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

Date: April 23, 2019

CNOOC

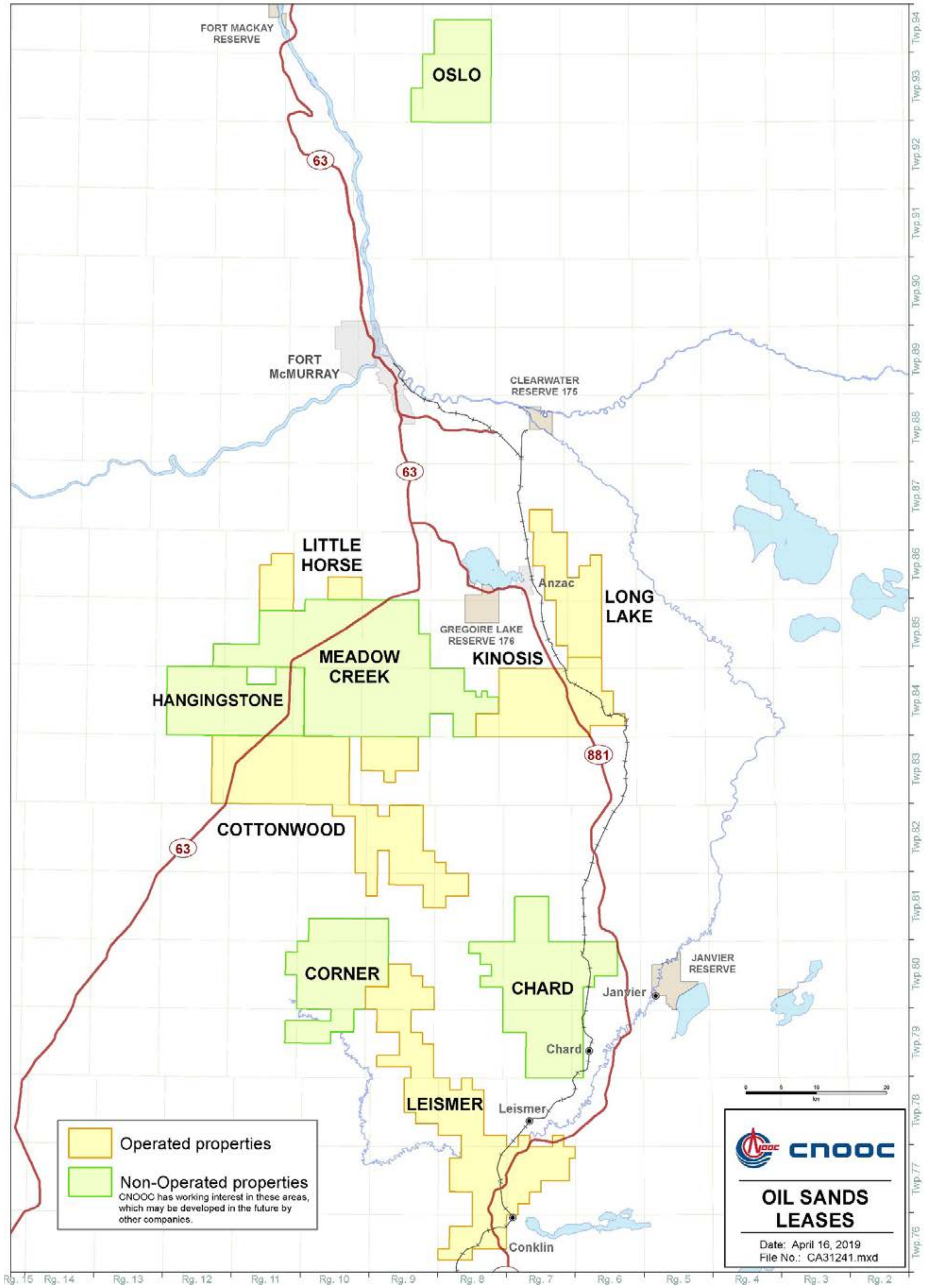
Forward Looking Statements

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 the UK North Sea, offshore West Africa, the United States and Western Canada.
- 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)

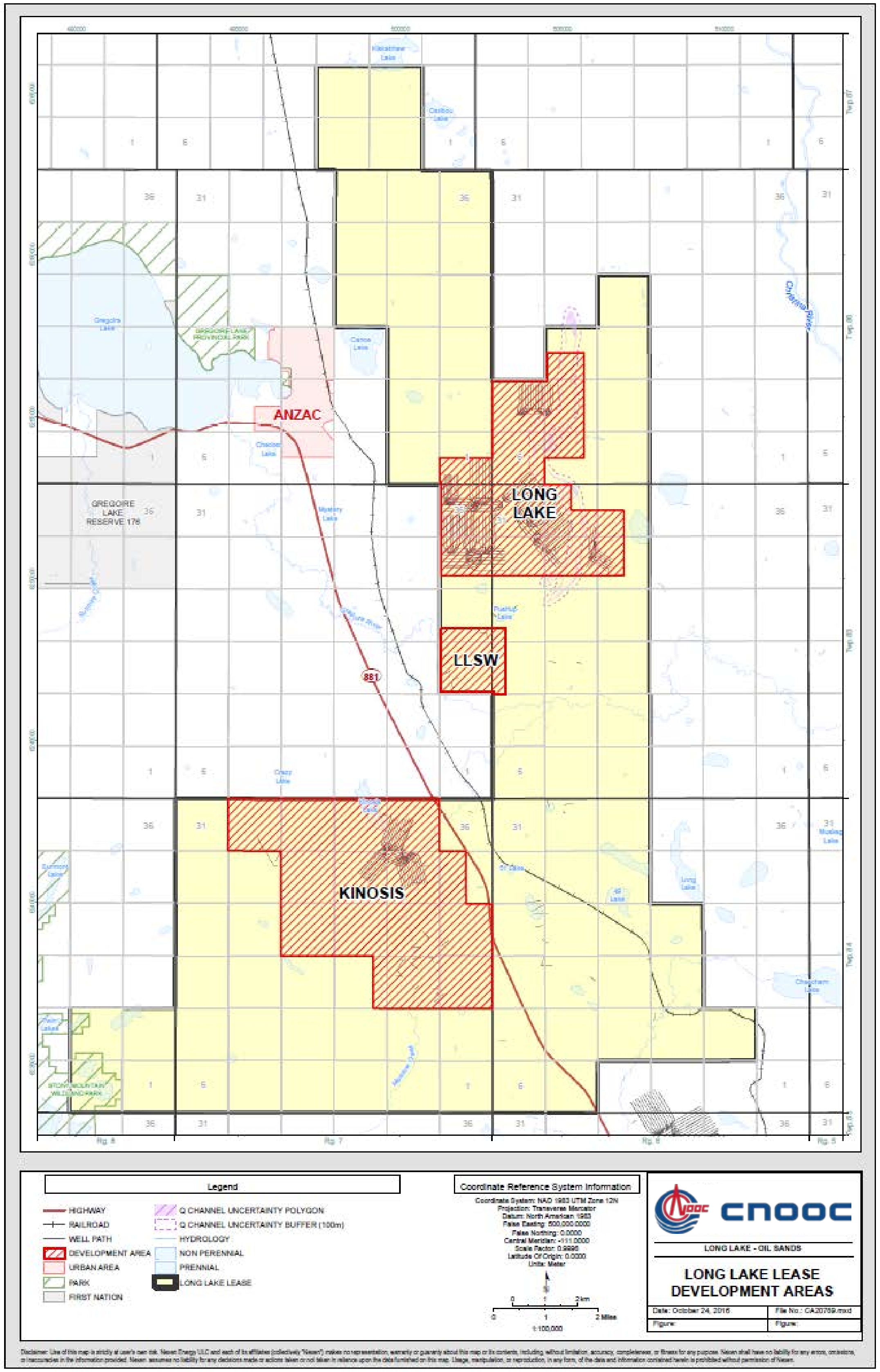
Long Lake and Kinosis

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

	Design (K1A*) m³/d	Design (K1A*) 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; Drilled infills on Pad 3, 6; Drilling commenced on LLSW SAGD well pairs

2018 Summary

- Long Lake pads exhibited strong and stable performance throughout the year.
  - Infills on Pad 5 and Pad 8 commenced production
  - Drilled Infills on Pad 3 and Pad 6
  - Highest annual average production with lowest observed SOR
- Disposal line leak curtailed production in Q3 2018
- Site preparation and drilling of sustaining SAGD wellpairs in LLSW began in Q4 2018
- K1A Recovery Project
  - Completed Front End Engineering Design for K1A pipeline replacements
  - Project sanctioned in Q4 2018
  - Commenced Execute stage engineering Nov 2018

Geology and Geosciences Overview

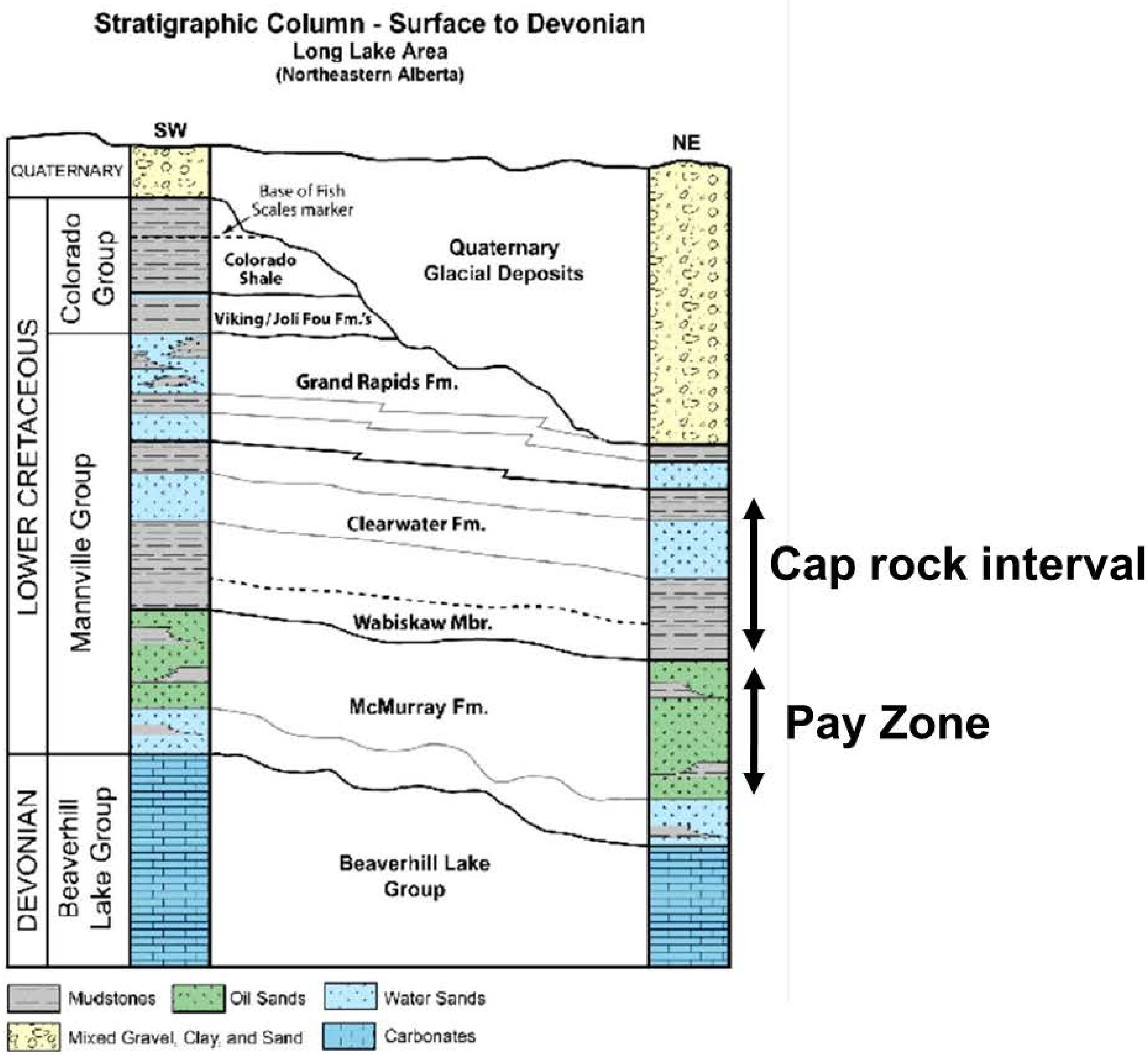
Subsection 3.1.1 (2)

Long Lake and Kinosis

Stratigraphy

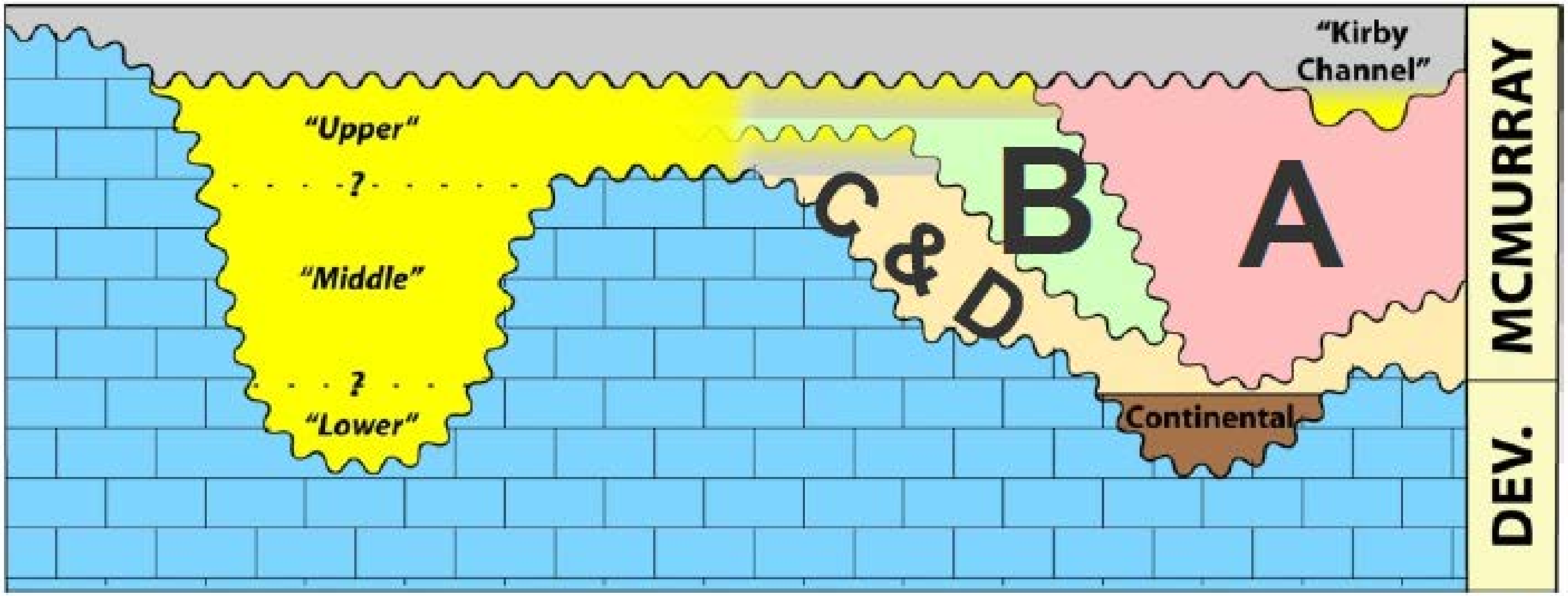
Reservoir: McMurray Fm.

Cap rock: Wabiskaw & Clearwater Fm.



CNOOC International's Regional Model

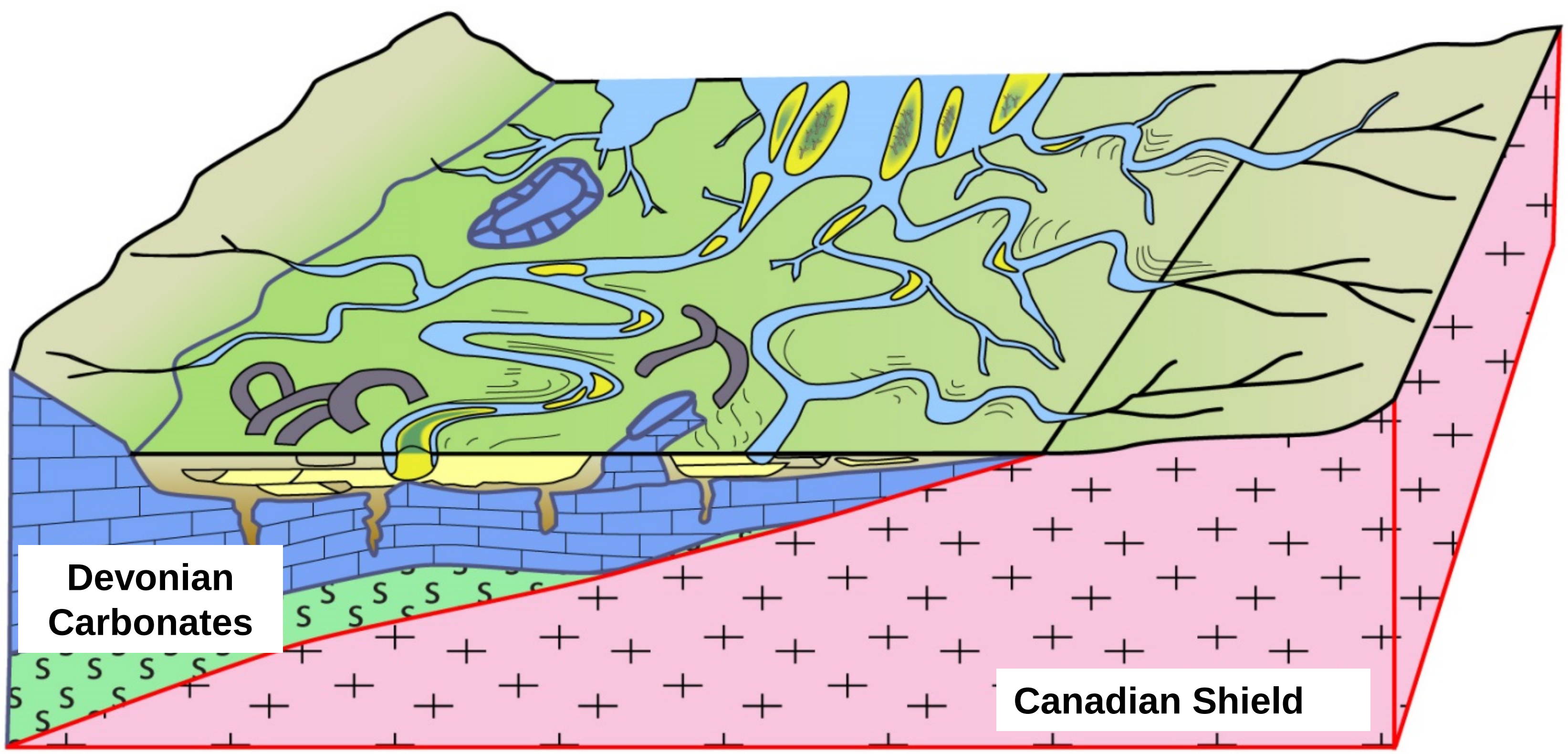
- Compound incised-valley system hung from several surfaces in the McMurray
- Multiple valleys:
  - C & D valleys (oldest)
  - A valley (youngest)
- Low-accommodation setting



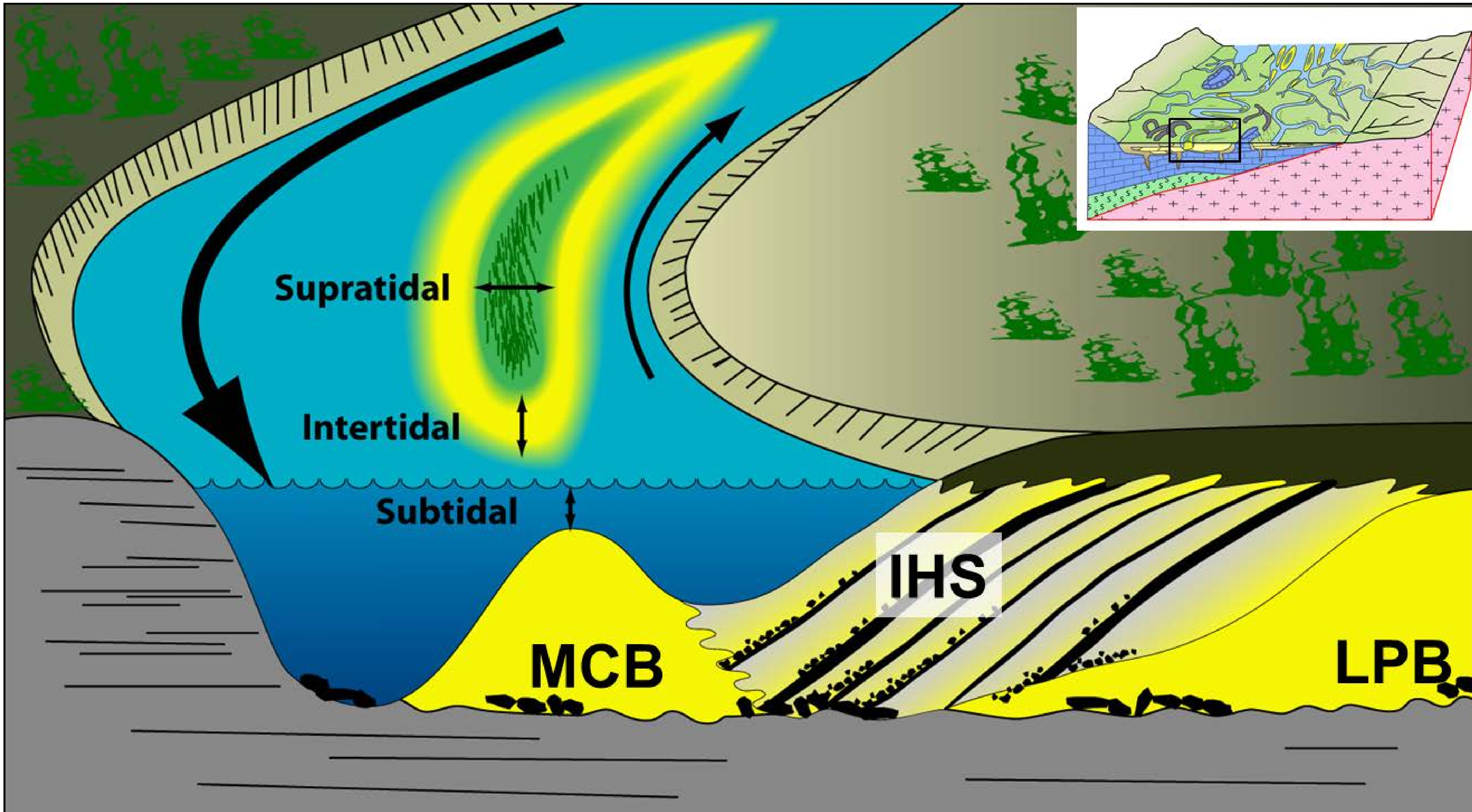
Jervey, 2003

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

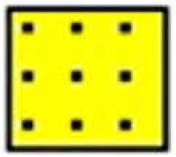


McMurray Geological Model and Reservoir Facies



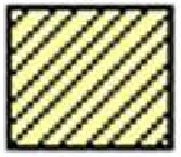
MCB = mid channel bar	Facies 1 & Facies 3
LPB = lower point bar	Facies 1 & Facies 3
IHS = inclined heterolithic stratification	Facies 2 & Facies 3 & Facies 4

CNOOC International Facies Codes



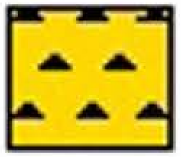
Sandstone .... Facies 1:

- clean crossbedded sandstone
- VSH 0 - 10%
- estuarine sands



Sandy IHS .... Facies 2:

- Inclined interbedded sandstone, and mudstone
- Vsh 10-50%
- Point-bar facies

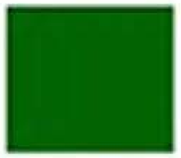


Breccia .... Facies 3:

- mud clast breccia
- sand supported and mud clast supported
- channel base facies

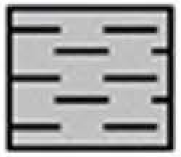
Muddy IHS.............. Facies 4:

- Inclined interbedded sandstone, and mudstone
- Vsh 50-90%
- Point-bar facies



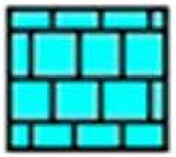
Mudplug.................. Facies 5:

- 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/Kinosis Devonian Structure

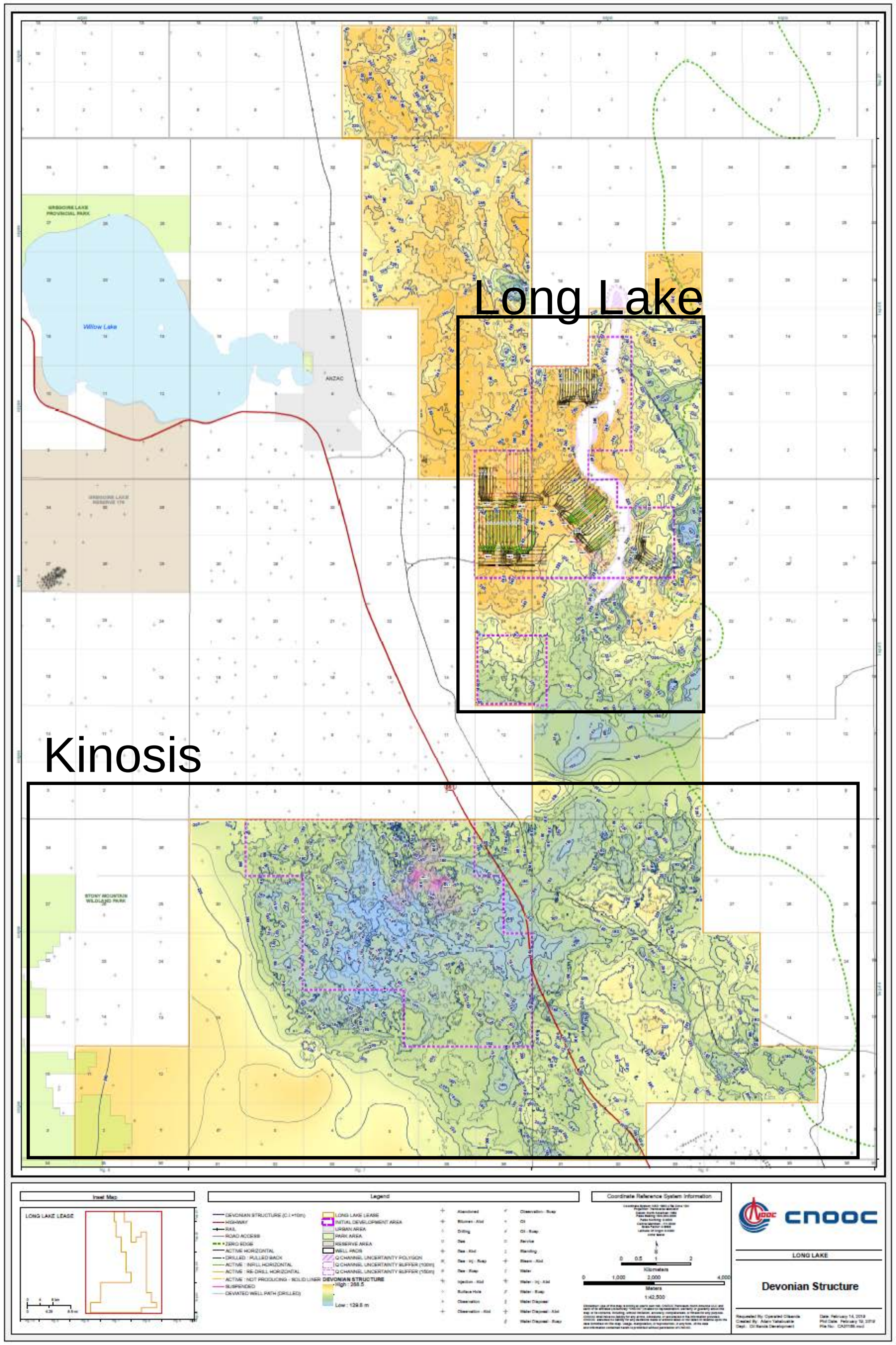
- DEVONIAN STRUCTURE (C.I.=10m)
- HIGHWAY
- RAIL
- ROAD ACCESS
- Zero bitumen edge
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

- 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)

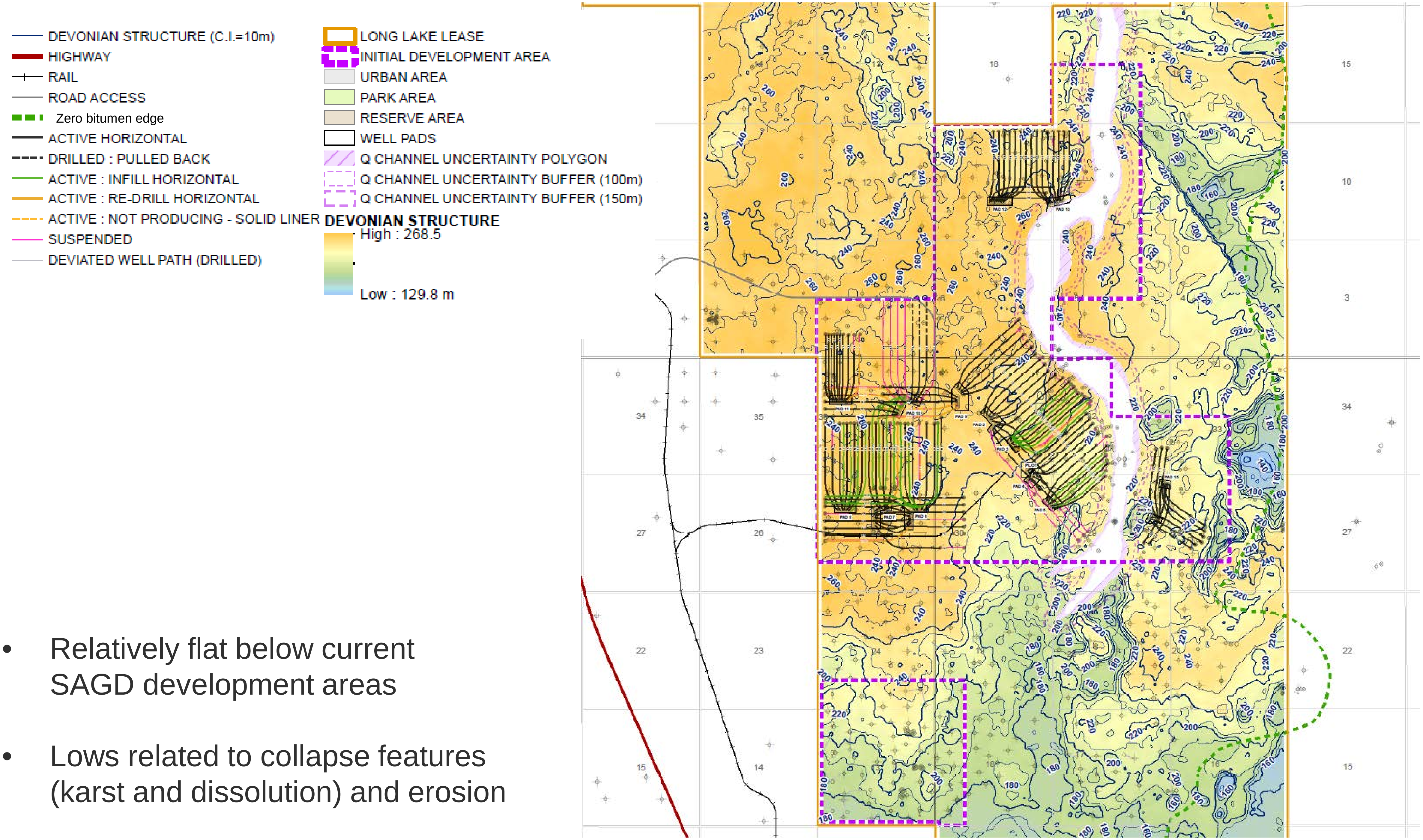
DEVONIAN STRUCTURE

High : 268.5

Low : 129.8 m

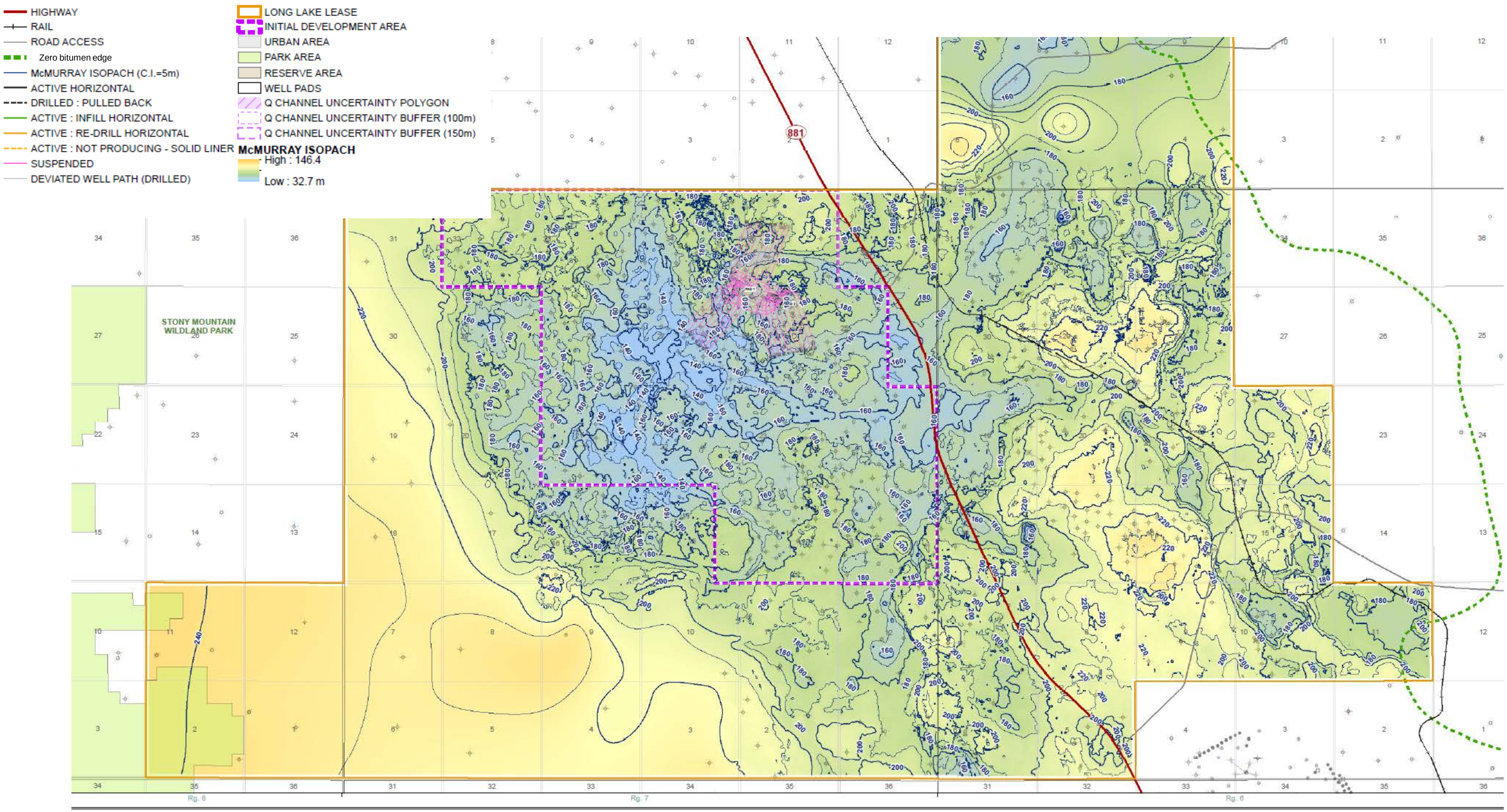


Long Lake Devonian Structure



- 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/Kinosis McMurray Structure

- HIGHWAY
- RAIL
- ROAD ACCESS
- Zero bitumen edge
- McMURRAY STRUCTURE (C.I.=5m)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
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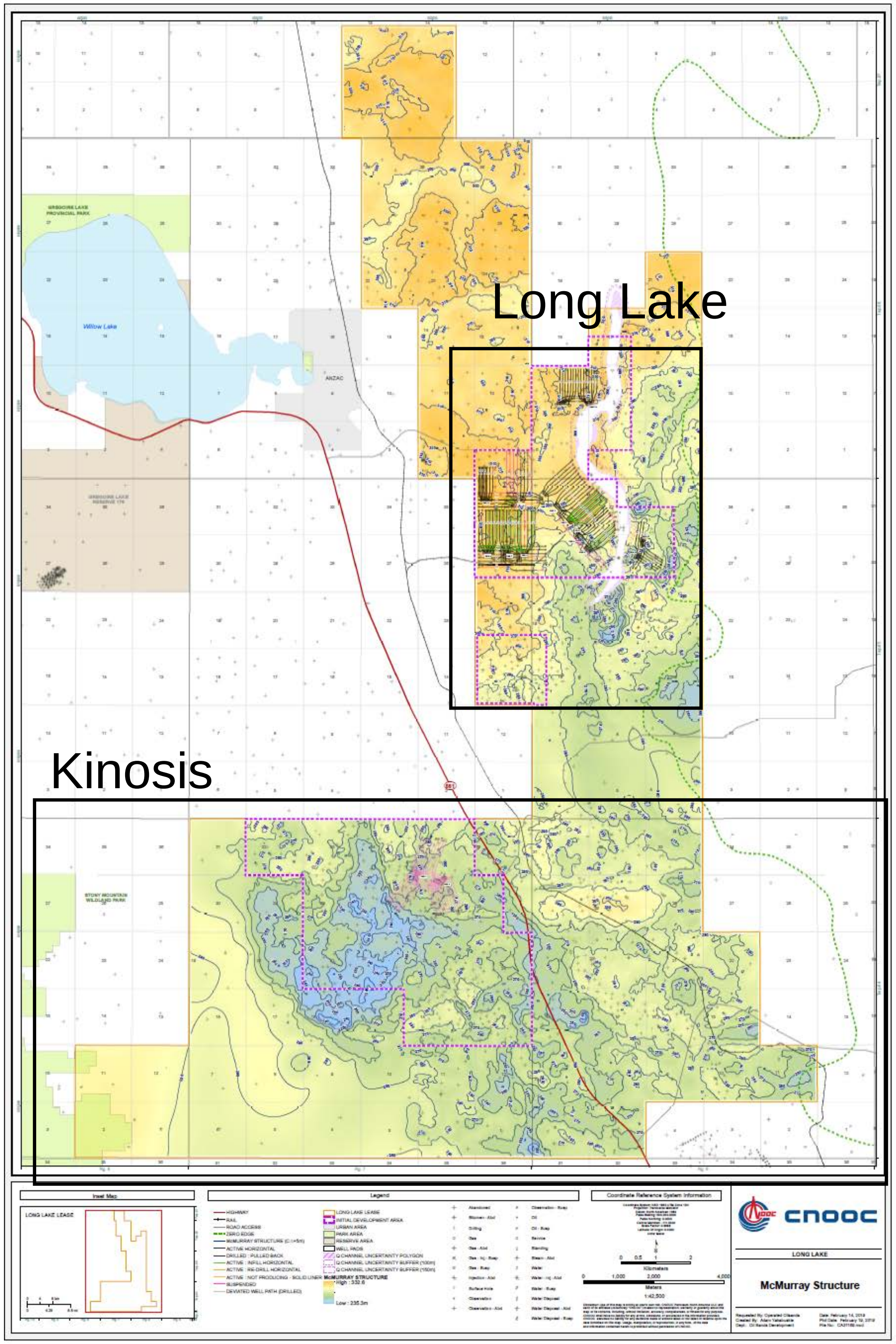
- Q CHANNEL UNCERTAINTY BUFFER (150m)

McMURRAY STRUCTURE

High : 332.6

Low : 235.3m



Long Lake McMurray Structure

- HIGHWAY
- RAIL
- ROAD ACCESS
- Zero bitumen edge
- McMURRAY STRUCTURE (C.I.=5m)
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McMURRAY STRUCTURE

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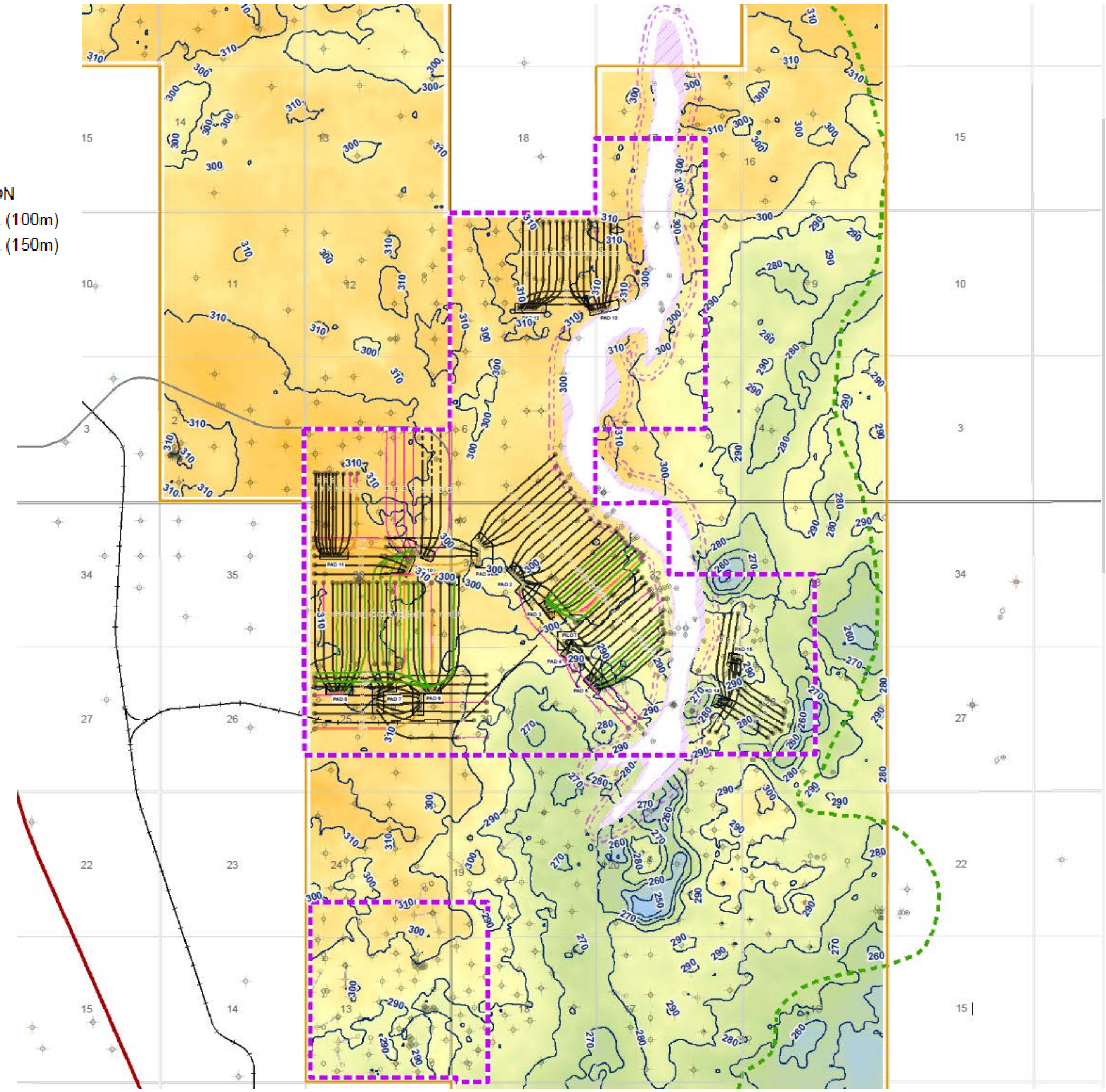
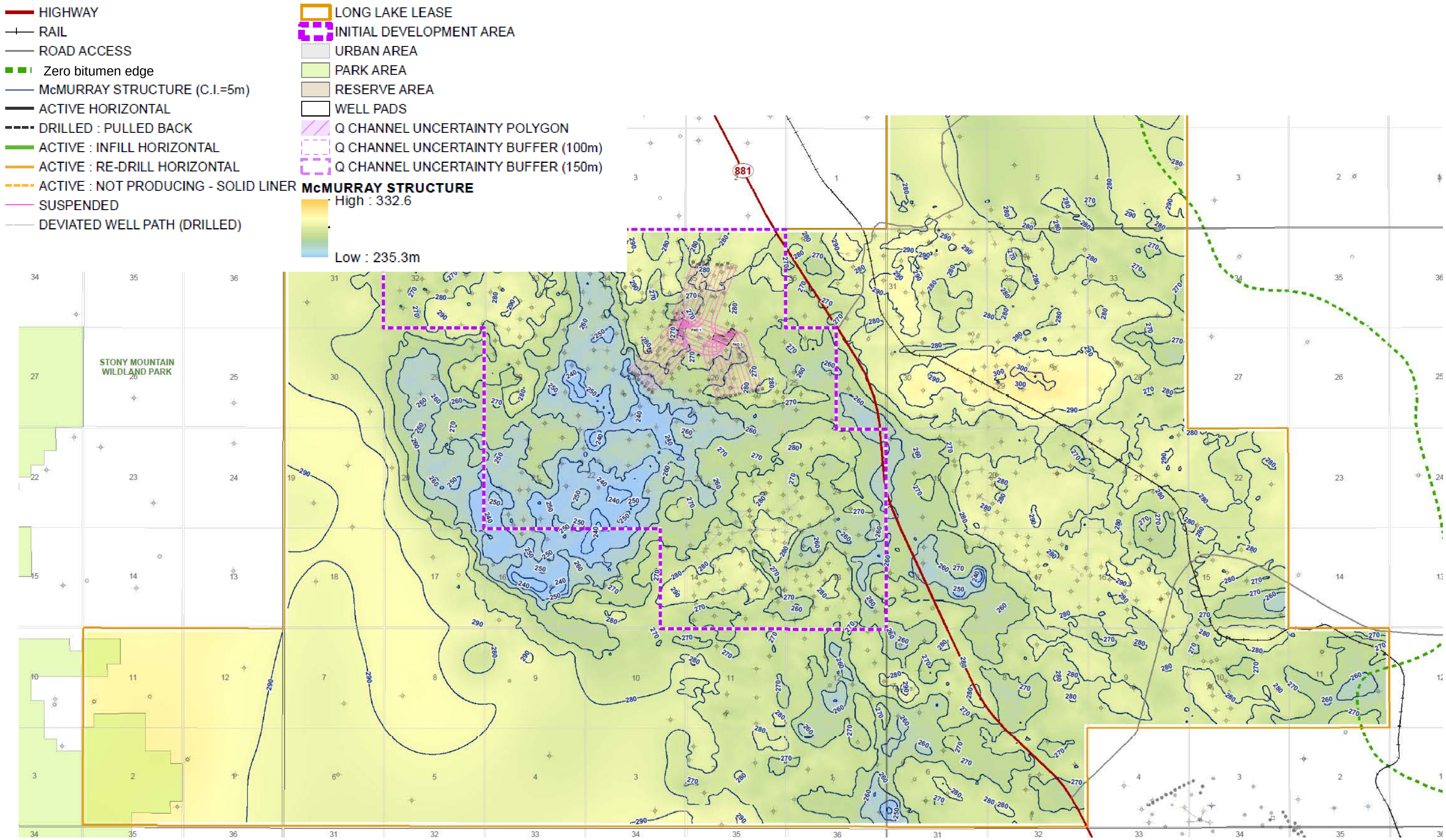


- Blue/Green-shaded areas are lows related to salt dissolution
- Subtle structural influences related to karsting, erosion on Devonian and differential compaction over muddier McMurray deposits

Kinosis McMurray Structure



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

Long Lake/Kinosis McMurray Isopach

- HIGHWAY
- RAIL
- ROAD ACCESS
- Zero bitumen edge
- McMURRAY ISOPACH (C.I.=5m)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
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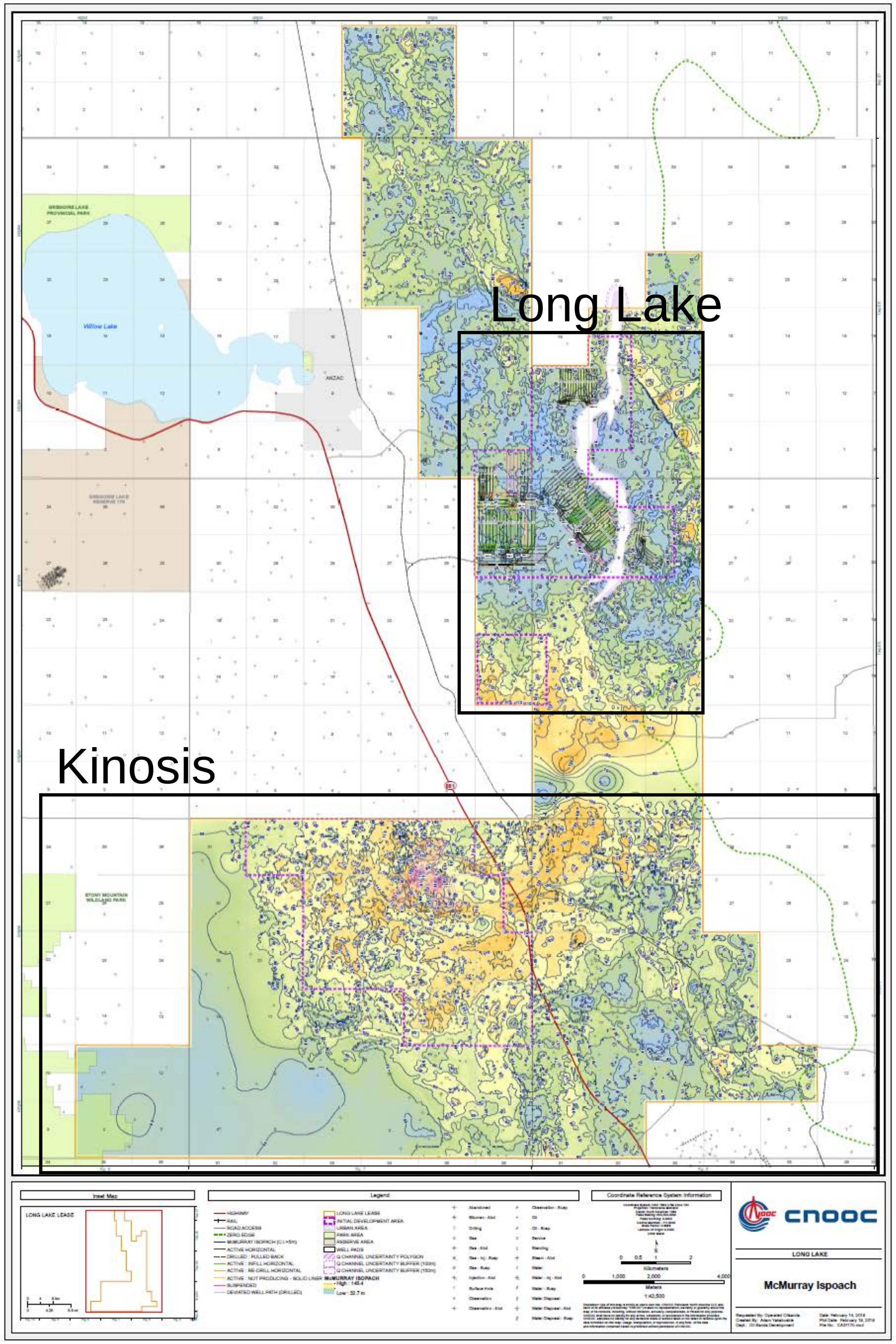
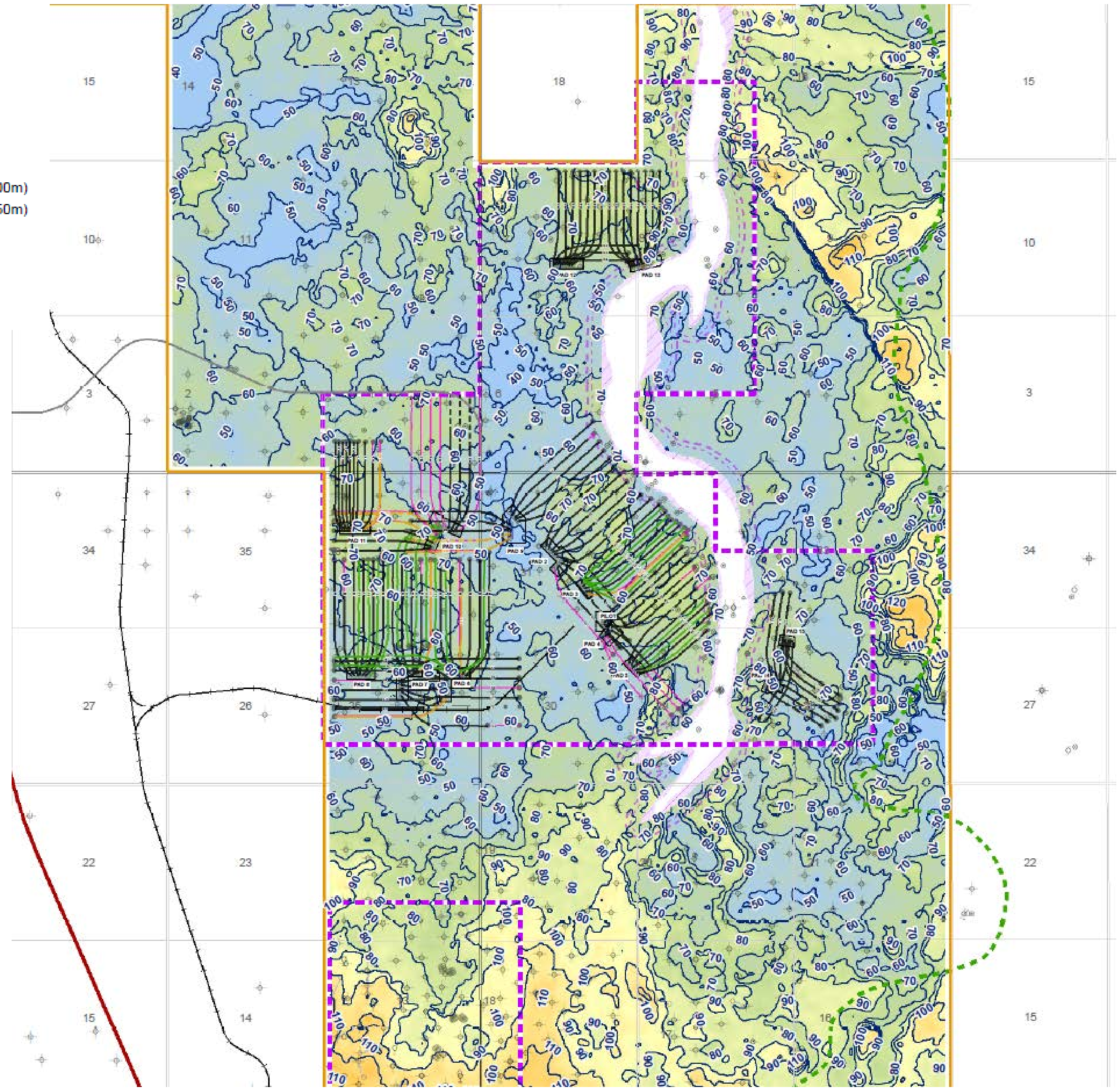
- Q CHANNEL UNCERTAINTY BUFFER (150m)

McMURRAY ISOPACH
High : 146.4
Low : 32.7 m

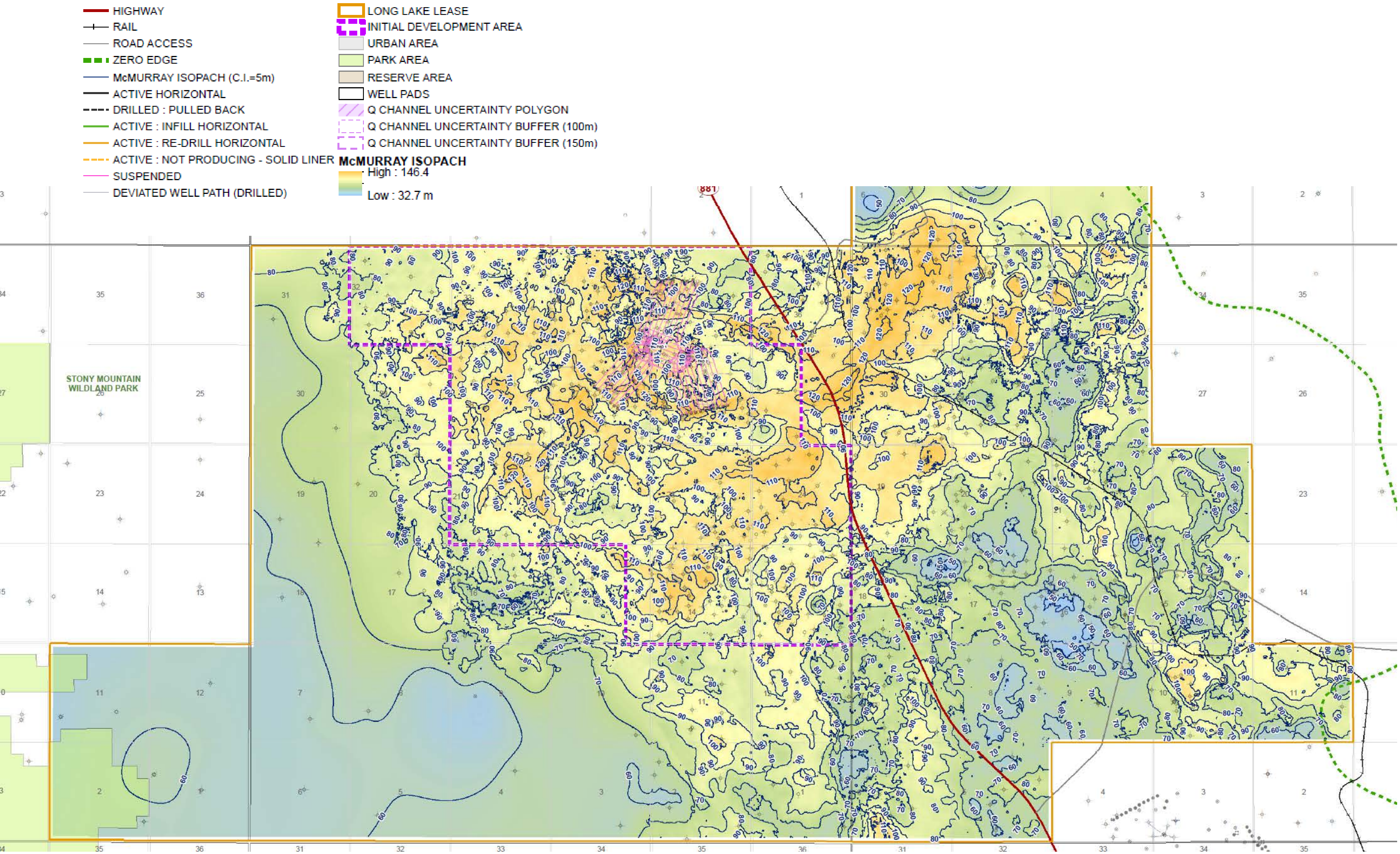


Long Lake McMurray Isopach



- 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

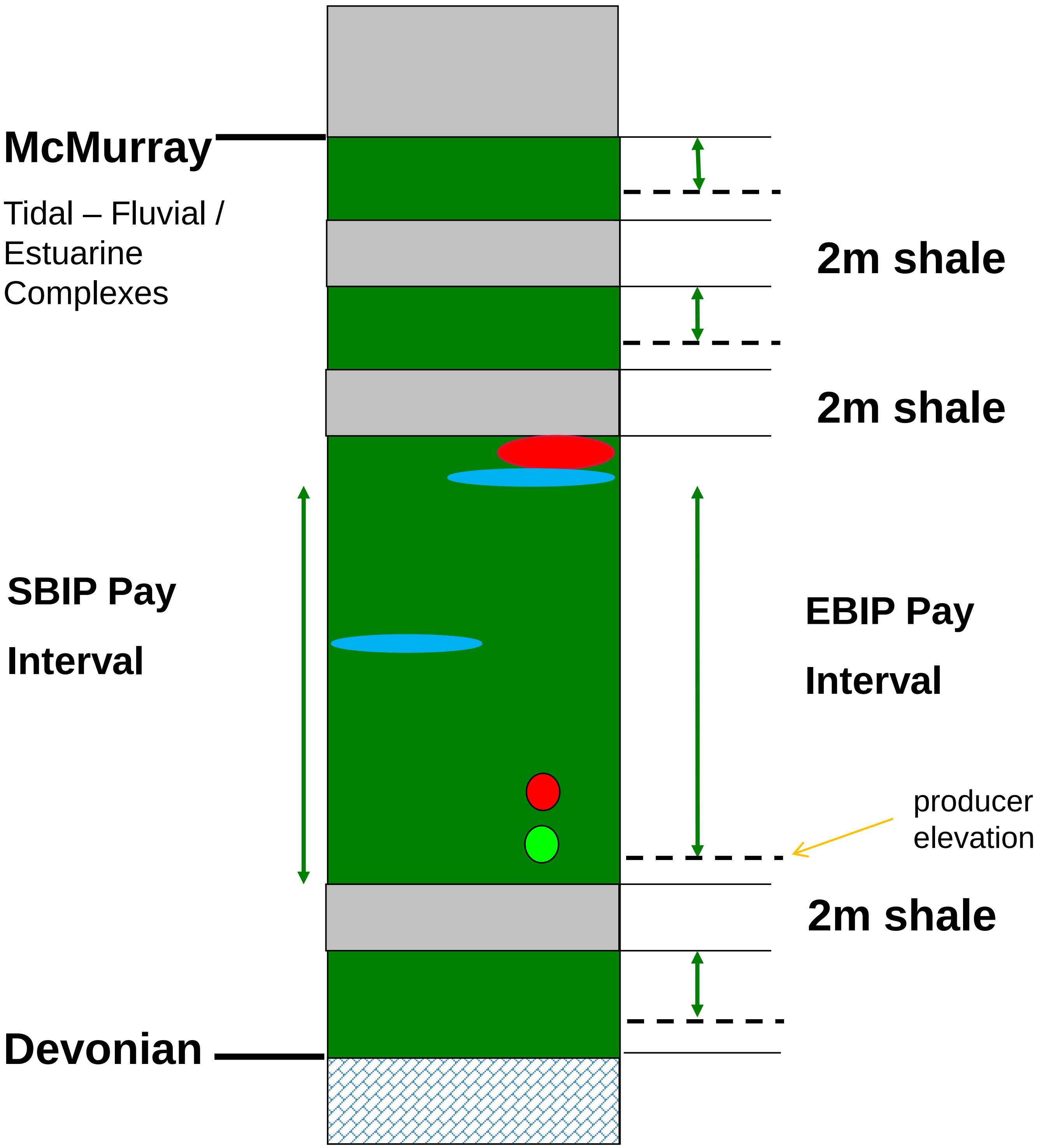
Pay and Exploitable Bitumen-in-Place Mapping Methodology

cnooc

- 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.

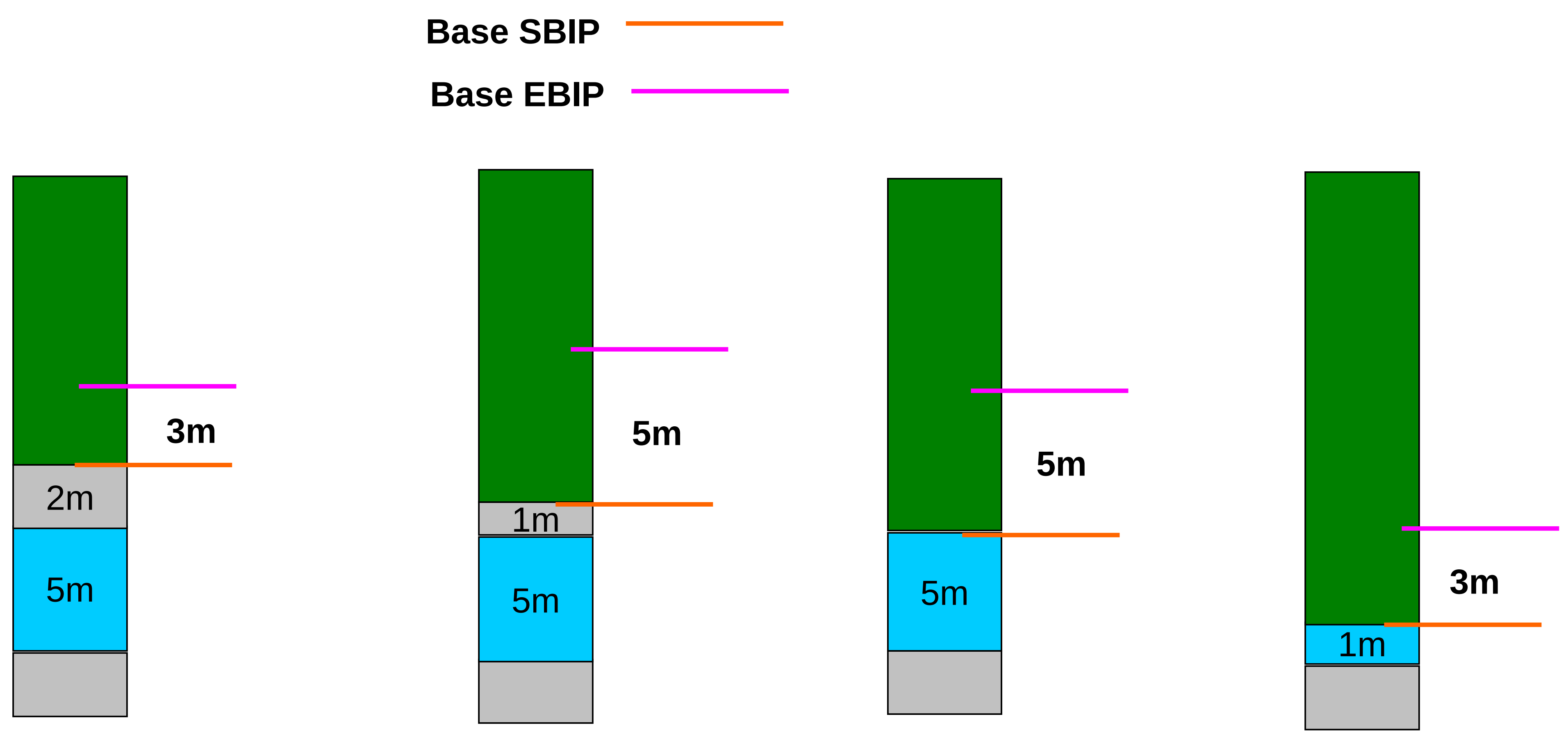
- Reservoir Rock
  - Sand
  - Breccia
  - IHS with < 30% V_{shale}
- High Water Saturation Interval
  - > 50% Swe (effective water saturation) and < 30% V_{shale}
- Minimum EBIP HPVH and Pay Interval Contour
  - $3m^3/m^2$ EBIP HPVH = 12m EBIP Pay Interval

Pay and Bitumen-in-Place Mapping Methodology

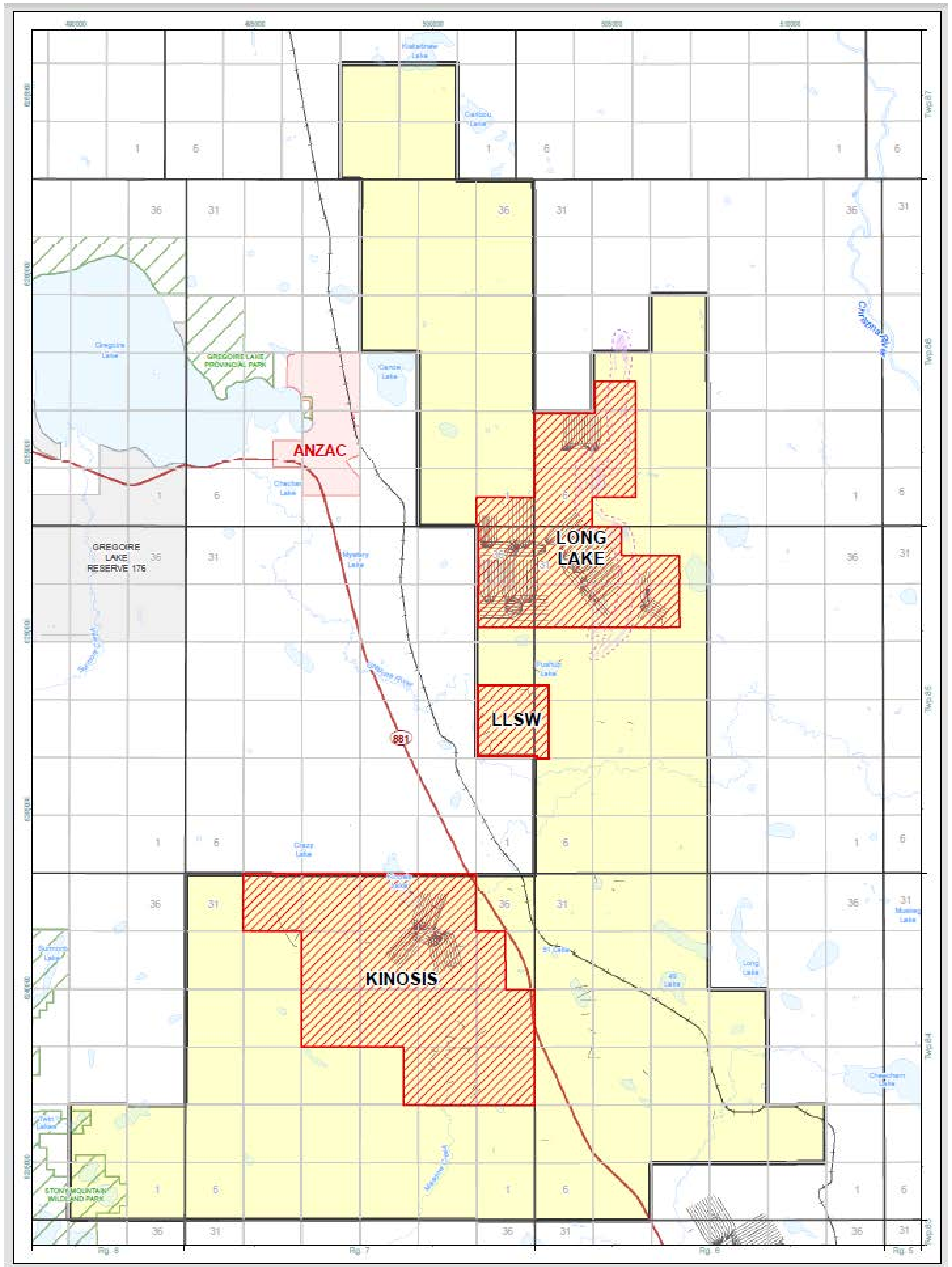


- **SBIP Pay Interval:**
  - < 30% V_{shale}
  - < 50% S_{we}
- May have associated:
  - gas interval(s)
  - high water saturation interval(s)
- Primary zone defined as the thickest pay interval <u>unless</u>:
  - an existing (or planned) horizontal well pair is within an interval
  - geologists have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



Legend

- HIGHWAY
- RAILROAD
- WELL PATH
- DEVELOPMENT AREA
- URBAN AREA
- PARK
- FIRST NATION
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- HYDROLOGY
- NON PERENNIAL
- PRENNIAL
- LONG LAKE LEASE

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 1 2 km

0 1 2 Miles

1:100,000

Long Lake Development Area EBIP and Average Reservoir Parameters

Long Lake (including Long Lake SW) Development Area EBIP

Long Lake EBIP (E^6m^3)	112

CNOOC International Cutoffs: HPVH > 3 m

Hydrocarbon Pore Volume Height

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

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)	179

CNOOC International Cutoffs: HPVH > 3 m

Hydrocarbon Pore Volume Height

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

Pay Average Reservoir Parameters

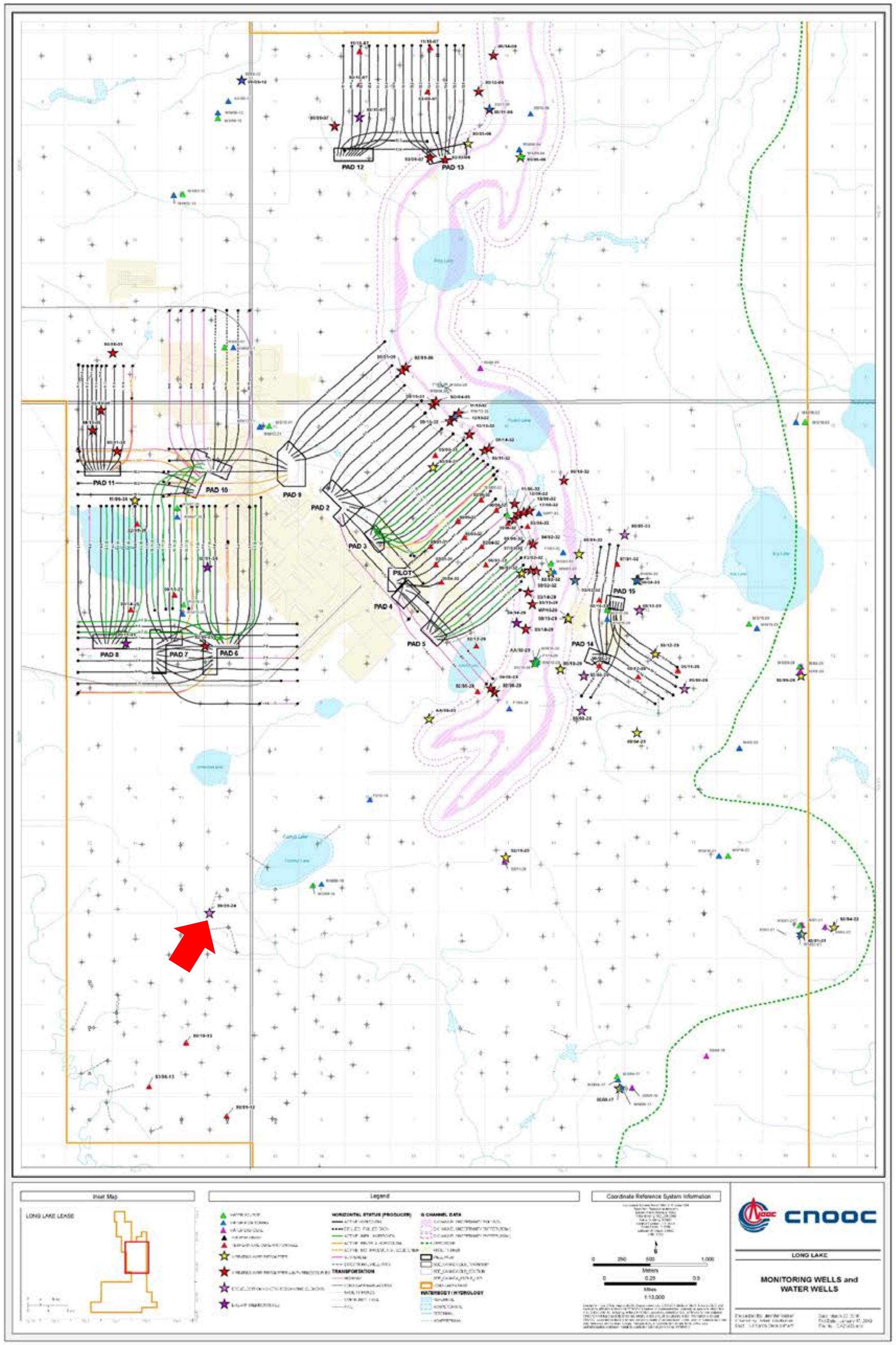
- Measured Depth (top) 280 mKB
- Thickness 33 m
- Effective Porosity 32 %
- Permeability From Core Plugs
  - k_{max} 4,030 mD
  - k_{vert} 2,347 mD
- Effective Water Saturation 26 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure
  - ~1,100 – 1,300 kPa

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

Long Lake 2018 Winter Program

- **109/08-24-085-07W4/0** observation well drilled in December, 2018
  - 93.2m deviated core
  - Open hole logging program
    - GR, Neutron, Density, Sonic, NMR, resistivity, image logs
  - 10 ERE sensors placed in well to monitor pressure and temperature
    - 2 in Clearwater A Sand
    - 8 in McMurray

UWI	Well Name	Well Licence	Year
109082408507W400	NEU CNOOC OBS NEWBY 8-24-85-7	491636	2018



Long Lake/Kinosis SBIP Pay Interval Isopach

- HIGHWAY
- RAIL
- ROAD ACCESS
- Zero bitumen edge
- SBIP ISOPACH (C.I.=5m)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
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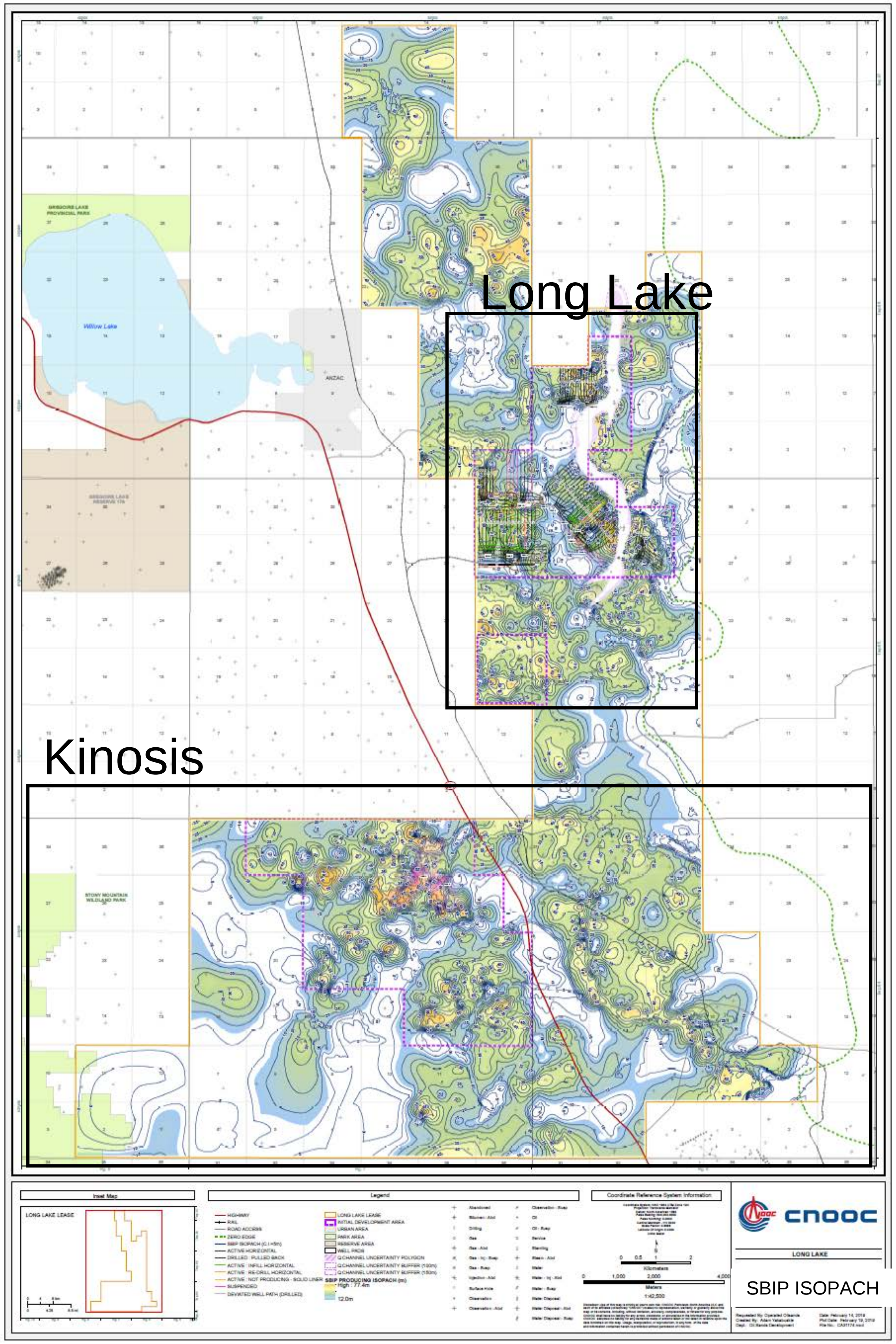
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP ISOPACH (m)

High : 77.4m

12.0m



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SBIP ISOPACH (m)

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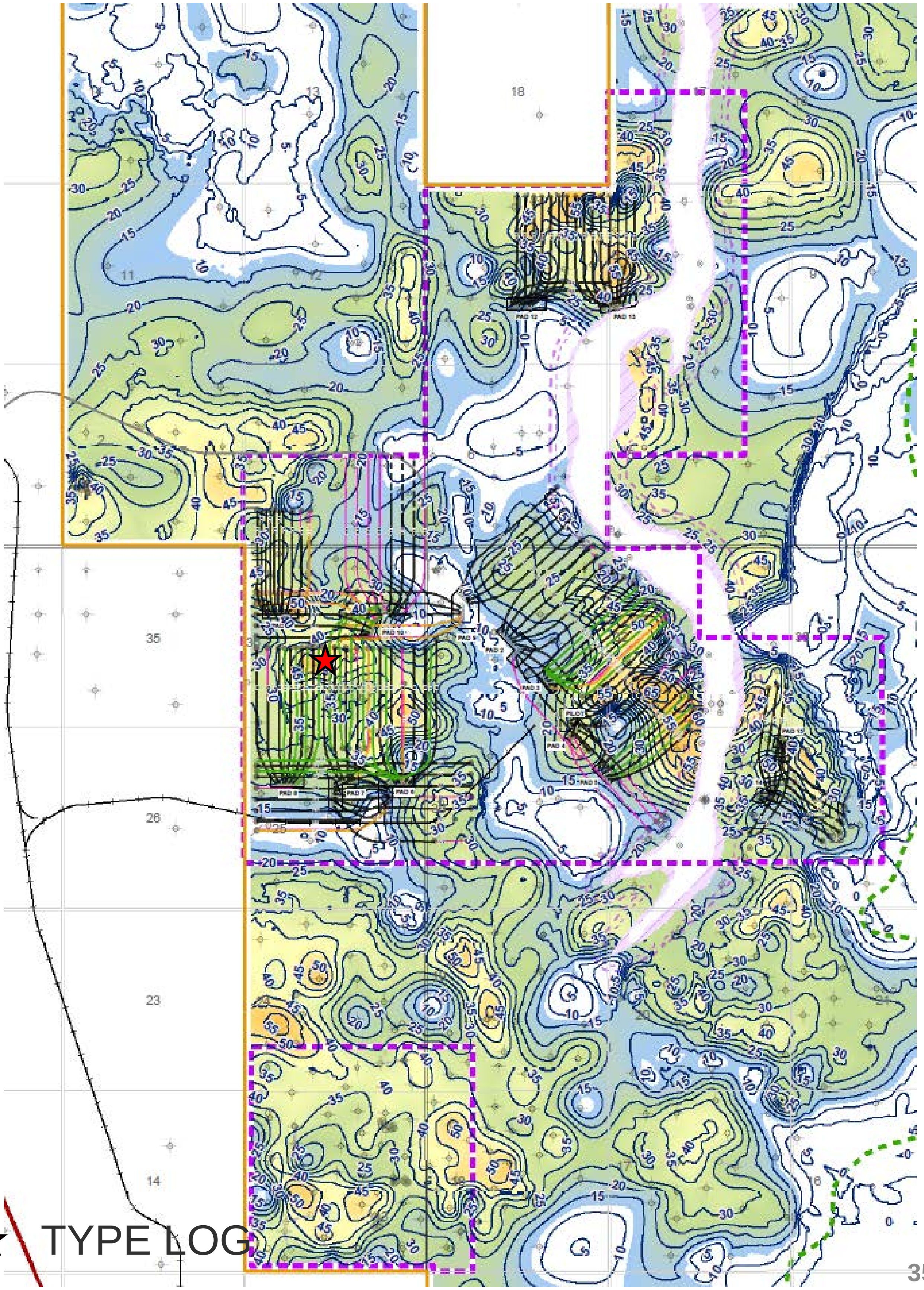
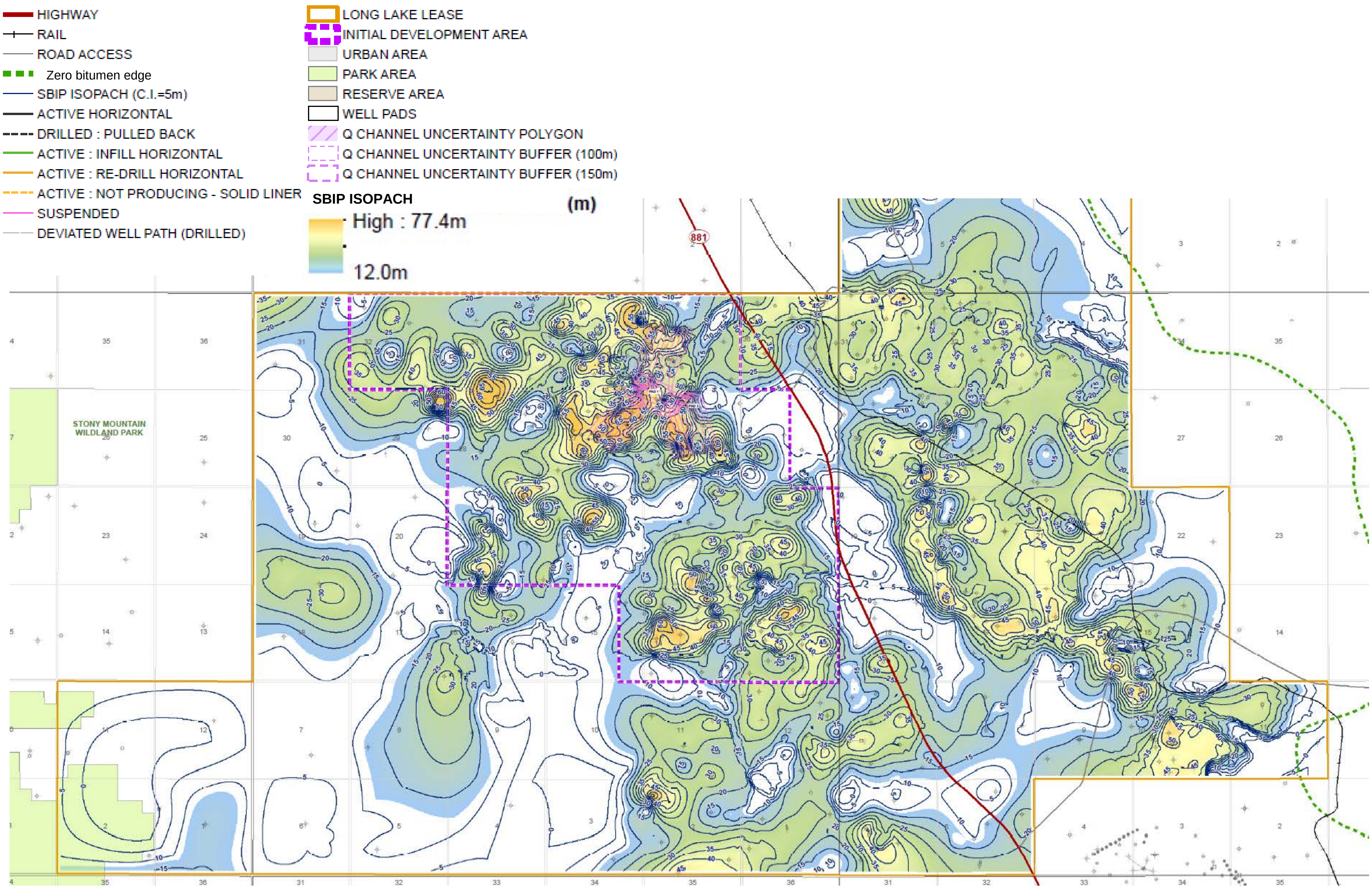
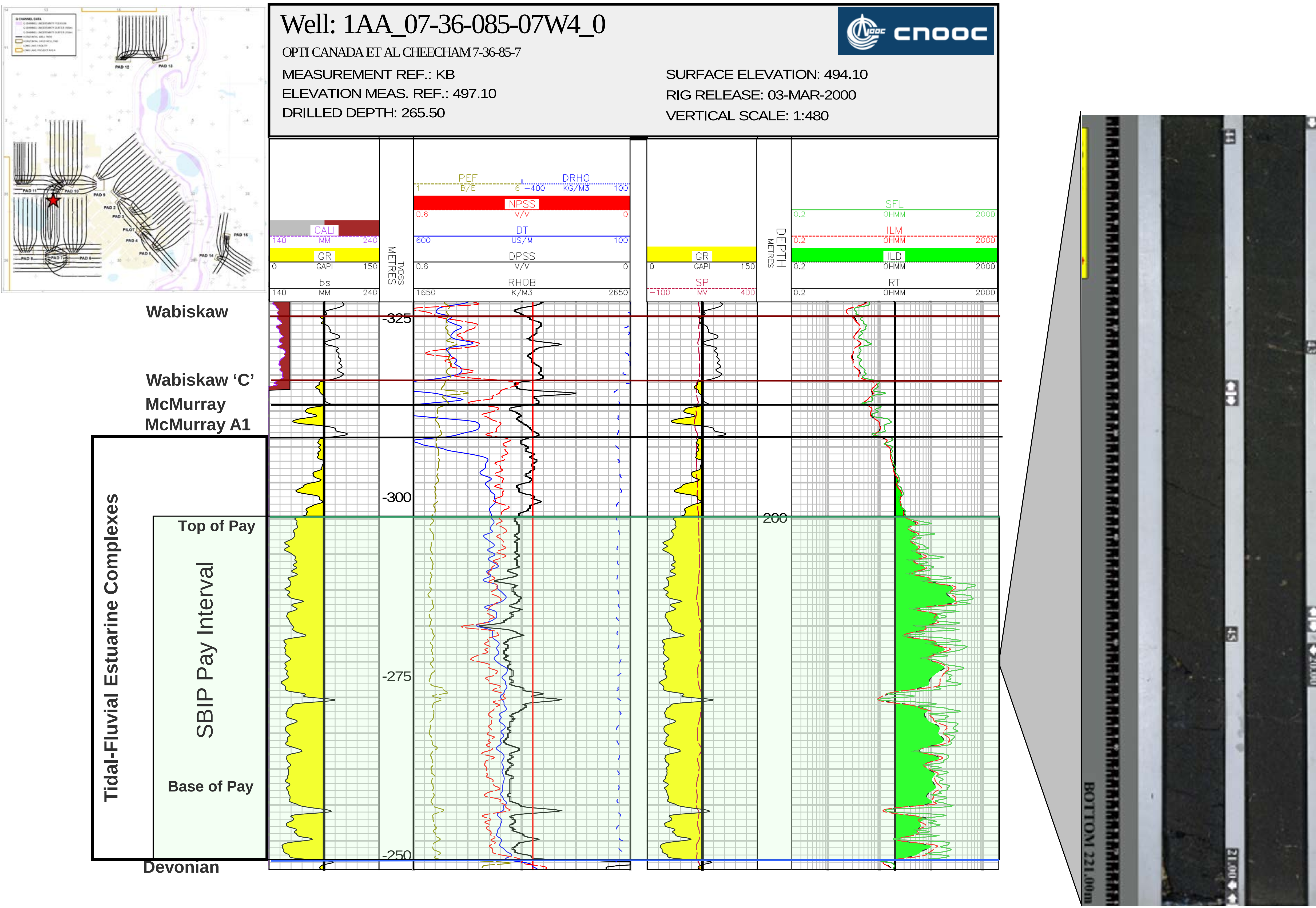


★ TYPE LOG

Kinosis SBIP Pay Interval Isopach



SBIP Type Log – 1AA/07-36-085-07W4

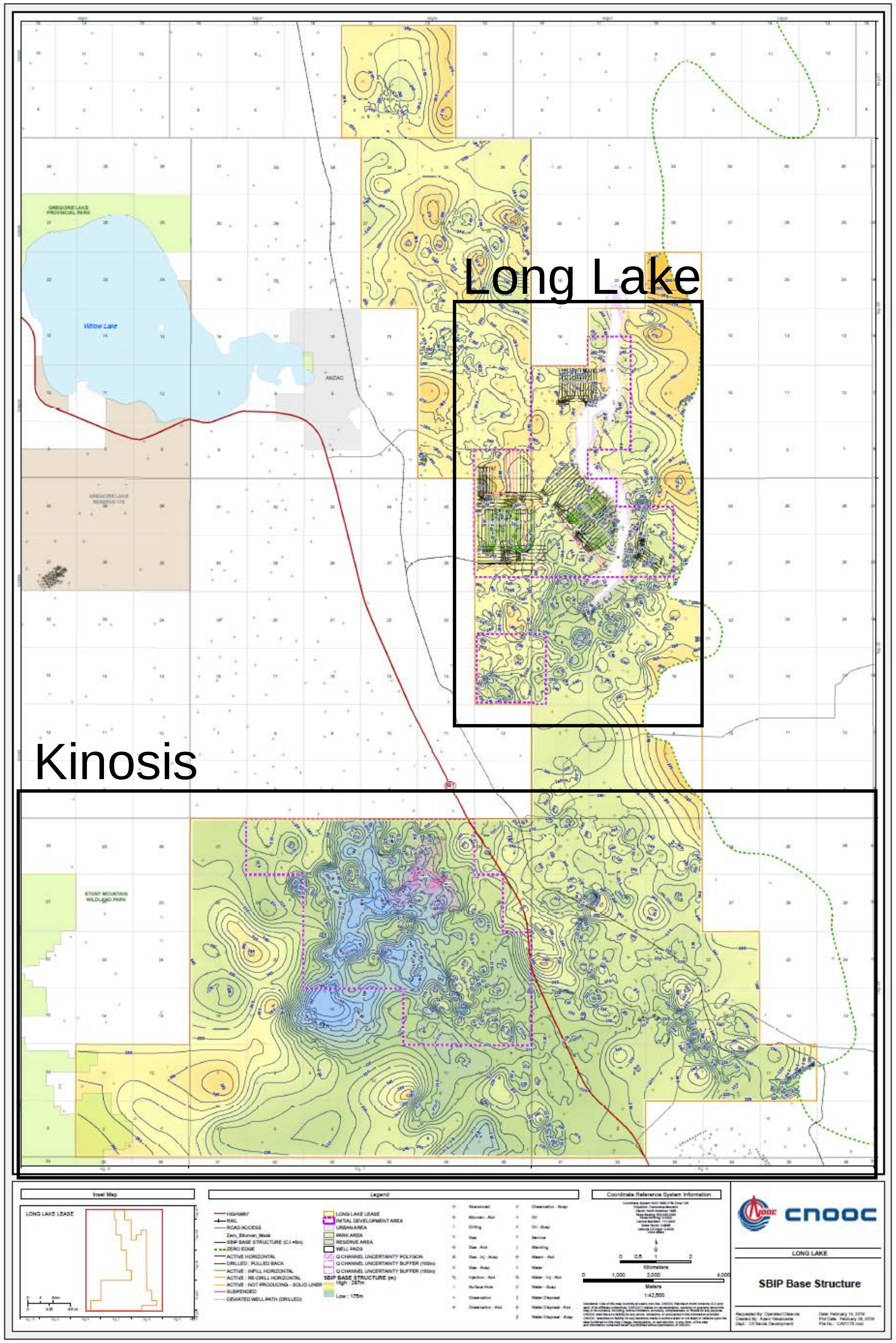


Long Lake/Kinosis SBIP Pay Interval Base Structure

HIGHWAY
RAIL
ROAD ACCESS
SBIP BASE STRUCTURE (C.I.=5m)
Zero bitumen edge
ACTIVE HORIZONTAL
DRILLED : PULLED BACK
ACTIVE : INFILL HORIZONTAL
ACTIVE : RE-DRILL HORIZONTAL
ACTIVE : NOT PRODUCING - SOLID LINER
SUSPENDED
DEVIATED WELL PATH (DRILLED)

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 BASE STRUCTURE (m)
High : 297m
Low : 175m

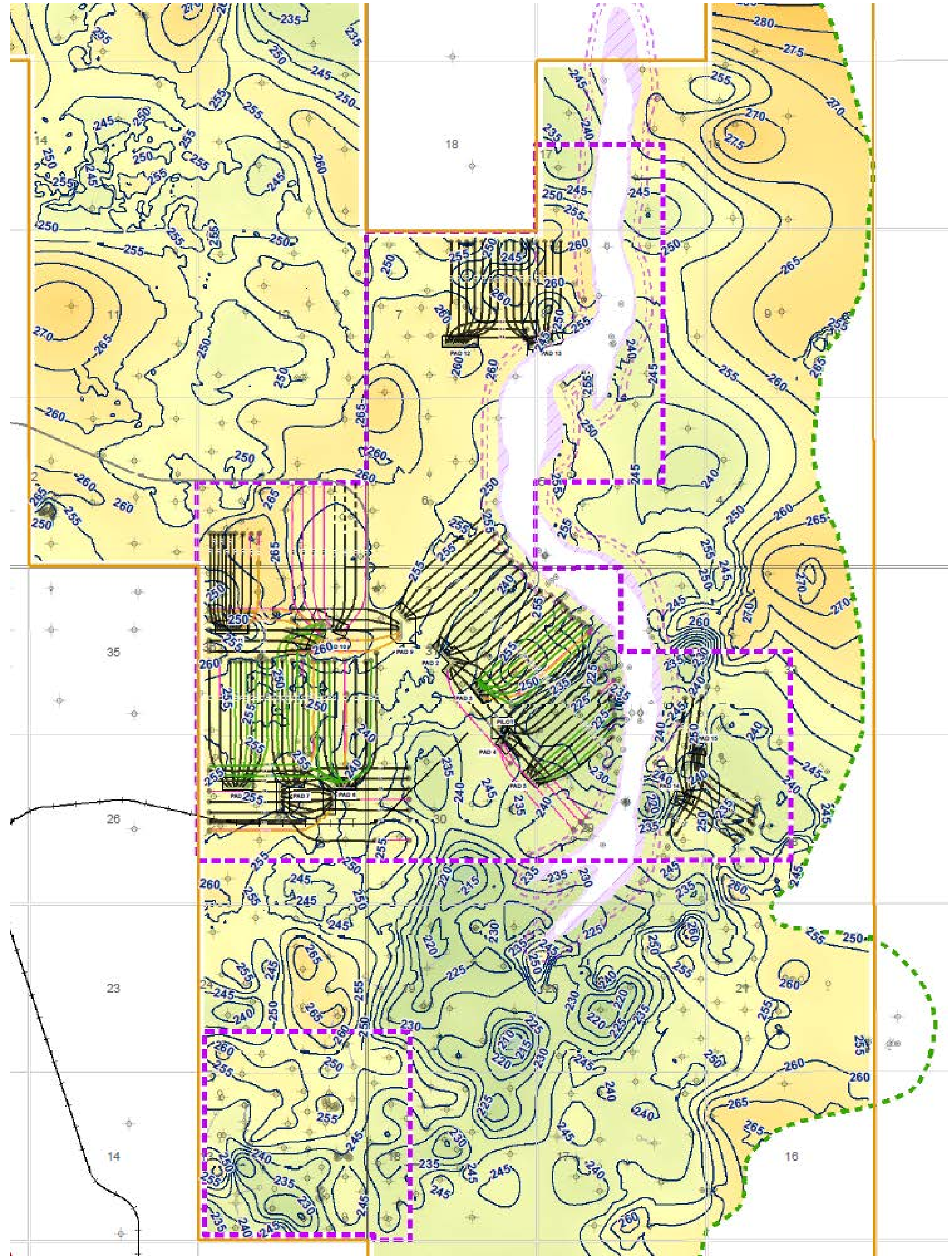


Long Lake SBIP Pay Interval Base Structure

HIGHWAY
RAIL
ROAD ACCESS
SBIP BASE STRUCTURE (C.I.=5m)
Zero bitumen edge
ACTIVE HORIZONTAL
DRILLED : PULLED BACK
ACTIVE : INFILL HORIZONTAL
ACTIVE : RE-DRILL HORIZONTAL
ACTIVE : NOT PRODUCING - SOLID LINER
SUSPENDED
DEVIATED WELL PATH (DRILLED)

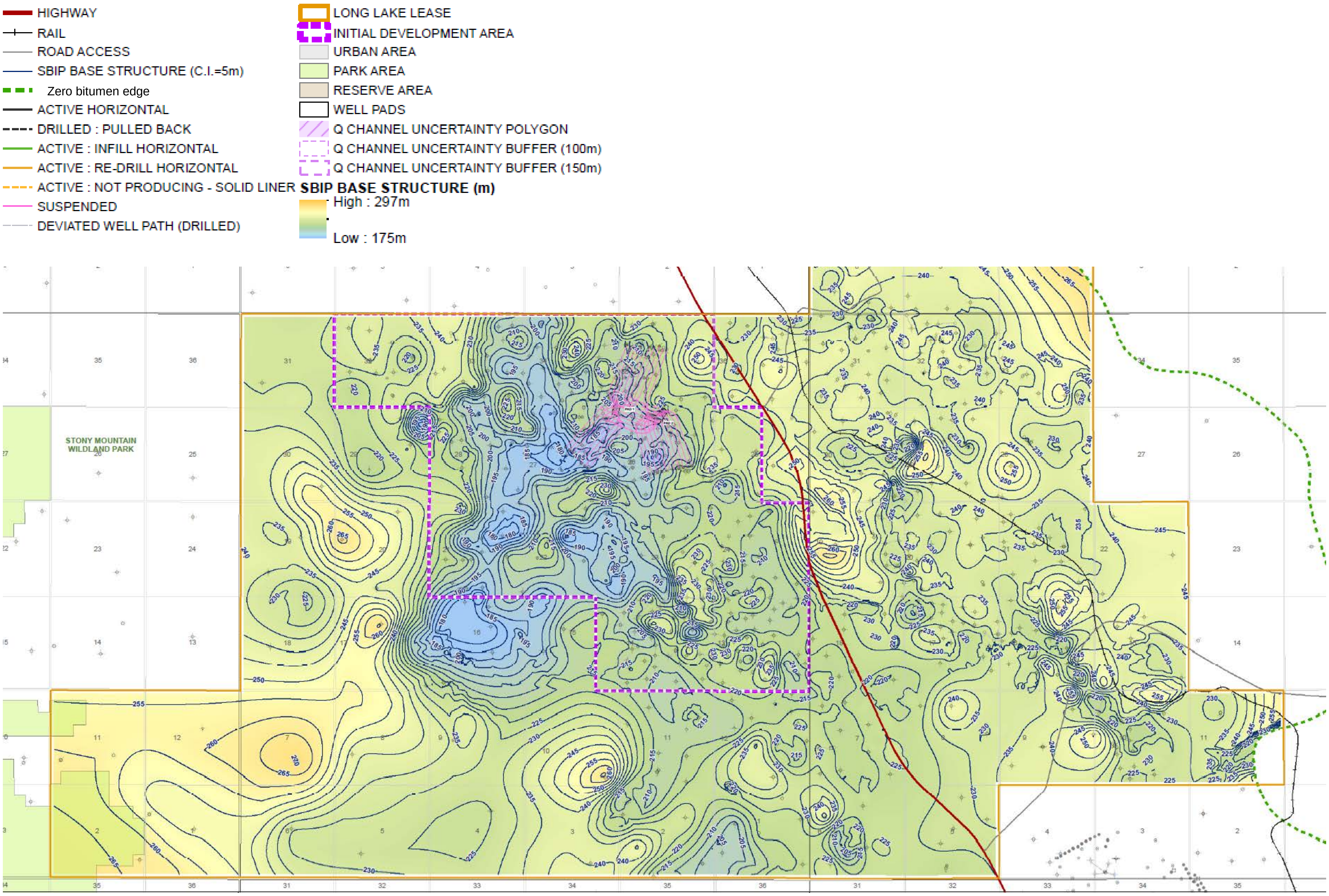
LONG LAKE LEASE
INITIAL DEVELOPMENT AREA
URBAN AREA
PARK AREA
RESERVE AREA
WELL PADS
Q CHANNEL UNCERTAINTY POLYGON
Q CHANNEL UNCERTAINTY BUFFER (100m)
Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP 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/Kinosis SBIP Pay Interval Top Structure

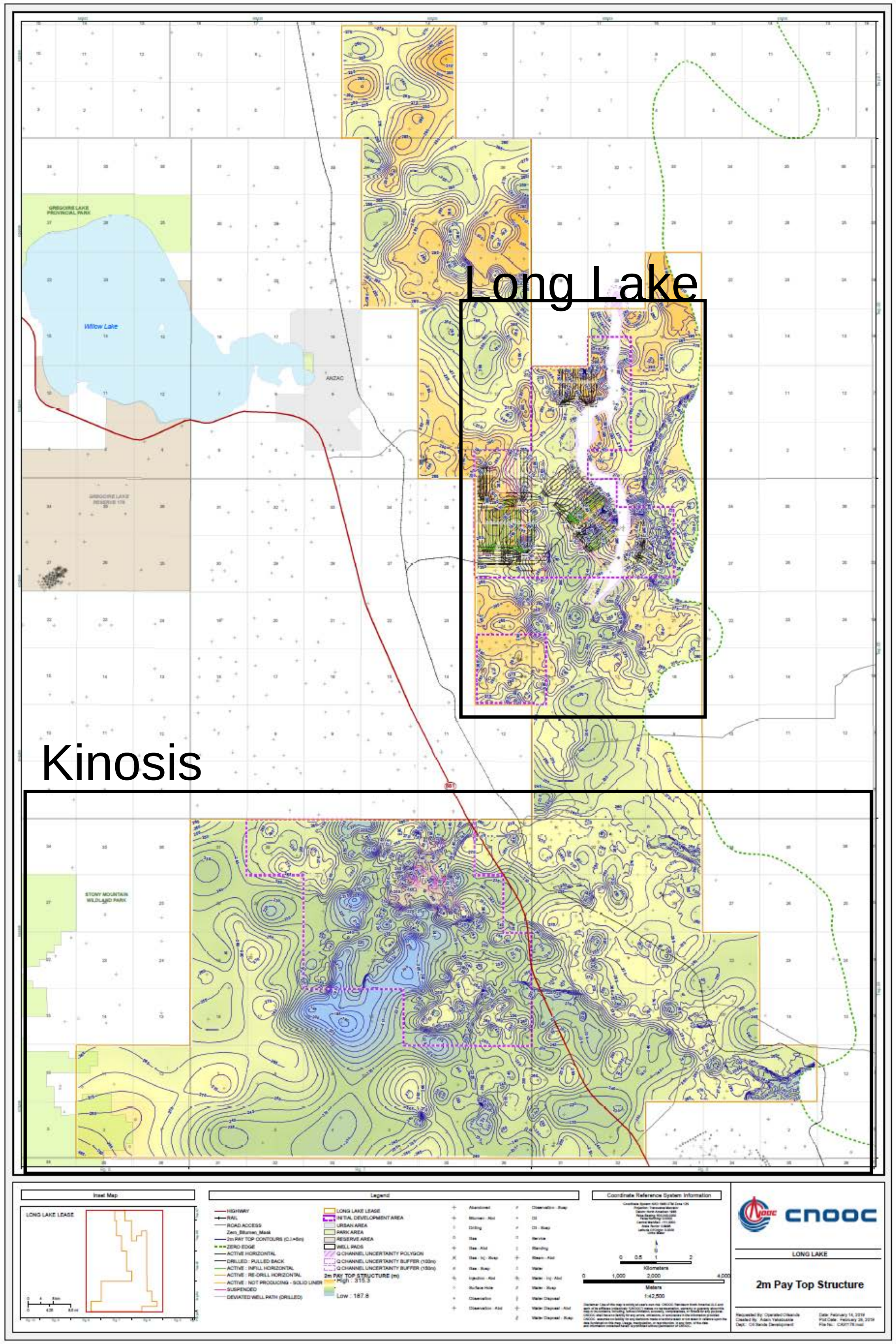
cnooc

- HIGHWAY
- RAIL
- ROAD ACCESS
- 2m PAY TOP CONTOURS (C.I.=5m)
- Zero bitumen edge
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)
- 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)

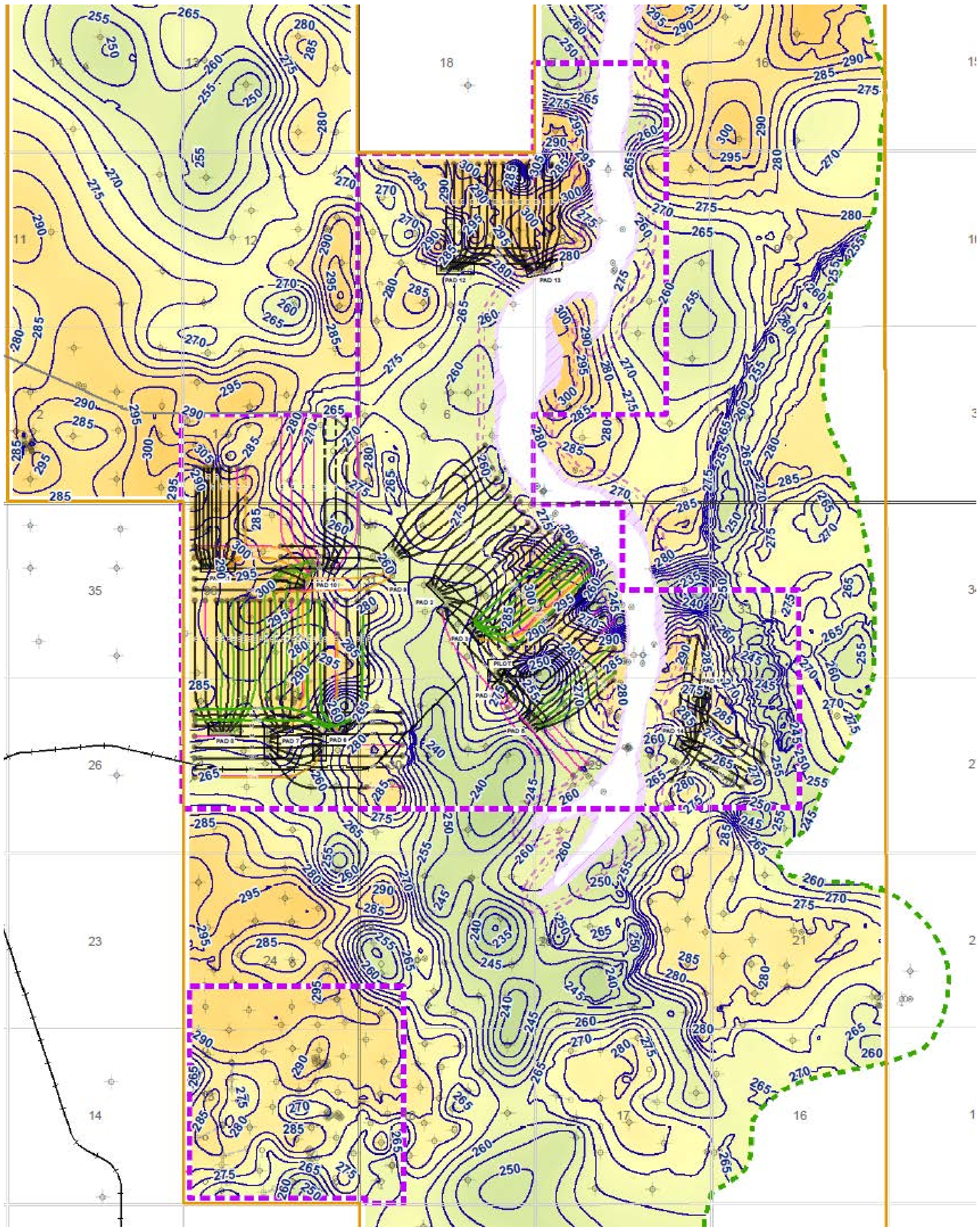
2m PAY TOP STRUCTURE (m)

High : 315.3m

Low : 193.5m



Long Lake SBIP Pay Interval Top Structure



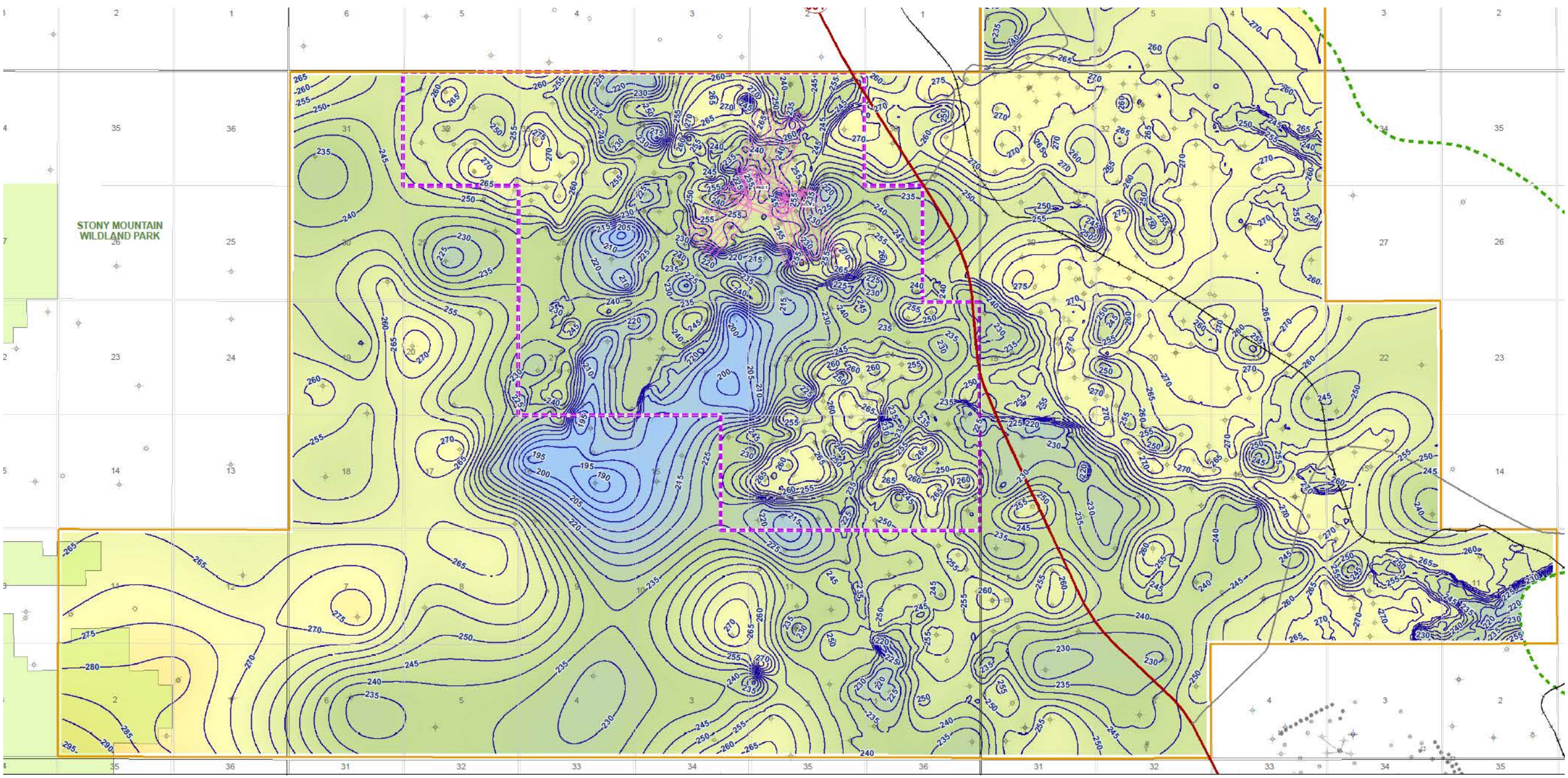
- Top of SBIP Pay Interval:
  - base of 2m or thicker shale
  - cumulative 4m shale
  - base of top gas
  - base of top water
  - top of McMurray tidal-fluvial estuarine complexes
- Bitumen in regional McMurray shorefaces and the McMurray A1 are not considered pay.

Kinosis SBIP Pay Interval Top Structure

HIGHWAY
RAIL
ROAD ACCESS
2m PAY TOP CONTOURS (C.I.=5m)
Zero bitumen edge
ACTIVE HORIZONTAL
DRILLED : PULLED BACK
ACTIVE : INFILL HORIZONTAL
ACTIVE : RE-DRILL HORIZONTAL
ACTIVE : NOT PRODUCING - SOLID LINER
SUSPENDED
DEVIATED WELL PATH (DRILLED)

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)

2m PAY TOP STRUCTURE (m)
High : 315.3m
Low : 193.5m



Long Lake/Kinosis HPVH Isopach over SBIP Pay Interval

- HIGHWAY
- RAIL
- ROAD ACCESS
- SBIP HPVH CONTOURS (C.I.=5m)
- Zero bitumen edge
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)
- 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)

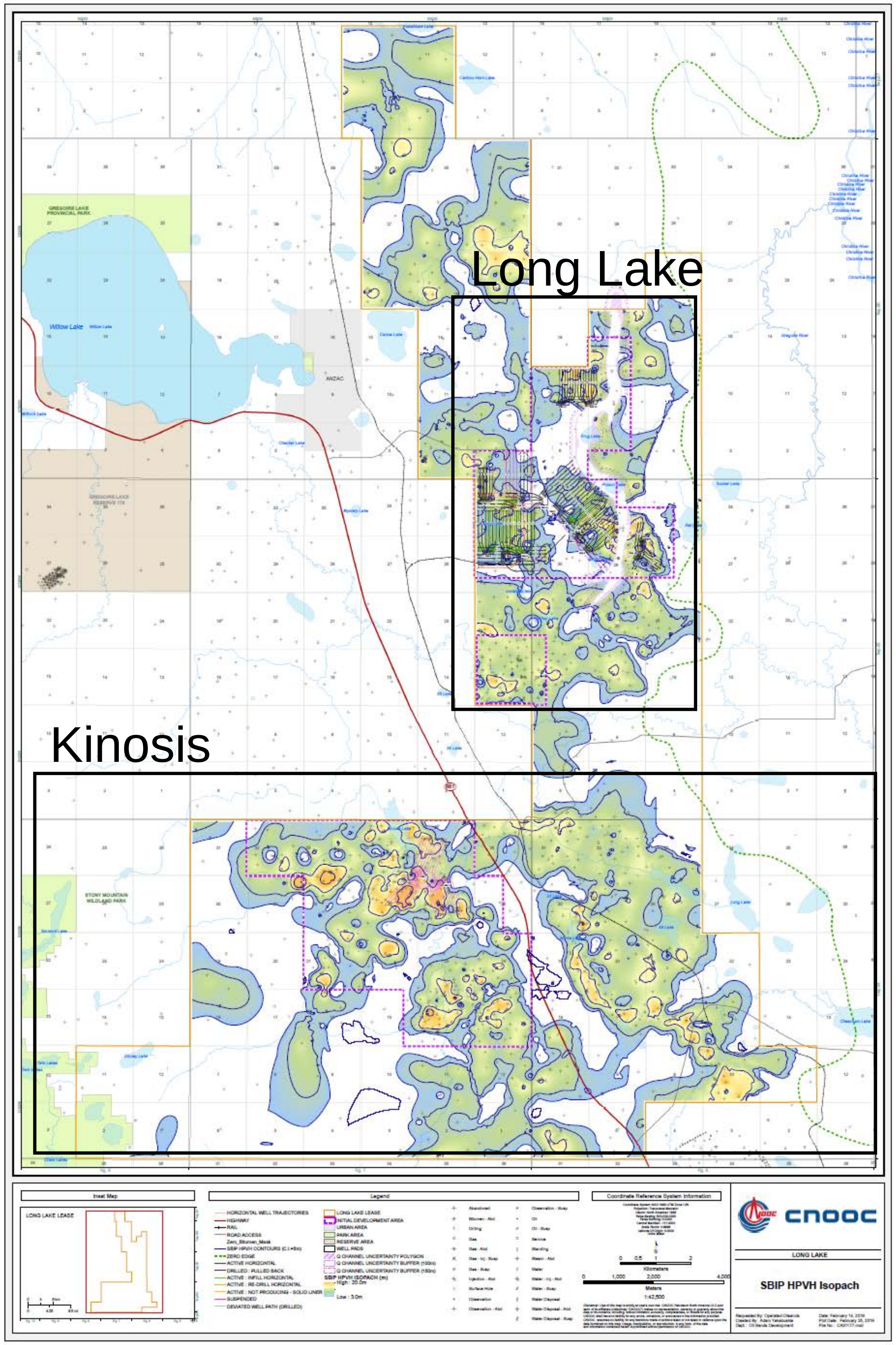
SBIP HPVH ISOPACH (m3/m2)

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



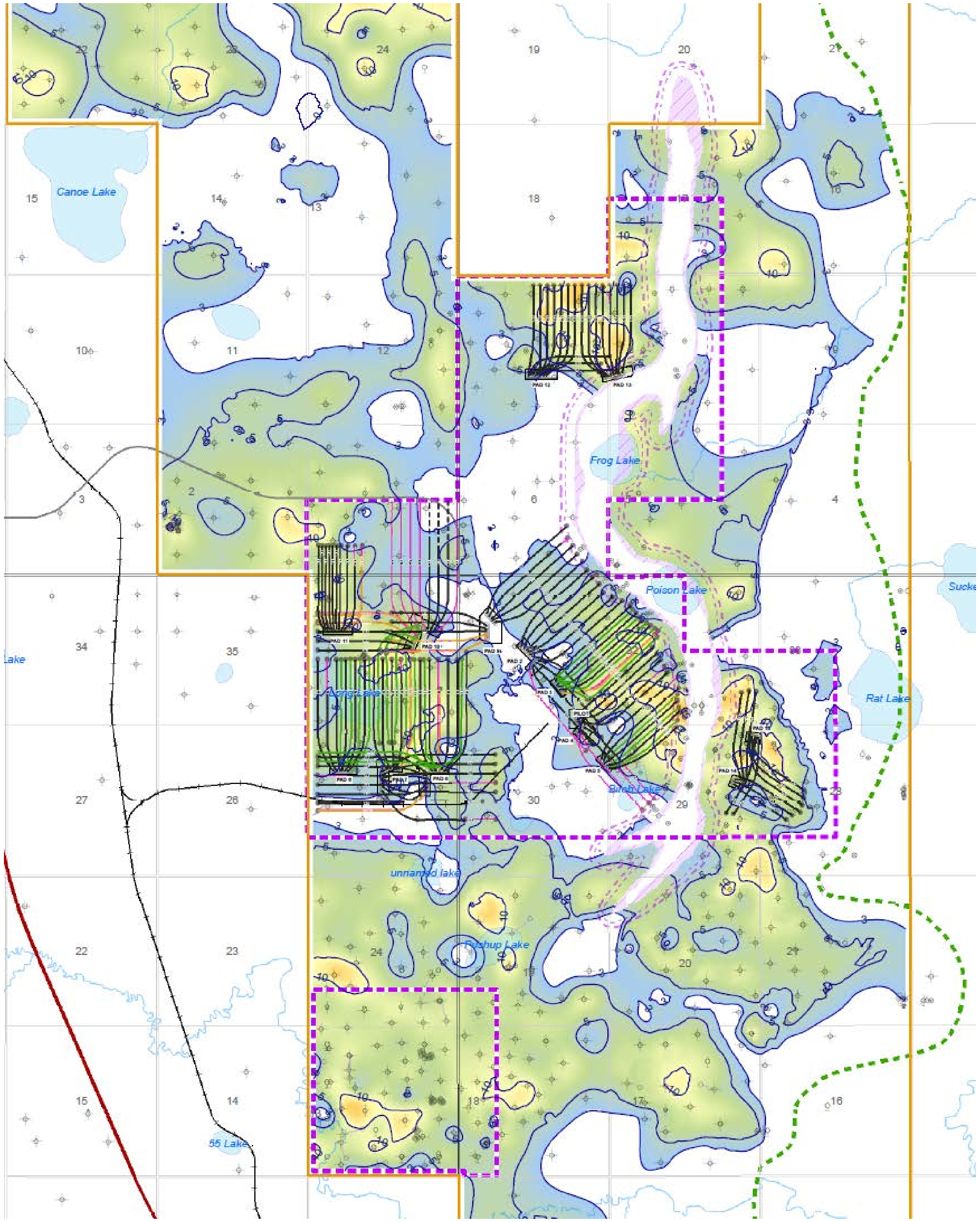
Long Lake HPVH Isopach over SBIP Pay Interval

- HIGHWAY
- RAIL
- ROAD ACCESS
- SBIP HPVH CONTOURS (C.I.=5m)
- Zero bitumen edge
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)
- 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 HPVH ISOPACH (m3/m2)

High : 20.0m

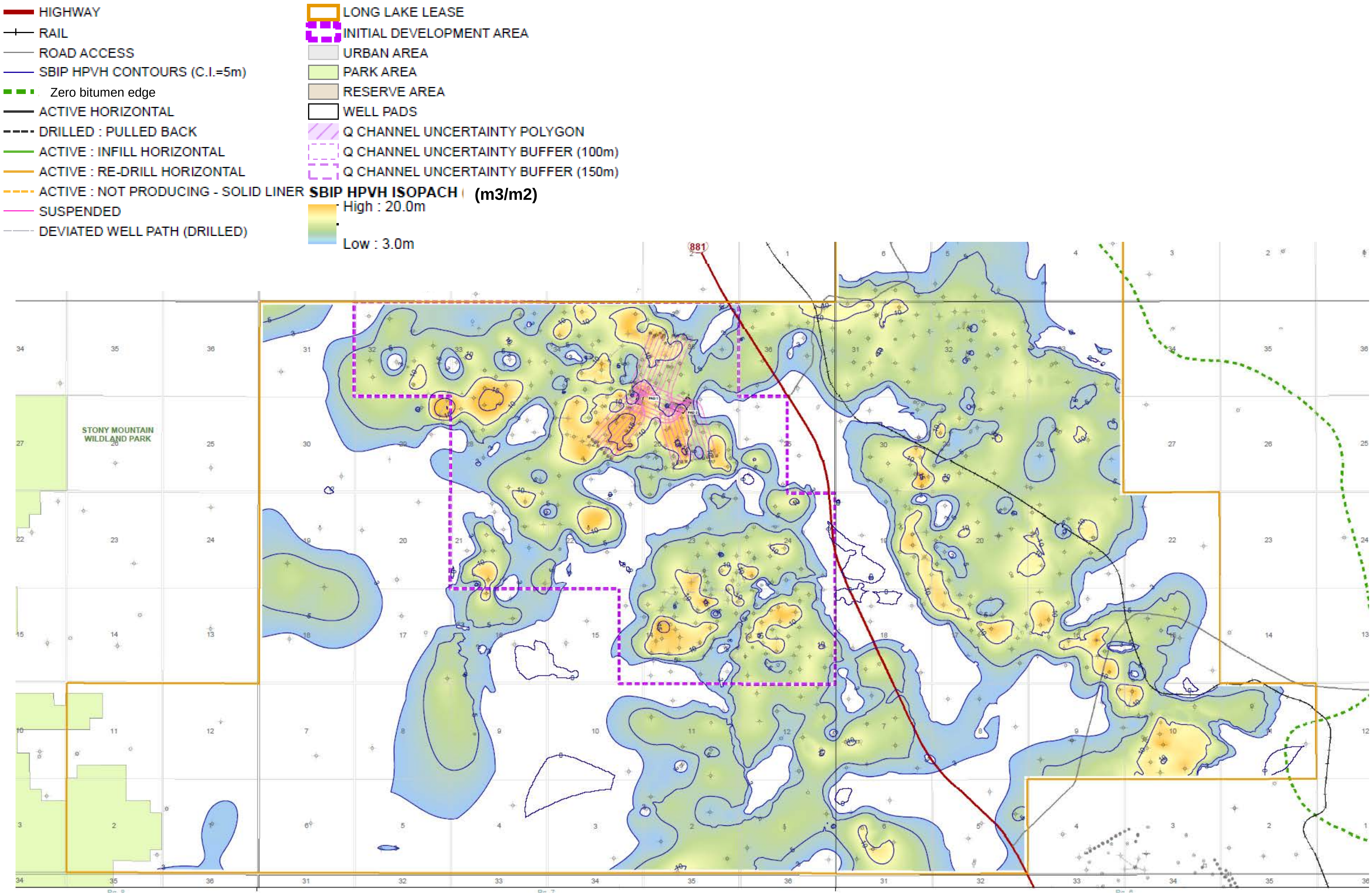
Low : 3.0m



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

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

Kinosis HPVH Isopach over SBIP Interval

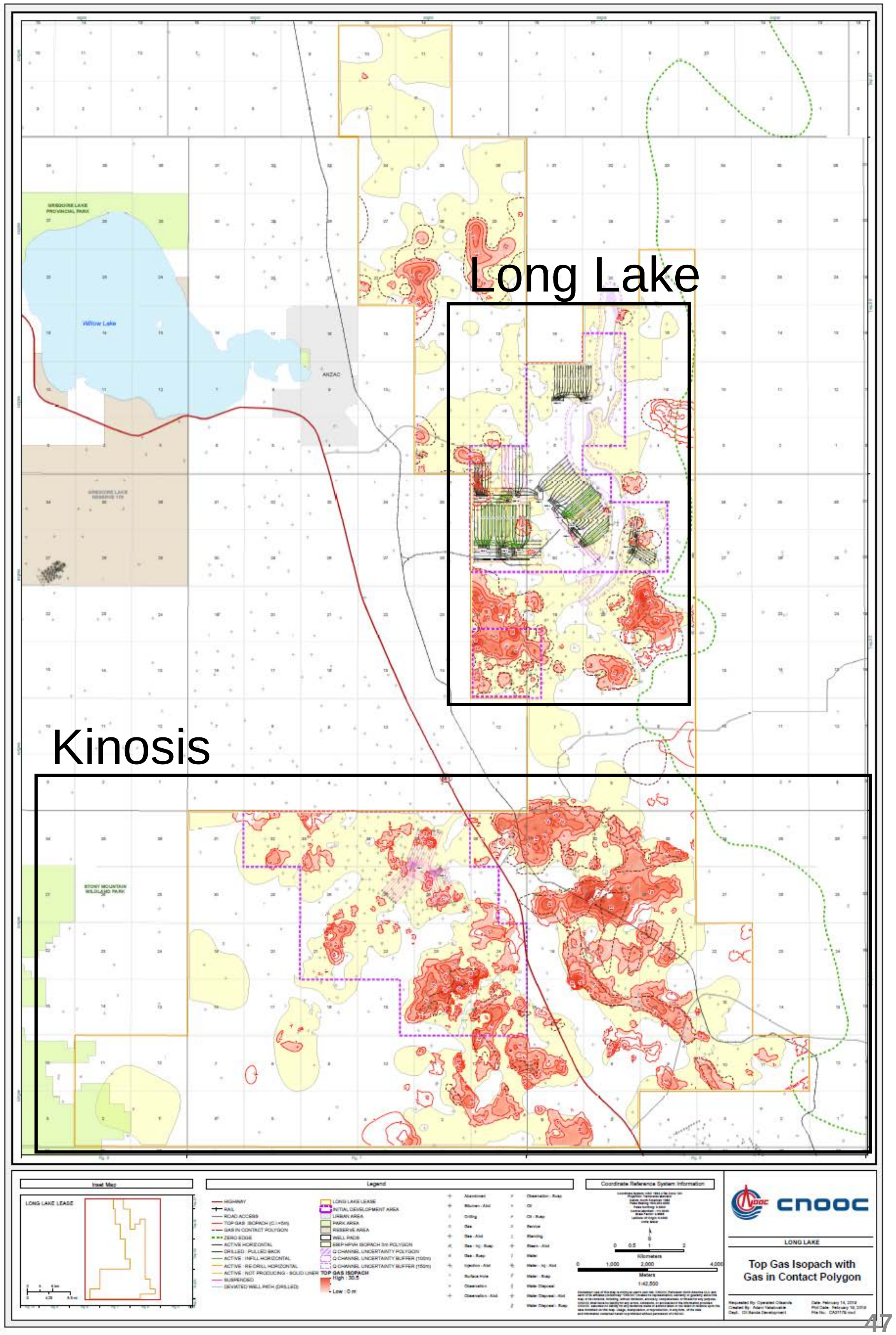


Long Lake Gas: Gas Interval(s) within and in contact with SBIP Interval

HIGHWAY
RAIL
ROAD ACCESS
TOP GAS ISOPACH (C.I.=5m)
GAS IN CONTACT POLYGON
Zero bitumen edge
ACTIVE HORIZONTAL
DRILLED : PULLED BACK
ACTIVE : INFILL HORIZONTAL
ACTIVE : RE-DRILL HORIZONTAL
ACTIVE : NOT PRODUCING - SOLID LINER
SUSPENDED
DEVIATED WELL PATH (DRILLED)

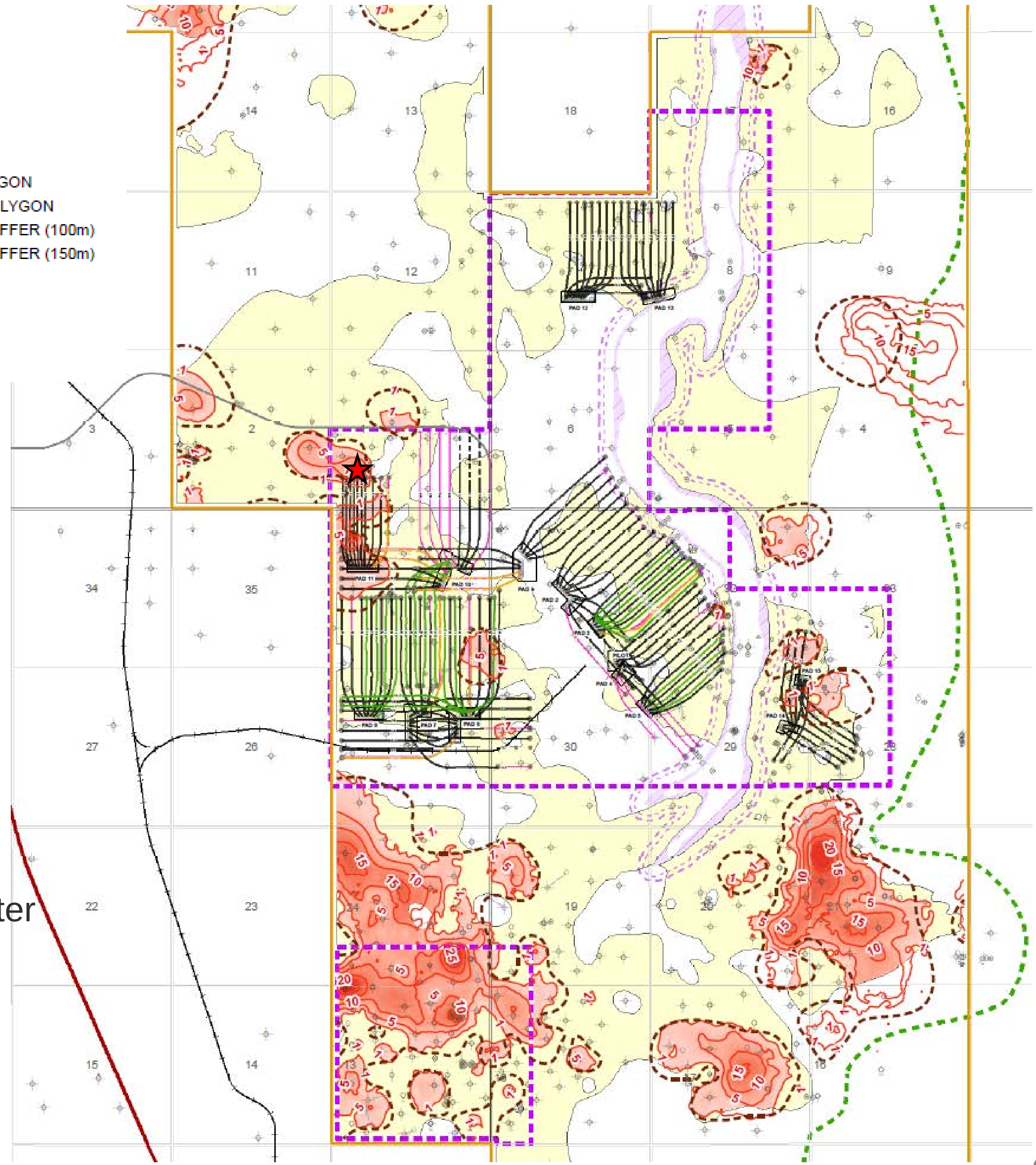
LONG LAKE LEASE
INITIAL DEVELOPMENT AREA
URBAN AREA
PARK AREA
RESERVE AREA
WELL PADS
EBIP HPVH ISOPACH 3m POLYGON
Q CHANNEL UNCERTAINTY POLYGON
Q CHANNEL UNCERTAINTY BUFFER (100m)
Q CHANNEL UNCERTAINTY BUFFER (150m)

TOP GAS ISOPACH
High : 30.5
Low : 0 m



- 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
  - contours clipped to 3m^3/m^2 HPVH SBIP contour

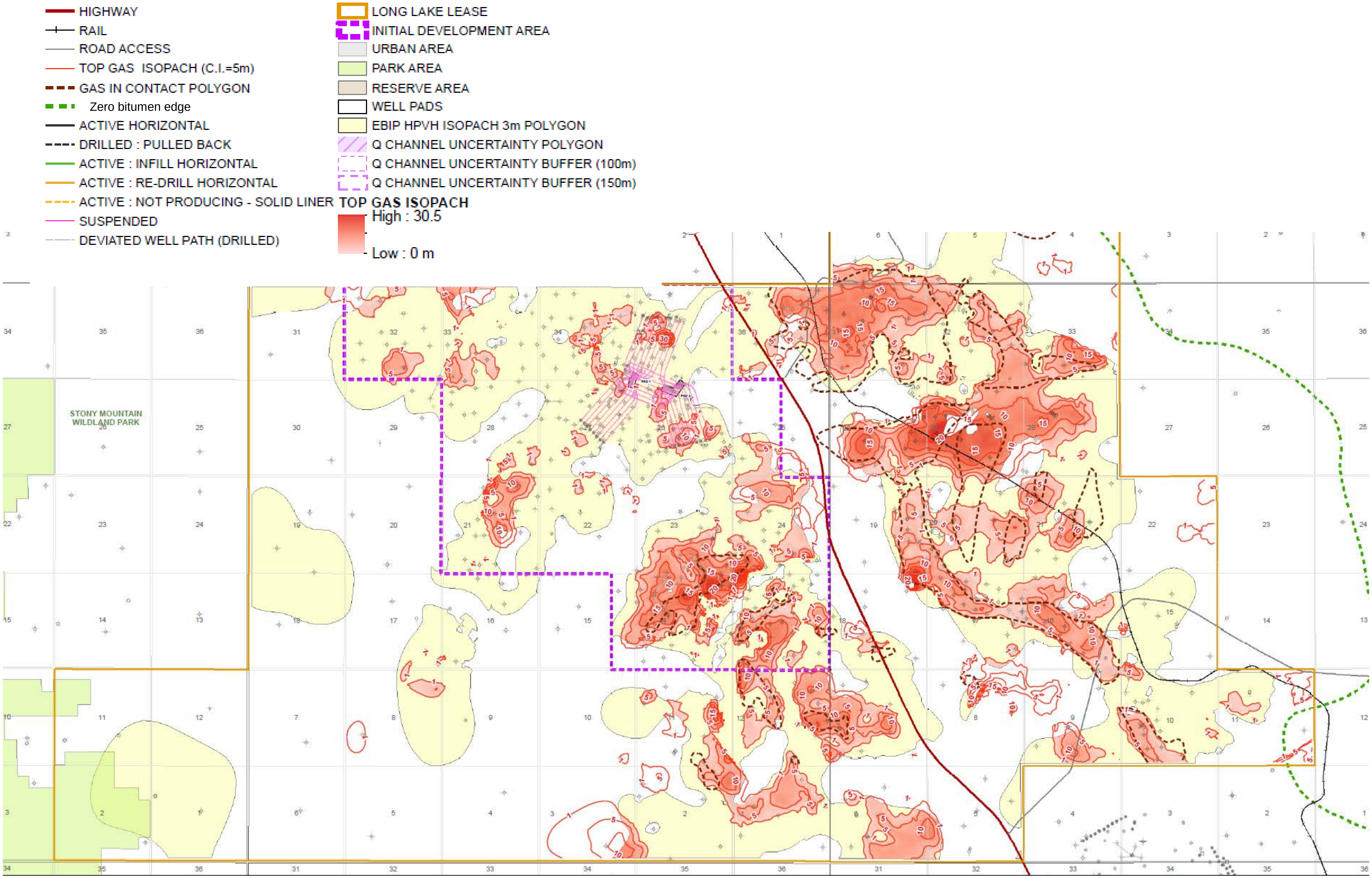
Long Lake Total Gas: Gas Interval(s) within and in contact with SBIP Interval



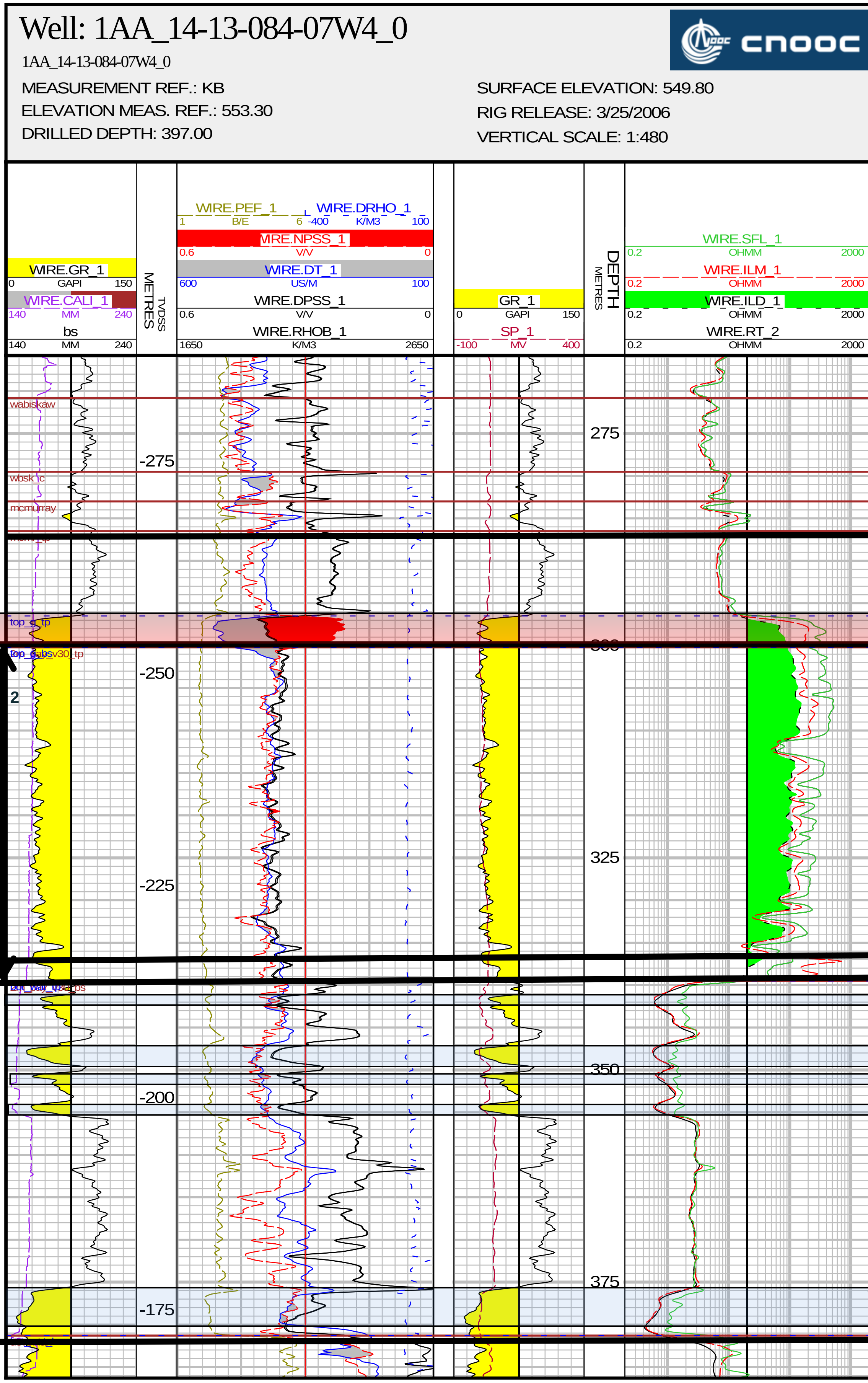
- Gas identified by neutron/density crossover.
- Gas associated with SBIP Interval:
  - within SBIP Interval
  - directly in contact with top water or top of SBIP interval
  - contours clipped to $3 m^3/m^2$ HPVH SBIP contour

★ TYPE LOG

Kinosis
Top Gas in the McMurray



Example Log:



McMurray Fluvial Estuarine Complex top

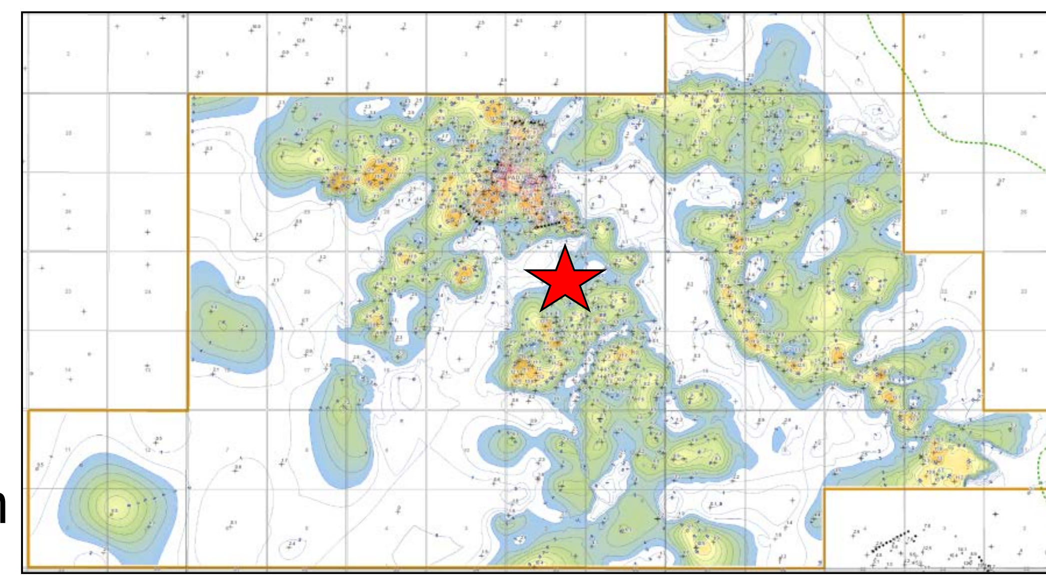
Top Gas

SBIP Interval

EBIP Pay Interval

Bottom Water

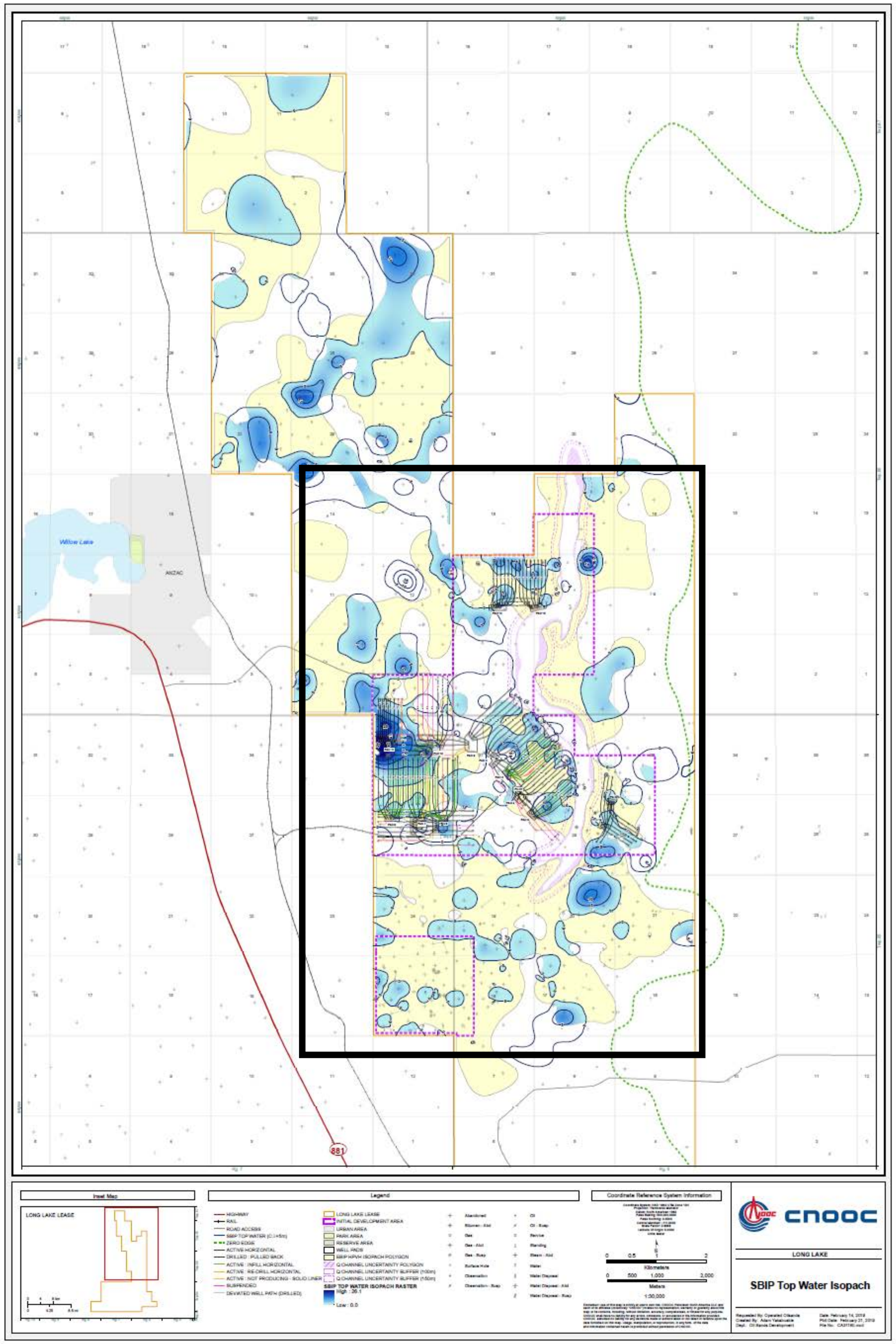
Devonian



HIGHWAY
RAIL
ROAD ACCESS
SBIP TOP WATER (C.I.=5m)
Zero bitumen edge
ACTIVE HORIZONTAL
DRILLED : PULLED BACK
ACTIVE : INFILL HORIZONTAL
ACTIVE : RE-DRILL HORIZONTAL
ACTIVE : NOT PRODUCING - SOLID LINER
SUSPENDED
DEVIATED WELL PATH (DRILLED)

LONG LAKE LEASE
INITIAL DEVELOPMENT AREA
URBAN AREA
PARK AREA
RESERVE AREA
WELL PADS
EBIP HPVH ISOPACH POLYGON
Q CHANNEL UNCERTAINTY POLYGON
Q CHANNEL UNCERTAINTY BUFFER (100m)
Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP TOP WATER ISOPACH RASTER
High : 26.1
Low : 0.0



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

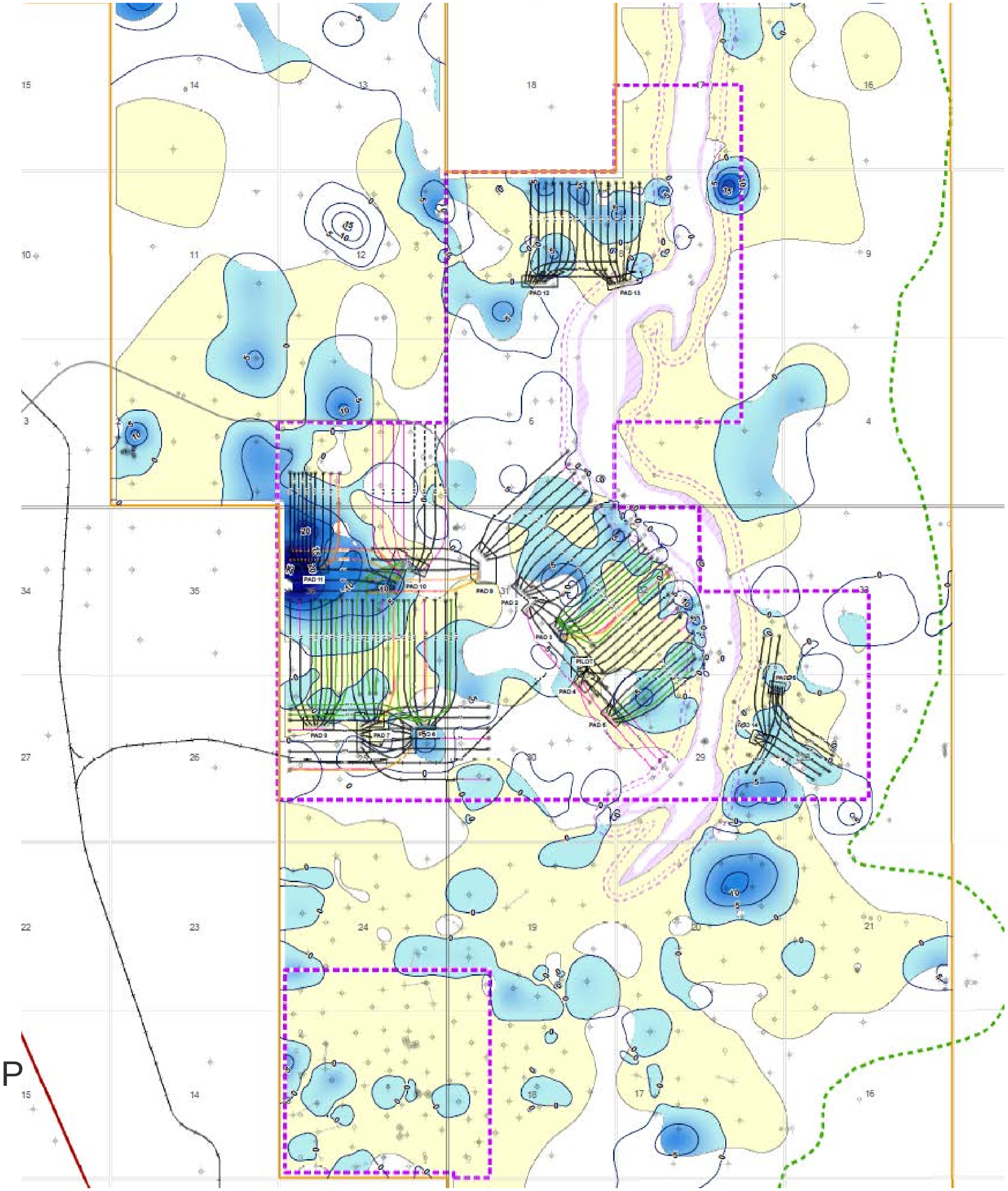
Long Lake Net Top Water Associated with SBIP Interval

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

SBIP TOP WATER ISOPACH RASTER

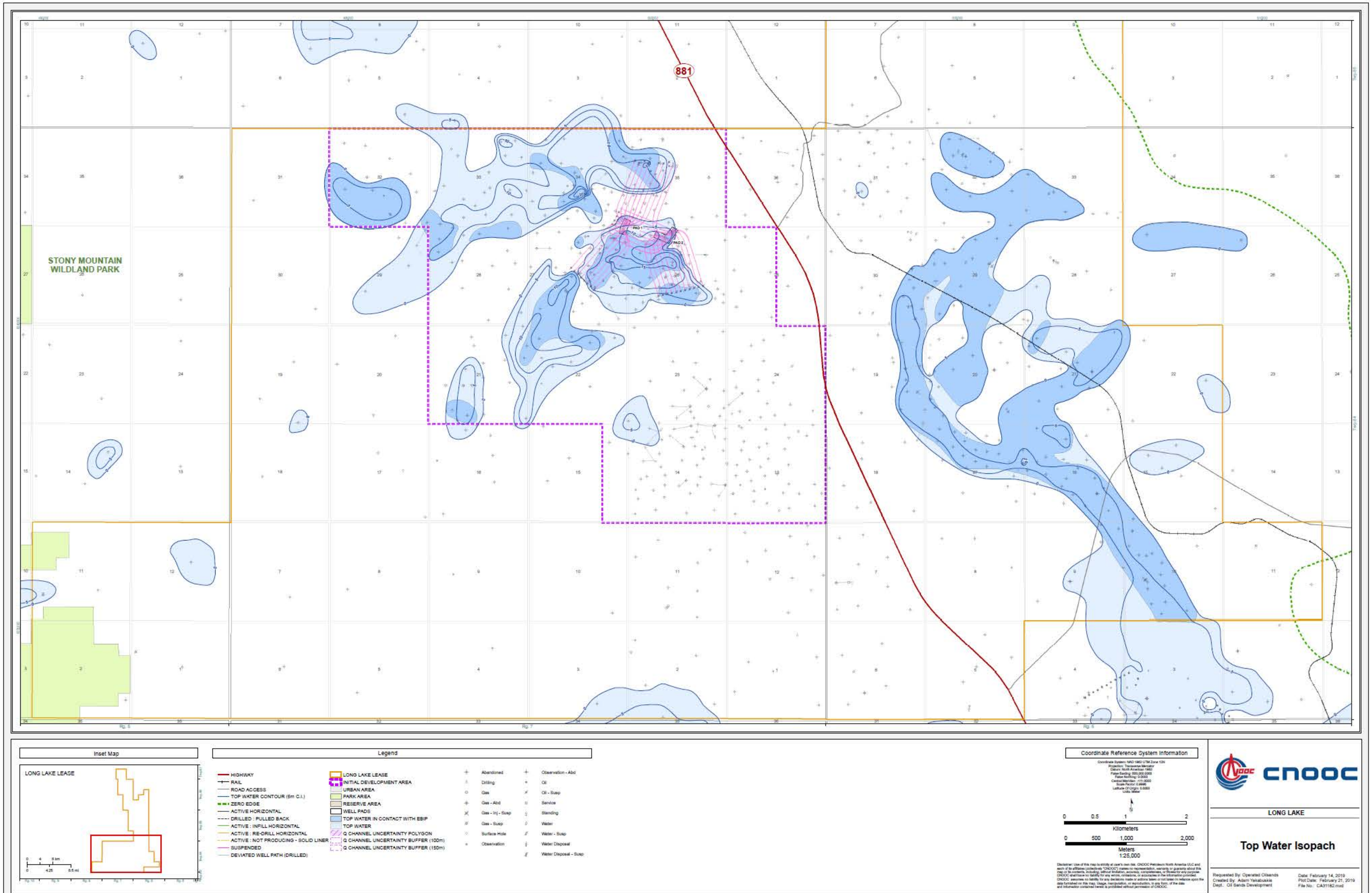
High : 26.1

Low : 0.0



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

Kinosis Net Top Water Associated with SBIP Interval



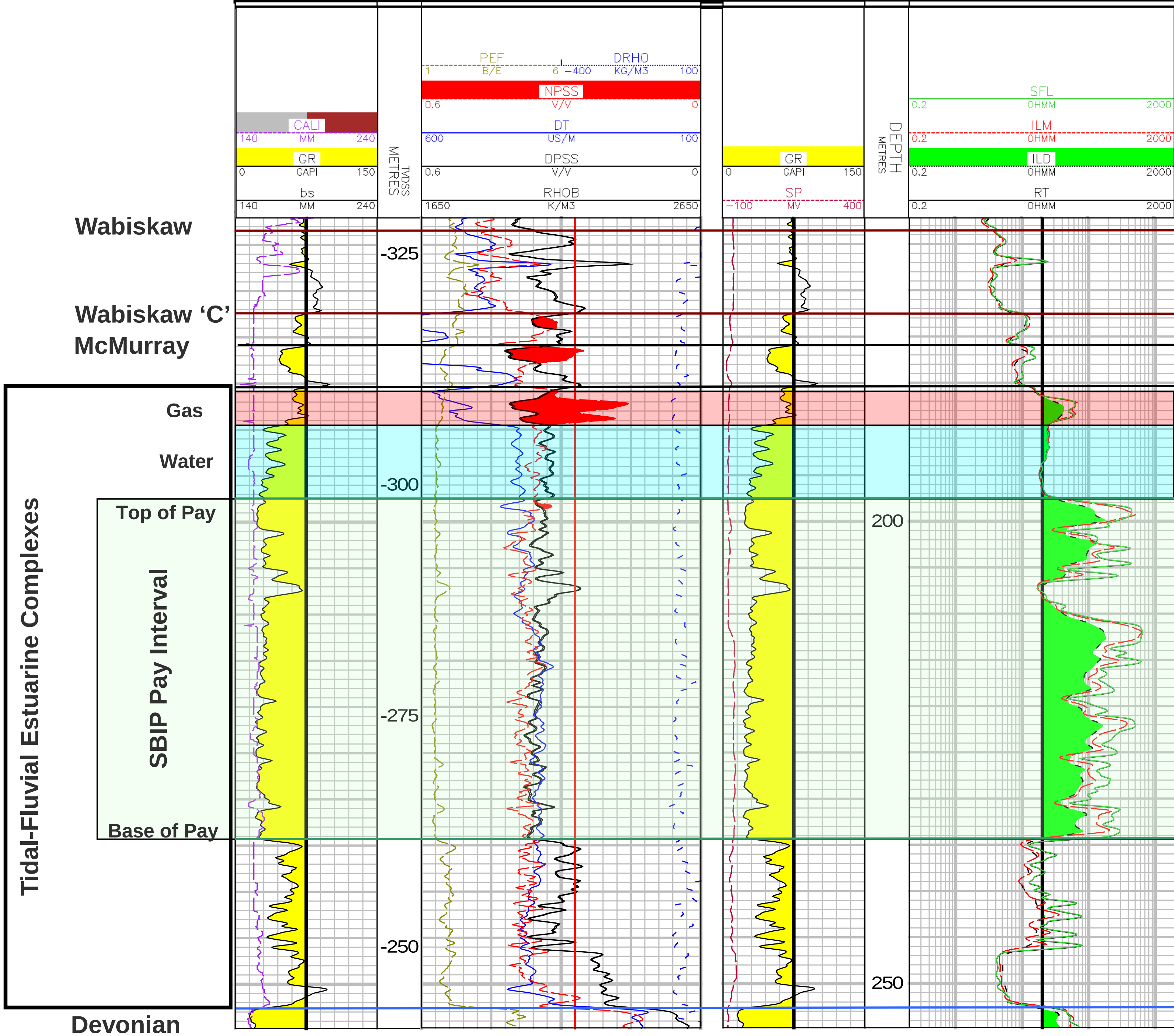
Top Impairment Type Log – 103/13-36-085-07W4

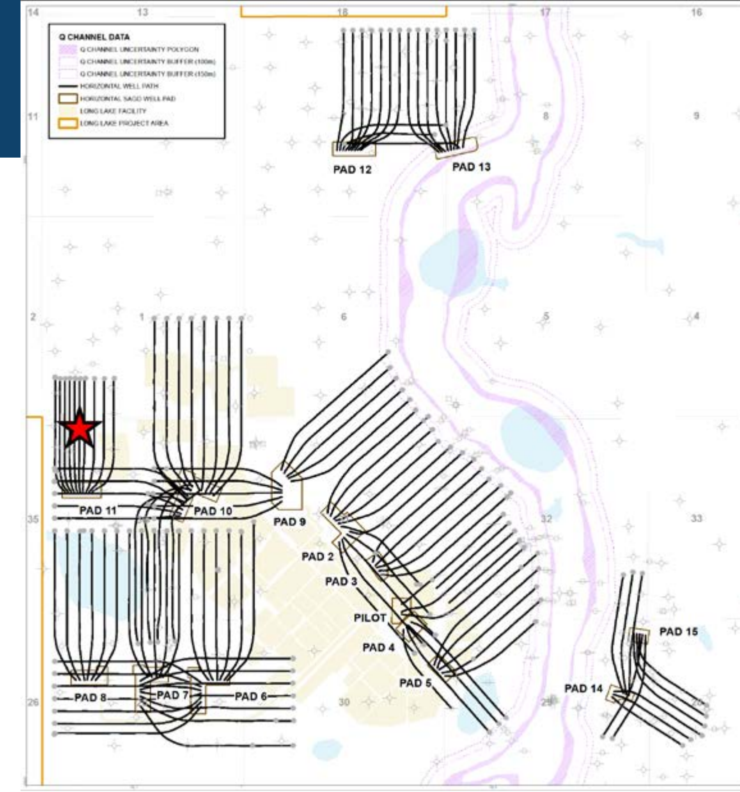
Well: 103_13-36-085-07W4_0

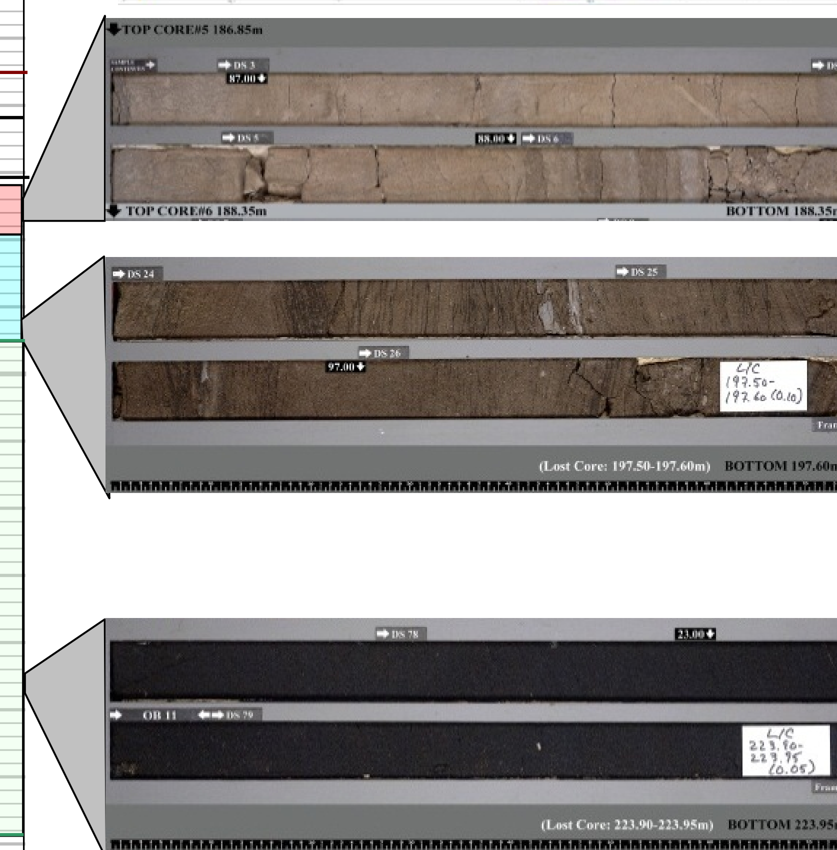
NEXEN OPTI NEWBY 13-36-85-7

MEASUREMENT REF.: KB
ELEVATION MEAS. REF.: 496.00
DRILLED DEPTH: 269.00

SURFACE ELEVATION: 492.30
RIG RELEASE: 06-FEB-2006
VERTICAL SCALE: 1:480



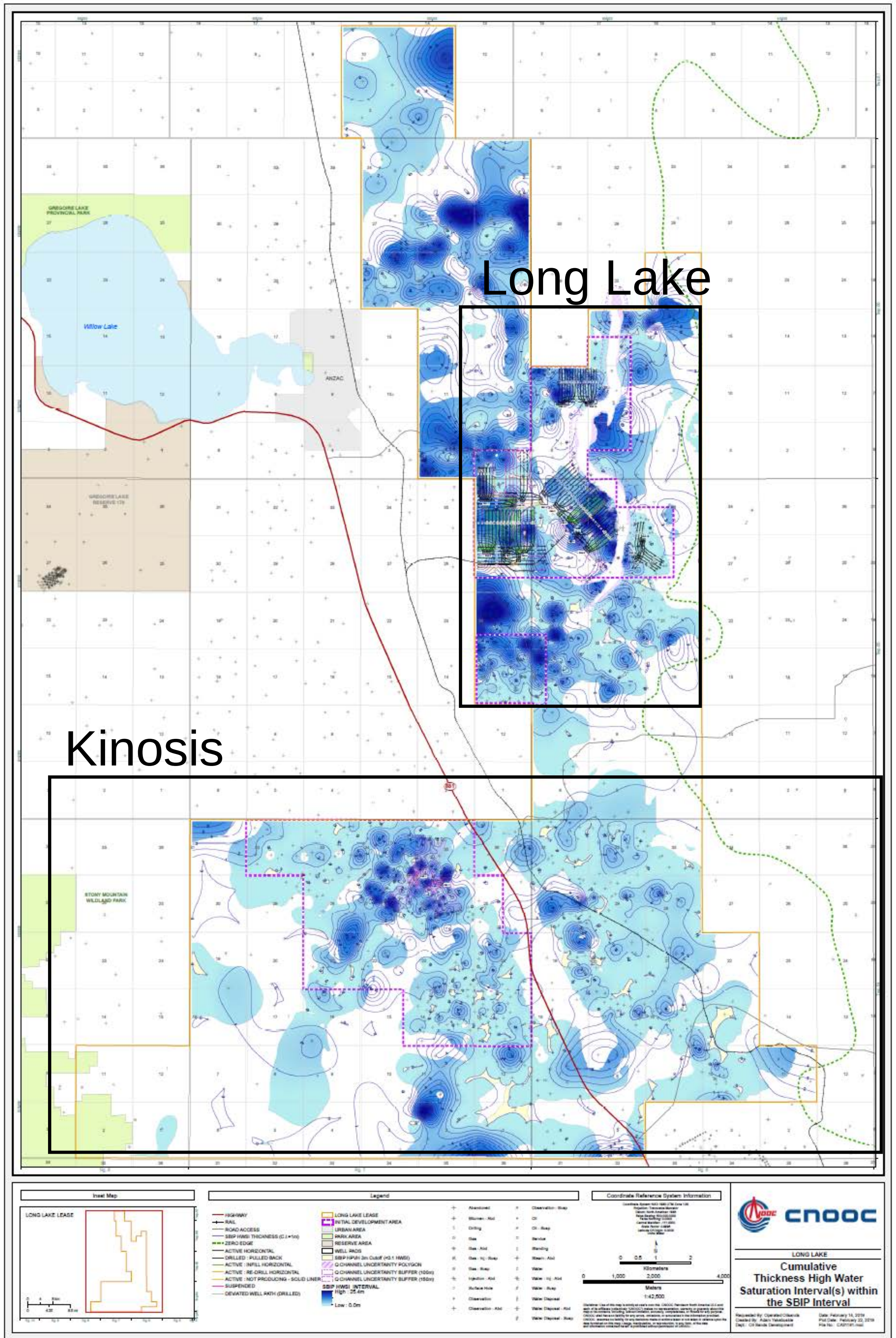




Long Lake Cumulative Thickness of High Water Saturation Interval(s) within SBIP Interval

- HIGHWAY
- RAIL
- ROAD ACCESS
- SBIP HWSI THICKNESS (C.I.=1m)
- ZERO EDGE
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)
- LONG LAKE LEASE
- INITIAL DEVELOPMENT AREA
- URBAN AREA
- PARK AREA
- RESERVE AREA
- WELL PADS
- SBIP HPVH 3m Cutoff (<0.1 HWSI)
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP HWSI INTERVAL
High : 25.4m
Low : 0.0m



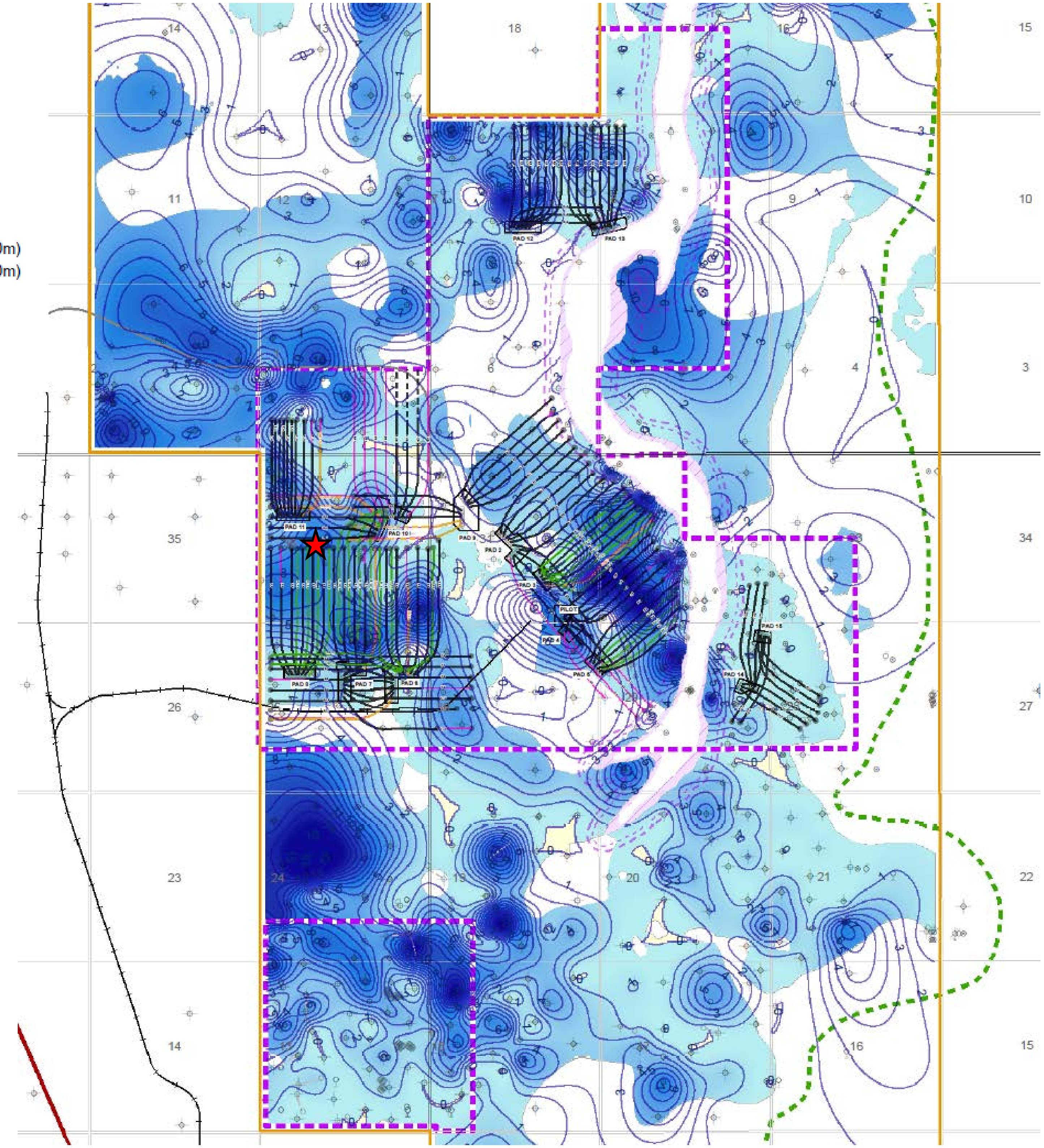
- > 50% Swe and < 30% V_{shale}
- Cumulative thickness of high water saturation interval(s) within SBIP interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour

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

HIGHWAY
RAIL
ROAD ACCESS
SBIP HWSI THICKNESS (C.I.=1m)
ZERO EDGE
ACTIVE HORIZONTAL
DRILLED : PULLED BACK
ACTIVE : INFILL HORIZONTAL
ACTIVE : RE-DRILL HORIZONTAL
ACTIVE : NOT PRODUCING - SOLID LINER
SUSPENDED
DEVIATED WELL PATH (DRILLED)

LONG LAKE LEASE
INITIAL DEVELOPMENT AREA
URBAN AREA
PARK AREA
RESERVE AREA
WELL PADS
SBIP HPVH 3m Cutoff (<0.1 HWSI)
Q CHANNEL UNCERTAINTY POLYGON
Q CHANNEL UNCERTAINTY BUFFER (100m)
Q CHANNEL UNCERTAINTY BUFFER (150m)

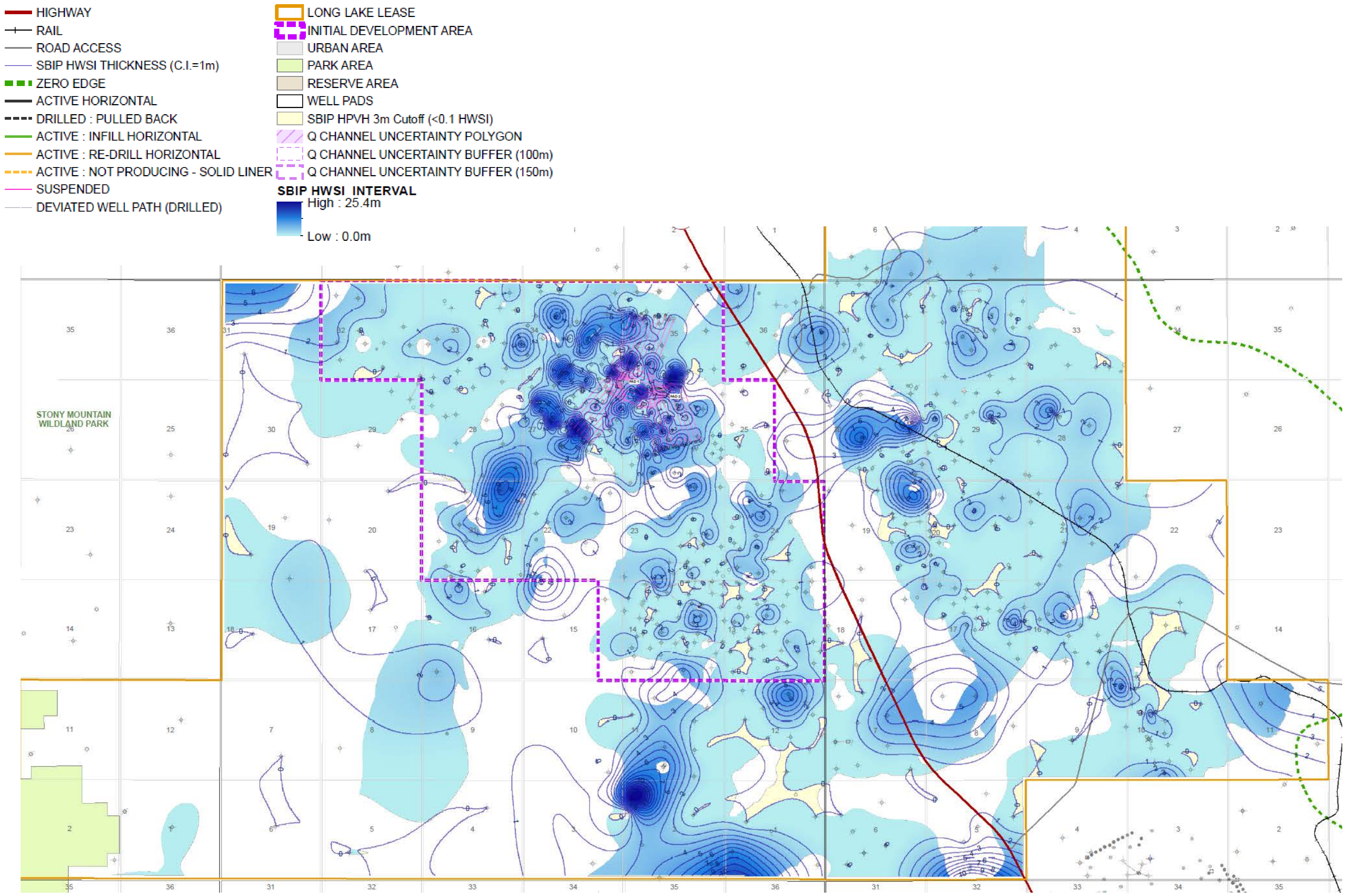
SBIP HWSI INTERVAL
High : 25.4m
Low : 0.0m



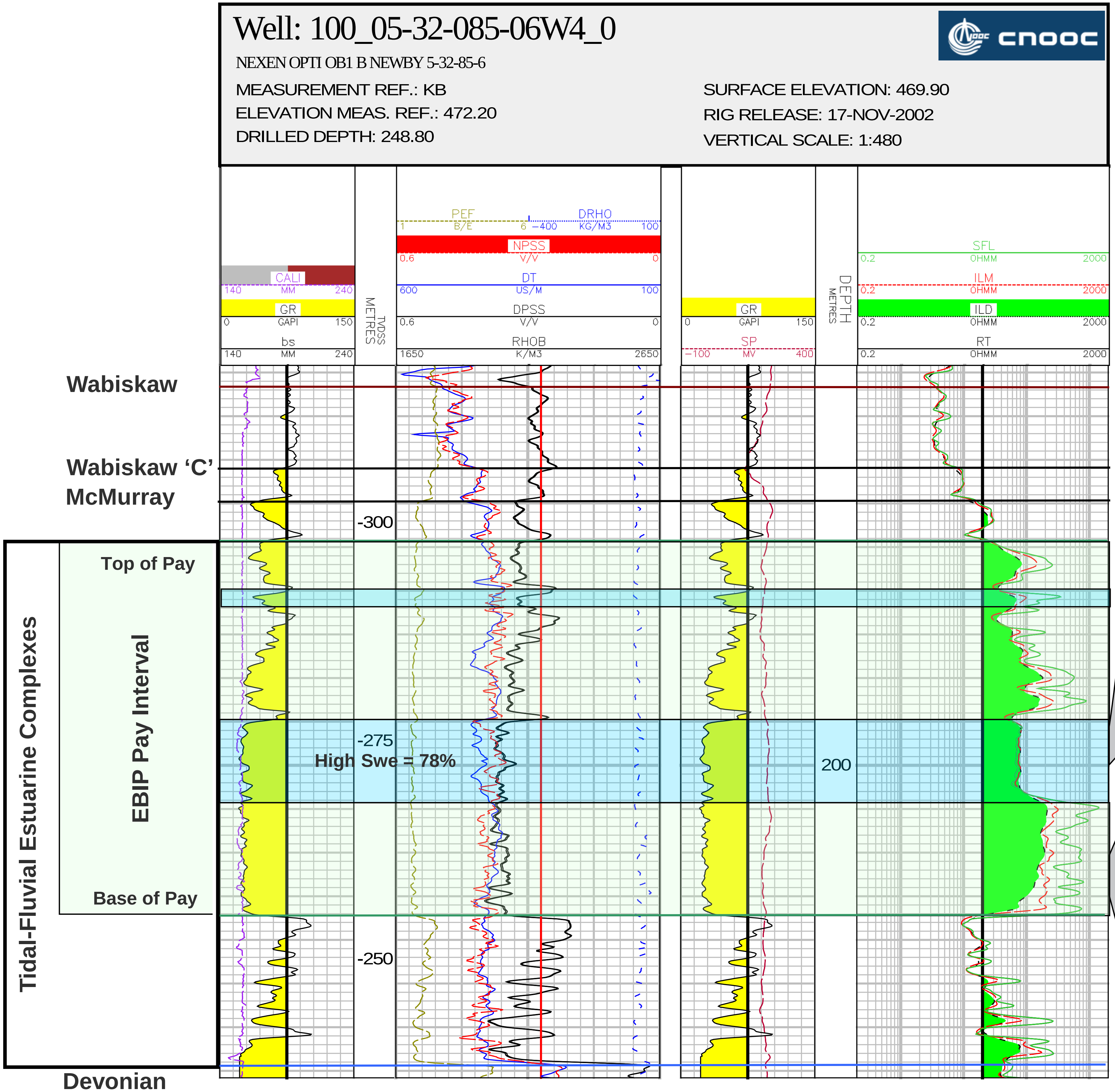
- > 50% Swe and < 30% V_{shale}
- Cumulative thickness of high water saturation interval(s) within SBIP interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour

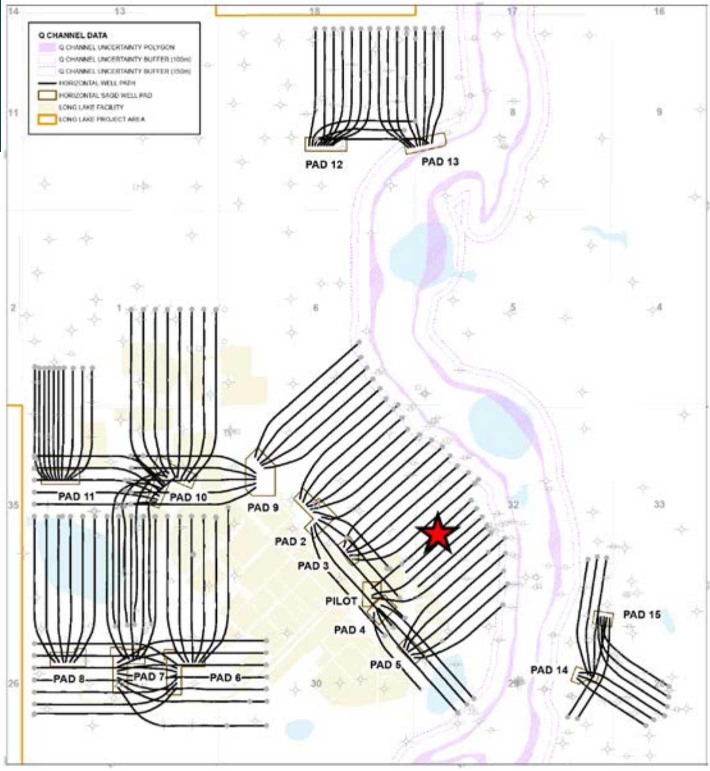
★ TYPE LOG

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

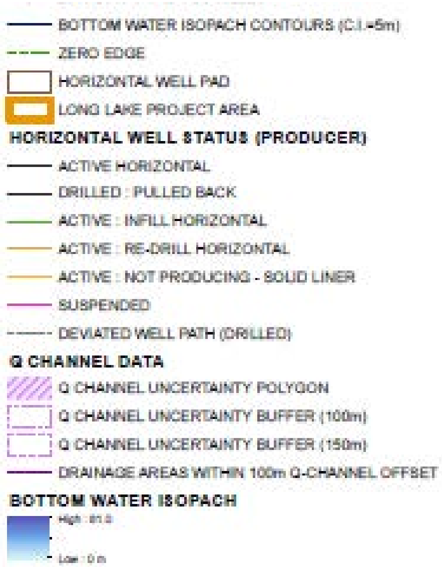


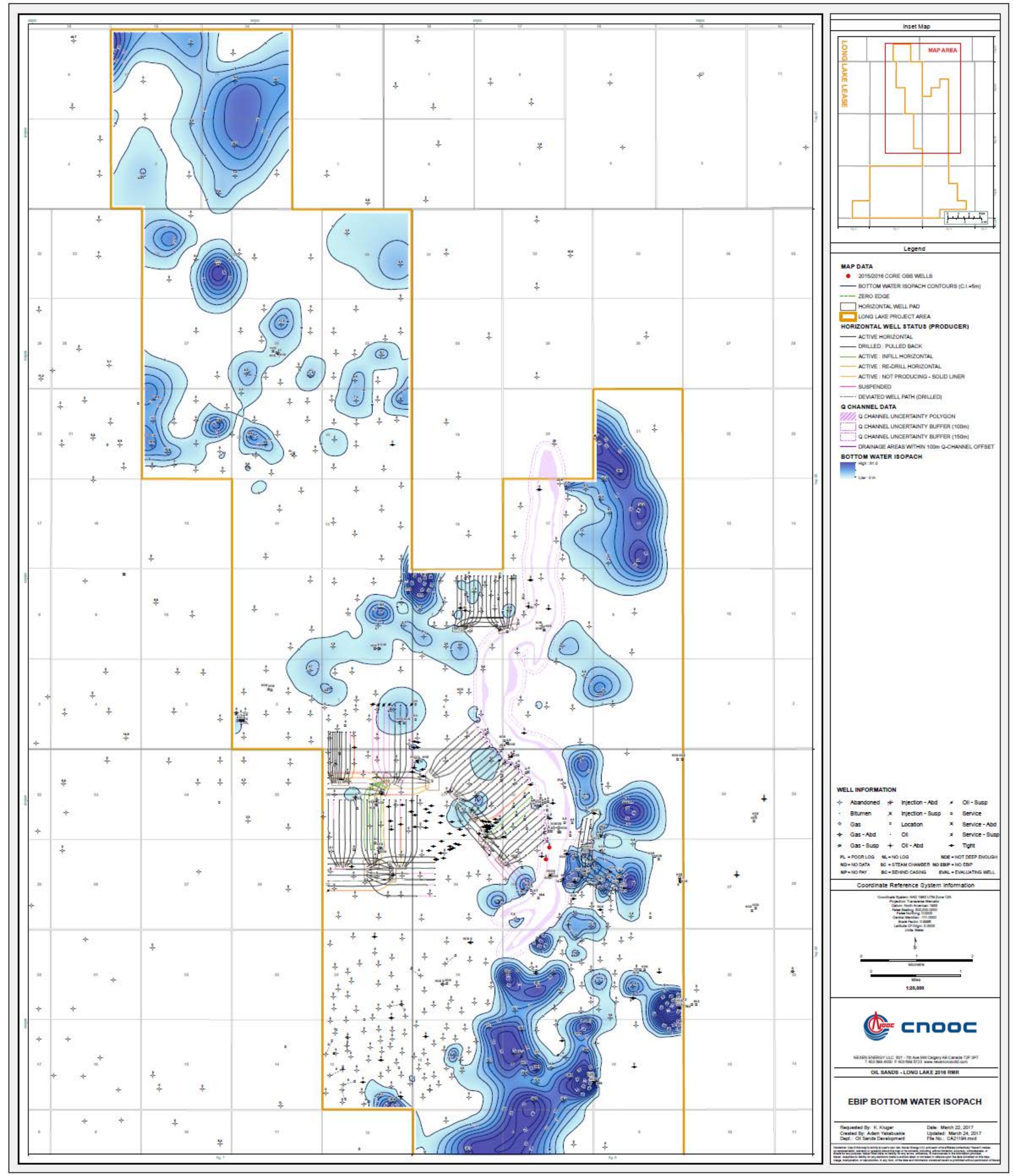
High Water Saturation Type Log
100/05-32-085-06W4





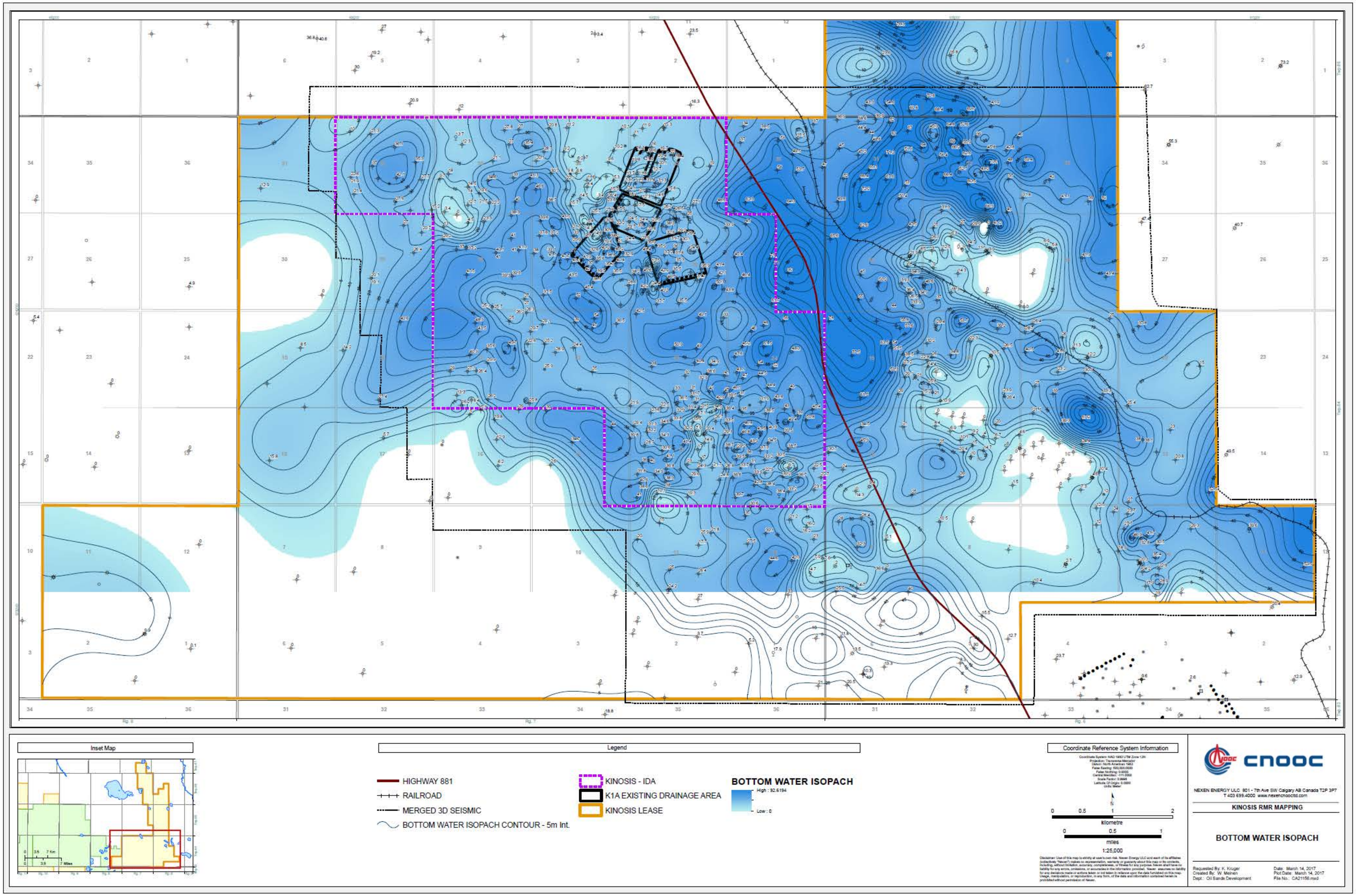
Long Lake Bottom Water in McMurray



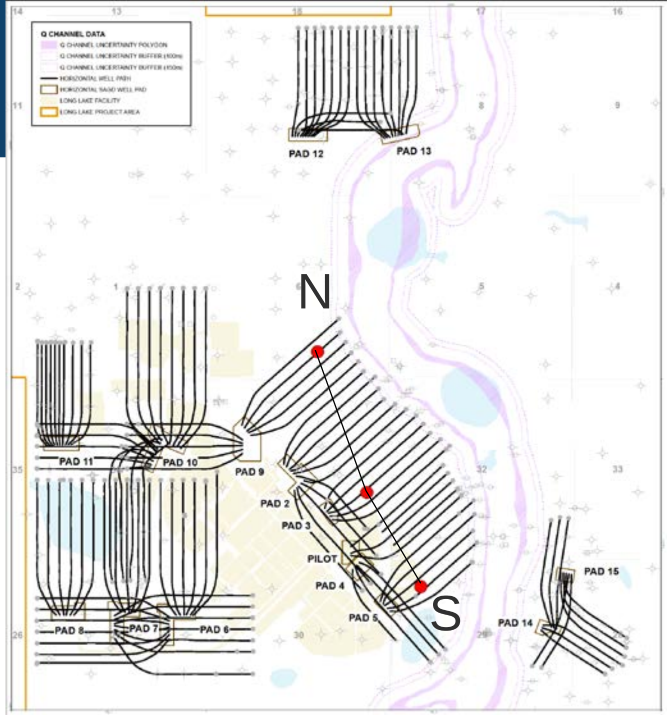


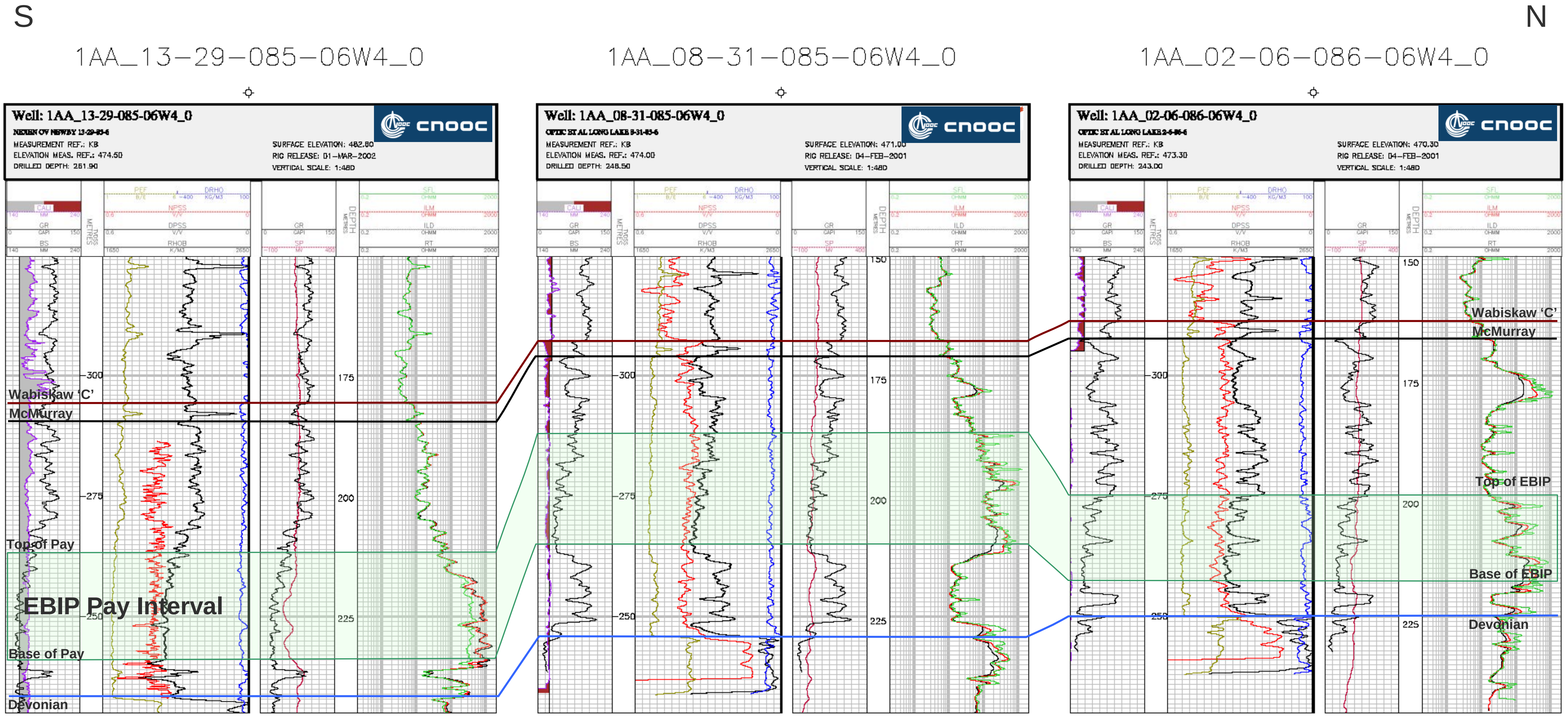
- > 50% Swe and < 30% V_{shale}.

Kinosis Bottom Water in the McMurray

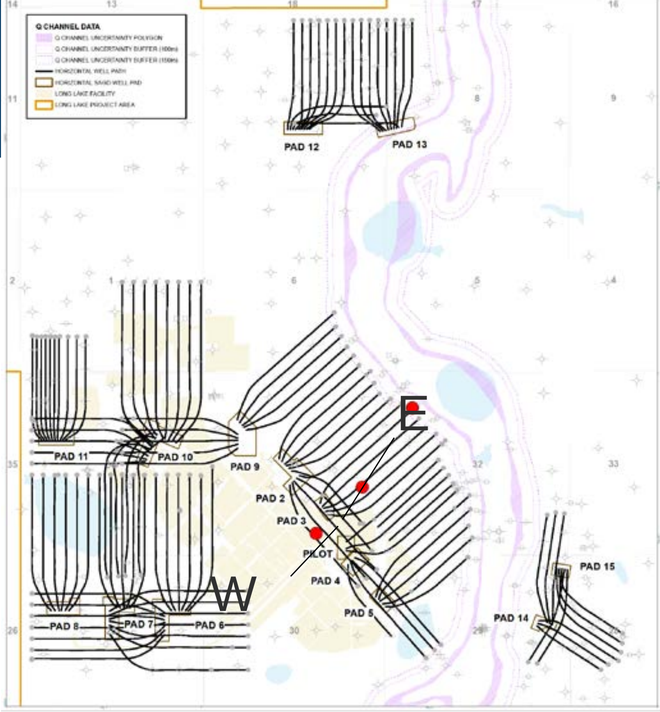


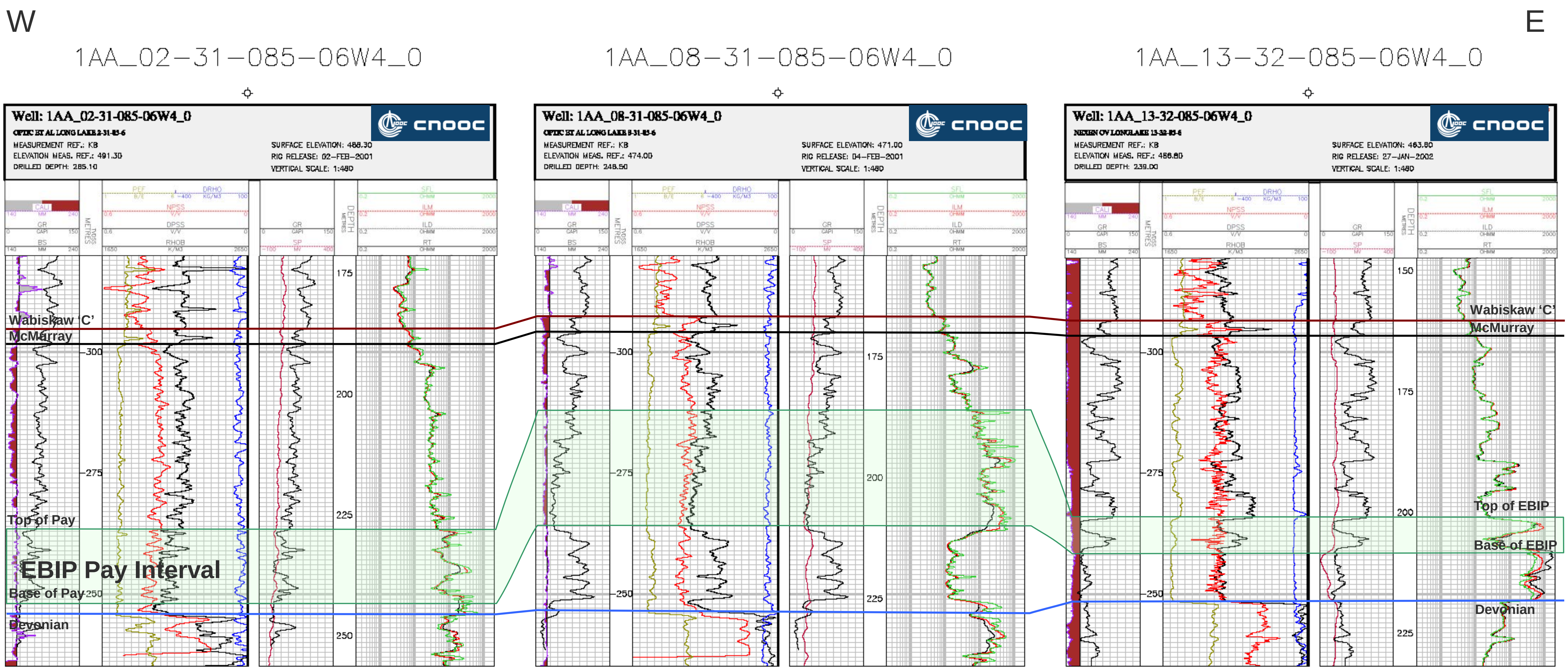
Representative structural cross-section of the East Side of Long Lake (South - North)



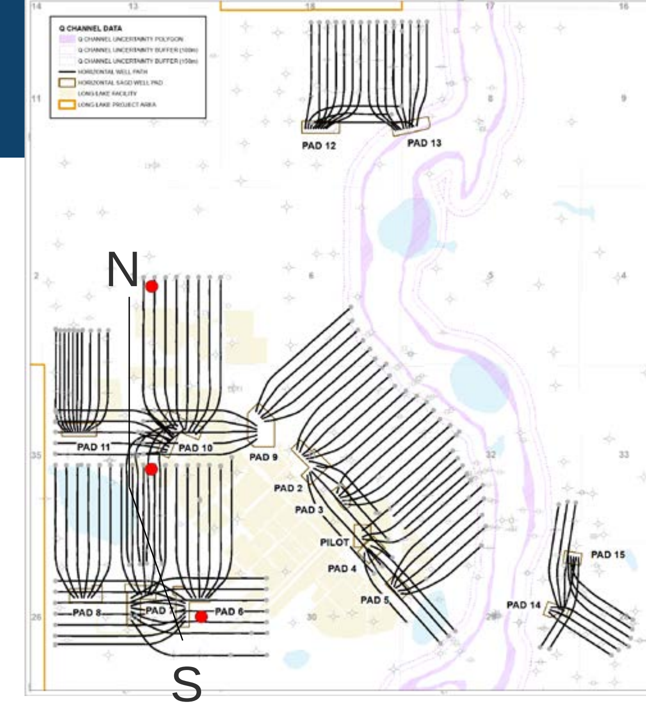


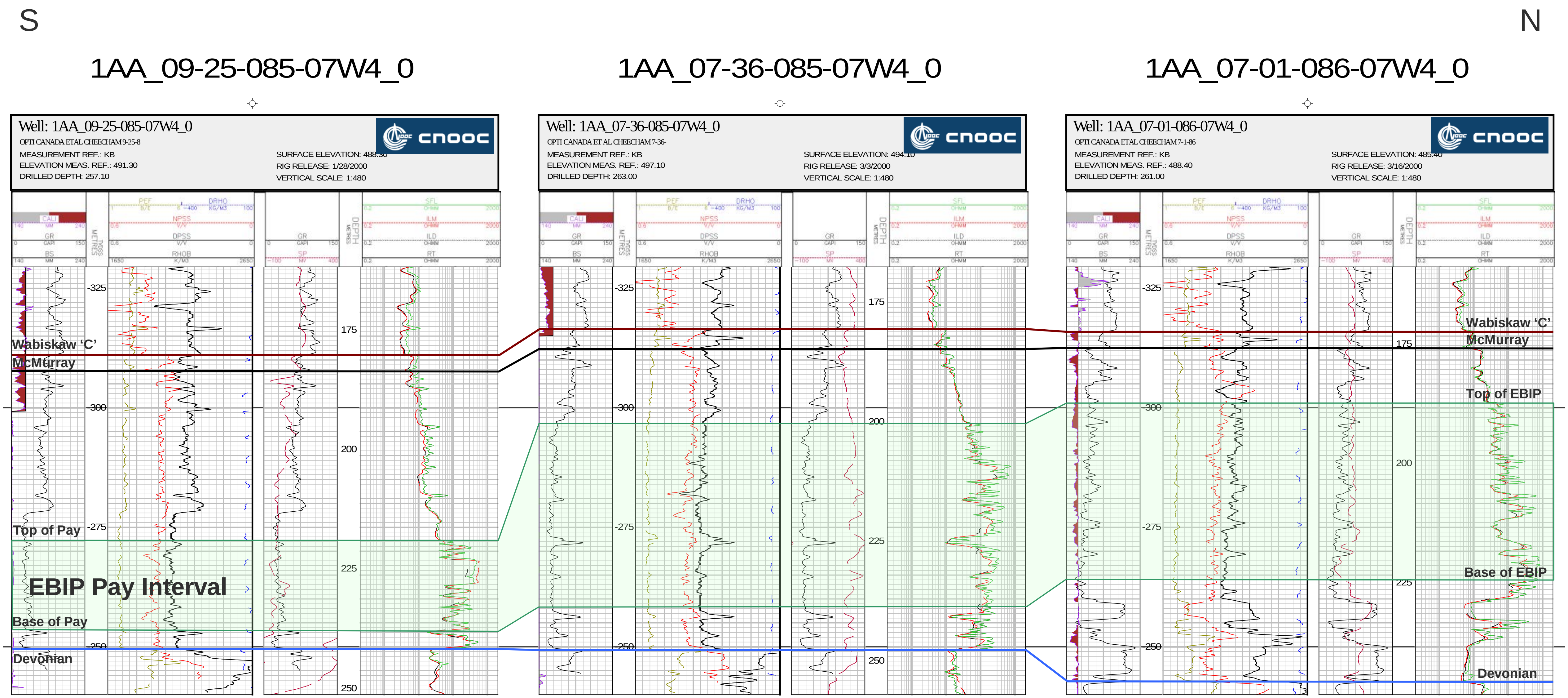
Representative structural cross-section of the East Side of Long Lake (West - East)



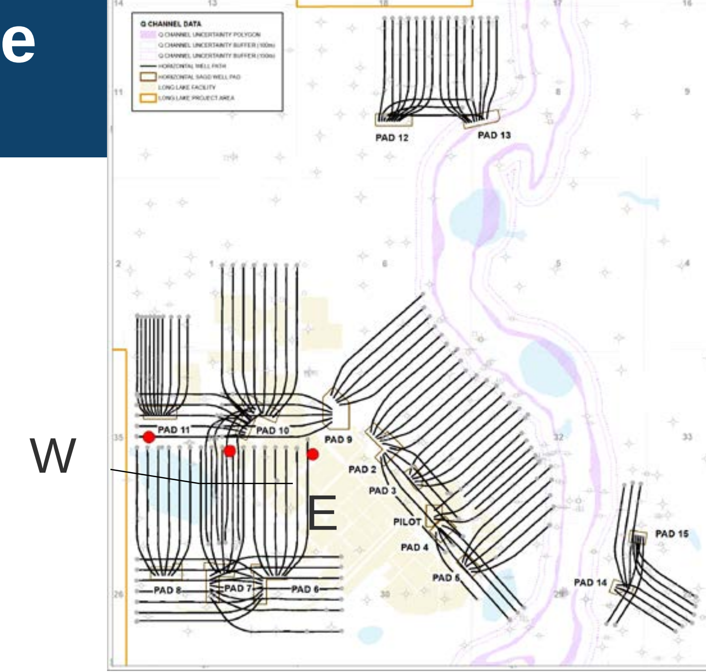


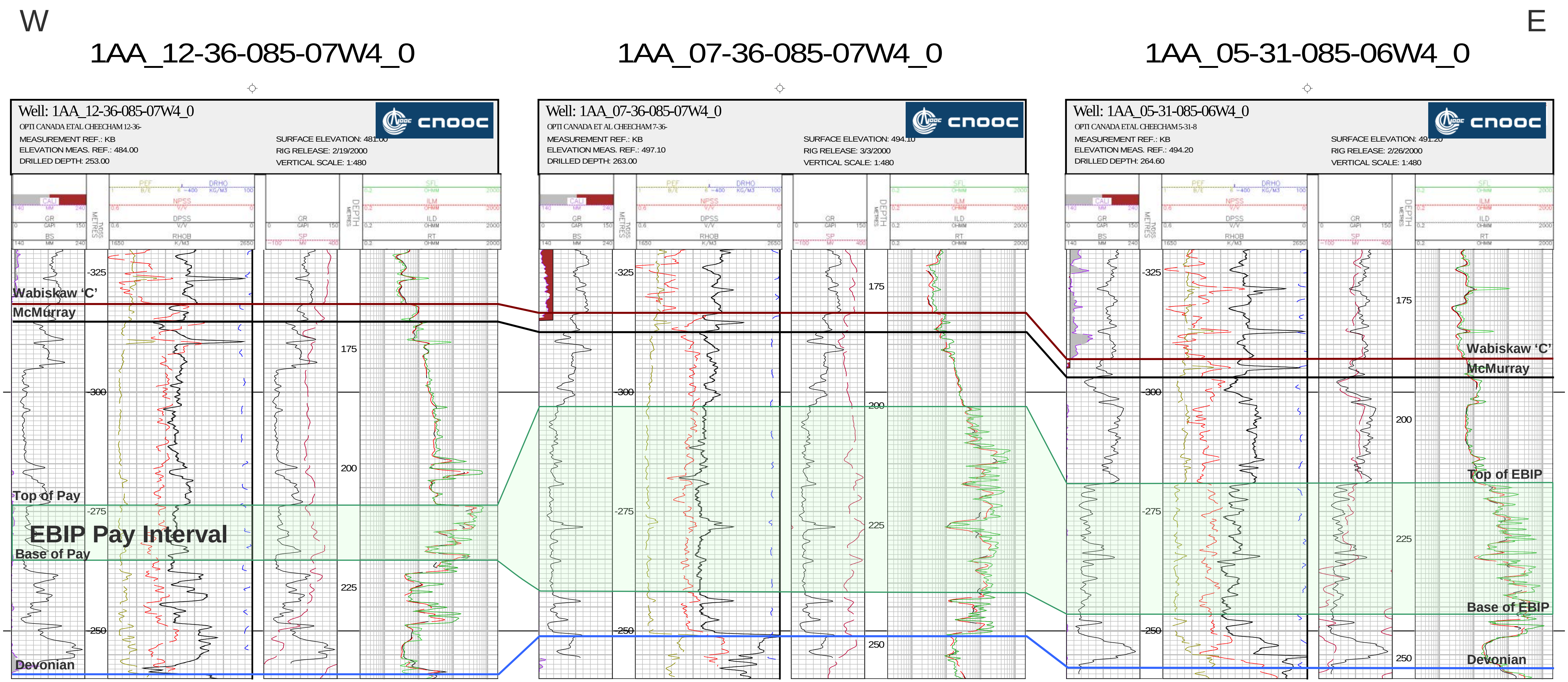
Representative structural cross-section of the West Side of Long Lake (South - North)



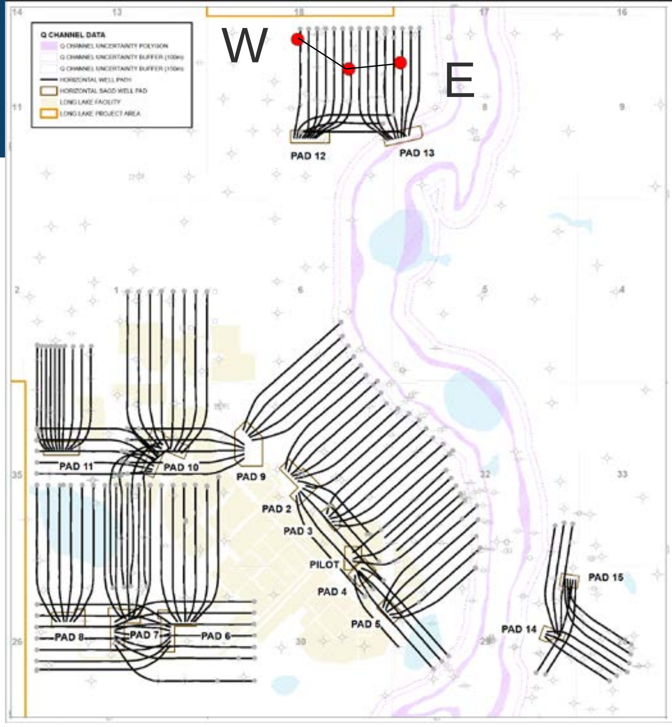


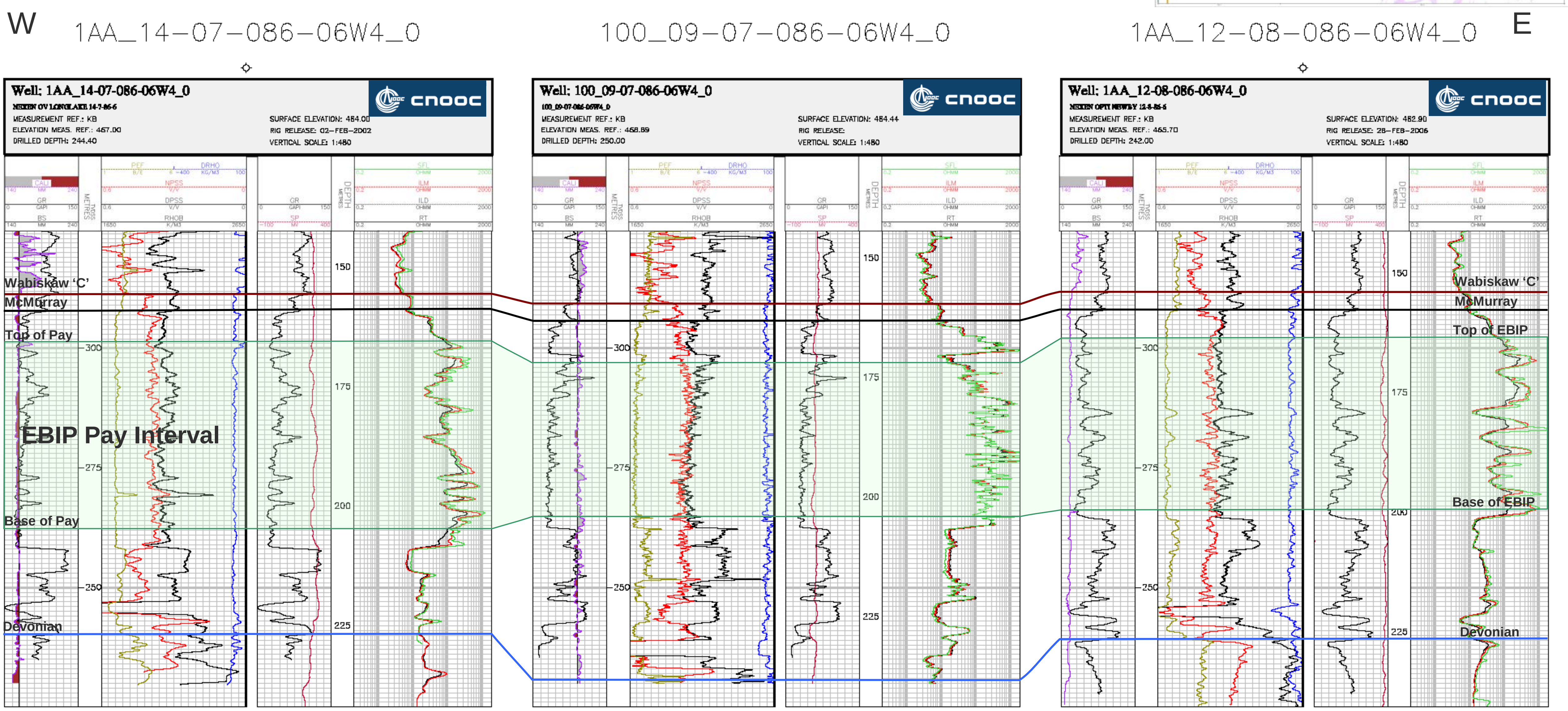
Representative structural cross-section of the West Side of Long Lake (West - East)



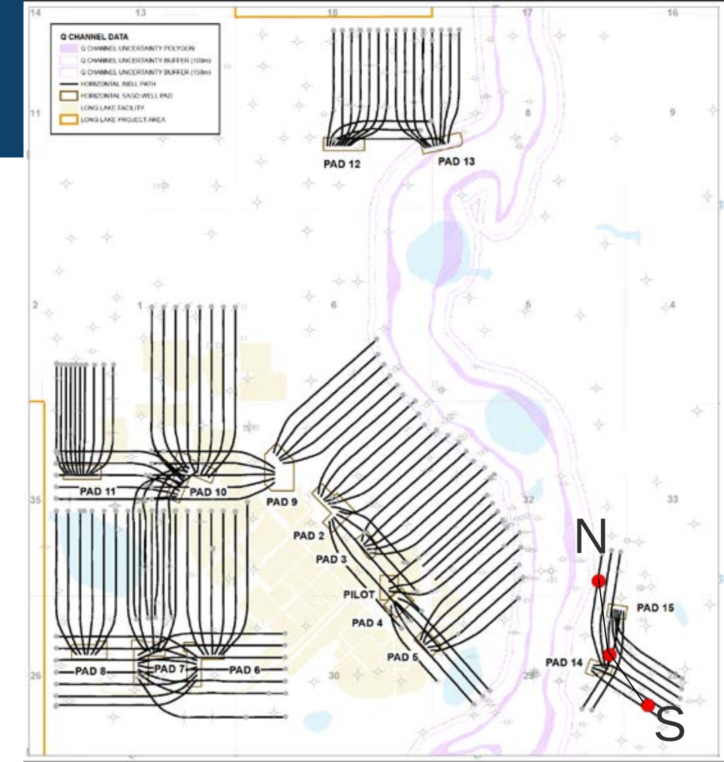


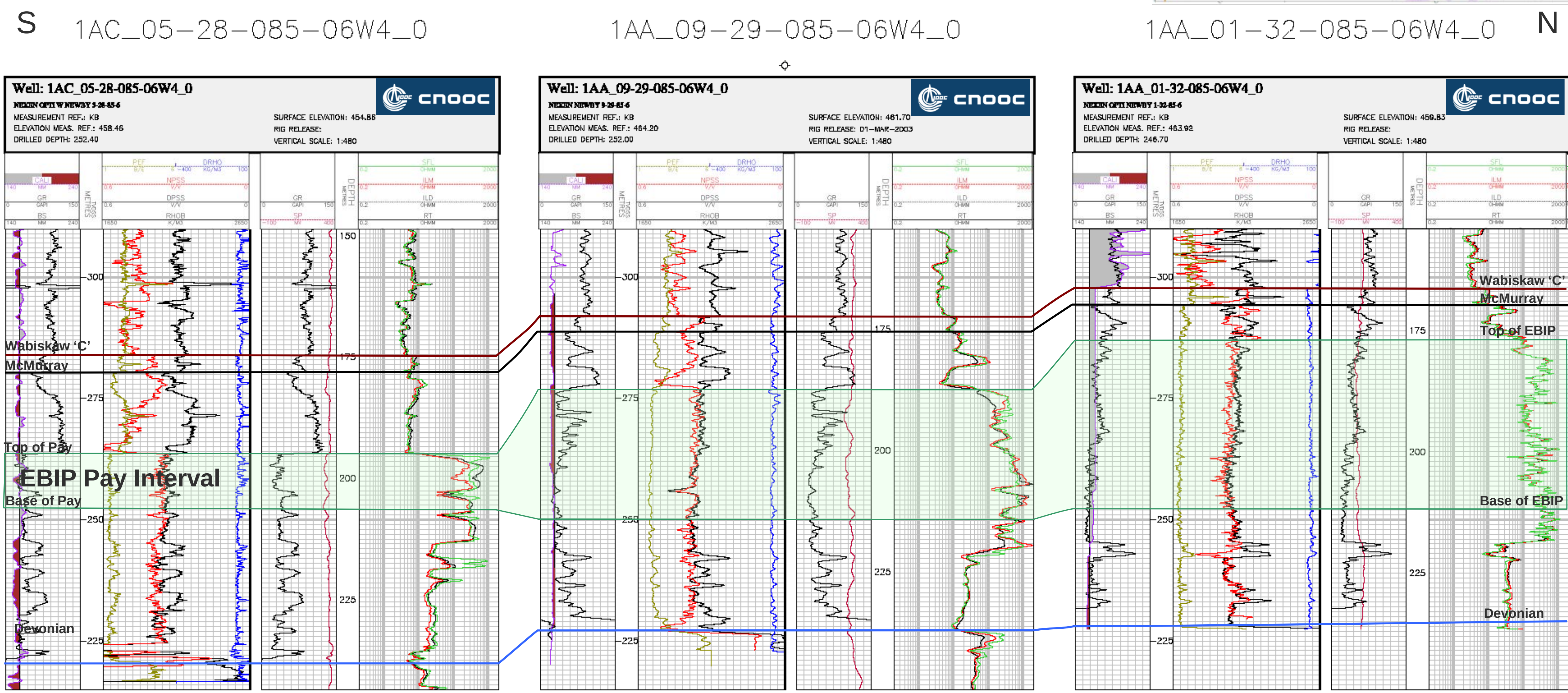
Representative structural cross-section of Pads 12 and 13



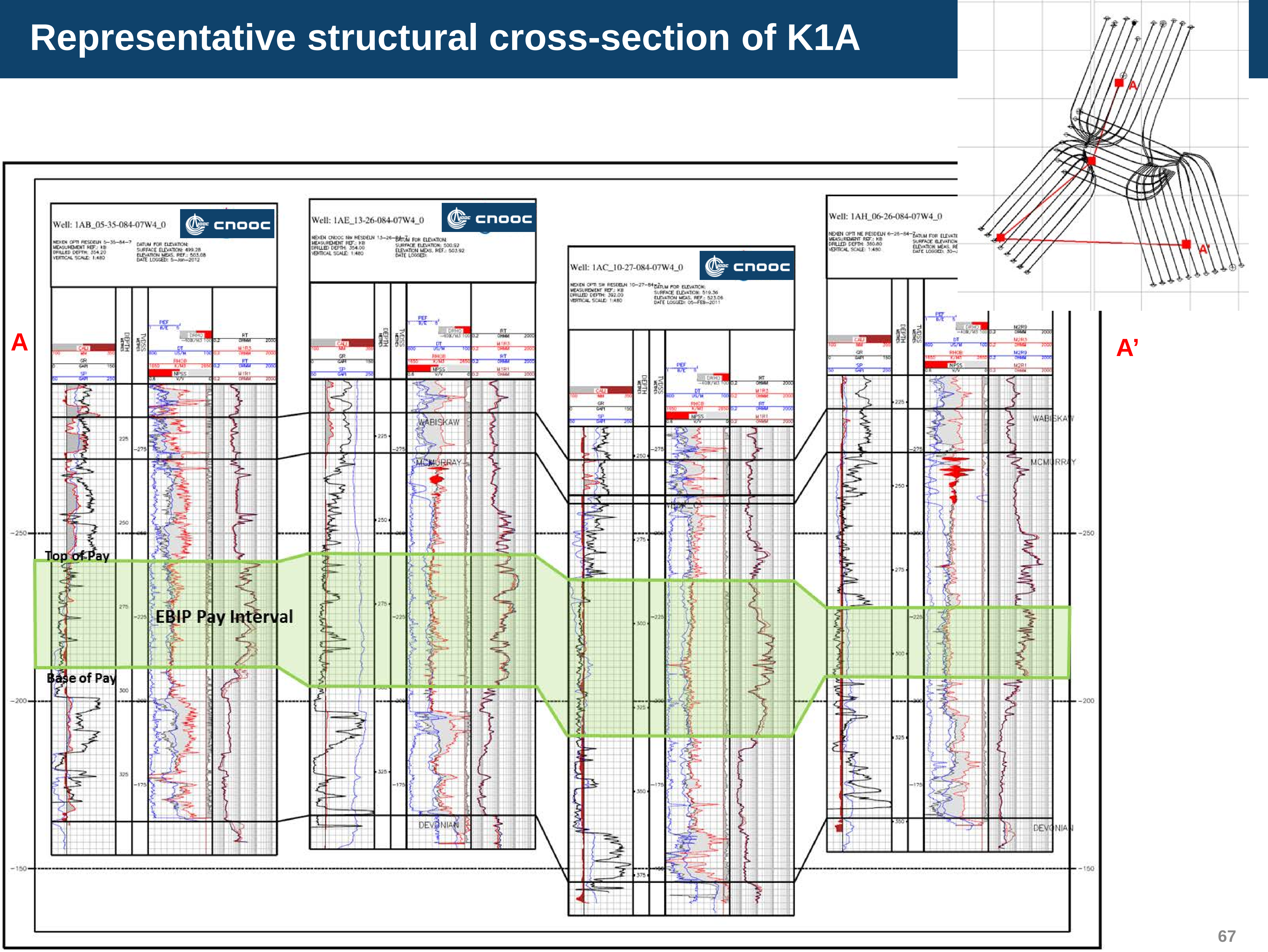


Representative structural cross-section of Pads 14 and 15

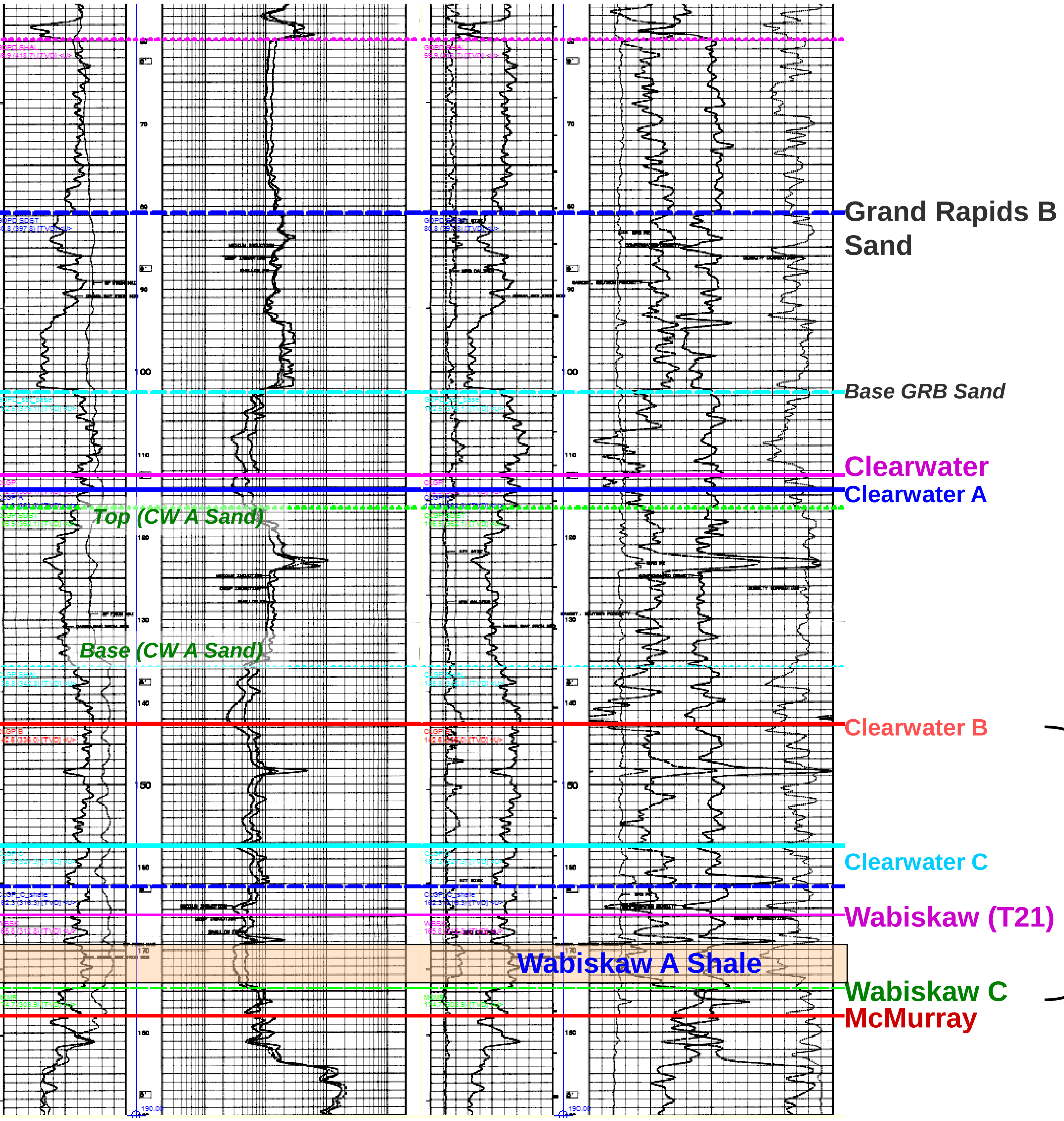




Representative structural cross-section of K1A



Long Lake Cap Rock Type Log



AA/08-20-085-06W4/0

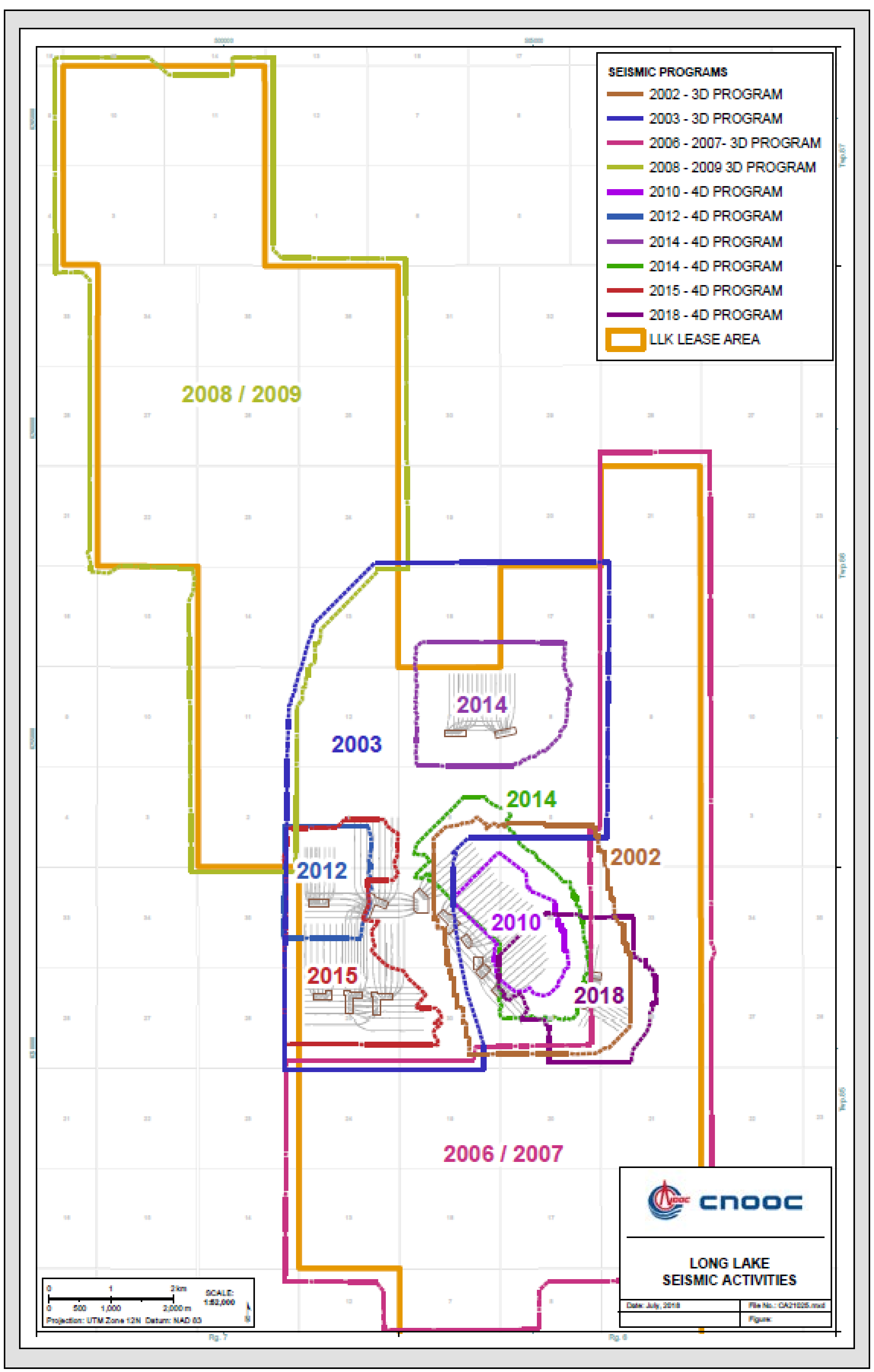
KB: 478.6 m
RR: 2001-01-09
TD: 255.0 m [TVD]
FormTD: BHL
Mode: Abnd
Fluid: N/A
OPTIC ET AL LONG LAKE 8-20-85-6

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

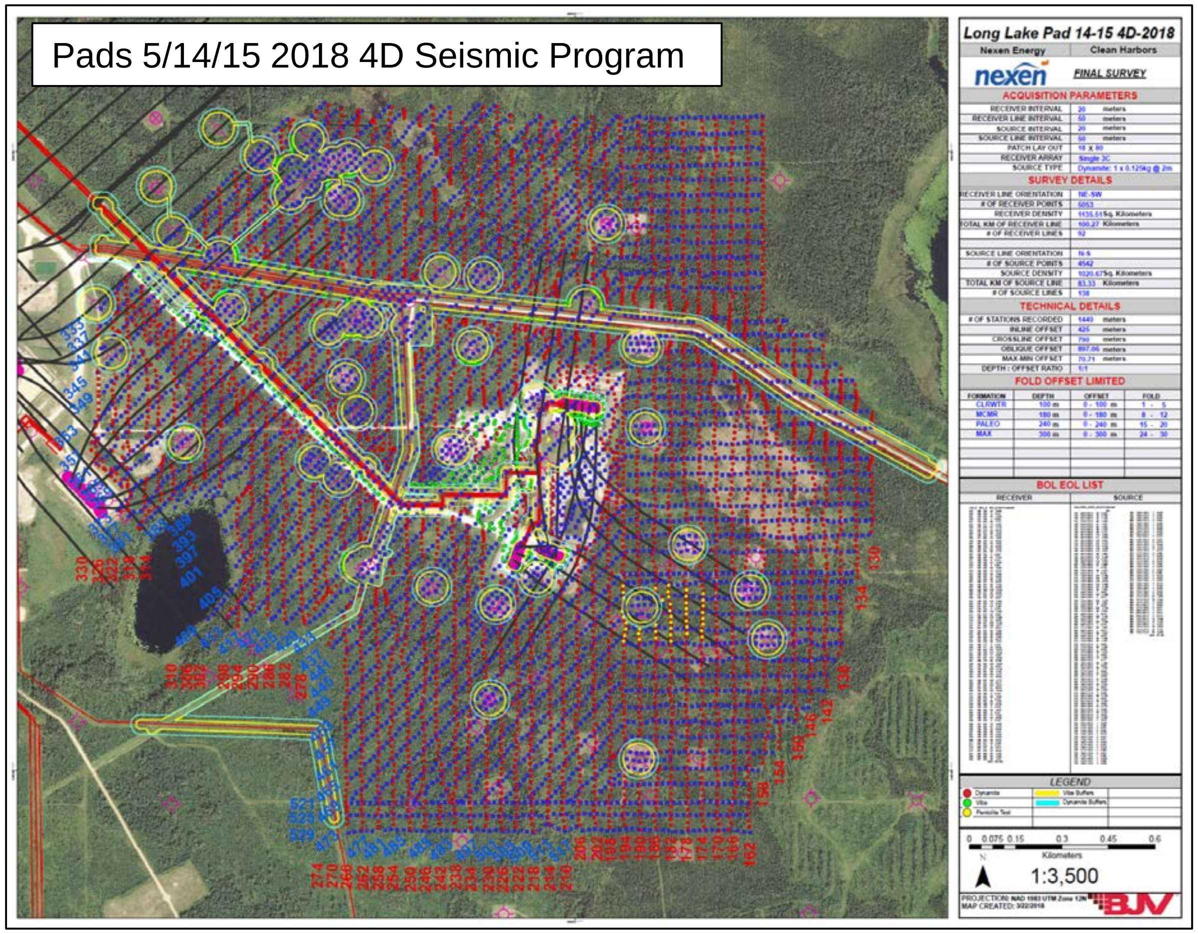
Long Lake Cap Rock Evaluation Image Logs 2018

UWI	Well Name	Well Licence	Year
109082408507W400	NEU CNOOC OBS NEWBY 8-24-85-7	491636	2018

Long Lake Seismic

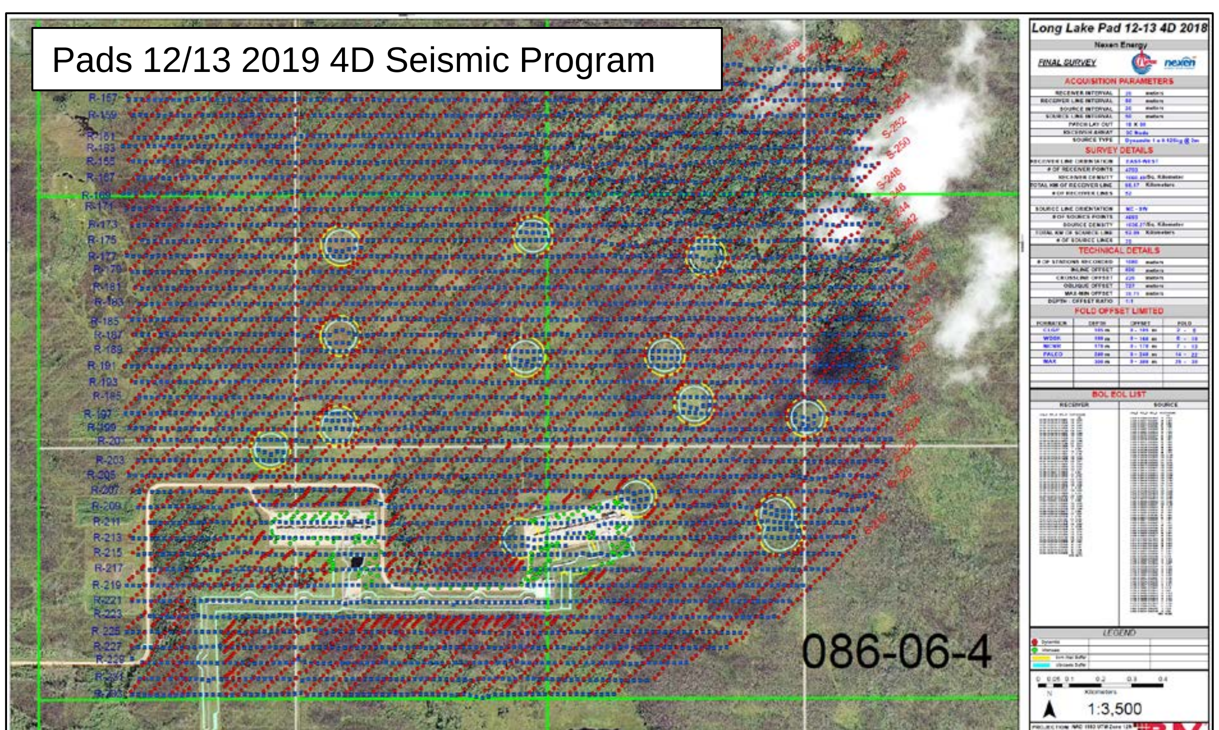


2018 and 2019 4D Monitor Survey Acquisitions



- A 4D Seismic monitor survey over Pads 14/15 was completed in mid-February 2018 as per Commercial Scheme Approval 9485YY

- Exploration Directive ED2006-15 requires a large source setback from water wells and observation wells. Given the numerous water and observation wells in the area, the set back requirements had a negative impact on the program. The decreased amount of shot points creates gaps in imaging the shallow section of the subsurface.

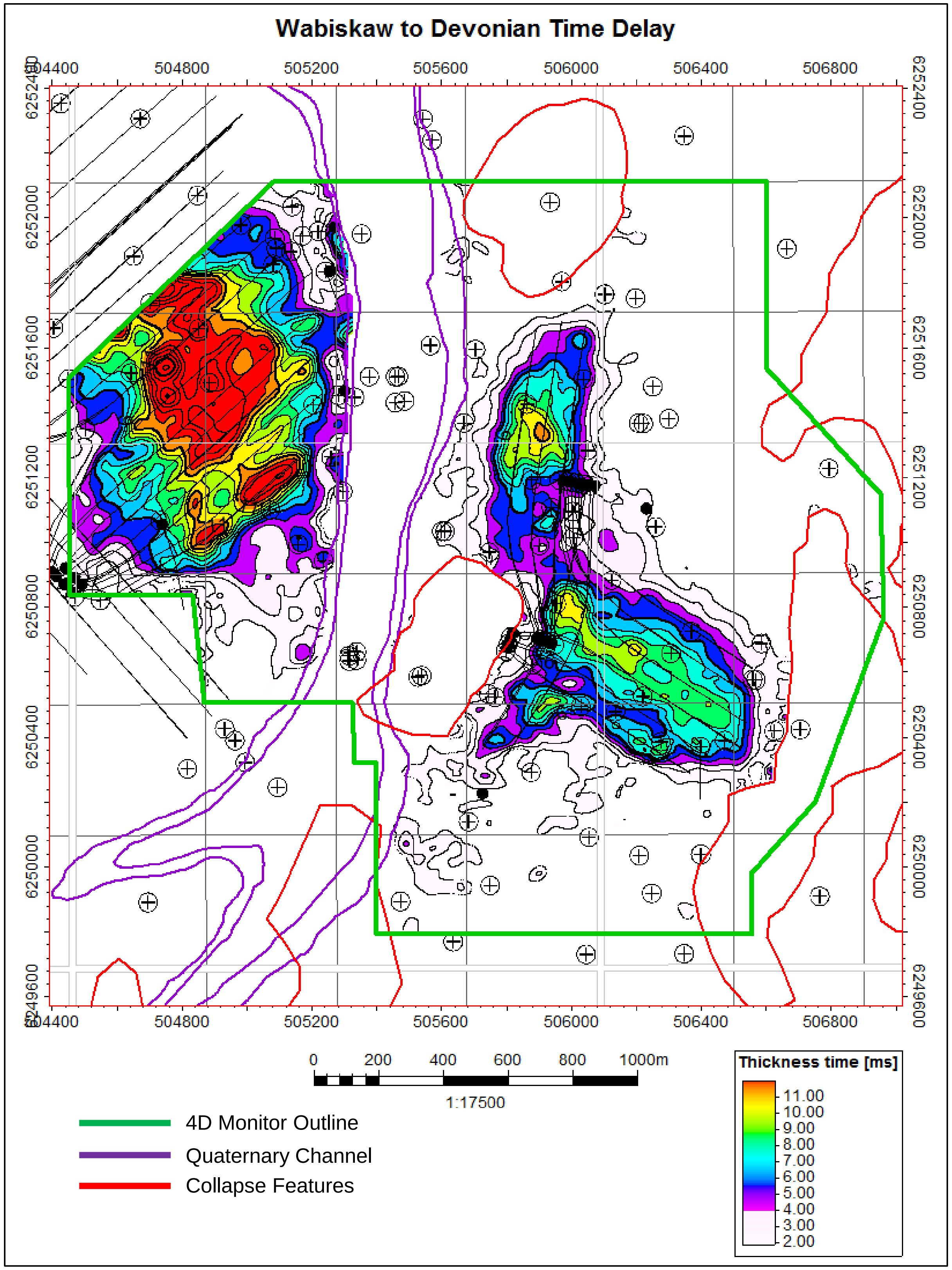


- A 4D Seismic monitor survey over Pads 12/13 was completed in January 2019, this was the second monitor survey to be acquired over Pads 12/13.

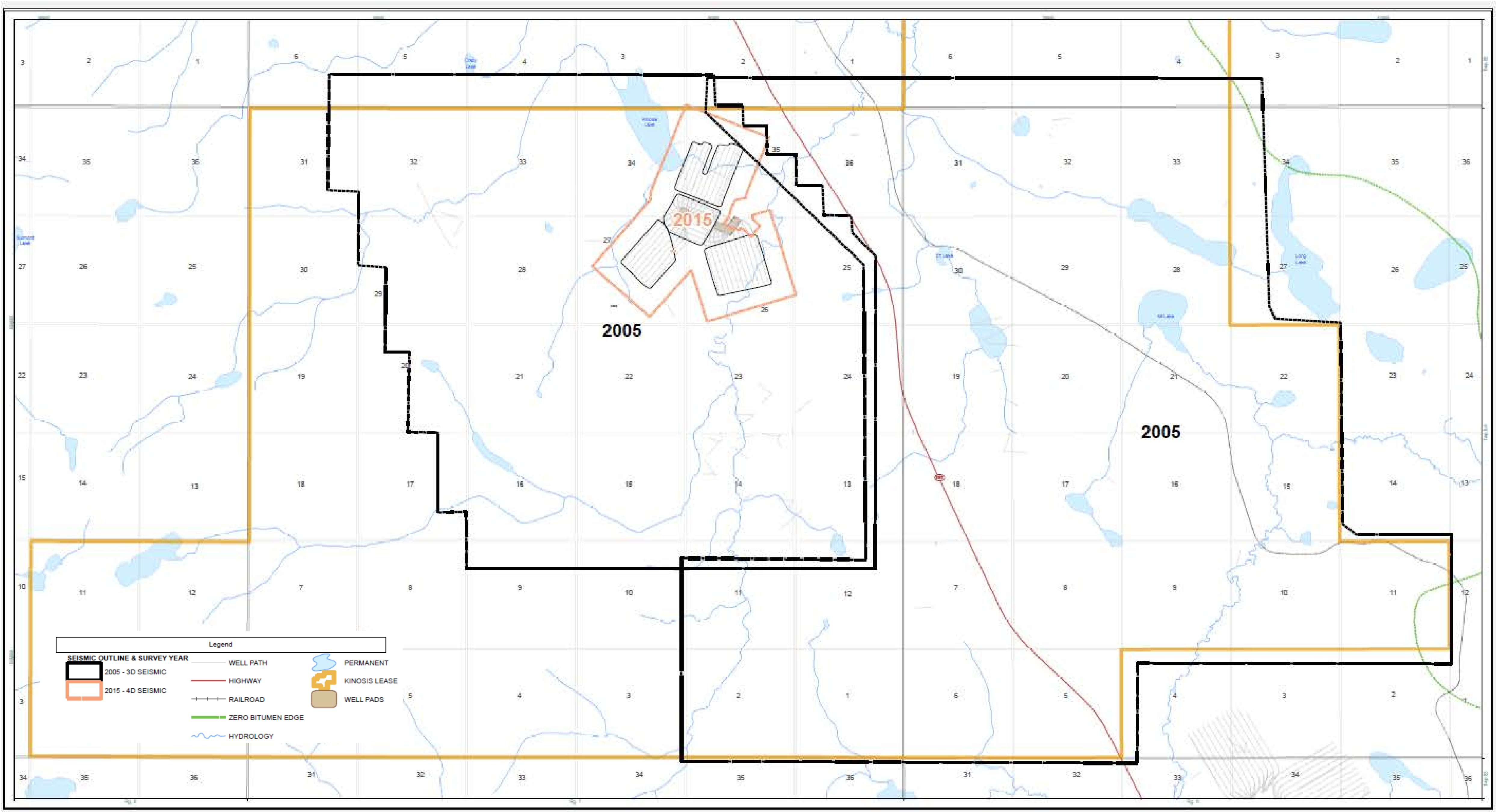
- There is not as much infrastructure, observation wells and water wells in this area compared to Pads 14/15 area, however, the required source setbacks still had a negative impact to the shallow subsurface data quality.

Pads 5, 14 & 15 2018 4D Seismic Monitor Survey

- 4D Monitor survey over Pads 14/15 was completed in mid-February 2018 as per Commercial Scheme Approval 9485YY.
- Displayed is a time delay map which is a difference between the Wabiskaw 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.

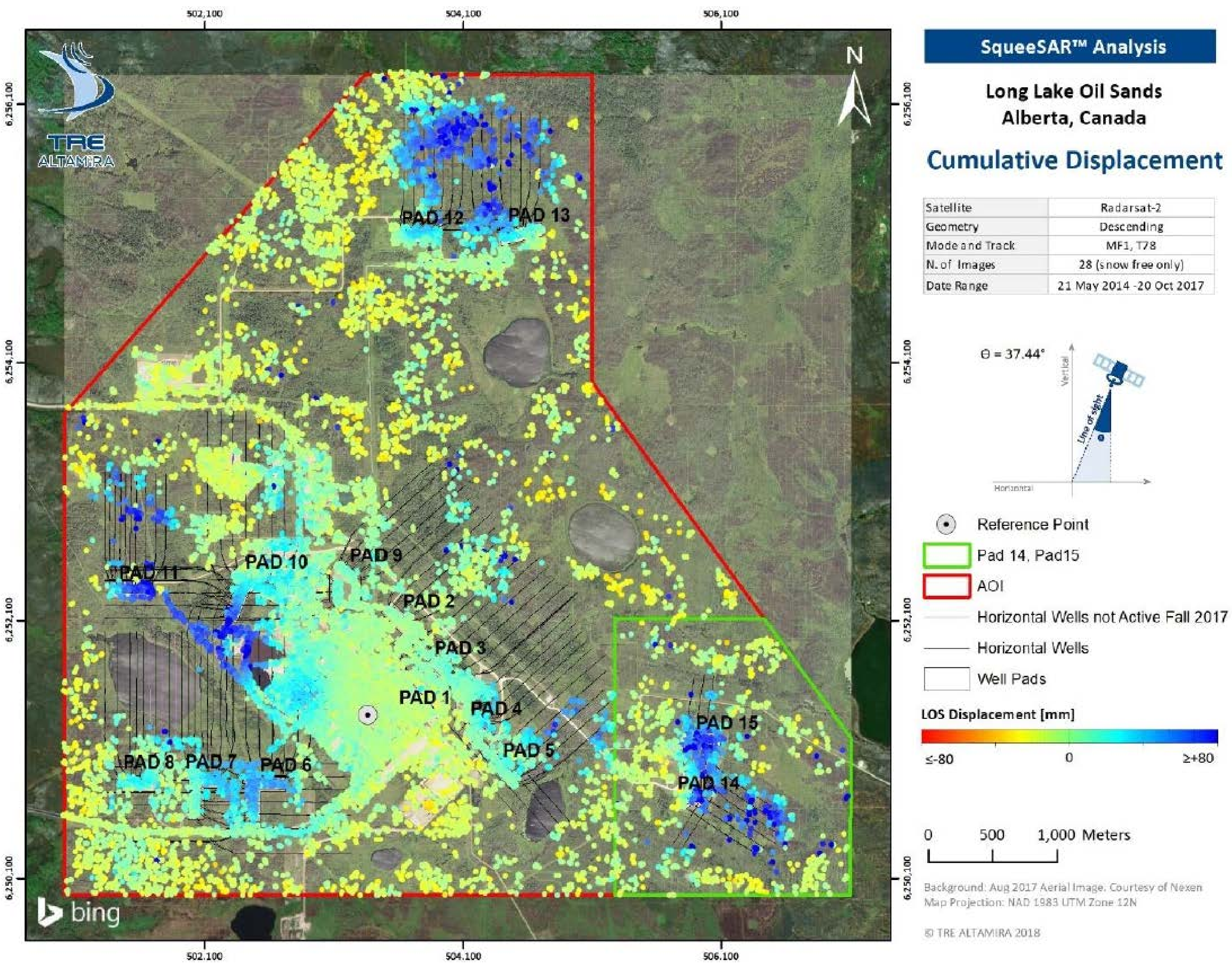


Kinosis Seismic
No 4D in 2018



Long Lake InSAR

- InSAR heave data was collected over a portion of Long Lake, immediately surrounding producing Pads 1-15
- 2014-2017 data was collected and processed by TRE-Altamira
- Maximum displacement over the ~4 year period reached ~100mm

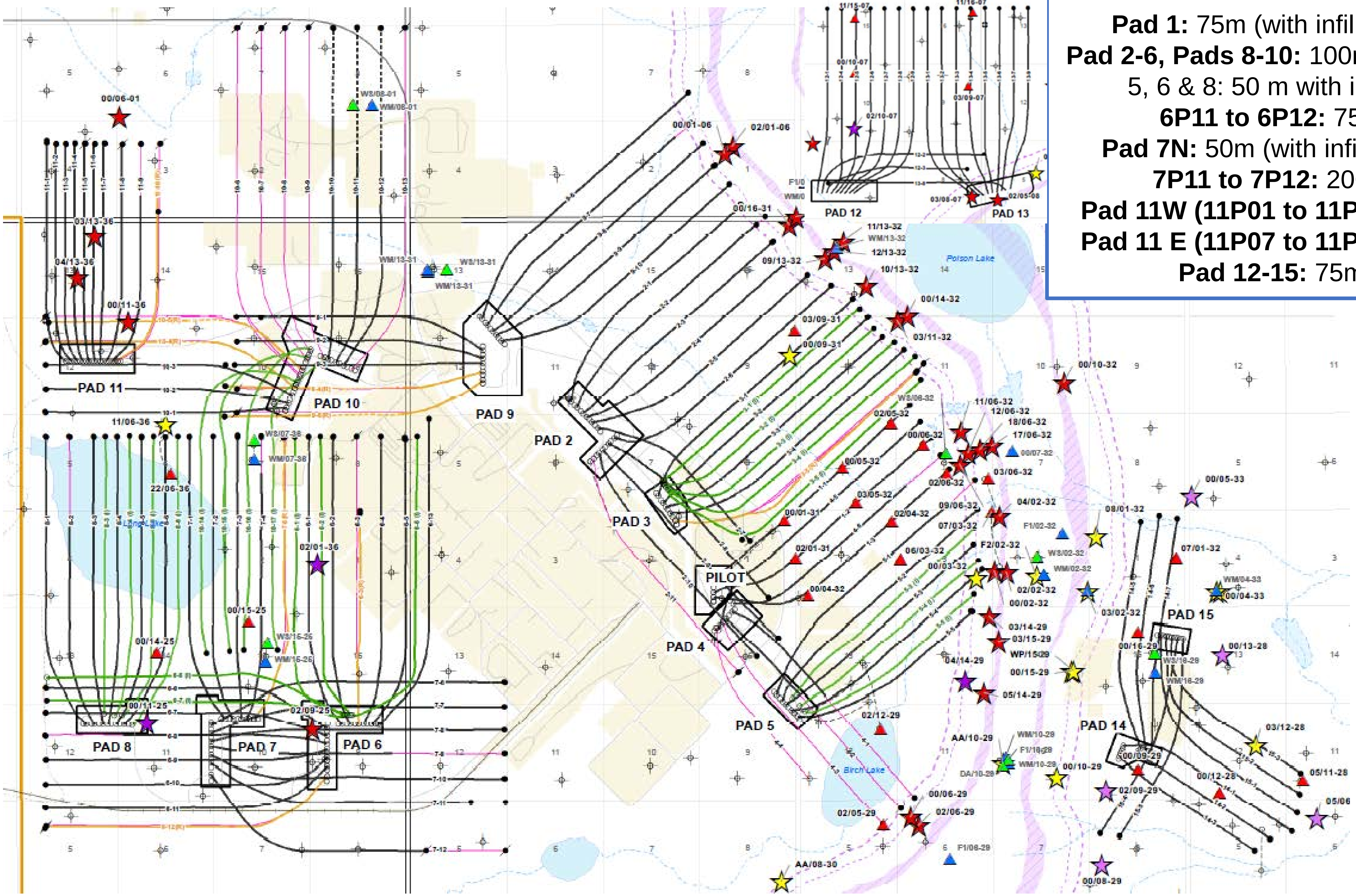


Drilling and Completions, Artificial Lift and Instrumentation

Subsection 3.1.1 (3,4,5)

Long Lake

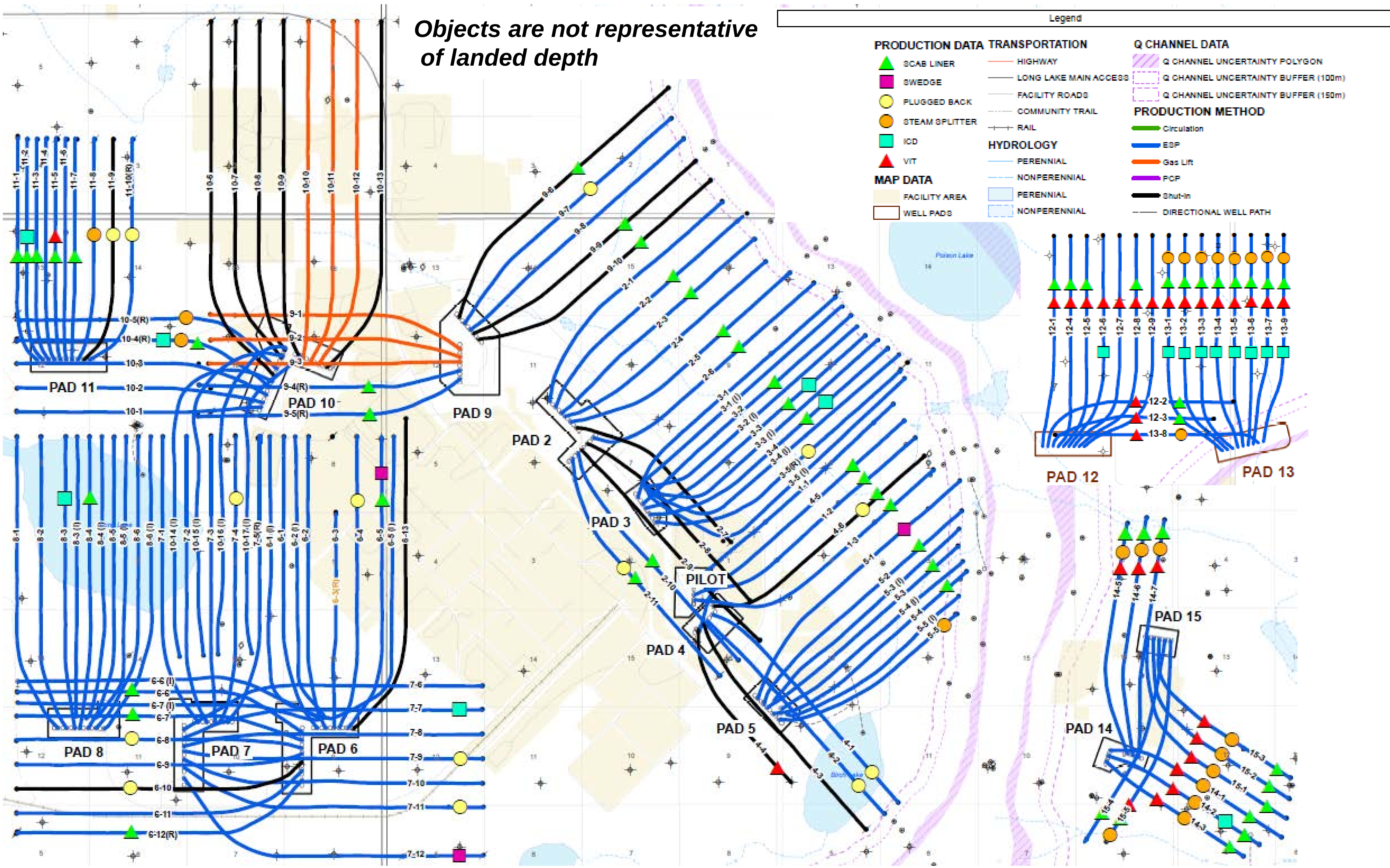
Long Lake
Horizontal Well Locations



Inter-well Spacing

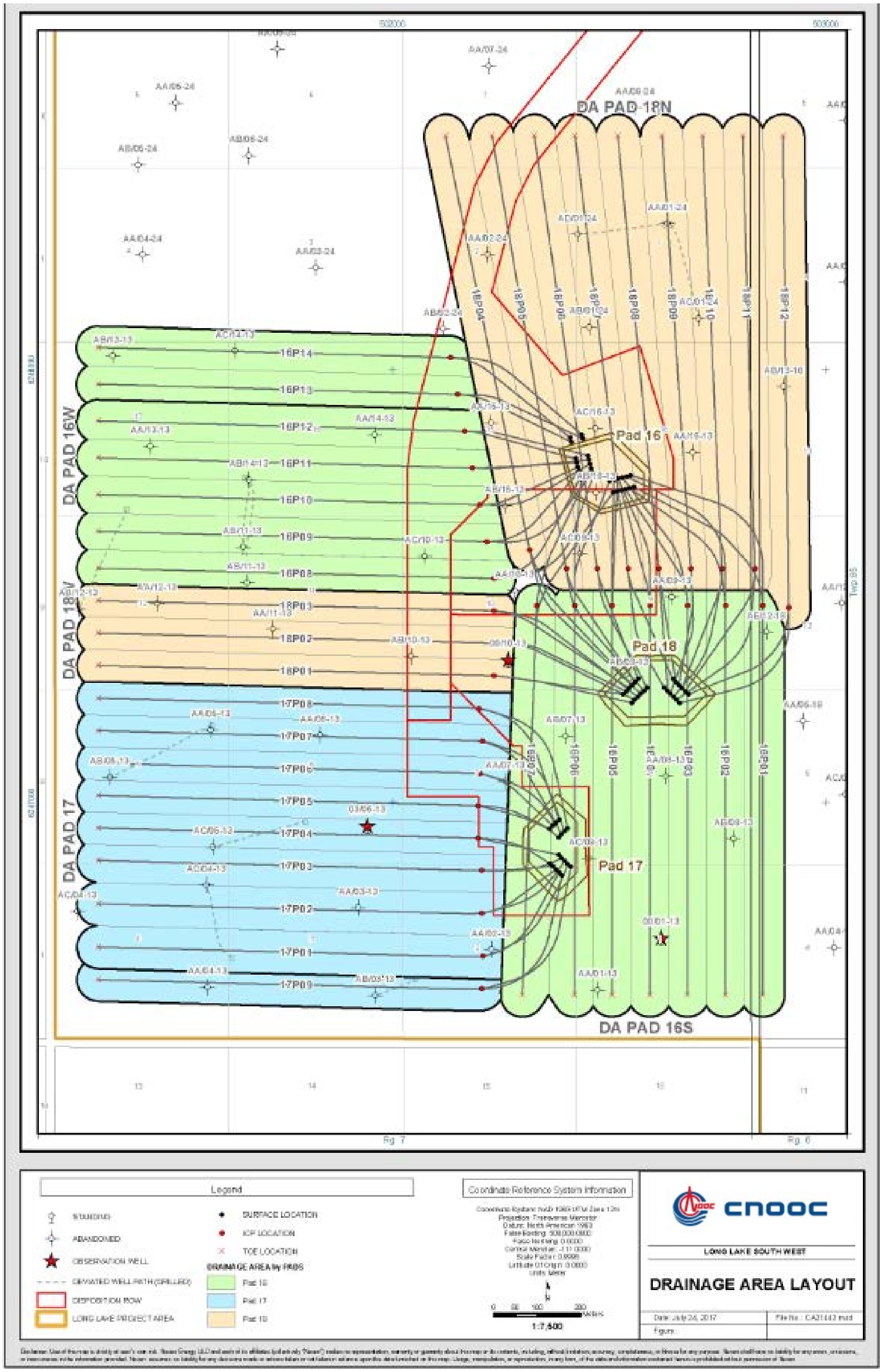
Pad 1: 75m (with infill pairs)
Pad 2-6, Pads 8-10: 100m (Pads 3, 5, 6 & 8: 50 m with infills)
6P11 to 6P12: 75m
Pad 7N: 50m (with infill wells)
7P11 to 7P12: 200m
Pad 11W (11P01 to 11P06): 40m
Pad 11 E (11P07 to 11P10): 80m
Pad 12-15: 75m

Long Lake Well Pair Completions Map 2018



Long Lake SW
Proposed Horizontal Well Locations

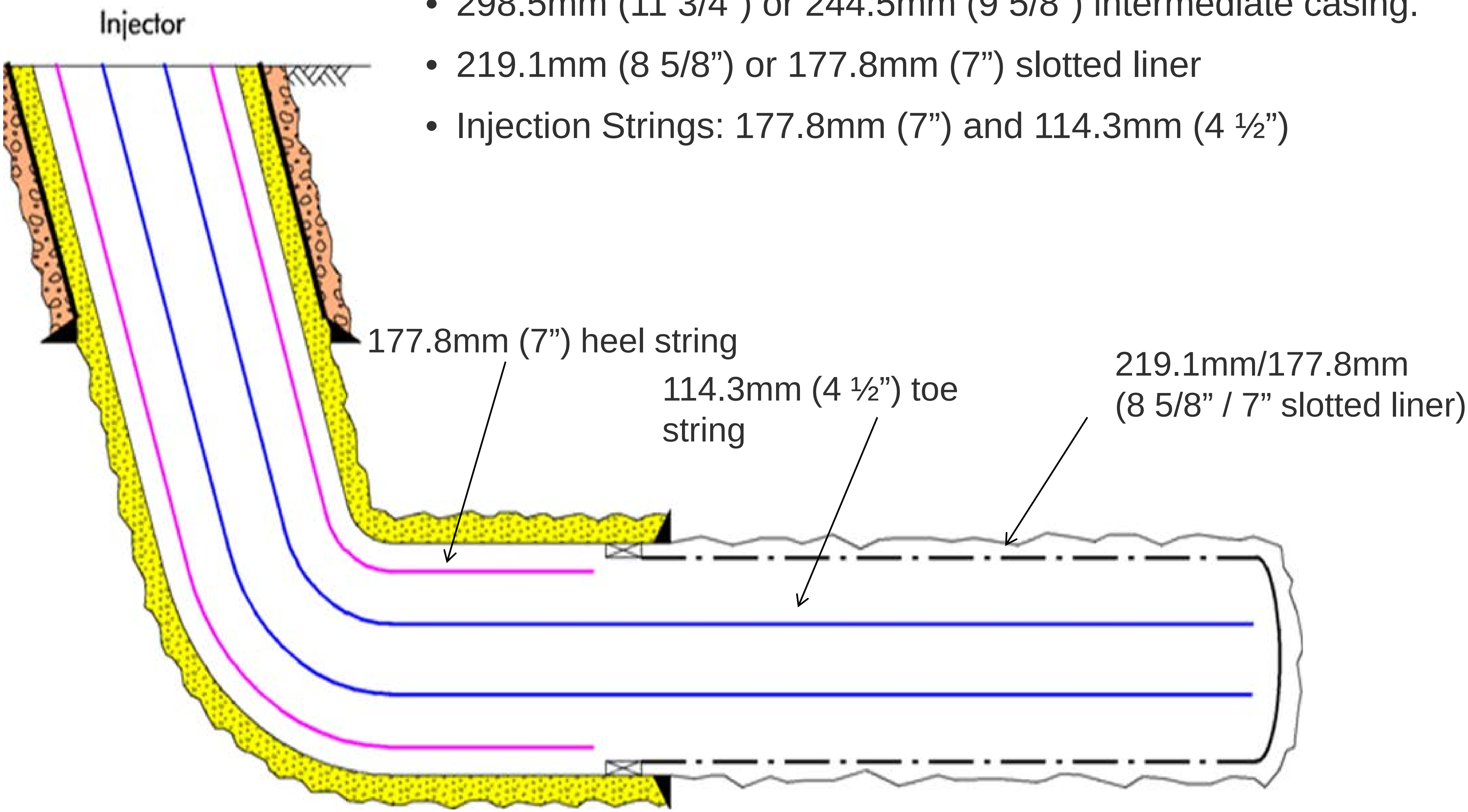
- LLSW sustaining Pads 16, 17, 18
- Commenced drilling Pad 16 surface holes in December 2018



Typical Injector Completion

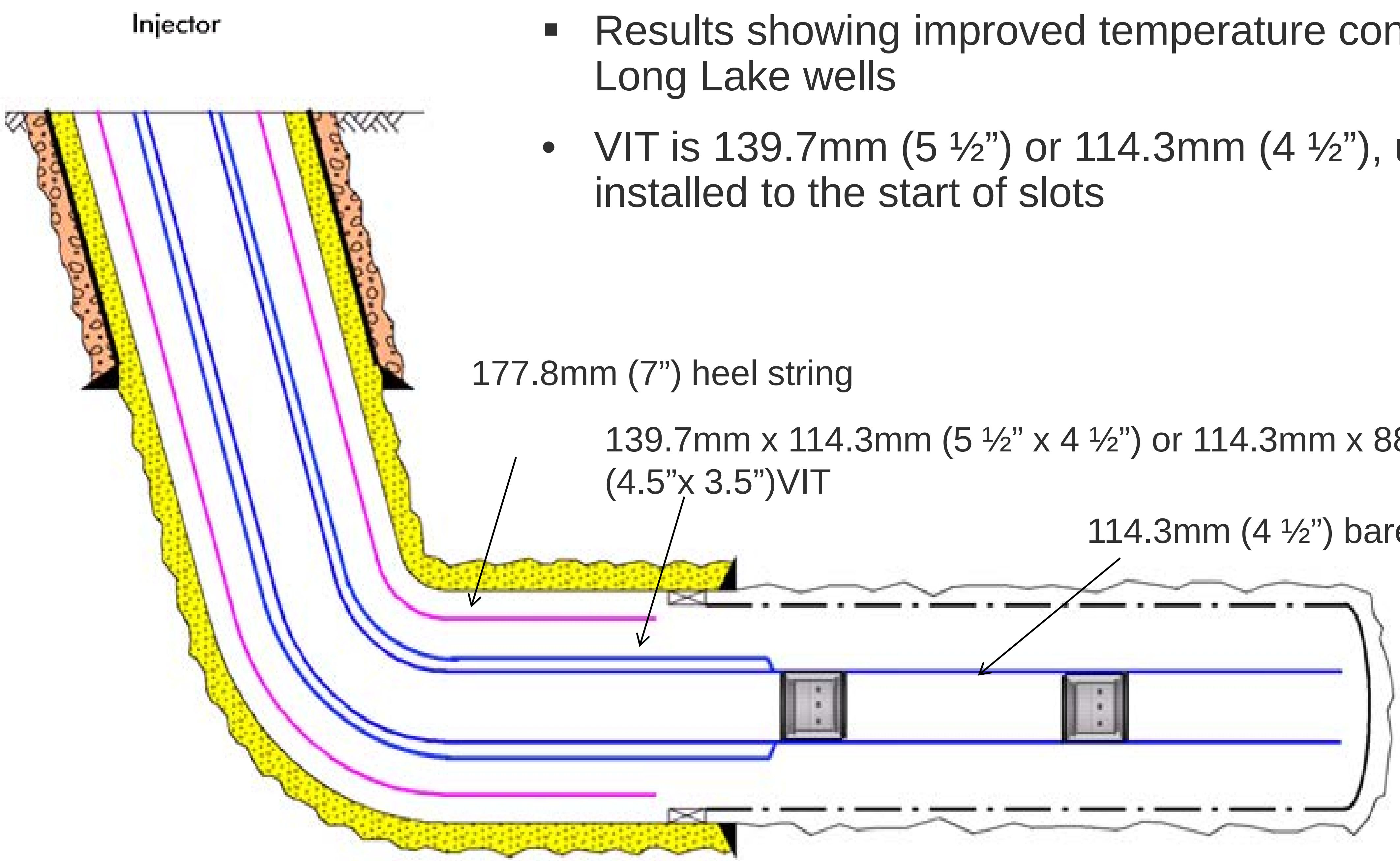
Concentric:

- 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")

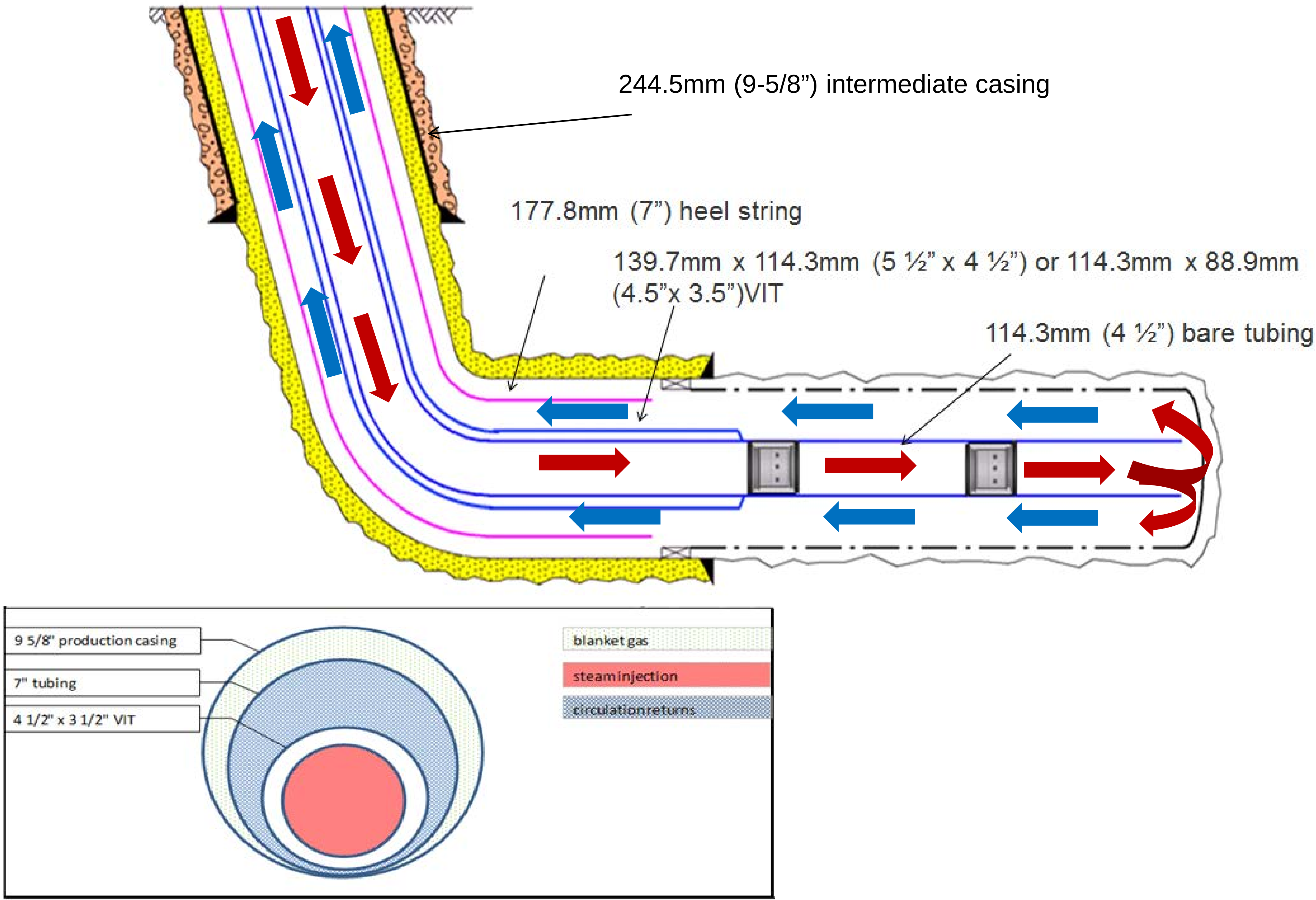


Vacuum Insulated Tubing (VIT) Injector Completion

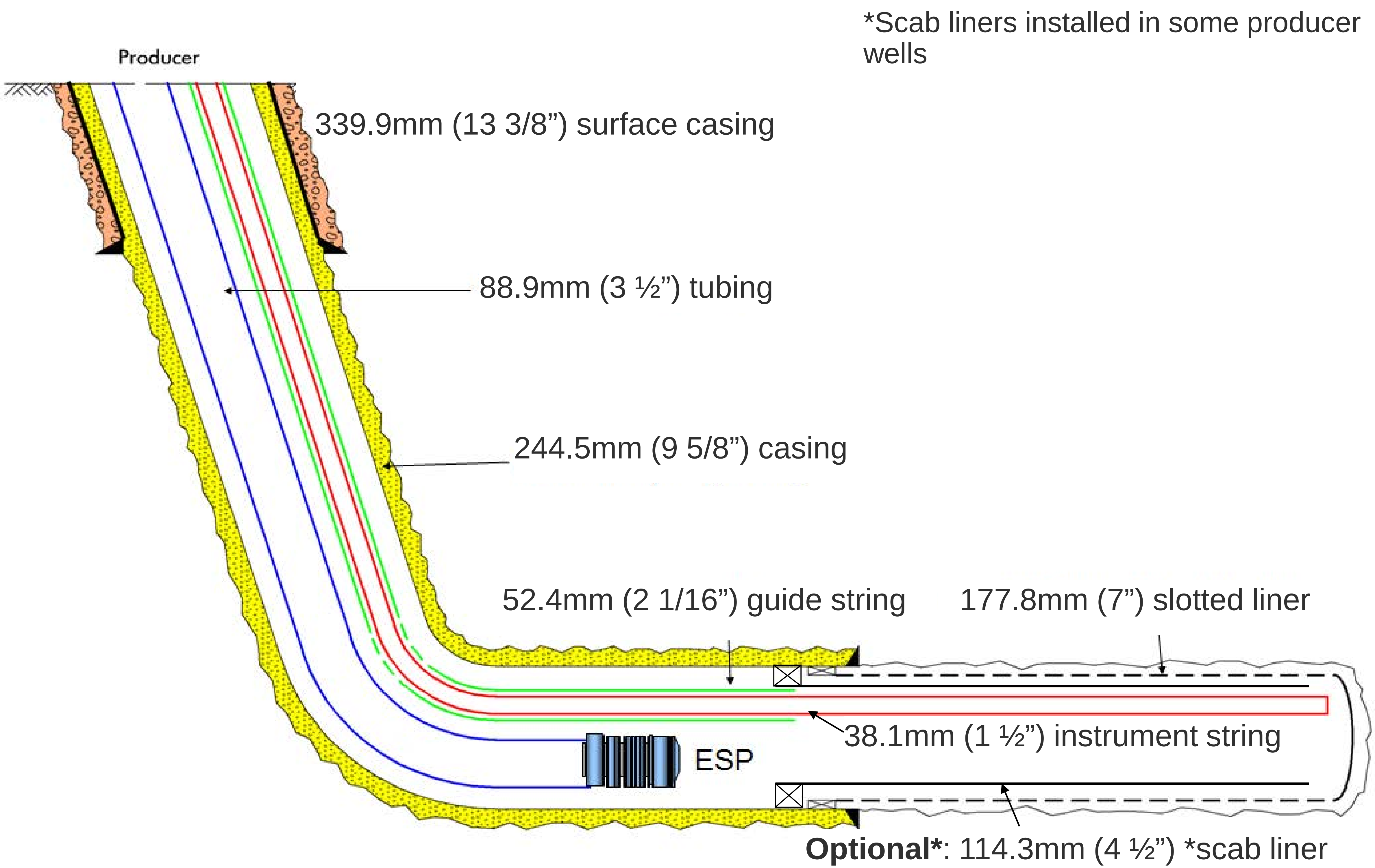
- All Kinosis wells, and a few Long Lake pads are completed with steam splitters in the long injection string
  - Results showing improved temperature conformance in Long Lake wells
- VIT is 139.7mm (5 ½”) or 114.3mm (4 ½”), usually installed to the start of slots



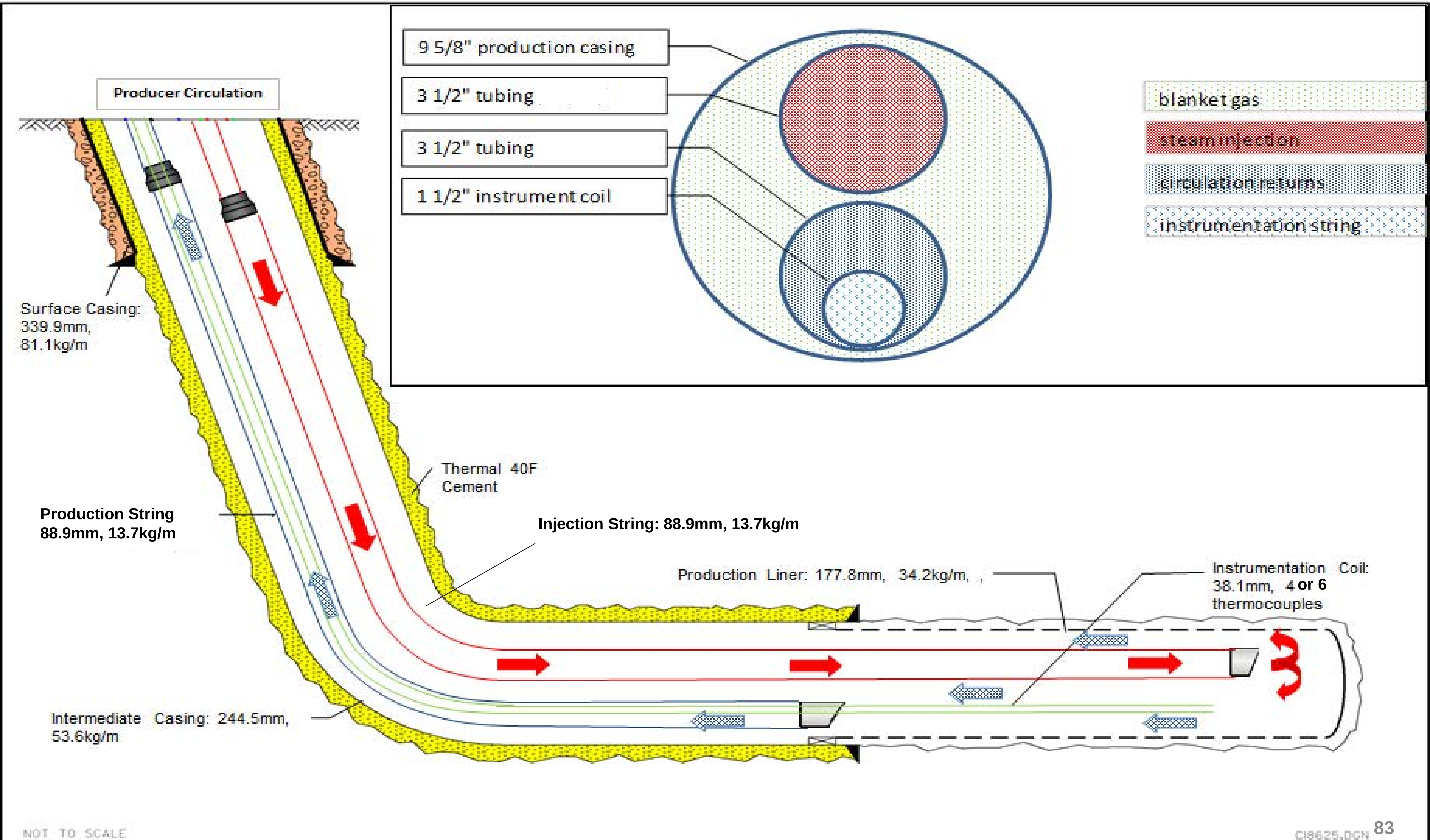
Typical Injector Circulation



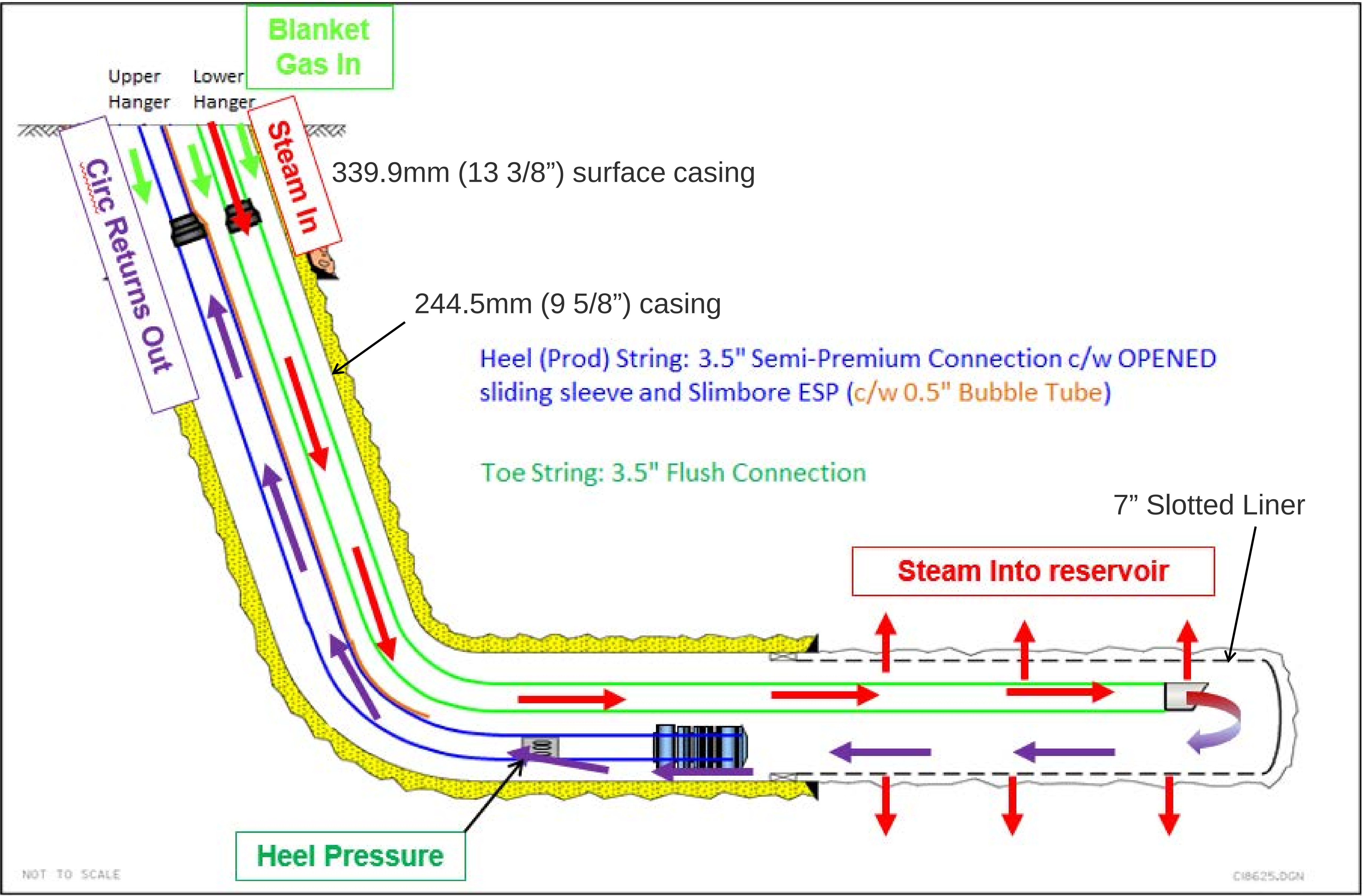
Typical Producer Completions – ESP



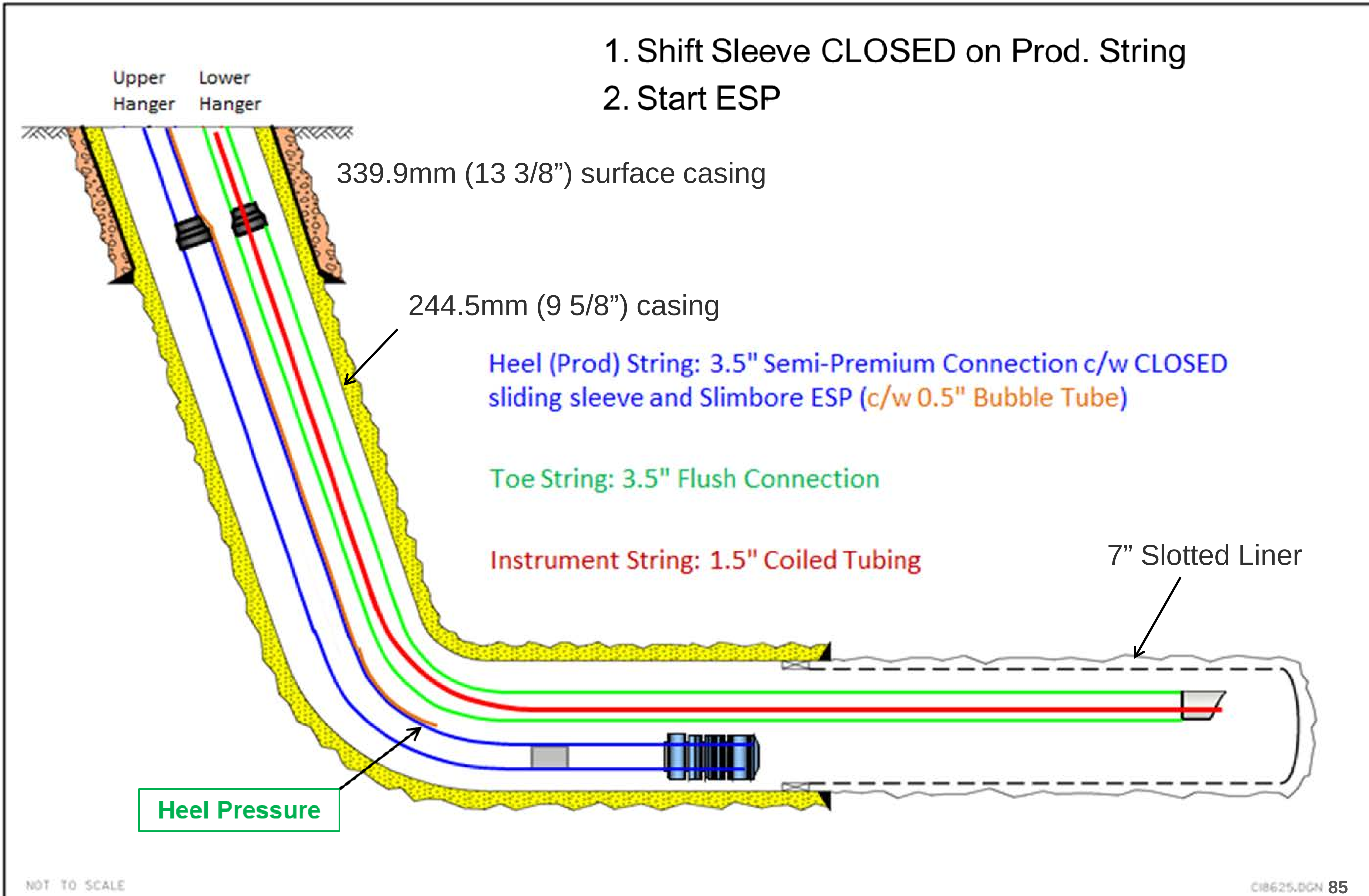
Typical Producer Circulation



Single Producer Completion (SPC) – Circulation Infill Wells



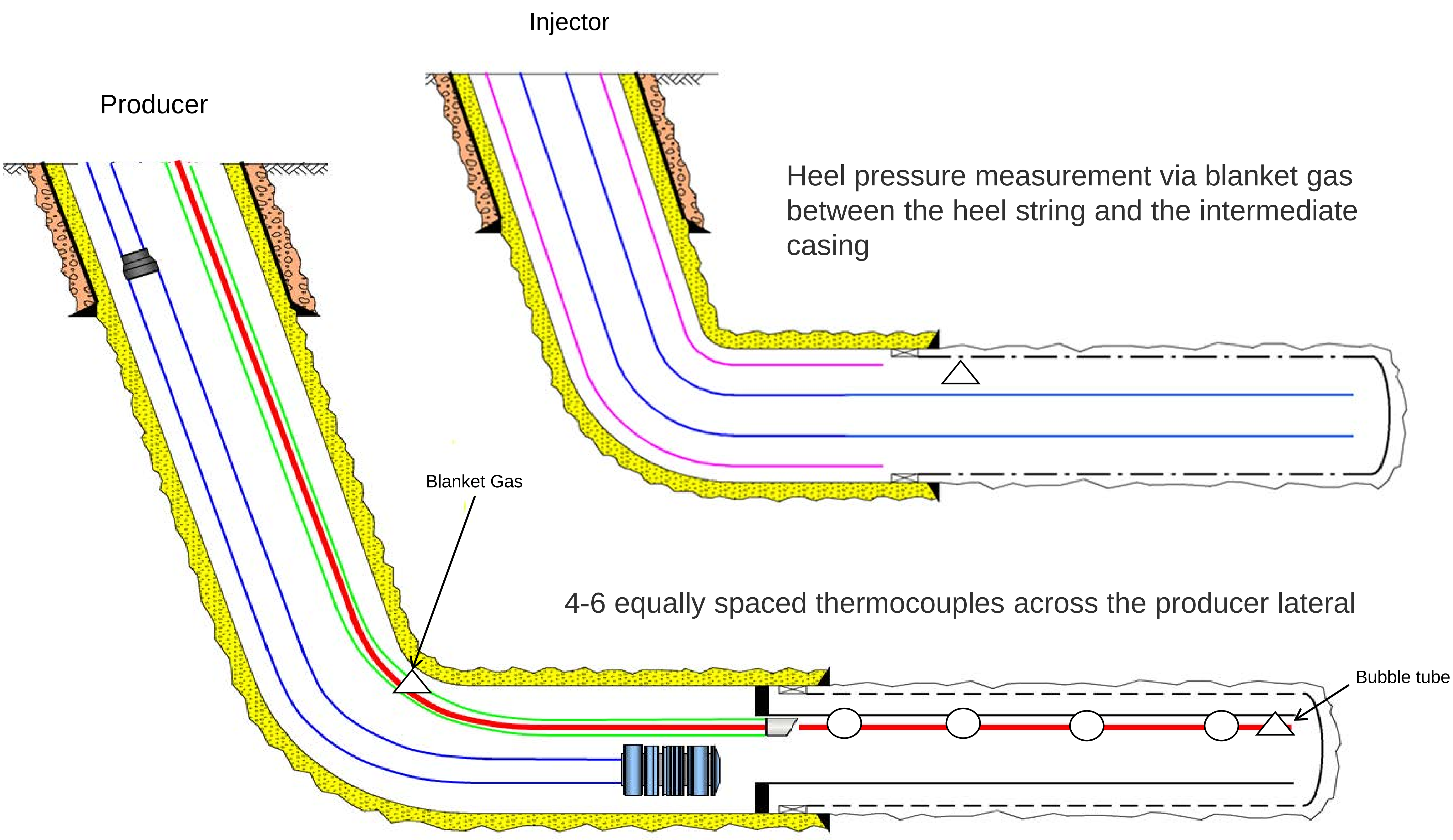
Single Producer Completion (SPC) – SAGD Infill Wells



Artificial Lift Performance

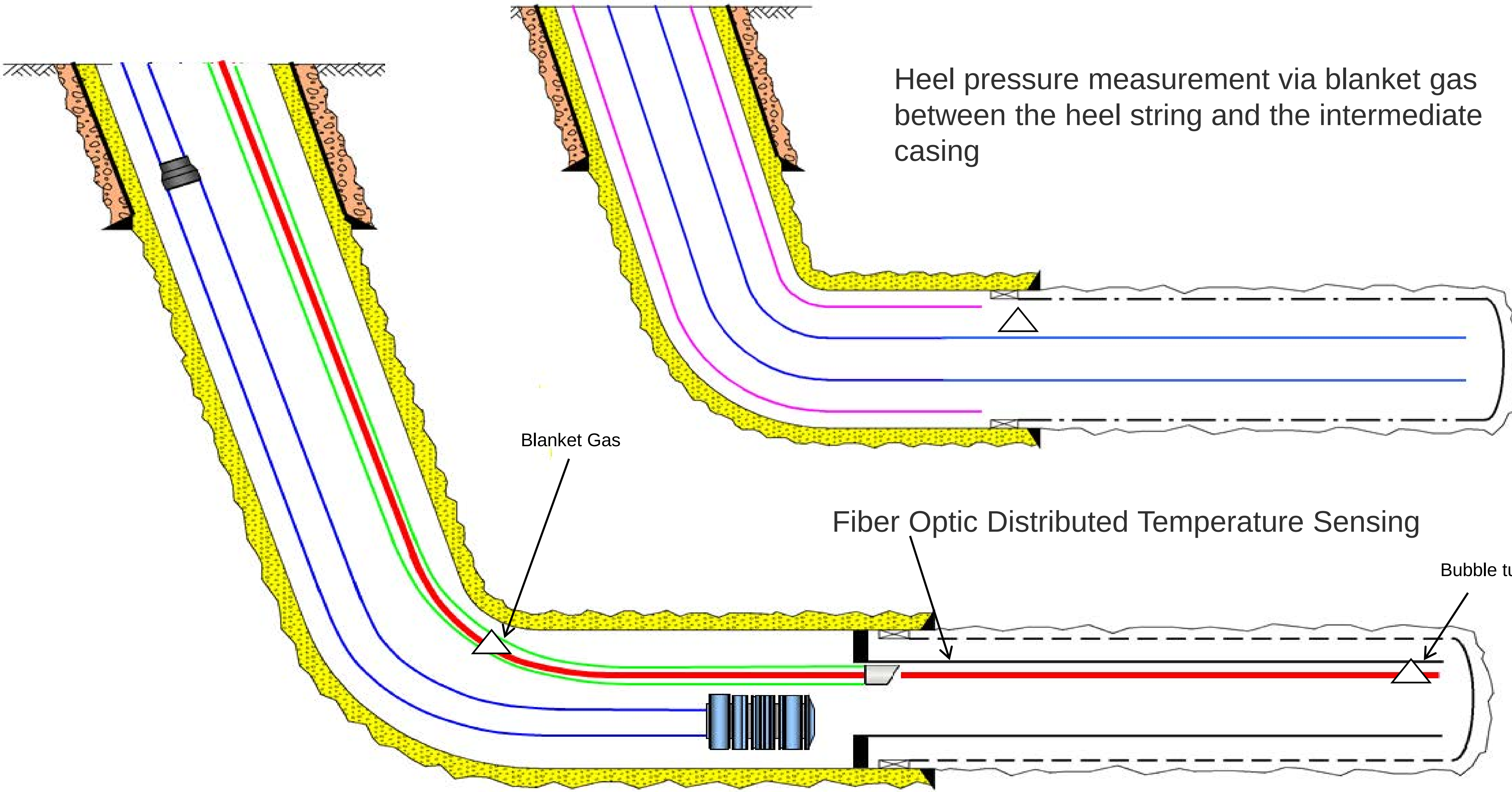
- Original gas lift completions have been converted to artificial lift via Electric Submersible Pumps (ESP) in most SAGD producers to allow production at lower steam chamber pressures.
  - 6 wells currently are on gas lift production
- ESPs installed in 116 SAGD wells:
  - Pump performance (at Dec 31, 2018):
    - Average Run Time: 597 days
    - Mean Time to Failure (cumulative): 930 days
    - Mean Time to Failure change (Dec 2017 – Dec 2018): +4%
  - 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



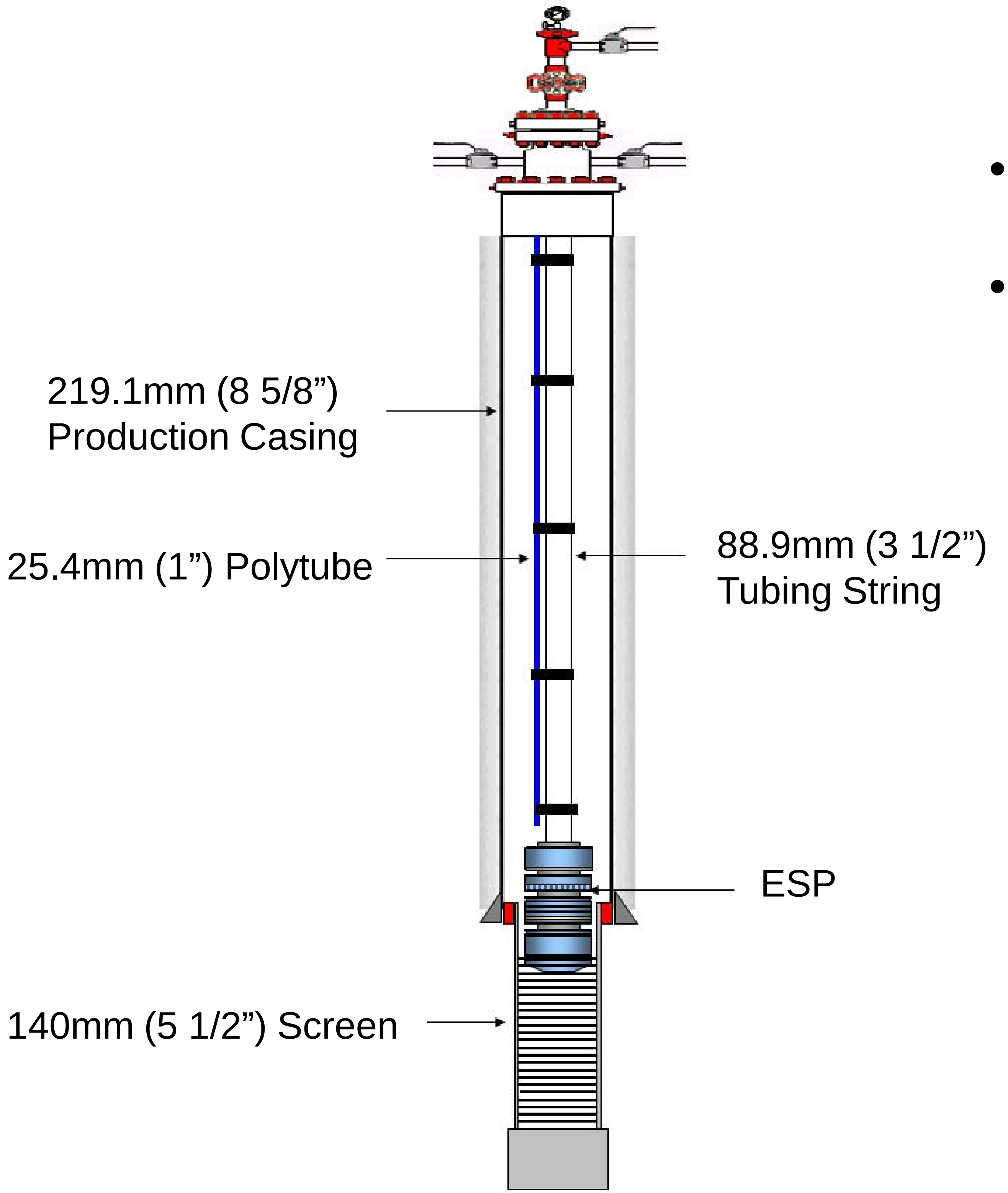
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

Alternate SAGD Instrumentation



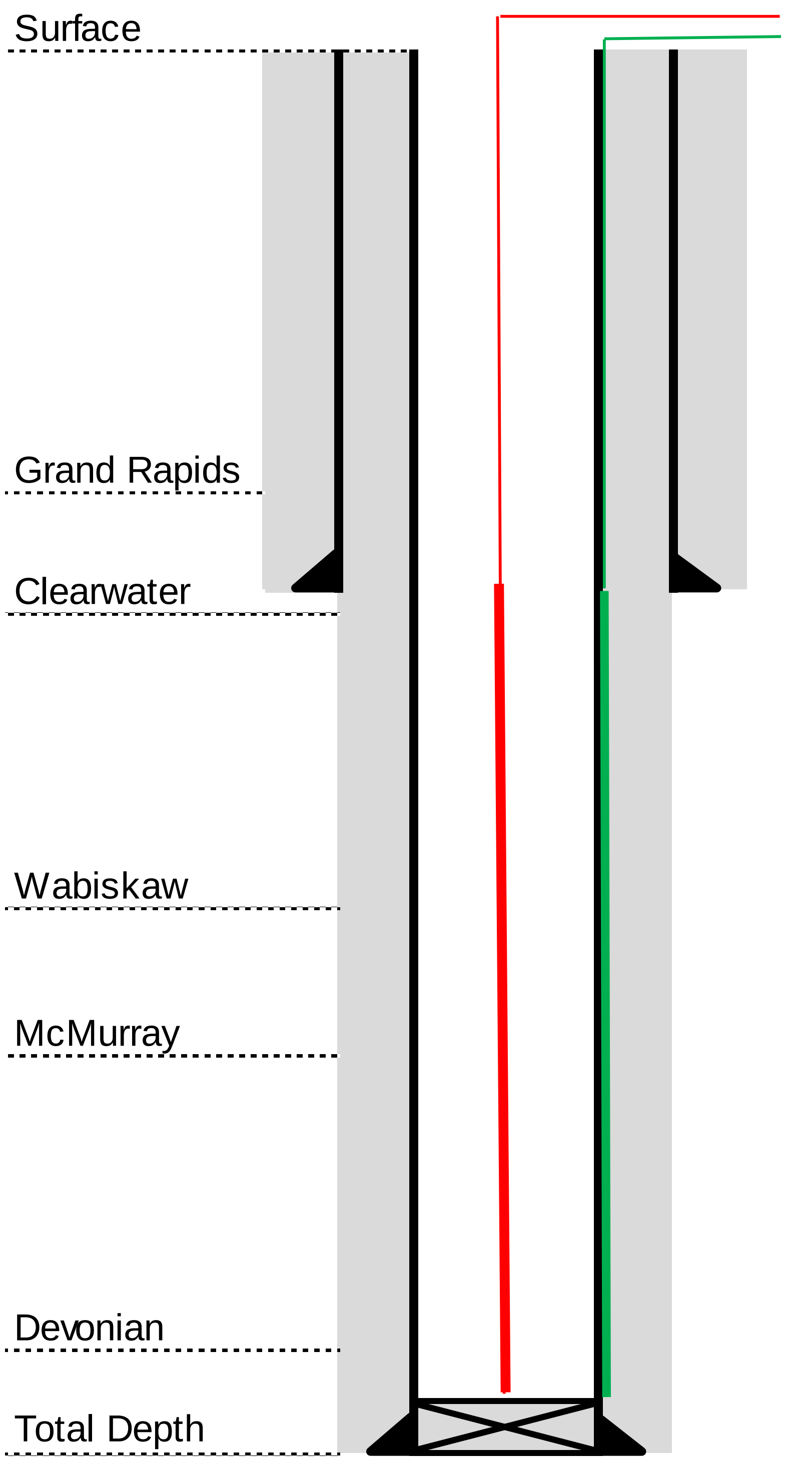
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

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



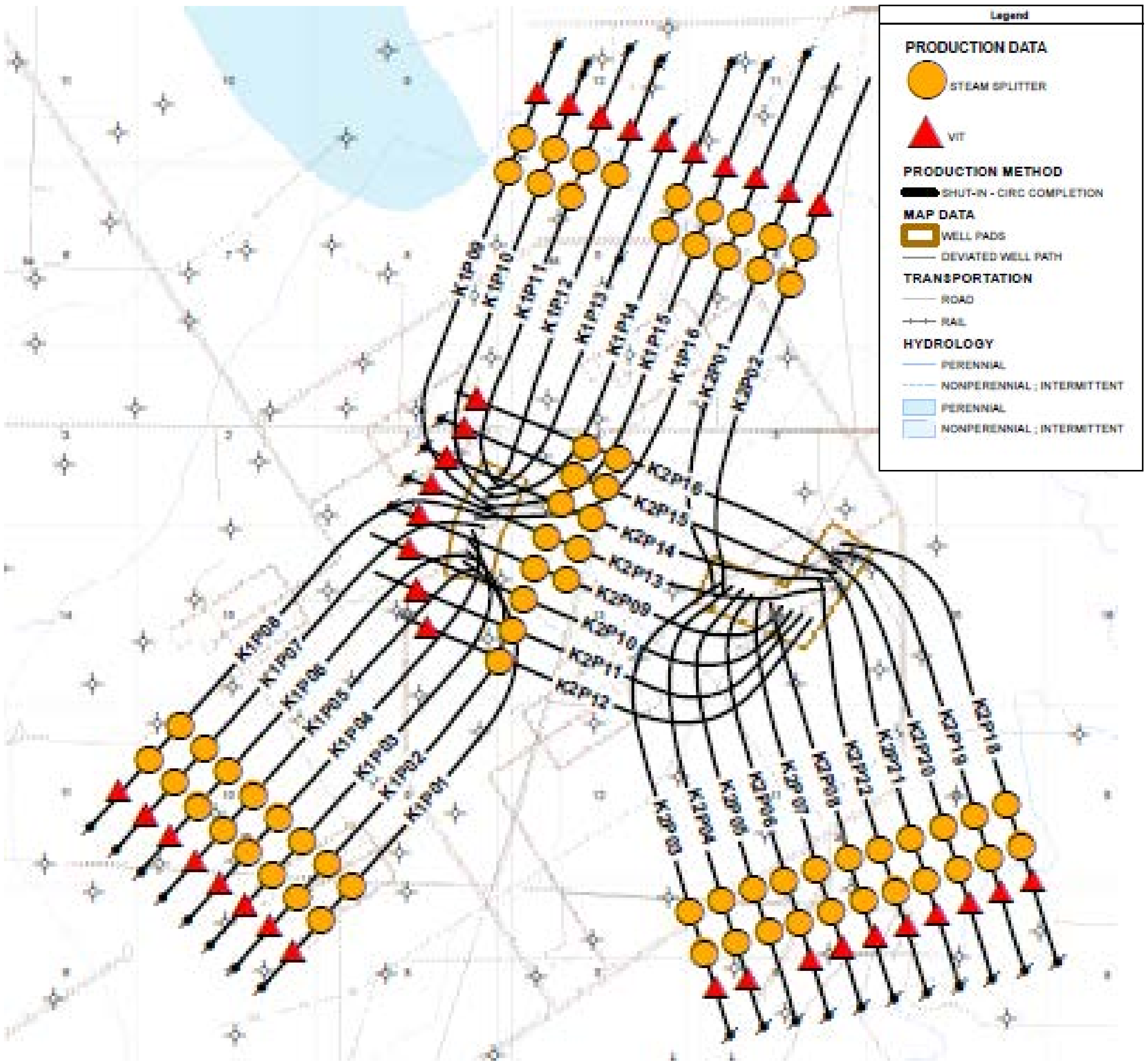
- Cement with Thermal 40 EXP cement
  - Vibrating wire piezometer sensors (green) are strapped outside the production casing providing pressure and temperature measurements
  - Thermocouple strings (red) provide temperature measurements
- Run a CBL on well with pressure pass if required

Drilling and Completions, Artificial Lift and Instrumentation

Subsection 3.1.1 (3,4,5)

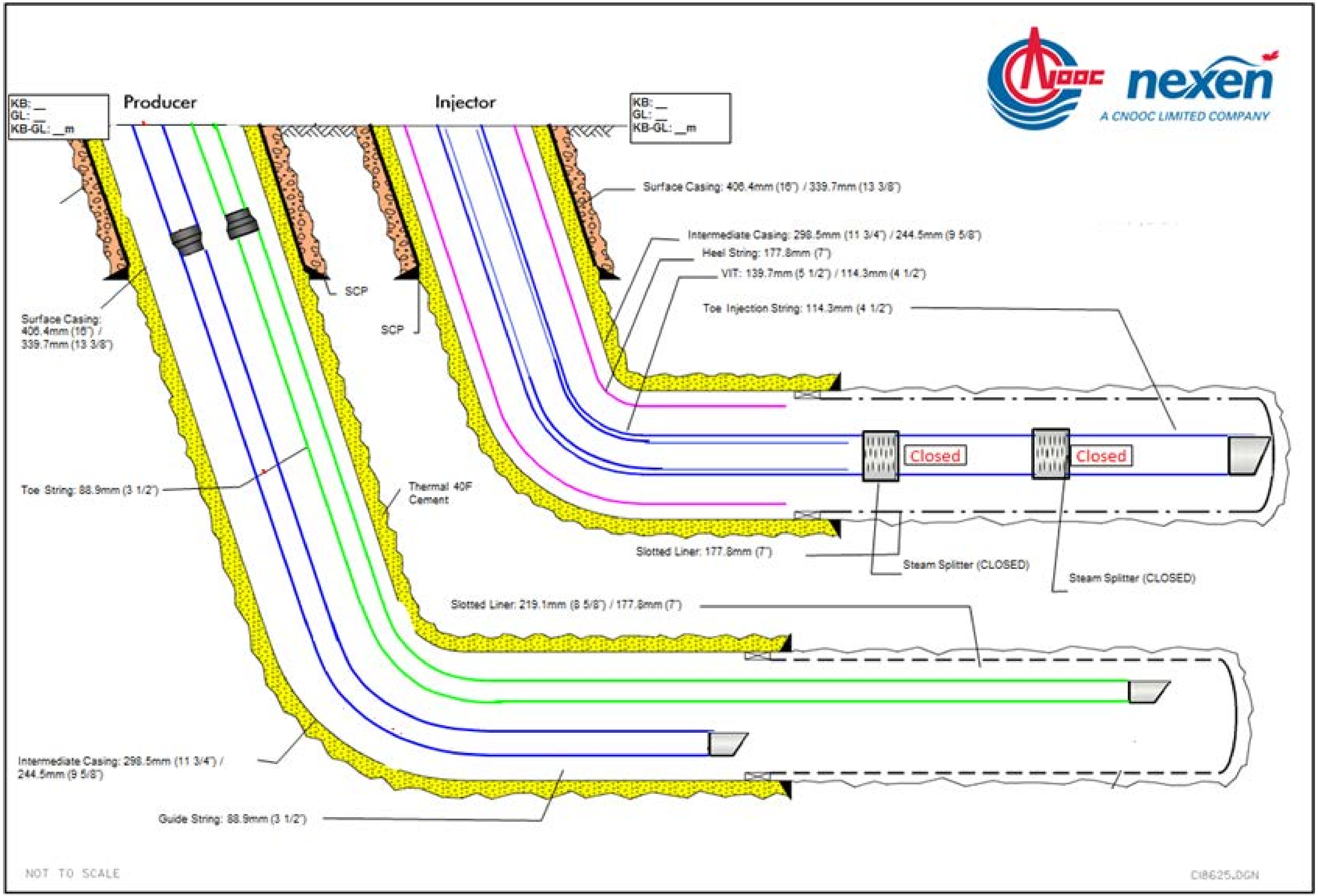
Kinosis

K1A Well Pair Completions Map as of Dec 31, 2018

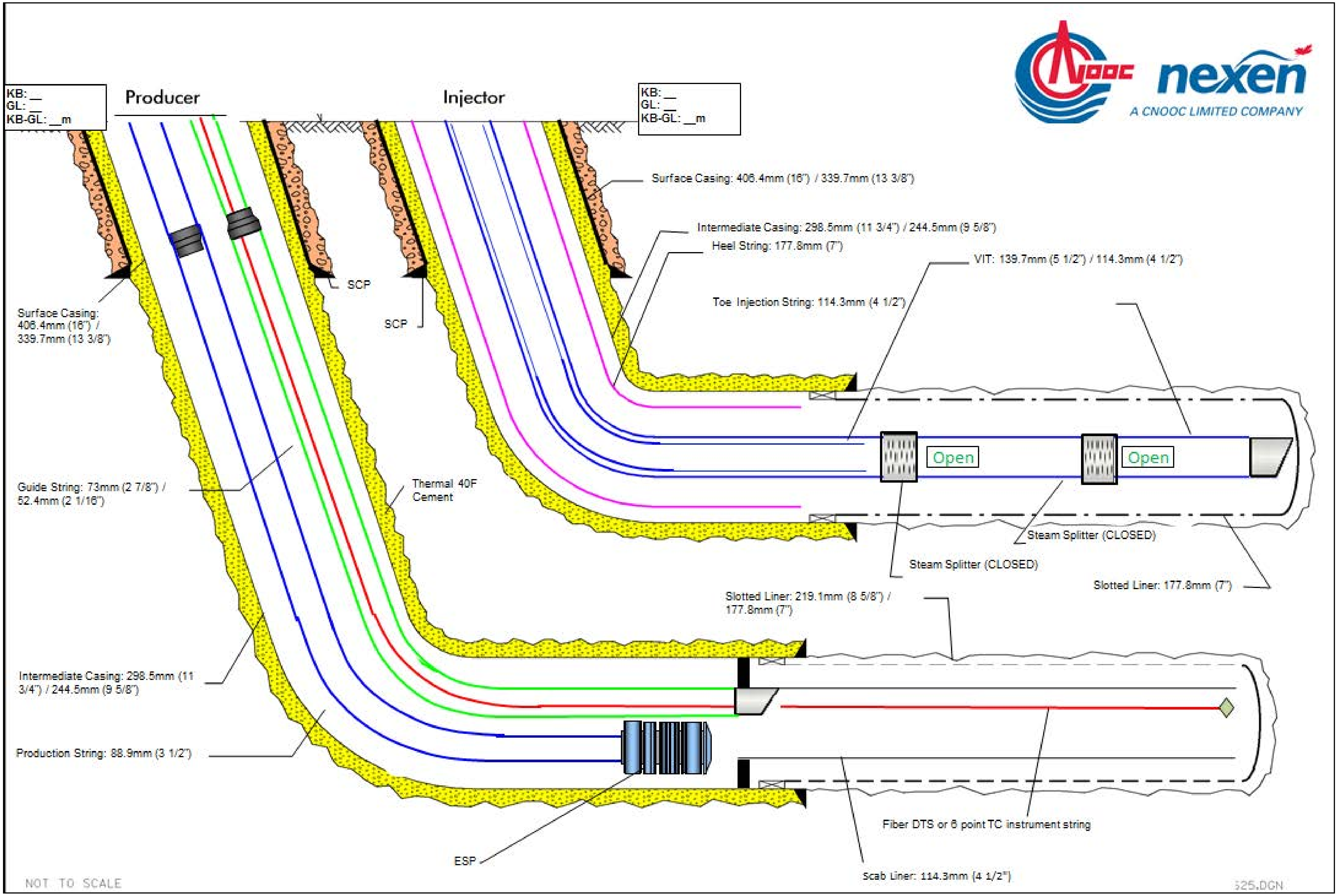


- On Jul. 15, 2015 a line rupture was discovered on the K1A produced emulsion line tie-back to Long Lake CPF.
  - Operations of both the remote steam generation facility (SGF) and well pairs at K1A were subsequently ceased and remain down.
- Status of wells as of Dec. 31, 2018:
  - 36 well pairs remain suspended, however are equipped for circulation.

Typical K1A Completion Schematic Circulation



Typical K1A Completion Schematic SAGD

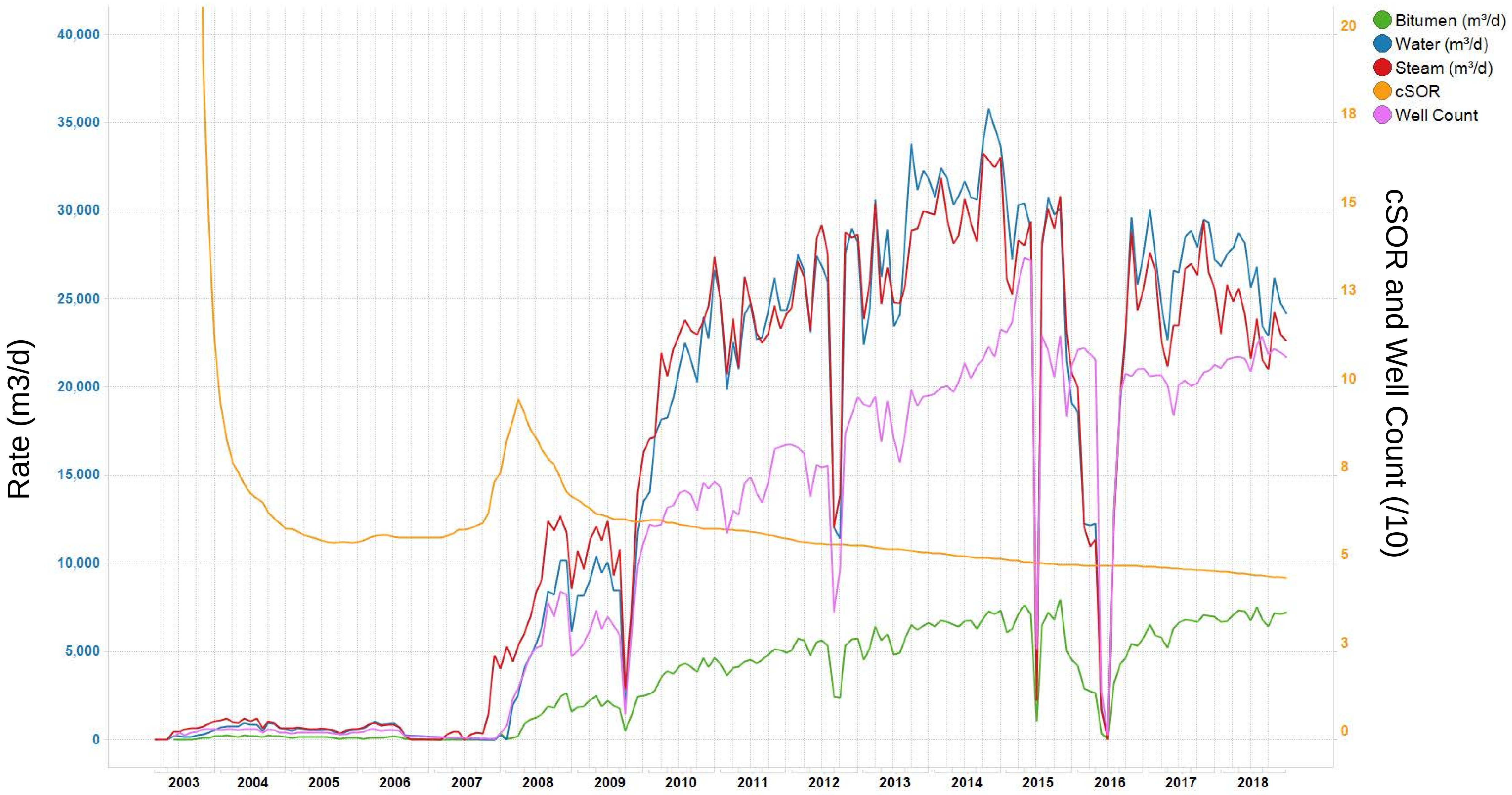


Scheme Performance
Subsection 3.1.1 (7)
Long Lake and Kinosis

Long Lake 2018 Performance

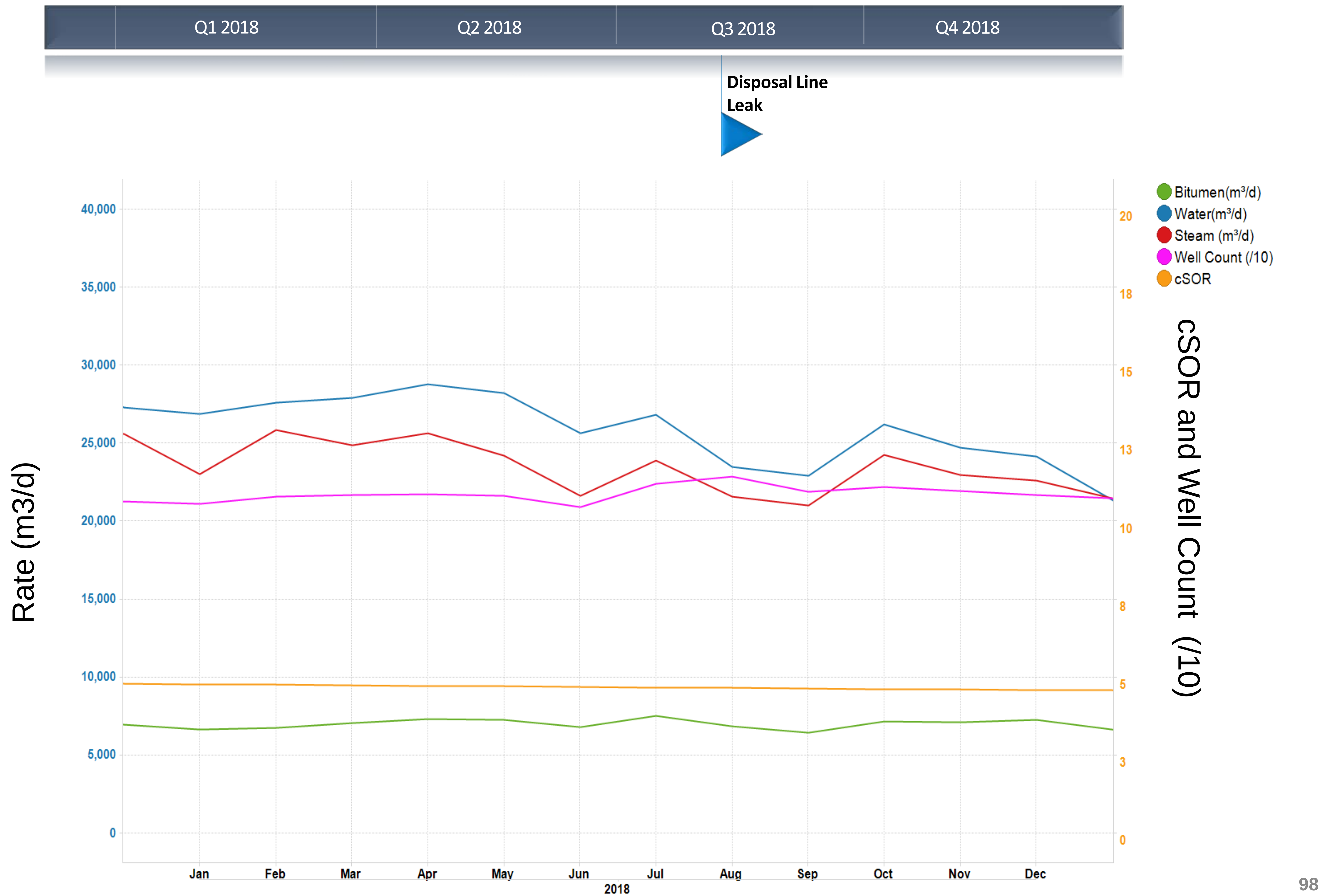
- Commercial SAGD:
  - LLK: 15 pads,120 well pairs; 114 active producing wells at year end
  - K1A: 2 pads, 37 well pairs; 0 active producing wells at year end
- Strong, steady performance exhibited throughout the year
  - Highest annual average production 44,470 bbl/d with lowest SOR of 3.5
- Disposal line outage in August limited production for several weeks
  - The disposal pipeline leak was the result of external corrosion which lead to anodic dissolution of the pipeline. Remediation activities are ongoing and a monitoring plan was submitted to the AER and is currently under review.

Scheme Performance
Field Level



**Graph includes K1A*

Scheme Performance
2018 Field Level Highlights



Scheme Performance
Recoverable Bitumen

Pad	Well Count	Cumulative Production, YE 2018 (e6m3)	EUR (e6m3)	EBIP (e6m3)	SBIP (e6m3)	EBIP		SBIP	
						Current RF	Estimated Ultimate RF	Current RF	Estimated Ultimate RF
LL-001	5	1.3	1.6	2.3	2.7	56%	72%	47%	60%
LL-002NE	6	0.9	1.3	2.3	3.2	38%	56%	27%	41%
LL-002SE	5	0.3	0.3	1.2	1.5	27%	28%	21%	23%
LL-003	5	1.4	1.9	2.7	3.8	50%	71%	36%	51%
LL-004	2	0.1	0.1	0.2	0.2	66%	66%	56%	56%
LL-005*	8	1.7	2.1	3.4	3.0	49%	62%	55%	70%
LL-006N	6	0.9	1.2	3.6	4.4	25%	34%	20%	28%
LL-006W	7	0.9	1.0	1.9	2.9	47%	54%	30%	35%
LL-007E	7	0.8	1.0	2.3	1.9	37%	46%	45%	55%
LL-007N*	9	2.5	3.1	3.6	4.1	70%	88%	61%	76%
LL-008*	10	1.6	2.4	3.5	3.3	46%	69%	49%	74%
LL-009NE	5	0.3	0.3	1.2	1.8	22%	25%	15%	17%
LL-009W	5	0.5	0.6	1.8	2.0	27%	33%	24%	29%
LL-010N	8	0.4	0.5	2.7	3.7	14%	19%	10%	14%
LL-010W	5	0.8	1.3	2.4	2.8	34%	53%	29%	46%
LL-011	10	1.4	1.7	2.4	3.0	59%	69%	48%	56%
LL-012	9	1.0	2.0	3.4	4.6	31%	58%	23%	43%
LL-013	9	1.4	2.1	3.3	4.3	41%	63%	32%	49%
LL-014/15E	6	0.4	0.8	1.3	1.9	31%	58%	21%	39%
LL-014N	3	0.4	0.7	1.4	1.8	28%	47%	22%	38%
LL-015S	2	0.2	0.3	0.6	0.7	31%	49%	27%	42%
K1A-A	9	0.0	2.5	4.3	5.8	0%	58%	0%	43%
K1A-B	8	0.0	2.2	3.9	4.8	0%	56%	0%	46%
K1A-C	8	0.1	3.0	5.1	6.4	2%	59%	2%	47%
K1A-D	11	0.0	3.0	5.3	7.0	1%	56%	1%	43%
Total	**168**	**19.3**	**37.1**	**66.1**	**81.6**	**29%**	56%	24%	45%

* Includes infill producers

Scheme Performance
Maximum Operating Pressures (MOP)

Field	Pad	Maximum (Reservoir) Operating Pressure (kPag, unless noted otherwise)
LLK	1	2950
LLK	2NE	2950
LLK	2SE	2950
LLK	3	2950
LLK	4	2950
LLK	4P5, 4P6	2600
LLK	5	2950
LLK	5P5	2950
LLK	9NE	2950
LLK	6N	2950
LLK	6W	2950
LLK	7N	2950
LLK	7E	2950
LLK	8	2950
LLK	9W	2950
LLK	10N	2950
LLK	10W	2950
LLK	11	2950
LLK	12	2,350 kPaa
LLK	13	2,350 kPaa
LLK	*14	2000 (at Dec 2018)
LLK	*15	2000 (at Dec 2018)
LLSW	16S	2750
LLSW	16W	2567
LLSW	17	2586
LLSW	18N	2586
LLSW	18W	2666
K1A	A	2000
K1A	B	3000
K1A	C	3000
K1A	D	3000

* 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.

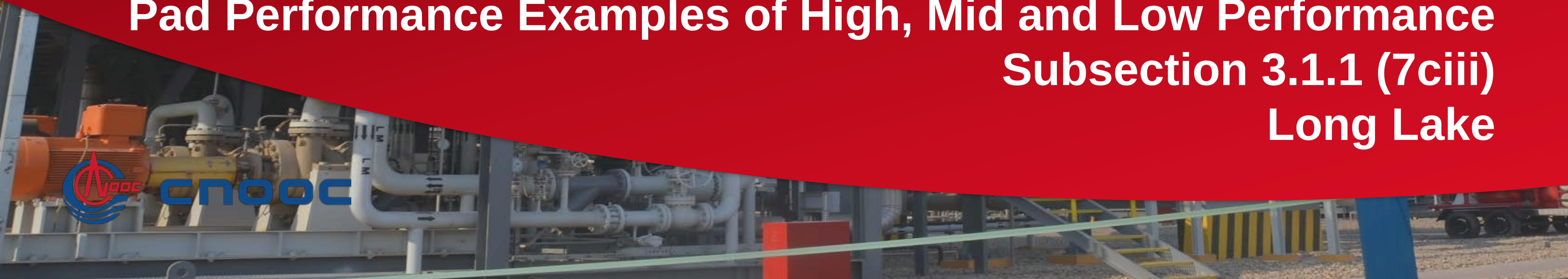
- Steam quality will be affected by injection header length. Pads 12/13 were modeled as these Pads represent the greatest header length from the CPF.

- 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

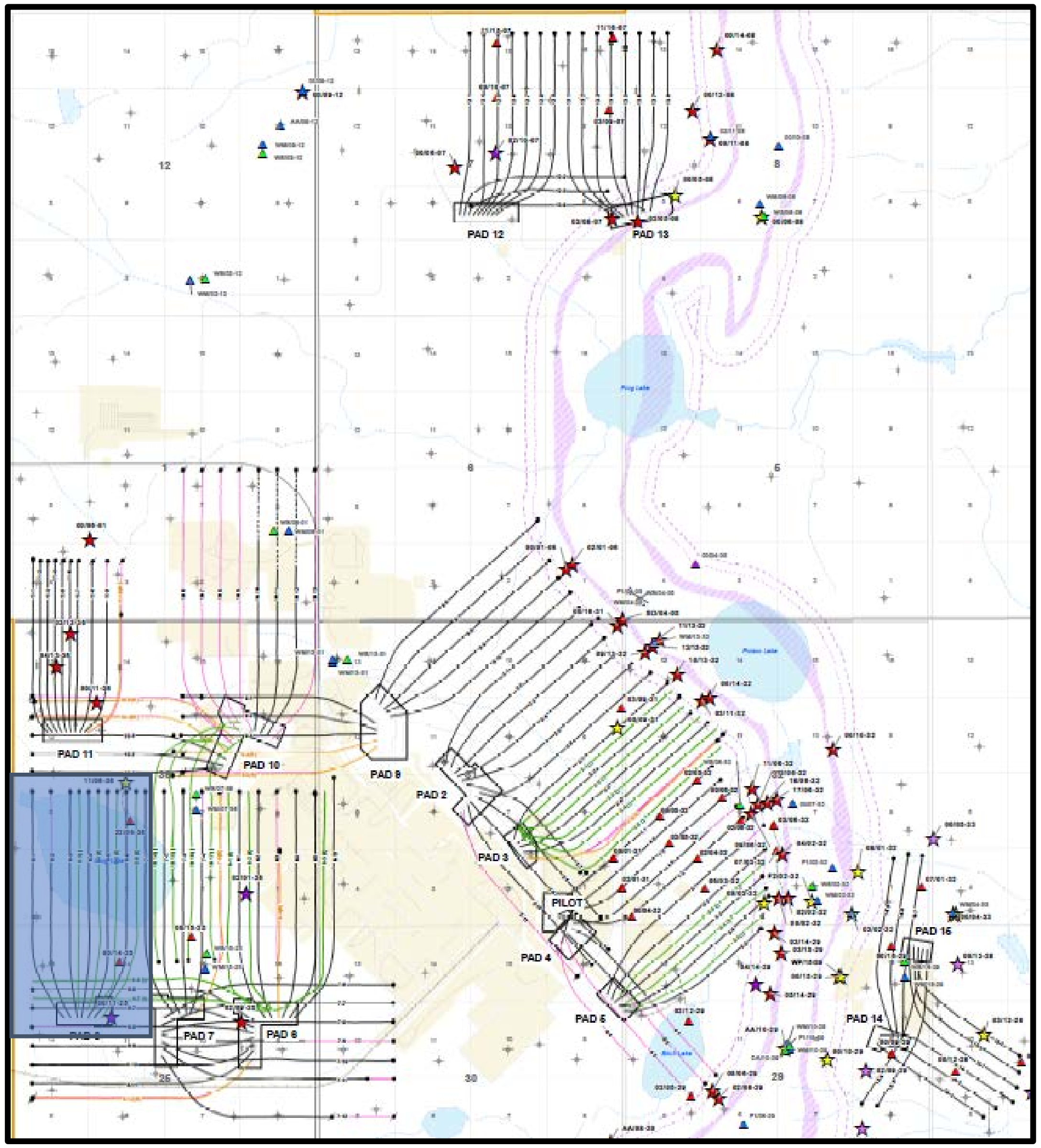


Examples of High, Mid, Low Recovery
High level comparison

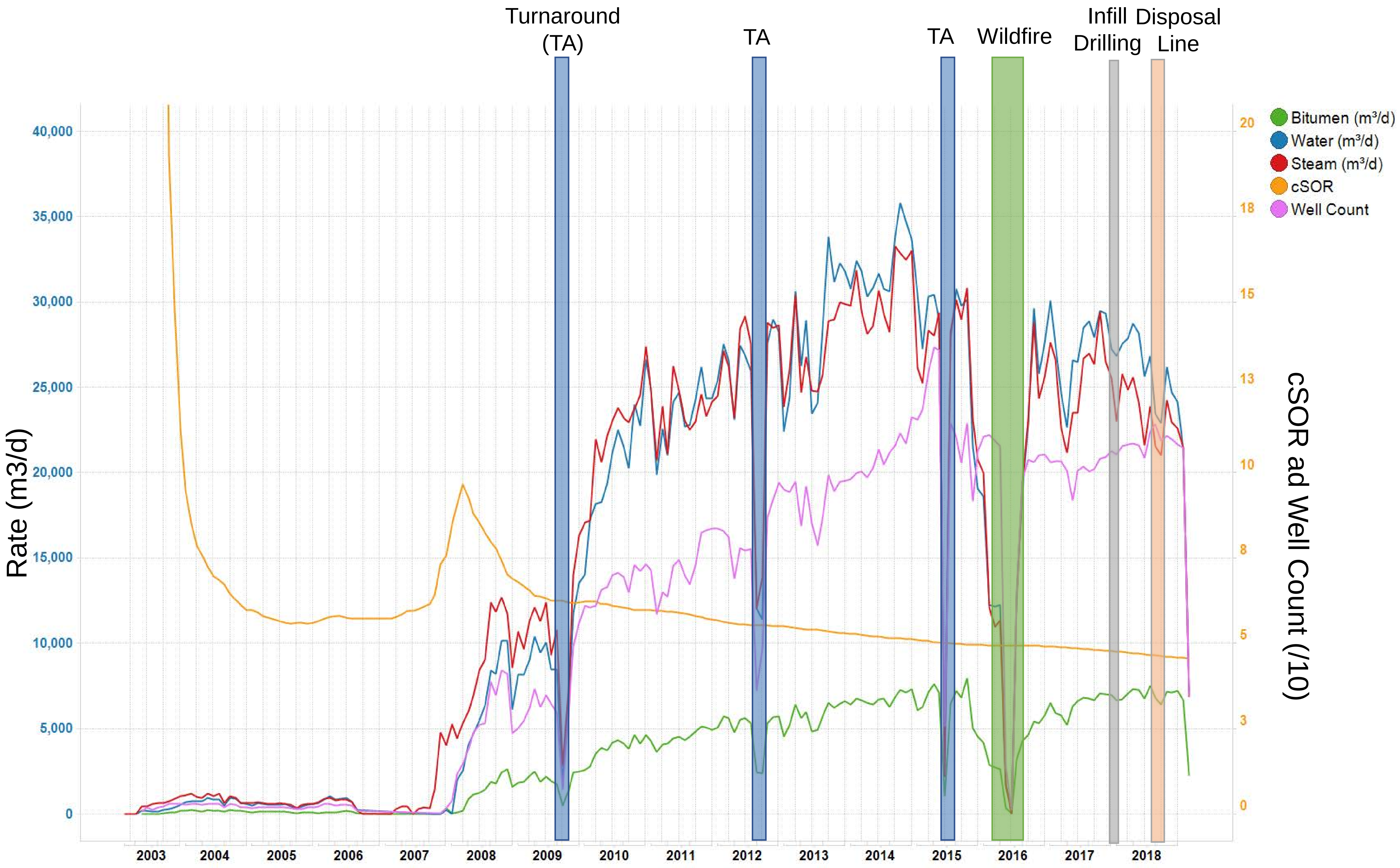
	Resource Quality (mapped average)	Performance	Operating Strategy
Pad 8 *High*	EBIP thickness: 31m S_{we}: 0.39	Well Peak Rate: 308m^3/d Current Pad EBIP RF: 46%	Infills on production July 2018
Pad 14N *Mid*	EBIP thickness: 23 m S_{we}: 0.22	Well Peak Rate: 141m^3/d Current Pad EBIP RF: 28%	LLK sustaining 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: 14%	Low priority, 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 has been producing with ICDs since December 2015
  - 8P06 has been producing without an injector since April 2015
- Four infill wells commenced production in July 2018
- Limited seismic data available due to surface lake
- Pad 8 is impacted by top water and lean zone; current operating pressure is lower than pressure in top water and lean zone
- YE 2018 EBIP RF is 46%

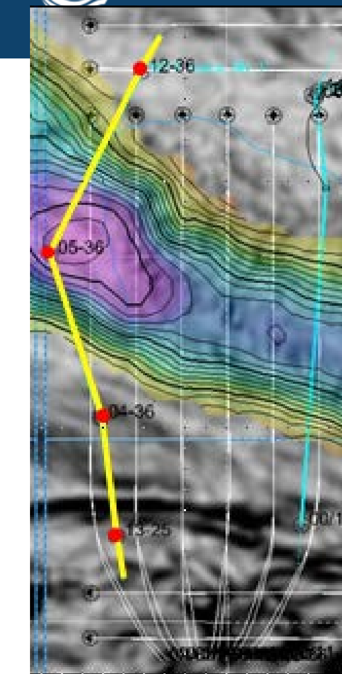


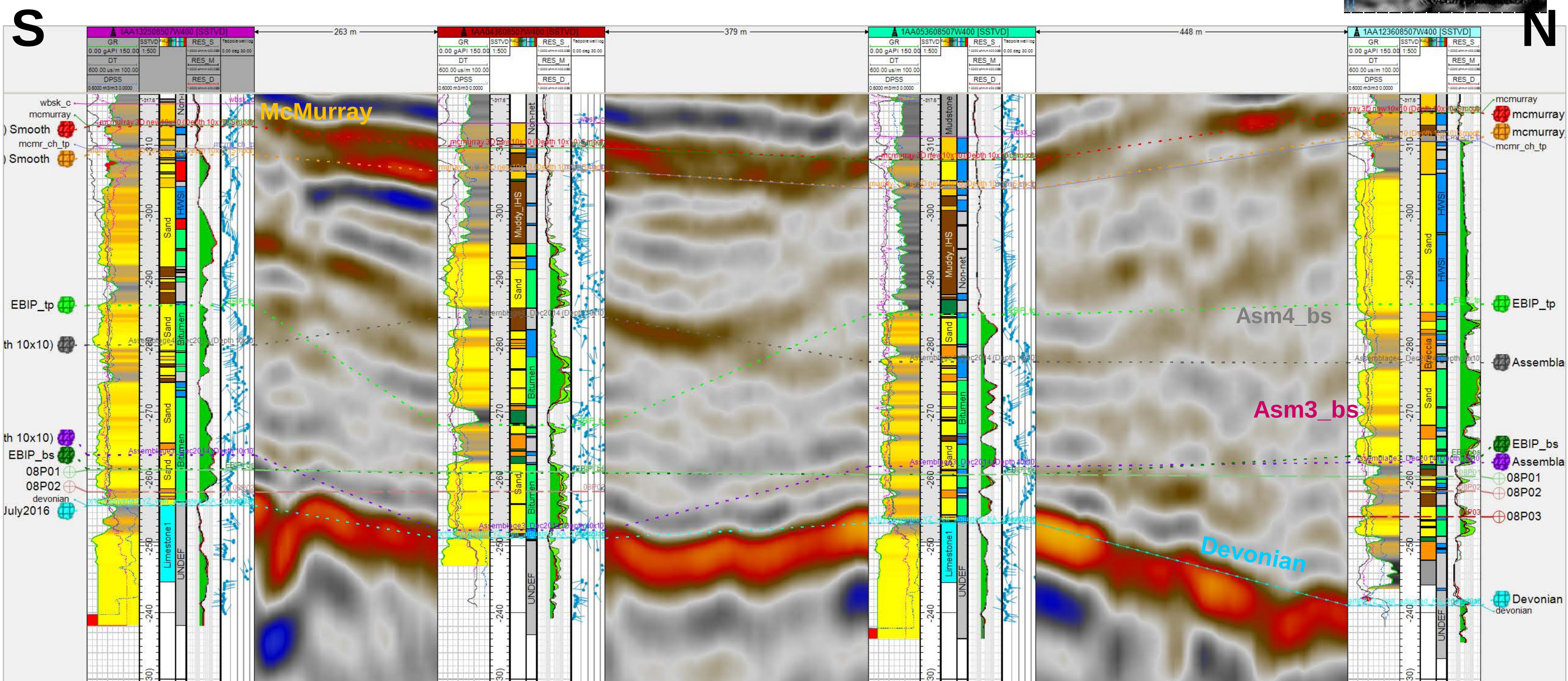
Example of High Recovery
Pad 8



Example of High Recovery
Pad 8 – Geology

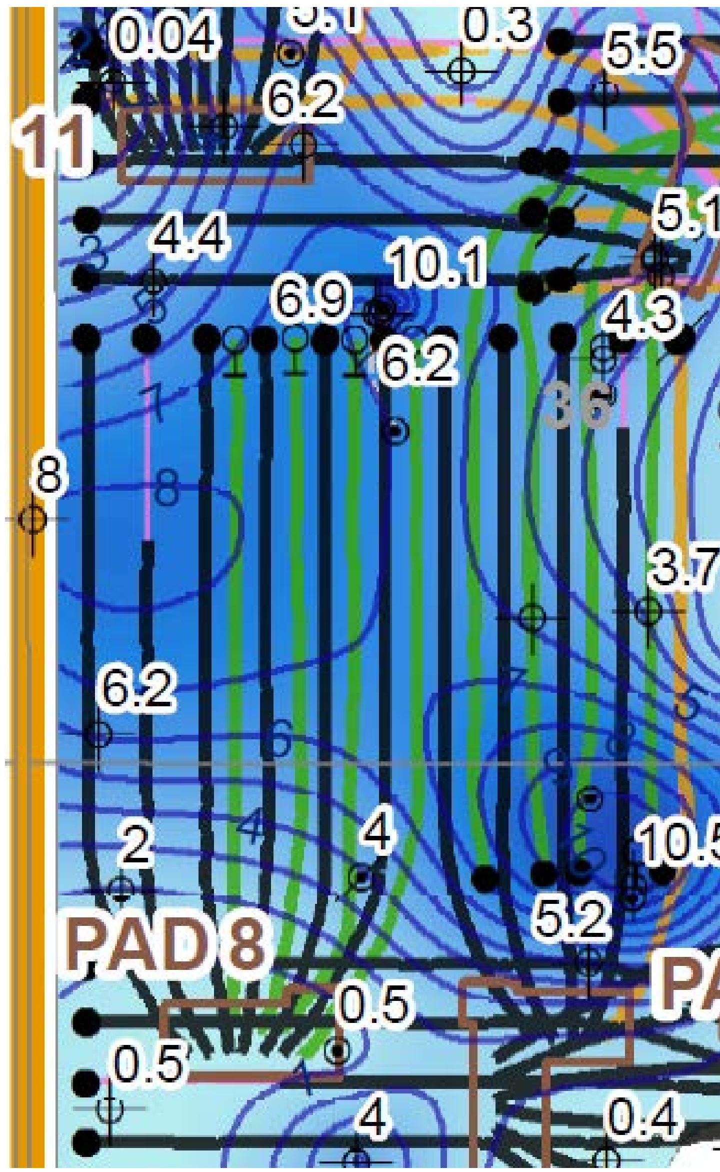
- Reservoir quality gets better from west to east on Pad 8
- Regional G&G study helps on Devonian structure interpretation in the area with no or unreliable seismic data
- Limited stranded pay below producers



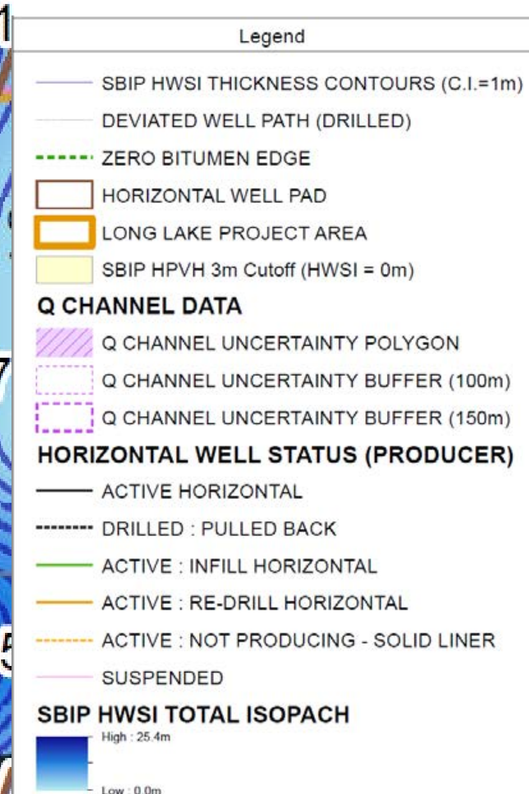


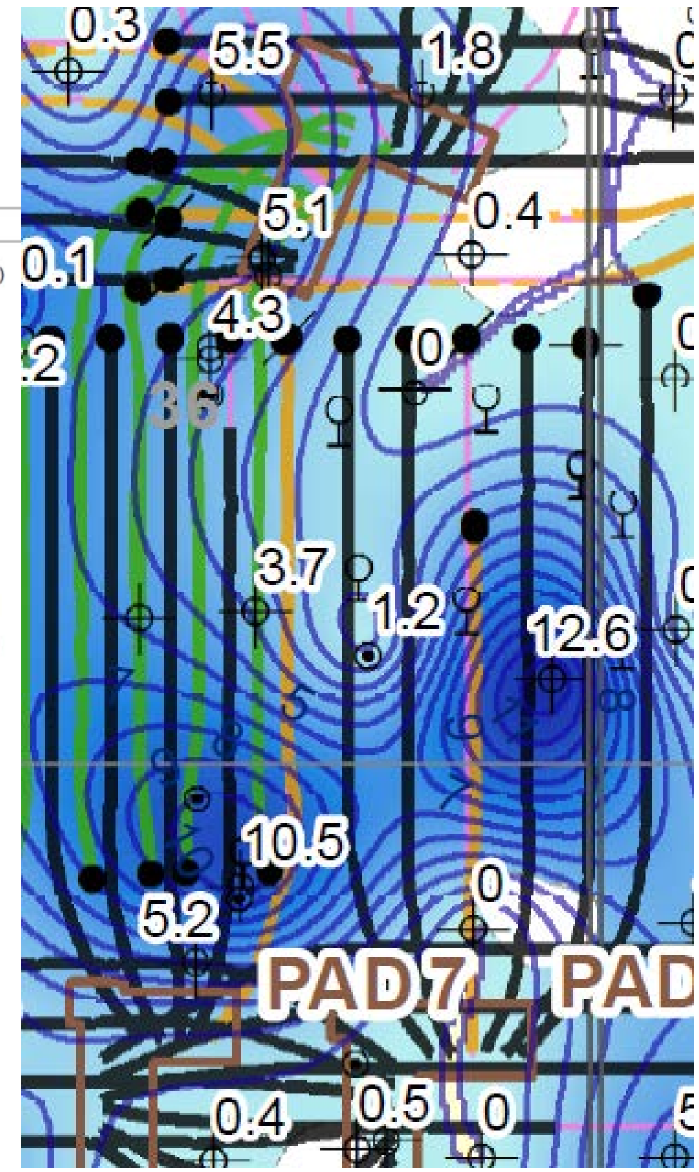
Example of High Recovery
Pad 8 – Geology

- Pad 8 toes are in connection with extensive water saturated intervals
- Top water is truncated by the mudplug cutting across Pads 8 and 7N



Top Water Associated with SBIP Interval

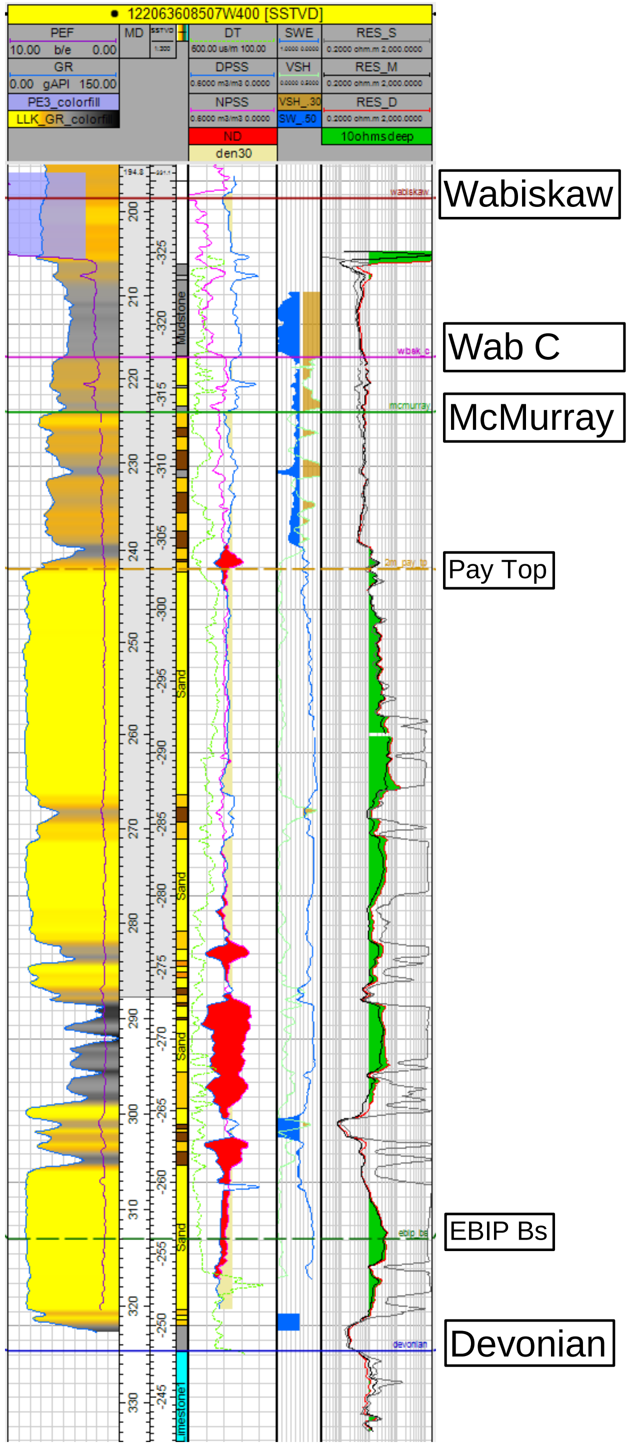




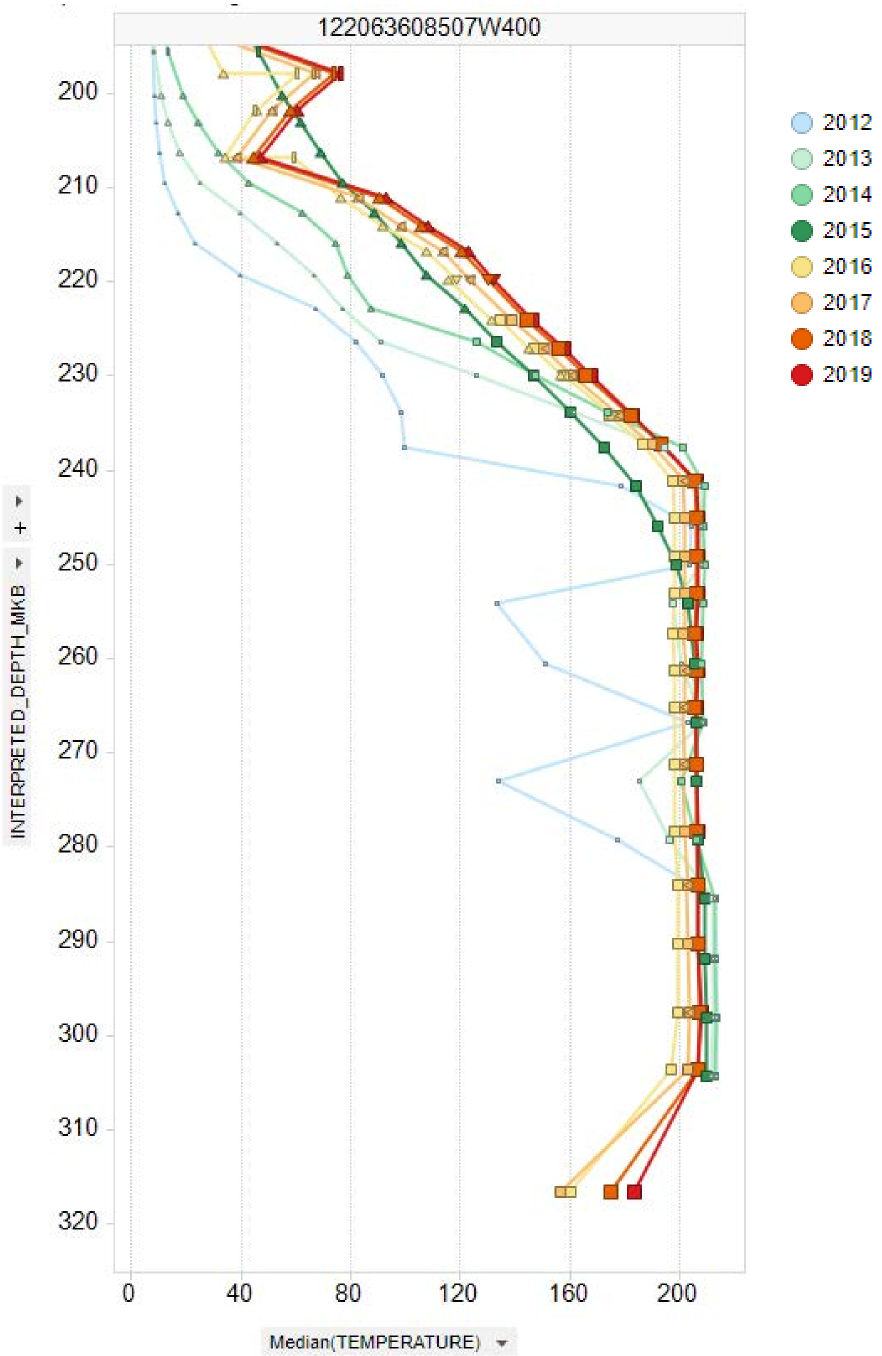
Cumulative Thickness of High Water Saturation Interval(s) within EBIP Interval

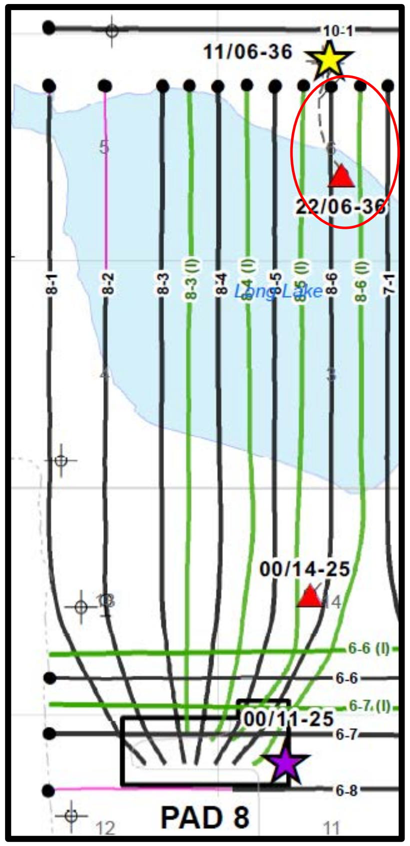
Example of High Recovery
Pad 8 – Monitoring

- 122/06-36
  - Deviated obs well drilled to avoid the surface lake



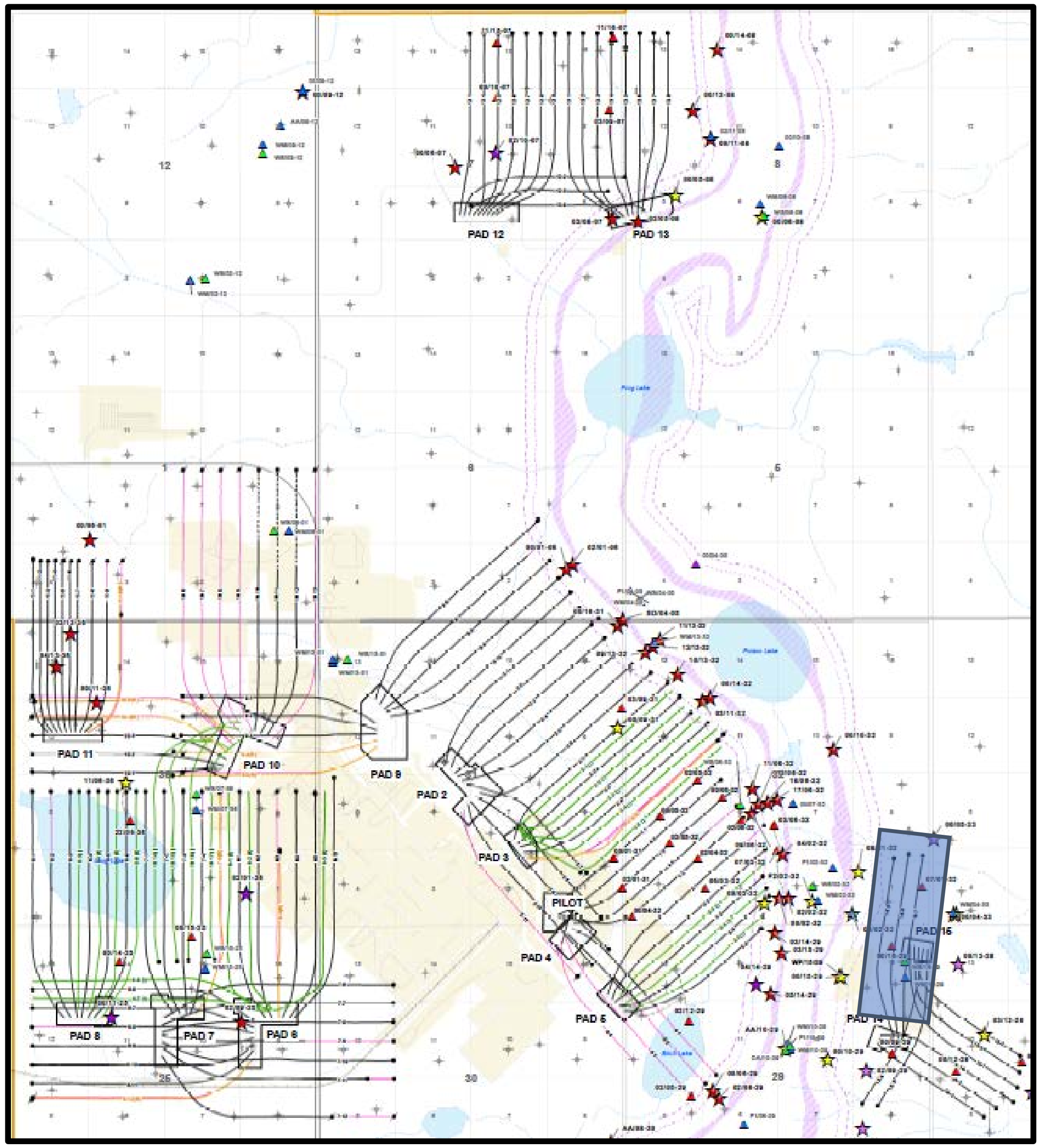
122/06-36 (08P06 offset)



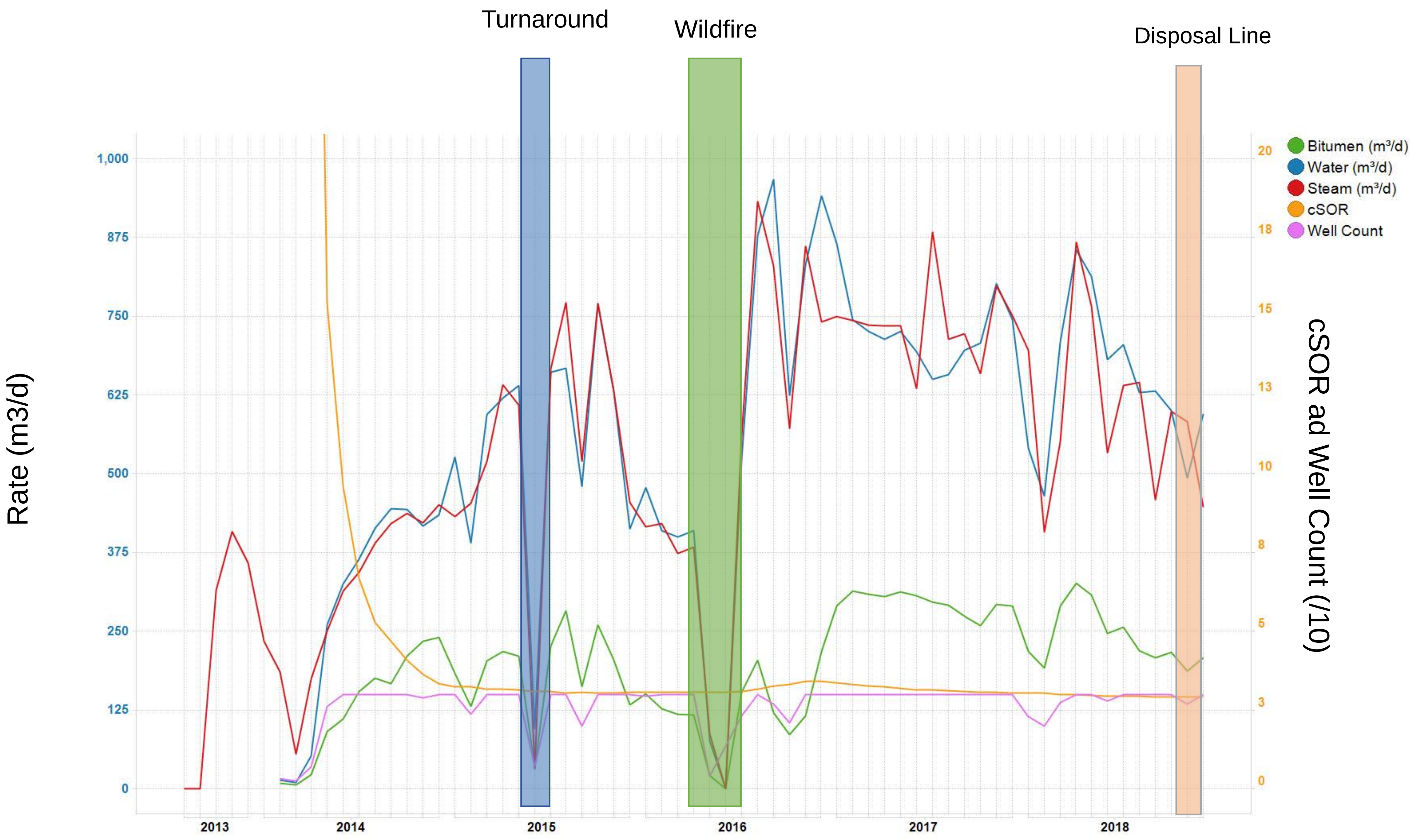


Example of Mid Recovery
Pad 14N

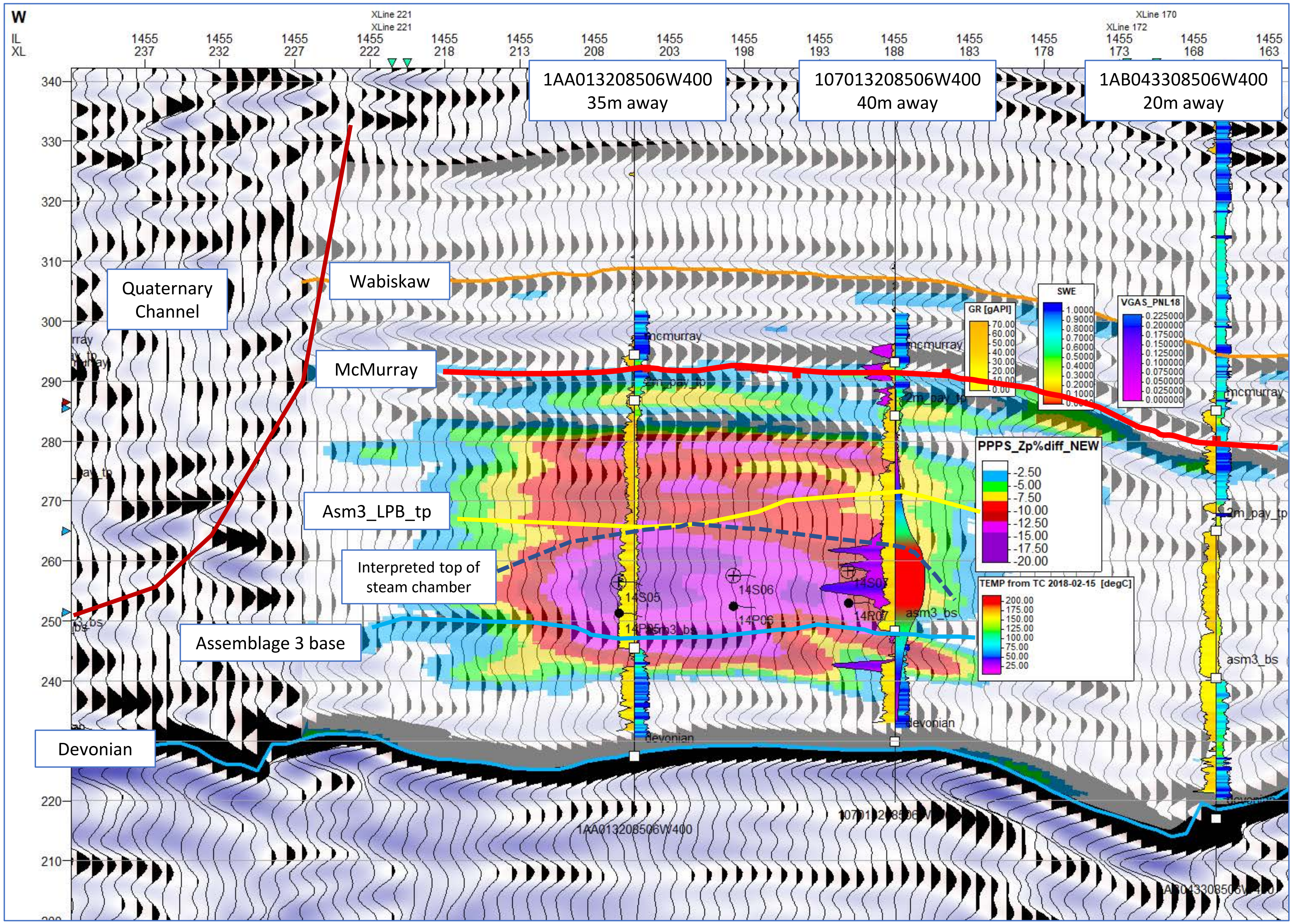
- Sustaining well pad, drainage area with 3 well pairs:
  - All wells equipped with ESPs
  - 75 m spacing
  - Sand control trial
- First oil production Q1 2014
- Due to complex reservoir, pad is operated in accordance with tapered pressure schedule and at/below Q-channel pressure
- YE 2018 EBIP RF is 28%

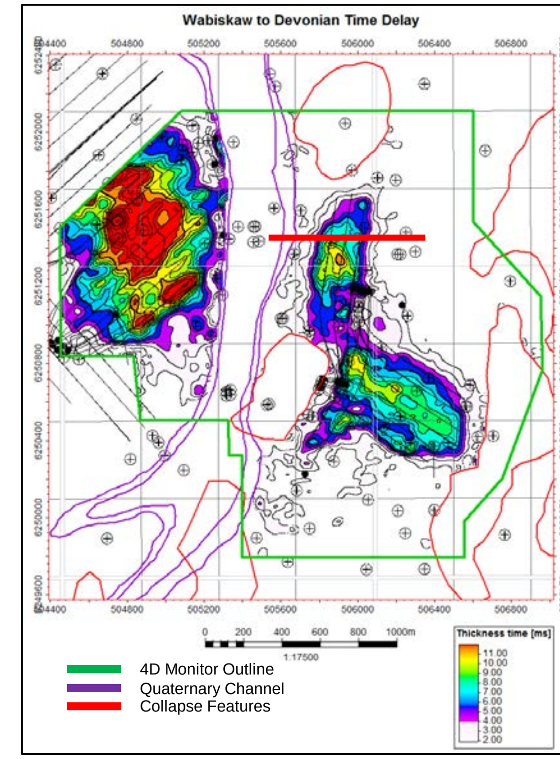


Example of Mid Recovery
Pad 14N

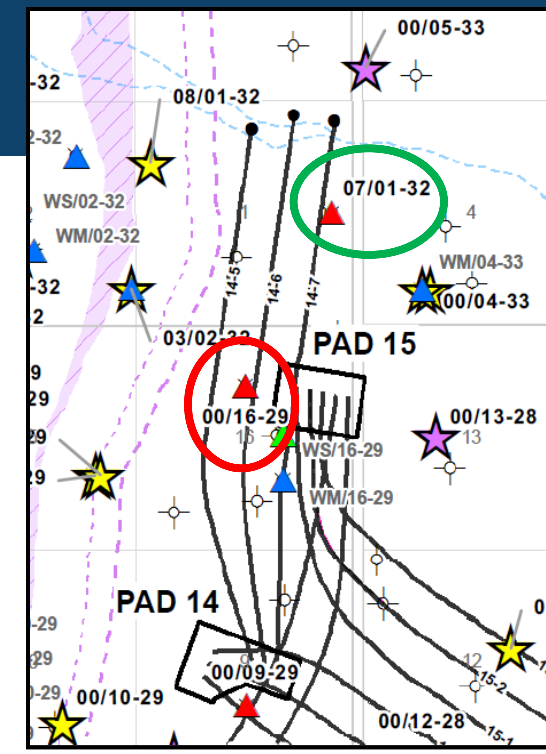


Example of Mid Recovery
Pad 14N - Geology & Geophysics, Inline 1455



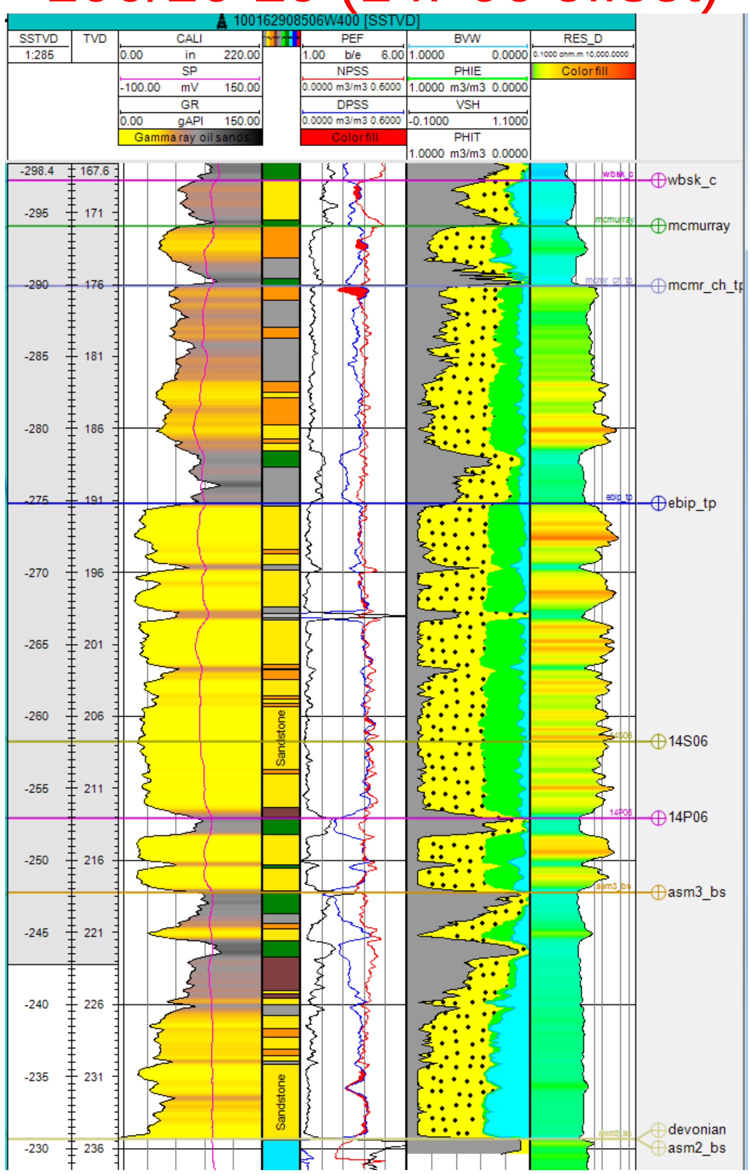


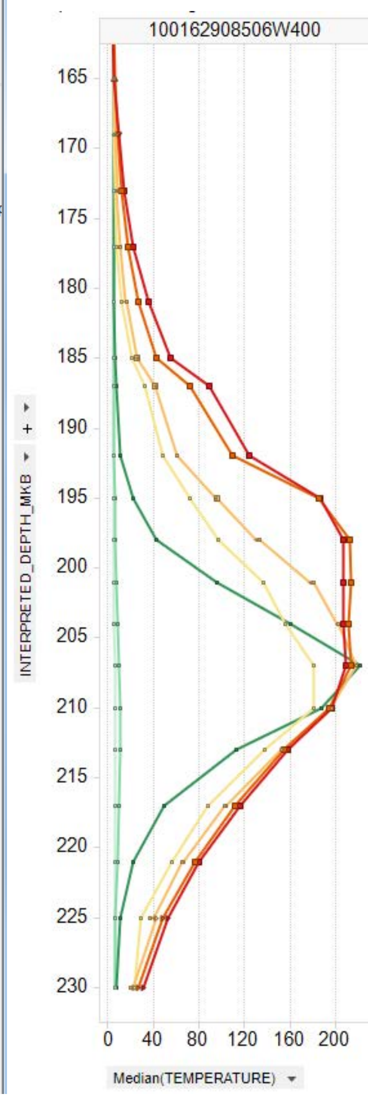
Example of Mid Recovery
Pad 14N



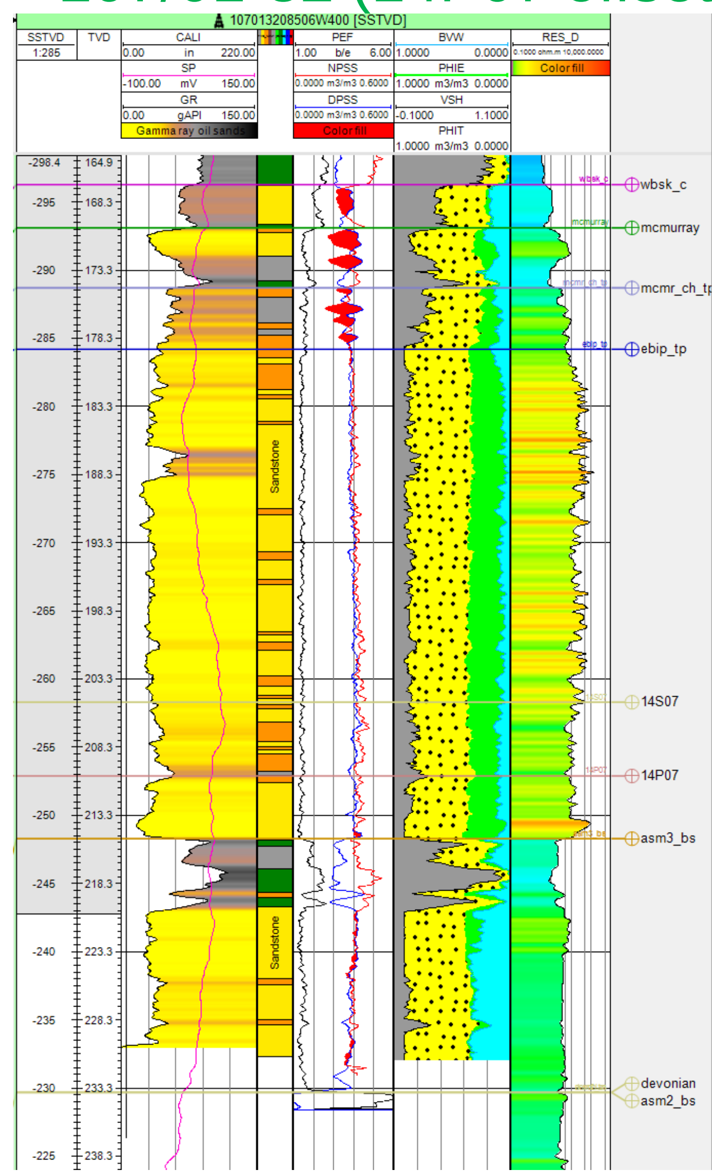
- Good quality reservoir
- Observation wells show vertical steam chamber growth impacted by local heterogeneity

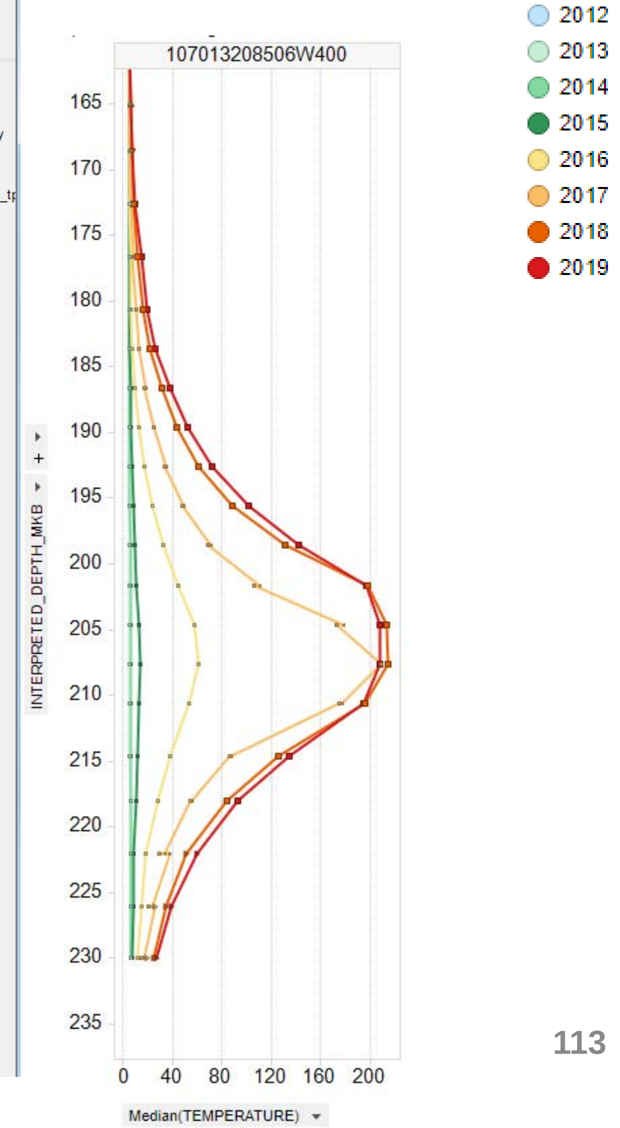
100/16-29 (14P06 offset)





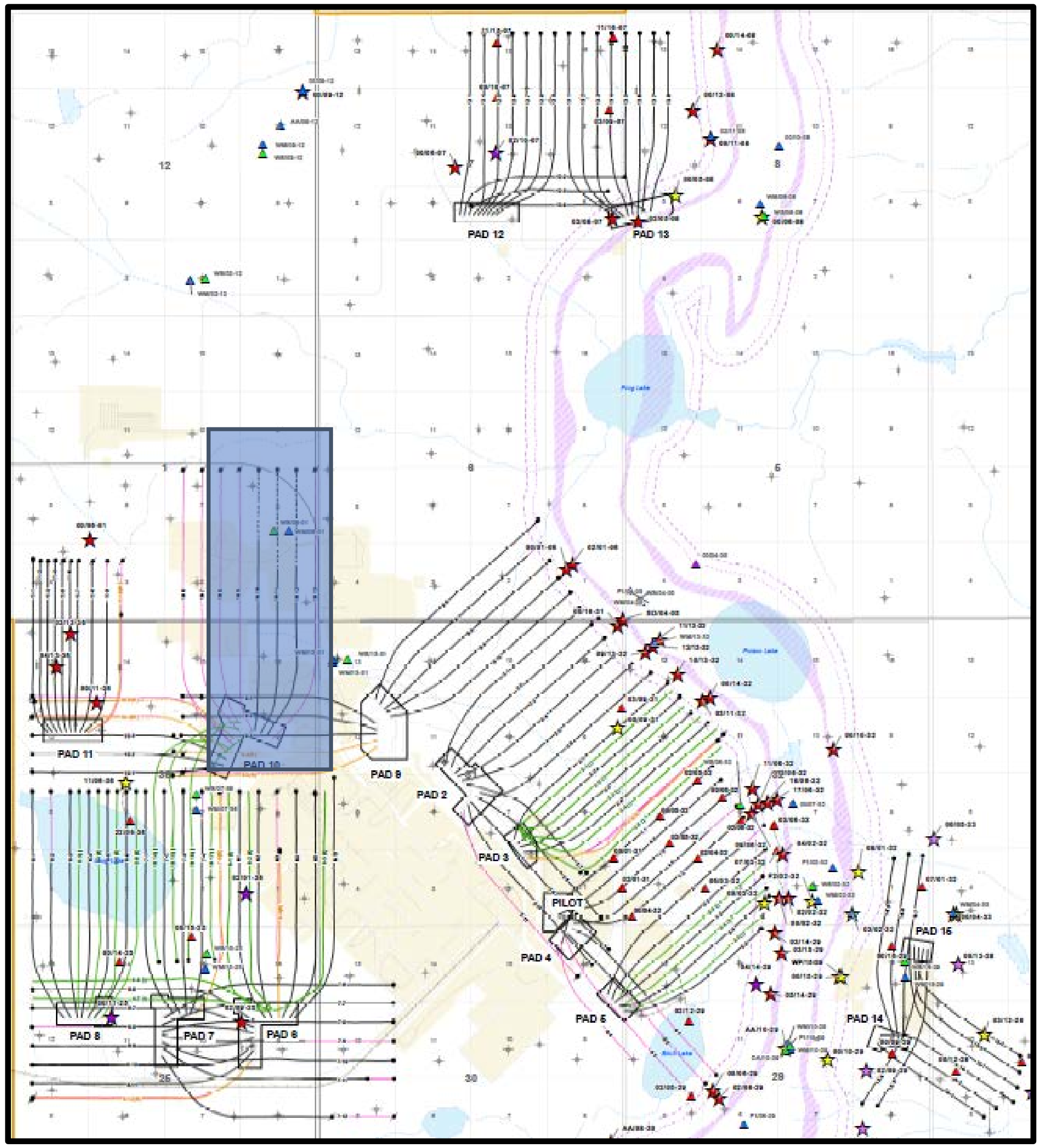
107/01-32 (14P07 offset)



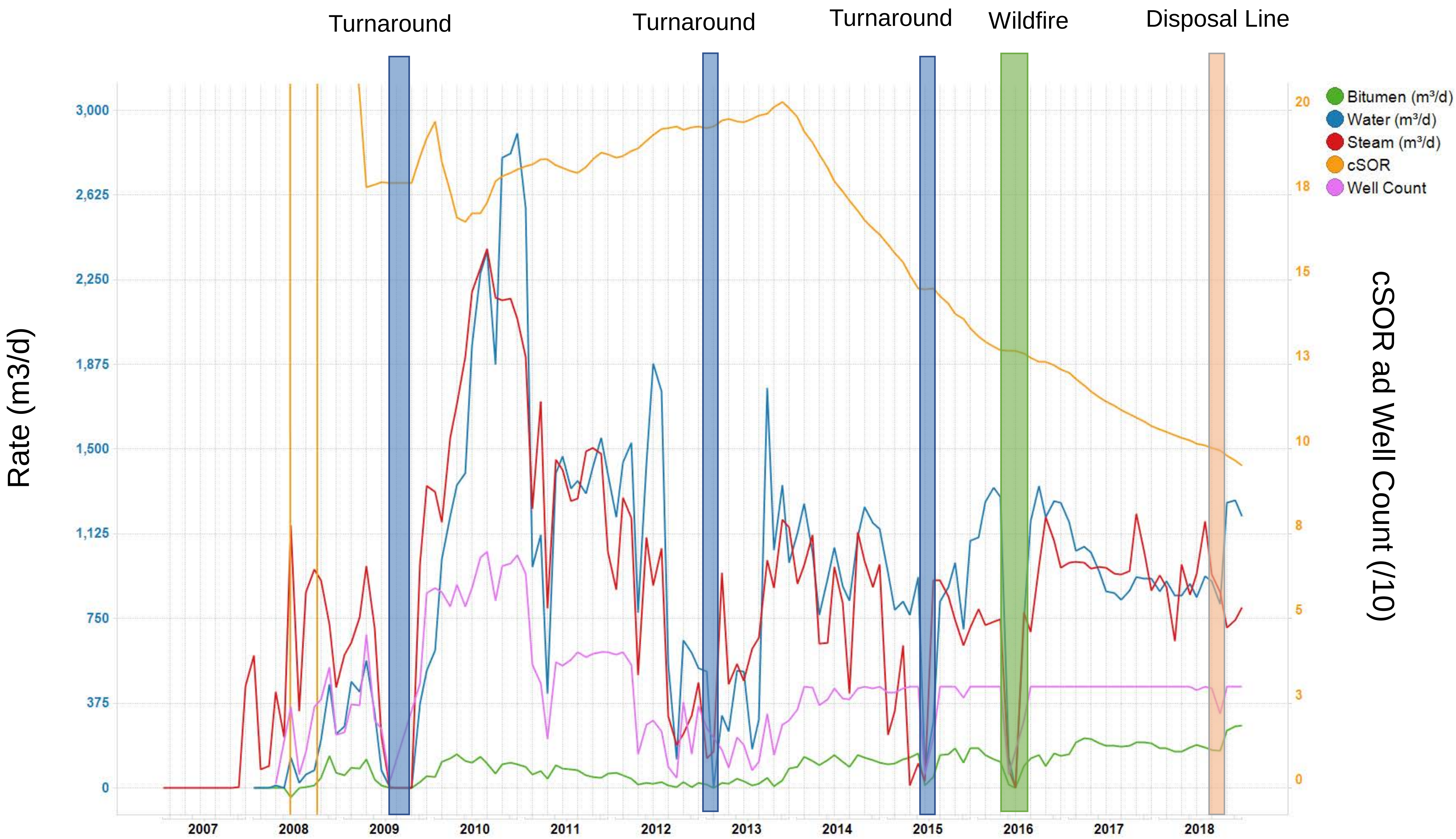


Example of Low Recovery
Pad 10N

- 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 resulting in stronger relative performance
- 2018 YE EBIP RF 14%

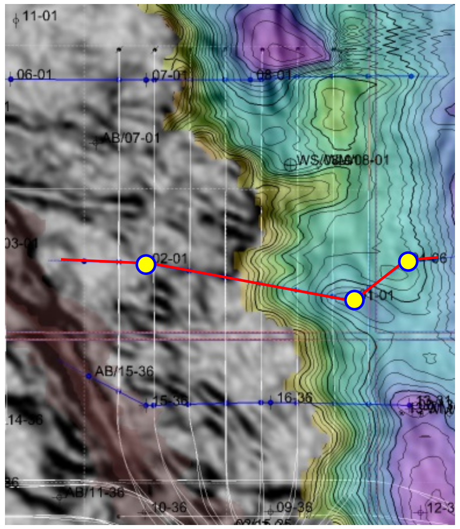


Example of Low Recovery
Pad 10N

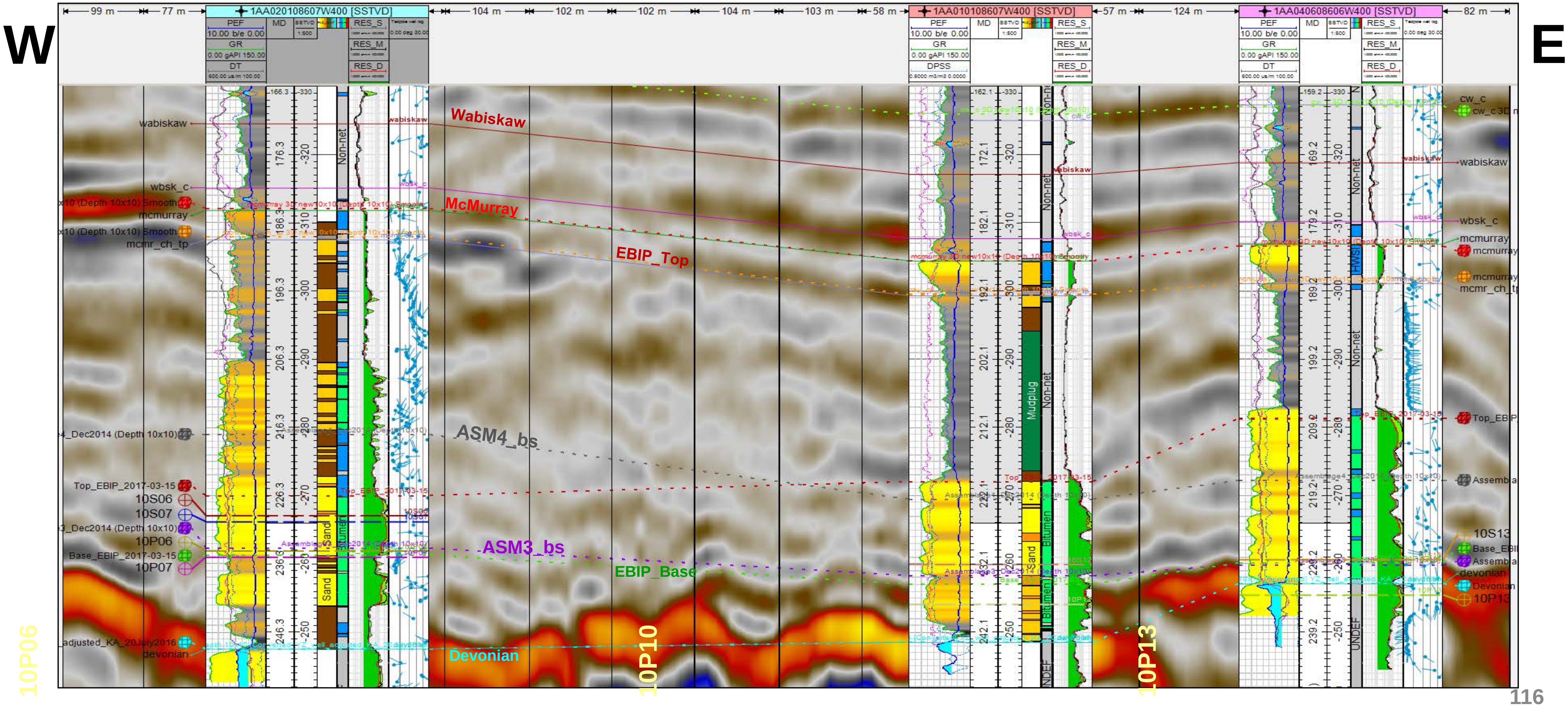


PAD 10N – X-section (W-E)
(across middle of wells)

- 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

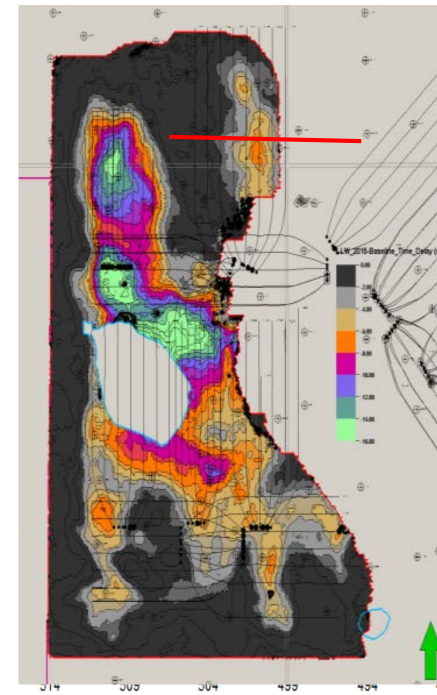


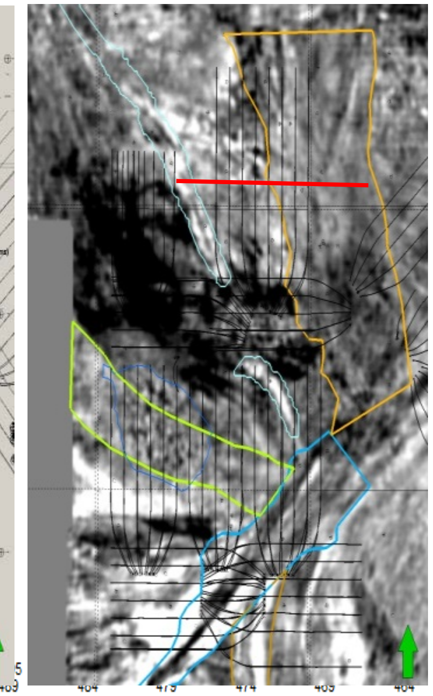
10N_W-E_xsec_Mids

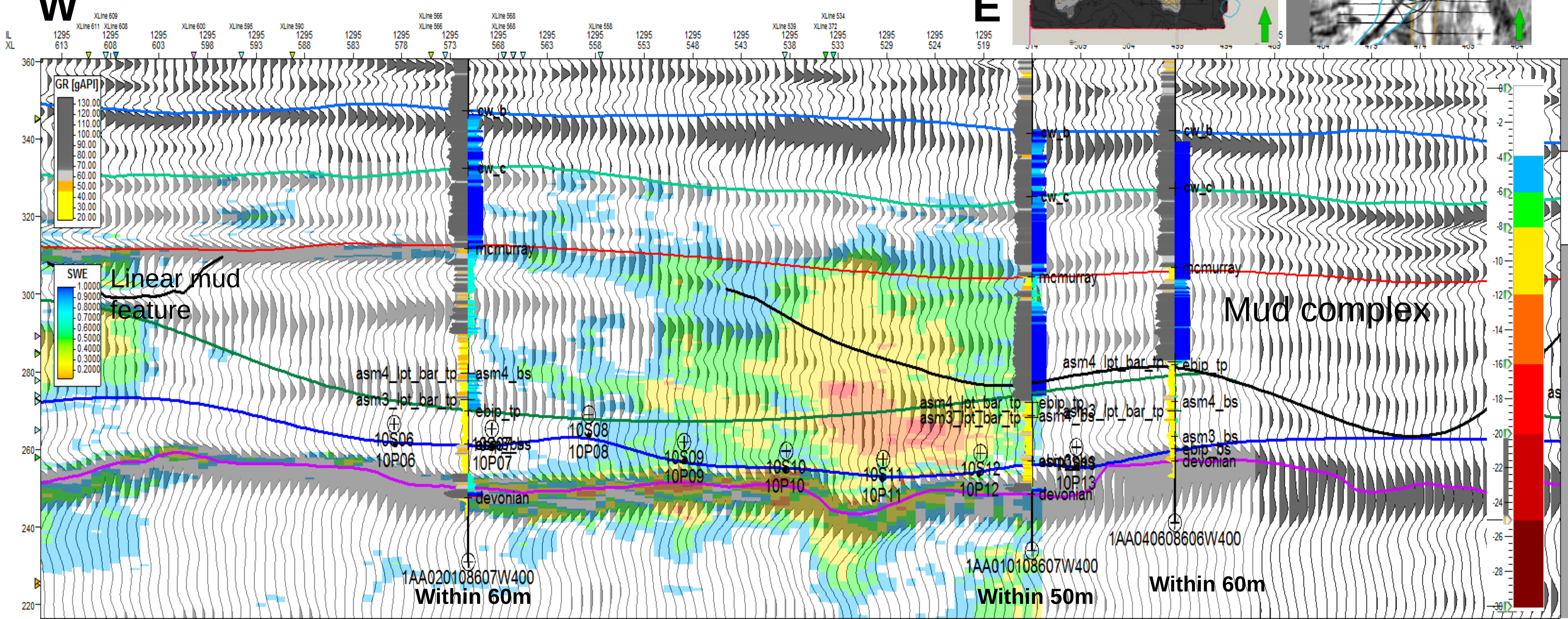


PAD10N cross section in the middle (W-E) with 4D anomaly

- Good steam chamber development in the mid section





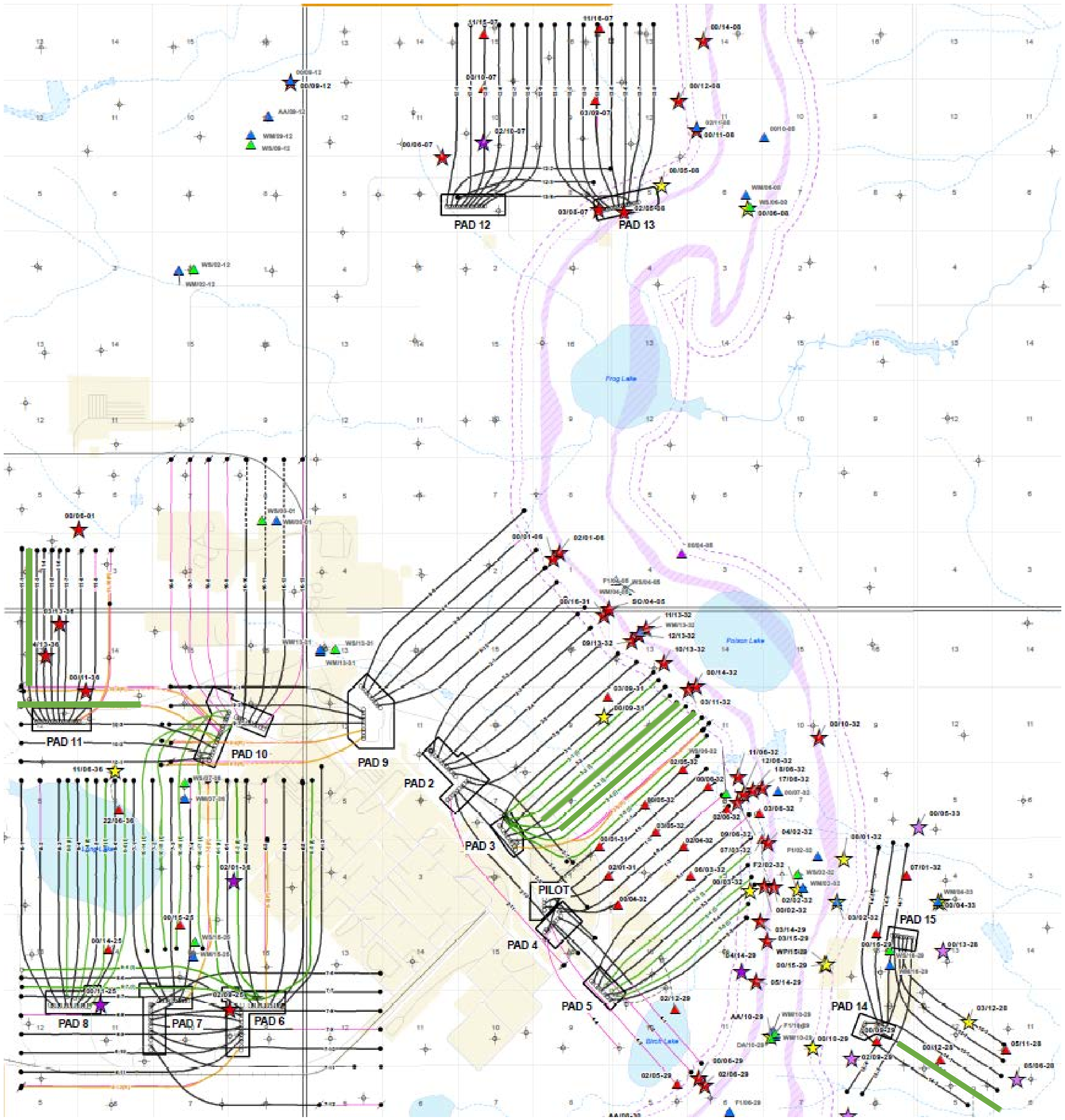


Learnings, Trials and Pilot Projects

Subsection 3.1.1 (7f)

Long Lake and Kinosis

2018 Liner Failures



- Liner failures in 2018
- Evaluated case by case to determine whether to repair, re-drill or shut in

Wells Re-drilled:

- None

Wells Repaired:

- 10P04 – Liner Failure Q2, ICD & Scab Liner
- 14P02 – Liner Failure Q3, ICD & Scab Liner
- 11P02, 03P04 and 03P03 – Liner failure Q4, packer assembly and ICD's

Wells Shut In – Ongoing Evaluation:

- 11P06 – liner failure Q4 2018

Well Re-drilled
Well Repaired
Well Shut in

2018 Liner Failures

Well	Well Pair ID	Failure Date (Year*)	Repair Action	Cause of Failure
10P04	LL-010-04	2018	ICD + Scab Liner	Steam Jetting
14P02	LL-014-02	2018	ICD + Scab Liner	Steam Jetting
11P02	LL-011-02	2018	ICD + Scab Liner	Steam Jetting
3P04	LL-003-04	2018	Wire Wrapped Screen (WWS)	Steam Jetting
3P03	LL-003-03	2018	ICD + Scab Liner	Steam Jetting
11P06	LL-011-06	2018	Liner Failure – to be repaired in 2019	Steam Jetting

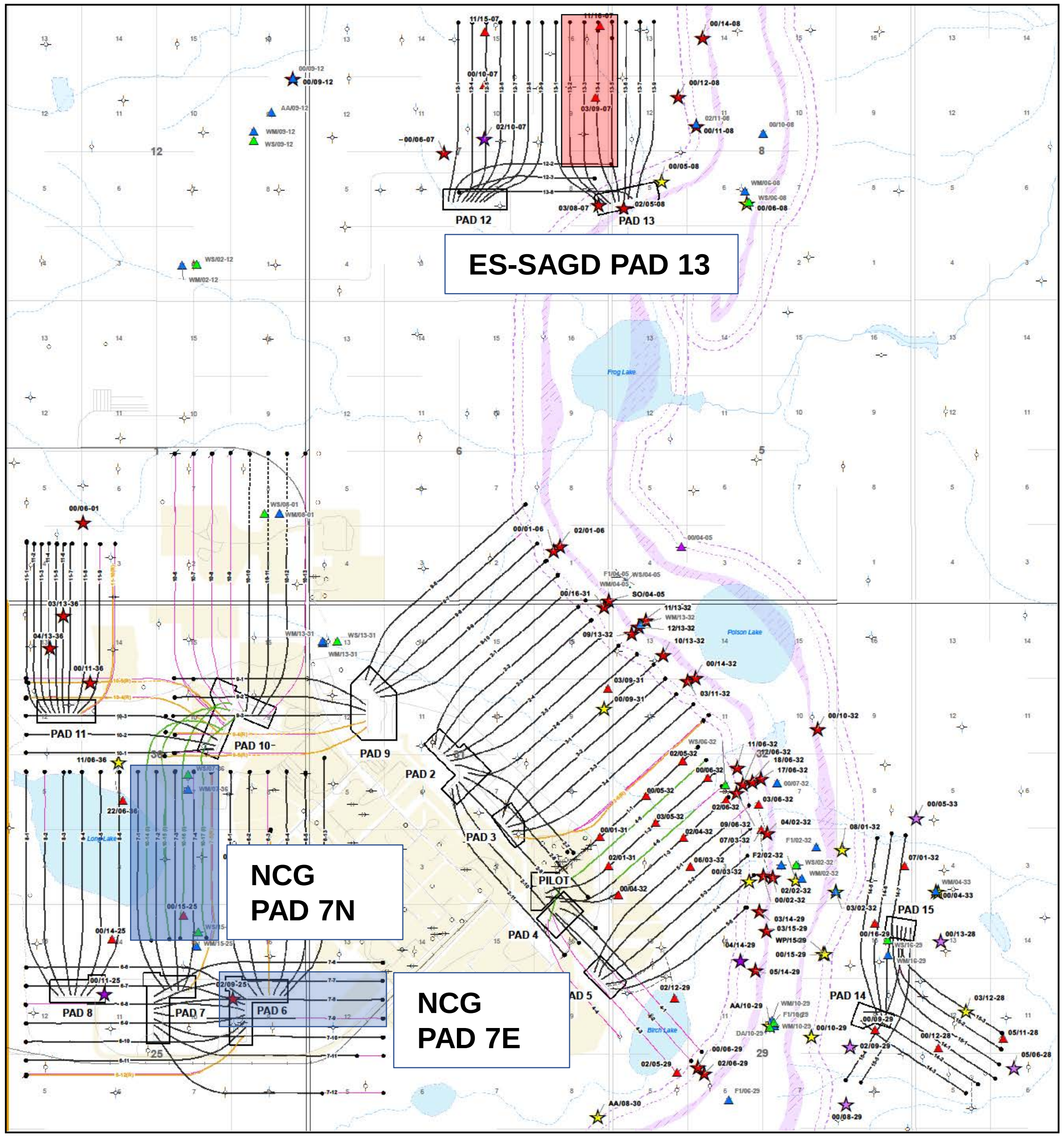
****Timing of actual failure uncertain in most cases; year noted is when failure was discovered and/or when investigative workover was initiated***

2018 Other Well Integrity Actions

Inactive Well Compliance Program (IWCP) D13 Compliance:

- The current “inactive well list” has 323 wells in total
  - 151 wells are observation wells, leaving the accurate total to be 172 inactive wells
- Of the 172 wells, 83 wells are in the IWCP and all 83 are compliant
- The 89 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 2018

Update on Co-Injection Projects



PAD 13 Solvent Co-Injection Pilot:

- ES-SAGD pilot monitoring ended Dec 2016
- Facilities decommissioning commenced Q4 2018

PAD 7E NCG Pilot:

- 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 2018
- Evaluating re-start of NCG injection in 2019

PAD 7N NCG Pilot:

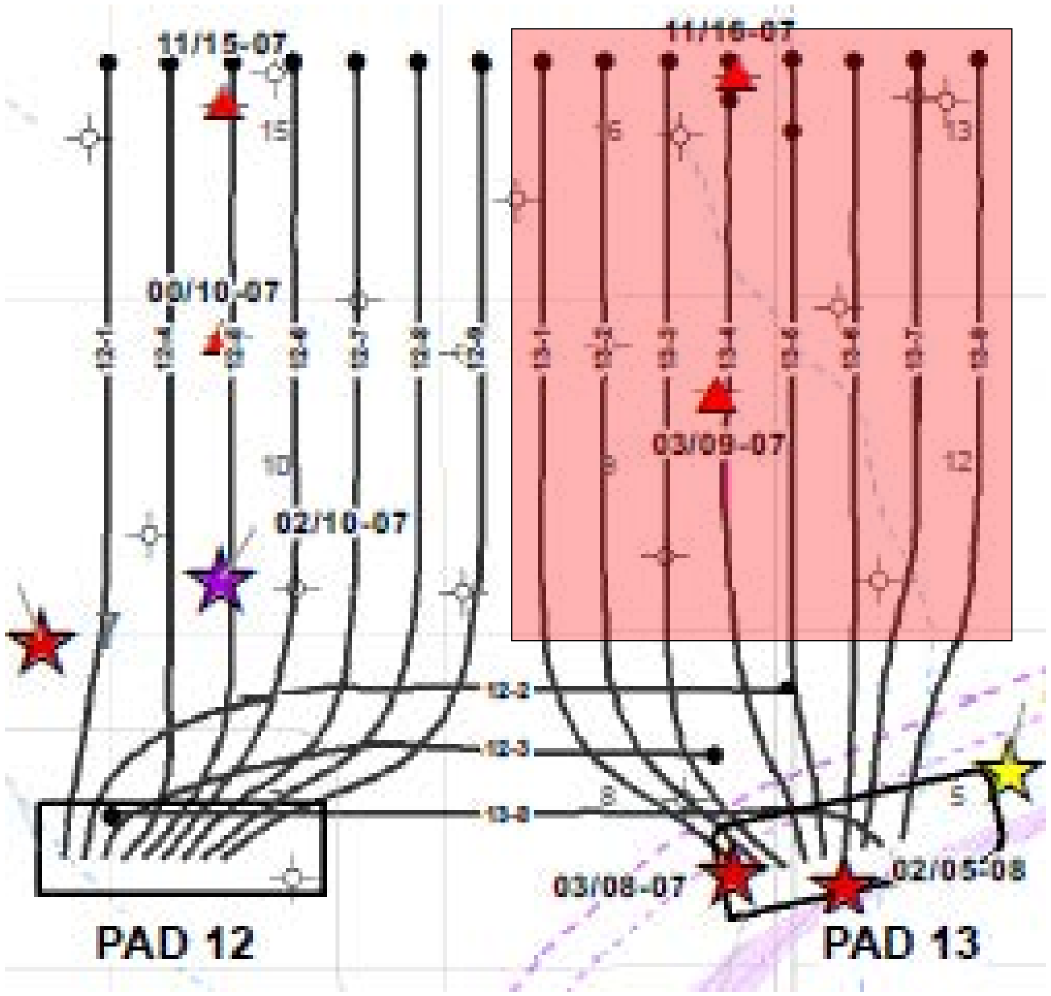
- Application approval 9485CC received in Q2 2014
- Construction of co-injection surface facilities complete Q2 2015 on 5 well pairs planned
- Short term NCG injection around 2015 facility turnaround
- No NCG injection through 2018
- Evaluating re-start of NCG injection in 2019

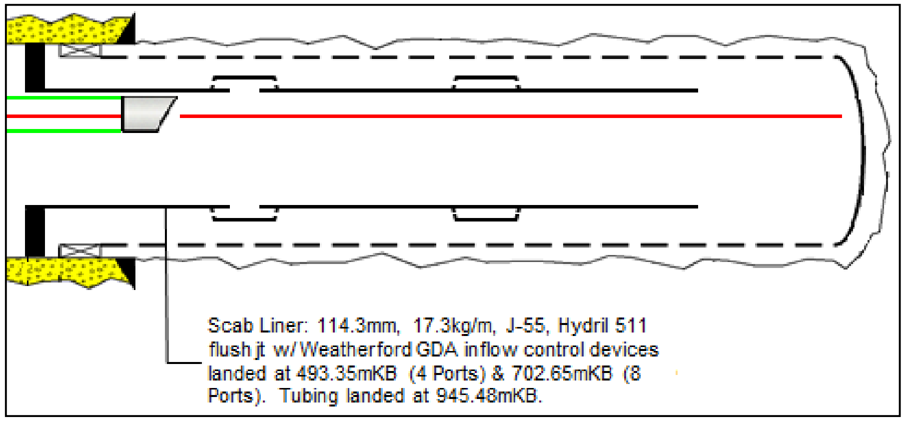
ICD Performance

- Simple Inflow Control Devices (liner ports) were installed in the Pad 13 producer scab liners during initial completion to promote “more even” production of fluid along the wellbore with expected benefits of:
  - Reduced pressure drop along the producer
  - Better conformance along the well

- Majority of wells with liner ports have been consistently good producers since SAGD conversion and are meeting production expectations:
  - Wells show good conformance
  - All ICDs remain in operation with no current plans to close, alter or remove the devices

- Liner ports were installed from initial pad start-up in conjunction with steam splitters & vacuum insulated tubing in the injectors making it difficult to isolate any benefit of just the ICD’s





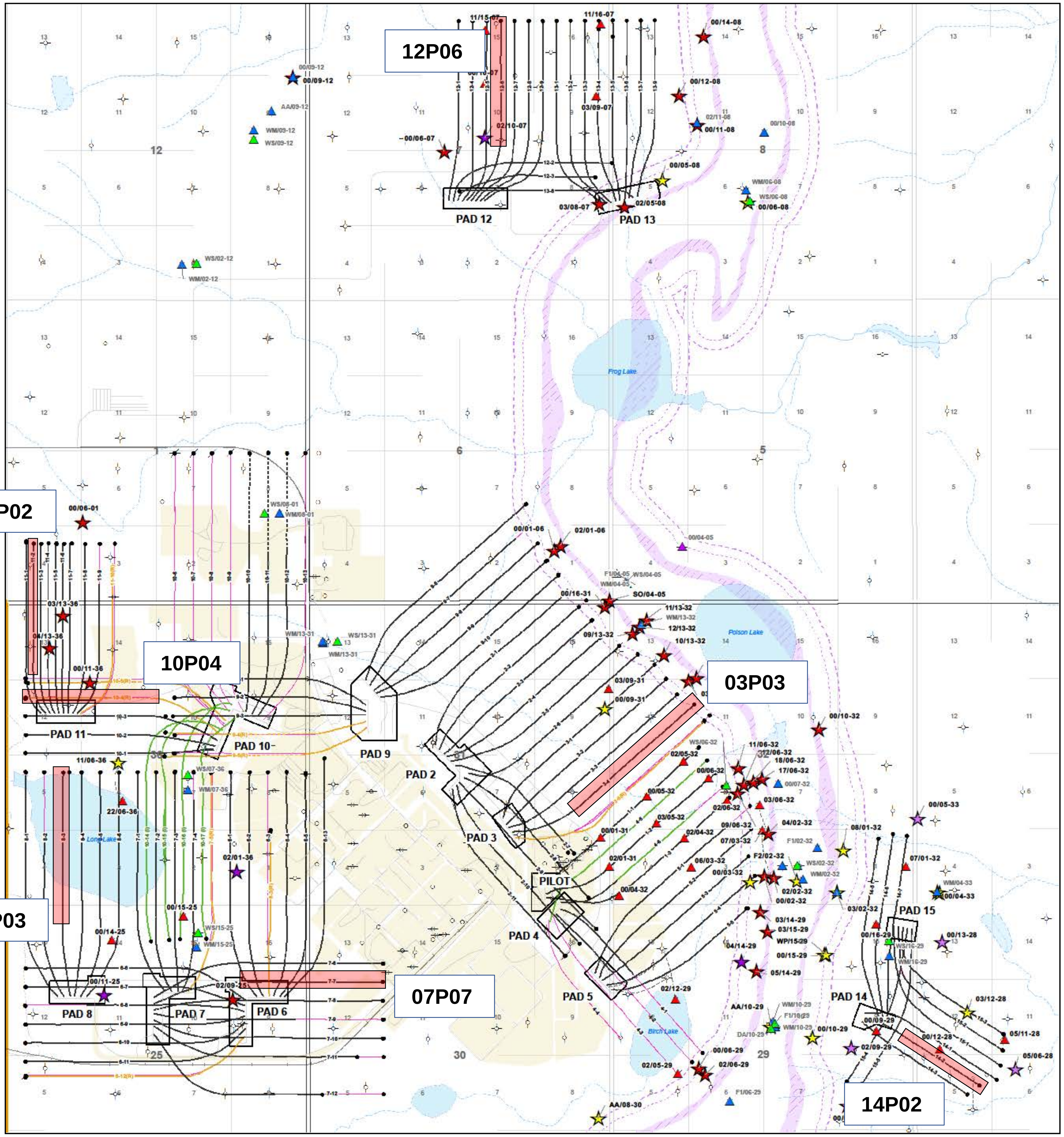
ICD Performance Cont'd

- 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
- 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
08P03	Dec 2015	23 ICD's, No Packers	Yes	Yes	Yes	Yes
12P06	Aug 2017	29 ICD's, No Packers	Yes	No	No	No
07P07	Dec 2017	28 ICD's, Isolated With 16 Swell Packers	Yes	No	No	No
10P04 [1]	Apr 2018	28 ICD's, Isolated With 7 Swell Packers	Yes	Yes	Yes	Yes
14P02	Aug 2018	14 ICD's, Isolated With 5 Swell Packers	Yes	No	Yes	Yes
11P02	Sep 2018	12 ICD's, Isolated With 7 Swell Packers	Yes	Under Evaluation	Under Evaluation	Under Evaluation
03P03	Dec 2018	14 ICD's, Isolated With 6 Swell Packers	Under Evaluation	Under Evaluation	Under Evaluation	Under Evaluation

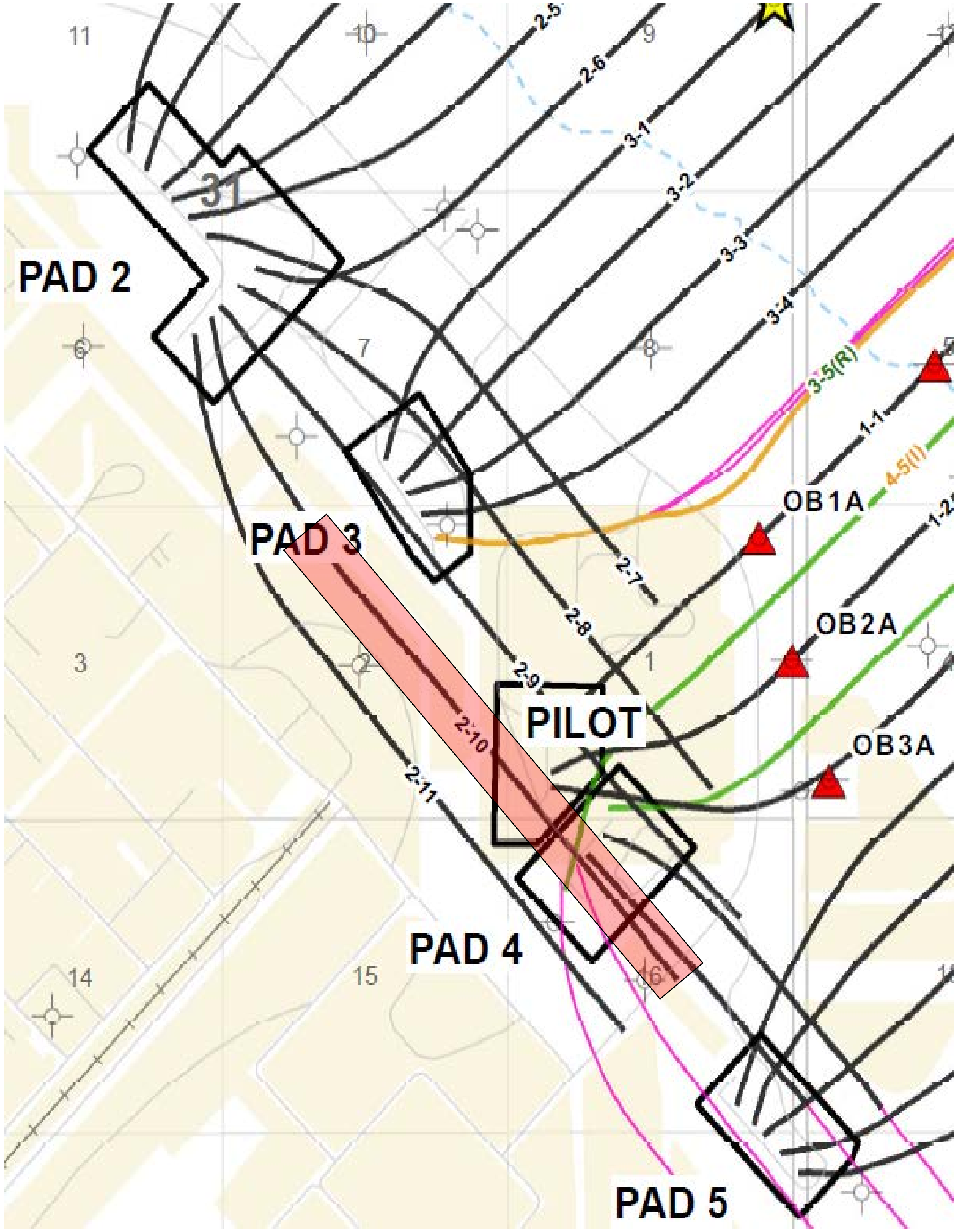
1. Effective well length also increased during workover

ICD Install Locations



- In general, ICD results have been positive to date and CNOOC International will continue to evaluate future ICD installations as opportunities become available

Unresolved Emulsion Injection



Trial to inject Unresolved Emulsion:

- Inject unresolved emulsion into active injector at LLK 02S10 location
- Injected a total of 65 m^3 of emulsion on six different occasions between May 2017 and March 2018
- Typically experienced increase in Injectivity Index and Delta-P between injector and producer, but any impact to pressure response was mitigated over time with continued steaming operations
- Based on the injection of limited volumes of residual emulsion it is concluded there are no long term impacts on injectivity and bitumen production
- The volumes of residual emulsion injected were small, particularly relative to the volume of residual emulsion generated and multiple injection wells would be required to manage the field wide volume of unresolved emulsion
- Trial approval expired at the end of March 2018 and at this time there is no plan for further injection of residual emulsion at LLK
- A final report of trial findings was submitted to the AER, dated June 11, 2018

Observation Wells
Subsection 3.1.1 (7)
Long Lake and Kinosis

Long Lake Observation Wells

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
- PROPOSED OBSERVATION WELLS

HORIZONTAL STATUS (PRODUCER)

- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DIRECTIONAL WELL PATH

TRANSPORTATION

- HIGHWAY
- LONG LAKE MAIN ACCESS
- FACILITY ROADS
- COMMUNITY TRAIL
- RAIL

Q CHANNEL DATA

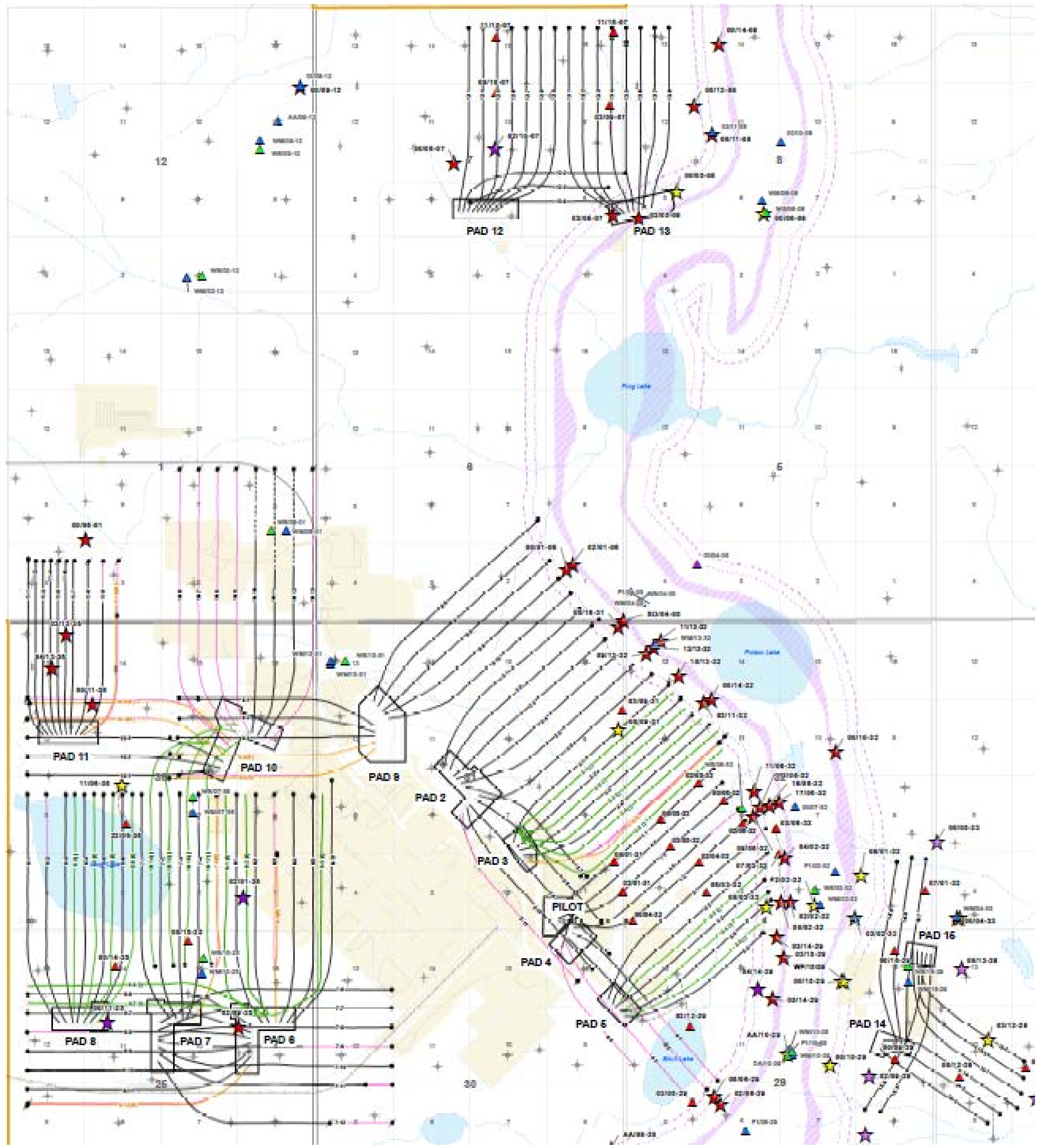
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

MAP DATA

- ZERO EDGE
- FACILITY AREA
- WELL PADS
- LONG LAKE LEASE

HYDROLOGY

- PERENNIAL
- NONPERENNIAL ; INTERMITTENT
- PERENNIAL
- NONPERENNIAL ; INTERMITTENT



Observation Wells – Long Lake

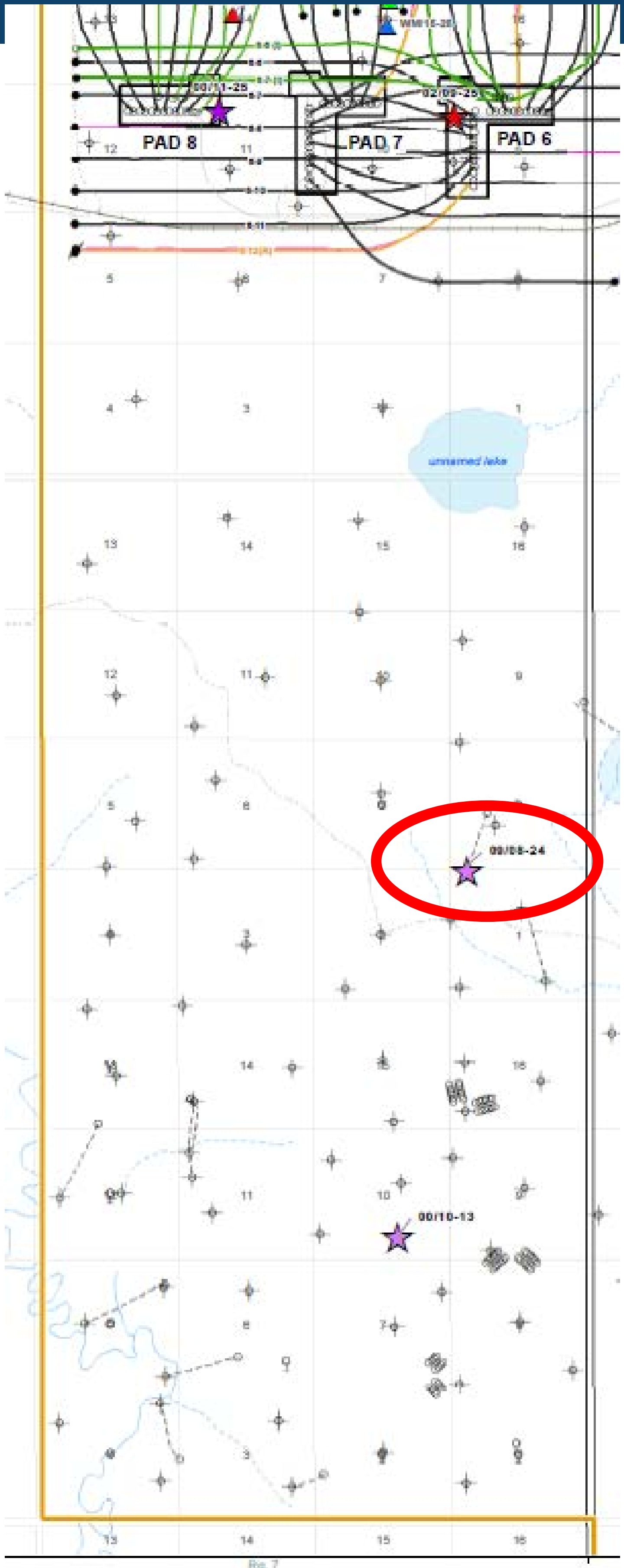
N/A – Greater than 300m to Q-channel or closest well pair

UWI	Closest Wellpair	Distance to Wellpair	Distance to Q channel (Max Edge)	Distance to Q channel (Min Edge)
100010608606W400	LL-009-09	69	45	70
100013108506W400	LL-001-01	1	N/A	N/A
100023208506W400	LL-005-04	51	29	44
100033208506W400	LL-005-04	7	103	120
100042808506W400	LL-014-03	297	N/A	N/A
100043208506W400	LL-001-03	12	N/A	N/A
100043308506W400	LL-014-07	219	N/A	N/A
100050808606W400	LL-013-09	115	68	87
100053208506W400	LL-001-01	3	N/A	N/A
100053308506W400	LL-014-07	109	N/A	N/A
100060108607W400	LL-011-08	118	N/A	N/A
100060708606W400	LL-012-01	67	N/A	N/A
100060808606W400	LL-013-09	N/A	87	50
100062908506W400	LL-004-02	52	97	145
100063208506W400	LL-001-02	4	283	N/A
100081708506W400	LL-014-03	N/A	N/A	N/A
100082908506W400	LL-015-04	128	236	N/A
100091208607W400	LL-012-01	N/A	N/A	N/A
100092908506W400	LL-015-04	10	N/A	N/A
100093108506W400	LL-003-01	3	N/A	N/A
100100708606W400	LL-012-05	5	N/A	N/A
100102908506W400	LL-014-03	279	99	140
100103208506W400	LL-005-01	N/A	7	42
100110808606W400	LL-013-09	230	109	138
100112508507W400	LL-006-07	46	N/A	N/A
100113608507W400	LL-010-05	4	N/A	N/A
100120808606W400	LL-013-09	132	179	213
100122808506W400	LL-014-01	32	N/A	N/A
100132808506W400	LL-015-05	164	N/A	N/A
100140808606W400	LL-013-09	263	23	33
100141708606W400	LL-013-09	N/A	41	8
100142508507W400	LL-008-06	28	N/A	N/A
100143208506W400	LL-003-03	135	3	42
100152508507W400	LL-010-16	17	N/A	N/A
100152908506W400	LL-014-05	203	100	113
100162908506W400	LL-014-06	18	286	N/A
100163108506W400	LL-002-03	97	46	57
102010608606W400	LL-009-09	112	10	27
102012108506W400	LL-014-01	N/A	N/A	N/A
102013108506W400	LL-001-02	1	N/A	N/A
102013608507W400	LL-006-01	35	N/A	N/A
102023208506W400	LL-005-04	101	20	7
102042208506W400	LL-014-01	N/A	N/A	N/A
102043208506W400	LL-001-03	4	N/A	N/A
102050808606W400	LL-013-06	36	4	28
102052908506W400	LL-004-05	2	N/A	N/A
105142908506W400	LL-005-05	281	12.8	55.6
103152908506W400	LL-005-05	161	14.3	13.2

UWI	Closest Wellpair	Distance to Wellpair	Distance to Q channel (Max Edge)	Distance to Q channel (Min Edge)
102053208506W400	LL-001-01	1	N/A	N/A
102062908506W400	LL-004-02	100	53	98
102063208506W400	LL-001-03	6	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	77	N/A	N/A
102100708606W400	LL-012-05	11	N/A	N/A
102112008506W400	LL-004-03	N/A	N/A	N/A
102122908506W400	LL-005-04	25	N/A	N/A
102152908506W400	LL-014-05	193	110	123
103023208506W400	LL-014-05	175	31	73
103053208506W400	LL-001-02	5	N/A	N/A
103063208506W400	LL-005-01	51	48	78
103080708606W400	LL-013-01	8	80	115
103090708606W400	LL-013-04	13	N/A	N/A
103093108506W400	LL-002-06	38	N/A	N/A
103113208506W400	LL-003-03	92	40	81
103122808506W400	LL-015-03	6	N/A	N/A
103133608507W400	LL-011-06	6	N/A	N/A
103142908506W400	LL-005-05	69	30	55
104023208506W400	LL-005-01	38	60	90
104133608507W400	LL-011-04	9	N/A	N/A
104142908506W400	LL-005-05	192	103	139
105062808506W400	LL-015-01	82	N/A	N/A
105112808506W400	LL-015-03	33	N/A	N/A
106033208506W400	LL-005-01	42	N/A	N/A
107013208506W400	LL-014-07	18	N/A	N/A
107033208506W400	LL-005-04	72	7	27
108013208506W400	LL-014-05	175	33	87
109063208506W400	LL-001-03	47	156	169
109133208506W400	LL-002-05	96	21	40
110133208506W400	LL-003-01	75	33	80
111063208506W400	LL-001-02	123	121	136
111063608507W400	LL-010-01	48	N/A	N/A
111133208506W400	LL-002-06	190	77	65
111150708606W400	LL-012-05	9	N/A	N/A
111160708606W400	LL-013-04	9	N/A	N/A
112063208506W400	LL-001-03	105	110	122
112133208506W400	LL-002-05	148	28	12
117063208506W400	LL-005-01	157	10	21
118063208506W400	LL-005-01	130	60	72
122063608507W400	LL-008-06	47	N/A	N/A
1AA083008506W400	LL-004-04	N/A	161	247
1AA102908506W400	LL-004-01	N/A	113	66
1F2023208506W400	LL-005-04	227	146	133
1S0040508606W400	LL-002-02	126	11	15
1WM043308506W400	LL-014-07	204	N/A	N/A

Long Lake SW
Proposed Observation Wells

- 109/08-24-085-07W4 drilled in December 2018
  - 93.2 m deviated core
  - Open hole logging program
    - GR, Neutron, Density, Sonic, NMR, resistivity, image logs
  - 10 ERE sensors placed in well to monitor pressure and temperature
    - 2 in Clearwater A Sand
    - 8 in McMurray
- Data from 2 observation wells will be activated in 2019
  - 109/08-24
  - 100/10-13
- 2 more observation wells are planned to be completed in 2019



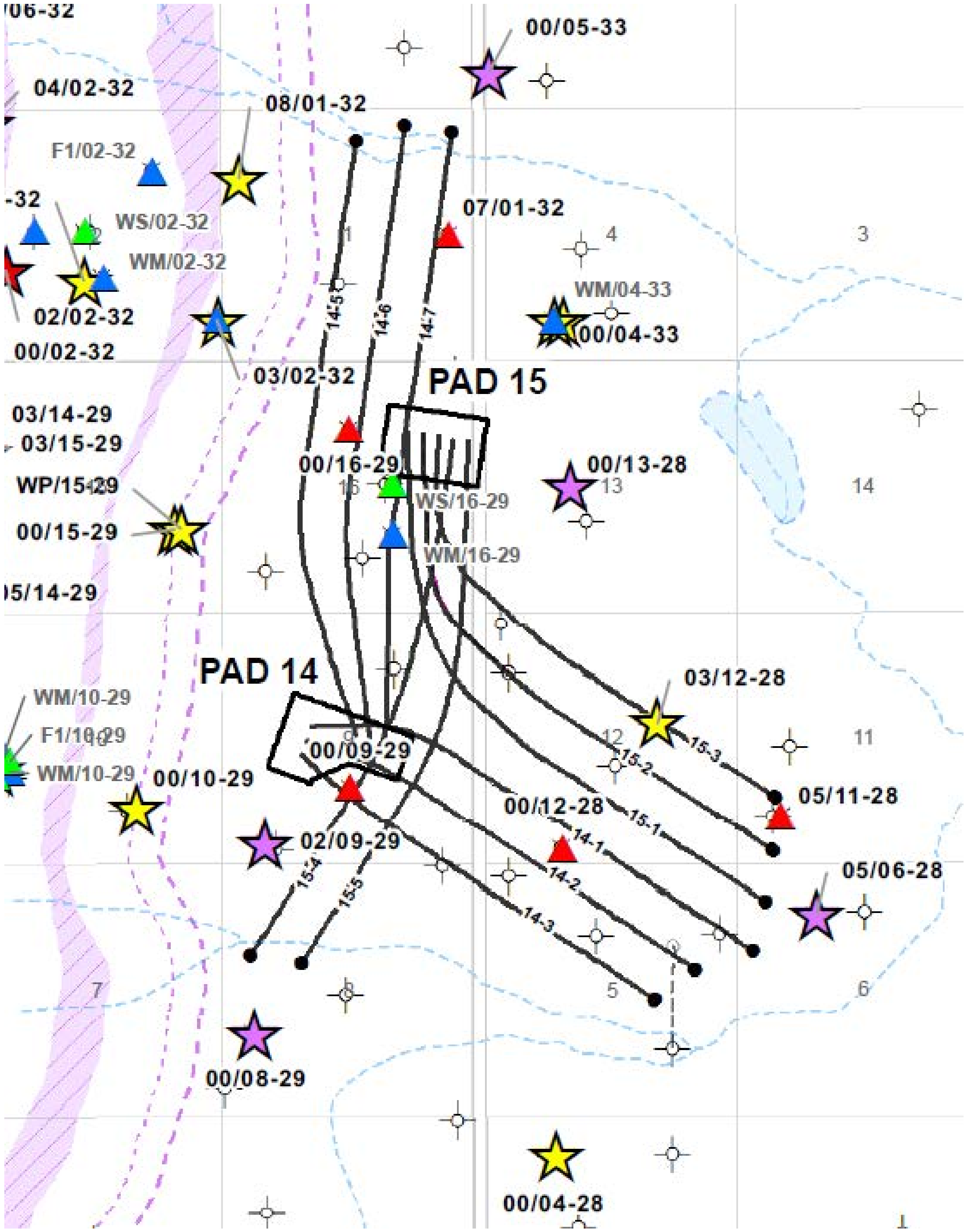
Pads 14/15 Observation Wells Caprock Monitoring

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	1010
100/05-33	119	341.2	CLWT A	980	1,001
100/13-28	116	341.9	CLWT A	1,000	1,007
102/15-29 (WP/15-29)	127	344.3	CLWT A	990	1,000
WM/04-33	115	343.8	CLWT A	970	966
	115.5	343.3	CLWT A	980	981

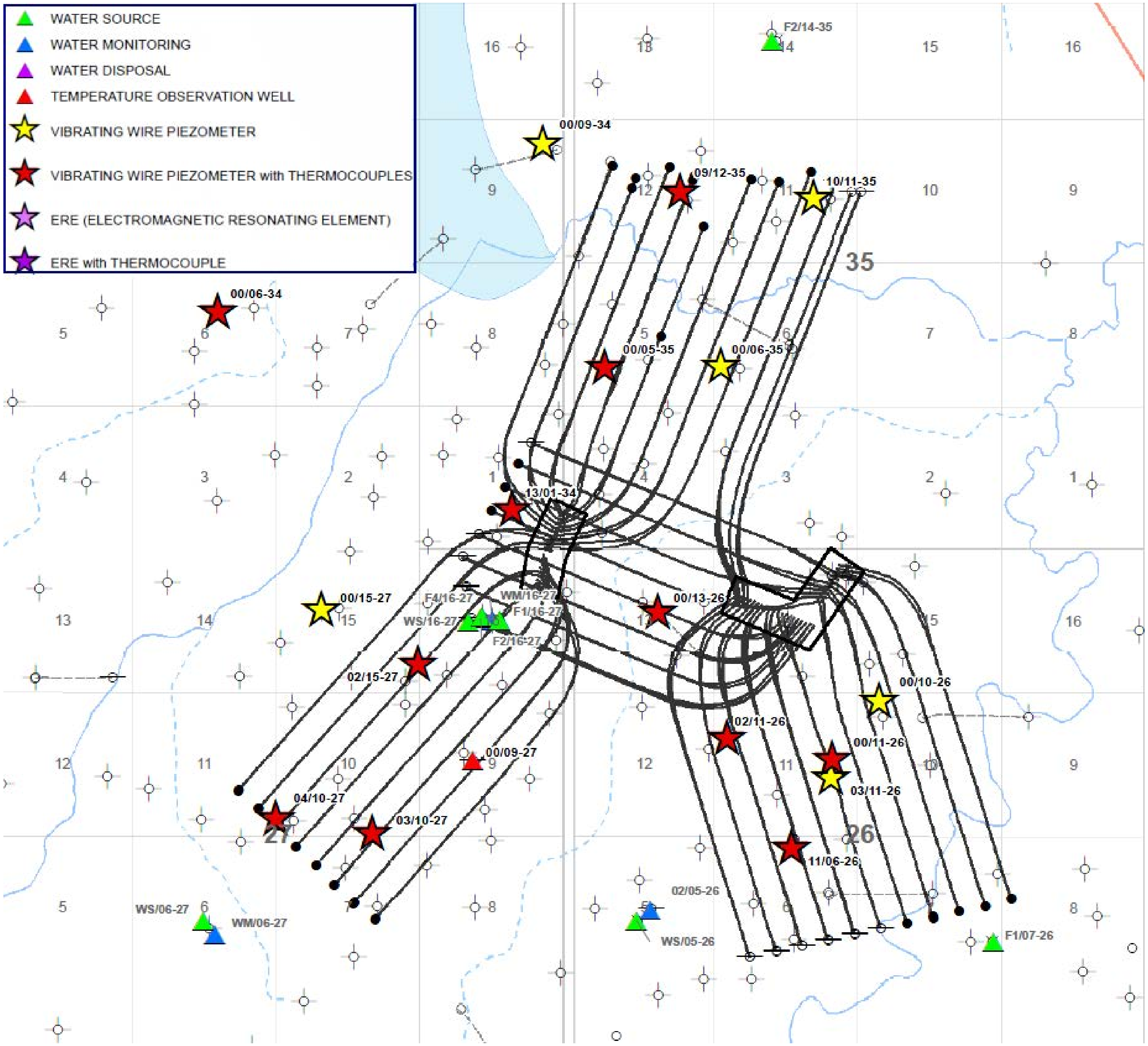
Pad 15 Baseline and Current Values

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	1,113
100/08-29	118.5	349.2	CLWT A	930	952
102/09-29	126.5	339.6	CLWT A	1,020	1,026
103/12-28	121.5	340.5	CLWT A	1,040	1,031



** December 2018*

K1A Observation Wells



Observation Well Challenges

- Multiple issues can impact the quality and confidence of observation well data.
- This 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;
    - Extreme persistent winter conditions were experienced in 2018 in excess of -50°C with wind chill.
  - 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 collaborated by adjacent sensors and do not correlate with subsurface operations.

Observation Well Challenges

- 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);
    - Thus far, we have had good success with these new technologies.
  - Regular inspections of surface equipment; and
  - Regular inspections of downhole sensors.
- Systems are in place to monitor observation well data daily 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.
- Thermocouple strings and piezometers are tested at the well to determine data validity (Loop resistances, internal resistances).

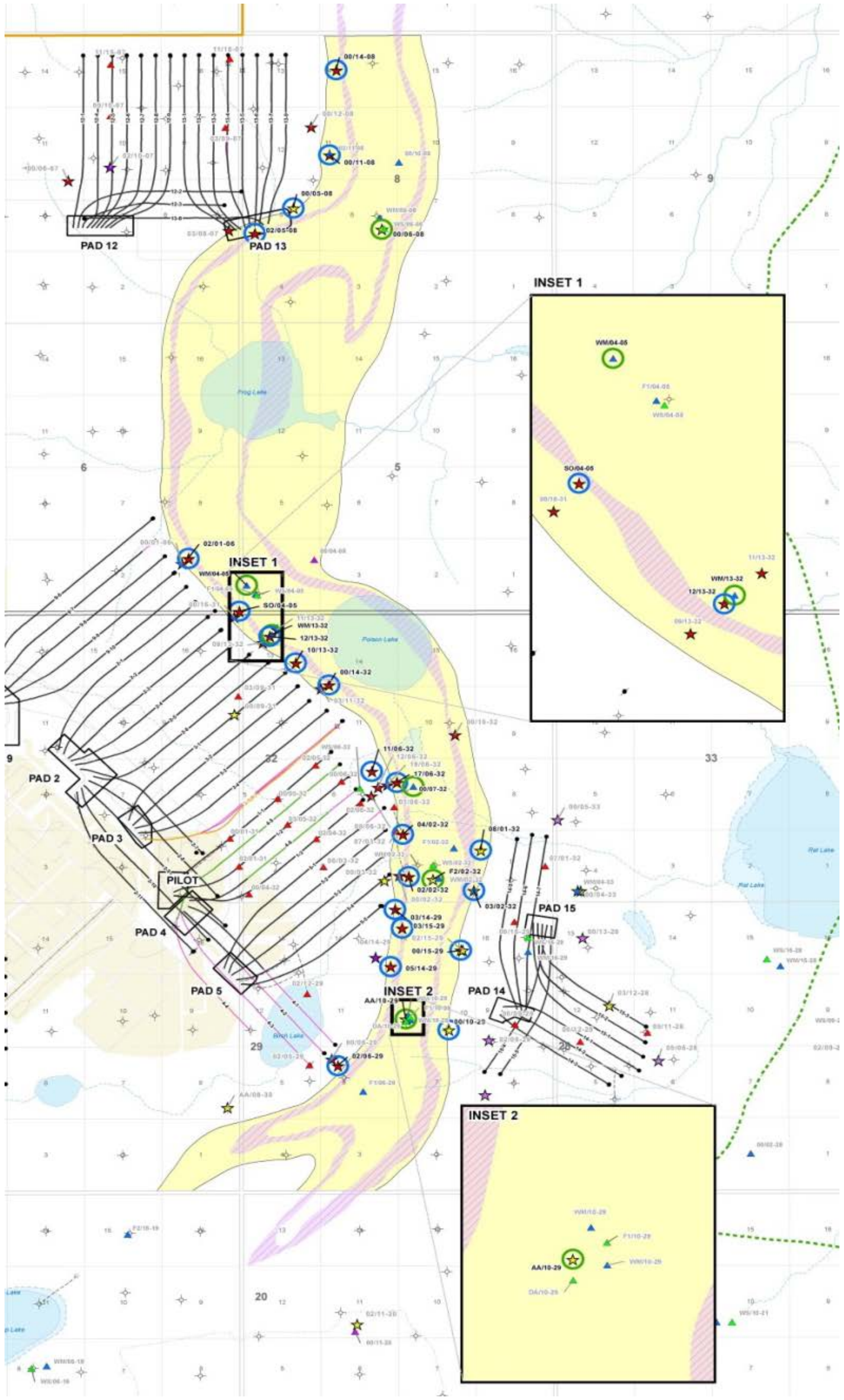
Original Q-Channel Operating Guidelines	Groundwater Management Plan Guidelines
• Temperatures to remain below 100°C [1] at any observation well in Area B [2] (AER Scheme Approval for Long Lake #9485 Clause #23). • SAGD well pairs to be operated such that pressures measured at the 100m observation wells will be less than or equal to Q-Channel (Q-Ch) pressure at the equivalent depth.	• New groundwater management plan reflects planned regulatory changes and technical evaluation based on risk. • Updated directive allows a shift in objective from considering the Q-Ch as a receptor to identifying specific receptors. • Receptors are protected by managing conditions within a defined area of the Q-Ch referred to as the Aquifer Management Unit (AMU). • SAGD well pairs to be operated such that pressures measured at the pressure monitoring wells will be less than or equal to Q-Ch pressure at the equivalent depth. • The plan includes staged responses triggered by pressure, temperature and chemistry thresholds.

(1) Q-Channel 100°C temperature clause in the Long Lake Scheme Approval is arbitrary.

(2) Area B is defined as any well between the toe of the SAGD well pairs and where the Q-Ch breaches the top of the McMurray.

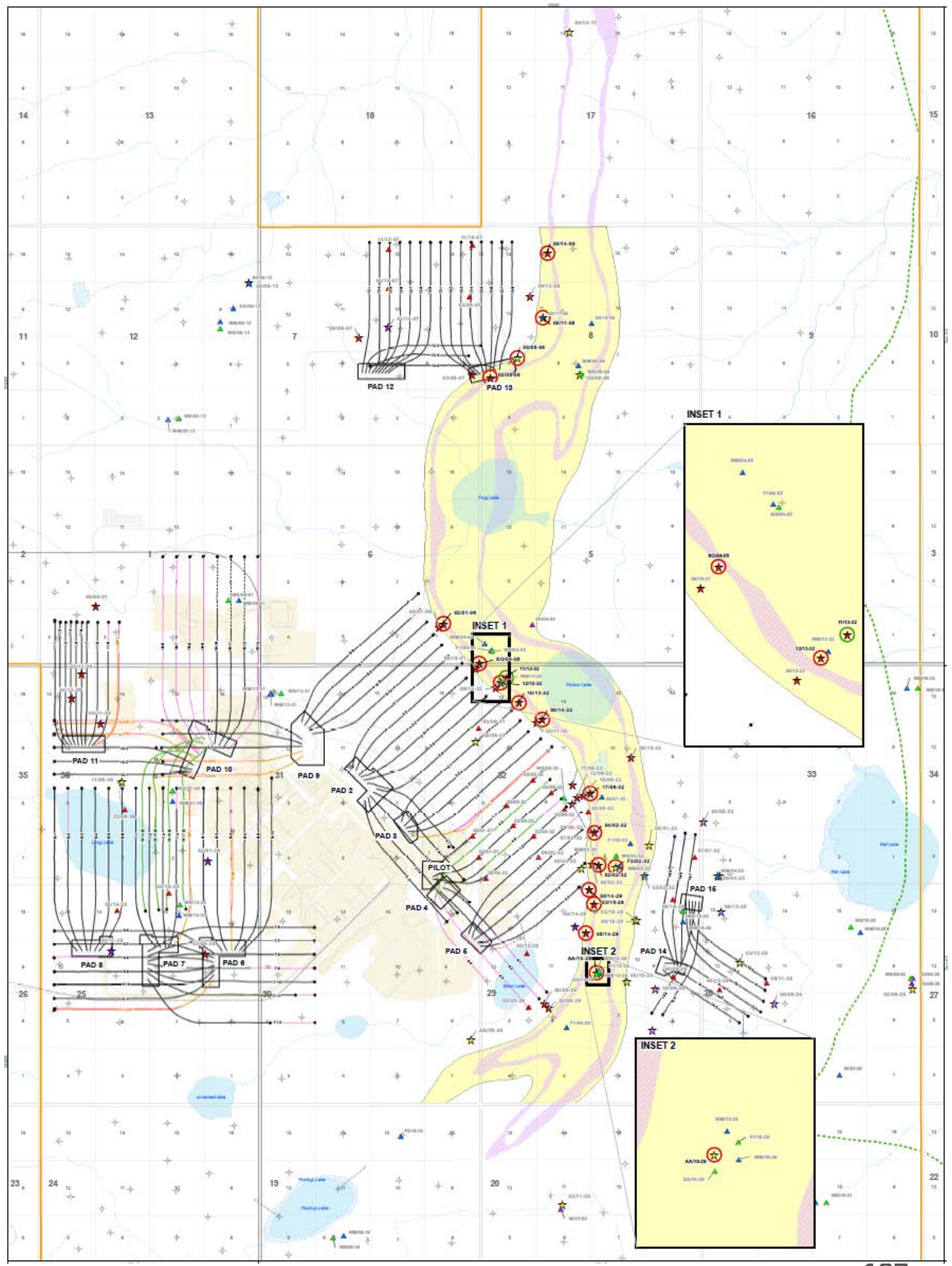
Pressure Monitoring Network

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
1WM/04-05-086-06W4/00	WM/04-05	Monitoring	Pressure
1WM/13-32-085-06W4/00	WM/13-32	Monitoring	Pressure



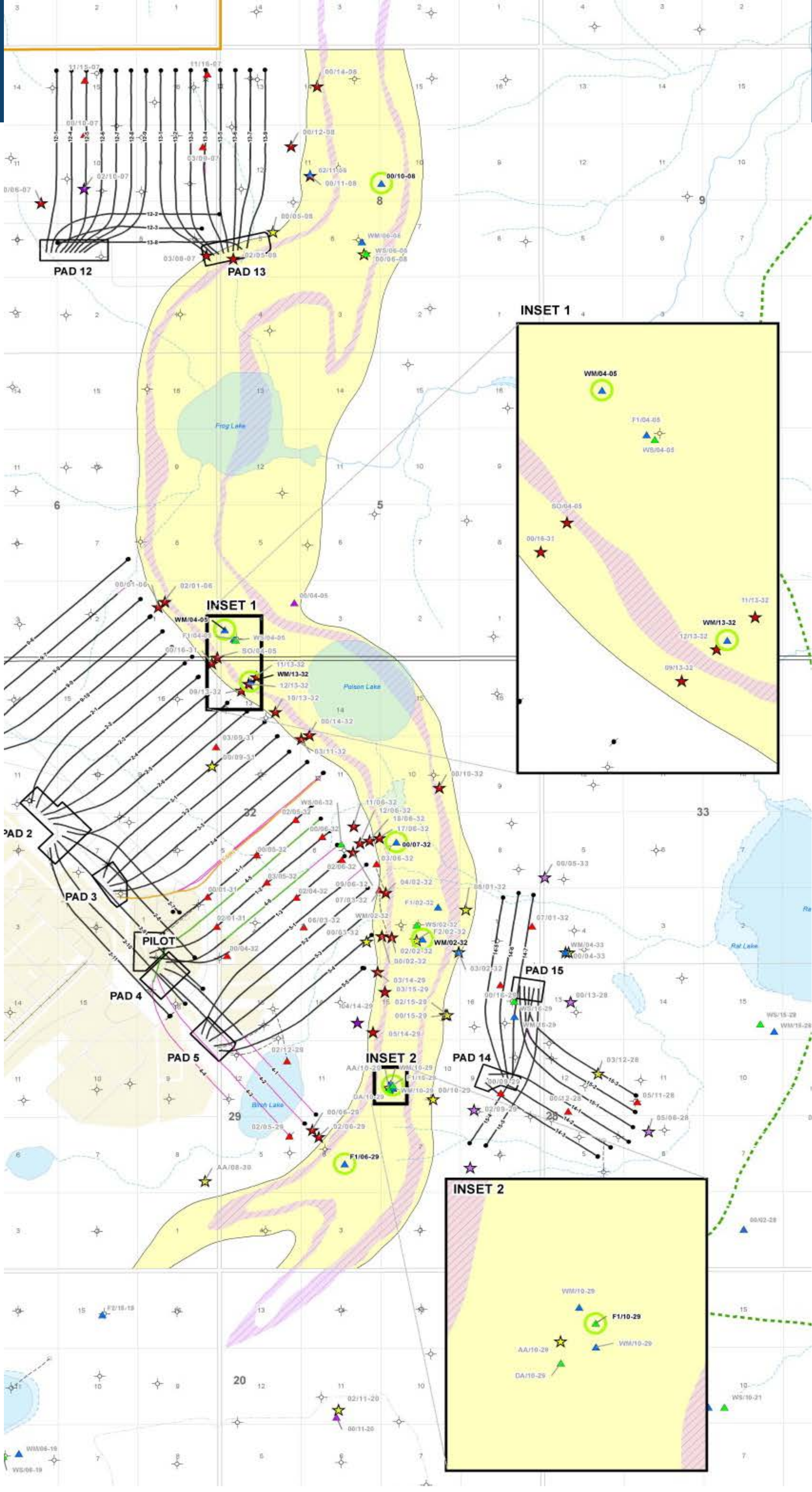
Temperature Monitoring Network

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



Chemistry Monitoring Wells

UWI	Abbreviation	Type	Parameters for Control / Management
100/07-32-085-06W4/00	00/07-32	Monitoring	Chemistry
100/10-08-086-06W4/00	00/10-08	Monitoring	Chemistry
1F1/02-32-085-06W4/02	F1/02-32	Monitoring	Chemistry
1F1/06-29-085-06W4/00	F1/06-29	Monitoring	Chemistry
1F1/10-29-085-06W4/00	F1/10-29	Monitoring	Chemistry
1WM/04-05-086-06W4/00	WM/04-05	Monitoring	Chemistry
1WM/13-32-085-06W4/00	WM/13-32	Monitoring	Chemistry



Application of GMP Monitoring Plan Operational Updates

- An updated groundwater management plan for the Q-Channel was initiated in the second half of 2017. The risk based plan has allowed CNOOC International to reintroduce steam to wells that had been shut in on Pads 2NE and 3.
- Due to the reintroduction of steam, the affected pads are able to achieve target pressures. 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 McMurray reservoir have also increased with the re-introduction of steam as anticipated. Temperatures in the Q-Channel have remained stable, including at well 112/13-32 where temperatures exceed baseline. 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 changes observed since the reintroduction of steam.

Future Plans
Subsection 3.1.1 (8)
Long Lake and Kinosis

Future Plans – Producing areas

- LLSW sustaining SAGD well pairs (Pads 16, 17, 18) will be drilled and completed in 2019-2020
- Continue to manage SAGD production according to surface constraints and capacity
- Acquisition of 4D seismic on Pads 12/13
- Evaluating re-start of NCG injection on Pad 7N and 7E
- Production opportunities:
  - Place infills at Long Lake on production: 10 wells drilled in 2018 on Pad 3 and 6
  - Planning infills on Pad 1, 5, 13 pending internal project sanction
  - Evaluate additional well pairs, infills and re-entries off existing well pads at Long Lake
- Advance plans for K1A recovery:
  - Progress construction of K1A replacement pipelines & restart of K1A facility

Future Plans - New Development

- Kinosis:
  - Progressing plans for development in the Kinosis East North (KEN) area (Townships 84-85, Ranges 6-7 W4M), targeting submission of scheme amendment in Q4 2019
  - Plan to re-start gas re-pressurization prior to KEN first steam

Future Plans – Pad Abandonments

- There are no anticipated pad abandonments for Long Lake or K1A pads in the next five years

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

Subsection 3.1.2

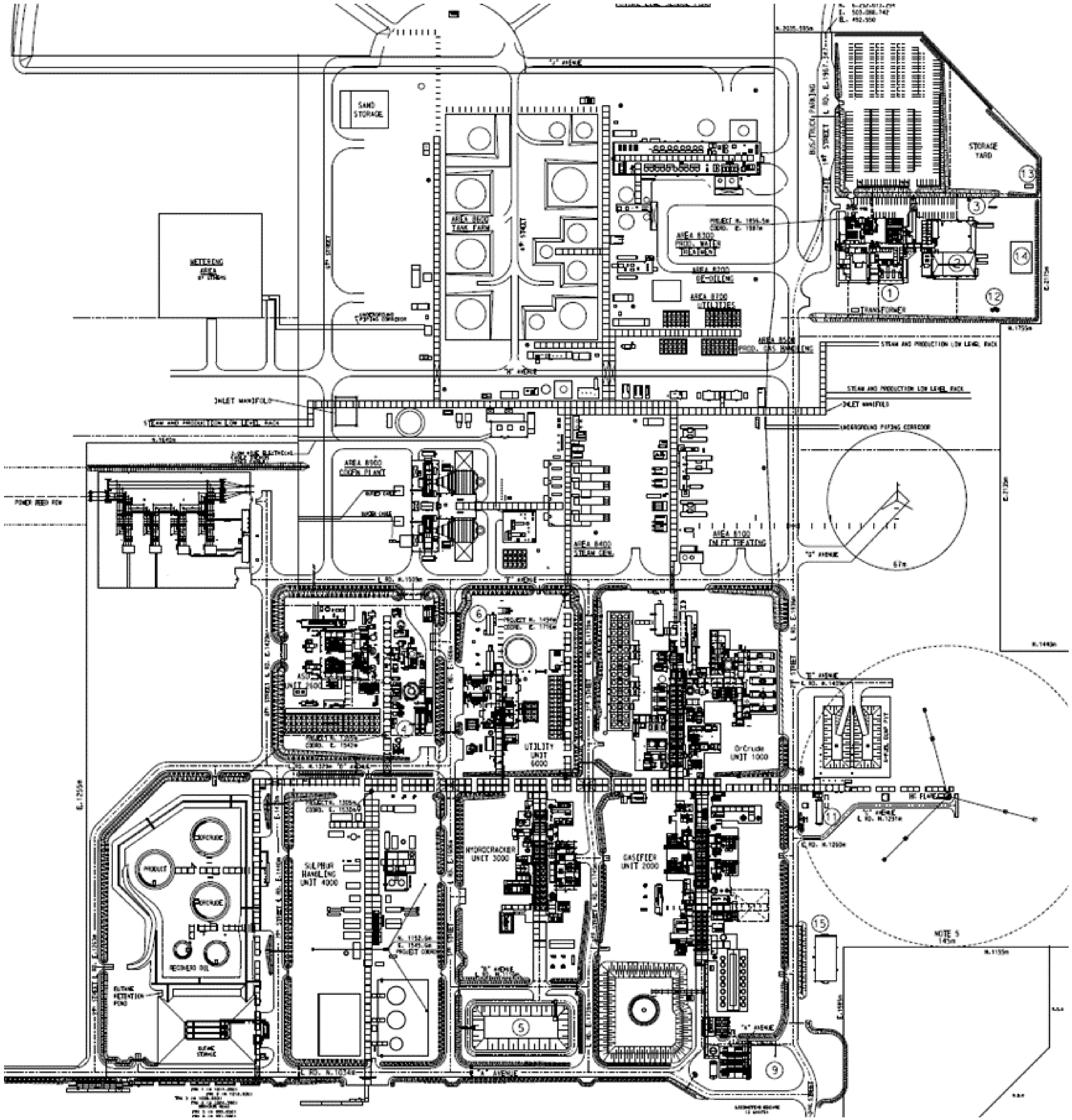
Long Lake and Kinosis

Facilities
Subsection 3.1.2 (1)
Long Lake and Kinosis

Long Lake Facilities

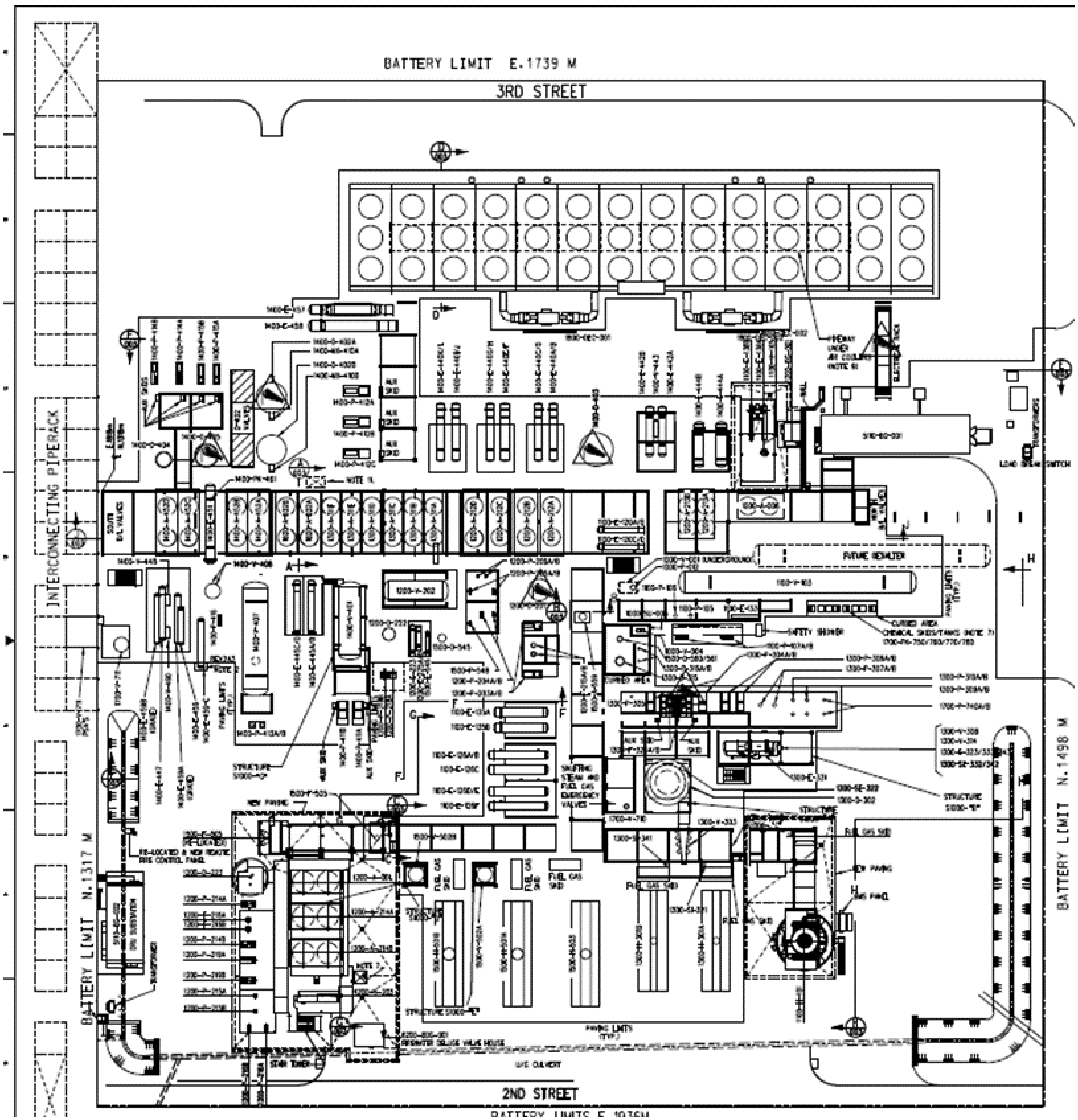
Long Lake facility overview with Pad 9 in the foreground - June 19, 2018

Long Lake Plot Plan



Subsection 3.1.2 (1a)

Diluent Recovery Unit Plot Plan

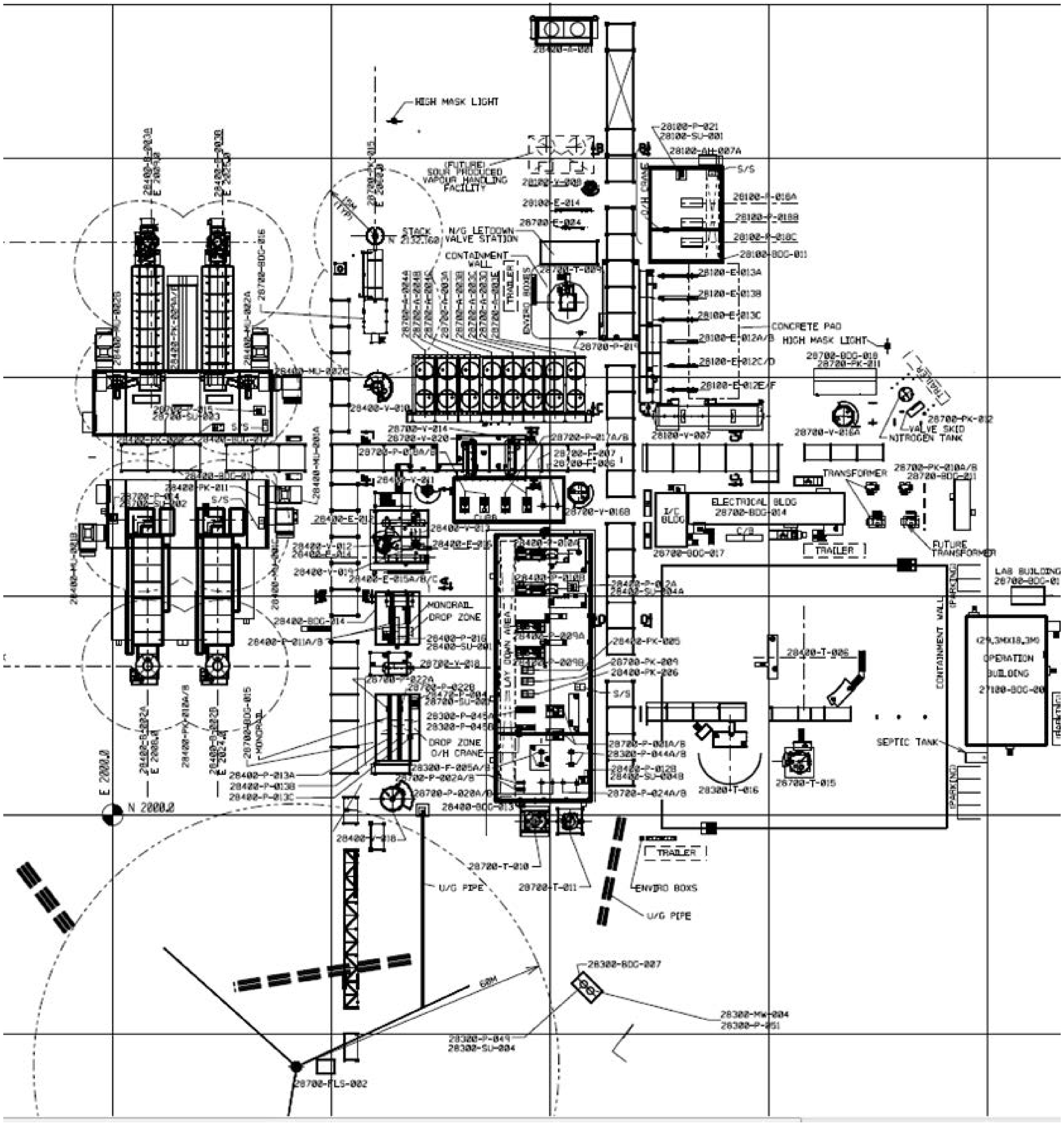


Subsection 3.1.2 (1a)

Kinosis Phase 1A (K1A)

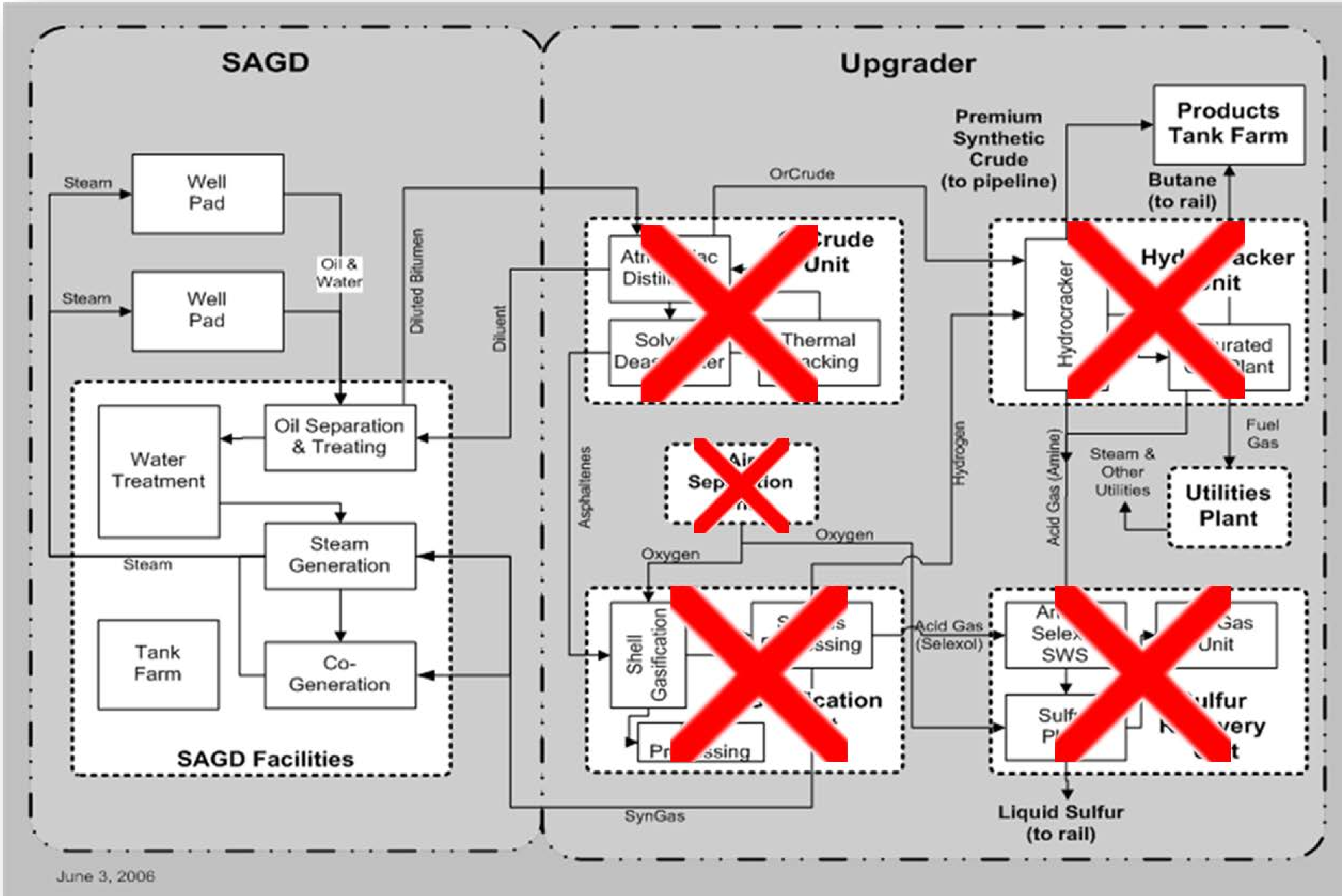
Aerial of K1A Steam Generation Facility with Well Pad 2 in the background – June 19, 2018

Kinosis Phase 1A Plot Plan

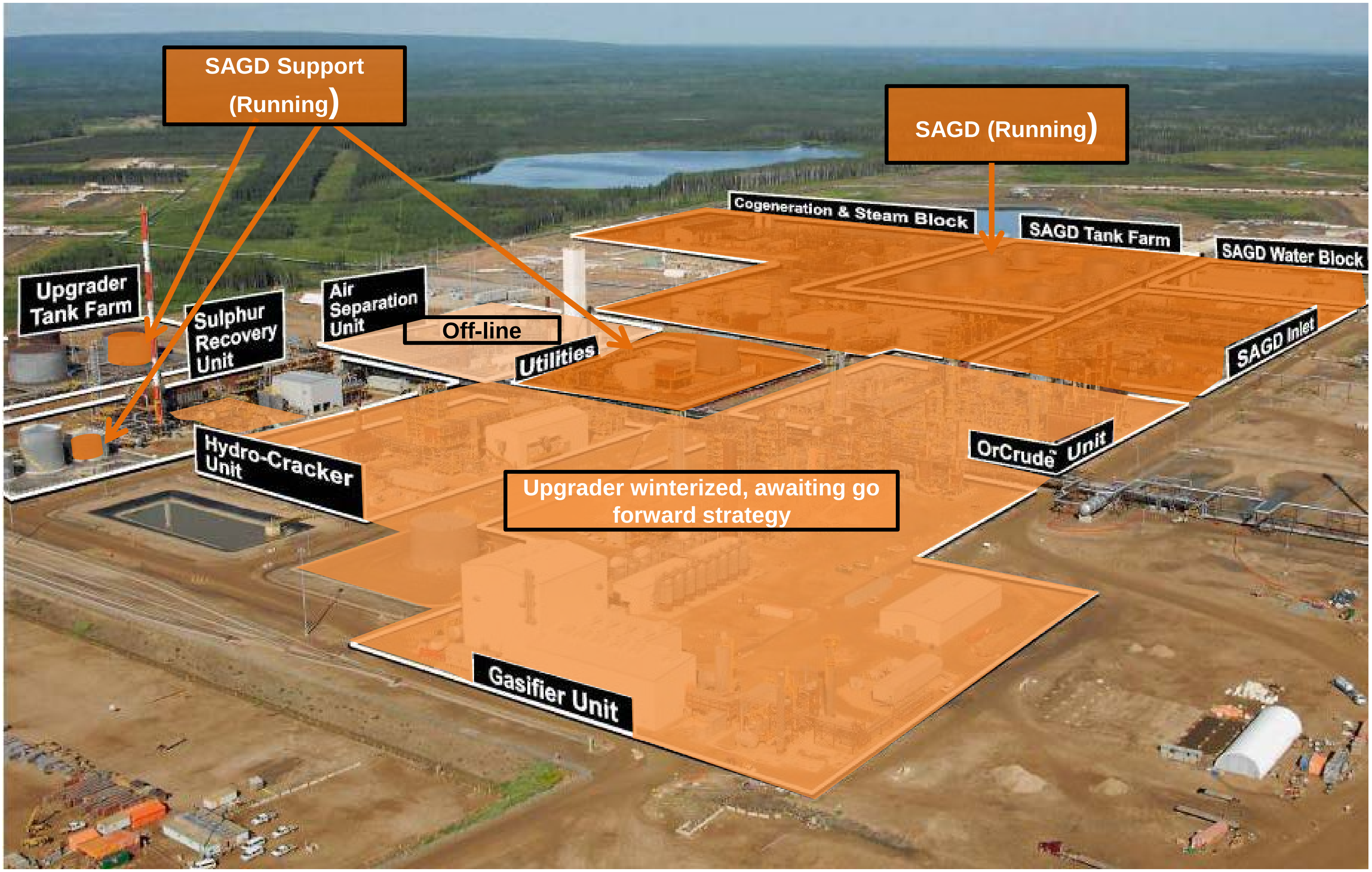


Subsection 3.1.2 (1a)

Current Plant Schematic



Subsection 3.1.2 (1b)


SAGD Support
(Running)
SAGD (Running)
Cogeneration & Steam Block
SAGD Tank Farm
SAGD Water Block
Upgrader Tank Farm
Sulphur Recovery Unit
Air Separation Unit
Off-line
Utilities
SAGD Inlet
Hydro-Cracker Unit
OrCrude Unit
Upgrader winterized, awaiting go forward strategy
Gasifier Unit

Facility Performance
Subsection 3.1.2 (2)
Long Lake and Kinosis

CNOOC

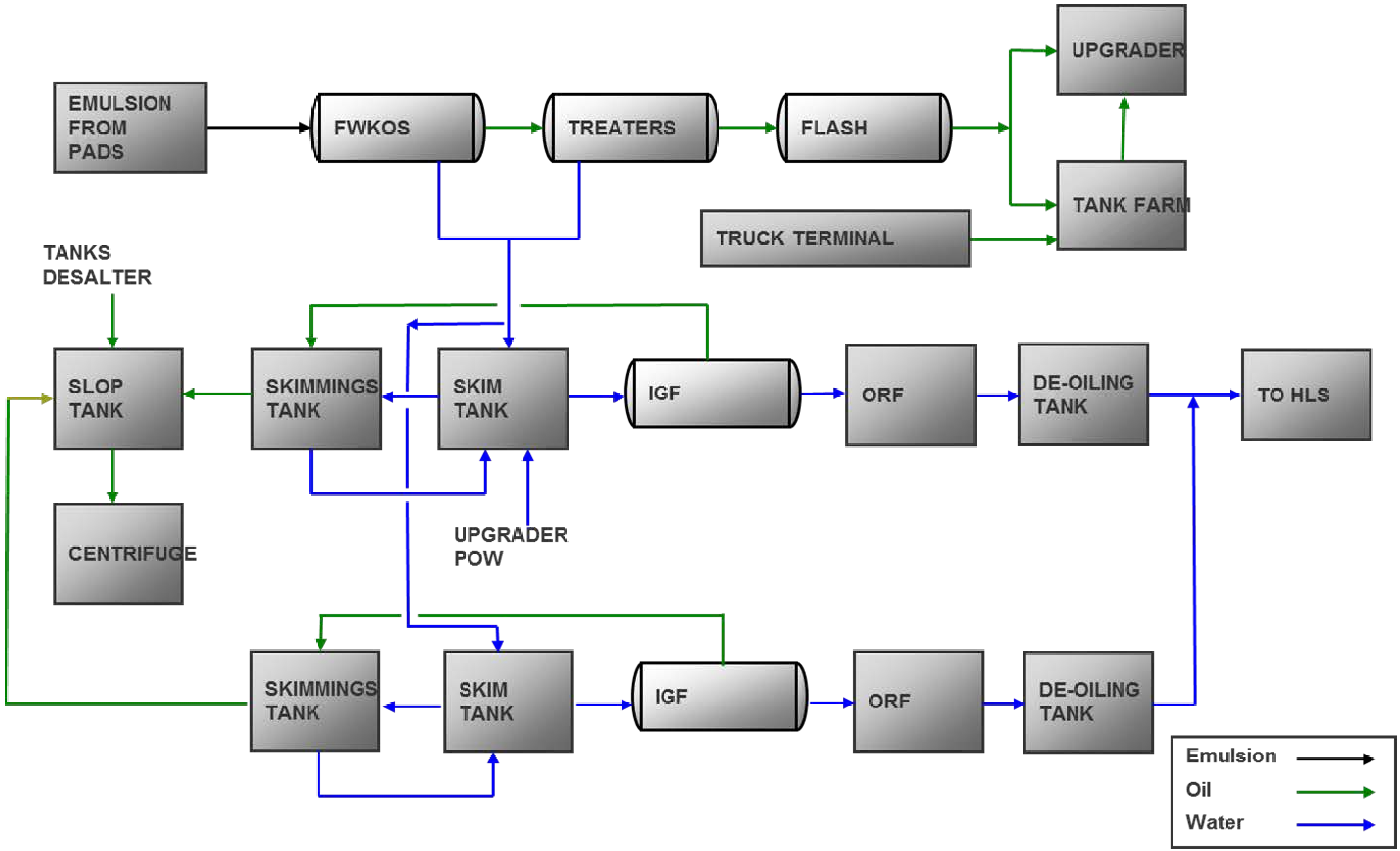
Facility Performance

Subsection 3.1.2 (2)

Long Lake Operations Summary - 2018

- Long Lake continued to operate in SAGD mode only, achieving a daily production average of 44,470 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.
- The Upgrader Flare shutdown Project was approved and executed in December 2018.
- Switched to 100% use of condensate as diluent in mid-2018.
- Rental Dilbit Chiller was put in service in the first week of May 2018, plan to use rental chiller until a decision on the Upgrader is made.
- Venting events were significantly reduced in 2018 following improvements to the inlet separation process and the Vapour Recovery Unit (VRU).
- Chemical treatment improvements are ongoing, particularly for the De-oiling section.
- Nitrogen generation package put in service September 2018. Additional demand not met by nitrogen skid is being purchased from a third party supplier.

Bitumen Treatment



Subsection 3.1.2 (2a)

Inlet and De-Oiling

- Pads 5 and 8 infill projects were completed and started up in 2018.
- The Dilbit Chiller project was executed and utilized successfully. Able to maintain true vapour pressure (TVP) targets with light diluent.
- Pressure re-rating of the inlet vessels was conducted and implemented successfully.
- The plant switched to 100% Fort Saskatchewan Condensate (CFT) as diluent by May of 2018.
- Improvements to De-oiling chemical treatment is in progress.
- Venting events have been reduced as a result of consistently better separation in Free Water Knock-Out (FWKO) drums after the introduction of reformulated chemicals.
- Dispersion model of venting events has been completed, learnings are being captured and a strategy on venting reporting is being developed.
- Successful transition to reformulated chemicals in May 2018 in Inlet treating resulted in reduced Produced Water (PW) Exchanger Fouling.
- Successfully completed the cleaning of FWKO drums A and B as planned.
- As part of the tank integrity program completed cleaning, inspection and repair of 6 SAGD tanks; external inspection, coating and insulation repair of BFW tank; and cleaning of one upgrader tank.
- Completed regulatory inspection of Induced Gas Floatation (IGF) drums in the Central Processing Facility (CPF) and Debottlenecking (DB) without production impact.

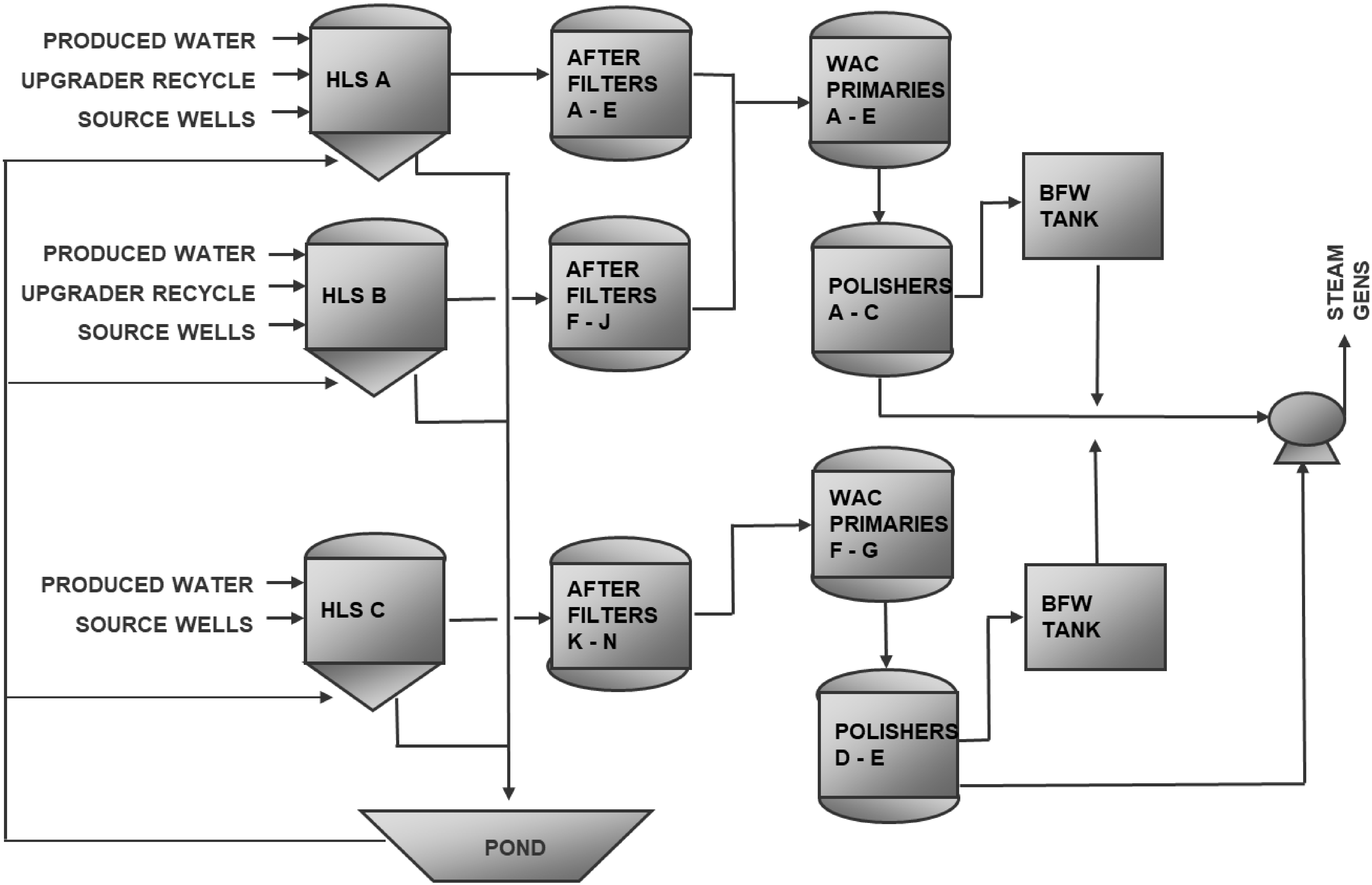
Subsection 3.1.2 (2a)

Tank Venting

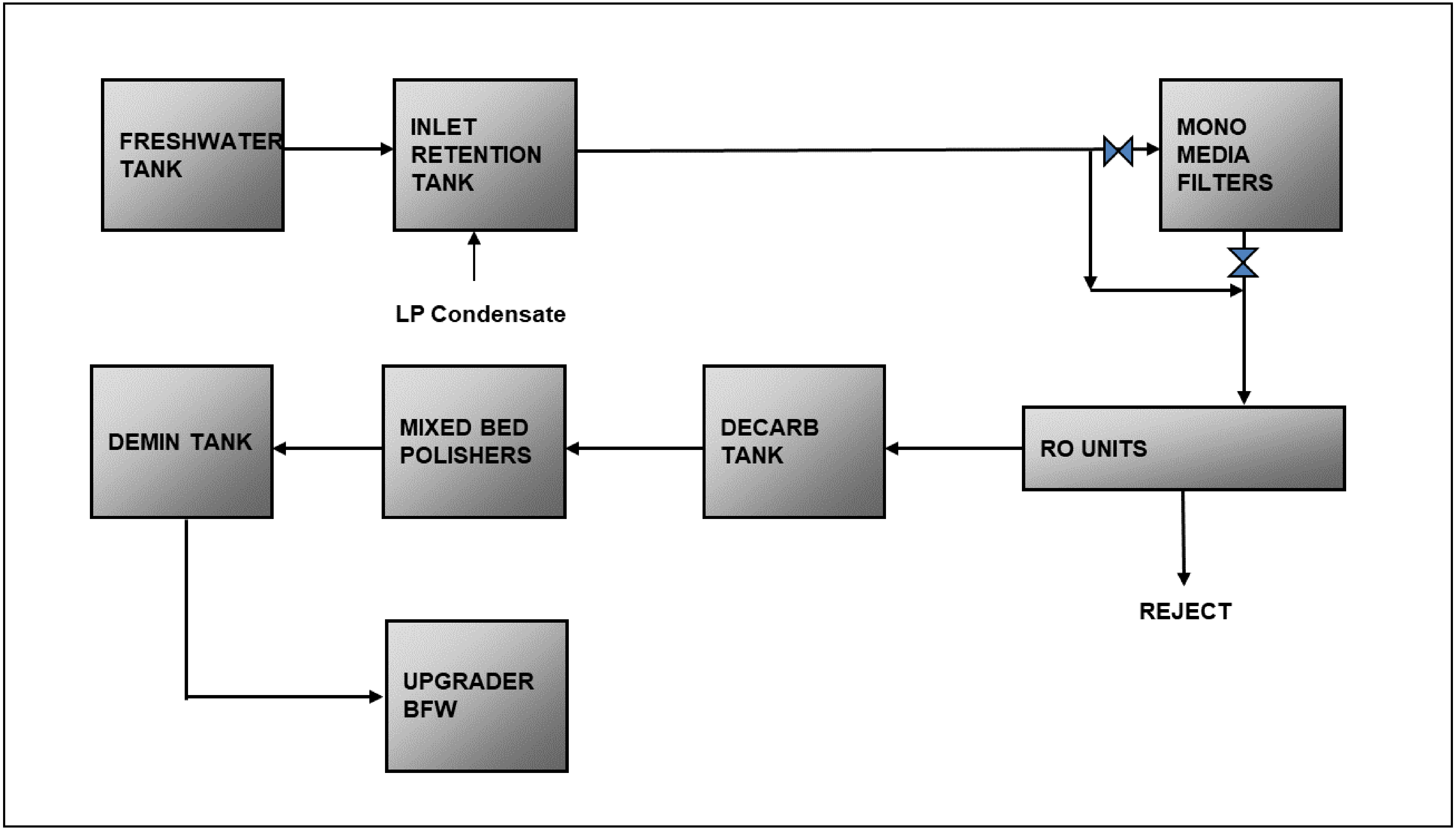
- Several venting incidents in 2018 led to the following actions to prevent re-occurrence:
  - Procedure put in place to ensure no process fluid off loading to Backwash and Slop Tank was strictly adhered to which reduced the number of venting incidents from these tanks.
  - Implementation of field modifications in order to handle light ends generated in the process efficiently by rerouting them to the Mixed Fuel gas header;
  - Optimization of the response of the Vapor Recovery Unit (VRU) by implementing changes to the process control strategy;
  - Dispersion model study was conducted from various tanks during venting incidents at various scenarios to determine that there were no adverse effects as required by AER.
  - Identified Immediate, mid and long term strategies in improving the VRU systems to handle vapour loads effectively; and
  - Also working with chemical vendor to improve treatment chemistry in inlet, to reduce off spec water going to de-oiling which results in venting incidents.
- Reporting criteria for single tank venting has been finalized and rolled out.
  - Future work will include dispersion modelling of multiple tank venting scenarios.

Water Treatment

Subsection 3.1.2 (2b)


PRODUCED WATER
UPGRADER RECYCLE
SOURCE WELLS
HLS A
AFTER FILTERS A - E
WAC PRIMARIES A - E
PRODUCED WATER
UPGRADER RECYCLE
SOURCE WELLS
HLS B
AFTER FILTERS F - J
POLISHERS A - C
BFW TANK
STEAM GENS
PRODUCED WATER
SOURCE WELLS
HLS C
AFTER FILTERS K - N
WAC PRIMARIES F - G
BFW TANK
POLISHERS D - E
POND

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. Issues with respect to the HLS sludge blowdown line plugging.

Weak Acid Cation (WAC) Unit Monitoring

- Optimized WAC resin usage by extending the service time between regeneration. Plan to maximize the resin usage until exhausted for 2019.
- 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.

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.
- Planning to conduct a trial to inject inorganic plus organic coagulant into HLS A during Q2 2019
- Reduced acid/caustic usage after extending the WAC service length.

Sludge Carry Over from HLSs

- Experience difficulties to maintain 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 may be required in 2019.

Lime Sludge Pond

- Pond B was dredged in 2018. A significant improvement in supernatant to HLSs water quality after dredging.
- The liner leakage rate has been controlled within regulatory limit.

Brackish Water

- The brackish system was not in use in 2018 as the operation was water long and brackish make-up was not required.
- Brackish header is out of service

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 2018, fresh water is used as water source to produced 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 emission.
- In December 2017, the IPSH line ruptured due to failed steam trap, which caused the HQW to shut down, and gas turbines had to reduce rates to meet NOx emission target.
- 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, to blend chemicals in the injection facility for use in the HLS.
- Utility water in the Battery, IF – end users of utility water (pump seals, VRU) cannot handle the high hardness and salinity of brackish water. The brackish water would cause issues in the chemical system as well.

Typical Water Quality (Produced and Disposed)

	pH	Conductivity (us/cm)	Turbidity (NTU)	Dissolved Hardness	Silica	Iron
Produced Water (Deoiled)	7 - 9.6 average 7.6	1,200 - 3,400 averag1,858	7 - 1760 average 327	3 - 50 average 11	32 - 290 average 154	n/a
Supernatant Water	8.3 -1 0 average 9	5,000 - 11,000 average 5500	90 - 1,000 average 642	50 - 297 average 153	20 – 243 average 63	n/a
Fresh Water	7 - 8.7 average 8.0	1,800 - 3,000 average 2,003	0 - 12 average 8	n/a	4 – 12 Average 8	0 - 2 average 1
Disposal Water	9.4 - 12 average 10.78	8,700 - 25,470 average 17245	n/a	3 - 27 average 11	400 - 542 average 450	2 - 5 average 3.3

- No brackish water chemistry in 2018

Subsection 3.1.2 (4)

Steam Generation

Fuel Consumption

- Syngas is no longer being used due to the shutdown of the Upgrader.
- Produced gas is no longer sweetened due to the shutdown of the SRU and the amine system. Sour produced gas is blended with pipeline natural gas for use as fuel gas in the boilers.
- Seeing corrosion on the Once Through Steam Generators' flue gas recirculation line, increased frequency of repairs.
- Reduced excess O2 in OTSG to 2% in order to reduce fuel
- Put HRSG in CASADE mode to maintain steam quality, and reduce fuel consumption

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 roof gets damaged after 1-2 years of operation. The roof material will be upgraded going forward.

Boiler Reliability

- High reliability of boilers in 2018 due to stabilized fuel supply.

Subsection 3.1.2 (2c)

Steam Generation

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

- **E-013 Exchangers** (Blowdown/MP Steam Condensers)
  - E-013 heat exchanger shows fouling in 2018, planning to switch to the other train

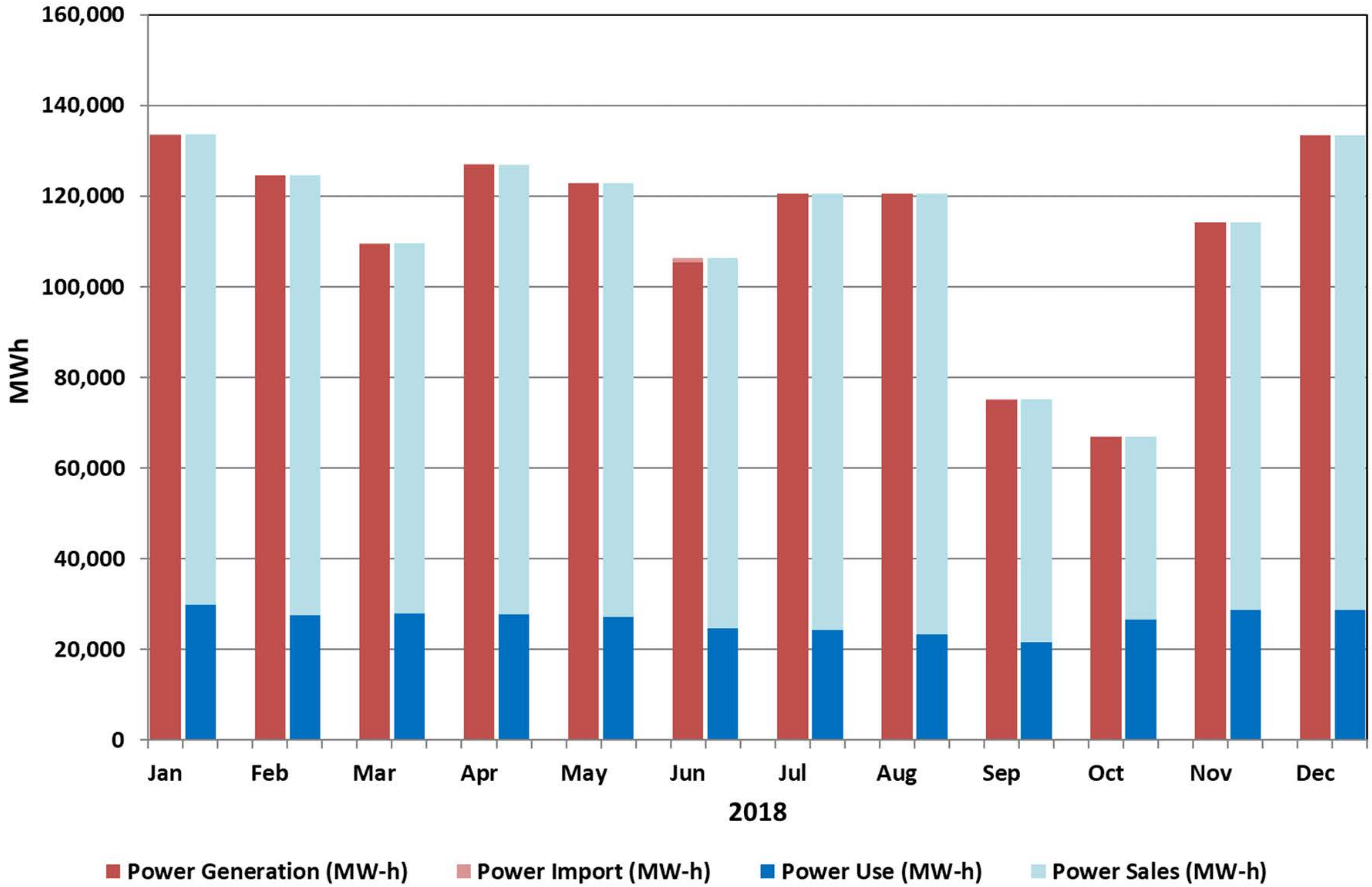
Subsection 3.1.2 (2c)

Power Generation

- **Emergency Power Supply**
  - Increased efforts have been made to improve reliability of the emergency generators and standby air compressors by utilizing external vendors to correct any deficiencies and implement preventative maintenance (PM) schedule on our behalf.

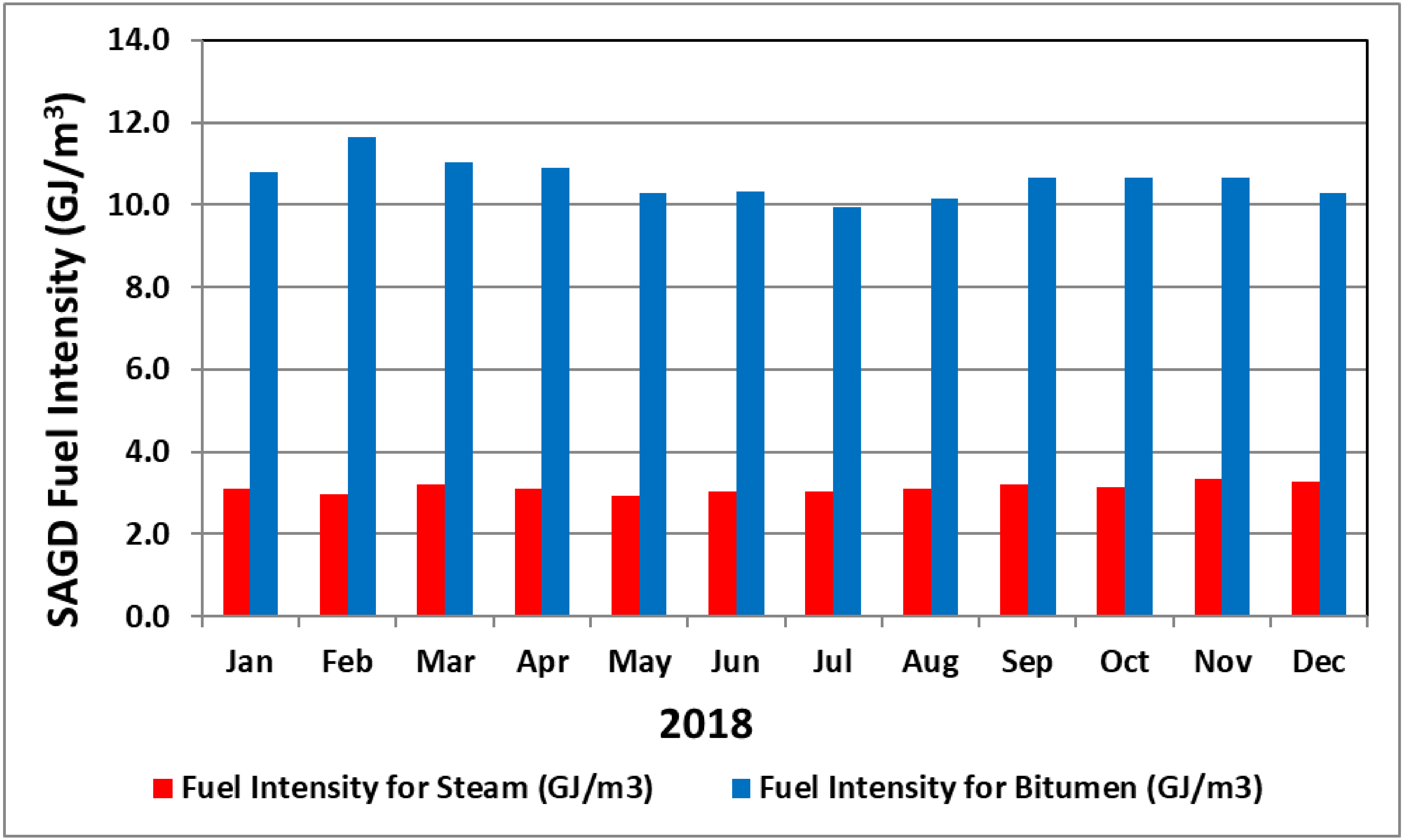
Subsection 3.1.2 (2d)

Total Power Usage



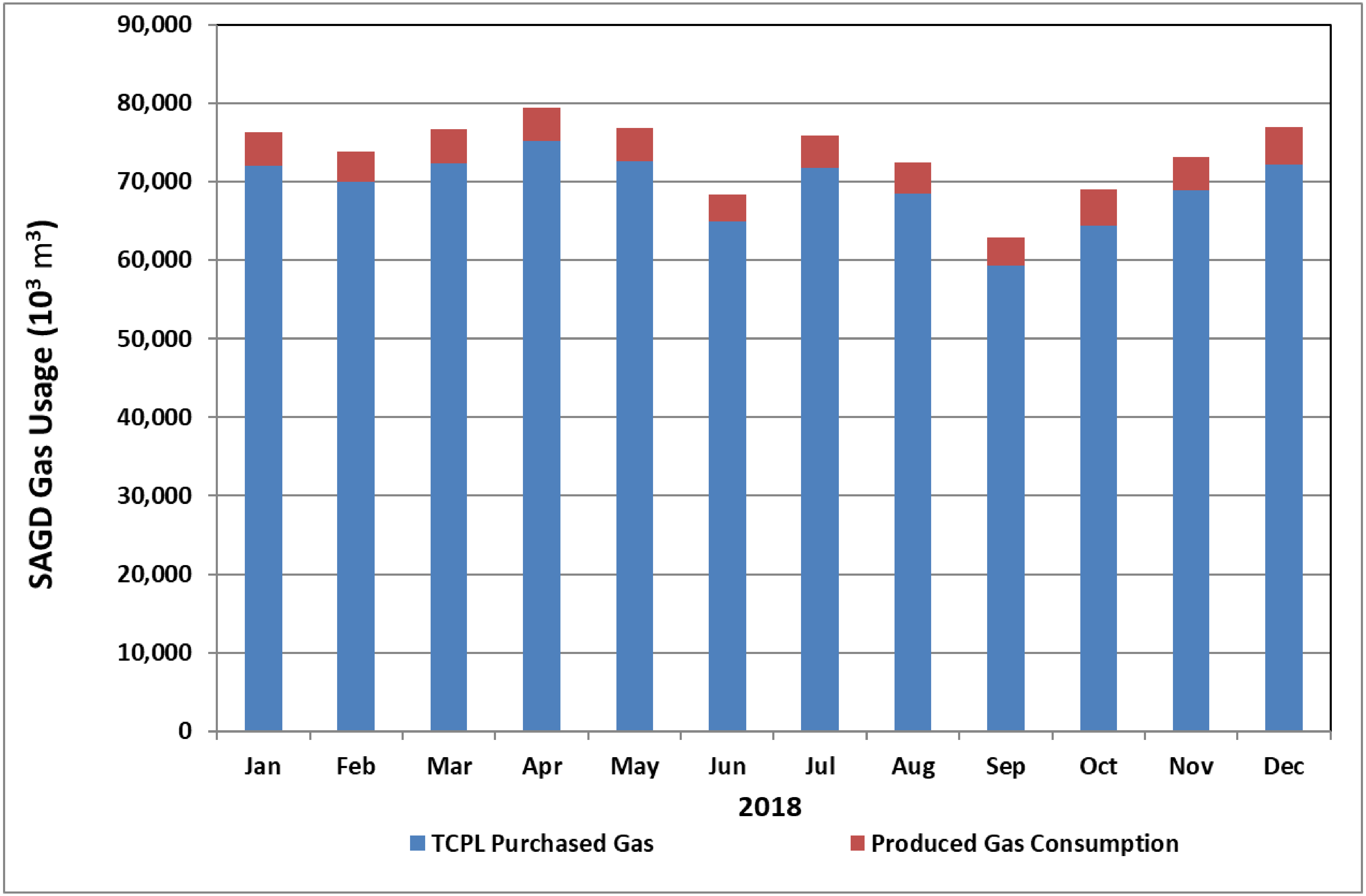
Subsection 3.1.2 (2d)

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)
2018	**(10^3m^3)**	**(10^3m^3)**
Jan	0.796	2.413
Feb	11.108	13.162
Mar	564.328	31.987
Apr	32.364	0.062
May	7.818	0.142
Jun	0.016	3.419
Jul	1.202	1.506
Aug	5.981	0.028
Sep	0.168	1.413
Oct	4.676	10.825
Nov	2.504	1.779
Dec	1.400	0.854
Total	**632.361**	**67.590**

- Higher vented volumes in March and April were related to oil-water separation issues in the free water knock-out (FWKO) drums. A chemical optimization trial was conducted in April 2018 with the objective of improving separation in the FWKOs and reducing venting events.
- Higher flared volumes in March were due to limited pump capacity to reduce/control the level in the discharge separator vessel of one of the vapour recovery unit compressors. The hydrocarbon condensate side of the discharge separator had to be frequently drained to flare. Maintenance repaired the stand-by pump and ordered a new pump as a preventative action.

Subsection 3.1.2 (2e)

Greenhouse Gas Emissions

- Long Lake's GHG intensity is trending downwards
  - The lower GHG intensity is associated with lower SORs, improved reliability, and efficient operations.
  - The move to in-situ only operations in 2016 reduced GHG emissions by removing upgrader emissions and the generation and combustion of syngas at Long Lake.

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

- Compliance is being met through improving Long Lake's GHG performance, using carbon credits to the maximum extent, and contributions to the technology fund.
  - Carbon credits include emissions performance credits and offset credits from CNOOC International's Soderglen wind farm asset.

- The new Carbon Competitiveness Incentive Regulation came into effect in 2018, replacing the SGER baseline system.
  - Long Lake is transitioning into the new system of output based allocations by product type, receiving GHG credits for both bitumen production and electricity exports.

Subsection 3.1.2 (2f)

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

Produced Bitumen Measurement

- Ten two-phase test separators with up to 12 well pairs for Pads 1-10, 12 & 13:
  - Currently testing two wells per day per separator. 12 hour test duration, with a minimum of one test per week per well.
  - Wells with ESPs are equipped with wellhead coriolis meters for daily optimization, which allows a longer well test duration for monitoring S&W profiles.
  - Bitumen cuts are based on an inline water cut analyzer (AGAR OW-201 meter) and manual cuts are taken for confirmation.
  - All ten wells on Pad 11 receive continuous well testing via individual coriolis flow measurement and AGAR water cut meters.
- The multiphase flow meter installed on Pad 14 is no longer operational. The test data is validated daily via the Coriolis and water cut meter on the test loop piping. We are still waiting for MARP audit/approval.
- The new AGAR multiphase flow meter installed on Pad 15 was operational for all of 2018.
- K1A pads were not in service for 2018.
- Bitumen samples collected from emulsion line are analyzed by Long Lake Lab to determine density as requested by Department of Energy.

Subsection 3.1.2 (3a)

Proration Factors

LLK Proration Factors 2018		
MONTH	**OIL**	**WATER**
2018-01	1.02	0.89
2018-02	1.02	0.90
2018-03	1.04	0.86
2018-04	1.04	0.86
2018-05	1.06	0.88
2018-06	1.02	0.88
2018-07	1.03	0.91
2018-08	1.01	0.92
2018-09	0.98	0.91
2018-10	1.00	0.93
2018-11	1.03	0.85
2018-12	1.05	0.86

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

Subsection 3.1.2 (3b)

Steam Production Measurement

This is the primary methodology for steam production reporting.

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

OTSG = Once through steam Generators (840X-B-001 A-F) x = 1 to 6

OTSGs (8401-B-001A-F) will be producing steam based on three criteria (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)

Steam Production Measurement

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

HRSGs will be producing steam based on three criteria (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)

Steam Injection Measurement

Steam injection is measured at the wellhead (estimating steam quality of 97% at the wellhead).

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 2018 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

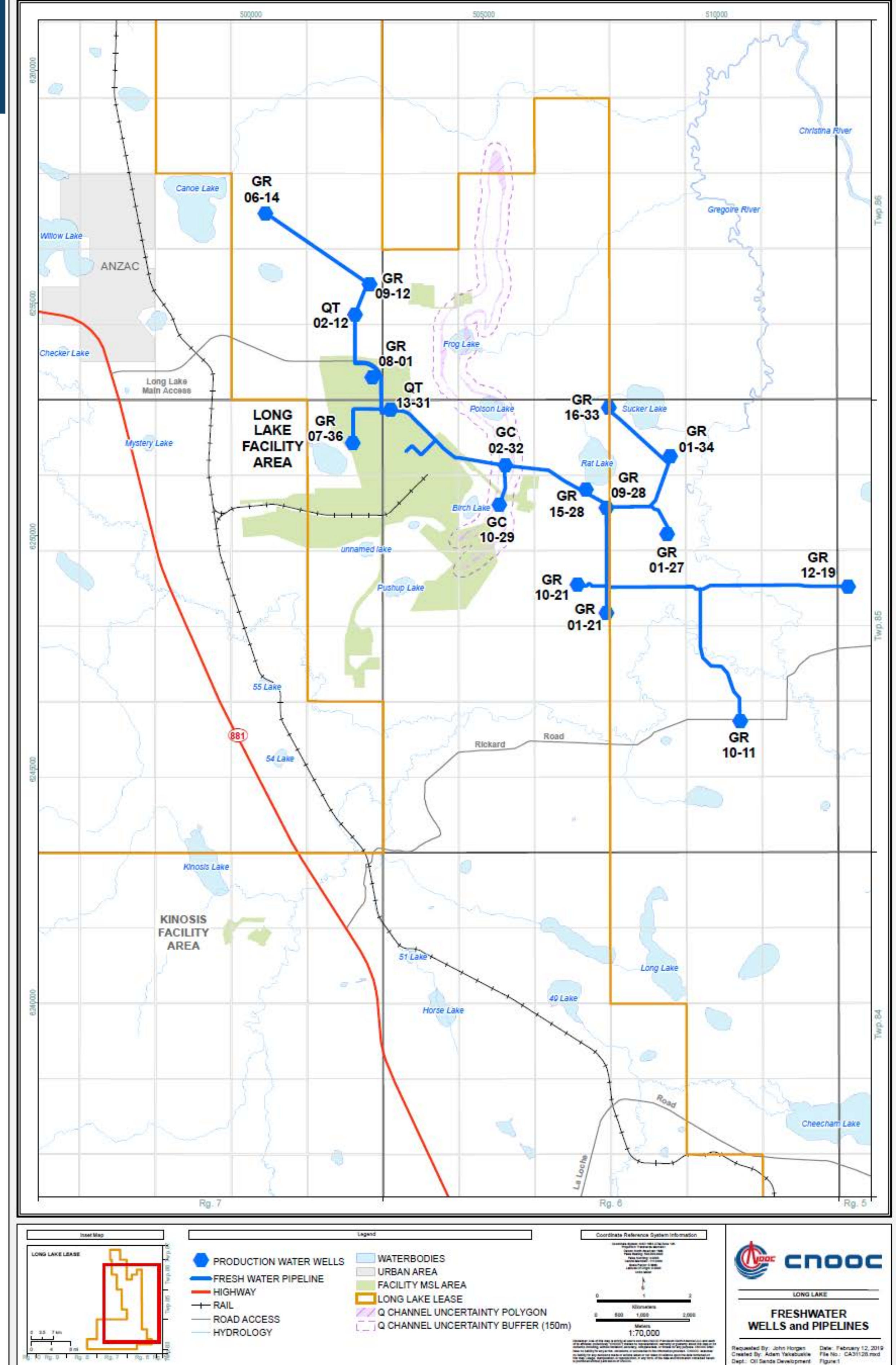
Subsection 3.1.2 (3a)

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

CNOOC

Freshwater Pipelines

- No fresh water wells drilled in 2018



Subsection 3.1.2 (4a)

Freshwater Pipelines (CONT'D)

Plant Operations	WA License# 235895-02-00		Salinity as Total Dissolved Solids		Jan-Dec 2018	
Location	**Formation**	**Fresh?**	**Sample Date**	**Concentration (mg/L)**	**Total (m3)**	**Annual avg. (m3/cd)**
01-21-85-06W4M	Grand Rapids	Y	8-Sep-17	1,700	63,243	173
01-27-85-06W4M	Grand Rapids	Y	7-Sep-17	1,300	32,478	89
01-34-85-06W4M	Grand Rapids	Y	7-Sep-17	1,500	94,362	259
02-12-86-07W4M	Quaternary	Y	7-Sep-17	640	86,174	236
02-32-85-06W4M	Gregoire Channel	Y	28-Mar-18	1,500	0	0
06-14-86-07W4M	Grand Rapids	Y	28-Jul-18	1,200	157,143	431
07-36-85-07W4M	Grand Rapids	Y	30-Jul-18	670	48,905	134
08-01-86-07W4M	Grand Rapids	Y	9-Sep-14	888	0	0
09-12-86-07W4M	Grand Rapids	Y	30-Jul-18	670	86,238	236
09-28-85-06W4M	Grand Rapids	Y	7-Sep-17	1,300	93,851	257
10-11-85-06W4M	Grand Rapids	Y	29-Jul-18	3,100	20,425	56
10-21-85-06W4M	Grand Rapids	Y	30-Jul-18	1,600	107,010	293
10-29-85-6W4M	Gregoire Channel	Y	11-Nov-17	1,500	1,648	5
12-19-85-05W4M	Grand Rapids	Y	29-Jul-18	2,200	28,828	79
13-31-85-06W4M	Quaternary	Y	30-Jul-18	530	24,161*	66
15-28-85-06W4M	Grand Rapids	Y	31-Jul-18	1,600	64,342	176
16-33-85-06W4M	Grand Rapids	Y	31-Jul-18	1,300	81,579	224
License Allocation 3,285,000 m3 (annual daily average of 9,000 m3/d)		**TOTAL**			***990,385***	**2,713**

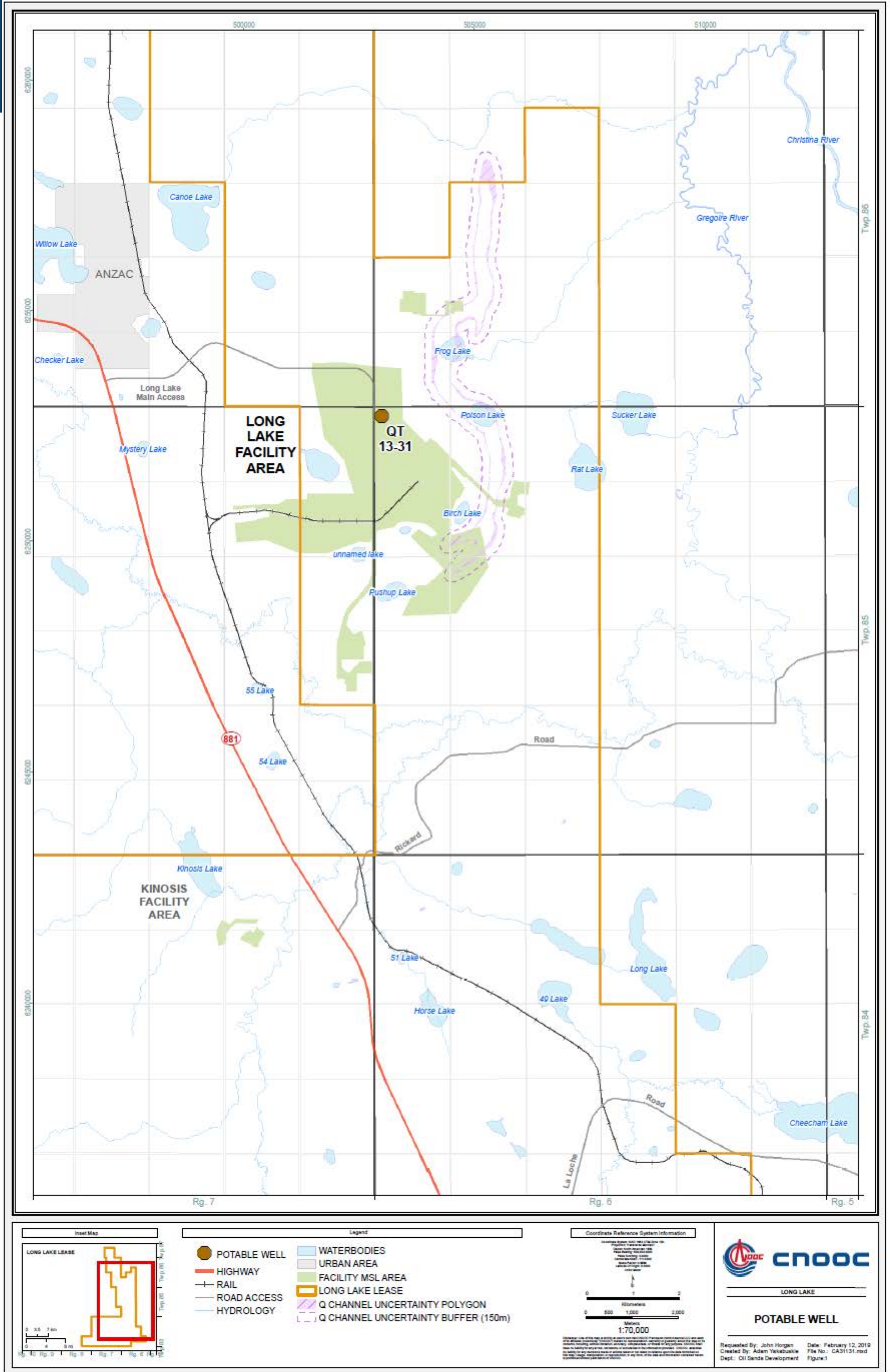
Potable	AENV# 235895-02-00				Jan-Dec 2018	
Location	**Formation**	**Fresh?**			**Total (m3)**	**Annual avg. (m3/cd)**
13-31-85-06W4M	Quaternary	Y	30-Jul-18	530	23,968	66

- 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 48,129 m^3 was diverted from well WS-QT-13-31-085-06W4 for domestic use. The volume of water rejected from the treatment plant (24,161 m^3) was re-used in the plant operations rather than being sent to disposal.

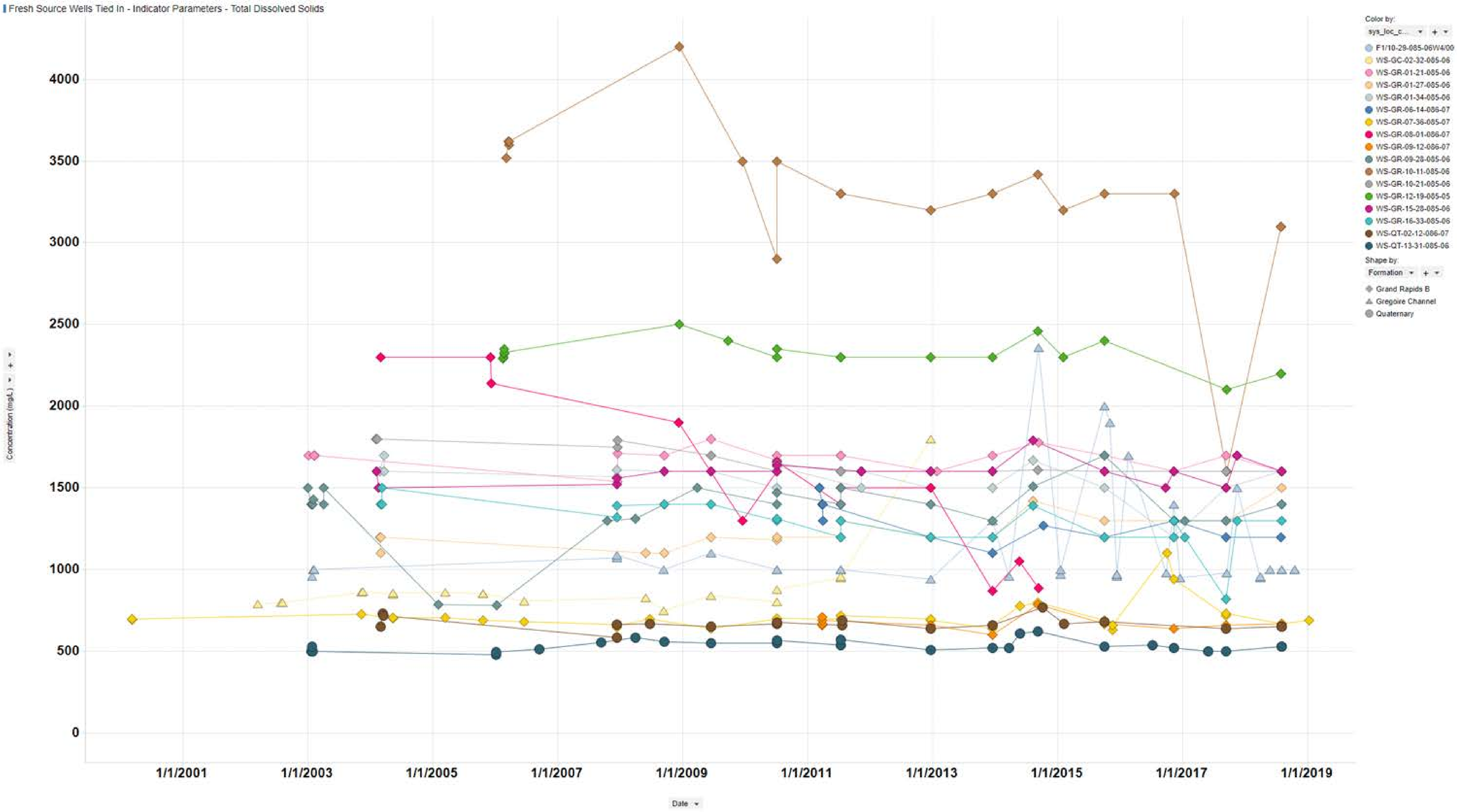
Potable Well

Aquifer:	Quaternary drift
Purpose:	Domestic (camp)
Location:	13-31-85-06W4
2018 diversion:	48,129 m^3/y
Average daily rate:	131 m^3/d



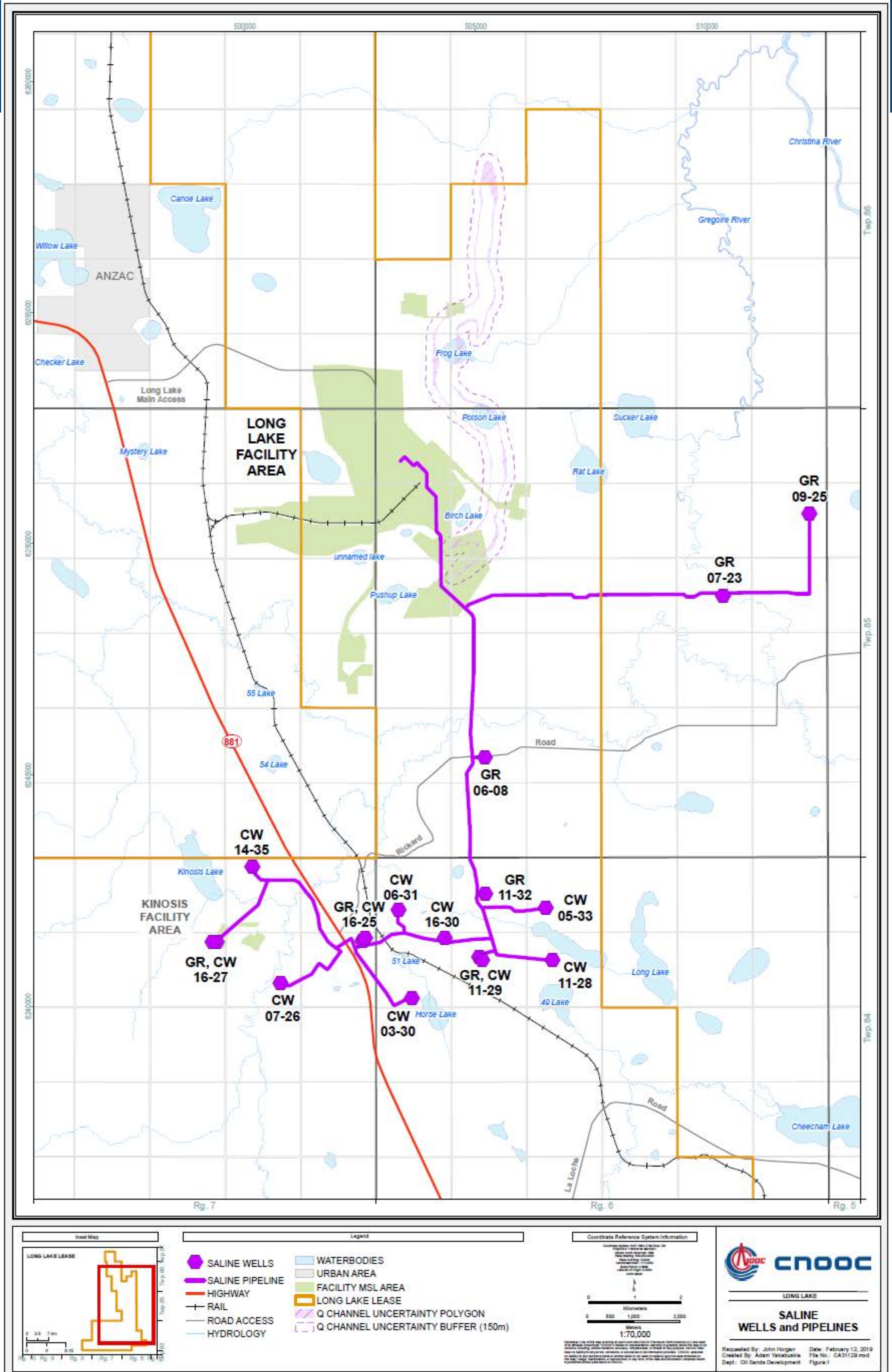
Subsection 3.1.2 (4a)

Fresh Water Source Wells Water Quality TDS



Saline Water Pipelines

- No new saline wells drilled in 2018



Subsection 3.1.2 (4a)

Saline Water Pipelines (CONT'D)

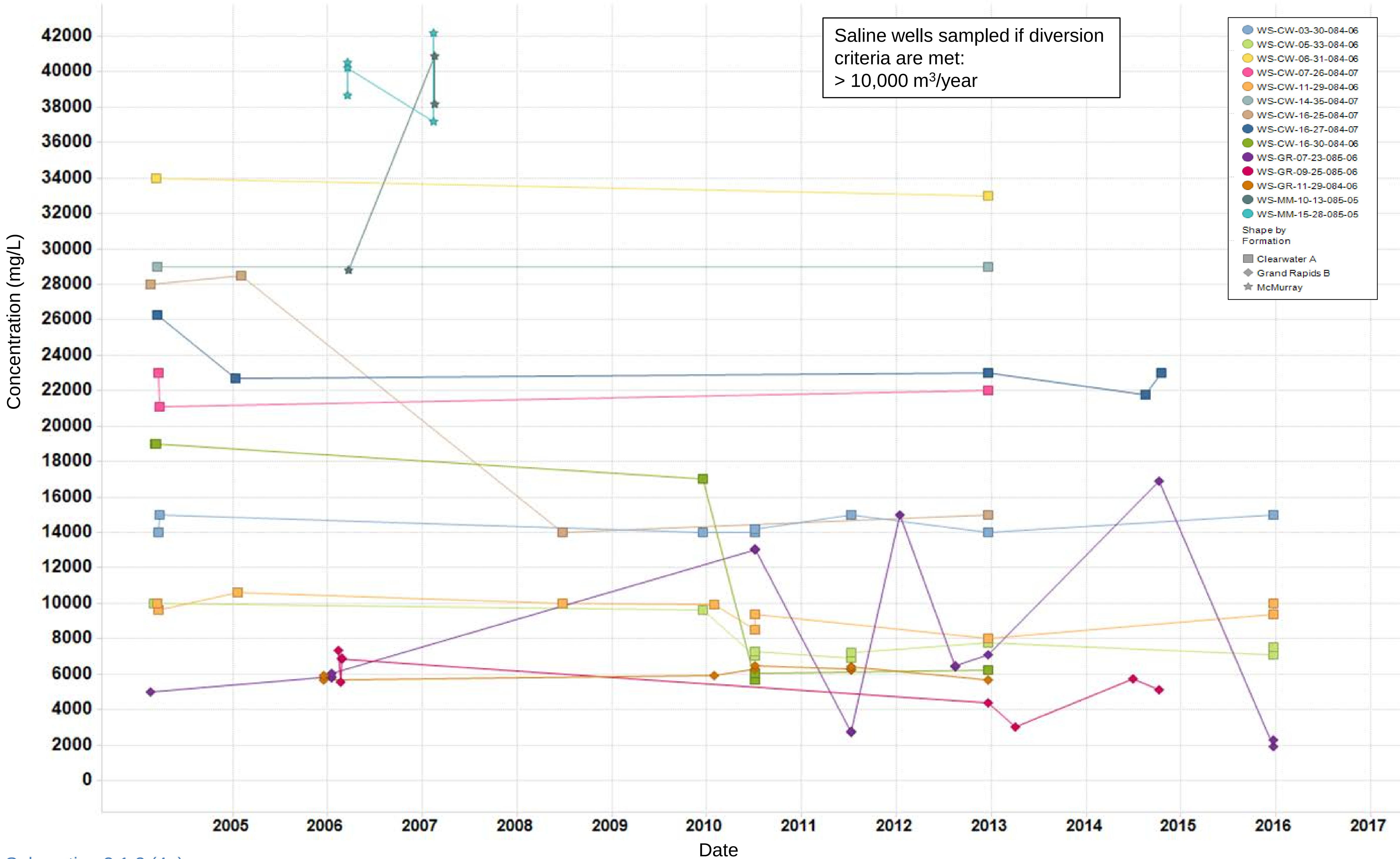
Plant Operations			Total Dissolved Solids			Jan-Dec 2018
Location	**Formation**	**Saline?**	**Sample Date**	**Concentration (mg/L)**	**Total (m3)**	**Annual avg. (m3/cd)**
1F2/03-30-084-06W4	Clearwater	Y	22-Dec-15	15,000	0	0
1F1/05-33-084-06W4	Clearwater	Y	22-Dec-15	7,500	0	0
1F1/06-31-084-06W	Clearwater	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 2018 as no water was diverted



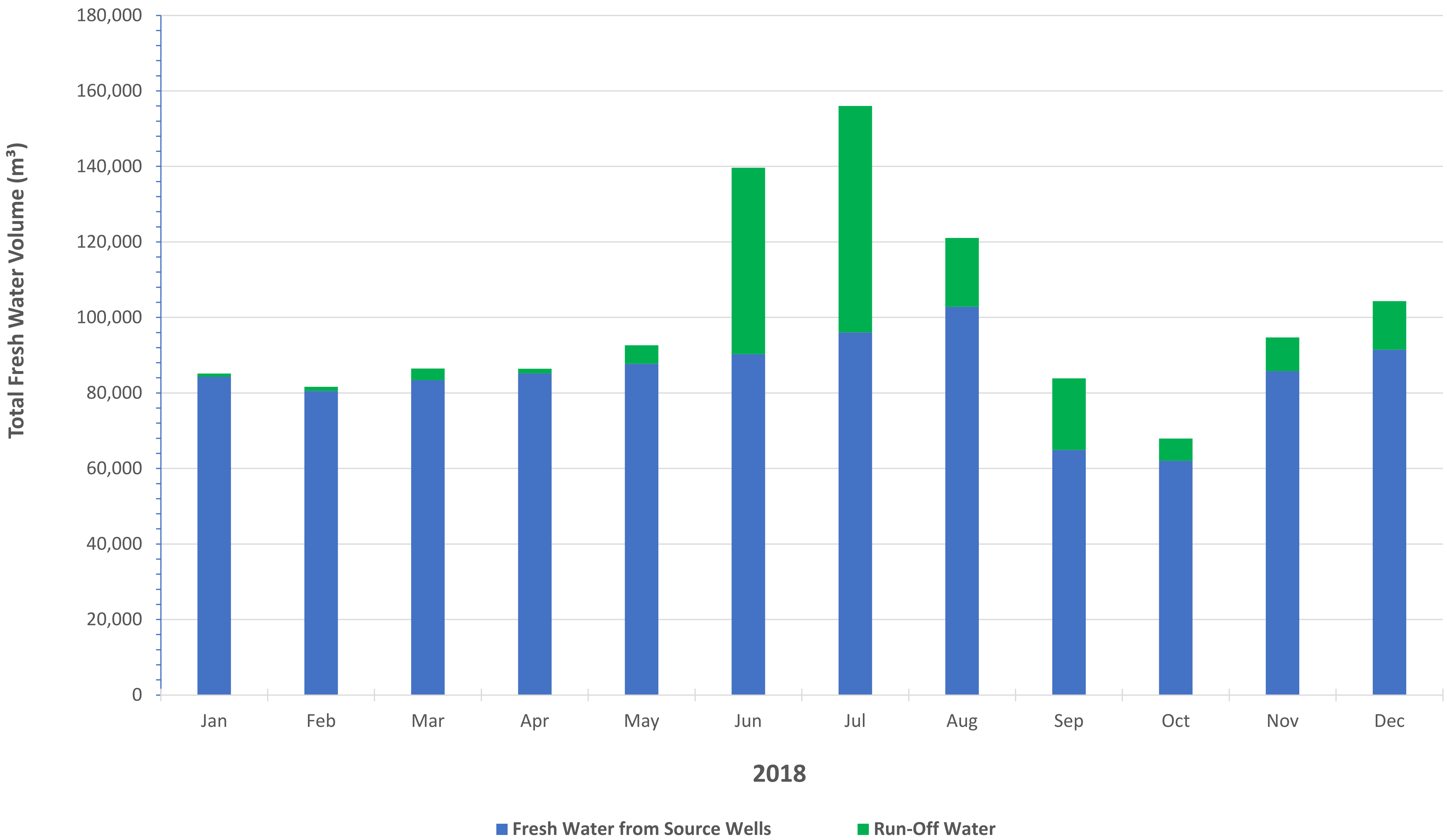
Subsection 3.1.2 (4a)

Other Water Sources

- Surface runoff to lime sludge ponds (Licence No. 00247843-01-00):
  - 2018: 185,407 m^3 (estimate)

- Well drilling, dust control, winter access freezing:
  - Licence No. 311818-00-01 and 354427-00-00: 16,383 m3
    - Volume higher than previous years due to water required for Long Lake infill drilling program, LLSW construction and winter access freeze in for K1A pipeline

Fresh Water Use Volumes



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

Subsection 3.1.2 (4b)

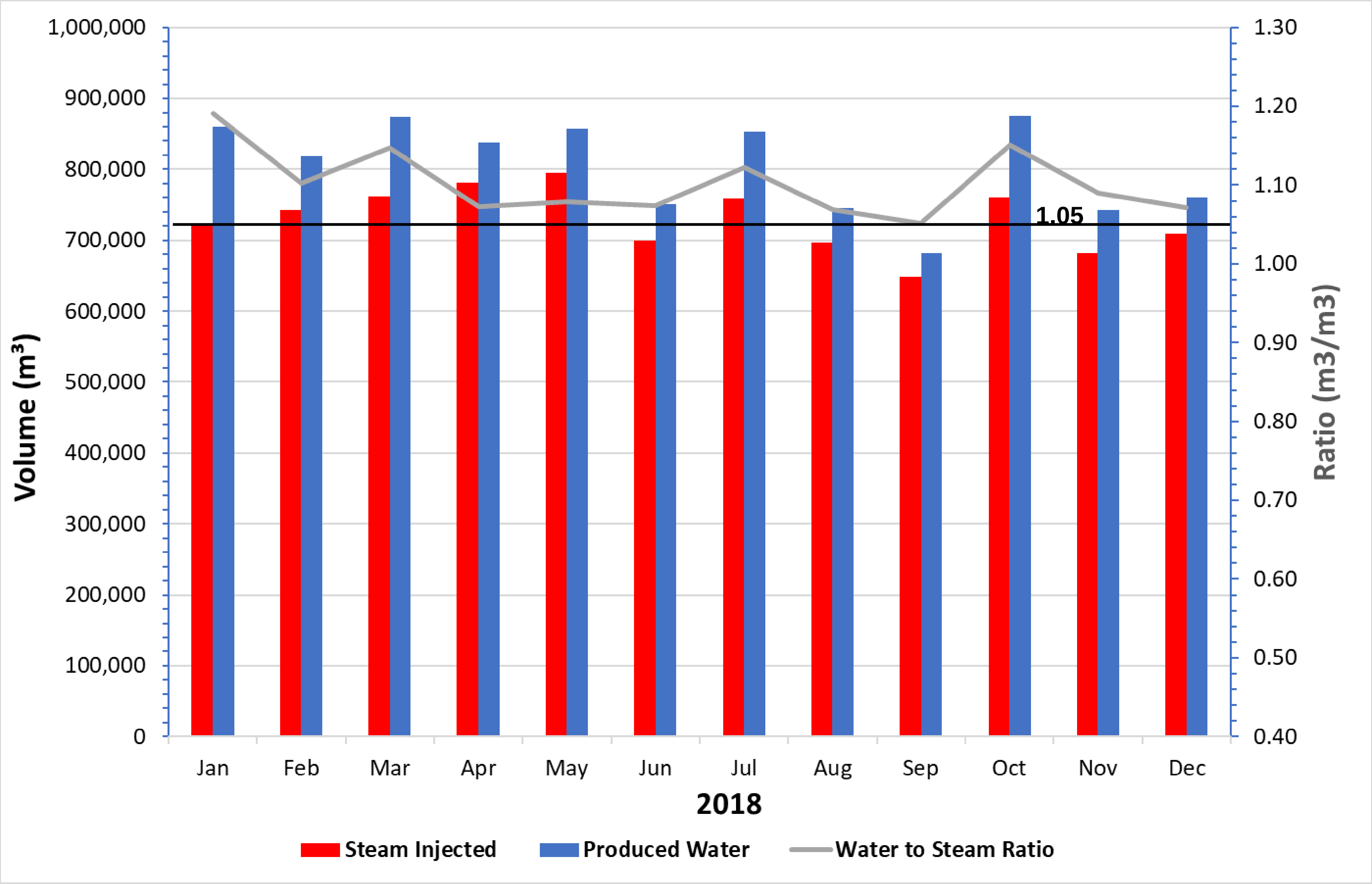
- Use of freshwater make-up (in decreasing amounts)
    1. Utility and plant use, recycled to SAGD for steam generation
    2. Demineralized water make-up (UPG and cogens)
    3. Domestic
    4. Others (incl. drilling)

Freshwater Uses in 2018 (m^3)				
	Total	Domestic	Recycled	Process
Main groundwater license (235895-02-00 as amended)	1,014,353	23,968	749,461	240,924
Surface runoff to ponds (includes K1A) (m^3)	185,407		185,407	
Various surface water sources - Drilling and other	16,383			
TOTAL	1,216,143			

- Saline water make-up:

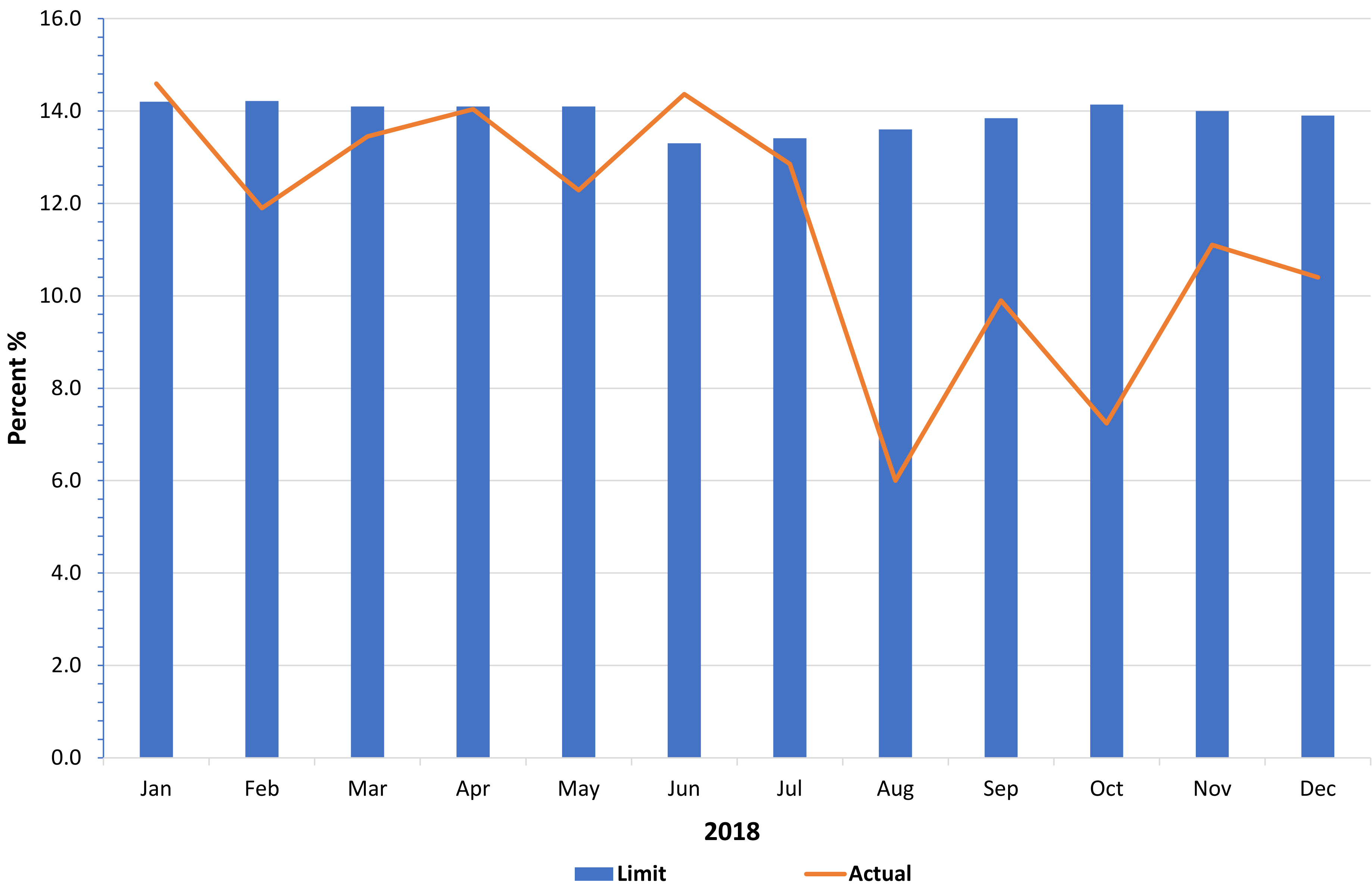
  0 m^3 in 2018 for steam make-up, average WSR = 1.1

Produced Water and Steam Injected Volumes



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

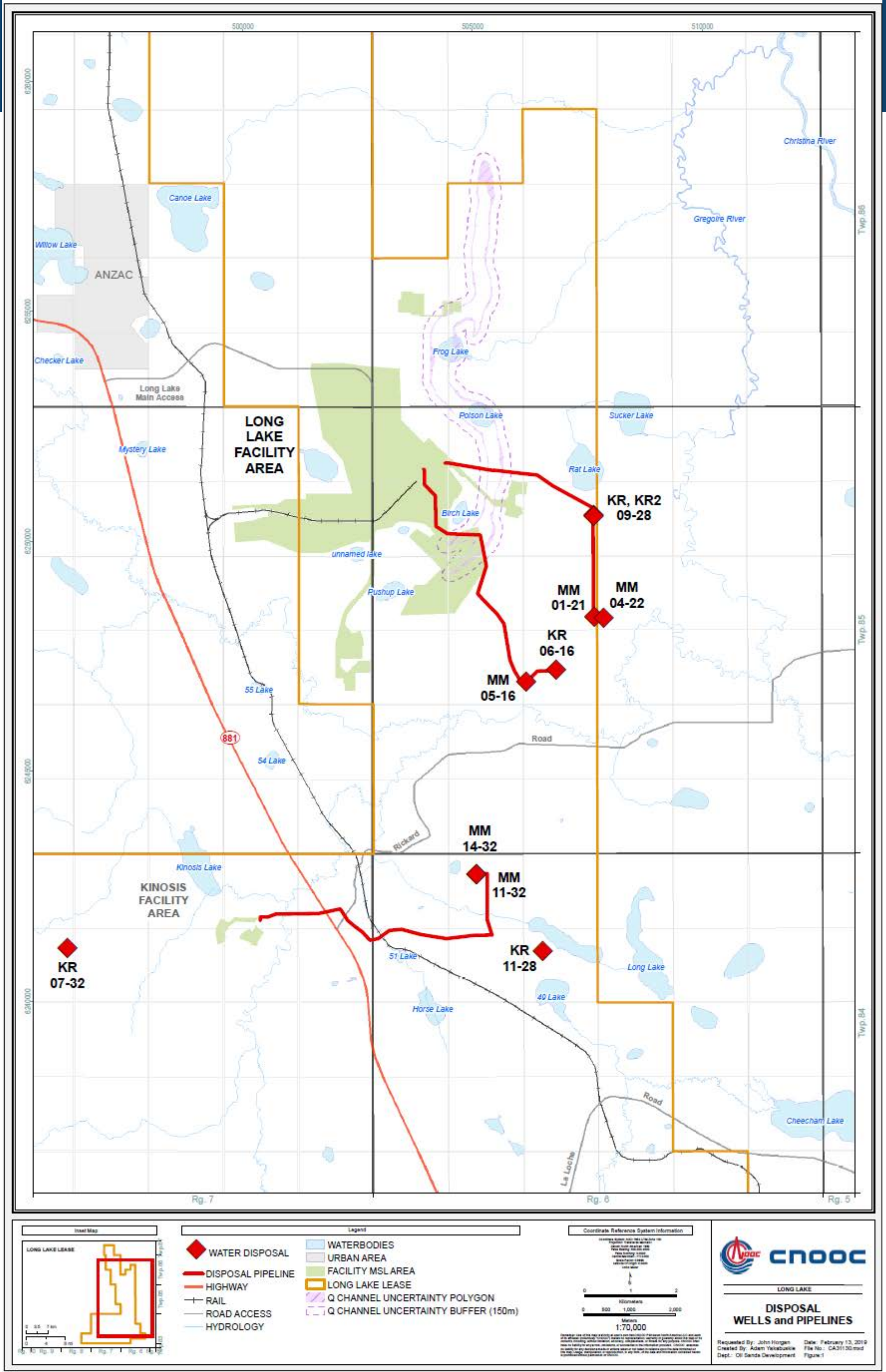
Note: CNOOC International received approval to have produced water disposal factor increased from 0.10 to 0.15 effective Oct 1, 2017.



Average Limit = 13.9 %

Average Actual = 11.6 %

Disposal Wells



Subsection 3.1.2 (4g)

Disposal Wells (CONT'D)

Class 1B Disposal Wells (Approval No. 10023J)

CNOOC Int ULC   Sumary of disposal activities 2018

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	335	1,203	1,732	403,022	1,431	3,000
WD-KR2-09-28-085-06	04/09-28-085-06W4/00	320	2,512	4,244	803,719	1,956	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				**1,206,741**		

Notes:

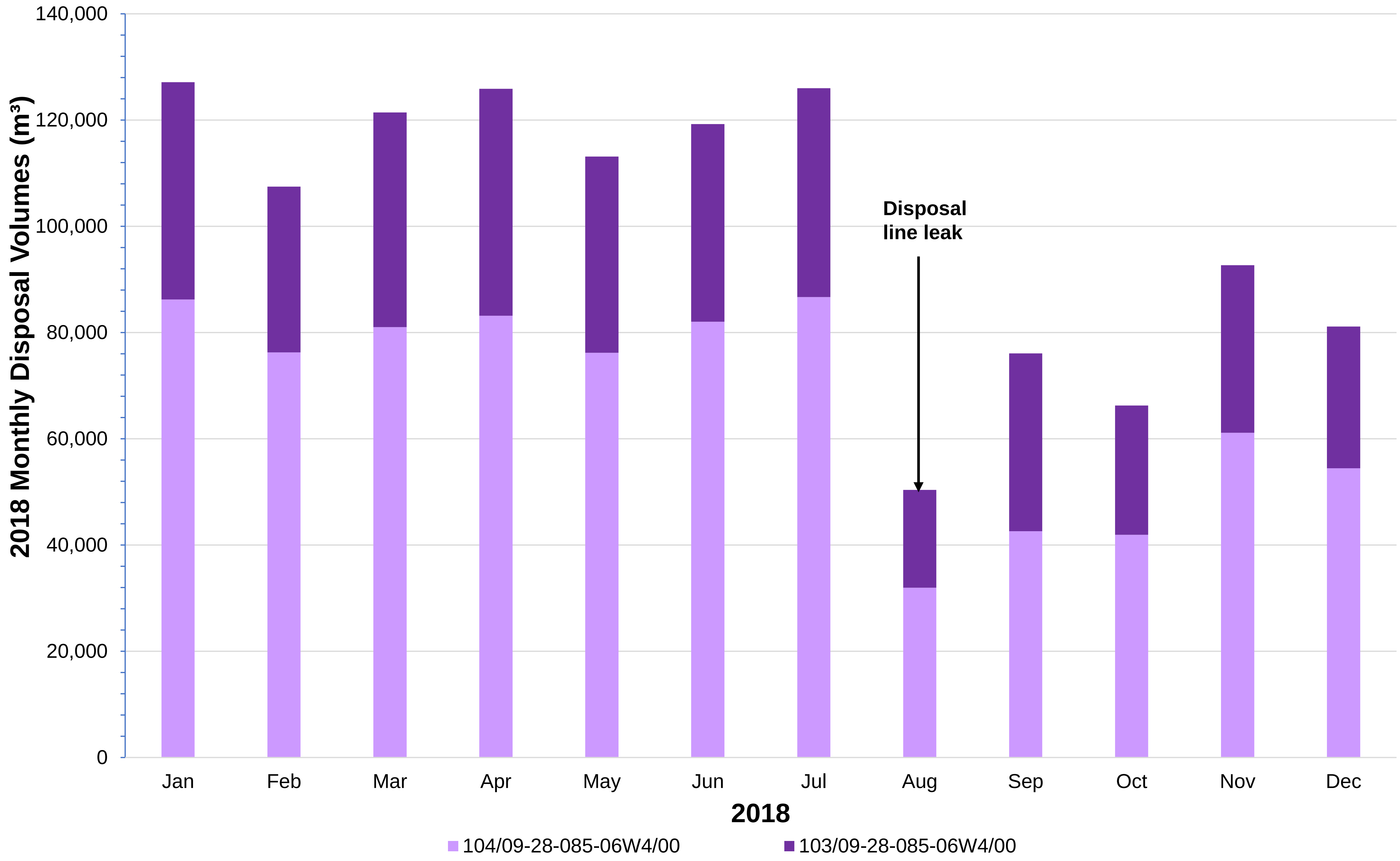
1. WHP = Well Head Pressure
2. Excluding days of no disposal

AER Approval # 11611	Class 1a	January - December 2018		
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

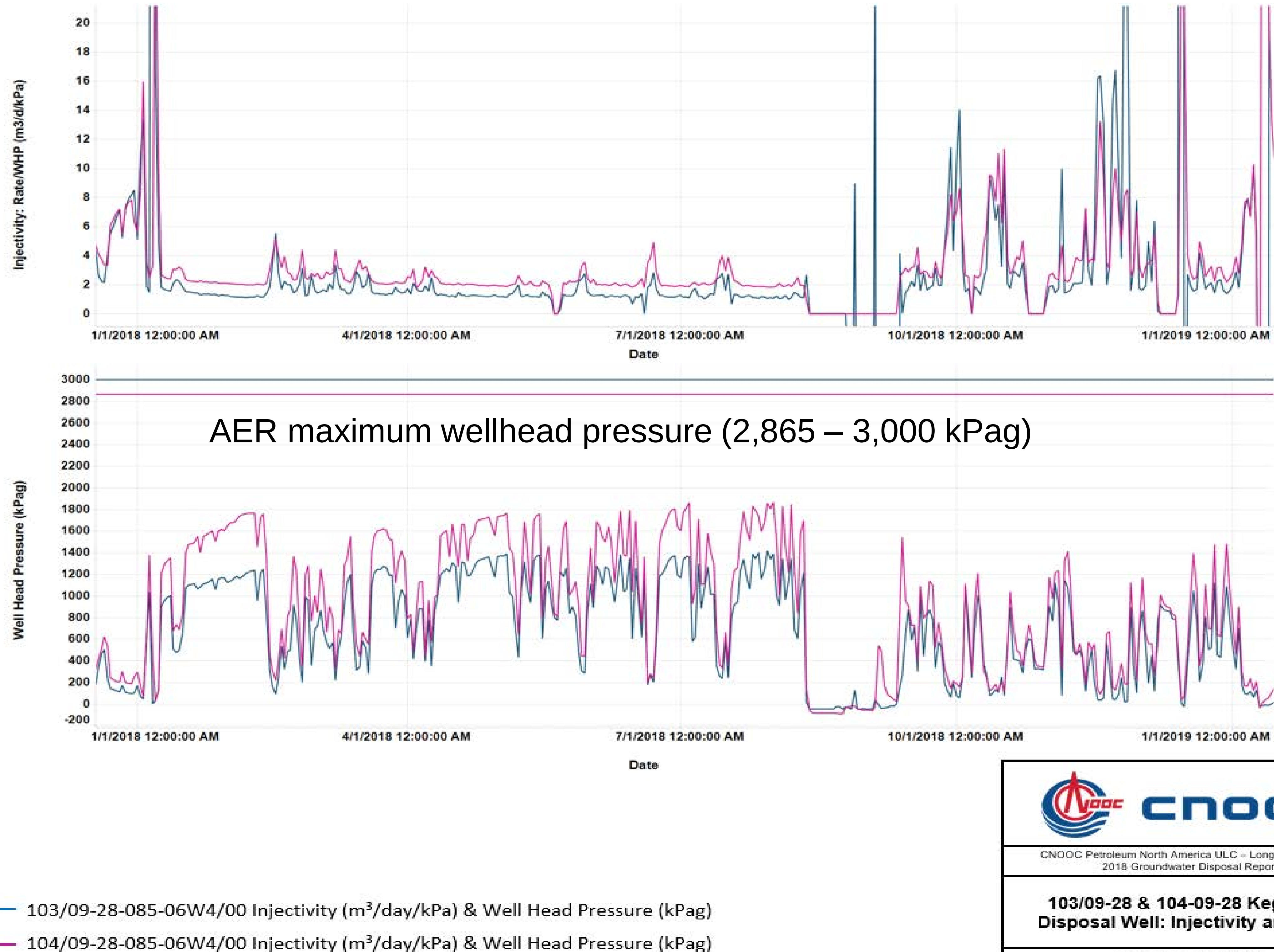
- Disposal capacity is adequate
- All wells passed annulus pressure test

Disposal Well Volumes - Class 1b



- 2018 disposal only to Keg River wells 103 and 104/09-28-085-06W4/00

Disposal Well - Well Head Pressures

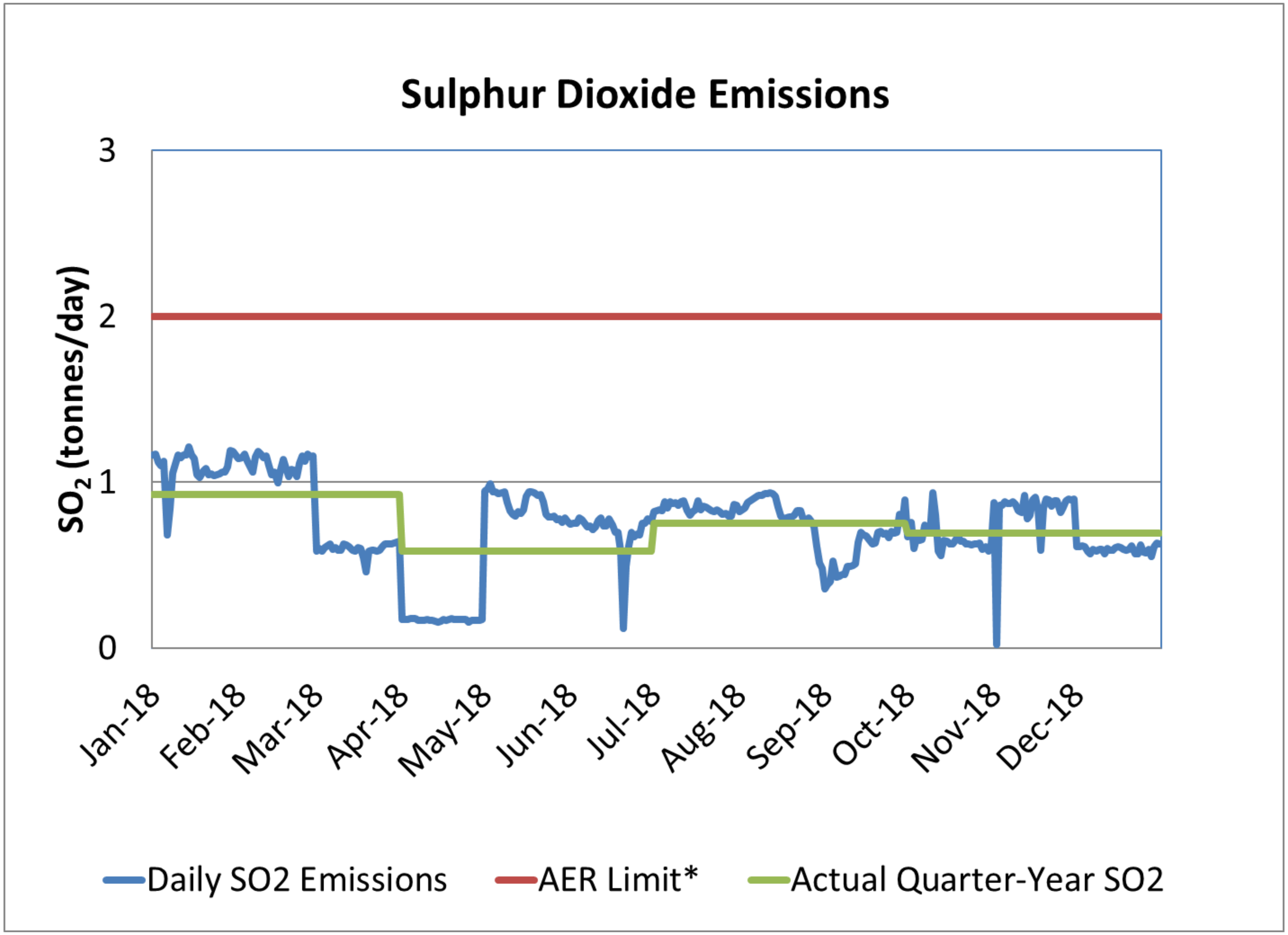


CNOOC
CNOOC Petroleum North America ULC – Long Lake Project 2018 Groundwater Disposal Report
103/09-28 & 104-09-28 Keg River Disposal Well: Injectivity and WHP
Date: March 2019

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

CNOOC

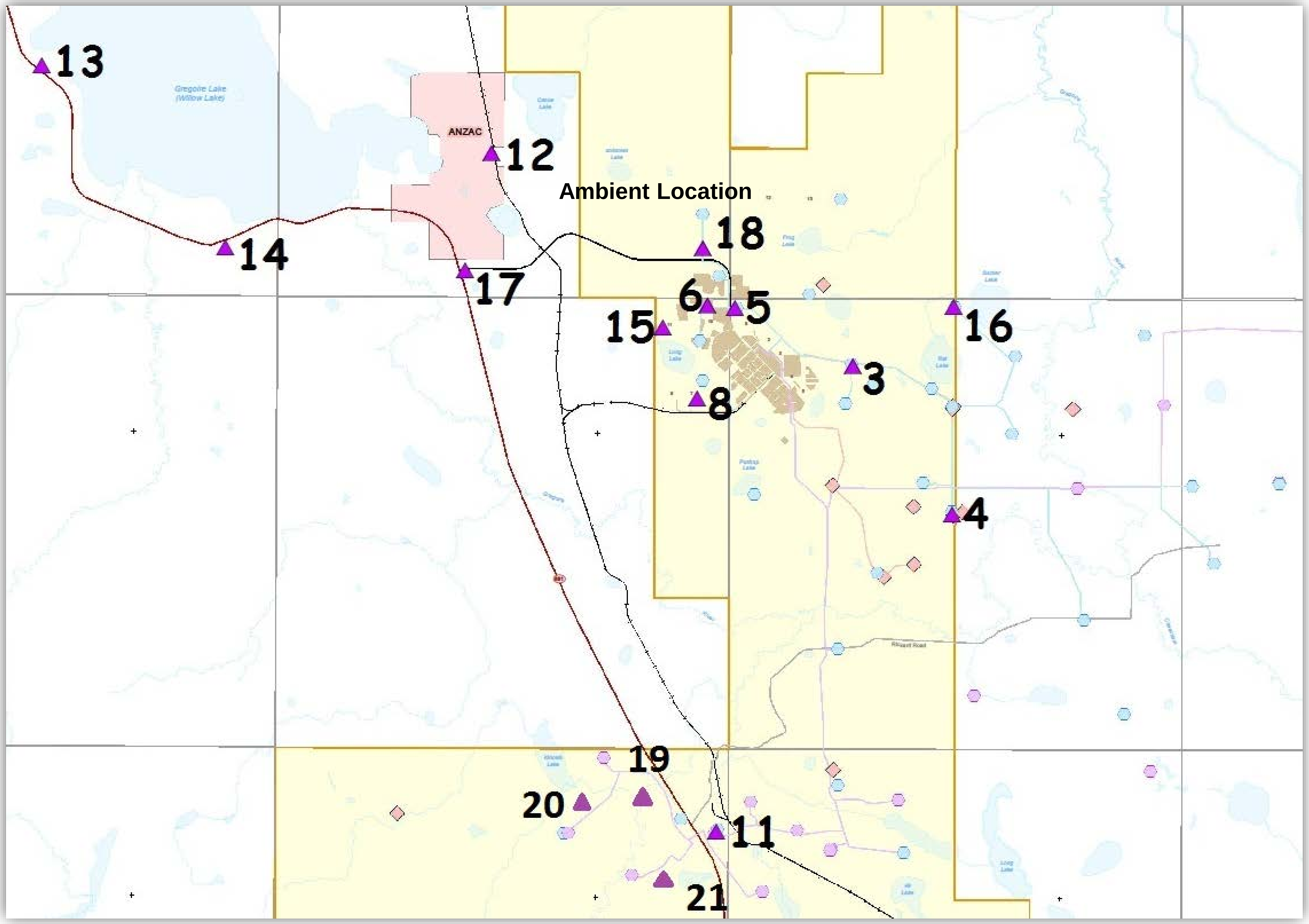
- Sulphur was not recovered at Long Lake in 2018.
- The annual average sulphur inlet was under 1 tonne/day and corresponding SO_2 emissions were under 2 tonnes/day.



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 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



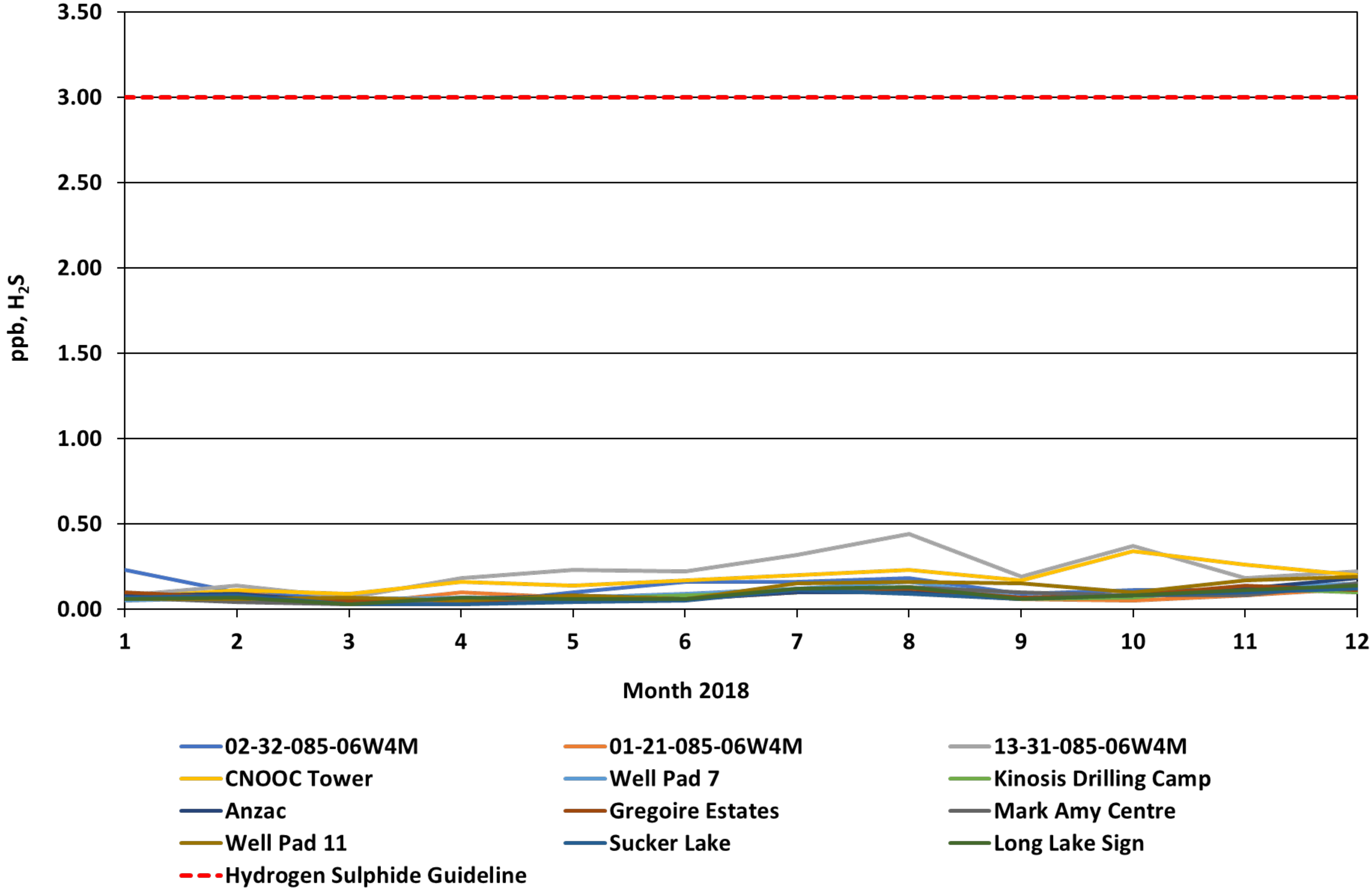
Subsection 3.1.2 (5d)

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

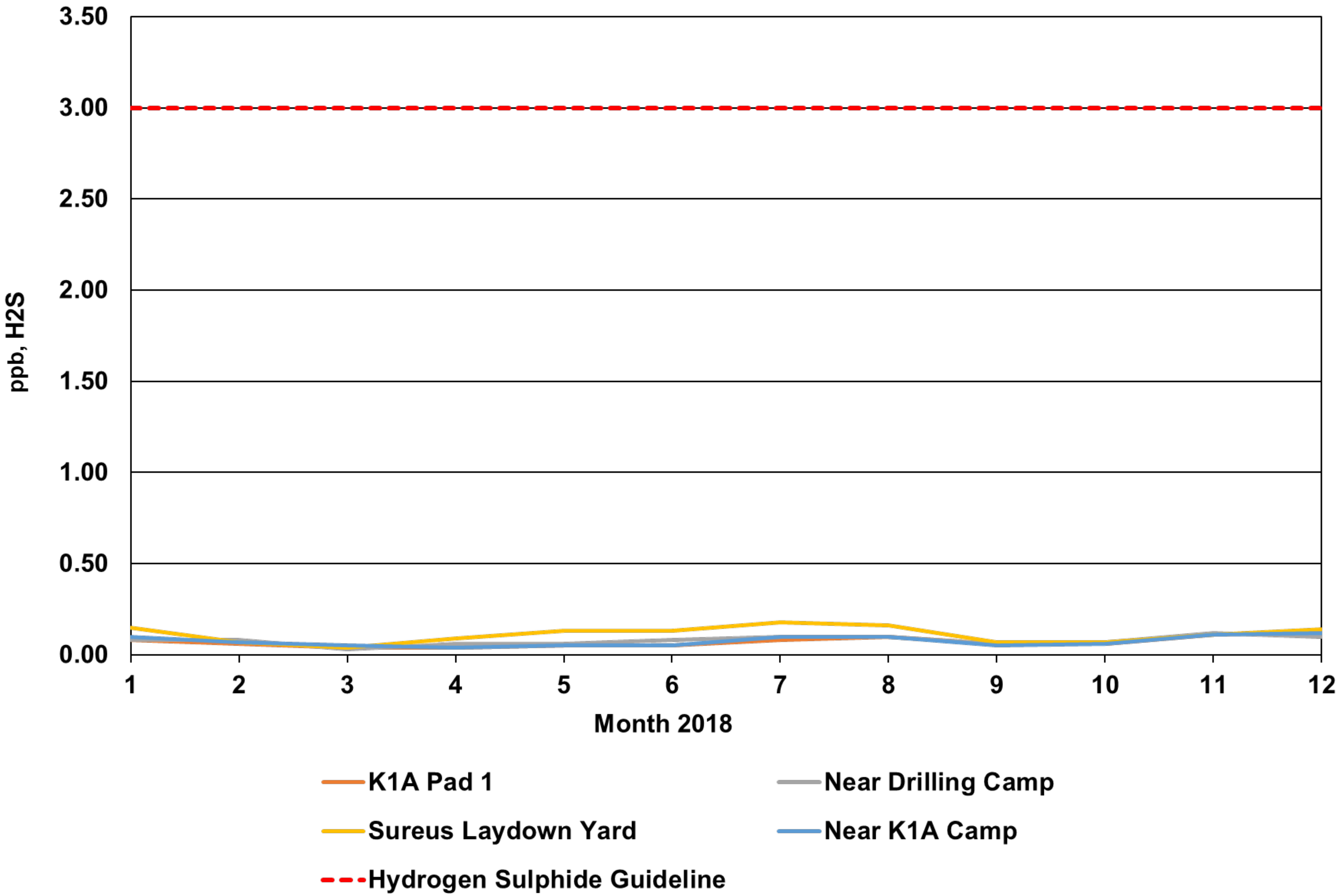
* K1A Passive Stations

Long Lake H_2S Passive Monitoring



Subsection 3.1.2 (5d)

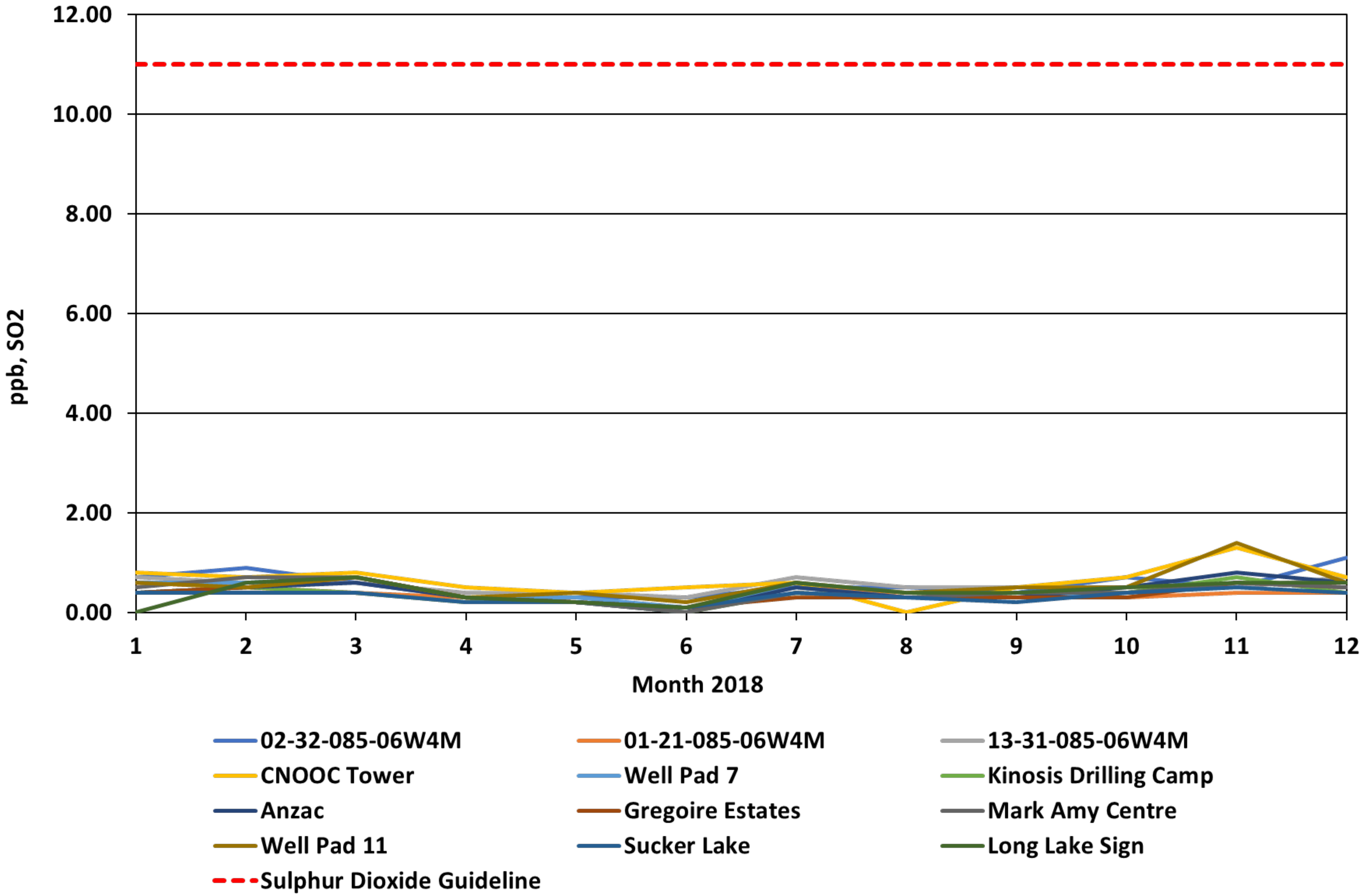
K1A H_2S Passive Monitoring



Subsection 3.1.2 (5d)

Long Lake SO_2 Passive Monitoring

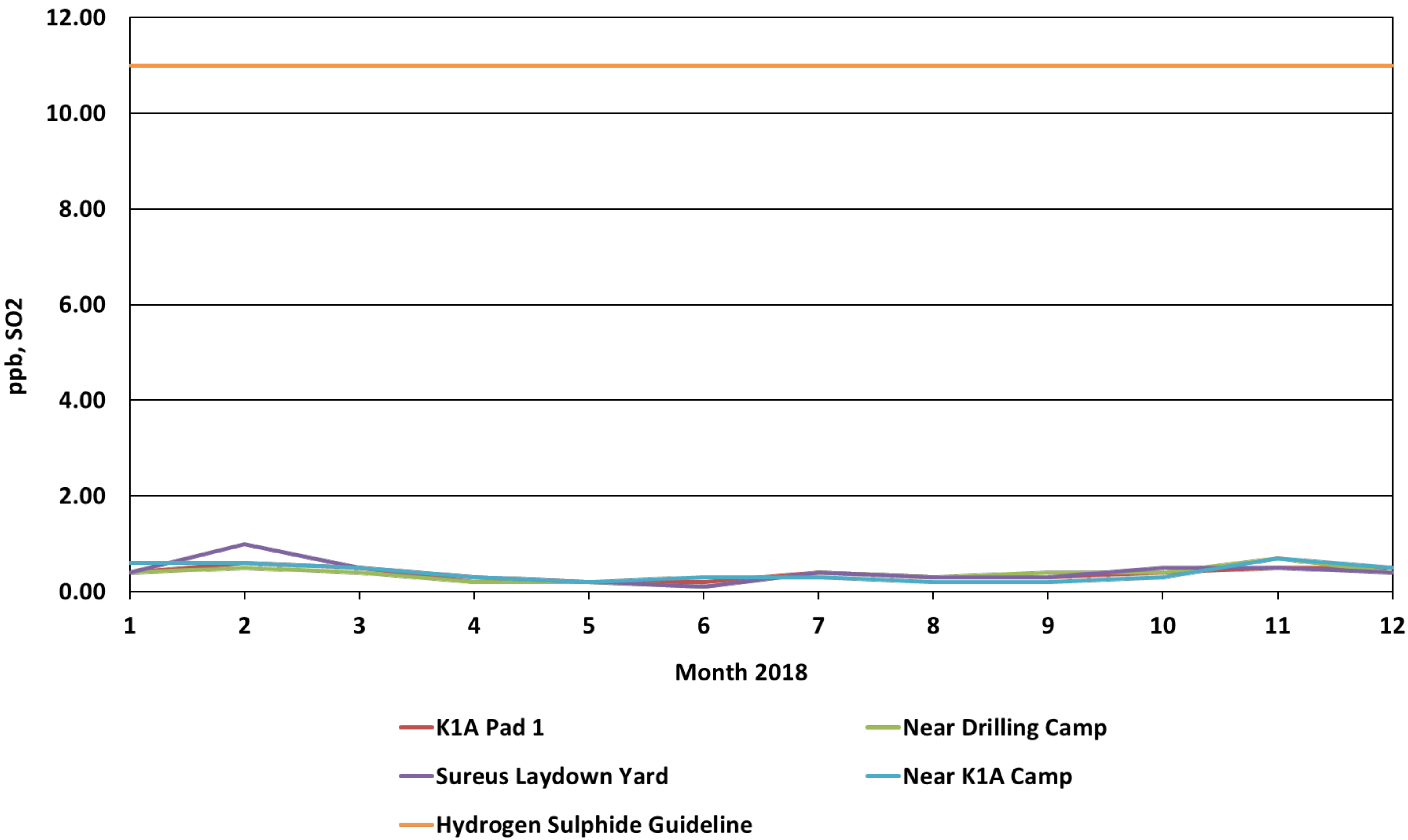
- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. No stations exceeded this limit in 2018.



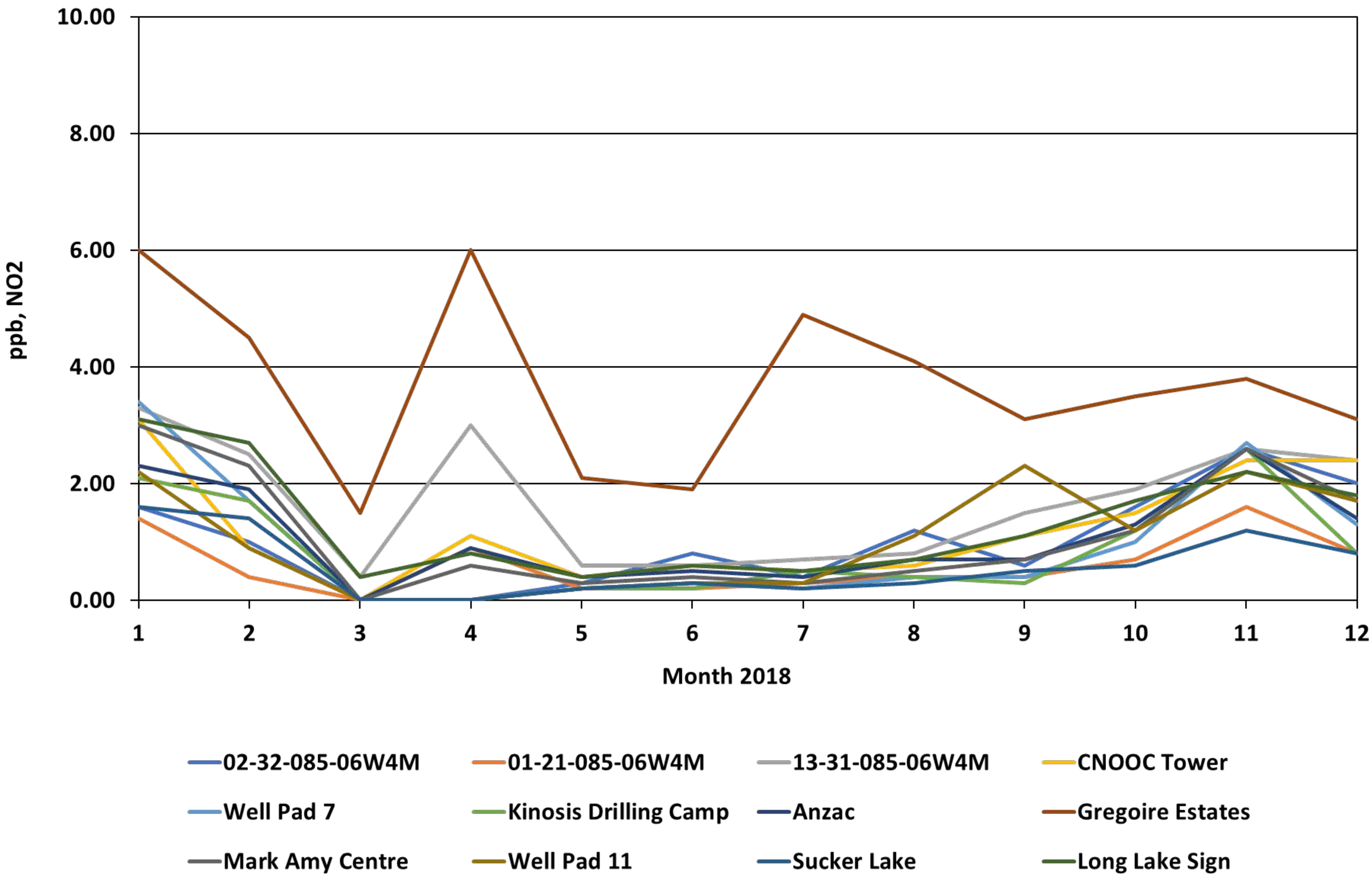
Subsection 3.1.2 (5d)

K1A SO_2 Passive Monitoring

- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. No stations exceeded this limit in 2018.

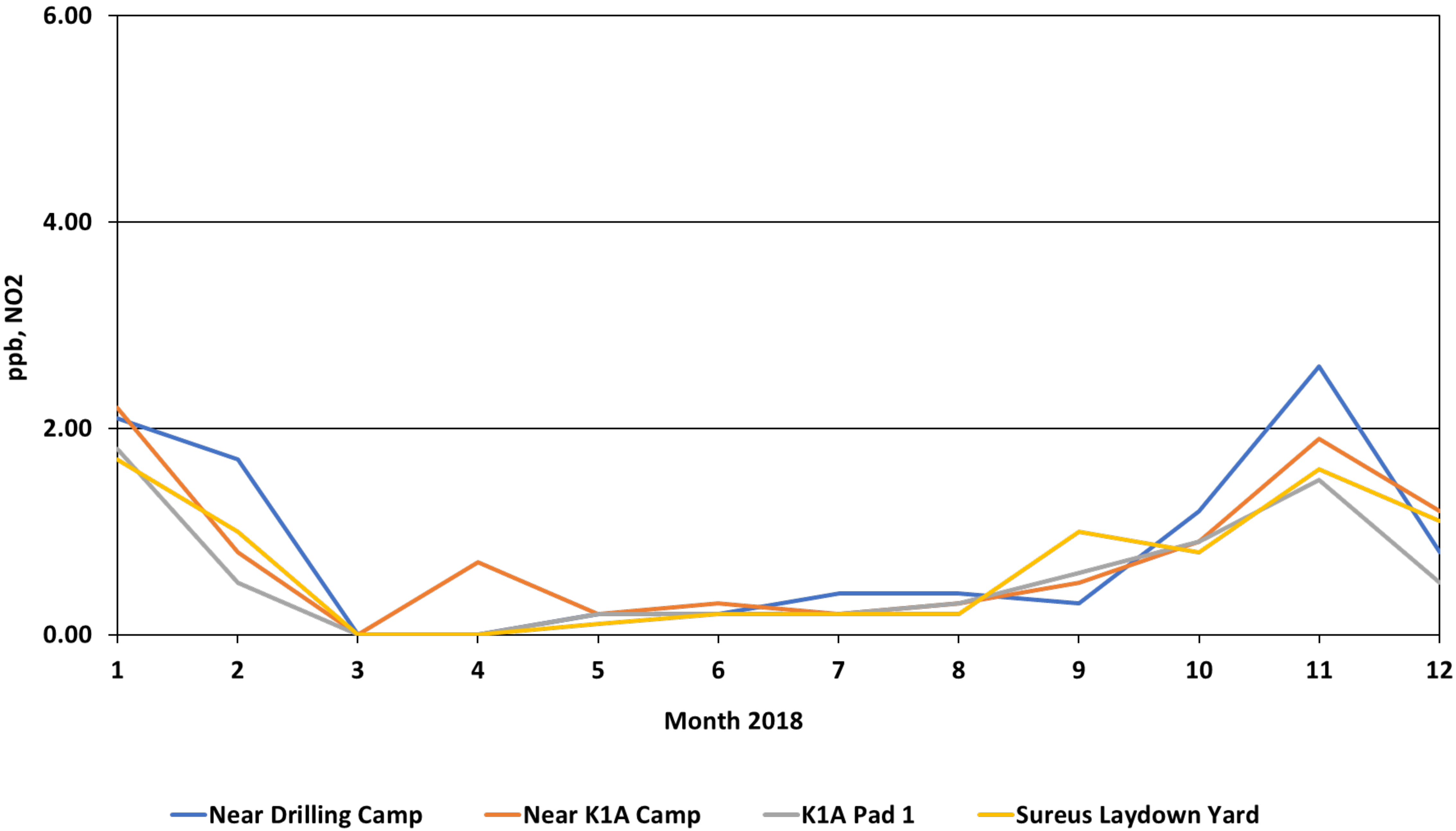


Long Lake NO_2 Passive Monitoring

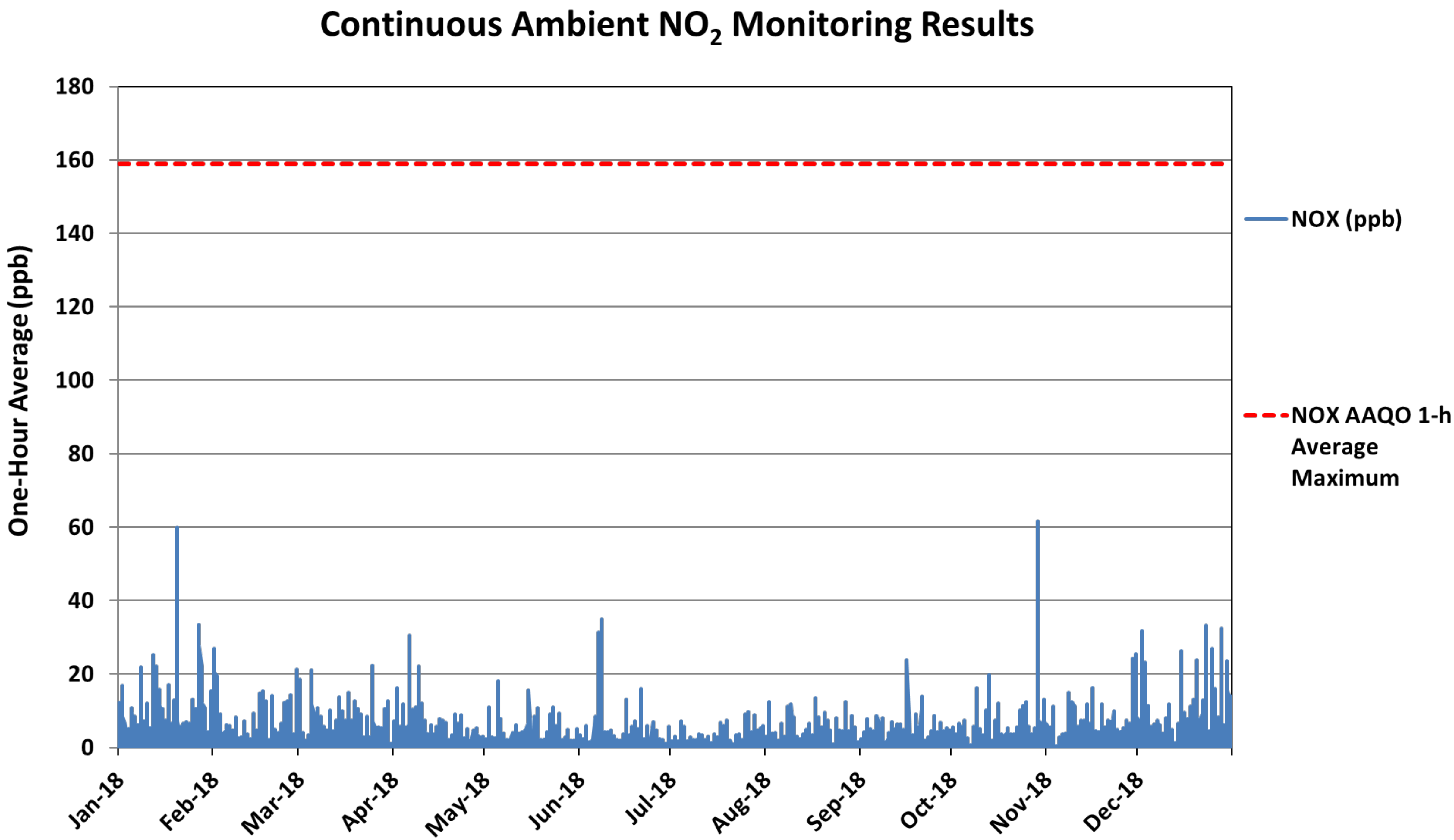


Subsection 3.1.2 (5d)

K1A NO_2 Passive Monitoring

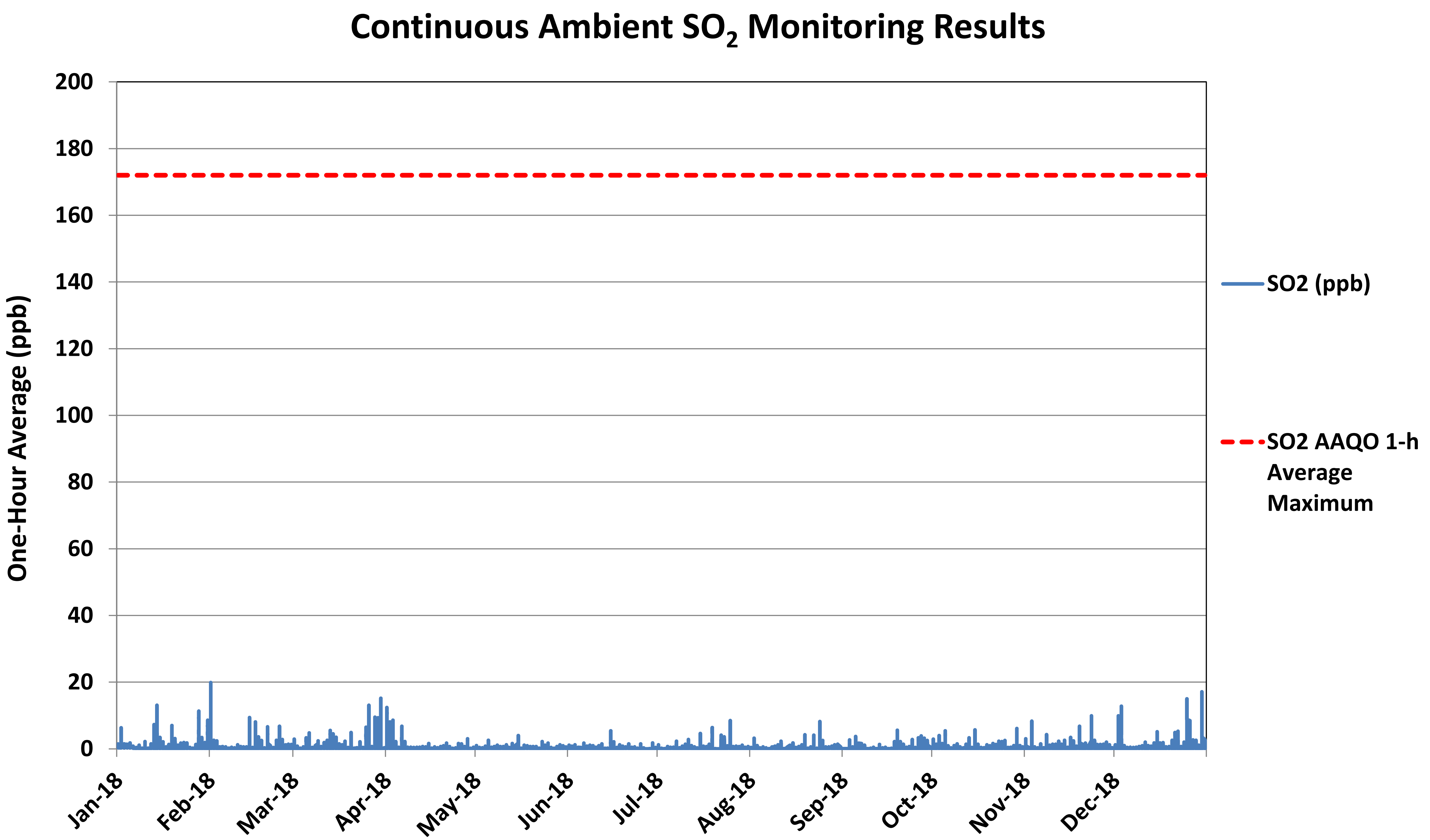


Subsection 3.1.2 (5d)

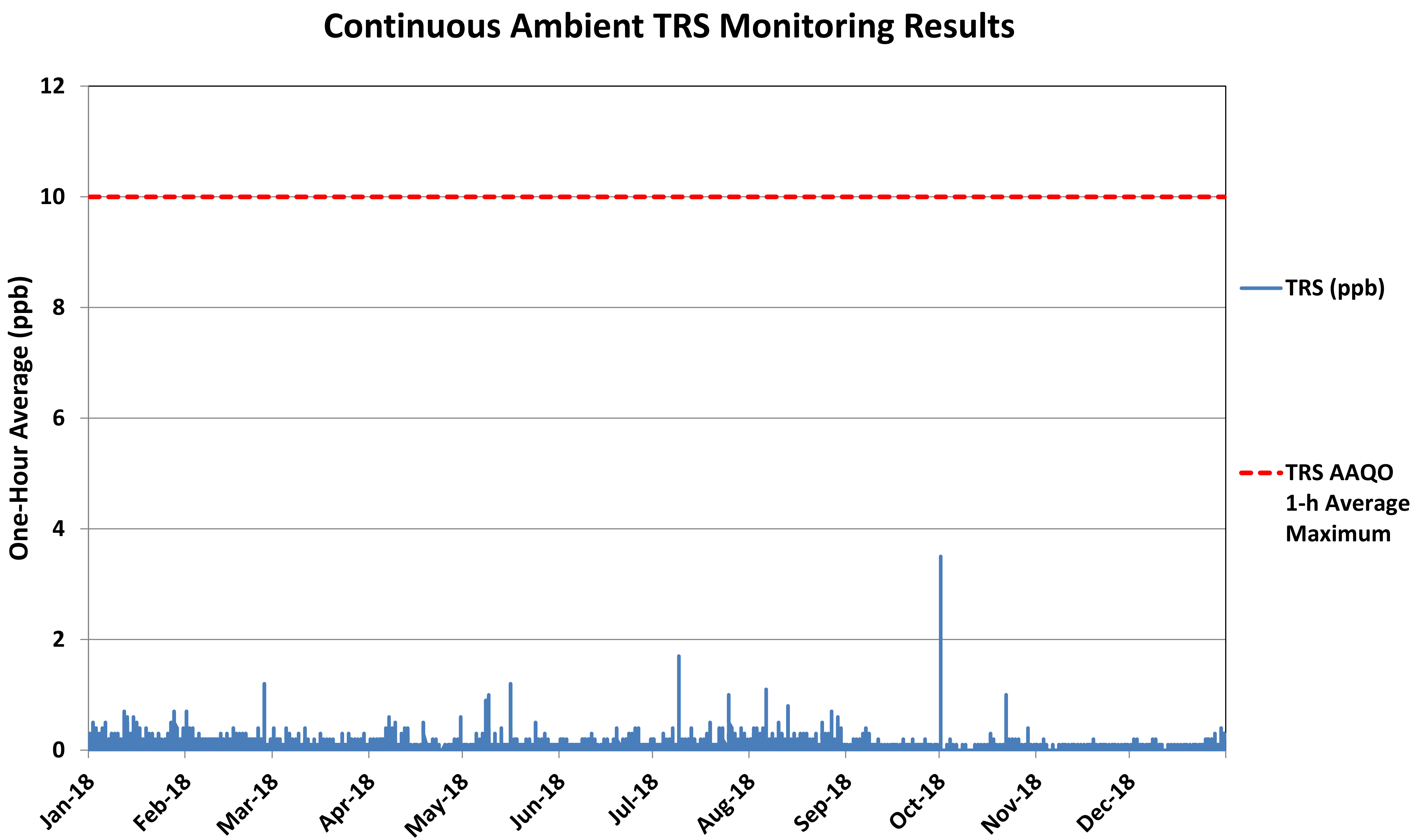


Subsection 3.1.2 (5d)

Anzac Ambient Monitoring
SO2 Hourly Maximum

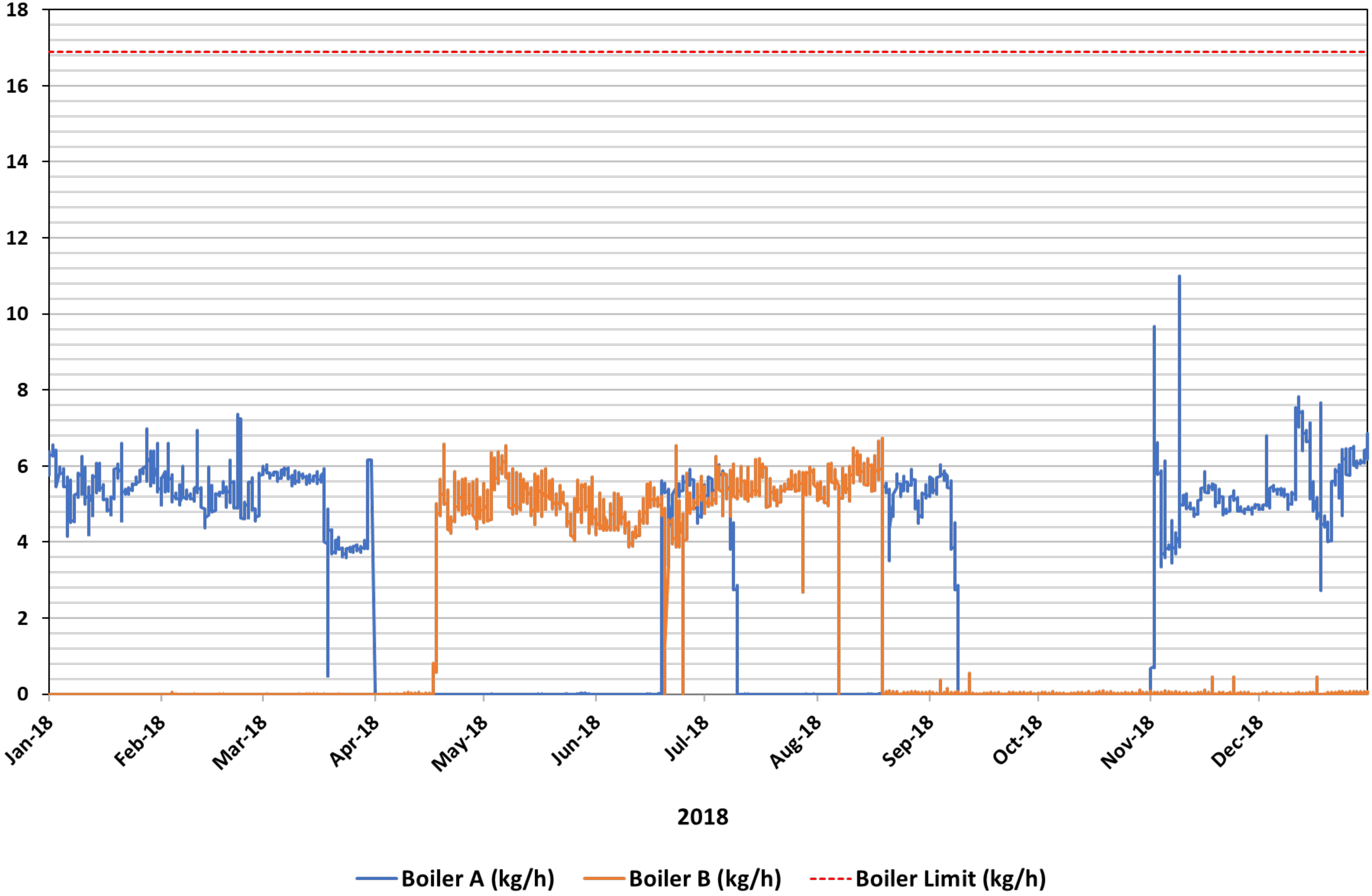


Anzac Ambient Monitoring
TRS Hourly Maximum



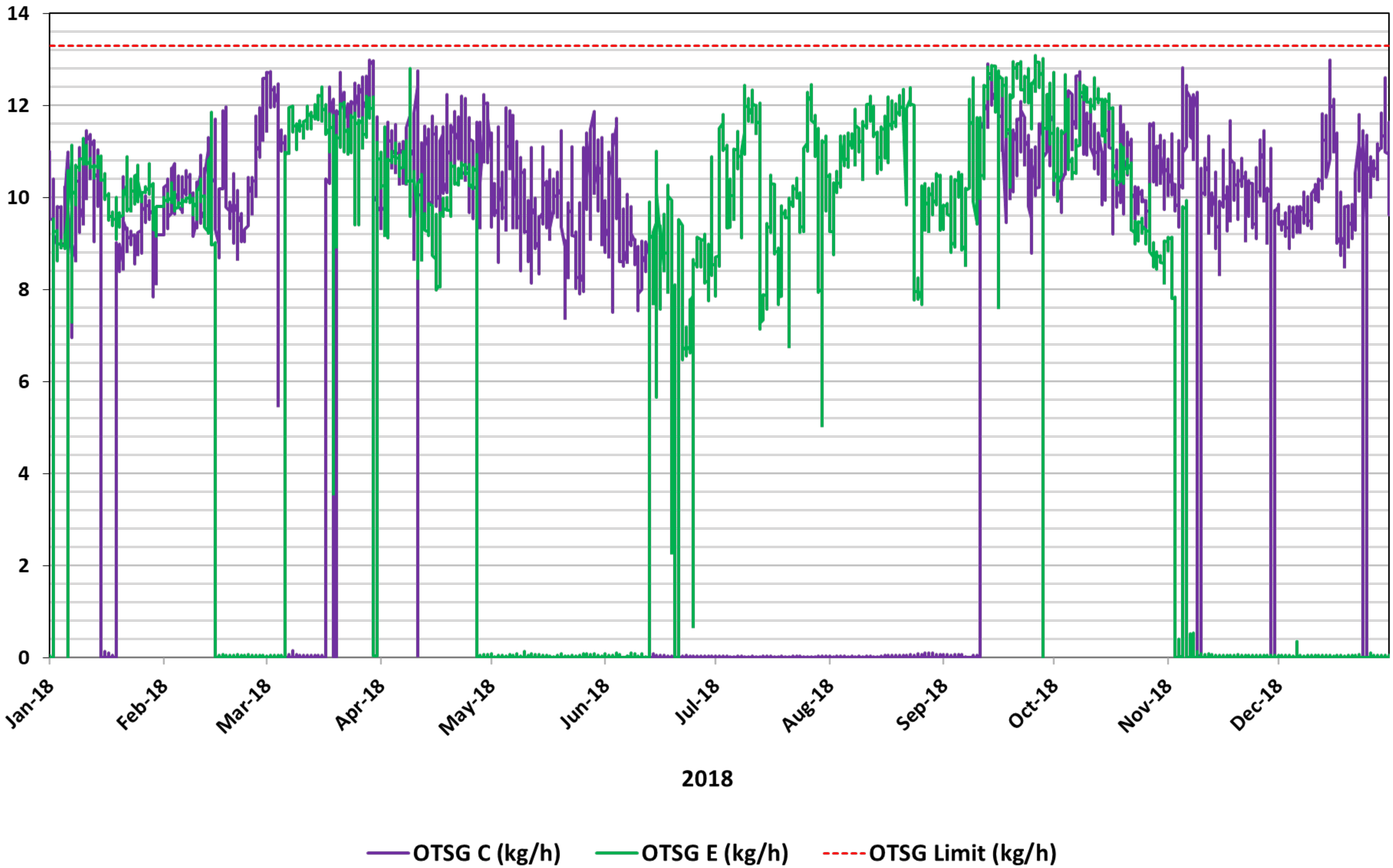
Subsection 3.1.2 (5d)

Hourly CEMS NOx - Boilers



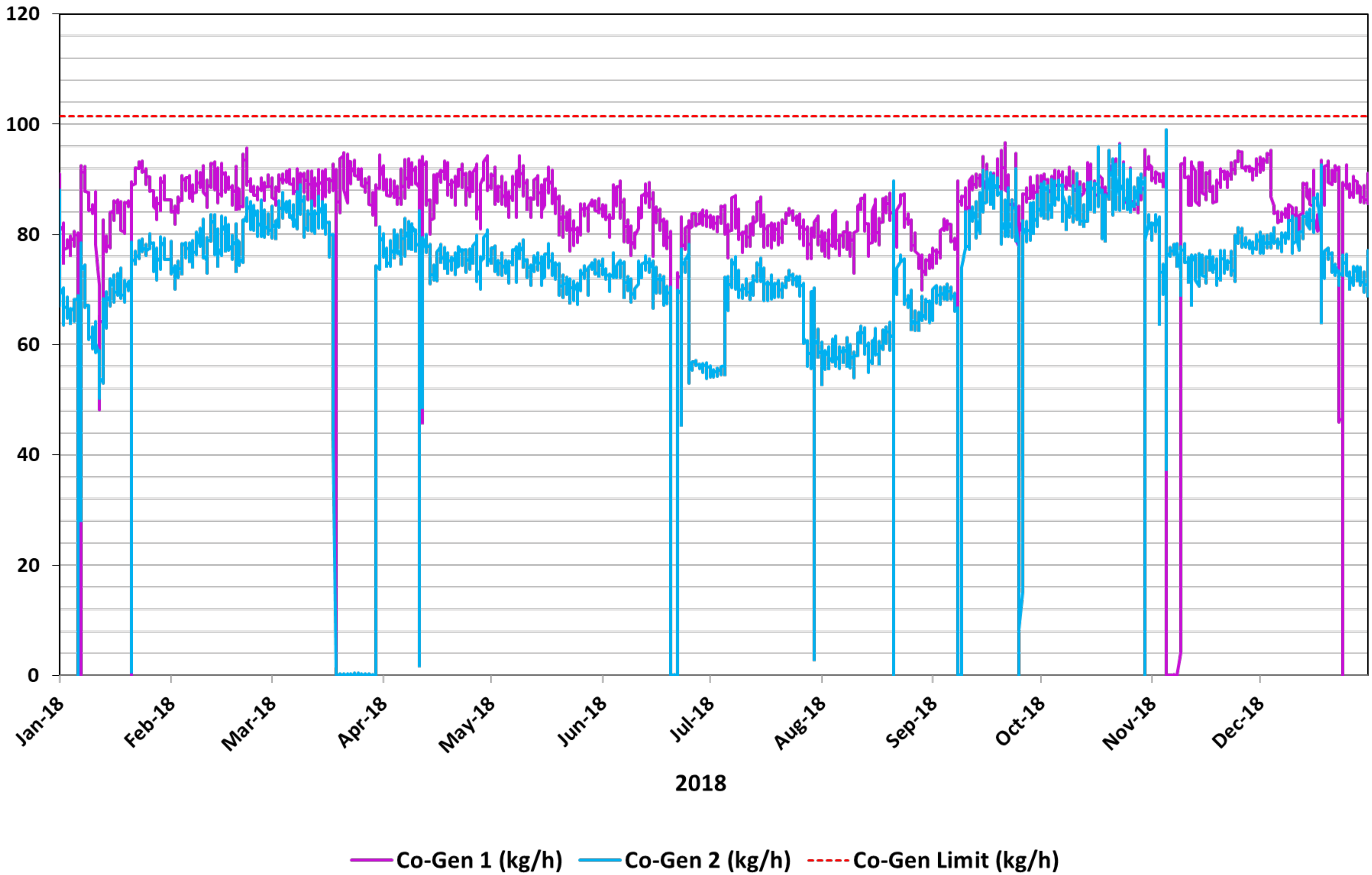
Subsection 3.1.2 (5d)

Hourly CEMS NOx – OTSG's



Subsection 3.1.2 (5d)

Hourly CEMS NOx – Co-Gen’s



Subsection 3.1.2 (5d)

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

- Inspections (9)
  - Satisfactory Inspections (9)
  - Unsatisfactory Inspections (0)

- Audit (1)
  - August 27, 2018 - the AER sent notice to CNOOC via email of a random audit for the well licence of 103/4-13-85-7W4 Lic# 0488432 (17S02). The audit covered D56 Table 7.6, from section 7.12.3 to section 7.13.4. The audit response was due September 4, 2018. CNOOC passed the audit and audit closure received September 26, 2018.

Subsection 3.1.2 (6a)

Compliance Discussion

Notices of Non-Compliance and Voluntary Self Disclosures	Status
Voluntary Self Disclosure On March 29, 2017, CNOOC requested an extension to bring 16 pipelines that had previously been part of the AER Suspension Order, issued August 29, 2015, into compliance. In addition, on the same day, CNOOC voluntarily self-disclosed that 36 additional inactive pipeline segments were non-compliant. The 52 lines were non-compliant under AER's Manual 005 (Pipeline Inspections) and require abandonment or suspension work and associated licence amendments to bring them into compliance.	Compliance achieved June 28, 2018
Voluntary Self Disclosure On July 17, 2018, CNOOC voluntarily self-disclosed a tear in the CPF Tank Farm liner. A temporary berm was created around the tear and ongoing monitoring of the area during each shift. Repairs were completed by liner repair company by July 22, 2018 to bring Tank farm liner back into compliance.	Compliance achieved August 2, 2018
Voluntary Self Disclosure On November 28, 2018, CNOOC submitted a voluntary self disclosure (VSD) to Alberta Energy for a core hole located at 1AA/03-02-077-08W4/00 Lic# 0346575 and an observation well located at 100/12-08-086-06W4/00 Lic# 0349586. Both wells were drilled in exceedance of their respective licenced total depth, resulting in a non-production trespass. The 1AA/03-02-077-08W4/00 has exceeded the respective well licence total depth of greater than 150m, resulting in an additional VSD to the AER.	Compliance achieved November 29, 2018

Subsection 3.1.2 (6a)(8)

Environmental Regulatory Compliance

Type of event	Number of Occurrences	Approval/Directive	Date	Description	Corrective Actions
Venting	44	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/Waste Water Treatment Plant	3	EPEA	Jan 6, 2018	Lost potable water to water distribution system due to fire in electrical panel.	Replaced electrical panel and fixed issue with potable water plant emergency generator.
			Mar 4, 2018	Waste water treatment facility exceeded the monthly permitted fecal geometric volume.	CNOOC International established and communicated a schedule for removal of the waste grease storage bin at the camp to ensure that scheduled grease trap cleaning is not inhibited.
			Mar 4, 2018	Lost potable water to water distribution system during distribution pump breaker failure due to heat tracing malfunction.	Repaired heat tracing and restored system back to service.
Non-Compliance - Water Sources	4	Water Act	Jan 30, 2018	Water Act license 247843-01-00 reporting error	The intent of the licence and the reporting conditions have been clarified. CNOOC International will conduct an internal review to improve how this licence is managed.
			April 9, 2018	Missing water level data for WM-01-34-085-06W4M (Water Act License 235895-01-00)	Replacement of damaged datalogger. CNOOC International will continue to monitor the datalogger during the quarterly field data collection program to ensure it is functioning properly.
			Jun 5, 2018	Water level and temperature data for LLK-MW08M is missing between 2018-05-06 and 2018-05-29.	Replacement of damaged datalogger. CNOOC International will continue to monitor the datalogger during the quarterly field data collection program to ensure it is functioning properly.
			Jun 5, 2018	Water level data for WM-GR-06-08-085-06W4M is missing between 2018-04-22 and 2018-05-26.	Replacement of damaged datalogger. CNOOC International will continue to monitor the datalogger during the quarterly field data collection program to ensure it is functioning properly.
Non-Compliance - Secondary Containment	1	Directive 55	Jul 17, 2018	VSD: Liner tear in the containment for Central Processing Facility (CPF) tank farm.	Repairs were completed by liner repair company by July 22, 2018 to bring Tank farm liner back into compliance.

Venting Events and Reporting Protocol

- Identification of venting events is determined by the PSV set point versus the practice of visual confirmation which resulted in an increase in reporting.
- Venting event have reduced significantly following improvement in plant stability and reliability.
- Venting reporting protocol approved by the AER was implemented on March 13, 2018.
  1. Venting of multiple tanks located in the same area (e.g. venting of two or more tanks in Table A or B will result in a reportable venting event) – requires a call to the AER (CIC notification)
  2. Venting duration over 4 consecutive hours in one event – AER one stop entry, no CIC notification or call
  3. Venting volume over 30,000 m3 in one event – AER one stop entry, no CIC notification or 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

Reportable Spills

Reportable Spill Summary	2014		2015		2016		2017		2018	
	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)
	17	1,551	26	5,937	7	120	5	37.6	10	379.6

- Total number of reportable spills went up from previous years and the volume released from reportable spills also increase due to the volume released from the disposal line leak in August of 2018.
- Reportable spill events (10)
  - January 5, 2018 – 26 m^3 Produced water leak in Inlet Treating (FIS 20180096)
  - January 14, 2018 – 1.5 m^3 RBW chemical spill at Pad 12 (FIS 20180208)
  - January 19, 2018 – 30 m^3 Source water well leak (raw water) (FIS 20180286)
  - January 29, 2018 – 0.2 m^3 Diesel leak from Generator fueling (FIS 20180415)
  - February 1, 2018 – 5 m^3 Supernatant release from line (FIS 20180454)
  - March 11, 2018 – 2.8 m^3 Diluted Bitumen (FIS 20180889)
  - March 11, 2018 – 36 m m^3 Utility water leak in Upgrader (FIS 20180888)
  - May 25, 2018 – 14 m^3 Pop Tank steam condensate release (FIS 20181693)
  - August 12, 2018 – 270 m^3 Disposal Line release (FIS 20182606)
  - December 15, 2018 – 0.04 m^3 Hydraulic release offsite (FIS 20183798)

Subsection 3.1.2 (6a)

AER Scheme Approval

- Amendments Approved in 2018:
  - Modifications to Long Lake Pads 3, 6 and 10 Infill Wells – June 15, 2018
  - PSV and Upgrader Flare – September 6, 2018
  - Long Lake Phase 3 Infills Pads 1, 10, 13 – November 23, 2018

Environmental Summary – Monitoring Programs

- All monitoring programs were conducted in accordance with regulatory approvals and most plans have been updated in 2016 with the issuance of the new approval.
  - 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;
  - Alberta Biodiversity Monitoring Institute (ABMI);
  - OSCA Black Bear Partnership Project.

Subsection 3.1.2 (6c)

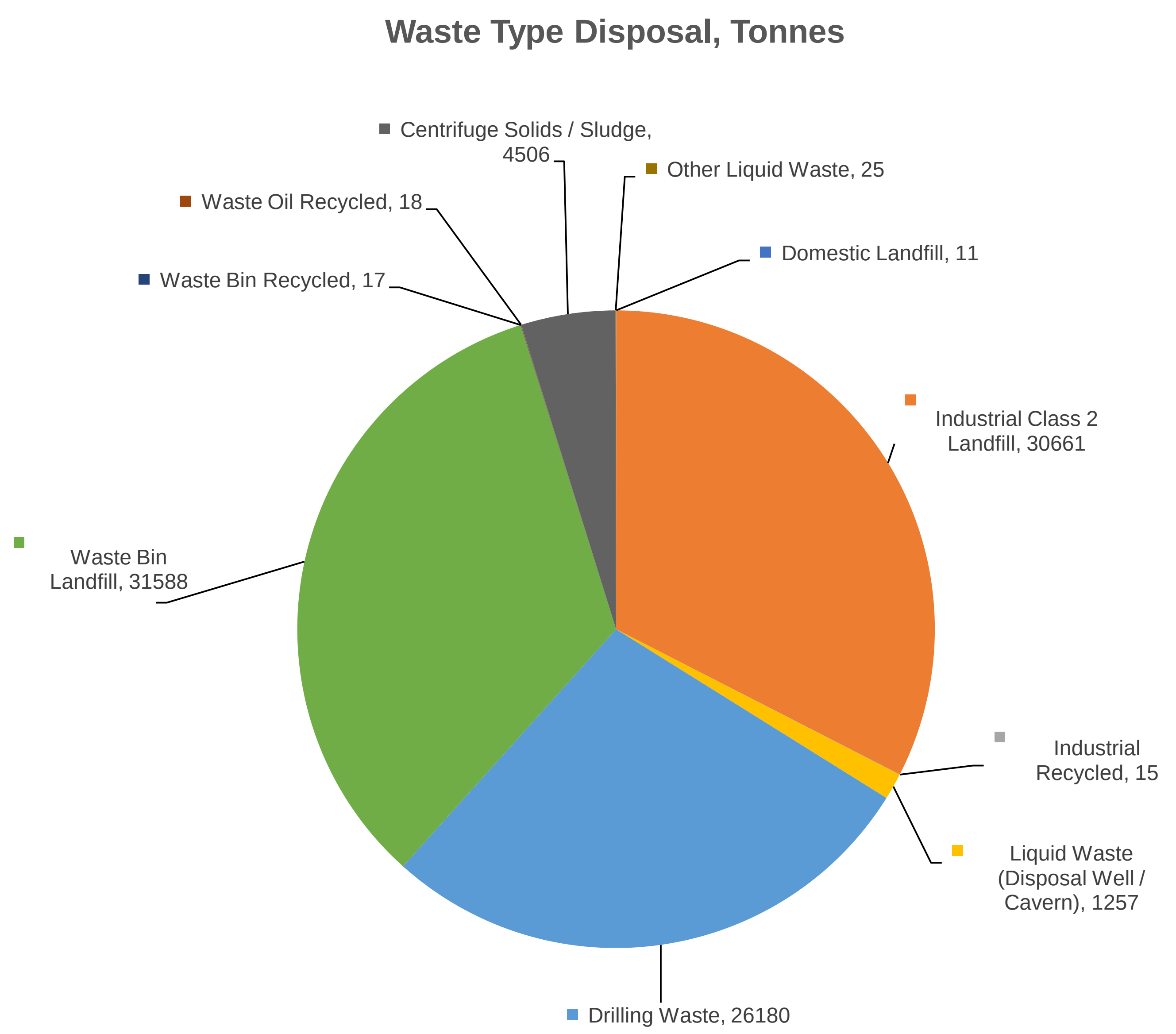
Environmental Summary: Innovation, Research & Reclamation Initiatives

- CNOOC International has recently withdrawn from full participation in Canada's Oil Sands Innovation Alliance (COSIA) but remains active in a number of joint industry projects focused on environmental performance improvement in land stewardship, water management and greenhouse gas reduction.
- Active members of the COSIA and CAPP Monitoring Working Groups.
- Actively engaged in industry caribou recovery efforts, specifically as the project lead for the Algar Caribou Restoration Project; a member of the ConocoPhillips led Caribou Recovery Pilot Project and a member of the Devon Energy led Regional Industry Caribou Collaboration (RICC).
- 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	31,588
Waste Bin Recycled	17
Waste Oil Recycled	18
Centrifuge Solids / Sludge	4,506
Other Liquid Waste	25
Total	**36,154**
Non-Hazardous Waste	**Tonnes**
Domestic Landfill	11
Industrial Class 2 Landfill	30,661
Industrial Recycled	15
Liquid Waste (Disposal Well / Cavern)	1,257
Drilling Waste	26,180
Total	**58,124**
Grand Total (Hazardous + Non-Hazardous Waste)	**94,278**



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

Future Plans - Surface

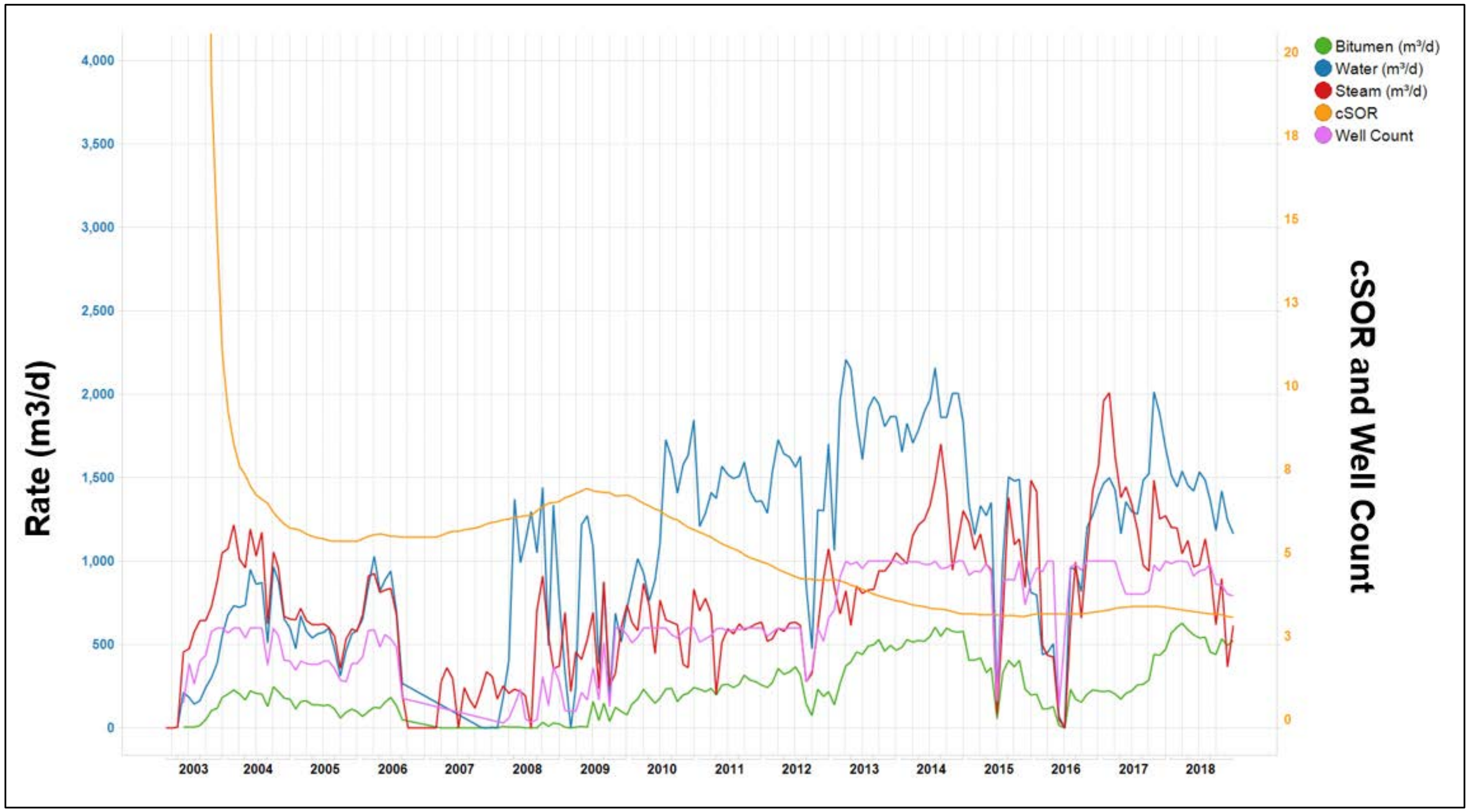
- Continue construction of LLSW well pads and flowline
- Progress construction of K1A replacement pipelines & restart of K1A Facility
  - Complete horizontal directional drilling for K1A replacement pipelines (commenced Jan 2019)
  - Progress detailed engineering and procure long lead materials for pipeline replacements
  - Commence preparation work for main pipeline construction Q3/Q4 2019
- The Upgrader will remain shut-in until a final business decision is made

Subsection 3.1.2 (9)

Appendix

Well Pad Performance
Subsection 3.1.7 (h)
Long Lake

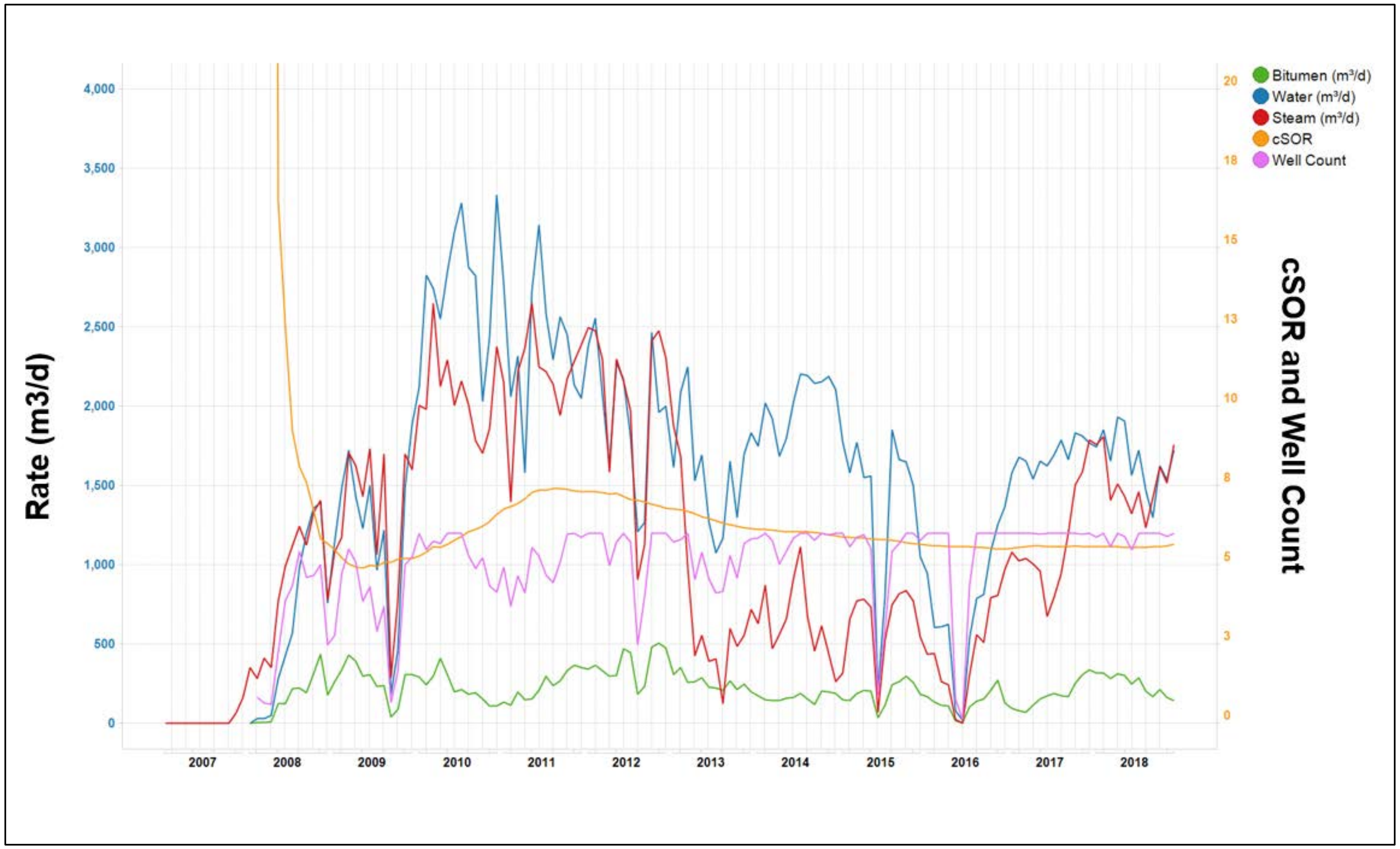
Pad 1 Production Summary



- All 5 wells on ESP
- Producers are showing strong performance after:
  - Increasing oil rate due to stable operations and improving oil cut in base wells
- cSOR is stable
- At YE, injection pressures were ~1,380-1,500 kPa

- Five well pairs (01P01 to 01P03, 04P05 and 04P06)
- Cumulative production of 1,272 E^3m^3 (EBIP RF 56%)

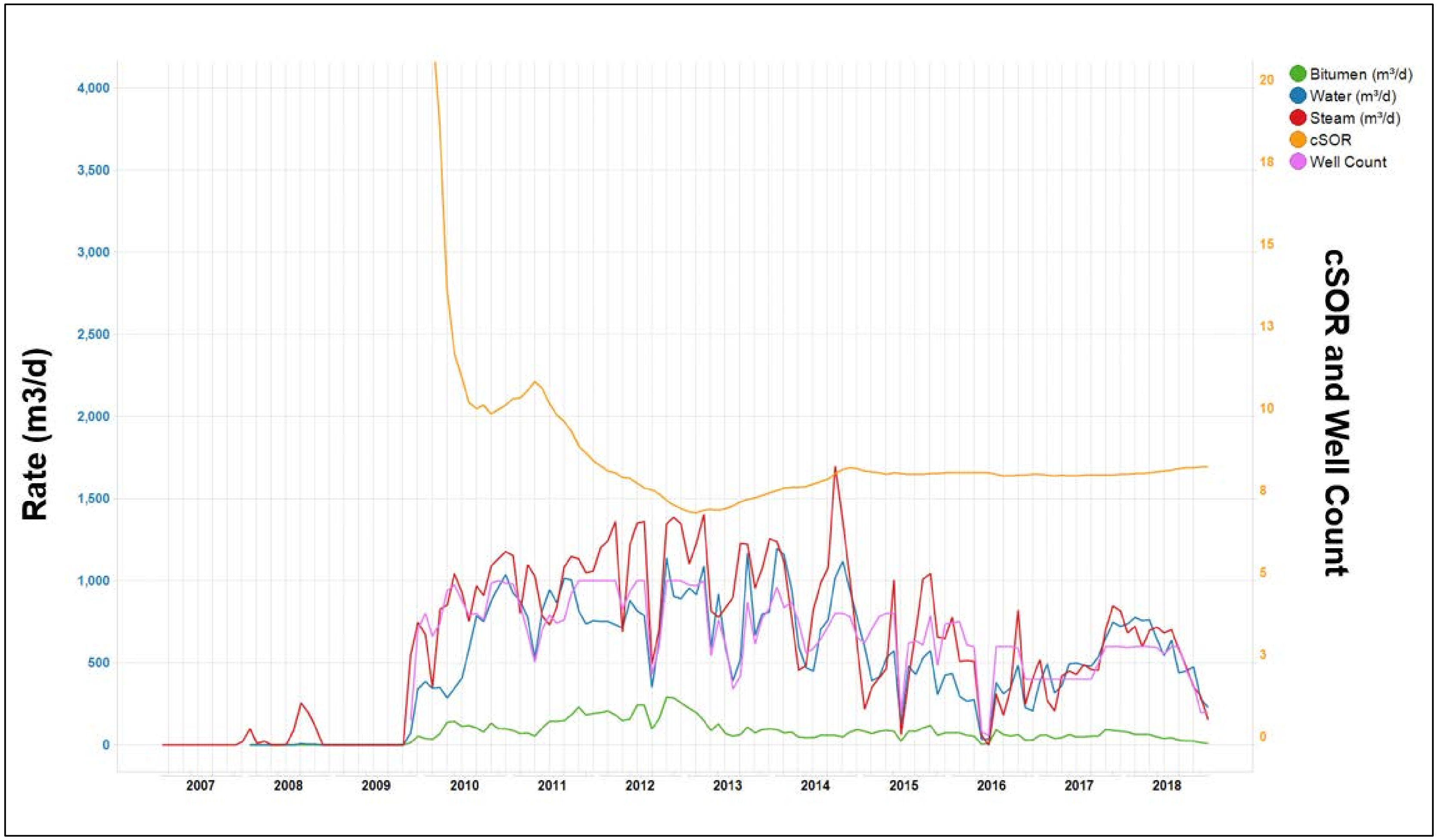
Pad 2NE Production Summary



- All 6 wells on ESP
- Steam injection resumed on 02S04, 02S05, and 02S06 in late 2017
- Stable production rates
- At YE, injection pressures were ~1,595 – 1,620 kPa

- Six well pairs (02P01 to 02P06)
- Cumulative production of 881 E^3m^3 (EBIP RF 38%)

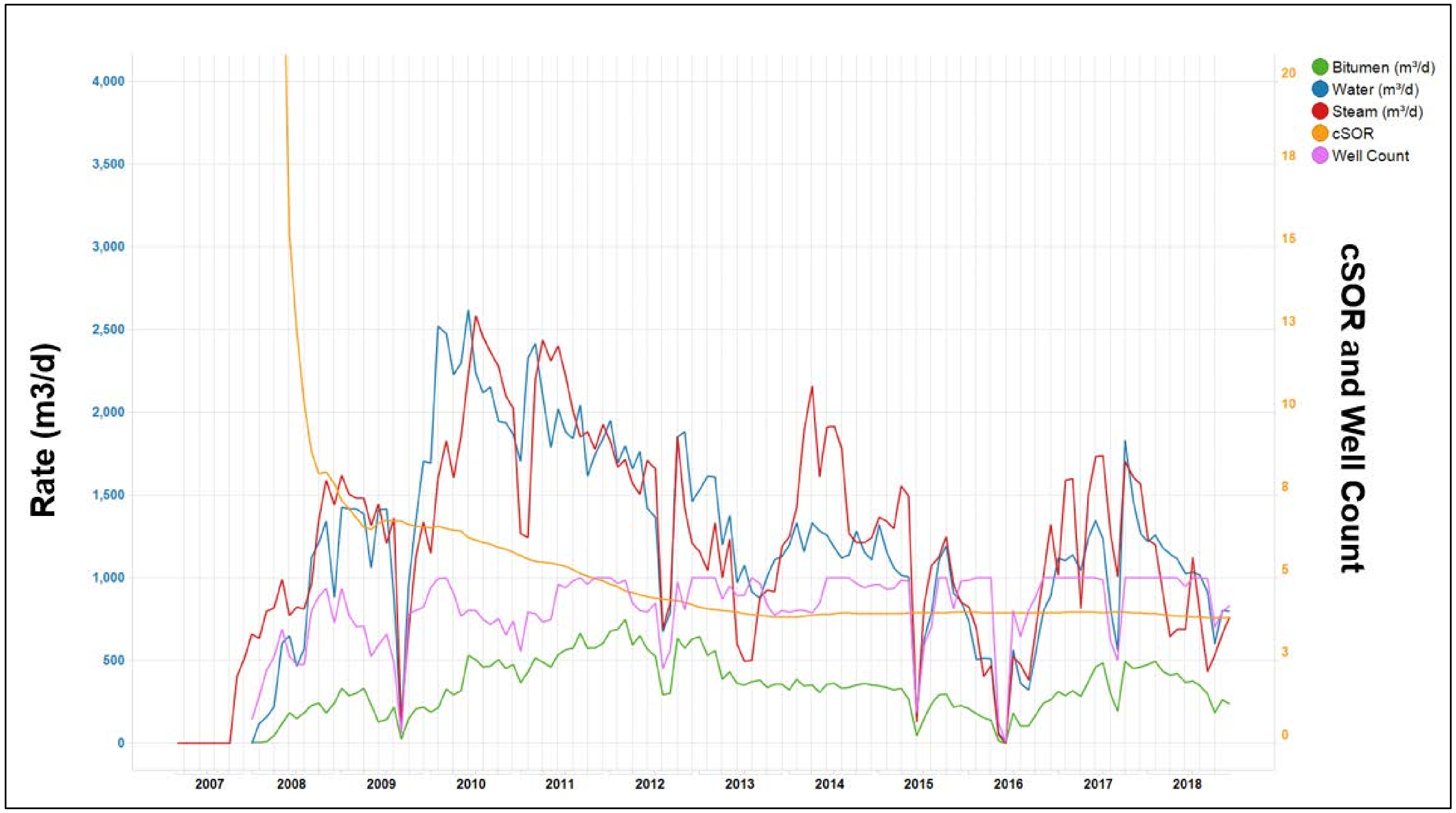
Pad 2SE Production Summary



- 1 well on ESP
- Low rate producers economically challenged
  - 2P07 on PCP and currently SI due to worn pump
  - 02P11 SI due to liner failure in 2014
  - 2P08, 2P09 ESP failures in 2018
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,390 – 1,470 kPa

- Five well pairs (02P07 to 02P11)
- Cumulative production of 314 E^3m^3 (EBIP RF 27%)

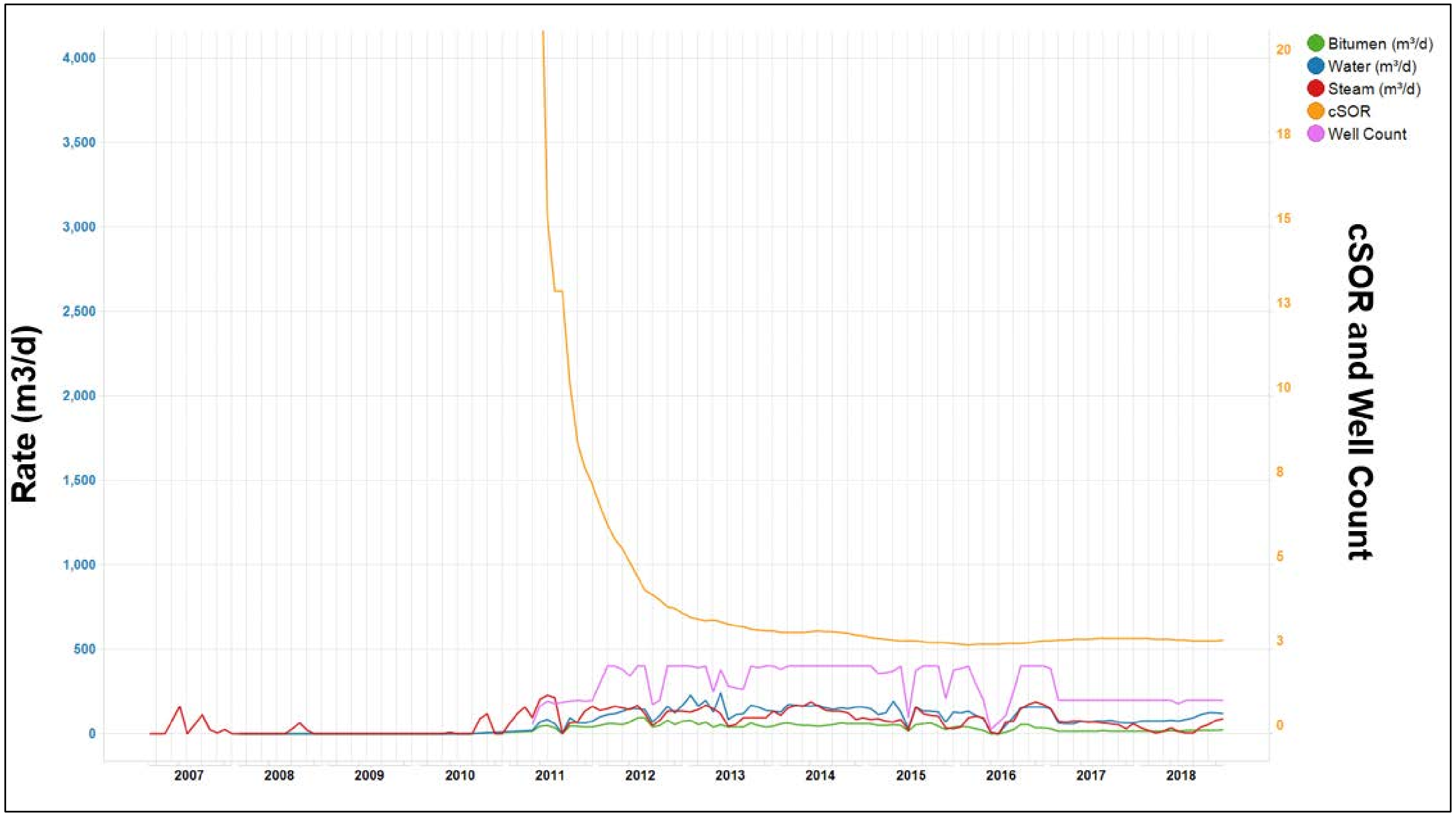
Pad 3 Production Summary



- All 5 wells on ESP
- Slight improvement has been observed in cSOR due to applying optimization plans in a stable operating condition.
- 5 infill wells drilled in 2018; to be brought on production in 2019
- At YE, injection pressures were ~1,410-1,600 kPa

- Five well pairs (03P01 to 03P05)
- Five infill well producers (03P01INF to 03P05INF)
- Cumulative production of 1,367 E^3m^3 (EBIP RF 50%)

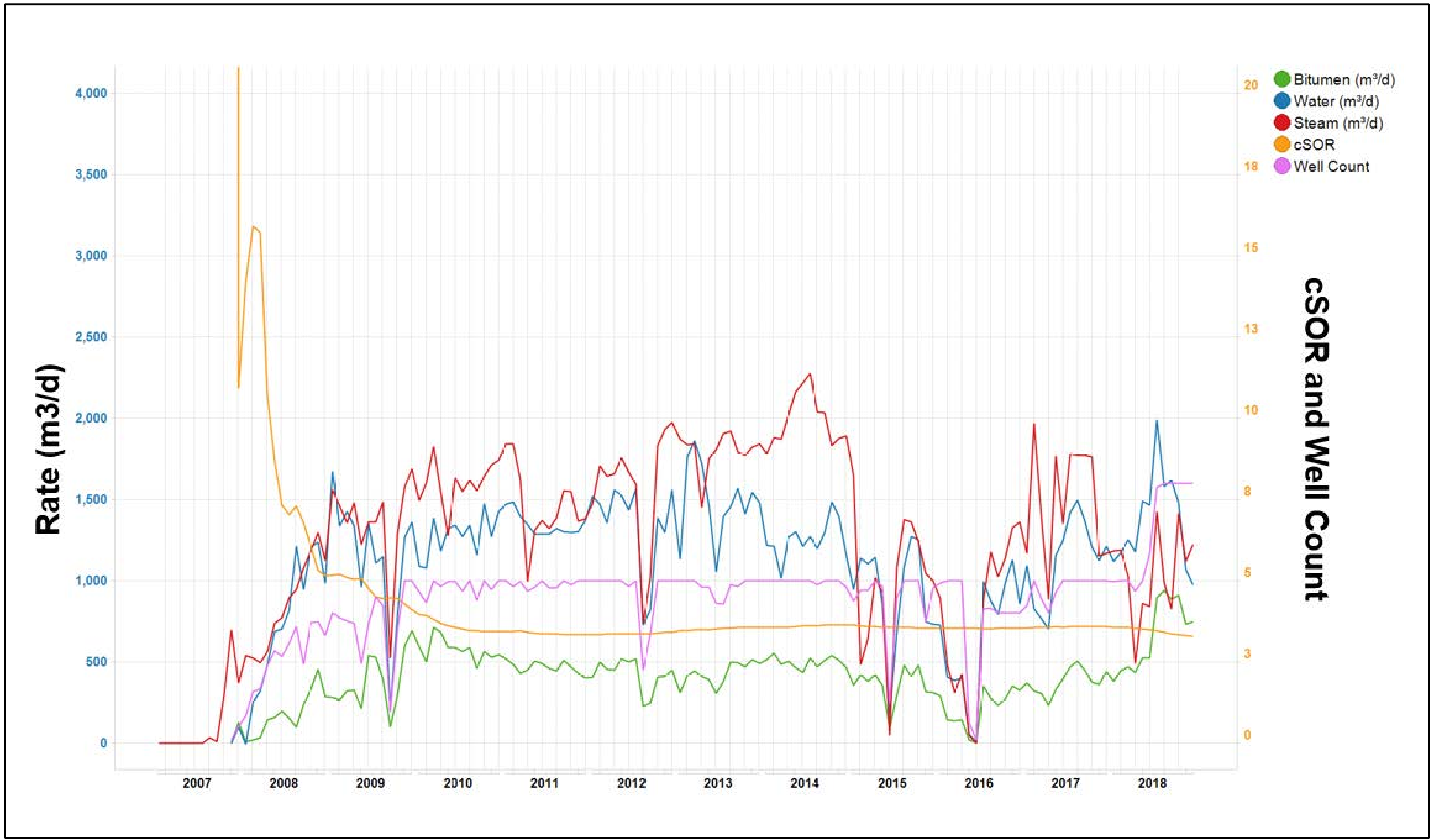
Pad 4 Production Summary



- 1 well on ESP (4P01)
  - ESP failure in 4P02 is not currently economically justifiable to replace due to very low oil production rate.
- Production performance stable.
- At YE, injection pressures were ~1,430-1450kPa

- Two well pairs (04P01 to 04P02)
- Cumulative production of 113 E^3m^3 (EBIP RF 66%)

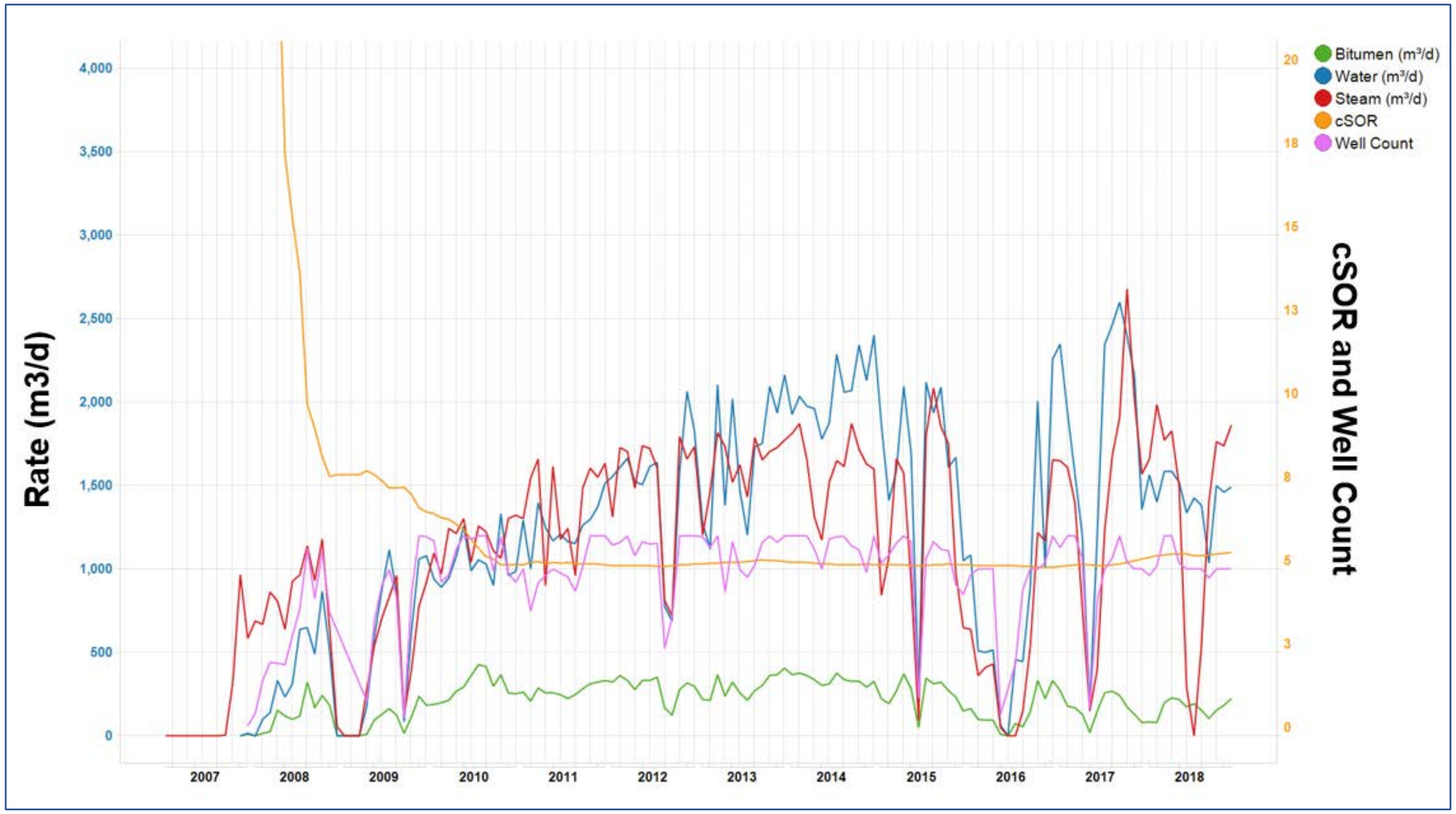
Pad 5 Production Summary



- All 8 wells on ESP
- 3 infill wells commenced production in mid 2018 contributing to increase in oil production rates and lowering cSOR
- At YE, injection pressures were ~1,470-1,570 kPa

- Five well pairs (05P01 to 05P05)
- Three infill well producers (05P03INF, 05P04INF, 05P05INF)
- Cumulative production of 1,671 E^3m^3 (EBIP RF 49%)

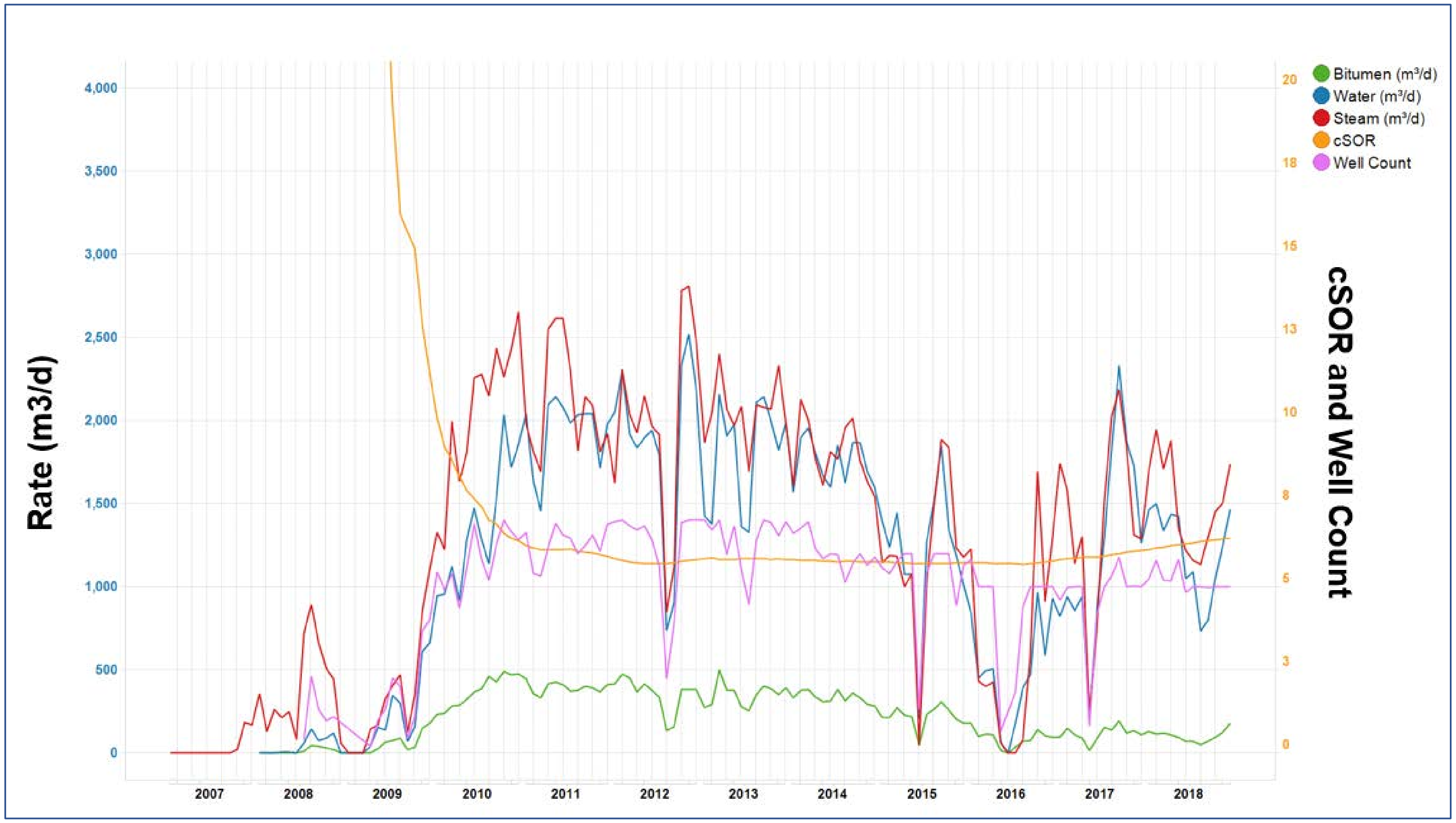
Pad 6N Production Summary



- Six well pairs (06P01 to 06P05, 06P13)
- Cumulative production of 885 E^3m^3 (EBIP RF 25%)

- 5 wells on ESP
  - ESP failure in 6P13 is not currently economically justifiable to replace
- Unbalanced operation strategy after wildfire outage has impacted production, working to stabilize
- 3 infill wells drilled in 2018, to be on production in 2019
- At YE, injection pressures were ~1,880–2,000 kPa

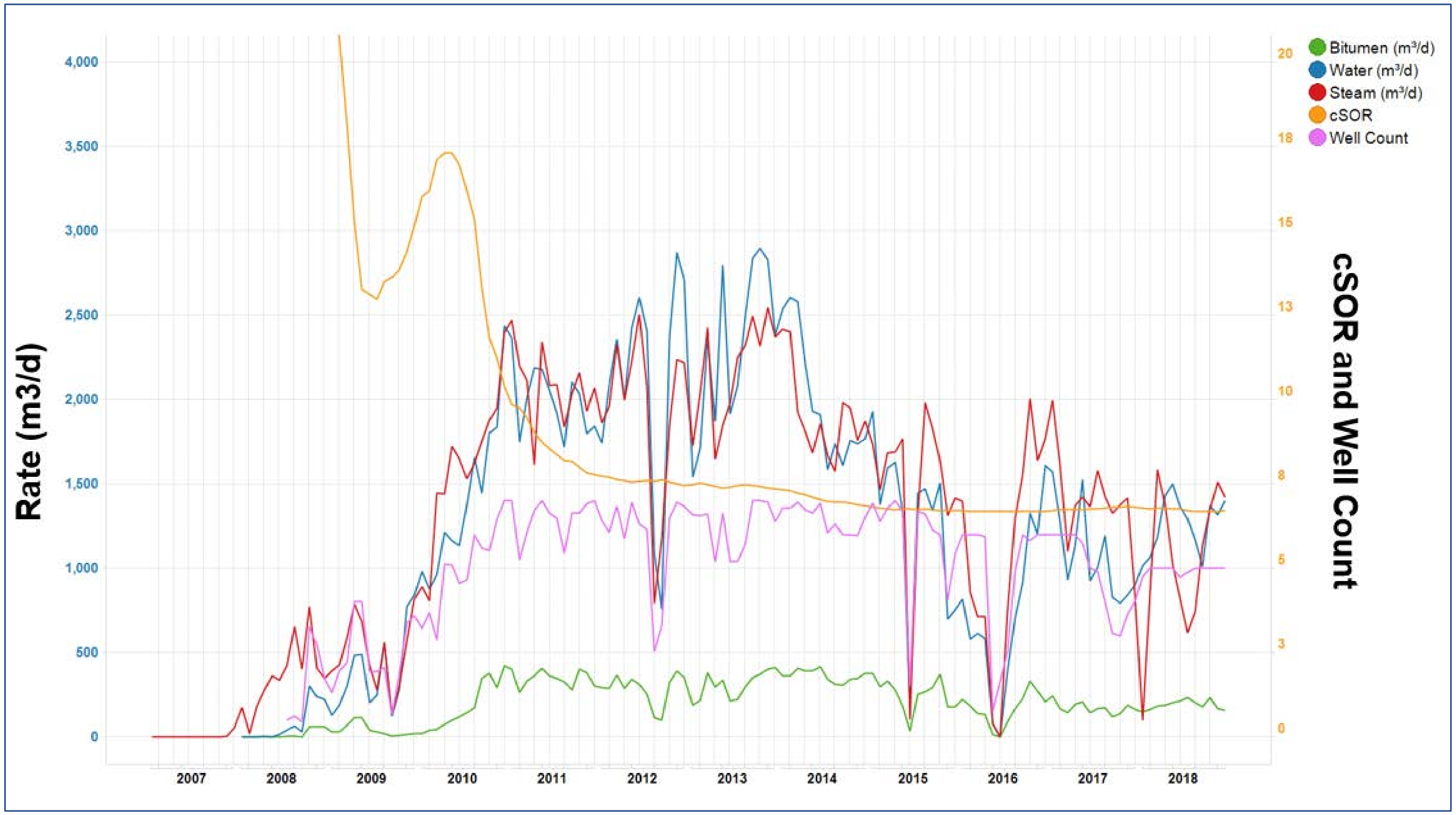
Pad 6W Production Summary



- 5 wells on ESP
  - 6P12 shut in due to liner failure in 2014
  - ESP failure in 6P10 is not currently economically justifiable to replace
- 2 infill wells drilled in 2018, to commence production in 2019
- At YE, injection pressures were ~1,740–1,960 kPa

- Seven well pairs (06P06 to 06P12)
- Cumulative production of 874 E^3m^3 (EBIP RF 47%)

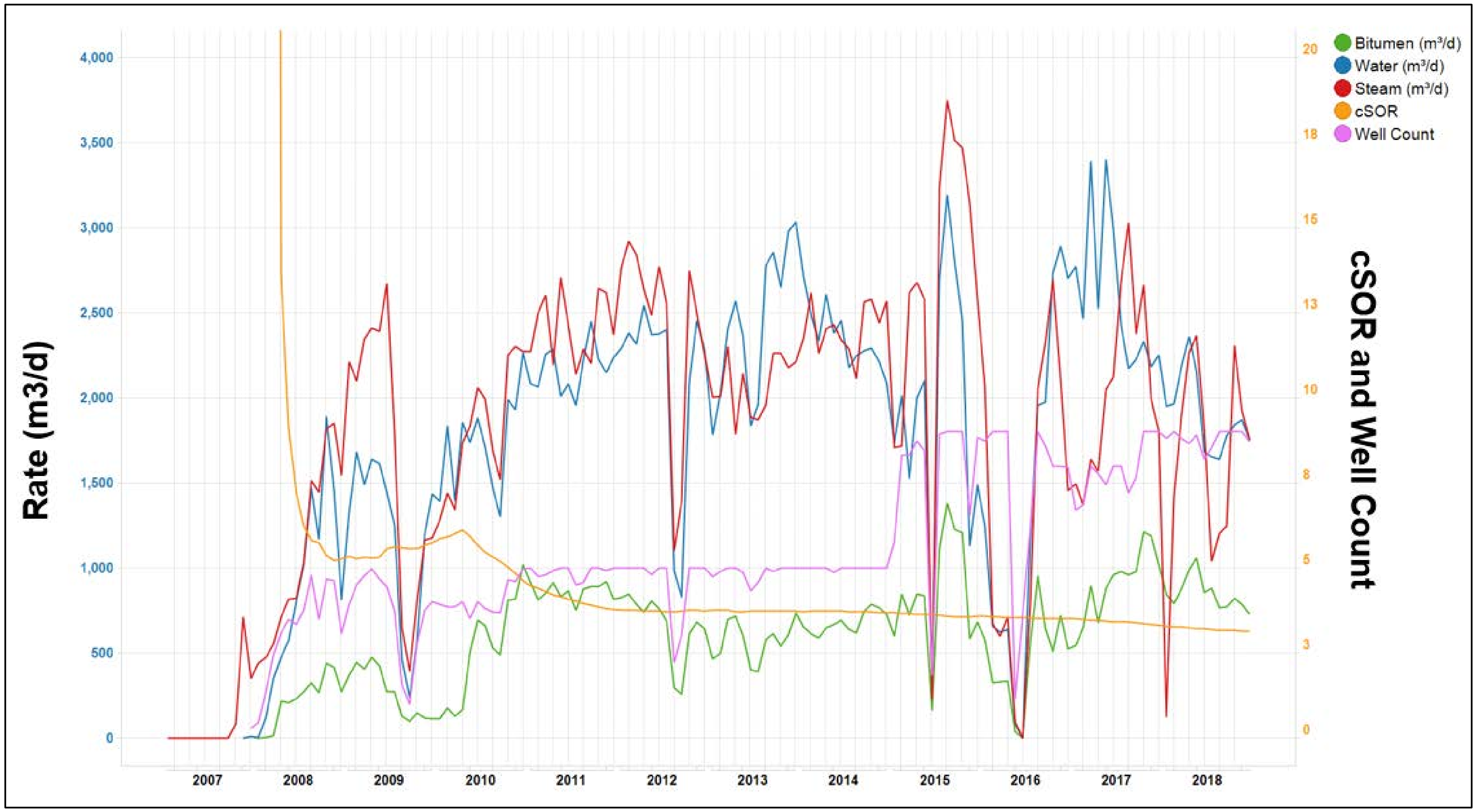
Pad 7E Production Summary



- Seven well pairs (07P06 to 07P12)
- Cumulative production of 847 E^3m^3 (EBIP RF 37%)

- 5 wells on ESP
  - 7P07 liner failure, installed ICD in Dec 2017
  - 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
- At YE, injection pressures were ~1,750–2,000 kPa

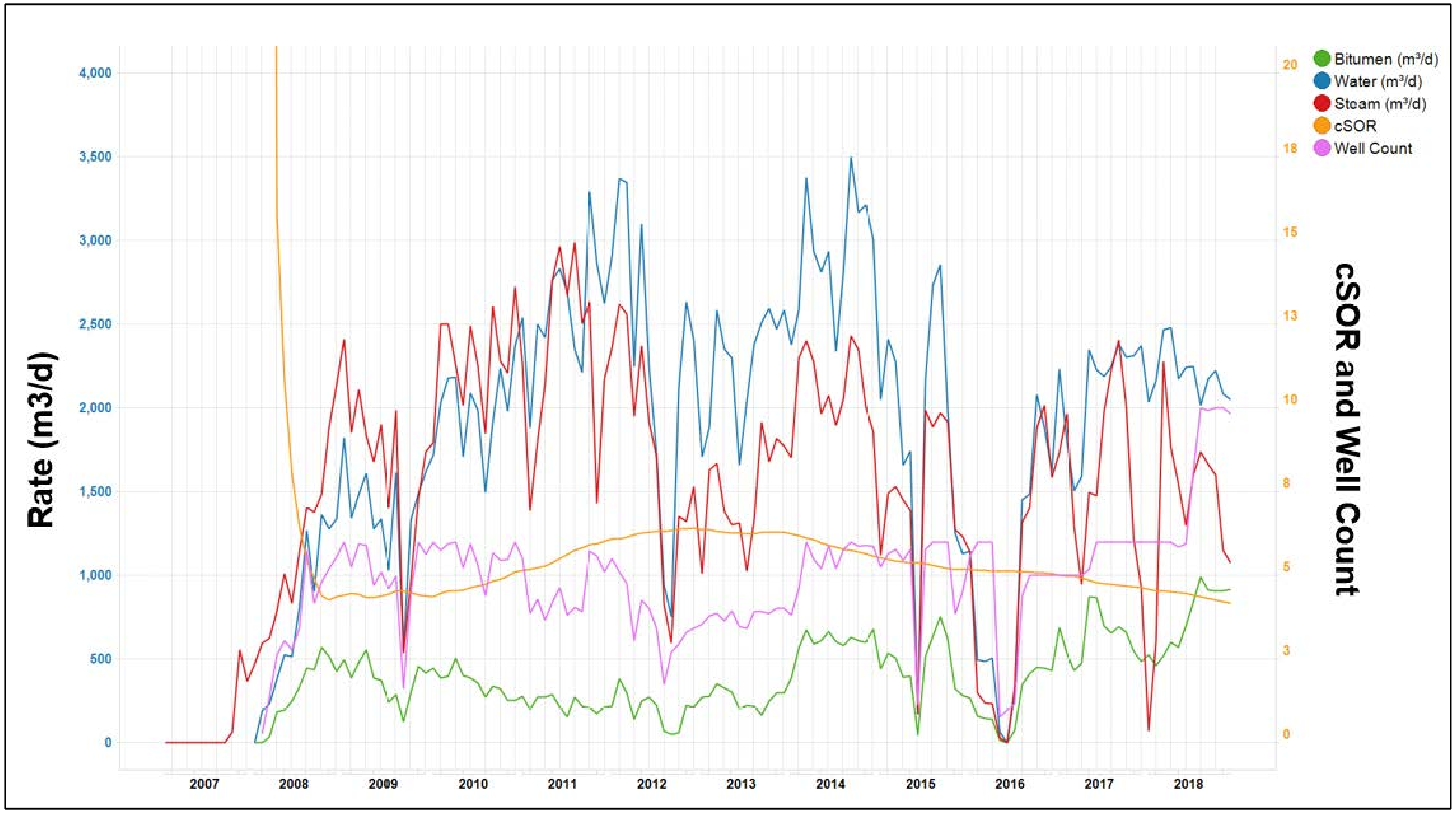
Pad 7N Production Summary



- All 9 wells on ESP
- Infill producer wells ramped up in Q1 2015 and have exhibited strong performance
- Evaluating restart of NCG co-injection
- At YE, injection pressures were ~1,850 – 2,000 kPa

- Five well pairs (07P01 to 07P05)
- Four infill producer wells (10P14 to 10P17)
- Cumulative production of 2,506 E^3m^3 (EBIP RF 70%)

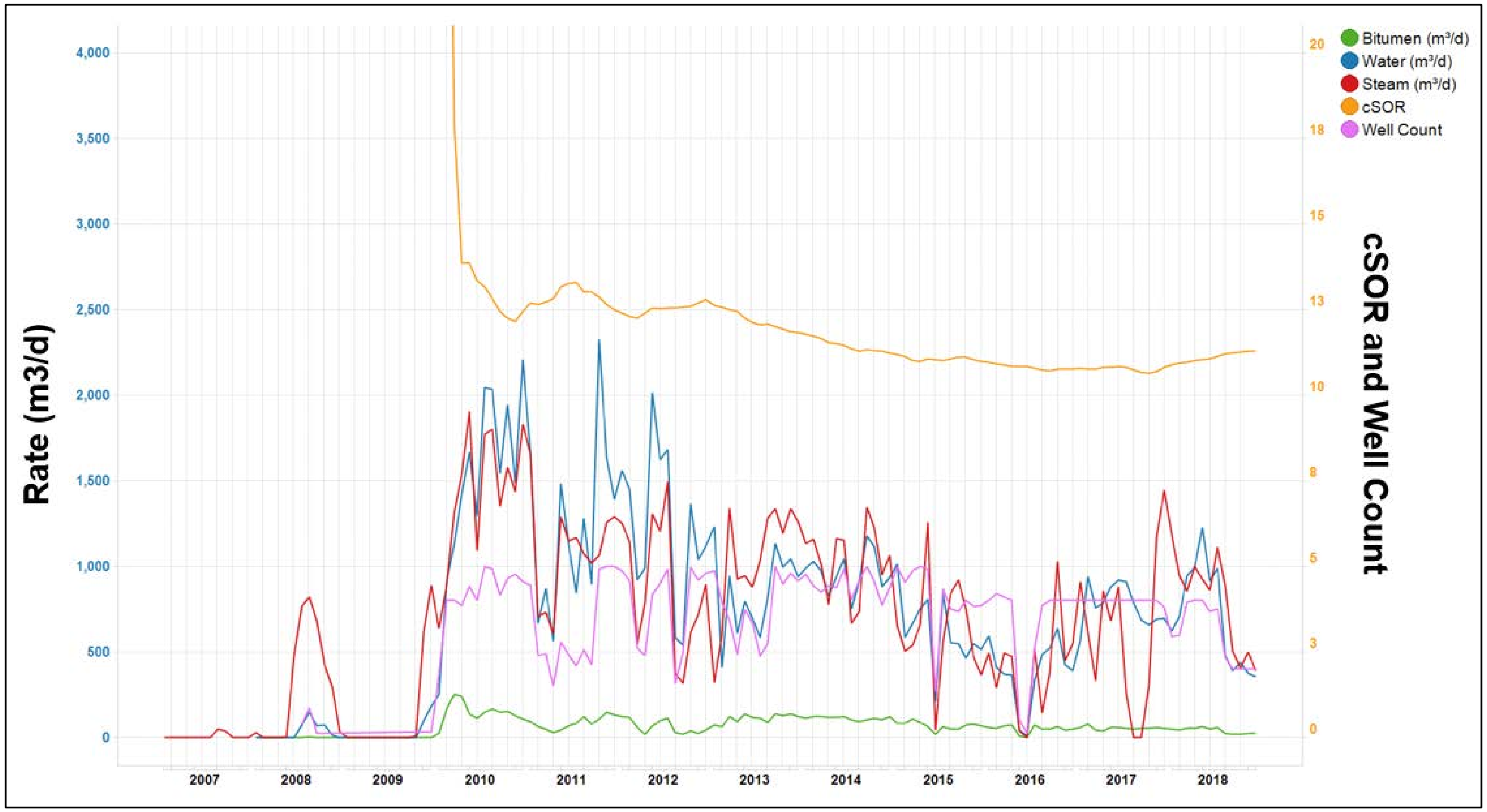
Pad 8 Production Summary



- All 10 wells on ESP
  - 08S06 failed in 2015, no observed detriment
- ICD's installed on 08P03 in 2015
- 4 infill wells on production in mid-2018
- At YE, injection pressures were ~1,750–1,810 kPa

- Six well pairs (08P01 to 08P06)
- Four infill well producers (08P03INF to 8P06INF)
- Cumulative production of 1,598 E^3m^3 (EBIP RF 46%)

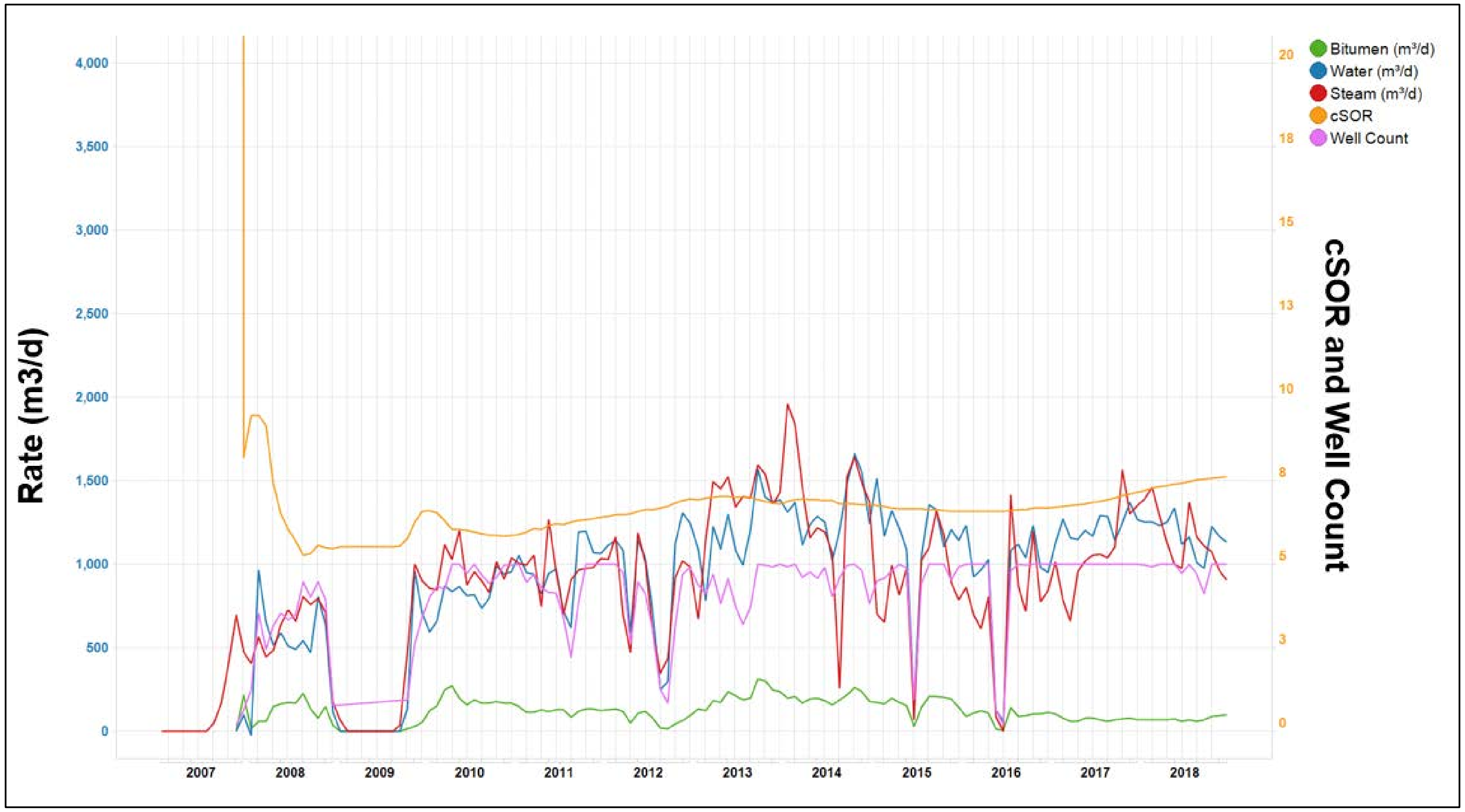
Pad 9NE Production Summary



- 2 wells on ESP
  - 9P06 SI due to insufficient inflow with current reservoir pressure
  - 9P09, 9P10 ESP failures in 2018
- Poor reservoir quality and unstable operation impacting performance; evaluating pressure blowdown trial
- At YE, injection pressures were ~1,510 – 1,590 kPa

- Five well pairs (09P06 to 09P10)
- Cumulative production of 271 E^3m^3 (EBIP RF 22%)

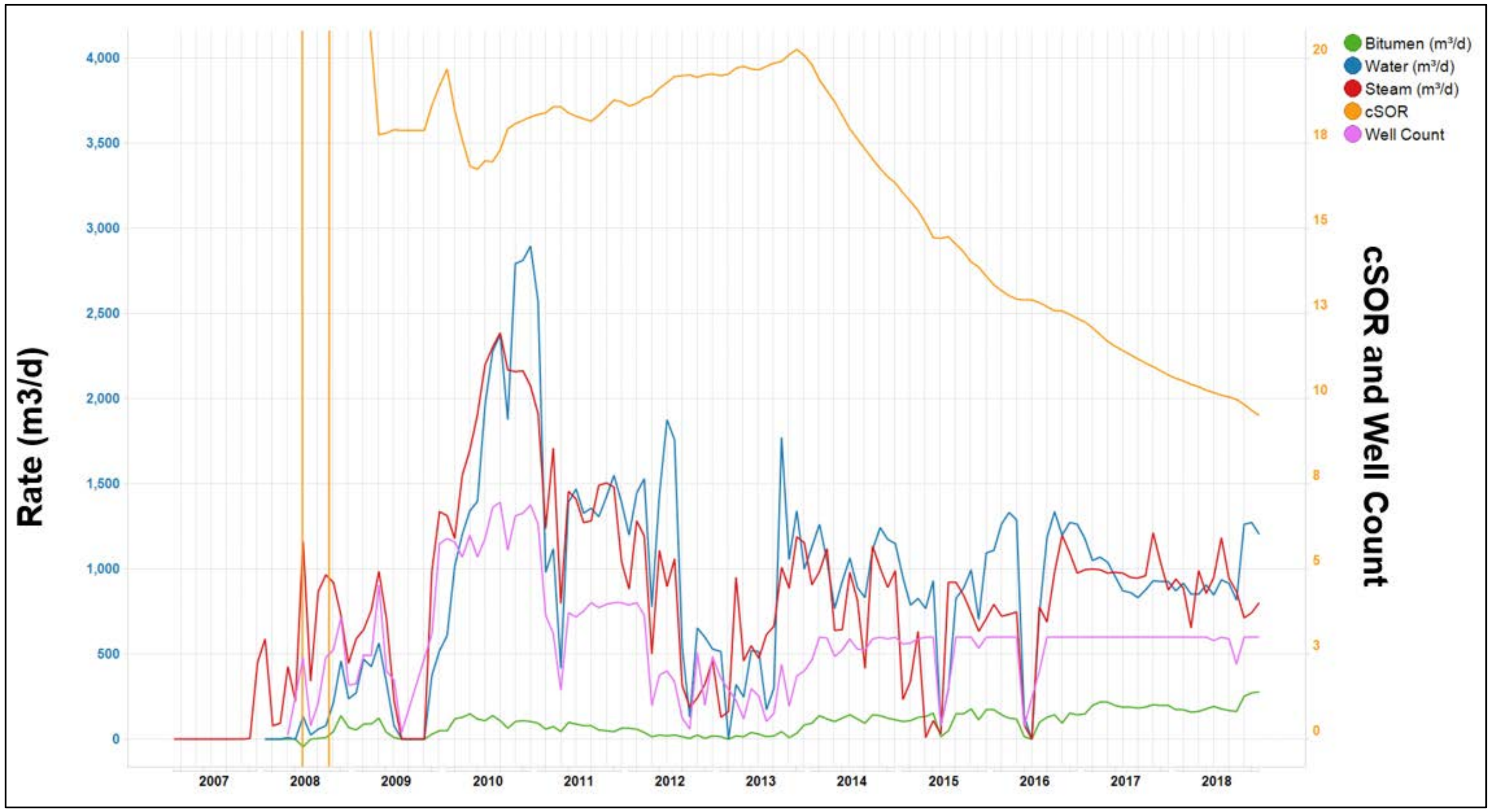
Pad 9W Production Summary



- 9P1-9P3 on gas lift
- 9P4 & 9P5 on ESP
- Stable operations
- At YE, injection pressures were ~1,825 - 1,980kPa

- Five well pairs (09P01 to 09P05)
- Cumulative production of 492 E^3m^3 (EBIP RF 27%)

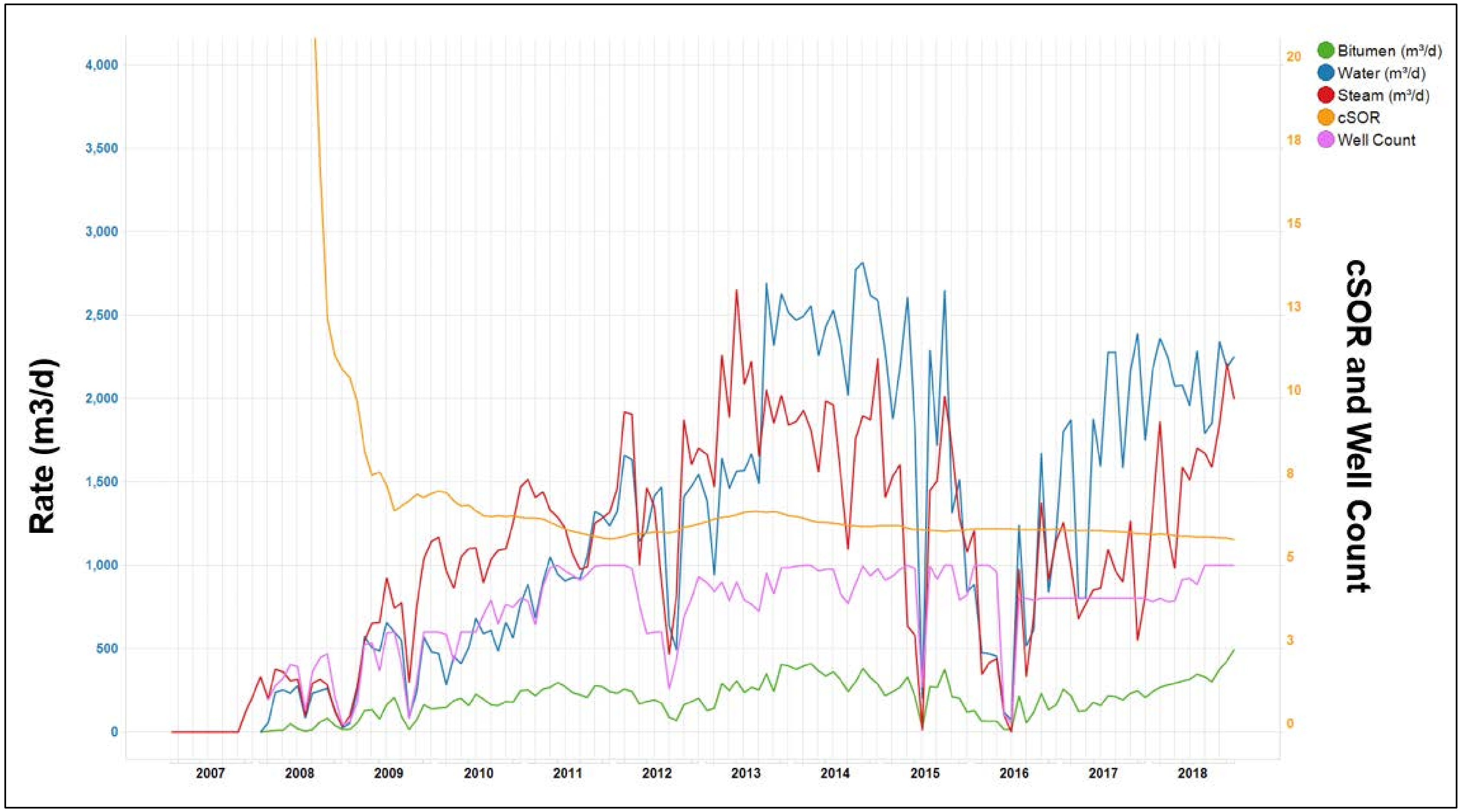
Pad 10N Production Summary



- 3 producing wells on gas lift
- Steady operation strategy has yielded a stable production performance
- At YE, injection pressures were ~1,970 - 2,000 kPa

- EIght well pairs (10P06 to 10P13)
- Cumulative production of 378E^{3}m^3 (EBIP RF 14%)

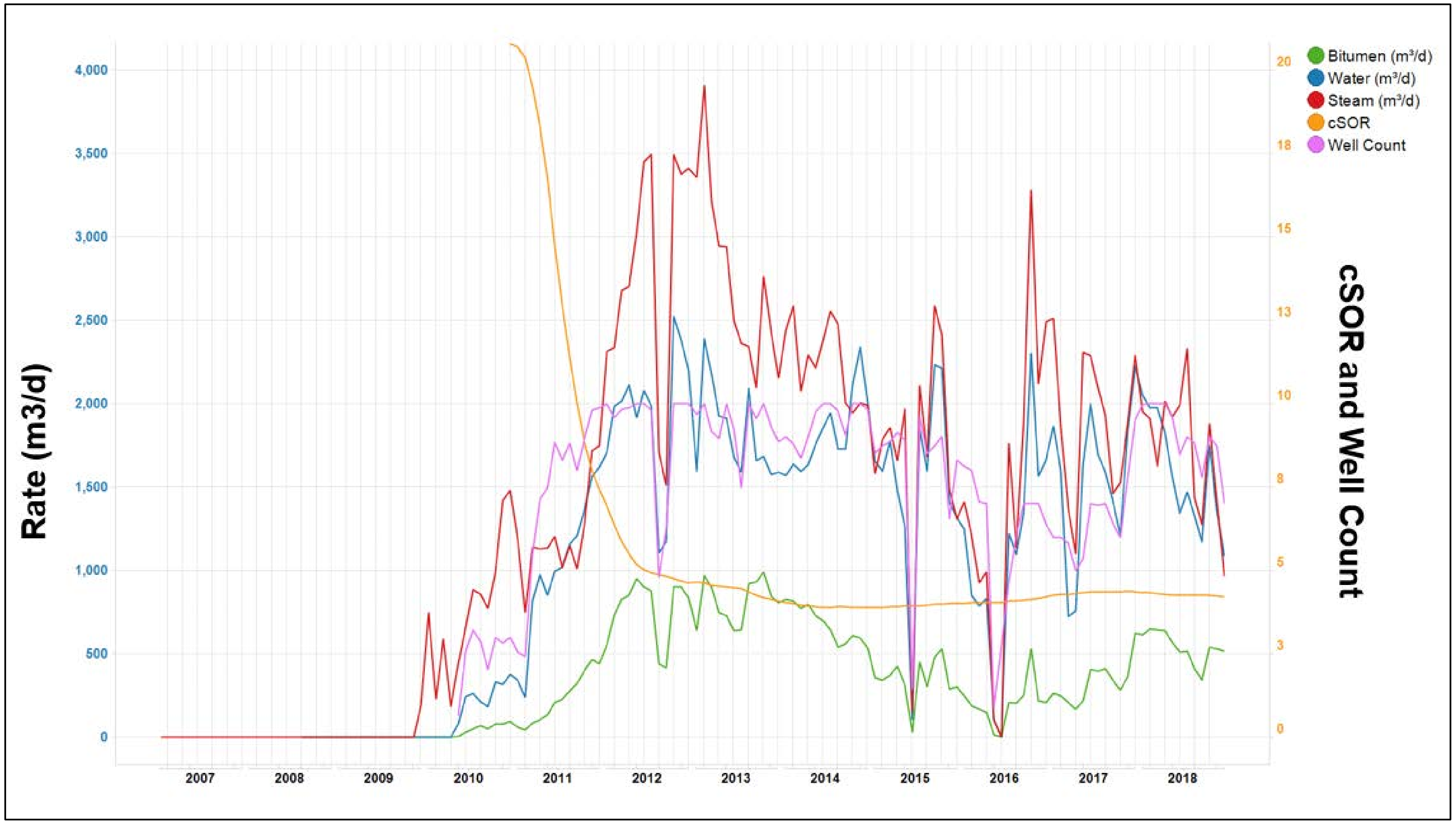
Pad 10W Production Summary



- 5 wells on ESP
- Pad continued to be impacted by top water
  - 10P04 liner failure equipped with WWS-ICDs to re-instate full wellbore length in 2018
- At YE, injection pressures were ~1,875–1,950 kPa

- Five well pairs (10P01 to 10P05)
- Cumulative production of 814 E^3m^3 (EBIP RF 34%)

Pad 11 Production Summary



- 9 wells are on ESP
  - 11P06 liner failure in 2018
  - 11P09 ESP failure in 2018
- Pad continues to be impacted by top water, yet has maintained fairly steady production rates
- At YE, injection pressures were ~1,760–1,895 kPa

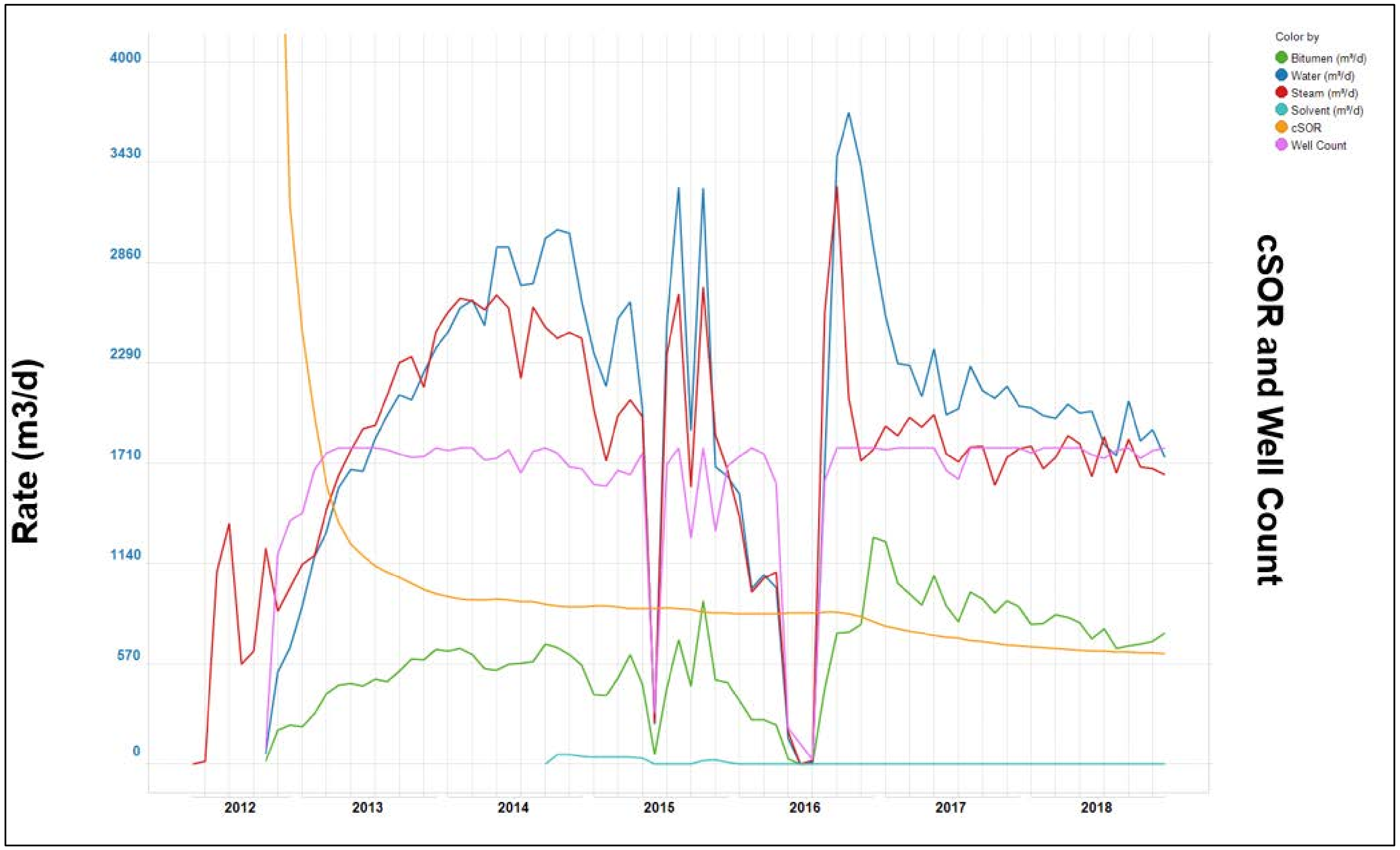
- Ten well pairs (11P01 to 11P10)
- Cumulative production of 1,439 E^3m^3 (EBIP RF 59%)

Pad 12 Production Summary

- All 9 wells are on ESP
- Exhibited steady production performance
- At YE, injection pressures were ~1,730 –1,790 kPa

- Nine well pairs (12P01 to 12P09)
- Cumulative production of 1031 E^3m^3 (EBIP RF 31%)

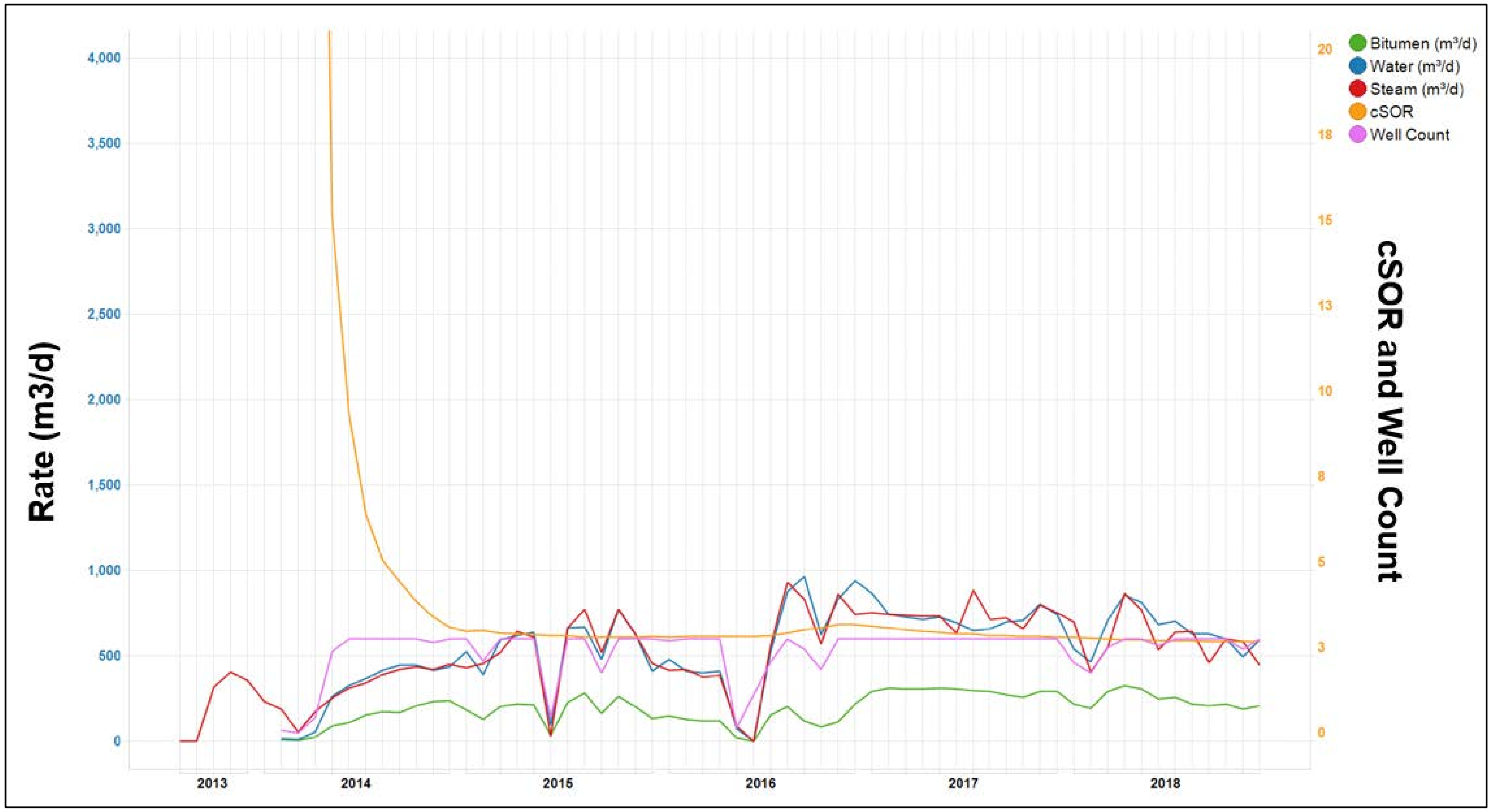
Pad 13 Production Summary



- All 9 wells are on ESP
- Exhibited stable production performance
- ES-SAGD project no longer operational
- At YE, injection pressures were ~1,700 –1,820 kPa

- Nine well pairs (13P01 to 13P09)
- Cumulative production of 1368 E^3m^3 (EBIP RF 41%)

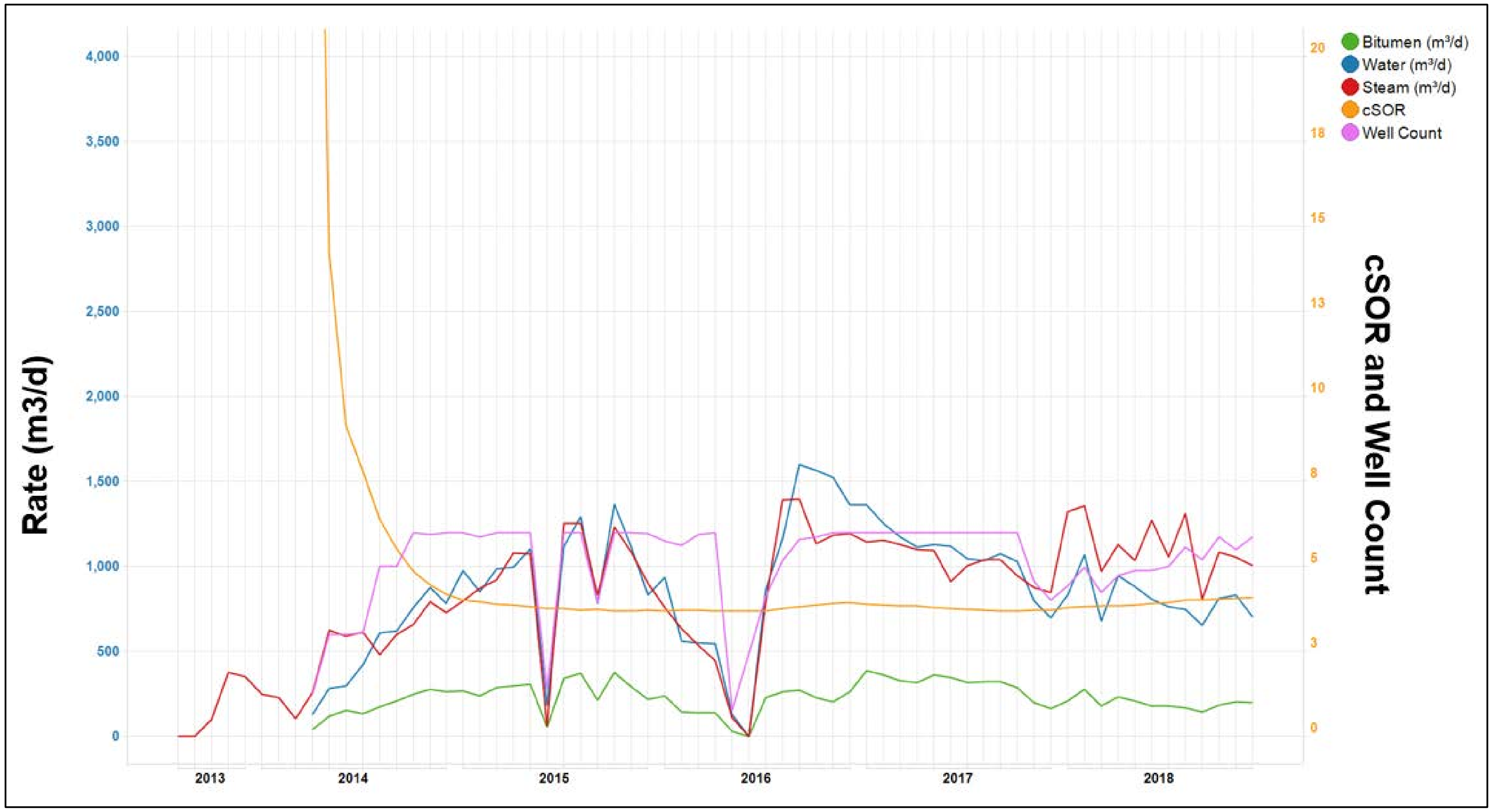
Pad 14N Production Summary



- All 3 wells on ESP
- Wells are stable, on plateau
- At YE, injection pressures were ~1,840 kPa

- Three well pairs (14P05 to 14P07)
- Cumulative production of 351 e^3m^3 (EBIP RF 28%)

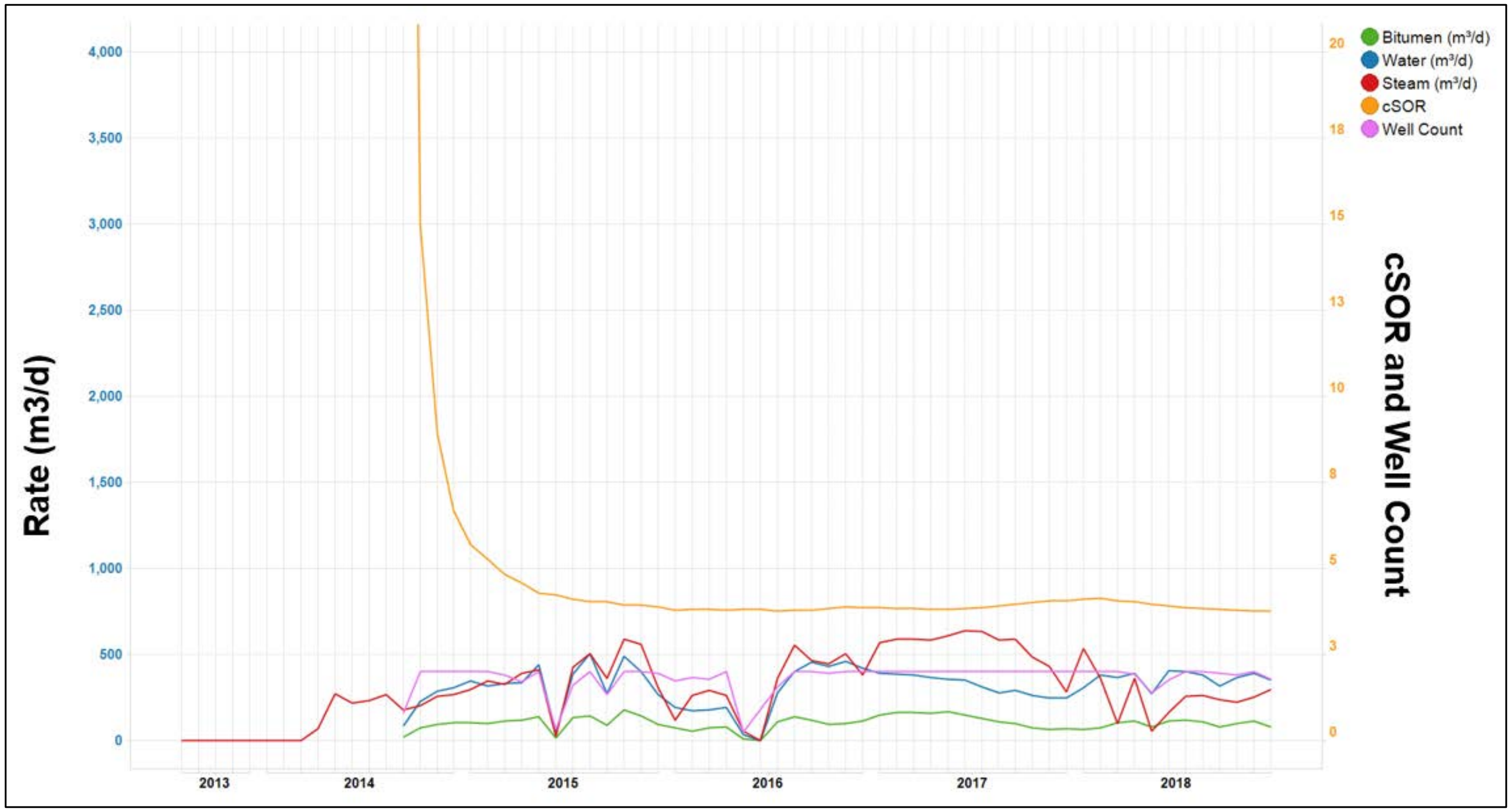
Pad 14/15E Production Summary



- All 6 wells on ESP
  - 14P02 liner failure in repaired with WWS-ICDs in 2018
- At YE, injection pressures were ~1,710–1,850 kPa

- Six well pairs (14P01 to 14P03 and 15P01 to 15P03)
- Cumulative production of 399 e^3m^3 (EBIP RF 31%)

Pad 15S Production Summary



- Both wells on ESP
- Moved to a balanced operating strategy
- At YE, injection pressures were ~ 1580 - 1,625kPa

- Two well pairs (15P04, 15P05)
- Cumulative production of 161 e^3m^3 (EBIP RF 31%)

Well Pad Performance
Subsection 3.1.7 (h)
Kinosis

K1A Production Summary

- All wellpairs inactive
  - K1P09 shut-in

- 37 well pairs drilled
- Cumulative production of 181 e^3m^3 (RF 1%)