Long Lake & Kinosis Oil Sands Project Annual Performance Presentation

This presentation contains information comply with Alberta Energy Regulator's Directive 054 – Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

CNOOC

Date: May 8, 2020

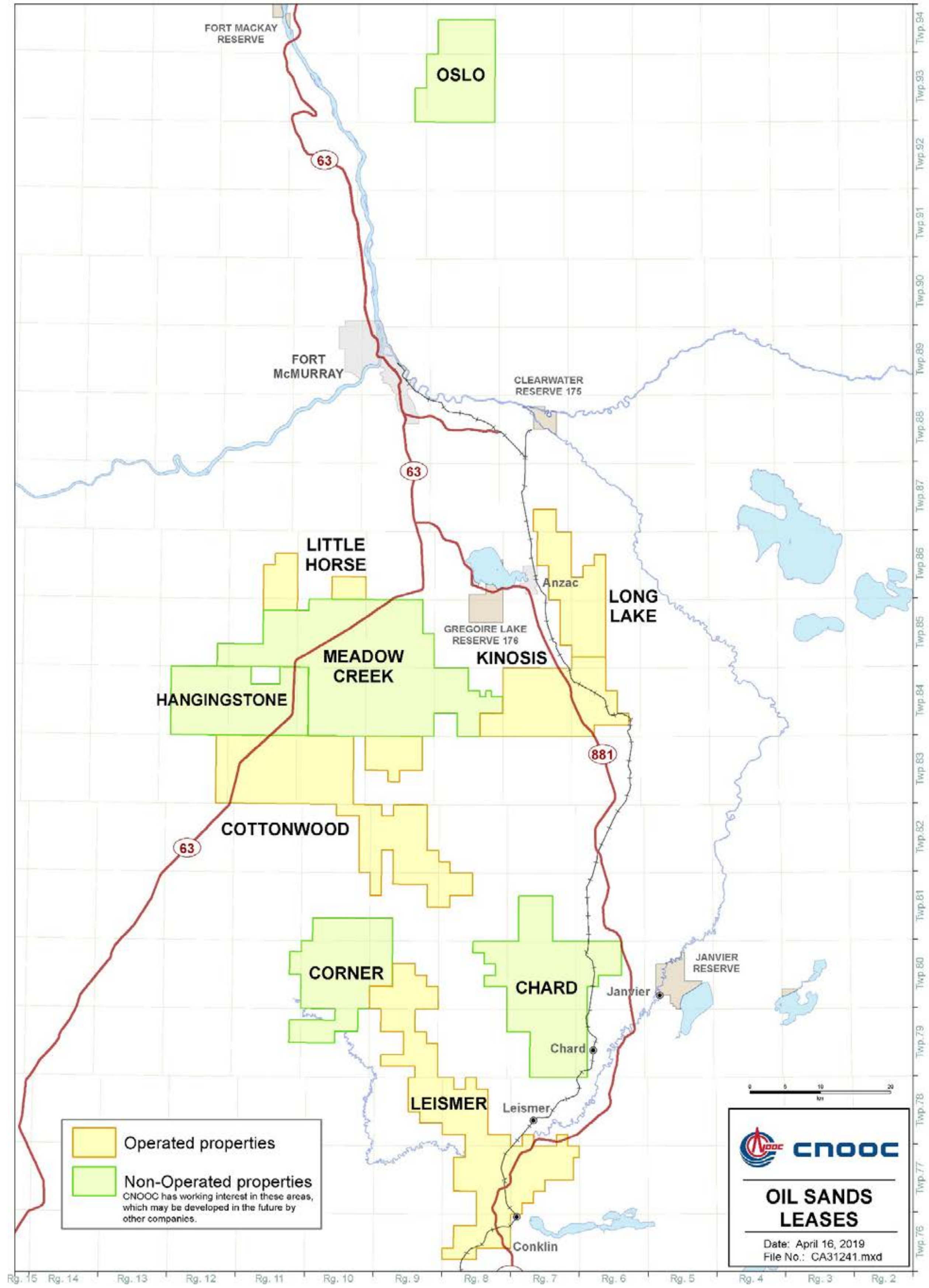
Forward Looking Statements

This document was prepared and submitted pursuant to Alberta regulatory requirements. It contains statements relating to reserves which are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the described reserves exist in the quantities predicted or estimated, and can be profitably produced in the future. There is no certainty that the reserves exist in the quantities predicted or estimated or that it will be commercially viable to produce any portion of the reserves described in this document.

Corporate Ownership

- CNOOC Petroleum North America ULC (formerly Nexen Energy ULC) ("CNOOC International") is an upstream oil and gas company responsibly developing energy resources in North America.
- CNOOC International is a wholly-owned subsidiary of the China National Offshore Oil Company Limited (CNOOC).

CNOOC International Oil Sands



Contents

Subsurface Operations Related to Resource Evaluation and Recovery

Subsection 3.1.1

Long Lake and Kinosis

Background of Scheme and Recovery Process

Subsection 3.1.1 (1)

Long Lake and Kinosis

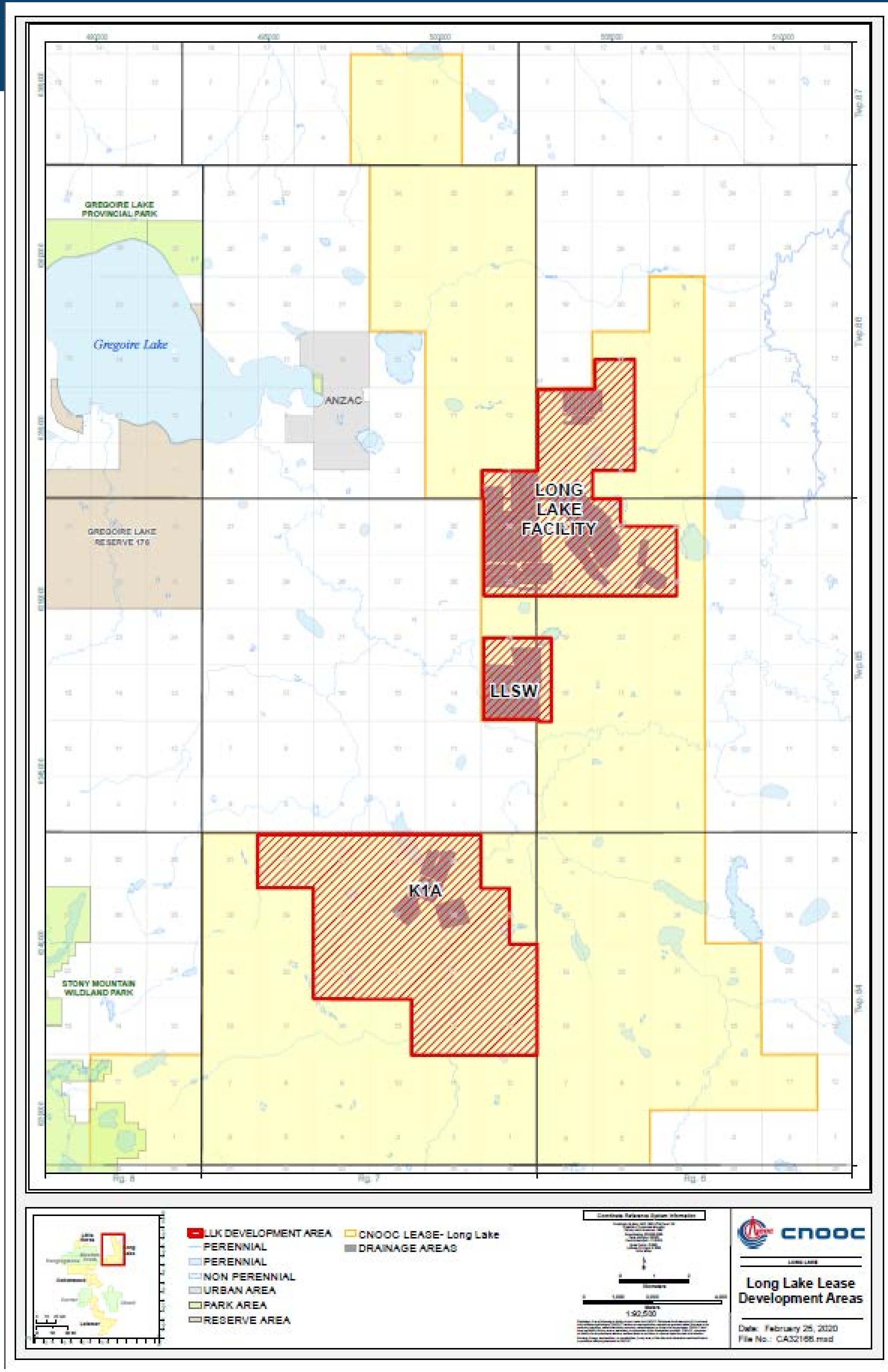
Long Lake Scheme Description

- Located approximately 40 km southeast of Fort McMurray.
- An integrated SAGD and Upgrader oil sands project producing from the Wabiskaw-McMurray deposit.

	Design (LLK) m³/d	bbl/d
Bitumen	11,130	70,000
Steam	37,000	233,000
SOR	3.3	

	Design (K1A*) m³/d	bbl/d
Bitumen	3,180	20,000
Steam	9,540	60,000
SOR	3.0	

*K1A – First 20K of 70K which is Phase 1A of Kinosis



CHRONOLOGY OF OIL SANDS OPERATIONS

Year	Activity
2000	EIA and regulatory submissions for the commercial Long Lake Facility (LLK)
2003	Regulatory approvals for the commercial LLK Facility
2003 - 2007	Production at the Long Lake SAGD Pilot Plant
2004	Construction begins for the commercial LLK Facility
2006	Regulatory amendments, including Pad 11
2007	Start of commercial bitumen production for the Long Lake Facility
2007	Regulatory submissions for Long Lake South (development of Kinosis lease)
2009	Regulatory approvals issued for K1A (First 20k bbls of Phase 1 of 2 of Kinosis (formerly Long Lake South))
2009	Start of operation of the LLK Upgrader
2010	Regulatory approvals for Pads 12 and 13
2012	First production from Pads 12 and 13
2012	Major turnaround for maintenance at Central Processing Facility (CPF) and Upgrader
2012	Regulatory approvals and construction begins for Pads 14, 15 and K1A Pads 1 and 2
2013	Increased production from LLK well pads, begin circulation at Pad 14
2014	K1A Pads 1, 2 and Pads 14, 15 start production
2015	Diluent Recovery Project start up; Pipeline leak ceases production at K1A; 7N Infills on production
2016	Hydro-Cracker Unit (HCU) Incident; Wildfire shut down Long Lake operations for ~2 months
2017	Commenced drilling infills on Pads 5 and 8
2018	Pads 5, 8 Infills on production; Drilling commenced on Pad 3,6 Infills & LLSW SAGD well pairs
2019	Pad 1,3,5,6,13 Infills on production; D&C completed on LLSW SAGD well pairs

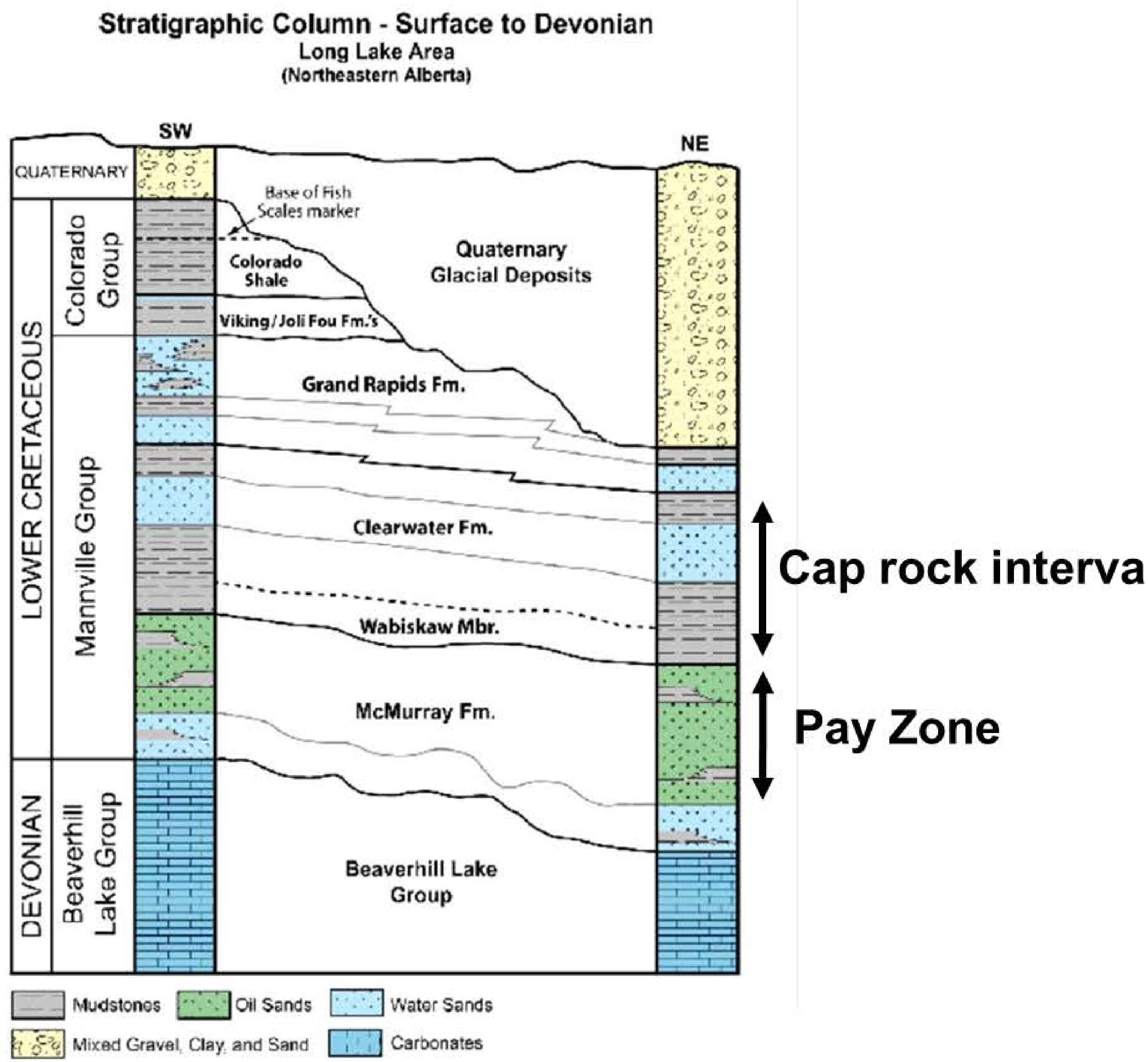
2019 Summary

- Long Lake pads exhibited strong and stable performance throughout the year.
  - Infills on Pad 1, 3, 5, 6 and Pad 13 commenced production
  - Highest annual average production with lowest observed SOR
- Managed production curtailment throughout 2019
- Completed drilling & completion of Long Lake South West (LLSW) sustaining SAGD well pairs
- K1A Recovery Project
  - Completed 9 of 12 trenchless pipeline crossings (commenced Jan 2019)
  - Continued progress on detailed engineering for pipeline replacements
  - Commenced facility restart inspections

Geology and Geosciences Overview
Subsection 3.1.1 (2)
Long Lake and Kinosis

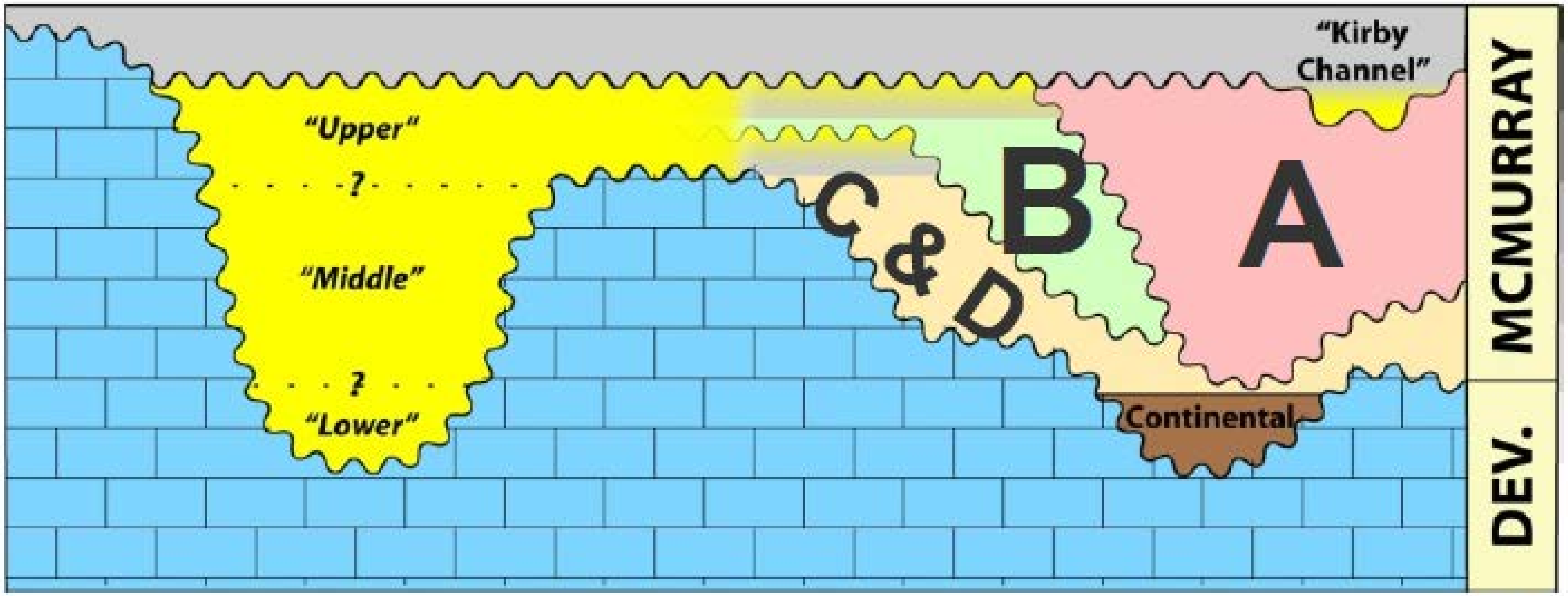
Reservoir: McMurray Fm.

Cap rock: Wabiskaw & Clearwater Fm.



CNOOC International's Regional Model

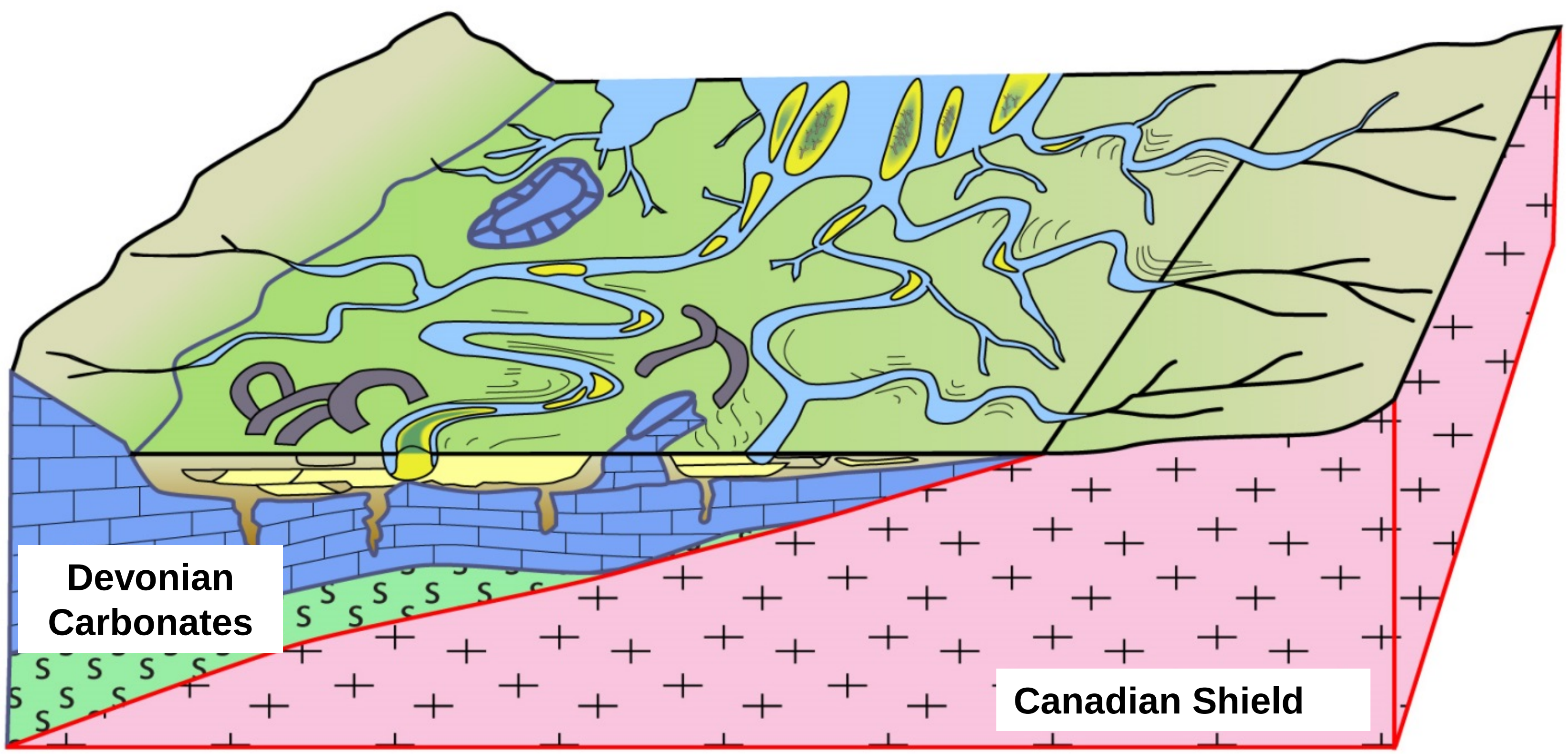
- Compound incised-valley system hung from several surfaces in the McMurray
- Multiple valleys:
  - C & D valleys (oldest)
  - A valley (youngest)
- Low-accommodation setting



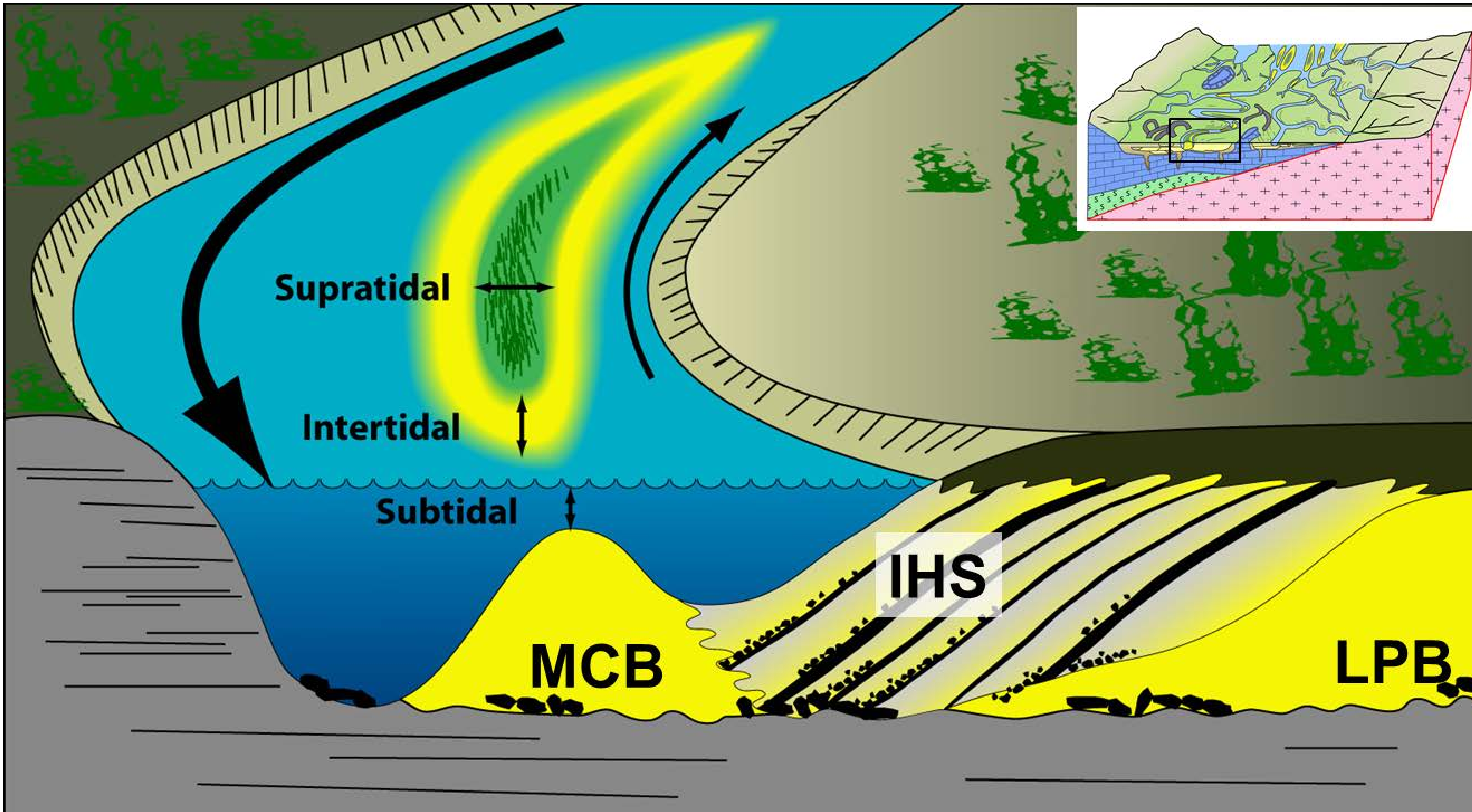
Jervey, 2003

Regional Depositional Model

- Tidal-Fluvial/Estuarine Complexes
  - Stacked channel systems including:
    - Mid-channel bars
    - Channel-tidal shoal complexes
    - Channel-point bar complexes
    - Mud plugs
- Estuarine/brackish water environment

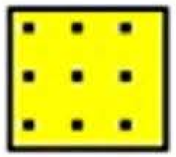


McMurray Geological Model and Reservoir Facies

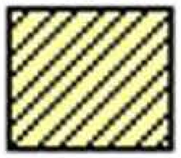


MCB = mid channel bar	Facies 1 & Facies 3
LPB = lower point bar	Facies 1 & Facies 3
IHS = inclined heterolithic stratification	Facies 2 & Facies 3 & Facies 4

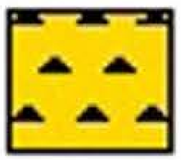
CNOOC International Facies Codes



Sandstone .... Facies 1:
- clean crossbedded sandstone
- VSH 0 - 10%
- estuarine sands



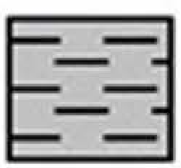
Sandy IHS .... Facies 2:
- Inclined interbedded sandstone, and mudstone
- Vsh 10-50%
- Point-bar facies



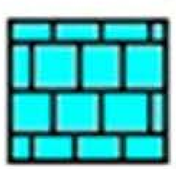
Breccia .... Facies 3:
- mud clast breccia
- sand supported and mud clast supported
- channel base facies

Muddy IHS .... Facies 4:
- Inclined interbedded sandstone, and mudstone
- Vsh 50-90%
- Point-bar facies

Mudplug .... Facies 5:
- muds and silts
- abandoned channel muds
- point bar facies

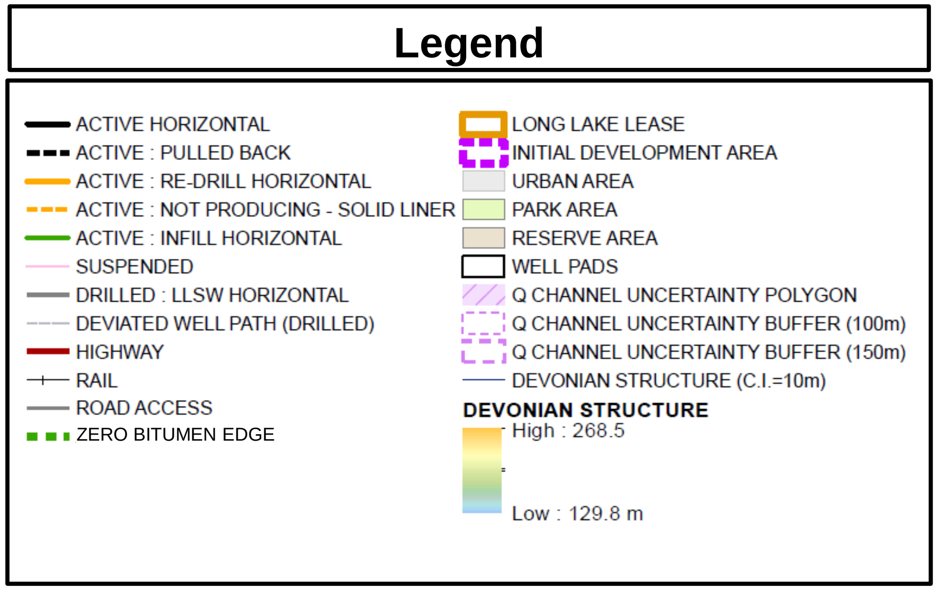


Mudstone .... Facies 6:
- Muds and silts
- abandoned channel muds
- Vsh >90%
- Point-bar facies

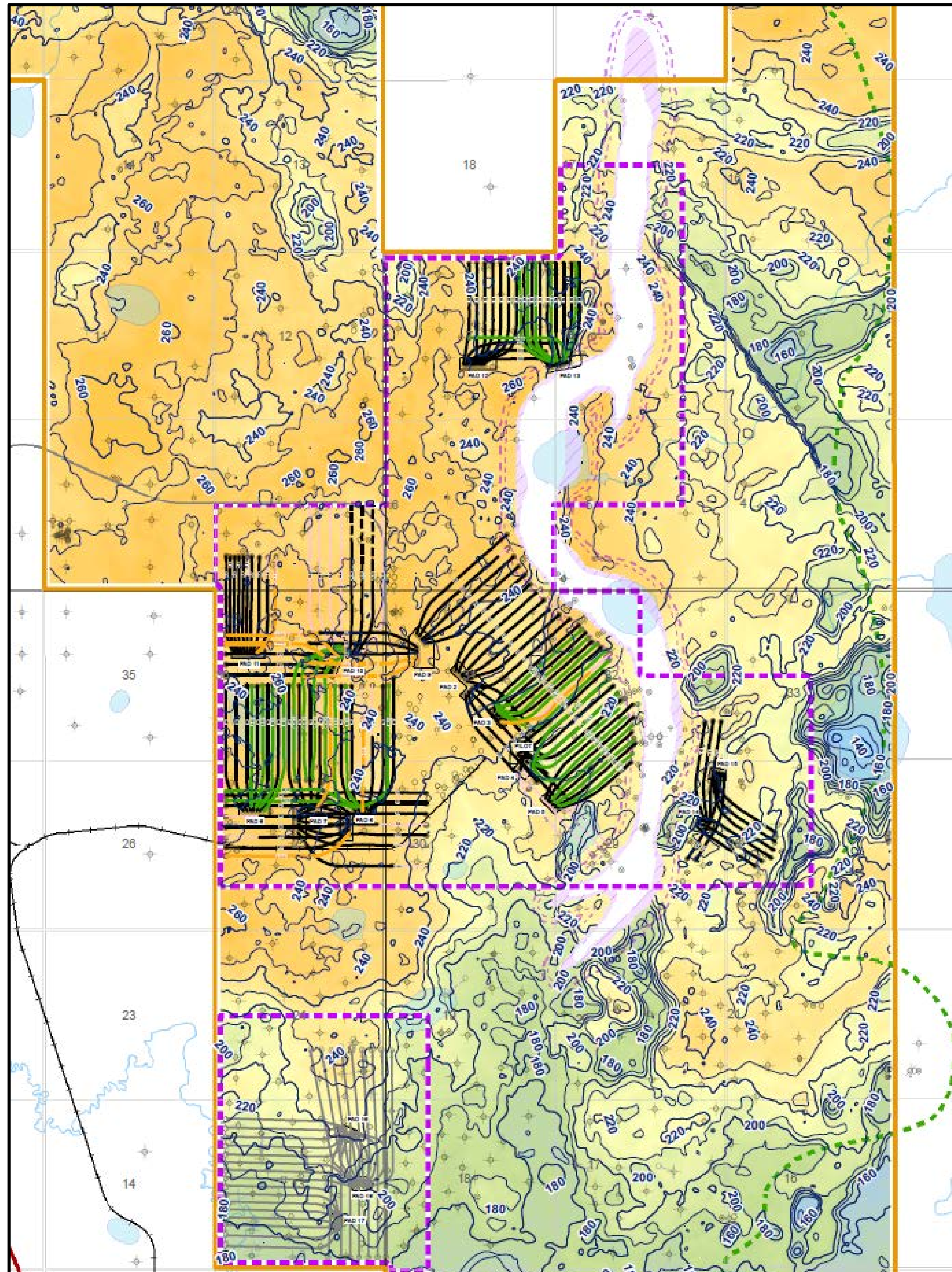


Limestone .... Facies 7:
- Devonian carbonates

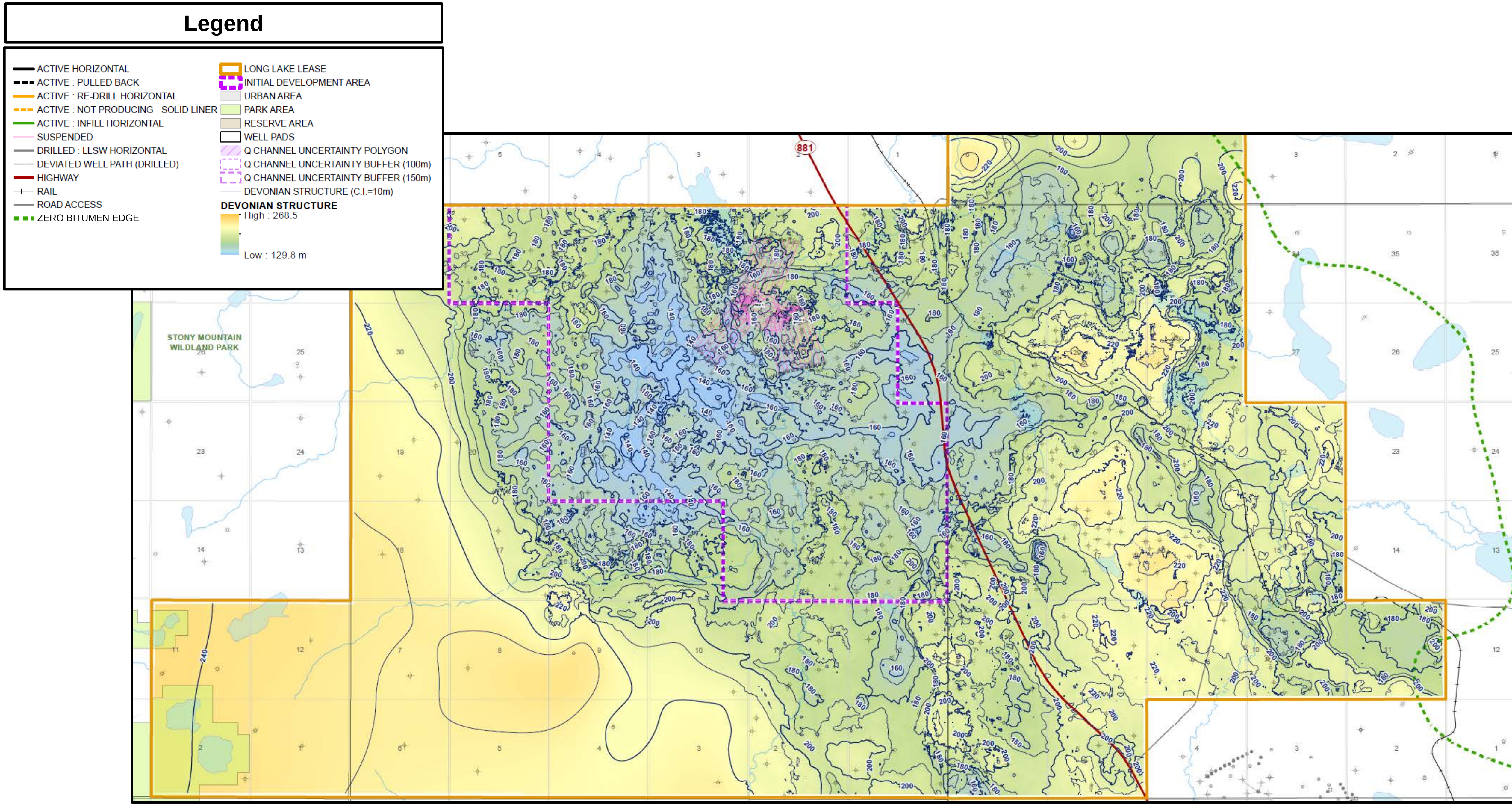
Long Lake Devonian Structure



- Relatively flat below current SAGD development areas
- Lows related to collapse features (karst and dissolution) and erosion



Kinosis Devonian Structure



- Structure controlled by Pre-Cretaceous erosion and dissolution of the Prairie Evaporite, Lotsberg and Cold Lake salts
- Has a significant effect on base of pay structure and bottom water contacts
- Timing of salt solutioning was pre-McMurray, syn-McMurray and post-McMurray
- Minor karsting on Devonian surface

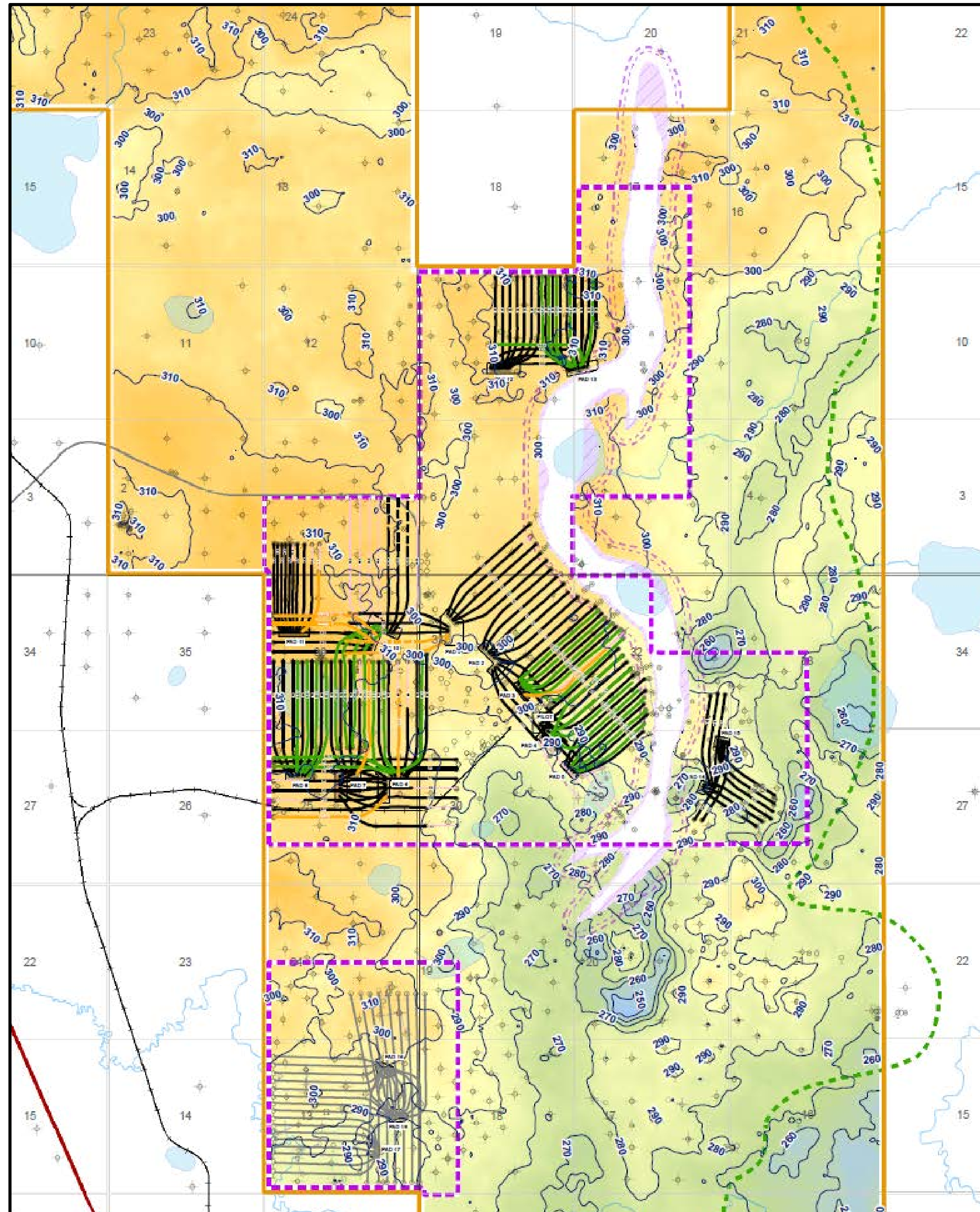
Long Lake McMurray Structure

cnooc

Legend

- ACTIVE HORIZONTAL
- ACTIVE : PULLED BACK
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- ACTIVE : INFILL HORIZONTAL
- SUSPENDED
- DRILLED : LLSW HORIZONTAL
- DEVIATED WELL PATH (DRILLED)
- HIGHWAY
- RAIL
- ROAD ACCESS
- ZERO BITUMEN EDGE
- LONG LAKE LEASE
- INITIAL DEVELOPMENT AREA
- URBAN AREA
- PARK AREA
- RESERVE AREA
- WELL PADS
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- McMURRAY STRUCTURE (C.I.=5m)

McMURRAY STRUCTURE
High : 332.6
Low : 235.3m



- Blue/Green-shaded areas are lows related to salt dissolution
- Subtle structural influences related to karsting, erosion on Devonian and differential compaction over muddier McMurray deposits

Kinosis McMurray Structure

Legend

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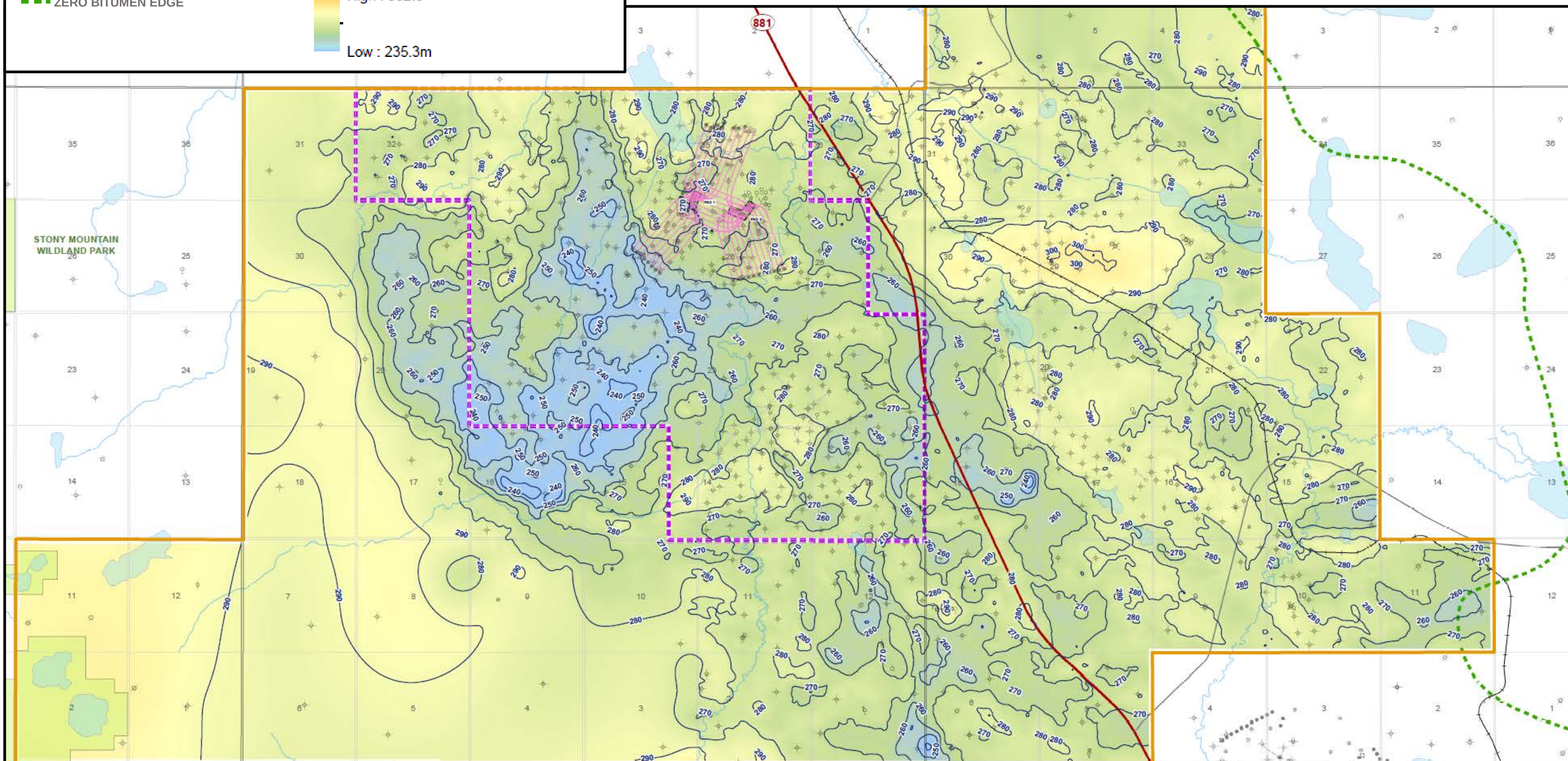
- McMURRAY STRUCTURE (C.I.=5m)

McMURRAY STRUCTURE

High : 332.6

Low : 235.3m

- Influenced by depositional elements that result in differential compaction
- Influenced by Devonian salt collapse



Long Lake McMurray Isopach

Legend

- ACTIVE HORIZONTAL
- ACTIVE : PULLED BACK
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- WELL PADS
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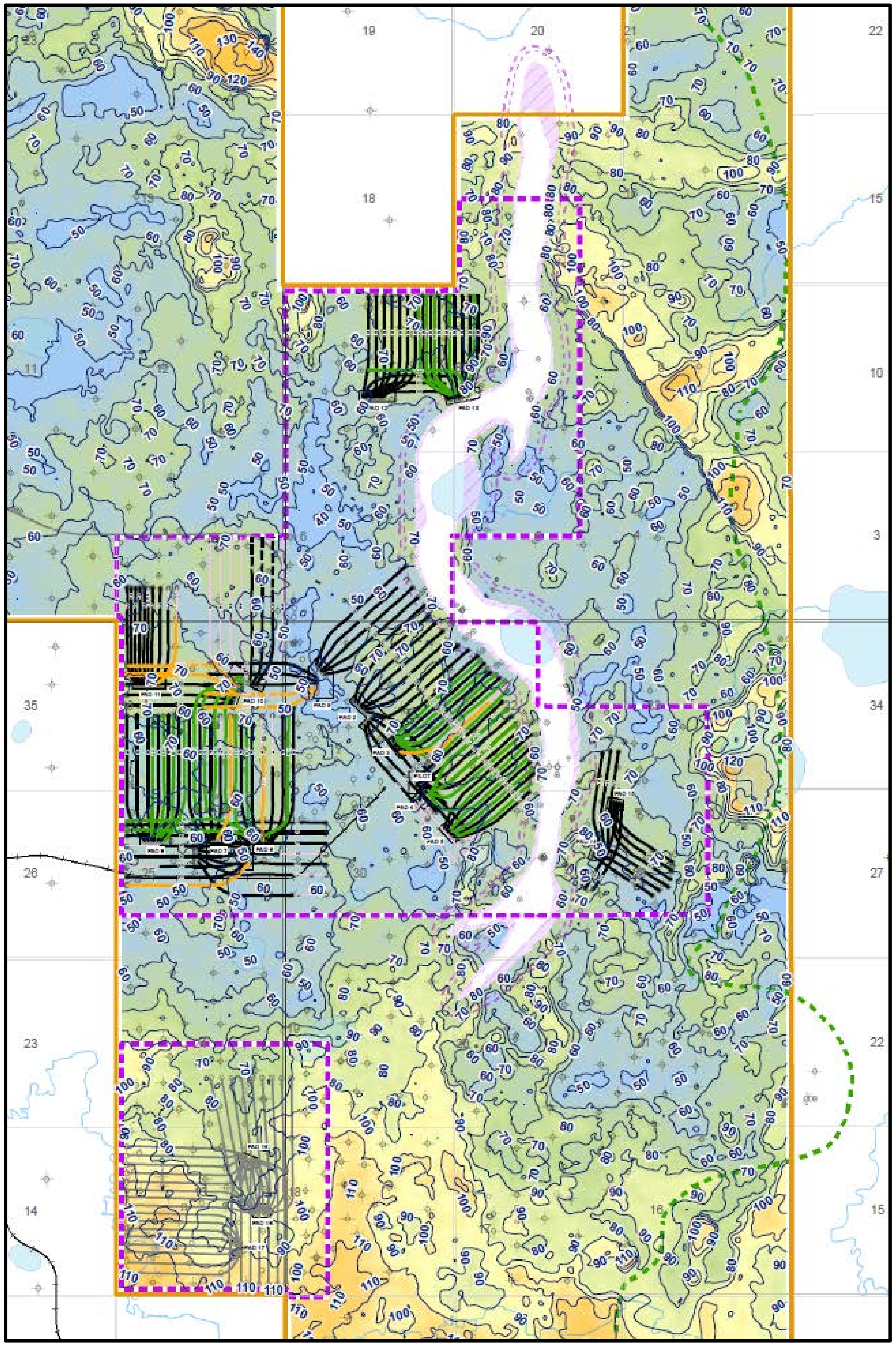
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- McMURRAY ISOPACH (C.I.=5m)

McMURRAY ISOPACH

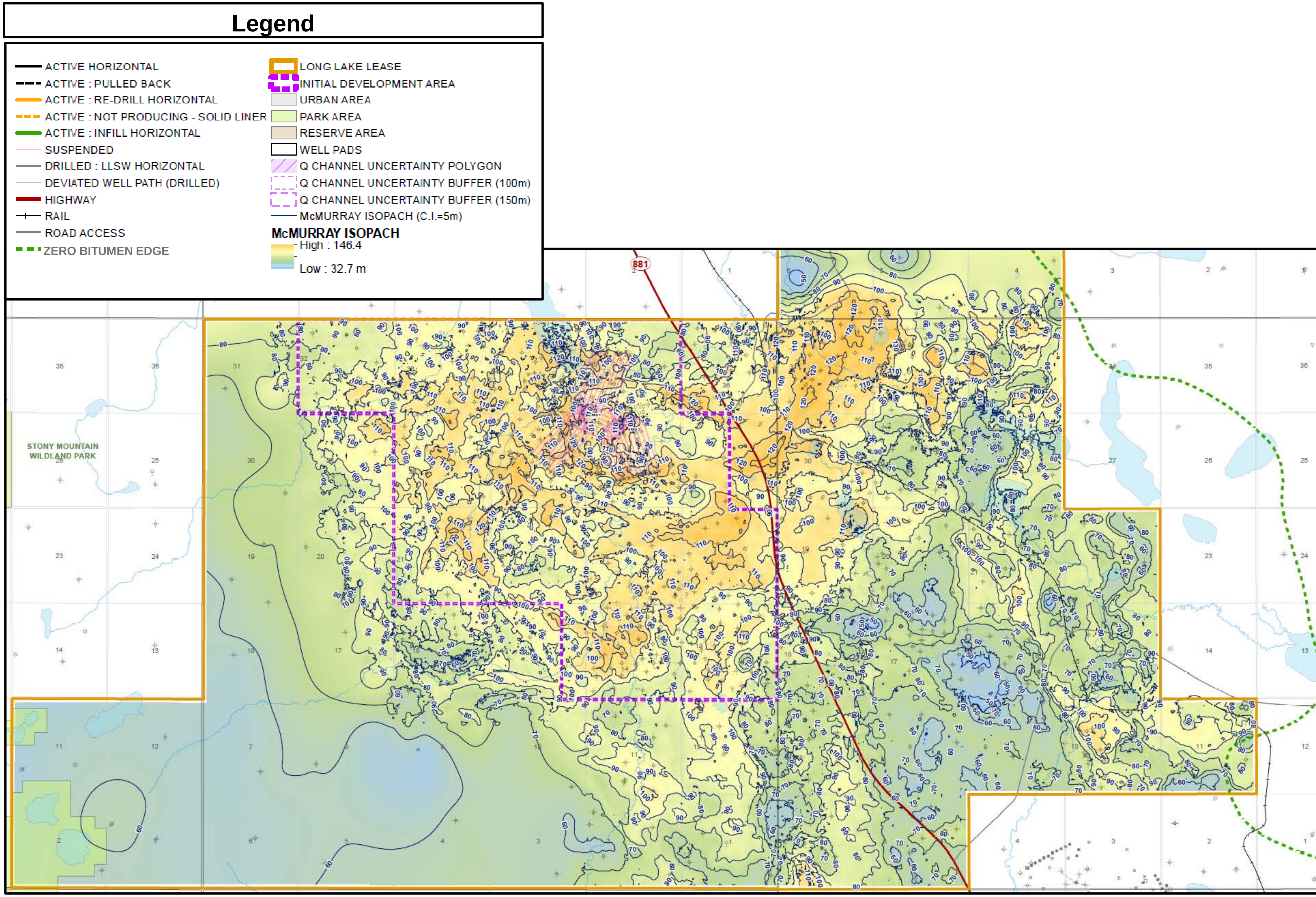
High : 146.4

Low : 32.7 m



- Relatively consistent isopach (50-70m) within producing area
- Thick areas associated with Devonian lows

Kinosis McMurray Isopach



Geology and Geosciences Pay and Exploitable Bitumen-in-Place Mapping Methodology

Subsection 3.1.1 (2)

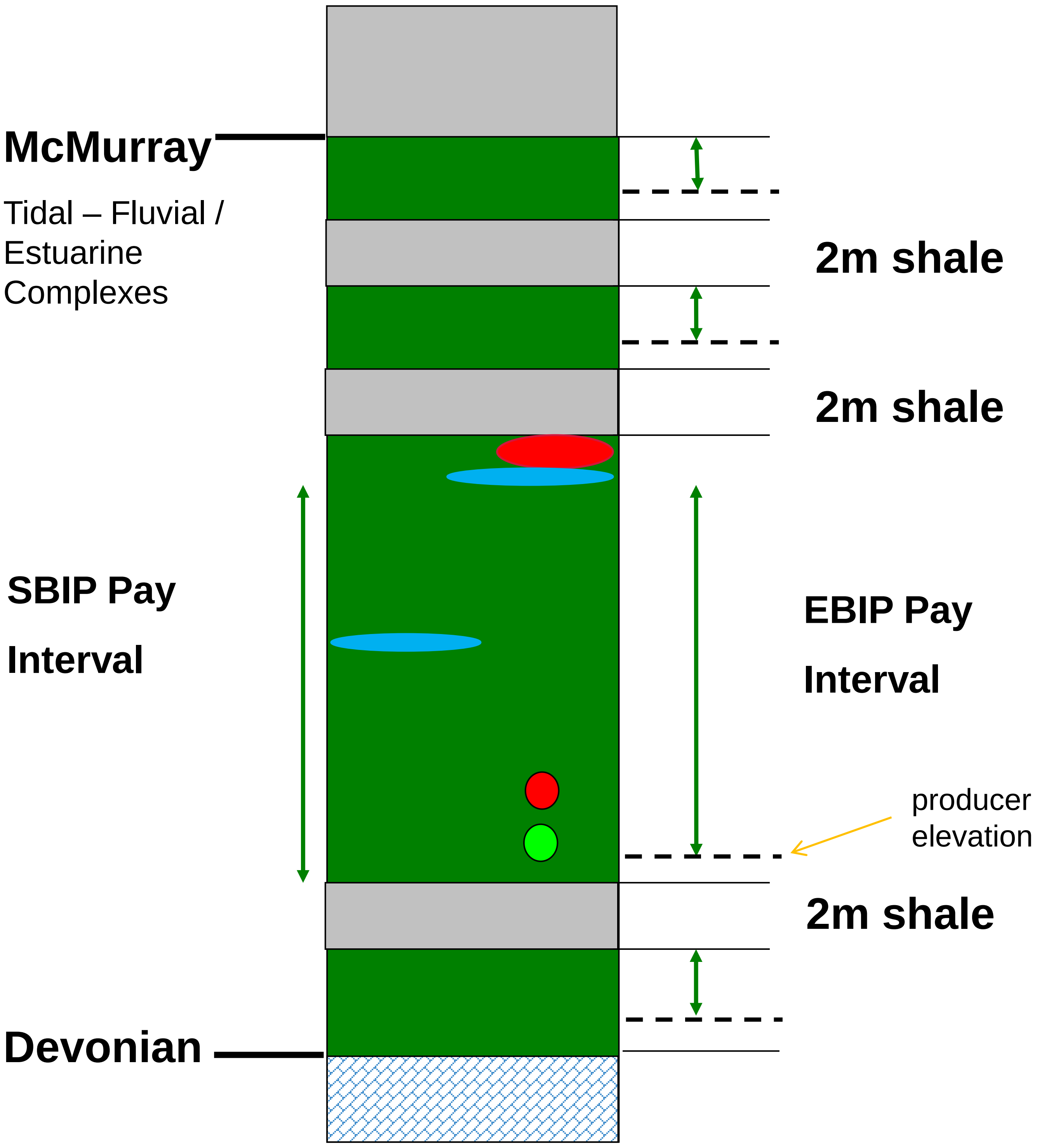
Long Lake and Kinosis

Pay and Exploitable Bitumen-in-Place Mapping Methodology

- Pay cut-offs:
  - Top of pay interval is a 2 m shale with > 30% Vshale
  - Focus on low Vshale intervals with thinner and fewer shale beds
  - Account for standoff from bottom water or non-reservoir
- Top of EBIP/SBIP Pay Interval:
  - Single shale interval (> 30% Vshale) of 2m
  - Cumulative shale interval (> 30% Vshale) of 4m
- Base of SBIP Pay Interval:
  - Base of bitumen pay/reservoir rock
- Base of EBIP Pay Interval:
  - Depth of an existing or planned horizontal well pair (EBIP pay base = producer well depth)
  - Stand-off from bitumen/water contact or non-reservoir
- Gas Interval(s) Associated with EBIP/SBIP Pay Interval
  - Gas identified by neutron/density crossover
- High Water Saturation Interval(s) Associated with EBIP/SBIP Pay Interval
  - > 50% Swe (effective water saturation) and < 30% Vshale
- EBIP will be calculated from a hydrocarbon pore volume height (HPVH) map.

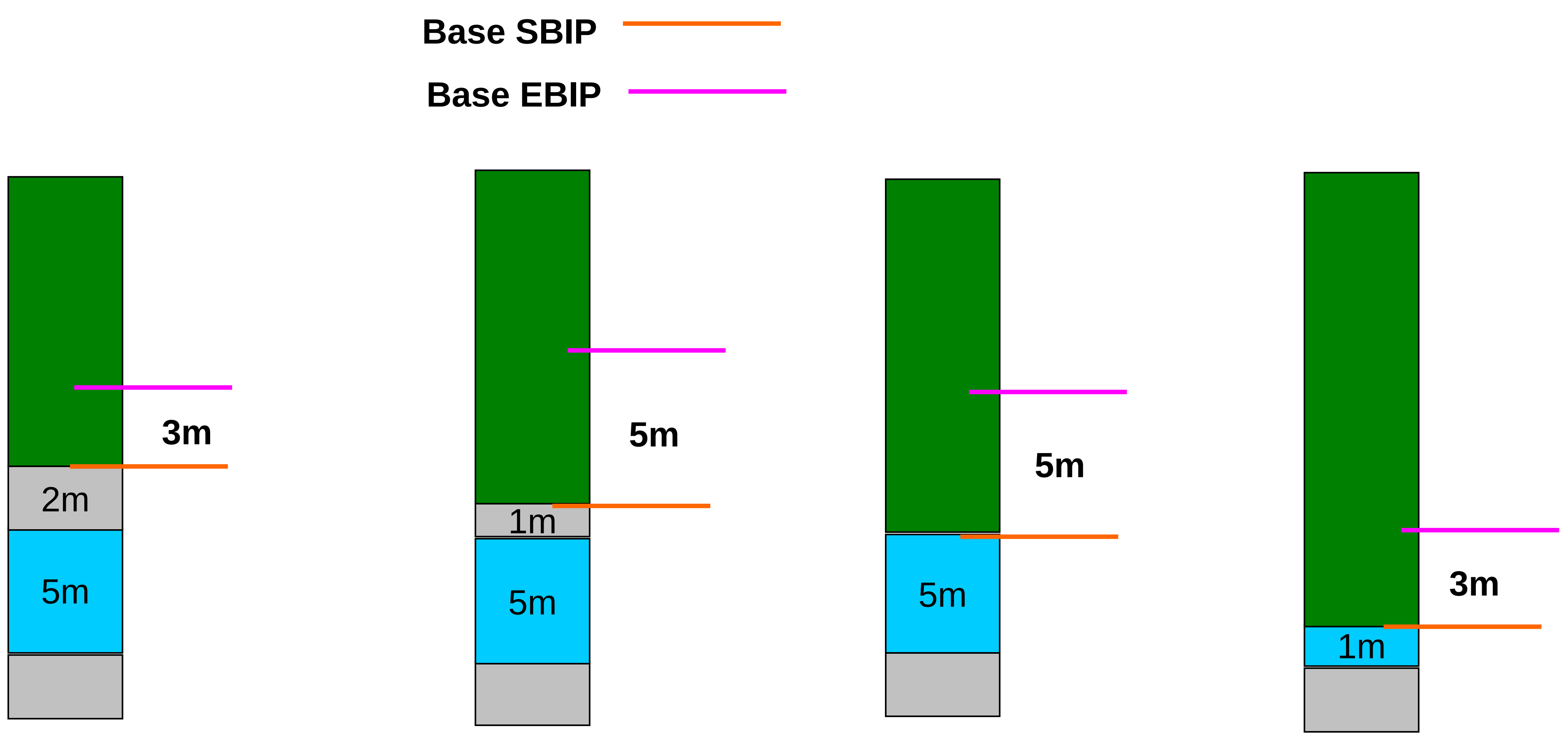
- Reservoir Rock
  - Sand
  - Breccia
  - IHS with < 30% V_{shale}
- High Water Saturation Interval
  - > 50% Swe (effective water saturation) and < 30% V_{shale}
- Minimum EBIP HPVH and Pay Interval Contour
  - $3m^3/m^2$ EBIP HPVH = 12m EBIP Pay Interval

Pay and Bitumen-in-Place Mapping Methodology

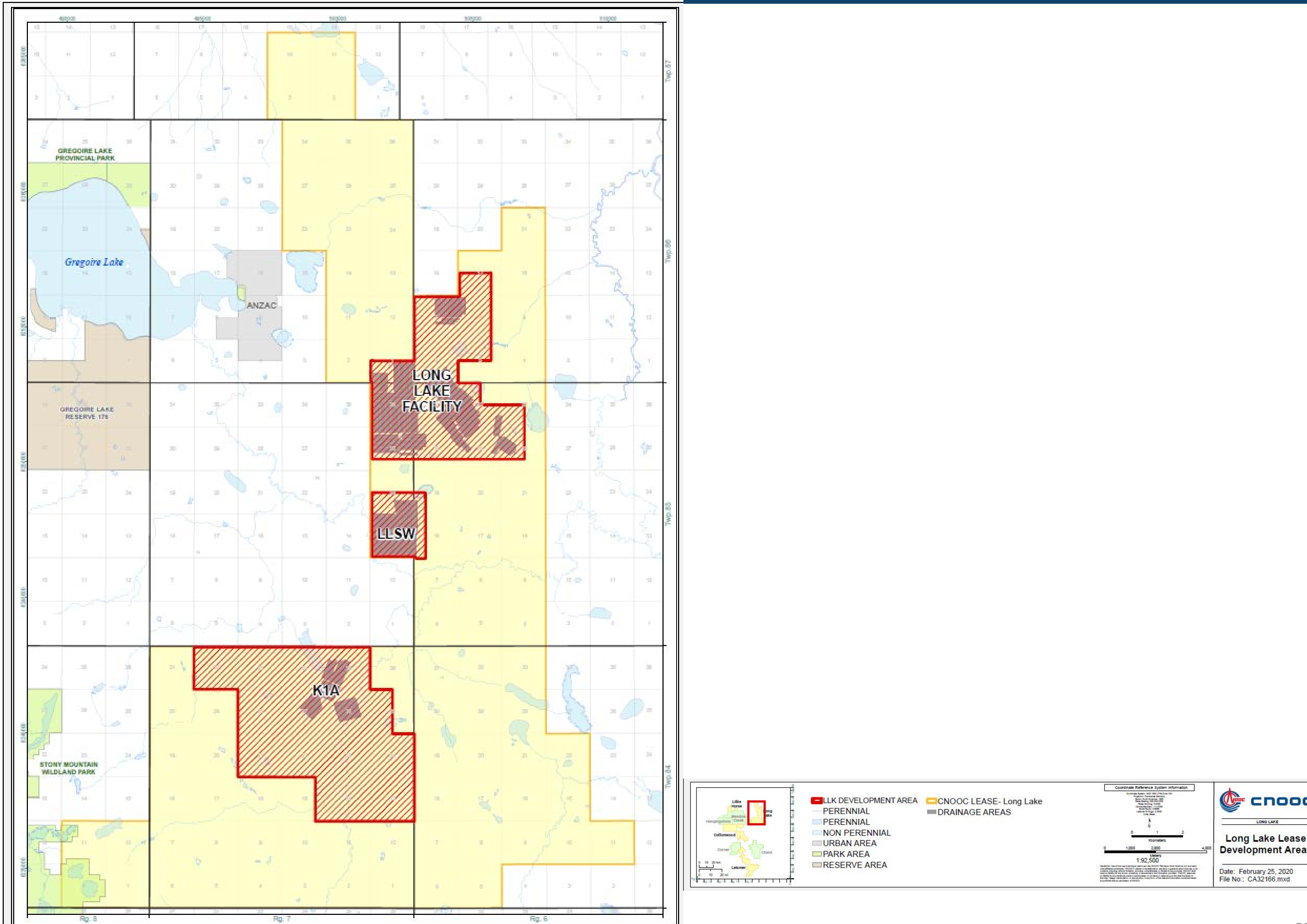


- **SBIP Pay Interval:**
  - < 30% V_{shale}
  - < 50% S_{we}
- May have associated:
  - gas interval(s)
  - high water saturation interval(s)
- Primary zone defined as the thickest pay interval unless:
  - an existing (or planned) horizontal well pair is within an interval
  - geologists have interpreted continuity of an interval across an area

- Base of EBIP Pay Interval:
  - Depth of an existing or planned horizontal well pair (EBIP Pay Interval base = producer well depth)
  - 3 m stand-off if no bottom water (minimum shale of 2 m thickness)
  - 5 m stand-off if in contact with bottom water (minimum bottom water thickness of 2 m)



Lease: Development Areas



Long Lake Development Area EBIP and Average Reservoir Parameters

CNOOC

Long Lake (including Long Lake SW) Development Area EBIP

Long Lake EBIP (E^6m^3)	137

CNOOC International Cutoffs: HPVH > 3 m

Hydrocarbon Pore Volume Height

$$HPVH = \sum_{pay\ bs}^{pay\ tp} (S_o * \Phi)$$

Long Lake EBIP Average Reservoir Parameters

- Measured Depth (top) 200 mKB
- Thickness 22 m
- Effective Porosity 31.2 %
- Permeability – Historical Plug Data
  - k_{max} 5,565 mD
  - k_{vert} 4,491 mD
- Effective Water Saturation 31.2 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure:

  ~1,000 – 1,100kPa @ 230m AMSL

Effective porosity, effective water saturation, and V_{shale} are calculated every 10 cm over the EBIP interval, and the average is derived.

Kinosis Development Area EBIP and Average Reservoir Parameters

Kinosis Development Area EBIP

Kinosis IDA	
EBIP (E^6m^3)	205

CNOOC International Cutoffs: HPVH > 3 m

Hydrocarbon Pore Volume Height

$$HPVH = \sum_{pay\ bs}^{pay\ tp} (S_o * \Phi)$$

Pay Average Reservoir Parameters

- Measured Depth (top) 280 mKB
- Thickness 33 m
- Effective Porosity 32 %
- Permeability From Core Plugs
  - k_{max} 4,030 mD
  - k_{vert} 2,347 mD
- Effective Water Saturation 26 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure
  - ~1,100 – 1,300 kPa

Effective porosity and effective water saturation are calculated every 10cm over the Pay interval, and the average is derived.

Long Lake SBIP Pay Interval Isopach

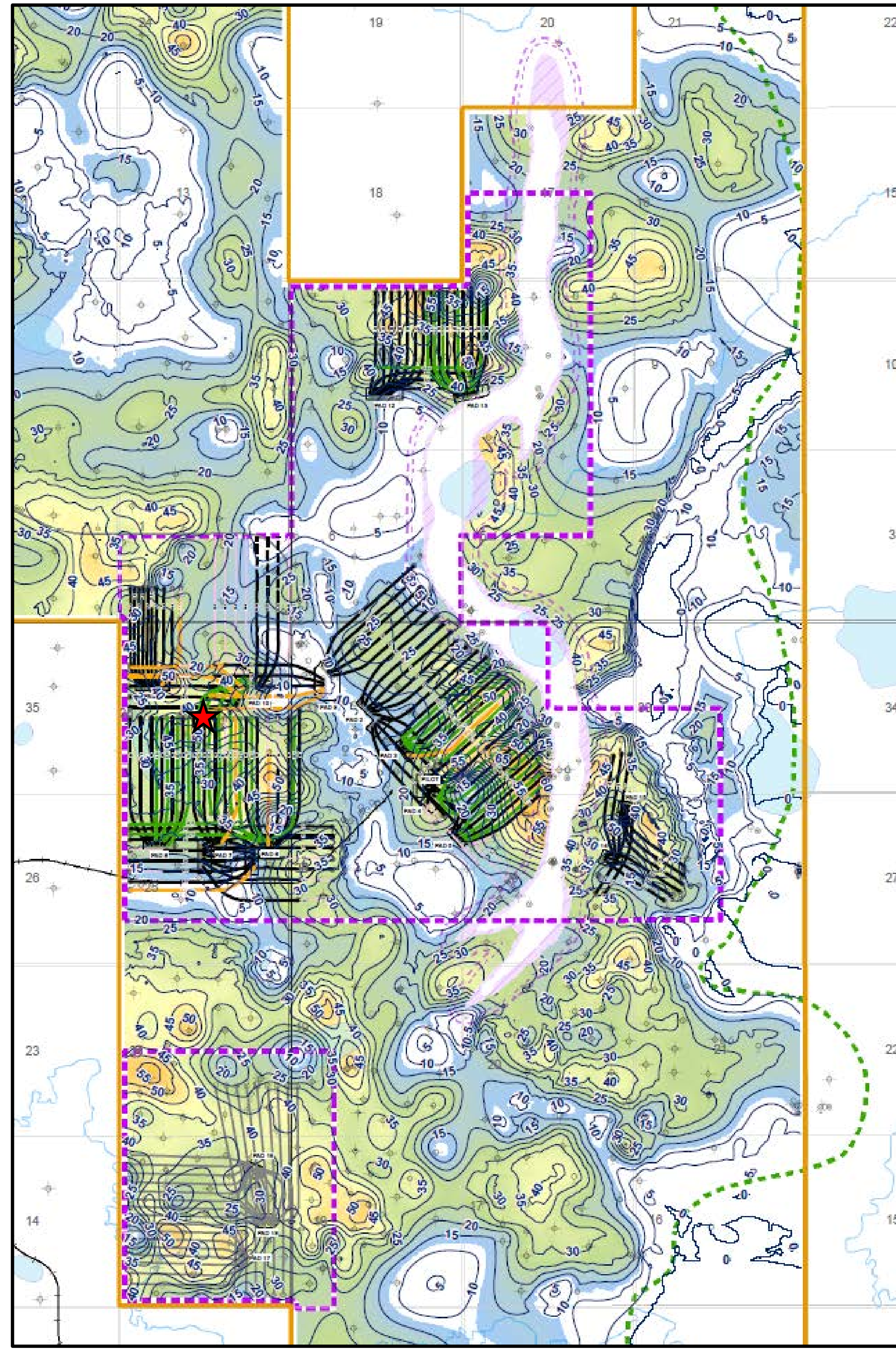
- ACTIVE HORIZONTAL
- ACTIVE : PULLED BACK
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- ACTIVE : INFILL HORIZONTAL
- SUSPENDED
- DRILLED : LLSW HORIZONTAL
- DEVIATED WELL PATH (DRILLED)
- HIGHWAY
- RAIL
- ROAD ACCESS
- ZERO BITUMEN EDGE
- LONG LAKE LEASE
- INITIAL DEVELOPMENT AREA
- URBAN AREA
- PARK AREA
- RESERVE AREA
- WELL PADS
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- SBIP ISOPACH (C.I.=5m)

SBIP ISOPACH (m)

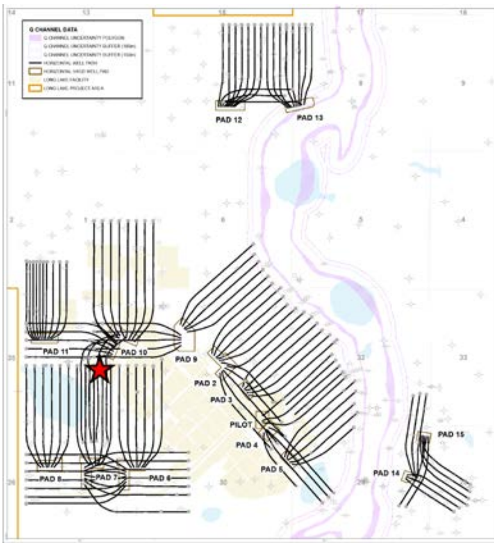
High : 77.4m

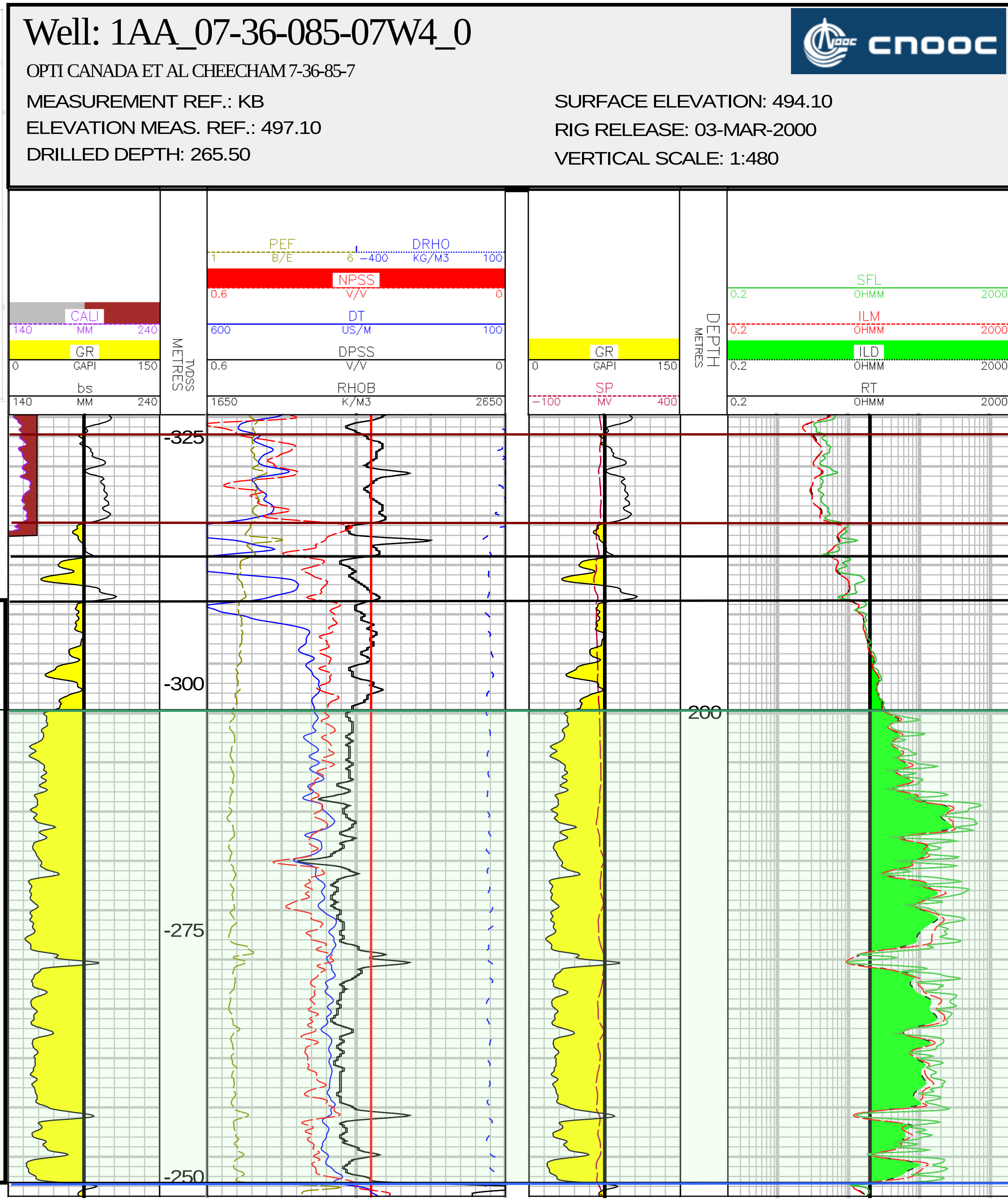
12.0m

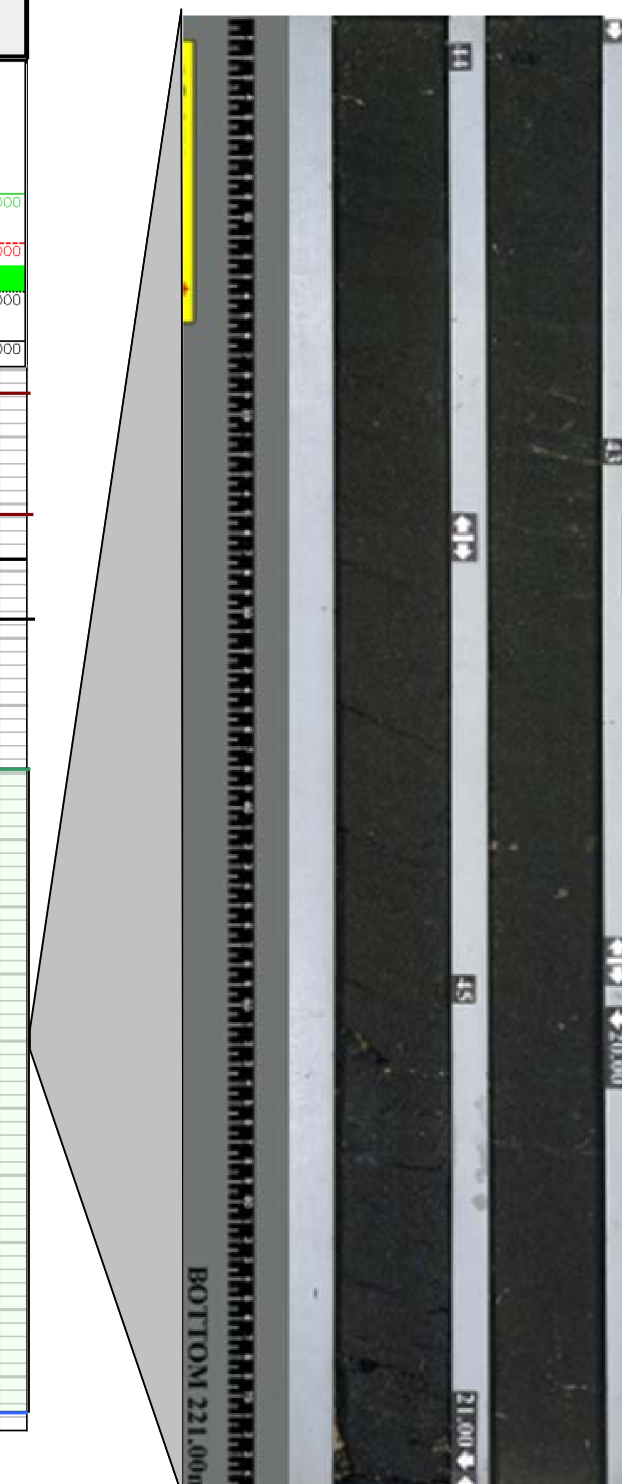
★ TYPE LOG



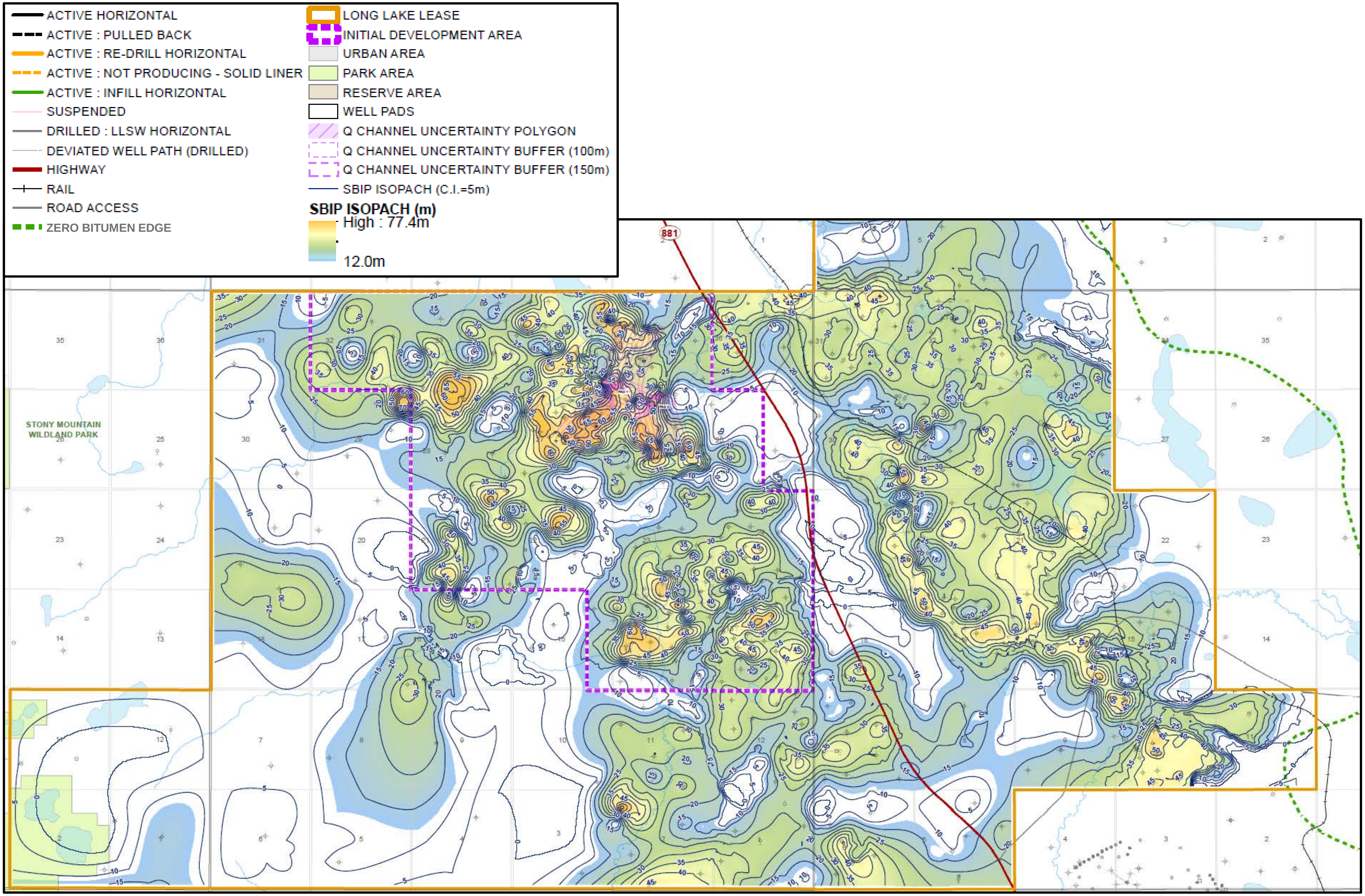
SBIP Type Log – 1AA/07-36-085-07W4







Kinosis SBIP Pay Interval Isopach



Long Lake SBIP Pay Interval Base Structure

- ACTIVE HORIZONTAL
- ACTIVE : PULLED BACK
- ACTIVE : RE-DRILL HORIZONTAL
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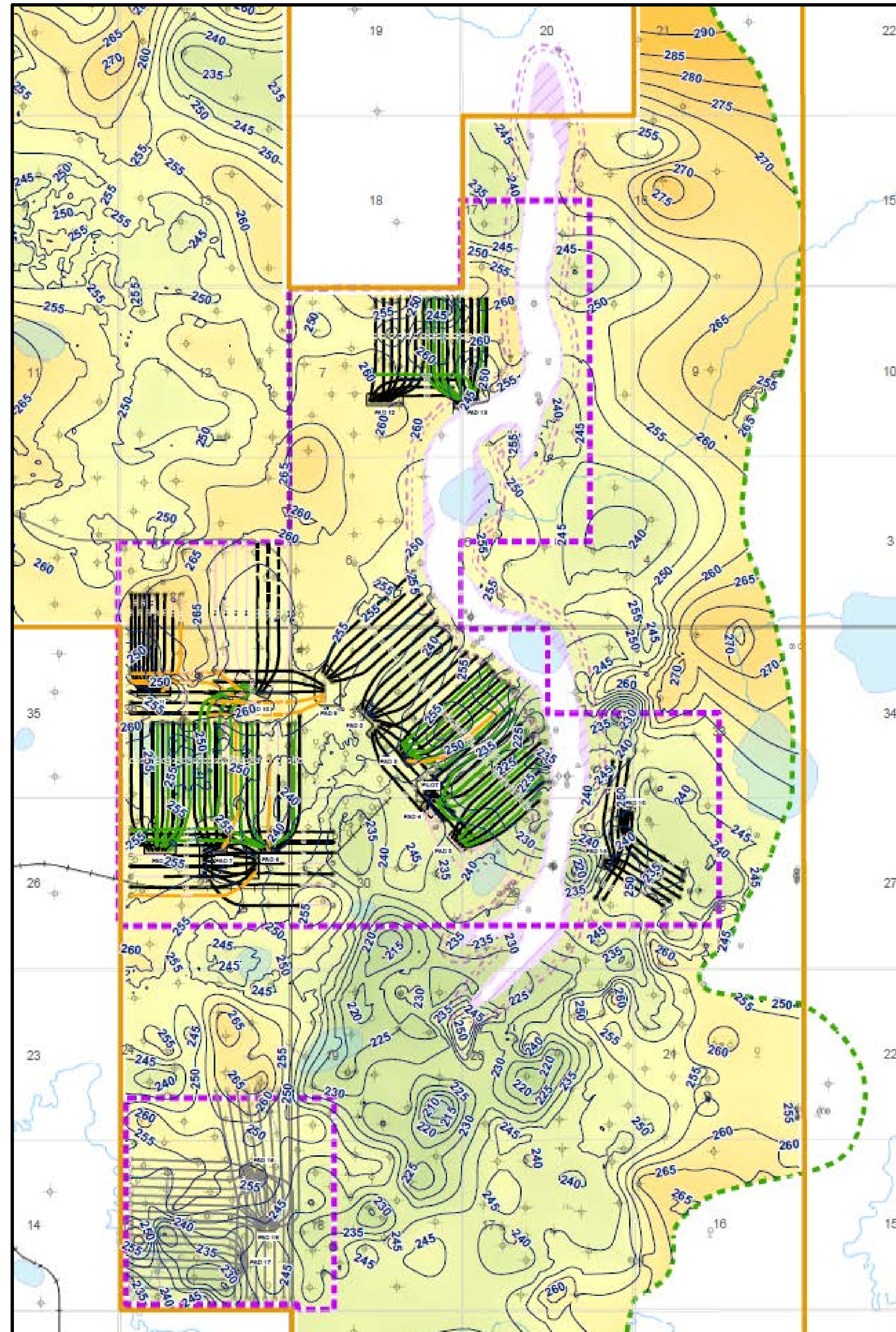
- WELL PADS
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- SBIP BASE STRUCTURE (C.I.=5m)

SBIP BASE STRUCTURE (m)

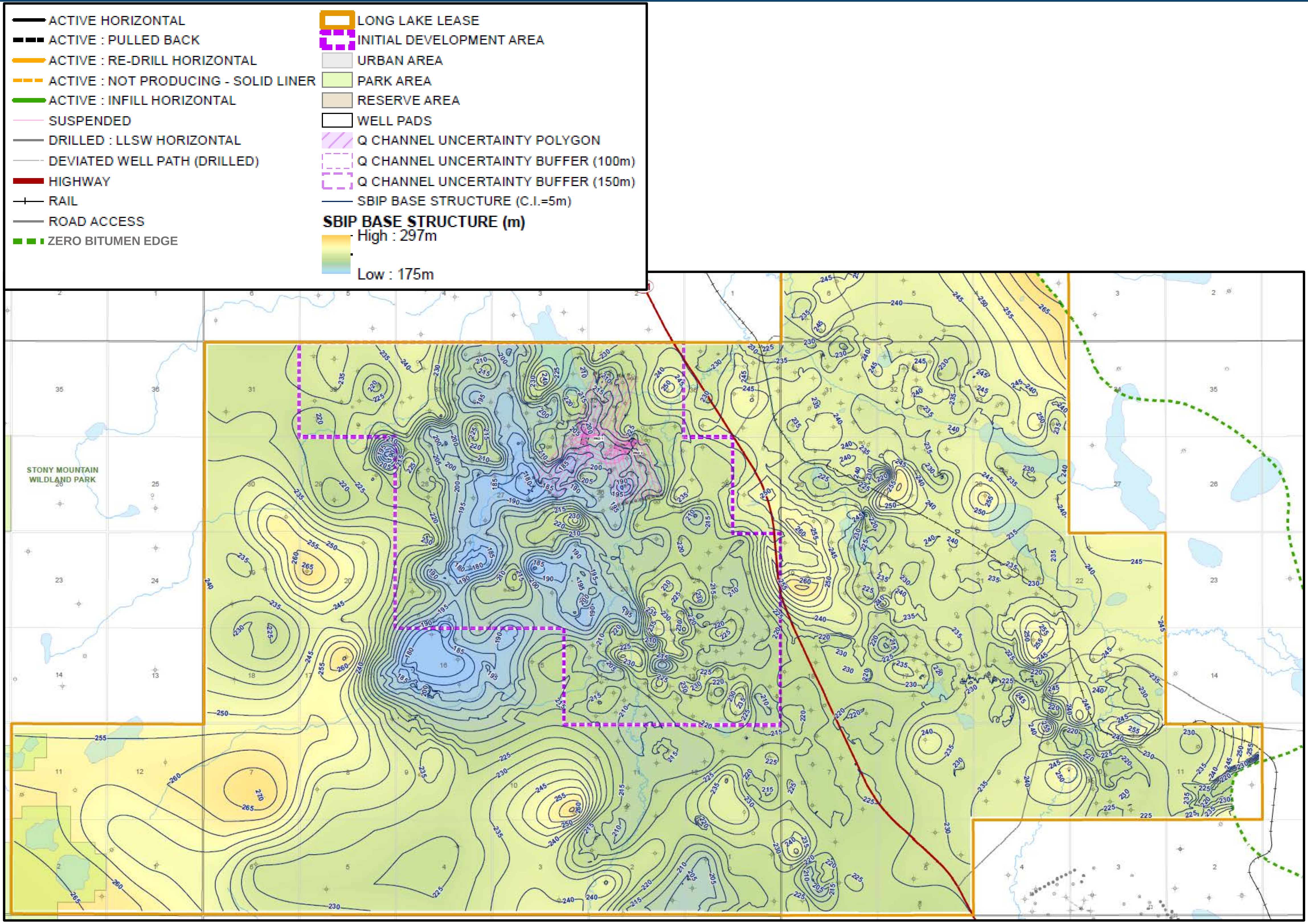
High : 297m

Low : 175m

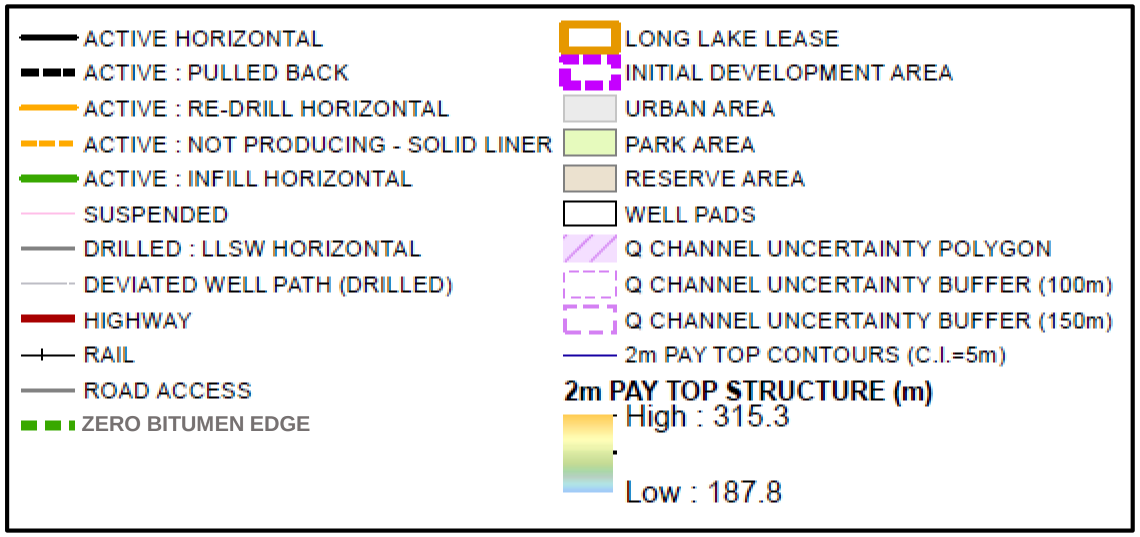


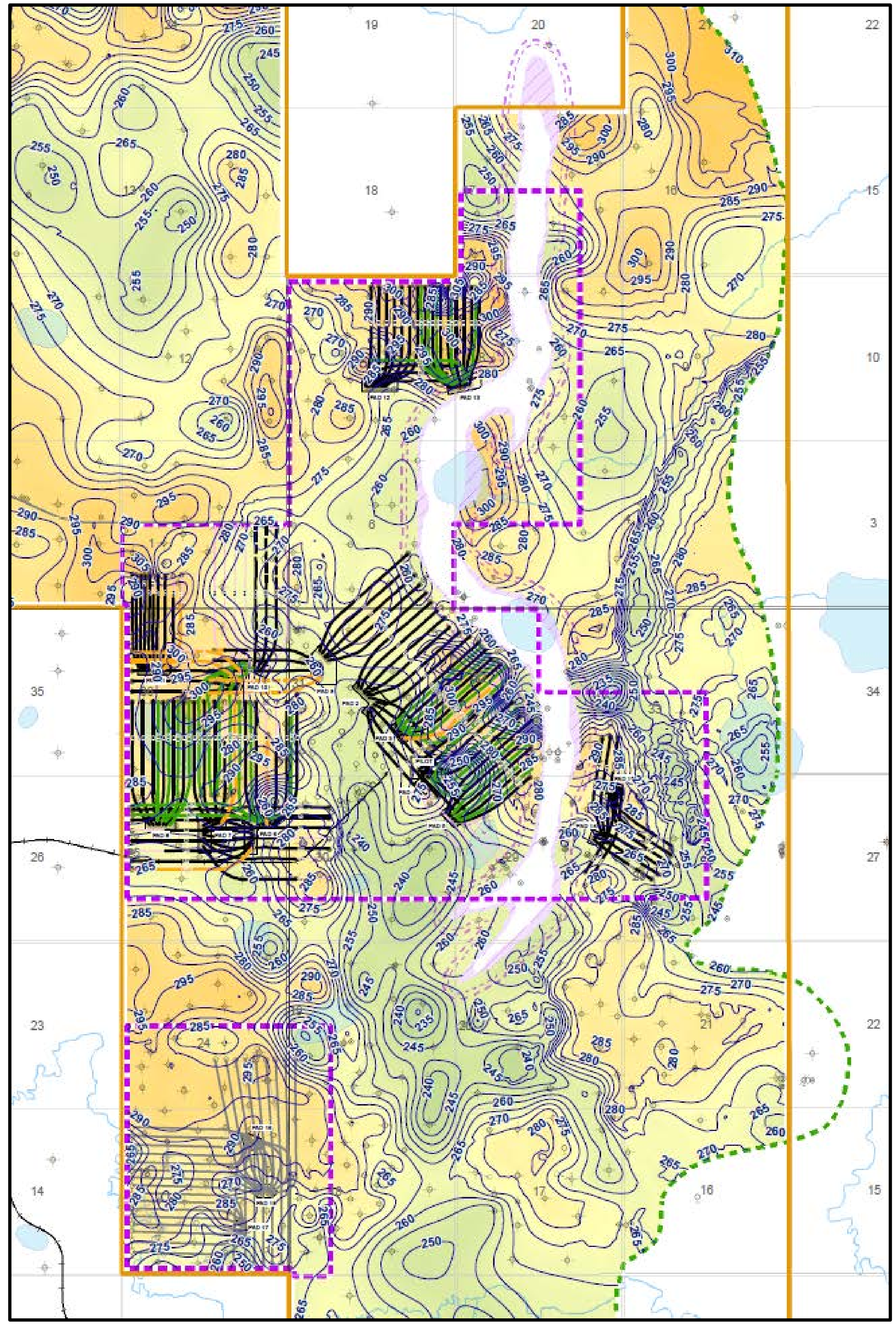
- Base of SBIP Pay Interval influenced by facies changes, karsting, erosion, salt dissolution, and bottom water

Kinosis SBIP Pay Interval Base Structure



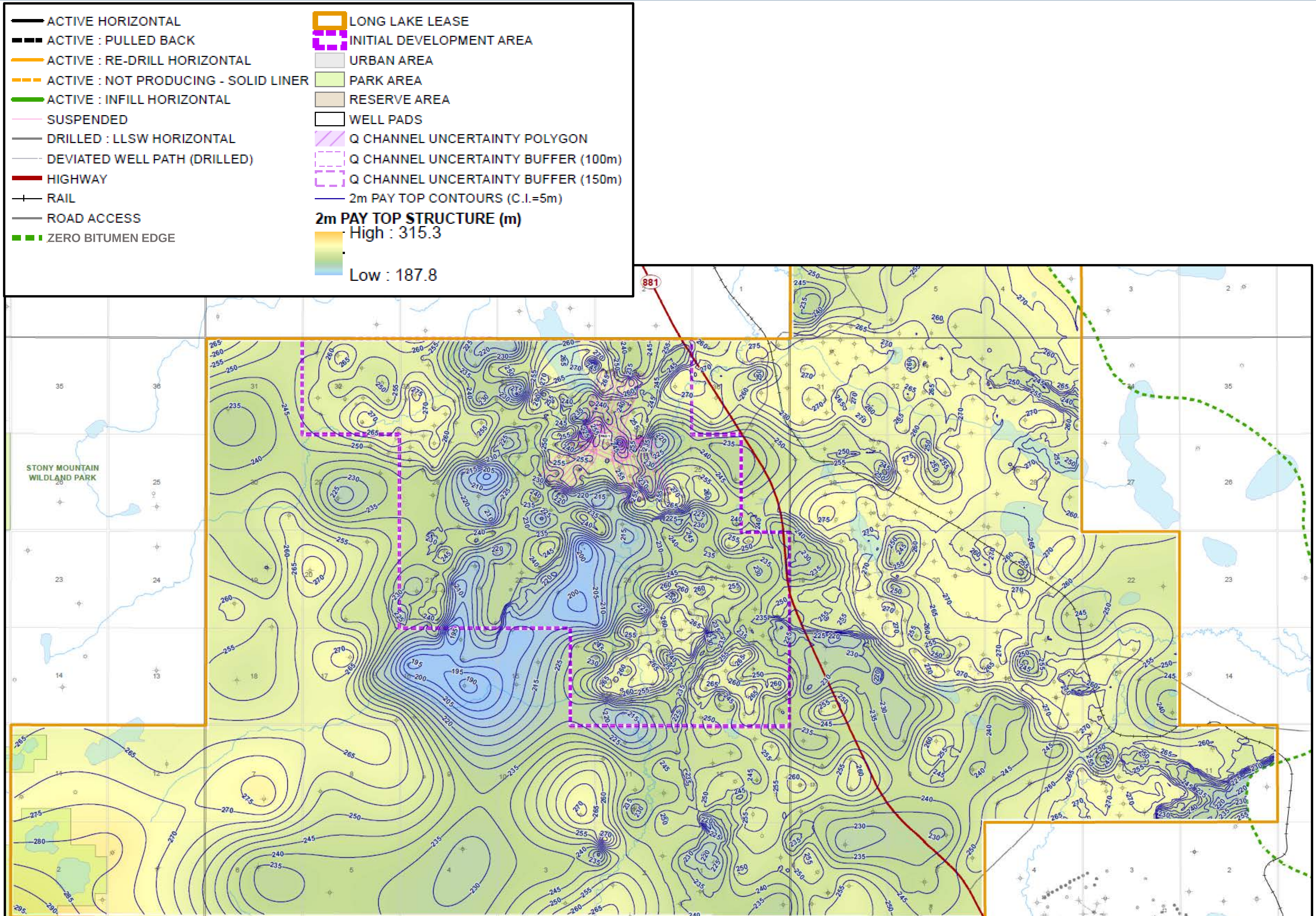
Long Lake SBIP Pay Interval Top Structure





- Top of SBIP Pay Interval:
  - base of 2m or thicker shale
  - cumulative 4m shale
  - base of top gas
  - base of top water
  - top of McMurray tidal-fluvial estuarine complexes
- Bitumen in regional McMurray shorefaces and the McMurray A1 are not considered pay.

Kinosis SBIP Pay Interval Top Structure



Long Lake HPVH Isopach over SBIP Pay Interval

- ACTIVE HORIZONTAL
- ACTIVE : PULLED BACK
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- ACTIVE : INFILL HORIZONTAL
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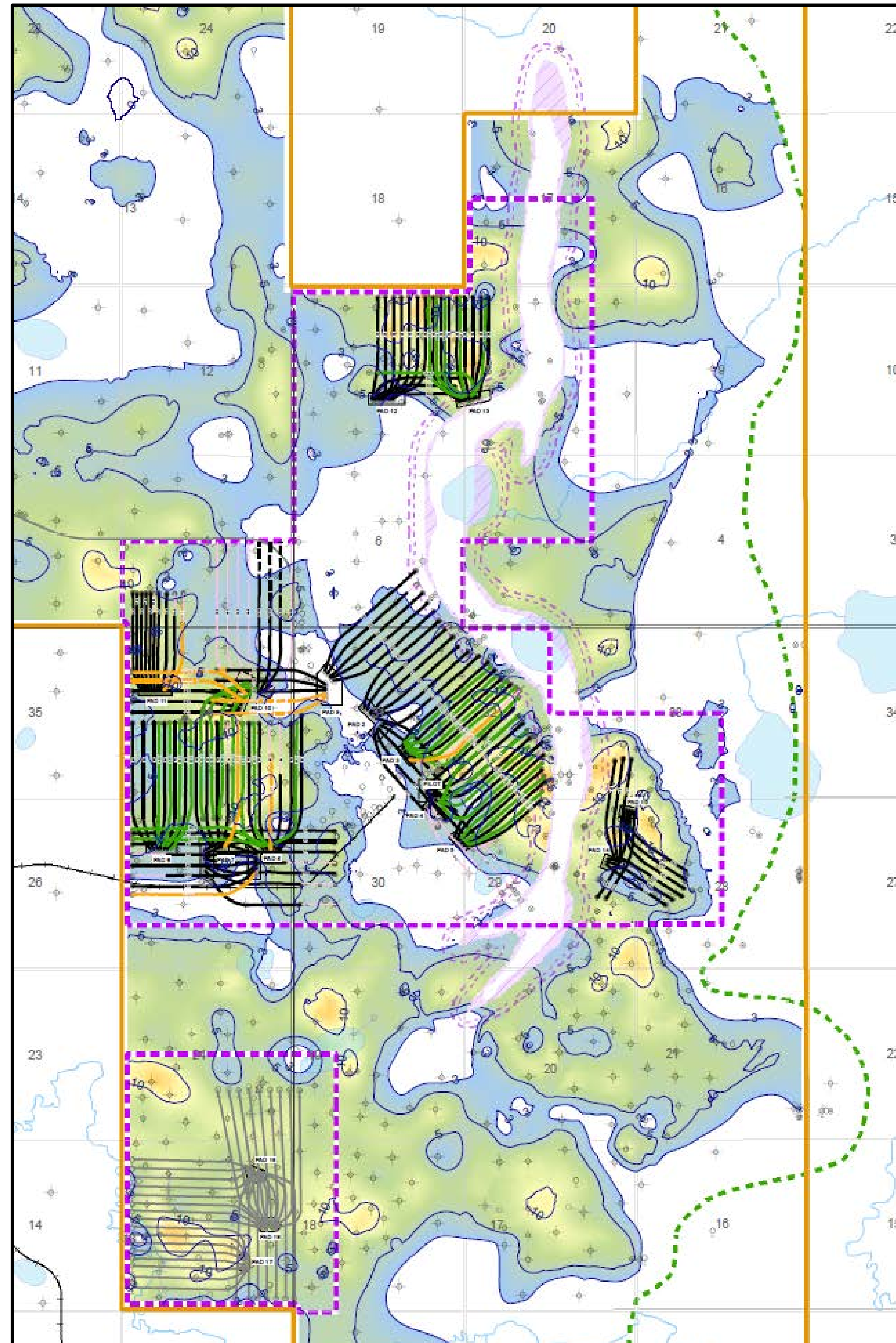
- RESERVE AREA
- WELL PADS
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- SBIP HPVH CONTOURS (C.I.=5m)

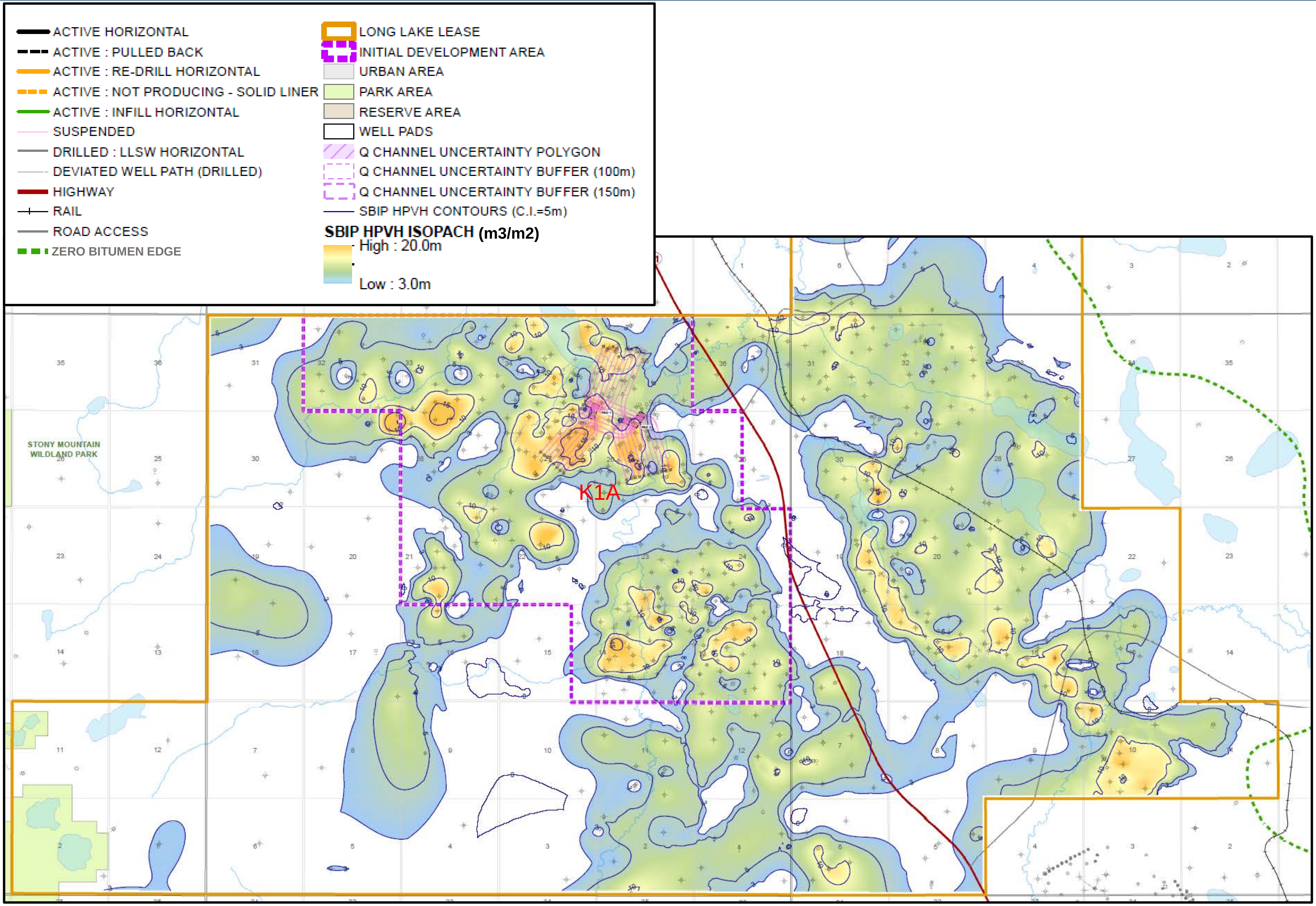
SBIP HPVH ISOPACH (m3/m2)
High : 20.0m
Low : 3.0m



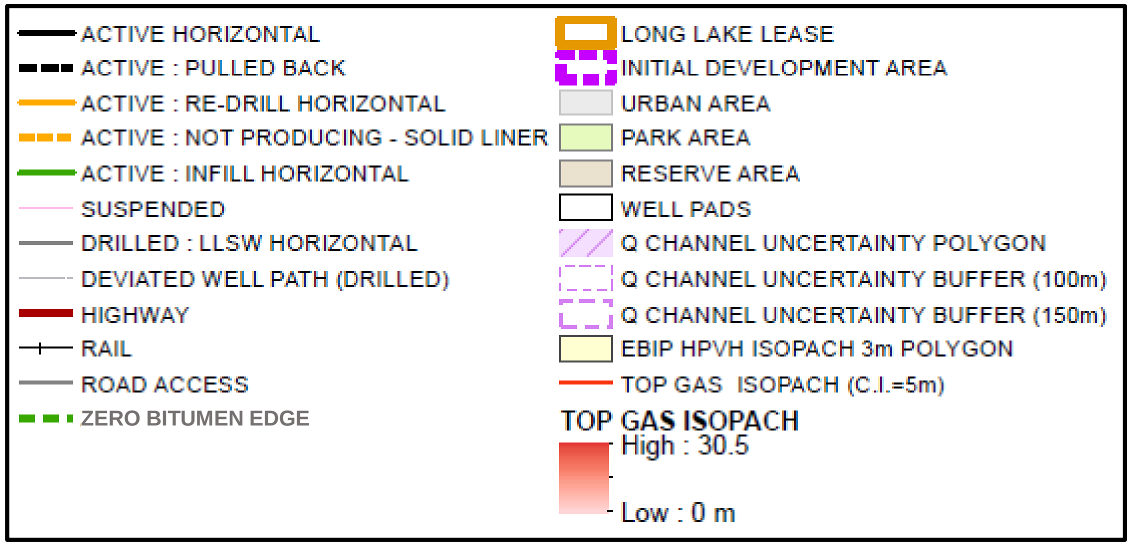
$$HPVH = \sum_{\text{Min pay bs}}^{\text{Min pay tp}} (So*\Phi)$$

- Colour shading : > $3m^3/m^2$ HPVH

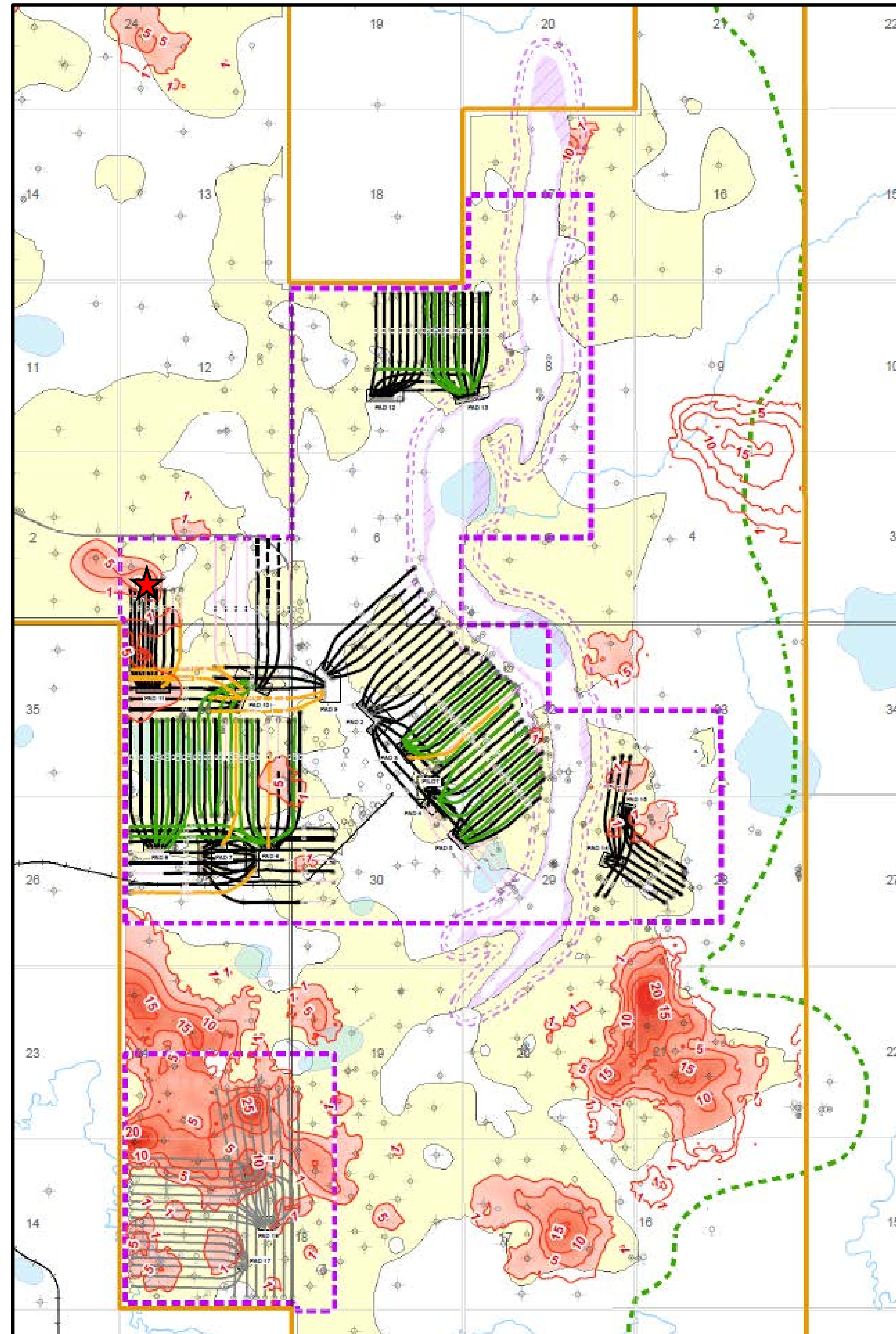
Kinosis HPVH Isopach over SBIP Interval



Long Lake Total Gas: Gas Interval(s) within and in contact with SBIP Interval

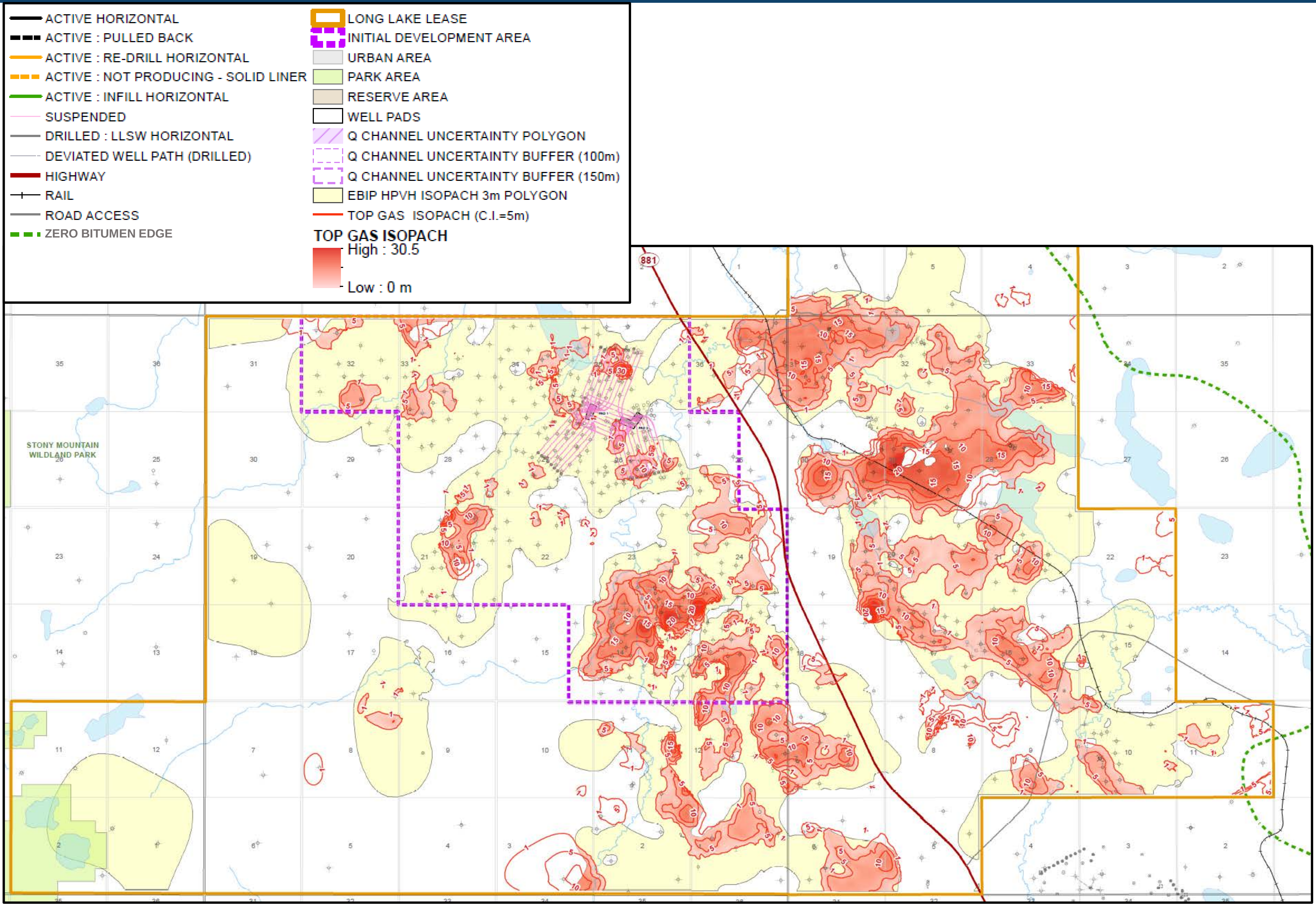


- Gas identified by neutron/density crossover.
- Gas associated with SBIP Interval:
  - within SBIP Interval
  - directly in contact with top water or top of SBIP interval
  - shading clipped to $3 m^3/m^2$ HPVH SBIP contour



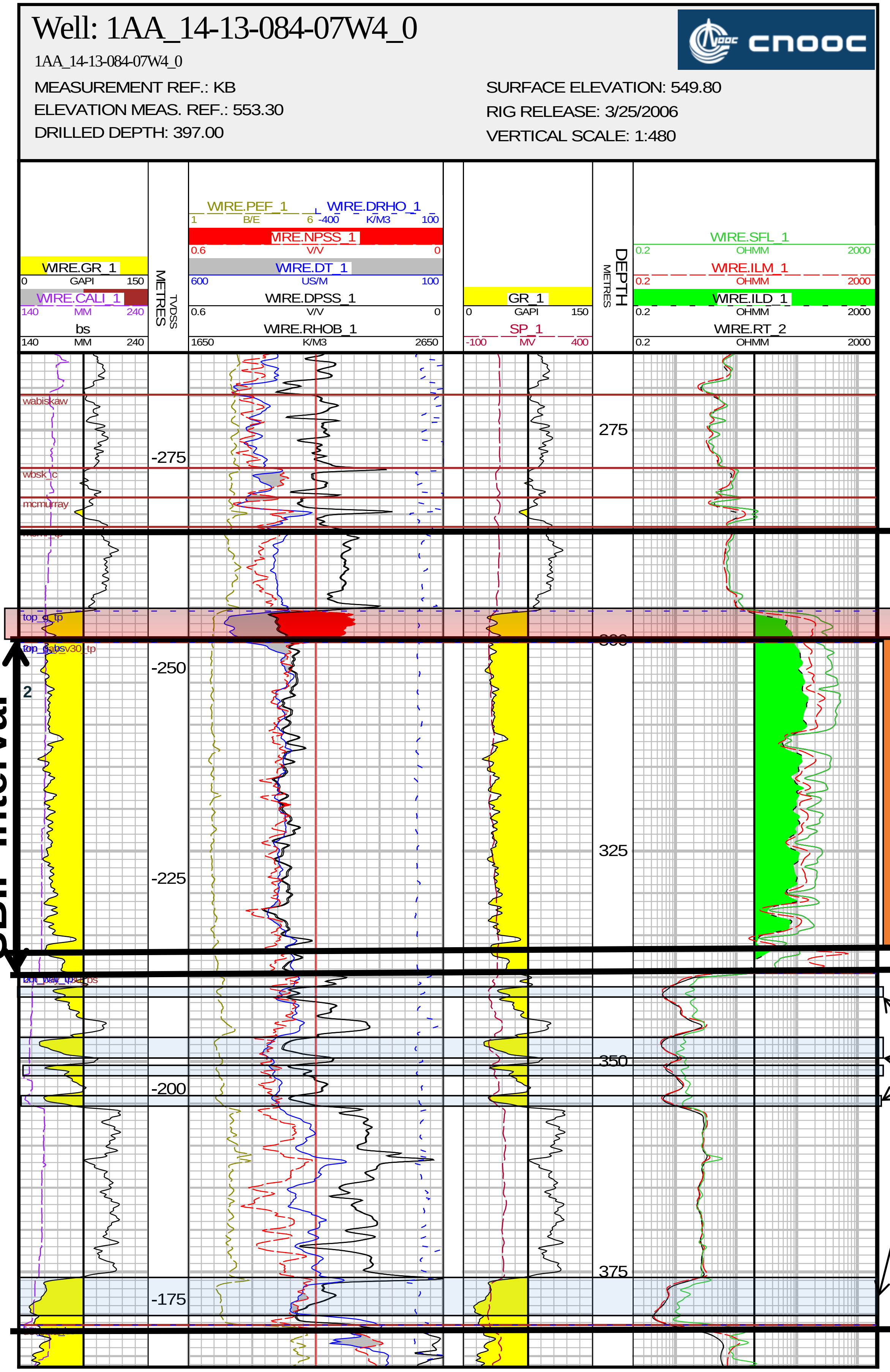
★ TYPE LOG

Kinosis
Top Gas in the McMurray



Example log: top gas

1AA/14-13-084-07W4



McMurray Fluvial Estuarine Complex top

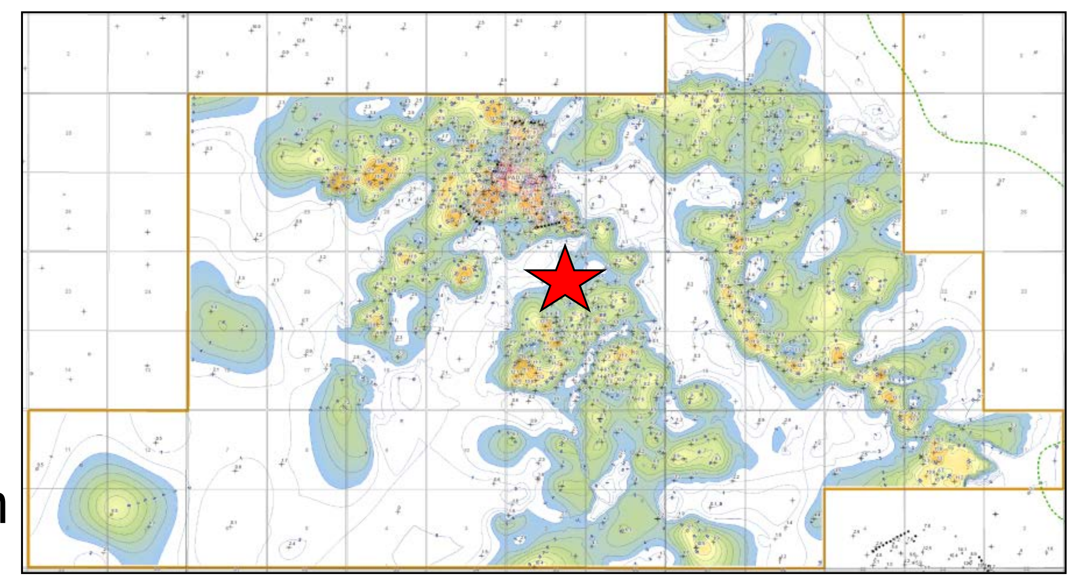
Top Gas

EBIP Pay Interval

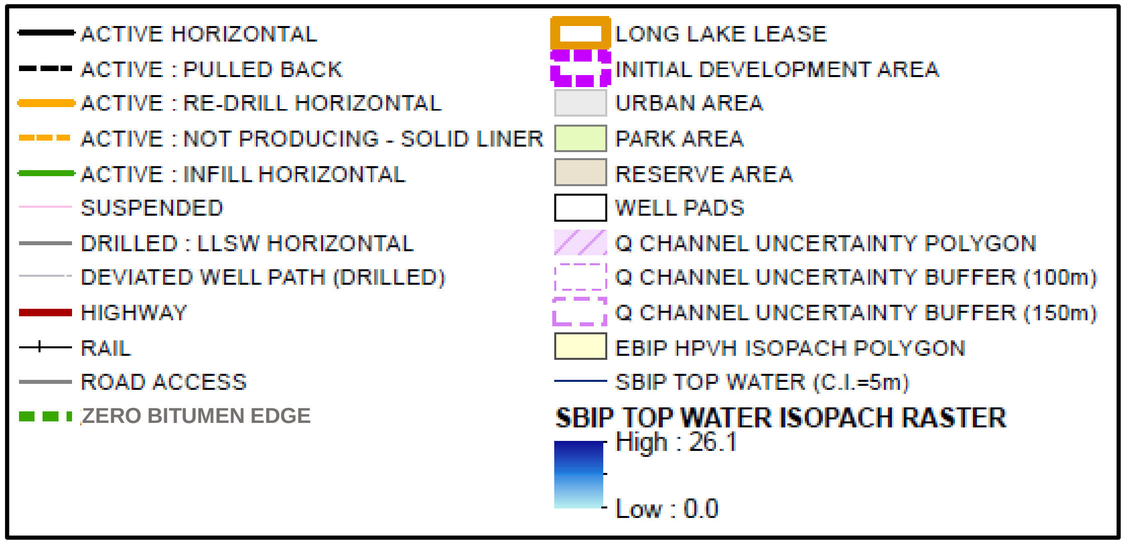
SBIP Interval

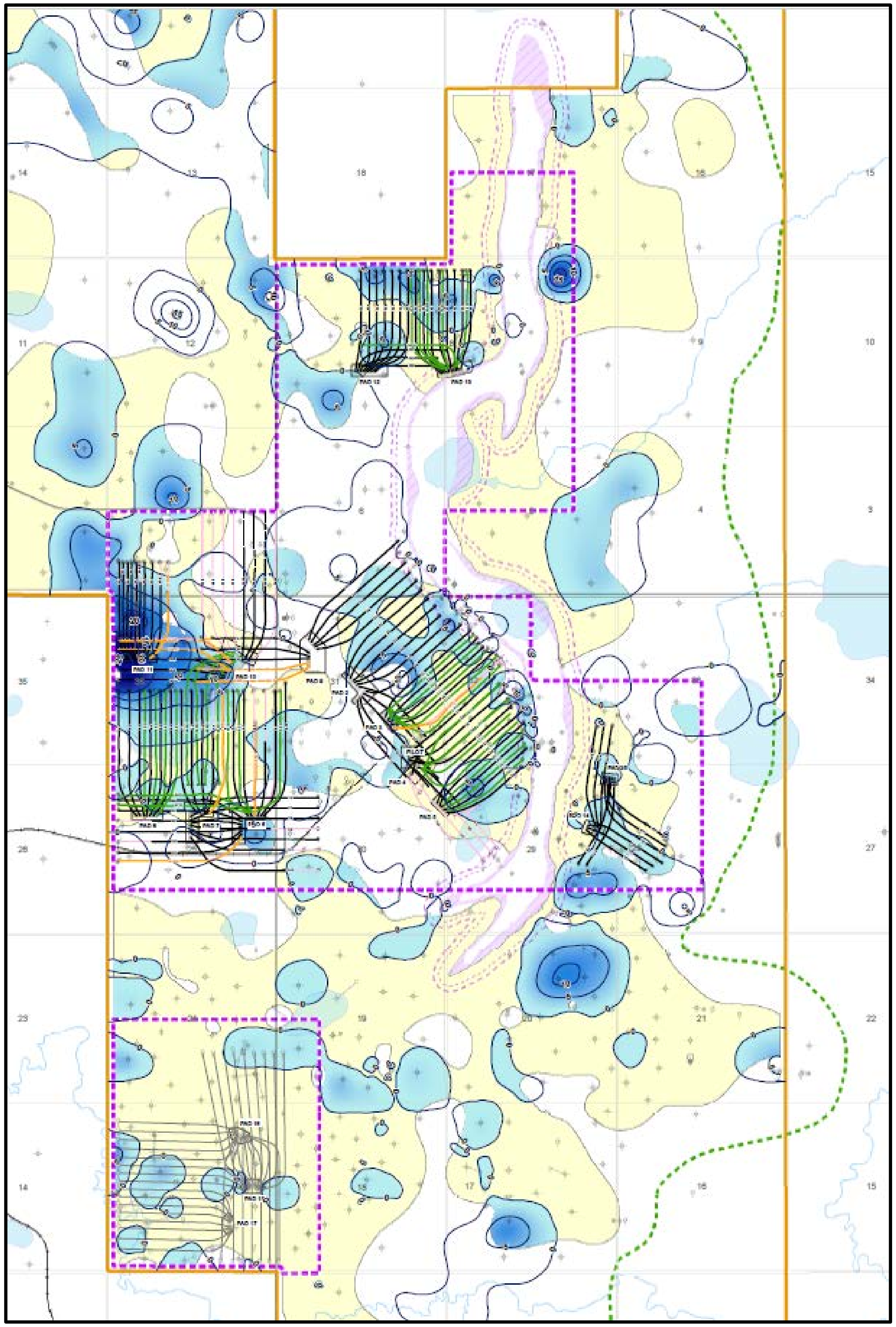
Bottom Water

Devonian



Long Lake Net Top Water Associated with SBIP Interval





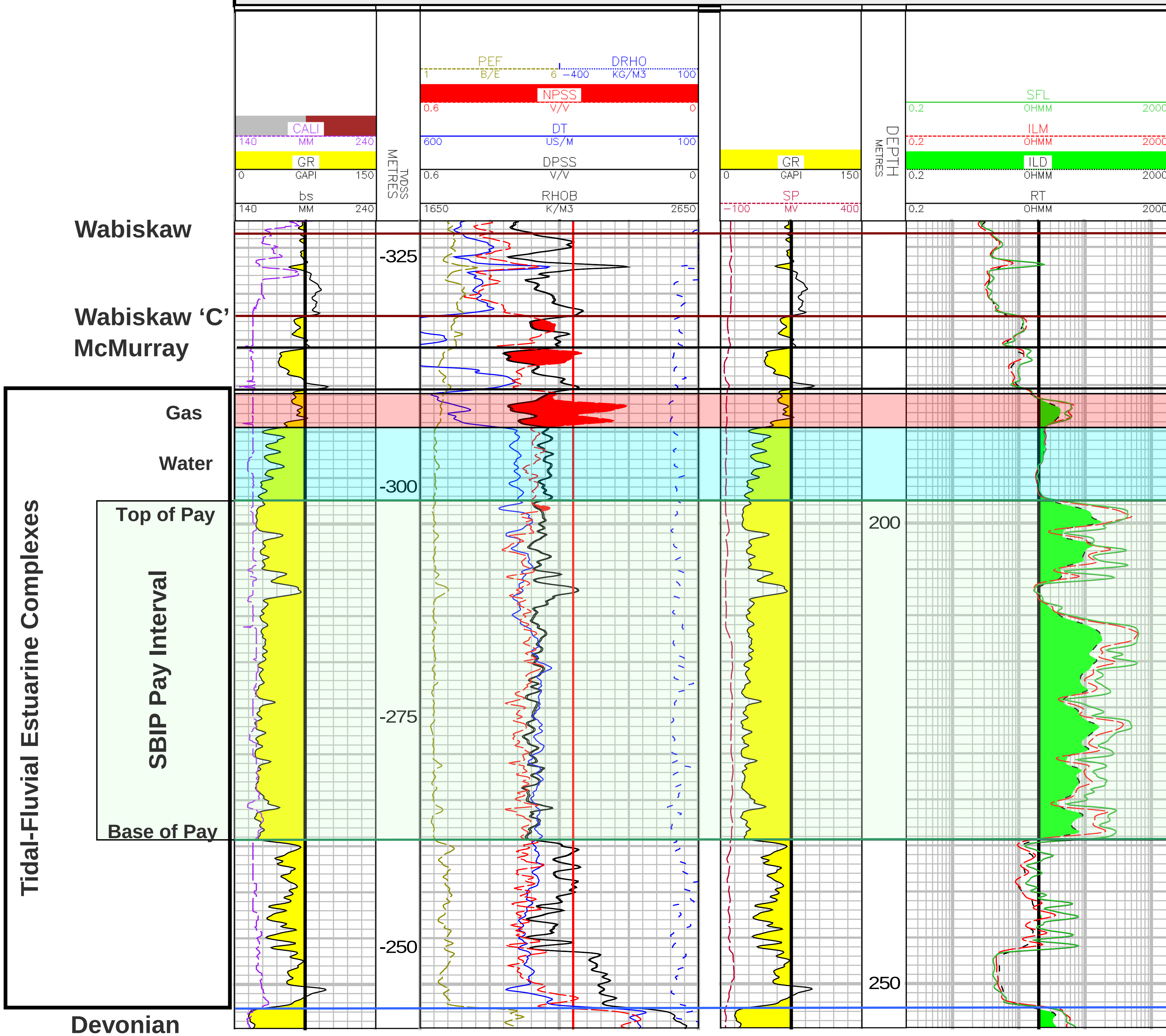
- > 50% Swe and < 30% V_{shale}
- Base of Bottom Water:
  - top of a > 2m > 30% V_{shale} shale interval
- Shading clipped to $3m^3/m^2$ HPVH SBIP contour

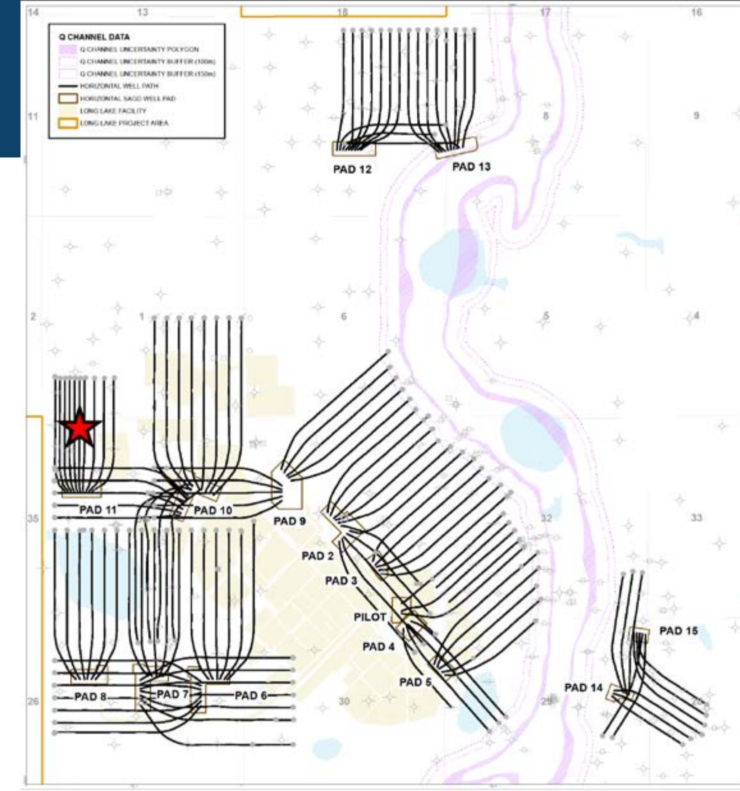
Top Impairment Type Log – 103/13-36-085-07W4

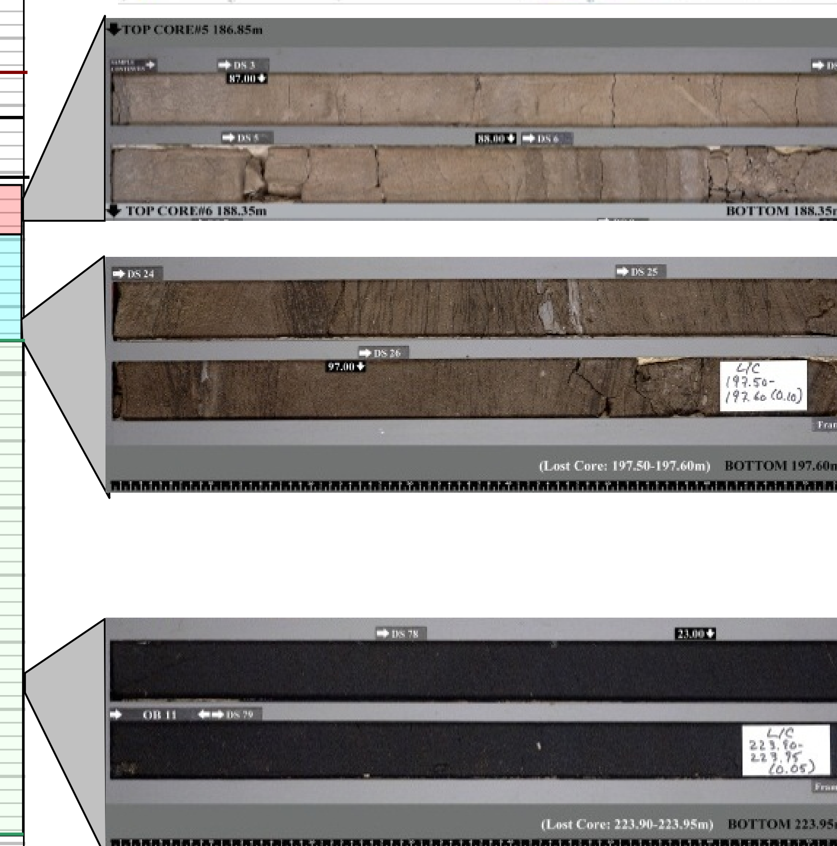
Well: 103_13-36-085-07W4_0

NEXEN OPTI NEWBY 13-36-85-7

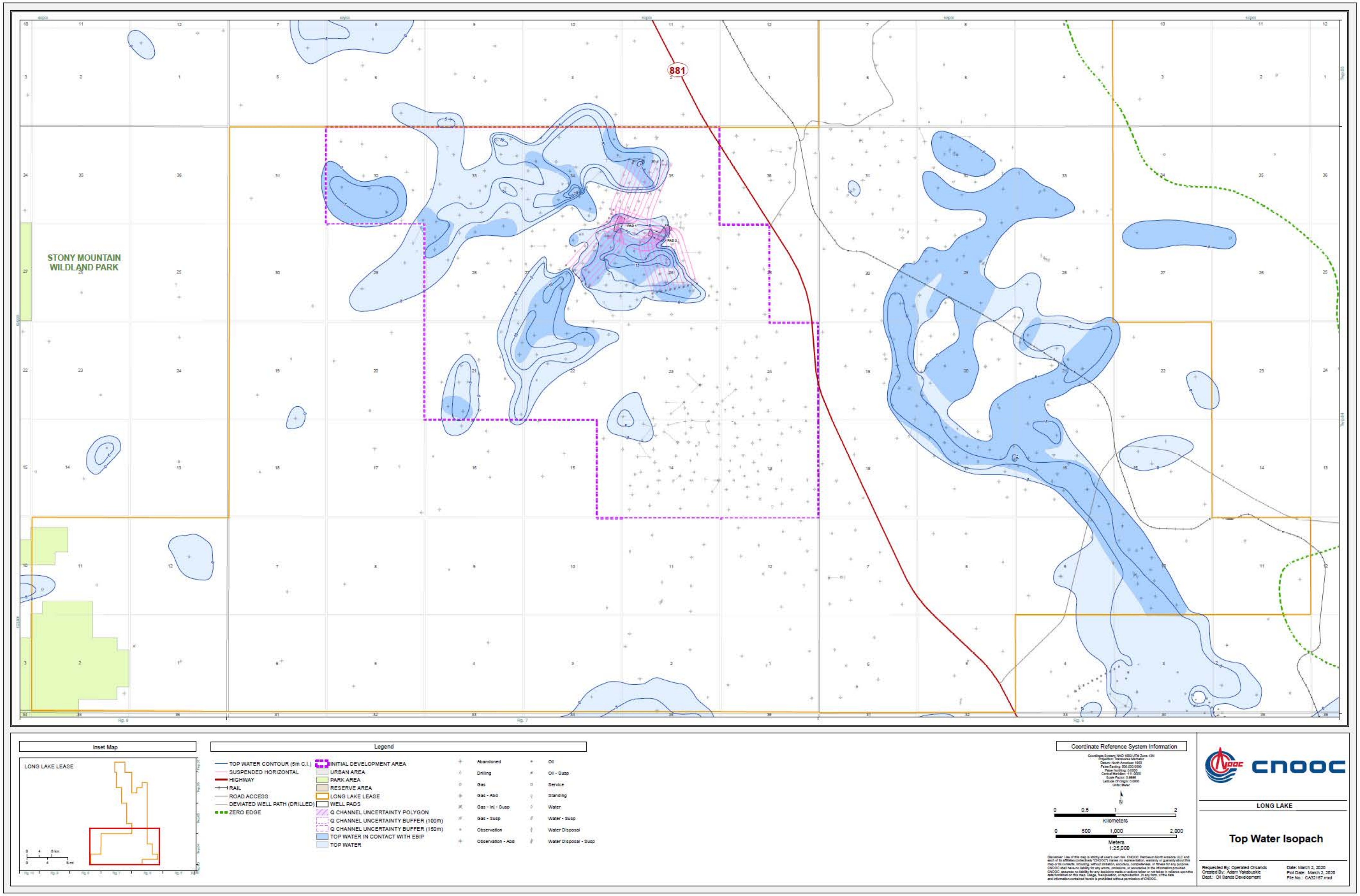
MEASUREMENT REF.: KB	SURFACE ELEVATION: 492.30
ELEVATION MEAS. REF.: 496.00	RIG RELEASE: 06-FEB-2006
DRILLED DEPTH: 269.00	VERTICAL SCALE: 1:480



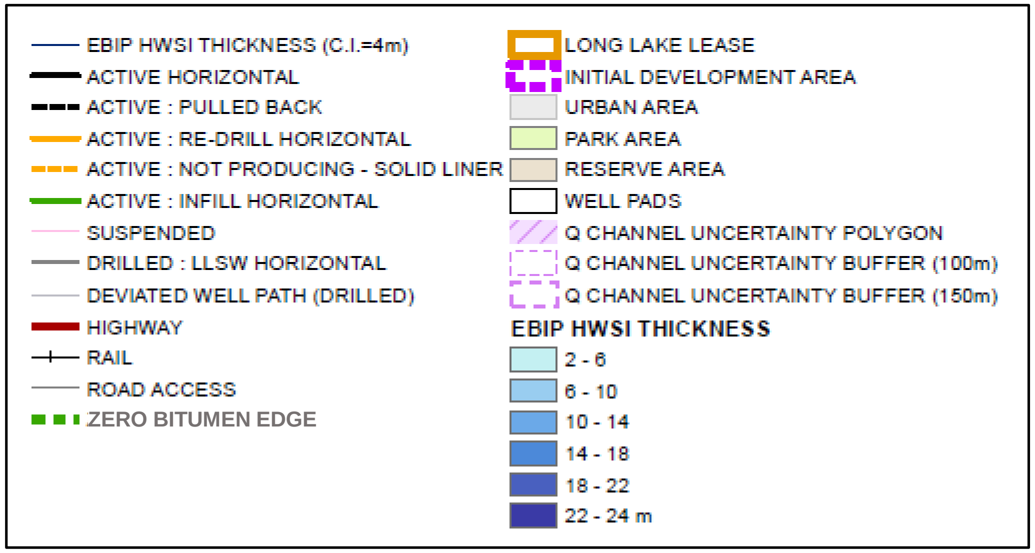


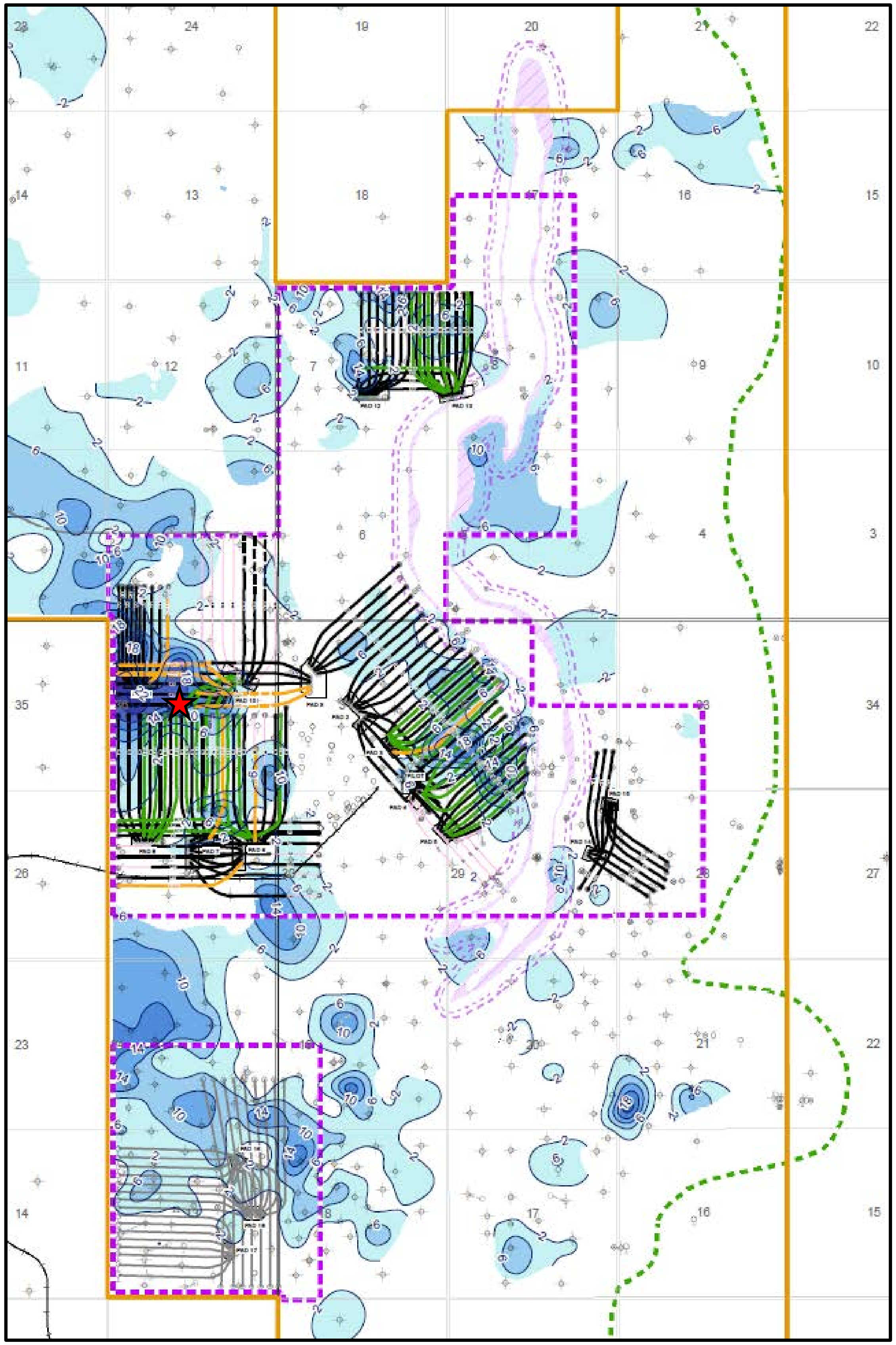


Kinosis Net Top Water Associated with SBIP Interval



Long Lake Cumulative Thickness of High Water Saturation Interval(s) within EBIP Interval

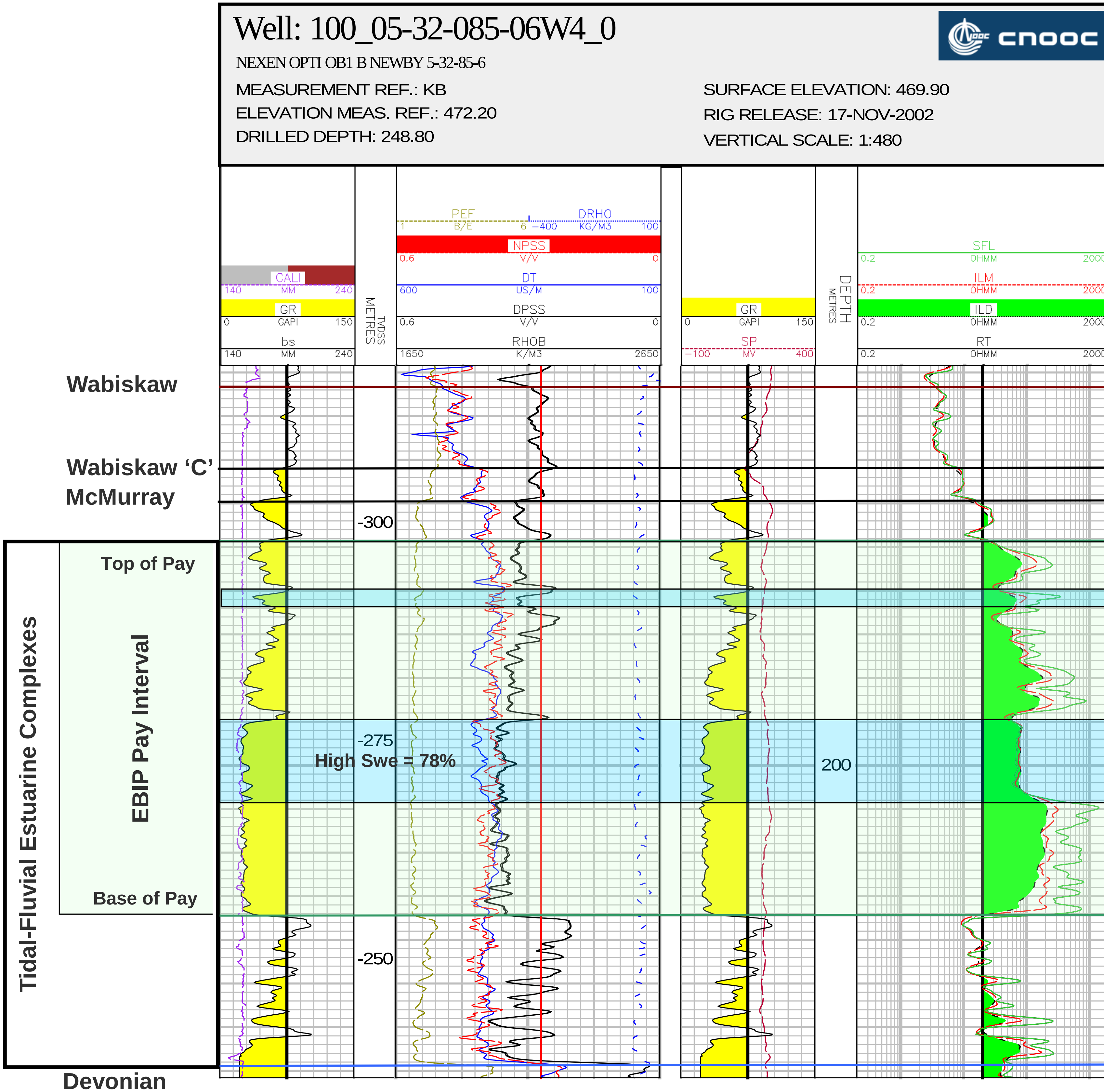


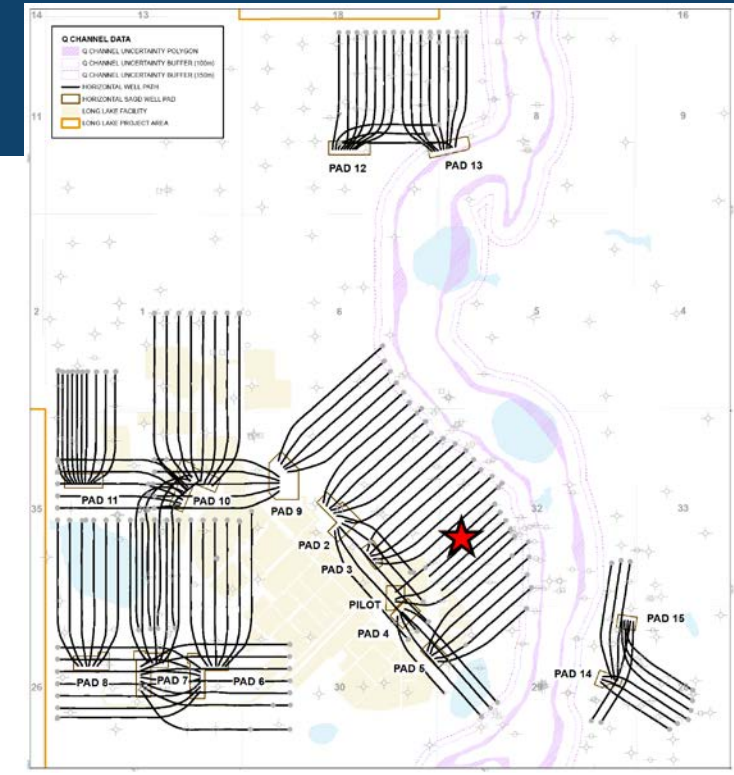


- > 50% Swe and < 30% V_{shale}
- Cumulative thickness of high water saturation interval(s) within EBIP interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour

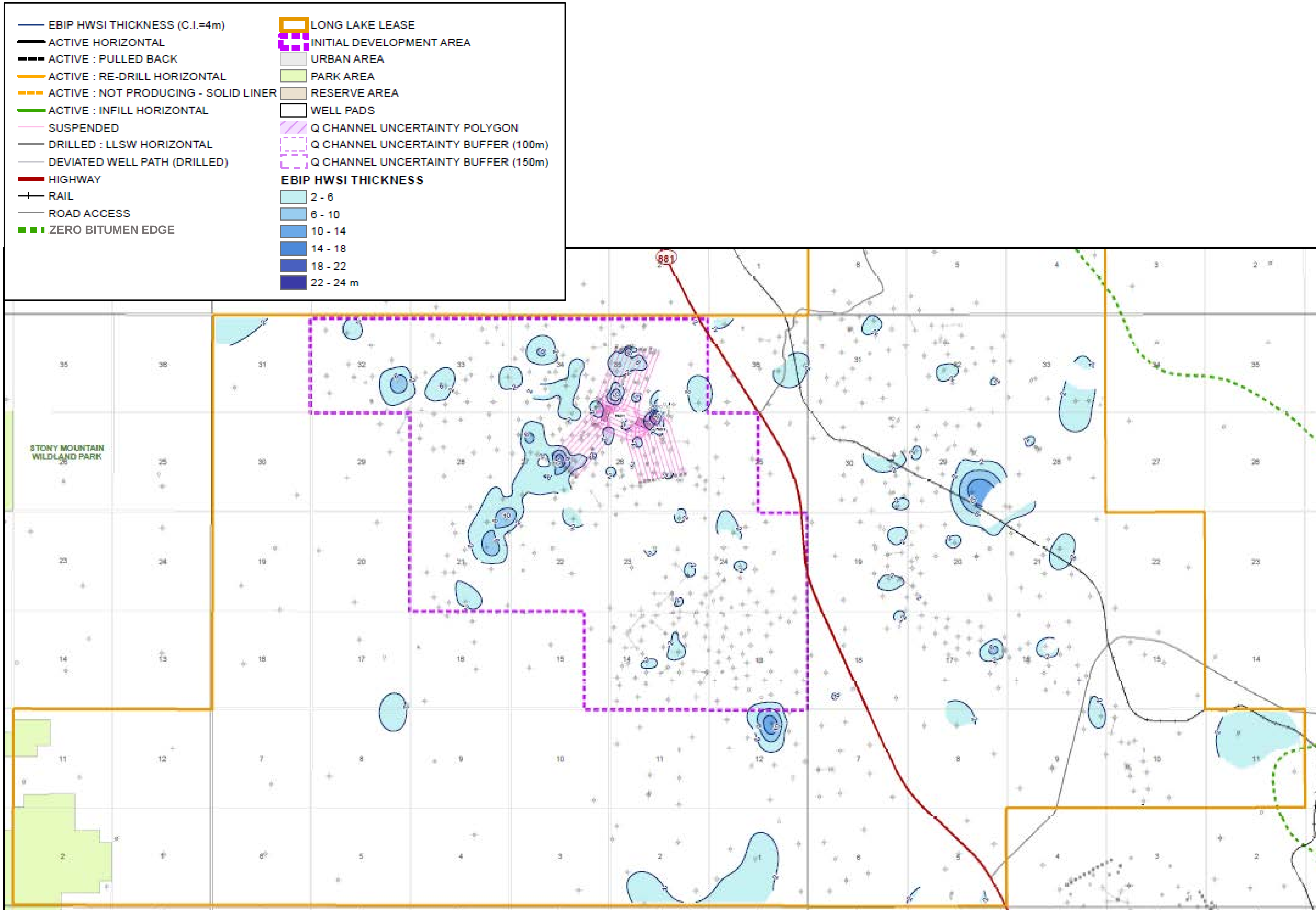
★ TYPE LOG

High Water Saturation Type Log
100/05-32-085-06W4

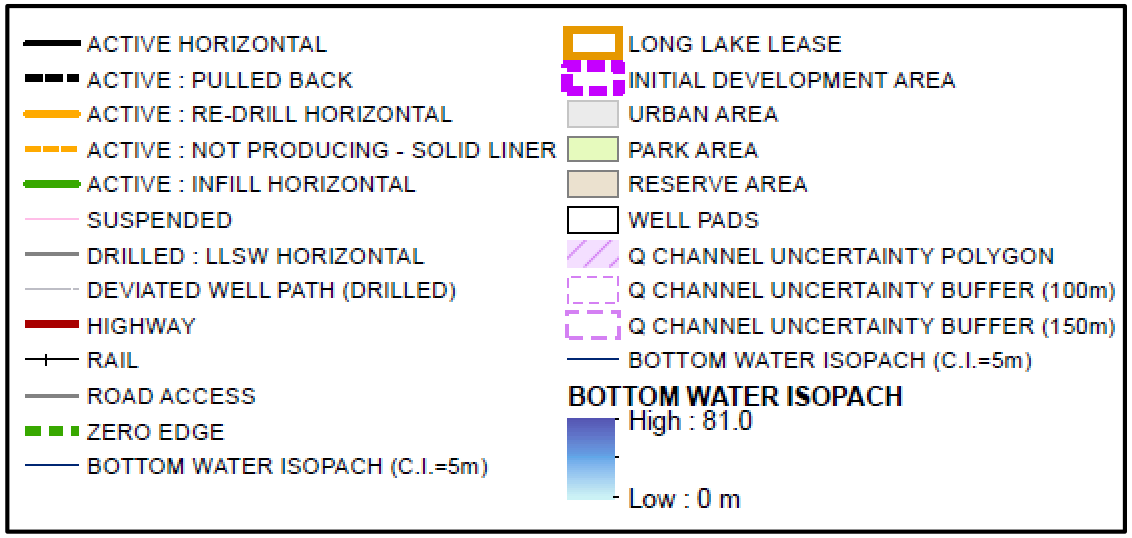


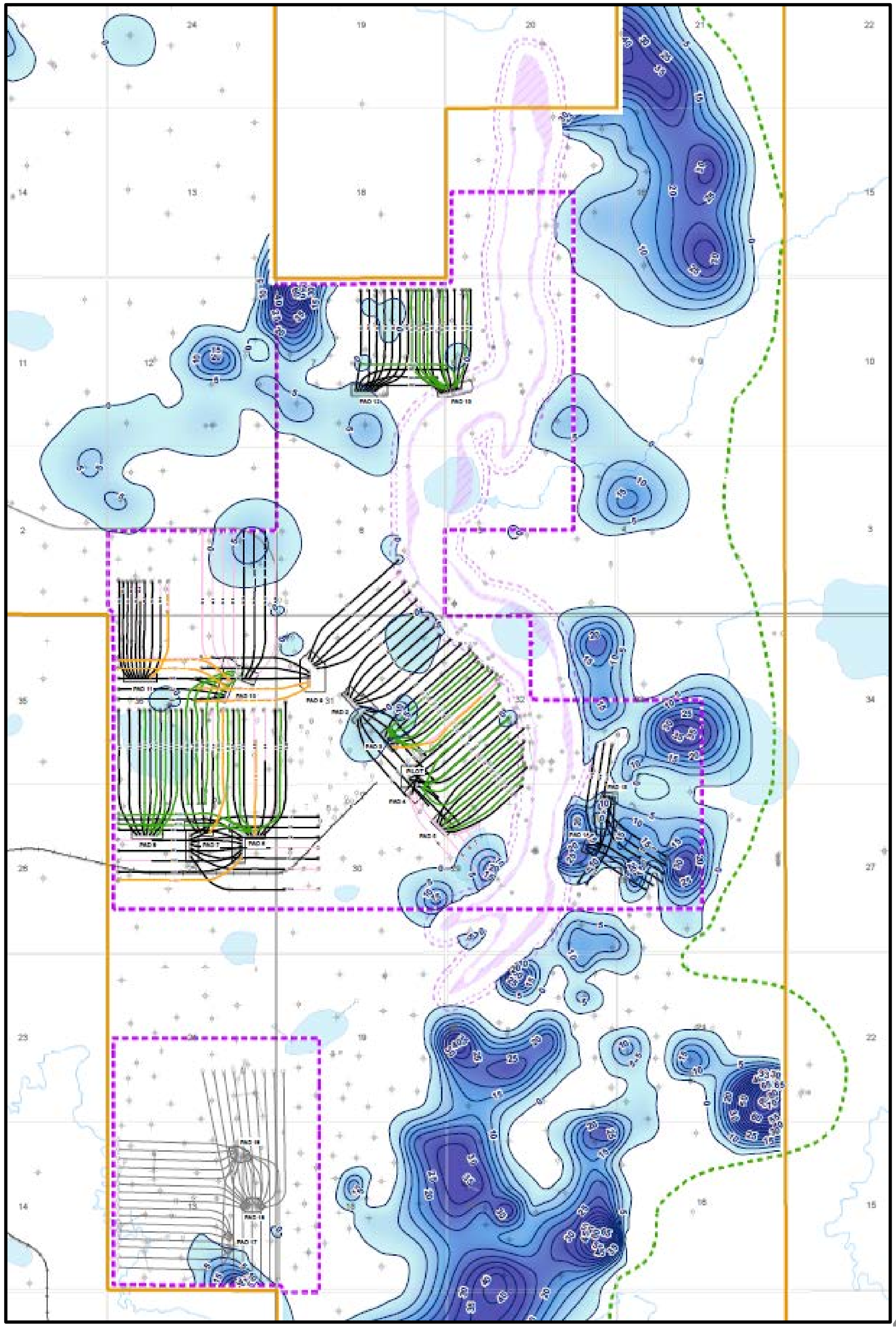


Kinosis Cumulative Thickness of High Water Saturation Interval(s) within EBIP Interval



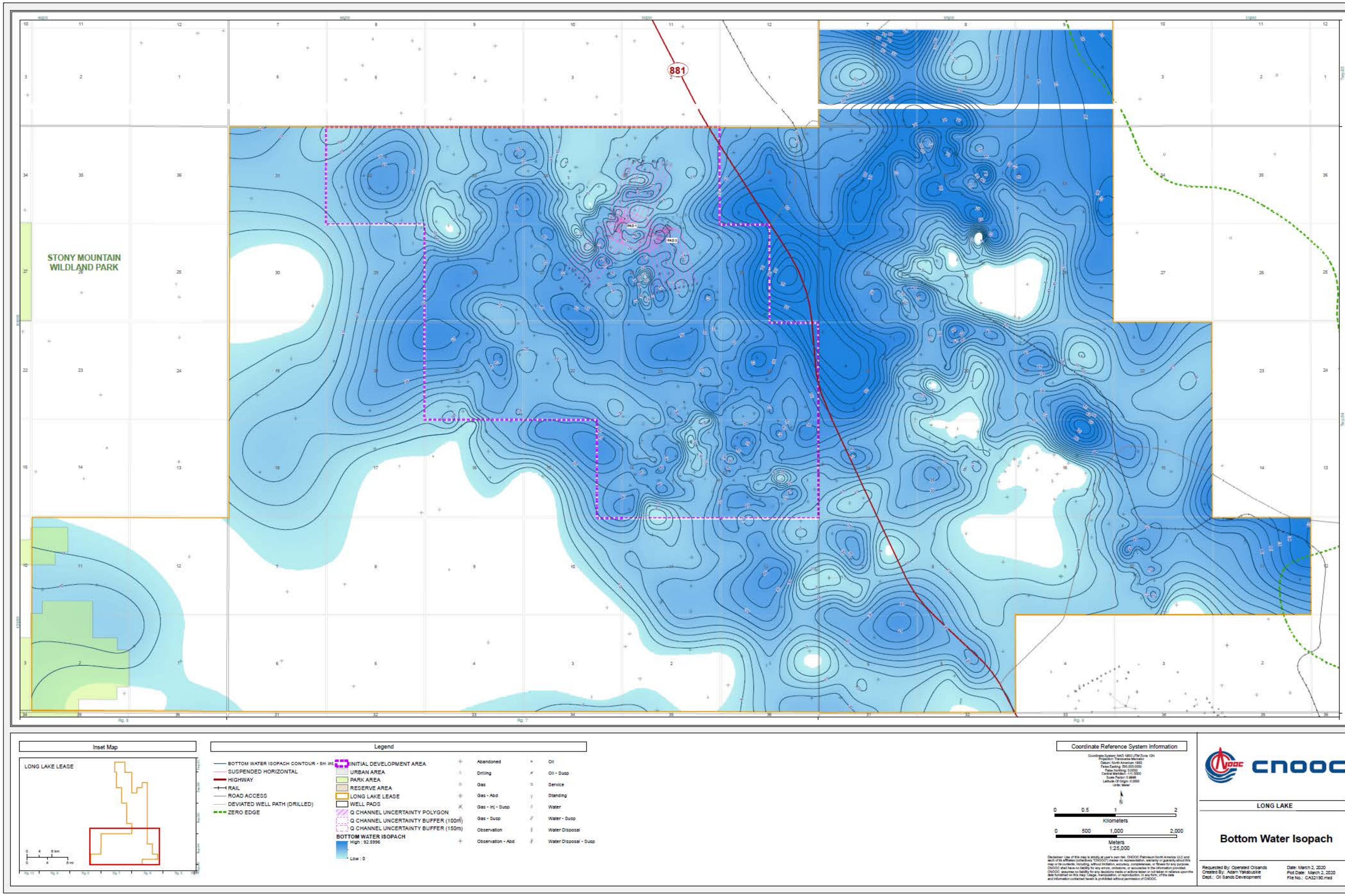
Long Lake Bottom Water in McMurray



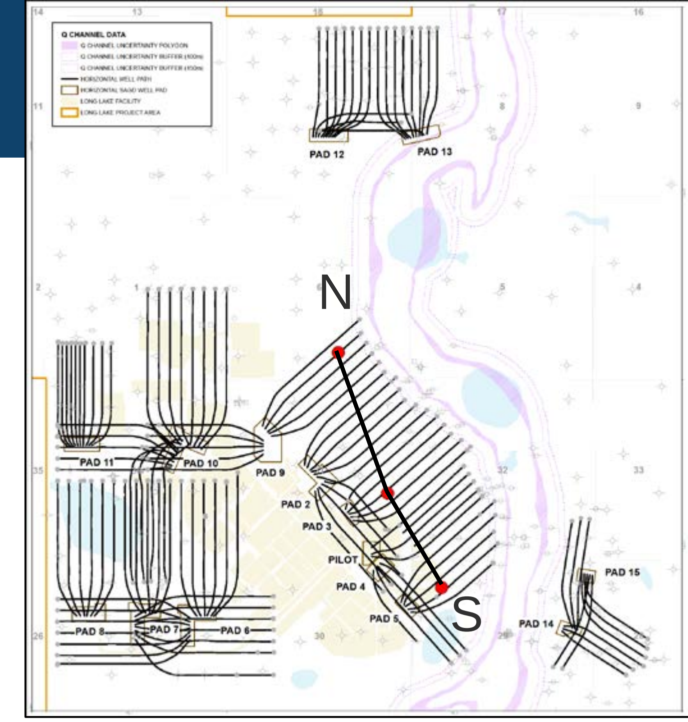


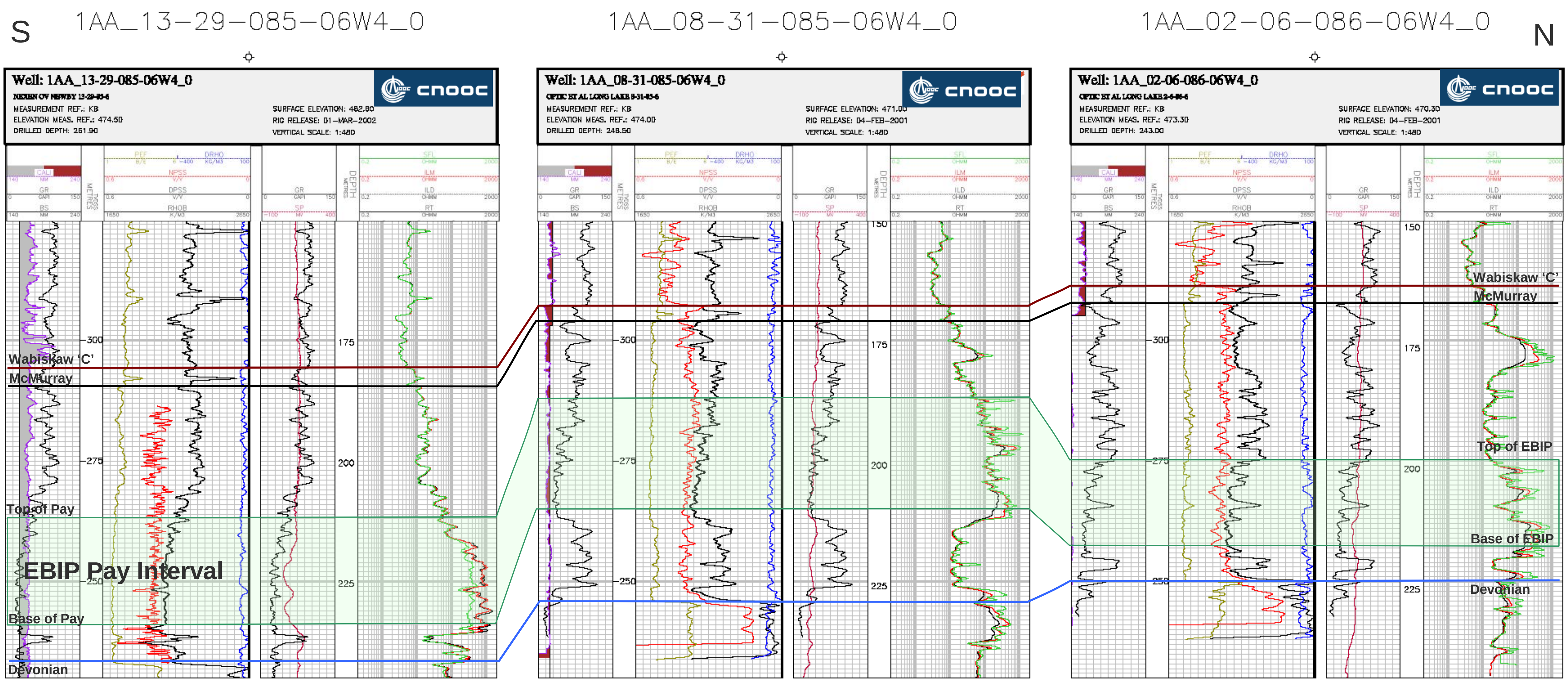
- > 50% Swe and < 30% V_{shale}.

Kinosis Bottom Water in the McMurray

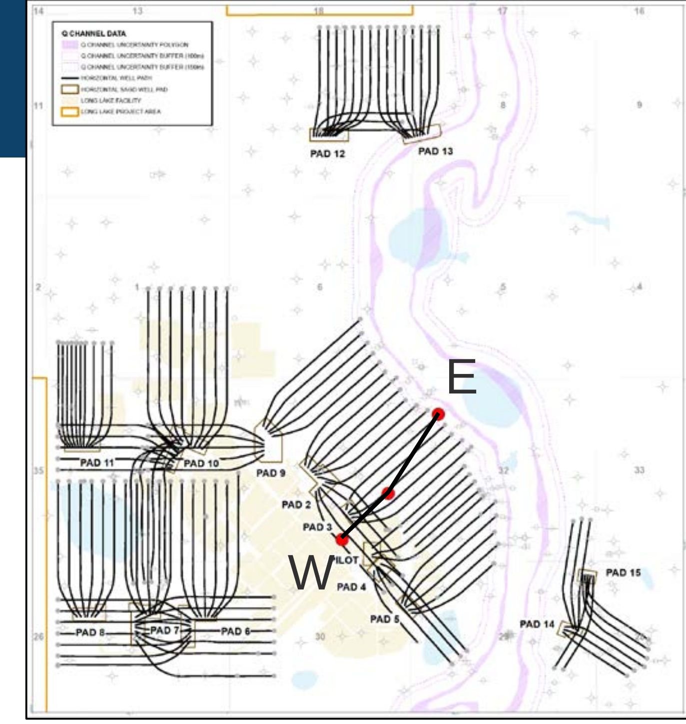


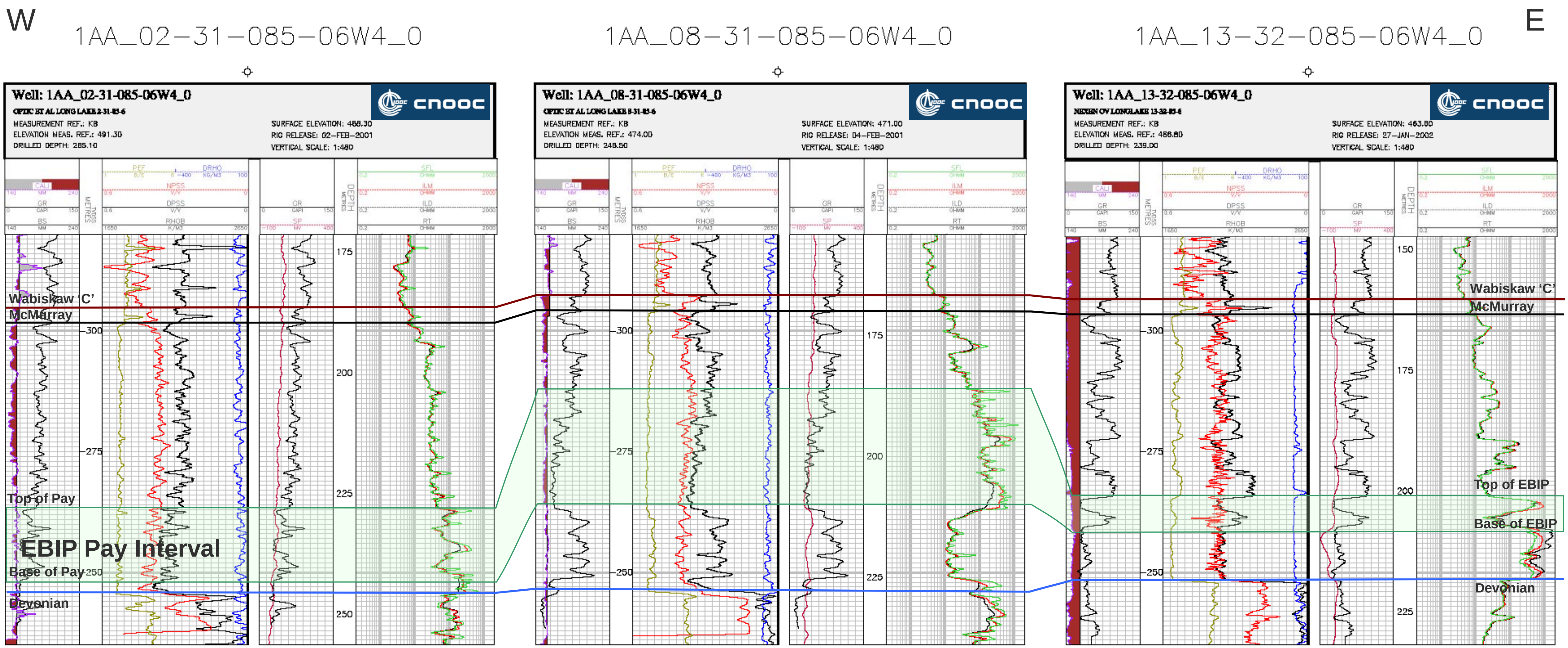
Representative structural cross-section of the East Side of Long Lake (South - North)



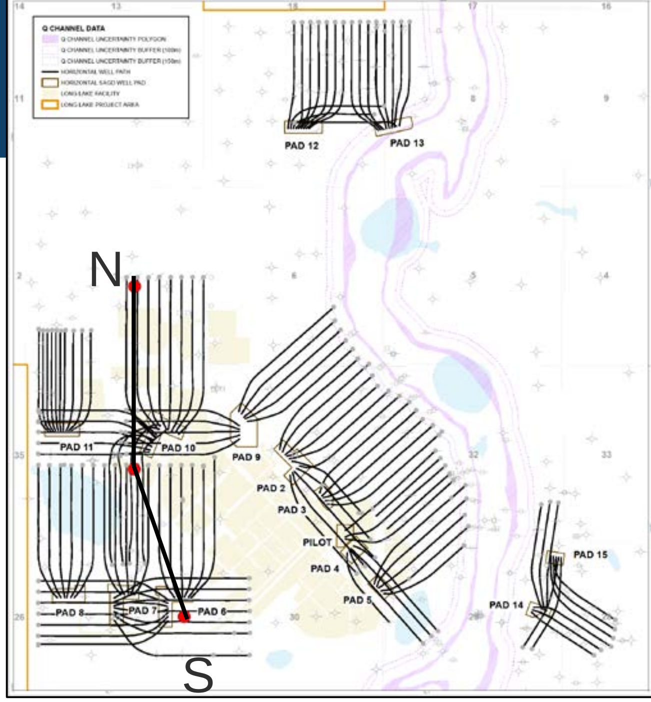


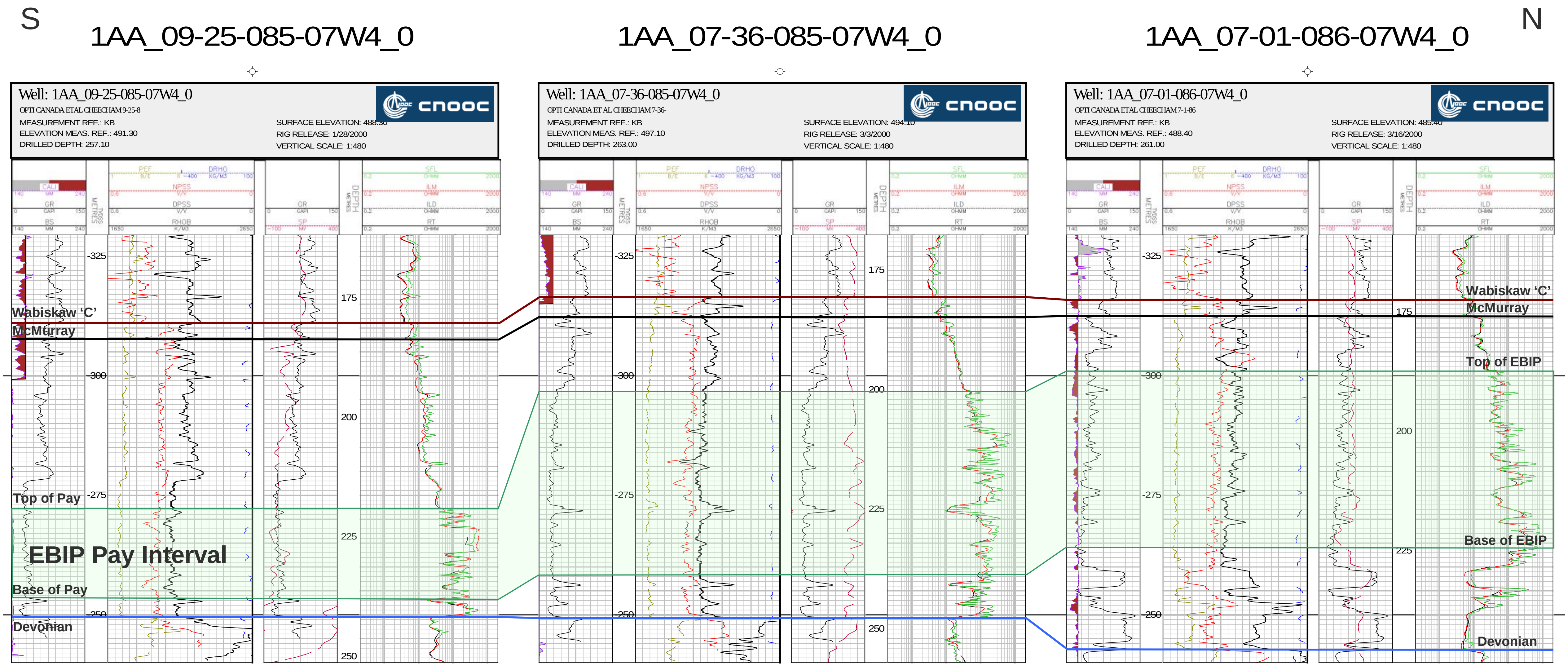
Representative structural cross-section of the East Side of Long Lake (West - East)



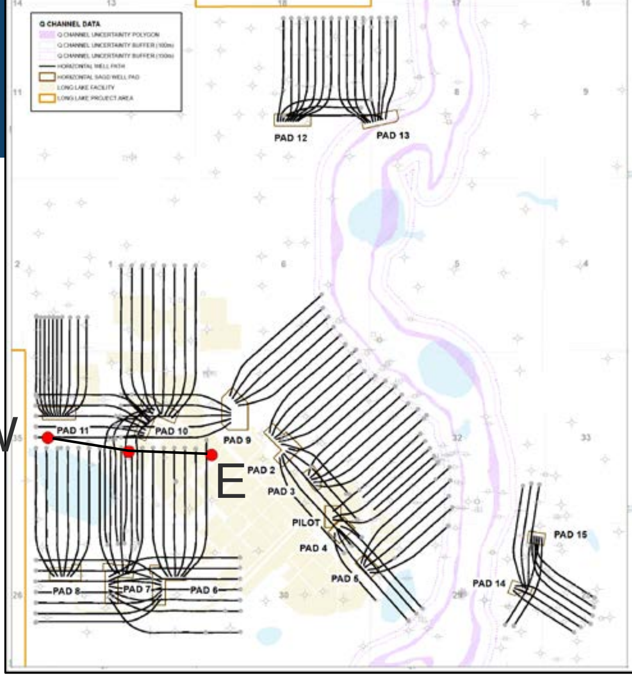


Representative structural cross-section of the West Side of Long Lake (South - North)





Representative structural cross-section of the West Side of Long Lake (West - East)



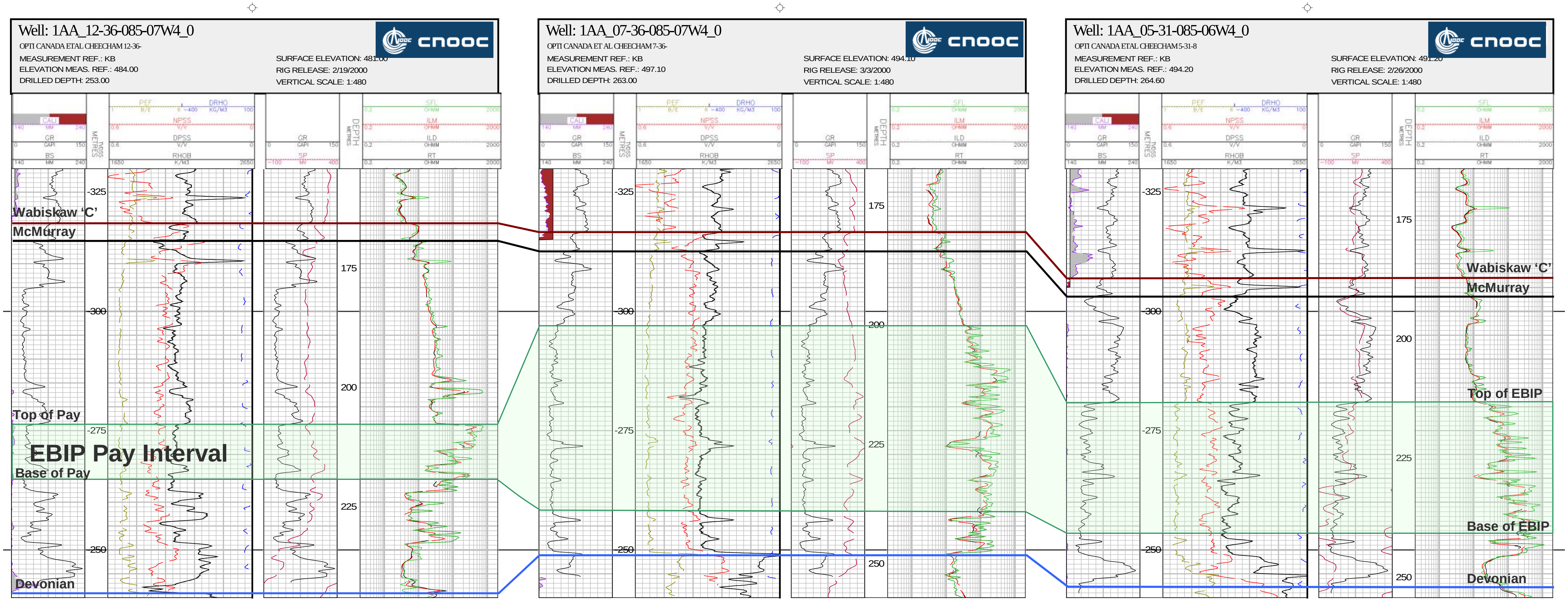
W

E

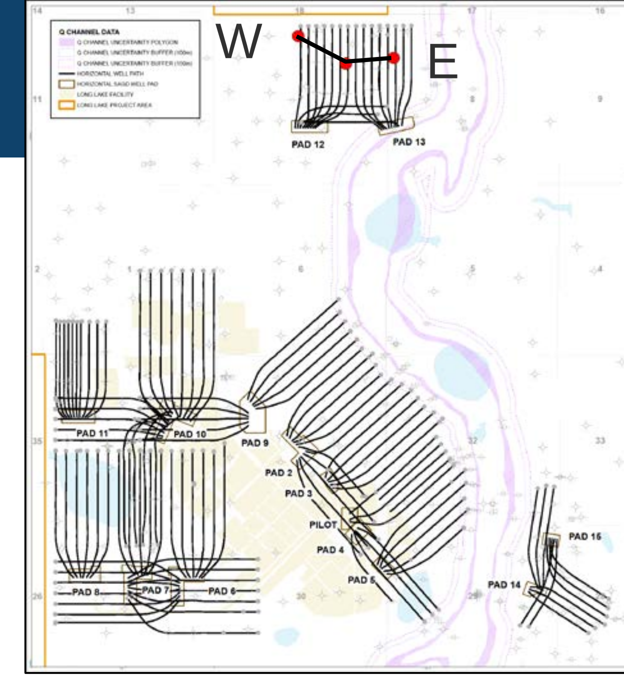
1AA_12-36-085-07W4_0

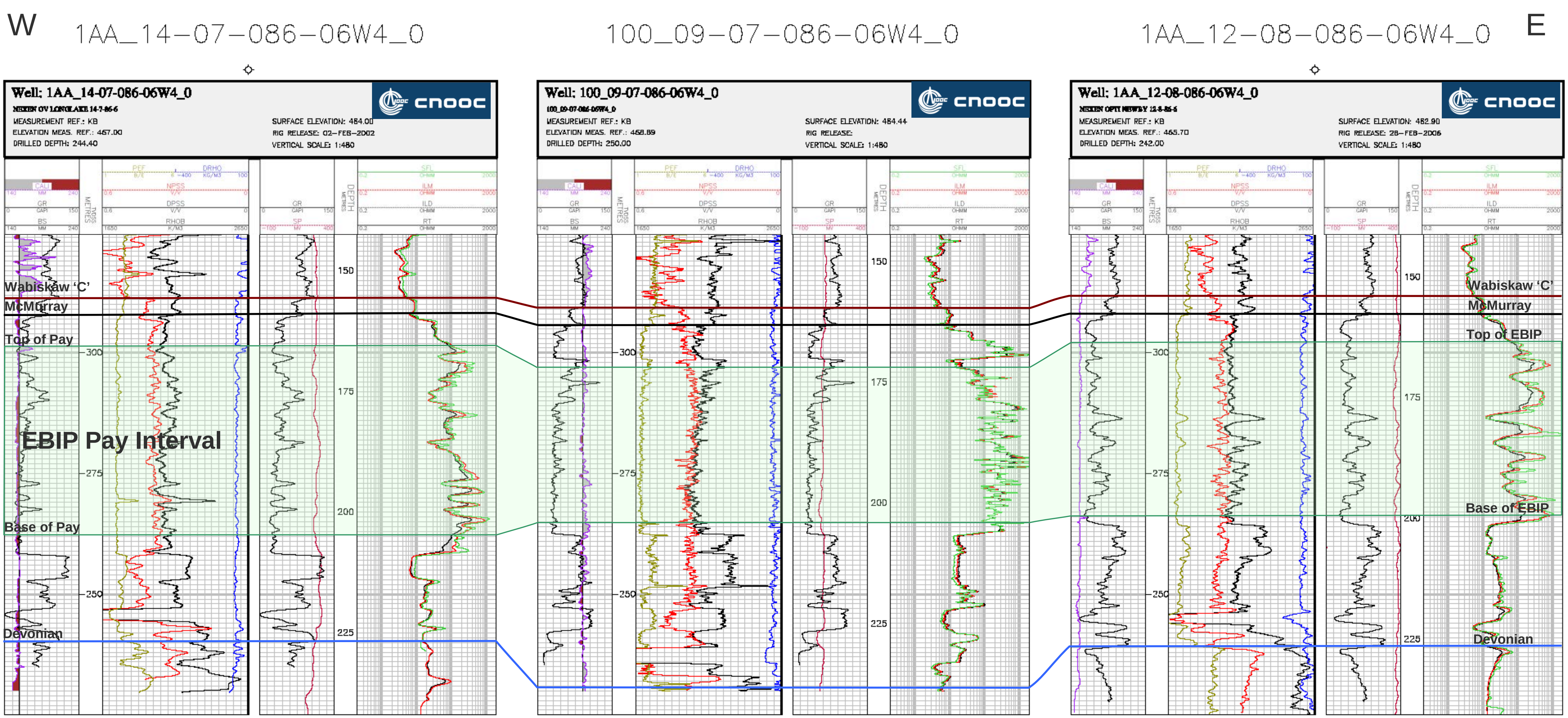
1AA_07-36-085-07W4_0

1AA_05-31-085-06W4_0

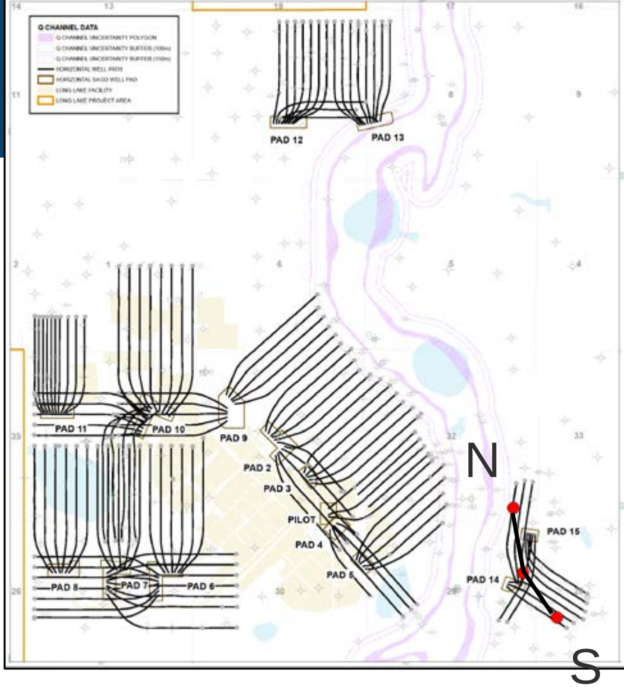


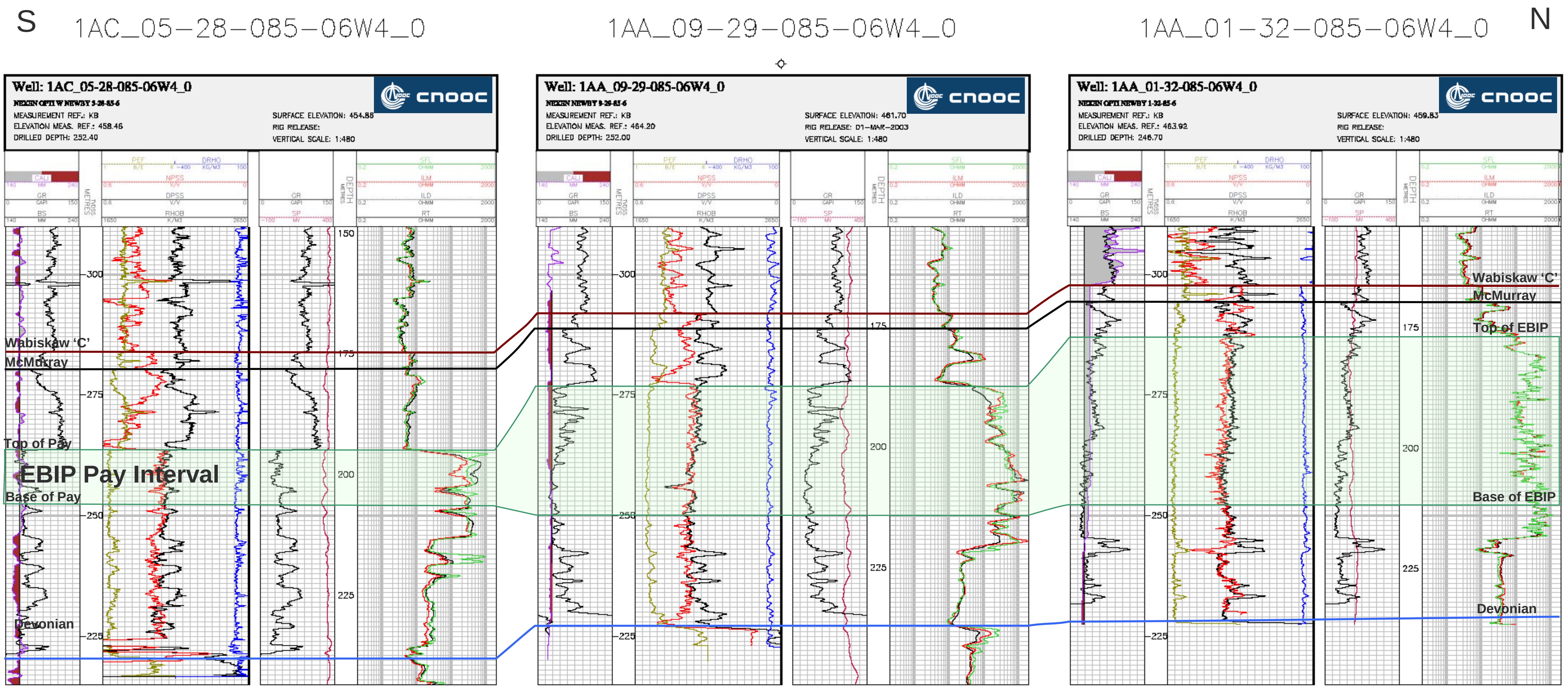
Representative structural cross-section of Pads 12 and 13



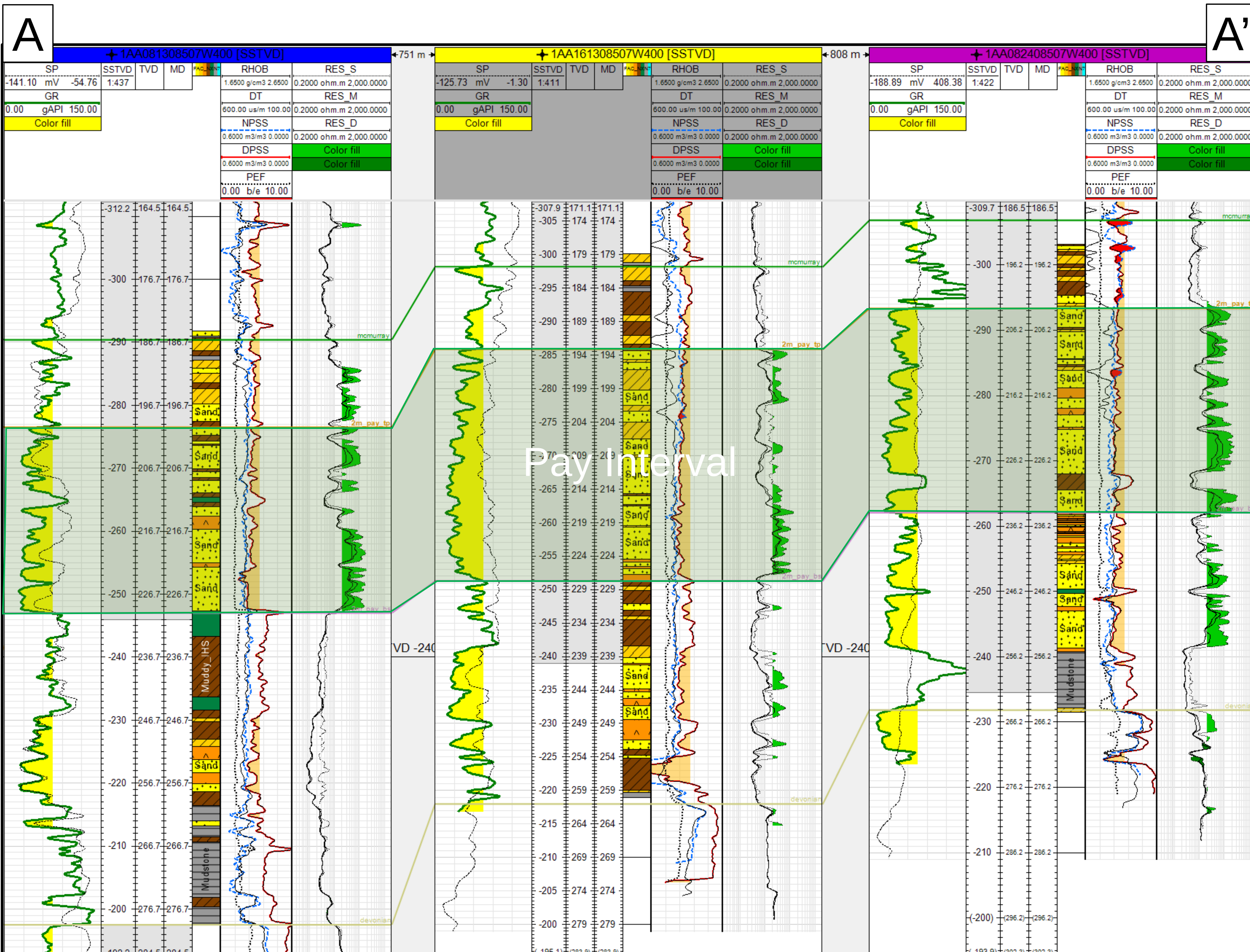


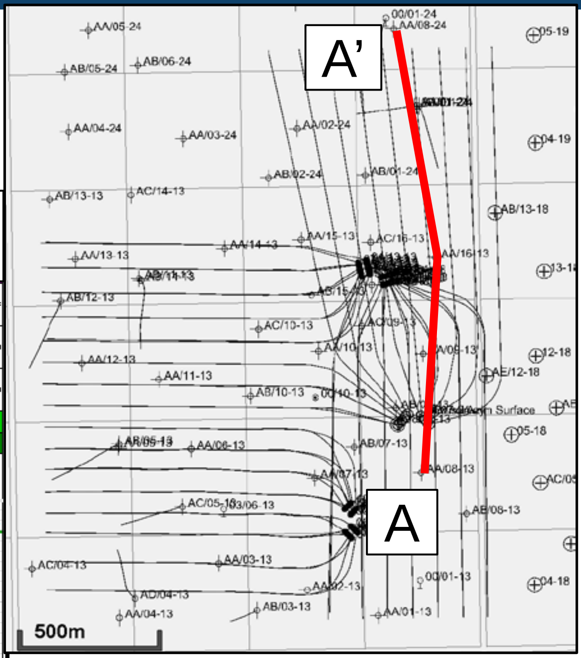
Representative structural cross-section of Pads 14 and 15



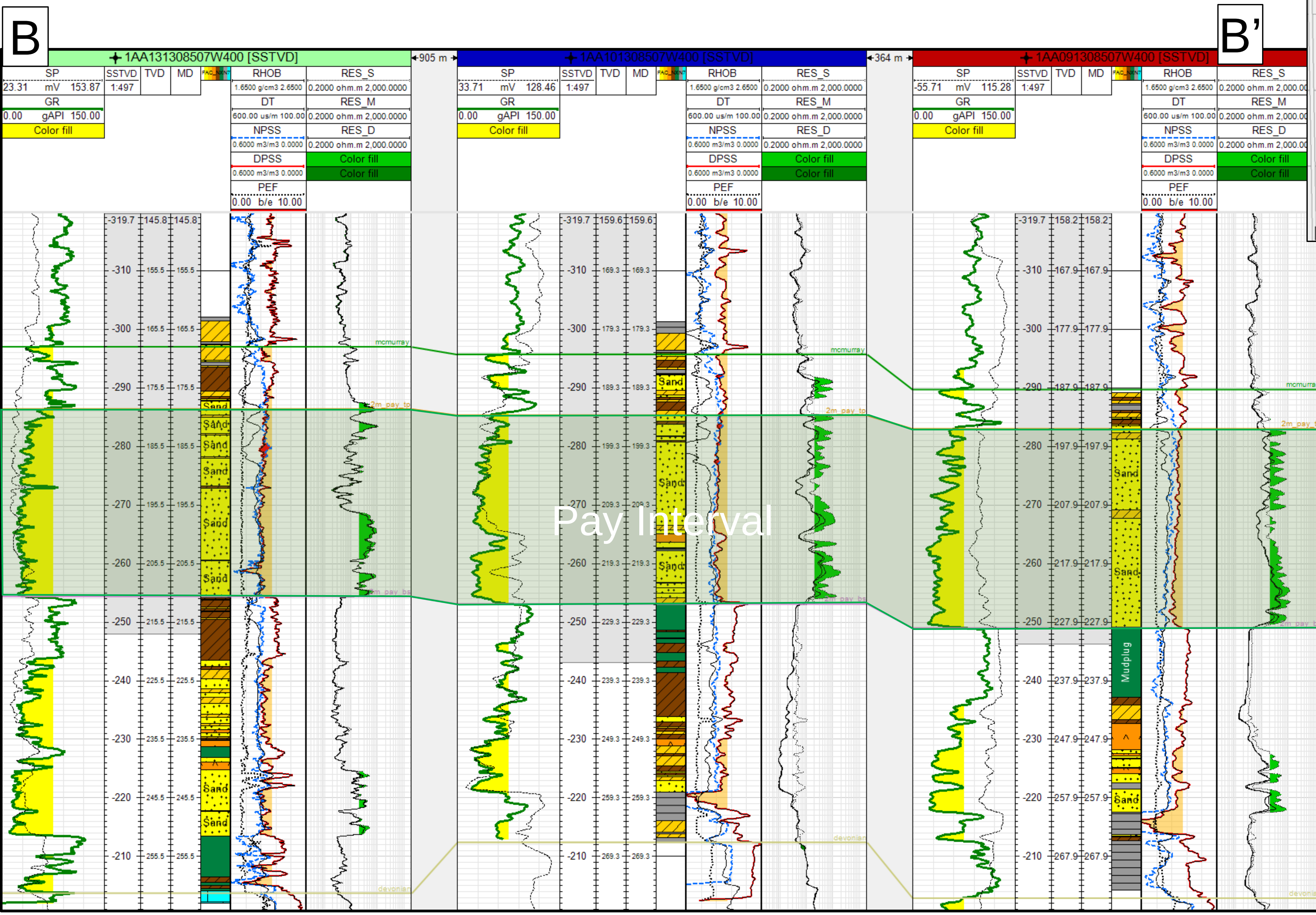


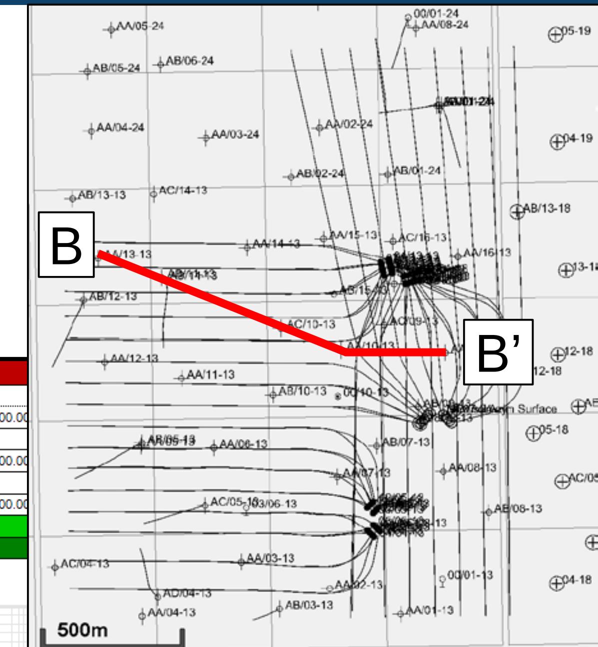
Representative structural cross-section of LLSW (S-N)



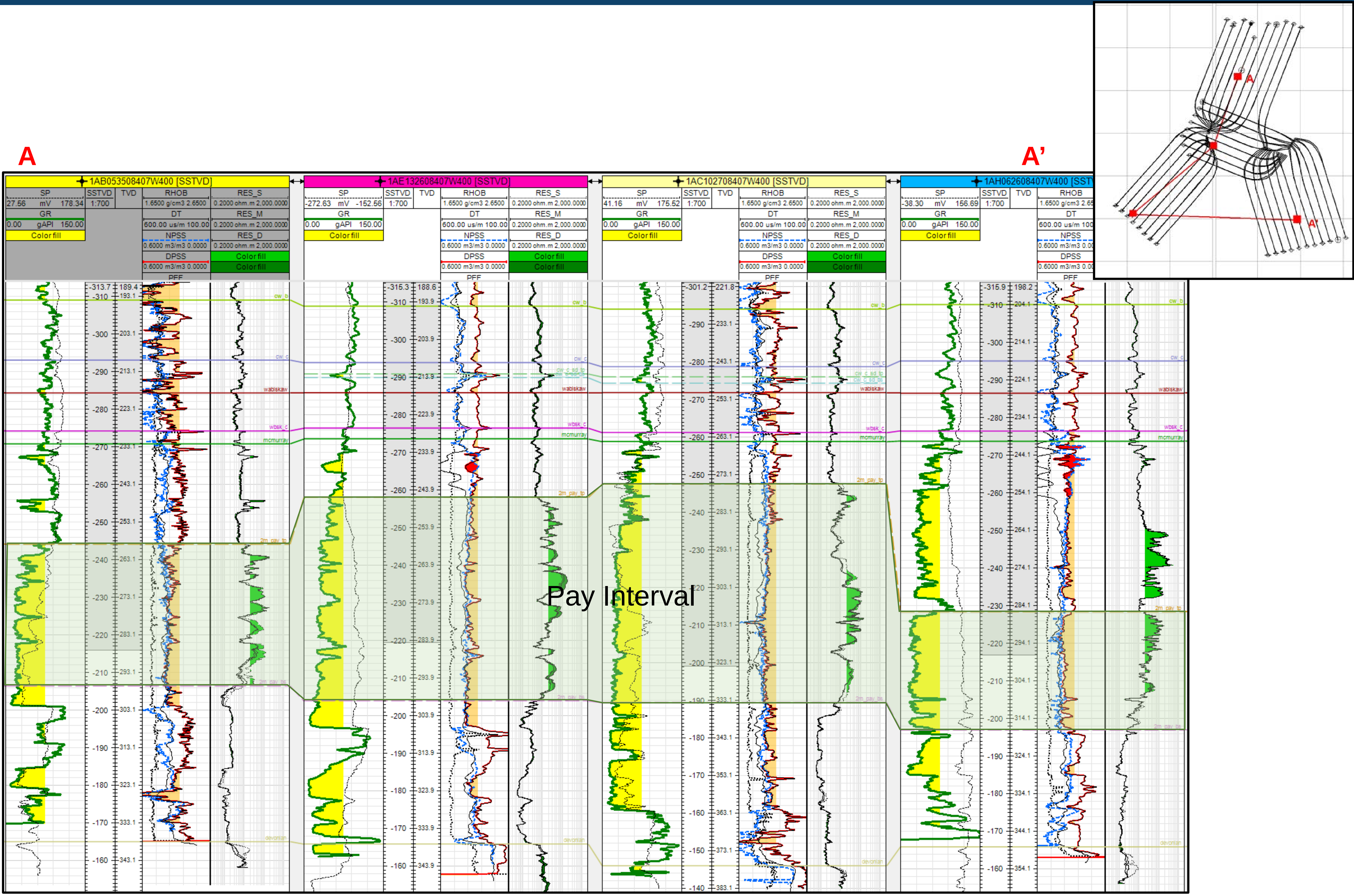


Representative structural cross-section of LLSW (E-W)

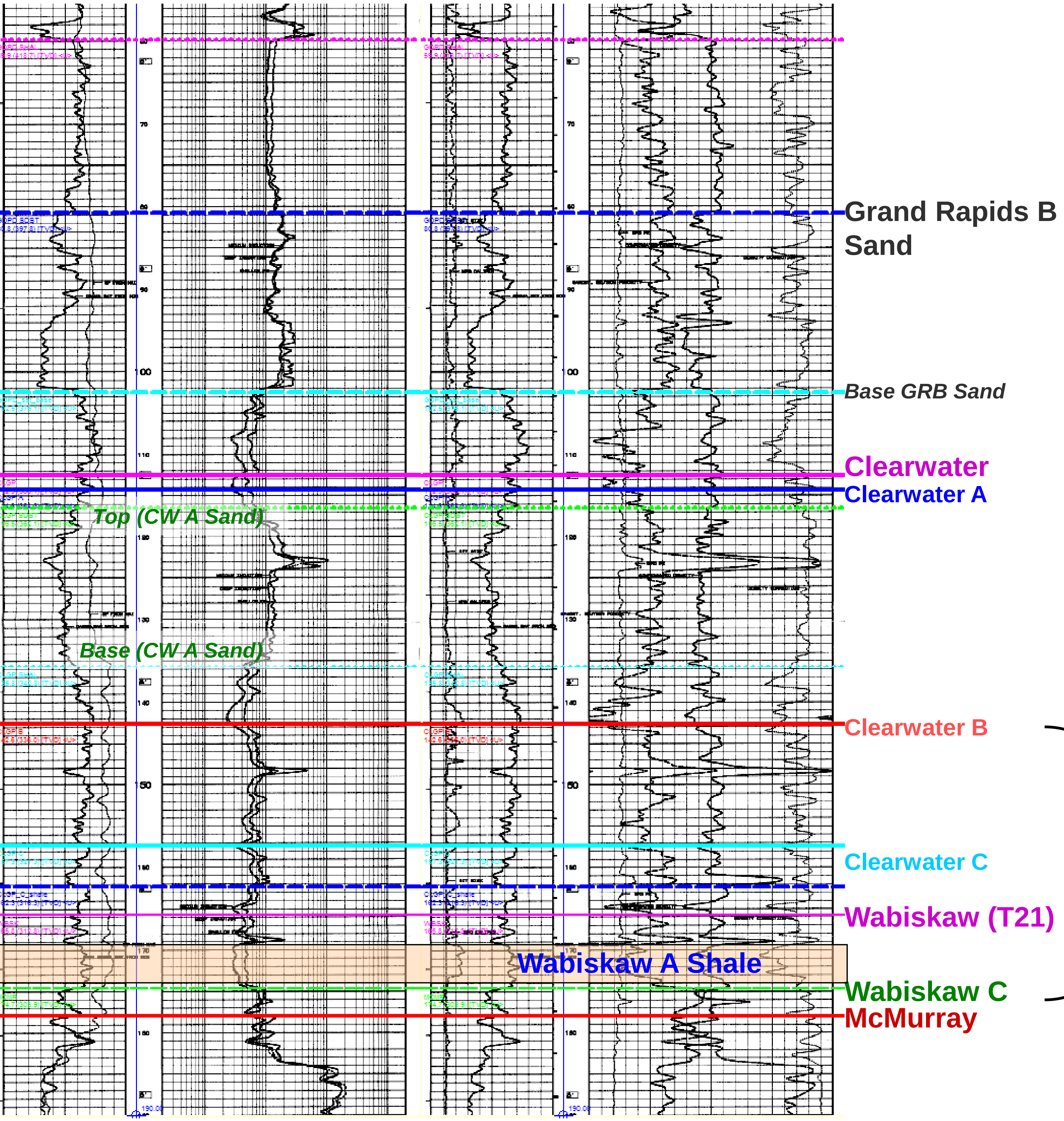




Representative structural cross-section of K1A



Long Lake Cap Rock Type Log



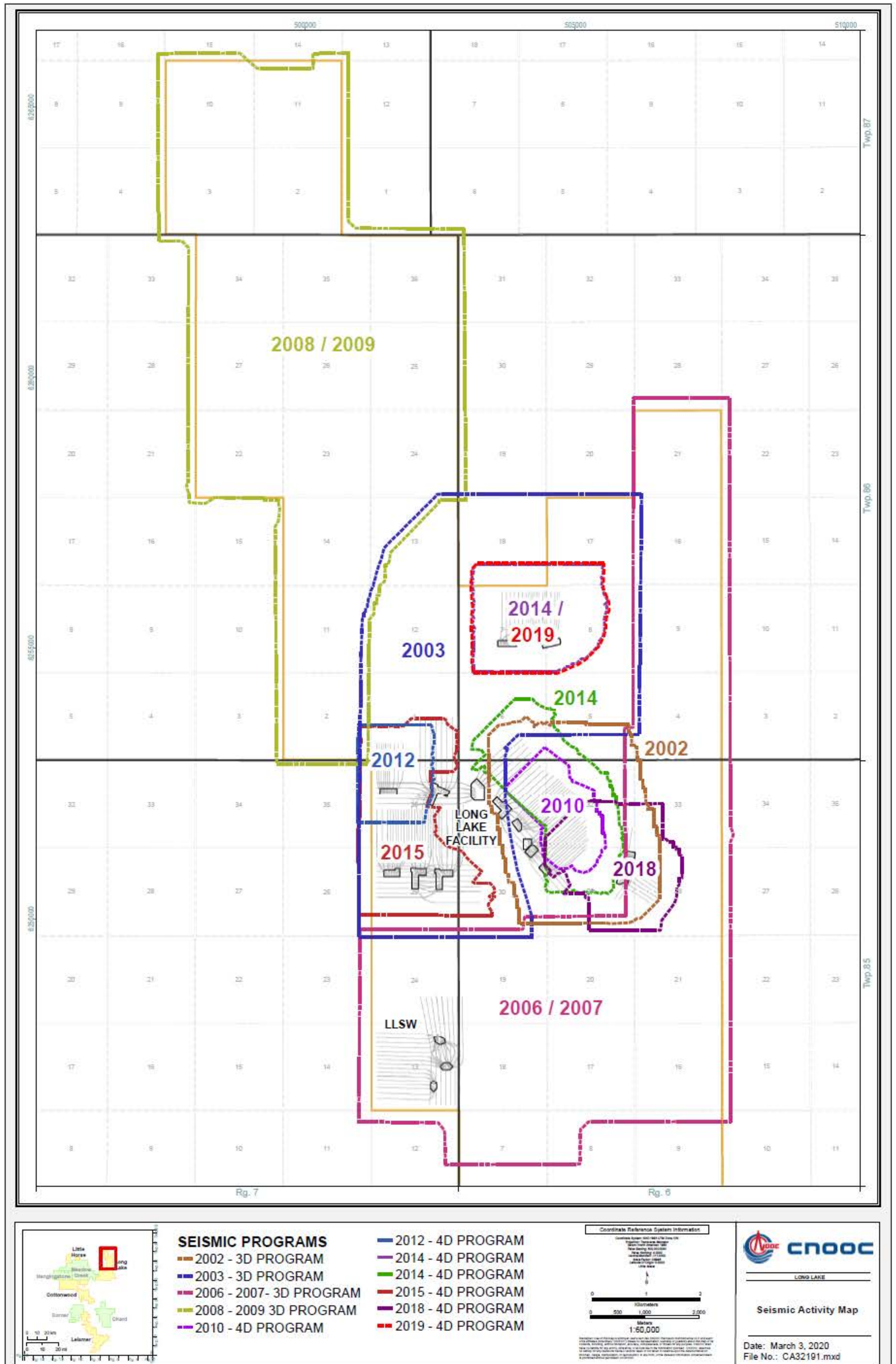
AA/08-20-085-06W4/0
KB: 478.6 m RR: 2001-01-09
TD: 255.0 m [TVD] FormTD: BHL
Mode: Abnd Fluid: N/A
OPTIC ET AL LONG LAKE 8-20-85-6

Cap rock defined as top of Clearwater B to top of Wabiskaw C sand

2019 Cased hole logging

UWI	Well Name	License No
103053208506W400	NEXEN OPTI OB2 B NEWBY 5-32-85-6	273675
100063208506W400	NEXEN OPTI OB2 C NEWBY 6-32-85-6	273676
102092508507W400	NEXEN CNOOC OBS NEWBY 9-25-85-7	451050
100112508507W400	NEU VWP NEWBY 11-25-85-7	473266
100152508507W400	NEXEN CNOOC OBS NEWBY 15-25-85-7	444147
102013608507W400	NEU VWP NEWBY 1-36-85-7	471590
104133608507W400	NEXEN OPTI VWP NEWBY 13-36-85-7	428452
103090708606W400	NEXEN CNOOC OBS NE NEWBY 9-7-86-6	444368
111160708606W400	NEXEN CNOOC OBS NEWBY 16-7-86-6	444078
100110808606W400	NEXEN OPTI VWP NEWBY 11-8-86-6	429631

Long Lake Seismic

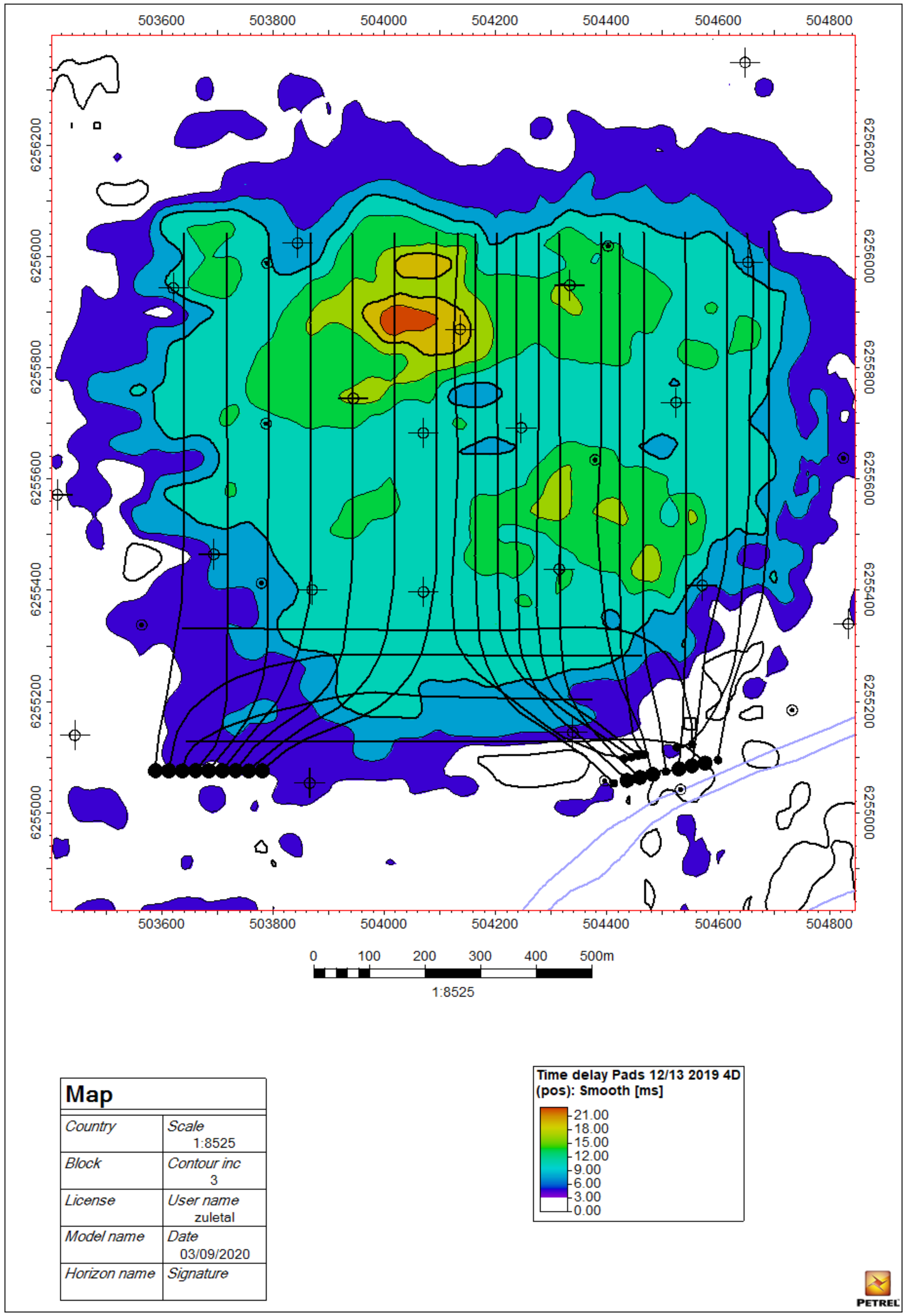


Pads 12/13 2019 4D Seismic Monitor Survey

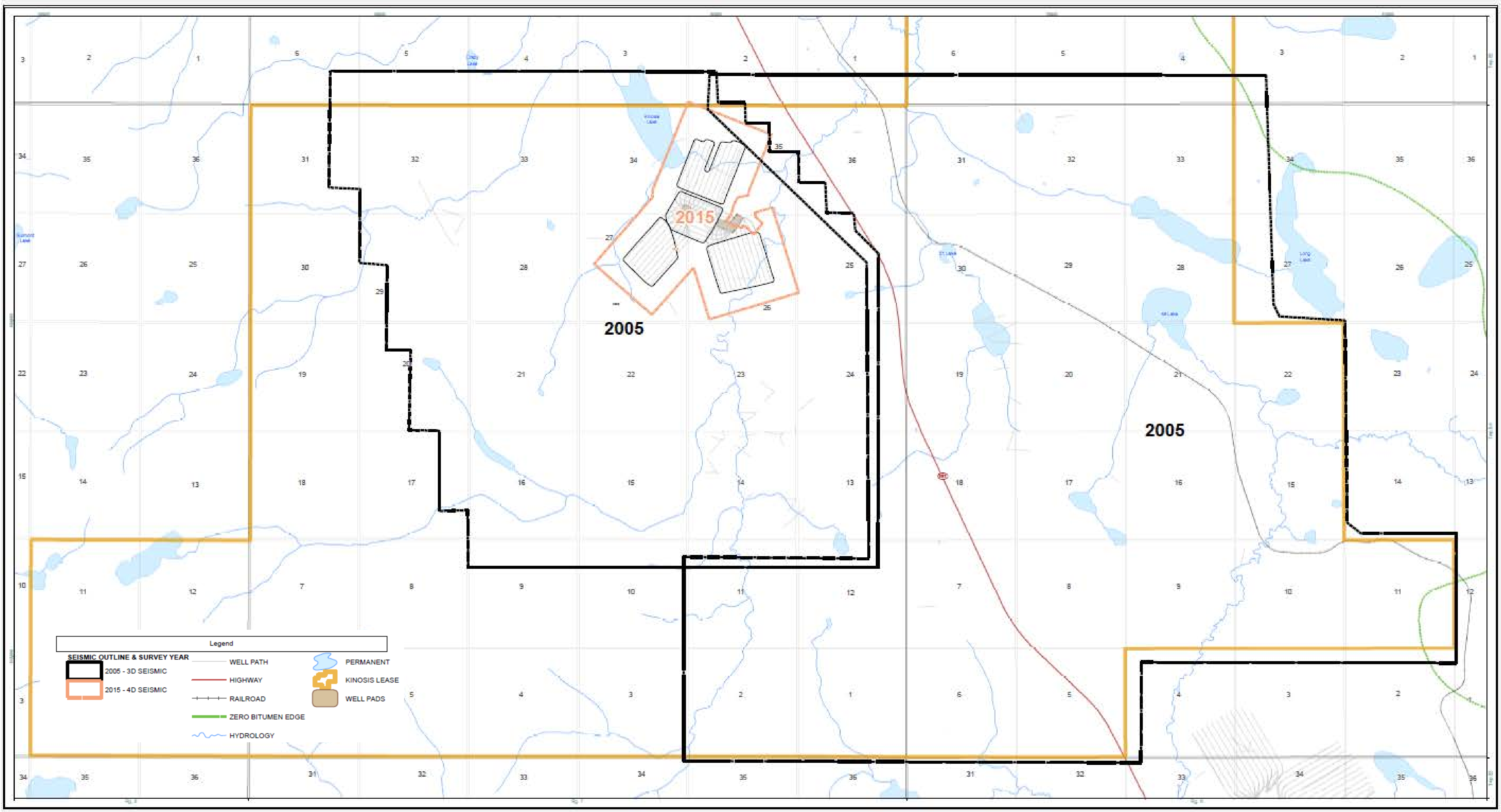
- 4D Monitor survey over Pads 12/13 was completed in mid-January 2019

- Displayed is a time delay map which is a difference between the Clearwater to Devonian isochron between the baseline and monitor surveys.

- It is interpreted that areas with larger time delay values (as a function of changes to reservoir properties) correspond with larger steam chamber development.



Kinosis Seismic
No 4D in 2019

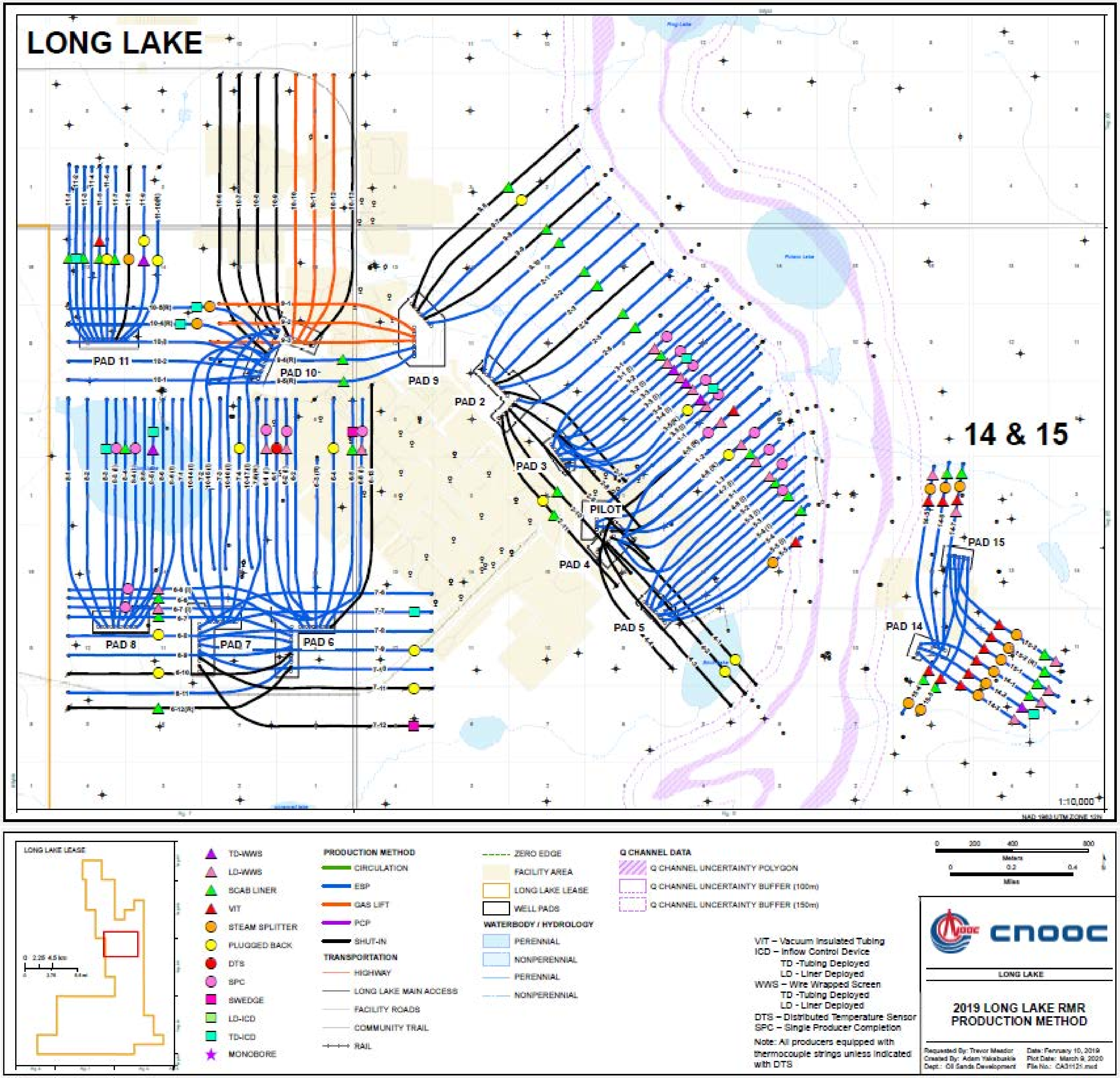


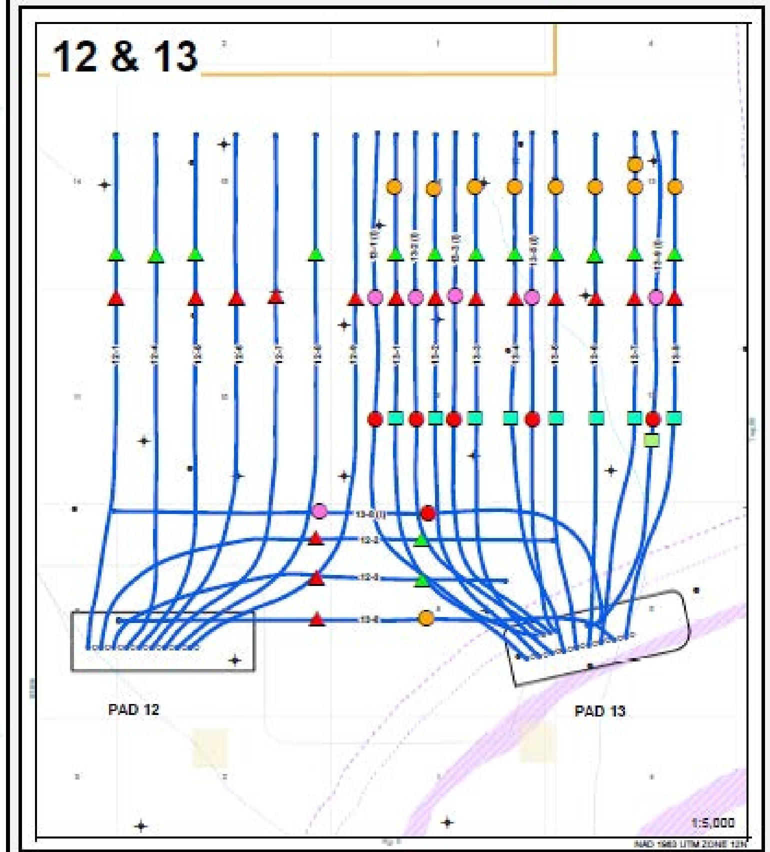
Drilling and Completions, Artificial Lift and Instrumentation

Subsection 3.1.1 (3,4,5)

Long Lake

Long Lake Horizontal Well Completions





Inter-well Spacing

Pad 1: 75m

Pad 2,9,10: 100m

Pad 3, 5, 6, 7: 100m +infills

Pad 6 (6P11-6P12): 75m

Pad 7 (7P11-7P12): 200m

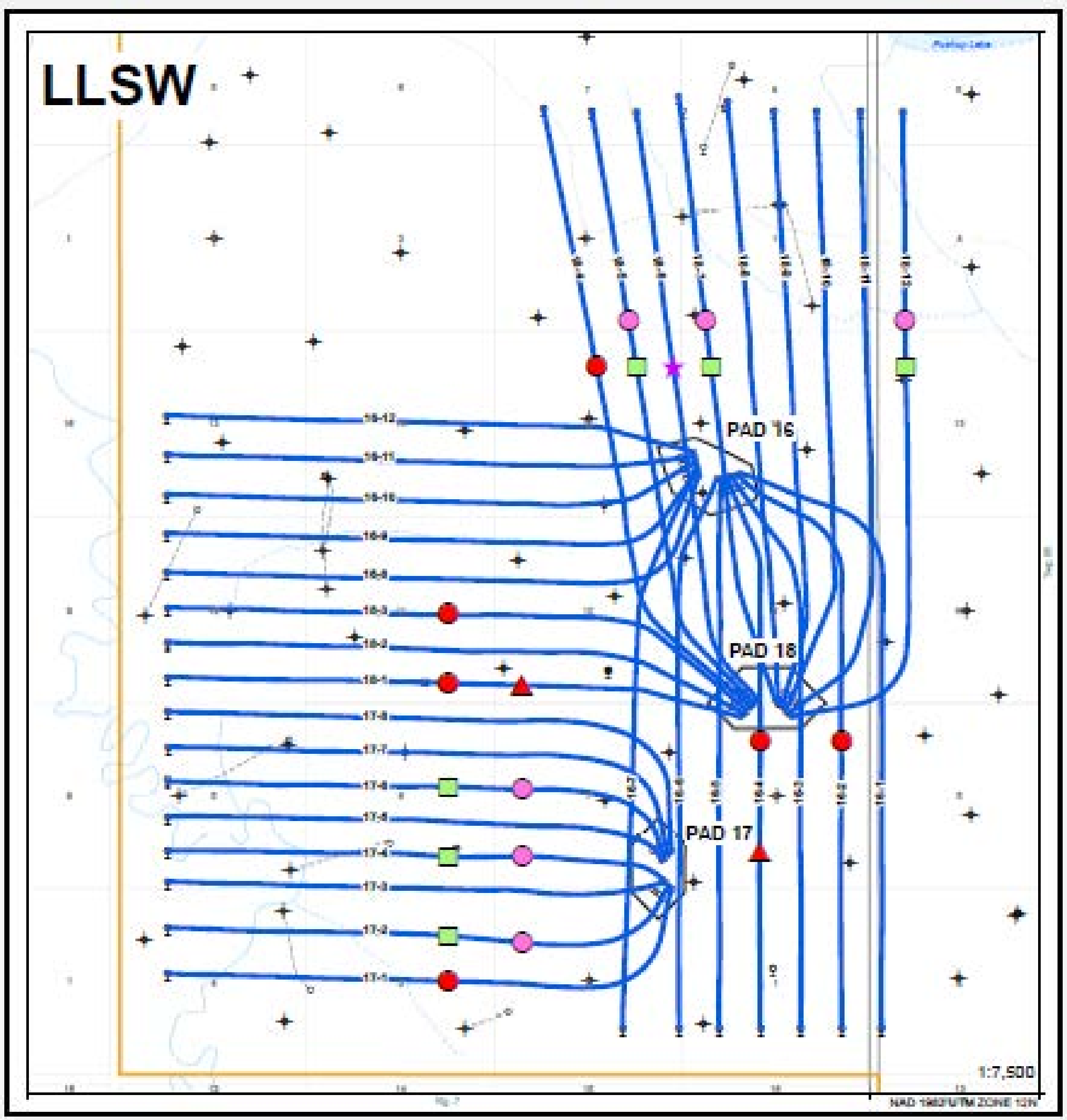
Pad 11 (11P01-11P06): 40m

Pad 11 (11P07-11P10): 80m

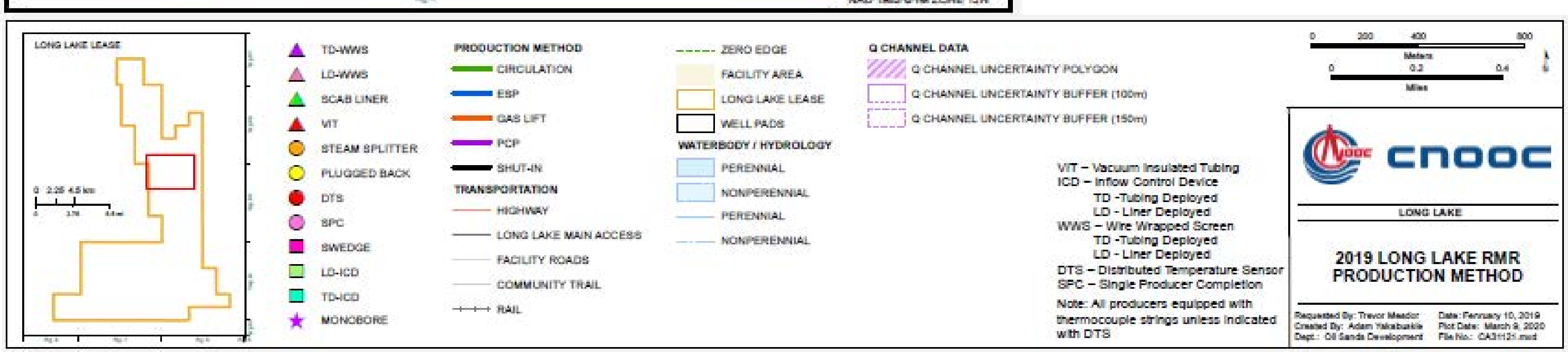
Pad 13: 75m +infills

Pads 12,14,15: 75m

Objects are not representative of landed depth



Inter-well Spacing
Pad 16S: 75m
Pad 16W: 75m
Pad 17W: 75m
Pad 17 (17P01-17P03): 100m
Pad 18N: 75m
Pad 18W: 75m

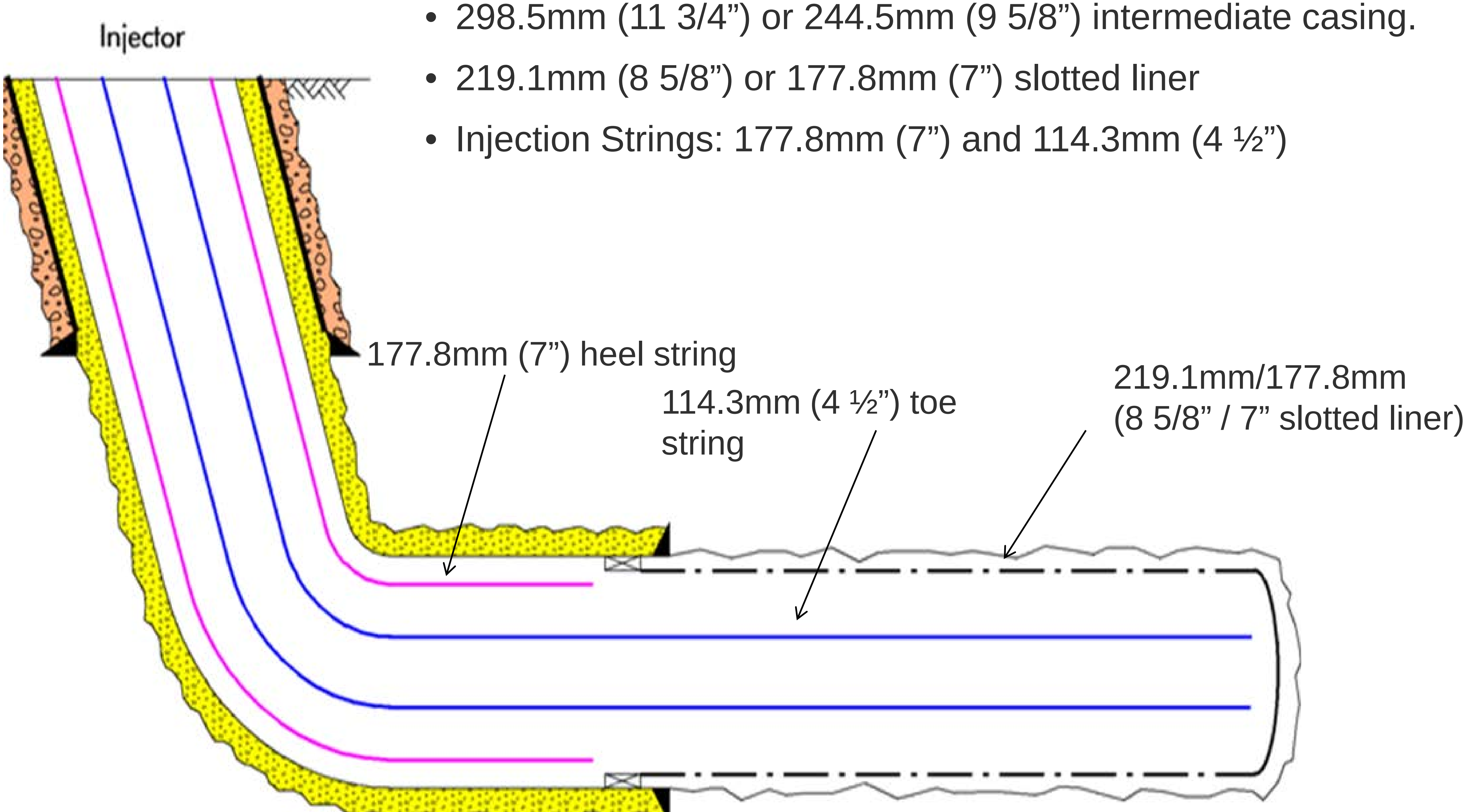


Objects are not representative of landed depth

Typical Injector Completion

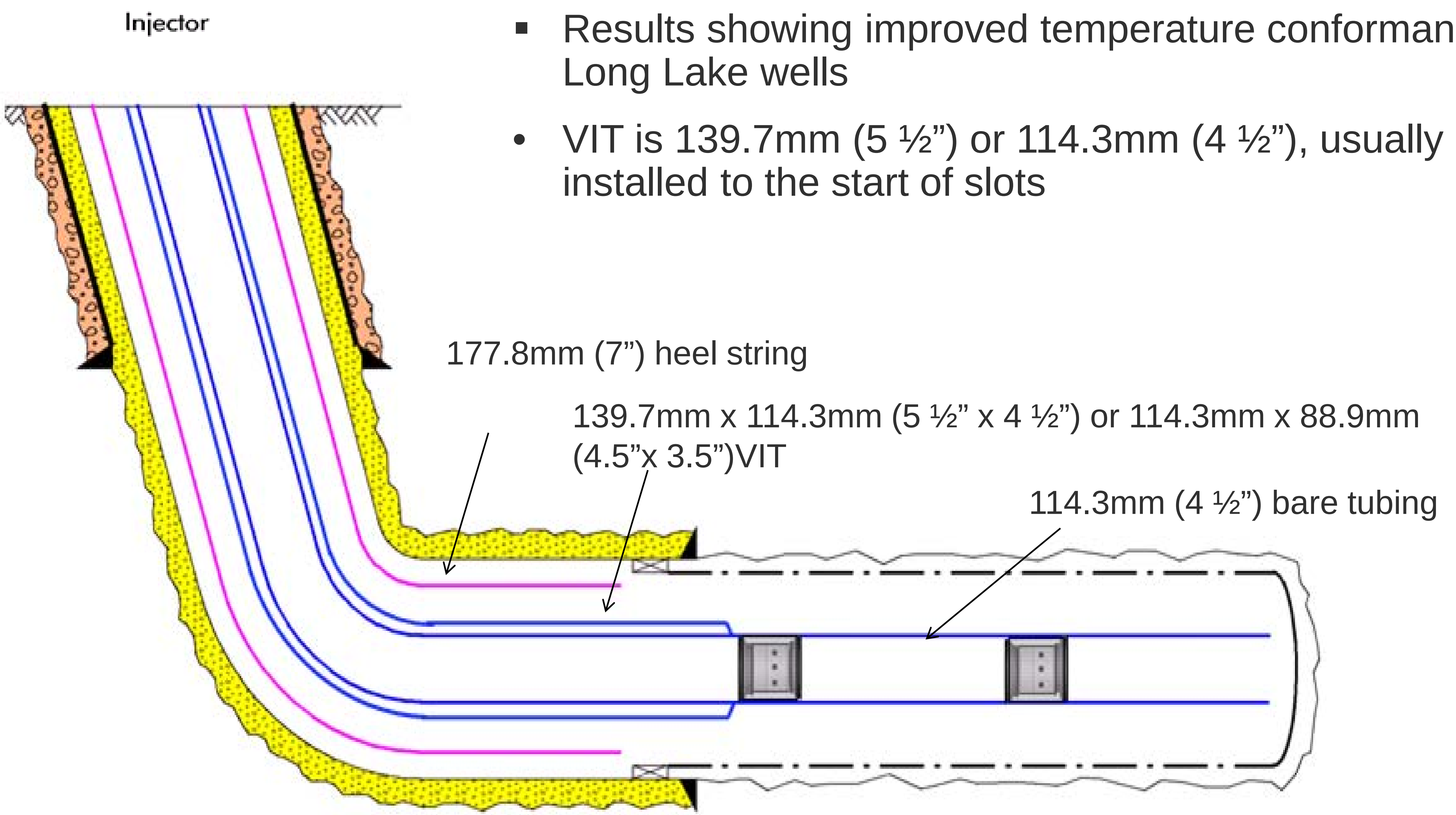
Concentric:

- Majority of Long Lake's design
- 406.4mm (16") or 339.9mm (13 3/8") surface casing
- 298.5mm (11 3/4") or 244.5mm (9 5/8") intermediate casing.
- 219.1mm (8 5/8") or 177.8mm (7") slotted liner
- Injection Strings: 177.8mm (7") and 114.3mm (4 ½")

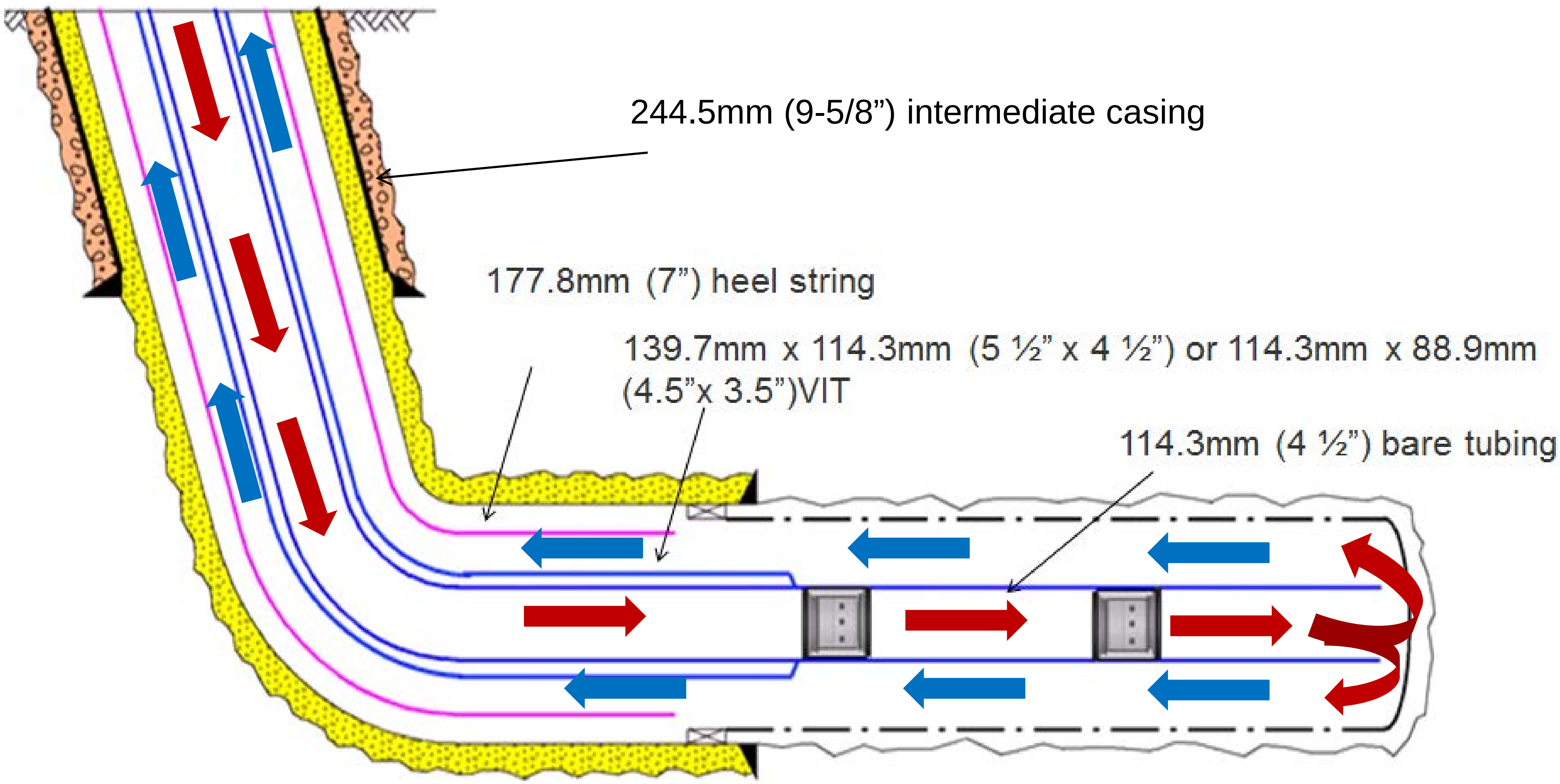


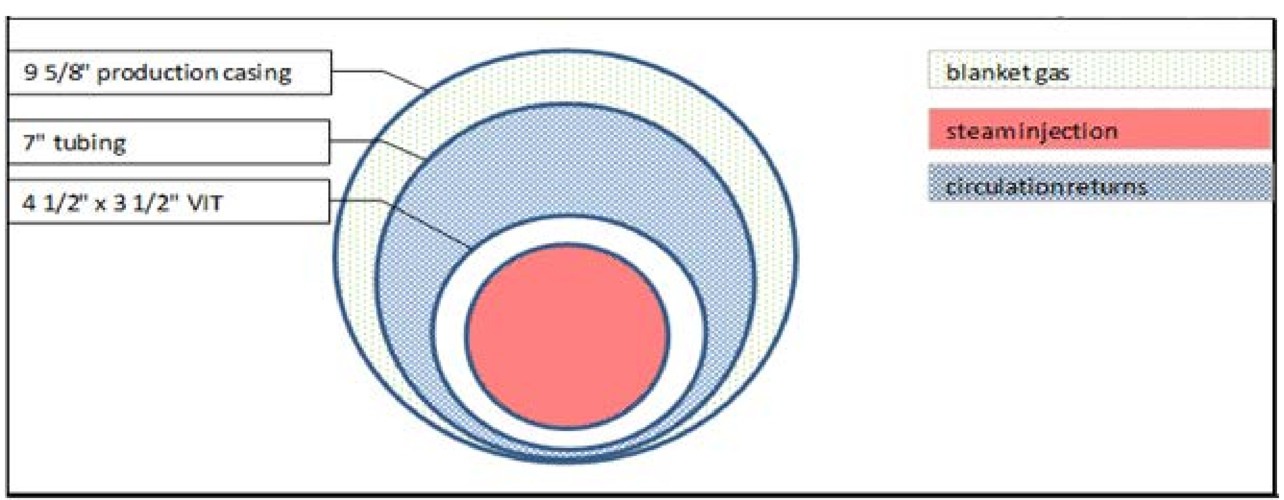
Vacuum Insulated Tubing (VIT) Injector Completion

- All Kinosis wells, and a few Long Lake pads are completed with steam splitters in the long injection string
  - Results showing improved temperature conformance in Long Lake wells
- VIT is 139.7mm (5 ½”) or 114.3mm (4 ½”), usually installed to the start of slots



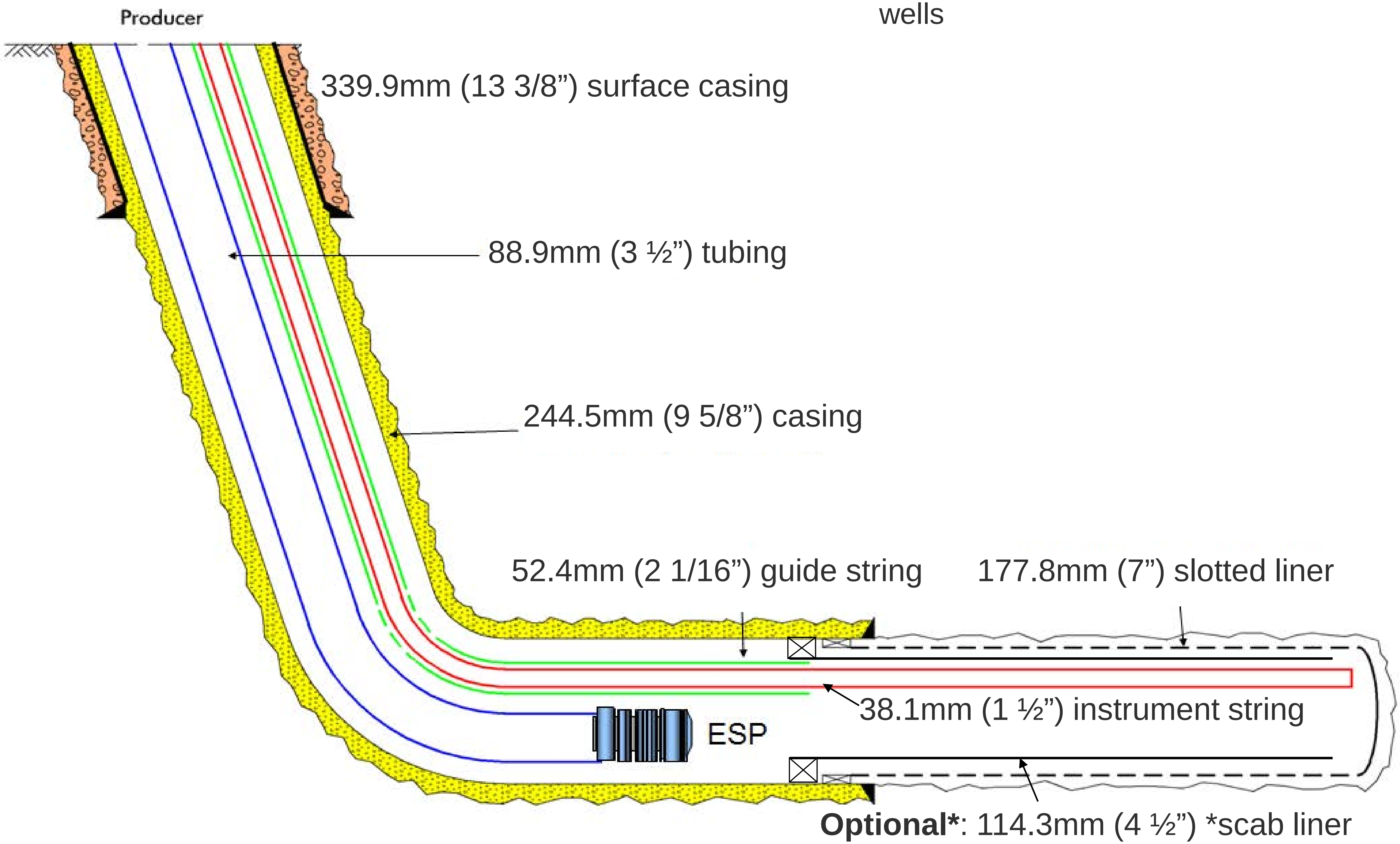
Typical Injector Circulation



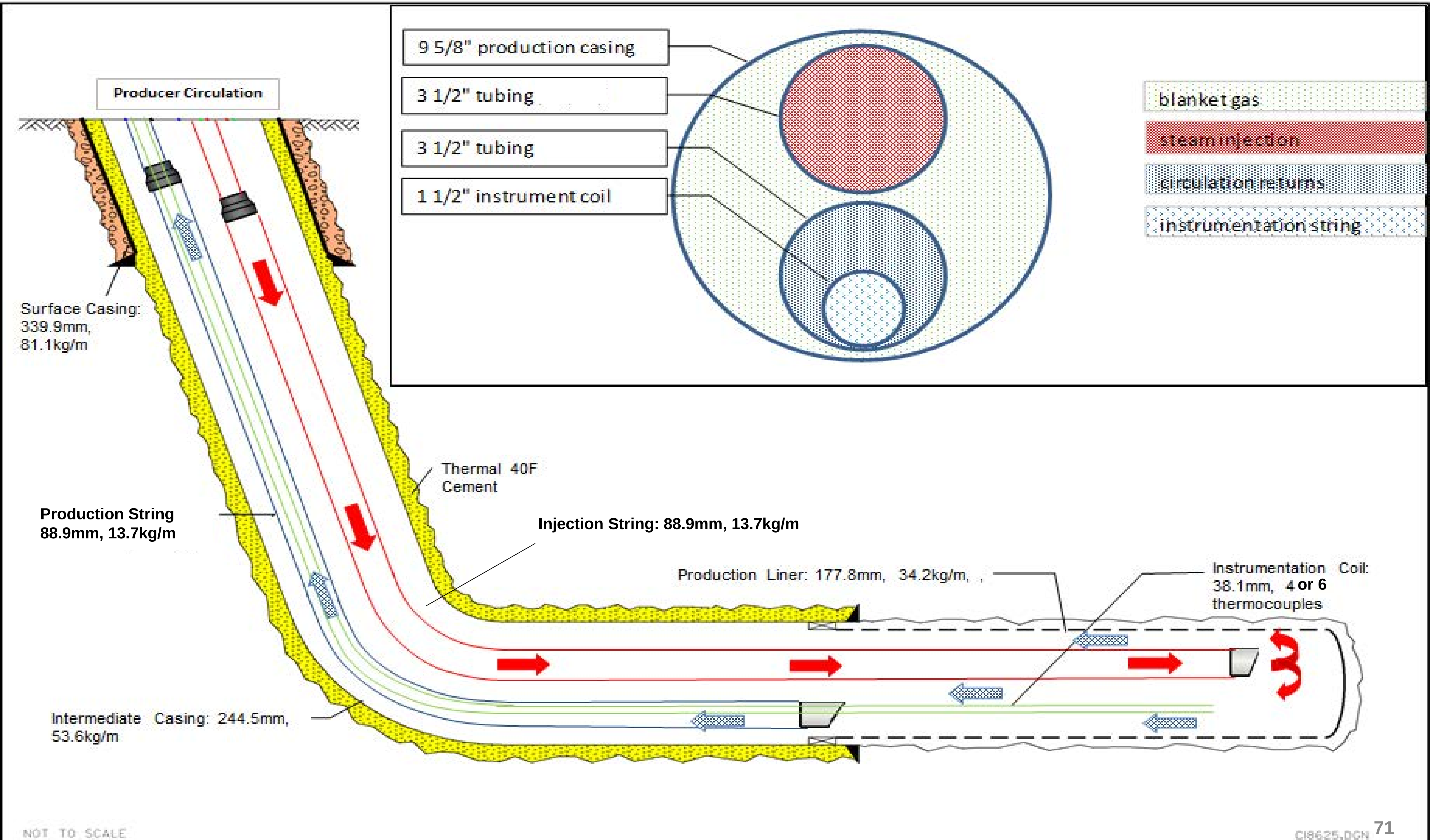


Typical Producer Completions – ESP

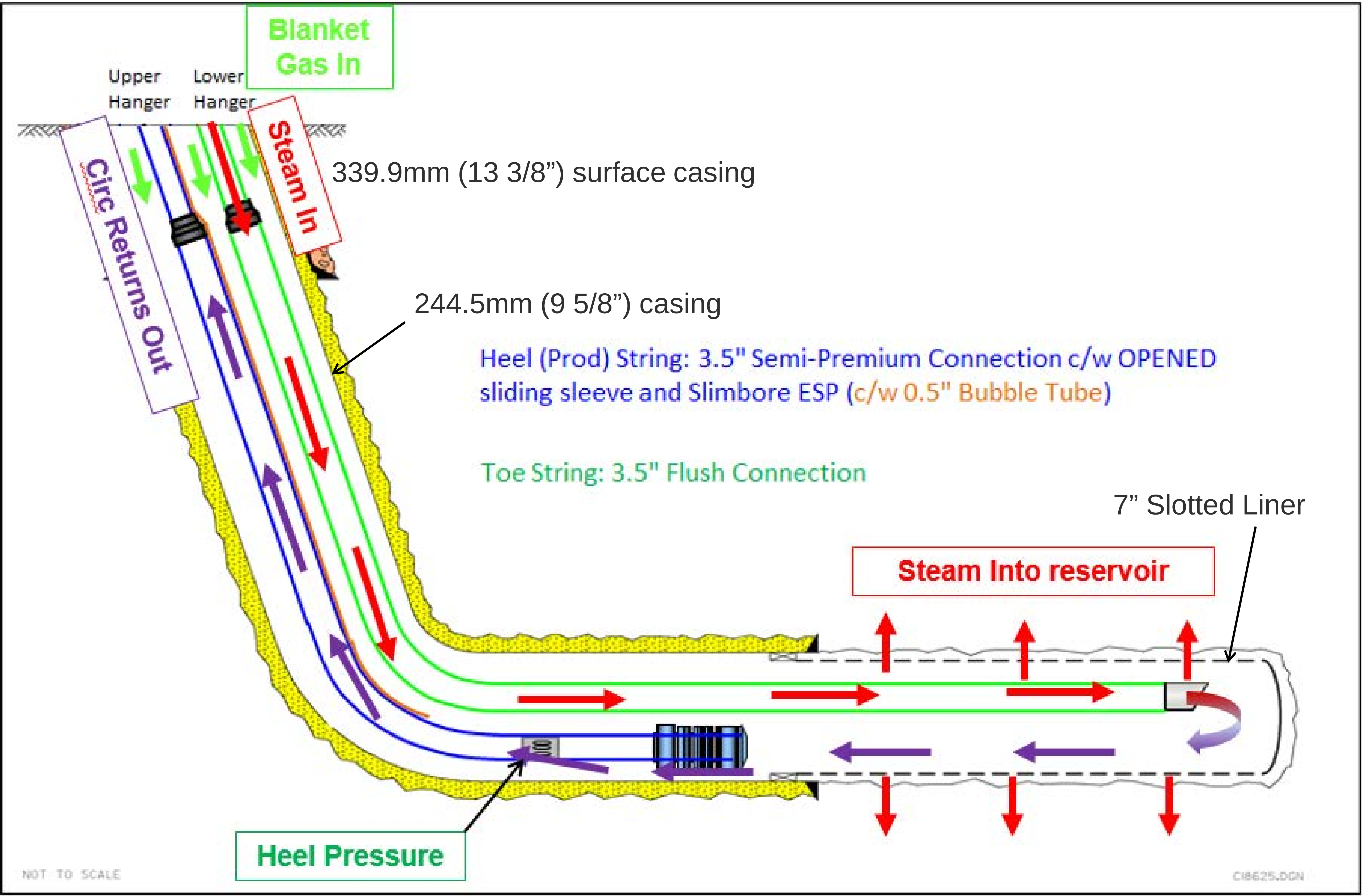
*Scab liners installed in some producer wells



Typical Producer Circulation

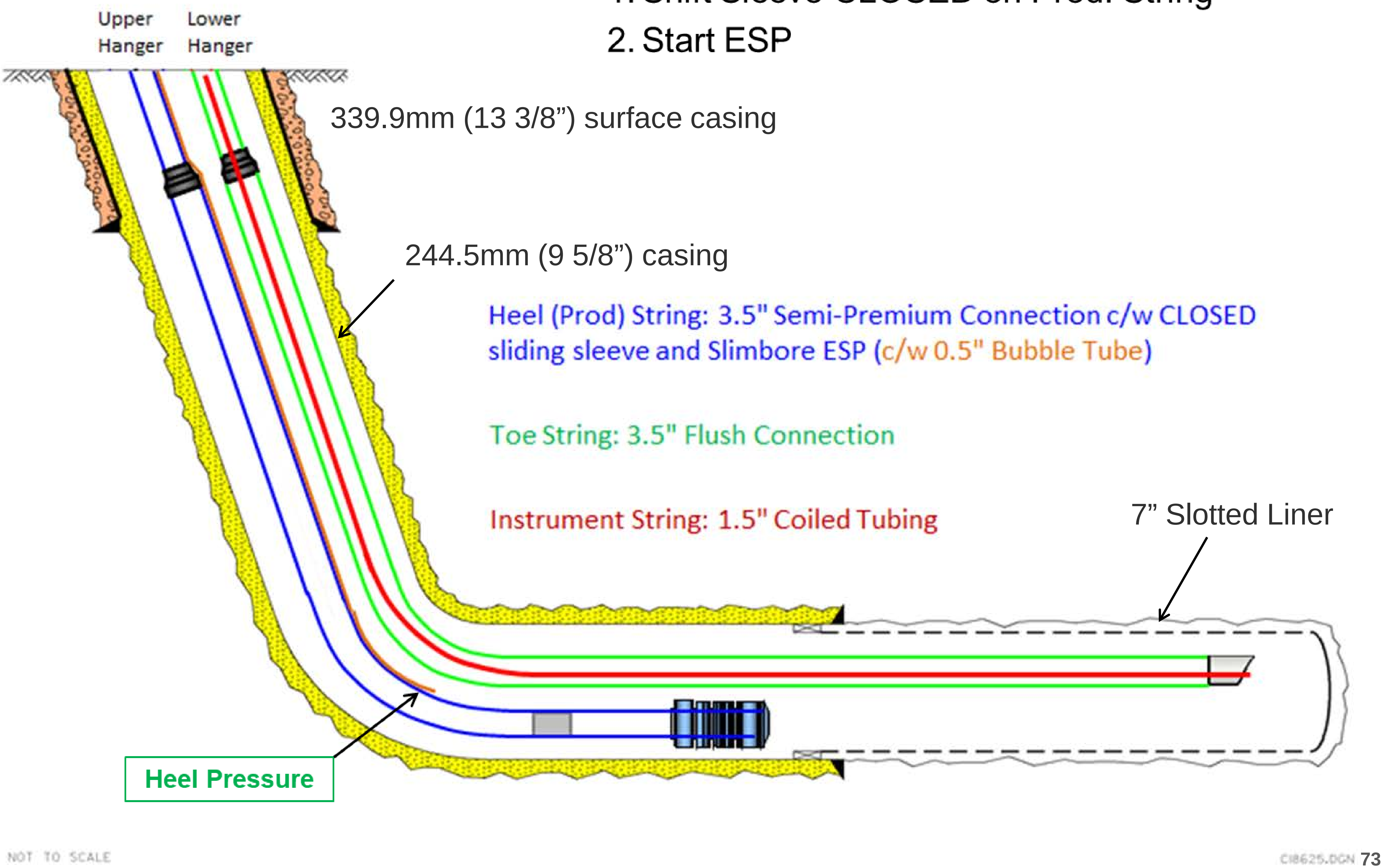


Single Producer Completion (SPC) – Circulation Infill Wells



Single Producer Completion (SPC) – SAGD Infill Wells

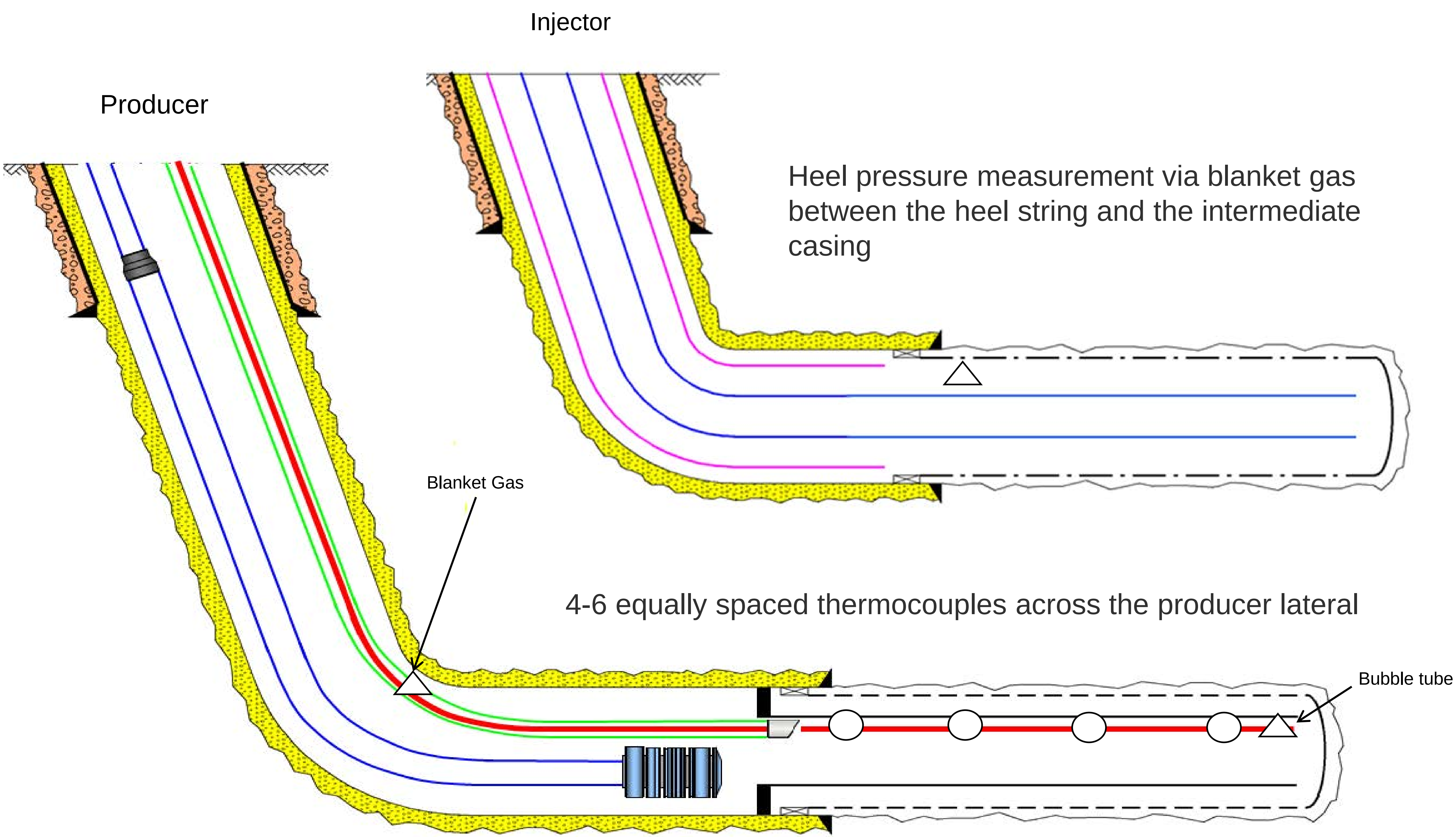
1. Shift Sleeve CLOSED on Prod. String
2. Start ESP



Artificial Lift Performance

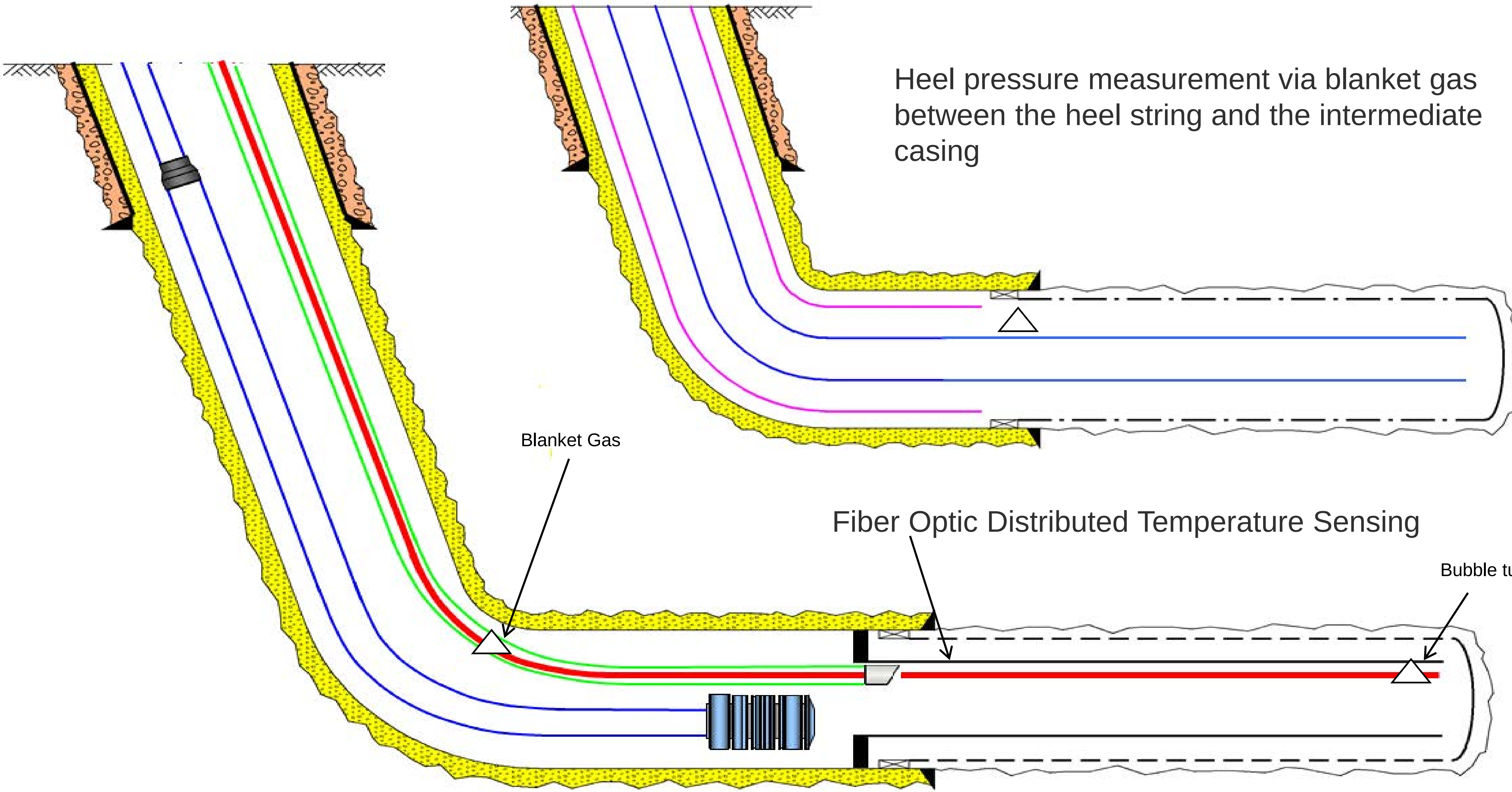
- Original gas lift completions have been converted to artificial lift via Electric Submersible Pumps (ESP) in most SAGD producers to allow production at lower steam chamber pressures.
  - 6 wells currently remain on gas lift production
- ESPs installed in 123 SAGD wells:
  - Pump performance (at Dec 31, 2019):
    - Average Run Time: 617 days
    - Mean Time to Failure (cumulative): 963 days
    - Mean Time to Failure change (Dec 2018 – Dec 2019): +5%
  - Operating temperatures have reached 215ºC
  - Pumps typically operate at pressures between 1,000 and 1,500 kPa (Producer)
  - Fluid production rates range from 75 – 1,100 m^3/d
- Active member of ESP Reliability Information and Failure Tracking System JIP
- ESPs and PCP use Variable Frequency Drive (VFD) to control pump speed and production rates.

SAGD Instrumentation



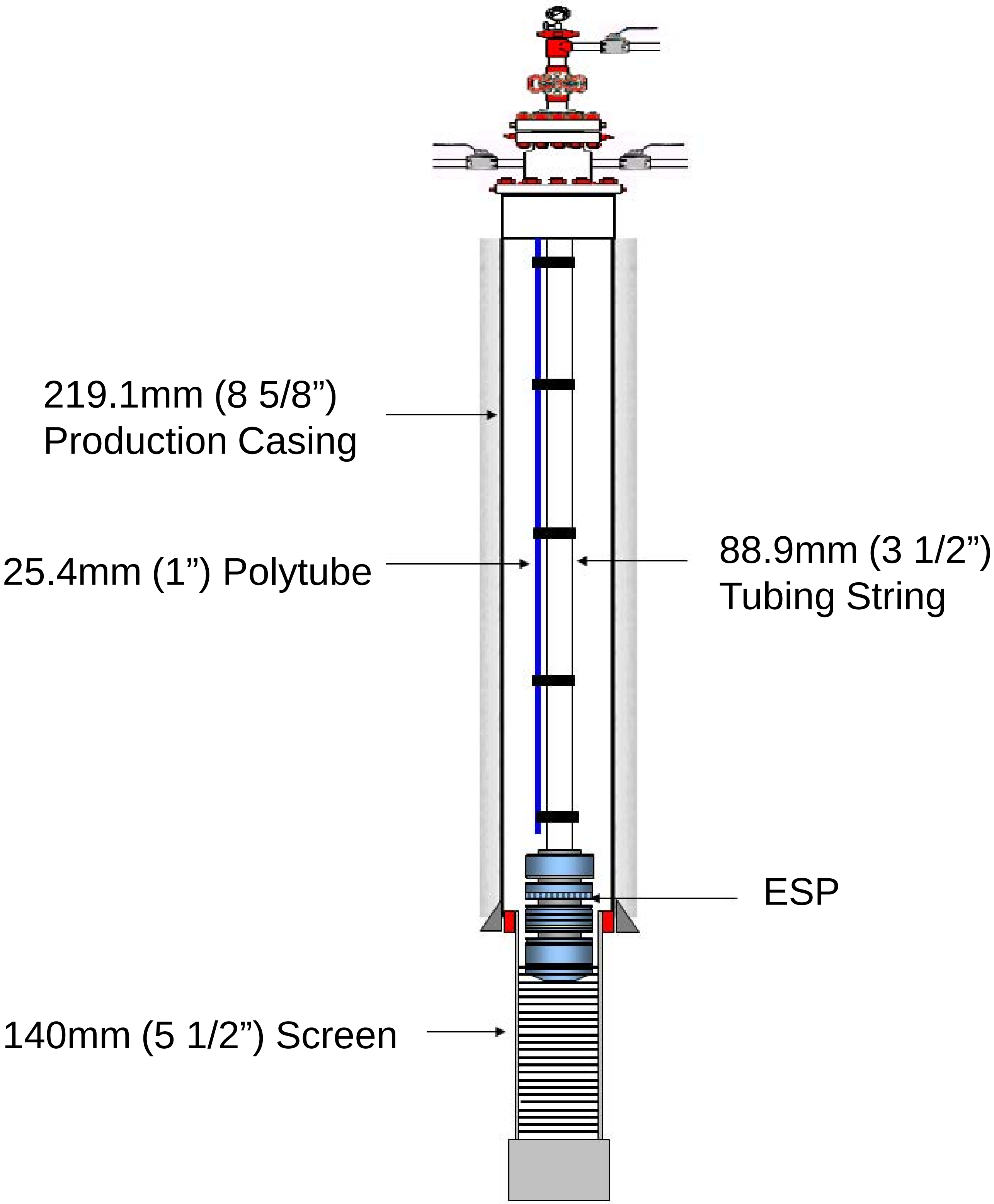
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

Alternate SAGD Instrumentation



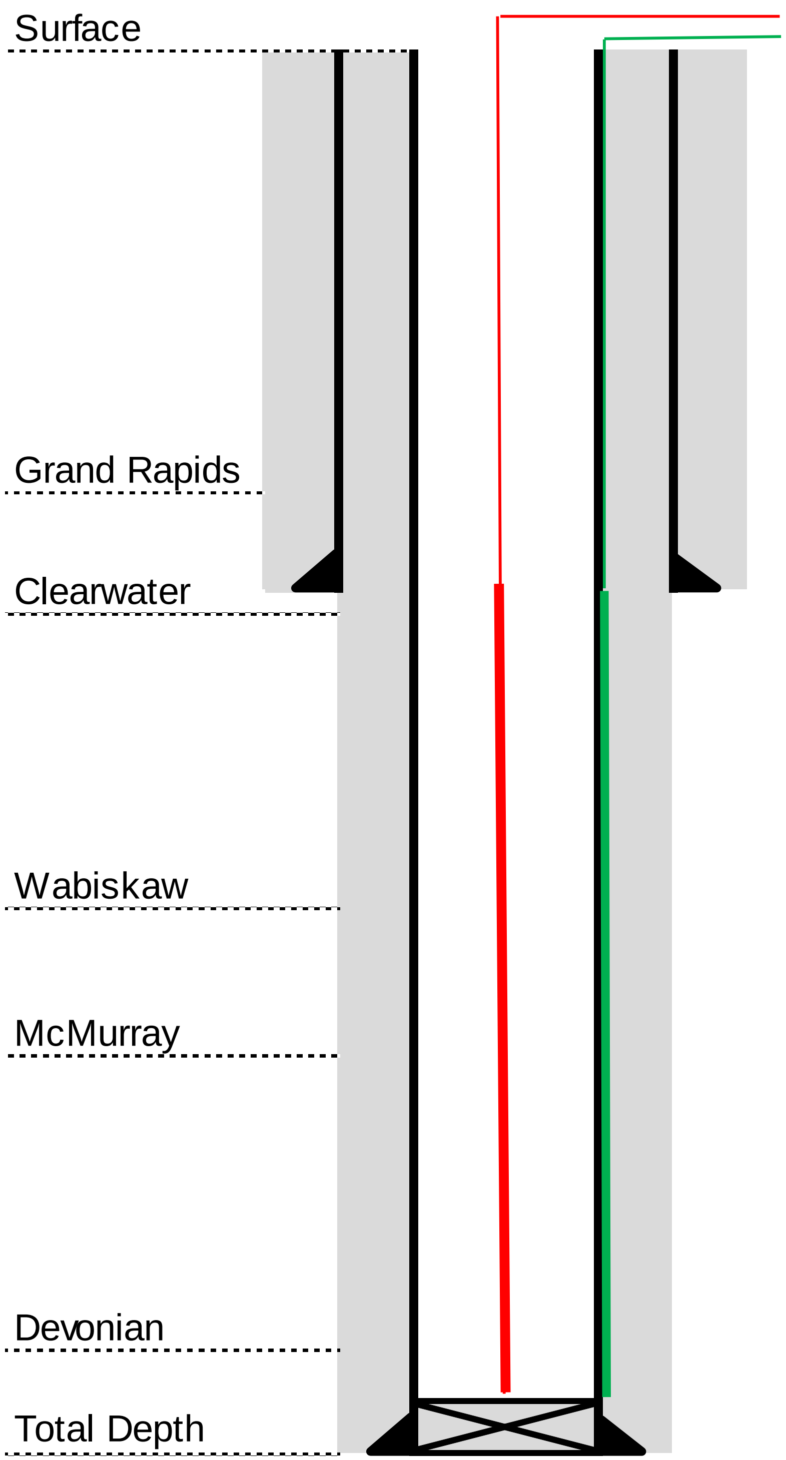
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

Typical Water Source Well



- ESP intake landed above the top of the water formation
- 18.3mm probe run through polytube and landed above the ESP
  - Monitors water level in casing

Current Observation Well Design and Operation



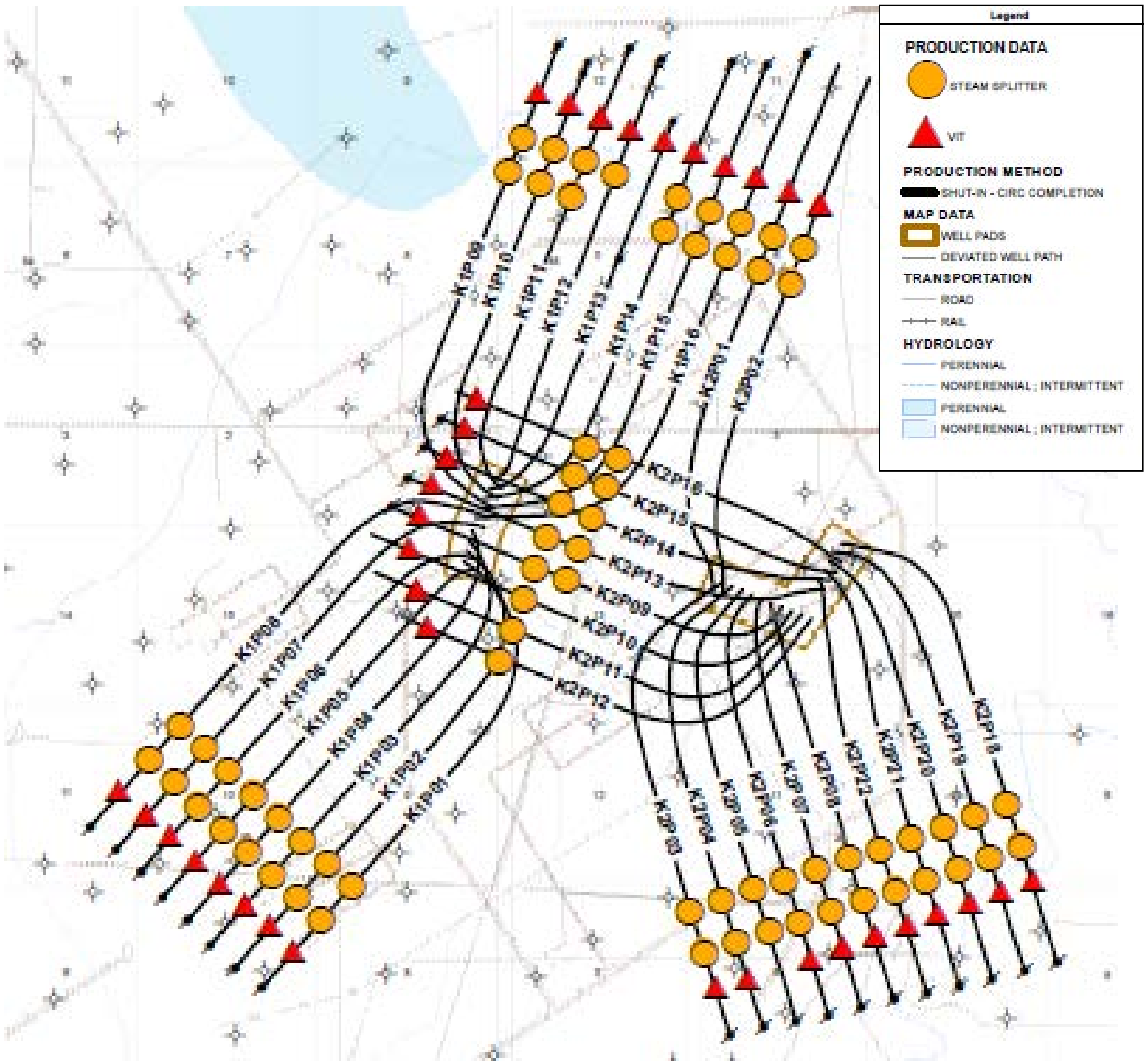
- Cement with Thermal 40 EXP cement
  - Vibrating wire piezometer sensors (green) are strapped outside the production casing providing pressure and temperature measurements
  - Thermocouple strings (red) provide temperature measurements
- Run a CBL on well with pressure pass if required

Drilling and Completions, Artificial Lift and Instrumentation

Subsection 3.1.1 (3,4,5)

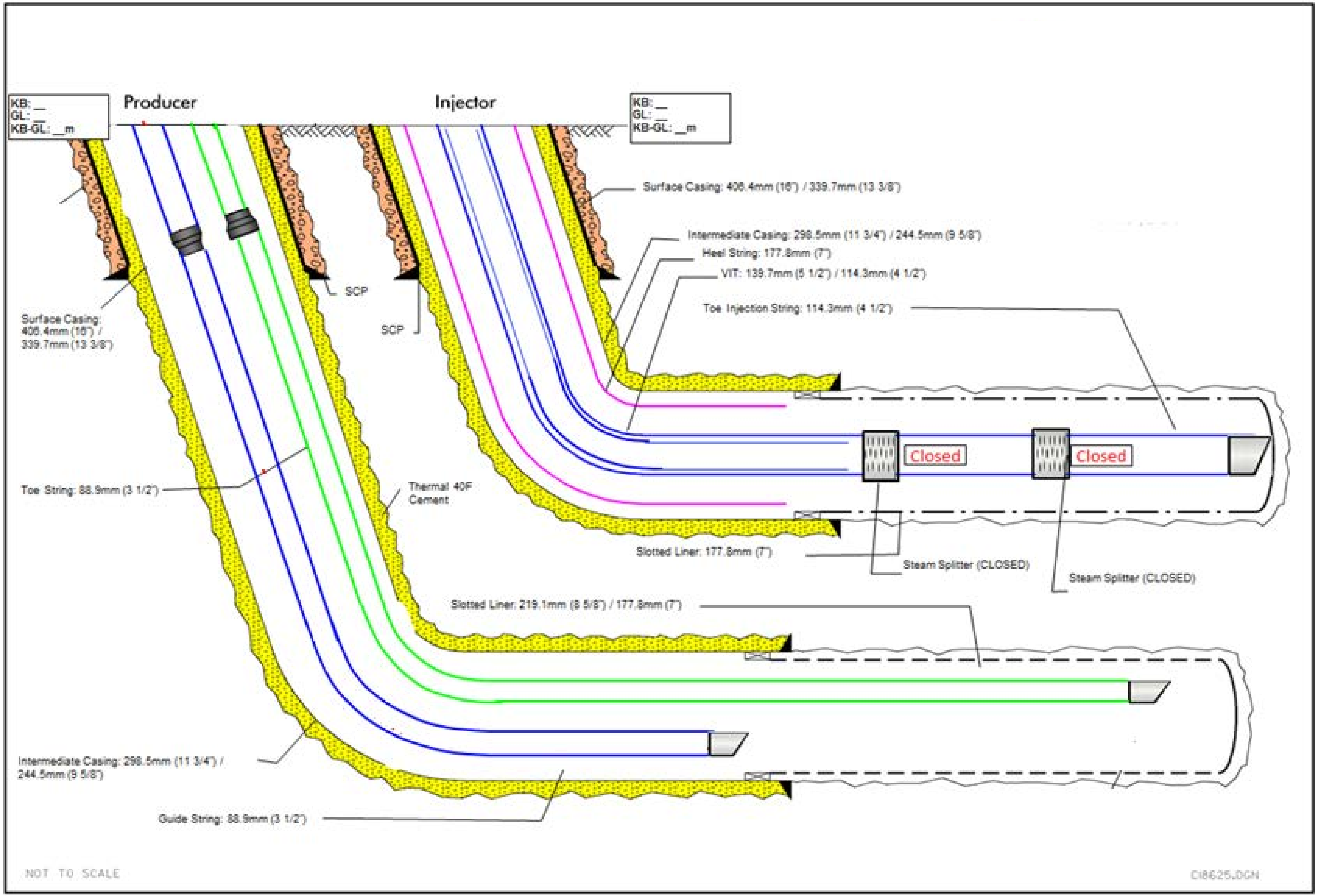
Kinosis

K1A Well Pair Completions Map as of Dec 31, 2019

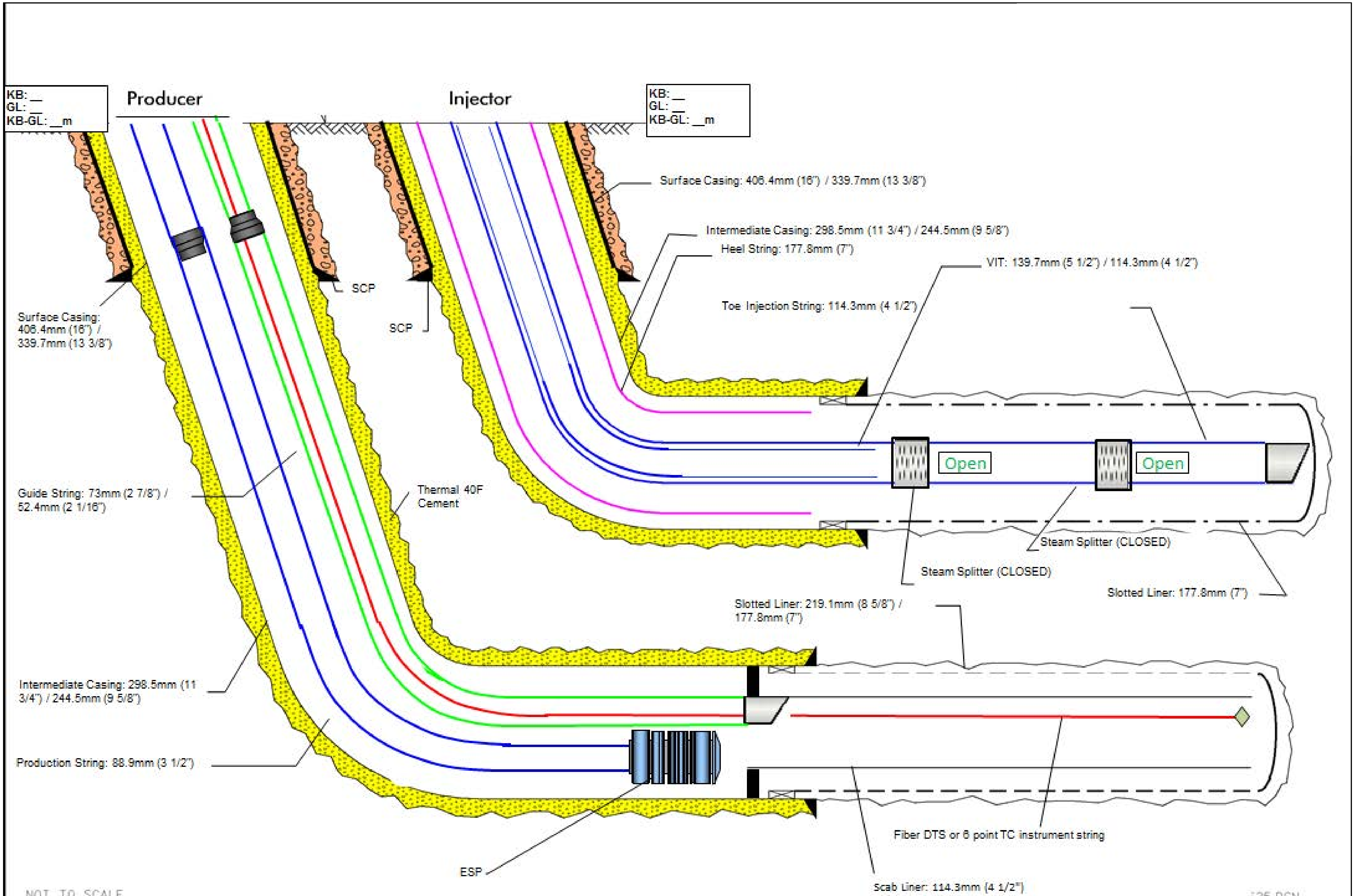


- On July 15, 2015 a line rupture was discovered on the K1A produced emulsion line tie-back to Long Lake CPF.
  - Operations of both the remote steam generation facility (SGF) and well pairs at K1A were subsequently ceased and remain down.
- Status of wells as of Dec 2019:
  - 36 well pairs remain suspended, however are equipped for circulation.

Typical K1A Completion Schematic Circulation



Typical K1A Completion Schematic SAGD

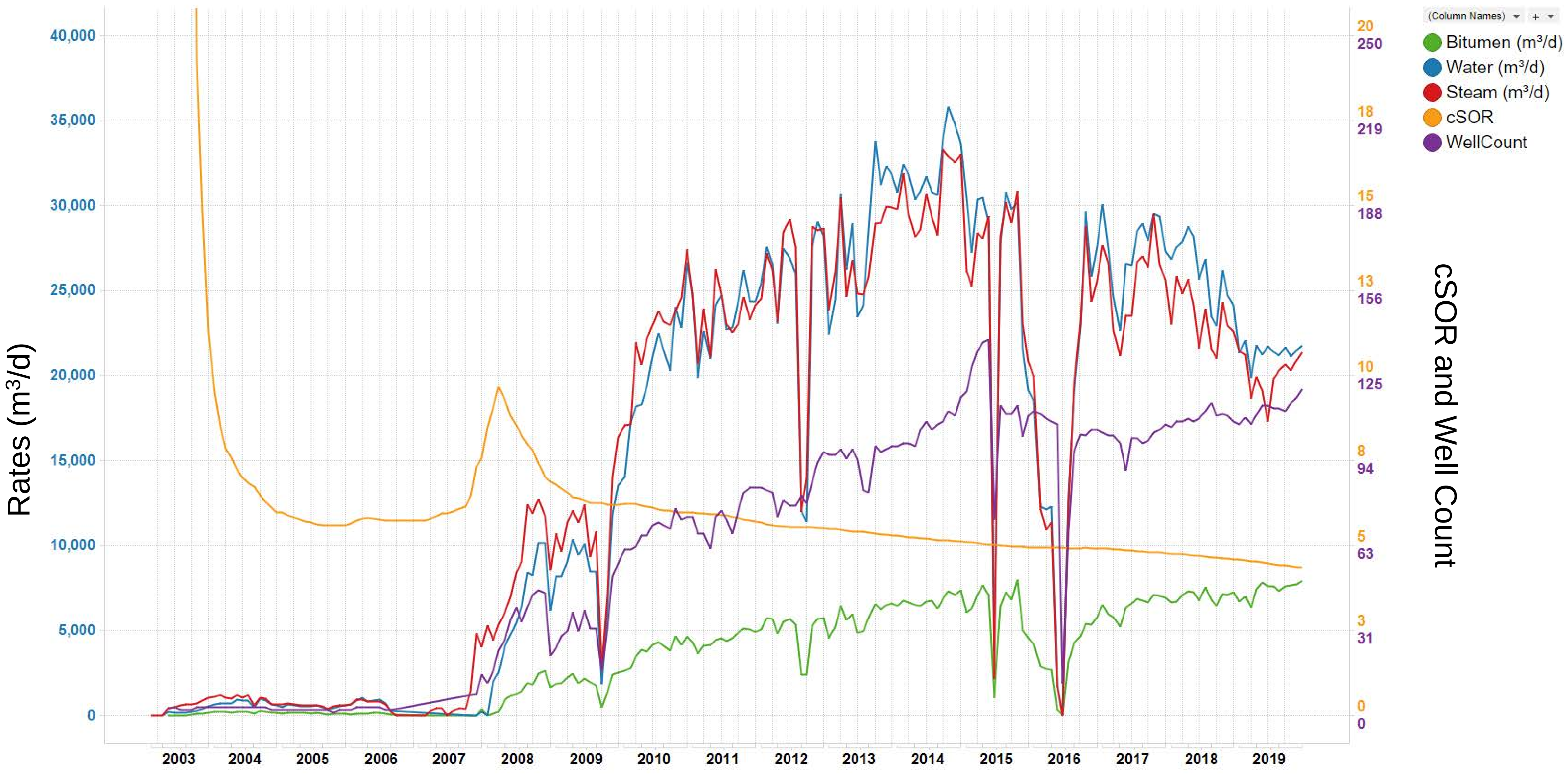


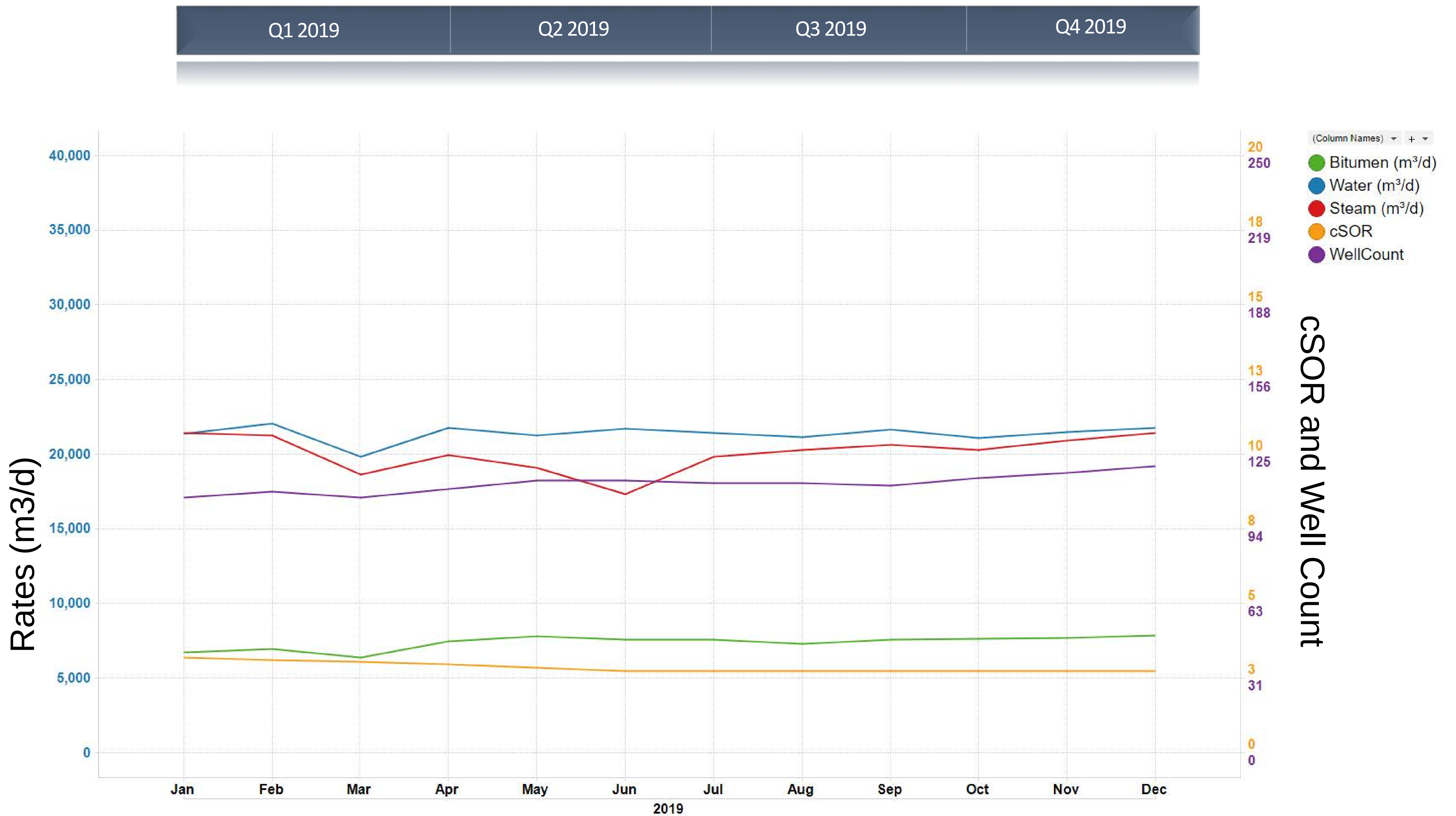
Scheme Performance
Subsection 3.1.1 (7)
Long Lake and Kinosis

Long Lake 2019 Performance

- Commercial SAGD:
  - Long Lake: 15 pads,121 well pairs + 31 infills; 123 active producing wells at year end
  - LLSW: 3 pads, 32 well pairs; 0 active producing wells at year end
  - K1A: 2 pads, 37 well pairs; 0 active producing wells at year end
- Strong, steady performance exhibited throughout the year
  - Highest annual average production 46,326 bbl/d with lowest SOR of 2.8

Scheme Performance
Field Level




Q1 2019
Q2 2019
Q3 2019
Q4 2019
Rates (m3/d)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
2019
20
250
18
219
15
188
13
156
10
125
8
94
5
63
3
31
0
0
cSOR and Well Count
(Column Names)
Bitumen (m³/d)
Water (m³/d)
Steam (m³/d)
cSOR
WellCount

Scheme Performance
Recoverable Bitumen

Pad	Well Count	Cumulative Production, YE 2019 (e6m3)	EUR (e6m3)	EBIP (e6m3)	SBIP (e6m3)	EBIP		SBIP	
						Current RF	Estimated Ultimate RF	Current RF	Estimated Ultimate RF
LL-001*	5	1.4	1.9	2.7	3.3	53%	70%	43%	56%
LL-002NE	6	0.9	1.1	2.5	3.2	37%	43%	29%	35%
LL-002SE	5	0.3	0.3	1.1	1.5	28%	28%	21%	21%
LL-003*	10	1.6	1.9	3.2	4.1	48%	60%	38%	47%
LL-004	2	0.1	0.1	0.1	0.2	94%	94%	61%	61%
LL-005*	10	1.9	2.2	3.5	4.0	56%	64%	49%	56%
LL-006N*	9	1.0	1.3	3.6	4.3	28%	37%	24%	31%
LL-006W*	9	1.0	1.2	2.3	2.8	42%	52%	34%	43%
LL-007E	7	0.9	1.0	2.1	2.7	43%	49%	34%	38%
LL-007N*	9	2.7	3.4	4.0	4.4	69%	85%	62%	77%
LL-008*	10	2.0	2.5	4.4	5.1	44%	56%	38%	49%
LL-009NE	5	0.3	0.3	1.2	1.9	23%	25%	14%	15%
LL-009W	5	0.5	0.6	1.7	2.0	31%	38%	27%	33%
LL-010N	8	0.4	0.5	2.7	3.7	15%	20%	11%	14%
LL-010W	5	1.0	1.6	2.6	3.2	40%	61%	33%	50%
LL-011	10	1.7	1.9	2.6	3.2	64%	74%	52%	60%
LL-012	9	1.2	2.1	3.6	4.8	35%	58%	26%	44%
LL-013*	15	1.6	2.5	3.8	4.9	42%	65%	33%	51%
LL-014/15E	6	0.4	0.6	1.3	1.9	34%	44%	24%	31%
LL-014N	3	0.4	0.9	1.4	1.8	28%	60%	23%	50%
LL-015S	2	0.2	0.4	0.8	0.9	23%	45%	21%	42%
LL-016S	7	0.0	2.0	3.6	4.5	0%	55%	0%	44%
LL-016W	5	0.0	1.5	2.7	3.0	0%	56%	0%	51%
LL-017	8	0.0	2.5	4.2	6.0	0%	60%	0%	42%
LL-018N	9	0.0	3.1	6.0	6.6	0%	51%	0%	46%
LL-018W	3	0.0	1.0	1.6	1.8	0%	62%	0%	54%
K1A-A	9	0.0	2.5	4.6	5.6	0%	54%	0%	45%
K1A-B	8	0.0	2.2	3.9	4.5	0%	57%	0%	49%
K1A-C	8	0.1	3.0	5.1	6.5	2%	59%	2%	46%
K1A-D	11	0.0	3.0	5.6	6.7	1%	54%	1%	45%
Total	**218**	**21.9**	**49.1**	**88.5**	**109.1**	**25%**	55%	20%	45%

* Includes infill producers

Scheme Performance
Maximum Operating Pressures (MOP)

Field	Pad	Maximum (Reservoir) Operating Pressure (kPag)
LLK	1	2,950
LLK	2NE	2,950
LLK	2SE	2,950
LLK	3	2,950
LLK	4	2,950
LLK	4P5, 4P6	2,500
LLK	5	2,950
LLK	5P5	2,950
LLK	9NE	2,950
LLK	6N	2,950
LLK	6W	2,950
LLK	7N	2,950
LLK	7E	2,950
LLK	8	2,950
LLK	9W	2,950
LLK	10N	2,950
LLK	10W	2,950
LLK	11	2,950
LLK	12	2,250
LLK	13	2,250
LLK	14	1,600*
LLK	15	1,600*
LLSW	16S	2,750
LLSW	16W	2,567
LLSW	17	2,586
LLSW	18N	2,586
LLSW	18W	2,666
K1A	A	2,000
K1A	B	3,000
K1A	C	3,000
K1A	D	3,000

* Tapered MOP

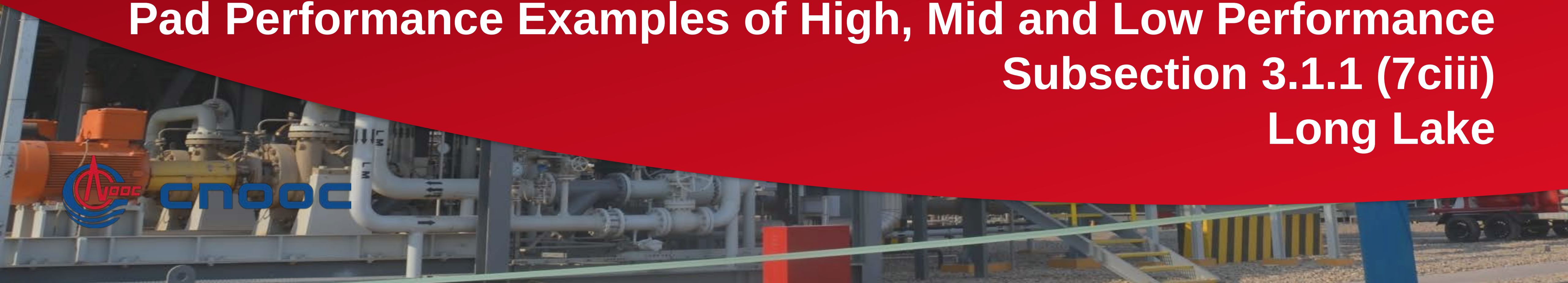
Scheme Performance
Methodology for Predicting Performance

- Future performance predictions are developed for each well pair using a combination of multiple forecasting tools:
  - Analytical tools (modified Butler models)
  - Simulation
  - Analogue data
- Probabilistic forecasts for each well pair are combined and aggregated to a field level forecast.
- Constraints and field assumptions are applied:
  - Plant constraints (steam, bitumen, water)
  - Planned & unplanned downtime:
    - Plant turnarounds
    - Steam outages
    - Well downtime (ESP failures, etc.)

Scheme Performance
Injection Steam Quality

- Injection steam quality is estimated at 95% at the wellhead.
- To validate, a HYSYS model of the steam injection header system from the CPF to Pads 12/13 has been run, based on the following parameters:
  - HP steam at the CPF HP separator at 9,000 kPa and 100% quality;
  - HP steam at the Pad 12/13 wellheads at 4,500 kPa;
  - No driplegs/steam traps modeled in HYSYS – conservative.
- As per the HYSYS model, HP steam quality at the injector wellhead is 92% (assuming no driplegs/steam traps).
- The steam injection header system operates with driplegs/steam traps, therefore estimate of 95% steam quality at the wellhead is reasonable. Steam quality will be affected by injection header length.
- No impact is expected on the bitumen recovery mechanism due to steam quality.

Pad Performance Examples of High, Mid and Low Performance
Subsection 3.1.1 (7ciii)
Long Lake

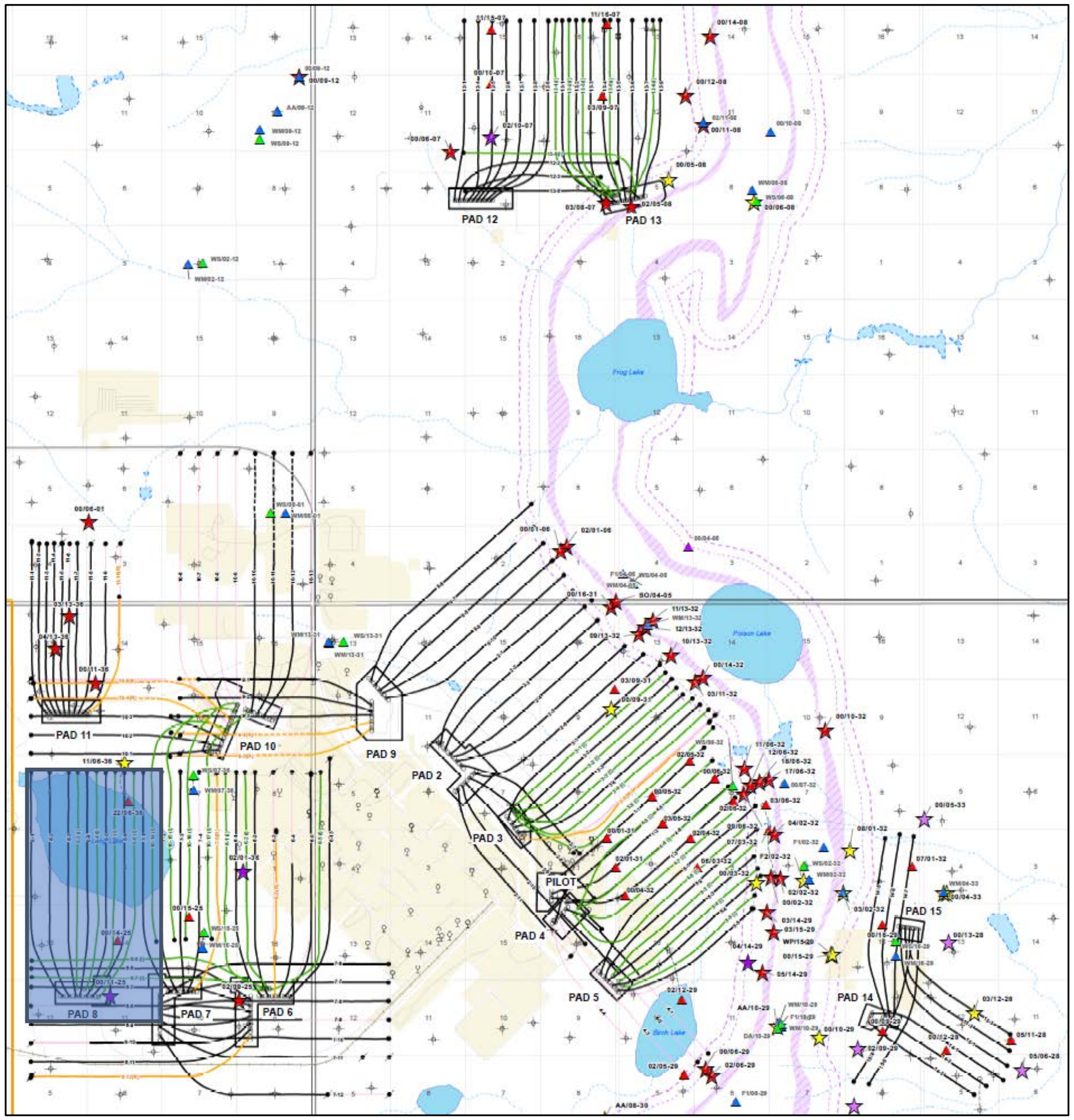


Examples of High, Mid, Low Recovery
High level comparison

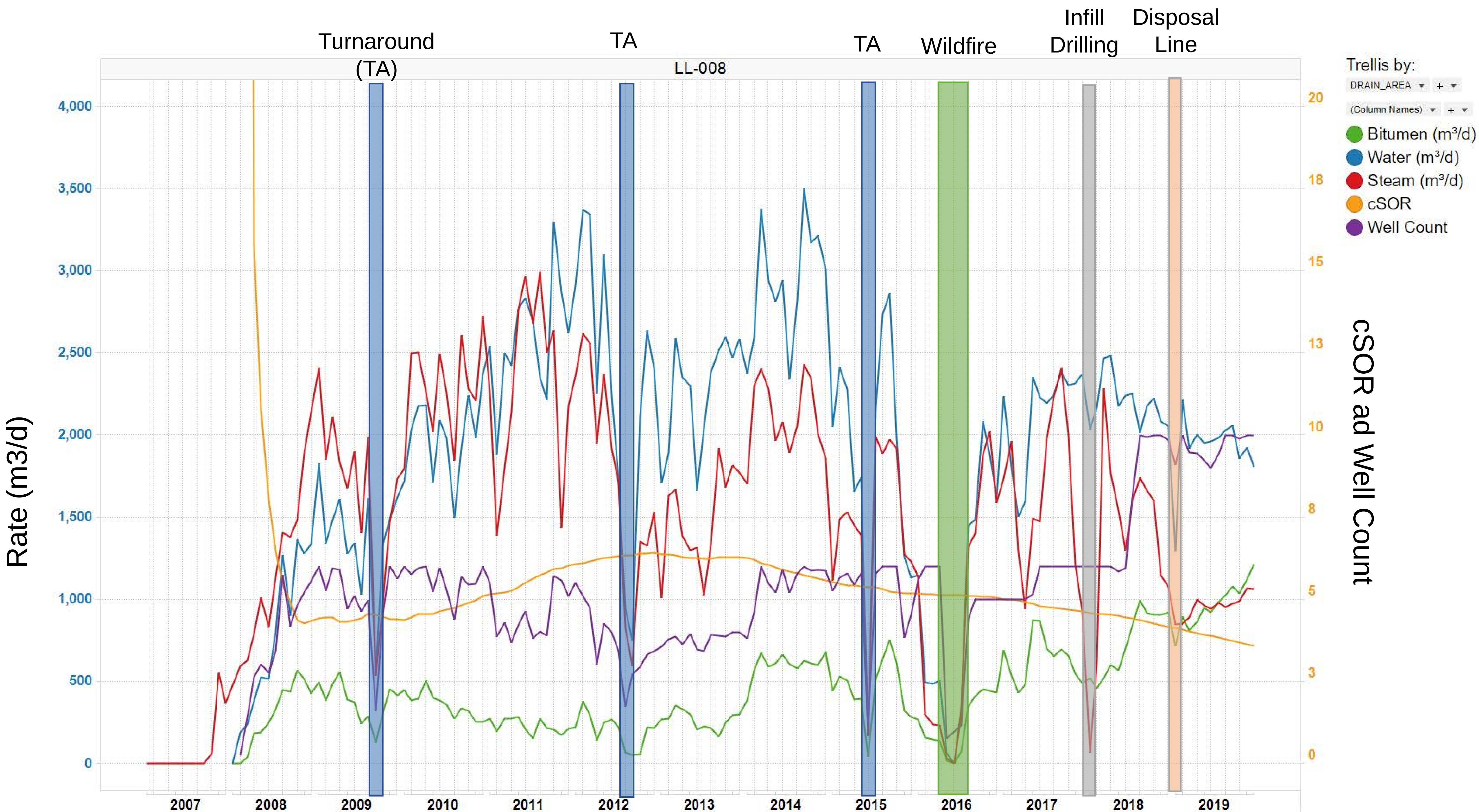
	Resource Quality (mapped average)	Performance	Operating Strategy
Pad 8 *High*	EBIP thickness: 31m S_{we}: 0.39	Well Peak Rate: 308m^3/d Current Pad EBIP RF: 44%	Infills on production July 2018
Pad 14N *Mid*	EBIP thickness: 23 m S_{we}: 0.22	Well Peak Rate: 141m^3/d Current Pad EBIP RF: 28%	LLK sustaining pad, Tapered pressure strategy
Pad 10N *Low*	EBIP thickness: 13 m S_{we}: 0.25	Well Peak Rate: 92m^3/d Current Pad EBIP RF: 15%	Not operated consistently historically

Example of High Recovery
Pad 8

- 6 base well pairs, all equipped with ESPs
- Conversion to SAGD beginning Q1 2008
  - 8P03 ICD install Dec-2015
  - 8S06 shut-in April 2015
- Four infill wells commenced production in July 2018 contributing to increased drainage area oil rates and lower cSOR
  - 8P05INF ICD install Jul-2019
- Pad 8 is impacted by top water and has limited seismic data available due to surface lake
- YE 2019 EBIP RF is 44%

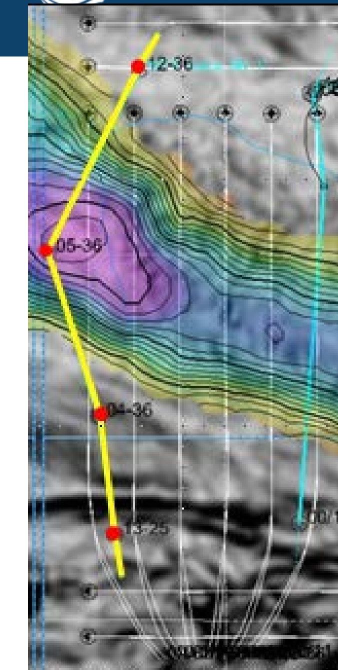


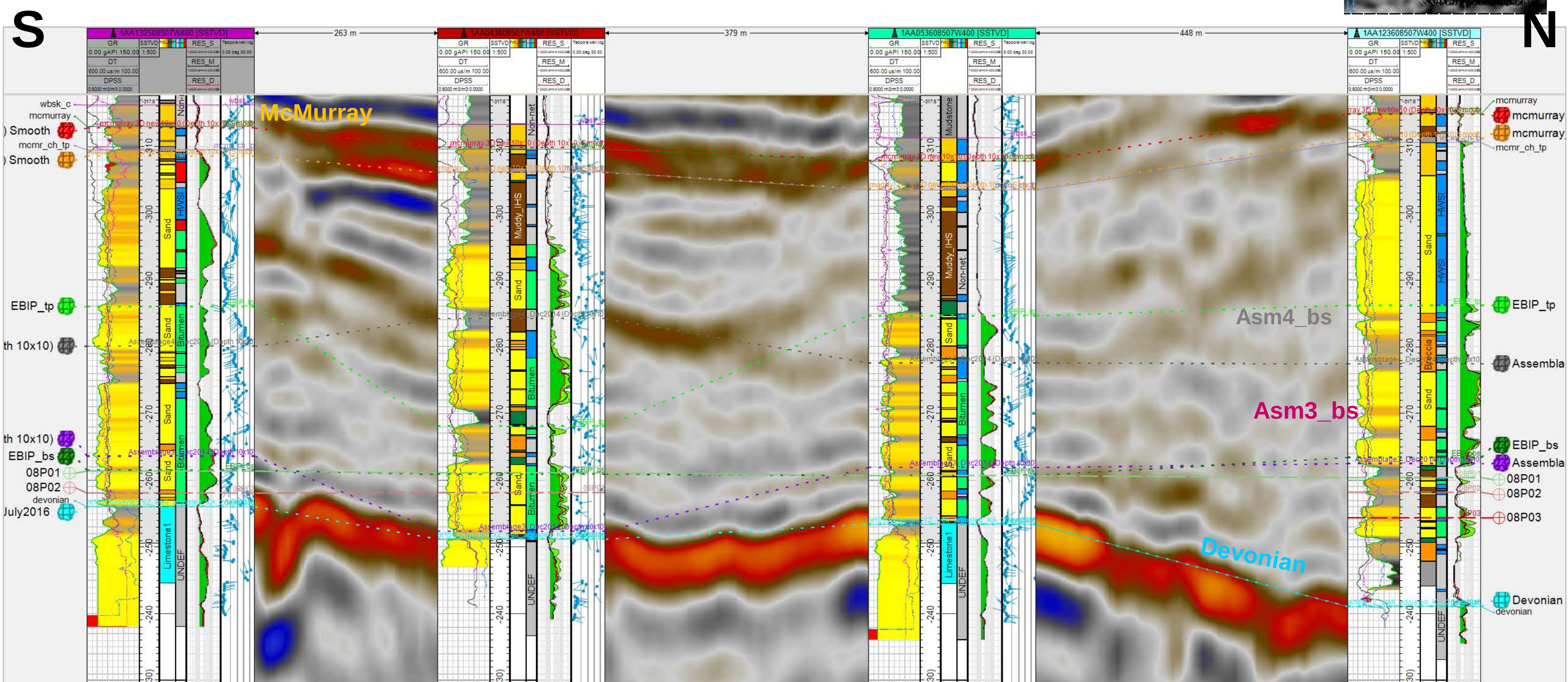
Example of High Recovery
Pad 8



Example of High Recovery
Pad 8 – Geology

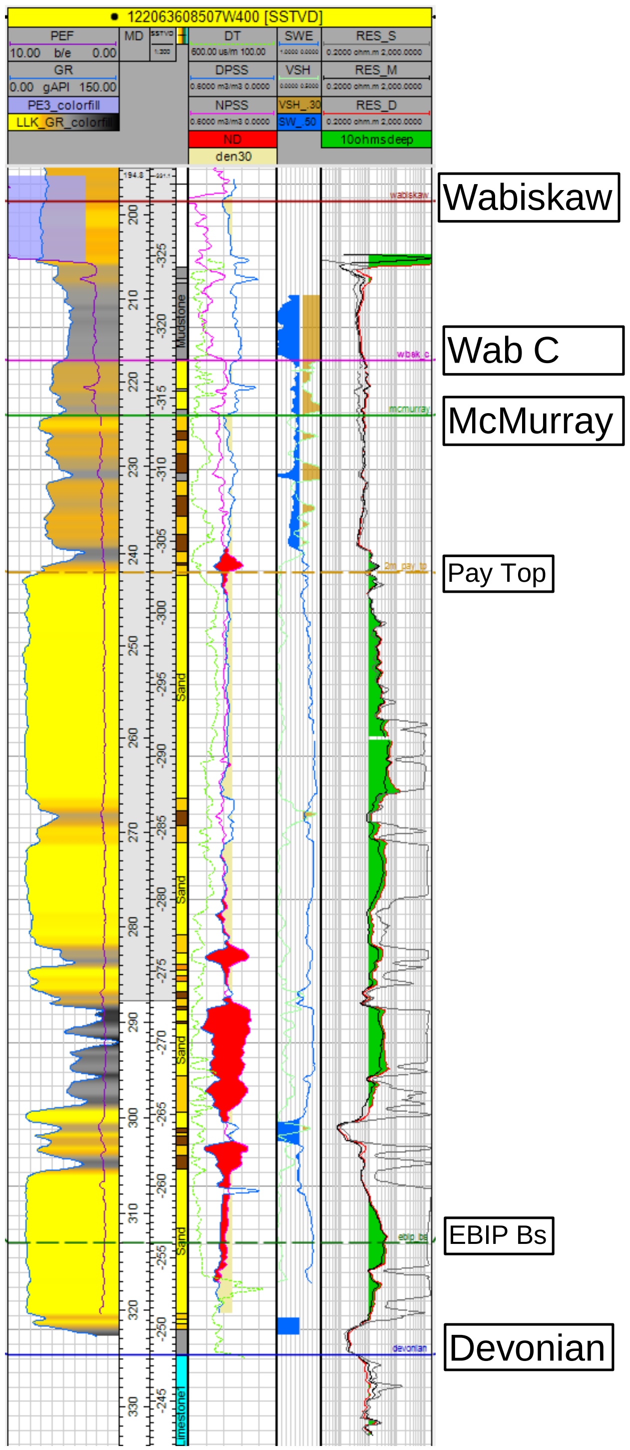
- Reservoir quality gets better from west to east on Pad 8
  - Regional G&G study helps on Devonian structure interpretation in the area with no or unreliable seismic data
  - Limited stranded pay below producers
  - Pad 8 toes are in connection with extensive water saturated intervals
  - Top water is truncated by the mudplug cutting across Pads 8 and 7N

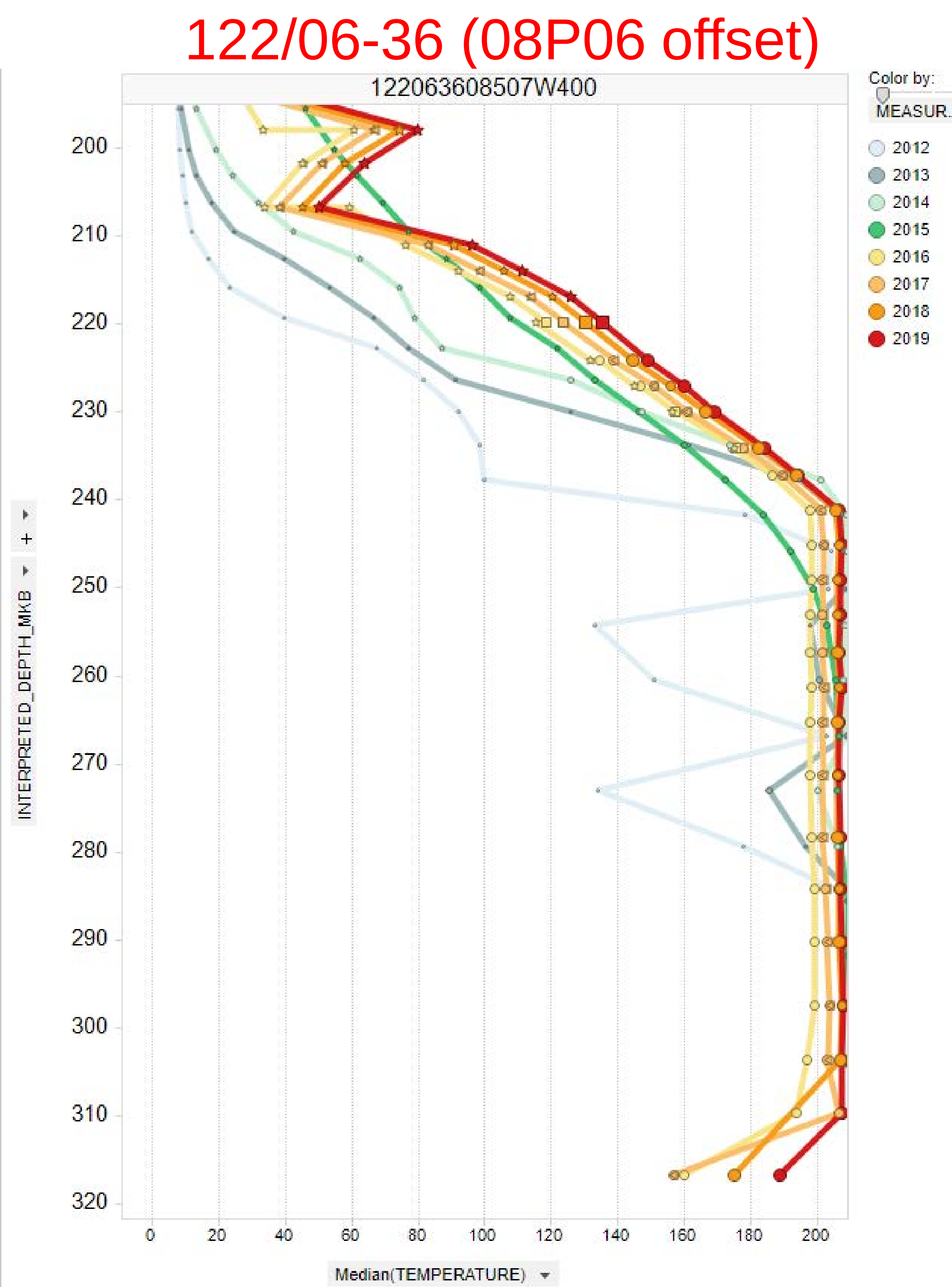


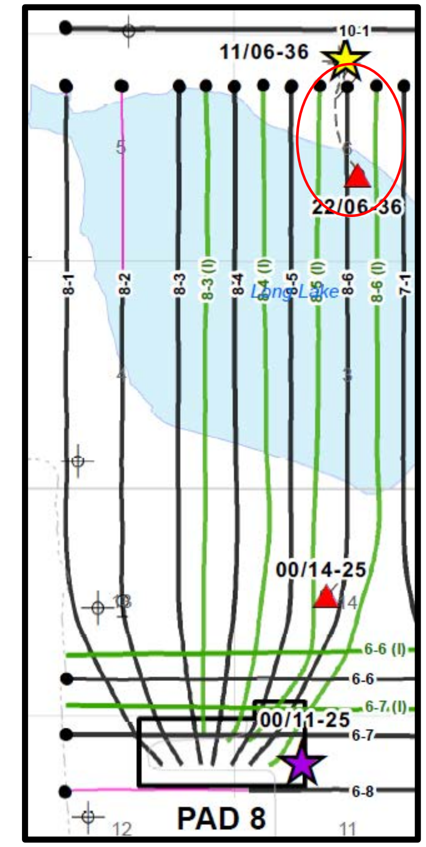


Example of High Recovery
Pad 8 – Monitoring

- 122/06-36
  - Deviated OBS well drilled to avoid the surface lake
  - Good quality reservoir
  - Observation wells show vertical steam chamber growth

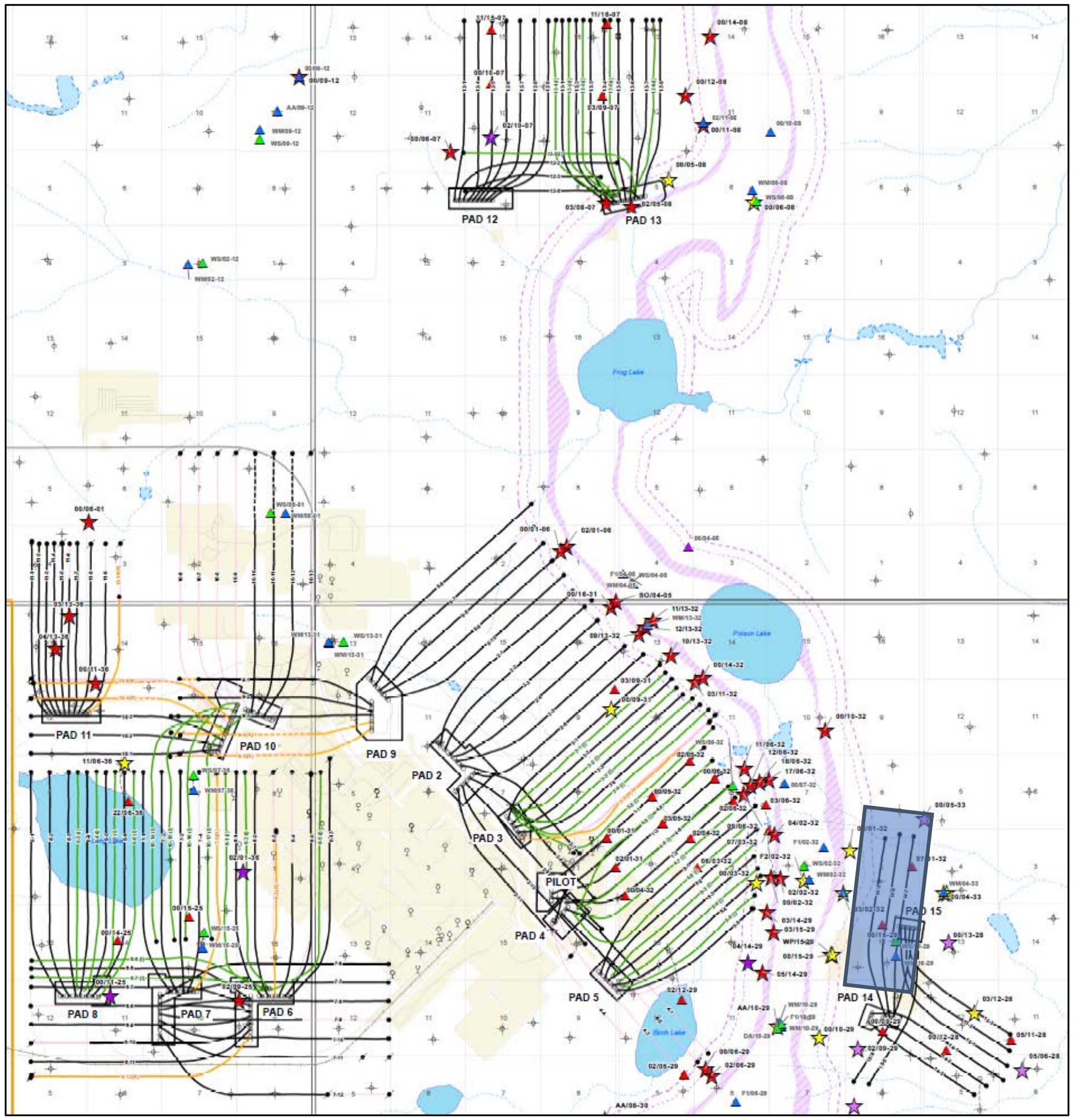




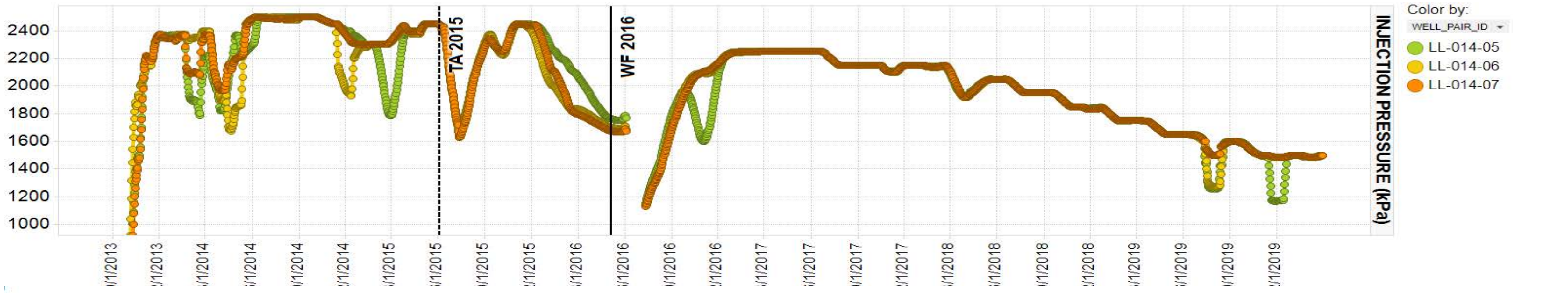


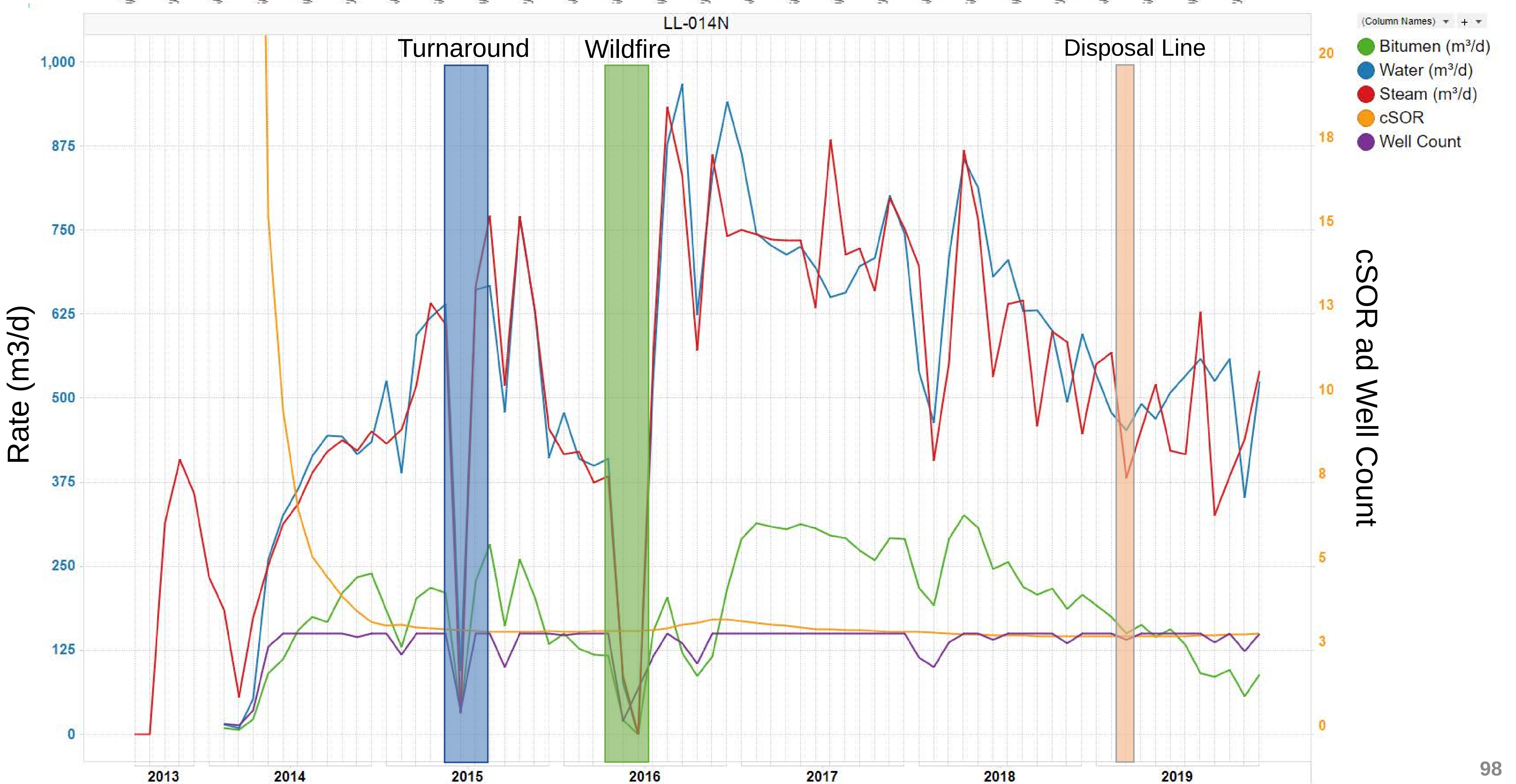
Example of Mid Recovery
Pad 14N

- Sustaining well pad, drainage area with 3 well pairs:
  - All wells equipped with ESPs
  - 75 m spacing
- First oil production Q1 2014
- Due to complex reservoir, pad is operated in accordance with tapered pressure schedule and at/below Q-channel pressure
- Tapered pressure has impacted performance in 2018-2019
- Evaluating infills and extension wells to further maximize resource recovery
- YE 2019 EBIP RF is 28%

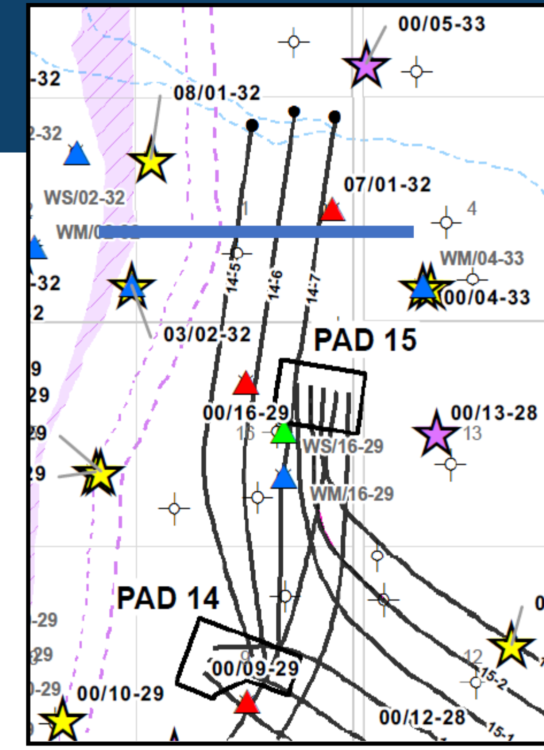


Example of Mid Recovery
Pad 14N

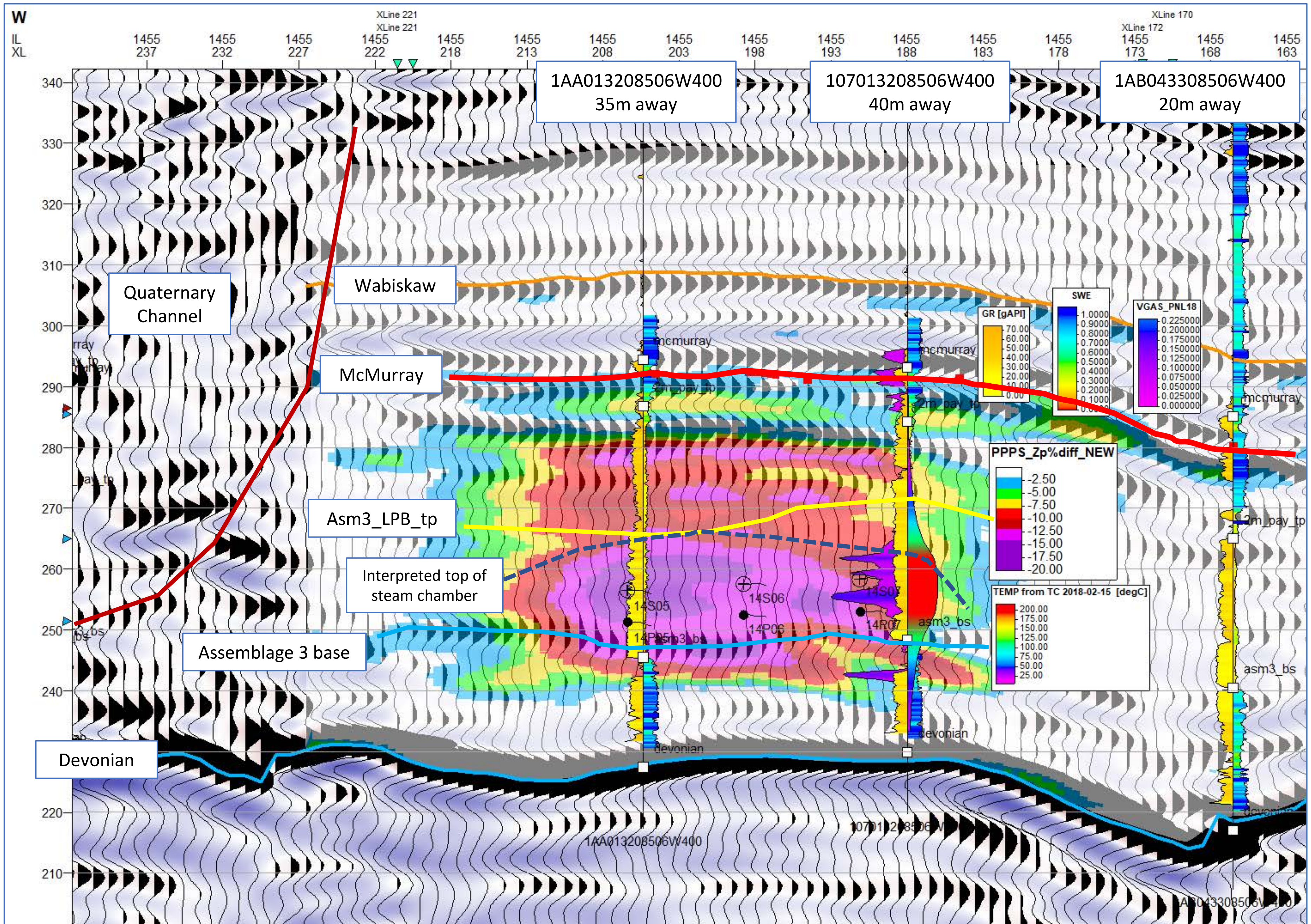




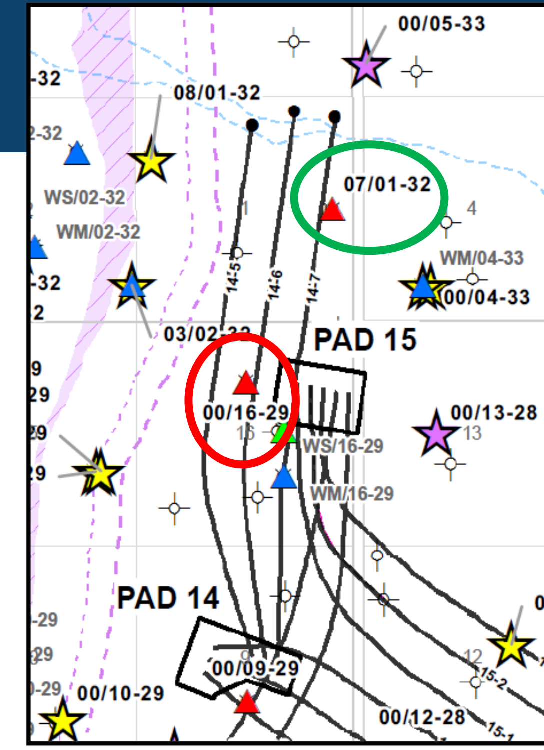
Example of Mid Recovery
Pad 14N - Geophysics



- 2018 4D seismic shows coalesced steam chambers corresponding to the high quality reservoir in the central portion of the drainage area

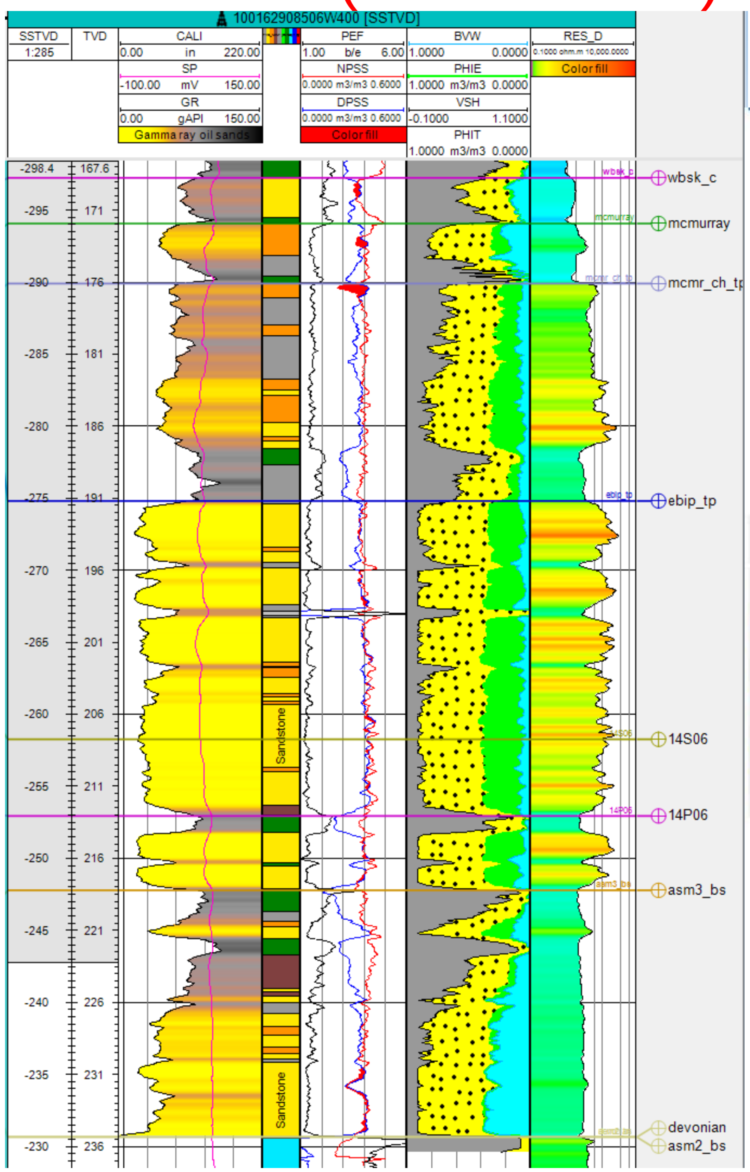


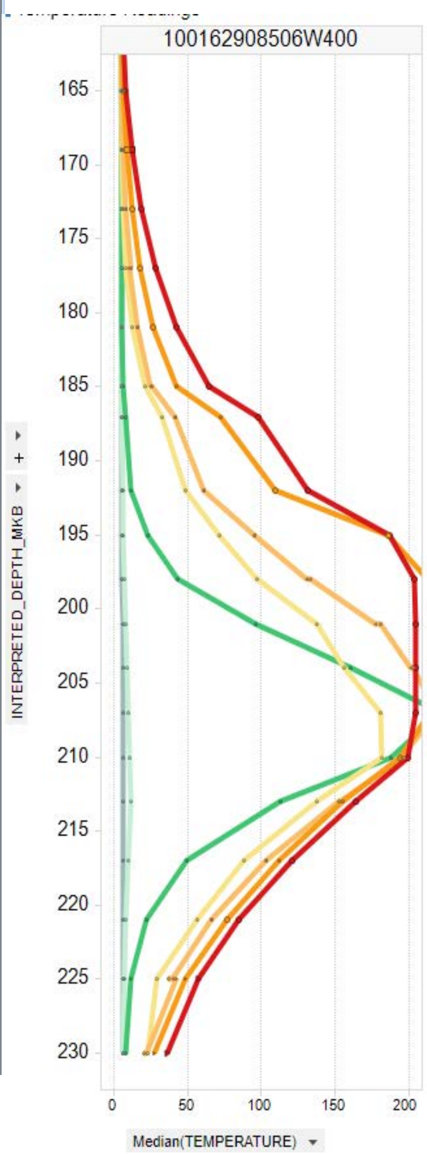
Example of Mid Recovery
Pad 14N - Geology



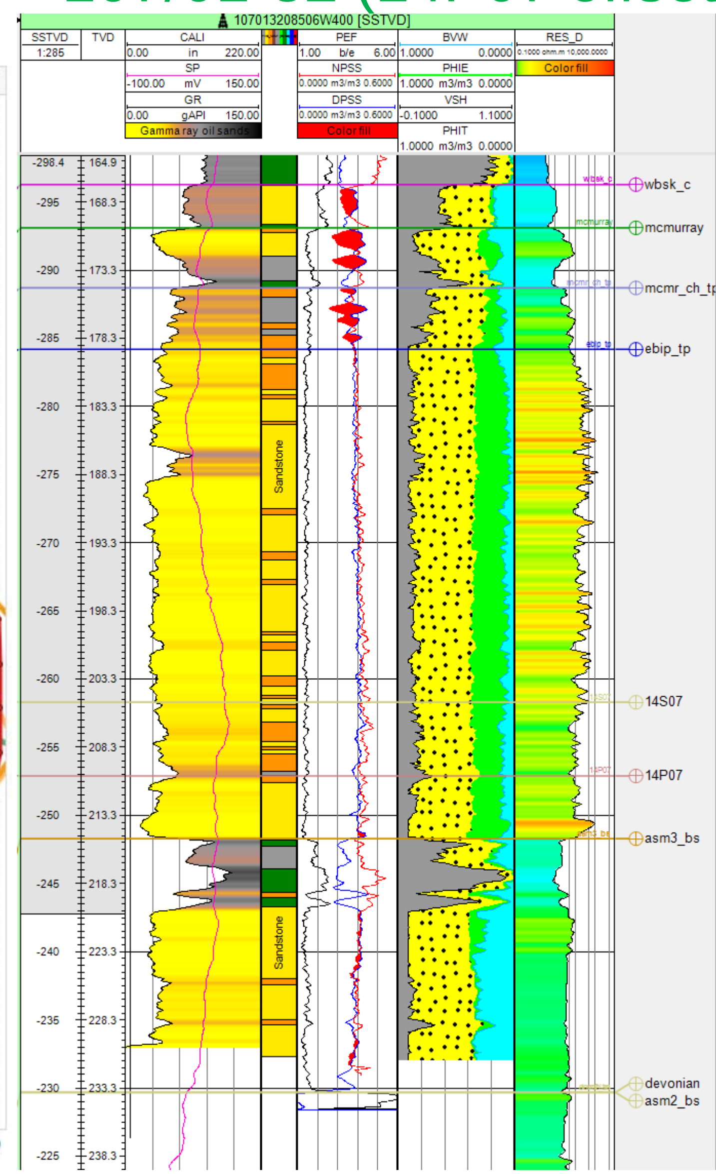
- Good quality reservoir, however temperature profiles in observation wells show vertical steam chamber growth impacted by local heterogeneity

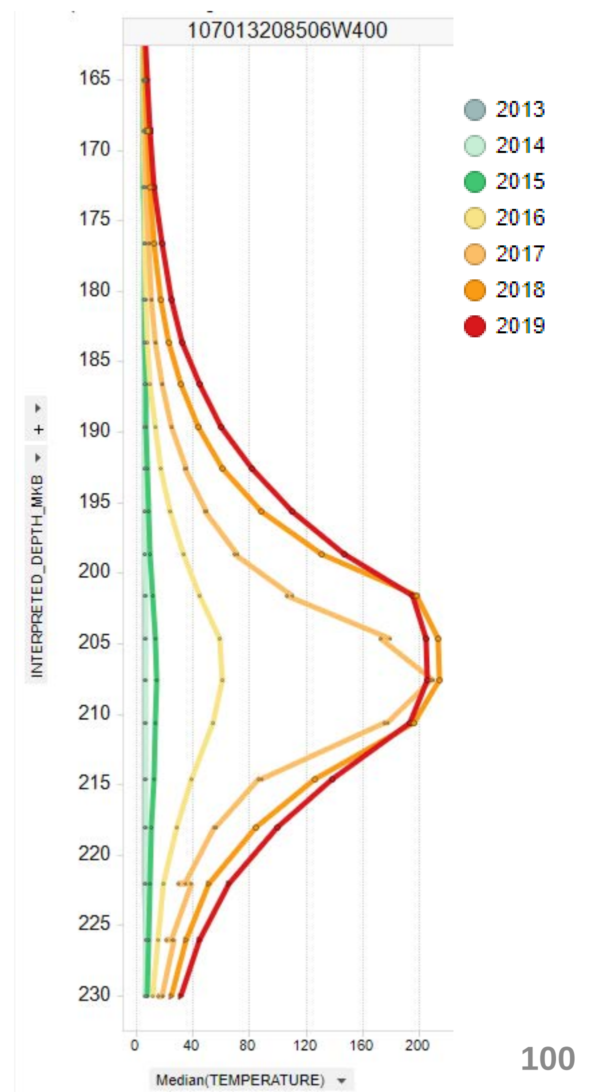
100/16-29 (14P06 offset)





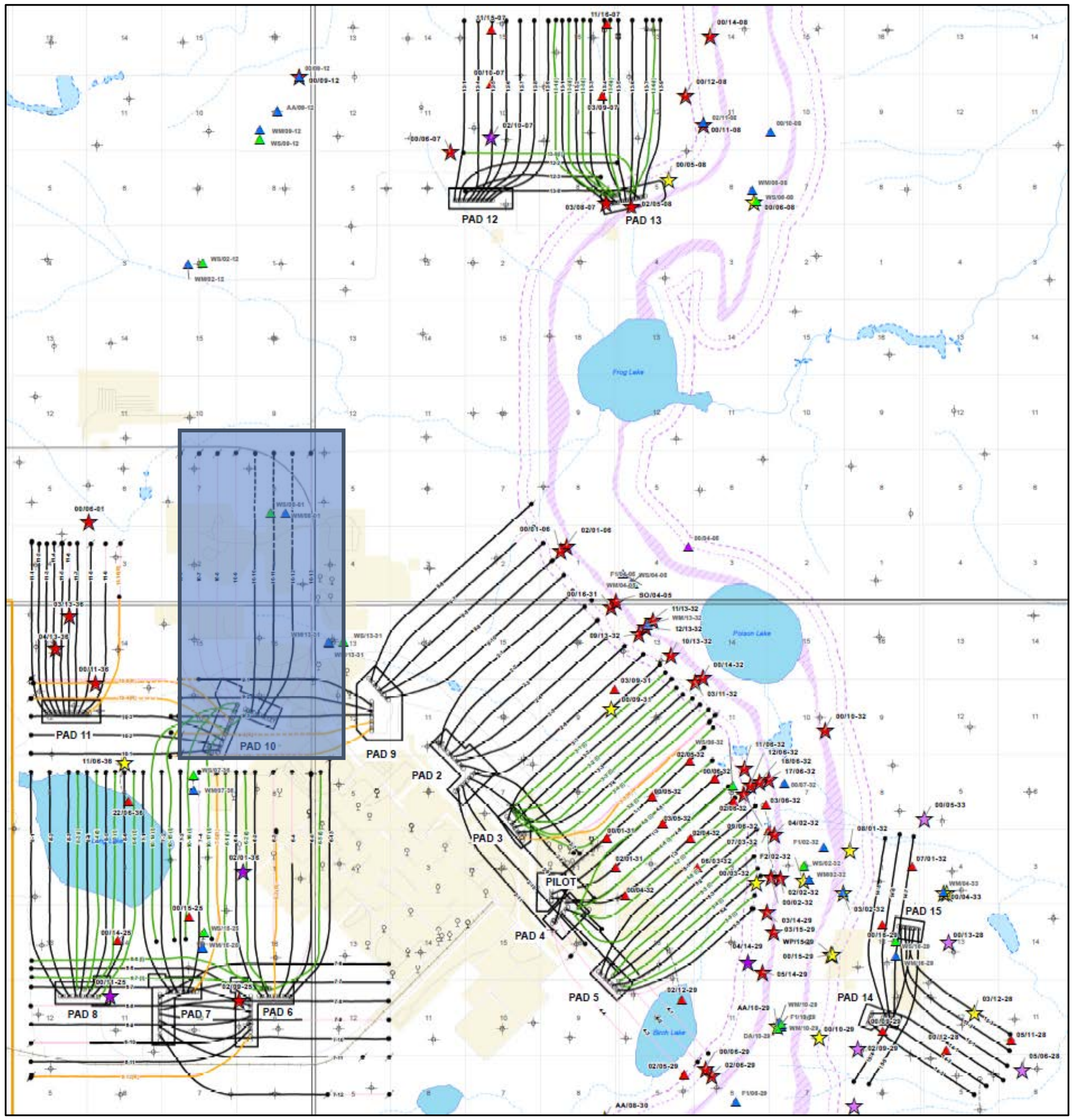
107/01-32 (14P07 offset)



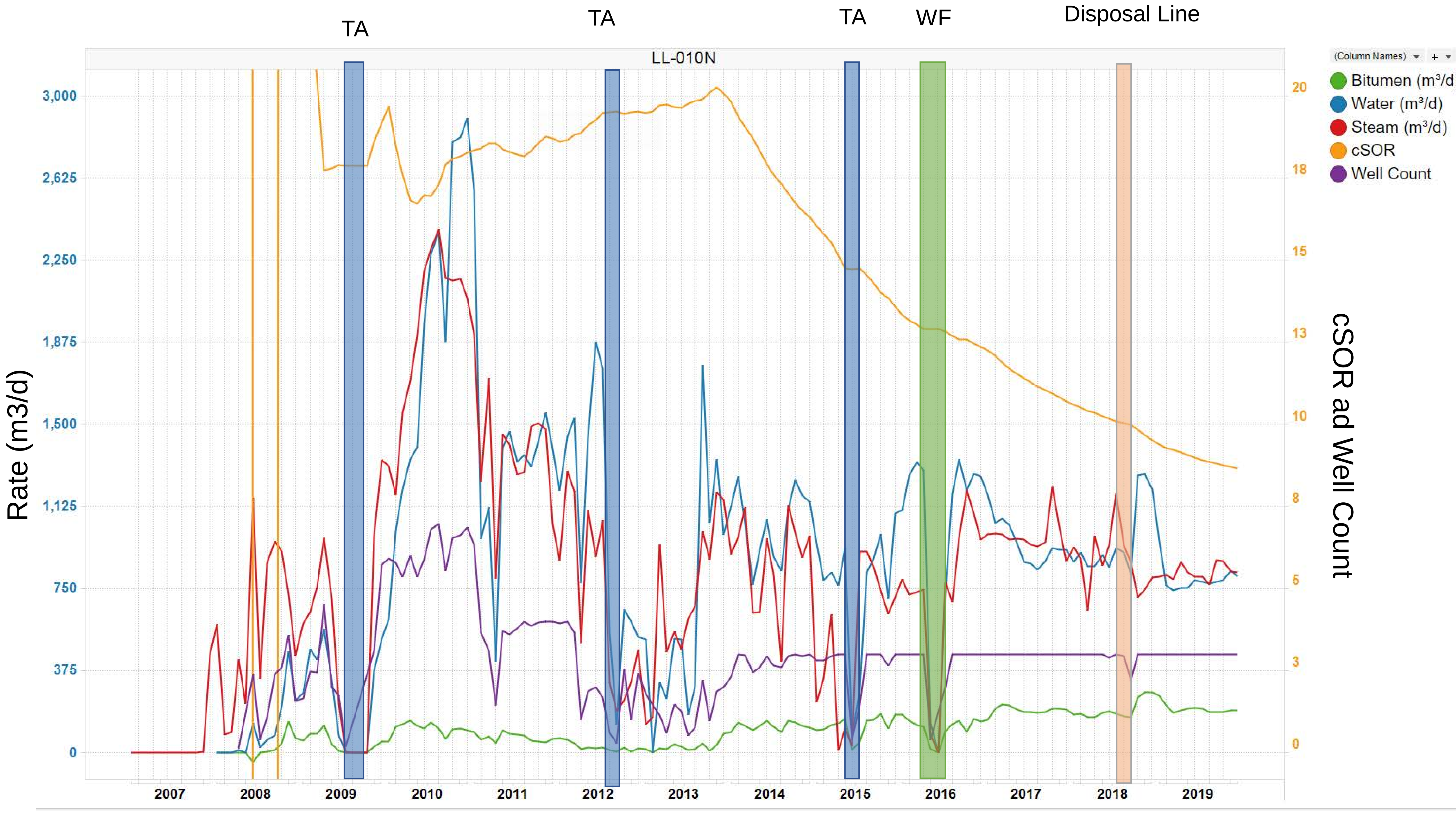


Example of Low Recovery
Pad 10N

- 8 well pairs:
  - 3 wells currently operational, on gas lift
  - 10P6-9 and 10P13 are long term shut in due to consistently poor performance; utilized surface equipment for 7N infills
- First oil production March 2010
- EBIP is generally very thin, <15m over most of the pad
  - long horizontal wells, pulled back in 2011 to focus on better reservoir
- Have had stable operation for remainder of wells resulting in stronger relative performance significantly decreasing cSOR
- Evaluating for infills & restarts of suspended wells in 2020
- 2019 YE EBIP RF 15%



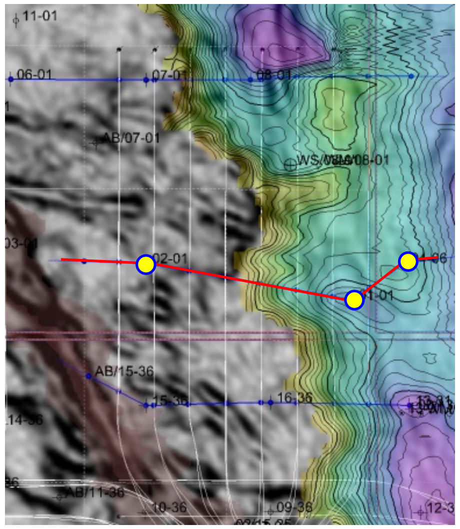
Example of Low Recovery
Pad 10N



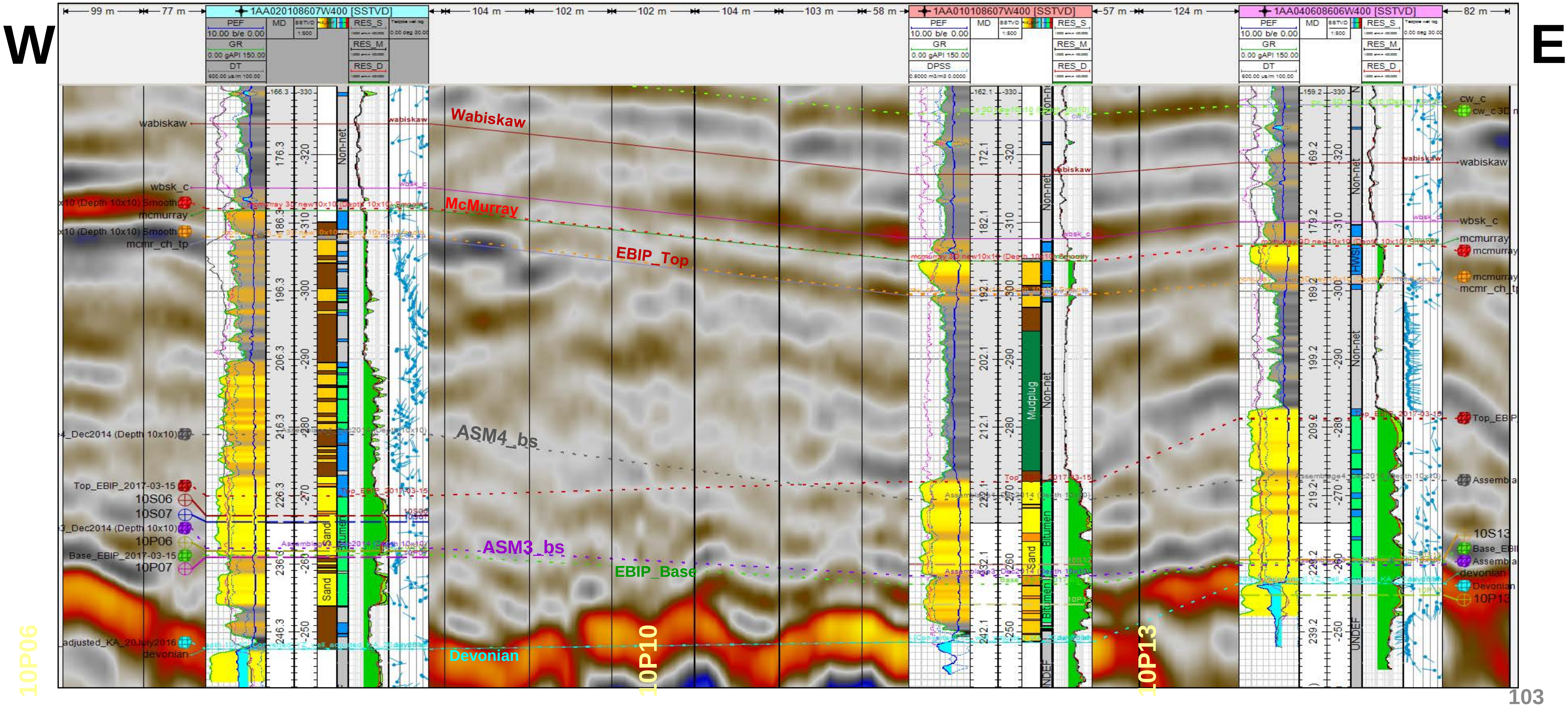
PAD 10N – X-section (W-E)
(across middle of wells)

cnooc

- Erosional Feature across western edge of pad and thick and wide mudplug along eastern edge of pad
- Upper McMurray (Assemblage 4) is part of the pointbar complex bounded by Erosional Feature in the west and thick and wide mudplug in the east
- Dominant dipping direction of IHS is to the east/northeast

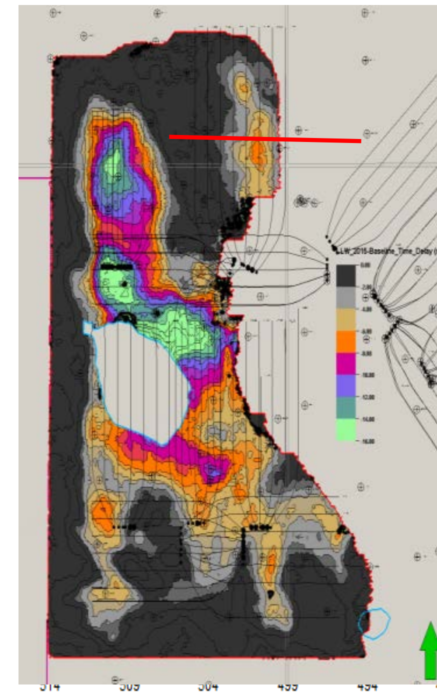


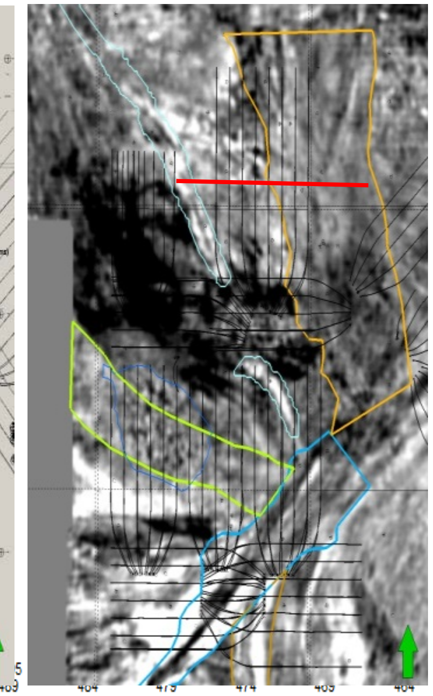
10N_W-E_xsec_Mids



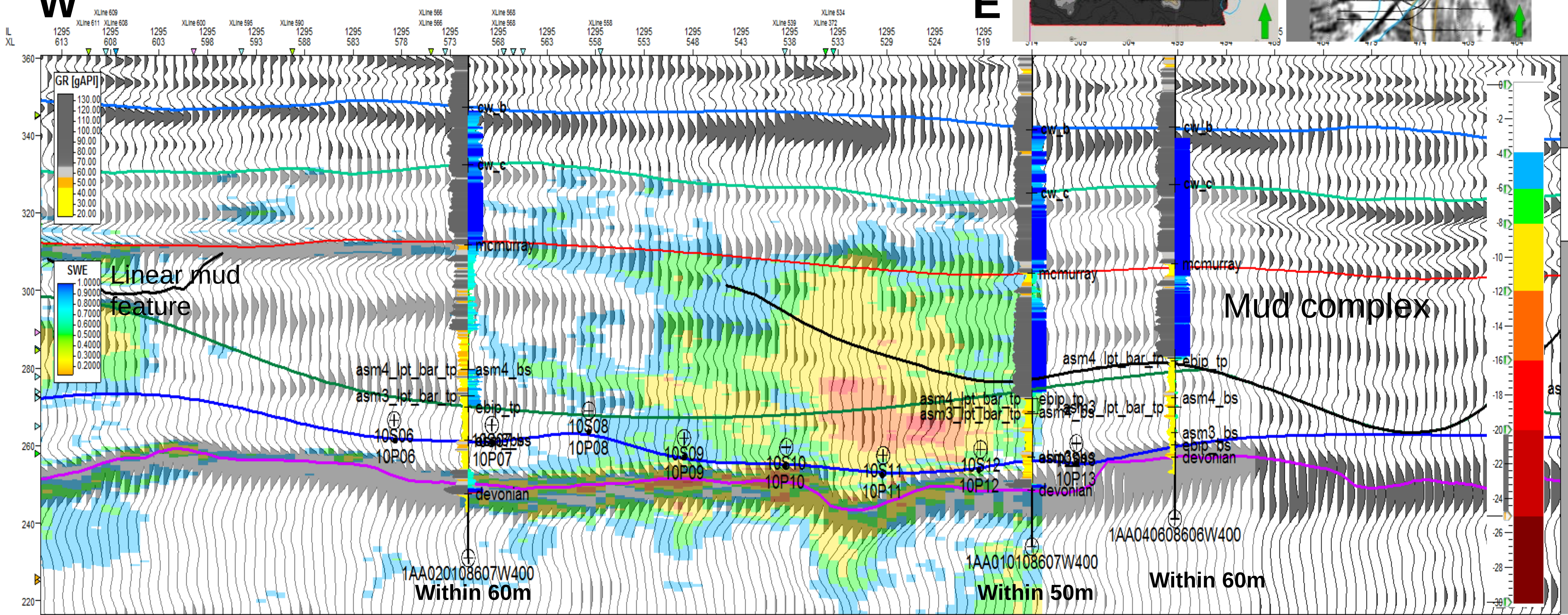
PAD10N cross section in the middle (W-E) with 4D anomaly

- Good steam chamber development was observed in 2015 4D in the mid section
- Evaluating infill & restart opportunities to extend capture of mobilized bitumen in the drainage area



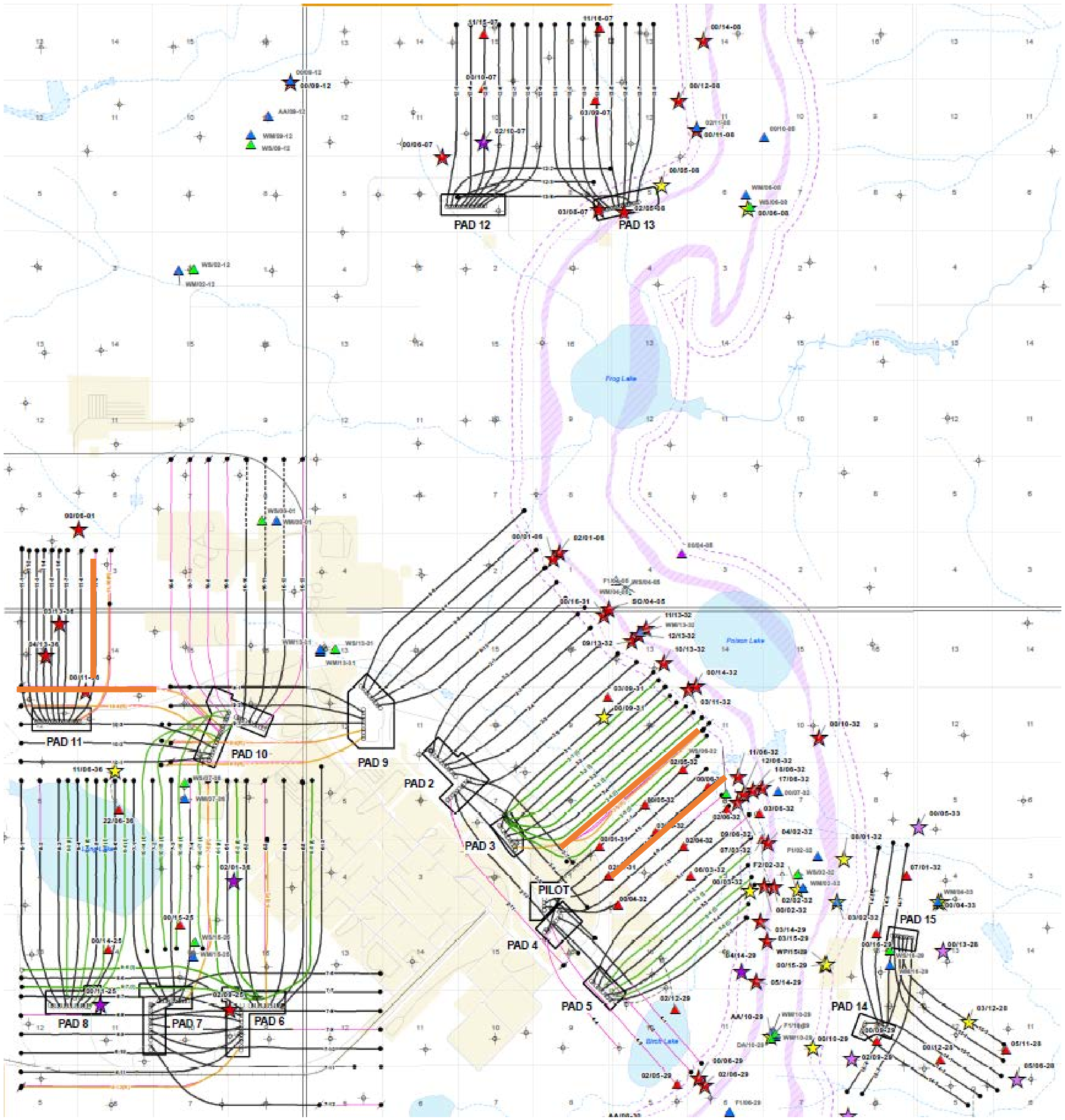


W E



Learnings, Trials and Pilot Projects
Subsection 3.1.1 (7f)
Long Lake and Kinosis

2019 Liner Failures



- Evaluated case by case to determine whether to repair, re-drill or shut in

Wells Re-drilled: None

Wells Repaired:

- 10P05 – Liner Failure Q2, WWS & ICD's
- 01P02 – Liner Failure Q2, WWS
- 11P09 – Liner Failure Q3, WWS
- 03P05 – Liner Failure Q4, WWS & ICD's

Wells Shut In – Ongoing Evaluation: None

Well Re-drilled
Well Repaired
Well Shut in

**Timing of actual failure uncertain in most cases; year noted is when failure was discovered and/or when investigative workover was initiated*

2019 Liner Failures

Well	Well Pair ID	Failure Date (Year*)	Repair Action	Cause of Failure
10P05	LL-010-05	2019	WWS + ICD Assembly	Steam Jetting
01P02	LL-001-02	2019	WWS	Steam Jetting
11P09	LL-011-09	2019	WWS	Steam Jetting
03P05	LL-003-05	2019	WWS + ICD Assembly	Steam Jetting

Timing of actual failure uncertain in most cases; year noted is when failure was discovered and/or when investigative workover was initiated

ICD Performance

- More rigorous ICD designs and installations have been completed in the past several years utilizing device geometry specifically designed to limit steam coning, promote hydrocarbon production and minimize potential for liner failures
- To date, ICD's with advanced geometry have been installed in a total of 10 wells, including the three wells worked over in 2019 as referenced below
- Production impacts have been noted as follows:

Well Name	Date of ICD Install /Workover	Equipment Installed	Improvement in Well Conformance	Reduction in Hot Spots or Overall Well Temperature	Increase in Total Fluid Production Rate	Increase in Bitumen Rate
10P05	May 2019	49 ICD's, Isolated with 9 Swell Packer	Yes	Yes	No	No
08P05INF	July 2019	34 ICD's, Isolated with 9 Swell Packers	Yes	Yes	Yes	Yes
03P05 [1]	Dec 2019	33 ICD's, Isolated with 9 Swell Packers	Yes	Yes	No	No

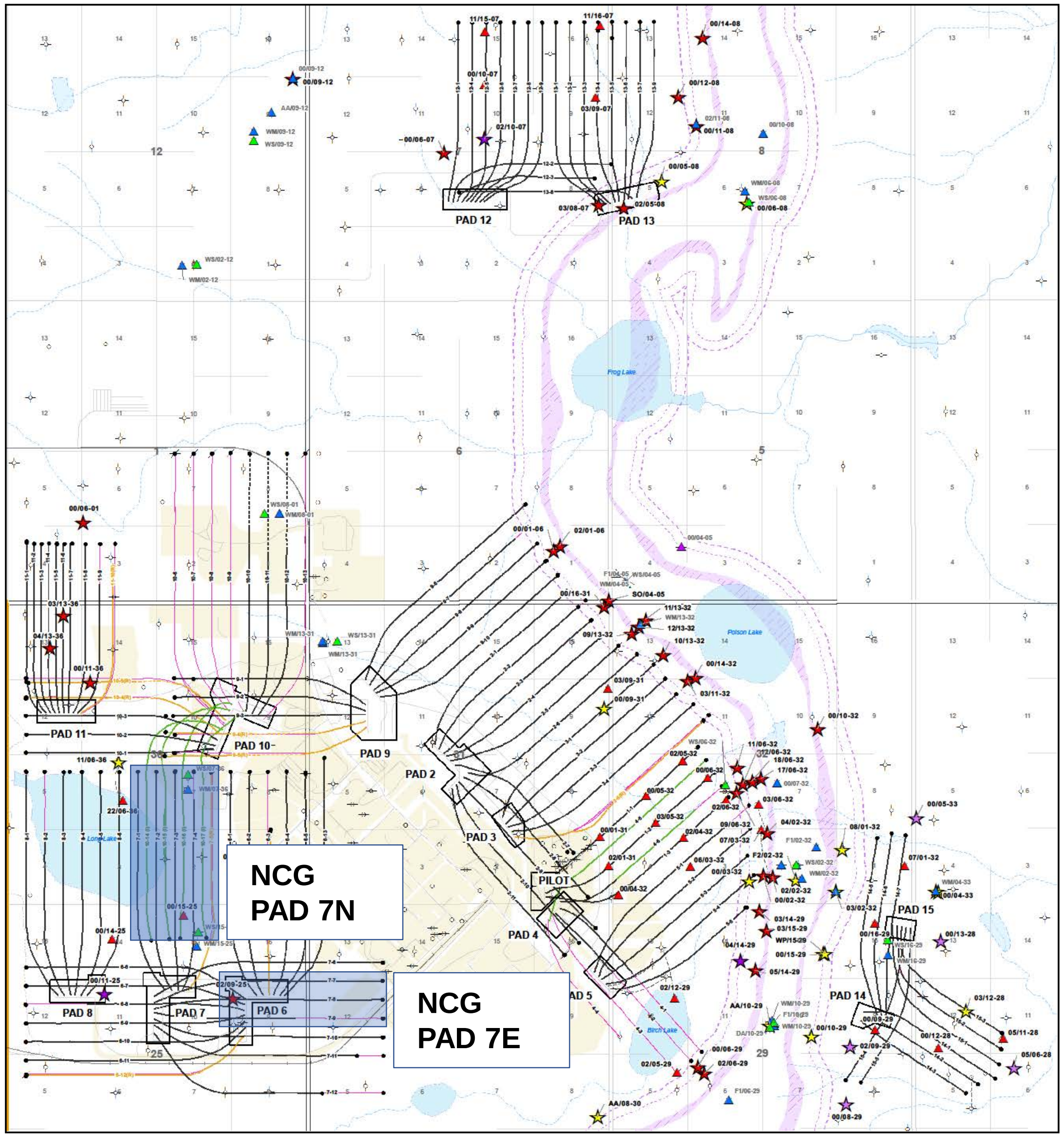
1. Performance impacted by offset infill wells on production in April 2019

2019 Other Well Integrity Actions

Inactive Well Compliance Program (IWCP) D13 Compliance:

- The current “inactive well list” has 332 wells in total
  - 151 wells are observation wells, leaving the accurate total to be 181 inactive wells
- Of the 181 wells, 85 wells are in the IWCP and all 85 are compliant
- The 96 wells that are not part of the IWCP are all compliant
- As CNOOC International completed the IWCP in 2017, there was no annual quota requirement for 2019

Update on Co-Injection Projects



PAD 7E NCG:

- Application approval 9485R received in Q3 2012
- Natural gas injection started Q4 2014 at 7P7 – 7P9
- Gas injection suspended after 2015 turnaround
- No NCG injection through 2019
- Evaluating re-start of NCG injection in 2020

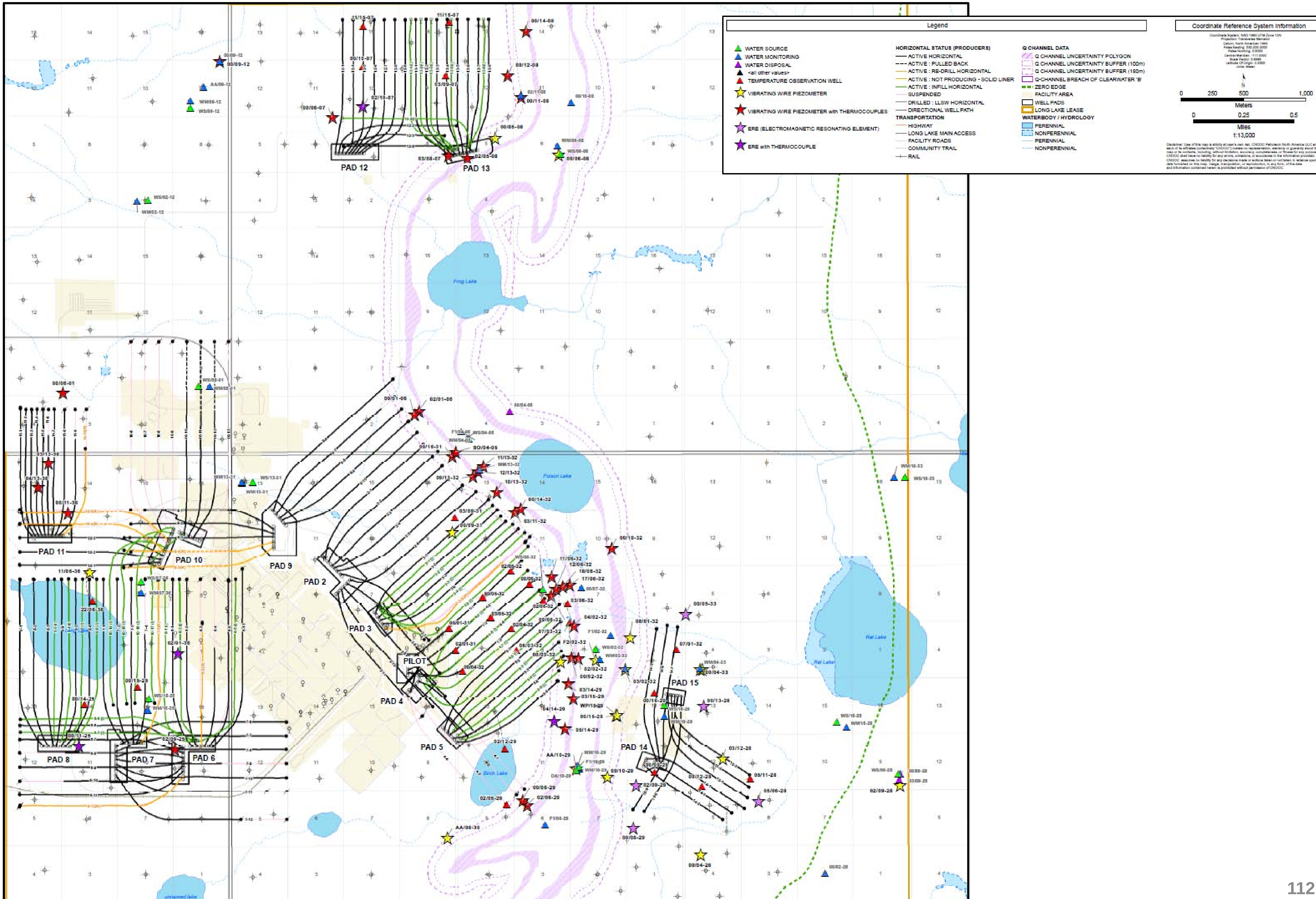
PAD 7N NCG:

- Application approval 9485CC received in Q2 2014
- Construction of co-injection surface facilities complete Q2 2015 on 5 well pairs planned
- Short term NCG injection around 2015 facility turnaround
- No NCG injection through 2019
- Evaluating re-start of NCG injection in 2020

Observation Wells
Subsection 3.1.1 (7)
Long Lake and Kinosis

Long Lake Observation Wells

No wells drilled in 2019



Observation Wells – Long Lake

N/A – Greater than 300m to Q-channel or closest well pair

UWI	Closest Wellpair	Distance to Wellpair	Distance to Q channel	
			Max Edge	Min Edge
100010608606W400	LL-009-09	67	45	70
100011308507W400	LL-018-01	39	N/A	N/A
100012408507W400	LL-018-07	38	N/A	N/A
100013108506W400	LL-001-01	8	N/A	N/A
100023208506W400	LL-005-04	54	29	44
100033208506W400	LL-005-04	30	103	120
100042808506W400	LL-014-03	297	N/A	N/A
100043208506W400	LL-001-03	20	N/A	N/A
100043308506W400	LL-014-07	232	N/A	N/A
100050808606W400	LL-013-09	115	68	87
100053208506W400	LL-001-01	3	N/A	N/A
100053308506W400	LL-014-07	126	N/A	N/A
100060108607W400	LL-011-08	118	N/A	N/A
100060708606W400	LL-012-01	80	N/A	N/A
100060808606W400	LL-013-09	N/A	87	50
100062908506W400	LL-004-02	50	97	145
100063208506W400	LL-001-02	23	283	N/A
100081708506W400	LL-014-03	N/A	N/A	N/A
100082908506W400	LL-015-04	149	236	N/A
100091208607W400	LL-012-01	N/A	N/A	N/A
100092908506W400	LL-015-04	11	N/A	N/A
100093108506W400	LL-003-01	9	N/A	N/A
100100708606W400	LL-012-05	10	N/A	N/A
100101308507W400	LL-016-04	27	N/A	N/A
100102908506W400	LL-015-04	283	99	140
100103208506W400	LL-003-05	N/A	7	42
100110808606W400	LL-013-09	230	109	138
100112508507W400	LL-006-07	109	N/A	N/A
100113608507W400	LL-010-05	17	N/A	N/A
100120808606W400	LL-013-09	158	179	213
100122808506W400	LL-014-01	41	N/A	N/A
100132808506W400	LL-015-03	240	N/A	N/A
100140808606W400	LL-013-09	264	23	33
100141708606W400	LL-013-09	N/A	41	8
100142508507W400	LL-008-06	42	N/A	N/A
100143208506W400	LL-003-03	135	3	42
100152508507W400	LL-007-03	47	N/A	N/A
100152908506W400	LL-014-05	205	100	113
100162908506W400	LL-014-06	22	286	N/A
100163108506W400	LL-002-03	102	46	57
102010608606W400	LL-009-09	106	10	27
102012108506W400	LL-014-01	N/A	N/A	N/A
102013108506W400	LL-001-02	5	N/A	N/A
102013608507W400	LL-006-01	115	N/A	N/A
102023208506W400	LL-005-04	103	20	7
102042208506W400	LL-014-01	N/A	N/A	N/A
102043208506W400	LL-001-03	35	N/A	N/A
102050808606W400	LL-012-03	223	4	28
102052908506W400	LL-002-10	24	N/A	N/A
102053208506W400	LL-001-01	11	N/A	N/A

UWI	Closest Wellpair	Distance to Wellpair	Distance to Q channel	
			Max Edge	Min Edge
102062908506W400	LL-004-02	102	53	98
102063208506W400	LL-001-03	8	217	235
102092508507W400	LL-007-08	7	N/A	N/A
102092808506W400	LL-015-03	N/A	N/A	N/A
102092908506W400	LL-015-04	85	N/A	N/A
102100708606W400	LL-012-05	83	N/A	N/A
102112008506W400	LL-004-03	N/A	N/A	N/A
102122908506W400	LL-005-04	50	N/A	N/A
102152908506W400	LL-014-05	213	110	123
103023208506W400	LL-014-05	176	31	73
103053208506W400	LL-001-02	5	N/A	N/A
103061308507W400	LL-017-04	21	N/A	N/A
103063208506W400	LL-005-02	138	48	78
103080708606W400	LL-013-08	125	80	115
103090708606W400	LL-013-04	13	N/A	N/A
103093108506W400	LL-002-06	37	N/A	N/A
103113208506W400	LL-003-03	91	40	81
103122808506W400	LL-015-03	36	N/A	N/A
103133608507W400	LL-011-06	36	N/A	N/A
103142908506W400	LL-005-05	94	30	55
103152908506W400	LL-005-05	167	14	13
104023208506W400	LL-005-02	134	60	90
104133608507W400	LL-011-04	15	N/A	N/A
104142908506W400	LL-005-05	213	103	139
105062808506W400	LL-015-01	117	N/A	N/A
105112808506W400	LL-015-03	37	N/A	N/A
105142908506W400	LL-005-05	290	13	56
106033208506W400	LL-005-01	45	N/A	N/A
107013208506W400	LL-014-07	20	N/A	N/A
107033208506W400	LL-005-04	73	7	27
108013208506W400	LL-014-05	176	33	87
109063208506W400	LL-001-03	47	156	169
109133208506W400	LL-002-05	97	21	40
110133208506W400	LL-003-01	78	33	80
111063208506W400	LL-001-02	124	121	136
111063608507W400	LL-010-01	51	N/A	N/A
111133208506W400	LL-002-06	189	77	65
111150708606W400	LL-012-05	47	N/A	N/A
111160708606W400	LL-013-04	34	N/A	N/A
112063208506W400	LL-001-03	104	110	122
112133208506W400	LL-002-06	147	28	12
117063208506W400	LL-001-03	200	10	21
118063208506W400	LL-001-03	152	60	72
122063608507W400	LL-008-06	68	N/A	N/A
1AA083008506W400	LL-004-03	N/A	161	247
1AA102908506W400	LL-004-01	N/A	113	66
1F2023208506W400	LL-005-04	252	146	133
1S0040508606W400	LL-002-03	146	11	15
1WM043308506W400	LL-014-07	222	N/A	N/A

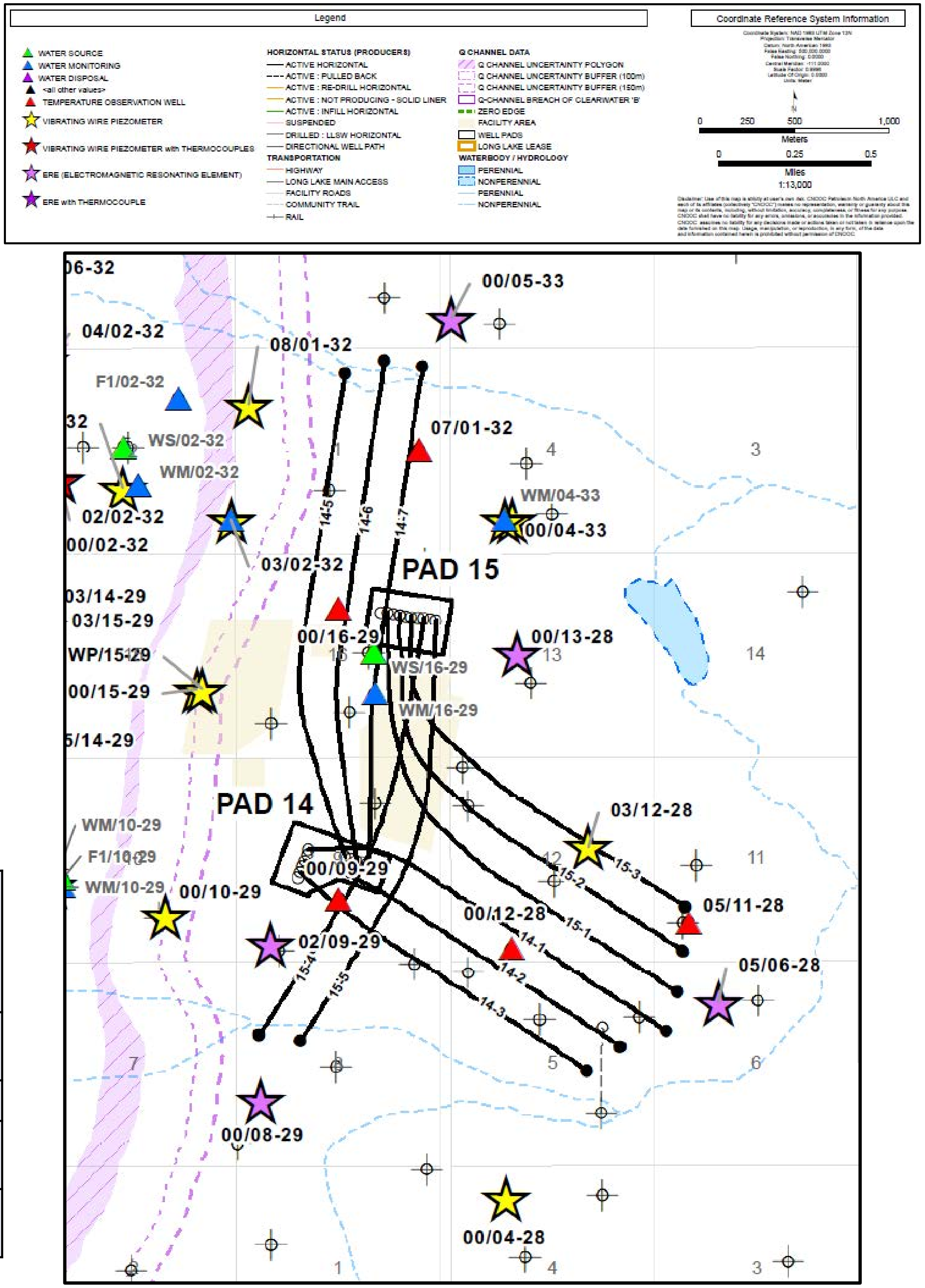
Pad 14 Baseline and Current Values

Well Name	Sensor Depth (mKB)	Sensor Elev. (mASL)	Formation	Base Line Pressure kPa_a	Current Pressure* kPa_a
100/04-28	126	335.6	CLWT A	1,015	1007
100/05-33	119	341.2	CLWT A	980	1,001
100/13-28	116	341.9	CLWT A	1,000	1,005
102/15-29 (WP/15-29)	127	344.3	CLWT A	990	972
WM/04-33	115	343.8	CLWT A	970	967
	115.5	343.3	CLWT A	980	983

Pad 15 Baseline and Current Values

Well Name	Sensor Depth (mKB)	Sensor Elev. (mASL)	Formation	Base Line Pressure kPa_a	Current Pressure* kPa_a
105/06-28	122.5	336.4	CLWT A	1,100	1,111
100/08-29	118.5	349.2	CLWT A	930	951
102/09-29	126.5	339.6	CLWT A	1,020	1,028
103/12-28	121.5	340.5	CLWT A	1,040	1,033

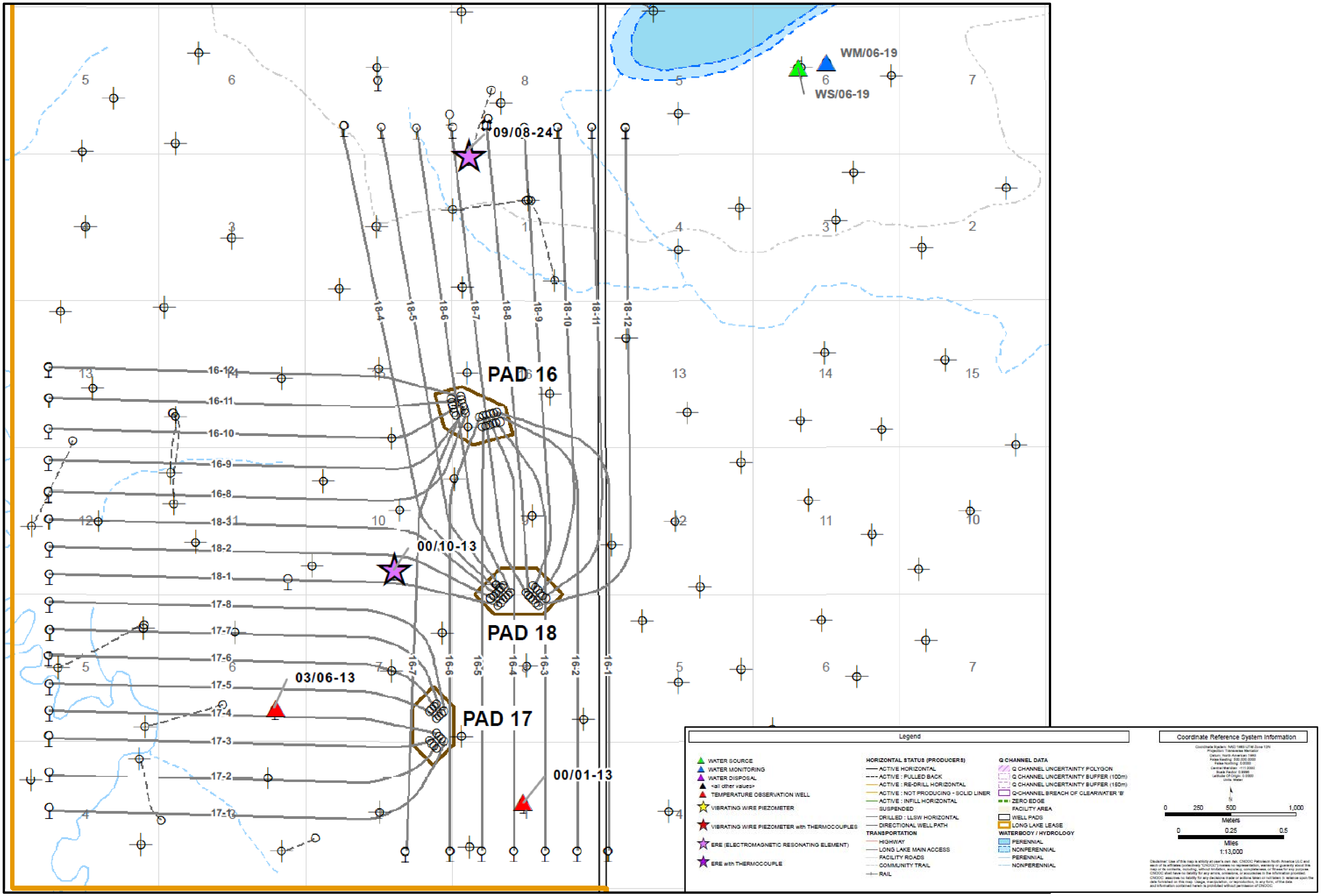
* *December 2019*



No changes to Baseline Pressures proposed.

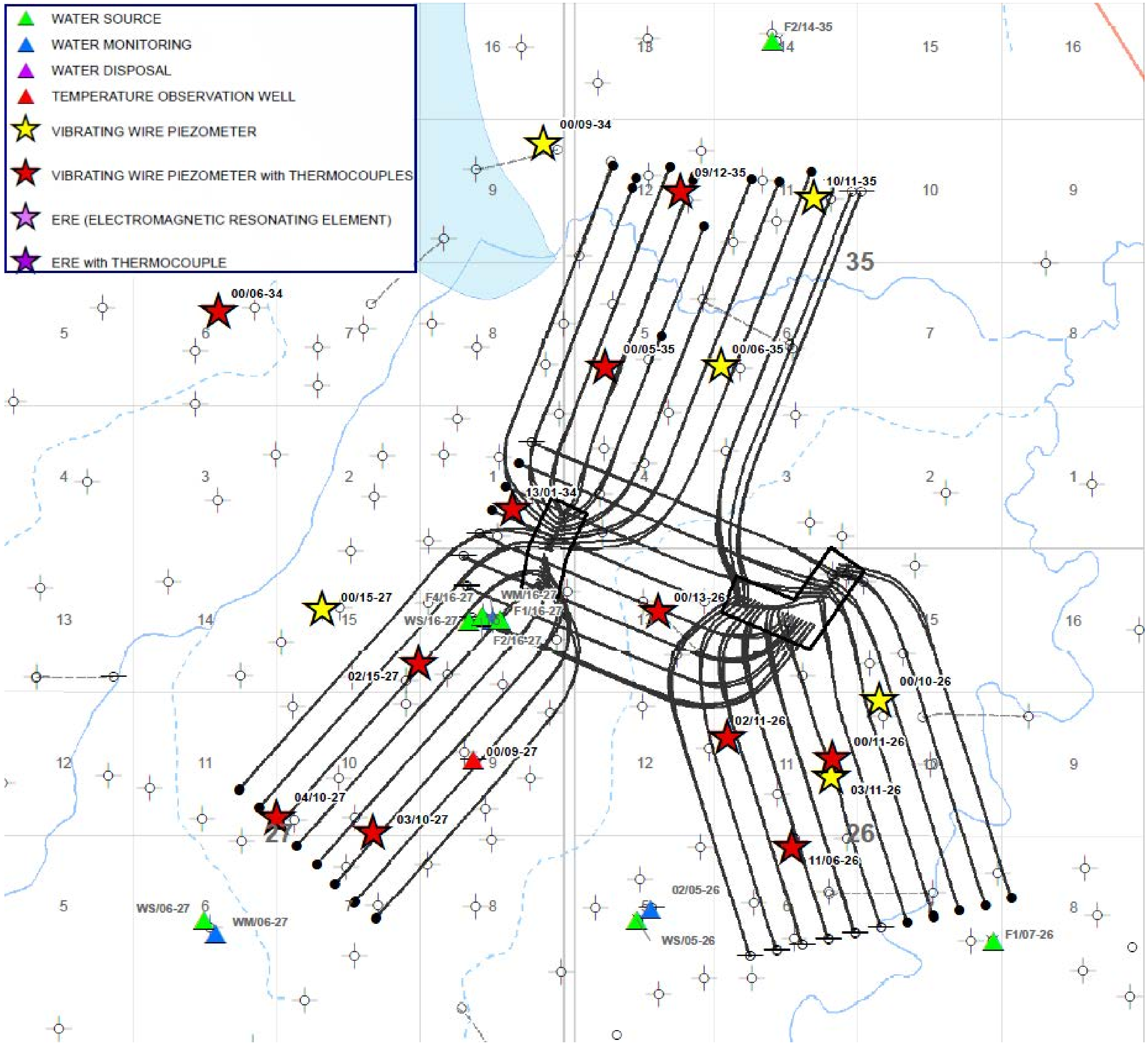
Long Lake SW Observation Wells

No wells drilled in 2019



K1A Observation Wells

No wells drilled in 2019



Observation Well Challenges

- Multiple issues can impact the quality and confidence of observation well data, can cause low confidence in the data set or invalid data all together.
  - Causes can include, but are not limited to:
    - Power supply to the well, primarily during winter months;
    - Mechanical issues such as battery failures;
    - Ambient temperature fluctuations;
    - Surface connection issues;
    - Downhole corrosion of sensors;
    - Expected run life of downhole sensors; and
    - Suspected defective sensor vintages.
- There are sensors that are also considered to be of low confidence as the pressure readings are suspect; they are not corroborated by adjacent sensors and do not correlate with subsurface operations.
- CNOOC International continuously works with various vendors to increase reliability in both well operations and data quality which includes:
  - Utilizing different technologies (ERE gauges, GORE thermocouple bundles);
  - Regular inspections of surface equipment; and
  - Regular inspections of downhole sensors.
- Systems are in place to monitor observation well data to track and identity potential issues
  - CNOOC International performs integrated reviews with data and subsurface personnel.
  - Vendor and maintenance crews are scheduled routinely to address issues and determine data validity

Groundwater Management Plan Operating Guidelines

- Groundwater management plan protects receptors by managing conditions within a defined area of the Q-Ch referred to as the Aquifer Management Unit (AMU).
- The plan includes staged responses triggered by pressure, temperature and chemistry thresholds.
- The control and monitoring wells are identified on the following slides.
- Pressures in the reservoir at all pads adjacent to the Q-Channel continue to be maintained at/below reference pressures in the Q-Channel.
- Temperatures in the Q-Channel have remained stable. No changes in temperature have been observed in the PoM for temperature at well 111/13-32.
- Groundwater quality in the Q-Channel has remained stable with no recent changes observed.

Temperature Monitoring Network

UWI	Abbreviation	Type	Parameters for Control / Management
100/05-08-086-06W4/00	00/05-08	Monitoring	Temperature
100/11-08-086-06W4/00	00/11-08	Monitoring	Temperature
100/14-08-086-06W4/00	00/14-08	Monitoring	Temperature
100/14-32-085-06W4/00	00/14-32	Monitoring	Temperature
102/01-06-086-06W4/00	02/01-06	Monitoring	Temperature
102/02-32-085-06W4/00	02/02-32	Monitoring	Temperature
102/05-08-086-06W4/00	02/05-08	Monitoring	Temperature
103/14-29-085-06W4/00	03/14-29	Monitoring	Temperature
103/15-29-085-06W4/00	03/15-29	Monitoring	Temperature
104/02-32-085-06W4/00	04/02-32	Monitoring	Temperature
105/14-29-085-06W4/00	05/14-29	Monitoring	Temperature
110/13-32-085-06W4/00	10/13-32	Monitoring	Temperature
112/13-32-085-06W4/00	12/13-32	Monitoring	Temperature
117/06-32-085-06W4/00	17/06-32	Monitoring	Temperature
1S0/04-05-086-06W4/00	S0/04-05	Monitoring	Temperature
1AA/10-29-085-06W4/00	AA/10-29	Monitoring	Temperature
1F2/02-32-085-06W4/00	F2/02-32	Monitoring	Temperature
111/13-32-085-06W4/00	11/13-32	PoM	Temperature

Legend

WATER SOURCE
WATER MONITORING
WATER DISPOSAL
TEMPERATURE OBSERVATION WELL
VIBRATING WIRE PIEZOMETER
VIBRATING WIRE PIEZOMETER with THERMOCOUPLES
ERE (ELECTROMAGNETIC RESONATING ELEMENT)
ERE with THERMOCOUPLE
MONITORING
POINT of MANAGEMENT

HORIZONTAL STATUS (PRODUCERS)
ACTIVE HORIZONTAL
ACTIVE : PULLED BACK
ACTIVE : RE-DRILL HORIZONTAL
ACTIVE : NOT PRODUCING - SOLID LINER
ACTIVE : INFILL HORIZONTAL
SUSPENDED

TRANSPORTATION
HIGHWAY
LONG LAKE MAIN ACCESS
FACILITY ROADS
COMMUNITY TRAIL
RAIL
DIRECTIONAL WELL PATH

Q CHANNEL DATA
Q CHANNEL UNCERTAINTY POLYGON
ZERO EDGE
FACILITY AREA
WELL PADS
LONG LAKE LEASE
MANAGEMENT AREA (at the depth of the Grand Rapids B Top)

WATERBODY / HYDROLOGY
PERENNIAL
NONPERENNIAL
PERENNIAL
NONPERENNIAL

Note: The Management Area Polygon is vertically offset from the SAGD well pairs

Coordinate Reference System Information

Coordinate System: NAD 1983 UTM Zone 12N
Projection: Transverse Mercator
Datum: North American 1983
False Easting: 500,000.0000
False Northing: 0.0000
Central Meridian: -111.0000
Scale Factor: 0.9996
Latitude Of Origin: 0.0000
Units: Meter

N

0 250 500 1,000
Meters
0 0.25 0.5
Miles
1:12,000

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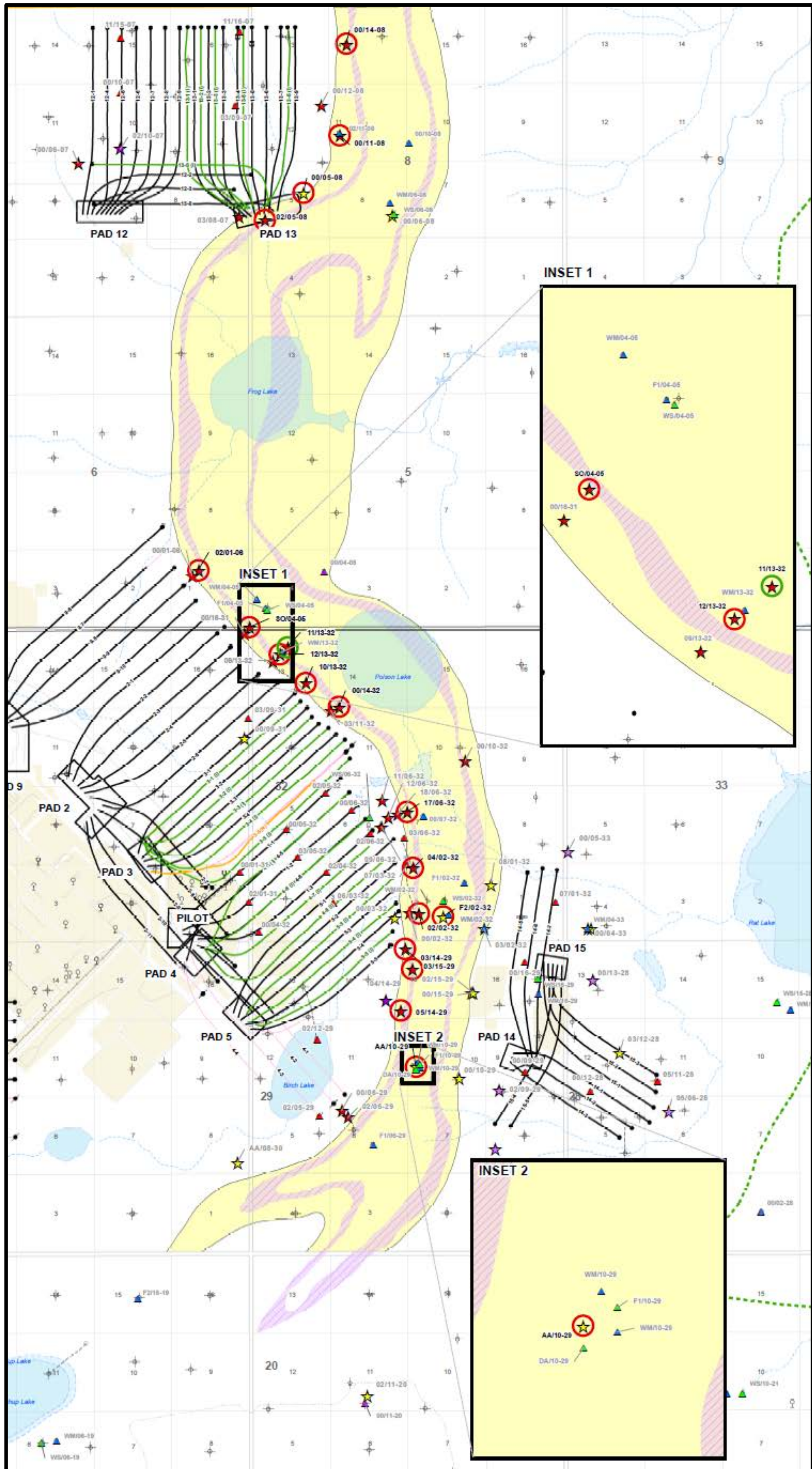
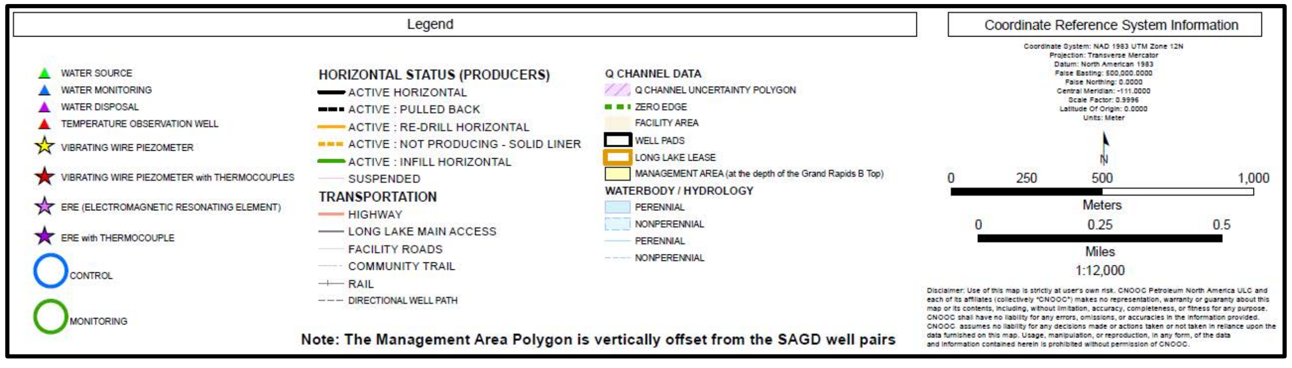
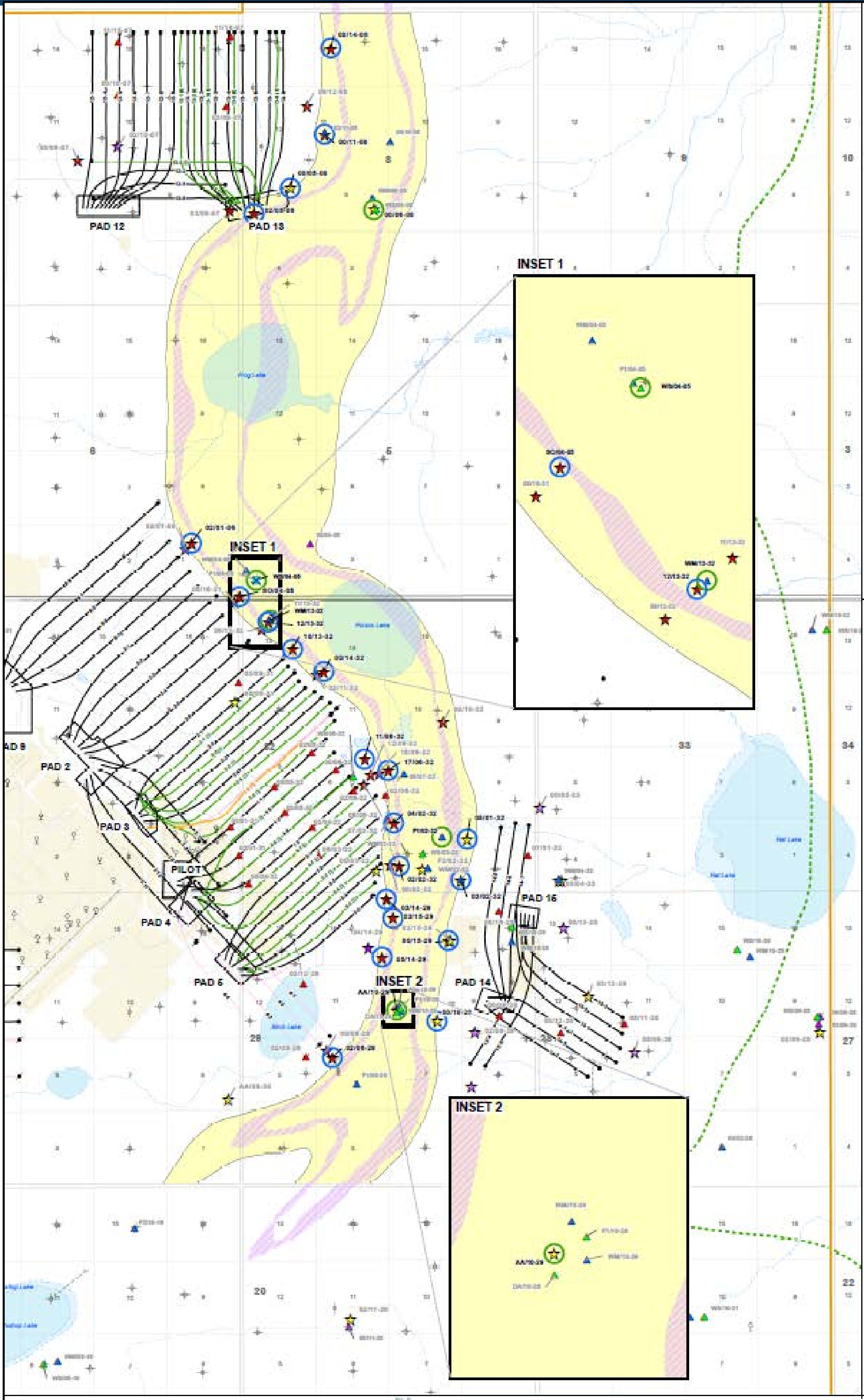


Pressure Monitoring Network

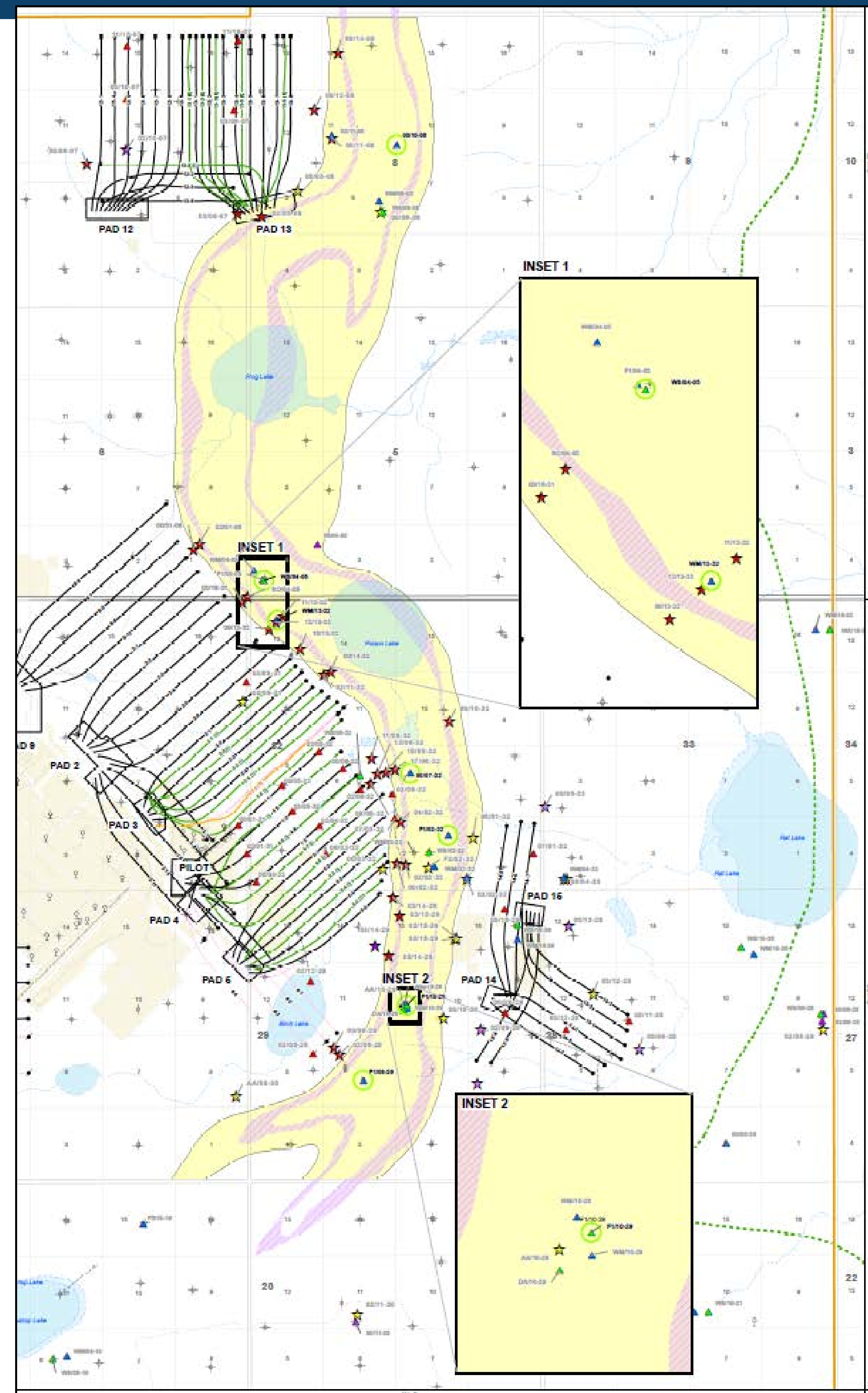
UWI	Abbreviation	Type	Parameters for Control / Management
100/05-08-086-06W4/00	00/05-08	Control	Pressure
100/10-29-085-06W4/00	00/10-29	Control	Pressure
100/11-08-086-06W4/00	00/11-08	Control	Pressure
100/14-08-086-06W4/00	00/14-08	Control	Pressure
100/14-32-085-06W4/00	00/14-32	Control	Pressure
100/15-29-085-06W4/00	00/15-29	Control	Pressure
102/01-06-086-06W4/00	02/01-06	Control	Pressure
102/02-32-085-06W4/00	02/02-32	Control	Pressure
102/05-08-086-06W4/00	02/05-08	Control	Pressure
102/06-29-085-06W4/00	02/06-29	Control	Pressure
103/02-32-085-06W4/00	03/02-32	Control	Pressure
103/14-29-085-06W4/00	03/14-29	Control	Pressure
103/15-29-085-06W4/00	03/15-29	Control	Pressure
104/02-32-085-06W4/00	04/02-32	Control	Pressure
105/14-29-085-06W4/00	05/14-29	Control	Pressure
108/01-32-085-06W4/00	08/01-32	Control	Pressure
110/13-32-085-06W4/00	10/13-32	Control	Pressure
111/06-32-085-06W4/00	11/06-32	Control	Pressure
112/13-32-085-06W4/00	12/13-32	Control	Pressure
117/06-32-085-06W4/00	17/06-32	Control	Pressure
1S0/04-05-086-06W4/00	S0/04-05	Control	Pressure
100/06-08-086-06W4/00	00/06-08	Monitoring	Pressure
1AA/10-29-085-06W4/00	AA/10-29	Monitoring	Pressure
1F1/02-32-085-06W4/02	F1/02-32	Monitoring	Pressure
1WS/04-05-086-06W4/00	WS/04-05	Monitoring	Pressure
1WM/13-32-085-06W4/00	WM/13-32	Monitoring	Pressure

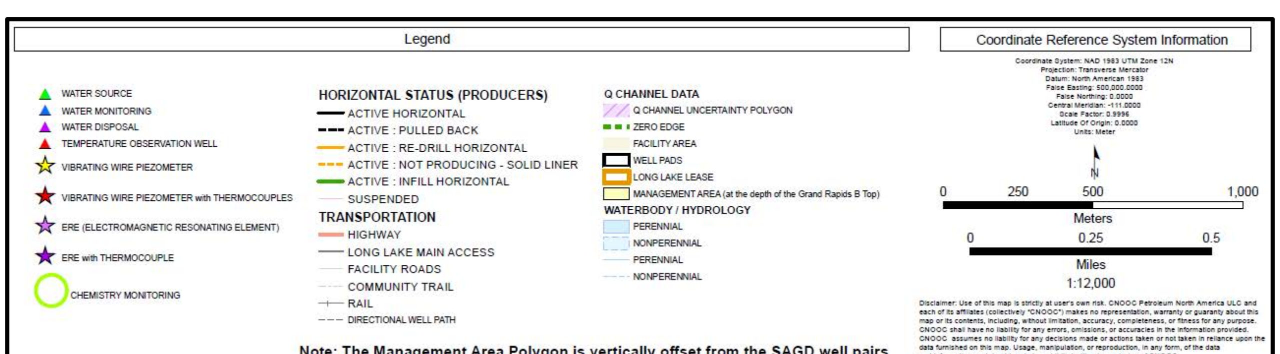




Chemistry Monitoring Wells

UWI	Abbreviations	Other names
100/10-08-086-06W4/00	00/10-08	
1WS/04-05-086-06W4/00	WS/04-05	WS-GC-04-05-085-06
1WM/13-32-085-06W4/00	WM/13-32	WM-GC-13-32-085-06
100/07-32-085-06W4/02	00/07-32	
1F1/02-32-085-06W4/00	F1/02-32	
1F1/10-29-085-06W4/00	F1/10-29	
1F1/06-29-085-06W4/00	F1/06-29	





Future Plans

Subsection 3.1.1 (8)

Long Lake and Kinosis

Future Plans – Producing Areas

- Commence operation of LLSW sustaining SAGD well pairs
- Continue to manage SAGD production according to curtailment, turnaround, surface constraints and commodity price conditions
- Evaluating re-start of NCG injection on Pad 7N and 7E
- Evaluating additional well pairs, infills and re-entries off existing well pads at Long Lake
- Winddown application in progress for Pad 9NE/2SE

Future Plans - New Development

- Long Lake:
  - Evaluating plans for sustaining pad development in the Long Lake area
- Kinosis:
  - Evaluating plans for development in the Kinosis area

Future Plans – Pad Abandonments

- There are no anticipated pad abandonments for Long Lake or K1A pads in the next five years
- Individual wells will be evaluated for long term suspension if rates are too low and are uneconomic to produce

Surface Operations and Compliance and Issues not Related to Resource Evaluation and Recovery

Subsection 3.1.2

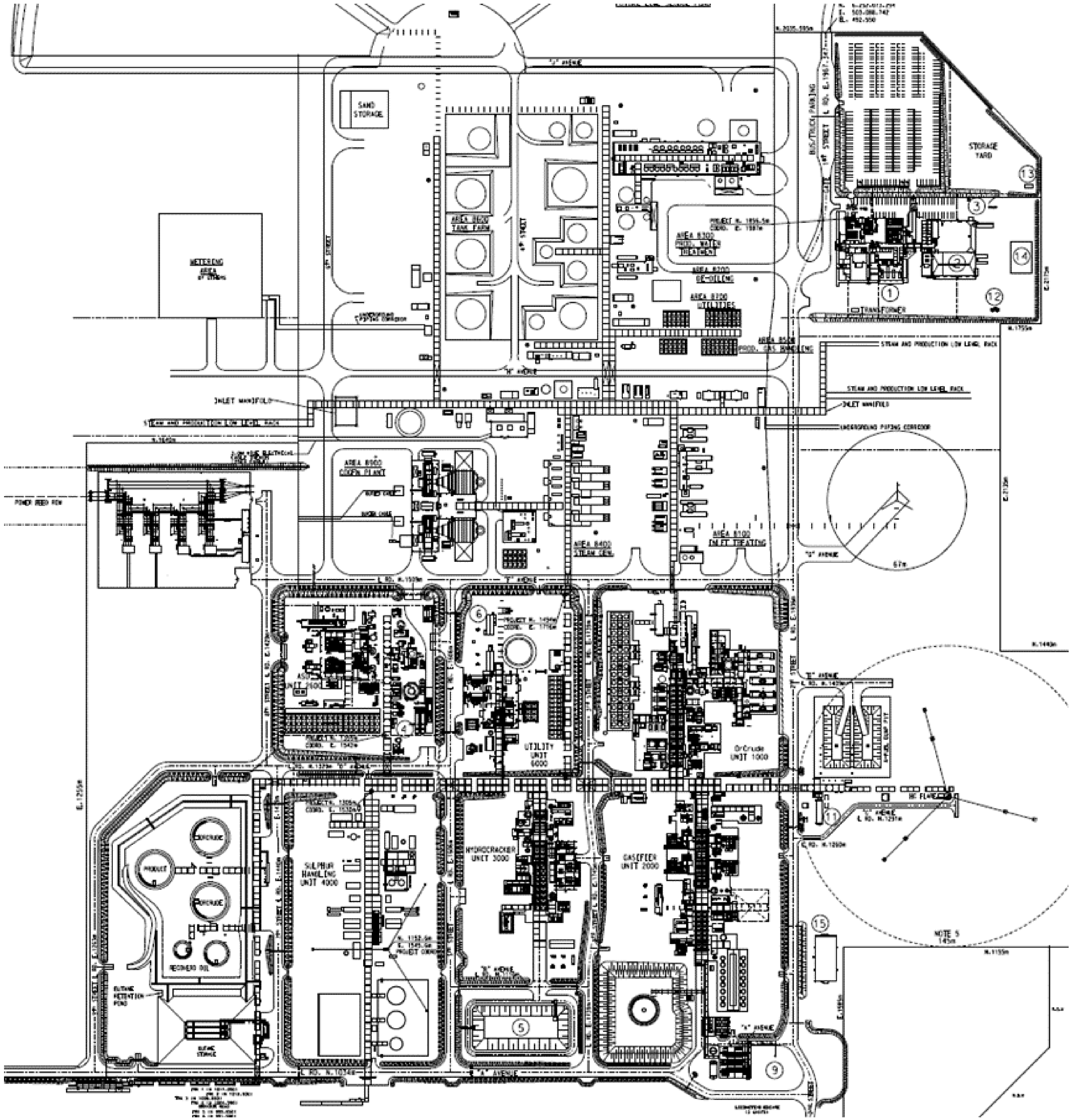
Long Lake and Kinosis

Facilities
Subsection 3.1.2 (1)
Long Lake and Kinosis

Long Lake Facilities

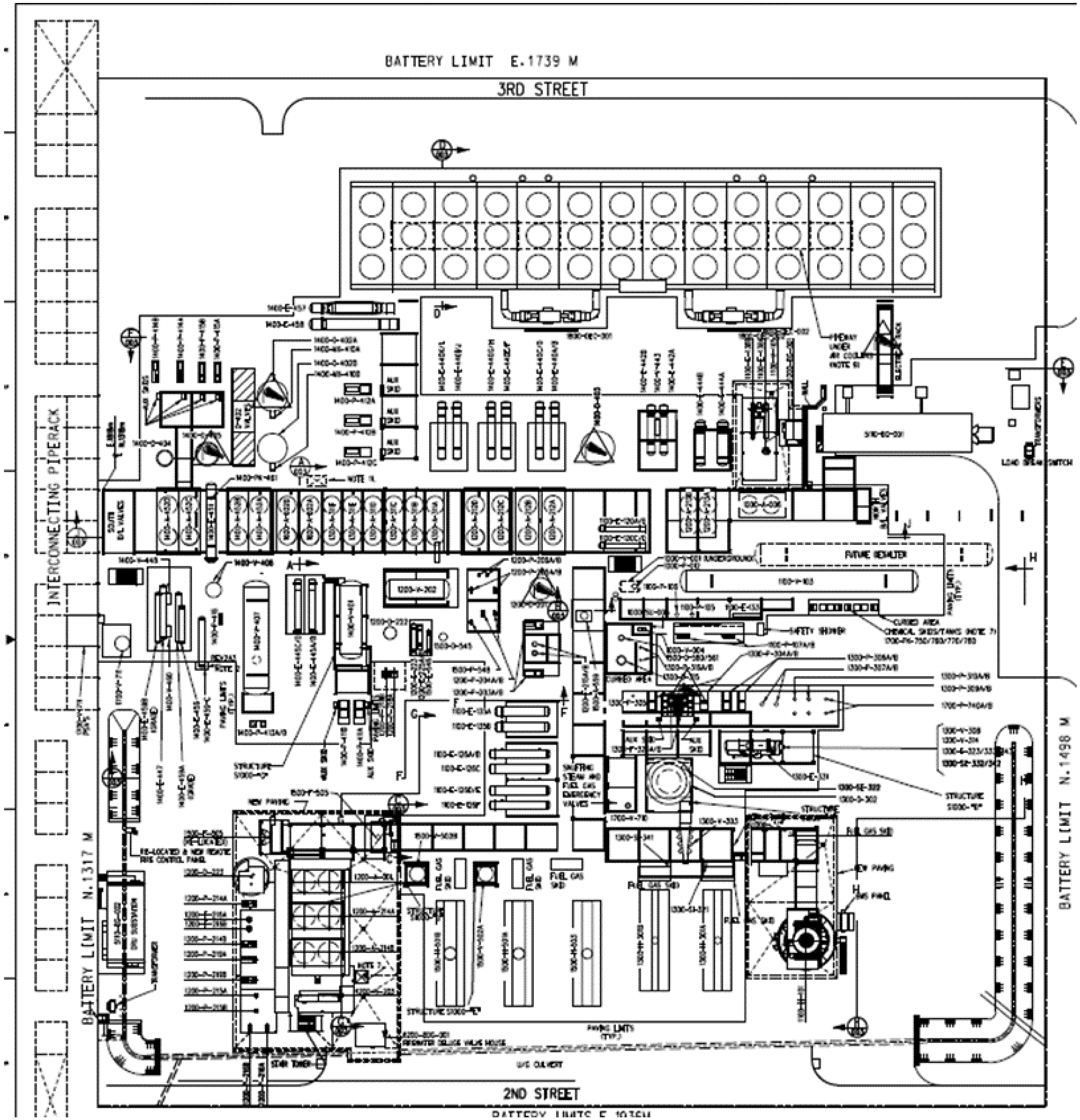
Long Lake facility overview with Pad 9 in the foreground - June 19, 2018

Long Lake Plot Plan



Subsection 3.1.2 (1a)

Diluent Recovery Unit Plot Plan

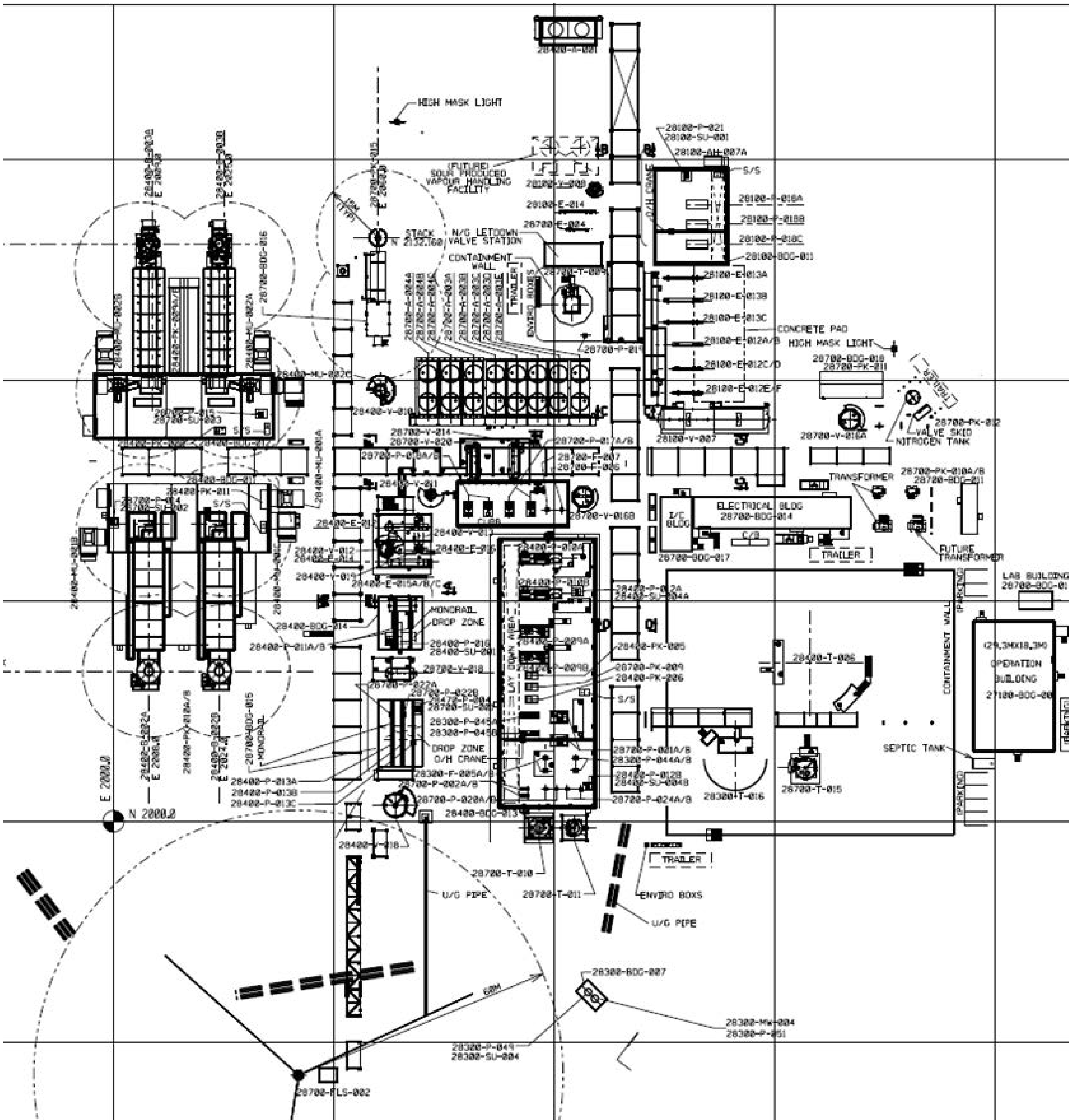


Subsection 3.1.2 (1a)

Kinosis Phase 1A (K1A)

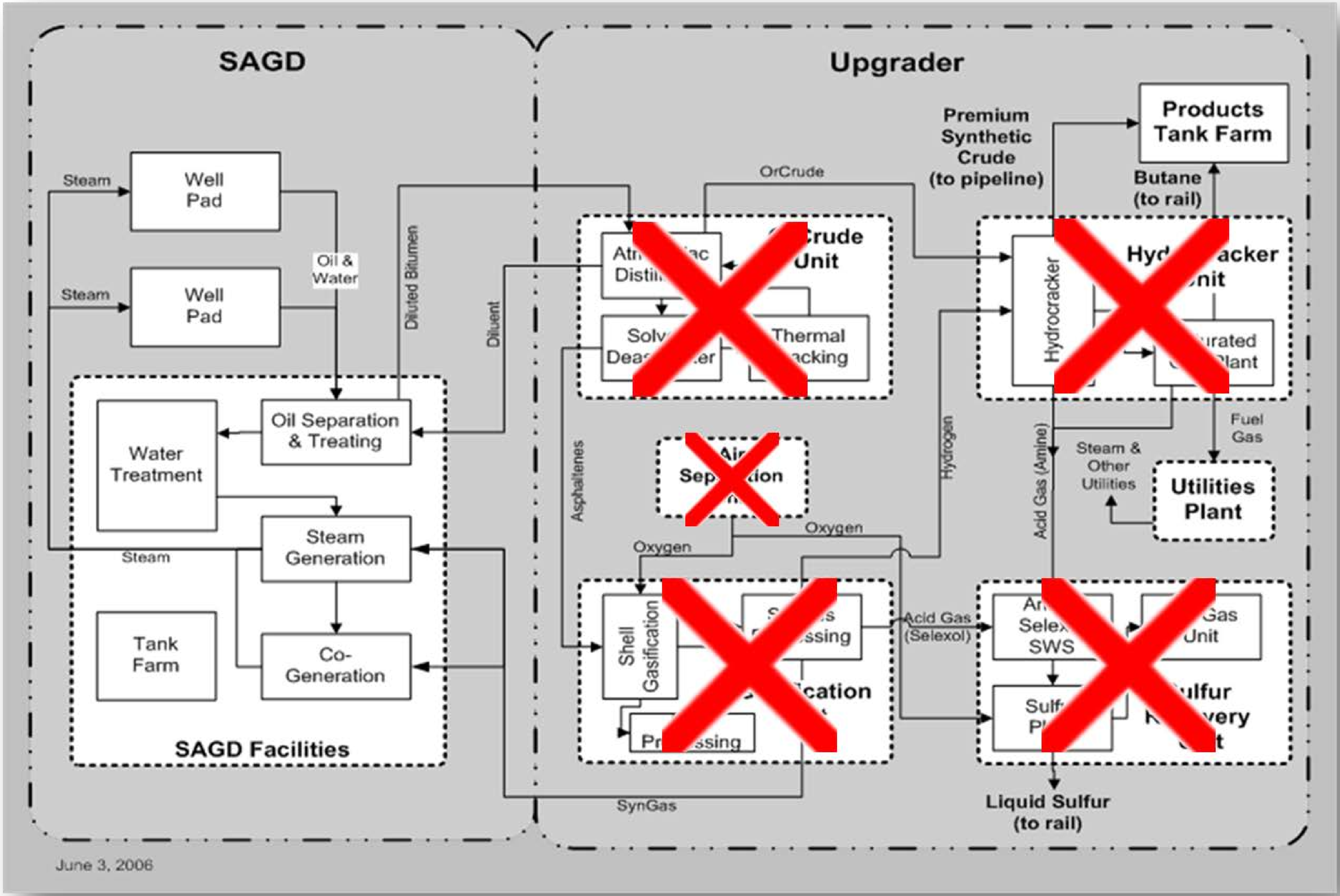
Aerial of K1A Steam Generation Facility with Well Pad 2 in the background – June 19, 2018

Kinosis Phase 1A Plot Plan



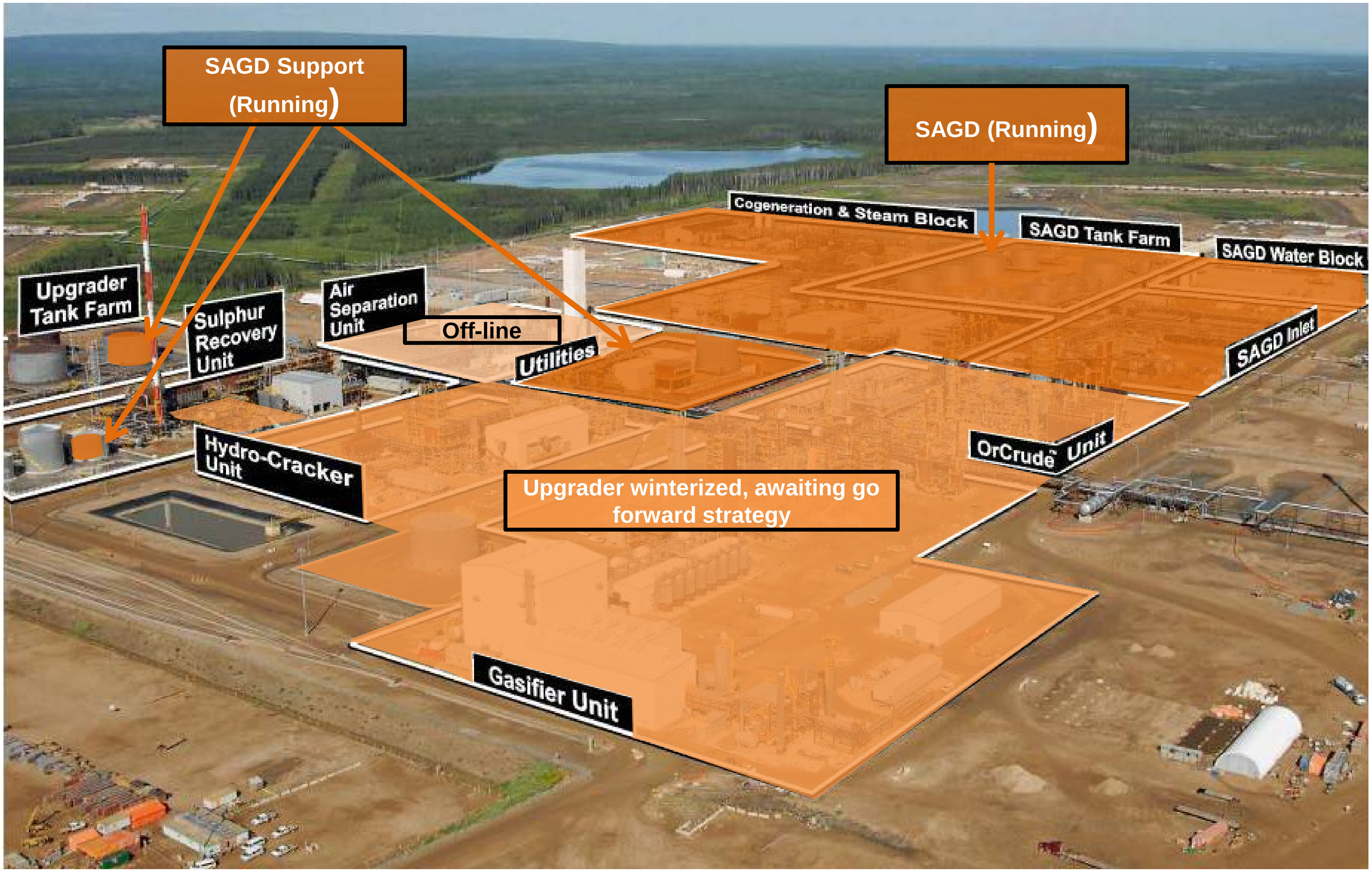
Subsection 3.1.2 (1a)

Current Plant Schematic



Subsection 3.1.2 (1b)

Current Long Lake Operations



Subsection 3.1.2 (1b)

Facility Performance
Subsection 3.1.2 (2)
Long Lake and Kinosis

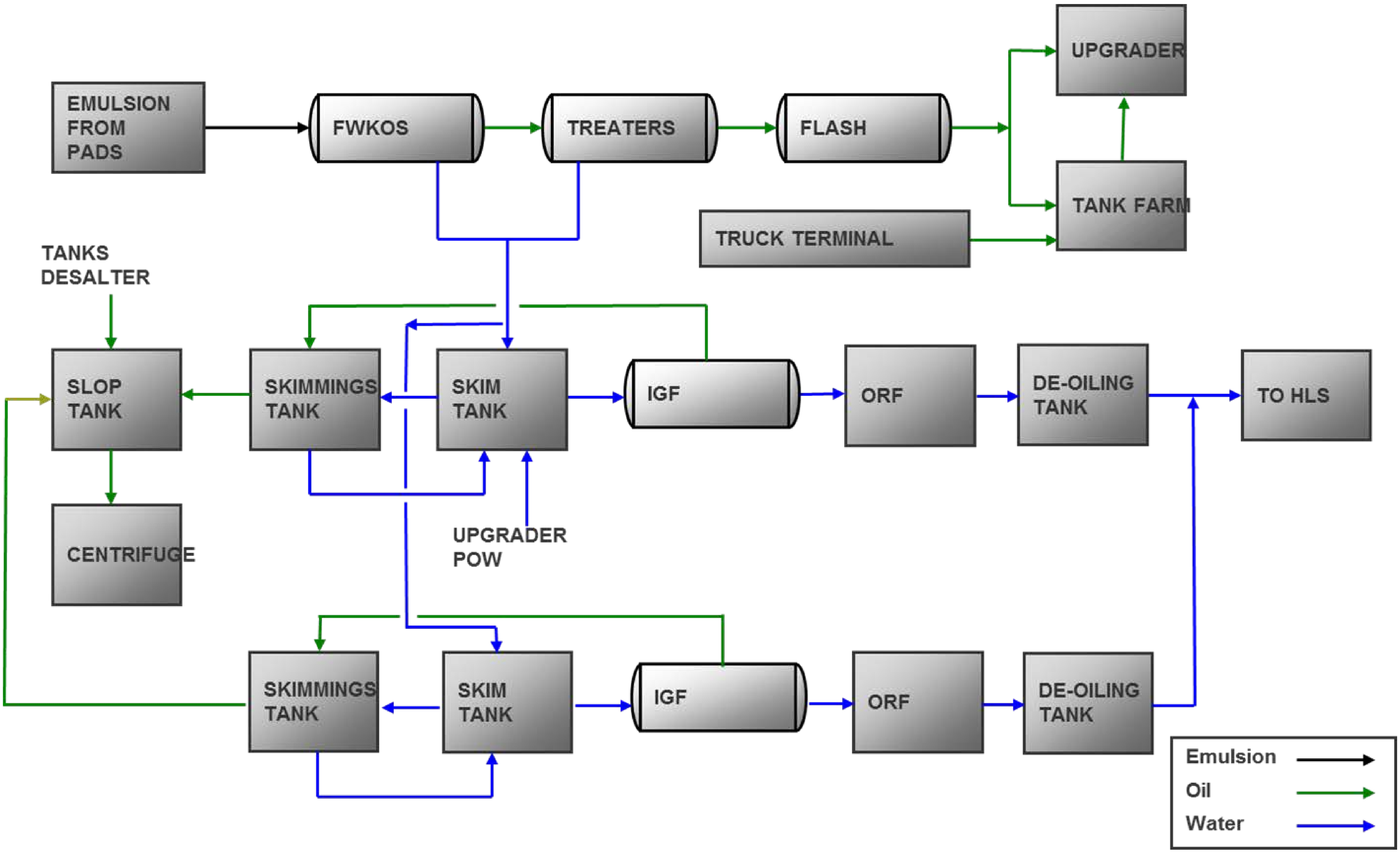
Facility Performance

Subsection 3.1.2 (2)

Long Lake Operations Summary - 2019

- Long Lake continued to operate in SAGD mode only, achieving a daily production average of 46,326 bpd.
- From the Upgrader area only the Utilities and Offsite (U&O) boilers, Superheater and Upgrader storage tanks are being used to support SAGD only operation.
- Continued 100% use of condensate as diluent.
- Rental Dilbit Chiller continued to be operated to achieve dilbit export temperature.
- Reduction of venting events was a priority in 2019. Follow up on improvements to the inlet separation process and the Vapour Recovery Unit (VRU) took place with project execution planned during turnaround 2020.
- Chemical treatment improvements throughout the facility are ongoing.
- Water carryover through monomedia vent was eliminated. Waste regeneration header cleaned and preventive maintenance in place.
- Fired heater compliance project currently in progress. This project is designed to meet the new Canadian Standards Association (CSA) B149.3-15 code update with regards to fuel systems and fired heaters.
- Installed temperature trip on disposal line to prevent exceeding maximum allowable temperature.

Bitumen Treatment



Subsection 3.1.2 (2a)

Inlet and De-Oiling

Infill projects

- Pads 1, 3, 5, 6 and 13 infill projects were completed and started up in 2019.

Tank farm and export

- The Dilbit Chiller continues to be operated and is able to maintain true vapour pressure (TVP) targets with light diluent.
- As part of the tank integrity program completed cleaning, inspection and repair of 8100-T-001 (Slop), 8200-T-003 (CPF skimmings), 8600-T-002 (diluent), started work on 8200-T-004 (de-oiled).

Inlet treating

- Using 100% Condensate (CFT) as diluent.
- Continued to observe reduced Produced Water (PW) Exchanger Fouling; no chemical cleaning was required in 2019.
- Monitoring of Free Water Knock-Out (FWKO) fouling performance continues and temperature scan of shell being used to understand fouling tendencies; this has helped identify outage schedule of FWKO.

De-oiling

- De-oiling completed several trials and mode of operation of skim tanks was changed to allow for better separation.
- Completed ABSA regulatory inspection of FWKO B, Treater 2A, oil removal filter (ORF) 14-A/B and ORF15-A; also completed inspection of five exchangers in Area 1.

Subsection 3.1.2 (2a)

Tank Venting

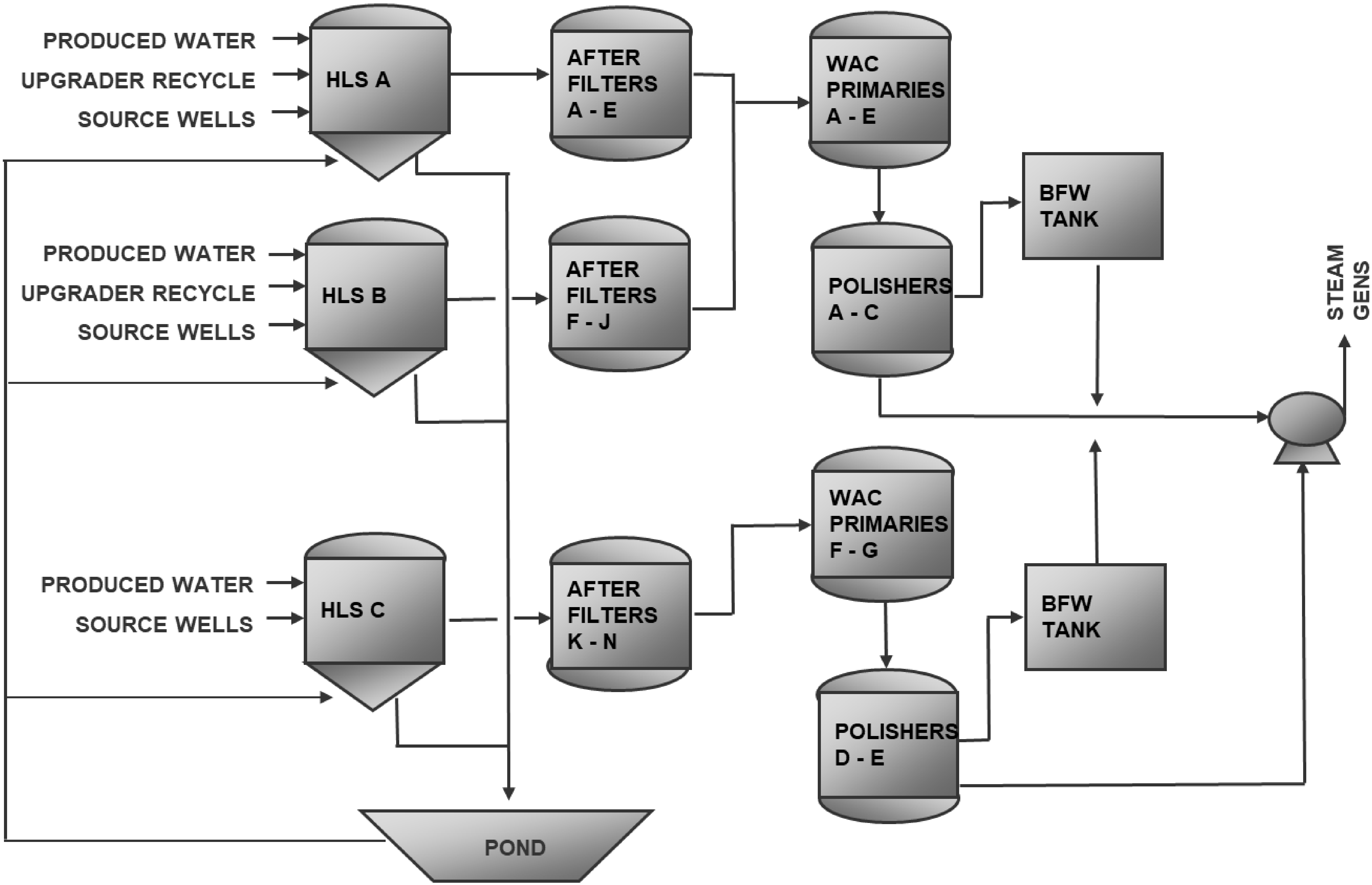
- Dispersion model by third party was completed to study complex and multi-tank venting scenarios in support of a new reporting strategy on multi-tank venting.
- Mid and long term strategies in improving the VRU systems to handle vapour loads effectively were identified; the project engineering work and design was completed in 2019 and will be part of 2020 turnaround execution.

Water Treatment

CNOOC

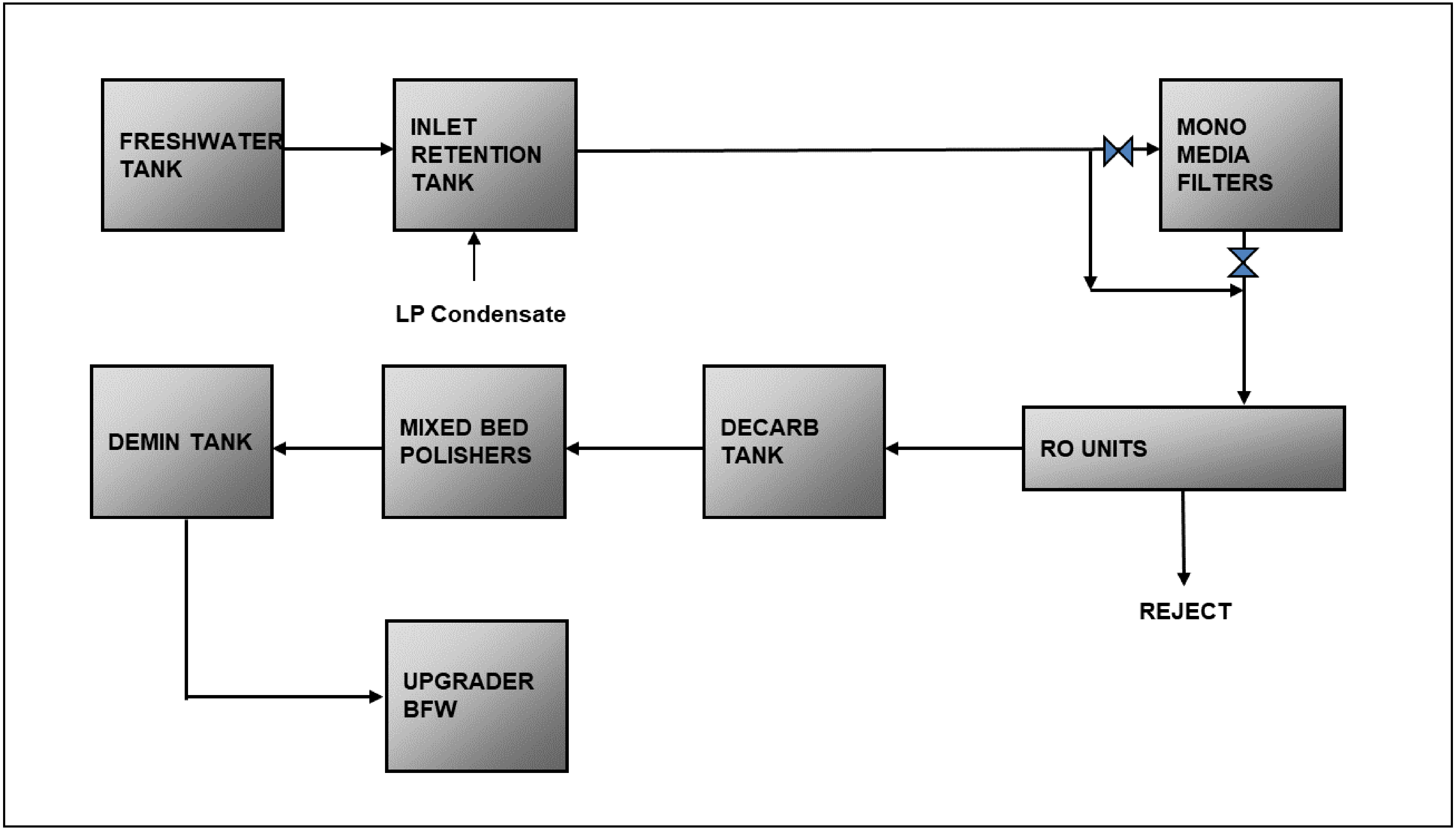
Subsection 3.1.2 (2b)

Produced Water Treatment



Subsection 3.1.2 (2b)

High Quality Water System



Subsection 3.1.2 (2b)

Hot Lime Softener (HLS) operation

- Coagulant dosage to HLS continues to be high since June 2017 due to the deoiled produced water quality change. A decreasing trend has been observed since December 2019 with the deoiled water quality improvement.

Sludge Carry Over from HLSs

- Experienced difficulties in maintaining HLS outlet turbidity due to de-oiled produced water quality issues.
- More frequent fouling of after filters has been observed due to turbidity carry over from HLSs, routine chemical cleaning on after filter media has been carried out with some improvement. Internal cleaning and/or media replacement has been completed on some filters with severe plugging and oil contamination.

Weak Acid Cation (WAC) Unit Monitoring

- Optimized WAC resin usage by extending the service time between regeneration. Service run or resin usage had been maximized until its exhaustion and it is now part of normal operation mode.
- WAC resin compaction has been observed and is being mitigated by maintaining the nitrogen scour step as part of the transfer in resin regeneration sequence.
- Resin deterioration observed in debottlenecking (DB) where produced water oil in water has been higher. Some resin replaced.

Water Treatment

Chemical Usage Optimization

- Inorganic coagulant along with the current organic coagulant is being injected into the HLS C since October 2018, resulting in reduction of the overall coagulant consumption. Results inconsistent during 2019, as the deoiled water quality still varies.
- Trial to inject inorganic plus organic coagulant into HLS A started in Q2 2019. Less effective when adding lime sludge pond supernatant as makeup water to HLS.
- Reduced acid/caustic usage after extending the WAC service length to maximum design hardness breakthrough.

Brackish Water

- The brackish system was not in use in 2019.

Water Carryover from Monomedia Vent

- Solids accumulations in the waste regeneration header found to be the main cause of water carryover. Header was mechanically cleaned and preventive maintenance is in place to avoid this from reoccurring.

Disposal Water Pipeline Reliability

- Preventive maintenance is being performed to minimize the risk of failures.
- Installed temperature trip on disposal line to prevent exceeding maximum allowable temperature.

Subsection 3.1.2 (2b)

Continued Fresh Water Use with Upgrader Down

Due to the design of the LLK facility, brackish water cannot be used in place of fresh water despite the Upgrader being largely shutdown. Fresh water is used within the LLK facility for the following purposes:

- High quality water system was running during most of 2019, fresh water is used as water source to produce boiler feed water for the utility boilers in the Upgrader. The water is converted to intermittent pressure superheated steam (IPSH) for the gas turbines to control NOx emissions.
- Since the Upgrader was shutdown, the fresh water usage has been reduced significantly. The majority of the fresh water is used to produce steam to control NOx emissions in the gas turbines.
- Fresh water is also used as cooling medium for Inlet treatment Produced Vapour heat exchangers and VRU compressors seal/ring, to blend chemicals in the injection facility for use in the HLS.
- Trialed the reuse of steam blowdown to help mitigate the current shortage of water for steam production.

Typical Water Quality (Produced and Disposed)

	pH	Conductivity (us/cm)	Turbidity (NTU)	Dissolved Hardness	Silica	Iron
Produced Water (Deoiled)	6.6 - 9.5 average 7.5	1,250 – 2,200 averag1,895	7 - 1760 average 327	2 - 40 average 8.7	36 - 382 average 167	n/a
Supernatant Water	7.0 -1 0.5 average 9.2	1,560 – 9,410 average 4,985	754 - >1,000	40 - 139 average 112	20 – 298 average 62	n/a
Fresh Water	7.0 – 9.0 average 8.0	1,240 - 3,240 average 2,003	0 - 23 average 5.4	112 - 120	4 – 12	0 – 2.9 average 1.3
Disposal Water	9.1 – 12.3 average 11.1	5,030 - 32,000 average 19,000	1 - 53	4 - 15	296 - 632	0.4 – 2.2

- No brackish water chemistry in 2019 - system is currently discontinued.

Subsection 3.1.2 (4)

Fuel Consumption

- Continued to have Syngas out of operation due to the shutdown of the Upgrader.
- Sour produced gas blended with pipeline natural gas for use as fuel gas in the boilers.
- Seeing corrosion on the Once Through Steam Generators (OTSG) flue gas recirculation (FGR) line. Upgraded the FGR duct for OTSG D to stainless steel metallurgy and other OTSG's on an as needed basis.
- Continued to operate with reduced excess O_2 in OTSG to 2%.

HRSG Duct Burner Fouling

- Since 2016 the duct burners were supplied with only natural gas and duct burner fouling rate has been reduced significantly.
- HRSG 1 roof damage was repaired with higher metallurgy stainless steel material. The roof material of HRSG 2 will be upgraded during the next outage.

Boiler Reliability

- High reliability of boilers in 2019 due to stabilized fuel supply.

Subsection 3.1.2 (2c)

Glycol Monitoring

- Increased monitoring/maintenance on various exchangers has greatly reduced glycol losses from previous years.

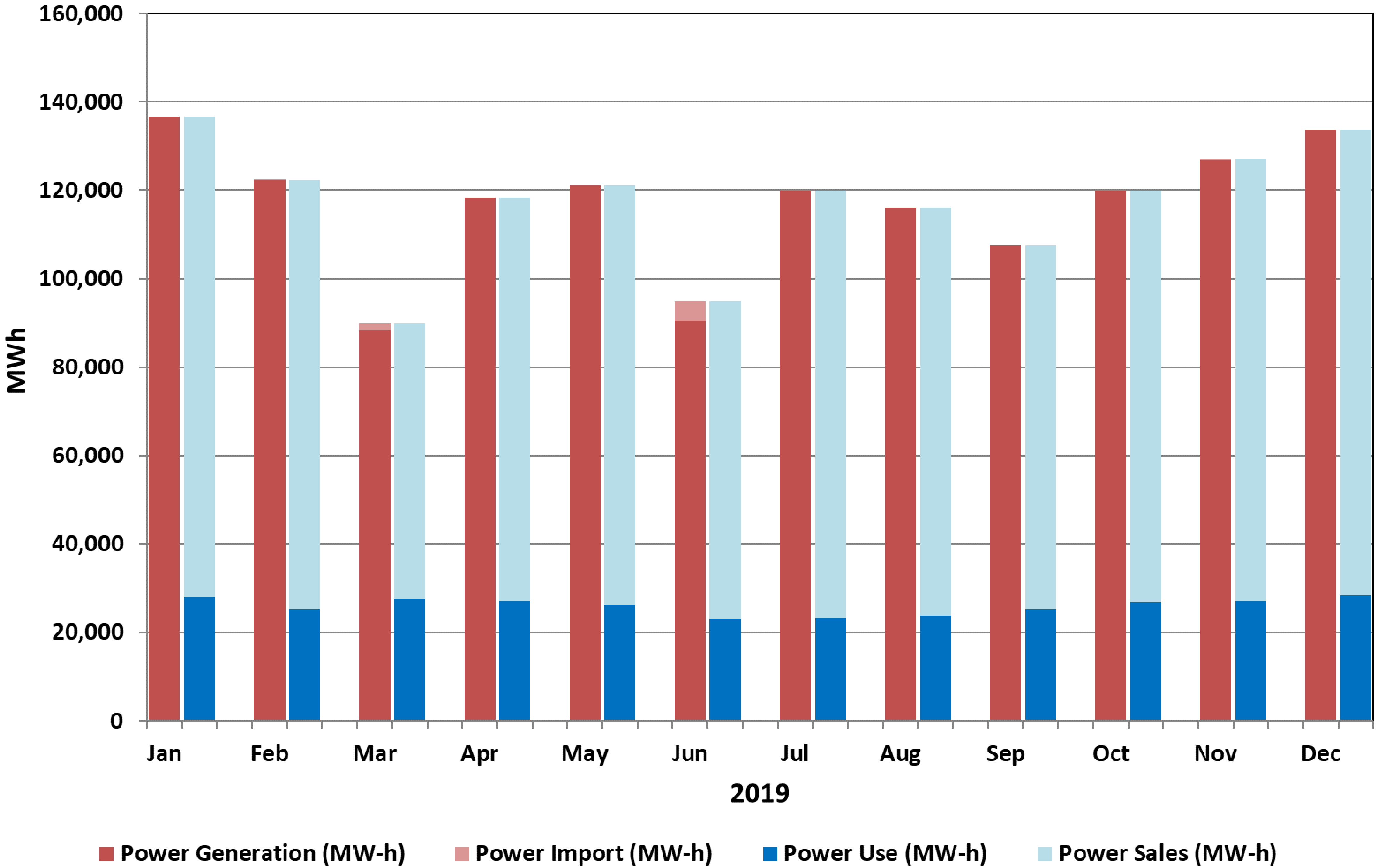
Chemical Usage Optimization

- Oxygen scavenger dosage for BFW is now based on dissolved oxygen measurement, rather than using sulfite residuals.
- Chelant chemical injected at fixed dosage, unless excursion in hardness is observed.

Fired Heater Compliance

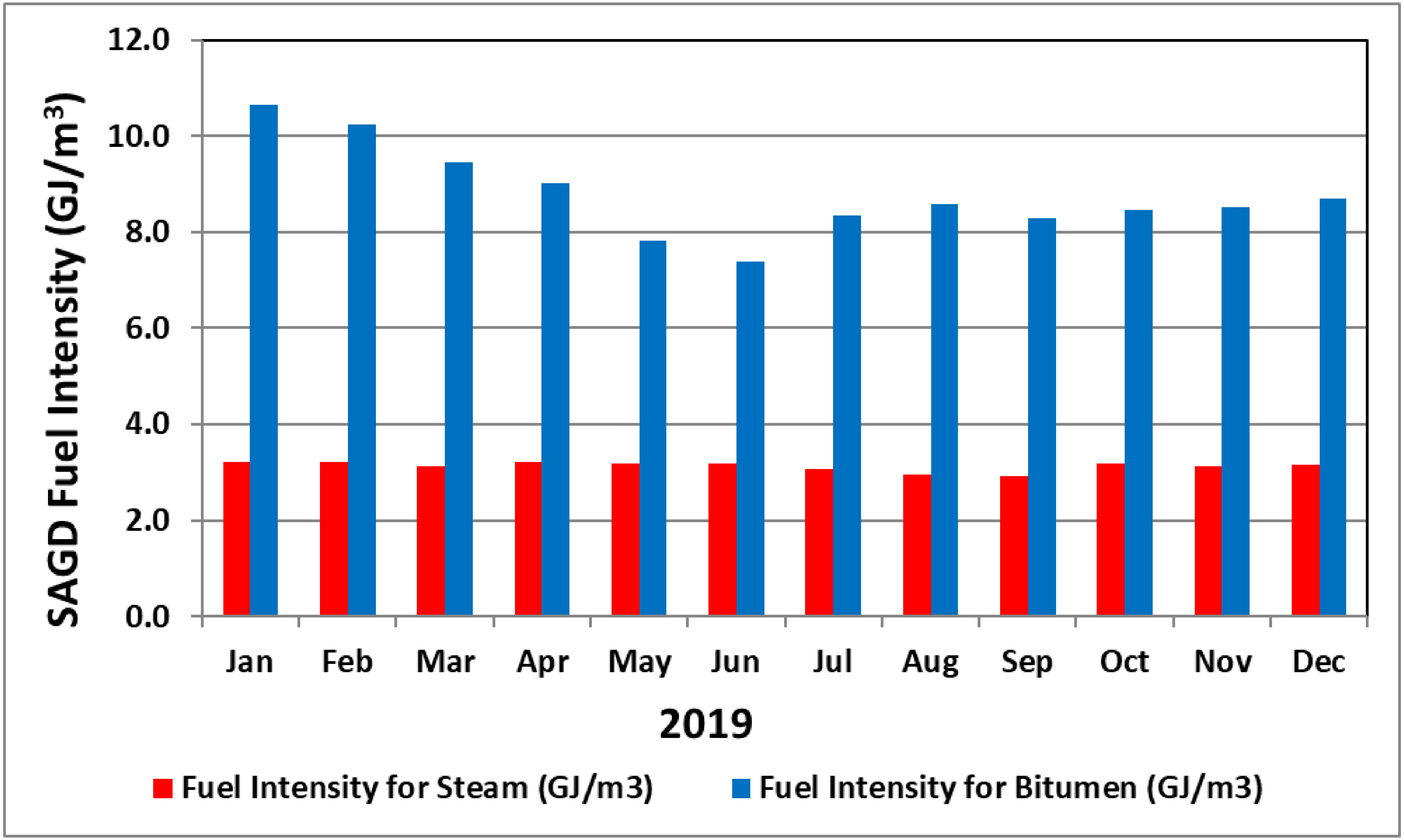
- This project is designed to meet the new CSA B149.3-15 code update with regards to fuel systems and fired heaters.
- OTSG A, C, F and HRSG 1 and 2 completed as planned.

Total Power Usage



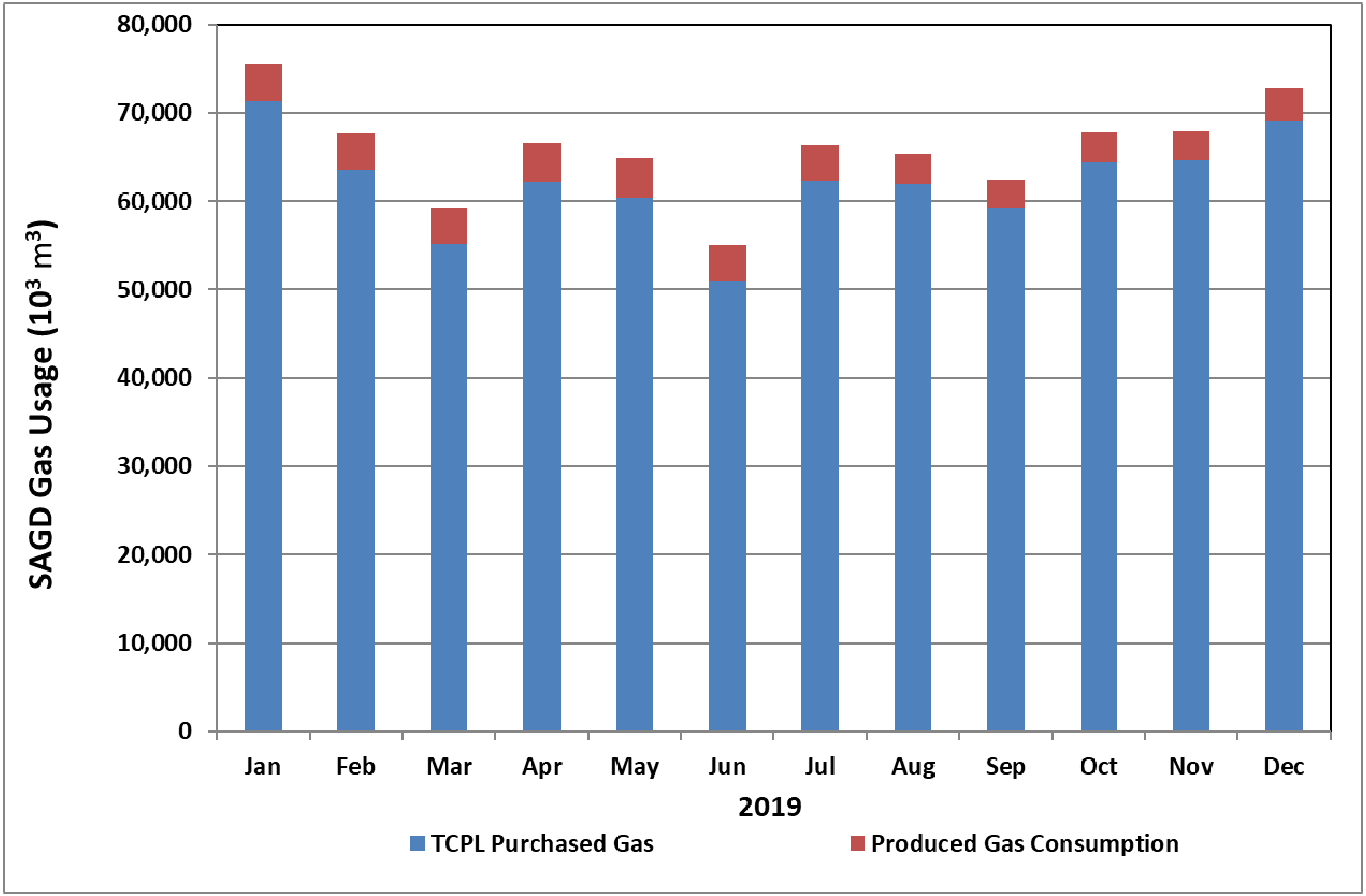
Subsection 3.1.2 (2d)

SAGD Energy Intensity (adjusted for power generation)



Subsection 3.1.2 (2d)

Total Gas Consumed (Purchased and Produced)



Subsection 3.1.2 (2e)

Total Gas Vented and Flared

Month	Total Vented Volume	Total Flared Volume (exclude Pilot gas)
2019	**(10^3m^3)**	**(10^3m^3)**
Jan	6.12	0.60
Feb	4.33	0.52
Mar	18.12	74.06
Apr	0	0.19
May	0.99	0.31
Jun	0.03	0
Jul	1.53	0.06
Aug	0.29	31.45
Sep	7.93	2.82
Oct	5.58	0
Nov	0.68	26.79
Dec	5.80	0.06
Total	**51.39**	**136.86**

- Higher vented volumes in March were related to oil-water separation issues in the free water knock-out (FWKO) drums due to loss of chemical injection. Plant reliability and chemical optimization have resulted in reduced venting events.
- Higher flared volumes in March, August and November were due to plant shut down that resulted from the boiler feed water leak, thunderstorm and device net communication failure, respectively.

Greenhouse Gas Emissions

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Kilotonnes (kT) CO_2e Emissions	3,228	3,189	3,613	4,139	4,384	3,547	1,582	1,883	1,868	1,687
GHG intensity (kg CO_2e/bbl bitumen produced)	361	307	316	310	280	249	199	126	115	100

- Long Lake's Greenhouse Gas intensity is trending downwards.
  - The lower intensity is associated with decreasing steam-to-oil ratios and improved reliability.
  - In 2016, the intensity decreased significantly when Long Lake began operating in SAGD only mode.

- Compliance is being met through improving Long Lake's GHG performance, using carbon credits, and contributions to the technology fund.

- The new Technology Innovation and Emissions Reduction Regulation came into effect in 2020, replacing the Carbon Competitiveness Incentive Regulation (CCIR) system.

Subsection 3.1.2 (2f)

Measurement and Reporting
Subsection 3.1.2 (3)
Long Lake and Kinosis

CNOOC

Methods used for estimating well production

- The Long Lake SAGD facility scheme is operated as a crude bitumen multi-well proration battery; facility sub type 345, in-situ oil sands with Sulphur reporting. Total battery production is allocated to all production wells based on individual well tests.
  - Well pads 2, 3, 6, 7, 8, 9, 10, 12 and 13 are equipped with test separators; with the 12 wells at pads 1, 4 and 5 sharing a single test separator. All test separators are two phase and are equipped with vapor and liquids meters, full stream AGAR OW-201 watercut analyzers, as well as effluent sample points.
  - Pad 11 has Coriolis meters in series with full stream AGAR OW-201 watercut analyzers on each wellhead and no test separator.
  - Pad 14 has a test loop with a Coriolis meter and a full stream AGAR OW-201 watercut analyzer and no test separator.
  - Pad 15 has a test loop with an AGAR MPFM-50 multi-phase flow meter and no test separator.
  - Long Lake Southwest Pads 16 to 18, expected to come on production starting in 2020, will also utilize the AGAR MPFM-50 in a test loop configuration with no test separator.
  - K1A pads were not in service for 2019.
  - Bitumen samples collected from emulsion line are analyzed by Long Lake Lab to determine density as requested by Department of Energy.

Optimization of Test Durations

- Well tests are used to determine bitumen and water production rates for each well. GORs are used to estimate gas production for each well. Each separator and test loop tests one well at a time.
- The test-to-test methodology is used to calculate the total estimated production for each well.
- Currently testing two wells per day per separator. 12 hour test duration, with a minimum of one test per week per well.
- The pad 11 wells shall be considered to be in continuous test; with flow and water cut determined via real time well head measurement.

Steam Injection Measurement

The total steam to the pads is allocated to each injection well based on individual steam injection meters located on each injection well's long and short tubing string.

CNOOC International measures the total steam at the individual well heads on each pad through the use of vortex meters and does not use a common meter to prorate HP steam to the wells. Through 2019 these meters were inspected, cleaned and calibrated. All wellhead meters have a preventative maintenance schedule to maintain the accuracy as per MARP and D-017.

As part of the revised plant production calculation the net steam to pads will be:

Net Steam (SAGD well pads) = TSP – HP to LP Letdown + LP steam vent

Where:

TSP =Total Steam Production

HP to LP Letdown = 8400-PV-553A & 563A

LP Steam vent = 8400-PV-553B & 563B

Steam Production Measurement

This is the primary methodology for steam production reporting.

Total Steam Production (TSP) = OTSG (Sum_p) + HRSG (Sum_p)

OTSG = <u>Once through steam Generators (840x-B-001 A-F), where x = 1 to 6</u>

OTSGs (8401-B-001A-F) will be producing steam based on the following formula (otherwise the value is zero).

$$\text{Steam Production} = \frac{\text{Boiler Feed Water Flow } (Sm^3/h) \times \text{Steam Quality } (\%)}{100}$$

$$= Sm^3/h$$

$$= Sm^3/h \times 24$$

$$= Sm^3/d$$

Subsection 3.1.2 (3a)

HRSGs - Heat Recovery Steam Generators (890x-B-001, where x = 1&2)

HRSGs will be producing steam based on the following formula (otherwise the value is zero).

$$\text{Steam Production} = \frac{\text{Boiler Feed Water Flow } (Sm^3/h) \times \text{Steam Quality } (\%)}{100}$$

$$= Sm^3/h$$

$$= Sm^3/h \times 24$$

$$= Sm^3/d$$

Subsection 3.1.2 (3a)

2019 Proration Factors

LLK Proration Factors 2019		
MONTH	**OIL**	**WATER**
2019-01	1.04	0.87
2019-02	1.01	0.87
2019-03	1.06	0.90
2019-04	1.02	0.94
2019-05	1.02	0.90
2019-06	1.02	0.91
2019-07	1.01	0.89
2019-08	1.03	0.89
2019-09	1.03	0.94
2019-10	1.05	0.88
2019-11	1.04	0.86
2019-12	1.03	0.85

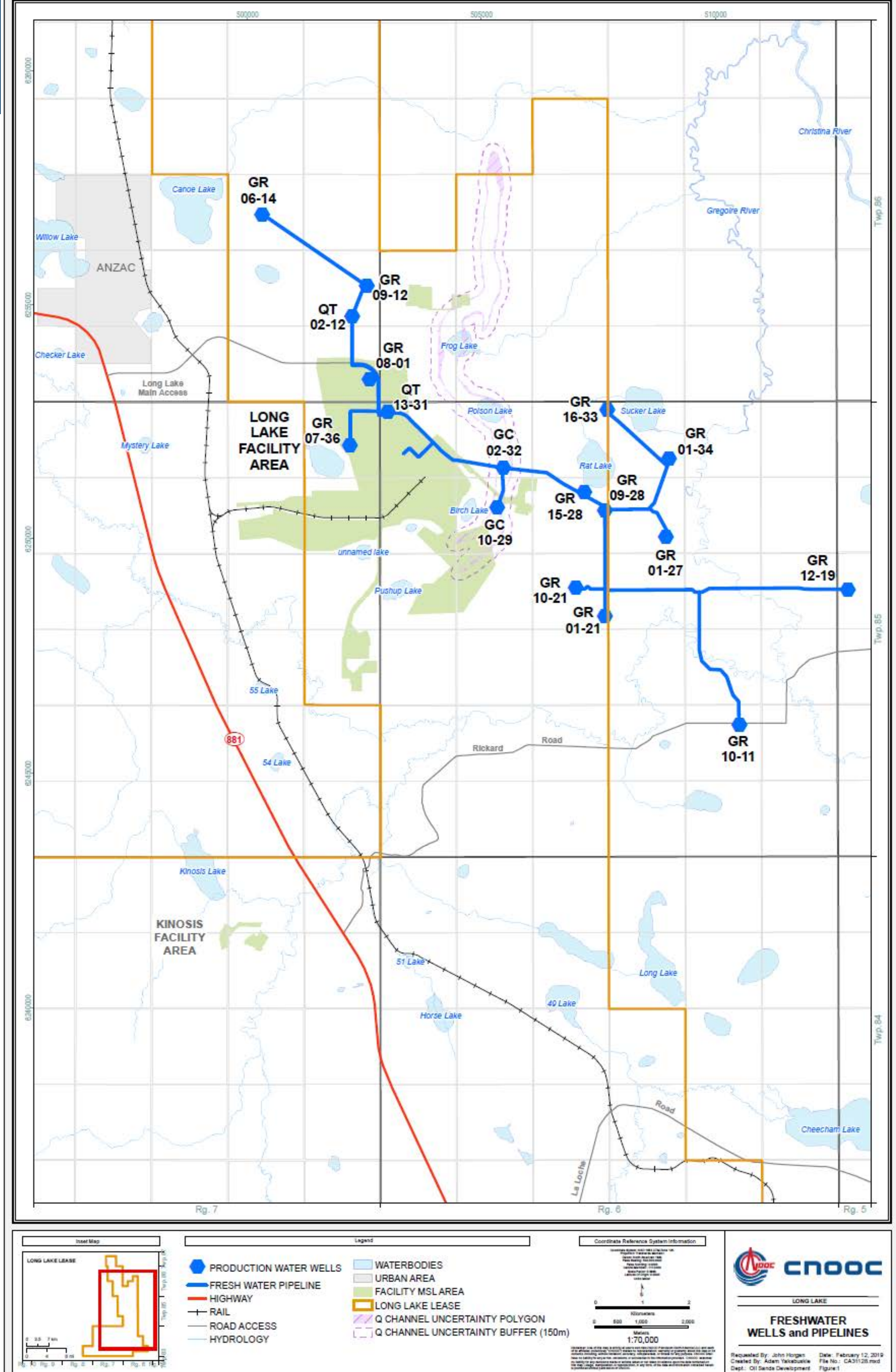
Dir 017: Heavy Oil Battery
Thermal recovery operations
(Petrinex subtypes 344 and 345)

- Oil = 0.85 - 1.15
- Water = 0.85 – 1.15
- Gas = no stated expectation due to the nature of thermal production

Water Production, Injection and Uses
Subsection 3.1.2 (4)
Long Lake

Freshwater Pipelines

- No fresh water wells drilled in 2019



Subsection 3.1.2 (4a)

Freshwater Pipelines (CONT'D)

Plant Operations	WA License# 235895-02-00		Salinity as Total Dissolved Solids		Jan-Dec 2019	
Location	Formation	Fresh?	Sample Date	Concentration (mg/L)	Total (m3)	Annual avg. (m3/cd)
01-21-85-06W4M	Grand Rapids	Y	09-Nov-19	1,700	72,019	197
01-27-85-06W4M	Grand Rapids	Y	11-Sep-19	980	37,413	103
01-34-85-06W4M	Grand Rapids	Y	11-Sep-19	1,600	90,114	247
02-12-86-07W4M	Quaternary	Y	08-Sep-19	640	164,650	451
02-32-85-06W4M	Gregoire Channel	Y	21-Nov-19	1,200	0	0
06-14-86-07W4M	Grand Rapids	Y	07-Sep-19	1,300	131,729	361
07-36-85-07W4M	Grand Rapids	Y	12-Sep-19	600	89,252	245
08-01-86-07W4M	Grand Rapids	Y	09-Sep-14	888	0	0
09-12-86-07W4M	Grand Rapids	Y	08-Sep-19	670	101,779	279
09-28-85-06W4M	Grand Rapids	Y	19-Nov-19	1,400	97,494	267
10-11-85-06W4M	Grand Rapids	Y	10-Sep-19	3,300	29,176	80
10-21-85-06W4M	Grand Rapids	Y	09-Sep-19	1,600	88,234	242
10-29-85-6W4M	Gregoire Channel	Y	09-Nov-19	1,000	17	0
12-19-85-05W4M	Grand Rapids	Y	10-Sep-19	2,200	28,348	78
13-31-85-06W4M	Quaternary	Y	19-Nov-19	530	26,078	71
15-28-85-06W4M	Grand Rapids	Y	11-Sep-19	1,500	100,540	275
16-33-85-06W4M	Grand Rapids	Y	11-Sep-19	1,200	78,669	216
License Allocation 3,285,000 m3 (annual daily average of 9,000 m3/d)		TOTAL			*1,135,512*	3,111

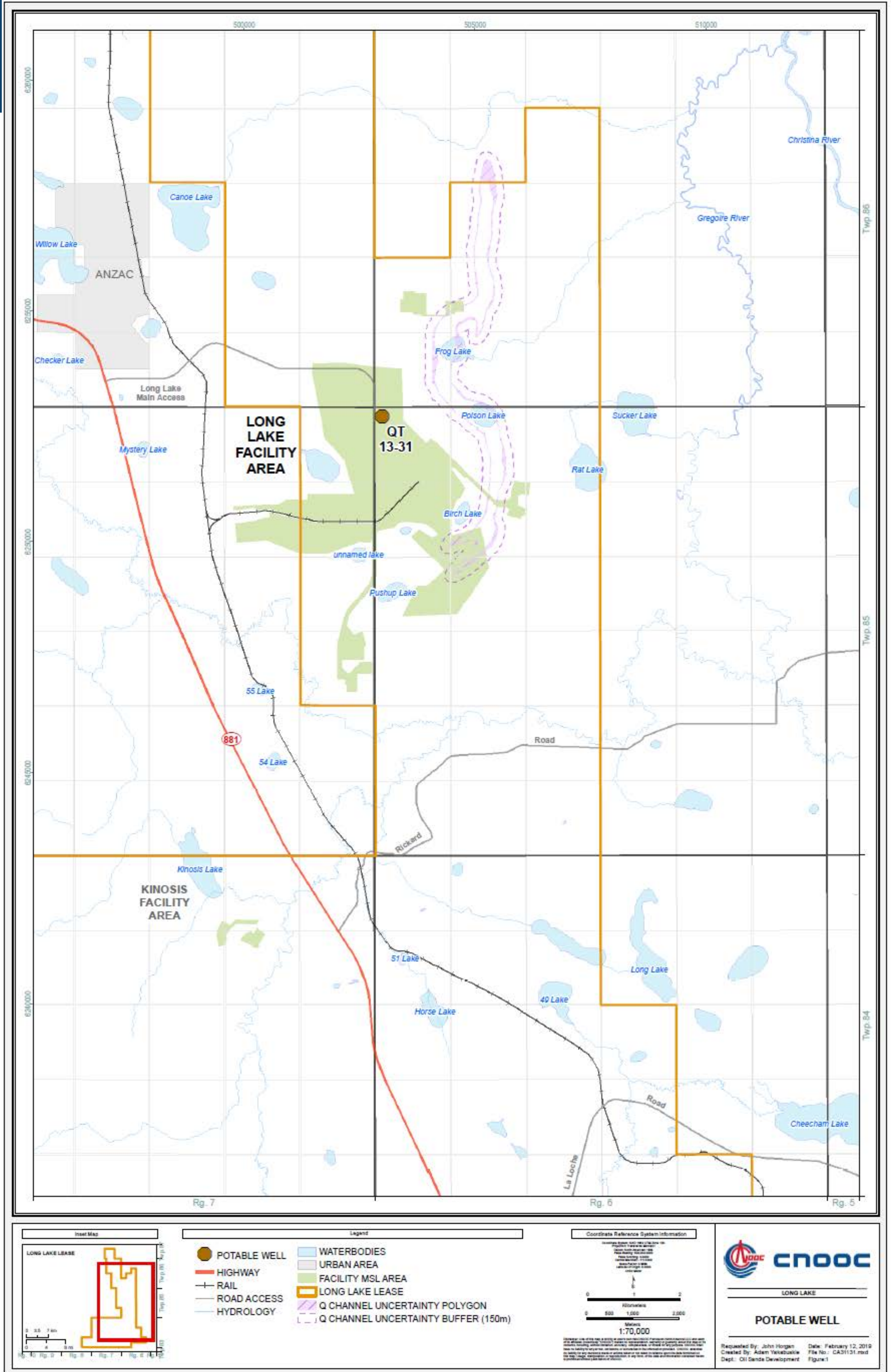
Potable	AENV# 235895-02-00				Jan-Dec 2019	
Location	Formation	Fresh?			Total (m3)	Annual avg. (m3/cd)
13-31-85-06W4M	Quaternary	Y	19-Nov-19	530	33,035	91

- Total of 17 wells tied in.
- WS Q 13-31-085-06W4 used for Long Lake domestic supply and plant safety eye wash and shower system.
- Groundwater samples are collected if source wells are diverted during the year.
- Well 1F1/10-29-085-06W4/00 only turned on for sampling

*Note: A total volume of 59,113 m^3 was diverted from well WS-QT-13-31-085-06W4 for domestic use. The volume of water rejected from the treatment plant (26,078 m^3) was re-used in the plant operations rather than being sent to disposal.

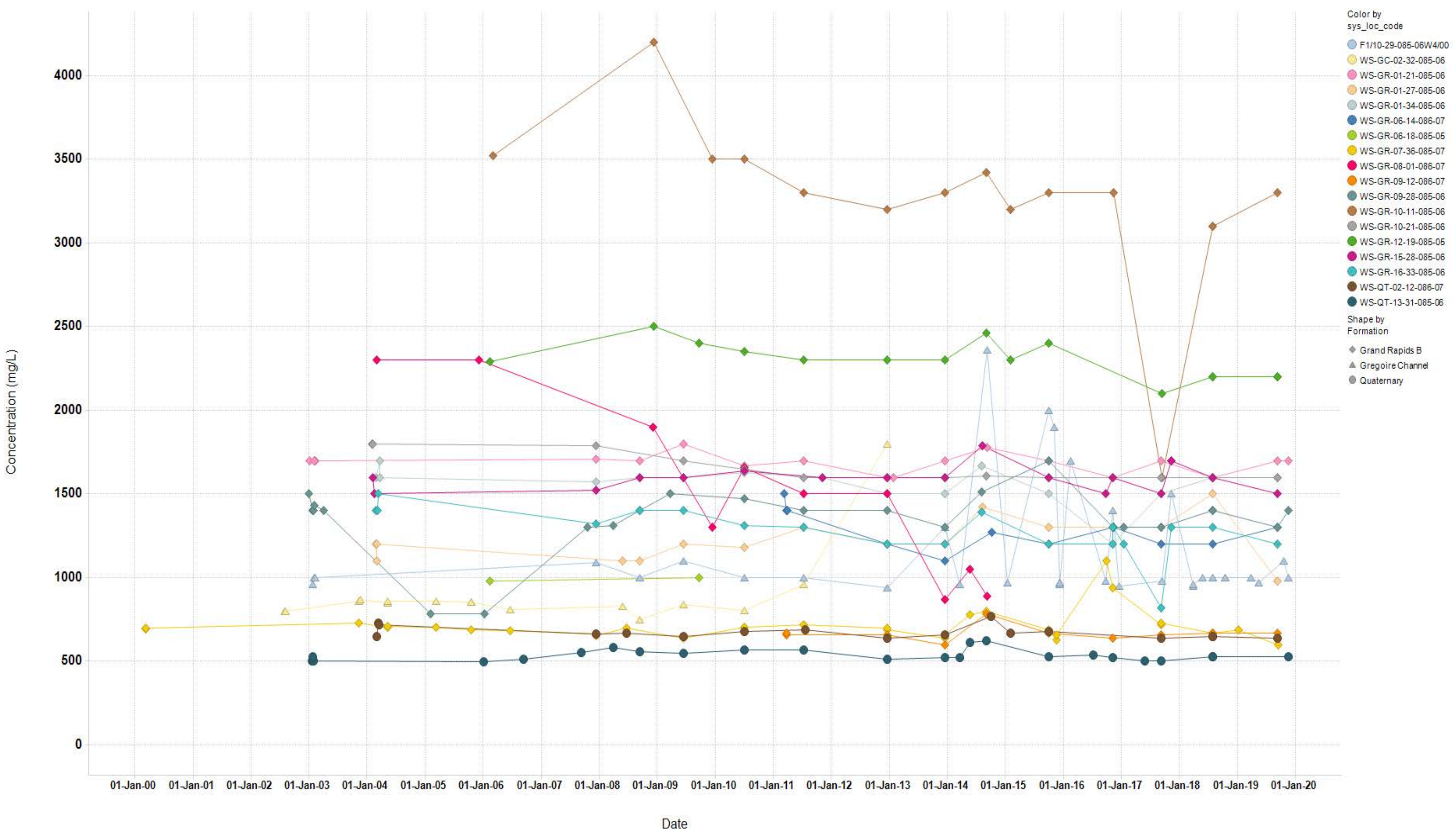
Potable Well

Aquifer: Quaternary drift
Purpose: Domestic (camp)
Location: 13-31-85-06W4
2019 diversion: 59,113 m^3/y
Average daily rate: 162 m^3/d



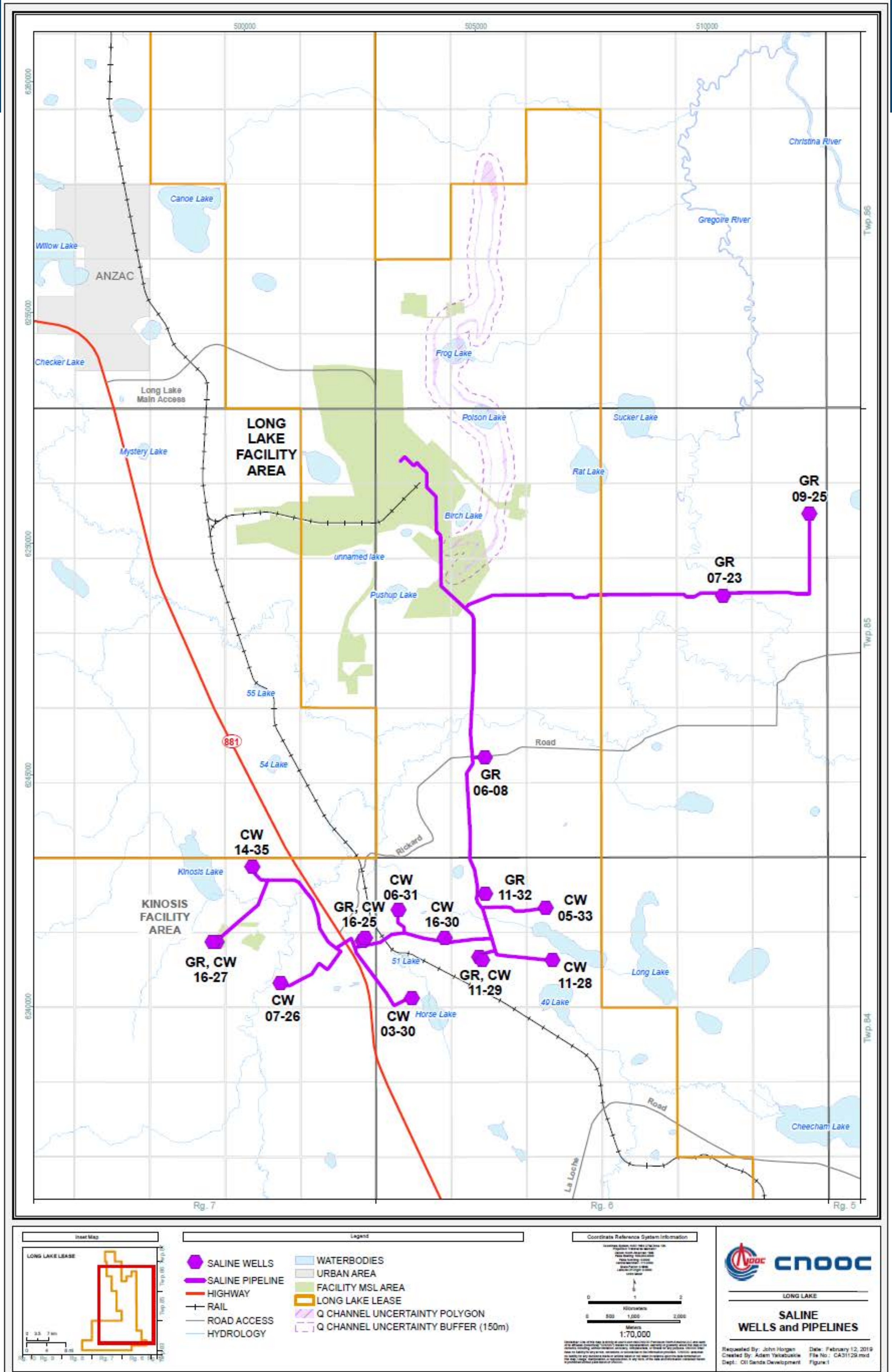
Subsection 3.1.2 (4a)

Fresh Water Source Wells Water Quality TDS



Saline Water Pipelines

- No new saline wells drilled in 2019



Saline Water Pipelines (CONT'D)

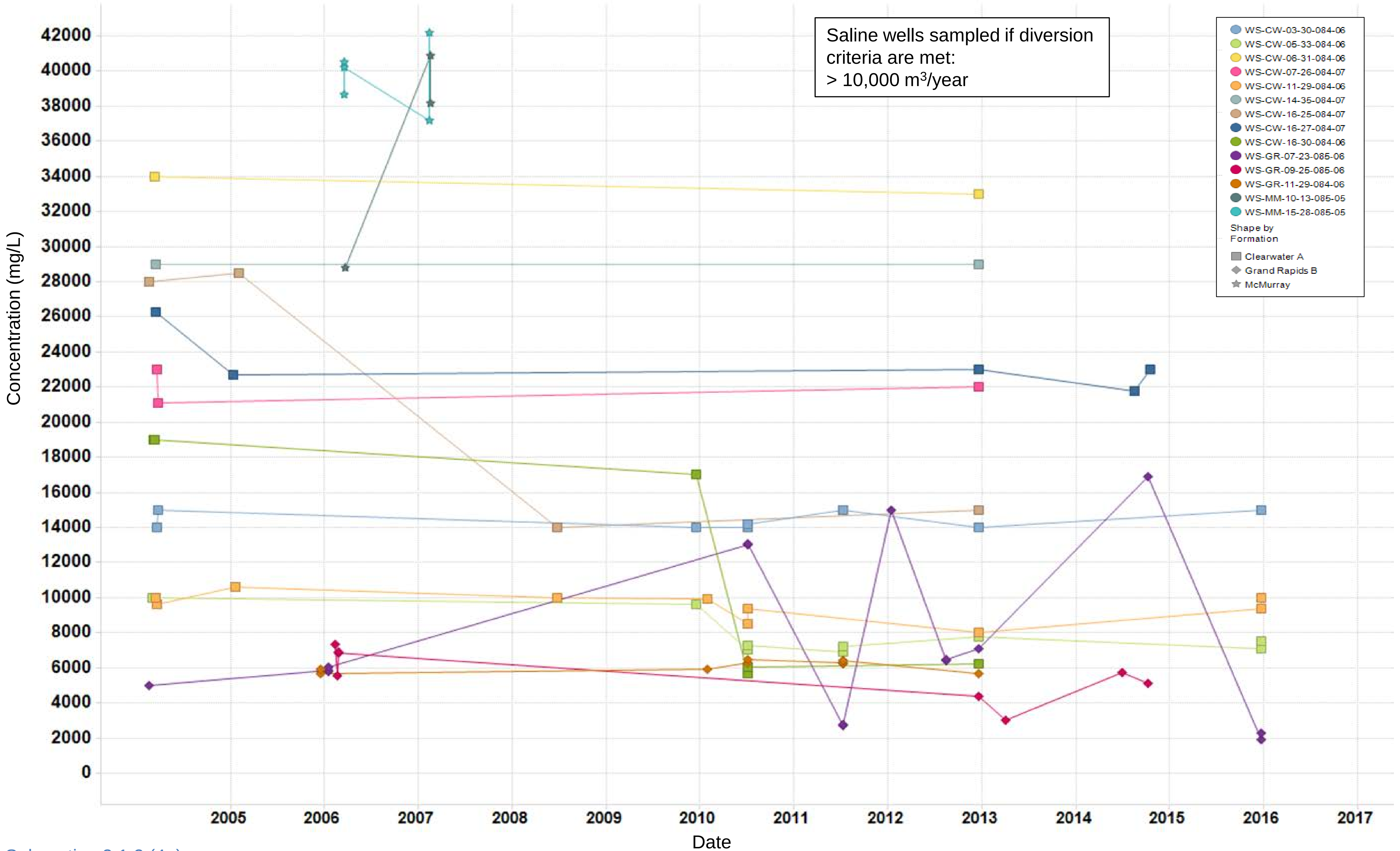
Plant Operations			Total Dissolved Solids			Jan-Dec 2019
Location	**Formation**	**Saline?**	**Sample Date**	**Concentration (mg/L)**	**Total (m3)**	**Annual avg. (m3/cd)**
1F2/03-30-084-06W4	Clearwater	Y	22-Dec-15	15,000	0	0
1F1/05-33-084-06W4	Clearwater	Y	22-Dec-15	7,500	0	0
1F1/06-31-084-06W	Clearwater	Y	19-Dec-12	33,000	0	0
07-23-85-06W4	Grand Rapids	Y*	22-Dec-15	2,300	0	0
1F1/07-26-084-07W4	Clearwater	Y	19-Dec-12	22,000	0	0
09-25-85-06W4	Grand Rapids	Y	9-Oct-14	5,130	0	0
1F1/11-29-084-06W4	Clearwater	Y	22-Dec-15	10,000	0	0
11-29-84-06W4	Grand Rapids	Y	19-Dec-12	5,700	0	0
1F1/14-35-084-07W4	Clearwater	Y	19-Dec-12	29,000	0	0
1F1/16-27-084-07W4	Clearwater	Y	16-Oct-14	23,000	0	0
1F1/16-25-084-07W4	Clearwater	Y	19-Dec-12	15,000	0	0
1F1/16/30/084/06W4	Clearwater	Y	19-Dec-12	6,200	0	0
Subtotal Saline Diverted Volume					*0*	0
06-08-85-06W4M	Grand Rapids	N	19-Dec-12	2,000	0	0
1F1/11-28-084-06W4	Clearwater	N	30-May-13	2,900	0	0
11-32-84-06W4M	Grand Rapids	N	1-May-16	3,600	0	0
16-25-84-07W4M	Grand Rapids	N	19-Dec-12	2,400	0	0
16-27-84-07W4M	Grand Rapids	N	13-Jan-17	1,800	0	0
Subtotal Non-Saline Diverted Volume					*0*	0
TOTAL VOLUME DIVERTED					0	0

* intermittent non-saline

Subsection 3.1.2 (4a,b)

Saline Source Wells Water Quality TDS

- Saline source wells were not sampled in 2019 as no water was diverted



Subsection 3.1.2 (4a)

Other Water Sources

- Surface runoff to lime sludge ponds (Licence No. 00247843-01-00):
  - 2019: 202,355 m^3 (estimate)
- Well drilling, dust control, winter access freezing:
  - Licence No. 311818-00-01 and 354427-00-00: 9,862 m3

Long Lake Industrial Runoff

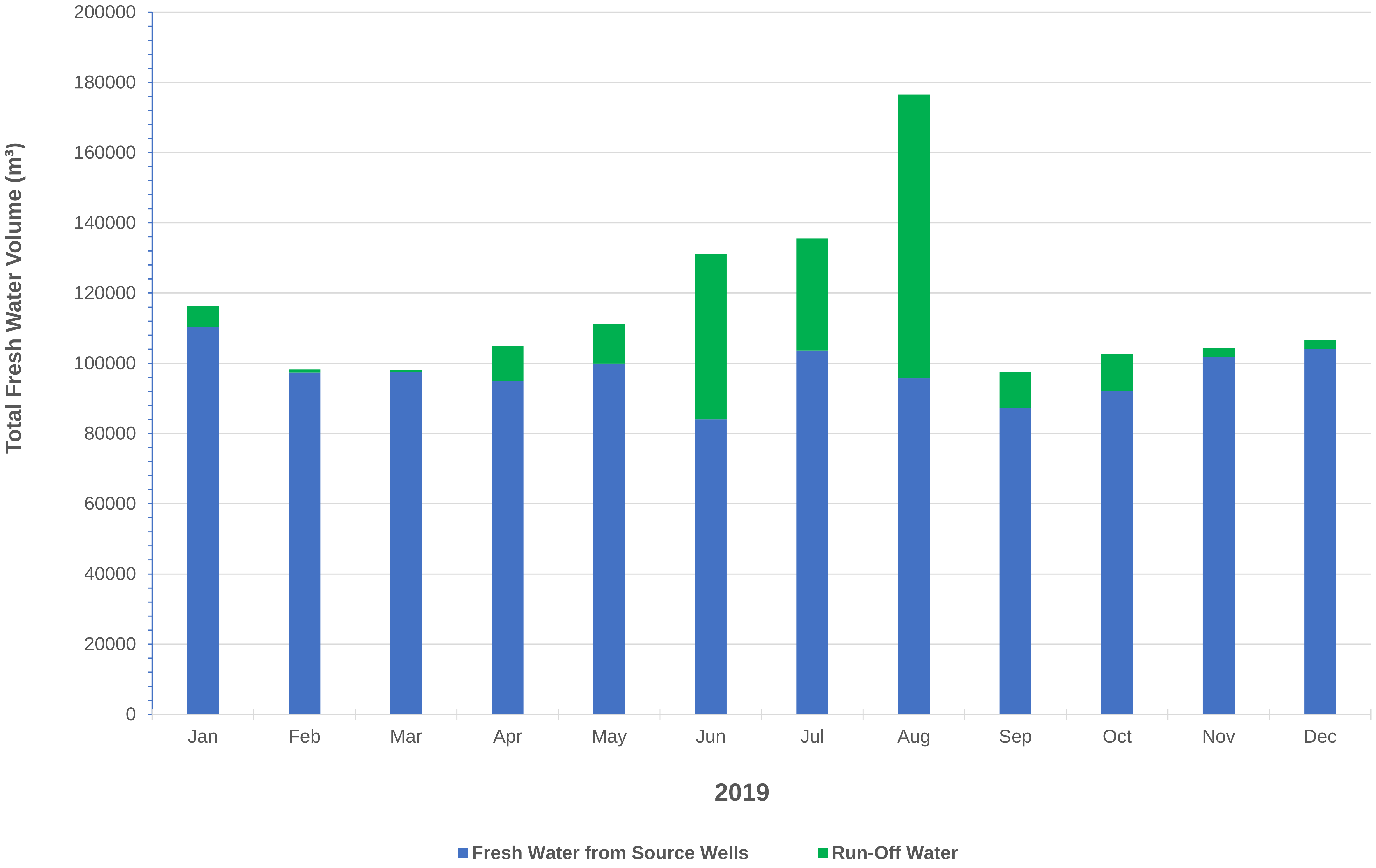
- Industrial runoff from the Long Lake central processing facility (CPF) is diverted to the lime sludge/water recycle ponds for industrial injection purposes (Diversion licence 00247843-01-00)
- In 2019, 12,156 m3 was released from the CPF ditch system to the environment when the lime sludge pond level was too high to accept runoff (i.e. upset conditions, heavy rain and/or spring melt)
- All water released to the environment from the Long Lake CPF and well pad industrial runoff control systems met discharge criteria for release to the environment

Table: Industrial runoff release sample results and volumes from the CPF and example well pads in 2019

Date	Discharge Point / Location	LSD (XX-XX-XXX-XX WXM)	Field pH	Lab pH	Field Cl (mg/L)	Lab Cl (mg/L)	Field pH	Field Cl (mg/L)	Visible Oil / Grease (Y/N)	Total Discharge Time (hrs)	Discharge Volume (m^3)
			For CPF				For Wellpads				
		Limits:	6.0 - 9.5		500		6.0 - 9.5	500			
March 22, 2019	Pad 12	07-07-086-06 W4M					6.0	86	N	10.00	720
March 23, 2019	Pad 14	09-29-085-06 W4M					6.0	<28	N	10.87	782
July 4, 2019	Pad 11	12-36-085-07 W4M					6.0	28	N	7.00	504
July 5, 2019	Pad 7	11-25-085-07 W4M					6.0	28	N	9.67	696
August 15, 2019	8200 Tank Farm Pond	05-31-085-06 W4M	7.0	8.3	28	9.0			N	7.25	957
August 18, 2019	Pad 2	07-31-085-06 W4M					6.0	28	N	8.67	312
August 18, 2019	Pad 6	09-25-085-07 W4M					6.0	28	N	6.08	219
August 19, 2019	6th Street	04-31-085-06 W4M	7.0	7.87	28	34			N	18.42	4863
August 20, 2019	6th Street	04-31-085-06 W4M	6.0	7.79	28	33			N	24.00	6336

Source: 2019 Long Lake Industrial Wastewater and Run-off Report (EPEA Approval 137467-01-00)

Fresh Water Use Volumes



*Includes domestic use from WS-QT-13-31-085-06W4

Subsection 3.1.2 (4b)

Water Make-up

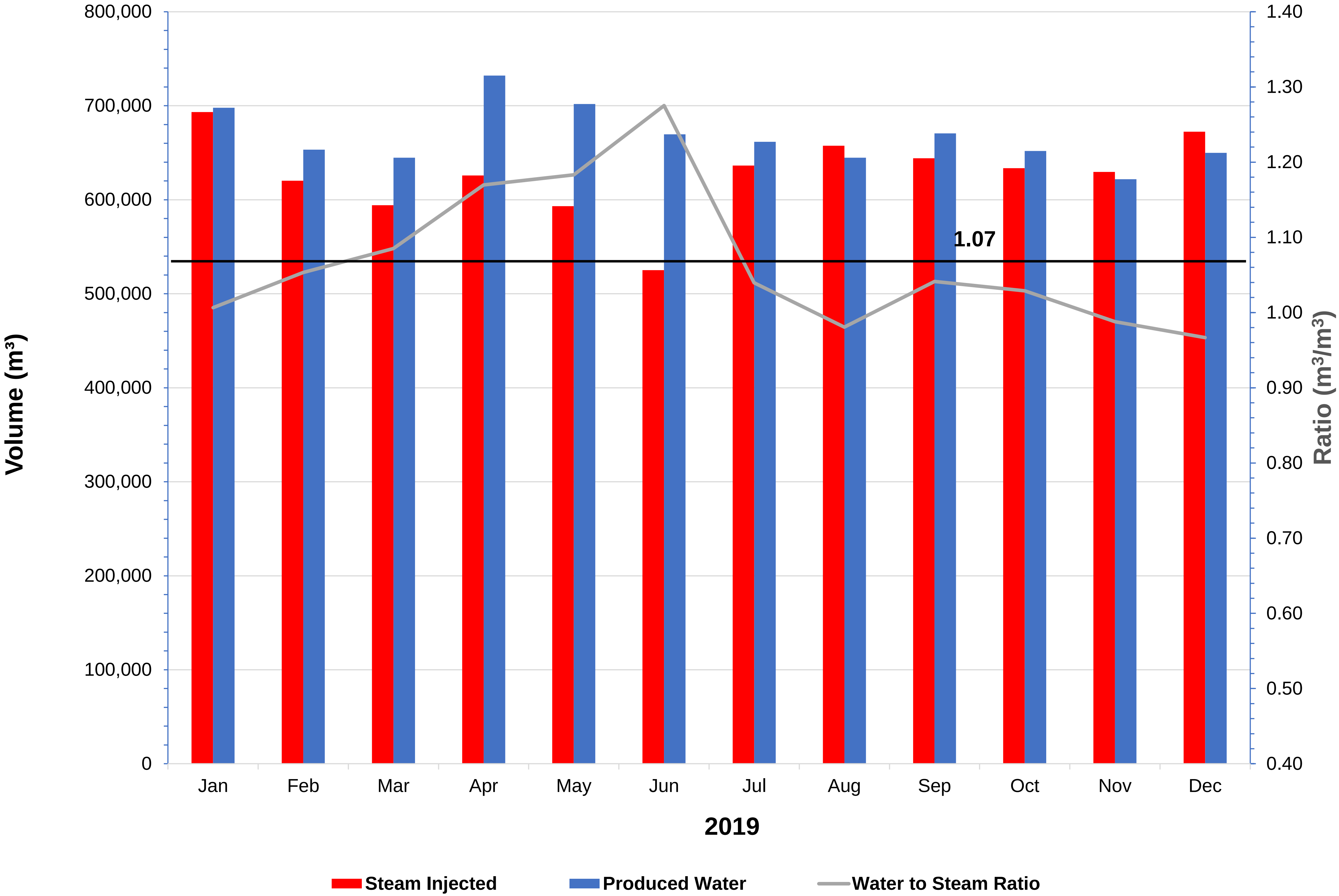
- Use of freshwater make-up (in decreasing amounts)
  1. Utility and plant use, recycled to SAGD for steam generation
  2. Demineralized water make-up (UPG and cogens)
  3. Domestic
  4. Others (incl. drilling)

Freshwater Uses in 2019 (m^3)				
	Total	Domestic	Recycled	Process
Main groundwater license (235895-02-00 as amended)	1,168,546	33,035	787,410	348,102
Surface runoff to ponds (includes K1A) (m3)	180,851		180,851	
Various surface water sources - Drilling and other K1A & LLK	9,862			
TOTAL	1,359,259			

- Saline water make-up:

  0 m^3 in 2019 for steam make-up, average WSR = 1.07

Produced Water and Steam Injected Volumes

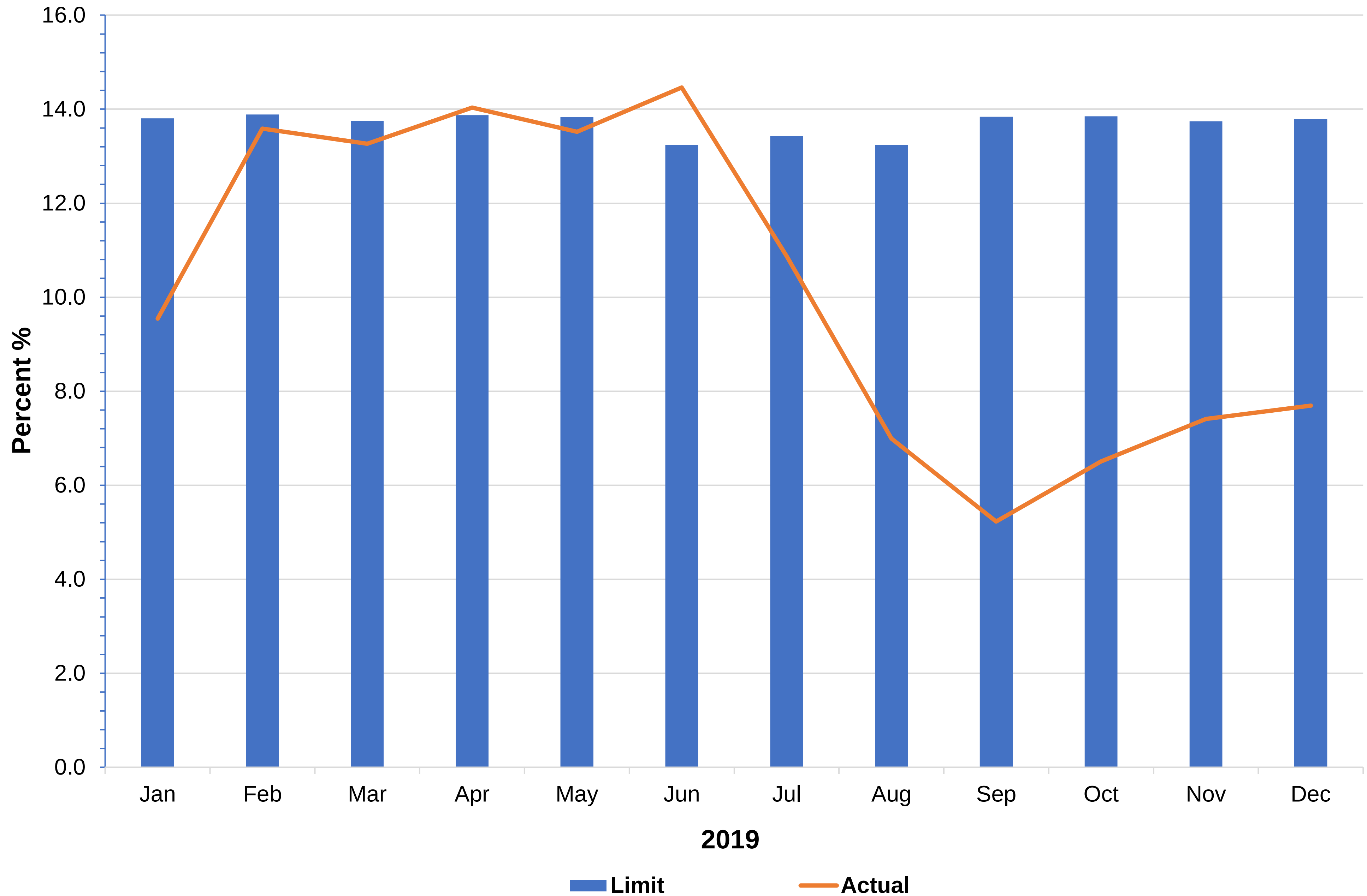


Subsection 3.1.2 (4c,d)

Water Management

$$\text{Disposal limit (\%)} = \frac{[(\text{Freshwater In}*D_f) + (\text{Brackish water In} *D_b + (\text{Produced water In}*D_p)]*100}{[(\text{Freshwater In}) + (\text{Brackish water In}) + (\text{Produced water In})]}$$

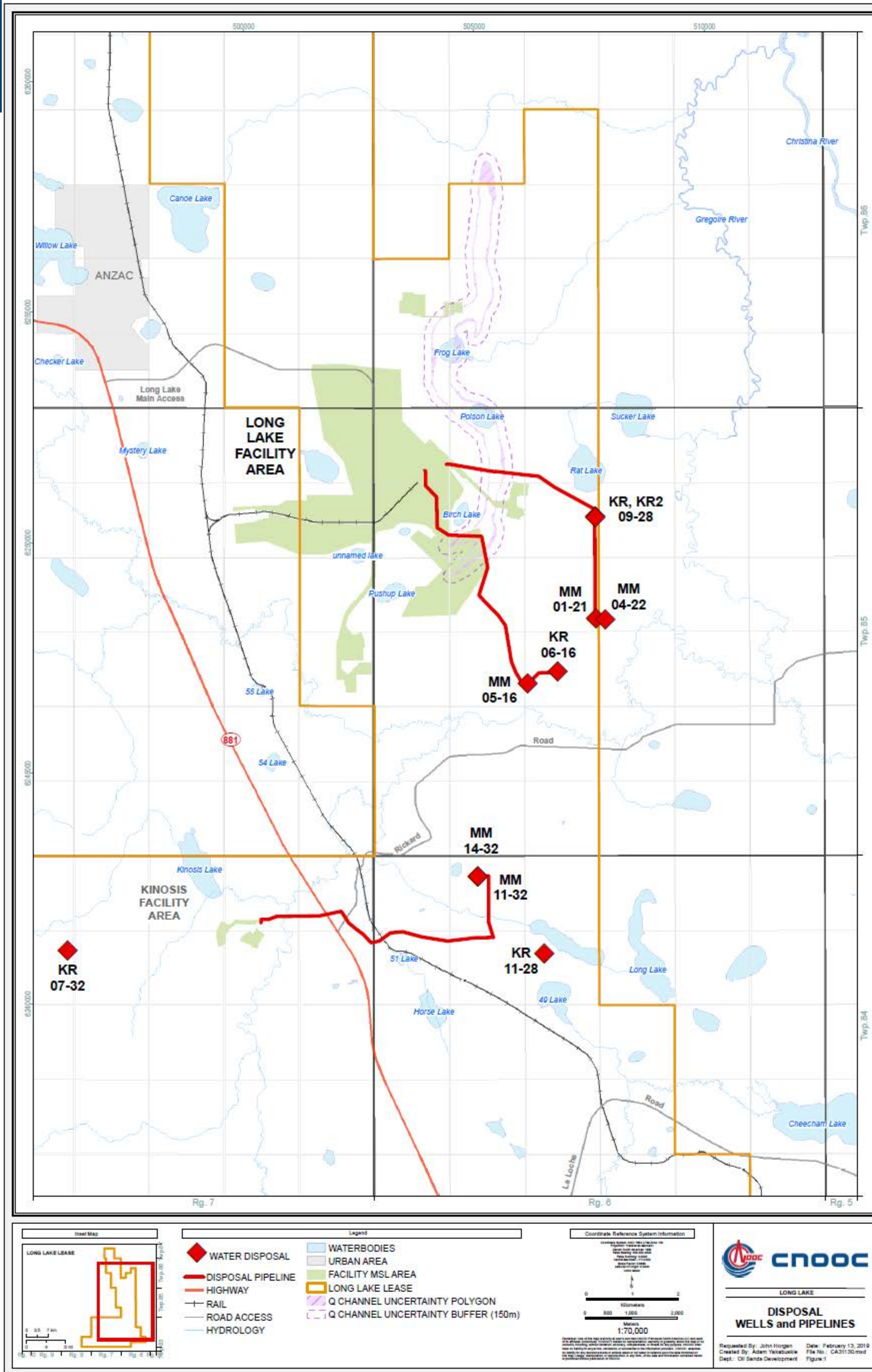
Note: CNOOC International received approval to have produced water disposal factor increased from 0.10 to 0.15 effective Oct 1, 2017 to Oct. 31, 2020.



Average Limit = 13.7 %

Average Actual = 10.3 %

Disposal Wells



Subsection 3.1.2 (4g)

Disposal Wells (CONT'D)

Class 1B Disposal Wells (Approval No. 10032K)
CNOOC Int ULC   Sumary of disposal activities 2019
Long Lake Project

Well ID	Unique Well Identifier	No. of Days of Disposal	Average Disposal Rate [2] (m^3/day)	Max. Disposal Rate (m^3/day)	Disposal Volume (m^3)	Maximum WHP [1] (kPag)	Maximum Allowable WHP (kPag)
WD-KR-11-28-084-06	00/11-28-084-06W4/00	0	0	0	0	0	3,000
WD-MM-11-32-084-06	00/11-32-084-06W4/00	0	0	0	0	0	3,960
WD-MM-14-32-084-06	00/14-32-084-06W4/00	0	0	0	0	0	3,700
WD-MM-04-22-085-06	00/04-22-085-06W4/00	0	0	0	0	0	3,950
WD-KR-09-28-085-06	03/09-28-085-06W4/00	345	819	1,799	282,520.5	1,466	3,000
WD-KR2-09-28-085-06	04/09-28-085-06W4/00	356	1,787	4,789	636,126	1,978	2,865
WD-KR-07-32-084-07	02/07-32-084-07W4/00	0	0	0	0	0	3,450
WD-MM-01-21-084-06	03/01-21-085-06W4/2	0	0	0	0	0	2,250
	Total				918,646.5		

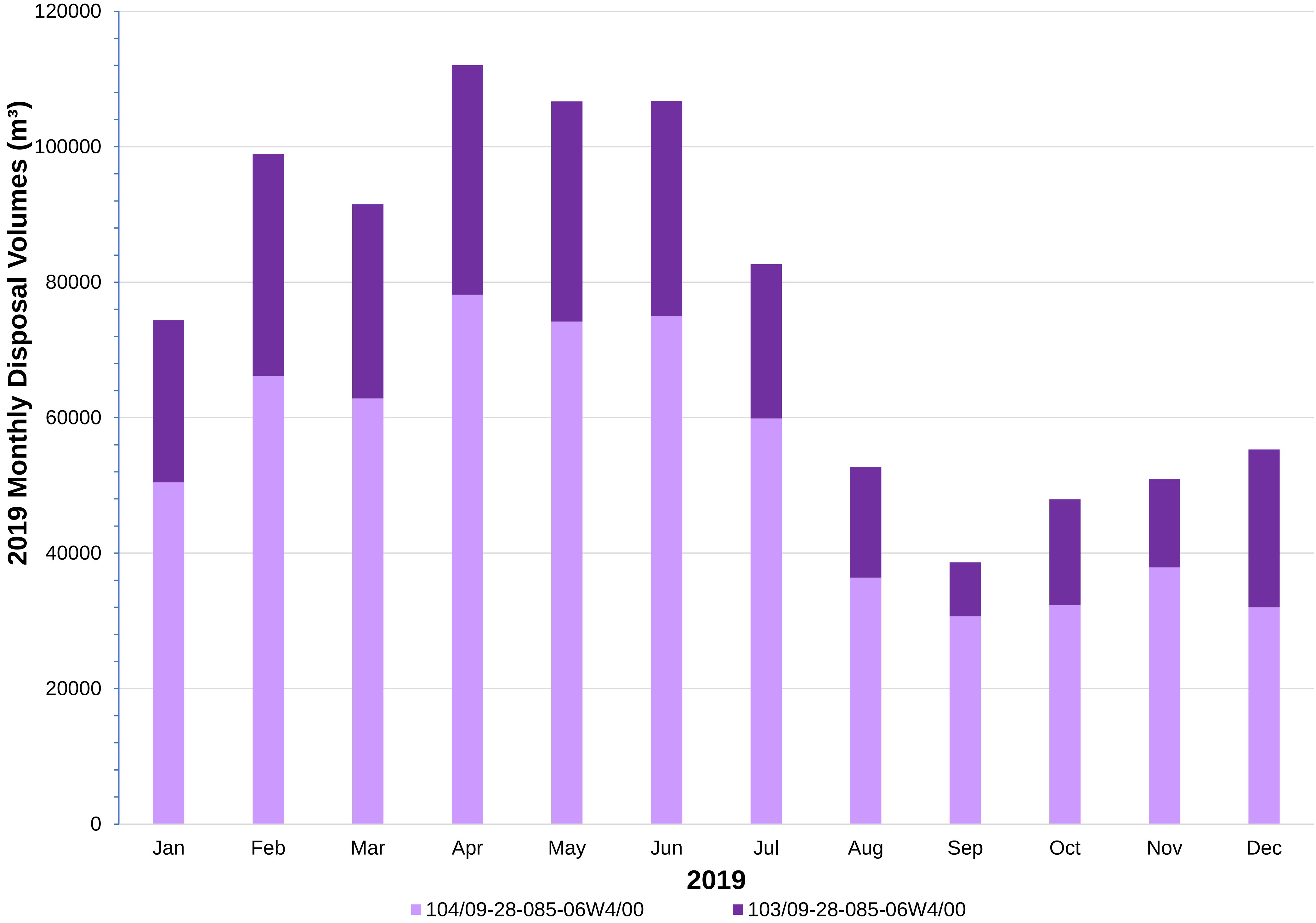
Notes:
1. WHP = Well Head Pressure
2. Excluding days of no disposal

AER Approval # 11611	Class 1a	January - December 2019		
Disposal Well		Max. WHP (kPag)	Total (m^3)	Annual avg. (m^3/cd)
100/06-16-085-06W4 KR*	-	-	-	-
100/05-16-085-06W4 McM*	-	-	-	-

*Well is suspended

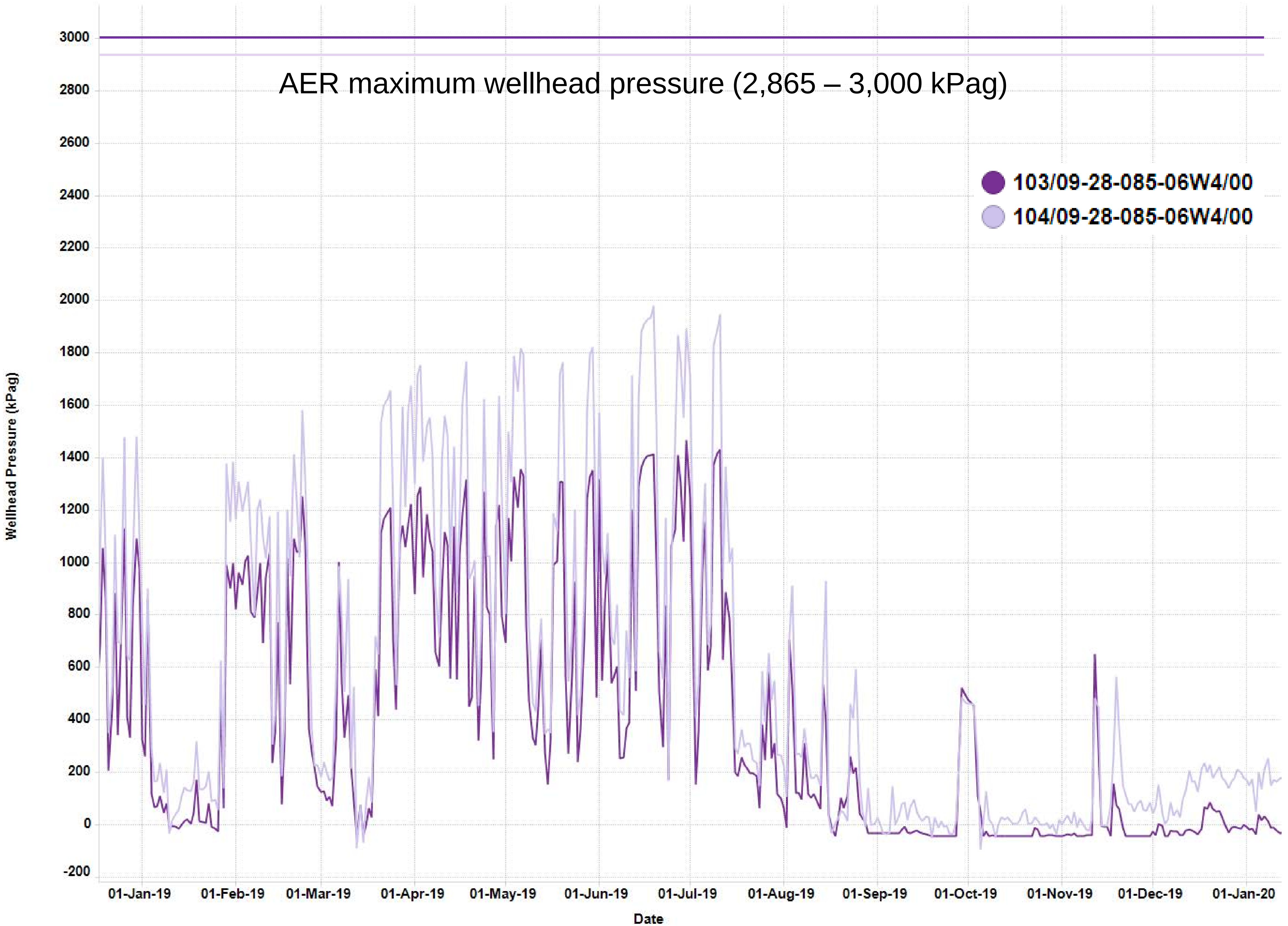
- Disposal capacity is adequate
- All wells passed annulus pressure test

Disposal Well Volumes - Class 1b



- 2019 disposal only to Keg River wells 103/ and 104/09-28-085-06W4/00

Disposal Well - Well Head Pressures

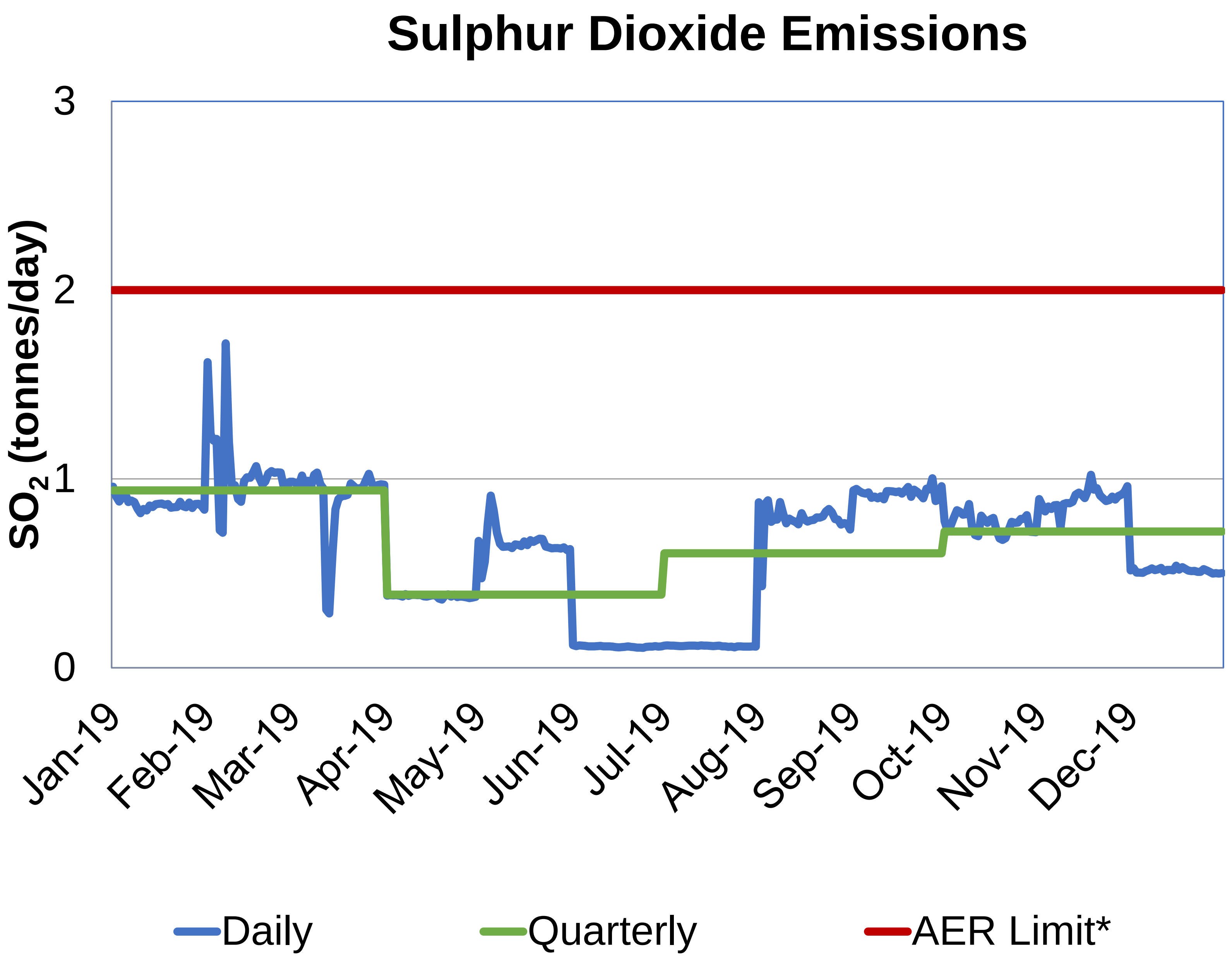


Sulphur Production and Air Emissions
Subsection 3.1.2 (5)
Long Lake and Kinosis

CNOOC

Sulphur Production

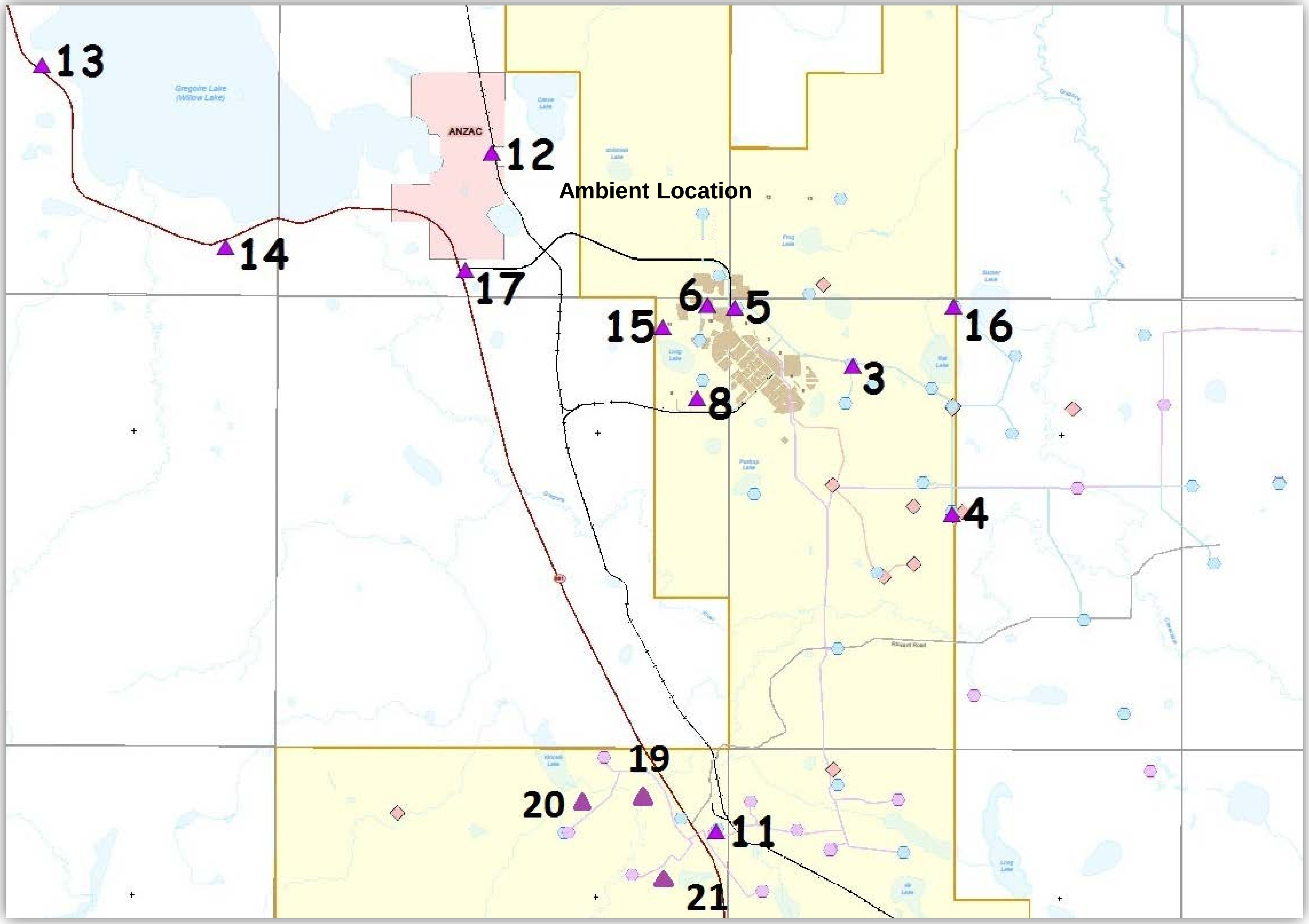
- Sulphur was not recovered at Long Lake in 2019 since SO_2 emissions were below the limit.



Air Monitoring

- Passive air monitoring for SO_2, H_2S, and NO_2 was conducted around the Long Lake and K1A facility in accordance with the EPEA approval.
- Continuous emissions of NO_2 were monitored using Continuous Emissions Monitoring (CEMS) as required by the EPEA. Relative Accuracy Test Audits and Manual Stack Surveys were completed as part of the performance testing requirements.
- Ambient Air Monitoring was conducted by the Wood Buffalo Environmental Association (WBEA) at the Anzac Ambient Air Monitoring Station on behalf of Long Lake operations. Continuous and intermittent data was submitted to the Director by the WBEA.
- Emissions of SO_2 and NO_2 from the Long Lake facility were summarized in the monthly and annual Air Emission Reports.

Passive Air Monitoring Locations
Long Lake & K1A

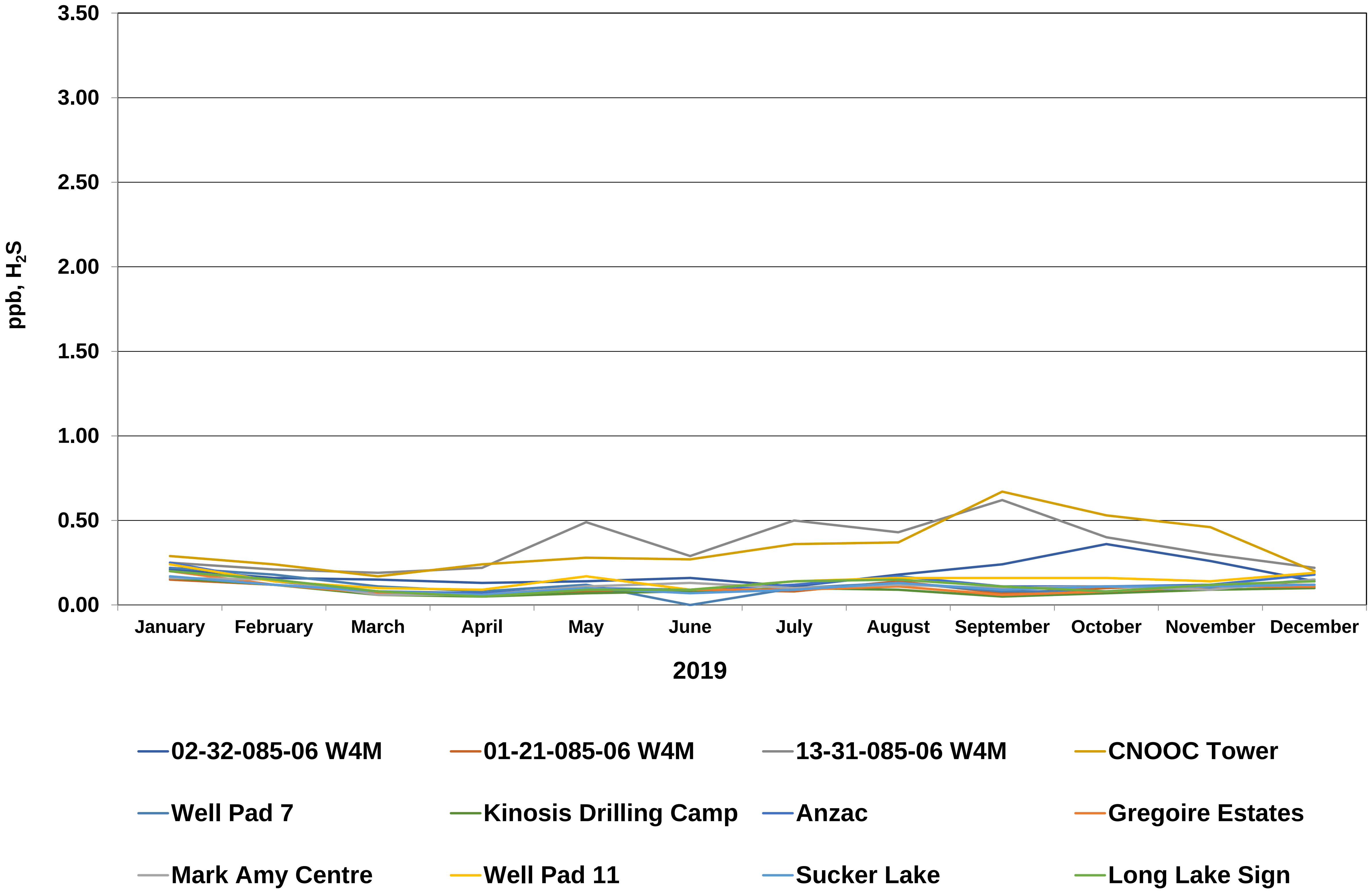


Passive Air Monitoring Station Status

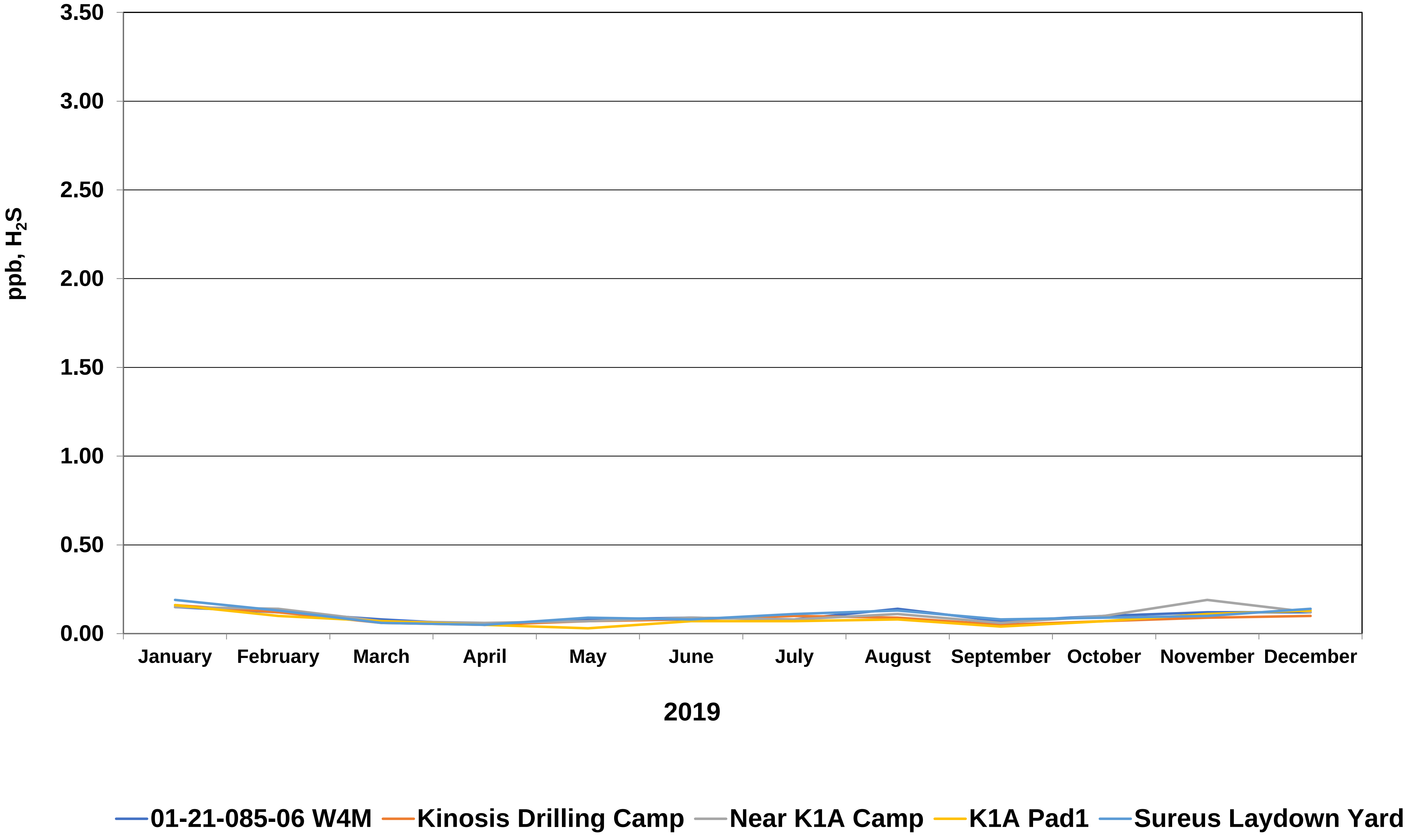
Station Number	Station Location	Status
1	SAGD Pilot Site SE- near Pilot flare stack	Discontinued in December 2010
2	SAGD Pilot Site NW Rear of the Pilot	Discontinued in December 2010
3	02-32-085-06 W4M Source Well	Active
4	01-21-085-06 W4M Source Well	Active
5	13-31-085-06 W4M Source Well	Active
6	CNOOC Tower	Active
7	Well Pad 9	Discontinued in January 2010
8	Well Pad 7	Active
9	Electrical Substation	Discontinued in December 2010
10	Beside Tankyard	Discontinued in December 2010
11*	Kinosis Drilling Camp	Active
12	Anzac	Active
13	Gregoire Estates	Active
14	Mark Amy Centre	Active
15	Well Pad 11	Active
16	Sucker Lake	Active
17	Long Lake Sign	Active
18	02-12-85-06 W4M Source Well	Discontinued in May 2014
19*	K1A Camp	Active as of June 2014
20*	K1A Pad 1	Active as of June 2014
21*	Surerus Laydown	Active as of June 2014

* K1A Passive Stations

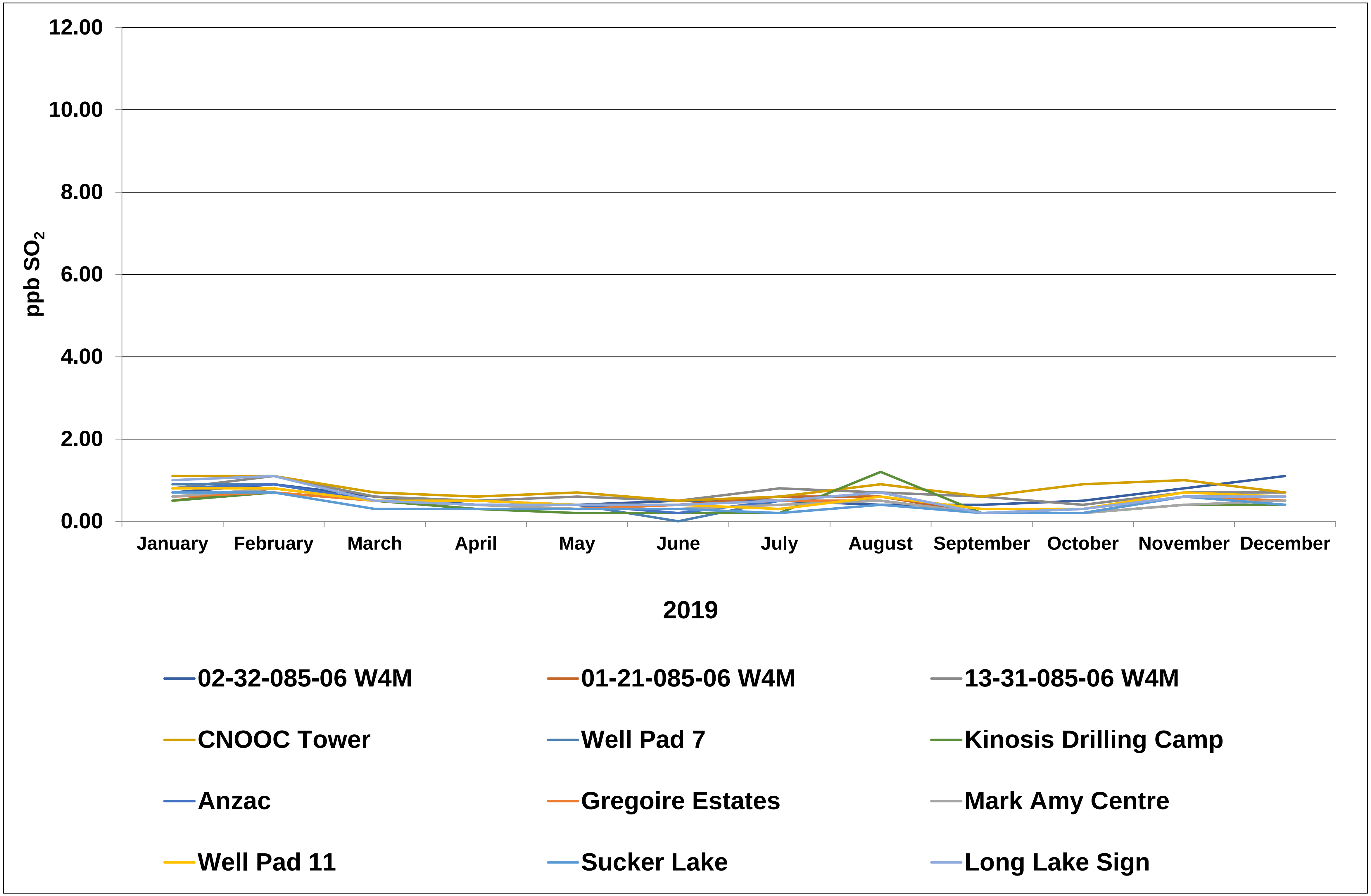
Long Lake H_2S Passive Monitoring



K1A H_2S Passive Monitoring

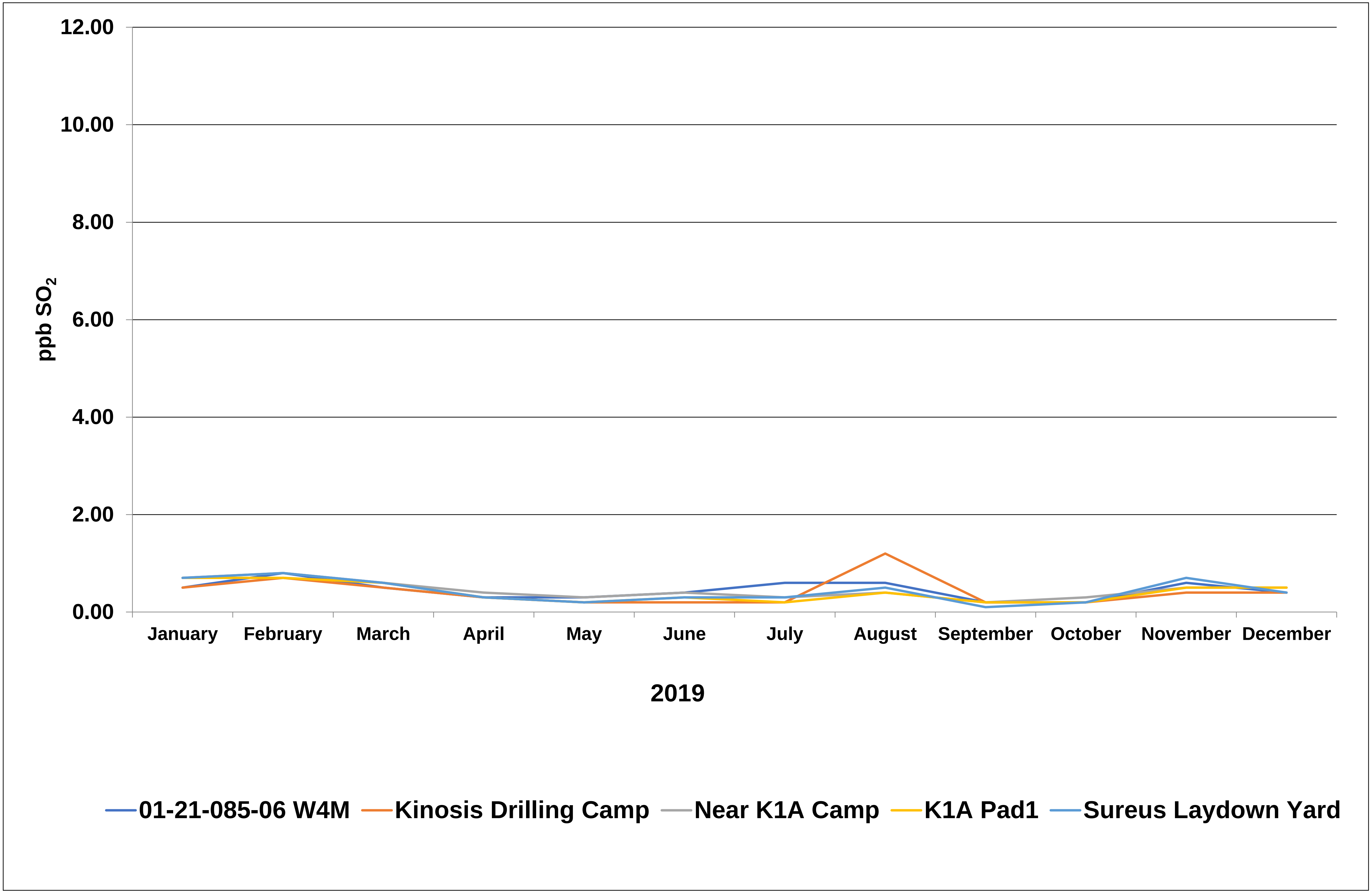


Long Lake SO_2 Passive Monitoring



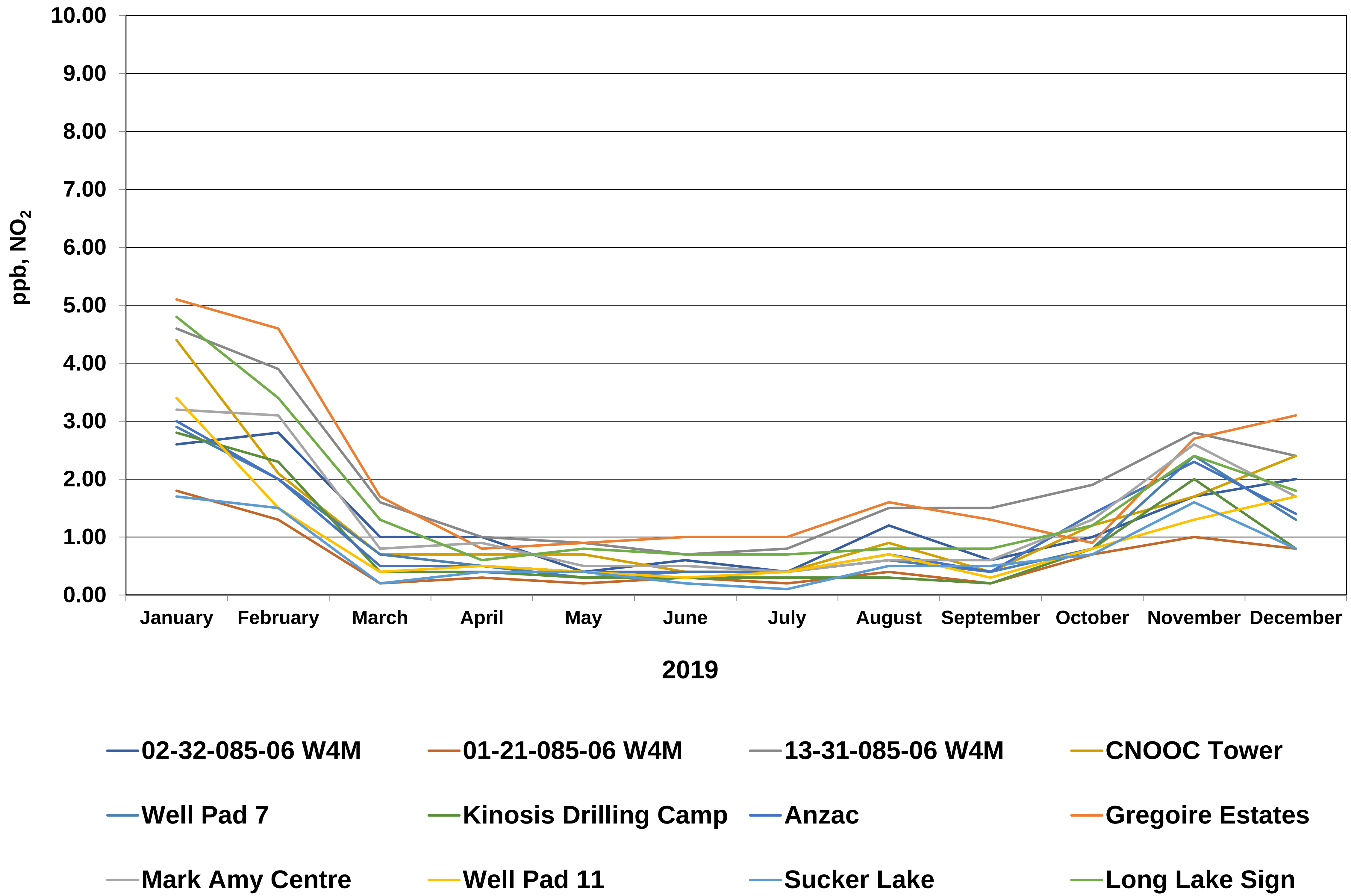
Subsection 3.1.2 (5d)

K1A SO_2 Passive Monitoring

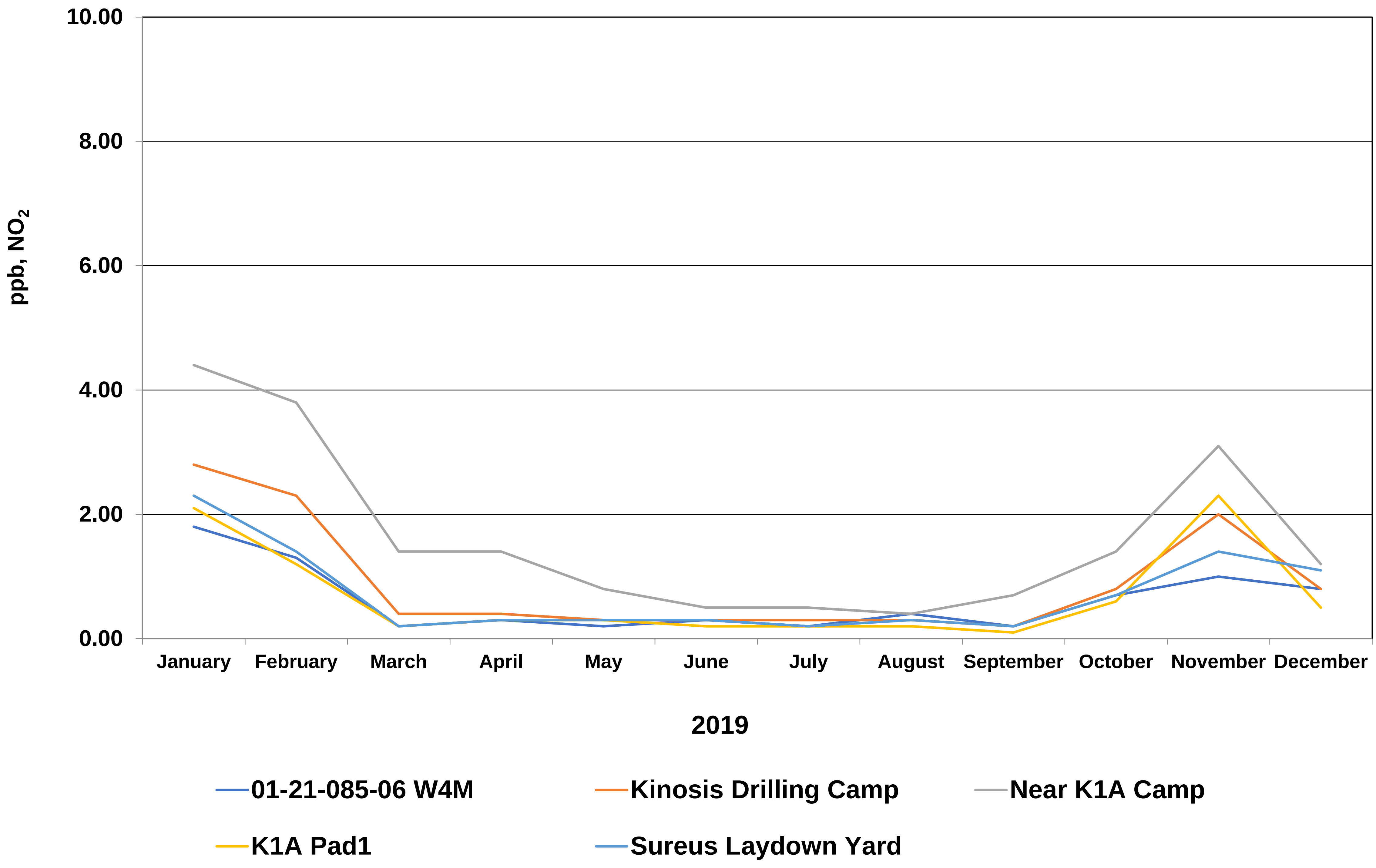


Subsection 3.1.2 (5d)

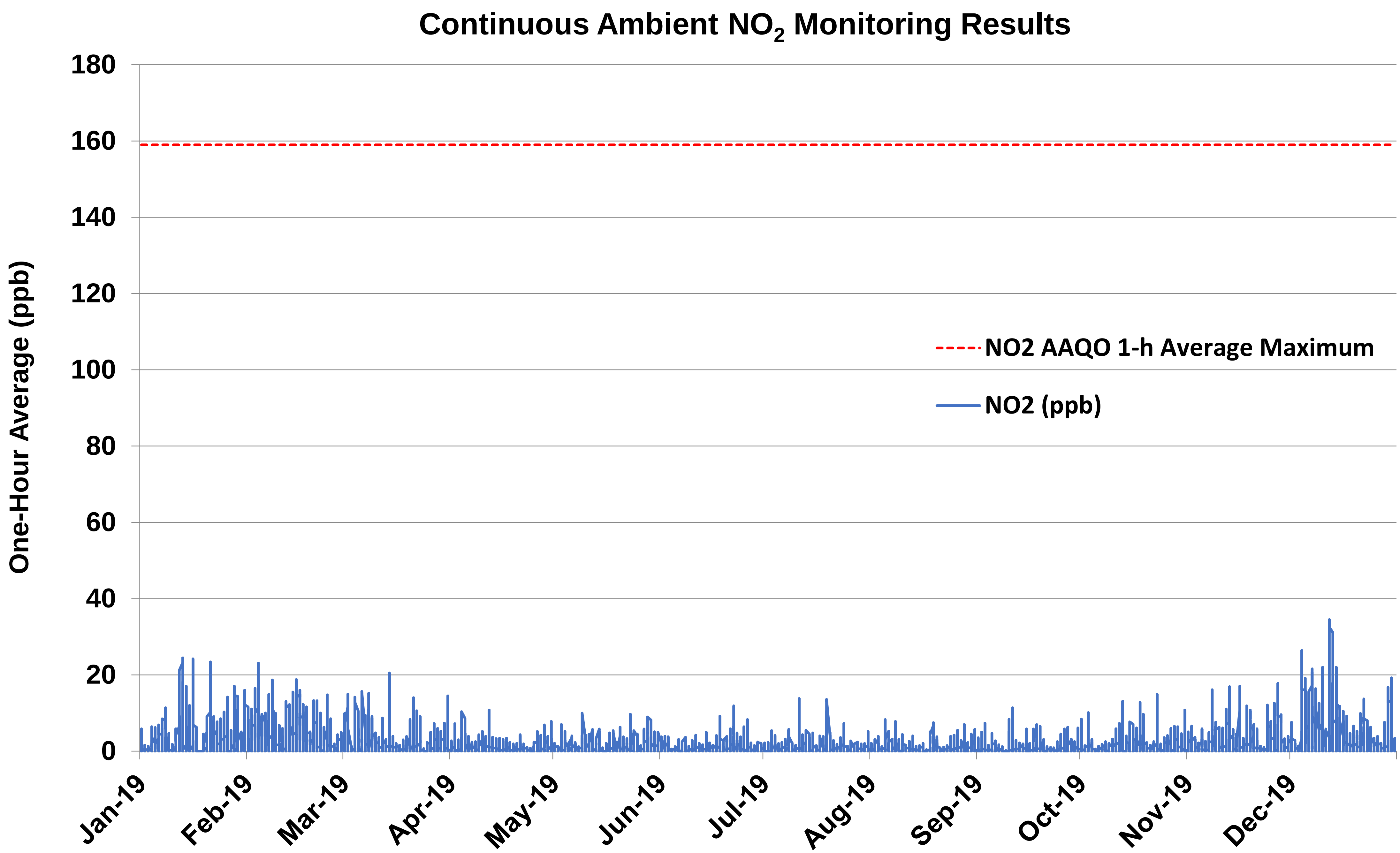
Long Lake NO_2 Passive Monitoring



K1A NO_2 Passive Monitoring

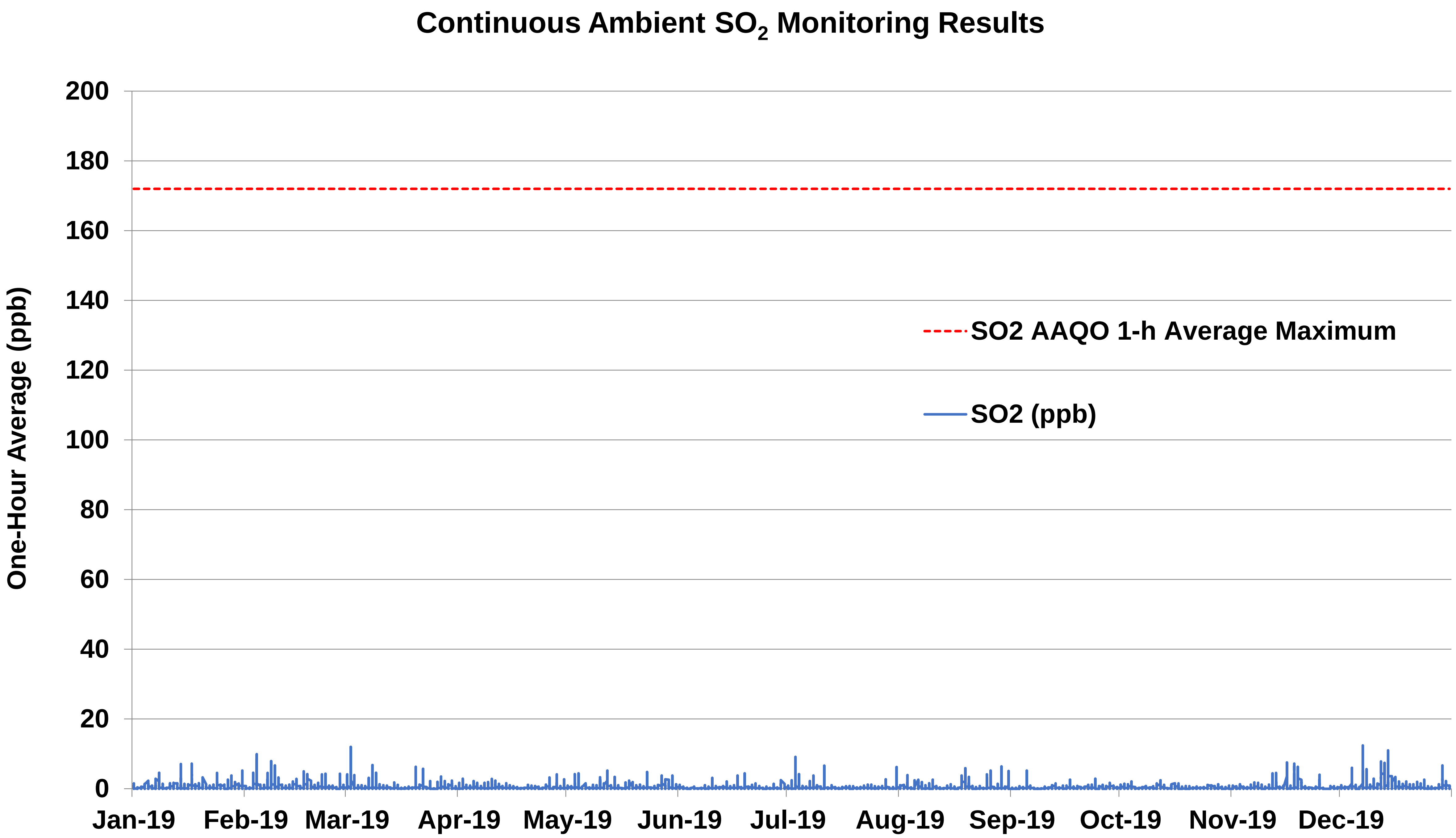


Anzac Ambient Monitoring
NO_2 Hourly Maximum

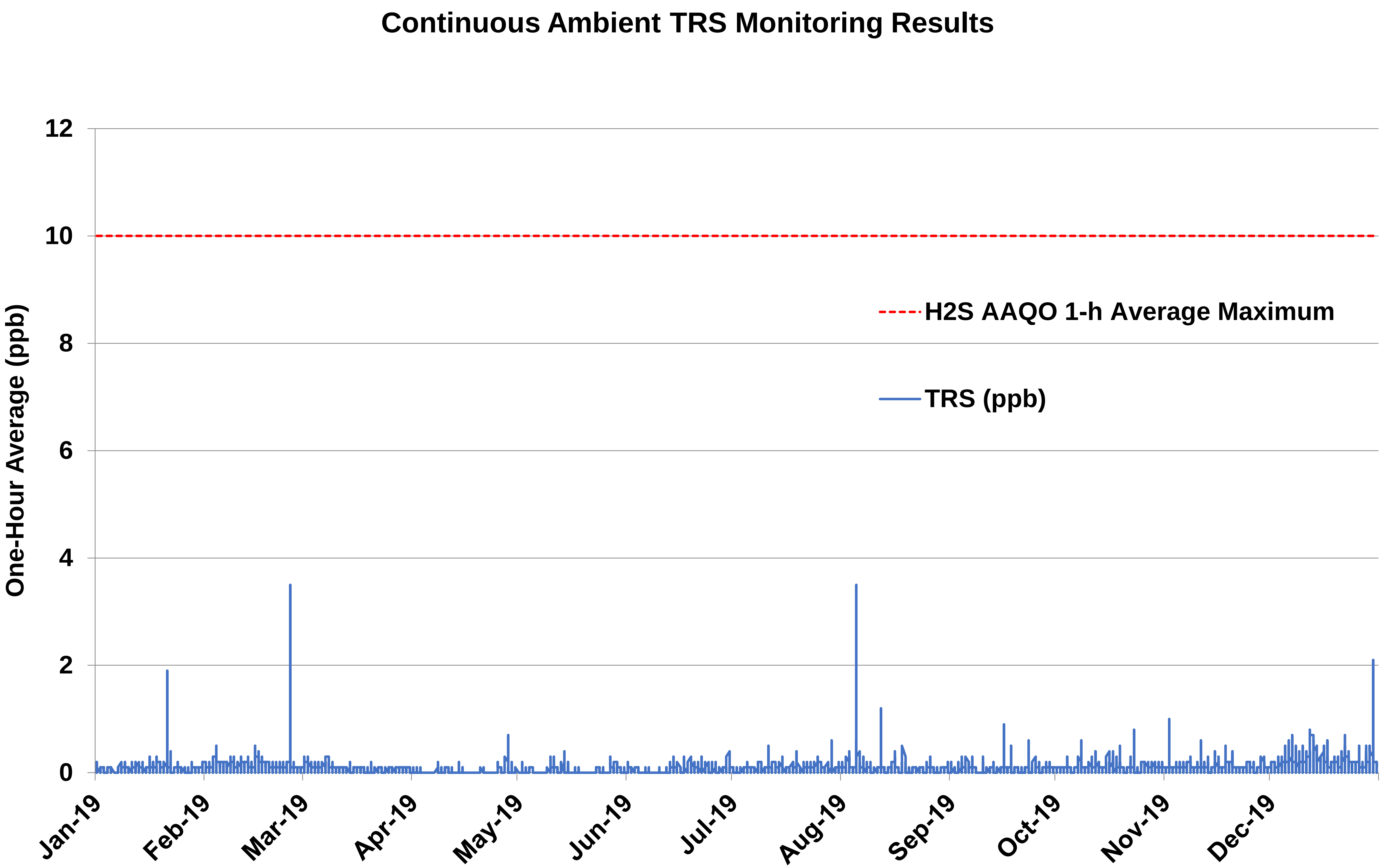


Subsection 3.1.2 (5d)

Anzac Ambient Monitoring
SO2 Hourly Maximum

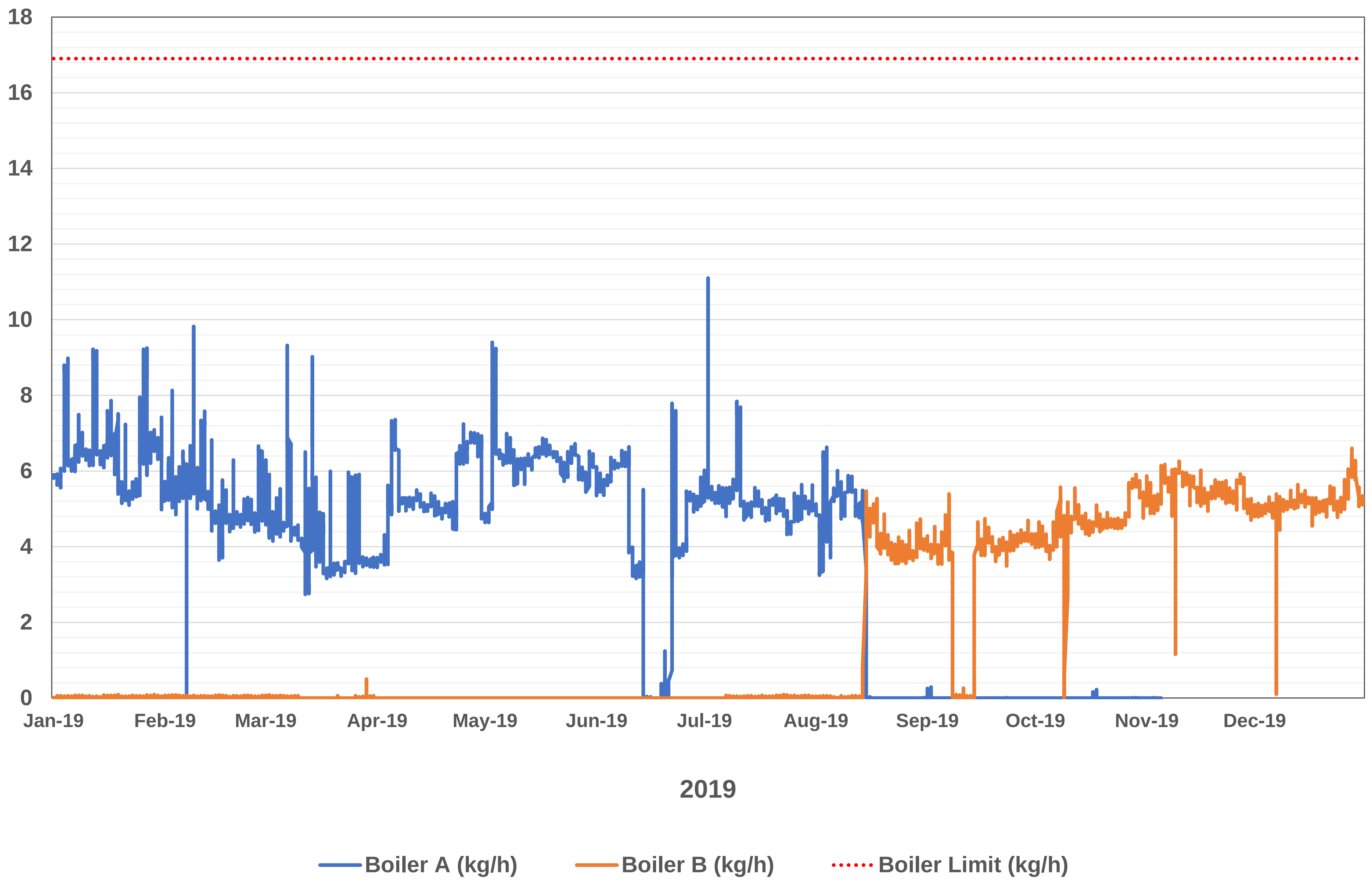


Subsection 3.1.2 (5d)



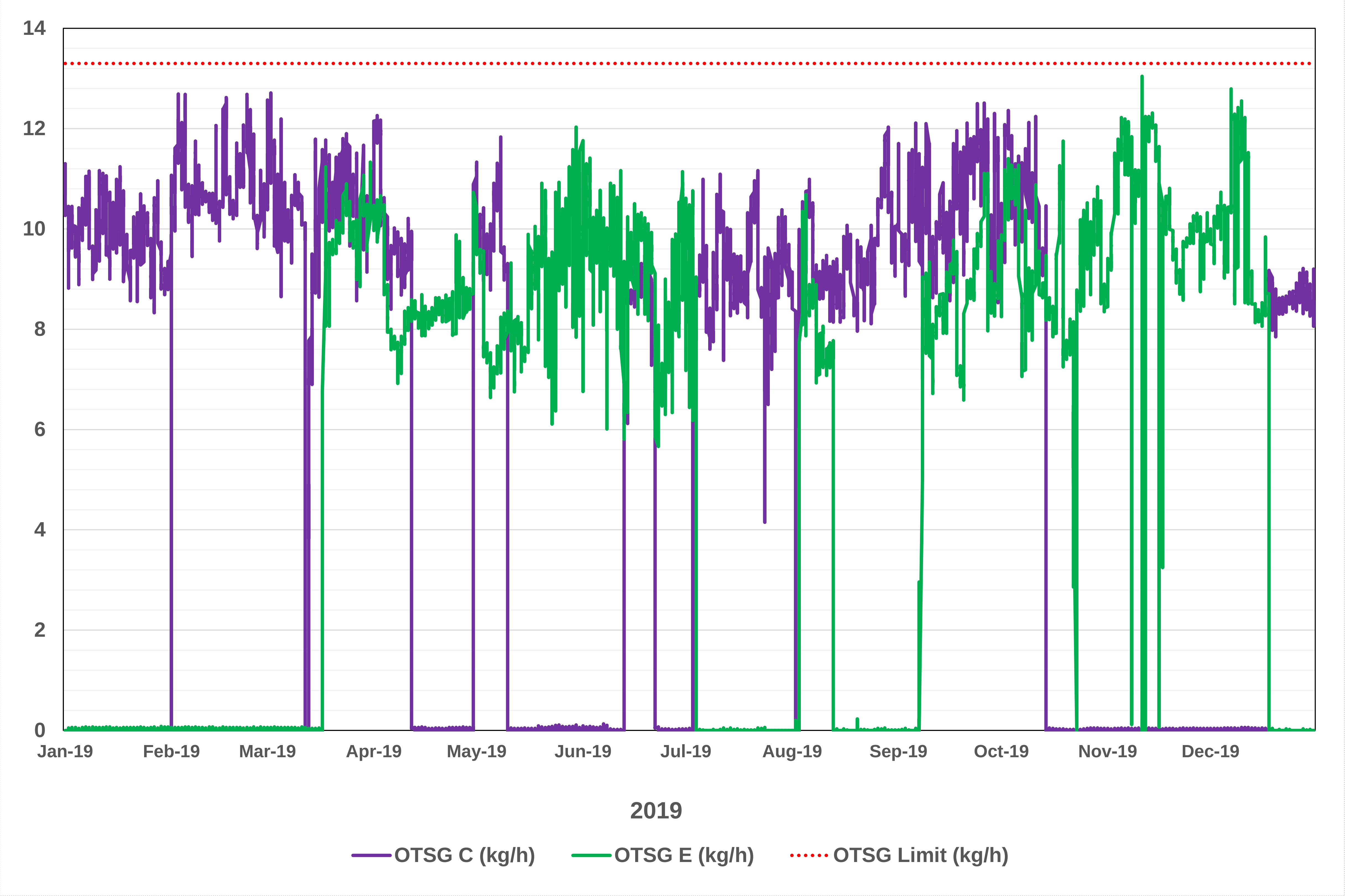
Continuous Ambient TRS Monitoring Results
One-Hour Average (ppb)
0
2
4
6
8
10
12
H2S AAQO 1-h Average Maximum
TRS (ppb)
Jan-19
Feb-19
Mar-19
Apr-19
May-19
Jun-19
Jul-19
Aug-19
Sep-19
Oct-19
Nov-19
Dec-19

Hourly CEMS NOx - Boilers



Subsection 3.1.2 (5d)

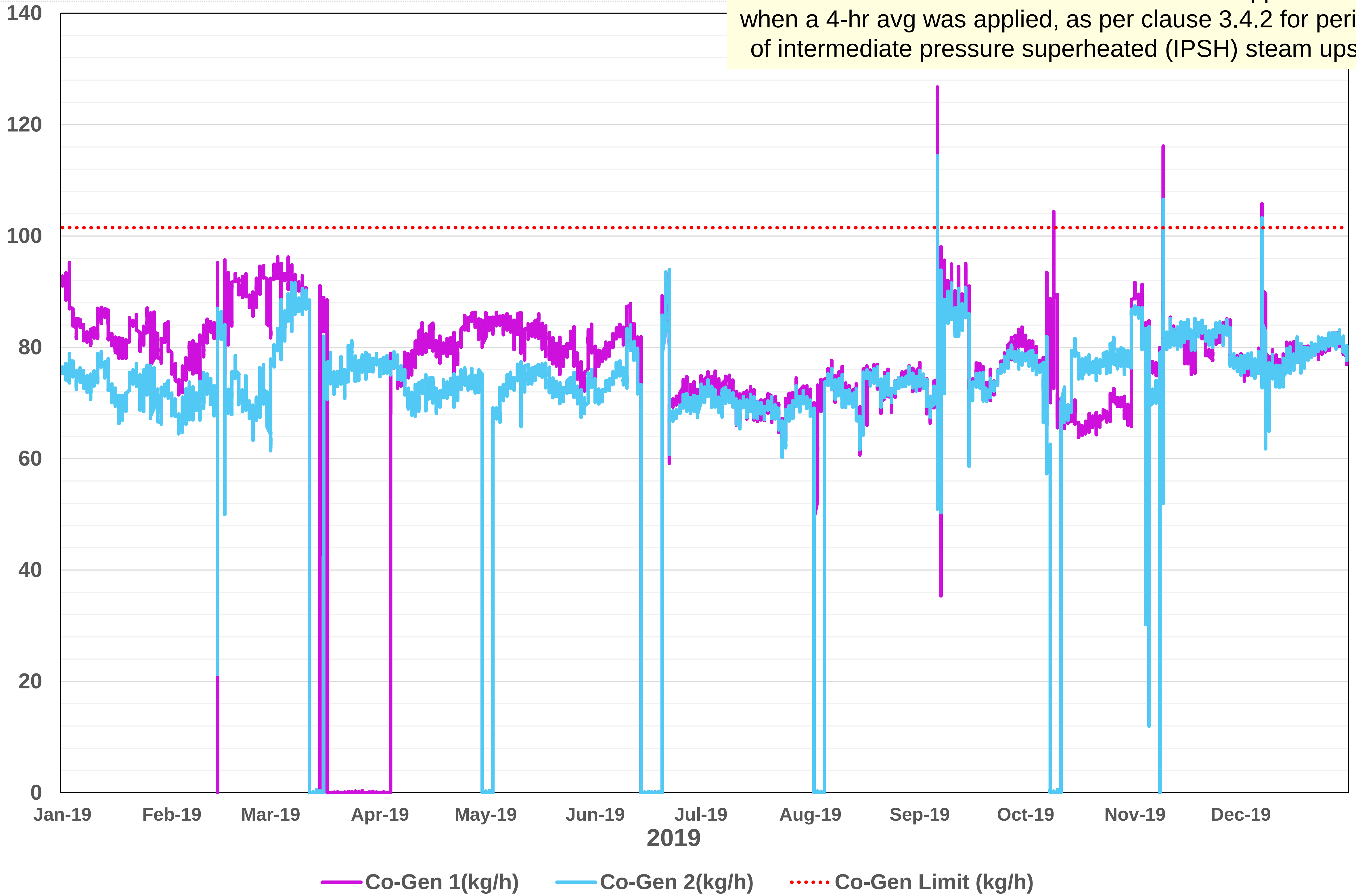
Hourly CEMS NOx – OTSG's



Subsection 3.1.2 (5d)

Hourly CEMS NOx – Co-Gen's

These 1-hr values did not exceed the EPEA approval limit when a 4-hr avg was applied, as per clause 3.4.2 for periods of intermediate pressure superheated (IPSH) steam upset.



Summary of Environmental Issues
Subsection 3.1.2 (6,7,8)
Long Lake

CNOOC

Compliance Statement

- To the best of CNOOC International's knowledge, the Long Lake facility is compliant with the conditions of its approvals and regulatory requirements subject to the items listed non-complaint in the summaries that follow.

Regulatory Compliance – Audits and Inspections

- AER Inspections (23)
  - Satisfactory Inspections (18)
  - Unsatisfactory Inspections (5)

Unsatisfactory Inspection Findings	Status
April 16, 2019 - AER performed a well site inspection (ID 486913) at surface location 12-36-085-07W4, which resulted in an Unsatisfactory Low Risk finding for a suspended well for a deficiency under Directive 013 for inadequate suspended wellhead security.	Compliance was achieved on April 30, 2019
April 16, 2019 - AER performed an oil facility site inspection (ID 486922) of the Long Lake Facility, 07-31-085-06W4, which resulted in an Unsatisfactory Low Risk finding for a deficiency under Directive 055 for inadequate secondary containment due to damaged tank farm liner.	Compliance was achieved on June 11, 2019
April 24, 2019 - AER performed pipeline inspection (ID 486915) from 01-31-085-06W4 to 09-28-085-06W4 as a follow-up from saltwater line corrosion failure that occurred in August 2018. An Unsatisfactory High Risk result was issued for failure to implement/follow procedures, inadequate leak detection program, failure to maintain cathodic protection; these are contraventions of the Pipeline Rules and CSAZ662-15.	Compliance was achieved on November 21, 2019
July 25, 2019 - AER performed a well site inspection (ID 490764) of an abandoned well at location 04-05-083-11W4, which resulted in an Unsatisfactory Low Risk finding under the Public Lands Act for prohibited noxious weeds being present on the site.	Compliance was achieved on August 13, 2019
October 23, 2019 - AER performed a drilling waste inspection (ID 495227) on a remote drilling sump at location 01-02-086-07W4, which resulted in Unsatisfactory High Risk findings under Directive 050 for failure to have the storage system physically closed within 18 months of rig release and improper site suitability assessment.	Compliance Action Plan in progress

Subsection 3.1.2 (6a)

- Audit (2)
  - May 2, 2019 - AER audit on Long Lake Annual Conservation & Reclamation (C&R) report (EPEA Approval No. 137467-01-00). CNOOC provided the requested information including updated PDA/C&C plan and several stockpile volumes on May 8, 2019 and the AER confirmed no further action would be required on May 21, 2019.
  - May 22, 2019 - AER audit on Kinosis Annual C&R report (EPEA Approval No. 236394-00-00). The AER requested several stockpile volumes which CNOOC indicated the work to obtain volumes would be completed by October 2019. The volumes were obtained and included it in the revised PLCRCPs submitted in October 2019 and authorized in February 2020. The information is included in the 2019 C&R report submitted March 31, 2020.

Compliance Discussion

Notices of Non-Compliance and Voluntary Self Disclosures	Status
Voluntary Self Disclosure The regen tank secondary containment was found to be leaking due to a breach and a VSD was submitted to the AER on June 6, 2019. Liner repairs were completed July 18, 2019. Contamination delineation is complete and remediation will be completed in the summer of 2020.	Compliance deadline of Sept 30, 2020
Voluntary Self Disclosure CNOOC submitted a VSD to the AER on October 25, 2019 for a measurement issue at the Long Lake SAGD facility that prevents the accurate reporting of gas production. An initial investigation was completed and early findings were provided in an update letter to the AER on December 16, 2019 with a commitment to provide an update on the investigation by March 31, 2020. AER accepted the VSD on February 4, 2020 with the condition that CNOOC provide quarterly progress reports and with a deadline of September 30, 2020 to address the compliance issue.	Compliance deadline of Sept 30, 2020

Subsection 3.1.2 (6a)(8)

Environmental Regulatory Compliance

Type of event	Number of Occurrences	Approval/Directive	Date	Description	Corrective Actions
Venting	5	EPEA	Various dates	Multiple tank venting	CNOOC International continues to address the number and duration of venting incidents by identifying root causes and implementing corrective actions for each venting event to prevent future occurrences.
Non-Compliance - Water Sources	2	Water Act	Aug 8, 2019	Water Act license 235895-02-00 water data loss	The damaged data logger was replaced. CNOOC International will continue to monitor the data logger during the quarterly field programs to ensure functionality.
			Nov 7, 2019	Late Annual report for Water Act License 315462-00-00	All reporting requirements are now tracked in CNOOC International's compliance management system with accountabilities assigned and automatic notifications sent ahead of compliance deadlines.

Venting Events and Reporting Protocol

1. Venting of multiple tanks located in the same area as per tables beside. (Ex. Venting of two or more tanks in table A or B will result in a reportable venting event). Yes, a call to AER

2. Venting duration over 4 consecutive hours in one event. AER OneStop entry, no call

3. Venting volume over 30,000 m^3 in one event. AER OneStop entry, no call.

Table A CPF Tanks	
Skim Tank	8200-T-002A
Skim Tank	8200-T-002B
Skimmings Tank	8200-T-003
De-Oiling Tank	8200-T-004
Dilbit Tank	8600-T-001A
Dilbit Tank	8600-T-001B
Dilbit Tank	8600-T-001C
Diluent Tank	8600-T-002
Backwash Tank	8200-T-011
Slop Tank	8100-T-001

Table B DB Tanks	
Skim Tank	8200-T-008A
Skim Tank	8200-T-008B
Skimmings Tank	8200-T-009
De-Oiling Tank	8200-T-0010
Dilbit Tank	8600-T-001A
Dilbit Tank	8600-T-001B
Dilbit Tank	8600-T-001C
Diluent Tank	8600-T-002
Slop Tank	8100-T-001

Subsection 3.1.2 (2e)

Reportable Spills

Reportable Spill Summary	2015		2016		2017		2018		2019	
	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)
	26	5,937	7	120	5	37.6	10	379.6	13	958.9

- Total number of reportable spills and volume went up from previous years due to surface releases from K1A pipeline horizontal directional drilling (HDD) and BFW line rupture.
- Reportable spill events (13)
  - January 19, 2019 – 19.5 m3 HDD Surface Release Deep Muskeg BFW line (FIS 20190203)
  - January 22, 2019 – 2.55 m3 HDD Surface Release Kinosis BFW line (FIS 20190224)
  - January 26, 2019 – 16.2 m3 Drilling Mud Released from the entry pit (FIS 20190261)
  - February 21, 2019 – 21.5 m3 HDD Surface Release Gregoire BFW line (FIS 20190552)
  - February 22, 2019 – 15.04 m3 HDD Surface Release Kinosis Creek PE line (FIS 20190553)
  - February 27, 2019 – 21.19 m^3 HDD Surface Release Intermittent Creek PE (FIS 20190615)
  - March 5, 2019 – 5.5 m^3 HDD Surface Release Deep Muskeg PE line (FIS 20190686)
  - March 12, 2019 – 130.6 m3 Produced vapor condensate line leak (FIS 20190776)
  - March 13, 2019 – 693 m3 DB to CPF boiler feedwater line rupture (FIS 20190818)
  - May 15, 2019 – 7.95 m3 HDD Surface Release Gregoire PE line (FIS 20191499)
  - June 17, 2019 – 5.86 m3 HDD Surface Release HWY 881 PE line (FIS 20191809)
  - July 8, 2019 – 15.5 m3 HDD Surface Release HWY 881 BFW line (FIS 20192119)
  - October 13, 2019 – 4.5 m3 8700-T-005C day tank Diesel over filled release (FIS 20193082)

AER Scheme and EPEA Approvals

- Kinosis EPEA approval renewal application approved July 5, 2019 (EPEA Approval No. 236394-01-00)
- Scheme Amendments Approved in 2019:
  - Long Lake Phase 3 Infills Pad 1 Amendment – February 6, 2019
  - Name Change to CNOOC Petroleum North America ULC – March 11, 2019
  - Addition of Permanent Lime Sludge Centrifuge – July 5, 2019
  - Addition of Chemical Storage Tanks – September 20, 2019
  - Expansion of LLSW Development Area – November 22, 2019

Environmental Summary – Monitoring Programs

- All monitoring programs were conducted in accordance with regulatory approvals
  - Groundwater monitoring
  - Hydrology and water quality monitoring
  - Wildlife monitoring
  - Wetland monitoring
  - Source emission and ambient air monitoring
  - Conservation and reclamation plans
  - Soil monitoring

Subsection 3.1.2 (6c)

Environmental Summary – Monitoring Programs

- Funded the regional Oil Sands Monitoring (OSM) program.
- Participation in regional stakeholder committees:
  - WBEA;
  - OSCA Black Bear Partnership Project.

Subsection 3.1.2 (6c)

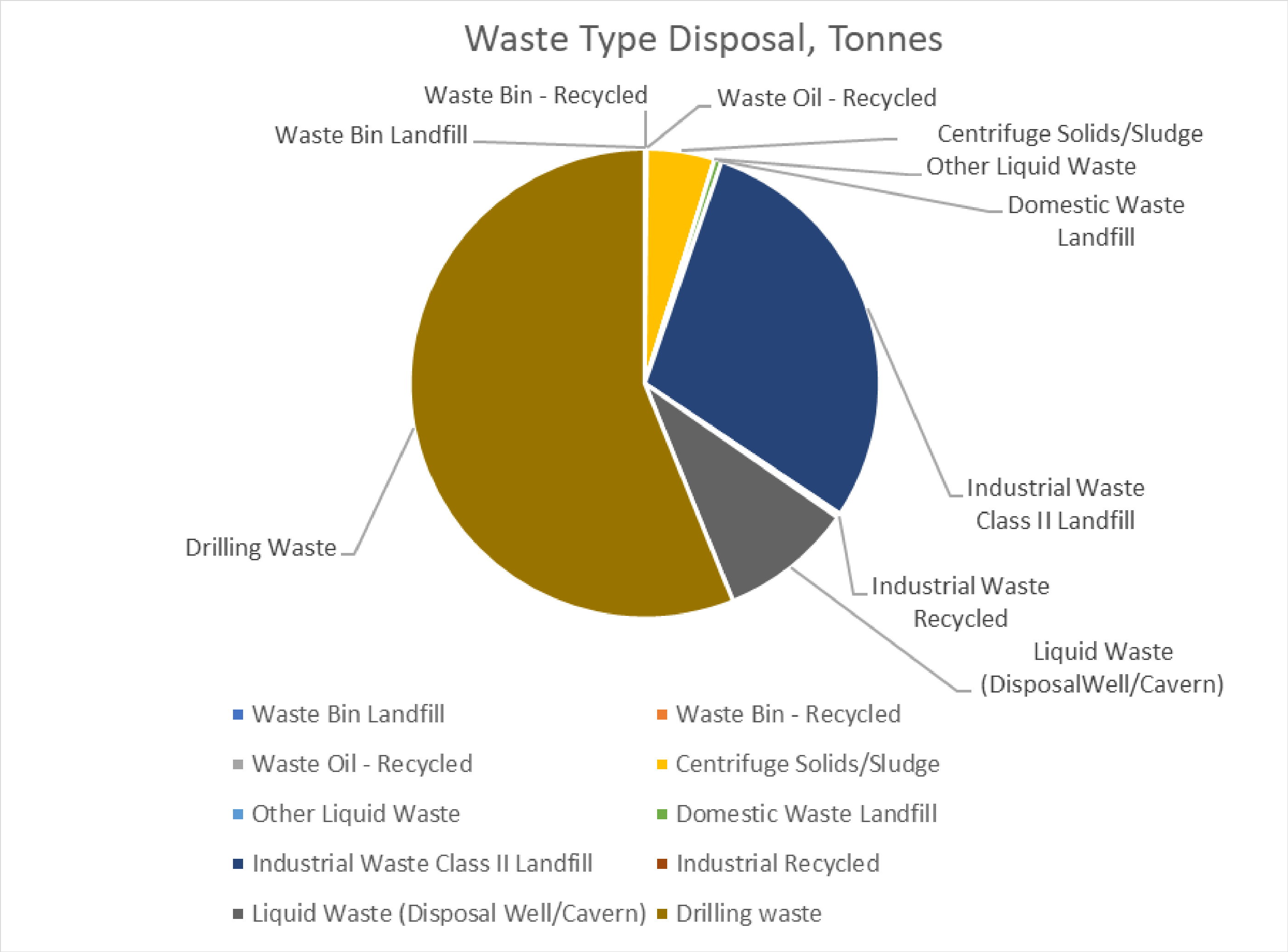
Environmental Summary: Innovation, Research & Reclamation Initiatives

- Active participant of the COSIA and CAPP Oil Sands Monitoring Working Groups.
- Actively engaged in industry caribou recovery efforts, specifically as the project lead for the Algar Caribou Restoration Project and a member of the CNRL led Regional Industry Caribou Collaboration (RICC).
- Member for the Boreal Monitoring Avian Productivity and Survivorship (MAPS) program, a continent-wide bird banding program designed to understand avian population dynamics and diversity in reclaimed habitats and in habitats subject to other industrial disturbances, as compared to natural areas. The MAPS program operates a bird-banding station at Long Lake.
- Member in the Industrial Footprint Reductions Options Group (iFROG) focused on improving oil sands construction and reclamation practices, particularly in wetland areas.
- Conducting an on-site cluster planting research trial with NAIT and ConocoPhillips to investigate alternate reclamation planting designs.
- Project partner on the Water Technology Development Centre (WTDC) located at Suncor Energy's Firebag facility. The WTDC will allow operators to speed the development and implementation of new water treatment technologies with expected reductions in water use and improved energy efficiency across the sector.
- Involved in the Carbon Xprize, a $20 million global competition to develop breakthrough technologies to convert CO_2 emissions from industrial facilities and power plants into valuable products; and the Alberta Carbon Conversion Test Centre.

Subsection 3.1.2 (6d)

Waste Disposal

Hazardous waste	Tonnes
Waste Bin Landfill	68
Waste Bin - Recycled	18
Waste Oil - Recycled	18
Centrifuge Solids/Sludge	3,472
Other Liquid Waste	3
Total	**3,579**
Non-Hazardous Waste	**Tonnes**
Domestic Waste Landfill	376
Industrial Waste Class II Landfill	21,652
Industrial Recycled	217
Liquid Waste (Disposal Well/Cavern)	6,848
Drilling waste	41,799
Total	**70,892**
Grand Total (Hazardous and Non-Hazardous Waste)	**74,471**



Similar to the previous years, the quantity of the water disposed down CNOOC Long Lake Class Ib disposal wells is not included as it is reported in separate slides.

Future Plans - Surface

- Commence operation of LLSW sustaining well pads
- Complete trenchless crossing program and progress detailed engineering for K1A replacement pipelines
- Assessing alternate Upgrader configurations and schedule options for Upgrader restart

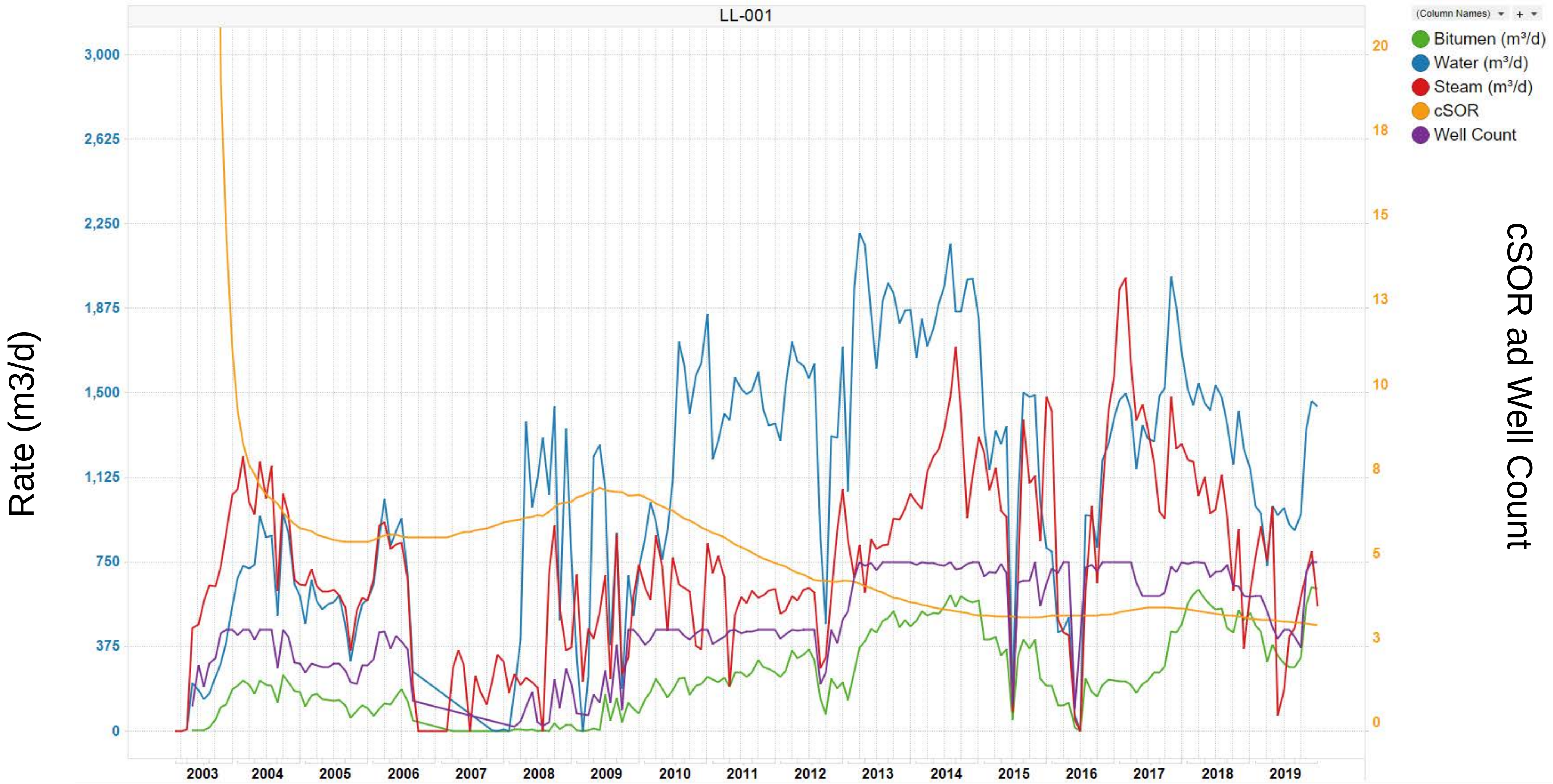
Subsection 3.1.2 (9)

Appendix

Well Pad Performance
Subsection 3.1.7 (h)
Long Lake

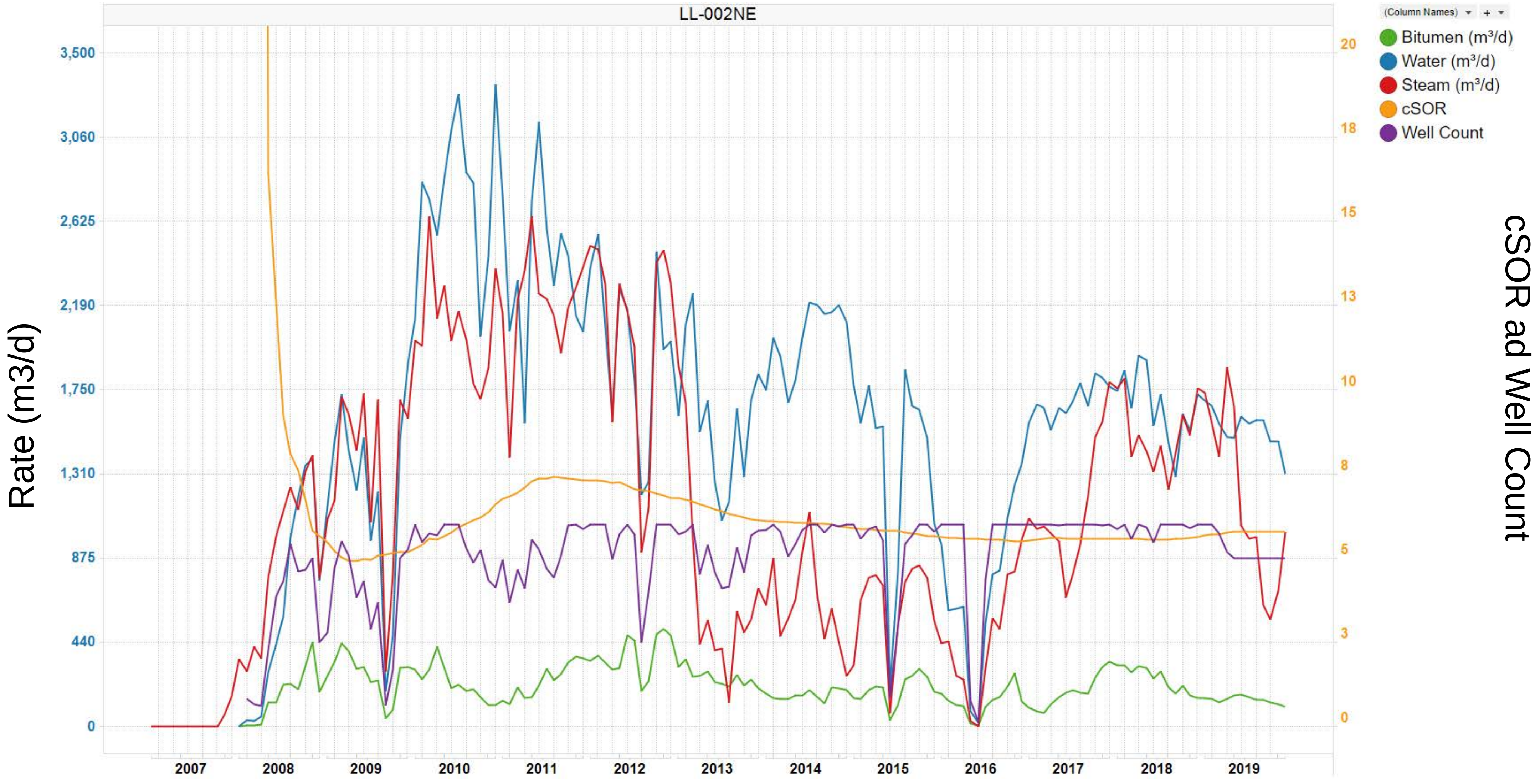
Pad 1 Production Summary

- Five well pairs (01P01 to 01P03, 04P05 and 04P06)
  - All 5 wells on ESP
  - Redrilled 2 wells deeper to access stranded pay in 2019
- cSOR is stable
- YE injection pressures were 1430-1520 kPa
- Cumulative production of 1,409 e^3m^3 (EBIP RF 53%)



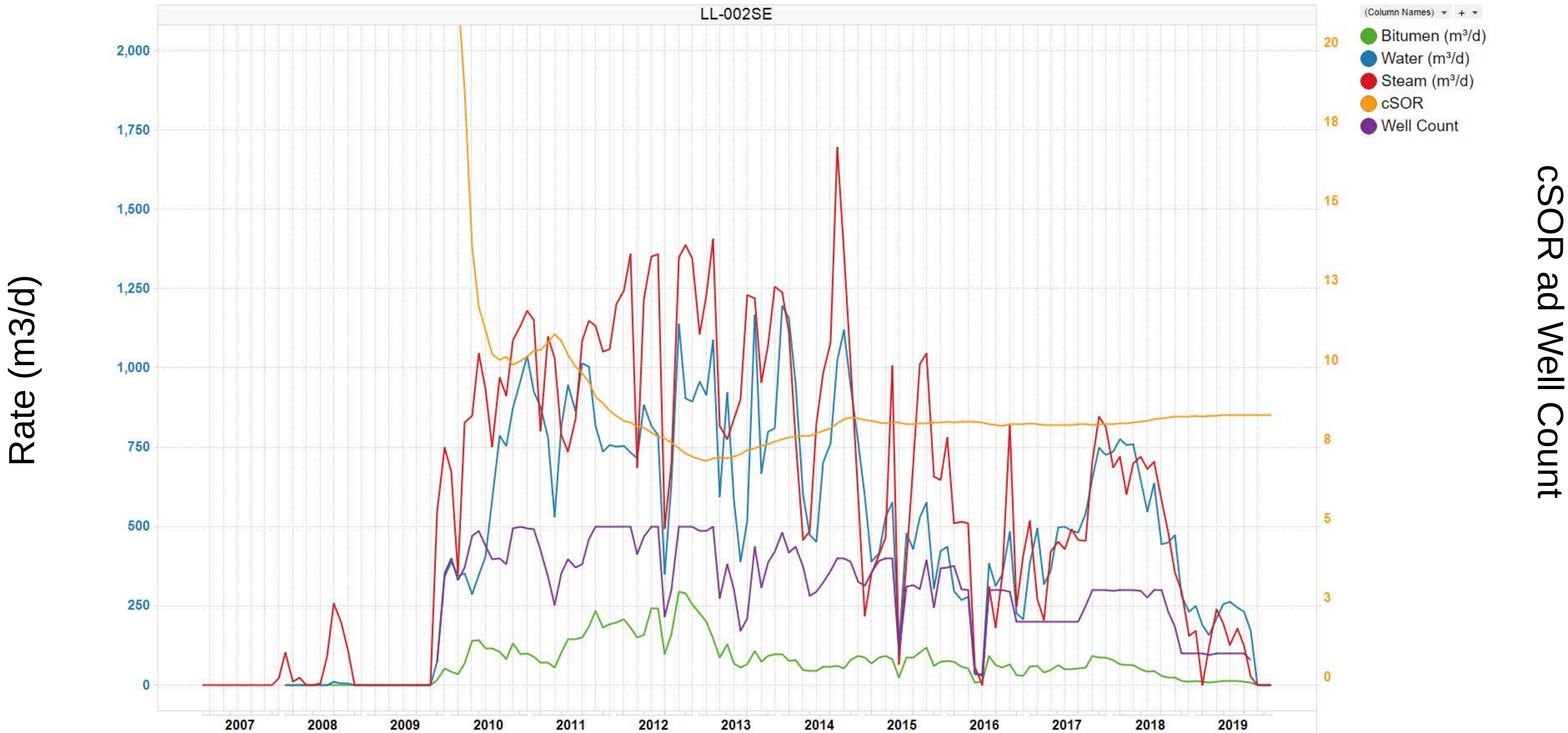
Pad 2NE Production Summary

- Six well pairs (02P01 to 02P06)
  - 5 wells on ESP
  - ESP failure in 2P04 is not currently economically justifiable to replace
- Stable fluid production rates
- YE injection pressures were 1440 – 1485 kPa
- Cumulative production of 932 e^3m^3 (EBIP RF 37%)



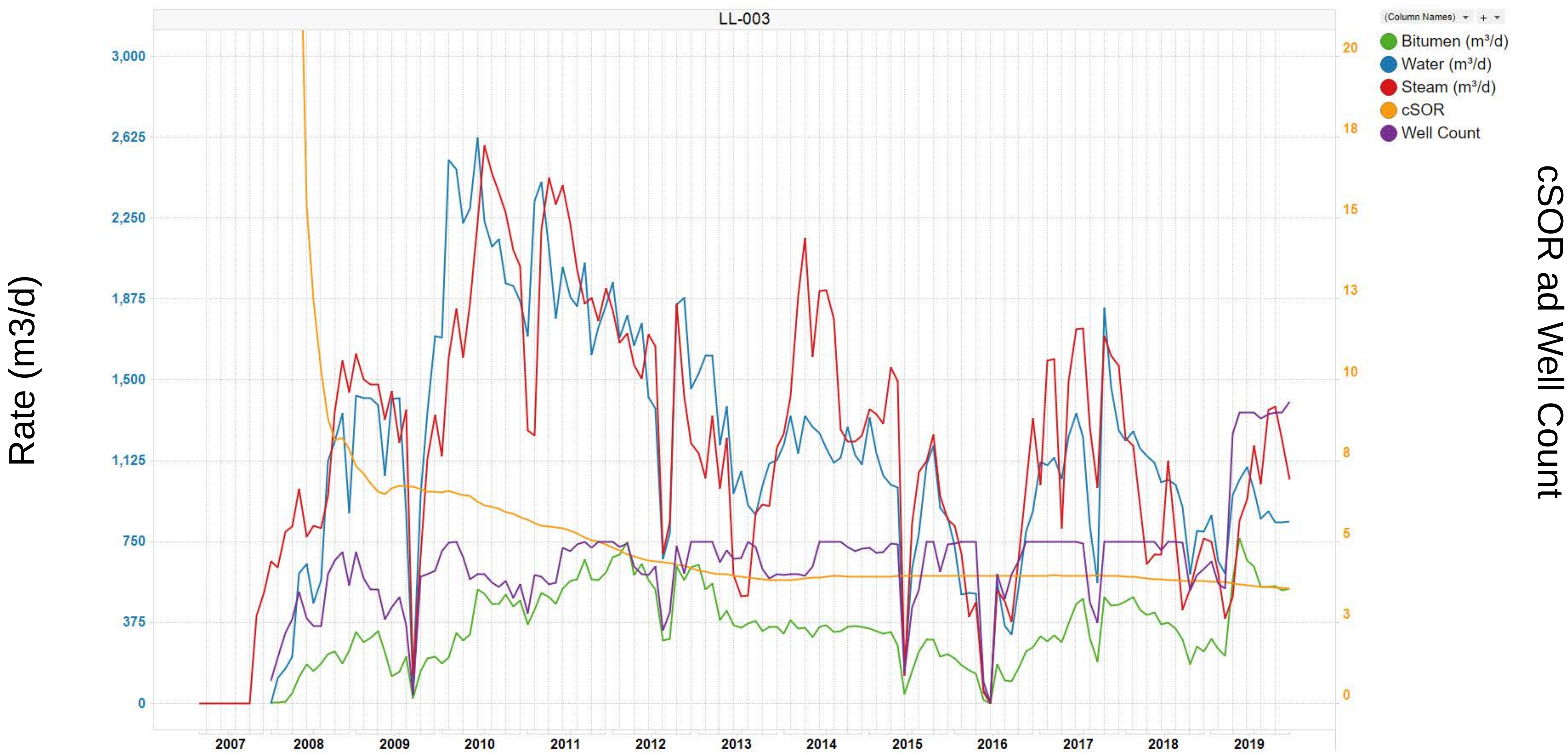
Pad 2SE Production Summary

- Five well pairs (02P07 to 02P11)
- Poor reservoir quality resulted in low rate producers that have been economically challenged for several years
  - 2P07 on PCP and currently SI due to worn pump
  - 02P11 SI due to liner failure in 2014
  - 2P08, 2P09 ESP failures in 2018
  - 2P10 ESP failure in 2019
- Progressing winddown application for drainage area
- YE injection pressures were 1325 – 1385 kPa
- Cumulative production of 317 e^3m^3 (EBIP RF 28%)



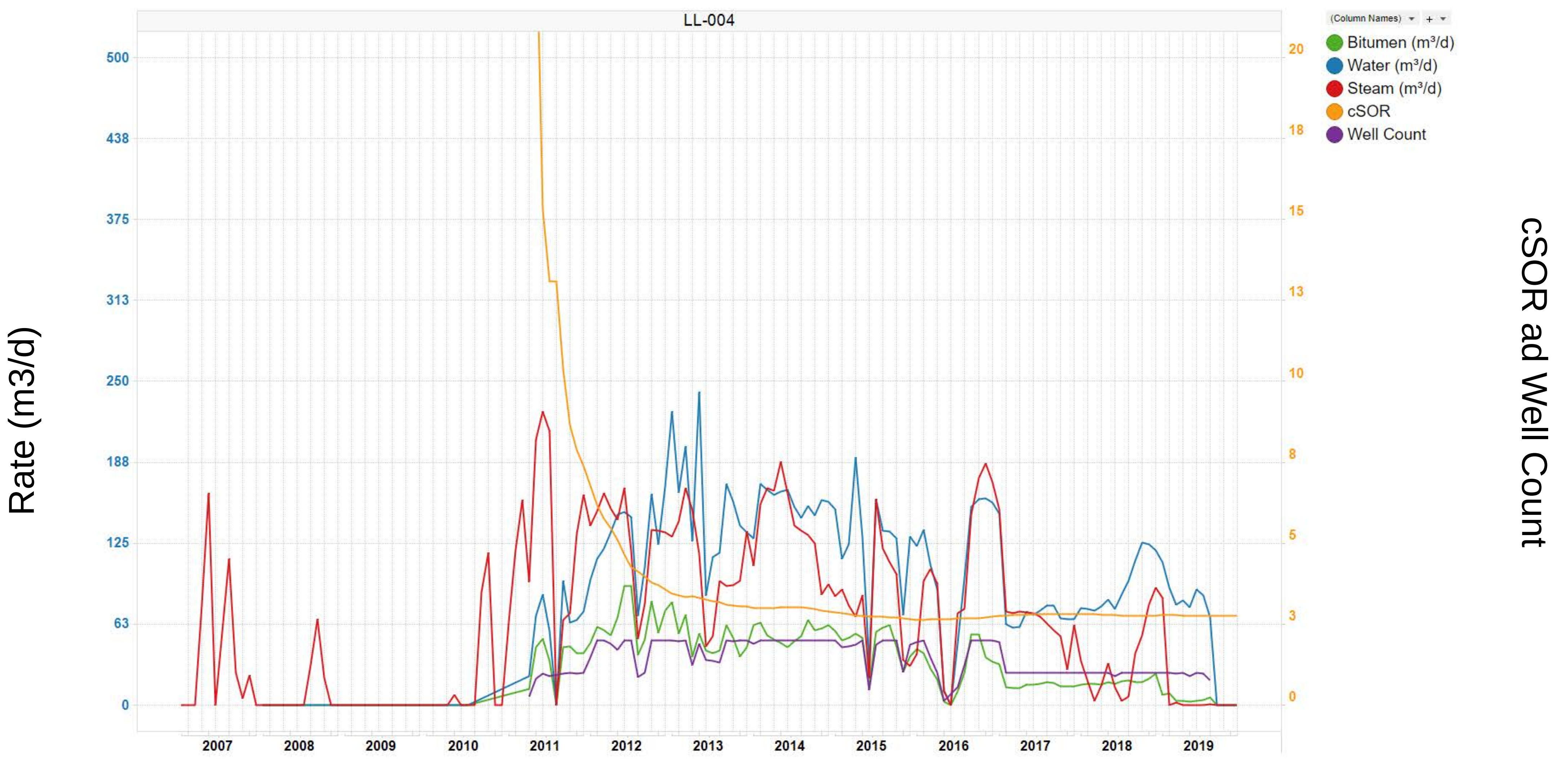
Pad 3 Production Summary

- Five well pairs (03P01 to 03P05)
  - Five infill well producers (03P01INF to 03P05INF) on production Q2 2019
  - All 10 wells on ESP
- Improvement has been observed in cSOR and oil due to infills on production
- YE injection pressures were 1460-1560 kPa
- Cumulative production of 1,553 e^3m^3 (EBIP RF 48%)



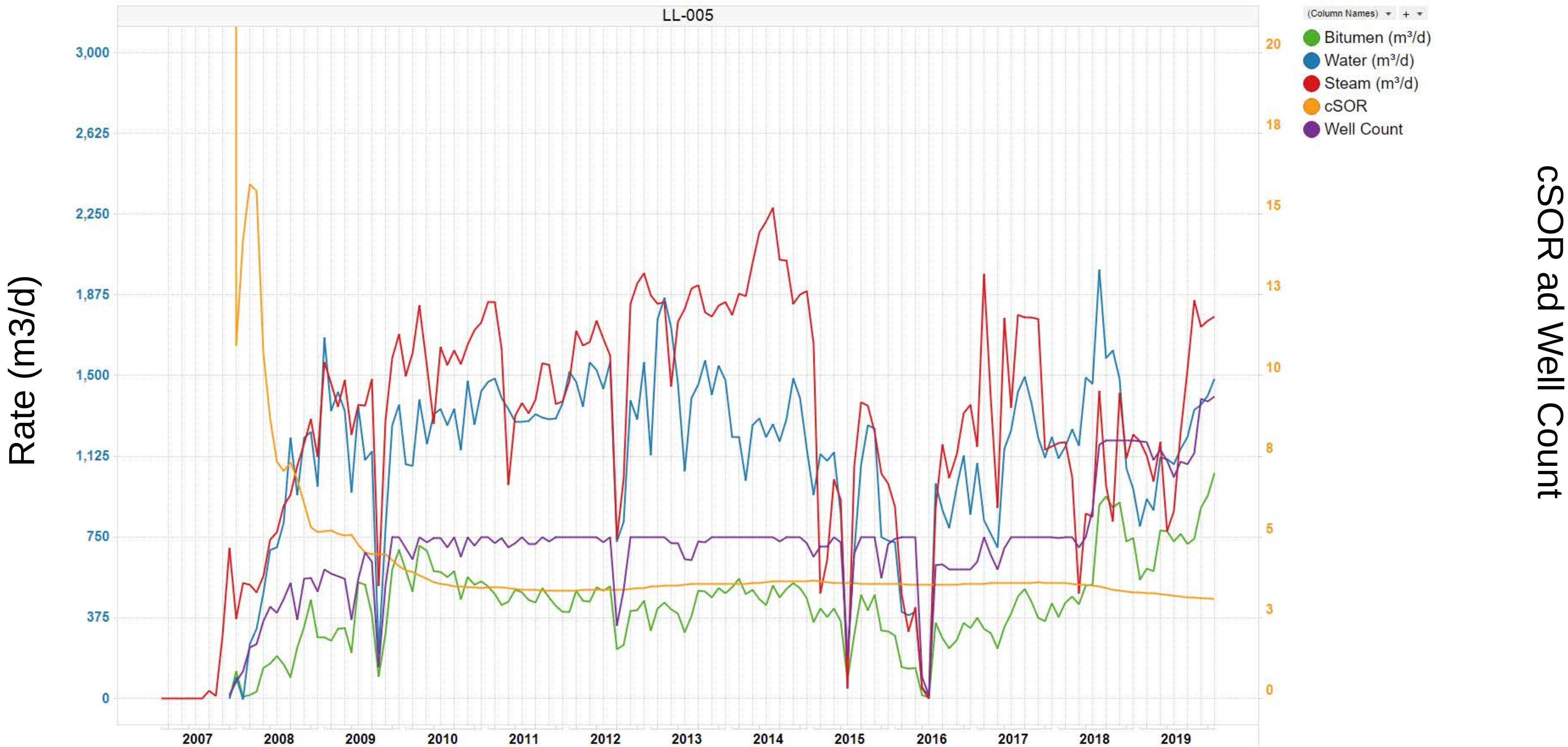
Pad 4 Production Summary

- Two well pairs (04P01 to 04P02)
  - Wells shortened in 2010 due to collapse feature
  - No active wells as ESP failures are not currently economically justifiable to replace due to very low oil production rate
  - Surface facilities have been re-utilized for Pad 1 infill re-drills
- Cumulative production of 114 e^3m^3 (EBIP RF 94%)



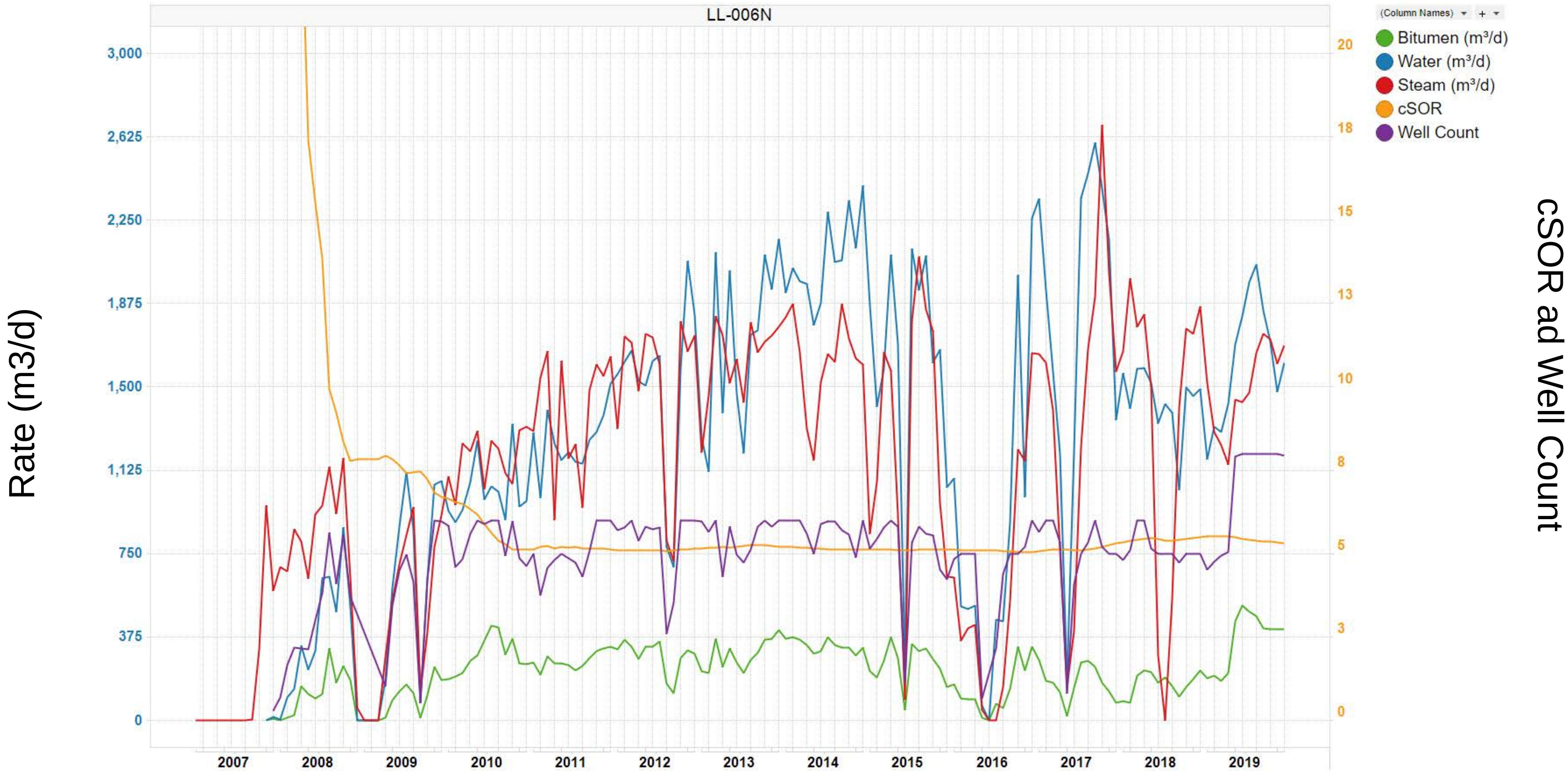
Pad 5 Production Summary

- Five well pairs (05P01 to 05P05)
  - Three infill well producers (05P03-05INF) on production mid-2018
  - Two additional infill producers (04P07, 04P08) on production Q4 2019
  - All 10 wells on ESP
- Infill wells contributing to increase in oil production rates and lowering cSOR
- YE injection pressures were 1505-1575 kPa
- Cumulative production of 1,949 e^3m^3 (EBIP RF 56%)



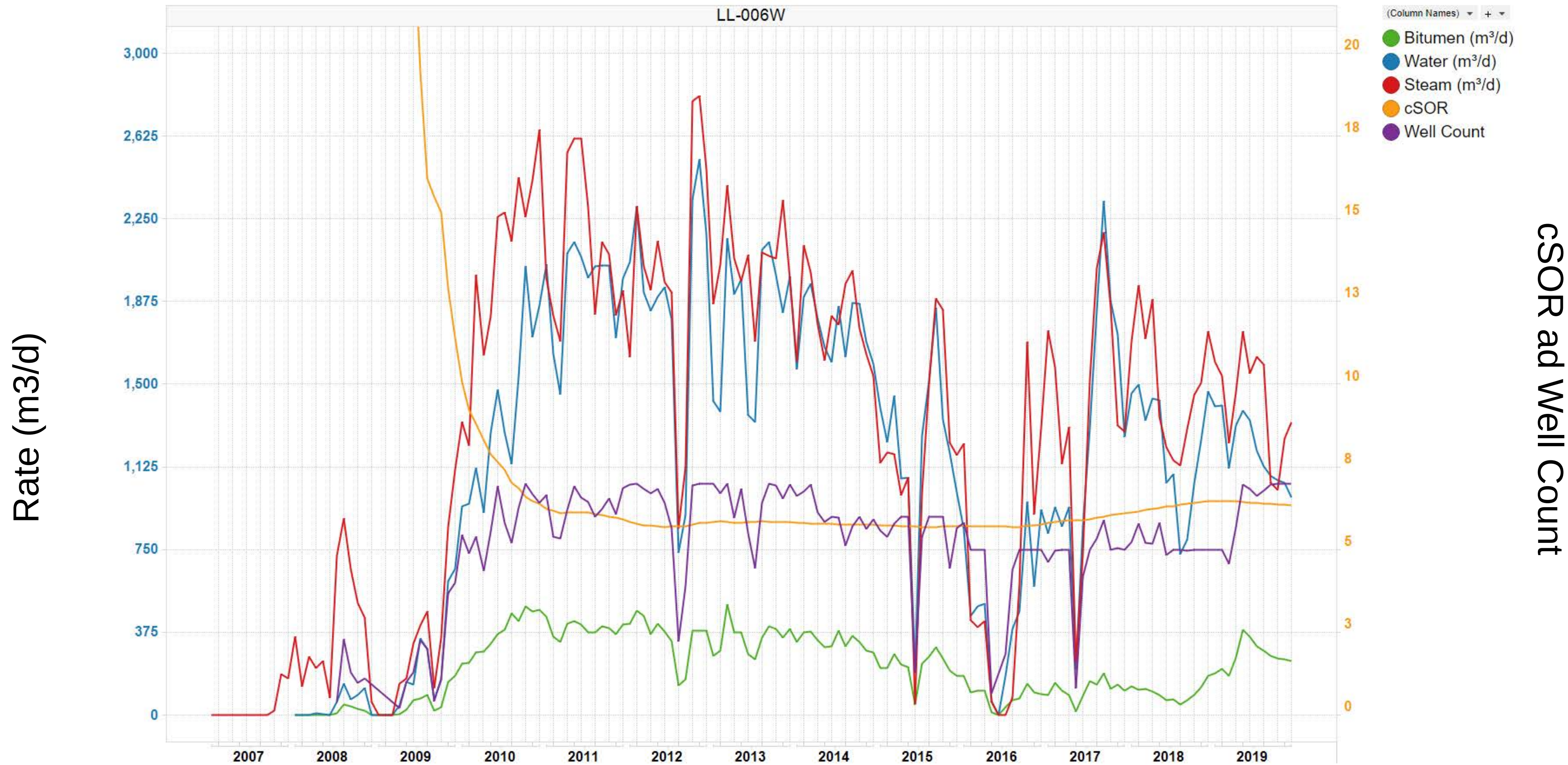
Pad 6N Production Summary

- Six well pairs (06P01 to 06P05, 06P13)
  - 3 infill wells on production Q2 2019
  - 8 wells on ESP
  - ESP failure in 6P13 is not currently economically justifiable to replace
- Infill wells contributing to increase in oil production rates and lowering cSOR
- YE injection pressures were 1795–1960 kPa
- Cumulative production of 1,018e^{3}m^3 (EBIP RF 28%)



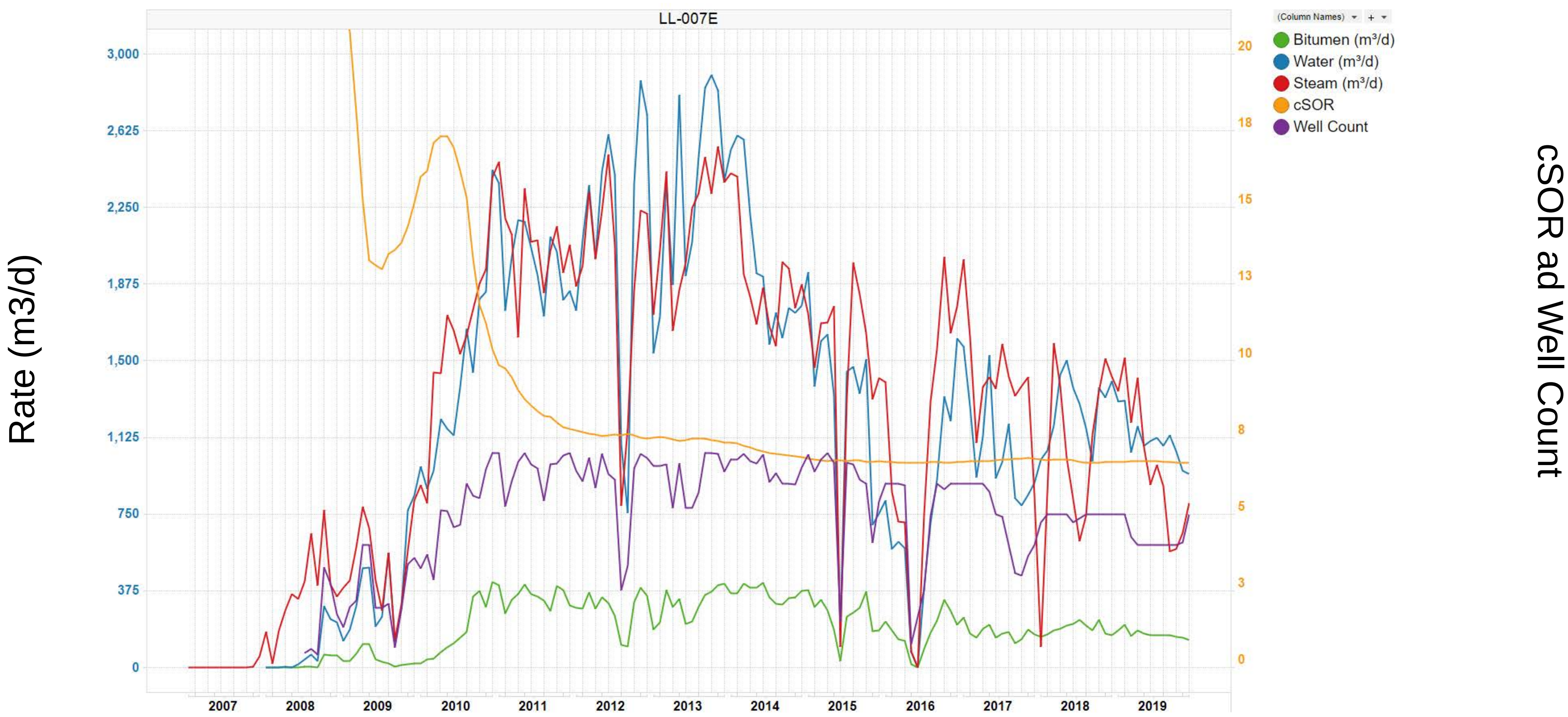
Pad 6W Production Summary

- Seven well pairs (06P06 to 06P12), 2 infills
  - 7 wells on ESP
  - 6P12 shut in due to liner failure in 2014
  - ESP failure in 6P10 is not currently economically justifiable to replace
- YE injection pressures were 1700–1900 kPa
- Cumulative production of 971 e^3m^3 (EBIP RF 42%)



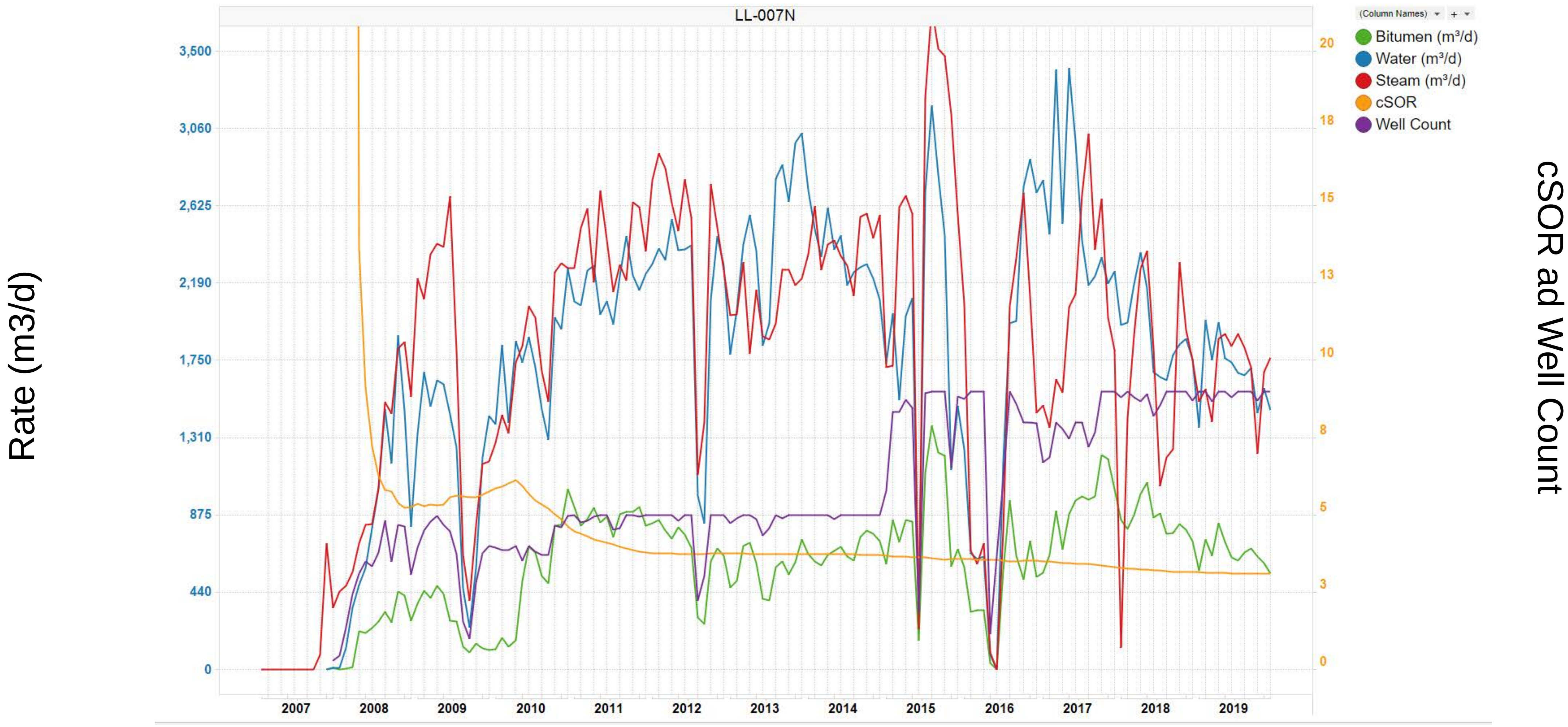
Pad 7E Production Summary

- Seven well pairs (07P06 to 07P12)
  - 5 wells on ESP
  - ESP failure in 7P11 is not currently economically justifiable to replace
  - 7P12 shut in due to liner failure
- NCG co-injection has not been operational since 2015 turnaround; evaluating restart in 2020
- YE injection pressures were 1620–1880 kPa
- Cumulative production of 907 e^3m^3 (EBIP RF 43%)



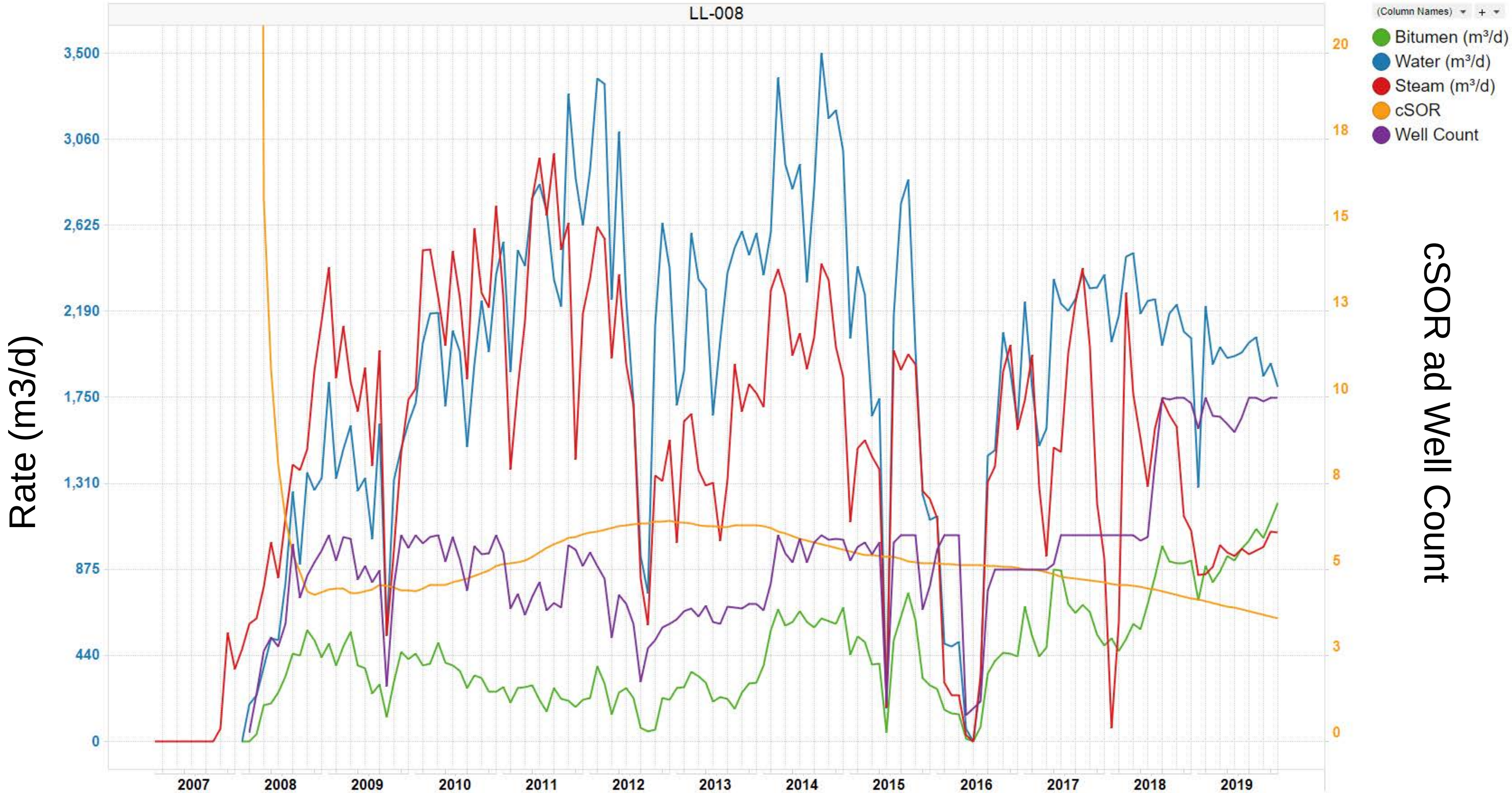
Pad 7N Production Summary

- Five well pairs (07P01 to 07P05)
  - Four infill producer wells (10P14 to 10P17) in 2015
  - All 9 wells on ESP
- Infill producer wells continue to exhibit strong performance
- Evaluating restart of NCG co-injection in 2020
- YE injection pressures were 1825 – 1905 kPa
- Cumulative production of 2745 e^3m^3 (EBIP RF 69%)



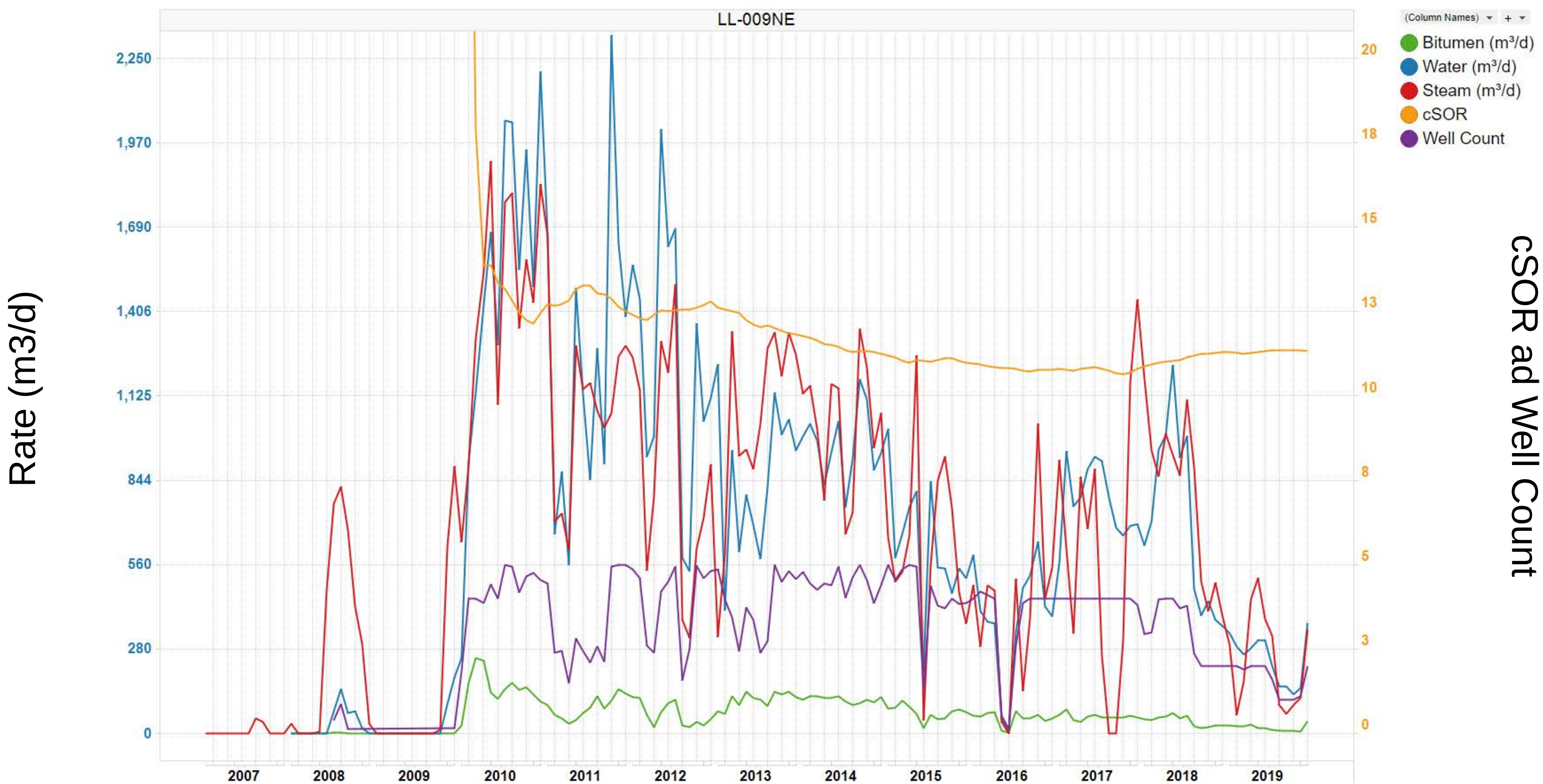
Pad 8 Production Summary

- Six well pairs (08P01 to 08P06)
  - Four infill well producers (08P03INF to 8P06INF) on production in mid-2018
  - All 10 wells on ESP
  - 08S06 failed in 2015, no observed detriment
  - ICD's installed on 08P03 in 2015 and 8P05INF in 2019
- Infill wells contributing to increase in oil production rates and lowering cSOR
- YE injection pressures were 1750–1795 kPa
- Cumulative production of 1,951 e^3m^3 (EBIP RF 44%)



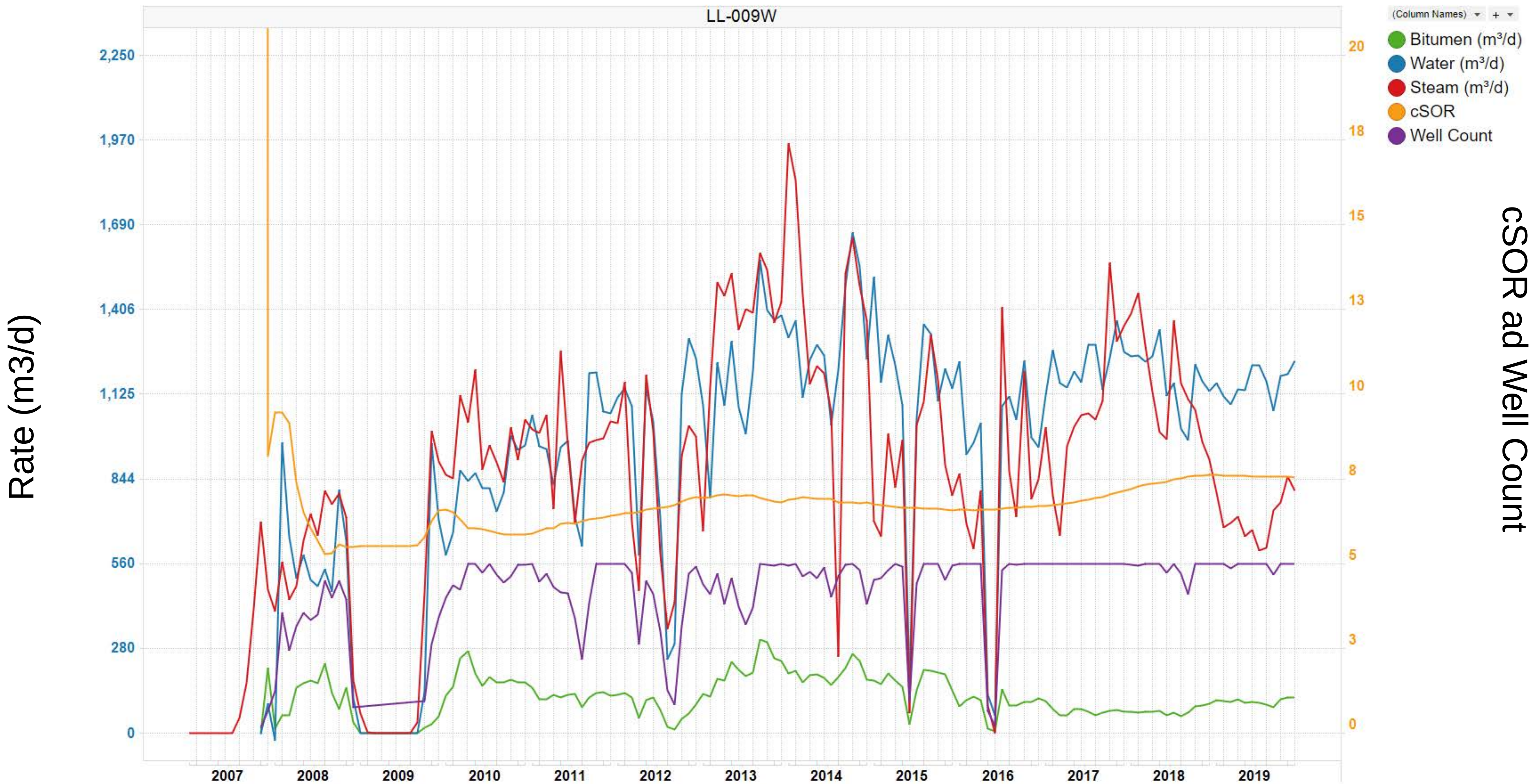
Pad 9NE Production Summary

- Five well pairs (09P06 to 09P10)
  - 2 wells on ESP
  - 9P06, 9P07, 9P09 ESP failures are not currently economically justifiable to replace
- Poor reservoir quality and unstable operation impacting performance; progressing winddown application for drainage area
- YE injection pressures were ~1460 kPa
- Cumulative production of 278 e^3m^3 (EBIP RF 23%)



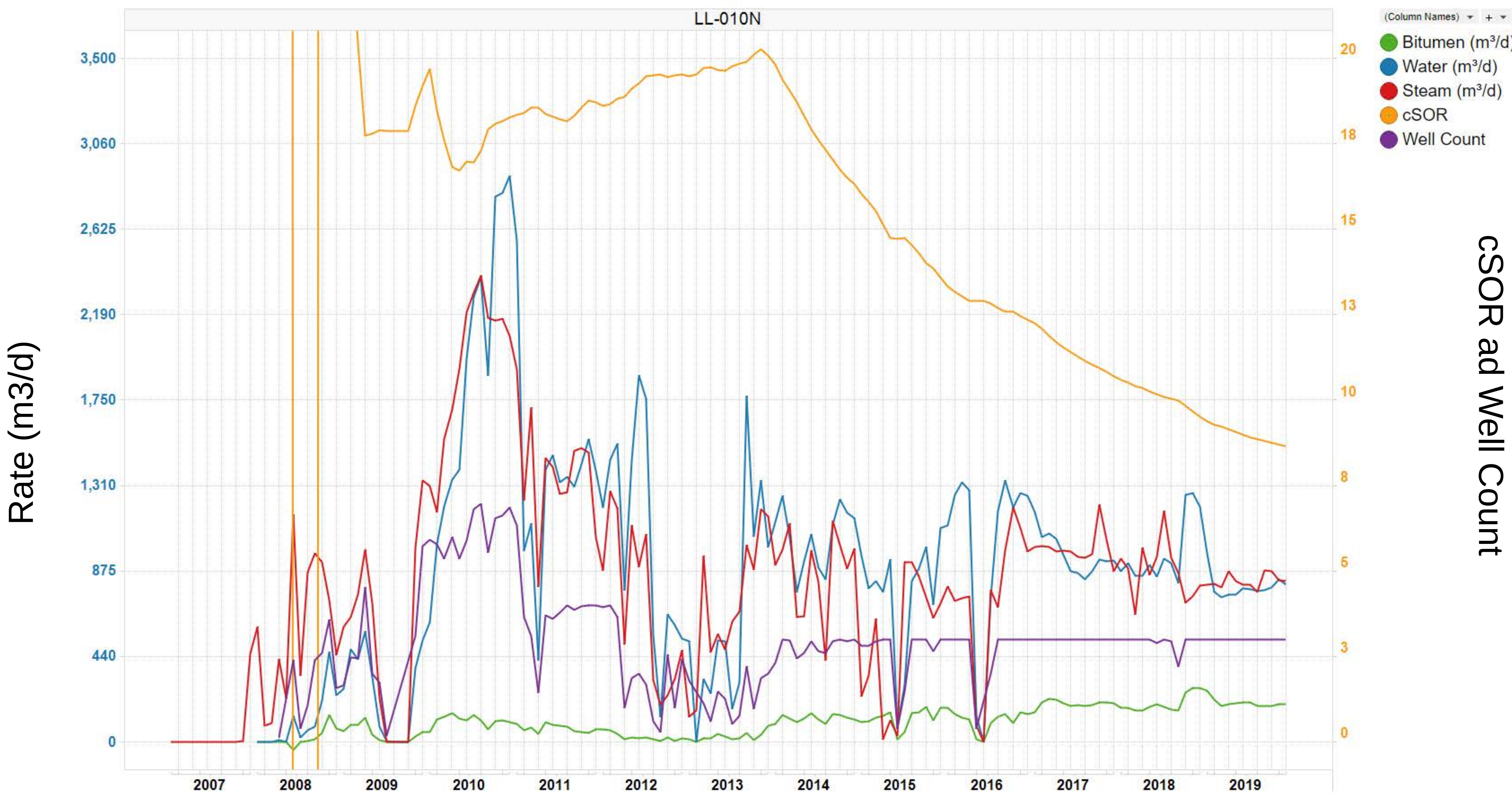
Pad 9W Production Summary

- Five well pairs (09P01 to 09P05)
  - 9P01-9P03 on gas lift, 9P04 & 9P05 on ESP
- Stable total fluid production
- YE injection pressures were 1810 - 1900kPa
- Cumulative production of 531 e^3m^3(EBIP RF 31%)



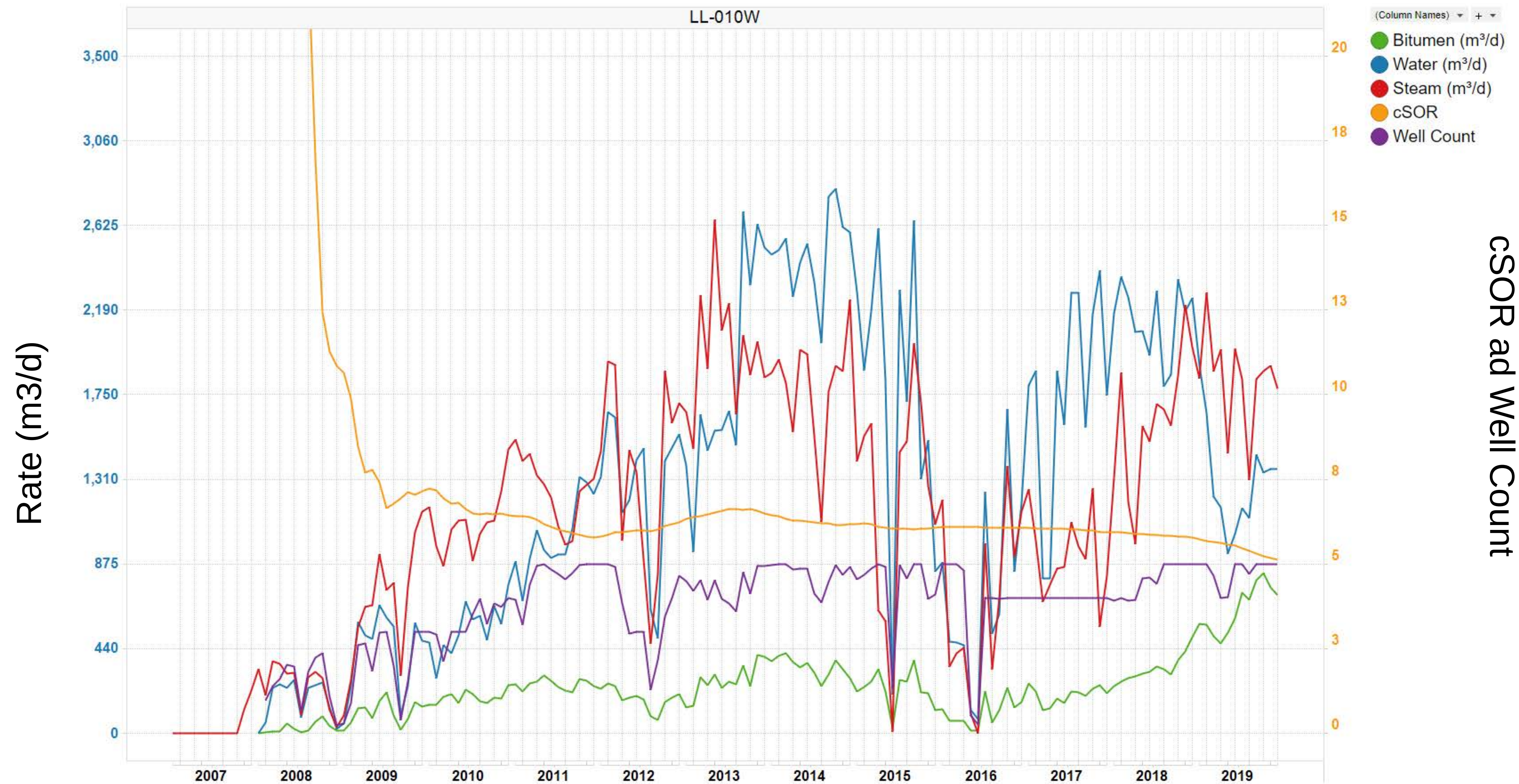
Pad 10N Production Summary

- Eight well pairs (10P06 to 10P13)
  - 3 producing wells on gas lift
- Steady operation strategy of current operational wells has yielded a stable production performance and shown improvement on cSOR
- YE injection pressures were 1810 - 1900 kPa
- Cumulative production of 405 e^3m^3 (EBIP RF 15%)



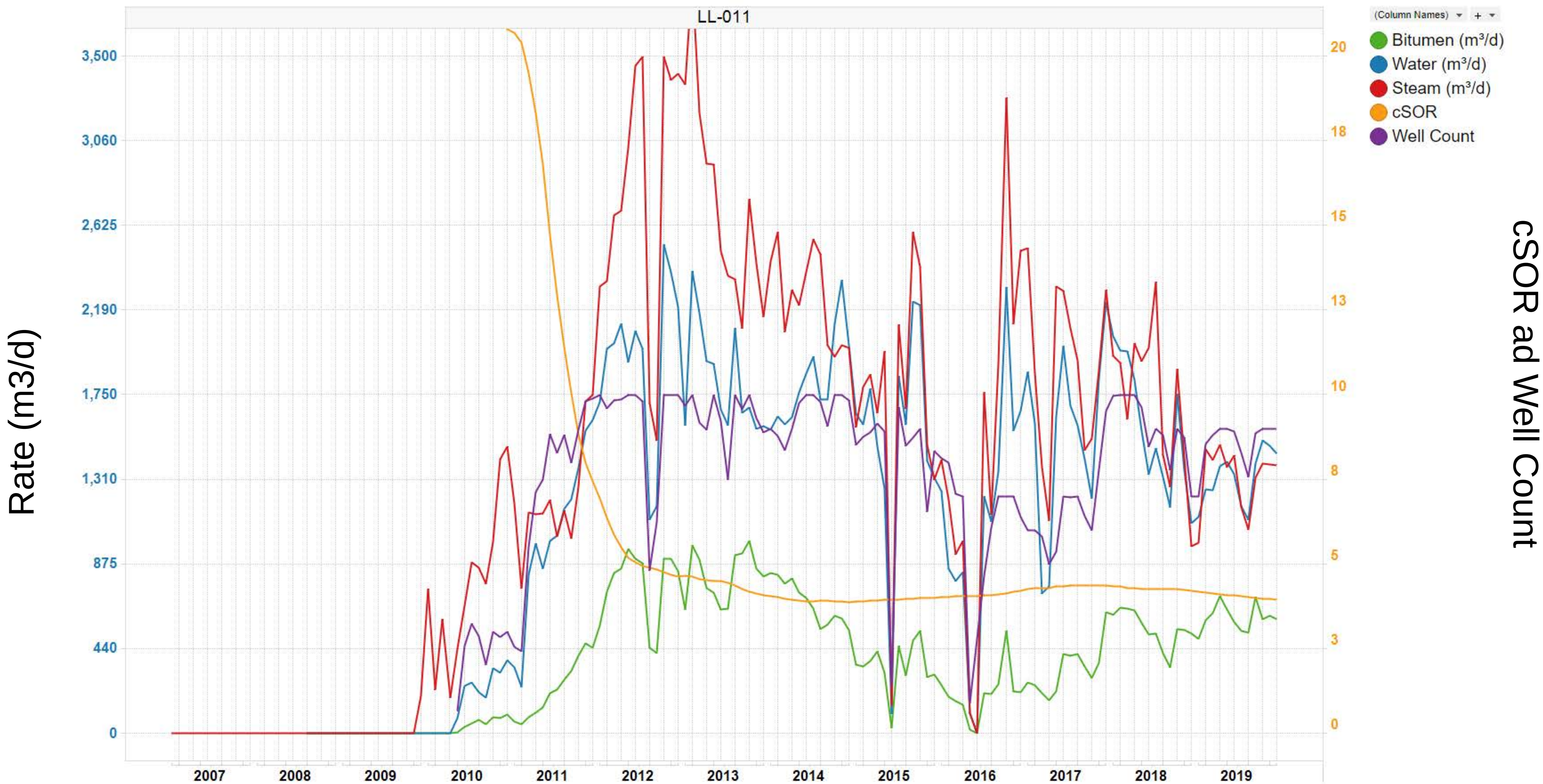
Pad 10W Production Summary

- Five well pairs (10P01 to 10P05)
  - 5 wells on ESP
- Observed improvement in oilcut in 2019
- YE injection pressures were 1890–1900 kPa
- Cumulative production of 1049 e^3m^3 (EBIP RF 40%)



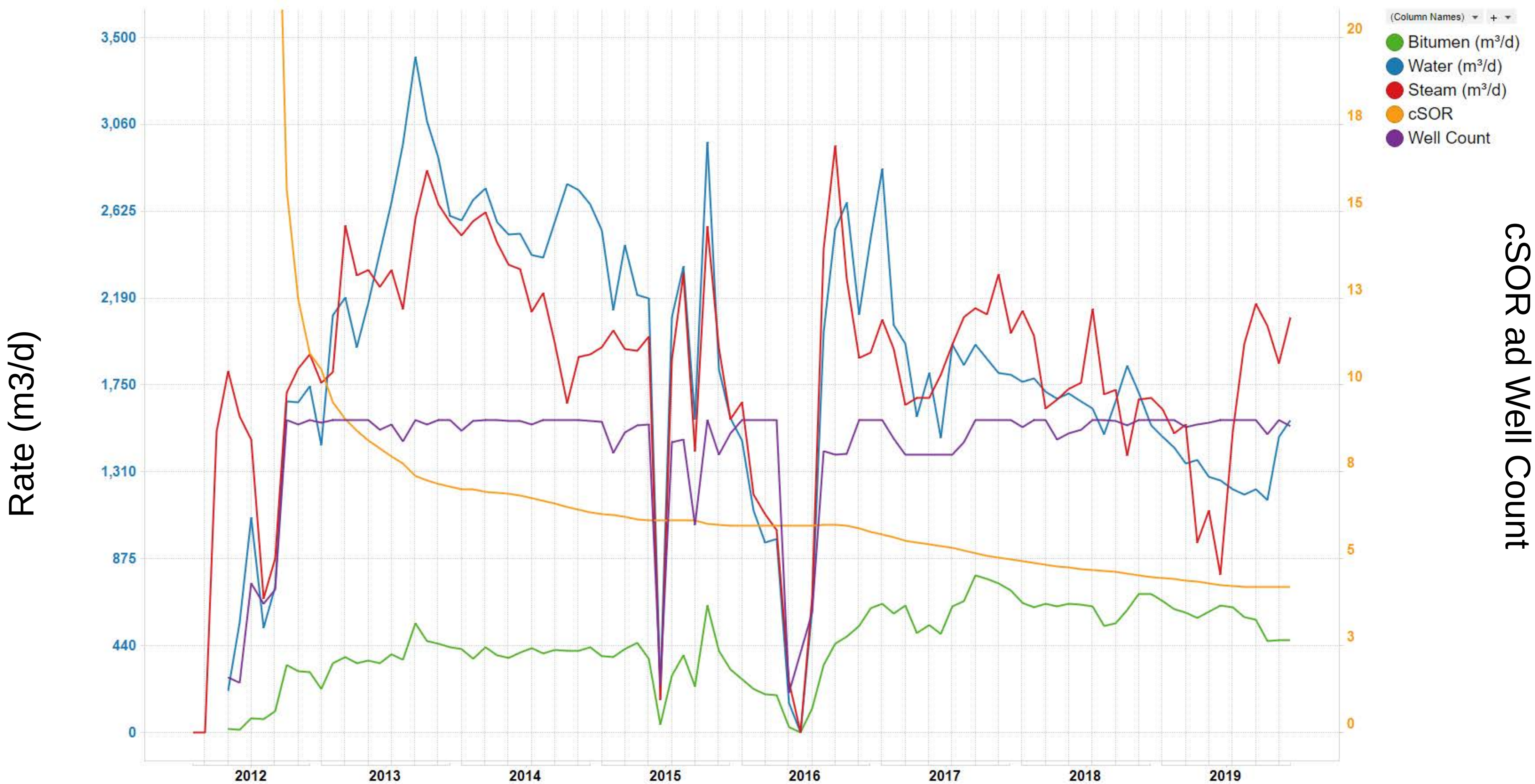
Pad 11 Production Summary

- Ten well pairs (11P01 to 11P10)
  - 9 wells are on ESP
  - 11P09 ESP failure is not currently economically justifiable to replace
- Pad continues to be impacted by top water, yet has maintained fairly steady production rates and observed increase in oilcut in 2019
- YE injection pressures were 1635 –1800 kPa
- Cumulative production of 1656 e^3m^3 (EBIP RF 64%)



Pad 12 Production Summary

- Nine well pairs (12P01 to 12P09)
  - All 9 wells are on ESP
- Performance impacted by Pad 13 infill drilling program in 2019
- YE injection pressures were 1660 –1735 kPa
- Cumulative production of 1240 e^3m^3 (EBIP RF 35%)



Pad 13 Production Summary

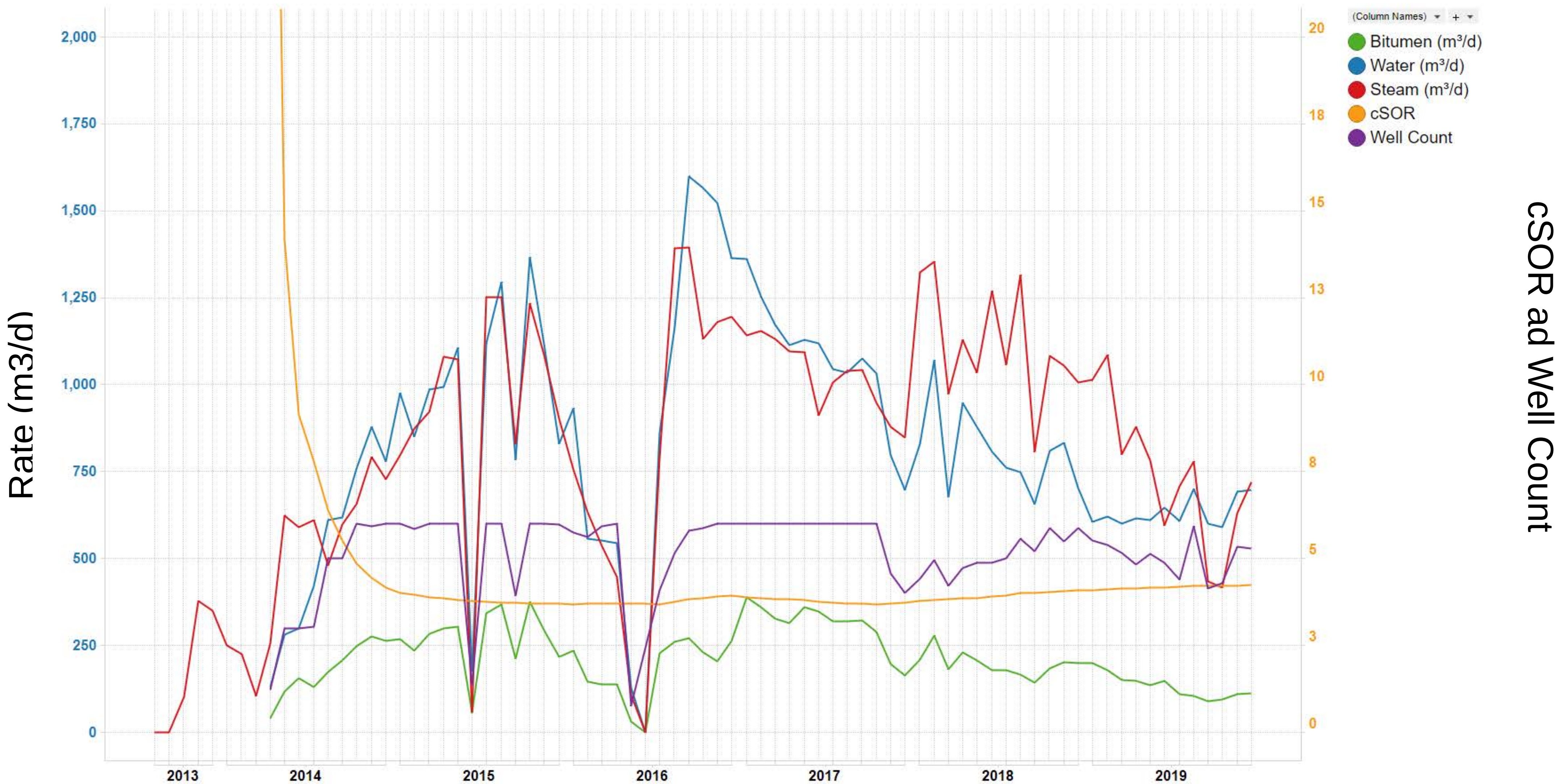
- Nine well pairs (13P01 to 13P09)
  - All 9 wells are on ESP
  - 6 infills wells drilled in mid-2019, to be on production in 2020
- Performance impacted by Pad 13 infill drilling program in 2019
- YE injection pressures were 1605 –1675 kPa
- Cumulative production of 1609 e^3m^3 (EBIP RF 42%)

Pad 14N Production Summary

- Three well pairs (14P05 to 14P07)
  - All 3 wells on ESP
- Performance impacted by steep tapered pressure strategy
- YE injection pressures were ~1500 kPa
- Cumulative production of 397 e^3m^3 (EBIP RF 28%)

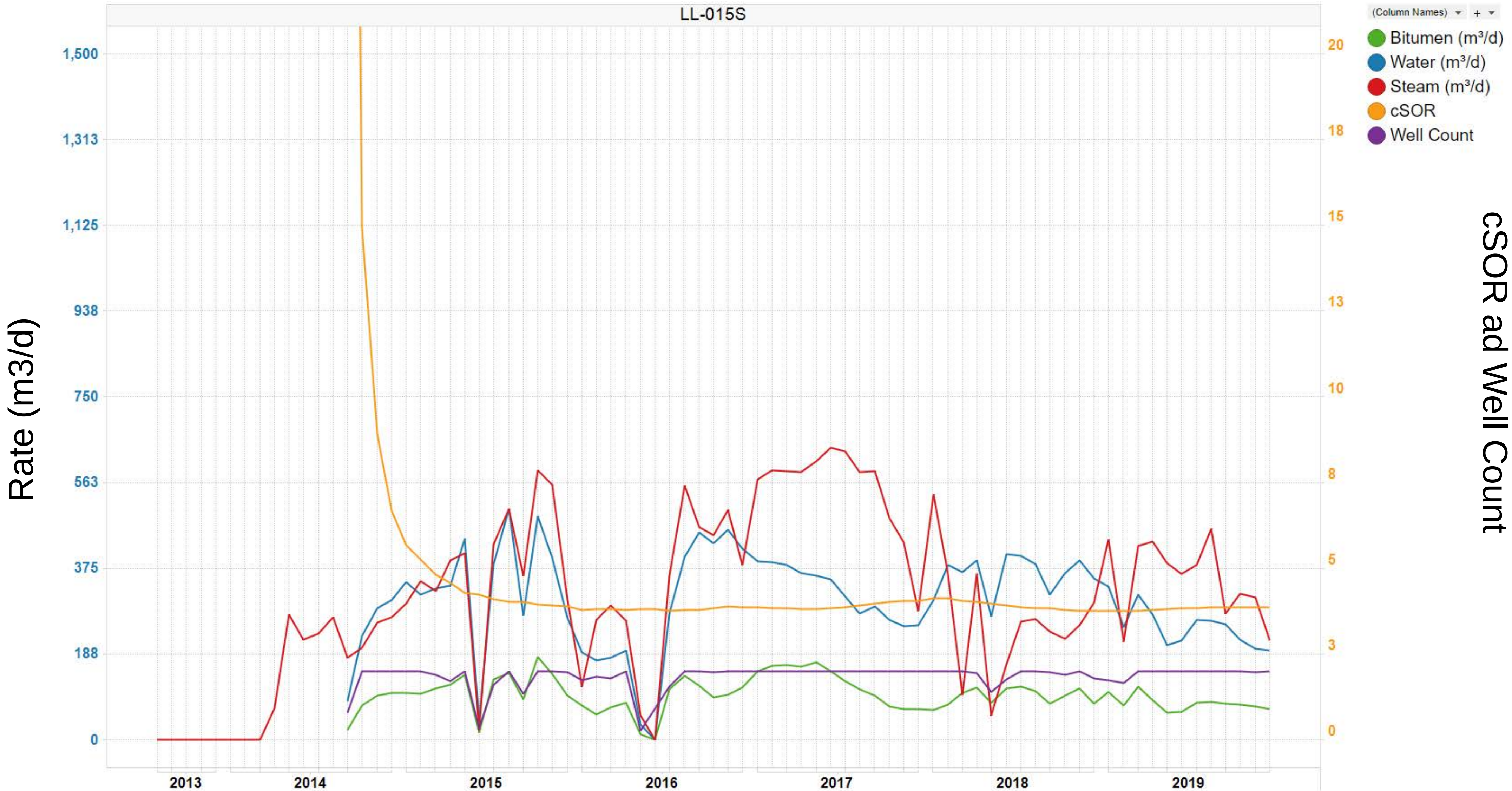
Pad 14/15E Production Summary

- Six well pairs (14P01 to 14P03 and 15P01 to 15P03)
  - All 6 wells on ESP
- Performance impacted by steep tapered pressure strategy and wells on intermittent production
- YE injection pressures were 1410 –1465 kPa
- Cumulative production of 446 e^3m^3 (EBIP RF 34%)



Pad 15S Production Summary

- Two well pairs (15P04, 15P05)
  - Both wells on ESP
- Performance impacted by steep tapered pressure strategy
- YE injection pressures were 1350- 1445kPa
- Cumulative production of 190 e^3m^3 (EBIP RF 23%)



Well Pad Performance
Subsection 3.1.7 (h)
Kinosis

K1A Production Summary

- 37 well pairs drilled
- All well pairs inactive pending construction of new pipeline
- Cumulative production of 181 e^3m^3 (RF 1%)