Long Lake Kinosis Oil Sands Project Annual Performance Presentation

November 15, 2016

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

nexen
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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.

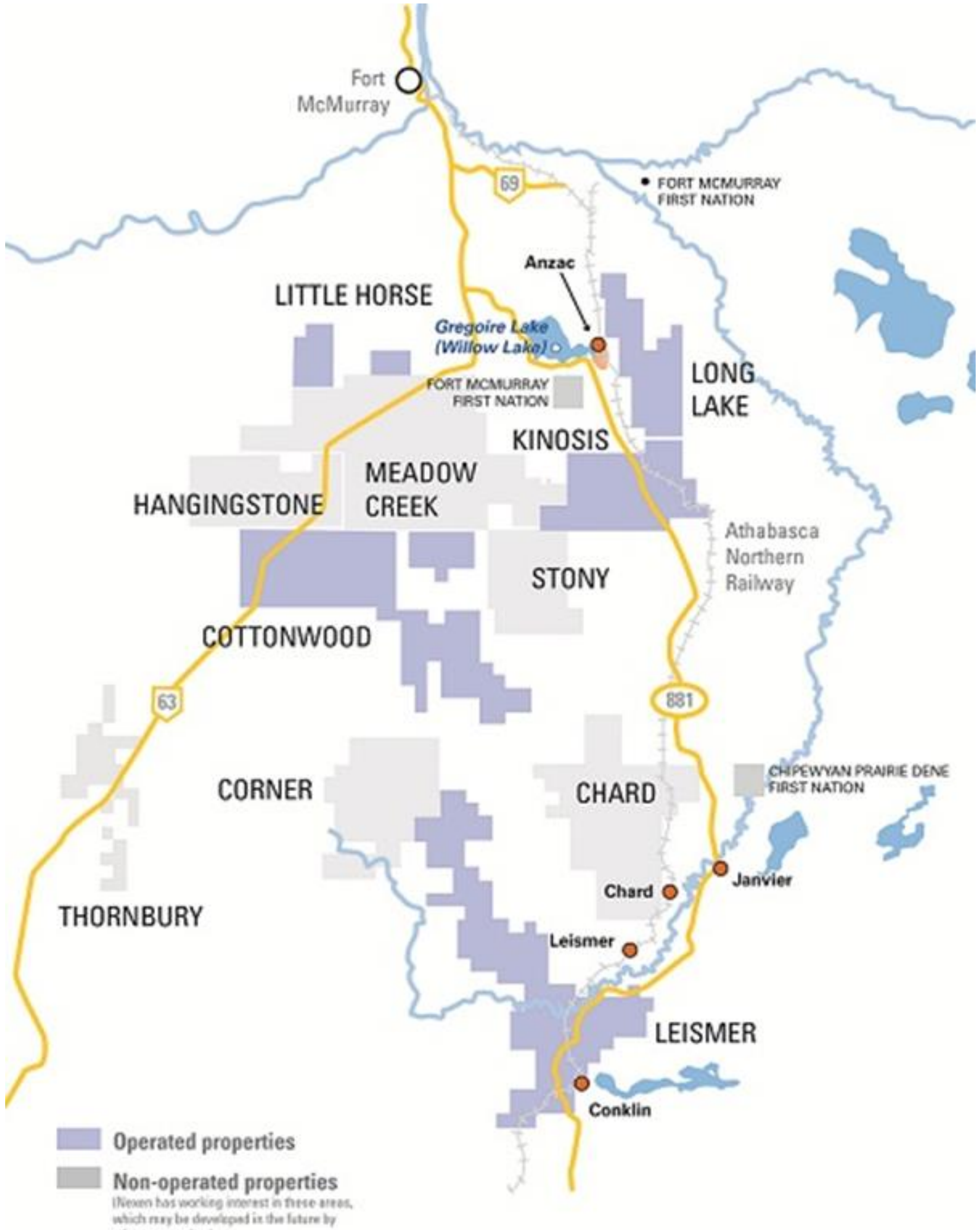
Corporate Ownership

- Nexen Energy ULC (Nexen) 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.

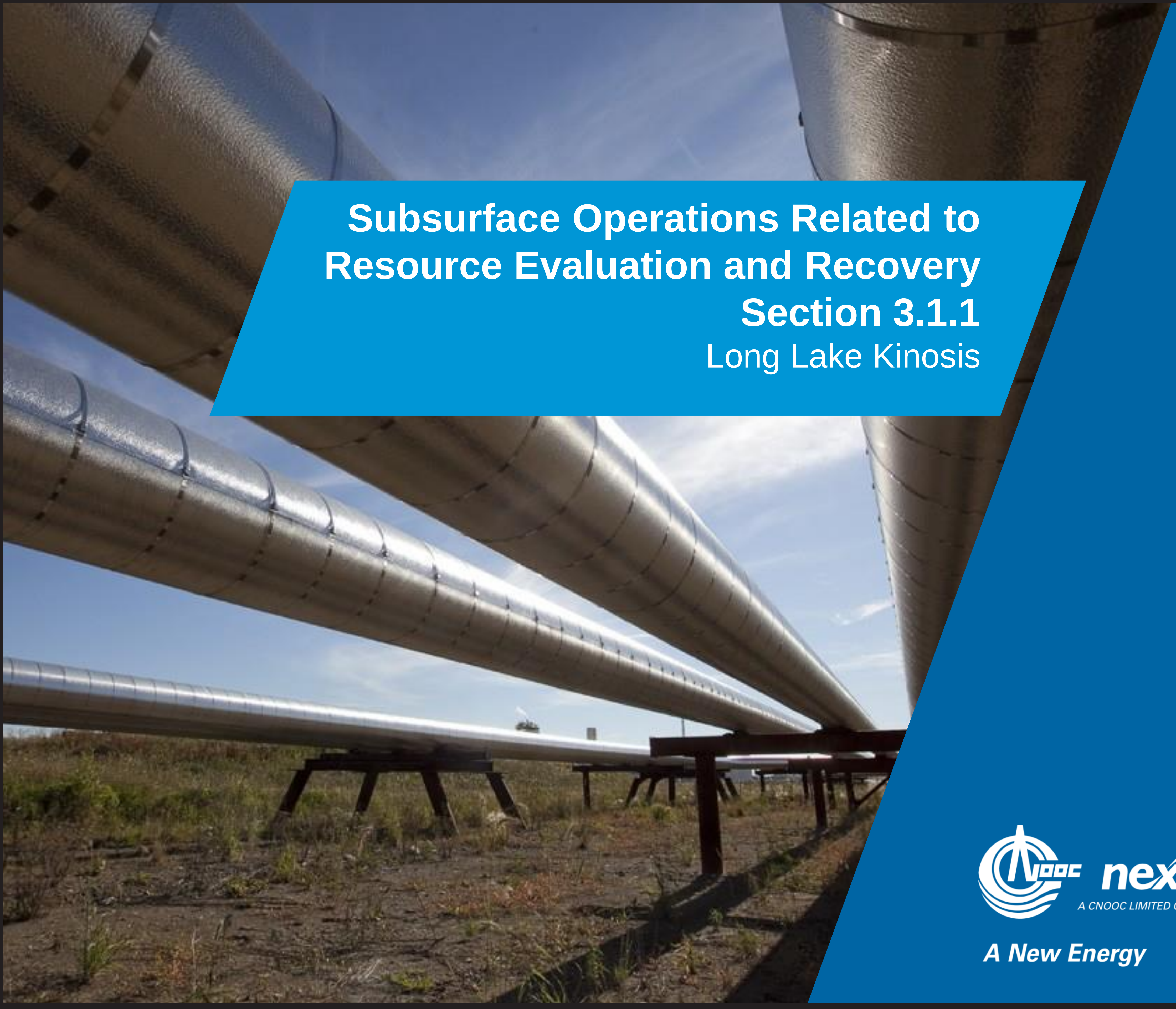
- Nexen is a wholly-owned subsidiary of the China National Offshore Oil Company (CNOOC) Limited.

- Nexen has three principal businesses: conventional oil and gas, oil sands and shale gas.

Nexen Oil Sands



Contents



Subsurface Operations Related to Resource Evaluation and Recovery Section 3.1.1

Long Lake Kinosis

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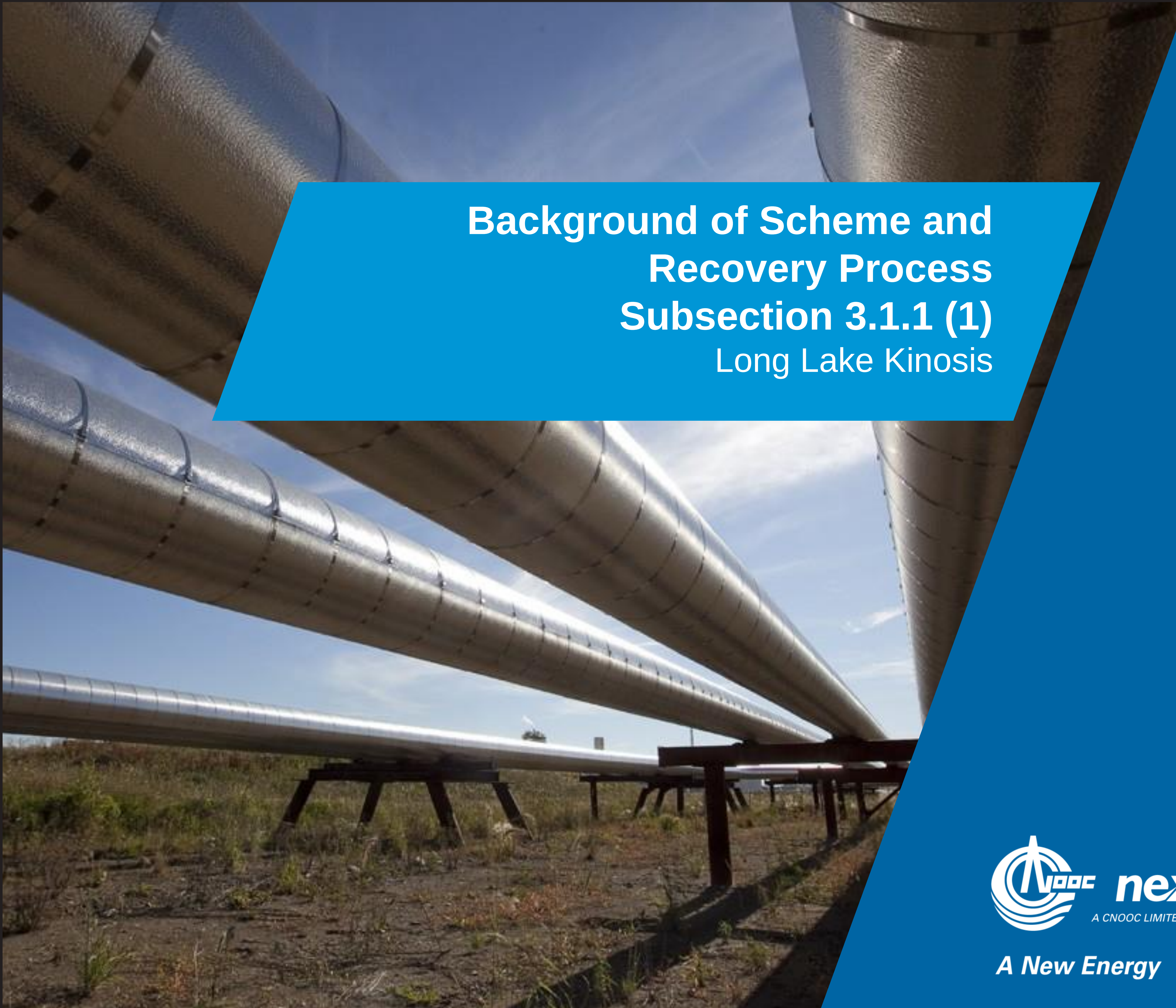

Background of Scheme and Recovery Process Subsection 3.1.1 (1)

Long Lake Kinosis

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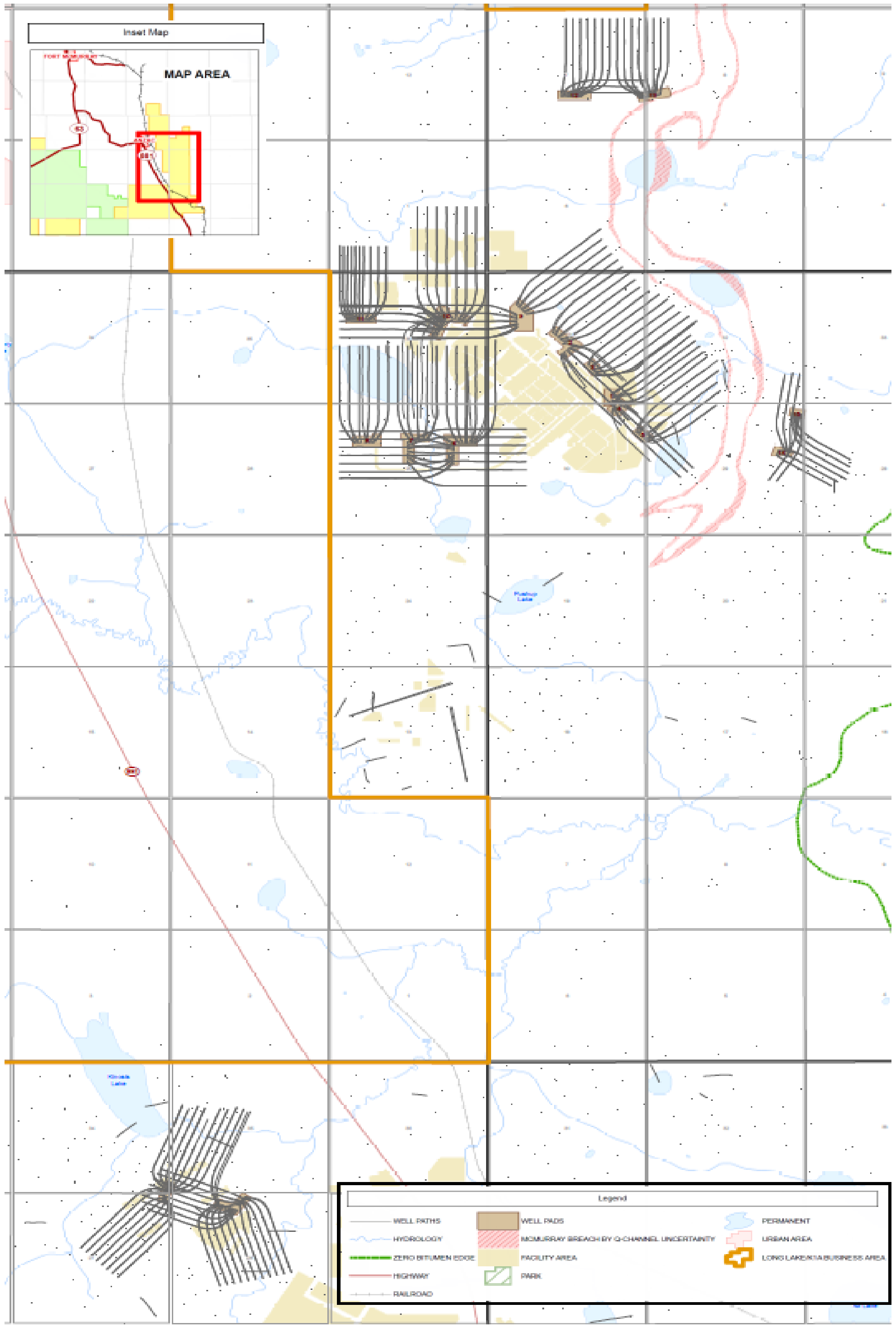
Long Lake Scheme Description

- Long Lake is located approximately 40 km southeast of Fort McMurray
- An integrated SAGD and Upgrader oil sands project producing from the Wabiskaw-McMurray deposit

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

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



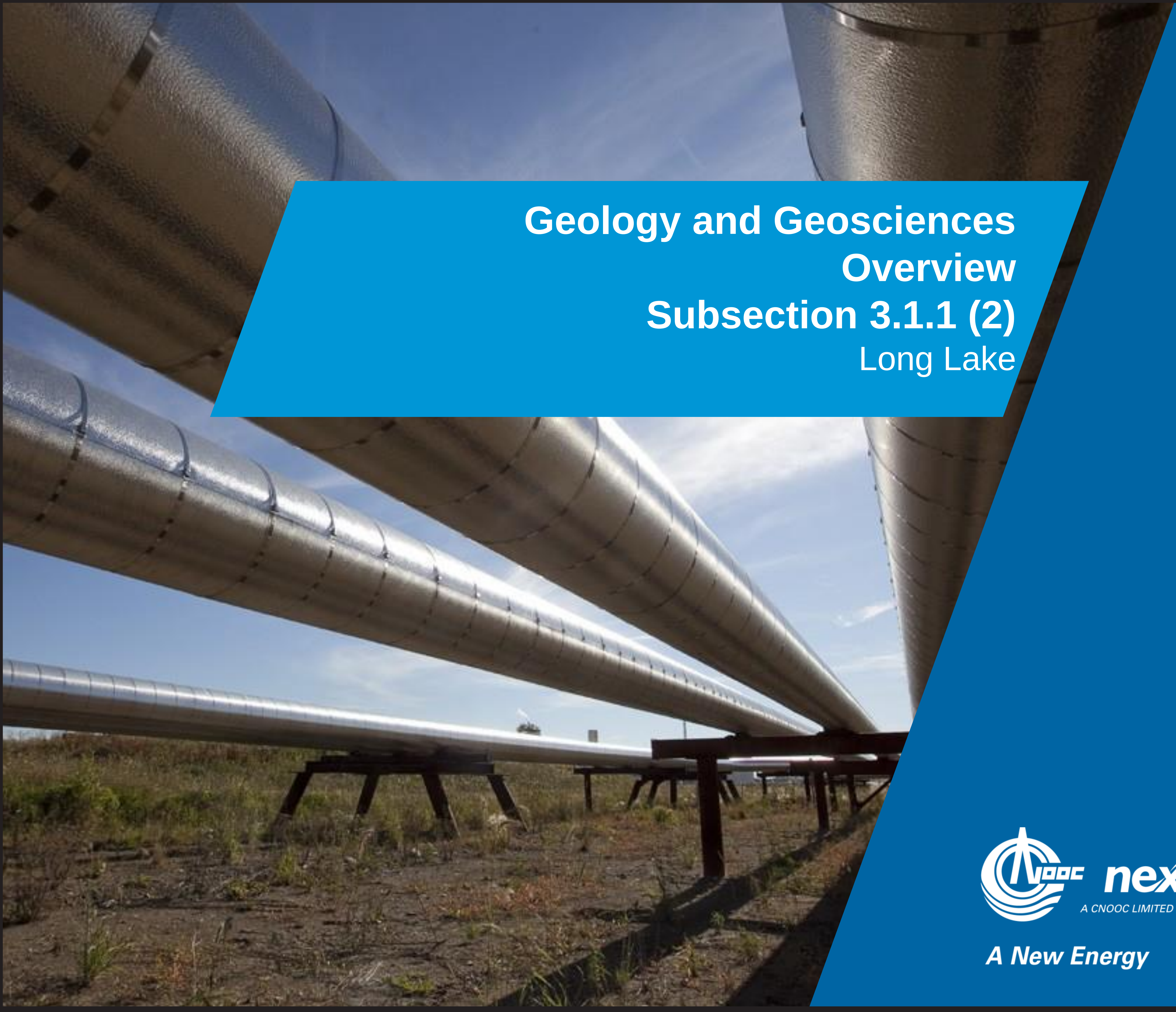
*K1A – First 20K of 70K which is Phase 1 of Kinosis

CHRONOLOGY OF OIL SANDS OPERATIONS

Year	Activity
2000	EIA and regulatory submissions for the commercial Long Lake Facility
2003	Regulatory approvals for the commercial Long Lake Facility
2003 - 2007	Production at the Long Lake SAGD Pilot Plant
2004	Construction begins for the commercial Long Lake 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 Long Lake 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 for Pads 14 and 15 and K1A
2012	Construction begins for K1A and Pads 14 and 15
2013	Increased production from Long Lake well pads, begin circulation at Pad 14
2014	K1A and Pads 14 and 15 started production
2015	Diluent Recovery Project Start up and Production at K1A suspended

2015 Summary

- K1A wells exhibited strong ramp up and continued to deliver strong performance in first half of 2015
- Long Lake pads continued to deliver strong performance
- A successful year at Long Lake for steam production and Syngas consumption
- Experienced higher than average facility downtime
- Successful Turnaround
- K1A emulsion line leak and issuance of Environmental Protection Order
- Pipeline suspension order



Geology and Geosciences Overview
Subsection 3.1.1 (2)
Long Lake

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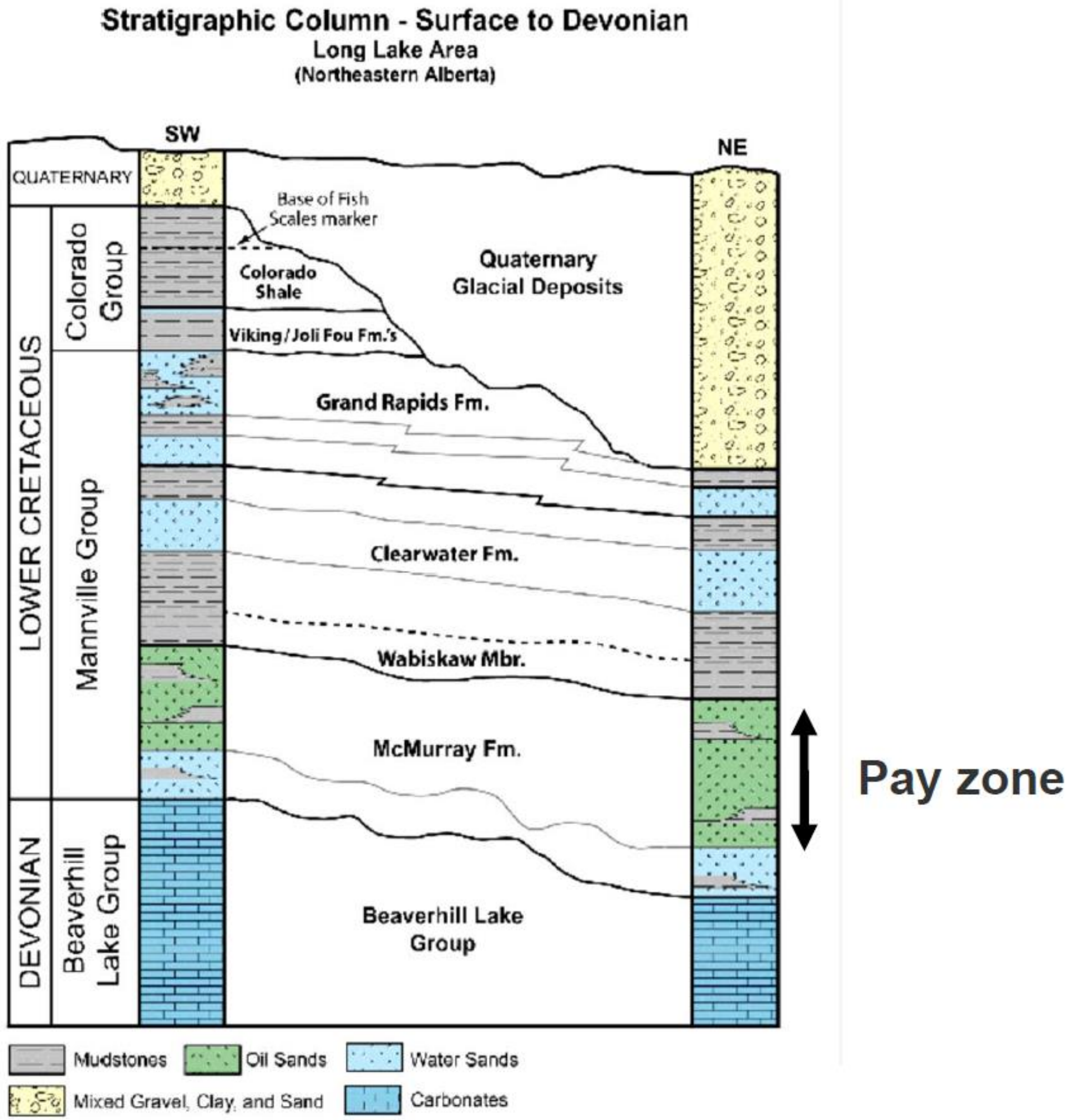
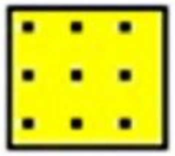
Stratigraphy

Reservoir: McMurray Fm.

Cap rock: Wabiskaw & Clearwater Fm.



Nexen Facies Codes



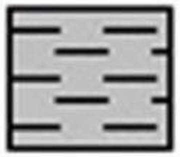
Sandstone .... Facies 1:
- clean crossbedded sandstone
- VSH 0 - 10%
- estuarine sands

Sandy IHS .... Facies 2:
- inclined interbedded sandstone, and mudstone
- VSH 10 - 30%
- point bar facies

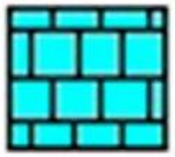
Breccia .... Facies 3:
- mud clast breccia
- sand supported and mud clast supported
- channel base facies

Muddy IHS .... Facies 4:
- inclined interbedded sandstone, and mudstone
- VSH 30 - 80%
- point bar facies

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



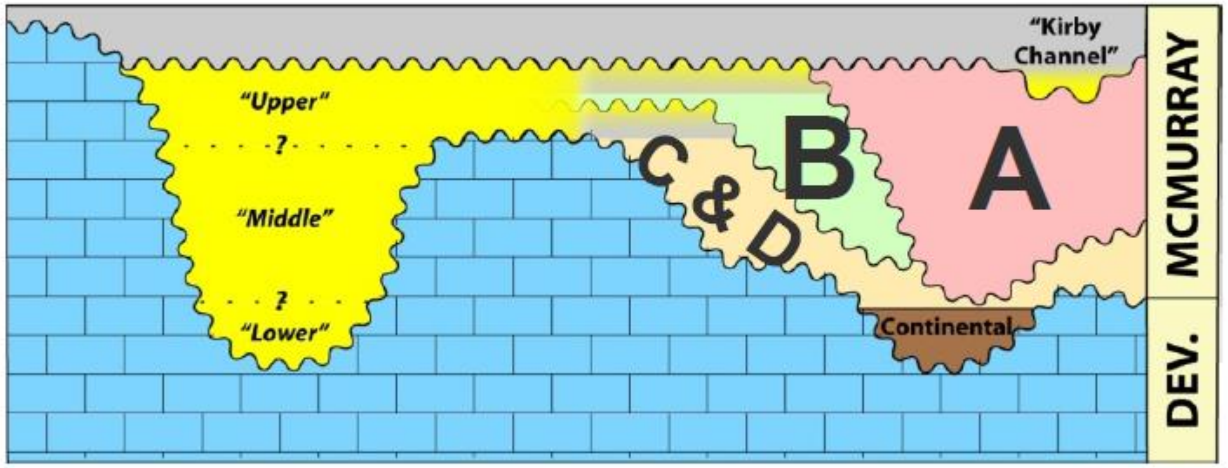
Mudstone .... Facies 6:
- flood plain deposits



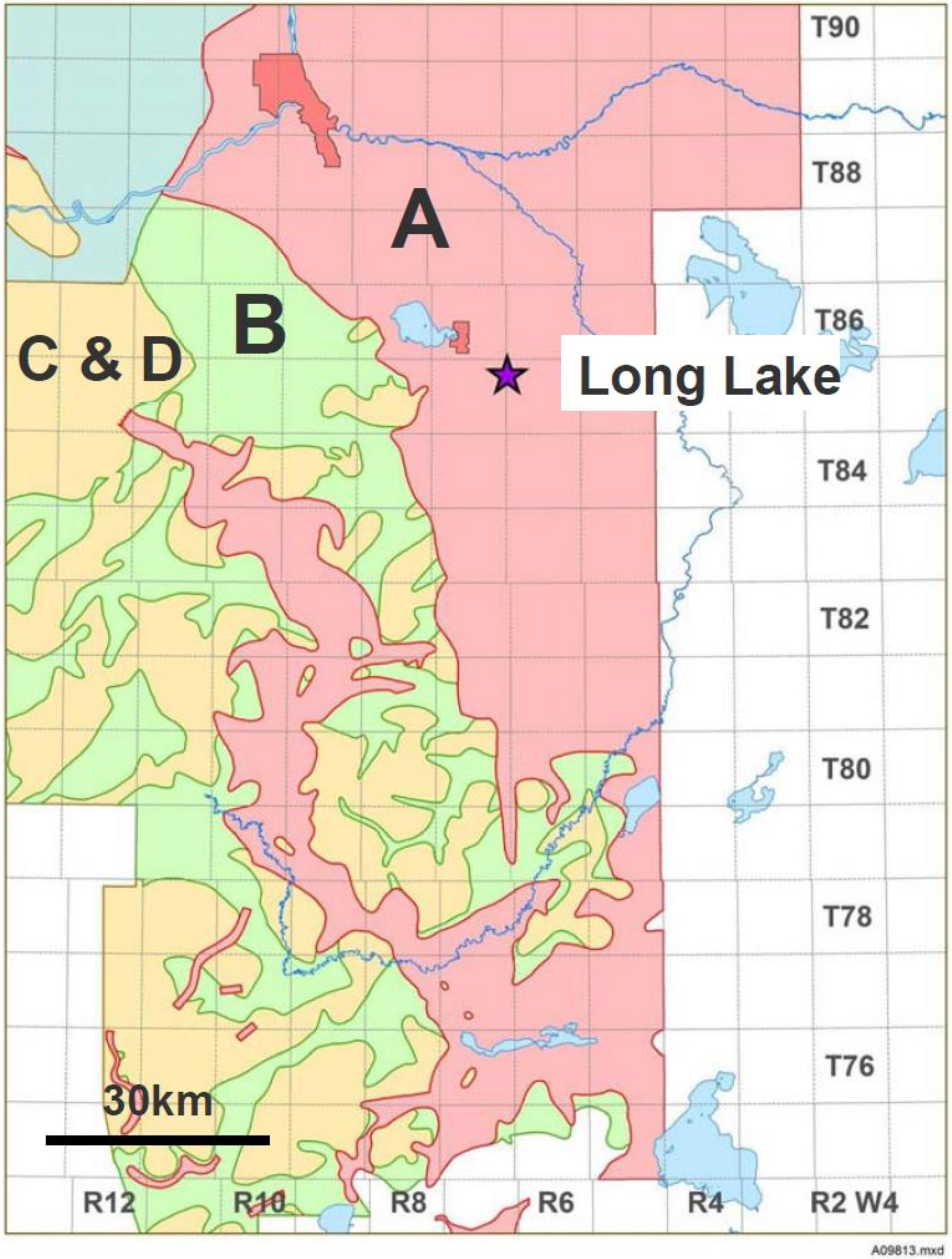
Limestone .... Facies 7:
- Devonian carbonates

Nexen's Regional Model

- Multiple valleys
  - C & D valleys (oldest)
  - A valley (youngest)
- In terms of sequence stratigraphy, it was a low-accommodation setting
- Compound incised-valley system hung from several surfaces in the McMurray

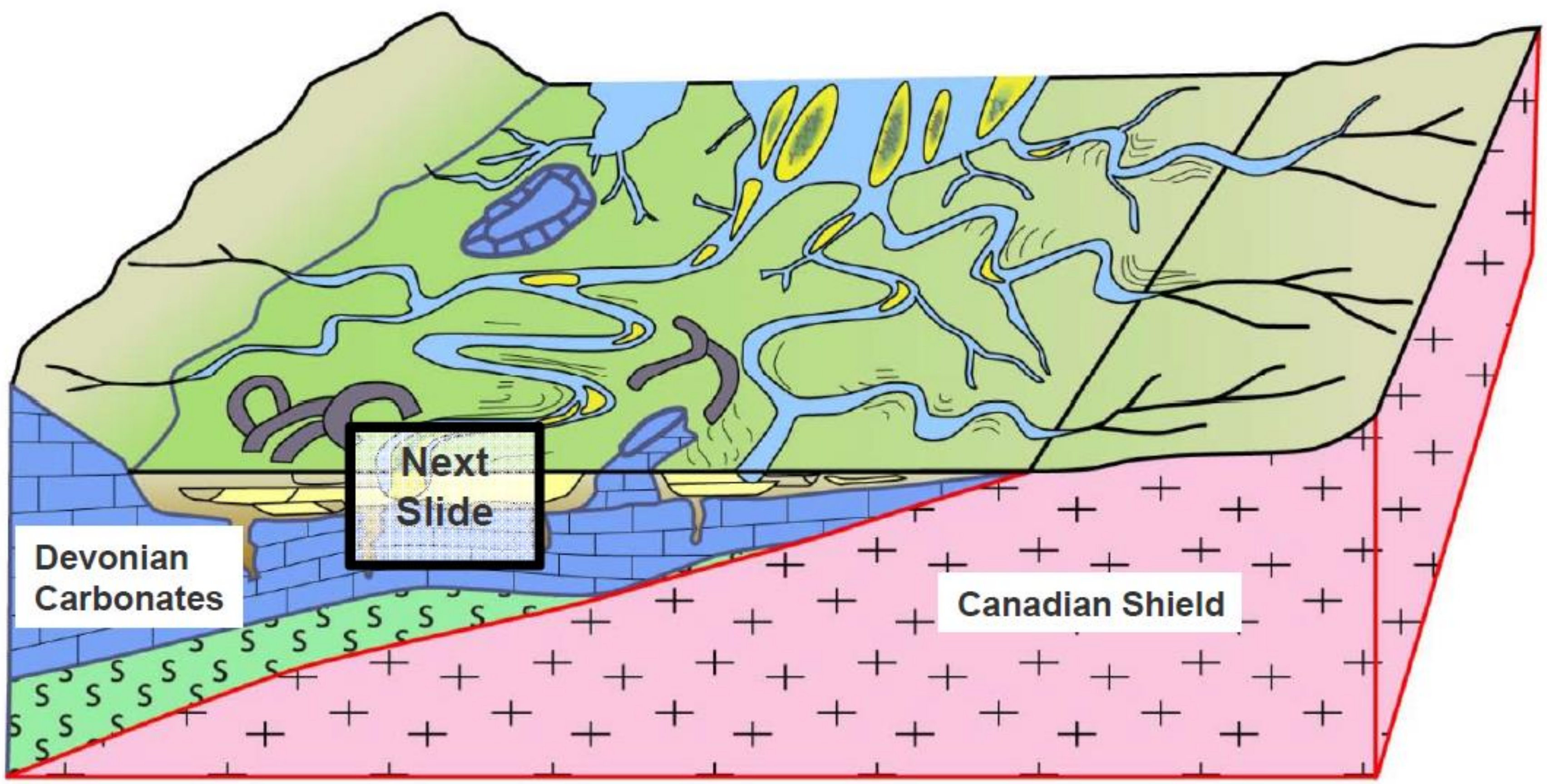


Jervey, 2003

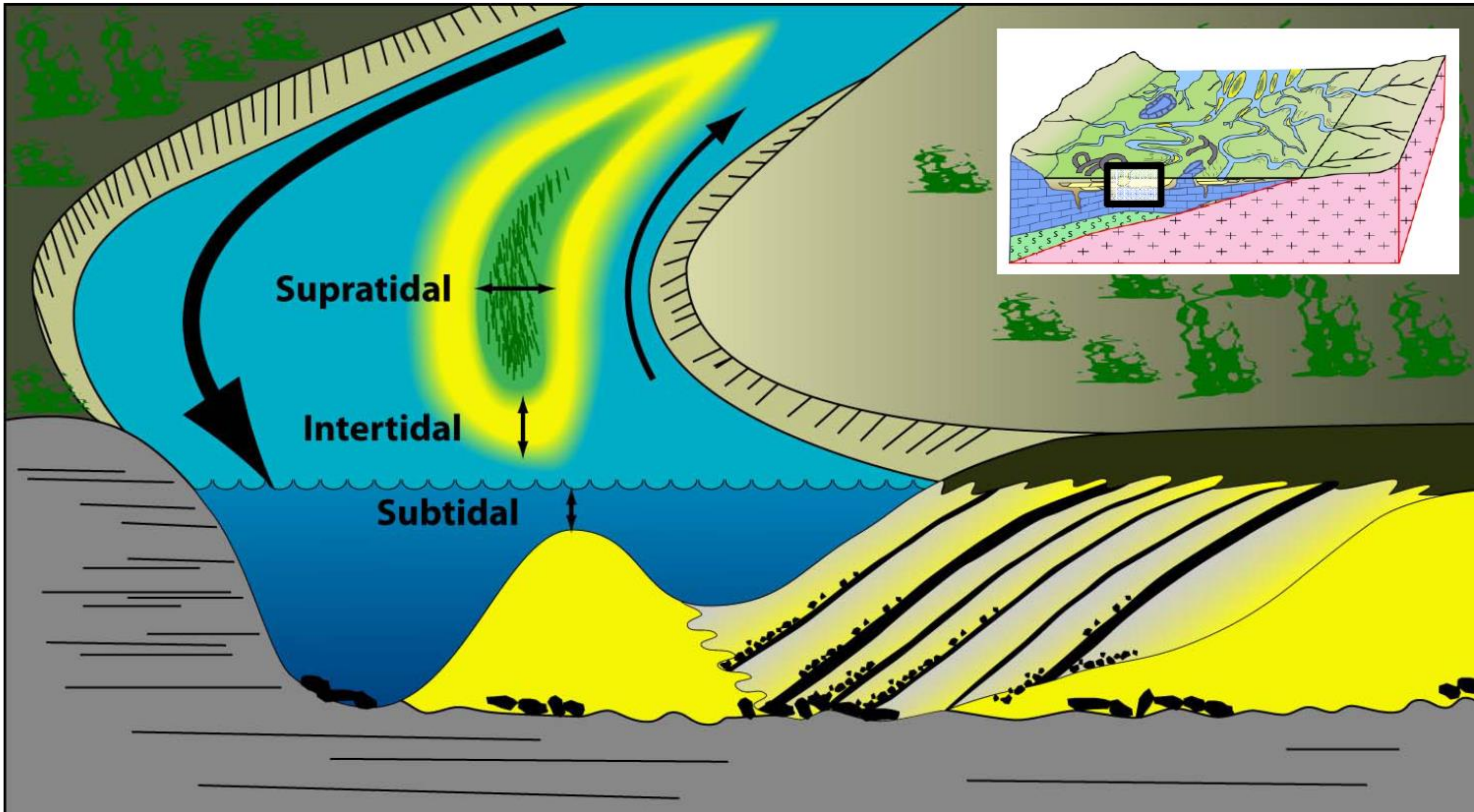


Regional Depositional Model

- 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

Long Lake Devonian Structure with Karst and Salt Dissolution Features

Legend

MAP DATA

- 2014/2015 CORE OBS WELLS
- ZERO BITUMEN EDGE
- DEVONIAN STRUCTURE CONTOURS (C.I.=10m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

HORIZONTAL WELL STATUS (PRODUCER)

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

Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

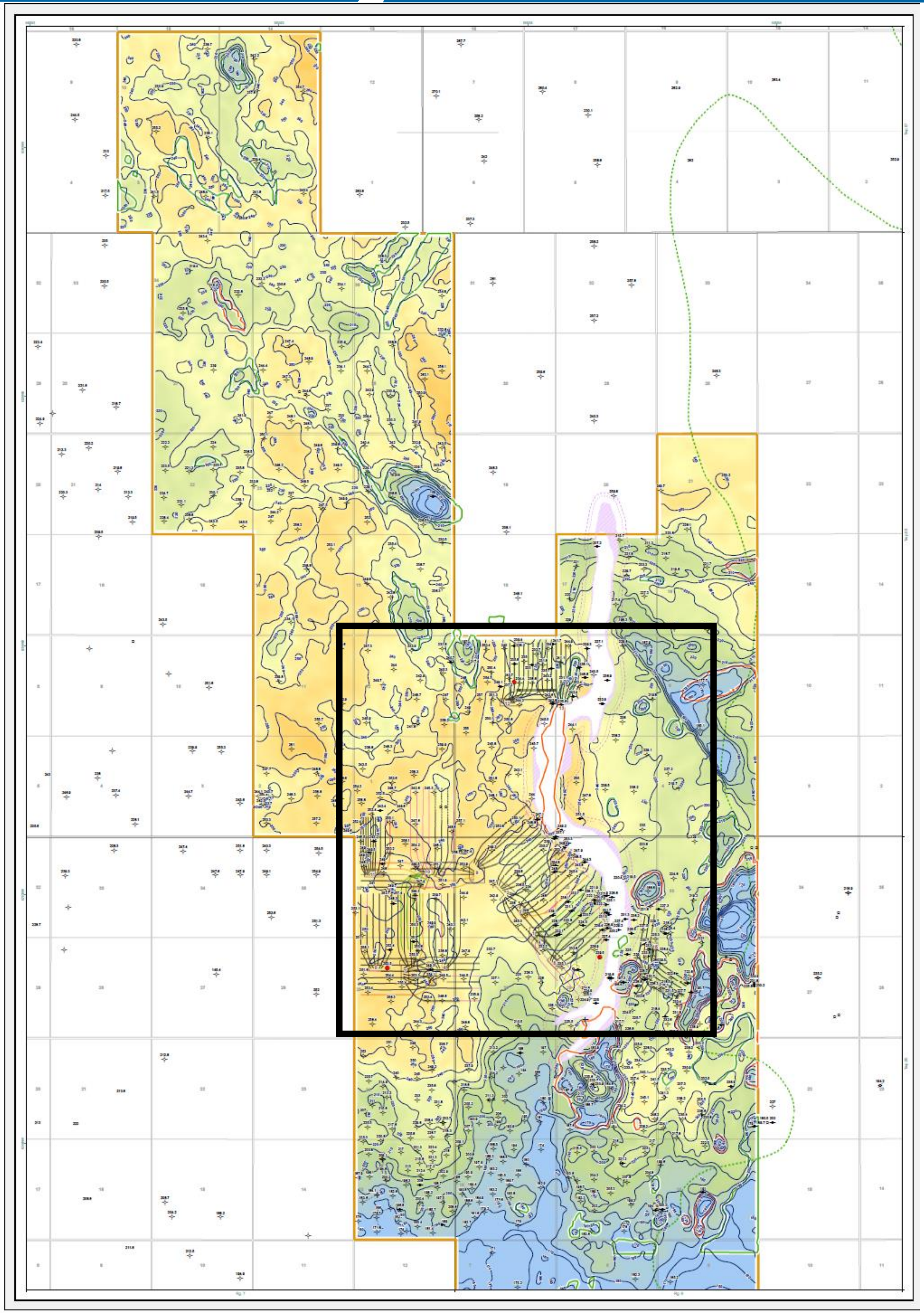
STRUCTURE EVENTS OVERLAY

- MULTI STAGE COLLAPSE
- PRE McMURRAY COLLAPSE
- POST McMURRAY COLLAPSE

DEVONIAN STRUCTURE RASTER

High : 271.9

Low : 132.5m



Devonian Structure with Karst and Salt Dissolution Features

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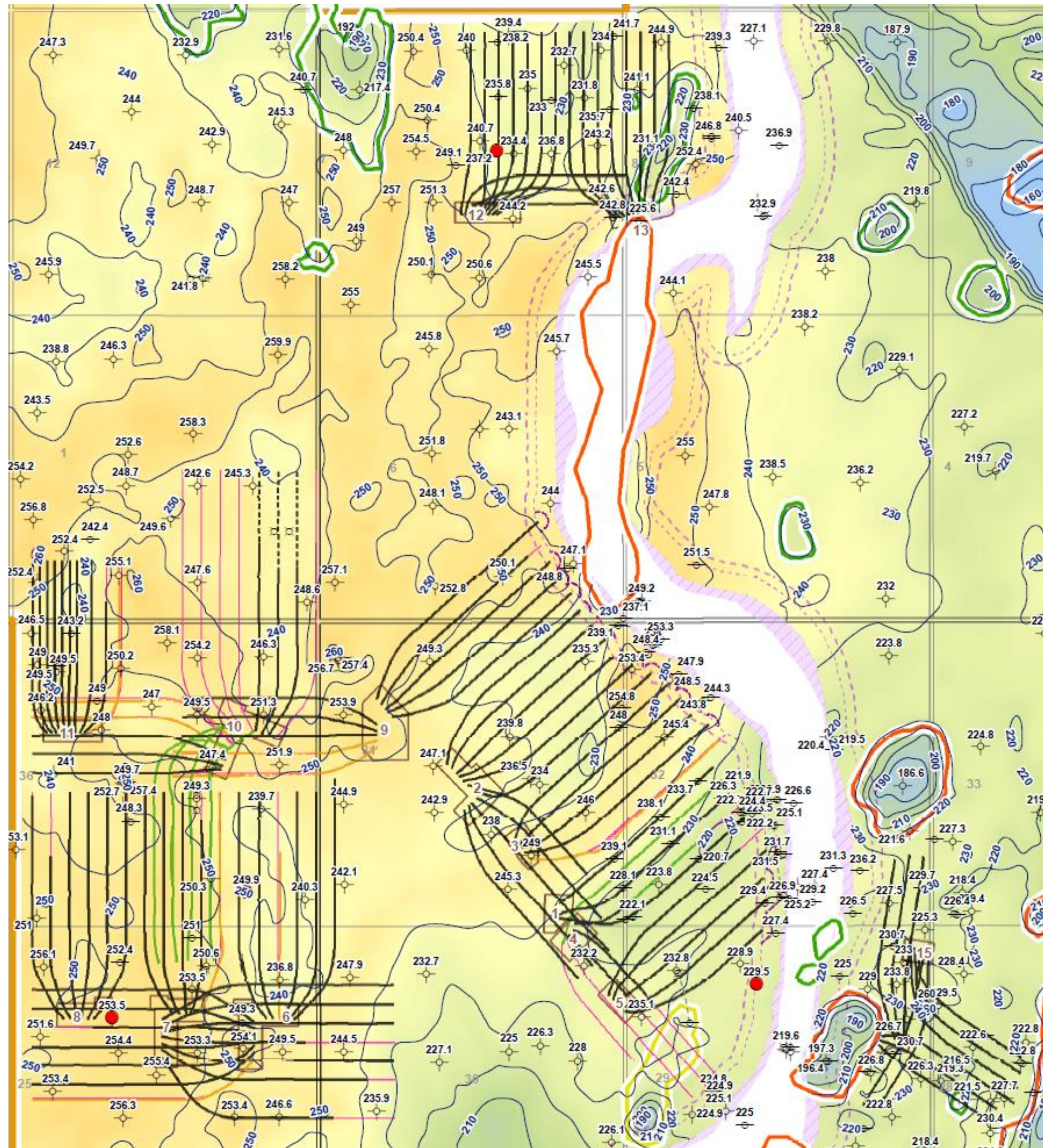

- Relatively flat below current SAGD development areas.
- Lows related to collapse features (karst and dissolution) and erosion.

Long Lake
McMurray Structure

Legend

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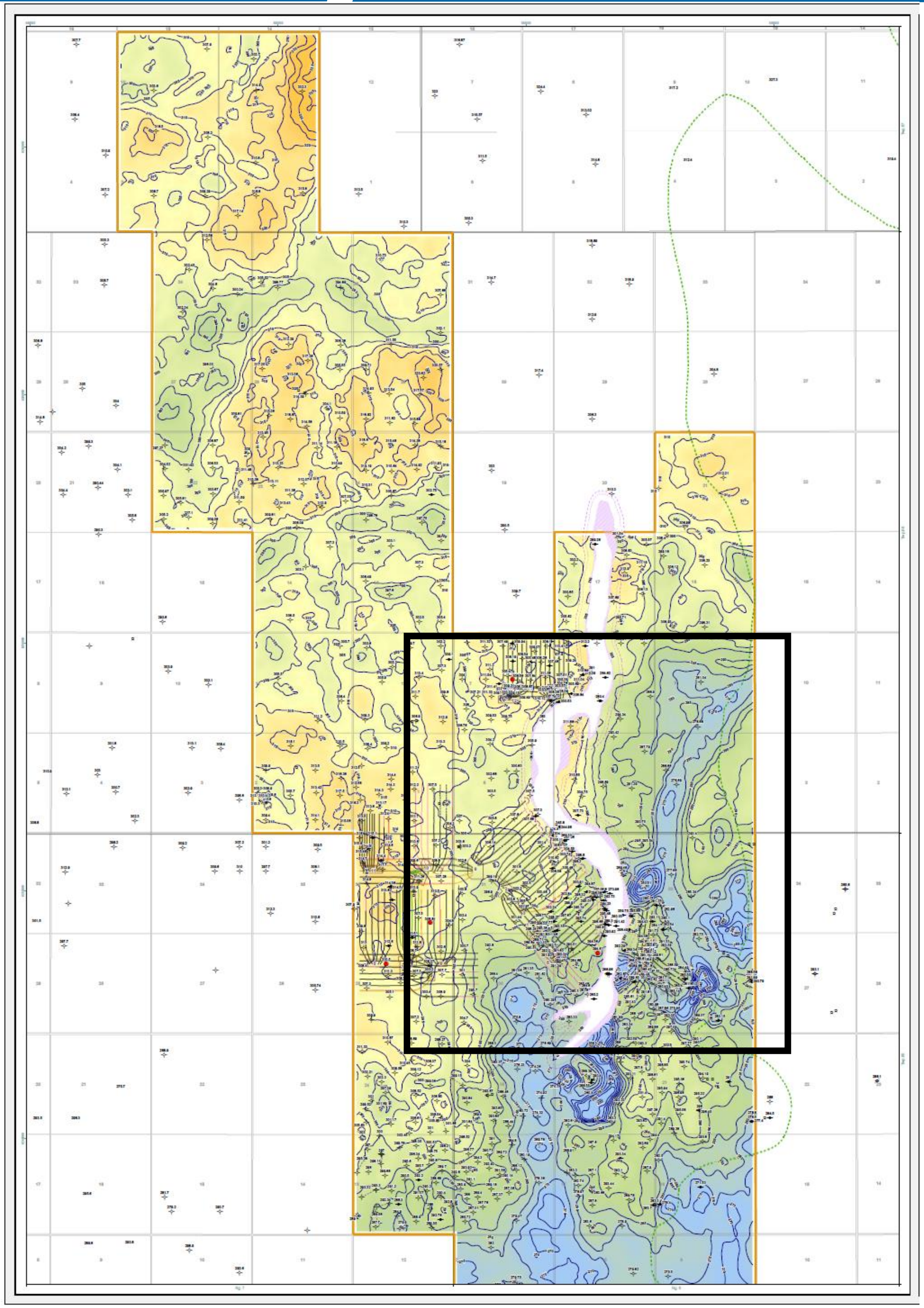
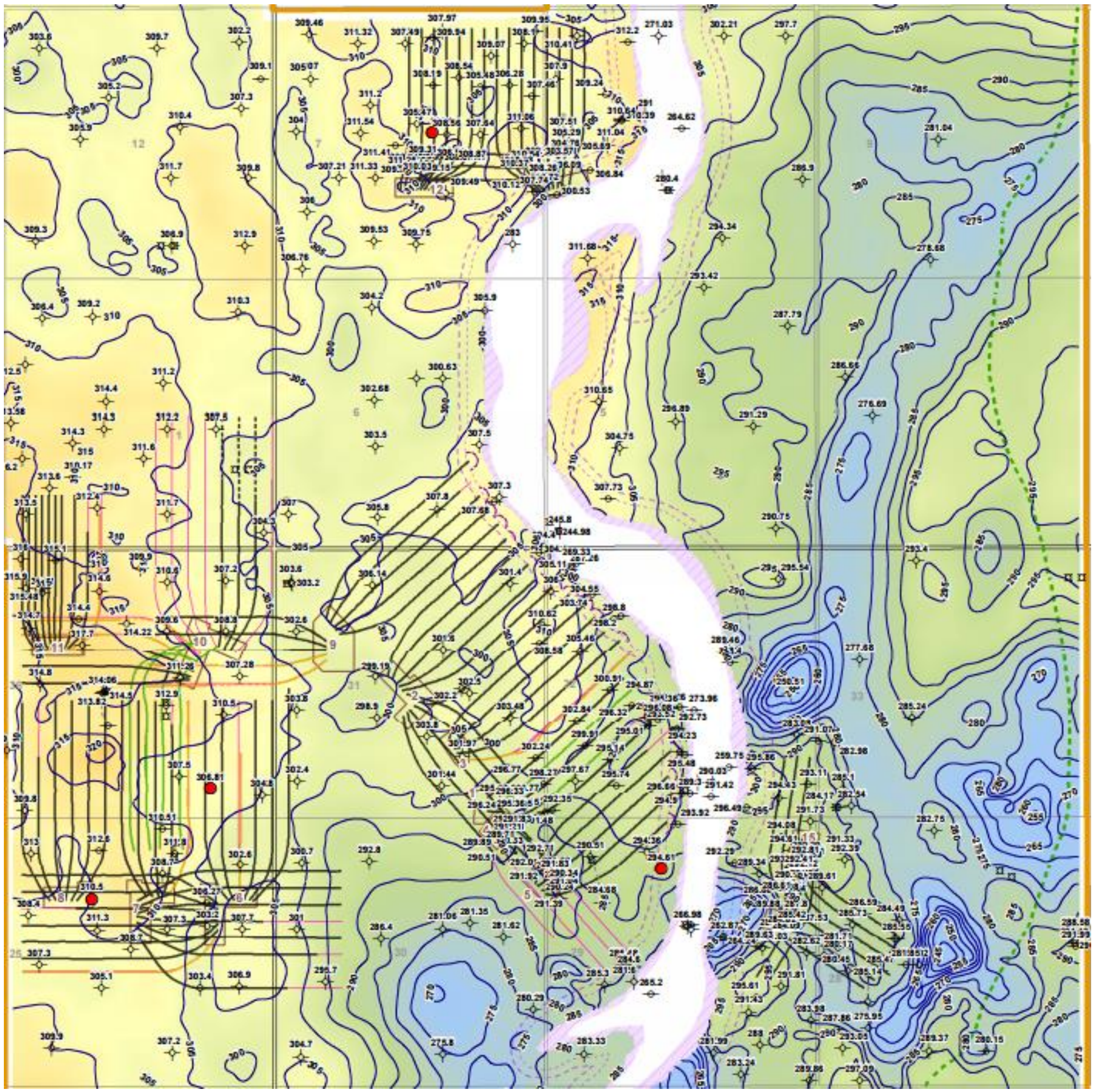
McMURRAY STRUCTURE

High : 337.5

Low : 242.0 m



Long Lake McMurray Structure



Legend

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- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

McMURRAY STRUCTURE
- High : 337.5
- Low : 242.0 m

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

Long Lake
McMurray Isopach

Legend

MAP DATA

- 2014/2015 CORE OBS WELLS
- McMURRAY ISOPACH CONTOURS (C.I.=10m)
- ZERO BITUMEN EDGE
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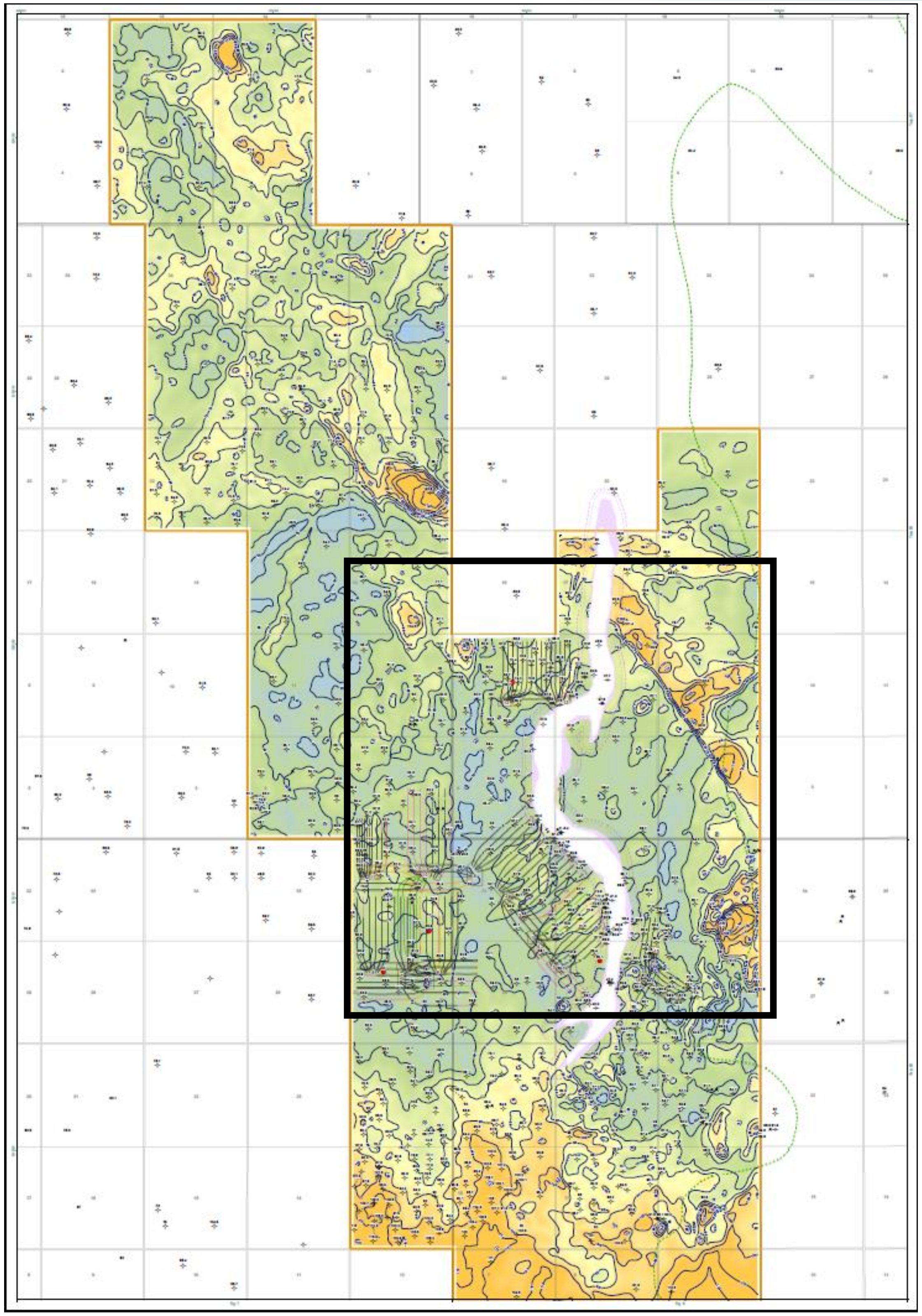
McMURRAY ISOPACH

High : 147.9

Low : 30.8 m



Long Lake McMurray Isopach

Legend

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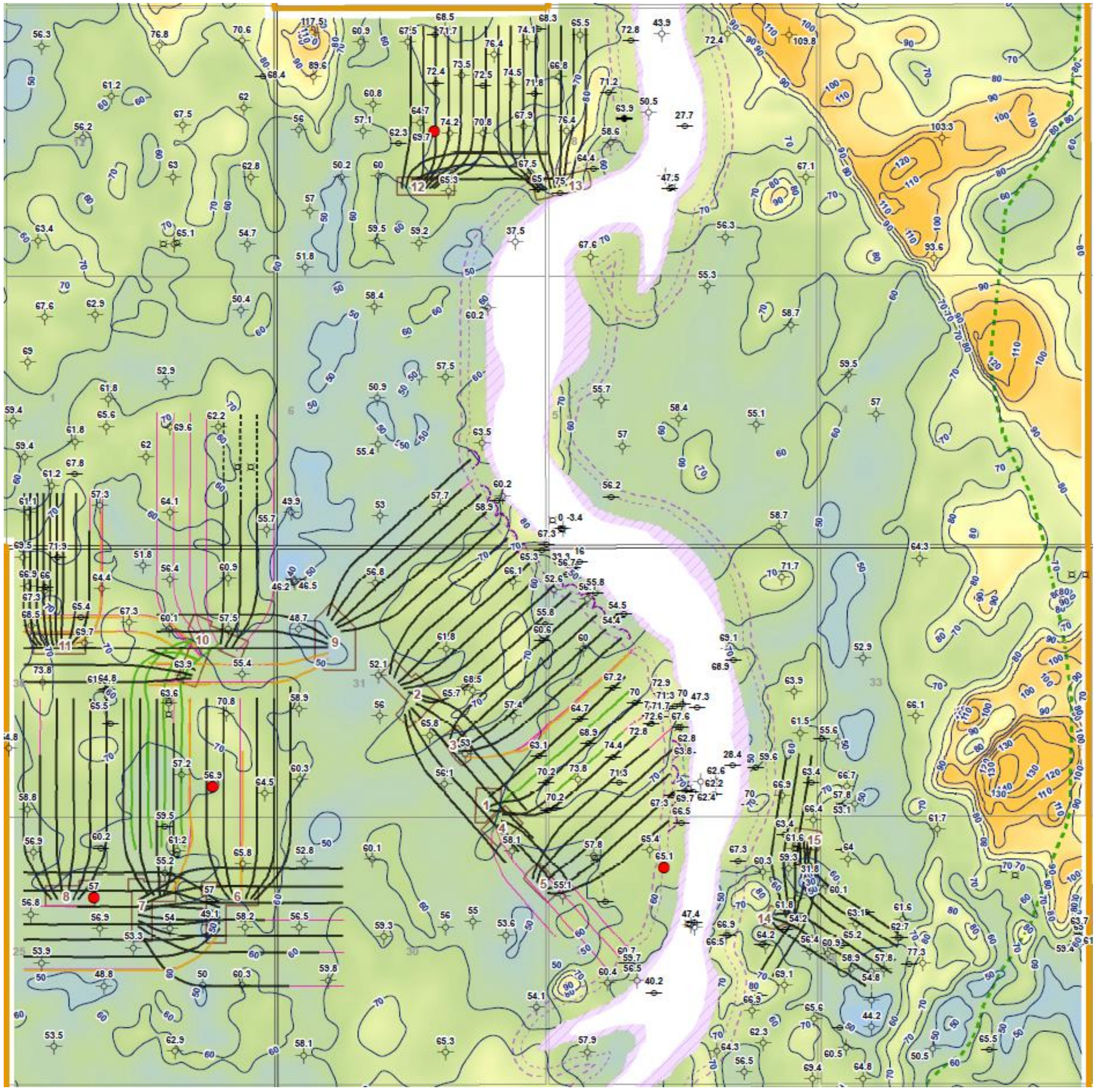
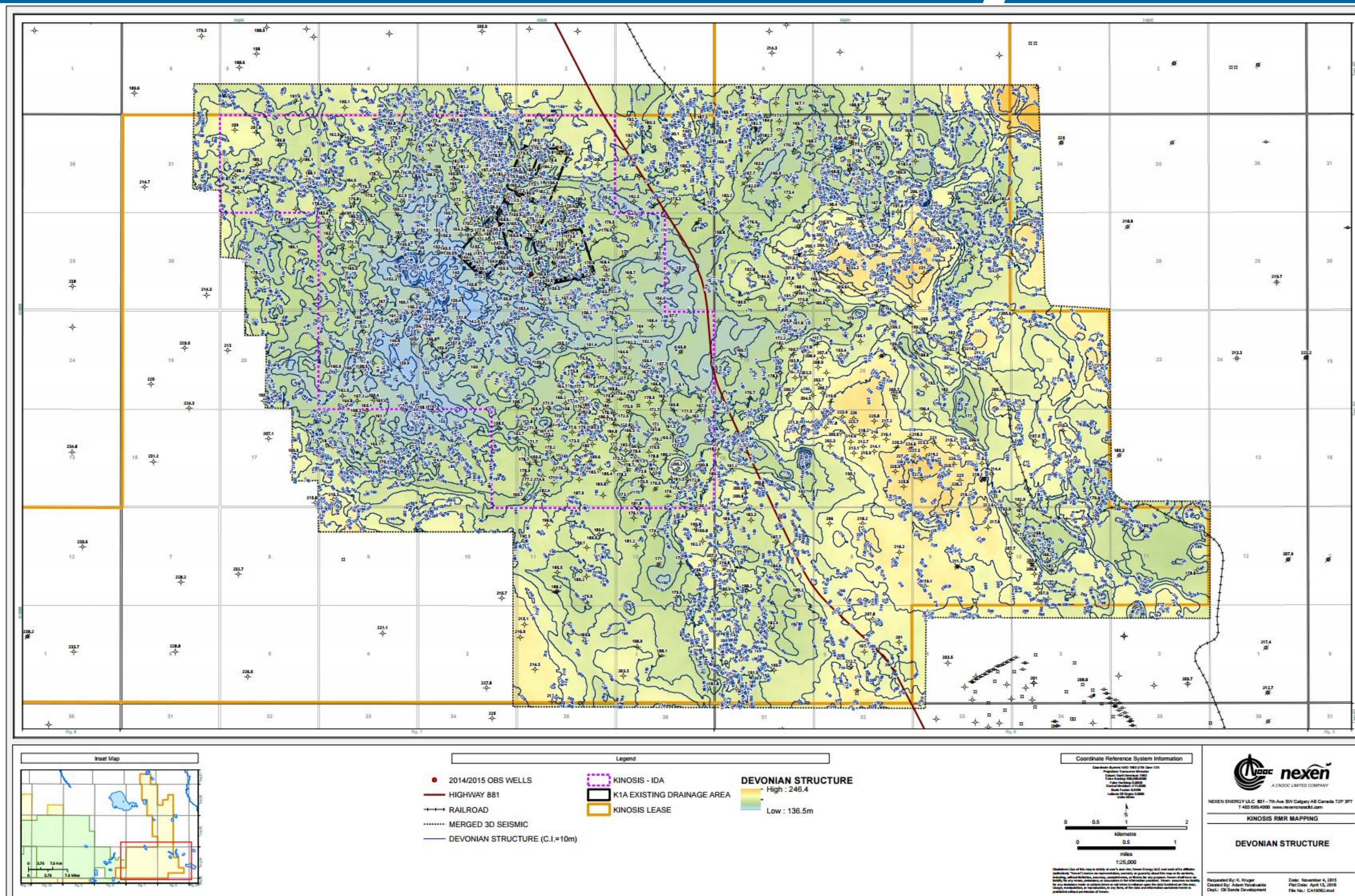


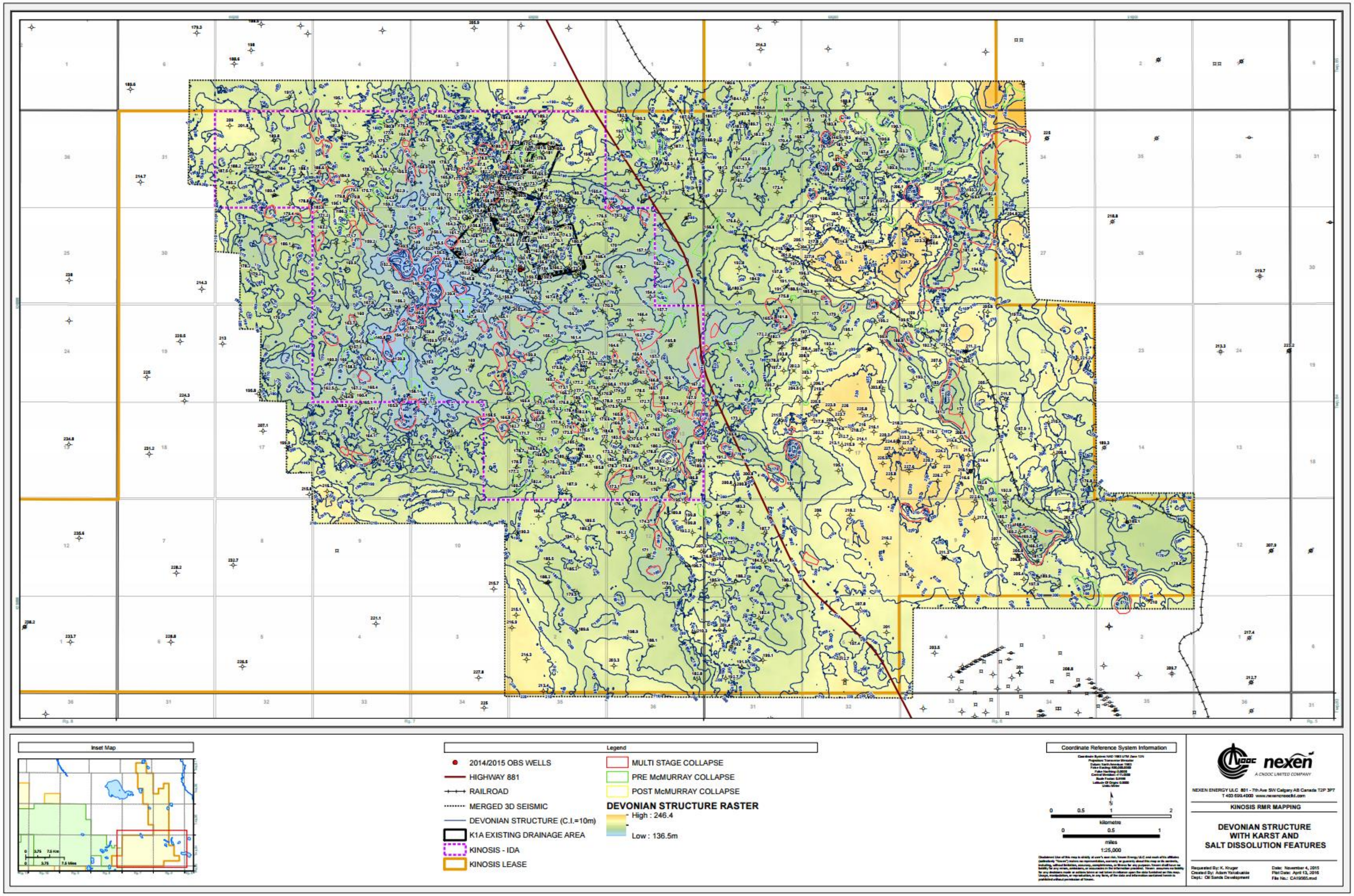
- Relatively consistent isopach (50-70m)
- Thick areas associated with Devonian lows

Structure - Top of Devonian

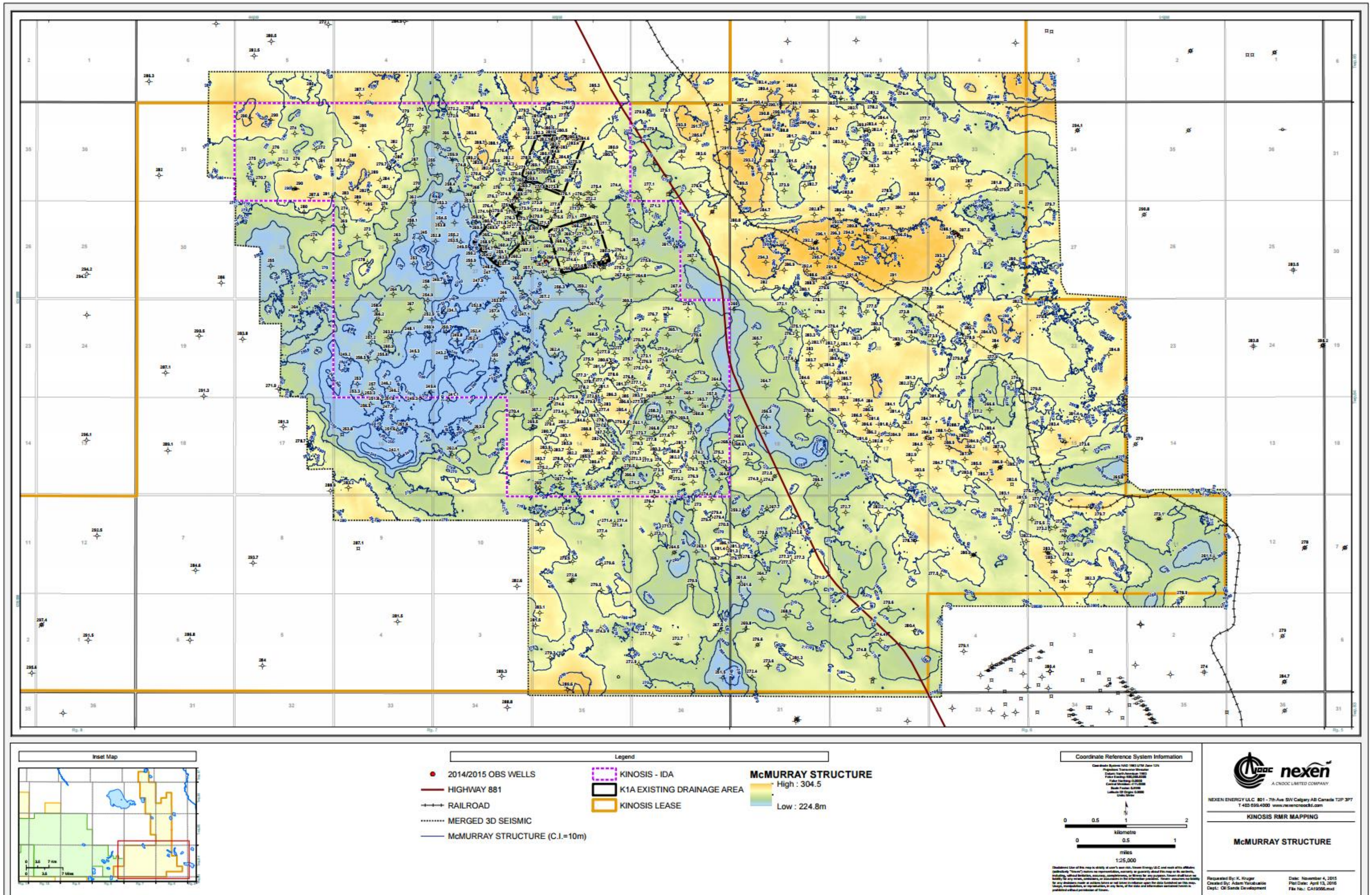


- Structure controlled by Pre-Cretaceous erosion and dissolution of the Prairie Evaporite, Lotsberg and Cold Lake salts.
- Has a significant effect on base of pay structure and bottom water contacts.
- Timing of salt solutioning was pre-McMurray, syn-McMurray and post-McMurray
- Minor karsting on Devonian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

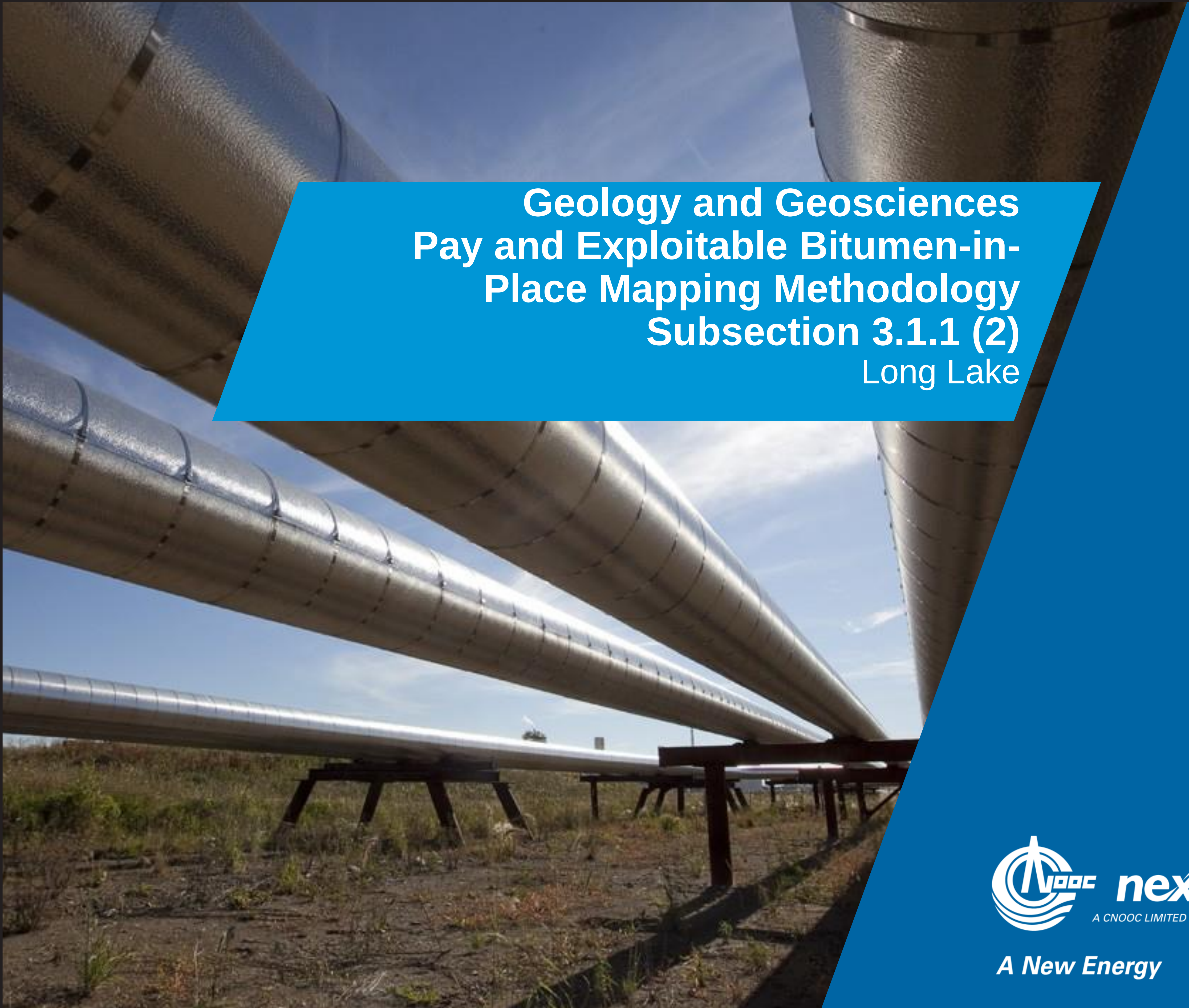
Devonian Structure with Karst and Salt Dissolution Features



Structure - Top of McMurray



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



Geology and Geosciences
Pay and Exploitable Bitumen-in-Place Mapping Methodology
Subsection 3.1.1 (2)

Long Lake

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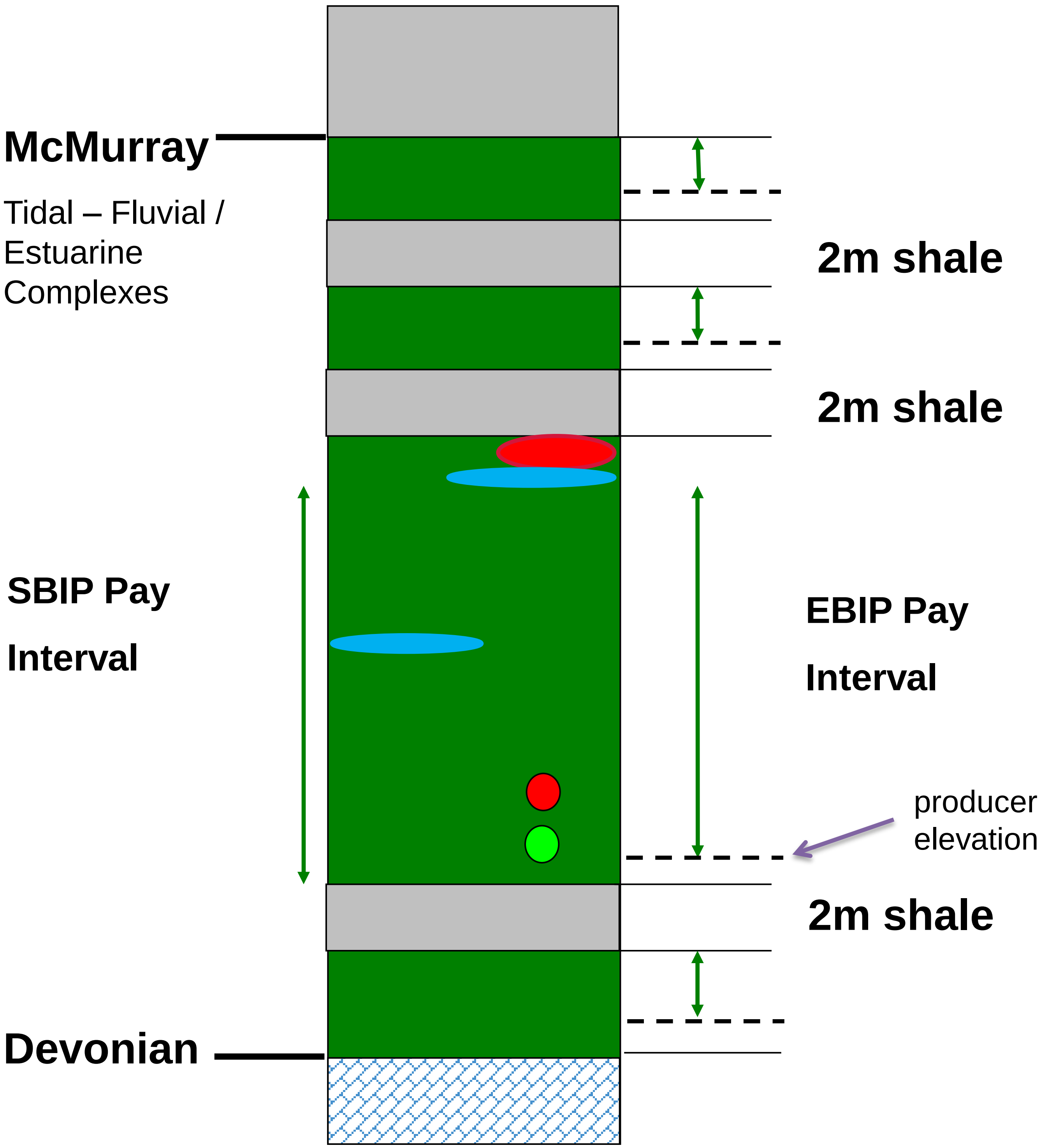
Pay and Exploitable Bitumen-in-Place Mapping Methodology

- Pay cut-offs:
  - top of pay interval is a 2m shale with >30%V_{shale}
  - Focus on low V_{shale} 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% V_{shale}) of 2m
  - Cumulative shale interval (> 30% V_{shale}) 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% V_{shale}
- 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
  - 3 m^3/m^2 EBIP HPVH = 12m EBIP Pay Interval

Pay and Bitumen-in-Place Mapping Methodology

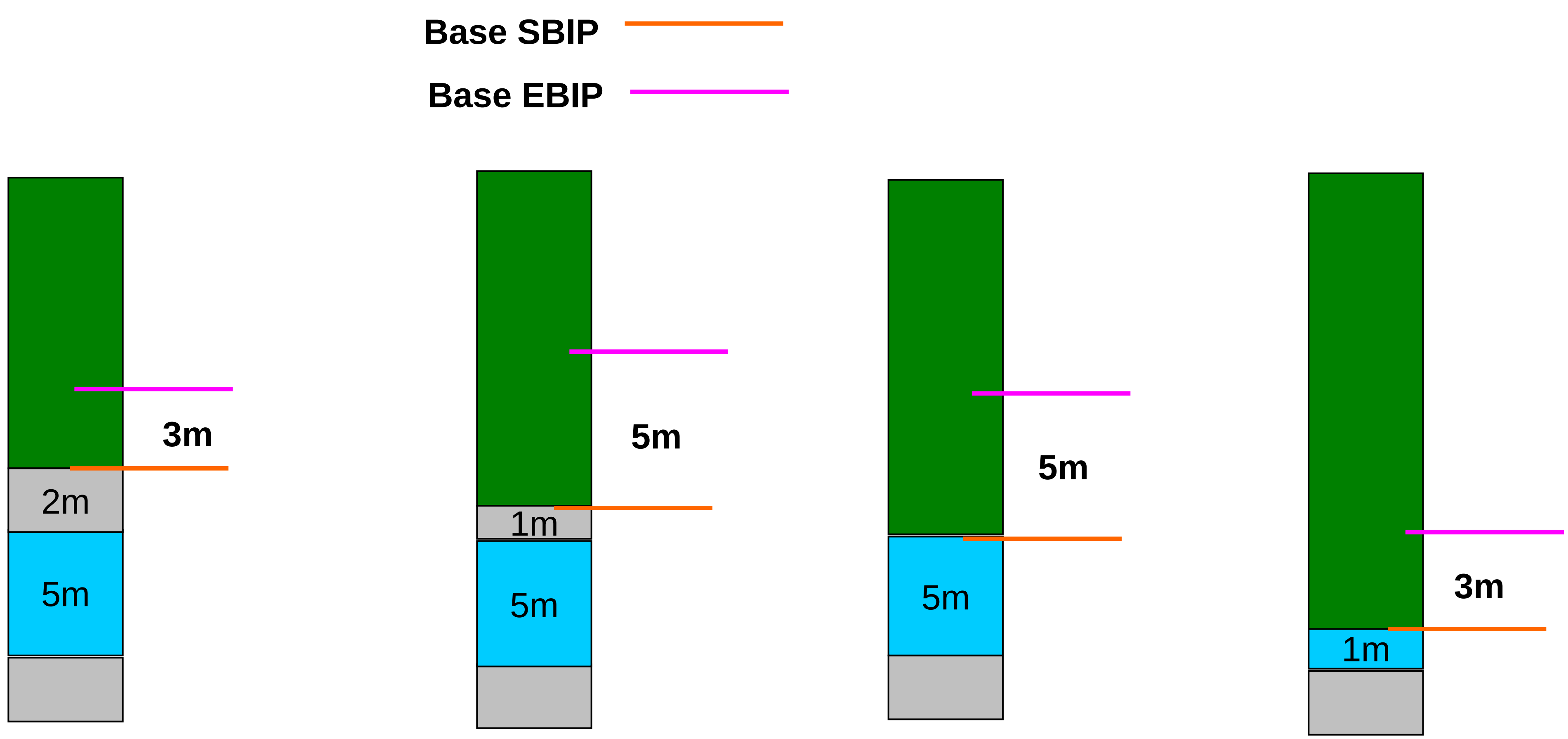


- **SBIP Pay Interval**
  - < 30% V_{shale}
  - < 50% Swe
- may have associated
  - gas interval(s)
  - high water saturation interval(s)

- Primary zone defined as the thickest pay interval unless:
  - an existing (or planned) horizontal well pair is within an interval
  - geologists have interpreted continuity of an interval across an area

Pay and Exploitable Bitumen-in-Place Mapping Methodology

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



Pay and Exploitable Bitumen-in-Place Mapping Methodology

Base of EBIP Pay Interval

- In areas where reserves are mapped but future well pairs have not been laid out, a 3m or 5m stand-off from the mapped base of the reservoir is applied when estimating EBIP
- Applying these stand-offs attempts to account for the volume of resource that may not be recoverable by future SAGD producer wells due to the following assumptions:
  - Wells will be placed at elevations that optimize the well pair extent through high quality reservoir
  - Maintaining a flat trajectory
  - Avoiding production risk due to bottom water where it occurs
- **3m** stand-off is applied above the base-of-reservoir where the base of reservoir is in contact with non-reservoir strata
  - Attempt to account for resource that will likely remain unproduced due to irregularities on the base-of-reservoir surface structure
- Stand-off is increased to **5m** where the base of the reservoir is mapped as being in contact with bottom water
  - “Contact” is considered to occur where there is less than a 2m shale interval between the top of bottom water and the base of the bitumen reservoir.
- 5m stand-off from the bottom water contact attempts to mitigate the following concerns:
  - Maintain sufficient stand-off between the producer and the bottom water surface to avoid early communication
  - Attempts to account for the uncertainty in the nature of the contact between the base-of-reservoir and bottom water
  - Uncertainty in the elevation of the bottom water contact
  - Allows steam chamber development along the entire length of the horizontal well pair during the early SAGD ramp up phase and should act as a baffle
- Once a SAGD well pair location is proposed for an area, the actual elevation of the producer well will then define the EBIP base

Producer Vertical Depth

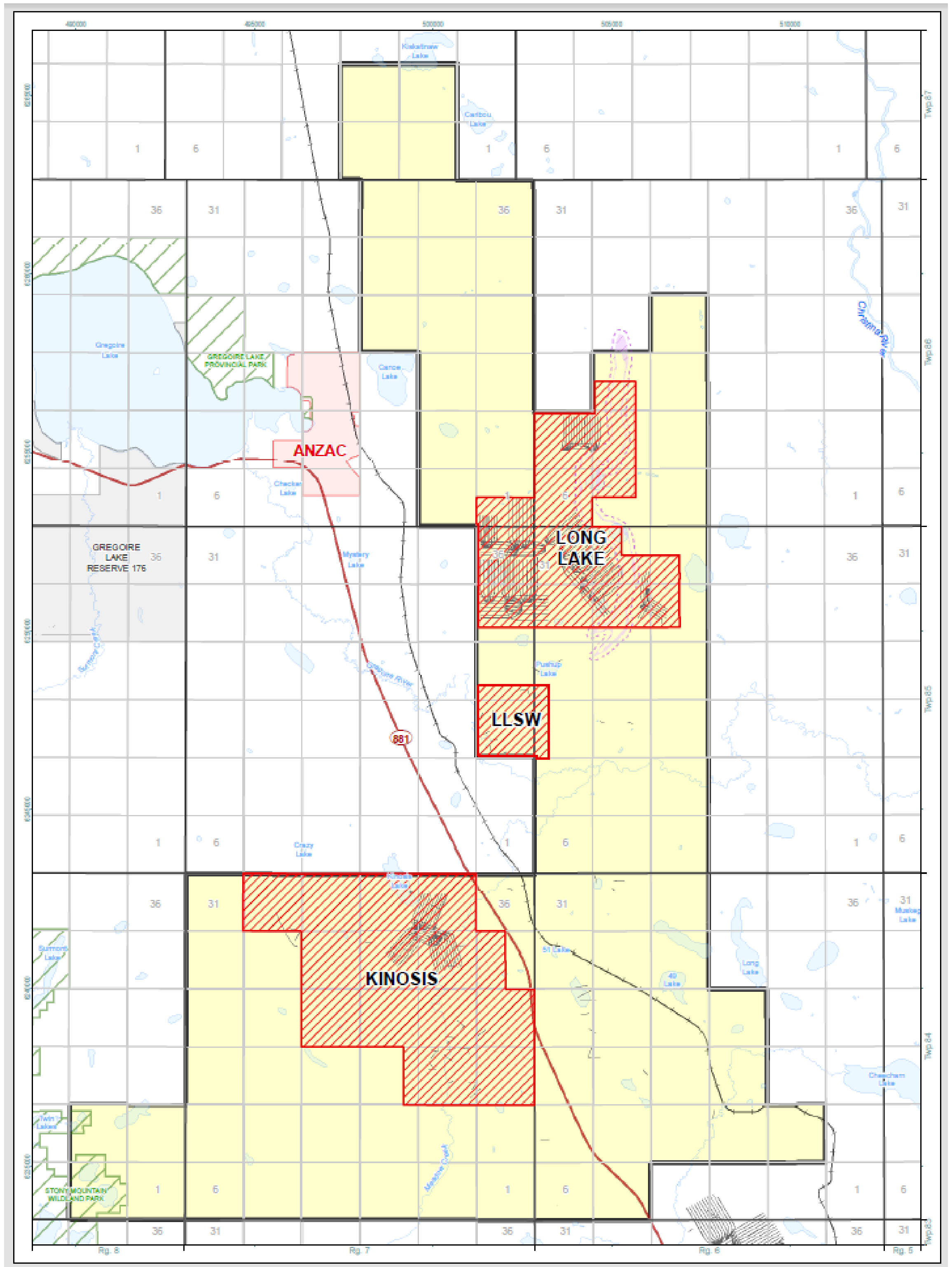
Considerations

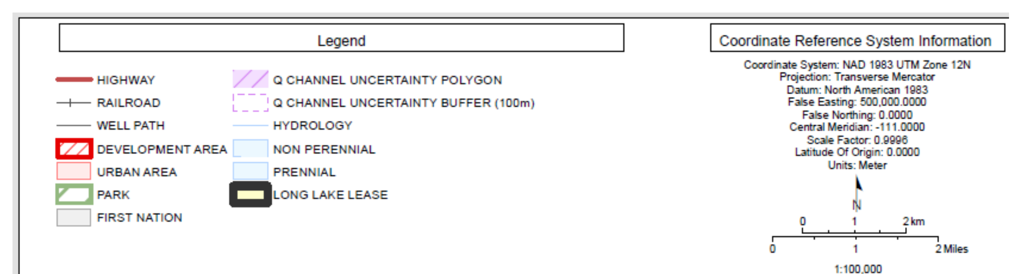
- Target high quality resource - preferentially staying above mud clast breccia
- Plan horizontal well pair orientation so as to minimize stranded pay and/or preserve secondary development opportunities
- Maintain a flat trajectory as much as possible

Constraints

- Minimum of 5m stand-off from bottom water (if present) to minimize the risk of a pressure sink coming in contact with the higher pressure steam chamber
- Max. elevation change between adjacent horizontal wells 15 m/100 m
- 3 to 5 m vertical deviation from intermediate casing point (ICP)
- Approximate maximum rise or dip rate 1m/50m

Lease: Development Areas





Long Lake Development Area EBIP and Average Reservoir Parameters

Long Lake (including Long Lake SW) Development Area EBIP

Long Lake EBIP (E^6m^3)	119

Nexen Cutoffs: h > 12 m or HPVH > 3 m

Hydrocarbon Pore Volume Height

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

Hydrocarbon Pore Volume Height (HPVH) is calculated from petrophysical logs calibrated to Dean Stark analysis.

Long Lake EBIP Average Reservoir Parameters

- Measured Depth (top) 200 m KB
- Thickness 22 m
- Effective Porosity 31.2 %
- V_{shale} 10.1 %
- Permeability – Historical Plug Data
  - Kmax 5565 mD
  - Kvert 4491 mD
- Effective Water Saturation 31.2 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure:

  ~1000 - 1100kPa @ 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)	206

Nexen Cutoffs: h > 12m or HPVH > 3 m

Hydrocarbon Pore Volume Height

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

Hydrocarbon Pore Volume Height (HPVH) is calculated from petrophysical logs calibrated to Dean Stark analysis.

Pay Average Reservoir Parameters

- Measured Depth (top) 280 m KB
- Thickness 34 m
- Effective Porosity 31 %
- Permeability From Core Plugs
  - Kmax 4030 mD
  - Kvert 2347 mD
- Effective Water Saturation 26 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure
  - ~1100 - 1300 kPa

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

Long Lake
SBIP Pay Interval Isopach

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Legend

- SBIP ISOPACH (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

PROSPECT AREA

- K1A PROSPECT

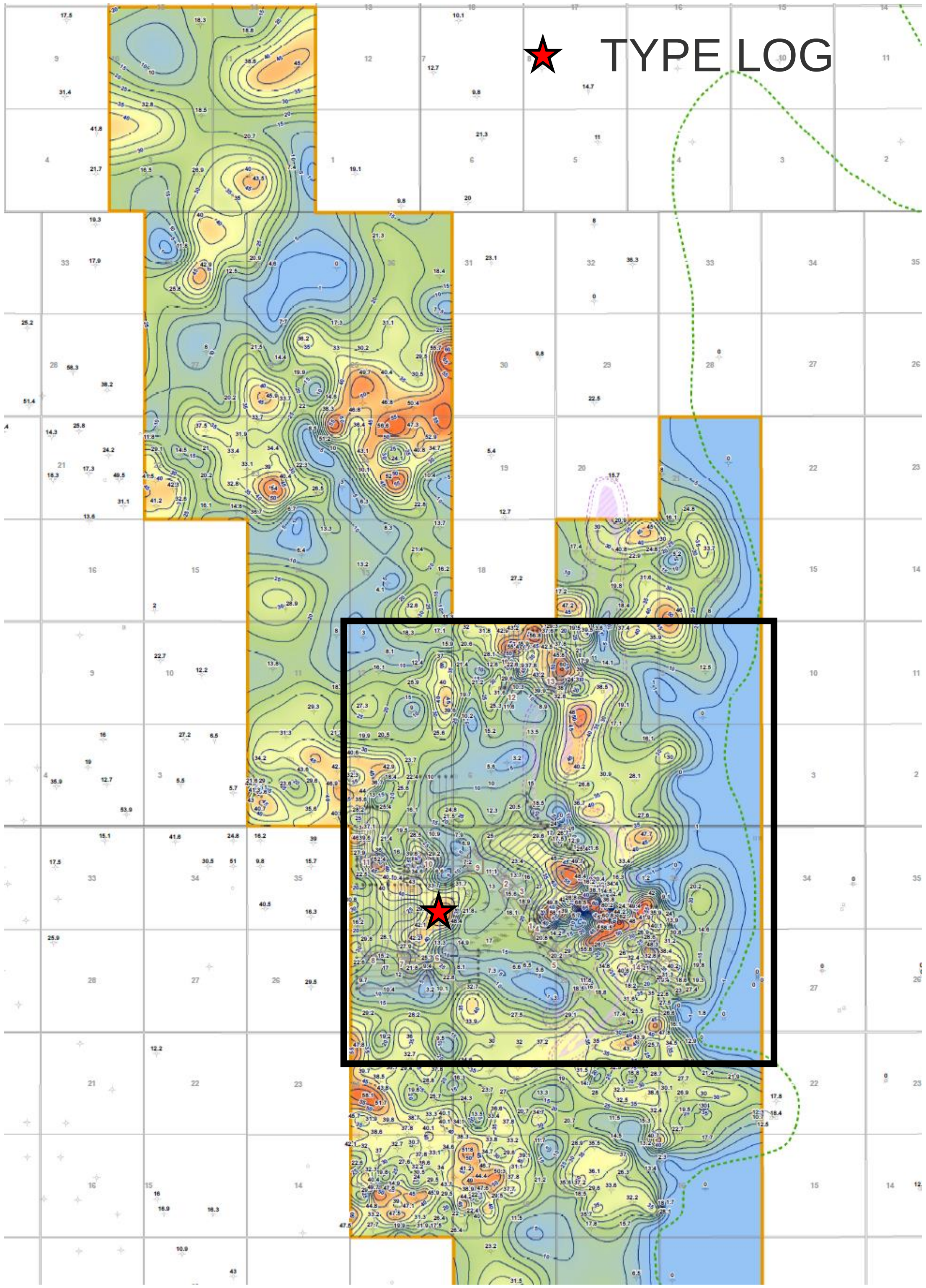
Q CHANNEL DATA

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

SBIP ISOPACH

High : 80.2

Low : 0 m



Long Lake
SBIP Pay Interval Isopach

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Legend

- SBIP ISOPACH (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

PROSPECT AREA

- K1A PROSPECT

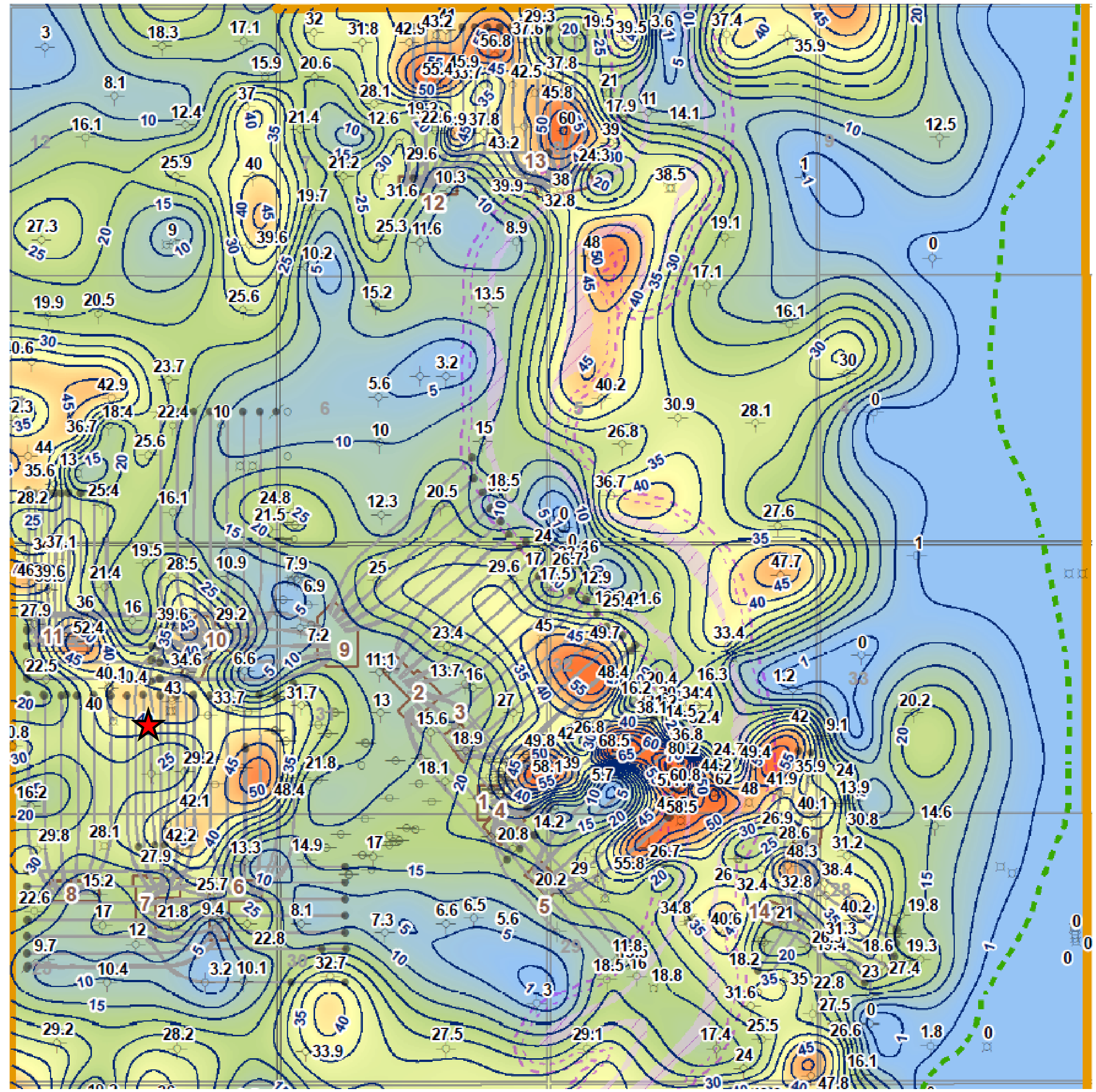
Q CHANNEL DATA

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

SBIP ISOPACH

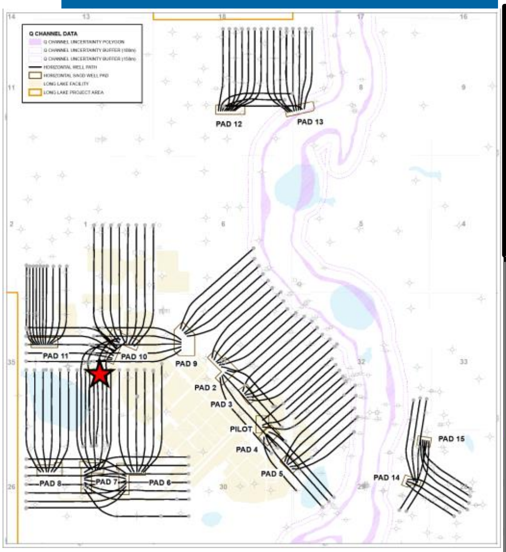
High : 80.2

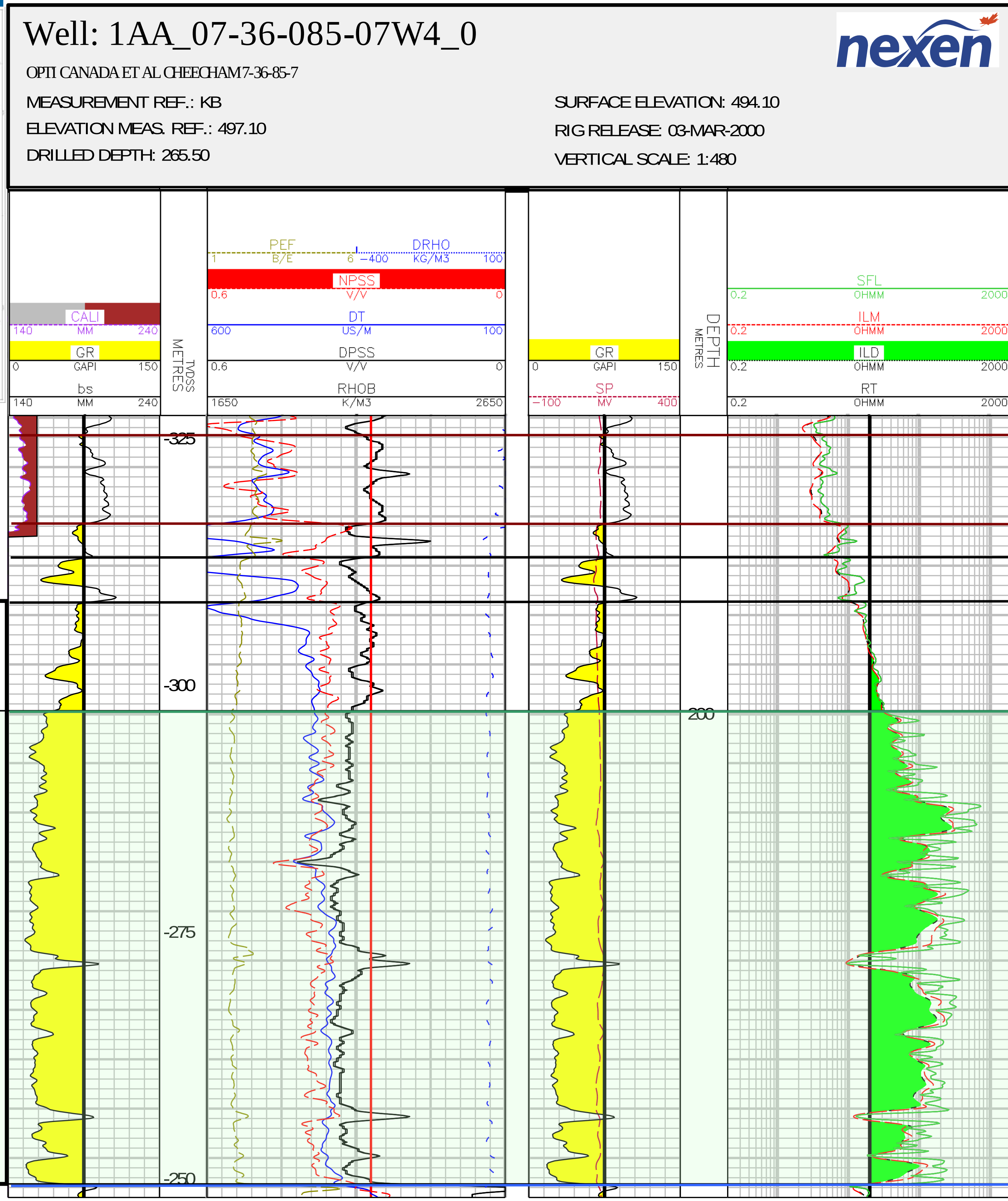
Low : 0 m

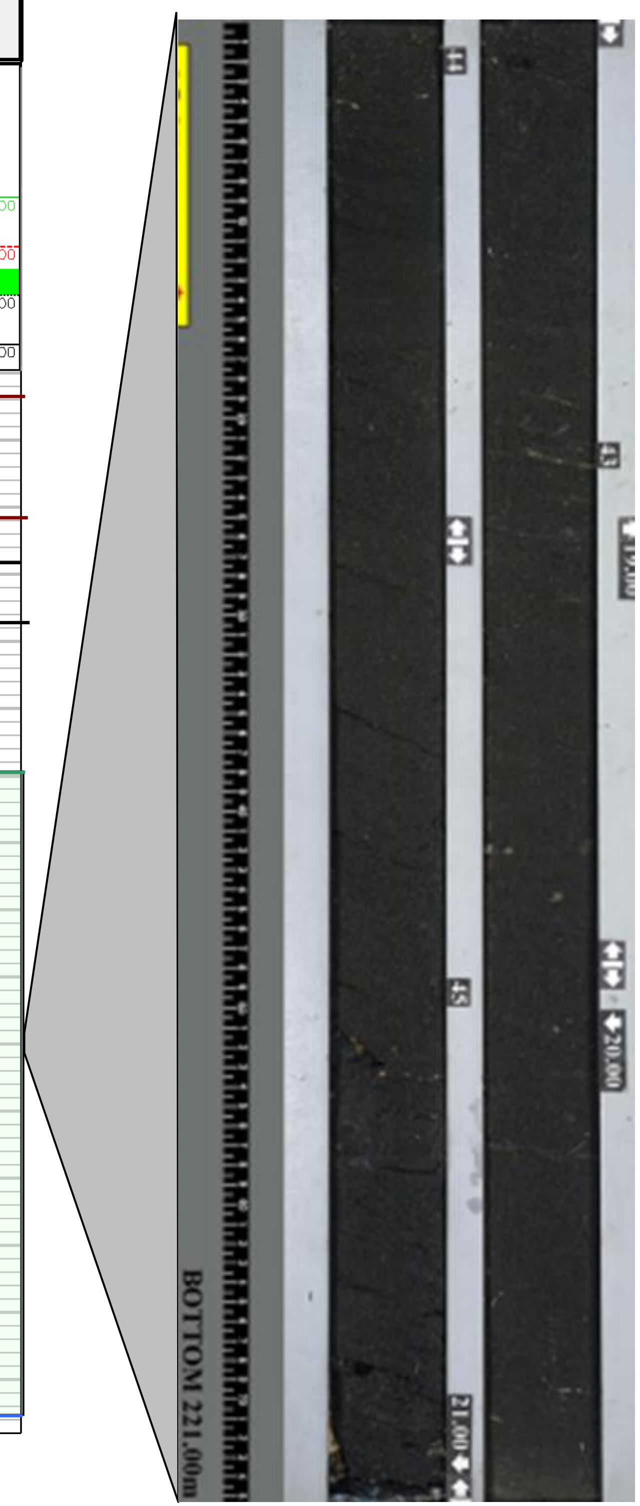


★ TYPE LOG

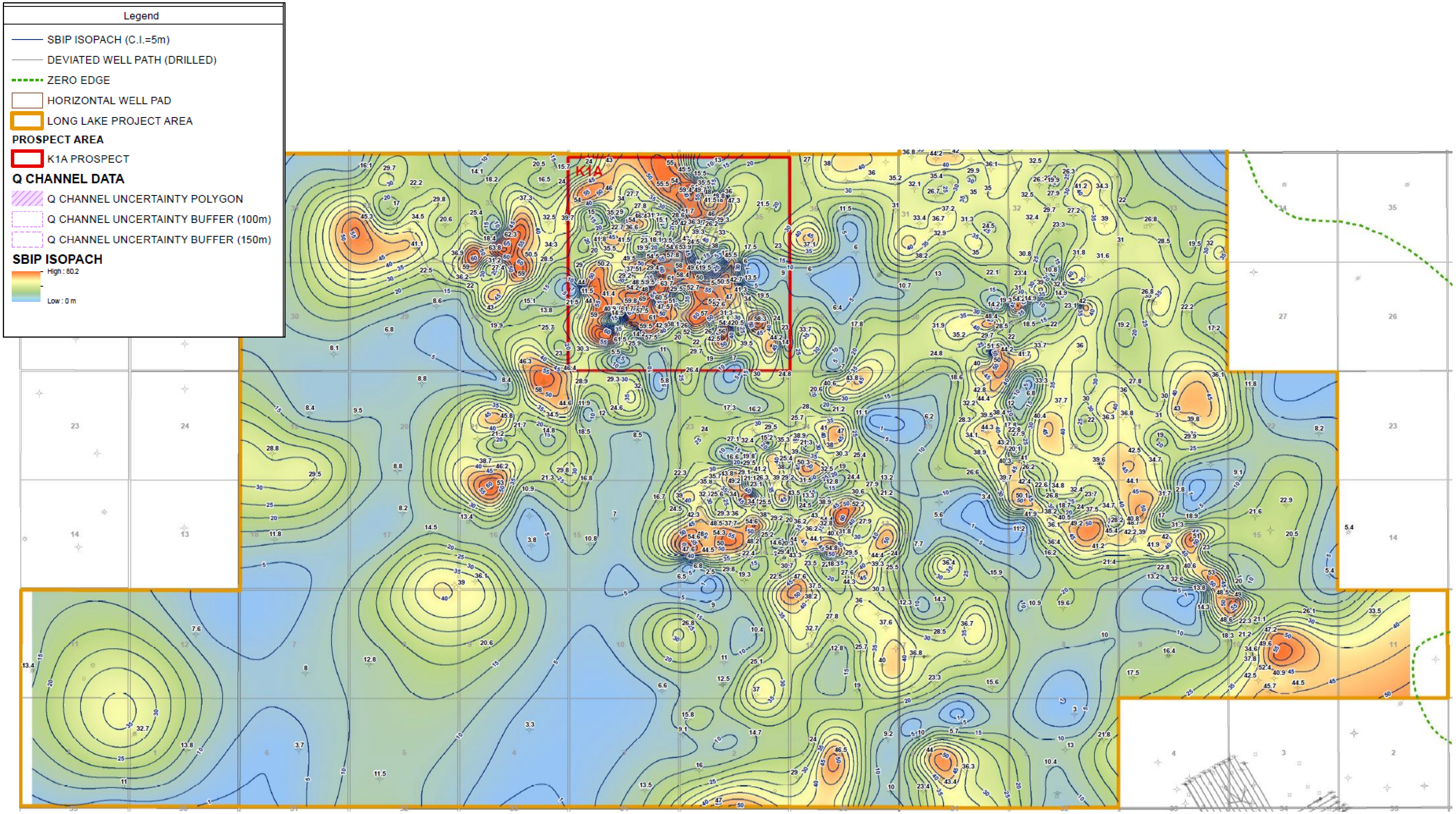
SBIP Type Log – 1AA/07-36-085-07W4





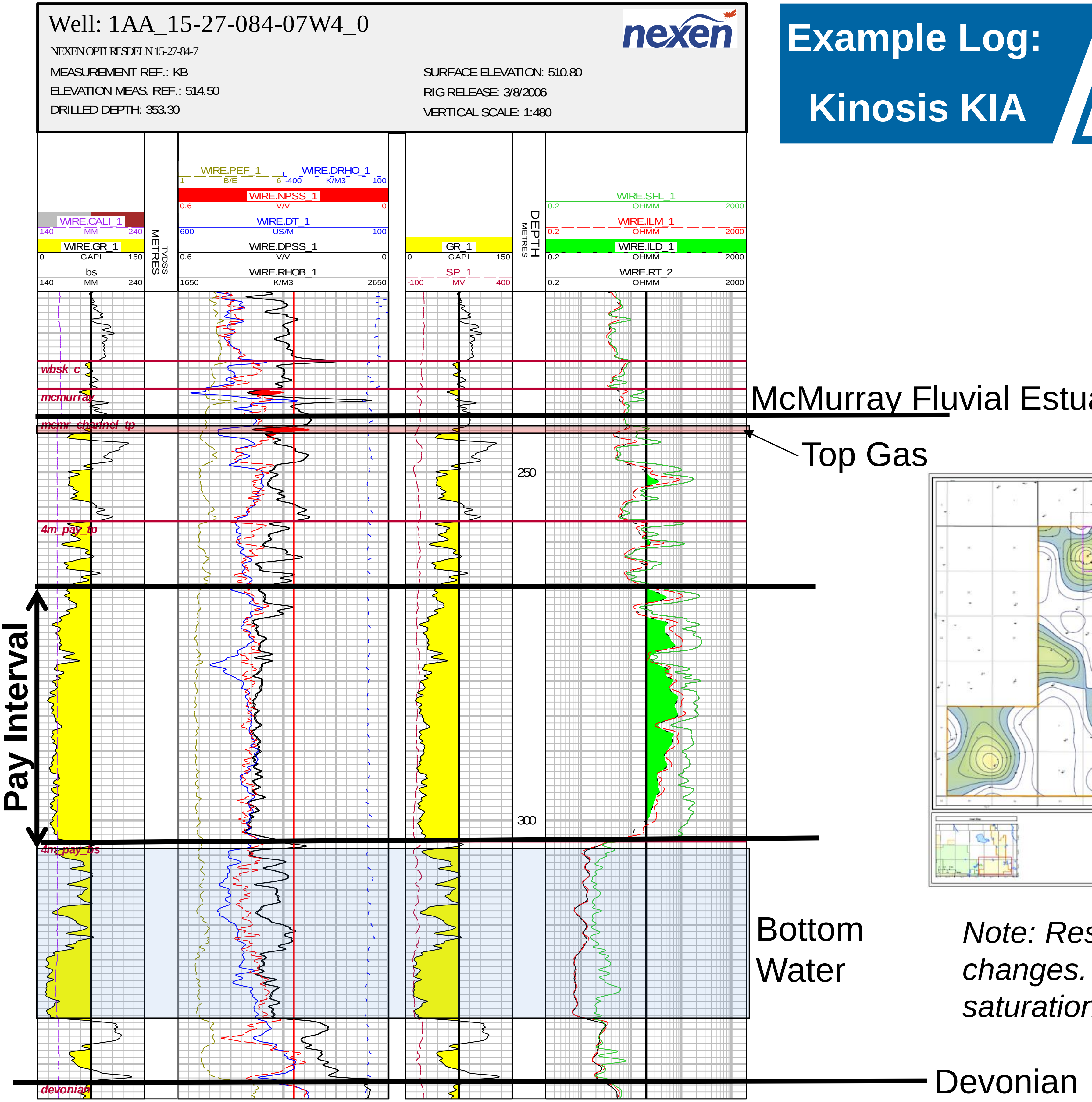


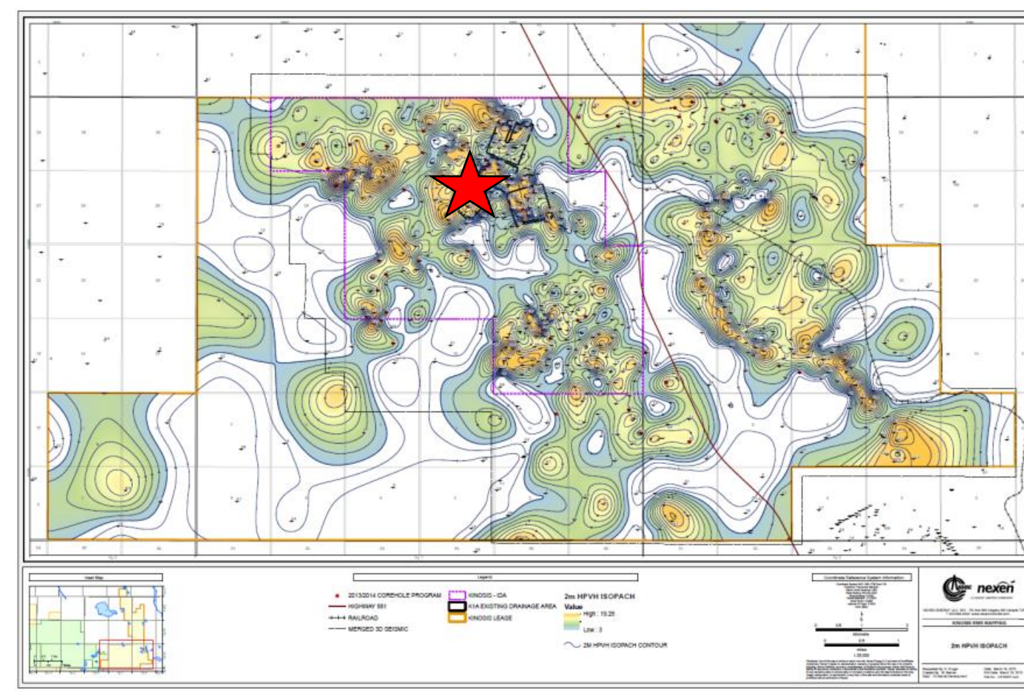
Kinosis
SBIP Pay Interval Isopach



Example Log:

Kinosis KIA





Note: Resistivity gradient is due to salinity changes. Core used to confirm oil saturations.

Long Lake
SBIP Pay Interval Base Structure

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Legend

- SBIP BASE STRUCTURE (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

PROSPECT AREA

- K1A PROSPECT

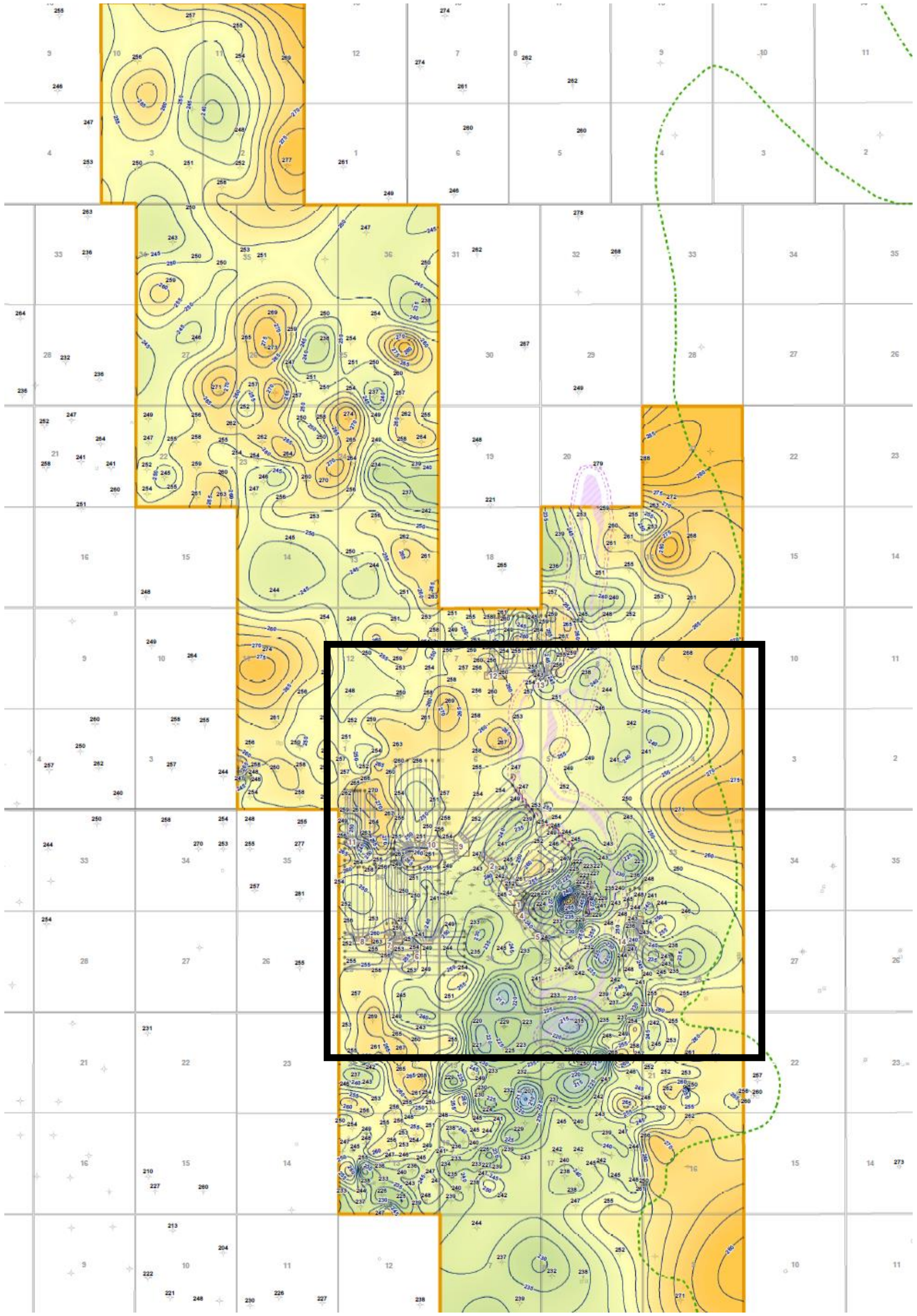
Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

SBIP TOP STRUCTURE

High : 288.5

Low : 167.3m



Long Lake
SBIP Pay Interval Base Structure

nexen
A CNOOC LIMITED COMPANY

Legend

- SBIP BASE STRUCTURE (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

PROSPECT AREA

- K1A PROSPECT

Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
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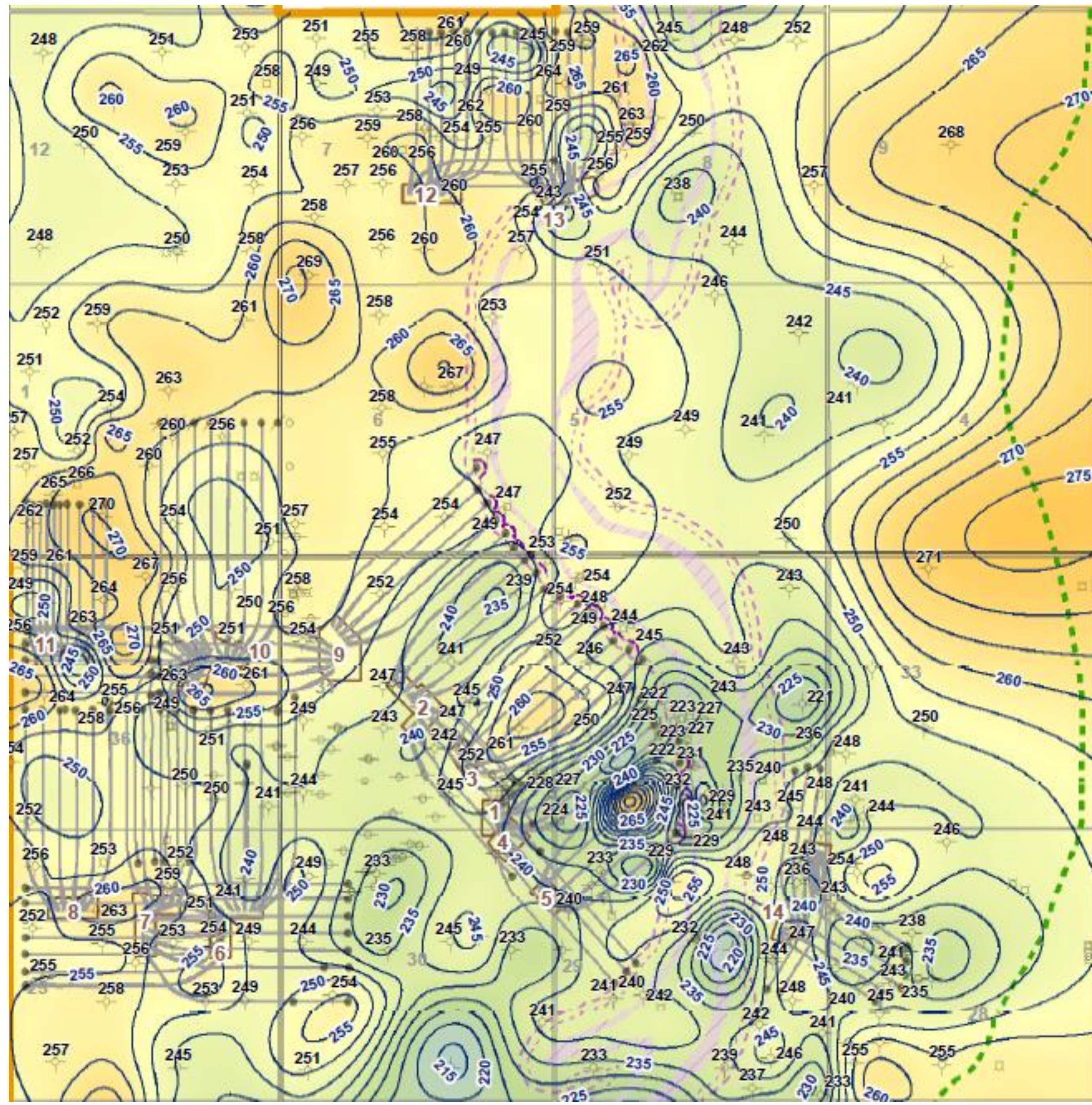
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

SBIP TOP STRUCTURE

High : 288.5

Low : 167.3m



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

Long Lake
SBIP Pay Interval Top Structure

Legend

- SBIP TOP STRUCTURE (C.I.=5m)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

HORIZONTAL WELL STATUS (PRODUCER)

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

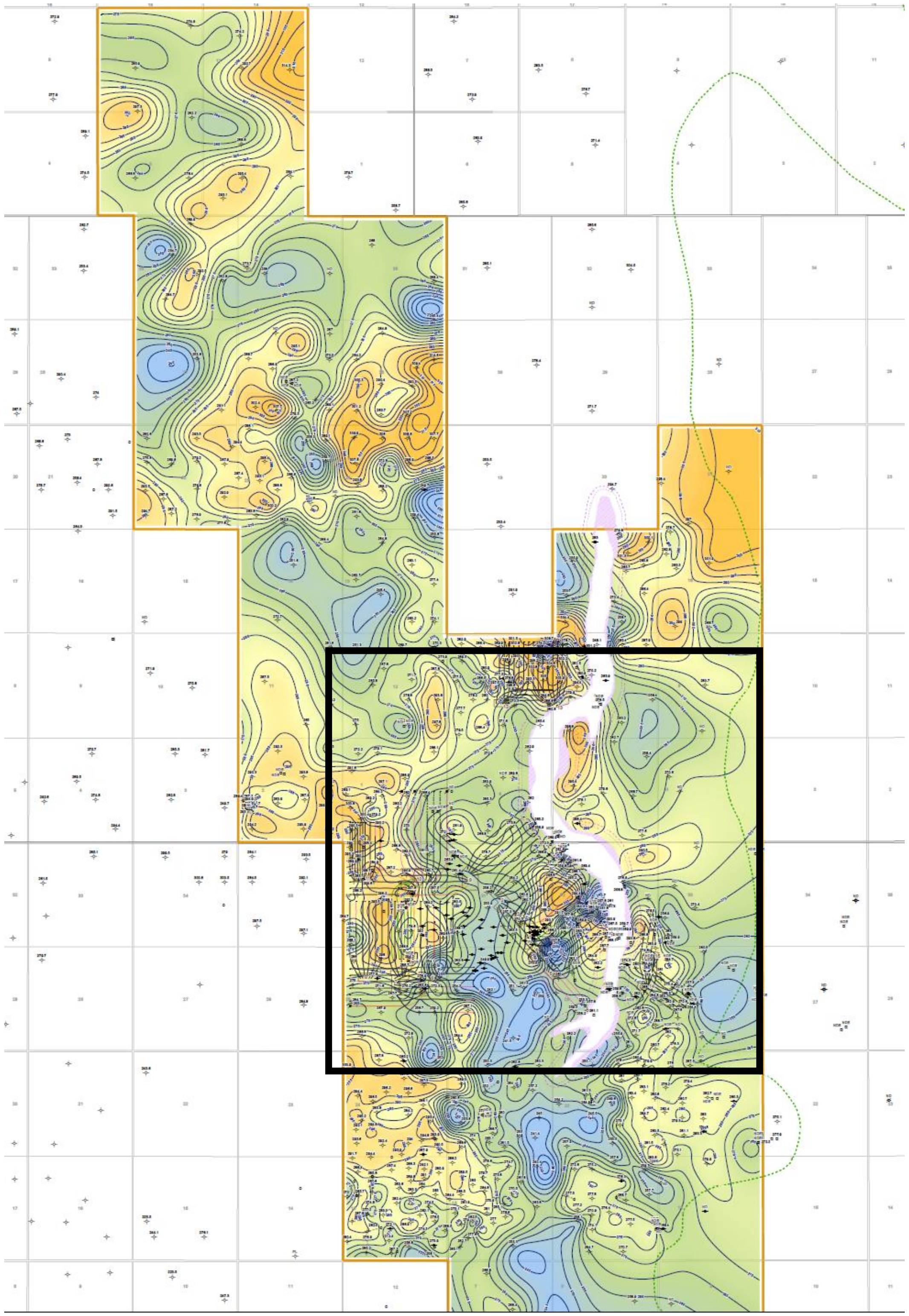
Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

SBIP TOP STRUCTURE RASTER

High : 324.7

Low : 172.6m



Long Lake
SBIP Pay Interval Top Structure

Legend

- SBIP TOP STRUCTURE (C.I.=5m)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

HORIZONTAL WELL STATUS (PRODUCER)

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

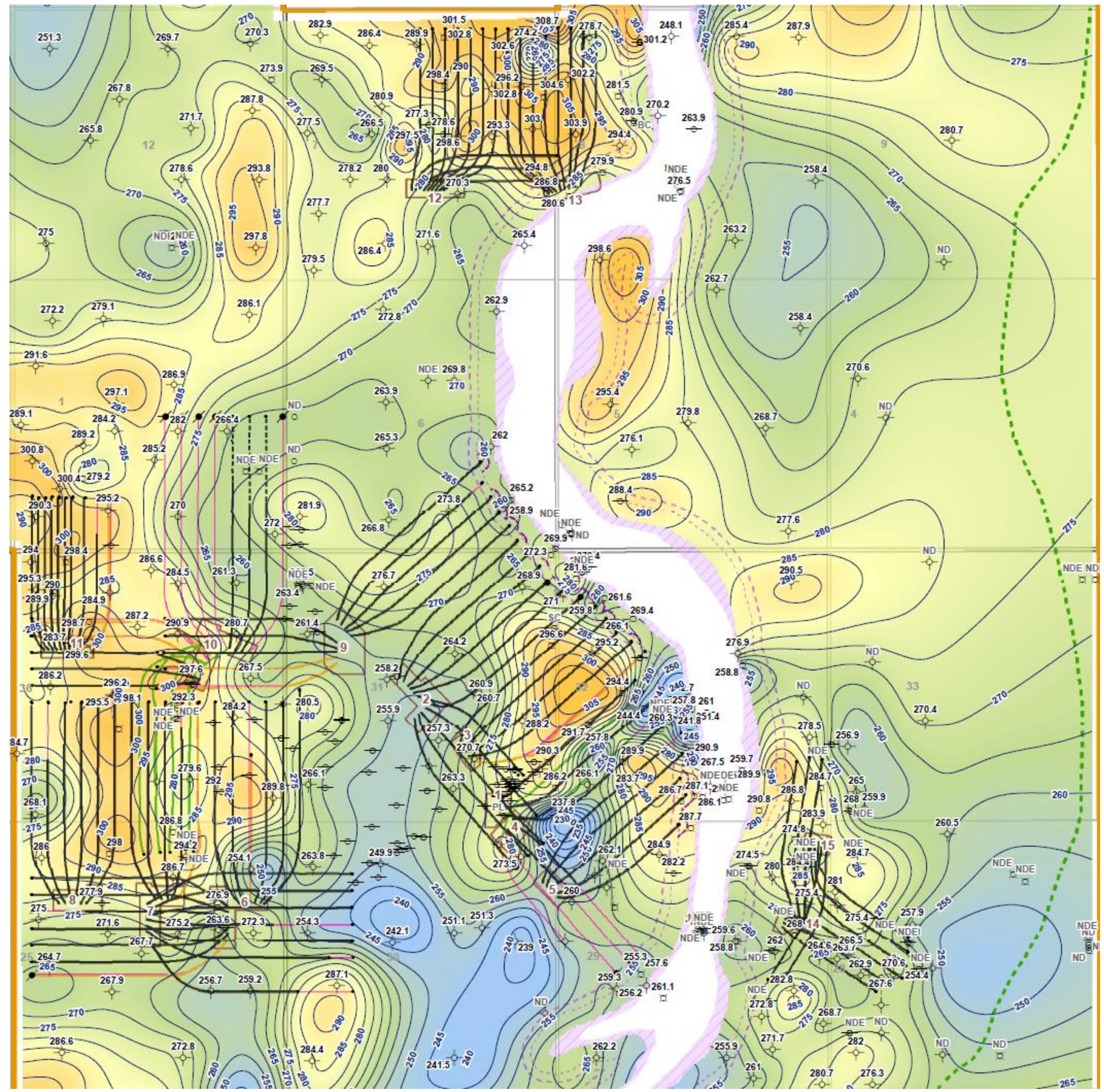
Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

SBIP TOP STRUCTURE RASTER

High : 324.7

Low : 172.6m



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

Kinosis
Structure of SBIP Base

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Legend

- SBIP BASE STRUCTURE (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

PROSPECT AREA

- K1A PROSPECT

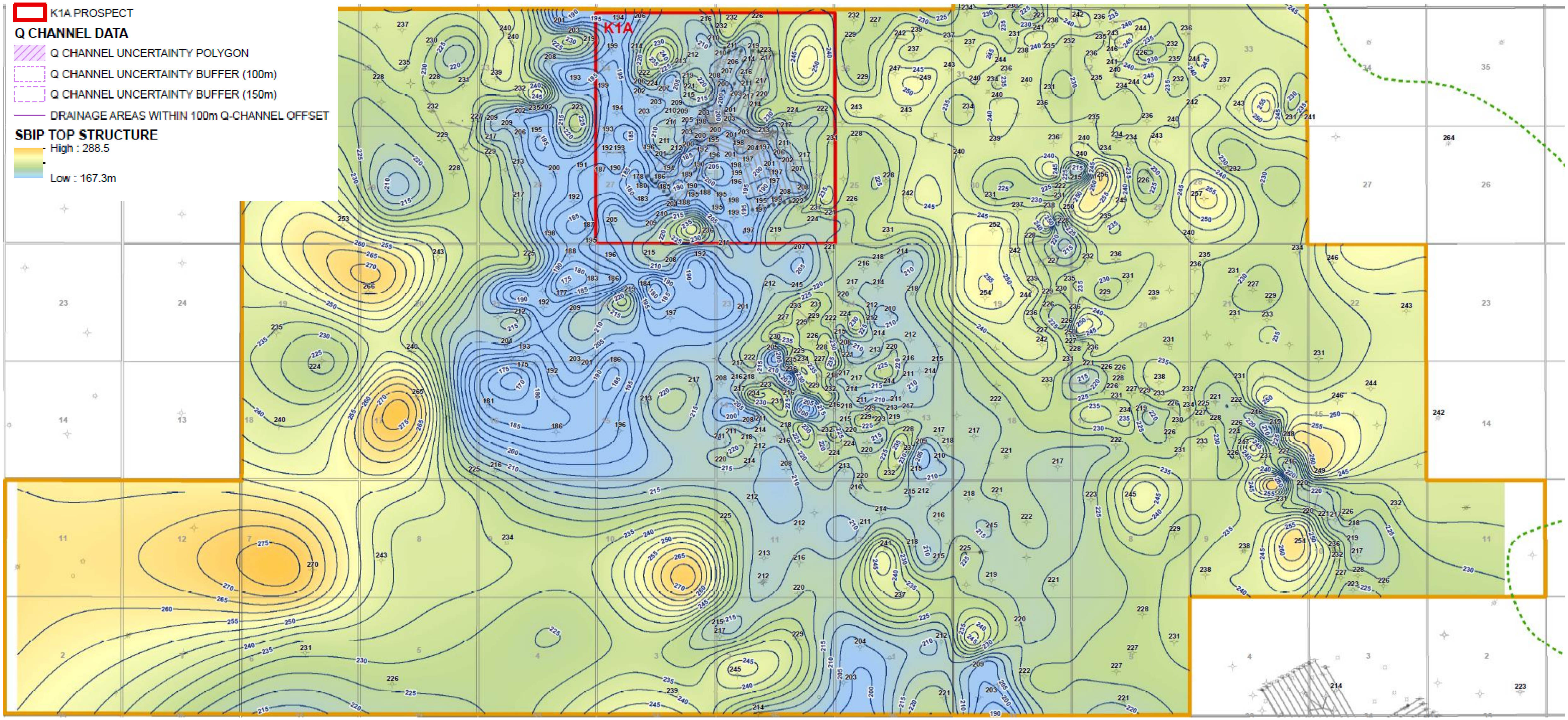
Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

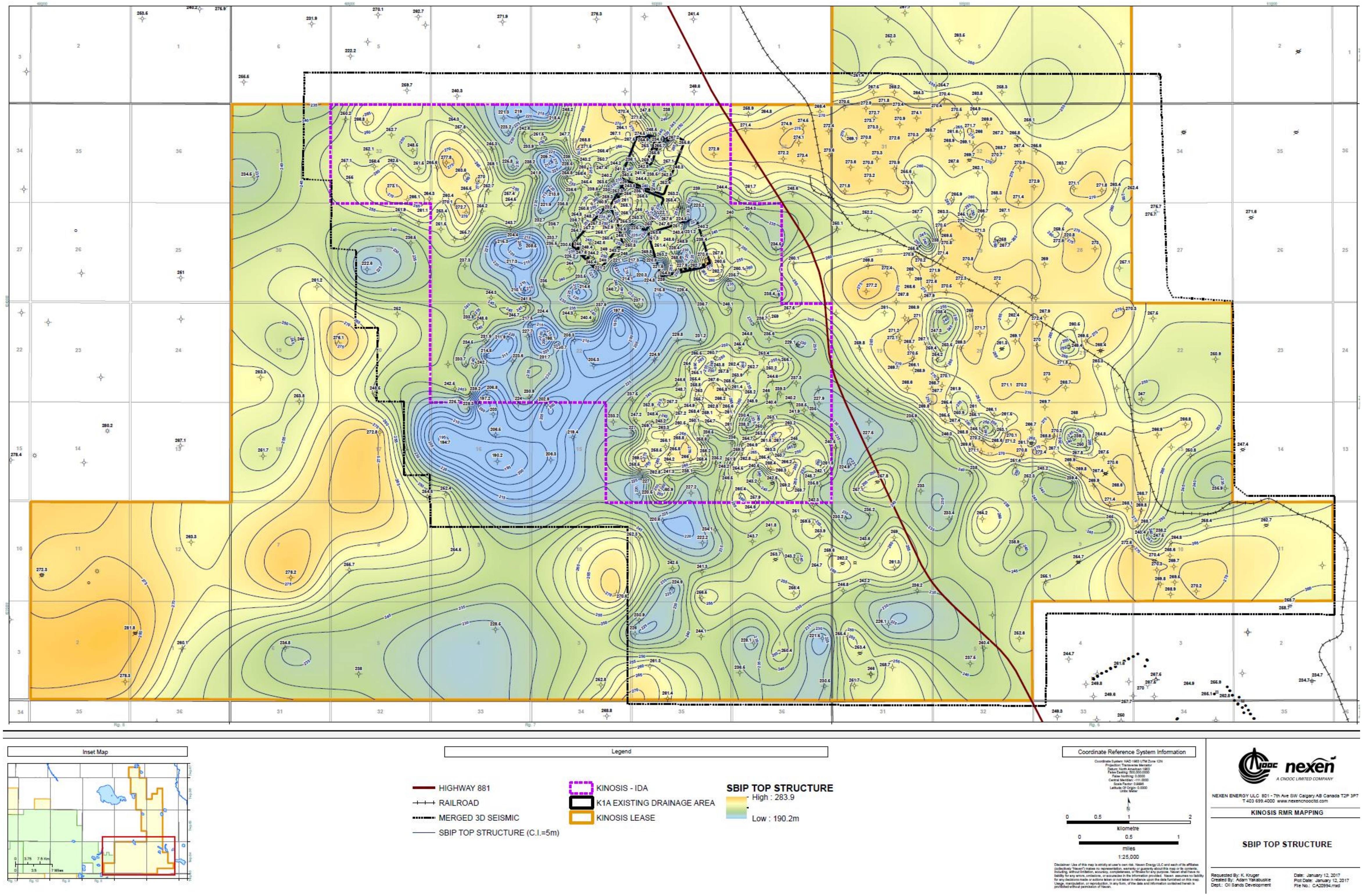
SBIP TOP STRUCTURE

High : 288.5

Low : 167.3m



Kinosis
Structure of SBIP Top



Long Lake
HPVH Isopach over SBIP Pay Interval

Legend

- SBIP HPVH ISOPACH (C.I.=1m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

PROSPECT AREA

- K1A PROSPECT

Q CHANNEL DATA

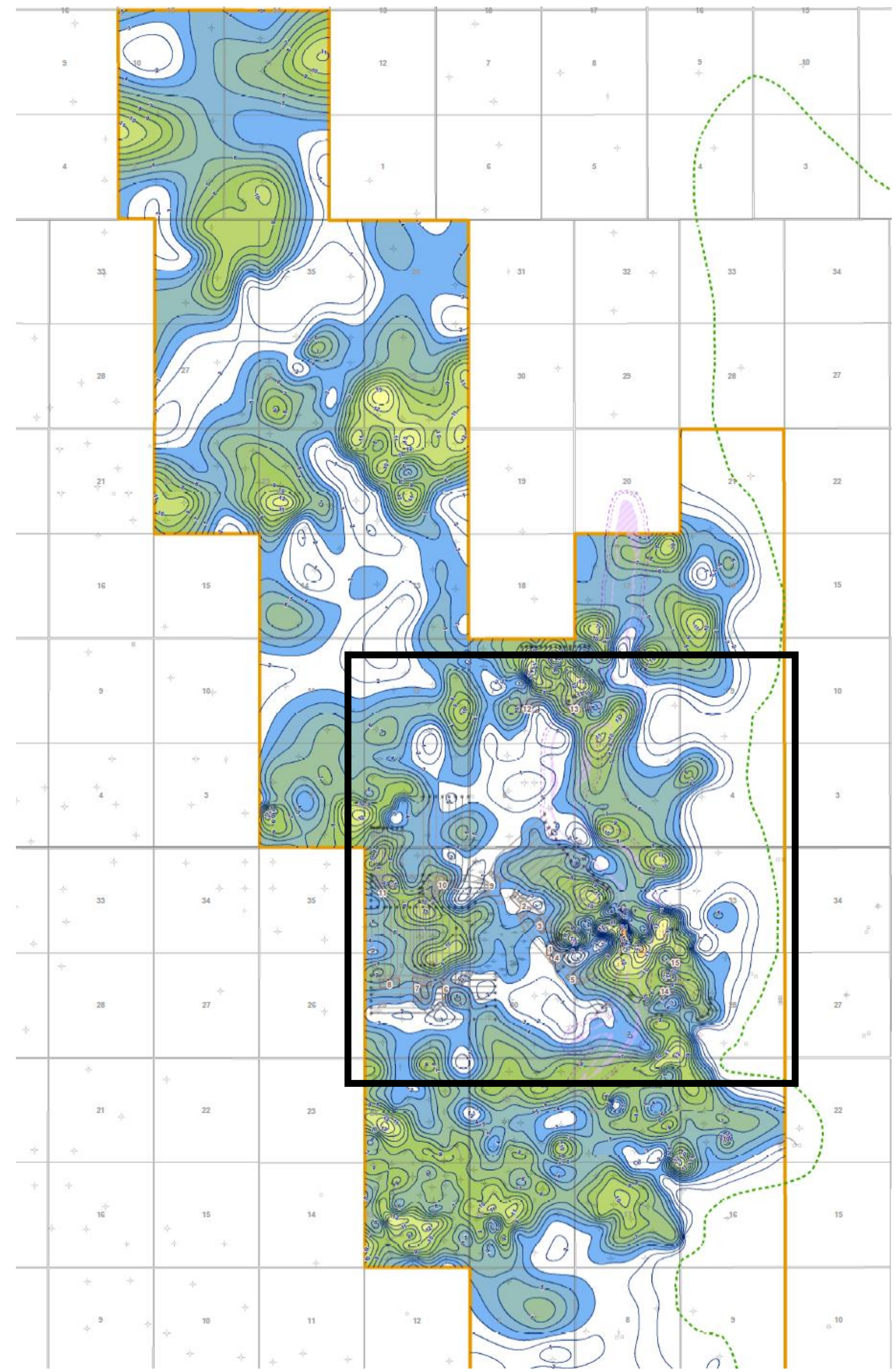
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP HPVH ISOPACH RASTER

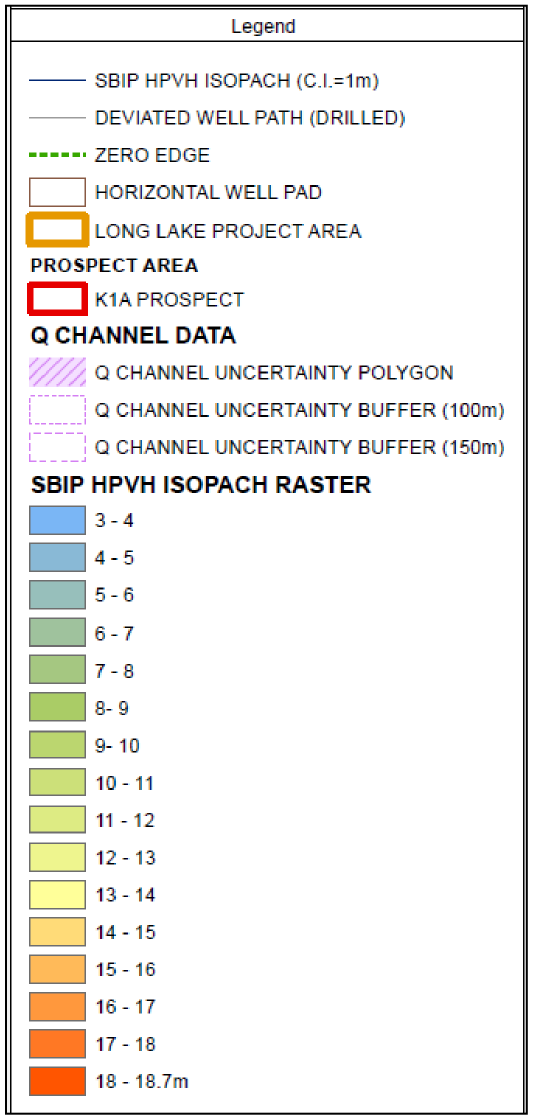
- 3 - 4
- 4 - 5
- 5 - 6
- 6 - 7
- 7 - 8
- 8- 9
- 9- 10
- 10 - 11
- 11 - 12
- 12 - 13
- 13 - 14
- 14 - 15
- 15 - 16
- 16 - 17
- 17 - 18
- 18 - 18.7m

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

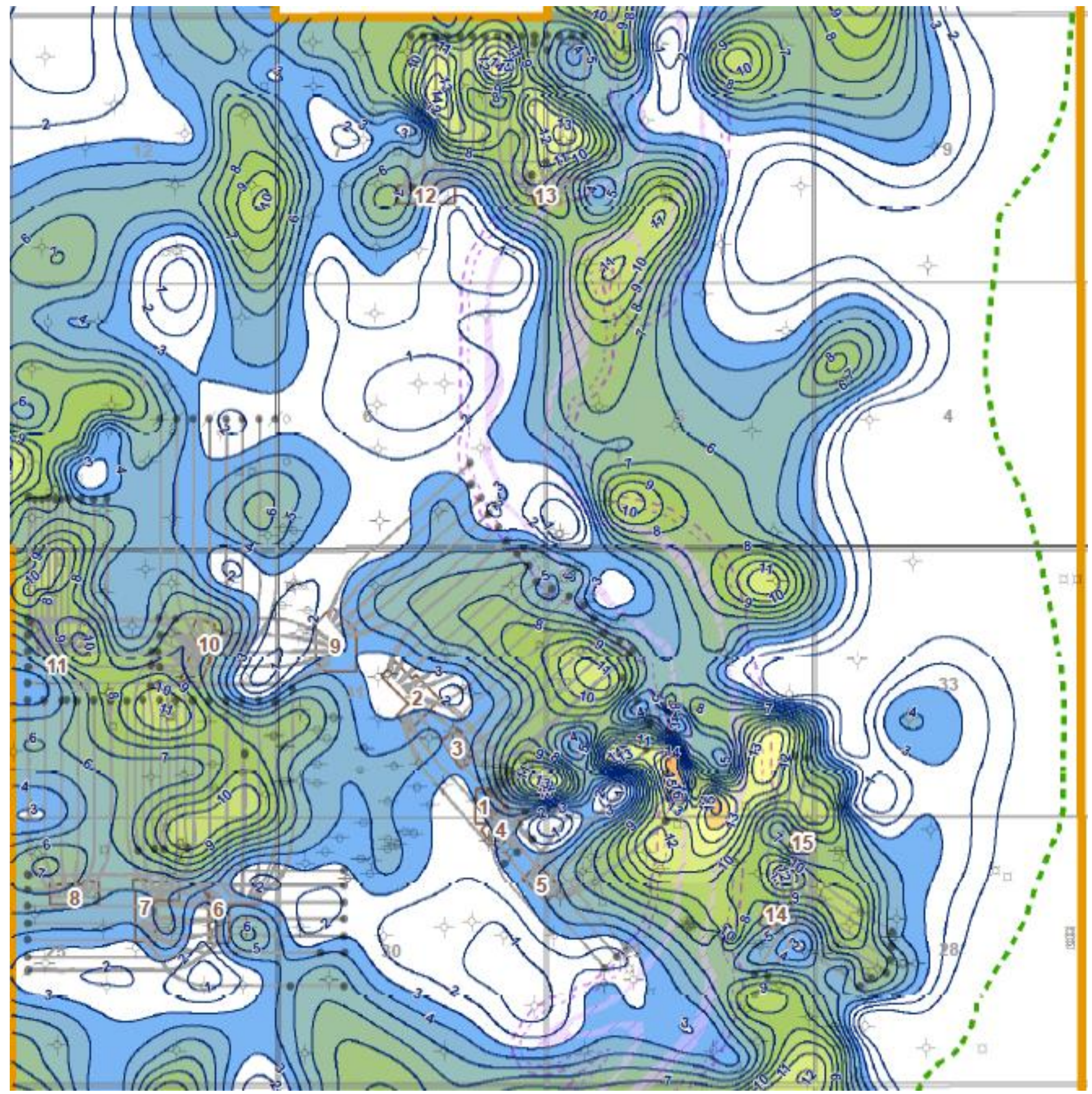
- Colour shading : > $3m^3/m^2$ HPVH



Long Lake
HPVH Isopach over SBIP Pay Interval

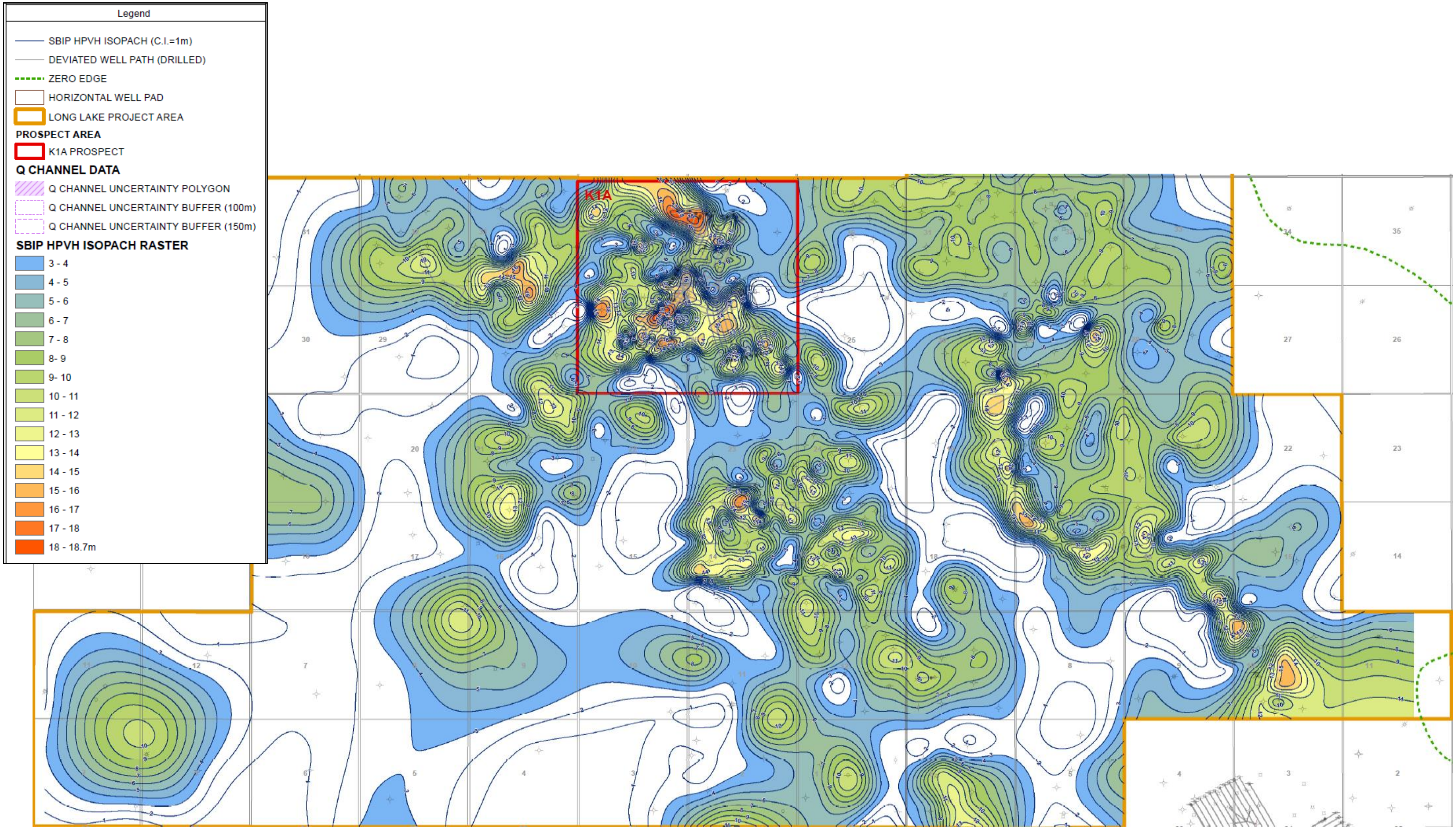


$$HPVH = \sum_{\text{Min pay bs}}^{\text{Min pay tp}} (So^{*}\Phi)$$



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

Kinosis
HPVH Isopach over SBIP Interval



Long Lake and Kinosis SBIP (HPVH) Volumes

Pad	Volume (m3)
LLK P01	1819334.31
LLK P02	4676731.80
LLK P03	3722430.15
LLK P04	1137221.36
LLK P05	3129433.19
LLK P06	6491203.51
LLK P07	5884271.75
LLK P08	3217436.41
LLK P09	3934821.14
LLK P10	3738599.97
LLK P11	2820272.15
LLK P12	4811773.97
LLK P13	3683918.71
LLK P14	4242701.79
LLK P15	2182764.43
K1A	11783622.62
K2A	12928364.88

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

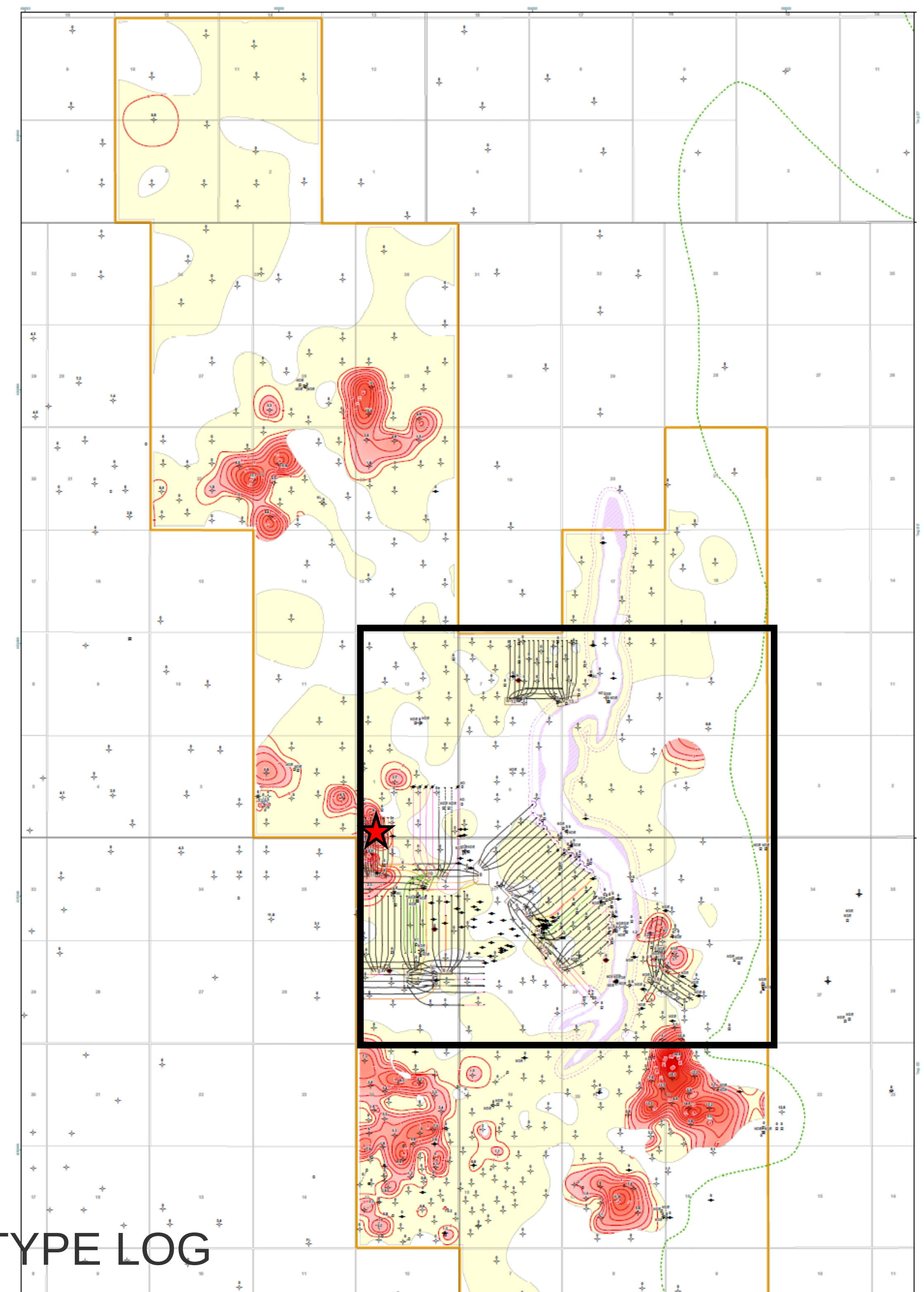
Legend

MAP DATA
- 2014/2015 CORE OBS WELLS
- EBIP TOP GAS ISOPACH (C.I.=2m)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA
- EBIP HPVH ISOPACH POLYGON

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

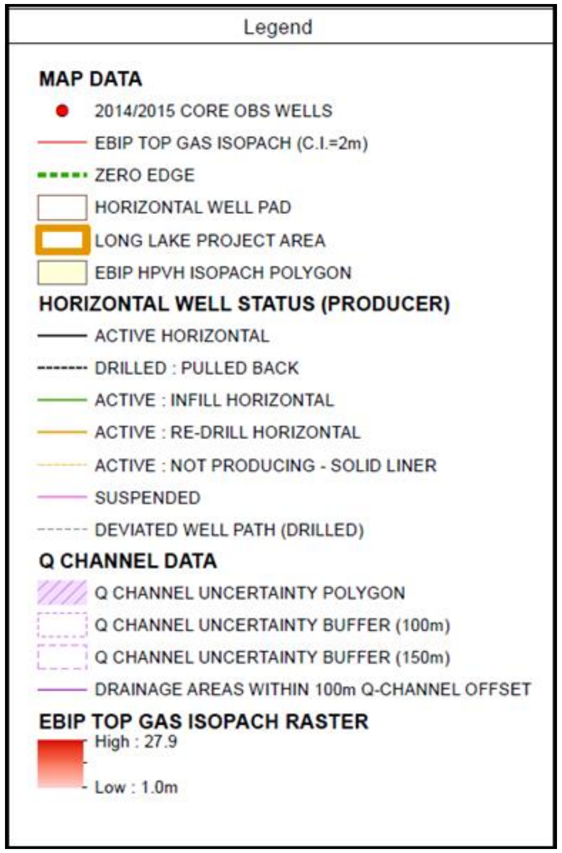
EBIP TOP GAS ISOPACH RASTER
- High : 27.9
- Low : 1.0m

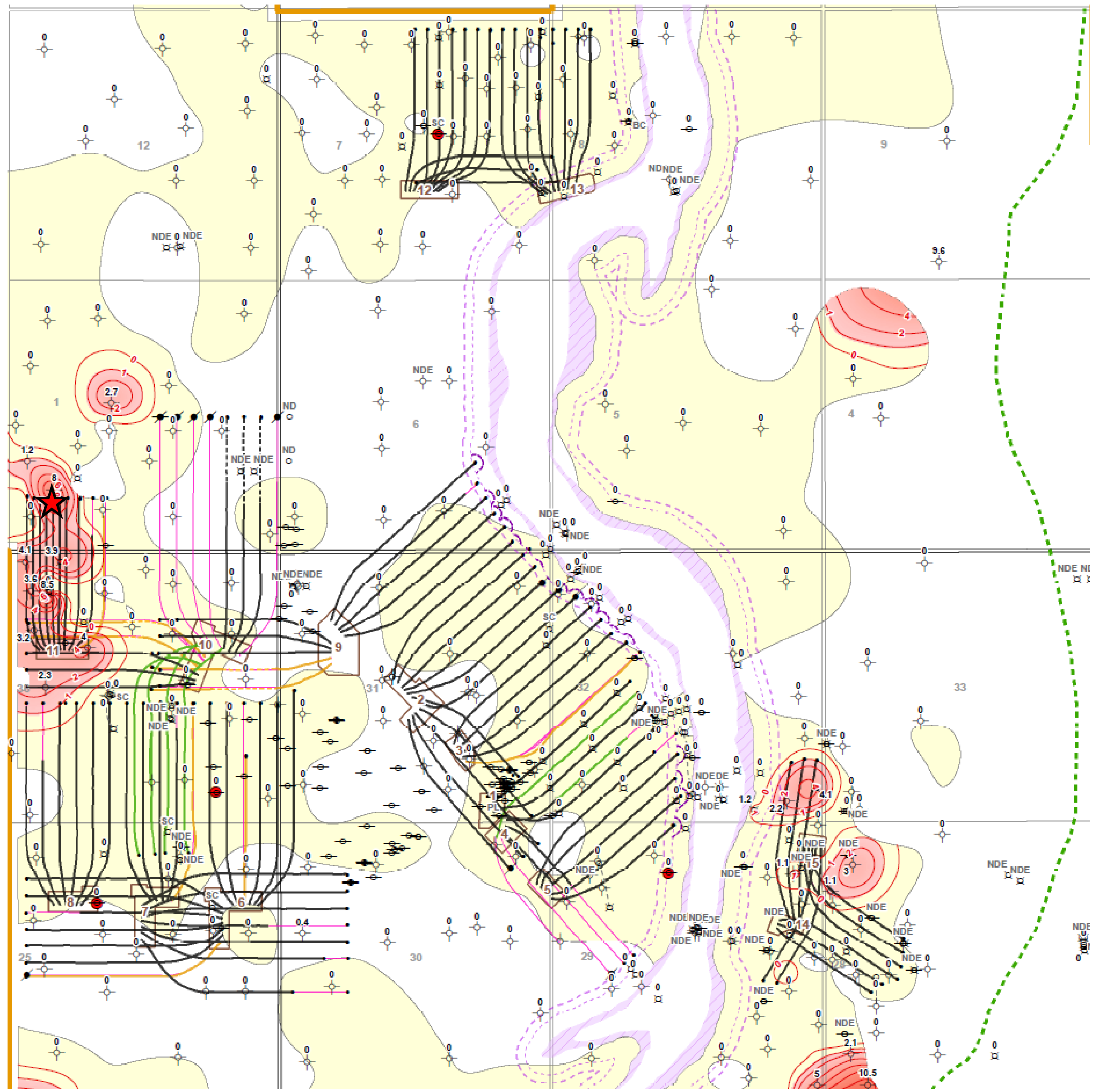


★ TYPE LOG

- 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

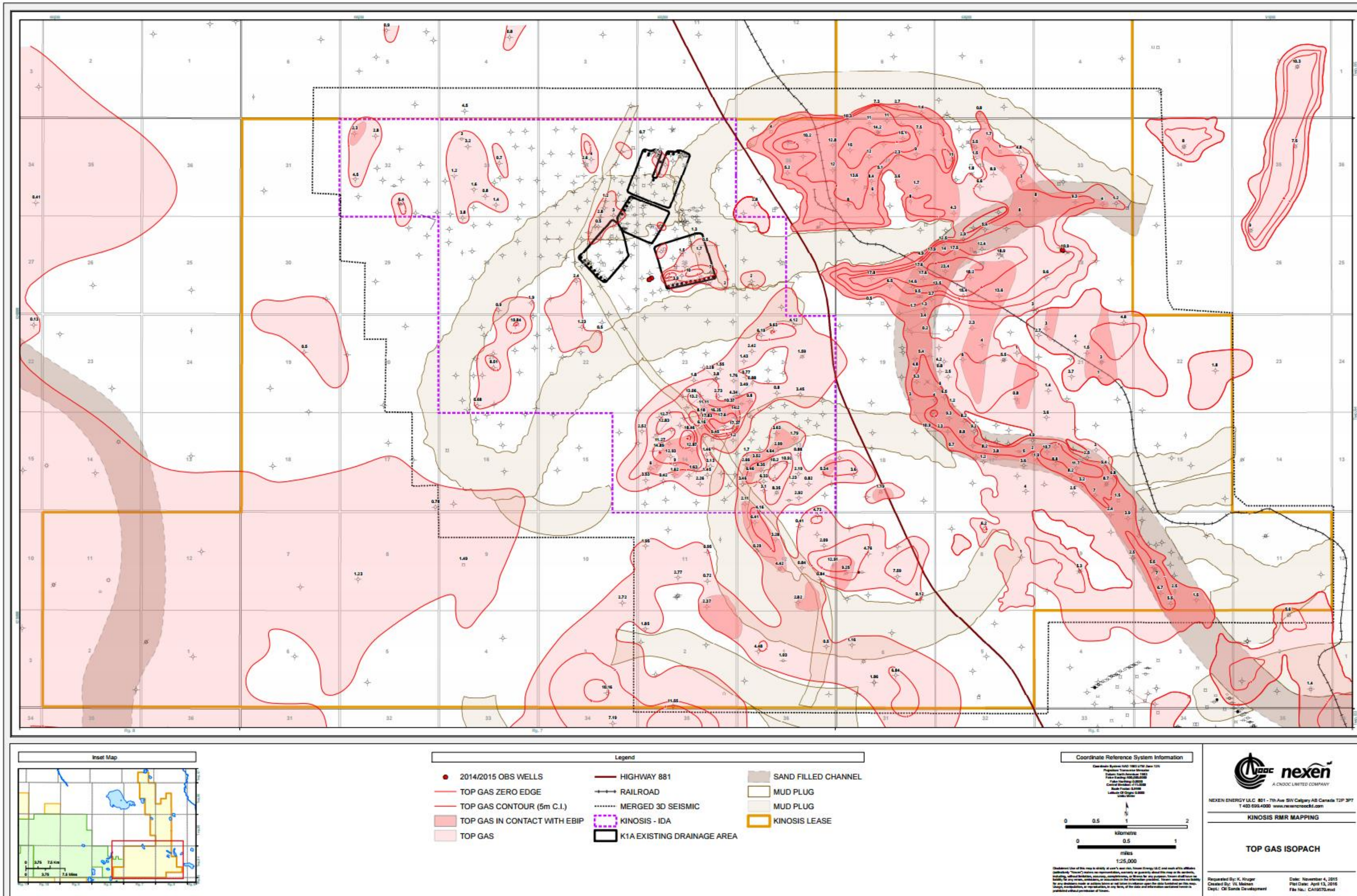




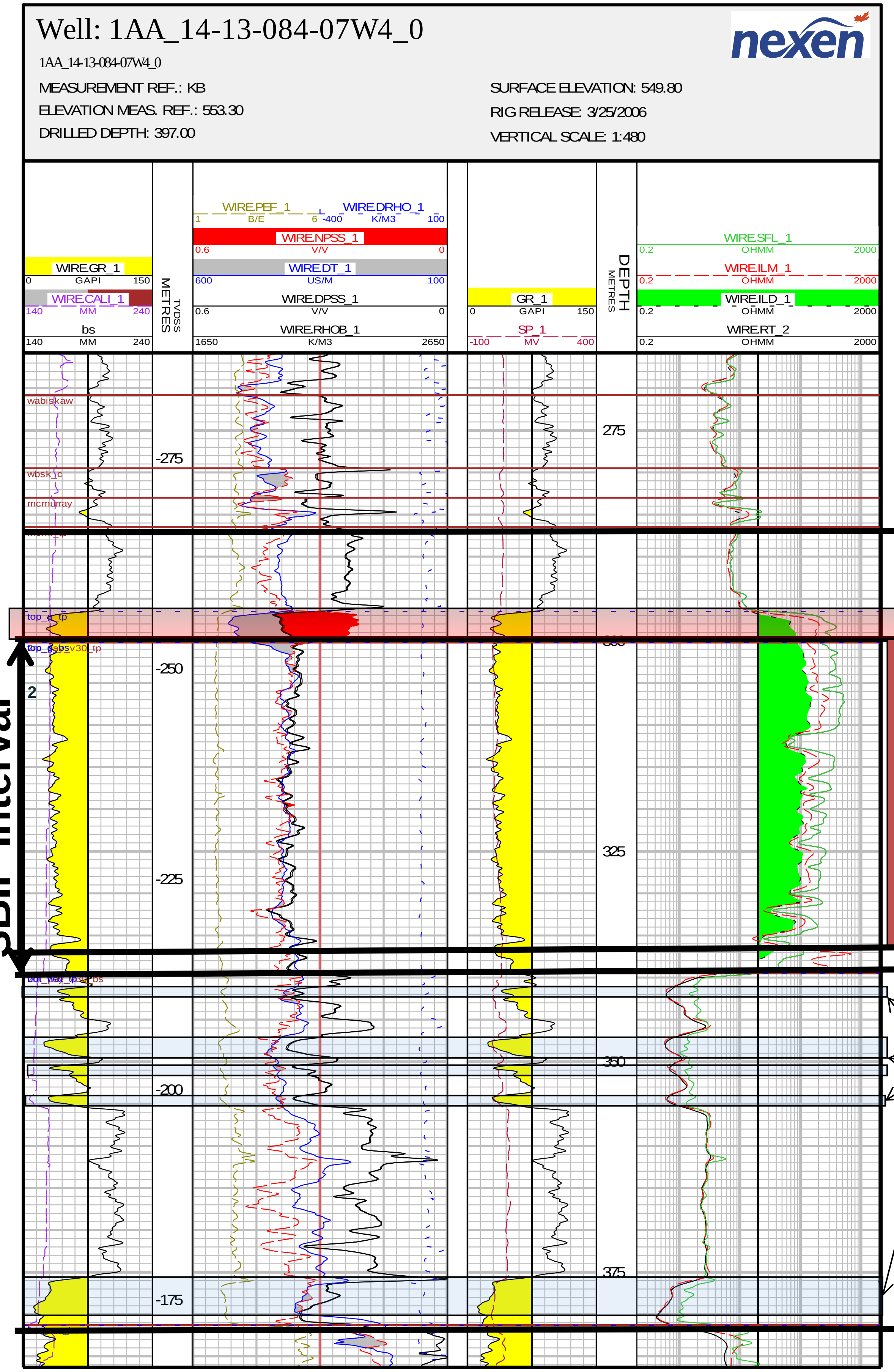
- Gas identified by neutron/density crossover
- Gas associated with SBIP Interval
  - within SBIP Interval
  - directly in contact with top water or top of SBIP interval
  - contours clipped to 3m^3/m^2 HPVH SBIP contour

★ TYPE LOG

Kinosis
Top Gas in the McMurray



Example Log: Kinosis IDA



McMurray Fluvial Estuarine Complex top

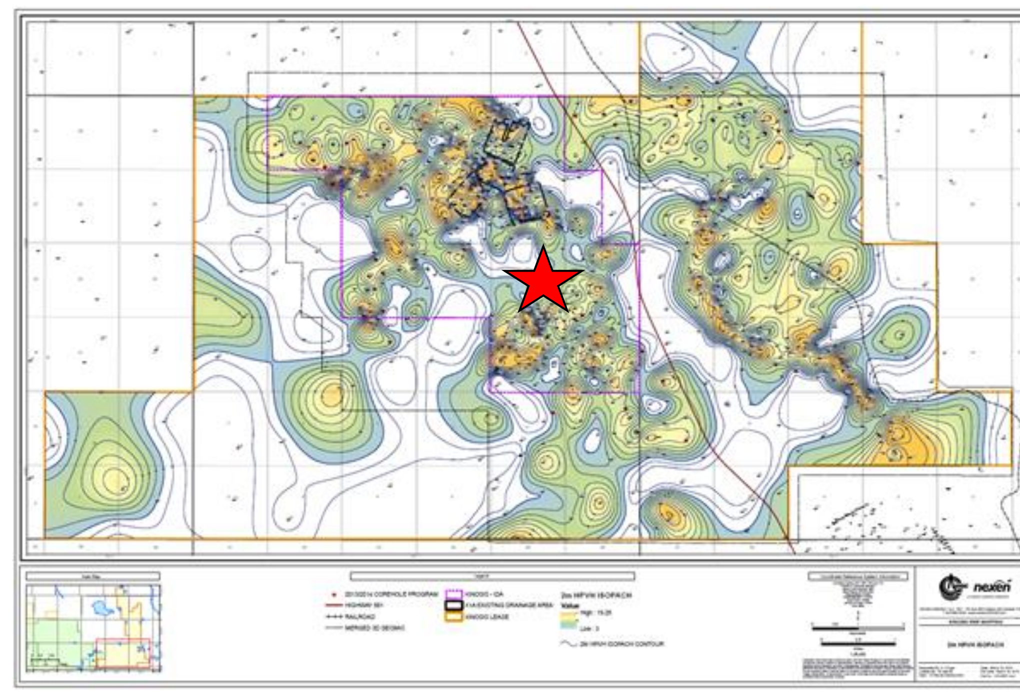
Top Gas

SBIP Interval

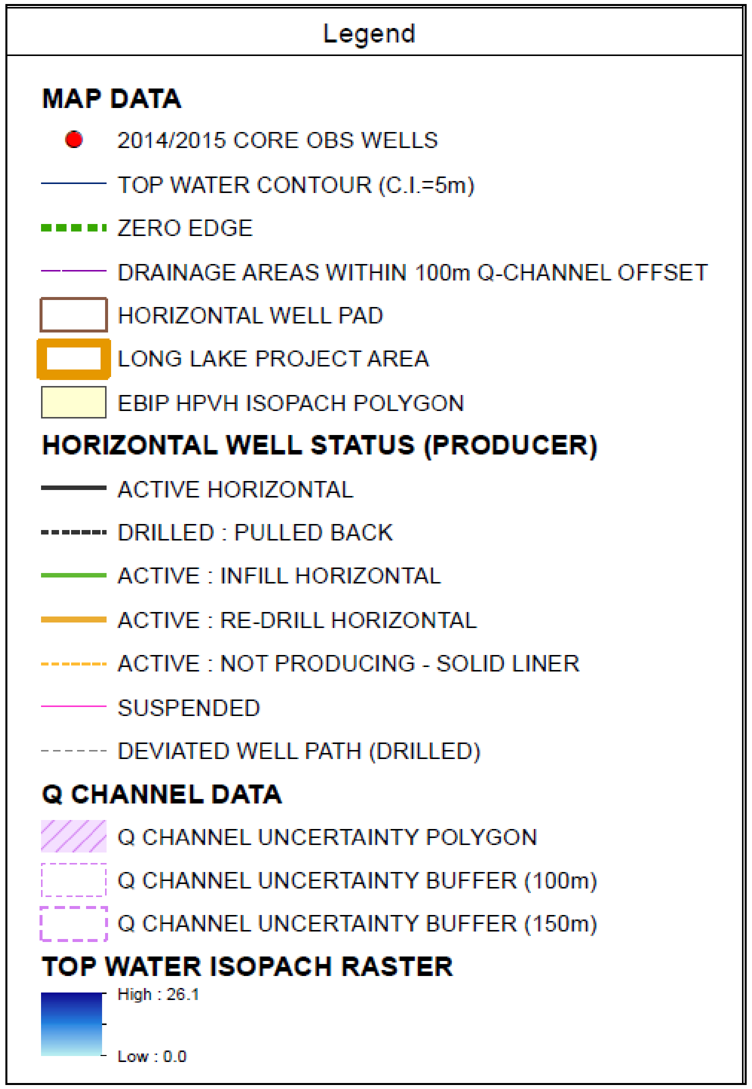
EBIP Pay Interval

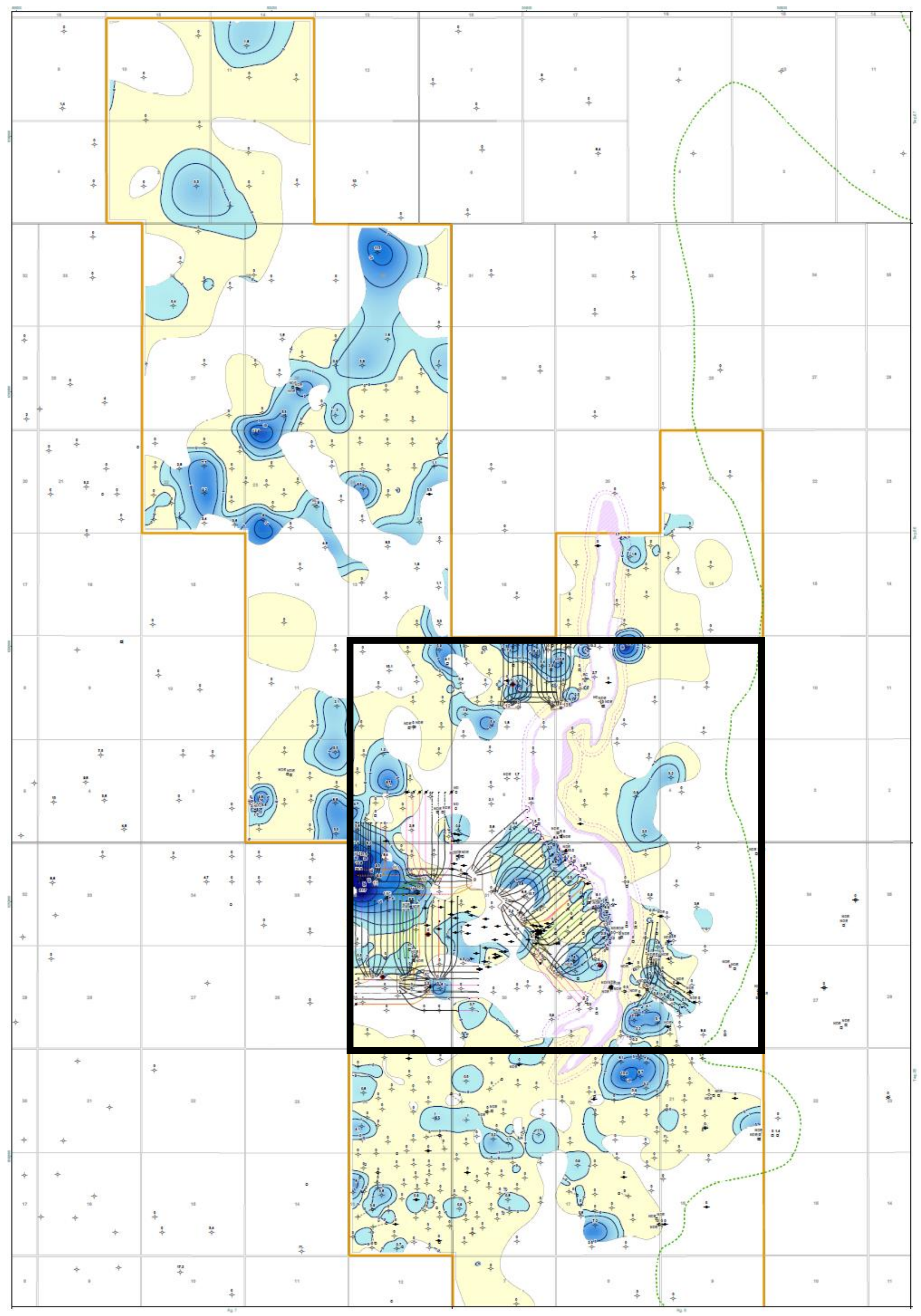
Bottom Water

Devonian



Long Lake
Top Water Associated with SBIP Interval





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

Long Lake
Top Water Associated with SBIP Interval

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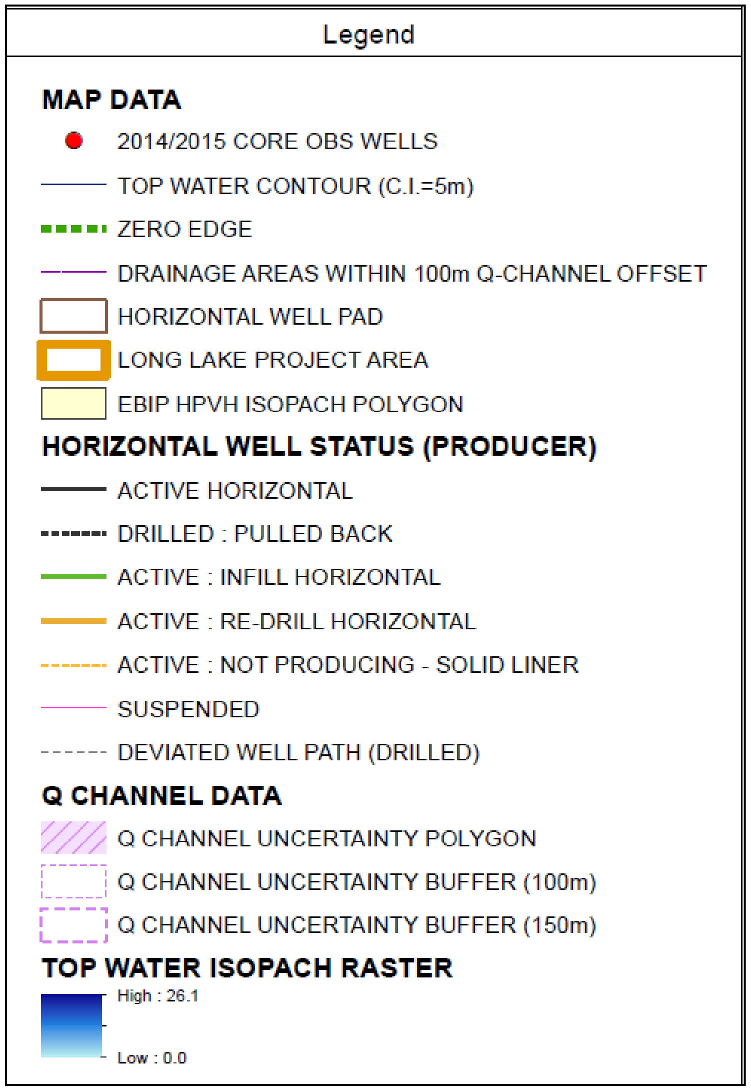
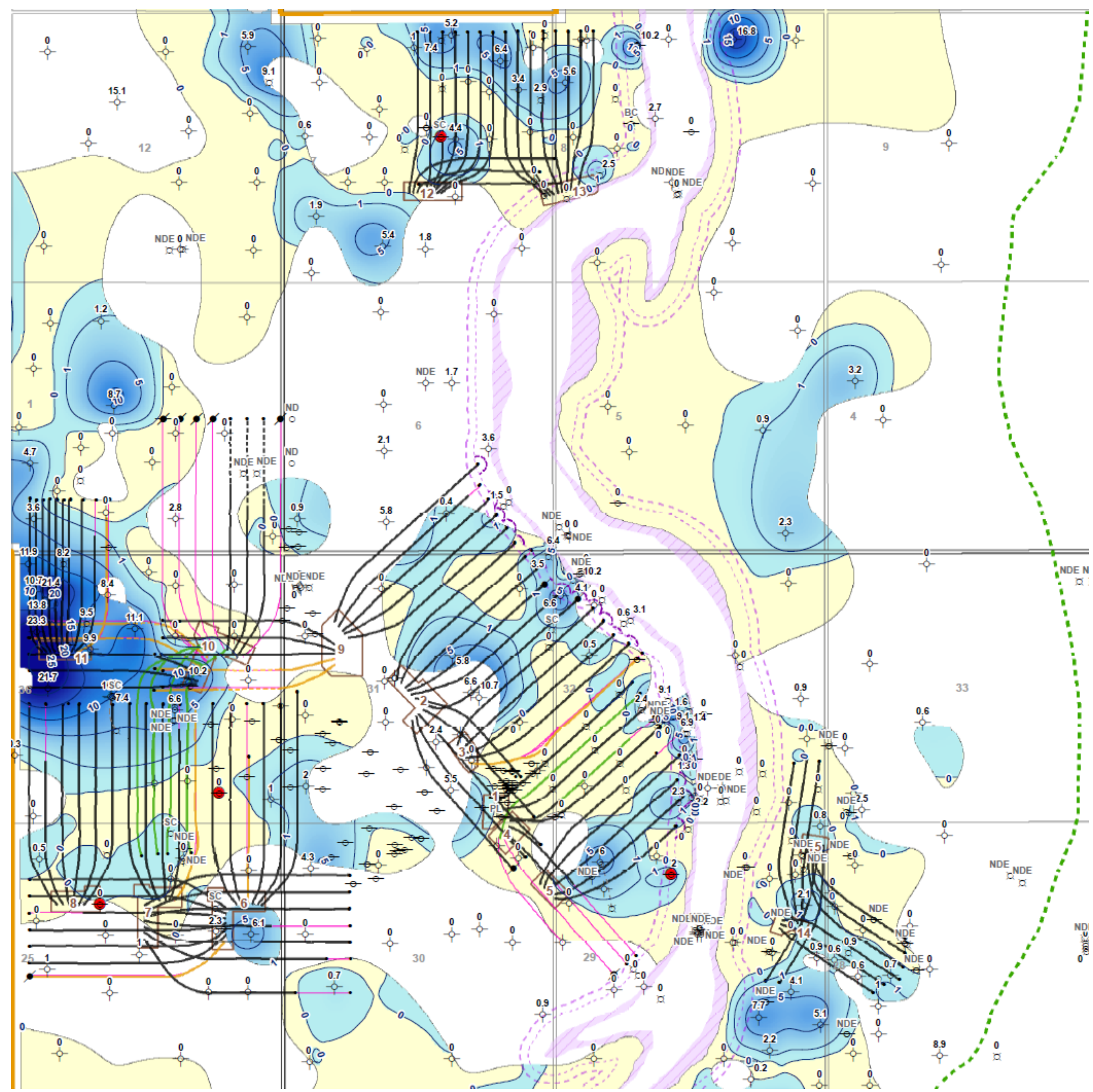
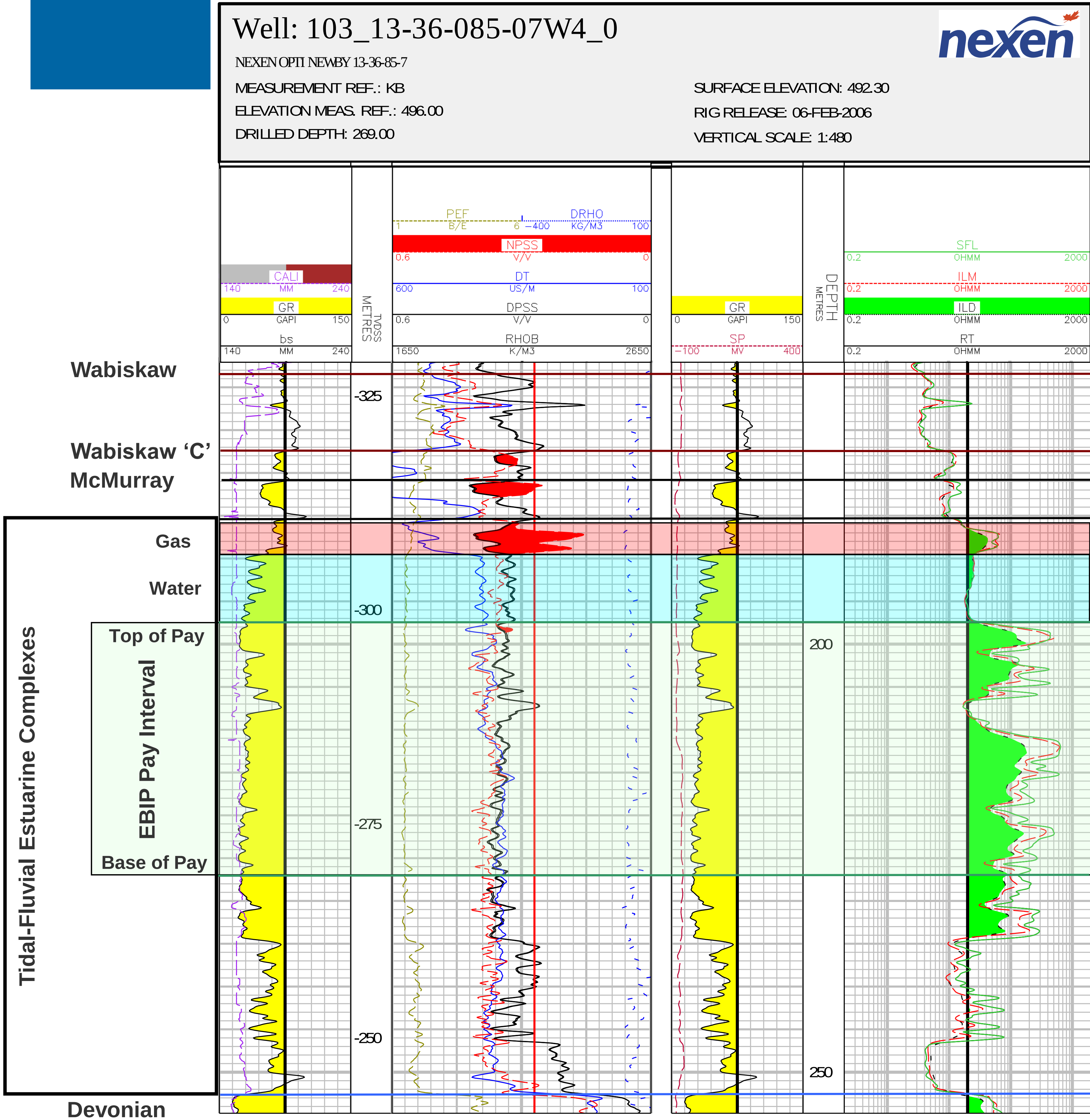
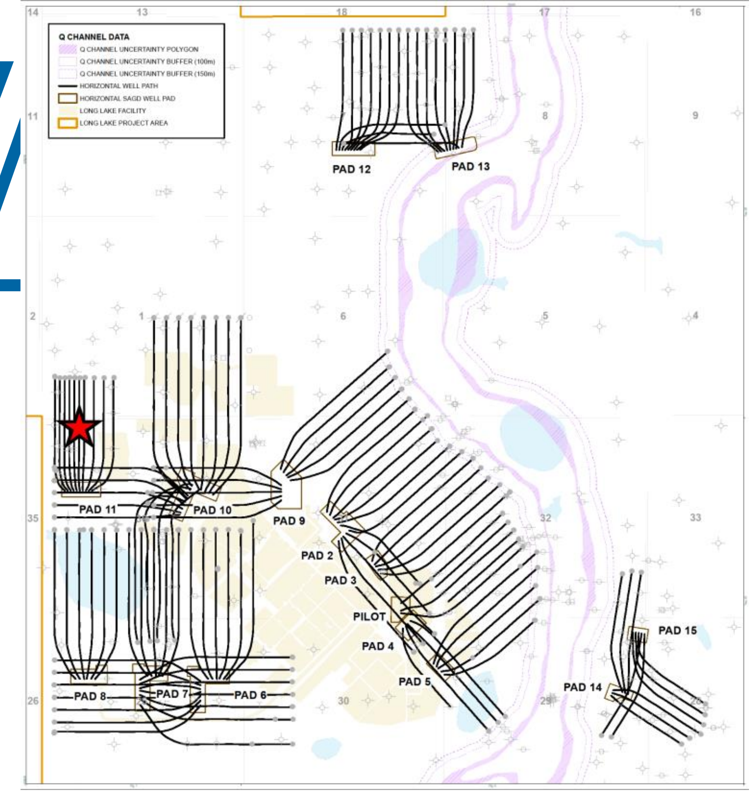


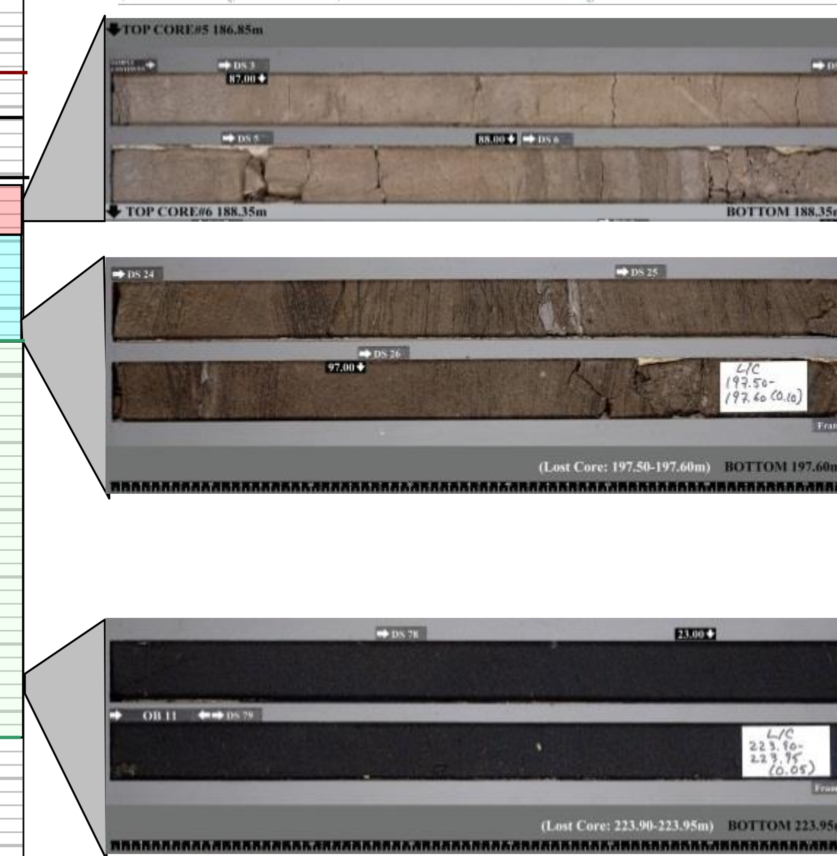


- > 50% Swe and < 30% V_{shale}
- Base of Bottom Water
  - top of a > 2m > 30% V_{shale} shale interval
- Contours clipped to $3m^3/m^2$ HPVH SBIP contour

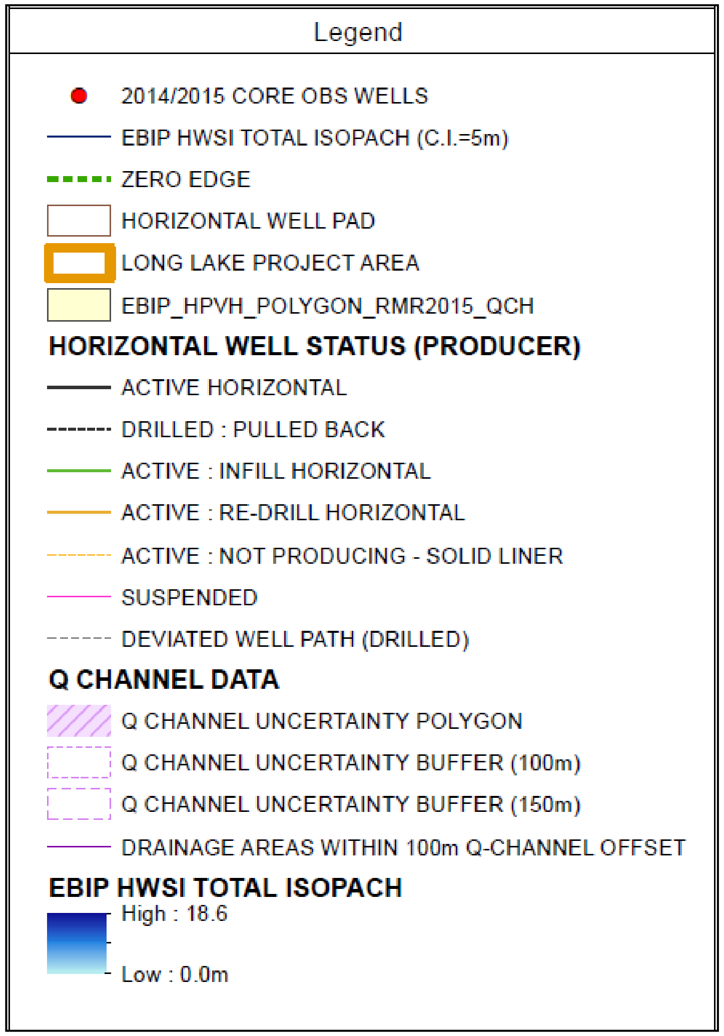
Top Impairment Type Log – 103/13-36-085-07W4



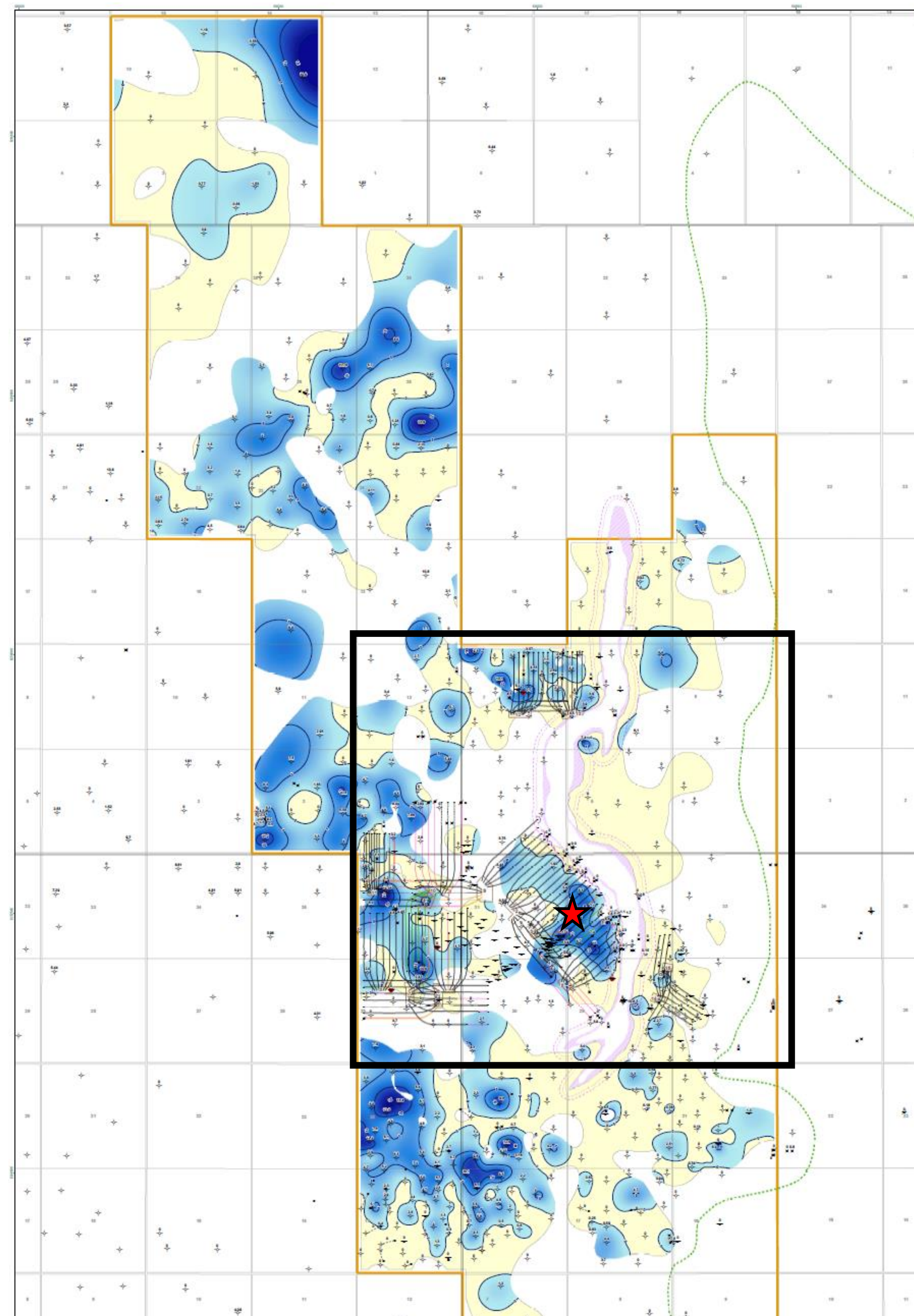




Long Lake Cumulative Thickness of High Water Saturation Interval(s) within EBIP Interval



★ TYPE LOG



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

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

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Legend

- 2014/2015 CORE OBS WELLS
- EBIP HWSI TOTAL ISOPACH (C.I.=5m)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA
- EBIP_HPVH_POLYGON_RMR2015_QCH

HORIZONTAL WELL STATUS (PRODUCER)

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

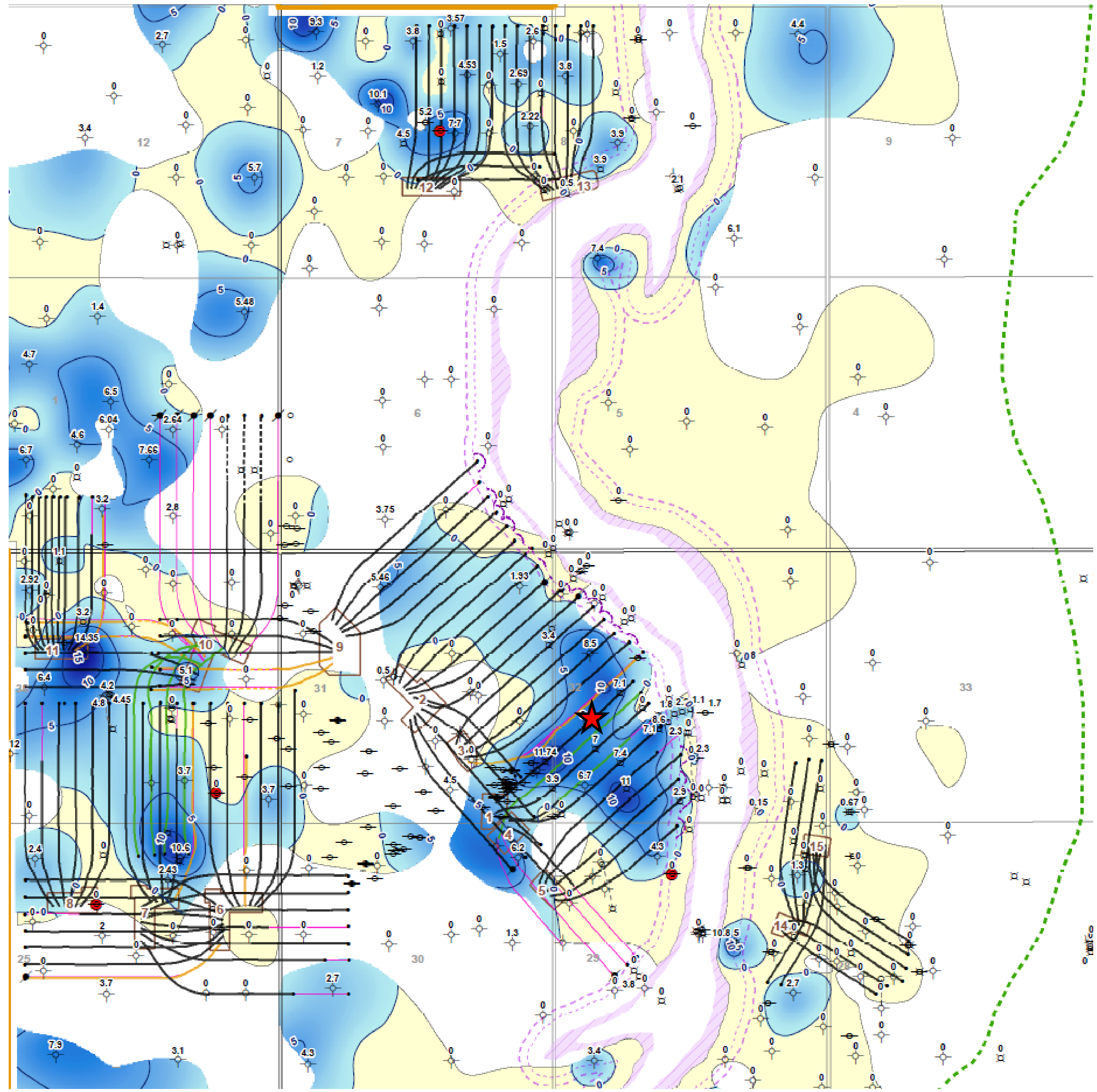
Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

EBIP HWSI TOTAL ISOPACH

High : 18.6

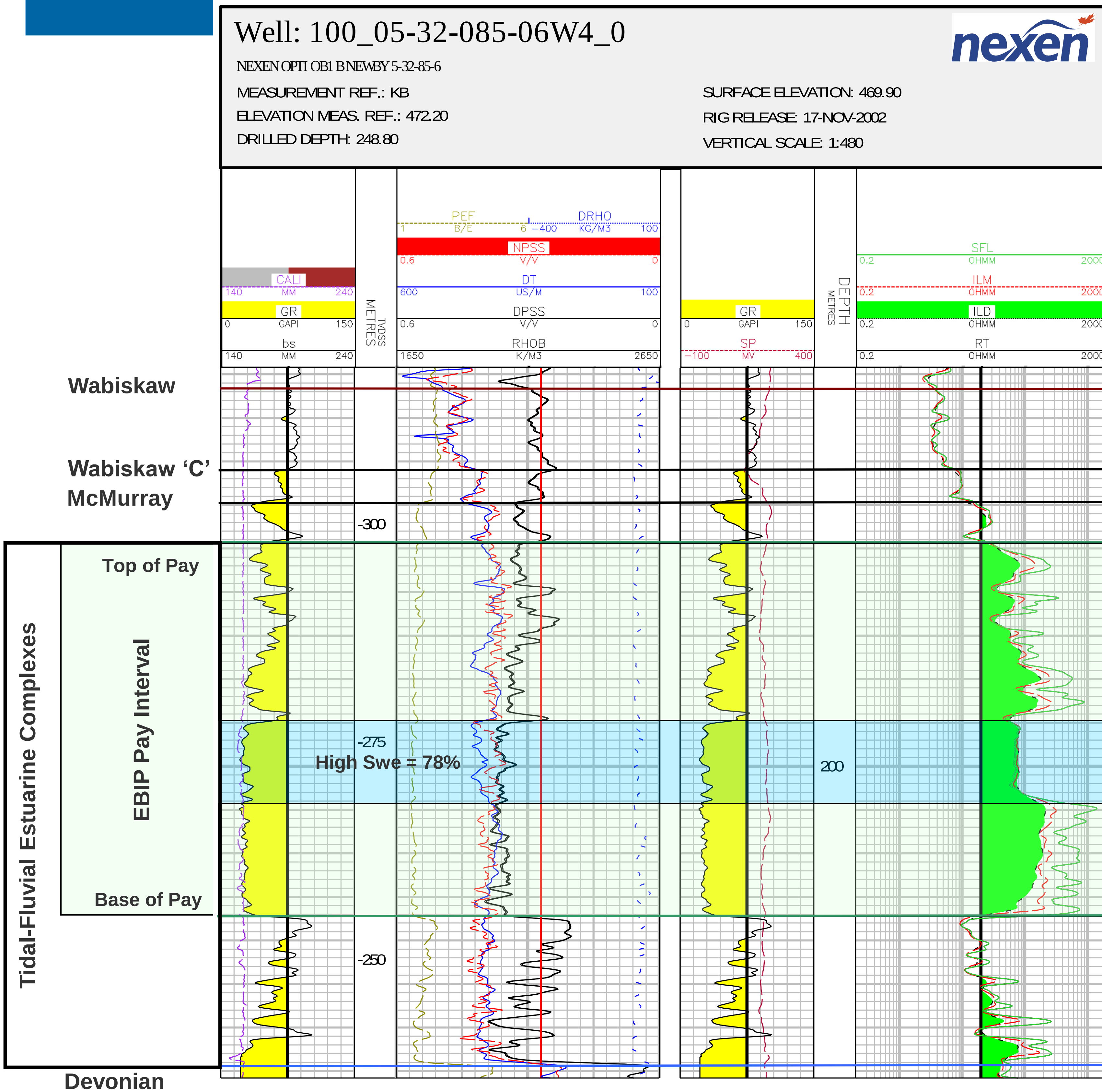
Low : 0.0m

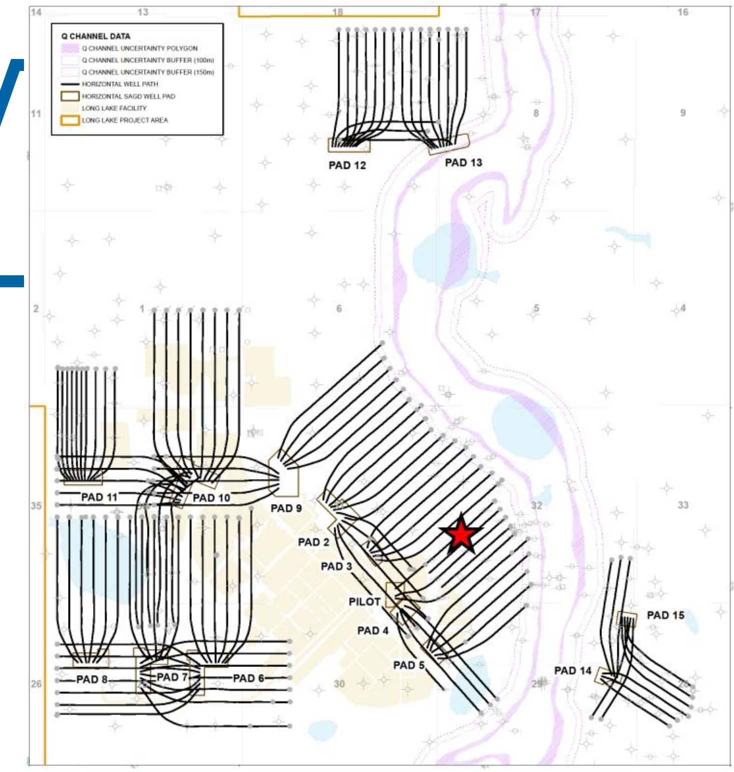


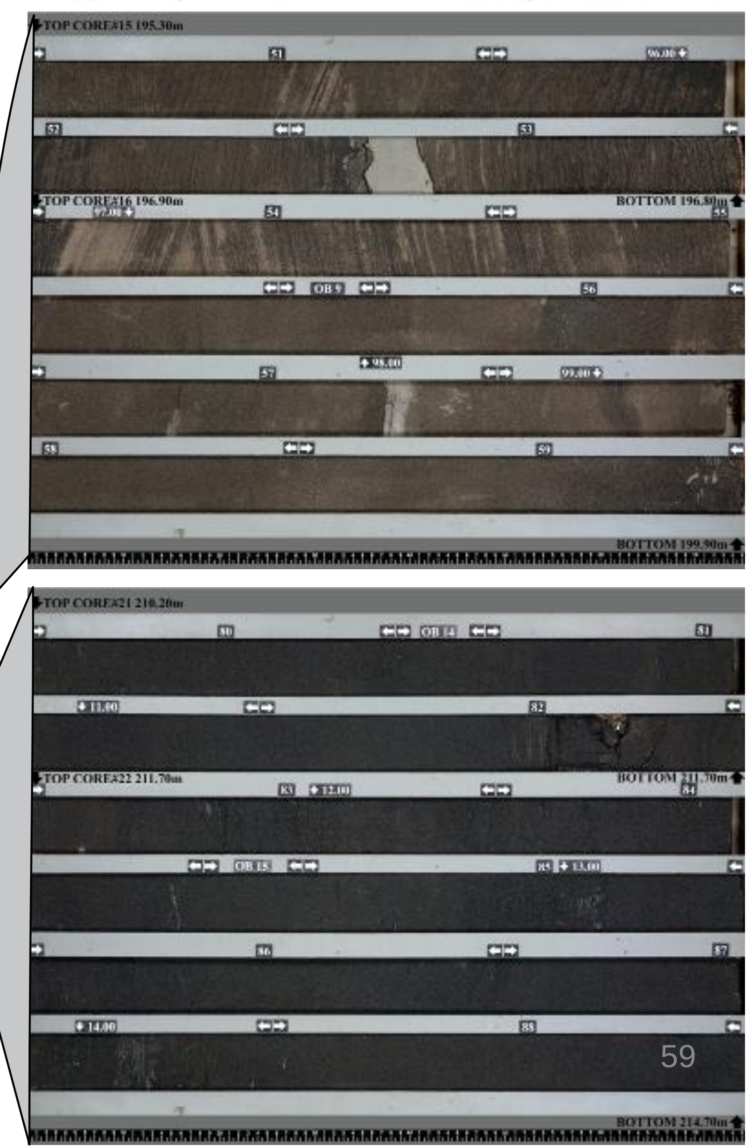
- > 50% Swe and < 30% V_{shale}
- Cumulative thickness of high water saturation interval(s) within EBIP interval
- Contours clipped to 3m^3/m^2 HPVH EBIP contour

★ TYPE LOG

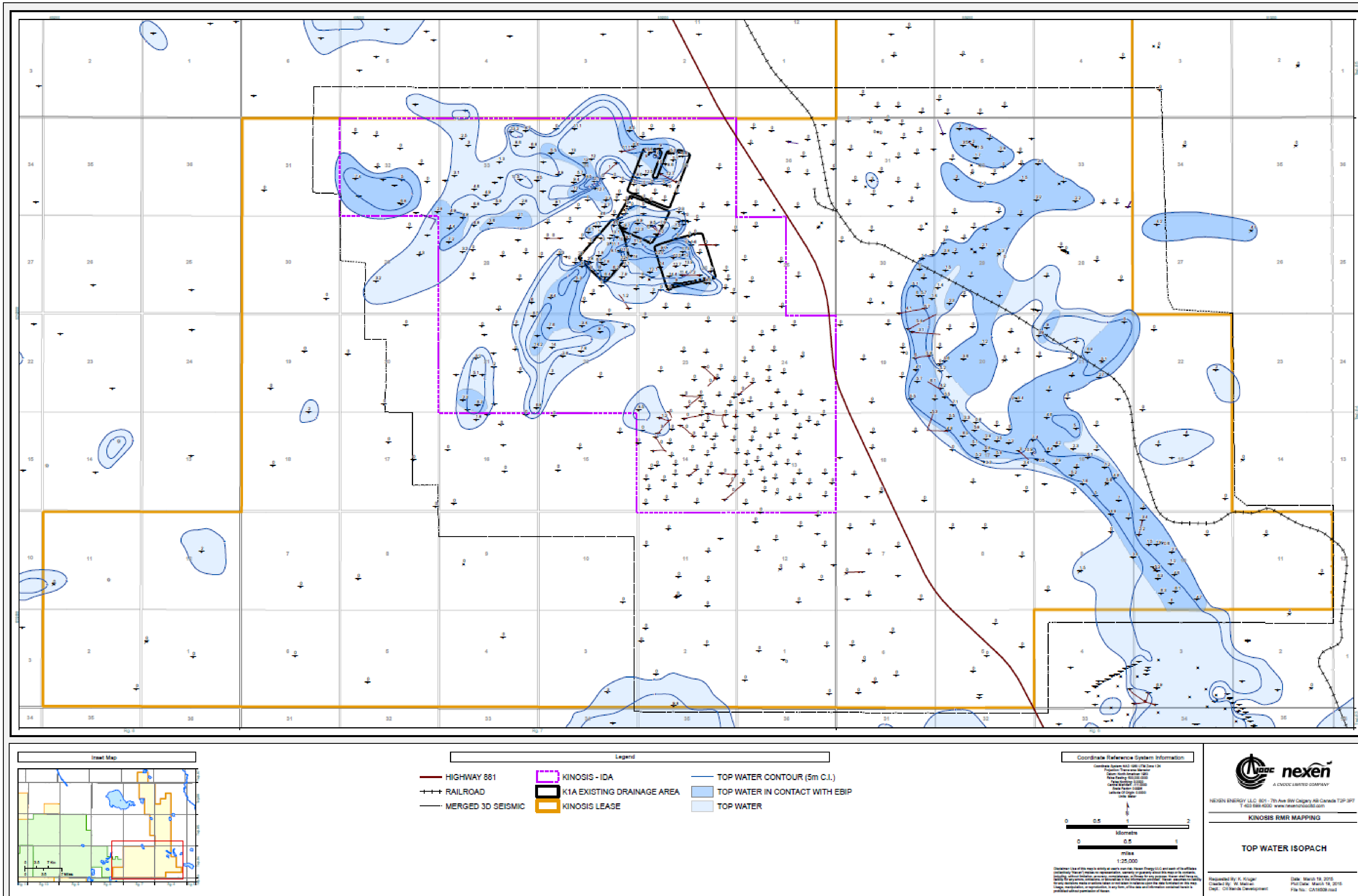
High Water Saturation Type Log
100/05-32-085-06W4



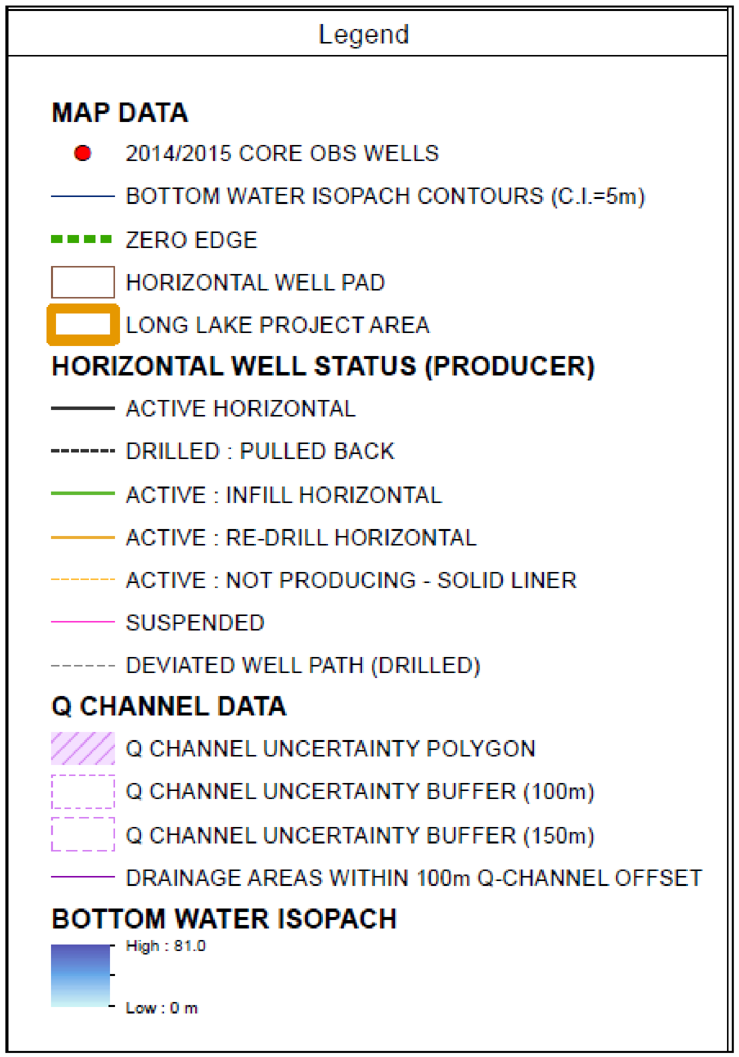


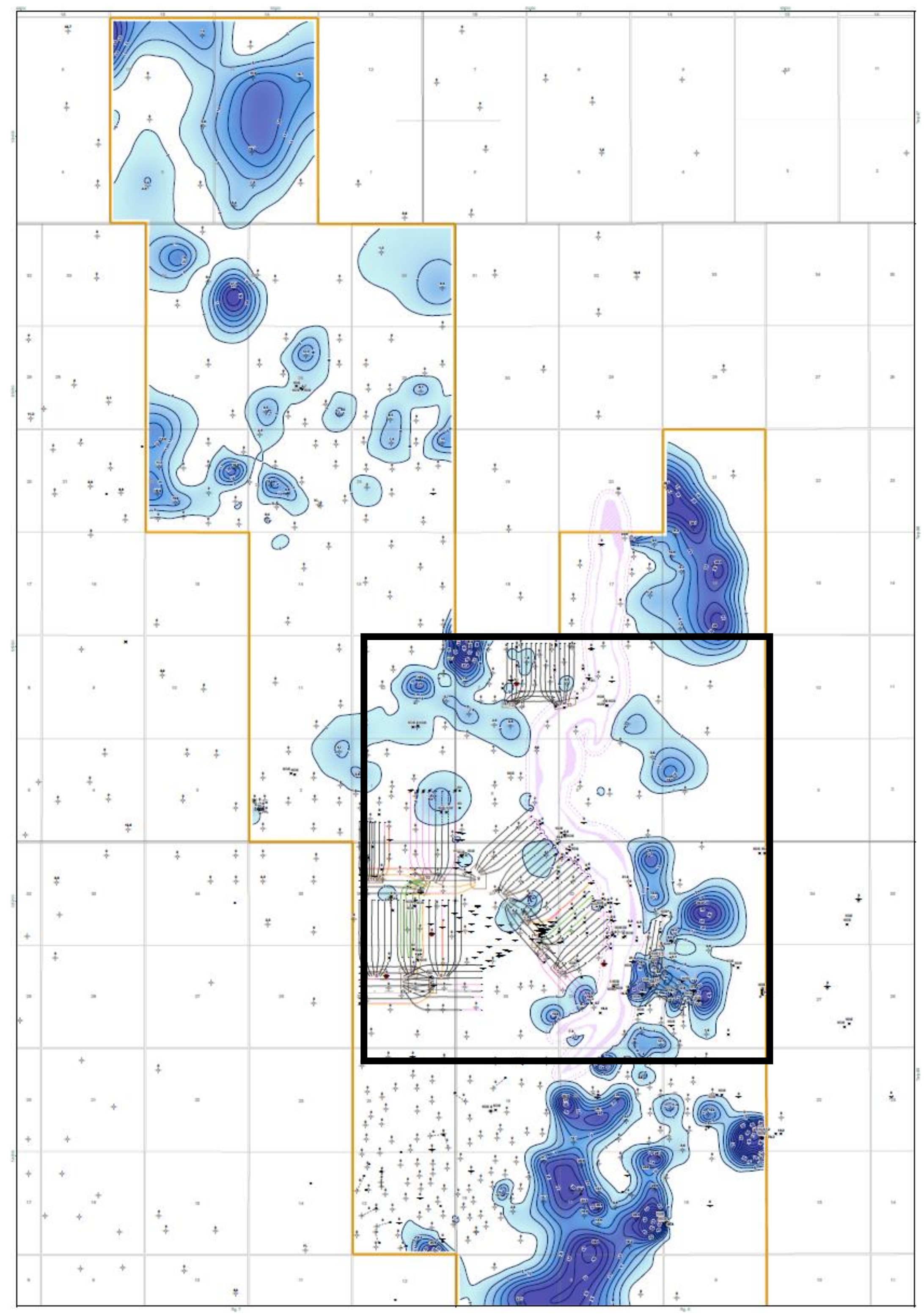


Kinosis
Top Water in the McMurray



Long Lake
Bottom Water Associated with EBIP Interval

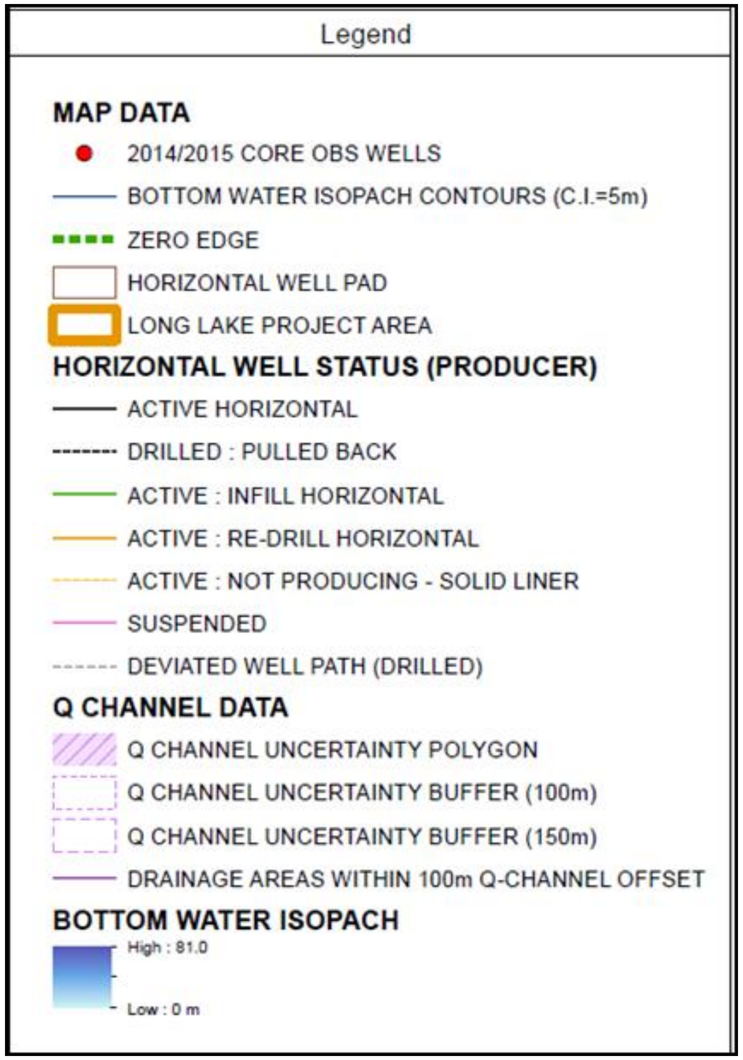


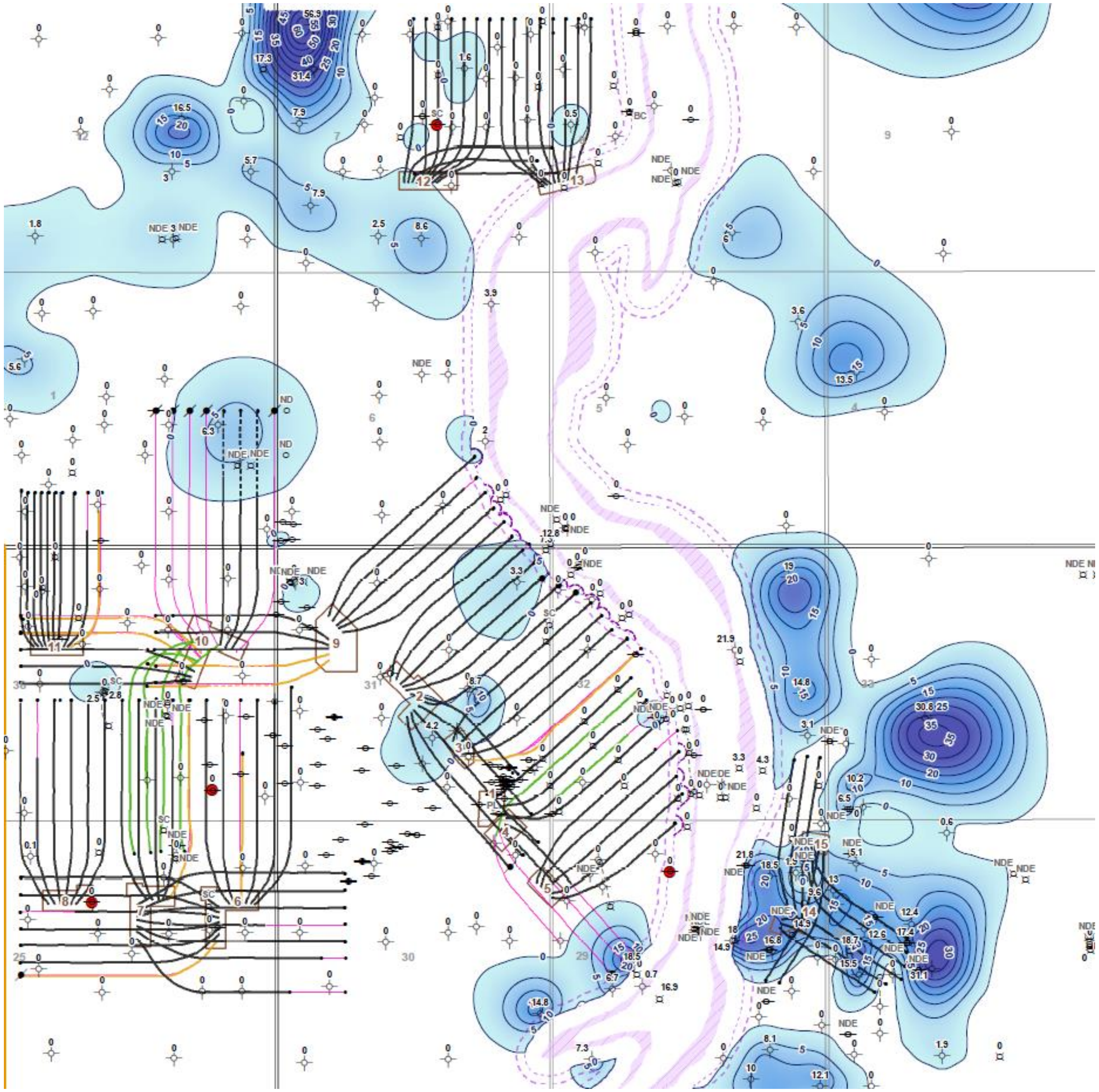


- > 50% Swe and < 30% V_{shale}
- Base of Bottom Water
  - top of a > 2m > 30% V_{shale} shale interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour

-

Long Lake
Bottom Water Associated with EBIP Interval





- > 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 EBIP contour

Kinosis
Bottom Water in the McMurray

nexen
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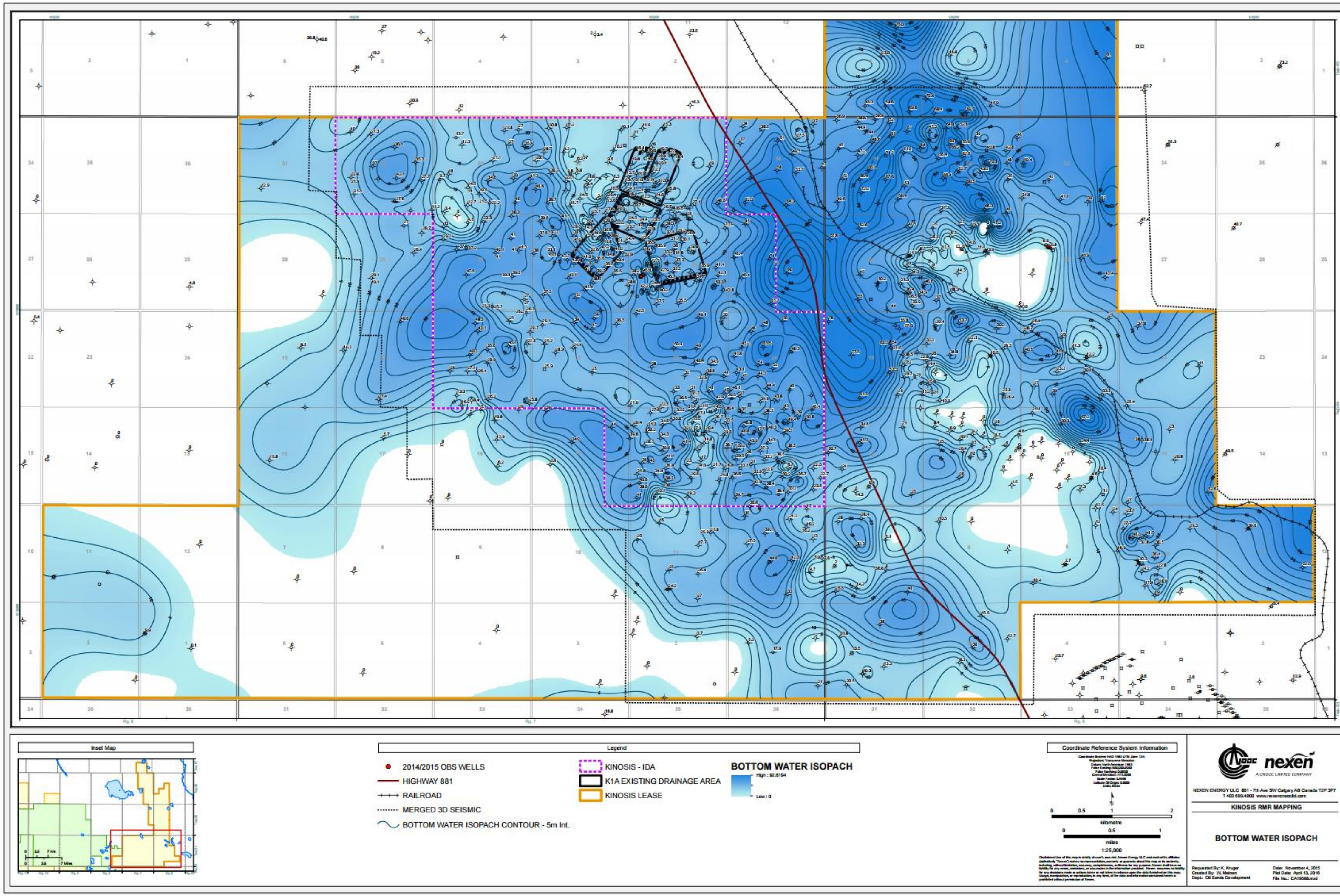
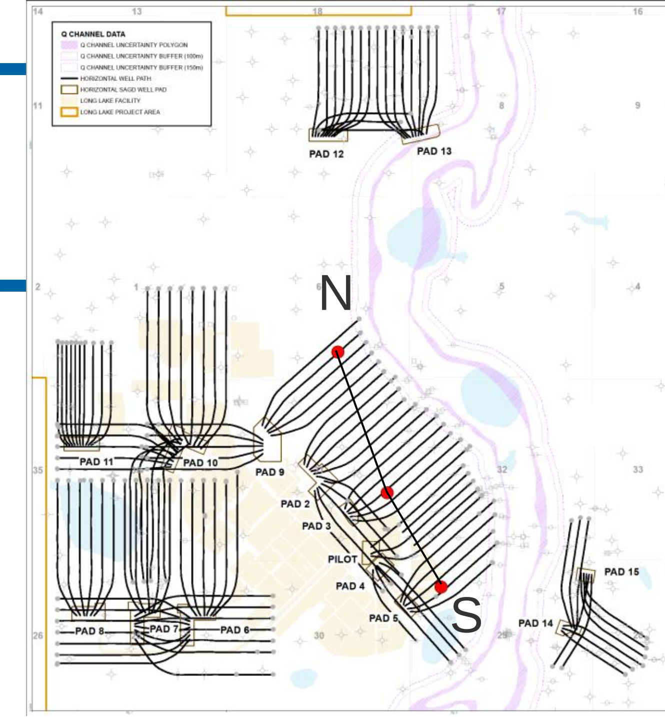
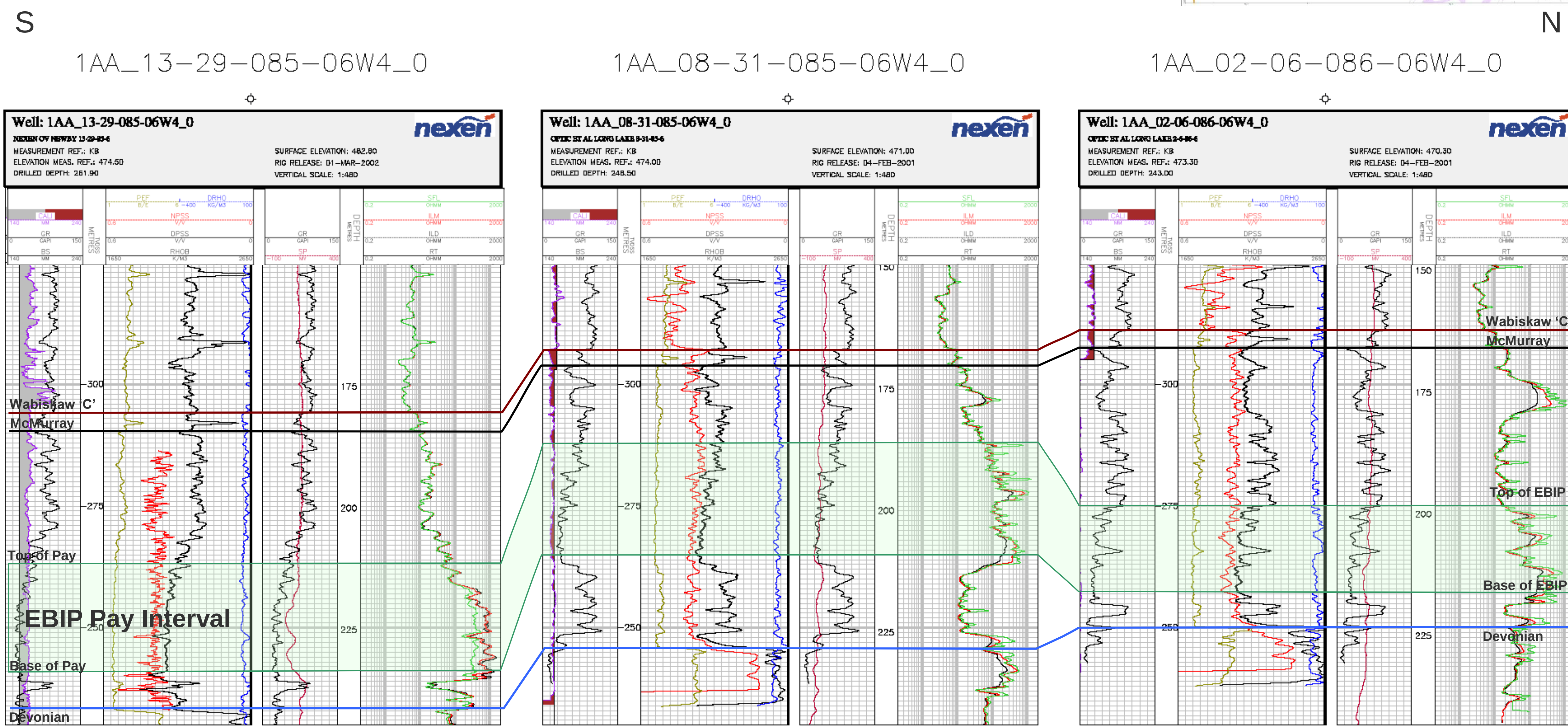
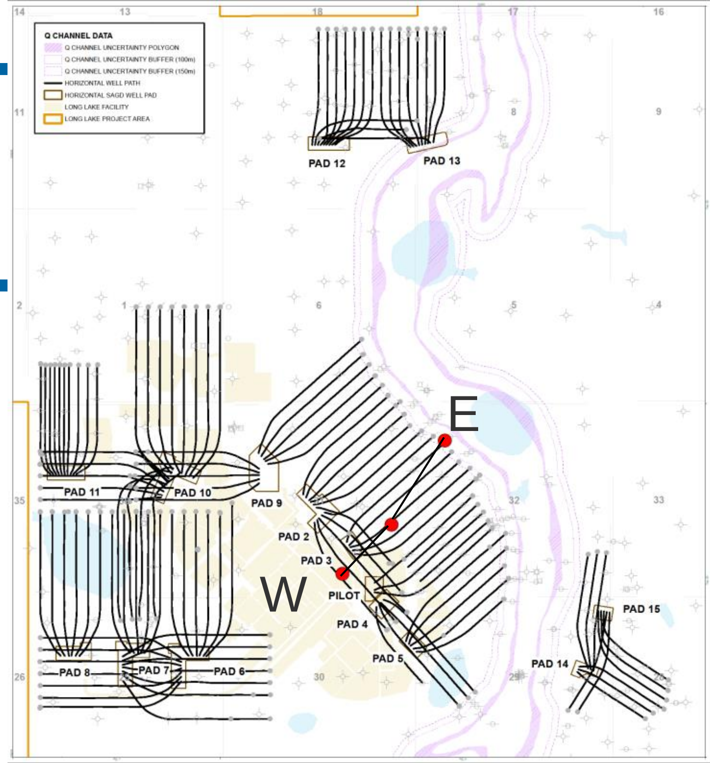


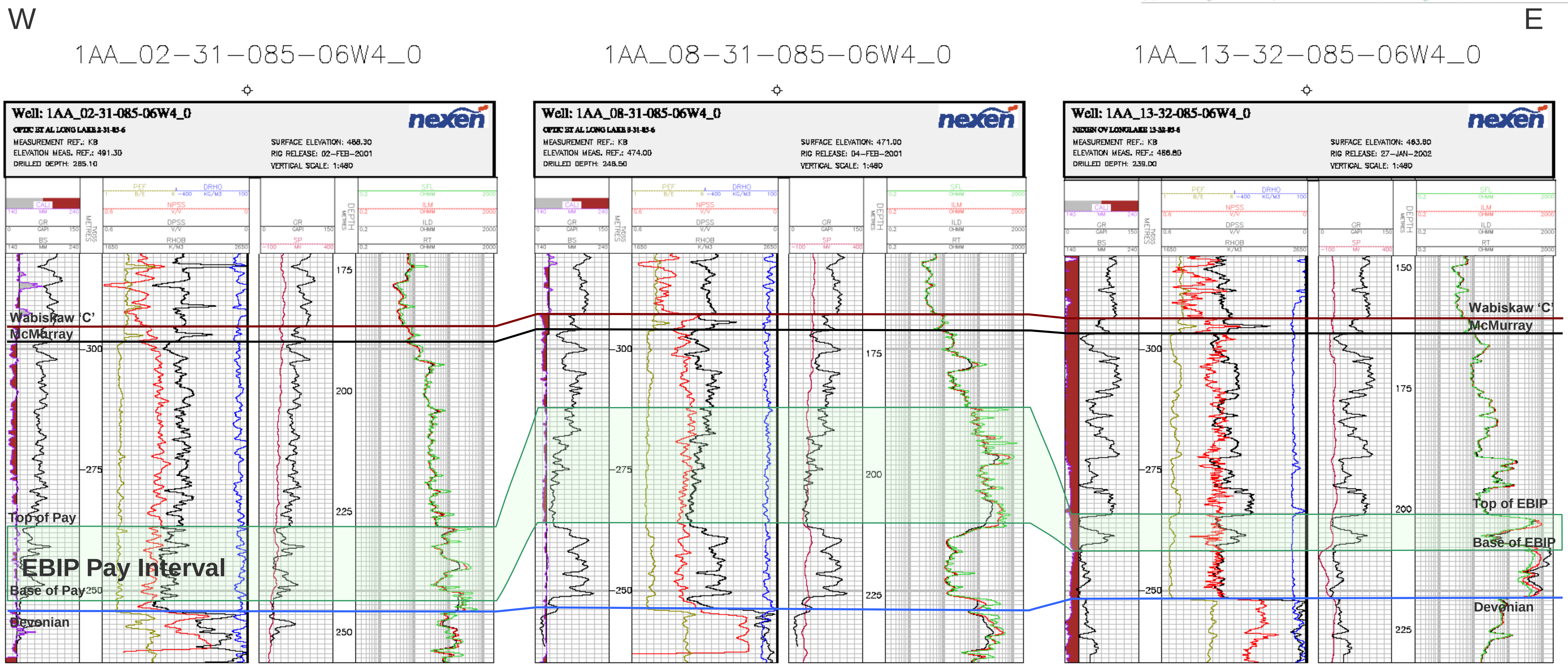
Representative structural cross-section of the East Side of Long Lake (South - North)



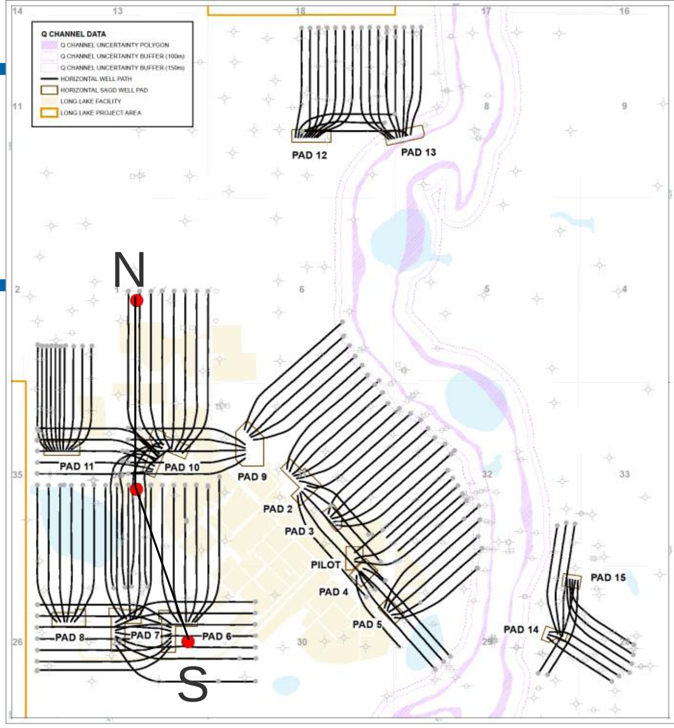


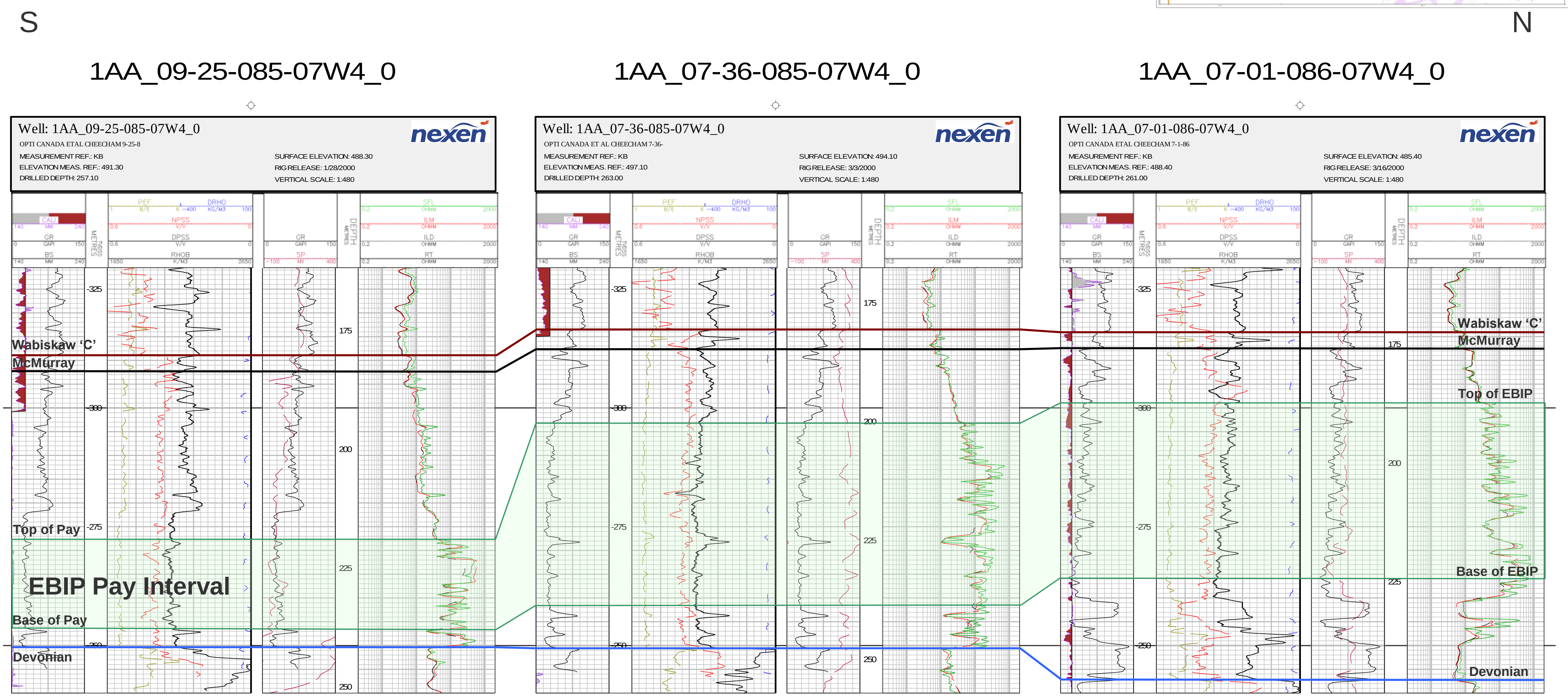
Representative structural cross-section of the East Side of Long Lake (West - East)



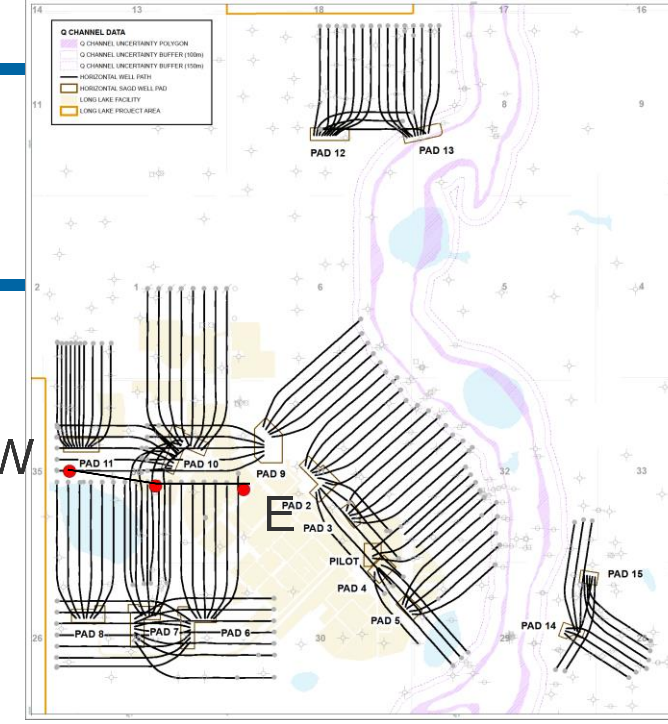


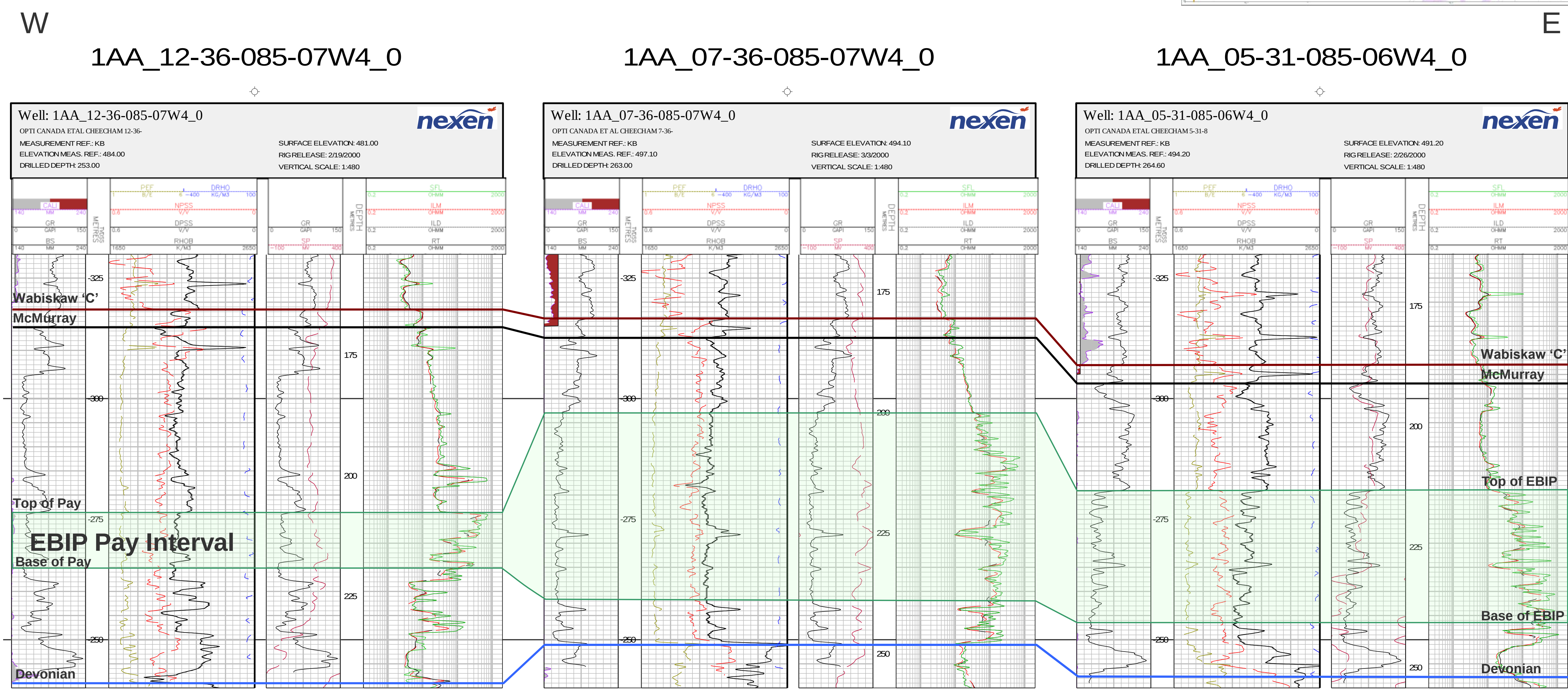
Representative structural cross-section of the West Side of Long Lake (South - North)



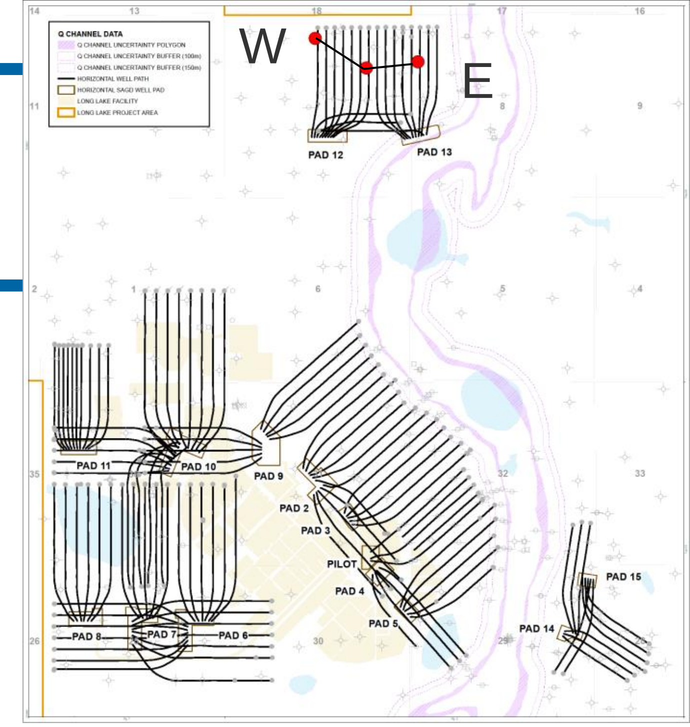


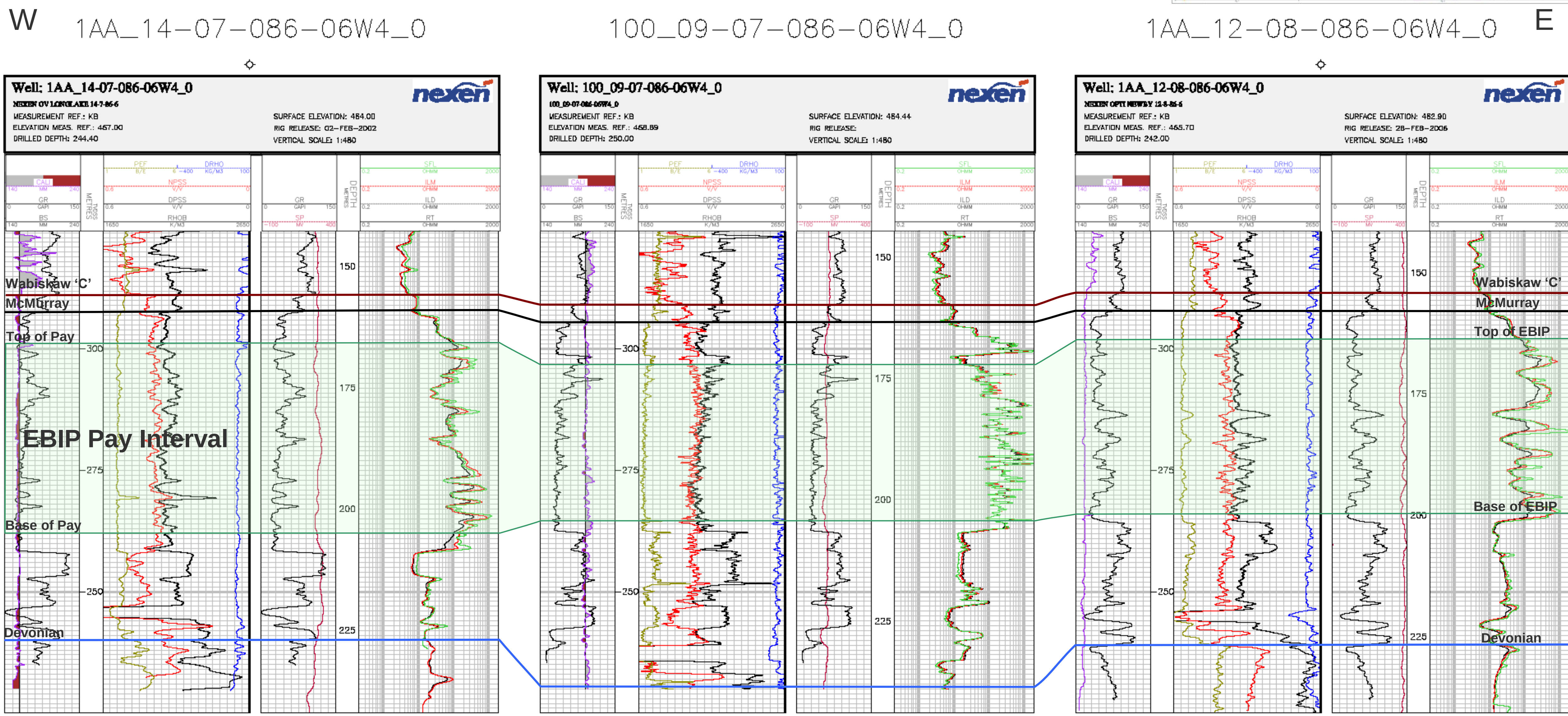
Representative structural cross-section of the West Side of Long Lake (West - East)



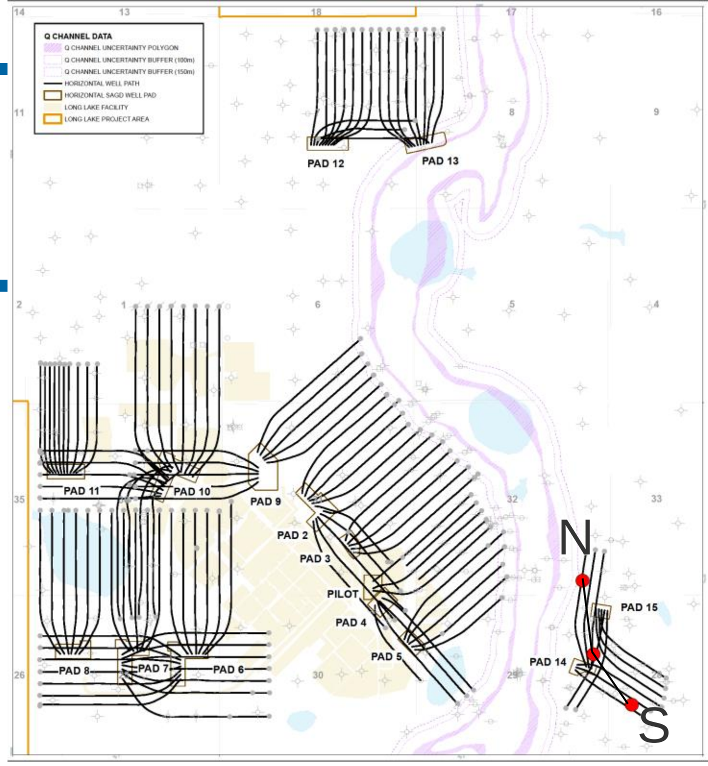


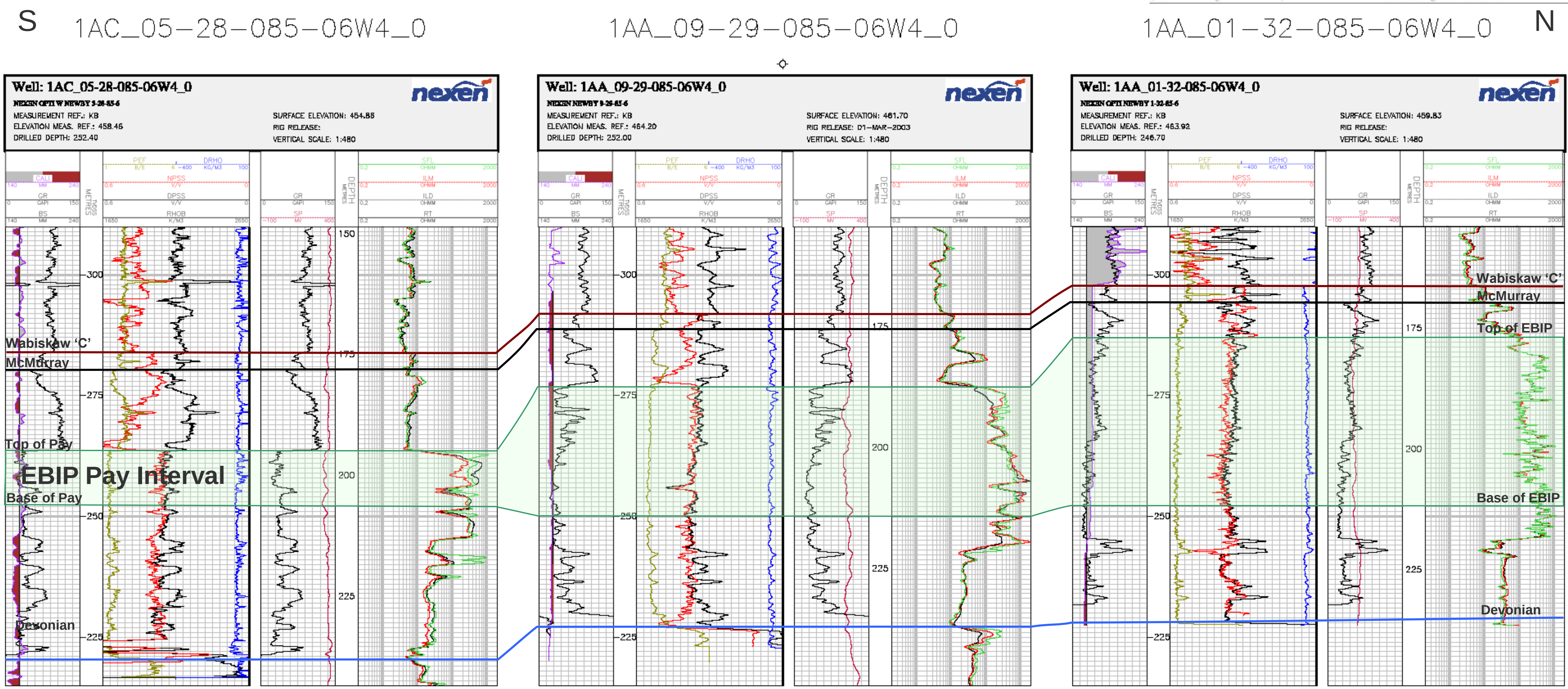
Representative structural cross-section of Pads 12 and 13



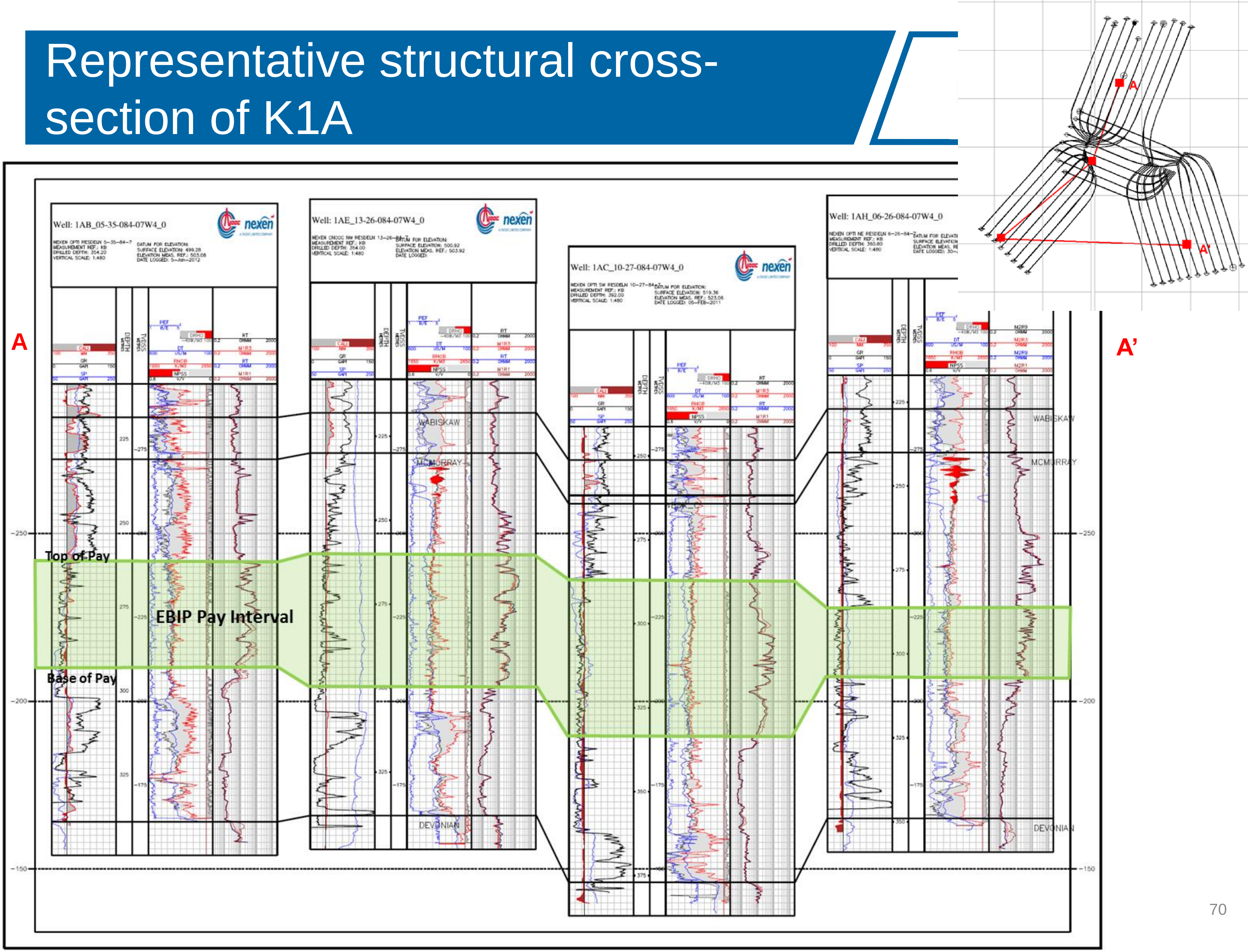


Representative structural cross-section of Pads 14 and 15





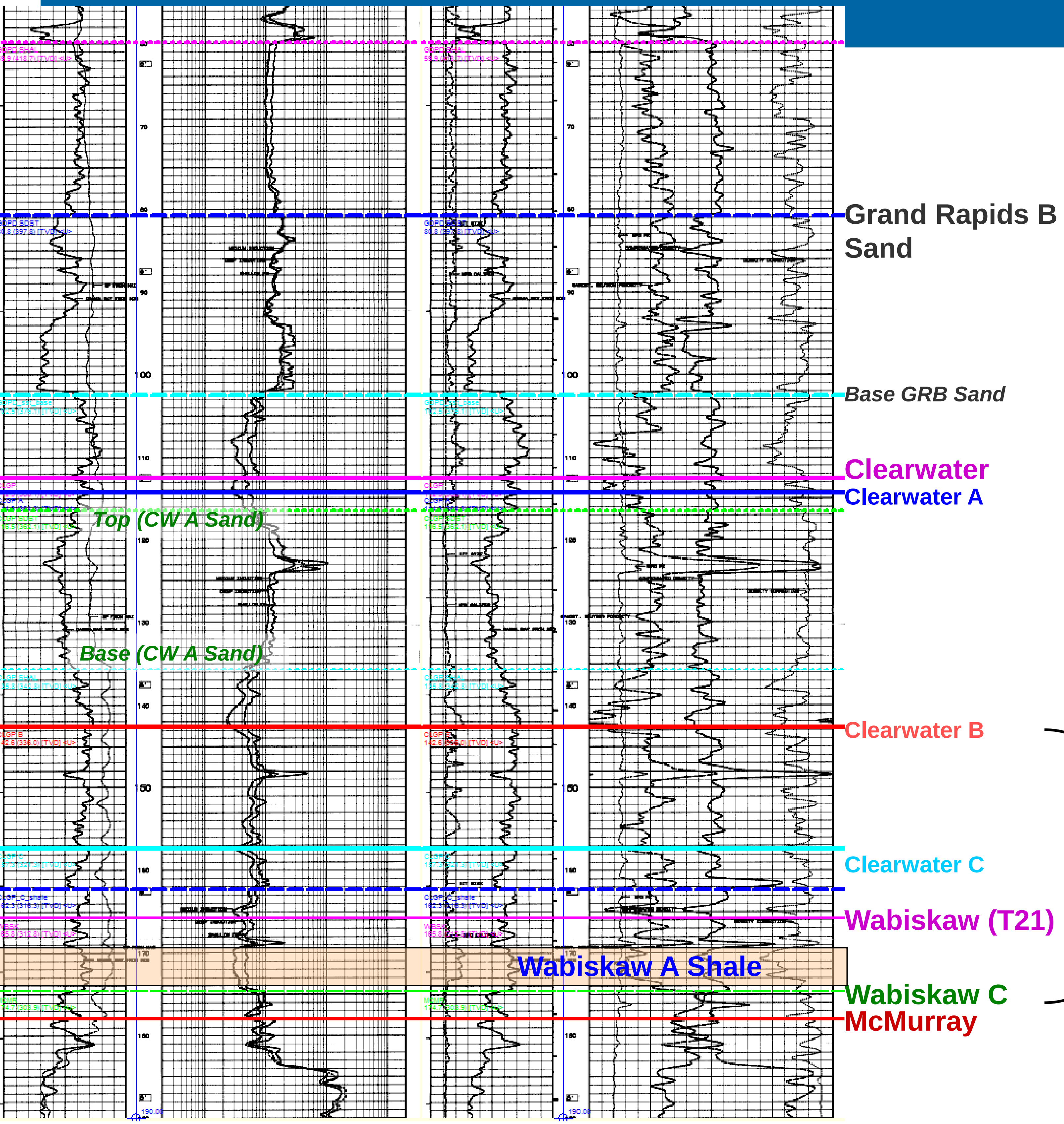
Representative structural cross-section of K1A



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

MINI-FRAC LOCATIONS
100090708606W400
1AB082908506W400
TRIAXIAL STRENGTH & DIRECT SHEAR TESTING
1AB082908506W400
XRD, PETROGRAPHY, & GRAIN SIZE ANALYSIS
1AA083208506W400
1AA102708607W400
1AA122808506W400
1AA142008506W400
100053308506W400
105062808506W400
102092908506W400
100102908506W400
103142908506W400
CAPROCK CORE
100053308506W400
100082908506W400
100110808606W400
100132808506W400
100140808606W400
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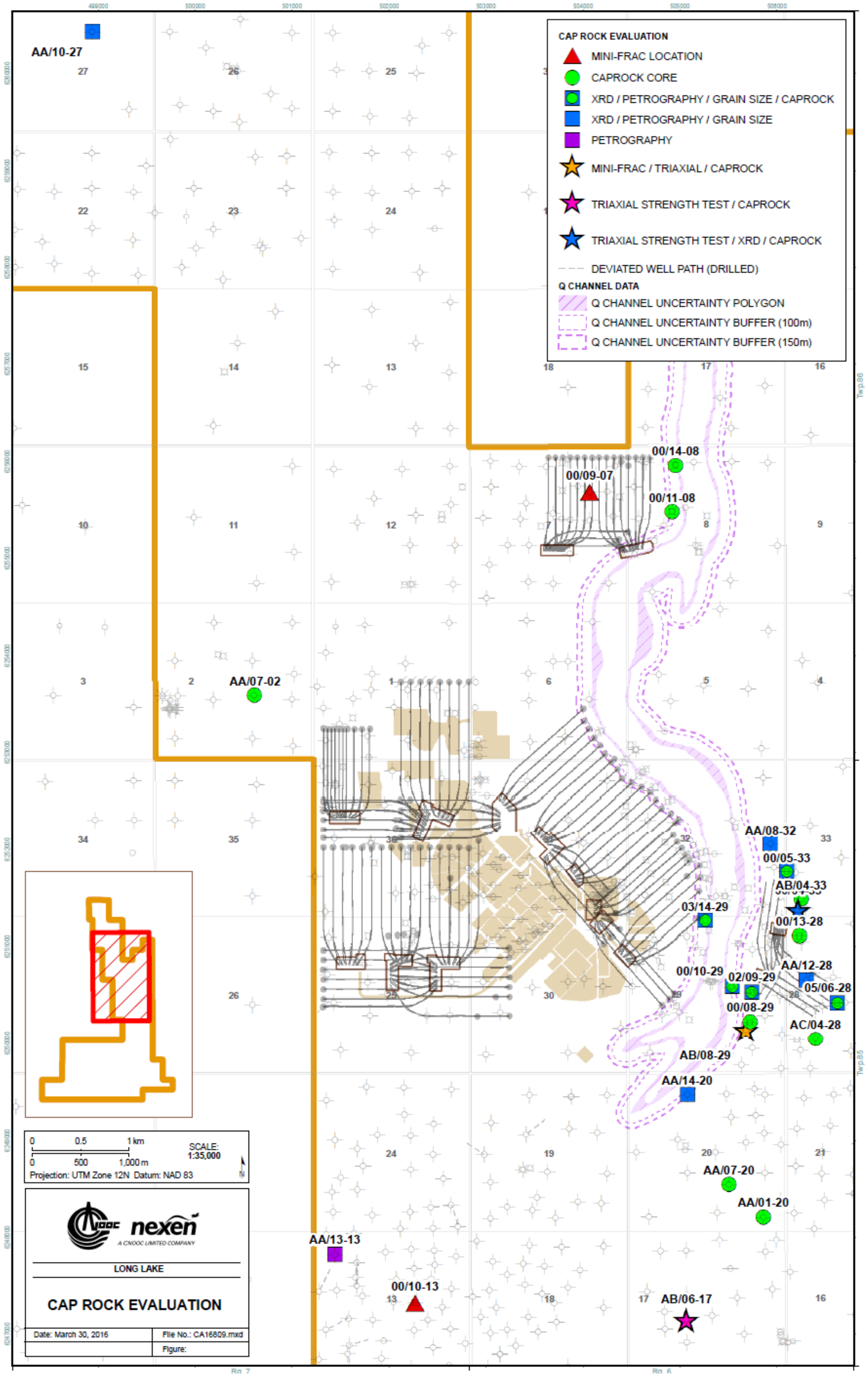
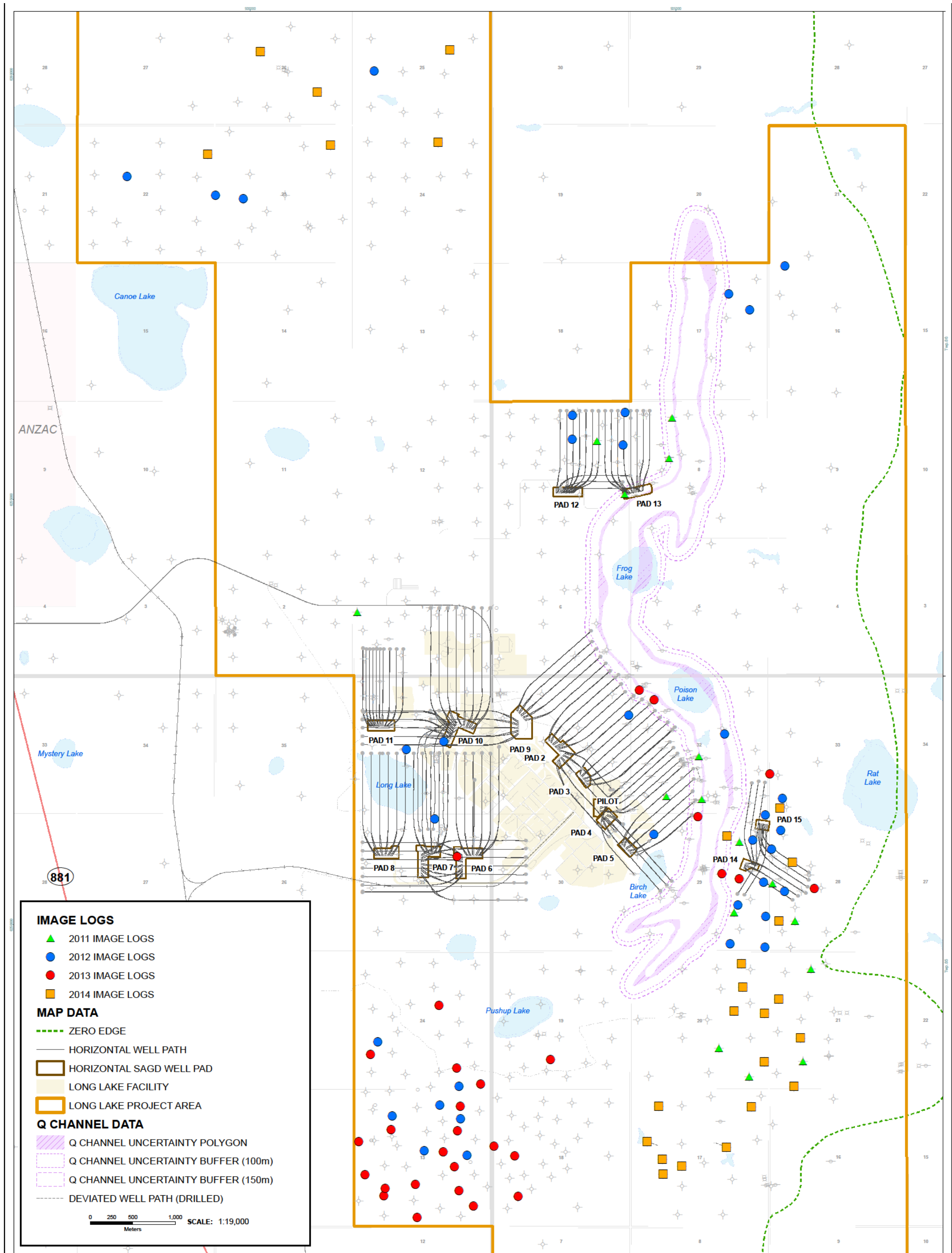


Long Lake
Cap Rock Evaluation Image Logs



Long Lake
Cap Rock Evaluation Image Logs

UWI	WELL_NAME	Licence No.	Year
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1AB052808506W400	Nexen OPTI Newby 5-28-85-6	0427602	2011
107033208506W400	Nexen OPTI OBS E Newby 3-32-85-6	0430940	2011
100140808606W400	Nexen OPTI VWP Newby 14-8-86-6	0429890	2011
1AB042108506W400	Nexen OPTI Newby 4-21-85-6	0427525	2011
117063208506W400	Nexen OPTI VWP E Newby 6-32-85-6	0428454	2011
1AA072008506W400	Nexen OPTI Newby 7-20-85-6	0427523	2011
1AB050108607W400	Nexen OPTI Newby 5-1-86-7	0426907	2011
1AB082908506W400	Nexen OPTI Newby 8-29-85-6	0427605	2011
1AB142108506W400	Nexen OPTI Newby 14-21-85-6	0427599	2011
100090708606W400	Nexen OPTI OBS Newby 9-7-86-6	0429878	2011
100110808606W400	Nexen OPTI VWP Newby 11-8-86-6	0429631	2011
1AB162908506W400	Nexen OPTI Newby 16-29-85-6	0427928	2011
1AA012008506W400	Nexen OPTI Newby 1-20-85-6	0427522	2011
1AC042808506W400	Nexen OPTI NE Newby 4-28-85-6	0427601	2011
106033208506W400	Nexen OPTI OBS W Newby 3-32-85-6	0429976	2011
100082908506W400	Nexen CNOOC OBS SW Newby 8-29-85-6	0443963	2012
100100708606W400	Nexen CNOOC OBS Newby 10-7-86-6	0443868	2012
109103608507W400	Nexen OPTI OBS Newby 10-36-85-7	0442823	2012
103093108506W400	Nexen CNOOC OBS E Newby 9-31-85-6	0444540	2012
1AD162908506W400	Nexen OPTI S Newby 16-29-85-6	0439561	2012
1AB101308507W400	Nexen OPTI SW Newby 10-13-85-7	0440277	2012
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111150708606W400	Nexen CNOOC OBS Newby 15-7-86-6	0443869	2012
1AA052508607W400	Nexen OPTI Newby 5-25-86-7	0439592	2012
1AA091708606W400	Nexen OPTI Newby 9-17-86-6	0439575	2012

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122063608507W400	Nexen OPTI OBS W Newby 6-36-85-7	0429990	2012
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1AB012908506W400	Nexen OPTI SE Newby 1-29-85-6	0439556	2012
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1AB091308507W400	Nexen OPTI SW Newby 9-13-85-7	0440276	2012
1AA151308507W400	Nexen OPTI Newby 15-13-85-7	0440282	2012

Long Lake
Cap Rock Evaluation Image Logs

UWI	Well Name	Well License	Year
1AB121808506W400	Nexen CNOOC S Newby 12-18-85-6-4	452419	2013
1AE121808506W400	Nexen CNOOC W Newby 12-18-85-6-4	452786	2013
1AB071308507W400	Nexen CNOOC Newby 7-13-85-7-4	452444	2013
1AC081308507W400	Nexen CNOOC SW Newby 8-13-85-7-4	452446	2013
1AC091308507W400	Nexen CNOOC NW Newby 9-13-85-7-4	452447	2013
1AC161308507W400	Nexen CNOOC W Newby 16-13-85-7-4	452406	2013
1AB052408507W400	Nexen CNOOC SW Newby 5-24-85-7-4	452408	2013
1AA102408507W400	Nexen CNOOC Newby 10-24-85-7-4	452410	2013
1AD041308507W400	Nexen CNOOC DD E Newby 4-13-85-7-4 (BH)	452682	2013
1AB051308507W400	Nexen CNOOC DD NW Newby 5-13-85-7-4 (BH)	452683	2013
1AC051308507W400	Nexen CNOOC DD SE Newby 5-13-85-7-4 (BH)	452872	2013
1AB111308507W400	Nexen CNOOC DD NW Newby 11-13-85-7-4 (BH)	452685	2013
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100101308507W400	Nexen CNOOC OBS Newby 10-13-85-7	453792	2013
102092508507W400	Nexen CNOOC OBS Newby 9-25-85-7	451050	2013
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105062808506W400	Nexen CNOOC OBS Newby 6-28-85-6	453531	2013
100102908506W400	Nexen CNOOC VWP S Newby 10-29-85-6	453585	2013
100011308507W400	Nexen CNOOC S Newby 1-13-85-7	0453603	2013
103061308507W400	Nexen CNOOC OBS SE Newby 6-13-85-7	0453571	2013
1AB031308507W400	Nexen CNOOC DD SE Newby 3-13-85-7	0452681	2013
1AB041808506W400	Nexen CNOOC NE Newby 4-18-85-6	0452427	2013
1AB121308507W400	Nexen CNOOC DD W Newby 12-13-85-7	0452684	2013
110133208506W400	Nexen CNOOC VWP SE Newby 13-32-85-6	0453560	2013
109133208506W400	Nexen CNOOC VWP W Newby 13-32-85-6	0453540	2013
103142908506W400	Nexen CNOOC VWP Newby 14-29-85-6	0453532	2013
102092908506W400	Nexen CNOOC OBS SW Newby 9-29-85-6	0453581	2013
1AB031908506W400	Nexen CNOOC NE Newby 3-19-85-6	0452424	2013

Long Lake
Cap Rock Evaluation Image Logs

UWI	Well Name	Well Licence	Year
100042808506W400	NEU CNOOC VWP NEWBY 4-28-85-6	461719	2014
100043308506W400	NEU CNOOC VWP S NEWBY 4-33-85-6	461840	2014
100152908506W400	NEU CNOOC VWP NEWBY 15-29-85-6	462042	2014
103122808506W400	NEU CNOOC VWP NEWBY 12-28-85-6	461749	2014
1AA022608607W400	NEU CNOOC NE NEWBY 2-26-86-7	462081	2014
1AA102508607W400	NEU CNOOC NEWBY 10-25-86-7	461064	2014
1AA112608607W400	NEXEN CNOOC NEWBY 11-26-86-7	462083	2014
1AA152408607W400	NEU CNOOC NEWBY 15-24-86-7	461063	2014
1AA162208607W400	NEU CNOOC NEWBY 16-22-86-7	462076	2014
1AA162308607W400	NEU CNOOC NEWBY 16-23-86-7	462078	2014
1AB012008506W400	NEU CNOOC NEWBY 1-20-85-6	461037	2014
1AB051708506W400	NEU CNOOC NEWBY 5-17-85-6	461031	2014
1AB052108506W400	NEXEN CNOOC NEWBY 5-21-85-6	461083	2014
1AB061708506W400	NEU CNOOC NEWBY 6-17-85-6	461614	2014
1AB092008506W400	NEU CNOOC NW NEWBY 9-20-85-6	461079	2014
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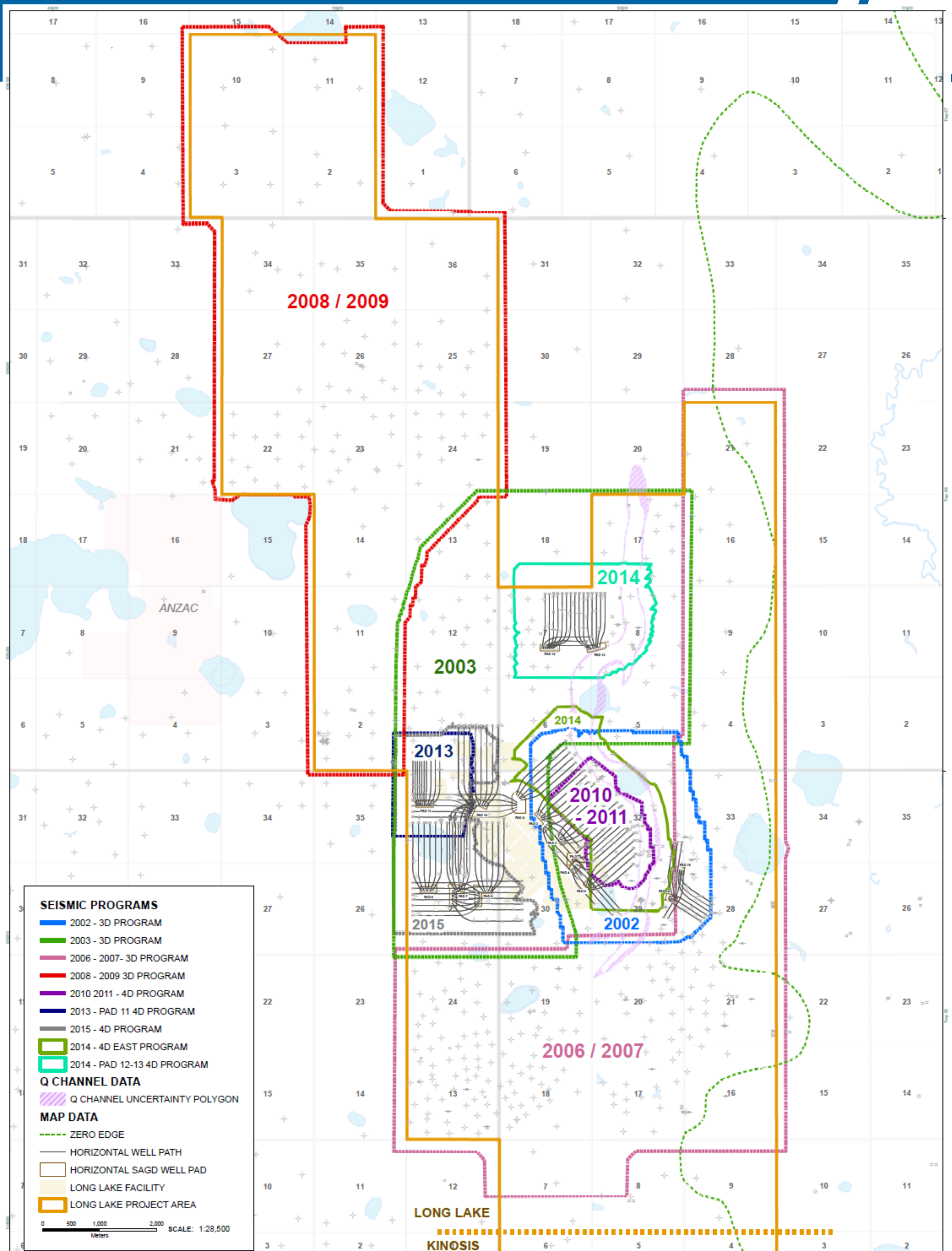
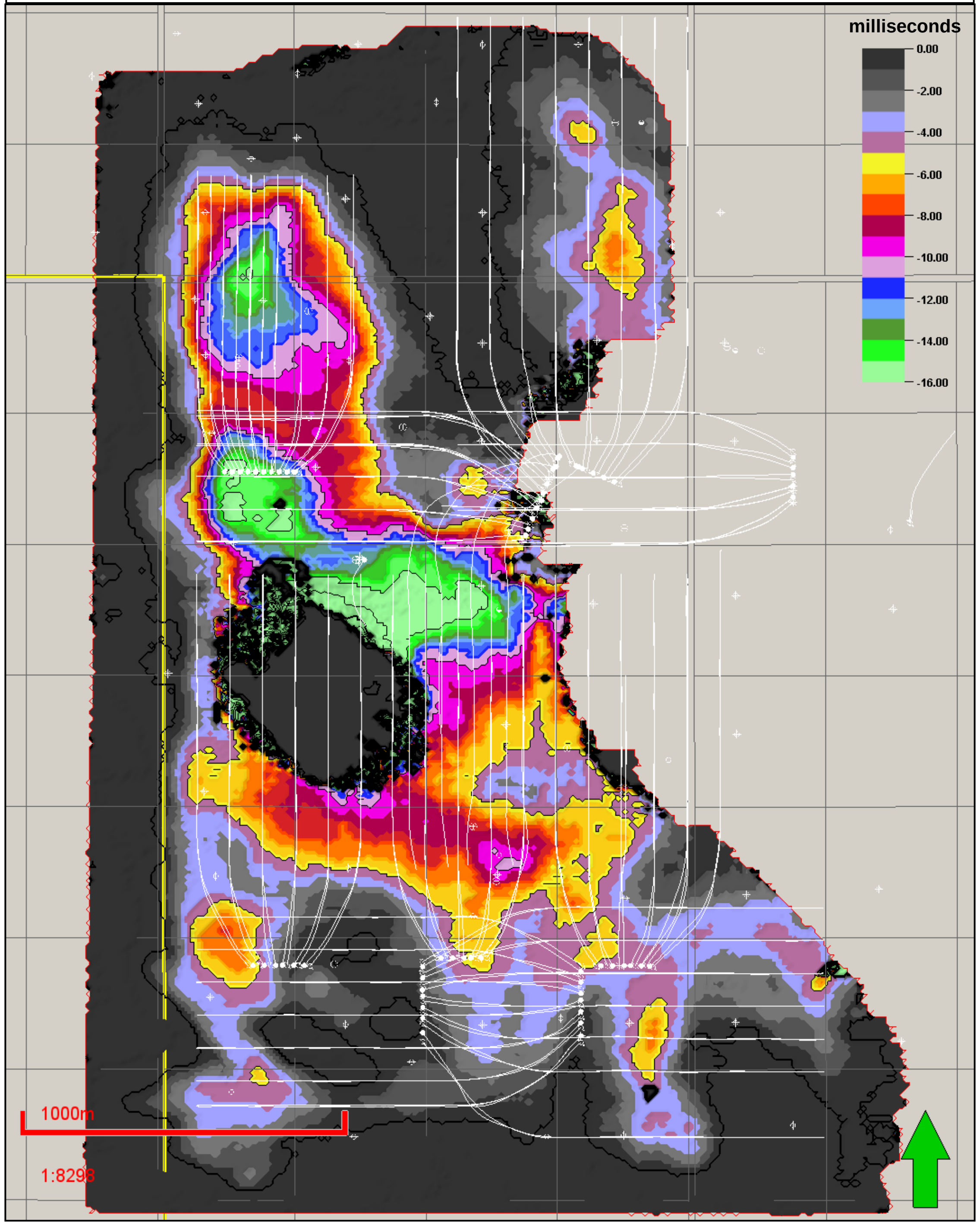
1AB122108506W400	NEU CNOOC NEWBY 12-21-85-6	461085	2014
1AB131708506W400	NEU CNOOC NEWBY 13-17-85-6	461034	2014
1AB161708506W400	NEU CNOOC NEWBY 16-17-85-6	461036	2014
1AB162008506W400	NEU CNOOC NEWBY 16-20-85-6	461081	2014
1AC042108506W400	NEU CNOOC NEWBY 4-21-85-6	461082	2014
1AC051708506W400	NEU CNOOC S NEWBY 5-17-85-6	461032	2014
1AC092008506W400	NEU CNOOC SW NEWBY 9-20-85-6	461080	2014
1AD092008506W400	NEU CNOOC SE Newby 9-20-85-6	461709	2014

Long Lake Seismic



Long Lake
2015 4D Seismic Monitor Survey

2015 4D Time-Delay Map with Lease Boundary



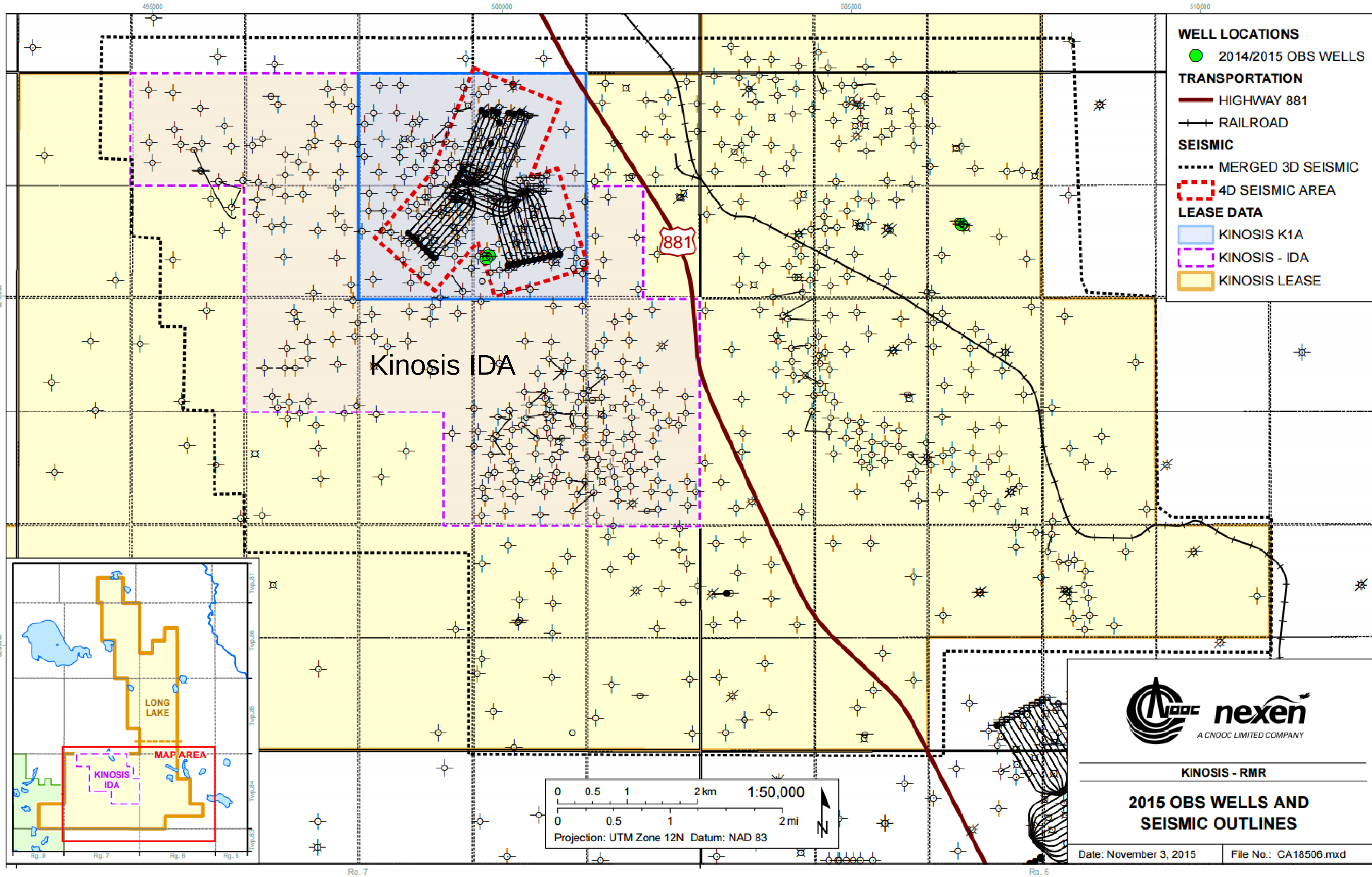
Time delay anomalies are the difference between the Devonian surface on the 2003 baseline seismic survey and the 2015 monitor seismic surveys.

These time delays generally represent steam chamber growth but also any changes in gas occurrence.

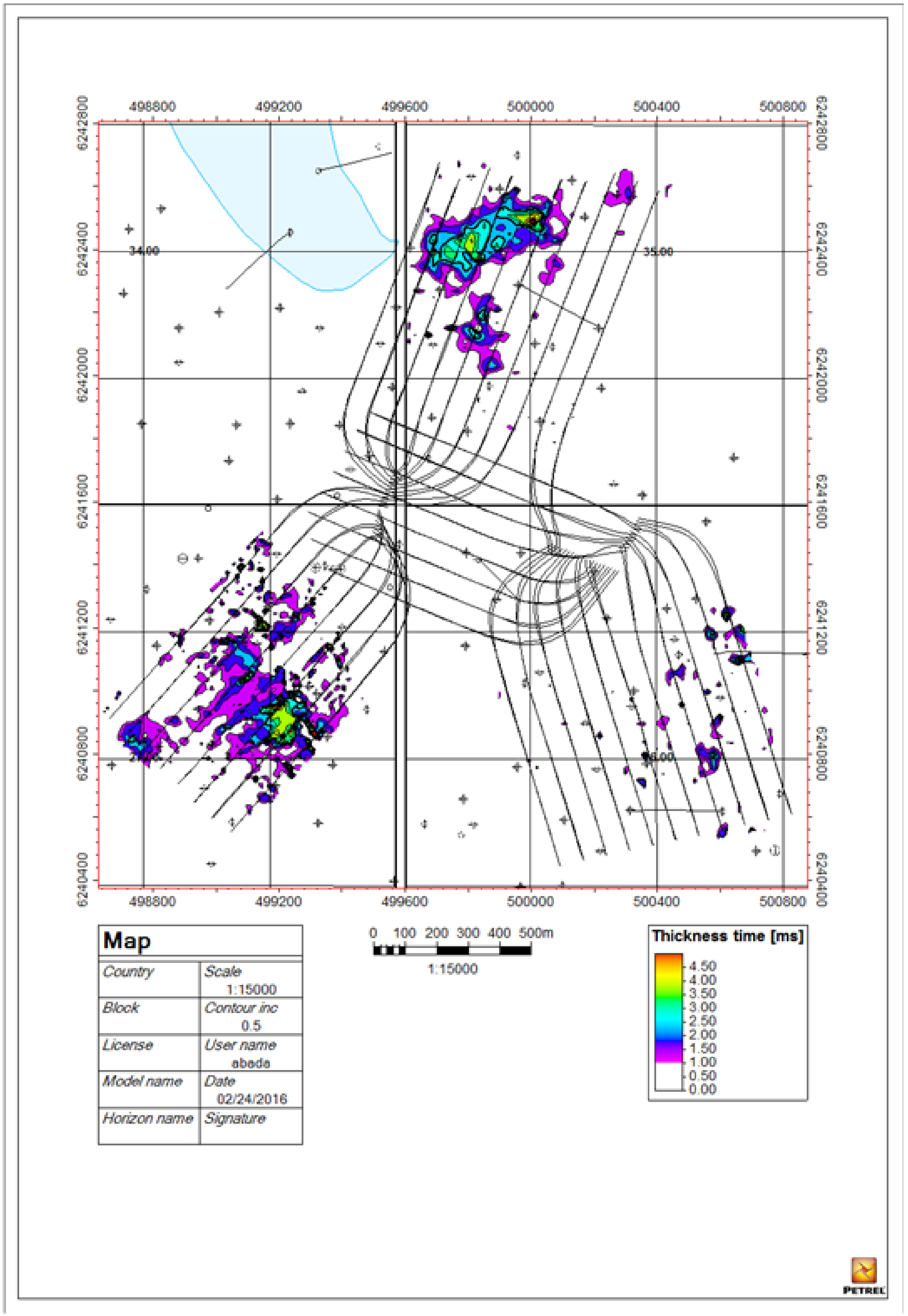
This survey covered Pads 6W, 7E, 7N, 8, 10N, 10W, 11 and portions of Pads 6N and 9W.

No seismic data was collected over the area covered by the lake (in grey) and surface facilities.

Kinosis – 2015 Activity and 3D Seismic Outline



K1A 4D



Time delay anomalies are the difference between the Devonian surface on the 2006 baseline seismic survey and the 2015 monitor seismic surveys over drainage areas A to the north, C to the west and D to the east.

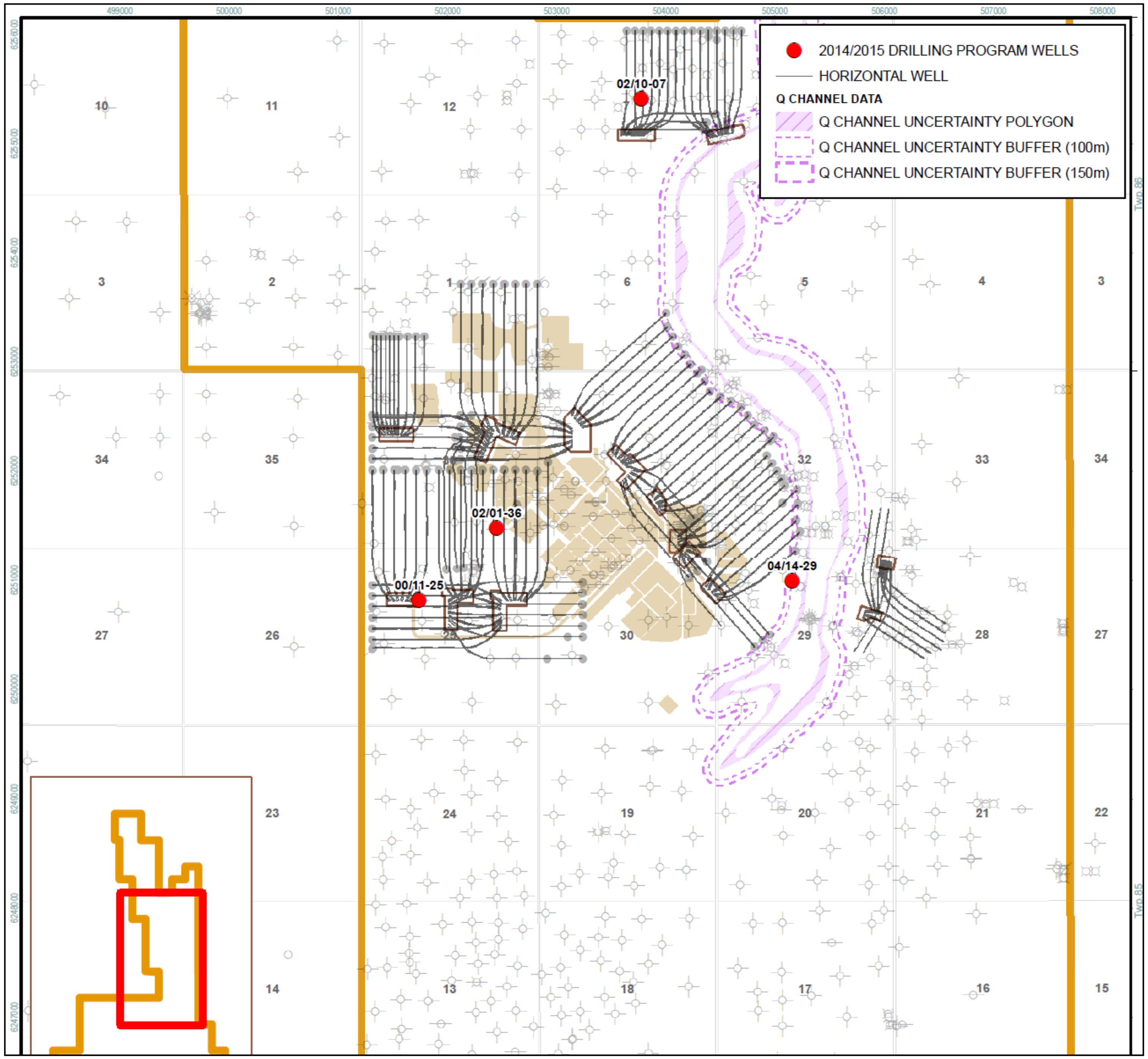
These time delays generally represent steam chamber growth but also any changes in gas occurrence.

These are the first monitor seismic surveys over the K1A pads.

Long Lake
2015 Winter Program

2015 Program

- **3** RST Wells
- **1** Q-Channel Monitoring Well
- Total =**4**



Long Lake
2015 Program

UWI	Well Name	Well License #	Core Collected
100112508507W400	NEU VWP NEWBY 11-25-85-7	0473266	No
102013608507W400	NEU VWP NEWBY 1-36-85-7	0471590	Yes
102100708606W400	NEU VWP S NEWBY 10-7-86-6	0473264	Yes
104142908506W400	NEU VWP S NEWBY 14-29-85-6	0472823	No

Kinosis 2015 Program

UWI	Well Name	Well License #	Core Collected
102052608407W400	NEU VWP RESDELN 5-26-84-7	0471371	No
103112808406W400	NEU VWP NEWBY 11-28-84-6	0472841	No
1WS052608407W400	NEU WSQ RESDELN 5-26-84-7W4M	NL-00213	No

Drilling and Completions, Artificial Lift and Instrumentation Subsection 3.1.1 (3, 4, 5)

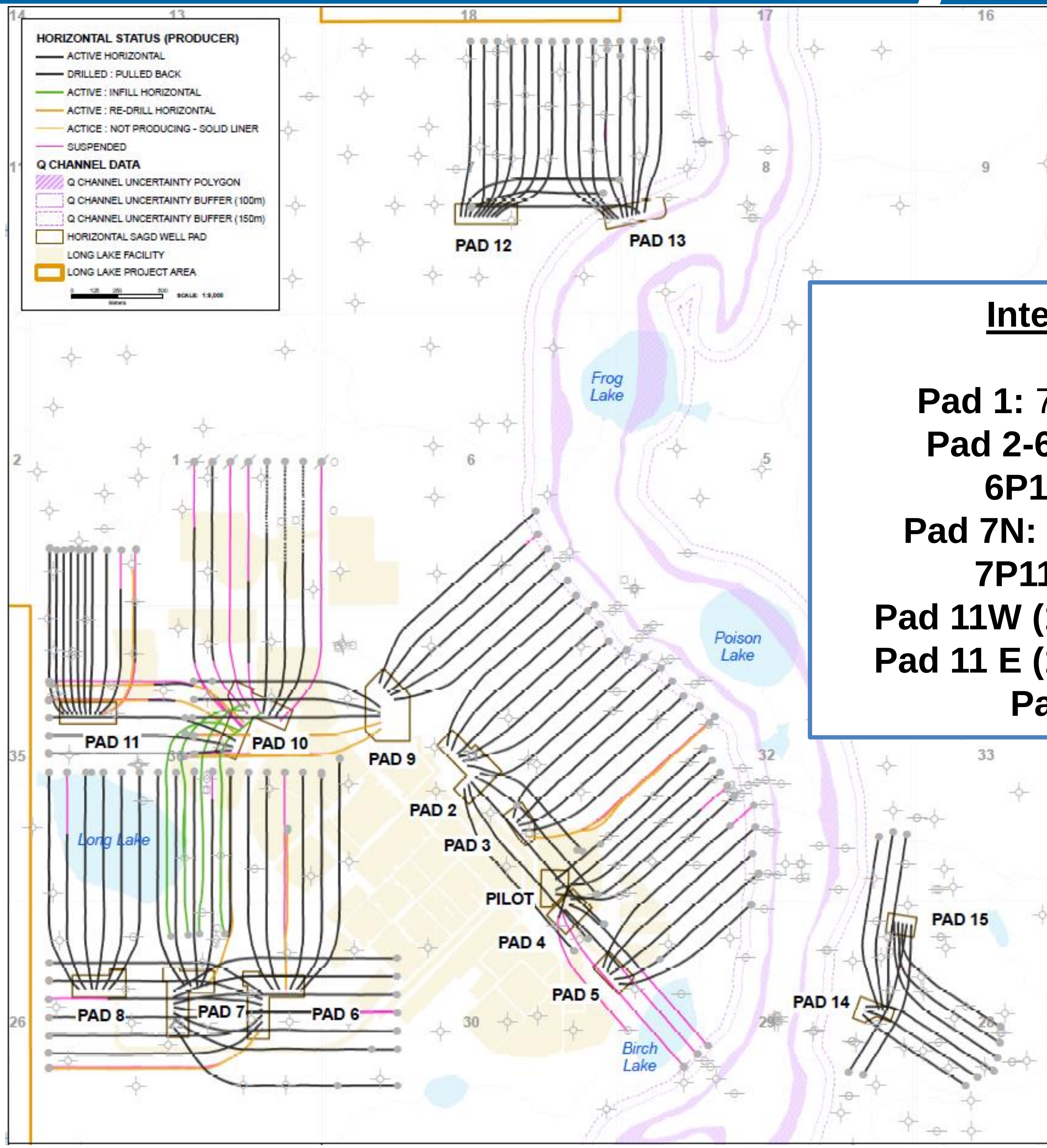
Long Lake

nexen

A CNOOC LIMITED COMPANY

A New Energy

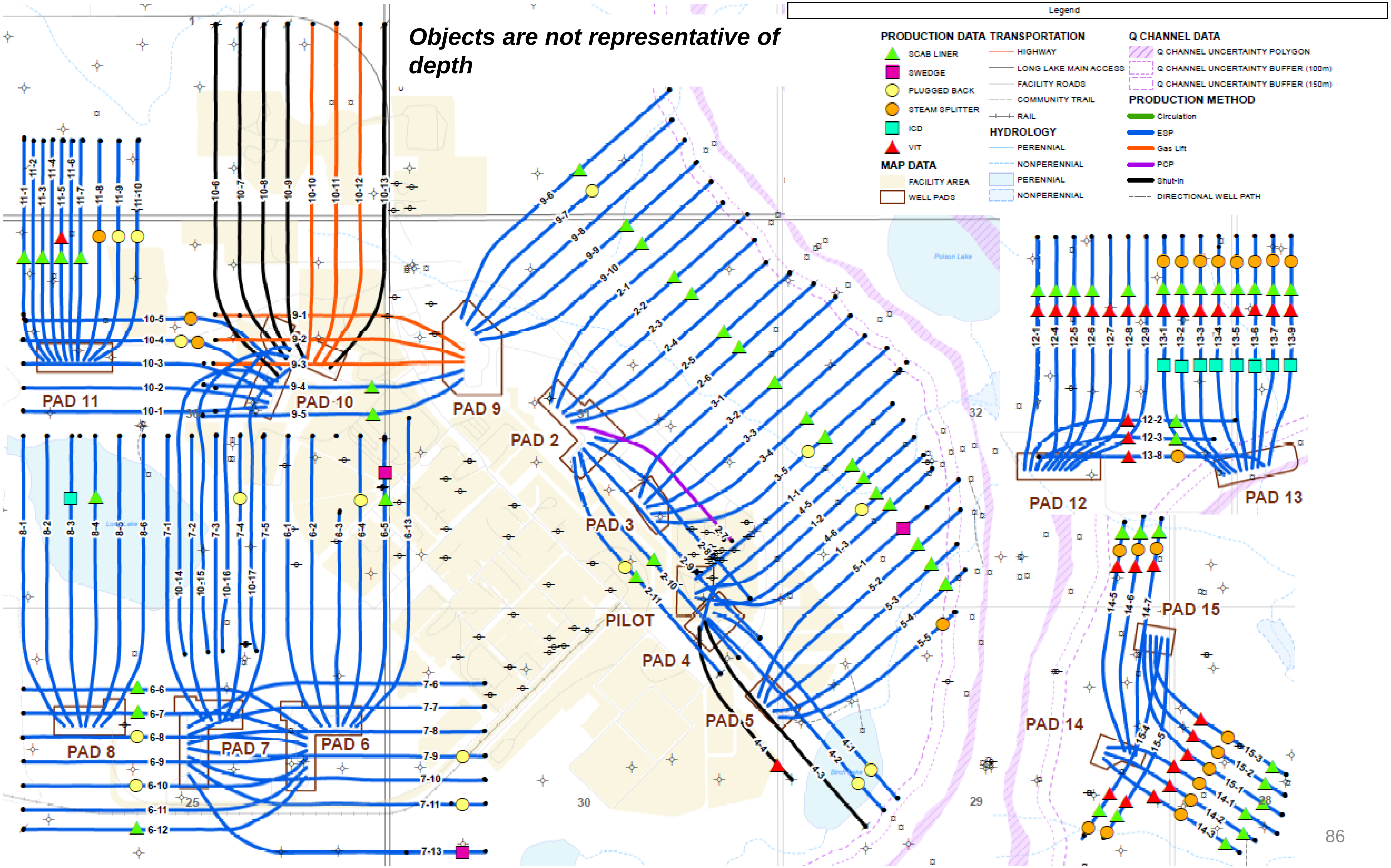
Long Lake
Horizontal Well Locations



<u>Inter-well Spacing</u>

Pad 1: 75m (with infill pairs)
Pad 2-6, Pads 8-10: 100m
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

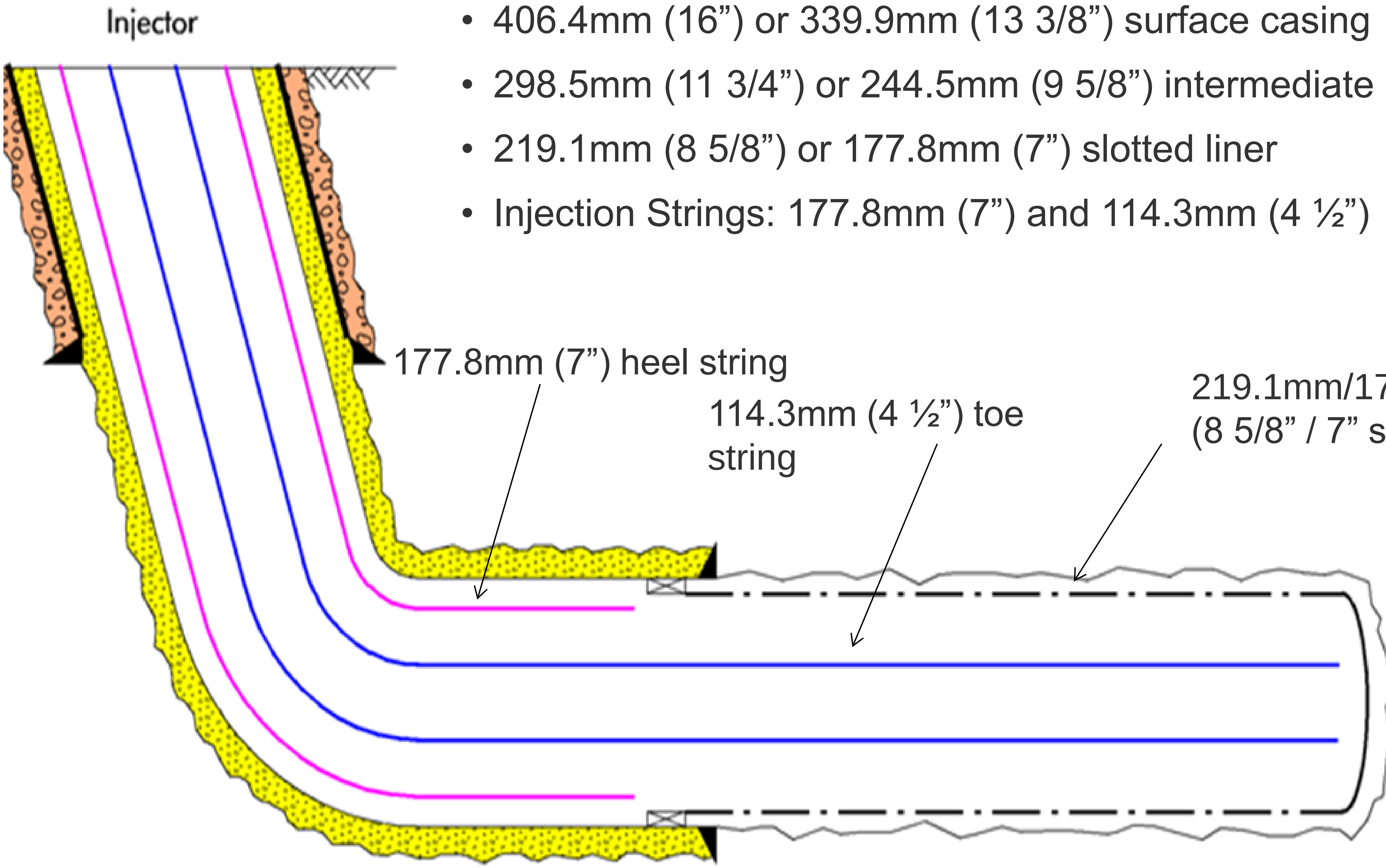
Long Lake Well Pair Completions Map through 2015



Typical Injector Completion

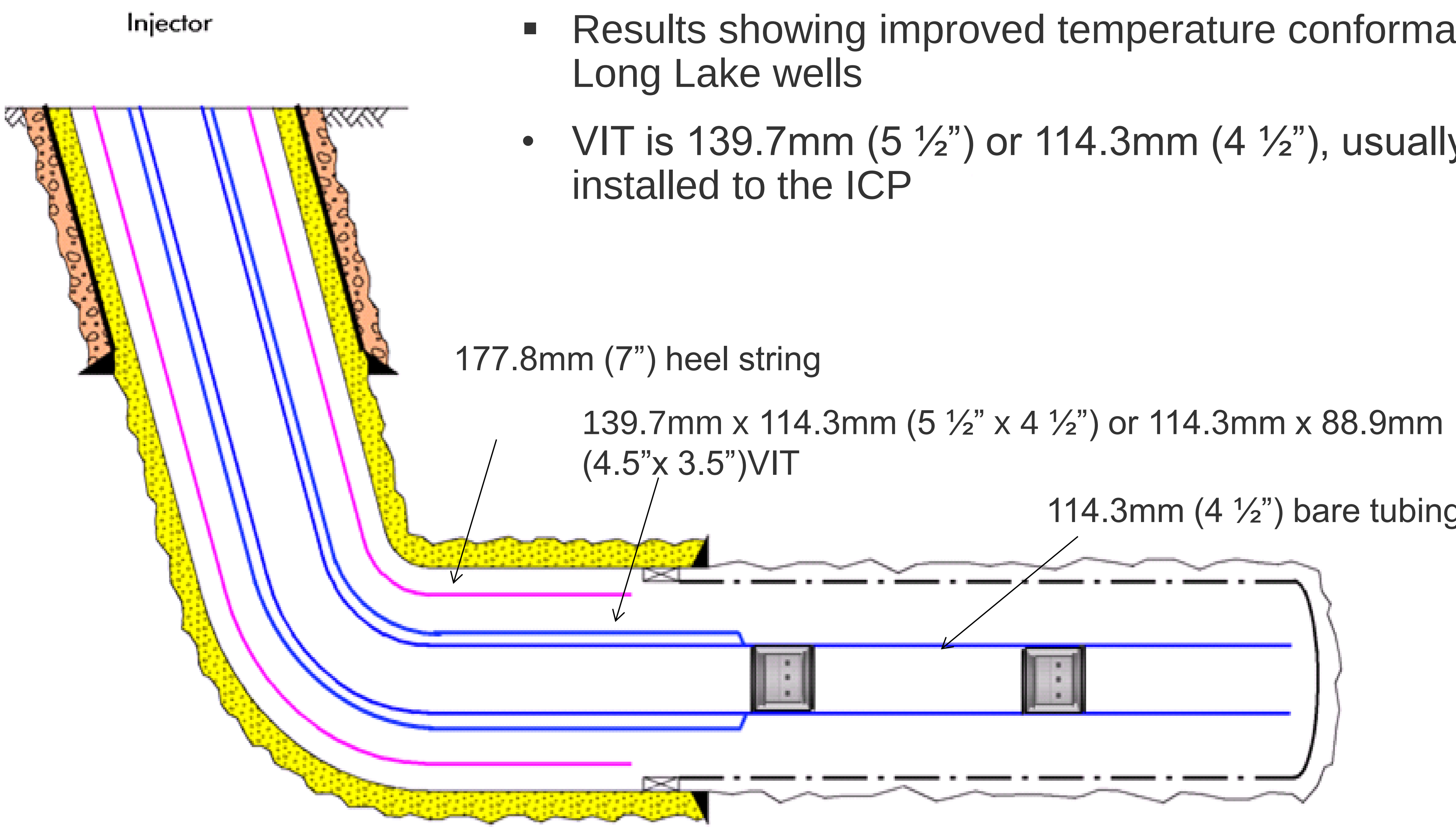
Concentric

- 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”)

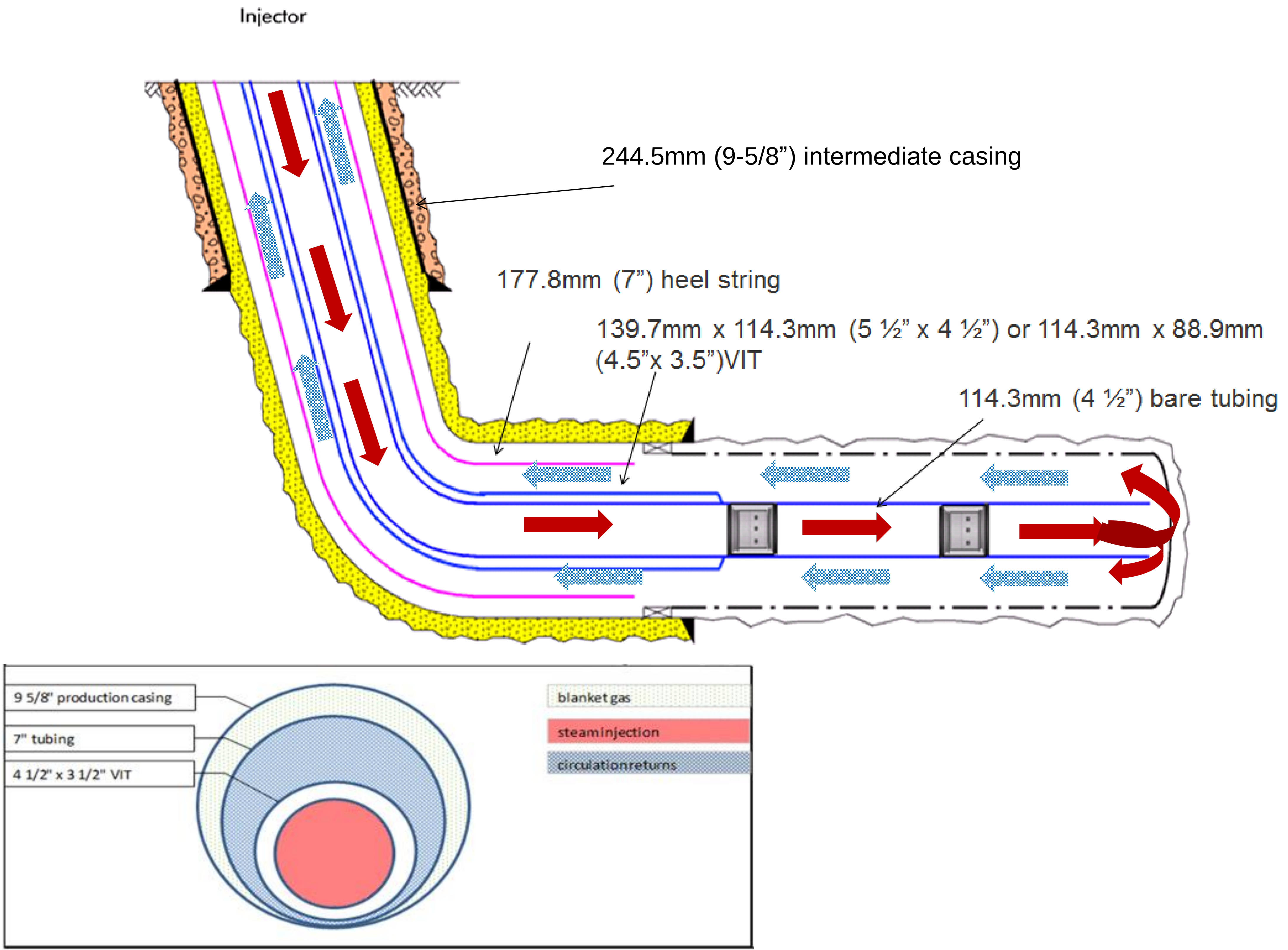


VIT Injector Completion

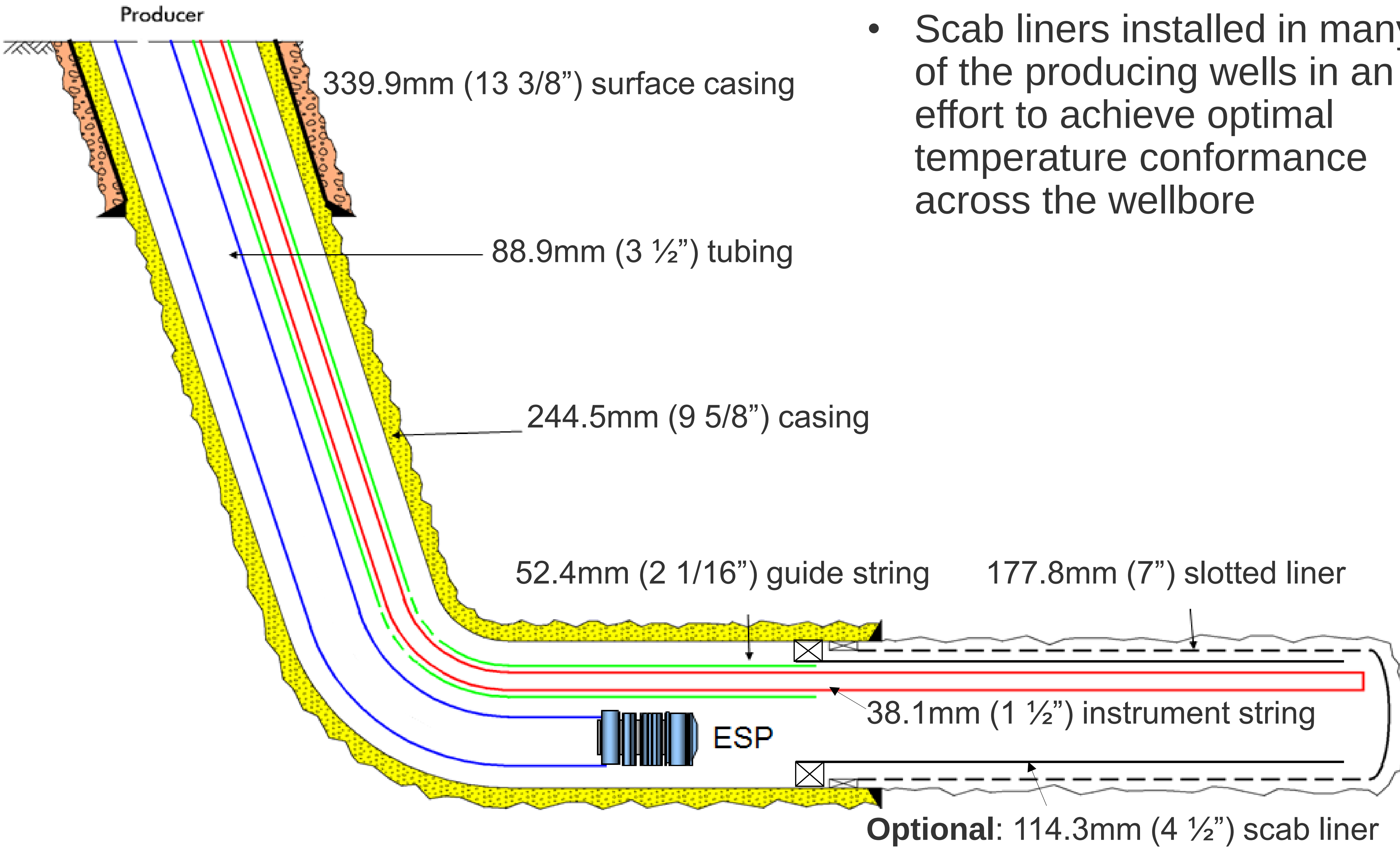
- All Kinosis wells, and a few Long Lake wells are completed with steam splitters in the long injection string
  - Results showing improved temperature conformance in Long Lake wells
- VIT is 139.7mm (5 ½”) or 114.3mm (4 ½”), usually installed to the ICP



Typical Injector Circulation



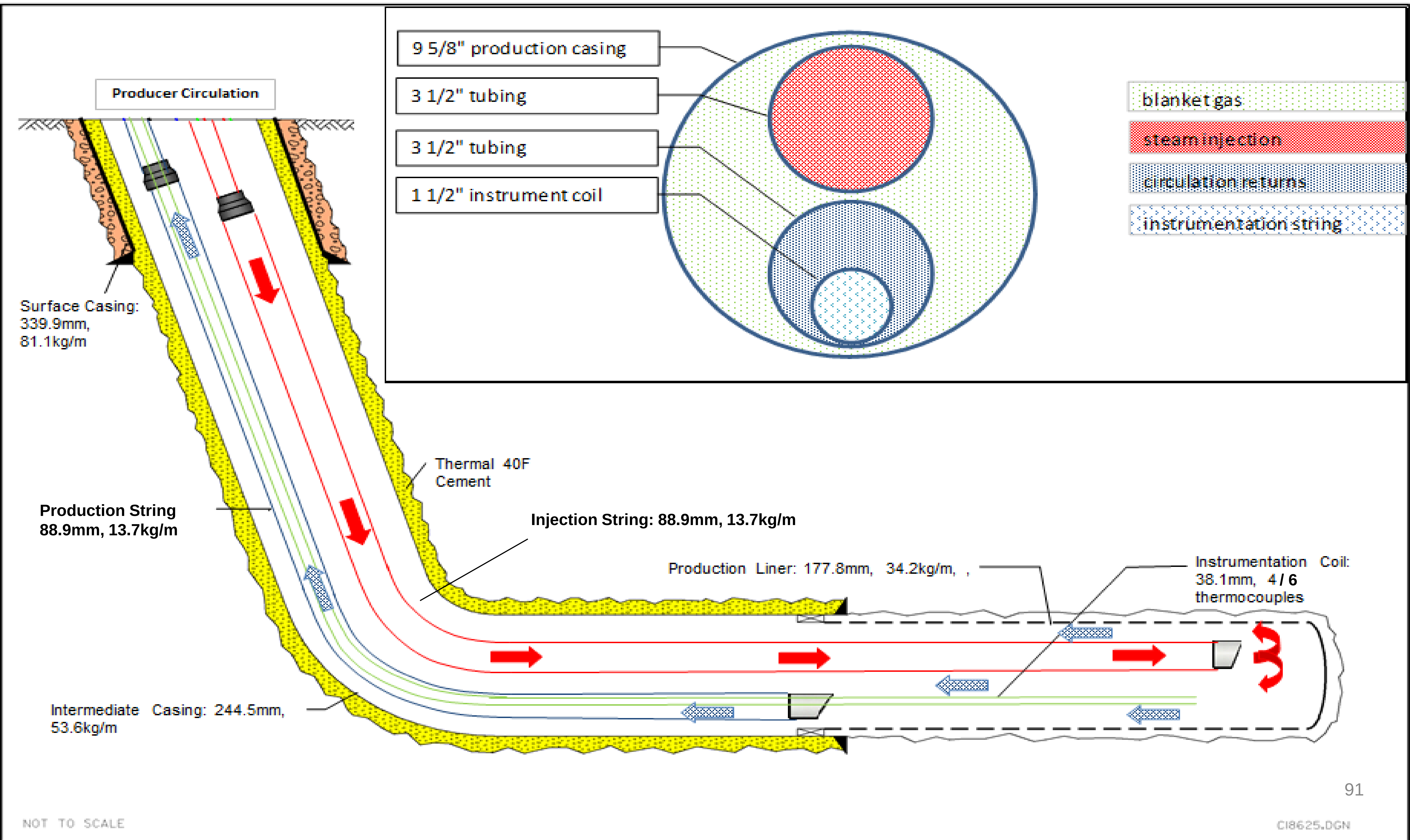
Typical Producer Completions – ESP



- Scab liners installed in many of the producing wells in an effort to achieve optimal temperature conformance across the wellbore

Typical Producer Circulation

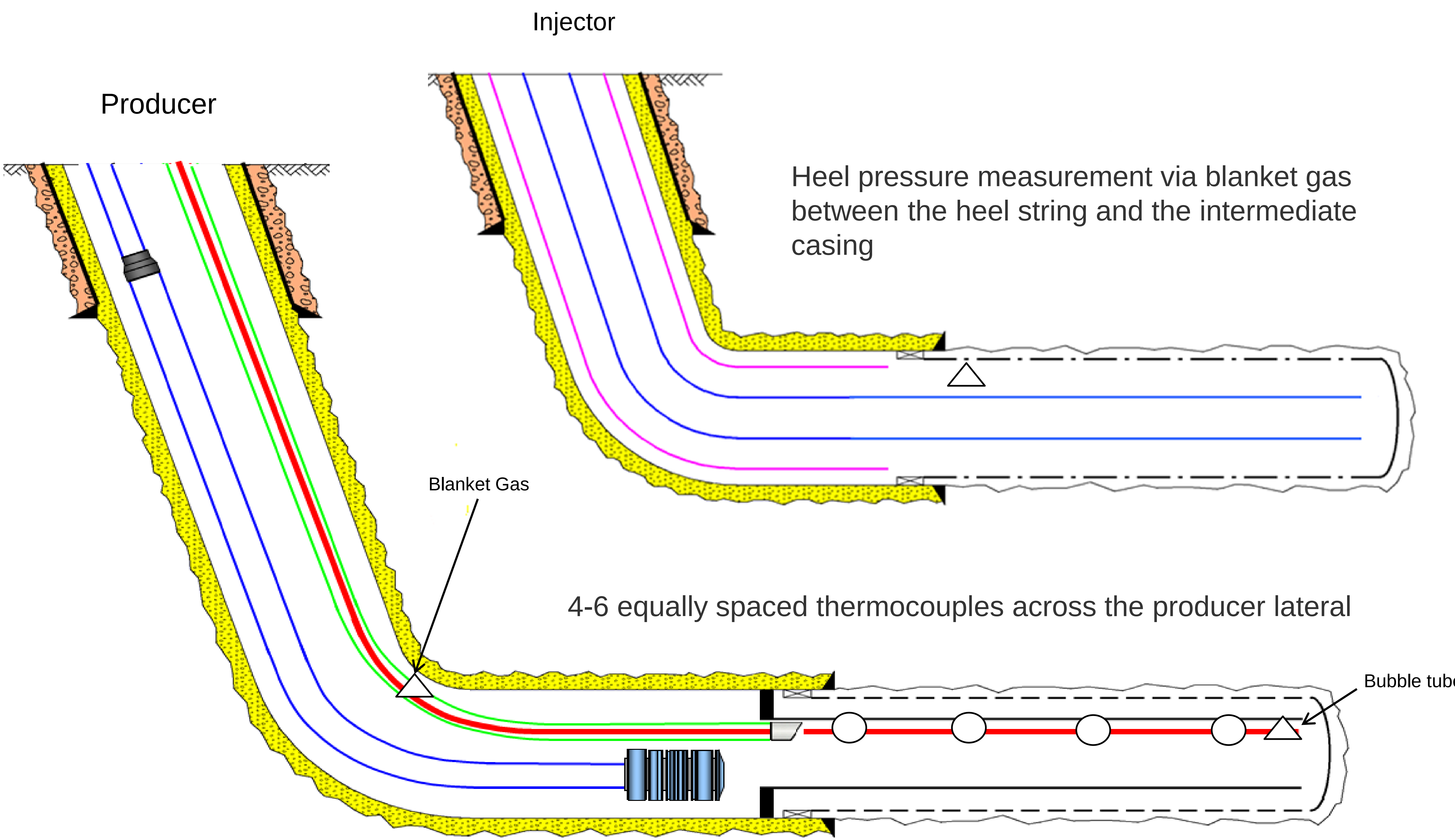
Producer Circulation



Artificial Lift Performance

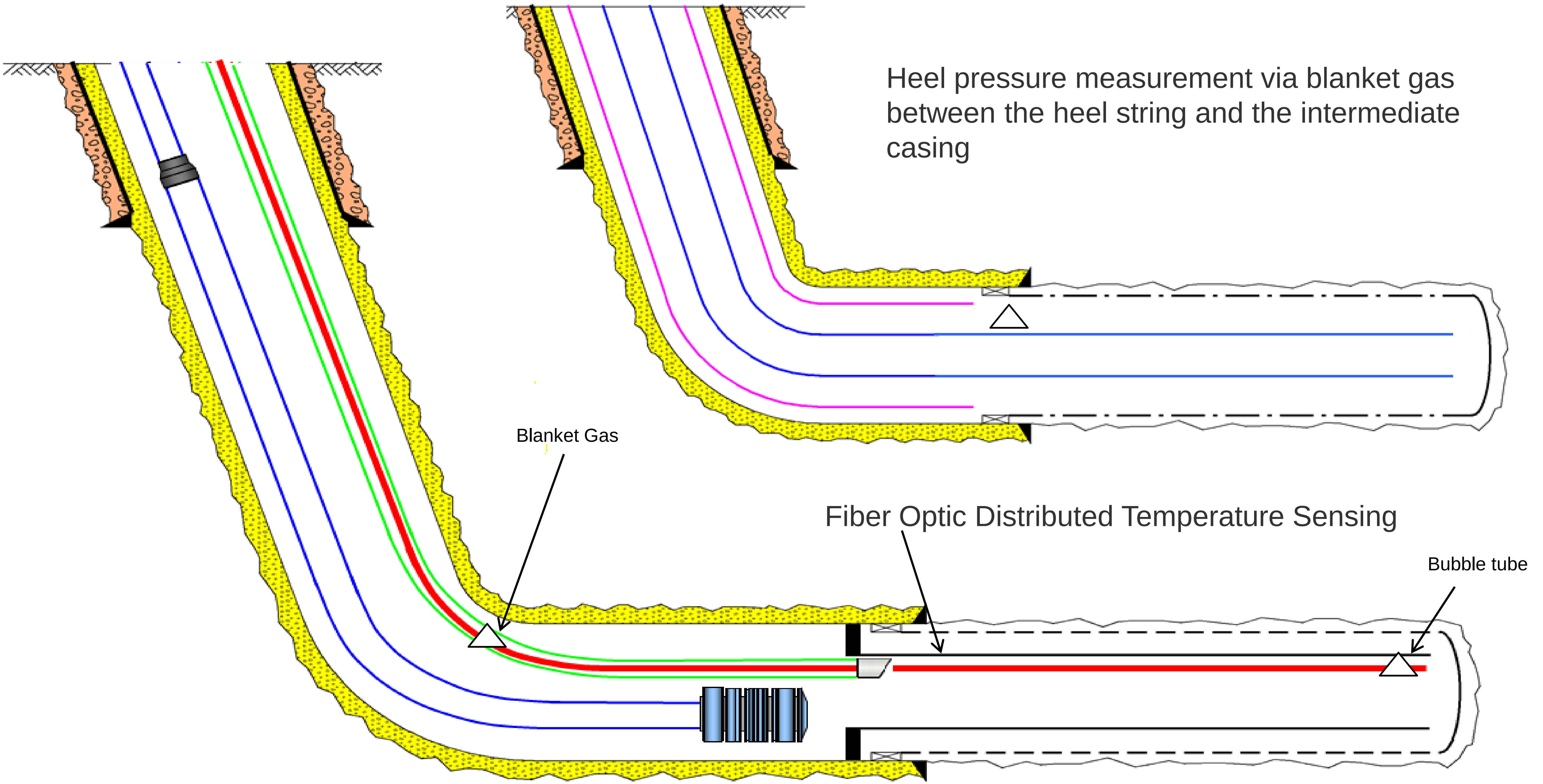
- Original gas lift completions have been converted to artificial lift via Electric Submersible Pumps (ESP) in most SAGD producers
  - 6 wells currently are on gas lift production
  - Conversions completed to allow production at lower steam chamber pressures (between 1400-2200 kPa)
- ESPs installed in 109 SAGD wells
  - Pump performance (at Dec 31, 2015):
    - Average Run Time: 441 days
    - Mean Time to Failure (cumulative): 749 days
    - Mean Time to Failure (450 Running Average): 983 days
  - Operating temperatures have reached 215ºC
  - Pumps operate at pressures between 1000 and 1500 kPa (Producer)
  - Fluid production rates range from 75 - 1100 m^3/d
- Active member of ESP Reliability Information and Failure Tracking System JIP
- Currently running 1 Progressive Cavity Pump (PCP) in 02P07
  - Kudu 1100-MET-750 metal stator and rotor installed Mar-2014 (continuous operations since)
- ESPs and PCP use Variable Frequency Drive (VFD) to control pump speed and production rates

SAGD Instrumentation



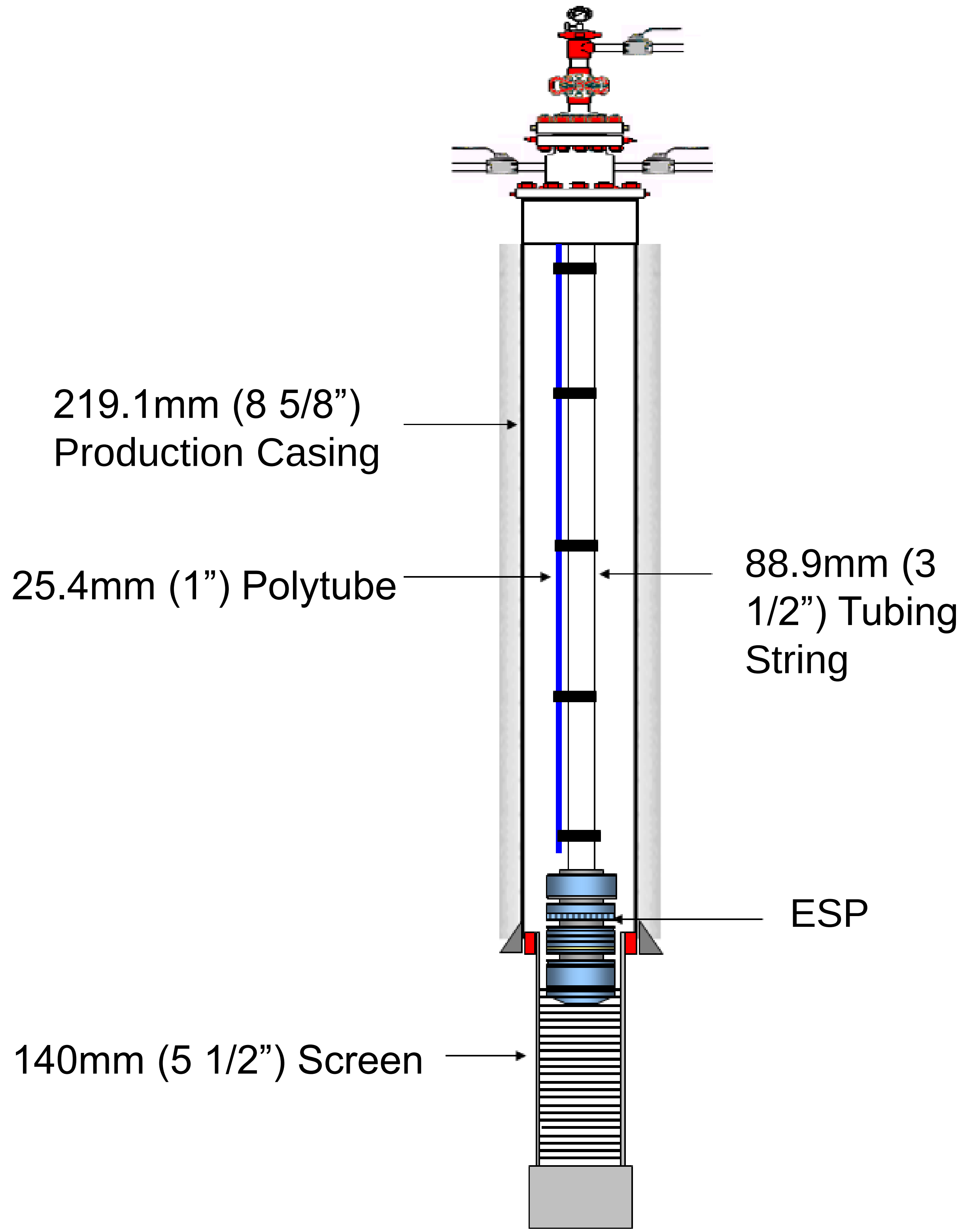
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

Alternate SAGD Instrumentation



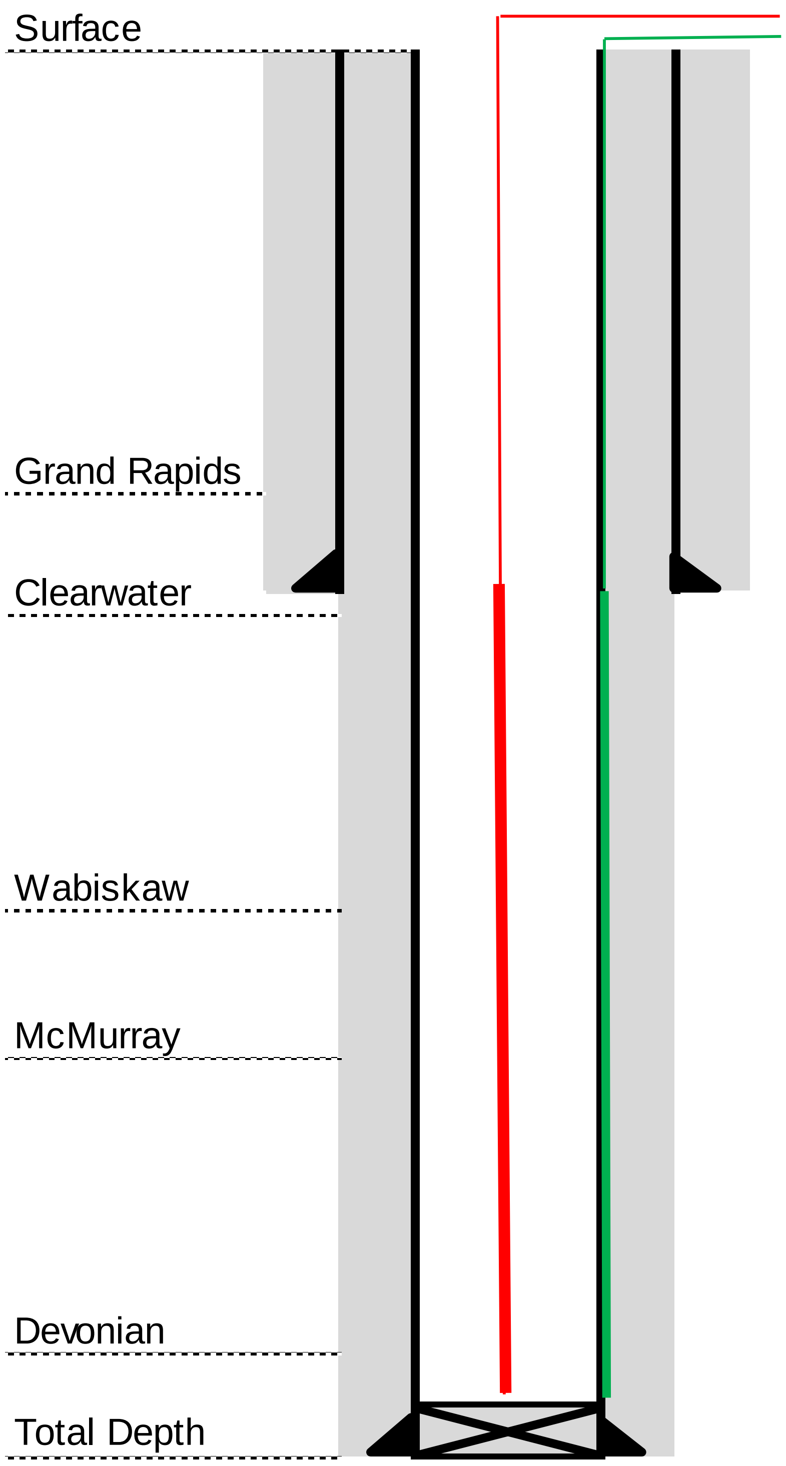
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

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 Design and Practices



- 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)

K1A

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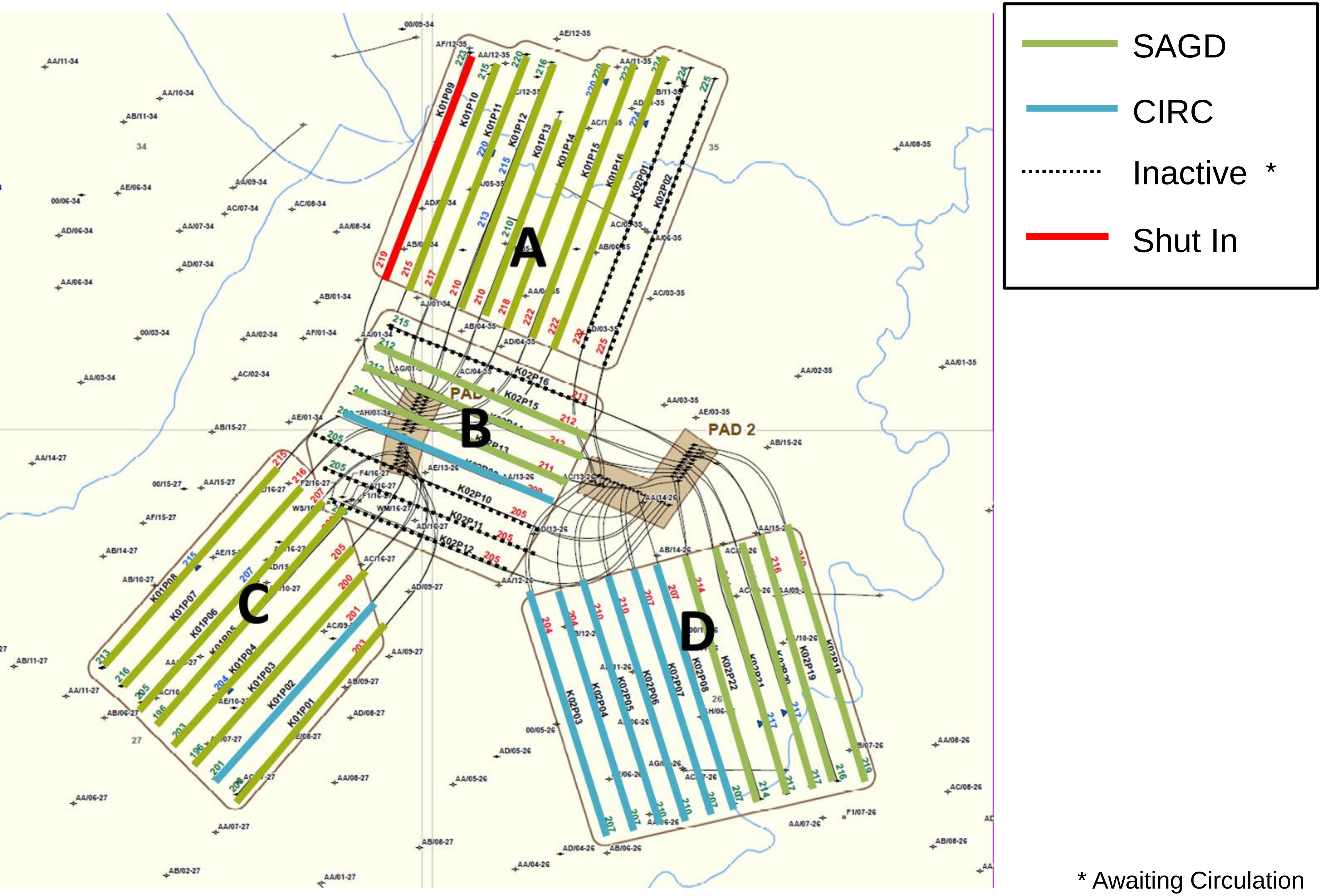
K1A Overview

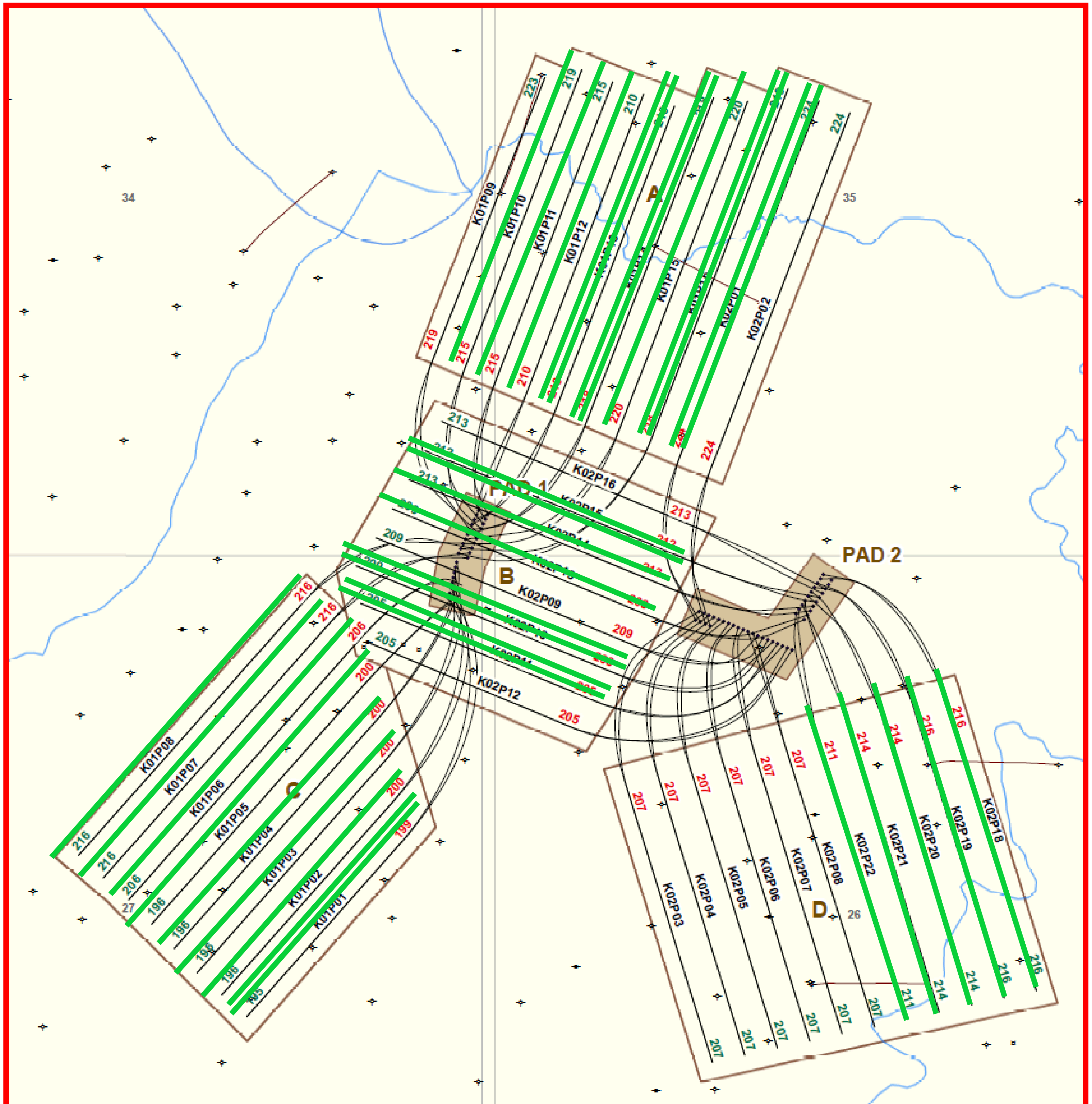
- On July 15, 2015 a line rupture was discovered on the K1A produced emulsion line tie-back to Long Lake CPF
  - Operations of both the remote steam generation facility (SGF) and well pairs at K1A were subsequently ceased and remain down
- Status of wells as at July 15, 2015
  - 22 well pairs were on SAGD and exhibiting strong production performance
    - Have been re-equipped in Q4 2015, ready for circulation
  - 8 well pairs were in circulation mode
  - 7 well pairs were inactive
- MOP revision on DAA approved for 2000kPa

Field Status as of July 15, 2015
(Prior to Detection of Pipeline Rupture)



* Awaiting Circulation

K1A Completions Summary (as of Dec. 31st, 2015)

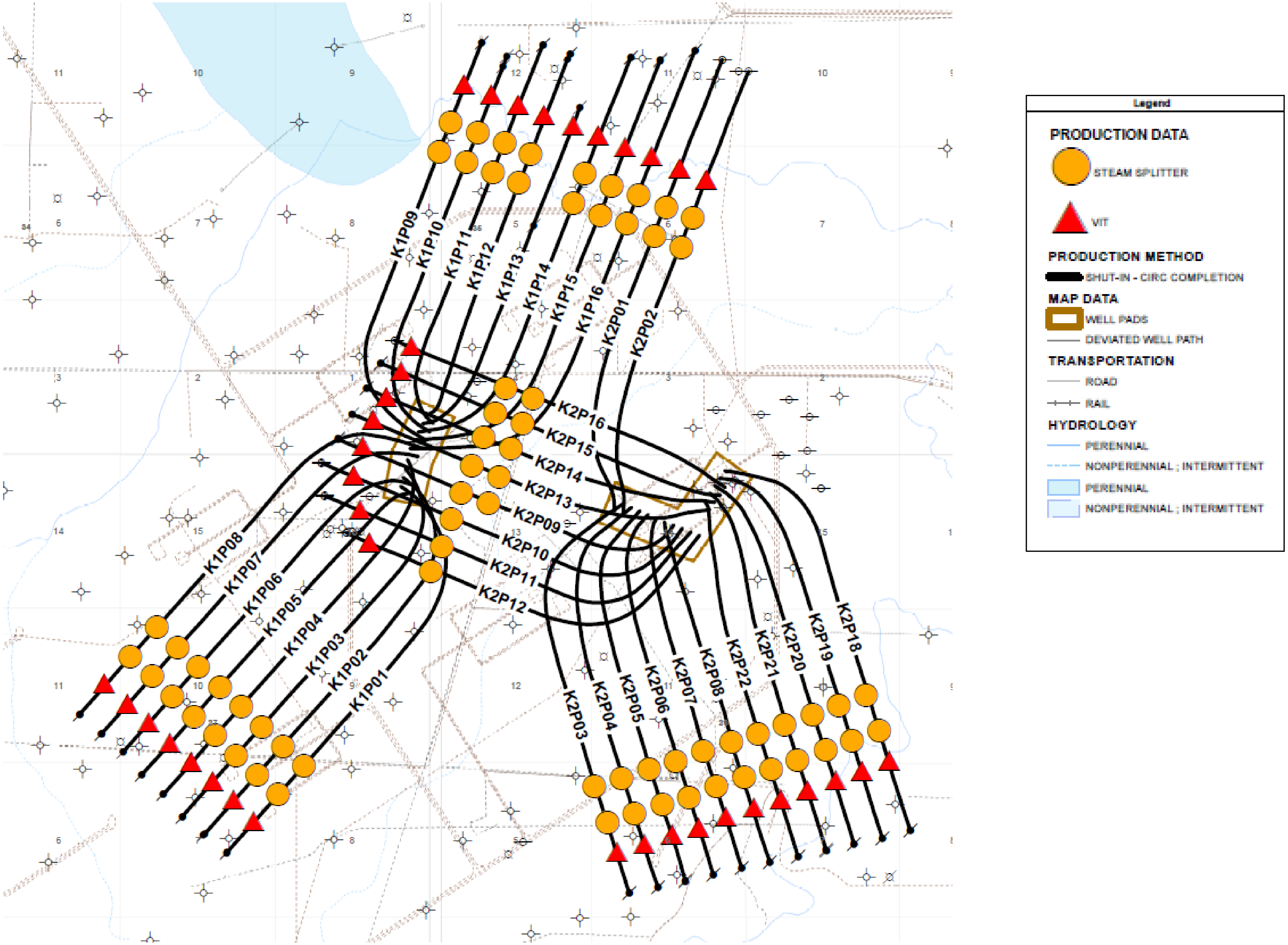


= workovers completed (34 wells)

<u>Completion Work – Post Pipeline Rupture</u>

- Pulled coil instrument string, ESP, scab liner, and guide string
- Installed circulation strings in well pairs that were on SAGD production
- Injected corrosion inhibitor in all well pairs

K1A Well Pair Completions Map as of Dec. 31, 2015



K1A Downhole Corrosion Inhibition Plan

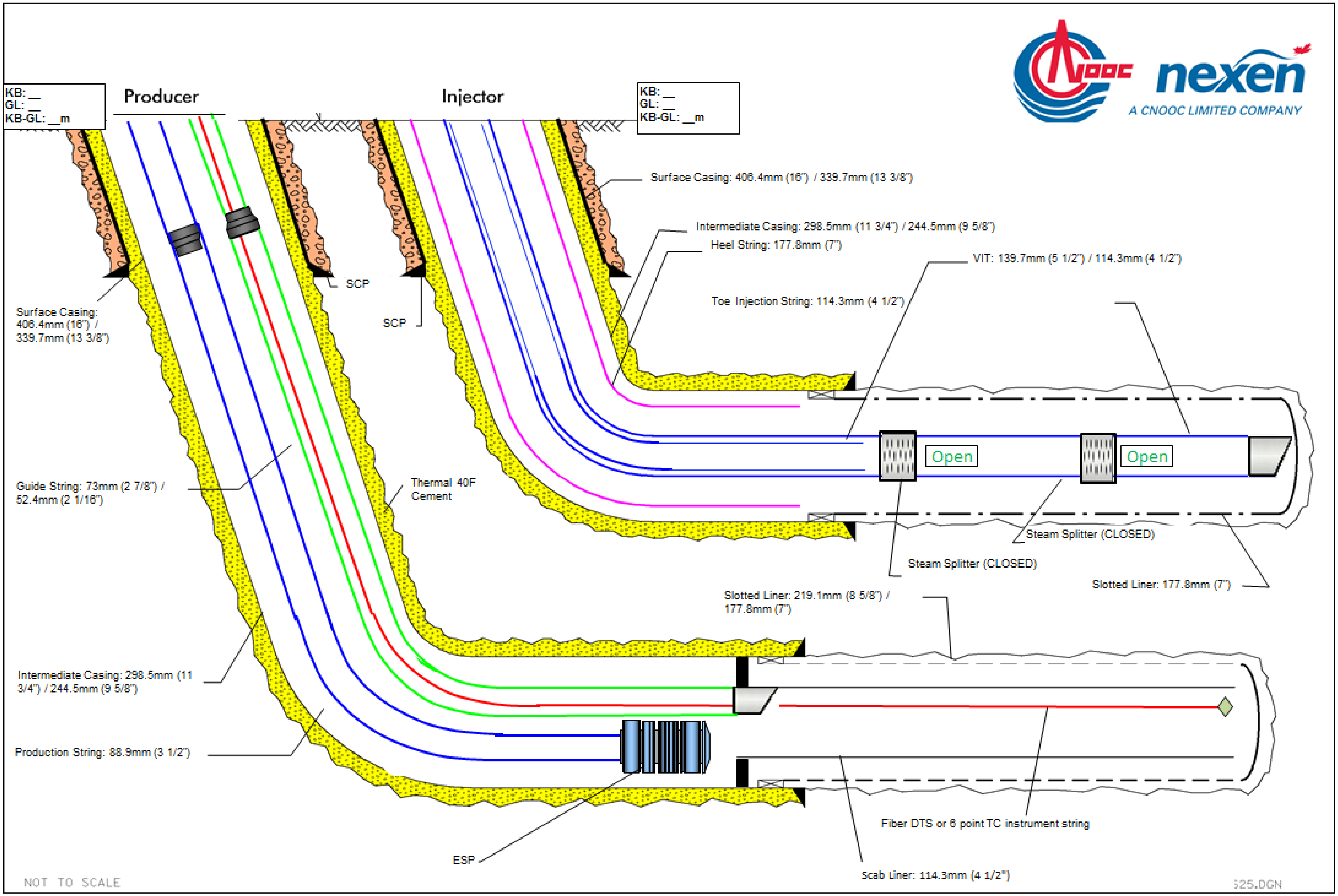
Objective:

- Injected inhibited fluid down casing and tubing of all 37 K1A SAGD well pairs to coat metal surfaces and deter corrosion.
- Inhibited fluid was a mixture of water, oxygen scavenger, biocide and corrosion inhibitor.

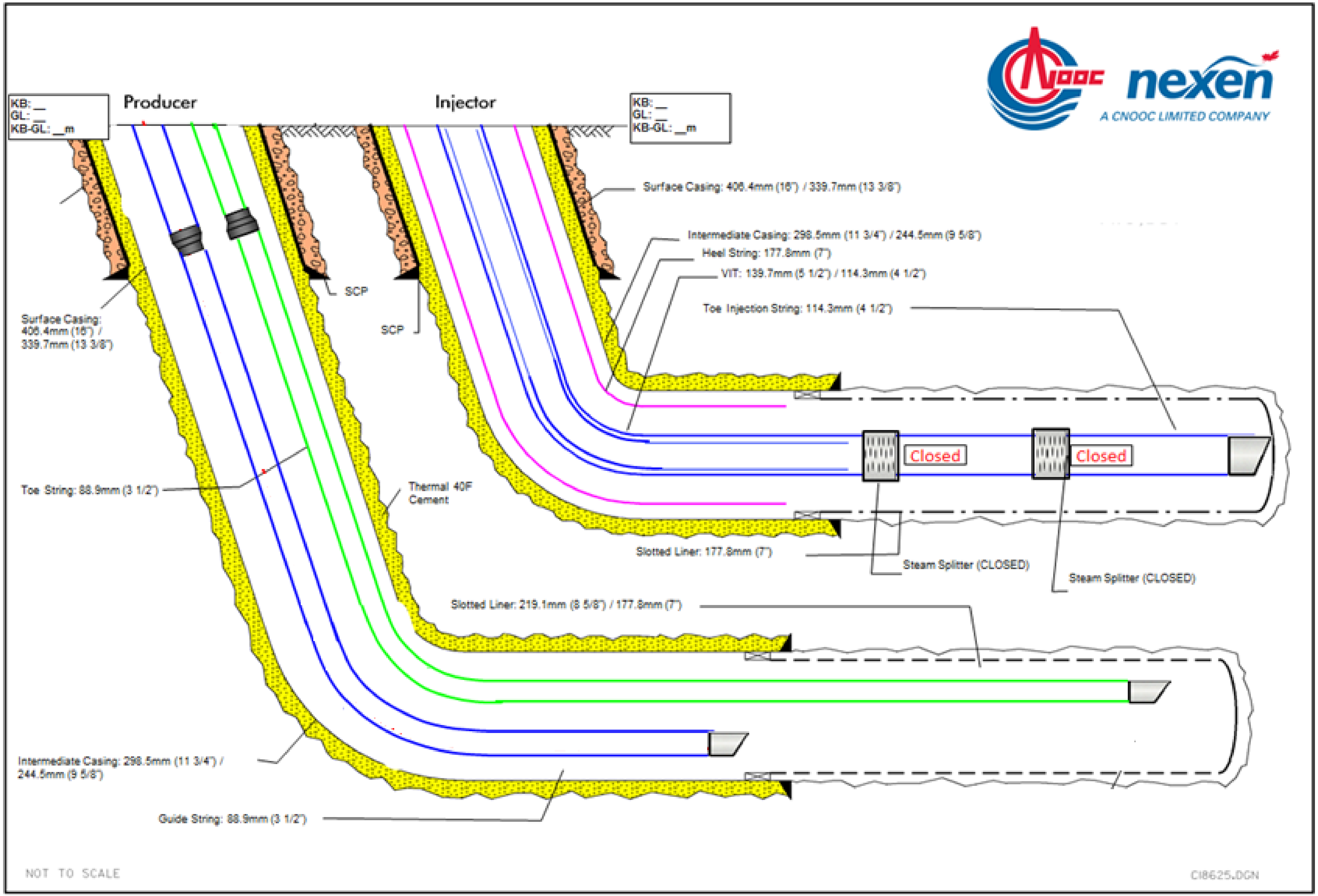
Operation:

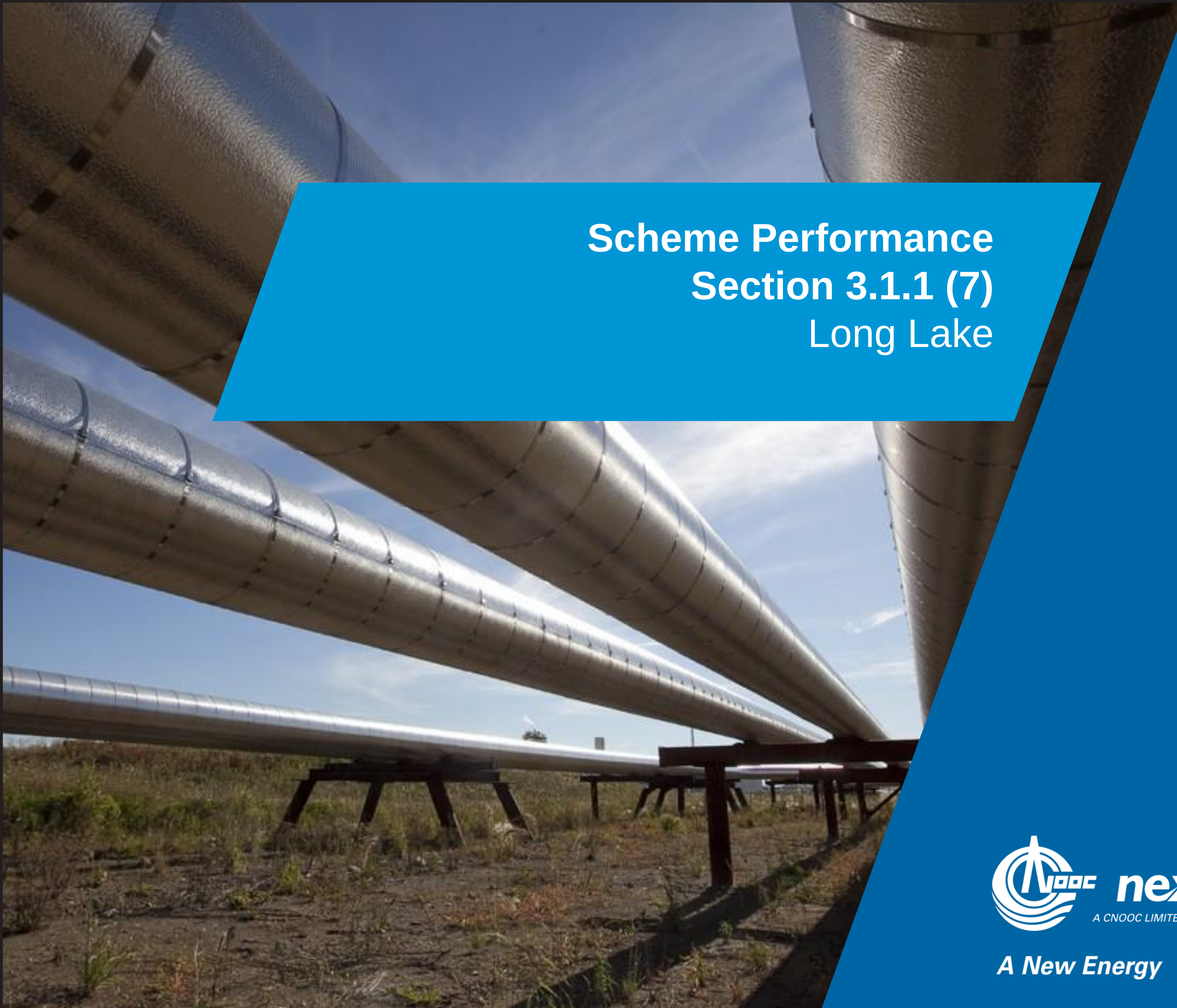
- 74 wells total
- Approximately 3300 m^3 inhibited fluid injected
- Bullhead: 60 wells
- Circulated: 14 wells

K1A Completion Schematic SAGD



Typical K1A Completion Schematic Circulation





Scheme Performance
Section 3.1.1 (7)
Long Lake

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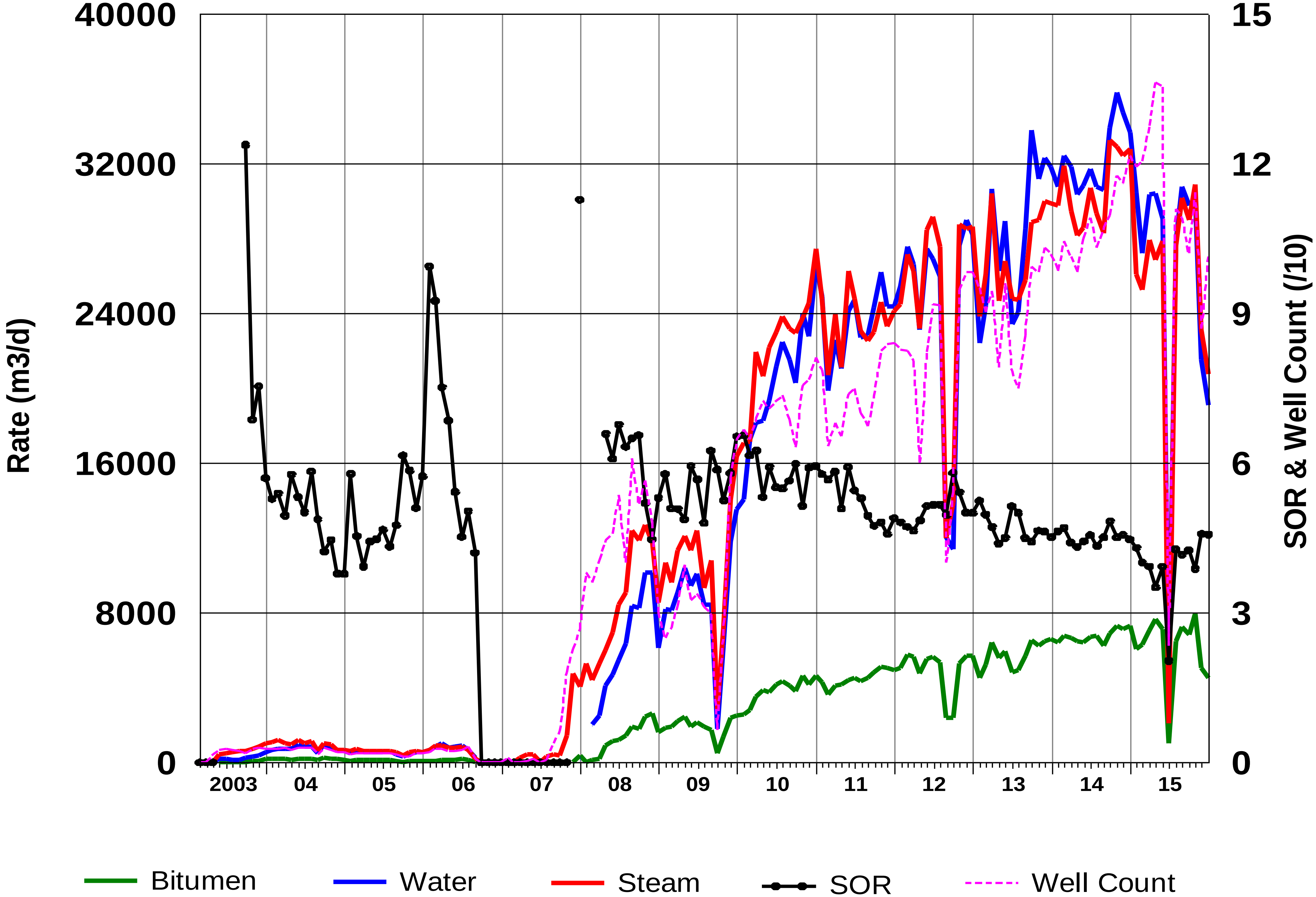
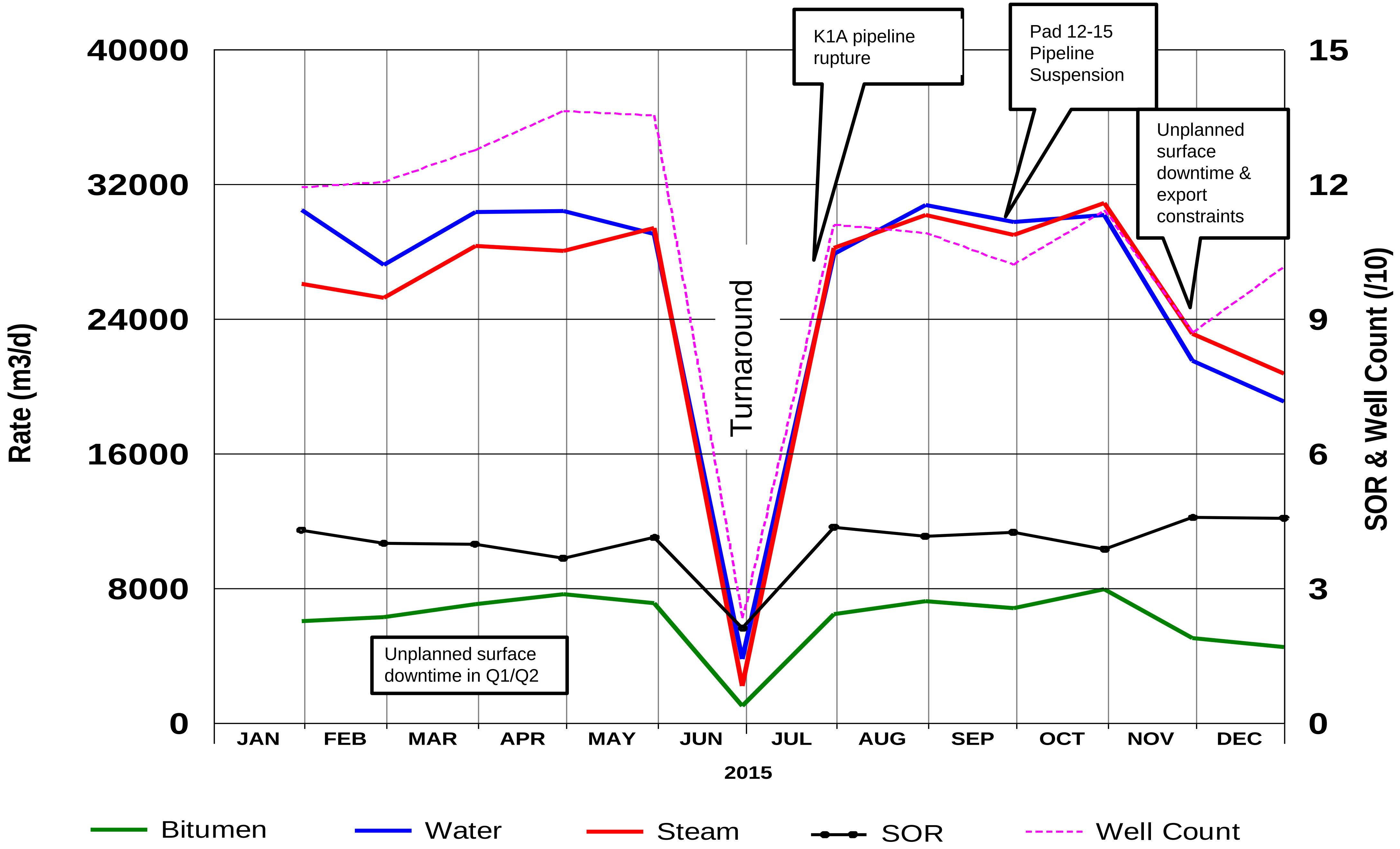
Field Performance



**Graph includes K1A*

2015 Field Performance



Long Lake 2015 Performance

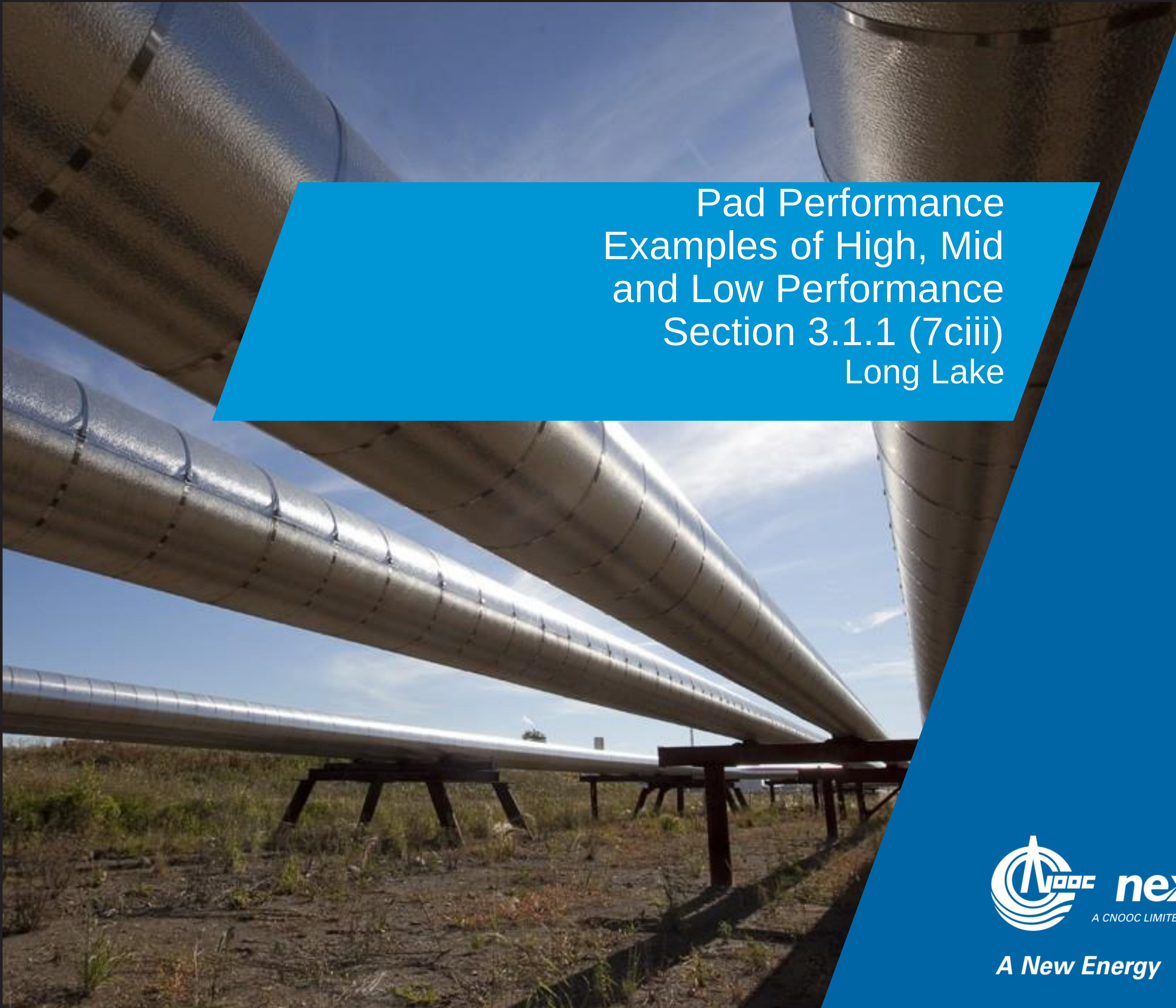
- Commercial SAGD
- Downhole injection pressure varies throughout the field, ranges from 1,400 kPa to 2,800 kPa
- K1A wells exhibited strong ramp up and Long Lake pads continue to deliver strong performance
  - However, many wells throttled throughout the year to accommodate various capacity constraints
  - Field shut in for ~21 days for plant turnaround in June 2015
  - Improved ramp up and field production performance post turnaround compared to 2012 turnaround
  - K1A well pairs shut-in July 15, 2015
  - Pads 12-15 shut in for ~10 days for pipeline suspension order in Sept 2015
- Long Lake: 15 pads and 120 well pairs, 112 producing wells at year end
- K1A: 2 pads and 37 well pairs, 0 producing at year end

Recoverable Bitumen

Pad	Num Wells	EBIP E^6 m^3	Estimated Ultimate RF	Recoverable Bitumen E^6m^3	Cum Production Dec. 2015 E^3 m^3	RF
1	5	2.1	66%	1.4	917	43%
2NE	6	2.4	40%	1.0	680	28%
2SE	5	1.2	29%	0.4	257	21%
3	5	2.5	56%	1.4	1,049	42%
4	2	0.2	60%	0.1	89	50%
5	5	3.3	49%	1.6	1,213	37%
6N	6	2.9	39%	1.1	713	24%
6W	7	2.0	55%	1.1	763	39%
7E	7	1.4	70%	1.0	655	47%
7N	9	3.2	72%	2.3	1,693	53%
8	6	3.0	50%	1.5	1,009	34%
9NE	5	1.1	28%	0.3	218	19%
9W	5	1.6	39%	0.6	405	25%
10N	3	1.1	27%	0.3	194	18%
10W	5	2.0	49%	1.0	582	29%
11	10	2.2	59%	1.3	1,049	48%
12	9	3.4	39%	1.3	459	14%
13	9	3.3	41%	1.3	584	18%
14	6	1.9	47%	0.9	206	11%
15	5	1.4	48%	0.7	106	8%
K1A	36	18.1	56%	10.1	181	1%
TOTAL	**156**	**60.2**	**51%**	**30.7**	**13,021**	22%

December 2015 Average Injection Pressures

Drainage Area / Pad	Average Injector Pressure (kPa)
LL-001	1523.63
LL-002NE	1338.98
LL-002SE	1504.58
LL-003	1413.77
LL-004	1371.01
LL-005	1532.48
LL-006N	1891.55
LL-006W	1706.46
LL-007E	1811.54
LL-007N	2034.68
LL-008	1890.03
LL-009NE	1366.27
LL-009W	1941.63
LL-010N	1933.92
LL-010W	1890.63
LL-011	1615.74
LL-012	1812.88
LL-013	1811.74
LL-014	2311.07
LL-015	2279.97



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

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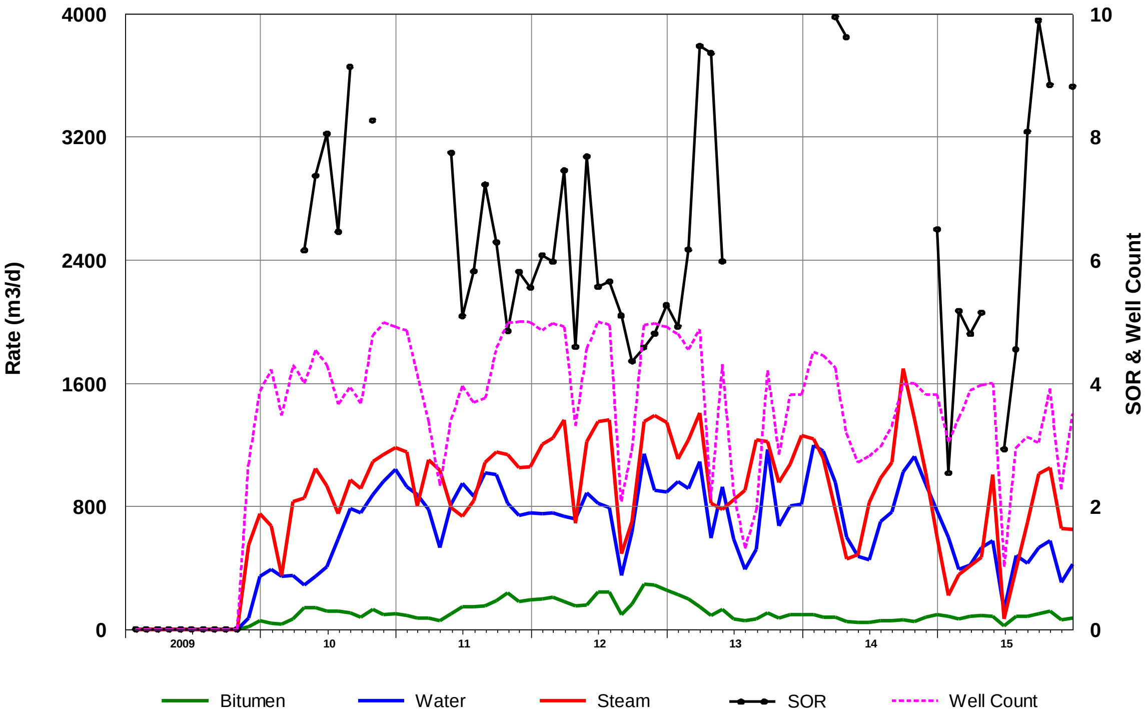
Examples of Low, Mid, High Recovery

- Low Recovery
  - Pad 2SE
- Mid Recovery
  - Pad 8
- High Recovery
  - Pad 11

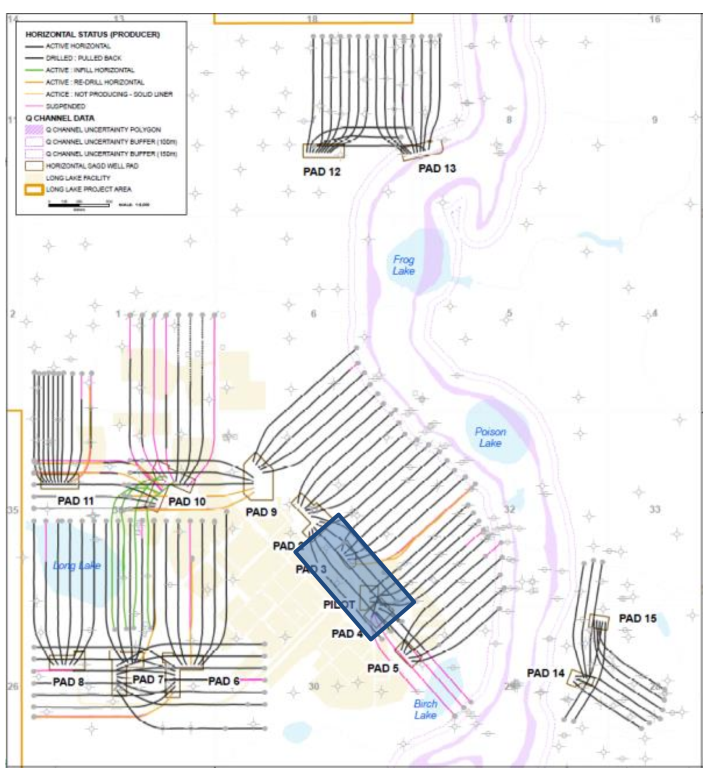
Examples of Low, Mid, High Recovery

- **Low Recovery**
  - **Pad 2SE**
- Mid Recovery
  - Pad 8
- High Recovery
  - Pad 11

Pad 2SE Production Summary



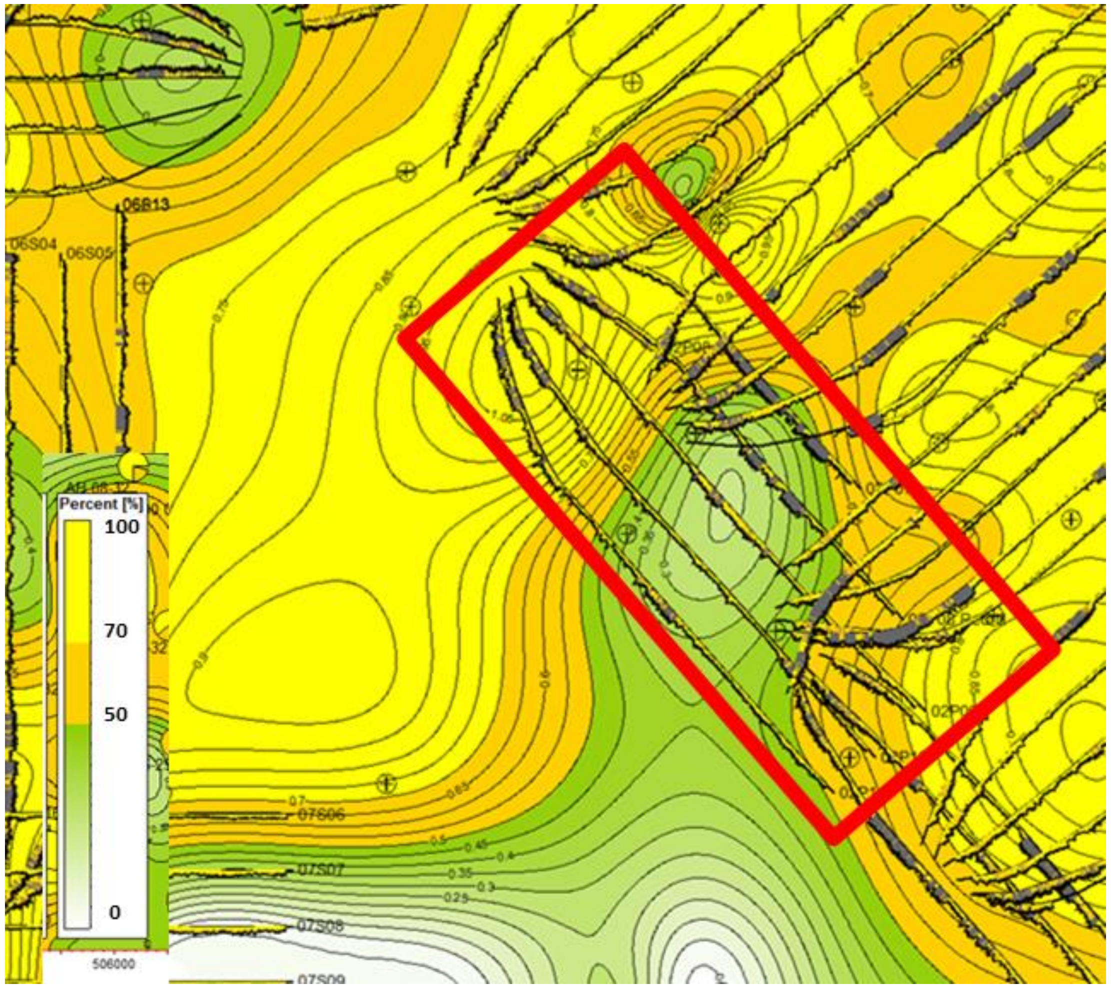
Well	EBIP (m^3)	Dec 2015 Cumulative Bitumen (m^3)	Dec 2015 RF (%)
02P07	229	40	17
02P08	271	57	21
02P09	259	48	19
02P10	306	73	24
02P11	155	39	25
Pad 2SE	**1219**	**257**	**21**



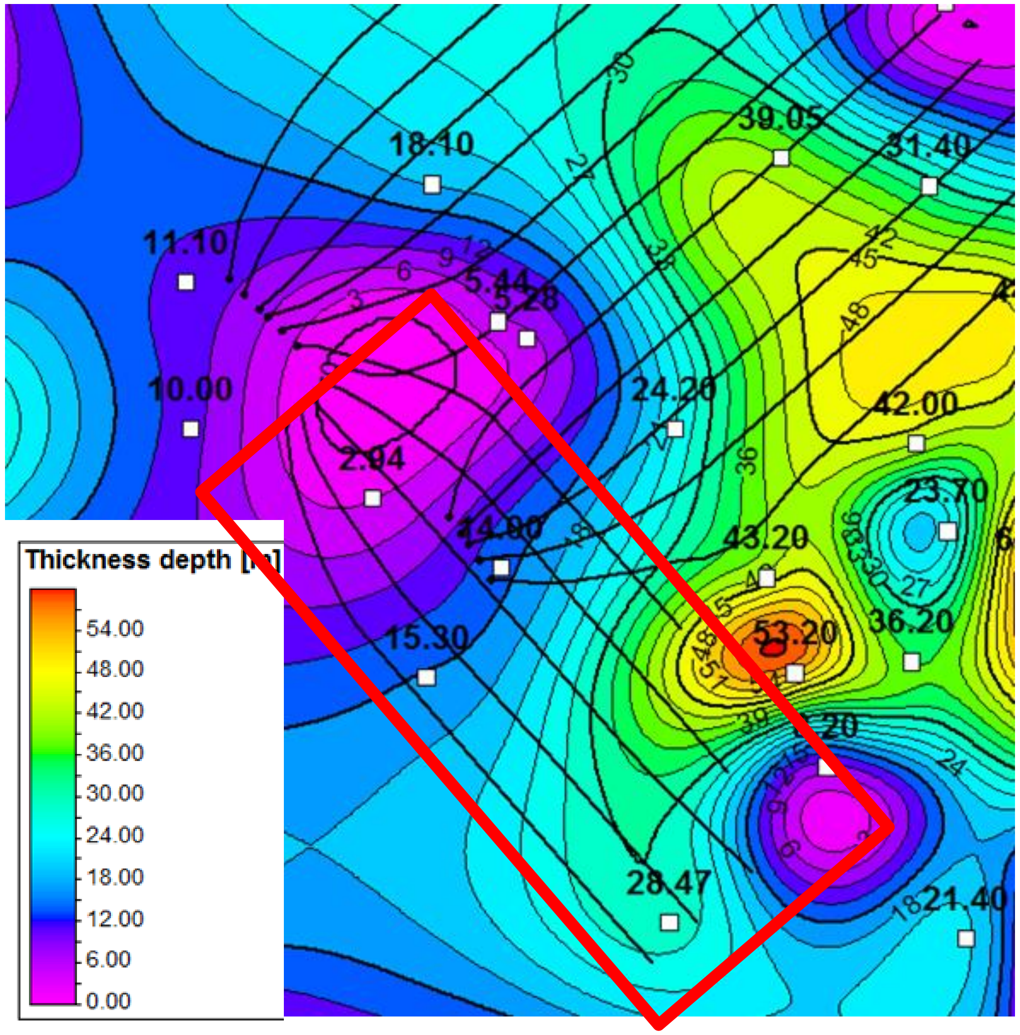
- 2P11 suspended since June 2014 due to multiple liner failures and unfavorable repair economics
- All wells initially started on gaslift. 2P07 converted to PC pump in 2010. 2P08/2P09/2P10 converted to ESP pump in 2010-2014
- Wells are low on priority list due to poor quality and performance, they get hit heavily when there are capacity restrictions.
- At YE, injection pressures were ~1,200 – 1,720 kPa

Pad 2SE Geology

- Sand Facies



- EBIP Interval



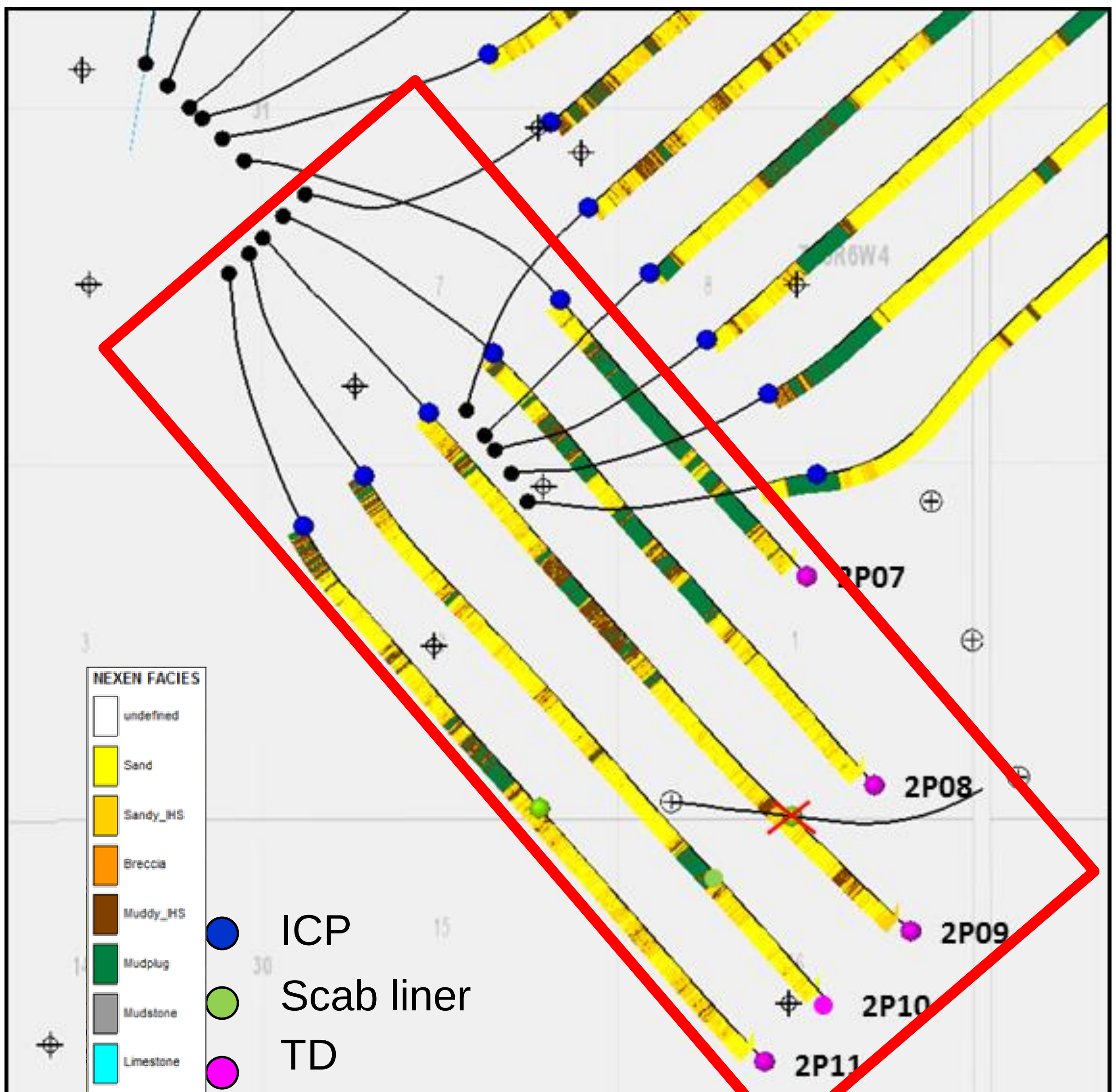
Pad 2SE Geology

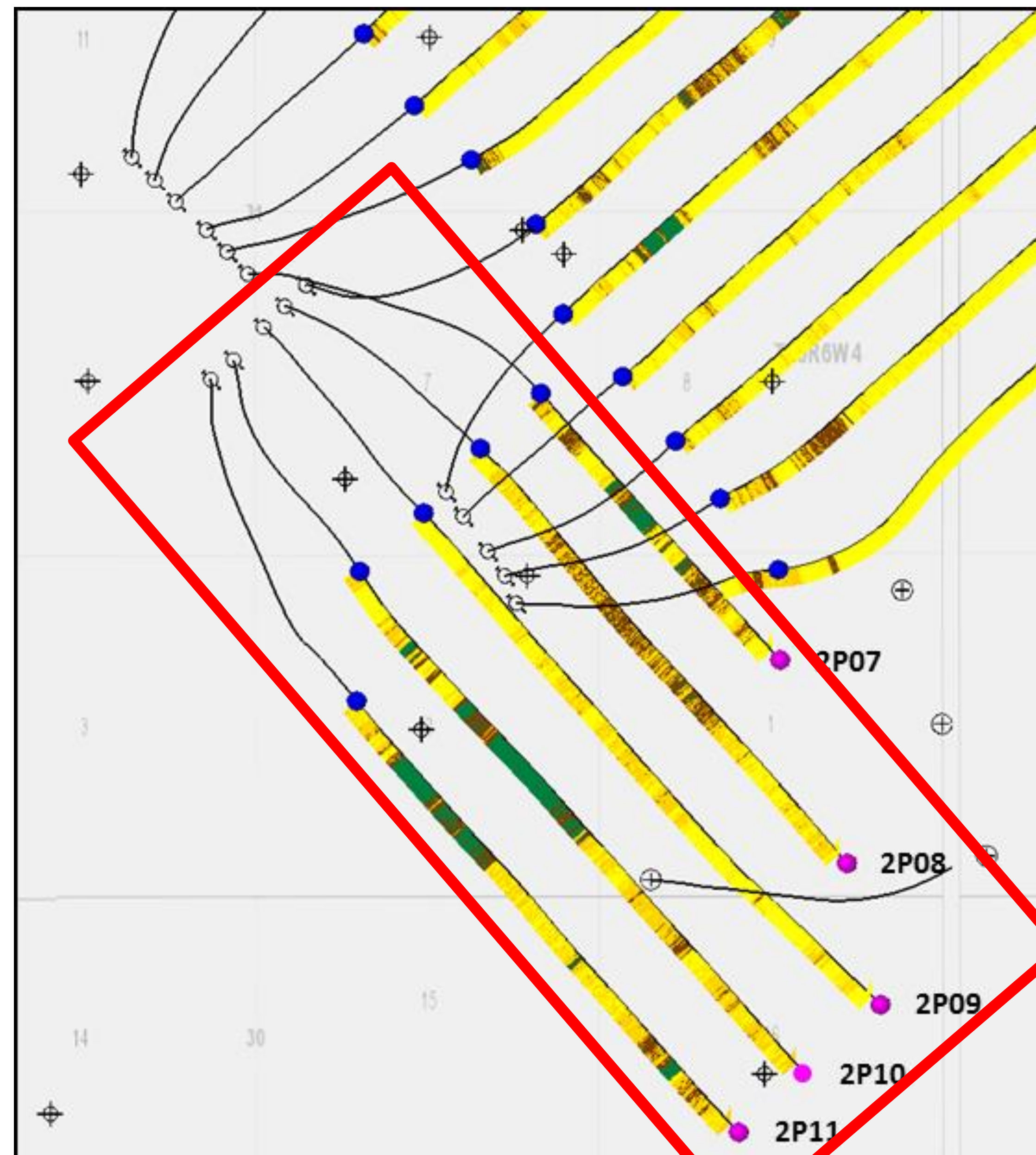
Producers

- Heel to mid sections of 2P07 and 2P08 drilled in low quality reservoir, dominated by mudstone facies.

Injectors

- 2P10 and 2P11 have a poor reservoir section towards the heel with the high GR.





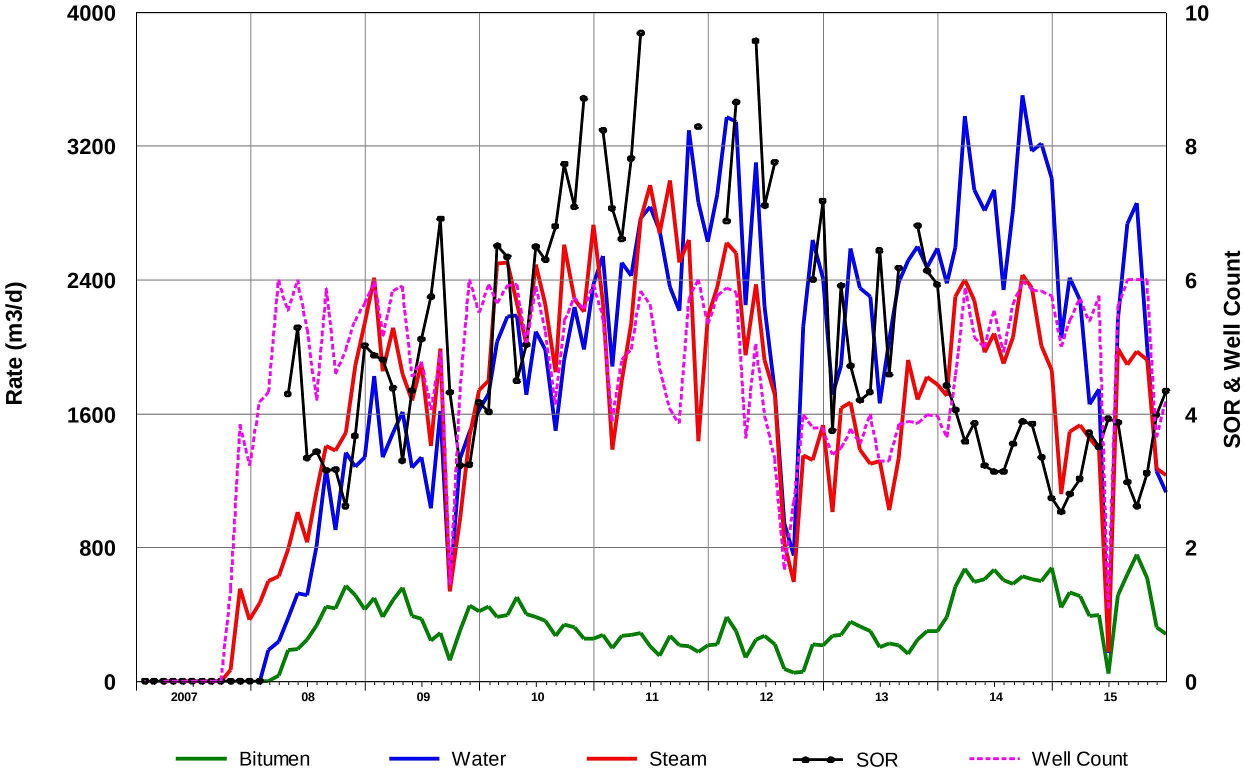
Examples of Low, Mid, High Recovery

- Low Recovery
  - Pad 2SE

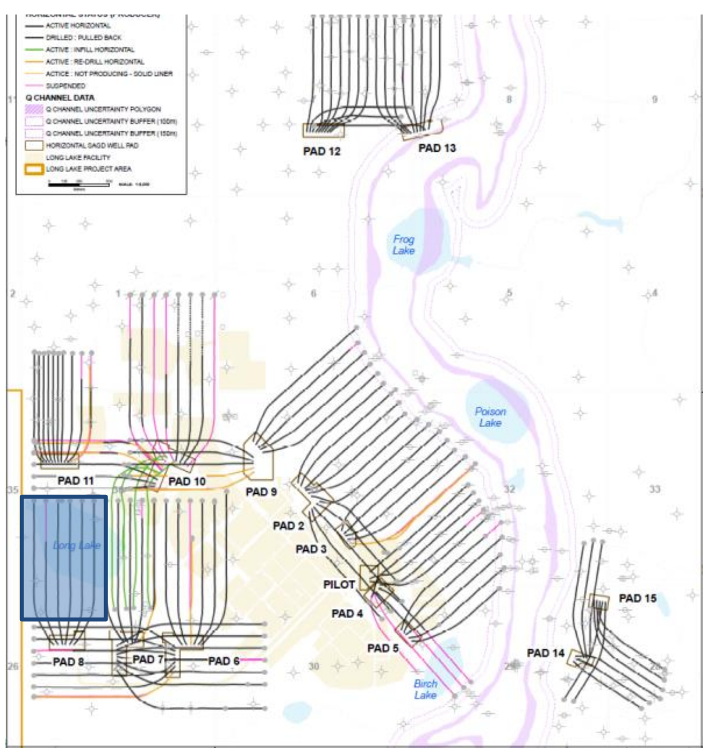
- **Mid Recovery**
  - **Pad 8**

- High Recovery
  - Pad 11

Pad 8 Production Summary



Well	EBIP 10^3 (m^3)	Dec 2015 Cumulative Bitumen 10^3 (m^3)	Dec 2015 RF (%)
08P01	303	55	18%
08P02	205	75	37%
08P03	508	113	22%
08P04	614	183	30%
08P05	658	300	46%
08P06	690	283	41%
Pad 8	**2978**	**1009**	**34%**

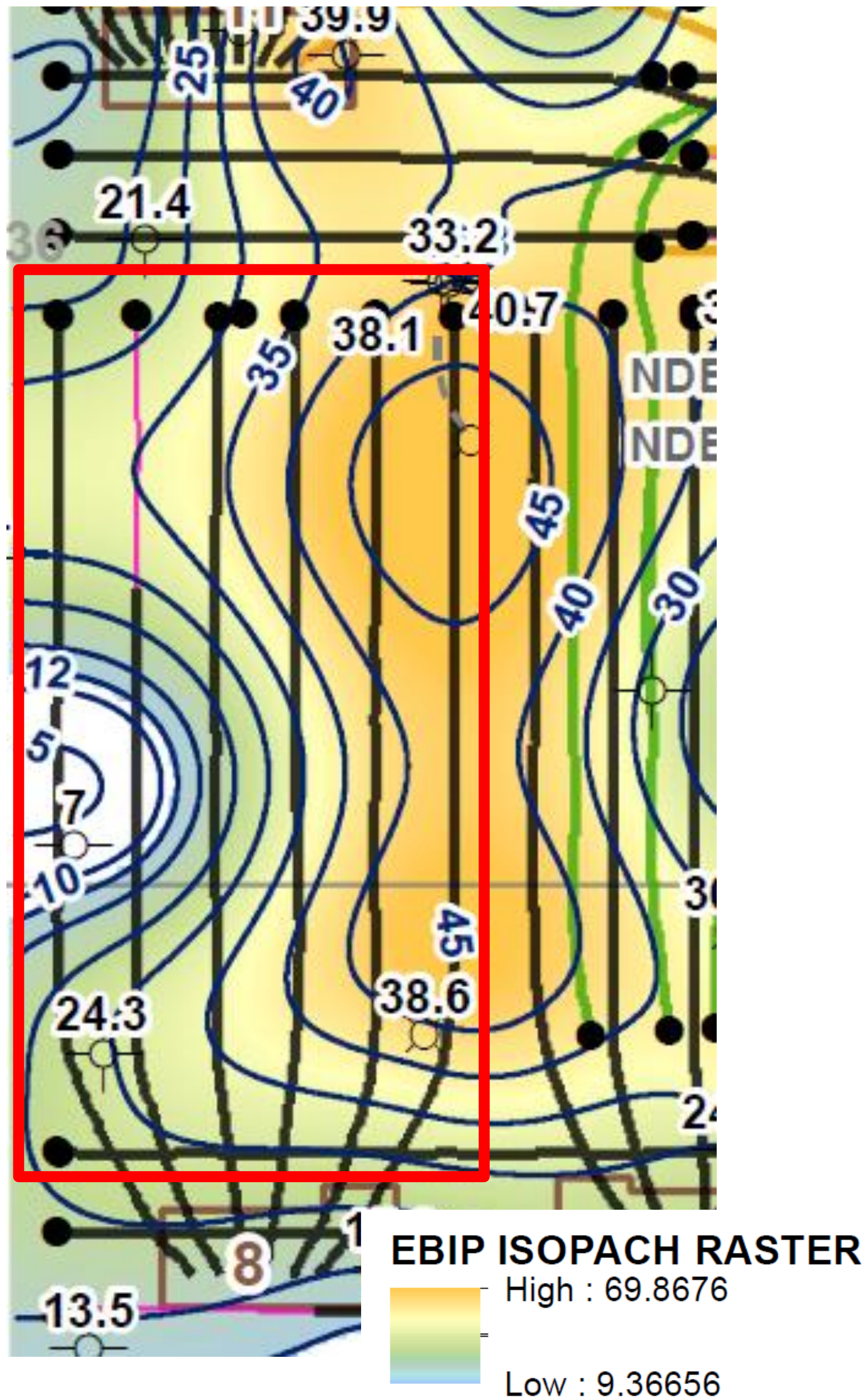


- Continuing to see strong production performance from east well pairs – west well pairs operated inconsistently
- 08S06 shut in Q1 2015 after workover following potential liner failure
  - Increased injection on offset injectors to support 08S06
  - No evidence of negative impact to 08P06 or surrounding wells production
- ICD installed on 08P03 in Dec. 2015
- Bridge plug at toe of 08P02 removed in Dec. 2015 to access additional reservoir

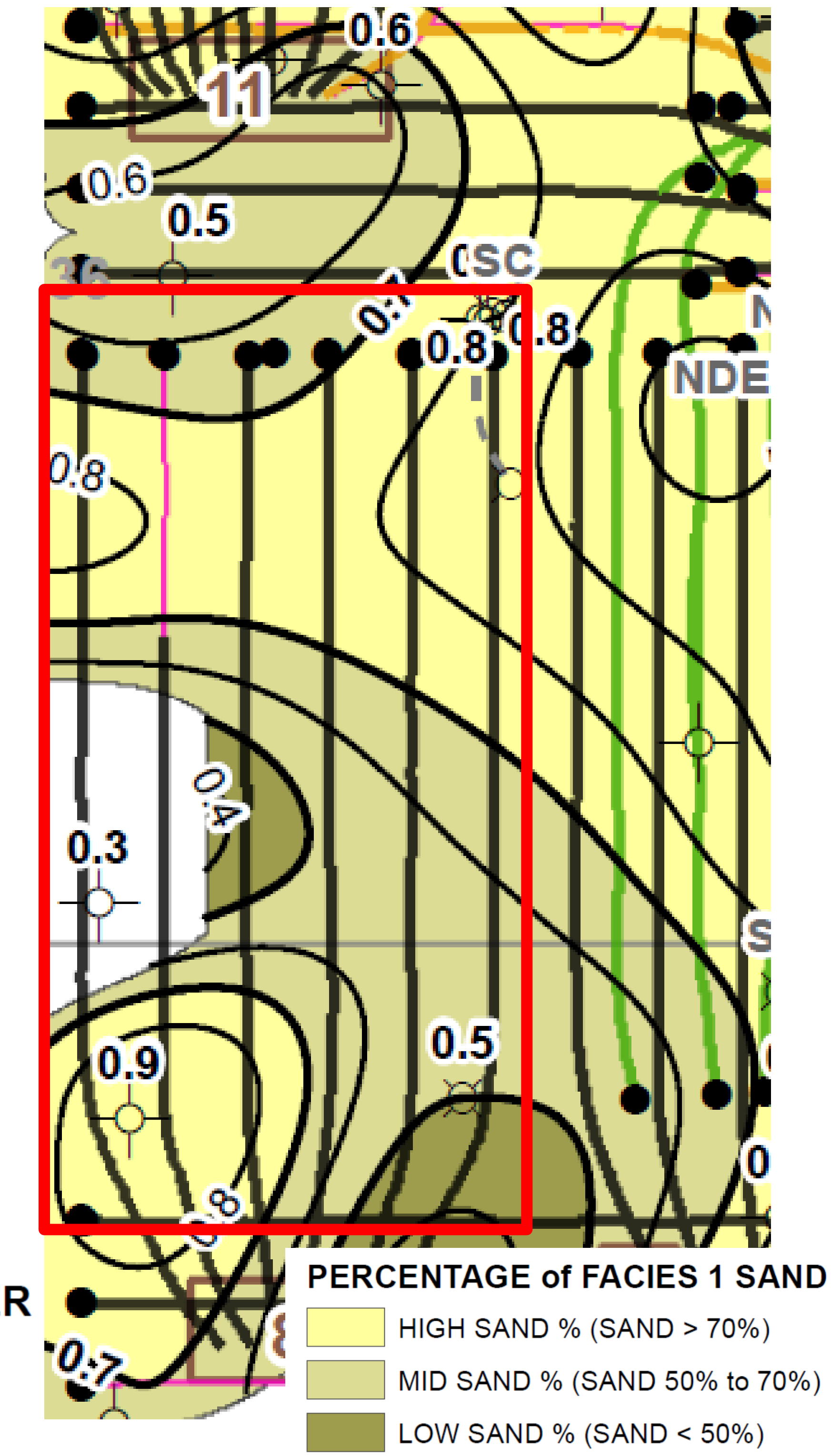
Pad 8 Geology

- Reservoir quality improves from east to west

EBIP ISOPACH



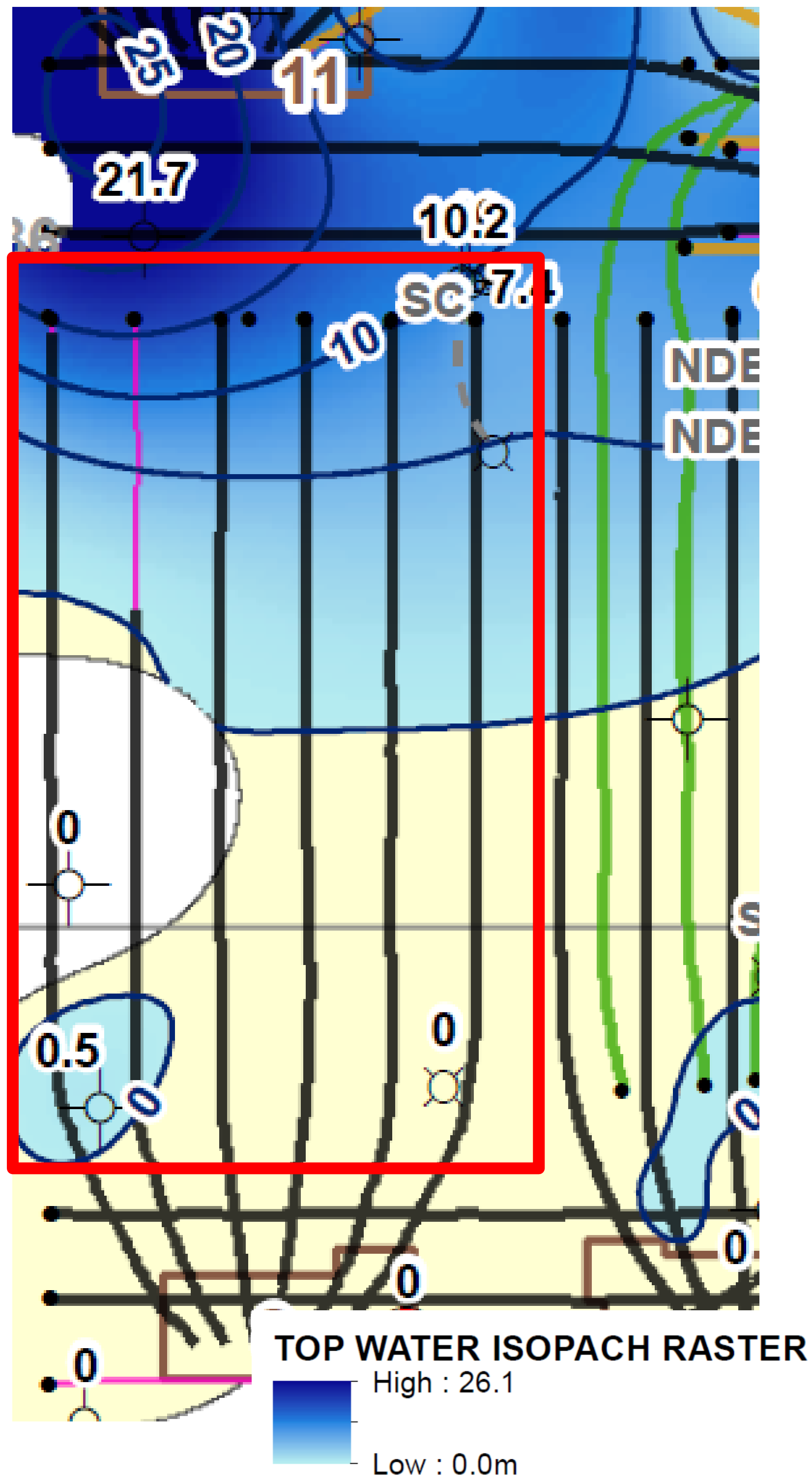
SAND FACIES PERCENTAGE



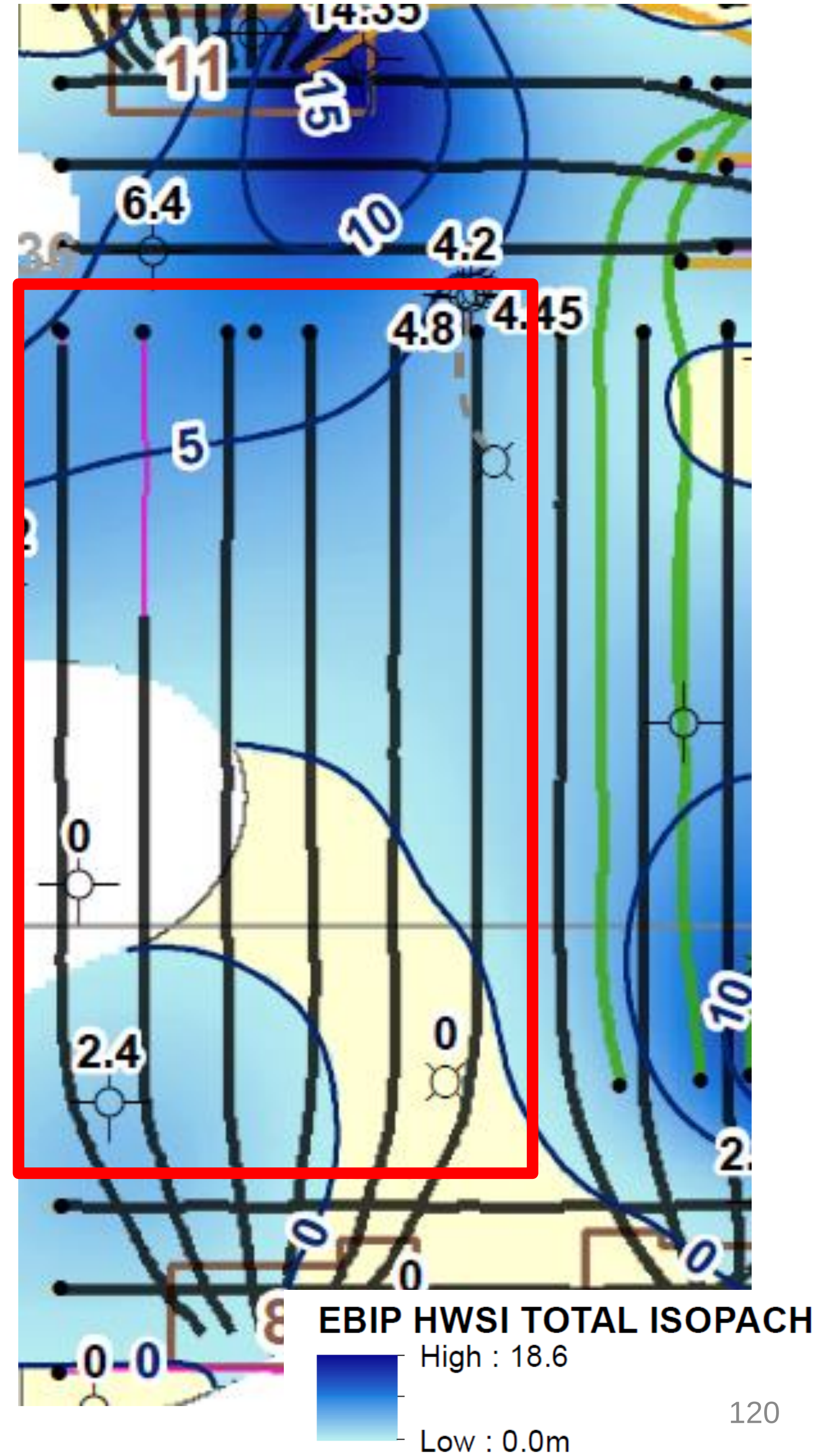
Pad 8 Geology

- High water saturation intervals throughout pad
- Top water at toes connected to extensive top water body on Pad 10W and Pad 11

HWSI ABOVE EBIP (TOP WATER)

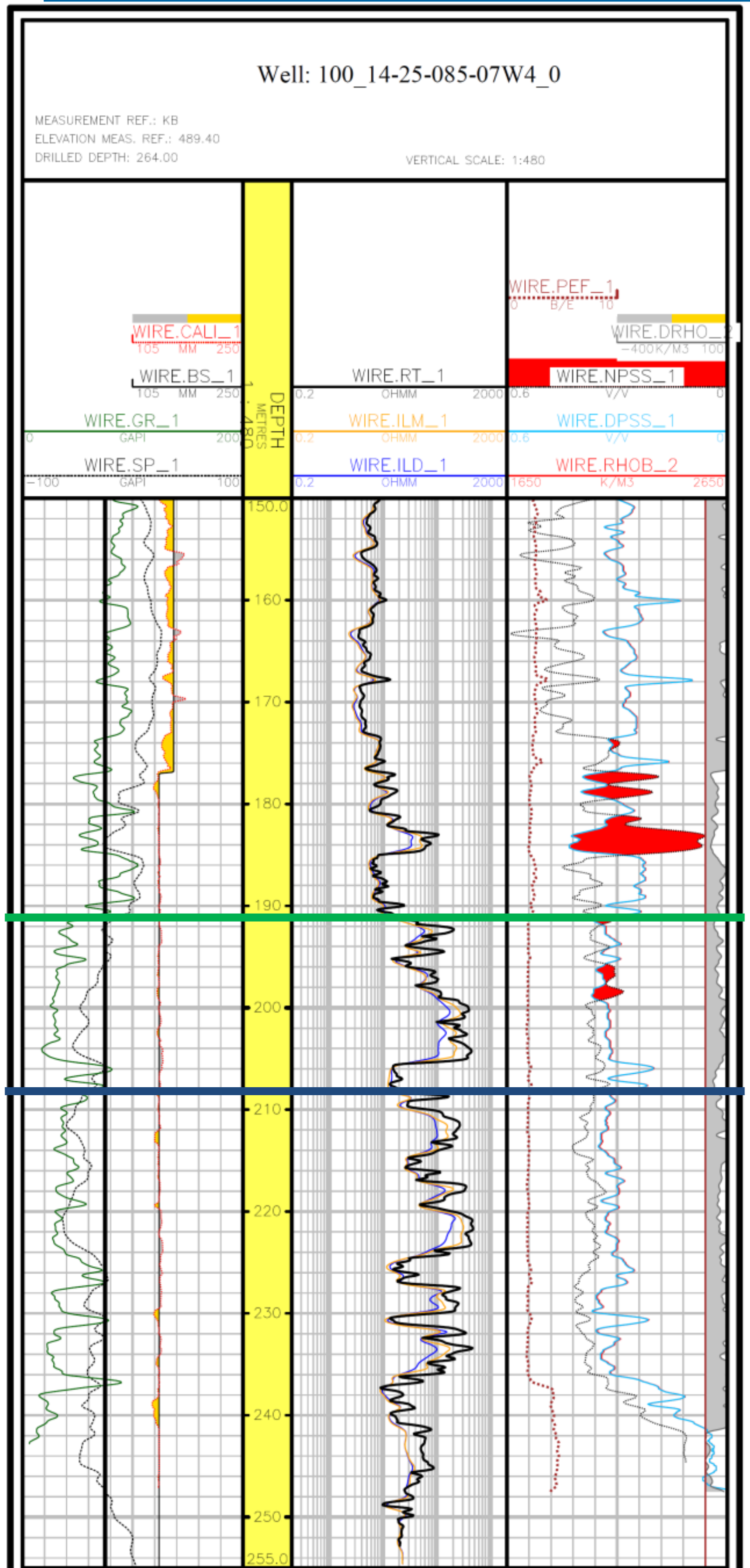


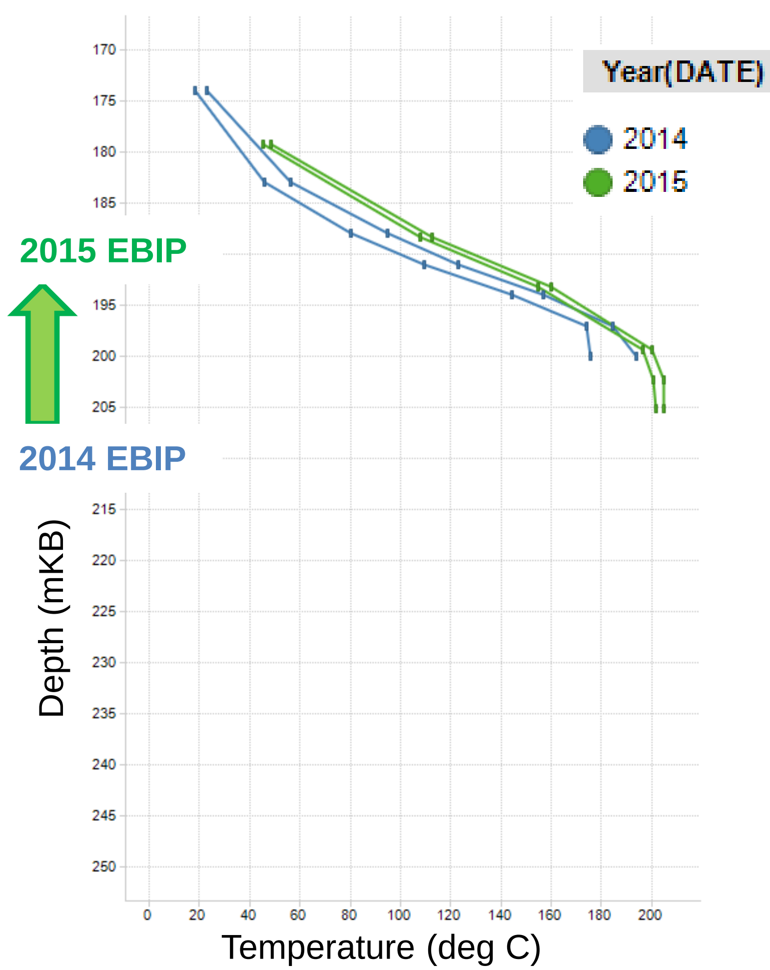
HWSI WITHIN EBIP

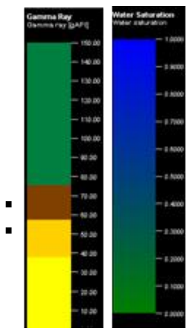


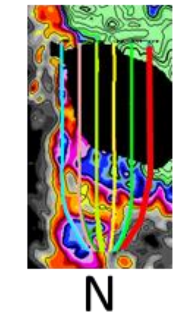
Pad 8 Secondary Zone

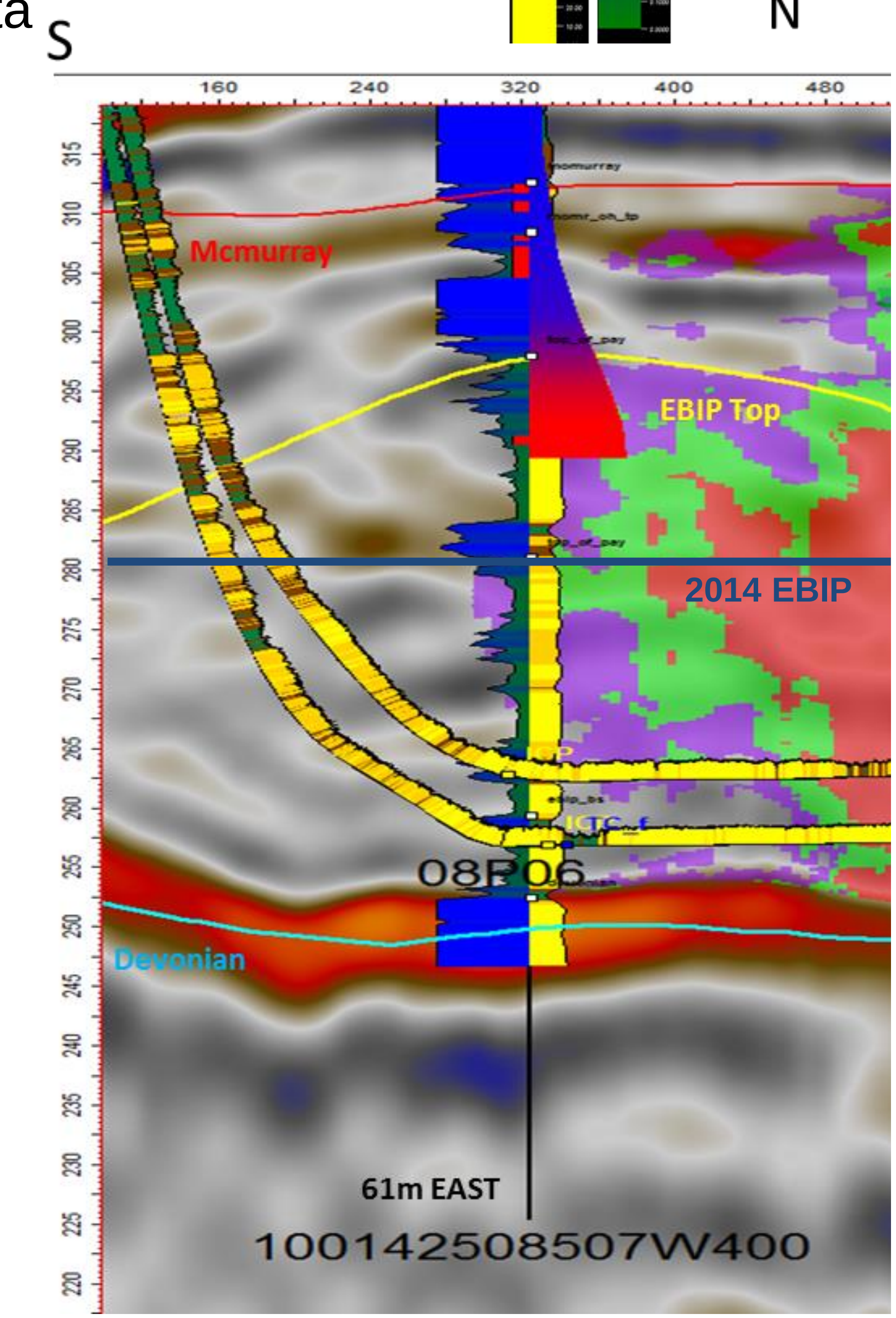
- Previously identified as potential secondary zone above primary EBIP on Pad 8 & 7N
- Increased EBIP top pick by 16.8m based on:
  - Obs well temperature data
  - 4D Seismic anomaly











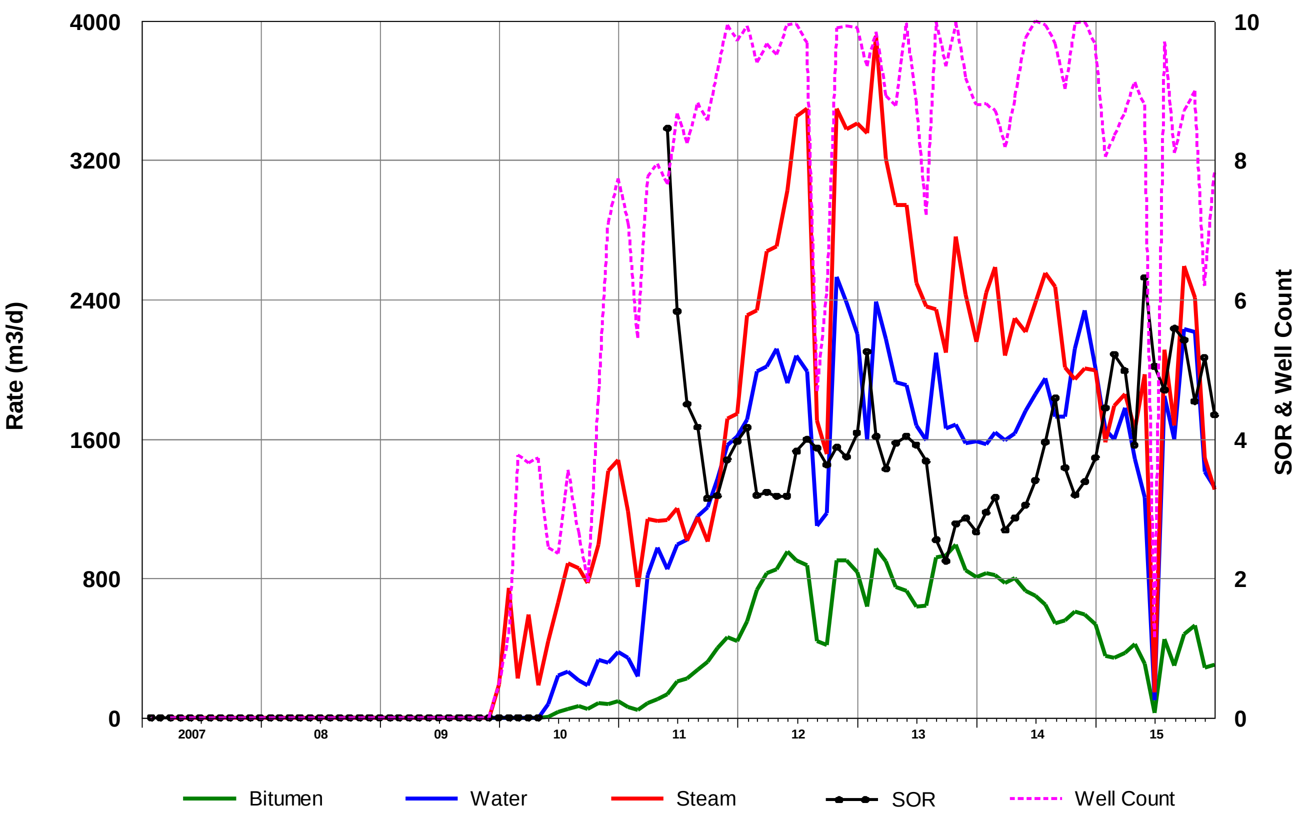
Examples of Low, Mid, High Recovery

- Low Recovery
  - Pad 2SE

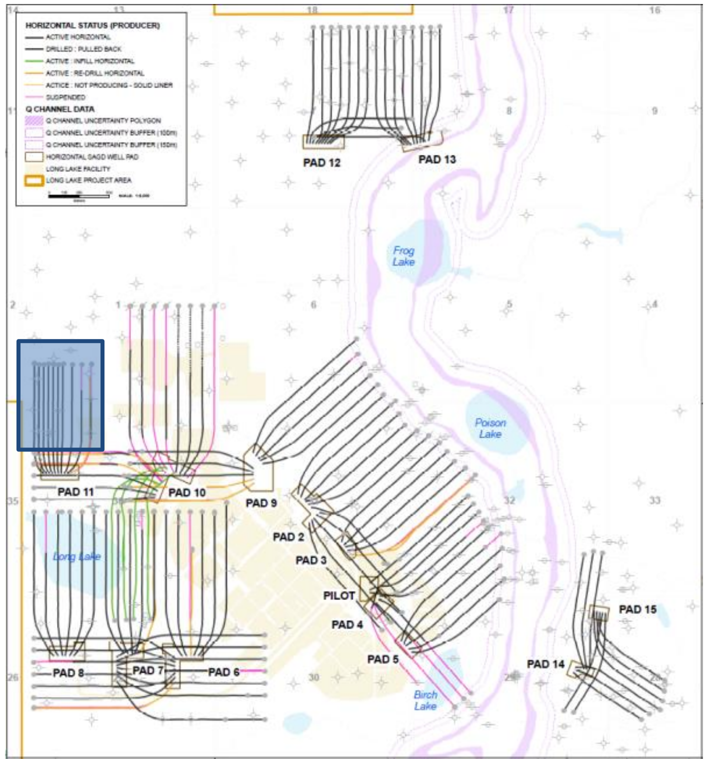
- Mid Recovery
  - Pad 8

- **High Recovery**
  - **Pad 11**

Pad 11 Production Summary



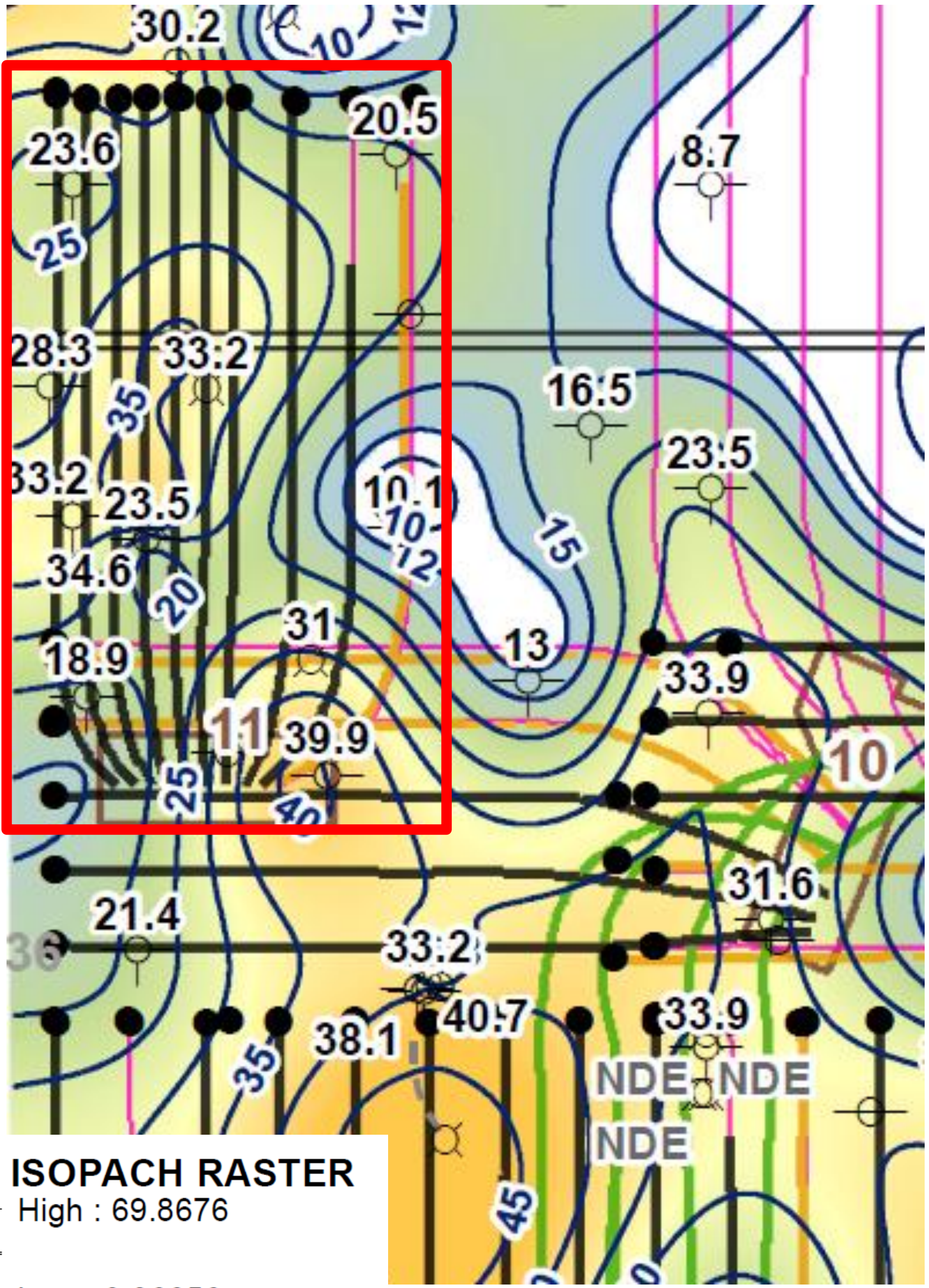
Well	EBIP 10^3 (m^3)	Dec 2015 Cumulative Bitumen 10^3 (m^3)	Dec 2015 RF (%)
11P01	324	158	49%
11P02	180	83	46%
11P03	180	115	64%
11P04	189	95	50%
11P05	191	70	37%
11P06	203	100	49%
11P07	286	120	42%
11P08	313	129	41%
11P09	193	132	68%
11P10	147	49	33%
Pad 11	**2206**	**1049**	**48%**



- All 10 wells are on ESP
- Tighter well spacing on west side of pad (40m vs 80m)
- Thick, relatively clean sand package with top water
- 2013 and 2015 4D has improved interpretation of IHS bedding and steam chamber development
- 11S08 has not operated since Aug 2015
- Decline in bitumen rates can be attributed to top water effect
- Maintain relatively low pressure to reduce steam loss
- At YE, injection pressures were ~1,710–1,750 kPa

Pad 11 Geology

EBIP ISOPACH

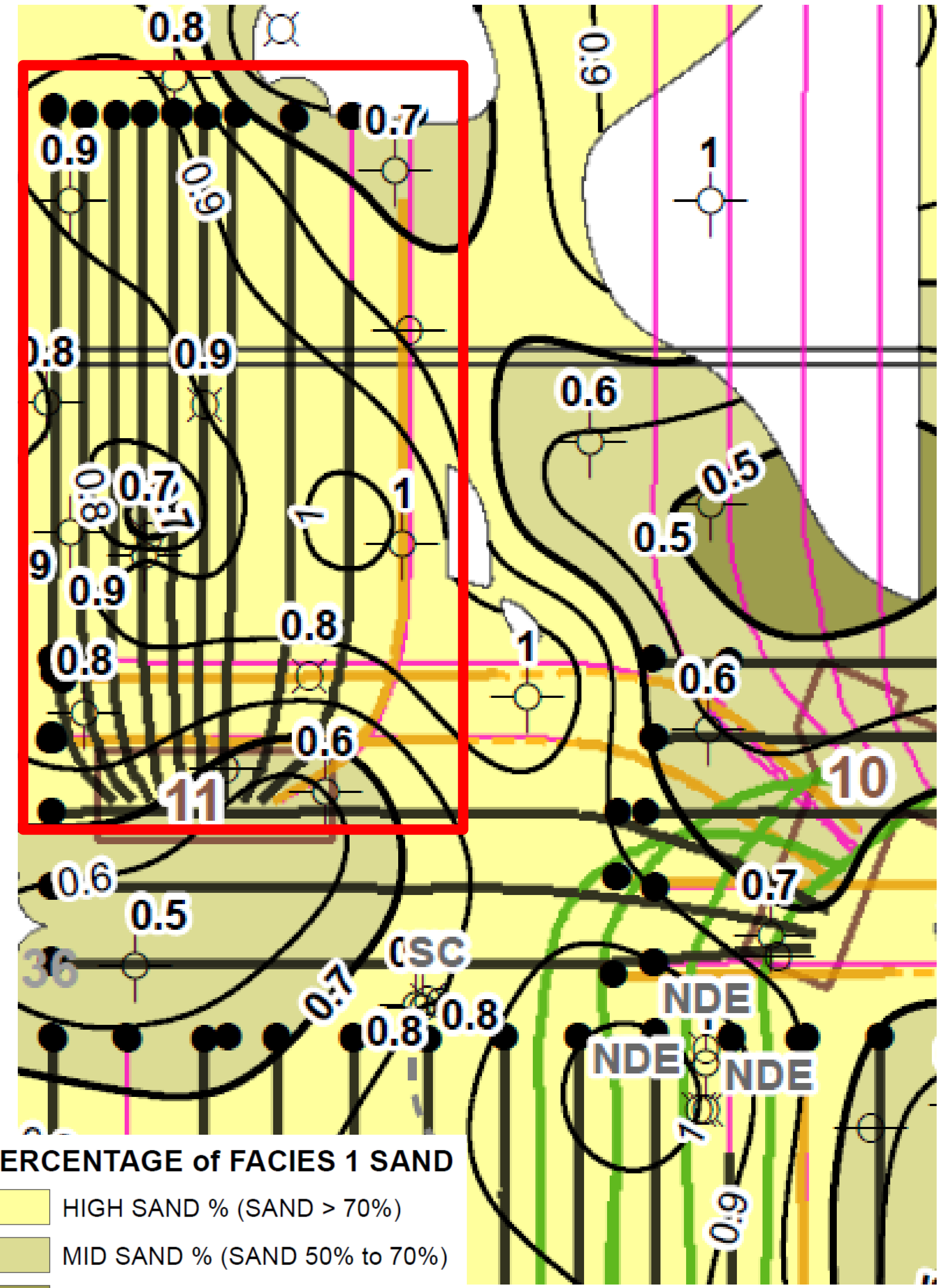


EBIP ISOPACH RASTER

High : 69.8676

Low : 9.36656

SAND FACIES PERCENTAGE

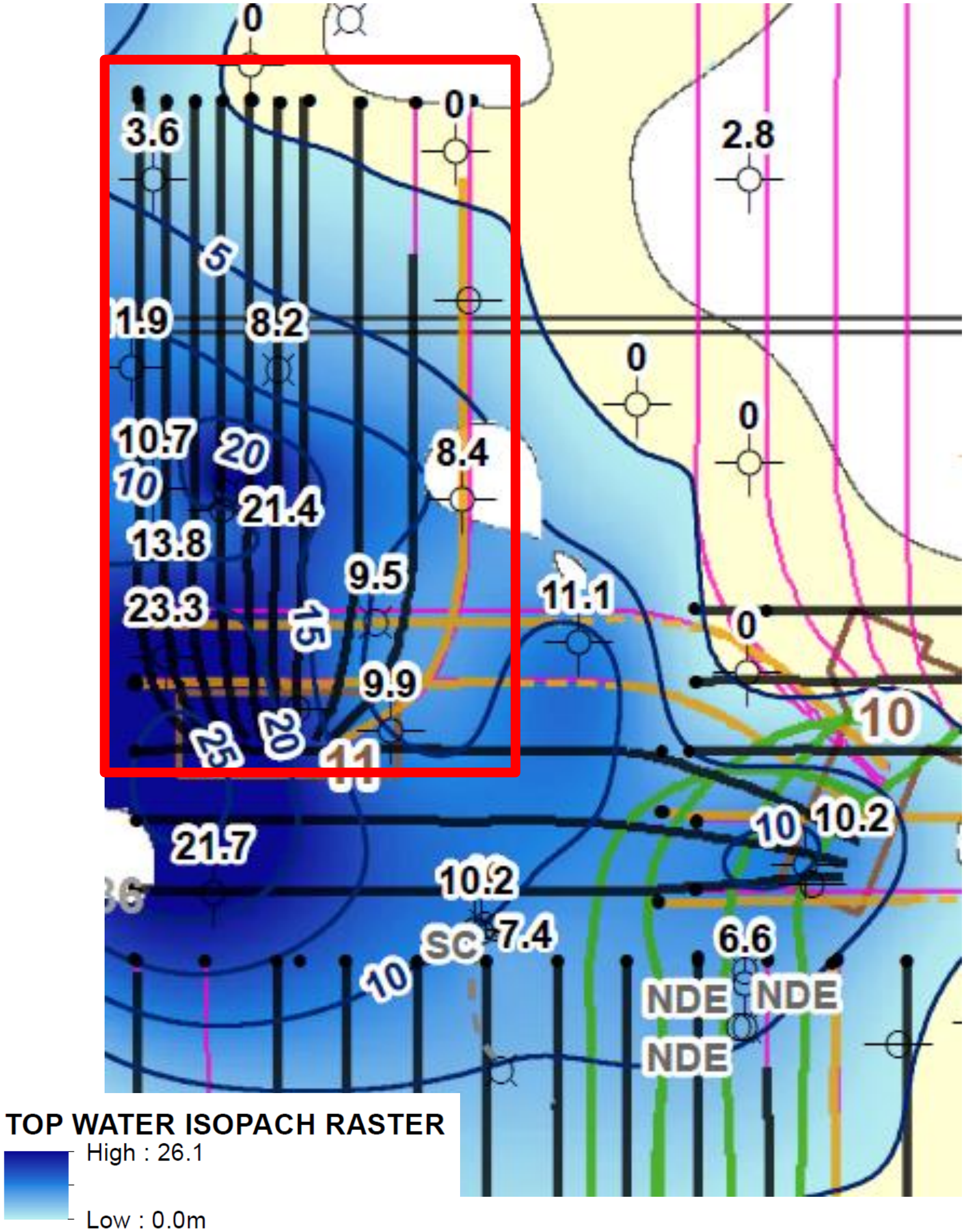


PERCENTAGE of FACIES 1 SAND

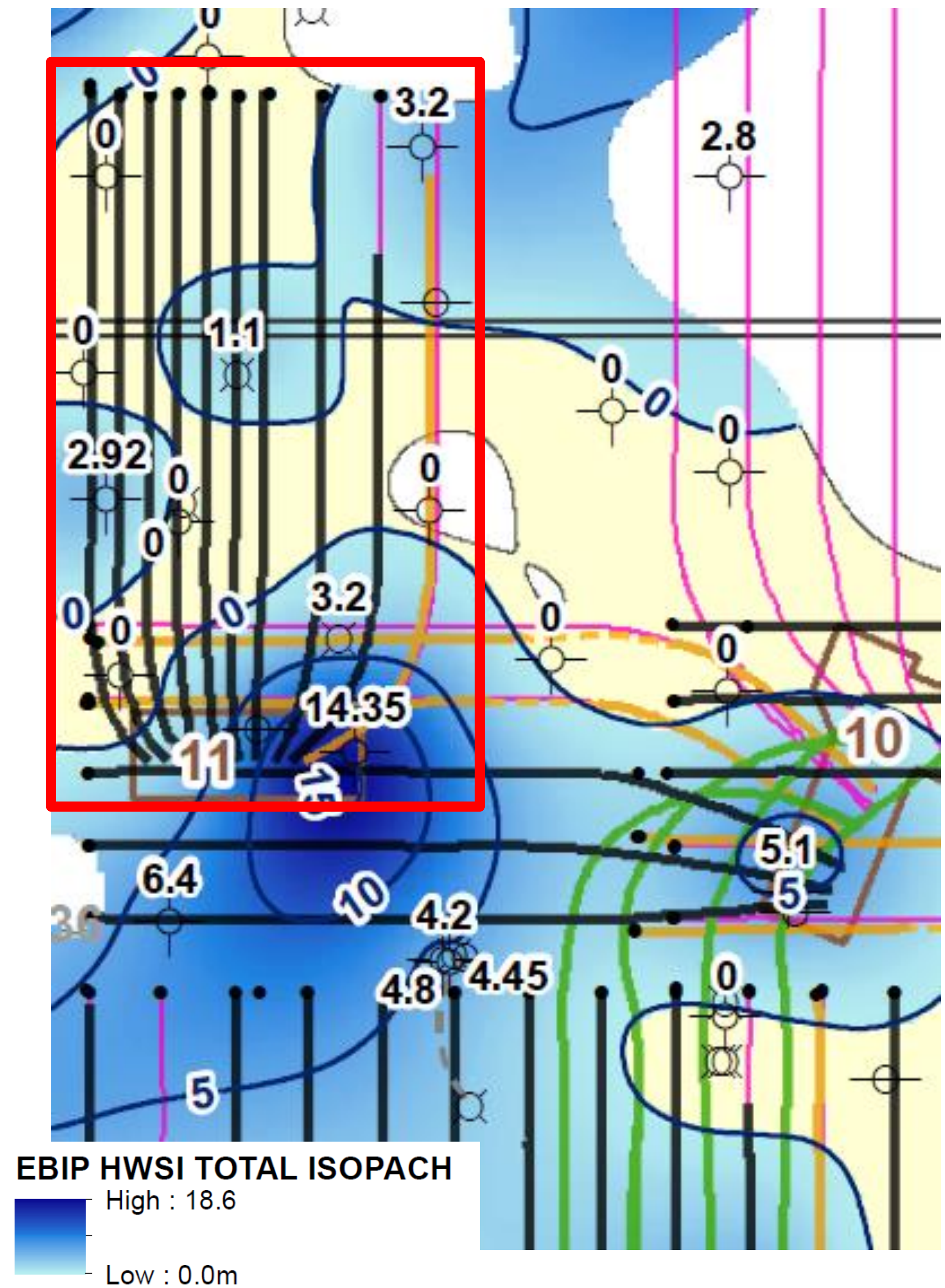
- HIGH SAND % (SAND > 70%)
- MID SAND % (SAND 50% to 70%)
- LOW SAND % (SAND < 50%)

Pad 11 Geology

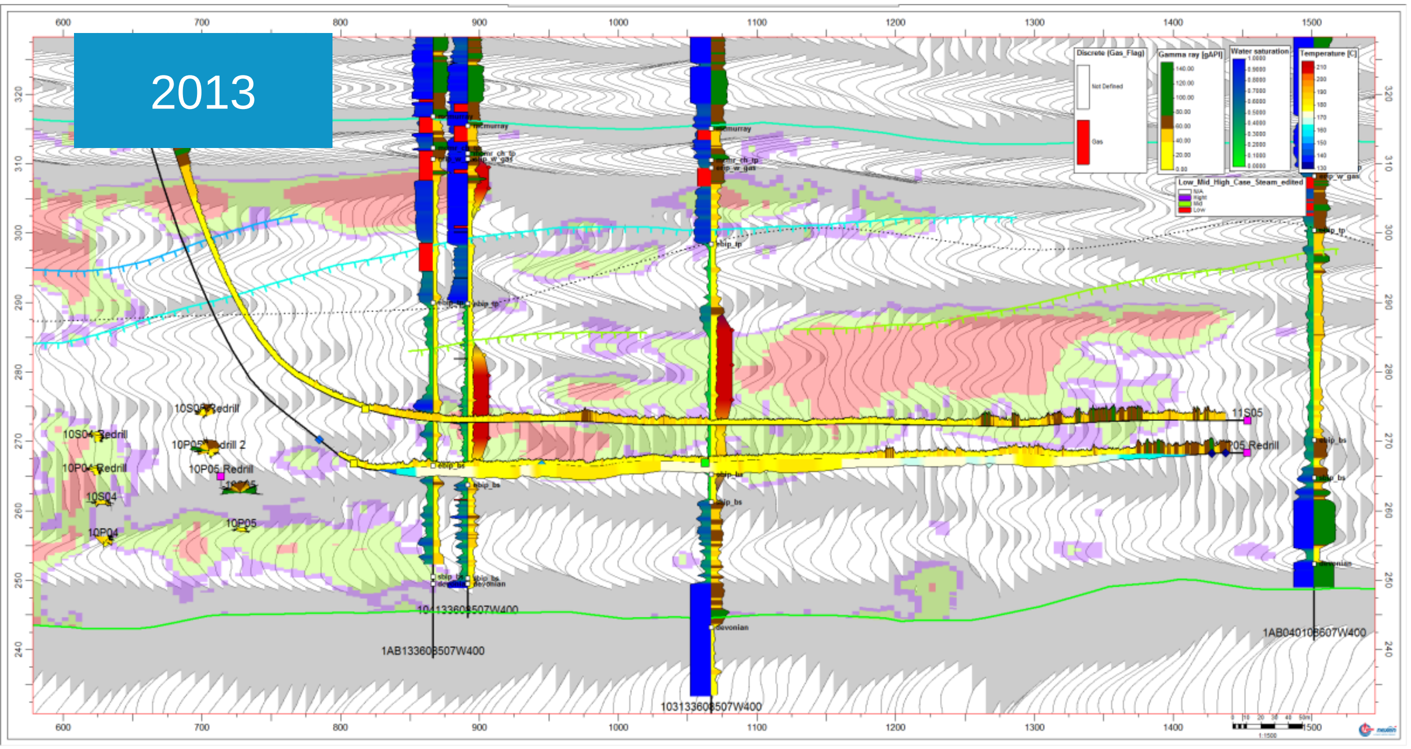
HWSI ABOVE EBIP (TOP WATER)

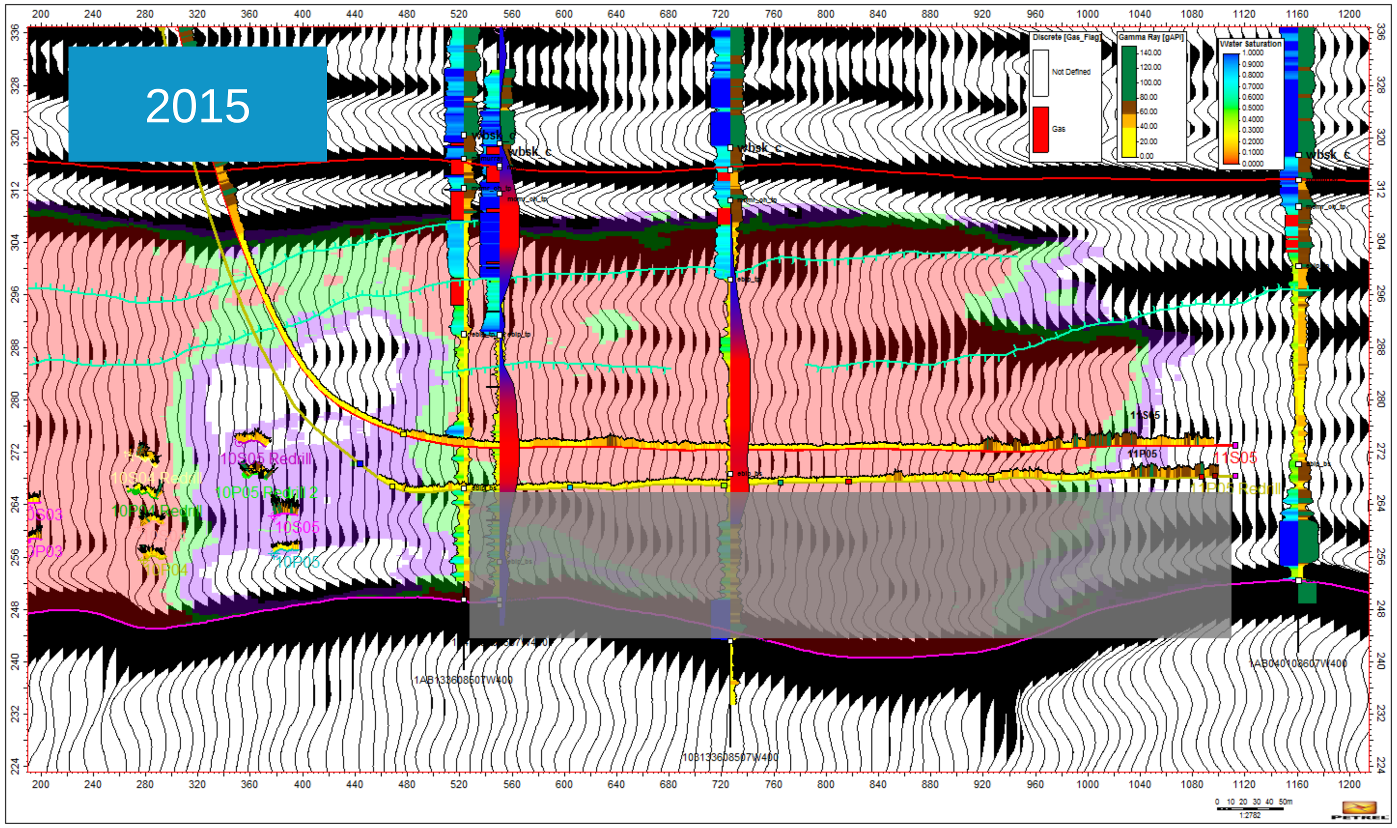


HWSI WITHIN EBIP



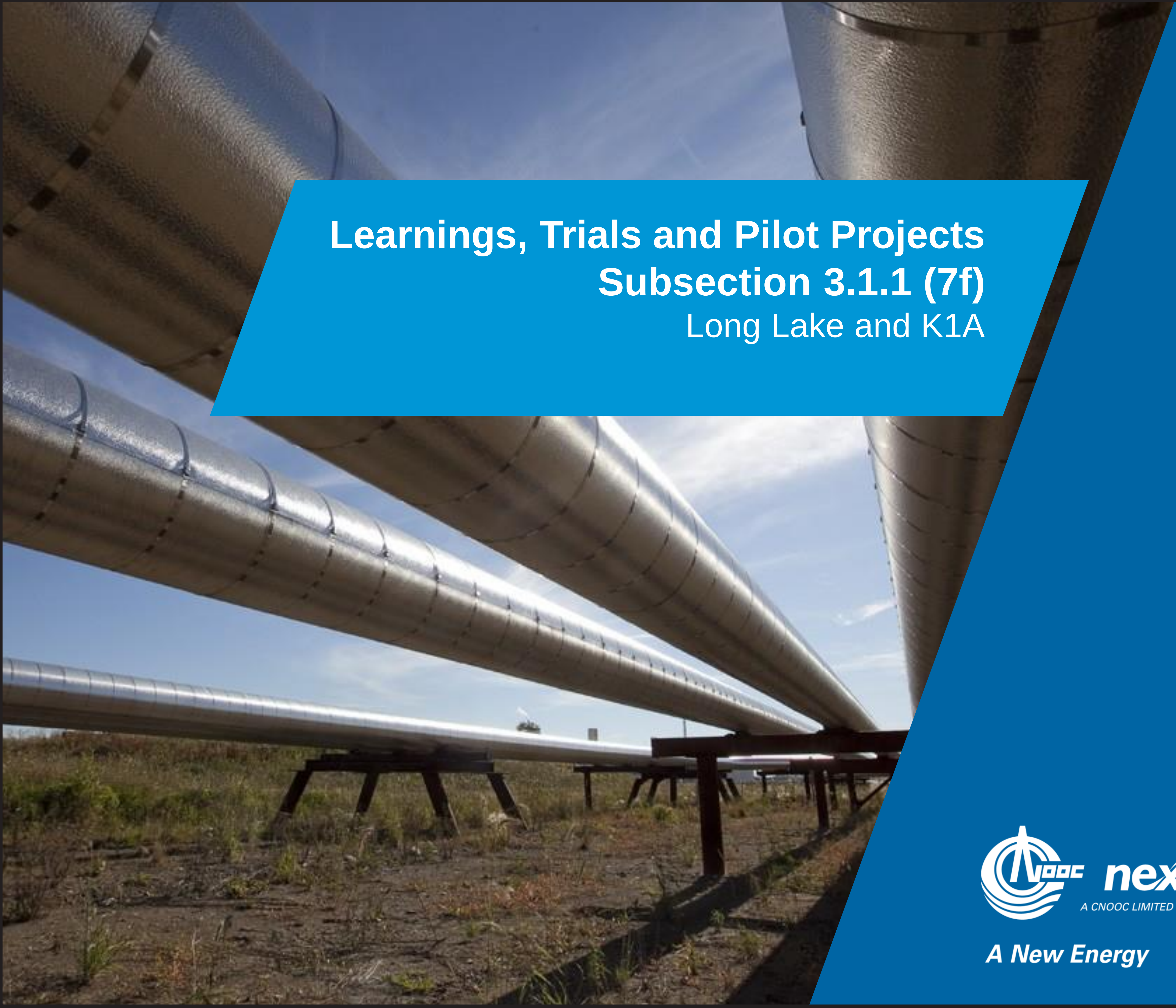
Pad 11





- Comparison of 2013 and 2015 4D seismic anomalies
  - Cross section : 11Pair05
- Continuing to see improved chamber development though EBIP interval – growth around IHS
- Challenging development by the toes where reservoir quality varies
- Larger development of anomalies through top water
- Connection to 10W through top water

Processing calibration issues



Learnings, Trials and Pilot Projects
Subsection 3.1.1 (7f)
Long Lake and K1A

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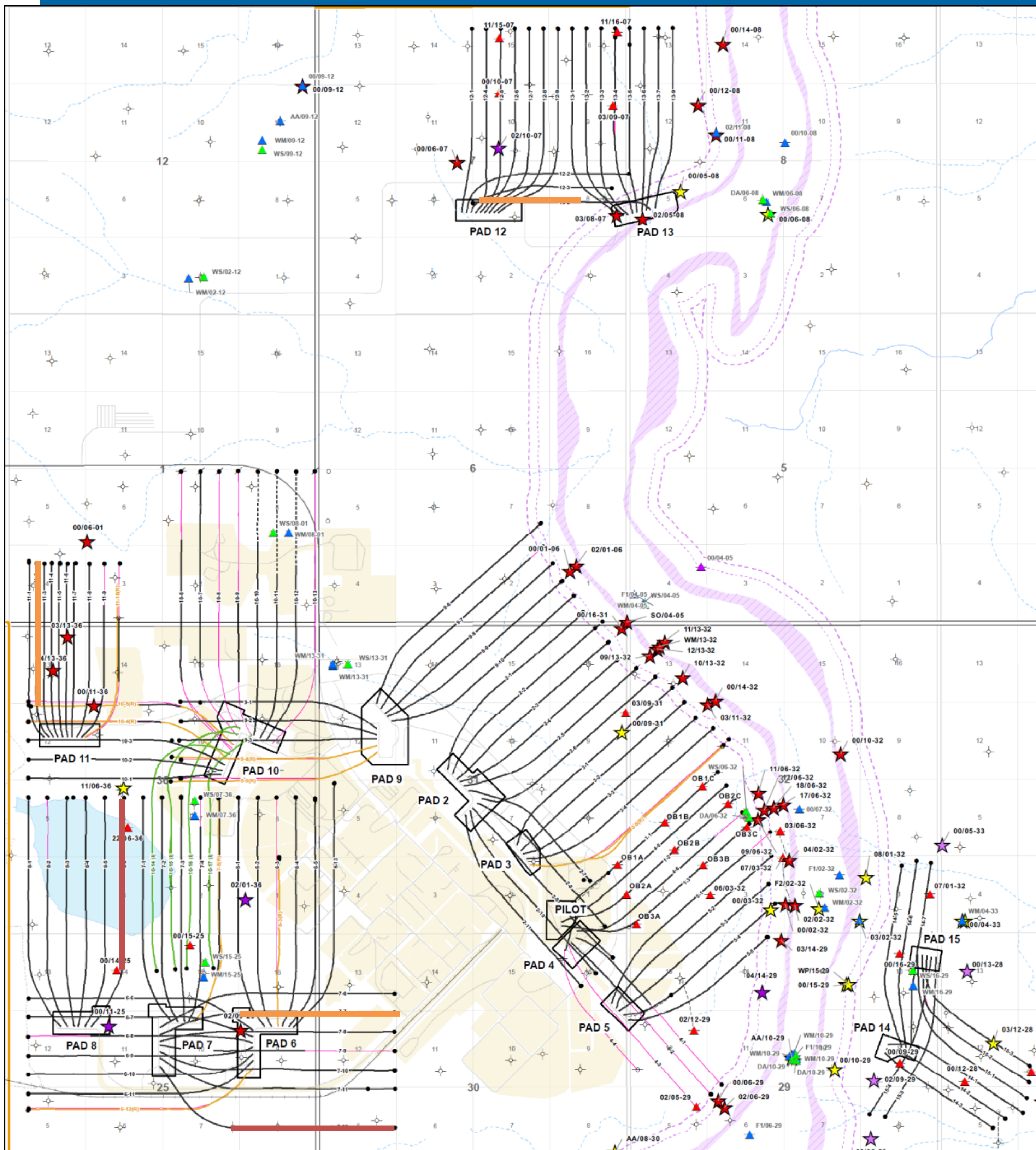
2015 Liner Failures



- 5 liner failures in 2015
- Evaluated case by case to determine whether to repair, re-drill or shut in

Wells Re-drilled

- None

Wells Repaired

- 11P02 – liner failure Q1, packer assembly
- 13P08 – liner failure Q2, packer assembly
- 07P07 – liner failure Q3, packer assembly

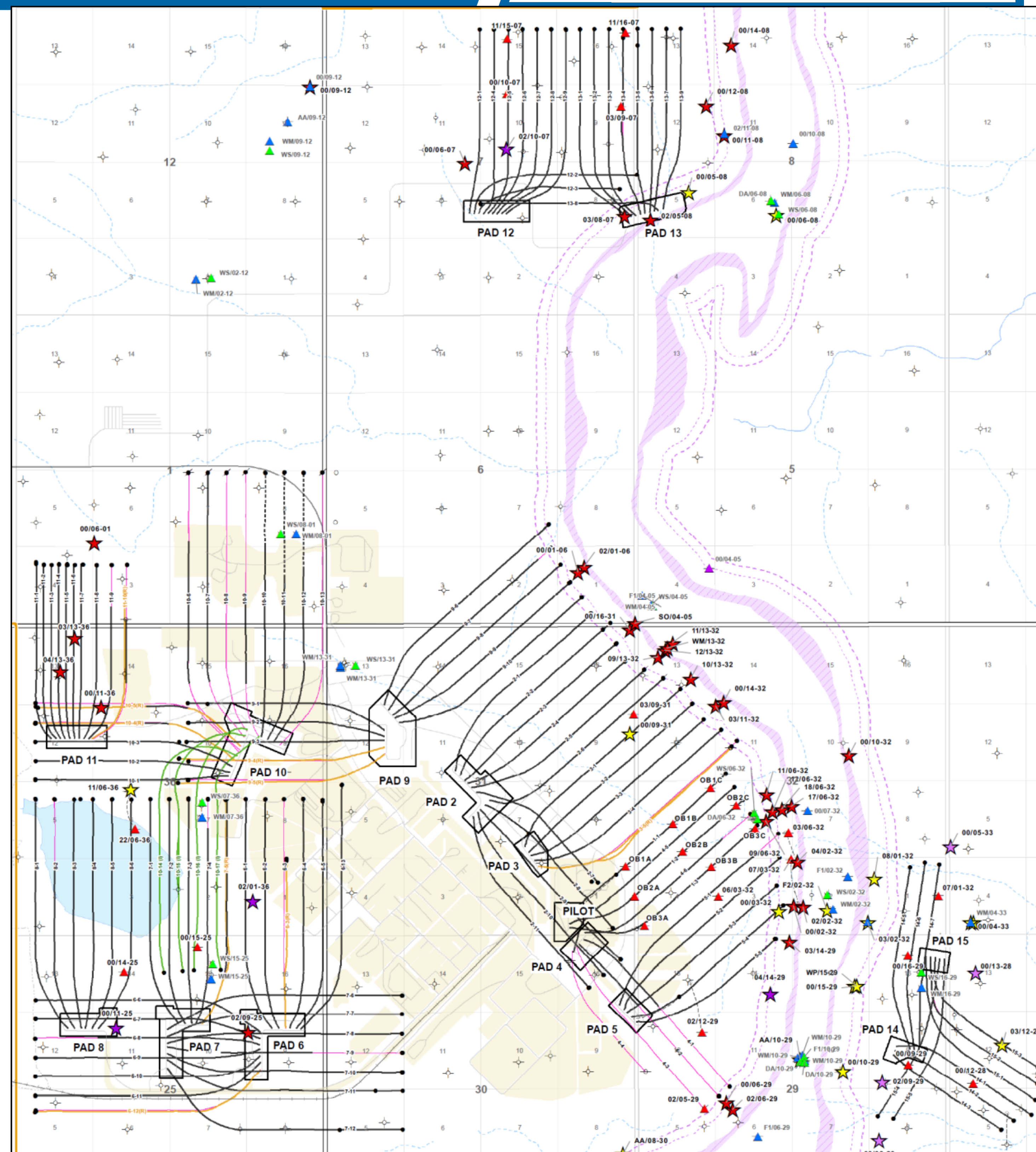
Wells Currently Shut In – Ongoing Evaluation

- 07P12 – liner failure Q3 2015
- 08S06 – liner failure Q1 2015

Well Re-drilled
Well Repaired
Well Shut in

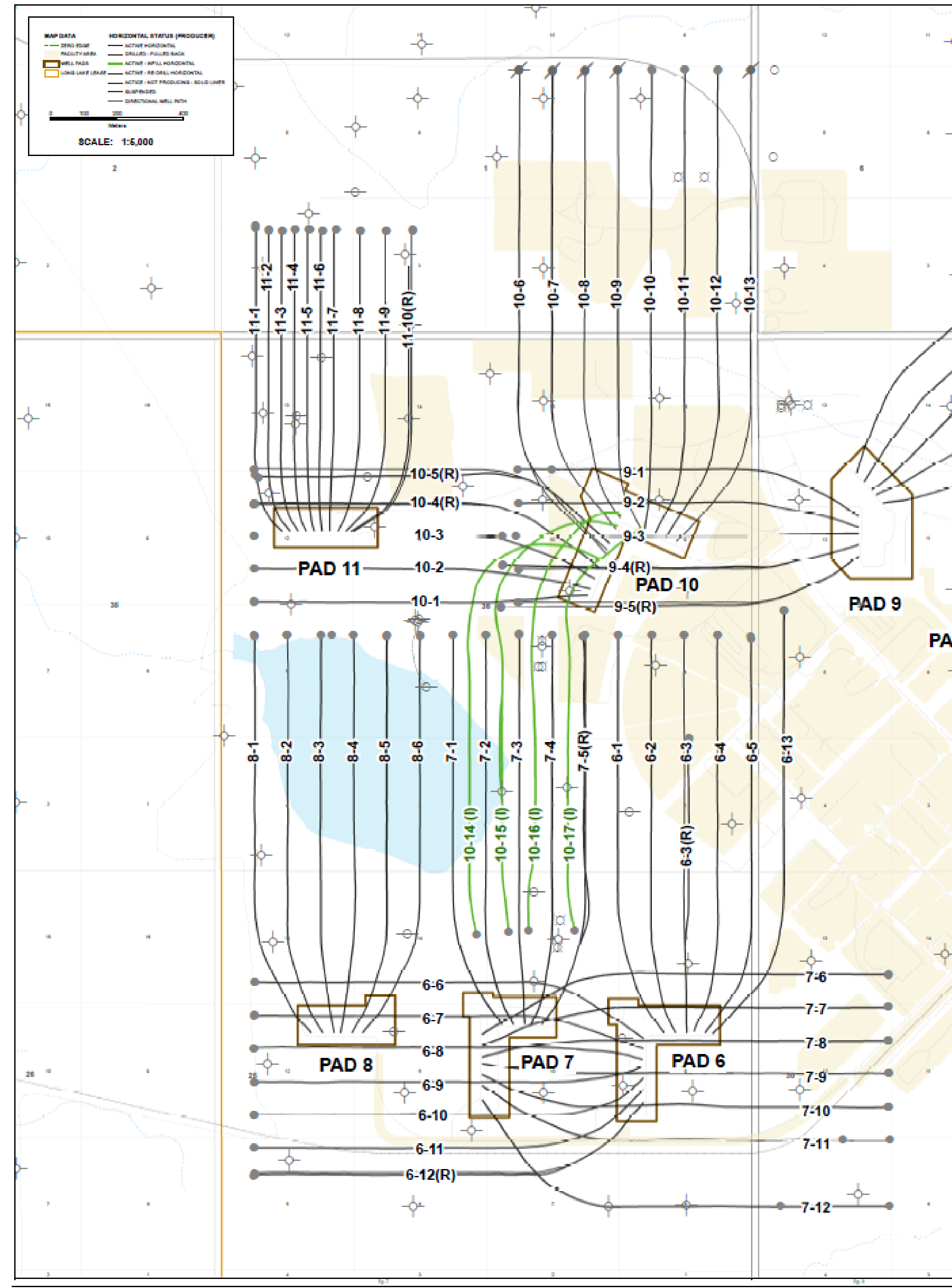
Liner Failures History

Well	Well Pair ID	Failure Date (Year)	Repair Action
2P11	LL-002-11	2013	Plugback
2P11	LL-002-11	2014	None - well left shut-in
3P05	LL-003-05	2012	Re-Drill
3S05	LL-003-05	2013	Re-Drill
3P05	LL-003-05	2014	Re-Drill
6P03	LL-006-03	2010	Re-Drill
6S03	LL-006-03	2011	Re-Drill
6P04	LL-006-04	2014	Plugback
6P08	LL-006-08	2011	Plugback
6P08	LL-006-08	2012	Plugback
6P09	LL-006-09	2014	None
6P10	LL-006-10	2014	Plugback
6P12	LL-006-12	2012	Re-Drill
6P12	LL-006-12	2014	None - well left shut-in
7P04	LL-007-04	2011	Plugback
7P04	LL-007-04	2011	Plugback
7P07	LL-007-07	2015	Packer Assembly
7P09	LL-007-09	2012	Plugback
7P11	LL-007-11	2012	Packer Assembly
7P11	LL-007-11	2014	Plugback / Packer Assembly
7P13	LL-007-13	2014	Packer Assembly
7P13	LL-007-13	2015	None - Well Left S.I.
8S06	LL-08-06	2015	Long string could not be pulled, cut string and left well shut in
9P07	LL-009-07	2012	Plugback
9P07	LL-009-07	2014	Plugback
10P04	LL-010-04	2014	Plugback
11P02	LL-011-02	2015	Packer Assembly
11P05	LL-011-05	2011	Re-Drill
11P10	LL-011-10	2013	Re-Drill
13P08	LL-013-08	2015	Packer Assembly
14P02	LL-014-02	2016	Packer Assembly



Pad 7N Infill Project Summary

- 4 infill producer wells drilled in 2014 using surface locations on Pad 10N
- Steam squeeze performed on infill wells prior to ramp up
  - 10P16 started up without steam squeeze due to high bottom hole temperatures
- All infill wells completed with ESPs, scab liners, and instrumentation (toe and heel pressure and 8 TC's)
- Strong performance seen thus far without negative impact on production from original SAGD well pairs
- Increased steam injection on original well pairs to support infills and 08P06 (08S06 shut in Q1 2015)

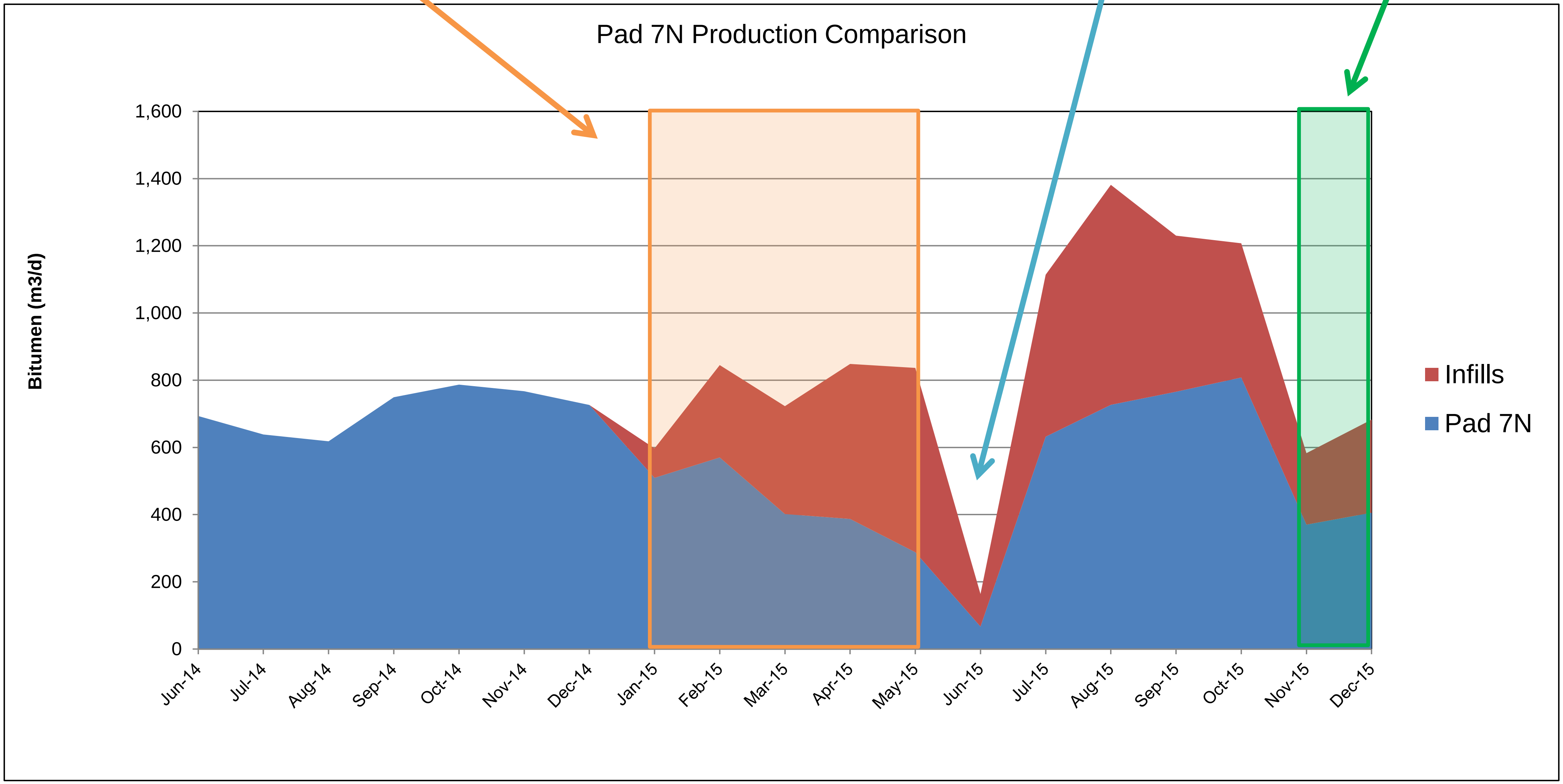


Pad 7N Infill Production Performance

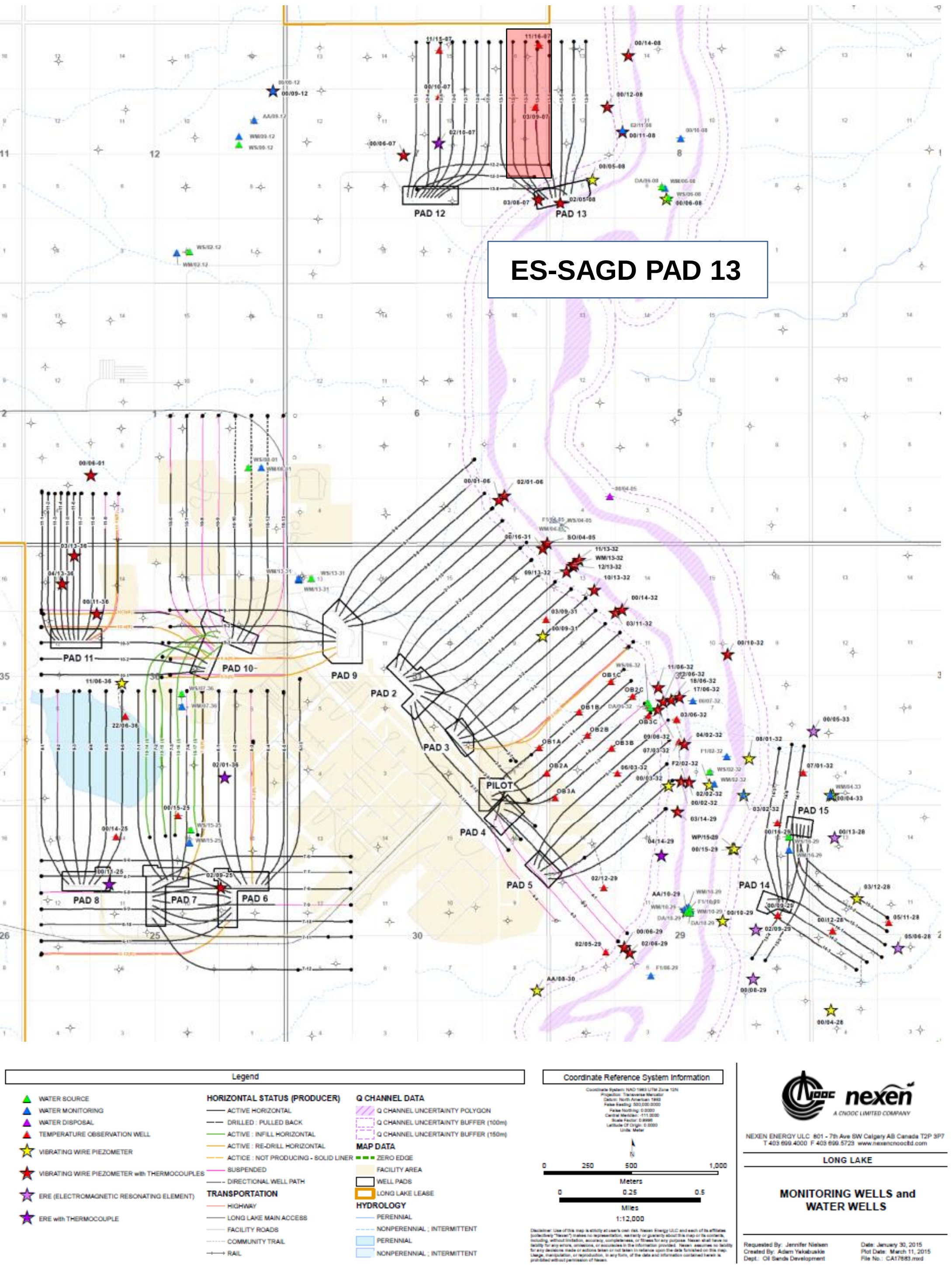
Throttled production on original SAGD well pairs due to surface constraints

Plant Turnaround

Throttled production on all wells due to surface constraints



Solvent Co-Injection Projects



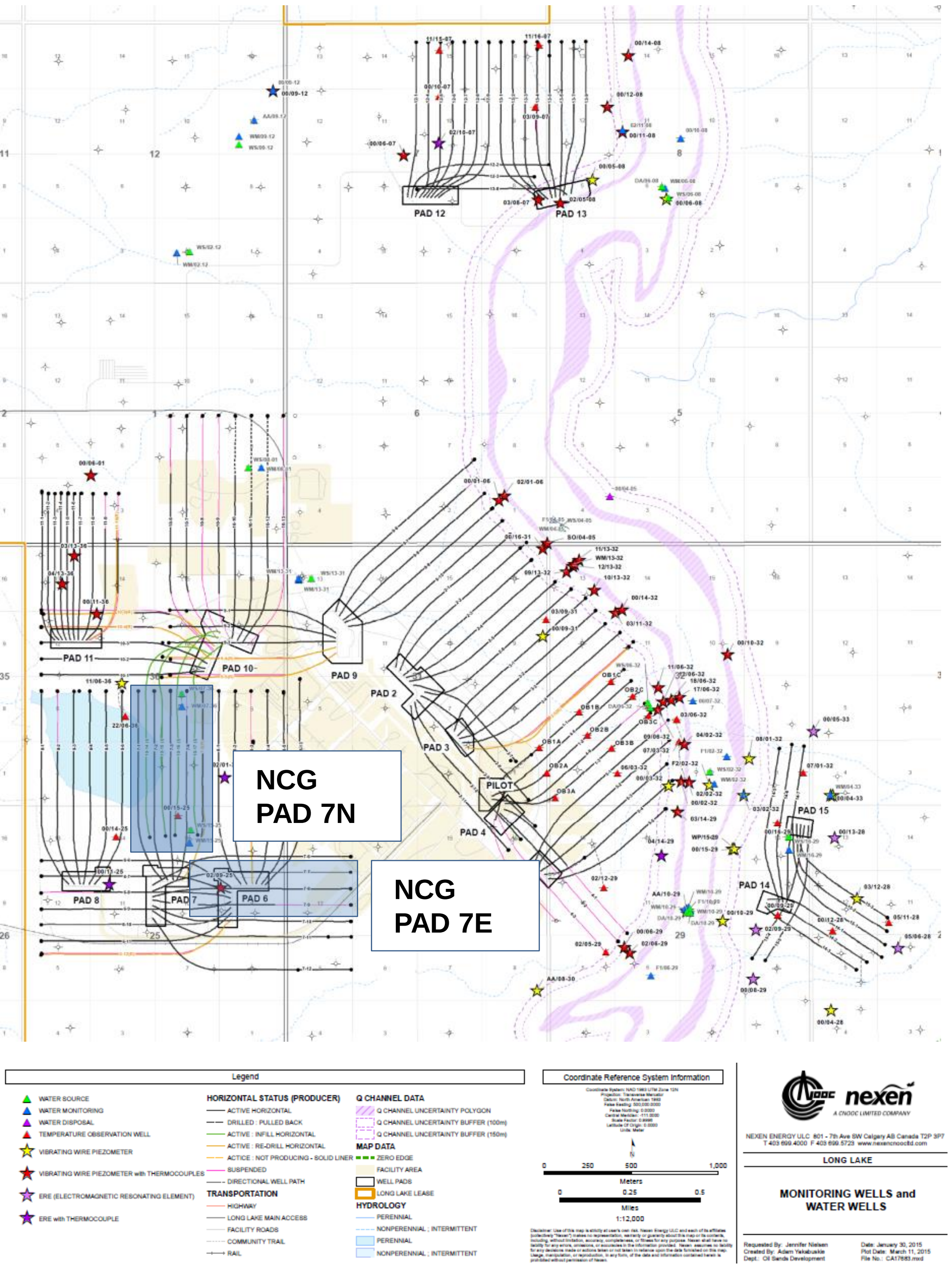
PAD 13 Solvent Co-Injection Pilot Test (2 years)

- Application approval 9485U was received in April, 2013
- Injected solvent being used is gas condensate (mostly C5 to C6 composition).
- Solvent injected at 12% of total injected volume (steam + solvent volume)

- Solvent co-injection started Oct. 2014 at 13S3 and 13S4.
- Solvent suspended in late 2015 due to inconsistent operations at Pad 13 caused by surface constraints.
- Indications of positive production uplift seen on a monthly basis despite lean zone impairment in the pilot area.
- Cumulative solvent recovery of 60%+ was ahead of simulation prediction as of year end 2015.

- Currently monitoring solvent recovery
- Re-evaluating pilot plans in light of surface interruptions.

NCG Co-Injection Projects



PAD 7E NCG Pilot Test

- Application approval 9485R received in September, 2012.
- Injected gas being used is natural gas.

- Gas injection started Oct. 2014 at 7P7 – 7P9.
- Early indications of iSOR reduction, however, due to unstable operating conditions the results were not conclusive.
- Gas injection suspended after turnaround
- Timing for pilot re-start being evaluated.

PAD 7N NCG Pilot Test

- Application approval 9485CC received in May, 2014.
- Construction of co-injection surface facilities complete April 2015.
- NCG co-injection in 5 well pairs planned.
- Injected gas to be used is natural gas.
- Timing for pilot startup being evaluated.

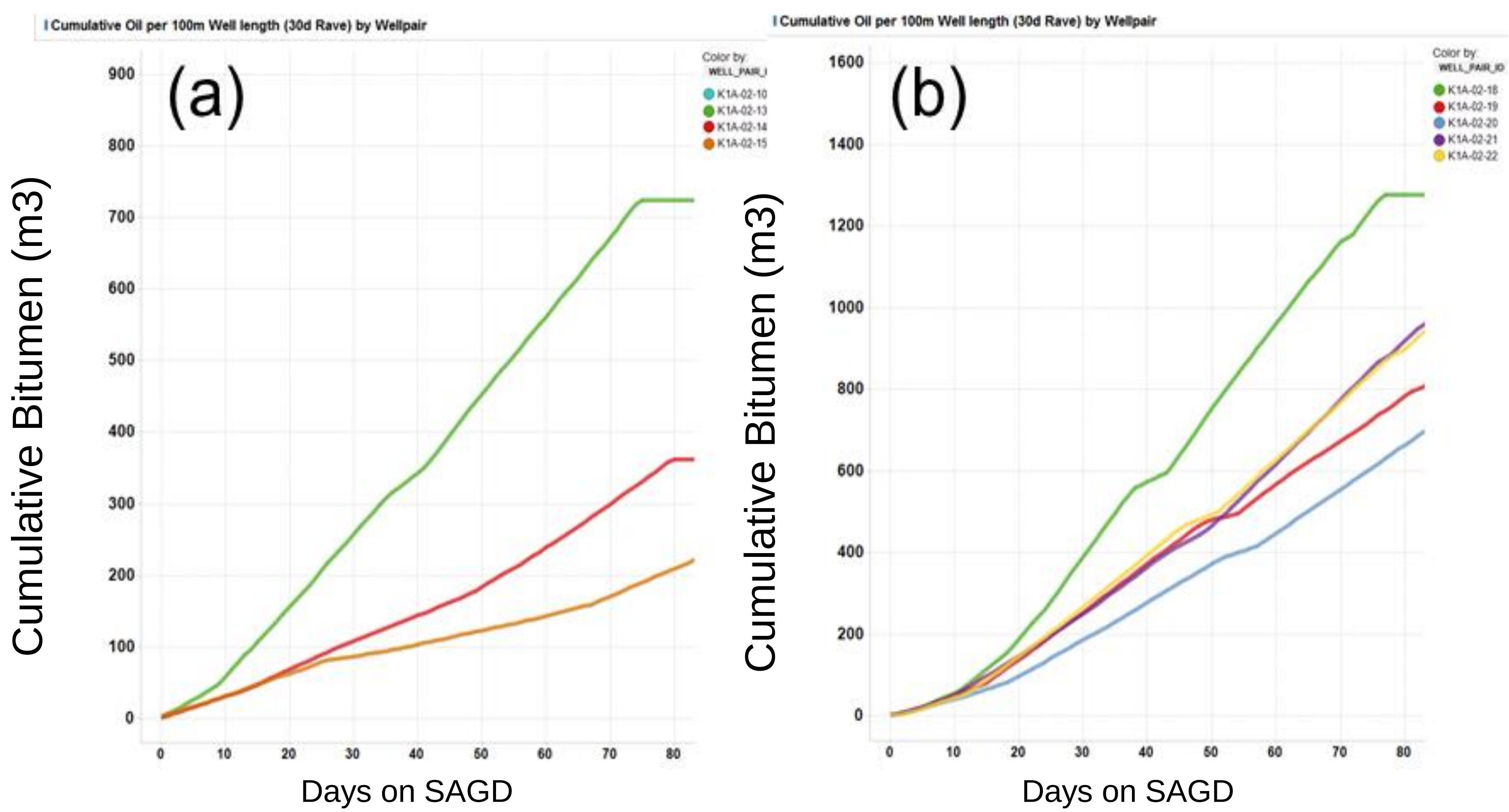
PAD 7E and 7N NCG Injection Test During TA

- Application approved in May, 2015.
- NCG injection on 3 well pairs on 7E and 5 well pairs on 7N
- Injected at ~20 E3M3/day/well for 8 days at PAD 7E and Pad 7N from May 28 – June 9, 2015.

- Impact on ramp up after turnaround was inconclusive due to equipment failure on the Pad 7 test separator.
- NCG injection did supply additional information about connectivity of the surrounding pads.

Diluent Trial

- Several wells at K1A were selected for diluent treatments to further expand data set
  - Injected 35-38m^3 diluent + BFW in three producers in the middle of the circulation period
  - Two wells had been converted to SAGD with no substantial differences to offset wells in terms of ramp up, illustrated as red lines in graphs below
  - Candidates require careful screening for formation heterogeneity, pressure containment and presence of high water saturation zones in close proximity of wellbores



Cumulative Oil Comparison to Offsets (a) K2P14, (b) K2P19

ICD Performance – PAD 13

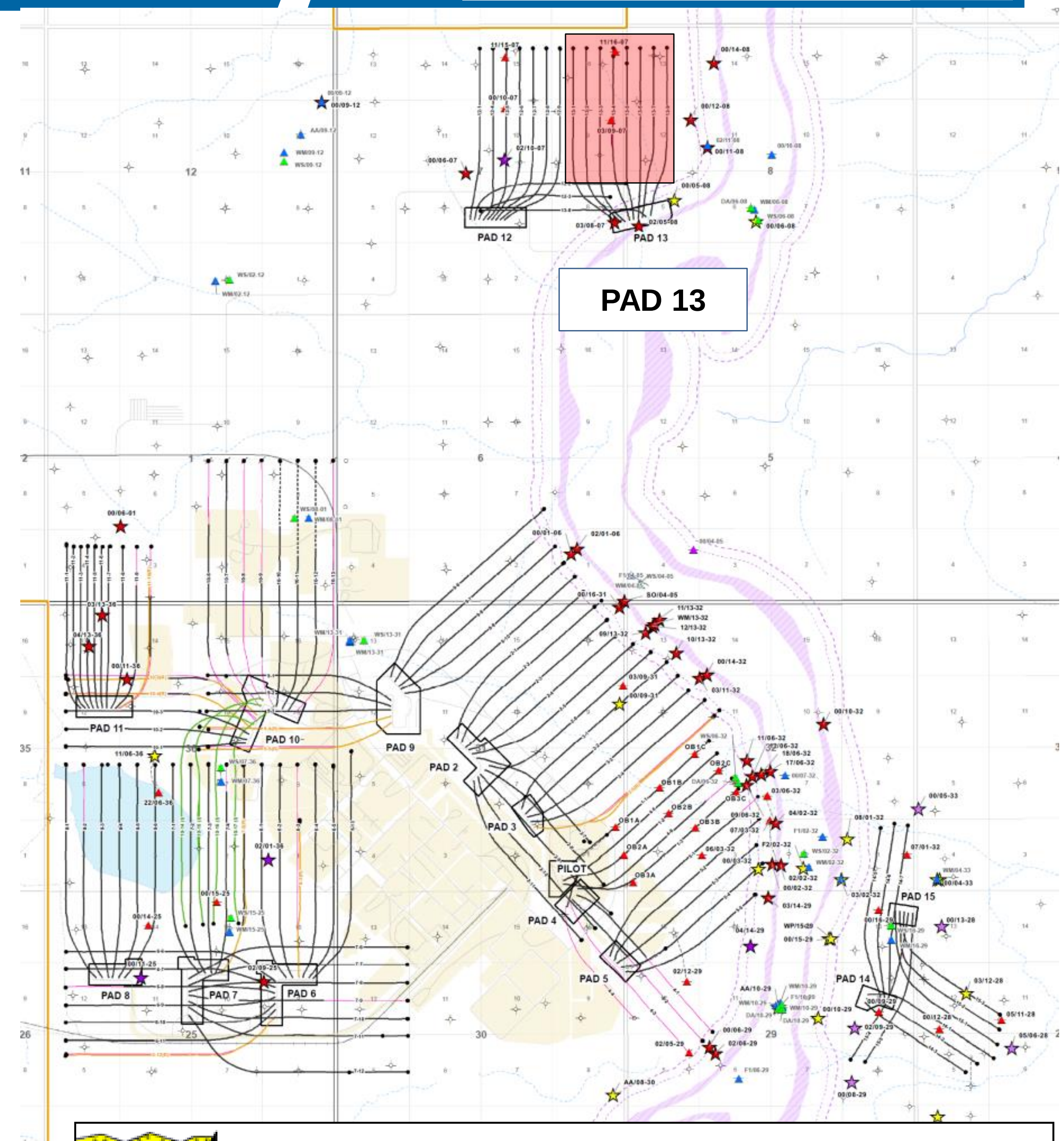
- In-flow control devices were installed in the producer scab liners with the intent to promote "more even" production of fluid along the wellbore with the expected benefits:
  - Reduced pressure drop along the producer
  - Better conformance along the well
  - Allow more representative temperature measurement from down-hole thermocouples

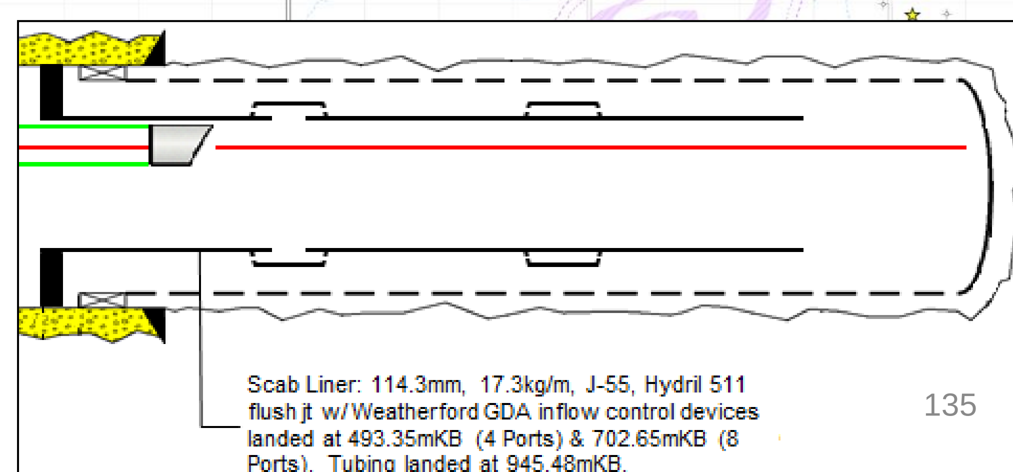
- Majority of wells with ICDs have been consistent good producers since SAGD conversion and are meeting production expectations

- All ICDs remain in operation with no current plans to close, alter or remove the devices

- 11 producers have 2 fixed sleeve ICDs (4 and 8 or 3 and 9 ports) and 2 have 1 fixed sleeve ICD (7 ports) installed along the lateral

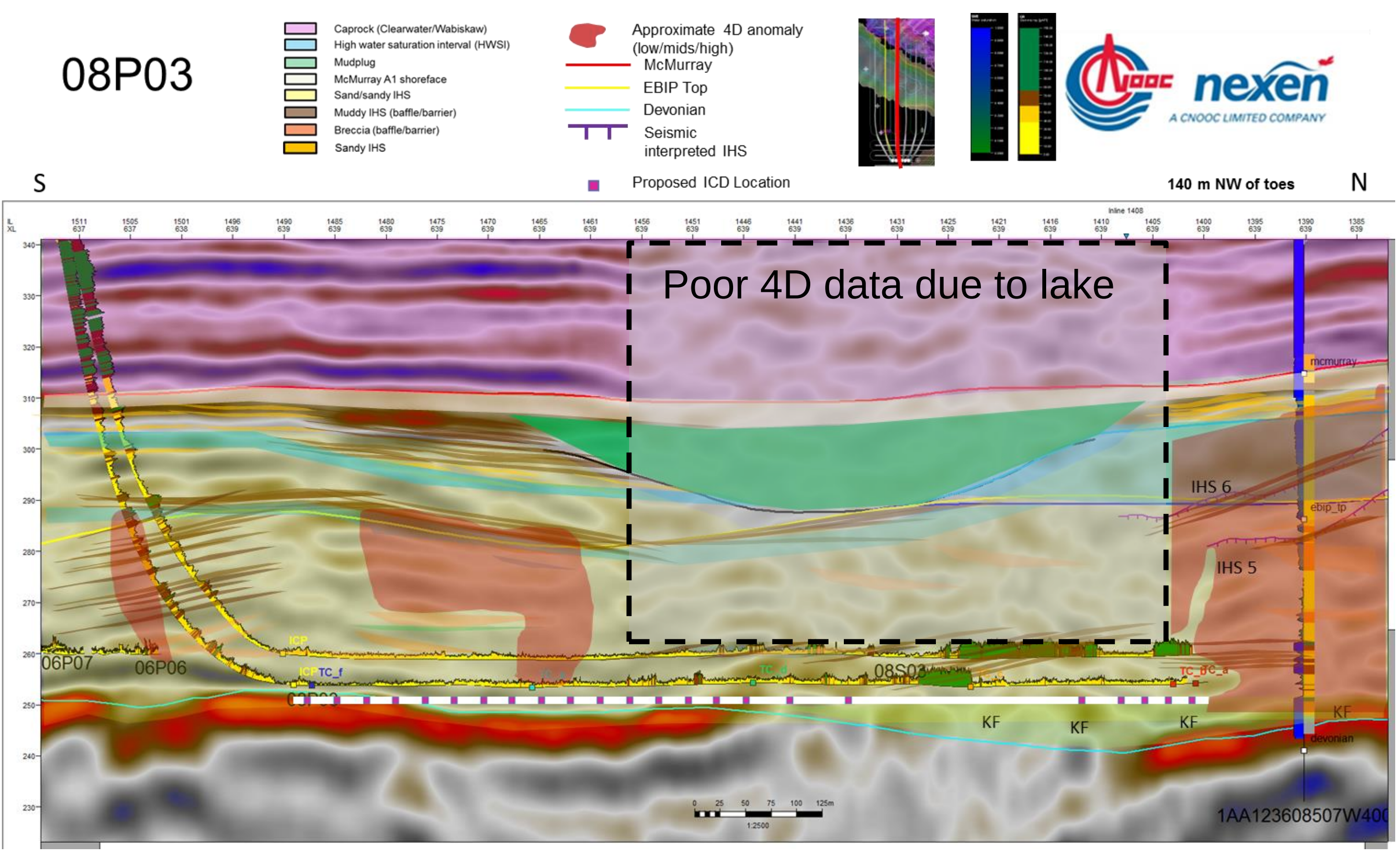
- Wells are showing good conformance

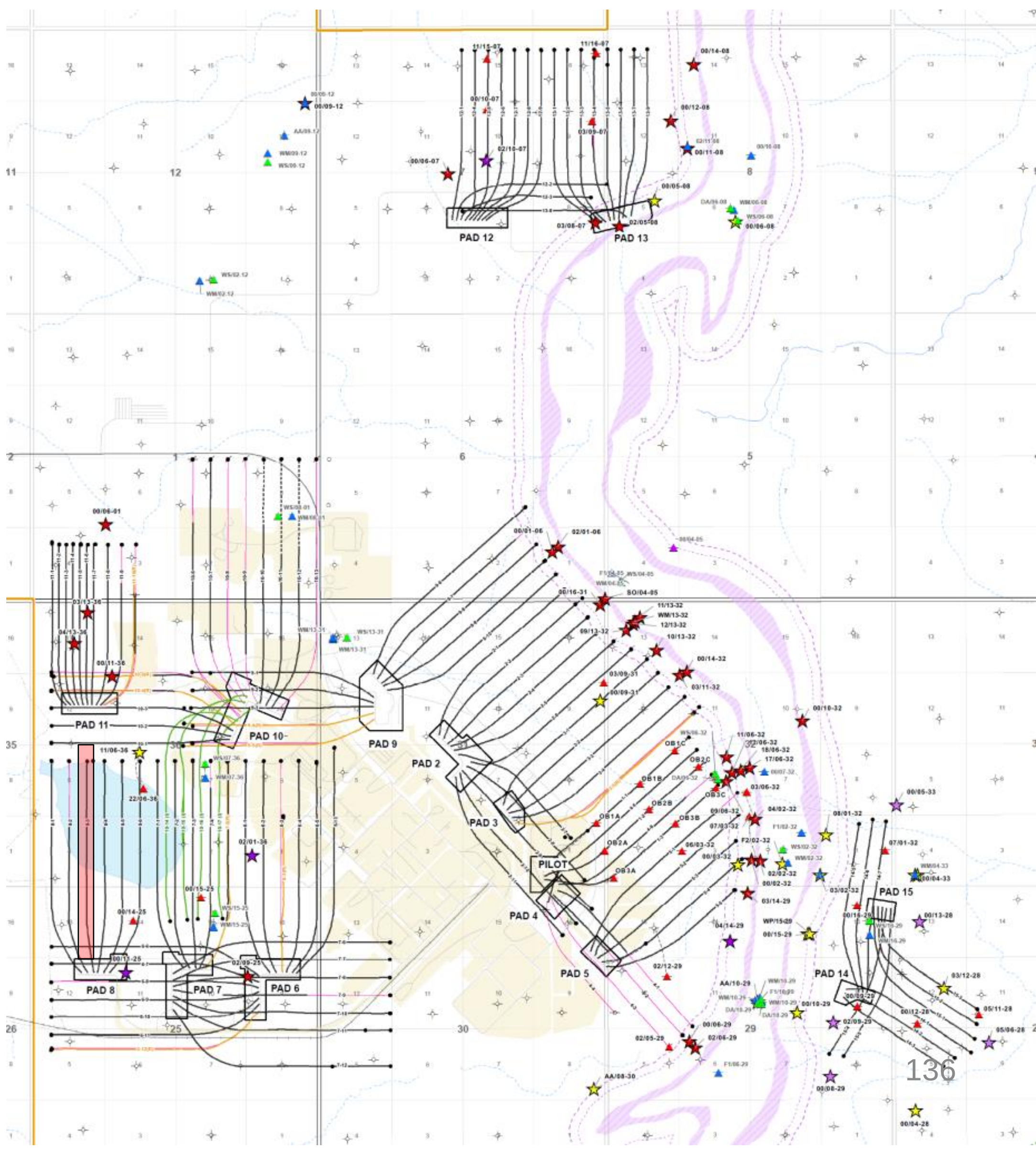




ICD Performance – 08P03

- In-flow control devices were installed on 08P03 during a pump change in Q4 2015 with the intent to promote “more even” production of fluid along the wellbore with the expected benefits:
  - Better conformance along the well
  - Reduced production impact due to “hot spot” at TC C
  - Increased contribution from toe
- 08P03 has not been operated consistently since ICD’s were installed
- Performance is still being evaluated





Observation Wells
Subsection 3.1.1 (7)
Long Lake

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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
- ACTICE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DIRECTIONAL WELL PATH

TRANSPORTATION

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

Q CHANNEL DATA

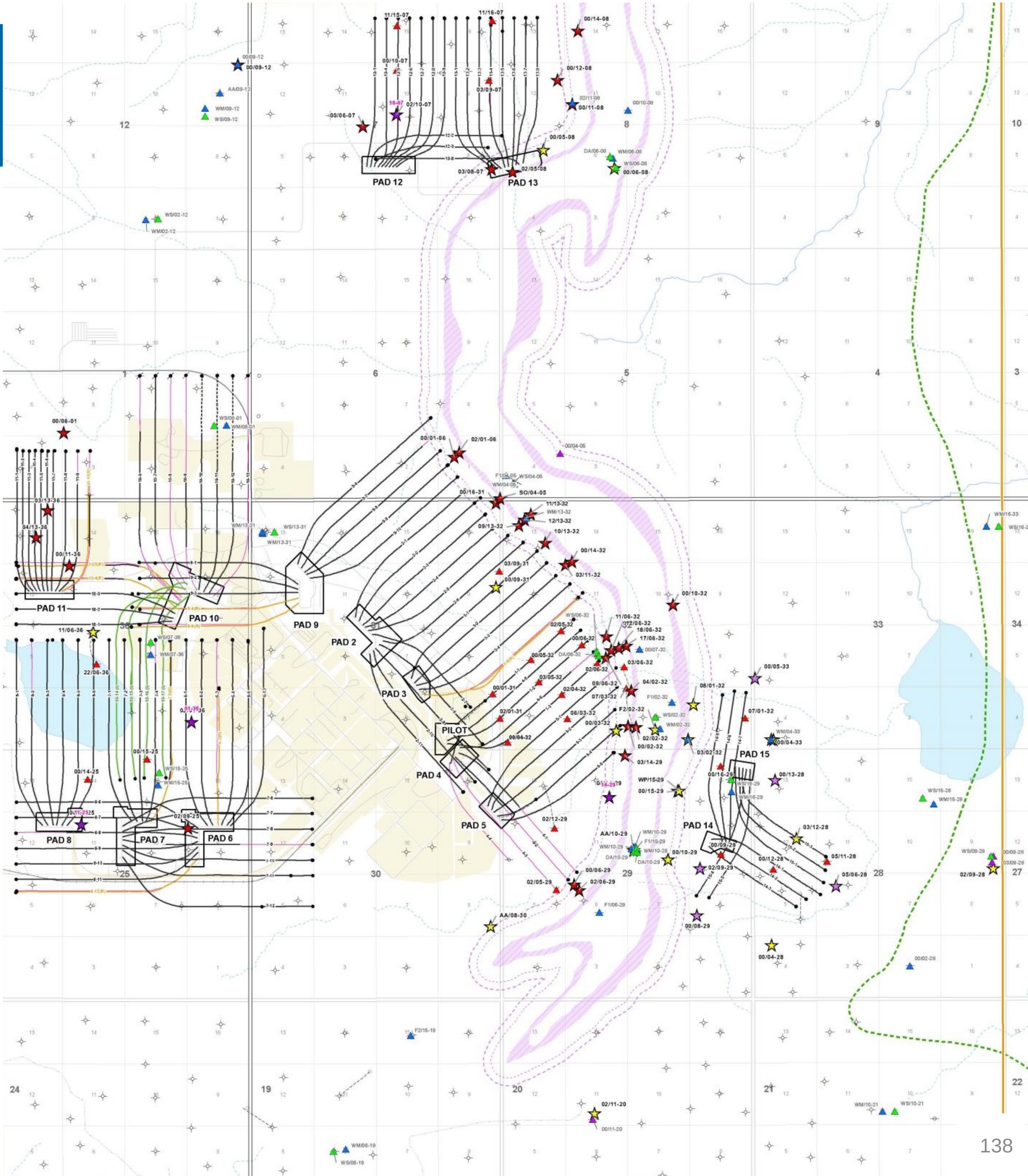
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

MAP DATA

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

HYDROLOGY

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



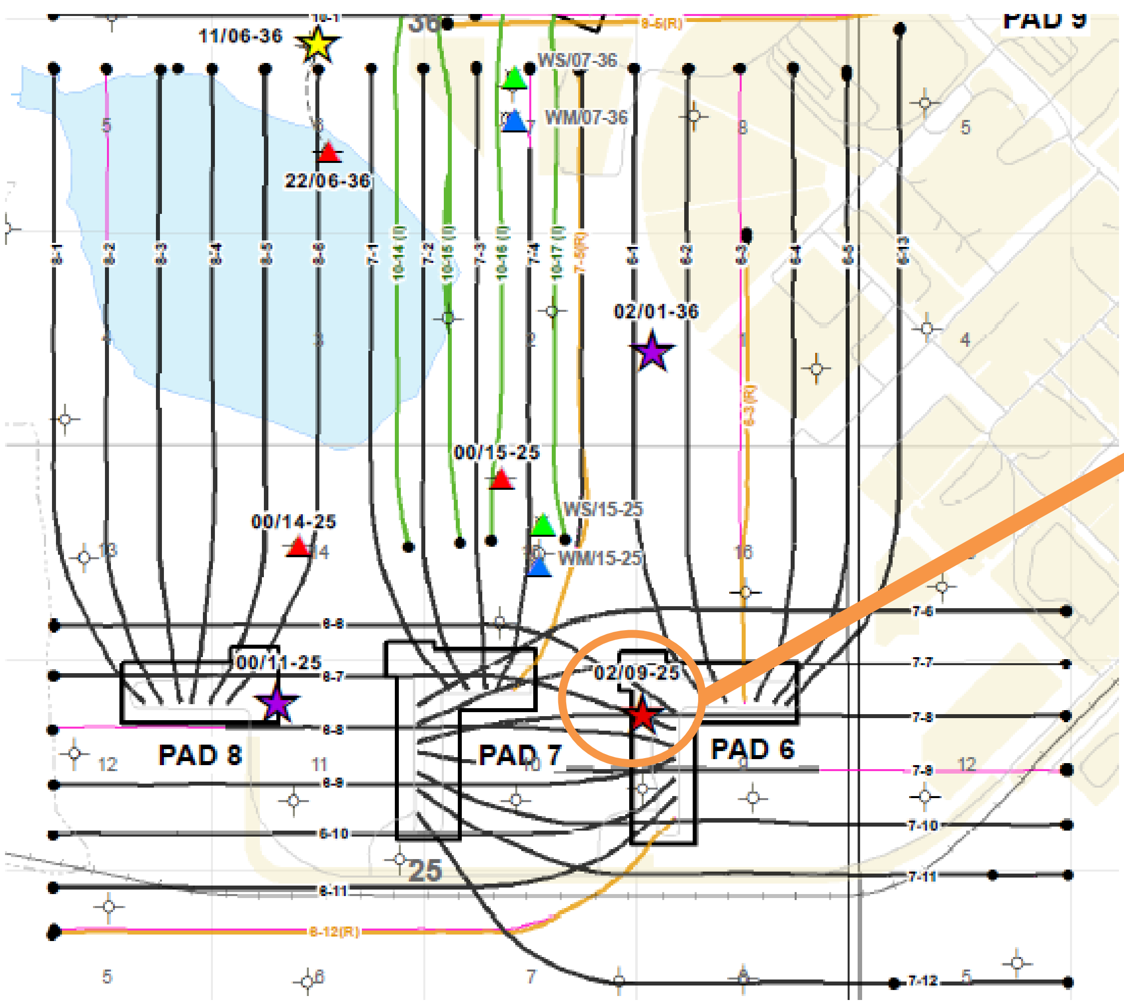
Observation Wells – Long Lake

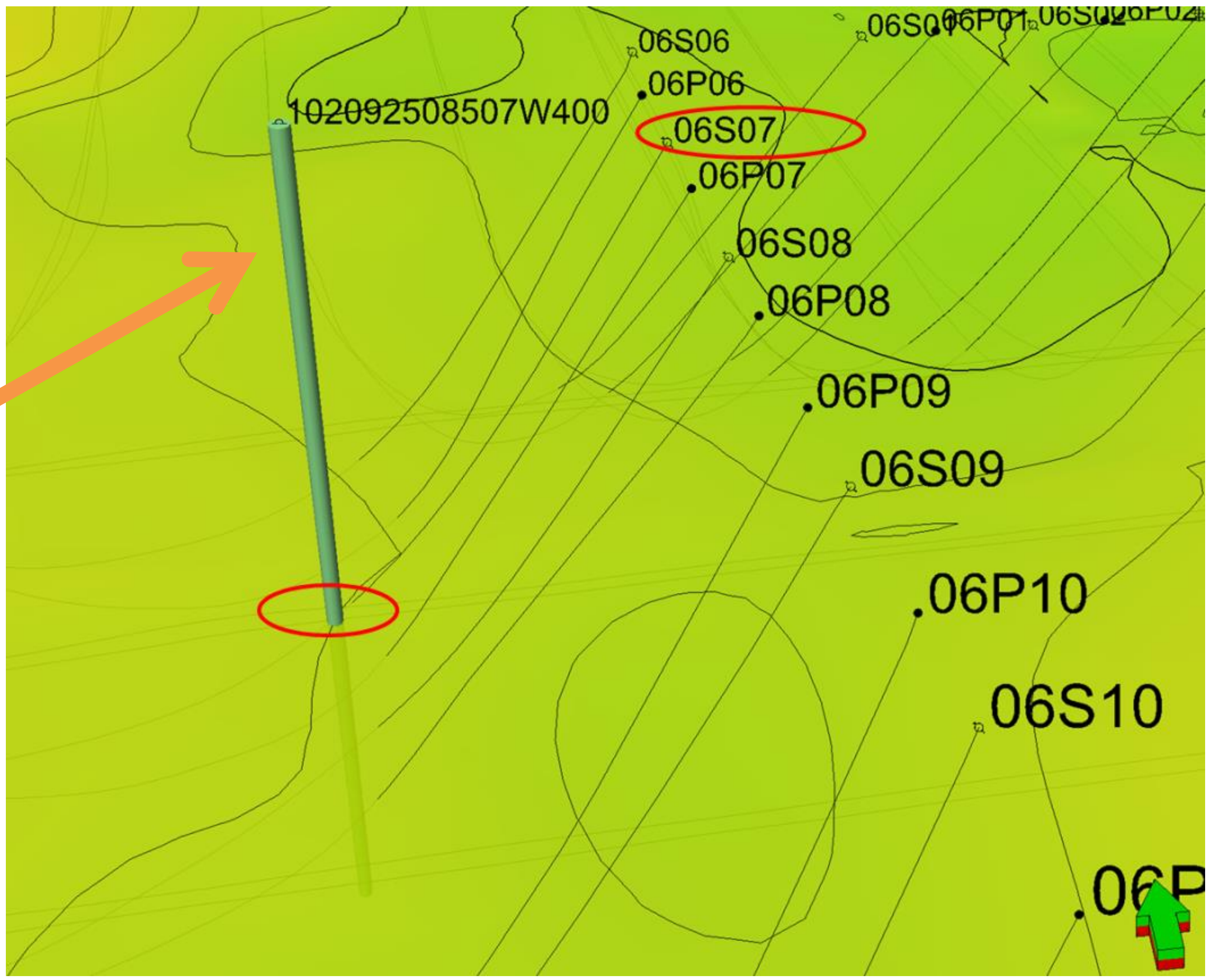
N/A – Greater than 300m to Q-channel or closest well pair

UWI	Closest Wellpair	Distance to Wellpair	Distance to Q channel	
			(Max Edge)	(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
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

Conductive Heating at 102/09-25

- Higher than expected temperatures were observed in the Clearwater A sand and caprock intervals in the 102/09-25 observation well
- The temperature in this interval had gradually increased since the observation well was drilled in 2012 (max of 60 deg C)
- Within the Clearwater A Sand, the obs well is very close to the build sections of Pad 6W producer and injector wells (<10m from 06S07)





Conductive Heating at 102/09-25

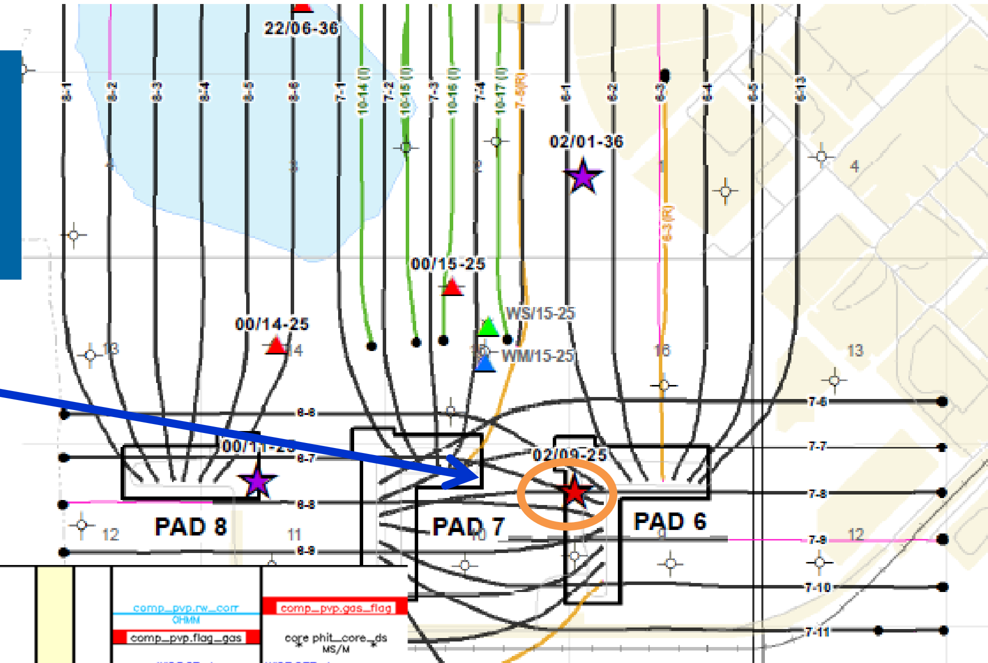
- Thorough analysis was done to determine the source of the temperature development, using the following data :
  - Full suite of logs (caliper, saturation, temperature, noise)
  - Conduction modeling
  - Review of geological and seismic data (including 2015 4D monitor)
  - Pressure & temperature data from other obs wells and neighboring well pairs

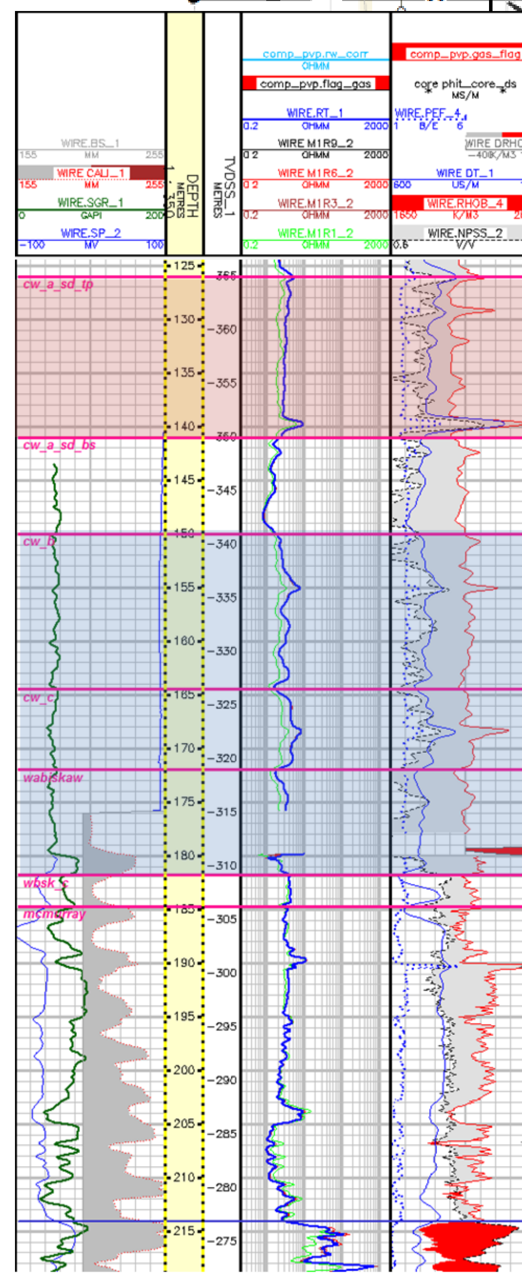
- Surrounding observation wells and water monitoring wells showed normal temperature and pressure trends within Clearwater A and Grand Rapids

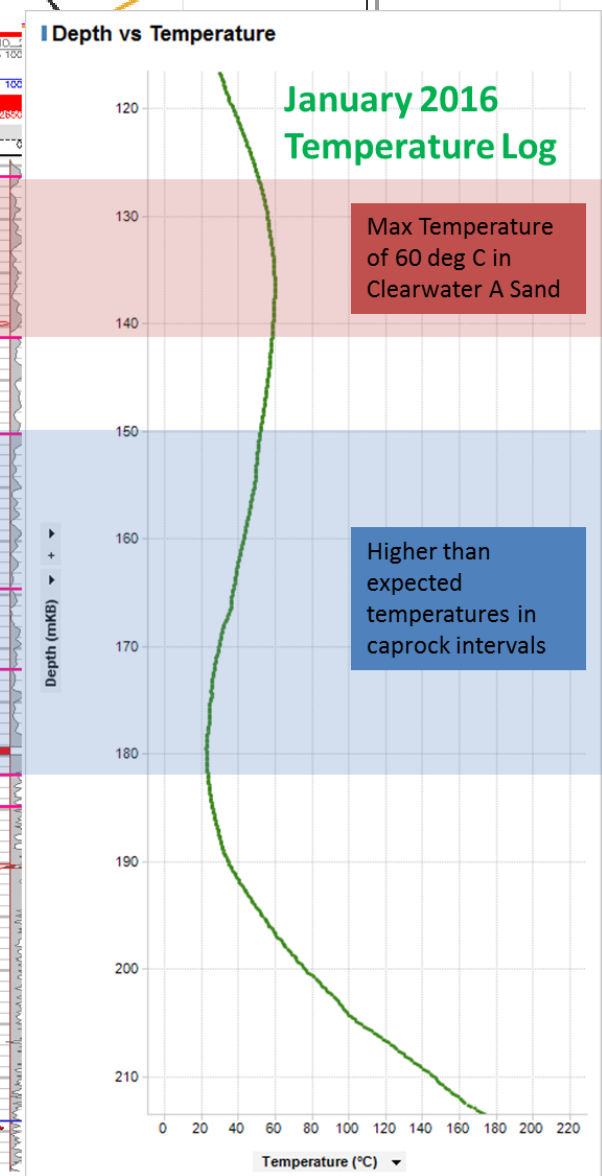
Conclusion : the temperature development was due to conductive heating from the build section of neighboring injector and producer wells

- This heat transfer is expected as part of thermal processes
- Based on conduction modeling, the area <100m around producer and injector wells is expected to be conductively heated in all formations
  - Dependent on fluid movement within interval

- Other observation wells with close proximity to SAGD well pairs have observed similar temperature changes
  - Pad 14/15 Obs Well (100/09-29) - 20m from 14Pair03







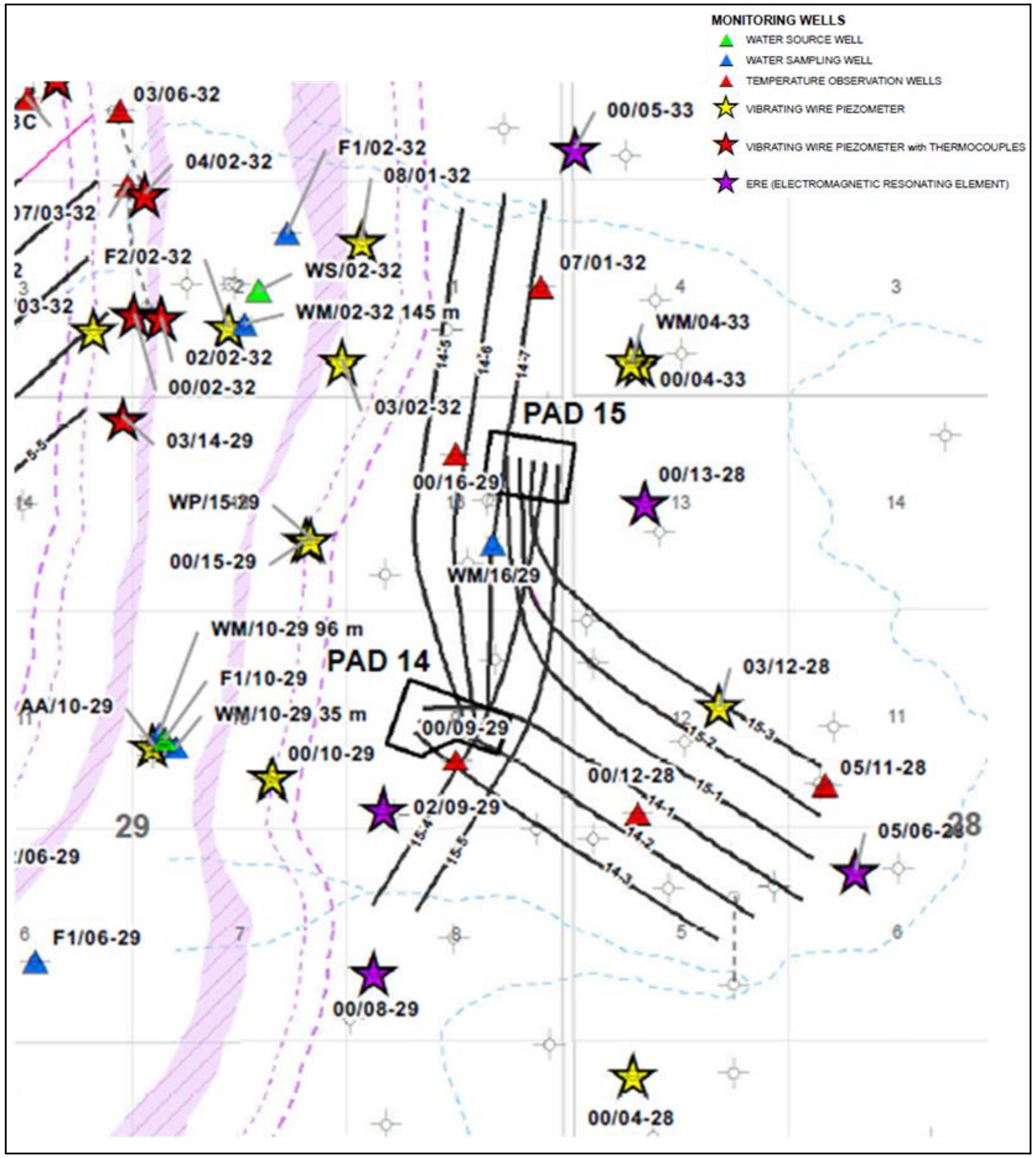
Pad 14/15 Observation Wells Caprock Monitoring

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	1015	1005
100/05-33	119	341.2	CLWT A	980	996
100/13-28	116	341.9	CLWT A	1000	1005
102/15-29	127	344.3	CLWT A	990	1001
WM/04-33	115	343.8	CLWT A	970	964
	115.5	343.27	CLWT A	980	981

Pad 15 Baseline and Current Values

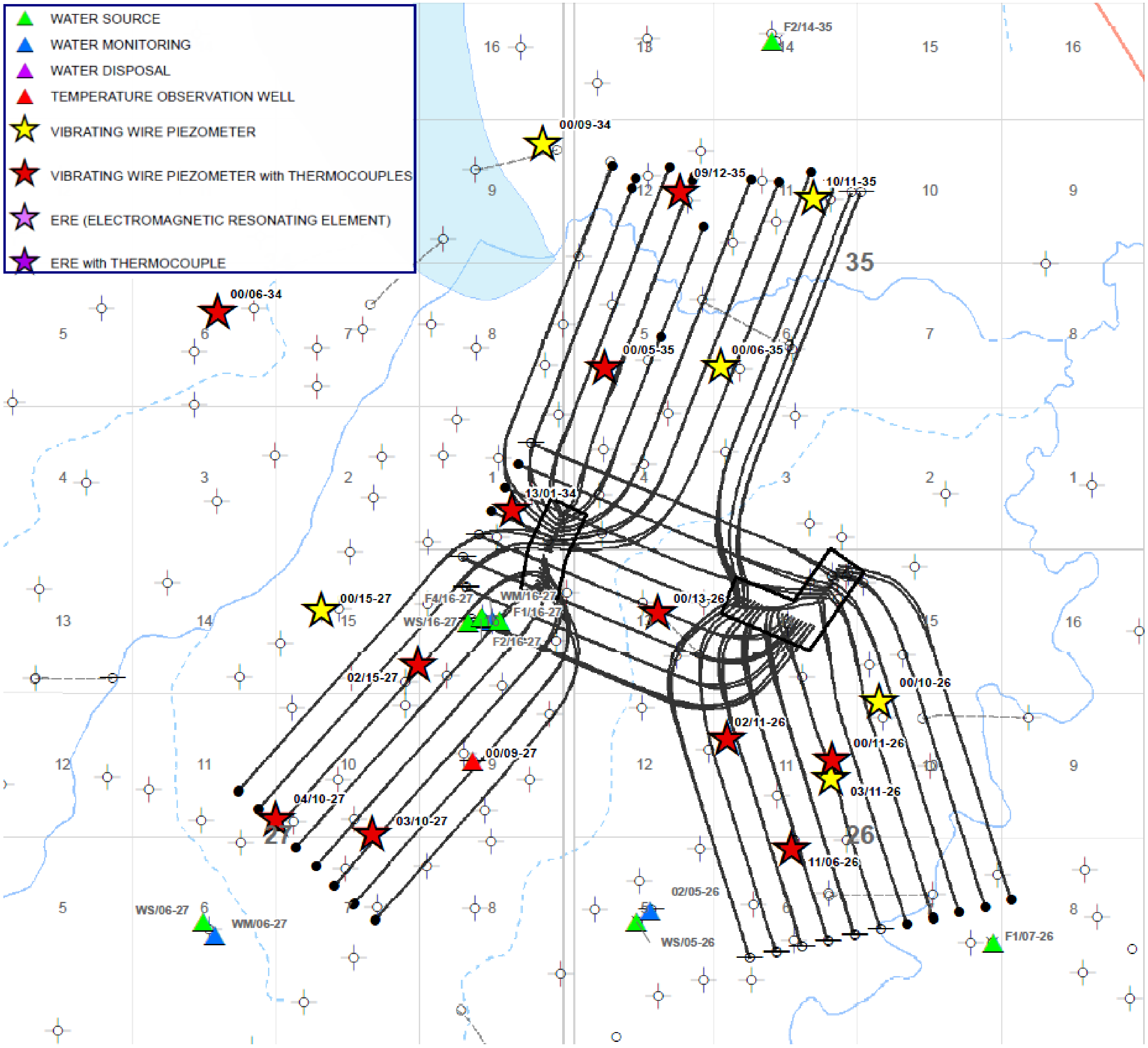
Well Name	Sensor Depth (mKB)	Sensor Elev. (mASL)	Formation	Base Line Pressure kPa_a	Current Pressure* kPa_a
105/06-28	122.5	336.4	CLWT A	1100	1106
100/08-29	118.5	349.2	CLWT A	930	940
102/09-29	126.5	339.6	CLWT A	1020	1017
103/12-28	121.5	340.5	CLWT A	1040	1027



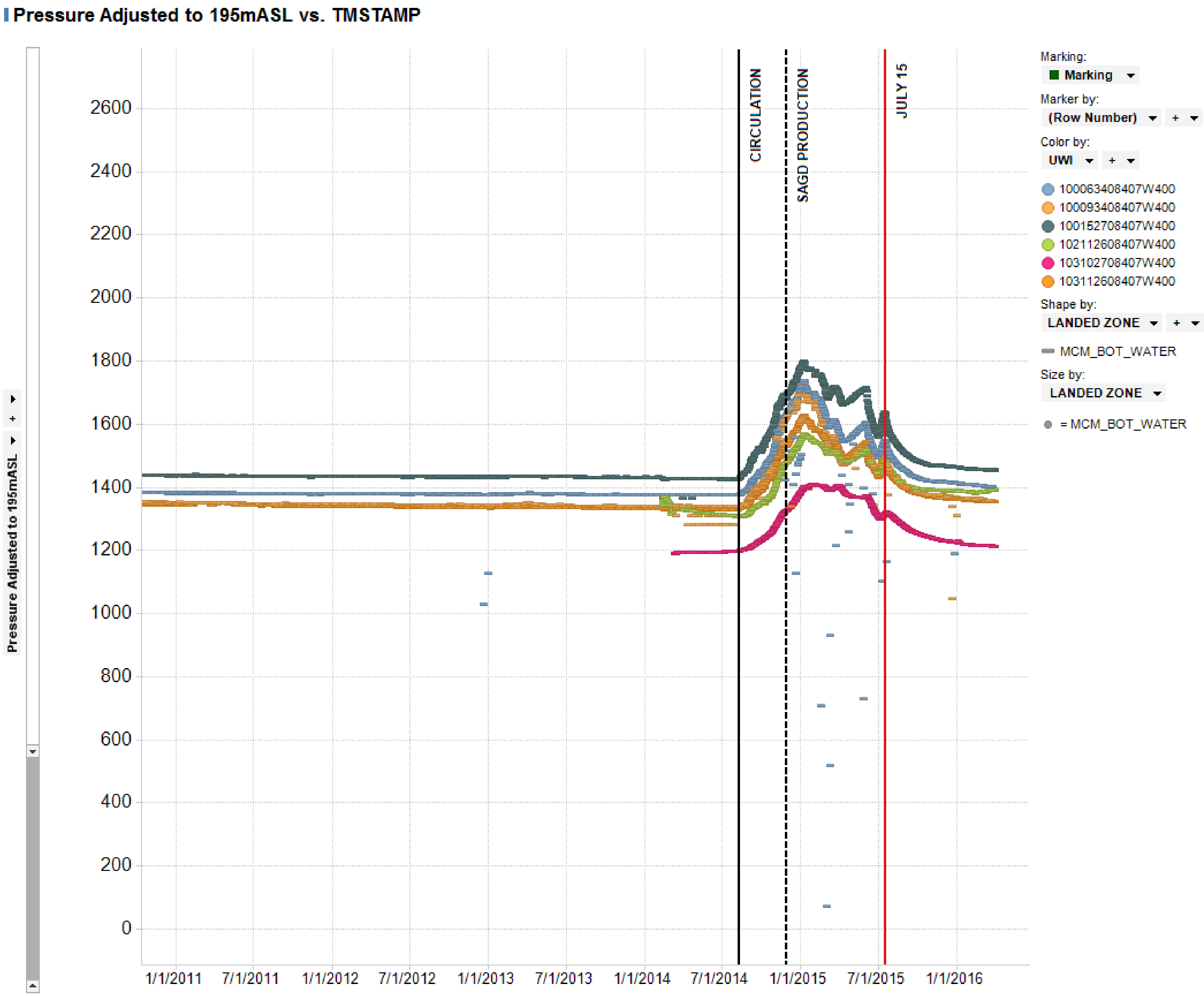
- DCS alarm is triggered +75kPa above baseline (Hi alarm) and DCS steam shut-in is triggered +100kPa (Hi-Hi alarm).

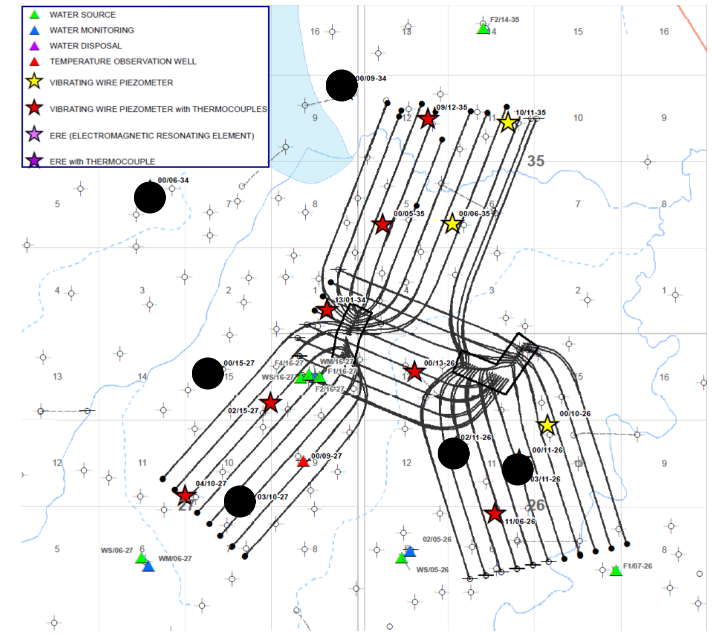
** December 2015*

K1A Observation Wells



Bottom Water Pressure





- Bottom water pressure response to initial operations and subsequent decrease on suspension

Future Plans
Subsection 3.1.1 (8)
Long Lake and Kinosis

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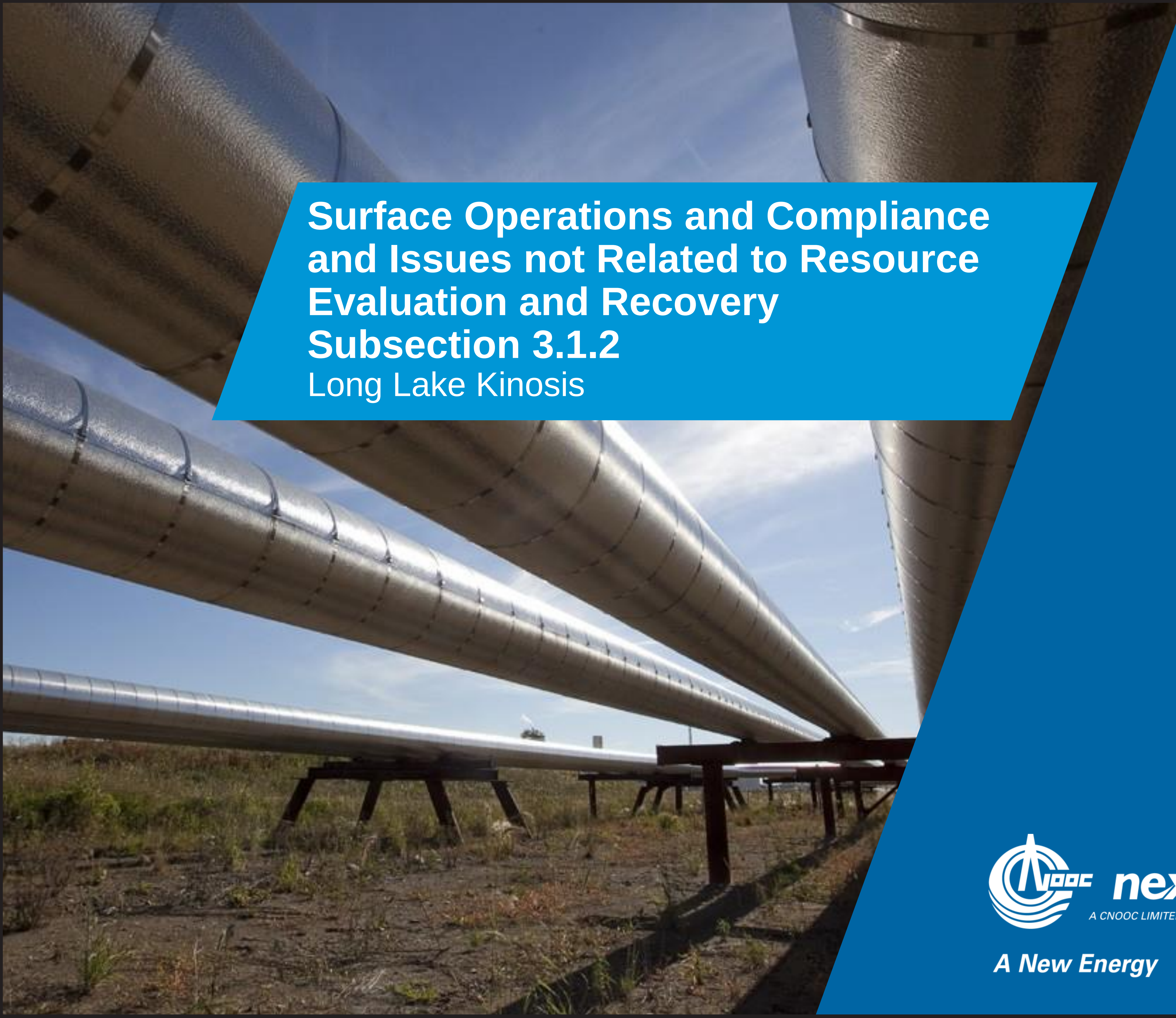
A New Energy

Future Plans – Producing areas

- Continue to manage SAGD production according to surface constraints and capacity
- Advance plans for K1A recovery
  - RCA submitted in July 2016
  - Working on final recommendation of repair vs replace
- Production opportunities
  - Continue to progress future infills at Long Lake
  - Evaluate additional well pairs off existing well pads at Long Lake
- Respond to Supplemental Information Requests to Q-Channel amendment application (2016)
- Respond to Supplemental Information Requests to 103/01-21 disposal application (2016)
- Submitted Category 1 request to postpone 4D seismic over Pads 14/15 to winter 2017/2018 due to immature steam chambers

Future Plans - New Development

- Long Lake
  - Long Lake SW (Pads 16 to 18)
    - Internal sanction anticipated in Q2 2017
    - Timing uncertain based on commodity price
- Kinosis
  - Planning for future projects significantly slowed down due to commodity prices
    - Gas re-pressurization project on hold



Surface Operations and Compliance and Issues not Related to Resource Evaluation and Recovery Subsection 3.1.2

Long Lake Kinosis

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Facilities
Subsection 3.1.2 (1)
Long Lake Kinosis

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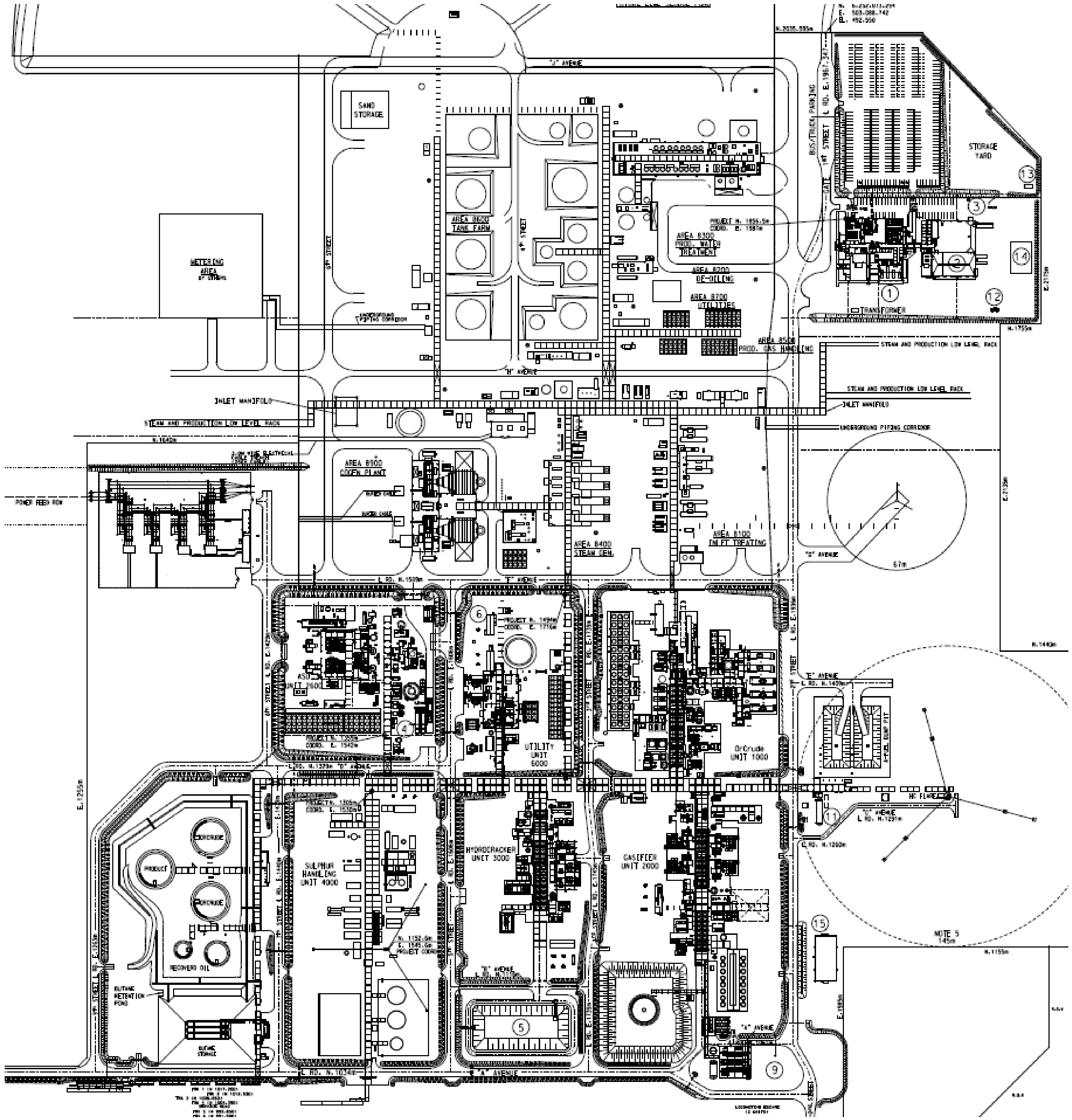
Long Lake Facilities

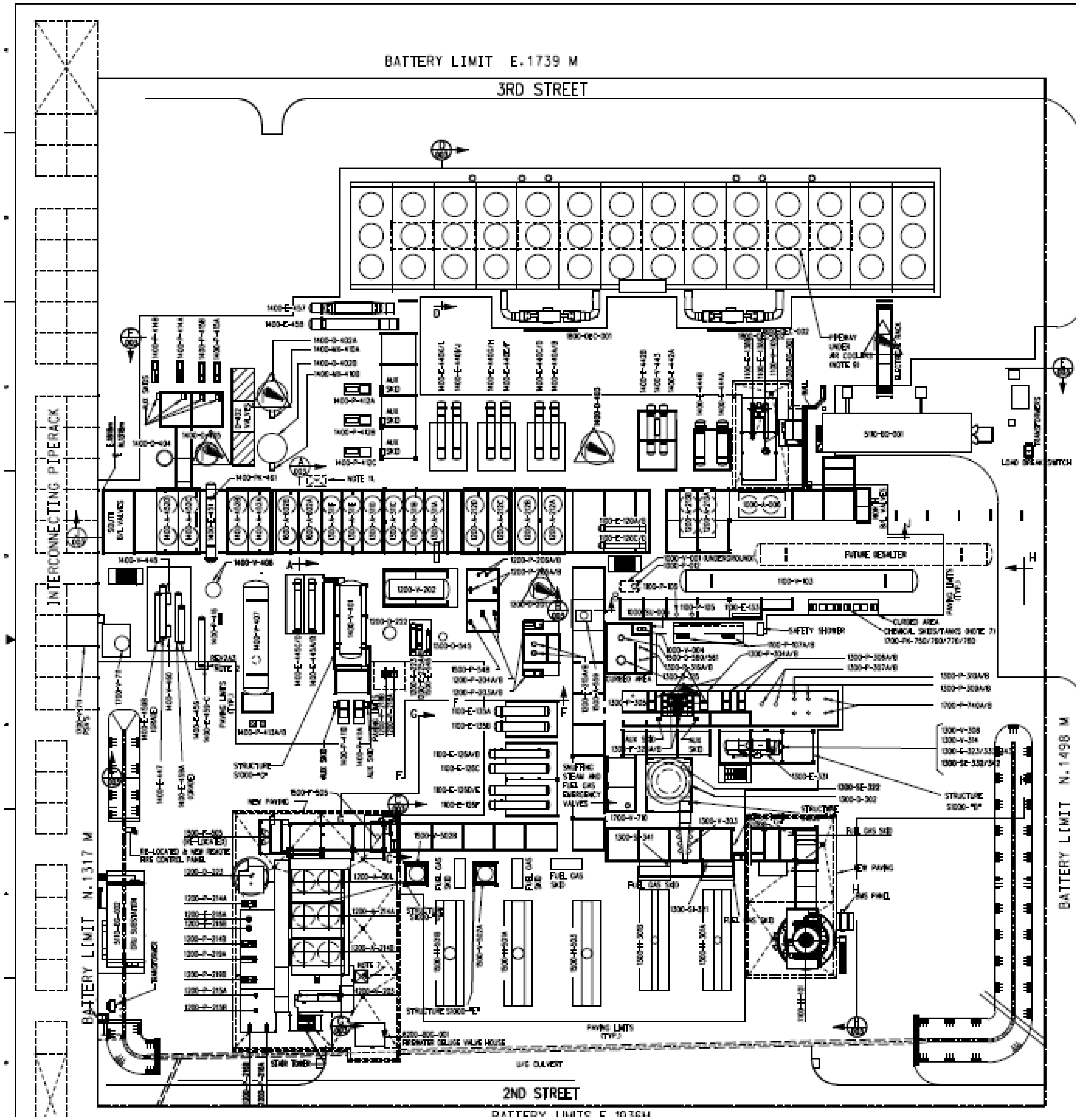
Long Lake overview with new DRU construction activities– October 22, 2014

Long Lake Plot Plan



Subsection 3.1.2 (1a)

Diluent Recovery Unit Plot Plan

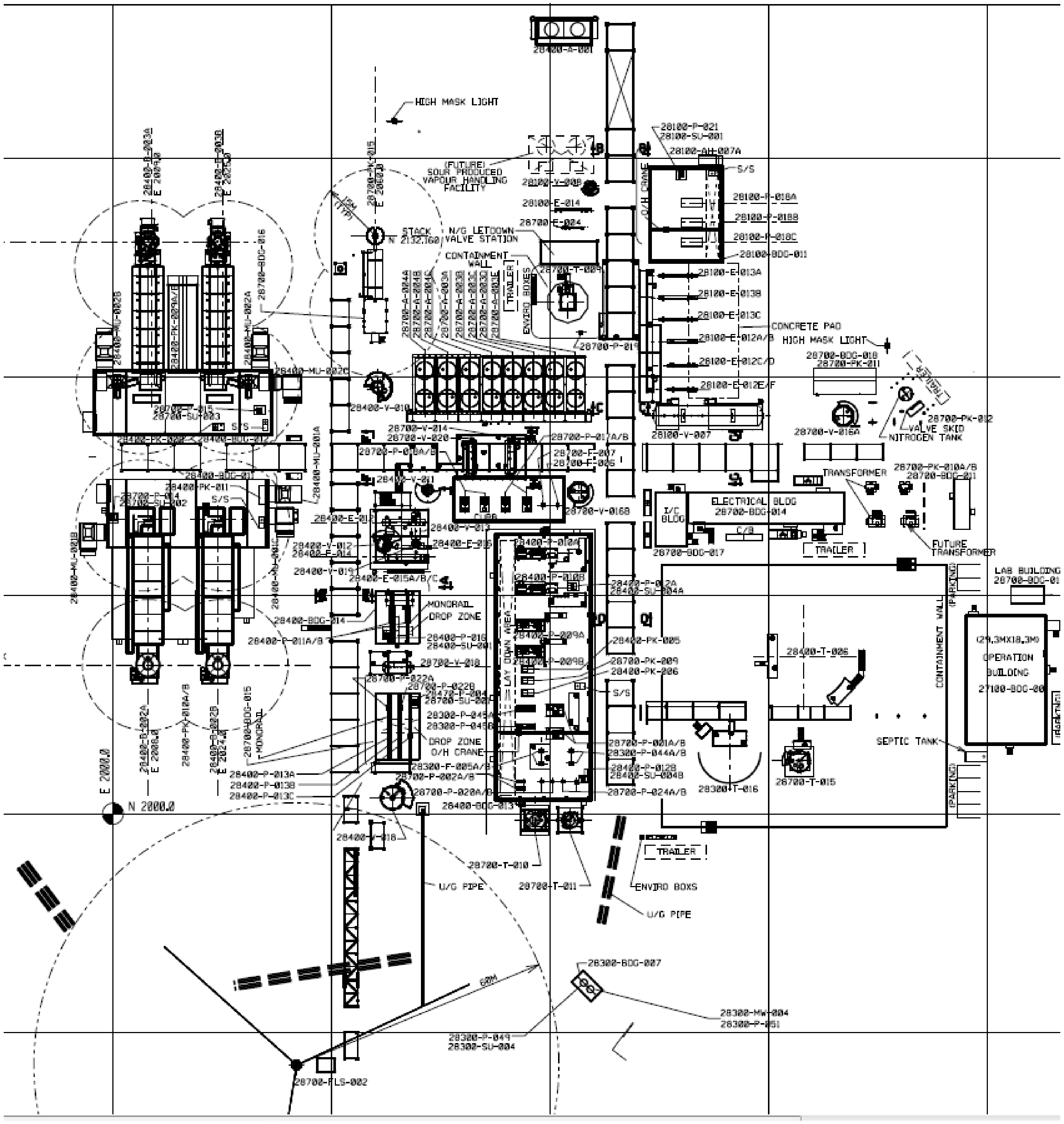


Subsection 3.1.2 (1a)

Kinosis Phase 1 (K1A)

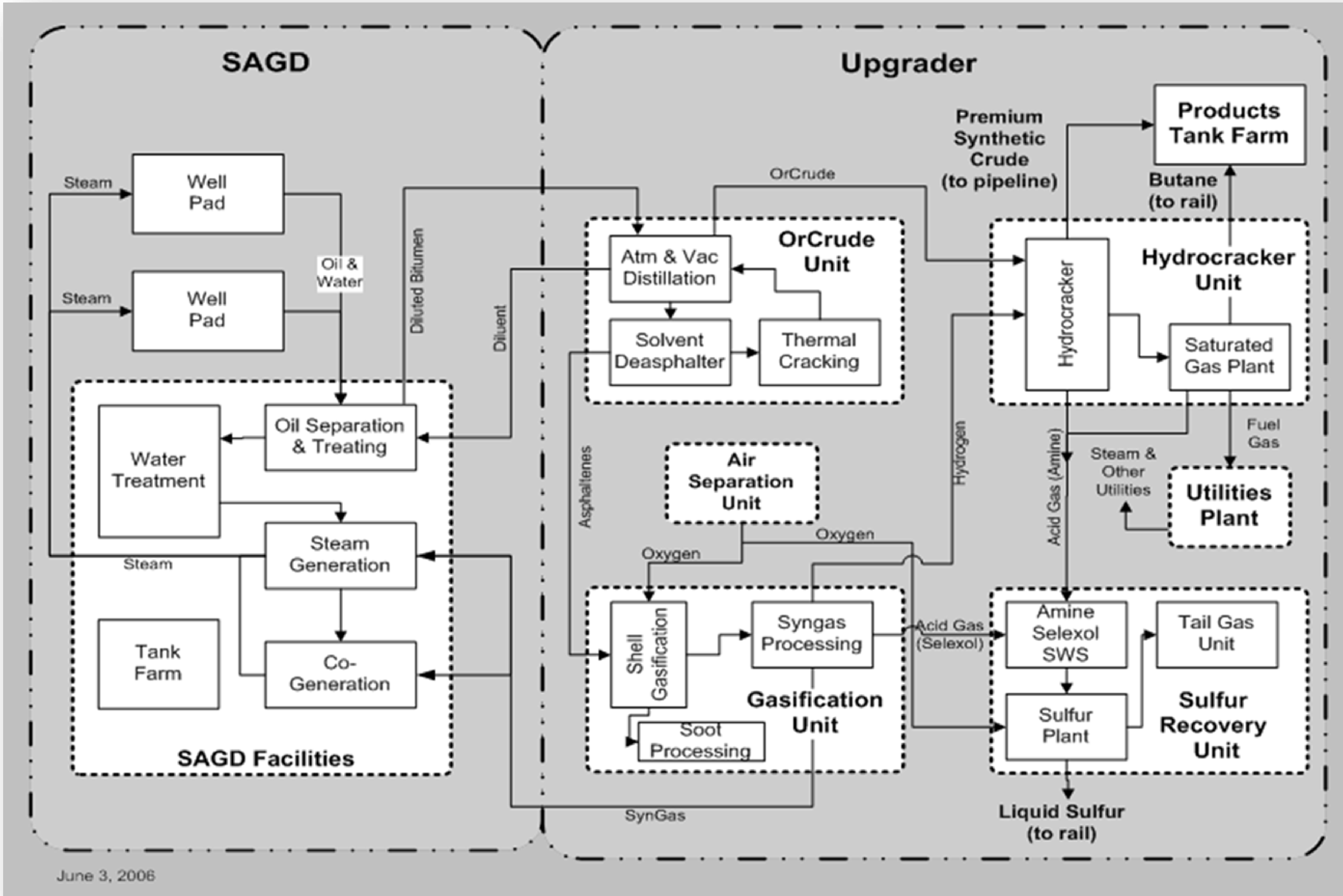
Aerial of Nexen's K1A Steam Generation Facility with Well Pads 2 in background – October 15, 2014

Kinosis Phase 1A (K1A) Plot Plan



Subsection 3.1.2 (1a)

Plant Schematic



Subsection 3.1.2 (1b)

Facility Performance Subsection 3.1.2 (2)

Long Lake Kinosis

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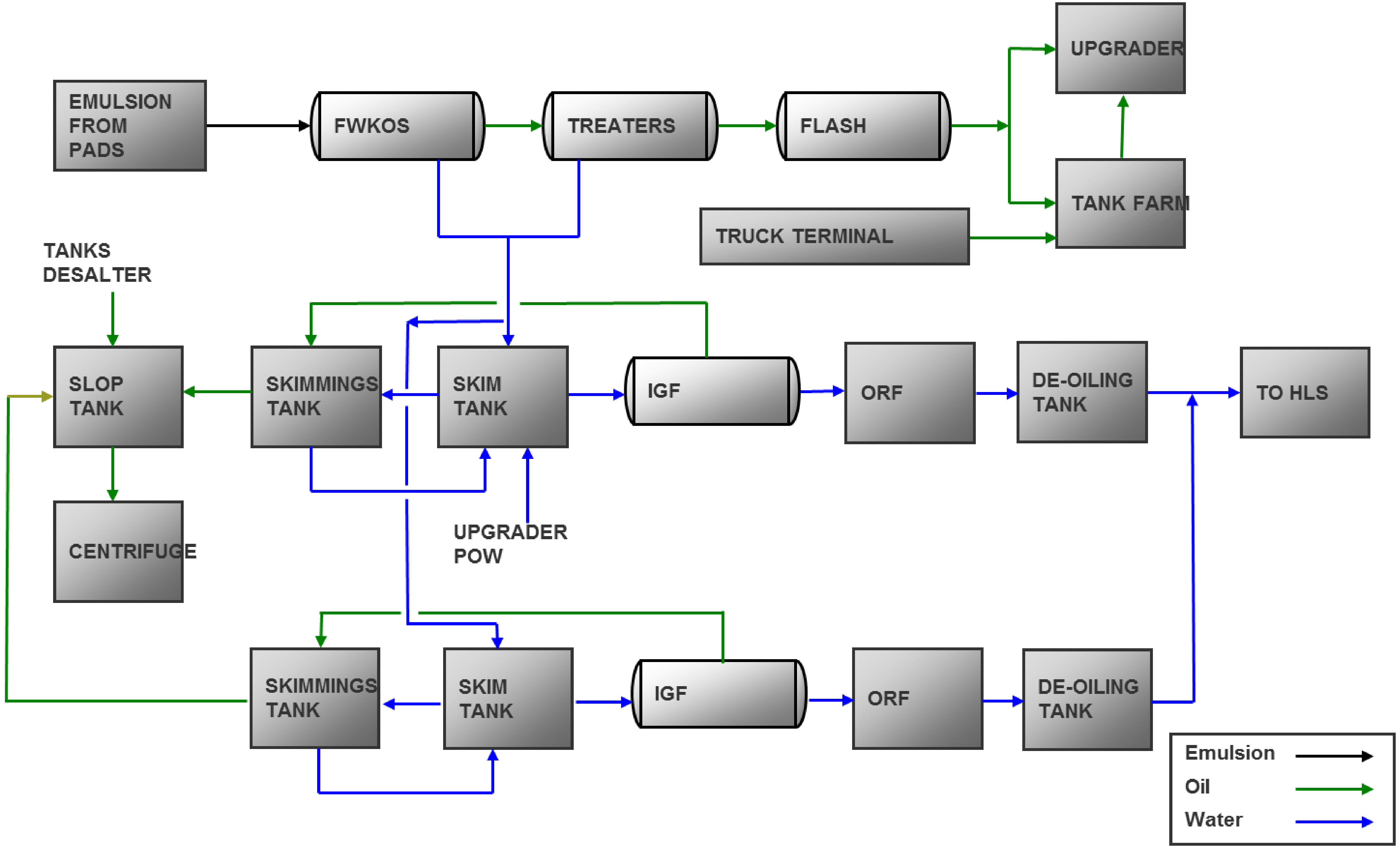
Facility Performance

Subsection 3.1.2 (2)

Bitumen Treatment



Bitumen Treatment

- **Chemical Injection**
  - Existing Demulsified Oil (DMO) and Reverse Breaker Water (RBW) injection chemicals providing satisfactory performance.
  - All DMO and RBW injection switched completely to Bulk Storage Systems from both East and West side pads. The injections systems are DCS controlled.
  - Trials conducted for replacement of polymer injection to FWKOs. The results are encouraging – good performance and no plugging of injection lines.
  - Proposal to also replace polymer for injection to de-oiling section.
  - Chemical injection skid provided in slop system - will help to inject chemicals for improving separation in slop tank.

Field and Inlet Treating

Venting Incidents

- Several venting incidents in October to December led to:
  - changes in operating philosophy such as maintaining better water dump (from Free Water Knock Outs (FWKO)) quality; and
  - proactively adjusting chemical injection to skim tanks before upstream exchanger switching to compensate for the temporary foulant than can be released while the switching process is occurring.

Field and Inlet Treating - Successes

- **Venting and Odour Issues**
  - Major reduction in odour issues after Diluent Recovery Unit (DRU) with elimination of cracked naphtha to SAGD.
  - PRVs and PVSVs installed with upgraded components during Turnaround on all tanks except dilbit tanks. These will be replaced on dilbit tanks in normal operation by taking one tank out of service at a time.
  - Encanex upgraded Vapor Recovery Unit (VRU) for centrifuge by installing chillers which increased capacity to handle more hydrocarbons in summer months resulting in better emissions control.
  - Hydrocarbon condensation inside VRU compressors was found to be causing reduction in VRU performance which was mitigated by operating diluent separator at a higher pressure than VRU discharge separator.

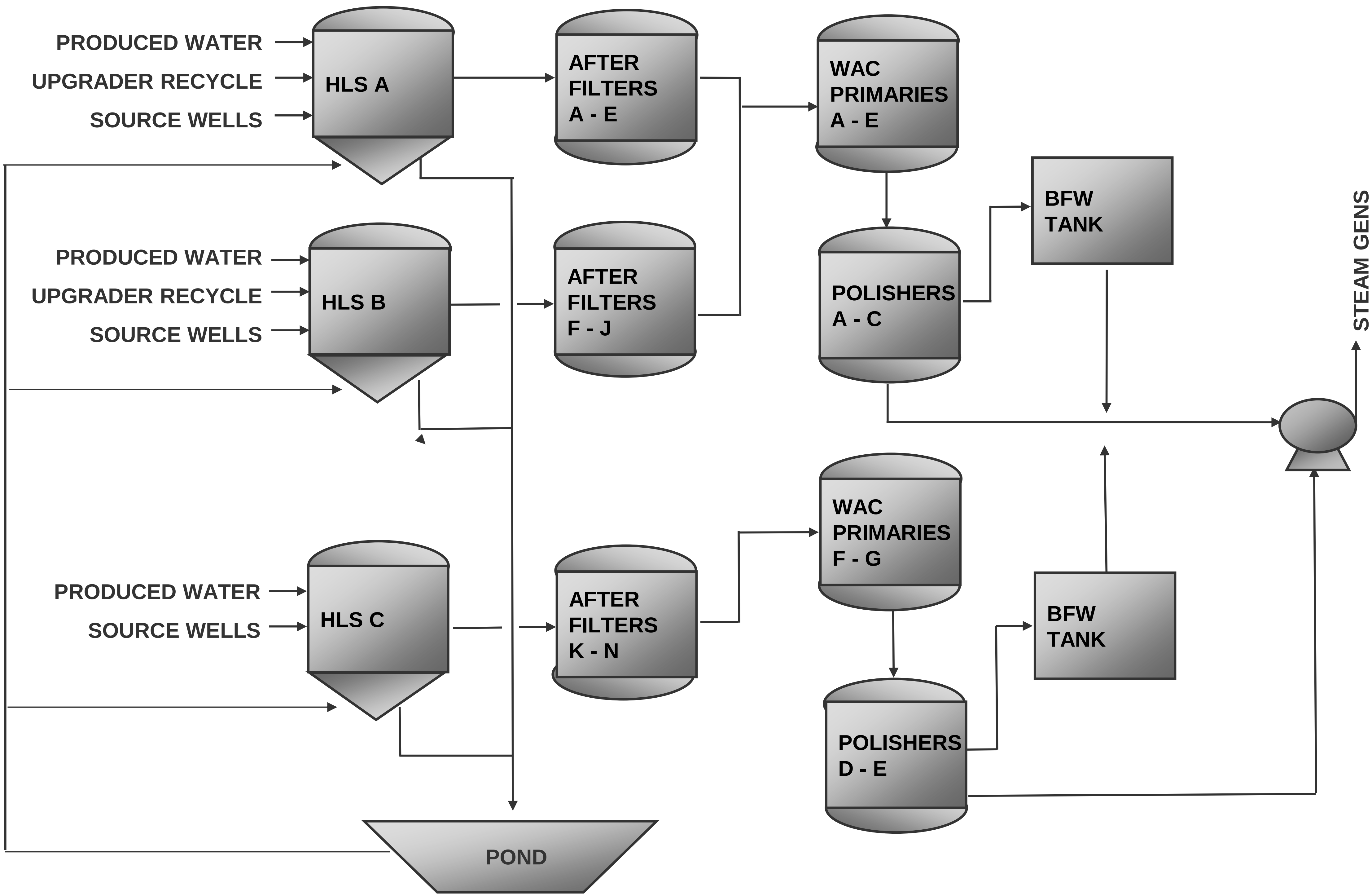
Field and Inlet Treating - Successes

- **Amine Contactor Foaming Issues**
  - After Turnaround, there were persistent foaming issues in Amine Contactor which were eventually resolved by changing filters in the Amine Regeneration Unit.
- **Naphtha Imbalance after DRU**
  - There is excess naphtha production when the Upgrader is operating at rates higher than SAGD. A dilbit tank has been used for storage of excess naphtha.
  - Naphtha stored on site is used as diluent when SAGD rate exceeds Upgrader rate.

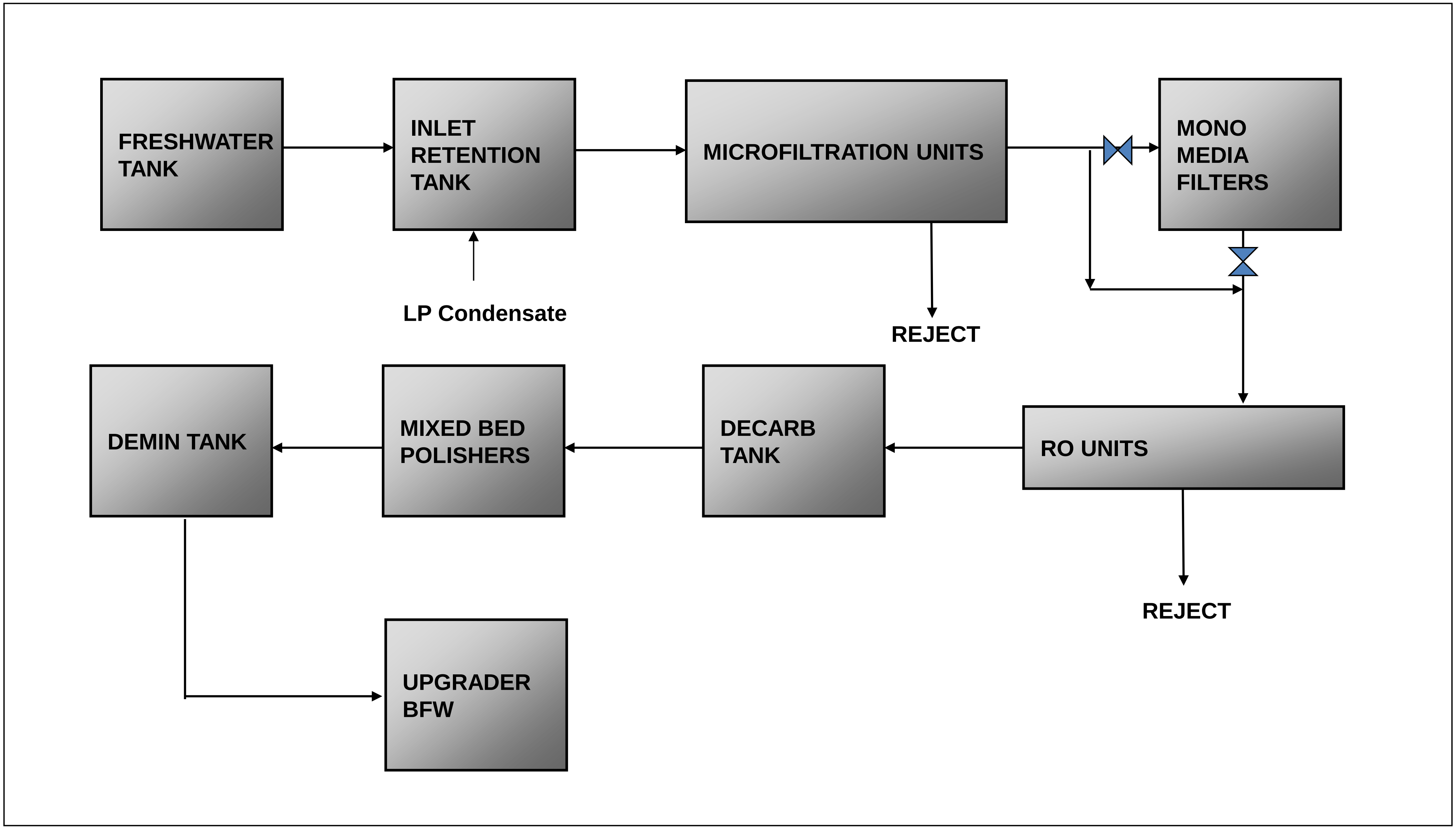
Water Treatment

Subsection 3.1.2 (2b)

Produced Water Treatment



High Quality Water System



Water Treatment - Successes

- **Produced Water (PW) Exchanger Performance**
  - No major issues with PW exchanger performance in 2015 with regularly scheduled steam and chemical cleaning.
  - Steam lines installed close to PW exchangers for steam cleaning. In the past, steam was taken from utility steam stations which was a bottleneck on extremely cold days due to insufficient amount of steam availability.
  - Glycol coolers in SAGD utilities plant were cleaned which helped to reduce glycol inlet temperature to E-006s and E-026s.
  - In order to address issues during hot summer days, a trial was conducted by installing temporary piping to recycle supernatant from the pond and mix with E-006 outlet. This was helpful in maintaining skim tank temperature even on very hot days.

Water Treatment - Successes

- **Blowdown recycle to Hot Lime Softener (HLS) units (tie in from Disposal system)**
  - Aids in hardness removal in the HLS units by providing alkalinity to the system.
  - Aids in a lower water recycle ratio (Directive 081).
  - Work on permanent system is ongoing.
- **After Filter Regulatory Inspections and Repairs**
  - Regulatory inspections carried out in Turnaround 2015.
  - Collapsed traps were found and daily technical monitoring was implemented to improve plant reliability and significant improvements in equipment damage.

Water Treatment - Successes Continued

- **Micro Filtration (MF) system improvements**
  - Increased technical monitoring on the MF system.
  - Sequence changes made to EFM procedures increased run time of the units.
  - Increased monitoring allowed better maintenance.
  - Cap and Cleans were carried out helping unplug fouled membranes.
- **Fresh Water Leak**
  - Final repair was completed during Turnaround 2015.

Water Treatment - Successes Continued

- **Mixed Bed Polishers**
  - After internal damage on interface laterals causing resin losses was identified.
    - Permanent repair to install new interface laterals during TA 2015 was carried out.
    - Design changed from horizontal plastic laterals to ‘slit type’ hastelloy lateral.
    - Resin losses were eliminated.
- **Chemical usage optimization**
  - Specifications for Silica on HLS outlet were changed from <50ppm to 35-45 ppm in efforts to save on magox usage and associated costs

Water Treatment - Updates

- **SAGD BFW treatment for hardness and silica**
  - Improvements required for the Lime/Magox systems
  - High fouling rate with online pH meters, unreliable and monthly PMs were started
- **Sludge carry over from HLSs**
  - Additional sludge taps on HLSs not preforming as designed
  - High fouling rate with online pH meters, unreliable
  - Daily monitoring of chemicals has allowed for effective control of HLS
- **Regen waste header fouled**
  - Design optimization of waste header ongoing

Water Treatment – Updates Continued

- **HLS internal cleaning intervals**
  - From the fouling observed during Turnaround 2015 in the HLS the 3 year interval for cleaning was changed to 2 years.
- **HQWS Analyzers**
  - Additional analyzers installed in HQWS to better control chemical injection and improve feed to RO.
  - Commissioning and automation for the HQWS analyzers to be completed in future.

Steam and Power Generation

Subsection 3.1.2 (2c, d)

Steam Generation

- **Record Years for Steam Production and Syngas Consumption**
  - 33,120 m^3/d peak of Steam Production
  - 5,269 m^3/d of peak Syngas Consumption
    - Proactive actions by Operators to use HP Syngas when available
- **Stable Operation at Kinosis 1A**
  - Proved to have an excellent reservoir and stable operation of the steam plant
- **Stricter Guidelines for Boiler Feed Water (BFW) excursions**
  - The Technical Team has increased proactive monitoring for operator reaction to offspec BFW.
  - Stricter response has been established in terms of following the Steam Quality Guidelines.

Steam Generation

- **Duct Burner Fouling**
  - Causing reduced steam production from HRSGs 1 and 2.
  - Working on the option of redistributing Syngas from duct burners to using Syngas for OTSG E/F.
    - This will give us the capability to produce more steam as less fouling in the HRSGs will be expected.
- **PSA Reliability (Upgrader)**
  - Inconsistent Syngas pressure from the Upgrader causes OTSGs and HRSGs to trip when pressure swings are too large
  - Work is ongoing to review and correct PSA issues

Steam Generation - Successes

- **Steam Production**
  - Improved Water balance has increased field production:
    - Consistent run time of process (steam to water and back);
    - Consistent steam production to the field;
    - Reservoir has responded positively and production has increased.
- **Glycol Monitoring**
  - Increased monitoring/maintenance on various exchangers has greatly reduced glycol losses from previous years.
  - Since end of 2015 there has been no need to order any glycol.
- **E-013 Exchangers** (Blowdown/MP Steam Condensers)
  - Upgrade to new metallurgy on 8400-E-013 A and C tube bundles have yielded better performance and we have not experienced a failure since their replacement.

Steam Generation - Successes

- **Natural Gas Tie in to Heat Recovery Steam Generator (HRSG) I and II**
  - Will help minimize fouling in the duct burners.
  - Tie in was complete in Nov 2015 and currently work is ongoing regarding the logic.
- **Turnaround 2015**
  - Excellent startup with zero incidents, Nexen's best startup timeline to date after a major outage.
  - Major Outage on Gas Turbine 1.
  - Regulatory inspections on HRSG I and II were carried out.
  - All failed Thermocouples/Thermowells were fixed.

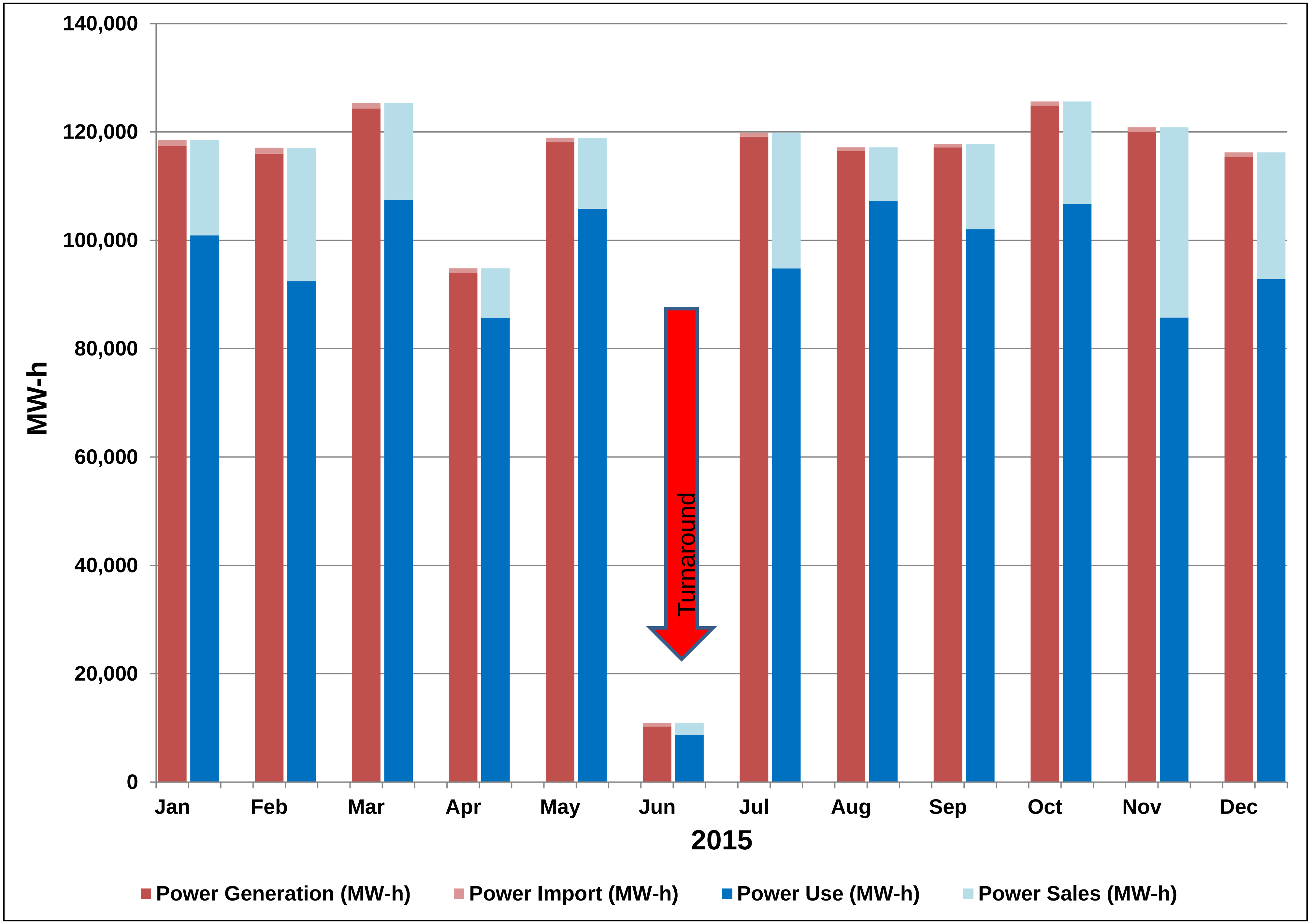
Steam Generation Successes

- **Air Extraction Unit**
  - Commissioned and tested the Air Extraction Unit for GTGs, which will increase power output during time where Syngas is being used.
- **Economizer Tube Failures on OTSGs**
  - Implemented better control of the water treatment program which resulted in:
    - Better water quality control in the Hot Lime Softer (HLS) units.
    - Less hardness breakthrough from the Weak Acid Cation (WAC) vessels.

Power Generation

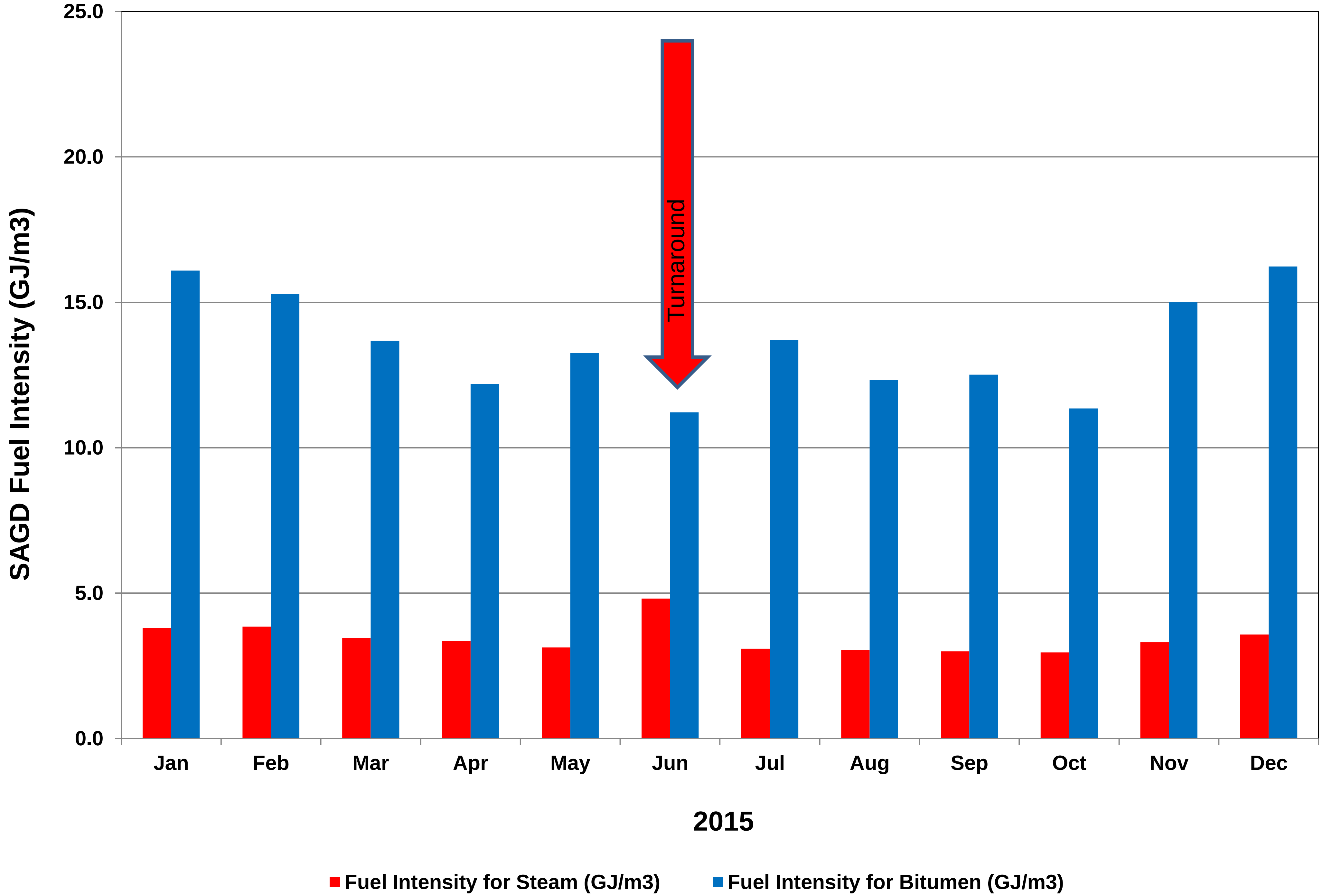
- **Emergency Power Supply**
  - Increased efforts have been put in to improve reliability of the emergency generators and standby air compressors by utilizing external vendors to correct any deficiencies and implement PM’s (preventative maintenance) schedule on our behalf.

Total Power Usage



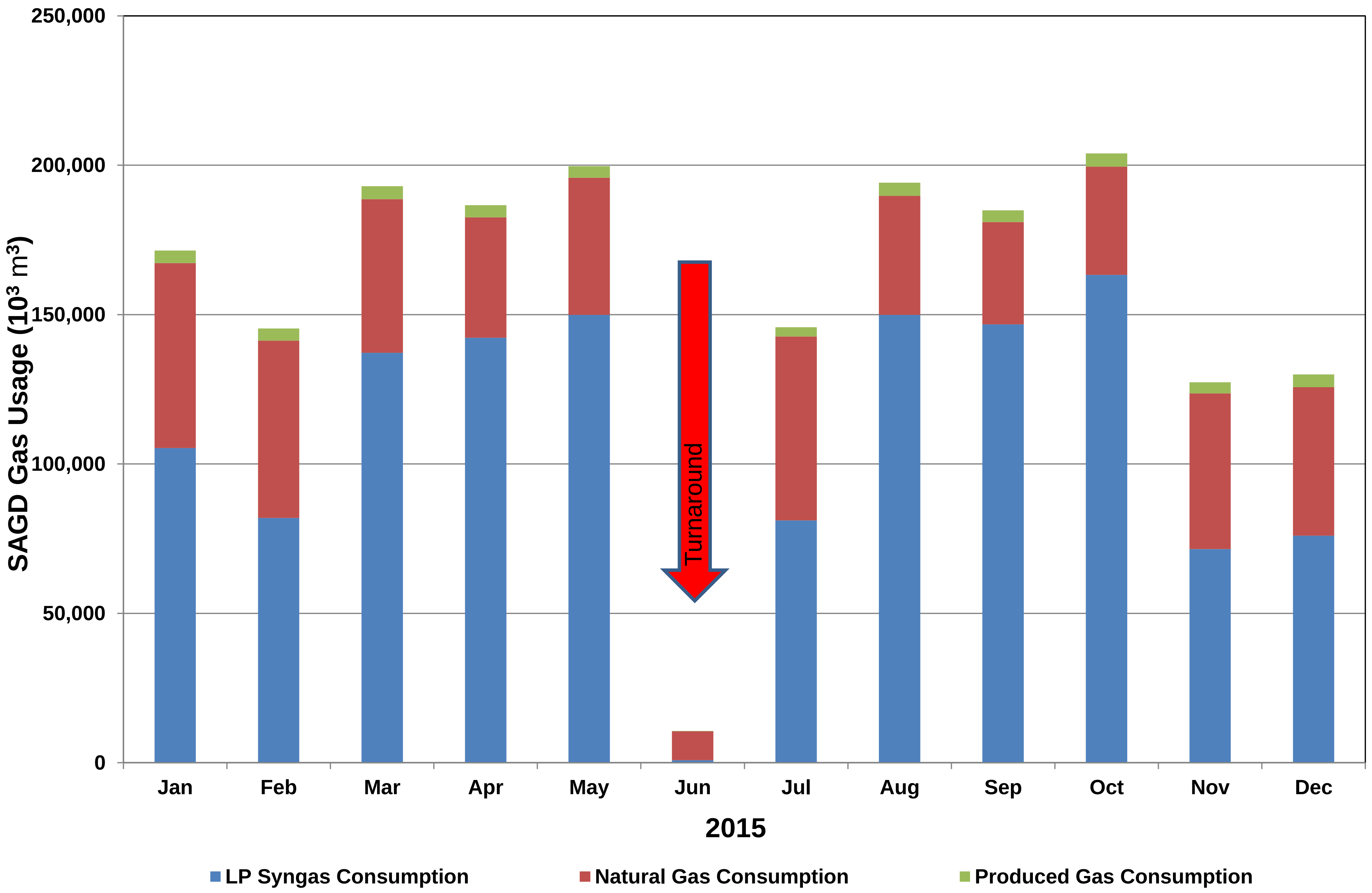
Subsection 3.1.2 (2d)

SAGD Energy Intensity (adjusted for power generation)



Subsection 3.1.2 (2d)

Total Gas Consumed (Purchased and Produced)



Subsection 3.1.2 (2e)

SAGD Venting and Flaring Summary

- 23 venting events at Long Lake;
- Released 4,325 m^3, with an average concentration of 200 ppm.
- Slop tank vented in October.

2015 LLK Venting Events

Month	No. of Venting Events	Total Vented Volume (Sm^3)	Produced Gas Flared (10^3 m^3)
Jan	1	255	20.8
Feb	0	0	26.4
Mar	0	0	29.2
Apr	2	11	28.3
May	1	6	29.2
Jun	0	0	69.6
Jul	0	0	23.2
Aug	0	0	15.8
Sep	0	0	22.5
Oct	7	3,989	18.1
Nov	3	2	15.3
Dec	9	64	25.2
Total	**23**	**4,325**	**323.6**

Subsection 3.1.2 (2e)

Greenhouse Gas Emissions

- Long Lake's GHG intensity is generally trending downwards
  - Lower GHG intensity is associated with lower SORs, improved reliability, and efficient operations

Year	2010	2011	2012	2013	2014	**2015**
Kilotonnes (kT) CO_2e Emissions	3,229	3,191	3,613	4,139	* 4,384	**3,547**
GHG intensity (kg CO_2e/bbl bitumen produced)	361	307	317	310	* 280	**250**

- Long Lake's GHG compliance costs are derived from a baseline of 2010-12 performance data
  - Long Lake's baseline includes the facility's three major products – bitumen, Premium Synthetic Crude and electricity
- Compliance is being met through reducing Long Lake's GHG intensity, the use of offsets from Nexen's Soderglen wind farm asset, and contributions to the technology fund
- Current GHG regulations (known as SGER) are rising in stringency, with 2017 being its last year
  - With reductions from baseline emissions of 15% in 2016 and 20% by 2017, the carbon price rises to $20 and $30 per tonne CO_2, respectively
- Regulations are being developed for a Carbon Tax on large GHG emitters from 2018 onwards
  - The new Carbon Tax is expected to account for all the emissions from Long Lake and deduct credits for in situ production, power generation, and upgrading

* Correction from 2014

Subsection 3.1.2 (2f)

Measurement and Reporting Subsection 3.1.2 (3)

Long Lake

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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.
- Multiphase flow meters installed on Pads 14 & 15 and K1A were operational for 2015.

Produced Bitumen Measurement

- Bitumen samples collected from emulsion line are analyzed by Long Lake Lab and 3rd Party lab to determine density as requested by Department of Energy.
- We have improved training for operations on manual sampling procedures/ sampling techniques in 2015.
- Improvements to MARP maintenance program is ongoing.

Proration Factors

LLK Proration Factors 2015

MONTH	OIL	WATER
Jan	0.83	1.05
Feb	0.81	0.89
March	0.85	0.89
April	0.85	0.84
May	0.83	0.89
June	0.90	1.01
July	0.88	0.90
August	0.86	0.87
Sept	0.81	0.81
October	0.87	0.93
November	0.86	0.94
December	0.85	1.02

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

Oil = 0.85000–1.15000
Water = 0.85000–1.15000

Per D017 Section 12.3.3 Gas Measurement:
A battery level GOR is used to determine well gas production.
Therefore, the gas proration is 1.00000.

Steam Production Measurement

- The two V-cone meters installed for steam measurement at CPF during 2012 Turnaround (8400-FIT-510,8400-FIT-518) have failed.
- A project is being initiated to have these meters replaced. In the interim we have a steam calculation method for total plant steam production and Net steam to pads.

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

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

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

1. Steam quality>50% (See Slide 177 Table 1 for tag IDs)
2. BFW Flow for OTSGs > 80 Sm^3/h (See Slide 177 Table 1 for tag IDs)
3. Blowdown valve opening <10% (See Slide 177 Table 1 for tag IDs)

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

$= \quad Sm^3/h$

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

$= \quad Sm^3/d$

Subsection 3.1.2 (3a)

Steam Production Measurement

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

HRSGs will be producing steam based on three criteria (otherwise the value is zero).

1. Steam quality>50% (See Slide 177 Table 2 for tag IDs)
2. BFW Flow for HRSGs > 190 Sm^3/h (See Slide 177 Table 2 for tag IDs)
3. Blowdown valve opening <10% (See Slide 177 Table 2 for tag IDs)

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

$$= Sm^3/h$$

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

$$= Sm^3/d$$

Steam Injection Measurement

- Steam injection is measured at the wellhead (estimating steam quality of 97% at the wellhead).
  - Nexen 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 2015 these meters were inspected, cleaned and calibrated. All wellhead meters have a preventative maintenance schedule to maintain the accuracy as per MARP.
- As part of the revised plant production calculation the net steam to pads will be:

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

TSP =Total Steam Production

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

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

Water Production, Injection and Uses Subsection 3.1.2 (4)

Long Lake

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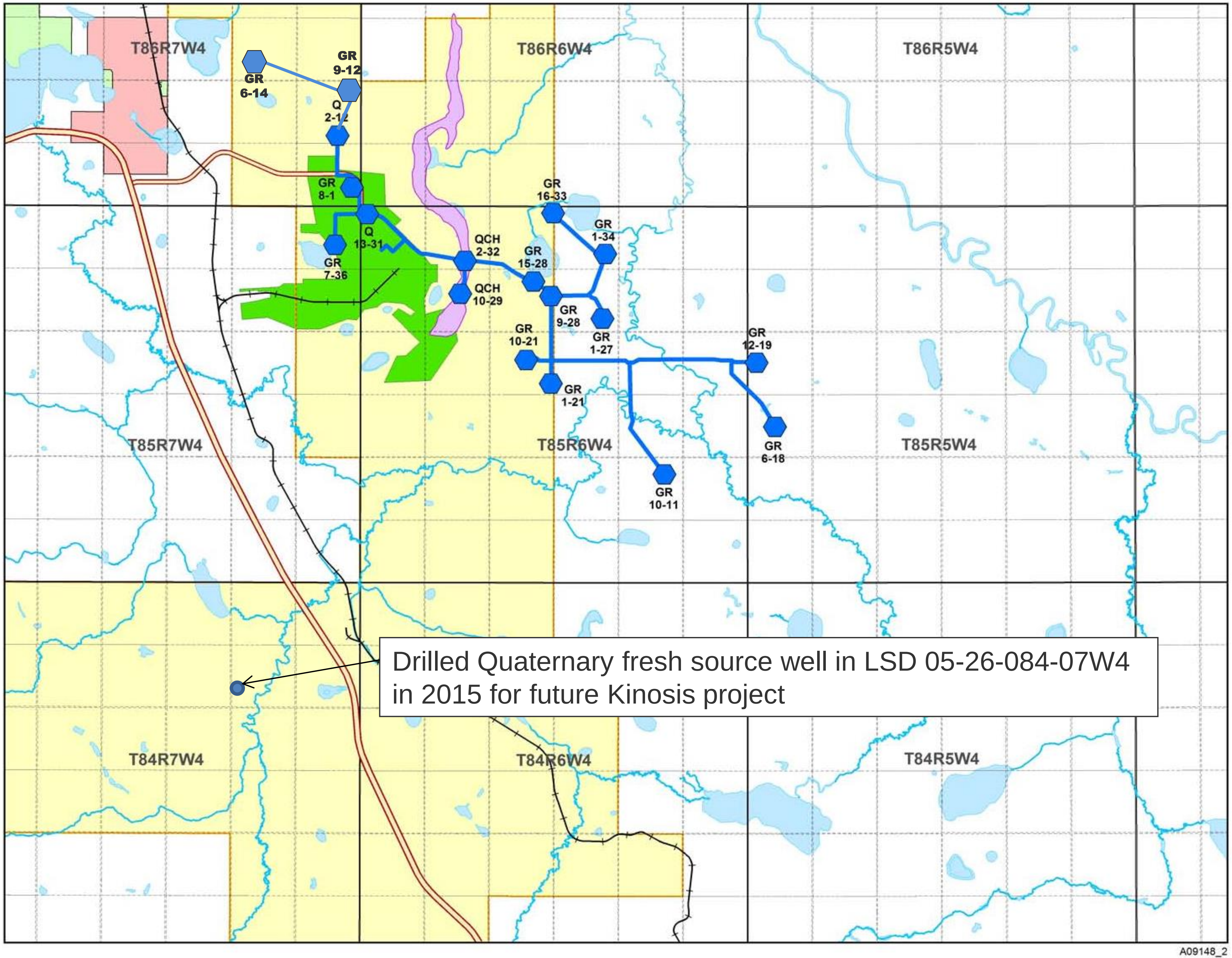
Freshwater Pipelines



Subsection 3.1.2 (4a)

Typical Water Quality (Produced and Disposal)

Typical Water Values

Table 1: Deoiled Water Typical Values

Stream	Deoiled Water – Area 1			
	pH	Turbidity (NTU)	Dissolved Hardness (mg/L)	Reactive Silica (ppm)
Average	8	77	15	153
Max	9.2	1,340	220	459
Min	7	5	4	2

Table 2: Supernatant Water Typical Values Specifications

Stream	Supernatant Water			
	pH	Turbidity (NTU)	Dissolved Hardness (mg/L)	Reactive Silica (ppm)
Average	10	98	154	47
Max	12	918	360	161
Min	8	9	21	2

Table 3: Brackish Water Typical Values Specifications

Stream	Brackish Water	
	Hardness (mg/L)	TDS
Average	674	21,779
Min	88	5,872
Max	2,200	38,493

Freshwater Pipelines (CONT'D)

Plant Operations	AENV# 235895-01-00		Total Dissolved Solids		Jan-Dec 2015	
Location	**Formation**	**Fresh?**	**Sample Date**	**Concentration (mg/L)**	**Total (m³)**	**Annual avg. (m³/cd)**
01-21-85-06W4M	Grand Rapids	Y	9-Sep-15	1,780	111,149	305
01-27-85-06W4M	Grand Rapids	Y	29-Sep-15	1,300	214,287	587
01-34-85-06W4M	Grand Rapids	Y	29-Sep-15	1,500	112,359	308
02-12-86-07W4M	Quaternary	Y	1-Oct-15	680	319,527	875
02-32-85-06W4M	Gregoire Channel	Y	18-Dec-12	1,800	0	0
06-14-86-07W4M	Grand Rapids	Y	1-Oct-15	1,200	105,269	288
06-18-85-05W4M	Grand Rapids	Y	22-Sep-09	1,000	0	0
07-36-85-07W4M	Grand Rapids	Y	17-Nov-15	660	338,132	926
08-01-86-07W4M	Grand Rapids	Y	9-Sep-14	888	0	0
09-12-86-07W4M	Grand Rapids	Y	4-Sep-14	786	217,997	597
09-28-85-06W4M	Grand Rapids	Y	7-Aug-14	1,510	47,098	129
10-11-85-06W4M	Grand Rapids	Y	29-Sep-15	3,300	307,751	843
10-21-85-06W4M	Grand Rapids	Y	29-Sep-15	1,600	74,765	205
10-29-85-6W4M	Gregoire Channel	Y	9-Dec-15	970	45,981	126
12-19-85-05W4M	Grand Rapids	Y	29-Sep-15	2,400	191,346	524
13-31-85-06W4M	Quaternary	Y	1-Oct-15	530	59,405	163
15-28-85-06W4M	Grand Rapids	Y	29-Sep-15	1,600	182,024	499
16-33-85-06W4M	Grand Rapids	Y	29-Sep-15	1,200	35,984	99
License Allocation 3,285,000 m3 (annual daily average of 9,000 m³/d)		**TOTAL**			**2.363,074**	**6,474**

Potable	AENV# 235895-01-00				Jan-Dec 2015	
Location	**Formation**	**Fresh?**			**Total (m³)**	**Annual avg. (m³/cd)**
13-31-85-06W4M	Quaternary	Y	1-Oct-15	530	73,110	200

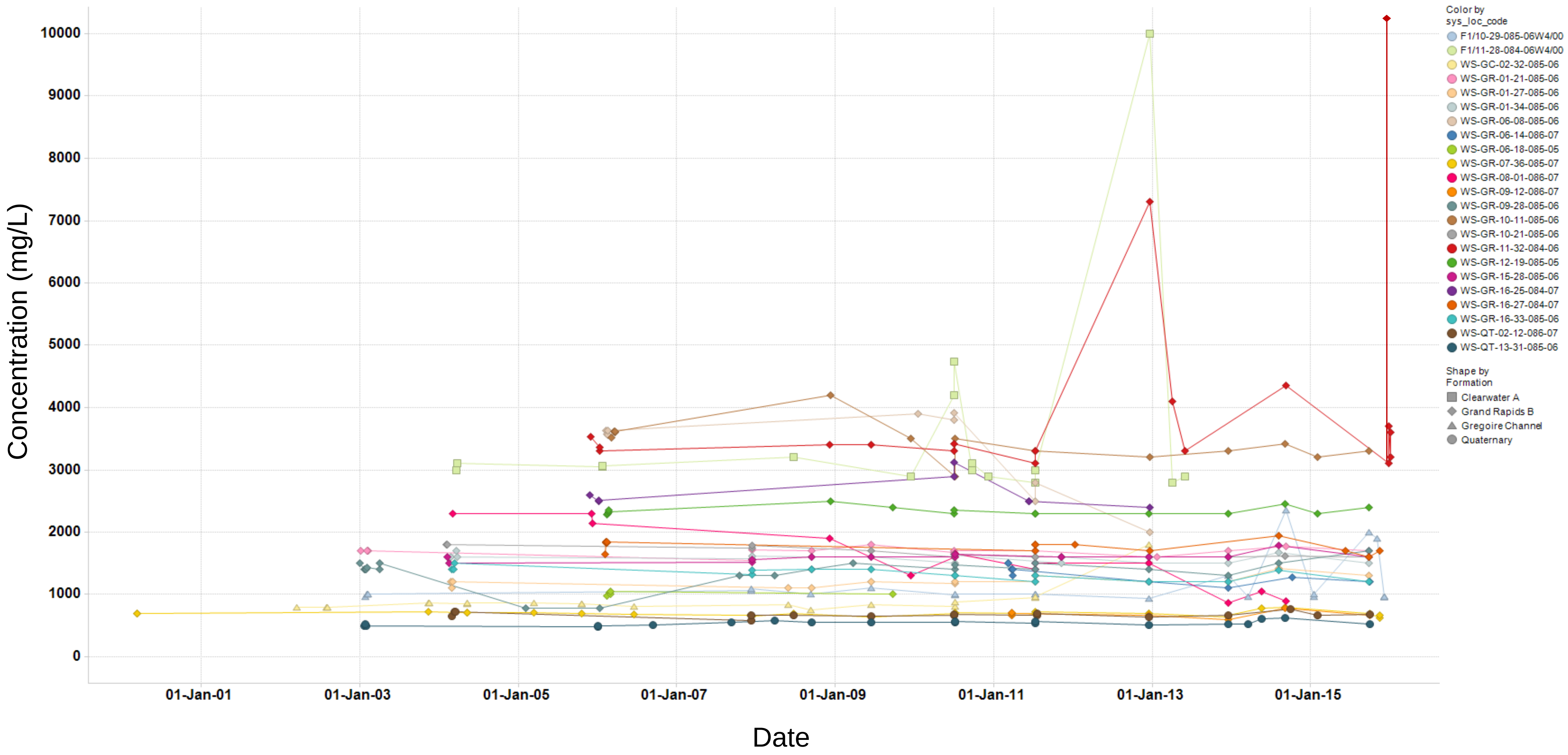
Other	AENV# 235895-01-01 (was 250344-01-00)				Jan-Dec 2015	
Location	**Formation**	**Fresh?**			**Total (m³)**	**Annual avg. (m³/cd)**
07-36-85-07W4M	Grand Rapids	Y	17-Nov-15	660	0	0

- Total of 18 wells tied in.
- WS Q 13-31-085-06W4 also used for potable water (73,110 m³ in 2015).
- Groundwater samples are collected if source wells are diverted during the year.

Volumes as reported in Petrinex and vary from those reported in Annual Reports

Subsection 3.1.2 (4a,b)

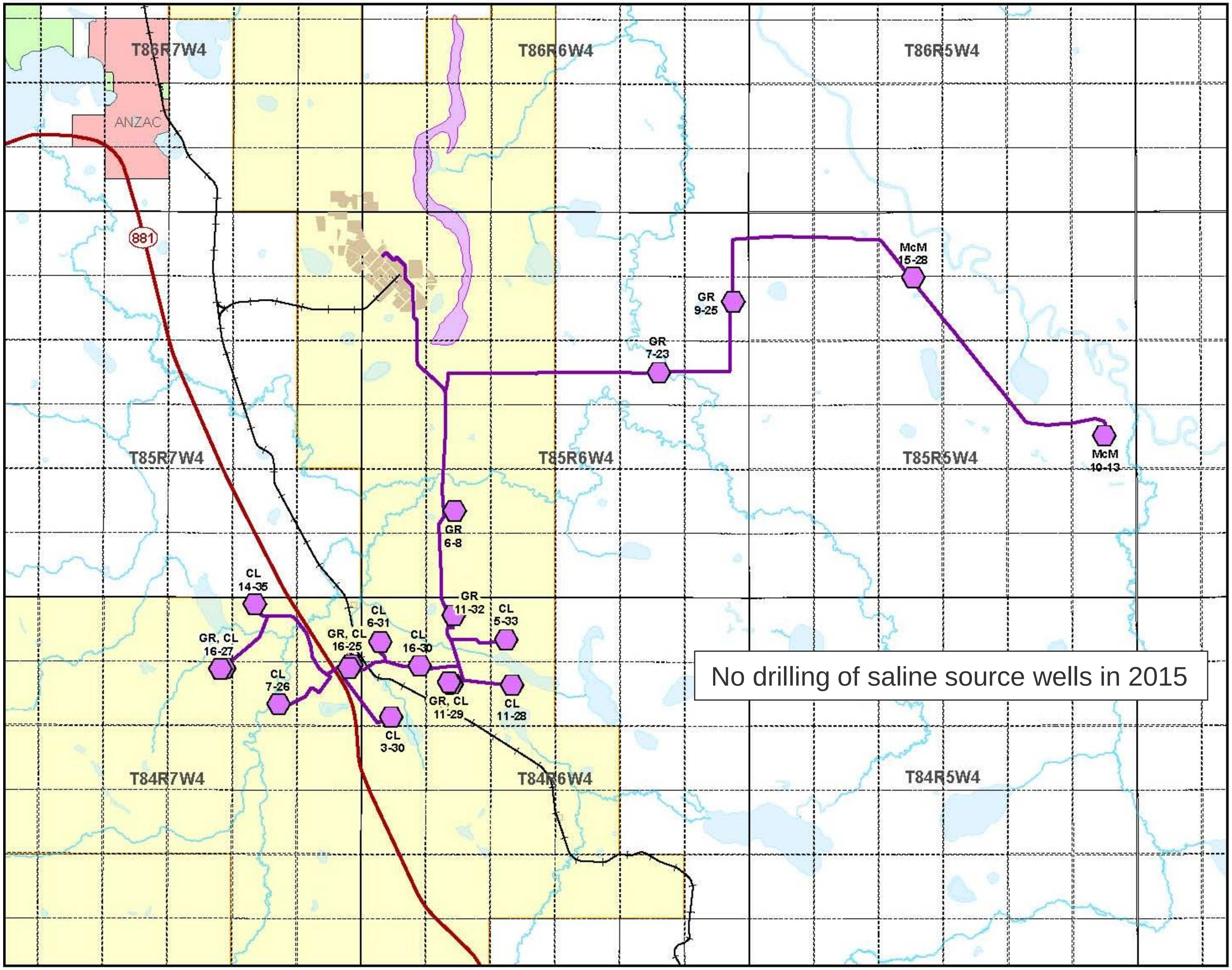
Fresh Water Source Wells Water Quality TDS



- Observed a sharp increase in TDS for WS-GR-11-32-084-06W4M.
- Increase was due to a check valve failure on the saline system.
- Pumped off well for 3 weeks until TDS recovered.

Subsection 3.1.2 (4a)

Saline Water Pipelines



No drilling of saline source wells in 2015

Saline Water Pipelines (CONT'D)

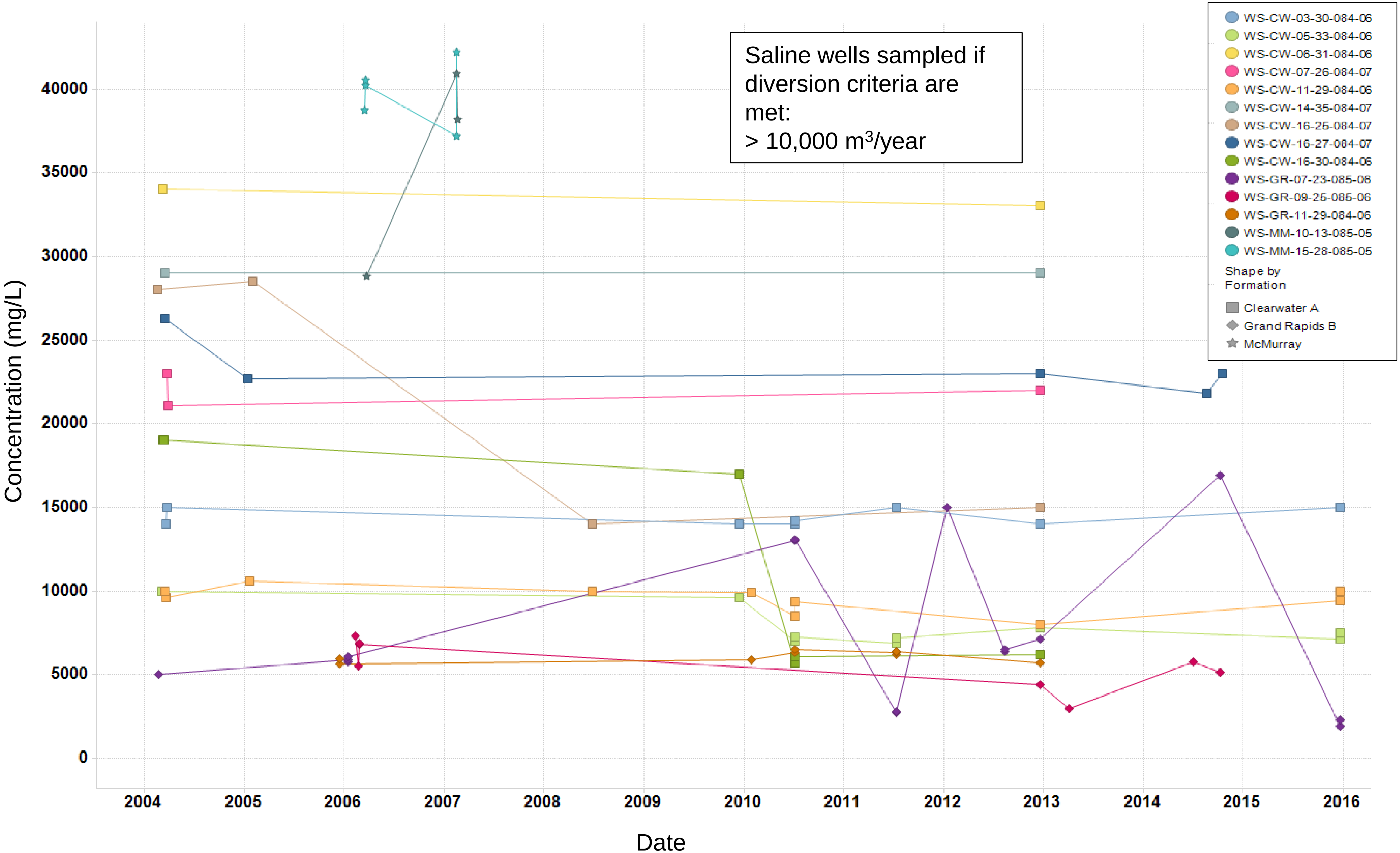
Plant Operations			Total Dissolved Solids		Jan-Dec 2015	
Location	**Formation**	**Saline?**	**Sample Date**	**Concentration (mg/L)**	**Total (m3)**	**Annual avg. (m3/cd)**
1F2/03-30-084-06W4	Clearwater	Y	22-Dec-15	15,000	11,218	31
1F1/05-33-084-06W4	Clearwater	Y	22-Dec-15	7,500	19,044	52
1F1/06-31-084-06W	Clearwater	Y	19-Dec-12	33,000	0	0
07-23-85-06W4	Grand Rapids	Y	22-Dec-15	2,300	22,417	61
1F1/07-26-084-07W4	Clearwater	Y	19-Dec-12	22,000	790	2
09-25-85-06W4	Grand Rapids	Y	9-Oct-14	5,130	0	0
1F1/10-13-085-05W4	McMurray	Y	18-Feb-07	38,200	0	0
1F1/11-29-084-06W4	Clearwater	Y	22-Dec-15	10,000	19,017	52
11-29-84-06W4	Grand Rapids	Y	19-Dec-12	5,700	1,362	4
1F1/14-35-084-07W4	Clearwater	Y	19-Dec-12	29,000	0	0
1F1/15-28-085-05W4	McMurray	Y	14-Feb-07	42,200	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	409	1
1F1/16/30/084/06W4	Clearwater	Y	19-Dec-12	6,200	2,419	7
Subtotal Saline Diverted Volume					**76,676**	**210**
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	29-Dec-15	3,700	13,436	36
16-25-84-07W4M	Grand Rapids	N	19-Dec-12	2,400	0	0
16-27-84-07W4M	Grand Rapids	N	16-Nov-15	1,700	2,752	8
Subtotal Non-Saline Diverted Volume					**16,188**	**44**
TOTAL VOLUME DIVERTED					**92,864**	**254**

- 19 wells tied in.
- 5 fresh wells tied into saline pipeline (SAGD startup, plant upsets, feed to HQWS).
- Isolation valves are installed on freshwater wells on the saline water pipeline.
- Saline wells are sampled if diversion criteria are met: > 10,000 m^3/year

**** Volumes as reported in Petrinex and vary from those reported in Annual Reports***

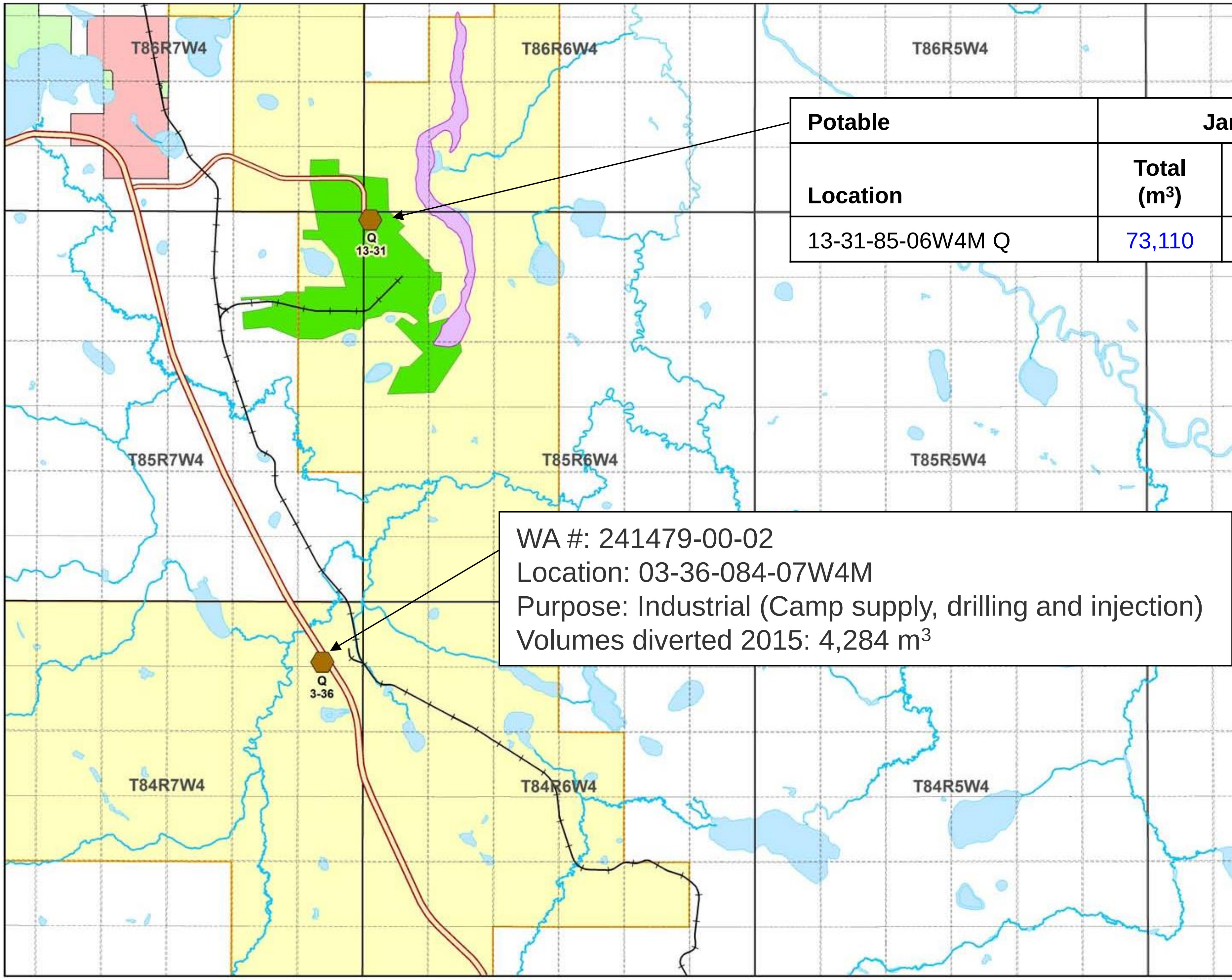
Subsection 3.1.2 (4a,b)

Saline Source Wells Water Quality TDS



Subsection 3.1.2 (4a)

Potable Well



Potable	Jan-Dec 2015	
Location	Total (m^3)	Annual avg. (m^3/cd)
13-31-85-06W4M Q	73,110	200

WA #: 241479-00-02
Location: 03-36-084-07W4M
Purpose: Industrial (Camp supply, drilling and injection)
Volumes diverted 2015: 4,284 m^3

Subsection 3.1.2 (4a)

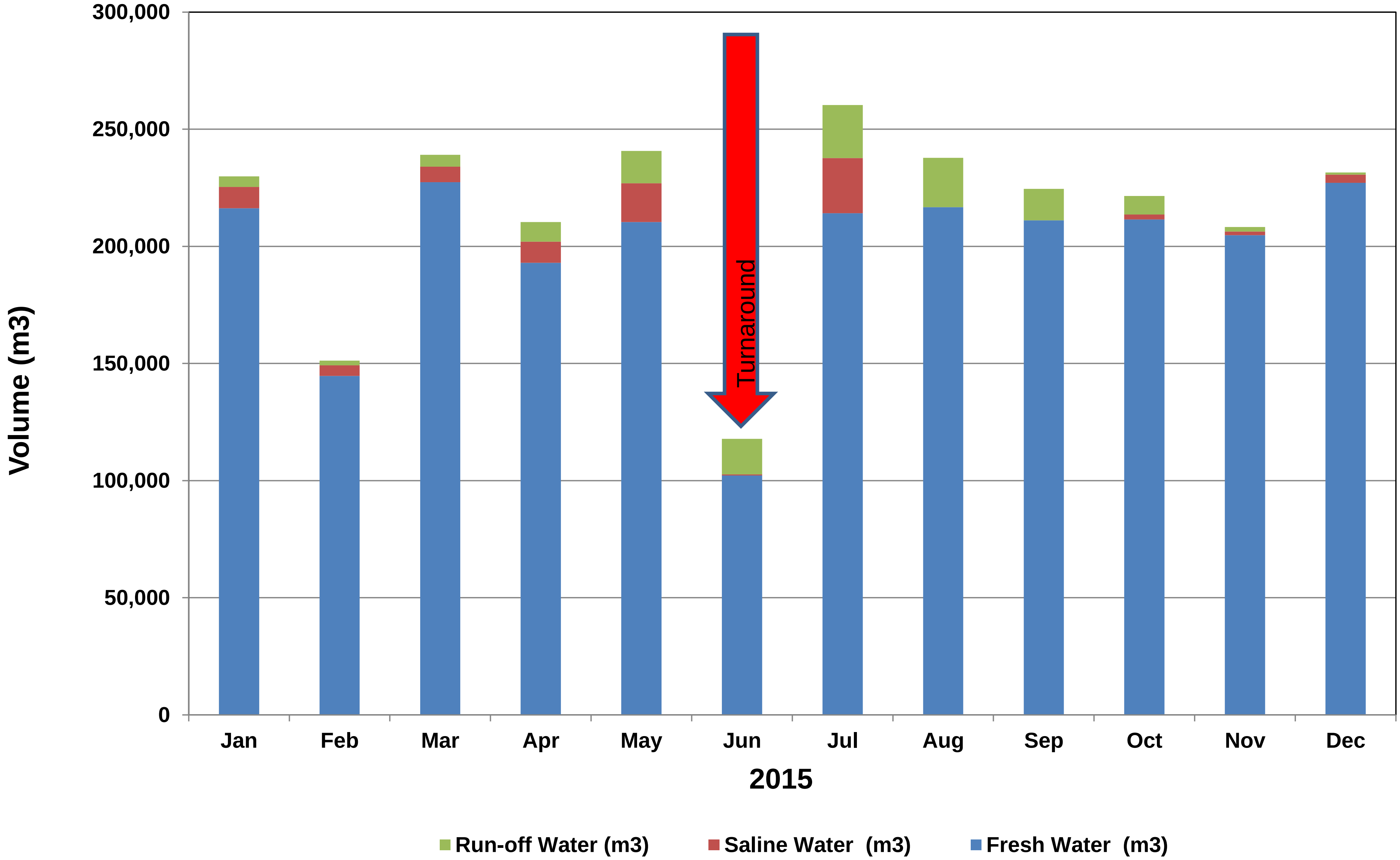
Other Water Sources

- Surface runoff to lime sludge ponds (00247843-00-00)
  - 2015: 117,015 m^3 (estimate)

- Corehole and SAGD drilling
  - Various TDLs: 7,308 m^3 in 2015

- K1A Emulsion Line Clean-Up and Remediation Activities
  - TDL No. 370811 for water reuse: 12,537 m^3 in 2015

Fresh and Brackish Water Use Volumes



Subsection 3.1.2 (4b)

Water Make-up

- Use of freshwater make-up (in decreasing amounts)
  1. Demineralized water make-up (UPG and cogens)
  2. Utility and plant use (UPG and SAGD)
  3. SAGD steam make-up (HLS's)
  4. Potable
  5. Others (incl. drilling)

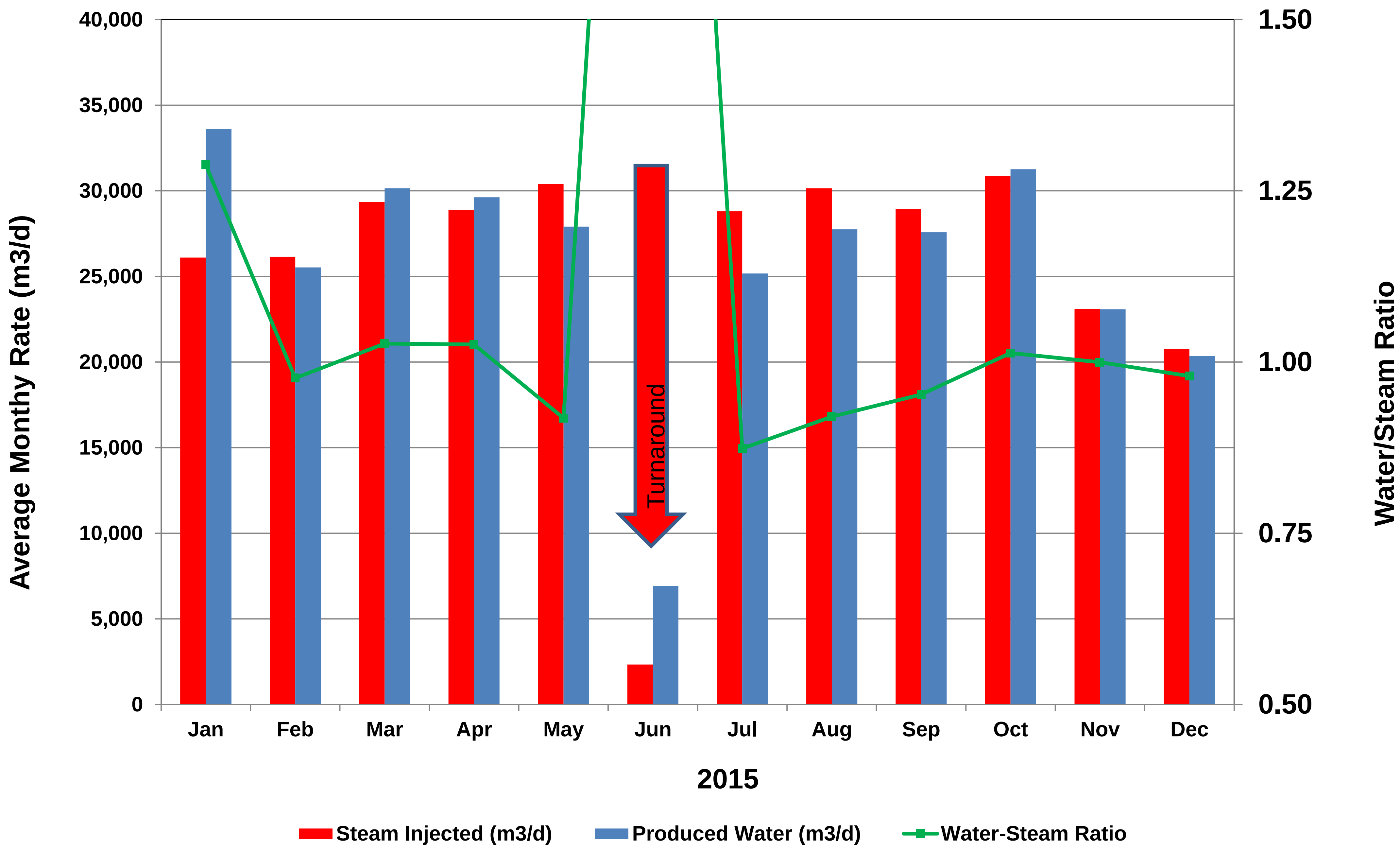
	Freshwater Uses in 2015 (m³)			
	*Total	Domestic	**SAGD	UPG
Main groundwater license (235895-01-00 as amended)	2,452,372	73,110	561,467	1,817,795
Surface runoff to ponds	117,015		117,015	
SAGD drilling	0		0	
Winter drilling program (Long Lake and Kinosis)	7,308		7,308	
Potable trucked to Long Lake	0		0	
TOTAL	**2,576,695**	**73,110**	**685,790**	**1,817,795**

- Saline water make-up:

  76,677 m³ in 2015 for steam make-up (HLS's)

** Volumes as reported in Petrinex and vary from those reported in Annual Reports*
*** Adjusted for process water returned from Upgrader and Utility water*

Produced Water and Steam Injected Volumes

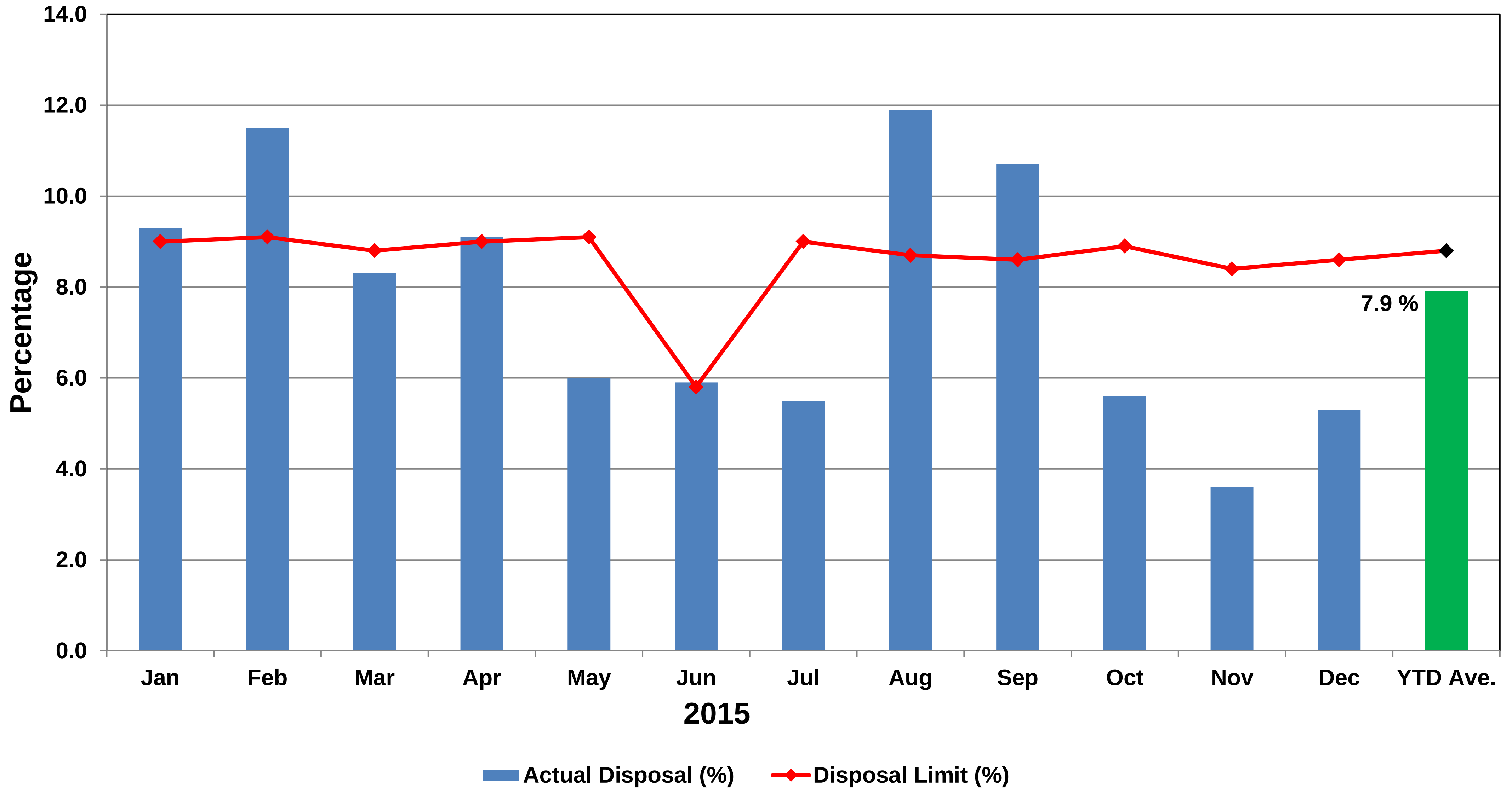


Subsection 3.1.2 (4c,d)

Water Management

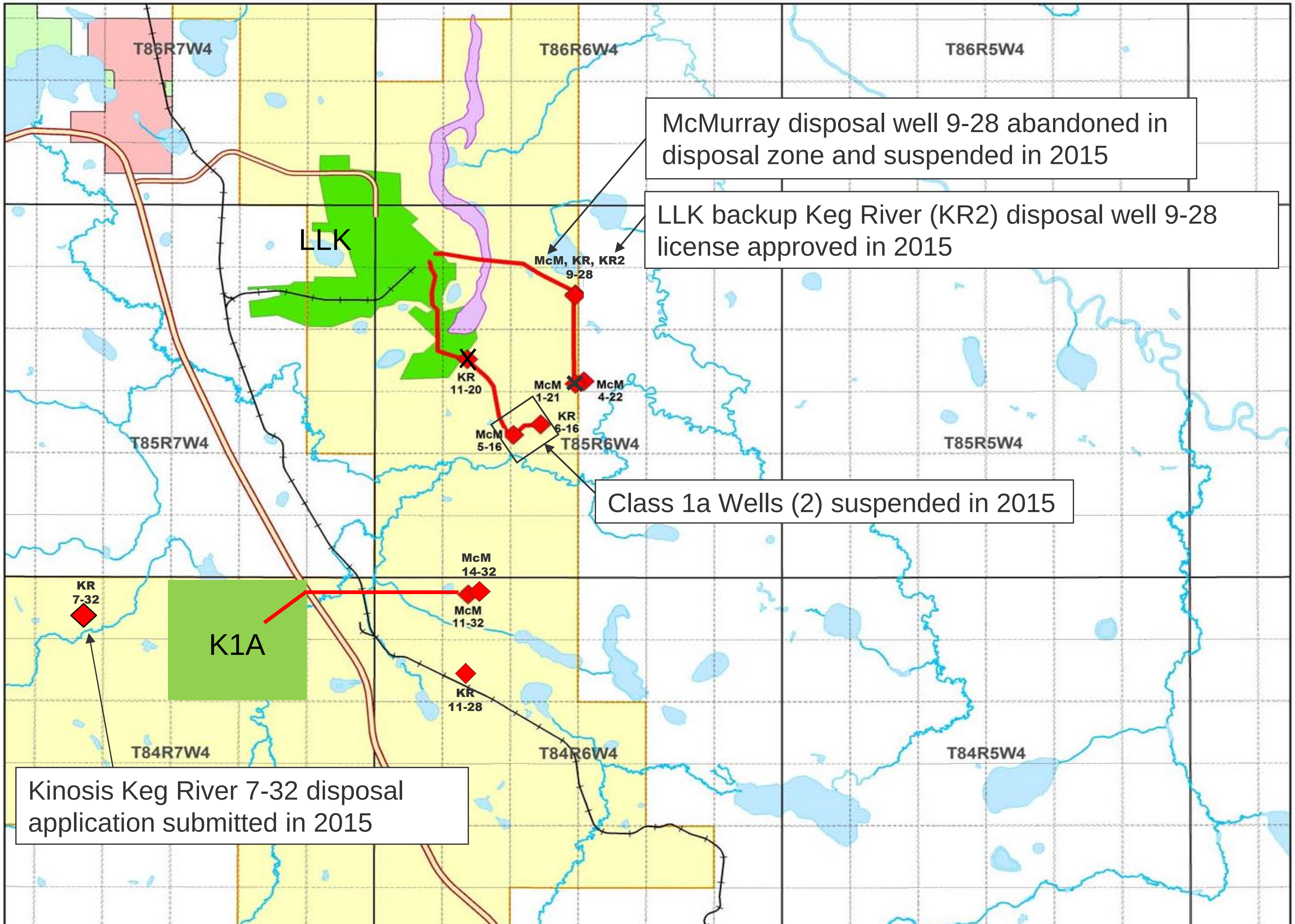
Nexen's disposal rate includes freshwater demand to the upgrader

Disposal limit (%) = $\frac{[(\text{Freshwater In}*0.03) + (\text{Brackish water In }*0.35) + (\text{Produced water In}*0.1)]}{[(\text{Freshwater In}) + (\text{Brackish water In}) + (\text{Produced water In})]}*100$



Subsection 3.1.2 (4e,f)

Disposal Wells



Subsection 3.1.2 (4g)

Disposal Wells (CONT'D)

AER Approval # 10023G	Class 1b	January - December 2015		
Disposal Well		**Max. WHP (kPag)**	****Total (m^3)**	**Annual avg. (m^3/cd)**
104/09-28-085-06W4/00 KR	Blowdown	1,151	455,351	1,248
103/09-28-085-06W4 KR	Blowdown	969	345,801	947
100/09-28-085-06W4 McM*	Blowdown	1,904	104,869	287
100/04-22-085-06W4 McM	Blowdown	2,702	3,615	10
100/11-32-084-06W4 McM	Blowdown	1,904	77,100	211
100/14-32-084-06W4 McM	Blowdown	2,060	2,839	8
100/01-21-085-06W4 McM*†	Blowdown	-	-	-
100/11-28-084-06W4/00 KR	Drilling fluids	-	-	-
TOTAL			**989,574**	**2,711**

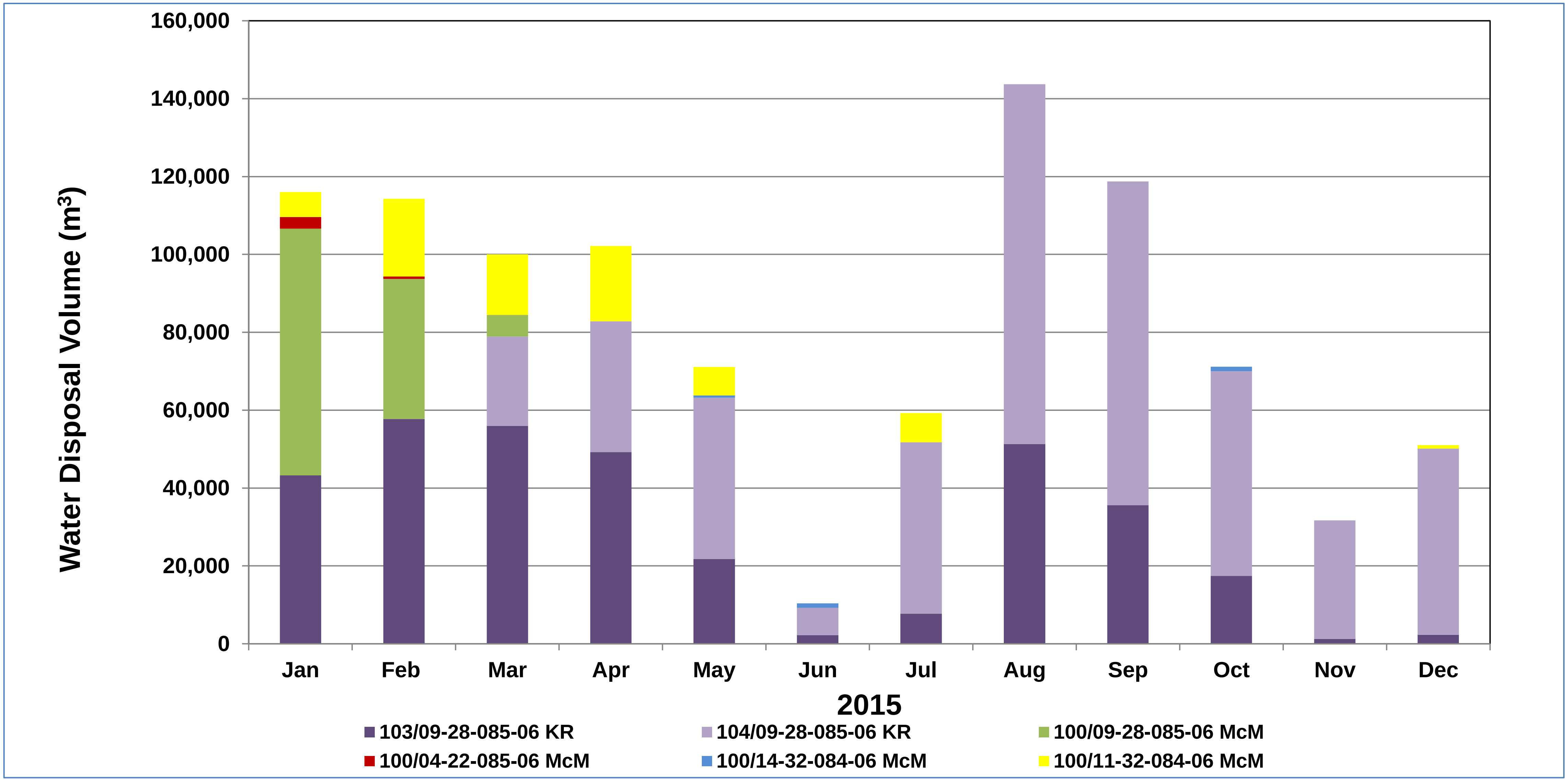
AER Approval # 11611	Class 1a	January - December 2015		
Disposal Well		**Max. WHP (kPag)**	**Total (m^3)**	**Annual avg. (m^3/cd)**
100/06-16-085-06W4 KR*	-	-	-	-
100/05-16-085-06W4 McM*	-	-	-	-

*Well is suspended
†Well was rescinded from approval 10023G

***** Volumes as reported in Petrinex and vary from those reported in Annual Reports***

- Disposal capacity is adequate.
- Disposal fluid temperature ~60°C.
- All wells passed annulus pressure test, except 100/09-28-085-06W4/00.
  - The 100/09-28-085-06W4/00 well was abandoned through McMurray Formation (disposal zone) and suspended above in 2015.
- Data Loss Notification wells (Clause 7 from Approval No. 10023G) :
  - 1F2/02-32-085-06W4/00 (Nov. 8 2015 – Feb. 21, 2016).

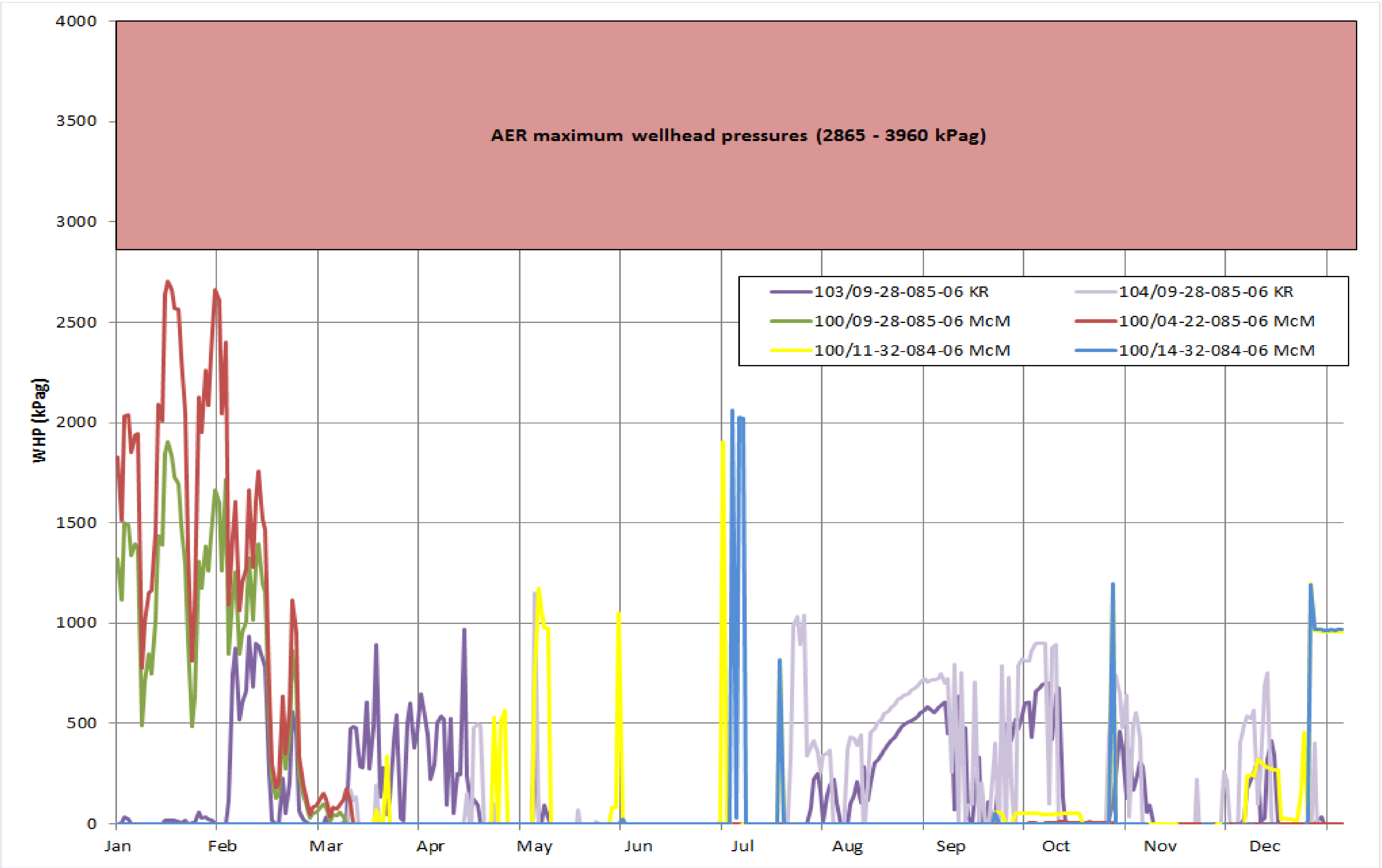
Disposal Well Volumes - Class 1b



- No disposal at suspended WD McMurray 1-21 in 2015
  - WD MM 1-21 was rescinded from approval 10023G
- No disposal at WD Keg River 11-28 in 2015

*** Volumes as reported in Petrinex and vary from those reported in Annual Reports*

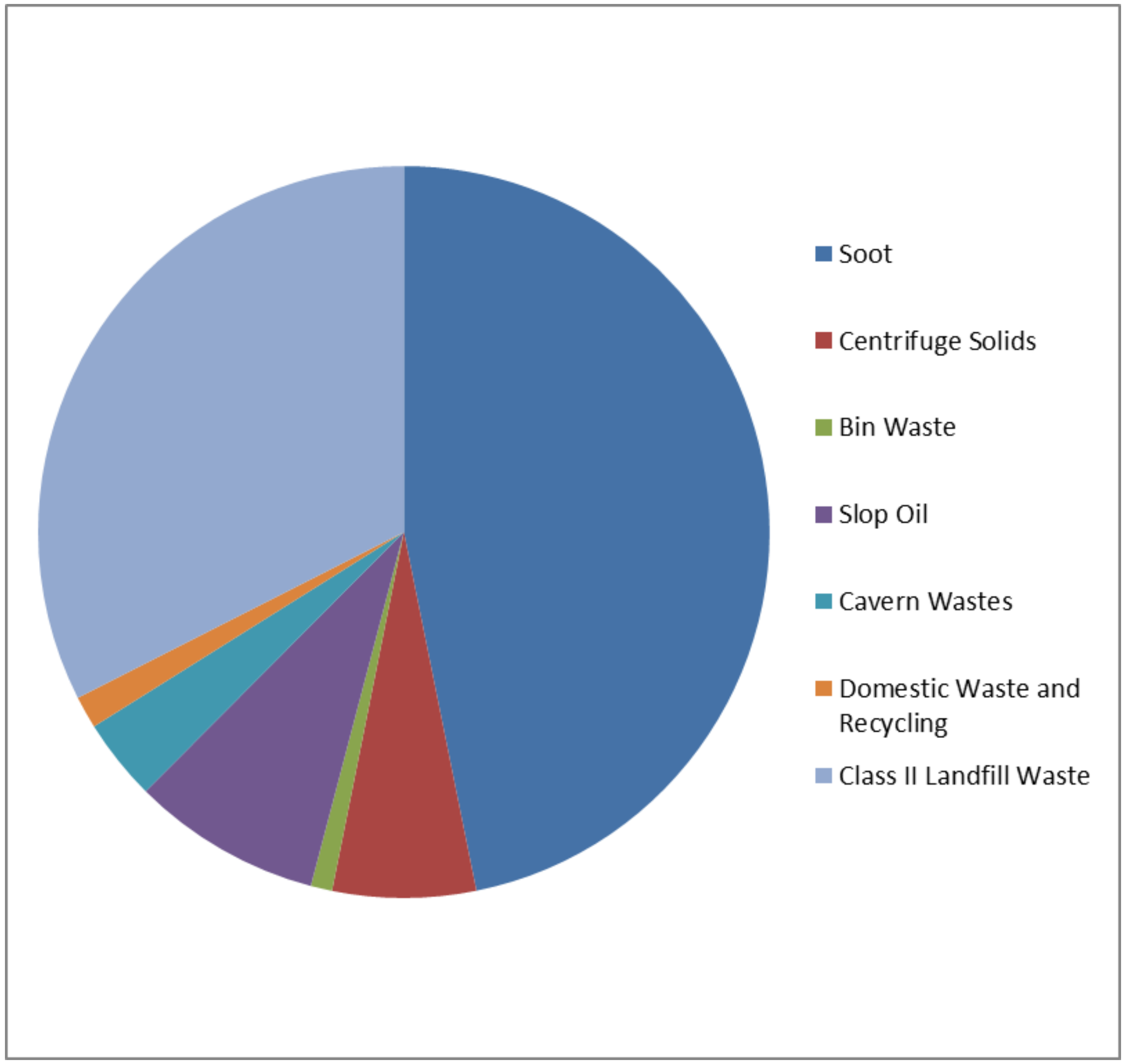
Disposal Well - Well Head Pressures



2015

Waste Disposal

Hazardous Waste	tonnes
Soot	38,560
Centrifuge Solids	5,215
Bin Waste	779
Slop Oil	6,895
Cavern Wastes	2,981
Total	**54,430**
Non-Hazardous Waste	
Domestic Waste and Recycling	1,179
Class II Landfill Waste	26,751
Total	**27,929**
Grand Total	**82,359**



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

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Sulphur Recovery Overview

The Long Lake sour gas processing system is located in the Upgrader area but is an integrated facility for treating sour gas produced from both the SAGD CPF and Upgrader. There are six subsystems in this unit:

1. **Amine Regeneration Subsystem**
   - The Amine Regeneration Subsystem is designed to remove H2S and CO2 from rich amine and produce lean amine for re-use in the OrCrude™, Hydrocracker Unit, AGU, SRU Subsystem, and SAGD;
2. **Selexol Regeneration Subsystem**
   - The Selexol Regeneration Subsystem is designed to remove H2S and CO2 from rich Selexol and produce lean Selexol for re-use in the Selexol Absorbing System;
3. **Sour Water Stripping Subsystem**
   - The Sour Water Stripping Subsystem is designed to strip H2S and NH3 from sour water coming from the OrCrude™, Hydrocracker Unit, AGU, and the SRU Subsystem. Stripped water is returned to the SAGD CPF and Upgrader for re-use and the acid gas exiting this system flows to the SRU subsystem;

Sulphur Recovery Overview Continued

4. **SRU Subsystem**
    - The SRU Subsystem converts Sulphur contaminants (mainly H2S) flowing from the Amine Regeneration, Selexol Regeneration, and Sour Water Stripping Subsystems into liquid Sulphur. The subsystem is also designed to destroy ammonia;
5. **Tail Gas Treating Unit (TGTU) Subsystem**
    - The TGTU Subsystem is designed to convert any Sulphur contaminants in the tail gas flowing from the SRU Subsystem back into H2S so that the H2S can be removed by amine solution in the TGTU Absorber. Any remaining Sulphur contaminants in the tail gas are oxidized in the incinerator before it is released to atmosphere; and
6. **Miscellaneous Utilities Subsystem**
    - The Miscellaneous Utilities Subsystem contains the acid gas flare and associated equipment, a natural gas heater, and various condensate collection drums, condensate blowdowns, flash drums, etc., that are necessary for the operation of the Sulphur recovery systems.

Sulphur Recovery Rates & Uptimes

Items		Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Average
Claus Units	% of Month Processing AG	91.2	100.0	97.8	100.0	100.0	2.9	73.2	100.0	100.0	100.0%	53.2	61.3	81.7
Sulphur Recovery	Monthly Recovery Rate (%)	98.9	99.8	99.8	99.6	99.6	99.6	99.5	99.6	99.8	99.8	99.3	99.5	99.5
Quarterly Recovery Rate (%)		99.5			99.6			99.6			99.5			99.5
Average Inlet Sulphur (Tonnes/day)		300.0	535.5	339.1	366.0	330.1	72.3	261.4	387.5	468.6	483.7	192.3	210.3	327.8
Average Monthly Sulphur Production (Tonnes/day)		296.6	534.2	338.4	364.4	328.6	72.0	260.0	385.9	467.7	482.5	190.9	209.4	326.4

Month	% Time TGTU in Operation with SRU Trains
January	97.8
February	100.0
March	100.0
April	100.0
May	100.0
June	81.0
July	99.4
August	100.0
September	100.0
October	100.0
November	92.4
December	98.6

Acid Gas Flaring Events Summary

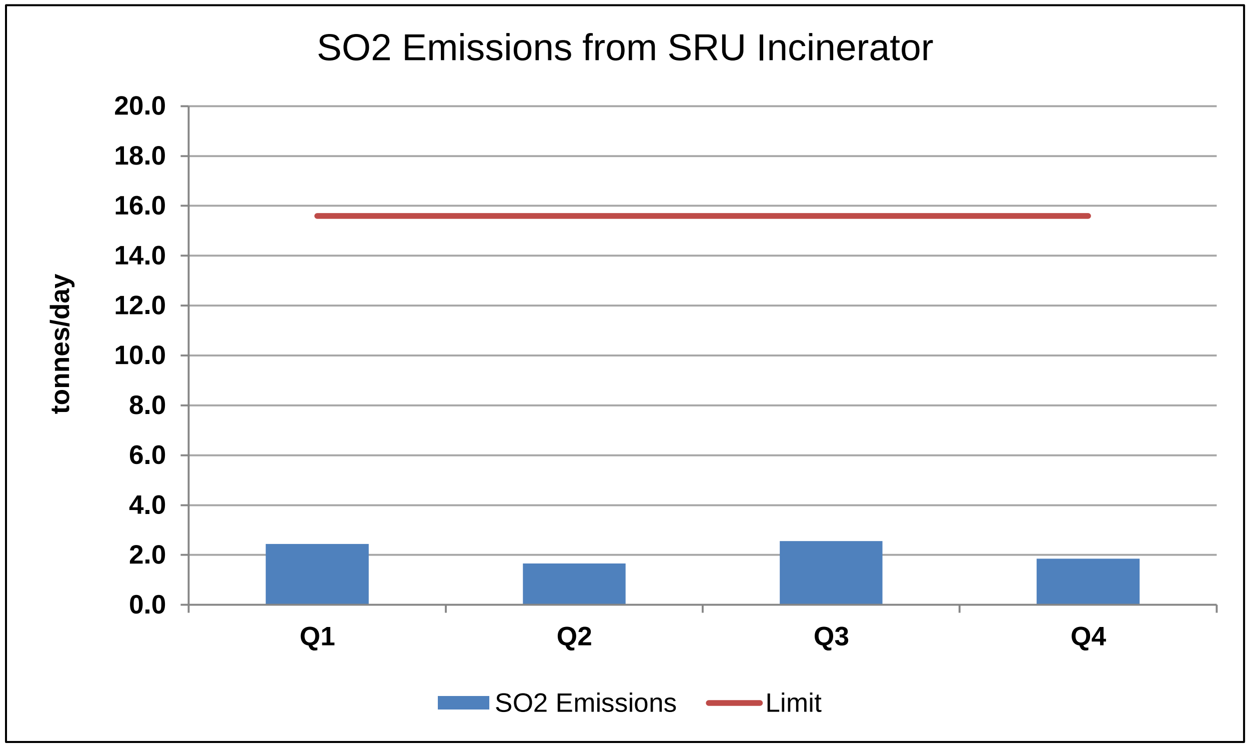
Month	AG Sources			SWAG Sources		
	Duration (h)	Volume (Sm^3)	SO_2 (Tonnes)	Duration (h)	Volume (Sm^3)	SO_2 (Tonnes)
January	85.4	33,621	88.2	0.0	0	0.0
February	129.9	4,690	3.7	0.0	0	0.0
March	17.3	4,665	3.2	0.0	0	0.0
April	0.0	0	0.0	0.0	0	0.0
May	0.0	0	0.0	0.0	0	0.0
June	720.0	92,990	2.5	0.0	0	0.0
July	216.0	107,935	2.9	0.0	0	0.0
August	23.0	49,666	2.8	0.0	0	0.0
September	0.0	0	0.0	0.0	0	0.0
October	0.0	0	0.0	0.0	0	0.0
November	359.6	2,842	1.5	0.0	0	0.0
December	41.7	8,878	13.7	14.4	11,596	0.2
2015 Total	**1,592.8**	**305,288**	**118.6**	**14.4**	**11,596**	**0.2**

AG : Acid Gas
SWAG : Sour Water Acid Gas

- Total SO_2 emissions due to acid gas flaring were 118.6 tonnes
- Acid Gas Flaring Events are part of the monthly air report submitted to Alberta Environment & Parks
- There was a substantial decrease in SWAG flaring in 2015, compared to 2014, due to fewer Upgrader shut down incidents
- The leading causes for the flaring events in 2015 were Upgrader trips and issues with the Recycle Gas Compressor in the HCU.

SO_2 Emissions

SO_2 Limits	Quarter	Total (tonnes)	Average (tonnes/day)	Limit (tonnes/day)
Long Lake Plant	ALL	1,519.6	4.2	18.5
K1A Plant	ALL	13.2	0.04	1.8
SRU Incinerator Stack	1st	219.7	2.4	15.6
	2nd	150.6	1.6	
	3rd	235.8	2.6	
	4th	169.8	1.9	



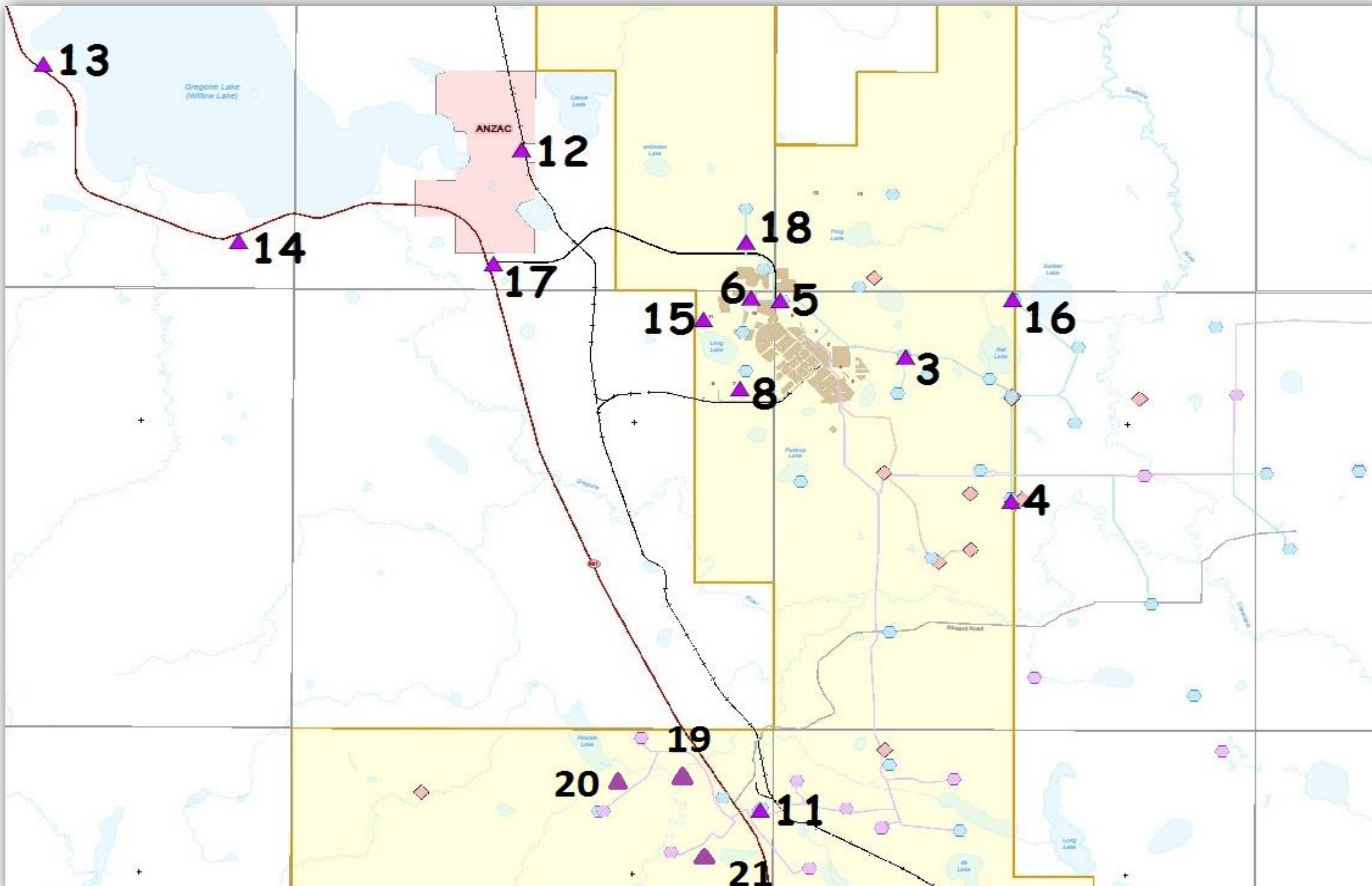
- The total amount of SO_2 emitted from the entire Long Lake Facility was 1,519.6 tonnes.
- The plant emitted an average of 4.2 tonnes/day, with a limit of 18.5 tonnes/day.
- From the SRU Incineration, the 3^{rd} quarter had the greatest average of SO_2 emissions, with 2.6 tonnes/day emitted. The limit is 15.6 tonnes/day/quarter.

Ambient Air Monitoring

- The Long Lake continuous air monitoring station is located approximately 35 km southeast of Fort McMurray on the northern edge of the hamlet of Anzac and is operated by the Wood Buffalo Environmental Association.
- The Anzac Station contains analyzers that continuously measure SO_2, O_3, TRS, THC, NO, NO_2, NO_X, PM 2.5, wind speed and direction, and temperature.
- There were 8 events in 2015 which exceeded the Alberta Ambient Air Quality Objectives (AAAQO). All of these events were attributed to forest fires burning in the region.

Date	Parameter	Concentration	Limit	AER Ref #
June 29	PM 2.5	78 µg/m^3	30 µg/m^3 24 hr avg	300127
June 30	PM 2.5	81 µg/m^3		300199
July 1	PM 2.5	58 µg/m^3		300242
July 2	PM 2.5	38 µg/m^3		300293
July 3	PM 2.5	108 µg/m^3		300350
July 4	PM 2.5	85 µg/m^3		300386
July 11	PM 2.5	146 µg/m^3		300736
July 12	PM 2.5	143 µg/m^3		300782

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	Nexen 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

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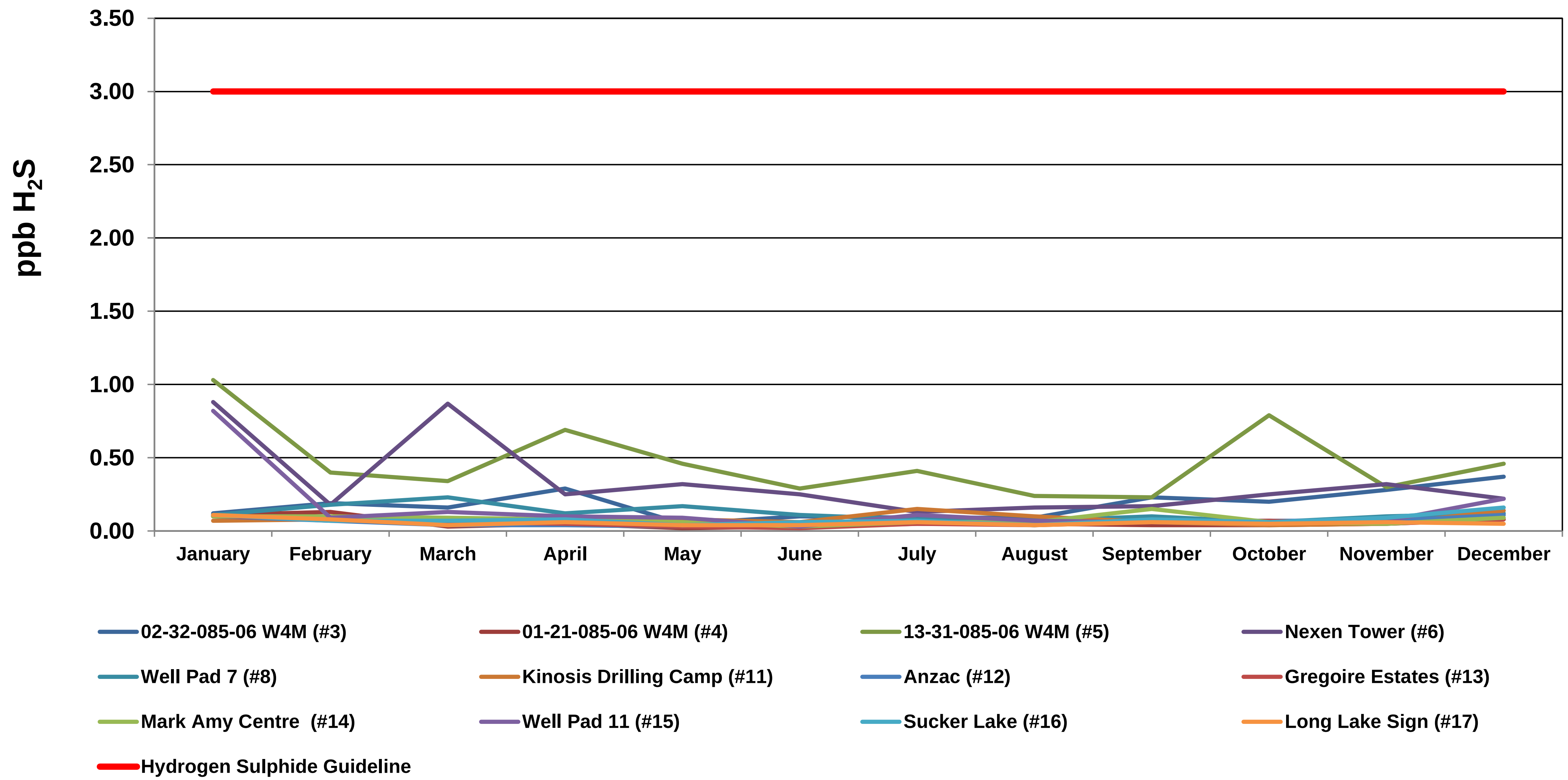
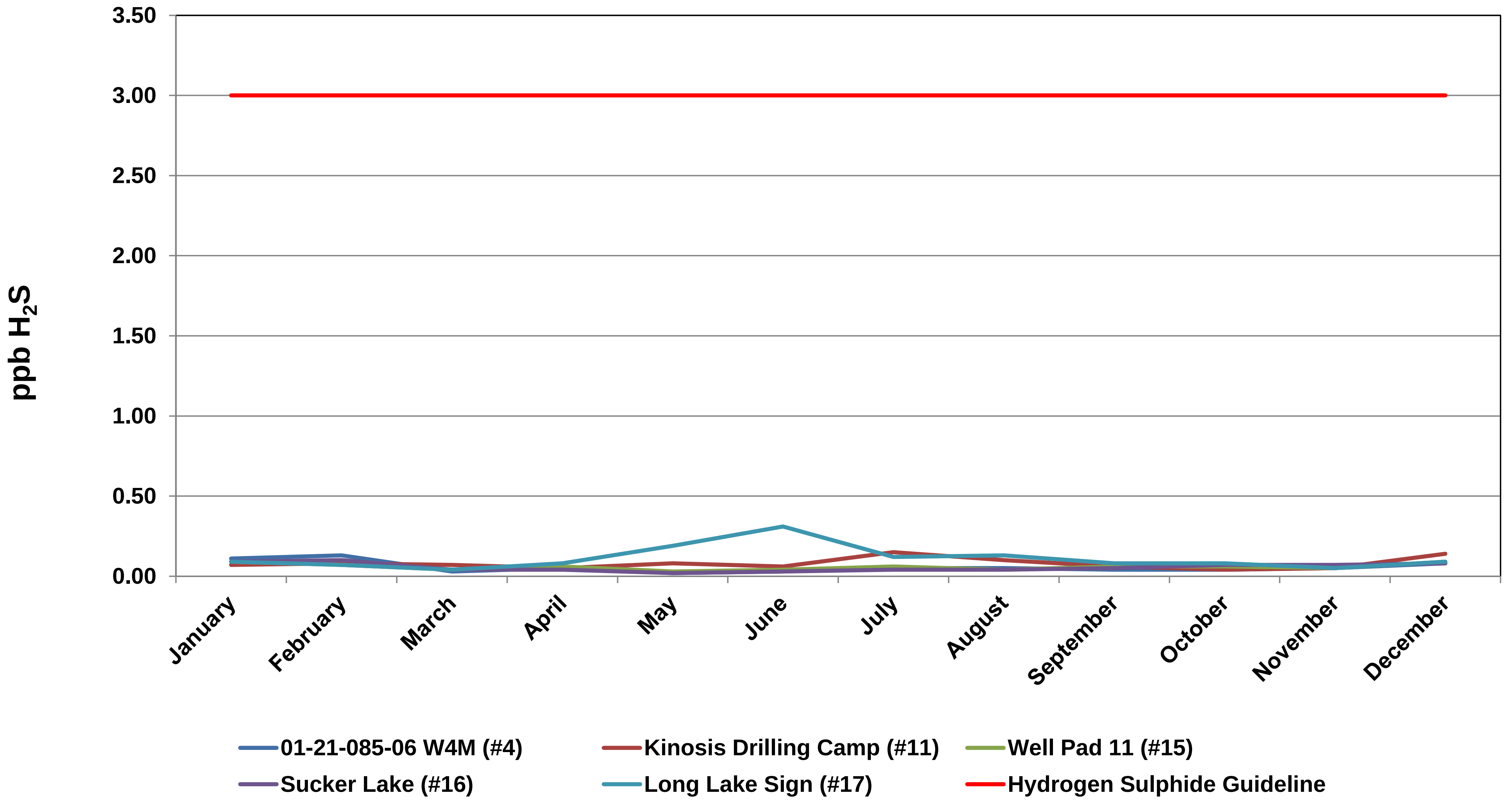
- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3ppbv. No stations exceeded this limit in 2015.



K1A H_2S Passive Monitoring

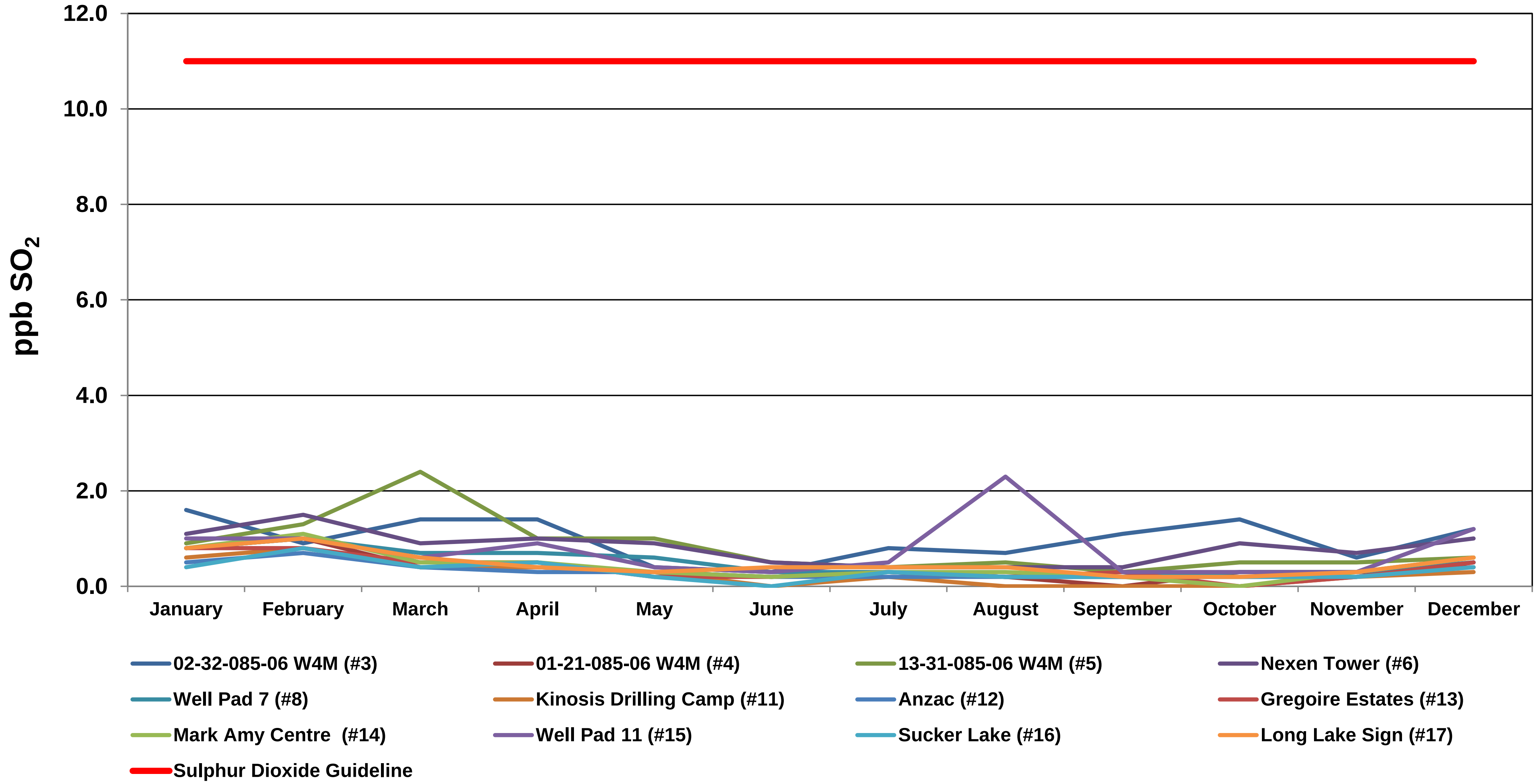
- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3 ppbv. No stations exceeded this limit in 2015.



Subsection 3.1.2 (5d)

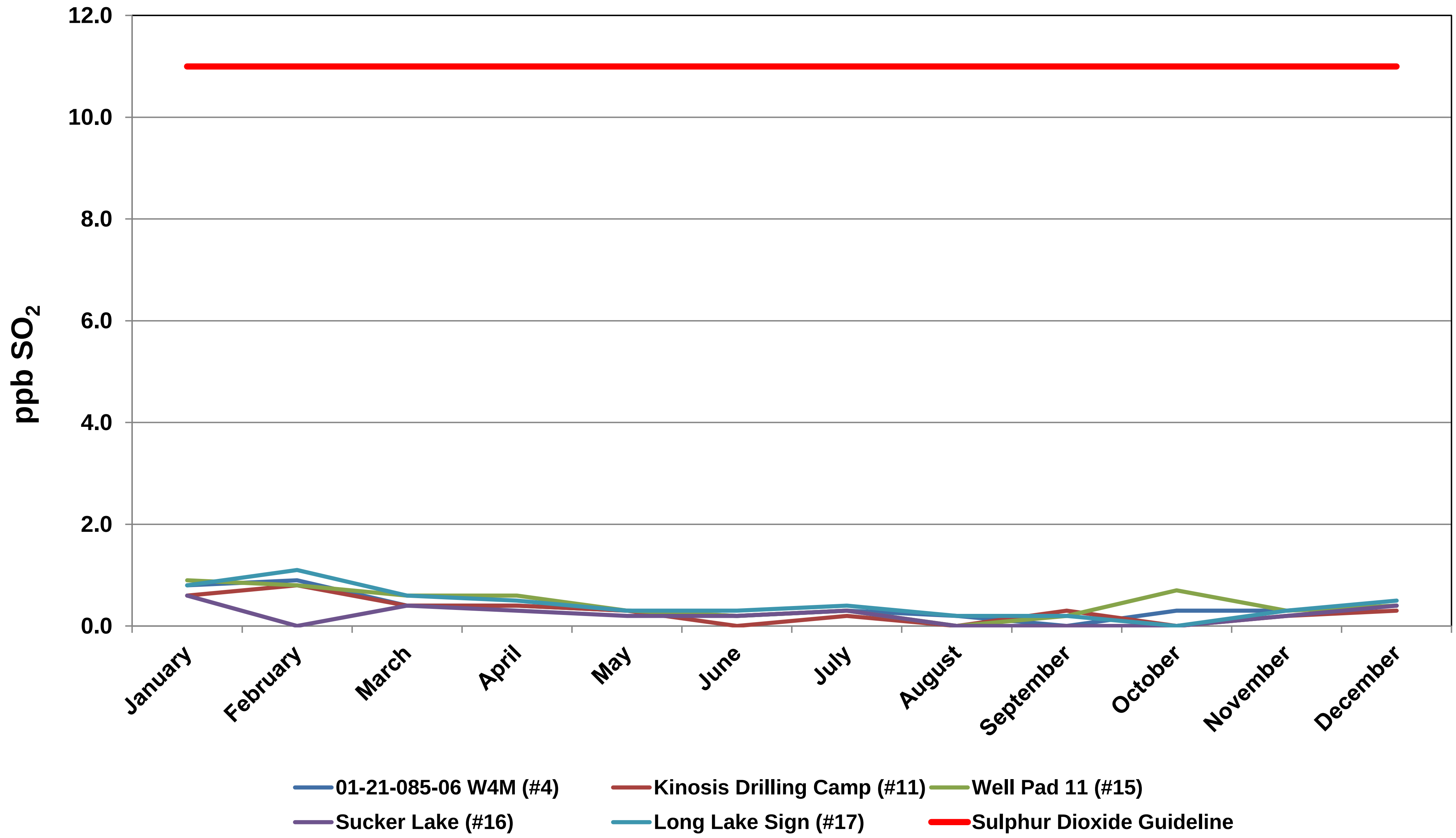
Long Lake SO_2 Passive Monitoring

- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. No stations exceeded this limit in 2015.



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 2015.



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

Long Lake

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Regulatory Compliance

- Inspections (78)
  - Satisfactory Inspections (62)
  - ~50 in relation to the K1A Pipeline Release
  - Unsatisfactory Inspections (16)
    - Mostly related to the pipeline suspension order
    - All actions related to these inspections have been resolved
- Voluntary Self Disclosures (7)
- Regulatory Notifications (7)
    - Environmental Protection Order (July 17)
    - Pipeline Suspension Order (August 28)

Environmental Regulatory Compliance

- 30 Notifications,17 Permit Violations and 26 Reportable Spills

Notifications and Permit Violations Summary	2012	2013	2014	2015
Oil Sands	191	98	52	47

- Totals are trending down from previous years
- In 2015, there were 31 hours (some during the same reportable event) where approval limits were exceeded based upon values measured by the CEMS units.
- Other permit violations included, flaring > 20 tonnes SO_2 (2), the SAGD flare extinguishing, and an increase in TDS (total dissolved solids) at a source well.

Reportable Spill Summary	2012		2013		2014		2015	
	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)
Oil Sands	32	430	20	548	17	1,551	26	*5,937

- Total number of reportable spills are up from previous years but the average volume of reportable spills is down from 2014 (including the K1A emulsion line release).

*Volumes include liquid and solid reportable releases

AER Scheme Approval

- Amendments Approved in 2015:
  - Field Trial Co-Injection of NCG with Steam at Pad 7N – Approved March 11, 2015
  - Long Lake Expansion of Development Area; Addition of Pad 19 – Approved July 19, 2015
  - Long Lake at Infill Wells at Pads 6N, 6W, 8 and 10W – Approved March 17, 2015
  - Kinosis Phase 1B CPF Location and Production Capacity – Approved April 24, 2015
  - Kinosis Phase 1B Well pads 39101 – 39104 – Approved August 17, 2015
  - Long Lake Pad 3 Infill Application – Approved July 9, 2015
  - K1A Drainage Area A Revision to MOP – Approved August 4, 2015
  - Long Lake Pad 5 Infill Application – Approved July 30, 2015
  - Long Lake Well Compatibility for Thermal Operations Pads 1 and 7 Infills – Approved November 16, 2015
  - Modifications to Pads 14 & 15 Operating Program – Approved December 17, 2015

AER Scheme Approval

- Applications Under Review in 2015:
  - Long Lake Southwest Modifications (Approved March 31, 2016)
- Amendments Approved in 2016:
  - Long Lake Well Compatibility for Thermal Operations Pads 5 and 8 – Approved September 22, 2016

Environmental Summary
Monitoring Programs

- Received the new EPEA Approval for Long Lake in October of 2015
- All monitoring programs were conducted in accordance with regulatory approvals and most plans will be updated in 2016 with the issuance of the new approval:
  - Groundwater monitoring
  - Hydrology and water quality monitoring
  - Soil monitoring
  - Wildlife monitoring
  - Wetland monitoring
  - Source emission and ambient air monitoring
  - Conservation and reclamation plans

Environmental Summary Monitoring Programs

- Funded the regional Joint Oil Sands Monitoring (JOSM)
- Participation in regional stakeholder committees:
  - Cumulative Environmental Management Association (CEMA)
  - Participation in the Wood Buffalo Environmental Association (WBEA)
  - Regional Aquatics Monitoring Program (RAMP)

Long Lake EPEA Approval Requirements

Schedule	Section	Topic	Report	Deadline	Status
IV		Air Emissions	VOC and RSC Emissions Monitoring Plan	November 16, 2016	In Progress
VI		Groundwater	Groundwater Monitoring Plan - Updated	April 30, 2016 Extension to Dec 15, 2016	In Progress
VII		Soil	Soil Monitoring Program Proposal	31-Jan-2017 31-Jan-2021	NA
		Soil	Soil Monitoring Program Report	Extension to Nov 30, 2016	In Progress
VII		Soil	Soil Monitoring Program Report	31-Jan-2018 31-Jan-2022	NA
VIII	4	Wildlife	Wildlife Mitigation Proposal	30-Apr-2016 Extension to June 15, 2016 Extension to June 30, 2016 (Due to Wildfire)	Complete
VIII	9	Wildlife	Woodland Caribou Monitoring and Mitigation Program Proposal	30-Apr-2016 Extension to June 15, 2016 Extension to June 30, 2016 (Due to Wildfire)	Complete
VIII	13	Wildlife	Wildlife Monitoring Program Proposal	30-Apr-2016 Extension to June 15, 2016 Extension to June 30, 2016 (Due to Wildfire)	Complete
VIII	17	Wildlife	Comprehensive Wildlife Report	15-May-2018 15-May-2021 15-May-2024	In Progress
IX	27	Construction, Decommissioning and Reclamation		June 30, 2017	NA
IX	40	Construction, Decommissioning and Reclamation	Wetland Reclamation Trial Program Proposal (Project Specific)	June 30, 2017	NA
IX	46	Construction, Decommissioning and Reclamation	Reclamation Monitoring Program Proposal	June 15, 2018	NA
XI	3	Wetlands and Waterbodies	Wetland and Water Body Monitoring Program	June 30, 2016 Extension to Dec 15, 2016	In Progress

Subsection 3.1.2 (6c)

Environmental Summary
Operational Initiatives

- Nexen worked with a consultant in cooperation with the AER to develop an Odour Monitoring Plan to identify any odour-producing sources at Long Lake which included:
  - ranking the sources by their potential to cause odour events at the local community Anzac; and
  - identifying the conditions that will lead to odour events in Anzac.
- This plan will help Nexen achieve compliance with both our approval conditions and Directive 60, and ensure that Long Lake is not negatively impacting the neighboring community.
- The monitoring program was scheduled to begin in the spring of 2016, however, due to the incident in early 2016, that resulted in reduced plant rates of the, it was decided in collaboration with the AER that implementation would be most effective once the plant returns to normal operations.
- Tank gaskets were changed to Teflon during Turnaround 2015. An RCA determined that Teflon was more compatible with the diluent material in the tank. This change reduced tank wisping incidents which can help to reduce potential odour issues.

Environmental Summary: Innovation, Research & Reclamation Initiatives

- Continued leadership in Canada's Oil Sands Innovation Alliance (COSIA) to accelerate the pace of environmental performance improvement.
  - Participation in the Land, Water, and Greenhouse Gas Environmental Priority Areas as well as the Monitoring working group.
  - Leading multiple Joint Industry Projects including caribou habitat restoration, reclamation practice studies, and wildlife monitoring technologies.

Compliance Statement

- To the best of Nexen's knowledge, the Long Lake Project is compliant with the conditions of its approvals and regulatory requirements subject to the items listed non-complaint of the Summary table that follows.

Compliance Discussion

Notice	Events that led to the non-compliance	Nexen action plan	Status
Environmental Protection Order (EPO) - section 113 of EPEA in relation to the 16-24-85-7W4 Pipeline Spill discovered July 15, 2015	Nexen identified a pipeline break that resulted in a release and regulatory investigations.	Nexen responded to numerous information requests and interviews.	All requests for information and interviews from EC and the AER have been responded to by Nexen.
Environment Canada and AER Lead an investigation in relation to the Pipeline Spill discovered July 15, 2015	Nexen identified a pipeline break that resulted in a release and regulatory investigations.	Nexen responded to numerous information requests and interviews. .	All requests for information and interviews from EC and the AER have been responded to by Nexen.
Notice of Noncompliance - Packer Testing 2014- 2 Disposal wells January 21, 2015.	Failure to perform packer isolation test by September 1, 2014.	Nexen conducted the packer isolation test and submitted results into the DDS system.	Compliance achieved January 29, 2015.
High Risk Enforcement Action- Failure to Comply with Directive 013: Suspension Requirements for 1 Oil Sands Well. Nexen received an initial notice to comply in May 2014 and was given until March 31, 2015 to achieve compliance.	Failure to submit the downhole work that was done prior to March 31, 2015 into the DDS system.	Nexen submitted the downhole work in the DDS system April 23, 2015.	Compliance achieved May 7, 2015.
Notice of Noncompliance- Outstanding submission of drilling waste information for 1 Oil sands well as per Directive 050: Drilling Waste Management. March 24, 2015.	Failure to submit drilling waste information within the 24 month due date.	Nexen submitted the drilling waste information in the DDS system.	Compliance achieved April 10, 2015.
Notice of Noncompliance- Outstanding submission of drilling waste information for 4 Oil sands wells as per Directive 050: Drilling Waste Management. May 19, 2015.	Failure to submit drilling waste information within the 24 month due date.	Nexen submitted the drilling waste information in the DDS system.	Compliance achieved June 11, 2015.
Notice of Noncompliance- Outstanding submission of drilling waste information for 4 Oil sands wells as per Directive 050: Drilling Waste Management. June 1, 2015.	Failure to submit drilling waste information within the 24 month due date.	Nexen submitted the drilling waste information in the DDS system.	Compliance achieved June 12, 2015.
Notice of Noncompliance- Outstanding Non-Abandoned Oil Sands Evaluation (OSE) wells July 16, 2015. 24 wells.	Failure to report surface abandonments for 6 wells through the DDS system within 30 days of completing the operation. 18 of the OSE wells were converted and were missing a license amendment and a Lahee classification change.	Nexen submitted the surface abandonment information in the DDS system. Nexen applied for license amendments and requested Lahee classification changes.	Compliance achieved August 14, 2015.

Compliance Discussion continued

Notice	Events that led to the non-compliance	Nexen action plan	Status
Suspension Order: Issued on August 28, 2015; under section 29 of the Pipeline Act- Suspend operations under the licenses of 15 Pipelines effective immediately	Nexen submitted a Self- Disclosure on August 25, 2015 of 102 identified Pipeline Segments that were in contravention of Manual 005: Pipeline Inspections.	Nexen immediately conducted the required inspections completed a number of corrective actions, and made numerous submissions to the AER. Three amendment orders were subsequently issued on September 6 and October 22, 2015 allowing Nexen to resume full operations.	Nexen is in compliance with the Manual 005 regulatory requirements identified in the Self-Disclosure letter of August 25, 2015.
Unsatisfactory Low Risk Crude Bitumen Group battery Inspection @ 7-31-85-6W4 June 5, 2015	Contravention of EPEA Approval in relation to fugitive emissions and industrial waste water.	AER field office provided Nexen with a remedial action plan to achieve compliance. Nexen complied with all items. 7 day letter requirement was waived.	Compliance achieved June 9, 2015
Unsatisfactory High Risk Natural Gas Pipeline Inspection @ 09-03-086-07W4 P39427 on Aug 31, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Sept 6, 2015
Unsatisfactory High Risk Water Pipeline Inspection @ 07-36-085-07W4 P39428 on Aug 31, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Sept 6, 2015
Unsatisfactory High Risk steam or produced vapour Pipeline Inspection @ 06-31-085-06W4 P52773 on Aug 31, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Sept 16, 2015
Unsatisfactory High Risk Crude Oil Pipeline Inspection @ 06-31-085-06W4 P52719 on Aug 31, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Sept 16, 2015
Unsatisfactory High Risk disposal, brackish water Pipeline Inspection @ 01-31-085-06W4 P39429 on Aug 31, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Oct 22, 2015

Compliance Discussion continued

Notice	Events that led to the non-compliance	Nexen action plan	Status
Unsatisfactory High Risk Steam or produced vapour Pipeline Inspection @ 02-07-086-06W4 P52777 on Sept 01, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Sept 16, 2015
Unsatisfactory High Risk Steam or produced vapour Pipeline Inspection @ 02-07-086-06W4 P53285 on Sept 01, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Sept 16, 2015
Unsatisfactory High Risk Water Pipeline Inspection @ 03-35-084-07W4 P54599 on Sept 01, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Oct 22, 2015
Unsatisfactory High Risk Natural Gas Pipeline Inspection @ 06-31-085-06W4 P43961 on Sept 01, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Sept 6, 2015
Unsatisfactory High Risk steam or produced vapour Pipeline Inspection @ 06-31-085-06W4 P52775 on Sept 01, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Sept 16, 2015
Unsatisfactory High Risk Natural Gas Pipeline Inspection @ 10-24-084-07W4 P51056 on Sept 01, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen continues to work with the AER on these inactive pipelines.	Nexen continues to work with the AER on these inactive pipelines.

Compliance Discussion continued

Unsatisfactory High Risk Natural Gas Pipeline Inspection @ 10-29-084-06W4 P51055 on Sept 01, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen continues to work with the AER on these inactive pipelines.	Nexen continues to work with the AER on these inactive pipelines.
Unsatisfactory High Risk Water Pipeline Inspection @ 16-27-084-07W4 P54531 on Sept 01, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Sept 6, 2015
Unsatisfactory High Risk Natural Gas Pipeline Inspection @ 05-08-086-06W4 P53287 on Sept 01, 2015	Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.	Nexen immediately conducted the required inspections and provided all requested data to the AER.	Compliance achieved Sept 16, 2015

Compliance Discussion - VSDs

Notice	Events that led to the non-compliance	Nexen action plan	Status
Voluntary Self Disclosure – temperature response/exceedance in 2015 while drilling 1 observation well; as per Scheme Approval 9485 January 30, 2015.	Nexen identified temperature exceedance after logging the well.	Nexen has submitted all requested data to the AER.	Compliance achievement date is Mar 30, 2015. June 4, 2015 the AER provided Nexen with a letter advising that prior to returning to normal steaming operations that AER be contacted.
Voluntary Self Disclosure - Directive 056: Energy Development Applications and Schedules.4 oil sands observations wells. Feb 12, 2015.	Nexen identified 4 oil sands observation wells that were converted to injection wells.	Nexen has submitted all amendments and Lahee classification changes to the AER.	Compliance achieved Sept 9, 2015.
Voluntary Self Disclosure -Directive 081: Water Disposal Limits and Reporting Requirements for Thermal In situ Oil Sands Schemes. Water balance issue at the Long Lake injection facility. March 24, 2015.	Nexen had a pipeline leak and it was discovered that the total flow was not recorded. Monthly balance exceeds 5.0 percent for 3 consecutive months.	Nexen submitted all pertinent data to the AER.	Compliance achieved March 24, 2015.
Voluntary Self Disclosure - thermal compatibility reviews prior to operating producer and injector wells- Scheme approval No. 9485. Multiple wells. April 22, 2015.	Nexen identified failure to perform thermal compatibility reviews during an internal assessment.	Nexen conducted the reviews submitted all pertinent data to the AER.	Compliance achieved Aug 14, 2015.
Voluntary Self Disclosure - Directive 020: Well Abandonment - 1 historical Oil Sands well where the downhole abandonment did not meet directive standard. December 16, 2015	Nexen identified the downhole abandonment issue when preparing well for a thermal wellhead change.	Nexen submitted an action plan and has commenced the remedial work.	Date to achieve compliance is Mar 31, 2017
Voluntary Self Disclosure- Directive 76: Operator Declaration Regarding measurement and reporting requirements, with respect to Theme 10-fuel, flare and venting at facility ID ABBT 0094109	Nexen identified contraventions in fuel, flare and venting during the 2015 EPAP audit at the Long Lake facility.	Nexen has created an action plan and is in the process of implementation.	Compliance achievement date is set to Oct 31, 2016.
Voluntary Self Disclosure - Directive 056: Energy and development applications and schedules & Directive 059: Well Drilling and completion data filing requirements - Oil and Gas Conservation Act-6 wells June 30, 2015	Nexen identified wellbores that experienced mechanical issues during drilling and Rig was subsequently skidding over leaving the original bore hole with no licence or information submitted to the AER.	Nexen submitted an action plan and received all approvals and submitted all pertinent data in the DDS system.	Compliance achieved July 20 and Oct 29, 2015

Reportable Spills

Incident Number	Location	License Number	Incident Date	Facility Type	Cause	Closed Date	Material	Volume (m^3)
20153365	07-31-085-06W4	F32978	27-Dec-15	Battery	Operator Error-Oversight	26-Jan-16	Process Water	5
20153364	05-08-086-06W4	F43133	24-Dec-15	Satellite	Equipment Failure-Malfunction		Crude Bitumen	5
20153325	03-35-084-07W4	P54769	17-Dec-15	Pipeline	Operator Error-Non-procedural		Process Water	0.1
20153223	07-31-085-06W4	F32978	4-Dec-15	Battery	Equipment Failure-Malfunction		Fresh water	300
20153126	09-28-085-06W4	P39429	24-Nov-15	Pipeline	Operator Error-Accidental			3.6
20153087	07-31-085-06W4	F32978	21-Nov-15	Battery	Equipment Failure-Malfunction	1-Dec-15	Process Water	160
20152824	10-30-085-06W4	F32978	19-Oct-15	Battery	Operator Error-Non-procedural	16-Dec-15	Process Water	7
20152815	07-31-085-06W4	F32978	17-Oct-15	Battery	Procedural or Design-Inadequate procedure	25-Nov-15	Condensate	5
20152791	15-25-085-07W4	F32978	14-Oct-15	Battery	Unknown-Unknown		Steam Condensate	19
20152773	01-31-085-06W4	P39429	1-Oct-15	Pipeline	Equipment Failure-Defect		Produced Water	2.3
20152437	16-24-085-07W4	P54767	9-Sep-15	Pipeline	Equipment Failure-Mechanical/Structural	24-Sep-15	Lubricants	0.1
20152116	12-36-085-07W4	W 0399031	8-Aug-15	Well	Operator Error-Accidental	22-Oct-15	Crude Bitumen/Steam	1.4/10
20151896	01-31-085-06W4	P39429	15-Jul-15	Pipeline	Equipment Failure-External corrosion		Boiler Blowdown/produced water	2.5/2.5
20151882	16-24-085-07W4	P54767	15-Jul-15	Pipeline			Crude Bitumen/Steam Condensate	1,650/3,350
20151852	02-35-084-07W4	F44559	6-Jul-15	Injection/Disposal Facility	Operator Error-Accidental	27-Jul-15	Chemicals	0.3

Reportable Spills continued

Incident Number	Location	License Number	Incident Date	Facility Type	Cause	Closed Date	Material	Volume (m^3)
20151850	07-31-085-06W4	F32978	6-Jul-15	Battery	Equipment Failure-Defect		Lubricants	0.9
20151659	07-31-085-06W4	F32978	18-Jun-15	Battery	Operator Error-Accidental	29-Jul-15	Condensate	3.7
20151552	07-31-085-06W4	F32978	8-Jun-15	Battery	Equipment Failure-External corrosion	11-Aug-15	Heating Oil	3
20151529	07-31-085-06W4	F32978	4-Jun-15	Battery	Operator Error-Oversight		Oily Sludge	23.1
20151517	07-31-085-06W4	F32978	3-Jun-15	Battery	Operator Error-Accidental	25-Jan-16	Oily Sludge	22
20151385	07-31-085-06W4	F32978	14-May-15	Battery	Operator Error-Non-procedural	31-Aug-15	Fresh Water	130
20151251	09-25-085-07W4	F45005	2-May-15	Satellite	Operator Error-Oversight	11-Dec-15	Fresh water	*3,900
20150998	07-31-085-06W4	F32978	1-Apr-15	Battery	Equipment Failure-Malfunction	21-Aug-15	Glycol	76
20150448	07-31-085-06W4	F32978	11-Feb-15	Battery	Operator Error-Oversight	23-Feb-15	Process Water	6
20150251	07-31-085-06W4	F32978	23-Jan-15	Battery	Equipment Failure-Mechanical/Structural	24-Apr-15	Glycol	5
20150191	07-31-085-06W4	F32978	16-Jan-15	Battery	Equipment Failure-Malfunction	21-Jan-16	Produced Water	2.5

* Classified as a Permit Violation by Nexen

Future Plans - Surface

- As a result of the Pipeline release and the Upgrader explosion Nexen is currently evaluating operating options which include:
  - SAGD only;
  - SAGD with an Upgrader; or
  - SAGD with modifications to the Upgrader.

Appendix

A CNOOC LIMITED COMPANY

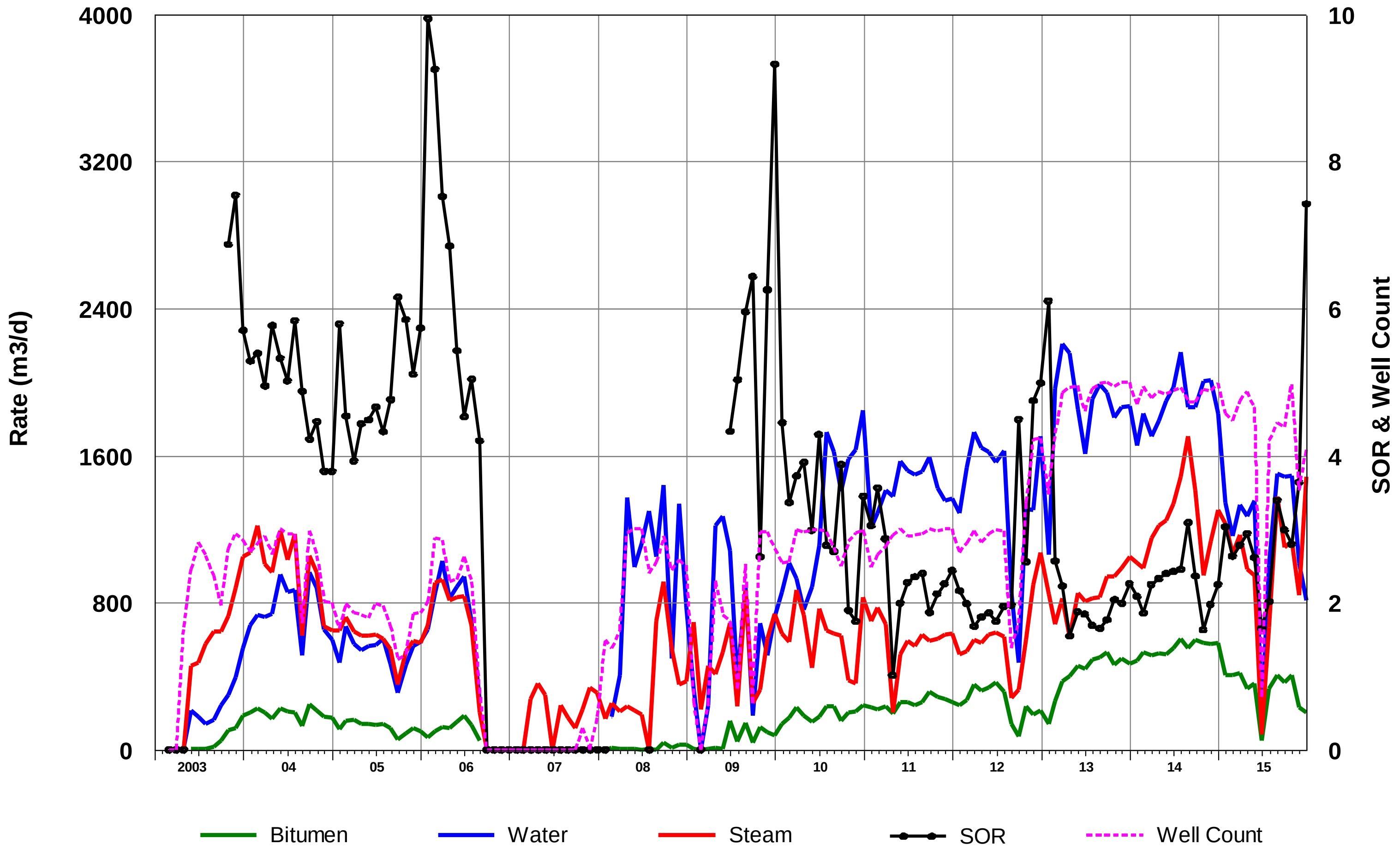
A New Energy

Well Pad Performance
Subsection 3.1.7(h)
Long Lake

A CNOOC LIMITED COMPANY

A New Energy

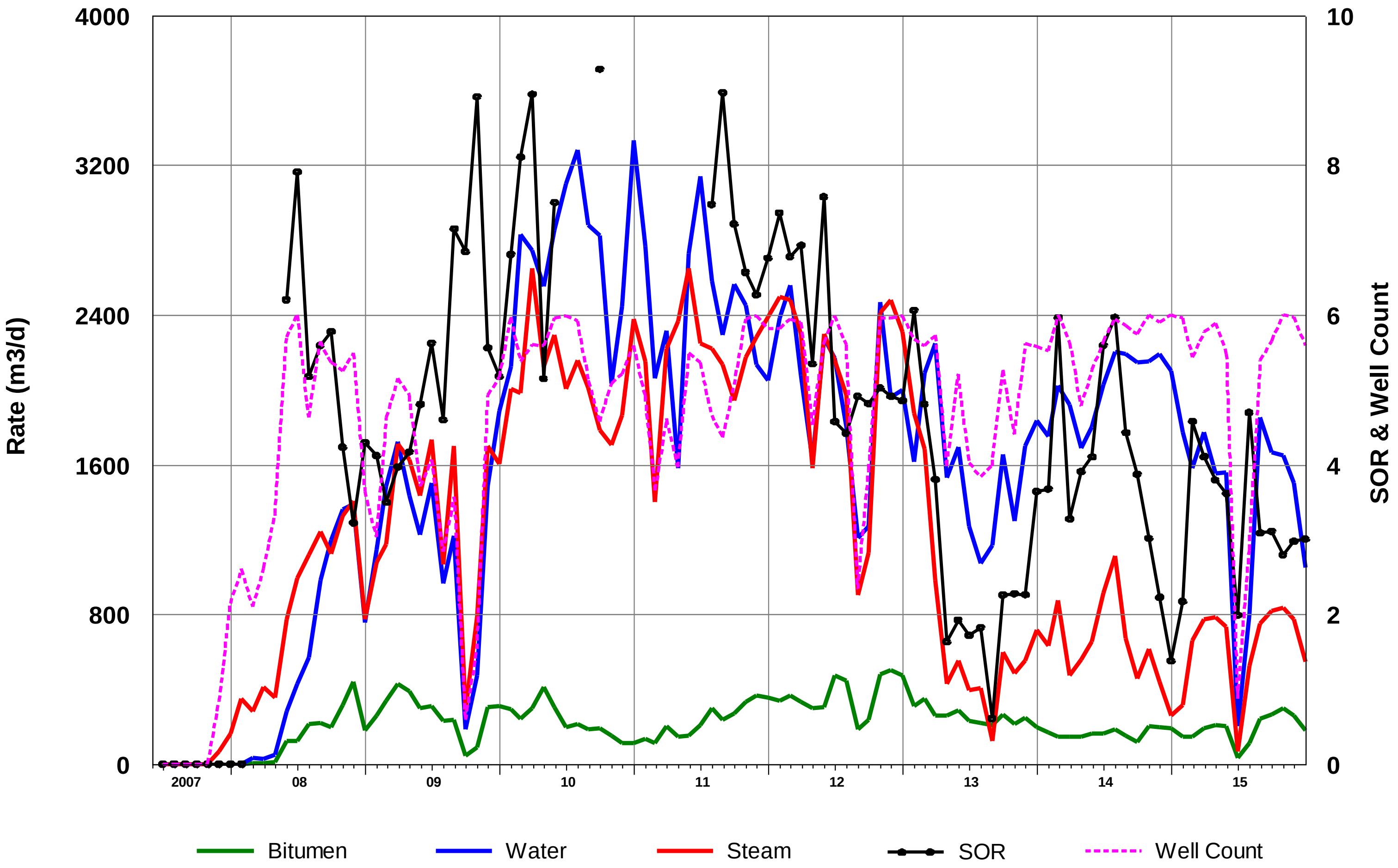
Pad 1 Production Summary



- All 5 wells on ESP
- Operational instability resulted in lower performance
- At YE, injection pressures were ~1,450-1,750 kPa

- Five well pairs (01P01 to 01P03, 04P05 and 04P06)
- Cumulative production of 917 E^3m^3 (RF 43%)

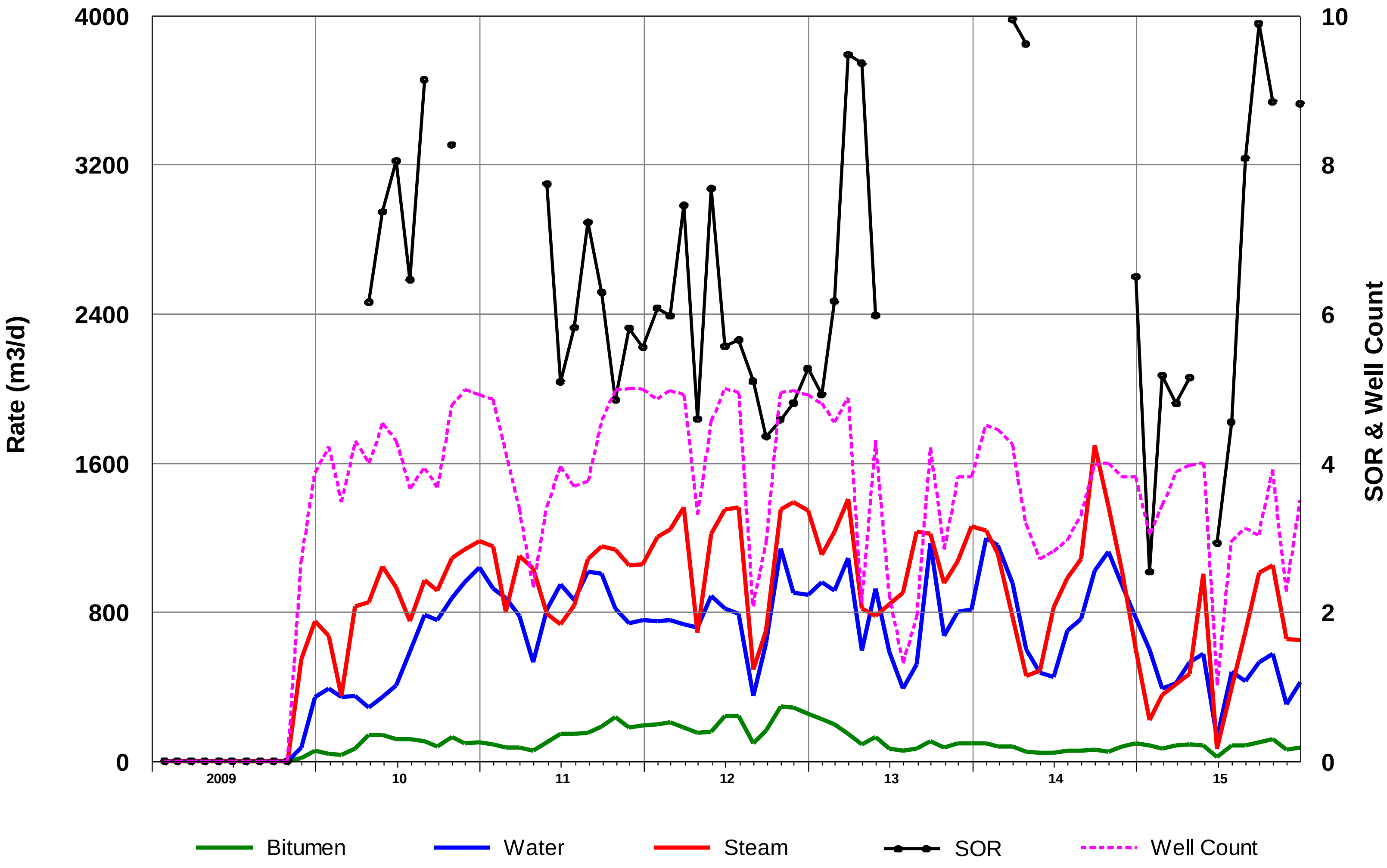
Pad 2NE Production Summary



- All 6 wells on ESP
- Steam SI to 02S04, 02S05 and 02S06
- Stable operations and steam injection helped maintain production
- At YE, injection pressures were ~1,200 – 1,485 kPa

- Six well pairs (02P01 to 02P06)
- Cumulative production of 680 E^3m^3 (RF 28%)

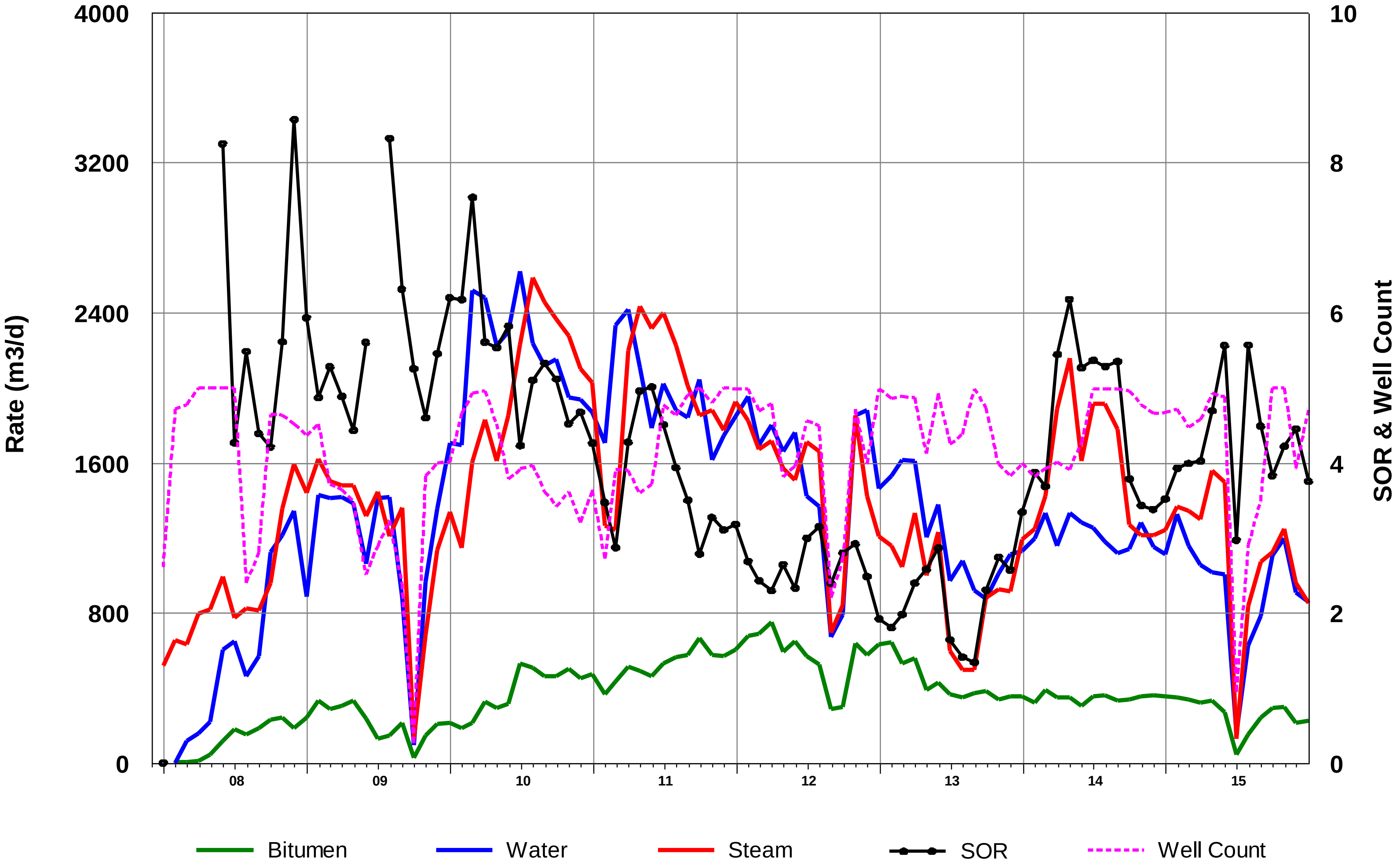
Pad 2SE Production Summary



- 2P8 - 2P10 on ESP
- 2P07 on PCP
- 02Pair11 SI due to liner failure
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,200 – 1,720 kPa

- Five well pairs (02P07 to 02P011)
- Cumulative production of 257 E^3m^3 (RF 21%)

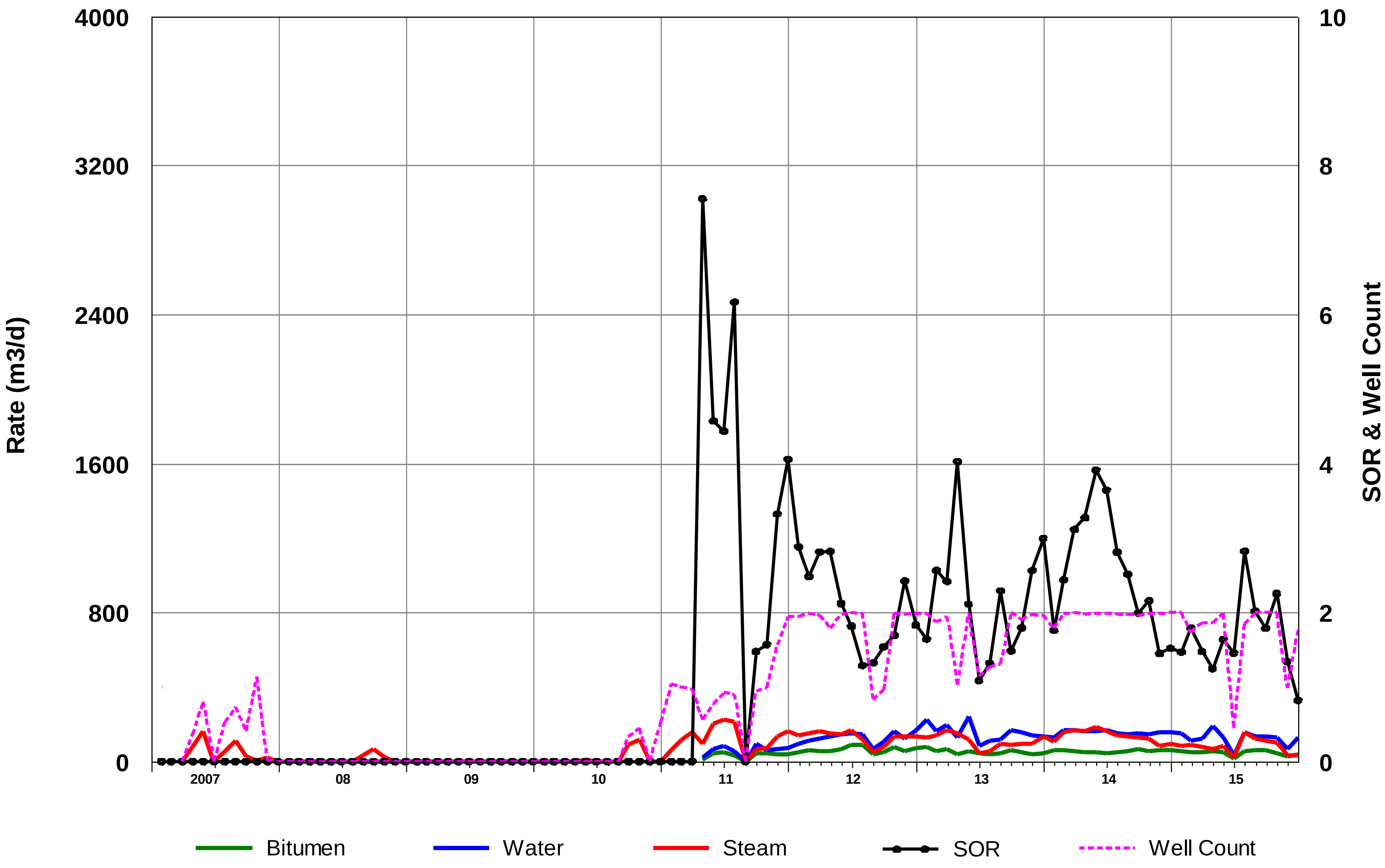
Pad 3 Production Summary



- All 5 wells on ESP
- Short-term steam reductions to 03S01
- At YE, injection pressures were ~1,285-1,550 kPa

- Five well pairs (03P01 to 03P05)
- Cumulative production of 1,049 E^3m^3 (RF 42%)

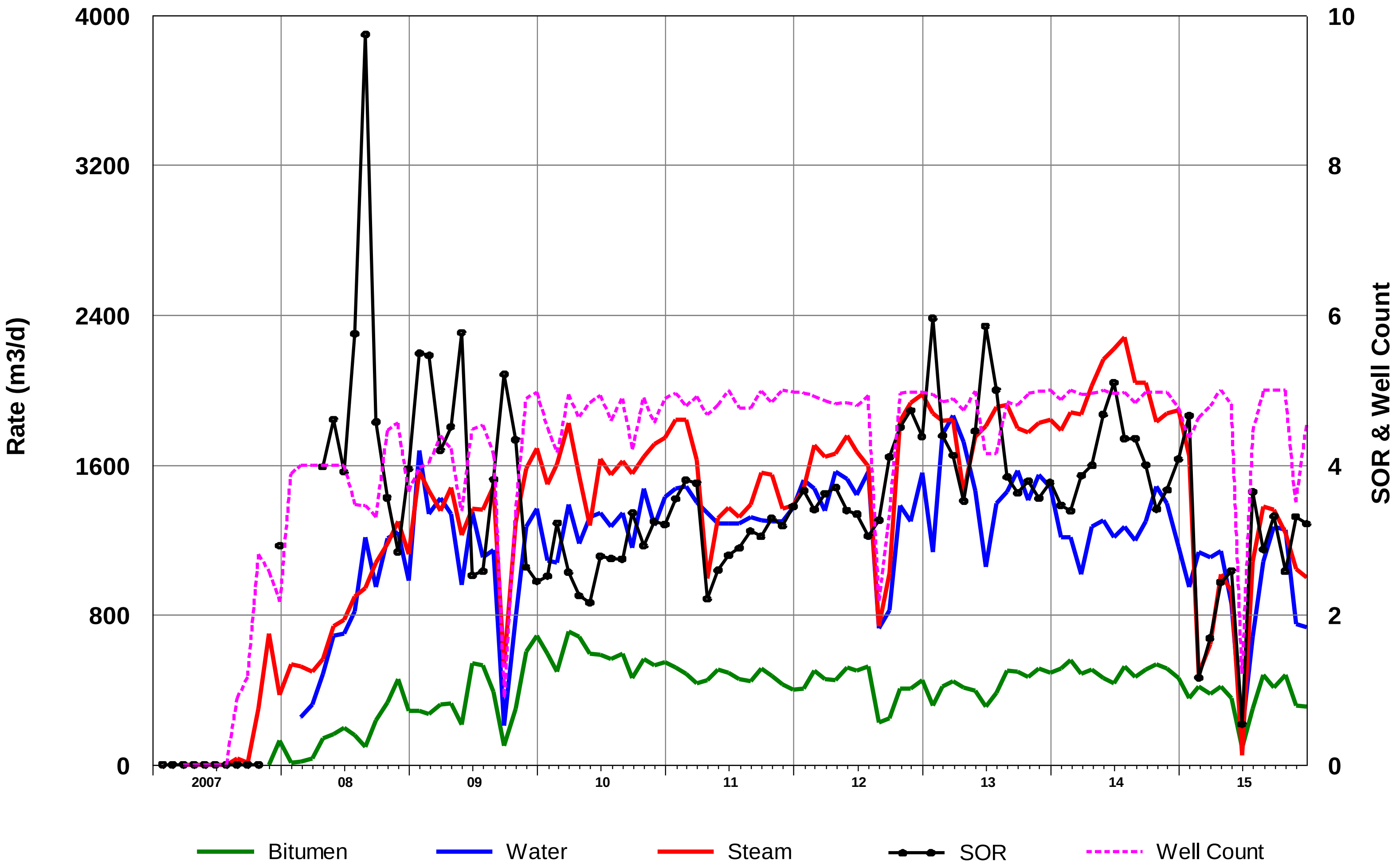
Pad 4 Production Summary



- All wells on ESP
- Stable operation helped maintain production
- At YE, injection pressures were ~1,260–1,515kPa

- Two well pairs (04P01 to 04P02)
- Cumulative production of 89 E^3m^3 (RF 50%)

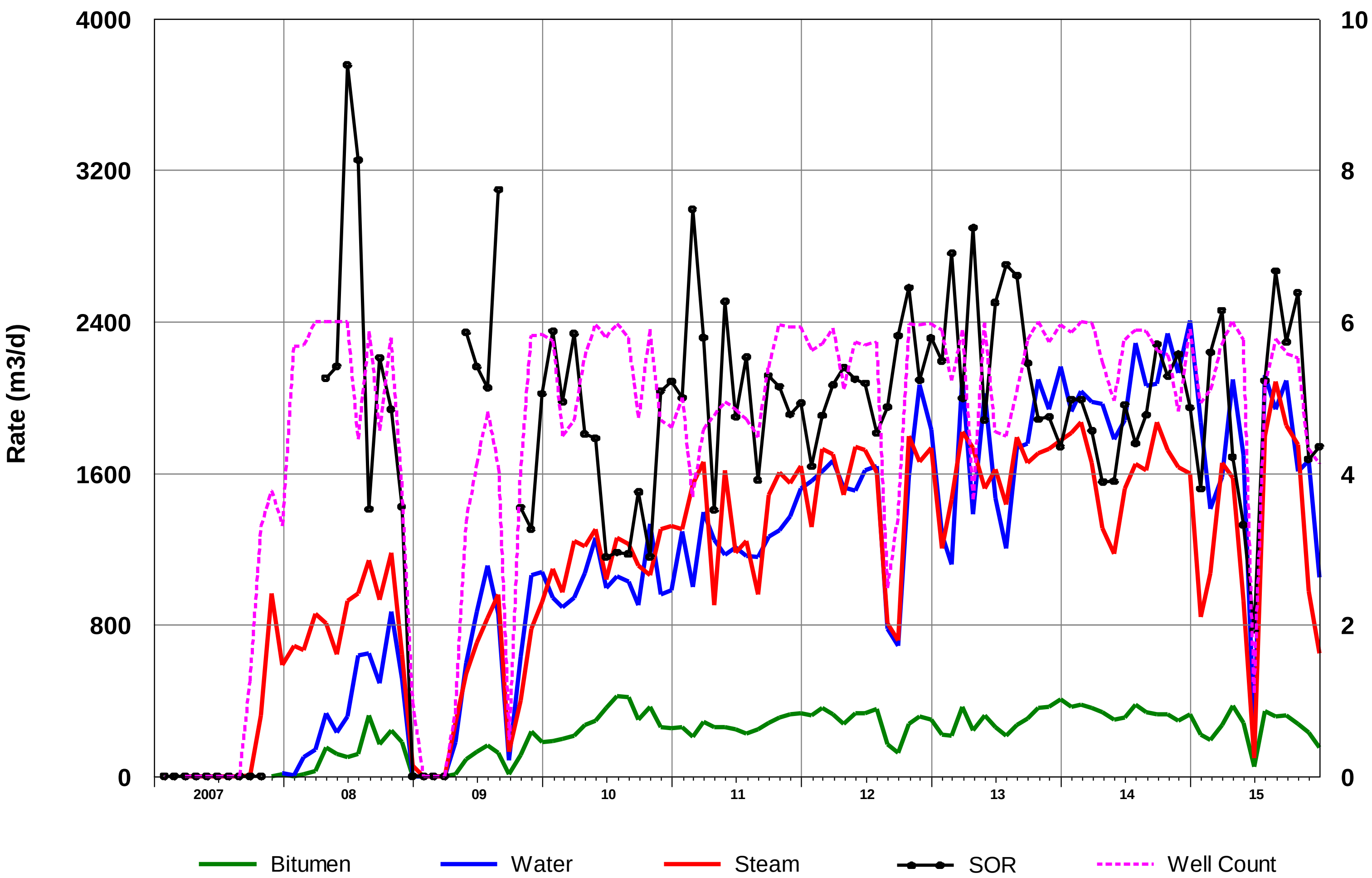
Pad 5 Production Summary



- Five well pairs (05P01 to 05P05)
- Cumulative production of 1,213 E^3m^3 (RF 37%)

- All 5 wells on ESP
- Steam was SI to 05S04 and 05S05
- Reduced steam injection pressures and operational instability resulted in lower performance
- 5S01 toe steam was restarted in Q3
- At YE, injection pressures were ~1,300–1,750kPa

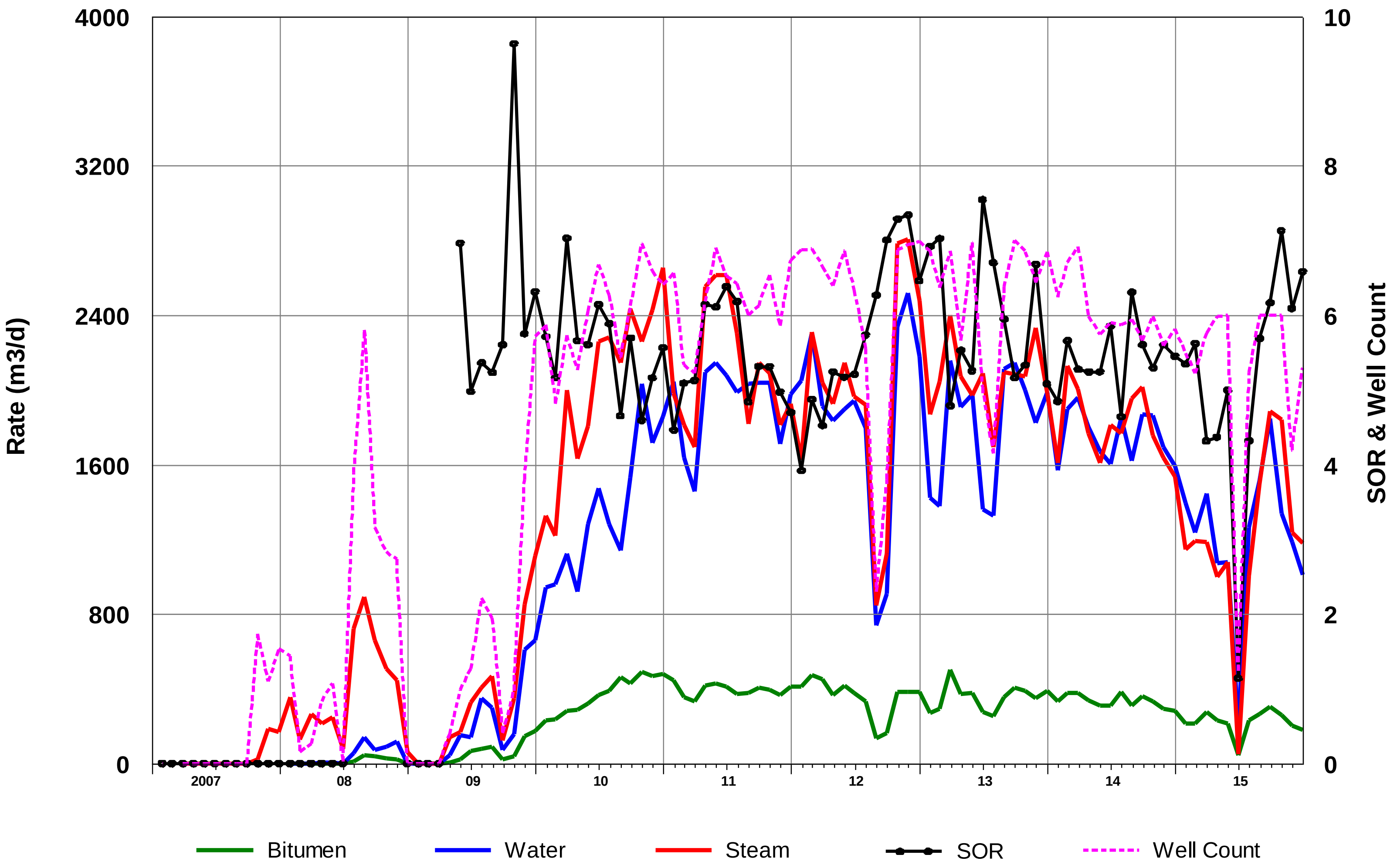
Pad 6N Production Summary



- Six well pairs (06P01 to 06P05 plus 06P13)
- Cumulative production of 713 E^3m^3 (RF 24%)

- All wells on ESP
  - 3 injector wells currently shut in or at minimum rates for different reasons
- Only three injectors are injecting to support 5 producer wells
- 6P4 plugged back due to poor reservoir quality at toe
- At YE, injection pressures were ~1,750–1,850kPa

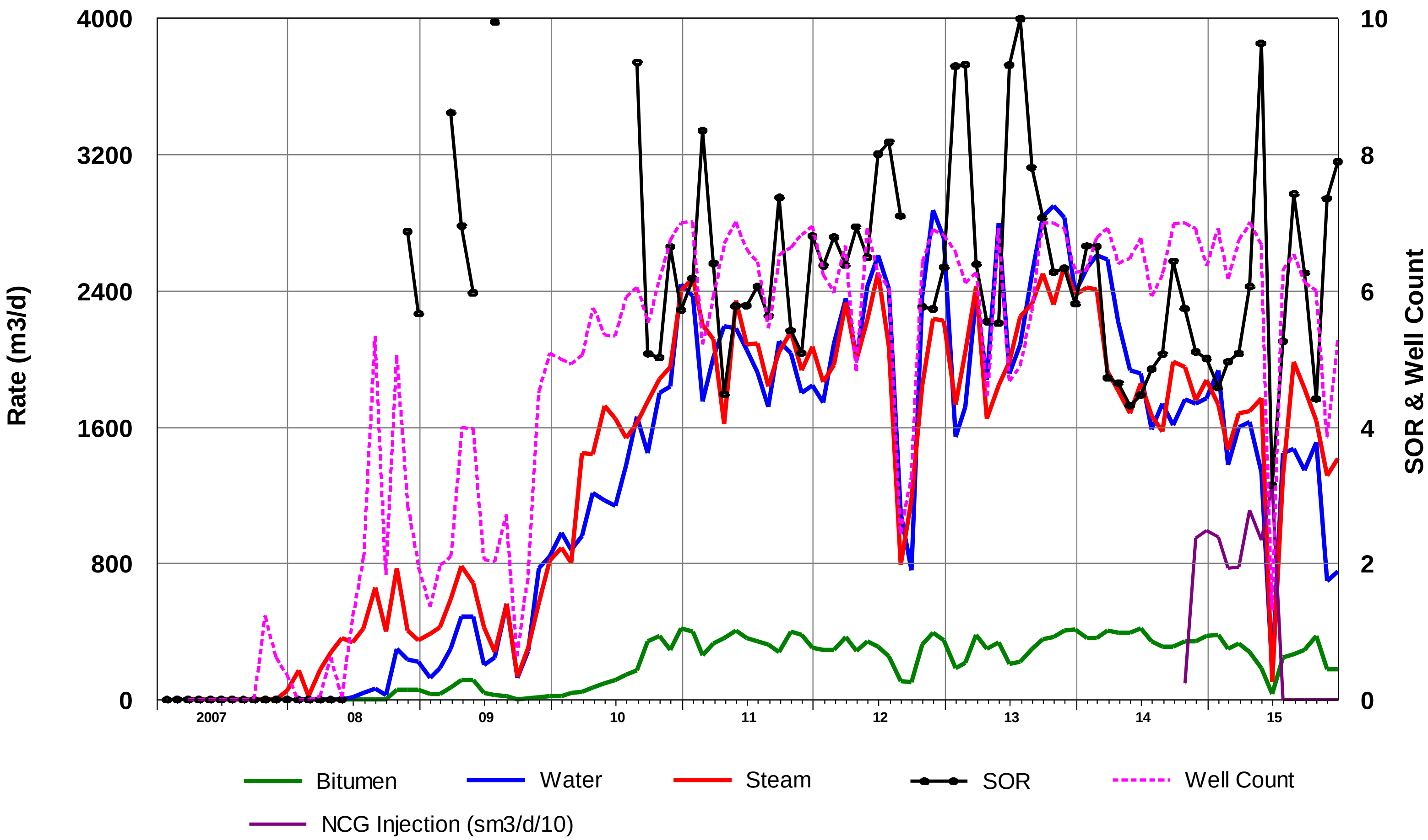
Pad 6W Production Summary



- All 7 wells on ESP
- Strong performance from 6P06
- 6P12 shut in due to potential liner failure on April 3th 2014
- At YE, injection pressures were ~1,450–1,650 kPa

- Seven well pairs (06P06 to 06P12)
- Cumulative production of 763 E^3m^3 (RF 39%)

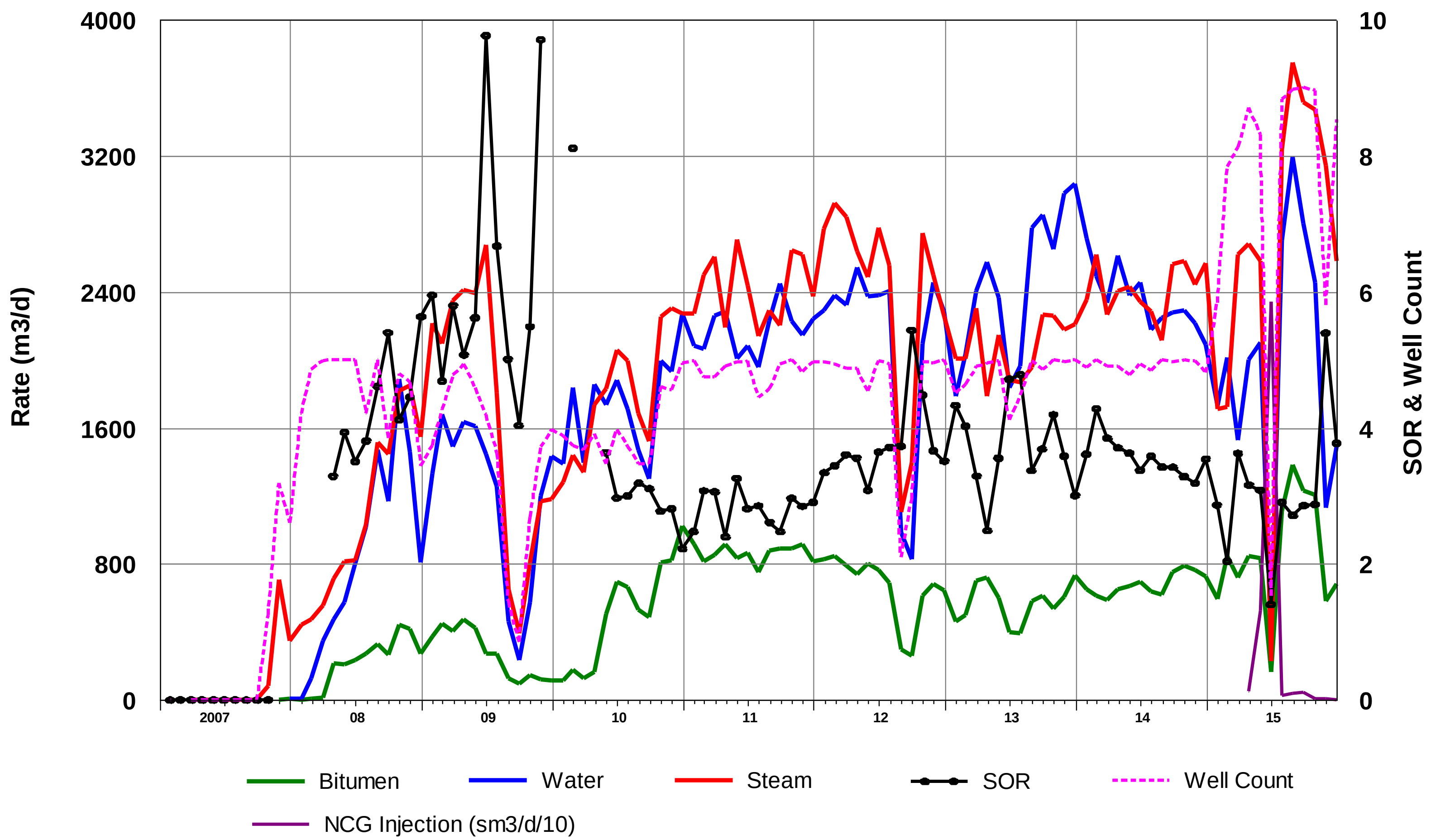
Pad 7E Production Summary



- Seven well pairs (07P06 to 07P12)
- Cumulative production of 655 E^3m^3 (RF 47%)

- All 7 wells on ESP
- Stable operation
- Continuing to see strong performance from northern well pairs
- At YE, injection pressures were ~1,850–2,050 kPa
- NCG co-injection started October 2014 on 07P07, 07P08, 07P09
- NCG co-injection has not been restarted since 2015 turnaround
- Liner failure on 07P07 repaired with liner and packer assembly
- 07P12 shut in due to potential liner failure

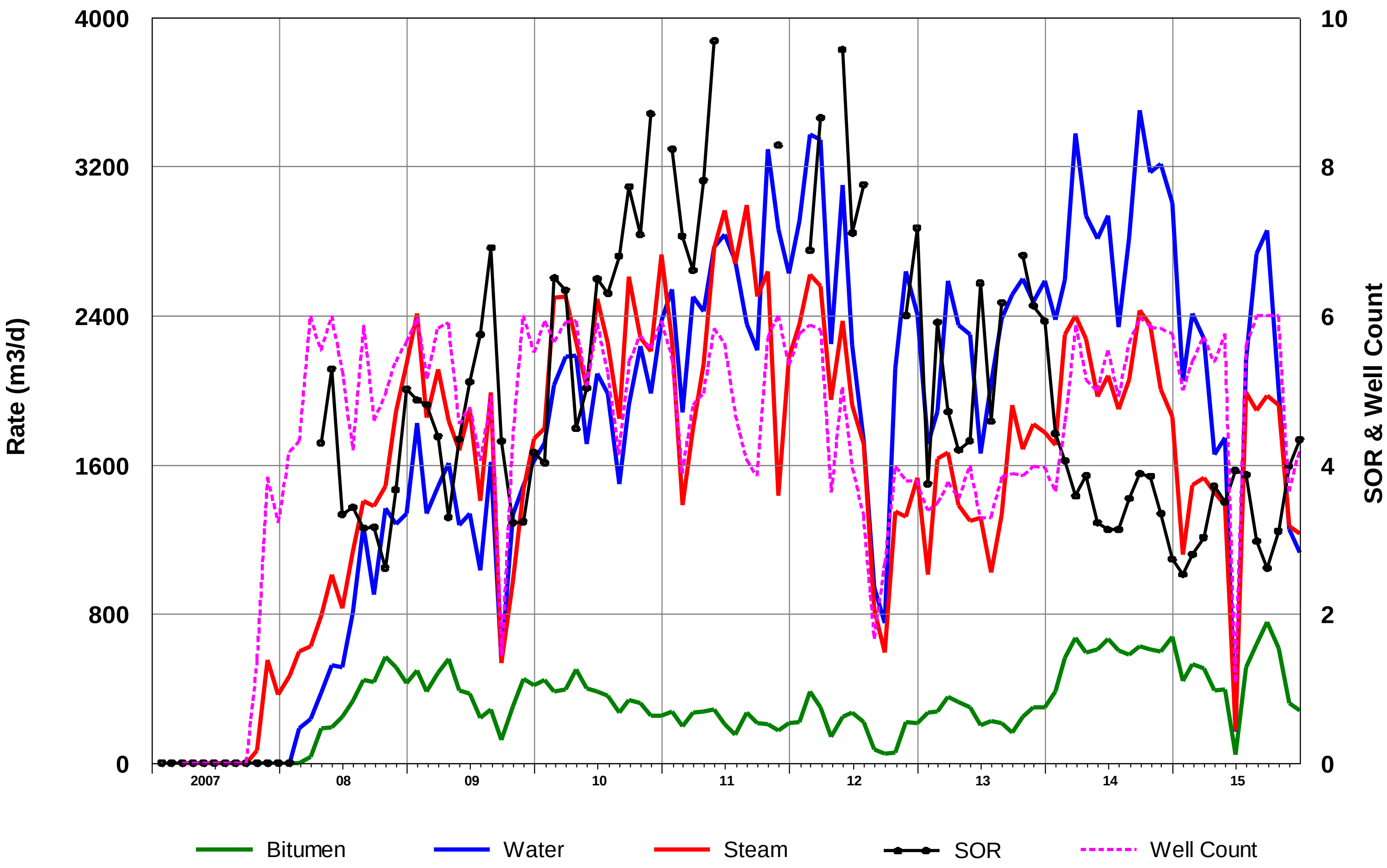
Pad 7N Production Summary



- Five well pairs (07P01 to 07P05)
- Four infill producer wells (10P14 to 10P17)
- Cumulative production of 1,693 E^3m^3 (RF 53%)

- All 9 wells on ESP
- Infill producer wells (drilled in 2014) ramped up after steam squeeze – one well started up without steam squeeze
- Strong performance from infill producer wells
- Completed construction for proposed NCG co-injection pilot project
- NCG co-injection expected to start in 2016
- Increased steam injection to support infill producer wells and neighboring Pad 8
- At YE, injection pressures were ~1,950 - 2,100 kPa

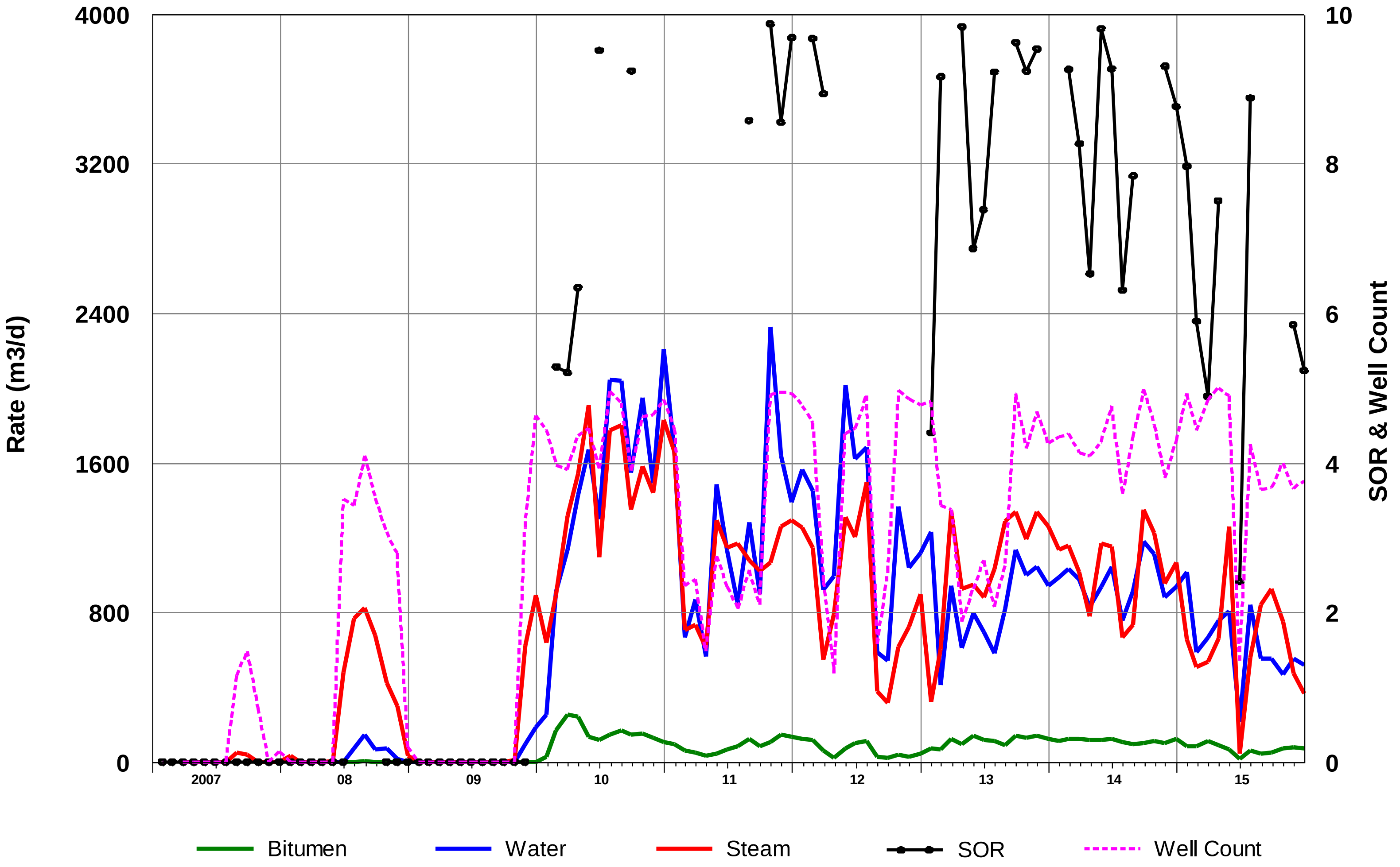
Pad 8 Production Summary



- All 6 wells on ESP
- 08S06 shut in after potential liner failure
- No observed negative impact to 08P06 production
- Increased injection on 08S05 to support 08P06
- ICD's installed on 08P03
- At YE, injection pressures were ~1,800–2,050 kPa

- Six well pairs (08P01 to 08P06)
- Cumulative production of 1,009 E^3m^3 (RF 34%)

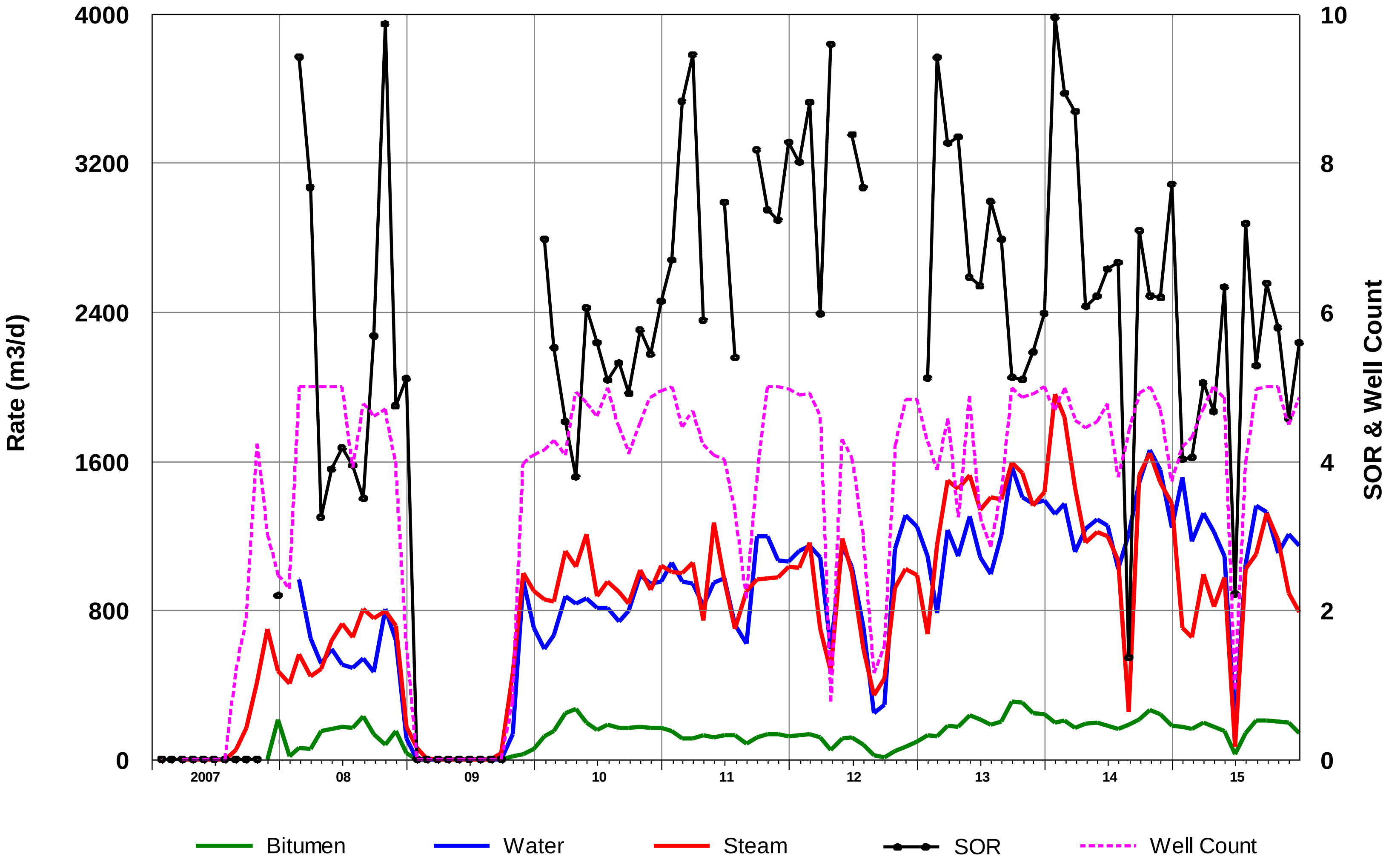
Pad 9NE Production Summary



- All 5 wells on ESP
- 9P07 plugged back at toe due to liner failure
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,350 – 1,900 kPa

- Five well pairs (09P06 to 09P10)
- Cumulative production of 218 E^3m^3 (RF 19%)

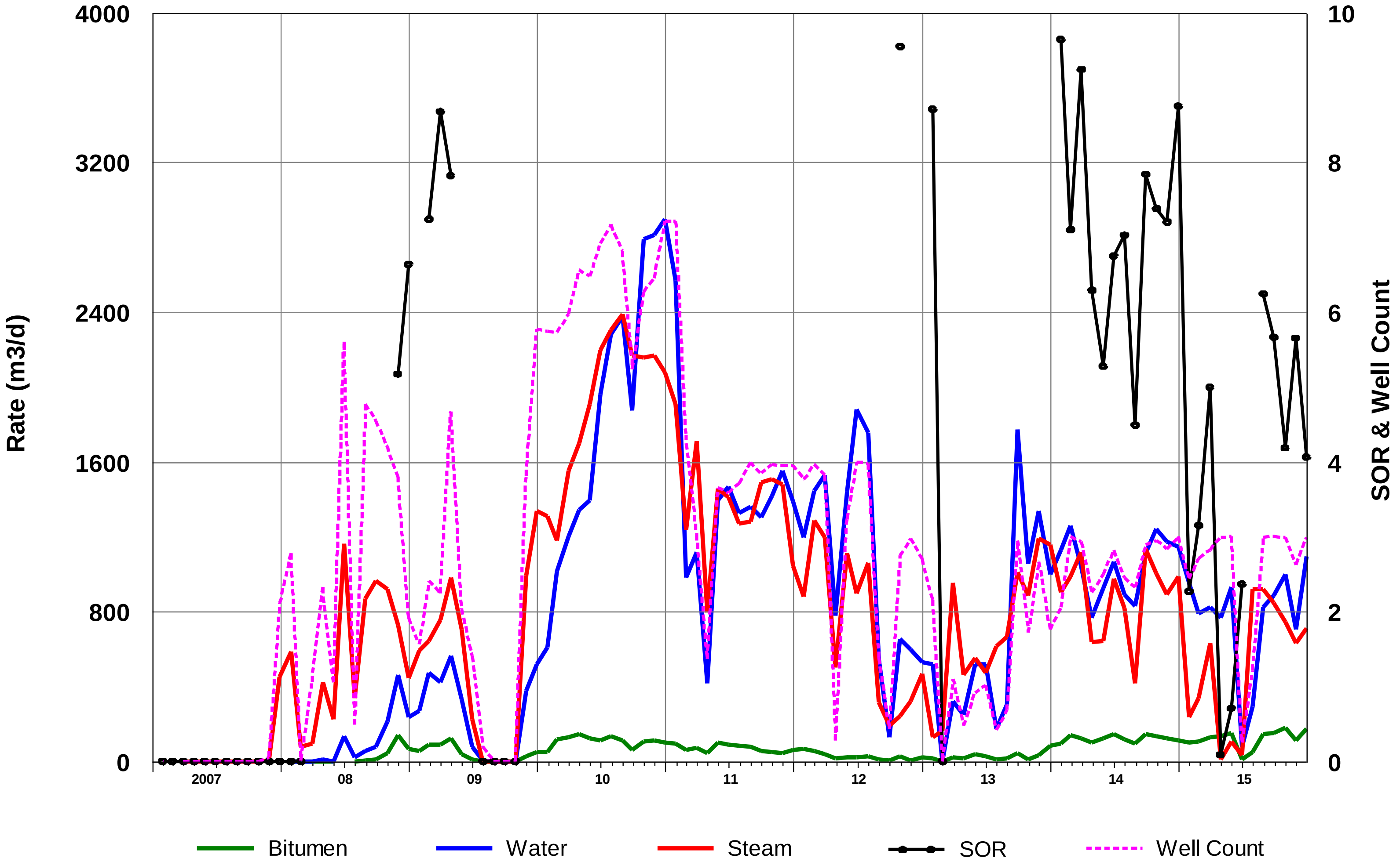
Pad 9W Production Summary



- 9P1-9P3 on gas lift
- 9P4 & 9P5 on ESP
- The wells don't witness obvious decline except 9P5
- At YE, injection pressures were ~1,800 - 1,850 kPa

- Five well pairs (09P01 to 09P05)
- Cumulative production of 406 E^3m^3 (RF 25%)

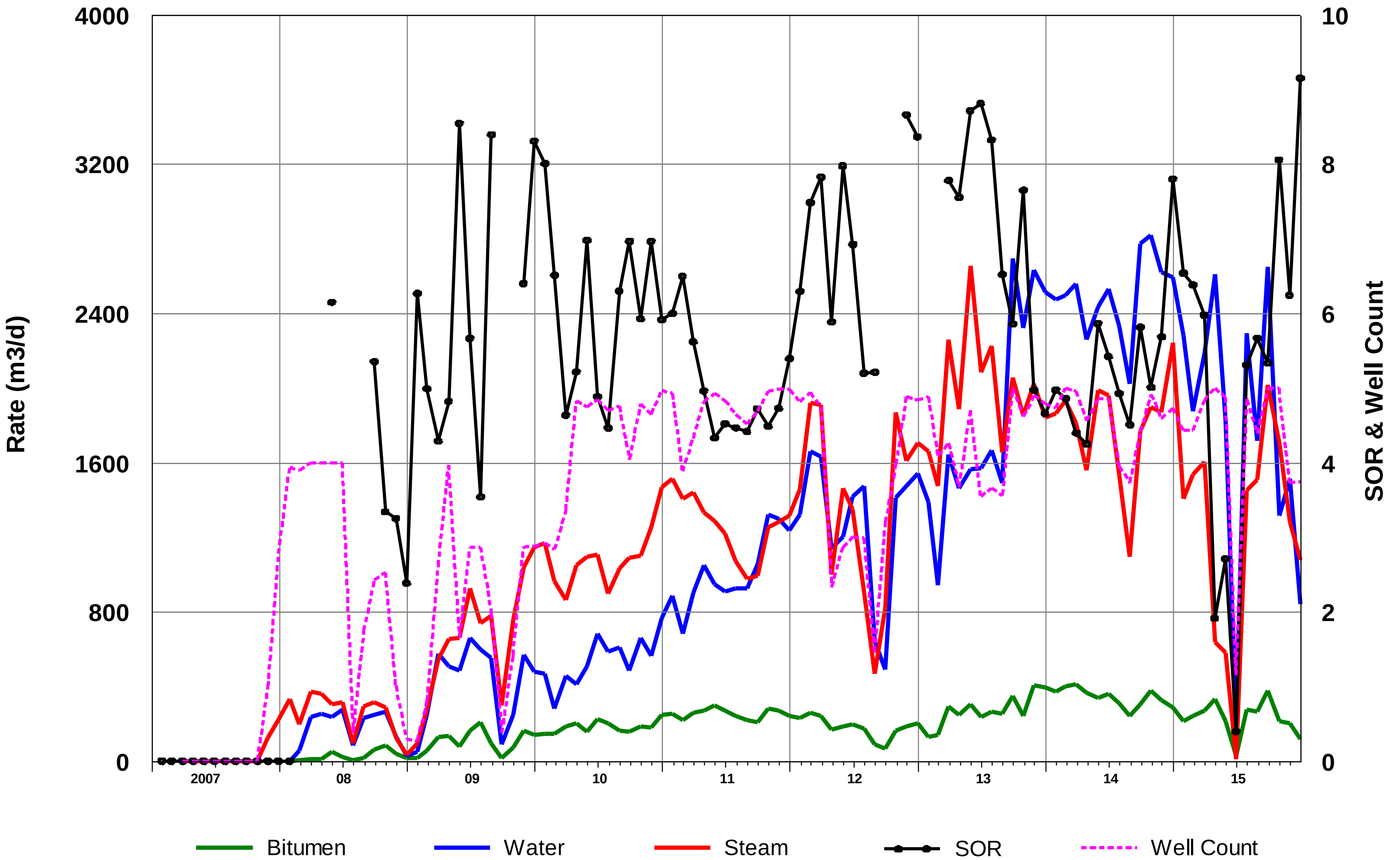
Pad 10N Production Summary



- All wells on gas lift
- Oil cut has improved steadily throughout the life of the well, resulting in improved bitumen production
- At YE, injection pressures were ~1,800 – 2,000 kPa

- Three well pairs producing (10P10 to 10P12)
- Cumulative production of 194 E^3m^3 (RF 18%)

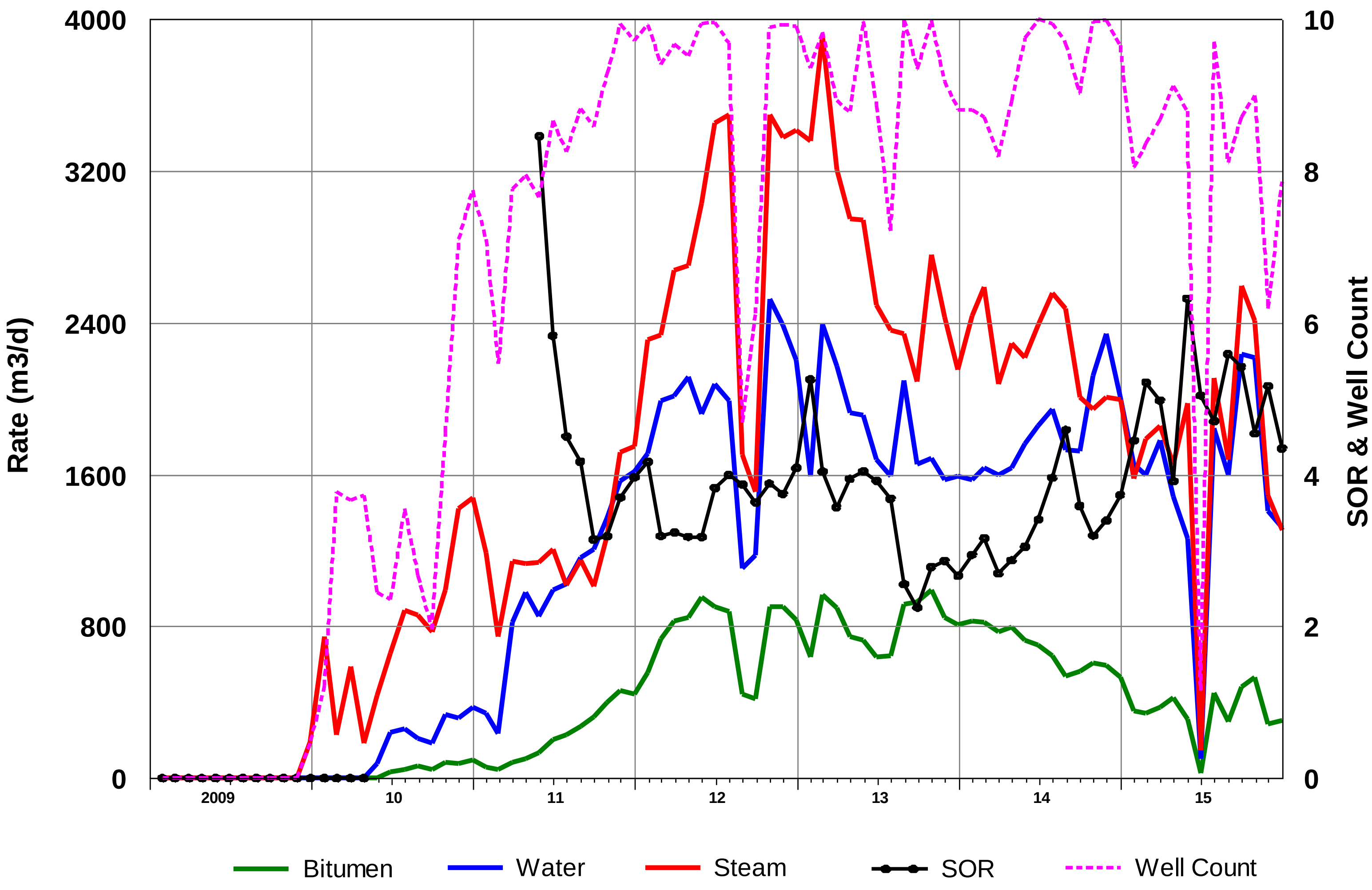
Pad 10W Production Summary



- All 5 wells on ESP
- Stable operation
- Performance impacted by top water WSR > 1.0
- At YE, injection pressures were ~1,830–1,950 kPa

- Five well pairs (10P01 to 10P05)
- Cumulative production of 582 E^3m^3 (RF 29%)

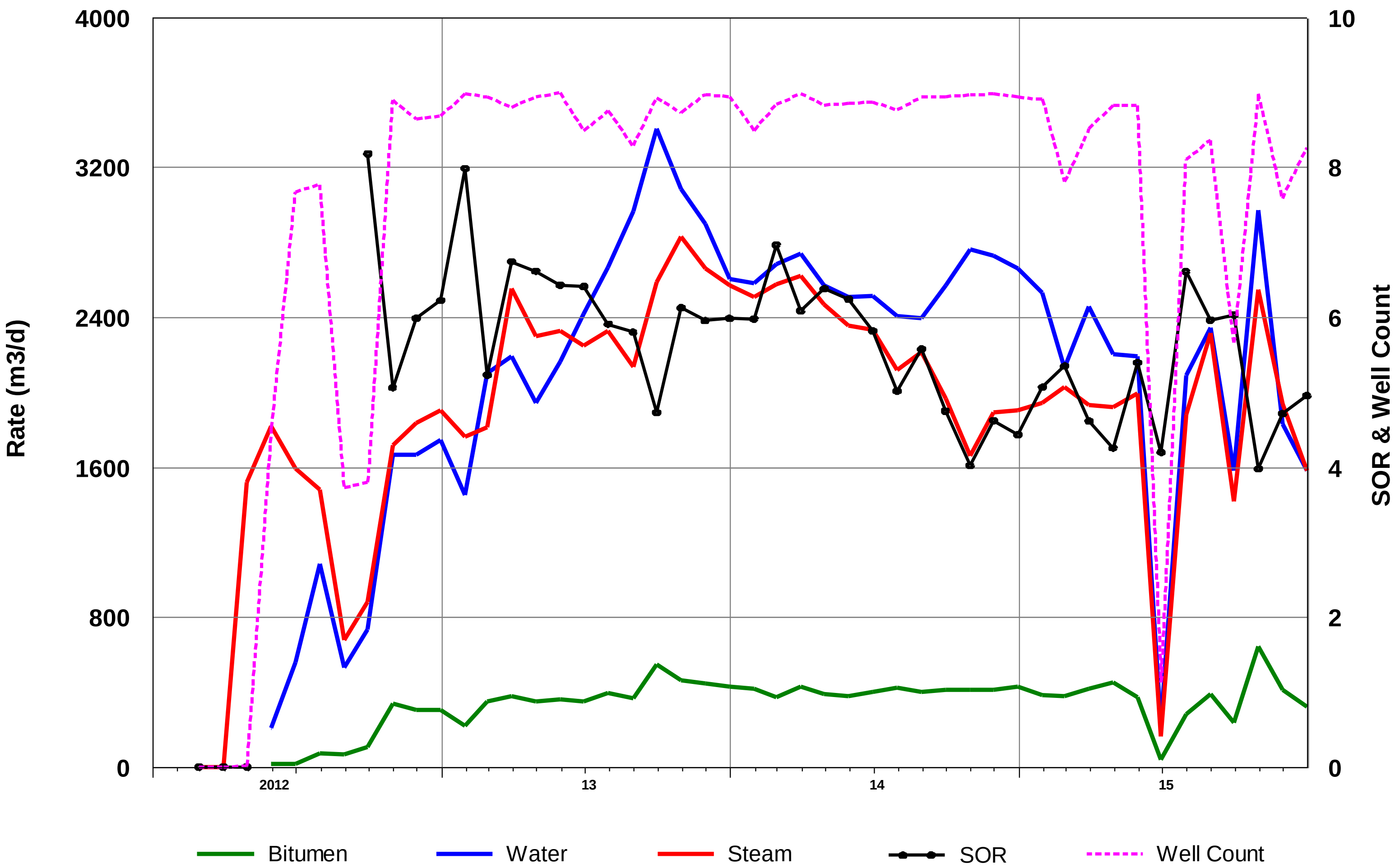
Pad 11 Production Summary



- Ten well pairs (11P01 to 11P10)
- Cumulative production of 1,050 E³m³ (RF 48%)

- All 10 wells are on ESP
- Pad in possible decline phase
- Decline in bitumen rates can likely be attributed to top water effect
- 11S08 shut in since steam kick during workover in Q3
- Liner failure on 11P02 repaired with liner and packer assembly
- At YE, injection pressures were ~1,710–1,750 kPa

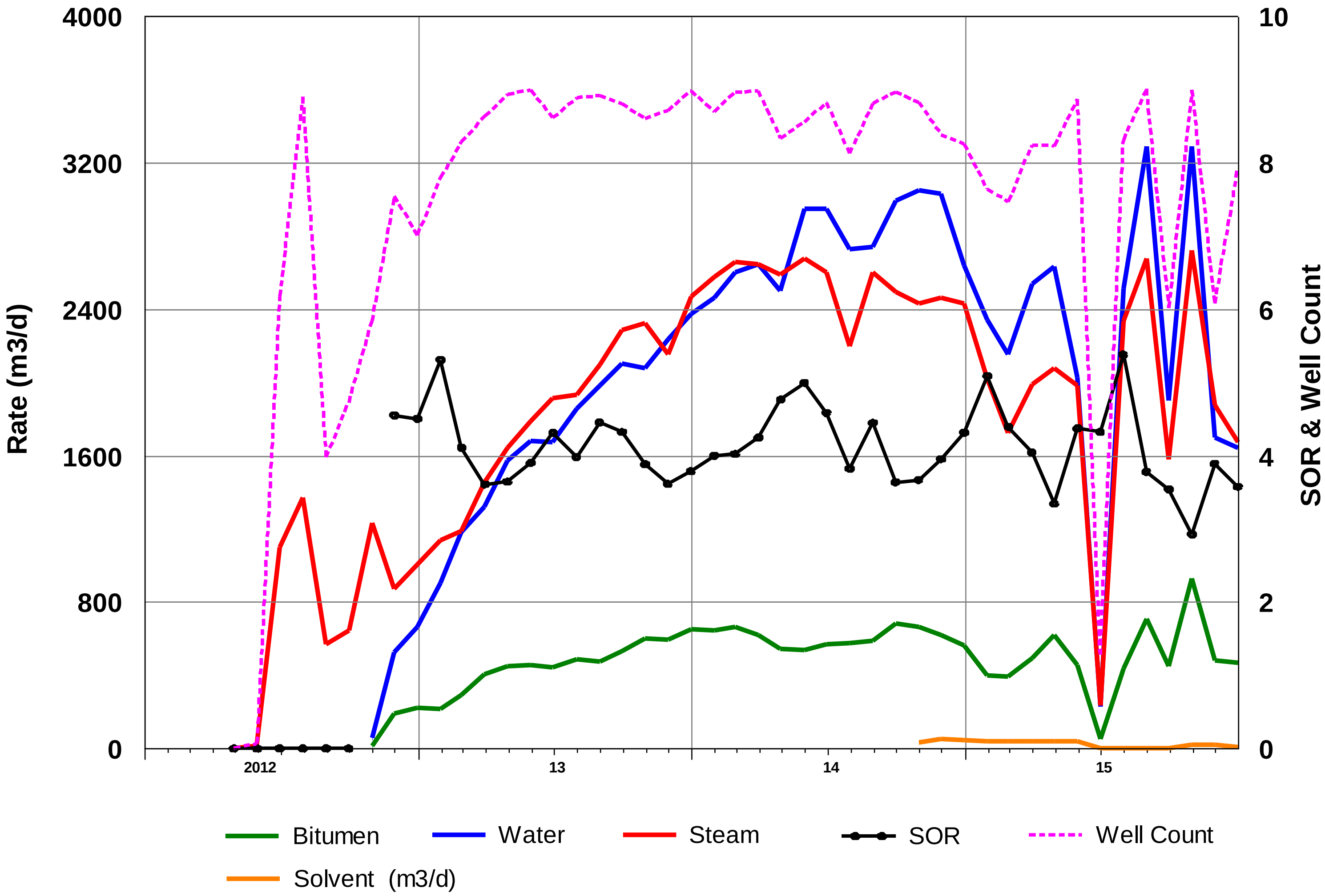
Pad 12 Production Summary



- All 9 wells are on ESP
- Flat bitumen rate attributed to lean zone and facility constraints
- At YE, injection pressures were ~1,700–1,870 kPa

- Nine well pairs (12P01 to 12P09)
- Cumulative production of 459 E^3m^3 (RF 14%)

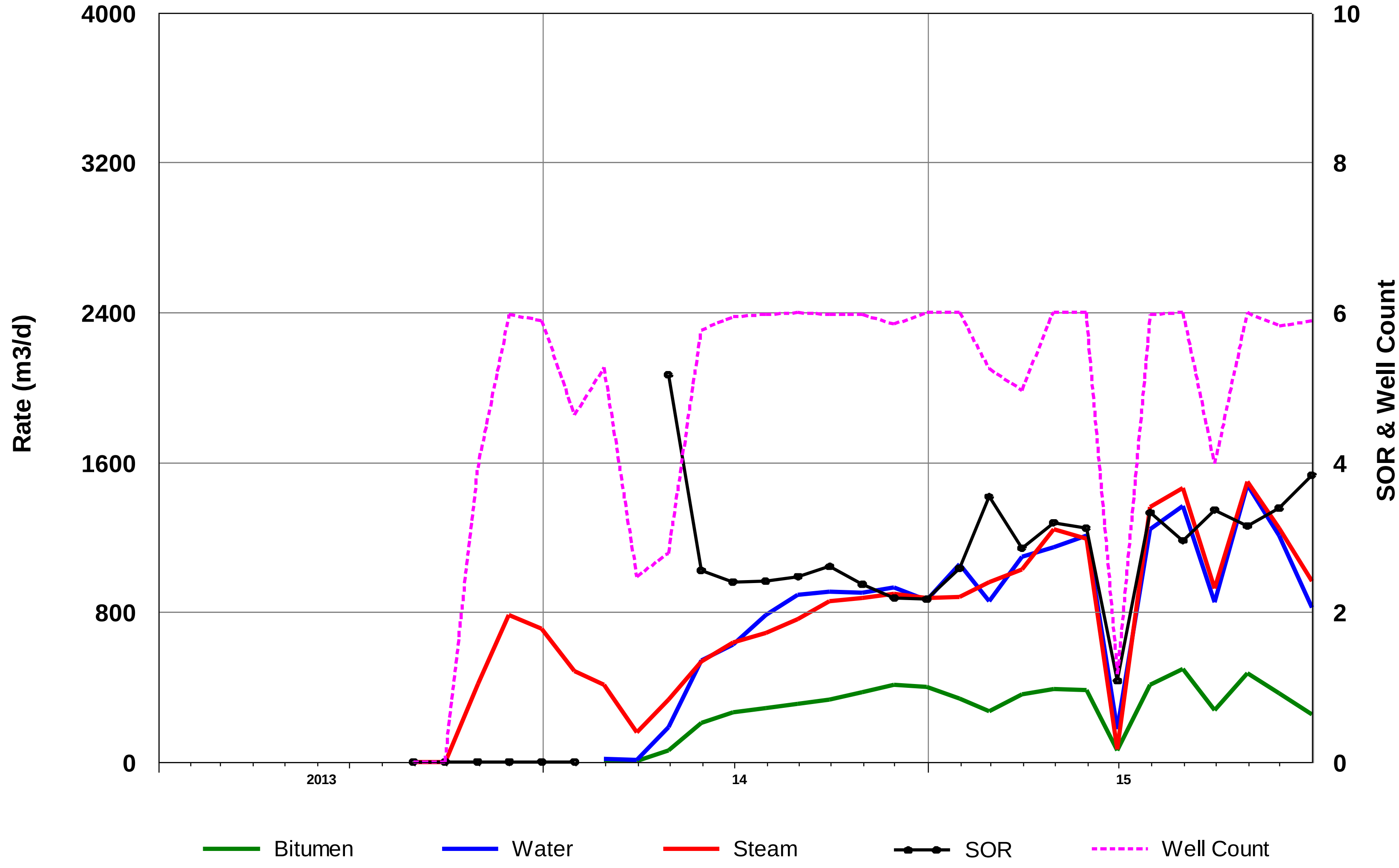
Pad 13 Production Summary



- Nine well pairs (13P01 to 13P09)
- Cumulative production of 584 E^3m^3 (RF 18%)

- All 9 wells are on ESP
- Flat bitumen rate attributed to lean zone and facility constraints
- Initiated ES-SAGD project at wells 13P3 and 13P4 in October, 2014. Limited solvent injection following T/A due to facility constraints.
- At YE, injection pressures were ~ 1,680–1,850 kPa

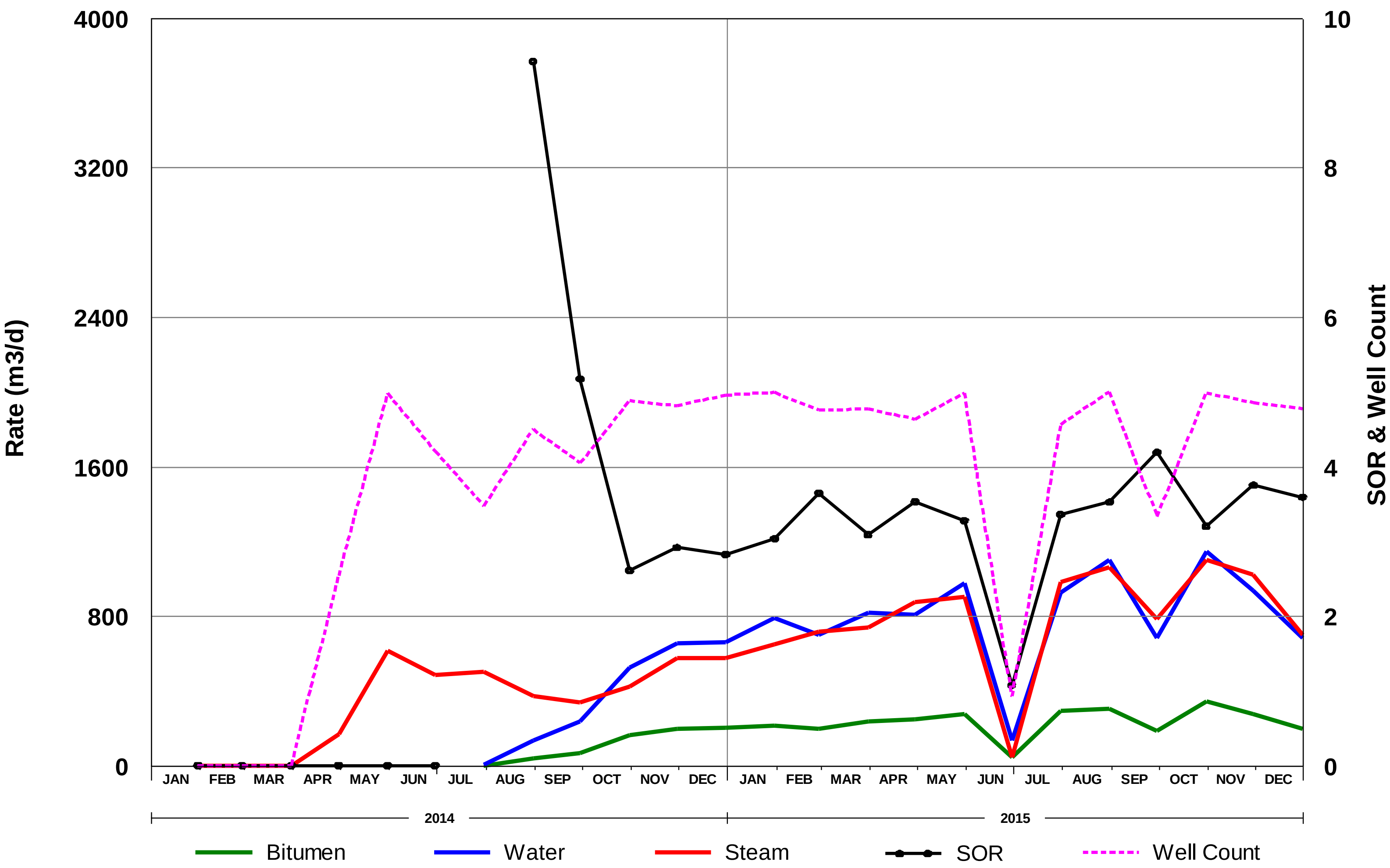
Pad 14 Production Summary



- All 6 wells on ESP
- SAGD conversion in Q2 2014
- All wells on ramp-up
- At YE, injection pressures were ~2,300 - 2,500kPa

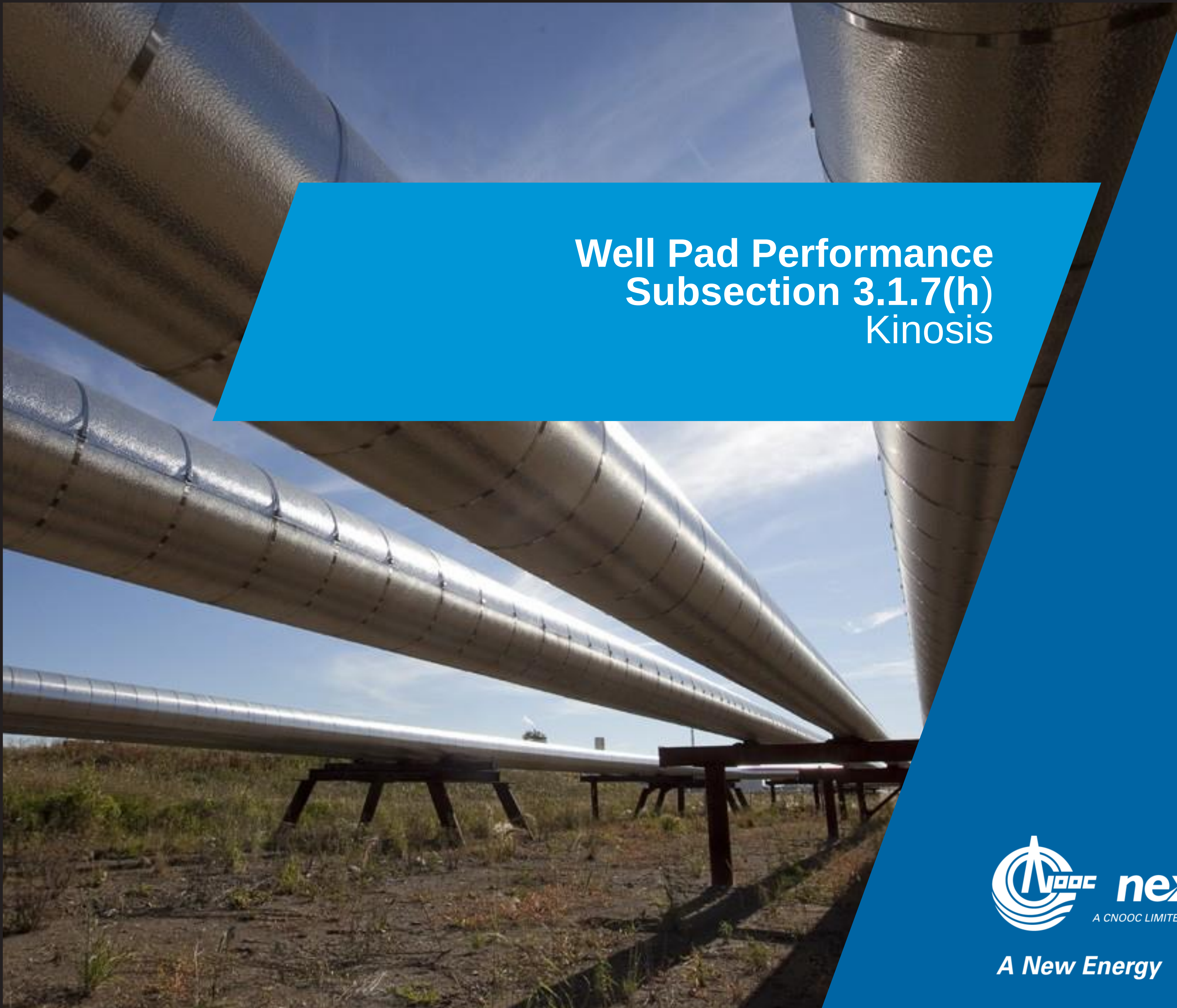
- Six well pairs (14P01 to 14P03 and 14P05 to 14P07)
- Cumulative production of 206 E^3m^3 (RF 11%)

Pad 15 Production Summary



- All 5 wells on ESP
- Last well converted to SAGD in Q4 2014
- All wells on ramp-up
- At YE, injection pressures were ~ 2,300 - 2,500kPa

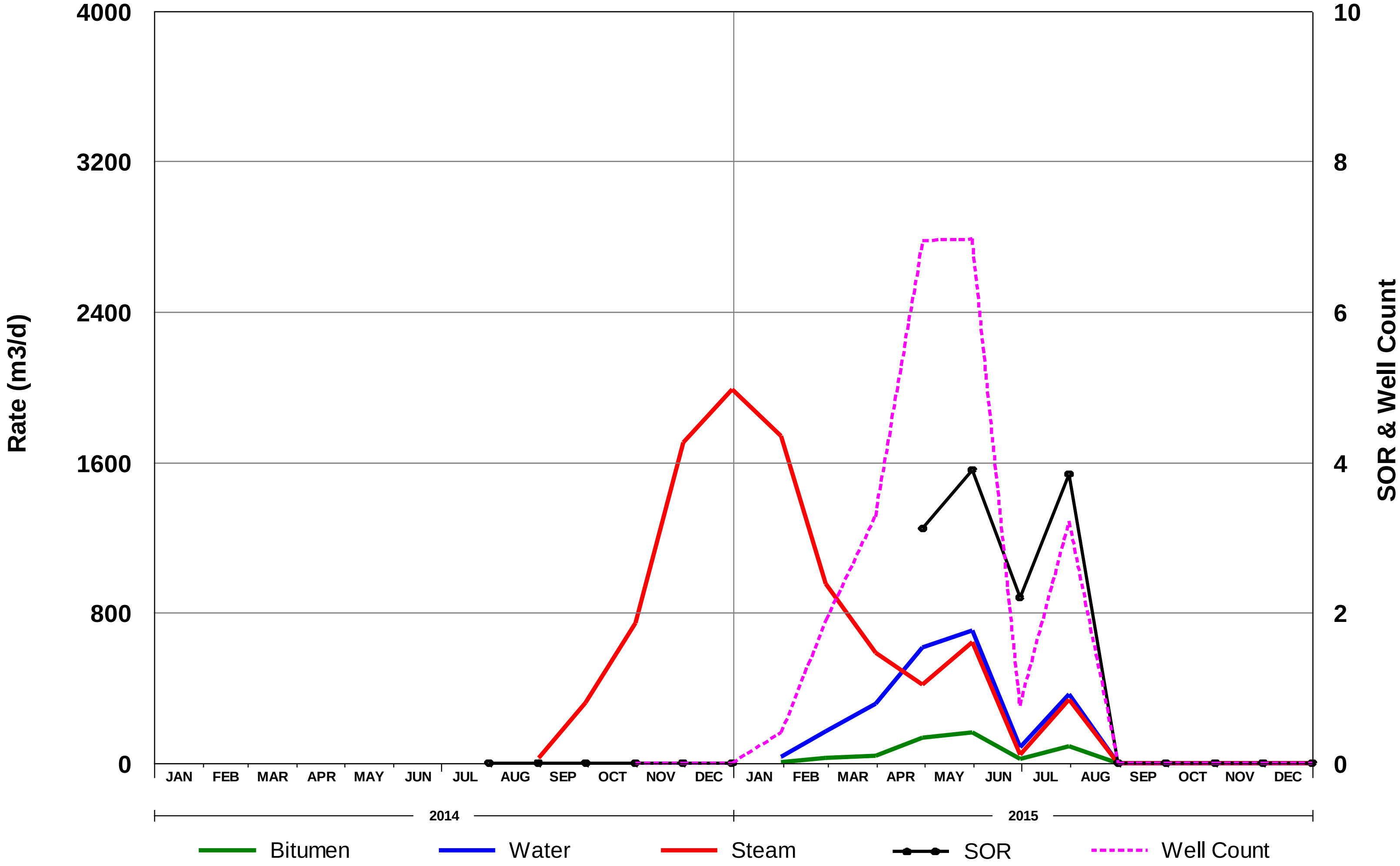
- Five well pairs (15P01 to 15P05)
- Cumulative production of 106 E^3m^3 (RF 8%)



Well Pad Performance
Subsection 3.1.7(h)
Kinosis

A New Energy

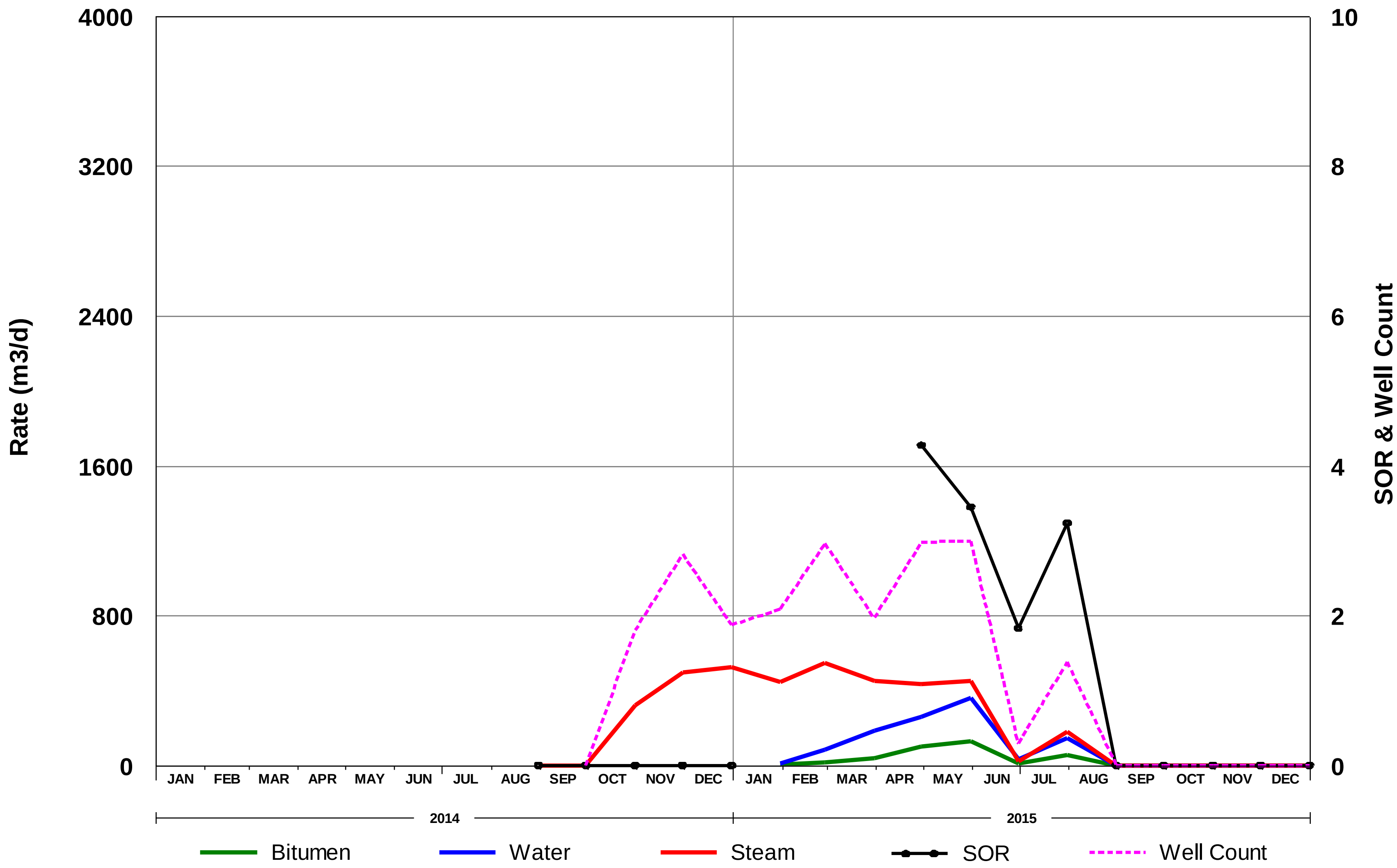
K1A-A Production Summary



- 6 pairs on production
  - K1P10 to K1P16
  - Operating pressures 1300 to 2800 kPa
  - Performance impacted by bottom water
- K1P09 shut-in
- K2P01, K2P02 were inactive

- Ten well pairs (K1P09 to K1P16, K2P01 to K2P02)
- Cumulative production of 15 E^3m^3 (RF 0.4%)

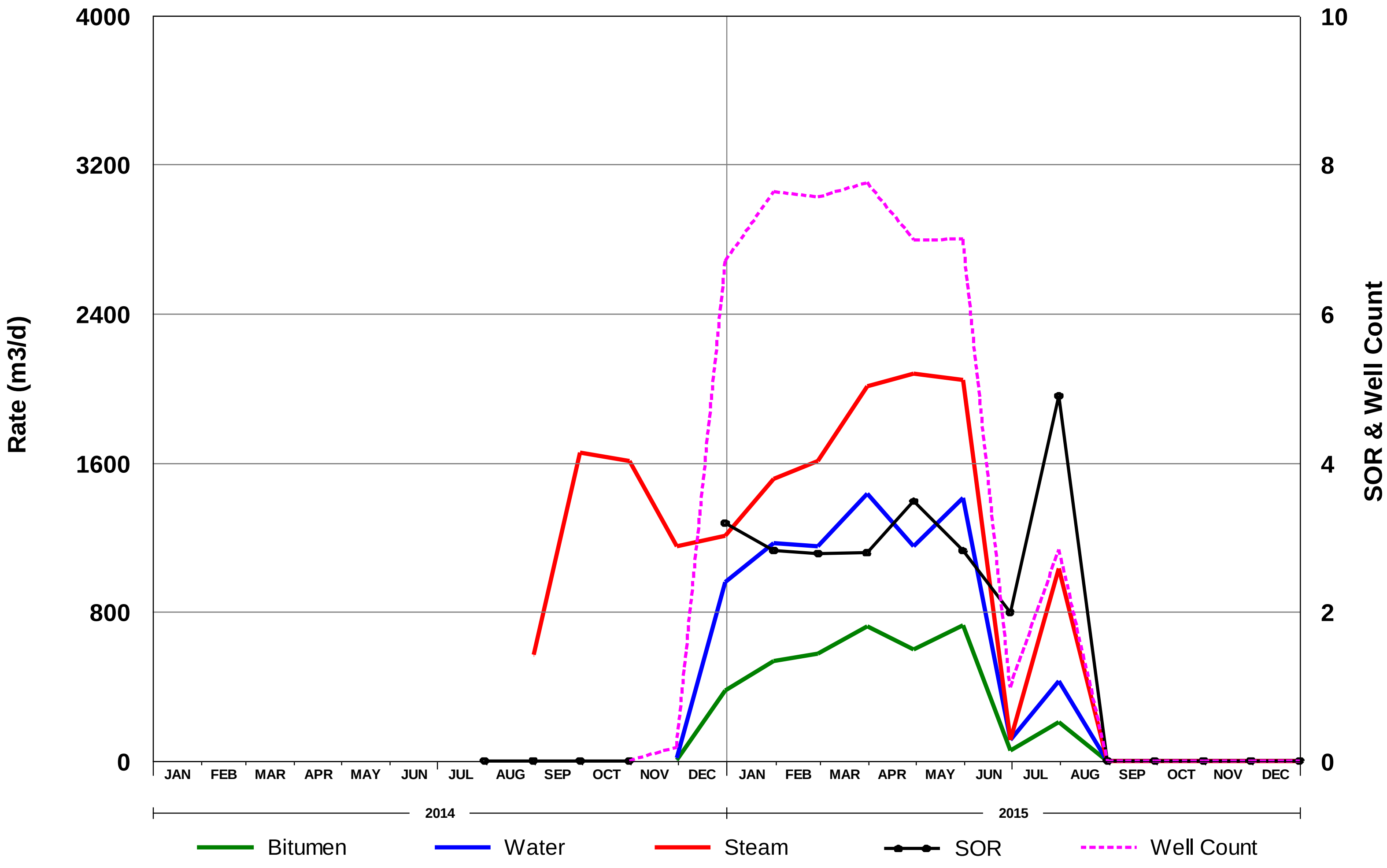
K1A-B Production Summary



- 3 well pairs on SAGD
  - K2P13 - K2P15
  - Pressures of 1800 to 2800 kPa
- K2P09 on circulation

- Eight well pairs (K2P09 to K2P16)
- Cumulative production of 11 E^3m^3 (RF 0.3%)

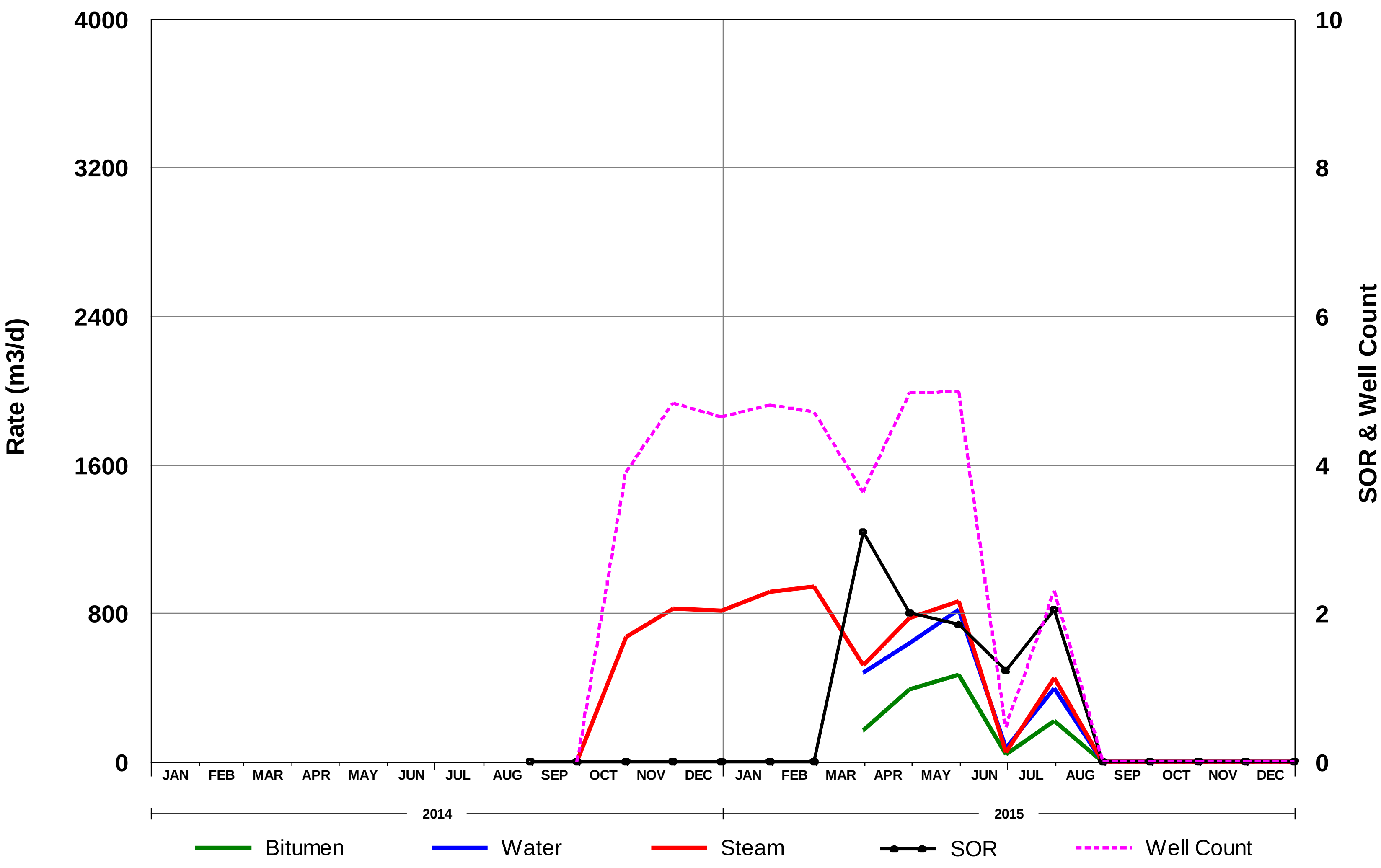
K1A-C Production Summary



- 7 well pairs on SAGD
  - K1P01, K1P03-K1P08
  - Operating Pressures from 1700 kPa to 2800 kPa
  - Demonstrating strong production performance
- K1P02 on circulation

- Eight well pairs (K1P01 to K1P08)
- Cumulative production of 116 E^3m^3 (RF 2.2%)

K1A-D Production Summary



- 5 well pairs on SAGD
  - K2P18 - K2P22
  - Maintain consistent operating pressure of 2800kPa
  - Exhibiting strong production performance
- 6 well pairs on circulation
  - K2P03 – K2P08

- Eleven well pairs (K2P03 to K2P08 and K2P18 to K2P22)
- Cumulative production of 39 E^3m^3 (RF 0.7%)