ConocoPhillips Canada Oil Sands | TOTAL

Annual Surmont SAGD Performance Review Approvals 9426, 11596, and 9460

April 28, 2015

Calgary, Alberta, Canada

- Introduction, Overview and Highlights
- Subsurface Resource Evaluation and Recovery
- Surface Operations and Compliance - Phase 1
- Future Plans
- Surface Operations and Compliance - Pilot Project

Introduction, Overview and Highlights

Ownership and Approvals

Ownership

- The Surmont In Situ Oil Sands Project is a 50/50 joint venture between ConocoPhillips Canada Resources Corp. and TOTAL E&P Canada Ltd; Operated by ConocoPhillips

Project History

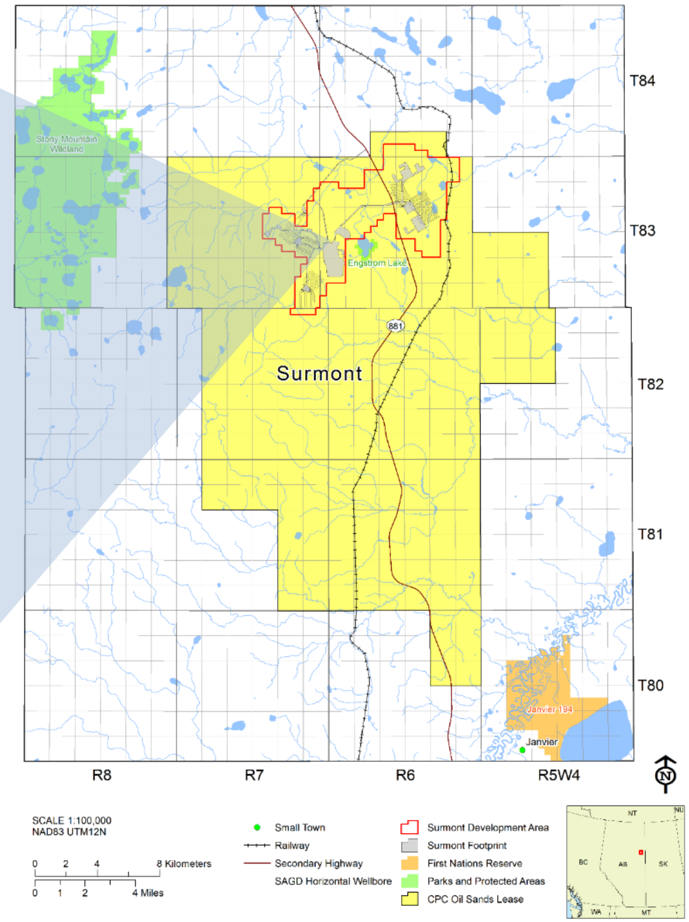
- 1997 - First steam at pilot project
- 2007 - First steam at Phase 1
- 2010 - Construction start at Phase 2

Approval Update - AER Approval No. 9426

- Amendments 9426Y and 9426Z
  - Geological Cross-Sections for Well Pads 262-1, 262-2, 266-2
- Amendments 9426AA and 9426BB
  - Sustaining Well Pads 104 and 267
- Amendments 9426BB and 9426CC
  - Outboard Wells for Well Pads 264, 265, 266
  - Buffer Well and Fishbone Well for Well Pad 266-2
- Application 1800069
  - Surmont Phase 3

Surmont Overview

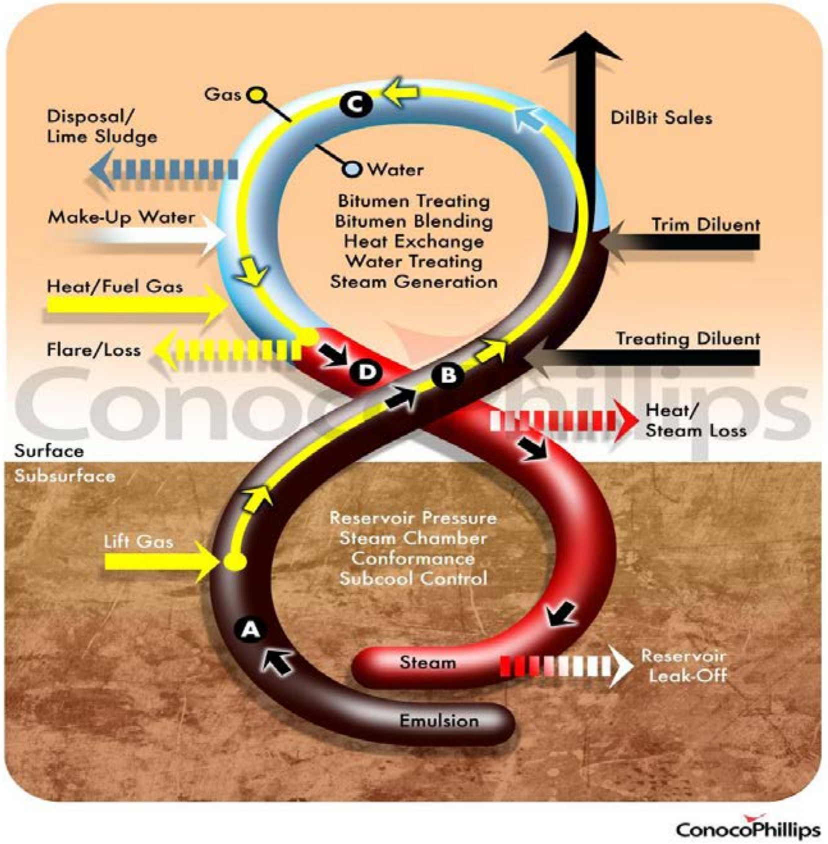
Phase 1 is focused on improving well & facility uptime and steam quality.



Surmont combined approved capacity is 21,624 m^3/d (136,000 bbl/cd)*
***(Phase 1 - 4,293 m^3/d , Phase 2 - 17,331 m^3/d)**

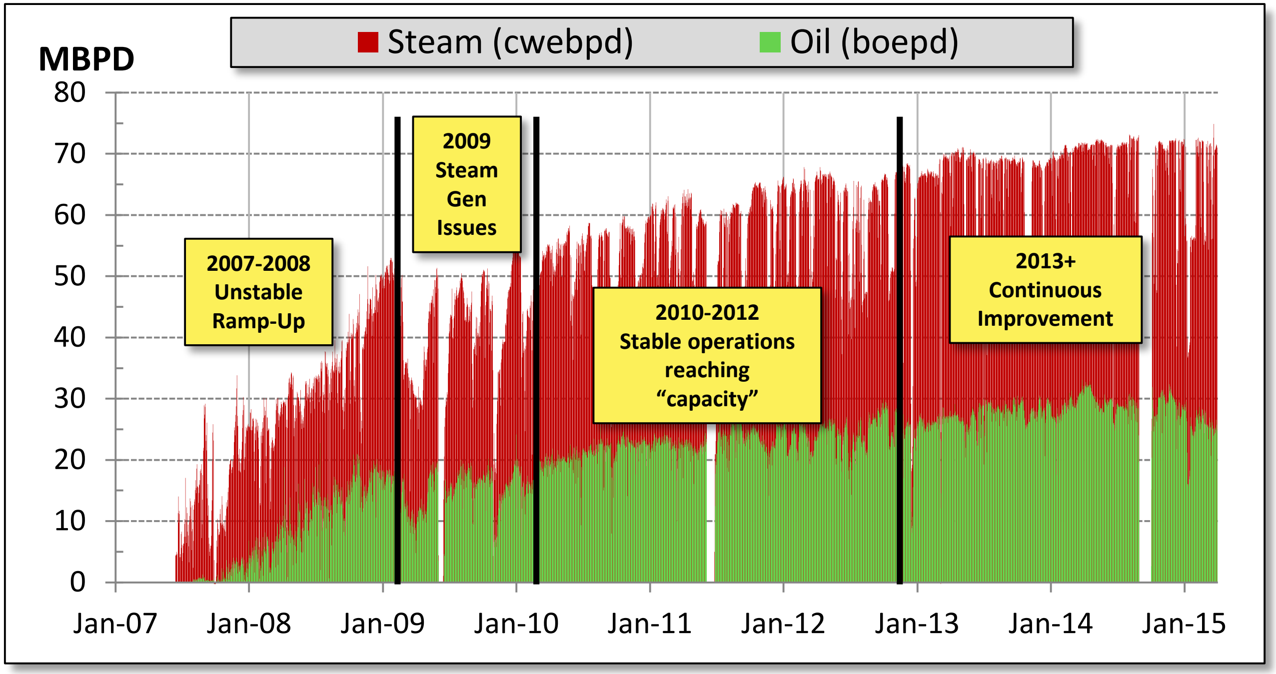
2014 Highlights

- **Continuous improvement results in record production**
  - Steam deliverability and uptime
  - ESP Run Time and Optimization
  - Total system concept to shelter volumes
- **Phase Two Operational Readiness**
  - Leveraging learnings from Phase 1 and other operators
  - Developing startup plans and procedures
  - Rehearsals/walkthroughs/etc
- **Sustaining pads**
  - Pad 101-24/25/26 deferred to 2016
  - Pad 103 start-up planned for 2015
- **Additional steam deferred to 2017**
  - May re-think this strategy in current economic environment

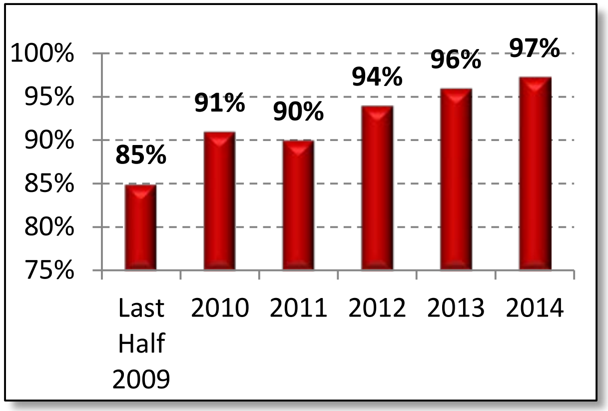


Surmont 1 Performance

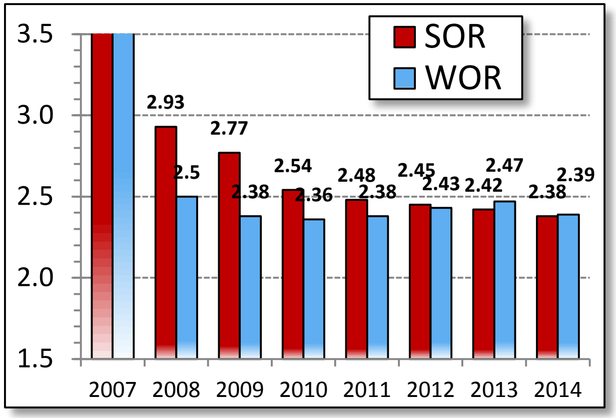
Historical Steam Injection and Bitumen Production



Average Steam Uptime



SOR and WOR



2007 Key Issues
- Commissioning
- Manpower
- Off-spec product
- Freezing
- Minimum Turndown

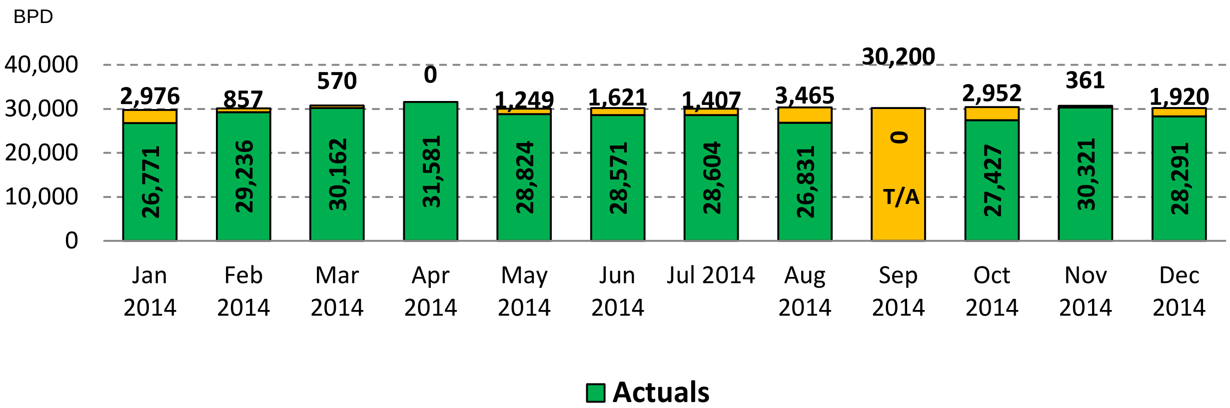
2008 Key Issues
- Freezing
- Off-spec product
- Plant Instability
- Well Integrity
- Well Constraints

2009 Key Issues
- OTSG integrity
- Front-end treatment
- 1st turnaround
- Well Constraints

2010-2012 Key Issues
- ESP installations/ repair
- OTSG maintenance
- 2011 Turnaround
- Well Constraints

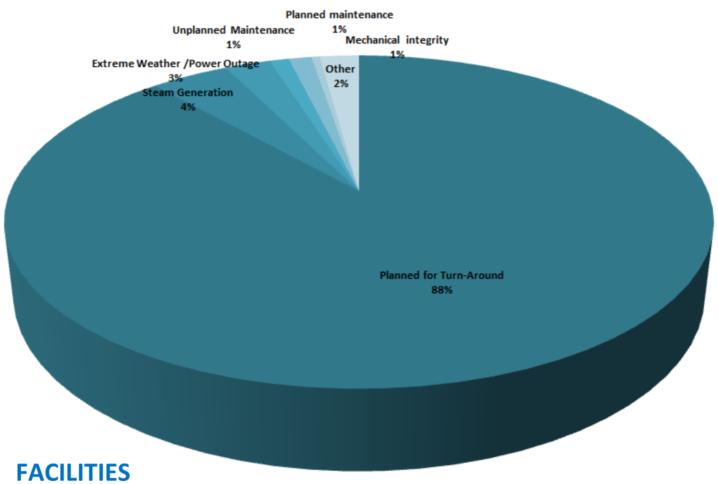
2013+ Key Issues
- ESP installations/ repair
- OTSG maintenance
- 2014 Turnaround
- Well & Facility Optimization

2014 Loss Production Rollup

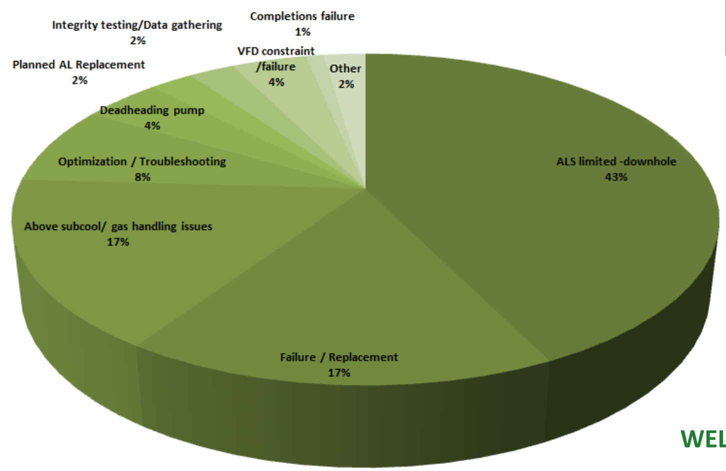


Losses Avg. History	
2014	3,737 bpd 1,220 bpd exc. T/A
2013	2,164 bpd
2012	2,437 bpd
2011	3,376 bpd

83% Facilities (incl. T/A and weather)
17% Wells



FACILITIES



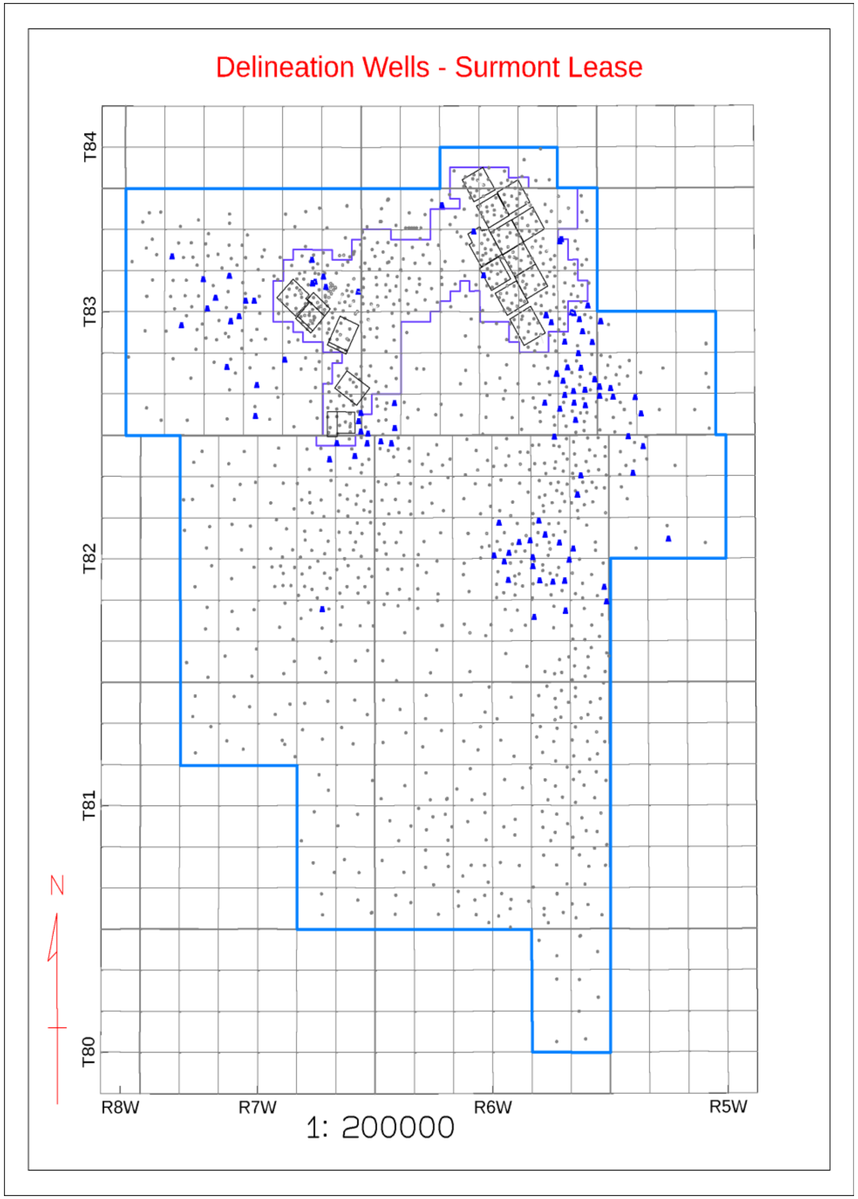
WELLS

Oil Losses Categories

Subsurface Resource Evaluation and Recovery

Subsection 3.1.1 (2)
Geology and Geophysics

2014-2015 Delineation Campaign and Well Density



1372 existing wells – 96 new

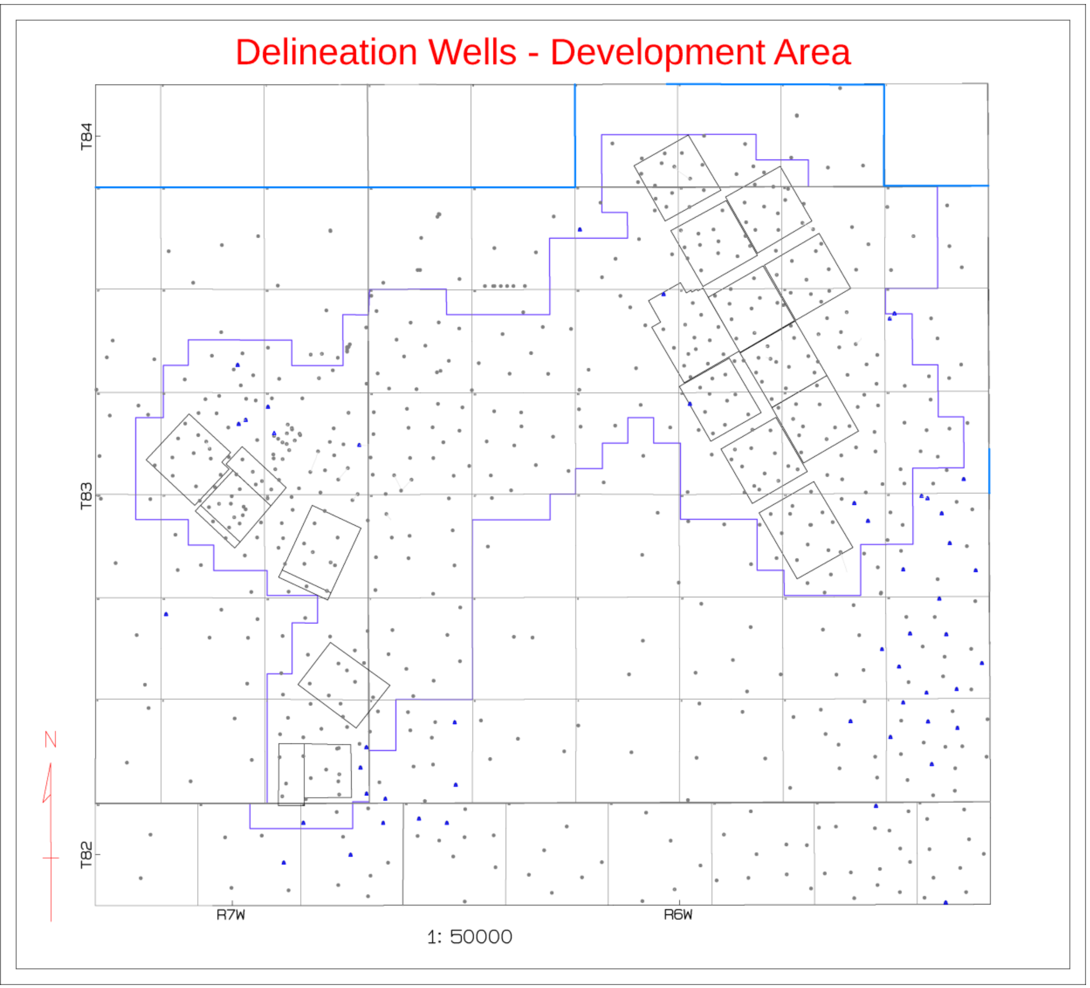
96 new vertical wells (as of Jan 31, 2015)

Phase 1 and Phase 2 Development Area

Drainage Areas

Surmont lease

2014-2015 Delineation Campaign and Well Density



Focus on Surmont Phase 1 sustaining pad locations as well as delineation of Phase 3

(only wells that penetrate the McMurray)

Existing wells

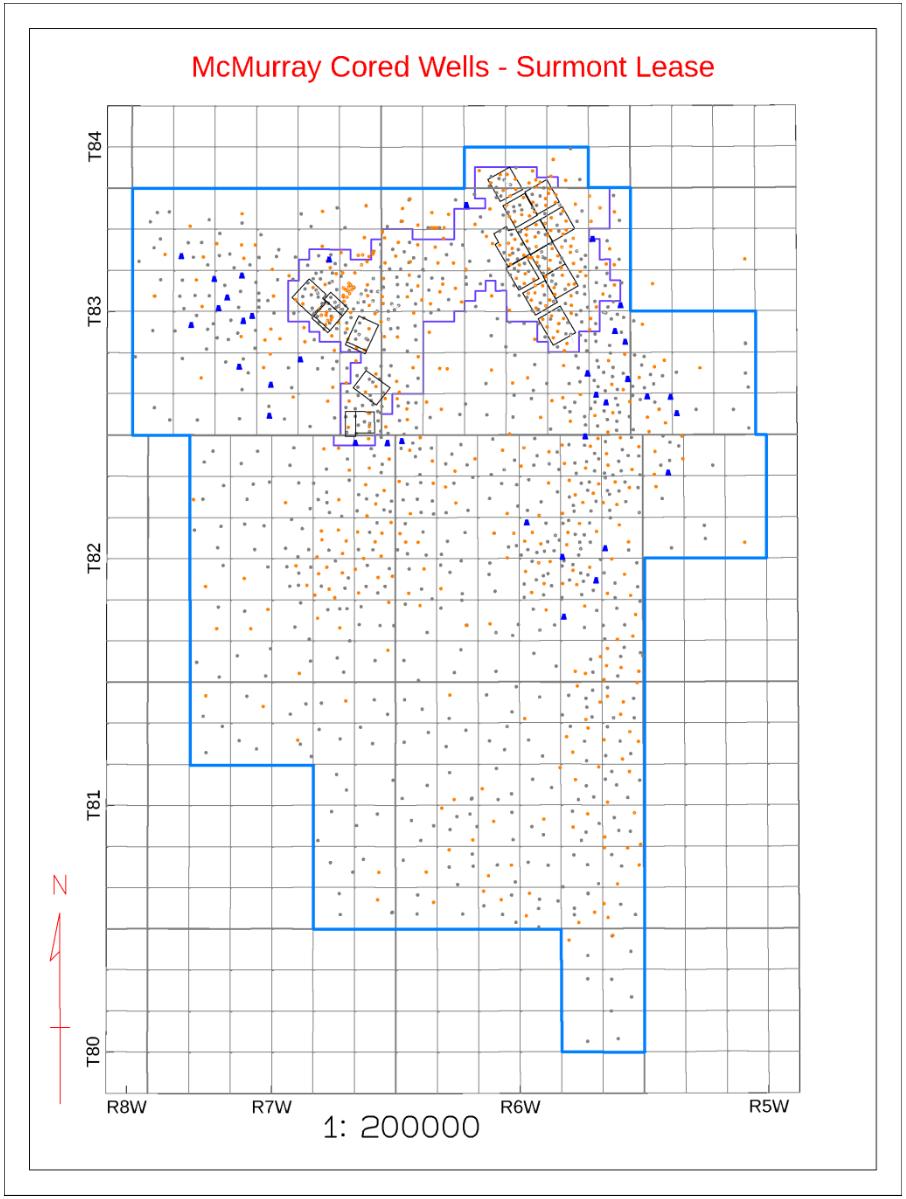
New vertical wells (as of Jan 31, 2015)

Phase 1 and Phase 2 Development Area

Drainage Areas

Surmont lease

2014-2015 Delineation Campaign and Core Density



1372 wells total

520 existing core wells

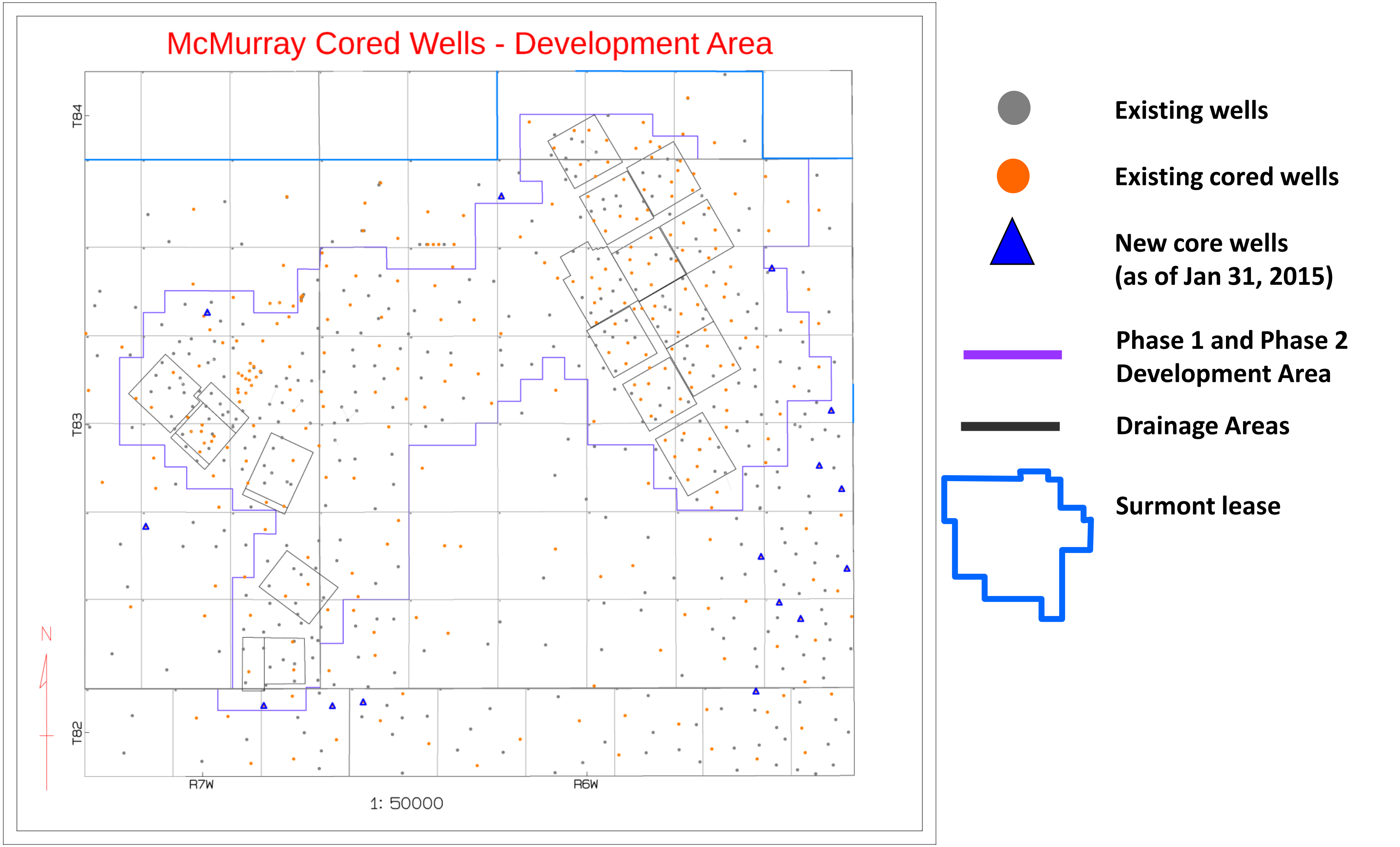
35 new core wells (as of Jan 31, 2015)

Phase 1 and Phase 2 Development Area

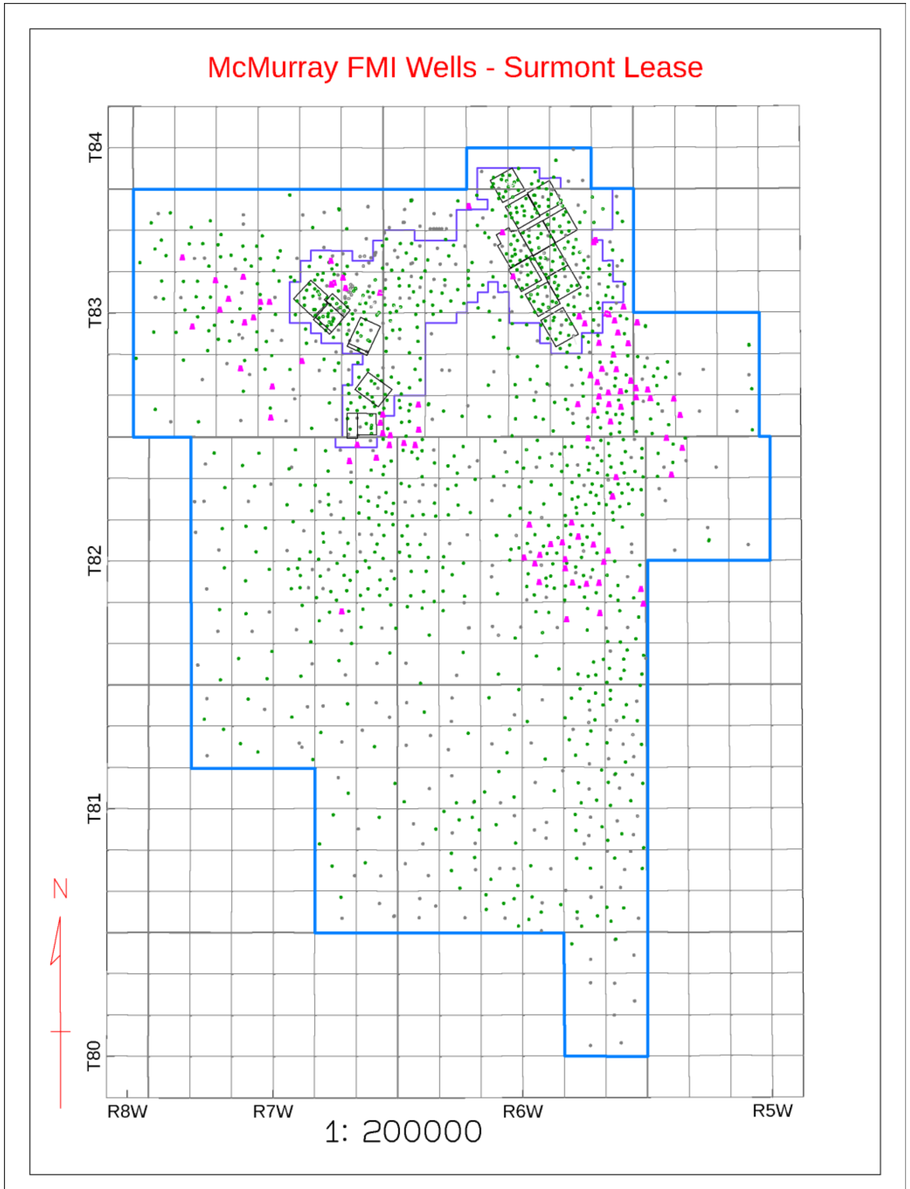
Drainage Areas

Surmont lease

2014-2015 Delineation Campaign and Core Density



2014-2015 Delineation Campaign and FMI/CMI Logs



100% Coverage of FMI/CMI Data in 2014/2015 program

- **Important for breccia identification**

1372 wells total

993 existing FMI/CMI wells

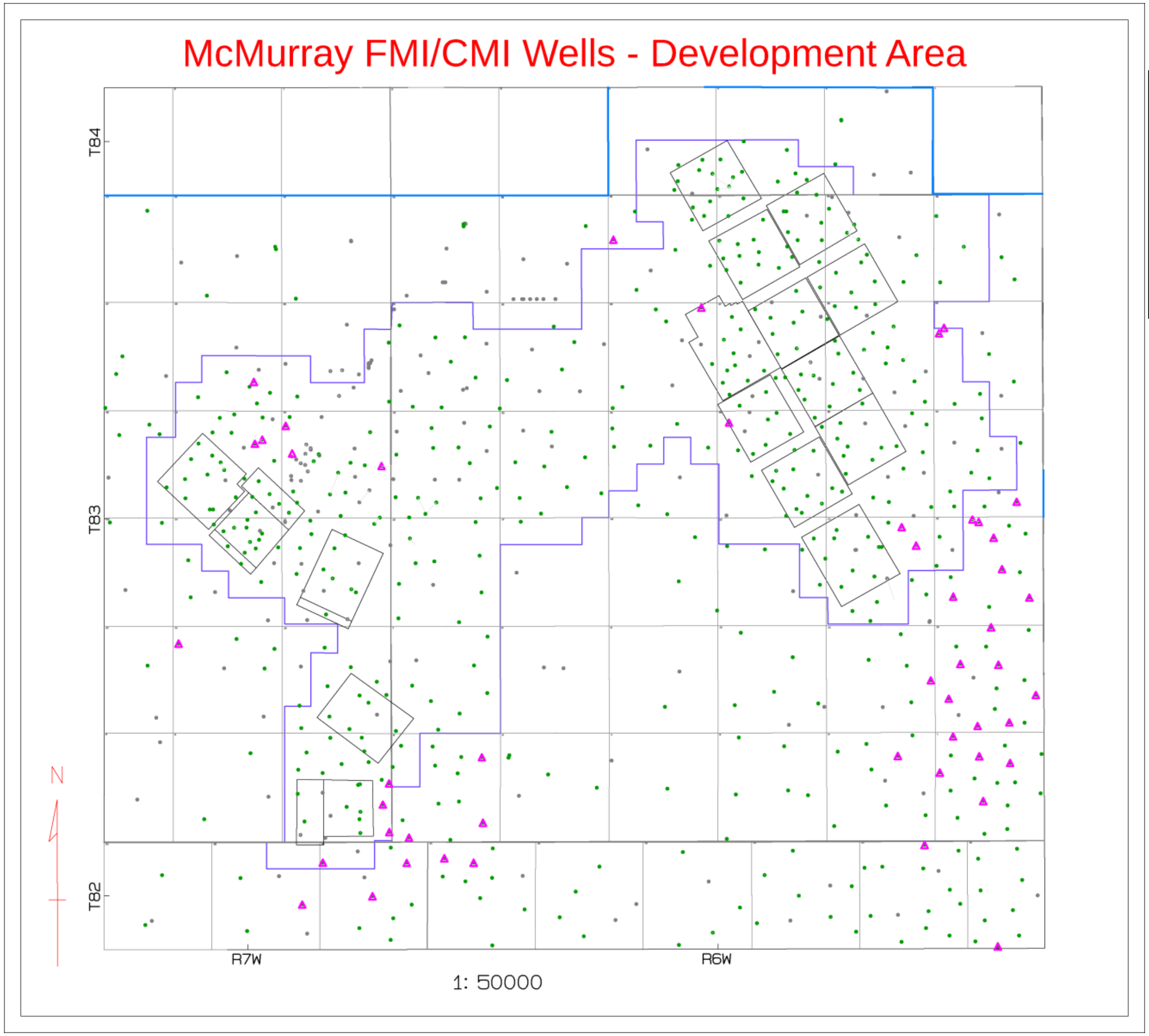
95 new FMI/CMI wells (as of Jan 31, 2015)

Phase 1 and Phase 2 Development Area

Drainage Areas

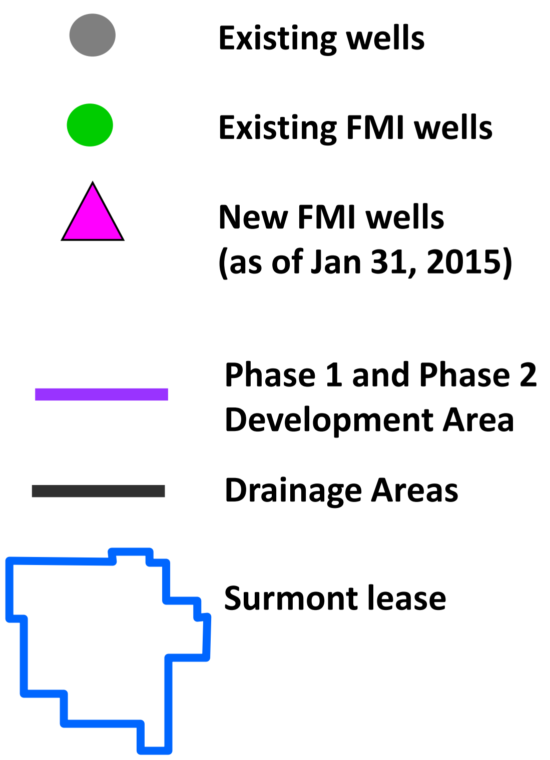
Surmont lease

2014-2015 Delineation Campaign and FMI/CMI Logs



100% Coverage of FMI/CMI Data in 2014/2015 program

- **Important for breccia identification**



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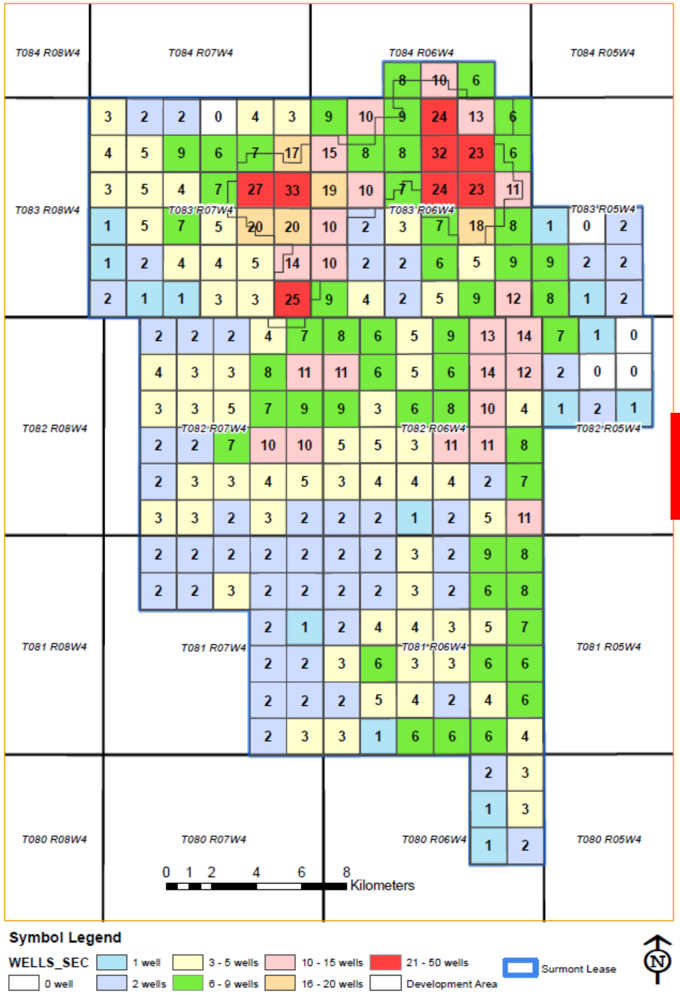
2014-2015 Delineation Campaign and Well Density

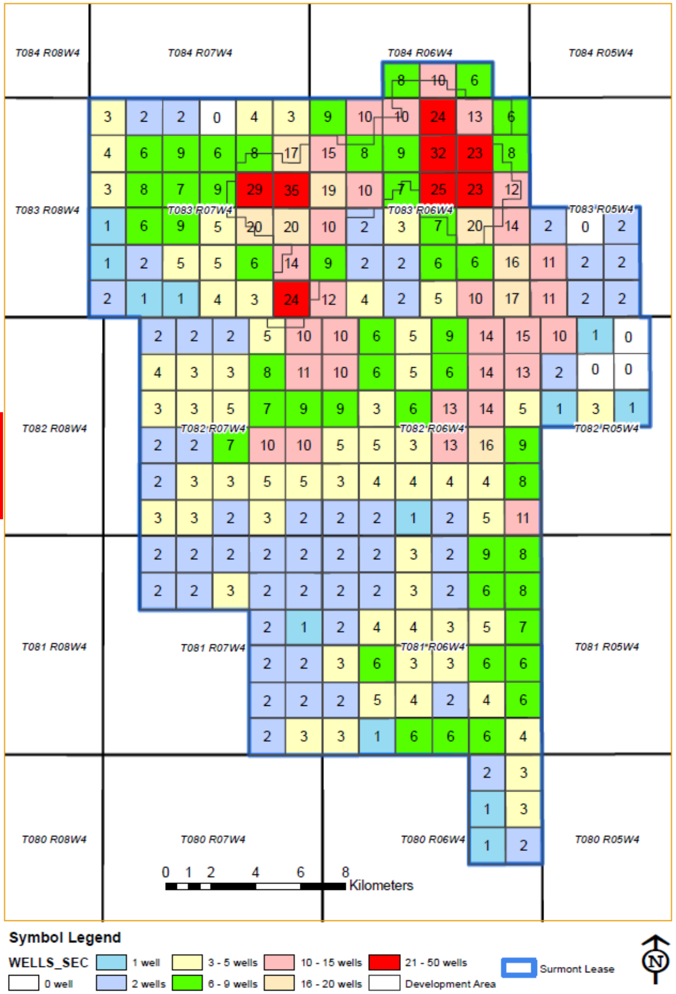
Delineation across Phase 1, 2, and 3

Delineation Well Density Map - Jan 2014



McMurray penetrated wells only

Delineation Well Density Map - Jan 2015



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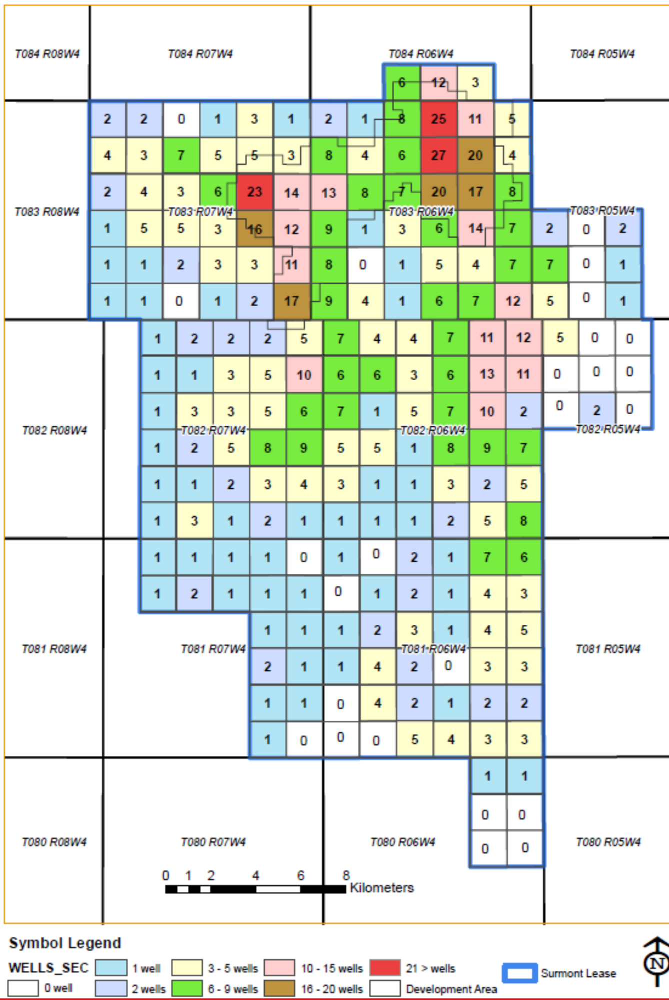
2014-2015 Delineation Campaign and FMI Logs

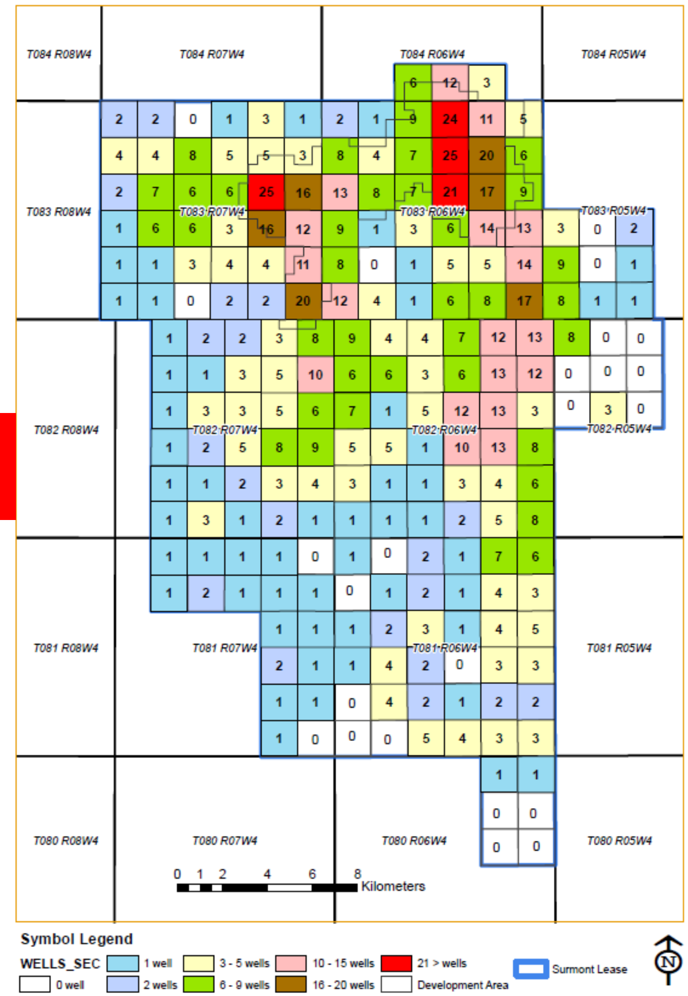
Increased Formation Micro Imaging density with latest drilling

FMI Well Log Density Map – Jan 2014



McMurray penetrated wells only

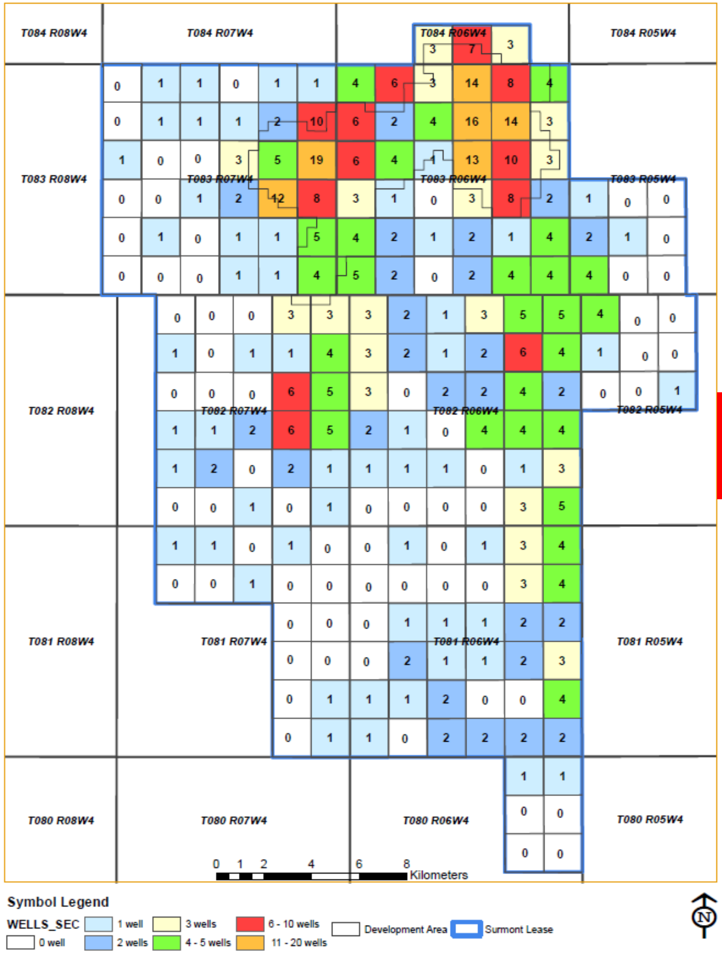
FMI Well Log Density Map – Jan 2015



2014-2015 Delineation Campaign and Well Density

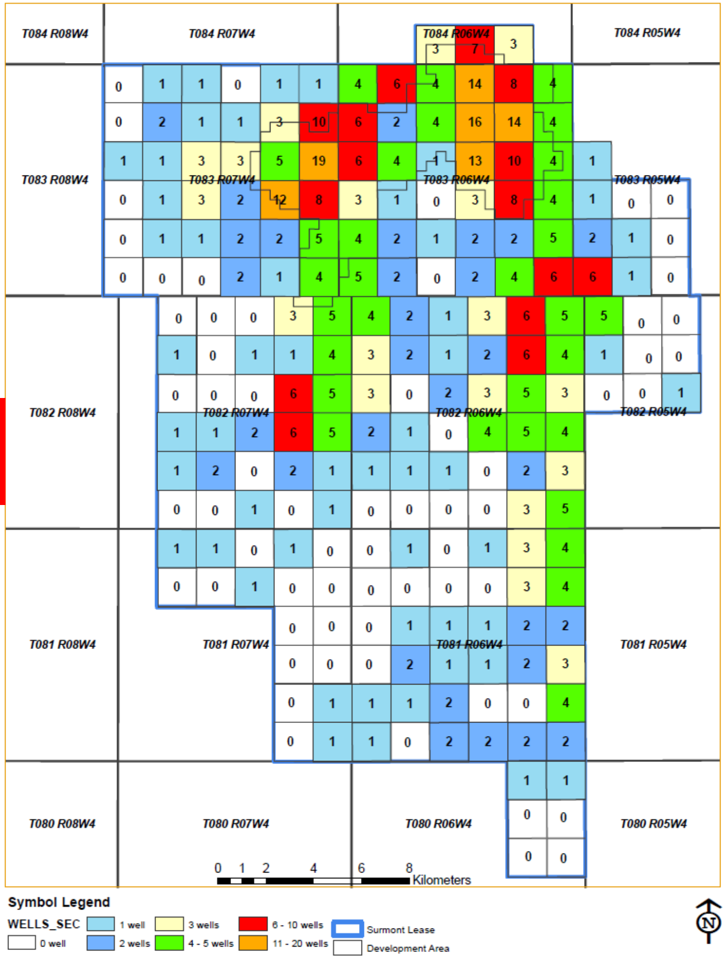
Increased core density with latest drilling

Cored Wells Density Map - Jan 2014



McMurray penetrated wells only

Cored Wells Density Map - Jan 2015



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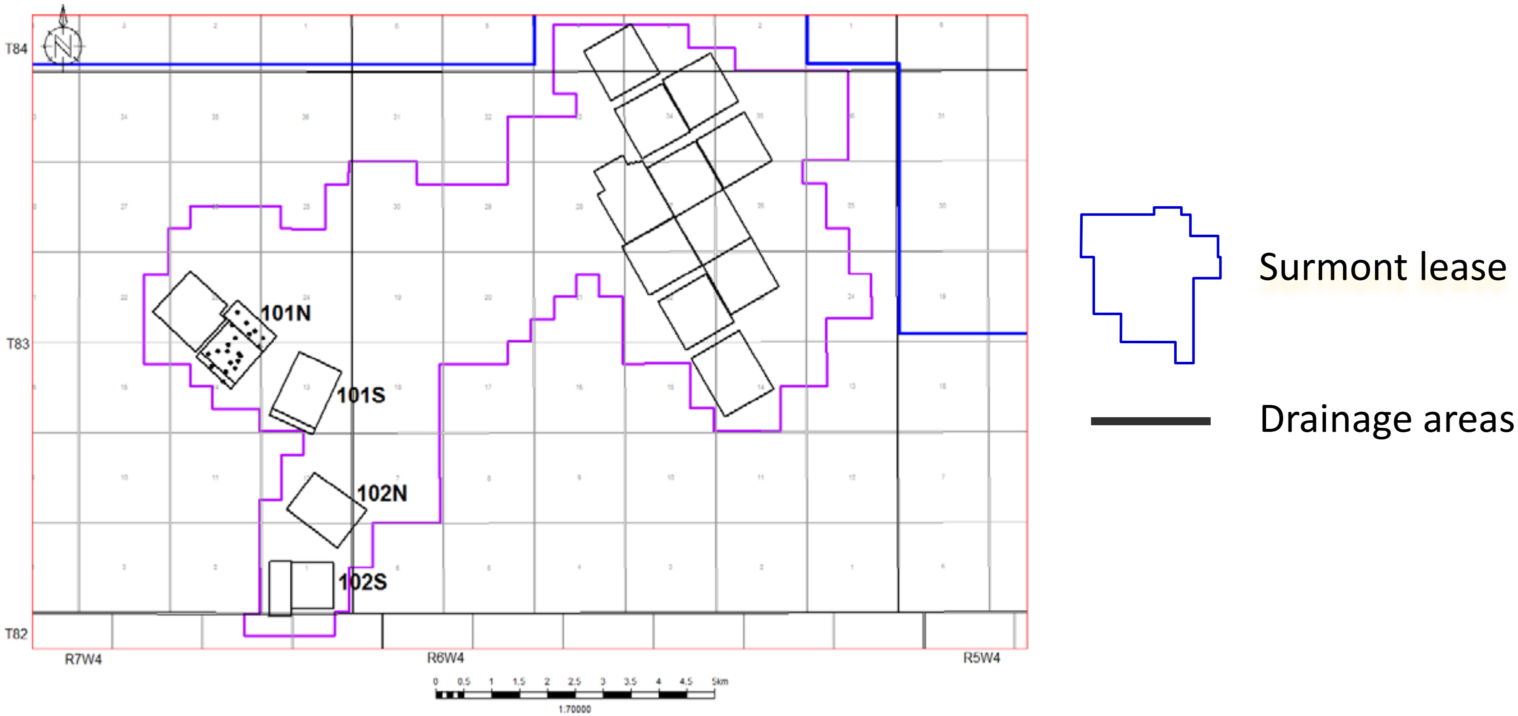
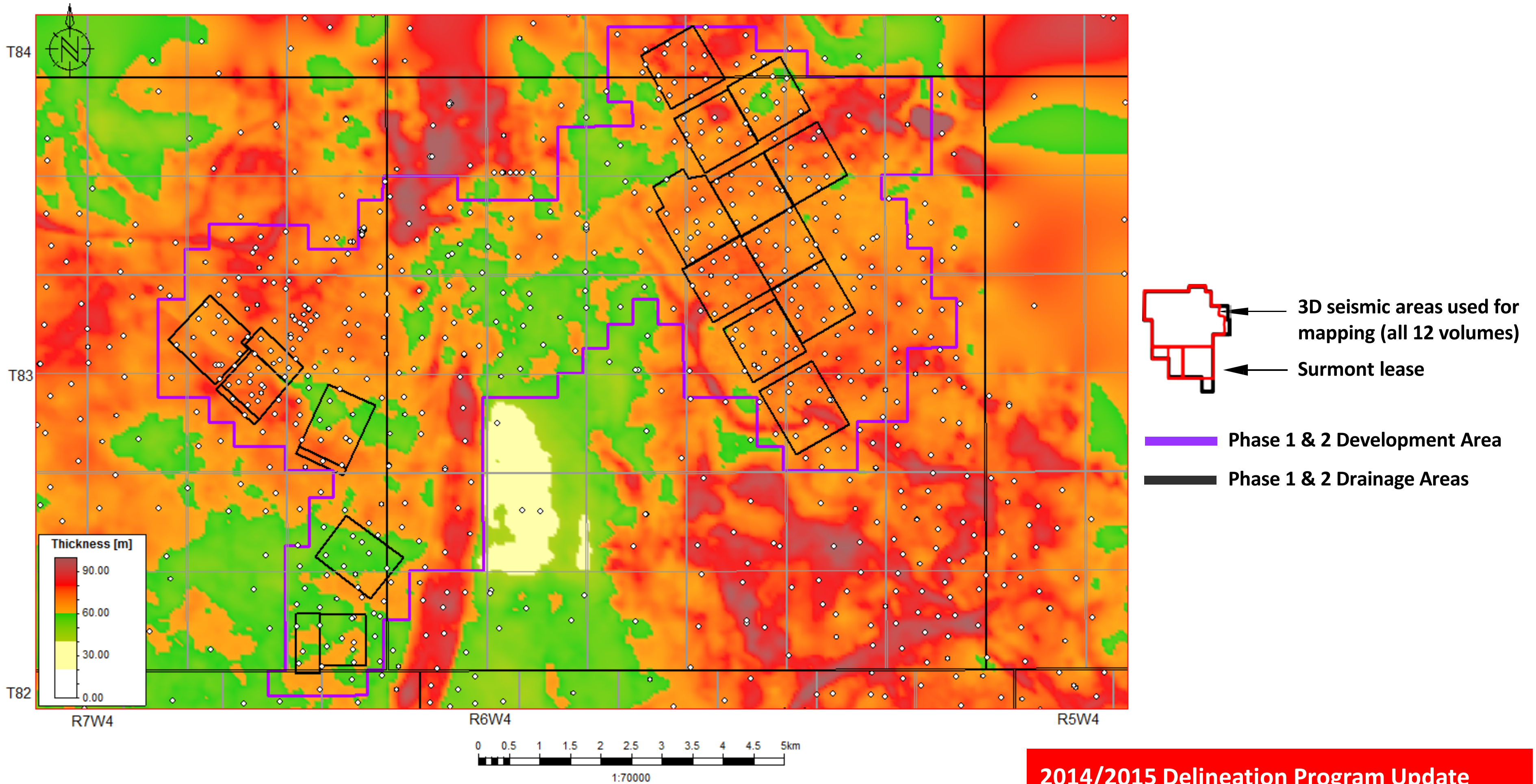
Reservoir Characteristics



Properties	101N	101S	102N	102S	Lease
Depth (masl)	270-215	270-215	270-215	270-215	~250
Phie in NCB	32.8%	33.6%	33.1%	31.7%	32.33%
So in NCB	81.8%	83%	81.6%	73.5%	78.61%
KH in NCB	4425 mD	5306 mD	4538 mD	3801 mD	4569 mD
KV in NCB	3670 mD	4452 mD	3785 mD	3119 mD	3807 mD
Initial Pressure (KPA)	1076	1117	1040	1138	~1000
Temperature (oC)	11	11	11	11	11

McMurray Gross Isopach



McMurray Gross Isopach

2014/2015 Delineation Program Update

- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

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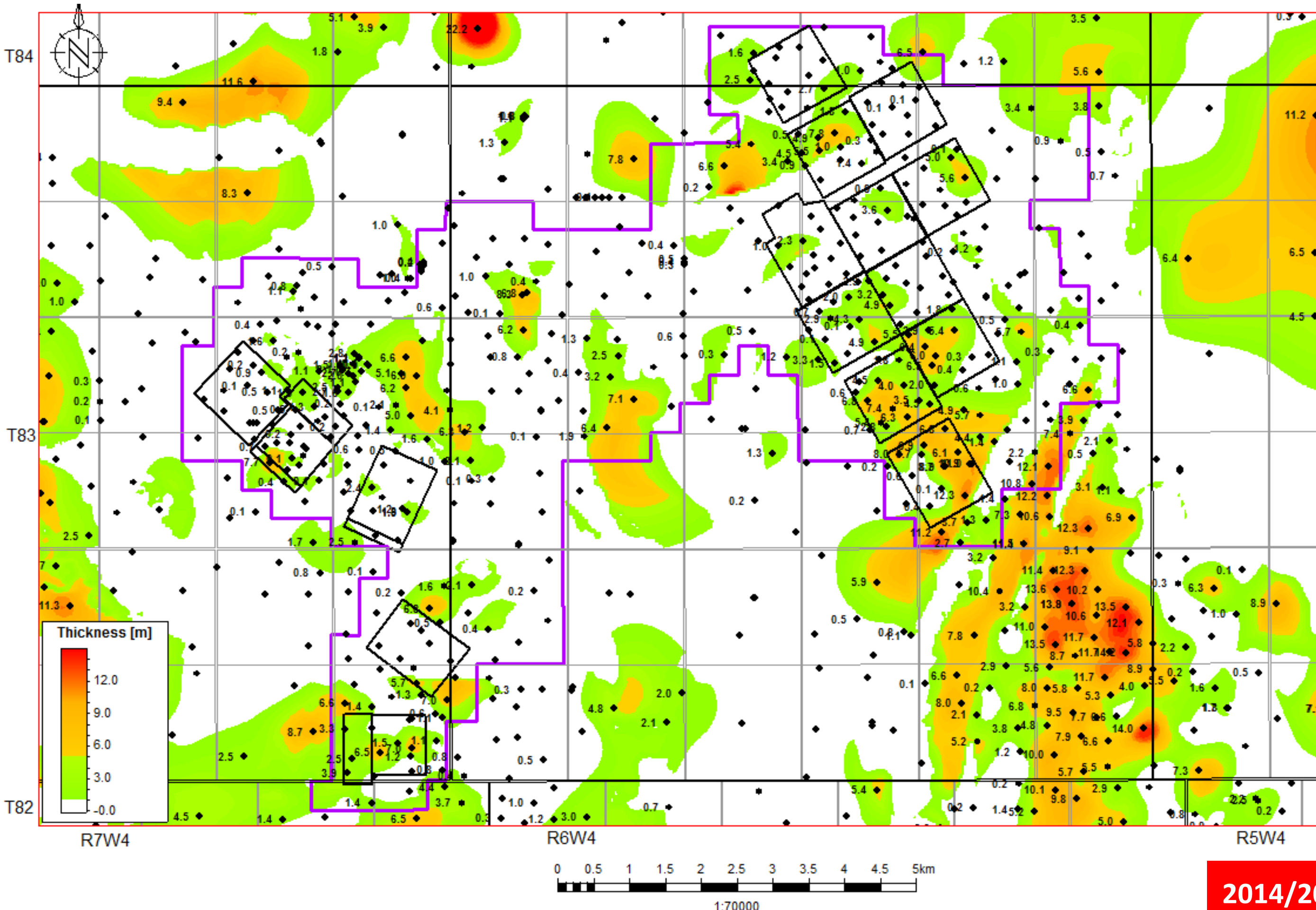
McMurray Net Gas Isopach



3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 & 2 Development Area

Phase 1 & 2 Drainage Areas

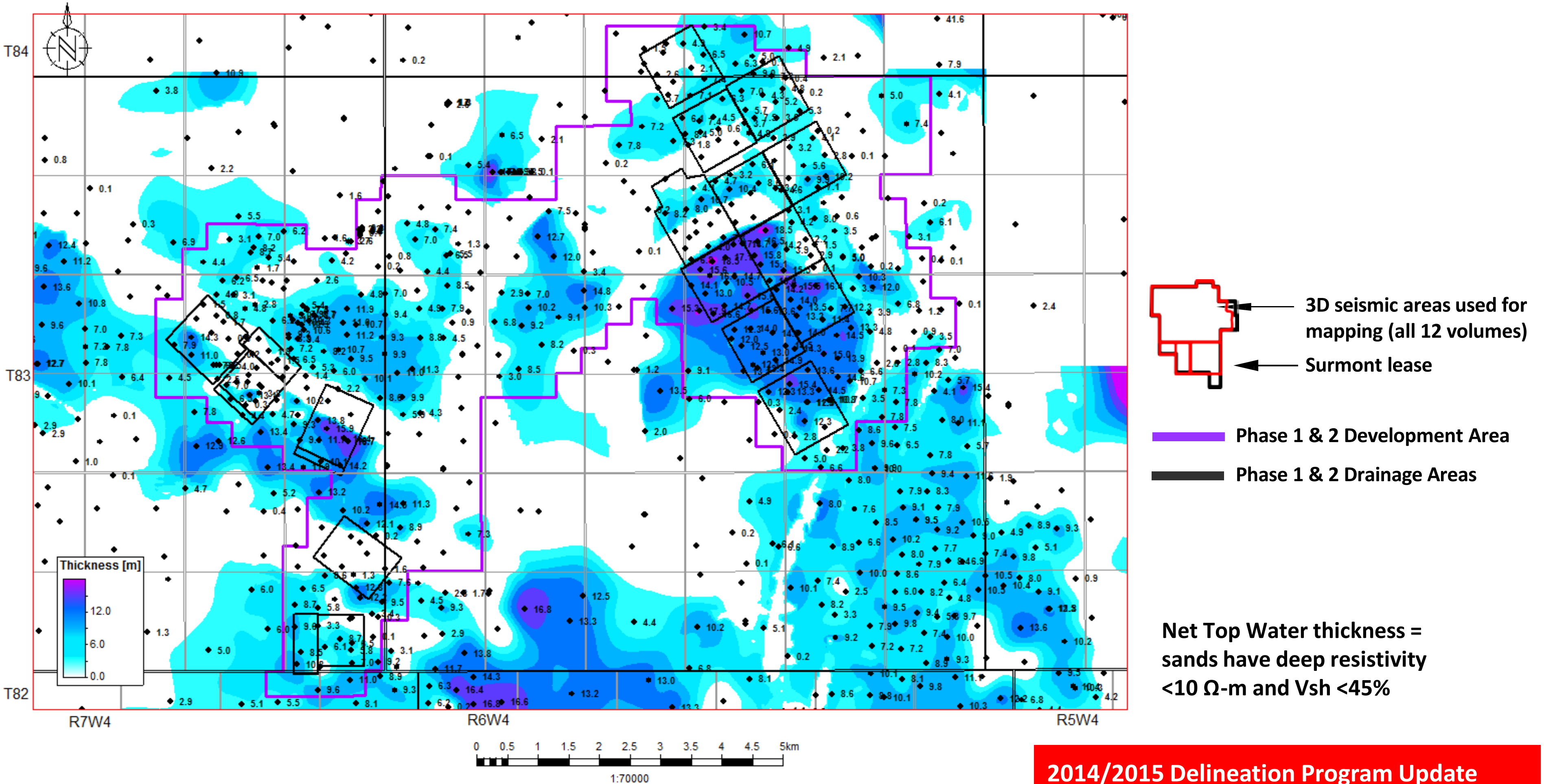
Net Top Gas thickness = sands have deep resistivity ≥10 Ω-m and Vsh <65%

McMurray Net Gas Isopach

2014/2015 Delineation Program Update

- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

McMurray Net Top Water Isopach



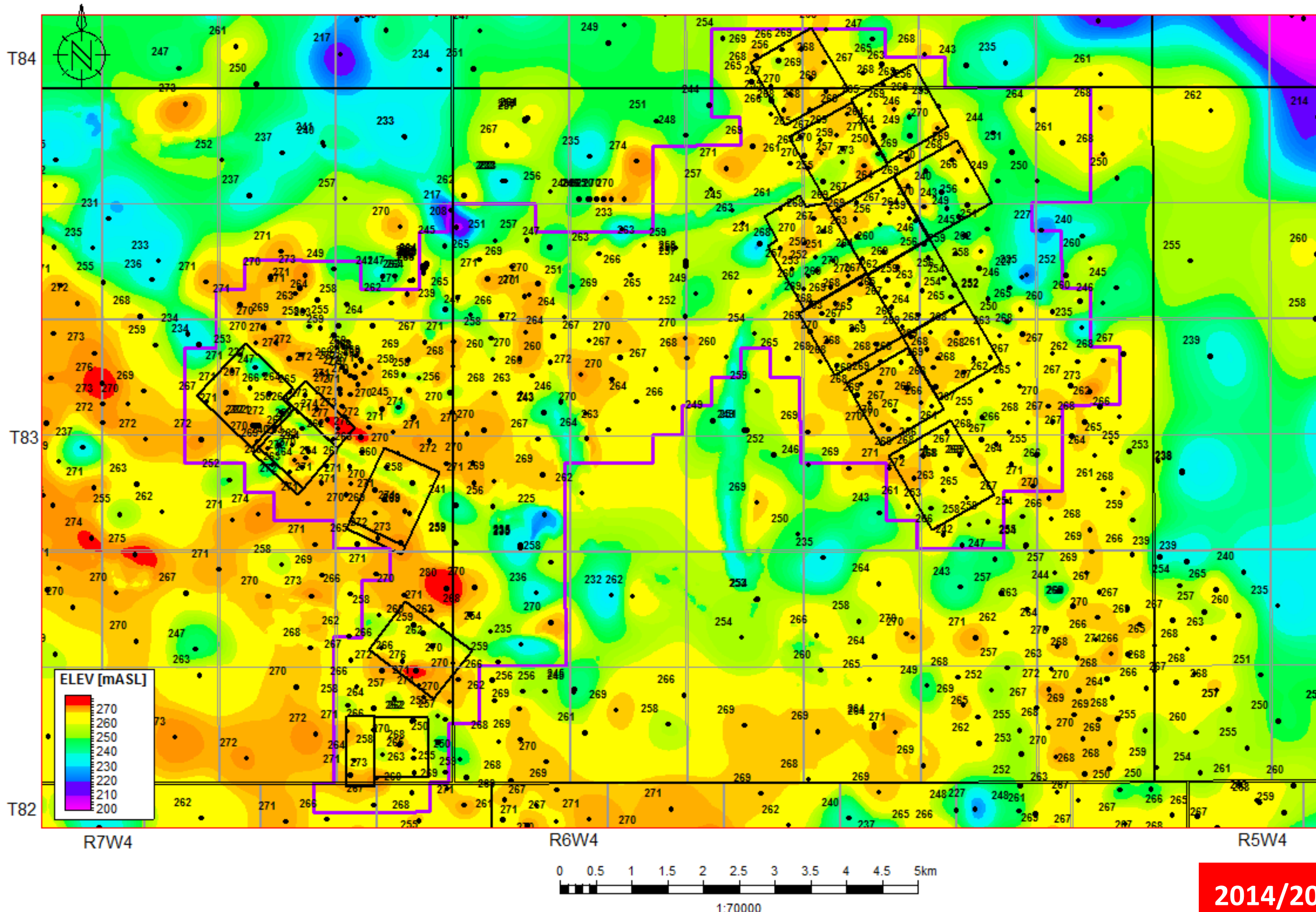
Net Top Water thickness = sands have deep resistivity <10 Ω-m and Vsh <45%

McMurray Net Top Water Isopach

2014/2015 Delineation Program Update

- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

McMurray Top Continuous Bitumen Structure



3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 & 2 Development Area

Phase 1 & 2 Drainage Areas

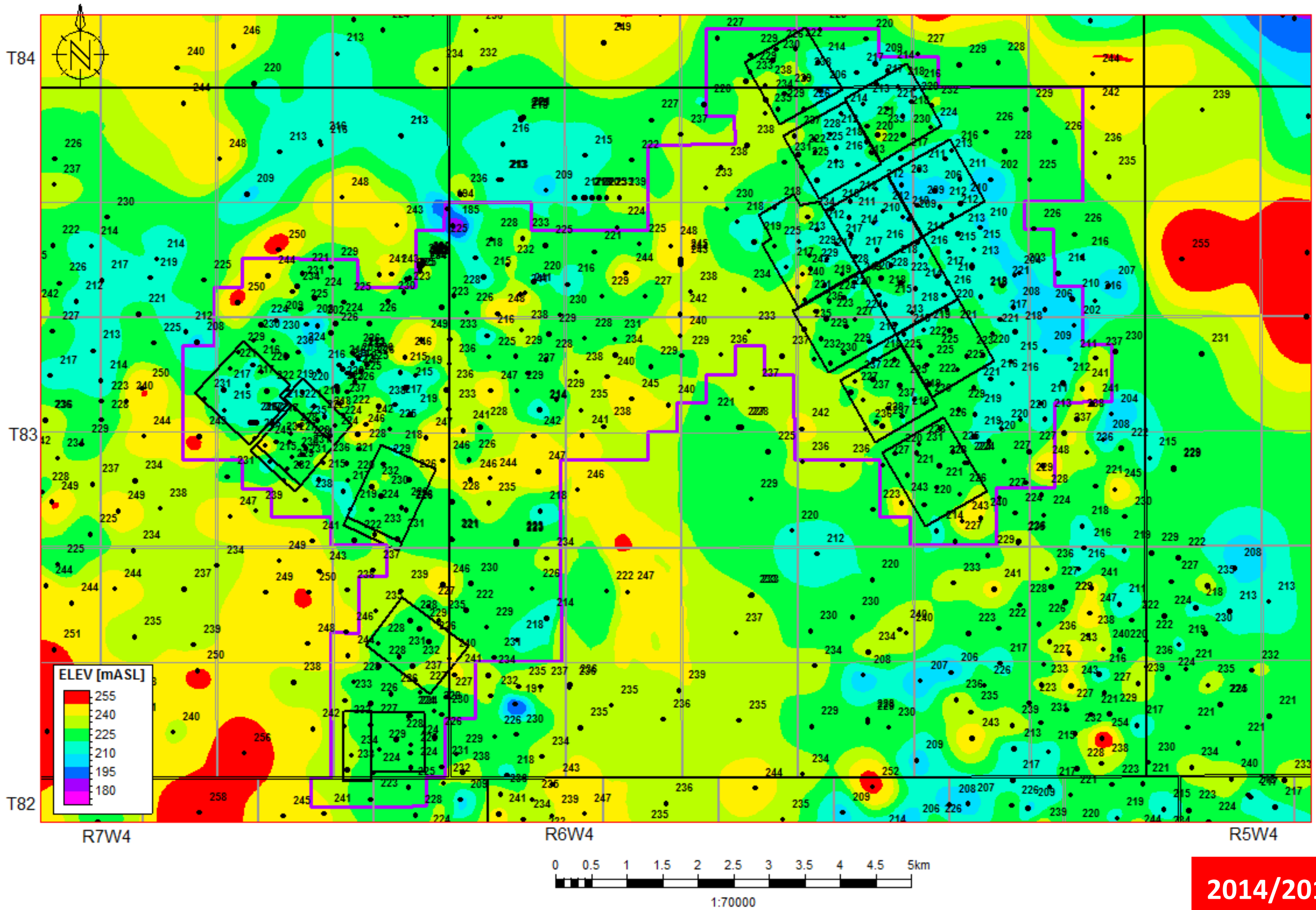
TCB = The uppermost limit of good reservoir, bitumen- bearing sands.

Top Continuous Bitumen Structure

2014/2015 Delineation Program Update

- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

McMurray Base Continuous Bitumen Structure



3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 & 2 Development Area

Phase 1 & 2 Drainage Areas

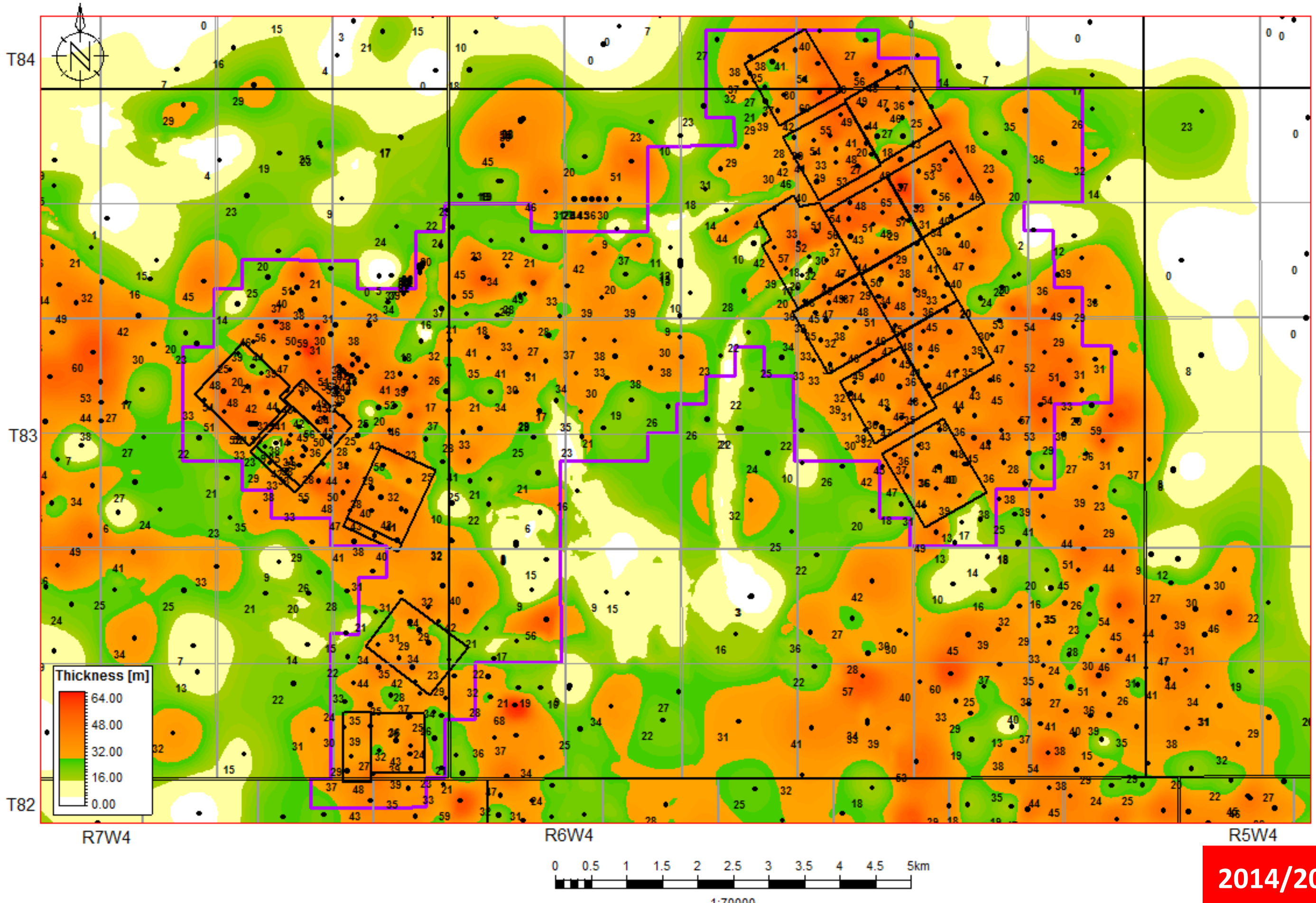
BCB = First occurrence of good reservoir, bitumen- bearing sands.

Base Continuous Bitumen Structure

2014/2015 Delineation Program Update

- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

McMurray Net Continuous Bitumen Thickness



3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 & 2 Development Area Phas

1 & 2 Drainage Areas

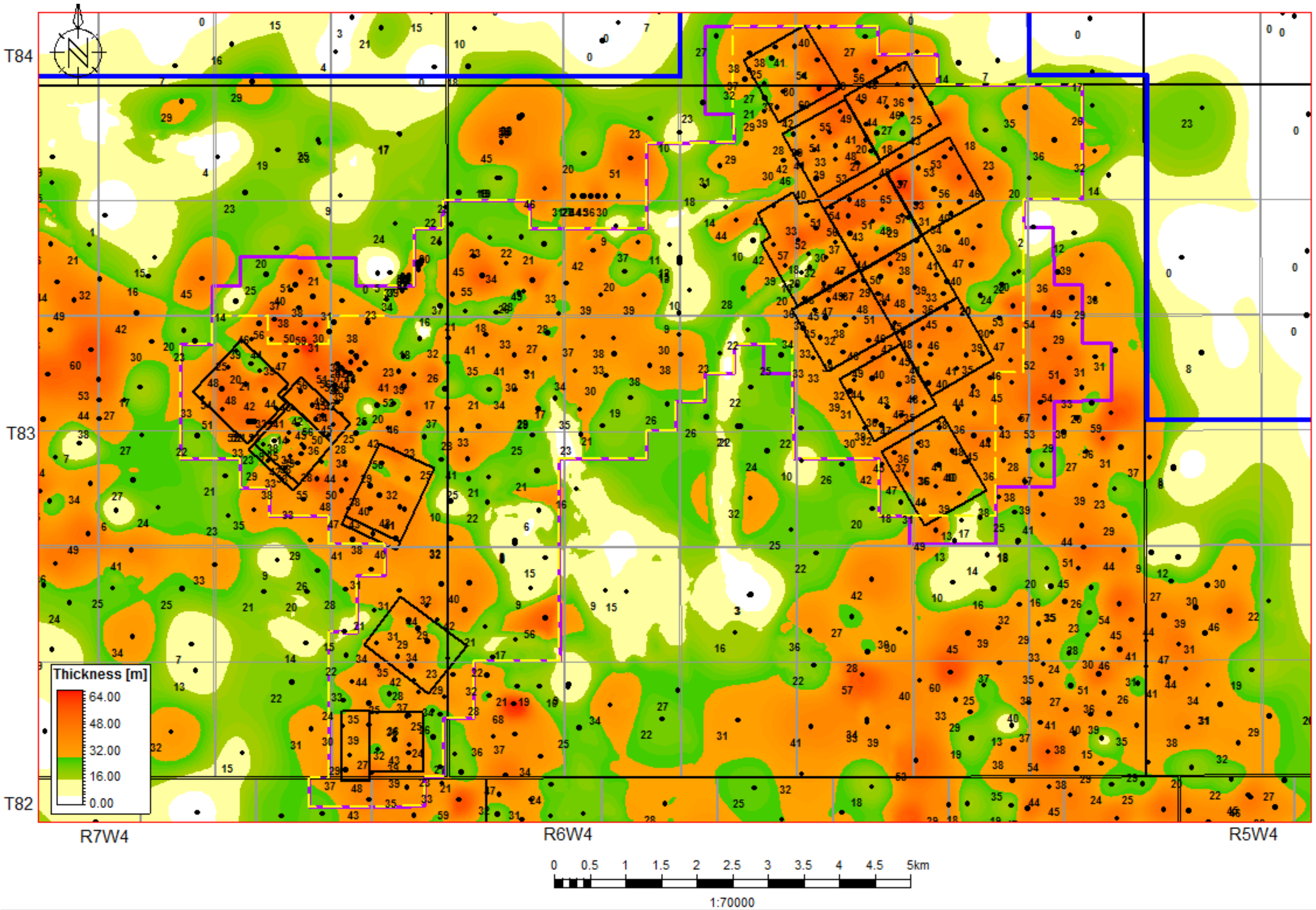
Net continuous bitumen = sands have deep resistivity > 40 Ω-m and Vsh <33%, and no shale greater than 3 m thick

McMurray Net Continuous Bitumen Pay

2014/2015 Delineation Program Update

- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

Surmont Lease OBIP



3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 & 2 Development Area

Phase 1 & 2 Drainage Areas

Surmont Lease OBIP

Properties	Development Area
NCB Thickness Range	0 to Greater than 30 m
Phie in NCB	32.33%
So in NCB	78.61%
OOIP in NCB > 18m	3362.23 MMbbls Deterministic

OBIP = Thickness x Phie x So x Area

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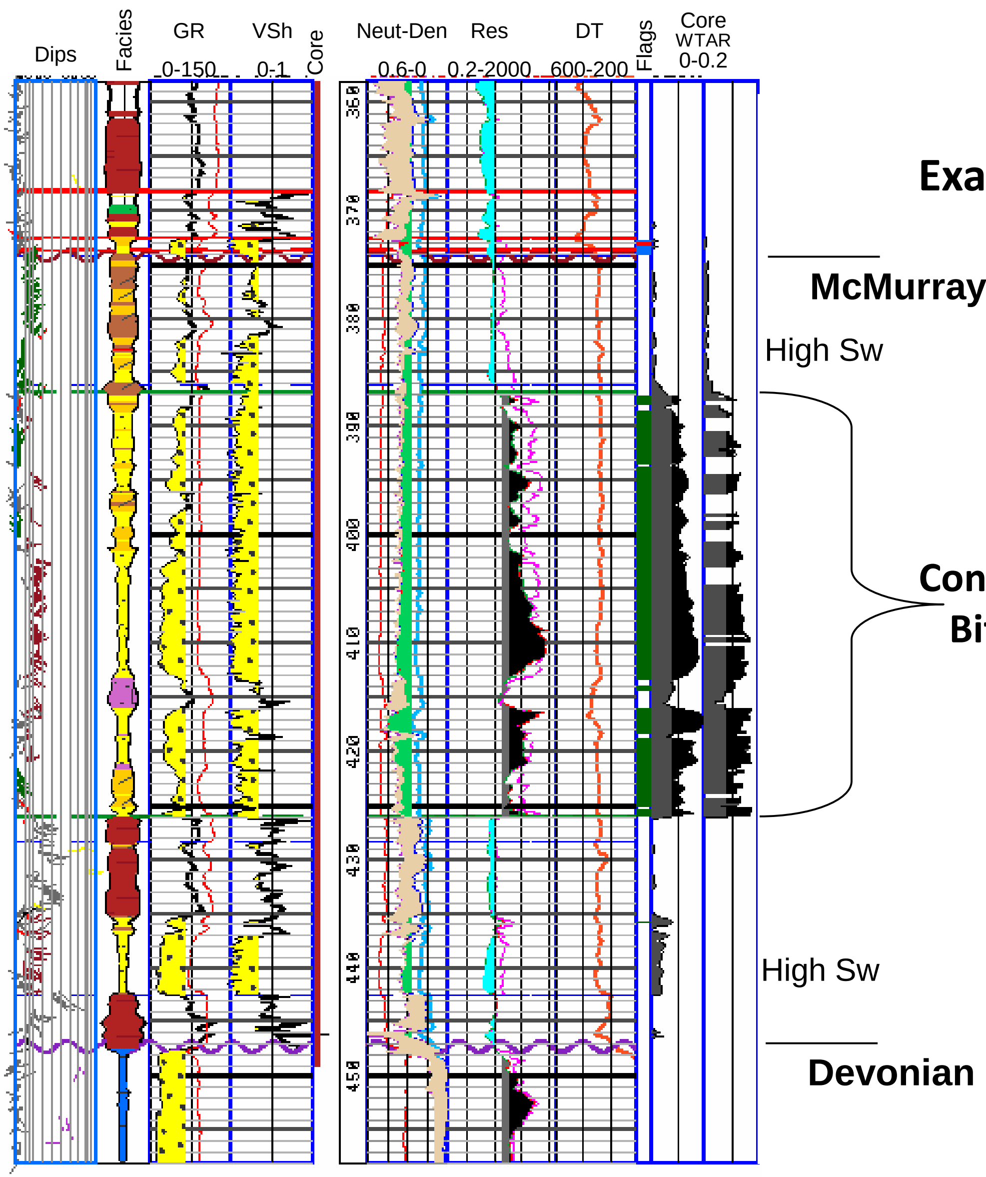
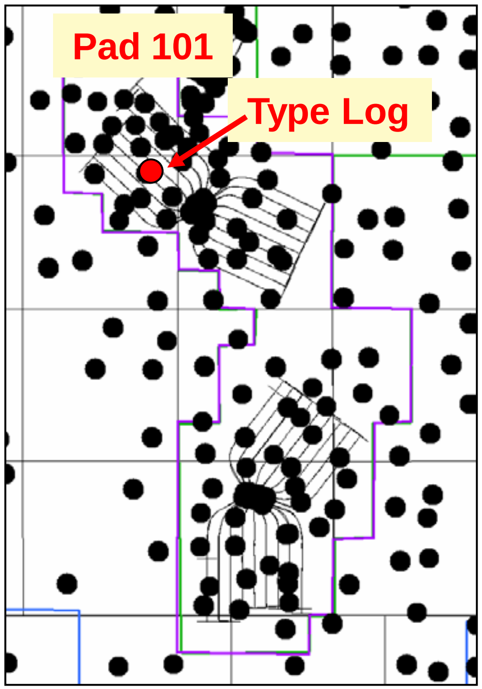
Phase 1 Type Log Well Pad 101



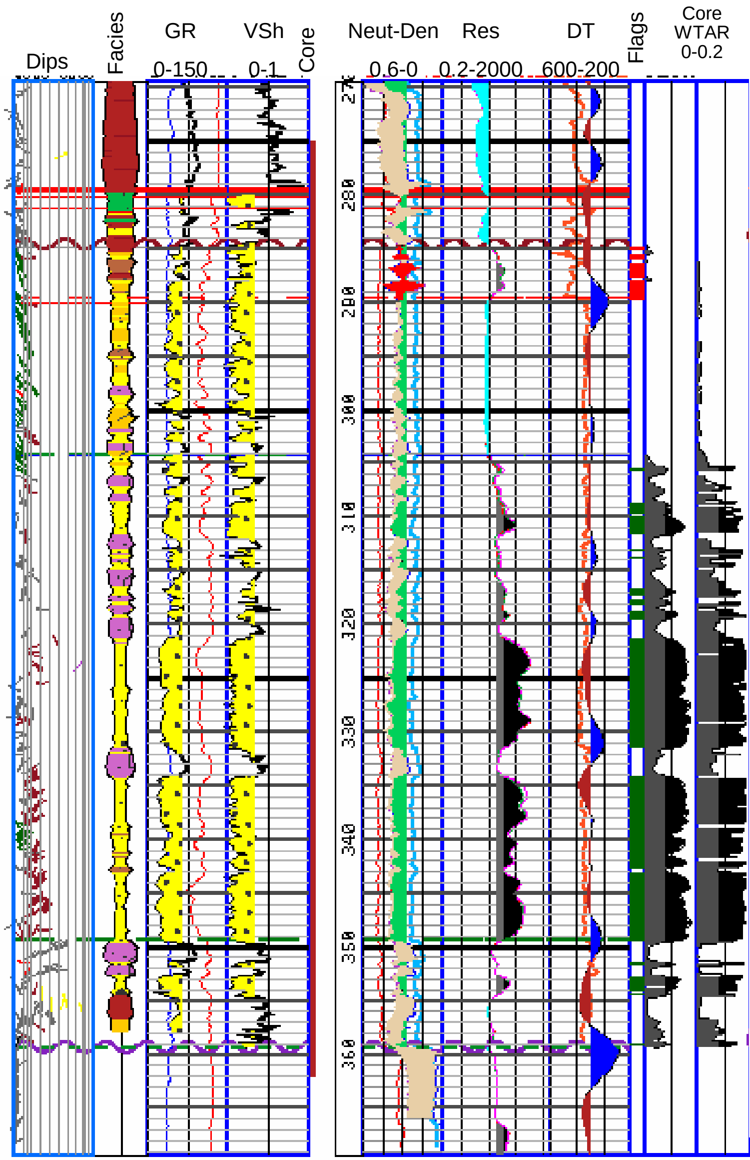
Example Log 100161408307w400

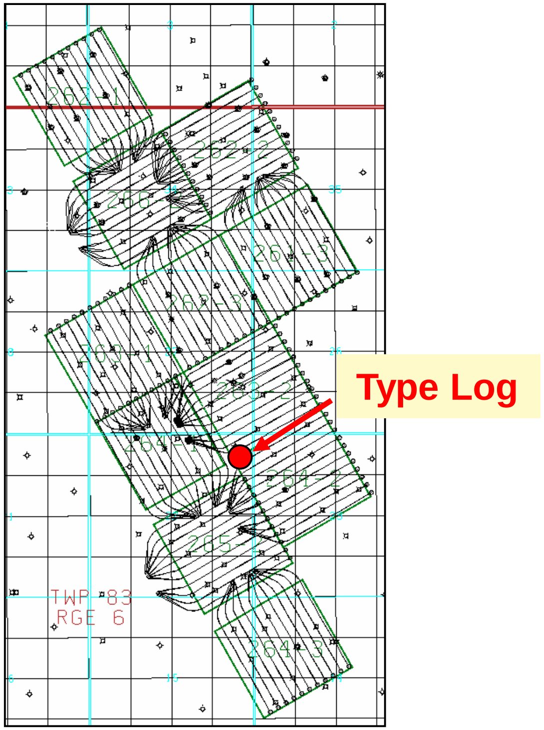


Phase 1 Area

Phase 2 Type Log – Well Pad 264-2

Example Log 100162208306w400





Phase 2 Area

Special Core Analyses Bitumen Viscosity Sampling

Objectives

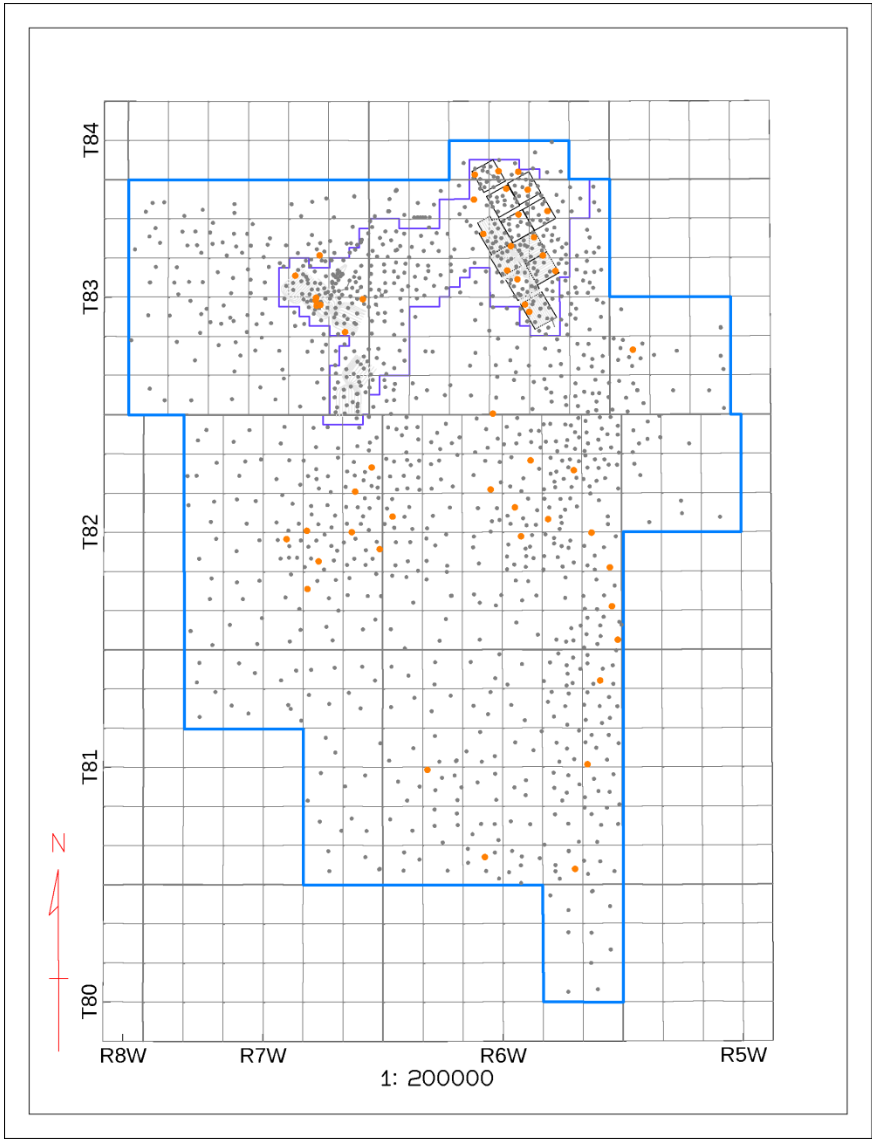
- Characterize vertical and lateral variance in viscosity at different temperatures
- Model the variance in bitumen properties and its implications for bitumen production rates during SAGD
- Characterize relationship between viscosity, density and geochemical composition

No change in 2014.

Viscosity increases with depth in the McMurray Formation.

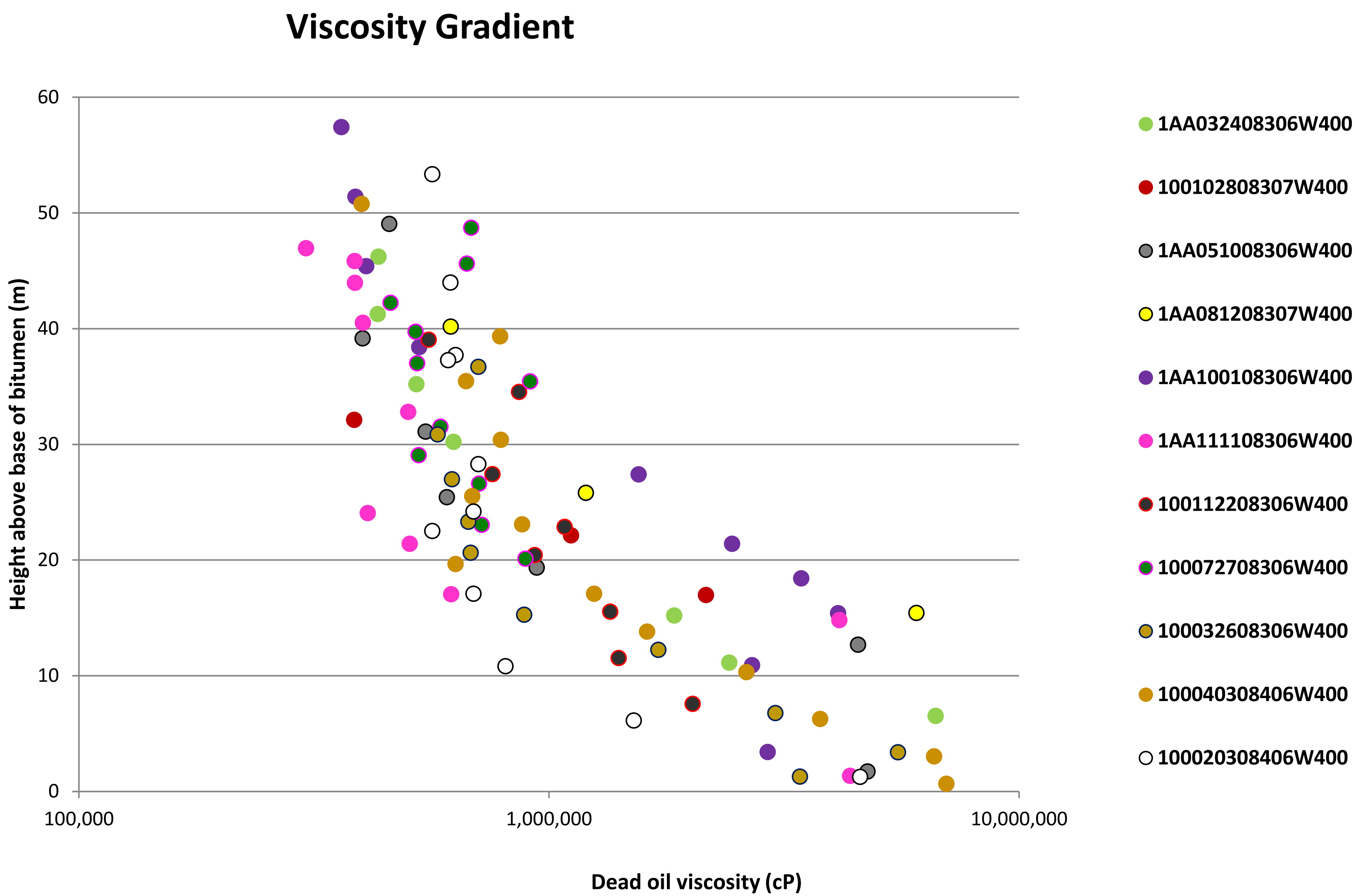
51 existing viscosity sample wells

Delineated Wells - Surmont



2013 – 2014 Delineation

Viscosity Gradient



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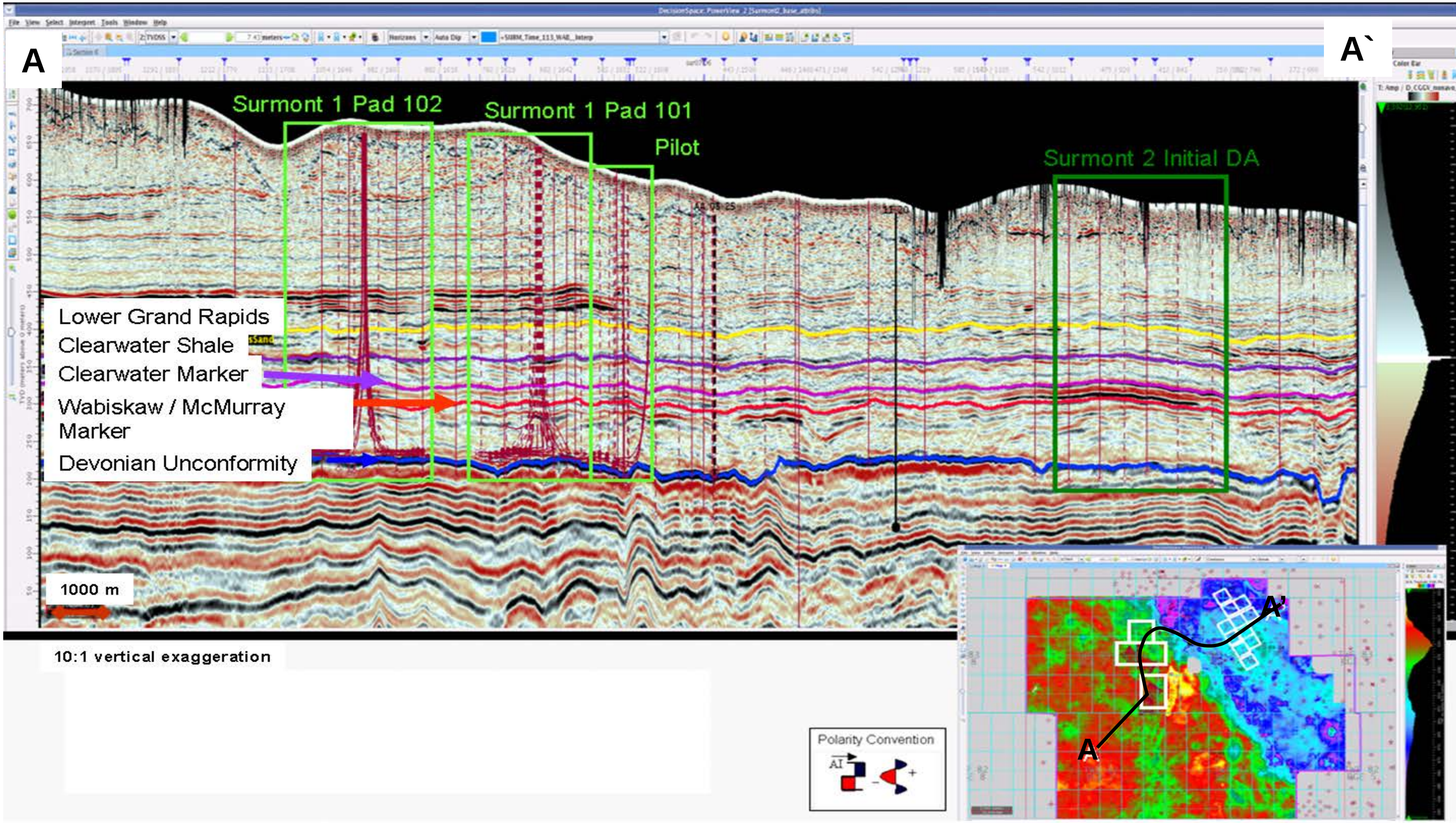
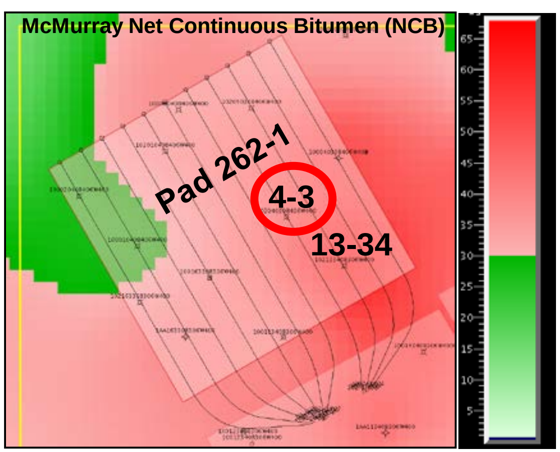
Representative Structural Cross Section

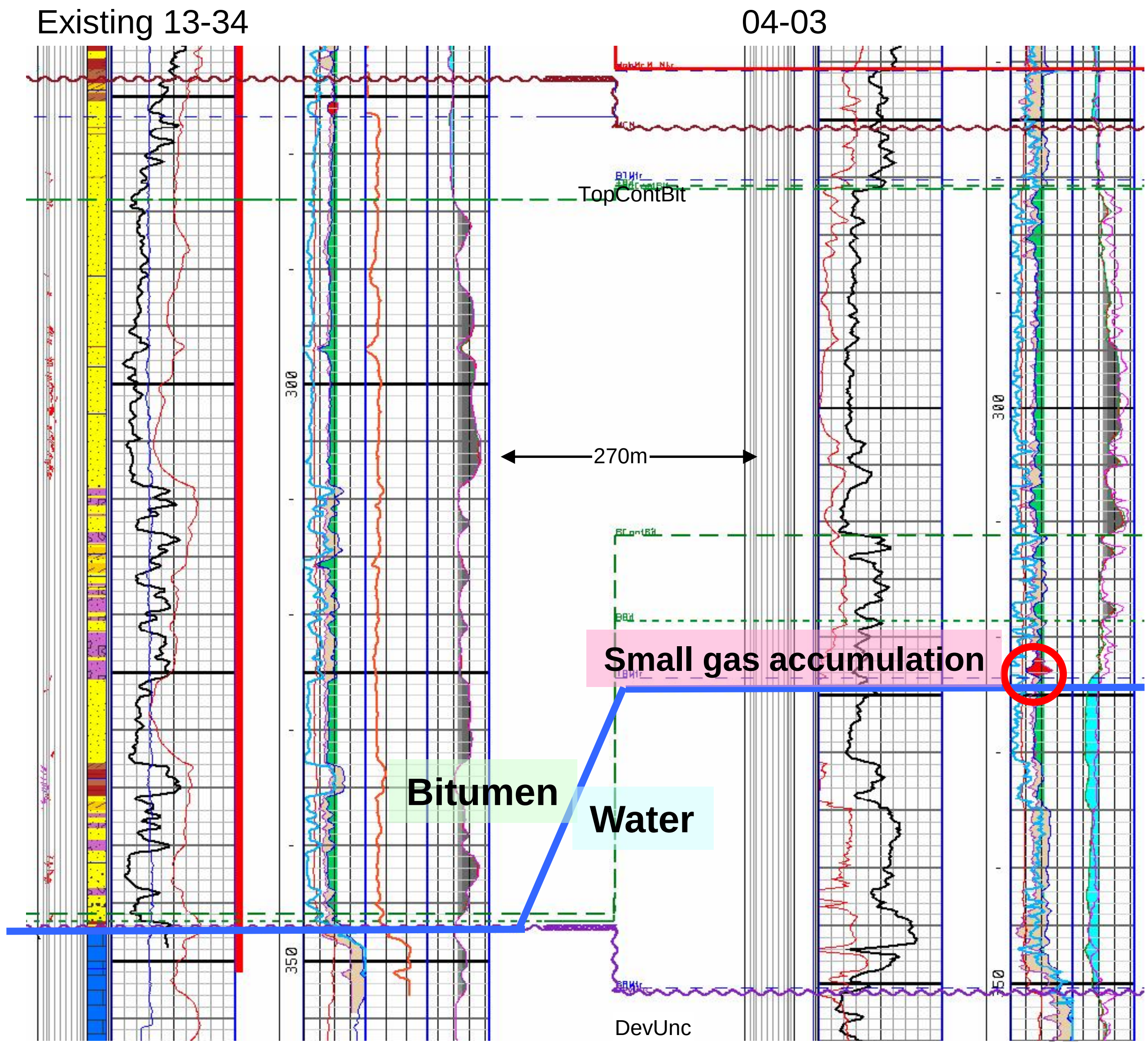


Well Pad 262-1 Variable Bitumen-Water Contact

- A well at 4-3-84-6 W4M intersected a raised bitumen/water contact, the contact is ~ 12 m higher than the nearest offset.
- The well also intersected a small gas pool under the bitumen.

- **The presence of basal water becomes a risk on Well Pad 262-1**



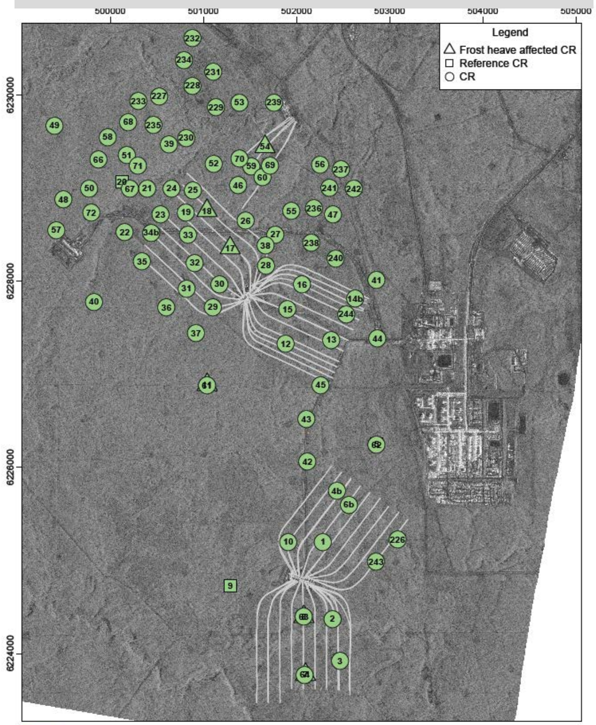


INSAR Surface Deformation Monitoring

- Interferometric Synthetic Aperture Radar Images
  - Data is collected every 24 days
- Data acquisition initiated after first steam in 2008
  - Data used for Geomechanical Model Calibration
  - CRs 1 to 20 installed March 2008
  - CRs 21 to 47 installed March 2010
  - CRs 48 to 72 installed March 2012
  - CRs 226 to 244 installed March 2014

- **Deformation currently in line with expectations**
- **Maximum deformation seen in CRs 29-33, over pad 101N.**
- **Several CRs were replaced in Spring 2014, including CR14 which was affected by frost heave.**

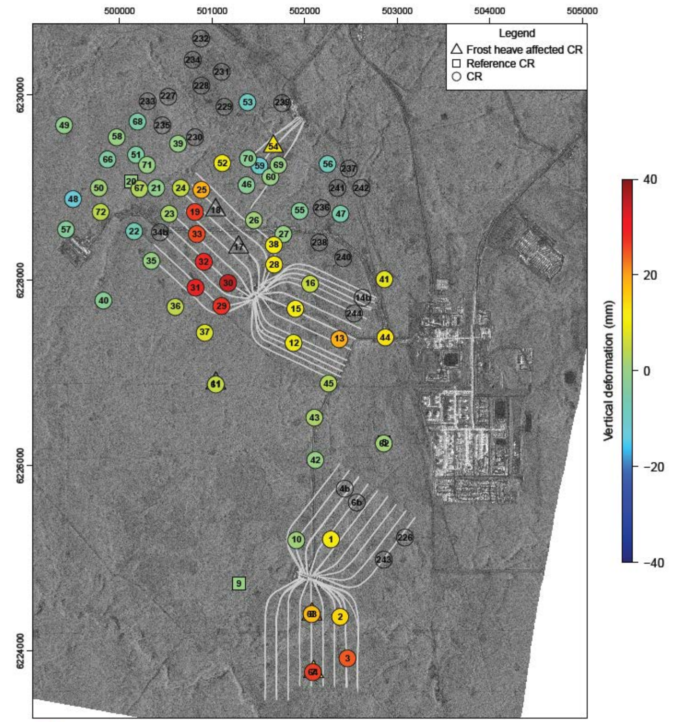
Location Map of CR Points



UTM 12N NAD27

MDA

Cumulative Deformation April 2012 to December 2014



UTM 12N NAD27

MDA

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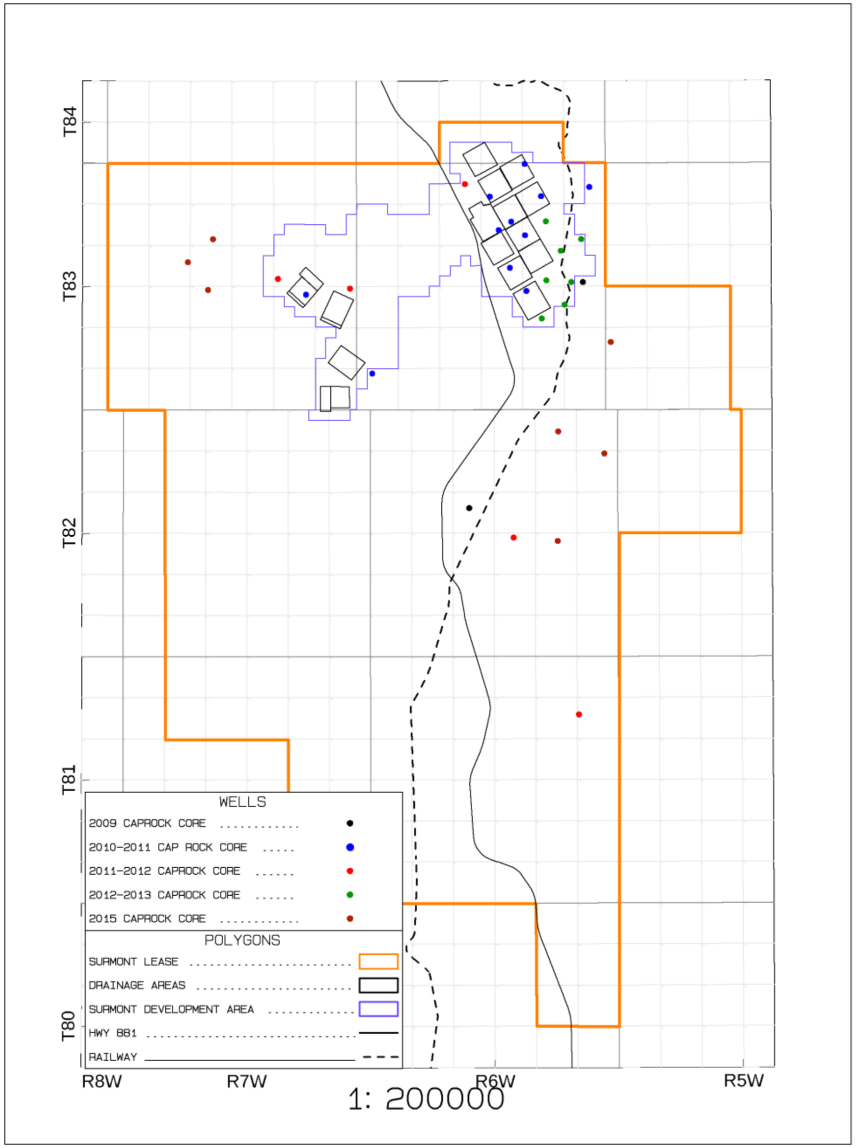
Caprock Integrity



- 7 new cap rock cores in 2015

- Cap rock interval investigation included:
  - Core description and analyses
  - Log interpretation and correlation
  - Seismic interpretation and correlation

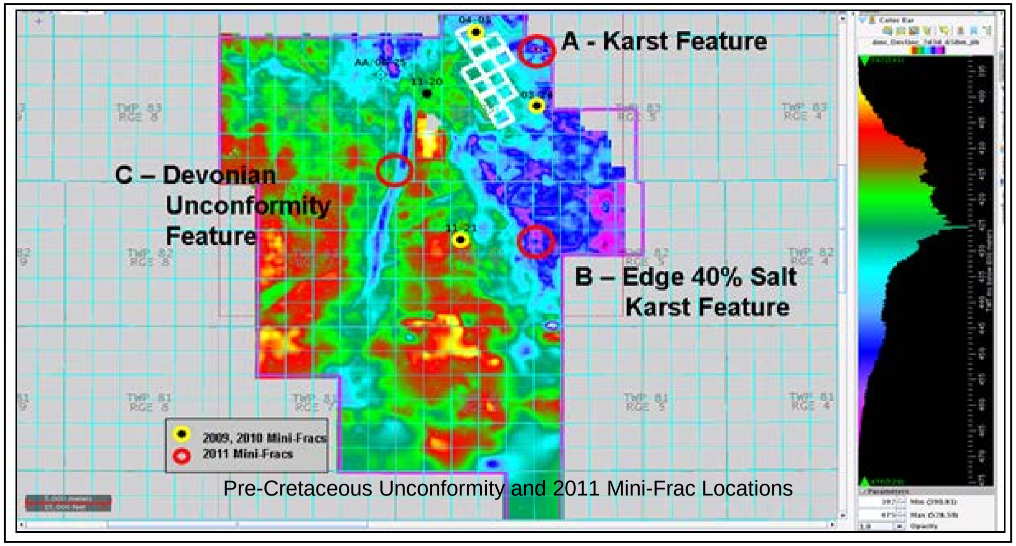
- Analytical methods included:
  - Visual core examination,
  - Reflected light microscopy,
  - Laser particle size analysis,
  - Biostratigraphic analyses,
  - X-ray diffraction for clay species,
  - QEMSCAN (quantitative mineralogy),
  - Chemostratigraphy (bulk geochemistry) and
  - MICP (mercury injection capillary pressure)

  analyses to determine seal capacity

Conclusions from the study:

- **The best seals within the cap rock interval are the deeper water deposits occurring on maximum flooding surfaces.**
- **These muds can be over 80% clay and are correlated throughout and beyond the Surmont lease.**

Maximum Operating Pressure



- Three mini-frac tests targeted the most structurally complex features currently identifiable across the lease based on mapped structures of the Devonian, McMurray, cap rock, and overburden.

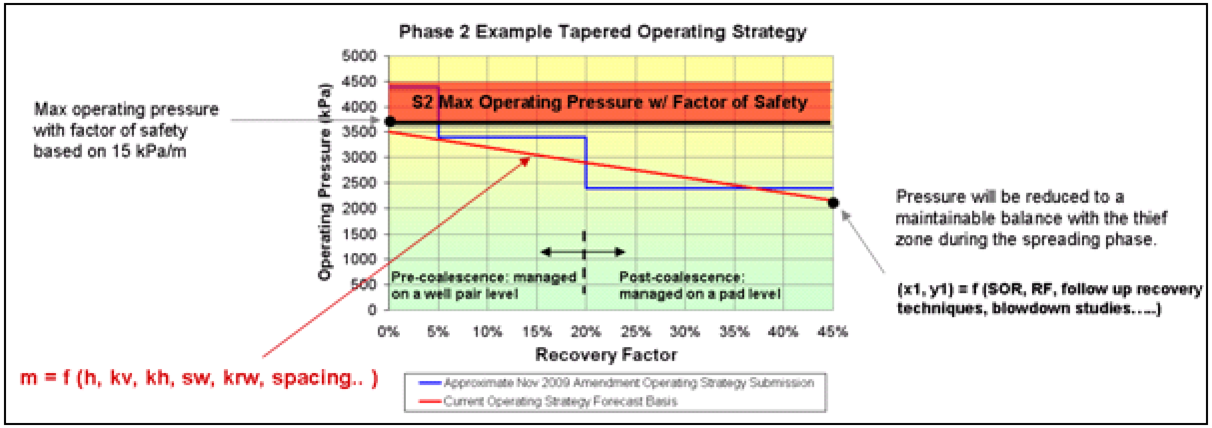
- All of the 2011 test locations were proposed to, and reviewed by the AER prior to execution of the tests. The locations include variability in other features such as proximity to gas depletion, overburden, karsting and other structural variability.

- Other Maximum Operating Pressure (MOP) supporting data, includes cap rock core samples subjected to tri-axial testing, log data, FMI interpretations, seismic, etc., combined with the overall cap rock characterization, reservoir simulation and geomechanical modeling.

Conclusions from the study:

- **In the 2011 testing, despite the varying conditions tested, the retained minimum stress gradient of the cap rock at 18.4 kPa/m was further validated .**
- **The recommended MOP gradient is 15 kPa/m (@SF=1.2) which is lower than previous by applying a higher factor of safety.**

Operating Strategy



- Based on the cap rock integrity studies, ConocoPhillips has proposed a maximum pressure of 15kpa/m.

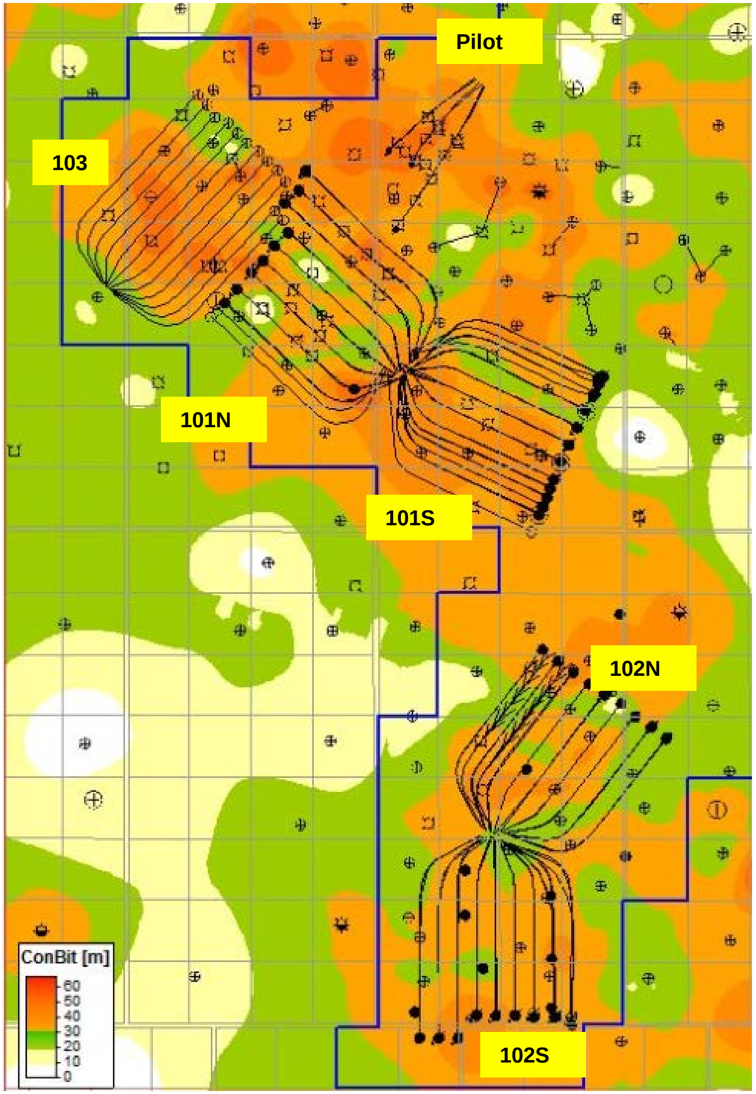
- Circulation optimization including dilation is an area of ongoing study.

- Pace of pressure drops will be largely driven by:
  - Specific, local reservoir properties,
  - Thief zone interactions,
  - Economics,
  - ESP installations,
  - Plant capacity, and
  - Global steam optimization.

ConocoPhillips continues to propose a flexible tapered strategy envelope bound by the cap rock integrity study and the associated MOP on one side and economic achievable pressures on the low side

Subsection 3.1.1 (3)
Drilling and Completions

Well Summary

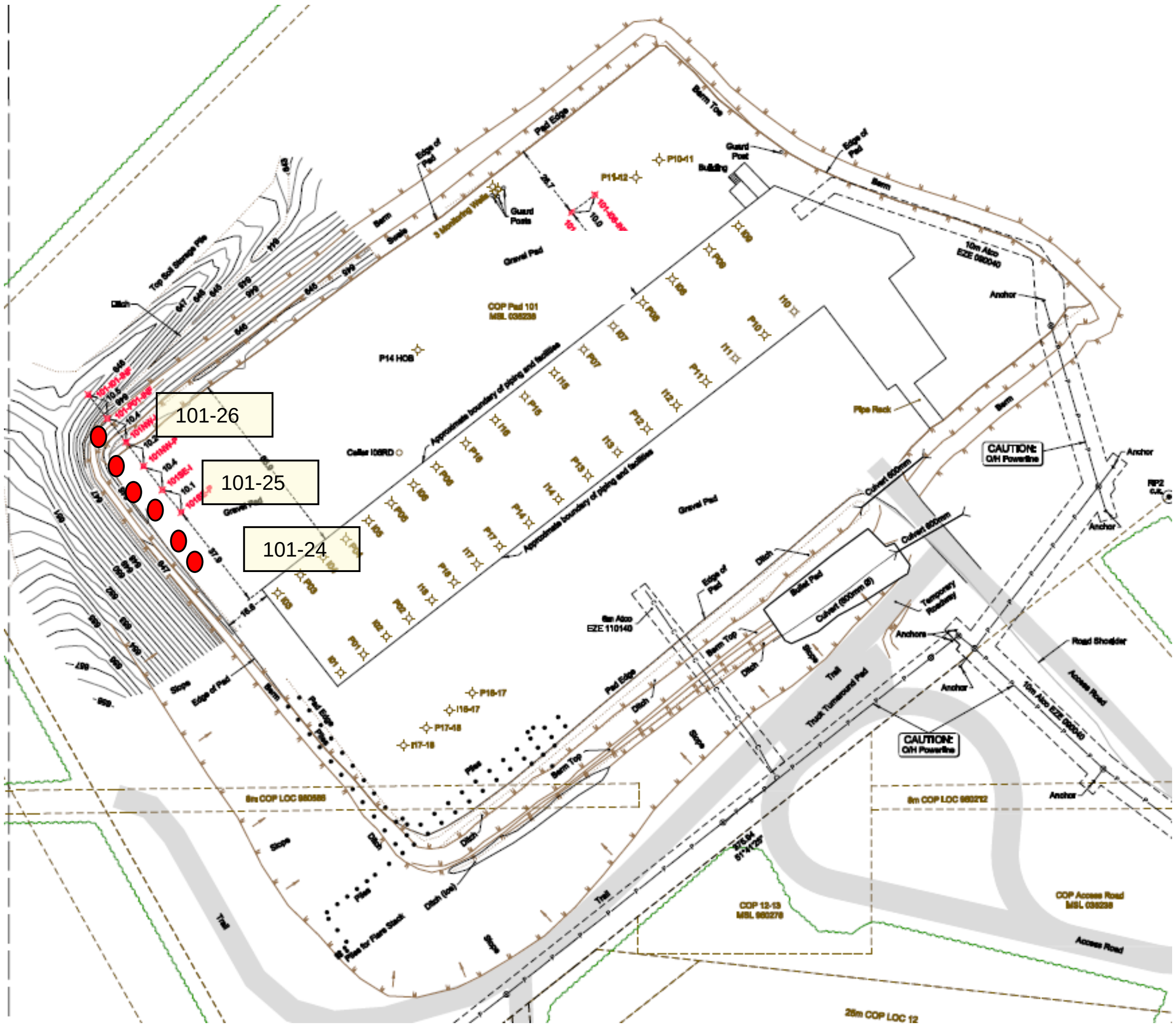


- 6 drainage areas
  - Pilot
  - 101 North
  - 101 South
  - 102 North
  - 102 South
  - Pad 103
- 56 well pairs, 4 infill producers

Pilot (3 well pairs)
Phase 1A (21 drilled – 20 completed)
Phase 1A redrills (3 wells)
Phase 1B (7 drilled – 7 completed)
Phase 1C (8 drilled well pairs – 8 completed)
Pad 101 South 2011-2012 Infills
Pad 103 (12 pairs drilled – 2 inj. wells completed)

Pad 101 Plot Plan

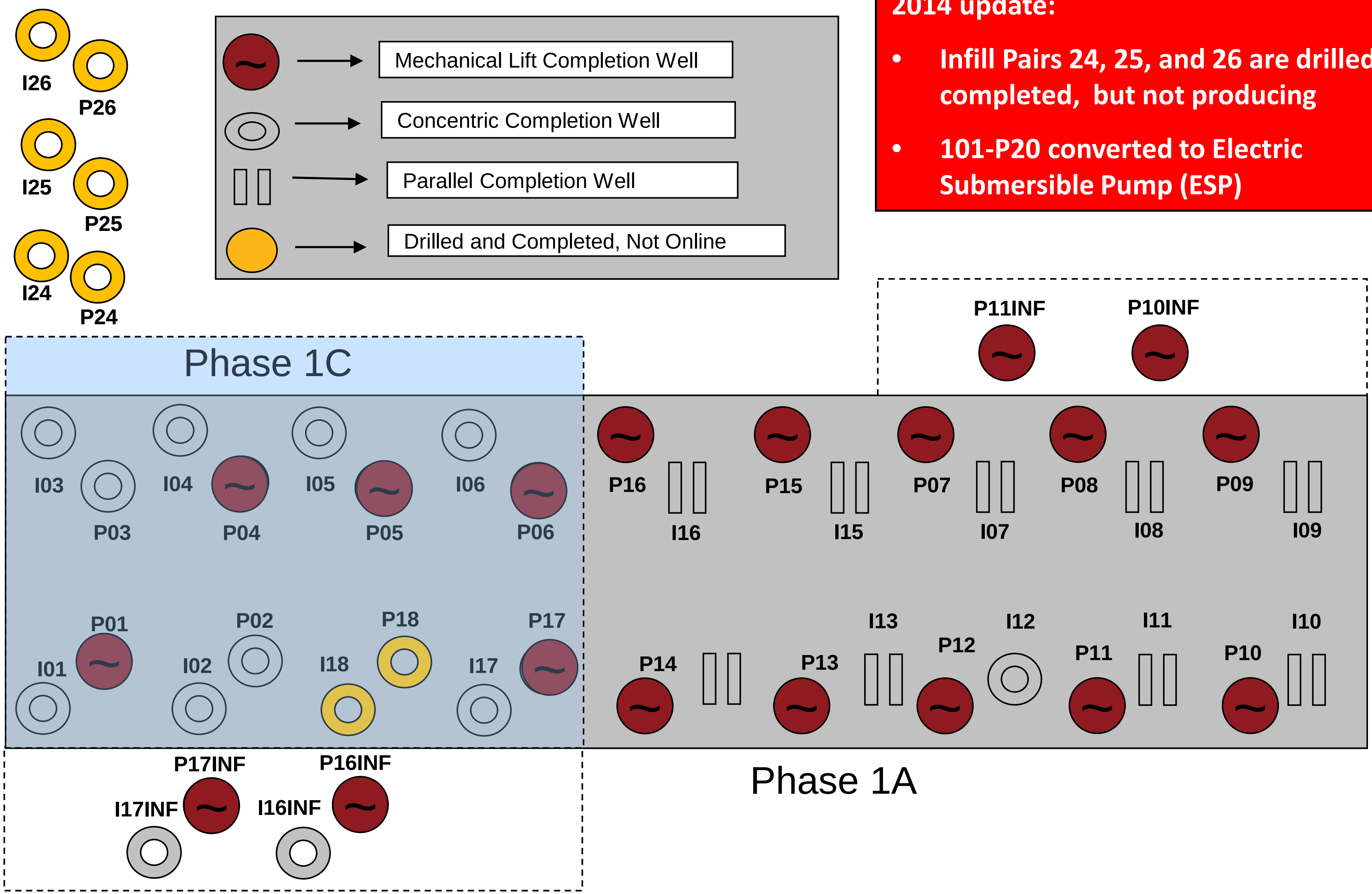
Surface Well Name	Downhole Well Name
101-01	101-10
101-02	101-11
101-03	101-12
101-04	101-13
101-05	101-14
101-06	101-17
101-07	101-18
101-08	101-02
101-09	101-01
101-10	101-03
101-11	101-04
101-12	101-05
101-13	101-06
101-14	101-16
101-15	101-15
101-16	101-07
101-17	101-08
101-18	101-09
101-19	101S16INF1
101-20	101S17INF1
101-21	101S10INF1
101-22	101S11INF1
101-24	101-24
101-25	101-25
101-26	101-26



Pad 101 Completions

2014 update:

- Infill Pairs 24, 25, and 26 are drilled and completed, but not producing
- 101-P20 converted to Electric Submersible Pump (ESP)



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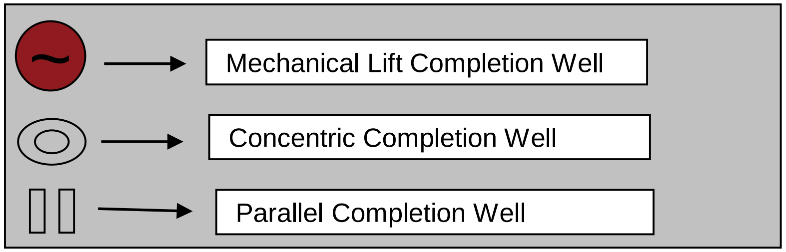
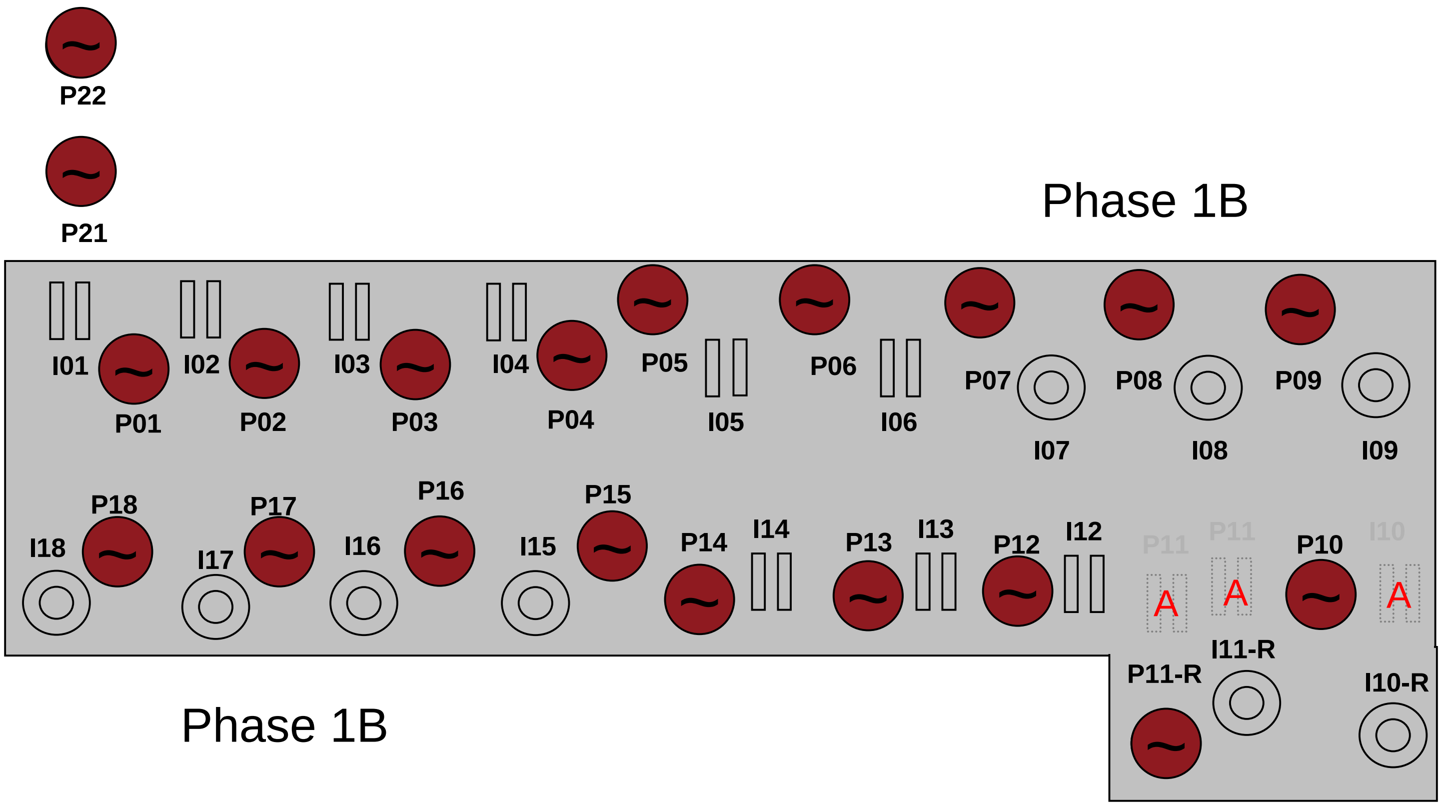
Pad 102 Completions



2014 Update:

- **Infill producers 21 and 22 Completed**



Pad 101 & 102 Well Completions

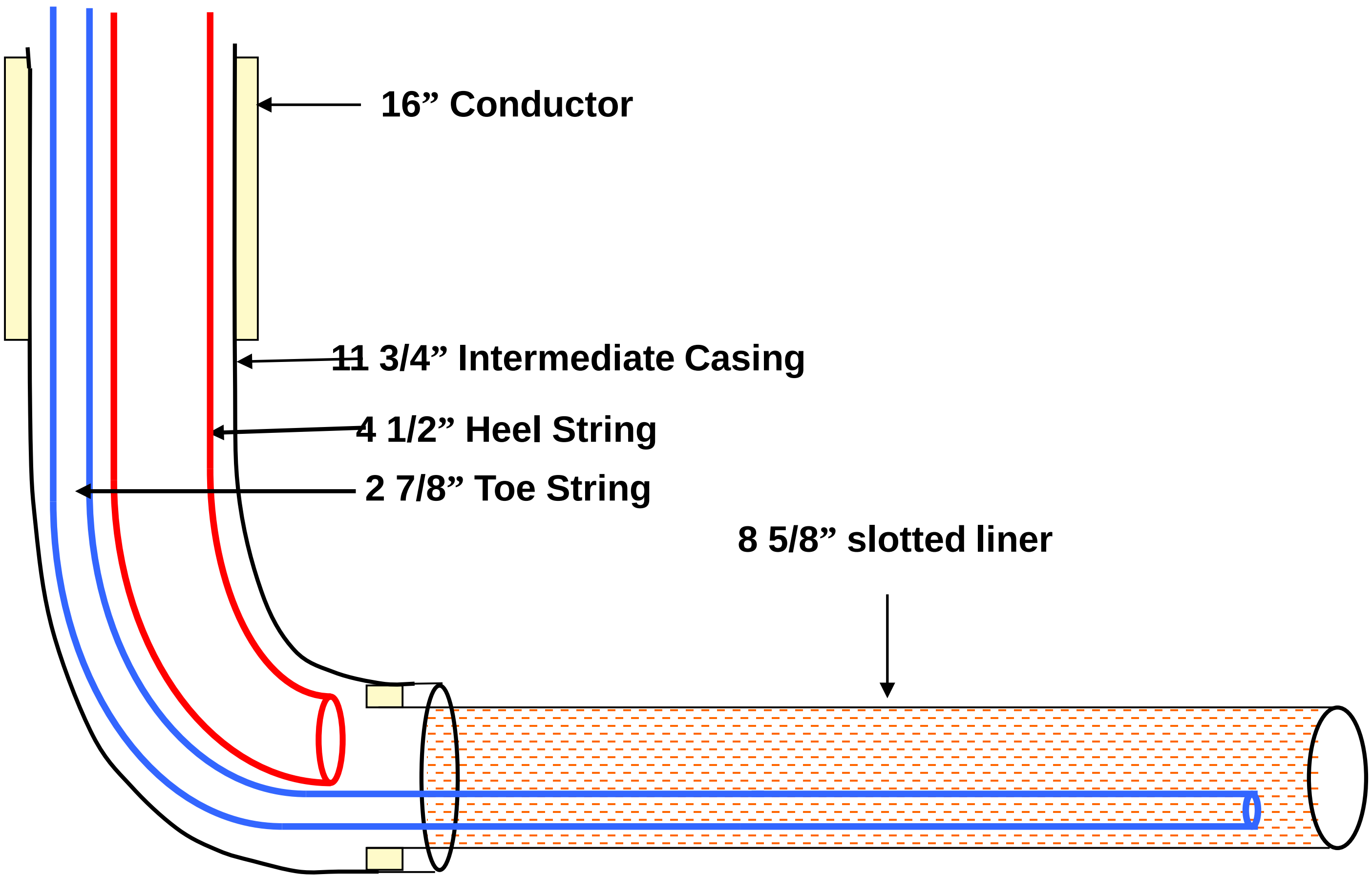
Well Identifier Surface (Downhole)	Producer Completion	Injector Completion
101-01 (10DH)	ESP	Parallel
101-02 (11DH)	ESP	Parallel
101-03 (12DH)	ESP	Concentric
101-04 (13DH)	ESP	Parallel
101-05 (14DH)	ESP	Parallel
101-06 (17DH)	ESP	Concentric
101-07 (18DH)	Concentric	Concentric
101-08 (02DH)	Concentric (Gas Lift)	Concentric
101-09 (01DH)	ESP	Concentric
101-10 03DH)	Concentric (Gas Lift)	Concentric
101-11 (04DH)	ESP	Concentric
101-12 (05DH)	ESP	Concentric
101-13 (06DH)	ESP	Concentric
101-14 (16DH)	ESP	Parallel
101-15 (15DH)	ESP	Parallel
101-16 (07DH)	ESP	Parallel
101-17 (08DH)	ESP	Parallel
101-18 (09DH)	ESP	Parallel
101-19 (17INF)	ESP	Concentric
101-20 (16INF)	ESP	Concentric
101-21 (10INF)	PCP	N/A
101-22 (11INF)	PCP	N/A

← This well is not online

Well Identifier Surface	Producer Completion	Injector Completion
102-1	ESP	Parallel
102-2	ESP	Parallel
102-3	PCP	Parallel
102-4	ESP	Parallel
102-5	ESP	Parallel
102-6	ESP (FCD)	Parallel (FCD)
102-7	ESP	Concentric
102-8	ESP	Concentric
102-9	ESP	Concentric
102-10	ESP	Concentric
102-11	ESP	Concentric
102-12	ESP	Parallel
102-13	ESP	Parallel
102-14	ESP	Parallel
102-15	ESP	Concentric
102-16	ESP	Concentric
102-17	ESP	Concentric
102-18	ESP	Concentric
102-21 (INF)	PCP	N/A
102-22 (INF)	PCP	N/A

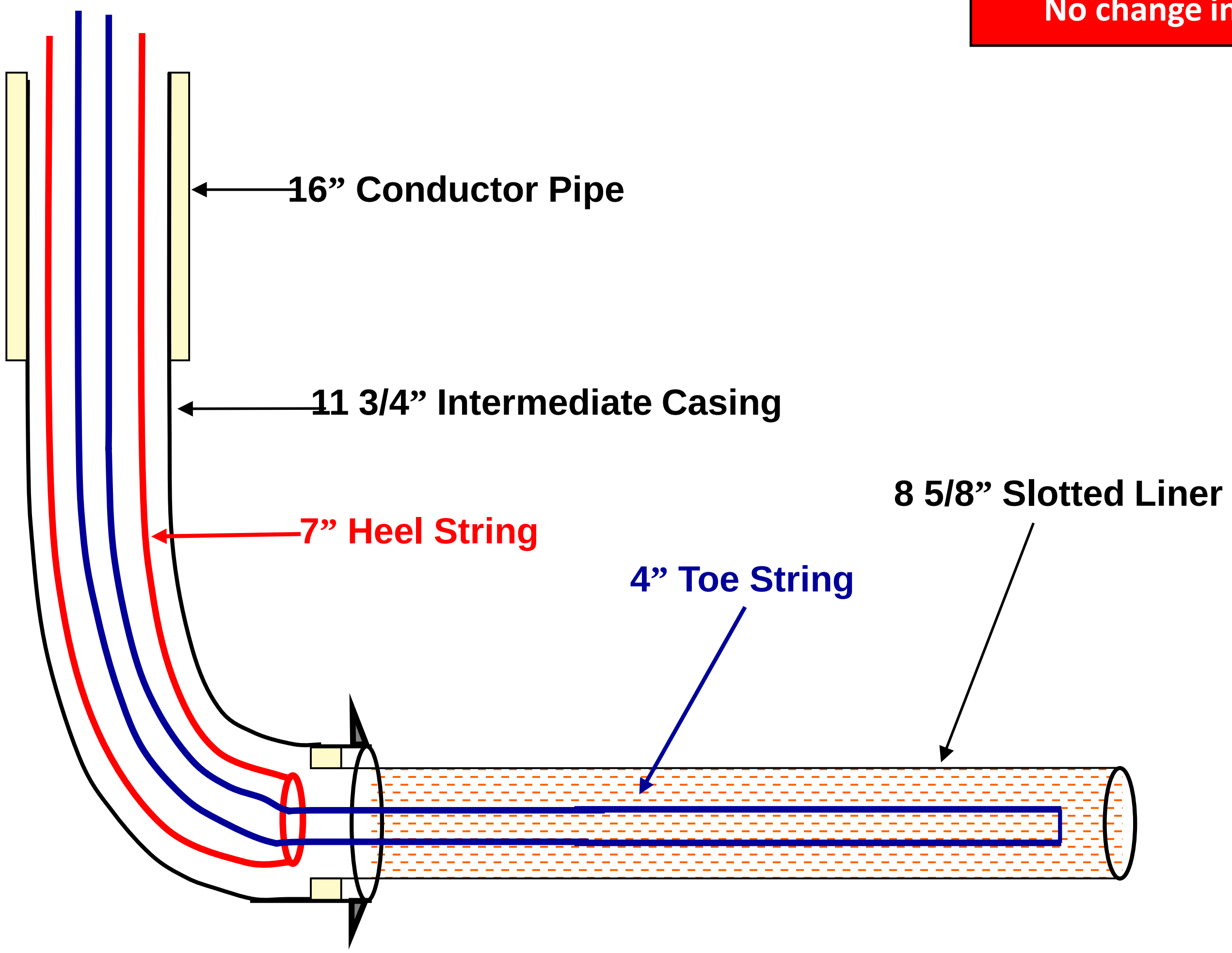
Phase 1 Typical Parallel Injector

No change in 2014



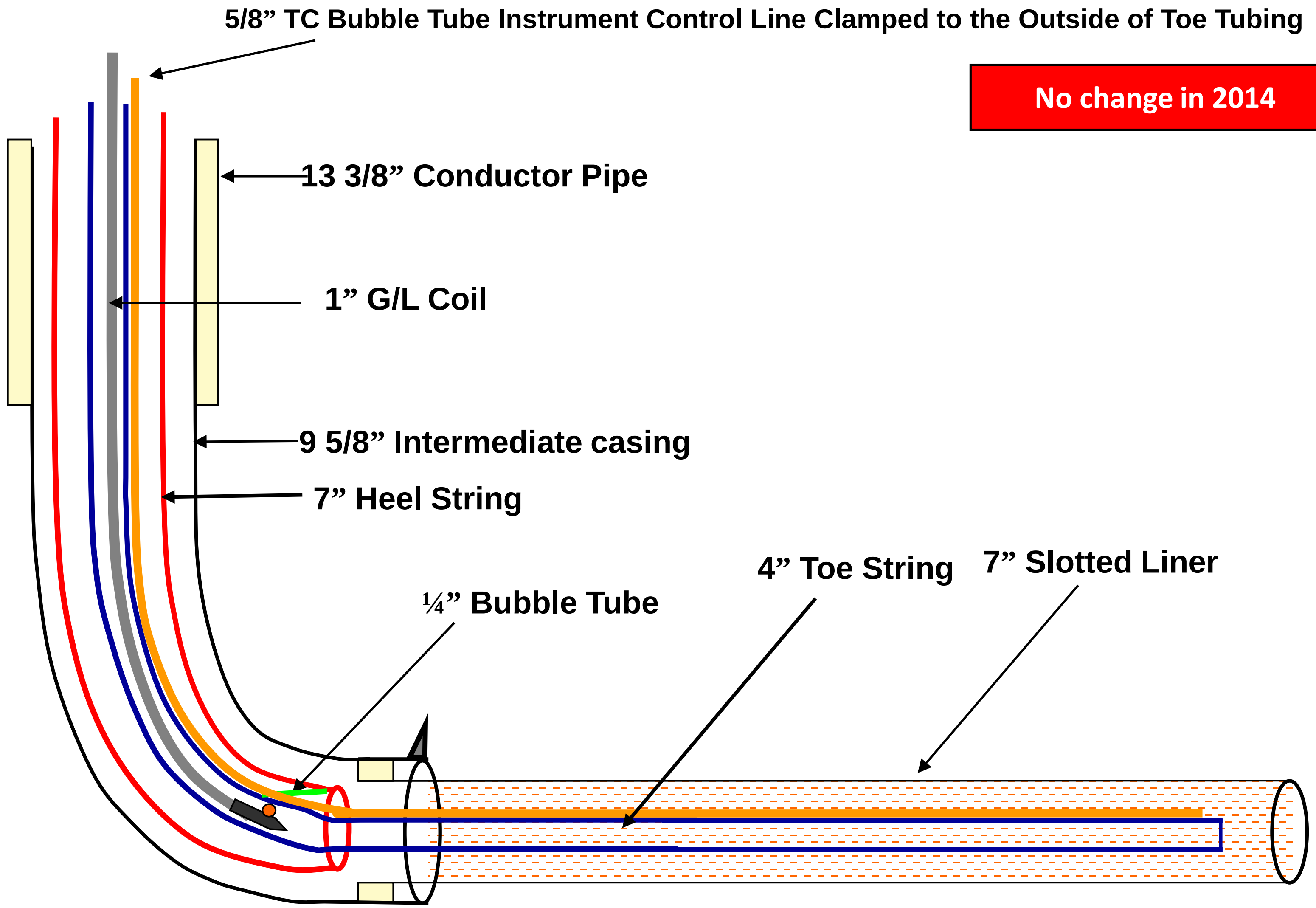
Phase 1 Typical Concentric Injector

No change in 2014



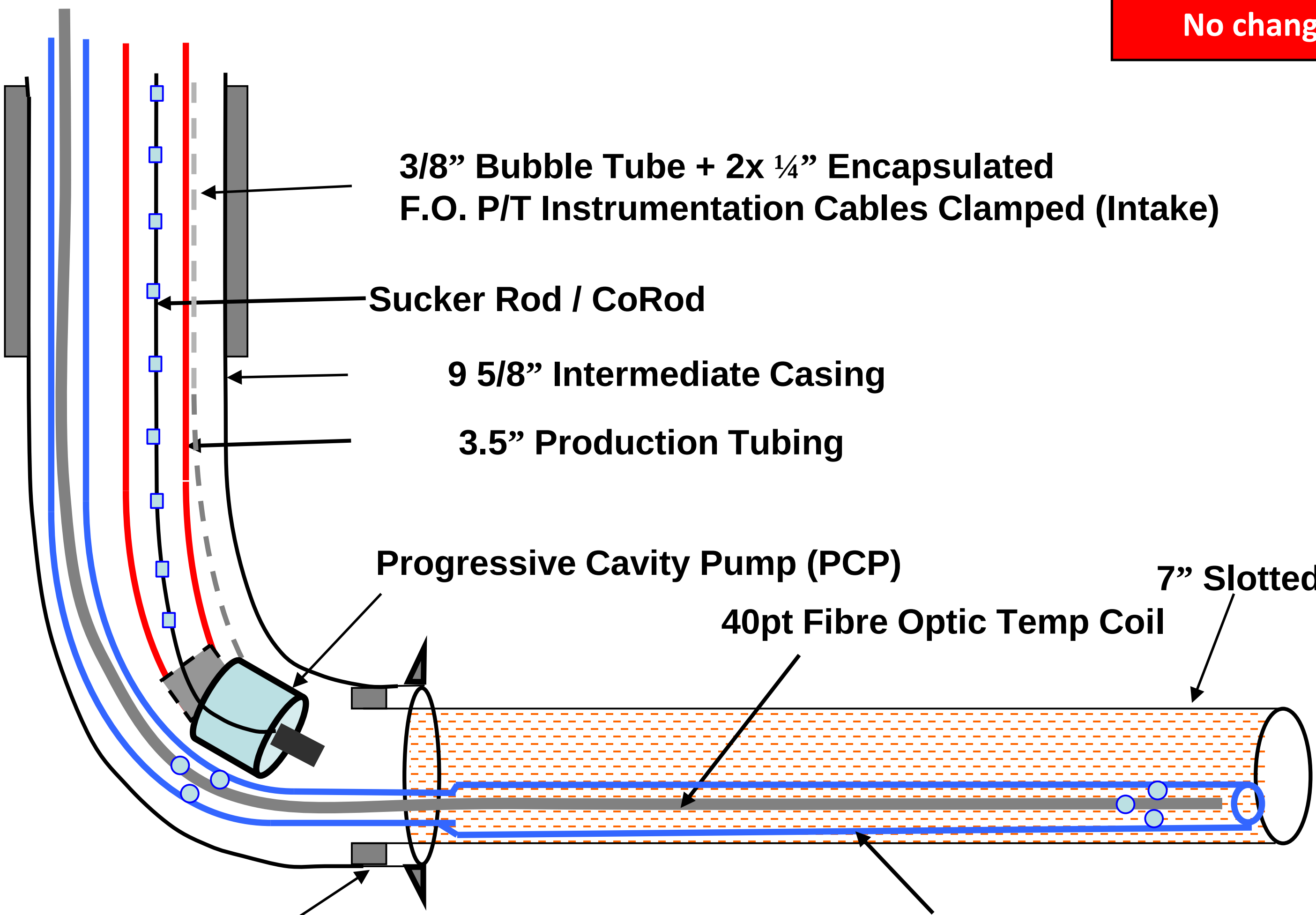
Phase 1 Typical Concentric Producer

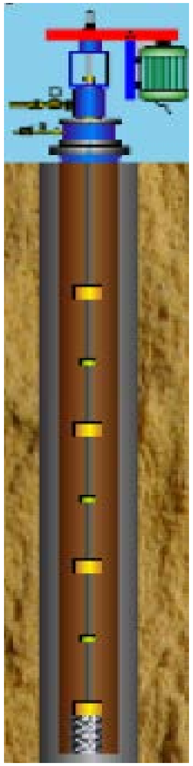
No change in 2014



Phase 1 Typical PCP Producer

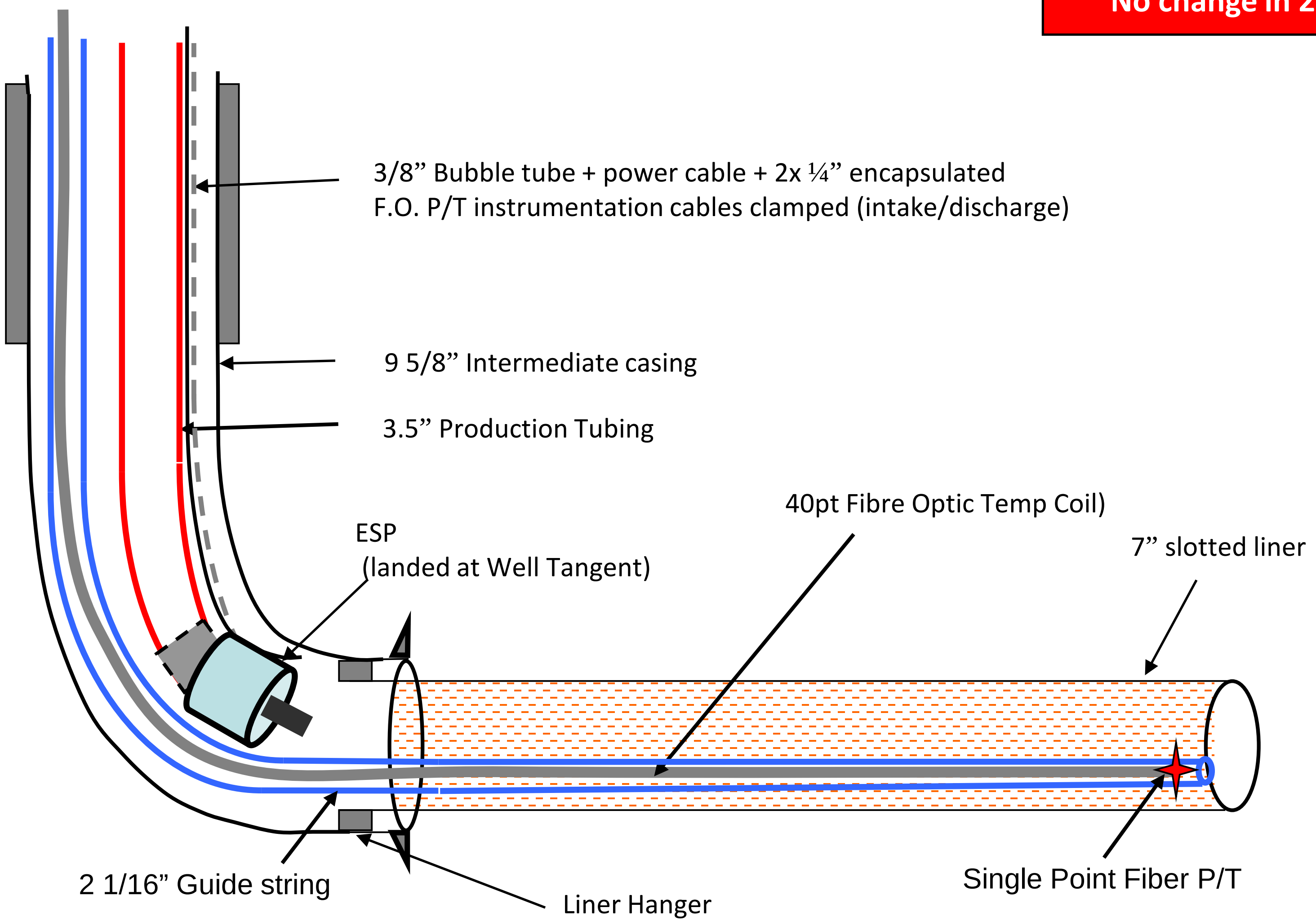
No change in 2014



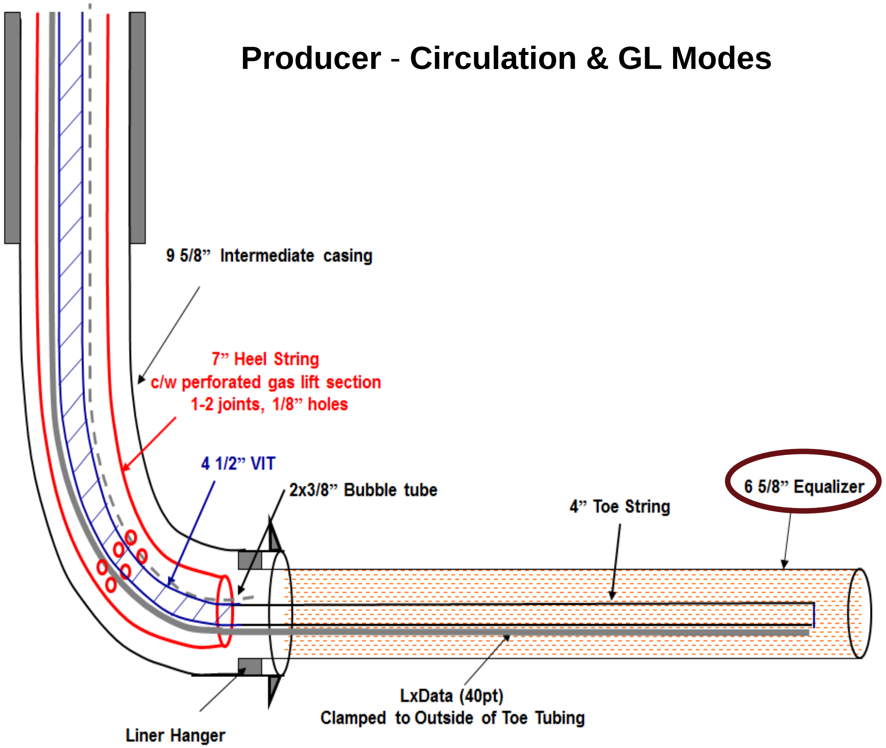


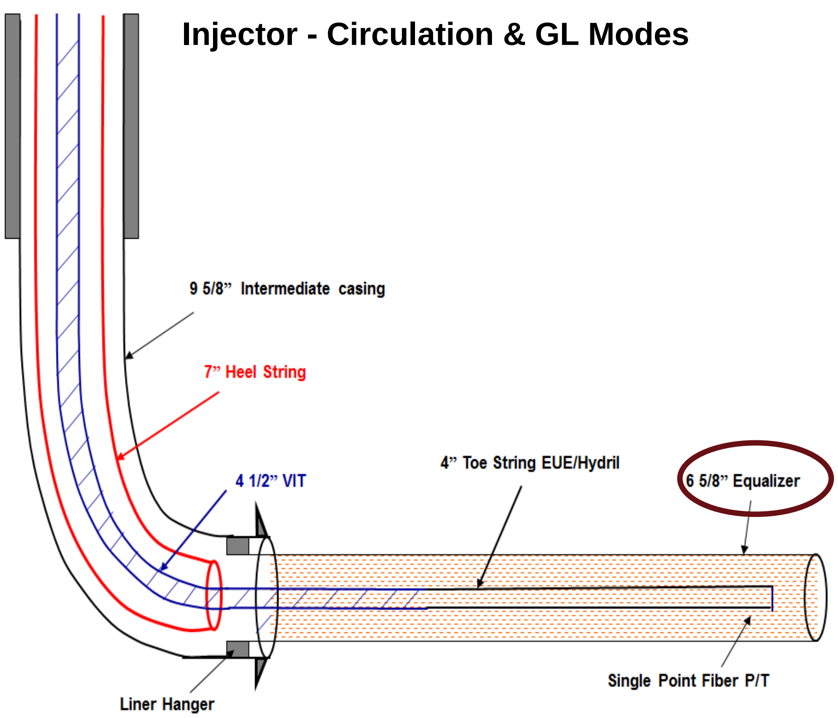
Phase 1 Typical ESP Producer

No change in 2014



2013 Infills on Pad 101 & Pad 102 have Flow Control Devices Installed





Typical Flow Control Device Completion

Short and long tubing strings during SAGD production:

- During initial circulation a toe tubing string is required, however due to the equalizing character of the FCDs a toe tubing string is not required.
- This concept was tested in the pilot well pair, 102-06, which showed that we could pull back the toe strings to the heel and still have good steam and production performance. However, depending on the injected steam rates, the toe presence of the toe string may not add significant pressure drop along the lateral in the case of the injector well and may not warrant the workover to pull back or remove the string.
- The option exists and can be evaluated on a well or pad level.
- The similar option exists for the producer well and the lateral instrumentation could be run on a separate coil. Again, this option could be evaluated on a well or pad level.

Subsection 3.1.1 (4)
Artificial Lift

Artificial Lift Types

Gas Lift

- Gas lift is effective with bottomhole operating pressures >3,000 kPa.
- Current production rates range from 100 m^3/d to 700 m^3/d of emulsion targeting 3,500 kPa

Electric Submersible Pump (ESP)

- ESP for thermal SAGD applications can be sized to meet the specific deliverability of the well.
- High temperature ESPs can operate at bottom hole temperatures up to 275 ºC.

Progressive Cavity Pumps (PCP)

- Generally PCPs have been used for low deliverability wells and where potential solids may be produced.*

* ConocoPhillips initial strategy for PCPs was to use them on low deliverability wells where the current ESP designs are deems less appropriate. However, installation of larger PCP are being considered for wells that may produce relatively “cold” viscous fluid for some time.

Artificial Lift Strategy

The artificial lift mode selection is reliant on the pressure strategy for any given well, or drainage area (DA).

- Phase 1A & C wells utilized Gas Lift (GL) and then converted to ESP after steam chamber coalescence.
- Only 2 wells in Pad 101 remain on GL at the end of 2014. The wells are scheduled for ESP conversion in 2015.
- PCP have been selected on wells where the initial deliverability may be low due technology trials, such as the infill fishbones producers on Pad 102. These wells may be converted to ESP after further on-stream evaluation.

Artificial Lift Performance

Population (on production):

- 34 ESP wells,
- 4 Infill PCP (101-10INF1, 101-11INF1, 102-21, 102-21)*,
- 1 PCP after GL (102-03)*, and
- 2 Gas Lift wells (101-02, 101-03)*

2014 Key Decisions:

- Installation of "Slim" ESP on two wells
    - (102-14, 102-16)*.
- Installation of GE ESP.

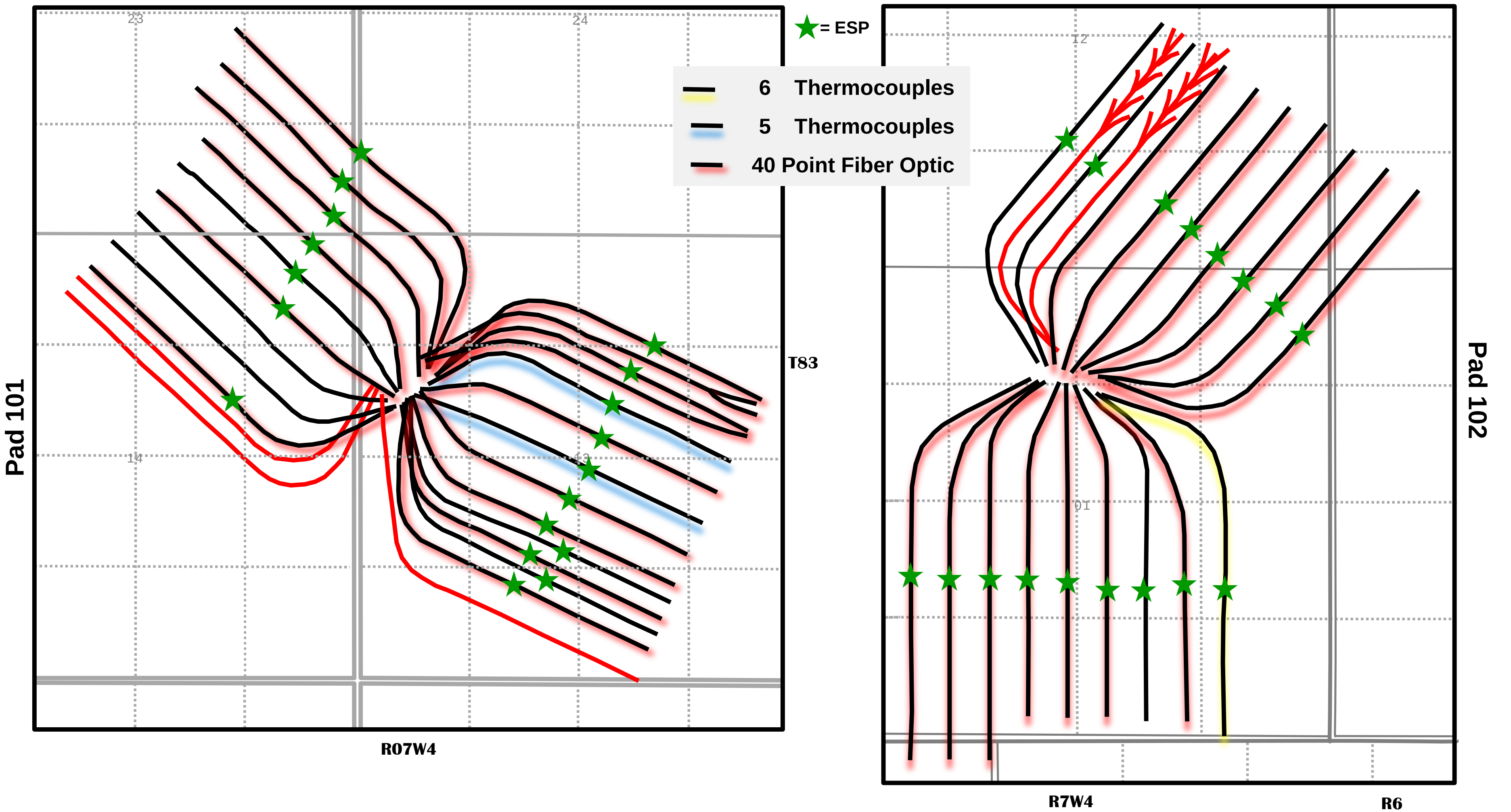
Update:

- 9 ESP failures total
- 2 ESP Proactive replacements
- ESP Average Runtime failed = 13 months
- ESP Mean Time To Failure: 27.9 months
- PCP Average Runtime failed = 1 month
- PCP Mean Time To Failure: 25.6 months

* Down hole locations

Subsection 3.1.1 (5)
Instrumentation in Wells

SAGD Well Instrumentation



- All ESP/PCPs are equipped with 40 point fiber optic
  - 101-03 and 101-05 are the only ESP conversions equipped with thermocouples (first ESP completions) with 5 points
- Heel instrumentation includes a bubble tube

Newly converted wells in 2014

- Pad 101 – 101-20 (16 INF)
- Pad 102 – 102-10

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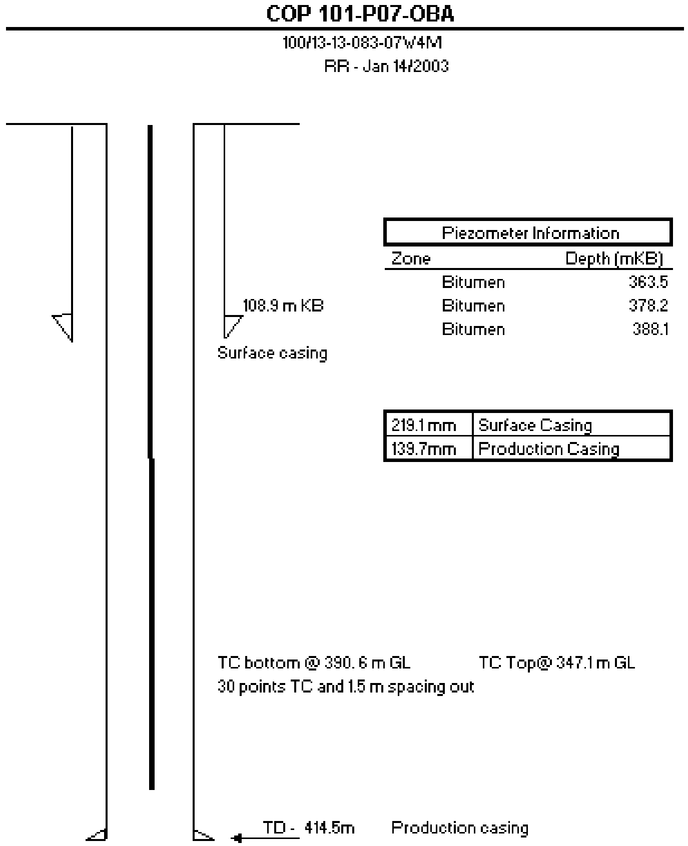
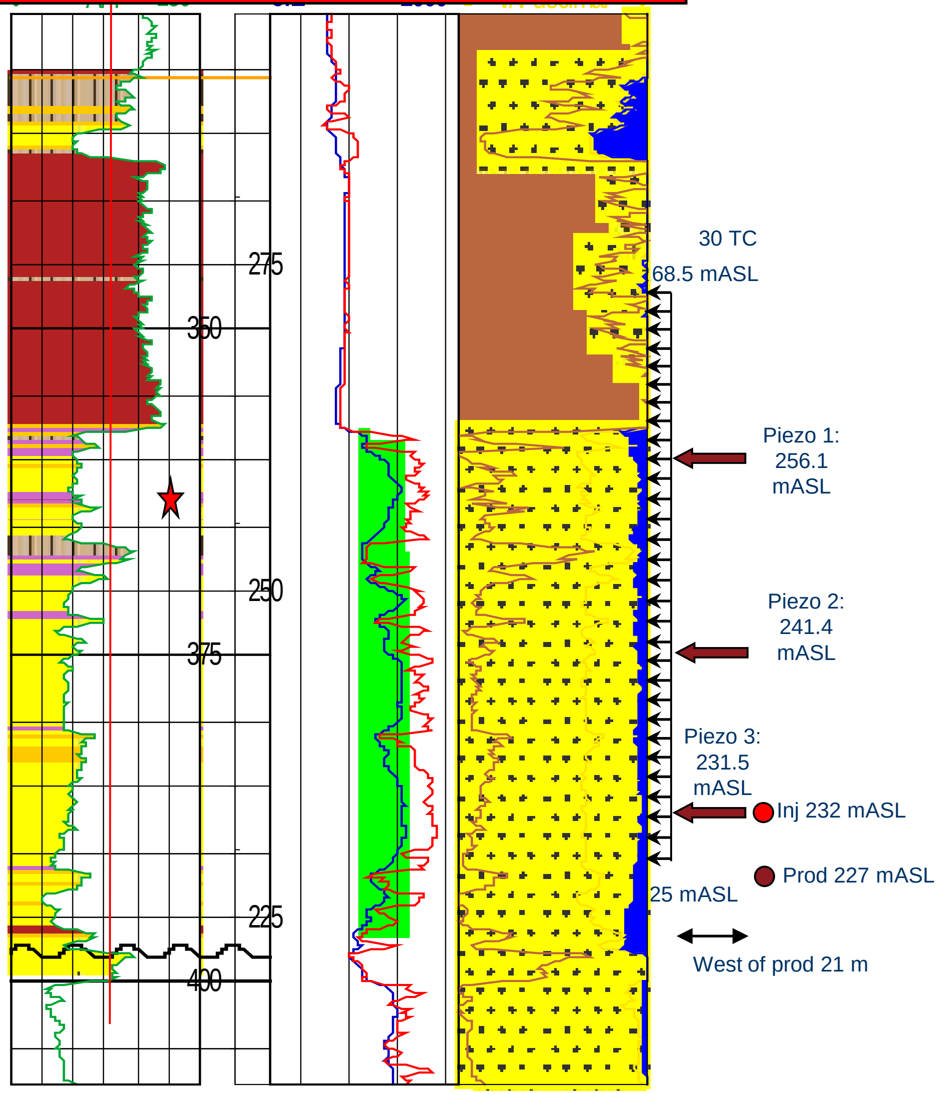
Typical Observation Well Measurement

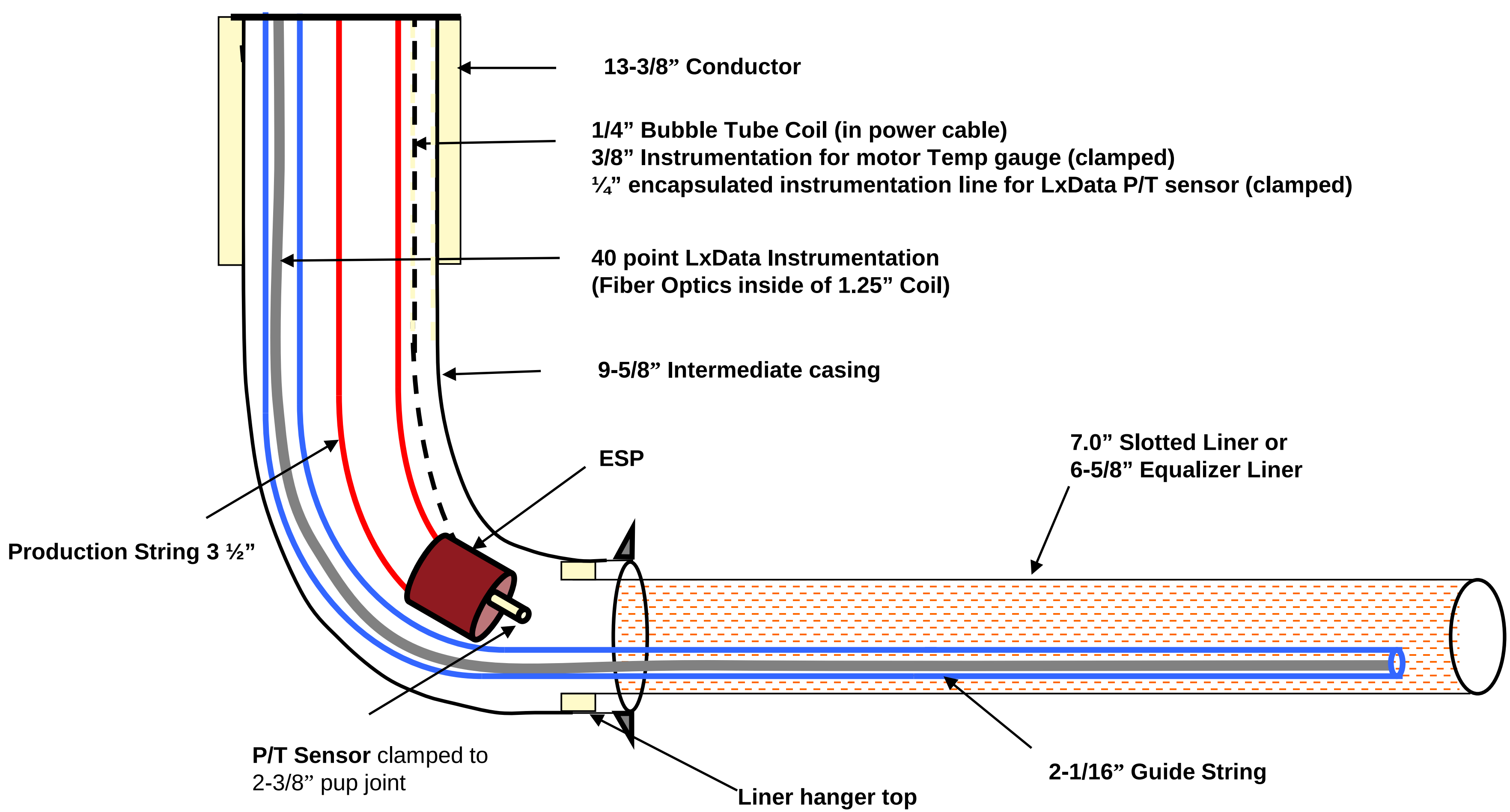
Soft cable Thermocouple (TC) strings were replaced by hard cable TC strings for improved well integrity

- Example thermocouple and piezometer (101-07-OBA)
- Typically 30 TC (1.5 m spacing)
- 2-3 piezometers placed at varying intervals





Typical ESP Well Configuration



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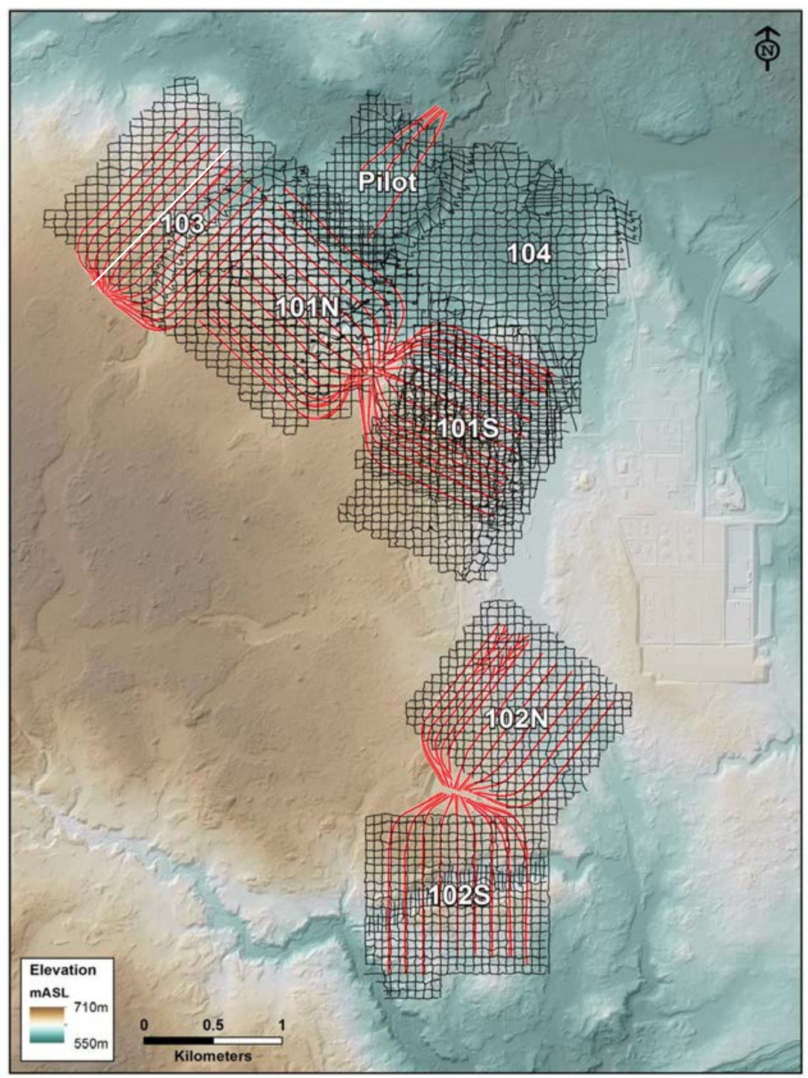
2014 Instrumentation Program Summary

- Lateral instrumentation is key to ensure proper well performance monitoring and integrity (for slotted liners).
- Pressure monitoring redundancy/backup in ESP wells is needed to avoid significant production losses or unnecessary ESP pulls.
- For circulation optimization, fibre optic pressure measure at the toe of the well will be incorporated in new well completions.

Subsection 3.1.1 (6)
4D Seismic

4D Seismic Location Map

Phase 1 Area



Pilot

- Buried analog single component geophones
- Cased dynamite shots (1/4 Kg) @ 9 m
- 13th monitor acquired in September 2014

Pad 101N

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 6th and 7th monitor acquired in March and September 2014

Pad 101S

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 8th monitor acquired in March 2014

Pad 102N

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 8th monitor acquired in April 2014

Pad 102S

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 5th monitor acquired in April 2014

Pads 103 and 104

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- Baseline acquired in April 2012

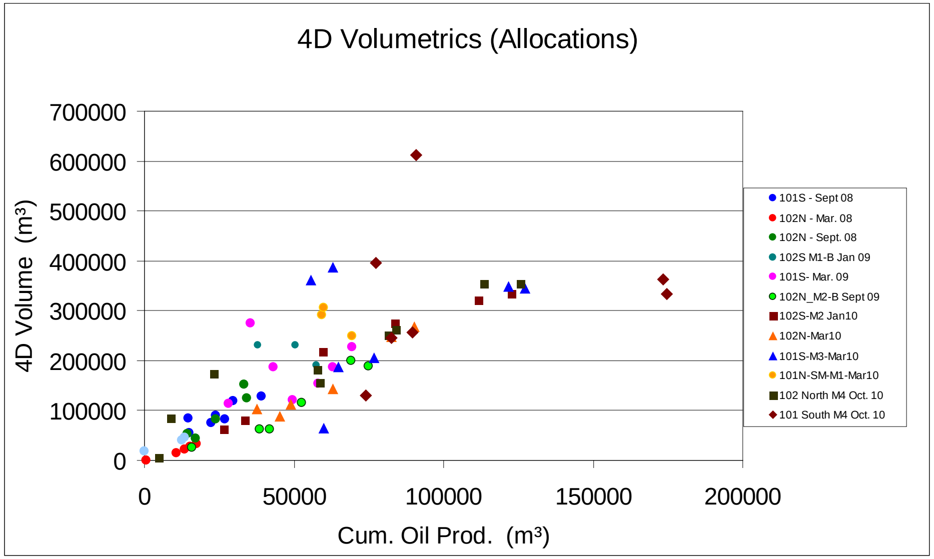
Phase 1 4D Seismic Program

PAD	2011		2012		2013		2014	
	Spring	Fall	Spring	Fall	Spring	Fall	Spring	Fall
101N			M	M	M	M	M	M
101S	M		M		M		M	
102N	M		M		M		M	
102S	M		M				M	
Pilot		M		M		M		M
103			B					
104			B					

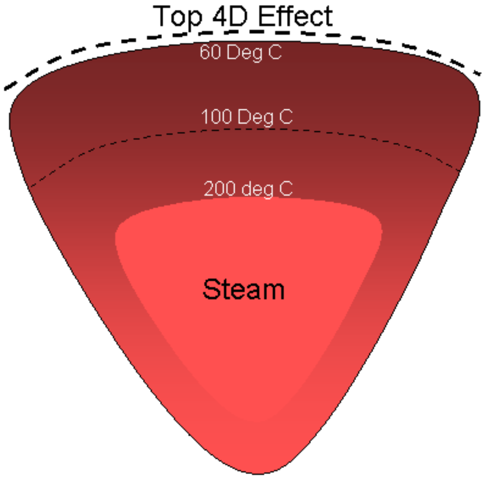
B Baseline   M Monitor

4D Seismic Workflow

- **Cross-plot of 4D anomaly volumes versus allocated SAGD oil production volumes from select Phase 1 well pairs.**



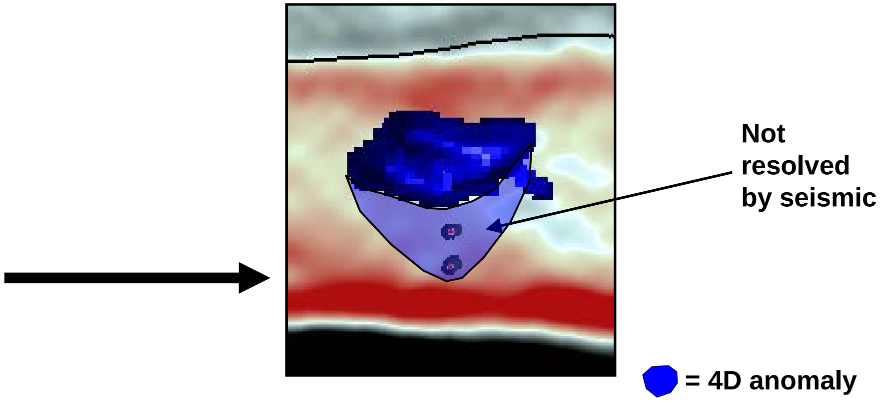
4D Observation



Temperature

Conceptual models for SAGD 4D Response

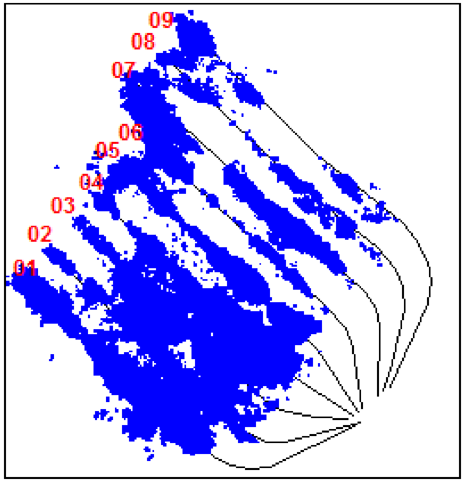
- **Because of seismic resolution there are some discrepancies between the total oil produced and the volume of 4D anomalies.**



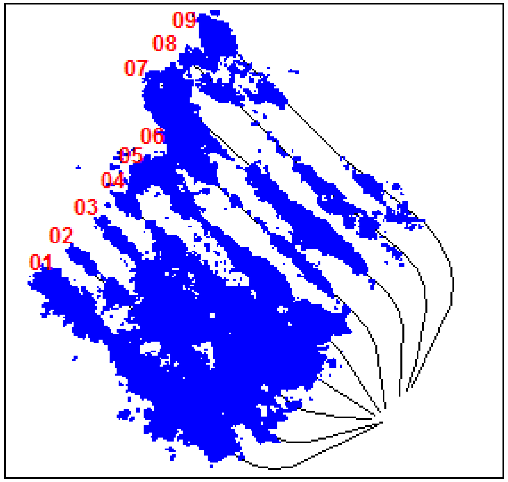
2014 4D Seismic Results Pad 101

- Well Pad 07/08/09, without a true baseline. For the rest of Well Pairs the 4D anomaly volumes have increased. Good conformance, especially at the heel. Well Pads 02/03 are E-SAGD pilot

101 North 6th monitor - March 2014

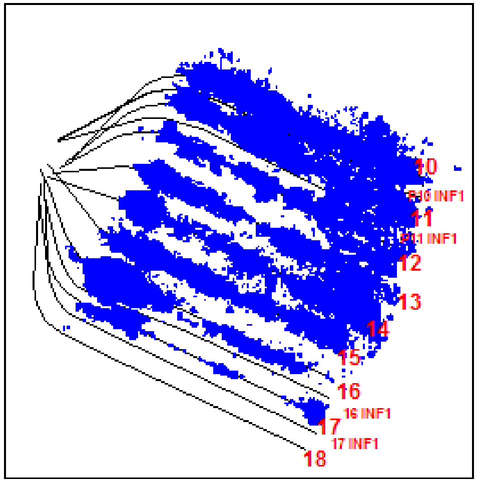


101 North 7th monitor - September 2014

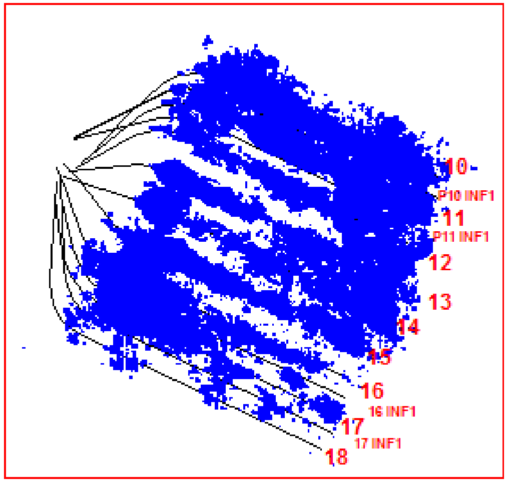


- 4D anomaly volumes have increased. Continued conformance improvement along Well Pad 10, 11,16,17.
- Infill wells drilled between Well Pads 10, 11, 12. 16, 17 and 18 to optimize production in a geological more complex zone.

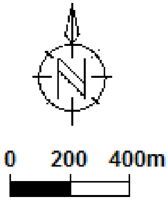
101 South 7th monitor - March 2013



101 South 8th monitor - March 2014



= 4D anomaly
~60 deg C Isotherm



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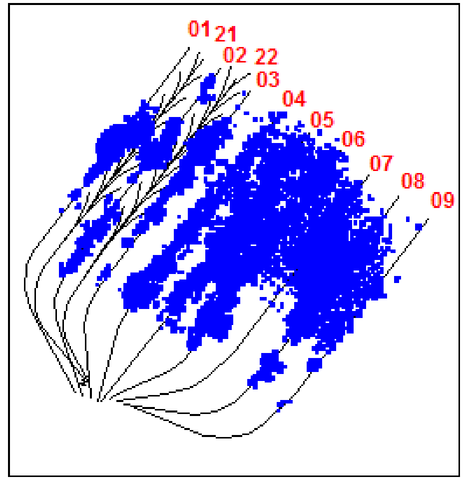
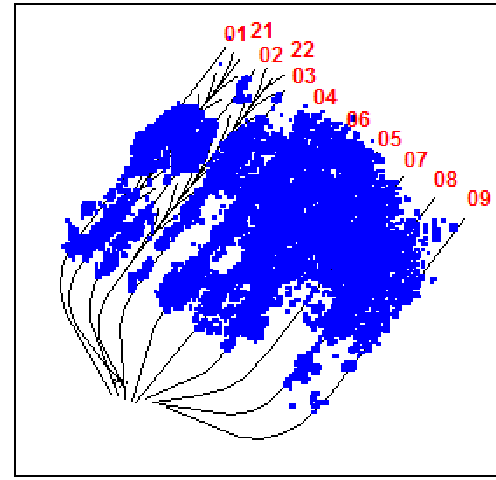
2014 4D Seismic Results Pad 102

- **4D anomaly volumes have increased. Improve conformance along well pairs 1 to 9.**

102 North 7th monitor - April 2013

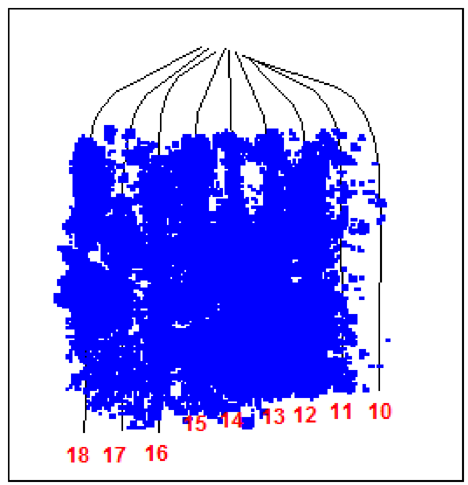


102 North 8th monitor - April 2014

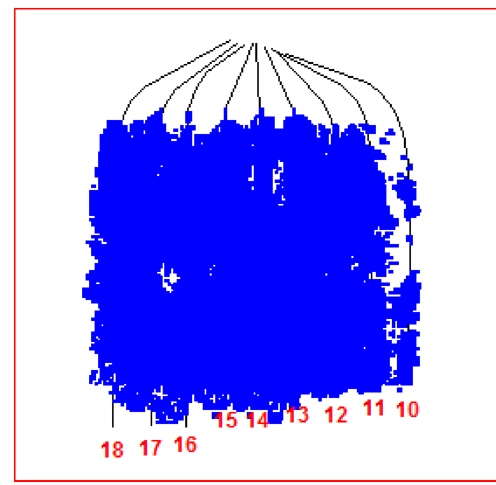


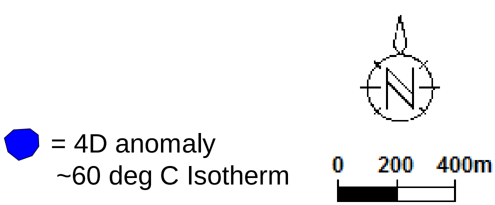
- **4D anomaly volume have increased. Improved conformance along well pairs 10 to 18.**

102 South 4th monitor -March 2012



102 South 5th monitor - April 2014





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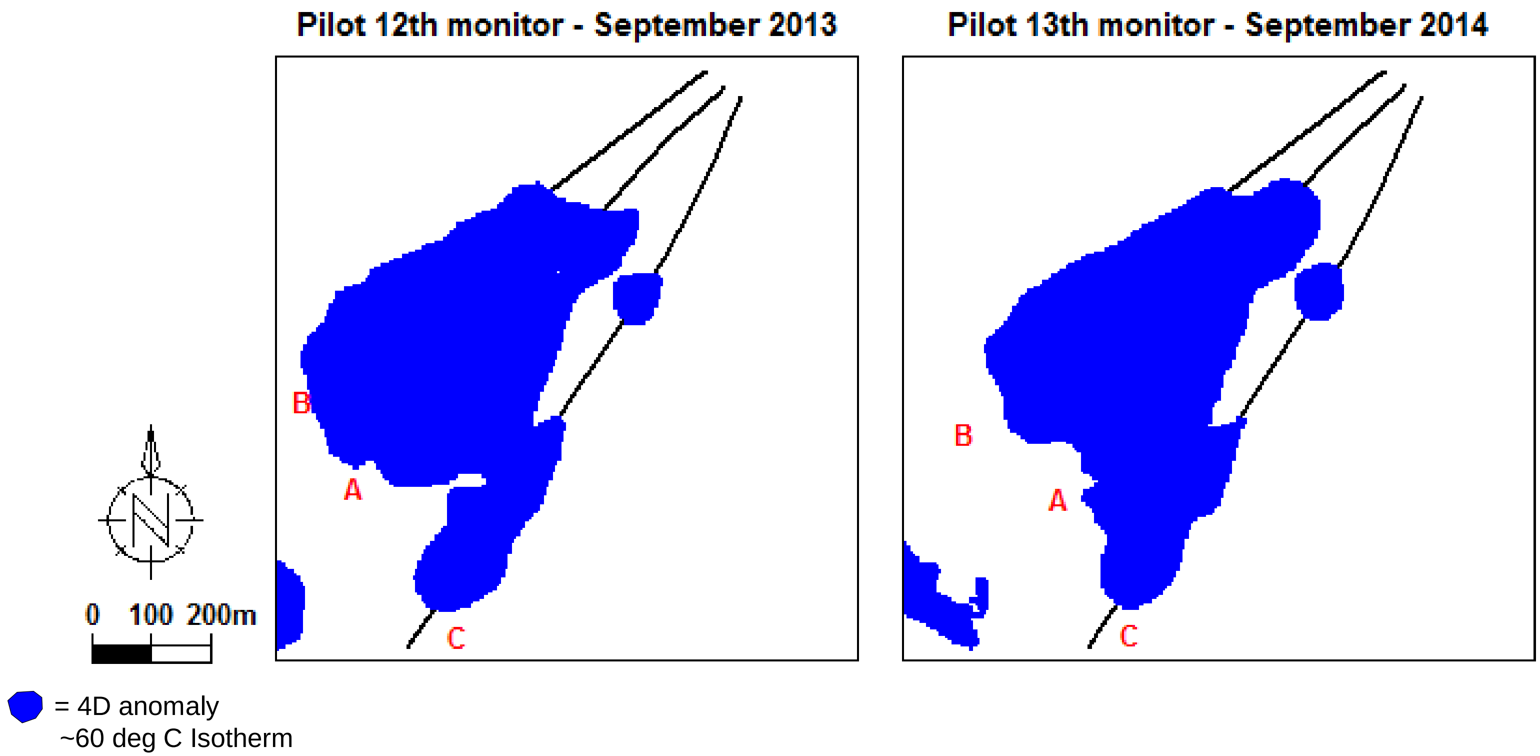
2014 4D Seismic Results Pilot

- Poor SAGD conformance in middle of well pair "C"
- Coalescence between well pair B/A and C



Seismic Examples: 101-P16 Conformance (Toe)

Problem:

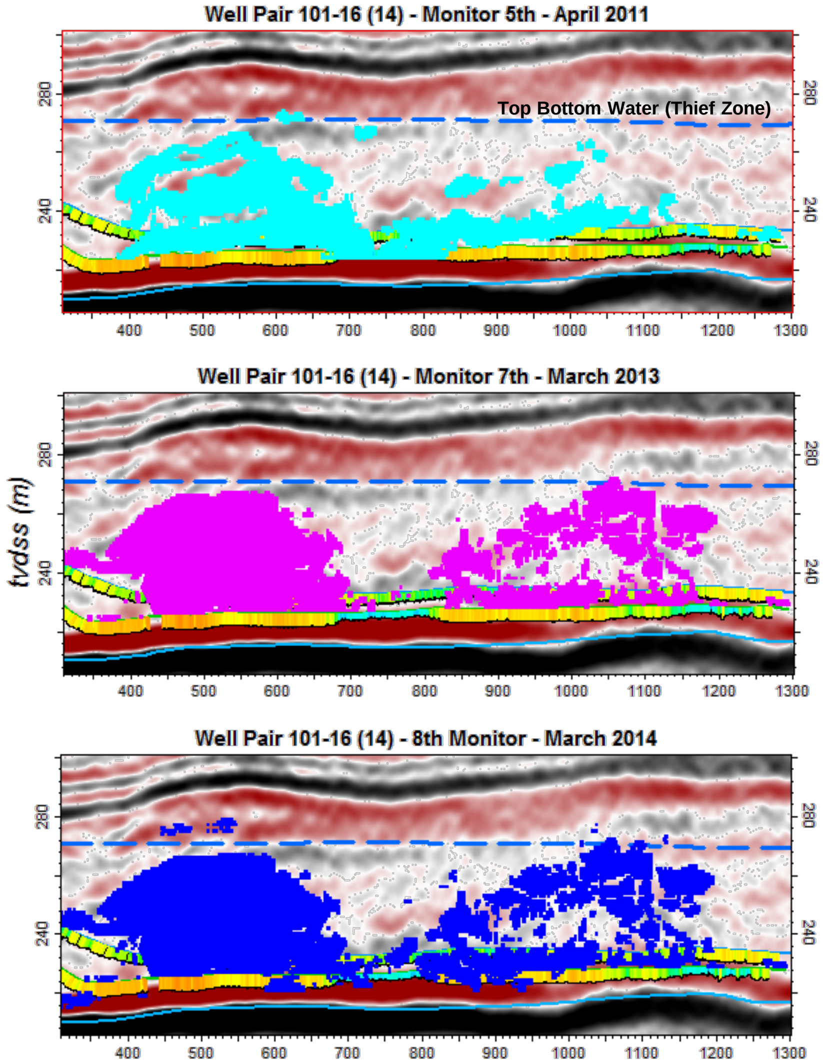
- Well pair 101-P16 lacking good conformance along well pair

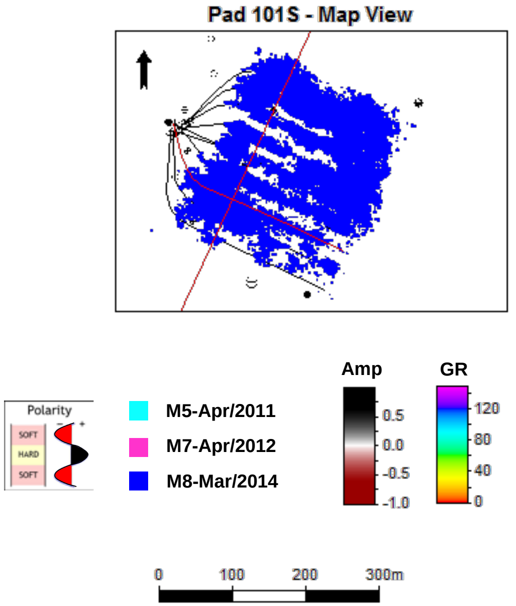
Action:

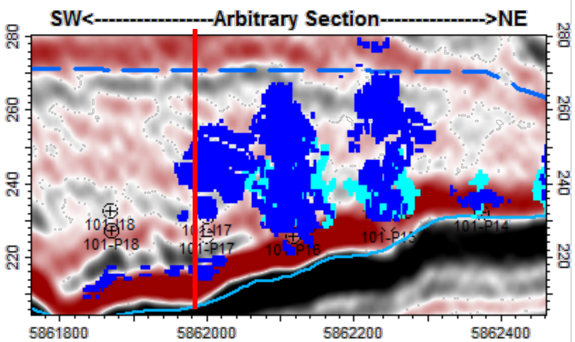
- Increase pressure of steam injection at toe

Results:

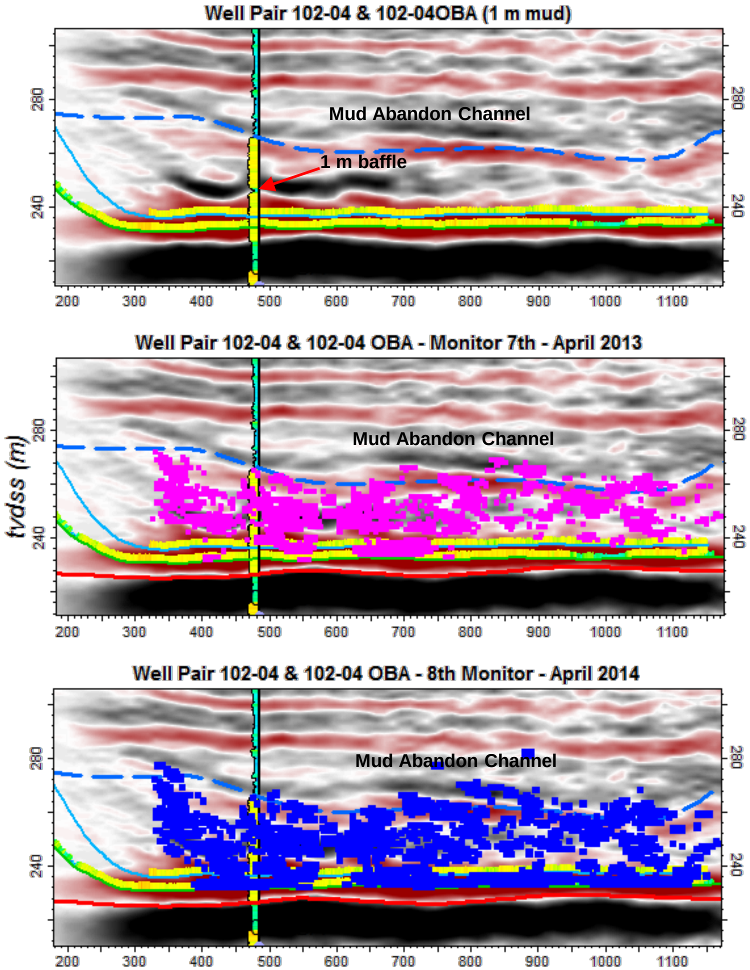
- Conformance improved at toe

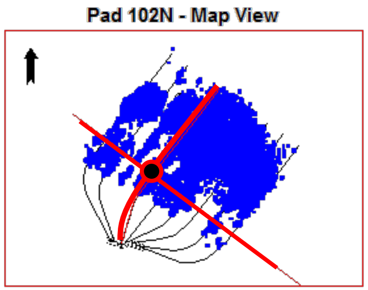


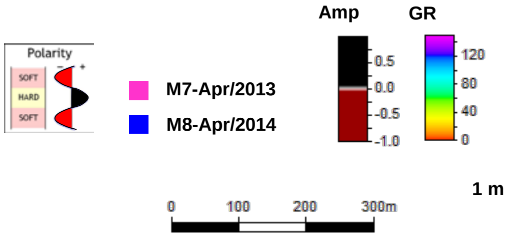


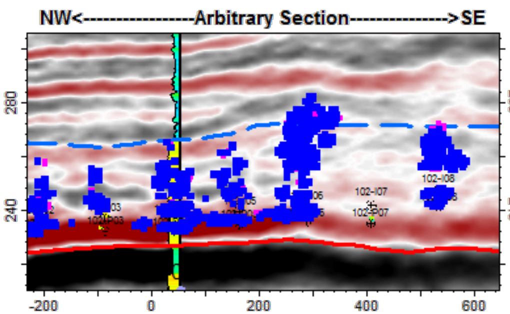


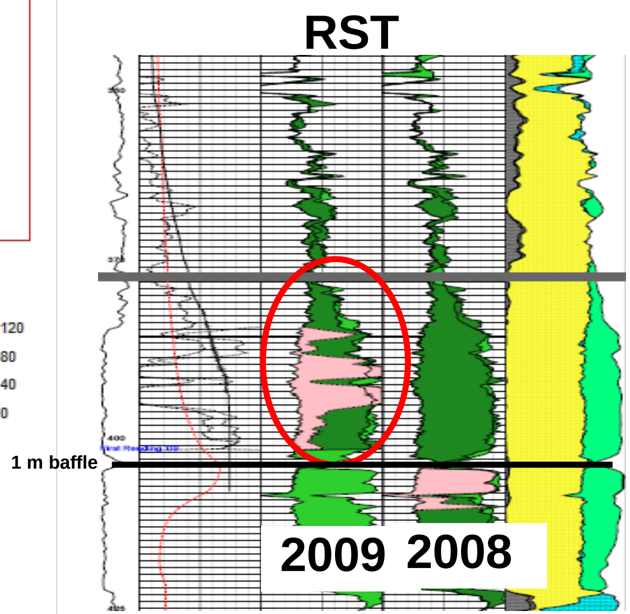
Seismic Examples: 102-04 OBA Baffle Breakthrough (Heel)









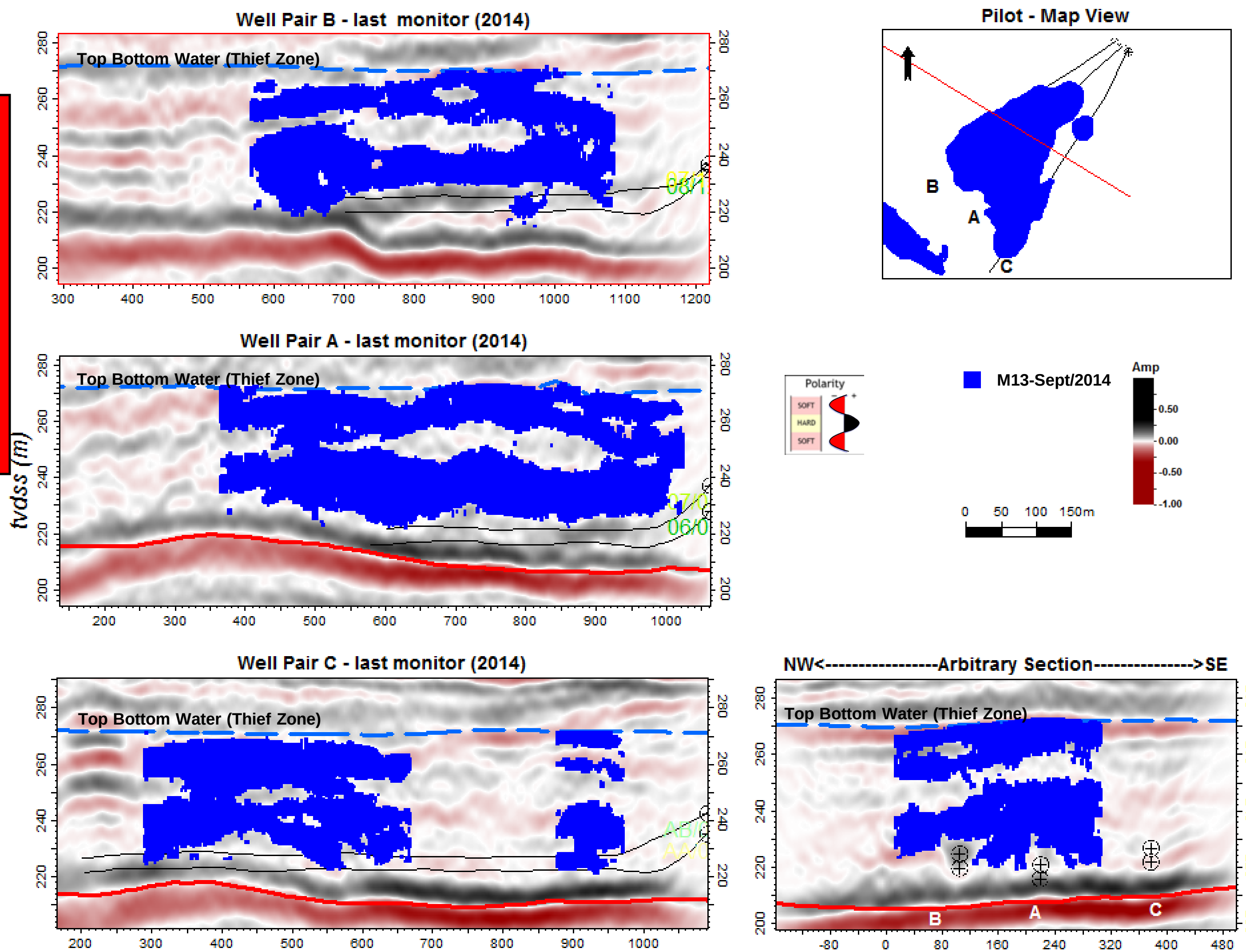


April 2014 4D survey with RST showing steam breakthrough through mudstone

- 2009 RST and 4D surveys confirmed recovery above mudstone
- Operating pressure reduced to manage thief zone interactions

Pilot 4D Seismic 13th Monitor

- Objectives - Top water and gas thief zone interaction.
- Poor SAGD conformance in middle of well pair “C”
- Coalescence between WP B/A and C



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4D Seismic Program 2014

- 4D seismic has proven very useful in monitoring and optimizing conformance and pressure strategy.
- 4D correlates with observation well data.
- Continuing to optimize heel/toe production/injection splits using 4D results.
- Ongoing efforts to history match reservoir models using 4D seismic.

Subsection 3.1.1 (7)
Scheme Performance

Scheme Performance

Pilot

	Bitumen Production bbl/d (m3/d)	Steam Injection bbl/d (m3/d)	iSOR v/v	WOR v/v	RWR %
2013	559 89	1910 304	3.40	5.52	-60%
2014	352 56	1409 224	4.05	7.69	-80%

Phase 1

	Bitumen production bbl/d (m3/d)	Steam injection bbl/d (m3/d)	ISOR v/v	WOR v/v	RWR %	Water Recycle %	Opp. Efficiency %
2011	21,673 3,446	53,676 8,534	2.48	2.38	4%	80.0%	87%
2012	24,251 3,856	59,442 9,450	2.45	2.43	1%	81.6%	93%
2013	27,135 4,315	65,571 10,425	2.42	2.47	-2%	87.1%	94%
2014	26,341 4,188	62,439 9,927	2.37	2.39	-1%	88.2%	95%

Pilot

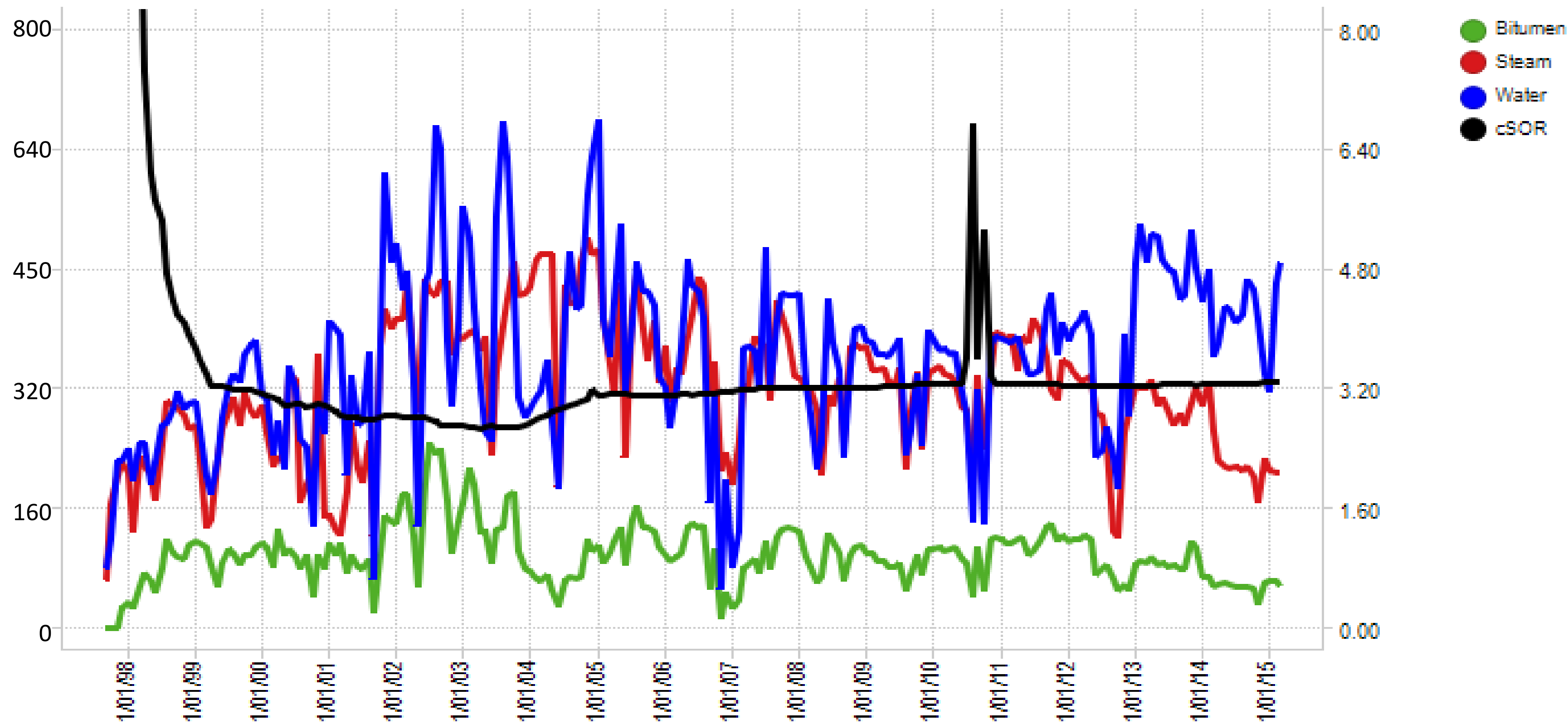
- Performance impacted by ESP and subcool target in 2014

Phase 1

- ESP installations in 2013 allowed for a drawdown of liquid levels in 2014 resulting in strong performance
- Benefited from high operating efficiency
- Conducted a successful turnaround in September
- Reservoir Water Retention (RWR) stabilizing with maturity of the steam chambers
- Operating pressures continuing to decline at approximately 250kPa/year

Pilot Performance History

Monthly Plant Production History (m3/d)



Data through Jan 31, 2015	
Plant CSOR	3.28
Plant CWSR	1.13
# Well Pairs Started (incl. infill producers)	2
2014 iSOR avg. (v/v)	4.20

Moderate performance in 2014 due to pump limitations and operating pressure

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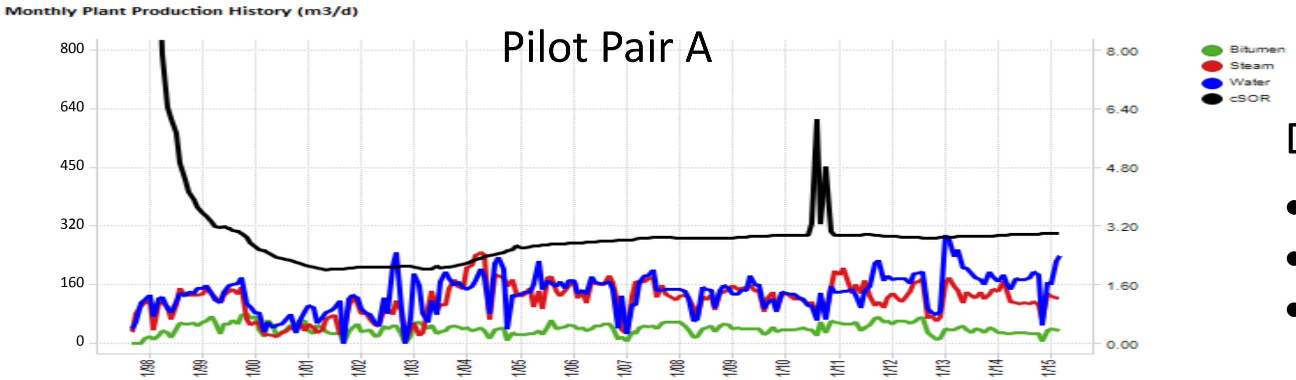
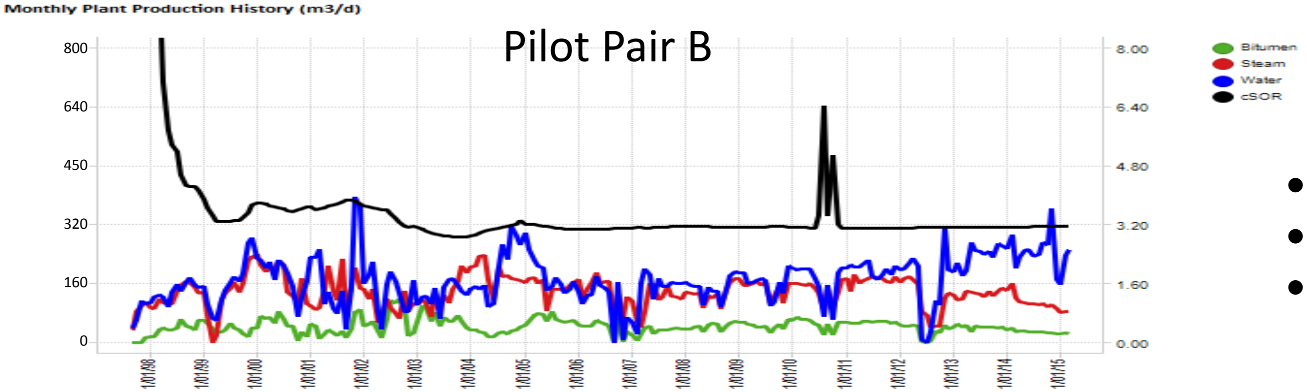
Pilot Performance History

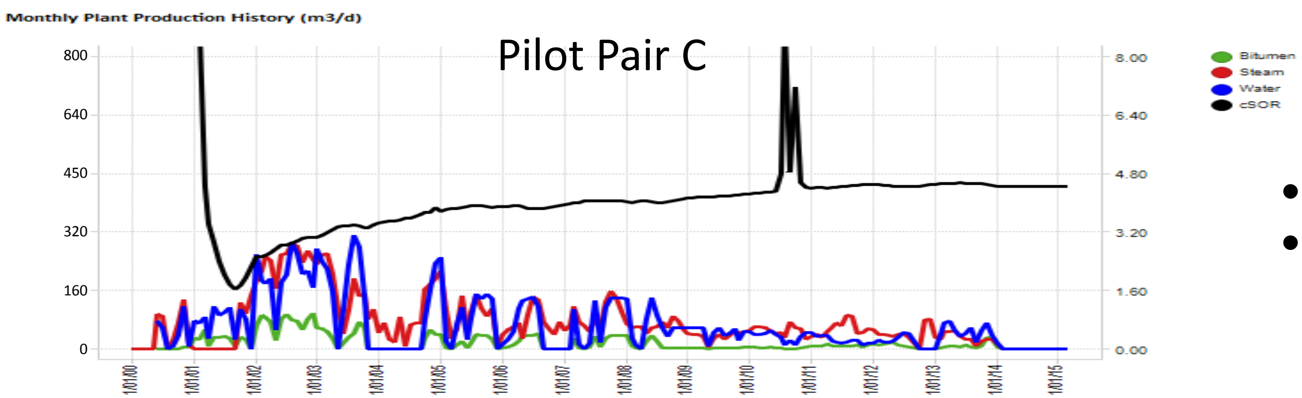


Data through Jan. 31, 2015

- Wellpair A cSOR = 4.32
- Wellpair A cWSR = 1.40
- Recovery Factor: 40.5%

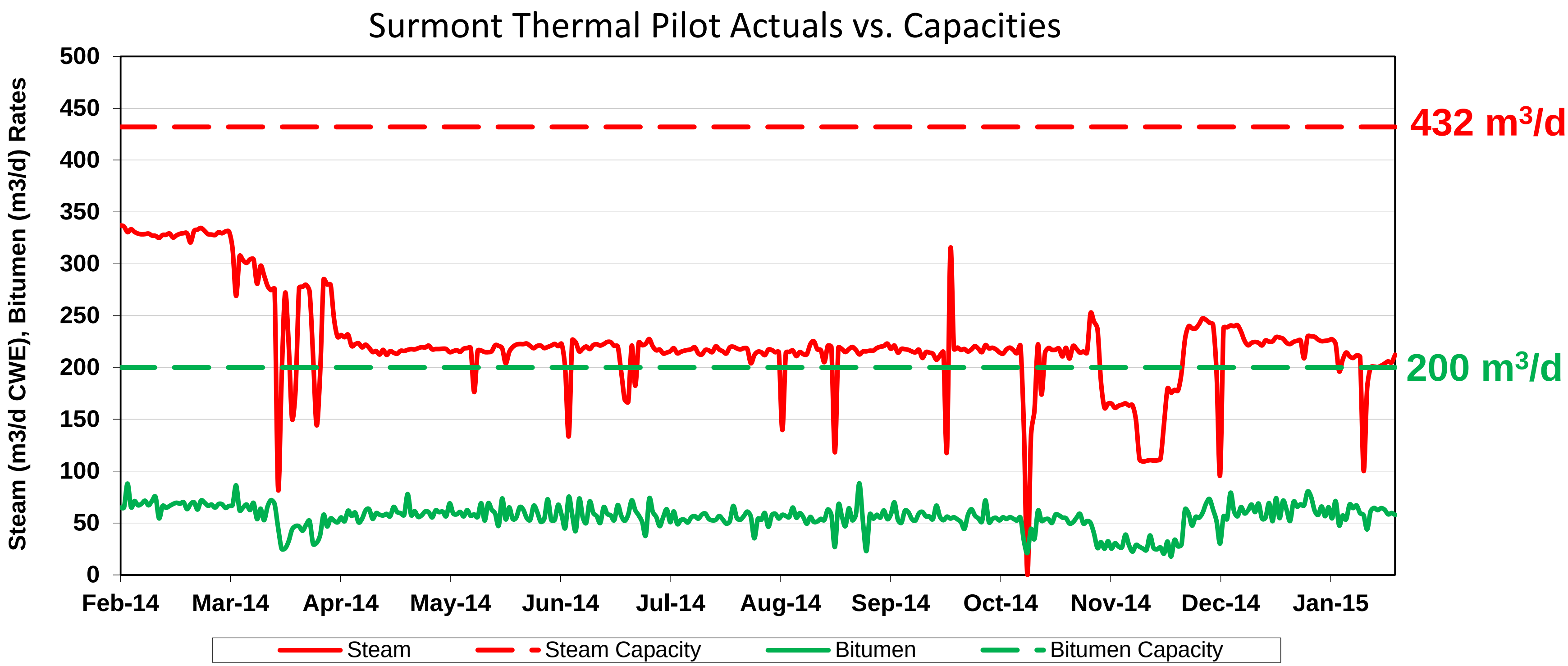


- Wellpair B cSOR = 3.71
- Wellpair B cWSR = 2.27
- Recovery Factor: 48.4%



- Last production 19Jan2014
- Recovery Factor: 7.8%

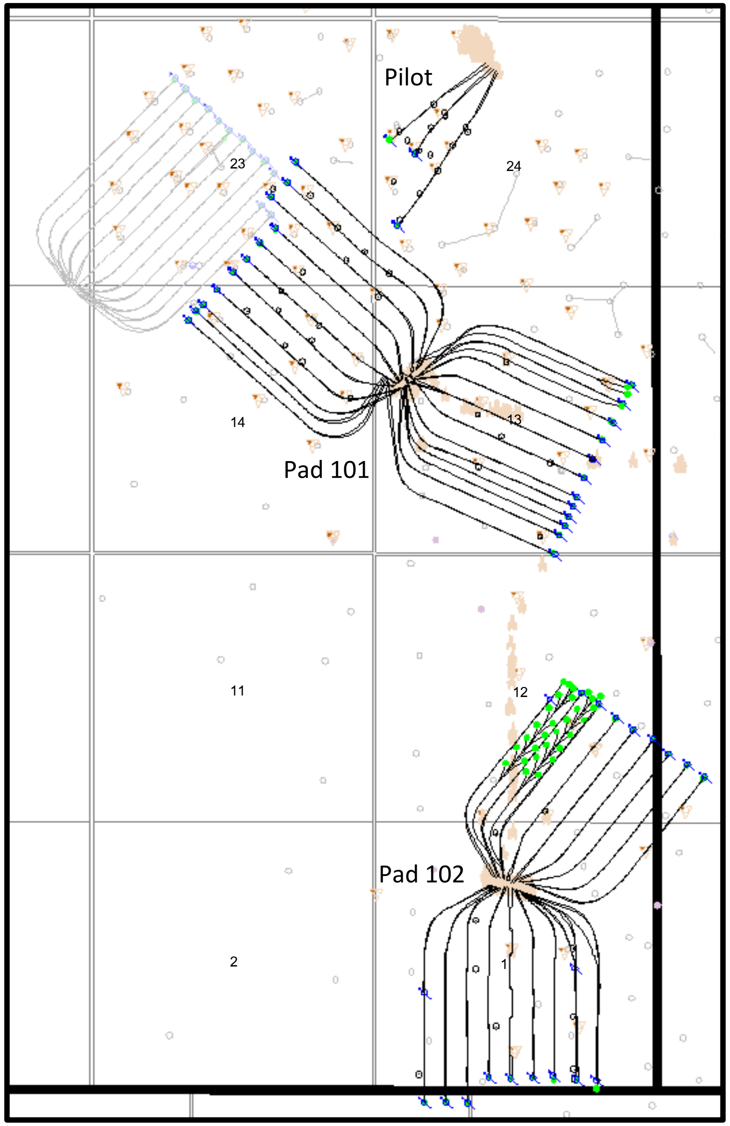
Pilot Production Capacity



Deviation from capacity due to:

- Reservoir pressure limiting steam requirement and corresponding production
- P3 pump had failed shutting in production from this well

Well Status



T83

R7W4

Status on January 31, 2015

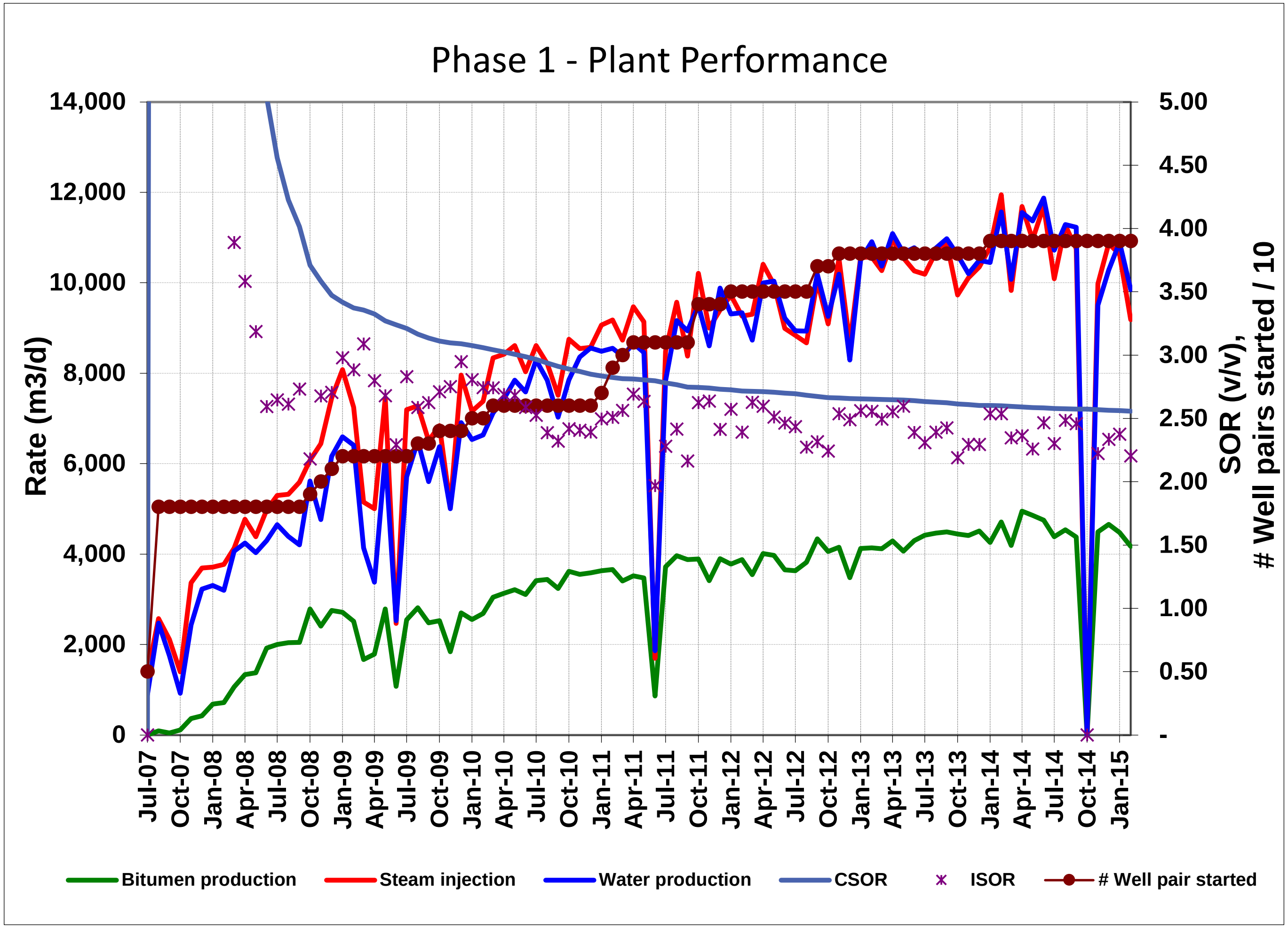
- Pilot:
  - 2 well pairs on SAGD
  - Well pair C shut in pending evaluation
- Phase 1:
  - 37 well pairs on SAGD
  - 2 infill producers
  - 2 infill fishbone producers
  - 4 cold well pairs
- Surmont Phase 1's first sustaining Pad planning to start injection/production in 2015
- 5 year outlook - no expected pad abandonments

Well Lists

Pilot		Surmont 1 Pad 101		Surmont 1 Pad 102	
Alias	**Phase**	**Alias**	**Phase**	**Alias**	**Phase**
P01	Pilot	101-P01 (10DH)	1A	102-P01	1A
P02	Pilot	101-P02 (11DH)	1A	102-P02	1A
P03	Pilot	101-P03 (12DH)	1A	102-P03	1A
		101-P04 (13DH)	1A	102-P04	1A
		101-P05 (14DH)	1A	102-P05	1A
		101-P14 (16DH)	1A	102-P12	1A
		101-P15 (15DH)	1A	102-P13	1A
		101-P16 (07DH)	1A	102-P14	1A
		101-P17 (08DH)	1A	102-P15	1A
		101-P18 (09DH)	1A	102-P06	1B
		101-P06 (17DH)	1C	102-P07	1B
		101-P07 (18DH)	1C	102-P08	1B
		101-P08 (02DH)	1C	102-P09	1B
		101-P09 (01DH)	1C	102-P16	1B
		101-P10 (03DH)	1C	102-P17	1B
		101-P11 (04DH)	1C	102-P18	1B
		101-P12 (05DH)	1C	102-P10	Injector Re-drill
		101-P13 (06DH)	1C	102-P11	Well Pair Re-drill
		101-P19 (17INF)	Infill Well Pair	102-P21	Infill Well
		101-P20 (16INF)	Infill Well Pair	102-P22	Infill Well
		101-P21 (10INF)	Infill Well		
		101-P22 (11INF)	Infill Well		

Phase 1 Performance History

- Good performances due to stable operations and well availability
- Stable iSOR for the past three years around 2.5



Data through Jan 31, 2015	
Plant CSOR	2.58
Plant CWSR	0.95
# Well Pairs Started (incl. infill producers)	39
2014 iSOR avg. (v/v)	2.37

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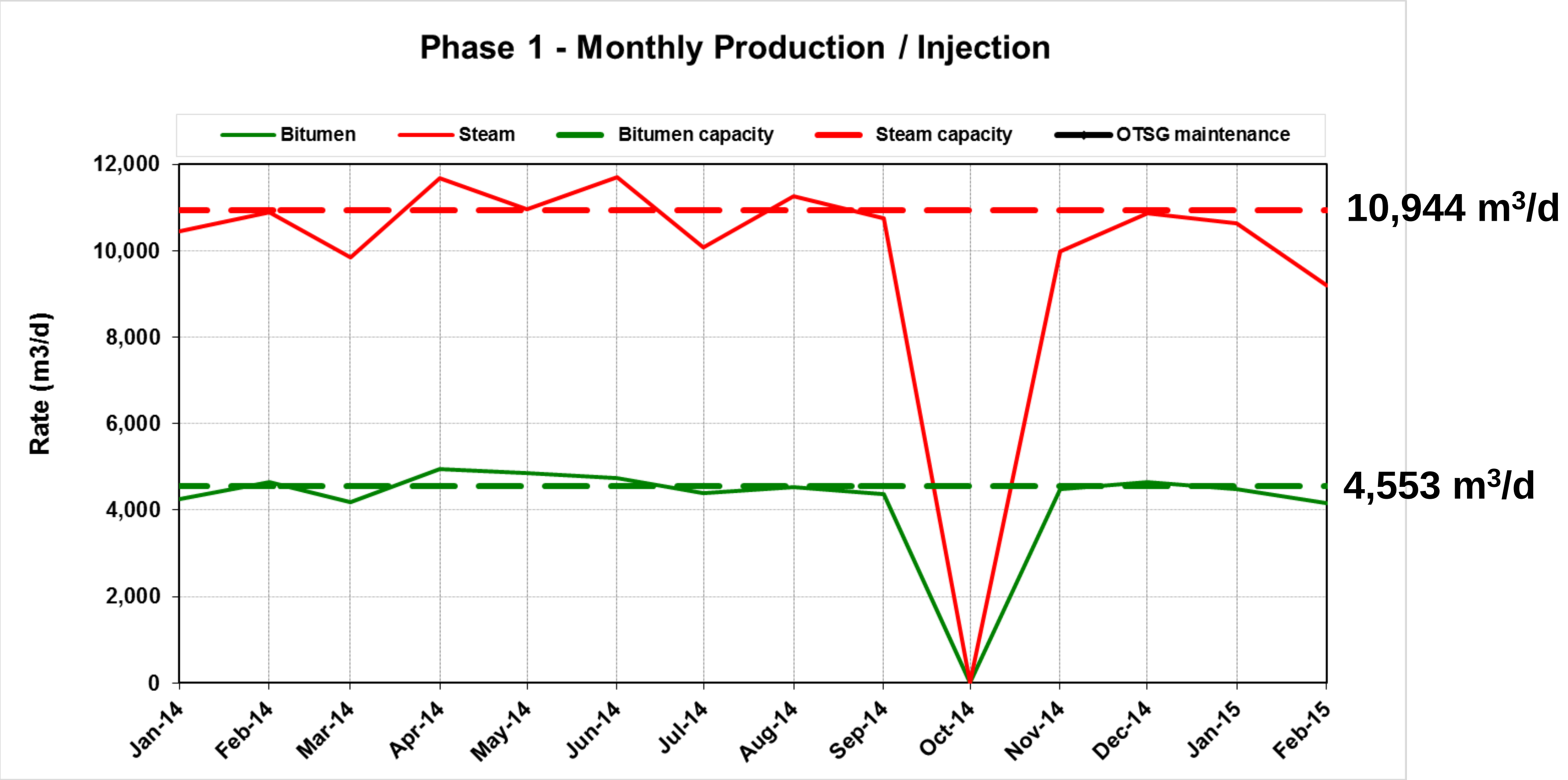
Phase 1 Production Capacity



Deviation from capacity due to:

- Planned / Unplanned power outages
- Well availability:
  - 2 ESP Conversions + 11 ESP Replacements
  - 1 SAGD Conversion (ESP Day1)
  - September Turnaround

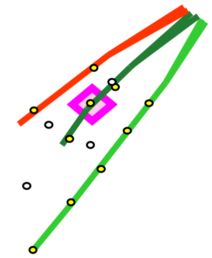
Observation Well Distances to Nearest Well Pair

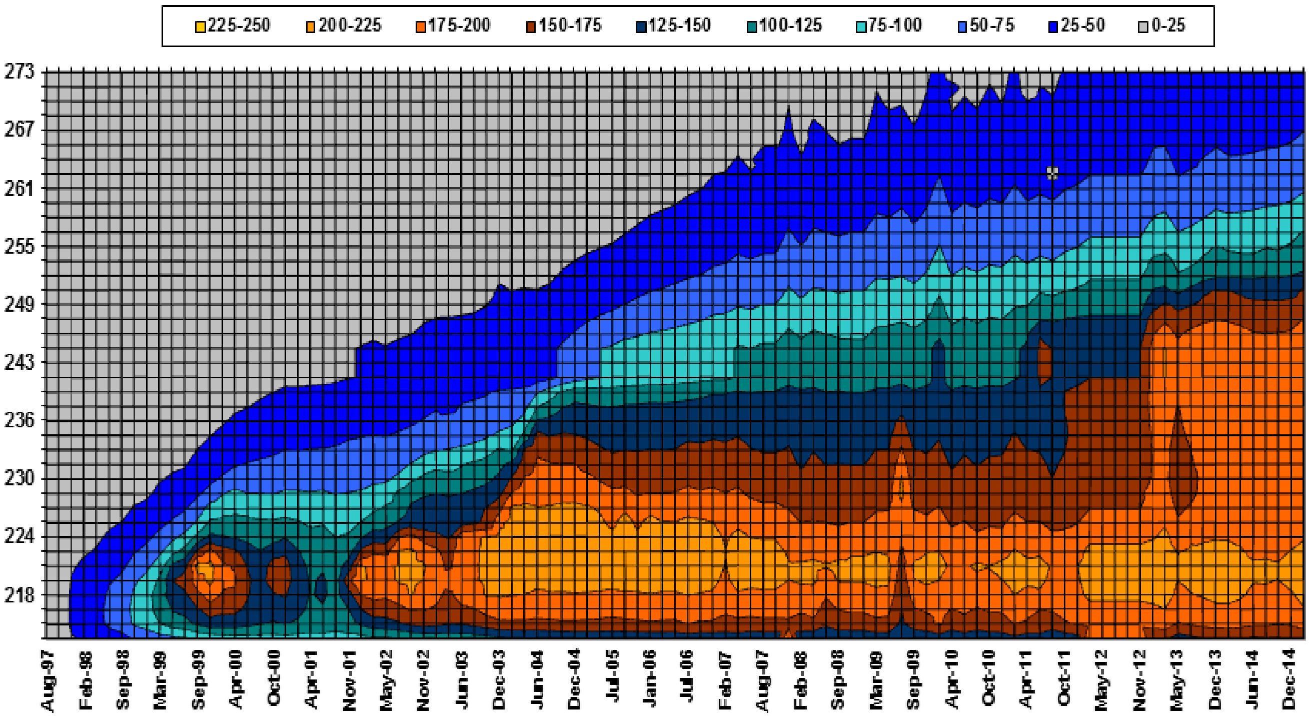
UWI	Alias	Distance to Wellpair (m)	UWI of Closest Well
1AA091408307W400	101-P02-OBA	1.7	103141408307W400
100091408307W400	101-P02-OBB	14.9	103141408307W400
100151408307W400	101-P02-OBC	29.9	103141408307W400
102151408307W400	101-P02-OBD	20.7	104141408307W400
100161408307W400	101-P03-OBB	13.6	102022308307W400
103151408307W400	101-P03-OBC	16.3	102022308307W400
102161408307W400	101-P04-OBB	6.0	103022308307W400
104151408307W400	101-P04-OBD	2.8	103022308307W400
100012308307W400	101-P05-OBD	39.6	106022308307W400
1AA012308307W400	101-P07-OBC	14.8	103072308307W400
100131308307W400	101-P07-OBA	21.9	103072308307W400
1AA072308307W400	101-P07-OBE	51.6	106072308307W400
102042408307W400	101-P08-OBB	0.8	102072308307W400
103012308307W400	101-P08-OBC	7.8	105072308307W400
102012308307W400	101-P08-OBD	2.7	102072308307W400
100082308307W400	101-P08-OBE	36.5	105072308307W400
102111308307W400	101-P11-OBA	13.8	106091308307W400
107081308307W400	101-P14-HOB	0.1	107081308307W400
100111308307W400	101-P14-OBA	41.5	100081308307W400
100061308307W400	101-P15-OBB	8.3	106071308307W400
105071308307W400	101-P15-OBD	5.0	103071308307W400
1AA061308307W400	101-P16-OBB	17.0	108021308307W400
1AA021308307W400	101-P18-OBE	57.4	106021308307W400
100140108307W400	102-P03-OBA	28.9	108081208307W400

UWI	Alias	Distance to Wellpair (m)	UWI of Closest Well
100021208307W400	102-P04-OBA	18.8	102081208307W400
100100108307W400	102-P11-OBA	11.0	106020108307W400
100070108307W400	102-P11-OBB	8.5	107020108307W400
105020108307W400	102-P11-OBE	7.6	106020108307W400
100030108307W400	102-P15-OBD	43.6	104030108307W400
100110108307W400	102-P16-OBA	37.6	100163508207W400
1AA060108307W400	102-P16-OBB	51.2	100163508207W400
100040108307W400	102-P18-OBE	36.3	106163508207W402
104122408307W400	OB17	15.4	108122408307W400
105112408307W400	OB18	0.3	106052408307W400
100112408307W400	OB20	16.3	1AA042408307W400
104112408307W400	OB21(Abandoned)	27.3	1AA042408307W400
105122408307W400	OB22(Abandoned)	1.2	108122408307W400
103122408307W400	OB23(Abandoned)	74.3	107122408307W400
102122408307W400	OB24	11.8	107052408307W400
102052408307W400	OB25	72.9	1AB042408307W400
108052408307W400	OB26A	3.6	1AA042408307W400
100052408307W400	OB28	170.2	1AA042408307W400
106122408307W400	OB36	3.3	106052408307W400
102112408307W400	OB37	14.0	1AB042408307W400
109052408307W400	OB38	5.9	1AB042408307W400
100042408307W400	OB39	1.6	1AA042408307W400
103112408307W400	OB41	16.0	106052408307W400

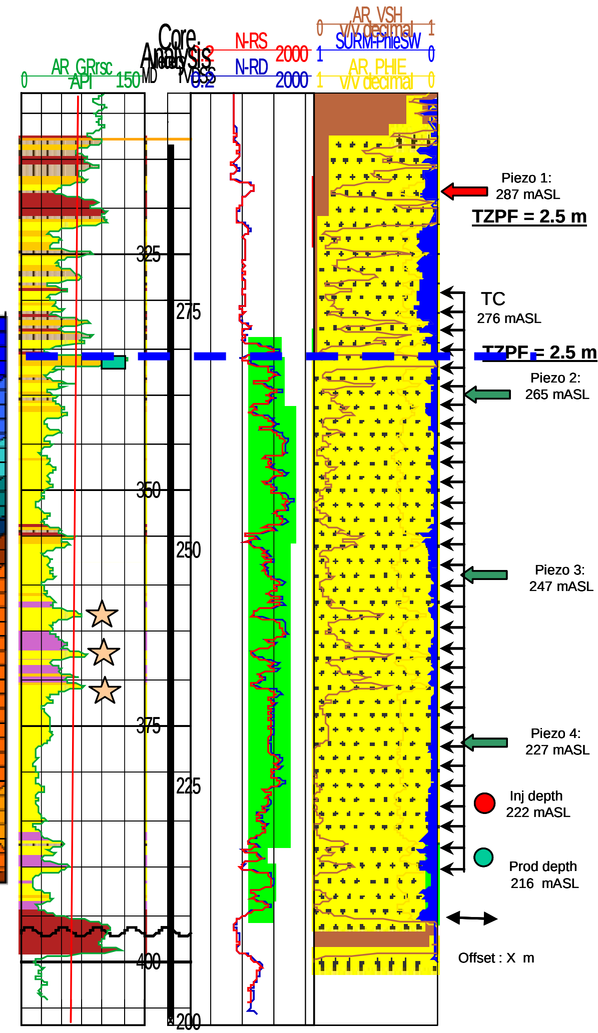
Pilot Well Pair A: OBS36 (Mid)

OBS 36: Heat keeps progressing above breccia

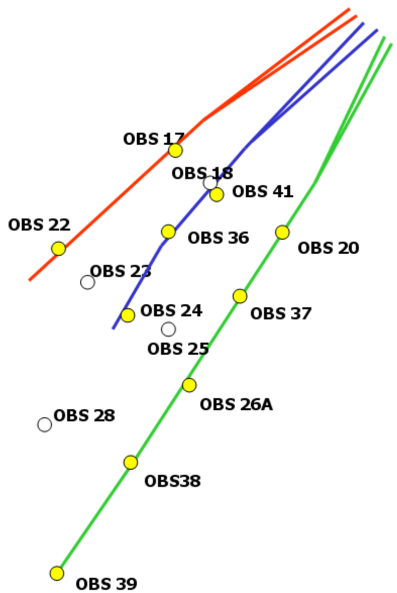


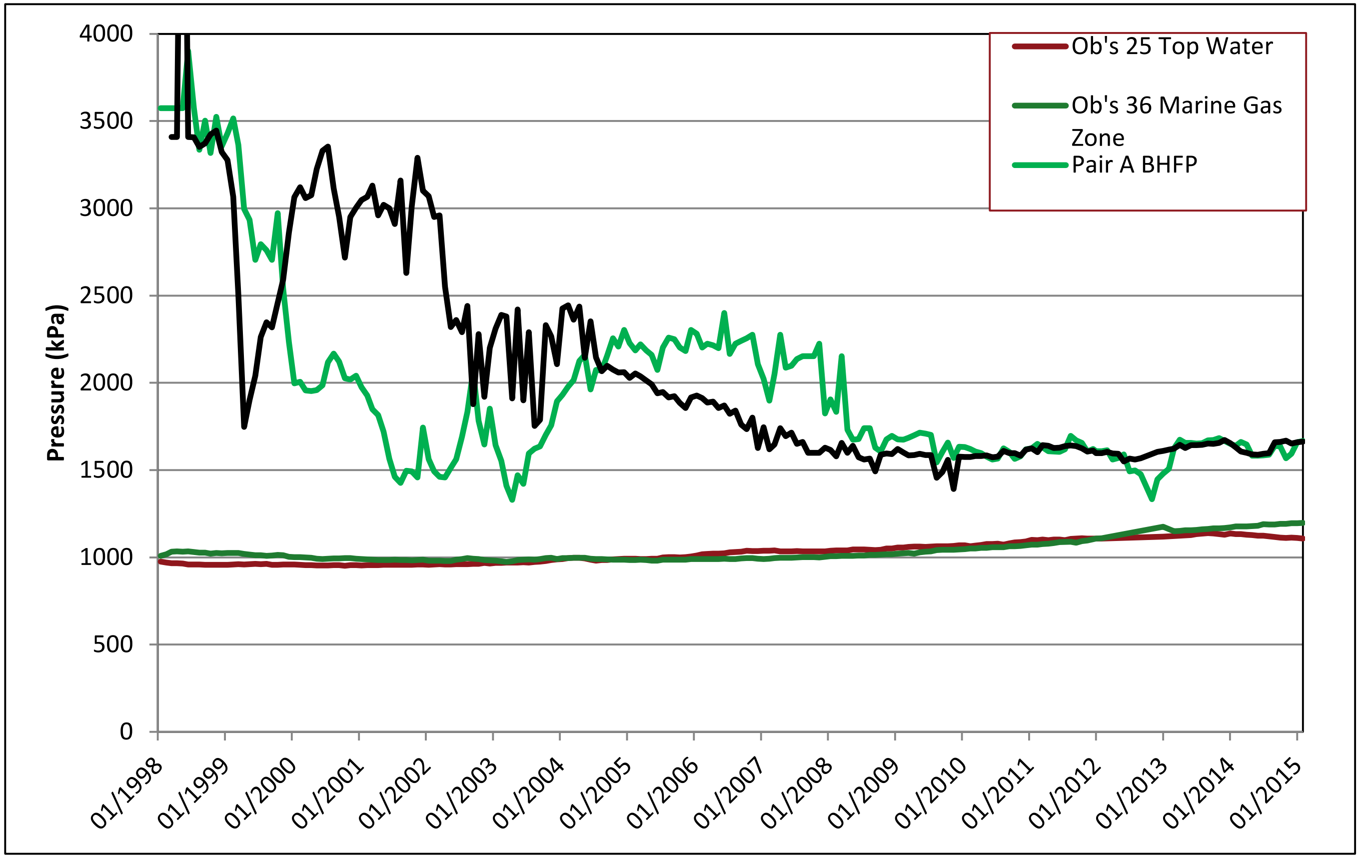


OBS36
A well pair (mid)



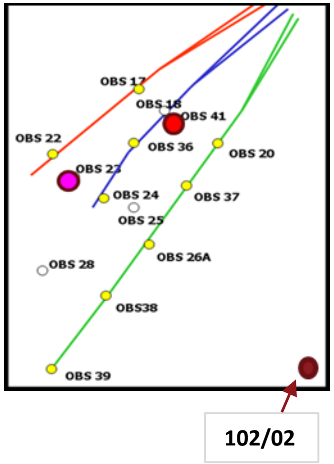
Pilot Chamber and Thief Zone Pressures





- Operated at 1600 kPa for 5-6 years with significant surface area of contact of chamber with thief zone
- Saturated steam temperatures observed in thief zone at OBS22 since 2009
- Gas pressure zones approximately 400kPa below steam chamber pressure

Top Gas Monitoring



OBS-23 (103/12-24-083)

- Tested 2 samples in early 2010 from McMR Gas Cap
- Lab gas chromatography with thermal conductivity detector (TCD GC) indicated H_2S conc. ~ 1.09% and 0.28%
- Well currently abandoned due to well integrity issues

OBS-41 (103/11-24-083)

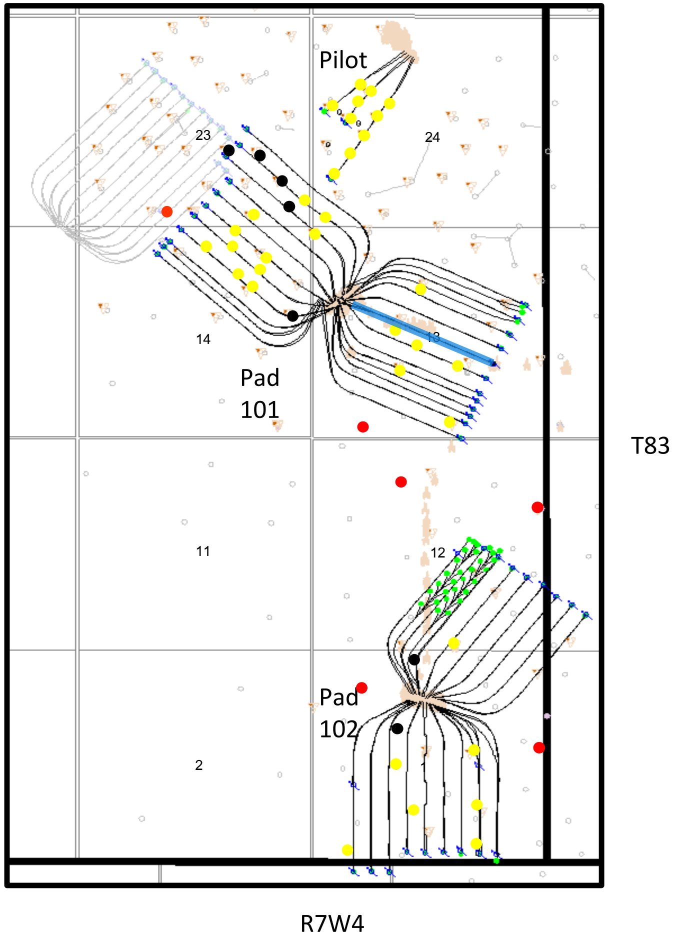
- Onsite field test on 6 samples in 2011 , 2 samples in 2012, 2 samples in 2013 and 6 samples in 2014 and 3 samples in January 2015
- H_2S con. measured (highest values): 0.61% (2011), 0.42% (2012) and 0.47% (2013)
- Considered representative sample and closest analog for Pad 101
- Most recent samples for H_2S concentrations:
  - Feb 5th, 2014
    - *Maximum of 6 samples: Field Observations: 0.42% (4216ppm); Lab Observations: 0.23% (2314ppm)*
  - Jan 10th, 2015
    - *Maximum of 3 samples: Field Observations: 0.27% (2711ppm); Lab Observations: 0.16% (1632ppm)*

OBS (102/02-24-083)

- Drilled in Feb 2013 for gas observation
- Onsite field test on 2 samples in 2013; Field Observation 0% (0ppm)
- Most recent samples for H_2S concentrations:
  - Feb 6th, 2014
    - *Maximum of 7 samples: Field Observations: 0.00% (0ppm); Lab Observations: 0.00% (<.1ppm)*
  - Jan 12th, 2015
    - *Maximum of 2 samples: Field Observations: 0.00% (0ppm); Lab Observations: 0.00% (1ppm)*

Reservoir Monitoring

Temperature Measurement



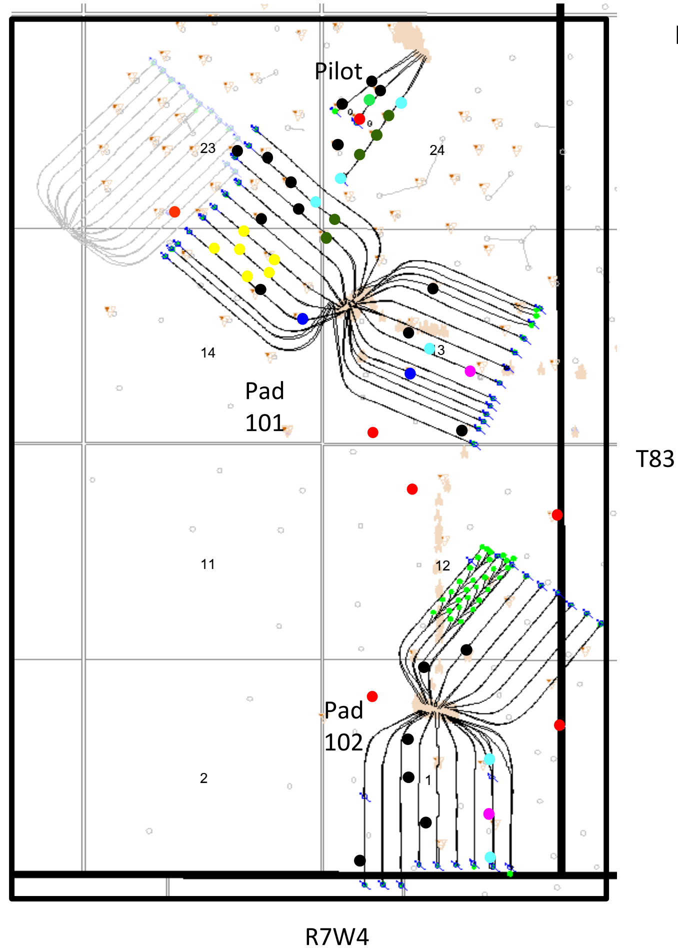
Thermocouple string installed

Horizontal observation well with fiber optic

No temperature monitoring

Pressure Measurement

(as planned after hard cable TC string installation)



Piezos in:

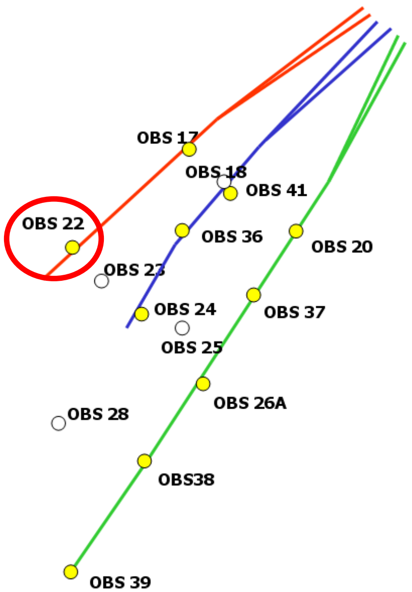
- Bitumen
- Top water
- Bitumen and top water
- Top gas
- Top gas, bitumen and top water
- E-SAGD observation wells with 10 piezometers per well monitoring:
  - bitumen zones
  - high water saturation zones
  - thief zone (water / gas)
  - cap rock
- No piezometer installed

No change in 2014

105/12-24-083-07W4 (Observation Well 22)

4D seismic anomaly observed in top of Clearwater formation around Observation Well 22 in 2013

- Anomaly confirmed in subsequent 2014 seismic data and voluntarily self-disclosed to AER
- Root cause confirmed to be thermal siphoning due to a casing leak
  - Casing leak caused water influx into well bore
  - Boiling column of water heated Clearwater formation sufficiently near well bore to break gas out of solution, appearing as an anomaly in 4D seismic analysis
  - Data acquisition and modeling confirmed thermal siphoning condition as root cause
  - Water test well 1F1/12-24-083-07 W4M samples confirmed no impact to Clearwater aquifer
- Observation Well 22 abandoned February, 2015 as per AER approvals
  - Thermal siphoning condition eliminated with abandonment of well



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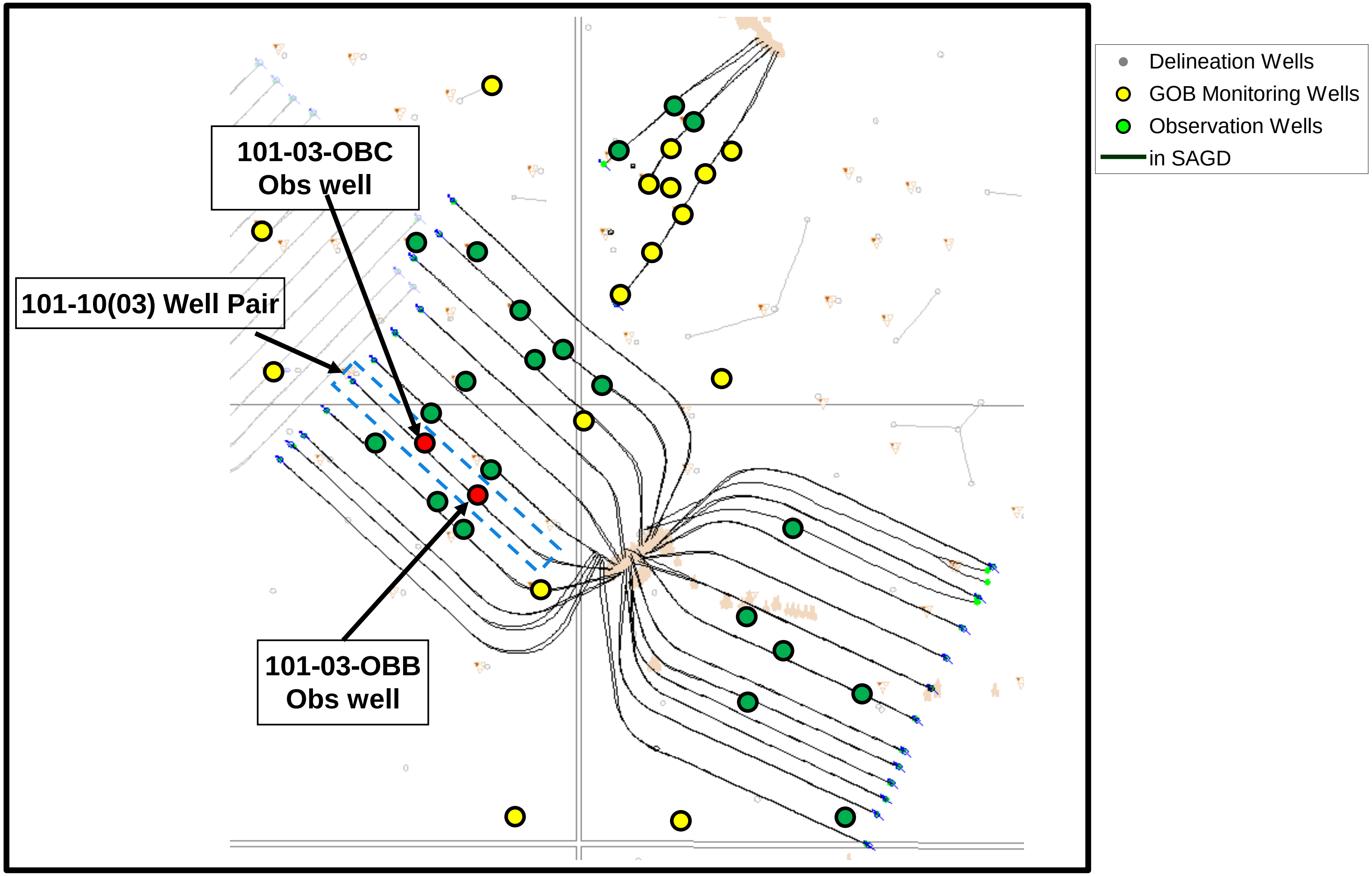
Steam Chamber Development

Well pair 101-10(03) (Pad 101 North)

- Start-up in Feb 2011



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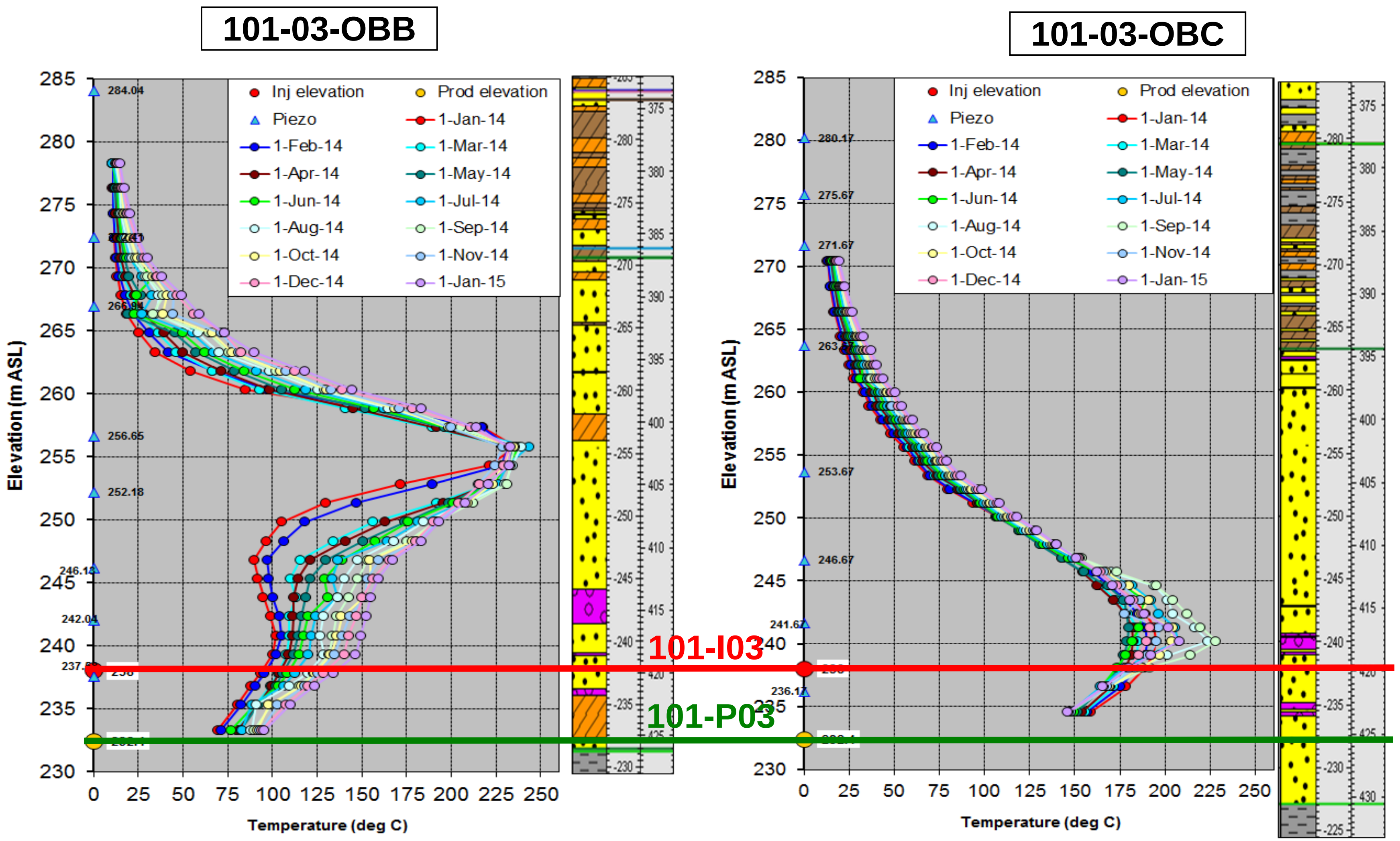
Steam Chamber Development Well Pair 101-03

Temperature Monitoring



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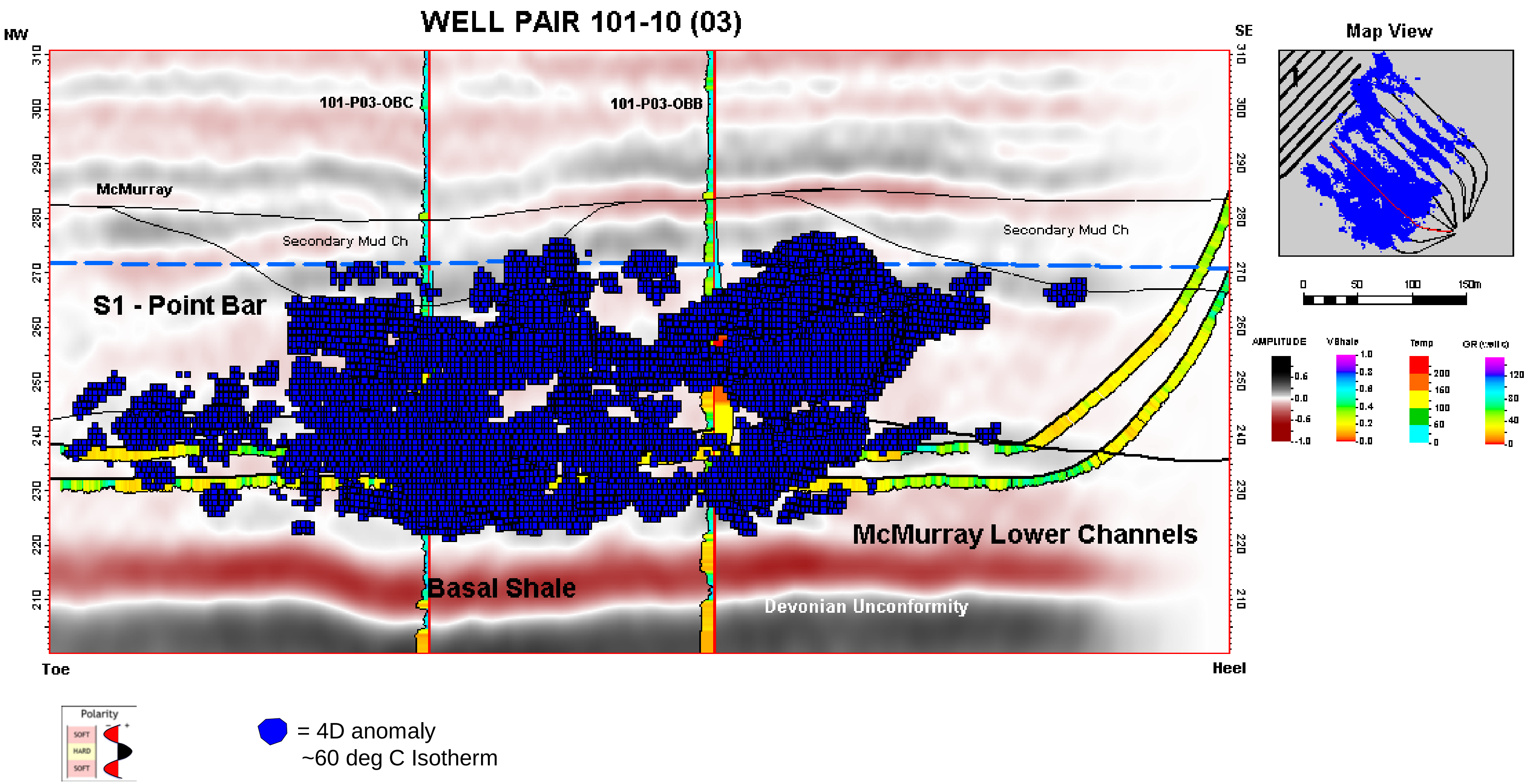
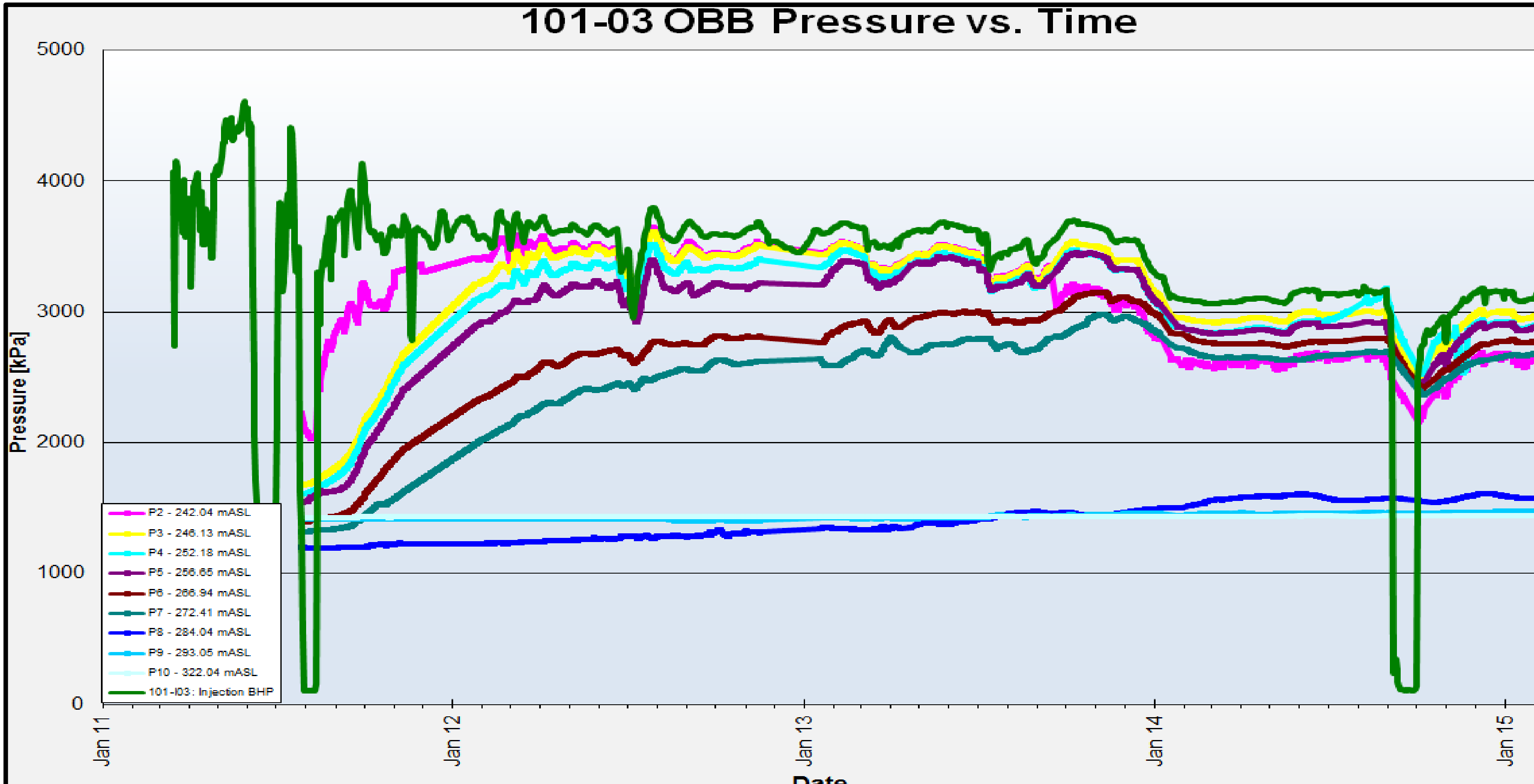
Steam Chamber Development Well Pair 101-03



Monitor 7 September 2014

Steam Chamber Development Well Pair 101-03

- Pressure Monitoring
  - Lower piezometers follow exactly 101-I03 BHP injection trend
  - Pressure response ahead of the temperature front – Most likely through mobile initial water



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OBIP and Recovery Factor

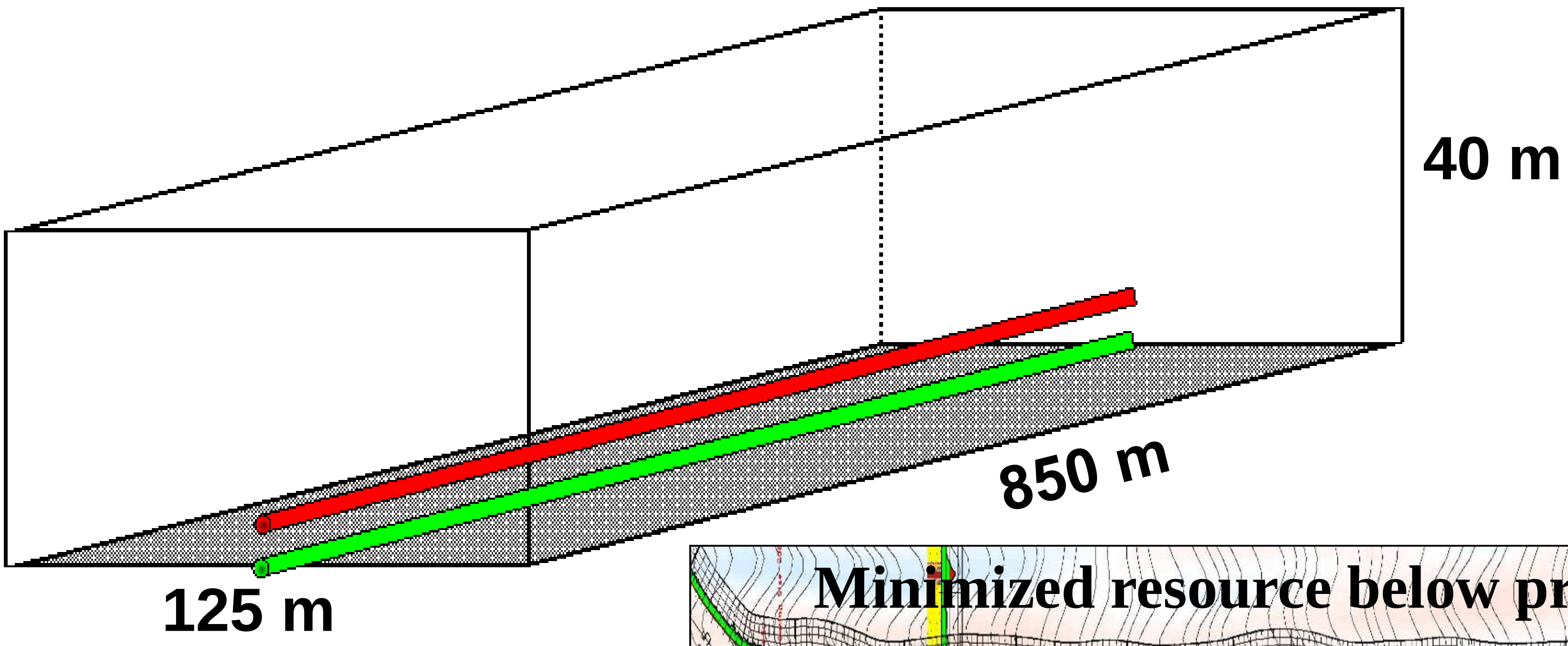
No change in 2014

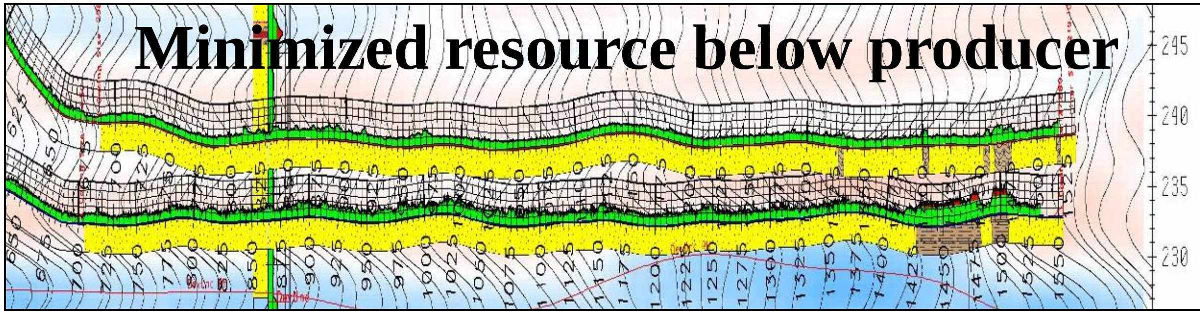
Average porosity = 33%

Average So = 80%

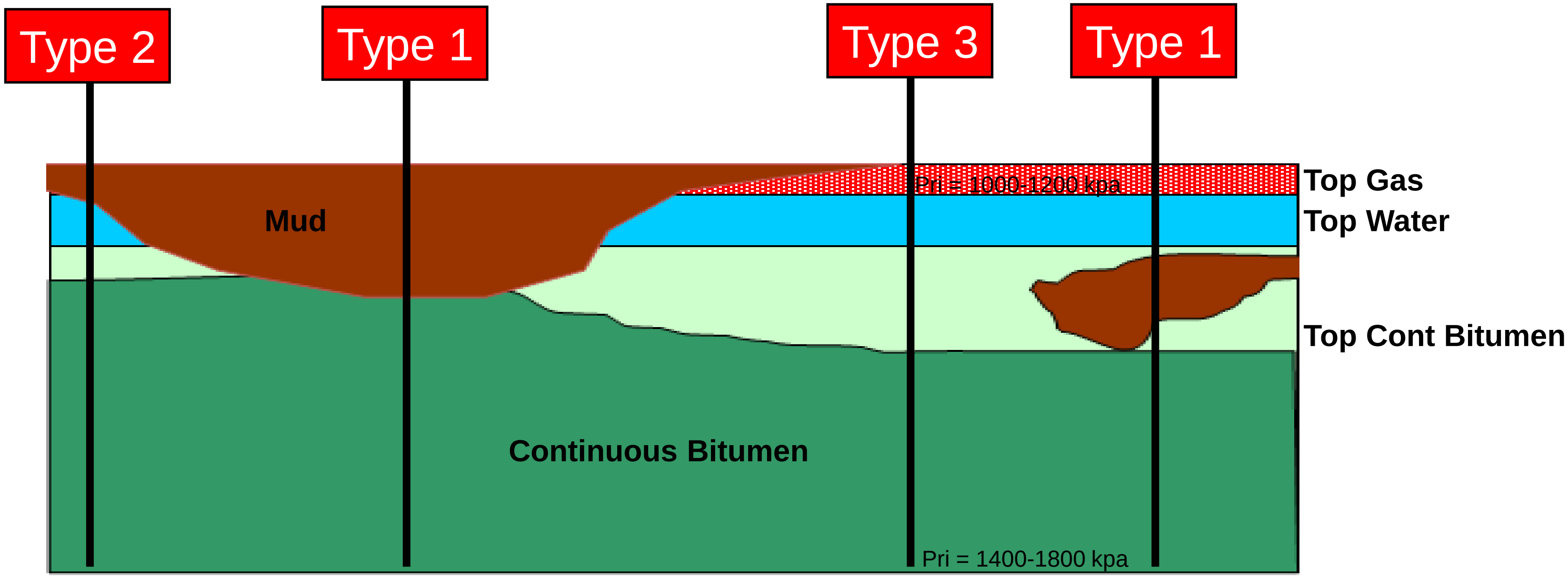
OBIP = bulk volume x Φ x So

NCB = producer
to Vsh cutoff of 33%





Recovery Factor vs Thief Zone Type



1 = No thief zone, highest recovery, 45%+

2 = Limited thief zone, medium recovery, 40%+

3 = Thief zone, lowest recovery, 30%+

* Recoveries based on simulations and in-house proxy tool

No change in 2014

OBIP and Recovery Factor (Jan 31, 2015)

Pilot and Phase 1 Recovery

Drainage area	OBIP (e3m3)	Avg Phi %	Avg So %	Expected Rf %	Cum Prod (e3m3)	Current Rf %
101N	7,296	32.5%	80.0%	50%	1,293	17.7%
101S	10,396	33.3%	80.3%	50%	2,353	22.6%
102N	7,379	32.7%	80.6%	50%	1,831	24.8%
102S	7,353	31.3%	74.2%	50%	2,842	38.6%
Pilot A	608	32.3%	82.9%	50%	247	40.6%
Pilot B	598	32.6%	83.1%	50%	289	48.4%
Pilot C	1,216	33.1%	84.8%	N/A	95	7.8%
Pilot A&B	1,205	32.4%	82.9%	50%	536	44.4%

OBIP = Thickness x Phi x So x Area

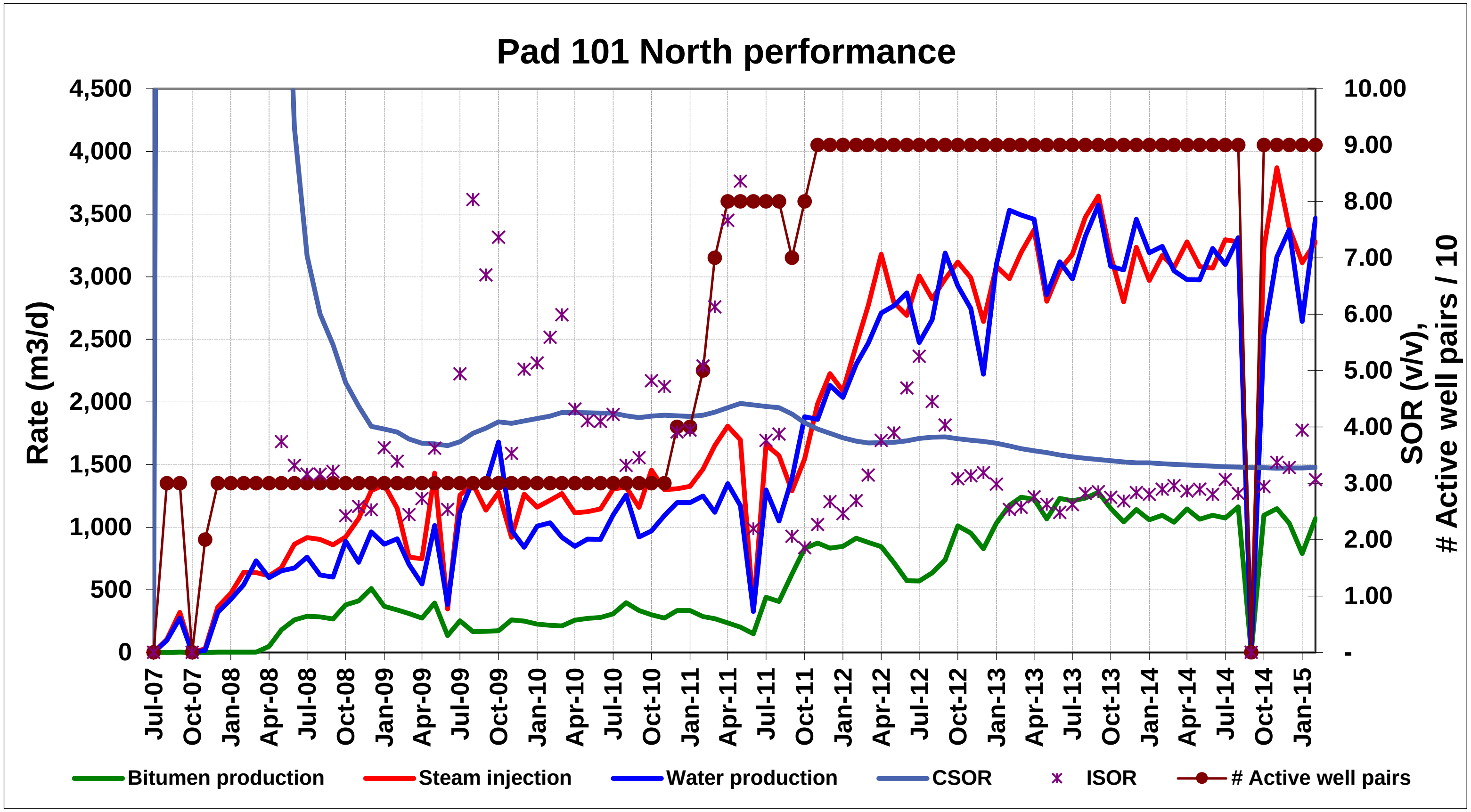
Thickness = Calculated from the top of continuous bitumen to the producer depth

Area = Polygons around each well pair of 125 m x length of lateral section

- *Expected ultimate recovery dependent on blowdown timing and operating strategy*

OBIP and Recovery Factor (Jan 31, 2015)

- Low Recovery Pad Example – Pad 101 North
  - 11 well pairs drilled
  - Low recovery essentially due to late start-up:
    - 3 well pairs started in 2007
    - 6 well pairs started end 2010 / beginning 2011
      - *2 well pairs scheduled for ESP conversion middle of this year (Q3/2015)*
    - 2 infill well pairs deferred to 2017 (101-25 & 26)



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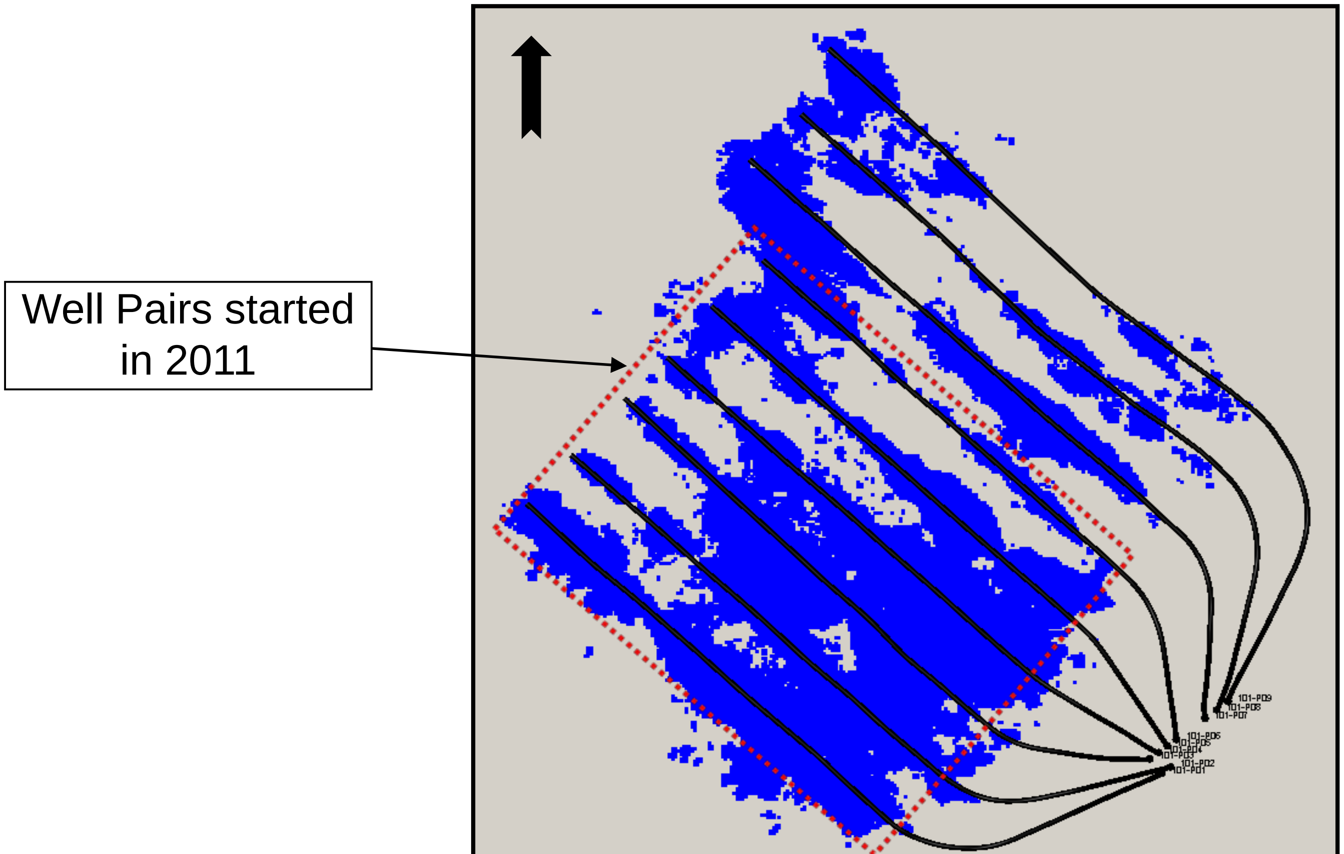
OBIP and Recovery Factor (Jan 31, 2015)

- Low Recovery Pad Example – Pad 101 North
  - 4D seismic monitoring – September 2014
  - Low recovery to date but still in the early time
  - Fairly good steam chamber conformance



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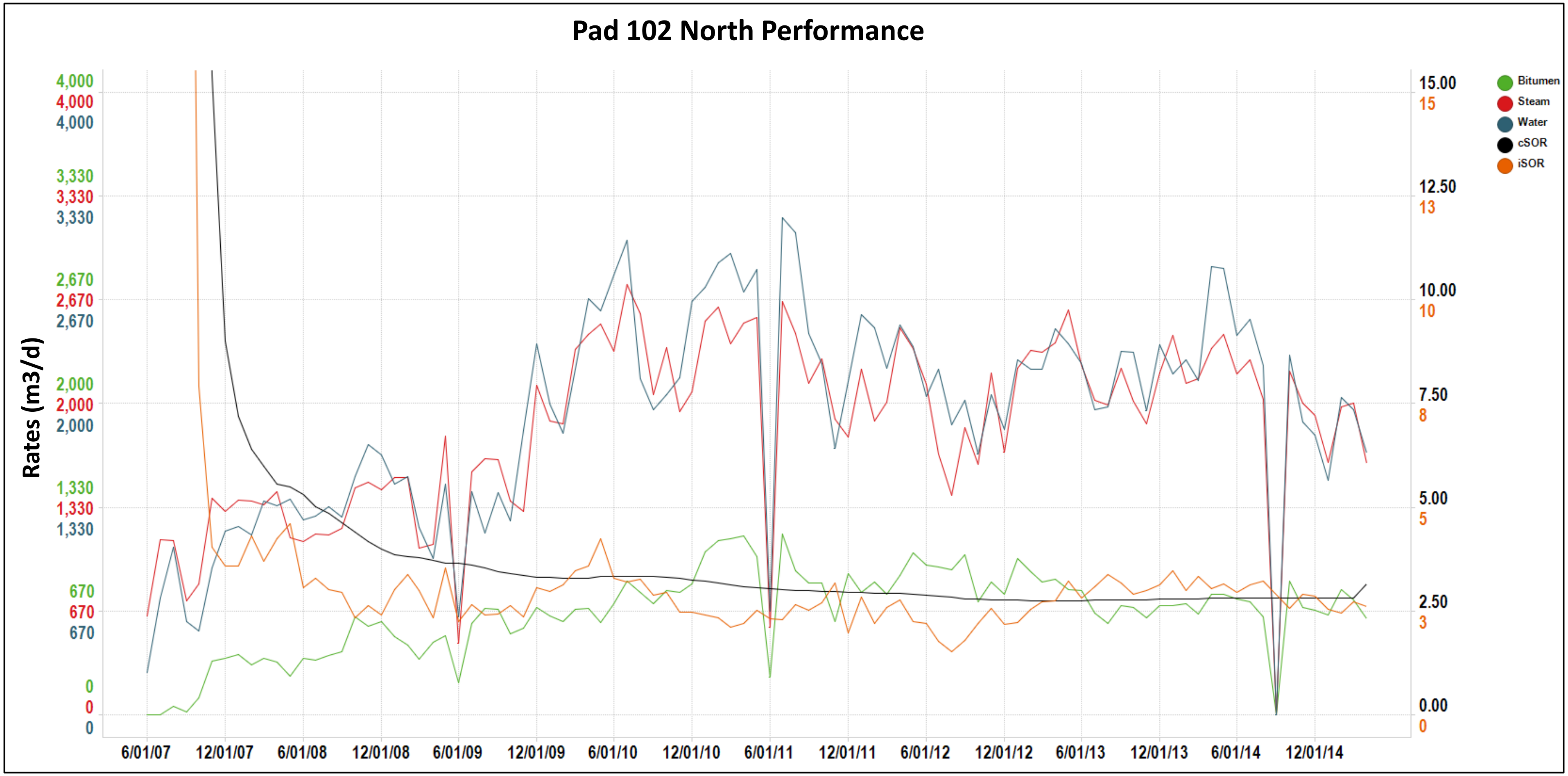
OBIP and Recovery Factor (Jan 31, 2015)

- Medium Recovery Pad Example – Pad 102 North
  - 9 well pairs drilled (2 cold fishbone infill producers)
  - Medium recovery at 32.7%



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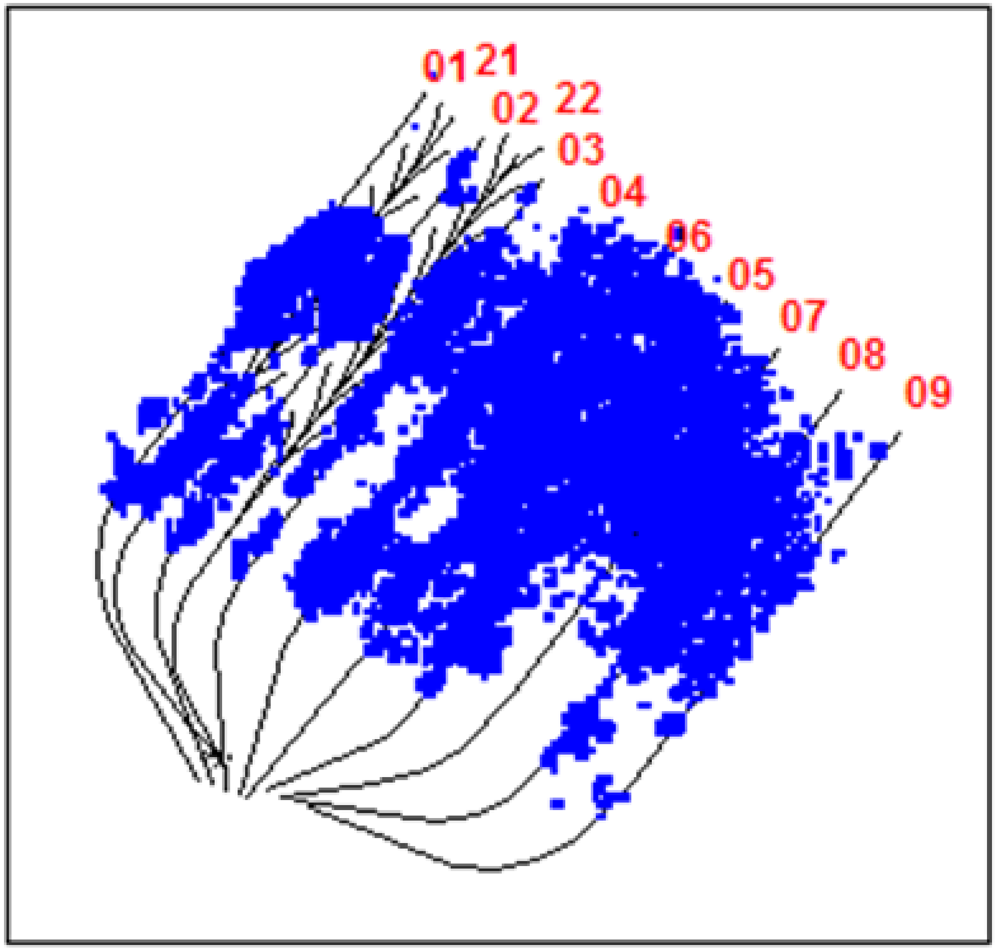
OBIP and Recovery Factor (Jan 31, 2015)

- Medium Recovery Pad Example – Pad 102 North
  - 4D seismic monitoring – September 2014 monitor
  - Good steam chamber development over mature wells



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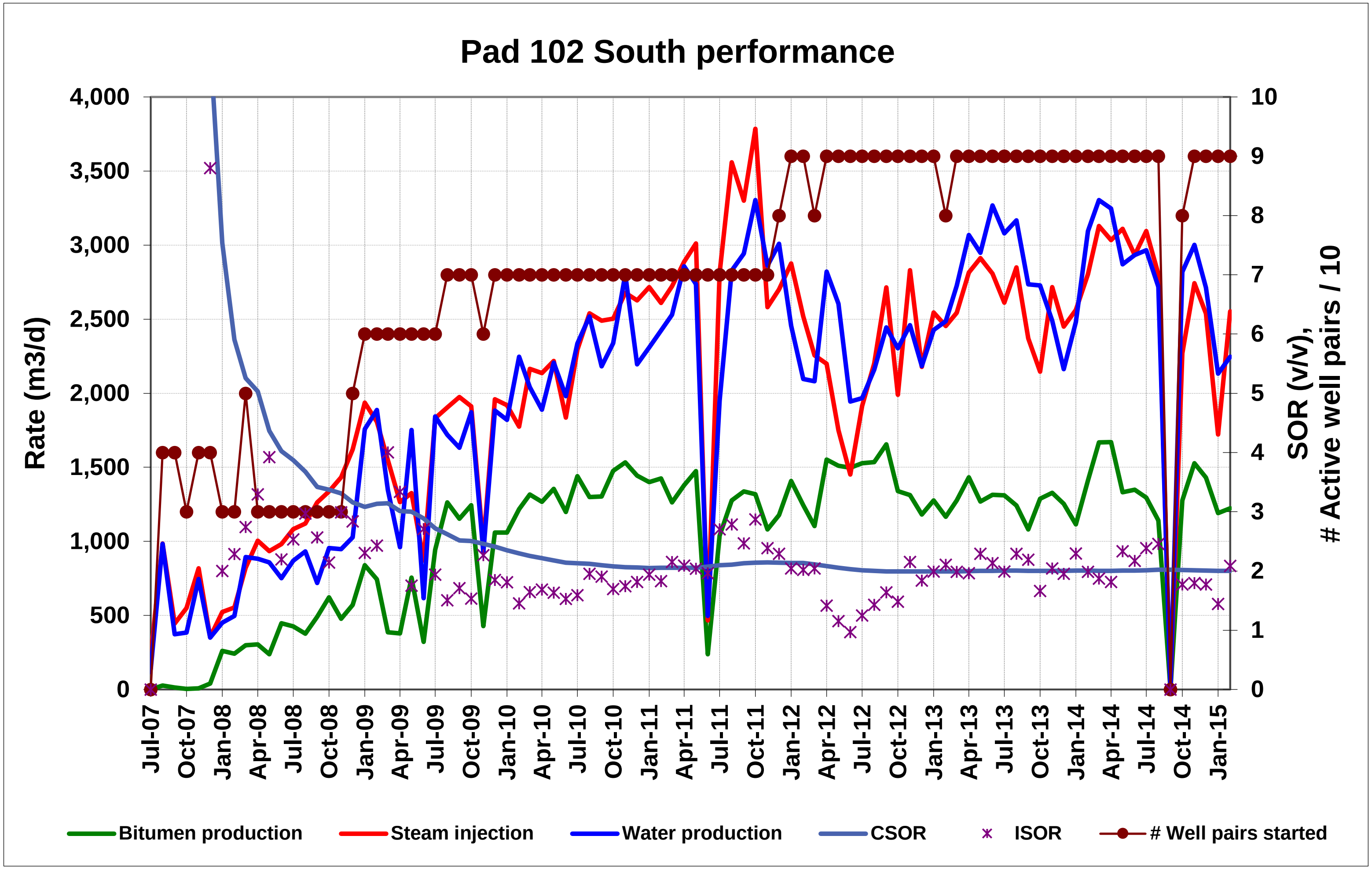
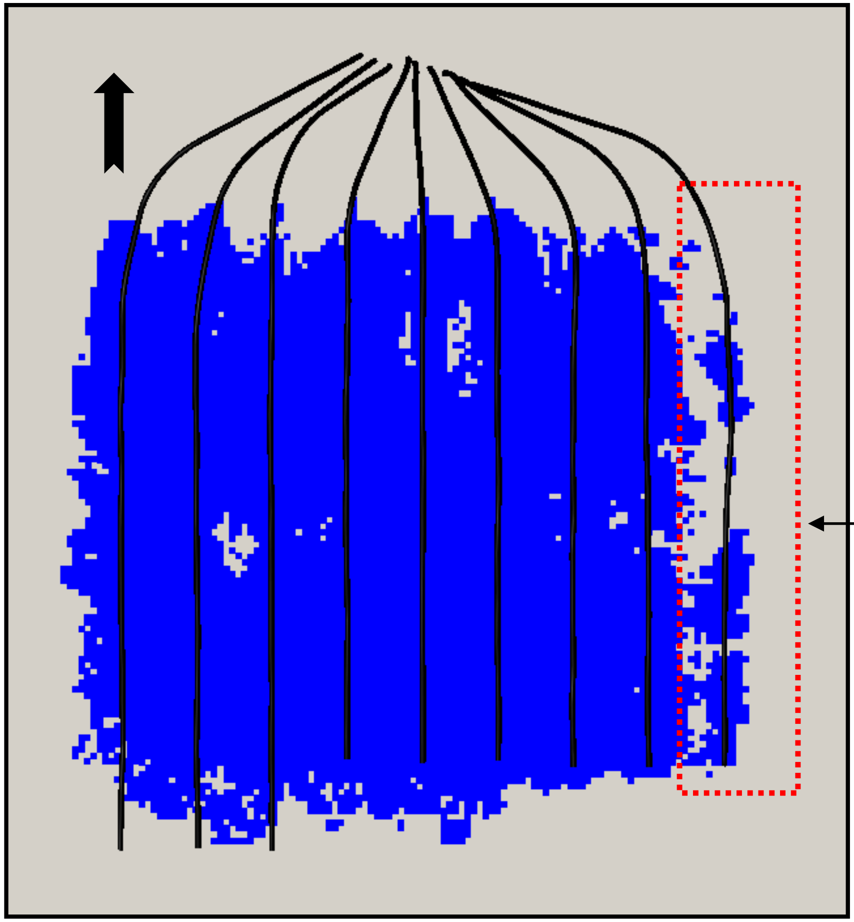
OBIP and Recovery Factor (Jan 31, 2015)

- High Recovery Pad Example – Pad 102 South
  - 9 well pairs drilled
  - High performance well pairs



OBIP and Recovery Factor (Jan 31, 2015)

- High Recovery Pad Example – Pad 102 South
  - 4D seismic monitoring – April 2014 monitor
  - Good steam chamber development over mature wells

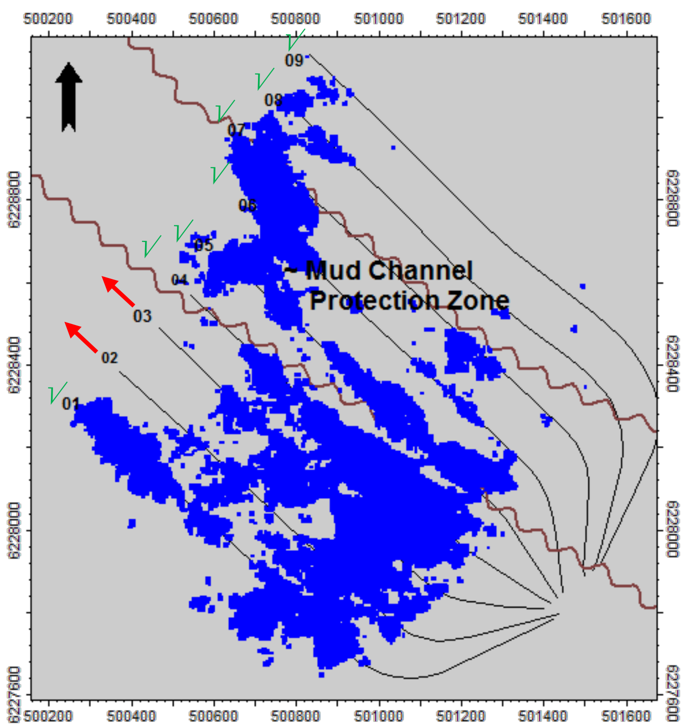


Well Pairs converted into SAGD in 2012 – 102-10 & 102-11

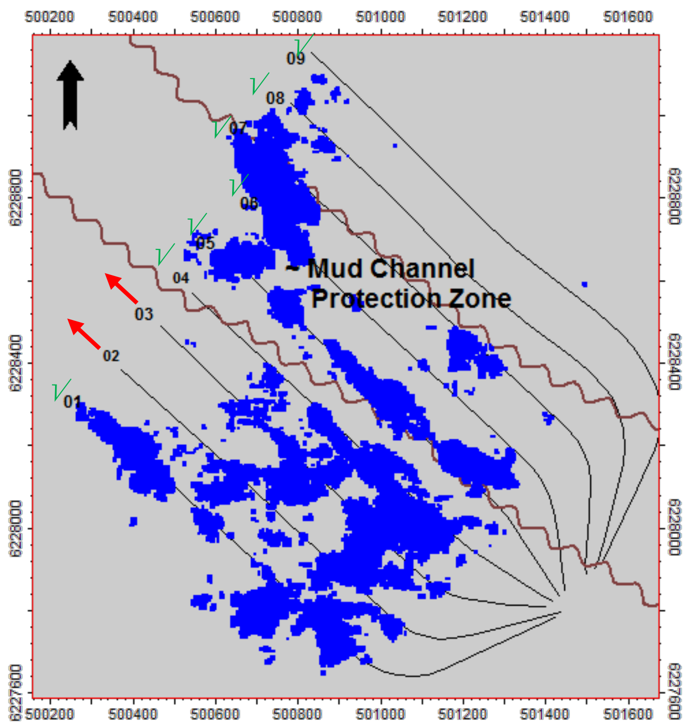
Top Steam Chamber Monitoring (4D Isocontours)

Pad 101 North

10 meters below Thief Zone (Water)

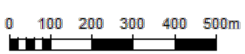


5 meters below Thief Zone (Water)



✓ ESP Converted

→ To be converted to ESP in 2015



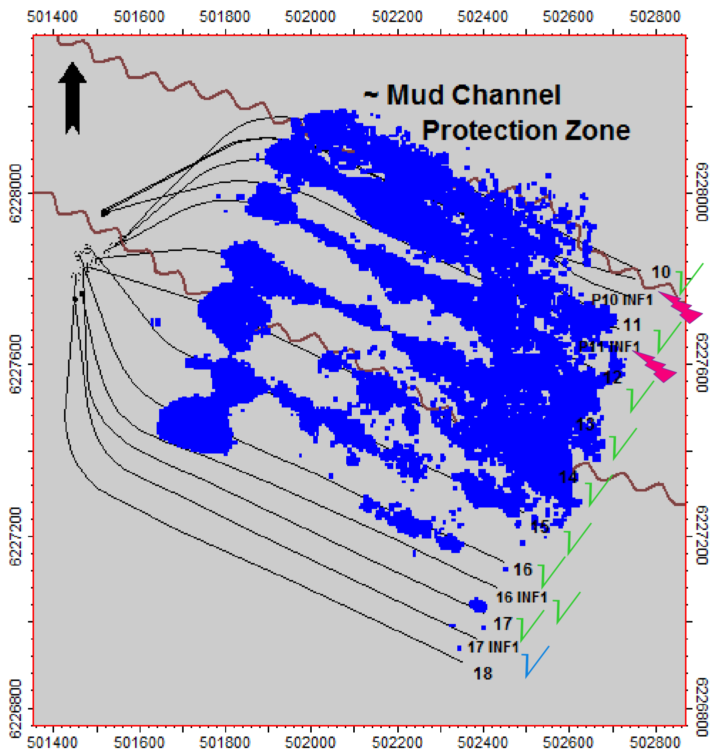
Latest available Phase 1 4D ~60°C isocontours

Steam chamber pressures have declined to 1,800 – 2,300 kPa

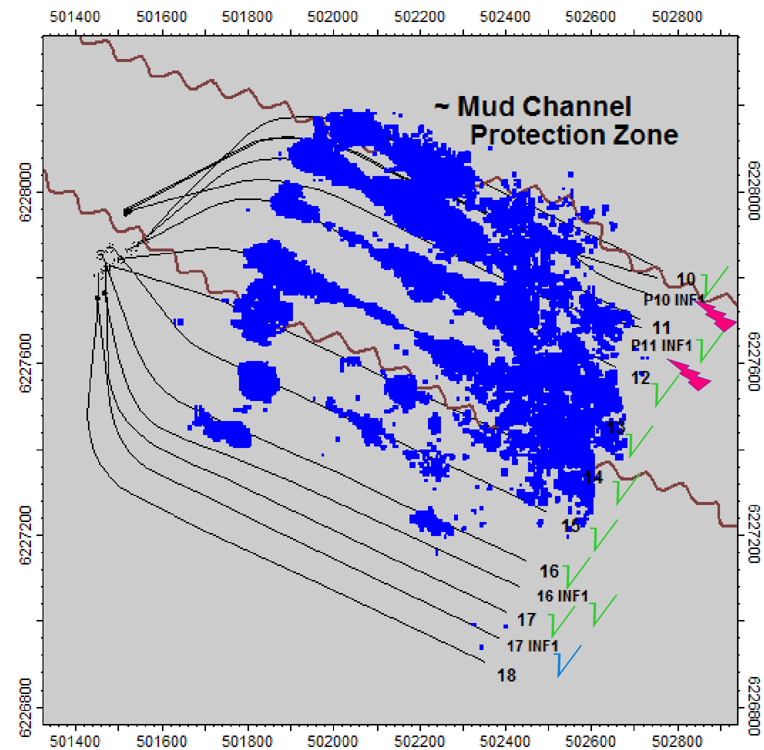
Top Steam Chamber Monitoring (4D Isocontours)

Pad 101 South

10 meters below Thief Zone (Water)



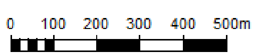
5 meters below Thief Zone (Water)



✓ ESP Converted

Operating on PCP

√ Converted to ESP in 2014

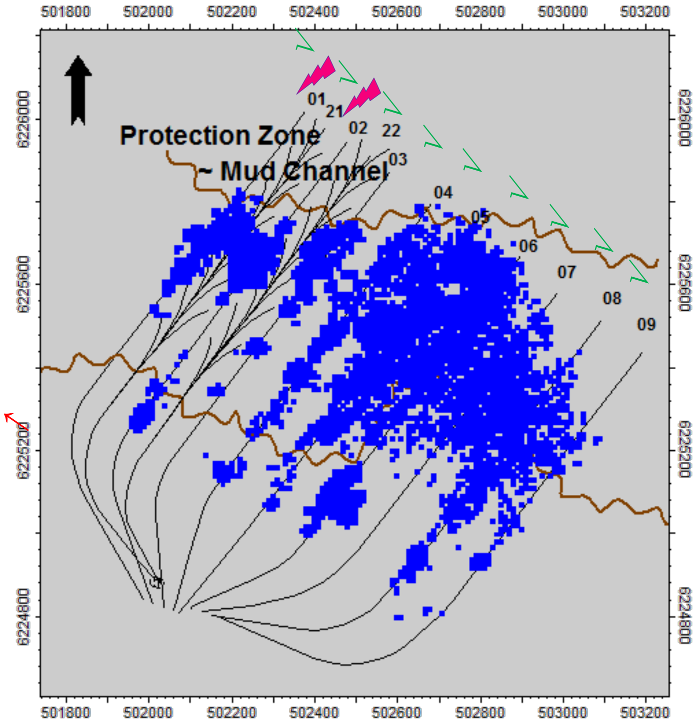


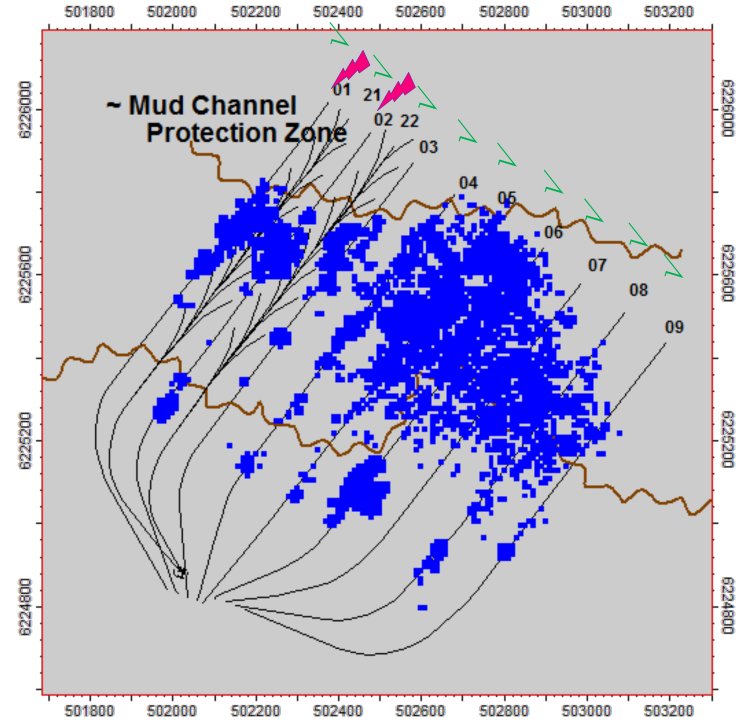
Steam chamber pressures have declined to 1,400 – 2,300 kPa

Latest available Phase 1 4D ~60°C isocontours

Top Steam Chamber Monitoring (4D Isocontours)

Pad 102 North (Monitor April 2014)





✓ ESP Converted

To be operated on PCP

0 100 200 300 400 500m

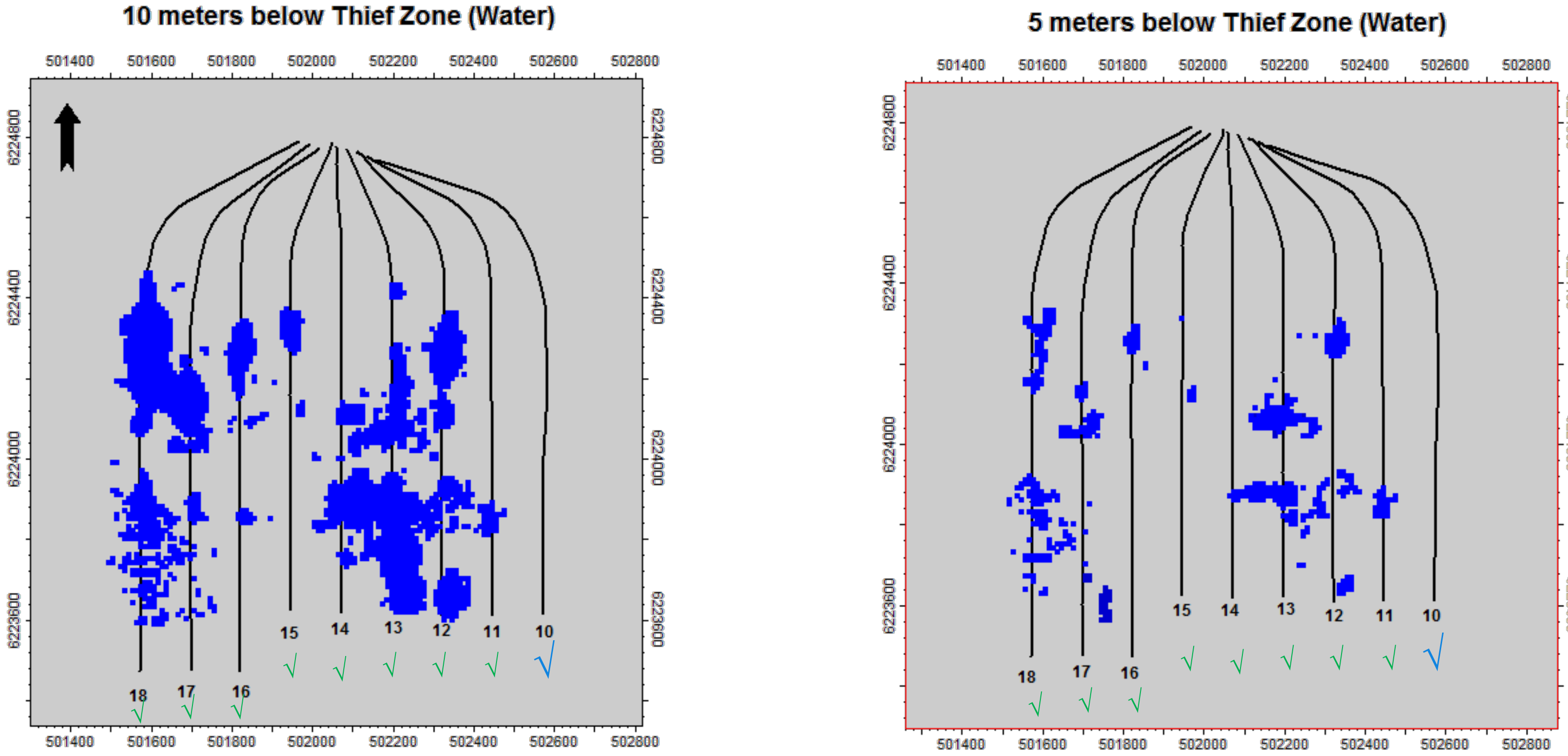
Latest available Phase 1 4D ~60°C isocontours

Steam chamber pressures have declined to 1,800 – 2,400 kPa

ConocoPhillips

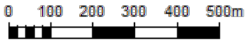
Top Steam Chamber Monitoring (4D Isocontours)

Pad 102 South



✓ ESP / PCP Converted

√ Converted to ESP in 2014



Steam chamber pressures have declined to 1,700 – 2,300 kPa

Latest available Phase 1 4D ~60°C isocontours

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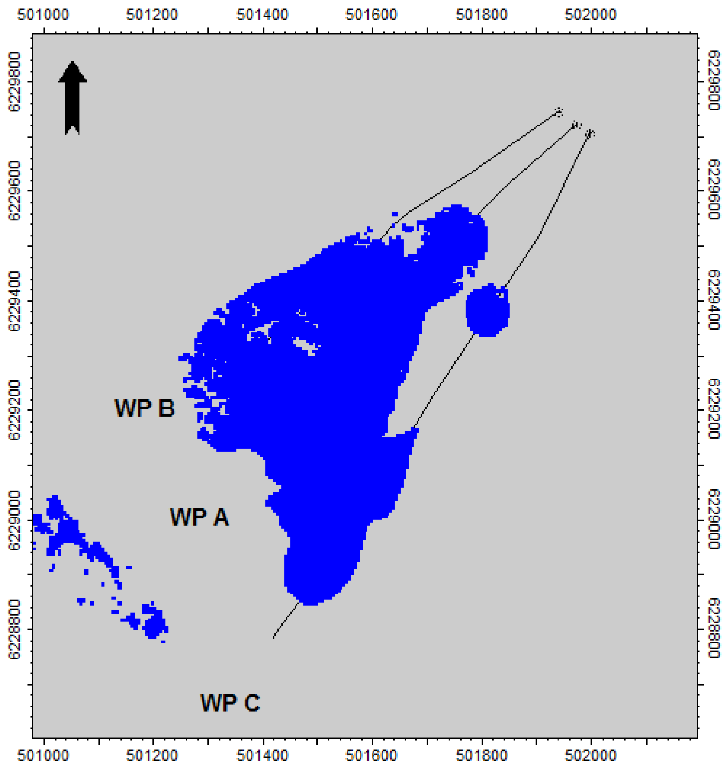
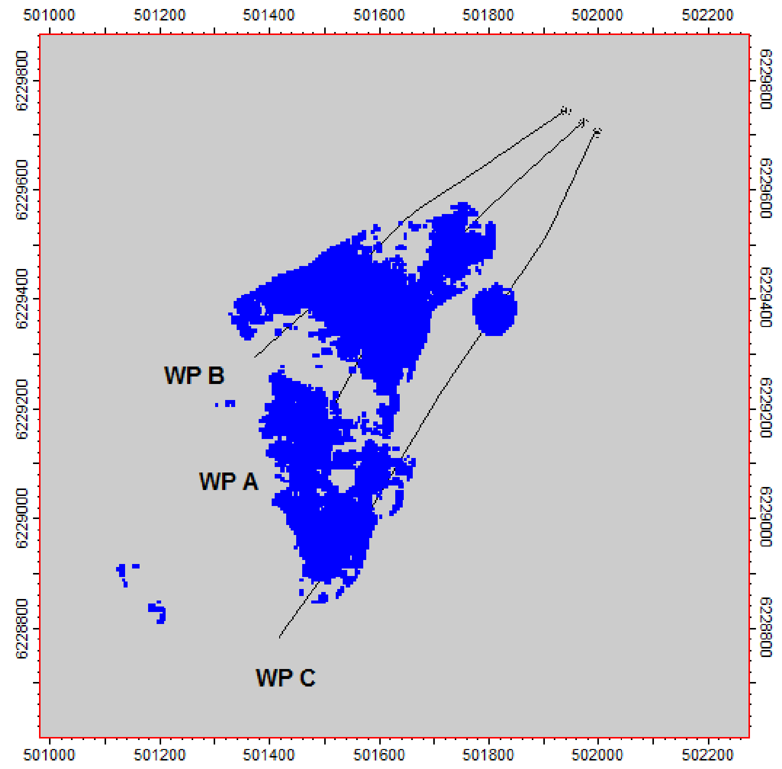
Top Steam Chamber Monitoring (4D Isocontours)

Pilot

10 meters below Thief Zone (Water)



5 meters below Thief Zone (Water)



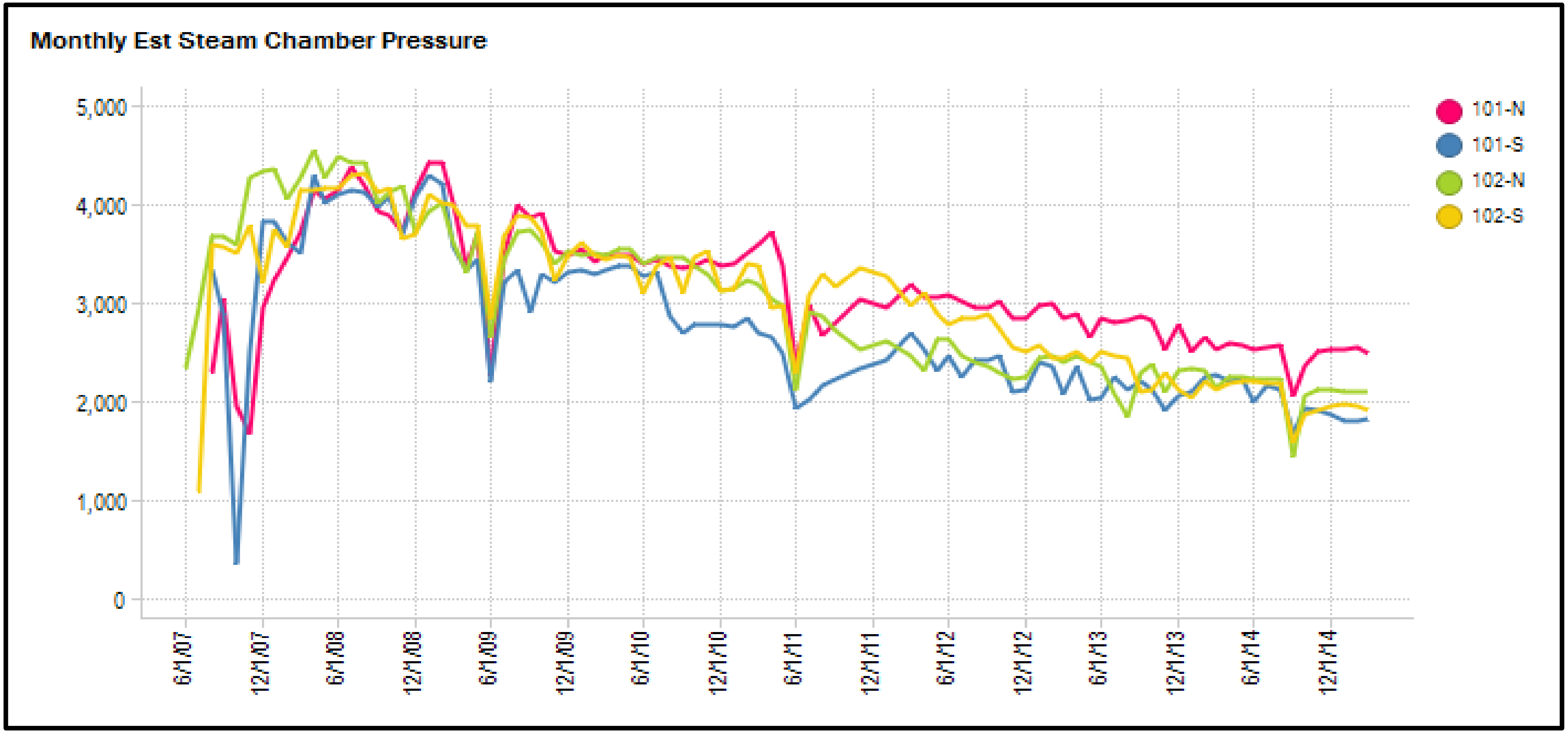
0 100 200 300 400 500m

Latest available Phase 1 4D ~60°C isocontours

Pilot operating pressure decreased to 1600 kPa for the last 5 years

Phase 1: Operating Pressure

- Operating Pressure
  - Progressively decrease operating pressure to manage interaction with top reservoir / thief zones
  - Well pairs converted to ESP to operate at lower pressure
  - 101 North at higher pressure due to ongoing technology trial



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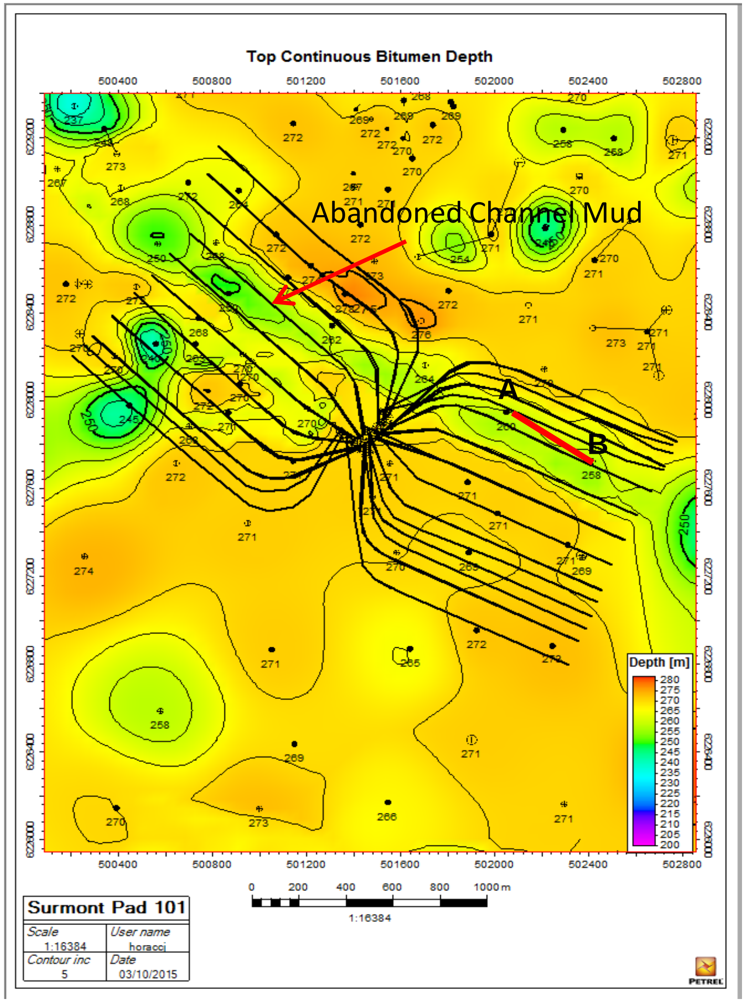
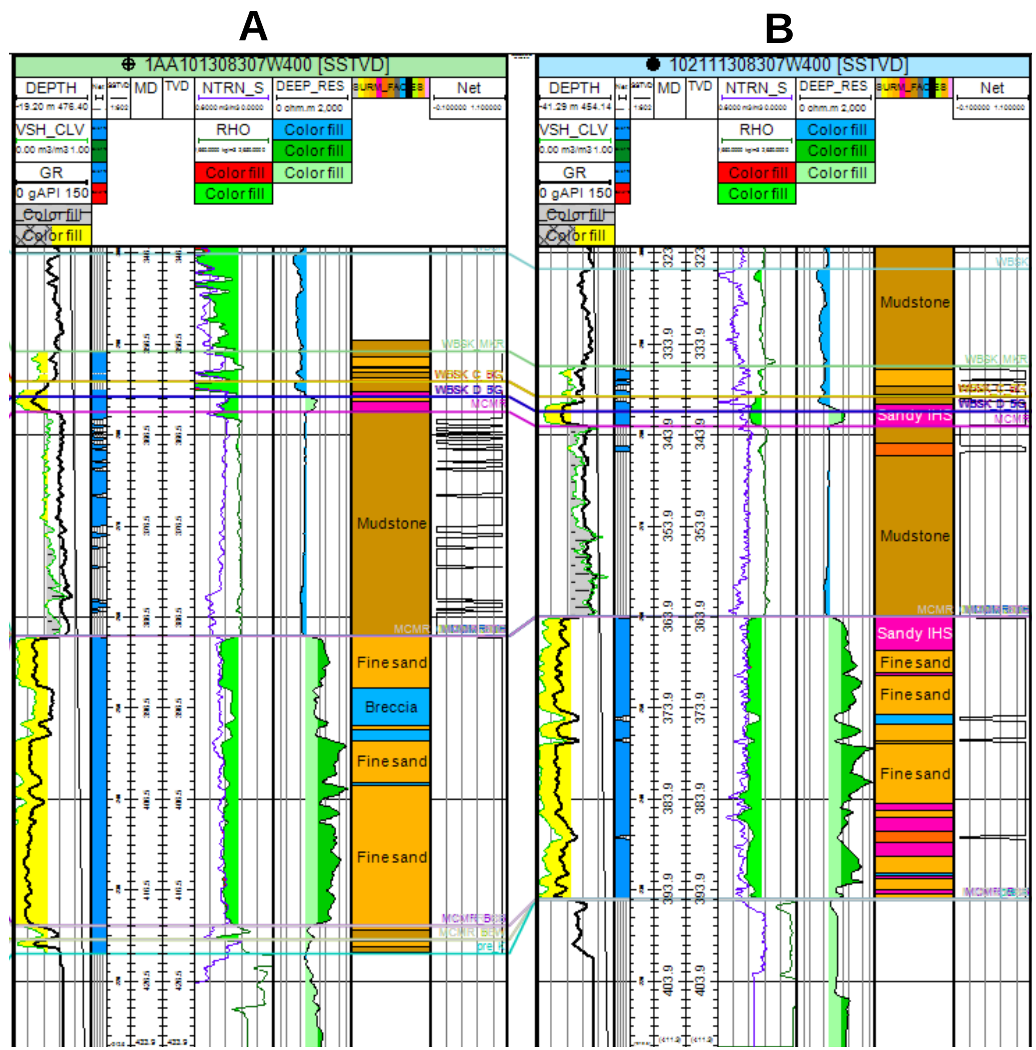
Phase 1: Pad 101 - Top Abandoned Mud Channel

- Pad 101: Abandoned mud channel overlaying bitumen interval





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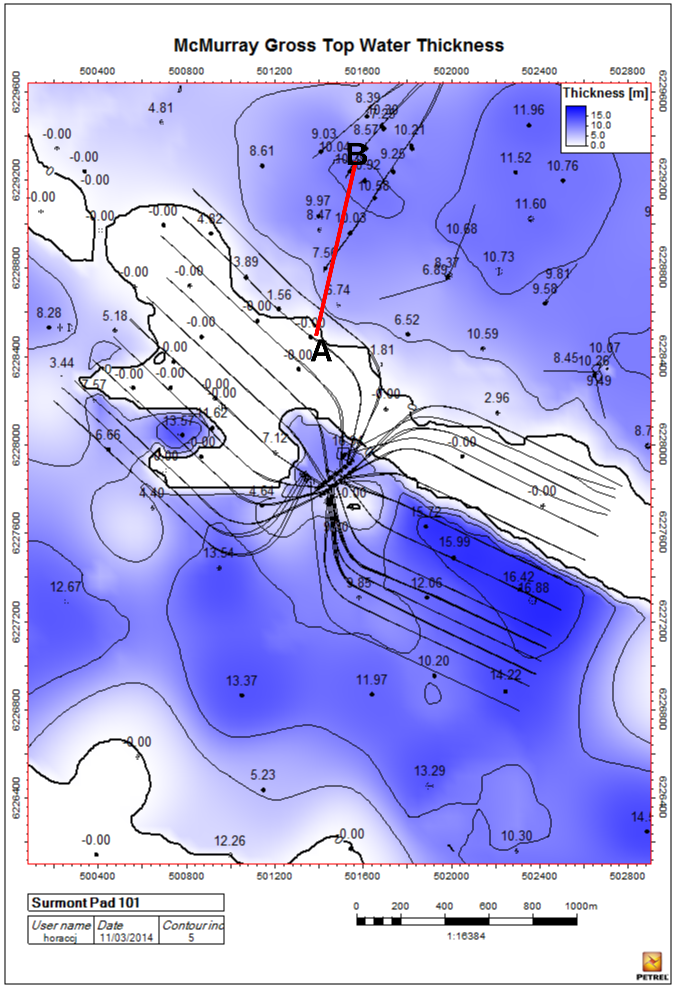
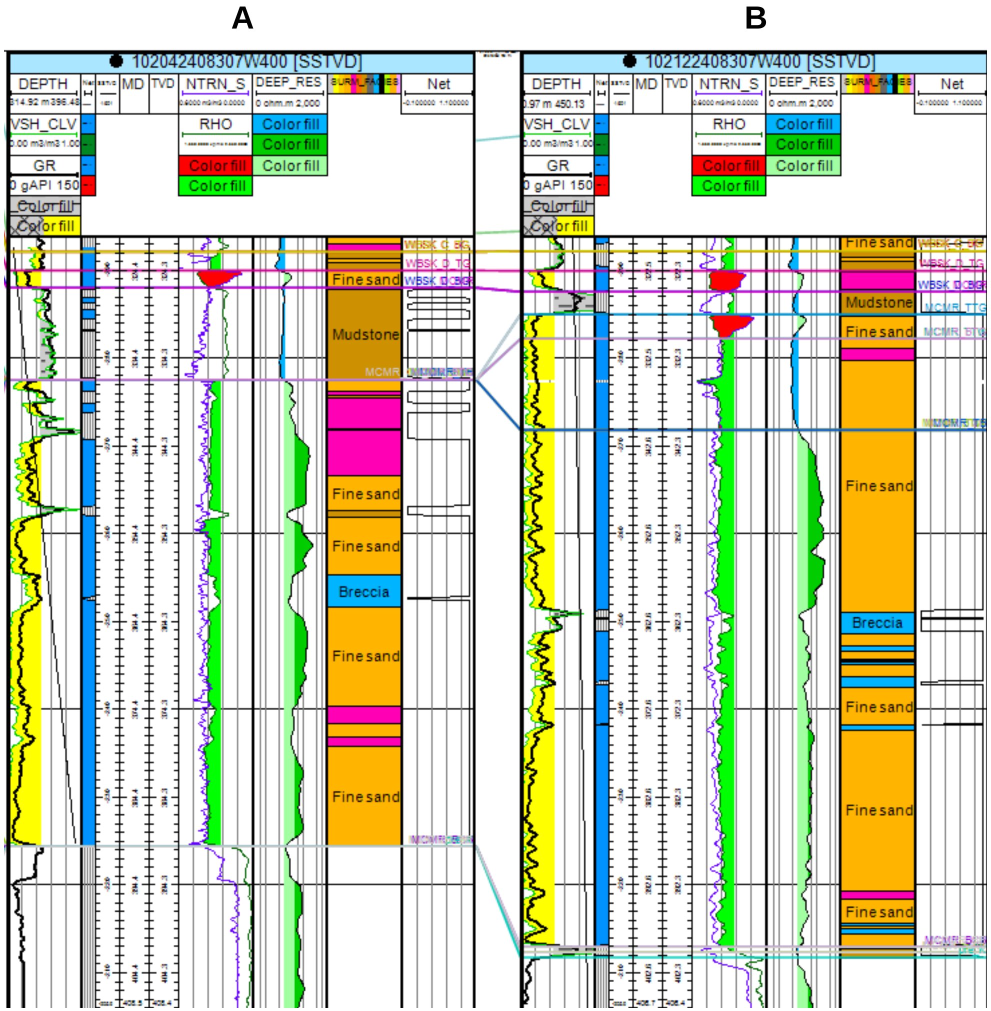
Phase 1: Pad 101 North - Top Water

- Top water: Extension of Pilot top water above Pad 101 North but limited





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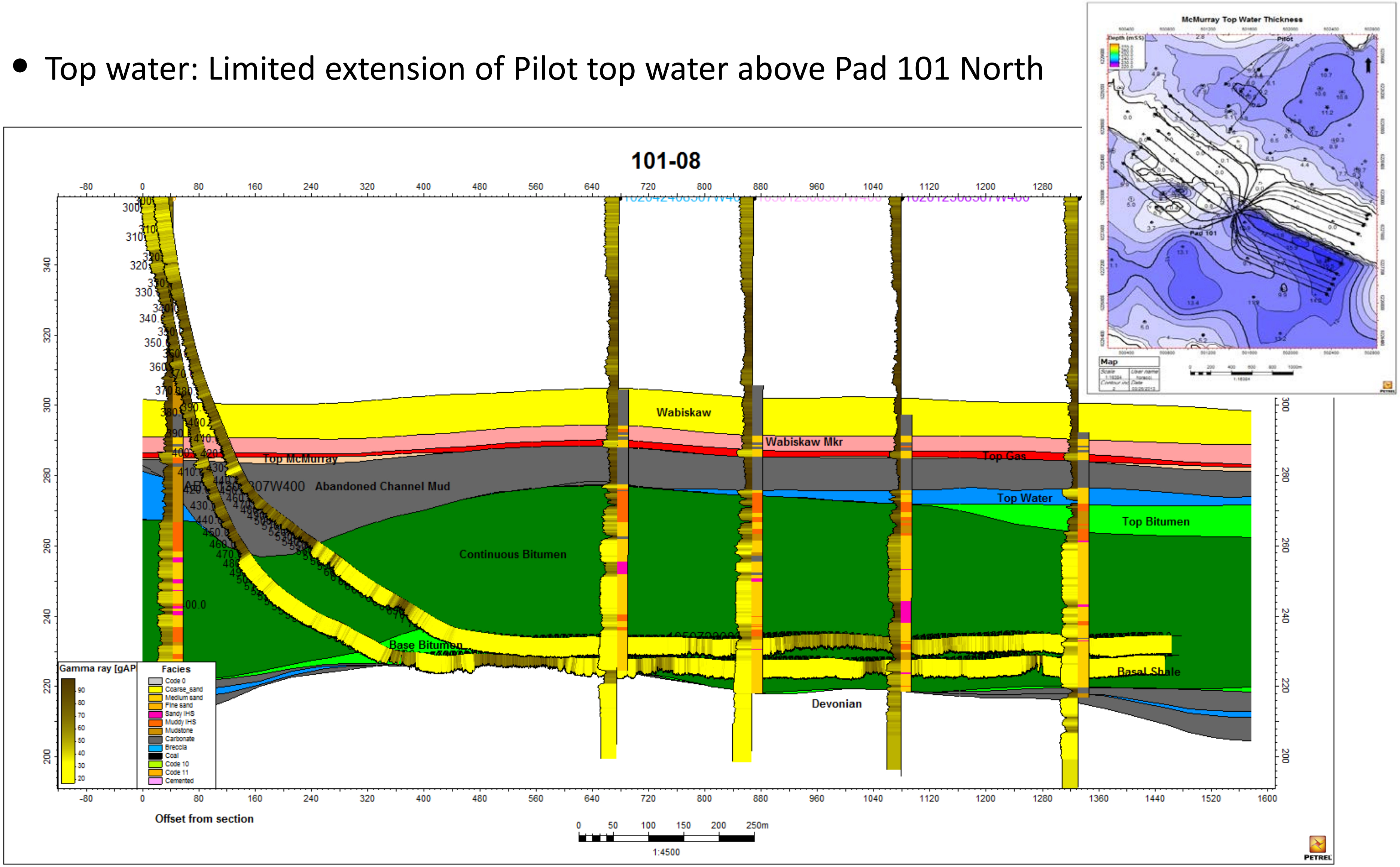
Phase 1: Pad 101 North - Top Water

- Top water: Limited extension of Pilot top water above Pad 101 North



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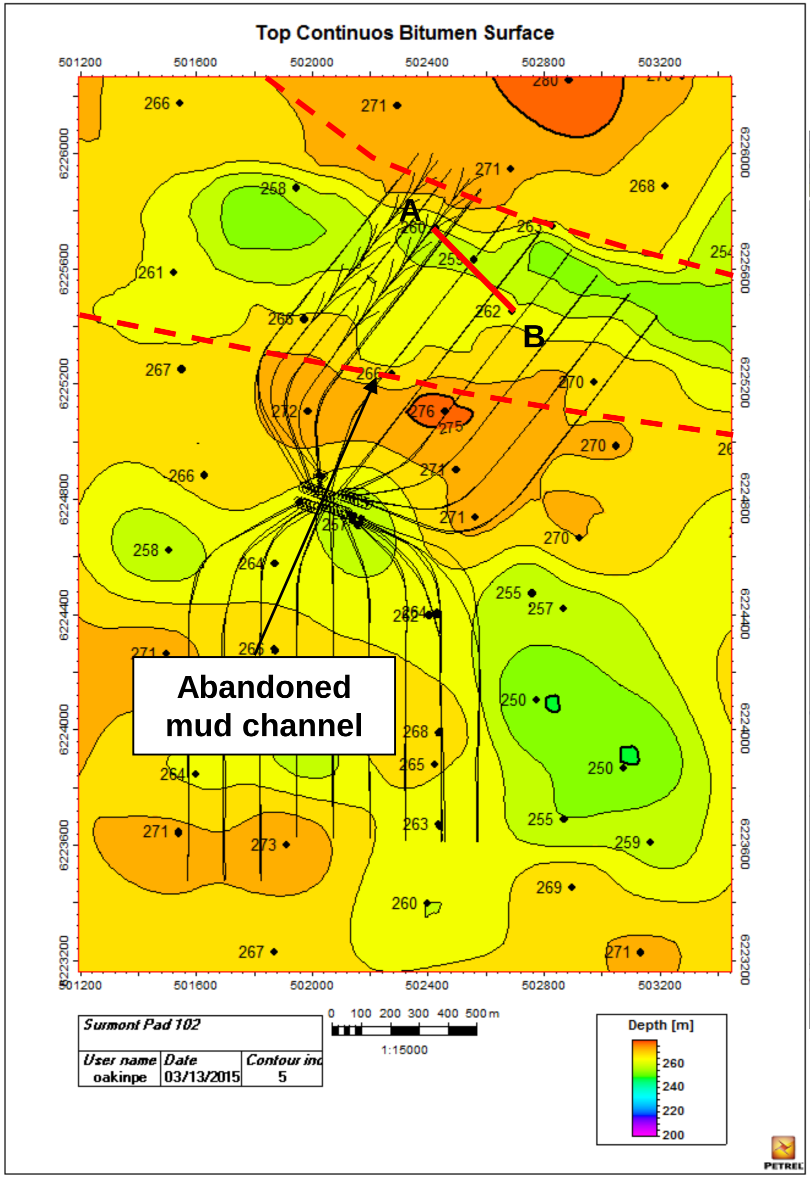
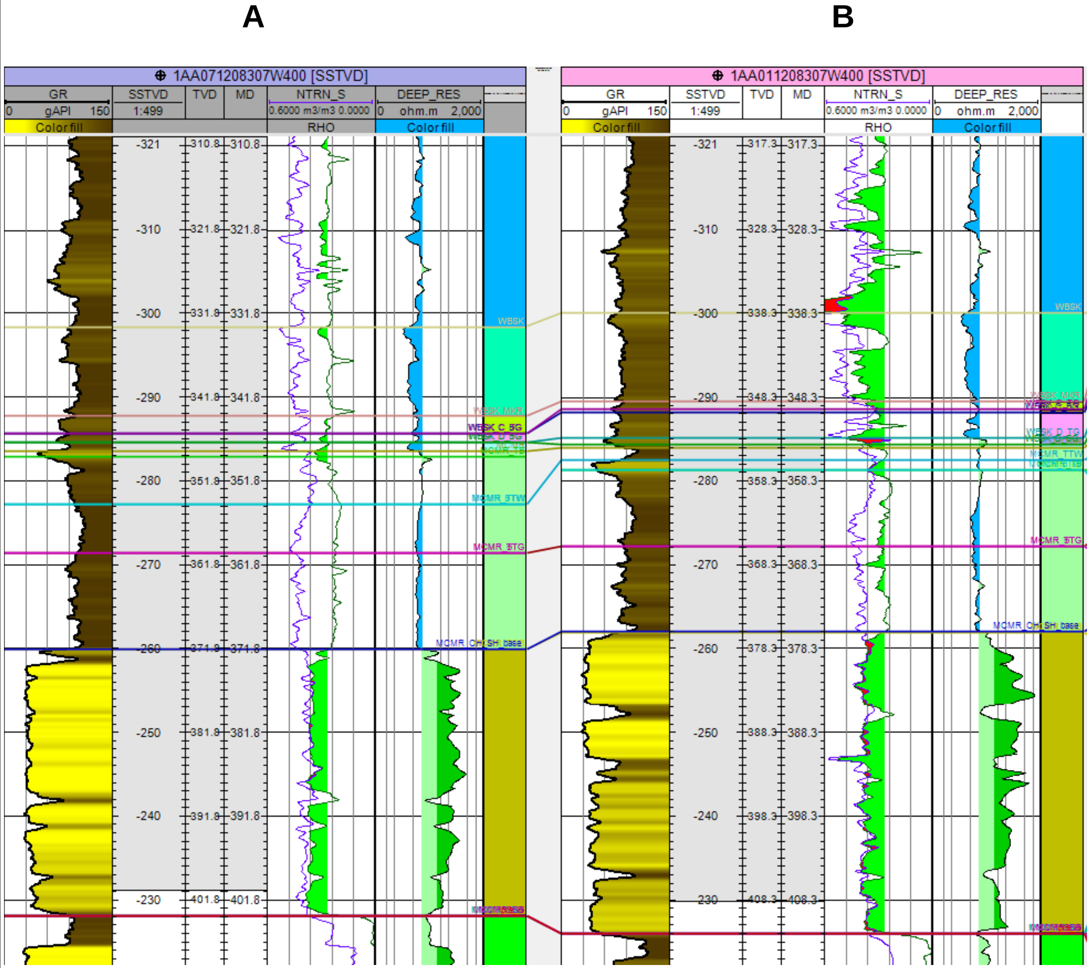
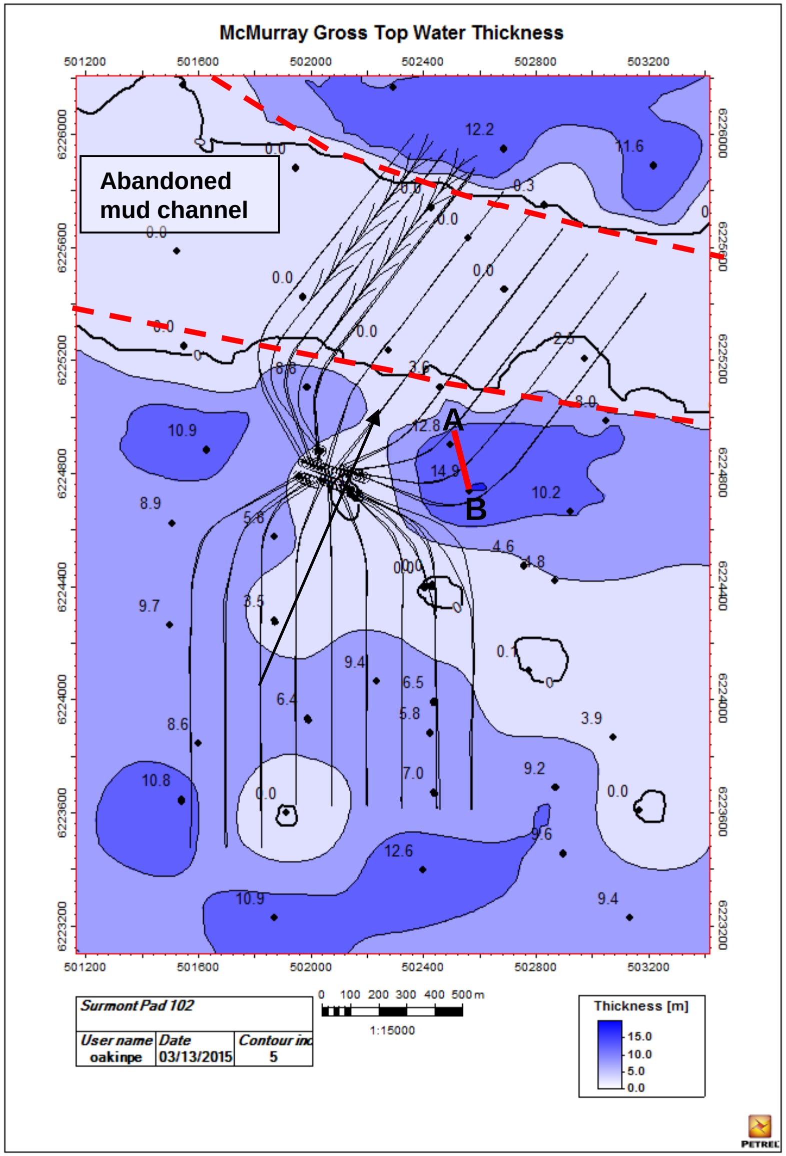
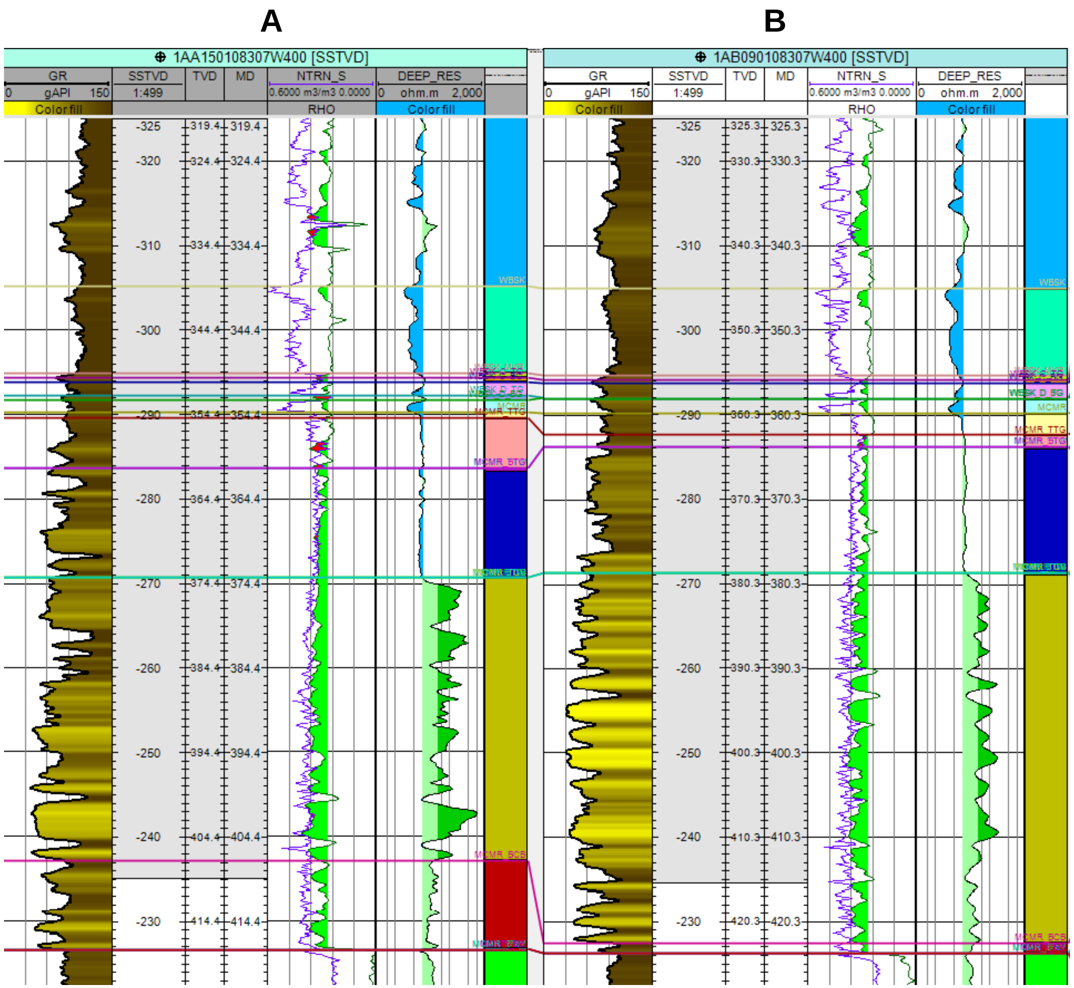
Phase 1: Pad 102 - Top Abandoned Mud Channel





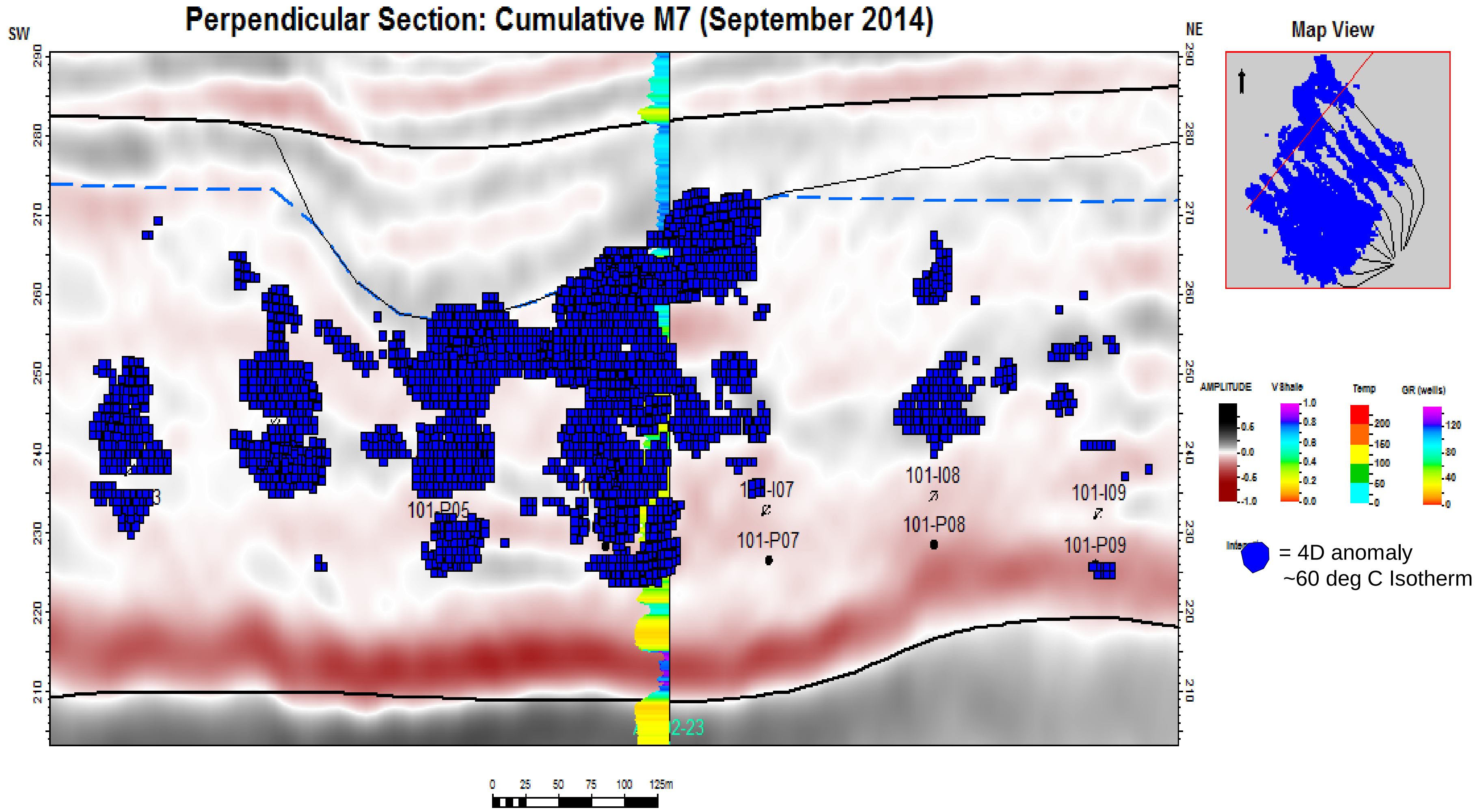
Phase 1: Pad 102 North - Top Water





Phase 1: Pad 101 North - Top Water

- Pad 101 North - Top water:
  - Development of the steam chamber towards top of reservoir – Monitor 7th Sept 2014



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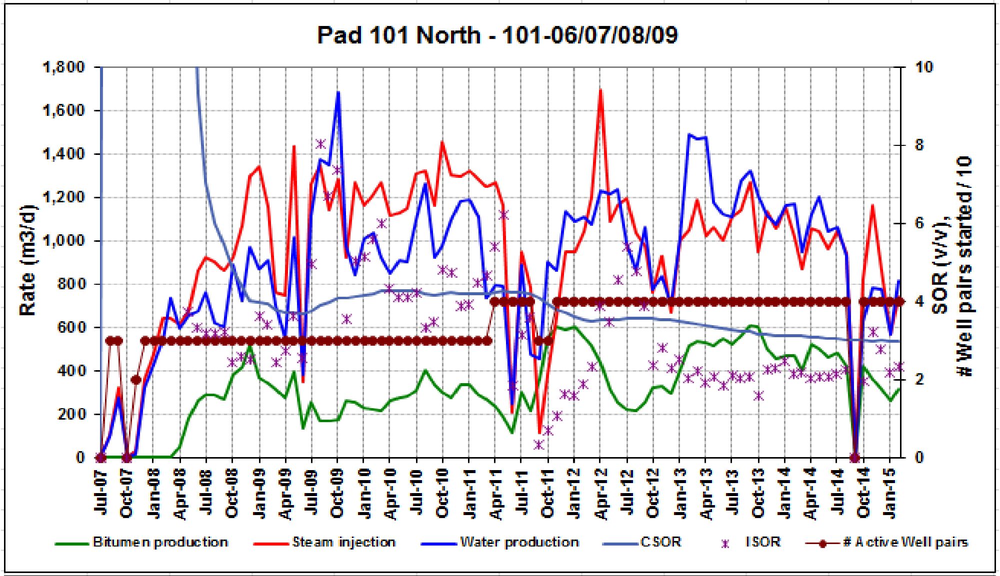
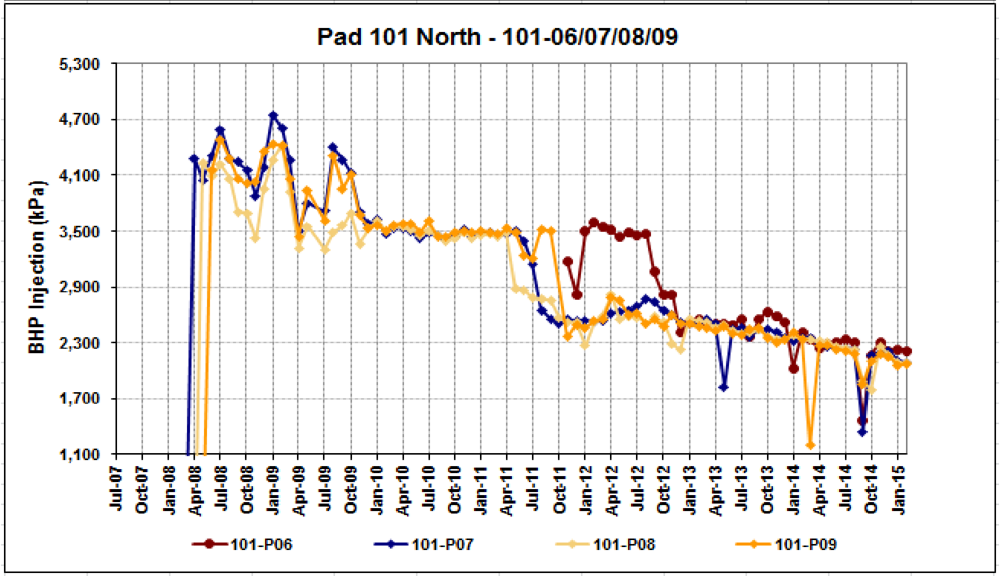
Phase 1: Pad 101 North - Top Water

- Pad 101 North - Top water:
  - Decrease operating pressure to manage interaction with top water and coalescence between well pairs
  - Well performances not impaired by top water
  - Stable pressure through 2014





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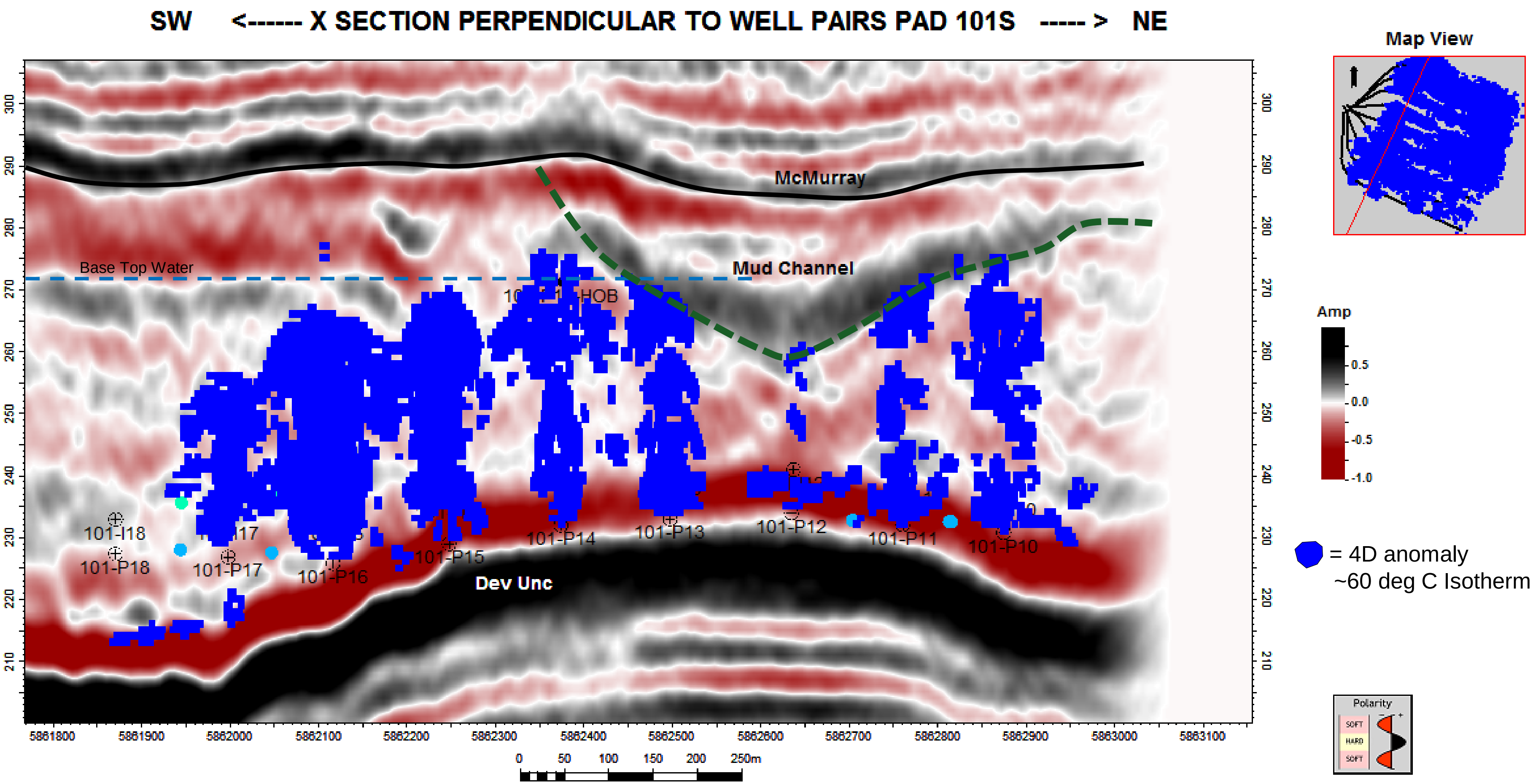
Phase 1: Pad 101 South - Top Abandoned Mud Channel

- Pad 101 South - Top abandoned mud channel:
    - Development of the steam chamber towards top of reservoir



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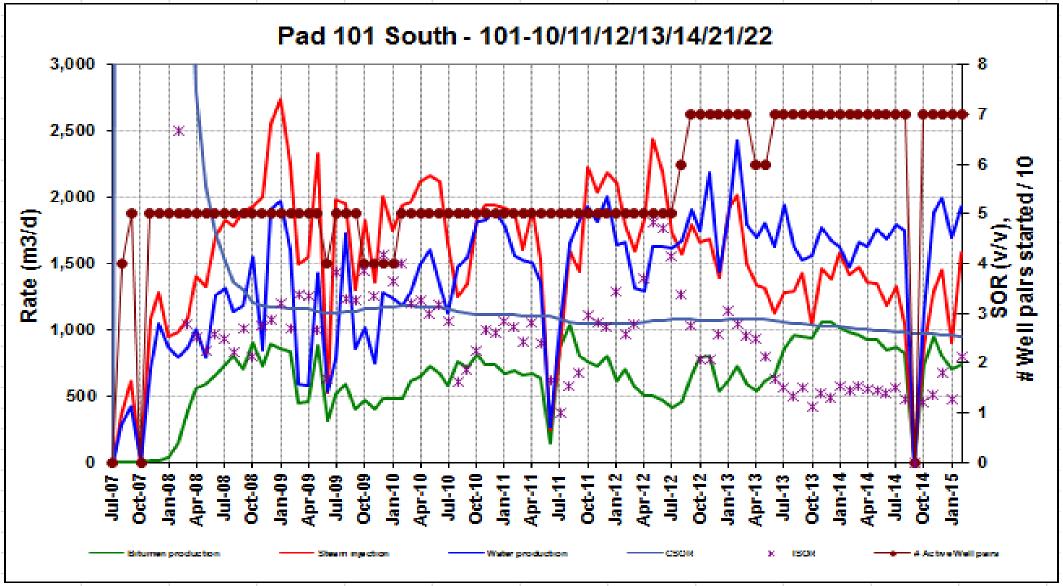
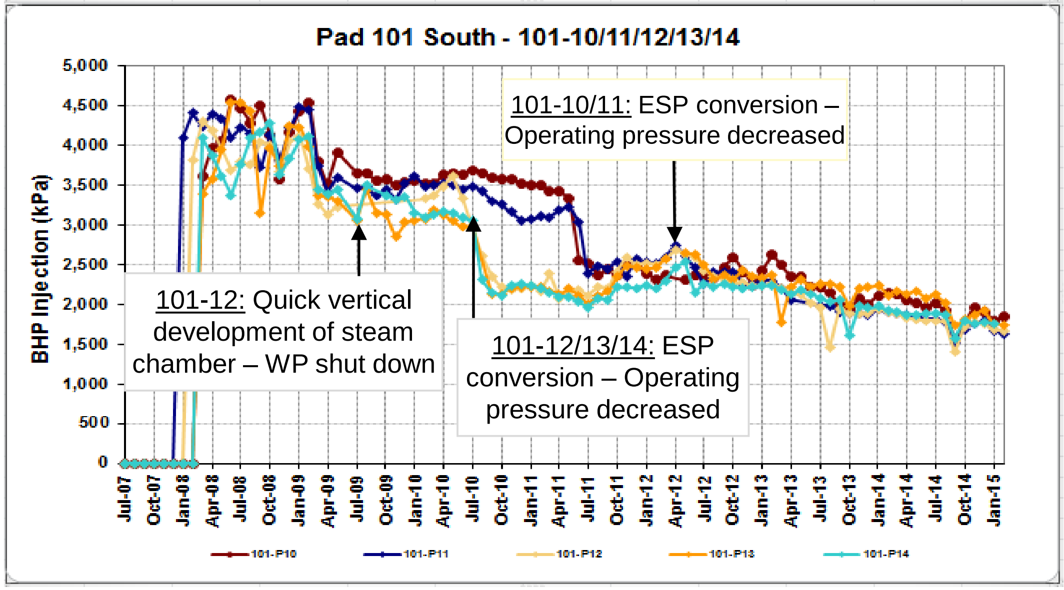
Phase 1: Pad 101 South Top Abandoned Mud Channel

- Pad 101 South (101-10/11/12/13/14)
  - June 2009: 101-12 steam chamber development up to the top reservoir. WP shut down. Restarted February 2010.
  - 101-12/13/14: ESP conversion in Aug/Sept 2010. Operating pressure decreased to manage interaction with the top of the reservoir
  - Stable performance since ESP conversion





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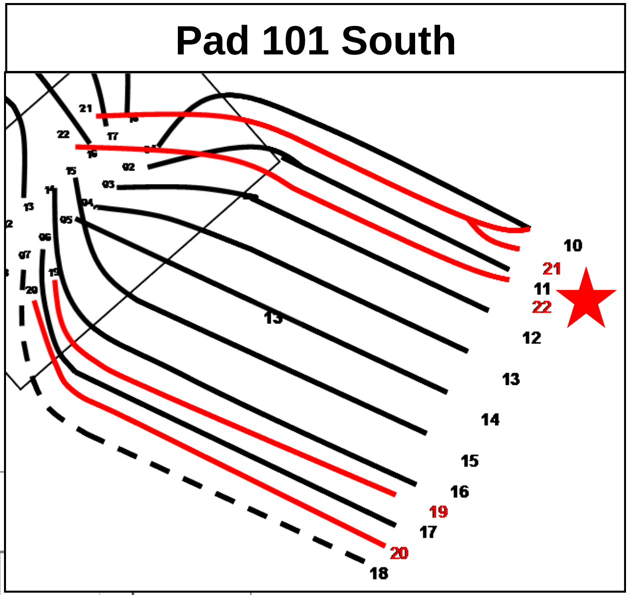
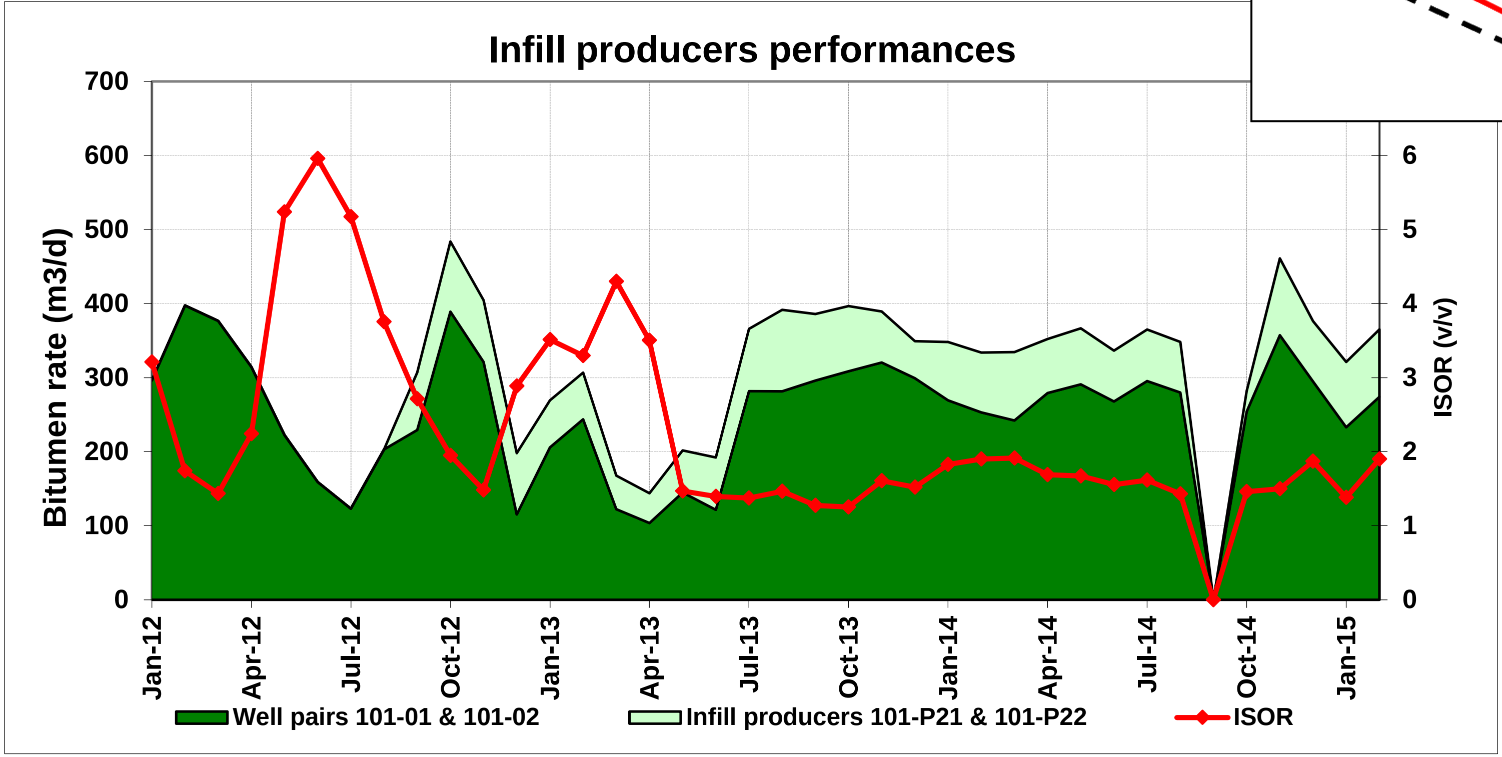
Phase 1: Pad 101 South - Infill Producer Performance

- Infill producers 101-P21 and 101-P22
  - Drilled in 2012
  - Open-hole hook in P21 and cased-hole hook in P22
  - Completed with PCP and started in Sept 2012
  - Steam injection through the guide string stopped in August 2014
  - Average daily bitumen rate ~38-47m3/d (per well)





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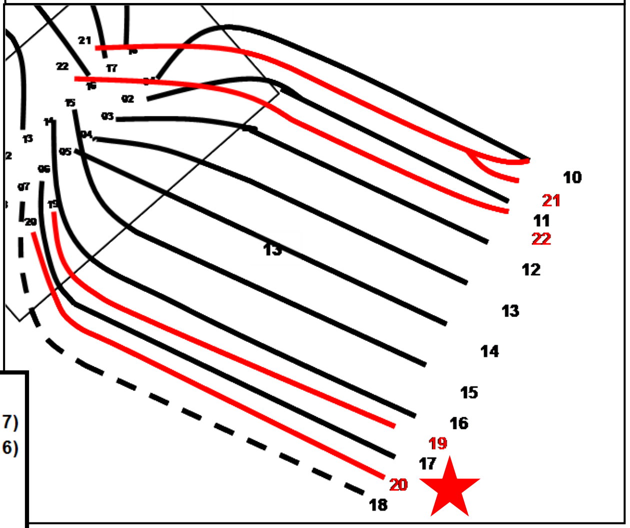
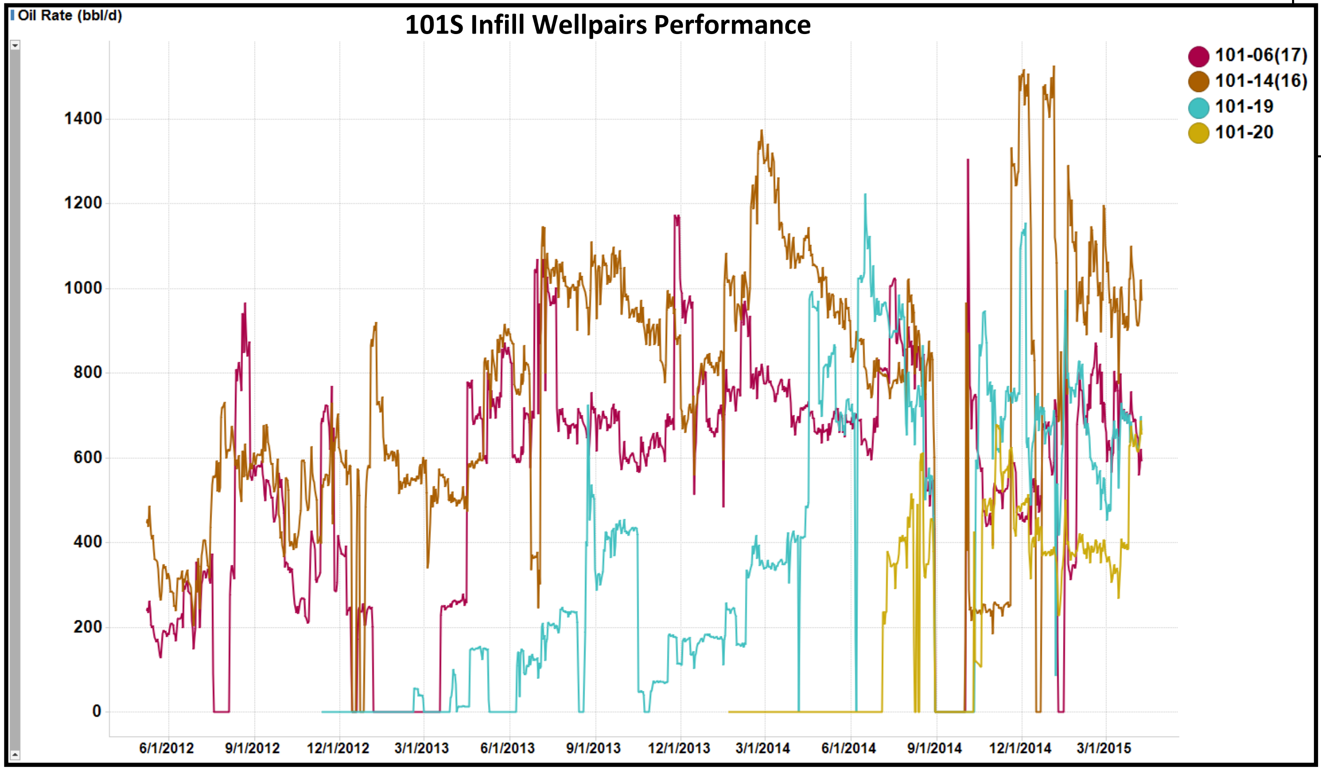
Phase 1: Pad 101 South Infill Well Pairs Performance

- Infill Well Pair 101-P19 (16INF) and 101-P20 (17INF)
  - Drilled in 2012
  - Completed with concentric VIT in the injectors and concentric non-VIT in the producers
  - Completed with ESP Day1
  - Average daily bitumen rate ~400-700bbl/d (per well)

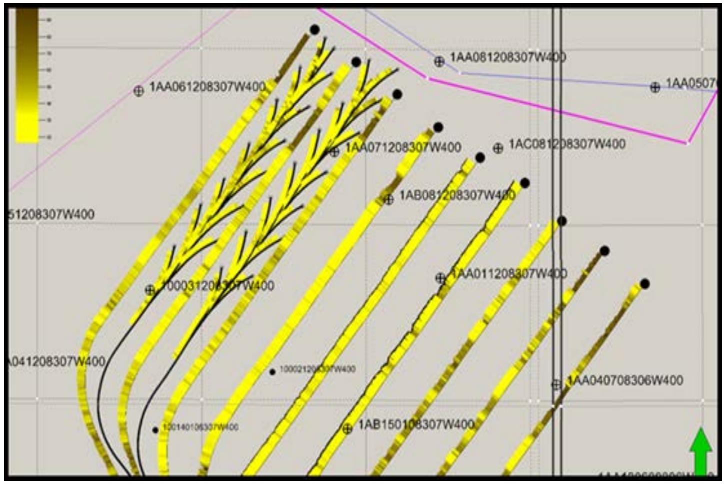


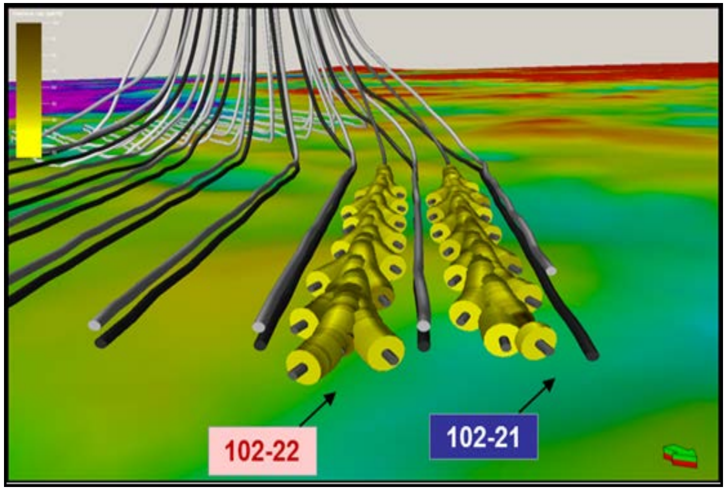


Phase 1: Pad 102 South - Fishbone Infill Producers

Key Milestones

- Drilled in Q3, 2013
- 1st fishbone well configuration ever in SAGD operations
- Successfully drilled 102-21 and 102-22 multilateral open-hole fishbone wells with approx. 14 ribs
- Successfully deployed flow control device (equalizer liner) in both fishbone wells
- 102-21 started in June 2014 and restarted in November after turnaround
- 102-22 started in November 2014
- No significant oil production to date (cold wellbore temperature)





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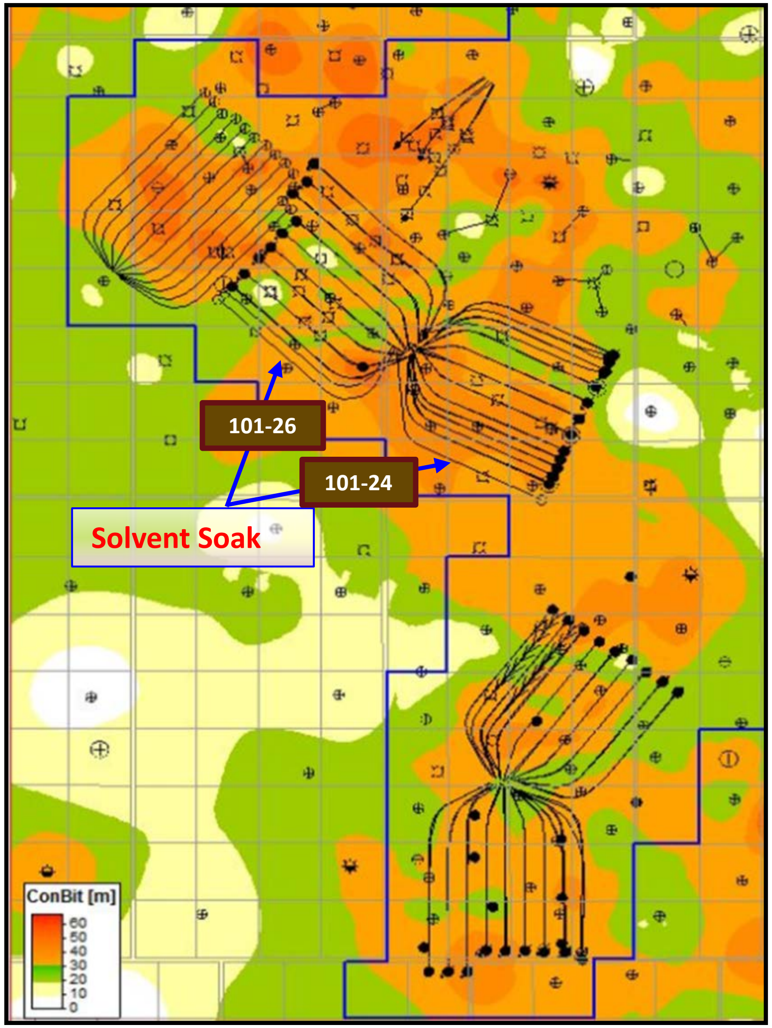
Solvent Soak Trial

Key Milestones

- Type of Solvent = Xylene
- Expected Injection Volume
  - Equivalent to 1 wellbore volume which is about 30 to 40 m3 of solvent per well (i.e., 60 to 80 m3 per well pair).
- AER Amendment Approval – 9426T
  - Received: July 17th, 2013
  - Trial deferred to 2016



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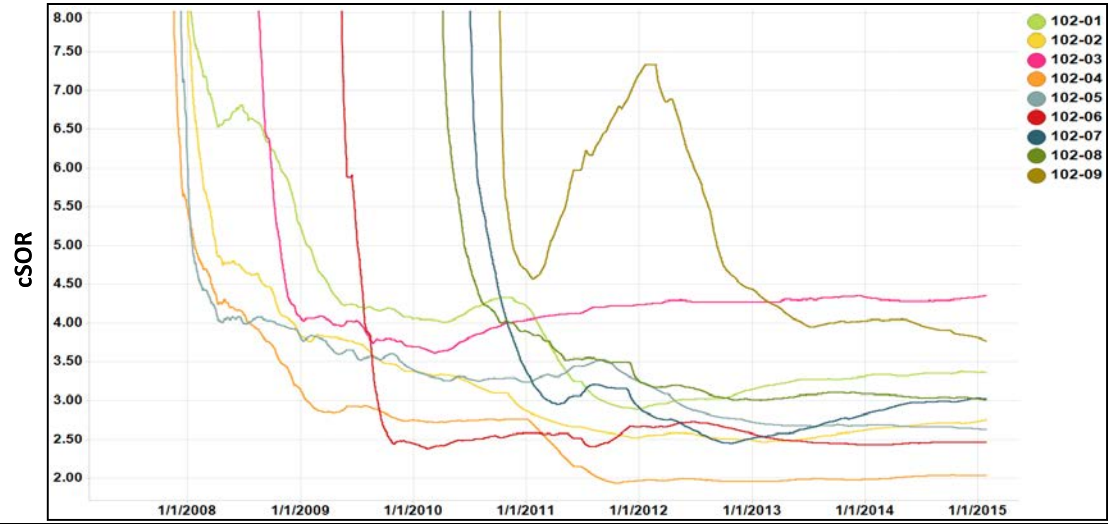
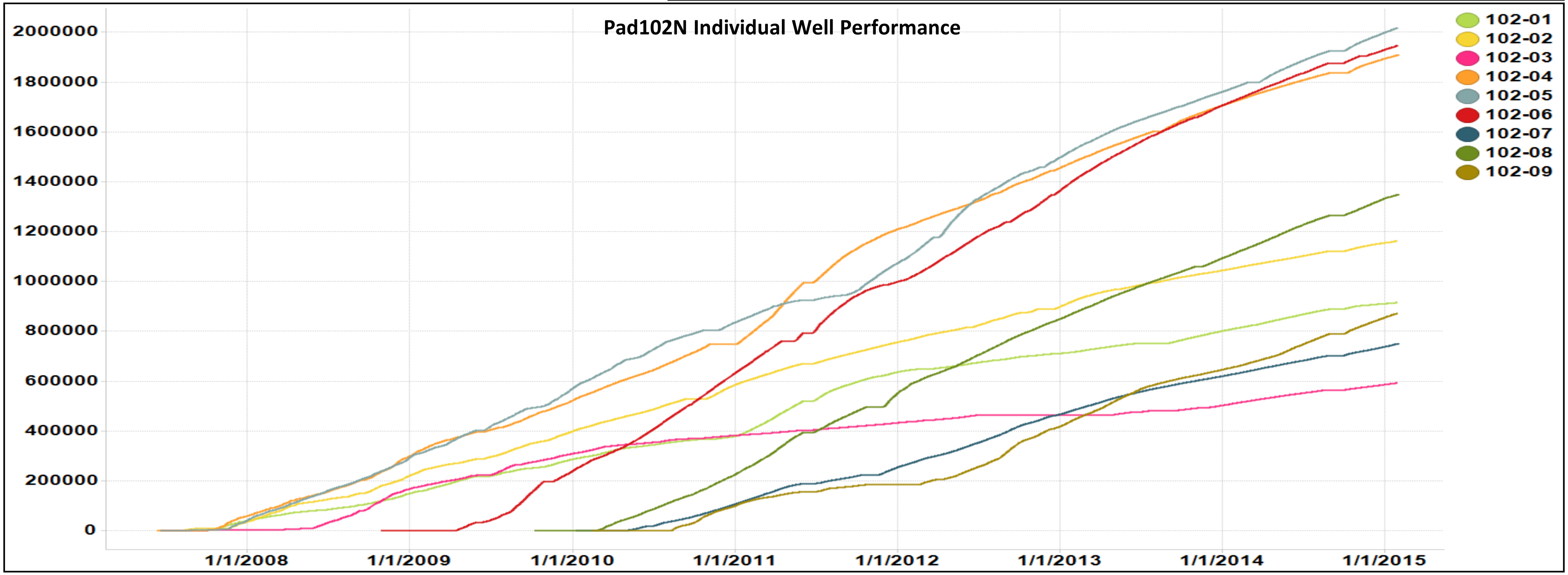
Pad 102 North Performance (102-06 Comparison)

Key Milestones

- Circulation Oct 2008
- First FCD deployed in Surmont
- Cumulative production of 1.95 MMbbl as of Jan31st 2015
- Cumulative SOR of 2.46 as of Jan31st 2015





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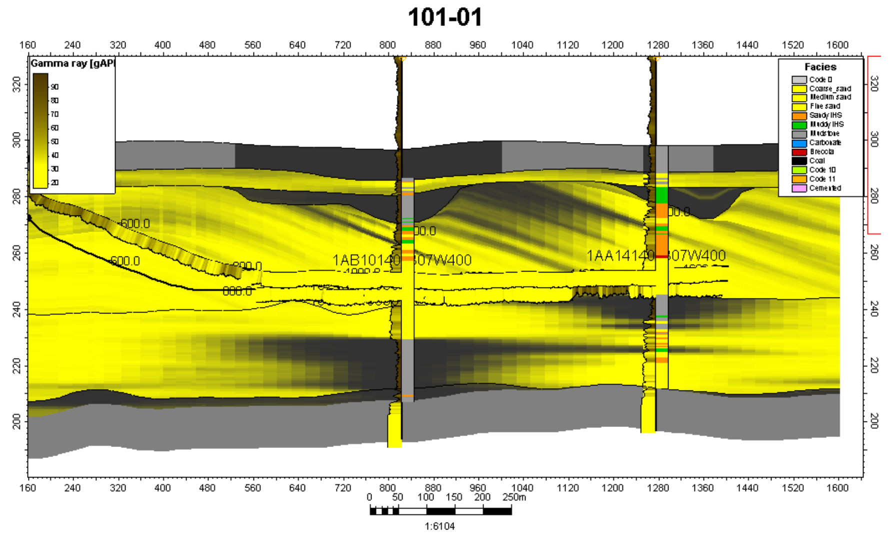
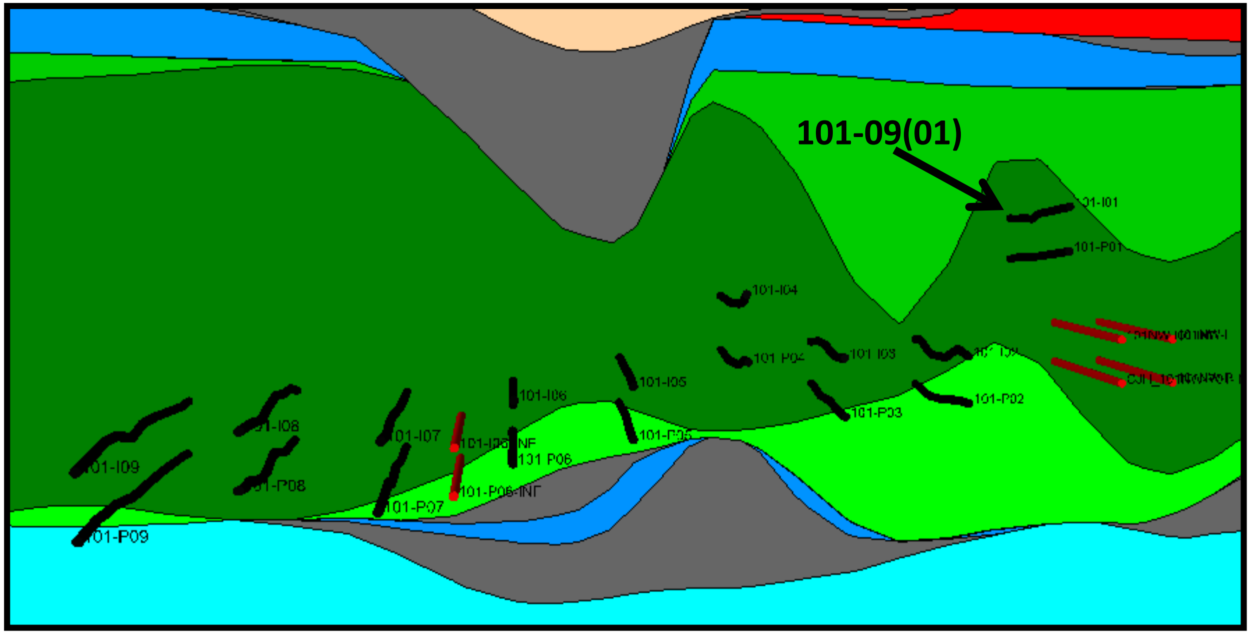
Vertical Placement of Horizontal Wells

- Reasons for higher vertical placement
  - 101-09(01) Drilled in Q4 2008
  - Drilled high to avoid low quality reservoir
  - Outboard infill wellpairs 101-25/26 drilled to recovery stranded resource





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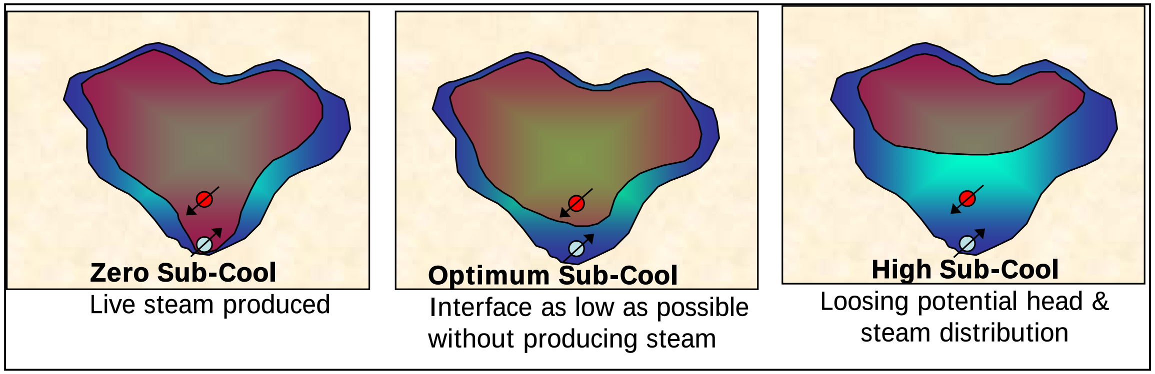
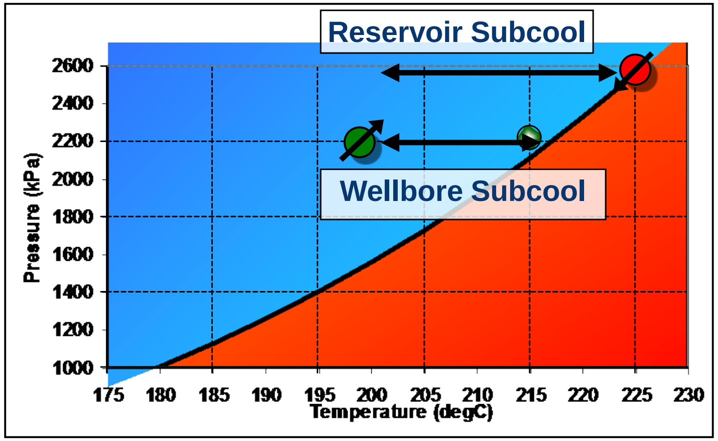
Key Reservoir and Operational - Learnings Summary

- Strong production performance in 2014 with record low iSOR
- History matching complete on new geo-model. This assists greatly in reservoir management and understanding steam chamber development.
  - Provides a greater understand of the pay zone, specifically with regards to thief zone interaction
  - Has helped to optimize the operating strategy to mitigate the thief zone interaction impact on performance
  - Aids in understand the steam chamber development in order to optimize well pad performance
- A greater understanding of the impact the Vacuum Insulated Tubing completion has on circulation was gained through the startup of wellpair 101-20.
- A Subsurface Containment Group was created to improve the geo-mechanical understanding and serve as a single point of contact for all containment questions and concerns.

Subcool Monitoring

- Subcool monitored in SAGD producer to avoid steam flashing through the liner and preserved its integrity
- Wellbore subcool:
  - Saturated temperature at producer BHP – Hottest Temperature in Prod
  - Used in ESP / PCP wells
  - Target is 8°C
- Reservoir subcool:
  - Saturated temperature at injector BHP – Hottest Temperature in Prod
  - Used in Gas Lift wells
  - Target is increased to 20°C to take into account uncertain ΔP between the injector and the producer





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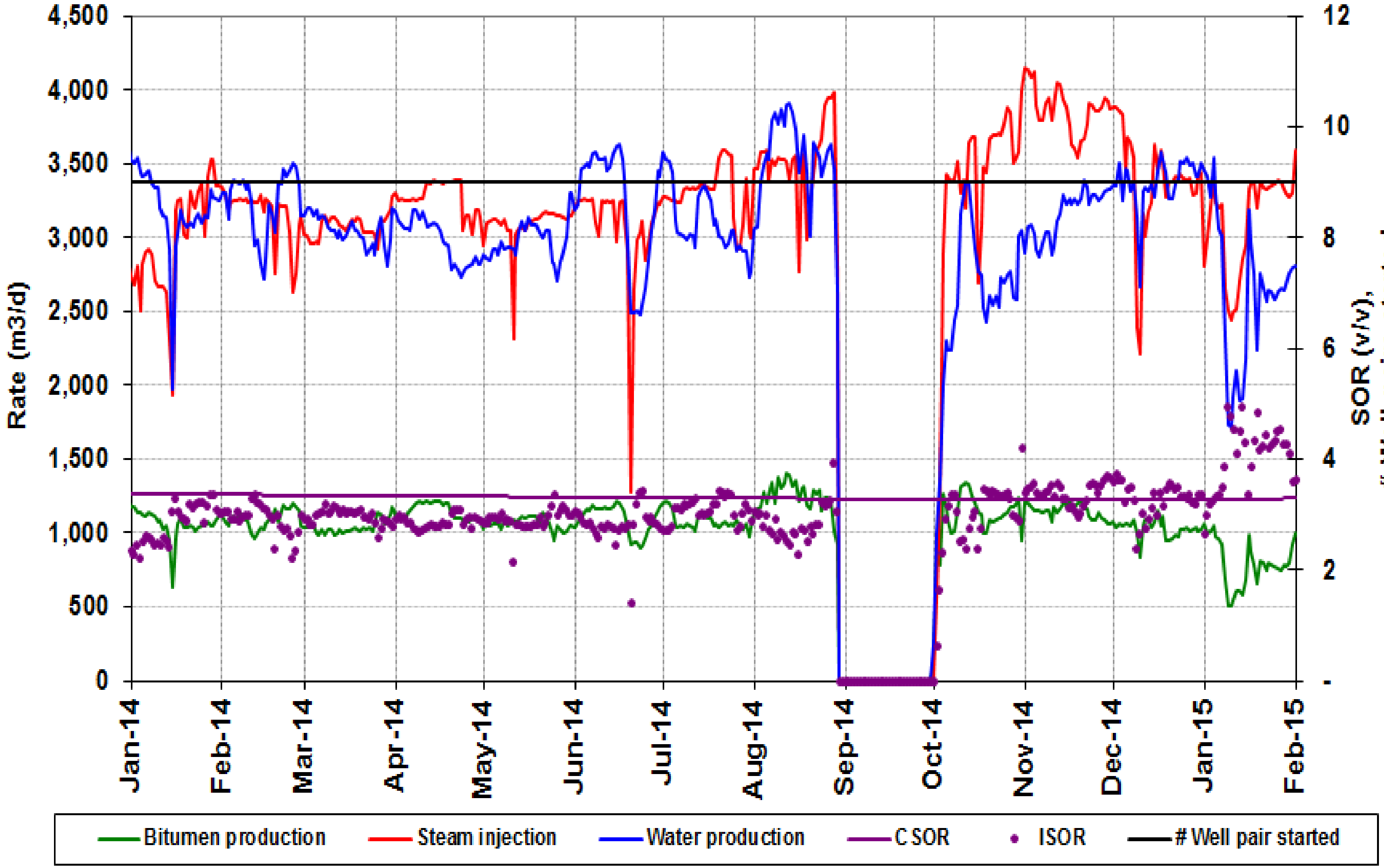
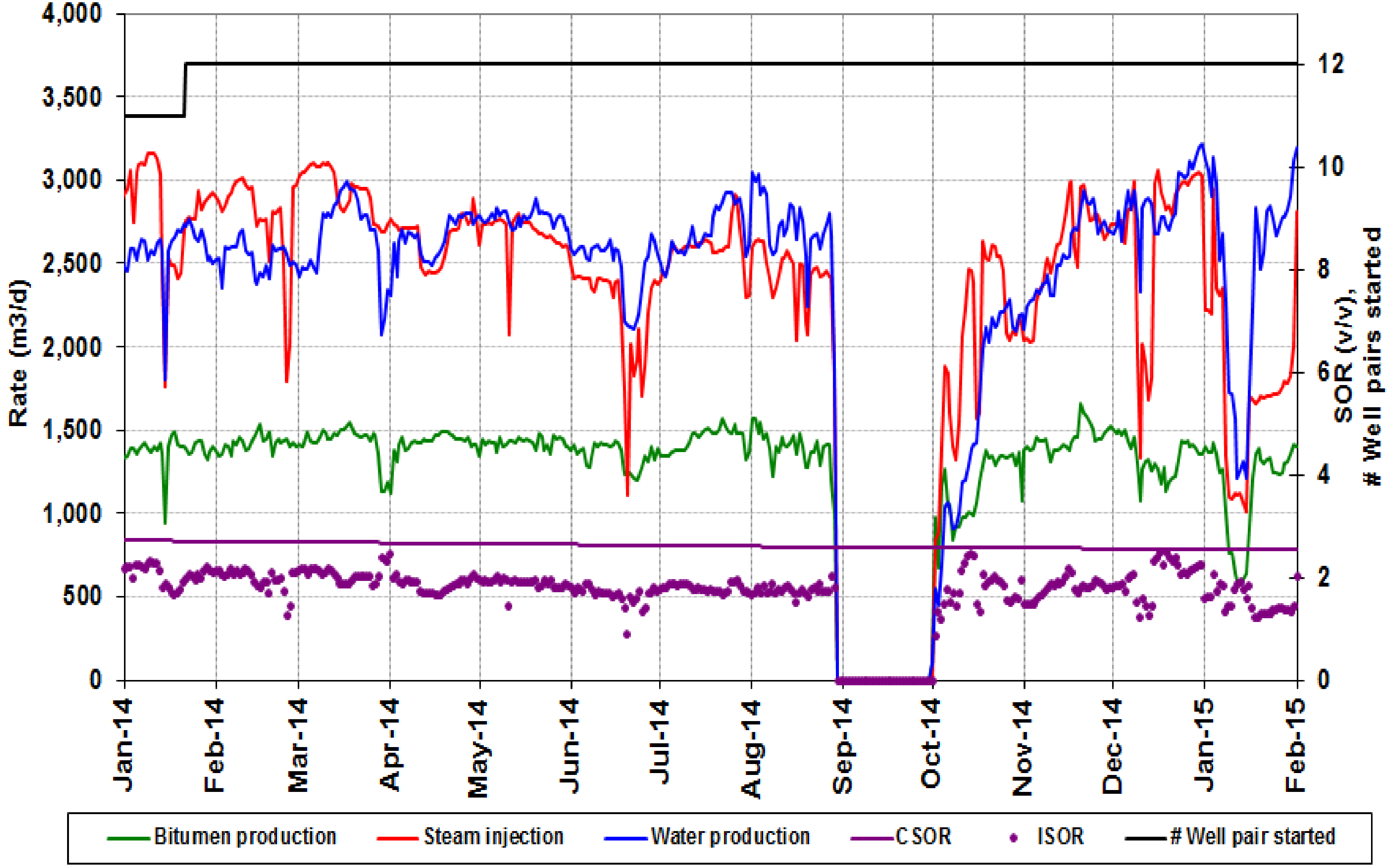
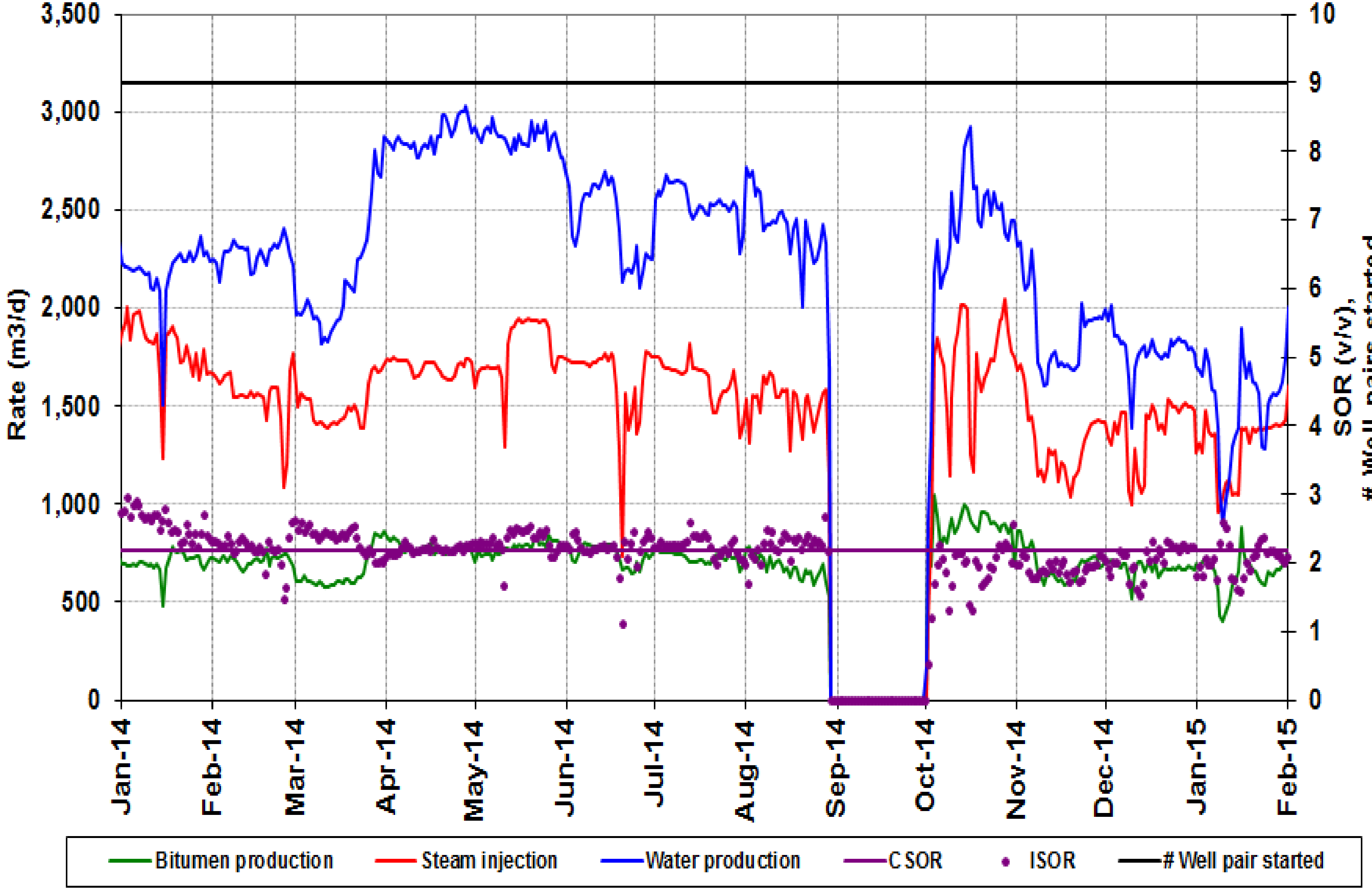
Phase 1: Pad 101 North Performance



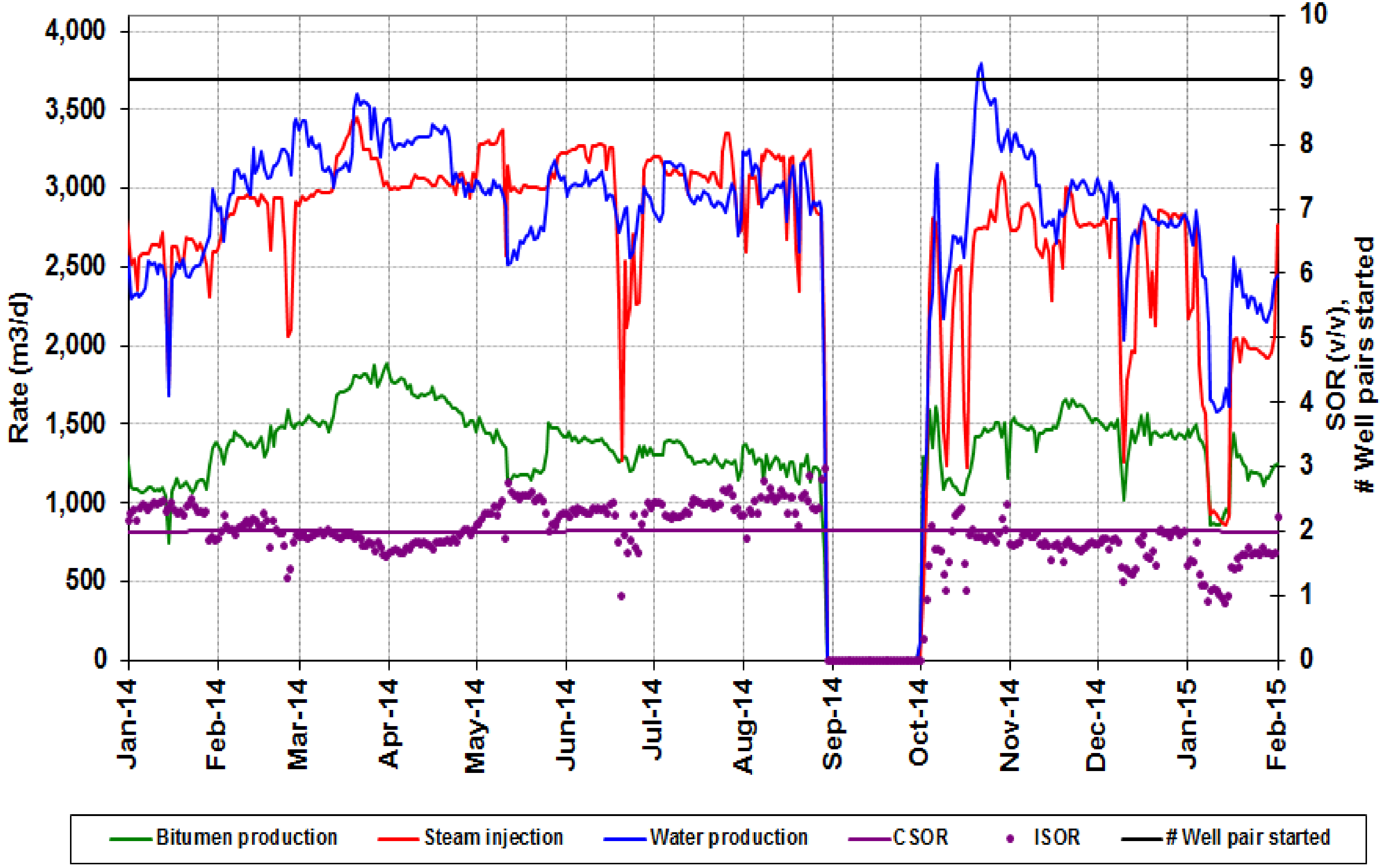
Phase 1: Pad 101 South Performance



Phase 1: Pad 102 North Performance

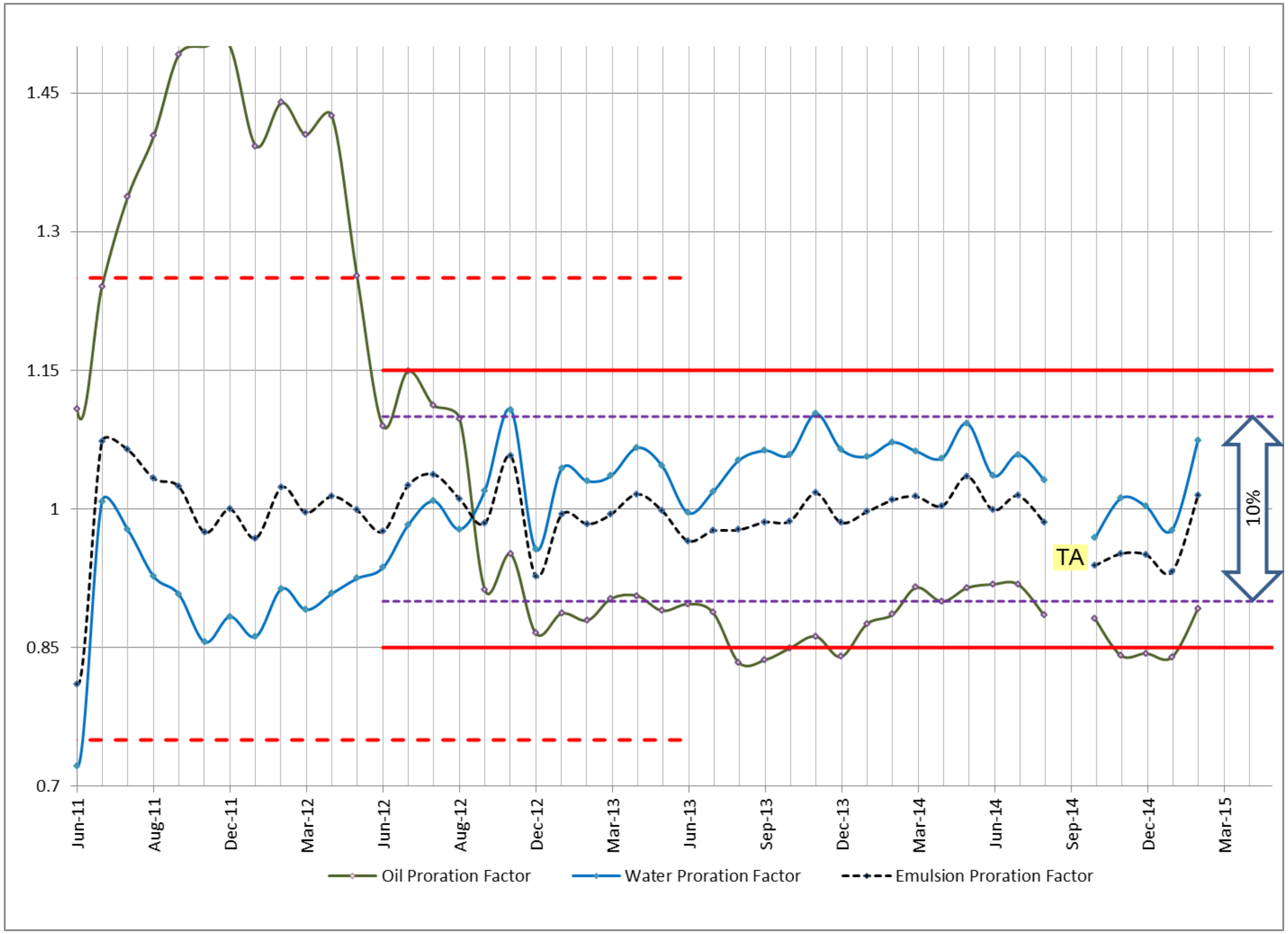


Phase 1: Pad 102 South Performance



Pad Performance Proration

- Stable proration factors
- Recurrent water cut metering calibration maintains consistency in SOR measurements and allocation calculations



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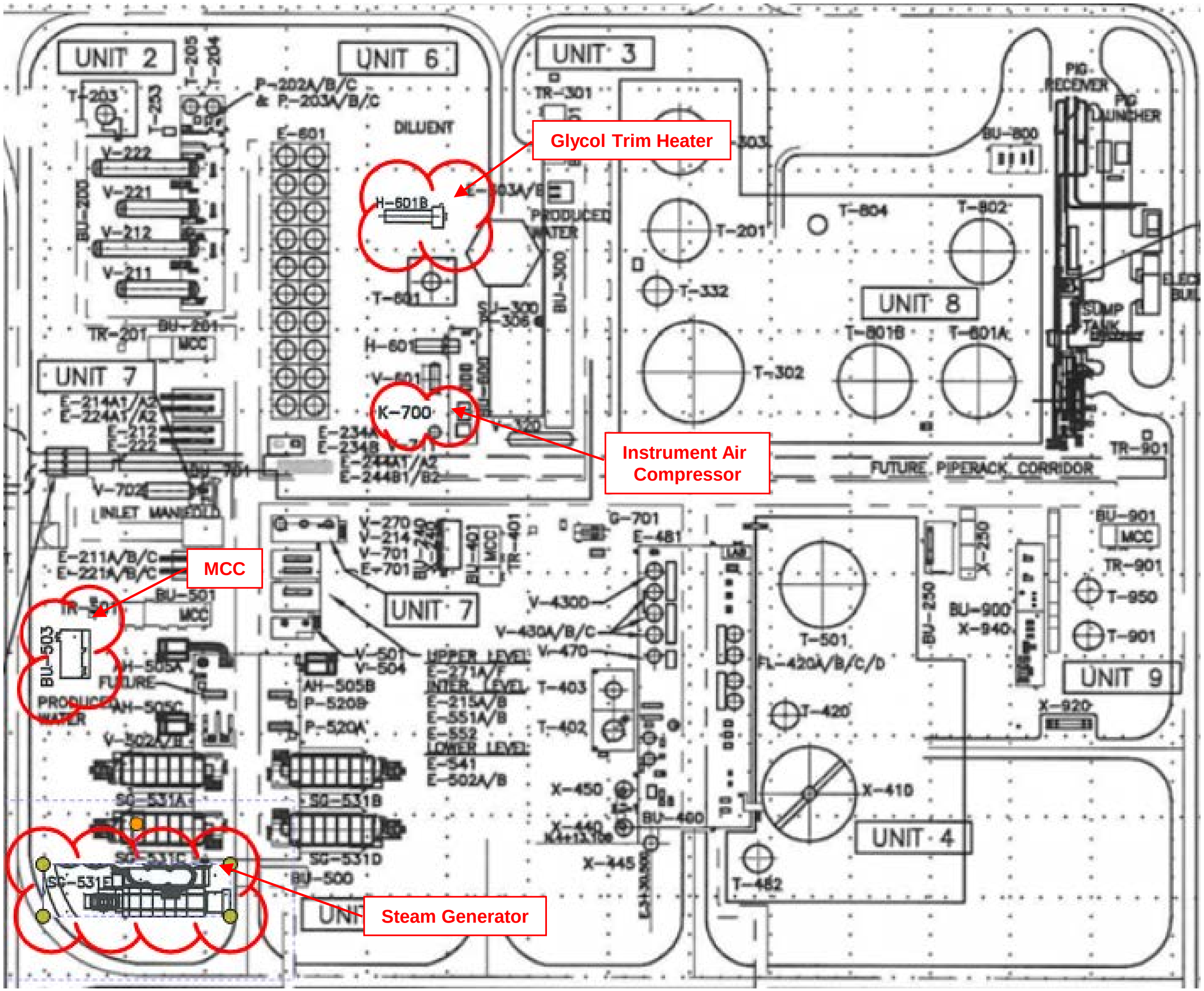
Surface Operations and Compliance
Phase 1 Approval 9426

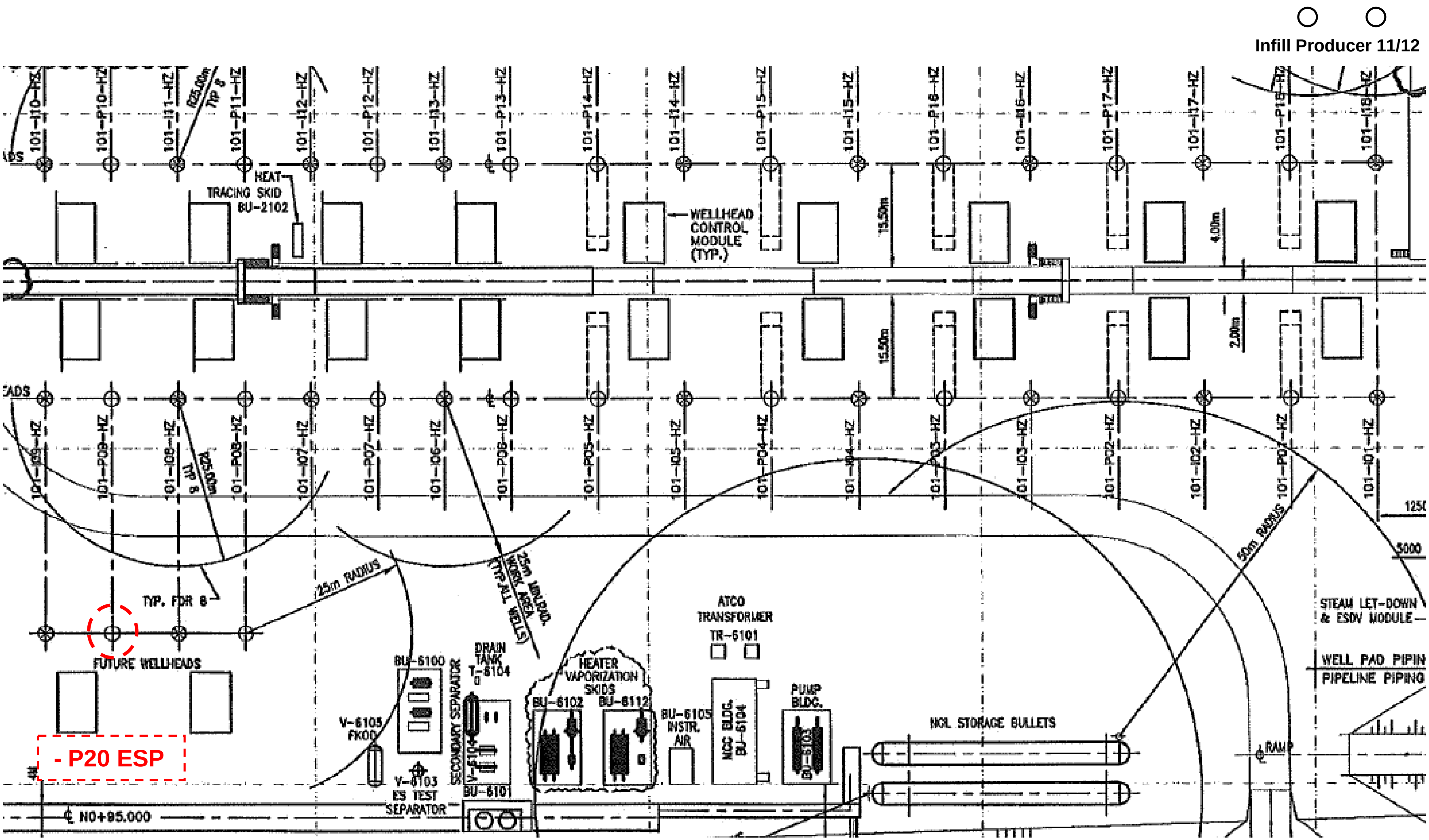
Facilities
Subsection 3.1.2 (1)

Phase 1 Plot Plan - CPF



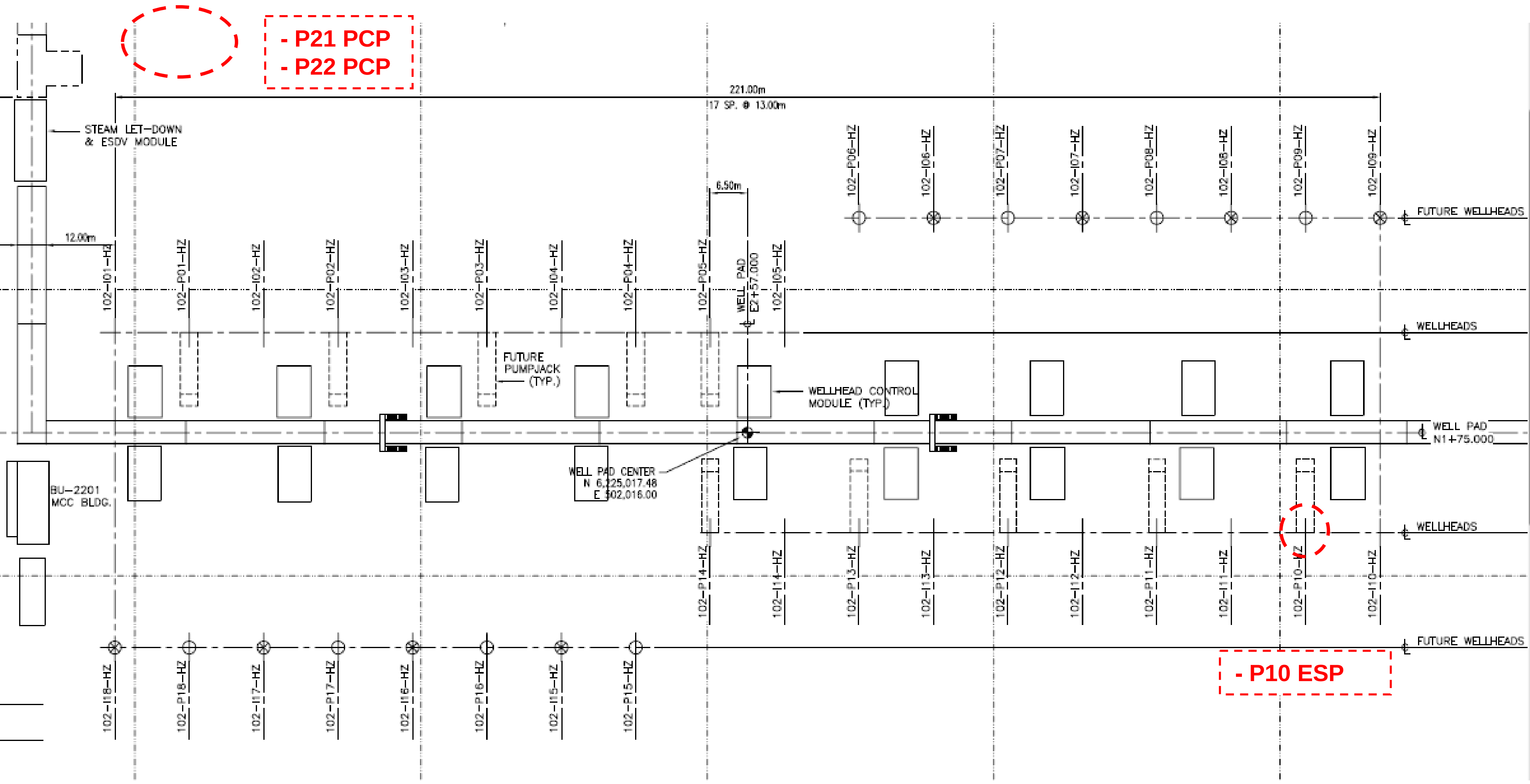
Plant optimization focus for Phase 1 CPF in 2013

Phase 1 Plot Plan - Pad 101



Artificial Lift Program added 1 new ESP wells in 2014

Phase 1 Plot Plan - Pad 102



Artificial Lift Program added 2 PCP & 1 ESP well in 2014
Multiphase Flow Meter

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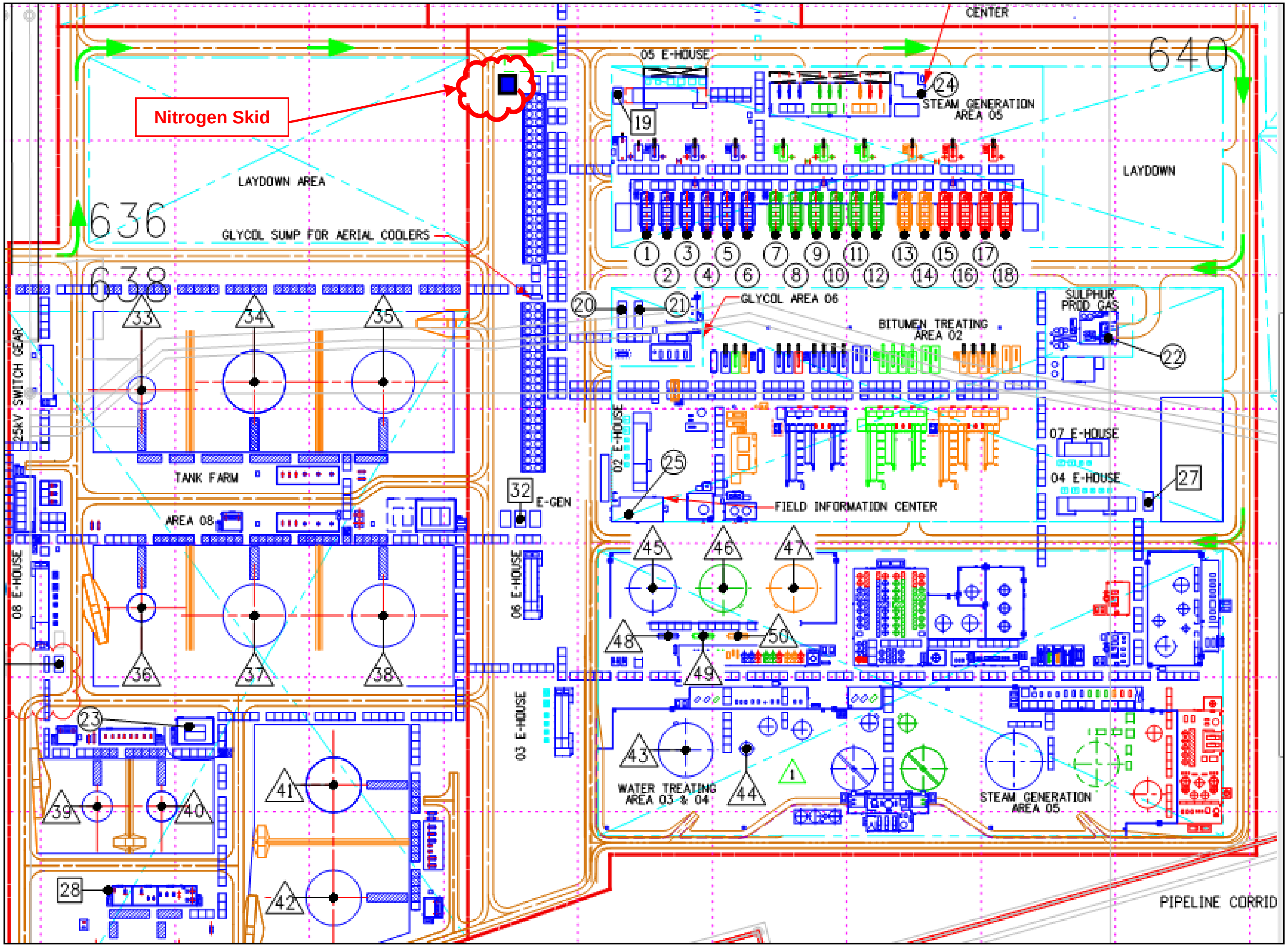
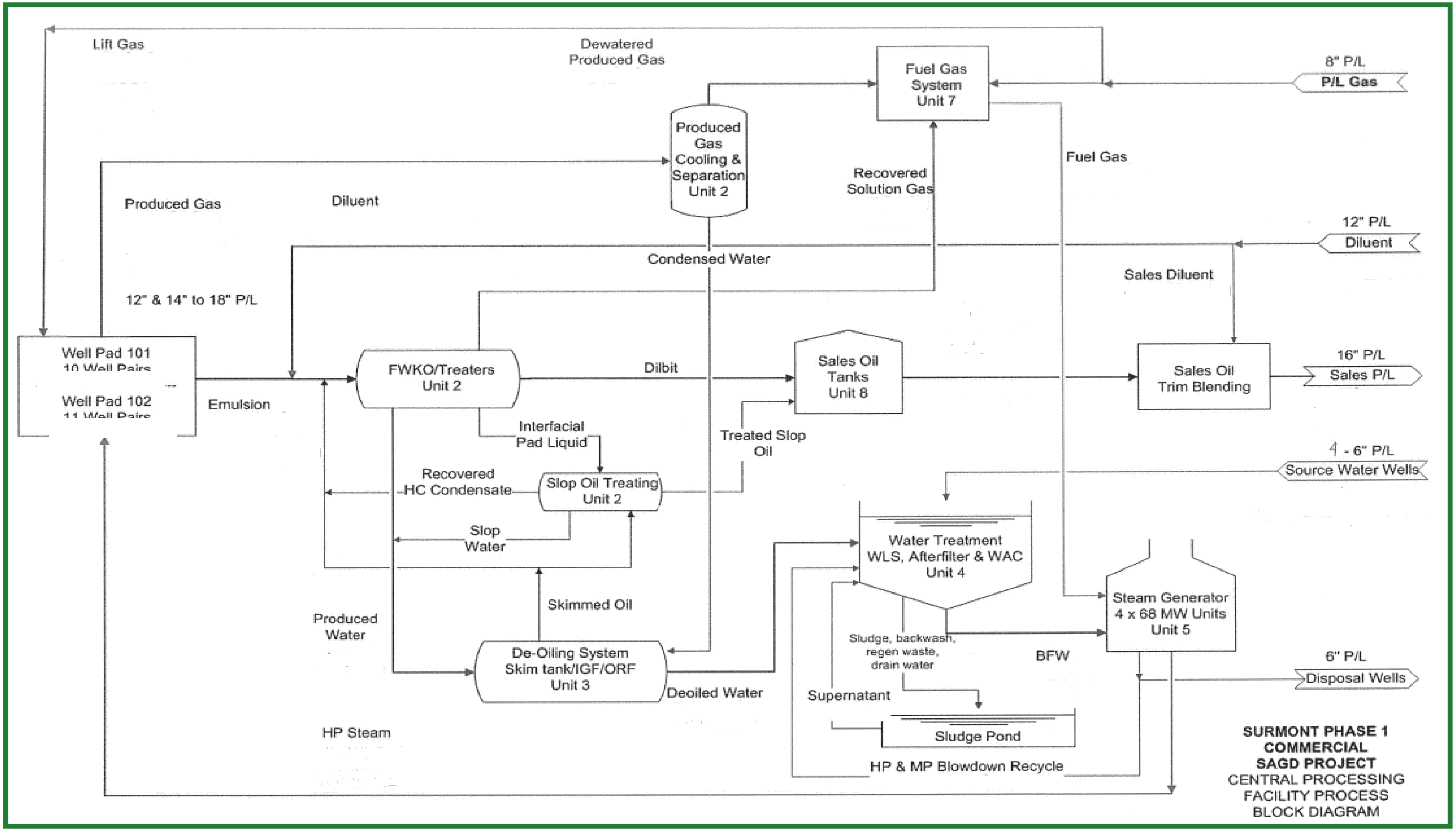
Phase 2 Plot Plan - CPF



Continued Focus on Construction and Commissioning at Surmont 2

Plant Schematic



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2014 Surmont Operations

2014 – Capital Projects

- Dresser Coupling Replacement: Replaced 26 Dresser couplings on Sales Oil and Diluent tank to more robust design
- Diluent Agitator: Agitator installed in the diluent tank to create more uniform blend
- New Economizer box: Built new economizer box with upgraded materials and additional monitoring capabilities
- Surmont 2 over 80% construction completed
- S1 Debottleneck: Added Glycol Trim Heater, Instrument Air Compressor, 500 area MCC, and a fifth Steam Gen (All of this equipment is not currently tied in or operational – this is to occur at a future date)

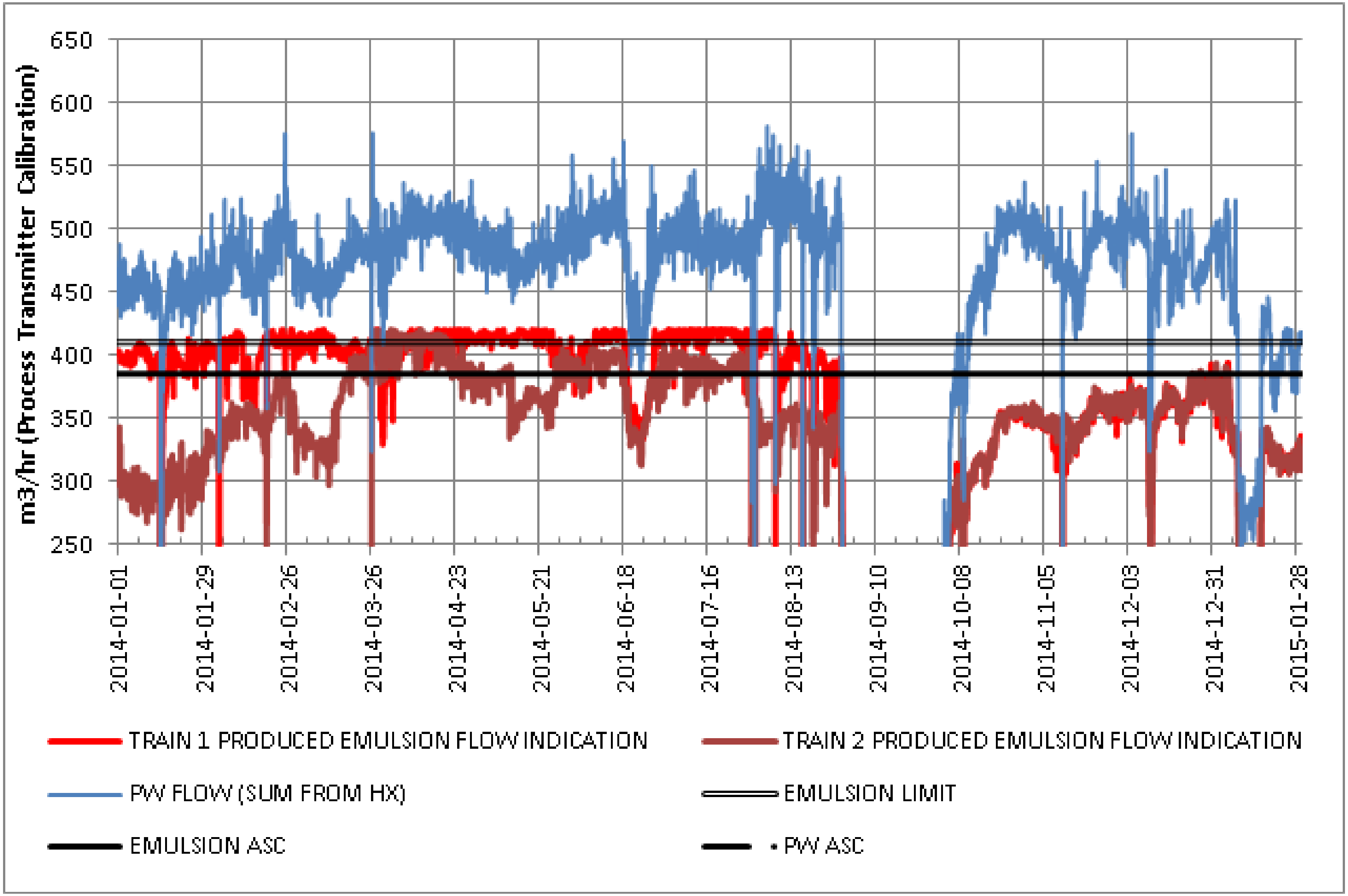
2014 – Optimization Focus Overview

- Steam optimization
  - Improve steam quality control.
  - Steam production and delivery development: Optimize Firing control to minimize steam production losses due to BFW temperature swings.
  - Steam quality control improvement trial on SG-531 C.
    - Step one of the trial completed (Firing 105% at 80% steam quality)
    - Step two will be firing 107% at 83%

2014 optimization and opportunity development focus

Facility Performance
Subsection 3.1.2 (2)

Facility Performance: Bitumen Treatment

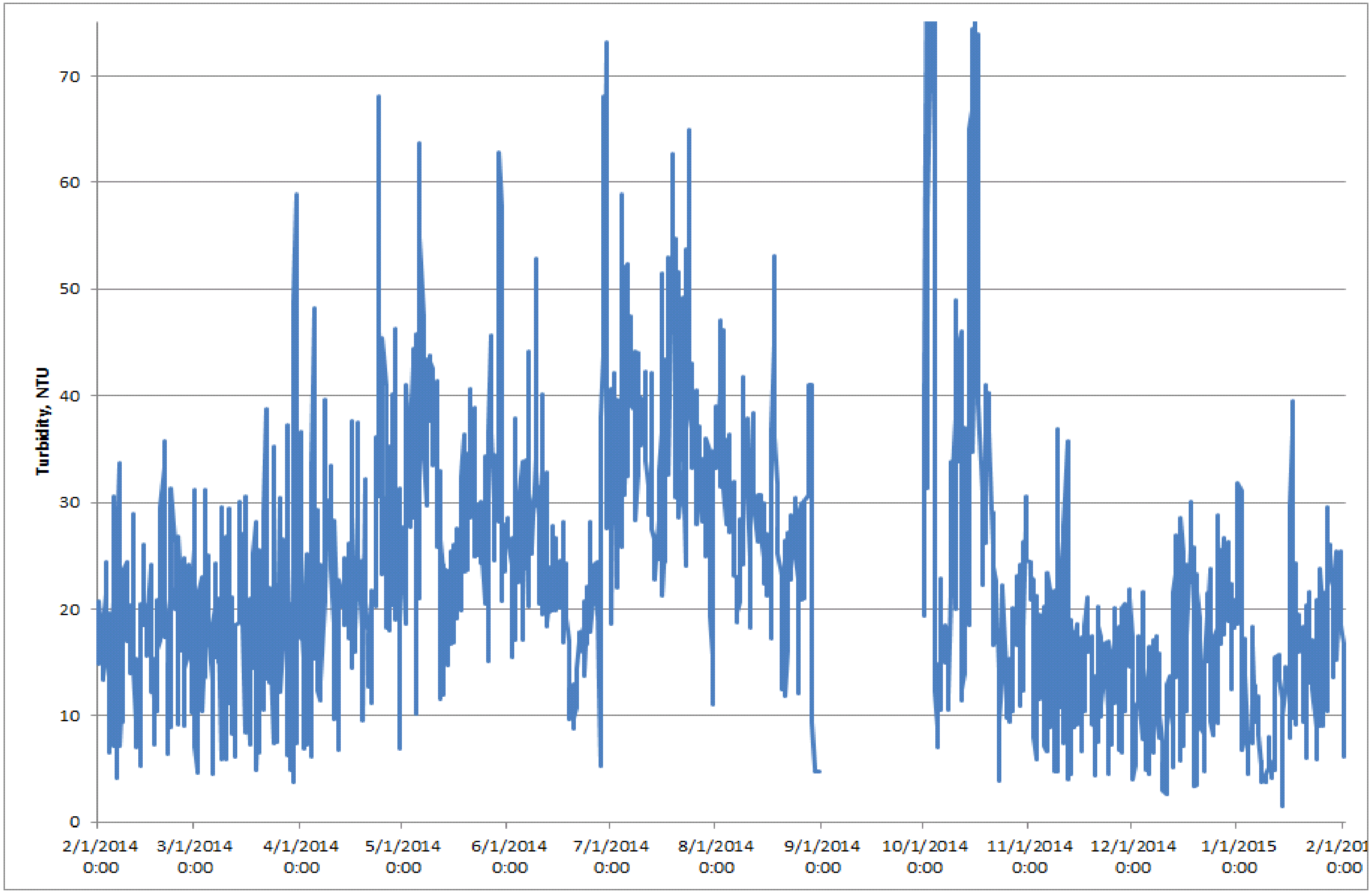


Facility Performance: Water Treatment

- Water Treatment plant operating as per design.
- Minor WLS operational challenges throughout the year, primarily in controlling turbidity swings leaving the warm lime softener.
- Sludge Pond dredged successfully in July 2014.
- Turnaround completed in October. Repairs conducted on roof of warm lime softener resulting from exterior corrosion.

Facility Performance: Water Treatment

Turbidity variation leaving the Warm Lime Softener
(Jan 31, 2014 to Jan 31, 2015)

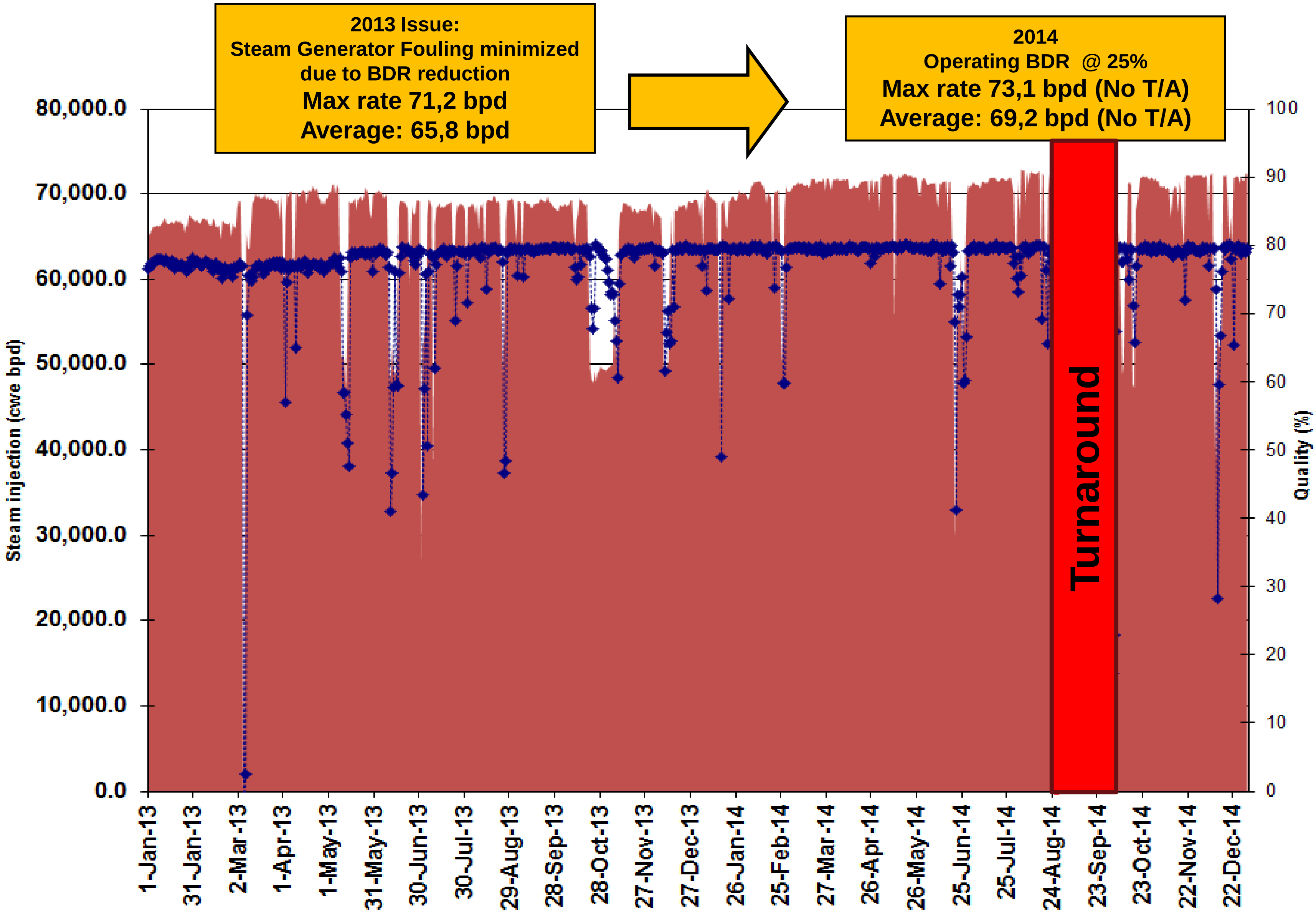


Facility Performance: Water Treatment

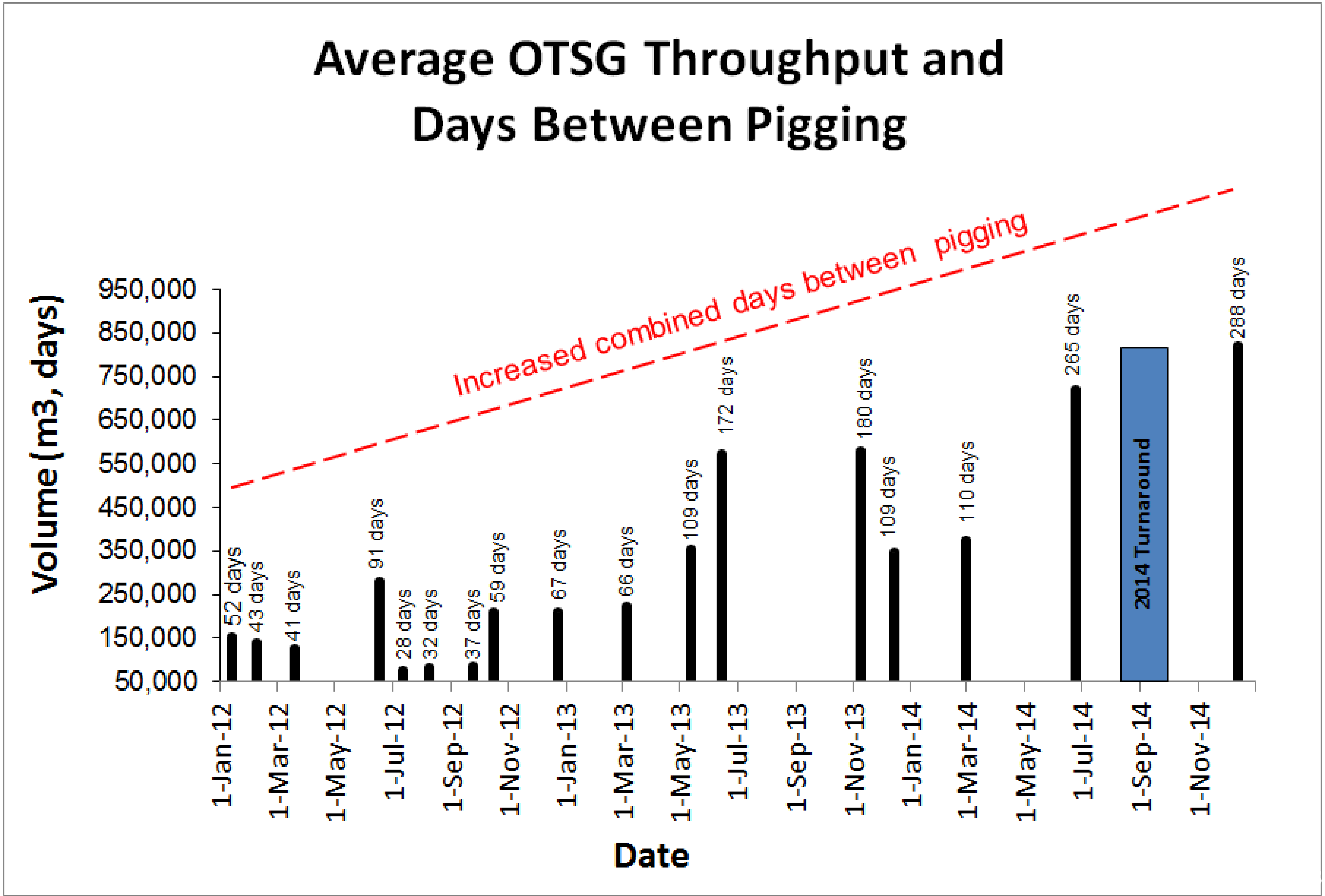
Boiler Feed Water Quality (Jan 31, 2014 to Jan, 31, 2015)

Parameter	BFW Specification	Avg. Value	% of time on Spec
Hardness (Dissolved), mg/L	<0.3	0.10	99.4
Silica, as SiO2, mg/L	<50	21.8	99.4
Bitumen in Water, ppm	<3.0	0.39	100
Turbidity, NTU	<3.5	2.42	98.8

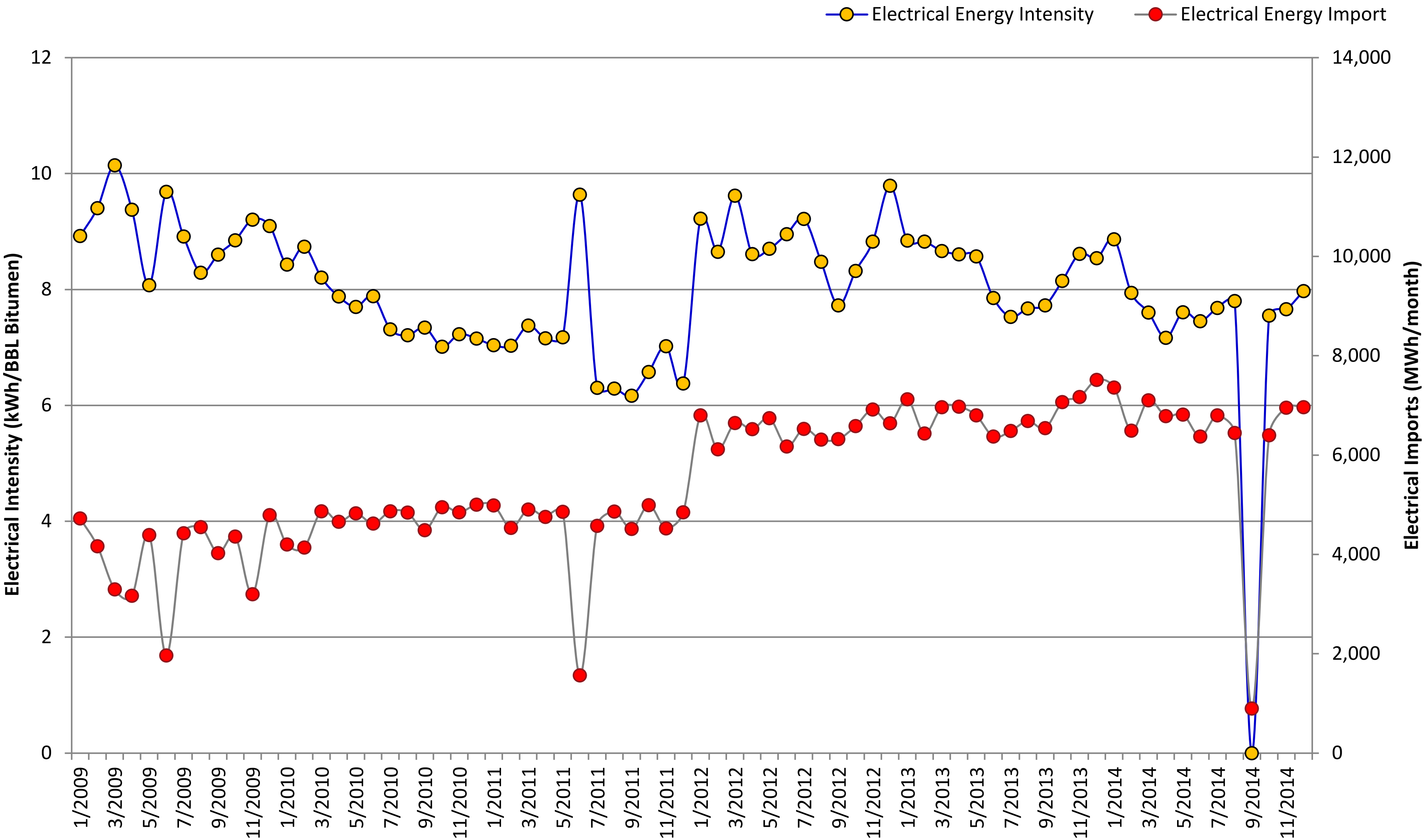
Facility Performance: Steam Generation



Facility Performance: Steam Generation (Pigging Frequency)



Facility Performance: Electricity Consumption



Electricity consumption has increased as wells are moved from gas lift to artificial lift

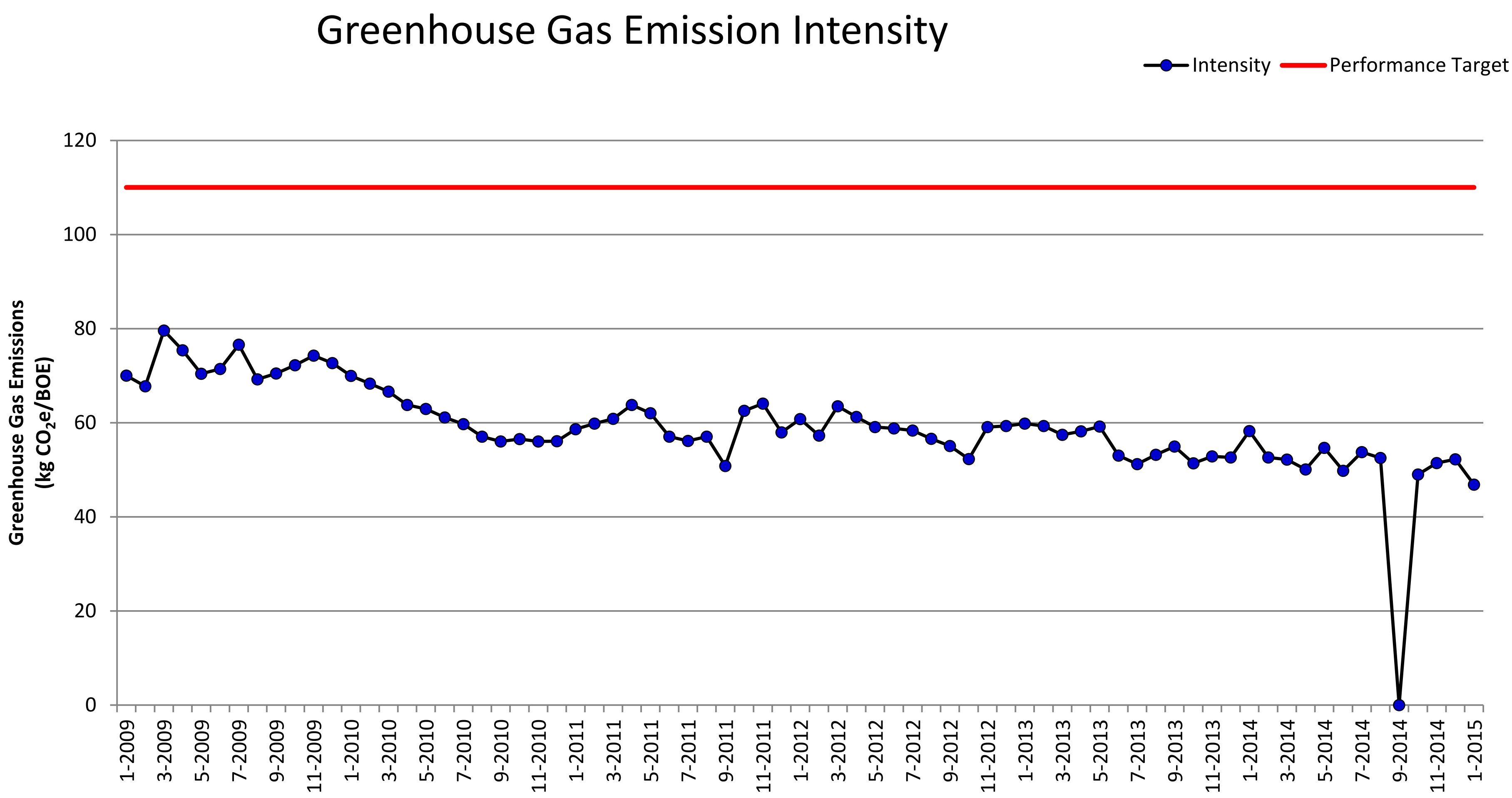
Facility Performance: Gas

	2007	2008	2009	2010	2011	2012	2013	2014	Units
Total Gas Imports (TCPL)	42,999	160,095	183,933	223,447	228,344	250,412	254,883	241,276	10^3m^3
Total Gas Flared	4,640.6	6,438.7	3,962.0	705.0	624.8	217.6	117.3	277.3	10^3m^3
Solution Gas Recovery Rate			60.6%	93.6%	94.5%	98.5%	99.2%	98.0%	

S1/S2 Produced Gas Interconnect

- Completed in 2014.
  - Will send all Produced Gas to Surmont 2 for sulfur removal.
  - Phase I Steam Generators will begin burning 100% TCPL gas.

Facility Performance: Greenhouse Gas



Exceeded Specified Gas Emitters Regulation Reduction Target of 8% for 2014

Measurement and Reporting
Subsection 3.1.2 (3)

Well Allocated Oil Production

Well Allocation Oil Production = Estimated Monthly Well Oil Production x Oil Proration Factor

Where:

Estimated Production	= Accepted well test / duration of test * on-stream hours
Oil Proration Factor	= Actual battery production / estimated battery production
Actual Battery Production	= Dispositions + Tank Inventory – Receipts + Shrinkage + External Shipments + (Load Oil to Wells inventories)

Where:

Dispositions	= Sales Oil shipped to Enbridge + Diluent send to Surmont Pilot
Tank Inventory	= Sales Oil tanks volume changes + Diluent tank volume changes + Slop tank oil inventory + Skim tank oil inventory
Receipts	= Sales Oil received from Surmont Pilot + Diluent received from Enbridge
Shrinkage	= Shrinkage adjustment
External Shipment	= Oil from slop trucked out to external facility

Sales Oil: Could be Dilbit or Synbit

Surmont MARP Rev 10 (SUR2-A0A-00-OPM-OPN-0045) – Submitted February 2015

Well Allocated Water Production

Well Allocation Water Production = Estimated Monthly Well Water Production x Water Proration Factor

Where:

Estimated Water Production	= Accepted well test / duration of test * on -stream hours
Water Proration Factor	= Produced water (PW) volume / estimated water production
PW Volume	= Dispositions + PW_{tanks} – Receipts + Load Water (LW) Inventory

Where:

Dispositions:	Battery PW Disposition to Injection Facility + Pilot Plant + Other
PW_{tanks} :	Battery PW Inventory, including net water content in oil storage tanks
Receipts:	PW received from other sources, including Injection Facility
LW Inventory:	Battery LW Inventory

Well Allocated Gas Production

Well Allocation Gas Production = Well Allocated Oil Production x Calculated Gas-Oil Ratio

Where:

Calculated Gas-Oil Ratio (GOR)	= Gas Production / Battery Bitumen Production
Gas Production	= Dispositions – Receipts

Where:

Dispositions	= Metered Flared Gas + Metered Steam Gen Fuel Gas + Utilities Fuel Gas + Gas for purging system
Receipts	= Fuel Gas Receipts from TCPL + eSAGD Produced Gas

Well Allocated Steam Injection

Estimated Volume of Injected Steam = Sum of Injected Steam to Wells x Steam Proration Factor

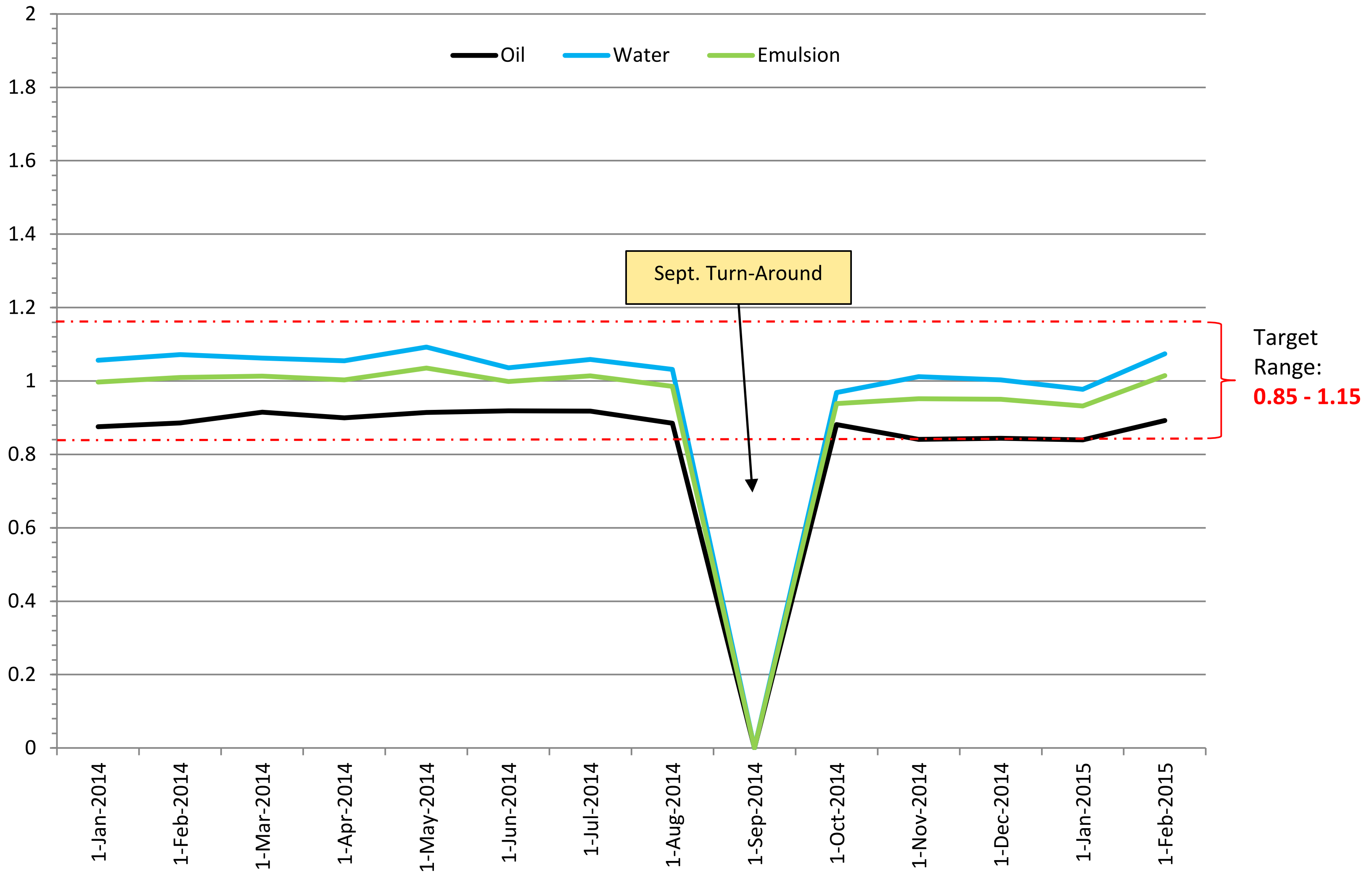
Where:

Steam Proration Factor = Steam Produced / Steam Measured

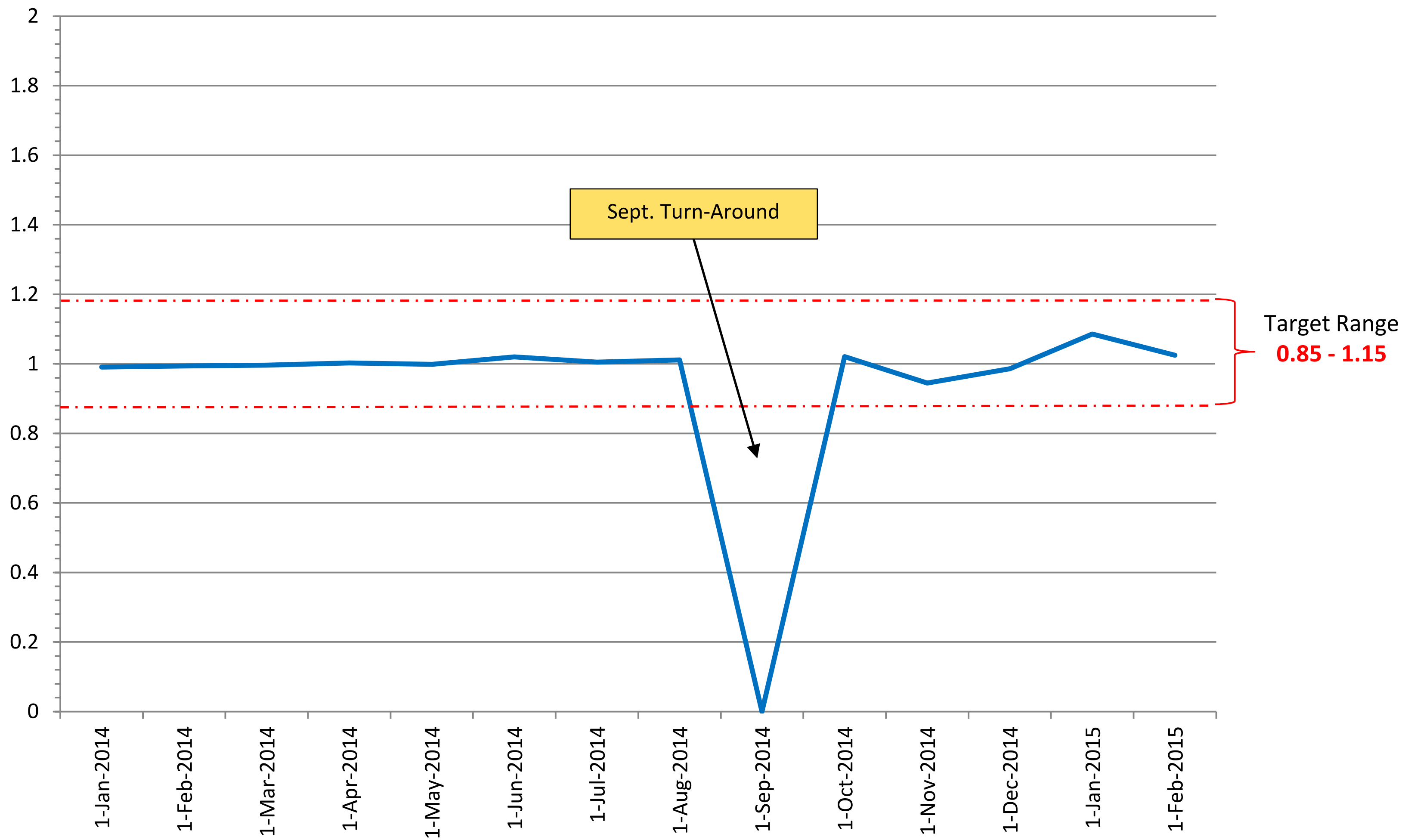
Steam Produced: Total Steam Meter to Well Pads – Steam Condensate Dropped Out – Steam Recovered at Pipeline – Steam to eSAGD wells

Steam Measured: Steam Injection to Heel and Toe String of each well

Production Proration Factors



Injection Proration Factors



Average Steam Proration for year 2014 = 1.0063

Well Testing

- CPC continues to assess well test performance, to optimize each individual well's test duration

- Phase Dynamic Water Cut Meter trial to ensure proper performance
  - Establish proper sampling procedures for meter calibration
  - Execute calibration per well
  - Perform meter validation after every calibration

- In preparation for the large number of Surmont 2 wells, CPC developed and tested an In-House program to automatically accept or reject well test results based defined criteria to ensure reporting compliance

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

Water Source Wells Non-Saline

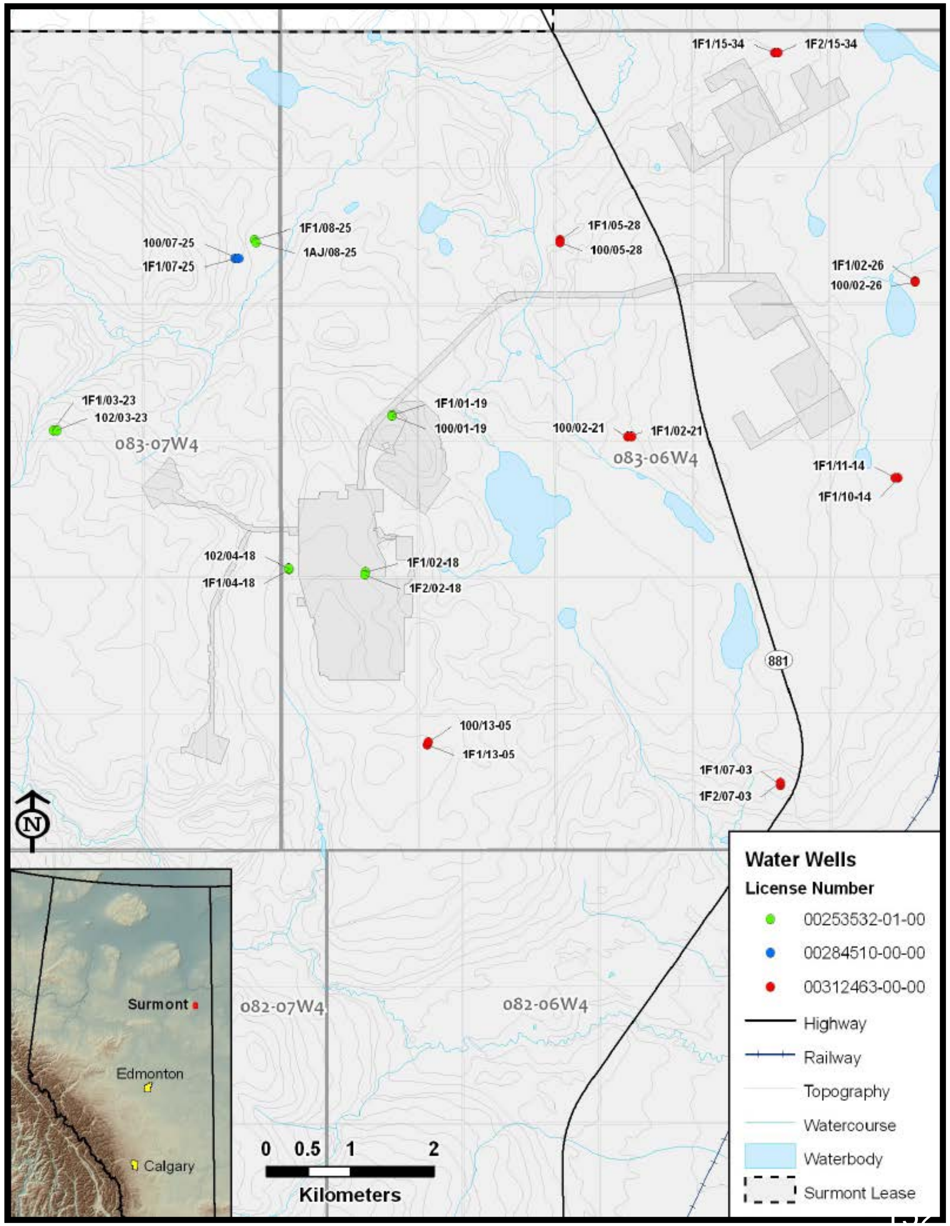
Surmont Pilot		
Source Well	**Observation Well**	**Formation**
1F1082508307W400	1AJ082508307W400	Lower Grand Rapids
1F1072508307W400	100072508307W400	Clearwater

Surmont Phase 1		
Source Well	**Observation Well**	**Formation**
1F1021808306W400	1F2021808306W400	Lower Grand Rapids
1F1041808306W400	102041808306W400	Lower Grand Rapids
1F1011908306W400	100011908306W400	Lower Grand Rapids
1F1032308307W400	100032308307W400	Lower Grand Rapids

Surmont Phase 2		
Source Well	**Observation Well**	**Formation**
1F1022108306W400	100022108306W400	Lower Grand Rapids
1F1022608306W400	100022608306W400	Lower Grand Rapids
1F1052808306W400	100052808306W400	Lower Grand Rapids
1F1070308306W400	1F2070308306W400	Lower Grand Rapids
1F1101408306W400	1F1111408306W400	Lower Grand Rapids
1F1130508306W400	100130508306W400	Lower Grand Rapids
1F1153408307W400	1F2153408307W400	Lower Grand Rapids

Notes

- All water currently used at the Surmont project is non-saline and non-potable (i.e., waters not readily or economically treatable for potable, domestic, agricultural or livestock use)
- Phase 2 source wells licenced December 14, 2012, only used for hydro testing



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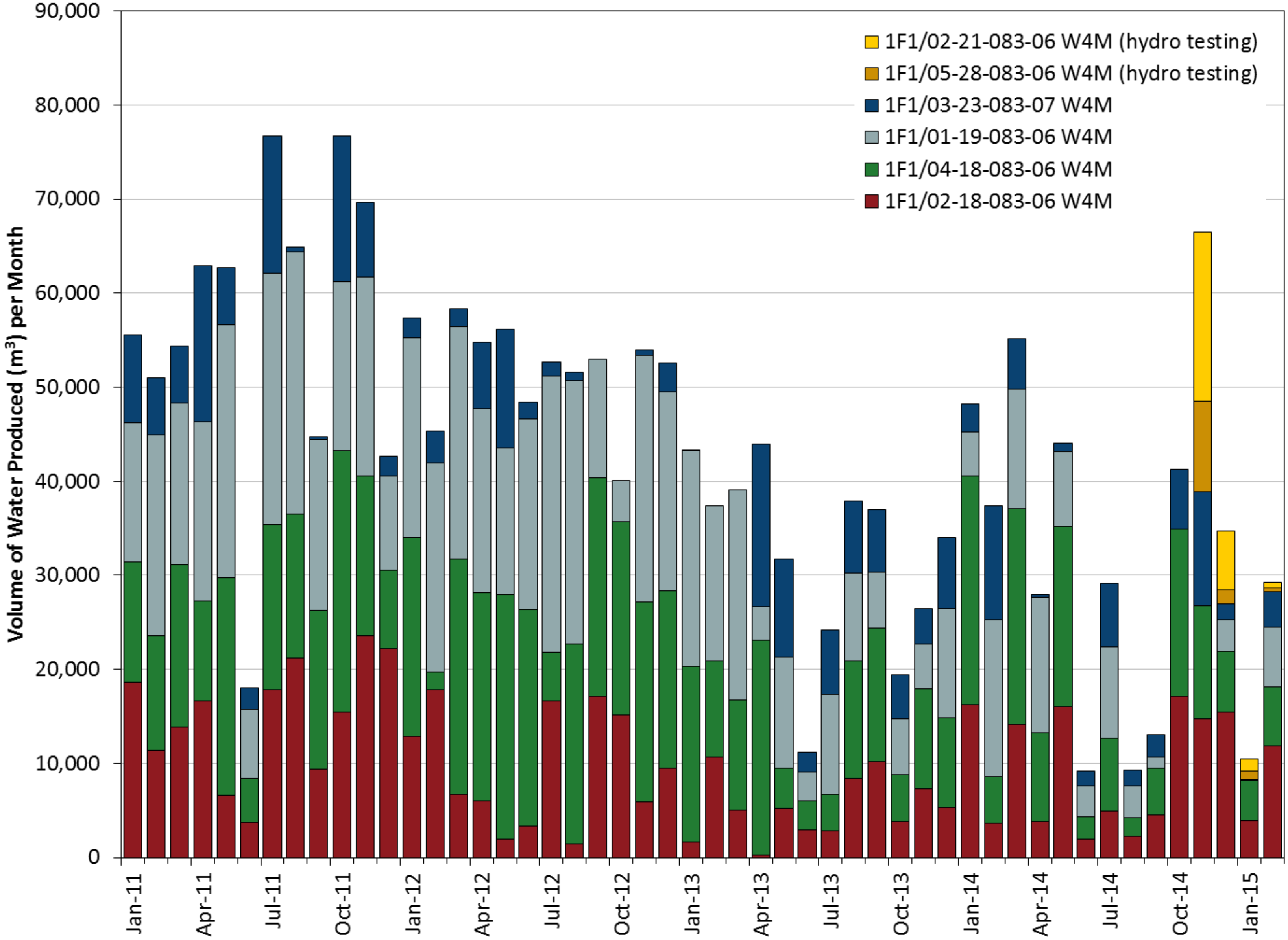
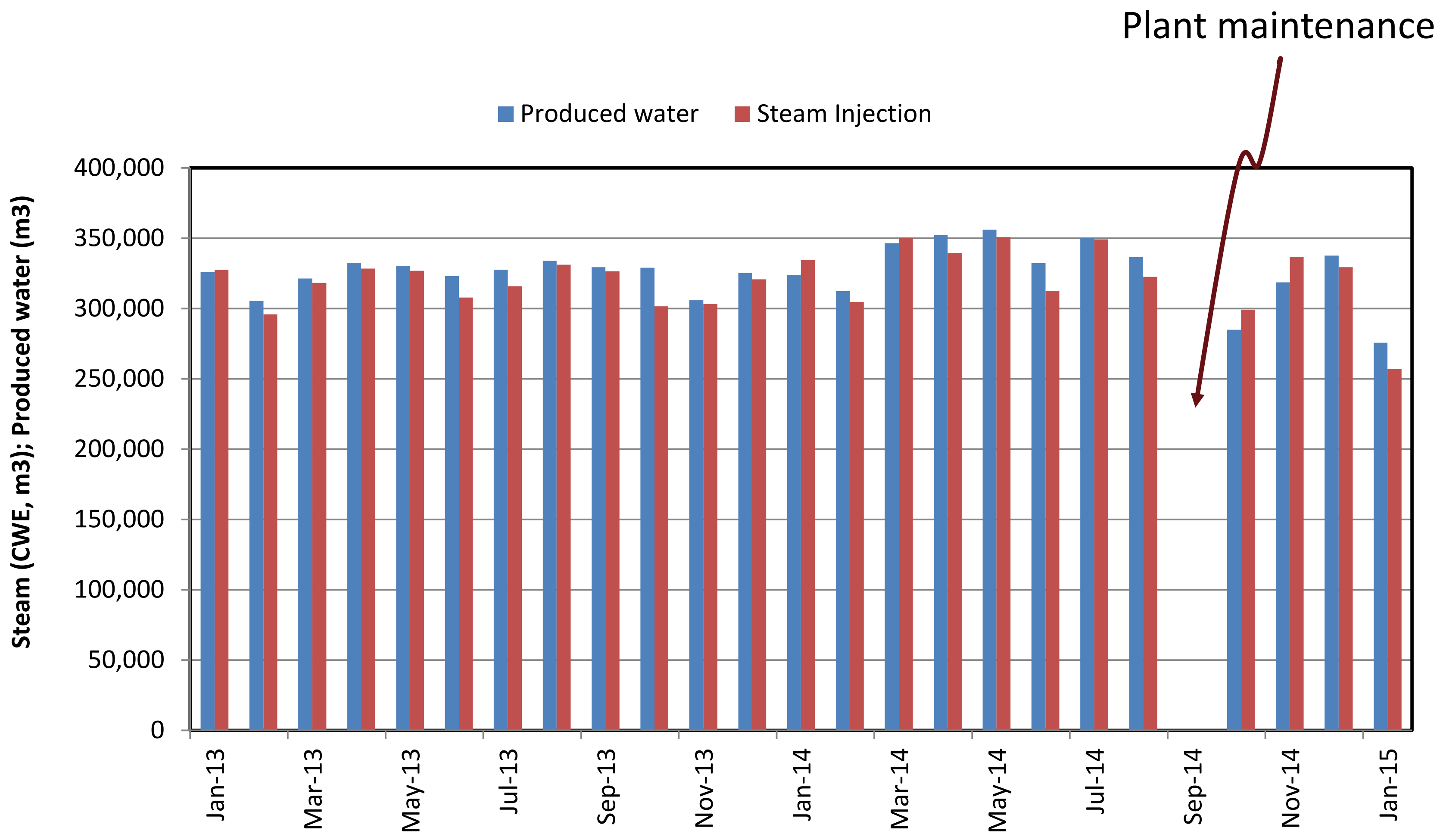
Water Source Wells Production Volumes



Water Production and Steam Injection Volumes

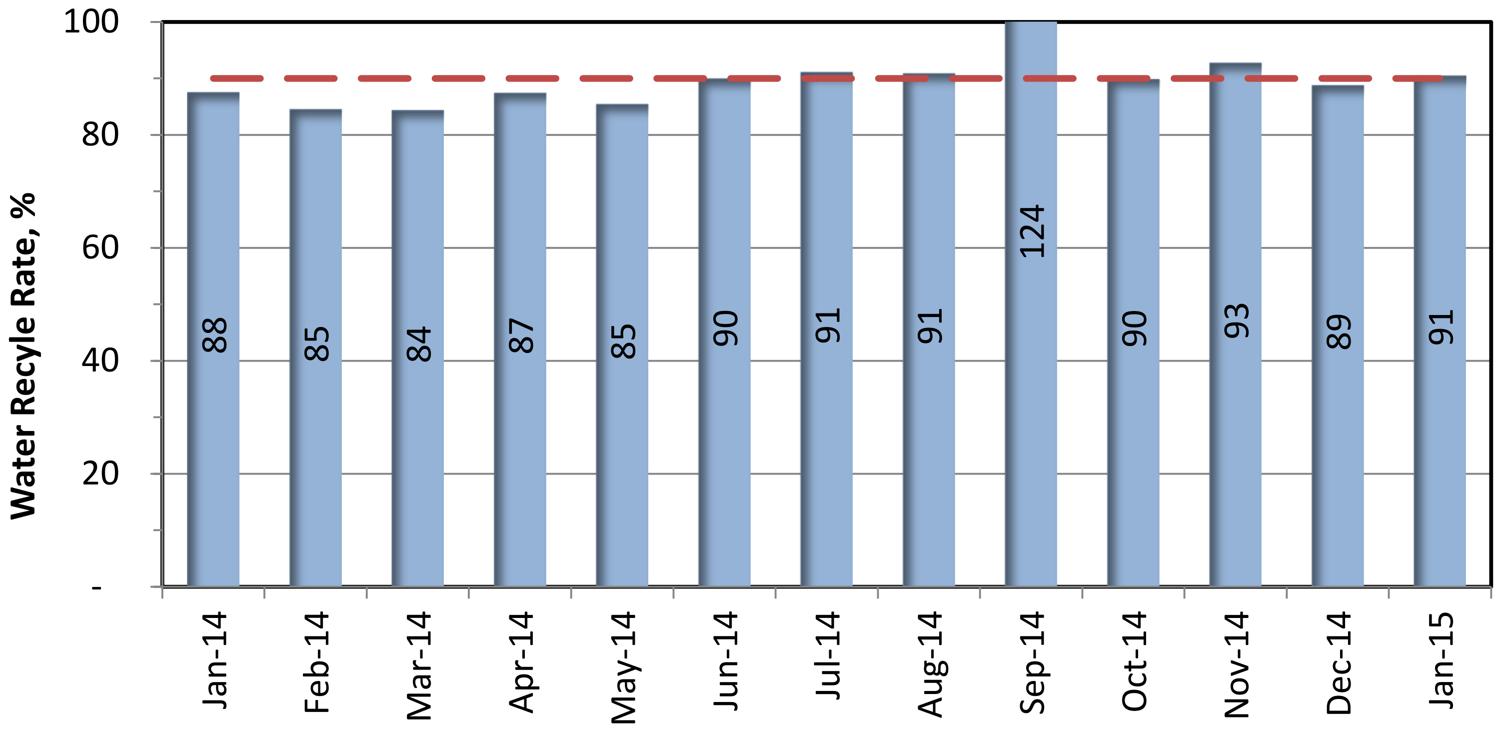


Water Recycle Rate (*Bulletin 2006-11*)

Continuous optimization and improvements:

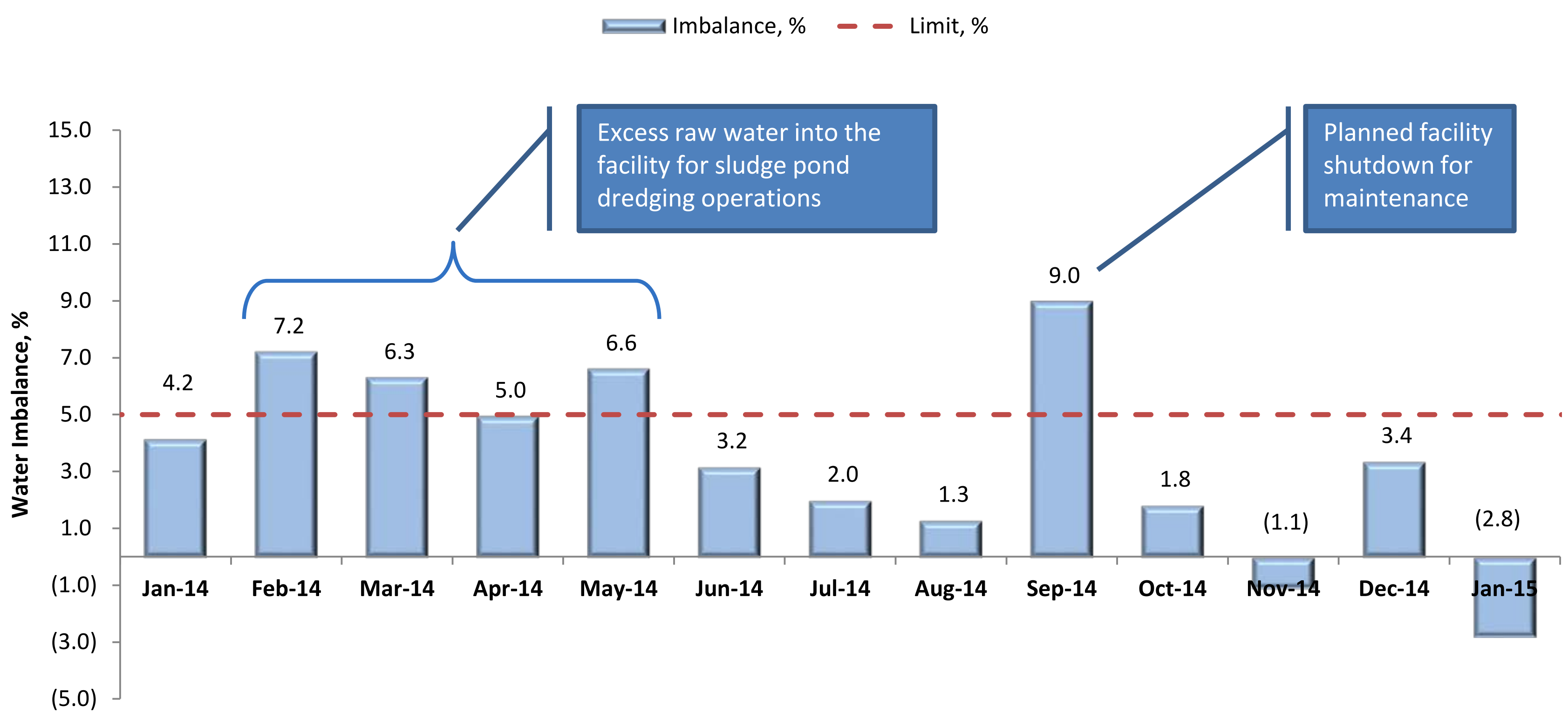
- Measurement
- Material balance for water systems
- Energy balance across steam generation
- Enhanced steam quality

Year	WRR, %
2012	81.9
2013	87.1
2014	88.2



Injection Facility Water Imbalance

- Surmont achieved *Directive 81* facility water imbalance compliance in 2014;
- Continuous improvement towards closing the water imbalance gap;
- Challenging to keep metering imbalance within 5% when performing large maintenance/repair projects (Feb-May 2014, Sept 2014)



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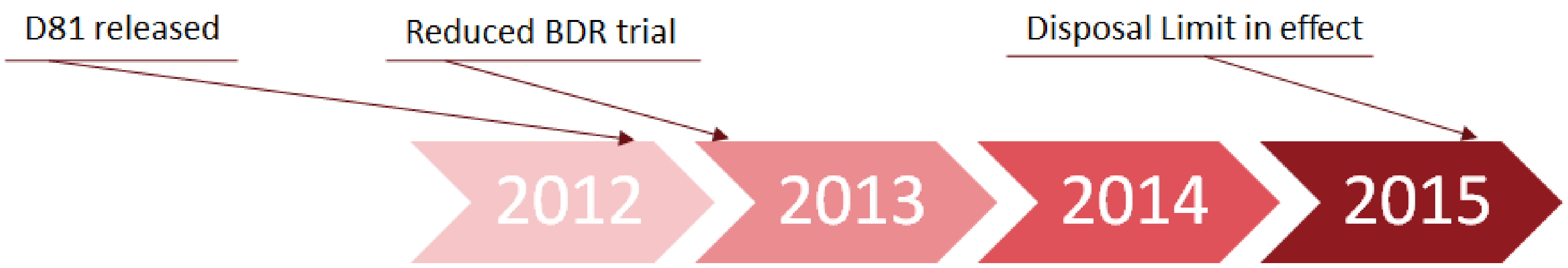
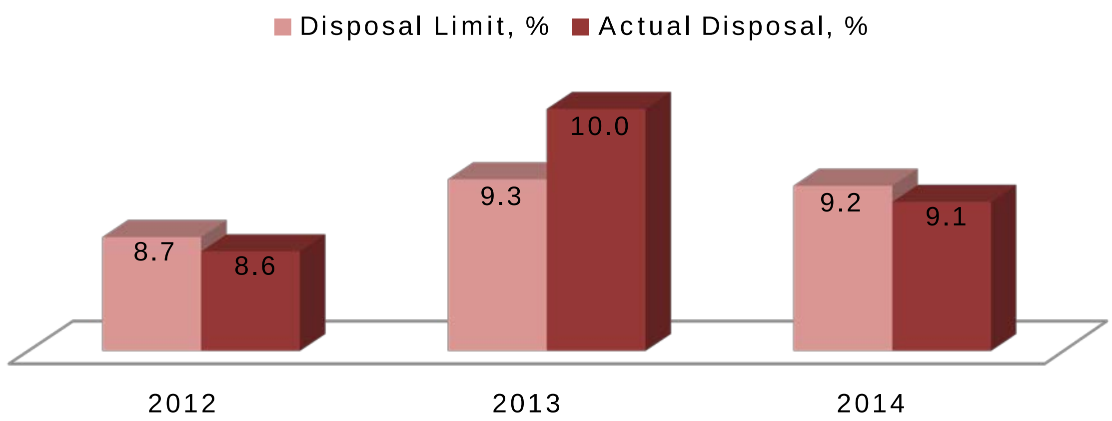
Water Disposal Performance (*Directive 81*)

From WRR to Disposal Limit regulation



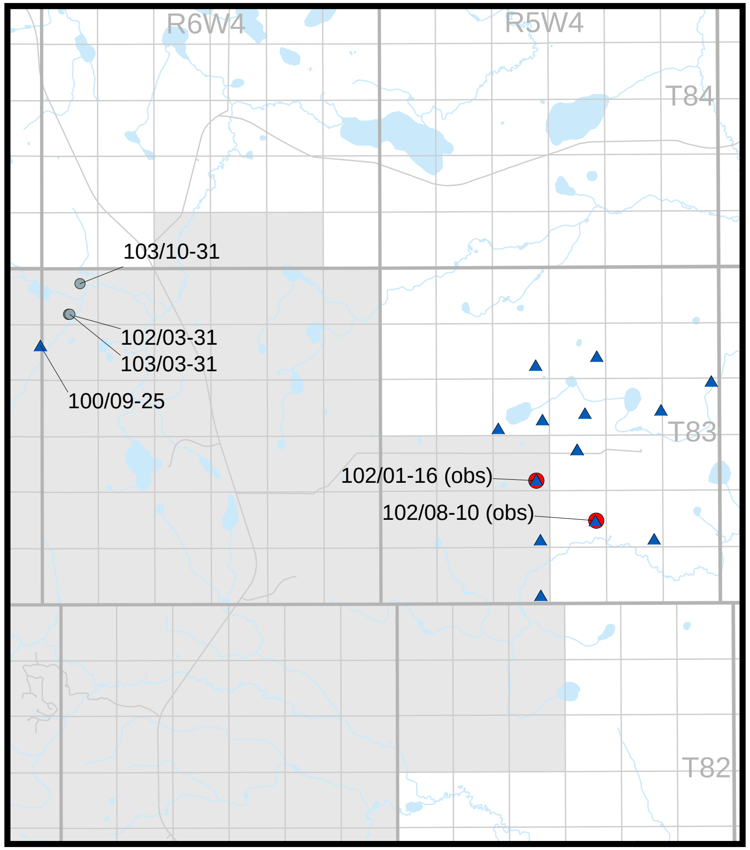


- Surmont achieved *Directive 81* disposal limit compliance in 2014 (9.1% actual vs. 9.2 % disposal limit) after completing blowdown recycle rate trials in 2013

- Average boiler blowdown recycle rate at Surmont 1 in 2014 was 53-58%

Water Disposal Wells

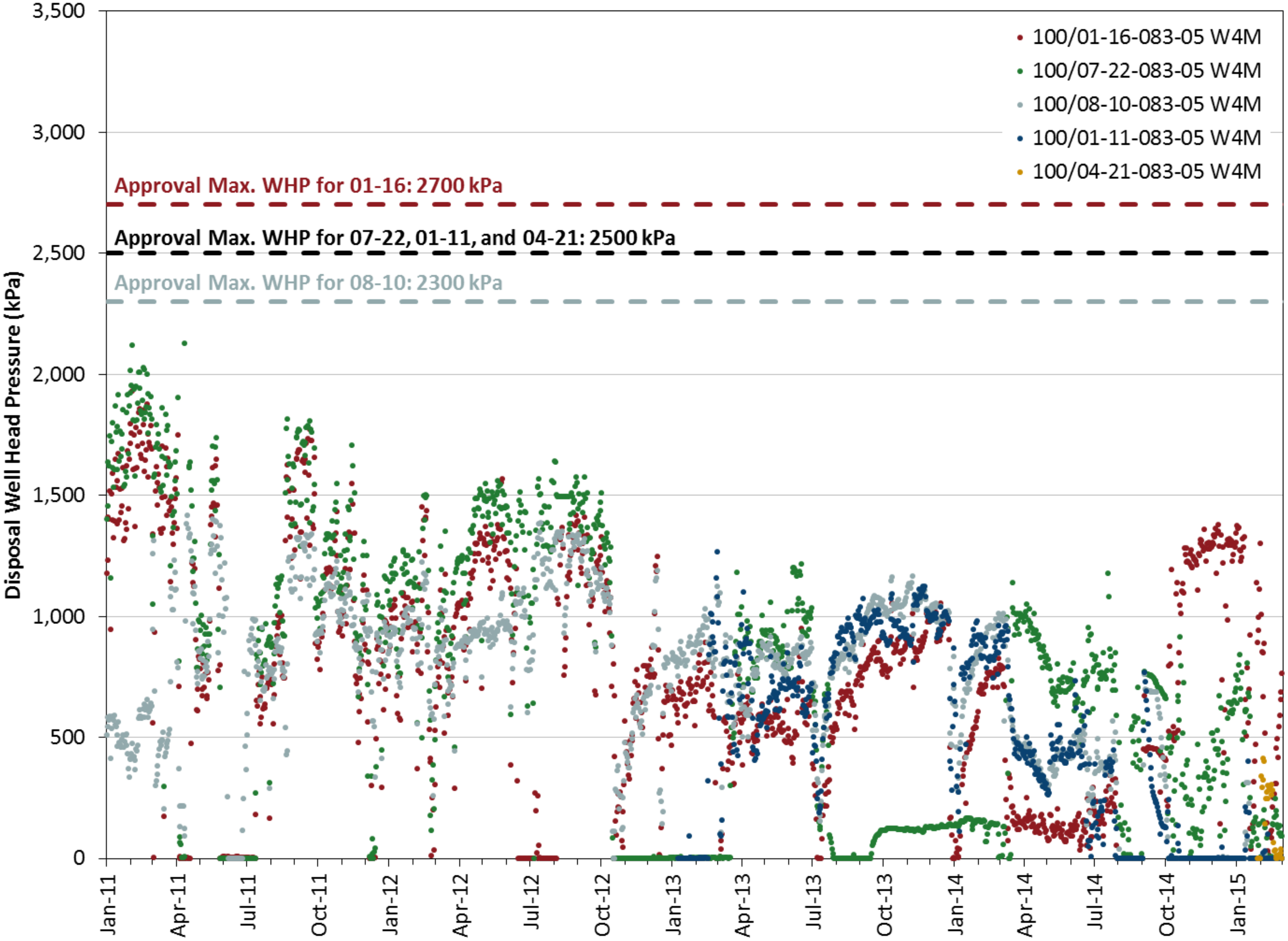
	Well	Zone Approved for Disposal	Maximum Wellhead Injection Pressure (kPa)	Well Status	AER Disposal Approval No.
INACTIVE	102/03-31-083-06W4/0	McMurray	3600	Abandoned	9573C
INACTIVE	103/03-31-083-06W4/0	McMurray	3600	Abandoned	9573C
INACTIVE	103/10-31-083-06W4/0	McMurray	3600	Abandoned	9573C
	100/09-25-083-07W4/0	Keg River	6000	Water Disposal	9573C
	100/01-16-083-05W4/0	McMurray	2700	Water Disposal	10044H
	100/07-22-083-05W4/0	McMurray	2500	Water Disposal	10044H
	100/08-10-083-05W4/0	McMurray	2300	Water Disposal	10044H
	100/01-11-083-05W4/0	McMurray	2500	Water Disposal	10044H
	100/04-21-083-05W4/0	McMurray	2500	Water Disposal	10044H
INACTIVE	100/01-04-083-05W4/0	McMurray	2500		10044H
INACTIVE	100/01-09-083-05W4/0	McMurray	3400		10044H
INACTIVE	100/10-15-083-05W4/0	McMurray	3400		10044H
INACTIVE	100/08-23-083-05W4/0	McMurray	3400		10044H
INACTIVE	100/16-24-083-05W4/0	McMurray	3400		10044H
INACTIVE	100/08-27-083-05W4/0	McMurray	3400		10044H
INACTIVE	100/01-28-083-05W4/0	McMurray	3400		10044H
INACTIVE	102/15-15-083-05W4/0	McMurray	3400		10044H
INACTIVE	102/08-21-083-05W4/0	McMurray	3400		10044H



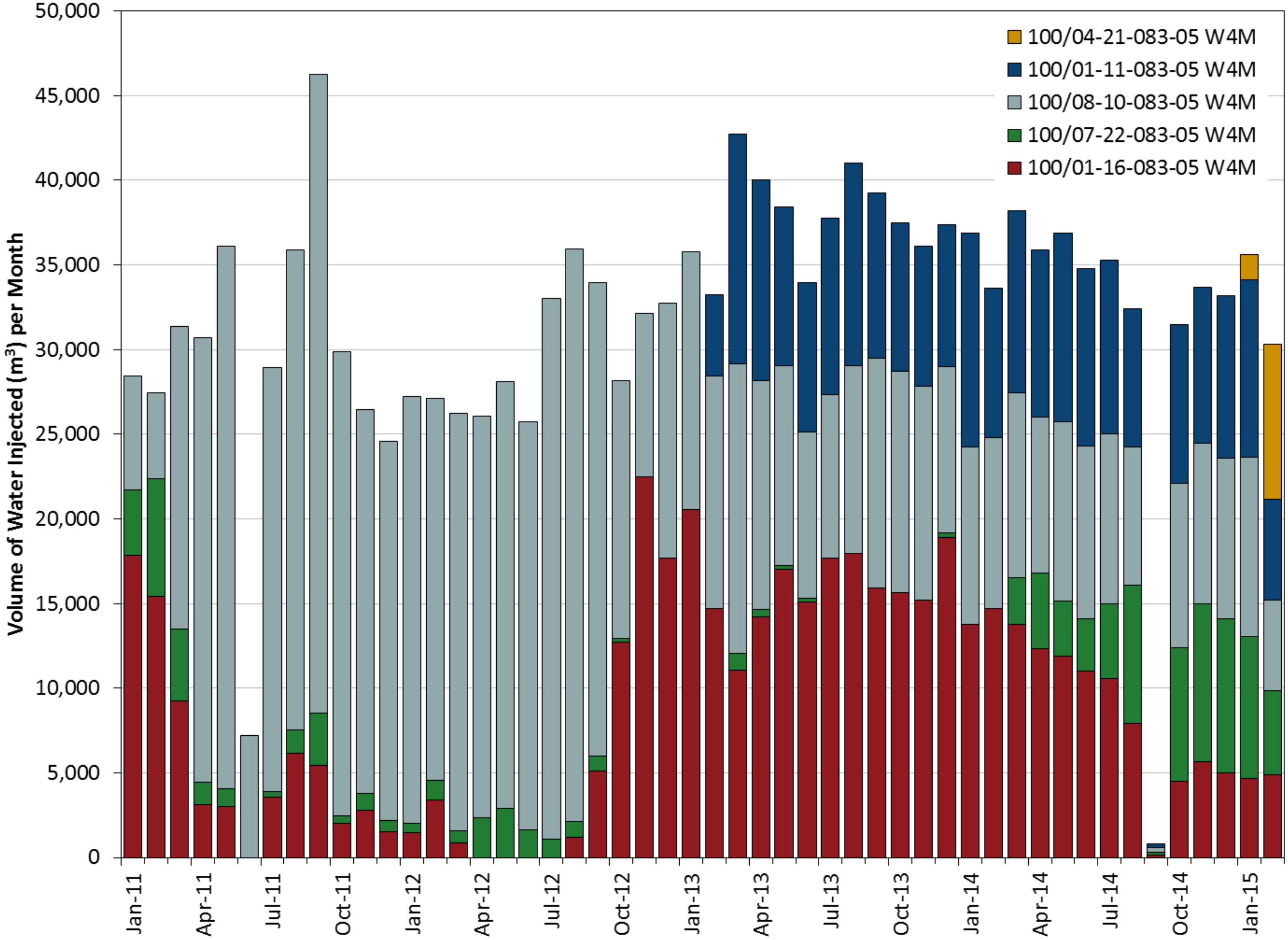
Notes

- Disposal to 100/09-25-083-07W4/0 ended December 2011
- As of December 2011, water transferred to Phase 1 via pipeline
- Disposal to 100/09-25-083-07W4/0 recommenced August 2014

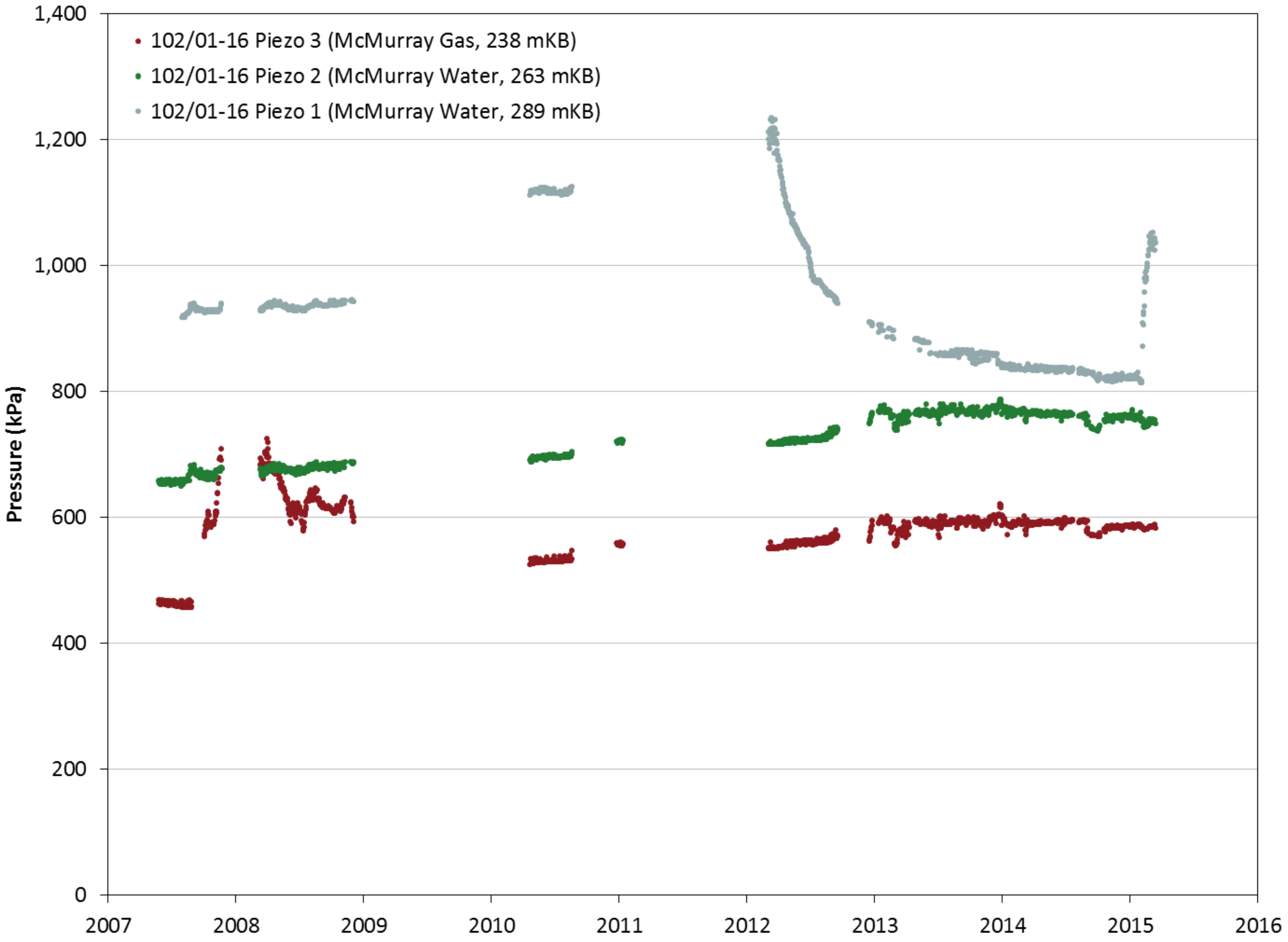
Water Disposal Wells Well Head Pressure (McMurray)



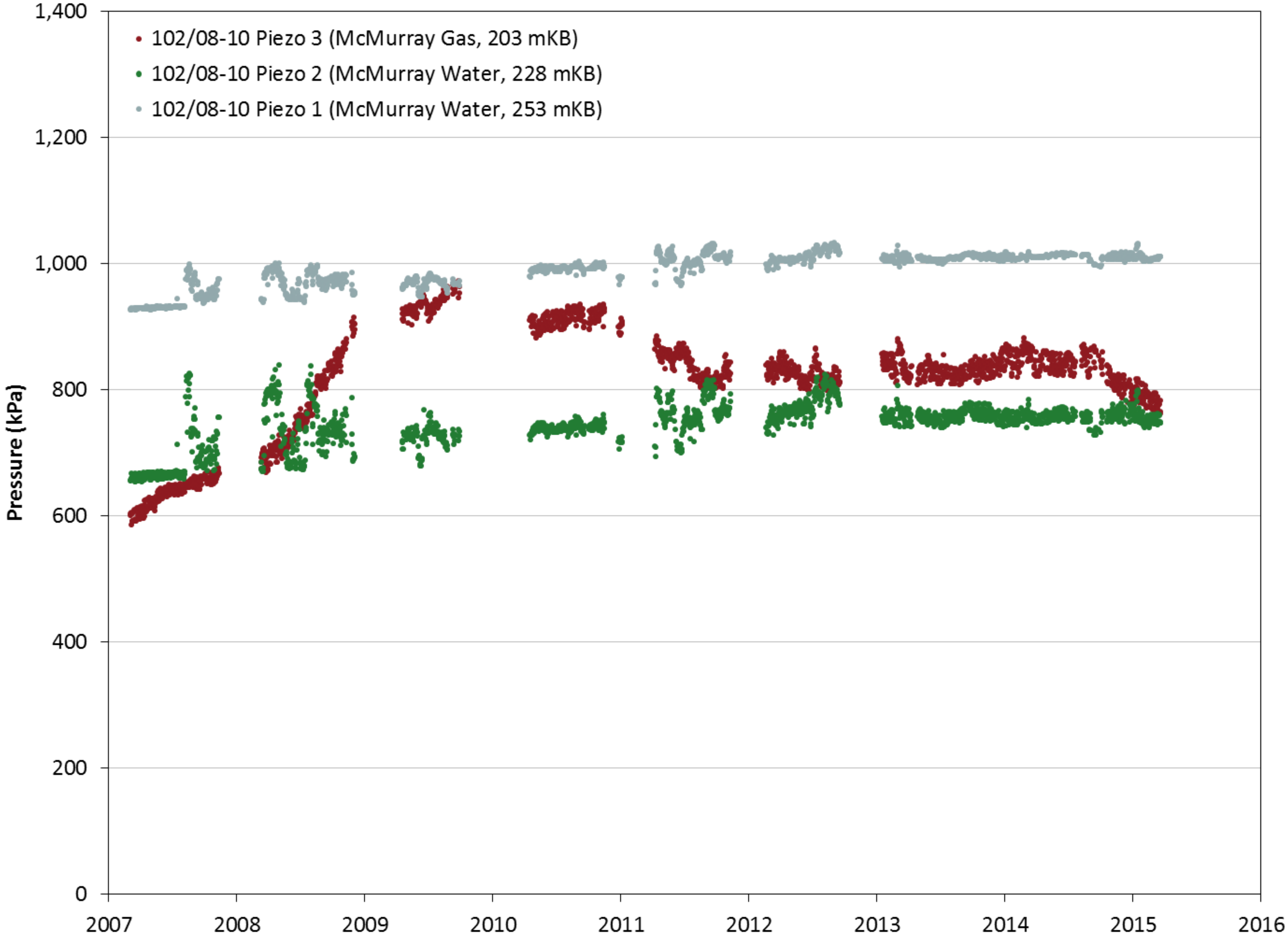
Water Disposal Wells Injection Rates (McMurray)



Water Disposal Well 100/01-16-083-05 W4M
Observation Well Pressure (McMurray)



Water Disposal Well 100/08-10-083-05 W4M
Observation Well Pressure (McMurray)



Typical Water Analysis

Parameter	Raw Makeup Water (mg/L)	Produced Water (mg/L)	Disposal Water (mg/L)
pH	8.5	7.5	8.8
Total Dissolved Solids (TDS)	1,400	1,800	22,000
Chloride	200	650	8,000
Hardness as $CaCO_3$	<0.5	10	5
Alkalinity as $CaCO_3$	900	300	2,650
Silica	8	240	200
Total Boron	6	40	250
Total Organic Carbon	15	450	2,000
Oil Content	<1	50	30

Waste Disposal

Waste Description	Disposal Weight (Tonnes)	Disposal Method
Dangerous Oilfield Waste	5,683	
Hydrocarbon/Emulsion Sludge	1,219	Cavern
Crude Oil/Condensate Emulsions	4,432	Oilfield Waste Processing Facility
Various	30	Landfill
Non-Dangerous Oilfield Waste	18,480	
Lime Sludge	18,329	Landfill
Various	151	Landfill
Well Fluids	66	Cavern

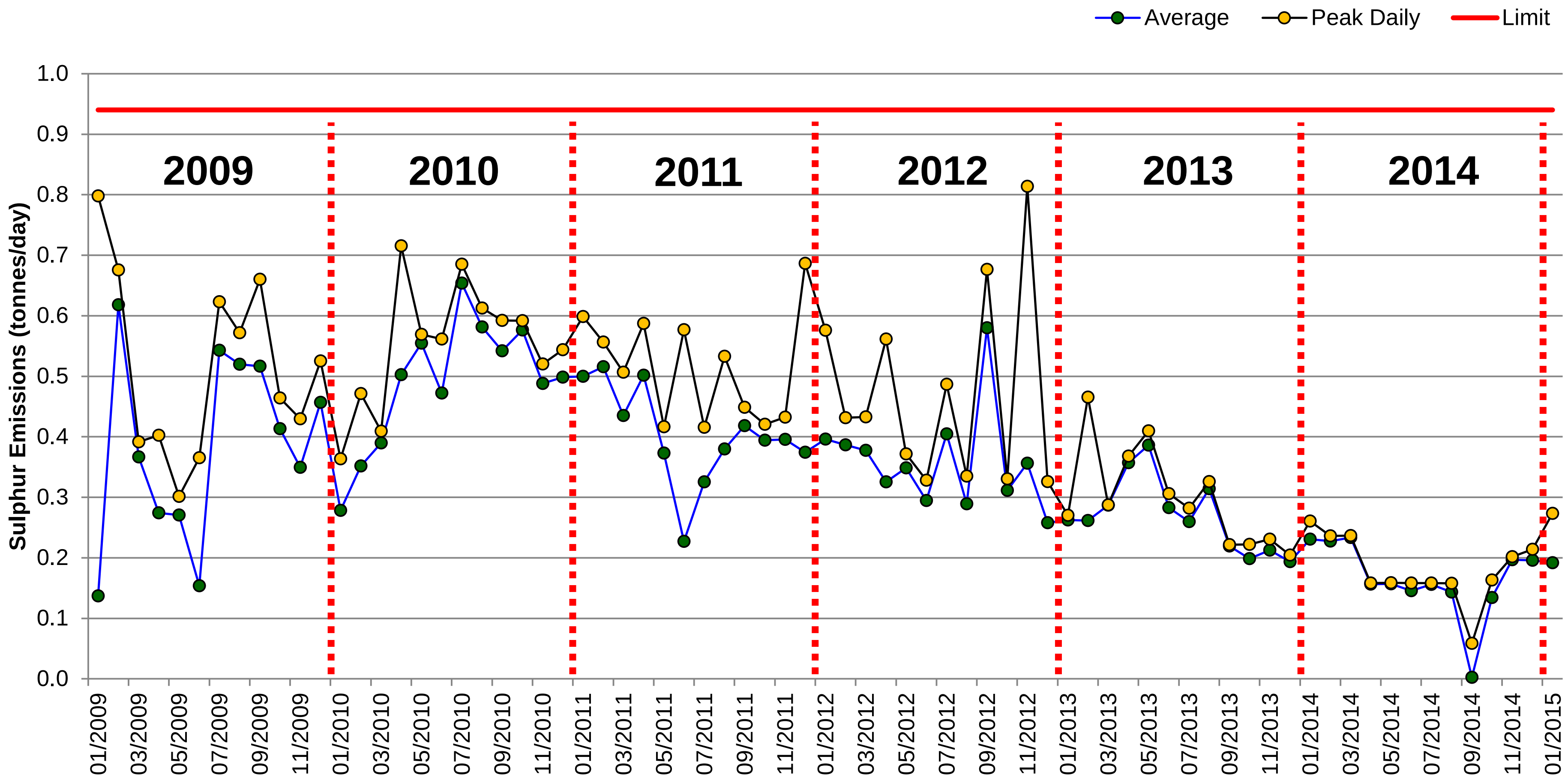
The Surmont 1 lime sludge pond was dredged in 2014

Waste Recycling

Waste Description	Disposal Weight (Tonnes)	Disposal Method
Oil	39	Used Oil Recycler
Empty Containers	22	Recycling Facility
Fluorescent Light Tubes	10	Recycling Facility
Batteries	7	Recycling Facility

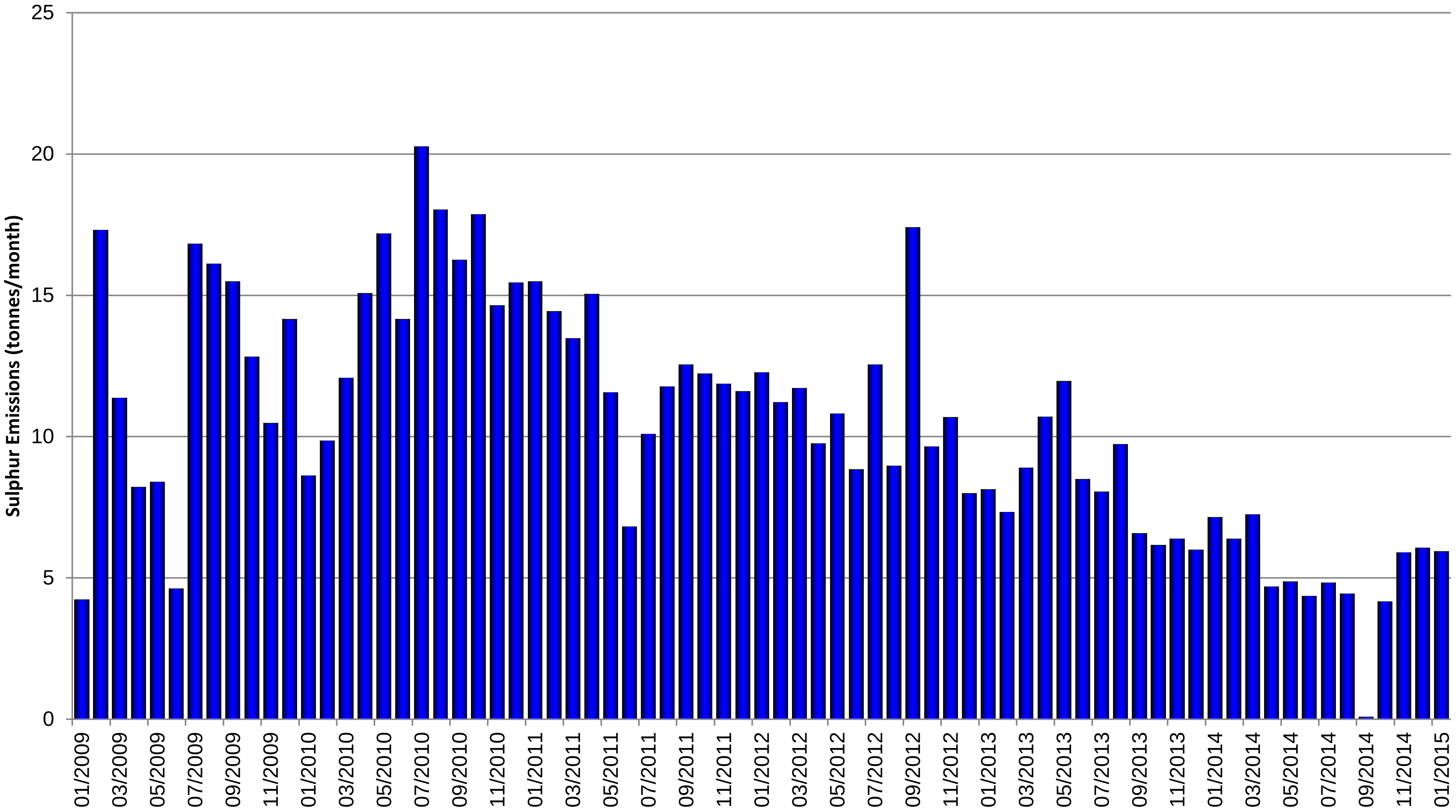
Sulphur Production
Subsection 3.1.2 (5)

Daily Sulphur Emissions

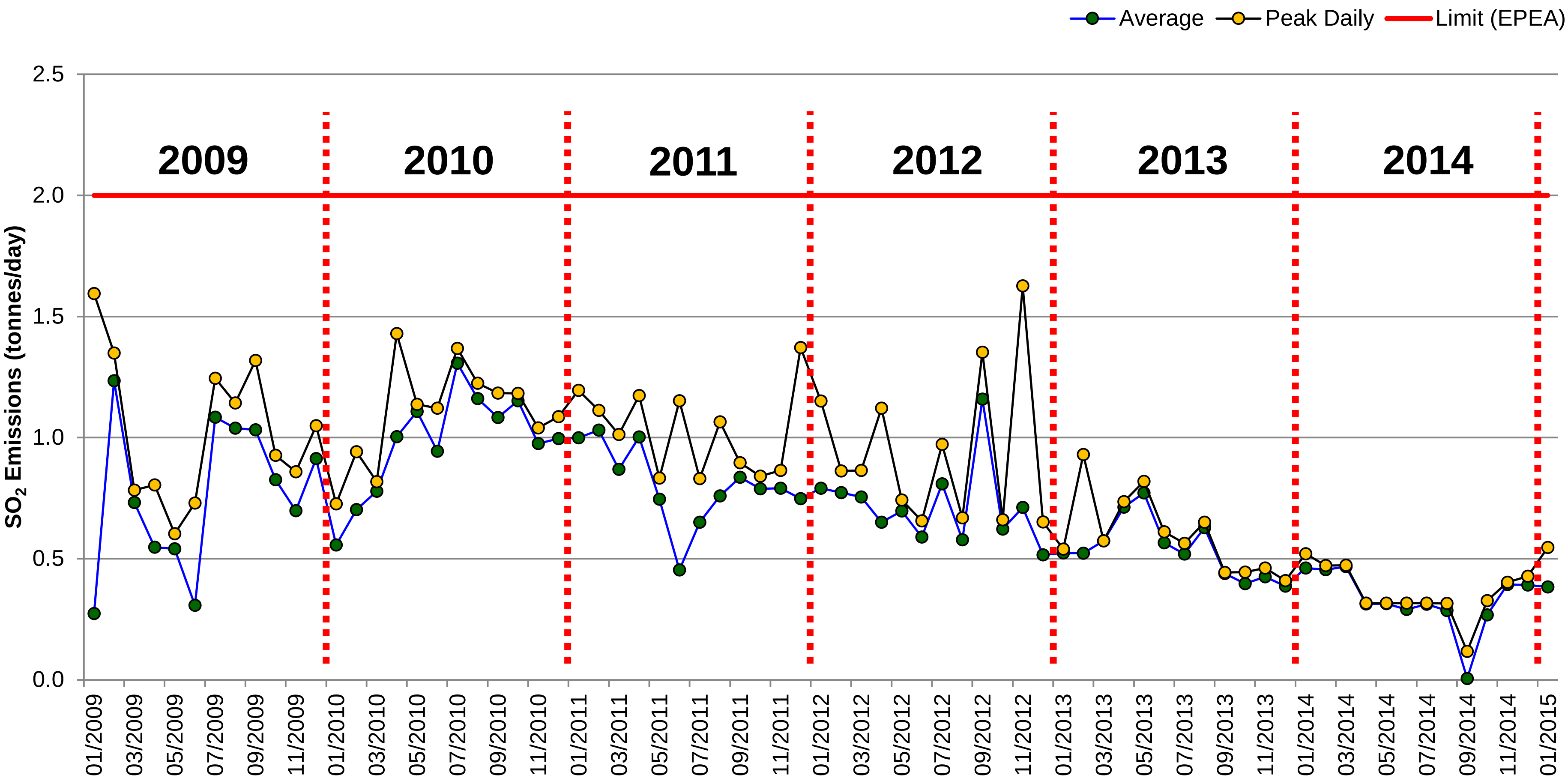


Sulphur emissions were below the AER limit of 0.94 tonnes/day.

Monthly Sulphur Emissions

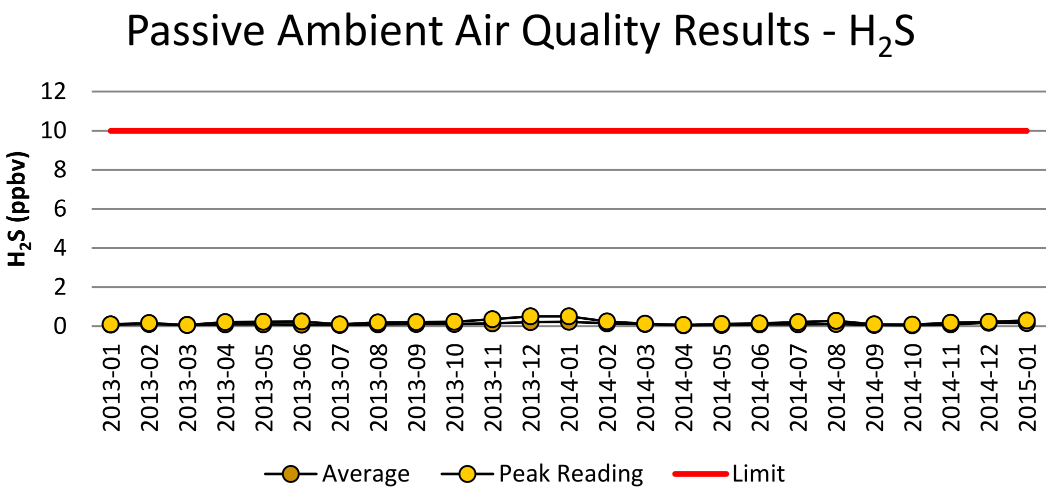


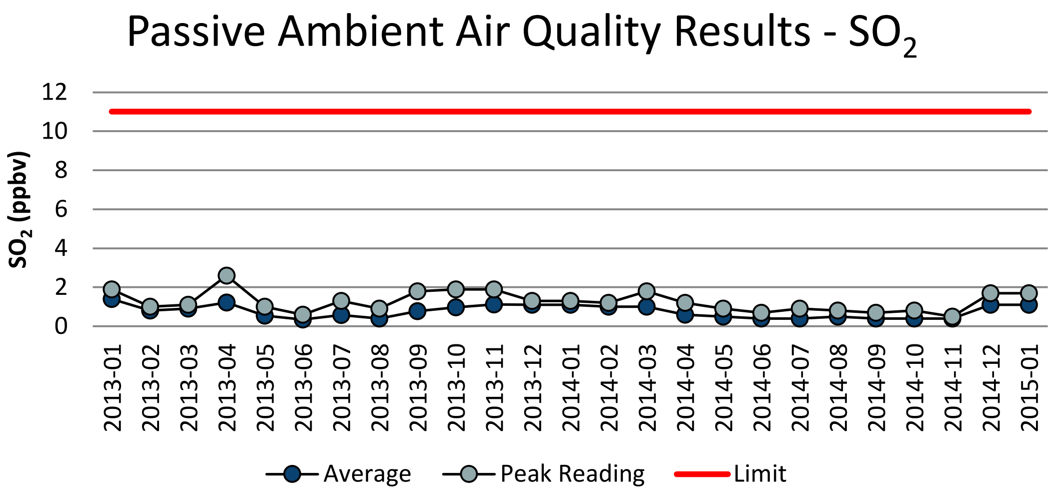
Daily SO_2 Emissions



SO_2 Emissions are well below the EPEA approval limit of 2 tonnes/day

Ambient Air Quality Monitoring





Passive ambient air monitoring - all Alberta Ambient Air Quality Objectives were met in 2014

Continuous ambient air monitoring - all Alberta Ambient Air Quality Objectives were met in 2014

Environmental Issues
Subsection 3.1.2 (6)

Environmental Compliance

Environmental Approval Contraventions

- Failure to submit 2013 Industrial Wastewater Report
  (Reference No. 289347).
  - Report is now submitted
- Ambient air quality monitoring trailer operated less than 90% of the time
  (Reference No. 289438)
  - This occurred during turnaround when electricity to the trailer was lost (no action required), still met all air monitoring requirements in 2014
- Failure to properly dispose of hydrotest fluids (Surmont 2 new lines)
  (Reference 289488)
  - Spill of hydrotest fluids containing biocide to ground. Area was monitored and biocide naturally attenuated.

Environmental Monitoring

Groundwater Monitoring Program

- 2014 results within historical/background concentrations

Integrated Wetlands Monitoring Program

- 2014 results within historical/background concentrations

Reclamation Programs

- No reclamation in 2014

Wildlife Monitoring Program

- Monitoring of above-ground pipeline completed in 2014

Participated in joint industry environmental monitoring committees in 2014 (WBEA, RAMP, JOSM, etc.)

Groundwater and Integrated Wetland Monitoring Programs extended to Surmont 2

Compliance Confirmation
Subsection 3.1.2 (7) + (8)

Compliance Confirmation

ConocoPhillips is in regulatory compliance for 2014 with the exception of the following:

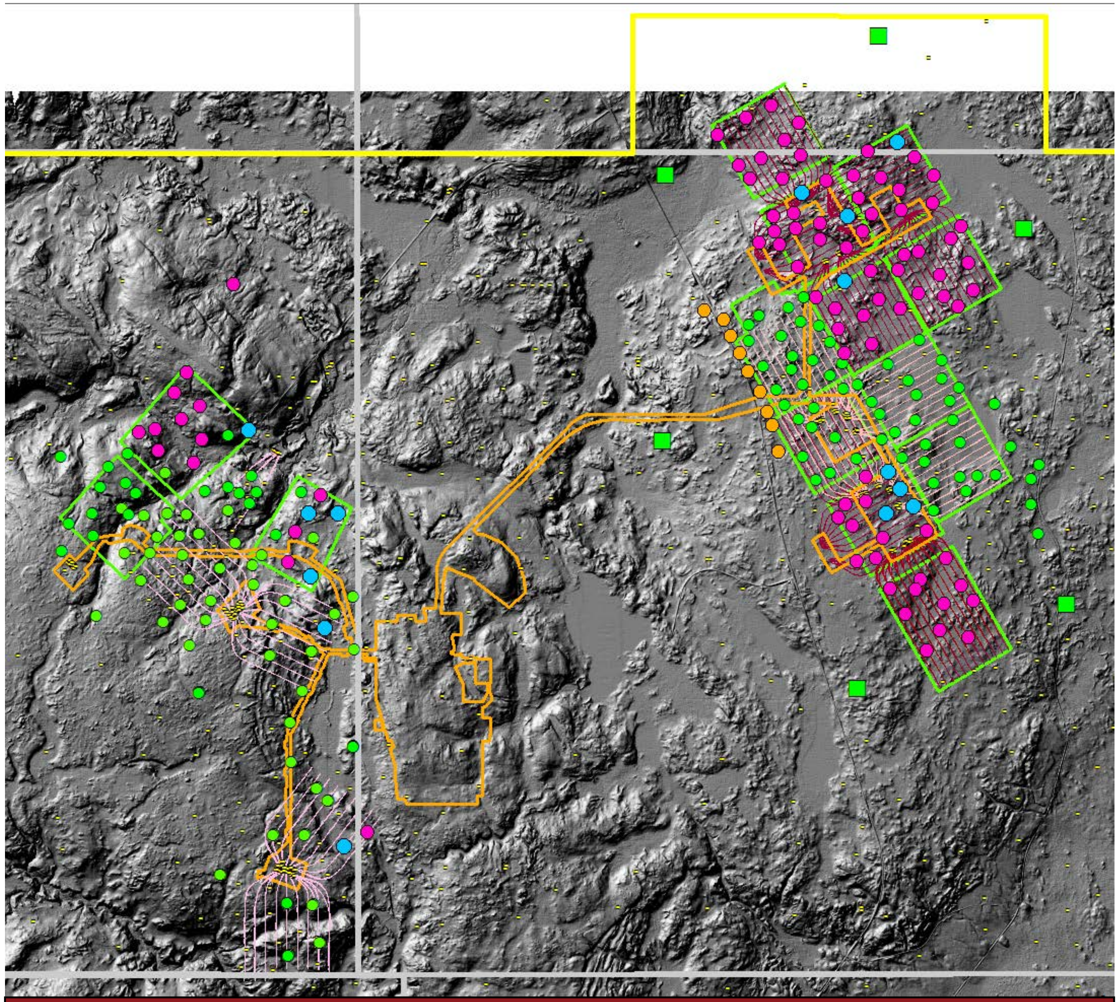
- Bulletin 2006-11 Water Recycle Rate
  - Self disclosure issued to AER in January 2015 (88.2% vs. 90%)
- *Directive 81* Injection Facility Water Imbalance
  - Self disclosure issued to AER in May 2014
  - Exceeded 5% imbalance for 4-month period coincident with lime sludge pond dredging (Feb – May 2014)
  - In compliance since June 2014
- Legacy wells
  - Being treated as routine abandonments with proper abandonment operations in progress

Subsection 3.1.1 (8), 3.1.2 (9)
Future Plans

Future Plans – Phase 1

- Continued research into OTSG fouling: evaluating chemical treatment
- 102-21/22 fish bone infill wells in 102N remained cold on startup. Evaluating alternative start-up plan.
- CPF Debottleneck including one OTSG addition is being reassessed.
- Phase 1 Infill Program: 101-24/25/26 alternative start-ups have been delayed to Q1 2016. Work remains to tie in wells.
- Pad 103 start-up and ramp-up

InSAR Program 2014/2015



CR Points occurring on an existing well lease can proceed. Additional approvals required for all other locations

2015 plans for ~ 10 near Hwy & S1

Control Reflectors (CR) installed February/March 2014

CR Installs in 2014	
S2 DA	80
Hwy and Pipeline ROW	8
Pad 104	16
Pad 102	2
Pad 101	1
Total	107

- existing CR
- new CR on well lease
- new CR in clearing
- new CR along highway

- Installing 12m pipe with pile driver vs. auger in previous years

S2 Project Execution Update

Execution Status

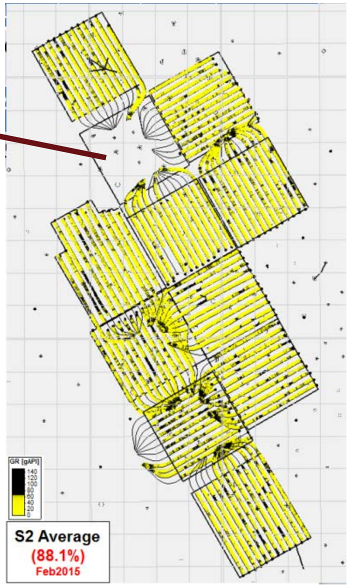
- Project to Date (End February) TRR 0.30
  - Best in industry
- Facilities Construction Progress
  - 92% construction completion
- Commissioning Progress
  - 75% Train A CPF commissioning progress
  - 58% commissioning progress
- First Steam target Q2 2015

- Drilling on complete on 10 of the initial pads, 119 of 129 well pairs, on plan
  - Drilling on last pad deferred to 2016 in line with projected well need
  - Well completions ongoing

S2 CPF January 2015

S2 SAGD Drilling Results

SAGD Drilling deferred to 2016



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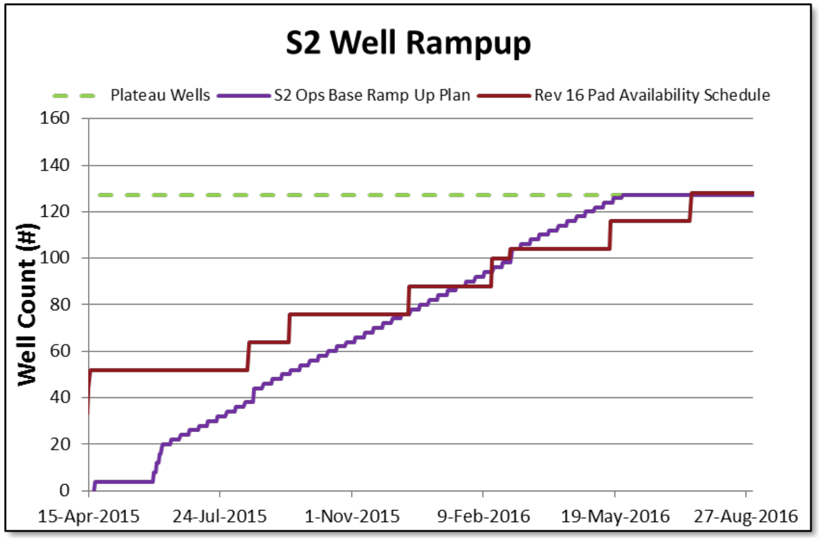
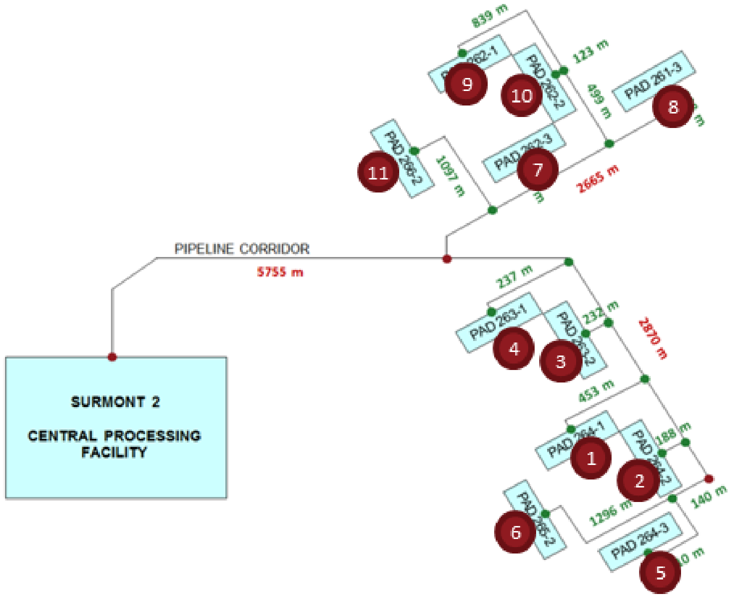
S2 Ramp-up

- Start-up Key Milestones
  - OTSG Testing
  - Bitumen Treating
- Pad 103 – Planned for Mid April, steamed from S1 to warm up lines
- Production expectations and the corresponding construction schedule for the project were based on Phase 1 experience and benchmarking against other operators.
- Well pads 264-1 and 264-2 brought online first (in parallel)
  - To be followed by 263-2 and 263-1
  - Long term pad order driven by construction schedule
- The well start up base plan is primarily based on a conventional circulation pre-heat period of 90 days





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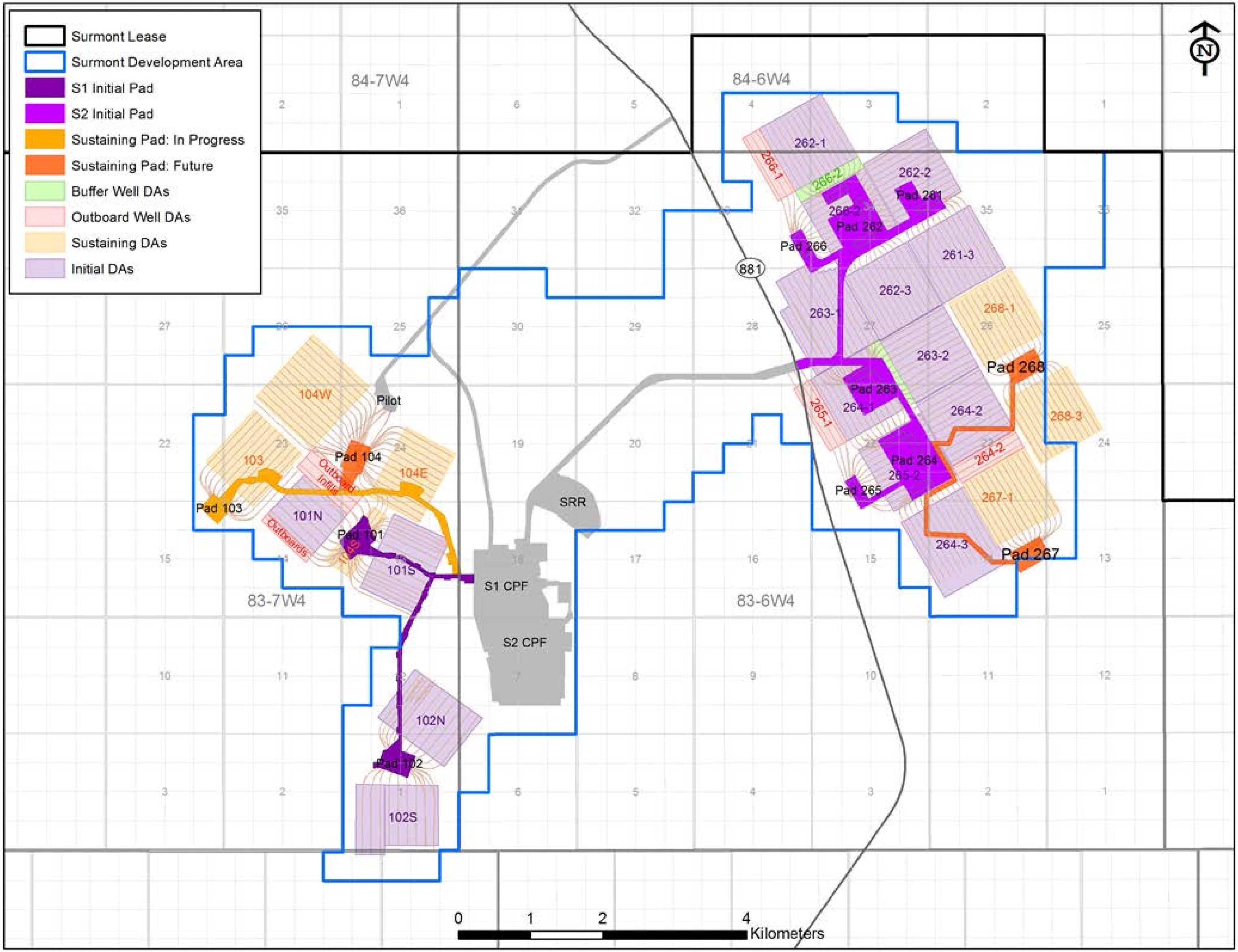
Liquid Scavenger Solution

- Intro to Liquid Scavenger
  - Required to treat additional sulfur compounds in the produced gas stream - Mercaptans
  - Replaces the Sulfurox unit
  - 2 Skid system with tanks for new solution and spent solution
  - Spent solution is disposed offsite
- Schedule
  - Start Execution 30-July-15
  - Skid 1 RFO 1-Nov-15
  - Skid 2 RFO 15-Jan-16
- Status
  - PO's for both Skids placed
  - Detailed engineering at 55%
  - Preparing to file for construction permit

Future Developments



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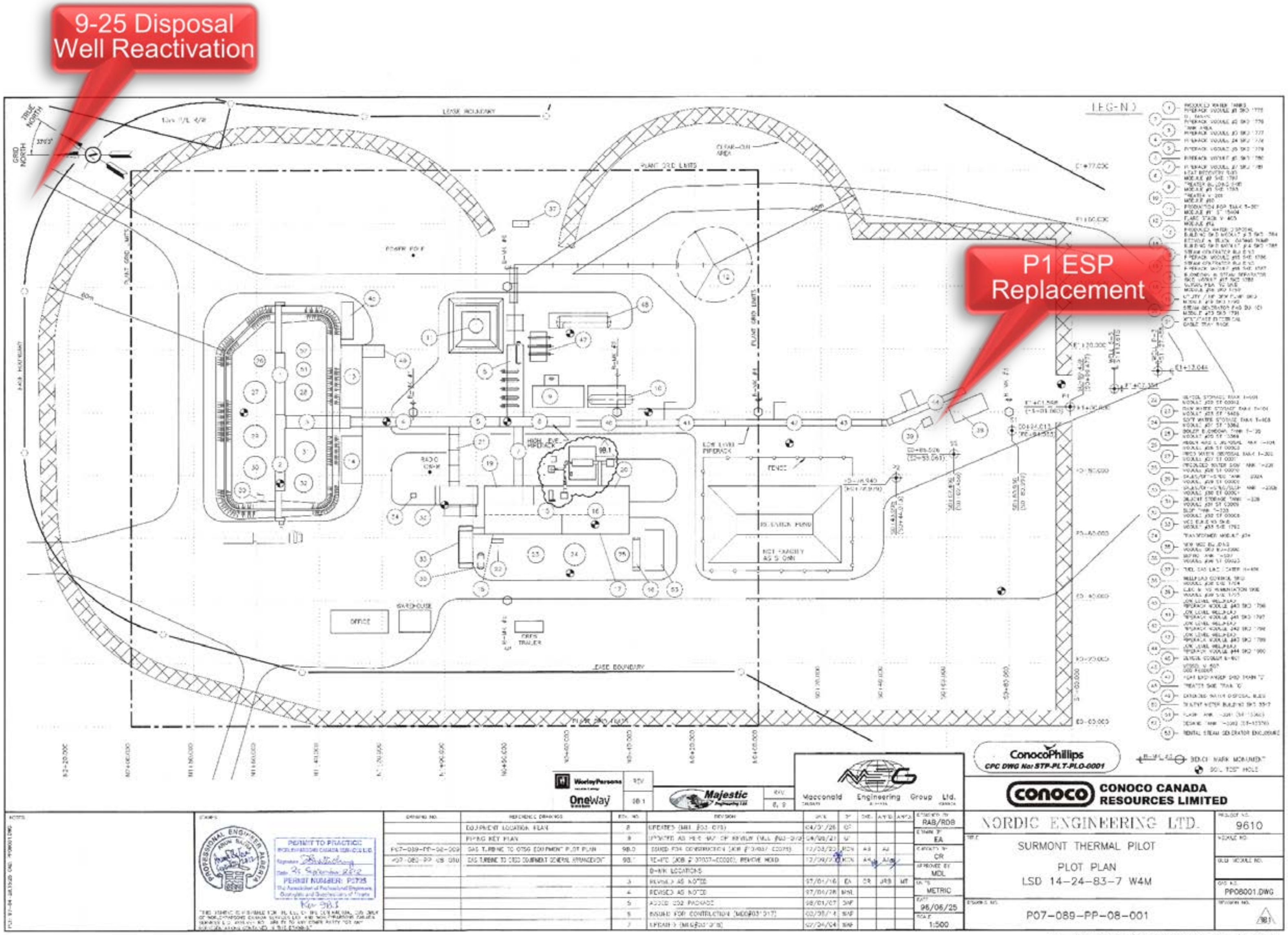
Surface Operations and Compliance
Pilot Project Approval 9460

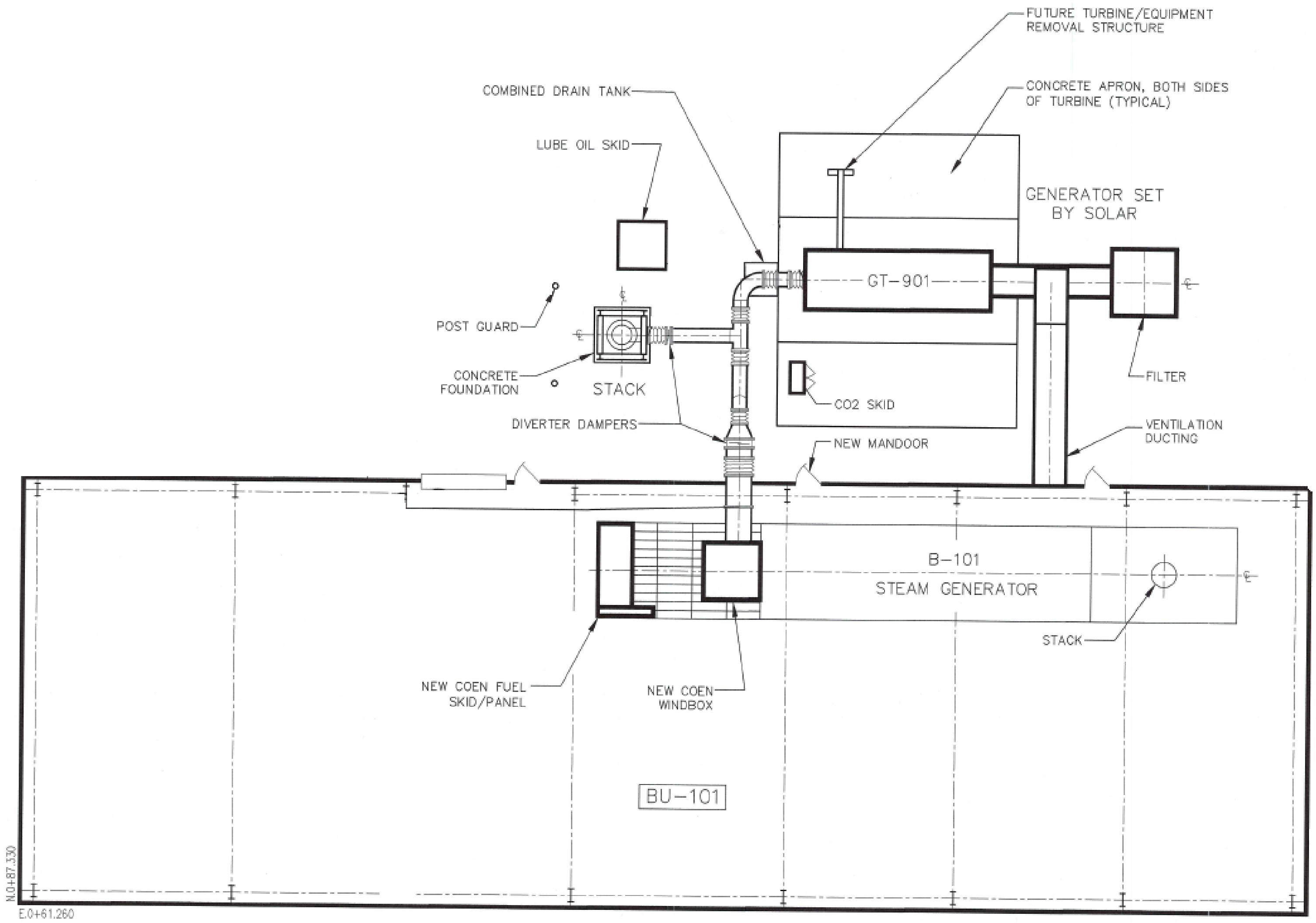
Facilities
Subsection 3.1.2 (1)

Site Survey Plan



2014 Work

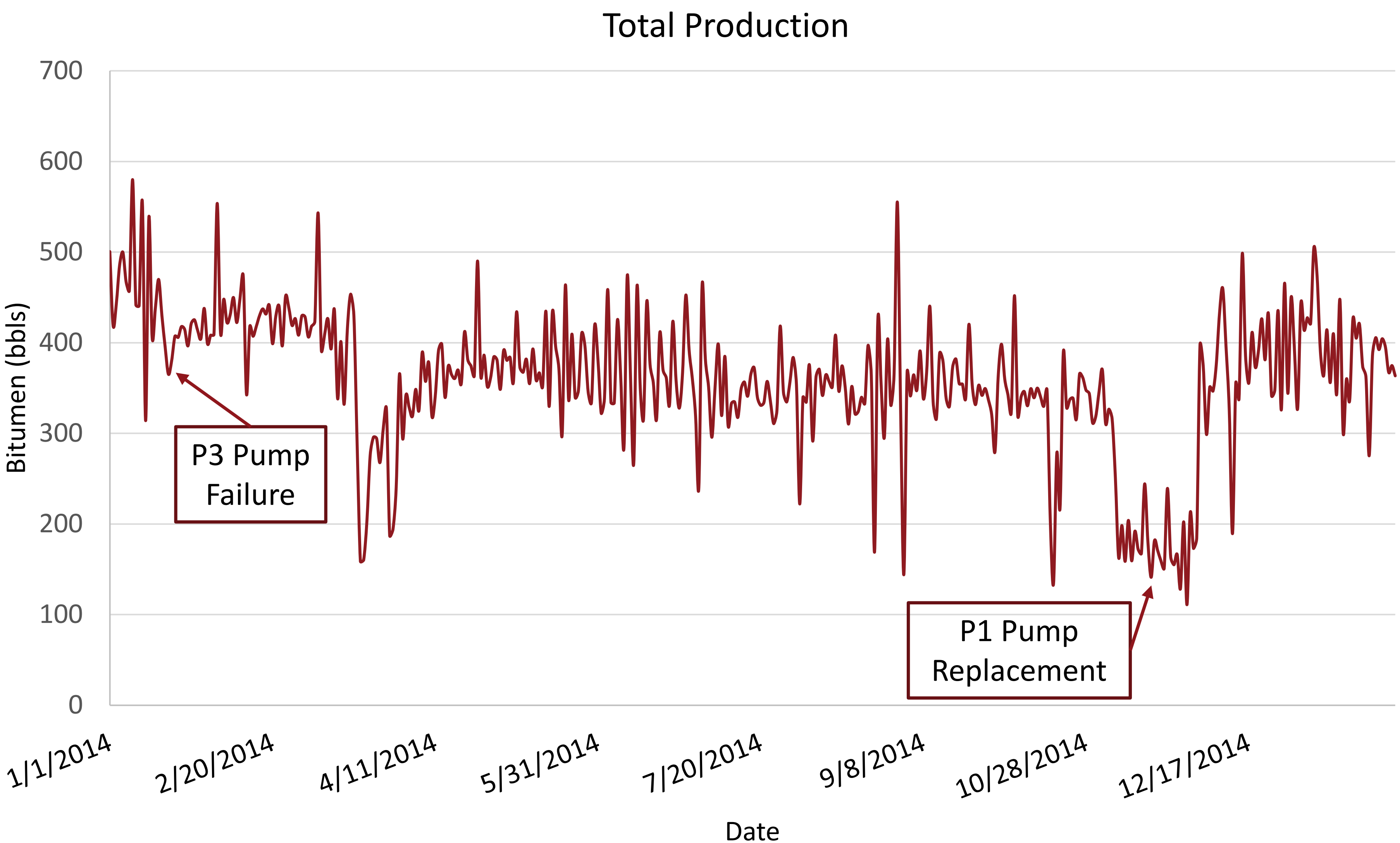
GT-OTSG



GT Trial Completed in 2014

Facility Performance
Subsection 3.1.2 (2)

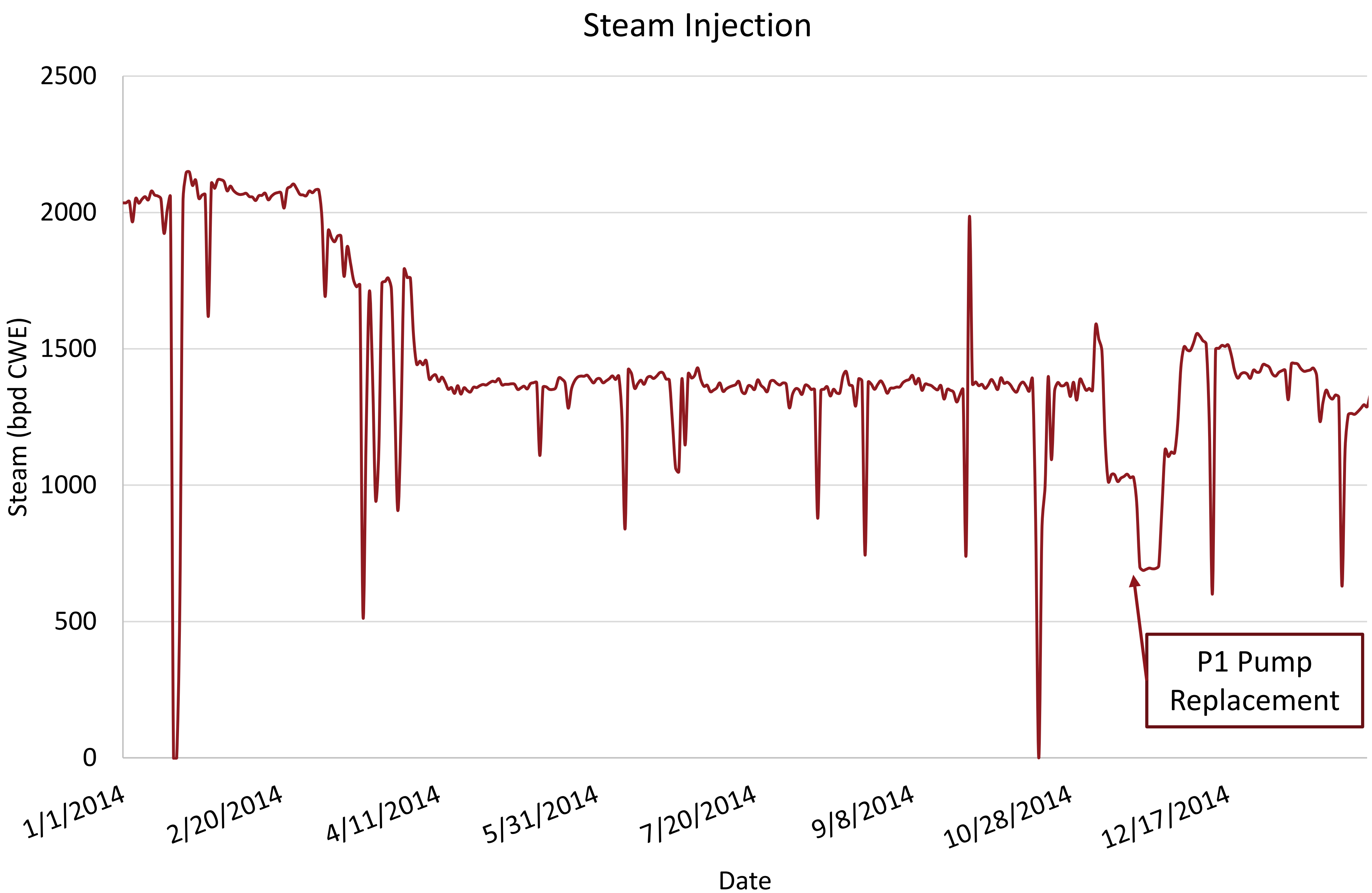
Pilot Plant Performance Bitumen Production



Average Production in 2013 = ~560 bbl/d

Average Production 2014 = ~356 bbl

Pilot Plant Performance Steam Generation



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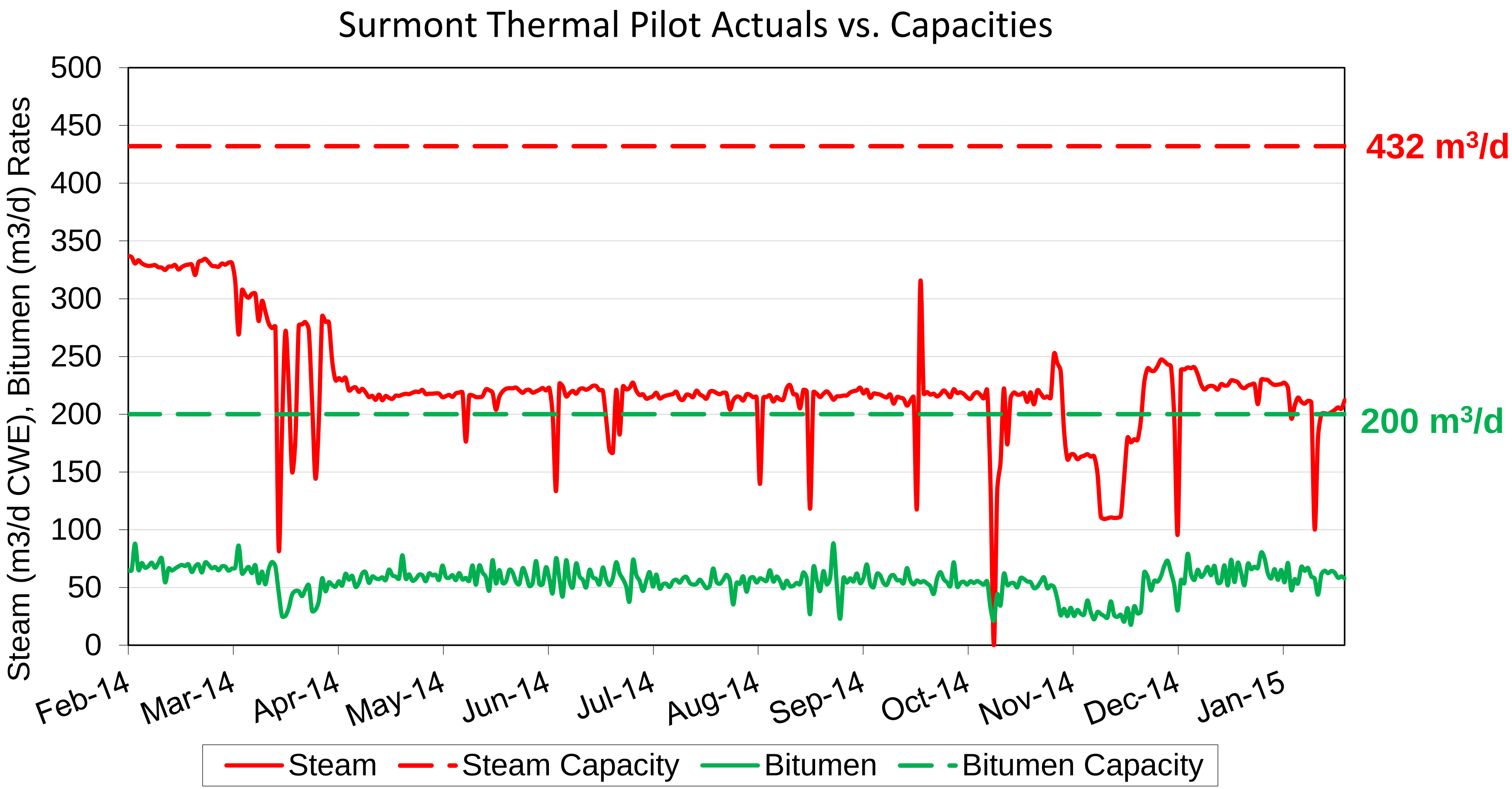
Pilot Plant Performance Capacities



Deviation from capacity due to:

- Reservoir pressure limiting steam requirement and corresponding production
- P3 pump failed shutting in production from this well
- ESP and subcool targets

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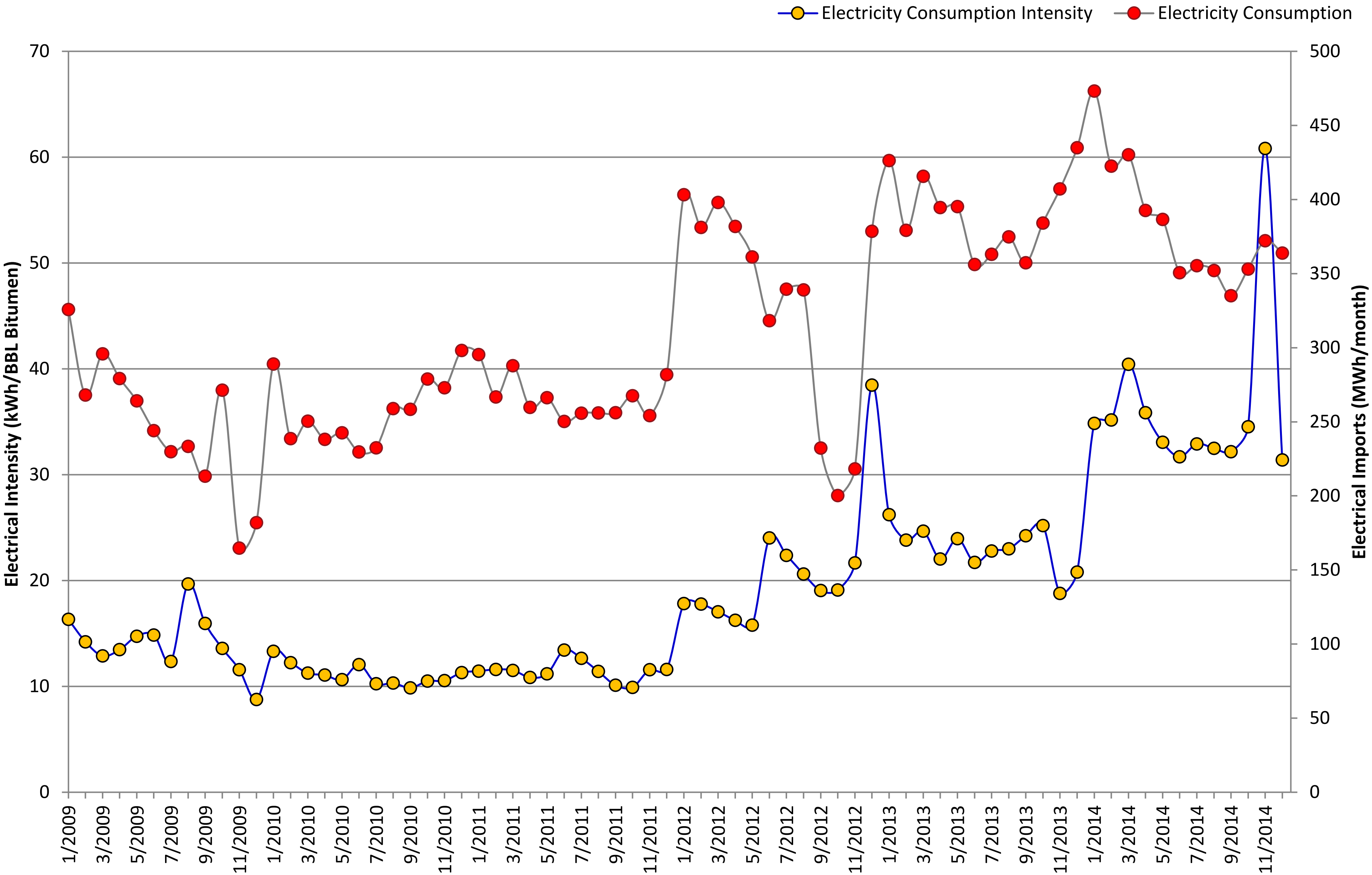
Pilot Plant Performance Electricity Consumption



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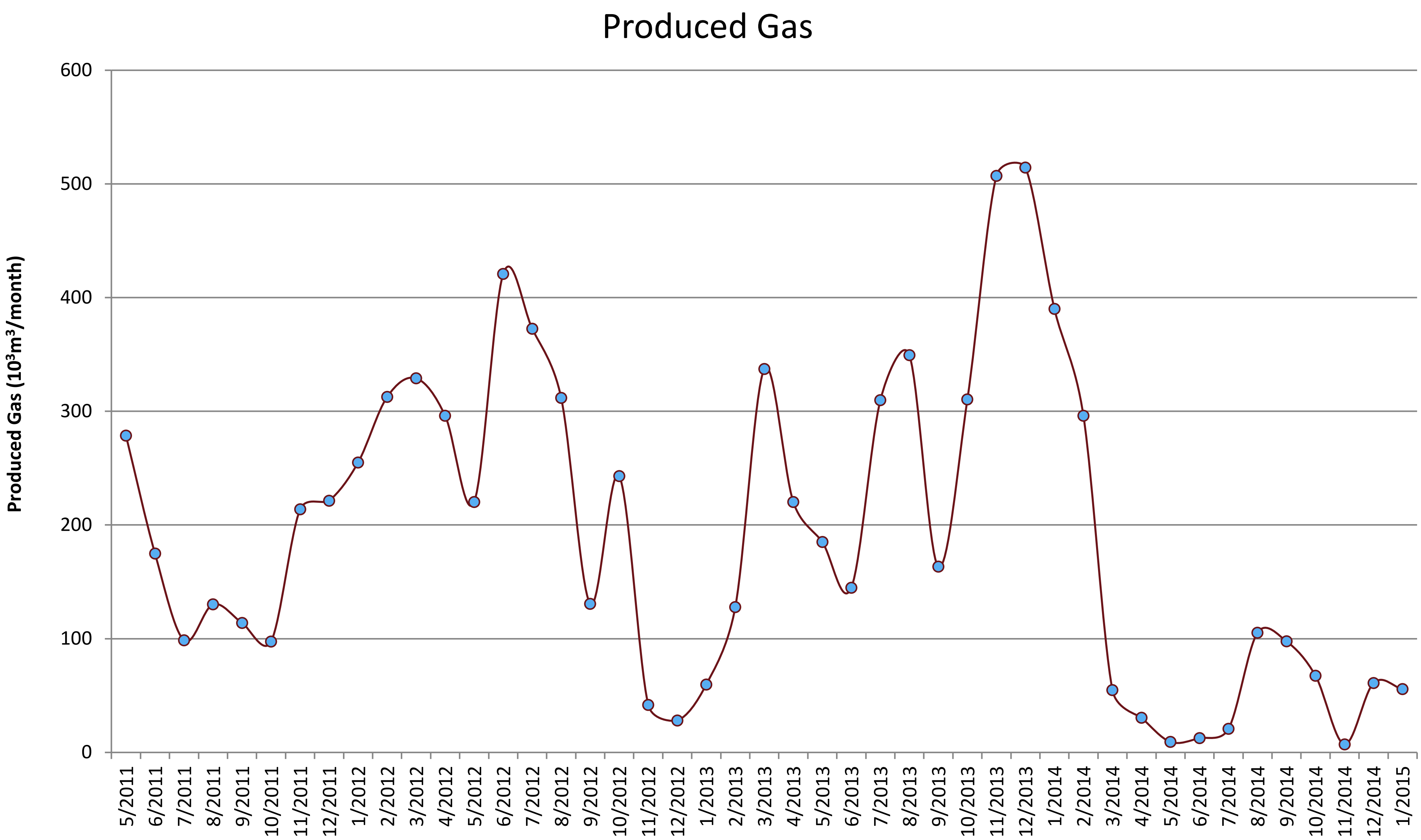
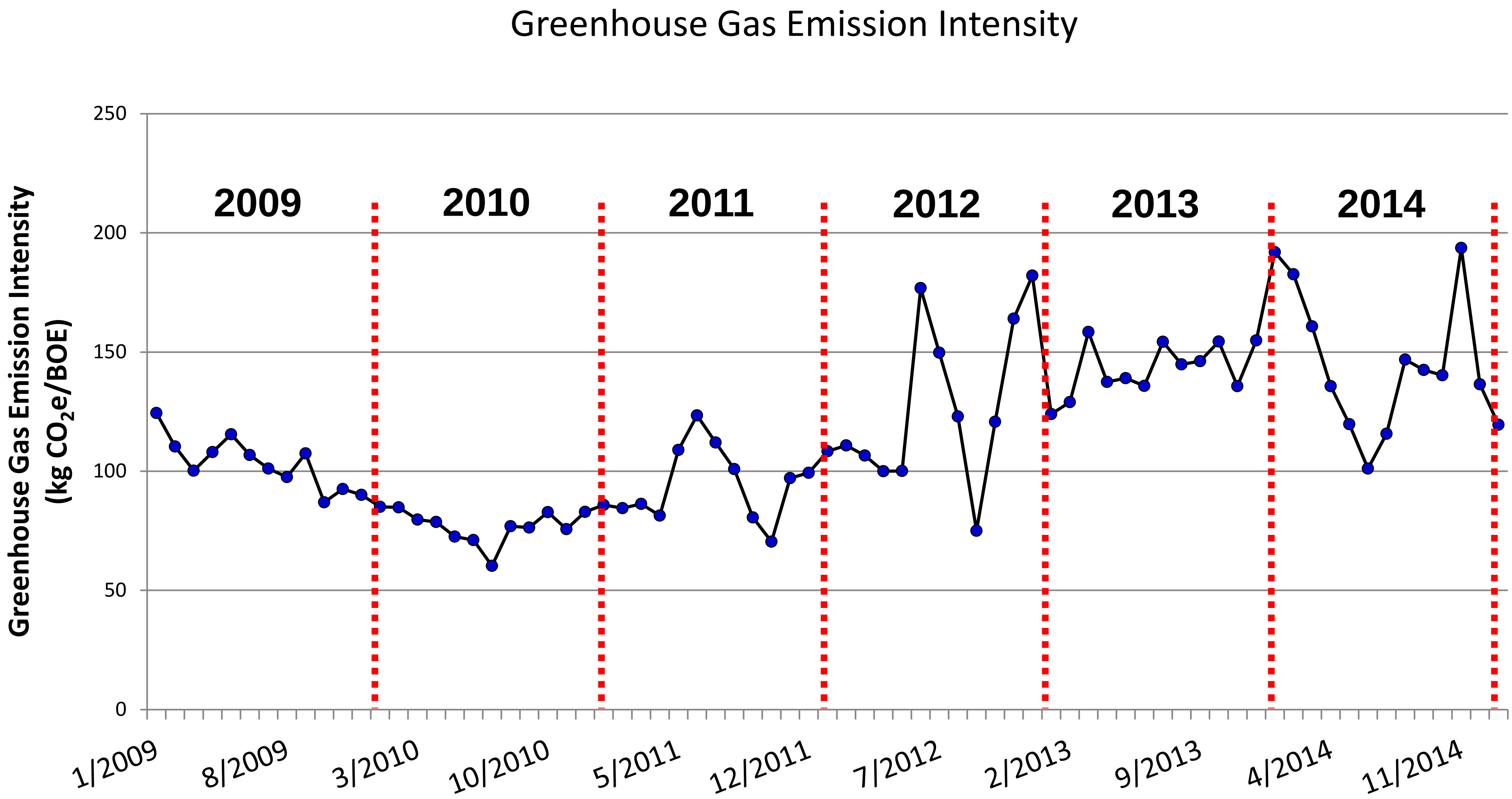
Pilot Plant Performance Produced Gas



Pilot Plant Performance Gas Usage

	2010	2011	2012	2013	2014	2015-01	units
Total Gas Imports (TCPL)	11,224	12,334	9,728	11,828	10,351	690	10^3m^3
Solution Gas	53.2	1,347.3	2,961.6	3,229.2	1,152.0	55.6	10^3m^3
Total Gas Vented	0	0	0	0	0	0	10^3m^3
Total Gas Flared	0.9	2.8	2.5	85.4	31.7	0.9	10^3m^3
Solution Gas Recovery	98.3	99.8	99.9	97.4	97.2	98.4	%

Pilot Plant Performance Greenhouse Gas



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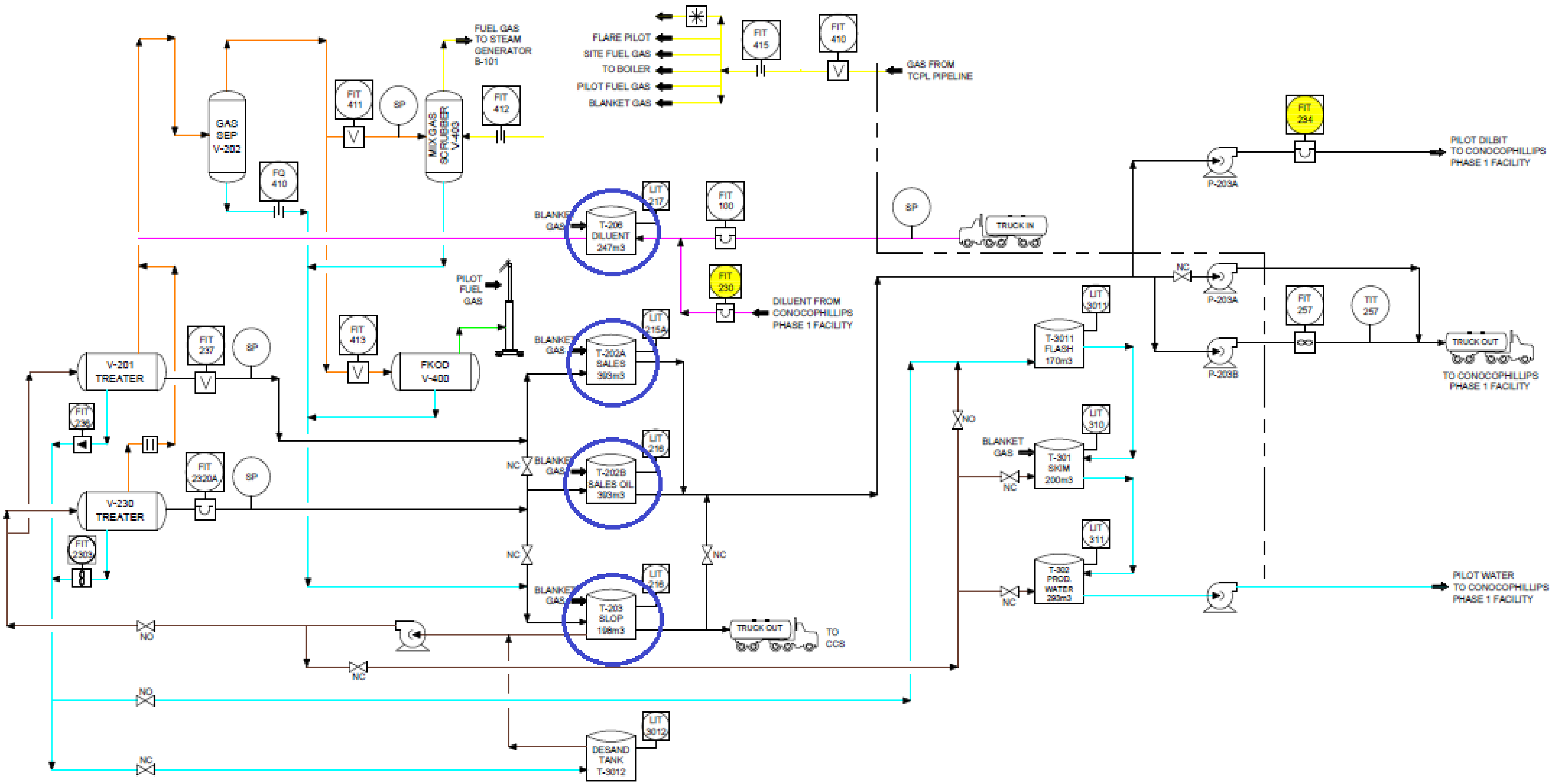
Measurement and Reporting
Subsection 3.1.2 (3)

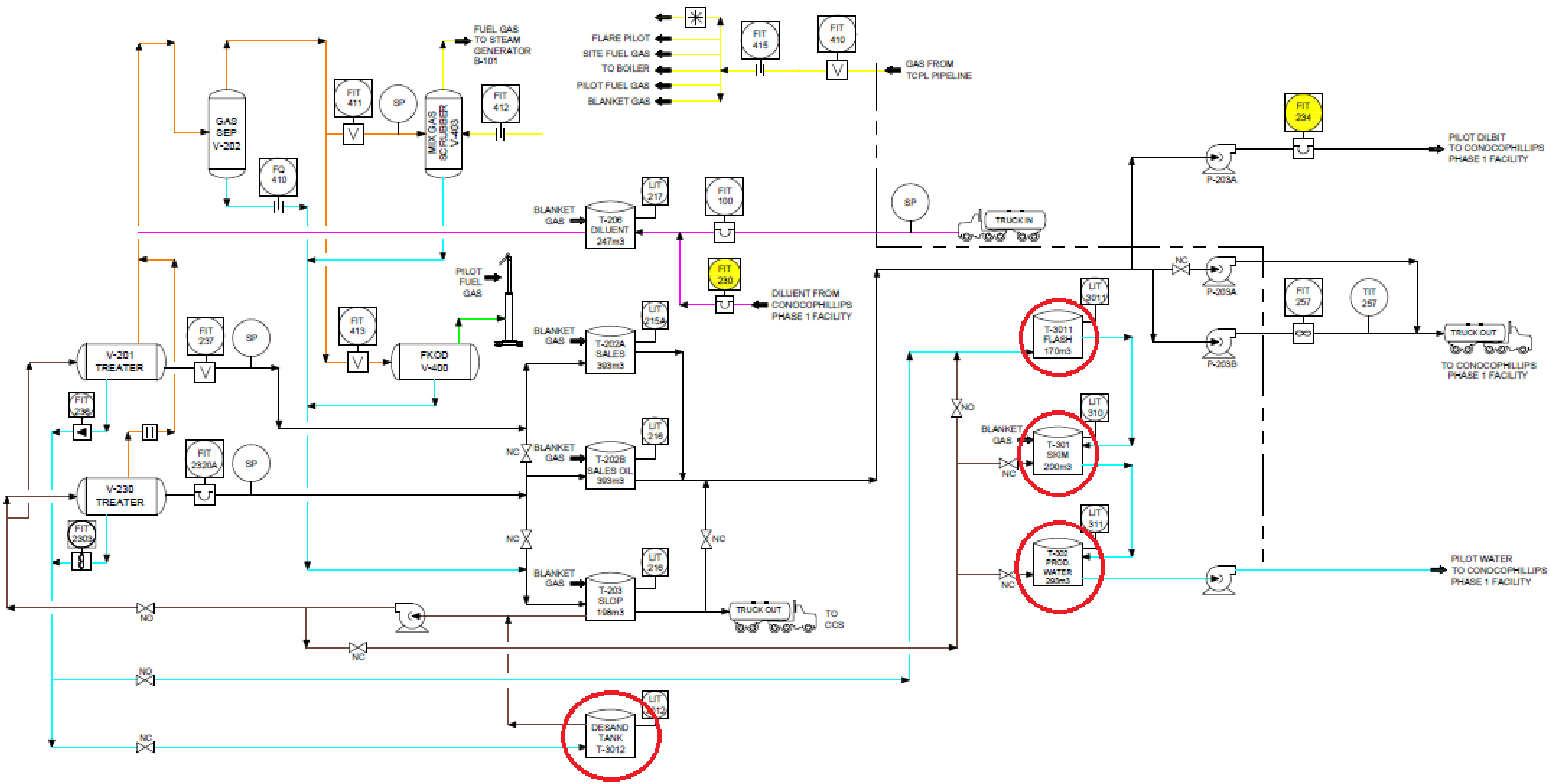
Bitumen Measurement and Reporting



Battery Actual Bitumen Production = [Closing Inventories – Opening Inventories (Oil portion of Sales and Slop)]/Shrinkage Factor – Diluent Received + [Closing Inventories – Opening Inventories (Diluent)] + [Closing – Opening (Injected Fluids into Producers)] + Sales Shipped to S1 and Trucked

Battery Estimated Bitumen Production = Well bitumen production is calculated from well tests (pro-rated battery)

Produced Water Measurement and Reporting



Water Production = [Closing inventories – Opening Inventories (Water portion of Sales, Slop, Flash, Skim and Produced Water)] – Water Content of Received Diluent or Oil + [Closing – Opening (Injected Fluids into Producers)] + Produced Water + Produced Water Truck Tickets + Water Content of Sales Oil

Battery Estimated Water Production = Well water production is calculated from well tests (pro-rated battery)

Measurement and Reporting Methods

Production Gas

- Total battery gas production estimated from inlet of FKOD, Scrubber and P3 usage
- Well gas production calculated from well oil production and GOR
- GOR is the battery gas production / the battery bitumen production
- Gas proration factor = total battery gas production / well test gas production

Steam

- Steam injection metered individually at each well and allocated using the group steam injection meter

Well Testing

- One well on test at a time
- Target at least two tests per well per month (24 hours in length)
- All well pairs tests regularly tested to meet minimum monthly target

No modifications in accounting formula

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

Water Source Wells Non-Saline

Surmont Pilot

Source Well	Observation Well	Formation
1F1082508307W400	1AJ082508307W400	Lower Grand Rapids
1F1072508307W400	100072508307W400	Clearwater

Surmont Phase 1

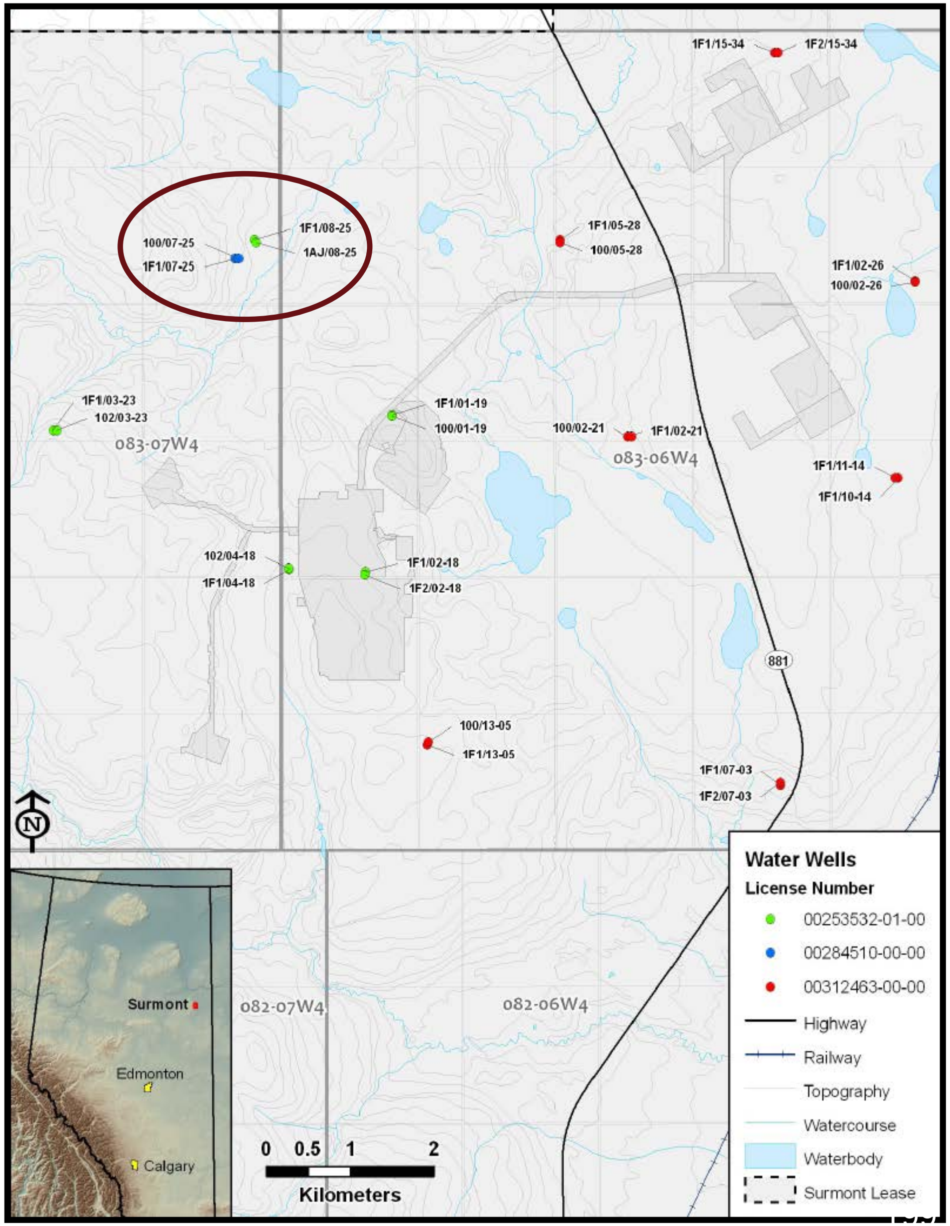
Source Well	Observation Well	Formation
1F1021808306W400	1F2021808306W400	Lower Grand Rapids
1F1041808306W400	102041808306W400	Lower Grand Rapids
1F1011908306W400	100011908306W400	Lower Grand Rapids
1F1032308307W400	100032308307W400	Lower Grand Rapids

Surmont Phase 2

Source Well	Observation Well	Formation
1F1022108306W400	100022108306W400	Lower Grand Rapids
1F1022608306W400	100022608306W400	Lower Grand Rapids
1F1052808306W400	100052808306W400	Lower Grand Rapids
1F1070308306W400	1F2070308306W400	Lower Grand Rapids
1F1101408306W400	1F1111408306W400	Lower Grand Rapids
1F1130508306W400	100130508306W400	Lower Grand Rapids
1F1153408307W400	1F2153408307W400	Lower Grand Rapids

Notes

- all water currently used at the Surmont project is non-saline and non-potable (i.e., waters not readily or economically treatable for potable, domestic, agricultural or livestock use)
- Phase 2 source wells licenced December 14, 2012, only used for hydro testing



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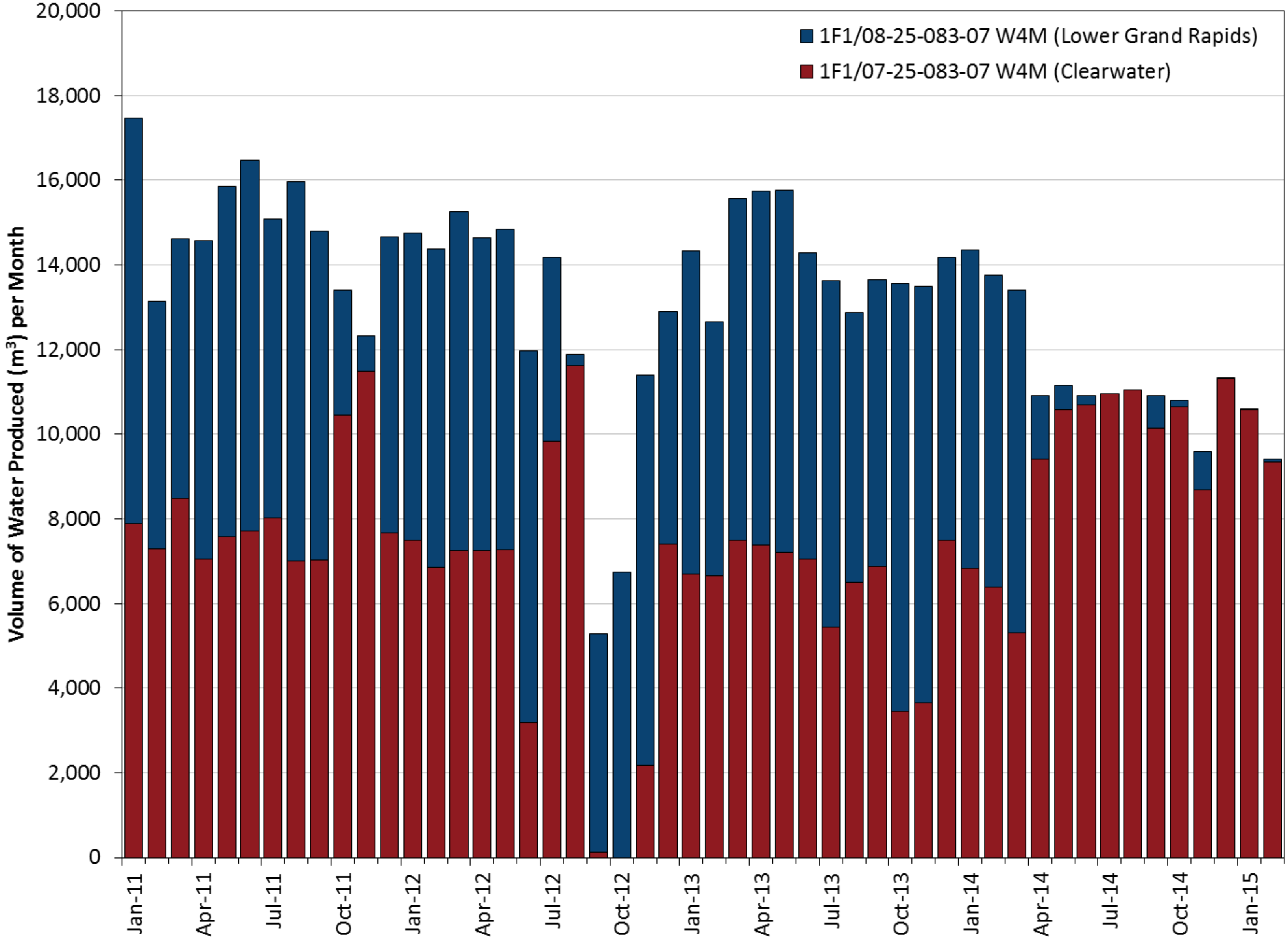
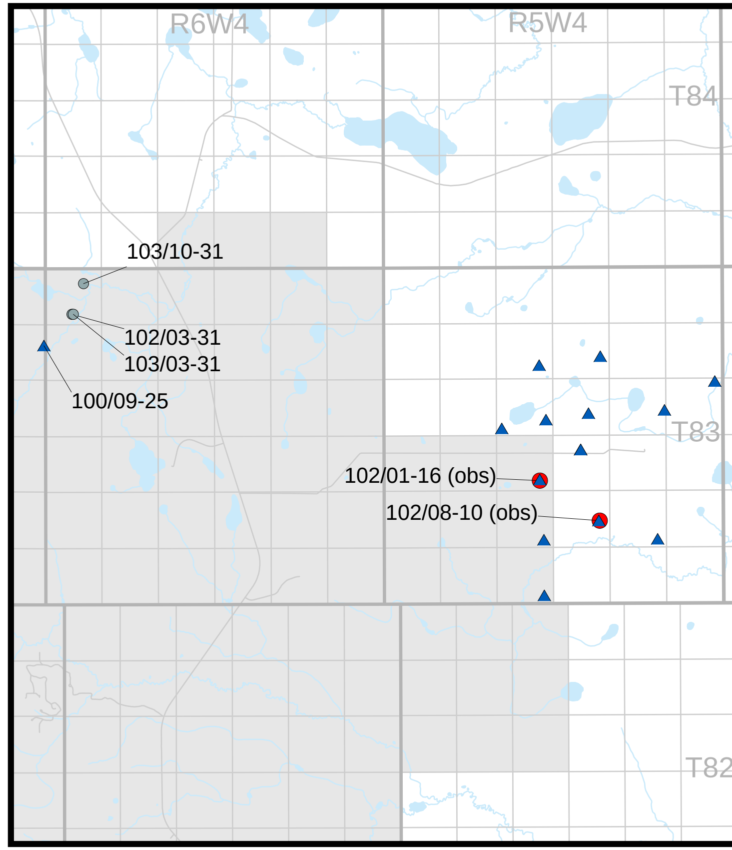
Pilot Water Source Wells Production Volumes



Water Disposal Wells

	Well	Zone Approved for Disposal	Maximum Wellhead Injection Pressure (kPa)	Well Status	AER Disposal Approval No.
INACTIVE	102/03-31-083-06W4/0	McMurray	3600	Abandoned	9573C
INACTIVE	103/03-31-083-06W4/0	McMurray	3600	Abandoned	9573C
INACTIVE	103/10-31-083-06W4/0	McMurray	3600	Abandoned	9573C
	100/09-25-083-07W4/0	Keg River	6000	Water Disposal	9573C
	100/01-16-083-05W4/0	McMurray	2700	Water Disposal	10044H
	100/07-22-083-05W4/0	McMurray	2500	Water Disposal	10044H
	100/08-10-083-05W4/0	McMurray	2300	Water Disposal	10044H
	100/01-11-083-05W4/0	McMurray	2500	Water Disposal	10044H
	100/04-21-083-05W4/0	McMurray	2500	Water Disposal	10044H
INACTIVE	100/01-04-083-05W4/0	McMurray	2500		10044H
INACTIVE	100/01-09-083-05W4/0	McMurray	3400		10044H
INACTIVE	100/10-15-083-05W4/0	McMurray	3400		10044H
INACTIVE	100/08-23-083-05W4/0	McMurray	3400		10044H
INACTIVE	100/16-24-083-05W4/0	McMurray	3400		10044H
INACTIVE	100/08-27-083-05W4/0	McMurray	3400		10044H
INACTIVE	100/01-28-083-05W4/0	McMurray	3400		10044H
INACTIVE	102/15-15-083-05W4/0	McMurray	3400		10044H
INACTIVE	102/08-21-083-05W4/0	McMurray	3400		10044H



Notes

- Disposal to 100/09-25-083-07W4/0 ended December 2011
- As of December 2011, water transferred to Phase 1 via pipeline
- Disposal to 100/09-25-083-07W4/0 recommenced August 2014

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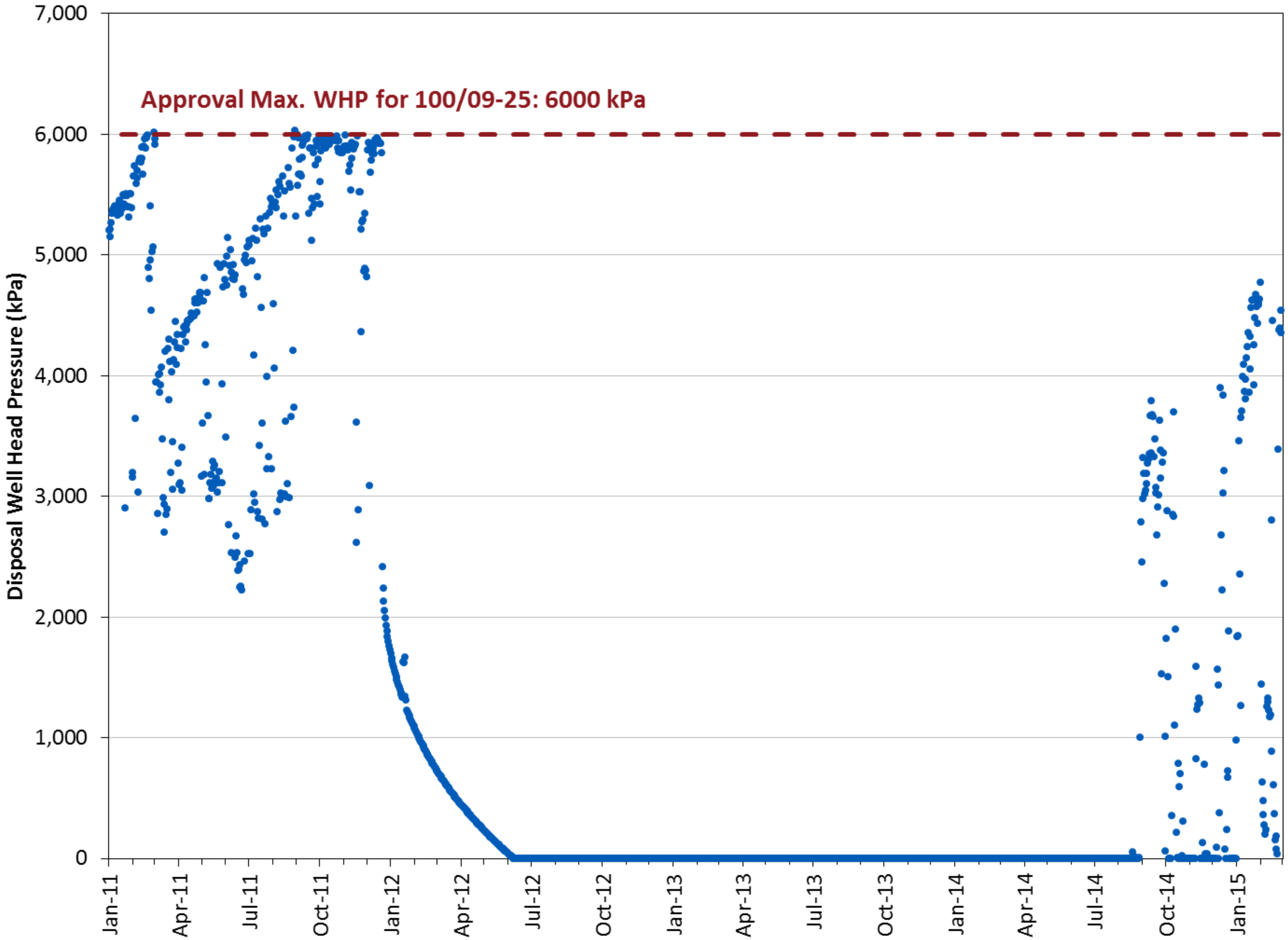
Pilot Water Disposal Well 100/09-25-083-07 W4M
Well Head Pressure (Keg River)



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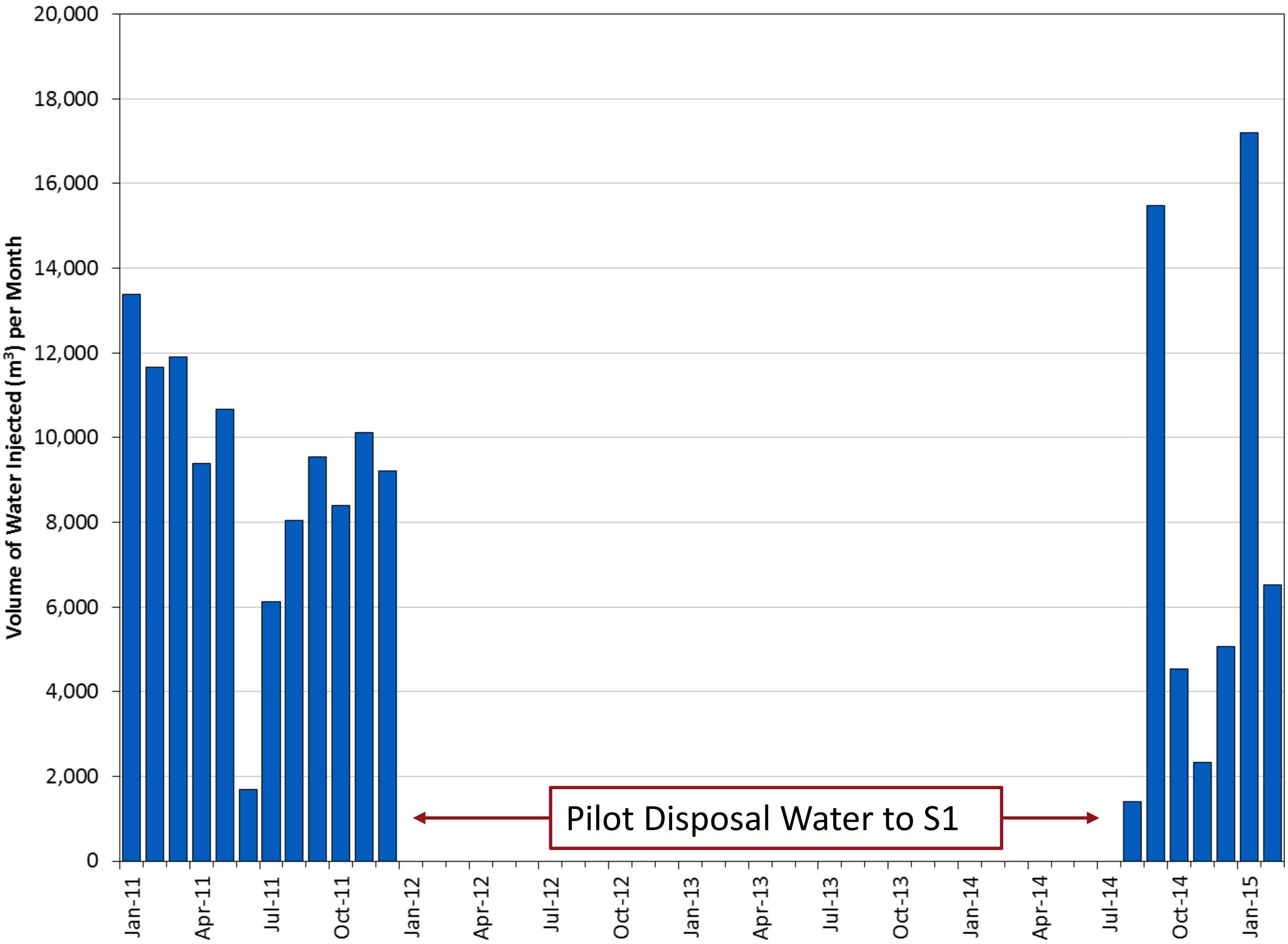
Pilot Water Disposal Well 100/09-25-083-07 W4M
Injection Rate (Keg River)



Waste Disposal & Recycling

Solid Waste

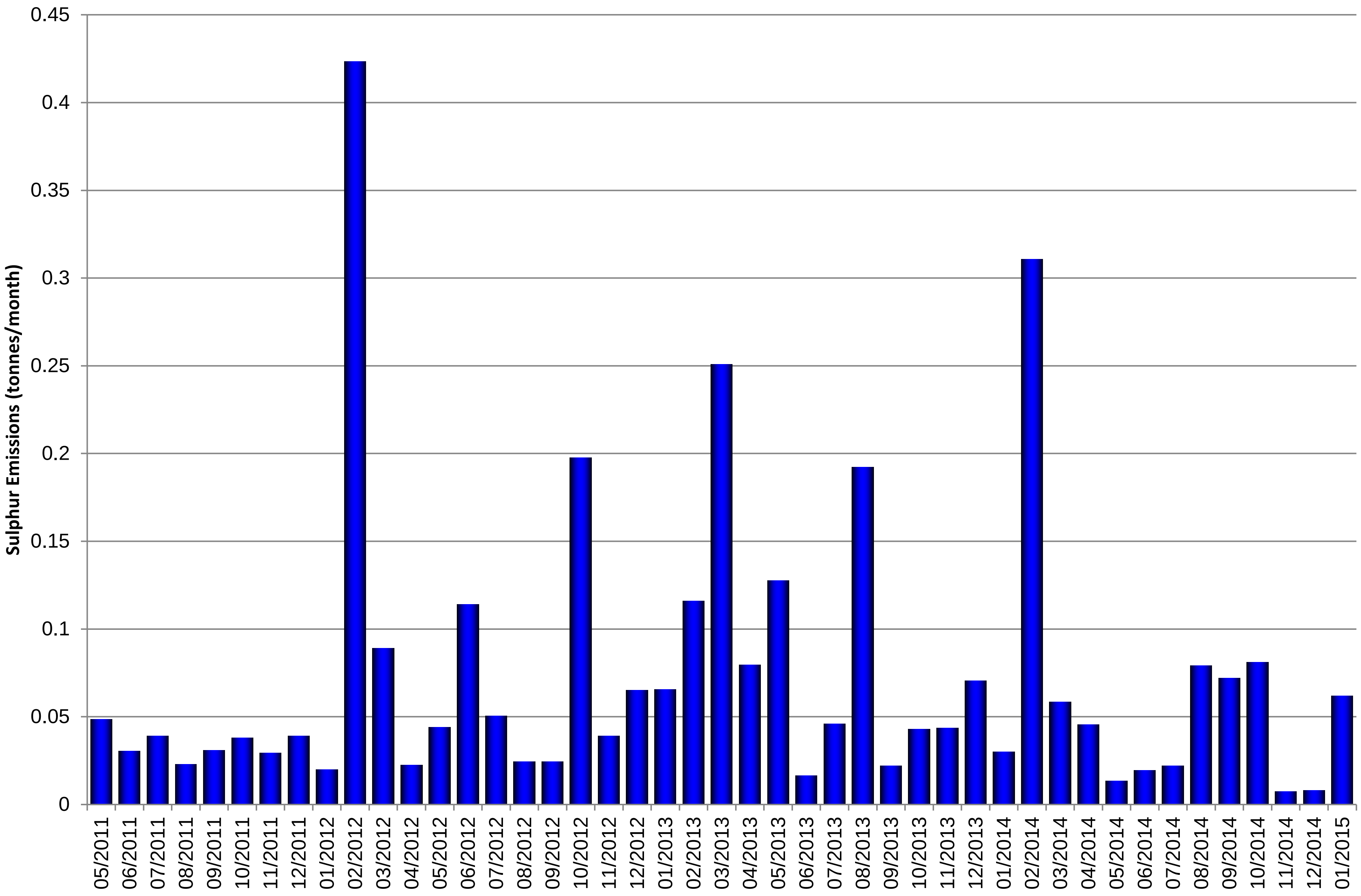
Waste Description	Disposal Weight (kg)	Disposal Method
Recycled Materials	970	Recycled
Dangerous Oilfield Waste	1,118	Landfill
Non-Dangerous Oilfield Waste	693	Landfill

Fluid Waste

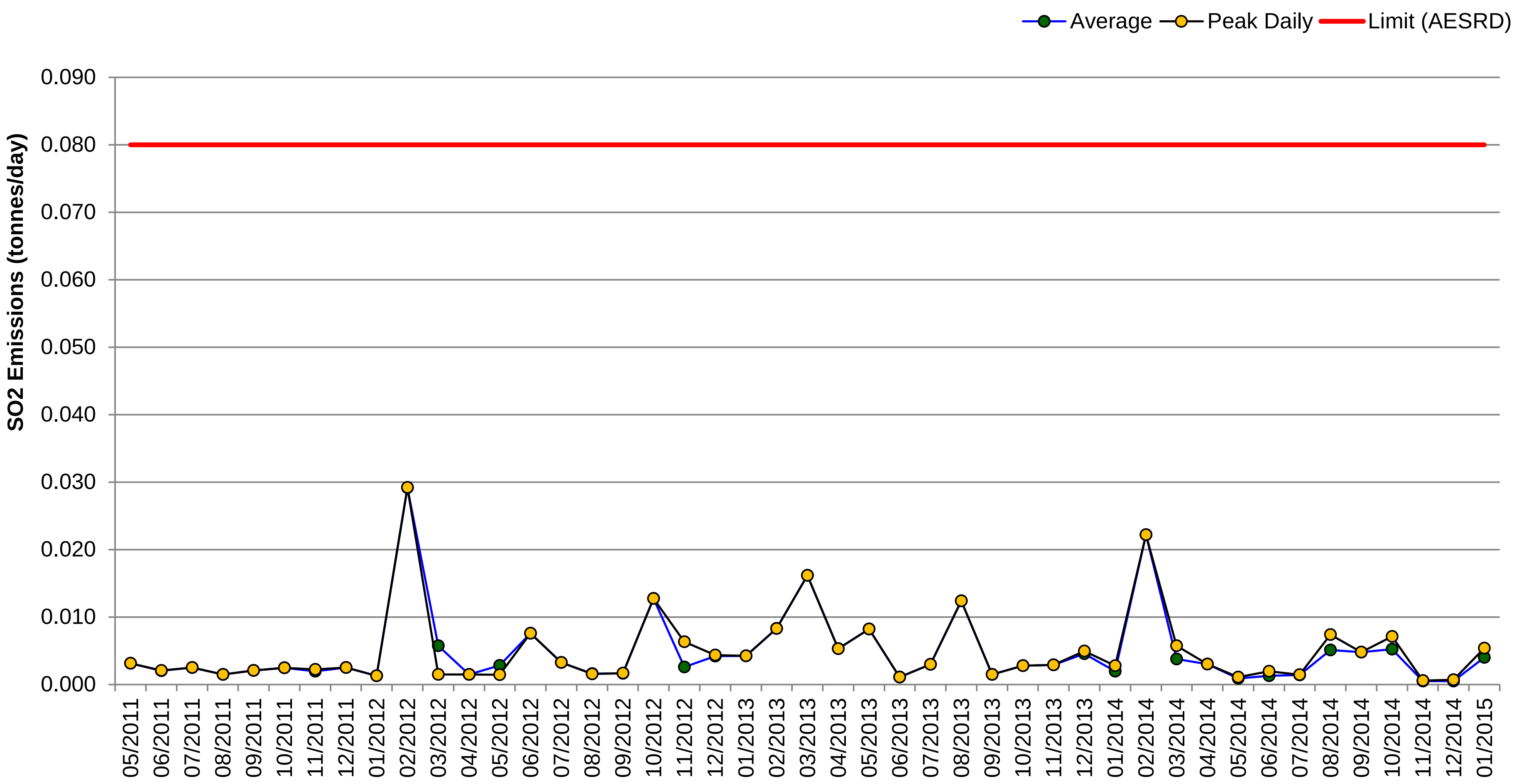
Waste Description	Disposal Volumes (m^3)	Disposal Method
Dangerous Oilfield Waste	352	Cavern
Non-Dangerous Oilfield Waste	288	Cavern

Sulphur Production
Subsection 3.1.2 (5)

Monthly Sulphur Emissions



Daily SO_2 Emissions



SO_2 emissions well below daily limit of 0.08 t/d

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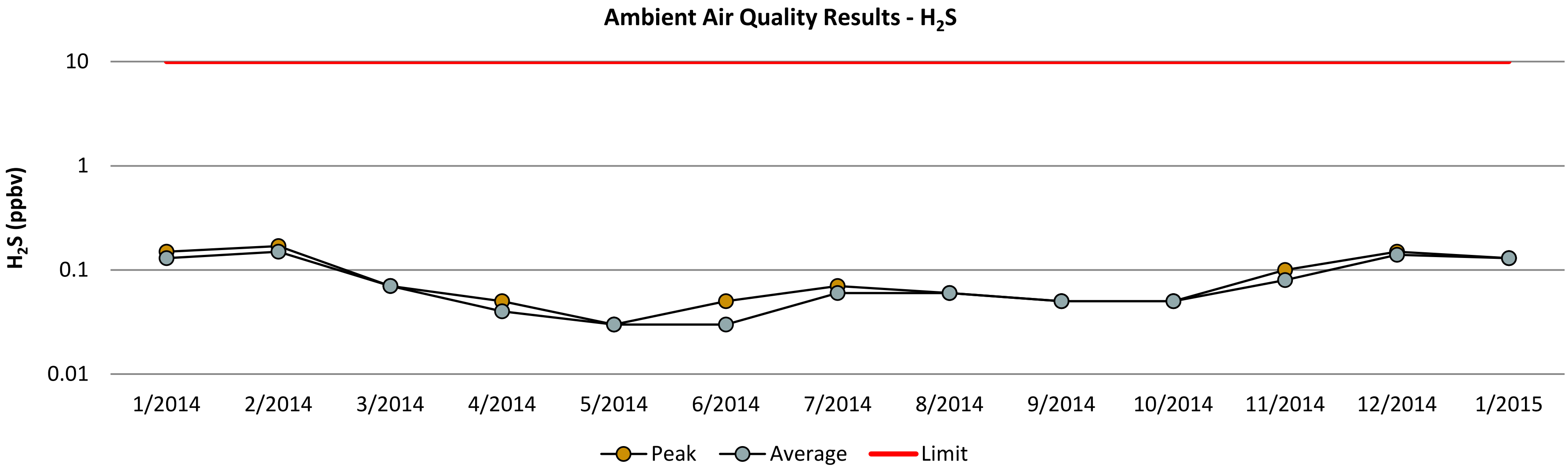
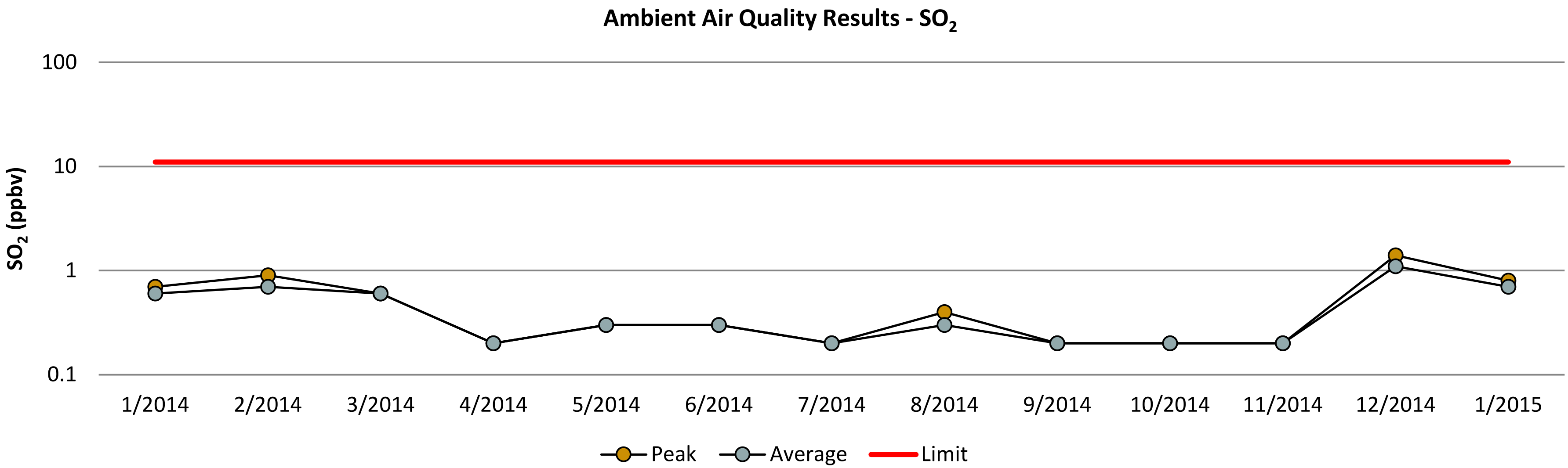
Ambient Air Quality Monitoring





Alberta Ambient Air Quality Objectives were met in 2014

Environmental Issues
Subsection 3.1.2 (6)

Environmental Compliance

Compliance

- 2013 Industrial Waste Water Report not submitted on site (Reference 289346)

Groundwater Monitoring

- 2014 results within historical/background concentrations

Soil Monitoring

- 2014 results within historical/background concentrations

Reclamation Programs

- No reclamation in 2014

Compliance Confirmation
Subsection 3.1.2 (7)

Compliance Confirmation

ConocoPhillips is in compliance in all areas of the regulations for all of 2014 with the exception of minor flare events exceeding the regulated time limit.

Noncompliance Issues
Subsection 3.1.2 (8)

Noncompliance

Flaring Events

- Thirteen flaring events sustained over four hours within 24 hour period.
  - Reported to Bonnyville field office and entered into DDS system without issues.
  - No events exceeded the 30 10^3m^3 daily volume limit.

Future Plans
Subsection 3.1.2 (9)

Future Plans

The pilot is licensed until 2019

- Thief zone pressure management
- Blowdown case studies
- Pilot shutdown
- Gas cap monitoring