Husky Oil Operations Limited
Tucker Thermal Project
Commercial Scheme No. 9835

Annual Performance Presentation
Alberta Energy Regulator

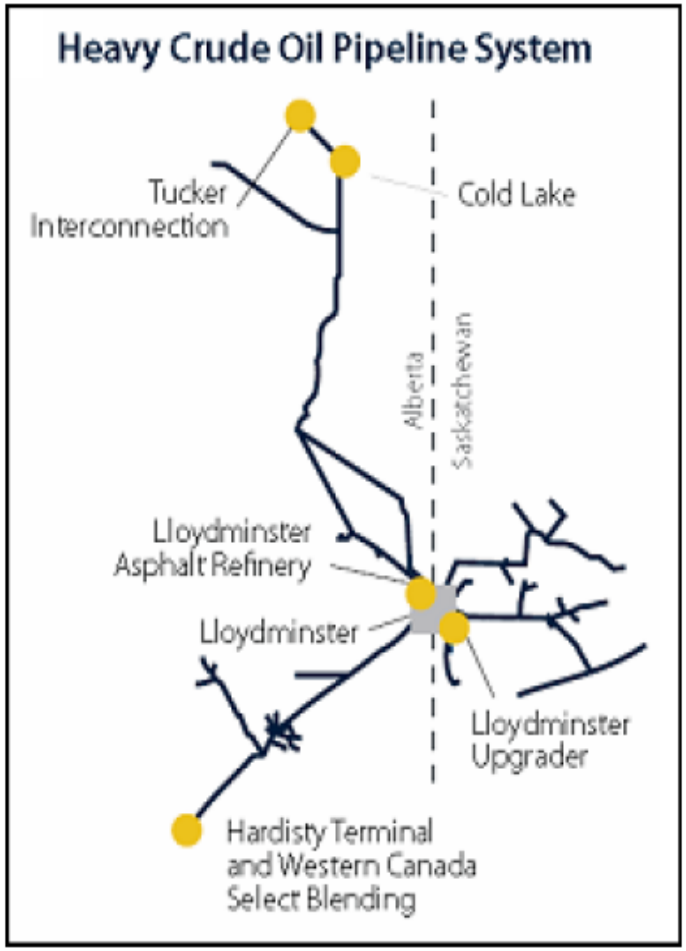
September 13, 2016

3.1.1. Subsurface – Table of Contents

1. Brief Background

Project Overview

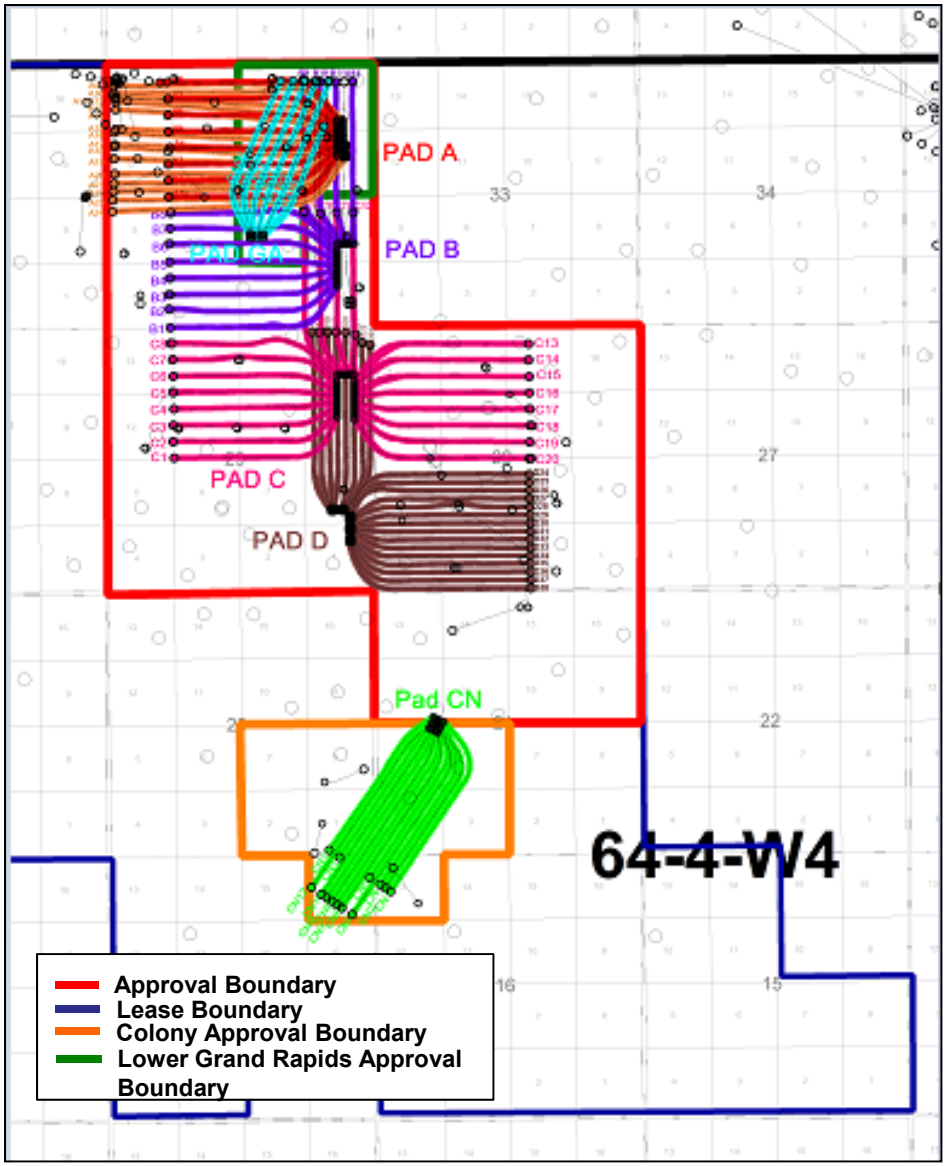
- AER Commercial Scheme Approval No. 9835
- 30,000 BOPD SAGD Project
- Clearwater and Grand Rapids Reservoirs
- 9-10º API Bitumen
- Integrated with Husky Pipeline & Upgrader
- Project completed in 24 months
- First Steam August 20, 2006
- First Production November 29, 2006



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
- Project Life Development:
  - ~140 well pairs; 35 year life

- 94 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



Site Overview

- 94 horizontal well pairs
- 7 infill producers

- Field Facilities – six well pads, infield pipelines & 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	34	45	0.31	0.56	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

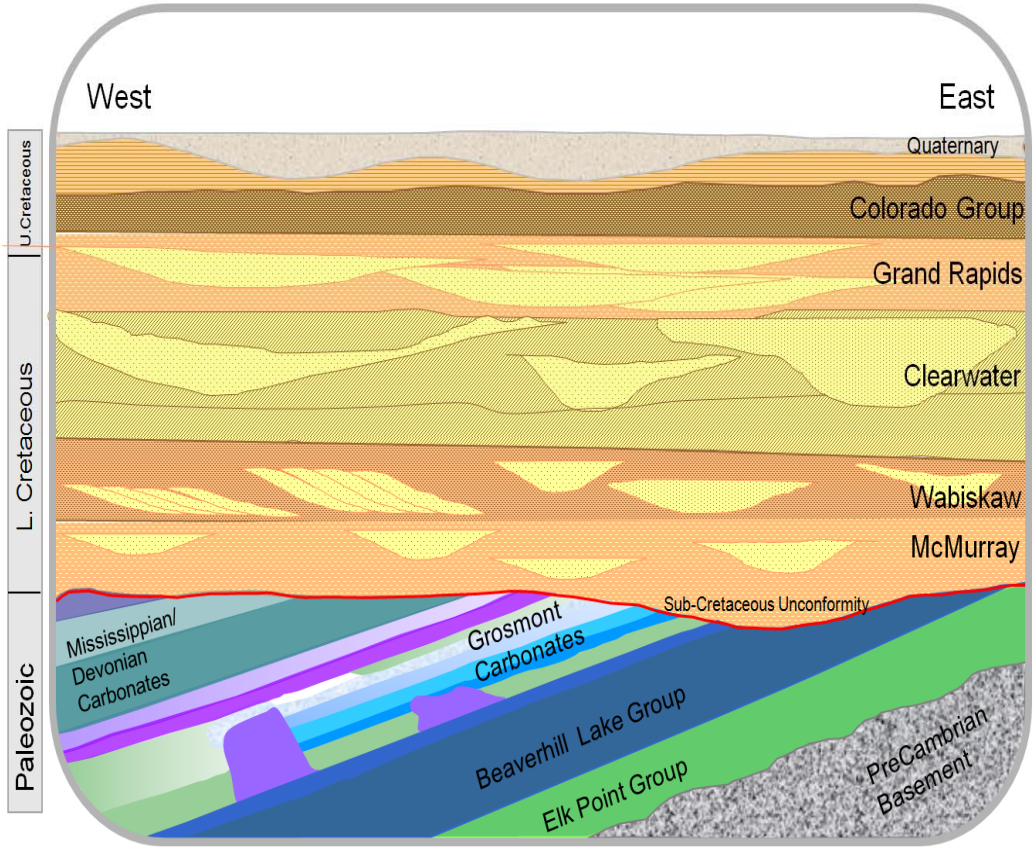
COLONY	OBIP ($X10^6$ m^3)	Thickness (m)	Φ	So	Original Pressure (kPa)	Original Temperature (°C)	Depth (m)	Vertical Permeability (mD)	Horizontal Permeability (mD)
CN Approval Area	2.8	10	0.3	0.79	2,500	12	305	2,400	4,000

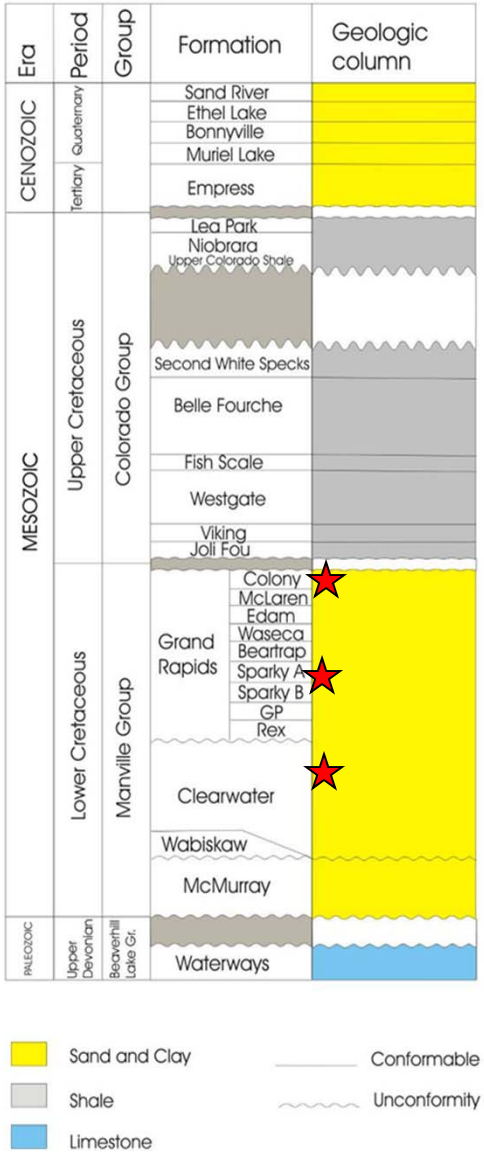
Notes:

Calculation: OBIP interval: Top of Formation → oil water contact
OBIP = Area x Thickness x Φ x S_o

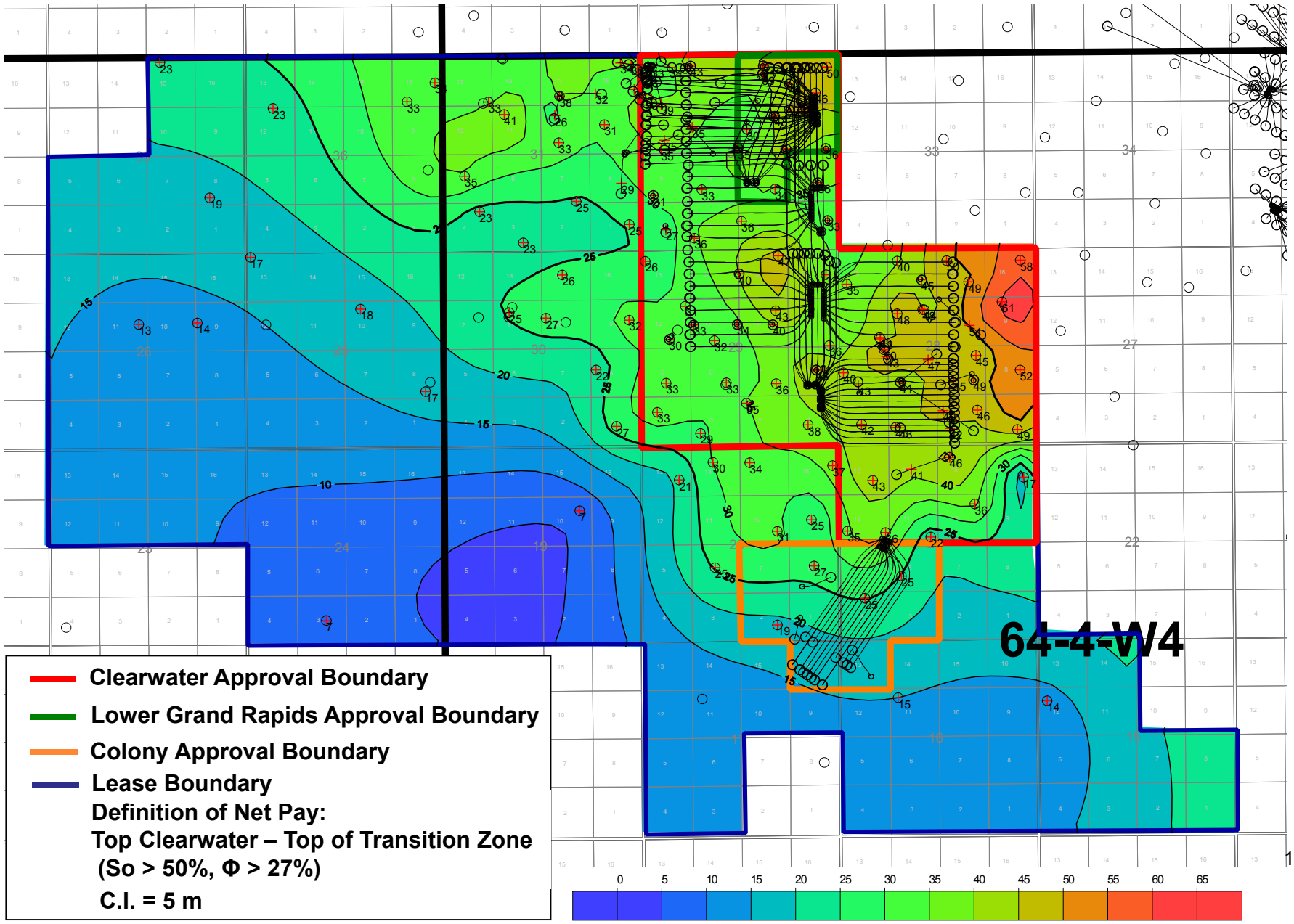
Regional Stratigraphy

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

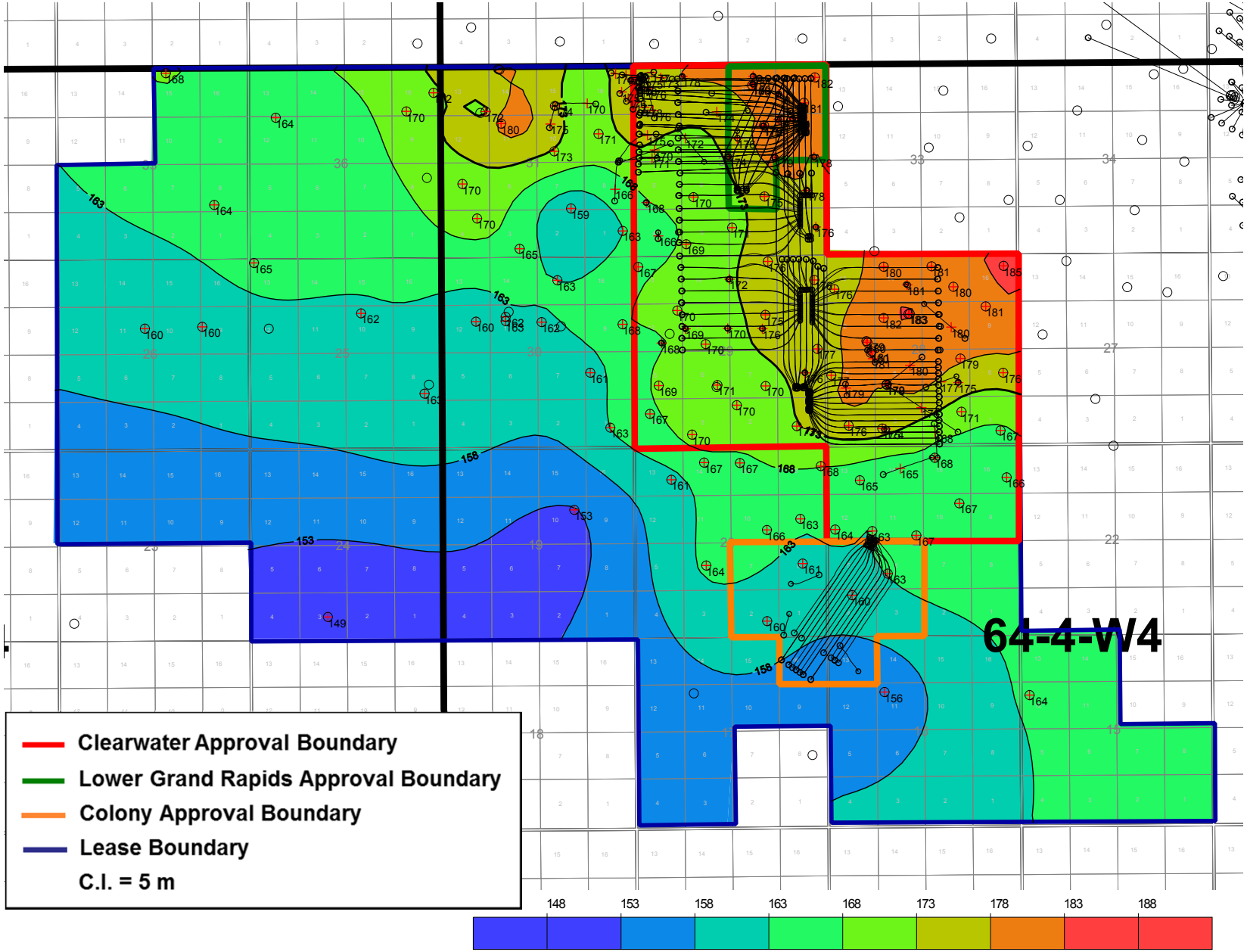




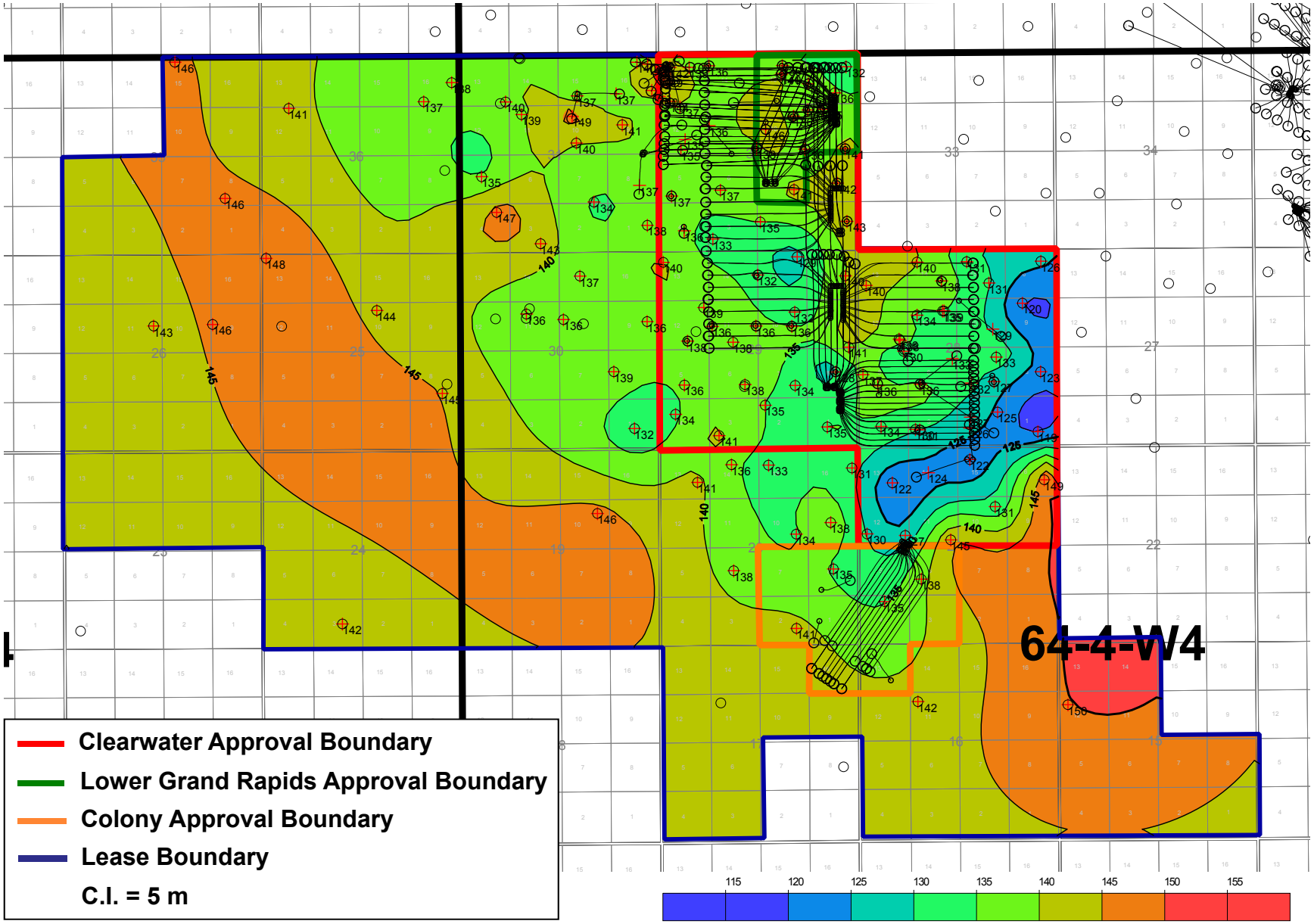
Isopach Map of Clearwater SAGD Net Pay



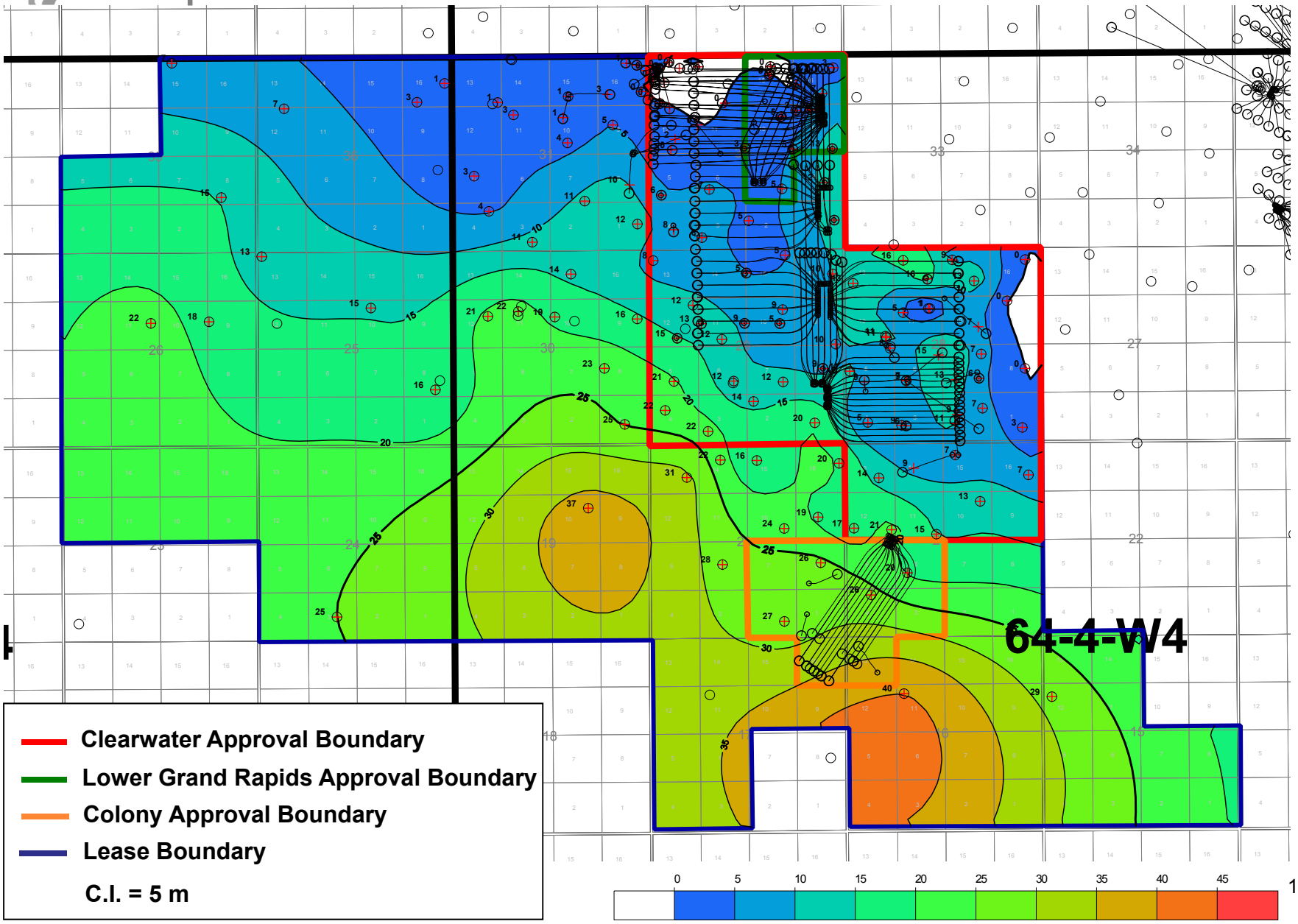
Structure Map of the Clearwater Top of Net Pay



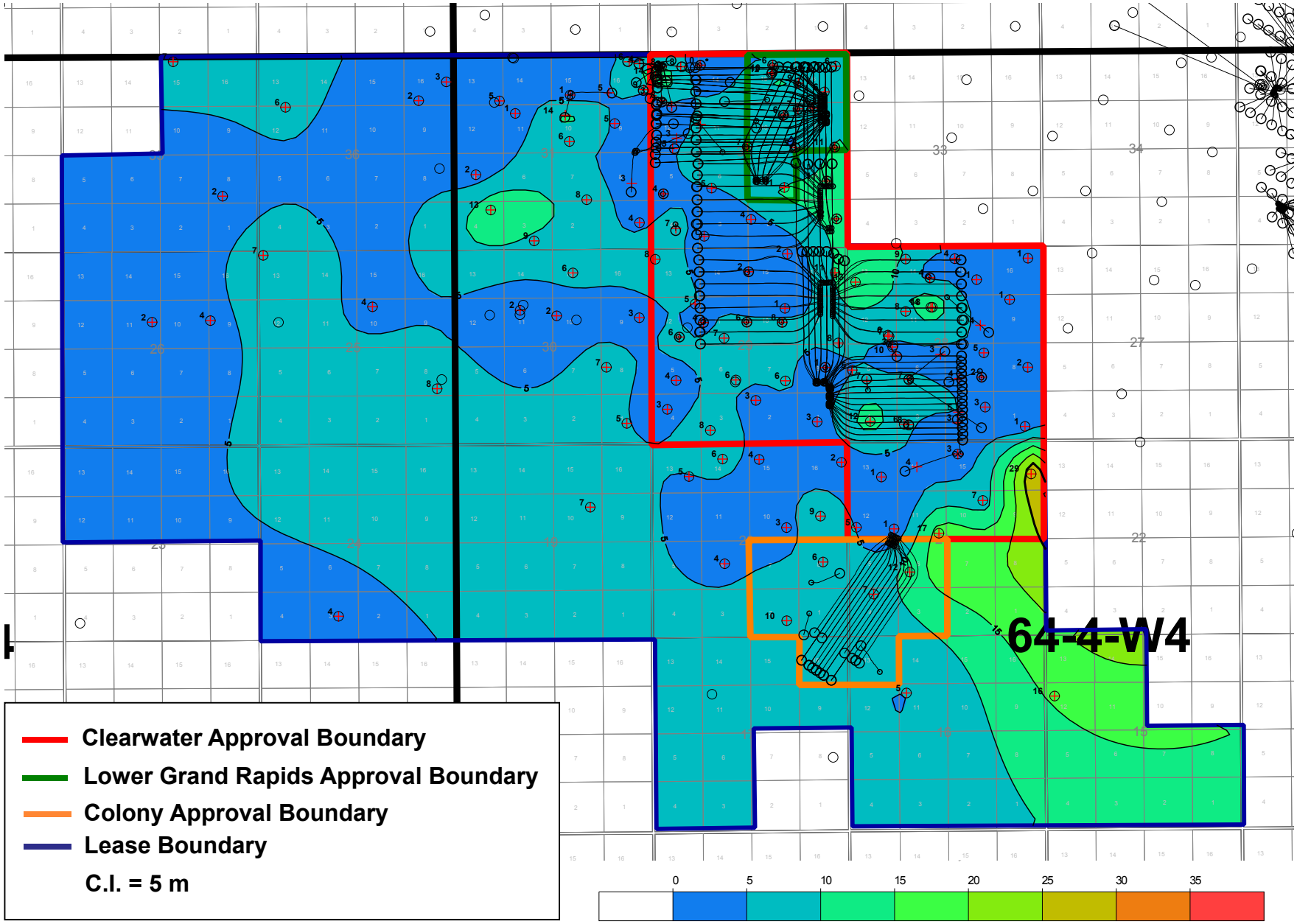
Structure Map of the Clearwater Base of Net Pay



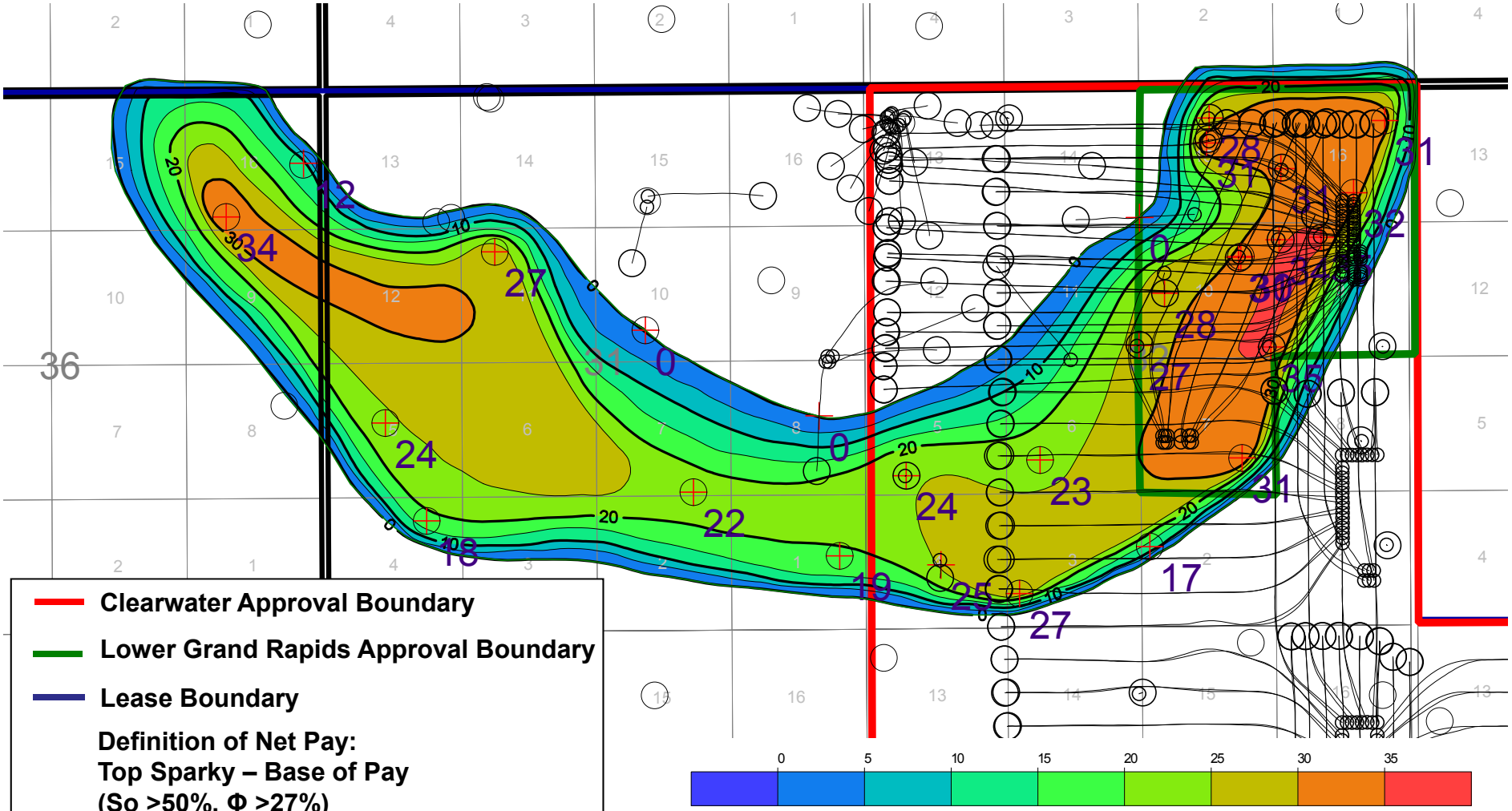
Isopach of Clearwater Bottom Water



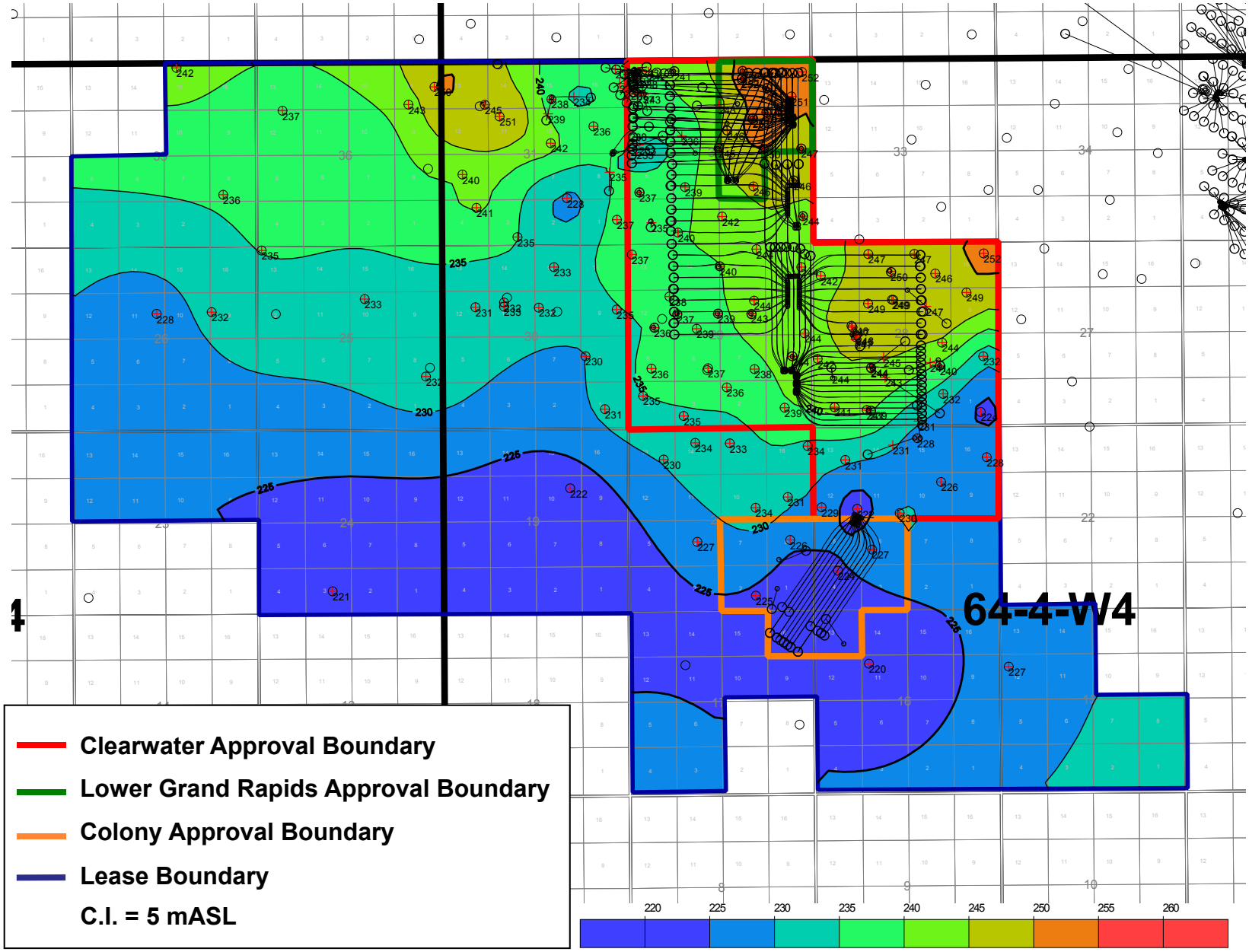
Isopach of Clearwater Transition Zone



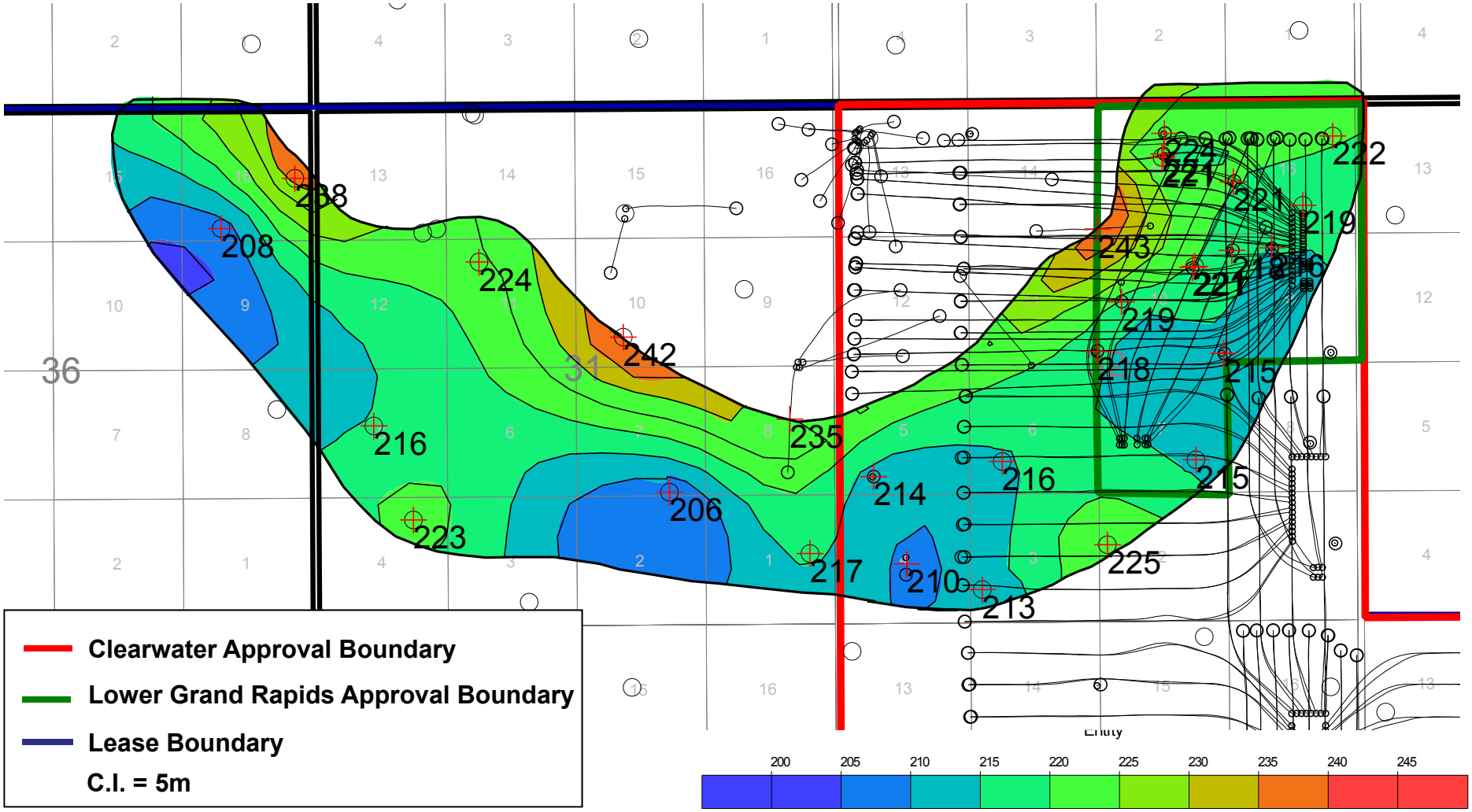
Isopach Map of Lower Grand Rapids SAGD Net Pay



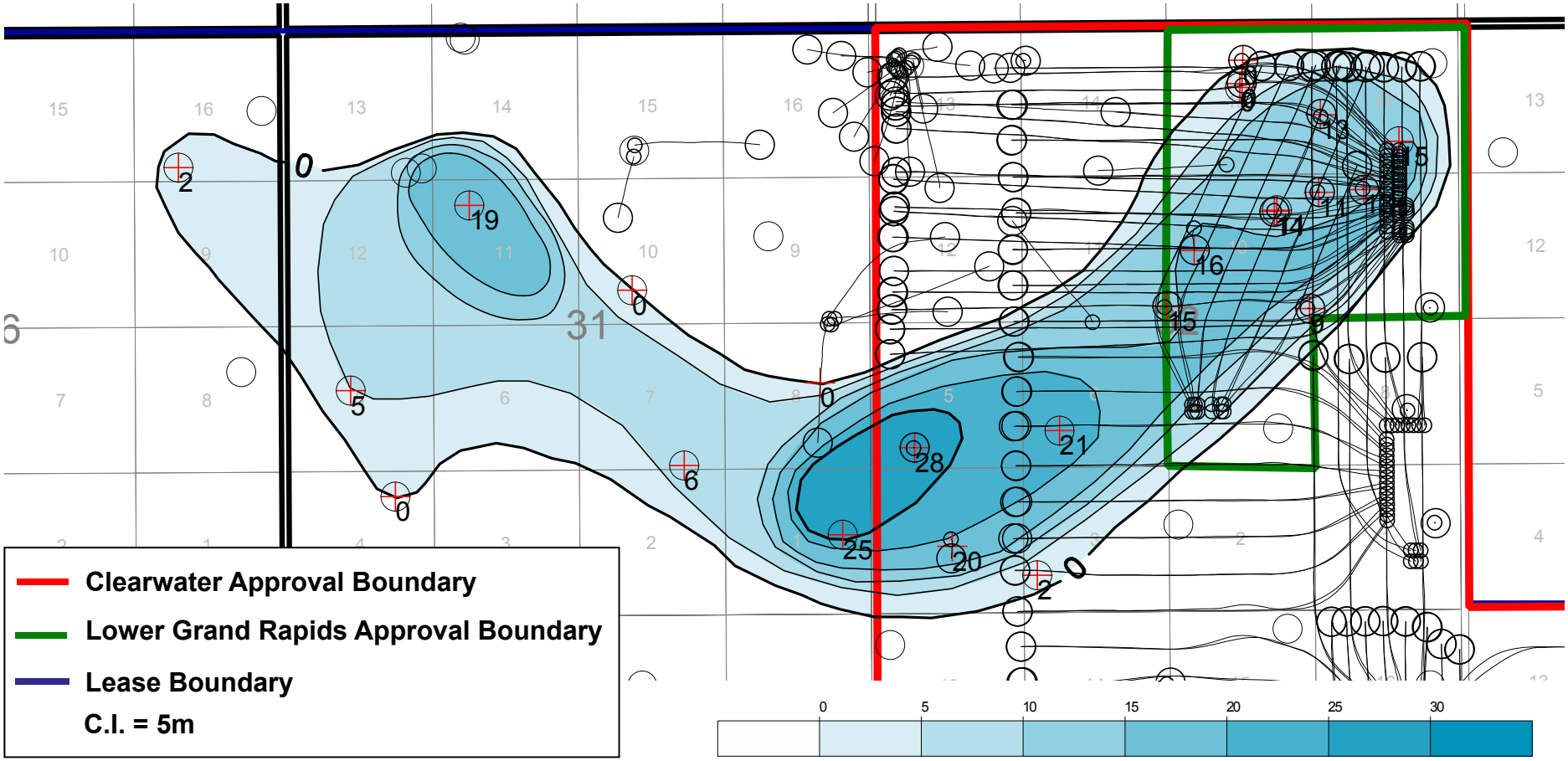
Structure Map of the Lower Grand Rapids



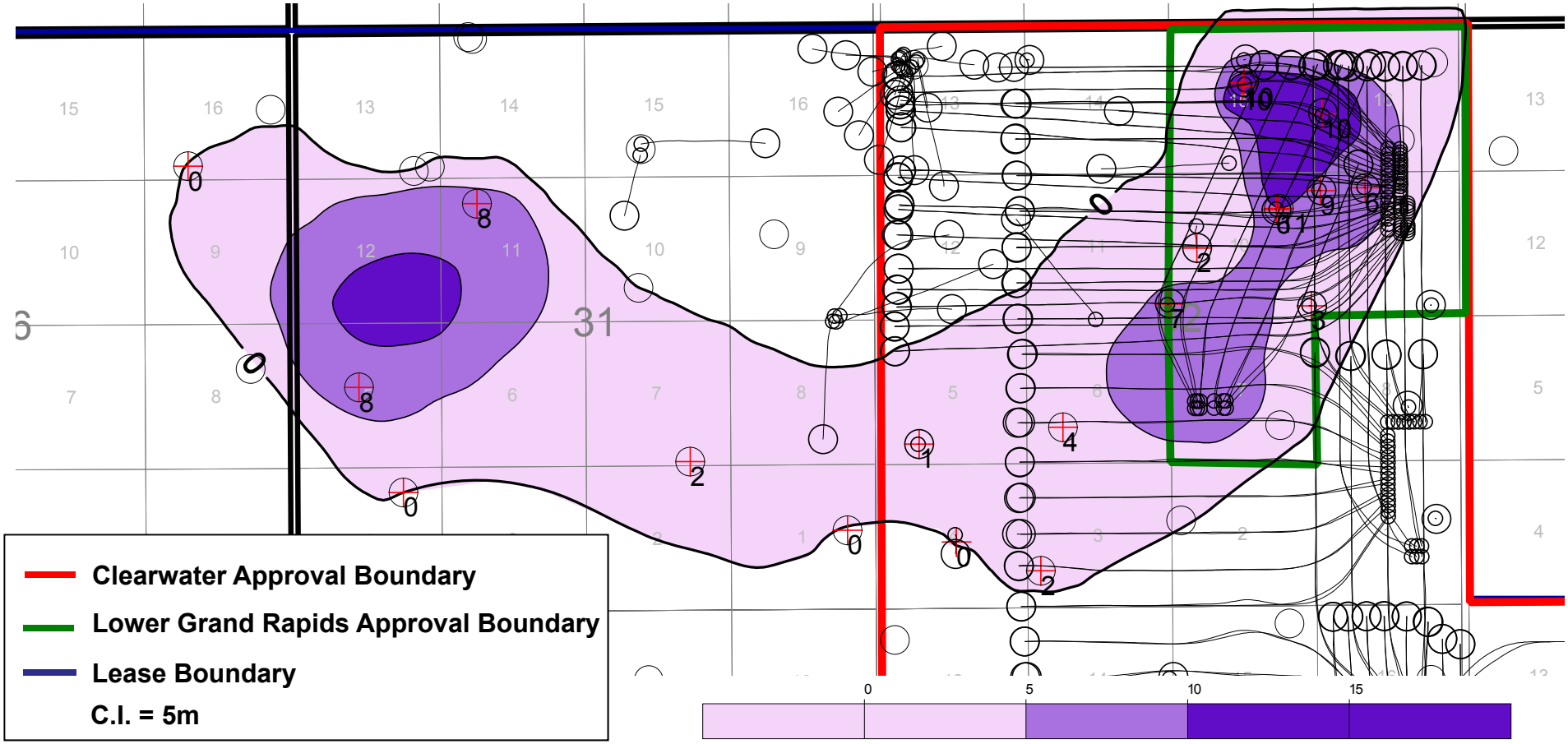
Structure Map of the Lower Grand Rapids Base of Net Pay



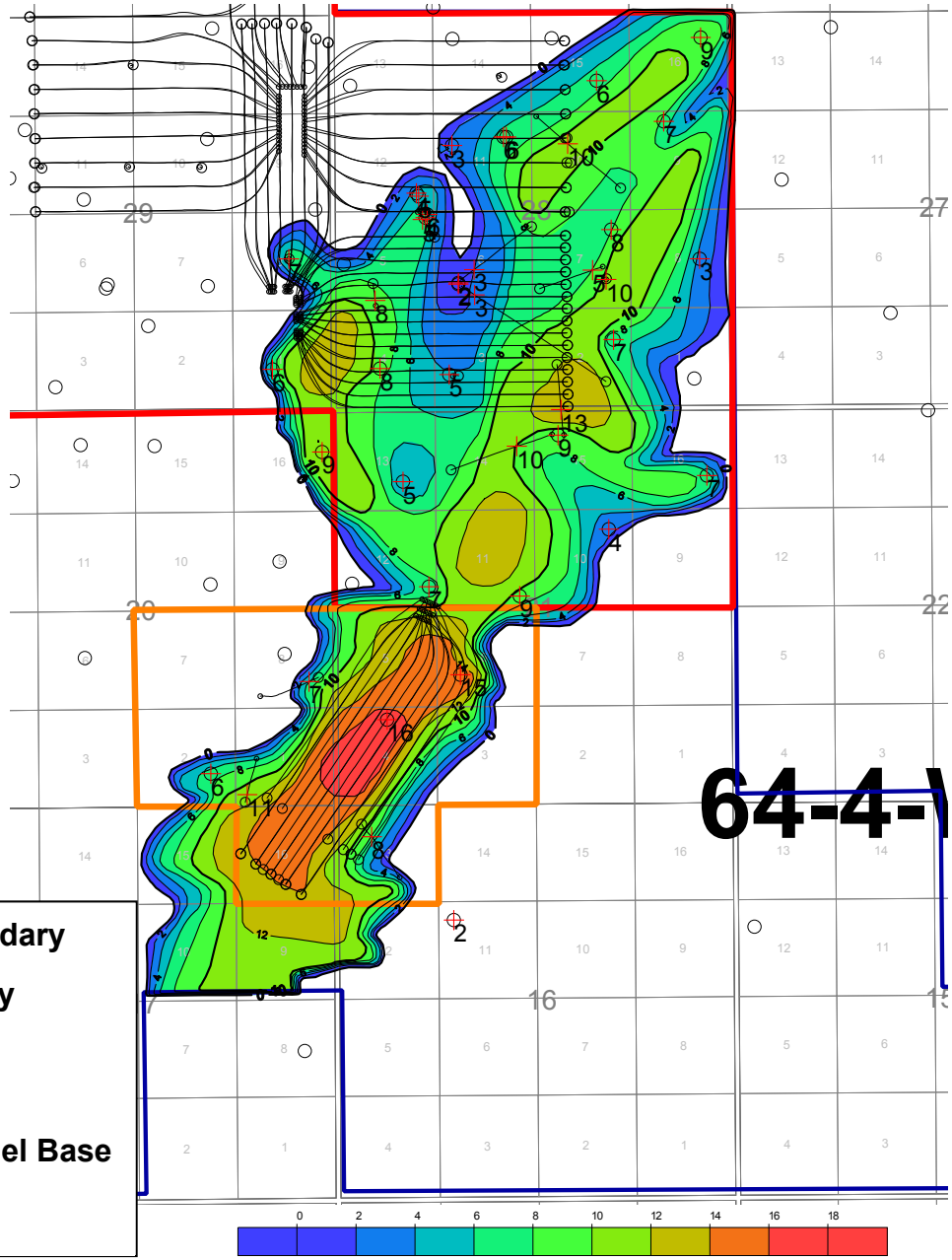
Isopach Lower Grand Rapids Bottom Water



Isopach Lower Grand Rapids Transition Zone



Isopach Map of Colony SAGD Net Pay



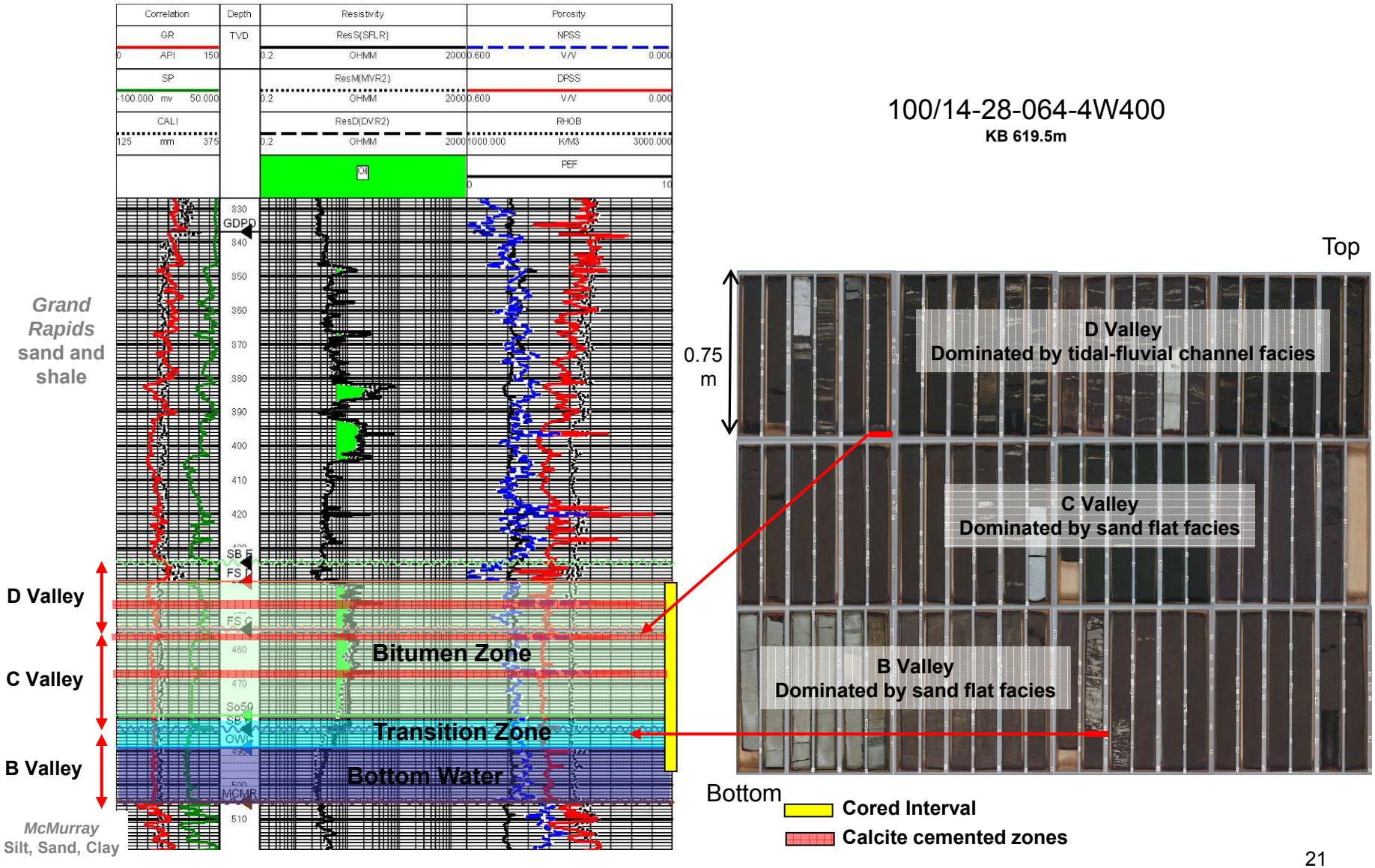
Clearwater Approval Boundary

Colony Approval Boundary

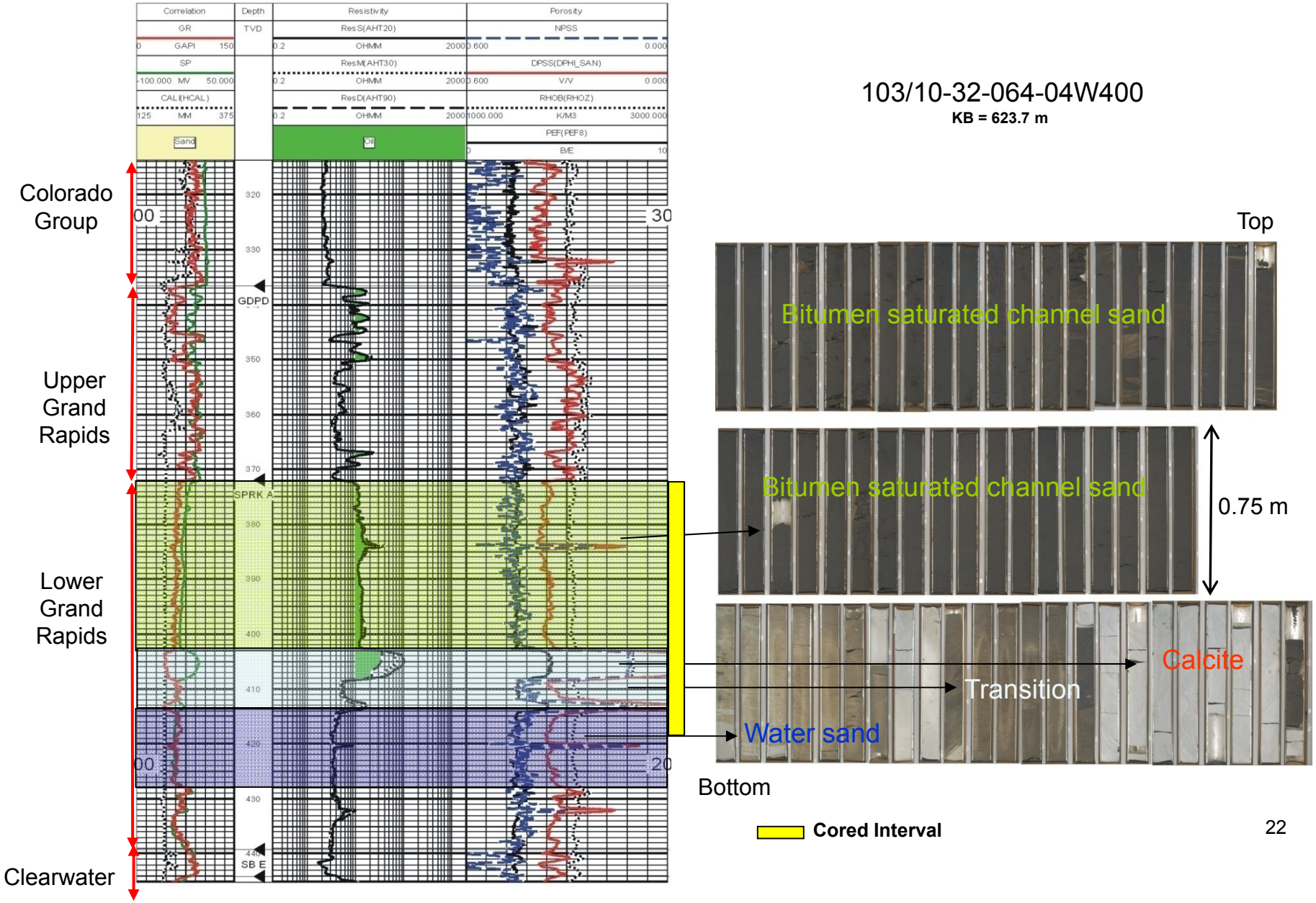
Lease Boundary

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

Clearwater Formation Type Log

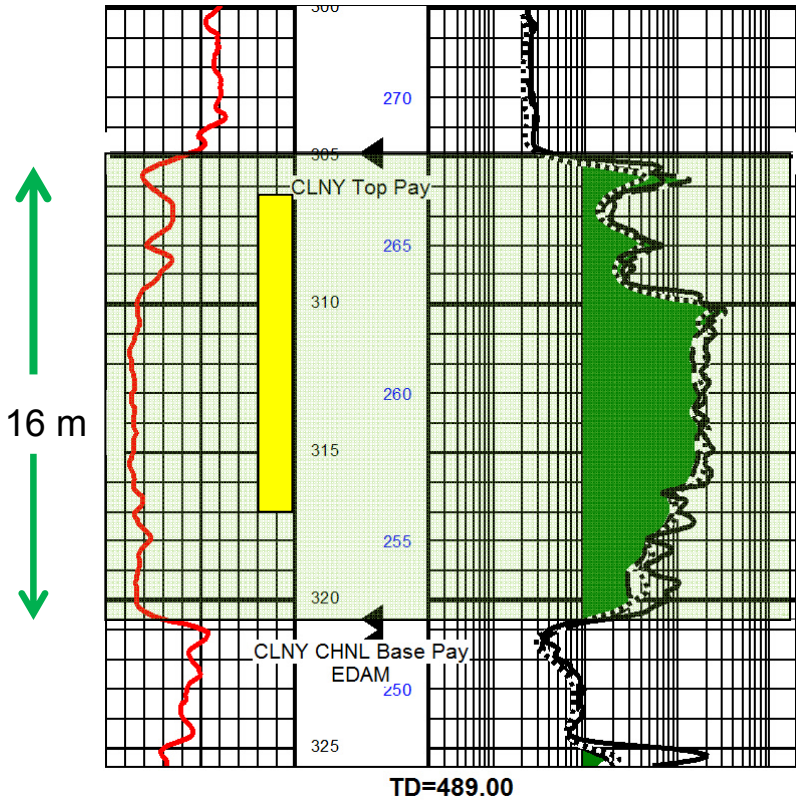


Sparky Formation Type Log



Colony Formation Type Log

100/04-21-064-04W00



Cored Interval

Top

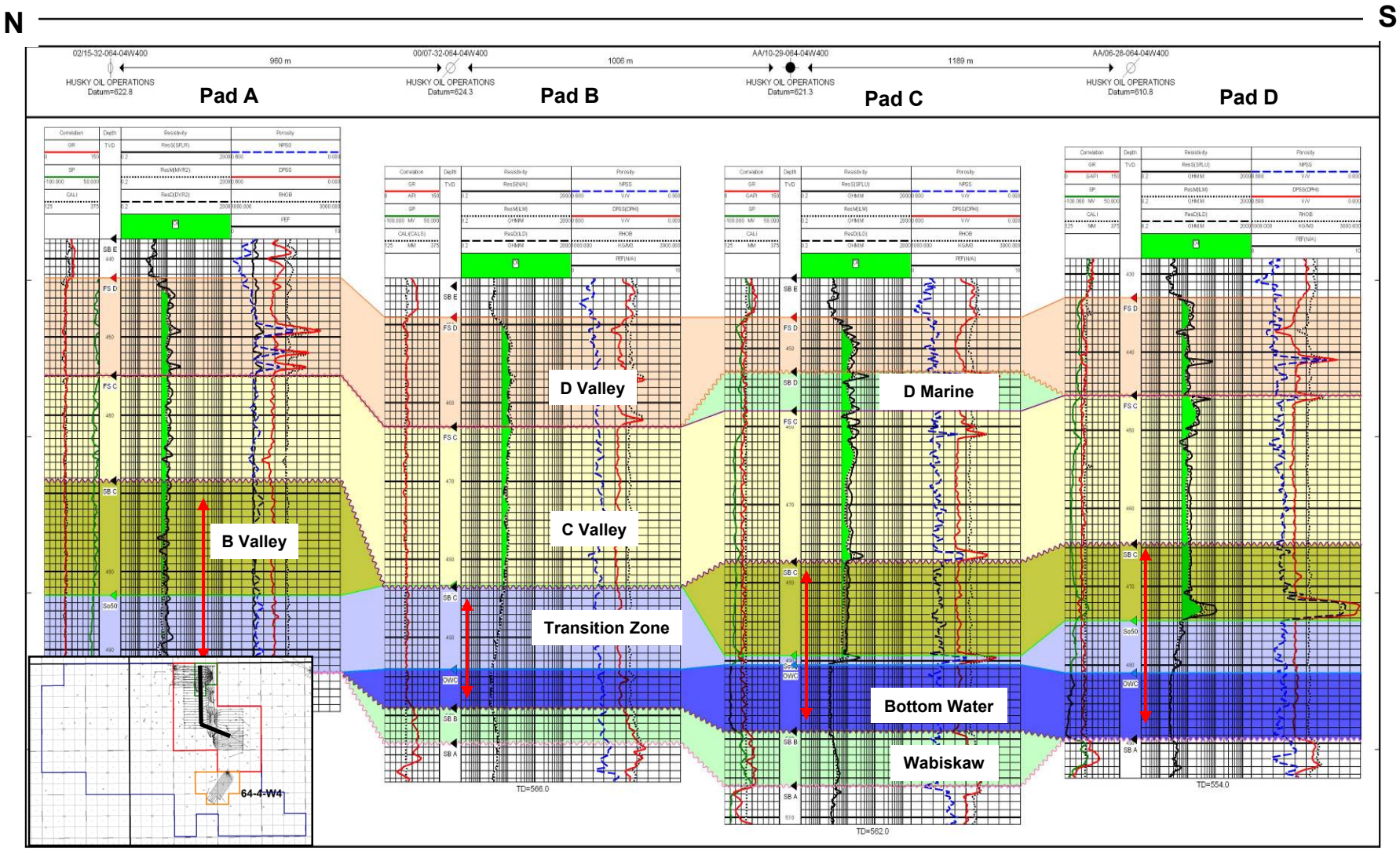
Bottom

0.75 m

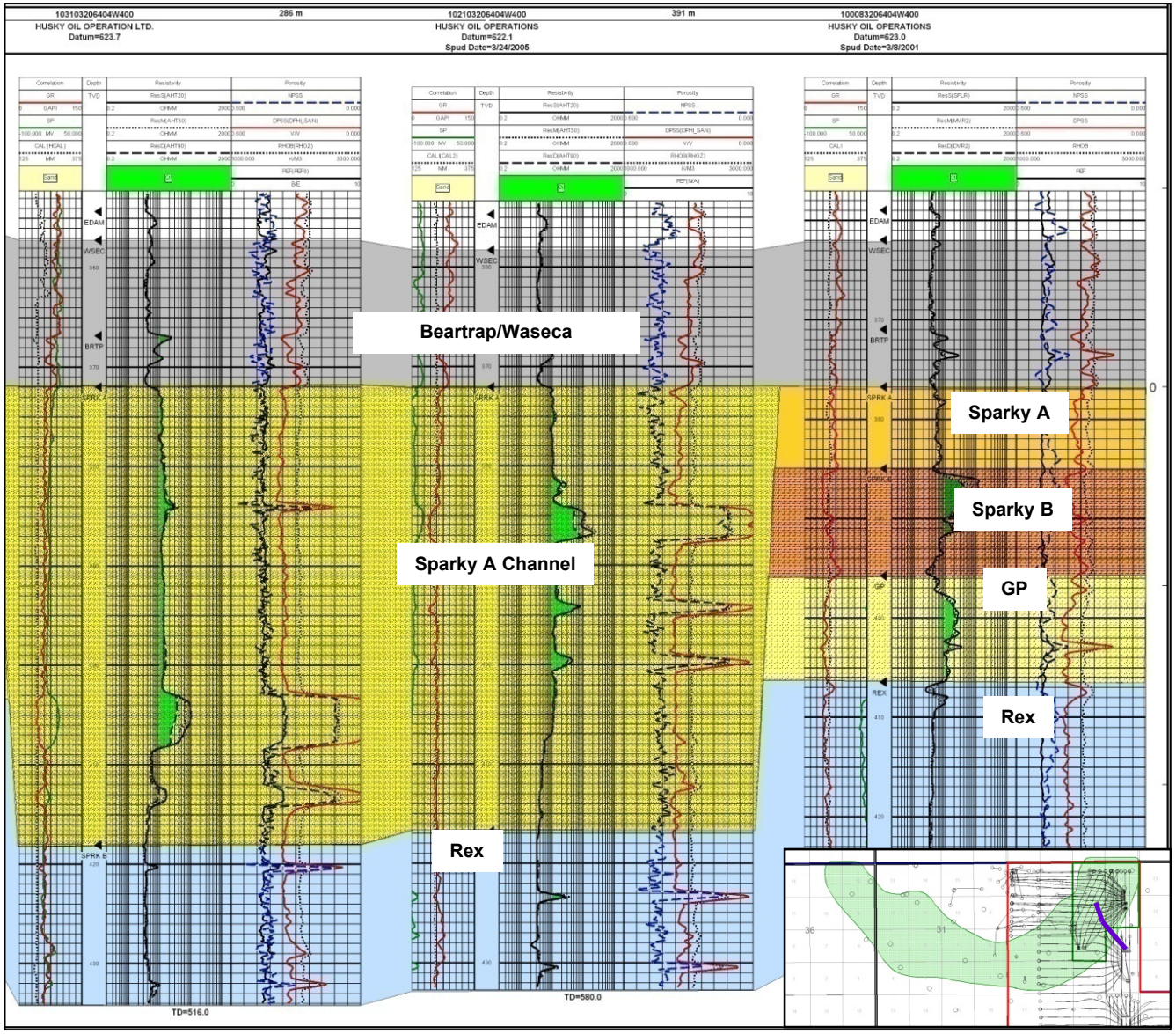
Cored Wells and Special Core Analysis

- No new wells cored or analysis completed in the reporting period

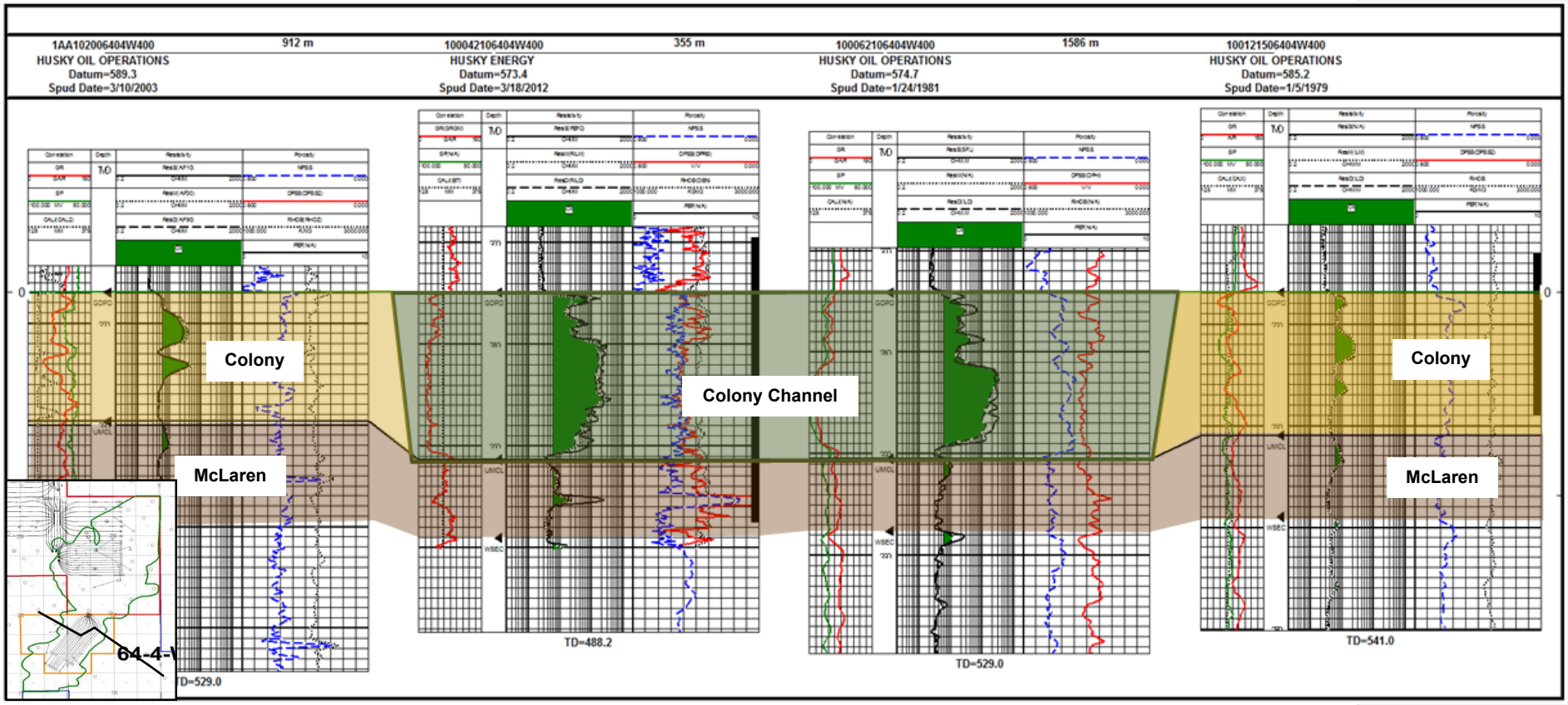
Representative Structural N-S Cross-section through the Approval Area



Representative Strike Cross-section through the Sparky Channel



Representative Strike Cross-section through the Colony Channel



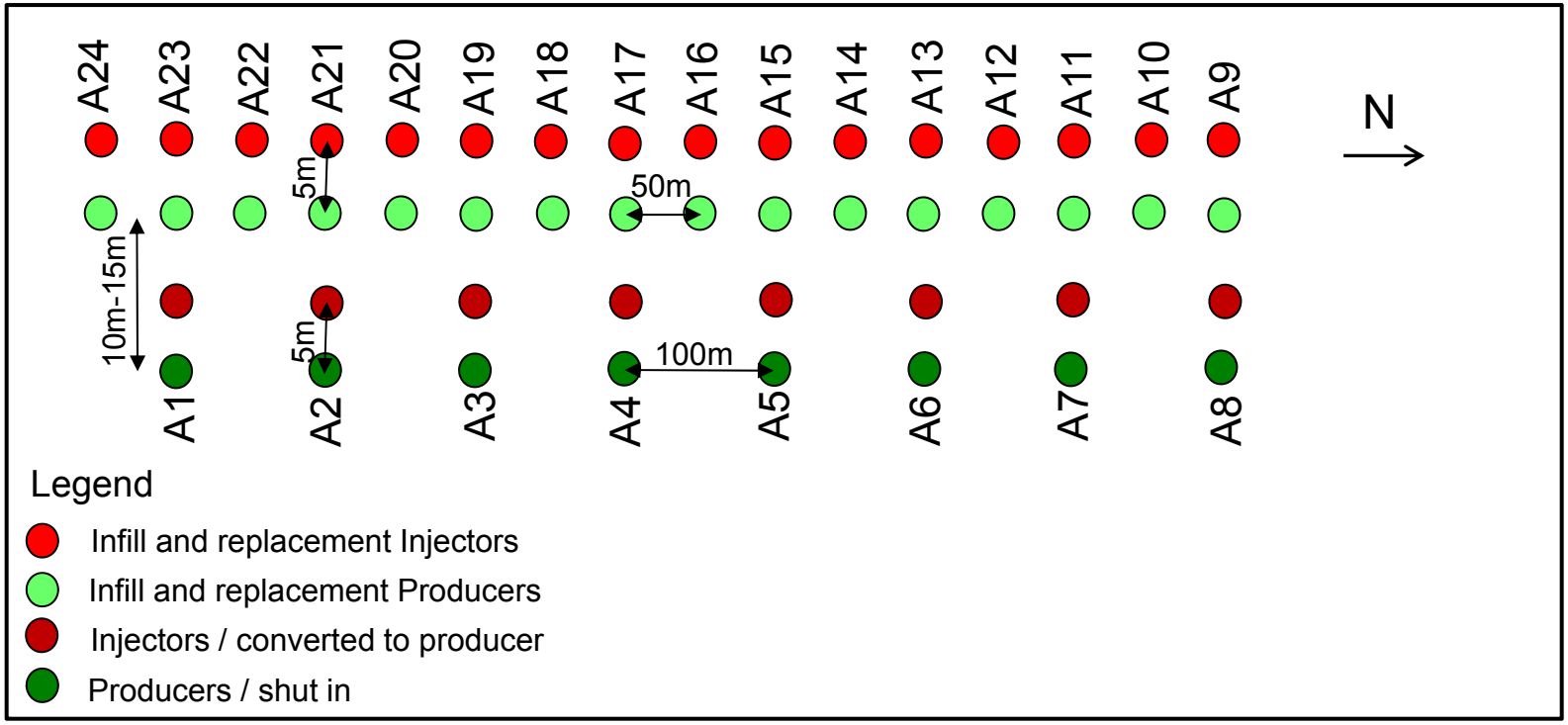
Surface/Subsurface Geomechanical Data/Analysis

Capping Shale Properties						
Well Pad	Issues to Date	Fracture Pressure Exceeded	Shale Depth (m)	Measured Fracture Gradient (kPa/m)	Measured Fracture Pressure (kPa)	Fracture Regime
CN	No	No	305	17.0	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

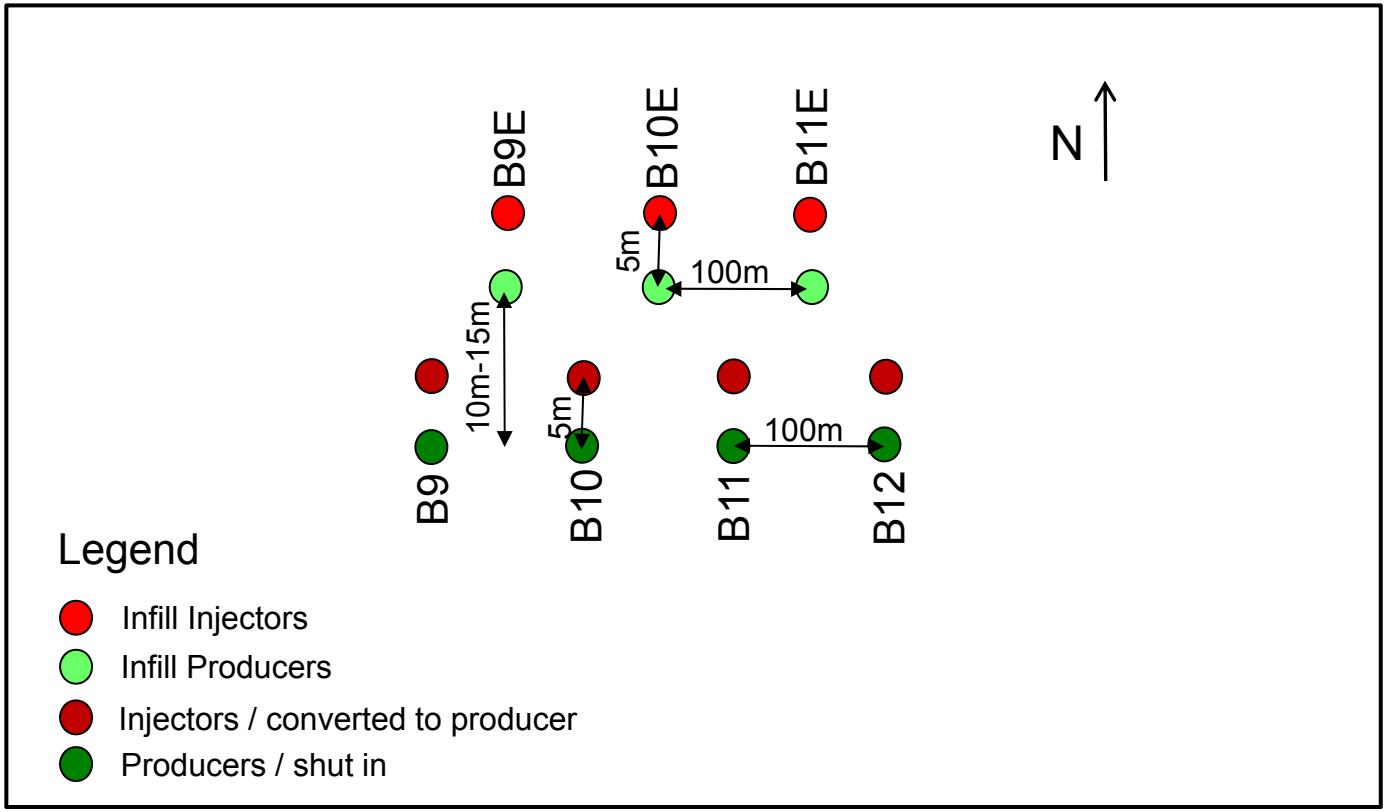
Pad A Well Spacing Schematic Cross-section

- 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 Cross-section

- 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 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
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

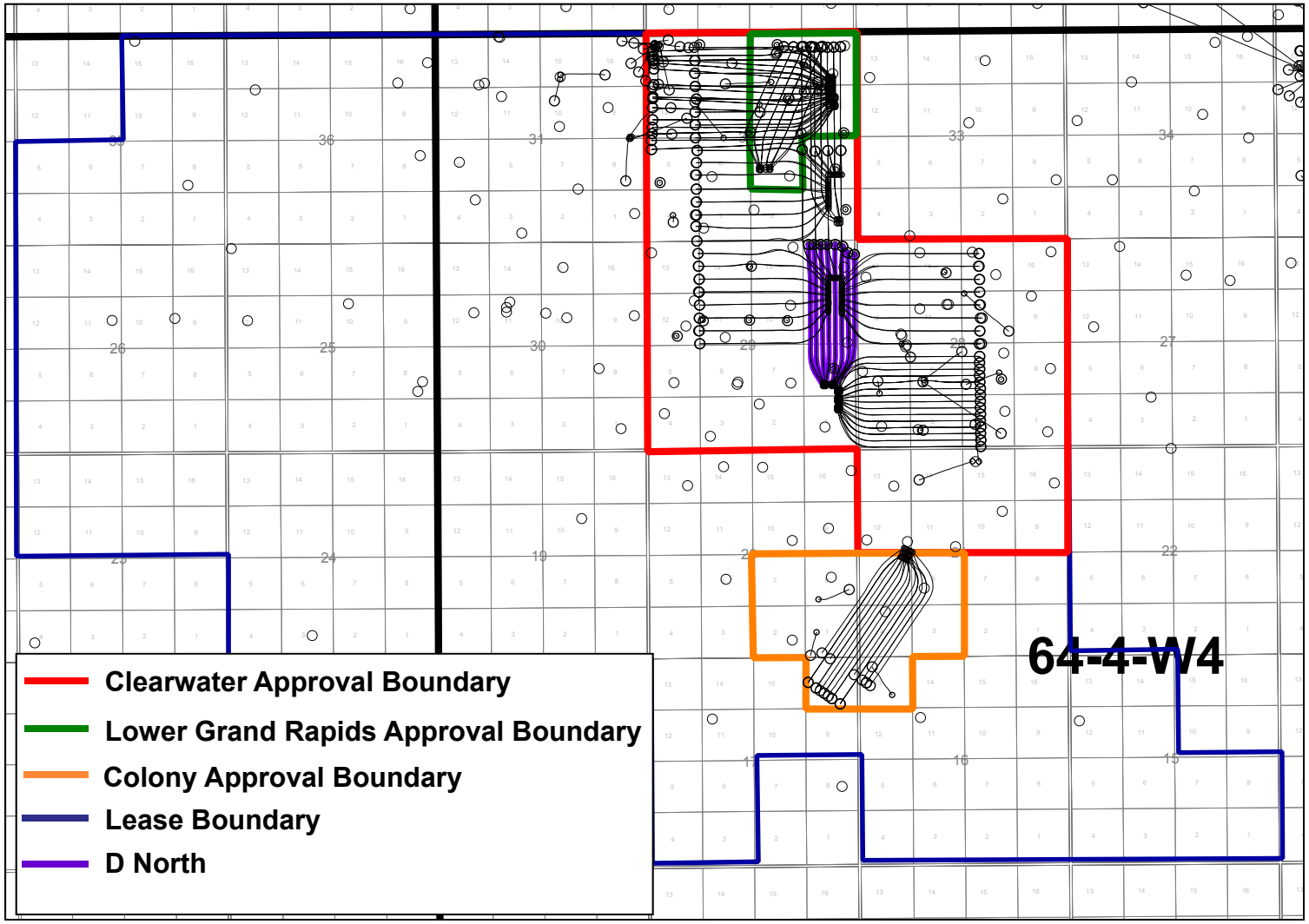
- No new Seismic data run or interpreted in the reporting period

3. Drilling and Completions

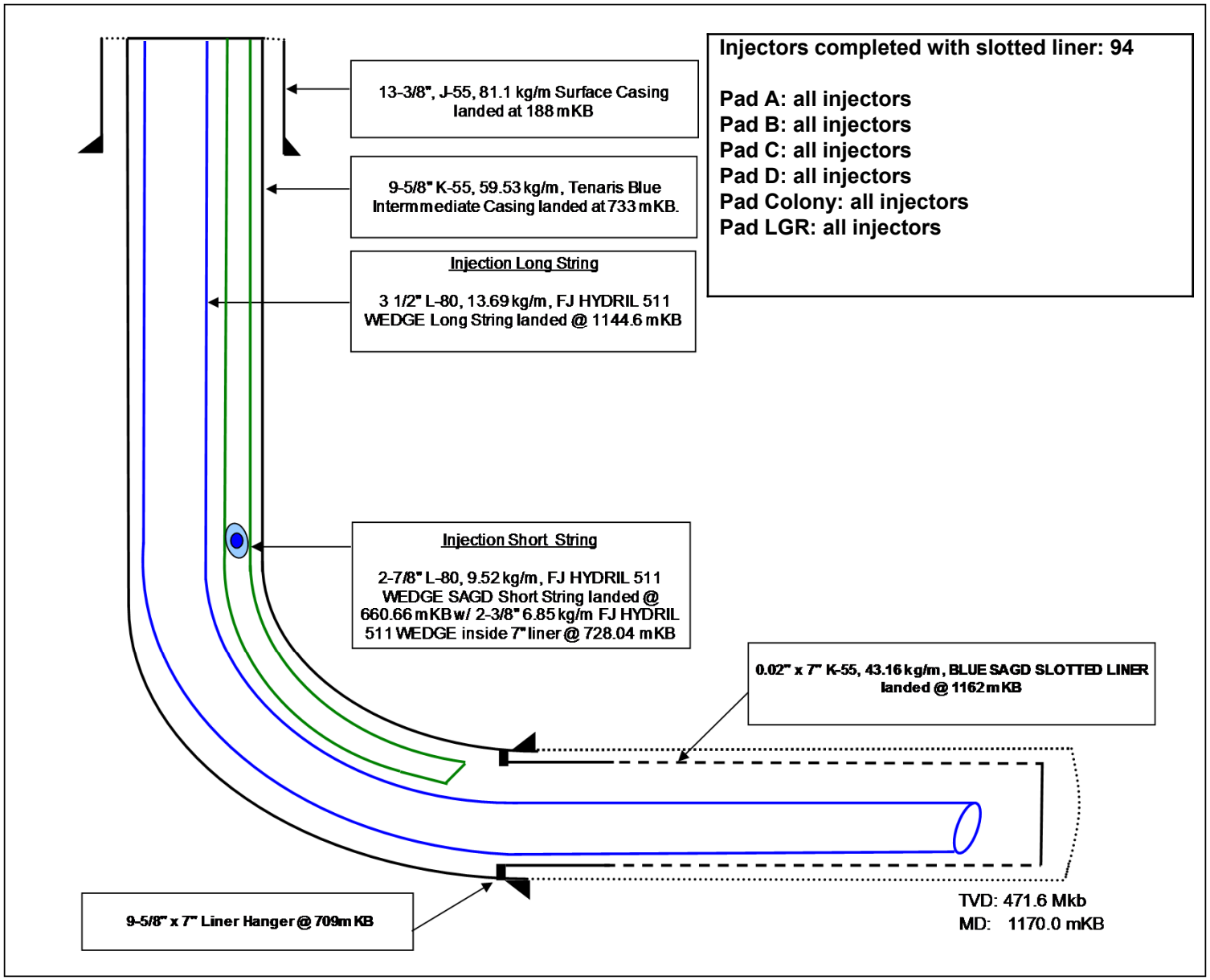
Drilling Results

Pad D North:

- 8 SAGD well pairs drilled in Q1 - Q2 2016



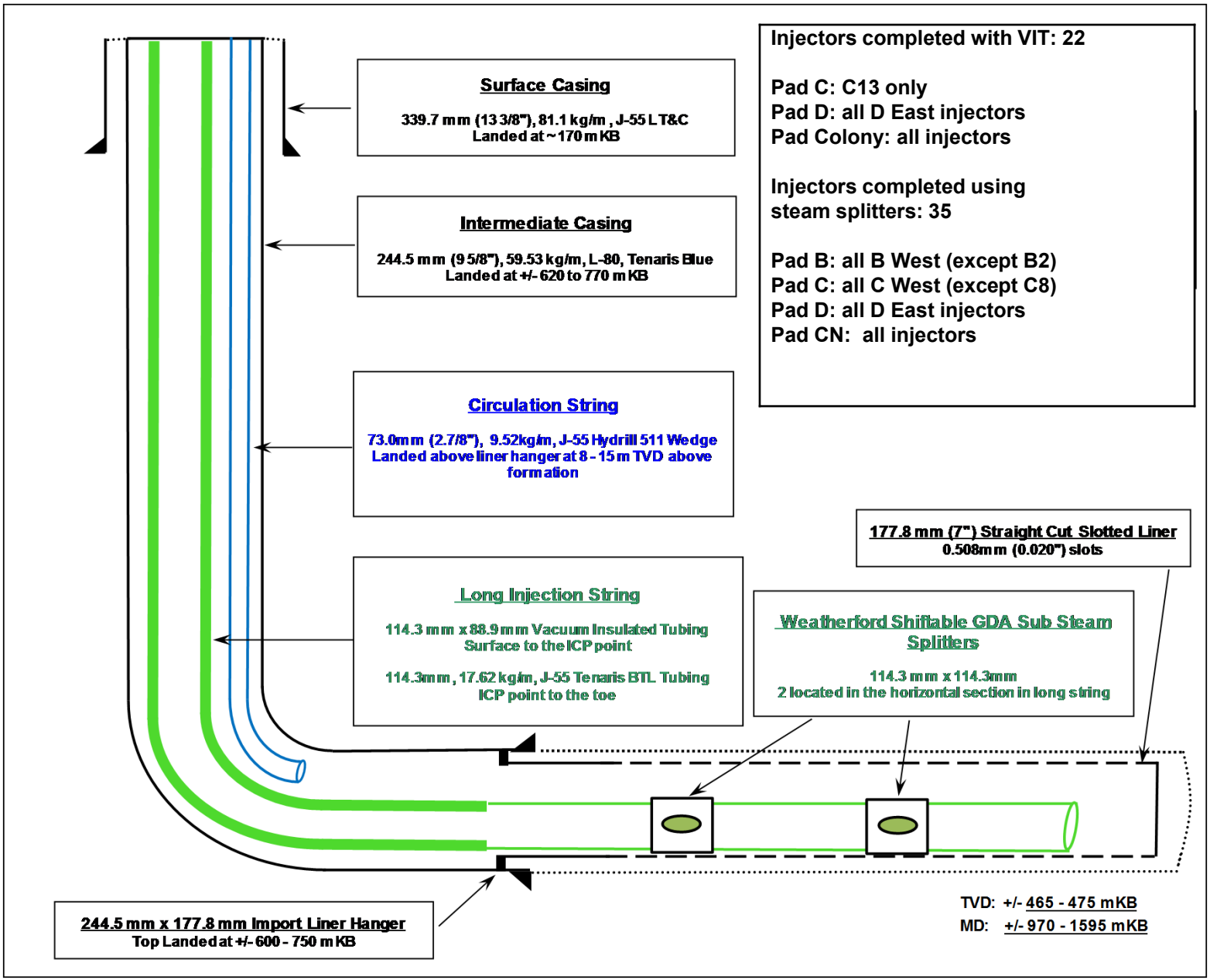
SAGD Well - Injector without VIT



Injectors completed with slotted liner: 94

Pad A: all injectors
Pad B: all injectors
Pad C: all injectors
Pad D: all injectors
Pad Colony: all injectors
Pad LGR: all injectors

SAGD Well - Injector with VIT



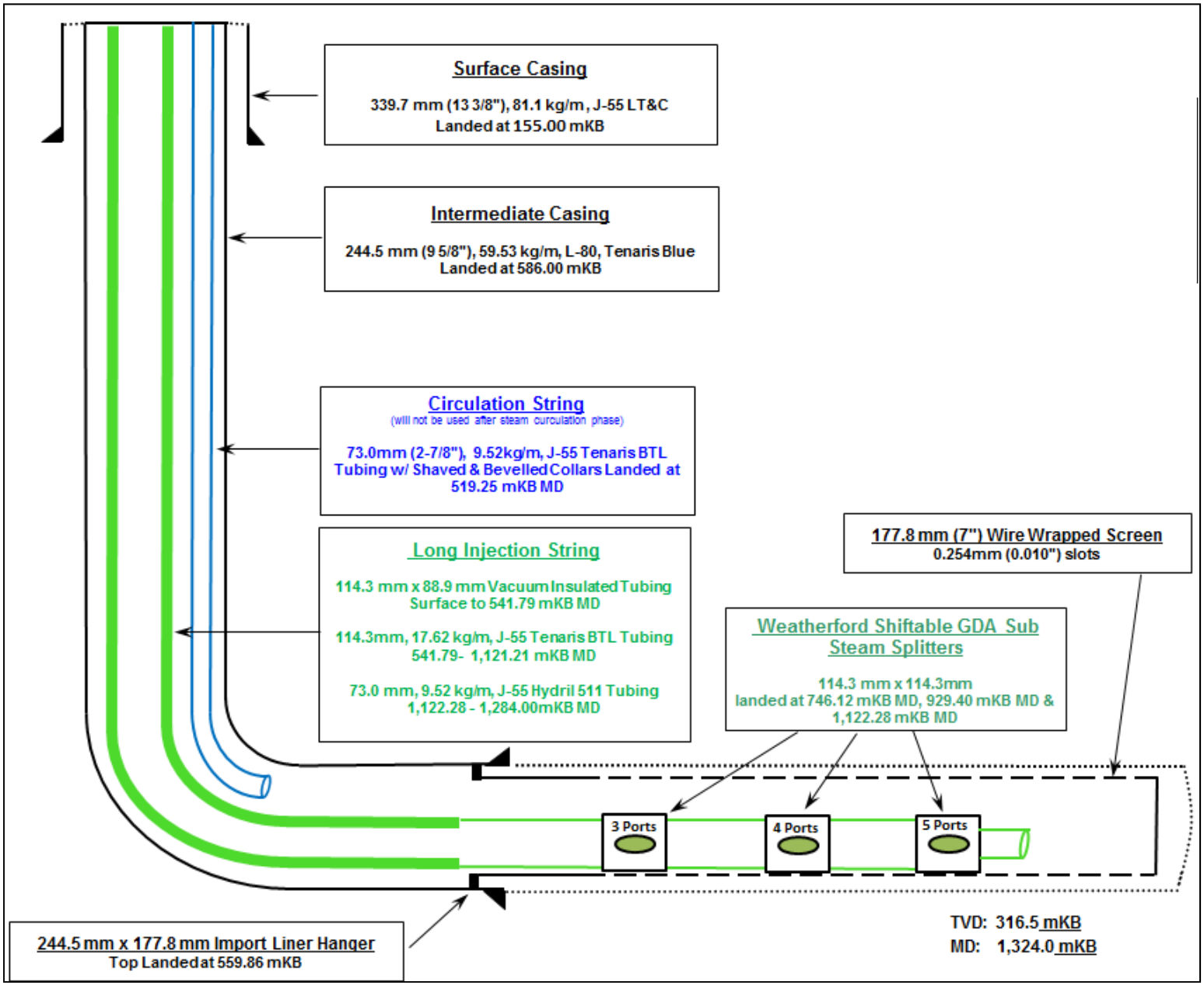
Injectors completed with VIT: 22

Pad C: C13 only
Pad D: all D East injectors
Pad Colony: all injectors

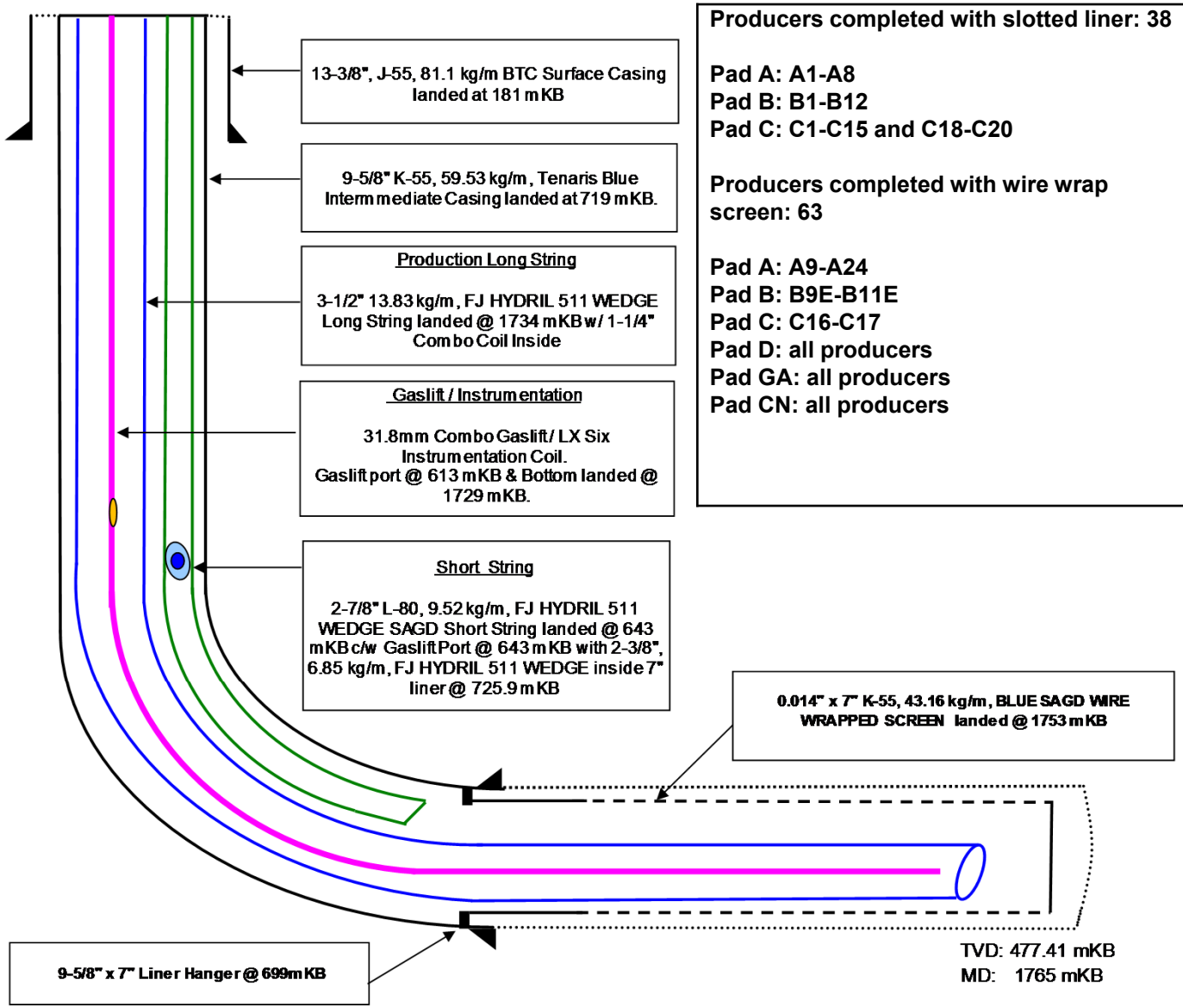
Injectors completed using steam splitters: 35

Pad B: all B West (except B2)
Pad C: all C West (except C8)
Pad D: all D East injectors
Pad CN: all injectors

SAGD Well Pad CN - Injector with VIT



SAGD Well - Producer with Gas-Lift



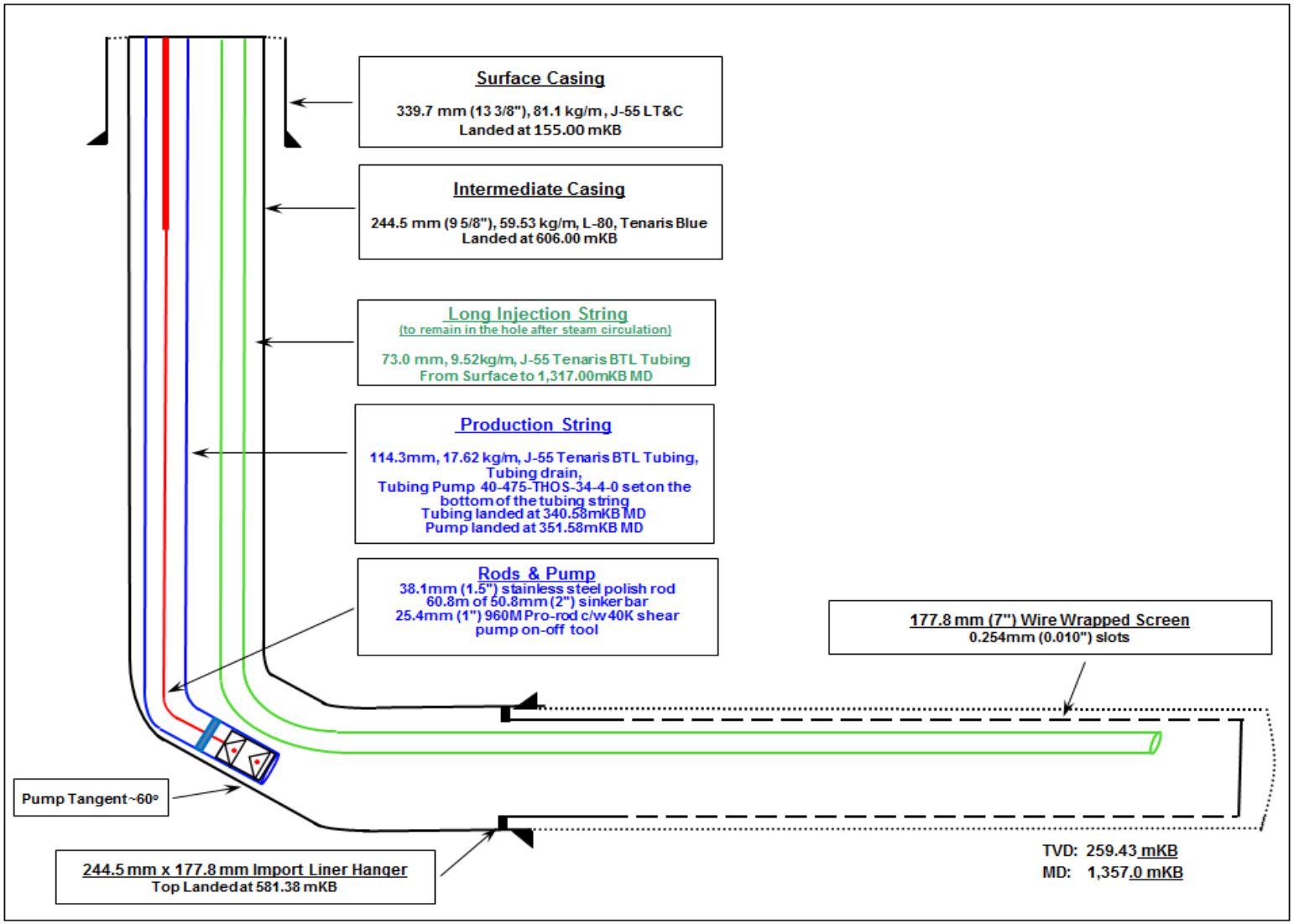
Producers completed with slotted liner: 38

Pad A: A1-A8
Pad B: B1-B12
Pad C: C1-C15 and C18-C20

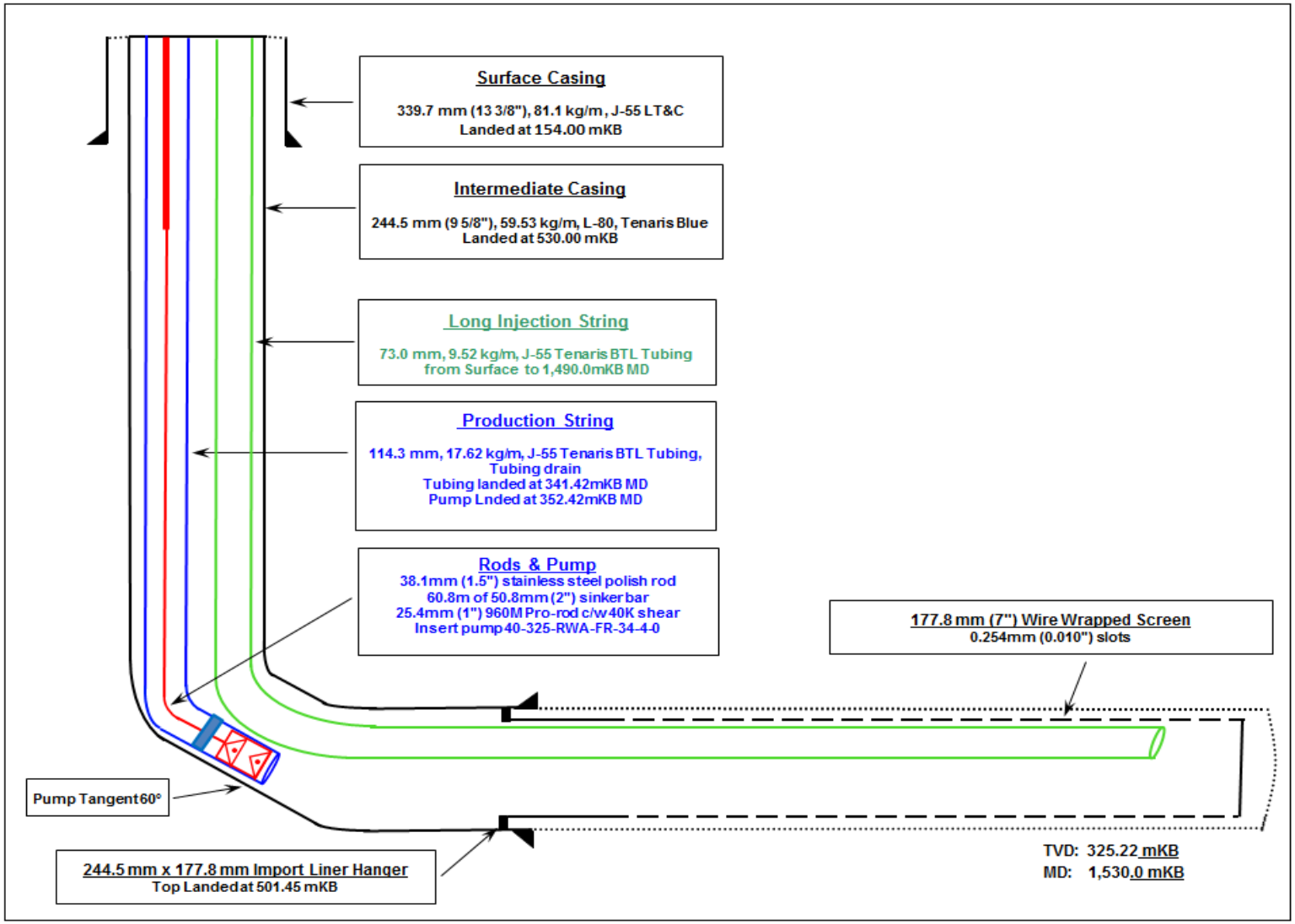
Producers completed with wire wrap screen: 63

Pad A: A9-A24
Pad B: B9E-B11E
Pad C: C16-C17
Pad D: all producers
Pad GA: all producers
Pad CN: all producers

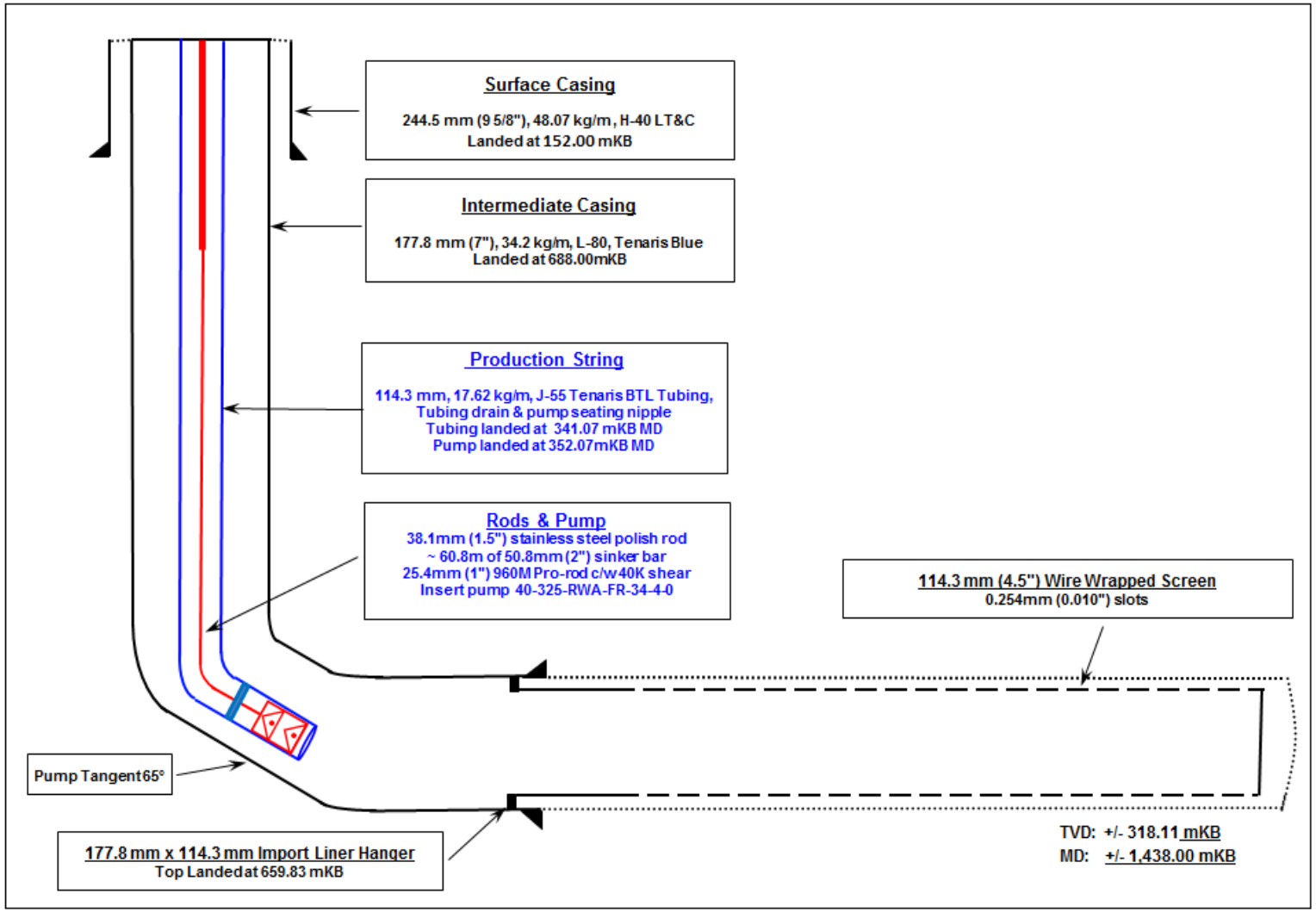
SAGD Well Pad CN - Producer with Rod-Pump



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



Infill Well Pad CN - Producer with Rod-Pump



Completion - Key Learnings

- Production - Slotted Liners vs Wire Wrap Screens:
  - Slotted liner scaling has been a chronic problem:
    - Short term solution - Acidization
    - Long term solution - perforated liners
  - Wire-wrapped screens, which increase the open area, have been used in producers drilled since 2009:
    - No scaling issues observed in these wells
  - Current plan is to complete future producers with wire wrap screen

- Injection - VIT (Vacuum Insulated Tubing) 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

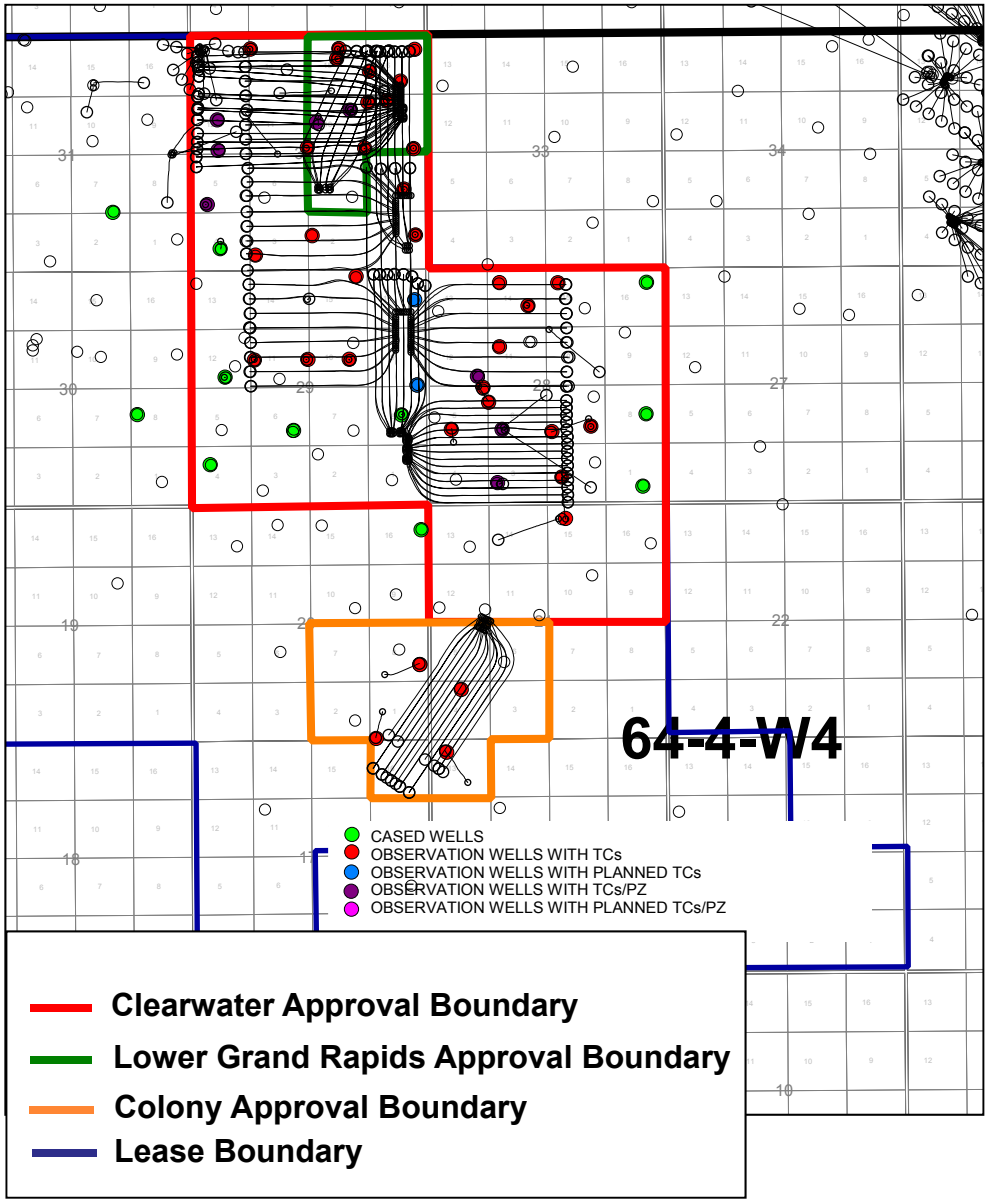
Artificial Lift

1. Rod-pump: Pad CN
   - 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

2. Gas-lift: All producers (except Pad CN)
   - 88 SAGD producers
   - 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

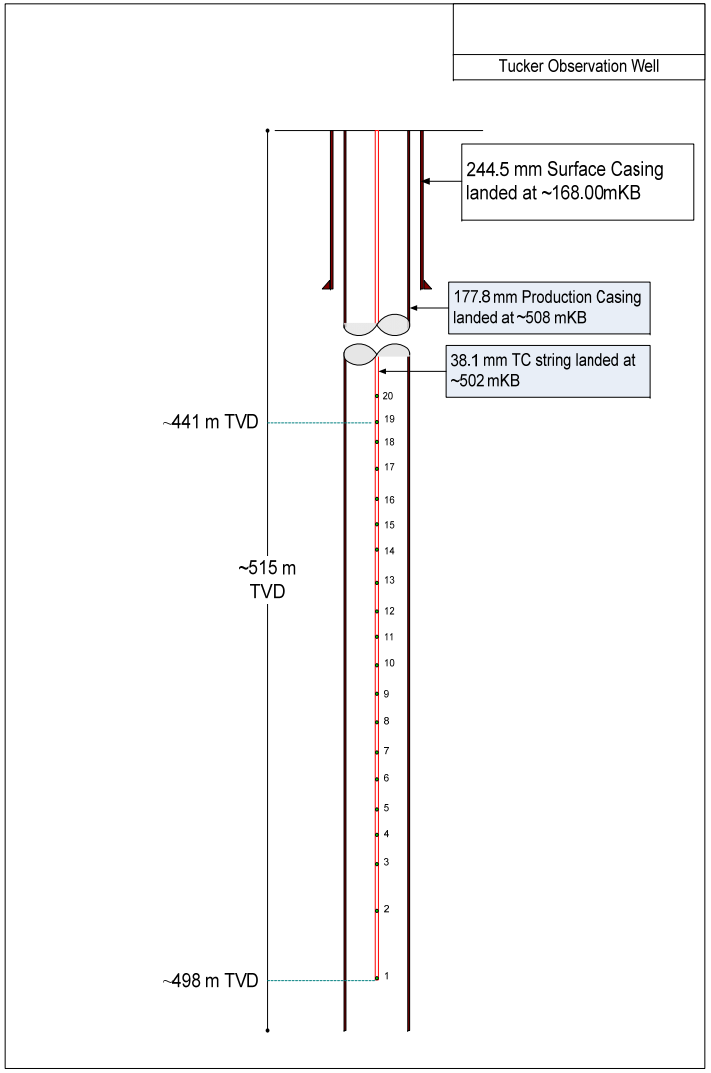
Instrumentation – Observation Wells Map



Instrumentation in OBS and SAGD Wells

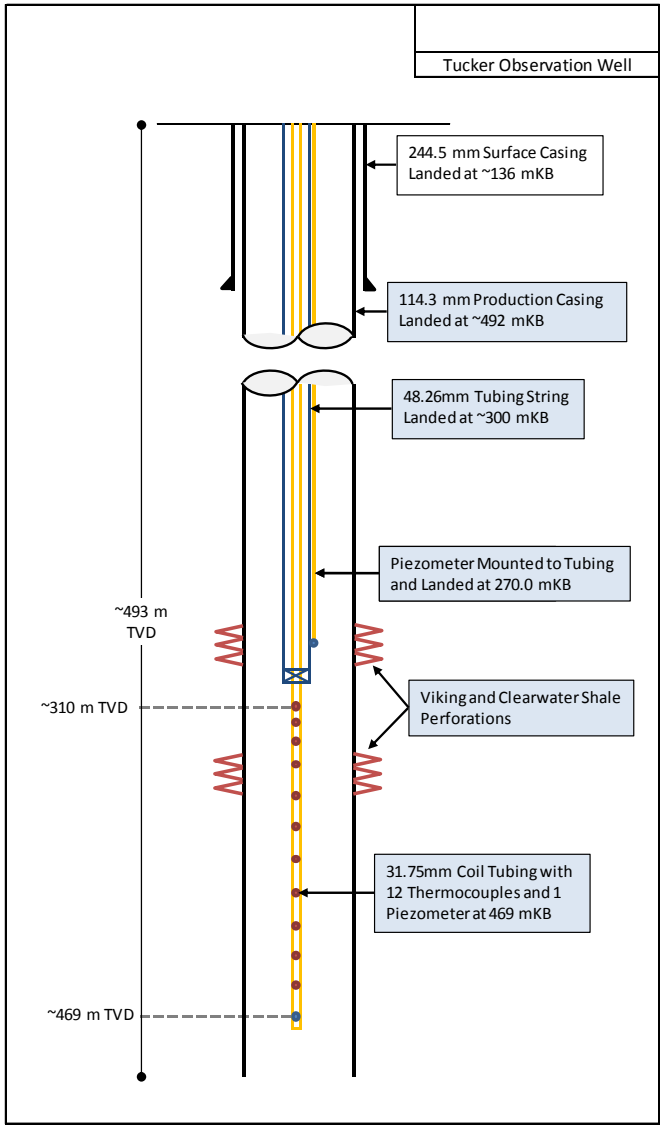
- 42 OBS Wells with Instrumentation:
  - 34 wells: thermocouple only
  - 8 wells: both thermocouple & piezometer
- 2 Planned OBS Wells (convert existing wells):
  - 2 wells for Pad D North: thermocouple only
- SAGD Injectors – wells use blanket gas to measure pressure and for insulation
- SAGD Producers – 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

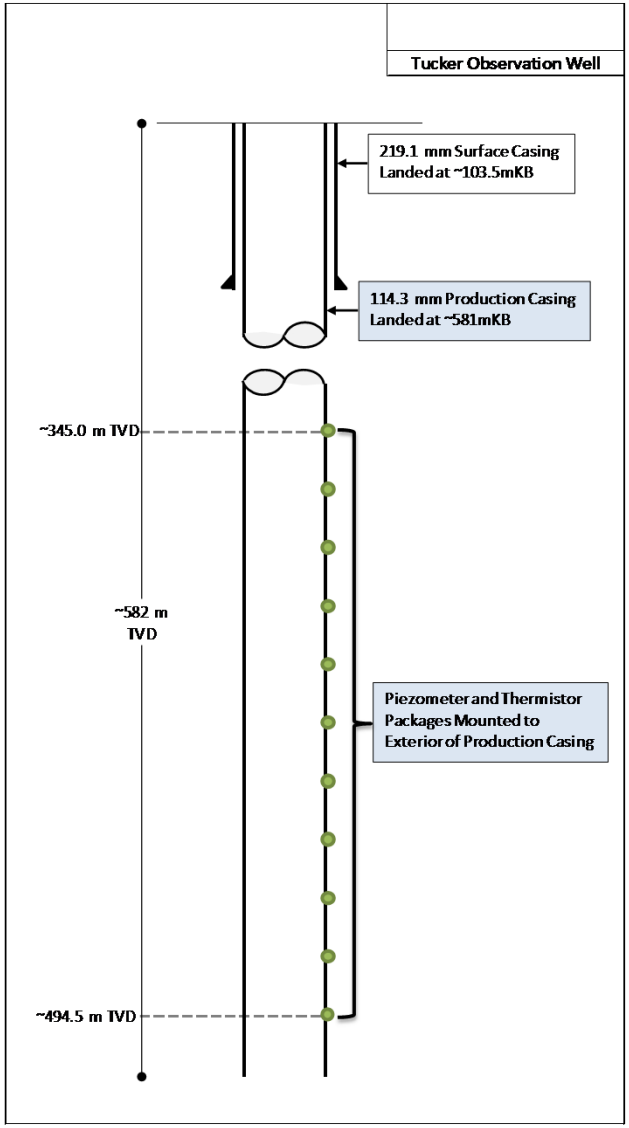


Thermocouple and Piezometer OBS Wells

Type 1 – Instrumentation Inside Tubing



Type 2 – Instrumentation Outside of Casing



Circulation Strategy

- Key learnings:
  - Same circulation strategy works for Colony and Clearwater
  - Colony had shorter circulation duration due to better reservoir quality and higher water mobility

Parameter	Clearwater	Colony
Steam Rate (m^3/d)	100-120	120-150
Pressure	Close to initial reservoir pressure	Close to initial reservoir pressure
Time	3 – 4 months	2 months

6. 4D Seismic

4D Seismic

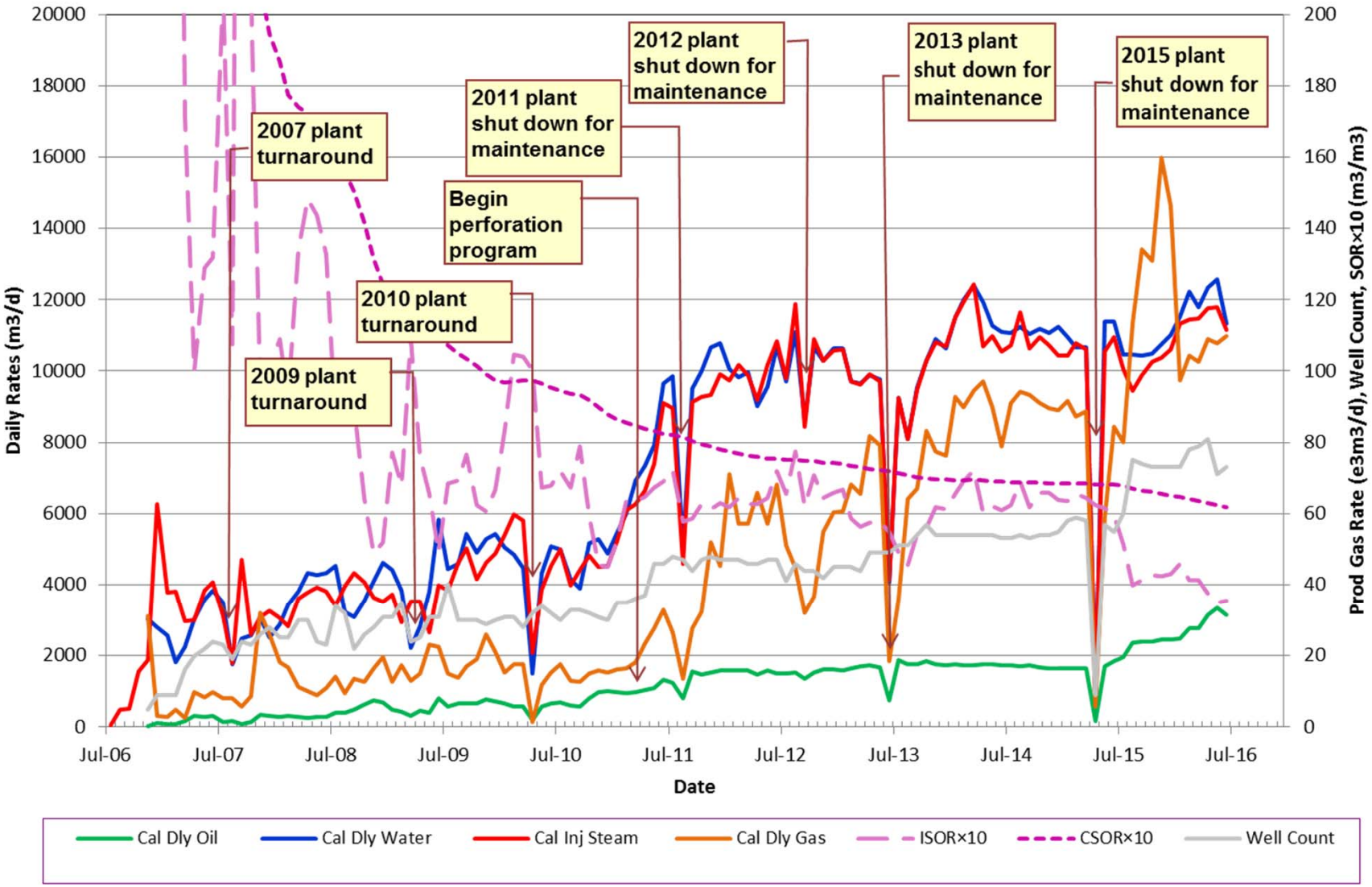
- No 4D seismic in the reporting period

7. Scheme Performance

Scheme Performance Prediction Methodology

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

Production and Injection History



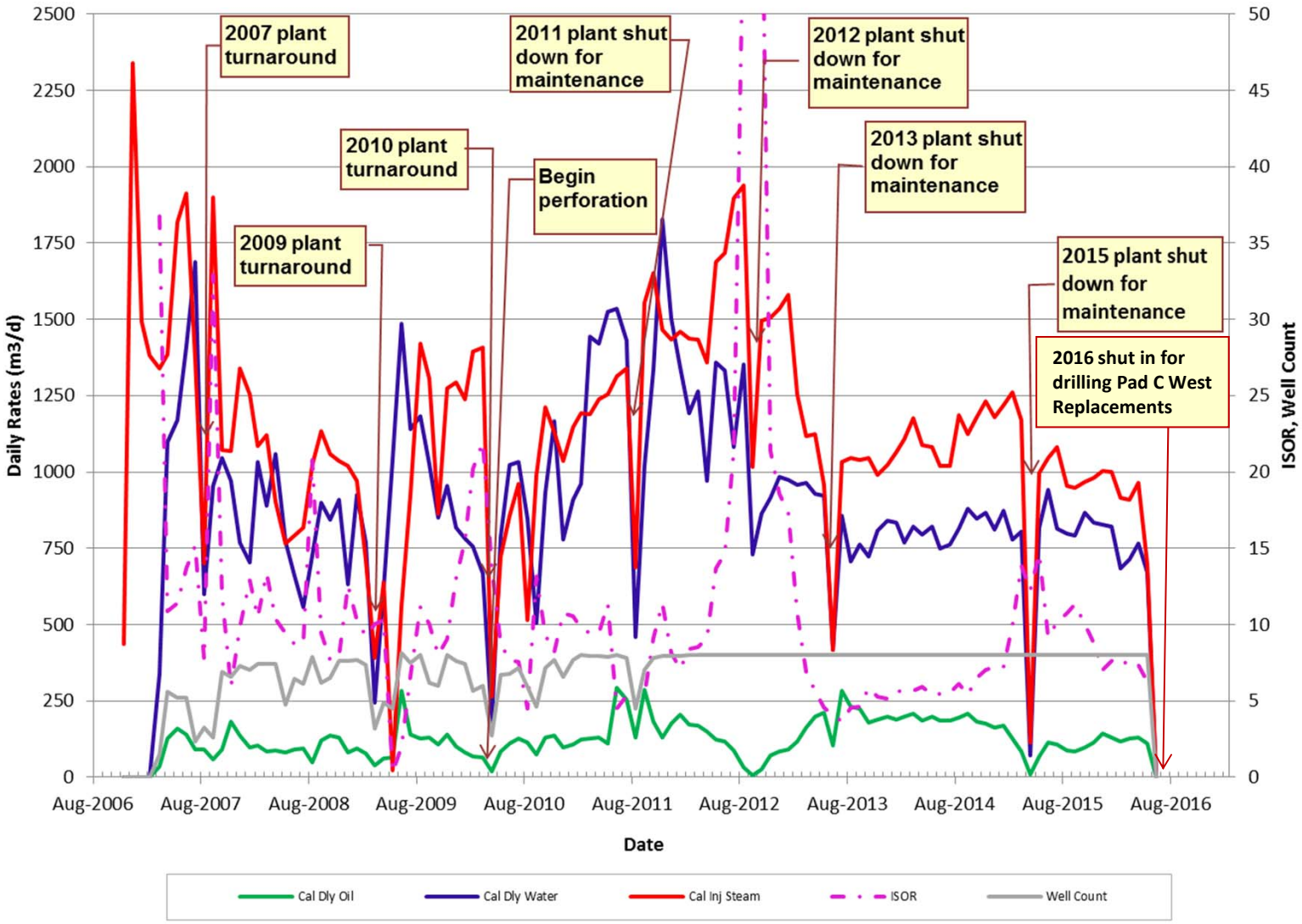
Production vs. Approval Capacity Variance

- 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 circulating
  - Variable steam chamber development

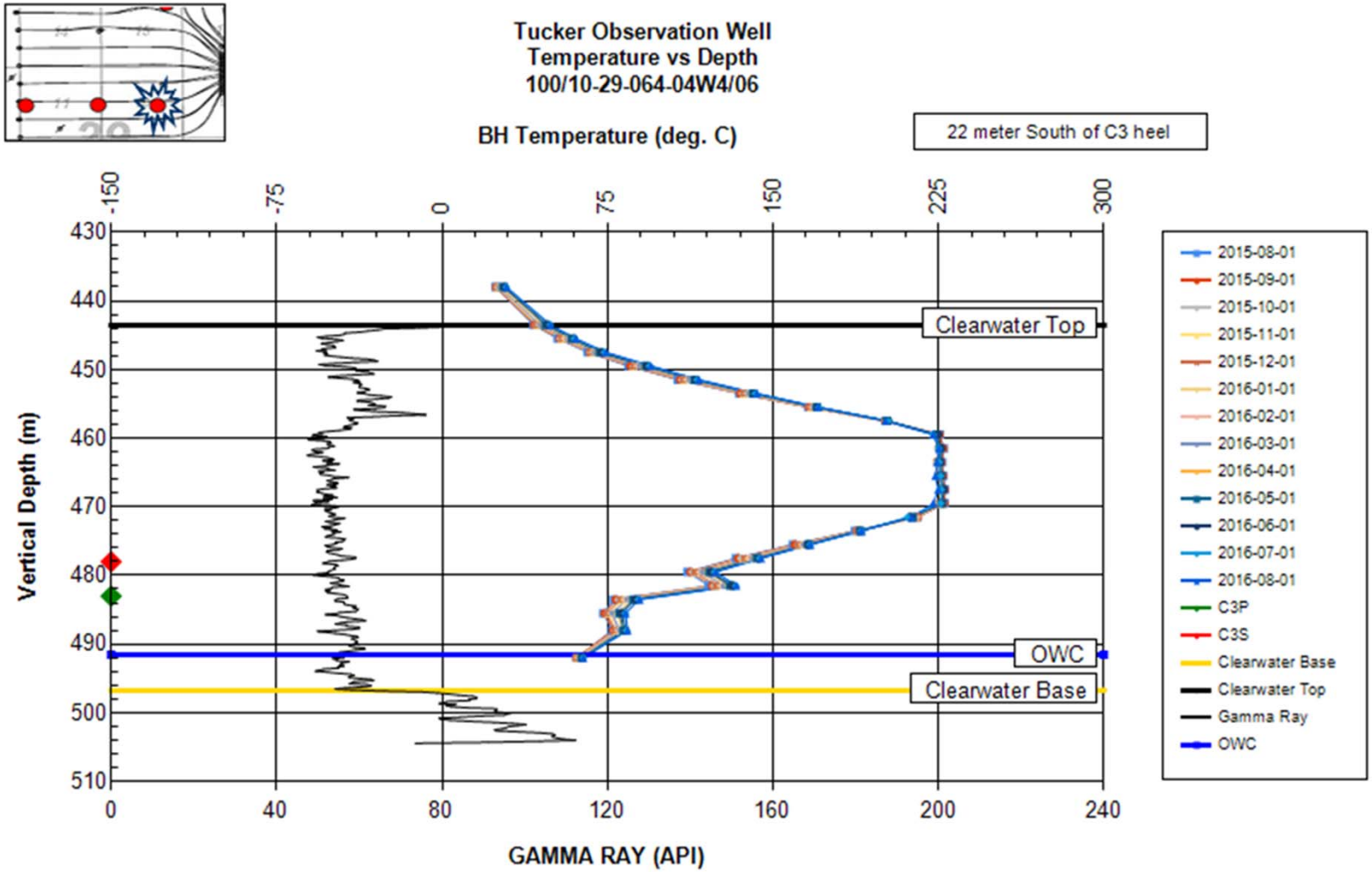
- All new well pairs drilled to the base of SAGD net pay
  - Pad C East
  - Pad B North Infill
  - Pad A Infill and Replacement Wells
  - Pad GA
  - Pad D East
  - Pad CN
  - Pad D North

- Revised completion of new wells
  - Dual string completions in both injector and producer
  - Injectors completed with VITs and steam splitters for Pads D East 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

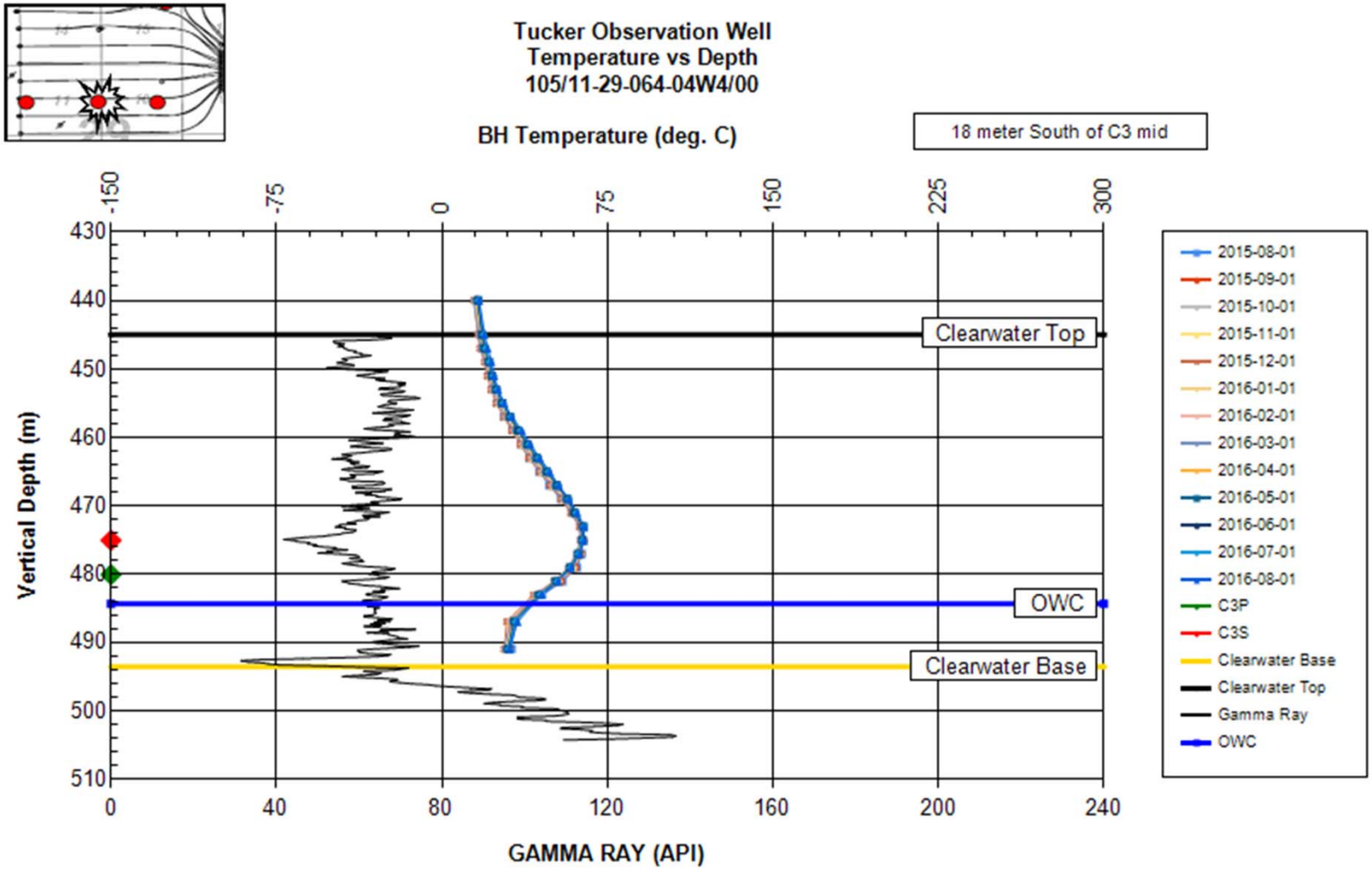
Pad C West Performance - Low Recovery Example



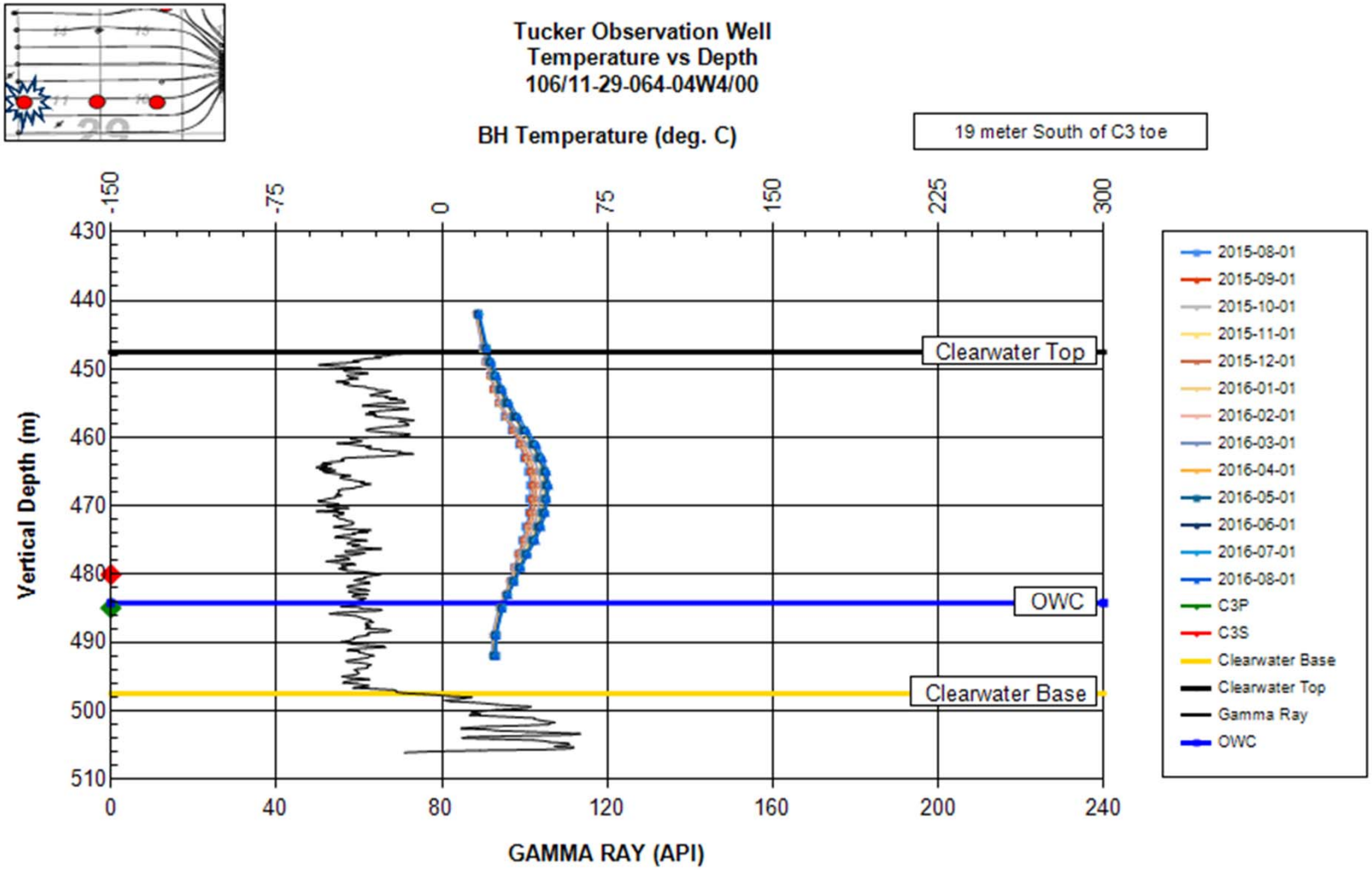
Pad C West Heel Observation Well



Pad C West Mid Observation Well



Pad C West Toe Observation Well



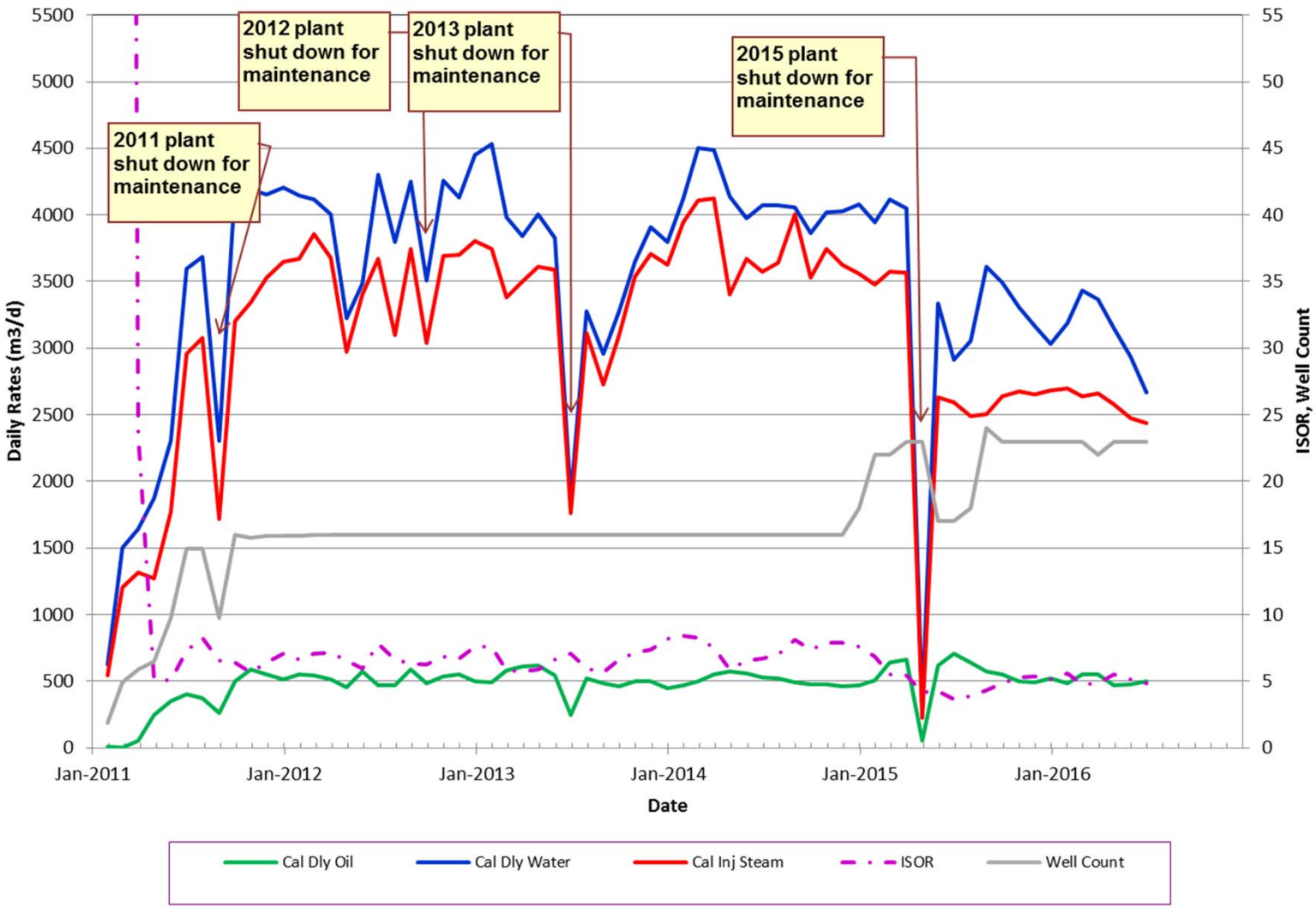
Discussion of Pad C West Performance

- The OBS well 22 m south of C3 Heel showing good steam chamber development

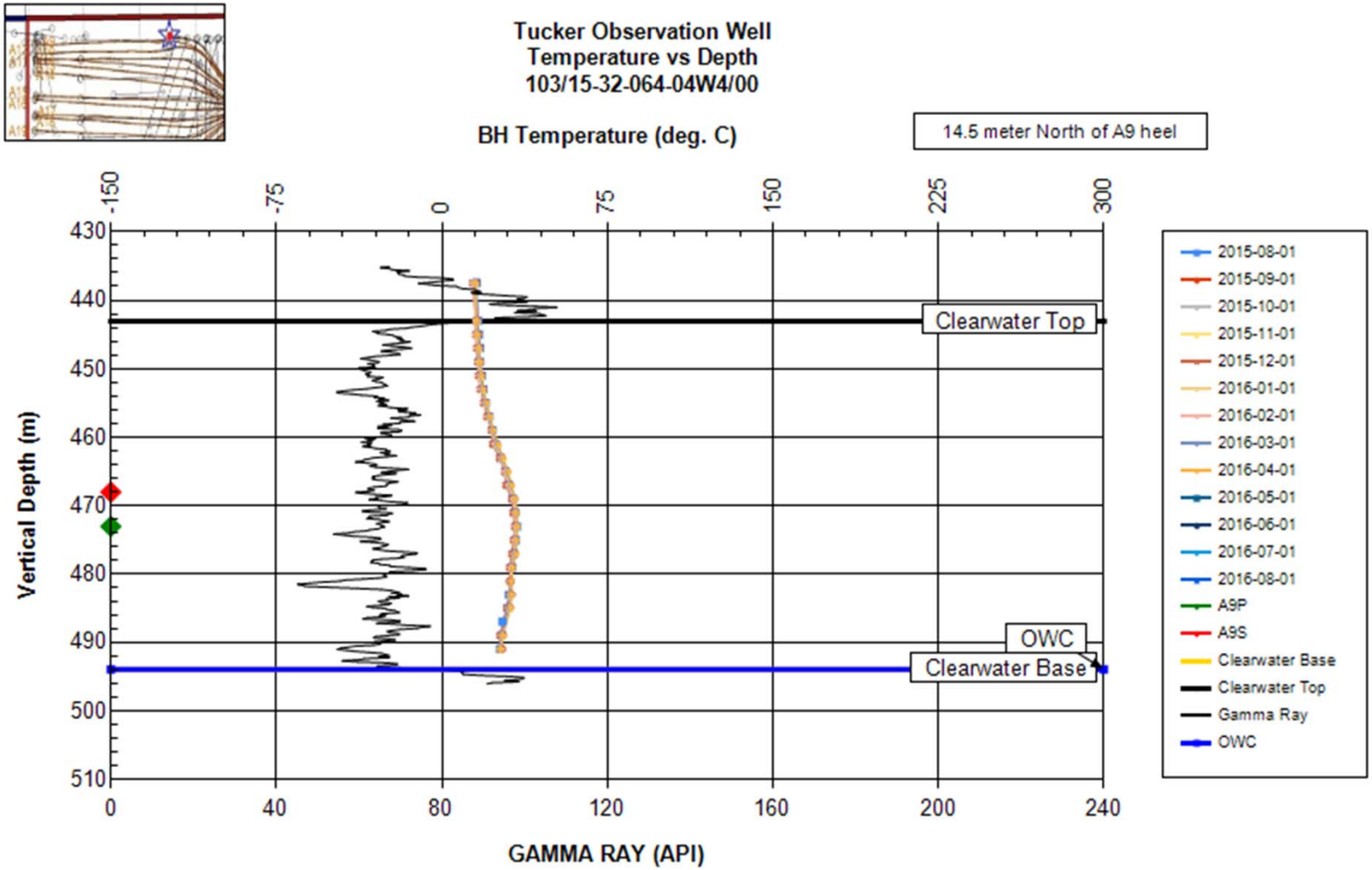
- Pad C West performance indicators as of July 31, 2016:
  - Cum. Oil: 436,027 m^3
  - Cum. Steam Injected: 3,962,865 m^3
  - Cum. Water Produced: 3,095,590 m^3
  - CSOR: 9.1

- Pad C West performance for the reported period:
  - Cum. Oil: 38,015 m^3
  - Oil Rate per well: 14.2 m^3/day
  - SOR: 8.4

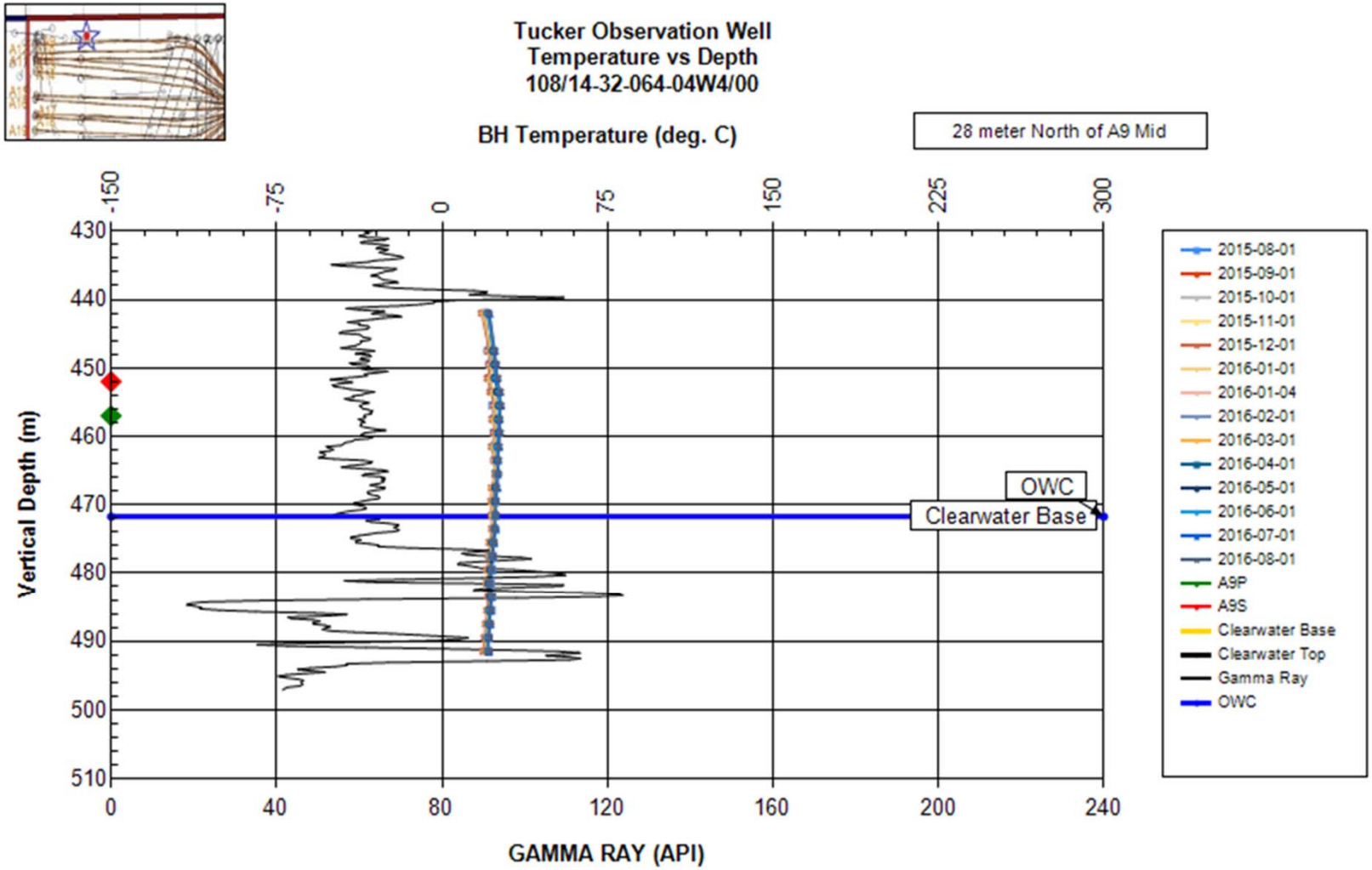
Pad A Performance - Medium Recovery Example



Pad A Wells Heel Observation Well



Pad A Wells Mid Observation Well



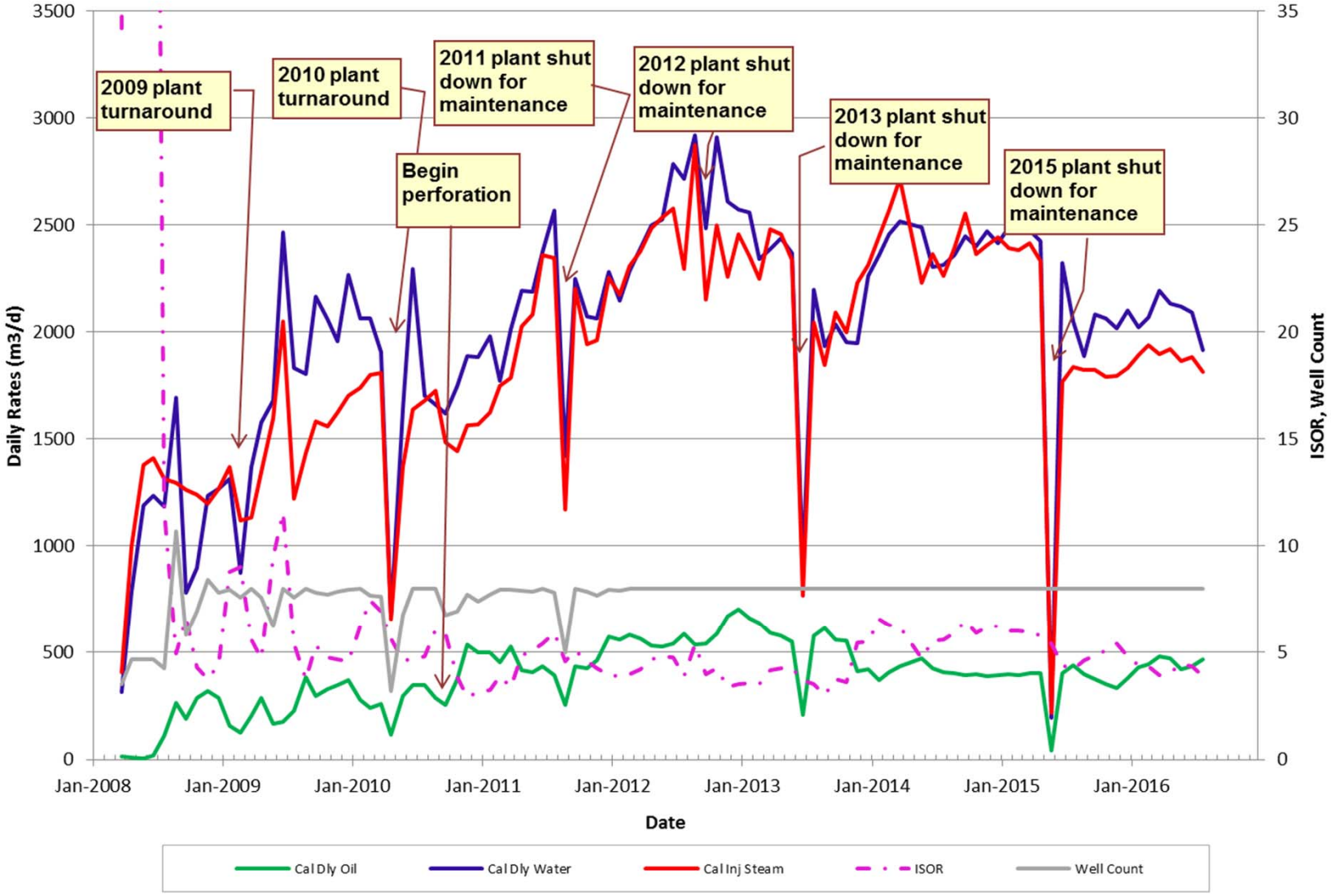
Discussion of Pad A Wells Performance

- The OBS well 14.5 m north of A9 heel showing minimal steam chamber development

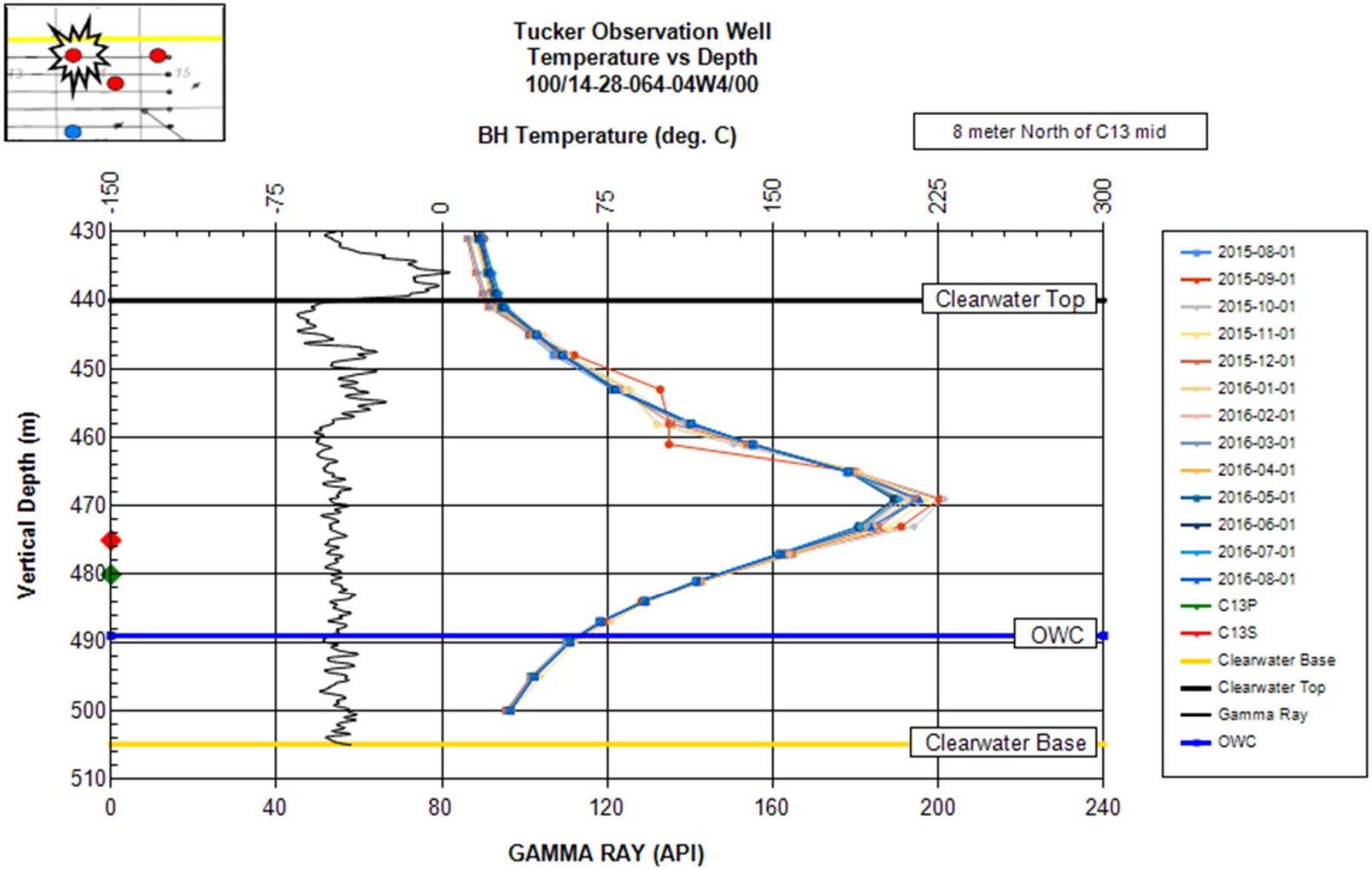
- Pad A performance indicators as of July 31, 2016:
  - Cum. Oil: 966,984 m^3
  - Cum. Steam Injected: 6,143,312 m^3
  - Cum. Water Produced: 7,057,765 m^3
  - CSOR: 6.4

- Pad A performance for the reported period:
  - Cum. Oil: 192,720 m^3
  - Oil Rate per well: 23.3 m^3/day
  - SOR: 4.9

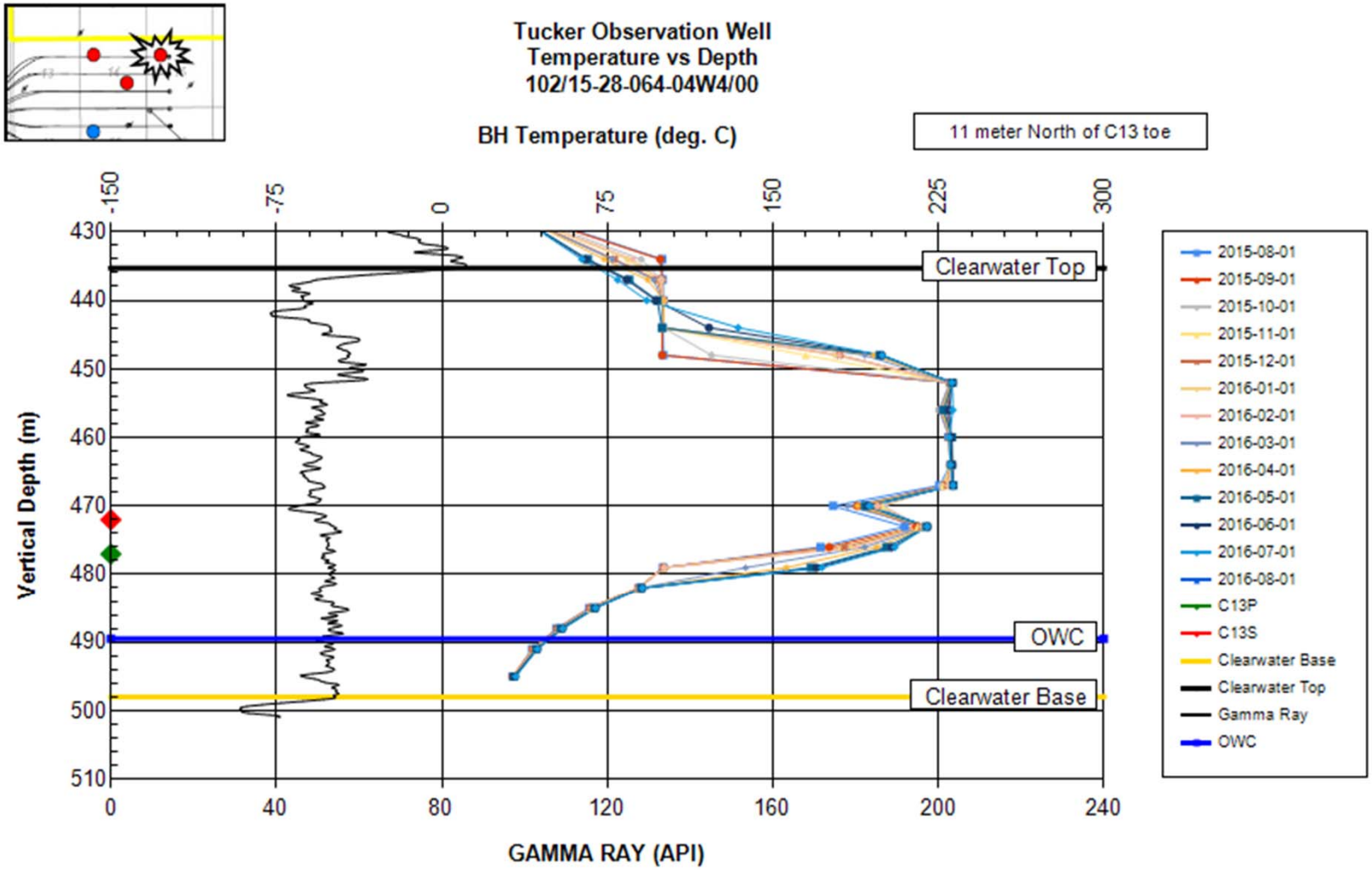
Pad C East Performance – High Recovery Example



Pad C East Mid-Section Observation Well



Pad C East Toe Observation Well



Discussion of Pad C East Performance

- The OBS well 11 m north of C13 toe is showing very good steam chamber development in both horizontal and vertical directions

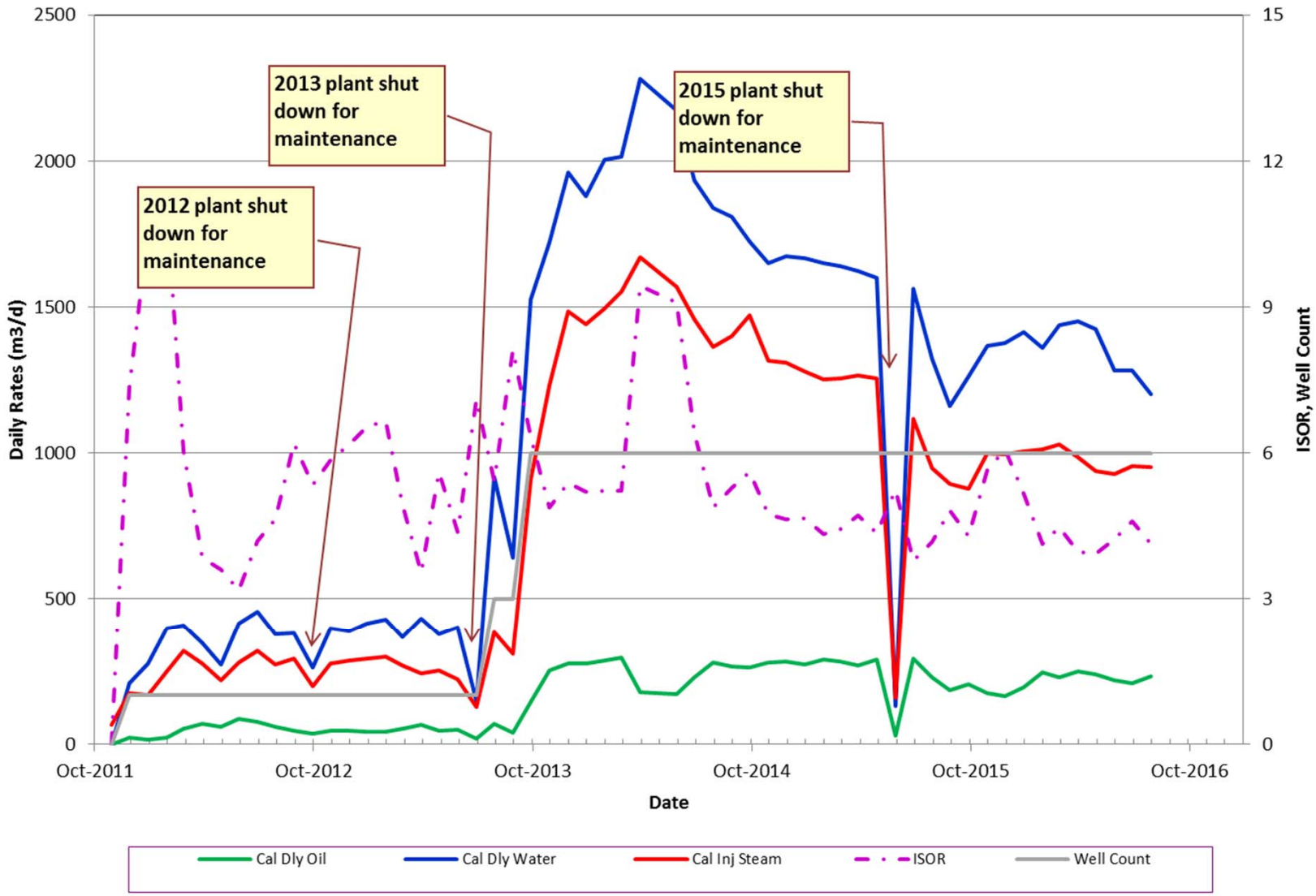
- Pad C East performance indicators as of July 31, 2016:
  - Cum. Oil: 1,188,189 m^3
  - Cum. Steam Injected: 5,733,349 m^3
  - Cum. Water Produced: 6,103,733 m^3
  - CSOR: 4.8

- Pad C East performance for the reported period:
  - Cum. Oil: 152,085 m^3
  - Oil Rate per well: 52.1 m^3/day
  - SOR: 4.5

- The well placement was mainly above the transition zone

- Circulation start-up strategy was successfully implemented

Pad Lower Grand Rapids (GA) Performance



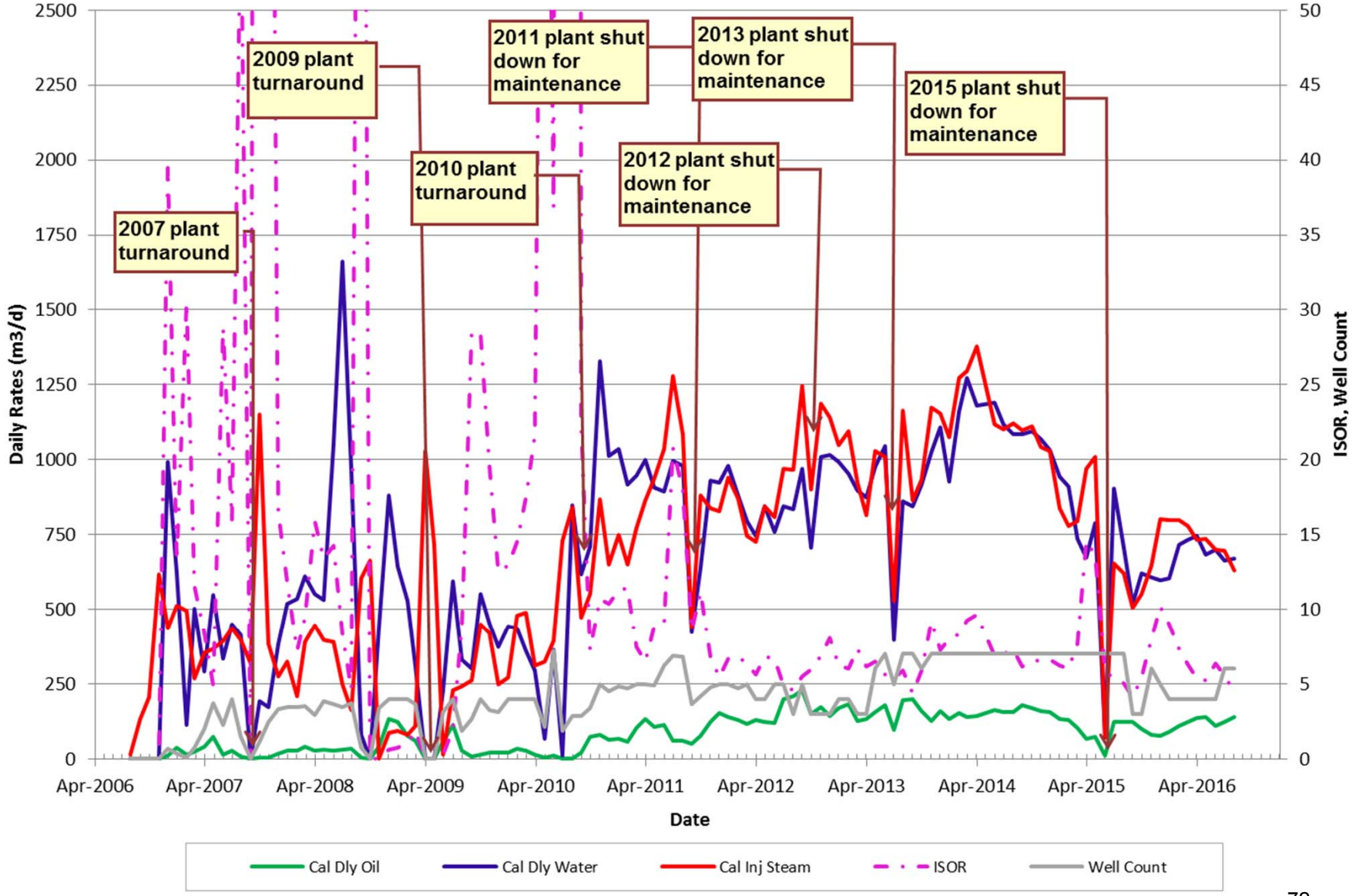
Discussion of Pad GA Performance

- Pilot well started in September 2011
- Remaining 5 Well Pairs started by September 2013

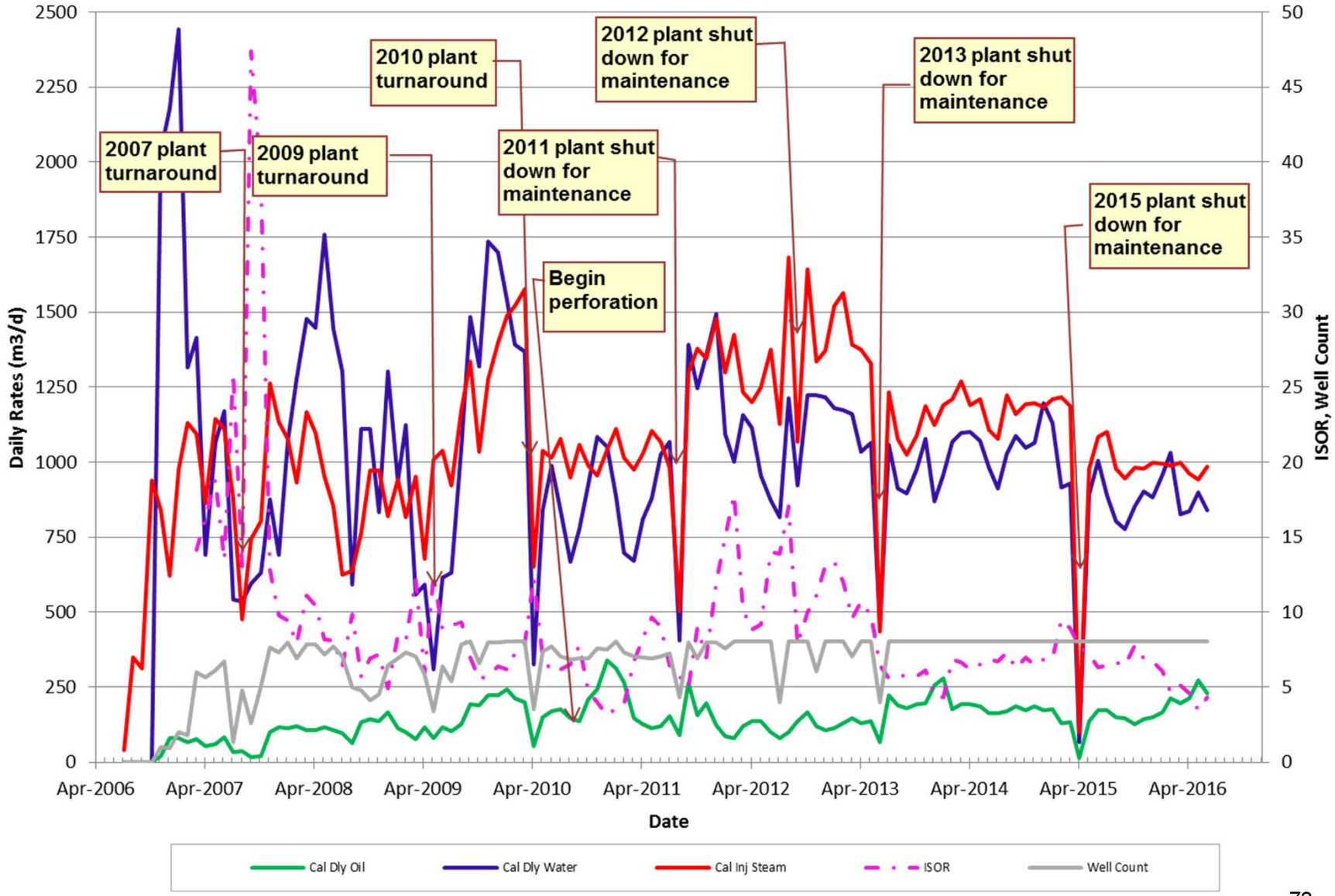
- Pad GA performance indicators as of July 31, 2016:
  - Cum. Oil: 276,470 m^3
  - Cum. Steam Injected: 1,389,878 m^3
  - Cum. Water Produced: 1,894,738 m^3
  - CSOR: 5.0

- Pad GA performance for the reported period:
  - Cum. Oil: 77,644 m^3
  - Oil Rate per well: 35.5 m^3/day
  - SOR: 4.5

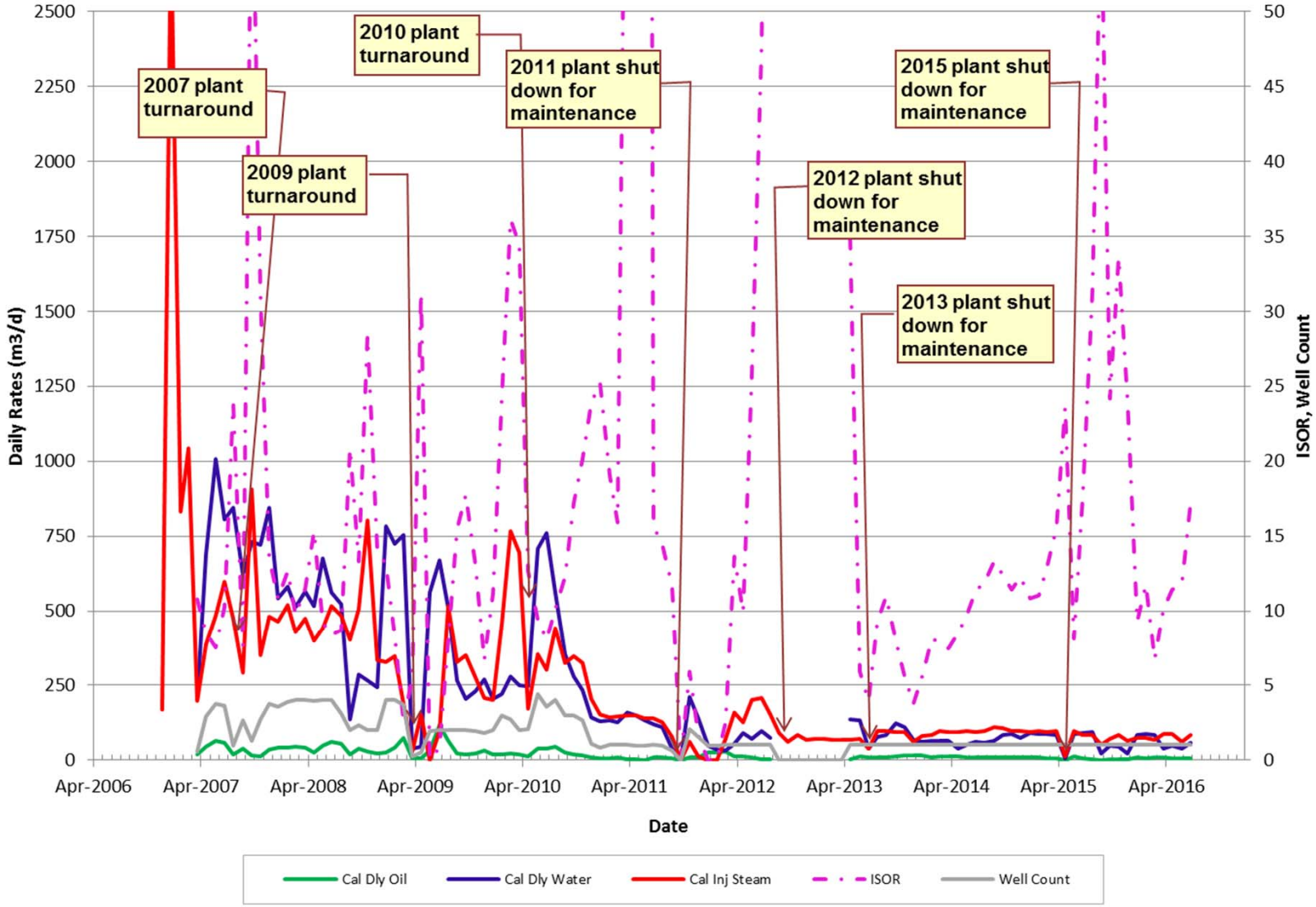
Pad B North Performance



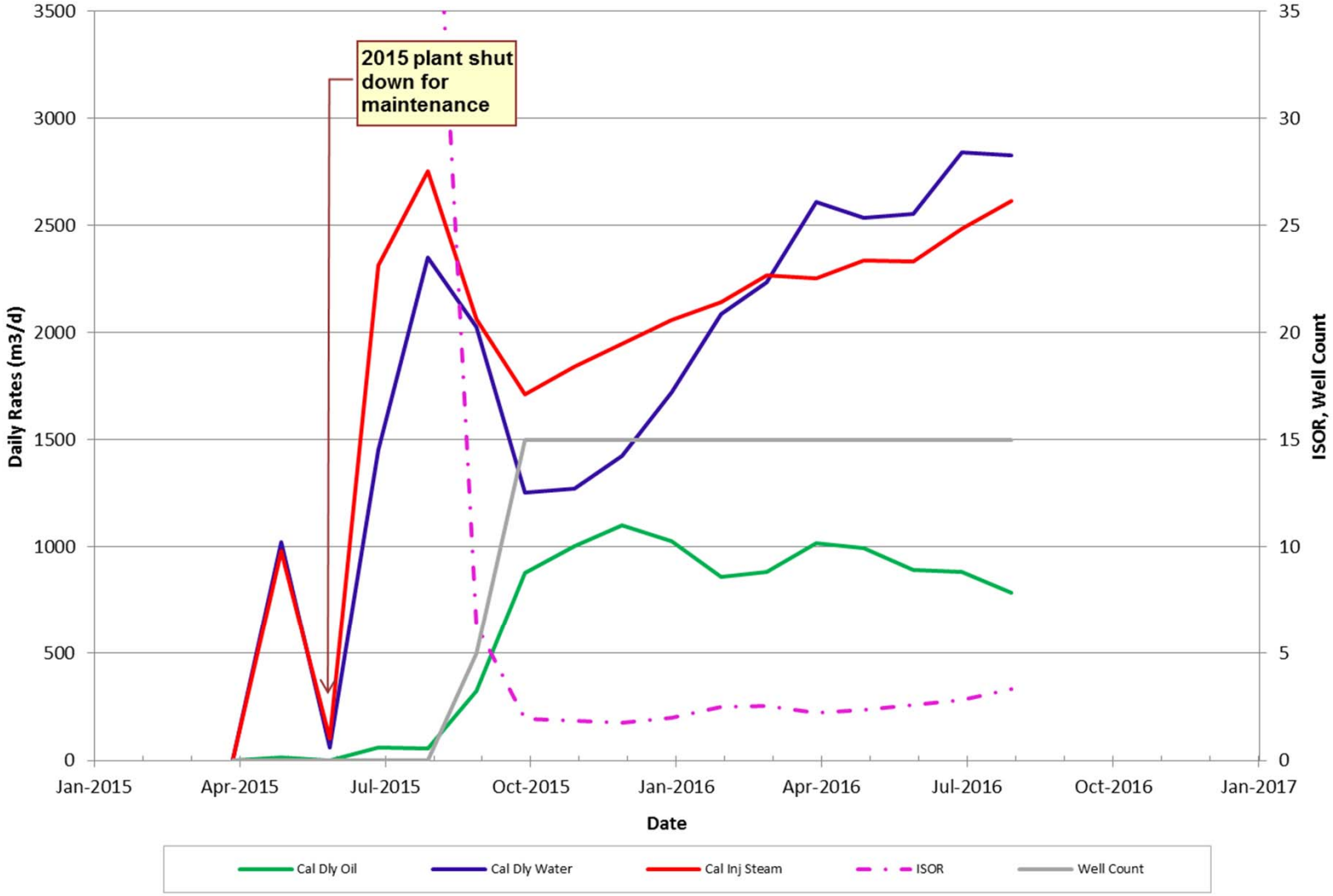
Pad B West Performance



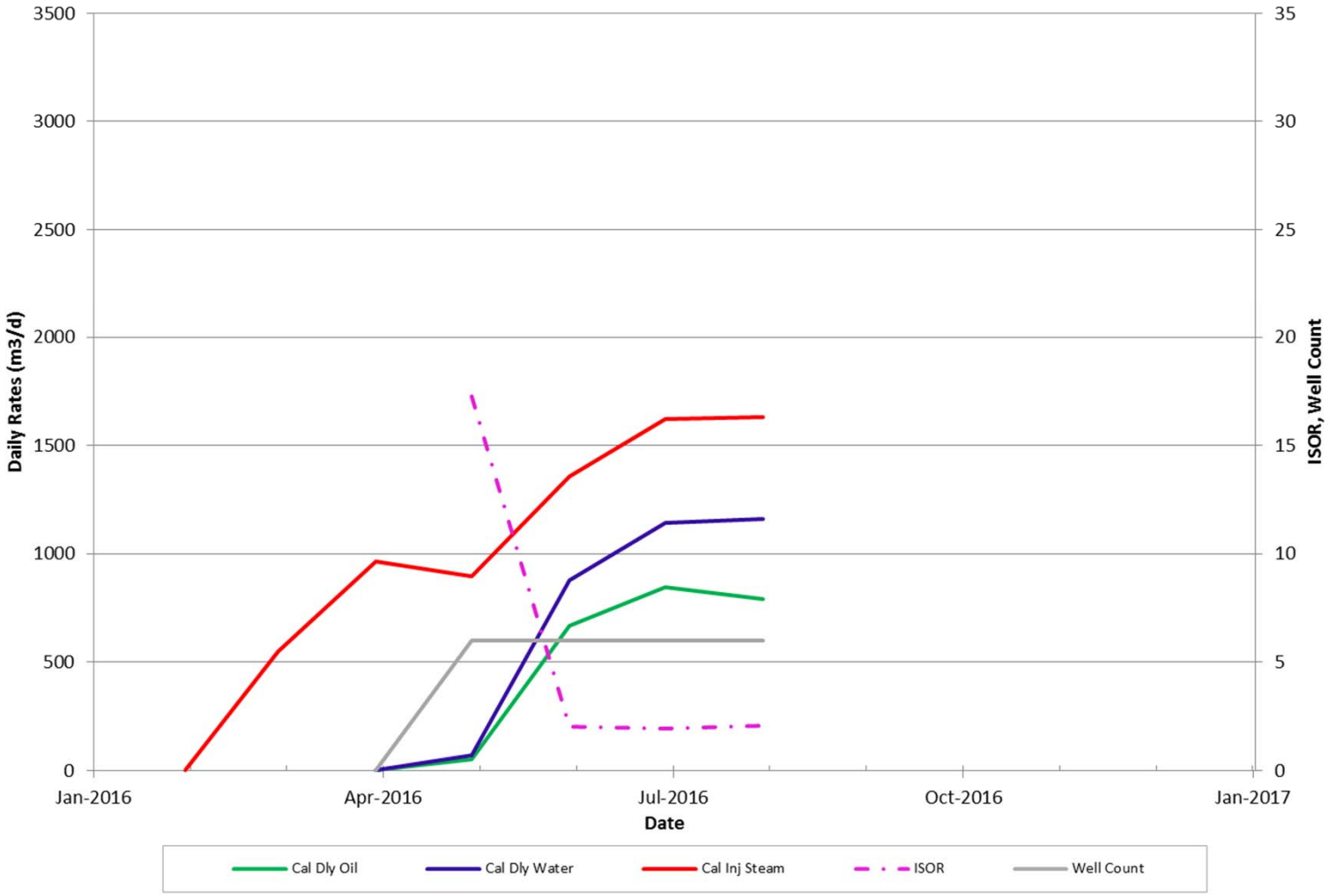
Pad C North Performance



Pad D East Performance



Pad Colony (CN) Performance



New Developments: Pads D North and C West

- Pad D North (8 SAGD well pairs):
  - All injectors will be equipped with VIT and steam splitters
  - All producers will be completed with dual string
  - Drilling completed Q2 2016

- Pad C West (8 Replacement wells):
  - AER Scheme Approval (9835N) received August 18, 2014
  - Drilling started in late July 2016
  - Scheduled for start-up in Q4 2016

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	OBIP (10^6 m^3)	Recovery to Date July 31, 2016 (10^3 m^3)	Recovery Factor to Date (%)	Estimated Ultimate Recovery (10^6 m^3)	Ultimate Recovery Factor (%)
A (24 well pairs)	5.4	1,025	19	3.1	59
B (15 well pairs)	7.2	820	11	3.0	42
C (20 well pairs)	10.2	1,682	17	5.1	50
GA (6 well pairs)	2.0	276	14	1.2	59
D East (15 pairs)	5.4	329	6	3.2	60
CN (6 well pairs + 7 infill)	1.6	72	5	1.0	60
Total	31.7	4,204	13	16.5	52

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 (2016/2017)

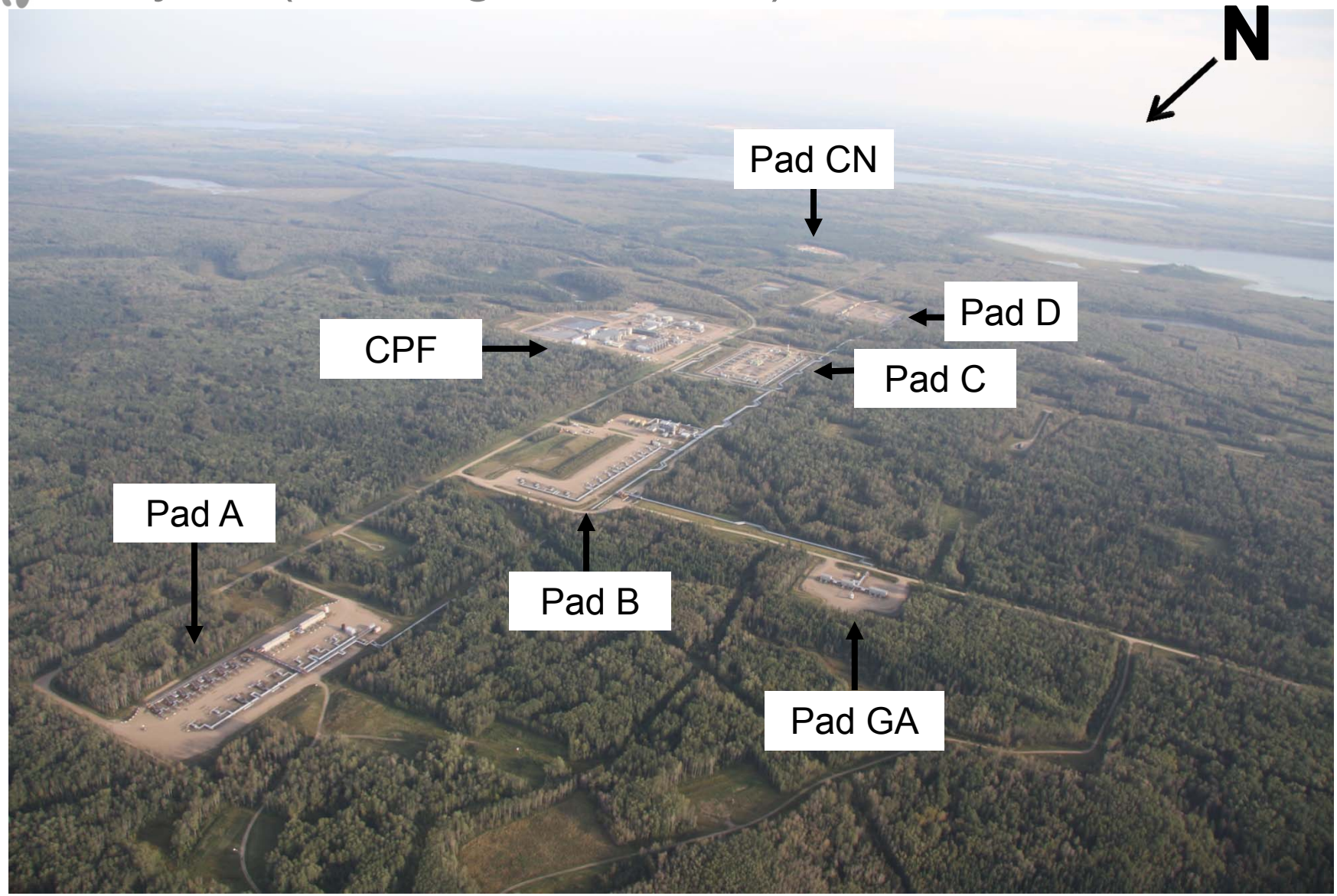
- Pad D North Development:
  - Finish construction, commission & start-up facilities (Q4 2016)
  - Complete 8 SAGD well pairs, circulate/start-up SAGD operations (Q4 2016)
- Pad C West Replacement Wells:
  - Drill & complete 8 replacement injectors and tie-in to existing facilities (Q4 2016)
  - Start-up and commence SAGD operations (Q4 2016)
- Pad D West Development:
  - AER Scheme Approval (9835T) received August 9, 2016
  - Drill & Complete 15 SAGD well pairs (Q1 - Q3 2017)
  - Construct facilities (2017/2018)

- Pad C North Future Development:
  - Based on performance at Pads A infill and replacement wells, B North infill wells, B West and C West replacement wells
  - Evaluate and propose a development strategy for optimizing the resource recovery

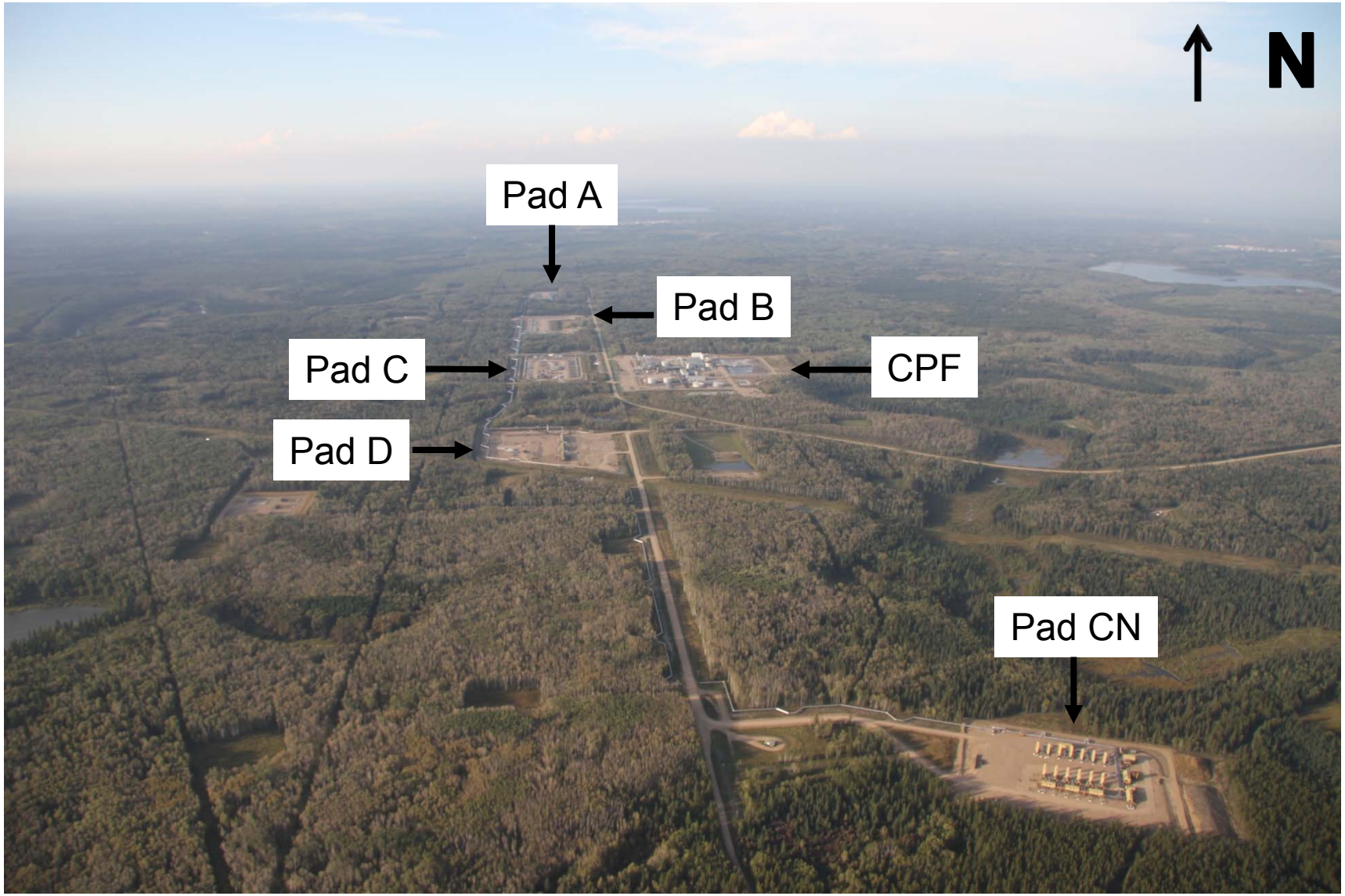
3.1.2. Surface - Table of Contents

1. Facilities

Layout (Looking Southeast)



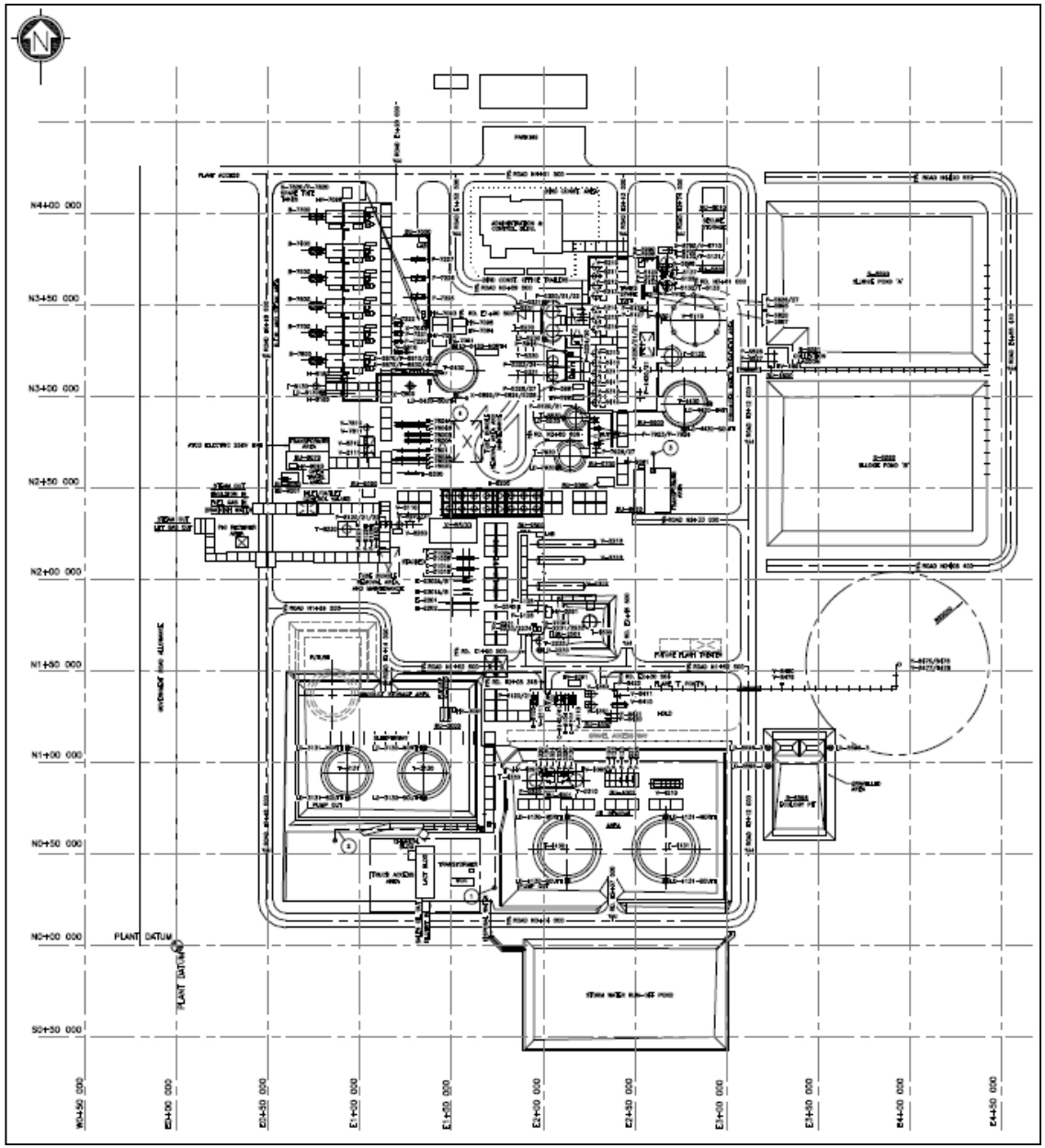
Layout (Looking North)



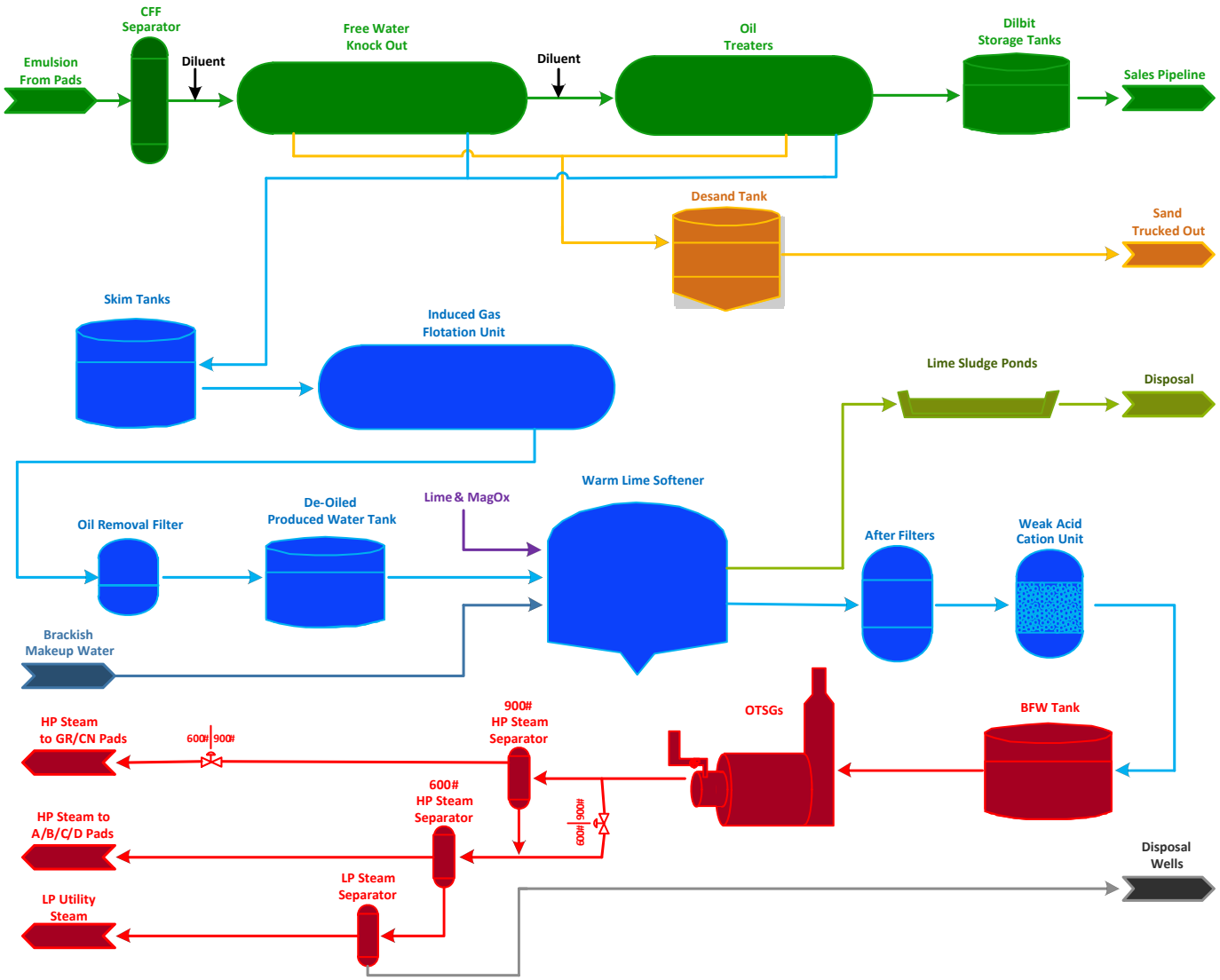
Central Processing Facility (CPF)

Central Field Facility (CFF - Located at Pad B)

Facility Plot Plan, Central Process Facility (CPF)



Facility Schematic



Facility Modifications

- Pad CN Commissioning:
  - Commissioned in February 2016 with first steam February 14, 2016

- Pad D North Drilling:
  - Drilling completed Q2 2016
  - Surface facility construction on-going with completion expected in Q4 2016

- Pad C West Replacement Wells:
  - Drilling new injectors and original injectors converted to producers in progress
  - Minor piping modifications

- Commissioning of a 6th OTSG:
  - Construction, commissioning and start-up completed Q4 2015

Pad CN

Pad D

Pad C and CPF

Facility Modifications – 6th OTSG Addition

2. Facilities Performance

Operating Issues

Operating issues:

- Several tube repairs necessary in one of the Once Through Steam Generators (OTSGs). Root cause has been determined as improper long term lay-up procedure, allowing water to lay in sections of the tubes.
- The de-oiled storage tank had severe corrosion under insulation (CUI) on the roof. Plans being developed to repair and reduce the risk of re-occurrence
- On-going leaking problems with the original dilbit coolers (plate and frame); purchased a new set.
- Erosion damage was found on the inlet emulsion pump and flow control valve.
- The Continuous Emissions Monitoring System (CEMS) unit on the new OTSG failed after 7 months.

Operating Limitations

- No limitations in the reporting period.

Process Water De-Oiling

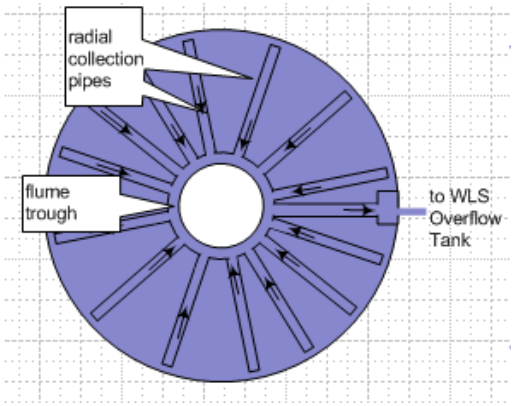
- The de-oiling process consists of 2 Skim Tanks (in series), IGF and 2 Oil Removal Filters

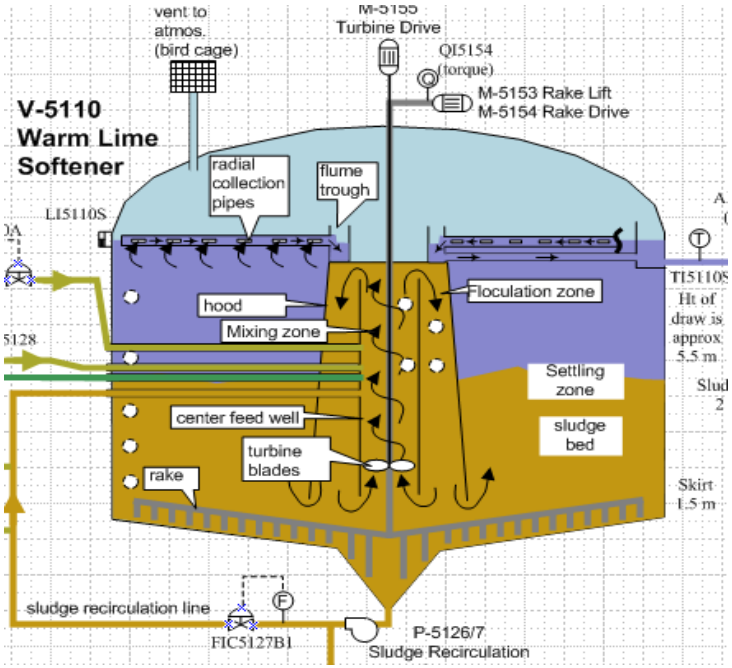
- The performance of the de-oiling equipment has been close to specifications; performing well

- De-Oiling KPI's are:
  - FWKO – 1,000 ppm (average 459 ppm)
  - IGF Inlet – 100 ppm (average 112 ppm)
  - IGF Out – 40 ppm (average 93 ppm)
  - ORF Outlet – 20 ppm (average 42 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





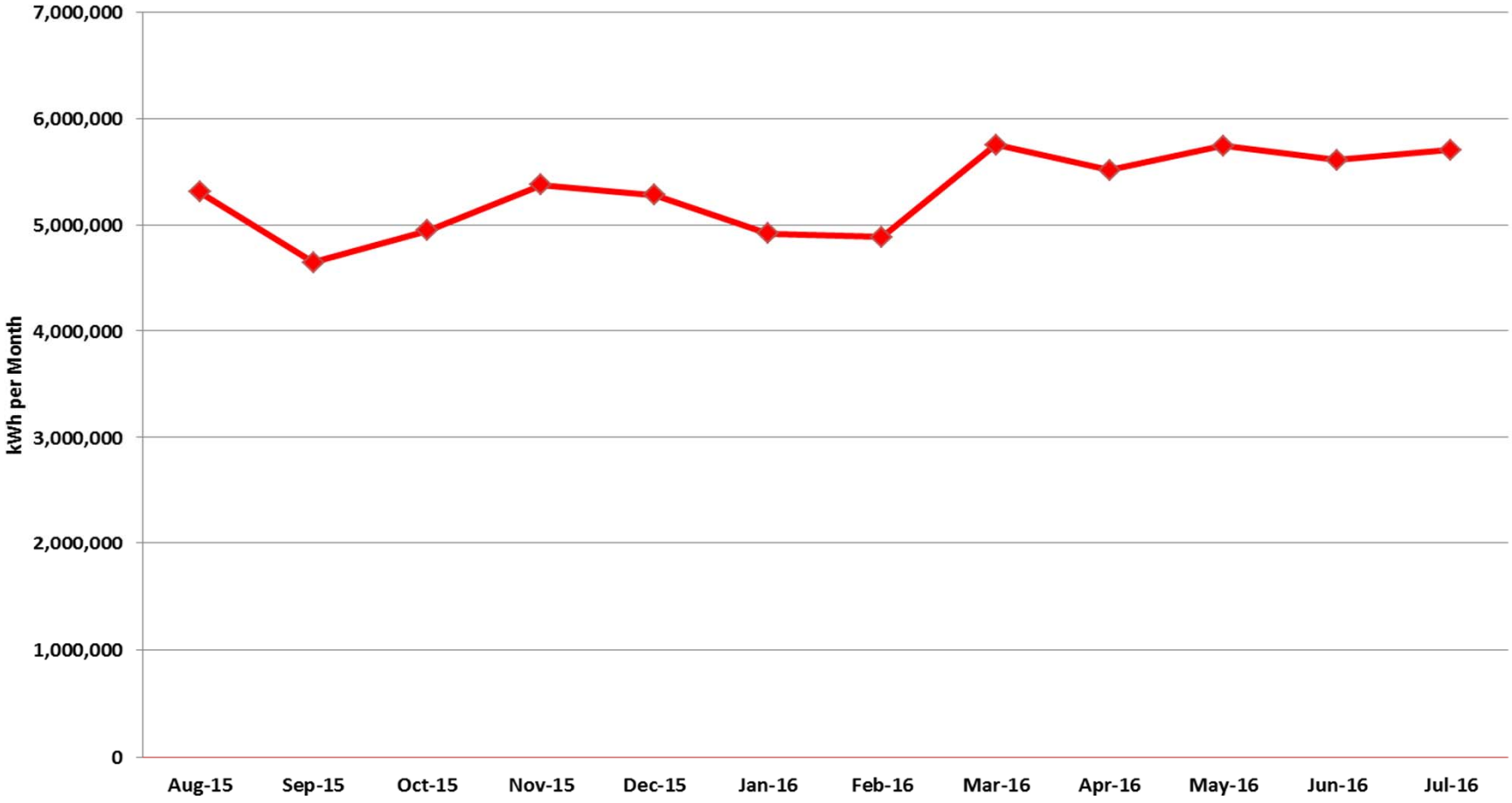
WLS Chemistry / Performance

- 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

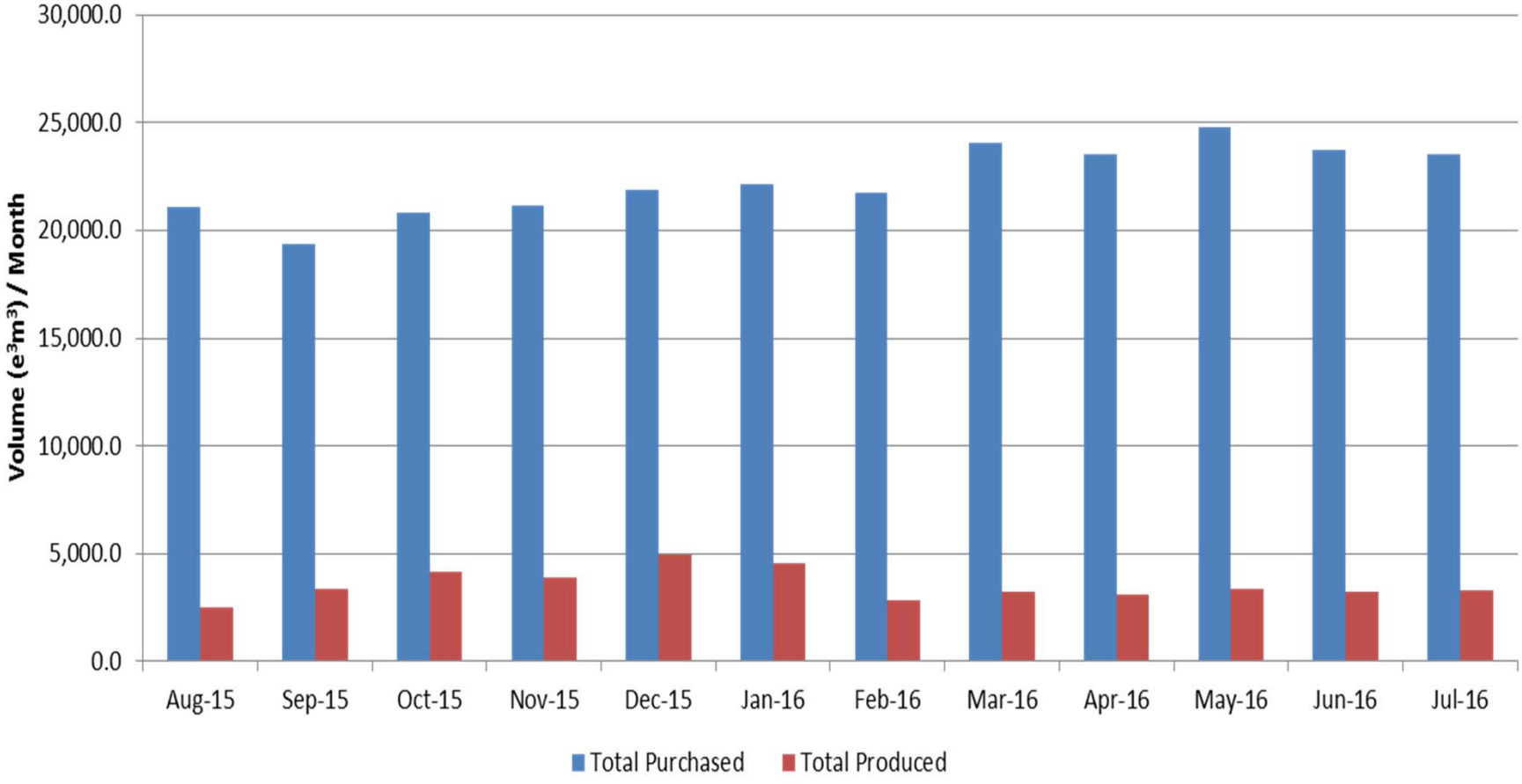
- Performance:
  - The WLS has performed very well to date

- Key KPIs:
  - Soluble Hardness – 30 ppm (average 7 ppm)
  - Silica – 50 ppm (average 41 ppm)
  - Turbidity – 20 NTU (average 17 NTU)

Power Consumption



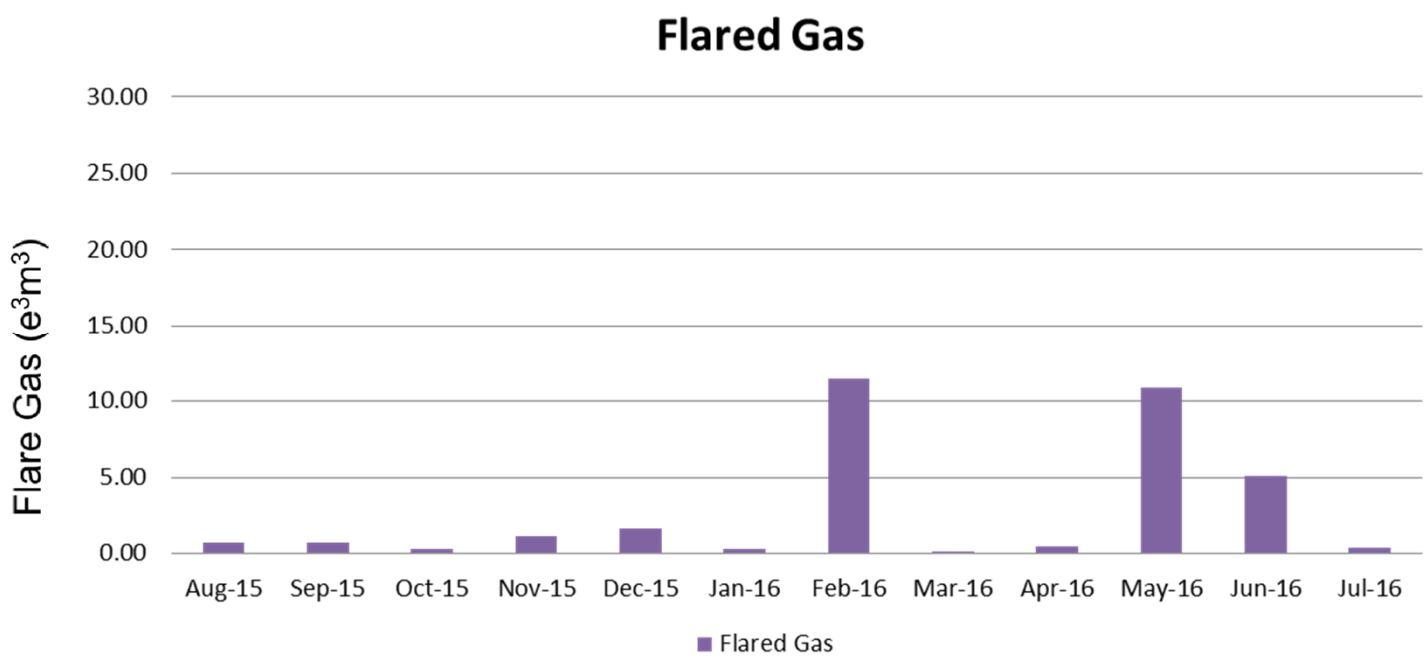
Gas Usage


30,000.0
25,000.0
20,000.0
15,000.0
10,000.0
5,000.0
0.0
Volume (e³m³) / Month
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Apr-16
May-16
Jun-16
Jul-16
Total Purchased
Total Produced

Flaring and Venting

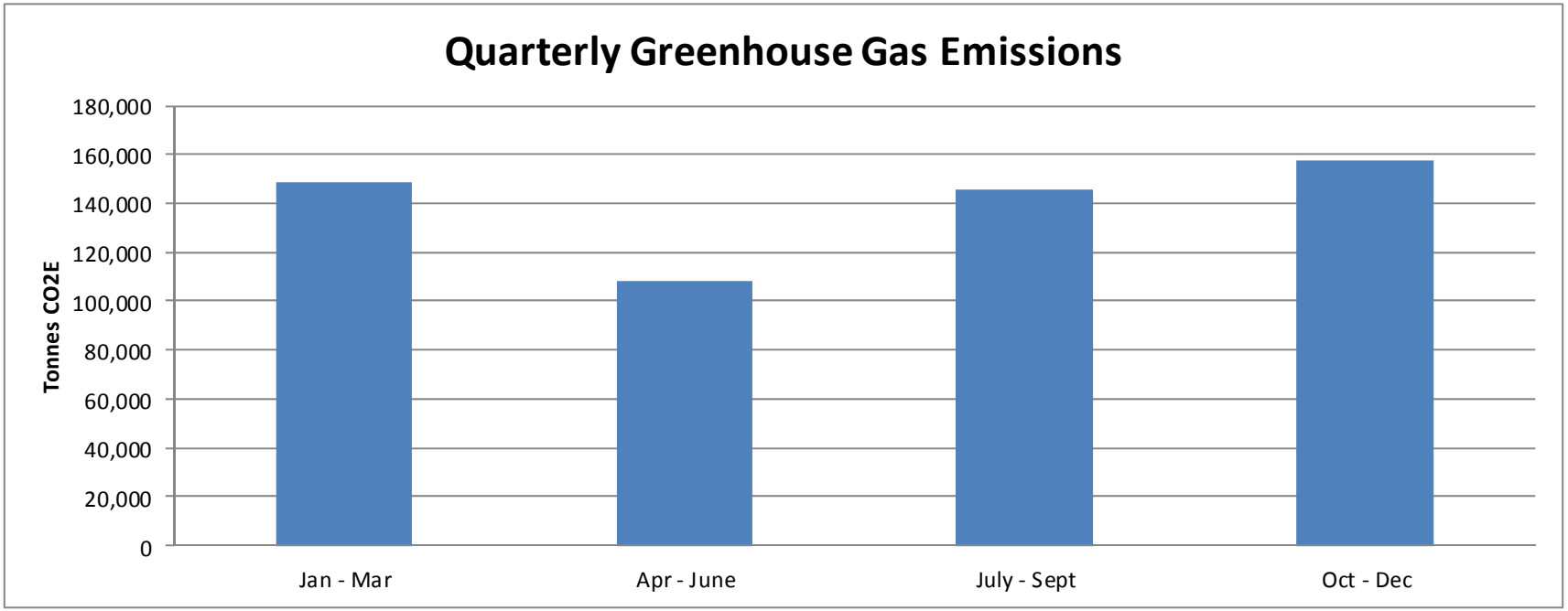
- No flaring events over 4 hours in duration or 30,000m^3
- No Venting

Date	Gas flare (e^{3}m^3)
Aug-15	0.70
Sep-15	0.71
Oct-15	0.34
Nov-15	1.16
Dec-15	1.62
Jan-16	0.32
Feb-16	11.44
Mar-16	0.11
Apr-16	0.46
May-16	10.91
Jun-16	5.07
Jul-16	0.36



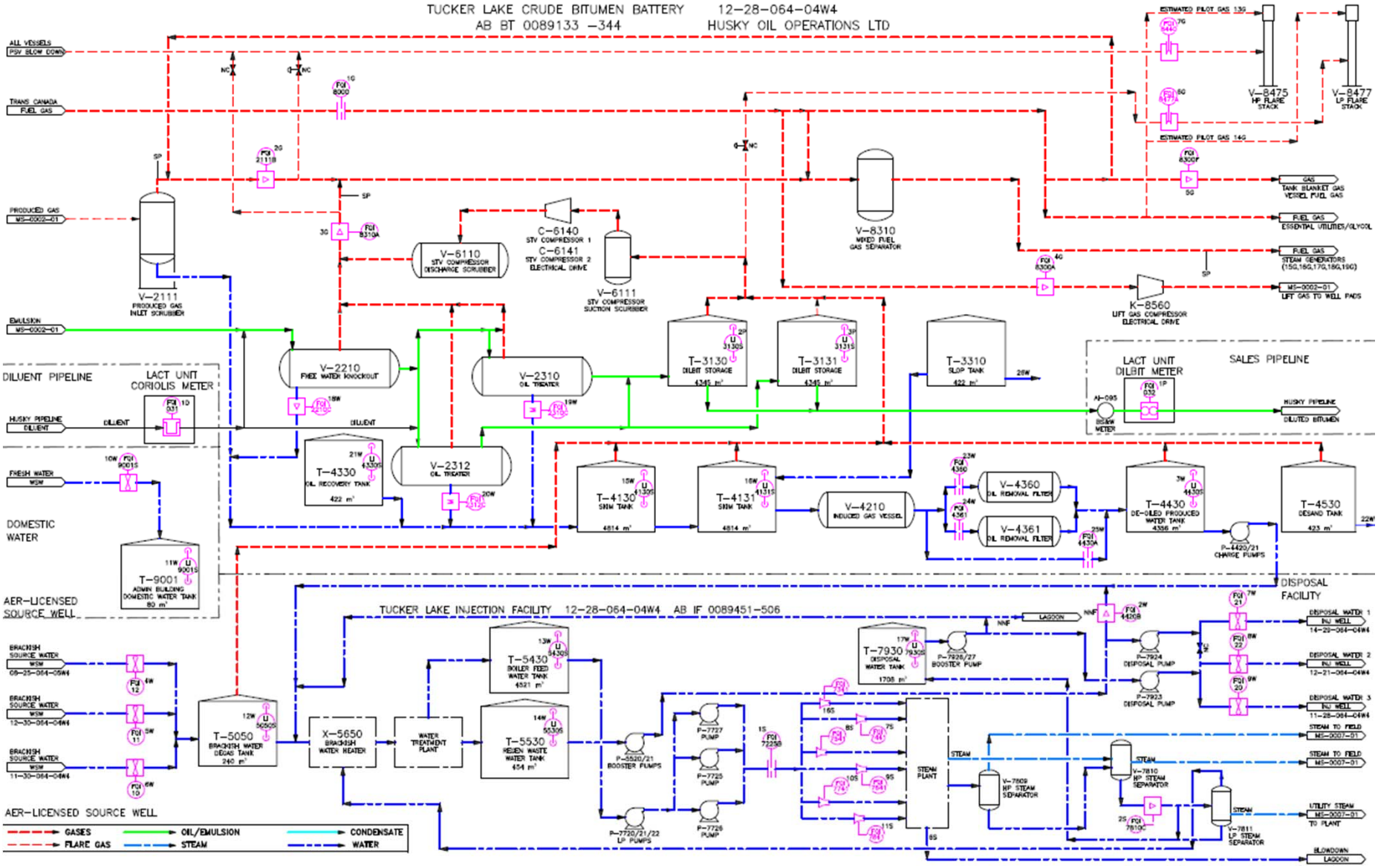
Green House Gas (GHG)

- Emission sources considered include stationary combustion associated with steam generators and glycol heaters, flaring, venting and fugitive emissions
- 560,670.19 tonnes of Carbon Dioxide Equivalent were emitted in 2015 (information taken from the Tucker Thermal 2015 report submitted under the Specified Gas Emitters Regulation)
- 4,936 emission performance credits generated

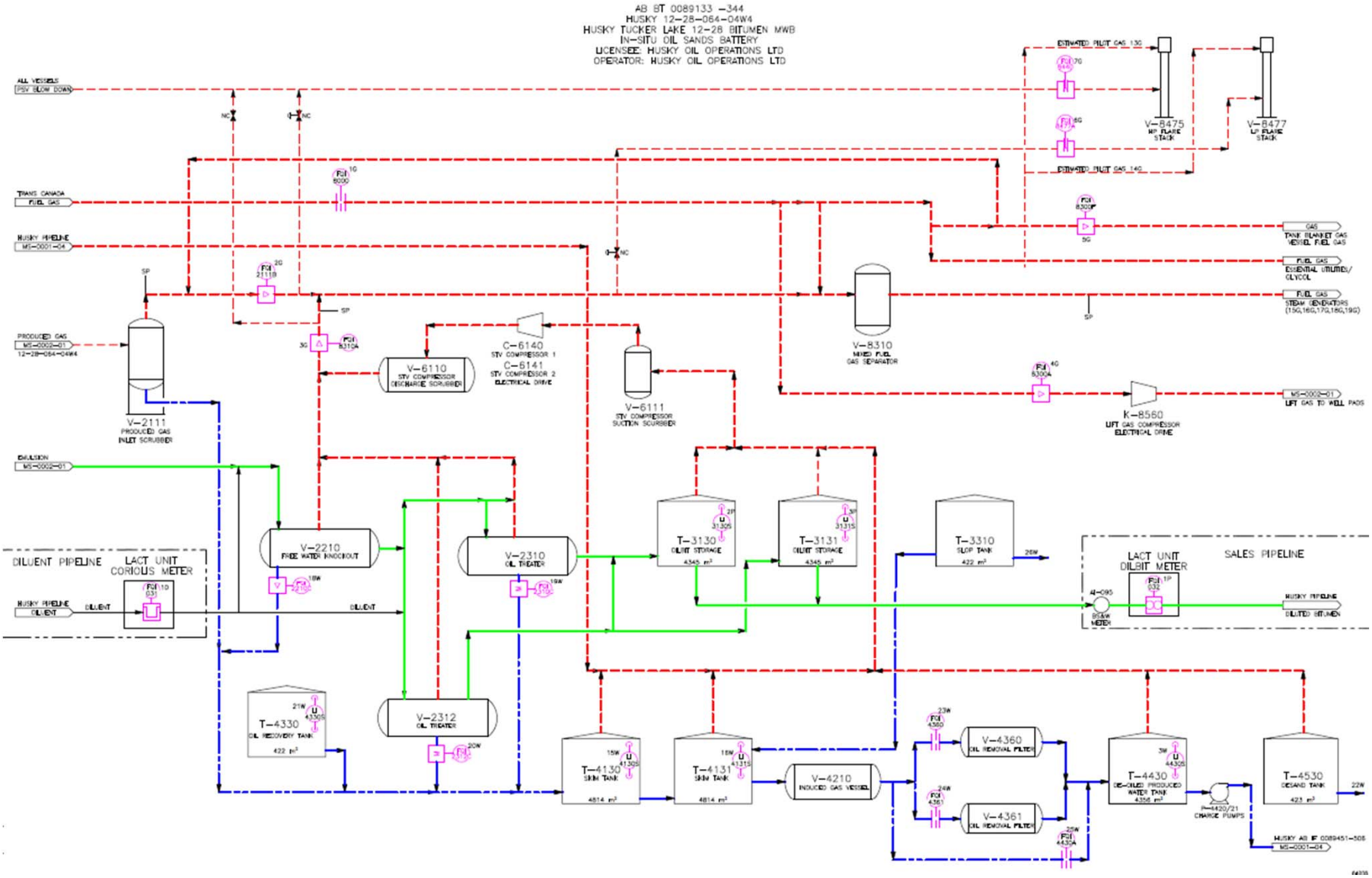


3. Measurement and Reporting

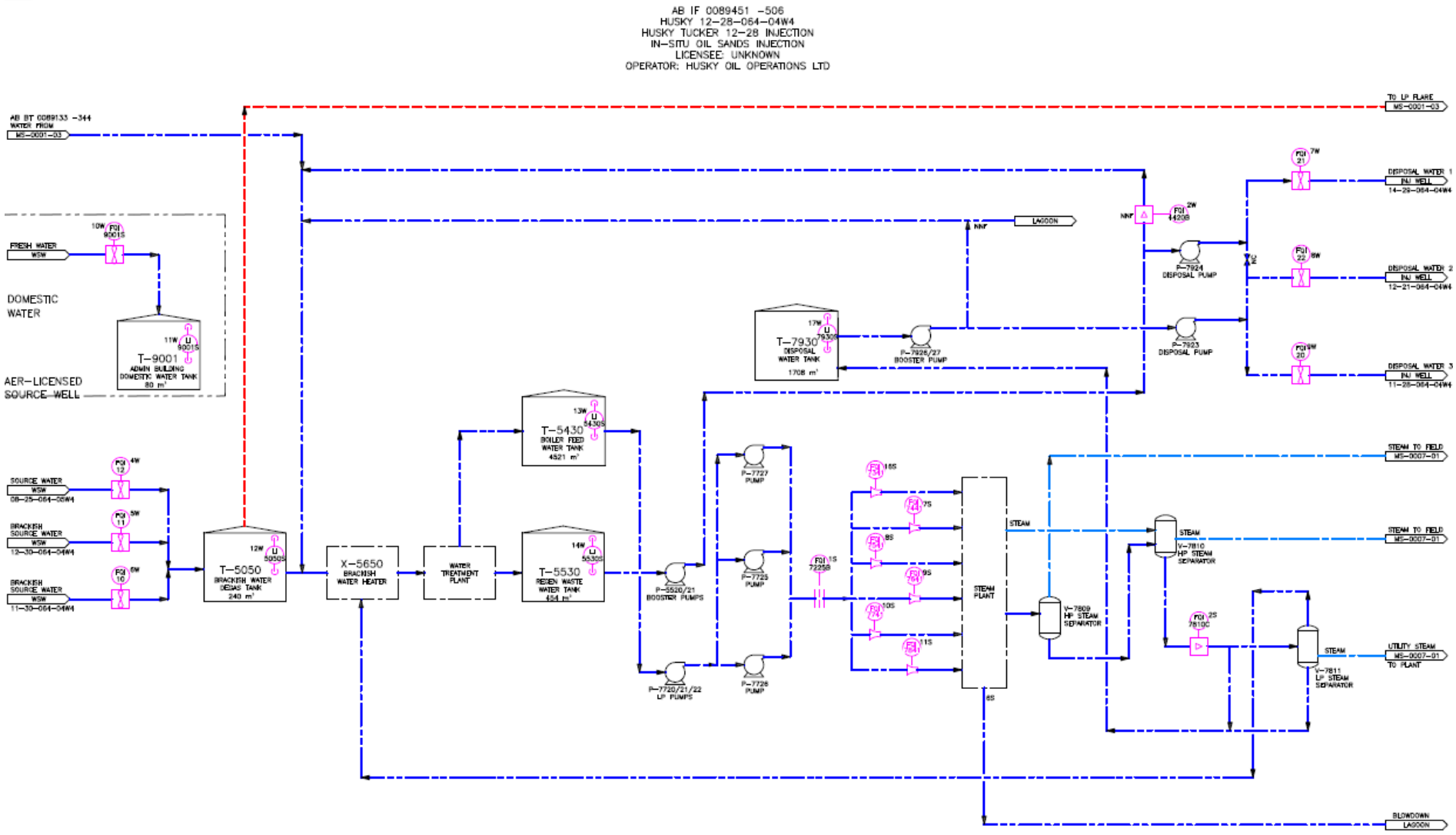
Measurement and Reporting Schematic - AB BT 0089133-344



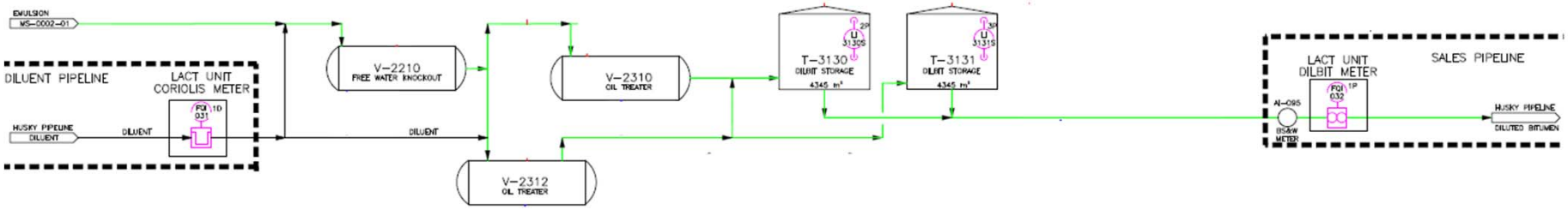
Battery Schematic - AB BT 0089133-344



Injection Facility Schematic - AB IF 0089451-506



Measurement and Reporting – Oil



OIL & DILUENT METERING

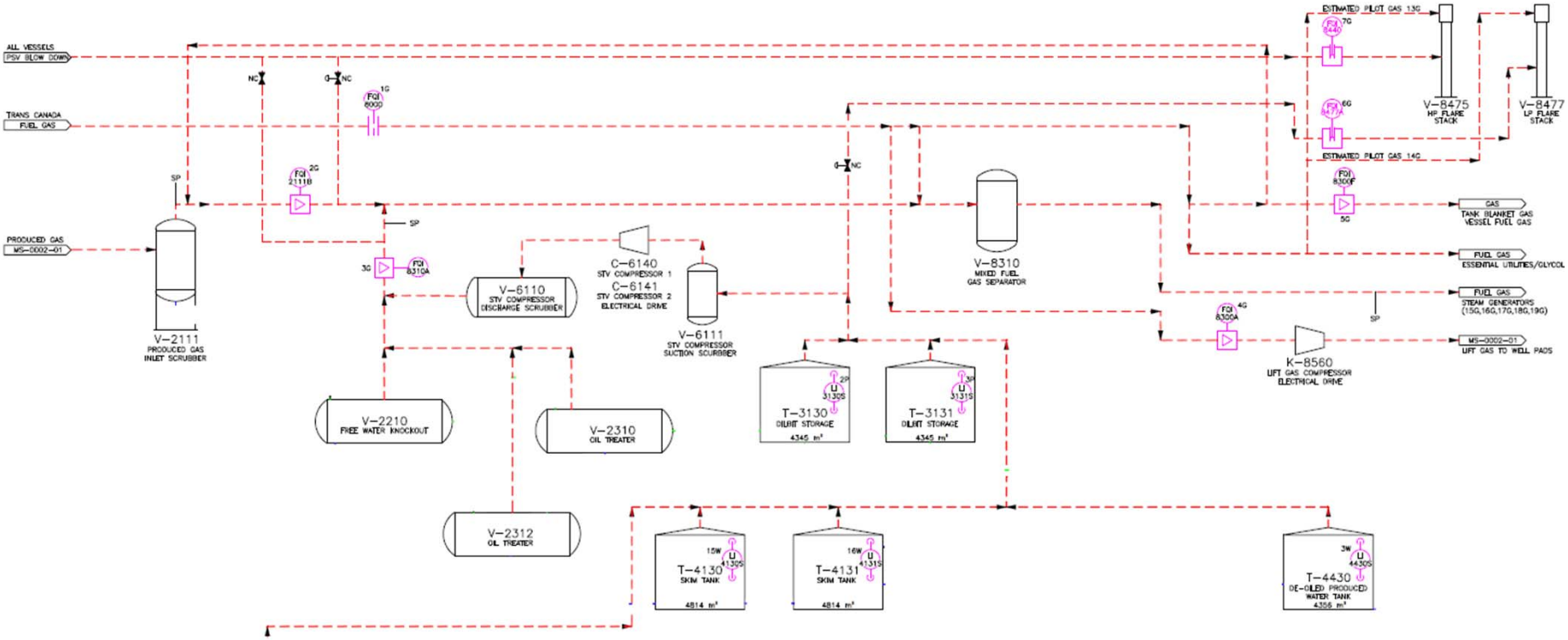
LABEL	TAG	P&ID#	DESCRIPTION
1P	FQI032		LACT DILBIT SALES FLOW TOTALIZER
2P	LI3130S	30MF02	DILBIT STORAGE TANK VOLUME
3P	LI3131S	30MF03	DILBIT STORAGE TANK VOLUME
1D	FQI031	30MF01	DILUENT TO PLANT FLOW TOTALIZER
2D			DILUENT FLASH VOLUME LOSS (CALCULATED)
3D			DILUENT SHRINKAGE VOLUME (CALCULATED)

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, (OFF 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

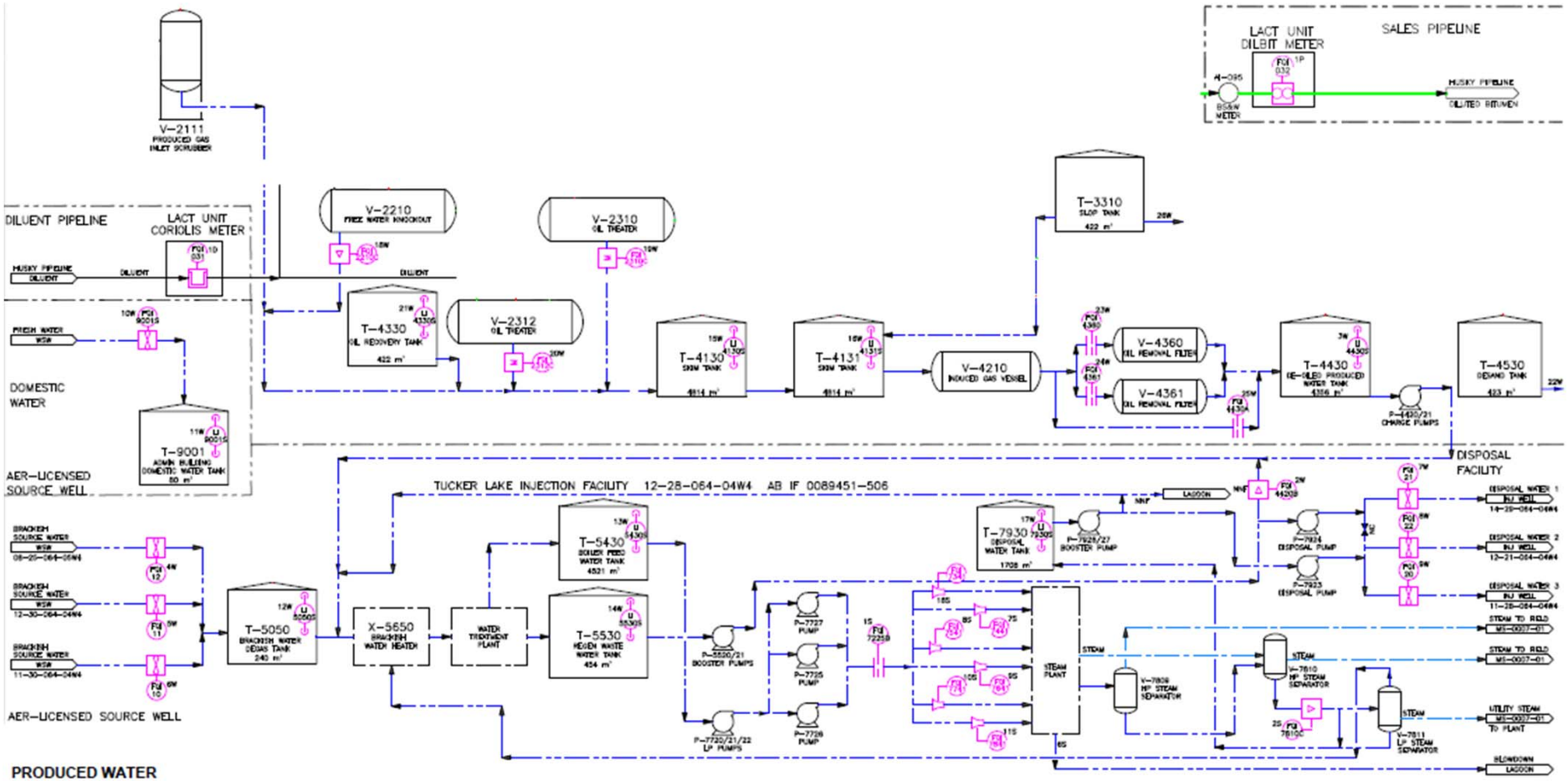
FLARED GAS = FLARE STACK METER TOTAL–FLARE SYSTEM PURGE GAS
= (6G+7G)–10G

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

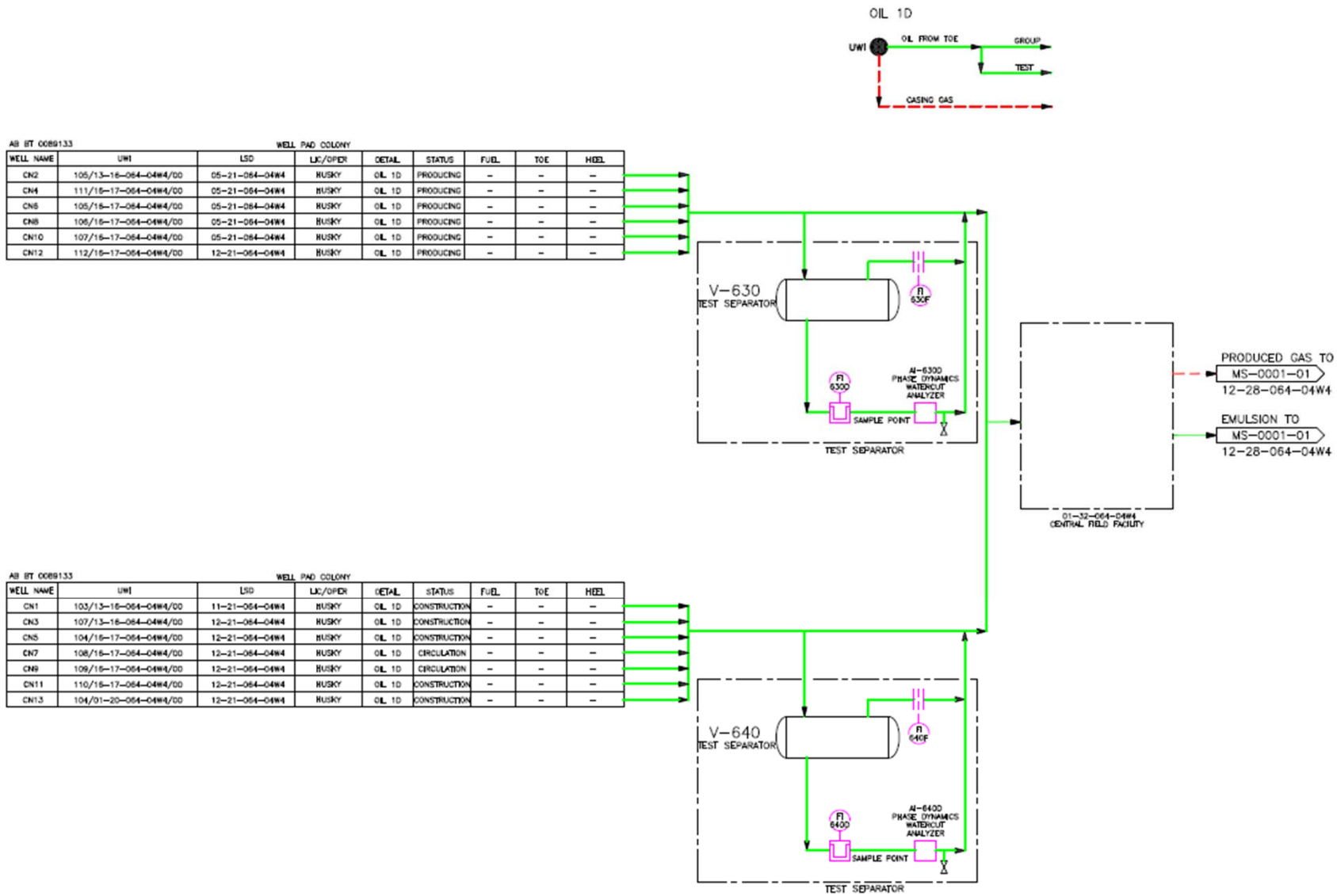
Measurement and Reporting – Primary and Secondary Produced Water

- On August 31, 2014 MARP was approved for primary and secondary produced water meters (unable to meet 5% difference)
- 2015 MARP submission detailed a proposed new primary and secondary water measurement:
  - Disposition to injection facility (primary) = produced water at FWKO + Oil Treaters - water pipelined out
  - Secondary produced water measurement method = produced water to ORF ± change in produced water inventory - water pipelined out -100
  - AER indicated deficiencies would be identified and communicated
    - No deficiencies were communicated
    - New water measurement was implemented February 2016
- Significant maintenance required for ultrasonic (USM) meter with limited improvement
- Oil content in FWKO and Treater produced water remains low (less than 500ppm)

Date	Unit of Measure	Primary Meter	Secondary Meter		
		ORF's Meters	FWKO+Treater Meters	WLS U/S Meter (USM)	WLS U/S Meter (Orifice Plate)
2015 Jan 1 – April 30	m^3/day	11,224	11,396	12,146	10,213
	% Diff		1.52% *	7.89% *	-9.44% *
2015 June 1 – Dec 31	m^3/day	10,852	10,843	11,934	9,718
	% Diff		-0.28% *	19.95% *	-11.02% *
2016 Jan 1 – Sept 30	m^3/day	11,615	11,647	13,003	10,450
	% Diff		0.28% *	23.91% *	-10.55%*

* % Difference = (Secondary – Primary) / [(Secondary + Primary) / 2] x 100%

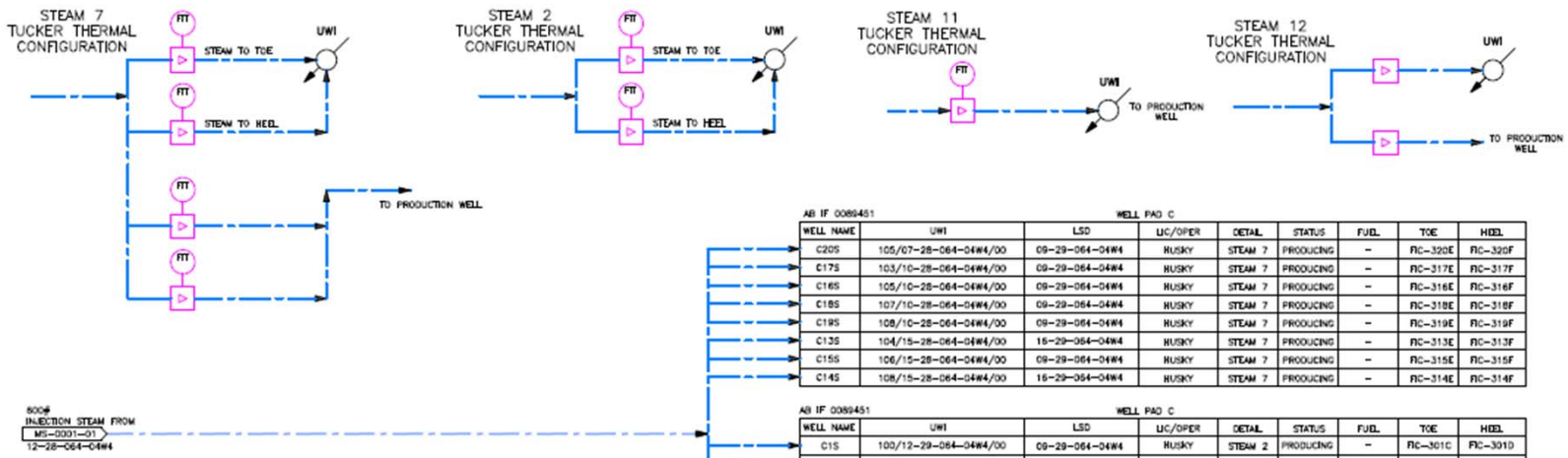
Measurement and Reporting – Pad CN Testing



WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
CN2	105/13-16-064-04W4/00	05-21-064-04W4	HUSKY	OIL 1D	PRODUCING	–	–	–
CN4	111/15-17-064-04W4/00	05-21-064-04W4	HUSKY	OIL 1D	PRODUCING	–	–	–
CN6	105/15-17-064-04W4/00	05-21-064-04W4	HUSKY	OIL 1D	PRODUCING	–	–	–
CN8	106/15-17-064-04W4/00	05-21-064-04W4	HUSKY	OIL 1D	PRODUCING	–	–	–
CN10	107/15-17-064-04W4/00	05-21-064-04W4	HUSKY	OIL 1D	PRODUCING	–	–	–
CN12	112/15-17-064-04W4/00	12-21-064-04W4	HUSKY	OIL 1D	PRODUCING	–	–	–

WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
CN1	103/13-16-064-04W4/00	11-21-064-04W4	HUSKY	OIL 1D	CONSTRUCTION	–	–	–
CN3	107/13-16-064-04W4/00	12-21-064-04W4	HUSKY	OIL 1D	CONSTRUCTION	–	–	–
CN5	104/15-17-064-04W4/00	12-21-064-04W4	HUSKY	OIL 1D	CONSTRUCTION	–	–	–
CN7	108/15-17-064-04W4/00	12-21-064-04W4	HUSKY	OIL 1D	CIRCULATION	–	–	–
CN9	109/15-17-064-04W4/00	12-21-064-04W4	HUSKY	OIL 1D	CIRCULATION	–	–	–
CN11	110/15-17-064-04W4/00	12-21-064-04W4	HUSKY	OIL 1D	CONSTRUCTION	–	–	–
CN13	104/01-20-064-04W4/00	12-21-064-04W4	HUSKY	OIL 1D	CONSTRUCTION	–	–	–

Measurement and Reporting – Steam Injection



600# INJECTION STEAM FROM MS-0001-01 12-28-064-04W4

AB IF 0089451 — WELL PAD C

WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
C20S	105/07-28-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 7	PRODUCING	–	AIC-320E	AIC-320F
C17S	103/10-28-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 7	PRODUCING	–	AIC-317E	AIC-317F
C16S	105/10-28-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 7	PRODUCING	–	AIC-316E	AIC-316F
C18S	107/10-28-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 7	PRODUCING	–	AIC-318E	AIC-318F
C19S	108/10-28-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 7	PRODUCING	–	AIC-319E	AIC-319F
C13S	104/15-28-064-04W4/00	16-29-064-04W4	HUSKY	STEAM 7	PRODUCING	–	AIC-313E	AIC-313F
C15S	106/15-28-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 7	PRODUCING	–	AIC-315E	AIC-315F
C14S	108/15-28-064-04W4/00	16-29-064-04W4	HUSKY	STEAM 7	PRODUCING	–	AIC-314E	AIC-314F

AB IF 0089451 — WELL PAD C

WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
C1S	100/12-29-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 2	PRODUCING	–	AIC-301C	AIC-301D
C2S	104/12-29-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 2	PRODUCING	–	AIC-302C	AIC-302D
C3S	107/12-29-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 2	PRODUCING	–	AIC-303C	AIC-303D
C4S	108/12-29-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 2	PRODUCING	–	AIC-304C	AIC-304D
C6S	106/13-29-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 2	PRODUCING	–	AIC-306C	AIC-306D
C7S	107/13-29-064-04W4/00	16-29-064-04W4	HUSKY	STEAM 2	PRODUCING	–	AIC-307C	AIC-307D
C5S	108/13-29-064-04W4/00	09-29-064-04W4	HUSKY	STEAM 2	PRODUCING	–	AIC-305C	AIC-305D
C8S	109/13-29-064-04W4/00	16-29-064-04W4	HUSKY	STEAM 2	PRODUCING	–	AIC-308C	AIC-308D
C9S	104/07-32-064-04W4/00	16-29-064-04W4	HUSKY	STEAM 2	PRODUCING	–	AIC-309C	AIC-309D

AB IF 0089451 — WELL PAD D

WELL NAME	UWI	LSD	LIC/OPER	DETAIL	STATUS	FUEL	TOE	HEEL
D24S	106/07-28-064-04W4/00	07-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-424H	AIC-424H
D25S	107/07-28-064-04W4/00	07-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-425H	AIC-425H
D26S	108/07-28-064-04W4/00	07-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-426H	AIC-426H
D27S	109/07-28-064-04W4/00	07-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-427H	AIC-427H
D28S	110/07-28-064-04W4/00	07-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-428H	AIC-428H
D29S	117/07-28-064-04W4/00	07-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-429H	AIC-429H
D30S	116/02-28-064-04W4/00	02-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-430H	AIC-430H
D31S	114/02-28-064-04W4/00	02-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-431H	AIC-431H
D32S	118/02-28-064-04W4/00	02-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-432H	AIC-432H
D33S	119/02-28-064-04W4/00	02-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-433H	AIC-433H
D34S	117/02-28-064-04W4/00	02-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-434H	AIC-434H
D35S	120/02-28-064-04W4/00	02-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-435H	AIC-435H
D36S	121/02-28-064-04W4/00	02-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-436H	AIC-436H
D37S	110/02-28-064-04W4/00	02-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-437H	AIC-437H
D38S	113/02-28-064-04W4/00	02-28-064-04W4	HUSKY	STEAM 12	PRODUCING	–	AIC-438H	AIC-438H

AB IF 0089451 — WELL PAD COLONY

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

AB IF 0089451

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

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
  - No testing completed during circulation on Pad CN

- Three Test Separator Designs (Well Tests):
  1. Blow-Case (Pads A Original, B, C East, C West):
     - Loadcell or level
     - Vortex for steam + natural gas
     - AGAR water-cut analyzer
  2. Conventional (Pads B North, A Infill & Replacement Wells, GA, D East):
     - 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, 2015 to July 31, 2016 = 45.1 m^3/m^3

Water Balance

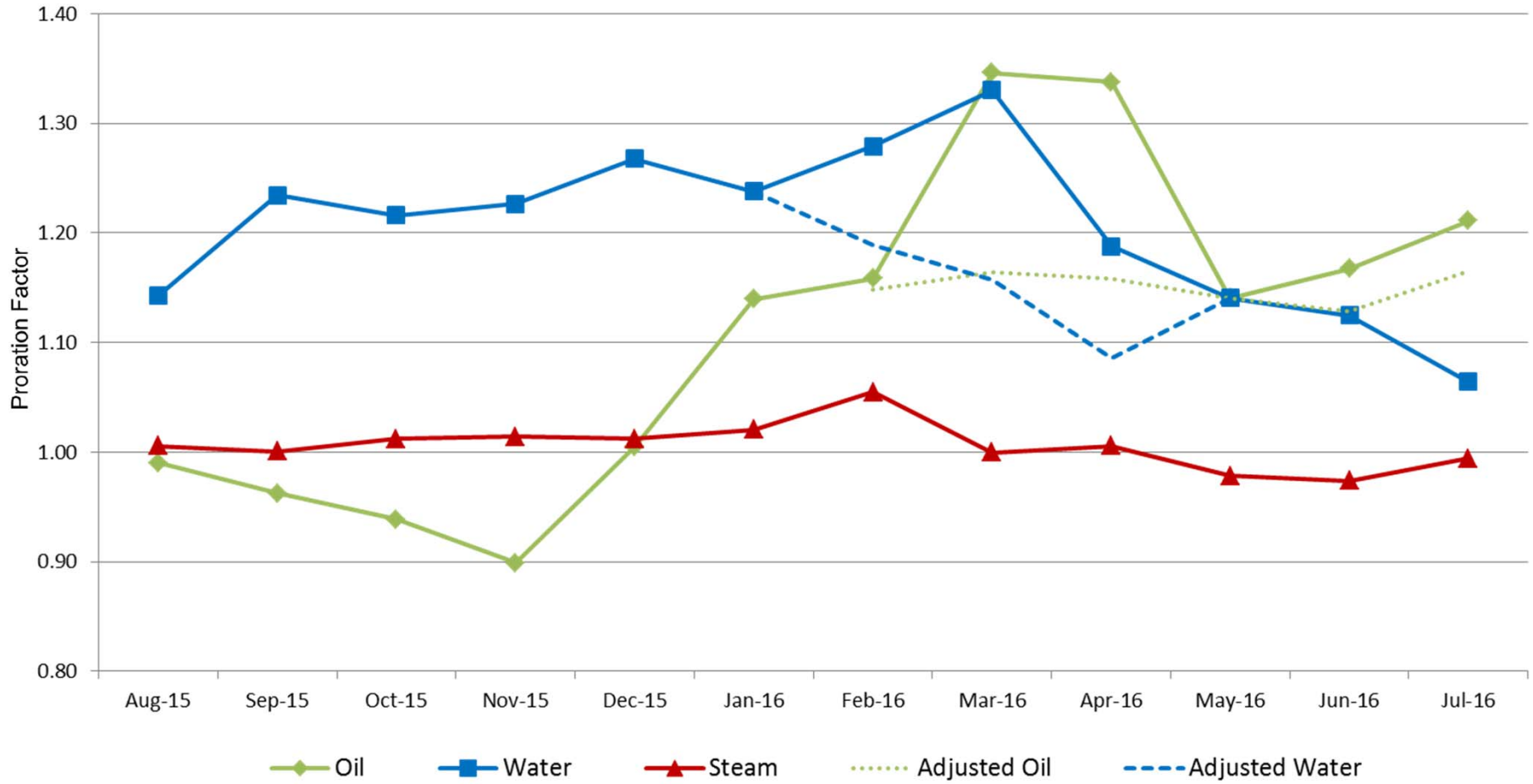
- Steam Injection:
  - Vortex meters on each well toe and heel
  - Total steam to field measured at the battery
  - Steam Proration = 1.005 m^3/m^3

- Water Proration Factors (see next slide):
  - Average 12-Month Rolling Proration Factors
    - Water = 1.208
    - Oil = 1.11

- 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	3.9	15.5
V-251/2	B1-12	4.5	9.7
V-351/2	C1-9	3.7	11.8
V-391/2	C13-20	4.1	16.4
V-170	A9-20	4.3	12.2
V-171	A21-24	7.2	17.8
V-213A	B9EP	22.3	28.9
V-214A	B10EP	22.8	28.8
V-215A	B11EP	26.2	39.1
V-540	GR01-06	5.1	21.6
V-440	D24-33	4.4	14.6
V-450	D34-38	5.8	15.9
V-630	CN2,4,6,8,10,12	18.3	4.7
V-640	CN7,9	Circulating	Circulating

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, 2016

- Technical issues identified with measurement equipment:
  - Lift gas meter transmitter range increased

- Husky Enhanced Production Audit Program (EPAP) completed

- Implemented improvements:
  - Detailed review of measurement schematics to include:
    - Pad CN test separator and steam injection
  - Correction factor for estimated produced water steam fraction volume portion
  - Operational procedure for on-line BS&W analyzer troubleshooting

- Future opportunities:
  - Pad CN Phase Dynamics individual well characteristics set-up
  - Test separators overhead gas meter sizing verification

4. Water Production, Injection and Uses

Brackish Water

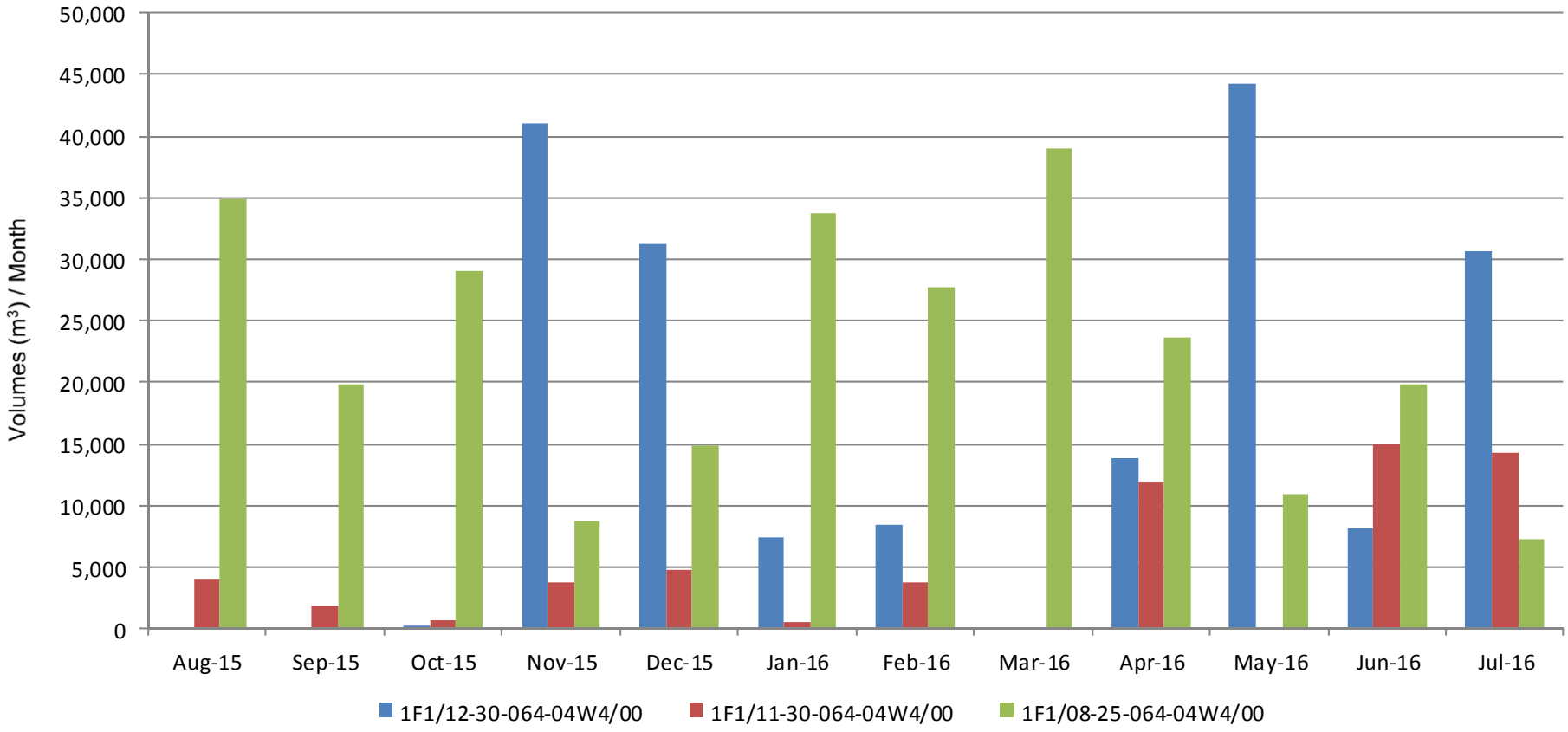
- Make-up water for steam generation
- McMurray Formation
- 3 Source Wells:
  - 1F1/11-30-064-04 W4M
  - 1F1/12-30-064-04 W4M
  - 1F1/08-25-064-04 W4M

Water Usage

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

- Normally no fresh water is used in our process

Brackish Water Consumption



Fresh Water

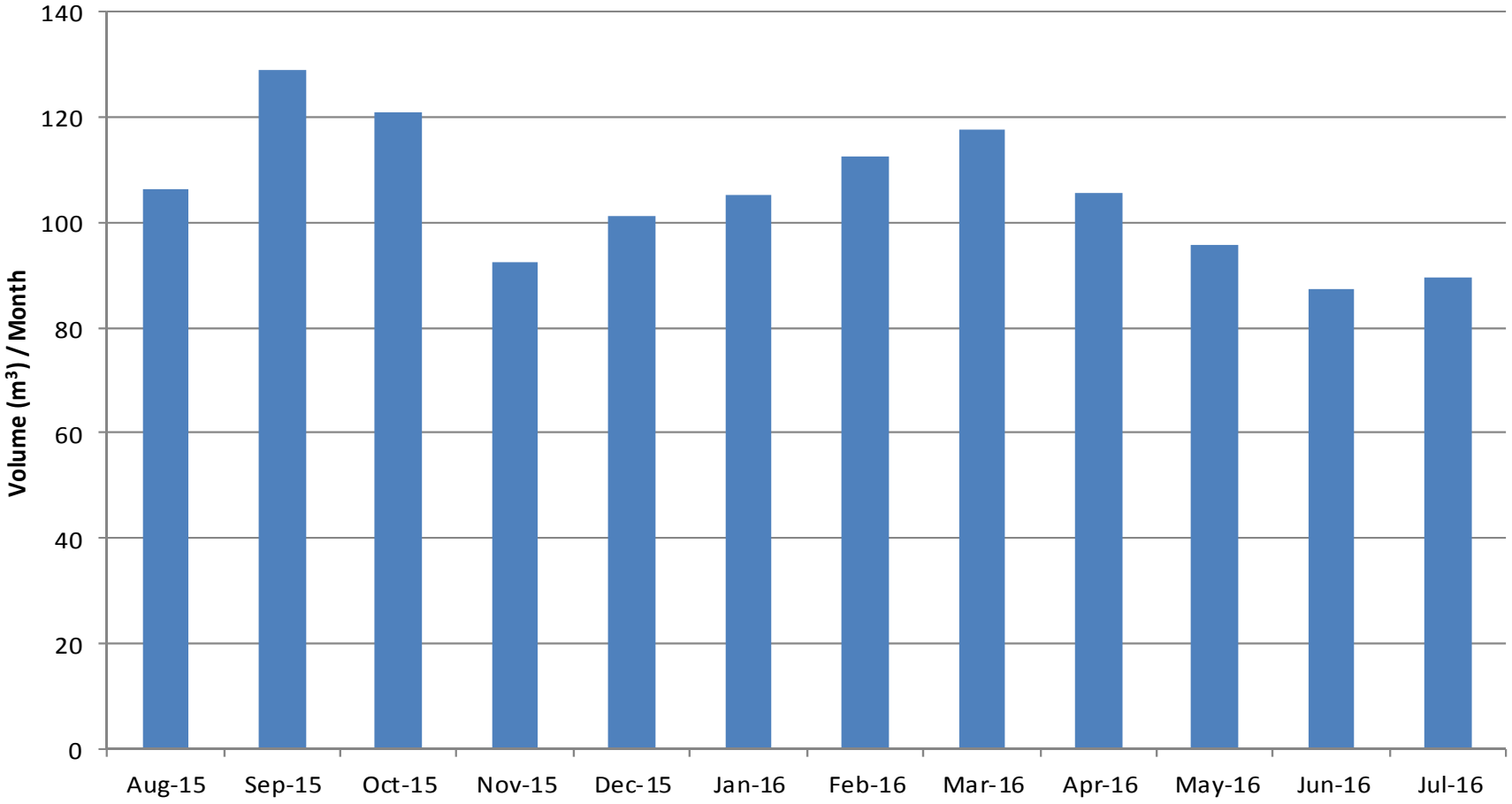
- Water Diversion Licence Amendment No. 00194427-00-01

- Domestic use only:
  - Safety showers / eye-wash stations
  - Cleaning water
  - Washroom / kitchen uses

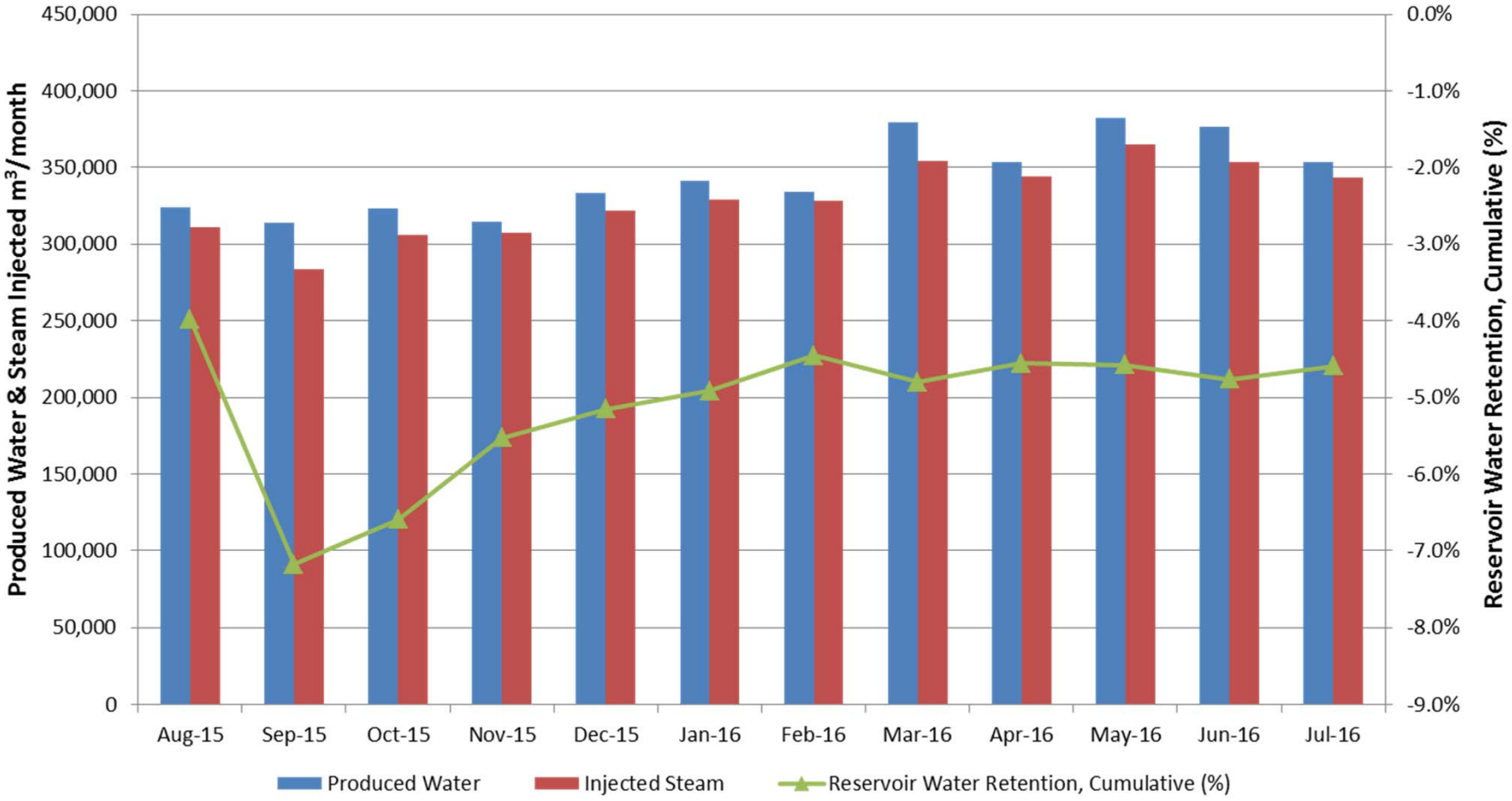
- Bonnyville Aquifer

- 12-28-064-04-W4

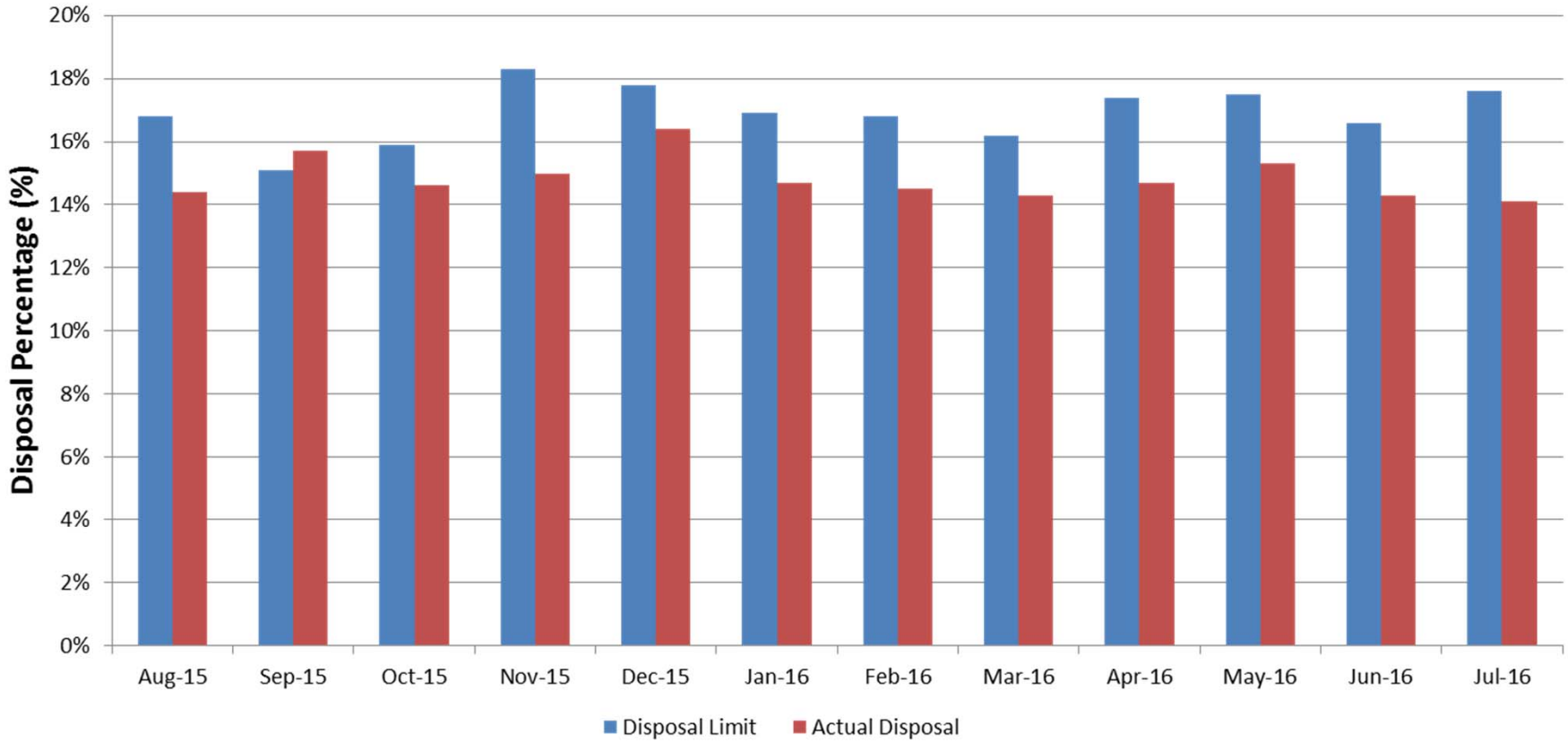
Fresh Water Consumption



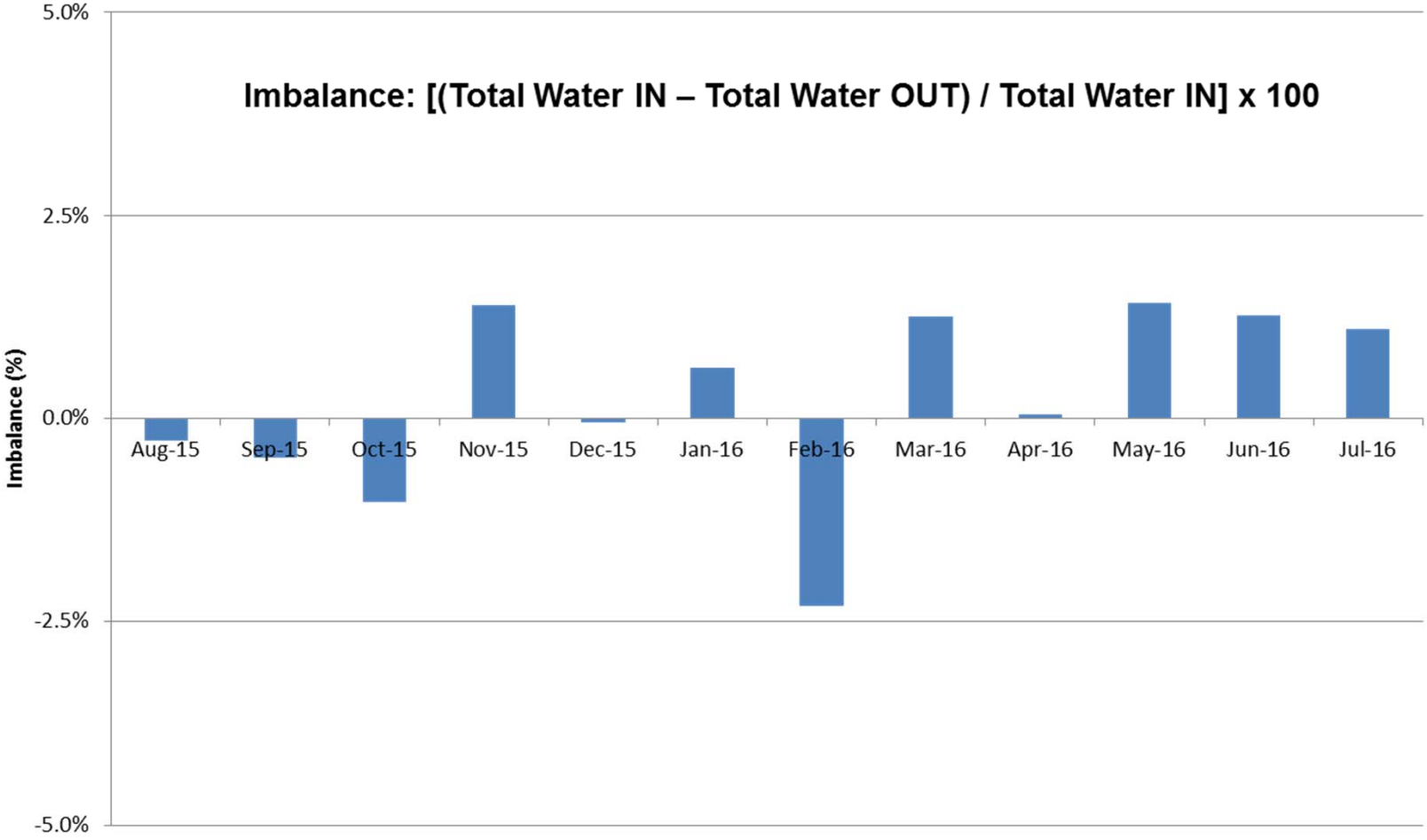
Produced Water & Steam Injected



Water Disposal Limits



Monthly Injection Water Balance



OTSG Blow-down Recycle

- OTSG blow-down is recycled to the Warm Lime Softener (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 40.4% of our blow-down back to the WLS

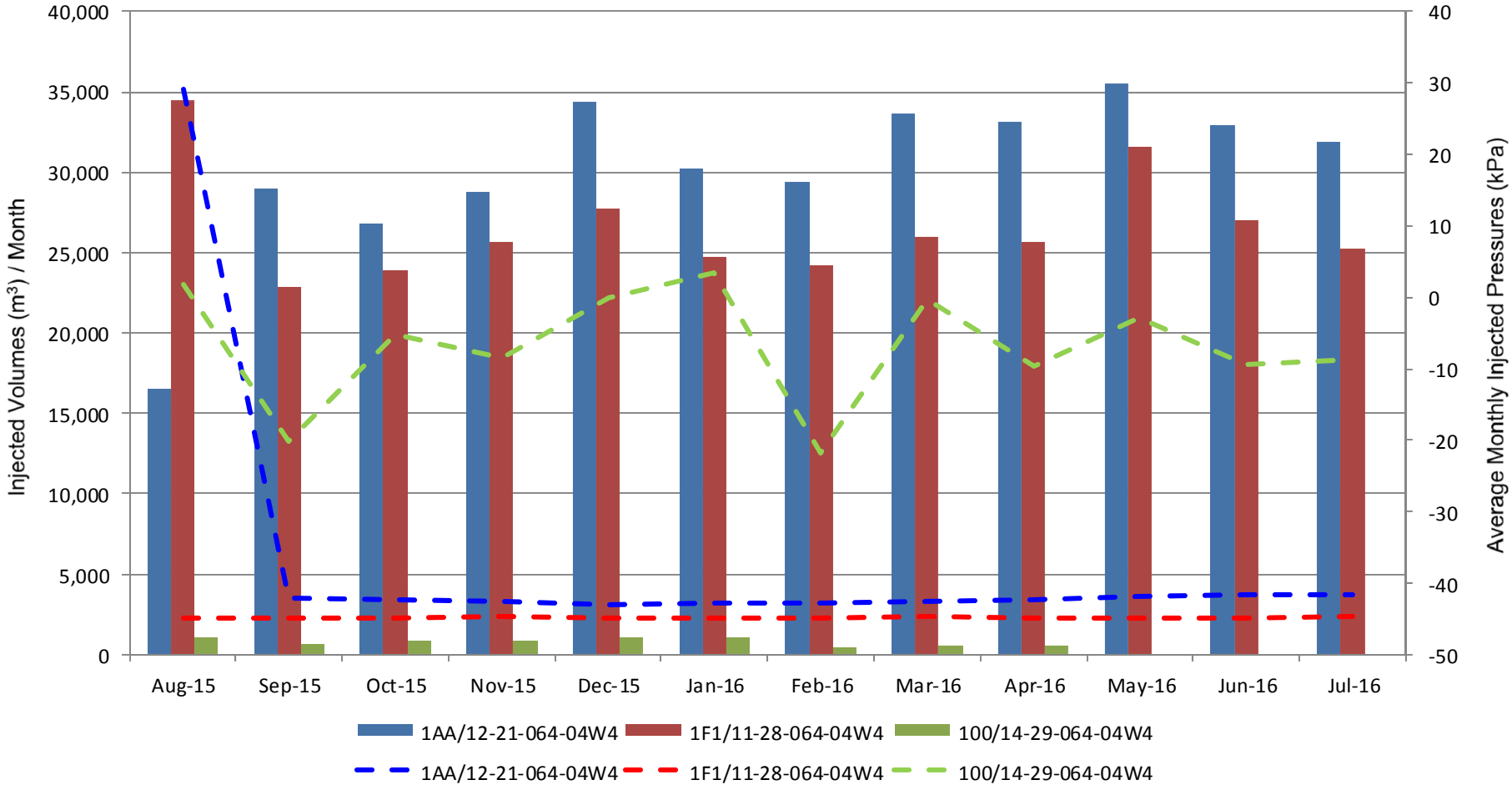
Disposal Wells

- 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	Total	Unit
ACID	Acid Solutions Unneutralized	Rbw Waste Management Ltd.	Other (specify)	0.113	m3
CAUS	Caustic Solutions Unneutralized, Spent	Rbw Waste Management Ltd.	Recycling Facility (excluding used oil)	0.2	m3
CLNRAG	Clean Rags	Rbw Waste Management Ltd.	Recycling Facility (excluding used oil)	0.205	m3
COEMUL	Interphase > 20%, Oil <= 30%	Elk Point Service Centre	Oilfield Waste Processing Facility	13	m3
	Interphase 0 - 10%, Oil <= 30%	Elk Point Service Centre	Oilfield Waste Processing Facility	36	m3
	Interphase 10.1 - 20.0%, Oil <= 30%	Elk Point Service Centre	Oilfield Waste Processing Facility	64	m3
	Cavern Waste Oil - Solids	Tervita - Lindbergh	Cavern	1648.08	m3
DOMWST	Garbage Domestic Waste	Rbw Waste Management Ltd.	Recycling Facility (excluding used oil)	67.06	m3
EMTCON	Empty Container (rbw Container)	Rbw Waste Management Ltd.	Recycling Facility (excluding used oil)	3.35	m3
FILWTT	Cavern Filter (Media) Water Treatment	Tervita - Lindbergh	Cavern	124.7	m3
GLYCHM	Glycol Solutions Containing Lead or Other Heavy Metals	Rbw Waste Management Ltd.	Recycling Facility (excluding used oil)	0.205	m3
INOCHM	Chemicals Inorganic	Rbw Waste Management Ltd.	Recycling Facility (excluding used oil)	1.4	m3
OILABS	Absorbents	Rbw Waste Management Ltd.	Recycling Facility (excluding used oil)	1.045	m3
OILRAG	Oily Rags	Rbw Waste Management Ltd.	Recycling Facility (excluding used oil)	1.1	m3
SLGHYD	Sludge Hydrocarbon	Tervita - Lindbergh	Cavern	16.48	m3
SMETAL	Metal Scrap	Rbw Waste Management Ltd.	Recycling Facility (excluding used oil)	4.76	m3
SOILCO	Contaminated Debris and Soil Crude Oil Condensate	Clean Harbors - Ryley Class Ia	Class Ia Landfill	7	m3
WSTMIS	Waste Miscellaneous	Rbw Waste Management Ltd.	Recycling Facility (excluding used oil)	11.2	m3
Grand Total				1999.90	m3

5. Sulphur Production

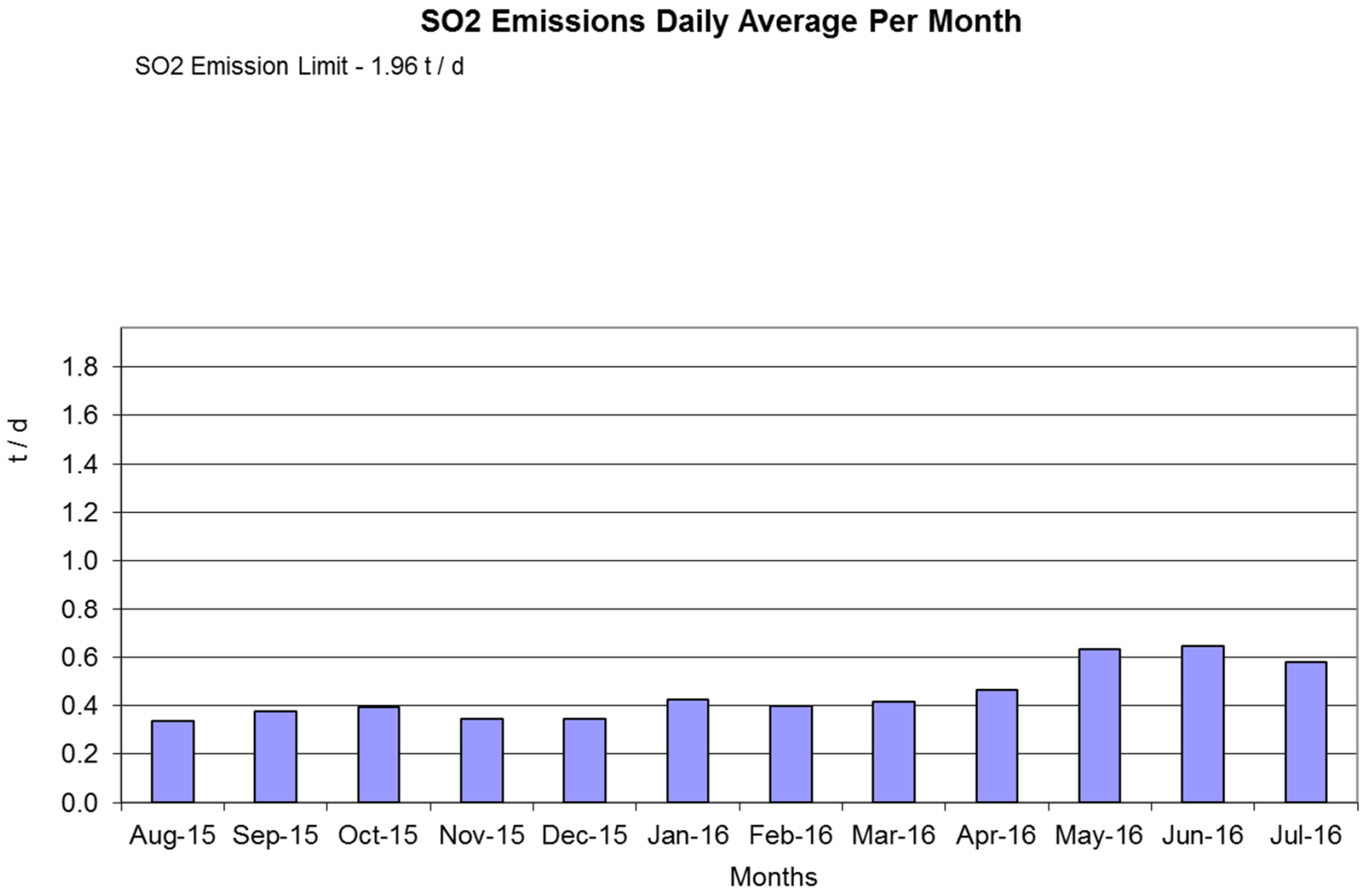
Sulphur Dioxide (SO_2) Sources

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

Quarterly SO_2 Emissions

Q3 2015 (August 2015 – October 2015)	33.91 tonnes
Q4 2015 (November 2015 – January 2016)	34.18 tonnes
Q1 2016 (February 2016 – April 2016)	38.61 tonnes
Q2 2016 (May 2016 – July 2016)	56.38 tonnes

SO_2 Emissions Trends



Peak and Average SO_2 Emissions

- August 1, 2015 to July 31, 2016:

SO_2 Emissions	
Average Daily (highest)	0.75 tonnes
Maximum Daily (highest)	0.96 tonnes

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

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
  - 366,971.6 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 2015 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 33,441 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

7. Compliance Statement

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 in this reporting period

8. Non-Compliance Events

Non-Compliance Issues

- Reportable Pipeline incident – Above ground pipeline release due to pin hole in control valve during start-up steaming of Pad CN:
  - Reported March14, 2015
  - Release contained on pad-site
  - Replaced failed valve with new valve and changed steam start-up operation
  - AER closure letter received July 26, 2016
- Berm breach – Pad C:
  - Reported March 30, 2016
- Alberta CEMS code – B7300 CEMS unit failure
  - Reported July 7, 2016
  - CEMS unit failed and sent to manufacturer (SICK) in Ontario for repairs
- Alberta CEMS code – B7800 CEMS unit failure
  - Reported August 23, 2016
  - After trouble shooting with manufacturer replacement parts shipped

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

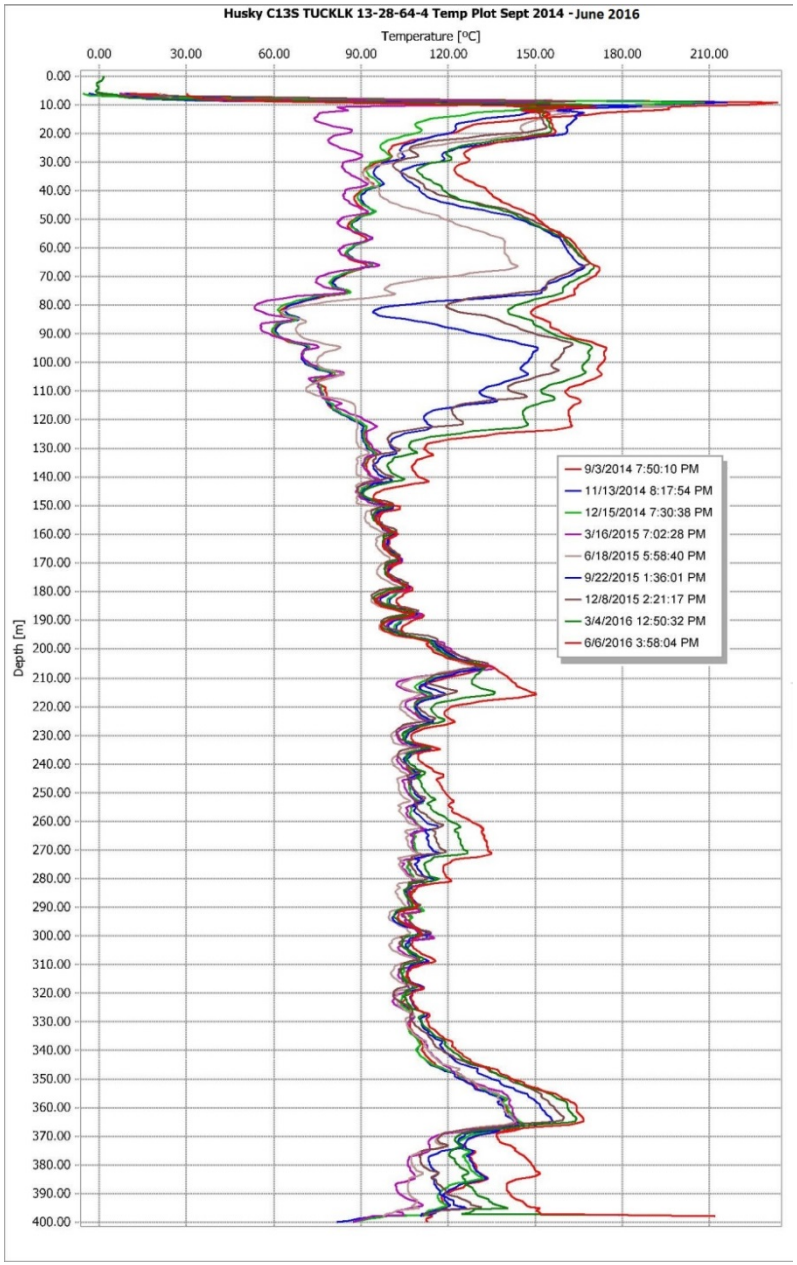
SCVF/GM Update – C13S

- 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 174 ºC between 90-100 m interval
  - 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 (September 2016)
- Husky will notify AER of any changes

8. Future Plans

Future Plans (2016/2017)

- Construct, commission & start-up Pad D North SAGD development
- Construct, commission & start-up Pad C West Replacement wells
- Start construction of Pad D West SAGD development