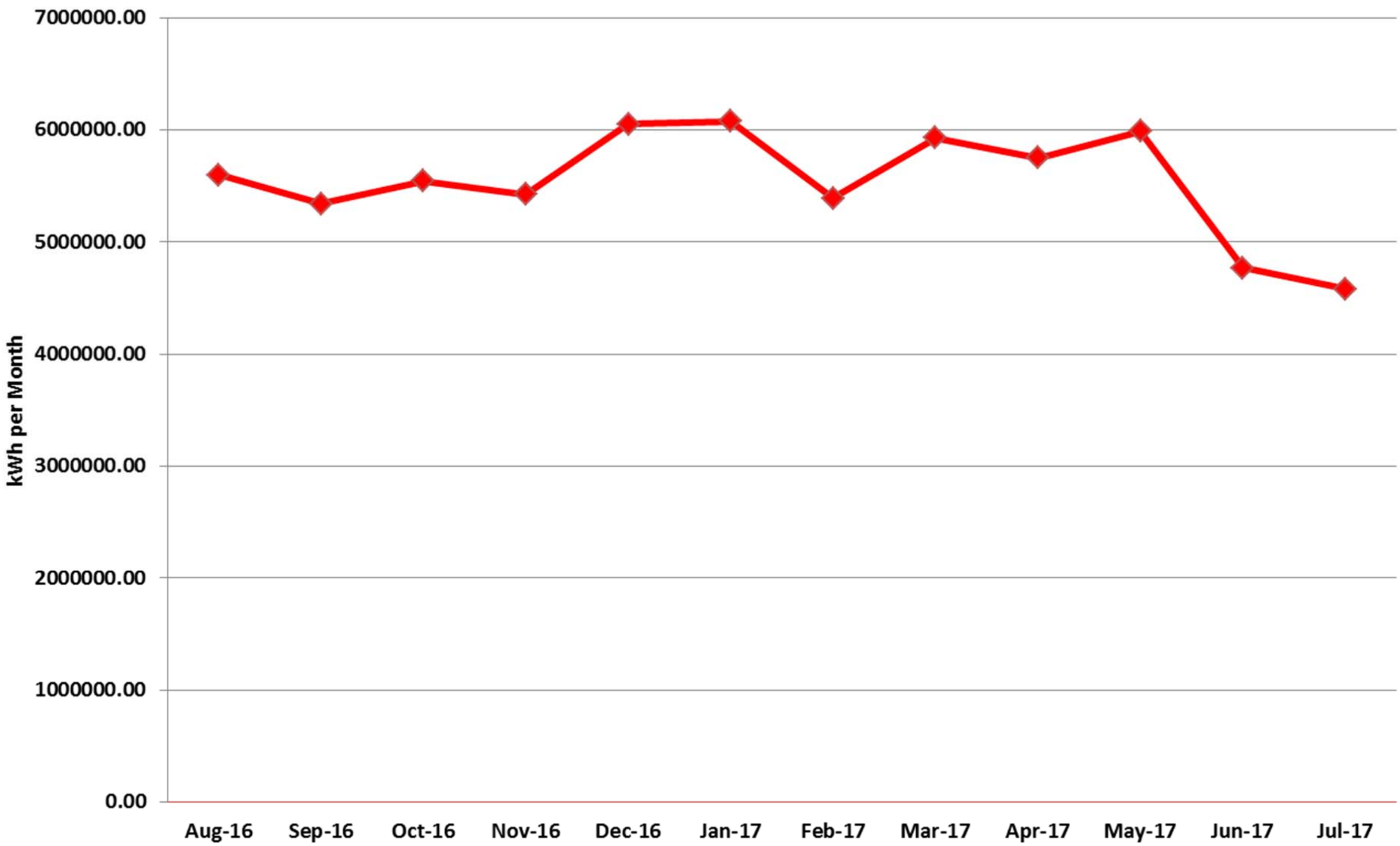
WLS Chemistry / Performance

- Chemistry:
  - Lime – primary hardness control
  - Magnesium Oxide (MagOx) – primary silica reduction
  - Caustic – water pH control, aids softening
  - Sodium Carbonate (soda ash) – permanent hardness removal
  - Polymer – coagulants and flocculants establish sludge bed control

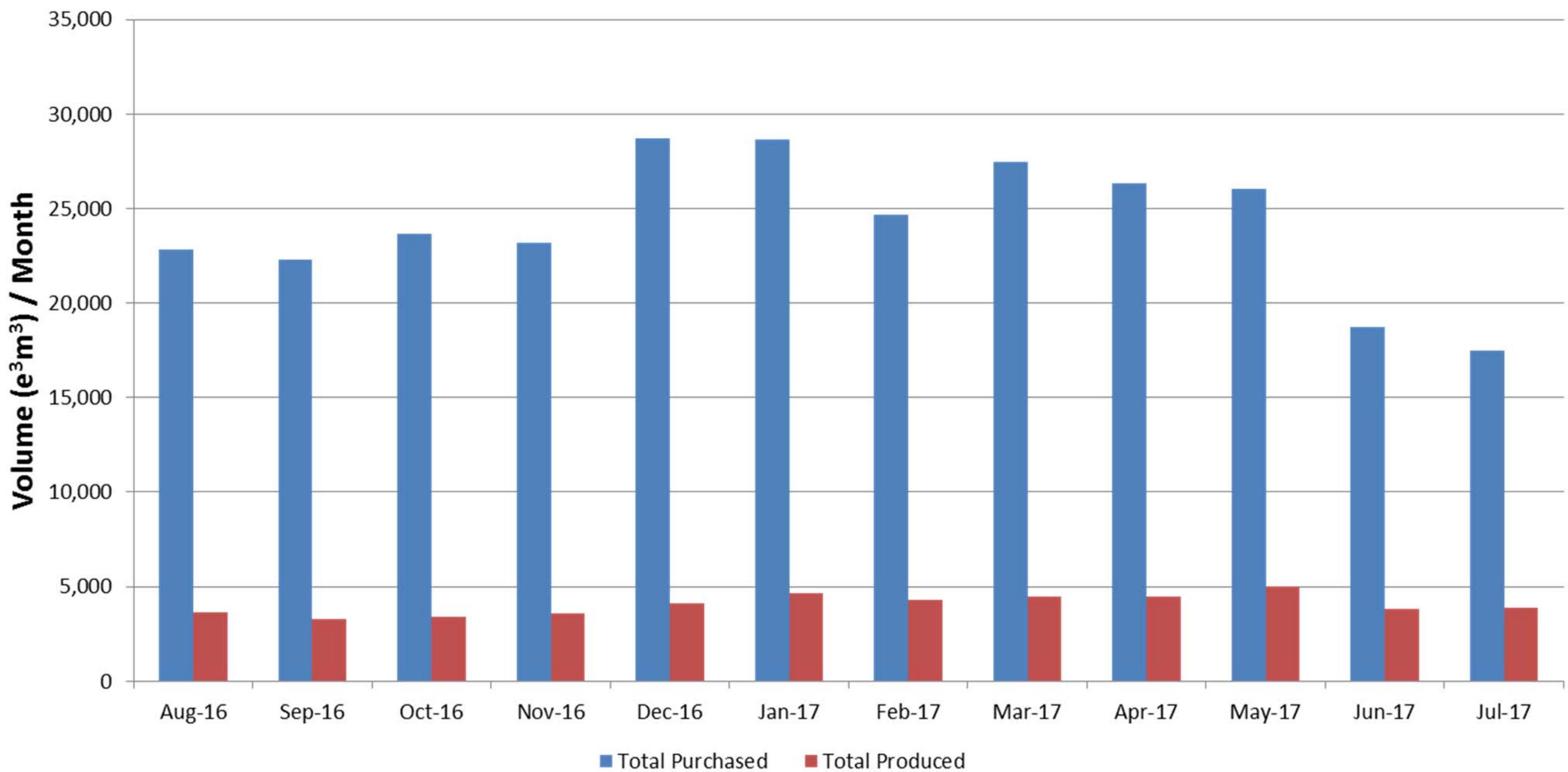
- Performance:
  - The WLS has performed very well to date

- Key KPIs:
  - Soluble Hardness – 25 ppm (average 9 ppm)
  - Silica – 50 ppm (average 45 ppm)
  - Turbidity – 20 NTU (average 17 NTU)

Power Consumption



Gas Usage

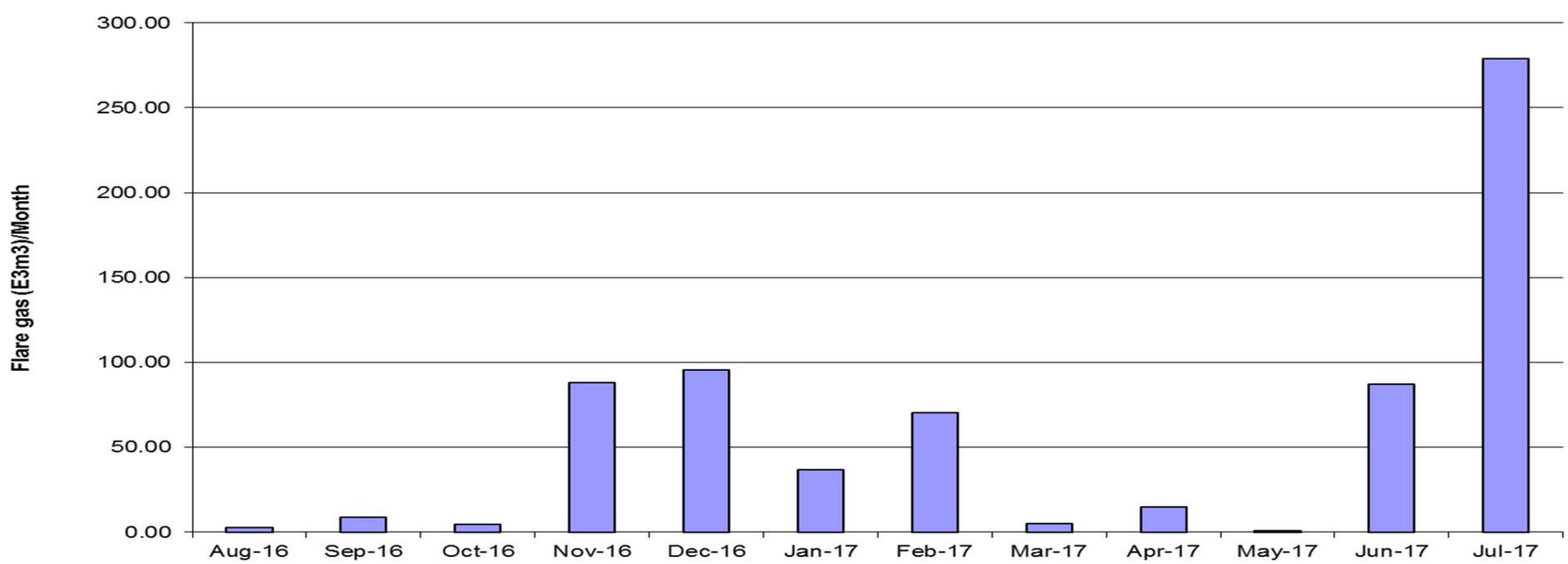


35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Volume (e^3m^3) / Month
Aug-16
Sep-16
Oct-16
Nov-16
Dec-16
Jan-17
Feb-17
Mar-17
Apr-17
May-17
Jun-17
Jul-17
Total Purchased
Total Produced

Flaring and Venting

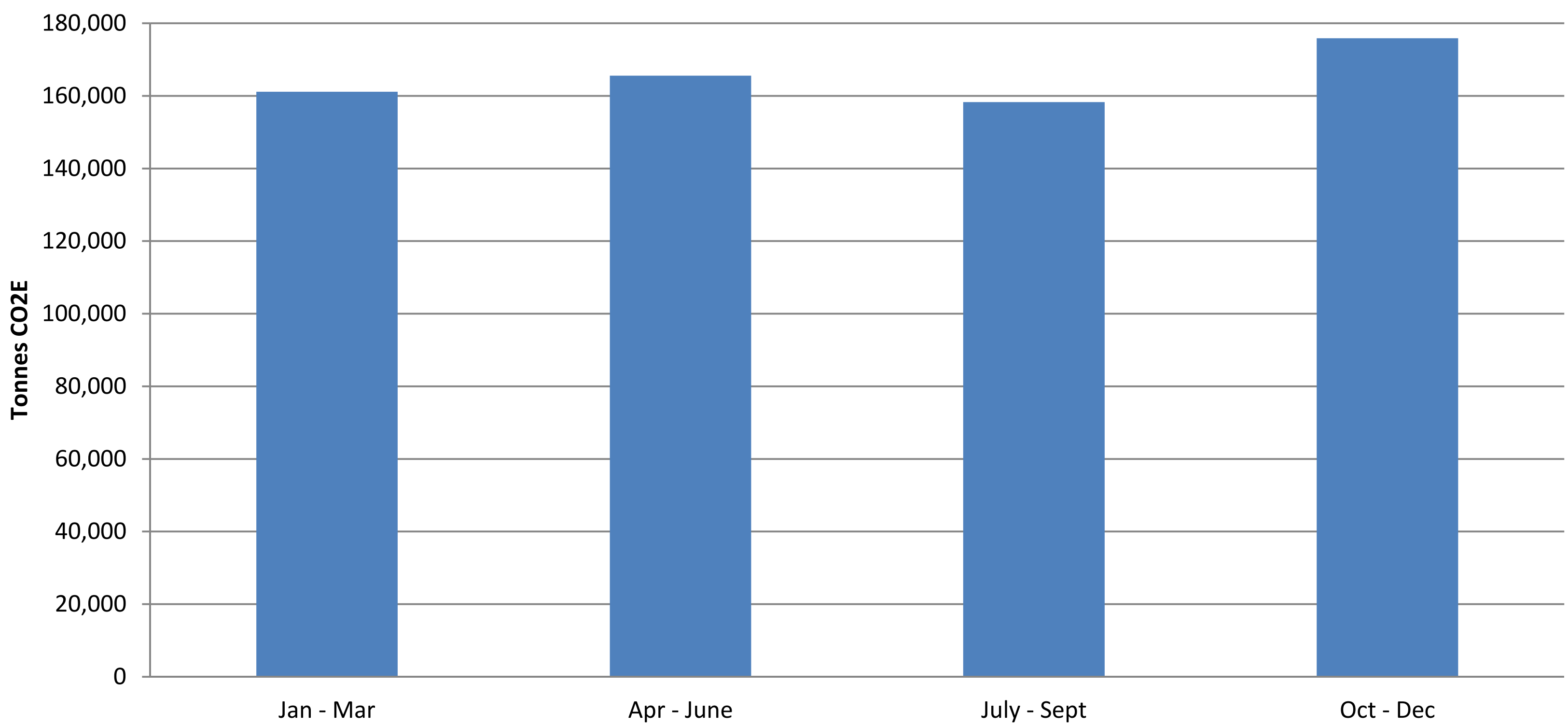
- There were 5 flaring events that were either over 4 hours in duration or over a volume of 30,000 m^3
- One venting notification March 21, 2017 at well, 1F1/11-30-064-04 W4M (brackish)

Date	Gas flare (E3m3)
Aug-16	2.89
Sep-16	8.59
Oct-16	4.70
Nov-16	87.90
Dec-16	95.66
Jan-17	36.73
Feb-17	70.45
Mar-17	5.02
Apr-17	15.01
May-17	0.86
Jun-17	87.03
Jul-17	279.05



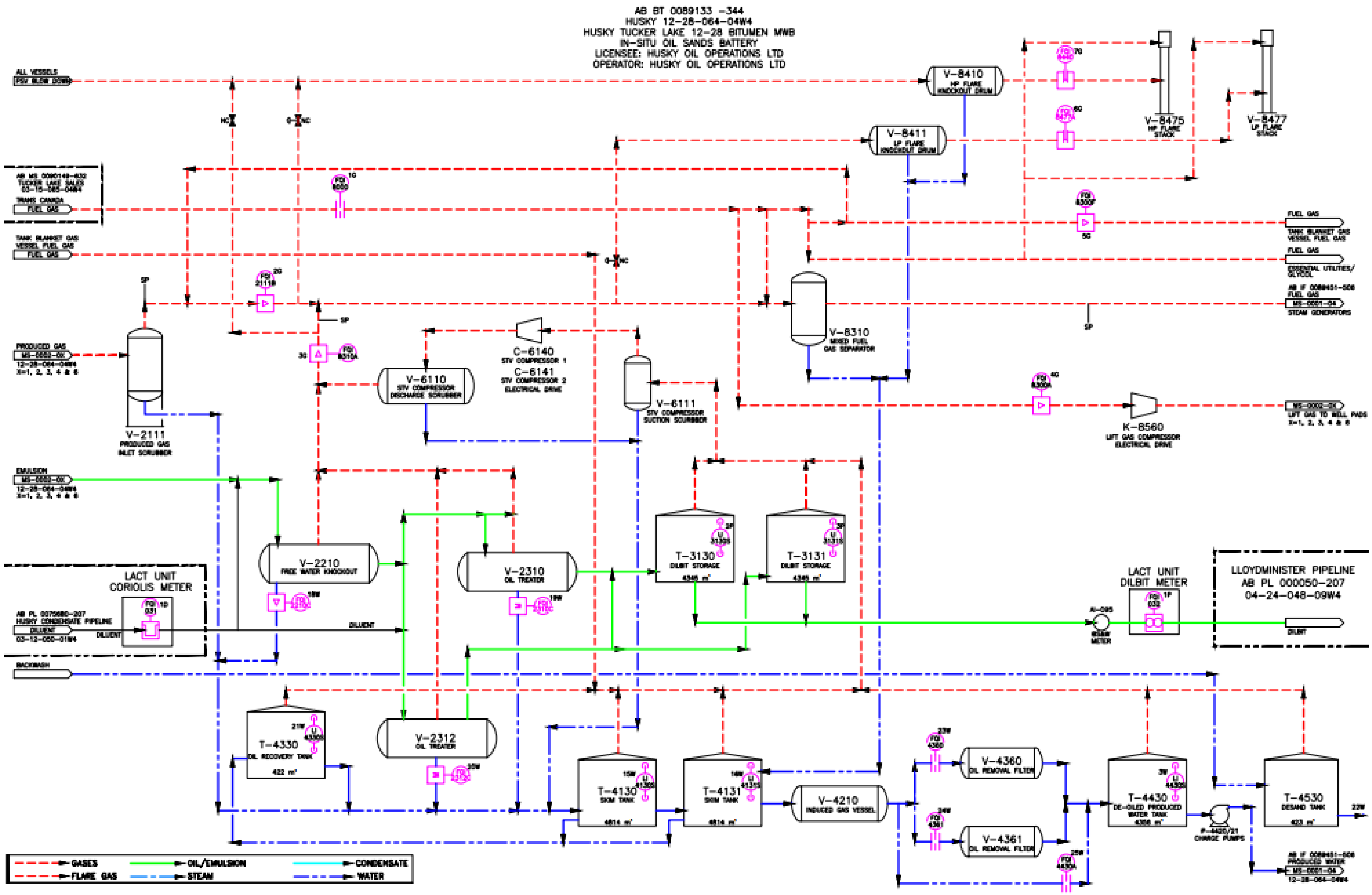
Green House Gas (GHG)

- Emission sources considered include stationary combustion associated with steam generators and glycol heaters, flaring, venting and fugitive emissions
- 660,886.38 tonnes of Carbon Dioxide Equivalent were emitted in 2016 (information taken from the Tucker Thermal 2016 Compliance report submitted under the Specified Gas Emitters Regulation)
- 252,241 emission performance credits generated

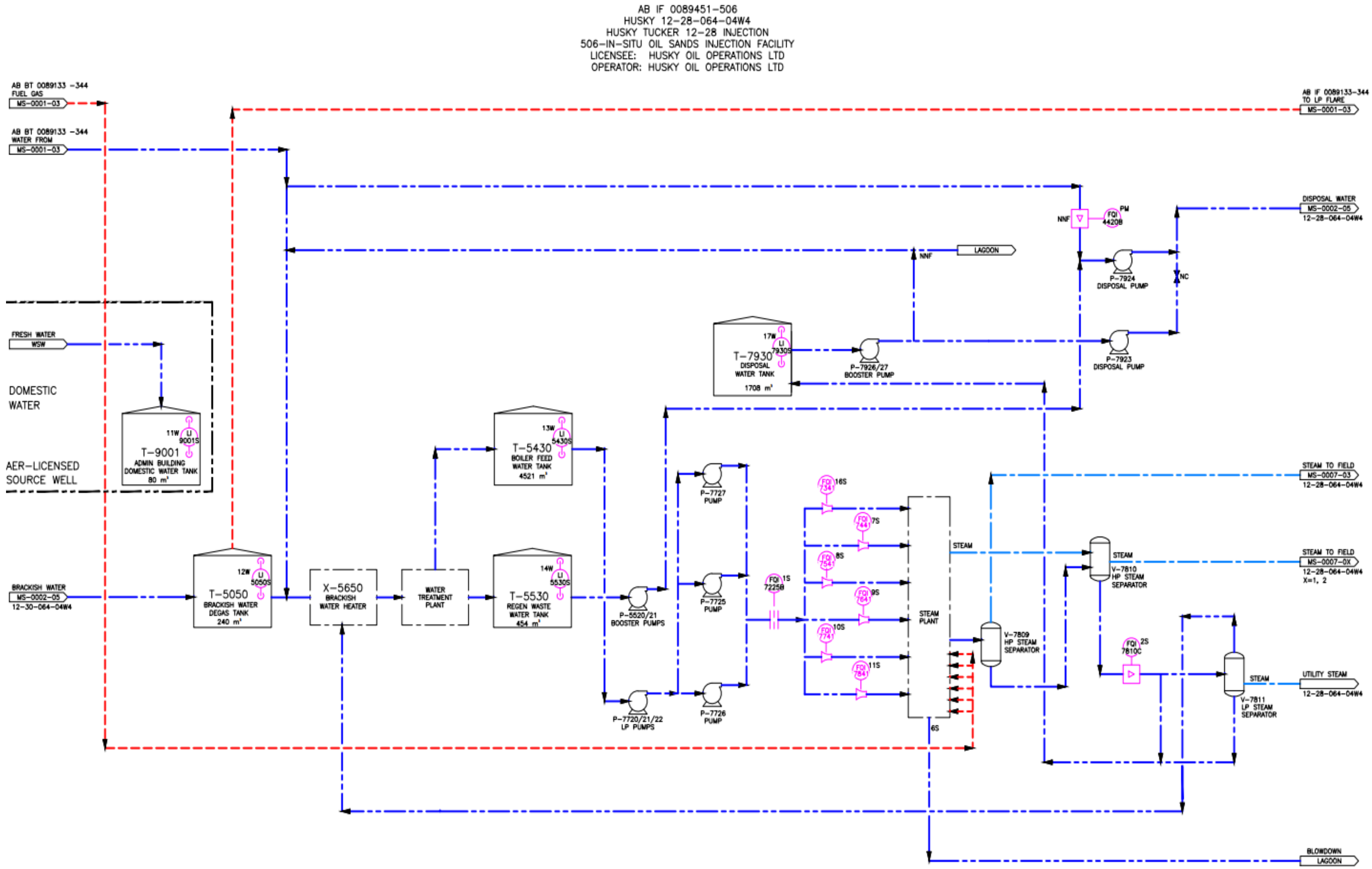


3. Measurement, Accounting and Reporting

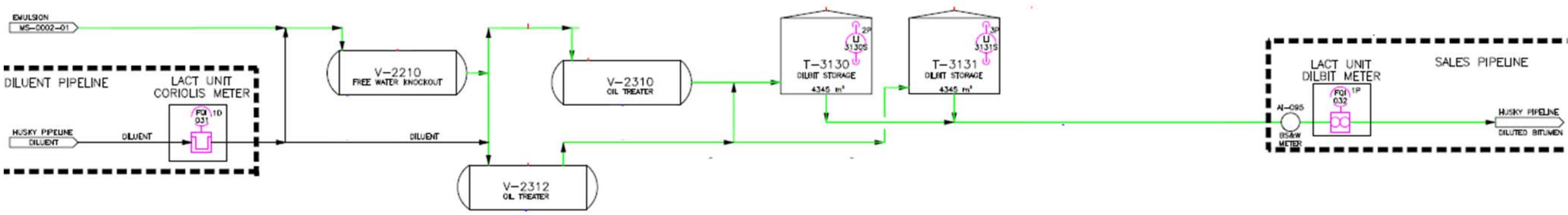
Battery Schematic - AB BT 0089133-344



Injection Facility Schematic - AB IF 0089451-506



Measurement and Reporting – Oil



OIL & DILUENT METERING

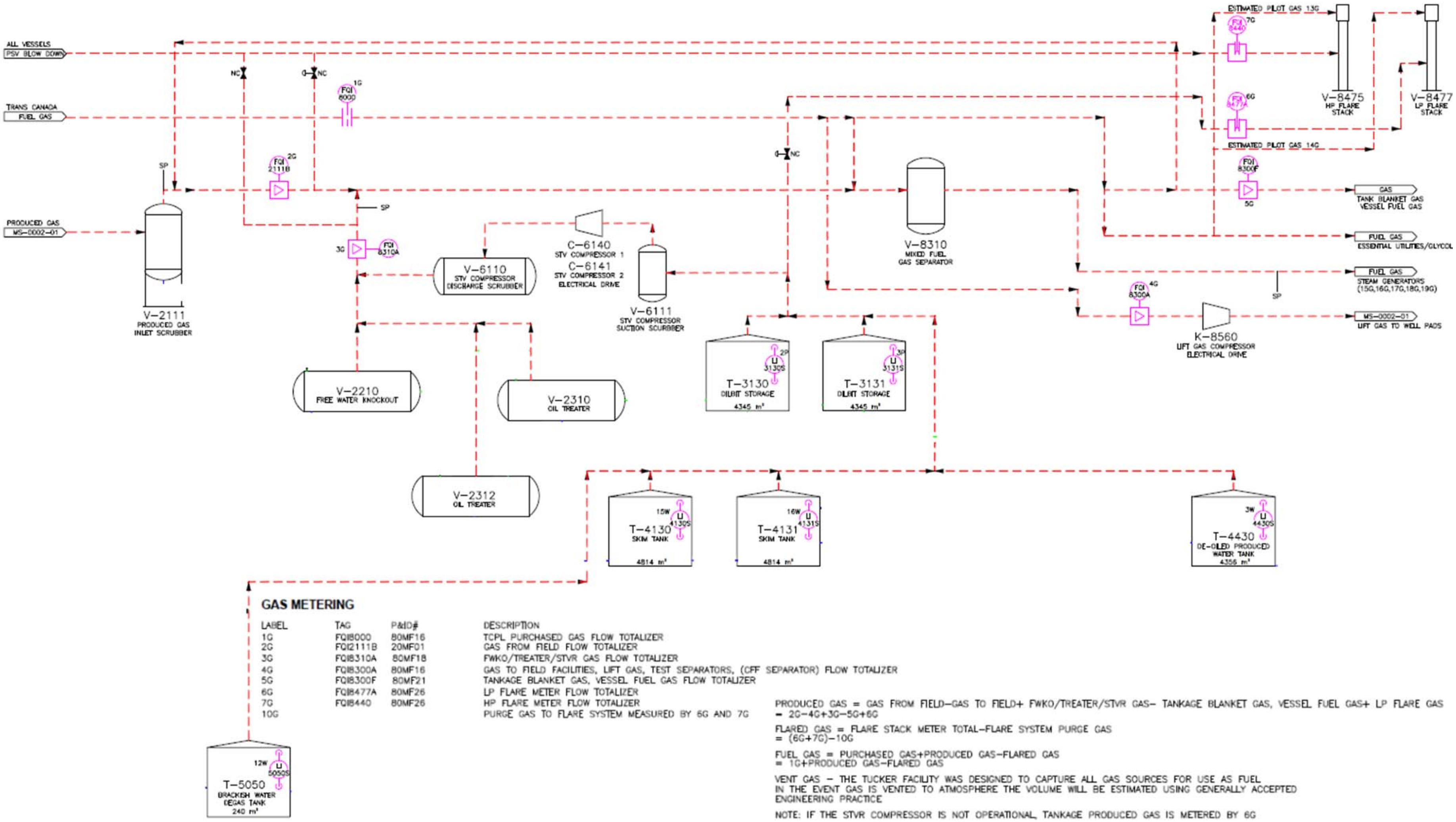
LABEL	TAG	P&ID#	DESCRIPTION
1P	FQI032		LACT DILBIT SALES FLOW TOTALIZER
2P	LI3130S	30MF02	DILBIT STORAGE TANK VOLUME
3P	LI3131S	30MF03	DILBIT STORAGE TANK VOLUME
1D	FQI031	30MF01	DILUENT TO PLANT FLOW TOTALIZER
2D			DILUENT FLASH VOLUME LOSS (CALCULATED)
3D			DILUENT SHRINKAGE VOLUME (CALCULATED)

OIL PRODUCTION TOTAL – (PIPELINE METER ± INVENTORY CHANGE)–NET DILUENT VOLUME ADDED+(SHRINKAGE AND FLASH VOLUME LOSS)
(1P*(1–(AI–095/100)))+(2P+3P)–1D+(2D+3D)

NOTE: OIL VOLUMES REPORTED TO THE AER ARE CORRECTED FOR SHRINKAGE AND FLASH IN ACCORDANCE WITH DIRECTIVE 17 SECTION 14.3 BY PRODUCTION ACCOUNTING

NOTE: AI–095 MEASURES SALES BS&W

Measurement and Reporting – Produced Gas



GAS METERING

LABEL	TAG	P&ID#	DESCRIPTION
1G	FQI8000	80MF16	TCPL PURCHASED GAS FLOW TOTALIZER
2G	FQI2111B	20MF01	GAS FROM FIELD FLOW TOTALIZER
3G	FQI8310A	80MF18	FWKO/TREATER/STVR GAS FLOW TOTALIZER
4G	FQI8300A	80MF16	GAS TO FIELD FACILITIES, LIFT GAS, TEST SEPARATORS, (CFF SEPARATOR) FLOW TOTALIZER
5G	FQI8300F	80MF21	TANKAGE BLANKET GAS, VESSEL FUEL GAS FLOW TOTALIZER
6G	FQI8477A	80MF26	LP FLARE METER FLOW TOTALIZER
7G	FQI8440	80MF26	HP FLARE METER FLOW TOTALIZER
10G			PURGE GAS TO FLARE SYSTEM MEASURED BY 6G AND 7G

PRODUCED GAS = GAS FROM FIELD–GAS TO FIELD+ FWKO/TREATER/STVR GAS– TANKAGE BLANKET GAS, VESSEL FUEL GAS+ LP FLARE GAS
= 2G–4G+3G–5G+6G

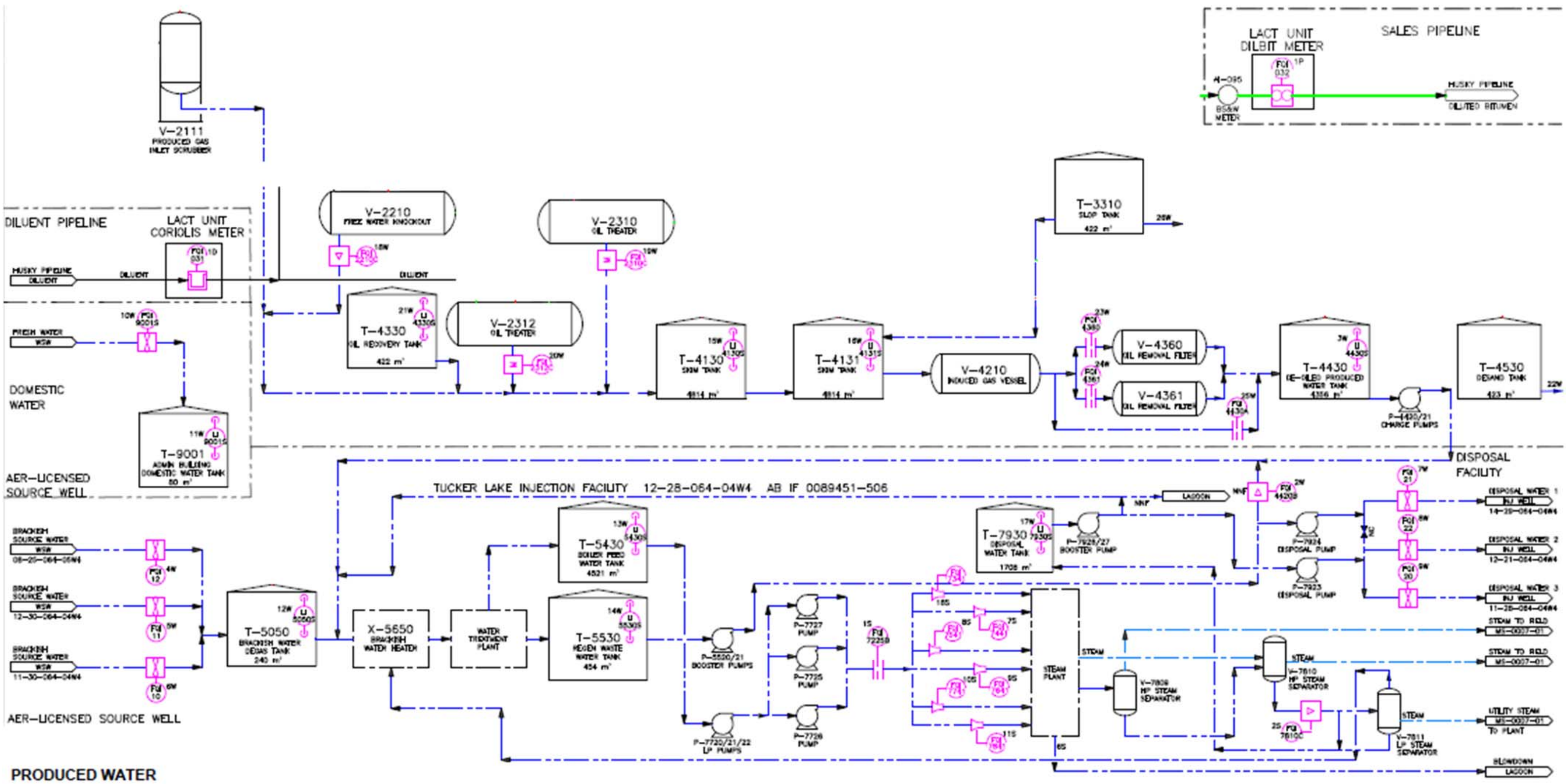
FLARED GAS = FLARE STACK METER TOTAL–FLARE SYSTEM PURGE GAS
= (6G+7G)–10G

FUEL GAS = PURCHASED GAS+PRODUCED GAS–FLARED GAS
= 1G+PRODUCED GAS–FLARED GAS

VENT GAS – THE TUCKER FACILITY WAS DESIGNED TO CAPTURE ALL GAS SOURCES FOR USE AS FUEL
IN THE EVENT GAS IS VENTED TO ATMOSPHERE THE VOLUME WILL BE ESTIMATED USING GENERALLY ACCEPTED ENGINEERING PRACTICE

NOTE: IF THE STVR COMPRESSOR IS NOT OPERATIONAL, TANKAGE PRODUCED GAS IS METERED BY 6G

Measurement and Reporting – Water and Steam



PRODUCED WATER

METHOD 1 – PRIMARY PRODUCED WATER MEASUREMENT
=FREE WATER KNOCKOUT WATER + OIL TREATER PRODUCED WATER + WATER PIPELINED OUT = 18W + 19W+ 20W + (1P * (AI–095/100))

* THE METHOD 1 – PRIMARY PRODUCED WATER SHOULD BE LISTED FIRST UNDER THE TITLE PRODUCED WATER. THE EXISTING PRIMARY PRODUCED WATER MEASUREMENT WILL NOW BECOME THE SECONDARY PRODUCED WATER MEASUREMENT. THE EXISTING SECONDARY PRODUCED WATER MEASUREMENT WILL BE REMOVED.

METHOD 2 – SECONDARY PRODUCED WATER MEASUREMENT
=PRODUCED WATER TO ORF ± CHANGE IN PRODUCED WATER INVENTORY + WATER TRUCKED OUT + WATER PIPELINED OUT
=(23W+24W+25W) ± CHANGE IN PRODUCED WATER INVENTORY (15W+16W+21W) + 22W + 26W + (1P*(AI–095/100))

STEAM TO FIELD

METHOD 1 – PRIMARY STEAM TO FIELD
= BOILER FEED WATER–STEAM SEPARATOR CONDENSATE–BLOW DOWN TO LAGOON
= 1S–2S–6S

METHOD 2 – SECONDARY STEAM TO FIELD
= Σ(BOILER FEED TO GENERATORS – STEAM SEPARATOR CONDENSATE – BLOWDOWN TO LAGOON)
= (7S + 8S + 9S + 10S + 11S + 16S) – 2S – 6S

Measurement and Reporting – Pad D North Testing

LIFT GAS FROM
MS-0001-01
12-28-064-04W4

AB BT 0089133 — WELL PAD D EAST

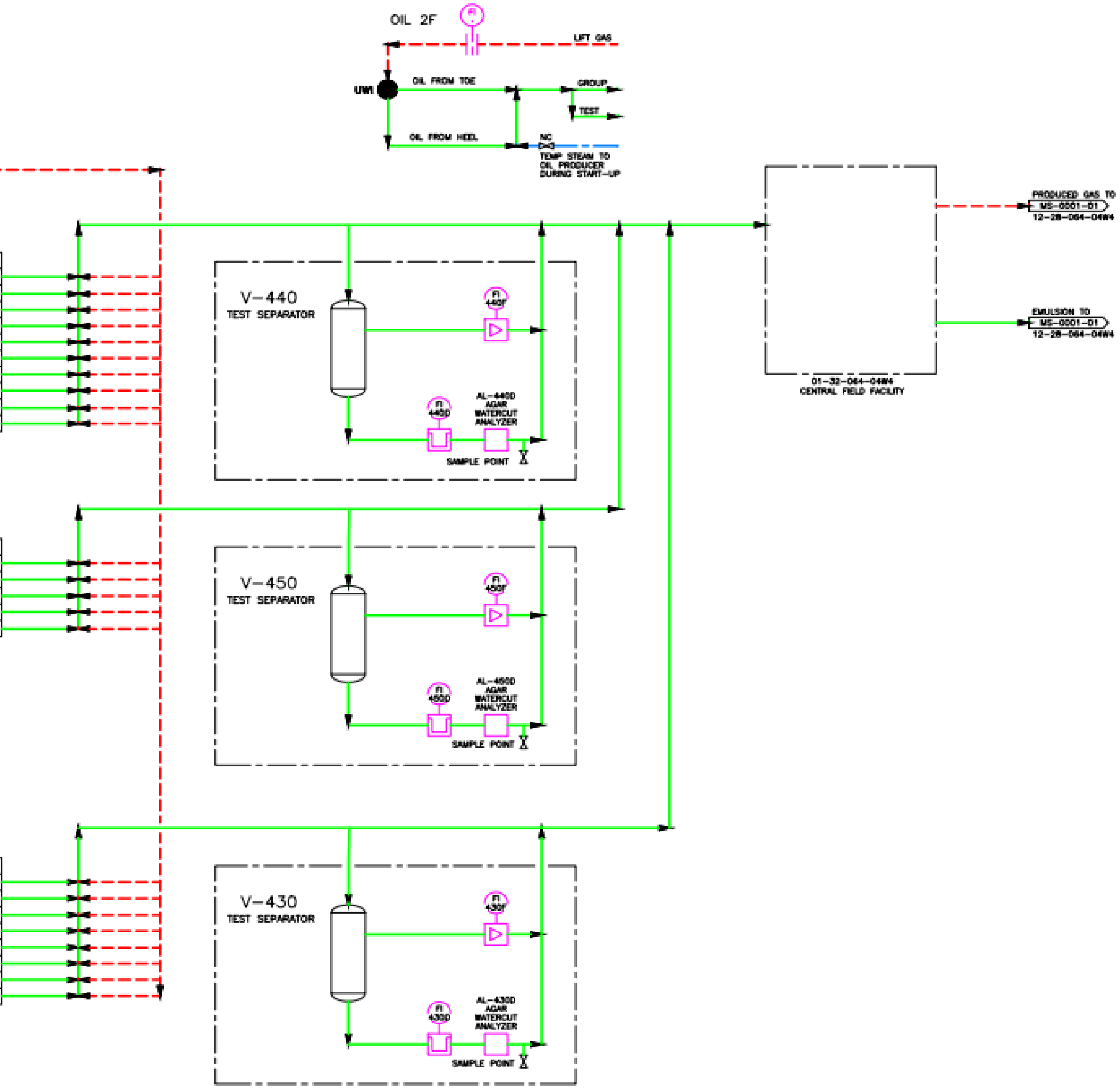
WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
D24P	111/07-28-064-04W4/00	07-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-424N	FIC-424P
D25P	112/07-28-064-04W4/00	07-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-425N	FIC-425P
D26P	113/07-28-064-04W4/00	07-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-426N	FIC-426P
D27P	114/07-28-064-04W4/00	07-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-427N	FIC-427P
D28P	115/07-28-064-04W4/00	07-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-428N	FIC-428P
D29P	116/07-28-064-04W4/00	07-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-429N	FIC-429P
D30P	104/02-28-064-04W4/00	02-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-430N	FIC-430P
D31P	105/02-28-064-04W4/00	02-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-431N	FIC-431P
D32P	106/02-28-064-04W4/00	02-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-432N	FIC-432P
D33P	107/02-28-064-04W4/00	02-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-433N	FIC-433P

AB BT 0089133 — WELL PAD D EAST

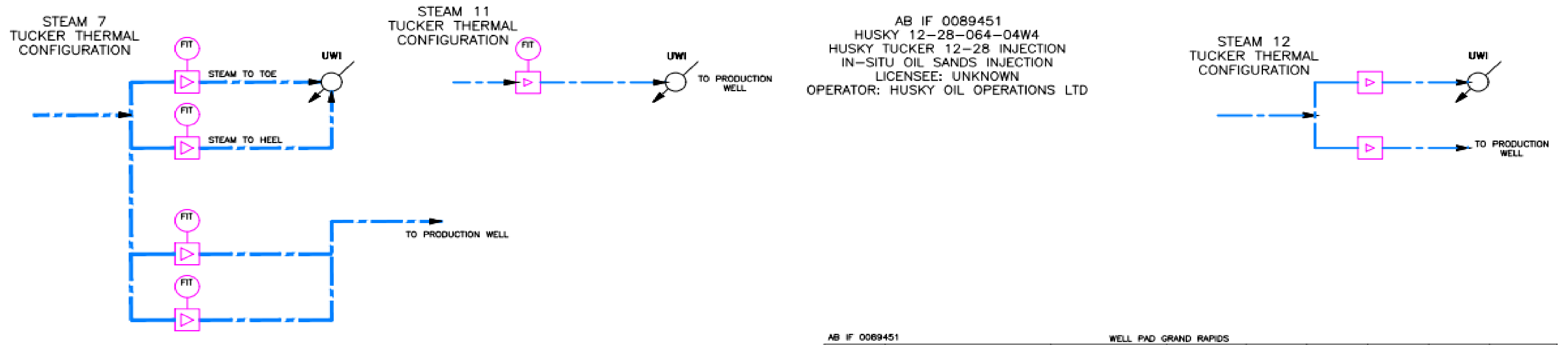
WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
D34P	112/02-28-064-04W4/00	02-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-434N	FIC-434P
D35P	111/02-28-064-04W4/00	02-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-435N	FIC-435P
D36P	115/02-28-064-04W4/00	02-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-436N	FIC-436P
D37P	108/02-28-064-04W4/00	02-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-437N	FIC-437P
D38P	109/02-28-064-04W4/00	02-28-064-04W4	HUSKY	OIL 2F	PRODUCING	–	FIC-438N	FIC-438P

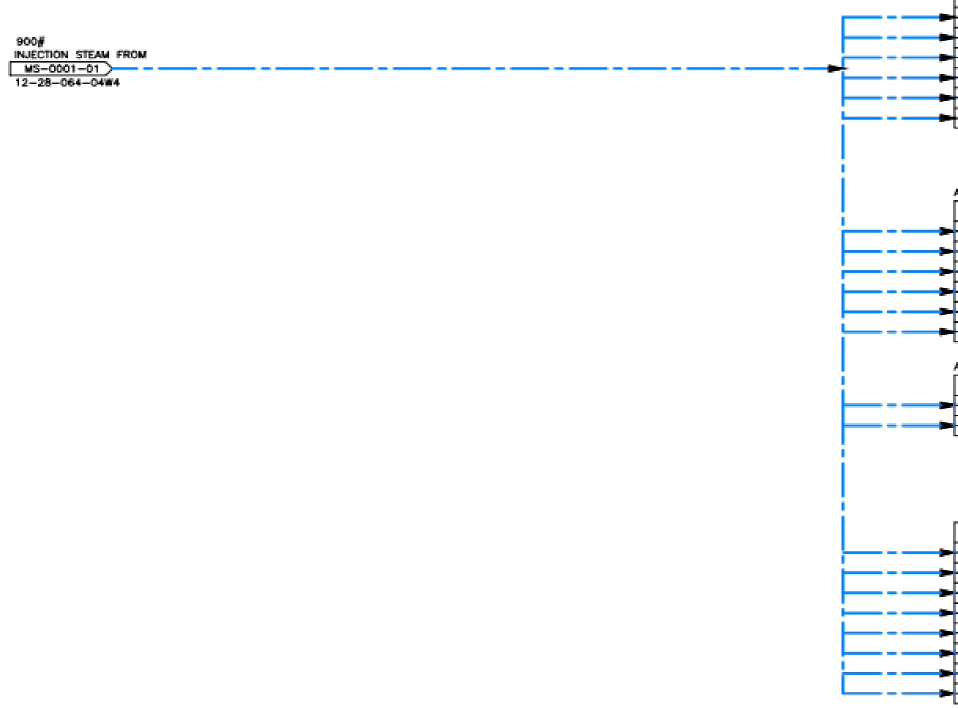
WELL PAD D NORTH

WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
D16P	104/16-29-064-04W4/00	08-29-064-04W4	HUSKY	OIL 2F	CIRCULATION	–	FIC-416N	FIC-416P
D17P	105/16-29-064-04W4/00	08-29-064-04W4	HUSKY	OIL 2F	CIRCULATION	–	FIC-417N	FIC-417P
D18P	107/16-29-064-04W4/00	08-29-064-04W4	HUSKY	OIL 2F	CIRCULATION	–	FIC-418N	FIC-418P
D19P	109/16-29-064-04W4/00	08-29-064-04W4	HUSKY	OIL 2F	CIRCULATION	–	FIC-419N	FIC-419P
D20P	111/16-29-064-04W4/00	08-29-064-04W4	HUSKY	OIL 2F	CIRCULATION	–	FIC-420N	FIC-420P
D21P	113/16-29-064-04W4/00	08-29-064-04W4	HUSKY	OIL 2F	CIRCULATION	–	FIC-421N	FIC-421P
D22P	115/16-29-064-04W4/00	08-29-064-04W4	HUSKY	OIL 2F	CIRCULATION	–	FIC-422N	FIC-422P
D23P	117/16-29-064-04W4/00	08-29-064-04W4	HUSKY	OIL 2F	CIRCULATION	–	FIC-423N	FIC-423P



Measurement and Reporting – Steam Injection





AB IF 0089451

WELL PAD GRAND RAPIDS

WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
GA05S	107/15–32–064–04W4/00	07–32–064–04W4	HUSKY	STEAM 7	PRODUCING	–	FIC–505H	FIC–505J
GA06S	108/15–32–064–04W4/00	07–32–064–04W4	HUSKY	STEAM 7	PRODUCING	–	FIC–506H	FIC–506J
GA01S	118/16–32–064–04W4/00	07–32–064–04W4	HUSKY	STEAM 7	PRODUCING	–	FIC–501H	FIC–501J
GA02S	123/16–32–064–04W4/00	07–32–064–04W4	HUSKY	STEAM 7	PRODUCING	–	FIC–502H	FIC–502J
GA03S	124/16–32–064–04W4/00	07–32–064–04W4	HUSKY	STEAM 7	PRODUCING	–	FIC–503H	FIC–503J
GA04S	125/16–32–064–04W4/00	07–32–064–04W4	HUSKY	STEAM 7	PRODUCING	–	FIC–504H	FIC–504J

AB IF 0089451

WELL PAD COLONY

WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
CN2	102/13–16–064–04W4/00	05–21–064–04W4	HUSKY	STEAM 12	PRODUCTION	–	FIC–602H	–
CN4	114/16–17–064–04W4/00	05–21–064–04W4	HUSKY	STEAM 12	PRODUCTION	–	FIC–604H	–
CN6	100/16–17–064–04W4/00	05–21–064–04W4	HUSKY	STEAM 12	PRODUCTION	–	FIC–606H	–
CN8	102/16–17–064–04W4/00	05–21–064–04W4	HUSKY	STEAM 12	PRODUCTION	–	FIC–608H	–
CN10	103/16–17–064–04W4/00	05–21–064–04W4	HUSKY	STEAM 12	PRODUCTION	–	FIC–610H	–
CN12	113/16–17–064–04W4/00	05–21–064–04W4	HUSKY	STEAM 12	PRODUCTION	–	FIC–612H	–

AB IF 0089451

WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
CN7	108/16–17–064–04W4/00	12–21–064–04W4	HUSKY	STEAM 11	CIRCULATION	–	FIC–607G	–
CN9	109/16–17–064–04W4/00	12–21–064–04W4	HUSKY	STEAM 11	CIRCULATION	–	FIC–609G	–

WELL PAD D NORTH

WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
D16S	103/16–29–064–04W4/00	08–29–064–04W4	HUSKY	STEAM 12	CIRCULATION	–	FIC–416H	–
D17S	106/16–29–064–04W4/00	08–29–064–04W4	HUSKY	STEAM 12	CIRCULATION	–	FIC–417H	–
D18S	108/16–29–064–04W4/00	08–29–064–04W4	HUSKY	STEAM 12	CIRCULATION	–	FIC–418H	–
D19S	110/16–29–064–04W4/00	08–29–064–04W4	HUSKY	STEAM 12	CIRCULATION	–	FIC–419H	–
D20S	112/16–29–064–04W4/00	08–29–064–04W4	HUSKY	STEAM 12	CIRCULATION	–	FIC–420H	–
D21S	114/16–29–064–04W4/00	08–29–064–04W4	HUSKY	STEAM 12	CIRCULATION	–	FIC–421H	–
D22S	116/16–29–064–04W4/00	08–29–064–04W4	HUSKY	STEAM 12	CIRCULATION	–	FIC–422H	–
D23S	102/16–29–064–04W4/00	08–29–064–04W4	HUSKY	STEAM 12	CIRCULATION	–	FIC–423H	–

Estimating Well Production

- Oil and Water Estimated by well test:
  - Battery level measurement prorated to wells based on the estimates
  - Correction factor applied to calculated well steam fraction volume

- Three Test Separator Designs (well tests):
  1. Blow-Case (Pads A Original, B, C East, C West):
     - Load-cell or level
     - Vortex for steam + natural gas
     - AGAR water-cut analyzer
  2. Conventional (Pads B North, A Infill & Replacement Wells, GA, D East, D North):
     - Coriolis meter for liquid
     - Vortex for steam + natural gas
     - AGAR water-cut analyzer
  3. Horizontal (Pad CN)
     - Coriolis meter for liquid
     - Orifice plate for steam + natural gas
     - Phase Dynamics water-cut analyzer

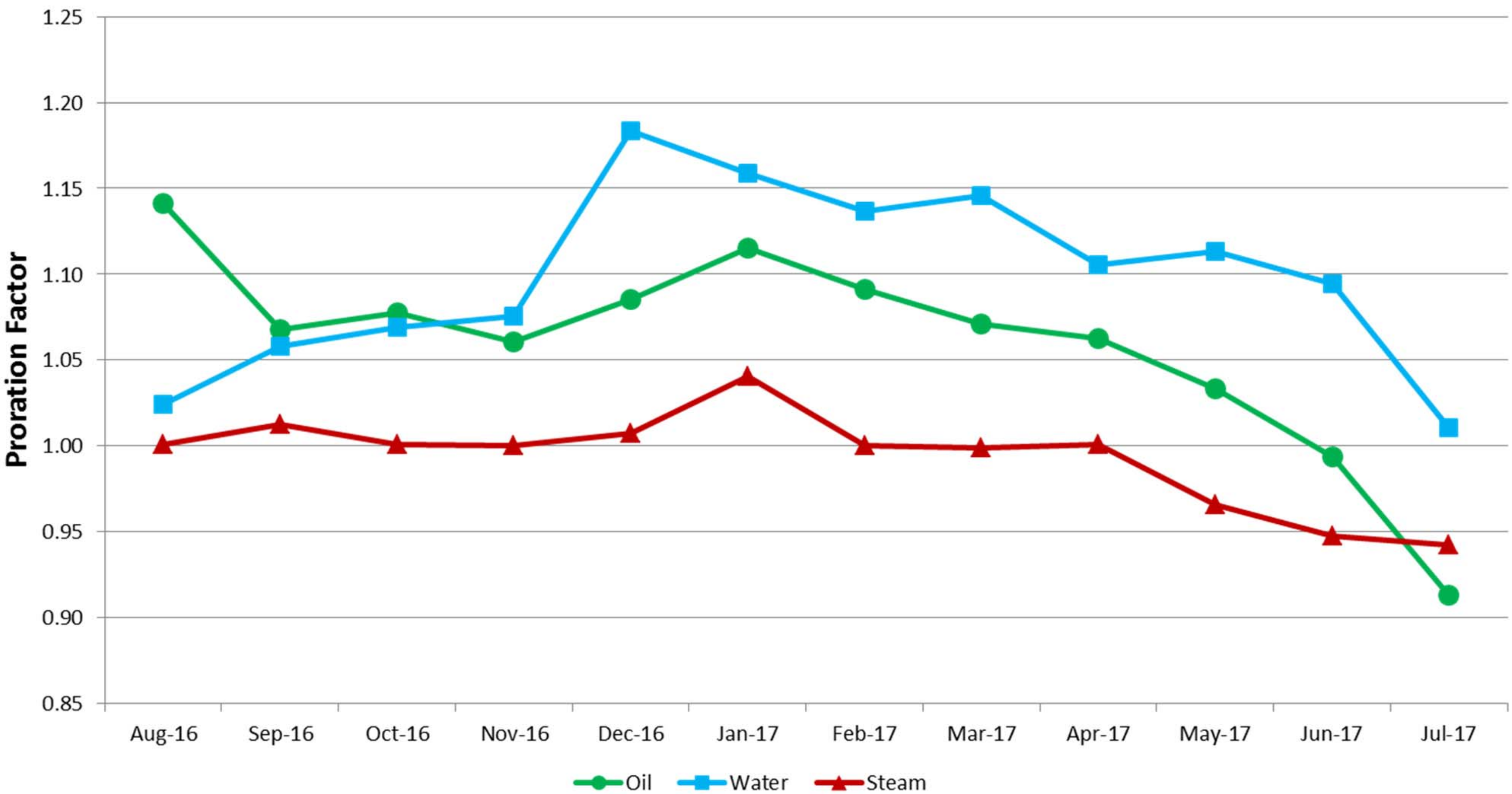
- Steam fraction calculated (from P_{sat} / P_{meas}) for all three designs

- Gas Measured at the Battery (proration = 1):
  - GOR for August 1, 2016 to July 31, 2017 = 43.3 m^3/m^3

Water Balance

- Steam Injection:
  - Vortex meters on each well toe and heel
  - Total steam to field measured at the battery
  - Steam Proration = 0.993 m^3/m^3
- Water Proration Factors (see next slide):
  - Average 12-Month Rolling Proration Factors
    - Water = 1.098
    - Oil = 1.059
- Water / Steam Meter Calibrations:
  - Metering equipment inspected / calibrated annually
  - Annual well steam injection meters inspection as per Directive 017
  - AGAR water cut analyzer calibration program as per Directive 017
  - MARP updated to include all new measurement meters and changes
- Metering Accuracy:
  - Accounting meters meets requirements as per Directive 017 single point measurement accuracy

Estimating Well Production – Proration Factors



Well Test Averages

Test Separator	Well Group	Average Test Duration (hours/test/month)	Average Test Frequency (well/month)
V-151/2	A1-8	4.7	14.0
V-251/2	B1-12	4.7	9.3
V-351/2	C1-9	4.6	10.0
V-391/2	C13-20	4.2	15.7
V-170	A9-20	5.5	10.6
V-171	A21-24	8.7	15.8
V-213A	B9EP	22.6	29.4
V-214A	B10EP	23.0	29.1
V-215A	B11EP	24.8	34.5
V-540	GR01-06	6.8	17.8
V-430	D16-23	6.3	7.6
V-440	D24-33	5.4	12.5
V-450	D34-38	6.9	14.0
V-630	CN2,4,6,8,10,12	16.1	7.1

Solvents and Condensable Gas

- Bitumen production accounts for diluent flash and volumetric shrinkage
- No solvent injection to reservoir
- There is no non-condensable gas injection

Measurement Initiatives – Continuous Improvement

- MARP updated February 28, 2017

- No technical issues identified with measurement equipment

- Implemented improvements:
  - Detailed review of measurement schematics to include Pad D North test separator and steam injection

- Future opportunities:
  - Pad CN Phase Dynamics individual well characteristics set-up
  - Test separators overhead gas meter sizing verification
  - Detailed review of measurement schematics to include Pads D West and D East test separator and steam injection

4. Water Production, Injection and Uses

Brackish Water

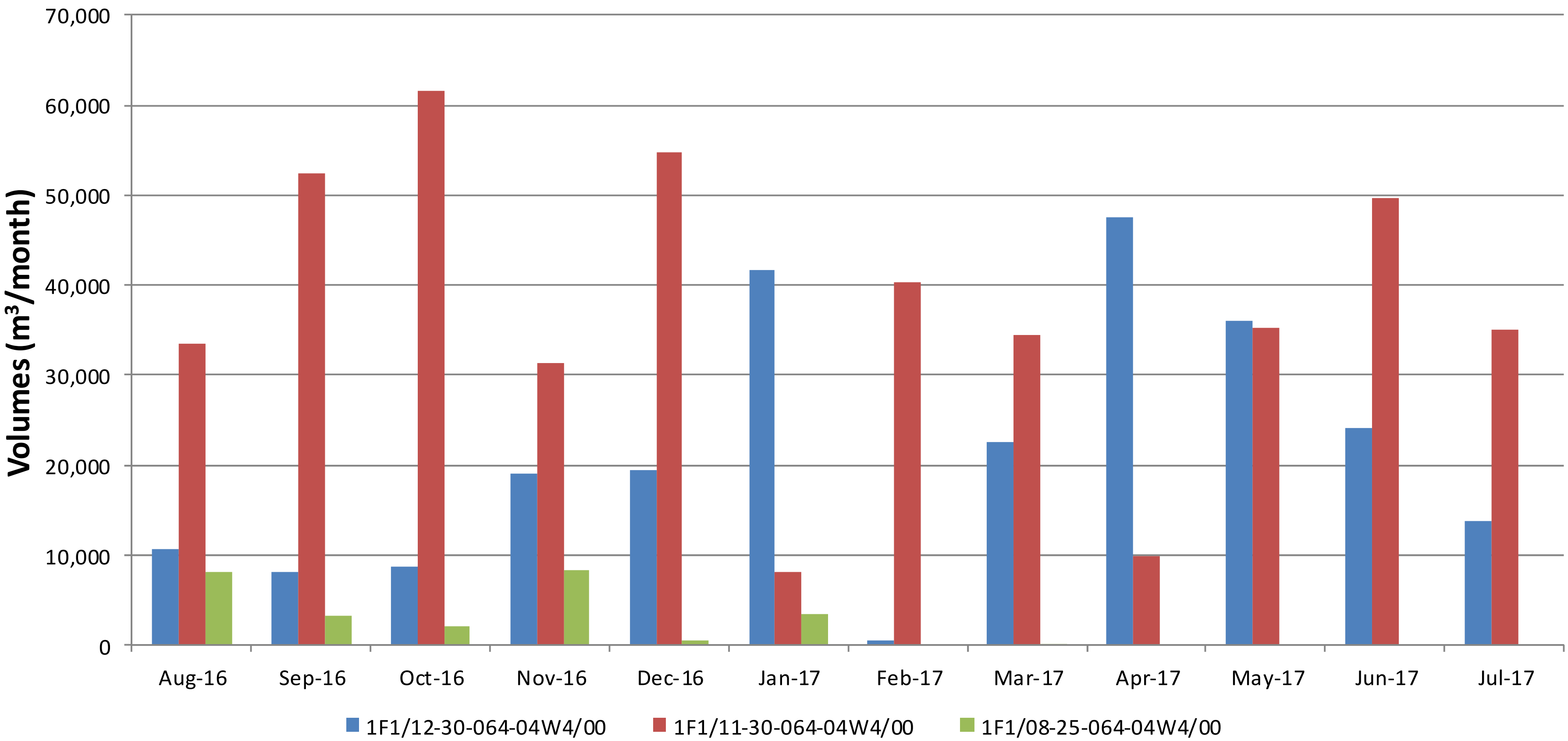
- Make-up water for steam generation
- McMurray Formation
- 3 Source Wells:
  - 1F1/11-30-064-04 W4M
  - 1F1/12-30-064-04 W4M
  - 1F1/08-25-064-04 W4M

Water Usage

- Using brackish water ~20,000 ppm Total Dissolved Solids (TDS) for steam generation (when required)

- Normally no fresh water is used in process

Brackish Water Consumption

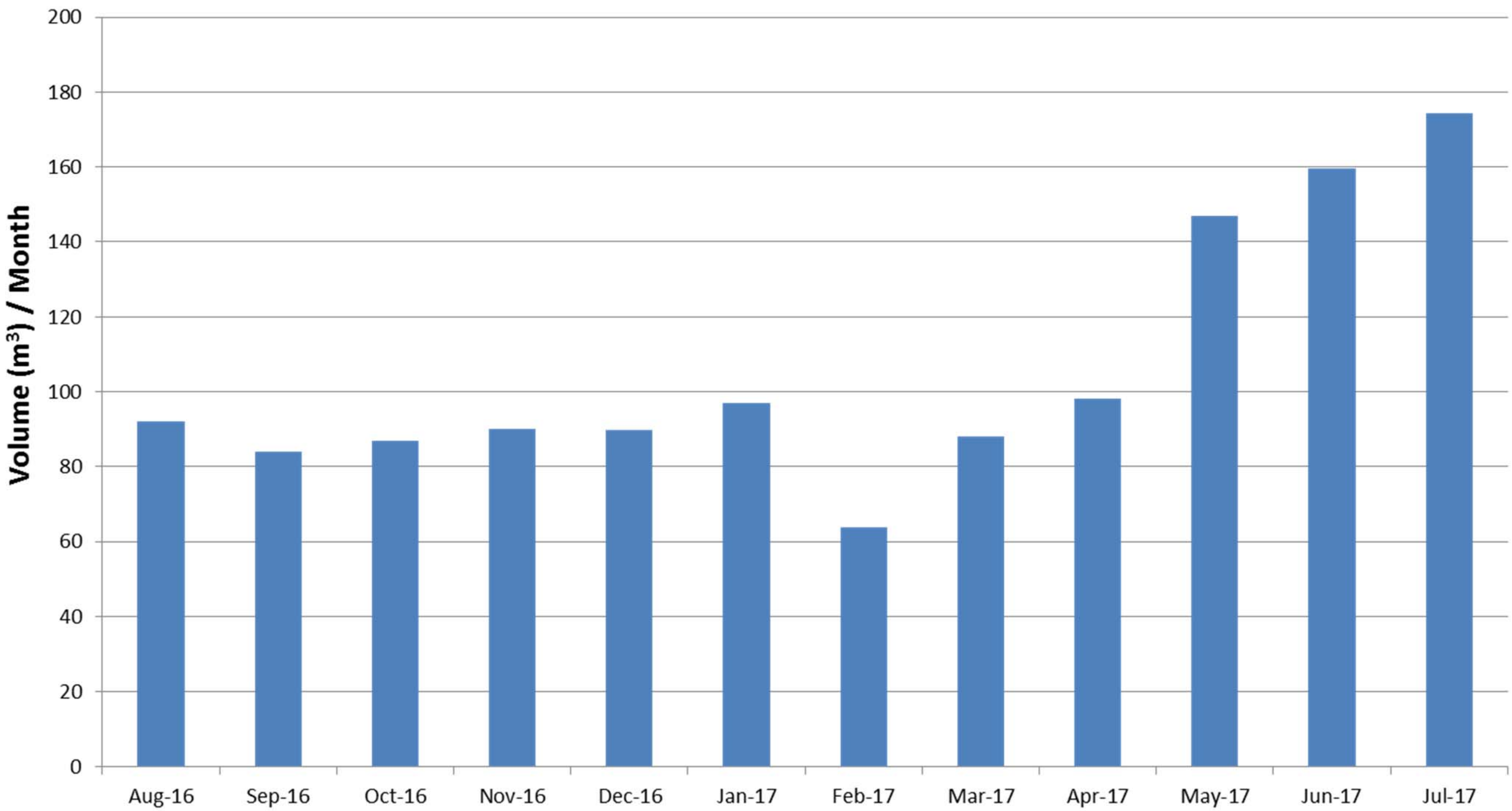


Fresh Water

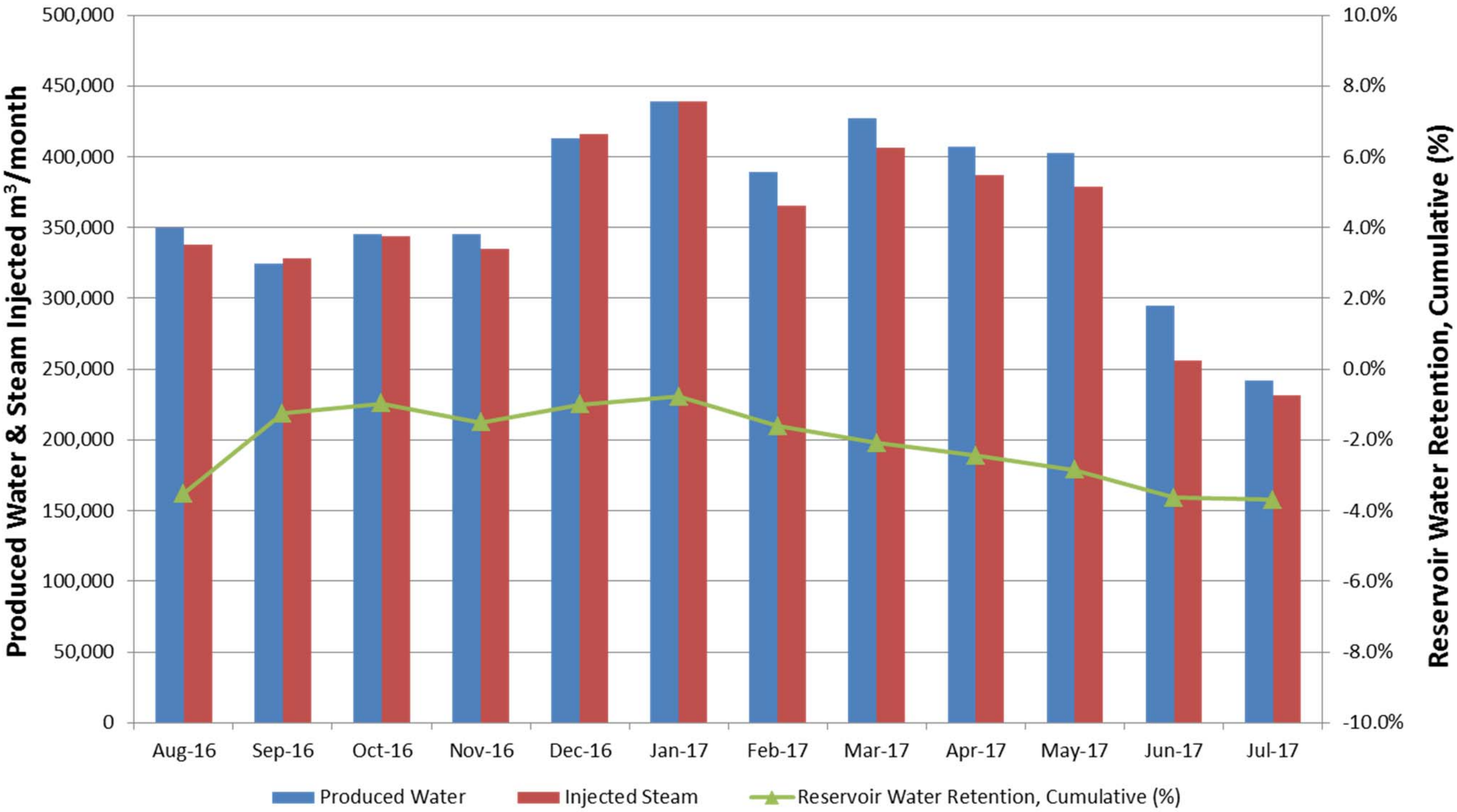
- Water Diversion License No. 00194427-00-01
  - Location well: 12-28-064-04-W4, on the Tucker CPF site
  - Bonnyville Aquifer
  - Domestic use only:
    - Safety showers / eye-wash stations
    - Cleaning water
    - Washroom / kitchen use

- Temporary Diversion License, TDL License No. 00395372
  - Required due to WLS shut-down and repair
  - Valid from June 16, 2017 to July 31, 2017
  - Approved for a maximum volume of 79,200 m^3
  - Actual volume used was 36,019 m^3

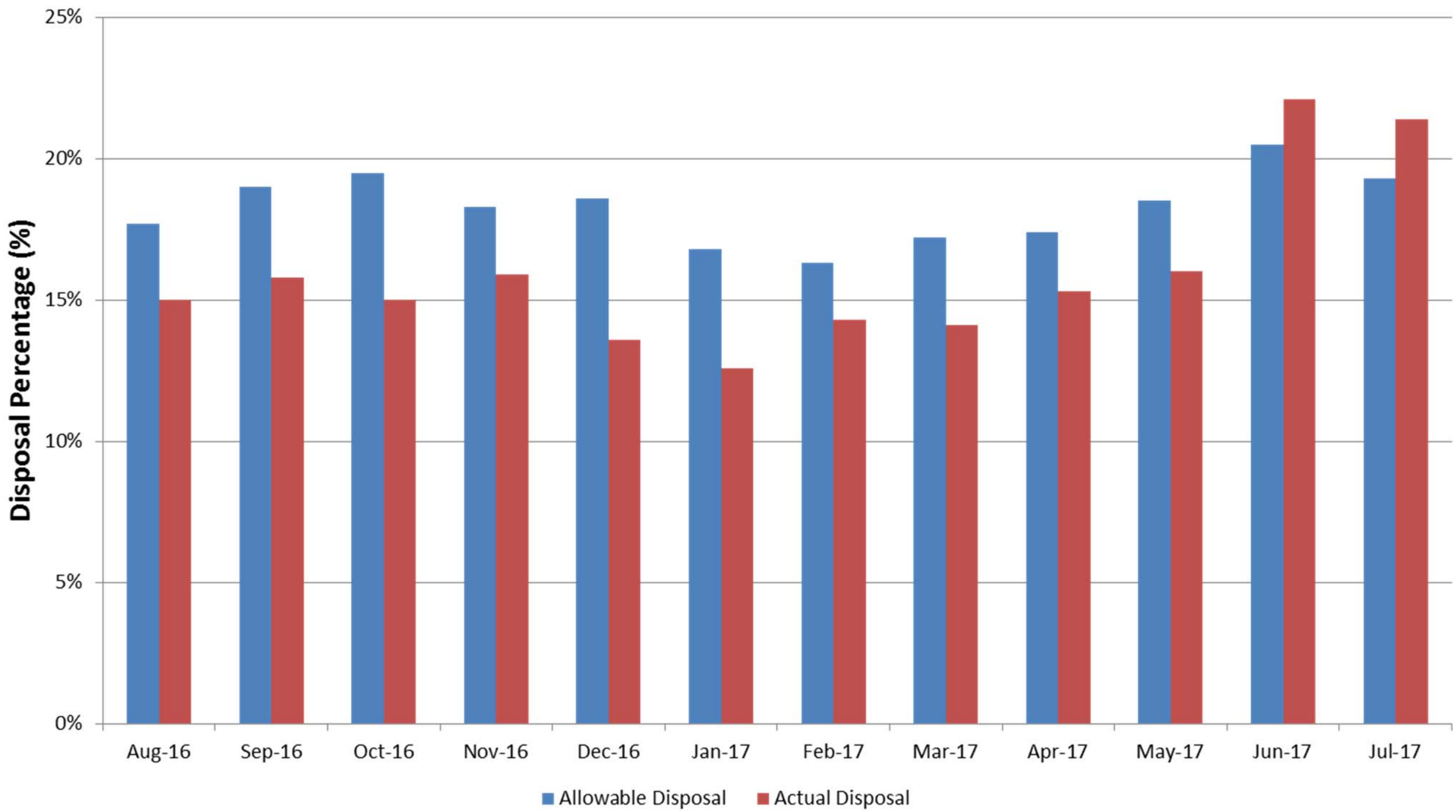
Fresh Water Consumption



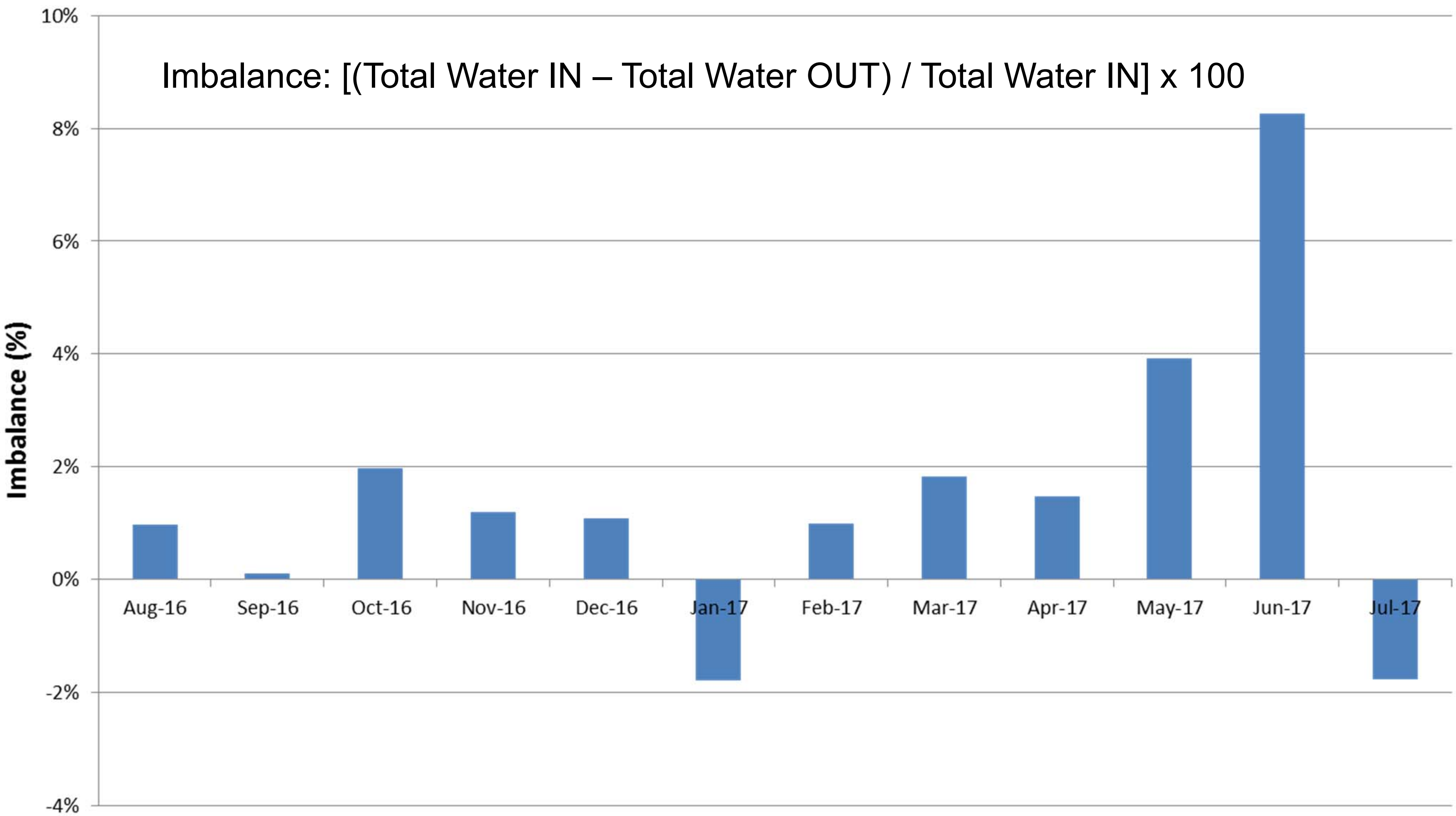
Produced Water & Steam Injected



Water Disposal Limits



Monthly Injection Water Balance



OTSG Blow-down Recycle

- OTSG blow-down is recycled to the WLS at a percentage that allows the total dissolved solids, out of the OTSG, to remain below 50,000 uS/cm
- Brackish water make-up has a very high TDS and affects OTSG blow-down recycle
- Recycle approximately 34% of blow-down back to the WLS

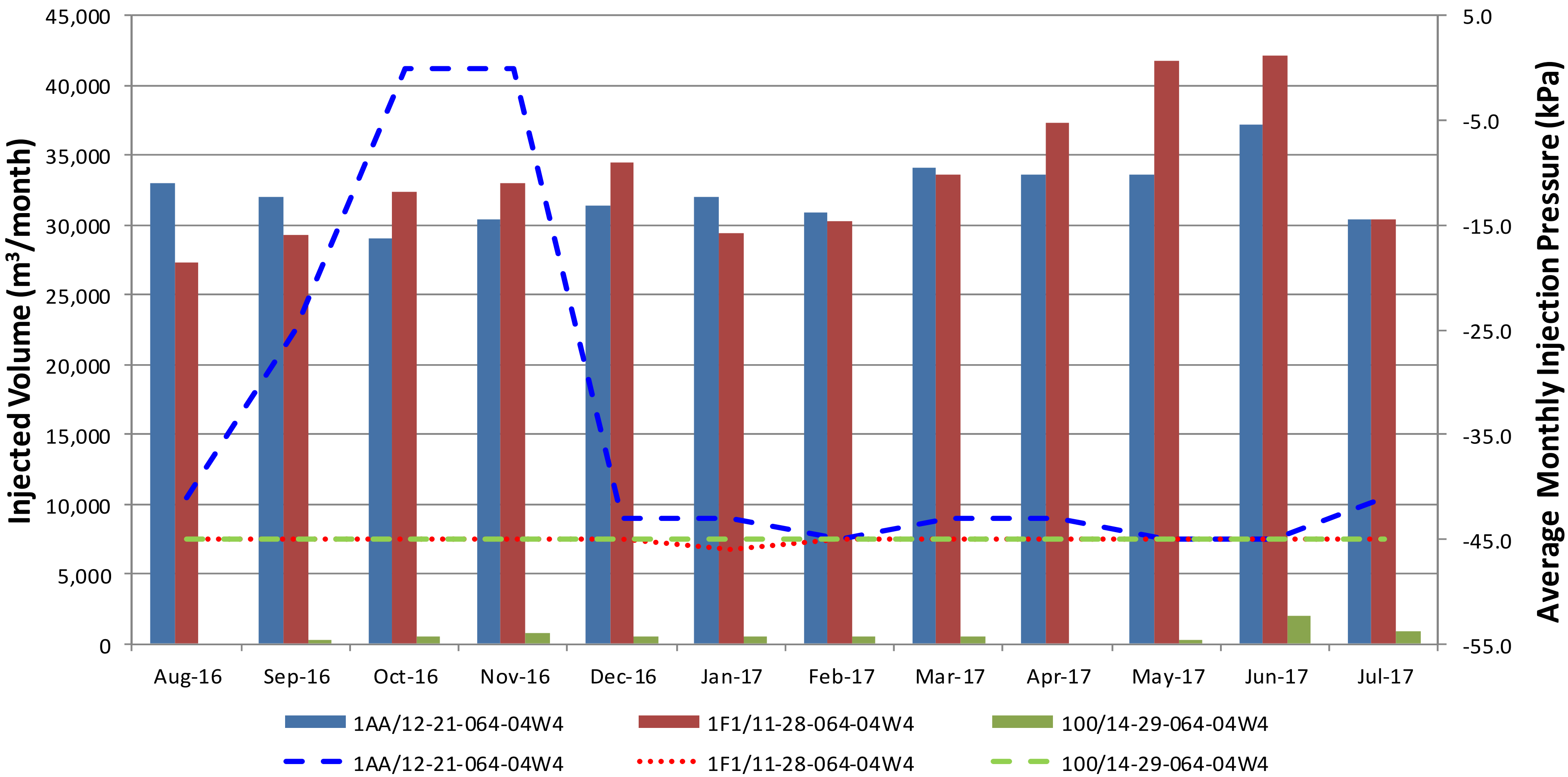
Disposal Wells

- AER Class 1 Wastewater Disposal Wells

- Boiler blow-down disposal:
  - 1AA/12-21-064-04 W4M (AER Approval 10591)
  - 1F1/11-28-064-04 W4M (AER Approval 10591)
  - 00/04-28-064-04W4/0 (AER Approval 10591A) – licensed

- Water treatment process disposal:
  - 00/14-29-064-04 W4M (AER Approval 10591)

Disposal Wellhead Injection Pressures & Volumes



Landfill Waste Handling

- No landfill within facility
- All landfill waste streams disposed offsite at licensed facilities

Waste Volumes

AER Waste Code	Waste Description	Location Sent To	Final Handling Method	Quantity	Unit
CAUS	Caustic Solutions Unneutralized, Spent	Rbw Waste Management Ltd	Other (specify)	0.06	m3
COEMUL	Condensate/Crude Oil Emulsions	Tervita Lindbergh	Cavern	1317.46	m3
	High Solids: Solids >40%	NewAlta Elk Point Service Centre	Oilfield Waste Processing Facility	314	m3
	Interphase > 20%, Oil <= 30%	NewAlta Elk Point Service Centre	Oilfield Waste Processing Facility	974.5	m3
	Interphase 0 - 10%, Oil <= 30%	NewAlta Elk Point Service Centre	Oilfield Waste Processing Facility	2613	m3
	Interphase 0 - 10%, Oil > 30%	NewAlta Elk Point Service Centre	Oilfield Waste Processing Facility	17.5	m3
	Interphase 10.1 - 20.0%, Oil <= 30%	NewAlta Elk Point Service Centre	Oilfield Waste Processing Facility	897	m3
	Interphase 10.1 - 20.0%, Oil > 30%	NewAlta Elk Point Service Centre	Oilfield Waste Processing Facility	20.5	m3
DOMWST	Domestic Waste	Rbw Waste Management Ltd	Recycling Facility (excluding used oil)	124.44	m3
EMTCON	Empty Containers	Rbw Waste Management Ltd	Recycling Facility (excluding used oil)	3.06	m3
FILOTH	Filters - Other (Raw Fuel Gas, NGL's)	Rbw Waste Management Ltd	Recycling Facility (excluding used oil)	10.08	m3
INOCHM	Chemicals Inorganic	Rbw Waste Management Ltd	Recycling Facility (excluding used oil)	2.8	m3
OILABS	Absorbents	Rbw Waste Management Ltd	Recycling Facility (excluding used oil)	1.96	m3
OILRAG	Rags Oily	Rbw Waste Management Ltd	Recycling Facility (excluding used oil)	1.4	m3
ORGCHM	Chemicals Organic	Rbw Waste Management Ltd	Other (specify)	0.02	m3
SAND	Stung Sand Wet	Tervita Lindbergh	Cavern	3	m3
	Shake-off Sand	NewAlta Elk Point Service Centre	Oilfield Waste Processing Facility	12.5	m3
SLGHYD	Cav Sludge Hydrocarbon	Tervita Lindbergh	Cavern	8.65	m3
	Interphase 0 - 10%, Oil <= 30%	NewAlta Elk Point Service Centre	Oilfield Waste Processing Facility	43	m3
	Interphase 10.1 - 20.0%, Oil <= 30%	NewAlta Elk Point Service Centre	Oilfield Waste Processing Facility	33	m3
SLGLIM	Lime Sludge	Tervita Bonnyville	Class II Landfill	18738.43	Tonnes
SMETAL	Metal Scrap	Rbw Waste Management Ltd	Recycling Facility (excluding used oil)	6.3	m3
SOILCO	Hydrovac Material	Tervita Lindbergh	Cavern	21	m3
	Contaminated Debris and Soil Crude Oil Condensate	Clean Harbors Ryley	Class Ia Landfill	5	m3
		Rbw Waste Management Ltd	Class Ia Landfill	1	m3
			Recycling Facility (excluding used oil)	16.5	m3
WATER	Cav Waste Produced Water	Tervita Lindbergh	Cavern	8.13	m3
WPAINT	Waste Paint	Rbw Waste Management Ltd	Other (specify)	0.02	m3
WSTMIS-R	Waste Hydraulic Hoses	Rbw Waste Management Ltd	Recycling Facility (excluding used oil)	0.7	m3

5. Sulphur Production

Sulphur Dioxide (SO_2) Sources

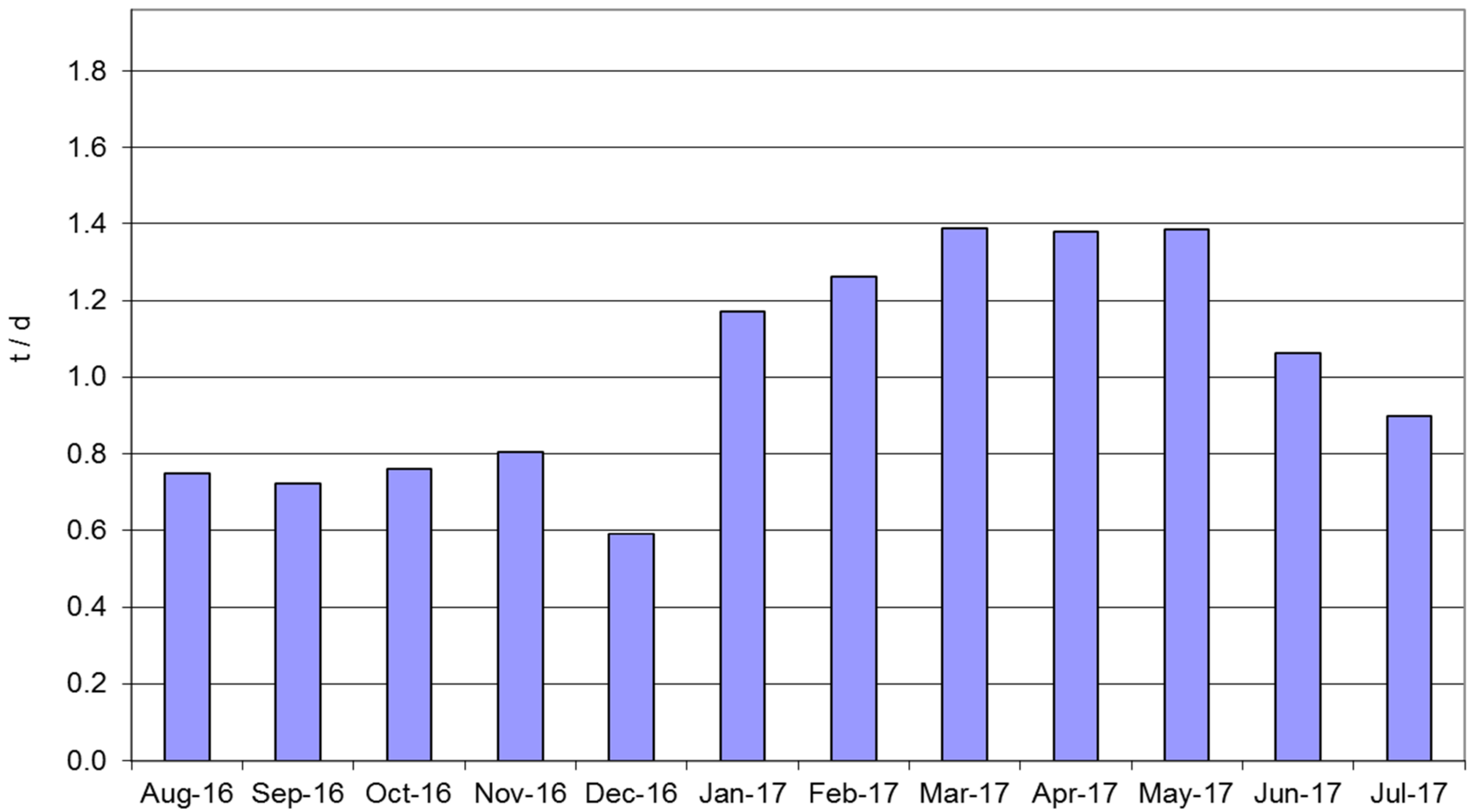
- Six Once-Through Steam Generators (OTSG)
- One High Pressure Flare Stack
- One Low Pressure Flare Stack

Quarterly SO_2 Emissions

Q3 2016 (August 2016 – October 2016)	68.46 tonnes
Q4 2016 (November 2016 – January 2017)	78.76 tonnes
Q1 2017 (February 2017 – April 2017)	119.36 tonnes
Q2 2017 (May 2017 – July 2017)	101.81 tonnes

SO_2 Emissions Trends

SO2 Emission Limit - 1.96 t / d



Peak and Average SO_2 Emissions

- August 1, 2016 to July 31, 2017:

SO_2 Emissions	
Average Daily (highest)	1.01 tonnes
Maximum Daily (highest)	1.48 tonnes

- Limit under EPEA Approval is 1.96 tonnes/day
- No exceedances

Ambient Air Monitoring

- Ambient air quality is currently monitored by the Lakeland Industry and Community Association (LICA) - Air Shed committee. LICA is under contract from Alberta Environmental Monitoring and Science Division (EMSD) of Alberta Environment and Parks (AEP) to provide these services

- No exceedences were recorded during the last reporting period

- Airshed quality results available on LICA website or Clean Air Strategic Alliance (CASA) Data Warehouse

- http://www.lica.ca/

- http://www.casadata.org/

6. Environmental Issues

Environmental – Compliance to Approvals

- EPEA Approval:
  - No compliance issues during this reporting period
- AER:
  - No compliance issues during this reporting period
- DFO:
  - No compliance issues during this reporting period

Environmental - Amendments to EPEA Approval

- No amendments to EPEA approval 147753-01-00 during the reporting period

Environmental – Wildlife

- As part of the regulatory approval, Husky has developed and implemented a Wildlife Monitoring Program (WMP) for:
  - Canadian toad distribution, abundance and population status
  - Above Ground Pipeline (AGP) monitoring to ensure wildlife can cross under the lines
  - Wildlife Habitat Enhancement Program (WHEP)

- Annual WMP report describes the observations and results collected during the previous year

Environmental - Industrial Wastewater

- Disposal Locations:
  - Boiler blow-down disposal 12-21-064-04W4M and 11-28-064-04W4M
  - Water treatment process disposal 14-29-064-04W4M
  - 382,710.2 m^3 was disposed

- Domestic Wastewater:
  - Domestic waste sludge is disposed of at the Cold Lake Municipal Treatment Facility or the Bonnyville Municipal Treatment Facility

- Industrial Run-off (from 2016 Annual Waste Water Report):
  - Total of six discharge locations (Well Pads: A, B, C, GA, CN and the run-off retention pond located on CPF)
  - A total of 58,710 m^3 surface water was discharged due to a very wet year
  - All discharges were in compliance with EPEA approval

Environmental - Soils

- No soil monitoring activities were conducted during the reporting period

Environmental – Air

- Air related monitoring, reporting and studies are conducted by Lakeland Industry and Community Association (LICA) under contract from Alberta Environmental Monitoring and Science Division (EMSD)

- The LICA airshed monitoring network consists of:
  - 4 continuous monitoring stations
  - 26 passive monitoring stations
  - 2 volatile organic compound and polycyclic aromatic hydrocarbon samplers, and
  - 2 soil acidification monitoring plots

Environmental – Ground Water

- Groundwater monitoring program includes:
  - CPF Groundwater: monitors shallow groundwater quality beneath the CPF
  - Pad-specific Groundwater: monitors possible impacts to groundwater quality
  - Regional Groundwater: monitors possible effects on regional groundwater quality between the project areas and the local lakes and streams
- Expansion to Groundwater Monitoring Program:
  - No additional expansion to the monitoring network occurred during this reporting period

Environmental – Initiatives

- Alberta Environmental Monitoring and Science Division (EMSD)
- Participation in the Lakeland Industry and Community Association (LICA)
  - Board of Directors
  - Beaver River Watershed Alliance
  - Airshed
- Participation in Alberta Biodiversity Monitoring Institute (ABMI)

Environmental – Reclamation

- Objectives of the Annual Report (demonstrate and document):
  - Compliance with the development and reclamation approval
  - Site conditions and successful reclamation
  - General project development (surface disturbances) and reclamation activities
  - Problem areas and resolution

- Site Clearing and Timber Salvage:
  - No site clearing or timber salvage occurred during this reporting period

- Vegetation Monitoring:
  - Annual weed monitoring and control as per Husky's best practices

- Reclamation Activities:
  - No permanent reclamation activities were completed during the reporting period

Compliance

- AER
  - All conditions of AER License F-32143 as well as all scheme approvals for the project were met during the reporting period
  - All conditions of the EPEA approval 147753-01-00 were met during the reporting period

Self Declarations

- No self declaration during this reporting period

8. Non-Compliance Events

Non-Compliance Events

- AER Contravention report, CIC # 315383, Aug 23, 2016. CEMS Code violation (<90% uptime) B7800 CEMS failure.
- AER Contravention report, CIC # 315429, Aug 23, 2016. D35S Uncontrolled Release.
- AER Contravention report, CIC #315677, Sept 27, 2016. Continuous Stack Emission Monitor EDR report late due to B-7800 CEMS monitor problems.
- AER Contravention report, CIC # 317165, Oct 12, 2016. Continuous Stack Emission Monitor EDR report late due to B-7300 CEMS monitor problems.
- AER Contravention report, CIC # 320177, Jan 19, 2017. CEMS Code violation (<90% uptime) B7800 CEMS failure.
- AER Contravention report, CIC # 320811, Feb 8, 2017. Brackish Water Tank overflow, contained within berm.
- AER Contravention report, FIS # 20172076, Jun 23, 2017. WLS release during sludge cleaning.
- AER Contravention report, FIS # 20172174, Jul 5, 2017. WLS release due to floor corrosion.

SCVF/GM Update – Summary

- On-going, yearly monitoring of existing, non-serious vent flows in accordance with AER ID 2003-01
- SCVF testing procedure ensures test accuracy & repeatability:
  - If vent flow exists, condenser used to separate and allow measurement of non-condensable flow
- Key learnings:
  - Dual-string completions used to inject steam to the heel and toe of wells
  - C13S SCVF issues mitigated with VIT installation

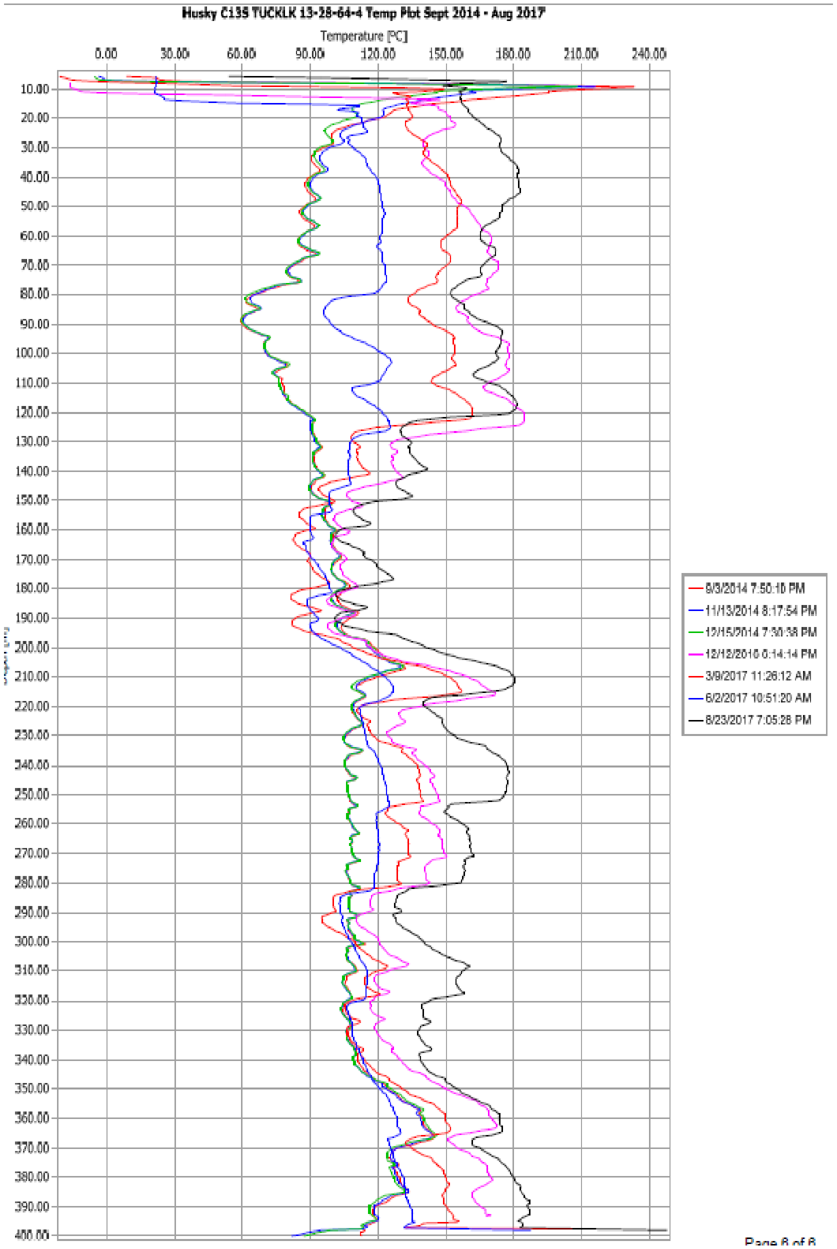
SCVF/GM Update – C13S

- C13S SCVF Update:
  - Currently, no SCVF
  - Quarterly of H_2S and SCVF
  - Quarterly monitoring of temperature
  - Temperature log trend deviation commenced in June 2015

- Background Information:
  - Installation of VIT and temp monitoring, December 20, 2013
  - Resumed steaming to test remediation, December 24, 2013
  - Results: No SCVF or H_2S since December 23, 2013
  - Update presentation to AER on May 29, 2014

- Husky commitment:
  - Quarterly monitoring of H_2S, SCVF and temperature
  - Update in annual performance presentation

SCVF/GM Update – C13S Cont'd



Status:

- Currently, no SCVF at C13S
- Multiple temperature deviations along tubing
  - Maximum temperature of approximately 187 ºC at 392 m depth
  - Increased temperature due to loss-of-insulating properties in the Vacuum Insulated Tubing (VIT)

Plan:

- Continue quarterly monitoring of temperature, SCVF and H_2S
- Next temperature log (December 2017)
- Husky will notify AER of any changes to SCVF

9. Future Plans

Future Plans (2017/2018)

- Construct, commission & start-up Pad D West SAGD development
- Pad B West Replacement Well development