Cenovus Christina Lake
In-situ oil sands scheme 8591
2015 update

Subsurface
June 24, 2015

Oil & gas and financial information

Oil & gas information

The estimates of reserves and contingent resources were prepared effective December 31, 2014 and the estimates of bitumen initially-in-place were prepared effective December 31, 2012. All estimates were prepared by independent qualified reserves evaluators, based on definitions contained in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101. Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates, is contained in our AIF and Form 40-F for the year ended December 31, 2014, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of those resources. Actual resources may be greater than or less than the estimates provided.

Total bitumen initially-in-place (BIIP) estimates, and all subcategories thereof, including the definitions associated with the categories and estimates, are disclosed and discussed in our July 24, 2013 news release, available on SEDAR at sedar.com and at cenovus.com. BIIP estimates include unrecoverable volumes and are not an estimate of the volume of the substances that will ultimately be recovered. Cumulative production, reserves and contingent resources are disclosed on a before royalties basis. All estimates are best estimate, billion barrels (Bbbls). *Total BIIP* (143 Bbbls); *discovered BIIP* (93 Bbbls); *commercial discovered BIIP* equals the *cumulative production* (0.1 Bbbls) plus *reserves* (2.4 Bbbls); *sub-commercial discovered BIIP* equals *economic contingent resources* (9.6 Bbbls) plus the *unrecoverable portion of discovered BIIP* (81 Bbbls); *undiscovered BIIP* (50 Bbbls); *prospective resources* (8.5 Bbbls); *unrecoverable portion of undiscovered BIIP* (42 Bbbls). Any contingent resources as at December 31, 2012 that are sub-economic or that are classified as being subject to technology under development have been grouped into the unrecoverable portion of discovered BIIP. Petroleum initially-in-place (PIIP) estimates for Pelican Lake are effective December 31, 2012 and were prepared by McDaniel. All estimates are best estimate discovered PIIP volumes as follows: *Mobile Wabiskaw* total PIIP (2.11 Bbbls); discovered PIIP (2.11 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0.03 Bbbls); unrecoverable discovered PIIP (1.72 Bbbls); undiscovered PIIP (0 Bbbls). *Mobile Wabiskaw development area* total PIIP (1.62 Bbbls); discovered PIIP (1.62 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.26 Bbbls); undiscovered PIIP (0 Bbbls). *Immobile Wabiskaw* total PIIP (1.33 Bbbls); discovered PIIP (1.33 Bbbls); cumulative production (0 Bbbls); reserves (0 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.33 Bbbls); undiscovered PIIP (0 Bbbls).

Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

Non-GAAP measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS such as, Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization (“Adjusted EBITDA”) and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Readers are encouraged to review our most recent Management’s Discussion and Analysis, available at cenovus.com for a full discussion of the use of each measure.

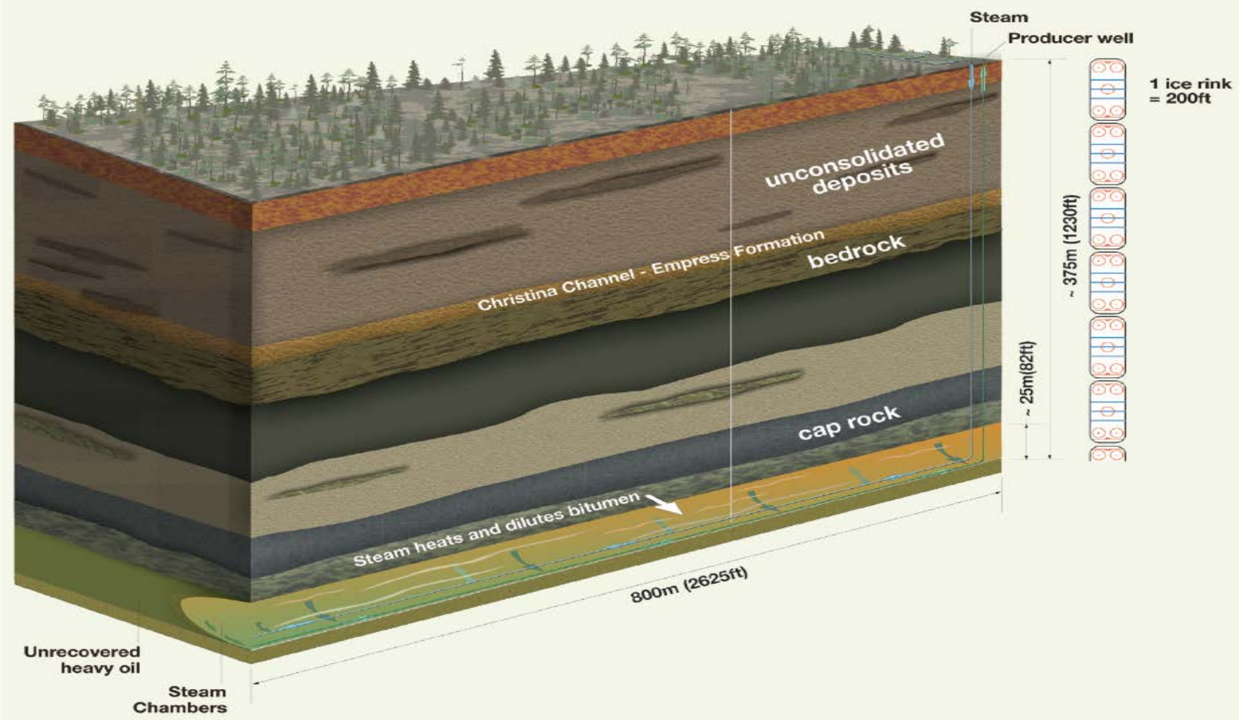
Subsection 3.1.1-1)
Brief background

Major scheme/project updates

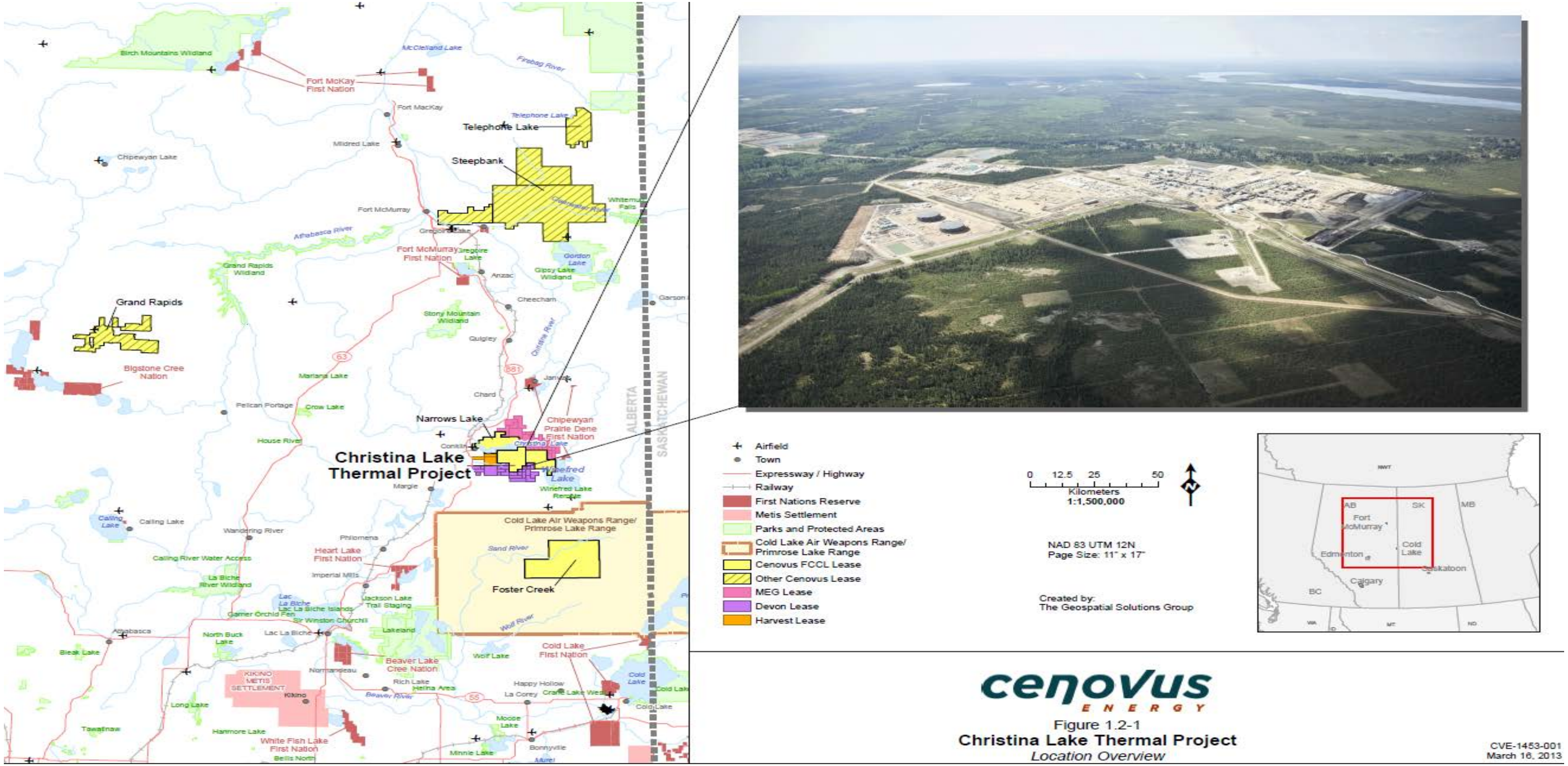
Q1 2000	EUB project approval
Q2 2002	First steam of phase A pilot
Q4 2005	Approval of phase B expansion
Q2 2008	Phase B expansion first steam
Q3 2008	Approval of phase C/D amendment
Q1 2010	Approval of large gas cap air re-pressurization
Q2 2011	Approval of phase E/F/G EIA application
Q2 2011	Phase C expansion first steam
Q2 2012	Phase D expansion first steam
Q4 2012	Approval of phase F and G amendment
Q1 2013	Filing phase H and eastern expansion EIA
Q4 2013	CDE 2nd stage OTSG amendment
Q3 2013	Approval of development area expansion
Q4 2014	Receipt of phase H and eastern expansion SIR round 2

Recovery process

- The Christina Lake Thermal Project uses the dual-horizontal well SAGD (steam-assisted gravity drainage) process to recover bitumen from the McMurray formation
- Two horizontal wells one above the other approximately 5 m apart
- Steam injected into upper well heat the bitumen and allows gravity to drain
- Oil and water emulsion pumped to the surface and treated



Area Map


Telephone Lake
Steepbank
Grand Rapids
Narrows Lake
Christina Lake Thermal Project
Foster Creek
Fort McKay First Nation
Bigstone Cree Nation
Chipewyan Prairie Dene First Nation
Cold Lake Air Weapons Range/ Primrose Lake Range
ALBERTA
SASKATCHEWAN
Airfield
Town
Expressway / Highway
Railway
First Nations Reserve
Metis Settlement
Parks and Protected Areas
Cold Lake Air Weapons Range/ Primrose Lake Range
Cenovus FCCL Lease
Other Cenovus Lease
MEG Lease
Devon Lease
Harvest Lease
0 12.5 25 50
Kilometers
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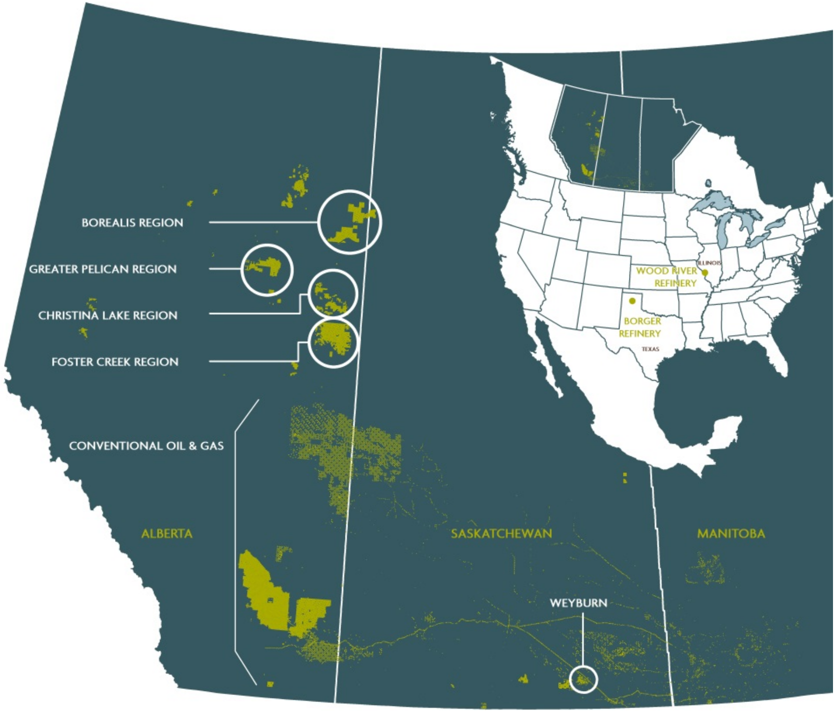
The Geospatial Solutions Group
cenovus ENERGY
Figure 1.2-1
Christina Lake Thermal Project
Location Overview
CVE-1453-001
March 16, 2013

Strong integrated portfolio

TSX, NYSE | CVE

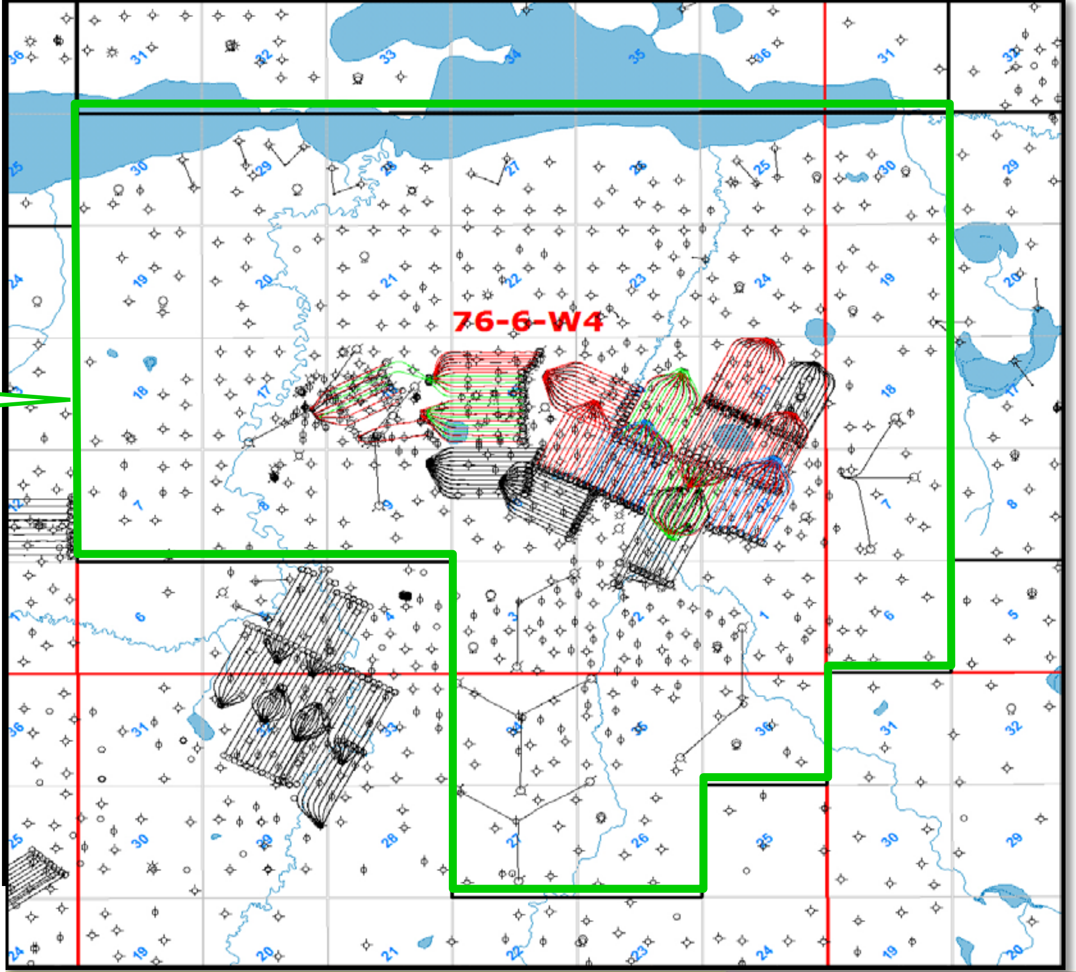
Enterprise value	C$25 billion
Shares outstanding	829 MM
2015F production	
Oil & NGLs	204 Mbbls/d
Natural gas	438 MMcf/d
2014 proved & probable reserves	3.9 BBOE
Bitumen	
Economic contingent resources*	9.3 Bbbls
Discovered bitumen initially in place*	93 Bbbls
Lease rights**	1.5 MM net acres
P&NG rights	5.6 MM net acres
Refining capacity	230 Mbbls/d net



Values are approximate. Forecast production based on midpoints of January 28, 2015 guidance. Cenovus land at December 31, 2014. *See advisory. **Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignee's behalf.

Scheme map

AER approved project area



Well pair drilled but not producing

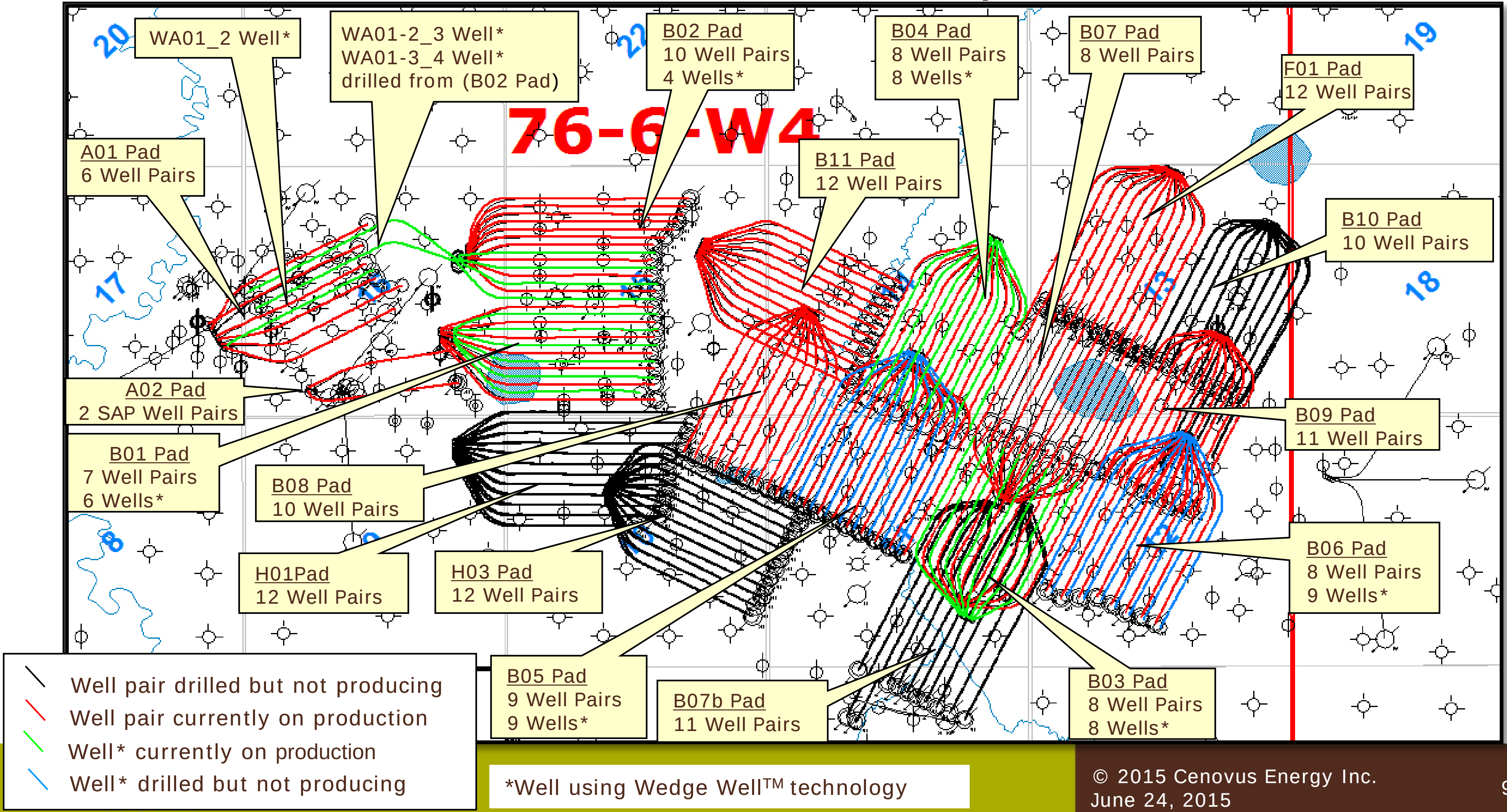
Well pair currently on production

Well* currently on production

Well* drilled but not producing

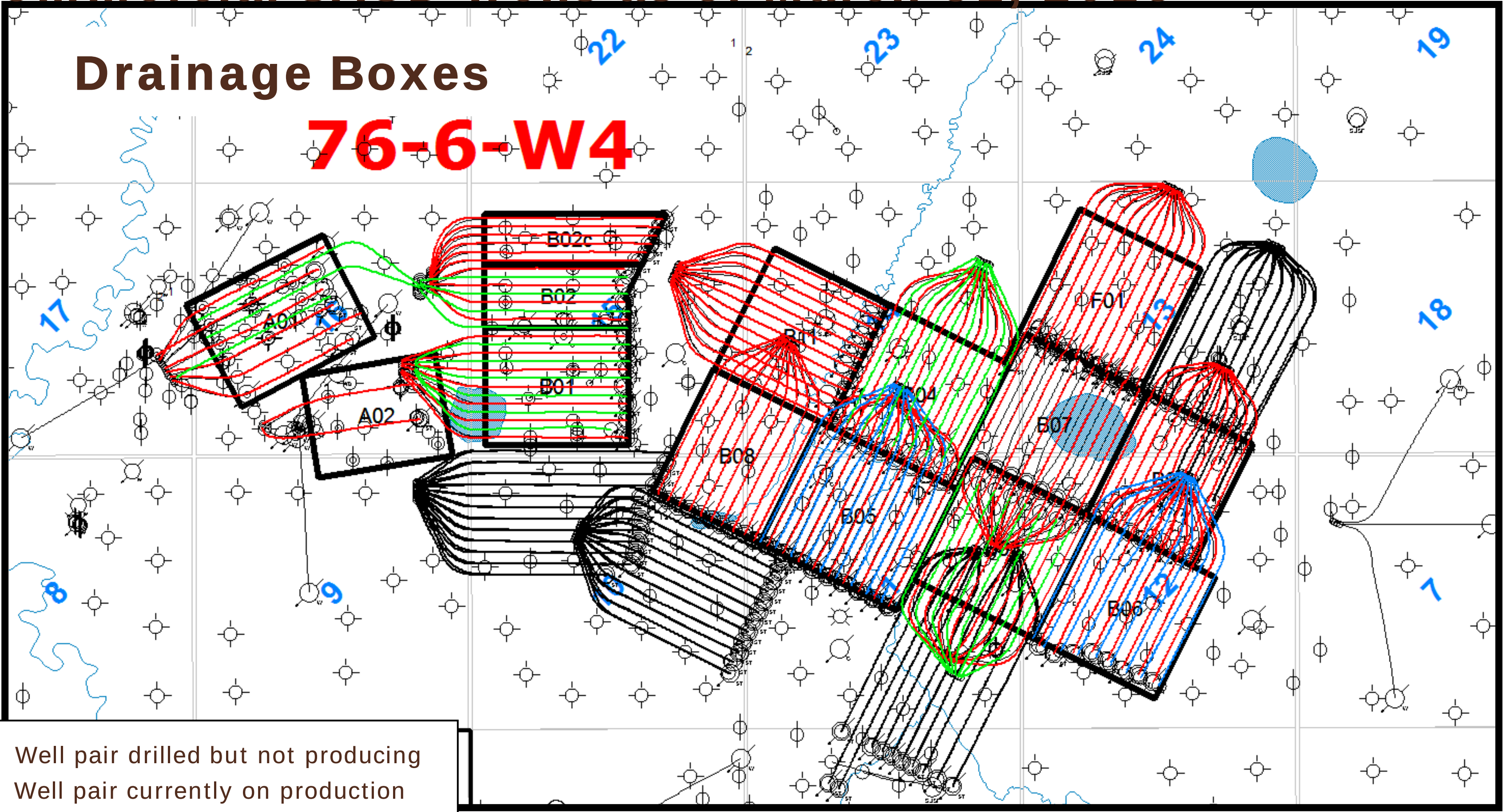
*Well using Wedge Well™ technology

Commercial SAGD wells as of March 31, 2015



*Well using Wedge Well™ technology

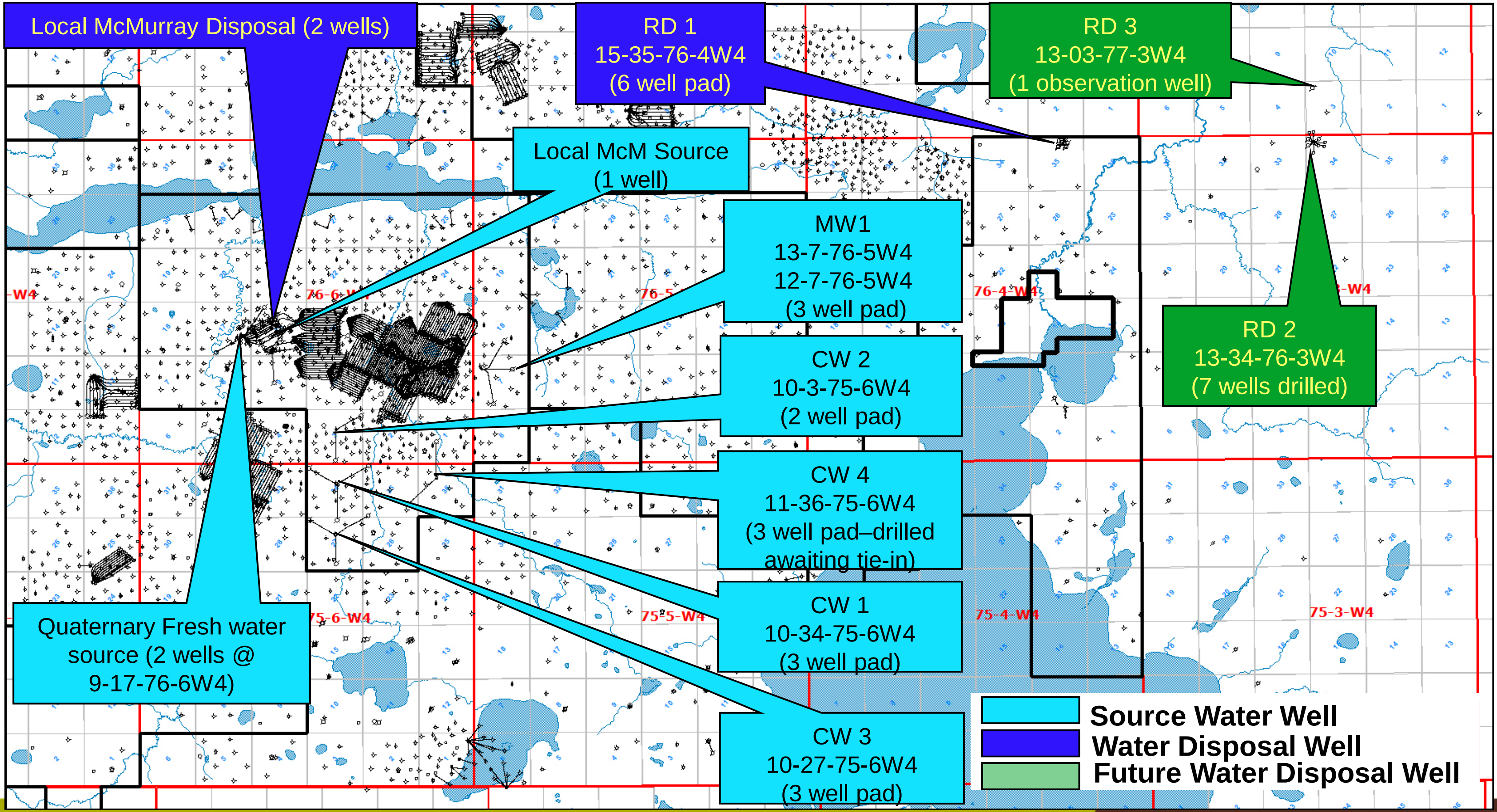
Commercial SAGD wells as of March 31, 2015



Well pair drilled but not producing
Well pair currently on production
Well* currently on production
Well* drilled but not producing

*Well using Wedge Well™ technology

Source and Disposal Wells as of March 31, 2015



Subsection 3.1.1 – 2) Geology and Geoscience

Ashley Saunders

Geologist

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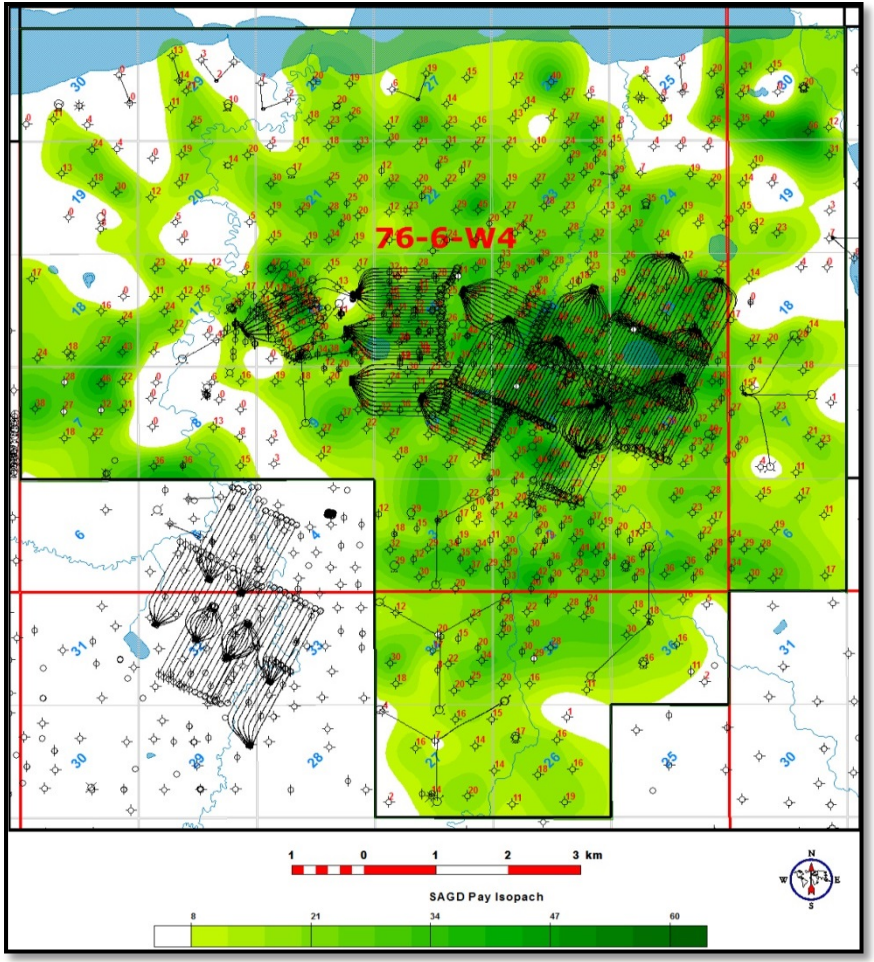
AER approved project area



Reservoir properties (project area)

Reservoir depth:	350m TVD
Original reservoir pressure:	2500 kPa
Original reservoir temperature:	12°C
Average horizontal permeability:	7.0 Darcies
Average vertical permeability:	4.2 Darcies
Average SAGD pay:	21 meters
Average porosity (Ø):	33%
Average oil saturation:	80%
Rock volume:	1,954 x 10^6 m^3
SOIP=	516 x 10^6 m^3

Note: Cenovus Volumetric Estimates, not IQRE estimates

SOIP = Rock Volume in Project area x phi (.33) x So (.80)

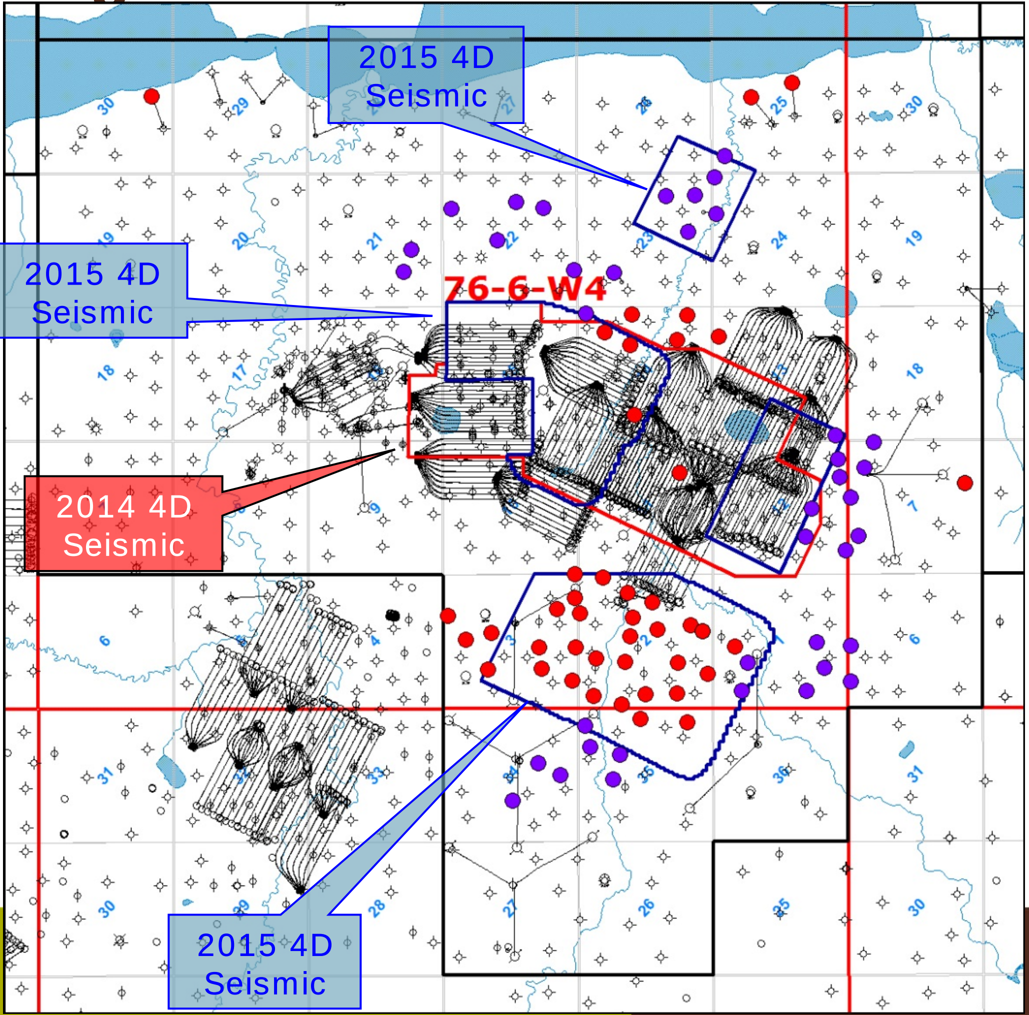
Christina Lake geological database

Stratigraphic wells within PA: 554
(-Cenovus 494/60 Others)- 2014
- 2D seismic - 155 km
- 3D seismic - 80 km^2

(entire project area now covered by 3D)
PA = Project Area

2014 strat wells

2015 strat wells



- **2014 4D – 11.86 km2**
- **2014 – 3 Strat Wells, 38 obs wells**

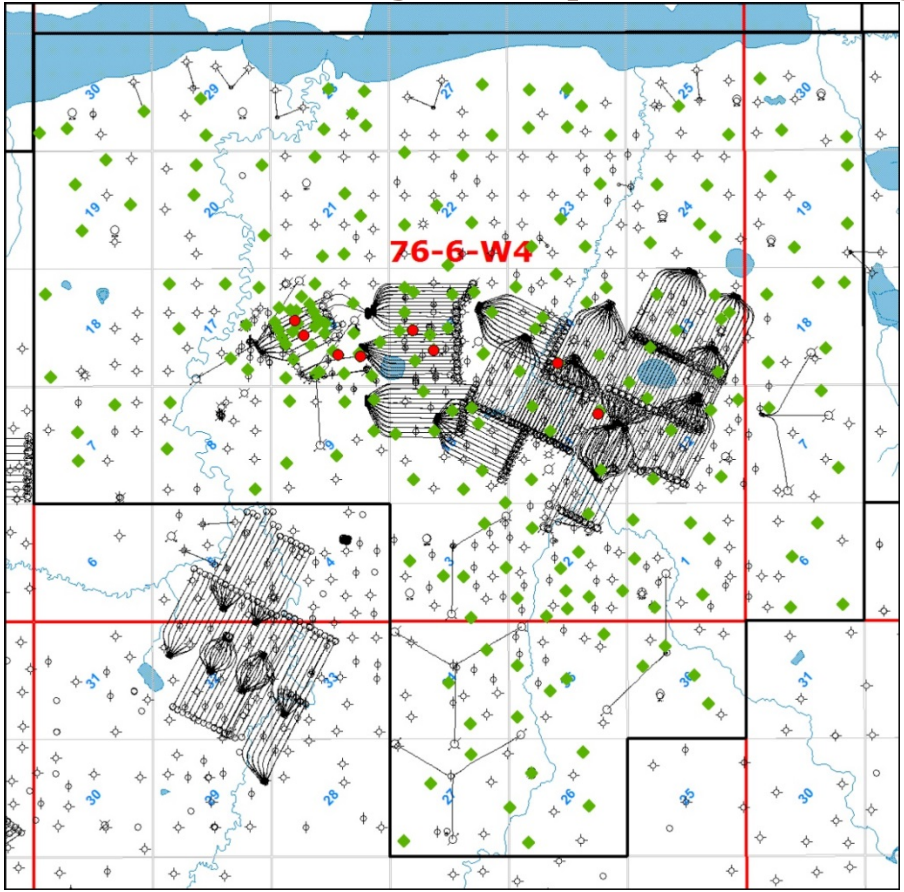
- **2015 – 4D - 14.32 km2**
- **2015 – 2 strat wells, 39 obs wells**

Christina Lake core analysis (McMurray)

- Total cored wells within PA- **203**
- 2015 cored wells within PA- 4
- 2014 cored wells within PA- 10
- Total steam chamber cores- 8

Analysis:

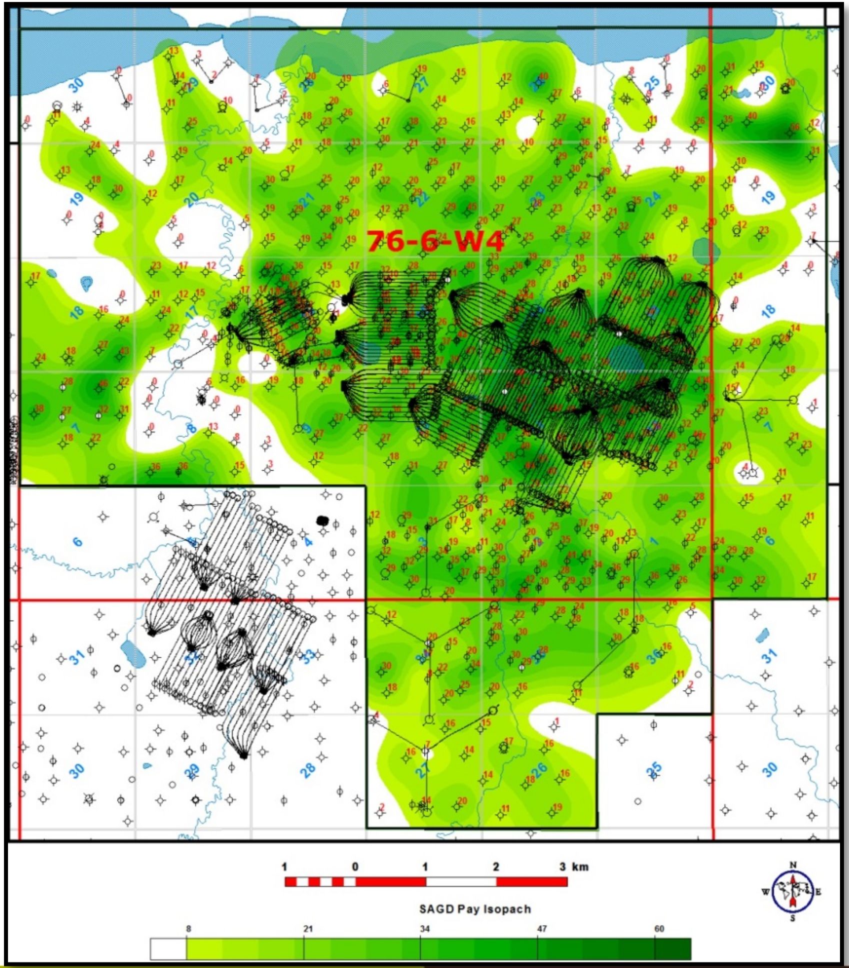
- Routine core analysis
- Photos



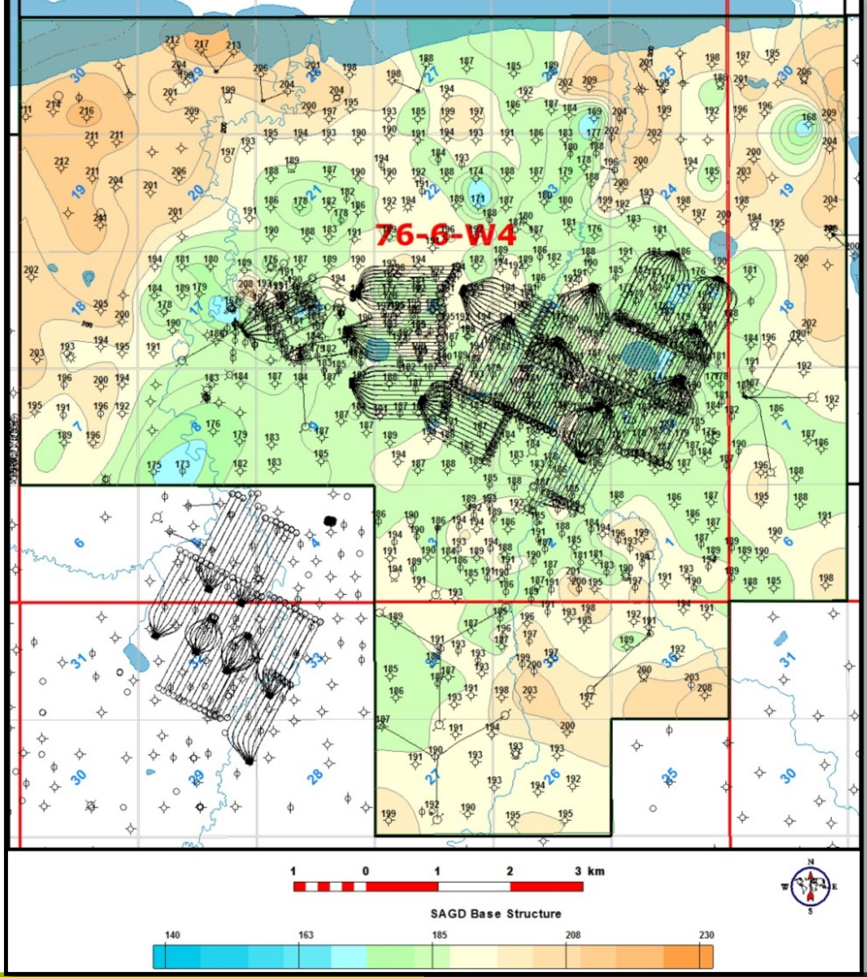
- Strat and strat/cored wells are generally abandoned
- Some strat and strat/cored wells are cased if they are further used for SAGD observation wells
- All abandoned and cased wells are examined for integrity by the completions department prior to SAGD startup

SAGD Pay Isopach

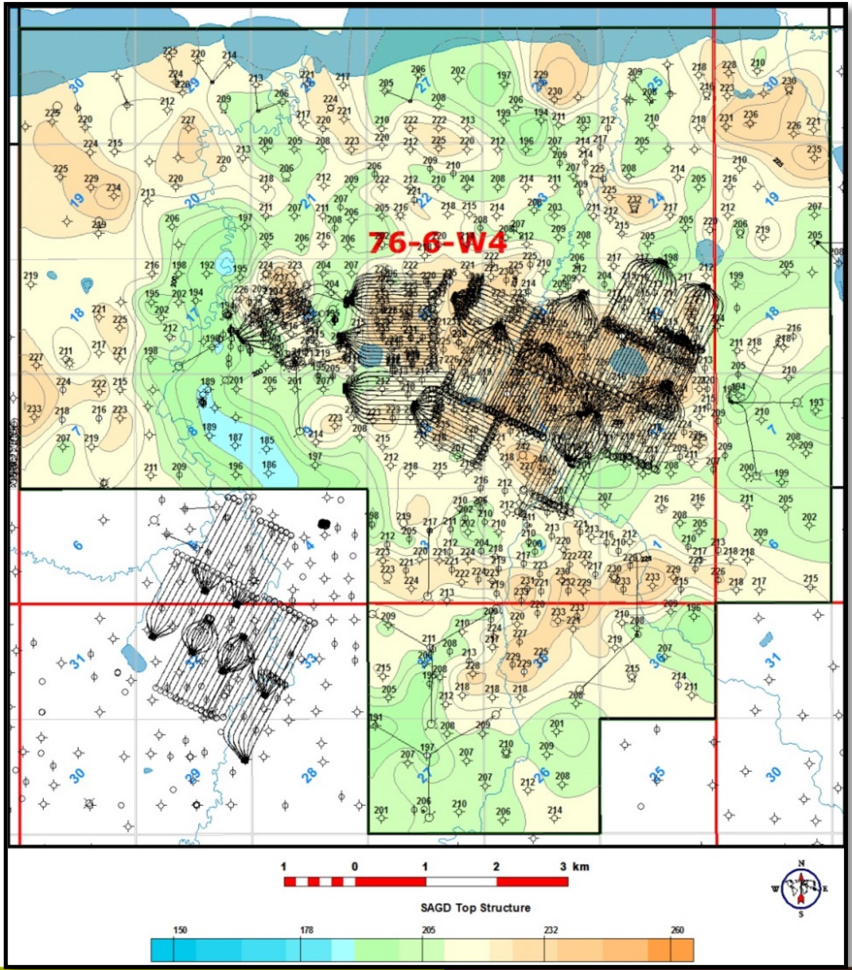
(Thickness in Meters)



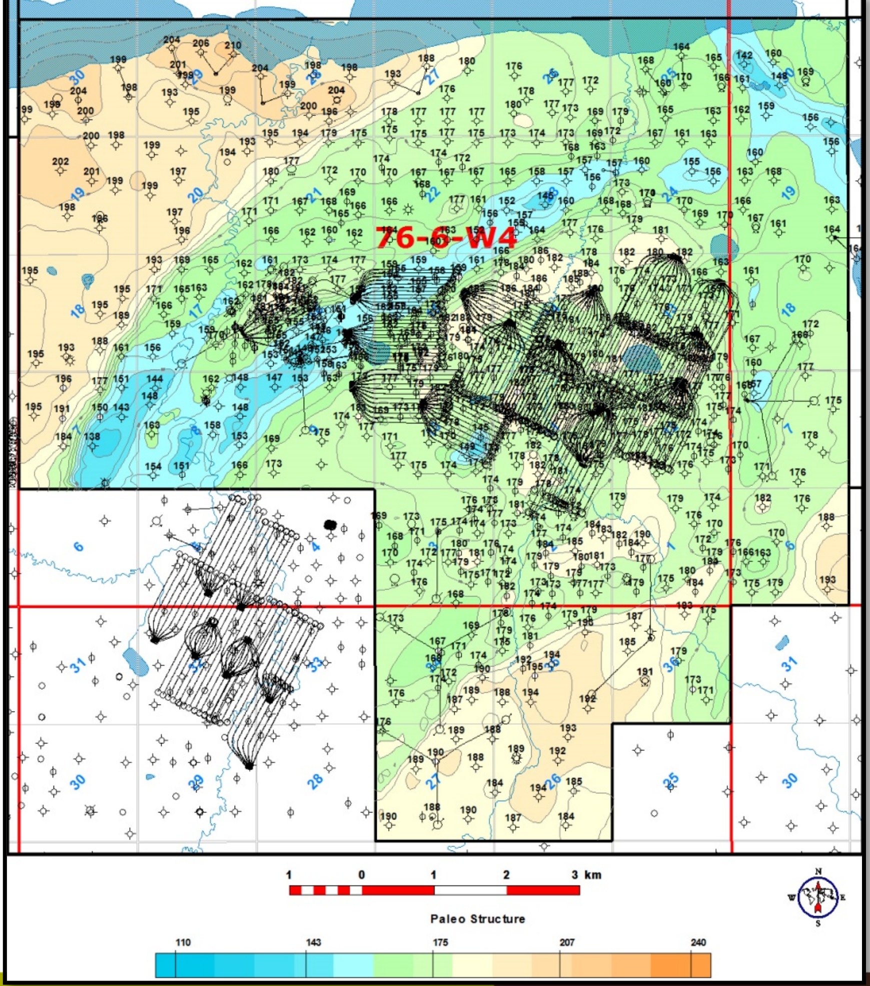
SAGD base structure
(SSTVD)



SAGD top structure
(SSTVD)

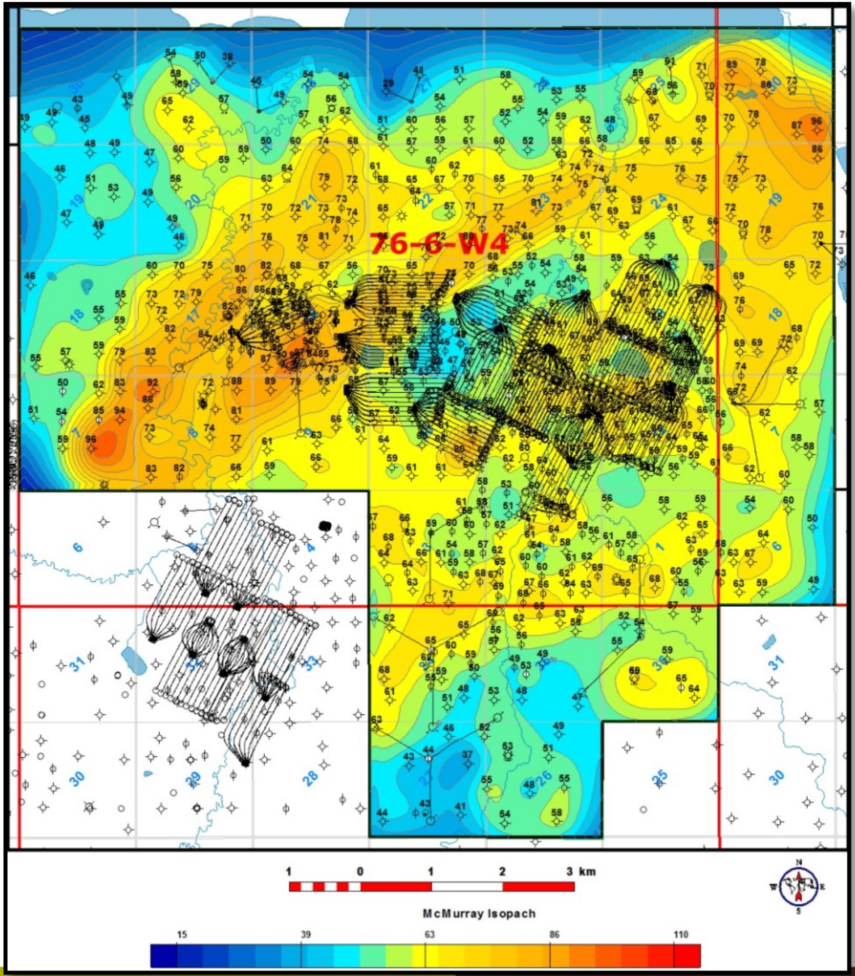


Paleozoic structure
(SSTVD)

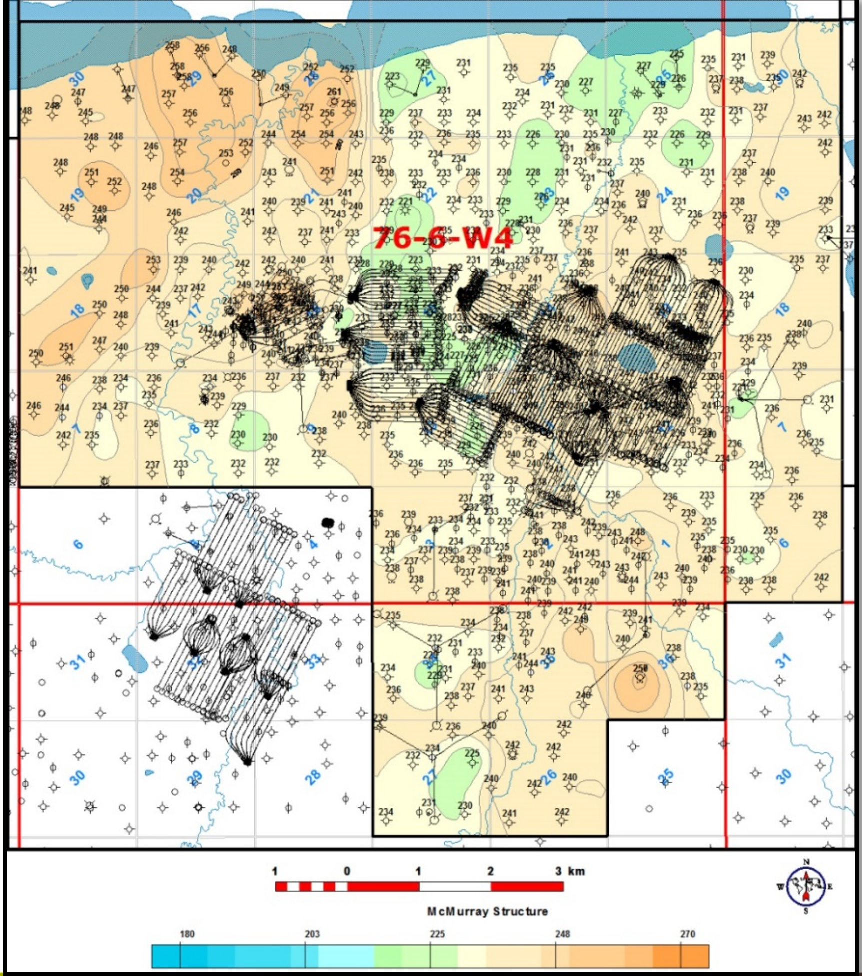


McMurray Isopach

(thickness in metres)

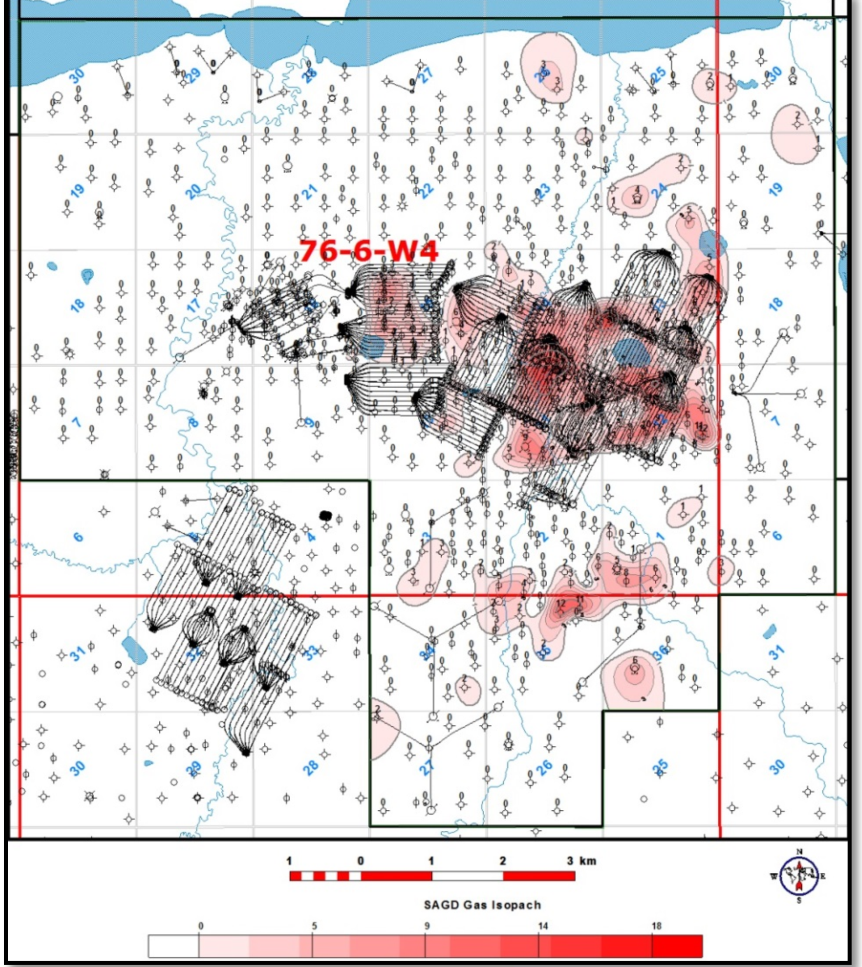


McMurray Structure
(SSTVD)



SAGD Gas Isopach

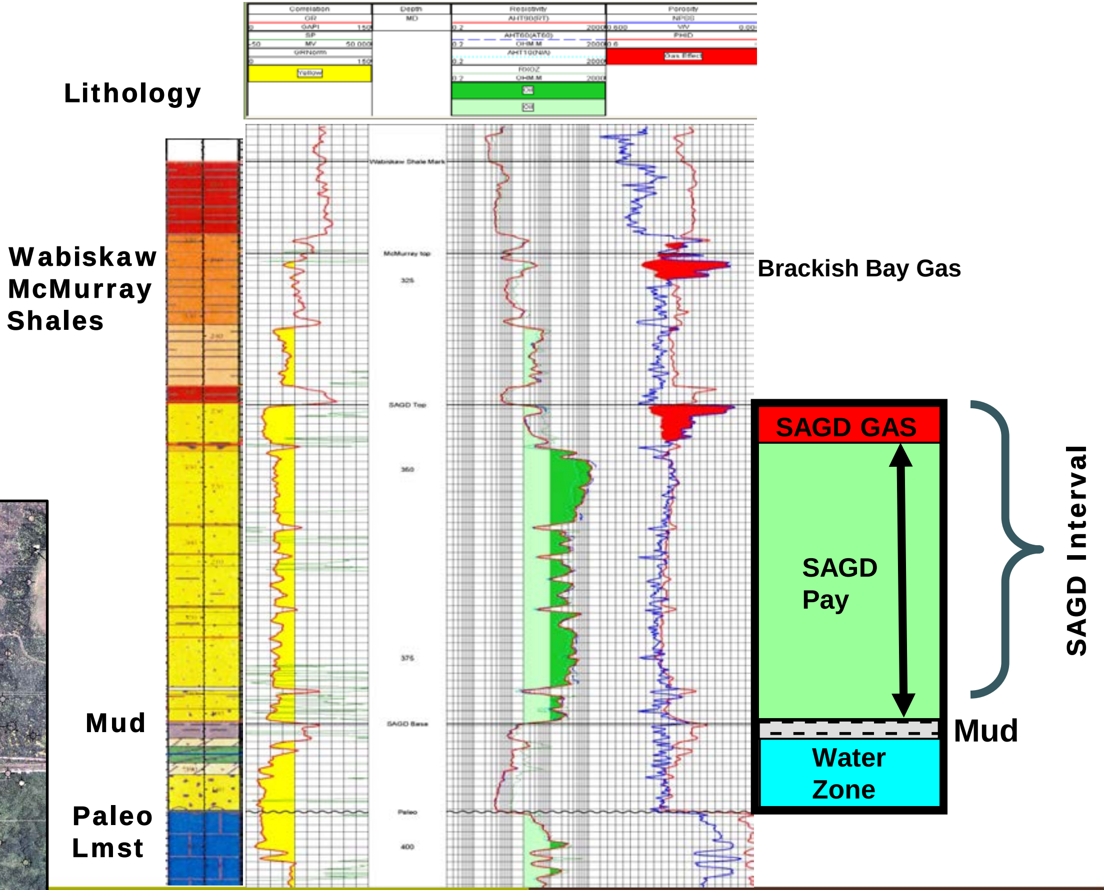
(thickness in meters)



Composite type log: Phase B

- Pervasive basal mud layer often separates bitumen and McMurray water
- Basal mud is discontinuous and ranges from 0-4 metres in thickness
- Provides a good marker during SAGD operations

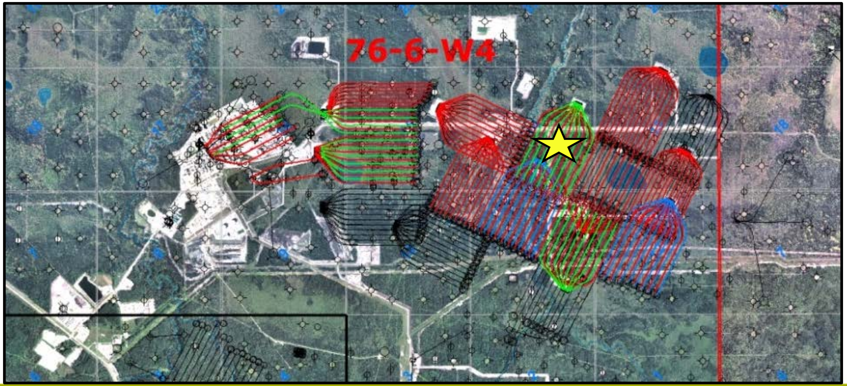
Location:



Composite type log: Phase CDE

- Pervasive basal mud layer often separates bitumen and McMurray water
- Basal mud is discontinuous and ranges from 0-4 meters in thickness
- Provides a good marker during SAGD operations

Location:

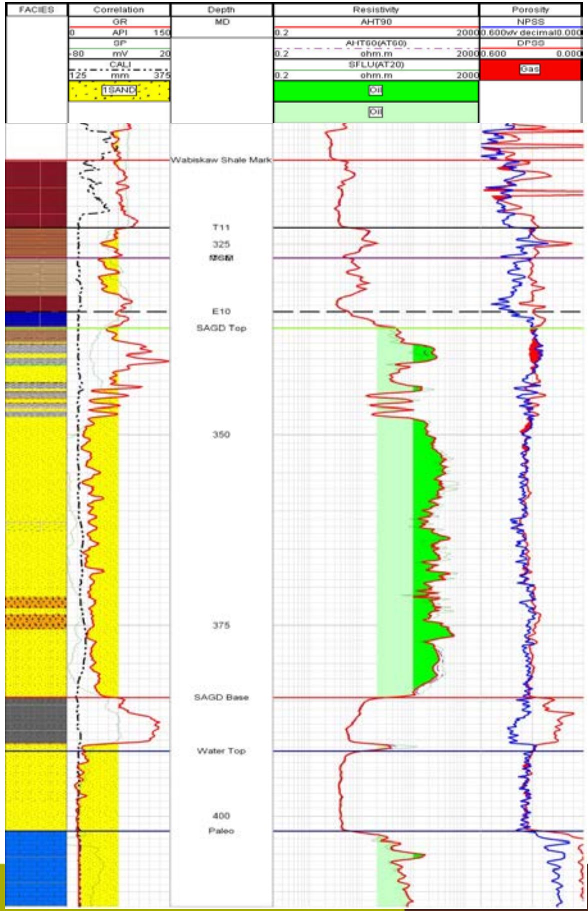


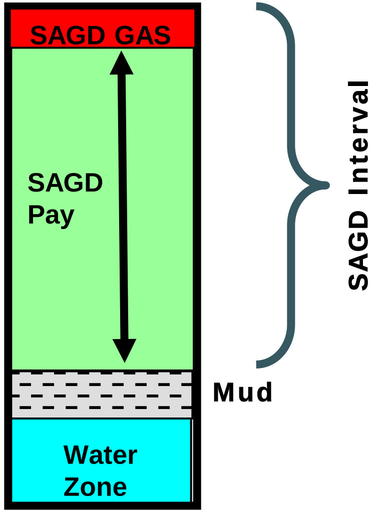
Lithology

Wabiskaw
McMurray
Shales

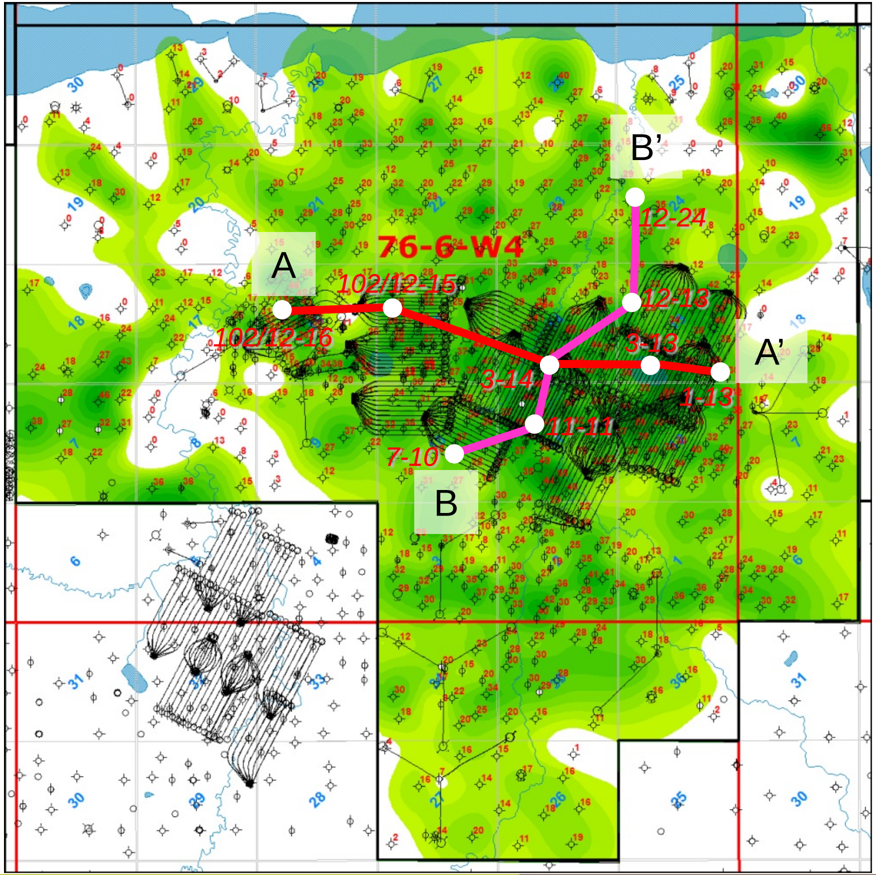
Mud

Paleo





Representative cross section



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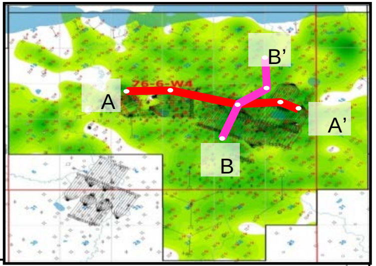
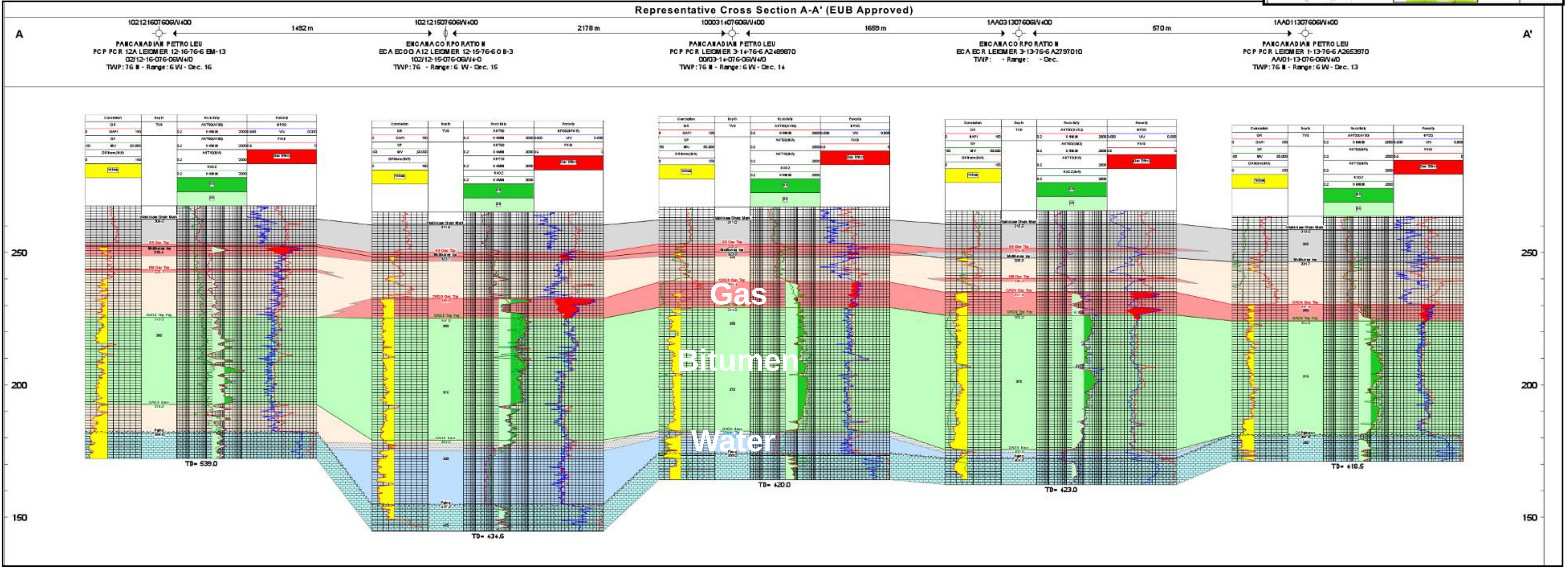
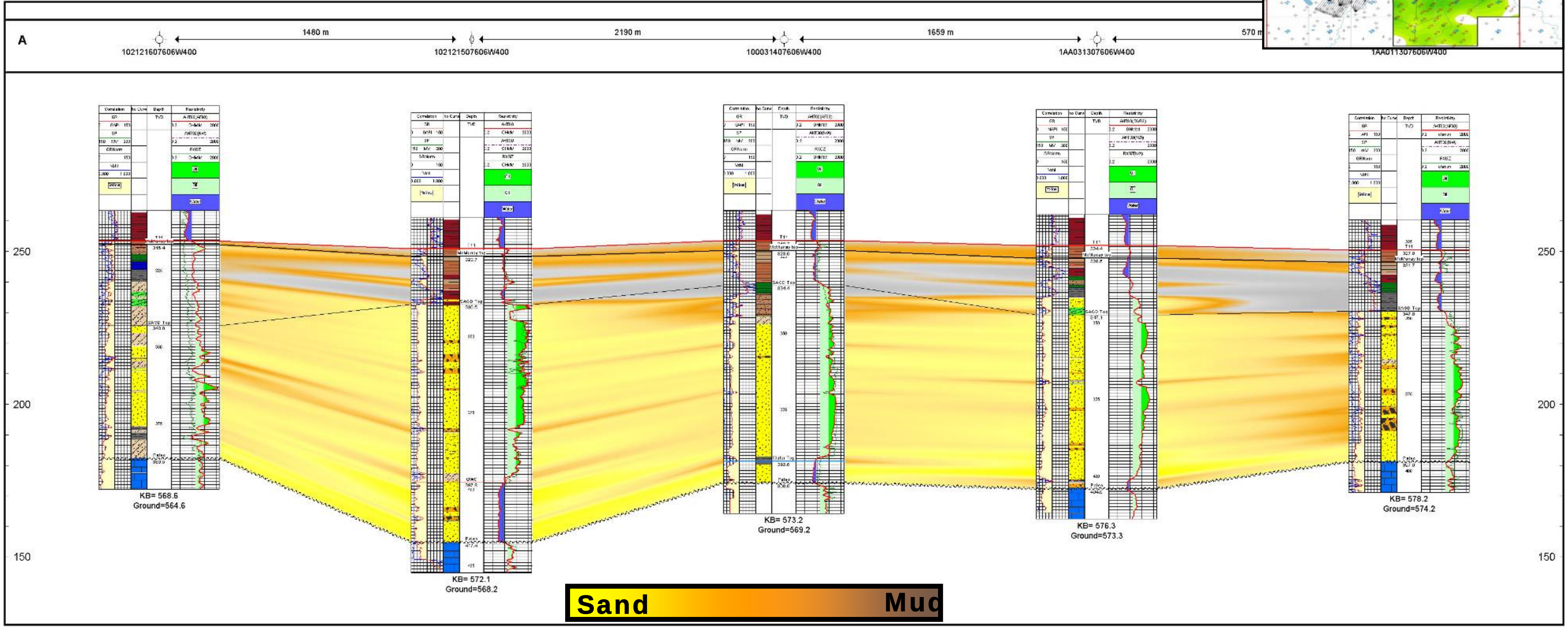
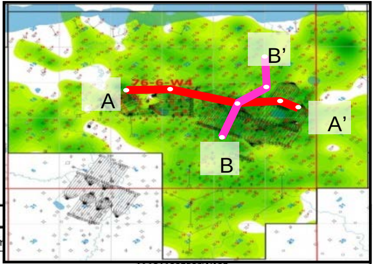
Cross section A-A' (saturation)





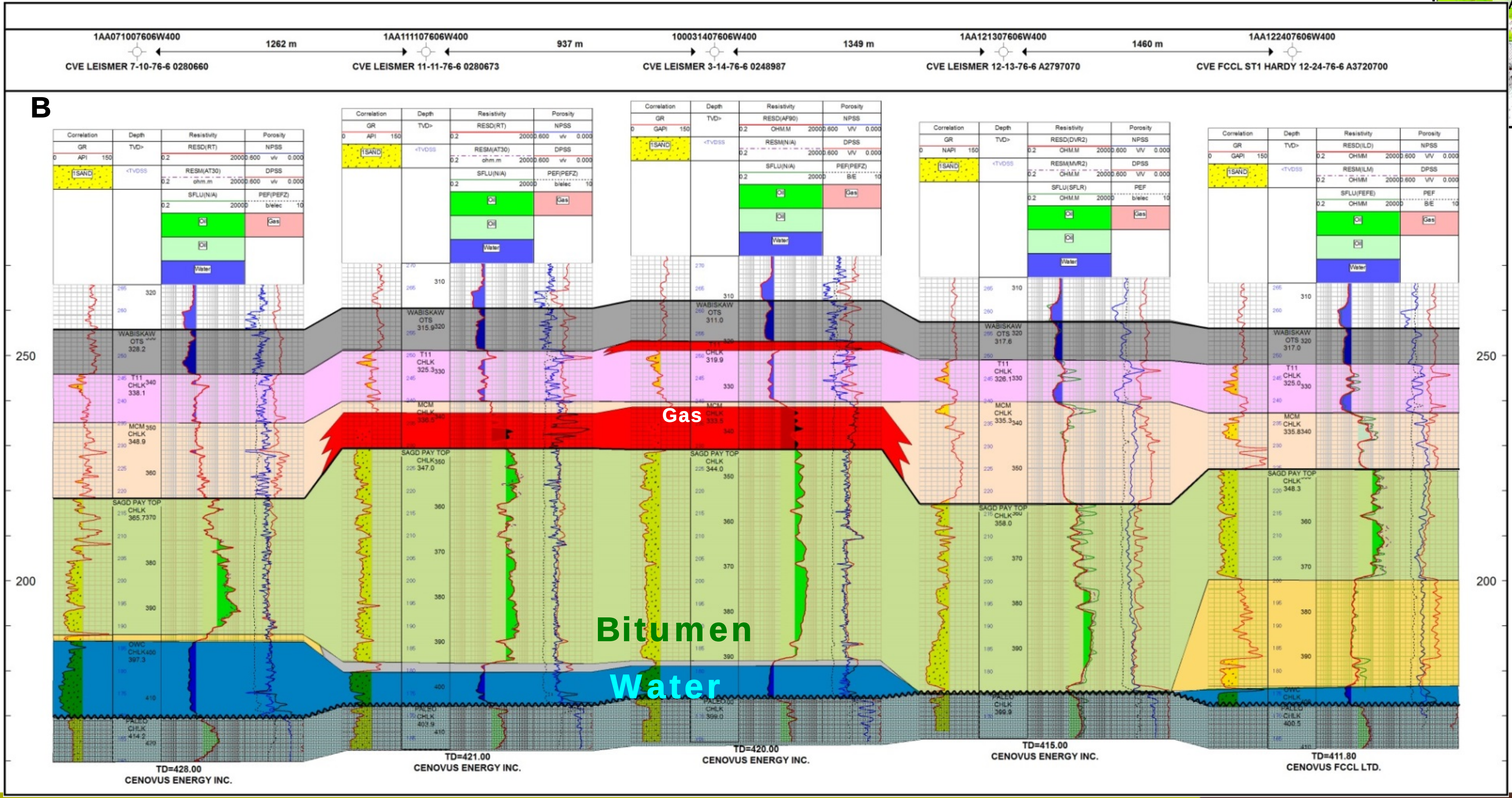
Cross section A-A’ (lithology)

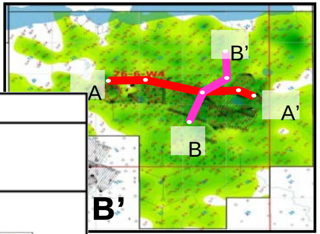




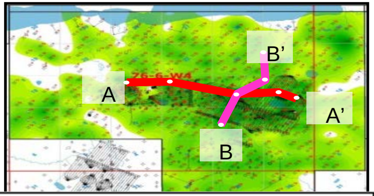
June 24, 2015

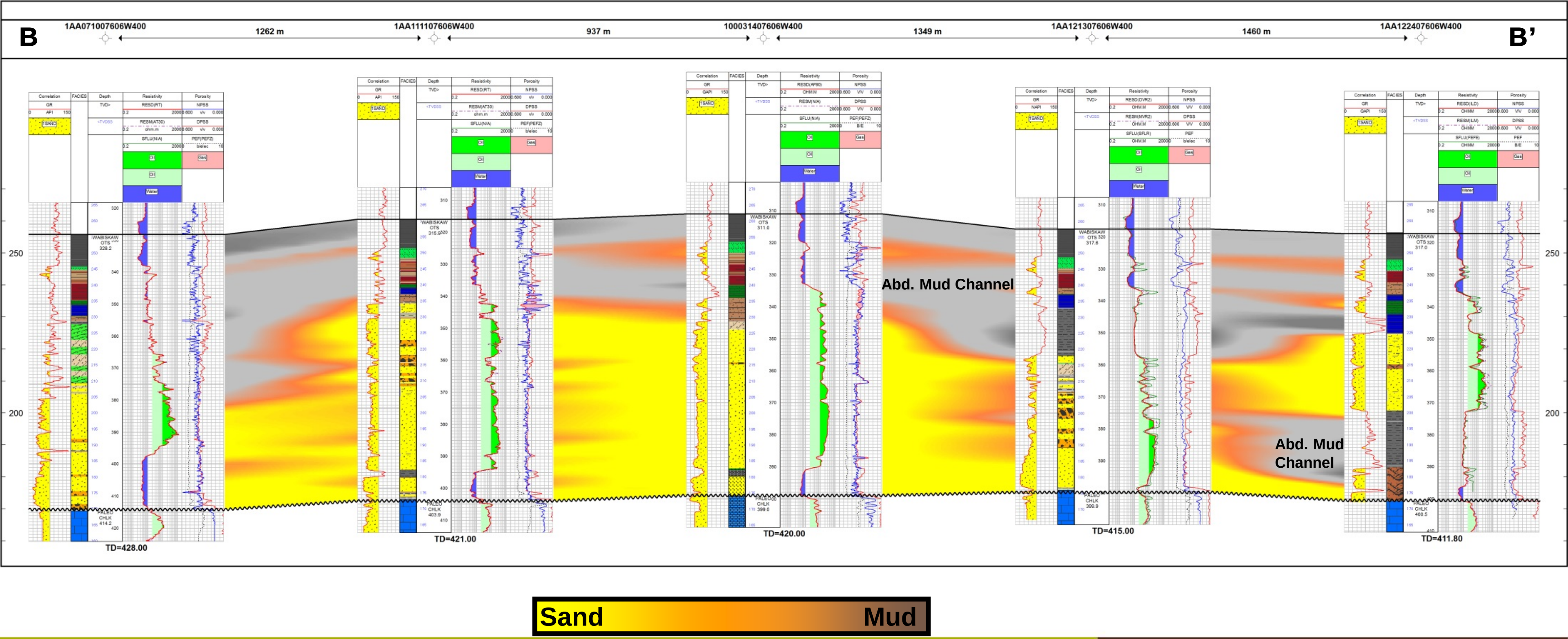
Cross section B-B' (saturation)





Cross section B-B' (lithology)



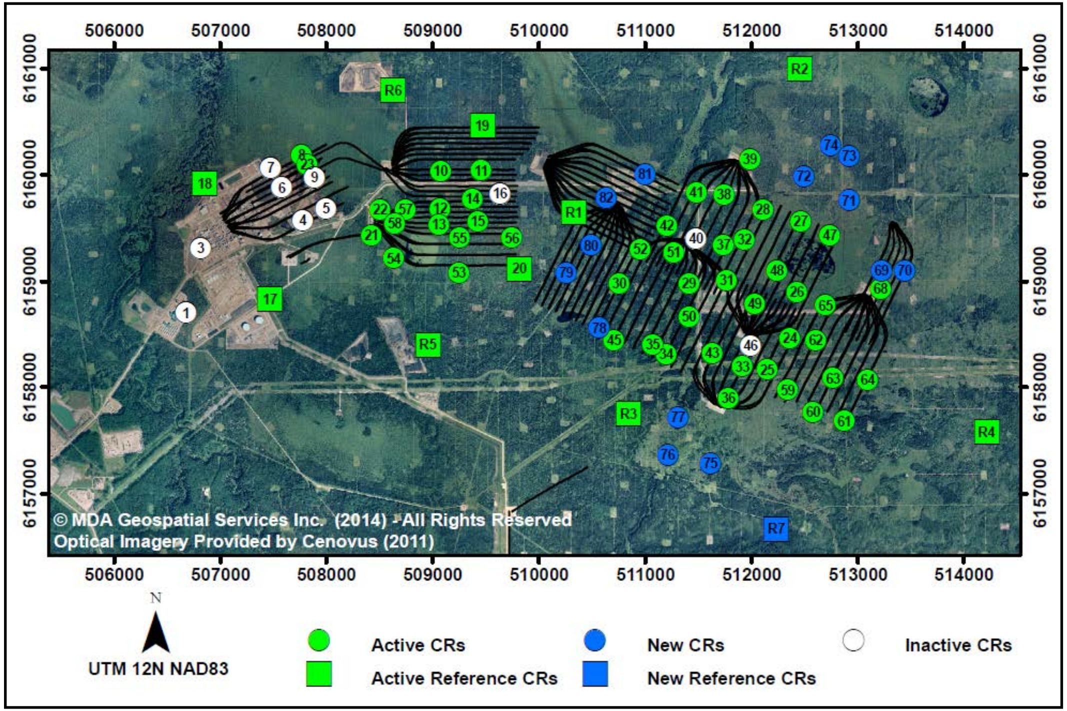


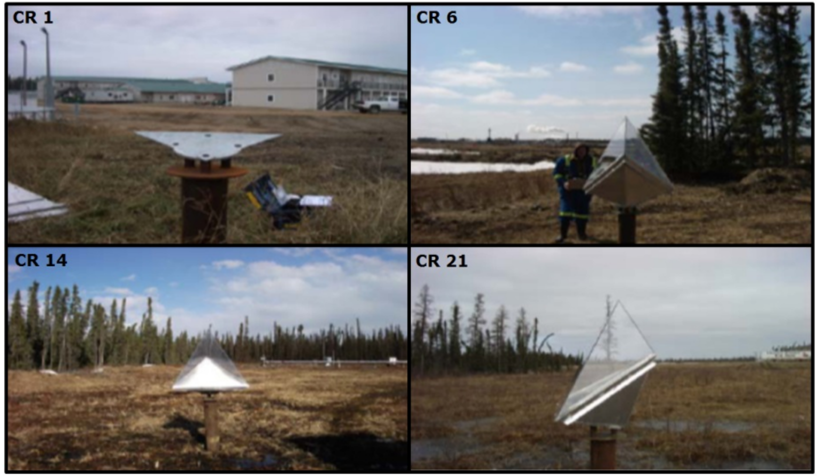
Geomechanical and surface heave

- Integrated InSAR (Synthetic Aperture Radar) Land Deformation Monitoring took place between April-October 2014 by MDA Geospatial Services Inc.
- The measurements were successfully made on 75 active corner reflector (CR) locations installed since April 2008
- In addition to the corner reflectors, the deformation profiles at 19,710 point targets were estimated (coherent target monitoring-CTM). The location of these points coincides in general with pad, pipeline and plant structures

Refer to Appendix 1 for detailed heave data

Corner reflector (CR) locations:





Current Corner Reflectors: 75
Current Reference Corner Reflectors: 11

Subsection 3.1.1 – 3) Drilling and Completions

Mike Ellis

Production Engineer

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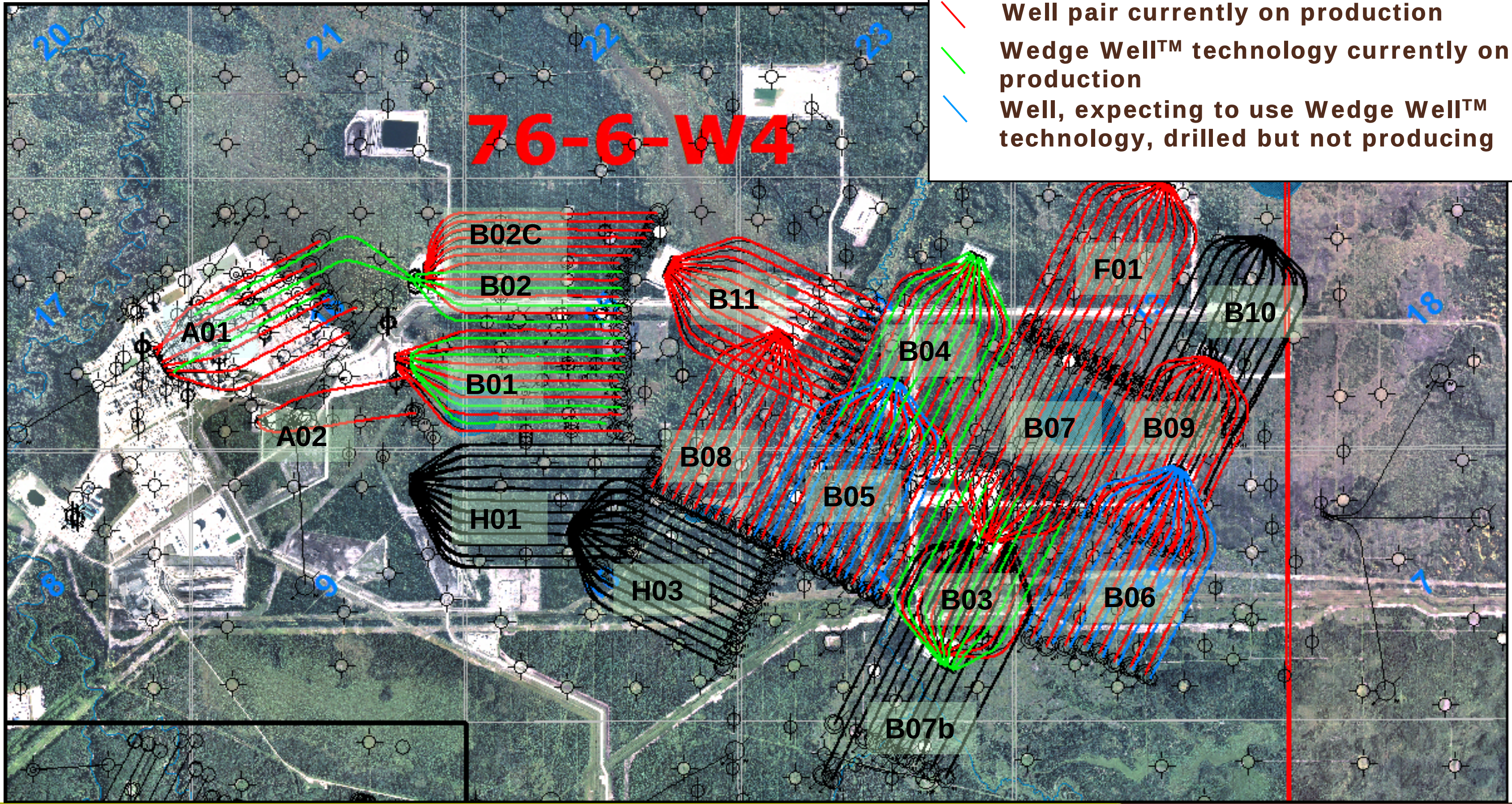
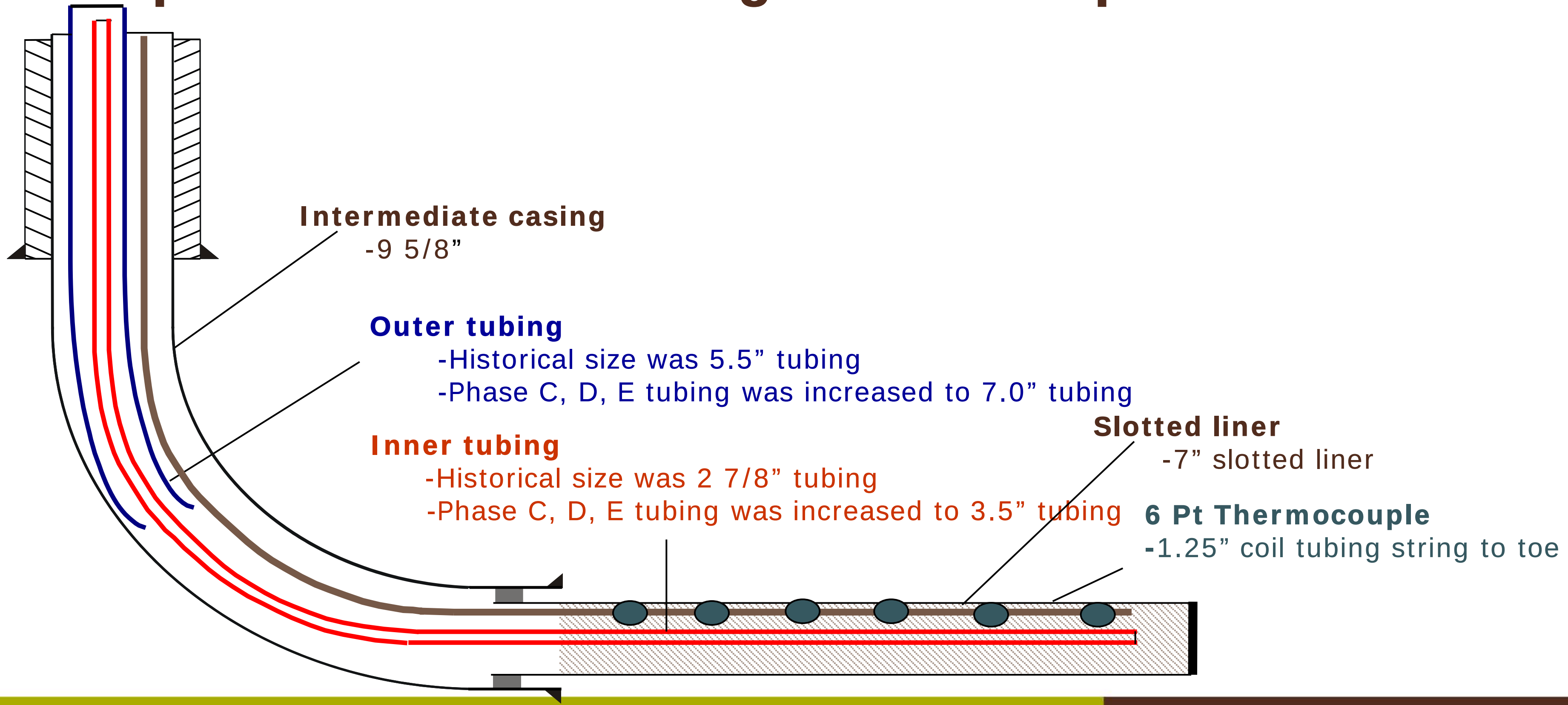
SAGD summary to date



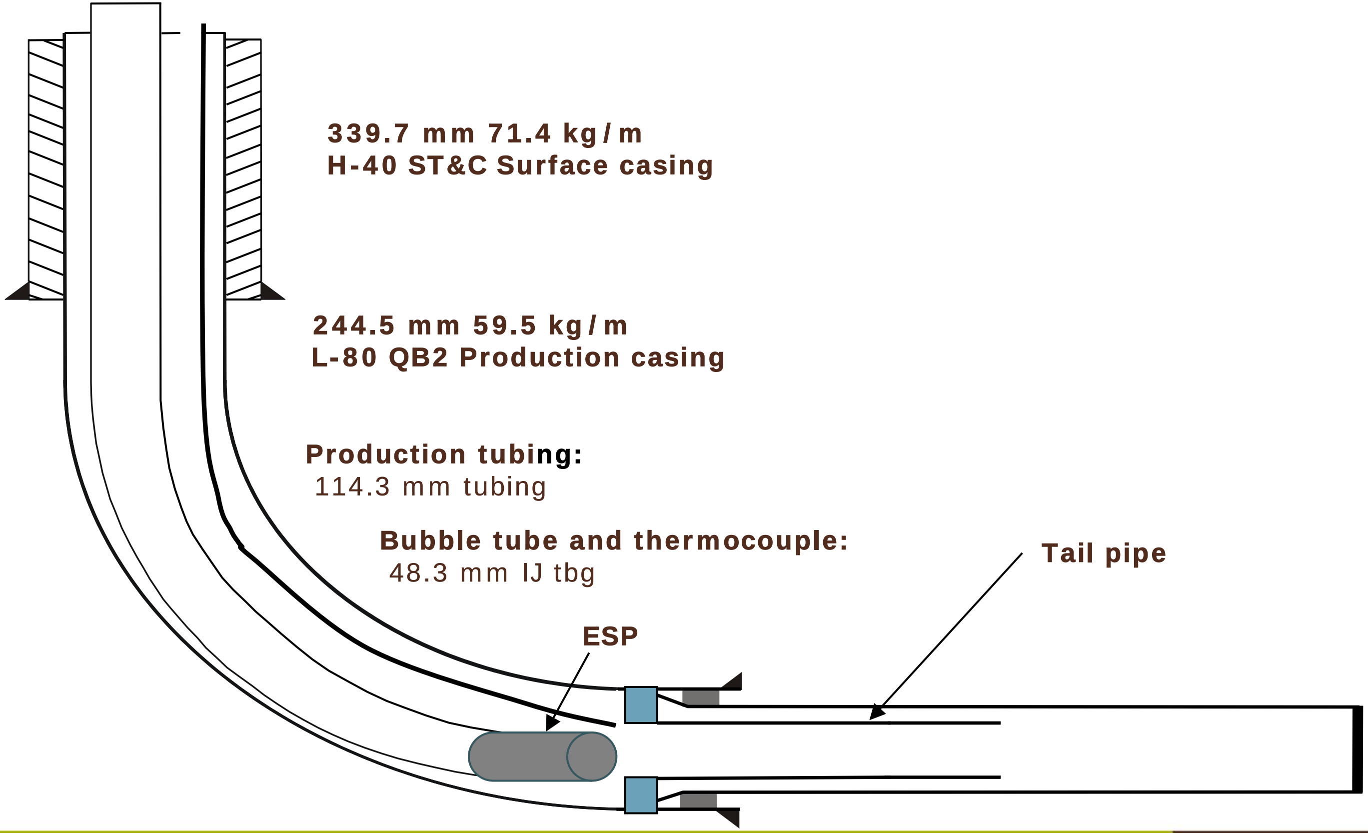
- Well pair drilled but not producing
- Well pair currently on production
- Wedge Well™ technology currently on production
- Well, expecting to use Wedge Well™ technology, drilled but not producing

June 24, 2015

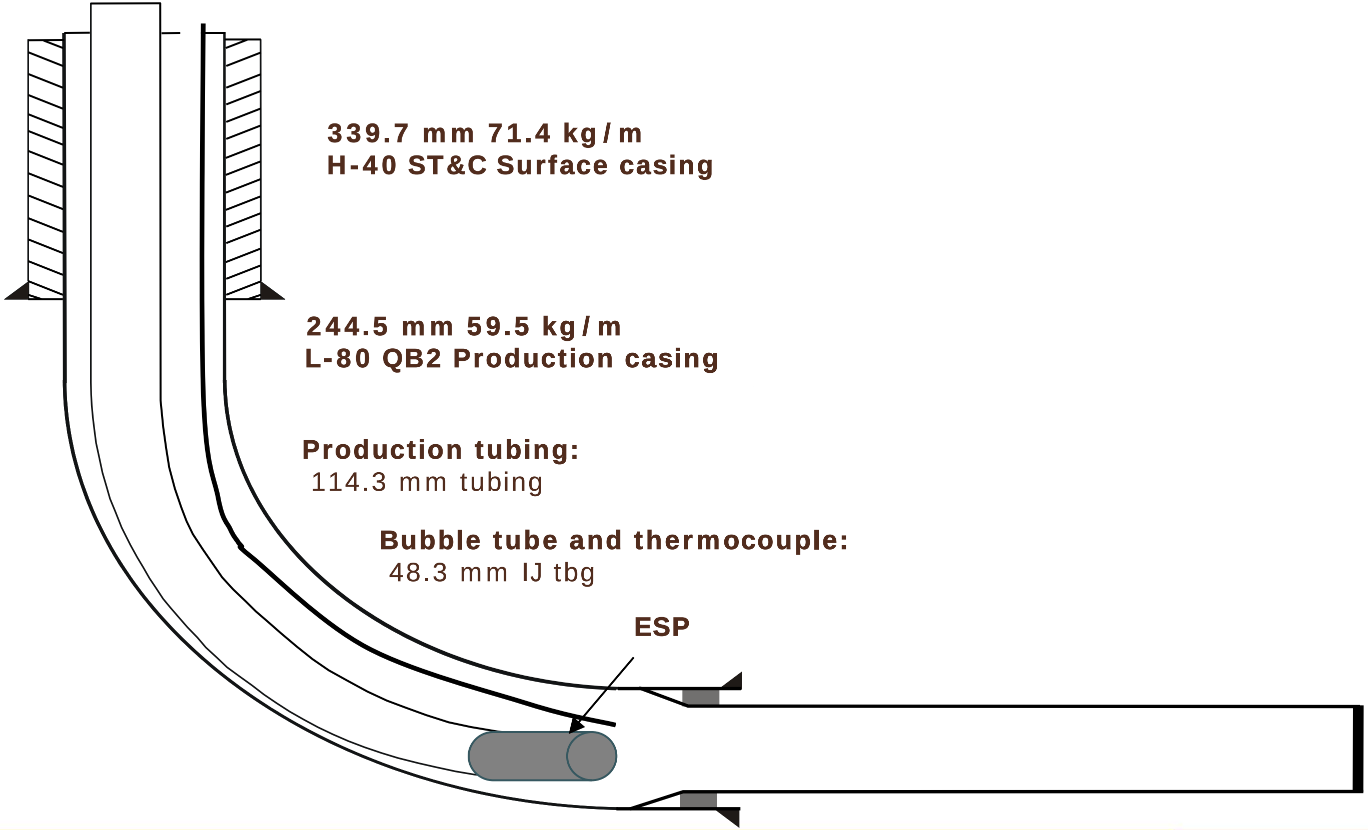
Sample circulation and gas lift completion



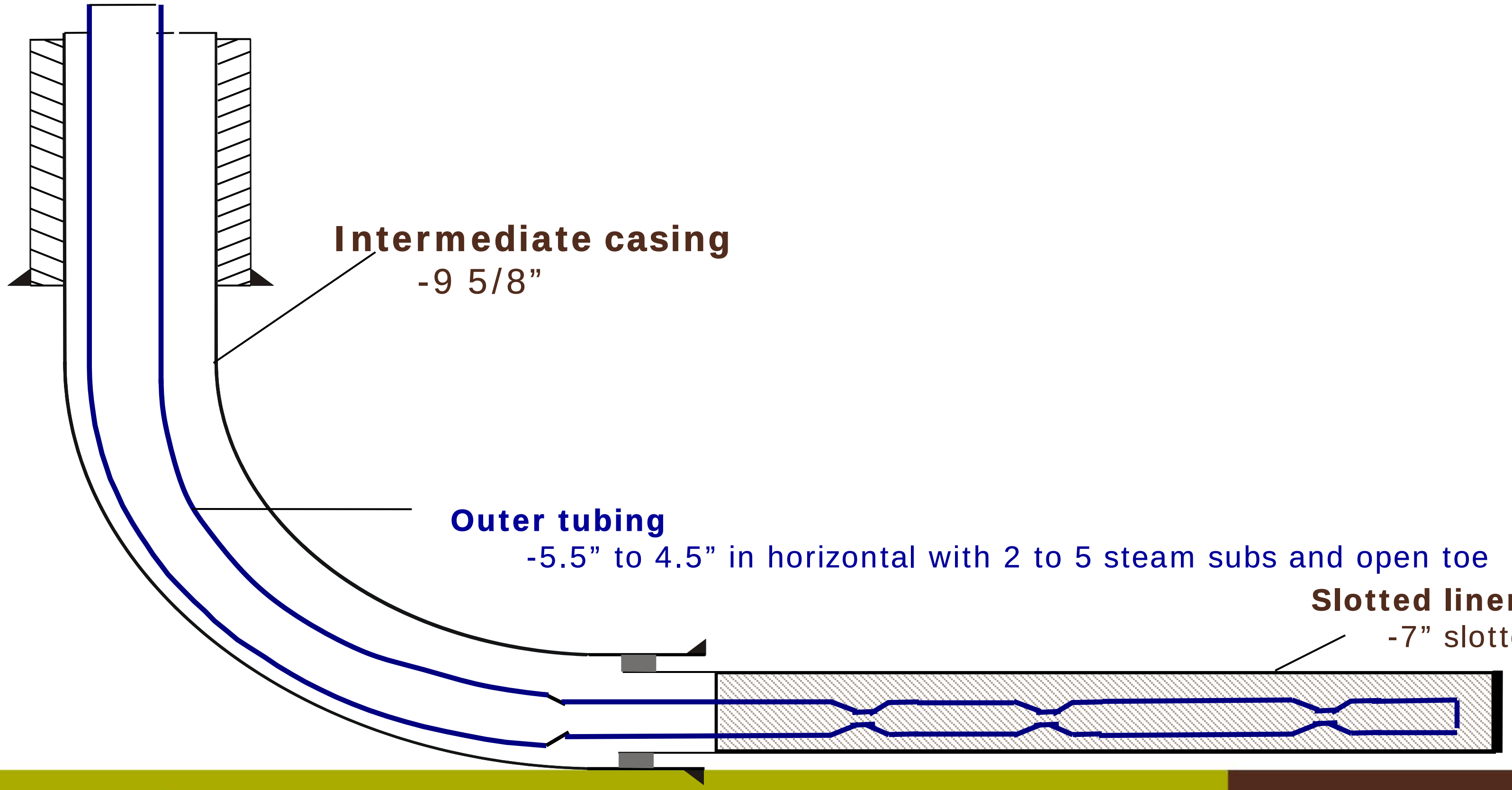
Sample ESP producer completion with tailpipe



Sample ESP producer completion without tailpipe



Sample injector completion



Inflow Control Devices (ICDs)

- No operational wells with ICDs
- First ICD production expected in 2016

Subsection 3.1.1 – 4) Artificial Lift

Mike Ellis

Production Engineer

cenovus ENERGY

Review of artificial lift by well

Pad	Start date	Total producers	Total gas lift producer wells	Total ESP producer wells	Total wells using Wedge Well™ technology and ESP
A Pad	2002	10	0	7	3
A02 Pad	2008	1	0	1	0
B01 Pad	2008	13	0	7	6
B02 Pad	2006	8	0	4	4
B02C Pad*	2013	6	0	6	0
B03 Pad	2011	16	0	8	8
B04 Pad	2011	16	0	8	8
B05 Pad	2012	9	0	9	0
B06 Pad	2012	8	0	8	0
B07 Pad	2012	8	0	8	0
B08 Pad	2013	10	0	10	0
B09 Pad	2014	11	0	11	0
B11 Pad	2013	12	0	12	0

**Note: B02C refers to the 6 well pairs on the north side of the B02 Pad Approved Drainage Box, which were drilled at a 50m lateral downhole spacing*

Artificial lift performance

Gas lift (0 current wells):

- Typical operating pressure 4,000 – 5,000 kPag
- No temperature limitations, go as hot as ~263^{o}C
- Average emulsion flow rate ~ 600-1600 m^3/d

ESP (128 current wells):

- Majority of wells were converted to ESP after a gas lift phase
- ESP conversion occurs when thief zone intersected or other optimization purposes
- Typical operating pressure 1,800 – 4,000 kPag
- No temperature limitations, go as hot as ~235^{o}C BHT
- Average emulsion flow rate ~ 200-1600 m^3/d

Subsection 3.1.1 – 5) Instrumentation

Mike Ellis

Production Engineer

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SAGD Well Pressure Instrumentation

At Christina Lake all production and injector wells are equipped with bubble tubes to measure downhole pressures.

Currently there are 2 sizes of bubbles tubes:

- $^3/_8$ **inch**
- $^1/_2$ **inch**

We are replacing all $^3/_8$ inch bubble tubes with $^1/_2$ inch to increase reliability.

Fiber pressure gauges have been trialed with poor results

Moving forward bubble tubes will continue to be the pressure instrumentation of choice at Christina Lake.

SAGD Well Temperature Instrumentation

At Christina Lake production wells use type 'K' thermocouples to measure downhole temperatures.

There are 2 thermocouple formats installed:

- **Single point installed at the heel**
- **6 point that is installed along the producer horizontal**

Distributed temperature sensing (DTS) fiber instrumentation will be used new wells and on a go forward basis. (B07B- Oct 2015 forward)

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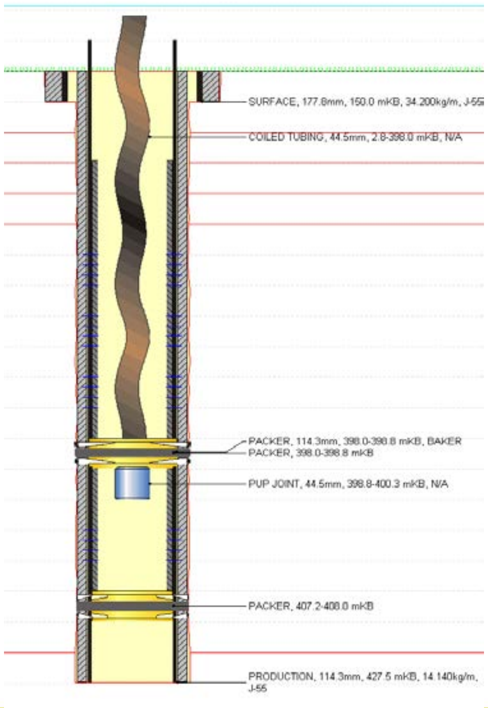
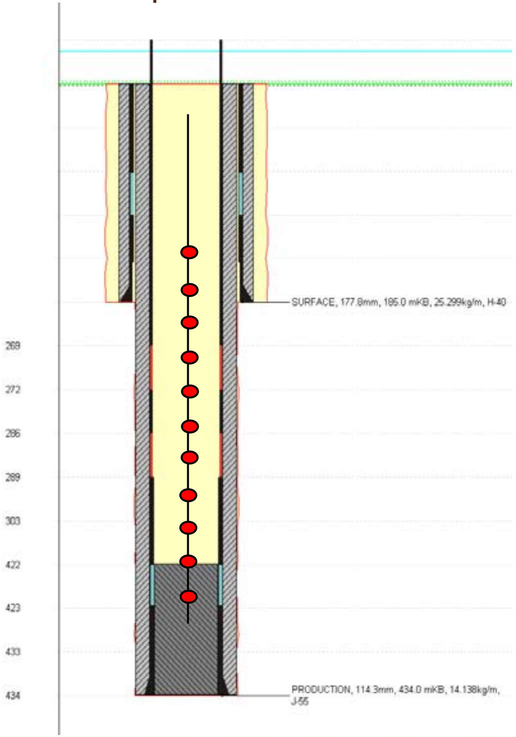
Instrumentation in observation wells (typical completions)

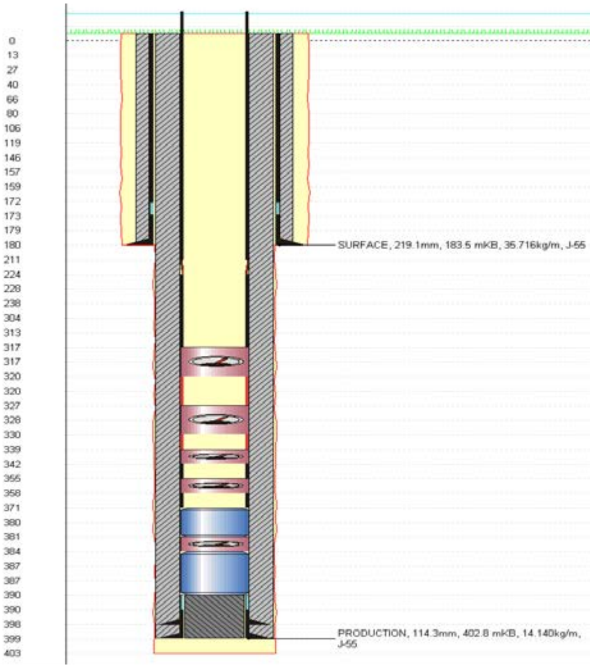
Hanging wire piezometer



Temperature observation



Cemented casing piezometers



Observation Well Equipment Reliability

Type 'K' Thermocouples

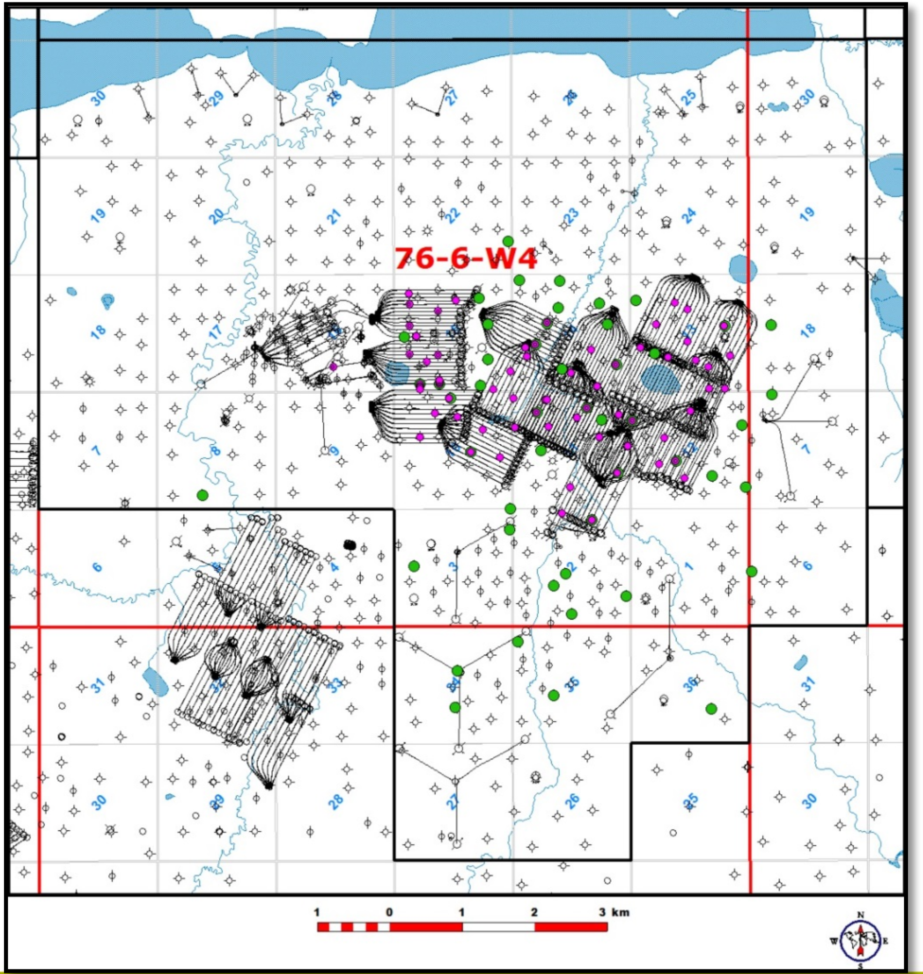
- Reliability has been very good
- Easy to replace if failed
- Thermocouple failures arise when the mineral insulated (MI) cable is compromised downhole.

Hanging piezometers

- Reliability has been good
- Easy to replace if failed
- Hanging piezometer failures occur most often during workovers. Either during RST logging or packer isolation work.
- Equipment failures have occurred but are rare.

Cemented piezometers

- Reliability has been poor
- Impossible to replace
- Early piezometer installs used standard vibrating wire piezometer rated to 80c – Many failed due to high temperatures
- Since 2013 – all piezometer installed have been high temperature vibrating wire piezometer rated to 250C – Have seen an increase in equipment reliability
- Have seen failures as a result of improper installation and well securement issues



Observation wells

Thermocouple well

Piezometer well

Subsection 3.1.1–5c) & d) instrumentation data

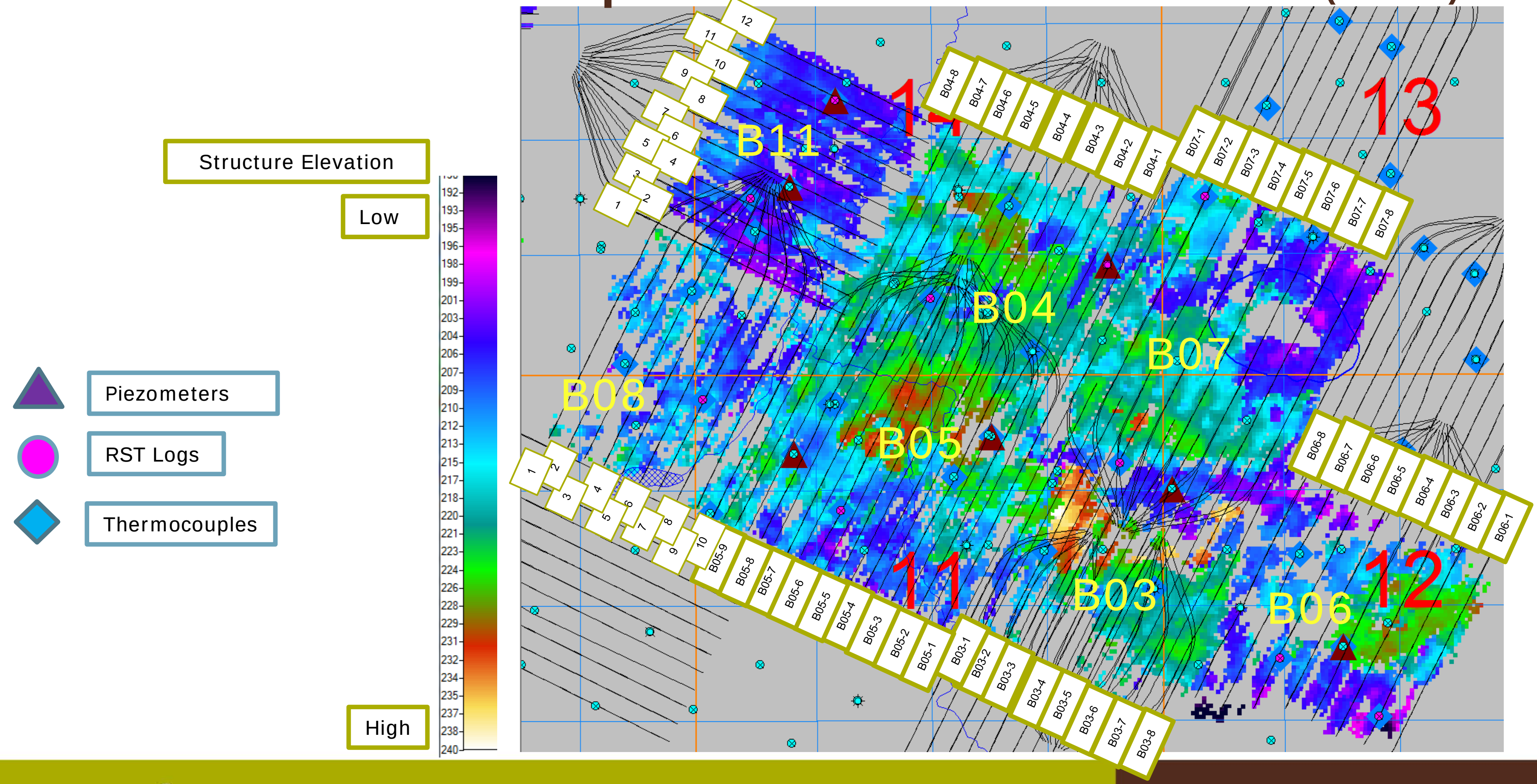
Requirements under subsection 3.1.1 5c) and d) are located in Appendices 2 & 3

Subsection 3.1.1 – 6)
4D Seismic

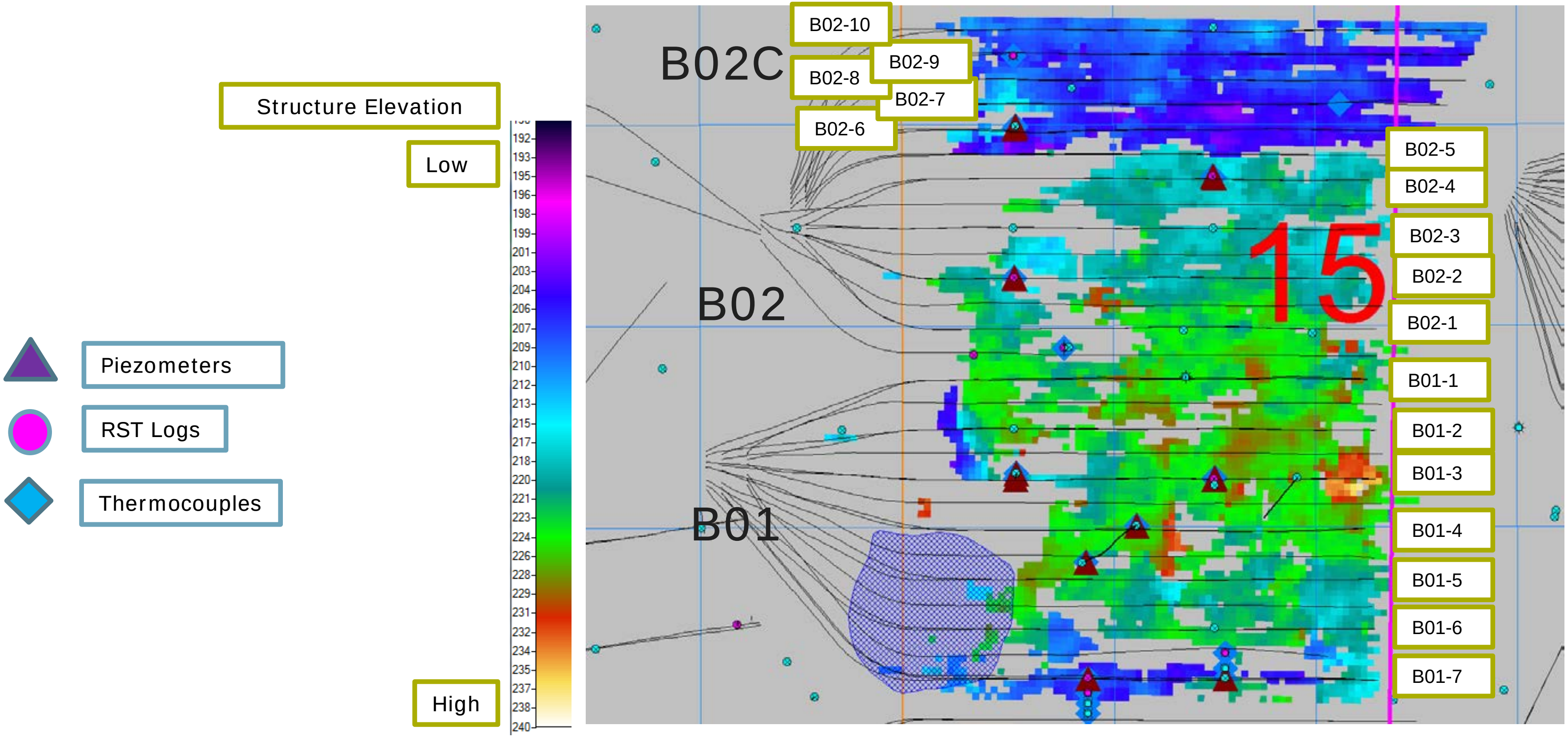
Kevin Beary

Reservoir Engineer

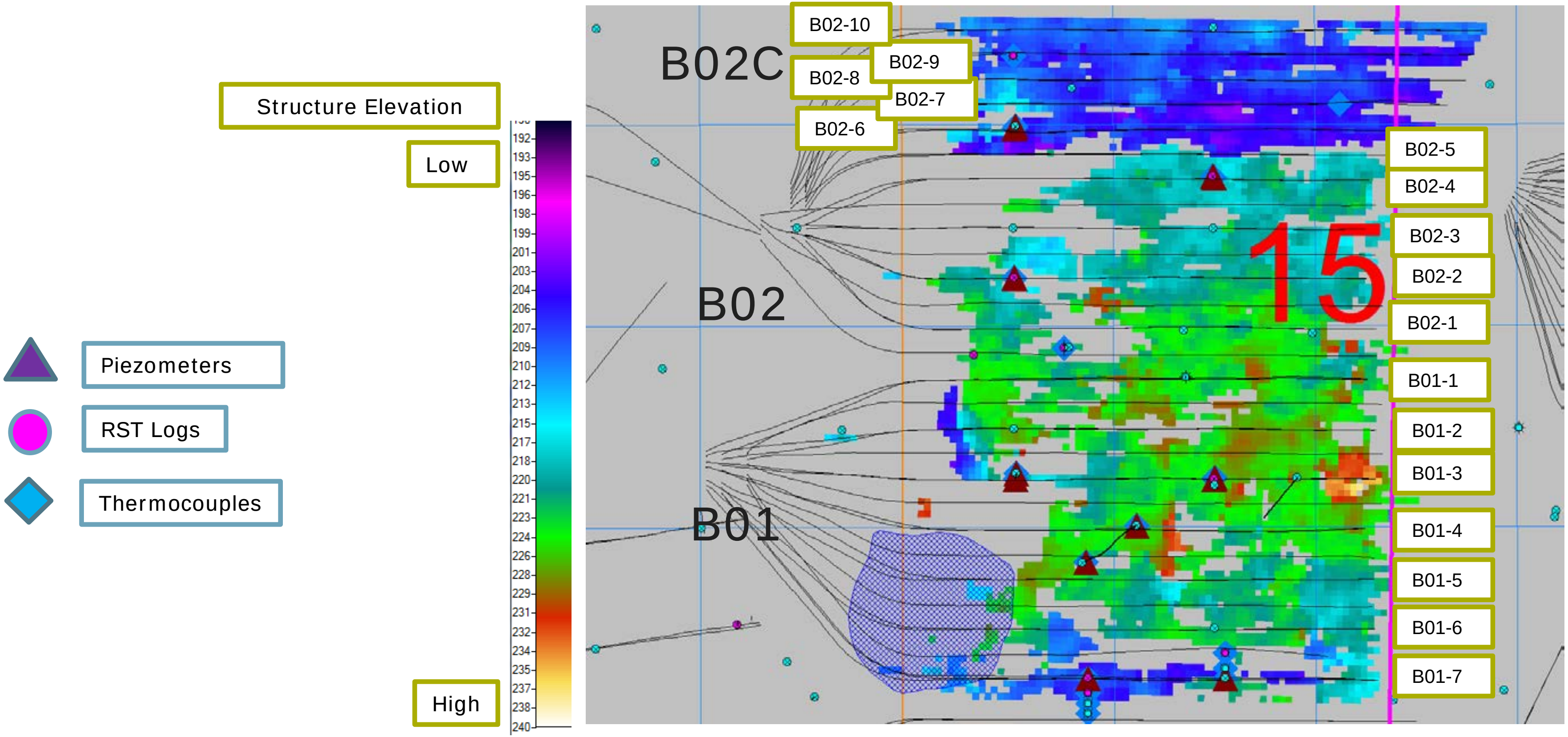
2014 Steam-affected top structure from 4D Seismic (TVDSS)



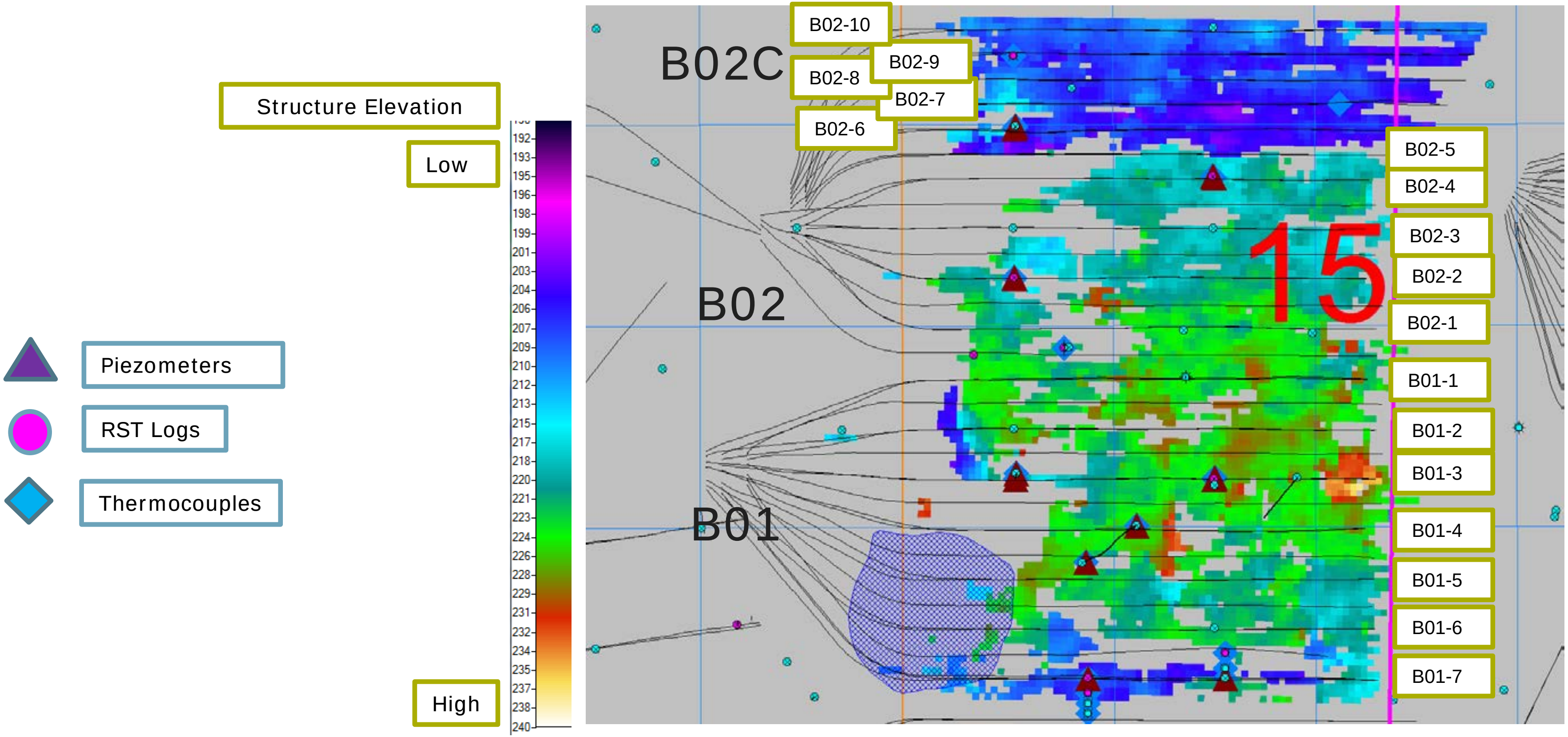
2014 Steam-affected top structure from 4D seismic (TVDSS)



2014 Steam-affected top structure from 4D seismic (TVDSS)



2014 Steam-affected top structure from 4D seismic (TVDSS)



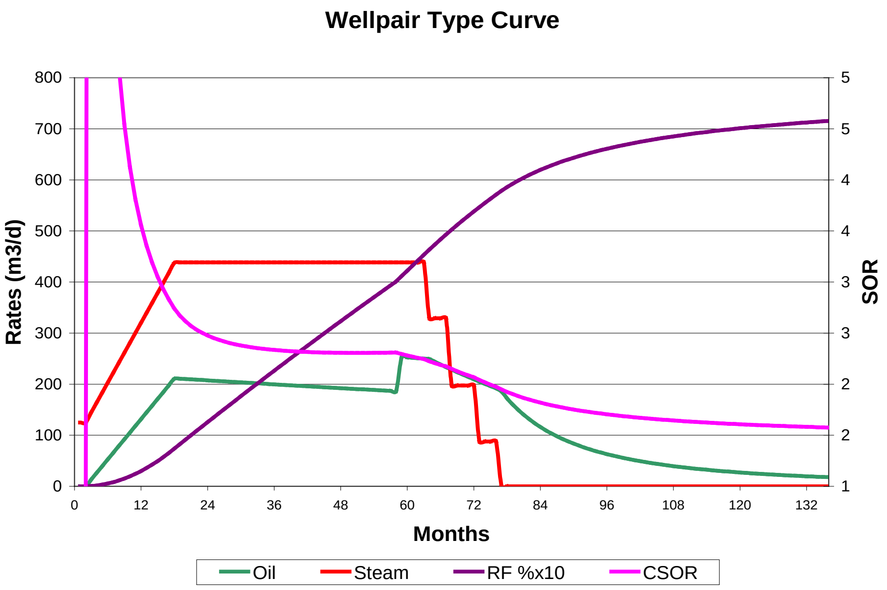
Subsection 3.1.1 – 7) Scheme performance

Kevin Beary

Reservoir Engineer

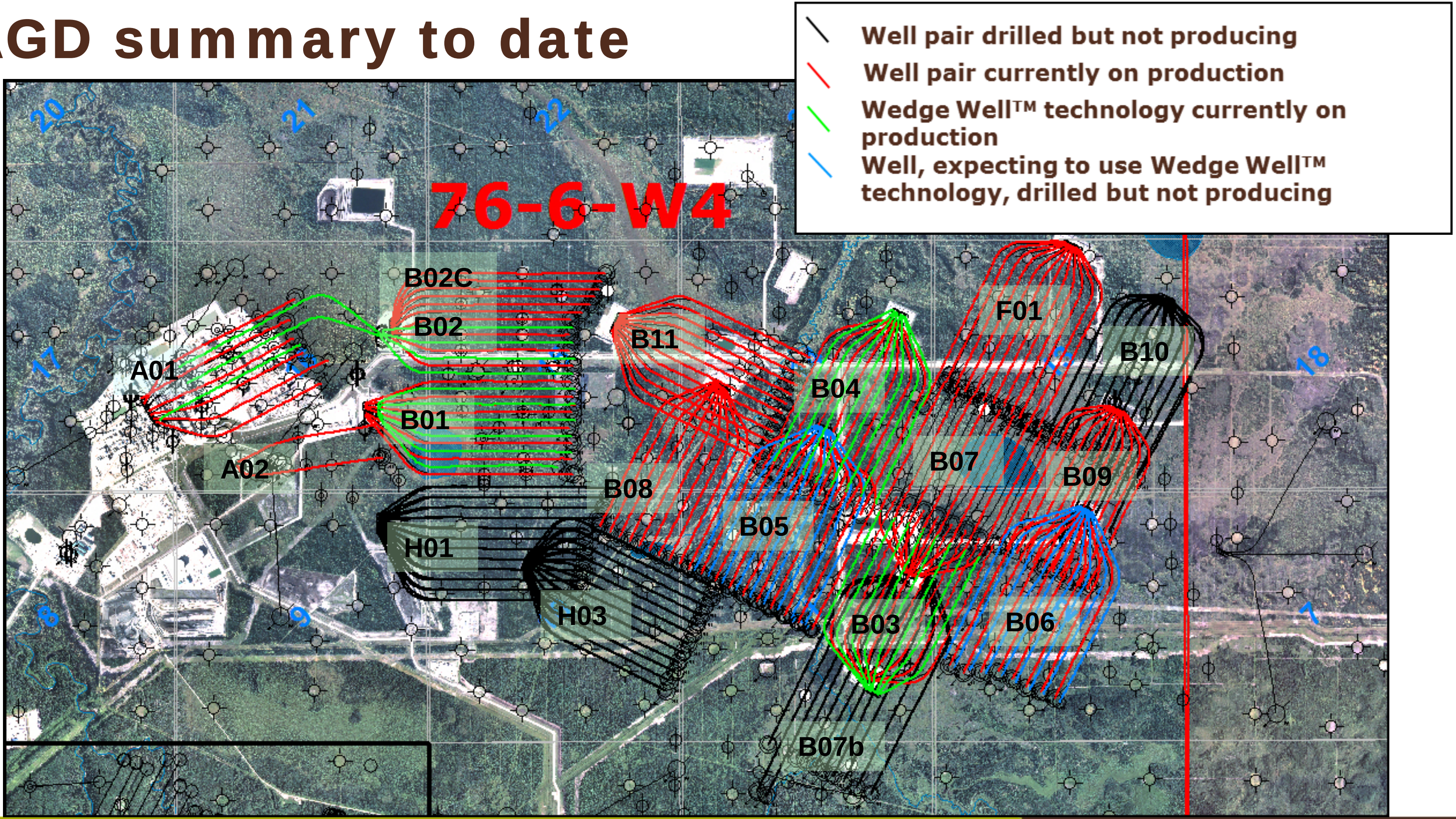
Scheme performance prediction

- Predict well pair performance based on modified Butler's equation
- Predict well pair CSOR using published CSOR correlations (Edmunds & Chhina 2002)
- Generate overall scheme production performance by adding individual well forecasts over time to honour predicted steam capacity and water treating availability



June 24, 2015

SAGD summary to date

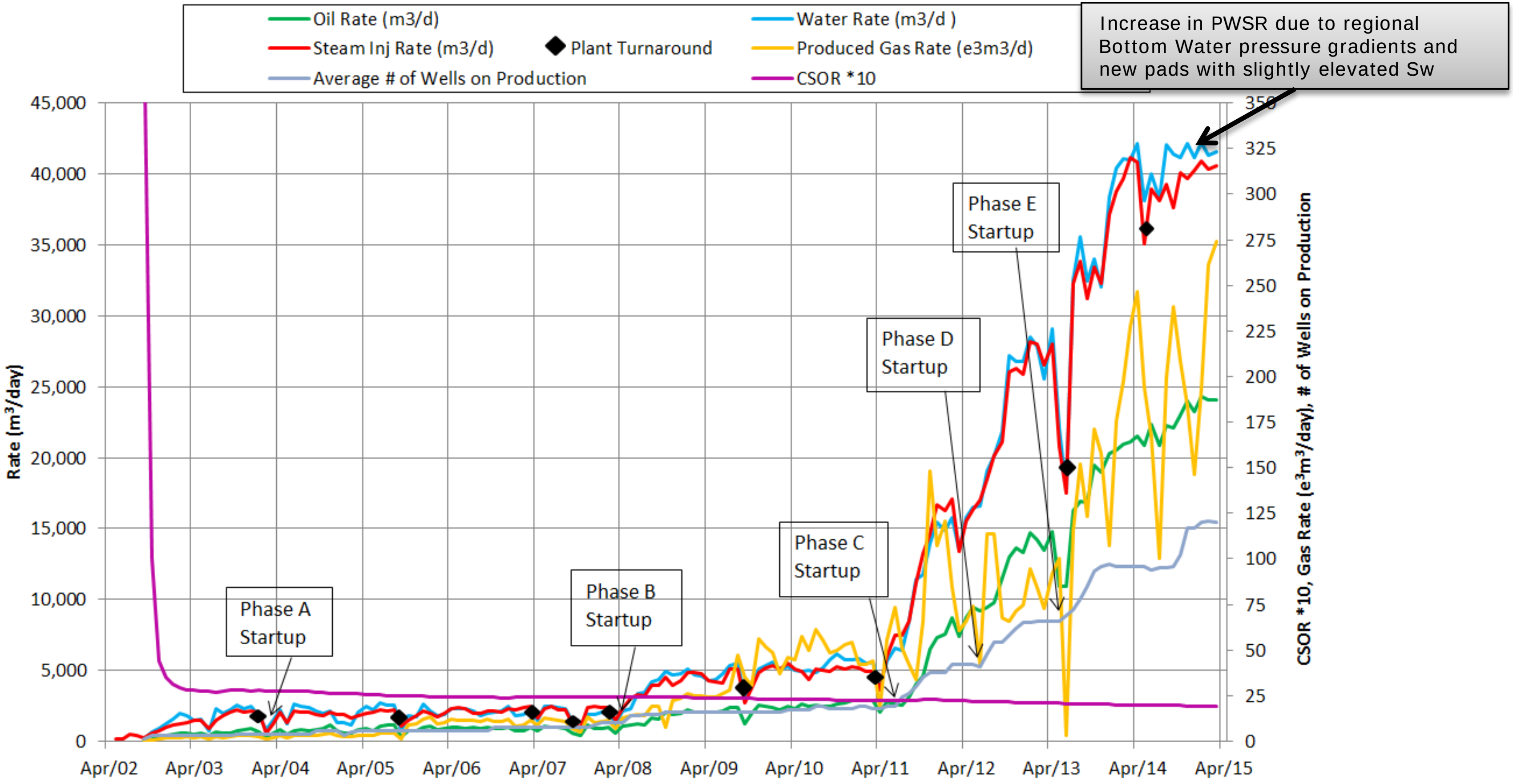


SAGD summary to date

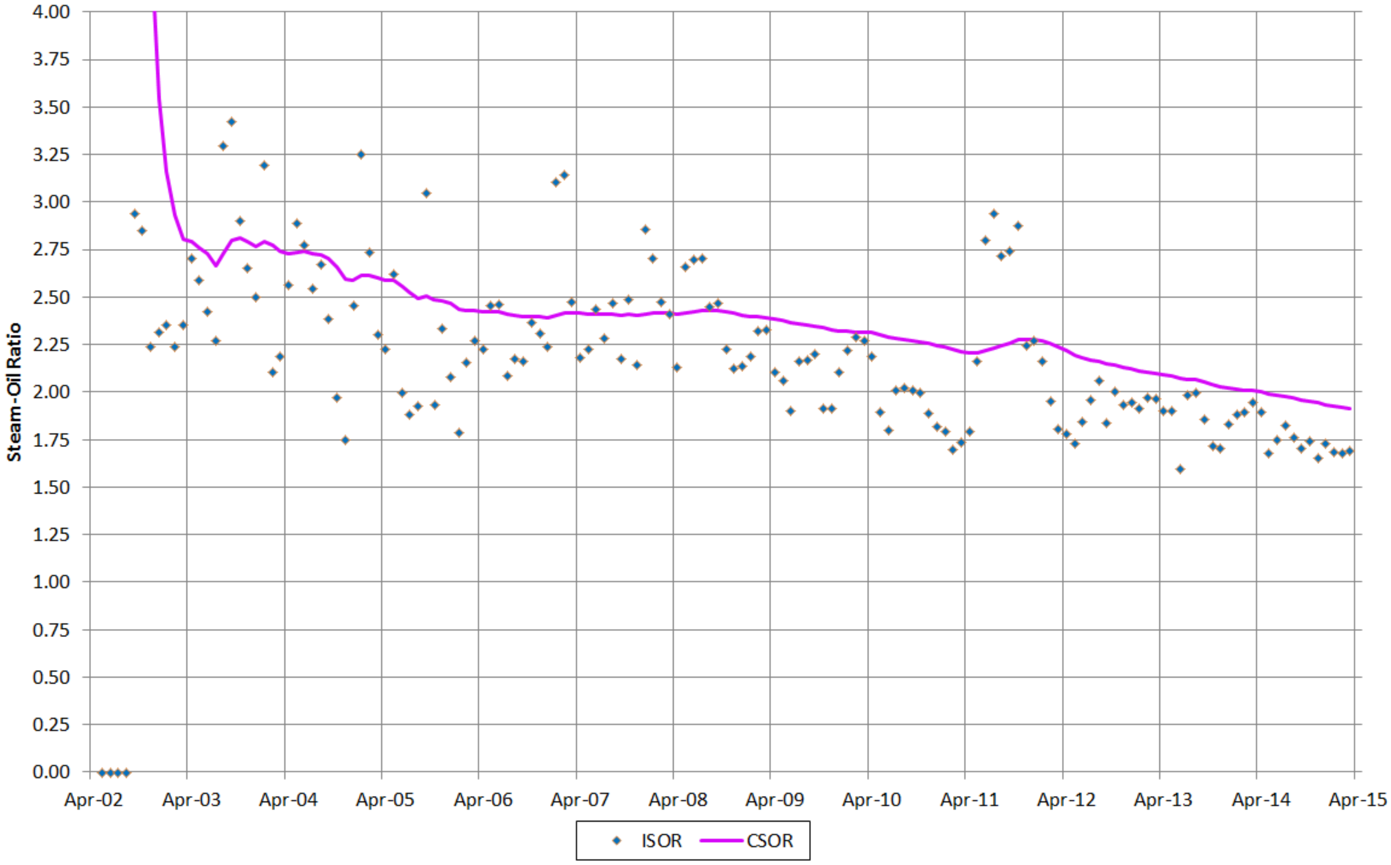
128 total production wells in operation to date:

- 98 standard well pairs
  - all on ESP, no gas lift
- one offset toe producer well
  - ESP
  - increase recovery from A01-3 well pair
- 29 wedge wells using patented Wedge Well™ technology
  - all on ESP
  - 3 located in A01 pad
  - 1 in between B01 and B02 pad
  - 6 located in B01 pad
  - 3 located in B02 pad
  - 8 located in B03 pad
  - 8 located in B04 pad

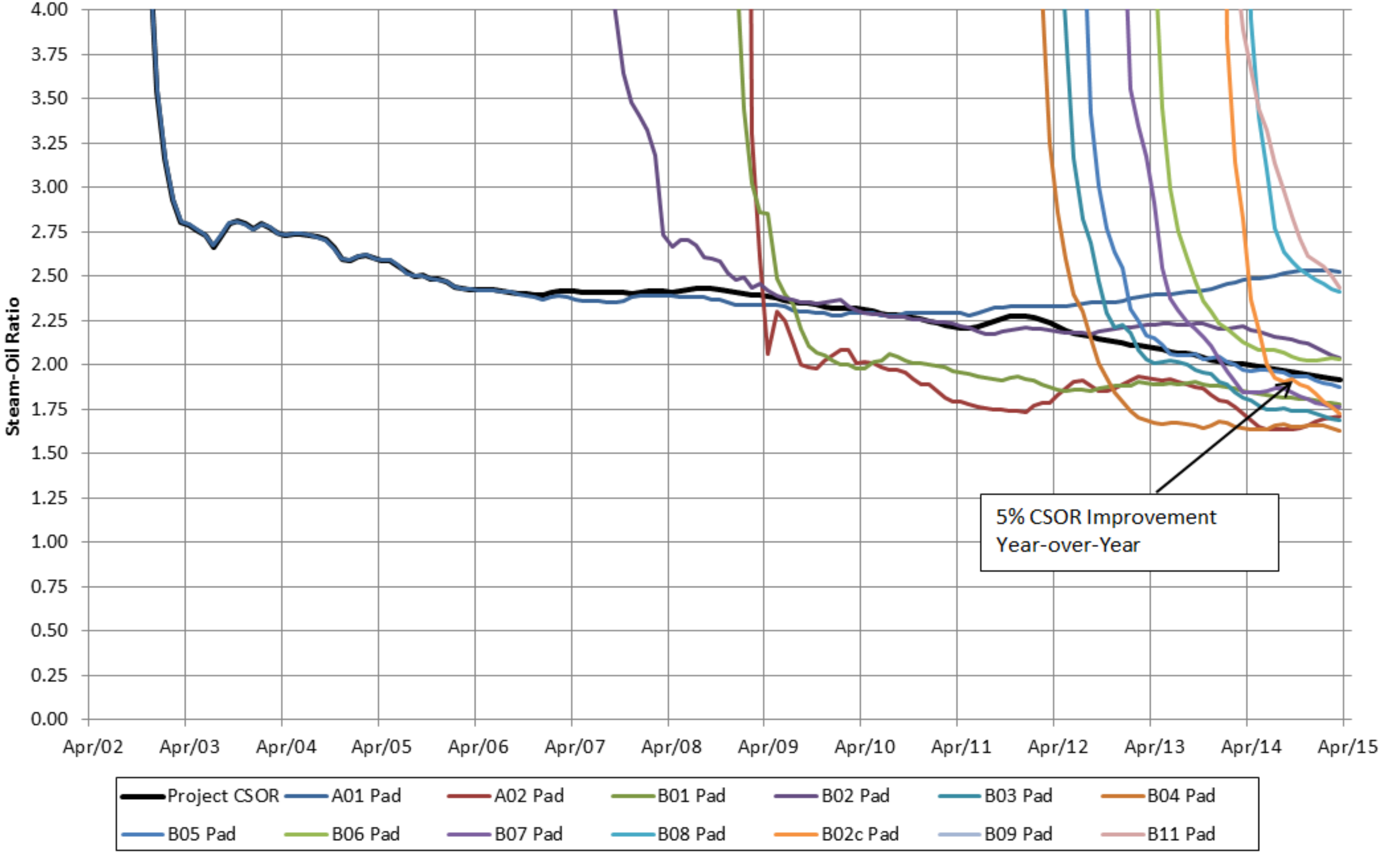
Christina Lake Performance



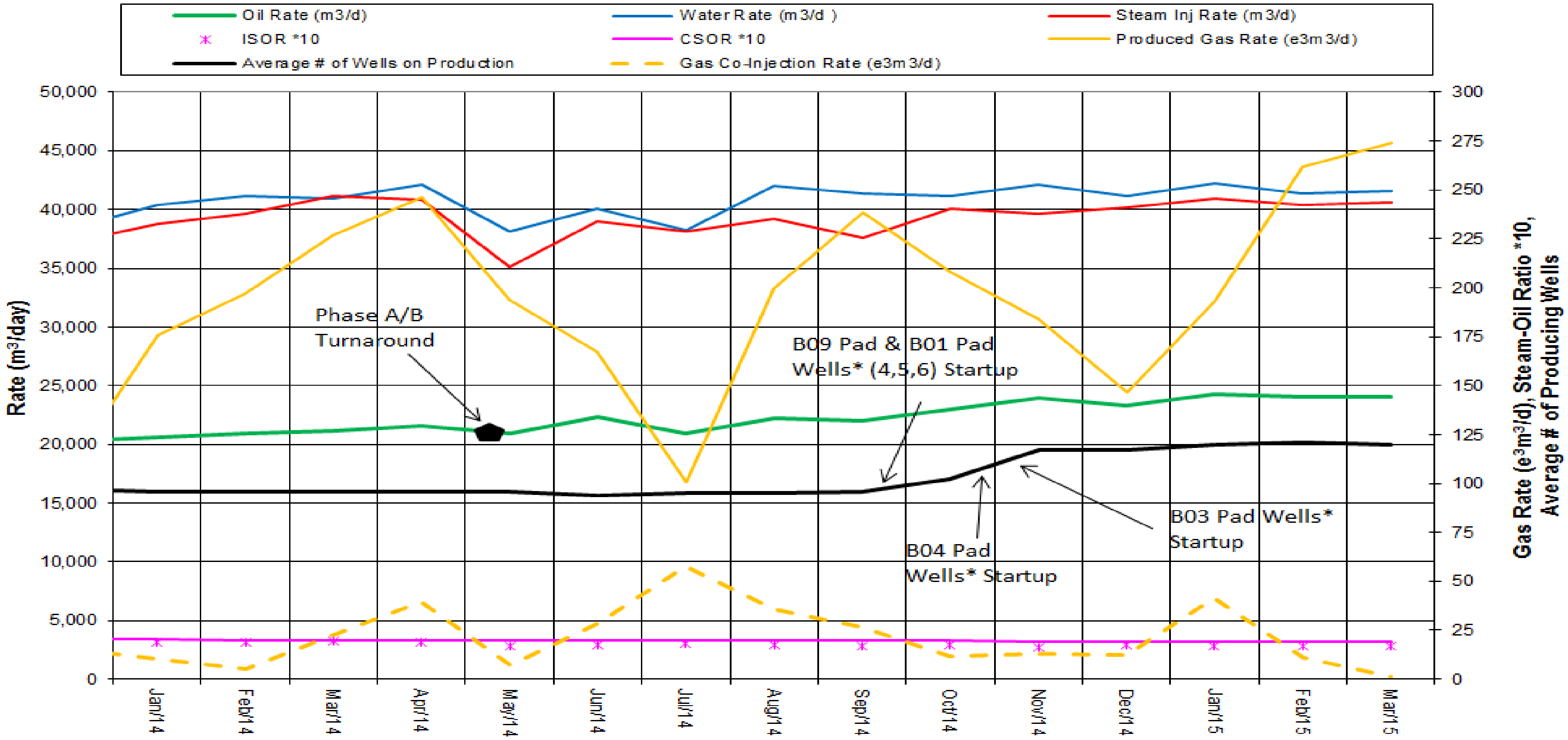
Christina Lake Project SOR



Christina Lake CSOR



Christina Lake Performance



*Well using Wedge Well™ technology

SAGDable vs. producible OIP (SOIP vs. POIP)

We are presenting two tables

- SAGDable OIP & producible OIP

We define SAGDable OIP as:

- (**Planned length**) x (Spacing) x (Net SAGD pay: ***<u>Base</u>*** *to top SAGD*) x (S_o) x (Ø)
- Used during the planning phase
- Doesn't change after well pair plans finalized
- Used to plan additional wells (Wedge Well™ technology, bypassed pay producers, re-drills, new pairs)
- We aim to drill the full planned length (typically 800m), and drill the producer well as low as possible in relation to Base SAGD

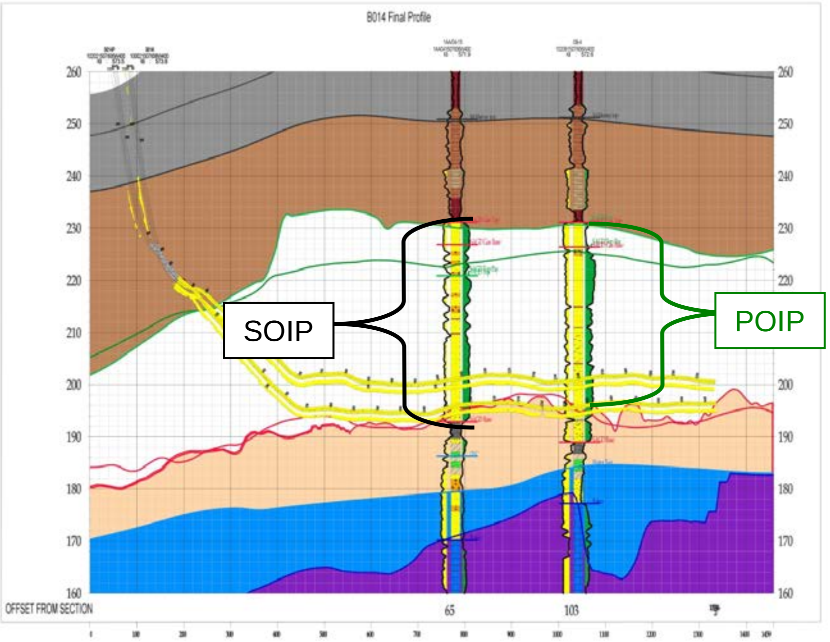
We define producible OIP as:

- (**Effective length**) x (Spacing) x (Effective pay: ***<u>Producer</u>*** *to top SAGD*) x (S_o) x (Ø)
- An "after-drilling" OOIP, based on well pair potential
- Changes with time and interpretation (obs. wells, 4D seismic, MWD error, etc.)
- Used to plan blowdown strategy
- This reflects actual well pair performance
    - incorporates actual overlapping slotted liner lengths initially (including blank sections <100m)
    - incorporates actual elevation of the producing well
    - incorporates lithology

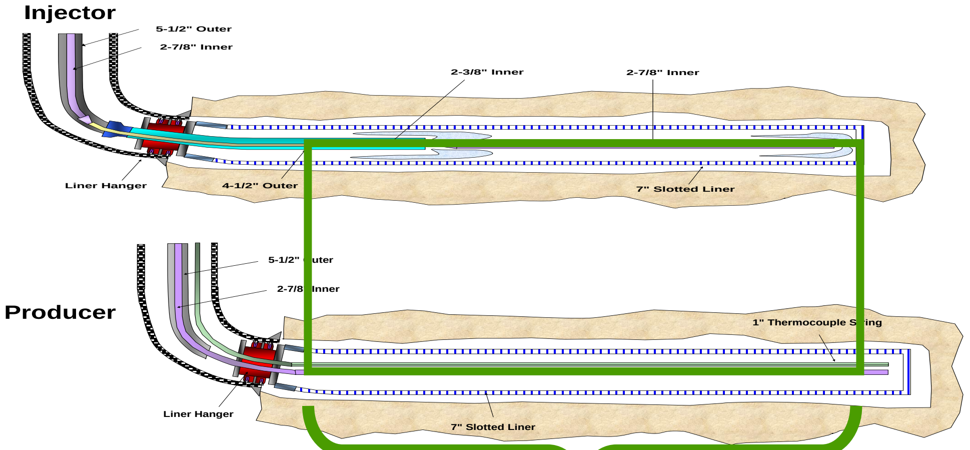
Producible OIP is always < SAGDable OIP

SAGDable vs. producible OIP (definition)

Vertical



Horizontal



Effective length - slotted liner overlap (POIP)

Planned length - ICP to TD (SOIP)

POIP and RF per pad

Note: Down spaced pads are not planned to incorporate Wedge Well^{TM} technology

Producible Oil in Place (POIP) and % Recovery									
Pad	Pad Area (m^2)	Cummulative Oil Production (Mm^3)*	AVG Porosity	AVG Oil Saturation	AVG Net Pay (m)	POIP (Mm^3)	Recovery*	Ultimate Recovery w/o Wedge Well^{TM} technology	Ultimate Recovery w/ Wedge Well^{TM} technology
A	616,615	2,164	0.35	0.79	26	2,965	73.0%	~ 75-80%	~ 80-85%
A02	490,777	344	0.34	0.84	26	401	85.9%	~ 80-85%	N/A
B01	594,325	2,992	0.34	0.85	28	4,083	73.3%	~ 75-80%	~ 80-85%
B02	323,240	2,030	0.33	0.84	30	2,453	82.7%	~ 75-80%	~ 80-85%
B02C (down spaced)	298,590	788	0.35	0.83	22	1,712	46.0%	~ 80-85%	N/A
B03	640,532	3,210	0.33	0.84	32	5,223	61.5%	~ 75-80%	~ 80-85%
B04	640,780	3,440	0.33	0.82	35	5,701	60.3%	~ 75-80%	~ 80-85%
B05	727,639	2,389	0.33	0.82	36	6,509	36.7%	~ 75-80%	~ 80-85%
B06	644,480	1,868	0.32	0.81	28	4,241	44.0%	~ 75-80%	~ 80-85%
B07	653,601	2,587	0.32	0.82	35	5,728	45.2%	~ 80-85%	N/A
B08 Pad (down spaced)	567,185	946	0.36	0.87	27	4,365	21.7%	~ 80-85%	N/A
B09 Pad (down spaced)	560,421	276	0.32	0.85	36	5,012	5.5%	~ 80-85%	N/A
B11 Pad (down spaced)	603,377	1,578	0.34	0.84	32	4,786	33.0%	~ 80-85%	N/A

% recovery = cum. production / SOIP

Ultimate Recovery % = ultimate cum. production / SOIP

**As of March 31, 2015*

Note: Resource estimates in this table are based on Cenovus volumetric calculations, and are not in accordance with National Instrument 51-101 guidelines. They are provided solely for the purpose of complying with Alberta regulatory requirements.

SOIP and RF per pad

Note: Down spaced pads are not planned to incorporate Wedge Well^{TM} technology

SAGDable Oil in Place (SOIP) and % Recovery									
Pad	Pad Area (m^2)	Cummulative Oil Production (Mm^3)*	AVG Porosity	AVG Oil Saturation	AVG Net Pay (m)	SOIP (Mm^3)	Recovery*	Ultimate Recovery w/o Wedge Well^{TM} technology	Ultimate Recovery w/ Wedge Well^{TM} technology
A	616,615	2,164	0.34	0.79	31	3,979	54.4%	~ 52-56%	~ 56-60%
A02	490,777	344	0.34	0.84	29	475	72.4%	~ 59-63%	N/A
B01	594,325	2,992	0.34	0.85	35	5,377	55.6%	~ 53-57%	~ 57-61%
B02	323,240	2,030	0.33	0.84	35	3,089	65.7%	~ 56-60%	~ 60-64%
B02C (down spaced)	298,590	788	0.35	0.83	29	2,243	35.1%	~ 53-57%	N/A
B03	640,532	3,210	0.33	0.84	42	7,015	45.8%	~ 52-56%	~ 56-60%
B04	640,780	3,440	0.33	0.82	42	7,079	48.6%	~ 56-60%	~ 60-64%
B05	727,639	2,389	0.33	0.82	43	8,161	29.3%	~ 56-60%	~ 60-64%
B06	644,480	1,868	0.32	0.81	35	5,584	33.4%	~ 53-57%	~ 57-61%
B07	653,601	2,587	0.32	0.82	41	6,960	37.2%	~ 58-62%	N/A
B08 Pad (down spaced)	567,185	946	0.33	0.75	36	4,659	20.3%	~ 66-70%	N/A
B09 Pad (down spaced)	560,421	276	0.32	0.83	43	6,203	4.4%	~ 57-61%	N/A
B11 Pad (down spaced)	603,377	1,578	0.33	0.80	38	5,998	26.3%	~ 56-60%	N/A

% recovery = cum. production / SOIP

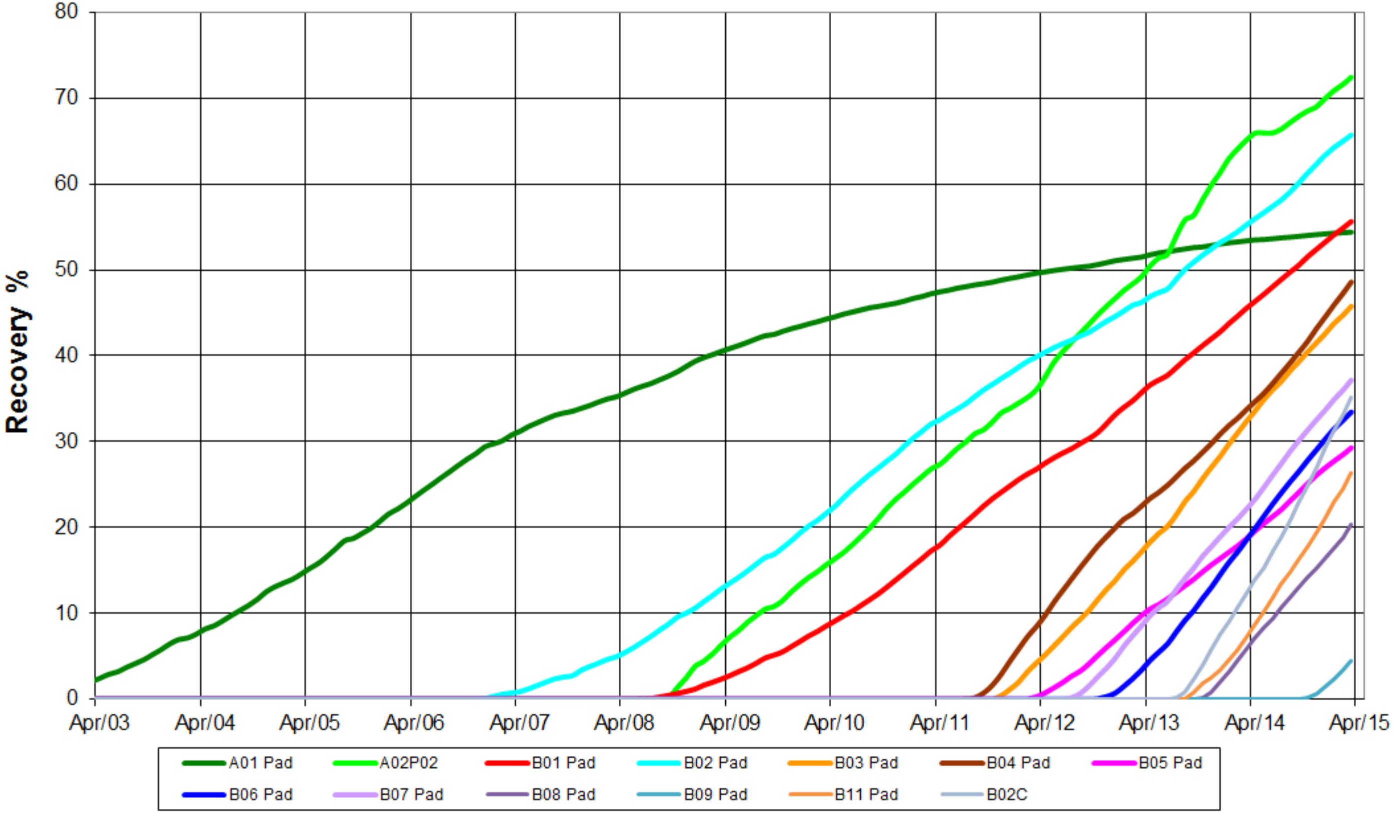
Ultimate Recovery % = ultimate cum. production / SOIP

**As of March 31, 2015*

Note: Resource estimates in this table are based on Cenovus volumetric calculations, and are not in accordance with National Instrument 51-101 guidelines. They are provided solely for the purpose of complying with Alberta regulatory requirements.

Christina Lake

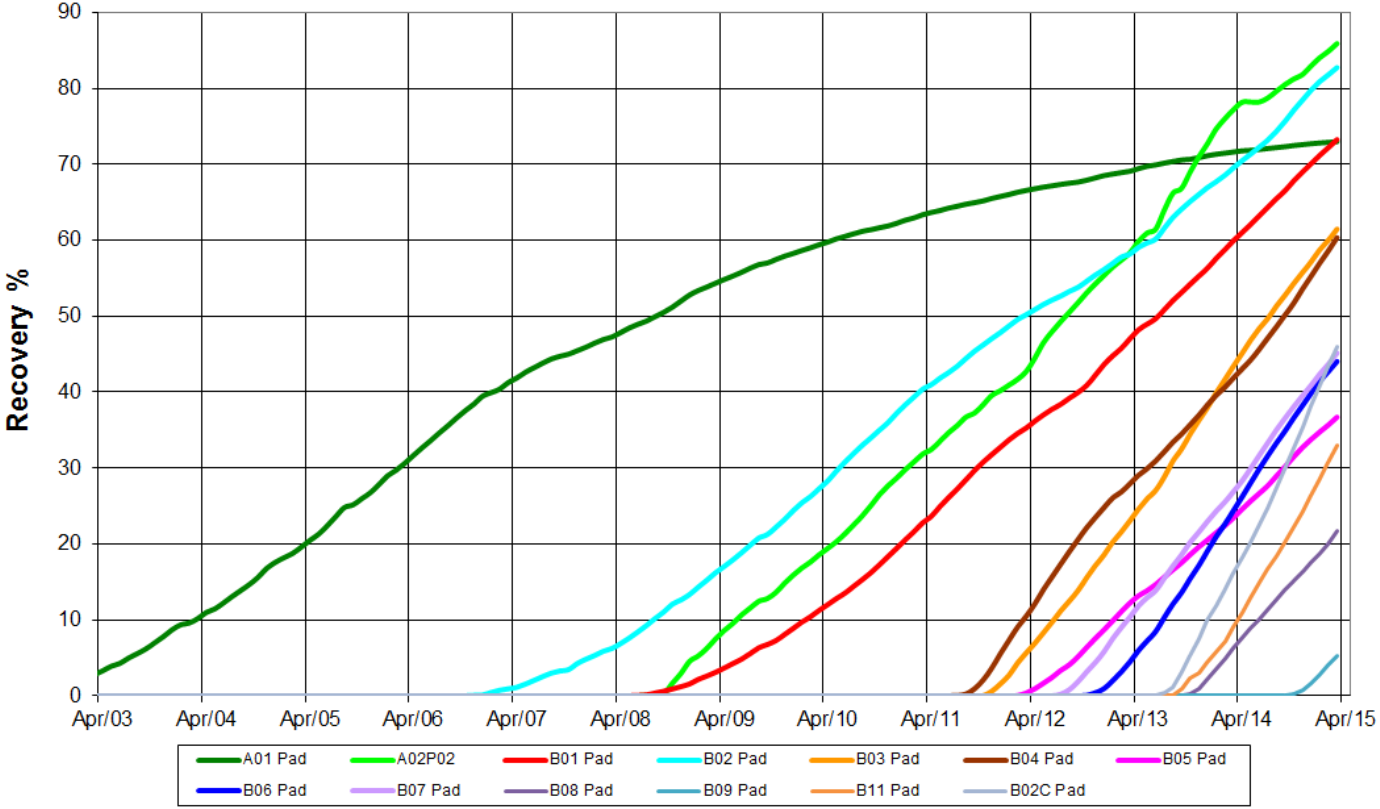
Cumulative % Recovery Based on CVE SAGDable OOIP (SOIP)



Note: For A02 pad, recovery based on 100m spacing drainage box

Christina Lake

Cumulative % Recovery Based on CVE SAGDable OOIP (POIP)

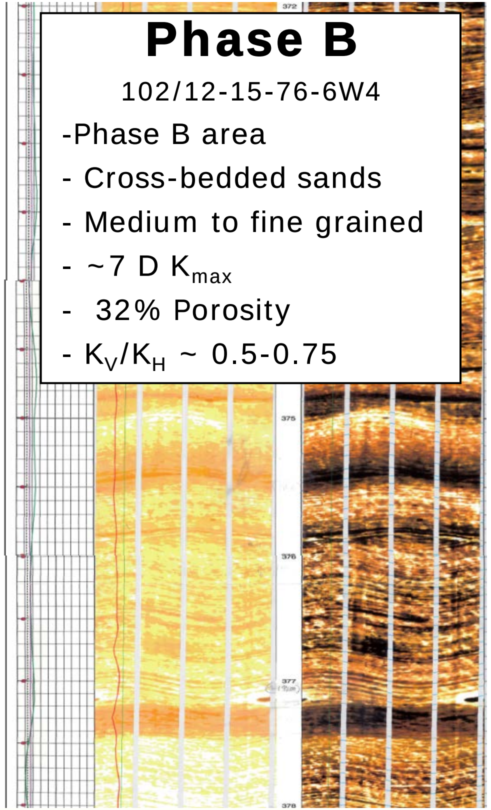


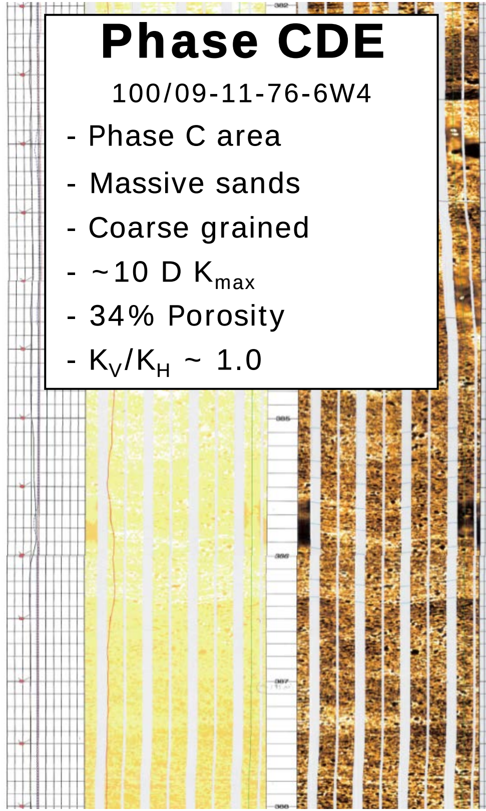
Note: For A02 pad, recovery based on 100m spacing drainage box

Varying reservoir quality pad patterns

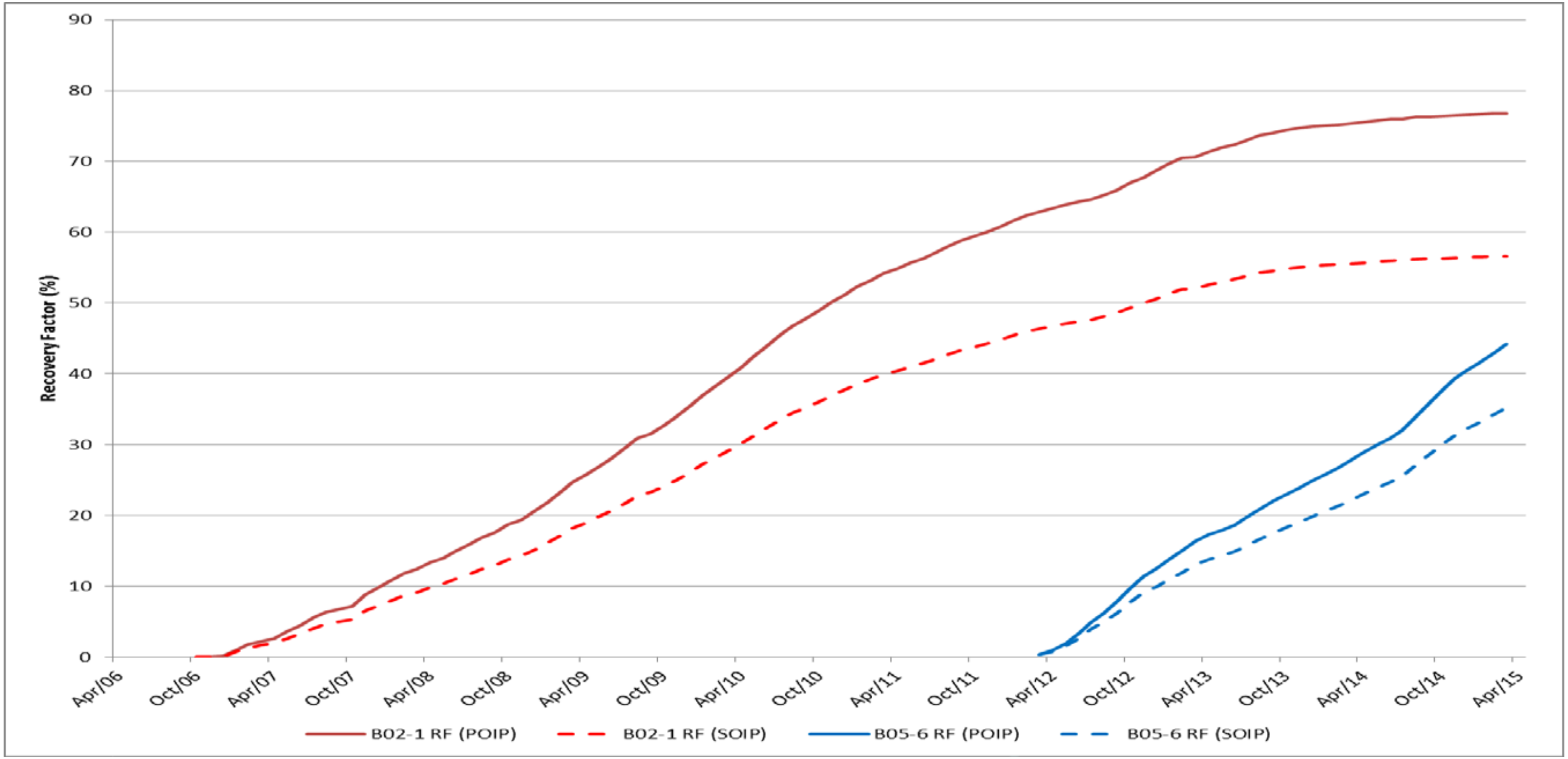
Two example well pairs provided in Subsection 3.1.1 – 7b) illustrate:

- B05-6: High reservoir quality
- B02-1: Medium reservoir quality
- Expect the same ultimate recovery long-term

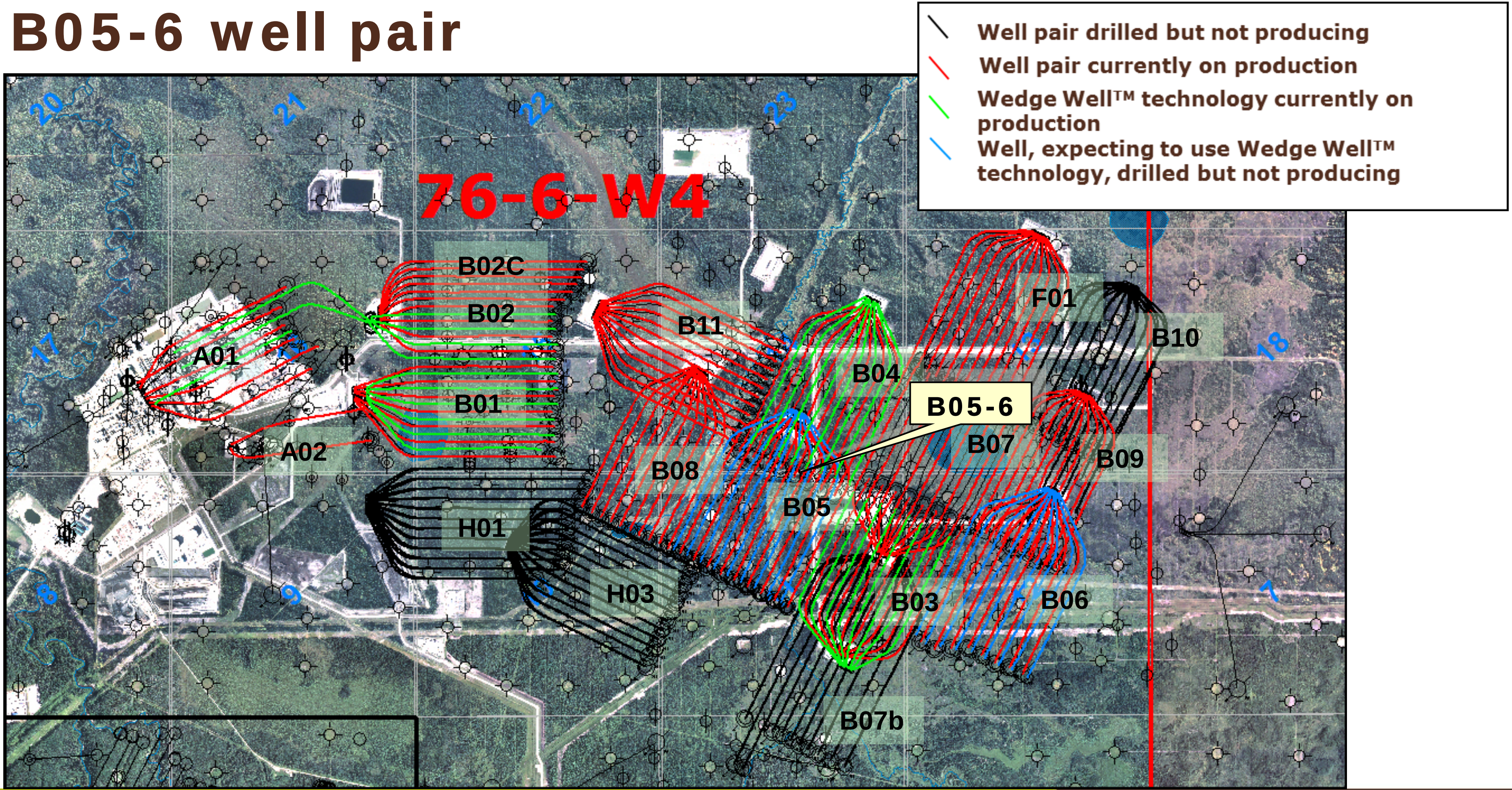


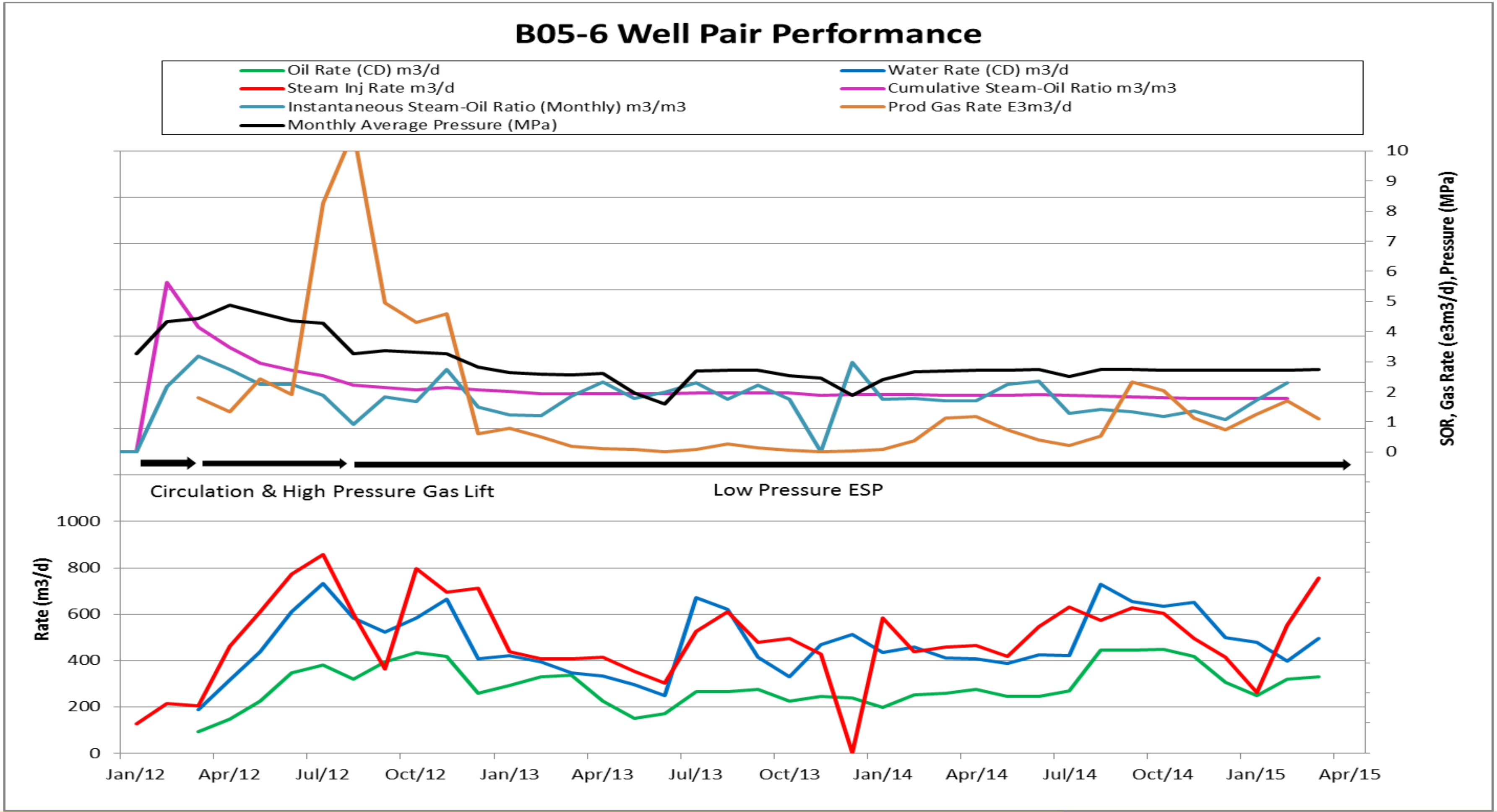


Cumulative % recovery B02-1 & B05-6



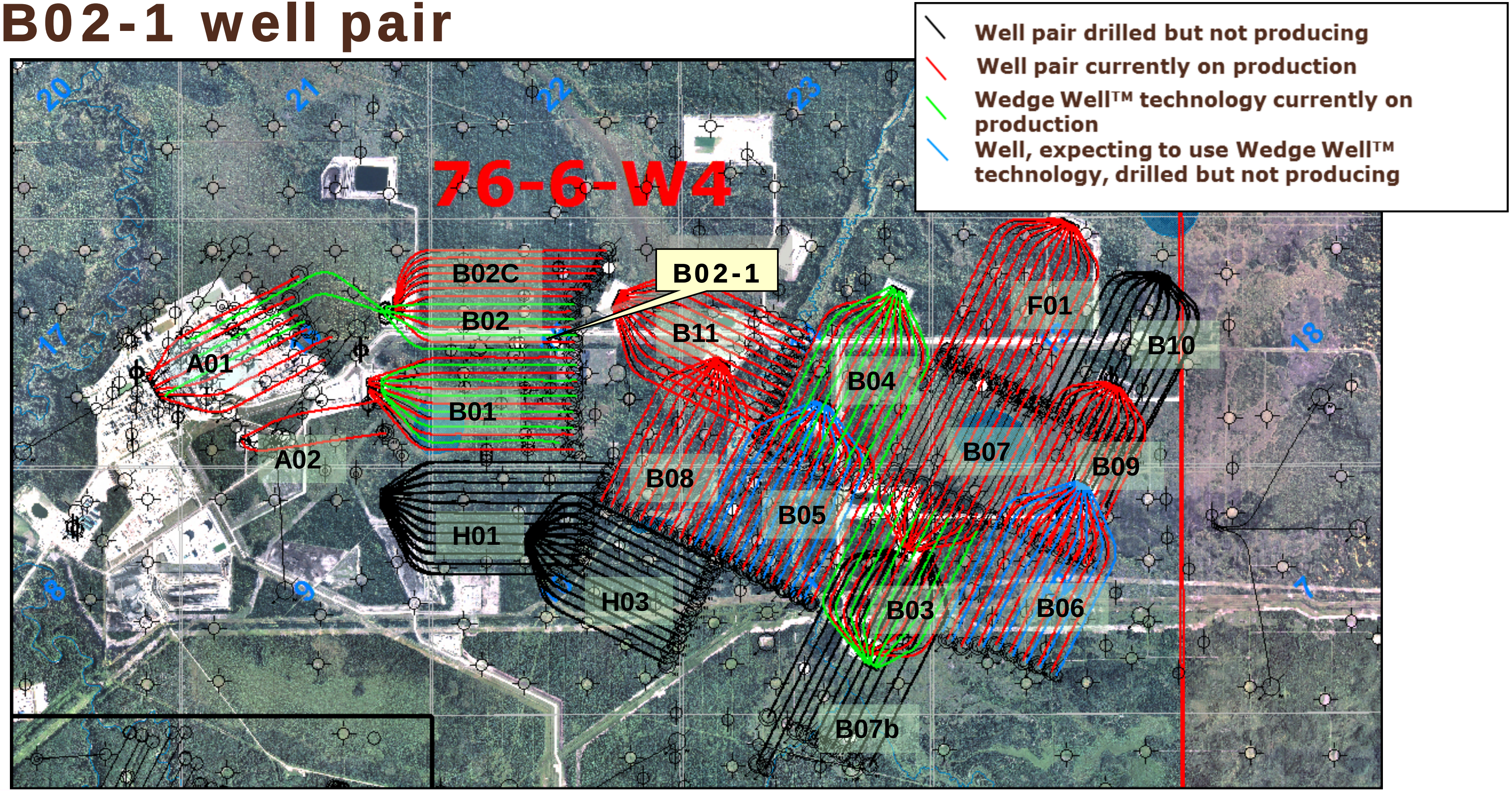
B05-6 well pair





B05-6 Well Pair Performance
Oil Rate (CD) m3/d
Water Rate (CD) m3/d
Steam Inj Rate m3/d
Cumulative Steam-Oil Ratio m3/m3
Instantaneous Steam-Oil Ratio (Monthly) m3/m3
Prod Gas Rate E3m3/d
Monthly Average Pressure (MPa)
Circulation & High Pressure Gas Lift
Low Pressure ESP
SOR, Gas Rate (e3m3/d), Pressure (MPa)
Rate (m3/d)
10
9
8
7
6
5
4
3
2
1
0
1000
800
600
400
200
0
Jan/12
Apr/12
Jul/12
Oct/12
Jan/13
Apr/13
Jul/13
Oct/13
Jan/14
Apr/14
Jul/14
Oct/14
Jan/15
Apr/15

B02-1 well pair



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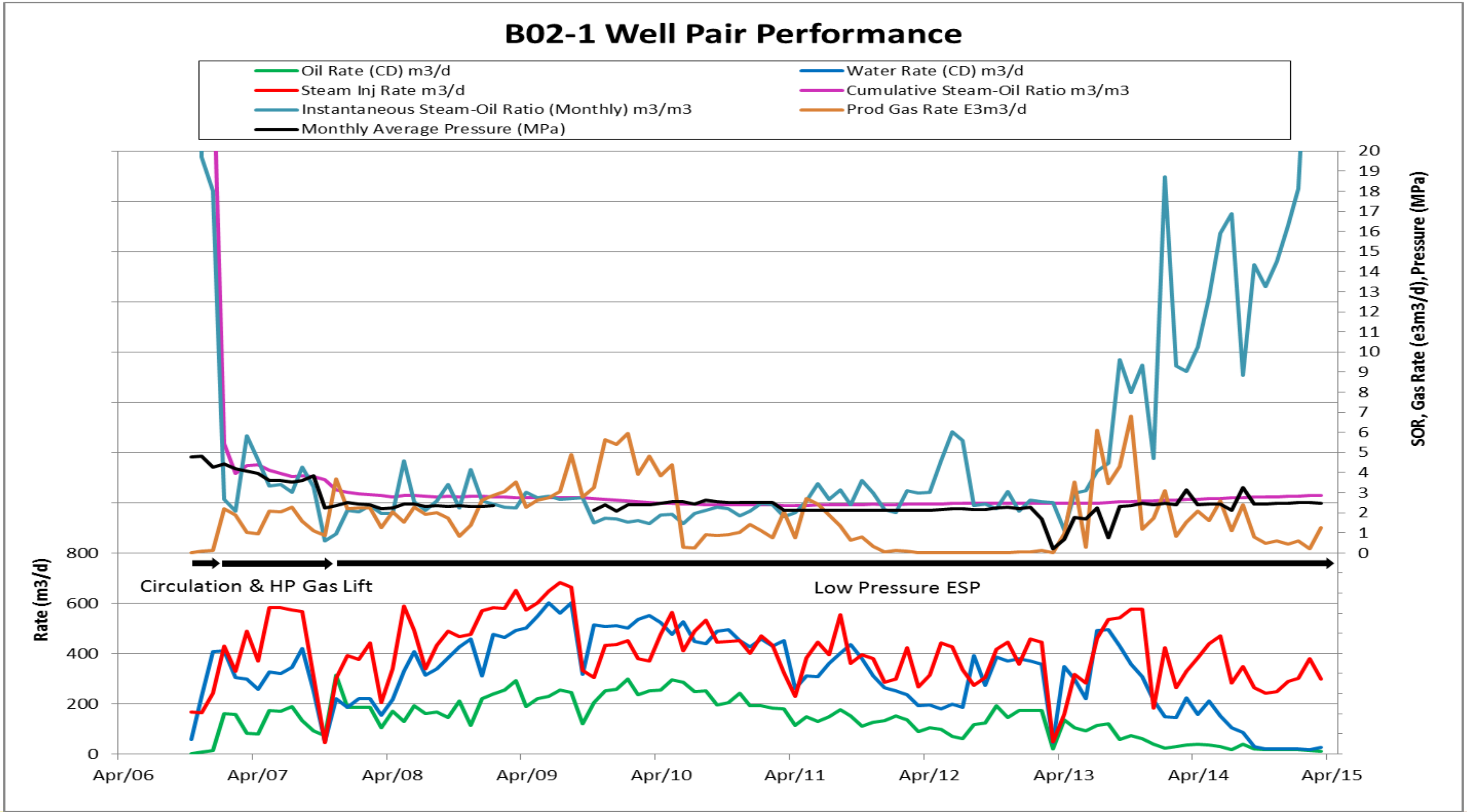
June 24, 2015

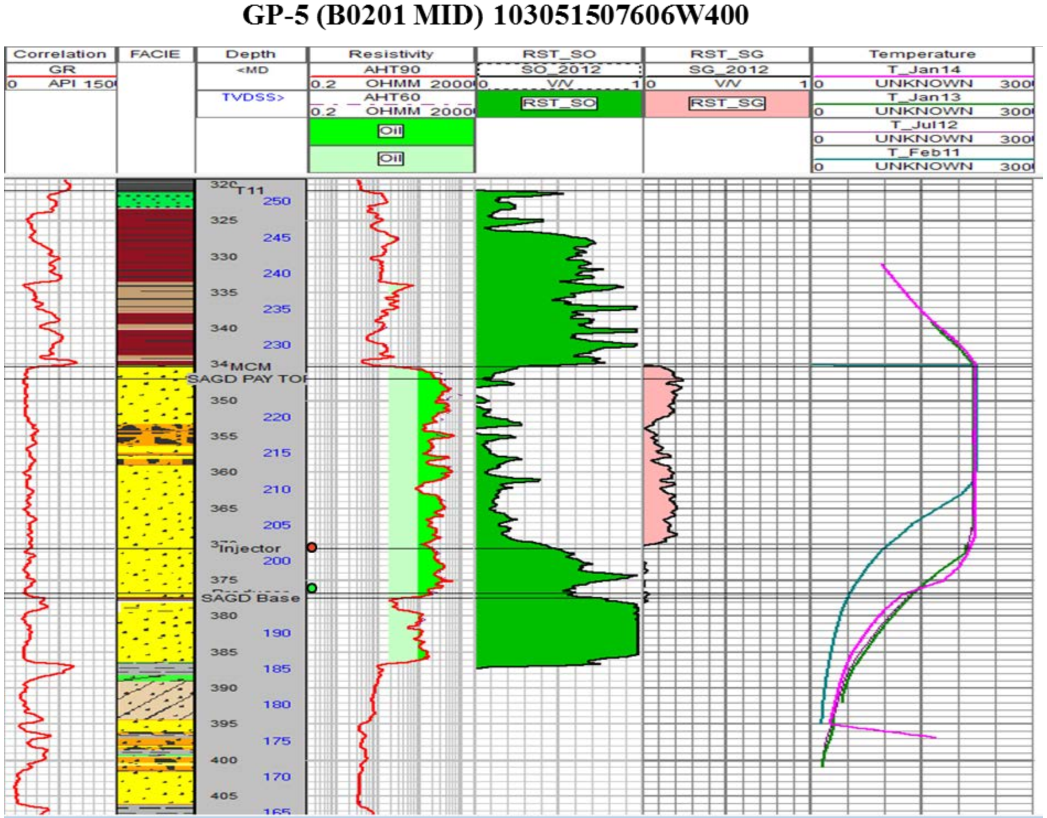

B02-1 Well Pair Performance
Oil Rate (CD) m3/d
Water Rate (CD) m3/d
Steam Inj Rate m3/d
Cumulative Steam-Oil Ratio m3/m3
Instantaneous Steam-Oil Ratio (Monthly) m3/m3
Prod Gas Rate E3m3/d
Monthly Average Pressure (MPa)
Rate (m3/d)
SOR, Gas Rate (e3m3/d), Pressure (MPa)
Circulation & HP Gas Lift
Low Pressure ESP
0
200
400
600
800
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
Apr/06 Apr/07 Apr/08 Apr/09 Apr/10 Apr/11 Apr/12 Apr/13 Apr/14 Apr/15

B02-1 iSOR in 2014

Why is B02P01 iSOR so high in 2014?

- **Declining production rates – has been declining since 2010**
- **Has produced over 2,700,000 bbl of oil**
- **Recovery rates of 76%**
- **Decline further accelerated by the B02W03 and B02W06 start ups**
- **Continue to maintain steam rates for B02 pad pressure support and blowdown trial baseline.**
- **B02 Pad is operated on a pad level – not overly concerned with an individual well having a high iSOR on this pad**

B02-1 well pair – observation well 103/05-15



Five year outlook – pad abandonments

- There are no anticipated pad abandonments for any of the Christina Lake wells in the next five years.

Wellhead steam quality

- Steam quality will be impacted by pipeline size and distance
- Current steam quality injected into all pads is calculated to be greater than 95%
- Currently steam head pressure is operated at 8.5 MPag with a corresponding steam temperature of 300°C
- Steam quality is not expected to impact well performance at this time

Subsection 3.1.1 – 7e) Injected fluids

Co-injection and blowdown trials

A01 pad methane co-injection

- **Methane co-injection until October 2014**
  - Natural gas was co-injected with steam into A01-1 to 3 and A01-5 & 6
  - The composition of this gas is ~99% pure methane as it is delivered to the wells from our main gas pipeline
  - Due to facility restriction on handling produced gas:
    - gas injection was intermittently shut off for extended periods
    - while co-injecting, gas injection rates were lower than the maximum approved rates
      - typical injection rates were 25 e3m3/d natural gas, 1,000 m3/d steam for the entire pad

A01 pad methane co-injection

- **Methane co-injection experience (2007 - 2014)**
  - Co-injection of methane with steam in SAGD has been demonstrated in the field to improve SOR
  - High percentage of injected methane appears to get produced preventing excessive accumulation in the steam chamber
  - Good understanding of how gas behaves in reservoir
    - allow for increased understanding of drainage from I.H.S

- **Pad partial/full blowdown as of November 2014**
  - Steam shut-in and chamber pressure being increased through methane injection in order to mitigate bottom water influx

A01 partial/full-blowdown on A01 pad

- **Pad partial/full blowdown as of November 2014**
  - November 2014: steam ramp down began on the entire pad
  - February 2015: full steam shut-in to all wells on the pad. Pressure maintenance continued through natural gas injection.
    - current chamber average operating pressure ~ 2100 kPa_g
    - so far no negative impact has been observed with the pad operations as a result of full methane injection. It's too early to comment on the trial performance
    - average concentration for Nov 2014 – March 2015
      - average methane injection rate 16 e3m3/d
      - CSOR has been maintained at 2.53 from November 2014 to March 2015 following a steady increase prior to steam ramp down

A01 pad general co-injection / blowdown performance

A01 pad phases of operation

Period	RF (%) (SOIP)	RF (%) (POIP)	CSOR (v/v)
Dec ’05 – Dec ’06 (co-injection: 12 months)	20.7 – 29.4 *(0.73%/mo)*	27.8 – 39.5 *(0.98%/mo)*	2.47 – 2.37
Dec ’06 – Dec ’07 (SAGD: 12 months)	29.4 – 34.2 *(0.40%/mo)*	39.5 – 45.9 *(0.53%/mo)*	2.37 – 2.36
Dec ’07 – Oct ’14 (intermittent/limited co-injection: 82 months)	34.2 – 54.0 *(0.24%/mo)*	45.9 – 72.5 *(0.32%/mo)*	2.36 – 2.53
Nov ’14– Mar ’15 (ramp/blowdown: 5 months)	54.0 – 54.4 *(0.08%/mo)*	72.5 – 73.0 *(0.1%/mo)*	2.53 – 2.53

B01/B02 pad rampdown/blowdown pilot

Conduct a temporary wind-down test on B01 and B02 pads

- timeframe: 6 months – 1 year
- well pairs: B02-1 to B02-4 ; B01-1 to B01-4
- steam will be brought back on after test is complete

B01-1 to B01-4: Blowdown test (6 month test)

- shut-in steam on all four wells
  - using gas cap (top down blowdown) to maintain pressure
- current pad RF: 73% POIP

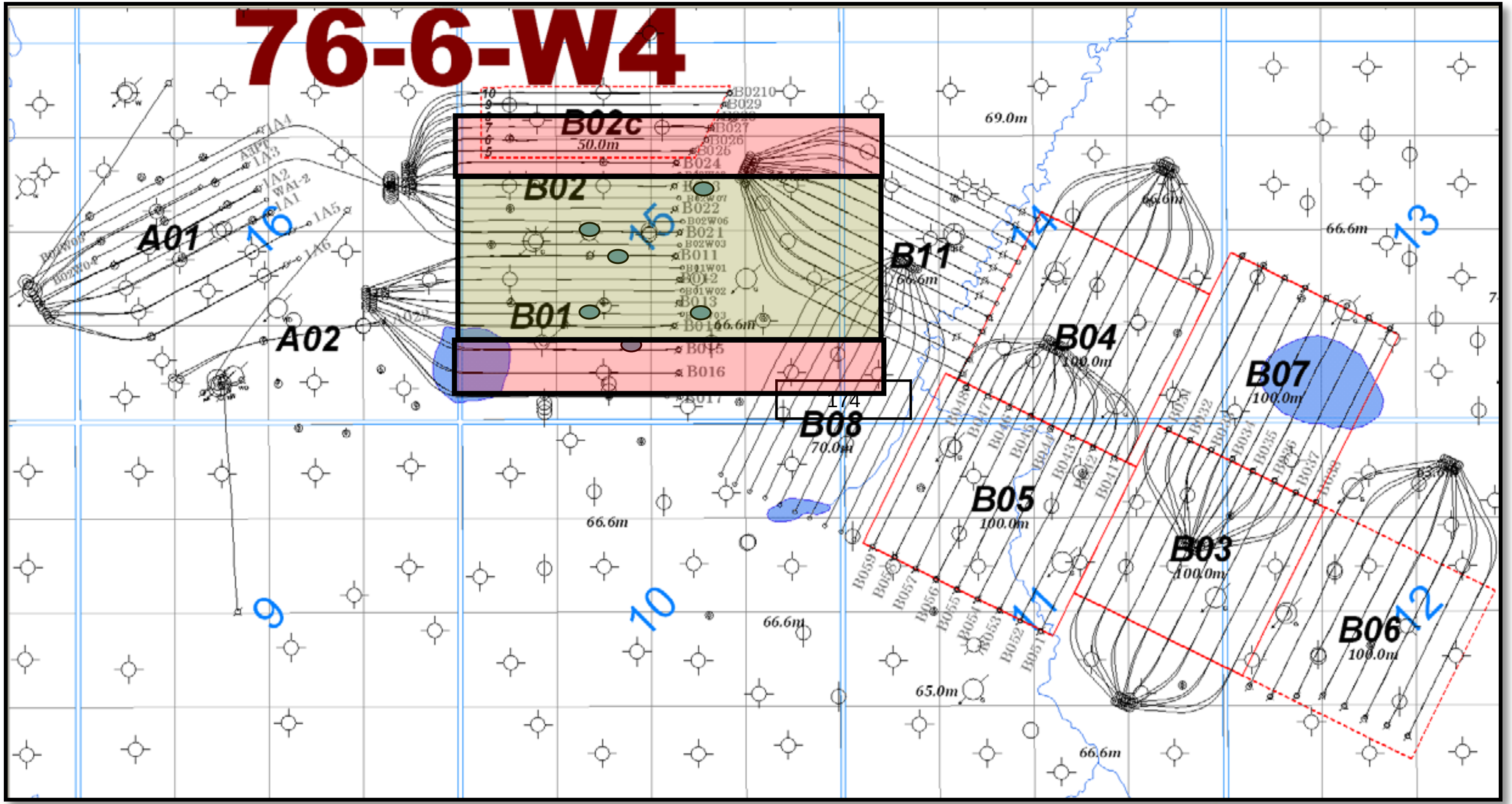
B02-1 to B02-4: Steam ramp-down test (1 year test)

- cut steam by 25% every 3 months (75%, 50%, 25%, 0%)
- current pad RF: 83% POIP

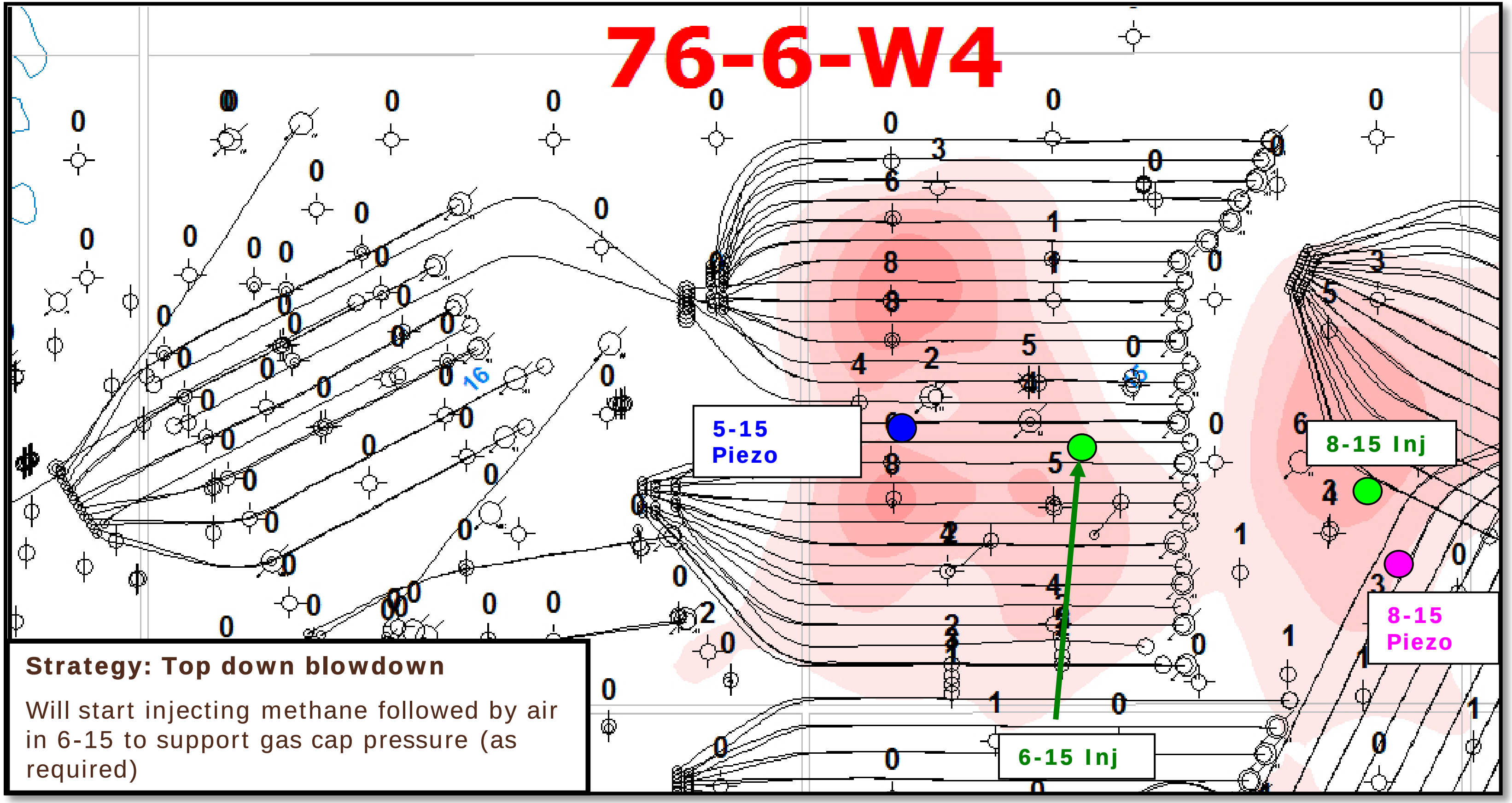
Planned start date: June 2015

- currently re-pressuring gas cap to ~2500 kPag in order to be in balance with bottom water
- steady SAGD operations to be continued until the wind-down test is started in mid-June 2015

B01/B02 pad rampdown/blowdown pilot location



B01/B02 pad rampdown/blowdown test setup



Strategy: Top down blowdown

Will start injecting methane followed by air in 6-15 to support gas cap pressure (as required)

Subsection 3.1.1 – 7e) Injected fluids

A02-2 SAP project

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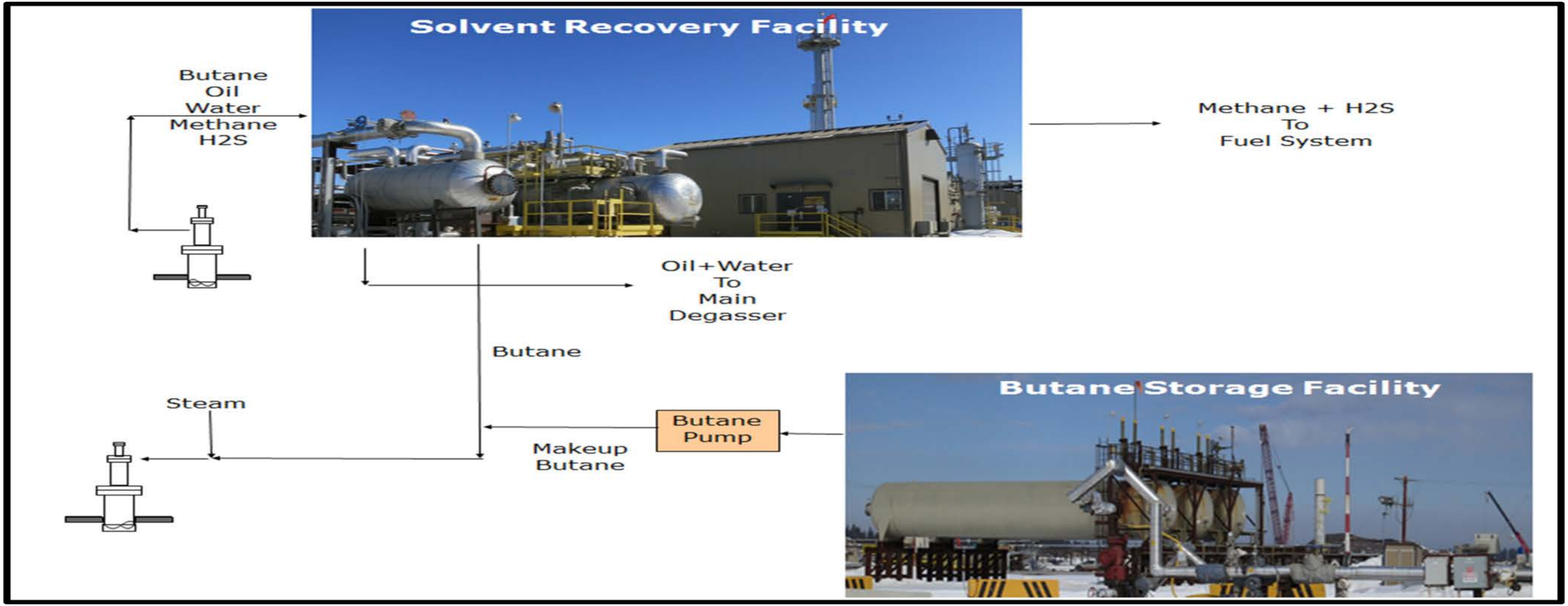
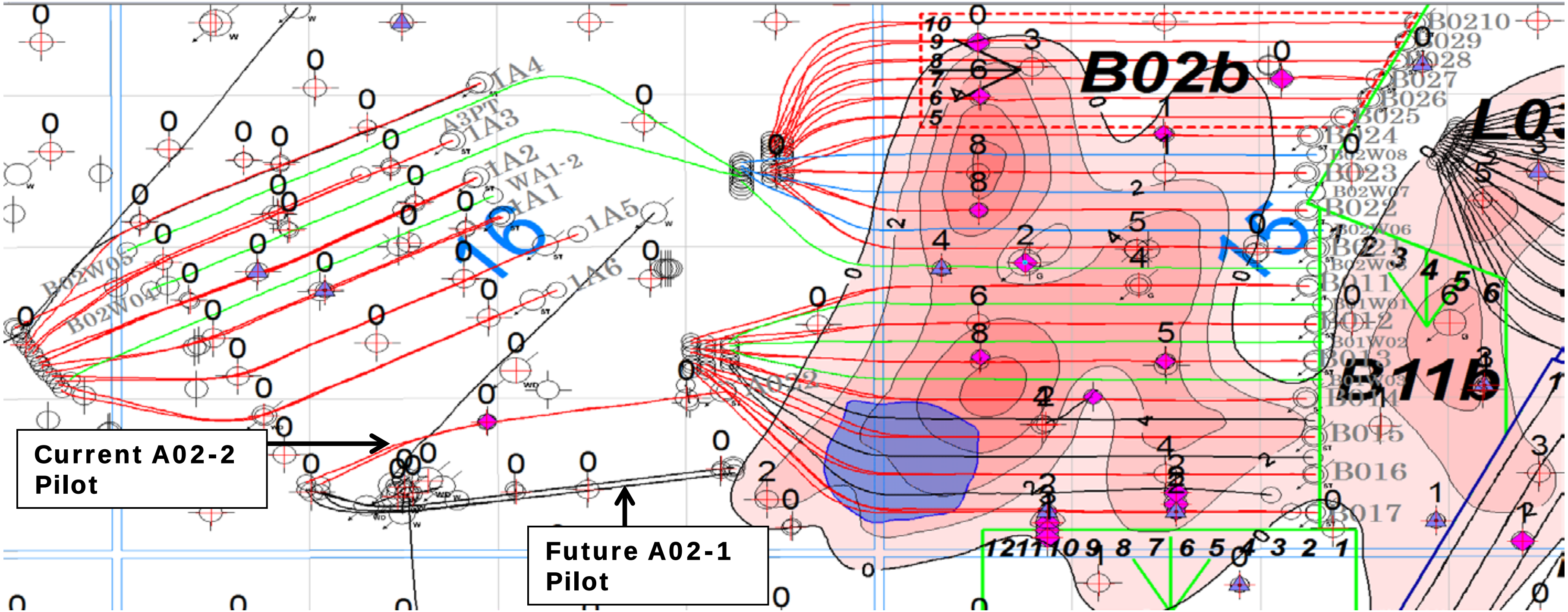
What is SAP?

- Solvent-aided process is a technological enhancement applied to our SAGD operations that helps us maximize the amount of oil recovered. Small amounts of solvent such as light alkanes (e.g. butane) or natural gas liquids are co-injected with steam to enhance the oil recovery process and improve associated project economics.
- Solvents primarily decrease SOR, thereby reducing the water usage. Reduction in water usage means lower CAPEX and OPEX required to process the water.
- Reduced water usage leads to fewer GHG emissions, and smaller footprint
- Solvents accelerate the oil production rate and reduce the steam usage, leading to a lower SOR, increased revenue and increased reserves. A02-2 SAP at CL : 30% SOR reduction and 20% increase in production
- Co-injection of light alkanes along with steam allows for wider well spacing, which leads to smaller footprint, lower capital cost and higher revenue

SAP process

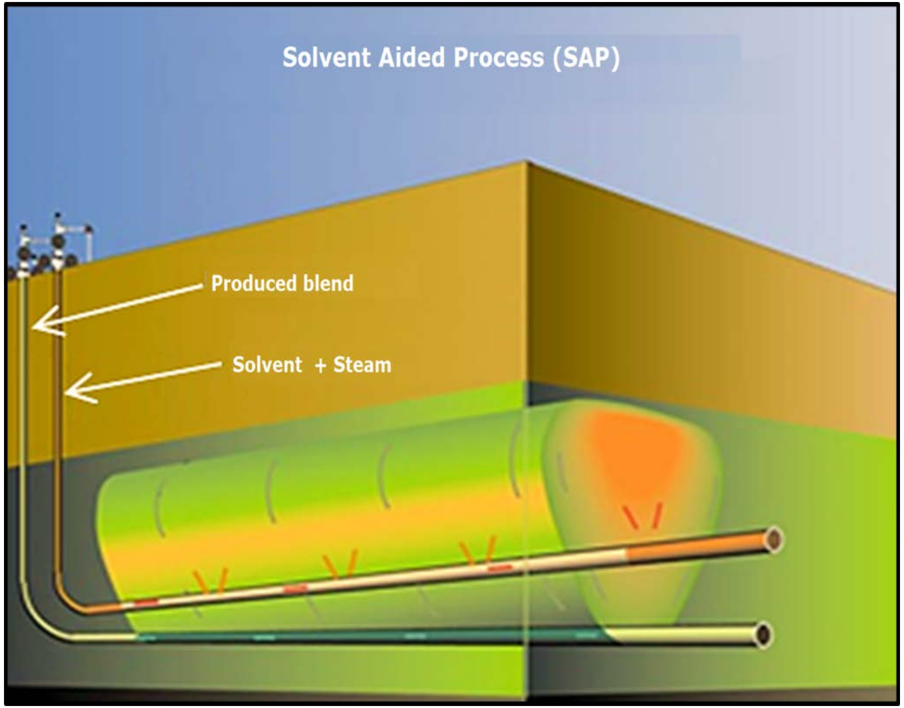

Solvent Recovery Facility
Butane
Oil
Water
Methane
H2S
Methane + H2S
To
Fuel System
Oil+Water
To
Main
Degasser
Butane
Steam
Butane
Pump
Makeup
Butane
Butane Storage Facility

A02 pad SAP

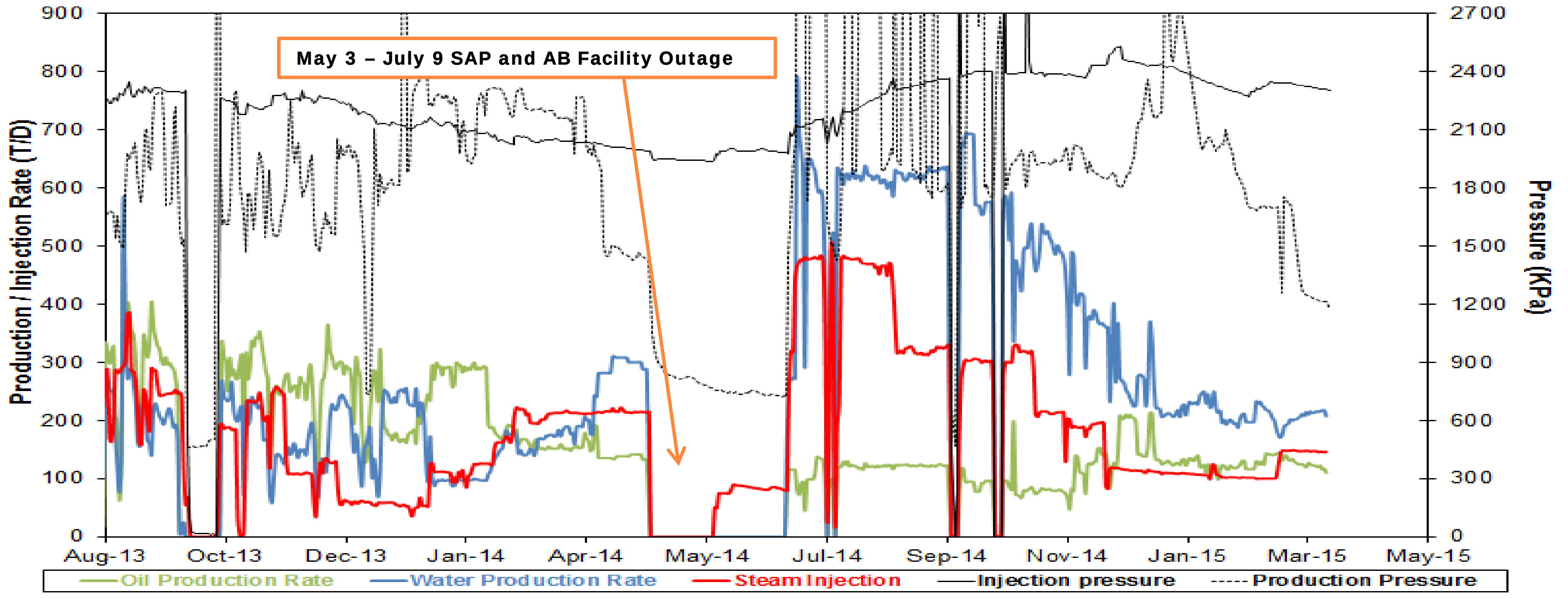

B02b
B11b
B02W05
B02W04
B0210
B029
B028
B027
B026
B025
B024
B02W08
B023
B02W07
B022
B02W06
B016
B017
1A4
A3PT
1A3
1A2
WA1-2
1A1
1A5
1A6
A022
Current A02-2 Pilot
Future A02-1 Pilot

Current A02-2 pilot

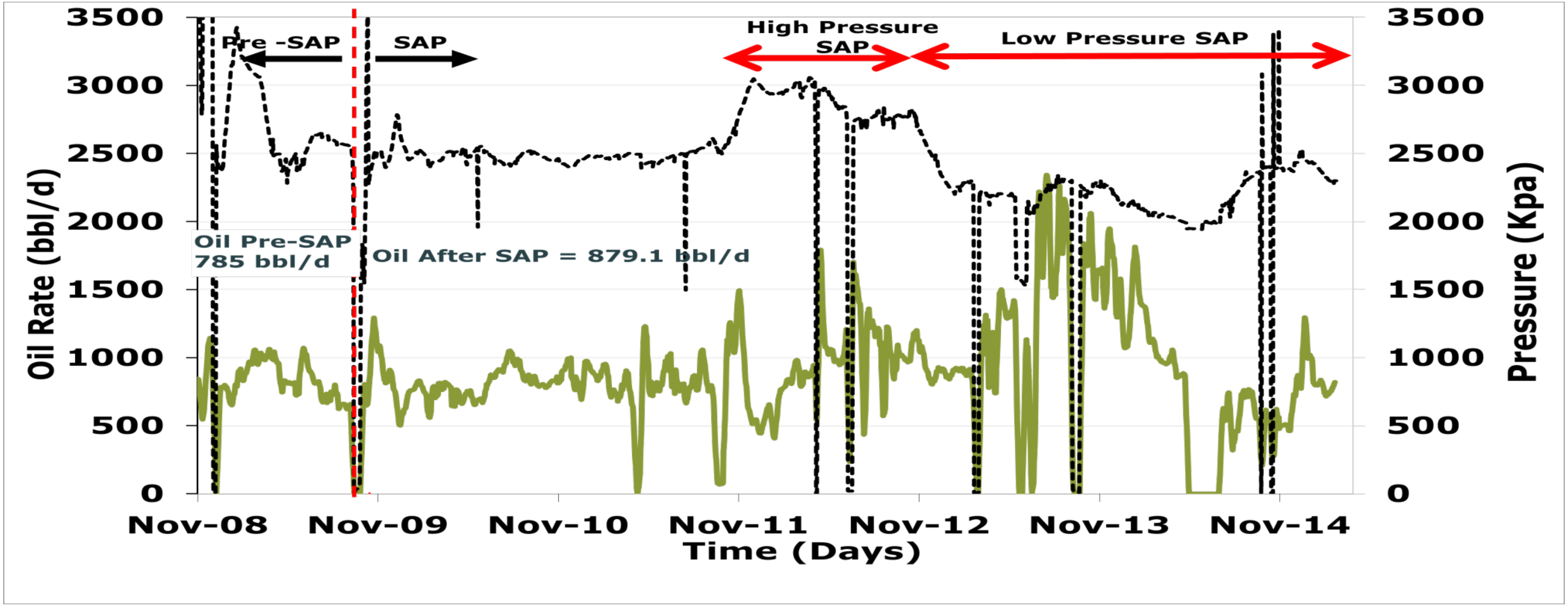
- Currently in low pressure ESP phase
- Injector BHP avg 2325 kPa
- Recycled butane injection only, no make-up butane at this time
- Will transfer butane injection over to A02-1
- Received blowdown approval on A02-2



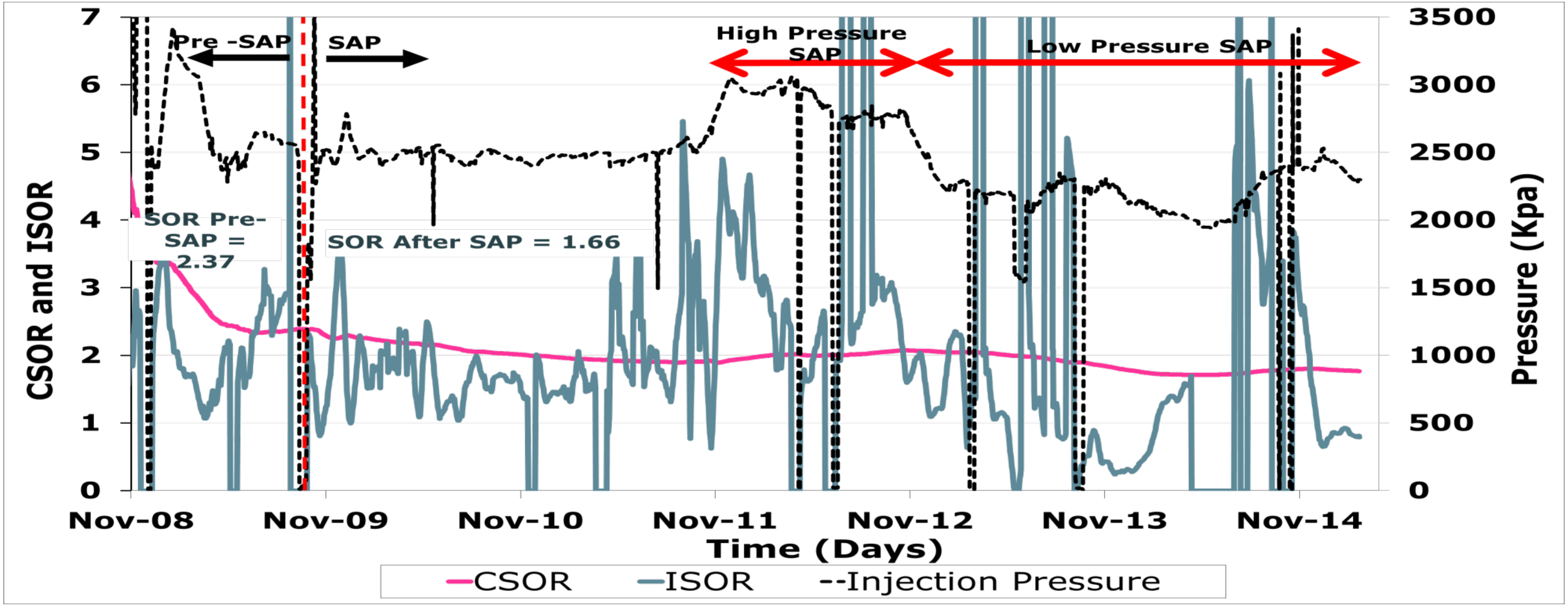
A02-2 production



Pre and post A02-2 well: oil production



Pre and post SAP A02-2 well: CSOR and ISOR



A02-2 Conclusions

- We believe SAP has resulted in lower than usual SOR
- We believe SAP has resulted in faster steam chamber lateral growth that could affect future well spacing
- Current butane recovery is 65% and will increase during blowdown (we do not believe that we have lost much butane to thief zones)
- We believe that SAP has not resulted in dramatically higher rates due to geology and well profile

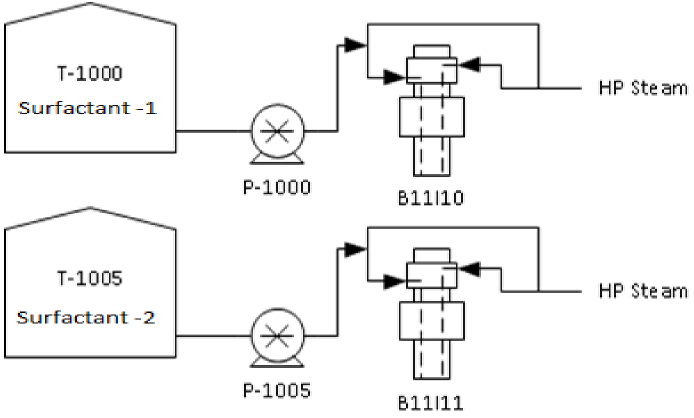
Subsection 3.1.1 – 7e) Injected fluids

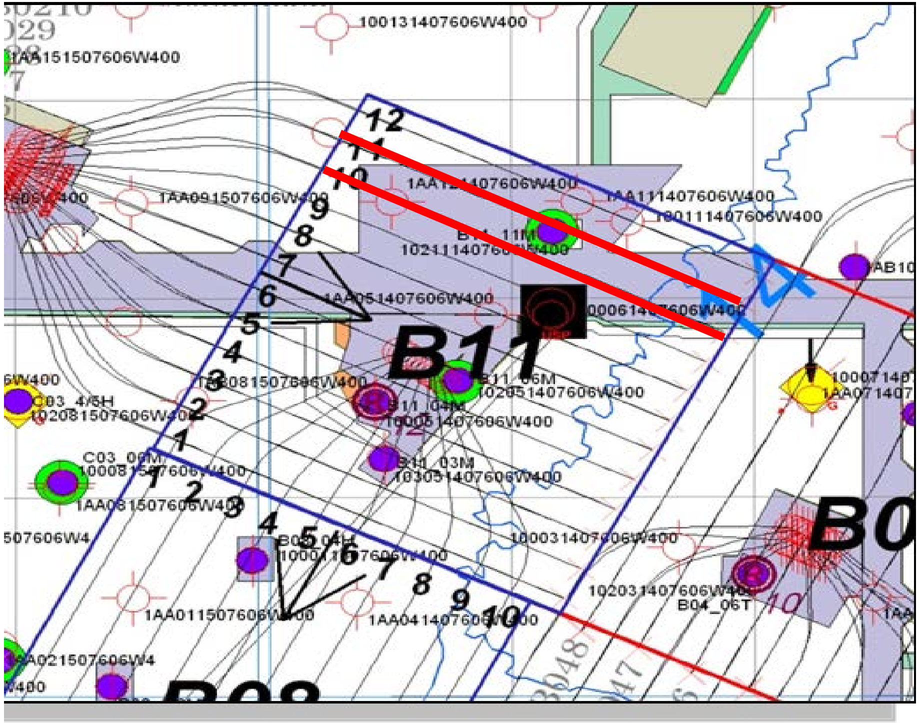
Surfactant steam Process (SSP) pilot

SSP pilot description

Surfactant steam process (SSP)

Co-inject surfactant at <0.30 wt% of steam rate





June 24, 2015

SSP well operation overview

- **July 2013** – First Steam
- **August 2013** – Conversion to gas lift
- **November 2013** – HP ESP (4000 kPa BHP)
- **January 2014** – Surfactant-steam co-injection begins

    Surfactant-1 → B11-10
    Surfactant-2 → B11-11

- **June 2014**- Present – LP ESP (2800 kPa BHP)
- Results are promising, however steam chambers have communicated with neighboring wells and the overlaying gas cap, therefore more results are required
- Plan to continue the pilot to the end of 2015

Subsection 3.1.1 – 7e) Injected fluids

B01-7 condenSAP

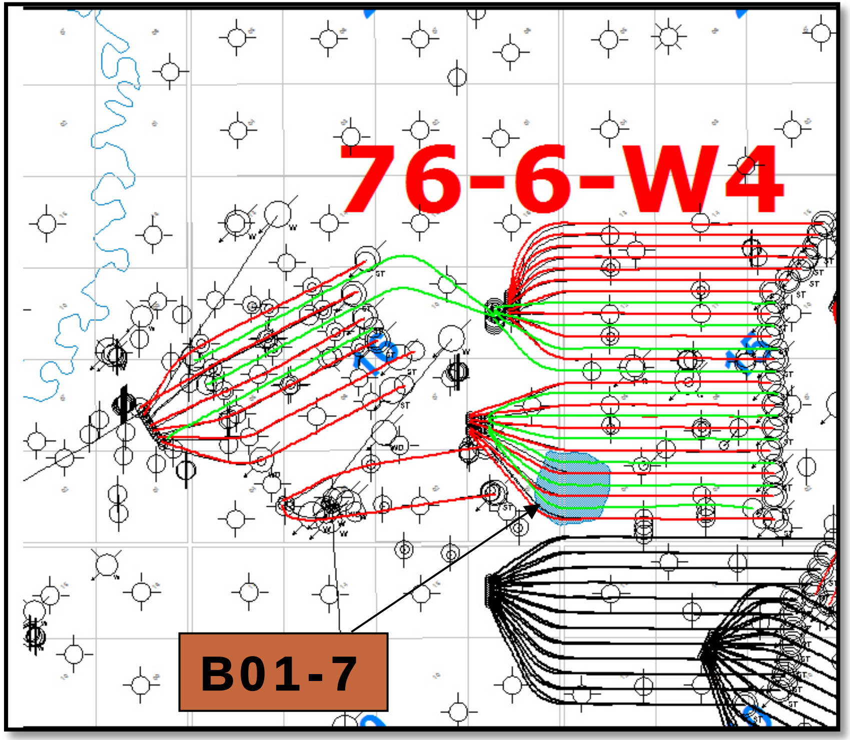
CondenSAP pilot

CondenSAP

- Using condensate mix as solvent

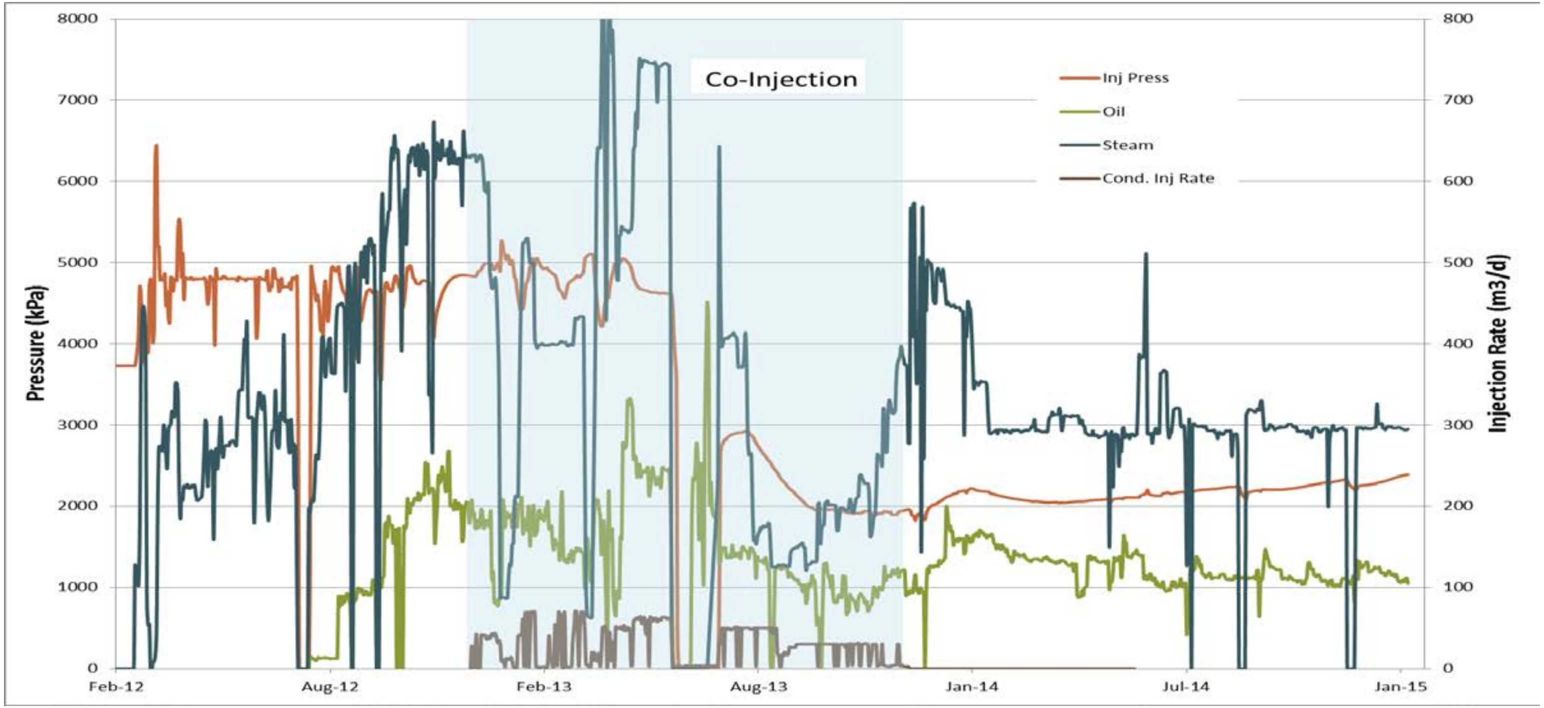
B01-7 CondenSAP

- Well pair currently operating on ESP
- Solvent injection: December 2012 to December 2013
- Currently bringing pressure in balance with gas cap



	Result	Comments
Cum. wt% solvent injected	5%	Solvent injection limited by vapour handling capacity and treating upsets in central processing facility (CPF).
Cum. solvent recovery (%)	15%	Solvent production limited by losses to top gas zone.

B01-07 production/steam



Condensate injection from 12-06-2012 to 12-08-2013

CondenSAP conclusions

- Relatively poor geology and facility issues have not allowed steady operation nor steady injection of condensate

- Pressure readings suggest that we have connected to the neighbouring gas cap
  - This would explain the low solvent recovery

- We do not have conclusive results from this pilot and it may have to be repeated

Subsection 3.1.1 – 7e) Injected fluids

B05-8 rise rate control test

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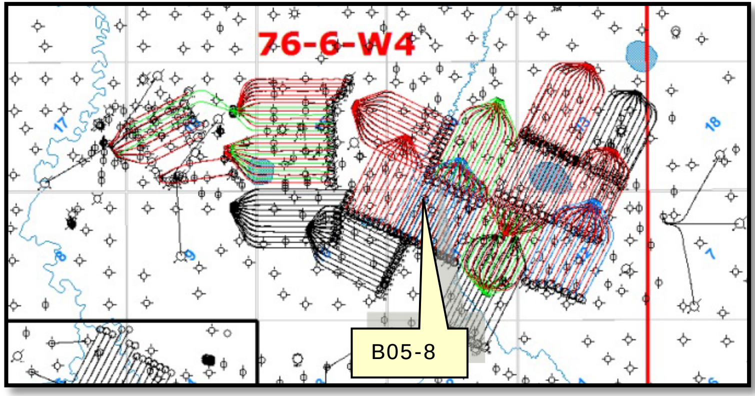
Rise rate pilot



- Location of rise rate pilot was moved to B05-8
- Modifications to the design were required in order to make the compressor system operational
- Intent of pilot was to inject air and steam during the chamber rise phase:
  - monitor if/how the shape of the chamber differs from regular SAGD as it grows vertically
  - monitor changes in the rate of steam rise
- B05-8 steam chamber has connected to gas cap under regular SAGD ops
  - rise rate control opportunity missed on B05-8
  - no plan to progress pilot in 2015
  - continue to evaluate future locations for the rise rate pilot

Subsection 3.1.1 – 7f)
2014 key learnings

Operating SAGD with top gas, bottom water

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Operations at Christina Lake

Thief zones:

- B01 to B11 pad are operating under a gas cap
- A01, B01 to B09 and B11 Pads have areas where Regional Bottom Water (BW) present with no shale break separating oil and BW

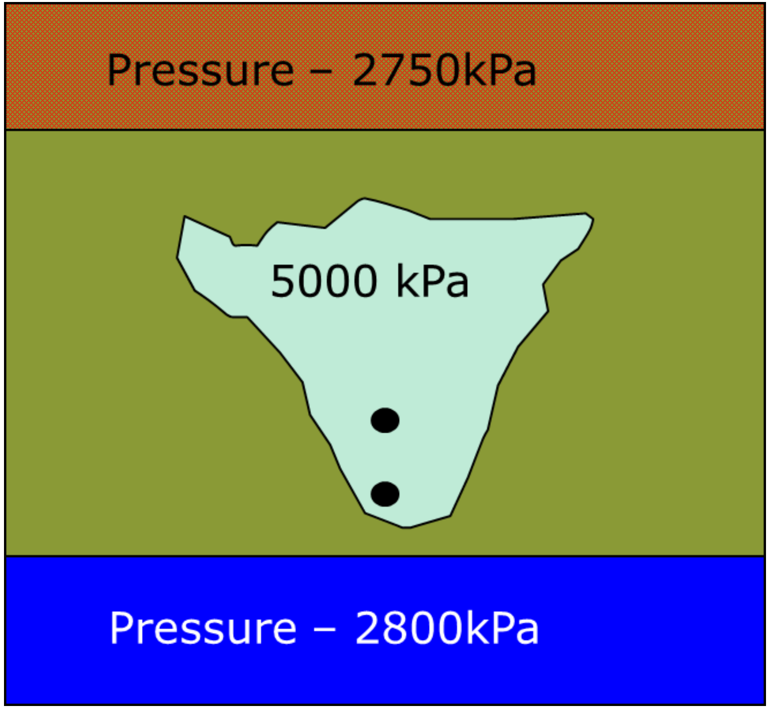
Well performance of these two situations will be discussed:

- gas cap communication only
- bottom water and gas cap communication

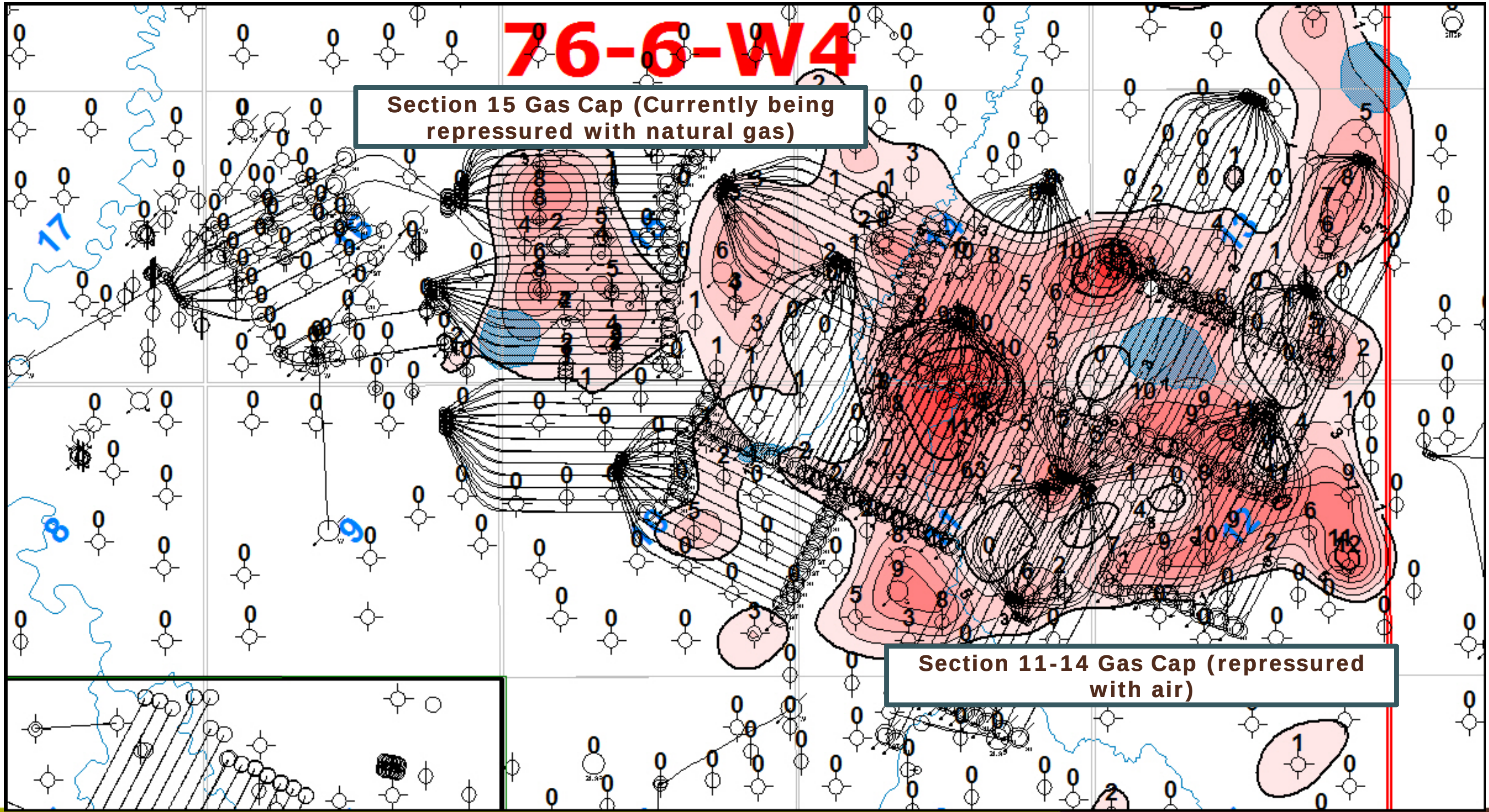
High pressure operations

For high pressure operations, the SAGD chamber has to be isolated from other zones

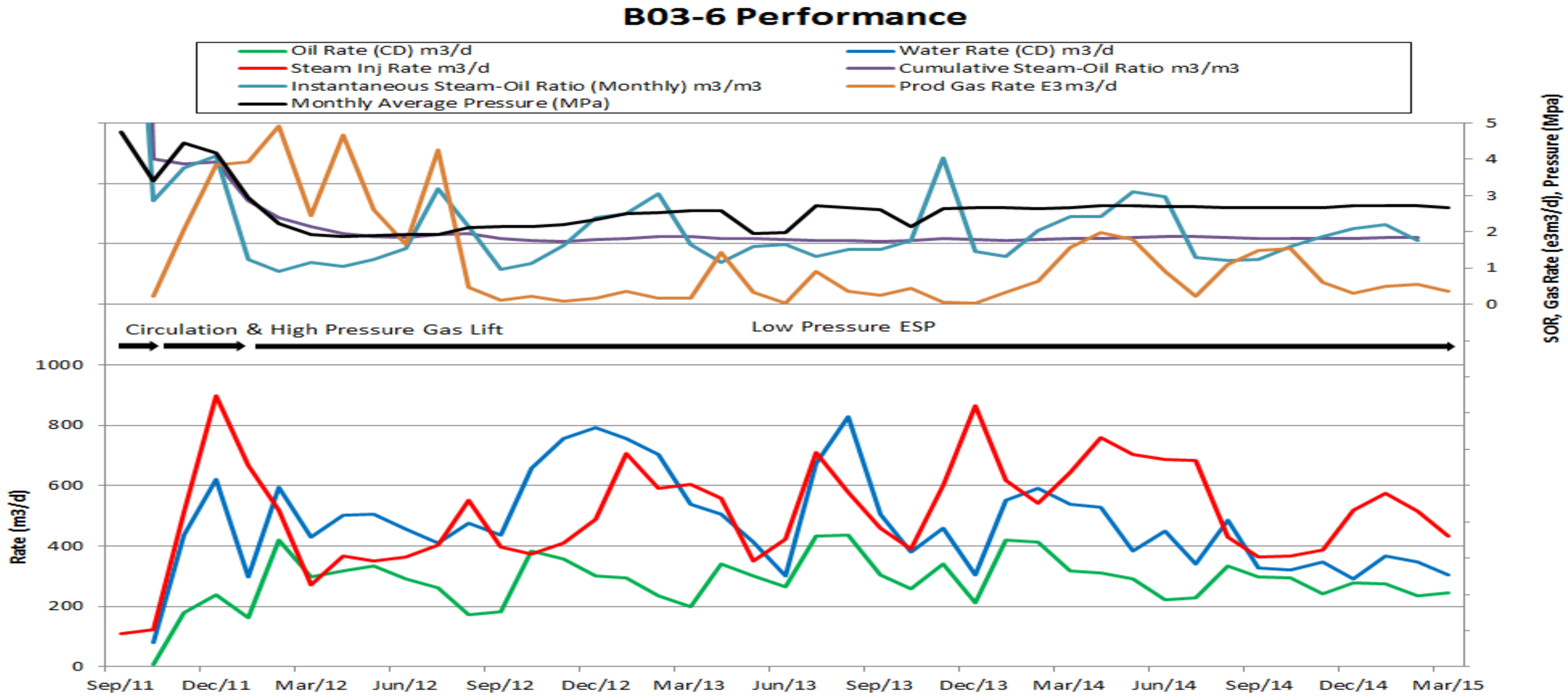
- no gas cap or bottom water contact



Gas cap at Christina Lake



B03-6: Gas Cap Communication



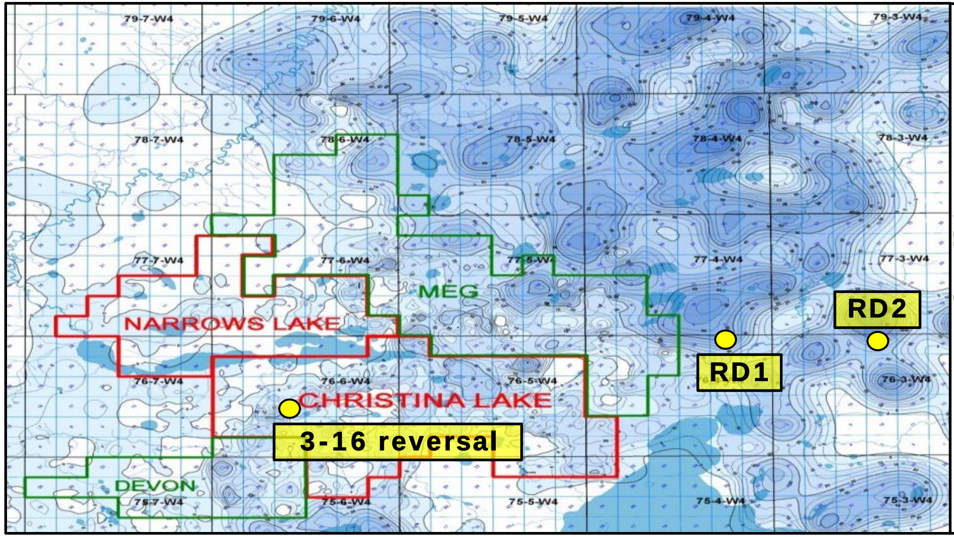
Bottom Water Pressure Influence

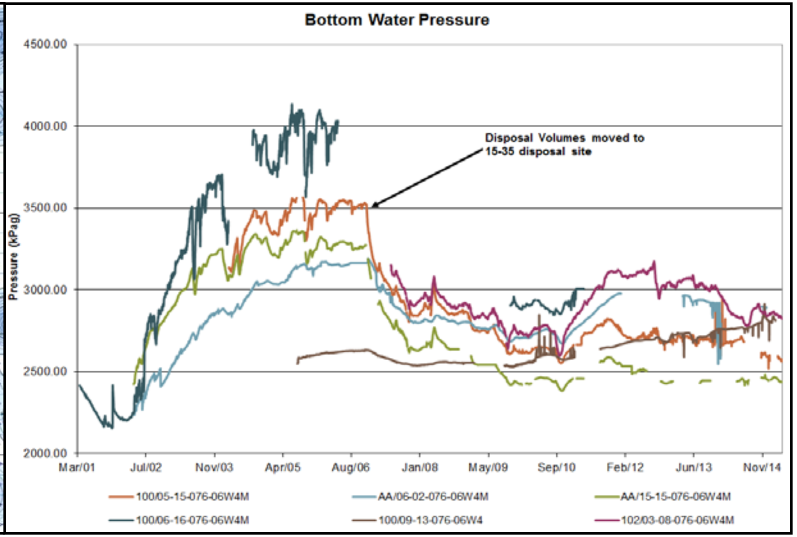
2002-2006: Historical disposal into the local bottom water aquifer caused an increase to bottom water pressure

- moved disposal to remote location (15-35-076-06W4, 28 km from CPF) and saw immediate and significant drop in aquifer pressure

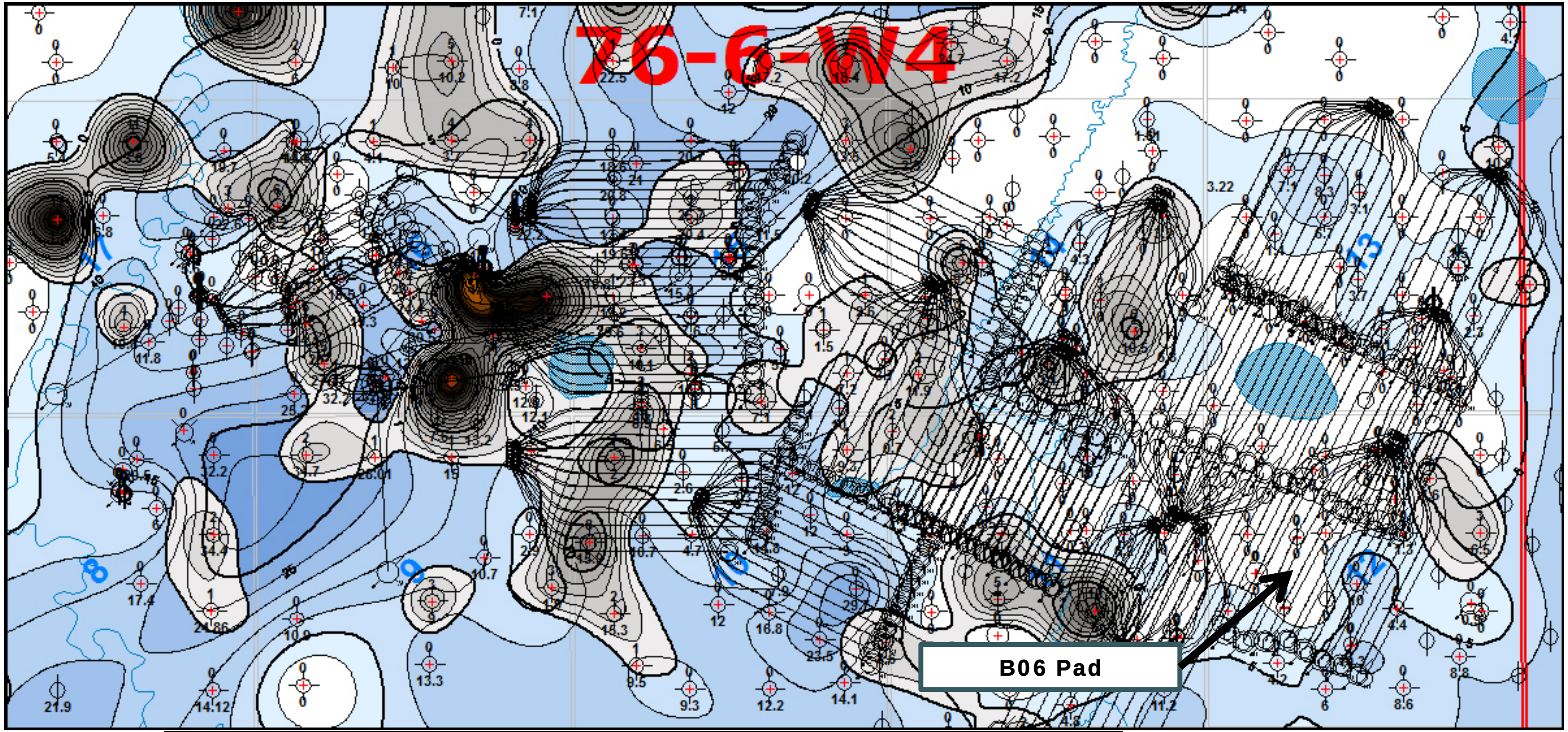
2010-2014: Regional activity from neighboring operators caused an increase to bottom water pressure

- reversed 1F5/3-16-076-06W4 local disposal well to a water production well
- developing an integrated strategy with regional partners to manage bottom water pressure





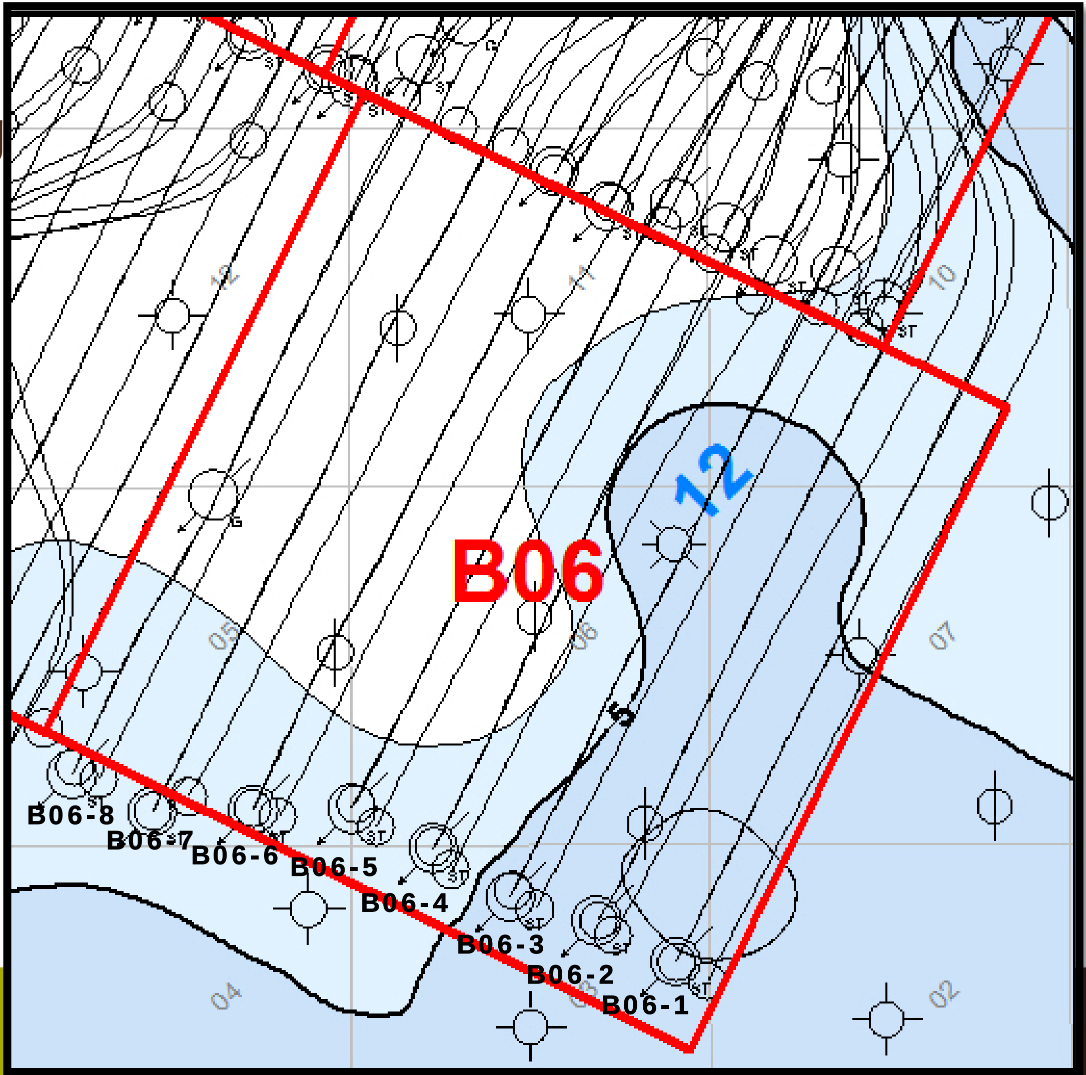
B06 Pad – Bottom water with no isolation



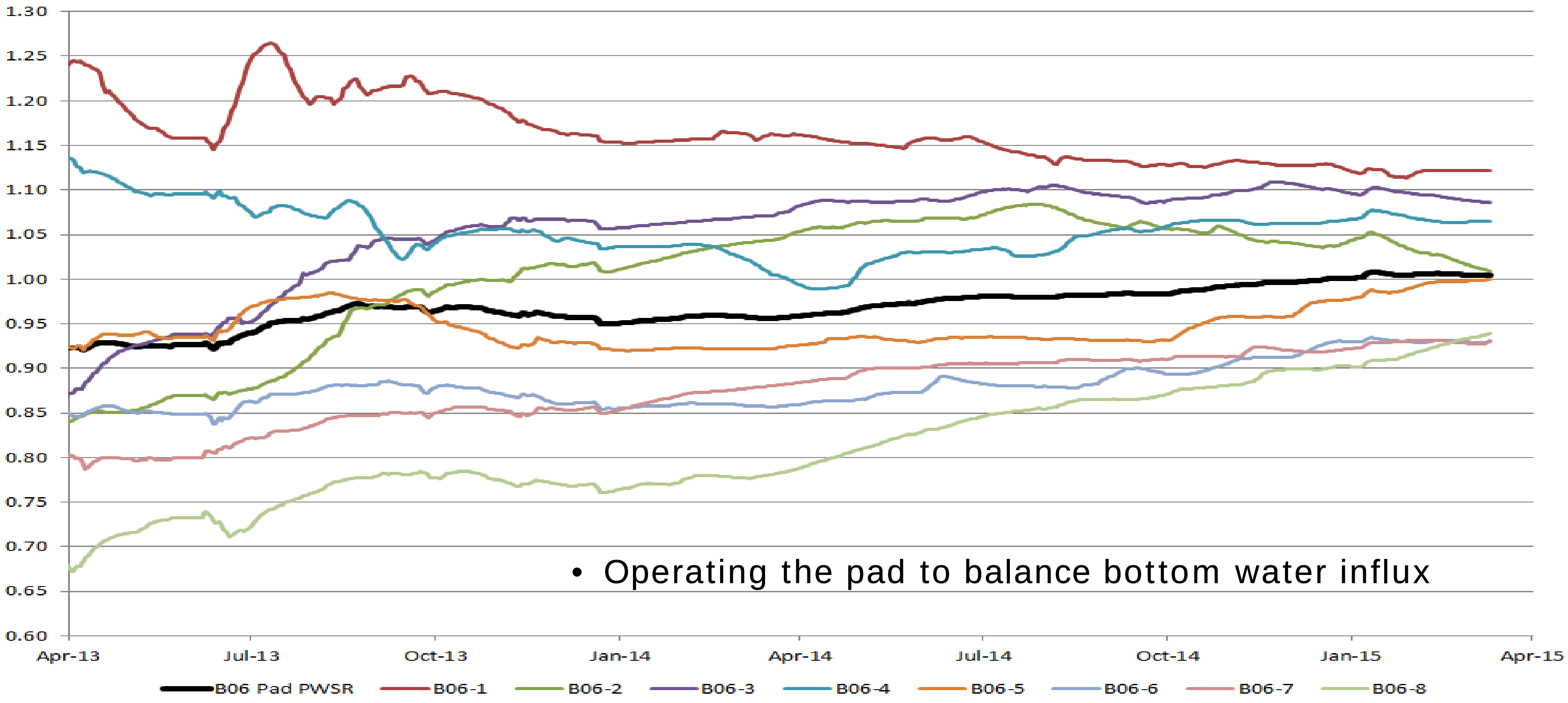
- **Blue** = bottom water
- **Grey/Black/Orange** = mud barrier (isolates oil & water zones)
- **Anywhere with blue and no grey: Oil in direct contact with water**

B06 pad: operating with bottom water

Ideally, we would like to operate in perfect pressure balance with the bottom water



B06 pad produced water to steam ratio (PWSR)



- Operating the pad to balance bottom water influx

Subsection 3.1.1 – 7f)
2014 key learnings

Patented Wedge Well™ technology

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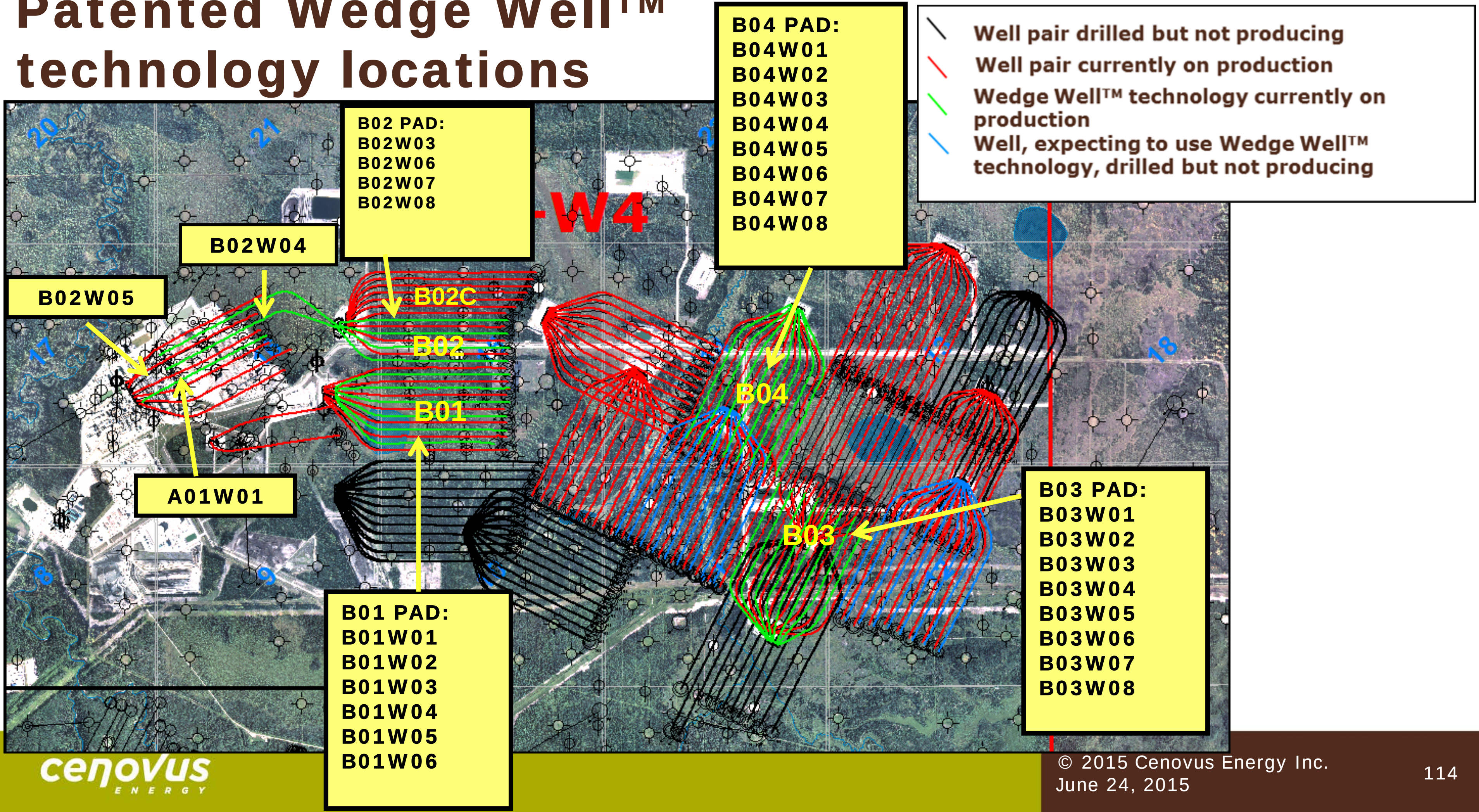
Patented Wedge Well™ technology locations

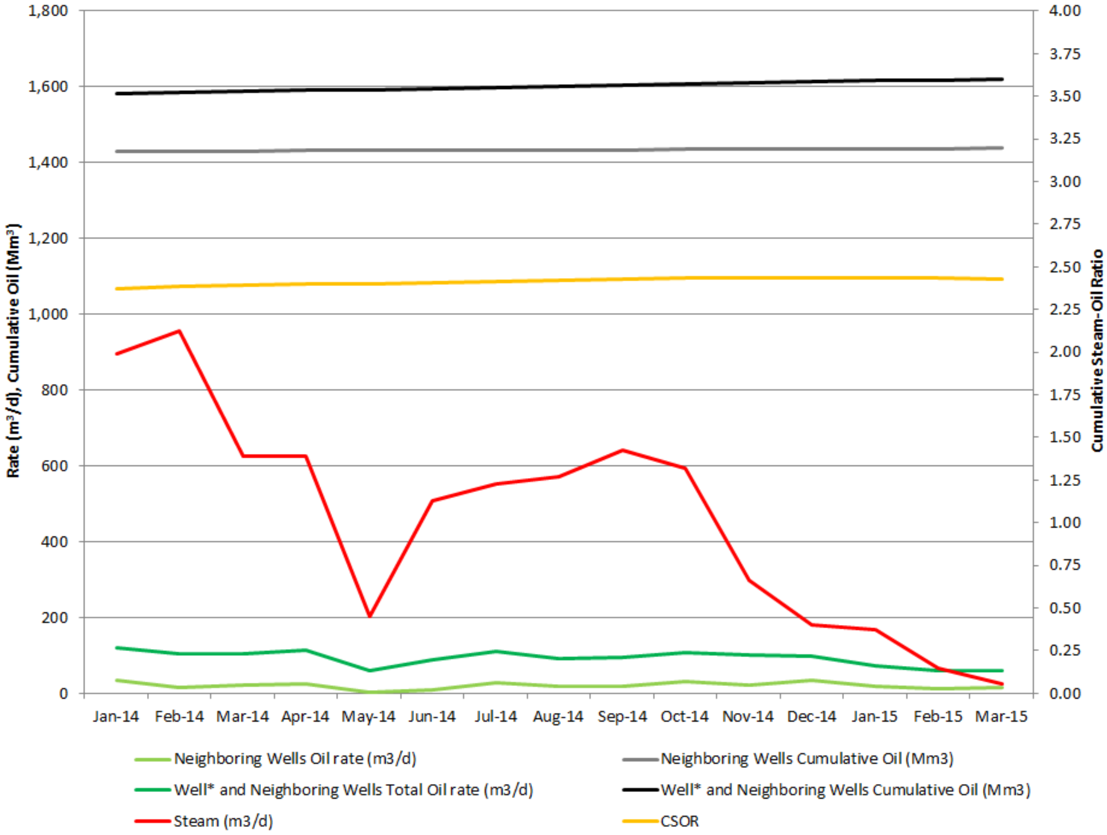


June 24, 2015

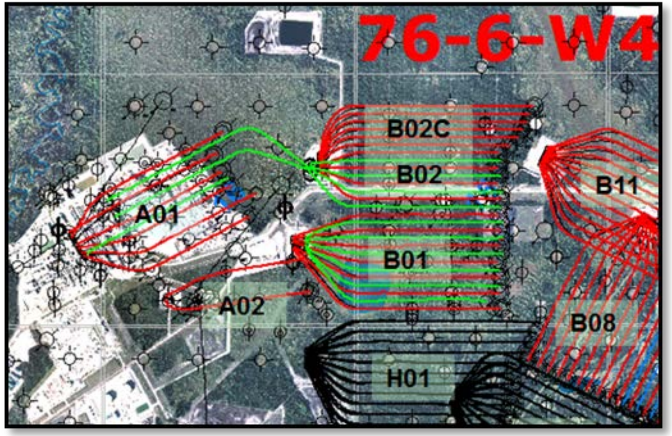
Wedge Well™ Placement

- Wedge Wells™ are typically landed at the same height as neighbouring producer wells
- Where the opportunity exists to lower the Wedge Wells™ relative to parent producers, they may be lowered by up to 2m
  - Variations greater than 2m are typically avoided, due to the operational impacts on parent pairs

A01 pad neighboring wells and patented Wedge Well™ technology performance



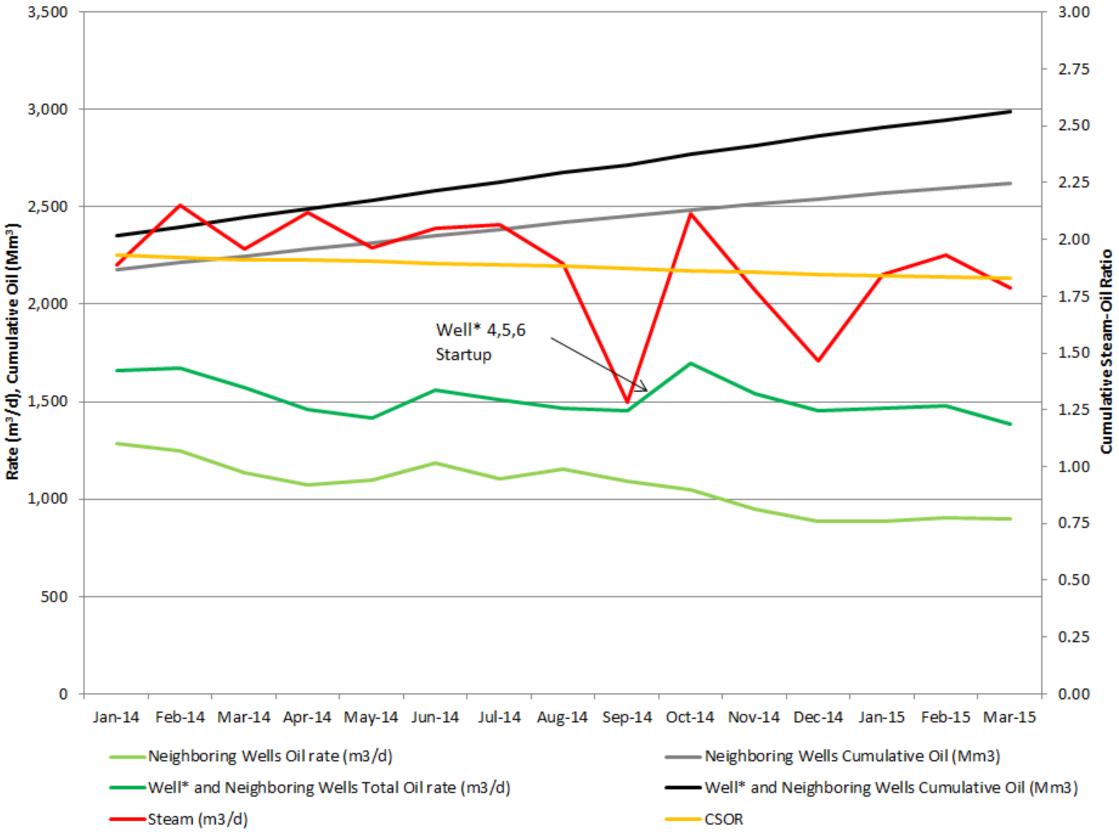
A01 pad wells using Wedge Well™ technology



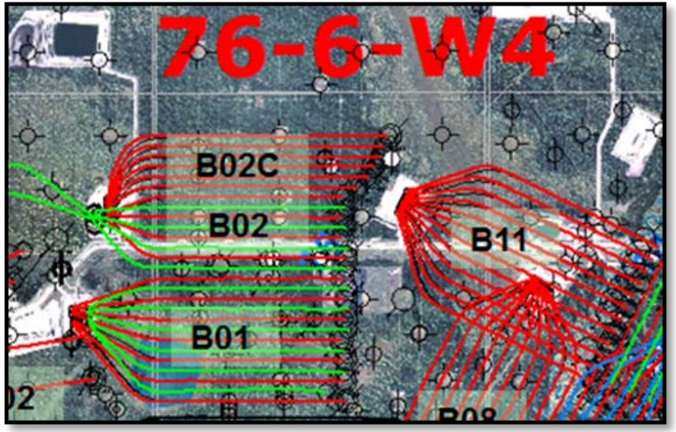
- B02W04 & B02W05 were drilled from B02 pad surface location

*Well using Wedge Well™ technology

B01 pad neighboring wells and patented Wedge Well™ technology performance



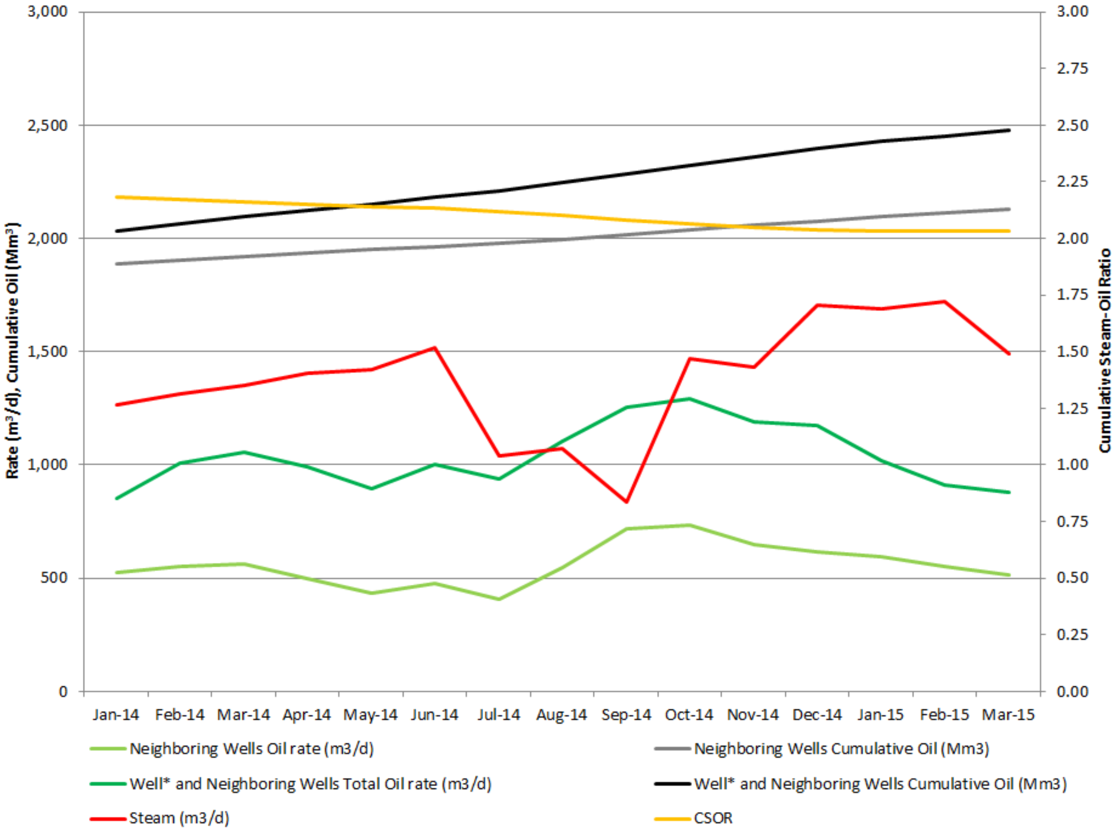
B01 pad wells using wedge Well™ technology



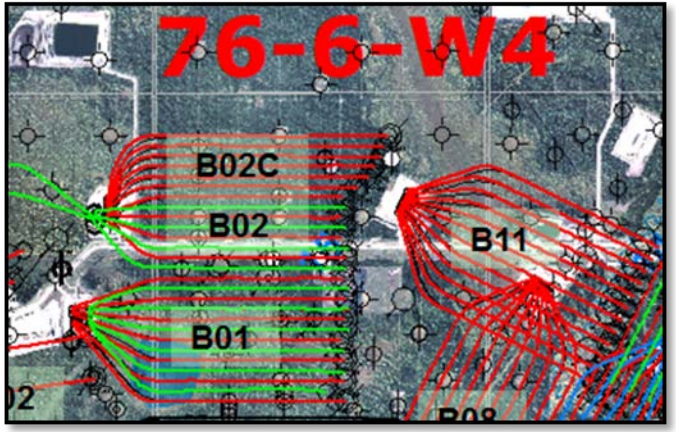
- B01W04,W05,W06 are located on the south side of B01 Pad

*Well using Wedge Well™ technology

B02 pad neighboring wells and patented Wedge Well™ technology performance

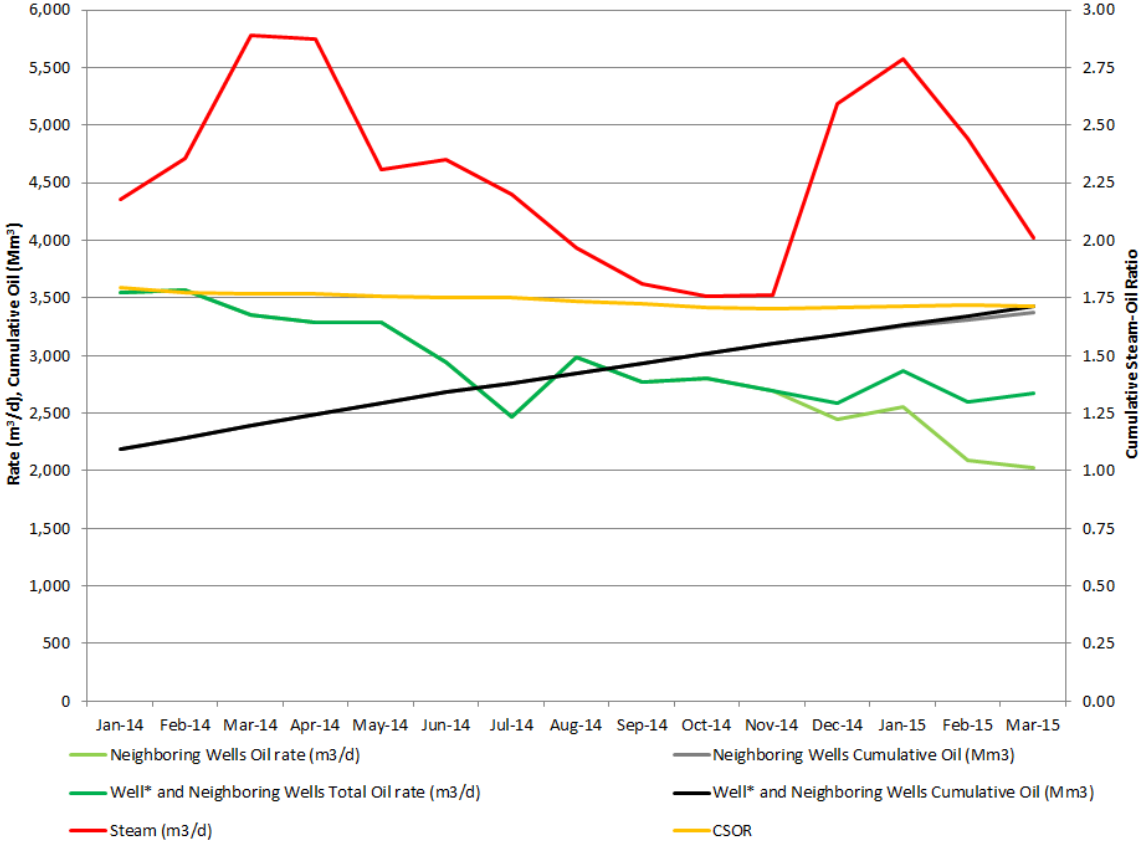


B02 Pad Wells Using Wedge Well™ technology

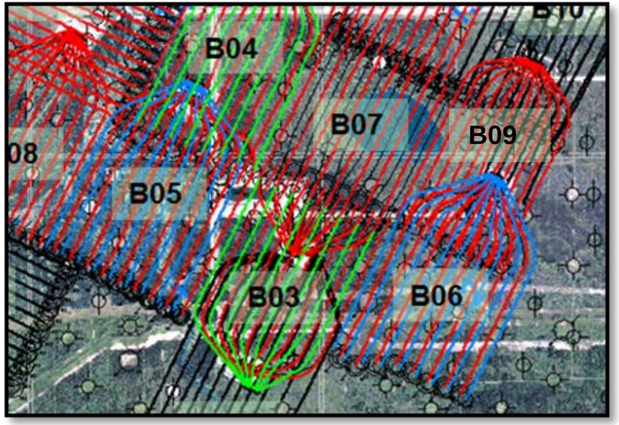


*Well using Wedge Well™ technology

B03 pad neighboring wells and patented Wedge Well™ technology performance



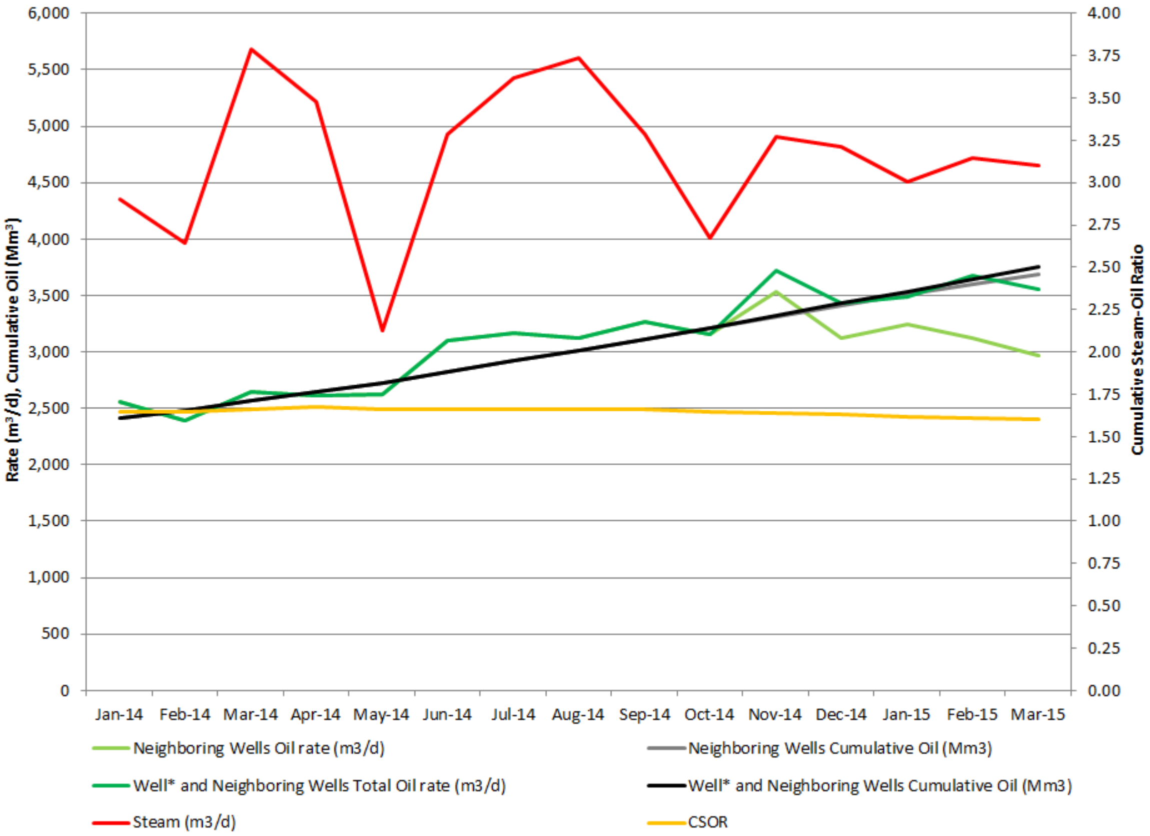
B03 Pad Wells Using Wedge Well™ technology



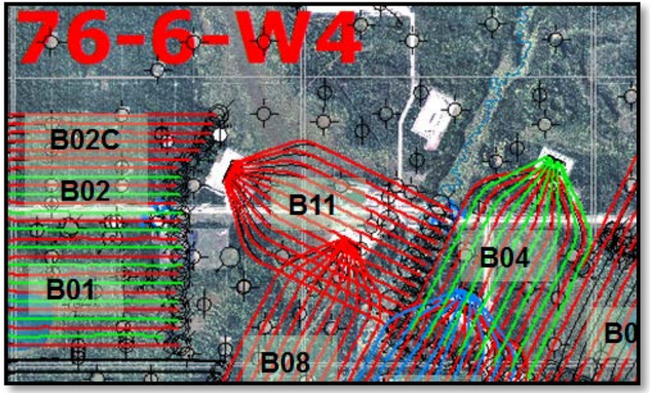
- B03W01 is not operational

*Well using Wedge Well™ technology

B04 pad neighboring wells and patented Wedge Well™ technology performance



B04 Pad Wells Using Wedge Well™ technology



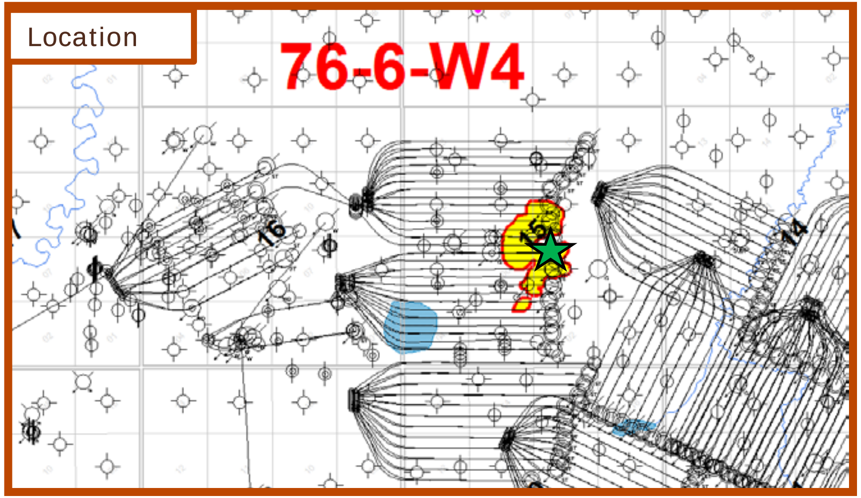
- B04W01 & 02 have not been started up

*Well using Wedge Well™ technology

Subsection 3.1.1 – 7f)
2014 key learnings

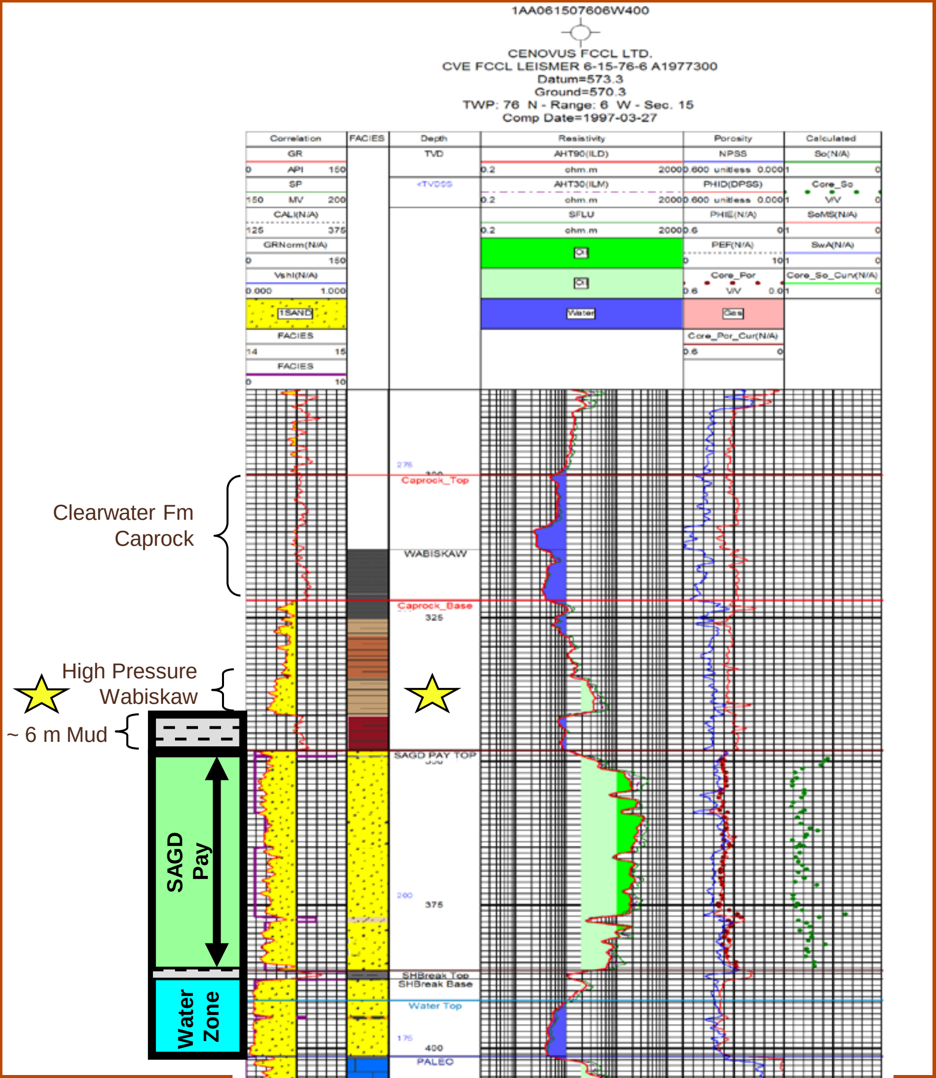
Wabiskaw Zone at Christina Lake

Zone Of interest: Wabiskaw

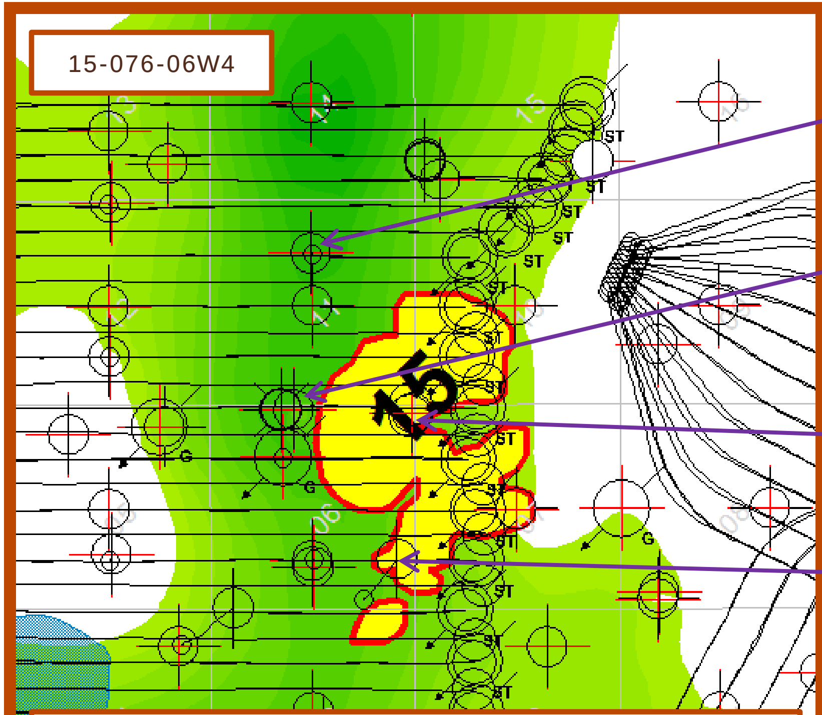


Over-pressured Wabiskaw first identified in April 2013 while attempting to drill a steam chamber core (107/06-15-76-6W4/00).

Conductive heating of bitumen in low-perm Wabiskaw from underlying steam chamber created an increase in reservoir pressure from ~2000 kPa to ~6500 kPa.



Wabiskaw observation wells in pressured area

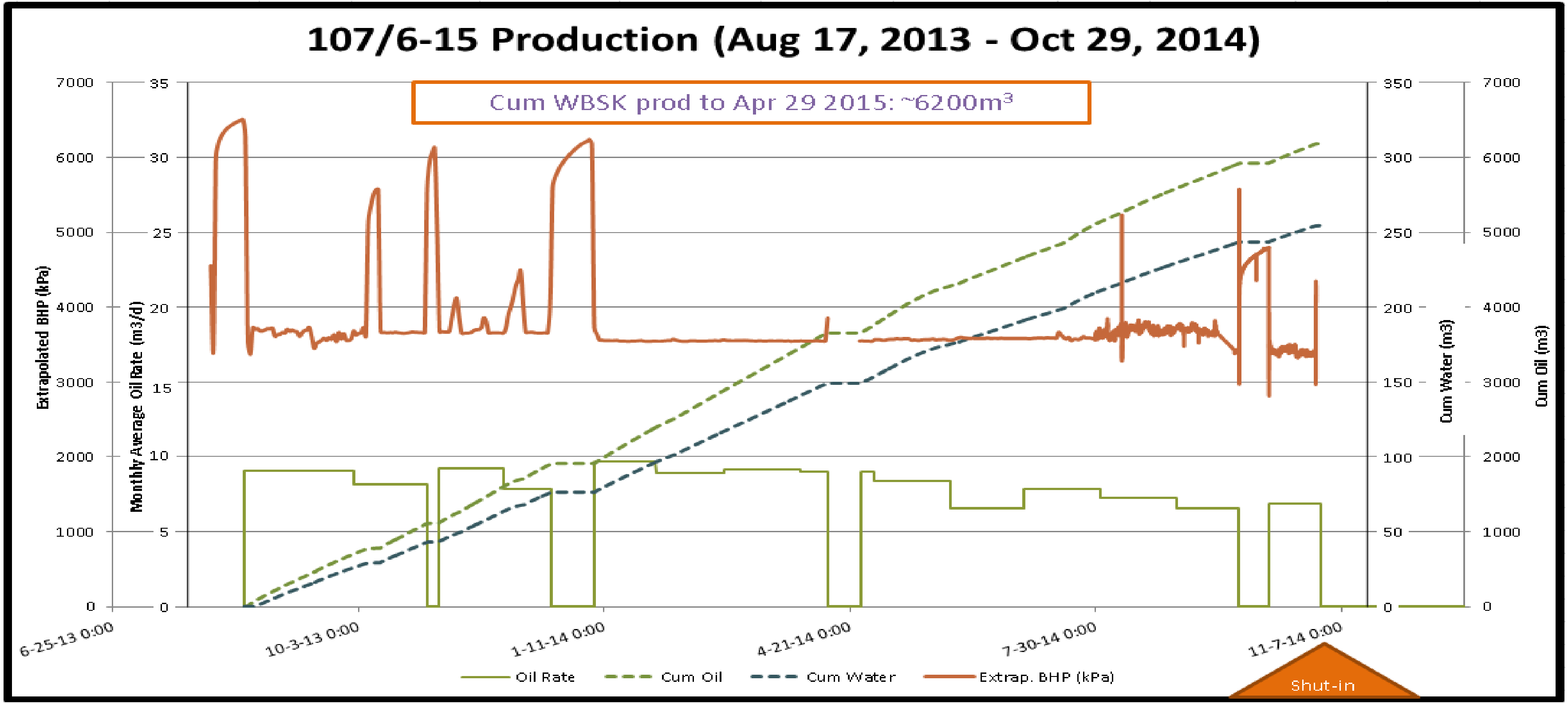


4D seismic changes (2011-2014) in WBSK
shown on WBSK pay map

100/11-15-76-6W4 Recompleted with pressure monitoring	**100/11-15-76-6W4** 4452-4673 kPag
108/06-15-76-6W4 Drilled and installed temperature and pressure monitoring (Fall 2013)	**108/06-15-76-6W4** 2615-3908 kPag 31.8-41.8℃ BHT
107/06-15-76-6W4 WBSK producing well	**107/06-15-76-6W4 Producer** 5086 kPag 18.5℃ (Shut-In) 3100 kPag 110℃ (Flowing)
109/06-15-76-6W4 Drilled and installed temperature and pressure monitoring (April 2014)	**109/06-15-76-6W4** 5703-6250 kPag 18.5℃ BHT

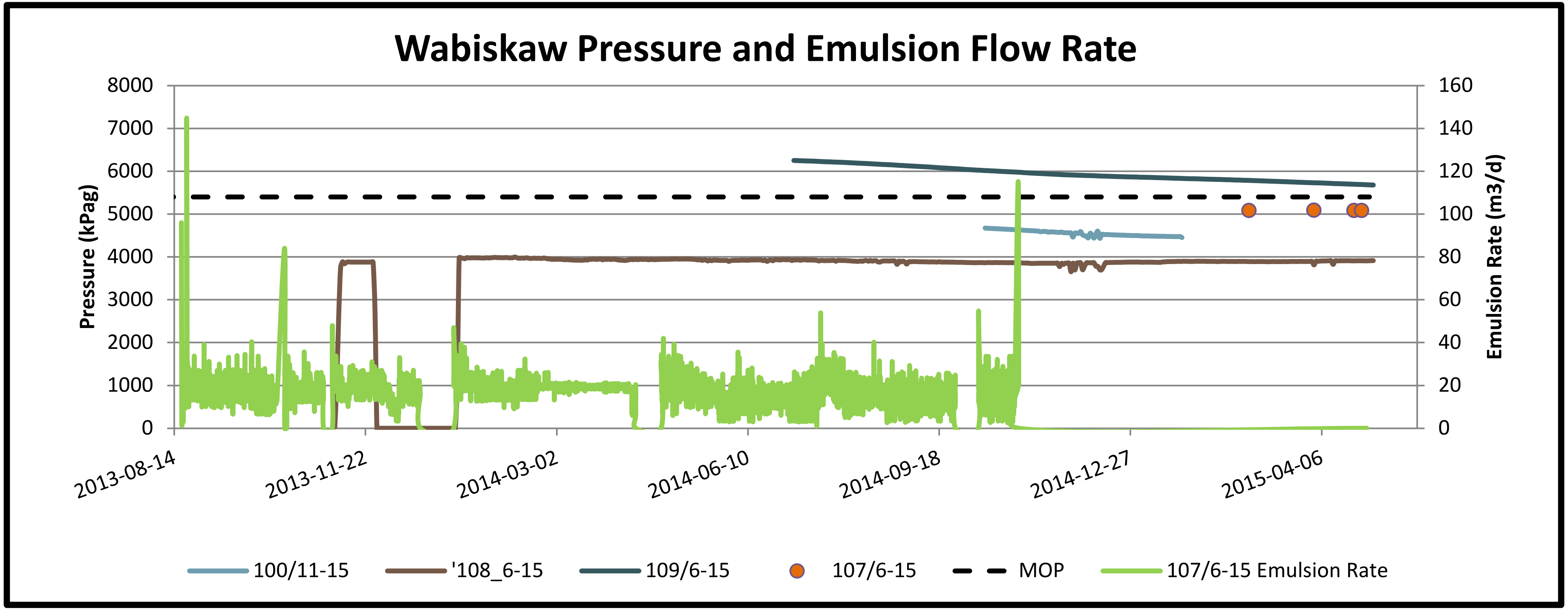
Data Ranges over Jan 2014-April 2015 period

Wabiskaw production: 107/06-15-76-6W4



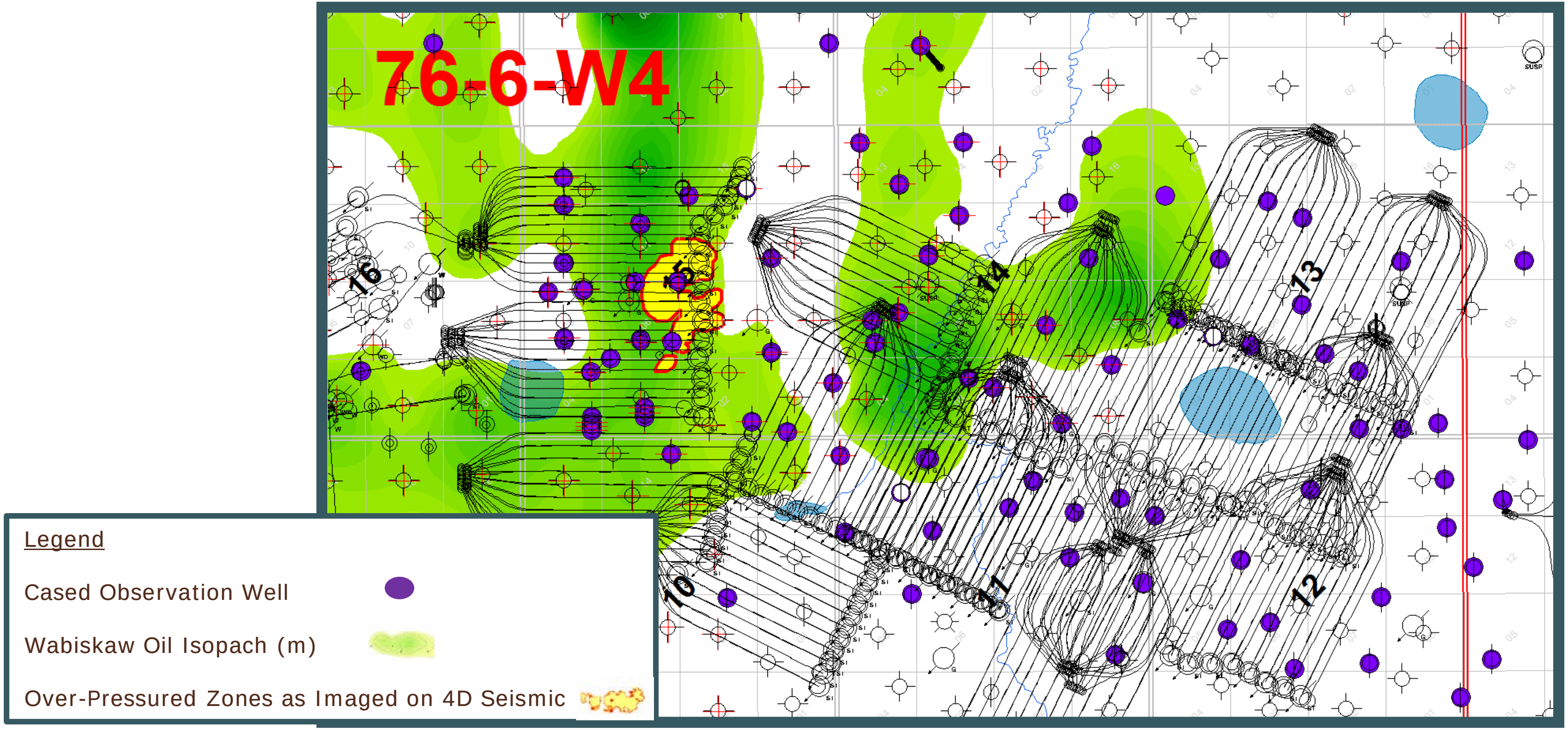
Note: the well was shut-in on Oct. 29, 2014 to recomplete the well and install a single-well battery facility.

Wabiskaw pressure and flow rates



Note: the well was shut-in on Oct. 29, 2014 to recomplete the well and install a single-well battery facility.

Existing observation wells within operating area



Subsection 3.1.1 – 7g) Information requests

Well trajectory guidelines

List of re-drills/re-entry wells in 2014-2015

The list of re-drill/re-entry wells in 2014-2015 is summarized in table below:

UWI	WELLNAME	RE-DRILL/RE-ENTRY REASON
104/15-12-076-06W4/00	CVE FCCL B10P01 LEISMER 15-12-76-6	Successfully drilled to a FTD of 1945m MD, unfortunately the BHA and drill string became stuck while back reaming at 1432m MD. After many days of attempting to retrieve the equipment, the internal components of the MWD tool were salvaged while the BHA and remainder of the drill string were left down hole. The well was side tracked at 761m MD.
104/15-12-076-06W4/02	CVE FCCL B10P01 LEISMER 15-12-76-6 S01	

Summary of well spacing in existing & future pads

The well spacing in existing pads is summarized in table below:

SAGD pad	Inter well pair spacing [m]
A01	110
A02	100
B01	100
B02	100
B03	100
B04	100
B05	100
B06	100
B07	100
B08	70
B11	67
B09	64

Future Pad Spacing

- All pads drilled in 2015/2016 will have inter well spacing of 65m - 70m

Criteria to determine standoff from bottom water

Cenovus optimizes the well position from the base of the reservoir and bottom water

- To maximize resource recovery and operational efficiency

Wells are targeted to land at ~50% oil saturation

- Excluding other factors such as potential barriers
- Planned trajectories are ~2m higher than this due to the drilling error that is consistently observed

Subsection 3.1.1 – 7g) Information requests

B02-2 bottom water influx

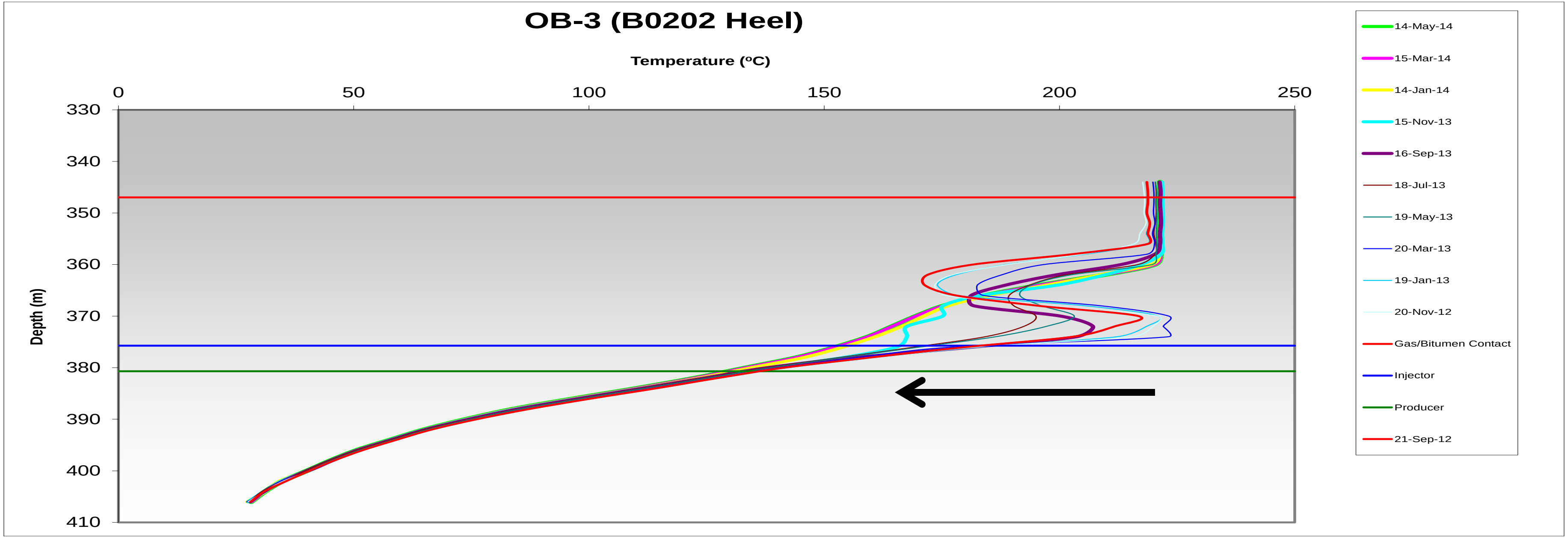
May 13, 2014
Application 1773237

cenovus ENERGY

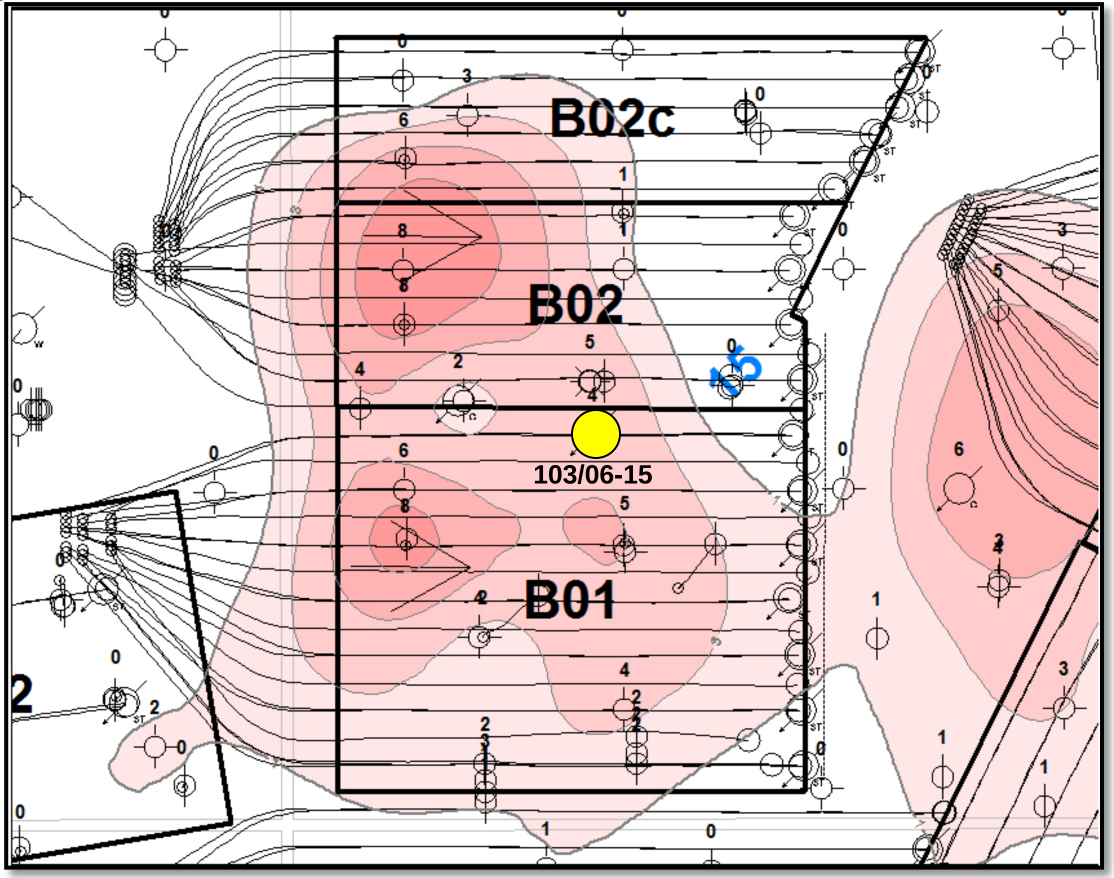
B02-2 bottom water influx

- Bottom water influx into B02 pad due to regionally elevated bottom water pressure
- Risk of flooding B01, B02 chambers, similar to challenges on A01 pad
- Large developed steam chamber; therefore, re-pressurization with steam would not be efficient
- Ability to inject natural gas into the gas cap to support chamber pressures and bring us in balance with bottom water pressure

B02-2 chamber cooling



6-15 Natural gas injection



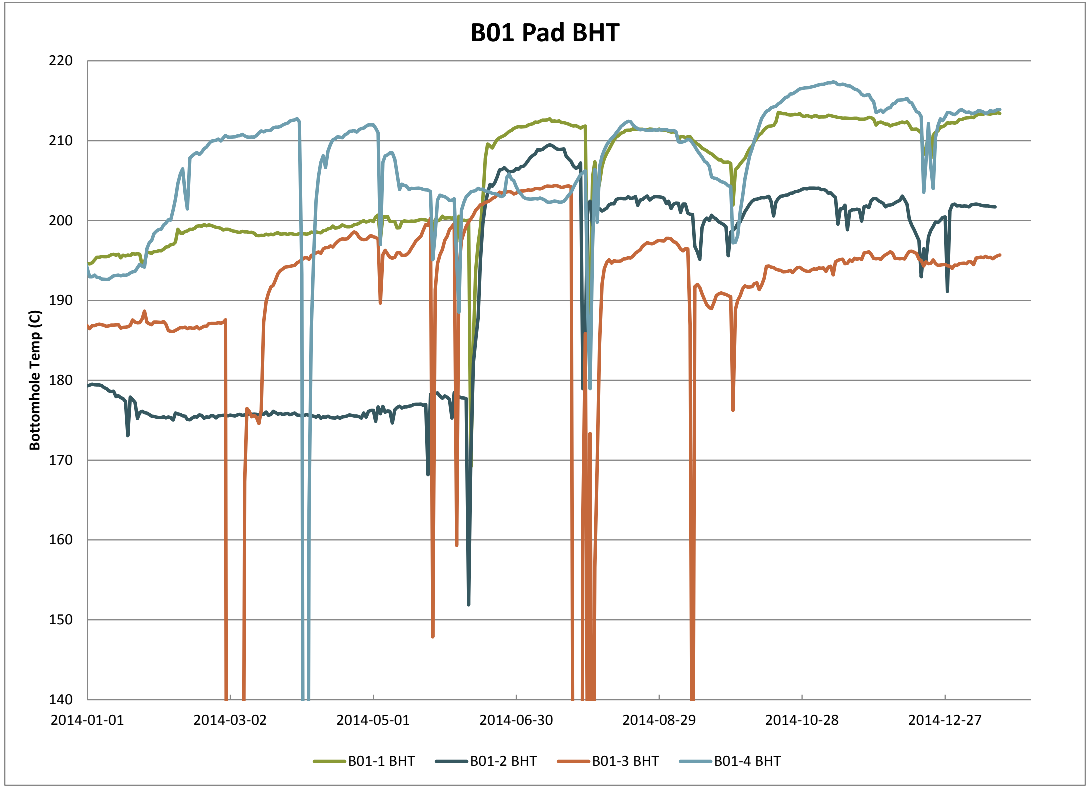
B01/B02 BHP

Well name	Current IBHP*
B01-1	2516 kPa
B01-2	2494 kPa
B01-3	2495 kPa
B01-4	2490 kPa
B01-5	2504 kPa
B01-6	2518 kPa
B02-1	2557 kPa
B02-2	Bubble tube inoperable
B02-3	2652 kPa
B02-4	2507 Kpa
B02-5	2566 kPa

*Current as of April 21, 2015

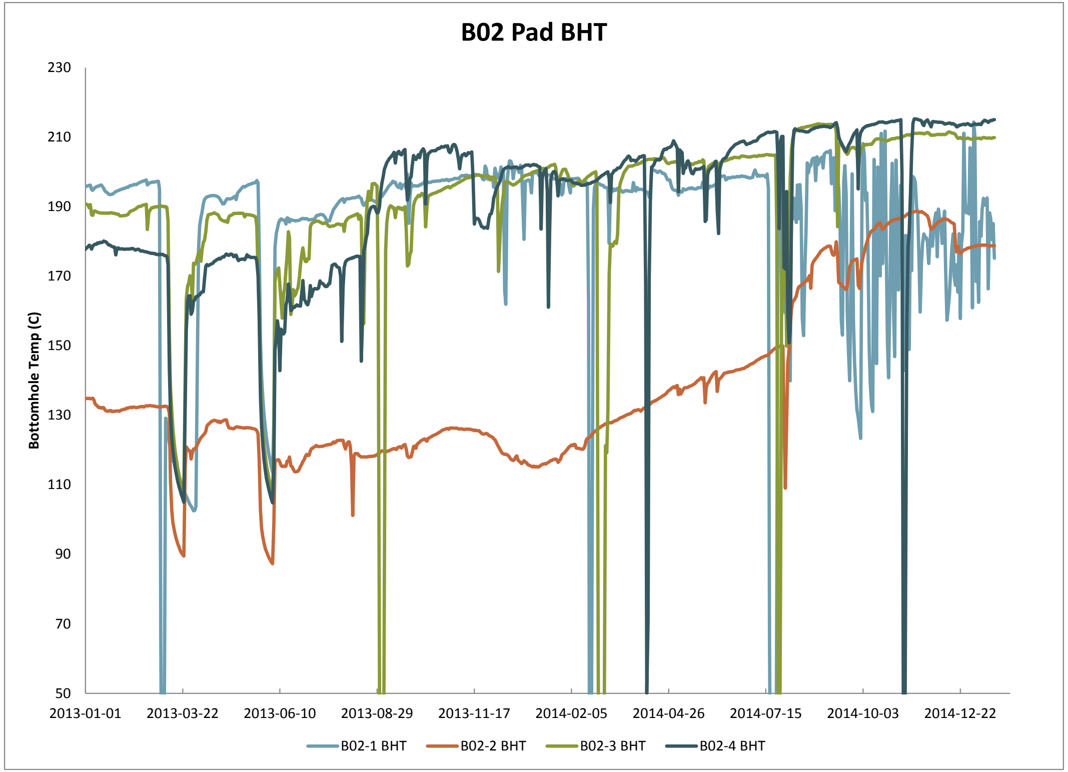
B01 BHT

- Bottomhole temperatures continue to rise with pressure
- No sign of bottom water cooling on any producing well



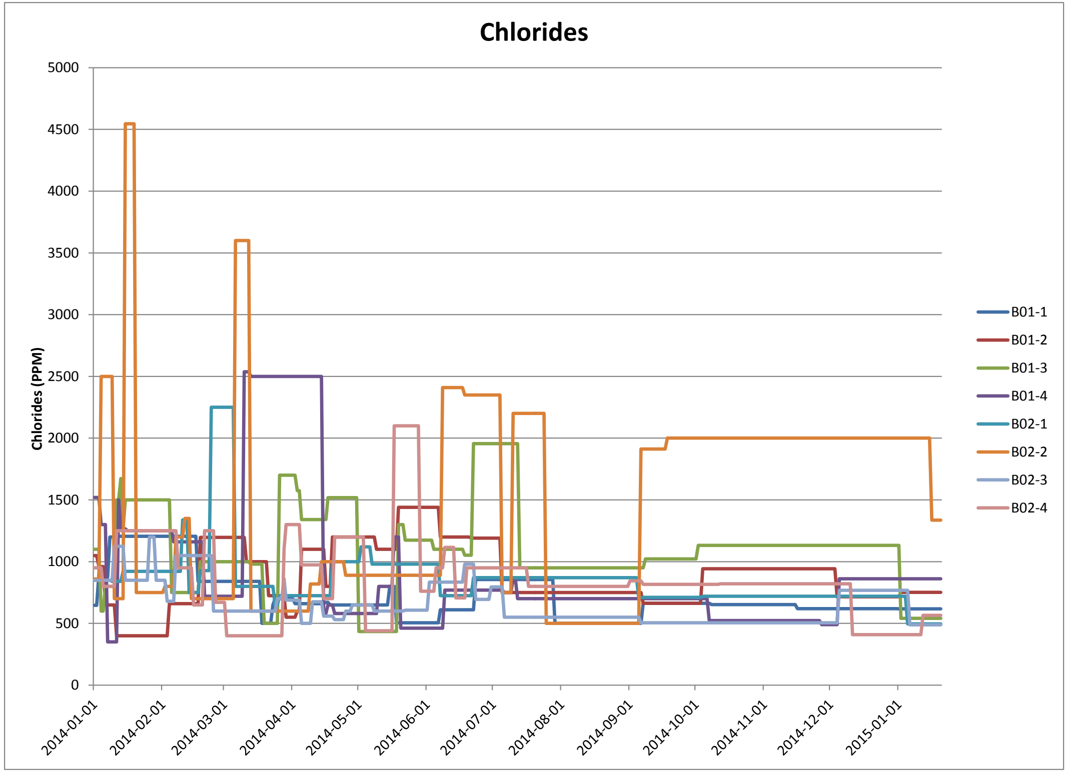
B02 BHT

- Bottomhole temperature continue to rise with pressure.
- B02-2 had shown performance degradation due to bottom water influx – successfully reversed with repressurization operations



Chlorides

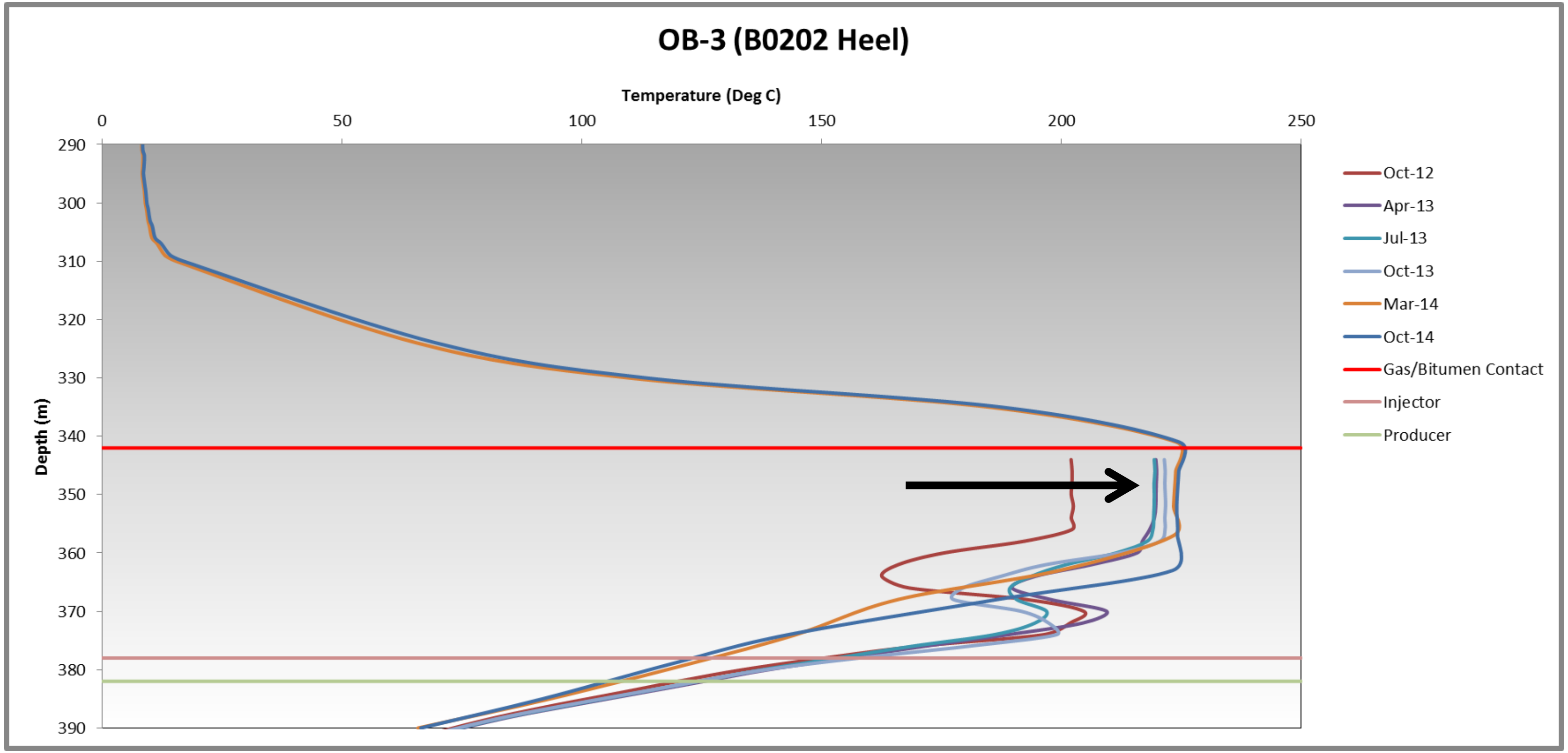
- **All chlorides trending down with chamber re-pressurization**



Path forward

- Bottom water has been mitigated
- Applied to AER to switch to air injection
- Once 2,500 kPag (corrected to account for bottom water piezometer stand-off) is reached, transition to rampdown/blowdown phase on B02-1 through B02-4, and B01-1 through B01-4
- Targeting Mid-June 2015 to begin blowdown trial
    - inject methane or air into section 15 gas cap to support pressure

B02-2 chamber temperature recovery



Subsection 3.1.1 – 7h)
Pad production plots

Pad production plots

Requirements under subsection 3.1.1 7h) are located in Appendix 4

Subsection 3.1.1 – 8) Future plans

Kevin Beary

Reservoir Engineer

cenovus ENERGY

Resource recovery strategy

Well/pad placement:

- 2015/2016 well pairs will be drilled as per the existing (or future) applications and approvals
- Well spacing/trajectories planned to be submitted for approval up to one year prior to construction/drilling

No changes in the overall resource recovery strategy (operating pressure, composition of injected fluid)

Any deviations will be applied for as future amendments

Filed applications

Category	Application	Date filed
3	Phase H and eastern expansion	March, 2013
1	Emulsion circulation during unscheduled plant shutdown	April, 2014
2	B01/B02 rampdown/blowdown pilot	April, 2014
1	Phase D aerial cooler equipment change	June, 2014
2	Casing gas re-injection B03-7	March, 2014
2	Air co-injection trial B05-8	July, 2014
2	L pad trajectory amendment	June, 2014
2	Producer well length extension (B10-1 to B10-5)	May, 2014
2	A01 permanent blowdown	August, 2014
2	A02-2 SAP methane injection to demonstrate butane recovery	August, 2014
2	B13 well length extension	December, 2014

Filed applications

Category	Application	Date filed
1	Ph CDE oil debottleneck	Feb, 2015
1	Multi directional wells SAGD enhanced lengths	March, 2015
2	Non-condensable gas ventilation well (B08 or H01)	March, 2015
2	L09, J05, L07 well length extension	March, 2015

Potential future applications

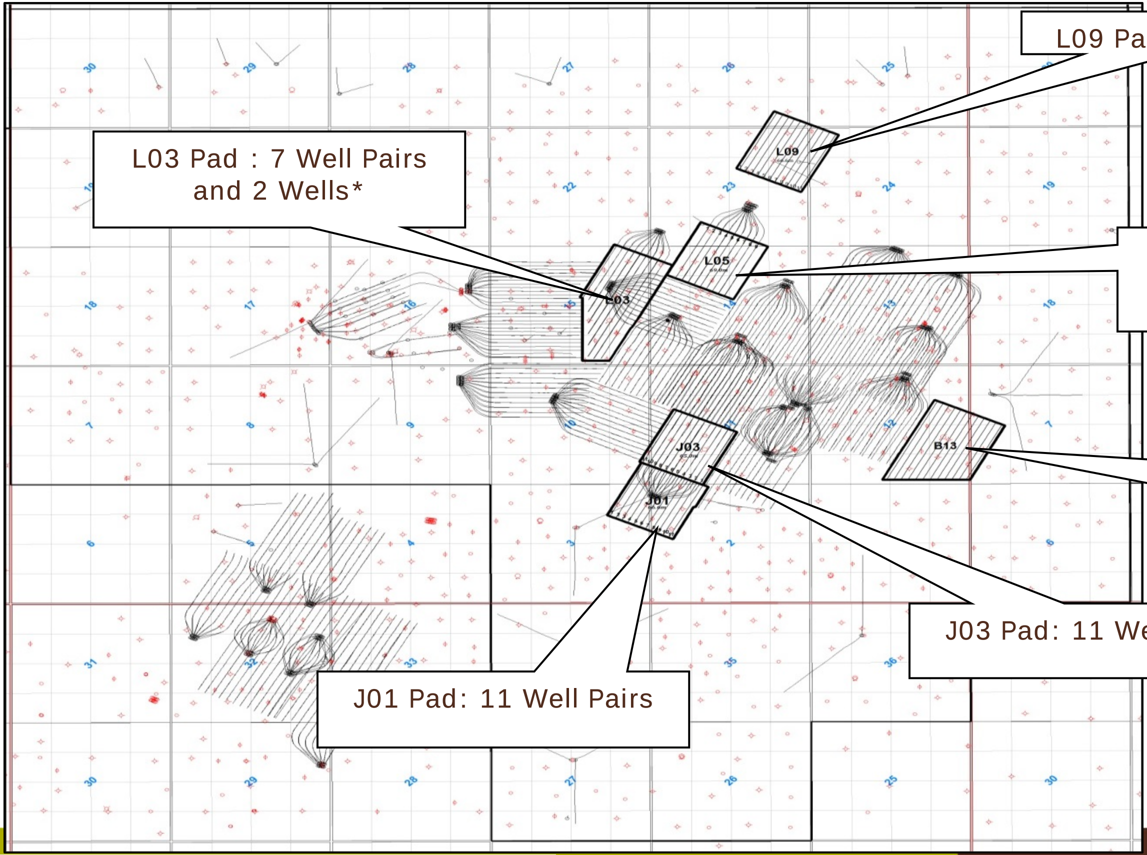
Category	Application	Planned filing date
2	Sustaining pad trajectory amendment	Q3 2015
2	B03/B04/B07 co-injection/blowdown	Q3 2015
3	Development area expansion	Q4 2015

Drilling plans - 2015

Pad	Pad type	Well count	Timing
J03	Production	11 well pairs	Q1 2015
L03	Production	7 well pairs and 2 wells*	Q1 2015
L05	Production	7 well pairs and 2 wells*	Q2 2015
B13	Production	12 well Pairs	Q2 2015
J01	Production	11 well pairs	Q2 2015
L09	Production	11 well Pairs	Q3 2015
MW1	Brackish source	3 wells	Q1 2015
MW4	Brackish source	3 wells	Q2 2015

*Wells using Wedge Well™ technology

SAGD drilling plans 2015



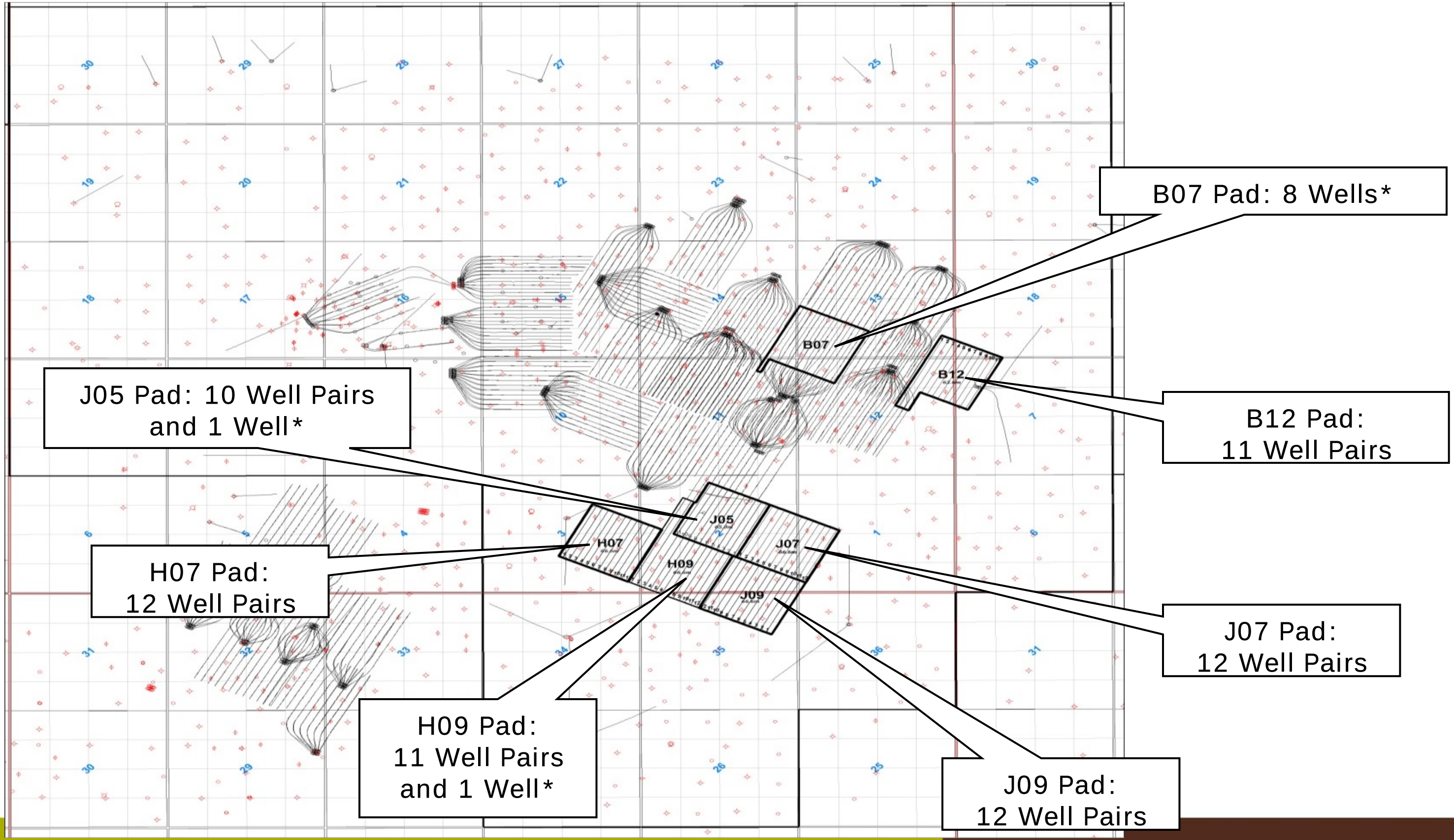
*Wells using Wedge Well™ technology

Drilling plans - 2016

Pad	Pad type	Well count	Timing
J07	Production	12 well pairs	Q1 2016
B07	Production	8 wells*	Q1 2016
J09	Production	12 well pairs	Q1 2016
H09	Production	11 well pairs and 1 well*	Q1 2015
J05	Production	10 well pairs and 1 well*	Q2 2016
H07	Production	12 well pairs	Q2 2016
B12	Production	11 well pairs	Q4 2016
RD2	Disposal	3 wells	Q2 2016

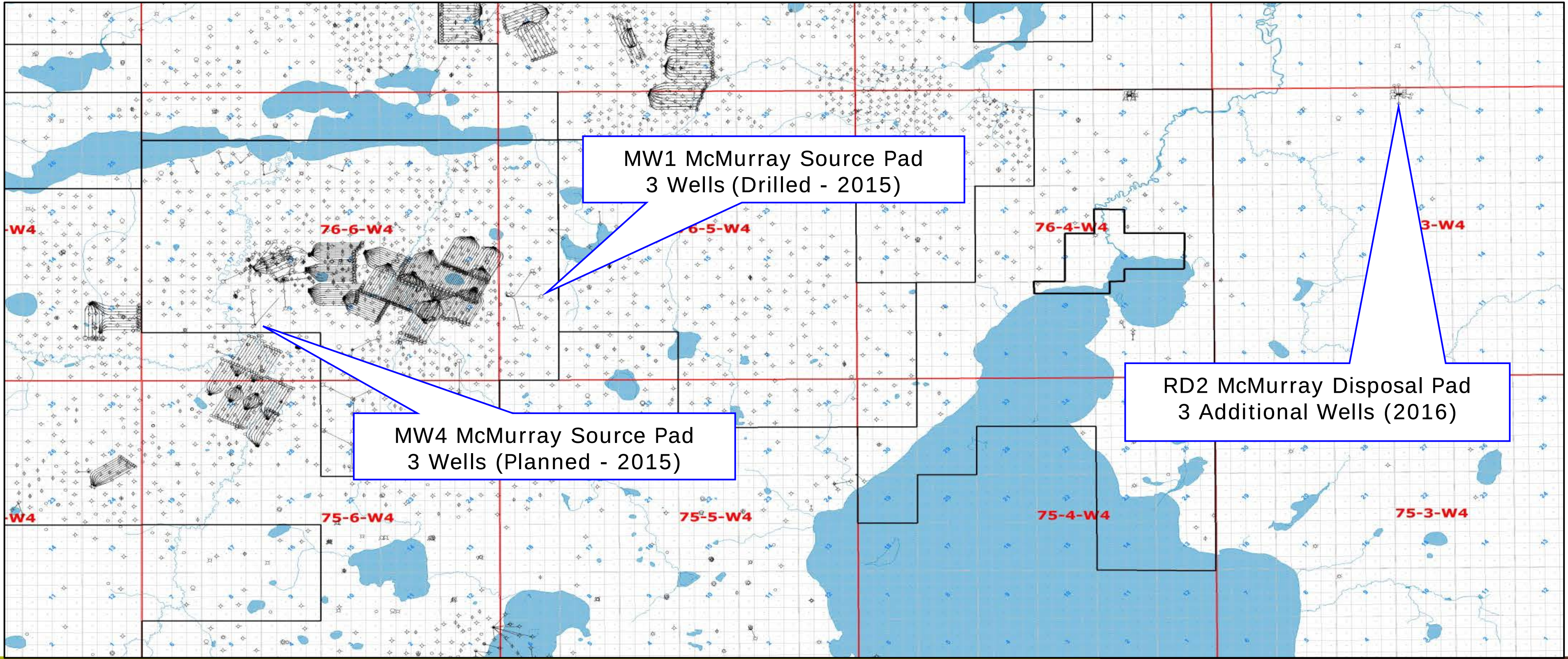
*Wells using Wedge Well™ technology

SAGD drilling plans 2016

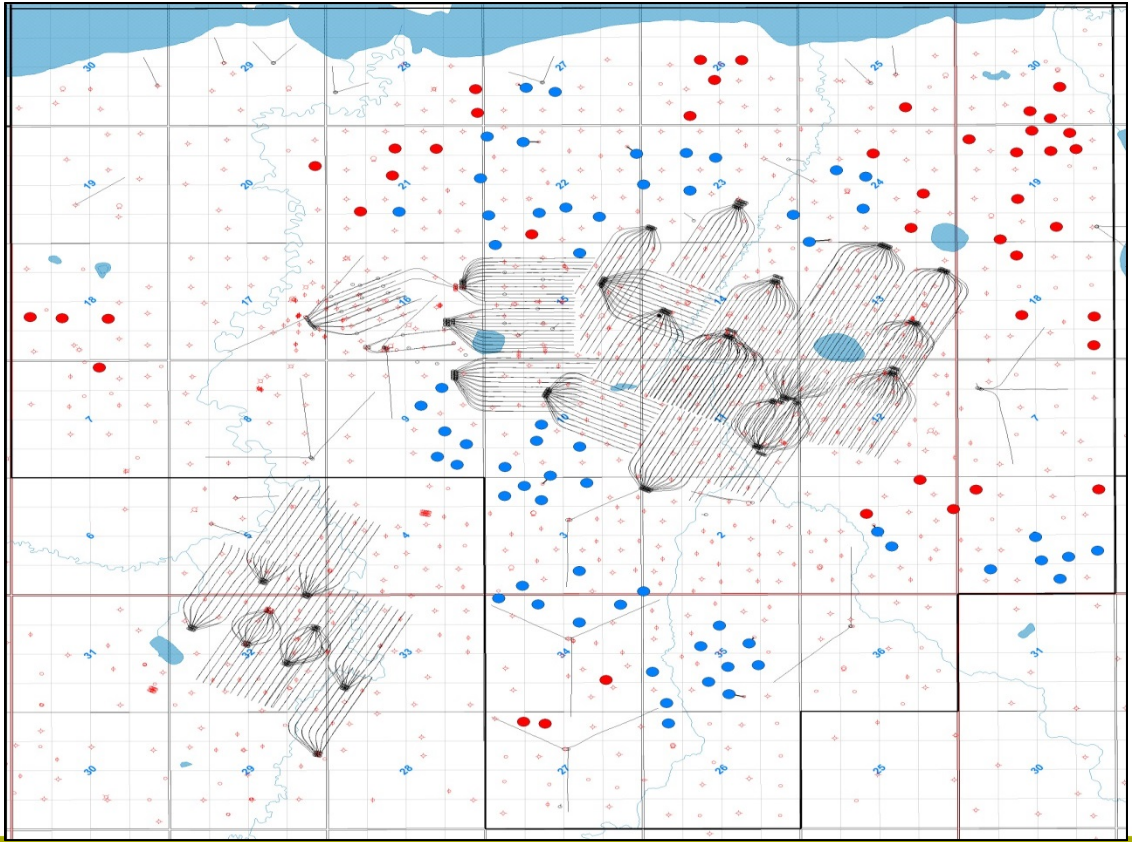


*Wells using Wedge Well™ technology

Source and disposal drilling plans



Future strat well drilling plans 2016



2016 Abandoned Strat Well
2016 Cased Observation Well

Steam strategy 2015

- Phase CDE second stage OTSG adding 6,695 m^3/d incremental capacity, bringing total capacity to 46,218 m^3/d
- One additional pad planned to start up with Phase CDE second stage OTSG: B07B (11 Well Pairs)
- The following pads are planned to start up for sustaining production: B05 Wedge Well™ technology, F01
  - total of 12 well pairs and nine wells using Wedge Well™ technology
- Blowdown operations:
  - planned to continue at A01 pad
  - pilot test planned to commence at B01-1 to B01-4 and B02-1 to B02-4
- No steam shortages expected on existing pads

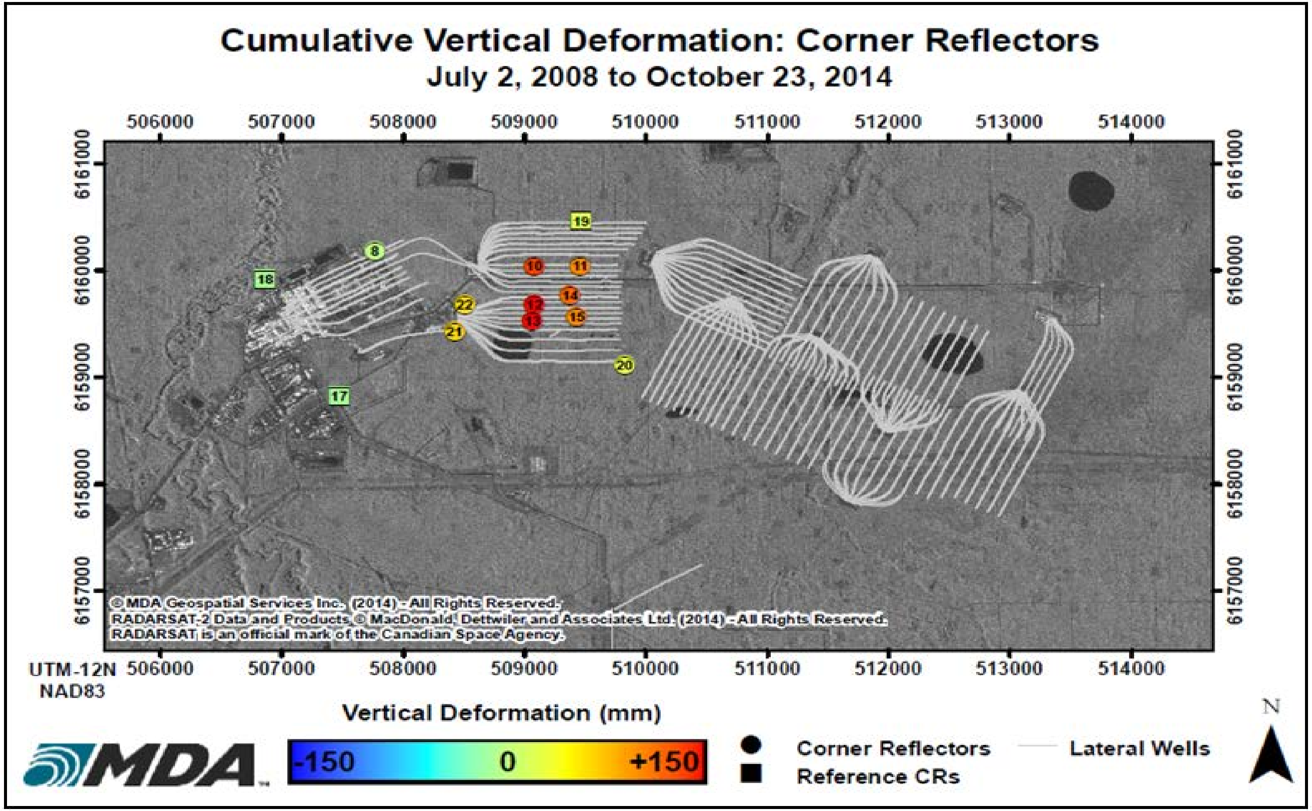
Steam strategy 2016

- Phase F OTSG adding 14,453 m^3/d incremental capacity, bringing total capacity to 60,672 m^3/d
- Two additional pads planned to start up with Phase F OTSG: H01, H03
  - total of 24 well pairs
- The following pads are planned to start up for sustaining production: B10, J03, L03, J01, B06 Wedge Well™ technology
  - total of 39 well pairs and nine wells using Wedge Well™ technology
- Rampdown/blowdown operations:
  - plan to continue at A01 pad
  - plan to continue at B01-1 to B01-4 and B02-1 to B02-4
  - plan to commence on B03, B04, B07 pad
- No steam shortages expected on existing pads

Appendix 1
Subsection 3.1.1 – 2)
Heave data

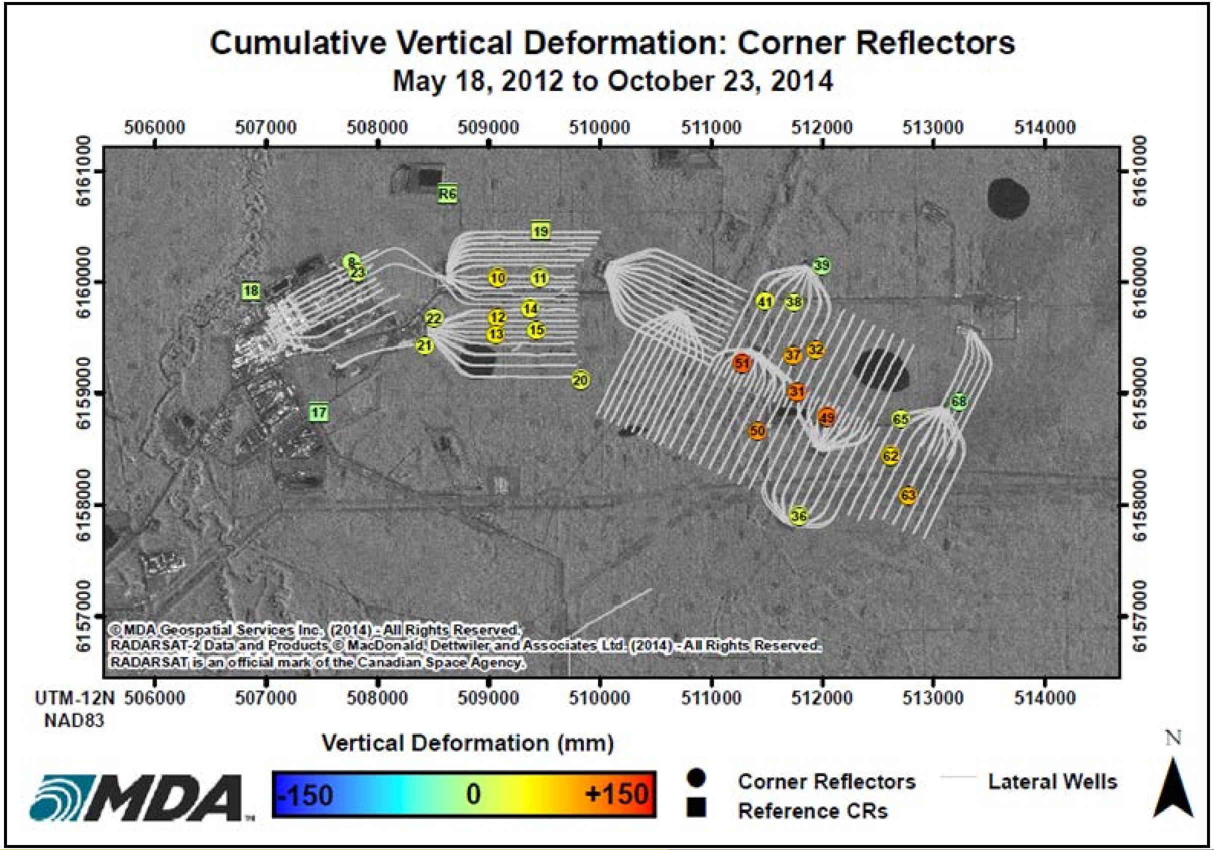
Cumulative vertical deformation:

July 2, 2008 to October 23, 2014 (~76 months)



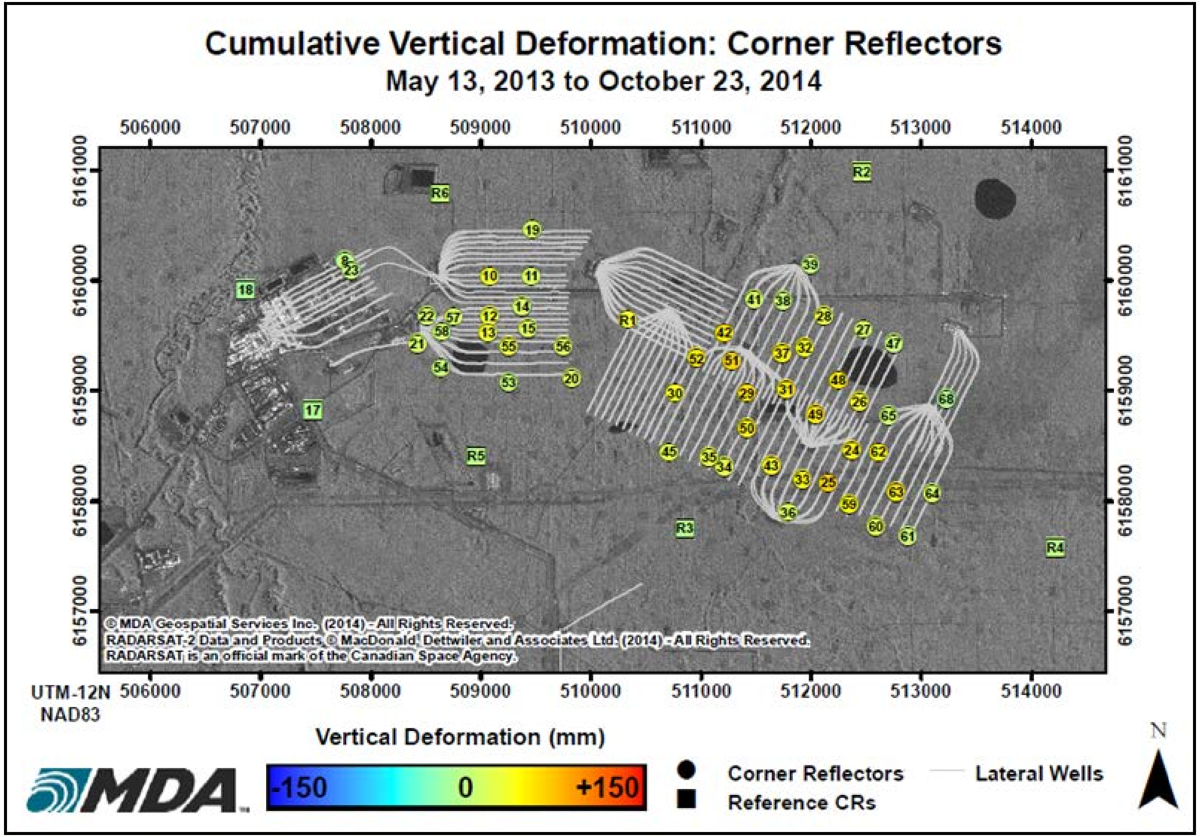
Cumulative vertical deformation:

May 18, 2012 to October 23, 2014 (~29 months)



Cumulative vertical deformation:

May 13, 2013 to October 23, 2014 (~17 months)



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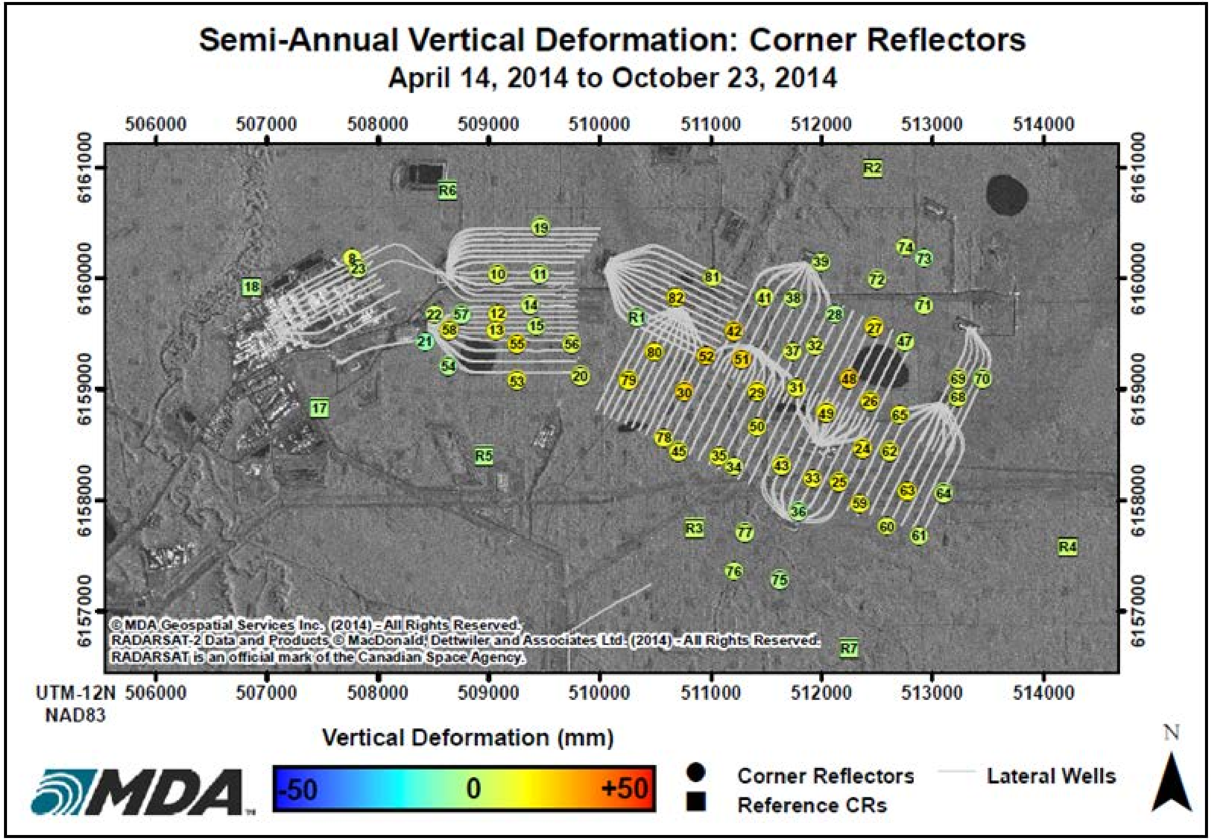
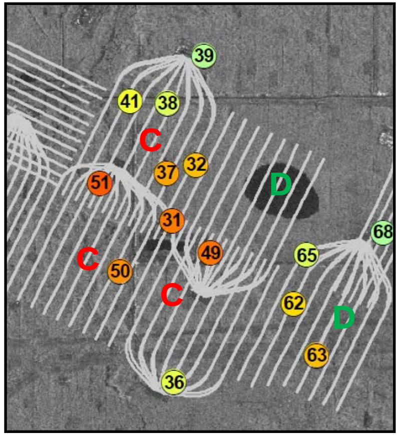
Cumulative vertical deformation:

April 14, 2014 to October 23, 2014 (~6 months)

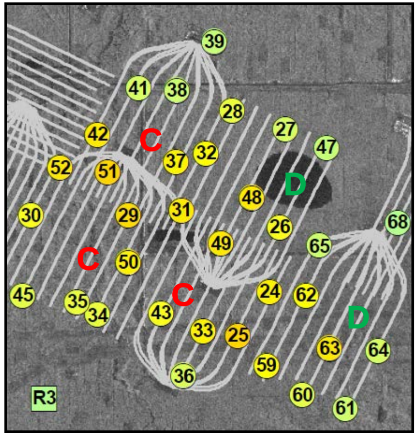


Cumulative vertical deformation: Phase C/D/E

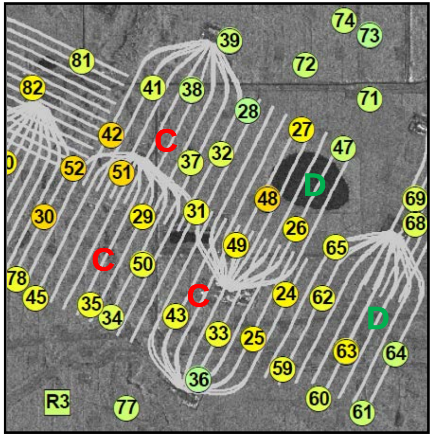
May 18, 2012 to October 23, 2014: Photo 1
May 13, 2013 to October 23, 2014: Photo 2
April 14, 2014 to October 23, 2014:Photo 3



(~29 months)

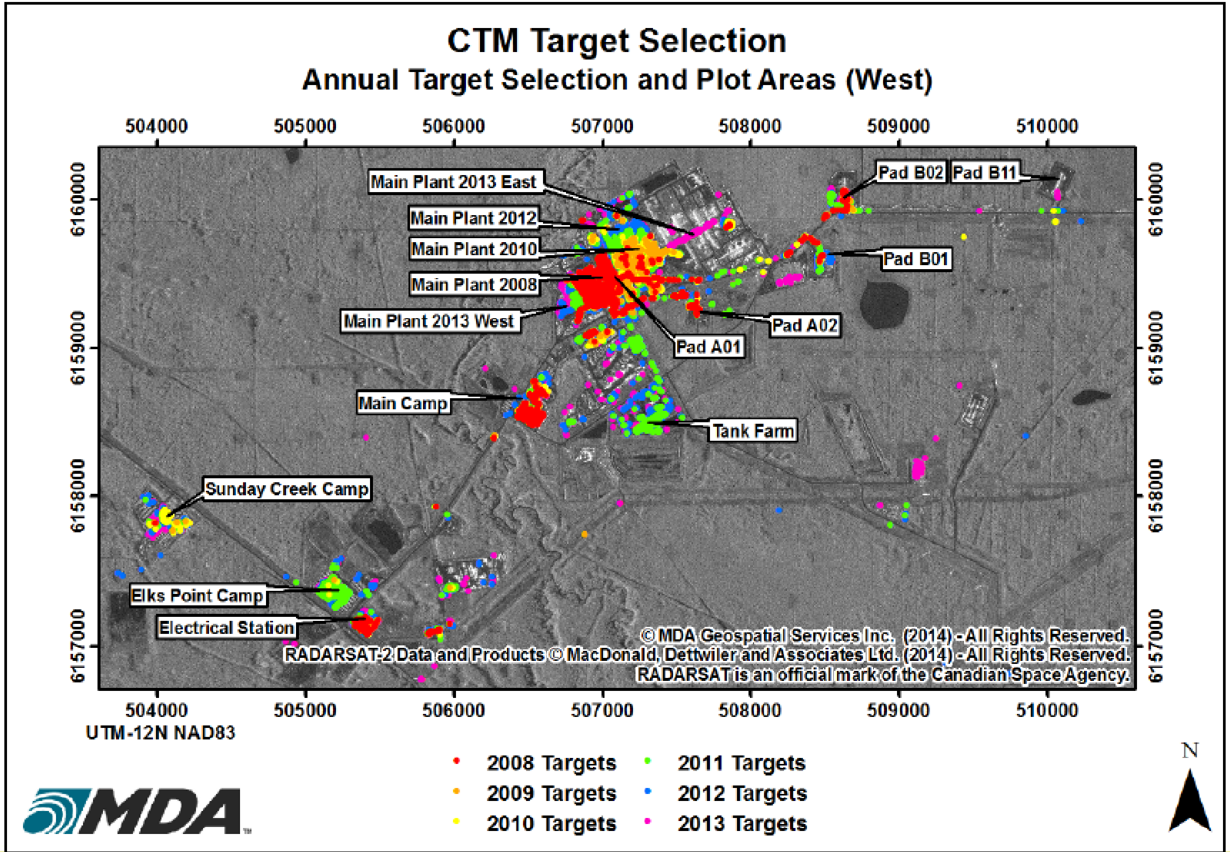


(~17 months)

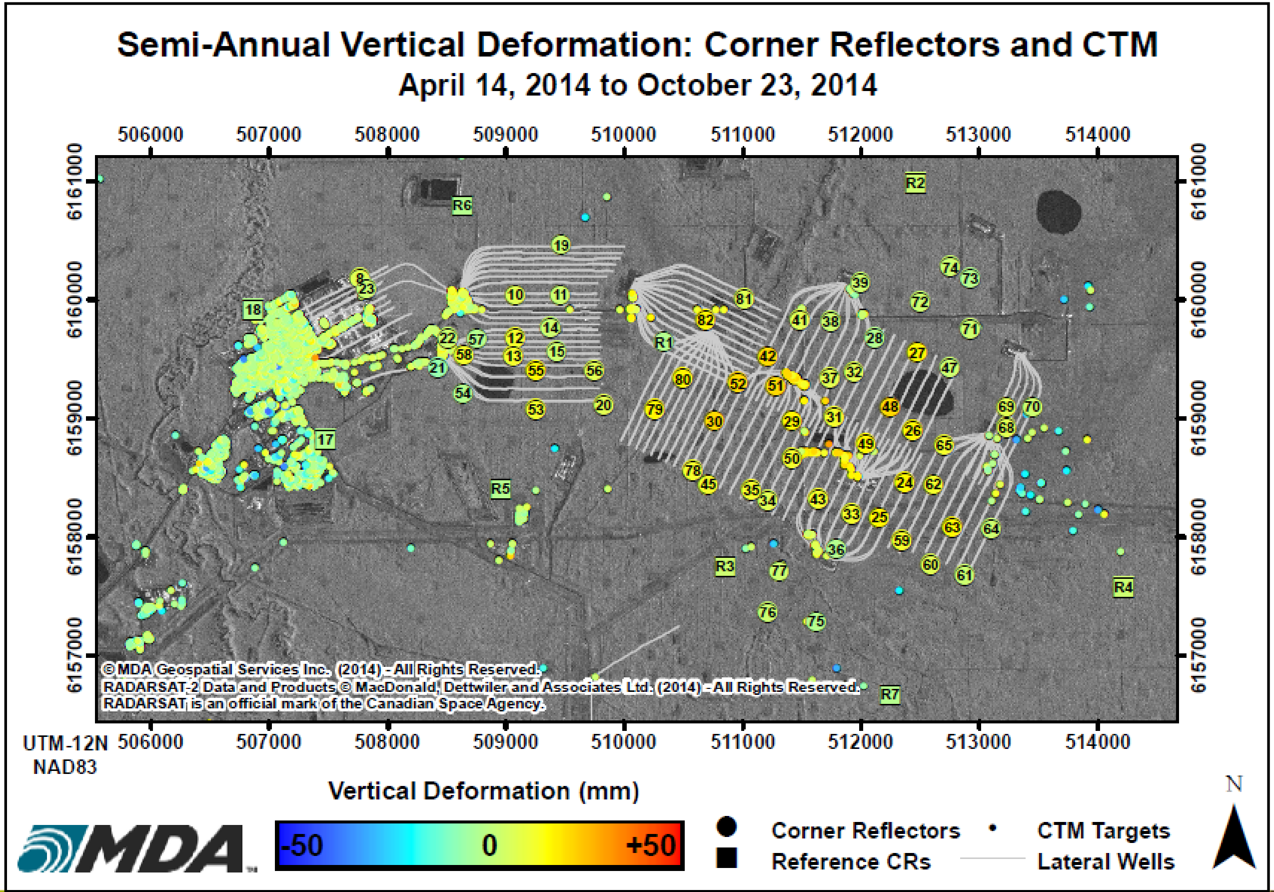


(~6 months)

Geomechanical and surface heave (Coherent Targets)

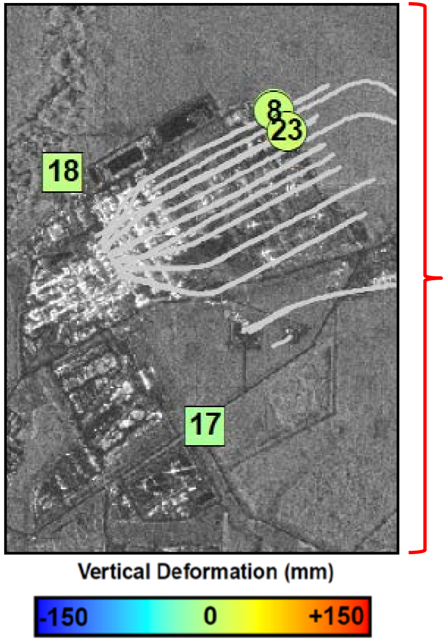


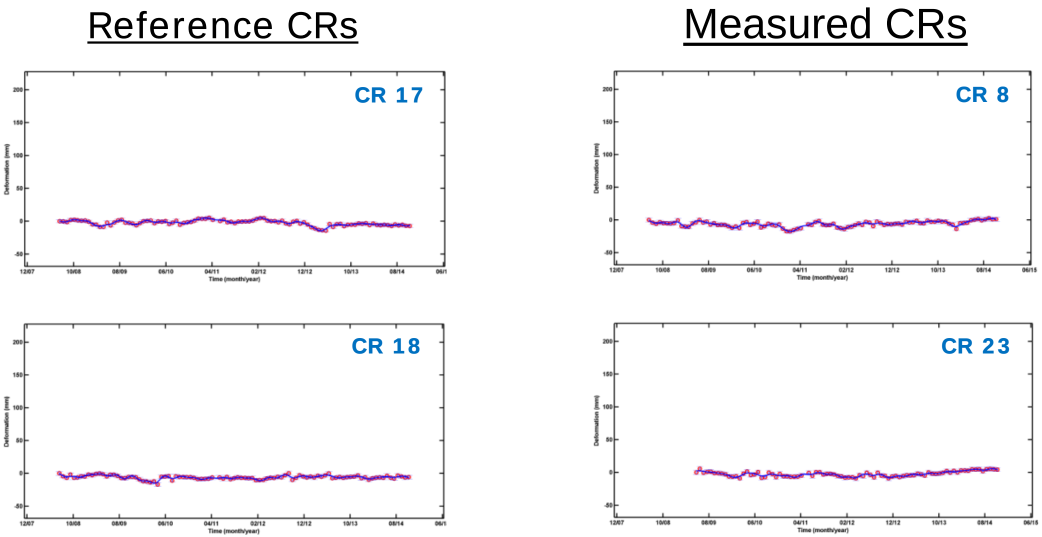
Geomechanical and surface heave (Coherent Targets)



Cumulative vertical deformation: Phase A

July 2, 2008 to October 23, 2014 (~76 months)

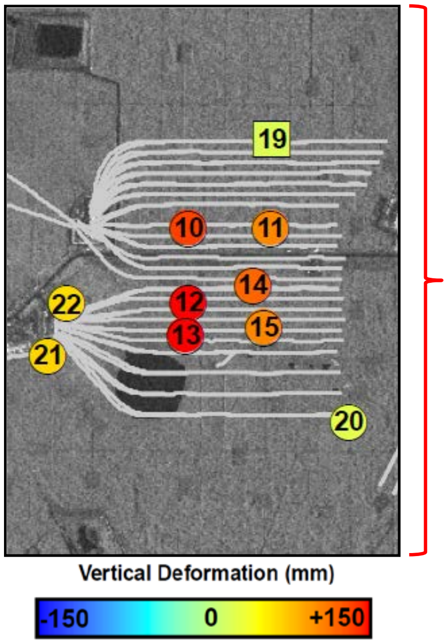




- Little to no deformation on CR 8 & 23
- 7 Corner Reflectors removed due to expanding infrastructure

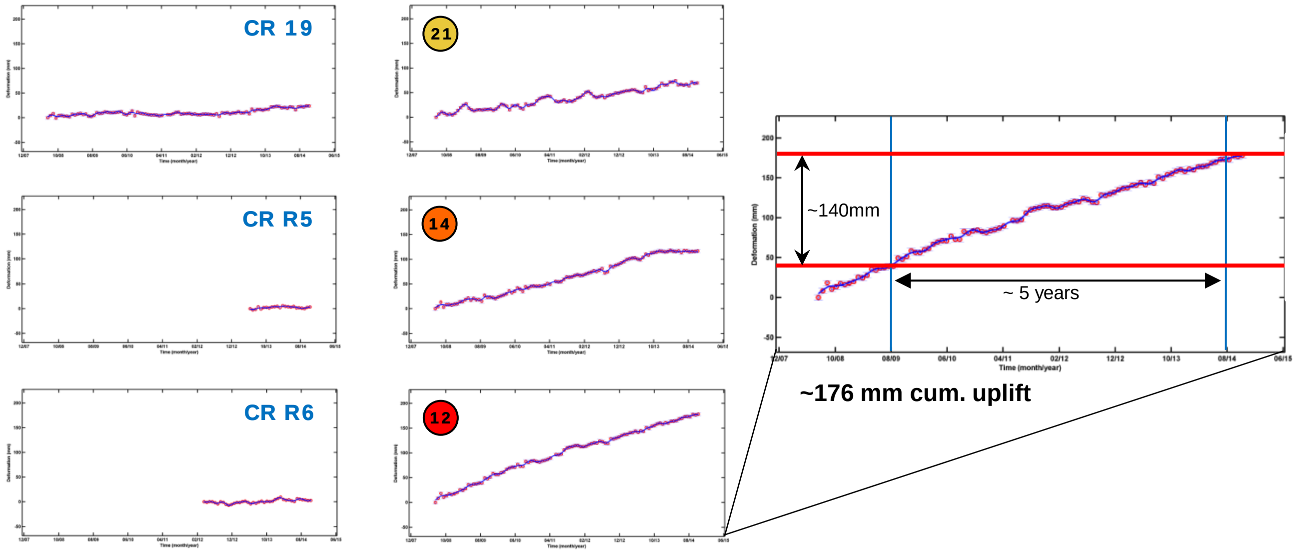
Cumulative vertical deformation: Phase B

July 2, 2008 to October 23, 2014 (~76 months)



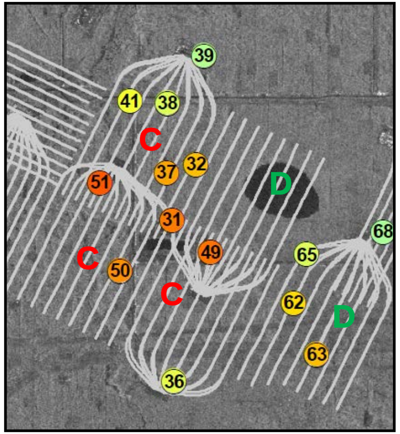
Reference CRs

Measured CRs



Cumulative vertical deformation: Phase C/D

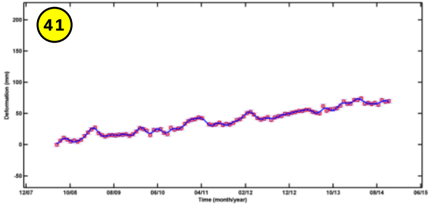
May 18, 2012 to October 23, 2014

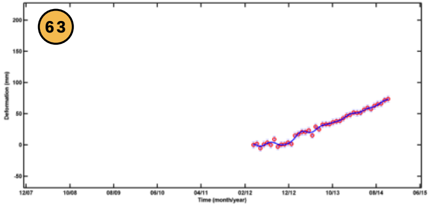


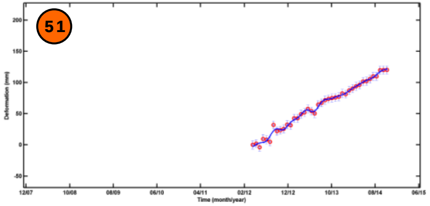
(~29 months)

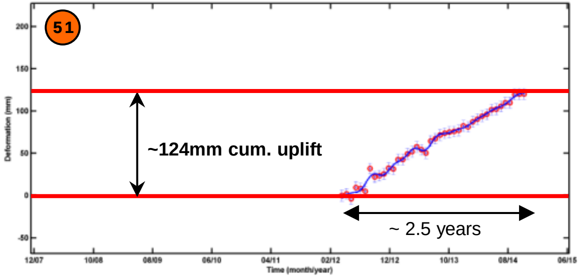
Vertical Deformation (mm)

Measured CRs





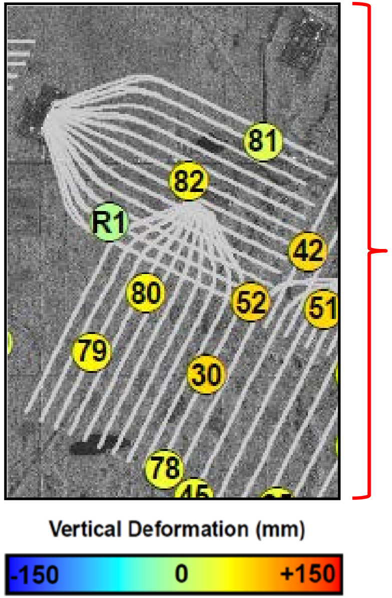




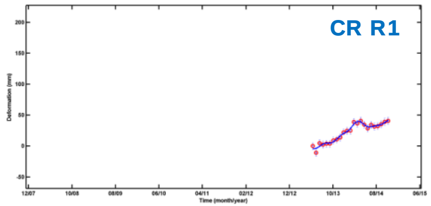
- Greatest uplift observed over the B03, B04, and B05 pads was as high as 124mm (CR#51)
- Vertical deformation over B03, B04, and B05 ranged between 20mm-124mm
- Greatest uplift observed over B06 was ~75mm (CR #63)

Cumulative vertical deformation: Phase E

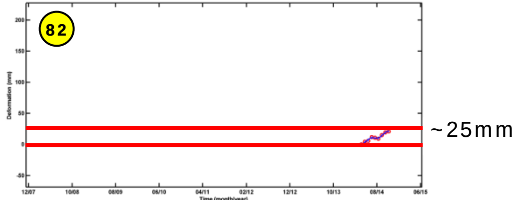
April 14, 2014 to October 23, 2014 (~6 months)

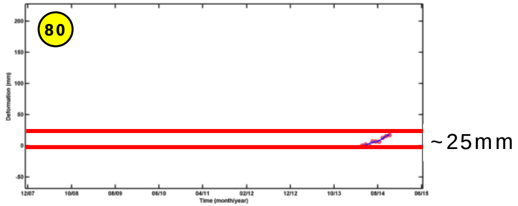


Reference CR



Measured CRs





Appendix 2
Subsection 3.1.1 – 5d)
Piezometer data

Piezometer summary

UWI	Year Landed	Cemented or Hanging	TVD	Piezometer Location	Pad
1AA/6-35-75-6W4/00	2011	Cemented	254.5	Water	Clearwater
			306.5	Water	
100/7-36-75-6W4/00	2011	Cemented	263.0	Water	Clearwater
			315.0	Water	
	2013	Hanging	419.0	Water	McMurray BW
100/10-34-75-6W4/00	2008	Hanging	321.0	Water	Clearwater
100/12-18-76-5W4/00	2010	Cemented	264.0	Water	Clearwater
			300.0	Water	
			412.0	Water	McMurray BW
1AA/6-2-76-6W4/00	2002	Cemented	342.5	Gas	C06 Pad
			366.0	Gas	
			382.5	SAGD	
			390.0	SAGD	
			401.5	Water	
102/3-8-76-6W4/00	2005	Hanging	418.5	Water	McMurray BW
100/07-10-76-6W4/00	2011	Cemented	350.5	SAGD	C02 Pad
			398.0	Water	
100/14-10-76-6W4/00	2011	Cemented	393.5	Water	C01 Pad
102/8-11-076-06W4/00	2012	Cemented	287.0	Water	B03 Pad
			338.0	Gas	
100/12-11-76-6W4/00	2008	Cemented	340.0	Gas	B05 Pad
			345.0	Gas	
			362.0	SAGD	
			385.0	SAGD	
1AA/13-11-76-6W4/00	2010	Cemented	330.0	Gas	B05 Pad
			337.3	Gas	
			350.0	SAGD	
			357.0	SAGD	
			379.0	SAGD	
100/15-11-76-6W4/00	2005	Cemented	332.0	Gas	B05 Pad
			342.0	SAGD	
			348.0	Gas	
			374.0	SAGD	
			401.0	Water	
102/6-12-76-6W4/00	2005	Cemented	333.5	Gas	B06 Pad
			348.0	SAGD	
			366.0	Gas	
			378.0	SAGD	
			395.0	SAGD	
100/13-12-76-6W4/00	2008	Cemented	331.5	Gas	B03 Pad
			349.5	Gas	
			360.0	SAGD	
			380.0	SAGD	
1AA/5-13-76-6W4/00	1998	Cemented	335.0	Gas	B07 Pad
			346.0	Gas	
			358.0	SAGD	
			368.0	SAGD	
			383.0	SAGD	
100/9-13-76-6W4/00	2005	Cemented	333.8	Gas	B10 Pad
			343.5	Gas	
			375.0	SAGD	
			398.0	SAGD	
			407.0	Water	

Piezometer summary

100/1-14-76-6W4/00	2008	Cemented	323.5	Gas	B04 Pad
			345.0	Gas	
			355.0	SAGD	
			372.0	SAGD	
			402.0	Water	
102/5-14-76-6W4/00	2010	Cemented	345.0	SAGD	B11 Pad
			393.0	Water	
100/9-14-76-6W4/00	2012	Cemented	279.2	Water	Clearwater
102/11-14-76-6W4/00	2005	Cemented	322.0	Gas	B11 Pad
			332.0	Gas	
			344.5	Gas	
			362.0	SAGD	
			385.0	SAGD	
112/2-15-76-6W4/00	2012	Cemented	226.2	Water	B01 Pad
			280.2	Water	
			348.3	Gas	
102/3-15-76-6W4/00	2011	Cemented	342.5	Gas	B01 Pad
			354.8	SAGD	
			366.0	SAGD	
100/4-15-76-6W4/00	2011	Cemented	351.5	SAGD	B01 Pad
			363.5	SAGD	
100/5-15-76-6W4/00	2004	Cemented	323.0	Gas	B01/B02 Pad
			340.5	Gas	
			350.5	SAGD	
			365.0	SAGD	
			396.0	Water	

100/8-15-76-6W4/00	2004	Cemented	325.0	Gas	C03 Pad
			334.0	Gas	
			342.5	Gas	
			356.0	SAGD	
			374.5	SAGD	
1AA/15-15-76-6W4/00	2002	Cemented	330.0	Gas	D01 Pad
			347.0	SAGD	
			358.0	SAGD	
			370.0	SAGD	
			403.0	Water	
1AA/15-02-076-06W4	2013	Cemented	395.0	Water	
100/09-15-076-6W4	2013	Cemented	275.0	Water	
			280.0	Water	
100/10-03-76-06W4	2011	Hanging	300.0	Water	Broken
108/06-15-76-06W4	2013	Cemented	331.5	Wabiskaw	Wabiskaw
			333.5	Wabiskaw	
			335.5	Wabiskaw	
			337.0	Wabiskaw	
1AB/14-14-76-6W4	2014	Cemented	237.0	Water	Wabiskaw
			286.0	Water	
			336.5	Wabiskaw	
1AB/13-13-76-6W4	2014	Cemented	239.0	Water	
			290.0	Water	
			395.0	Water	

Piezometer summary

1AB/01-10-76-6W4	2014	Cemented	244.0	Water	
			296.0	Water	
			402.0	Water	
1AA/12-03-76-6W4	2014	Cemented	259.0	Water	
			307.0	Water	
			422.0	Water	
1AB/01-02-76-6W4	2014	Cemented	265.0	Water	
			379.0	Water	
			434.0	SAGD	
			448.0	Water	
1AB/15-14-76-6W4	2014	Cemented	225.0	Water	No SCADA
			284.0	Water	
1AB/11-14-76-6W4	2014	Cemented	221.0	Water	
			277.0	Water	
1AC/06-02-76-6W4	2014	Cemented	255.0	Water	
			363.0	Water	
			410.0	Water	
1AB/03-14-76-6W4	2014	Cemented	230.0	Water	
			285.0	Water	
100/11-15-76-6W4	2014	Hanging	335.0	Wabiskaw	Wabiskaw
1AB/13-14-76-6W4/0	2015	Cemented	225.0	Water	L02
			270.0	Gas	
			340.0	Water	
			390.0	Water	
102/03-14-76-6W4/0	2012	Hanging	283.0	Water	
1AC/16-11-76-6W4/0	2014	Cemented	290.0	Water	
			331.5	Water	
1AB/16-03-76-6W4/0	2014	Cemented	246.0	Water	
			299.0	Water	
1AB/03-02-76-6W4/0	2014	Cemented	322.0	Water	

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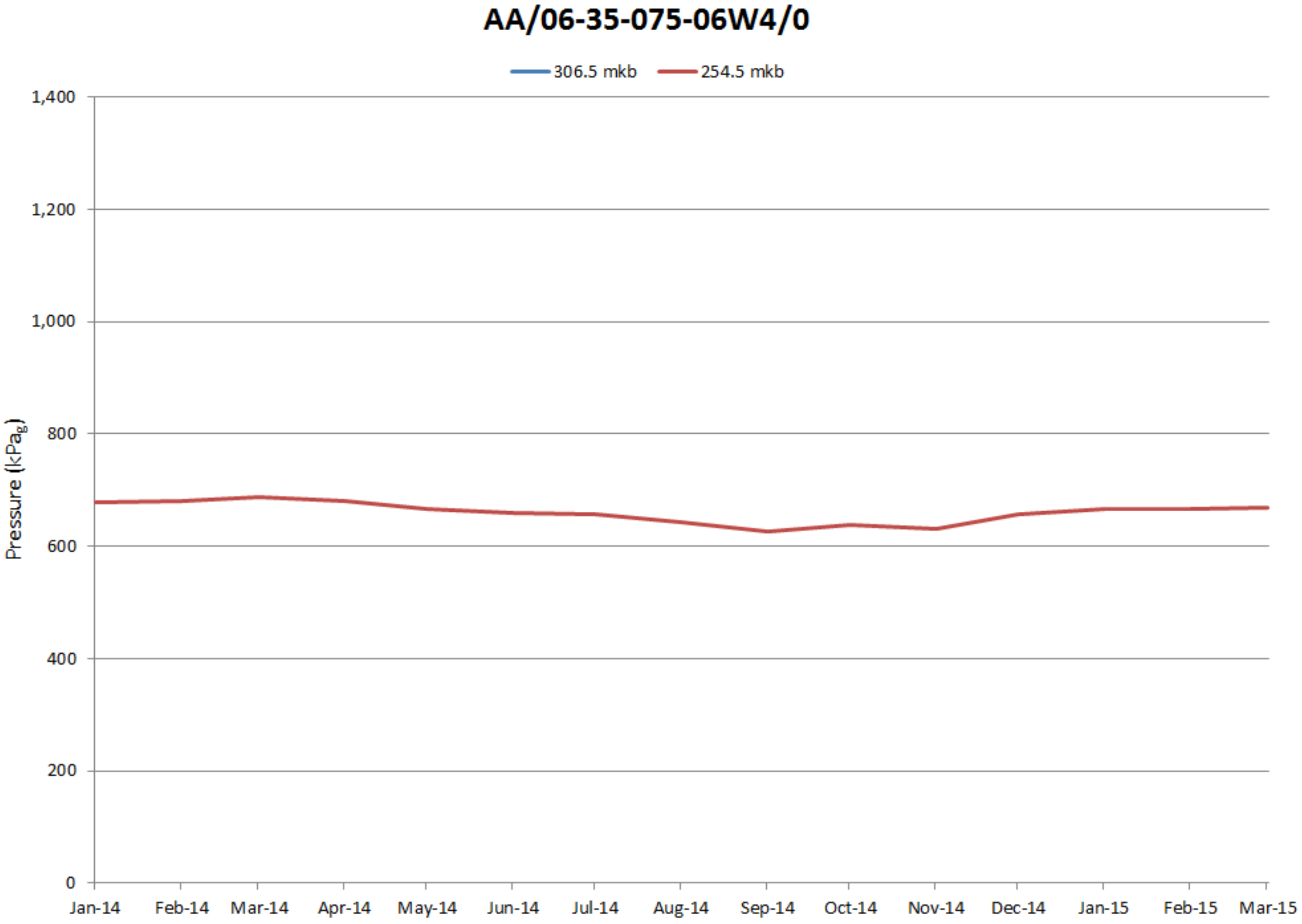
June 24, 2015



AA/06-35-075-06W4/0
306.5 mkb
254.5 mkb
1,400
1,200
1,000
800
600
400
200
0
Pressure (kPa_g)
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
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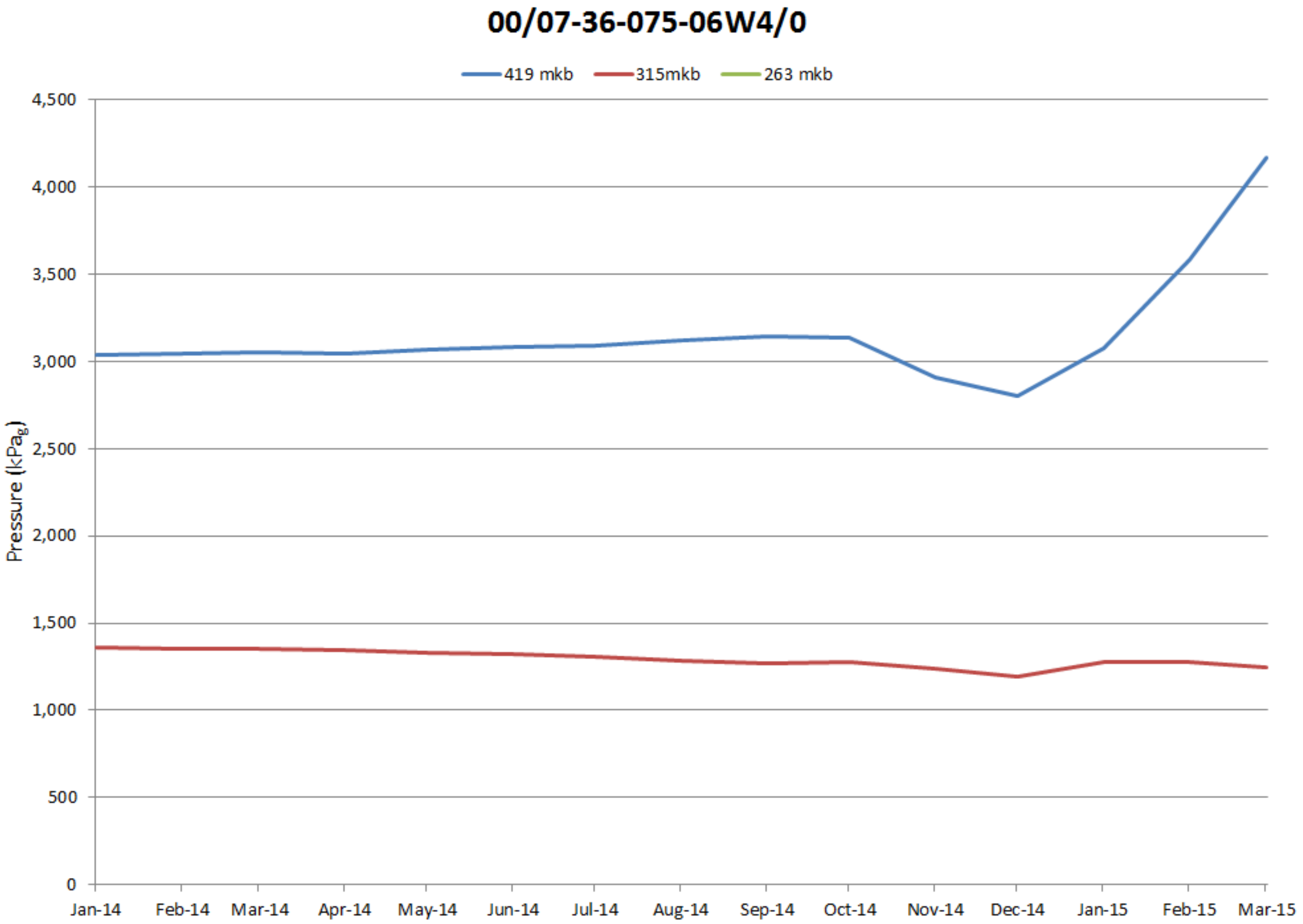
Jan-15
Feb-15
Mar-15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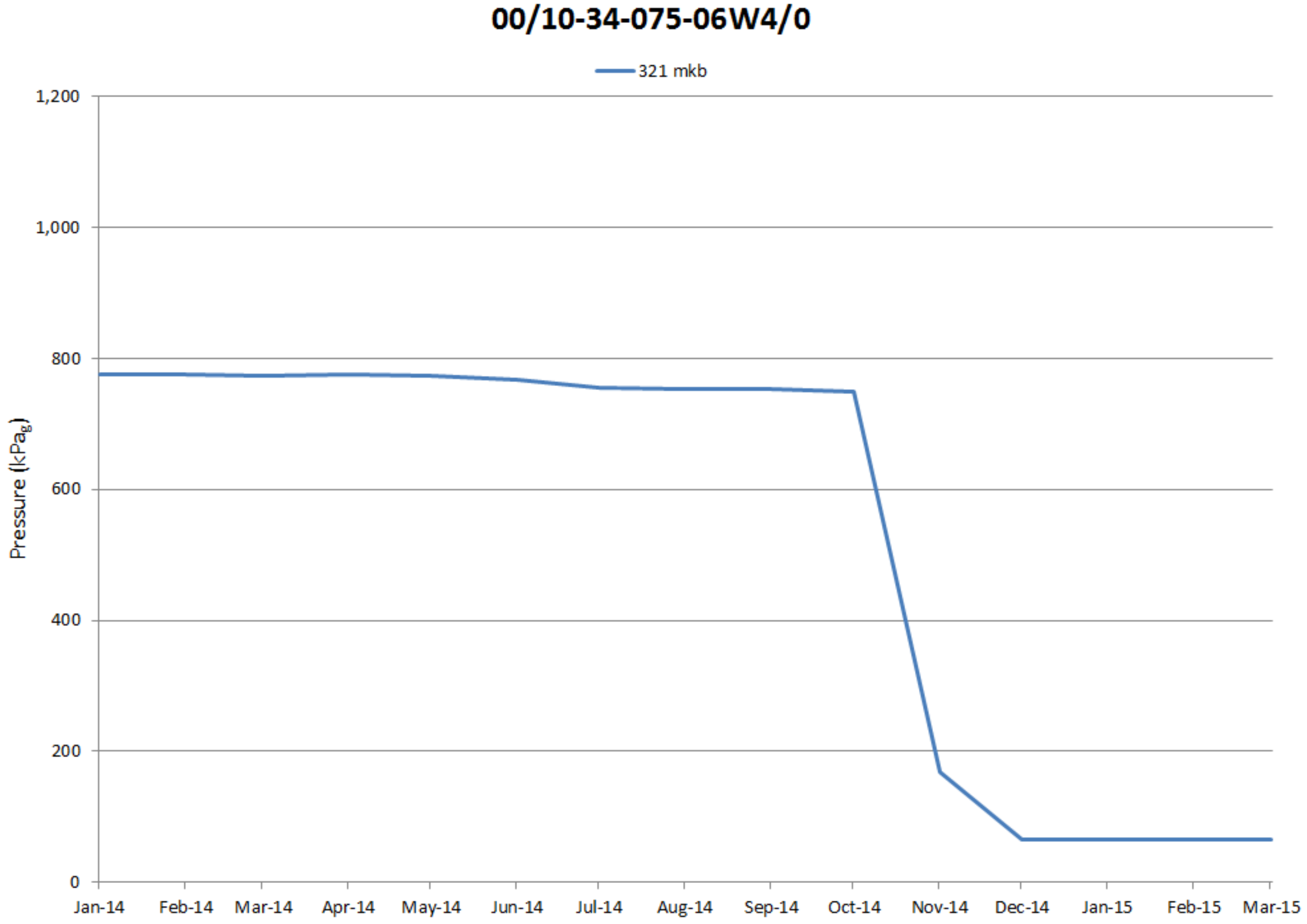
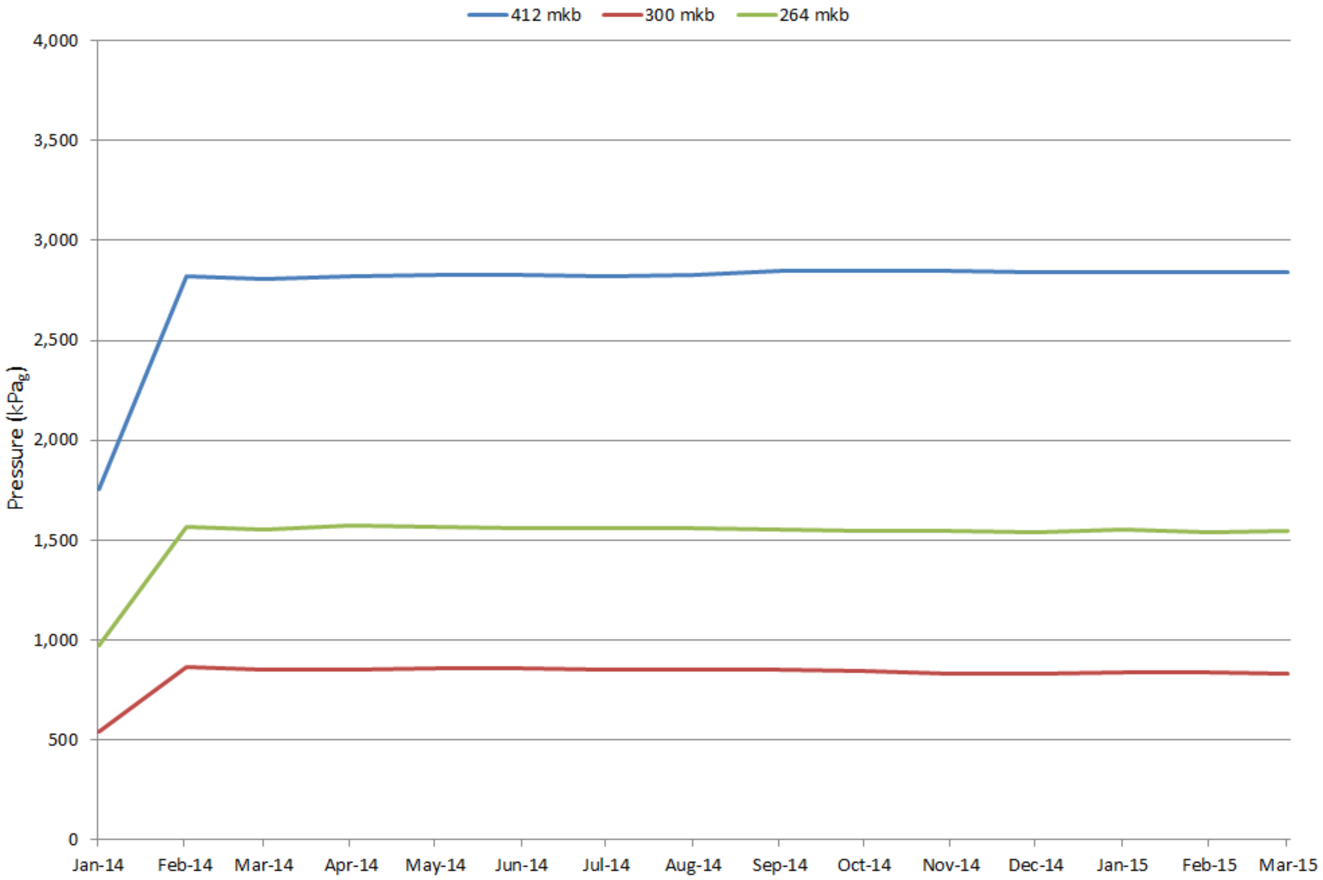
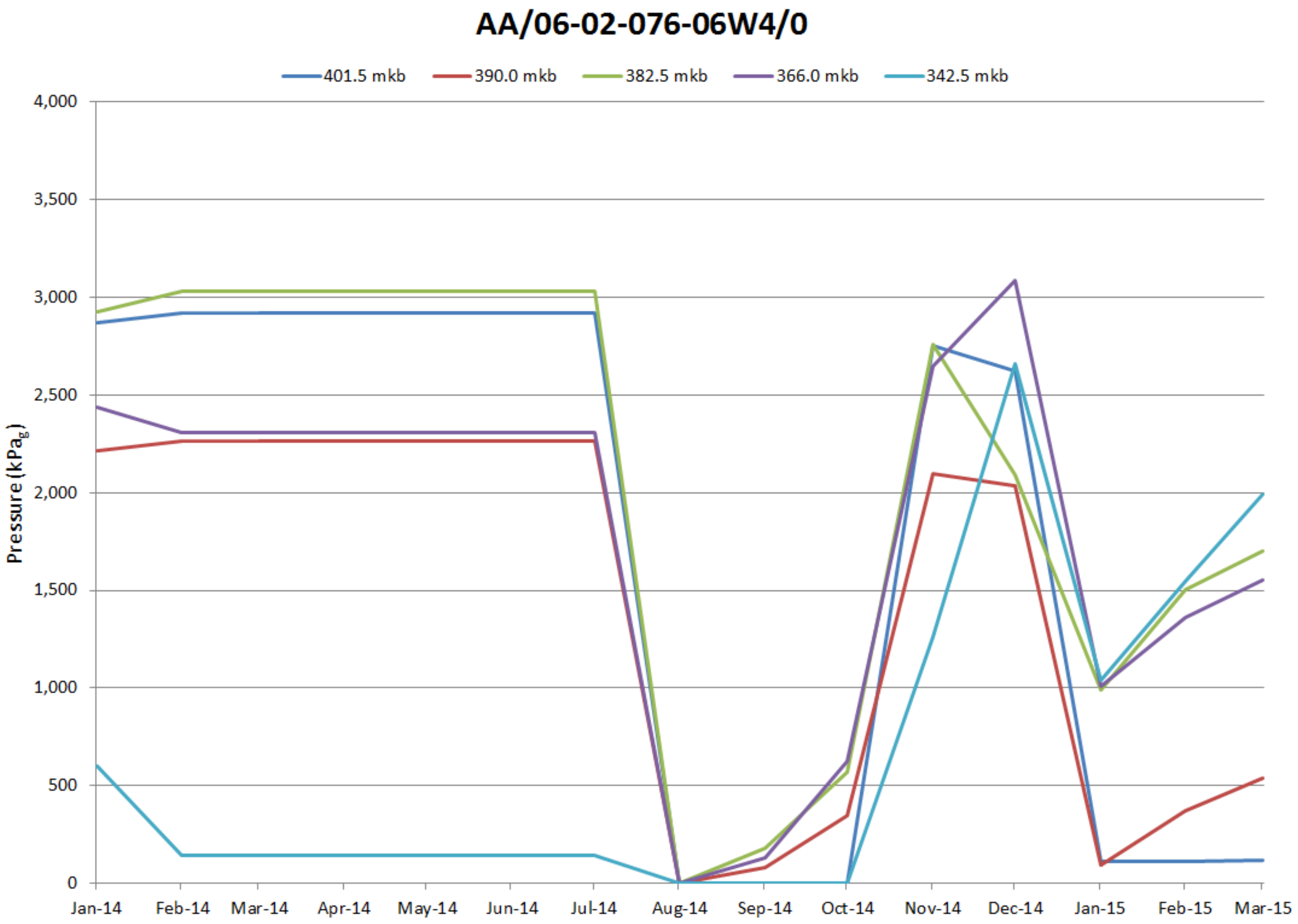
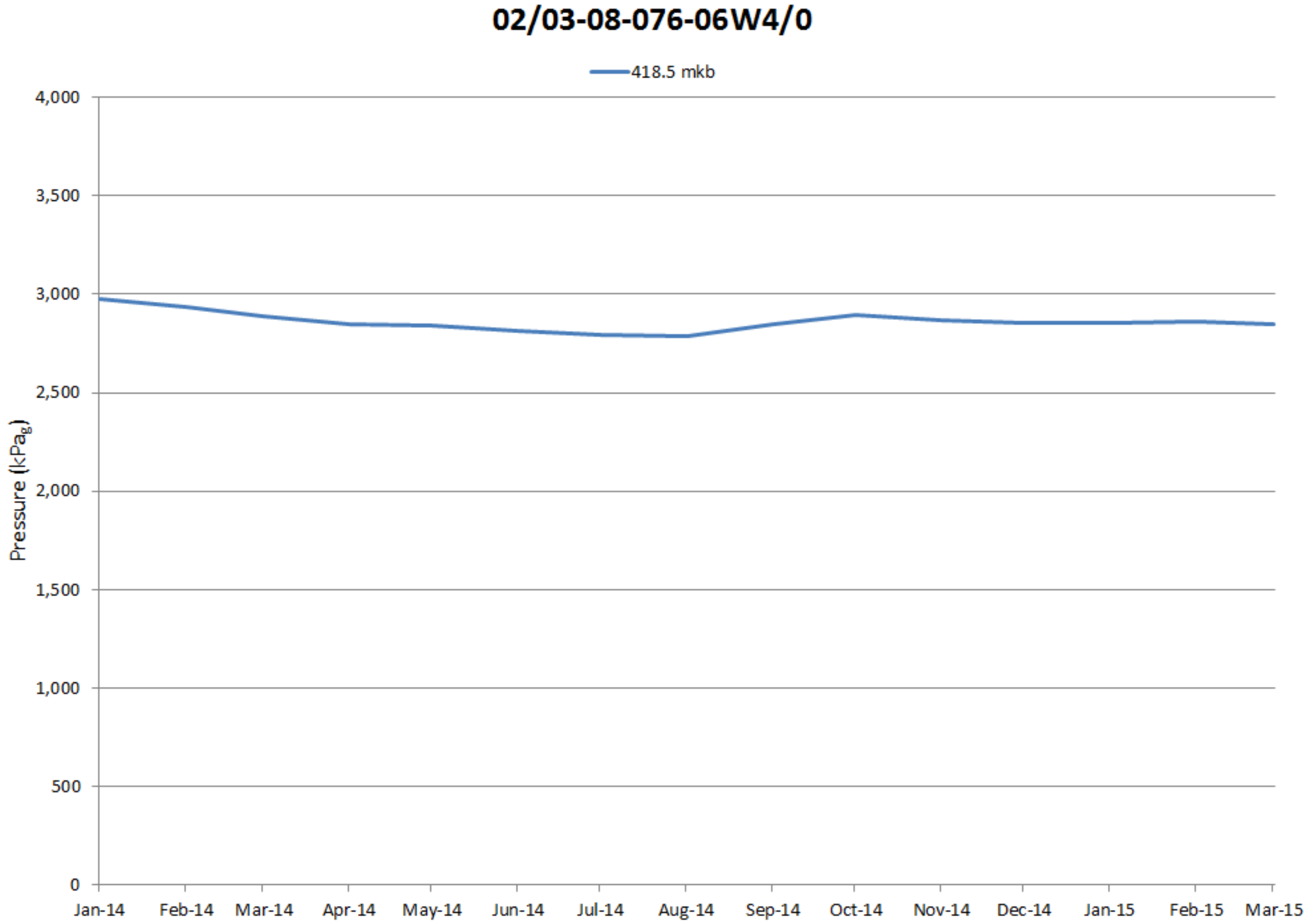
419 mkb
315mkb
263 mkb
Pressure (kPag)
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15


00/10-34-075-06W4/0
321 mkb
Pressure (kPa$_g$)
1,200
1,000
800
600
400
200
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

00/12-18-076-05W4/0




AA/06-02-076-06W4/0
401.5 mkb
390.0 mkb
382.5 mkb
366.0 mkb
342.5 mkb
Pressure (kPag)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15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418.5 mkb
Pressure (kPag)
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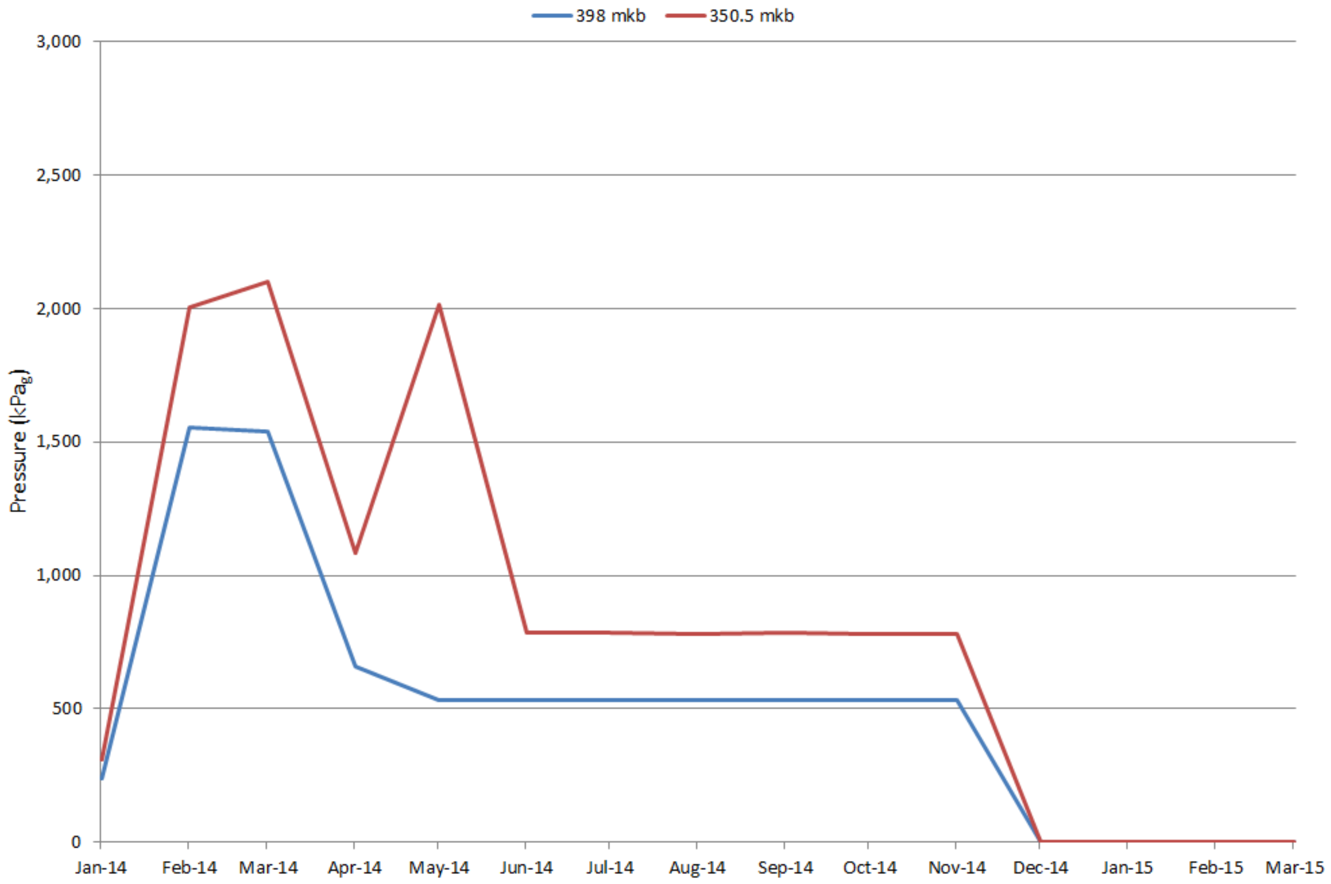
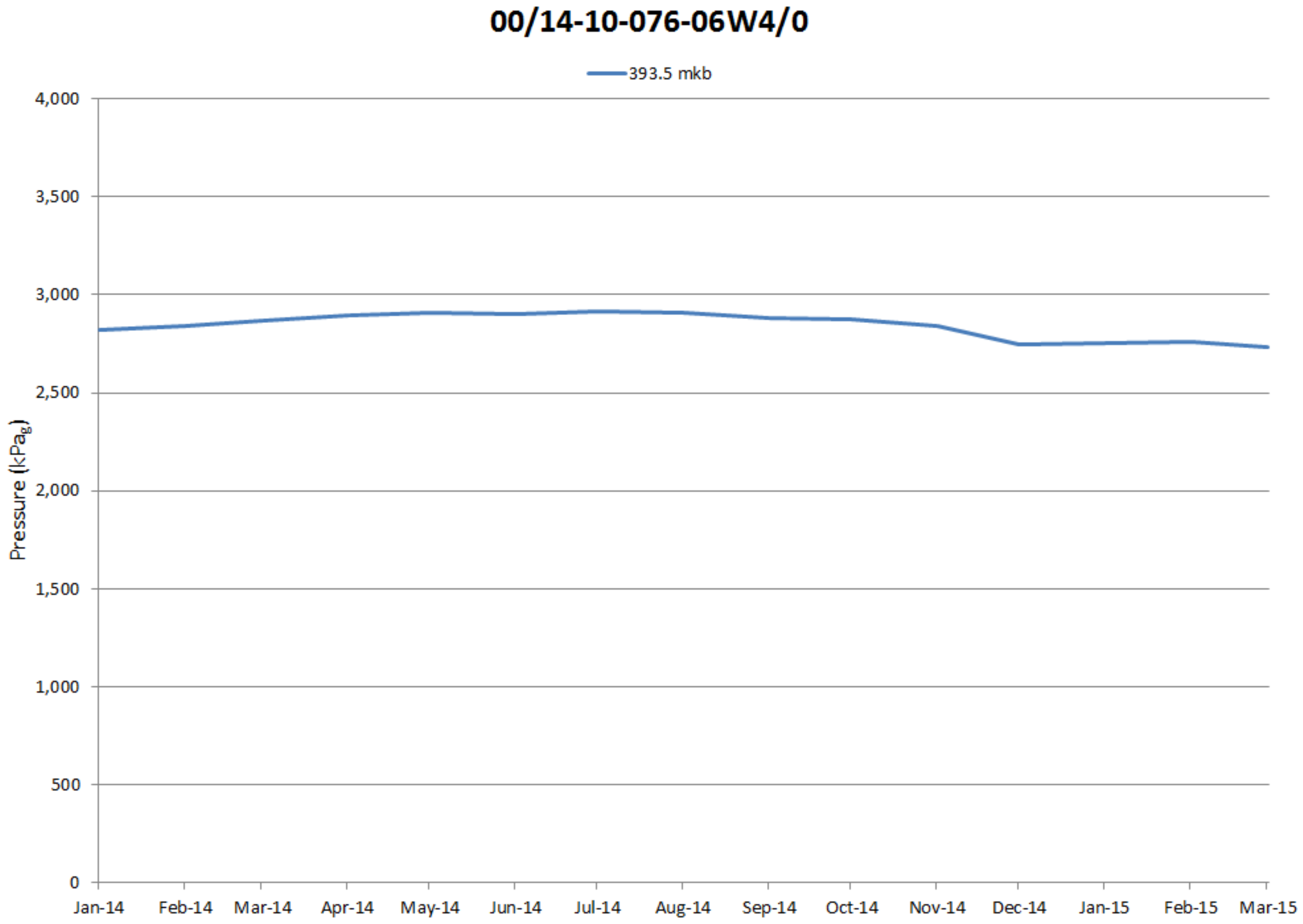
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

00/07-10-076-06W4/0




00/14-10-076-06W4/0
393.5 mkb
Pressure (kPag)
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3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
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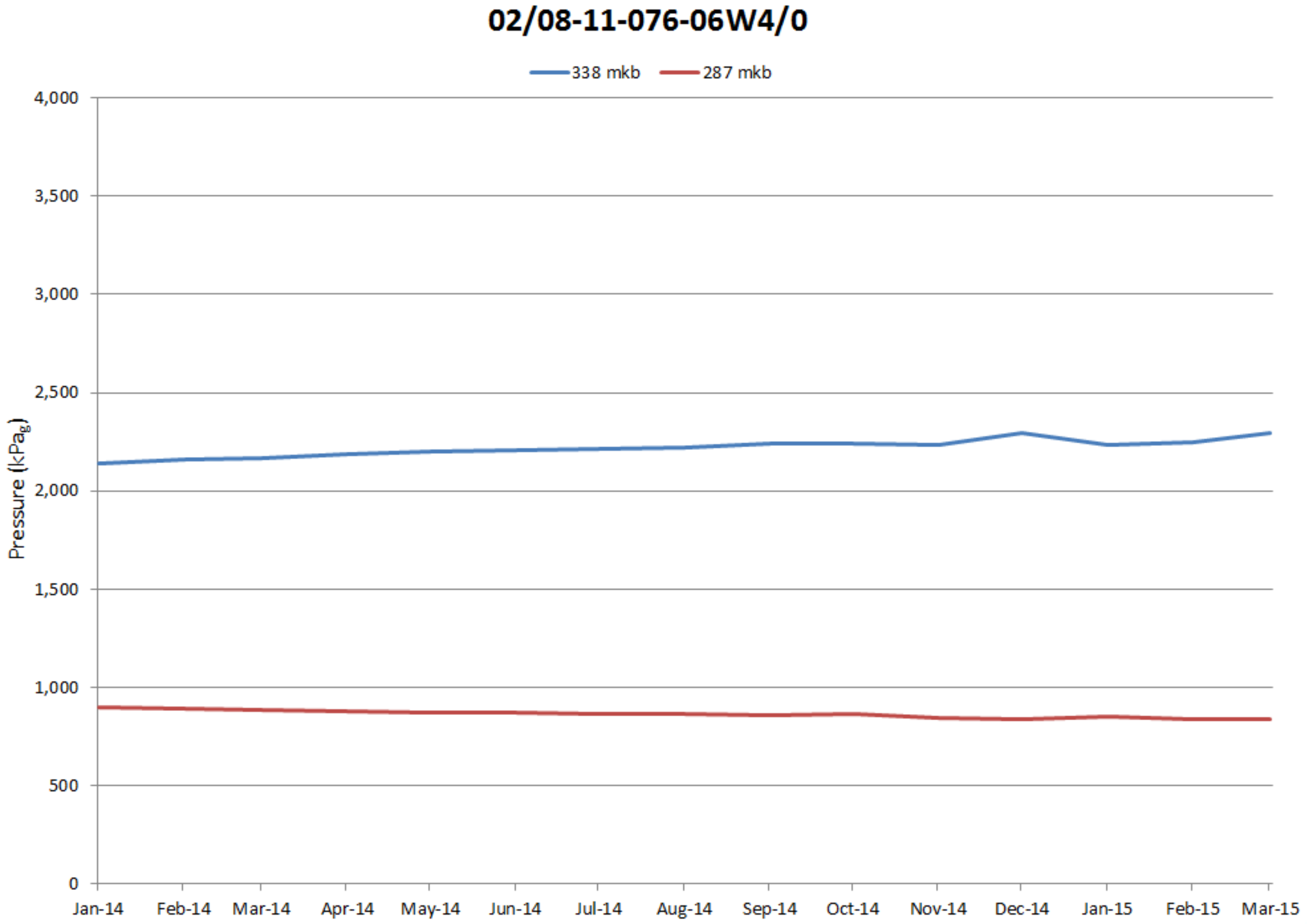
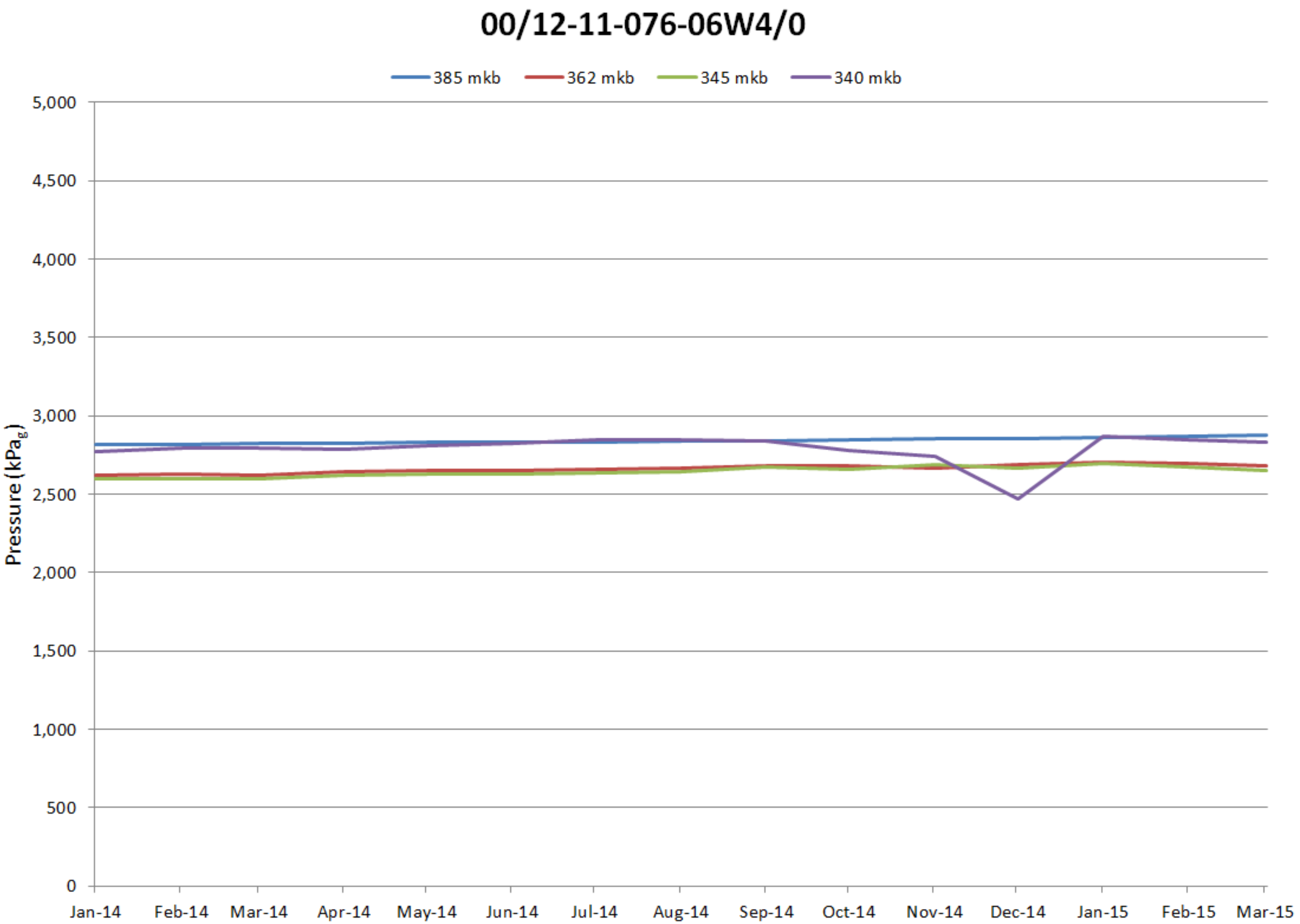
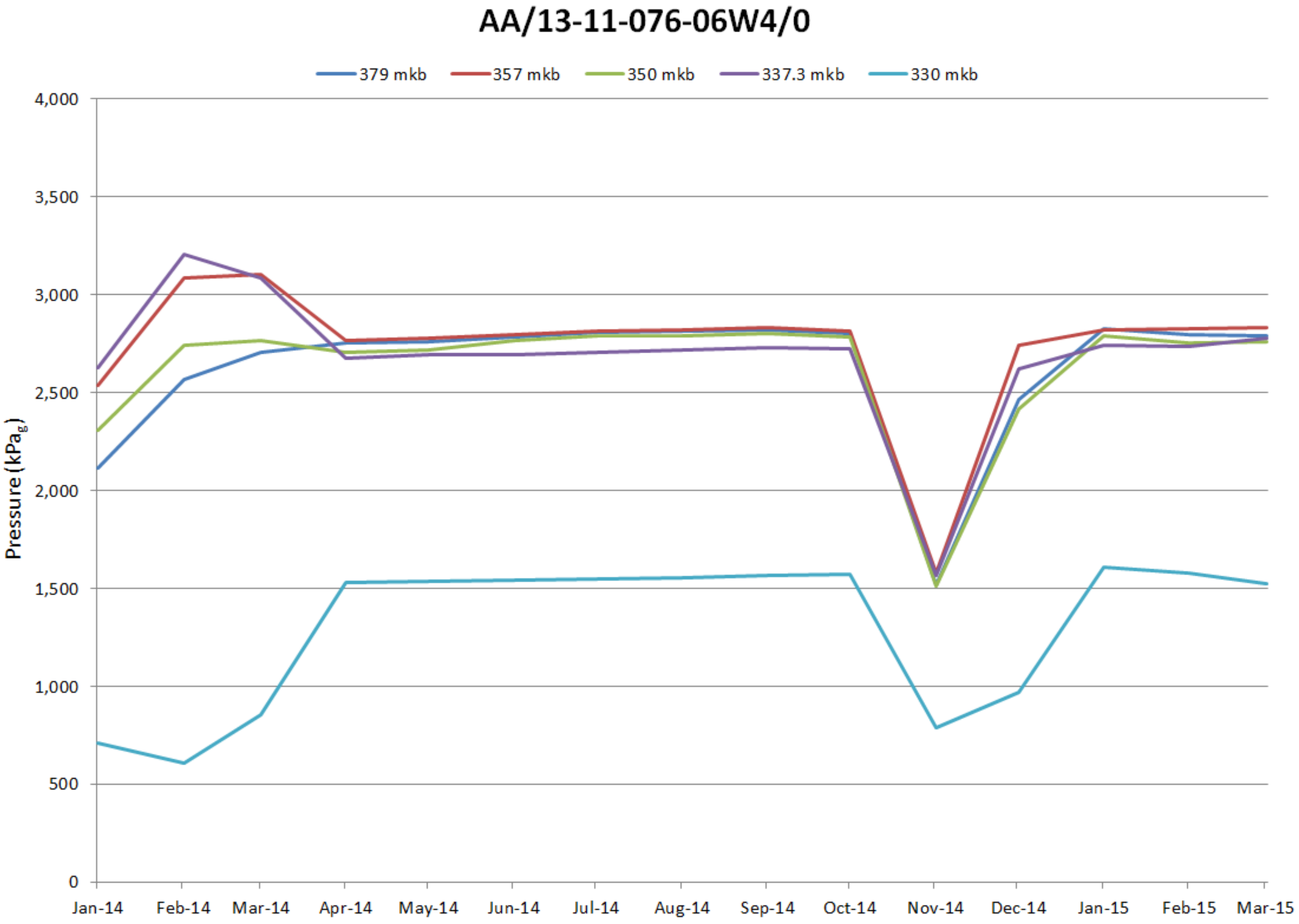
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

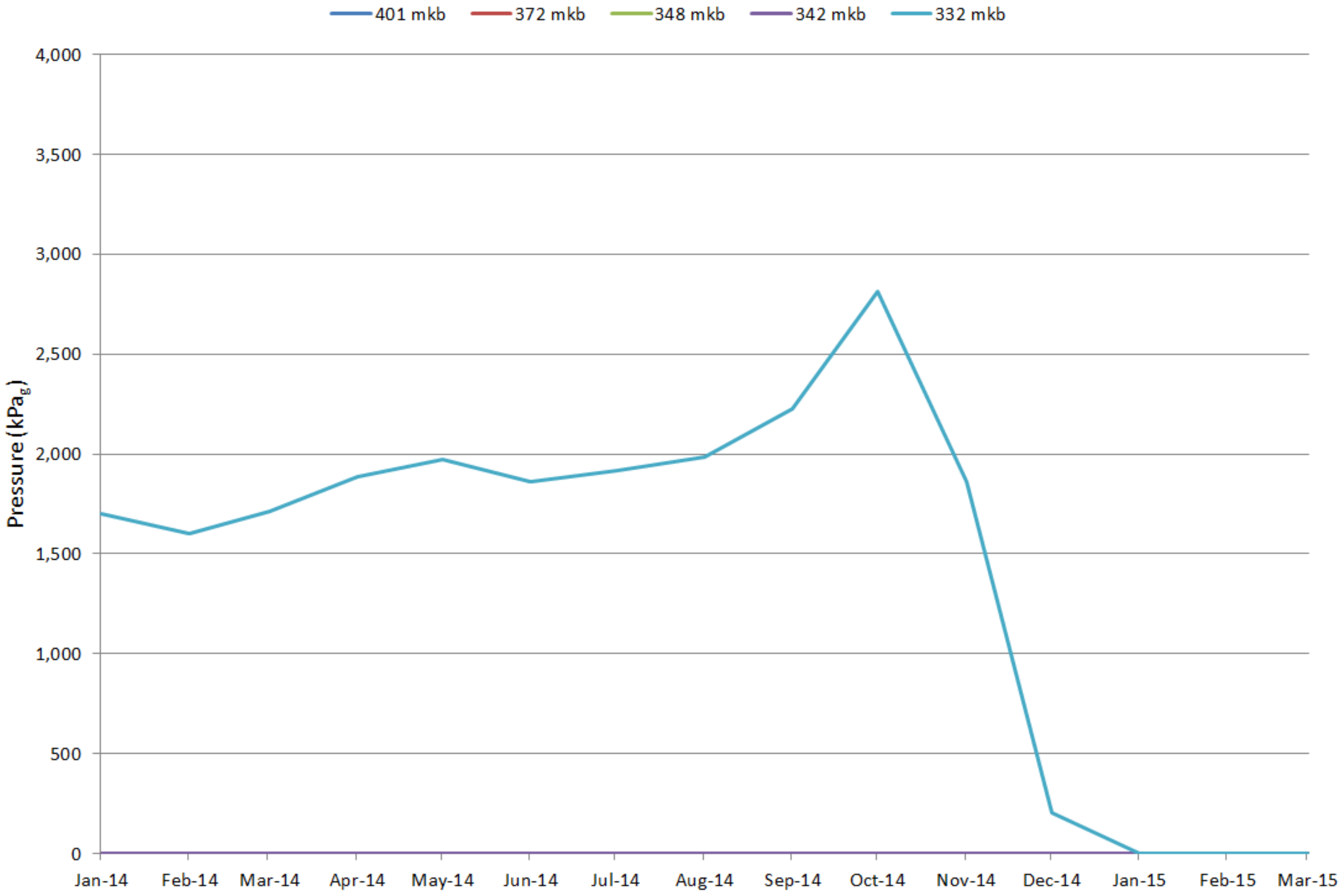

02/08-11-076-06W4/0
338 mkb
287 mkb
Pressure (kPag)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

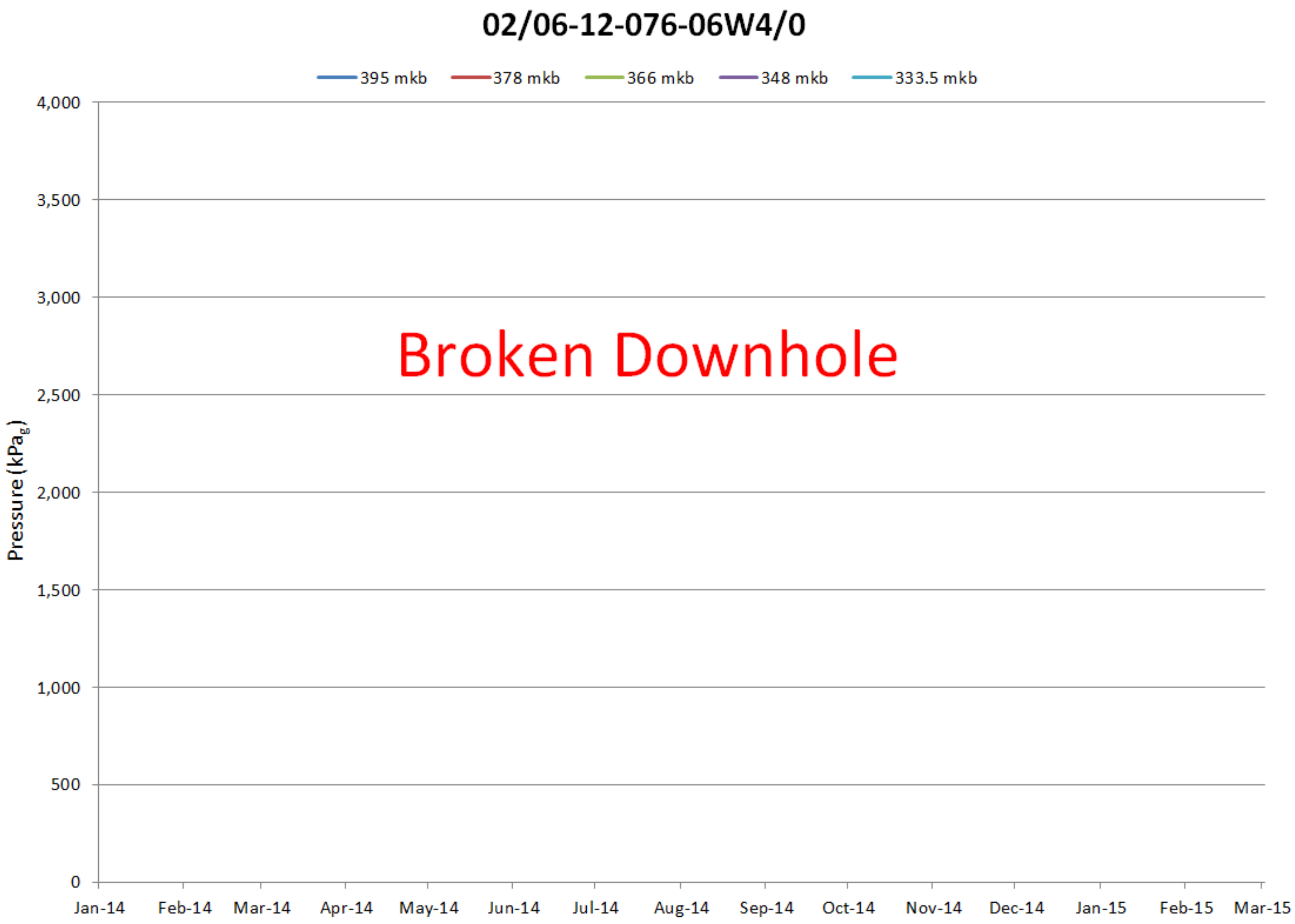


00/12-11-076-06W4/0
385 mkb
362 mkb
345 mkb
340 mkb
Pressure (kPag)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

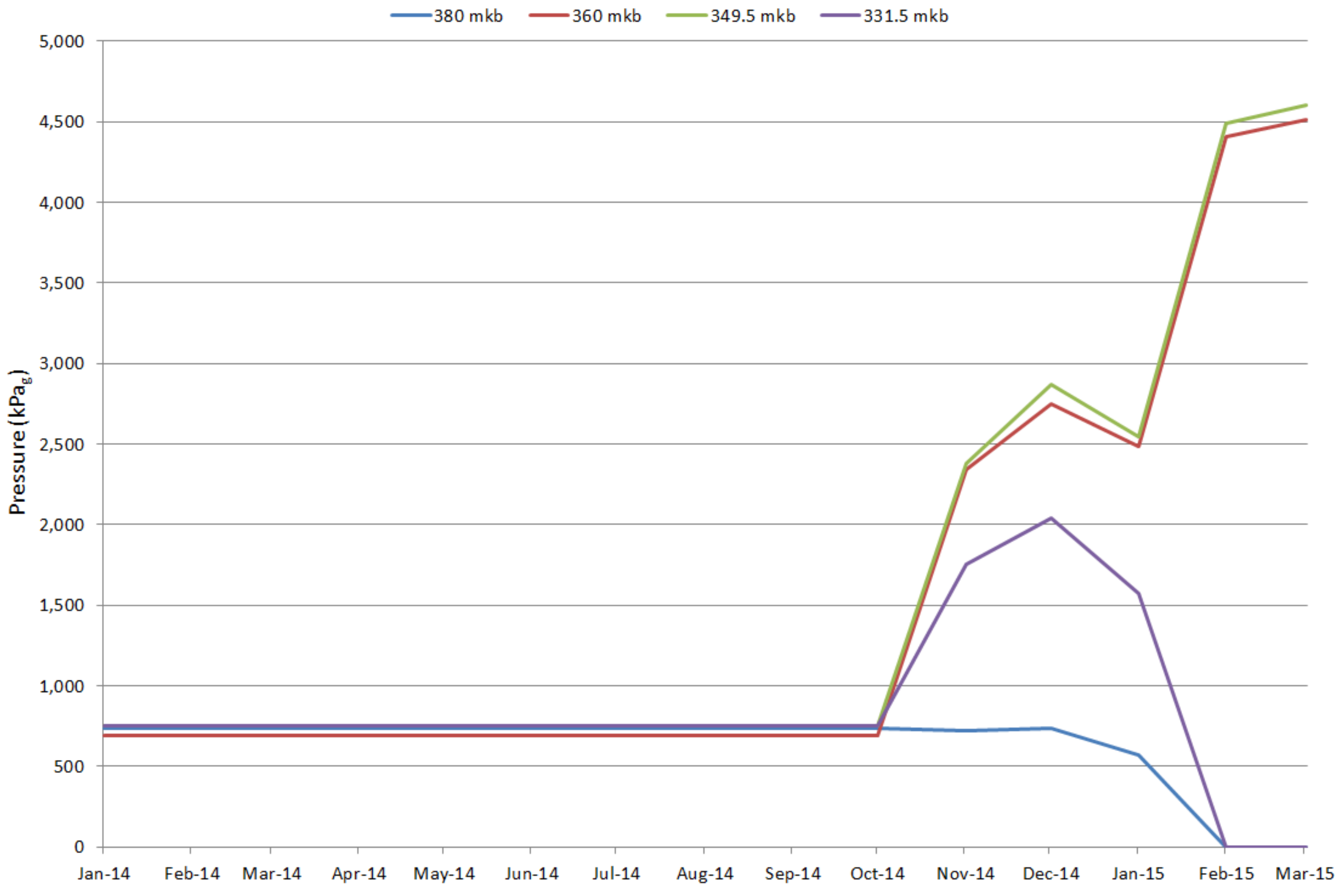

AA/13-11-076-06W4/0
379 mkb
357 mkb
350 mkb
337.3 mkb
330 mkb
Pressure (kPag)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

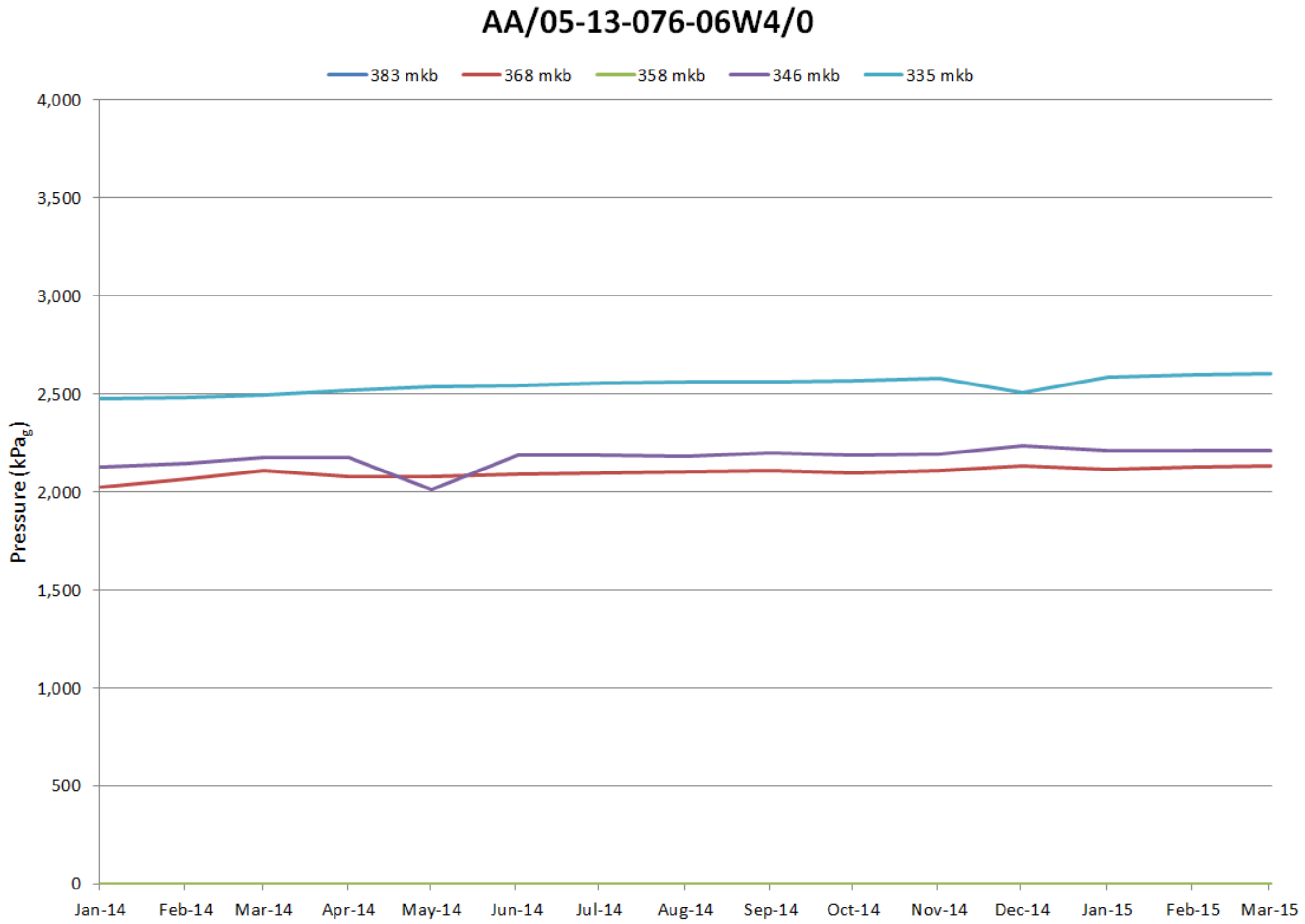
00/15-11-076-06W4M



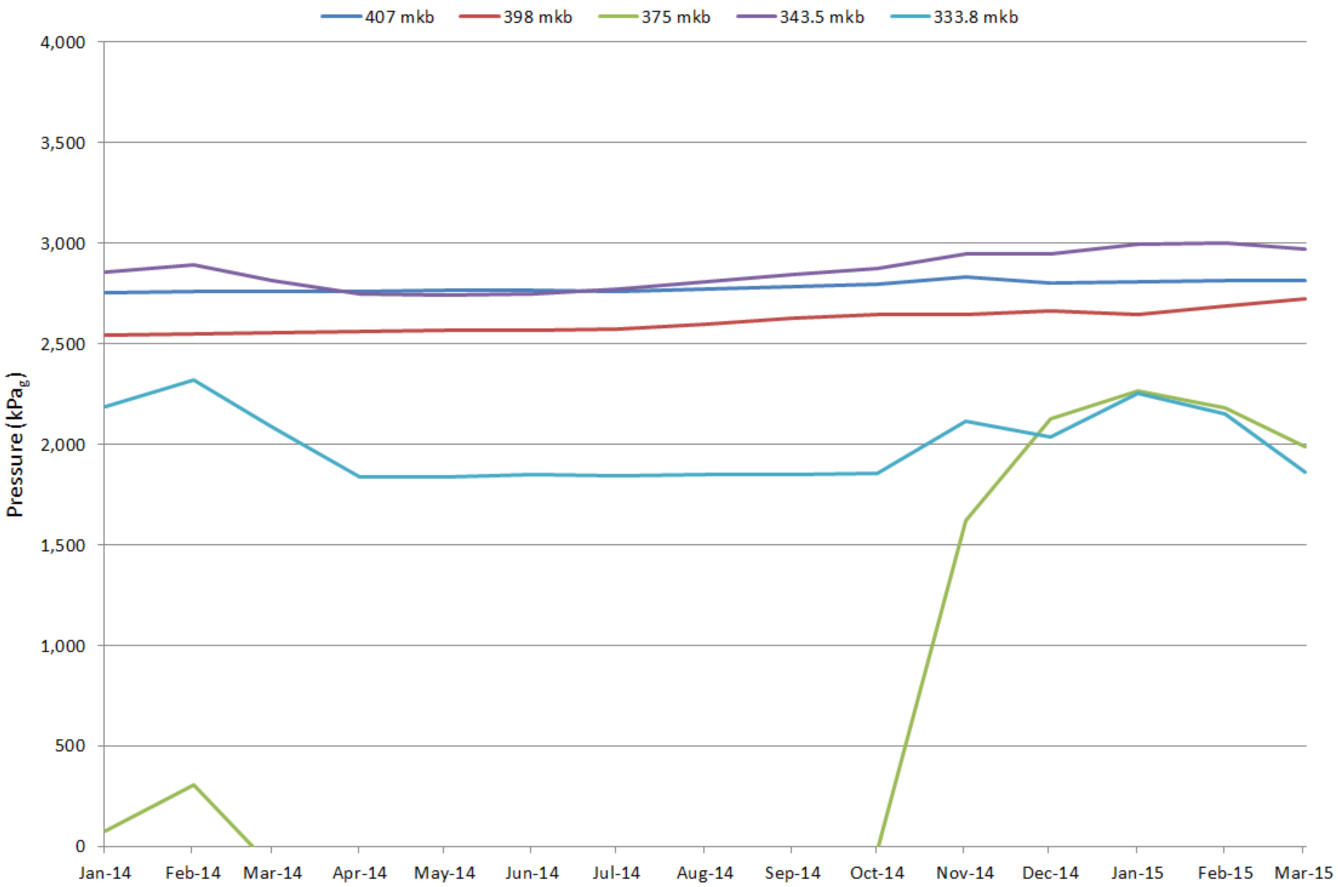

02/06-12-076-06W4/0
395 mkb
378 mkb
366 mkb
348 mkb
333.5 mkb
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPag)
Broken Downhole
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

00/13-12-076-06W4/0

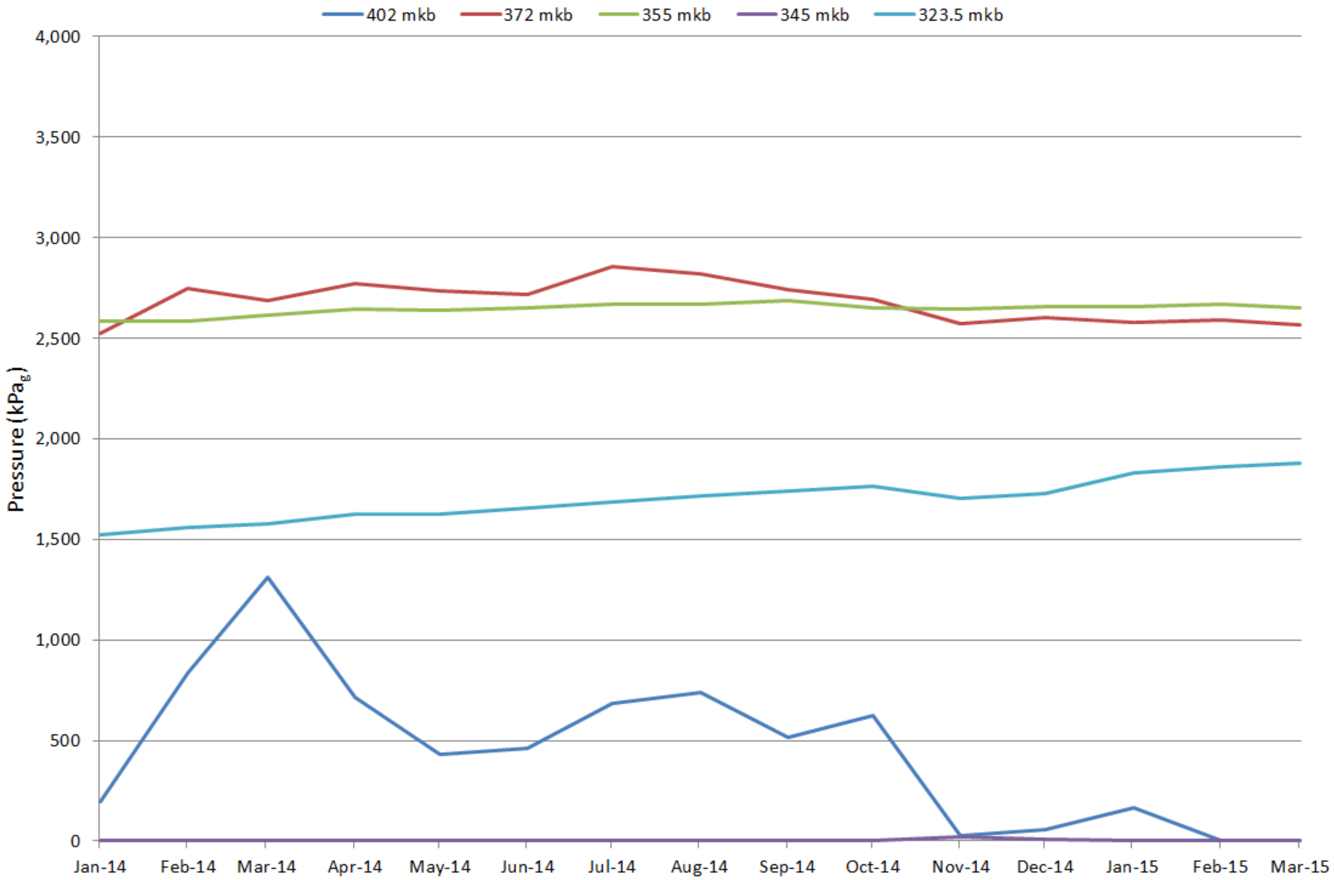



AA/05-13-076-06W4/0
383 mkb
368 mkb
358 mkb
346 mkb
335 mkb
Pressure (kPag)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

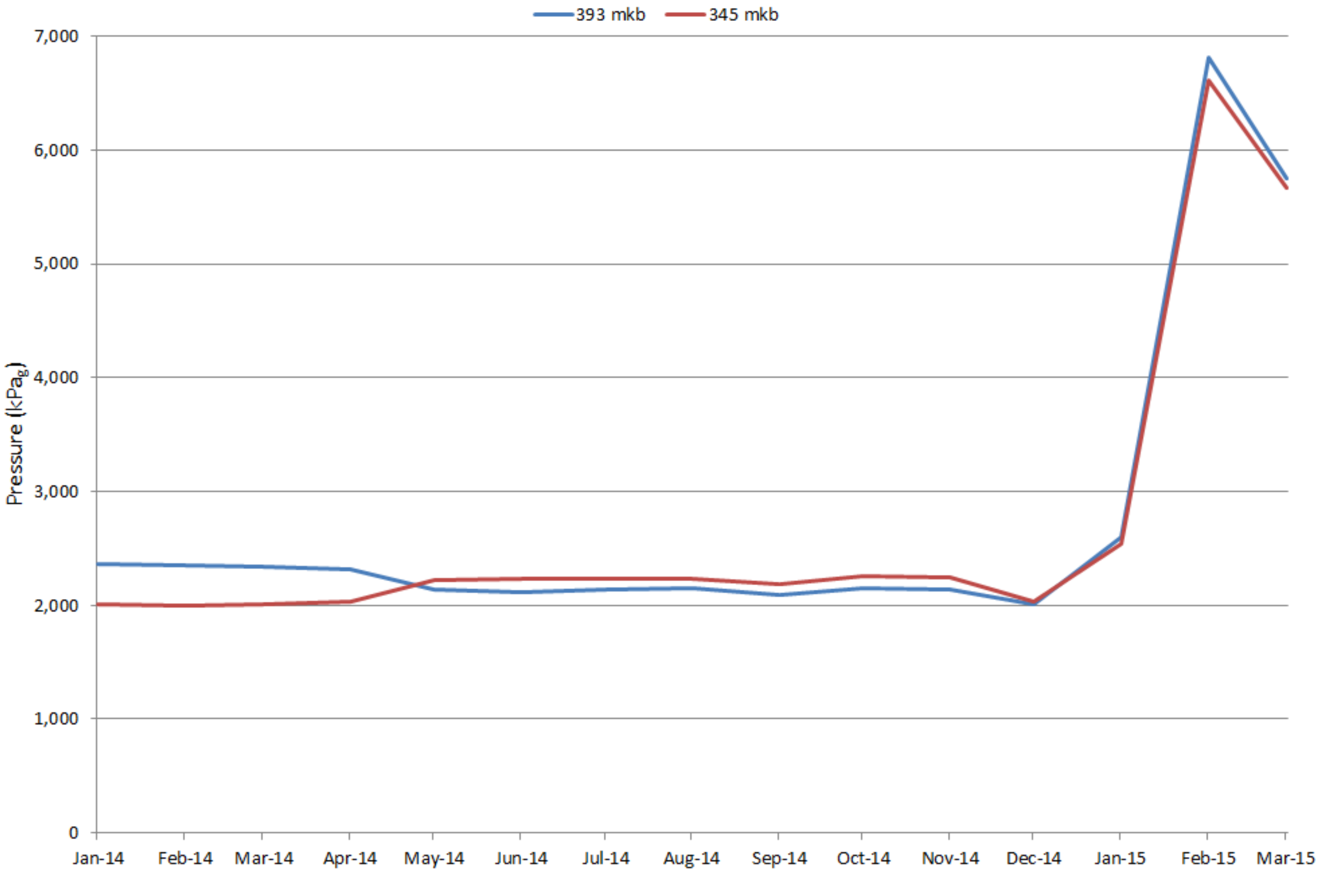
00/09-13-076-06W4/0

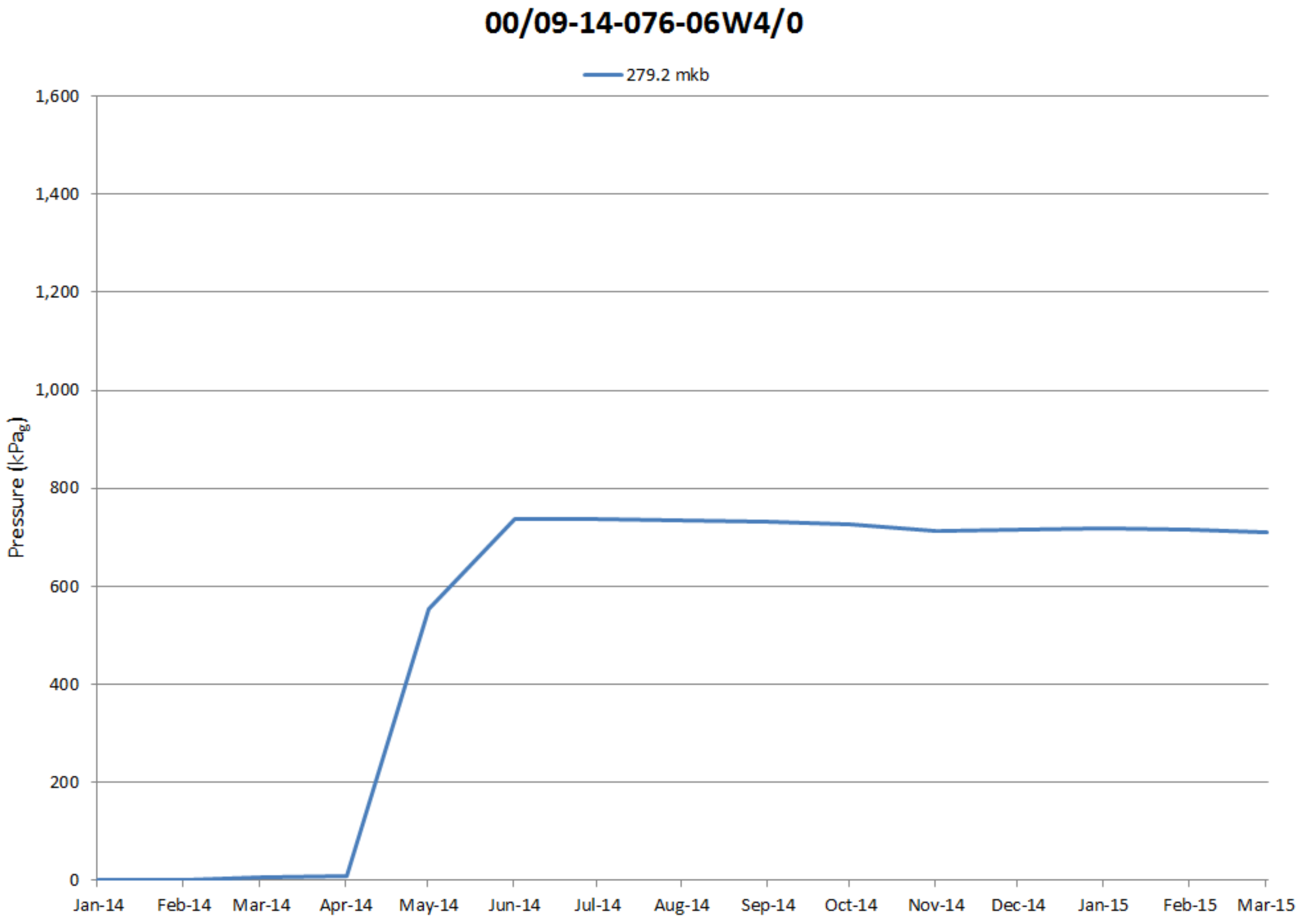


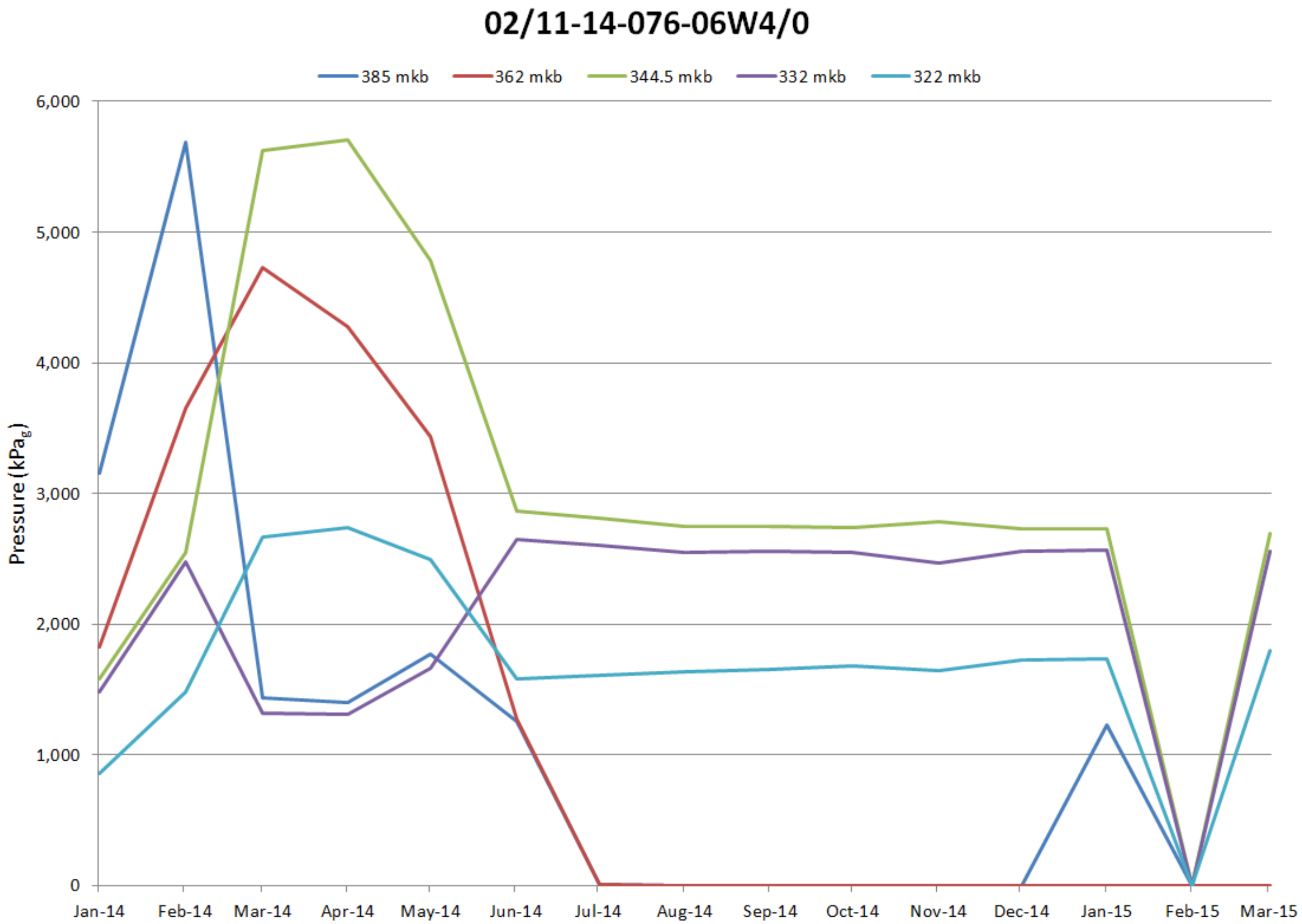
00/01-14-076-06W4/0

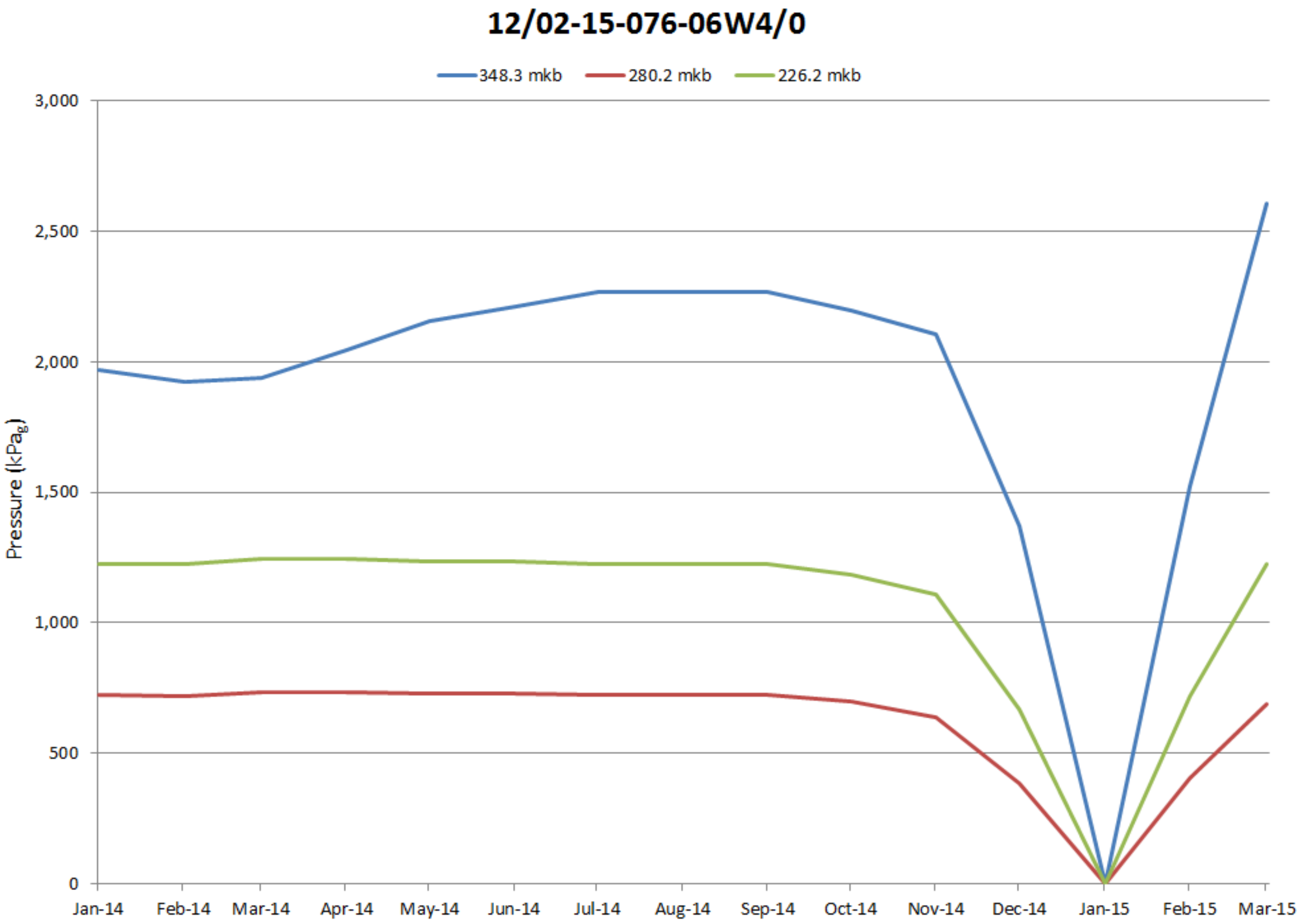


02/05-14-076-06W4/0



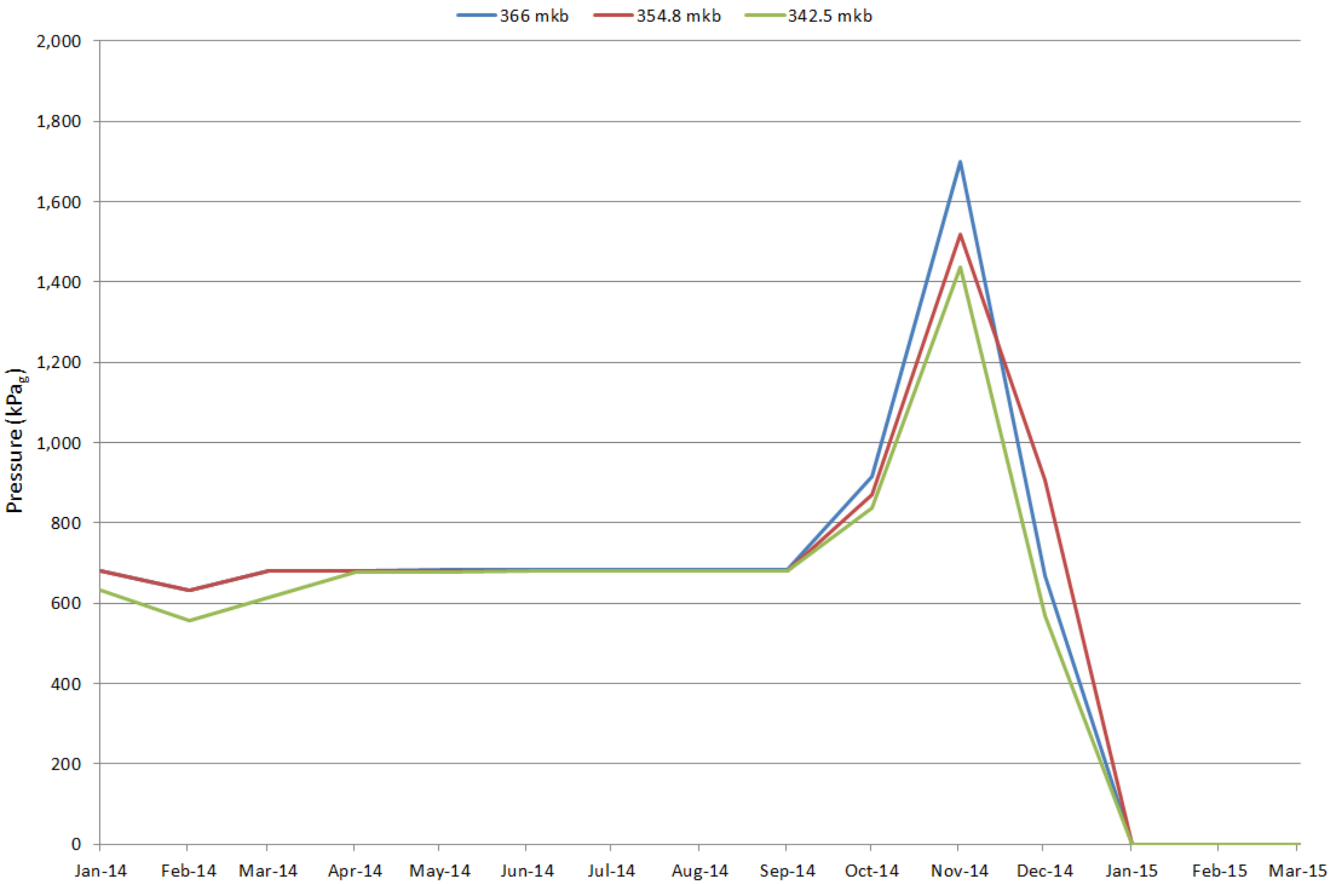

00/09-14-076-06W4/0
279.2 mkb
Pressure (kPa$_g$)
1,600
1,400
1,200
1,000
800
600
400
200
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15


02/11-14-076-06W4/0
385 mkb
362 mkb
344.5 mkb
332 mkb
322 mkb
Pressure (kPa$_g$)
6,000
5,000
4,000
3,000
2,000
1,000
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

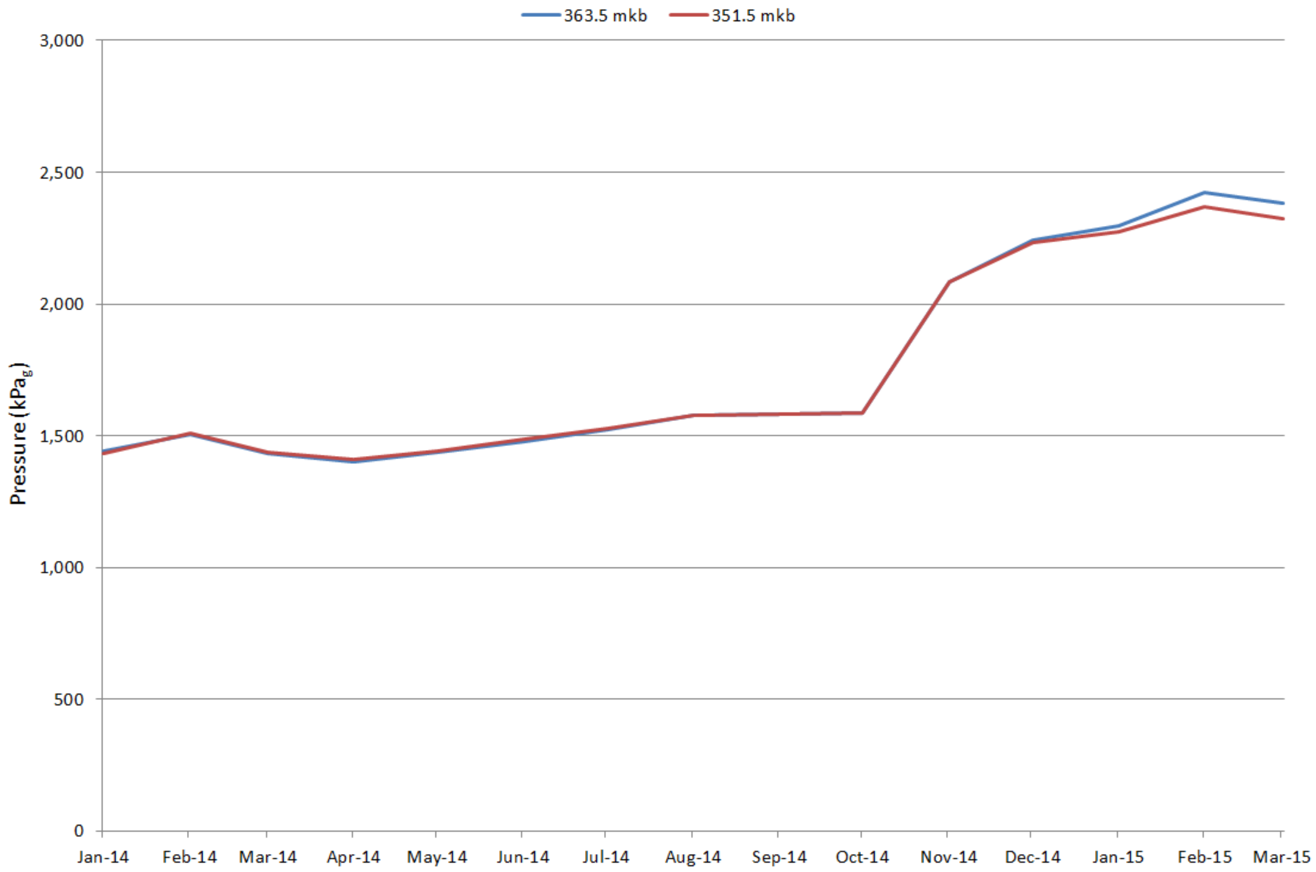


12/02-15-076-06W4/0
348.3 mkb
280.2 mkb
226.2 mkb
Pressure (kPag)
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

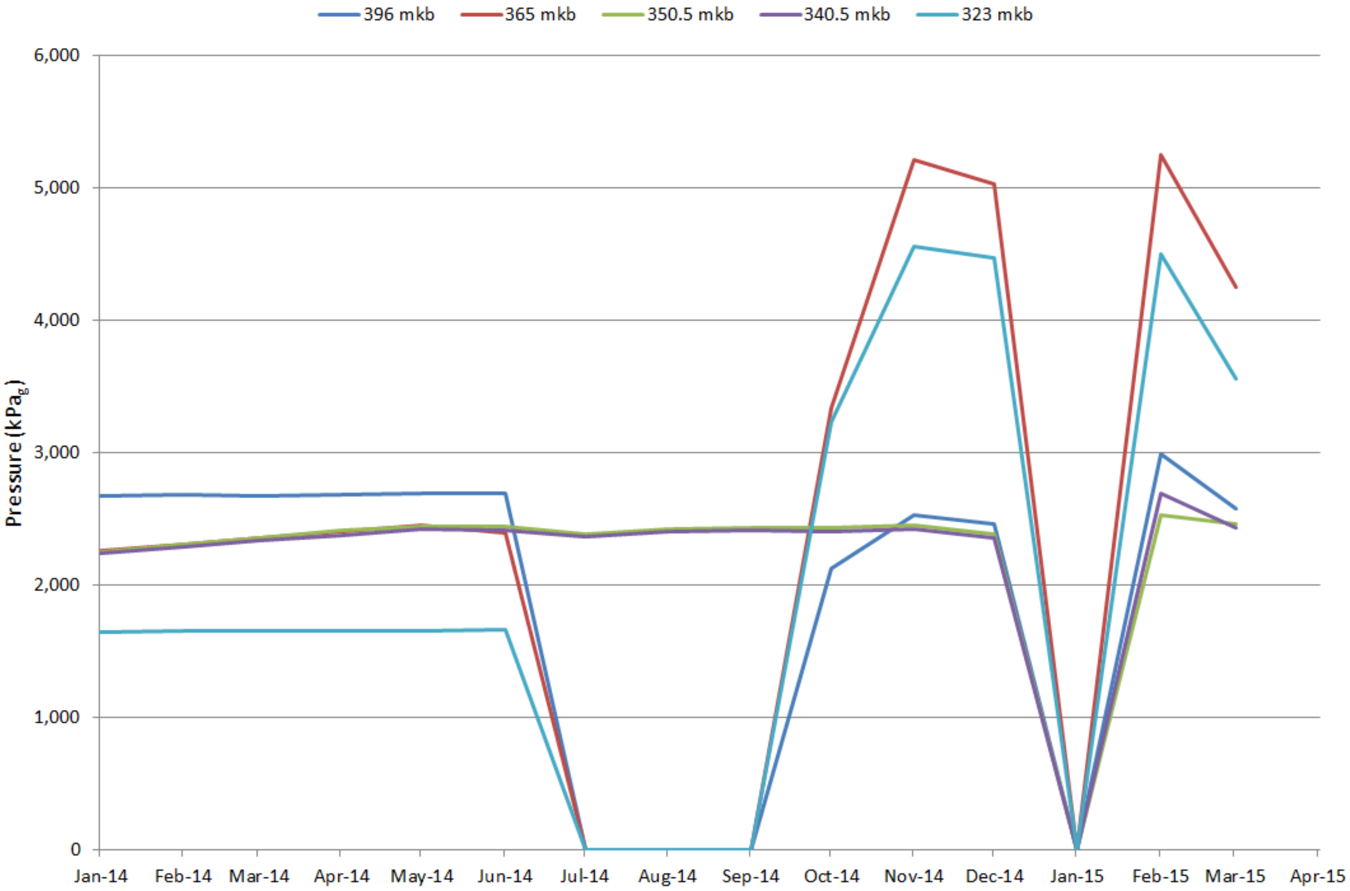
02/03-15-076-06W4/0



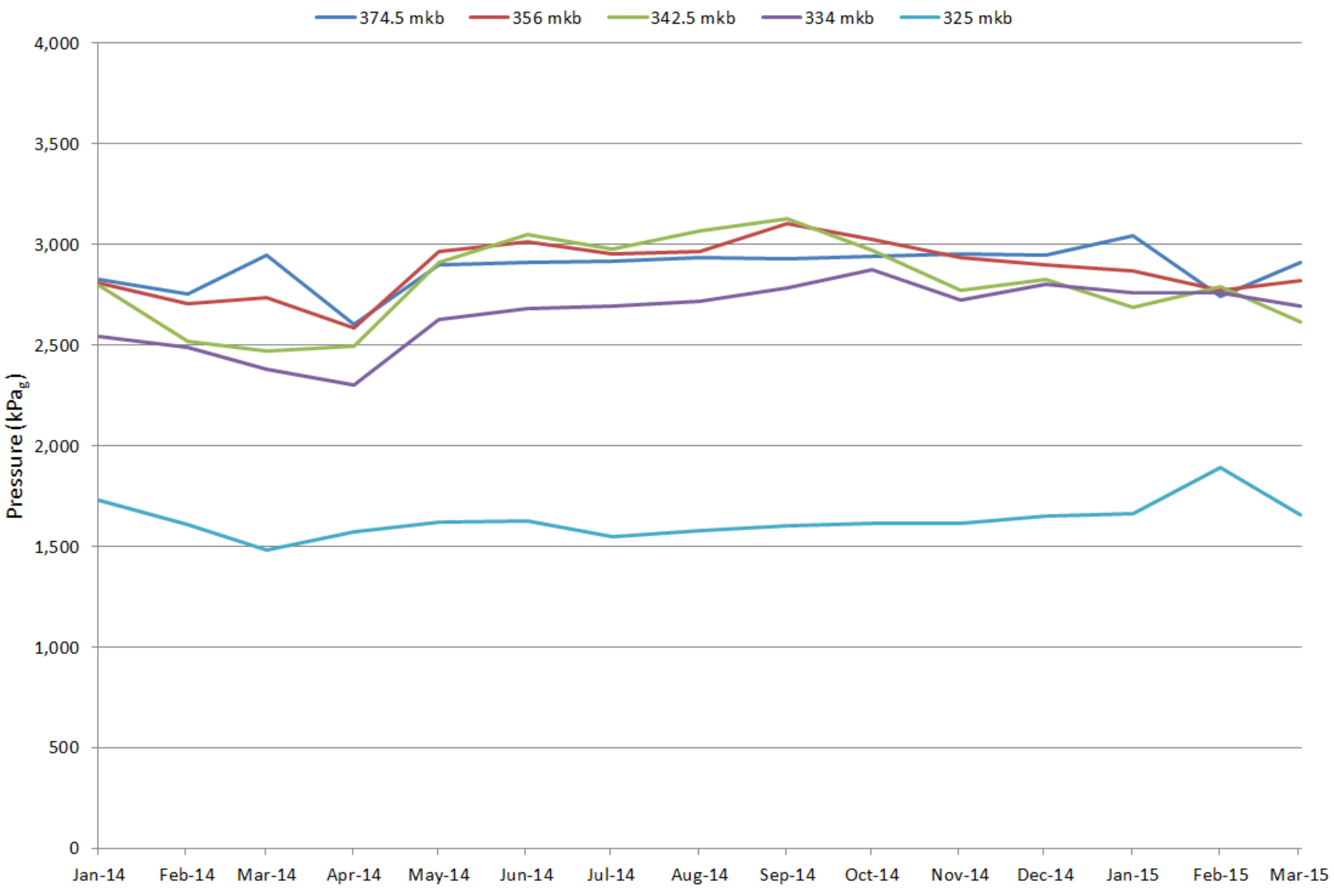
00/04-15-076-06W4/0



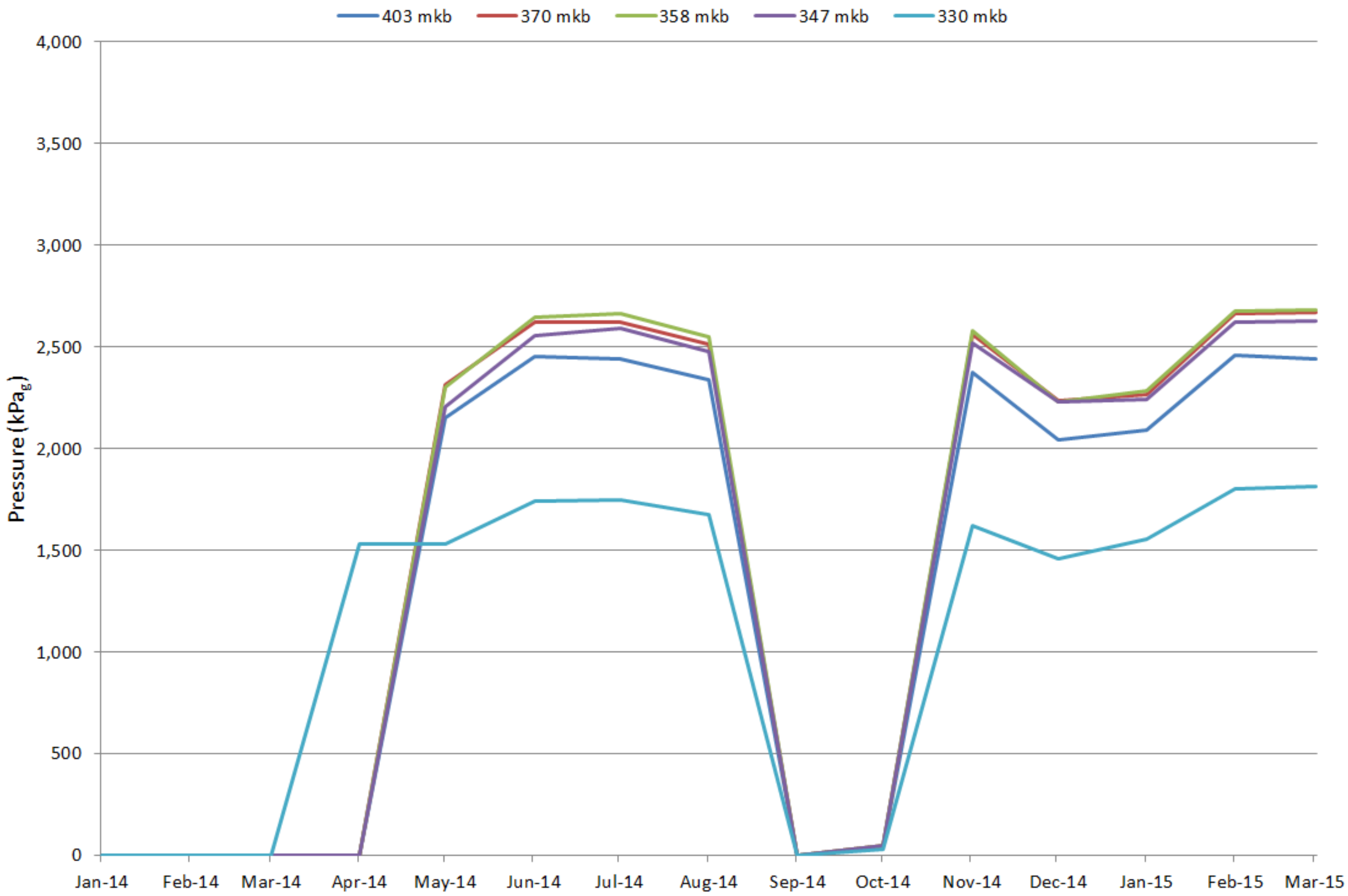
00/05-15-076-06W4M



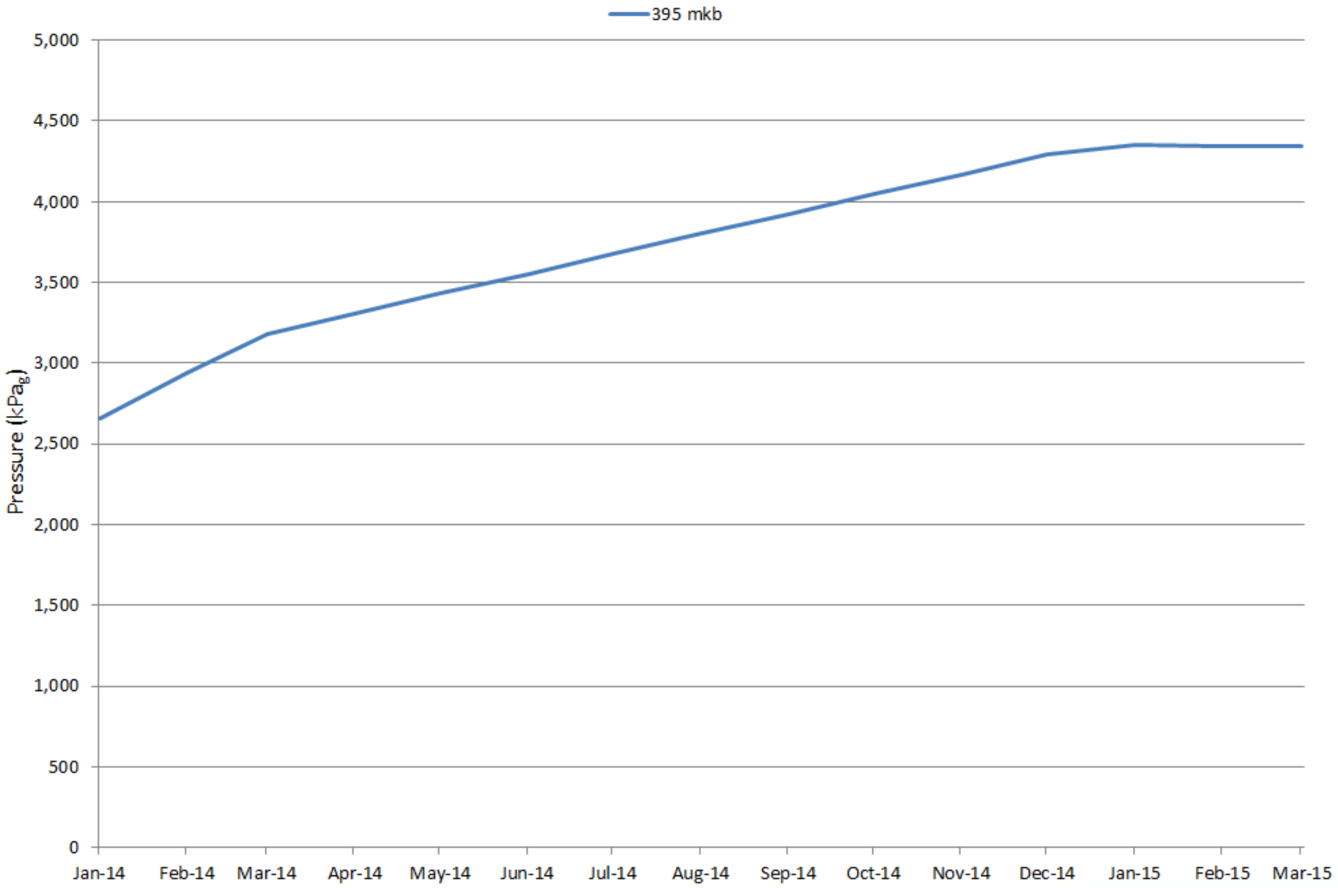
00/08-15-076-06W4/0

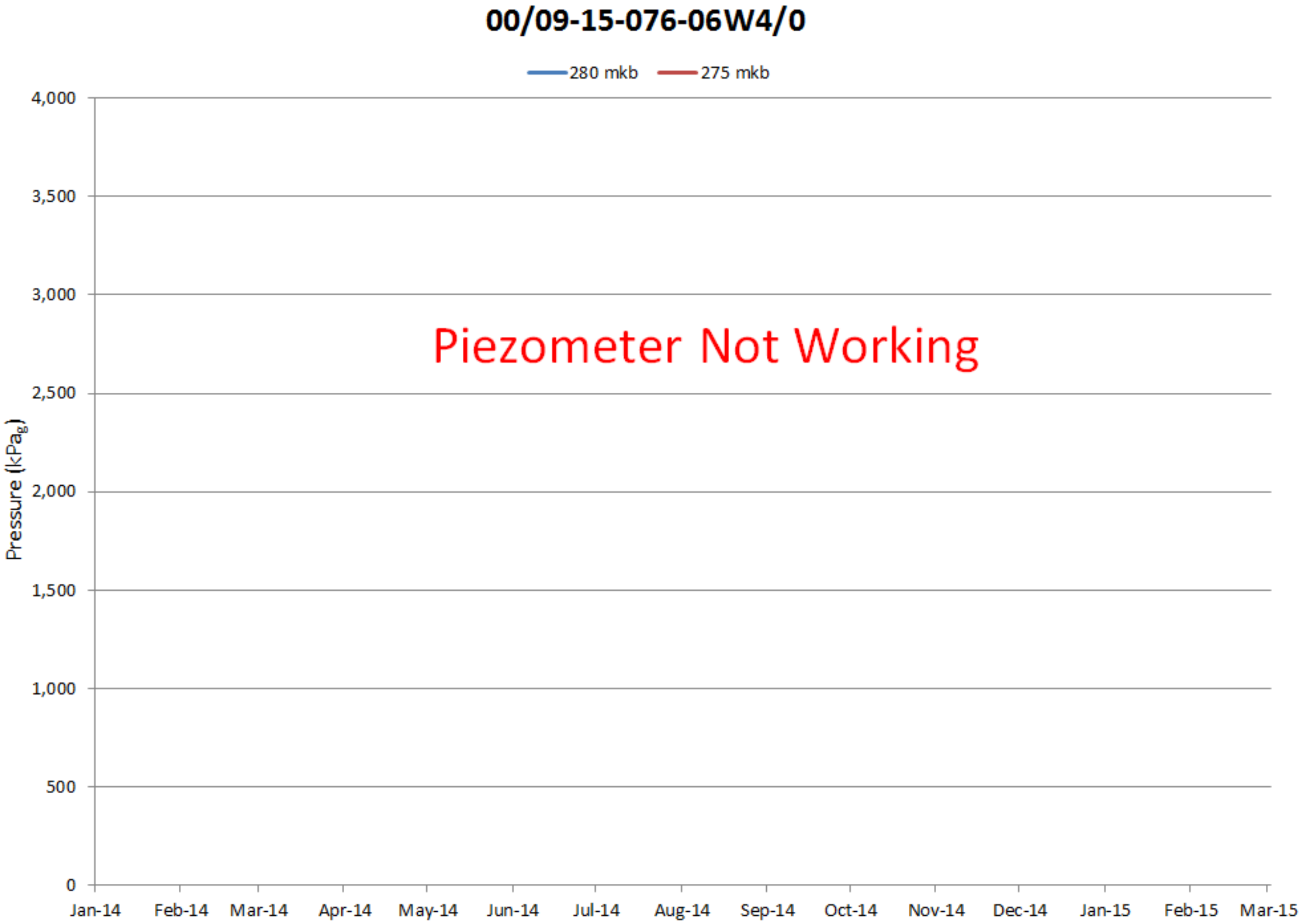


AA/15-15-076-06W4/0

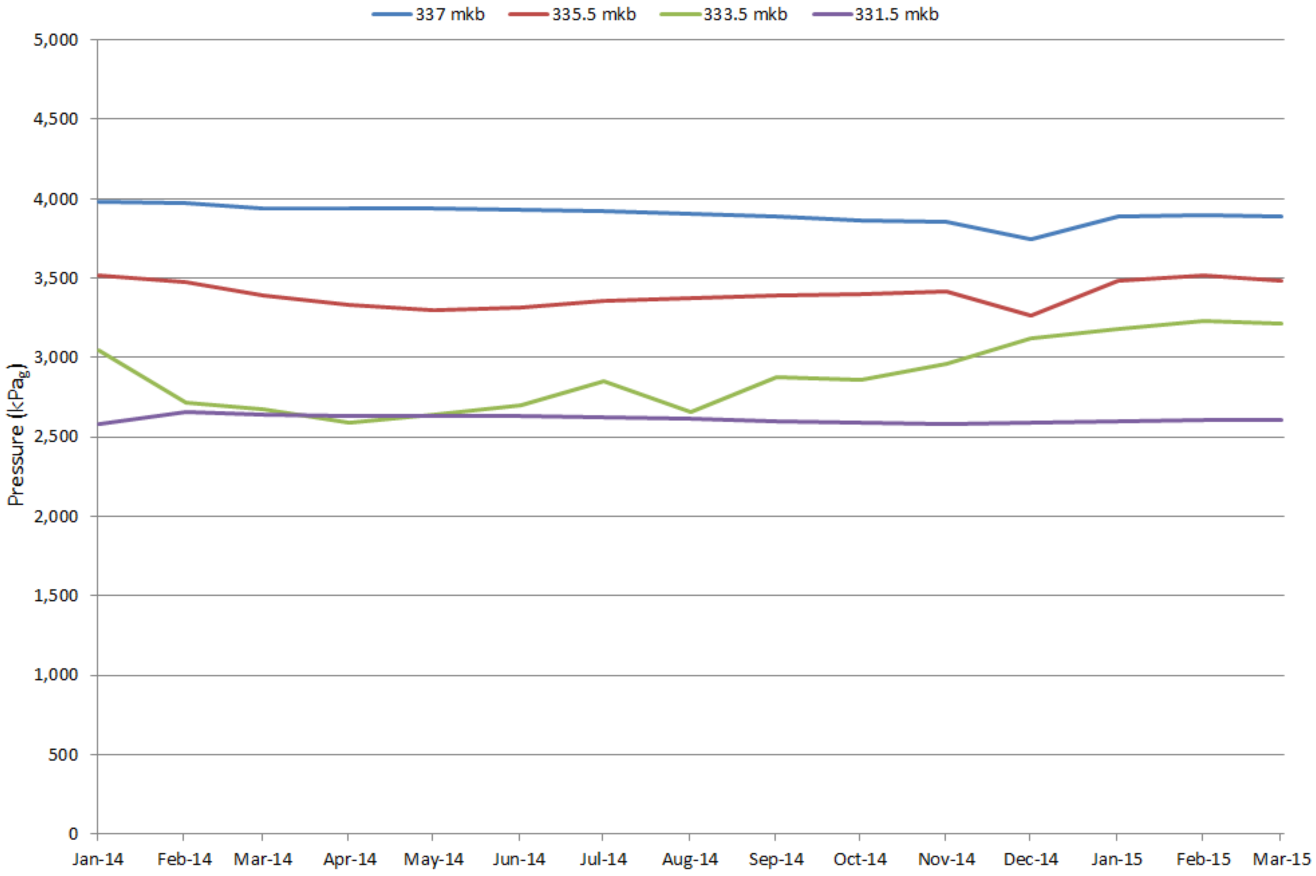


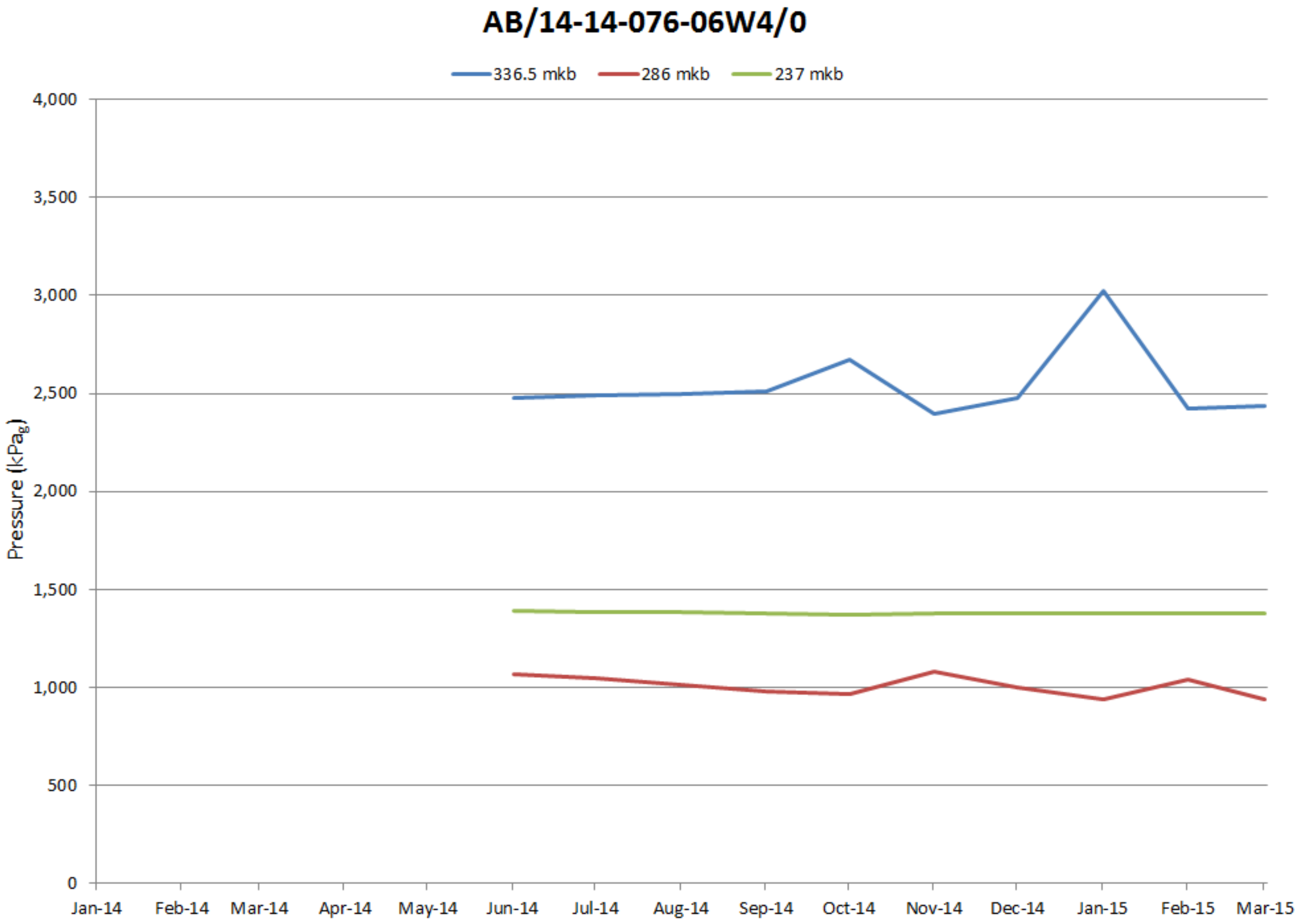
AA/15-02-076-06W4/0




00/09-15-076-06W4/0
280 mkb
275 mkb
Piezometer Not Working
Pressure (kPa_g)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

08/06-15-076-06W4/0





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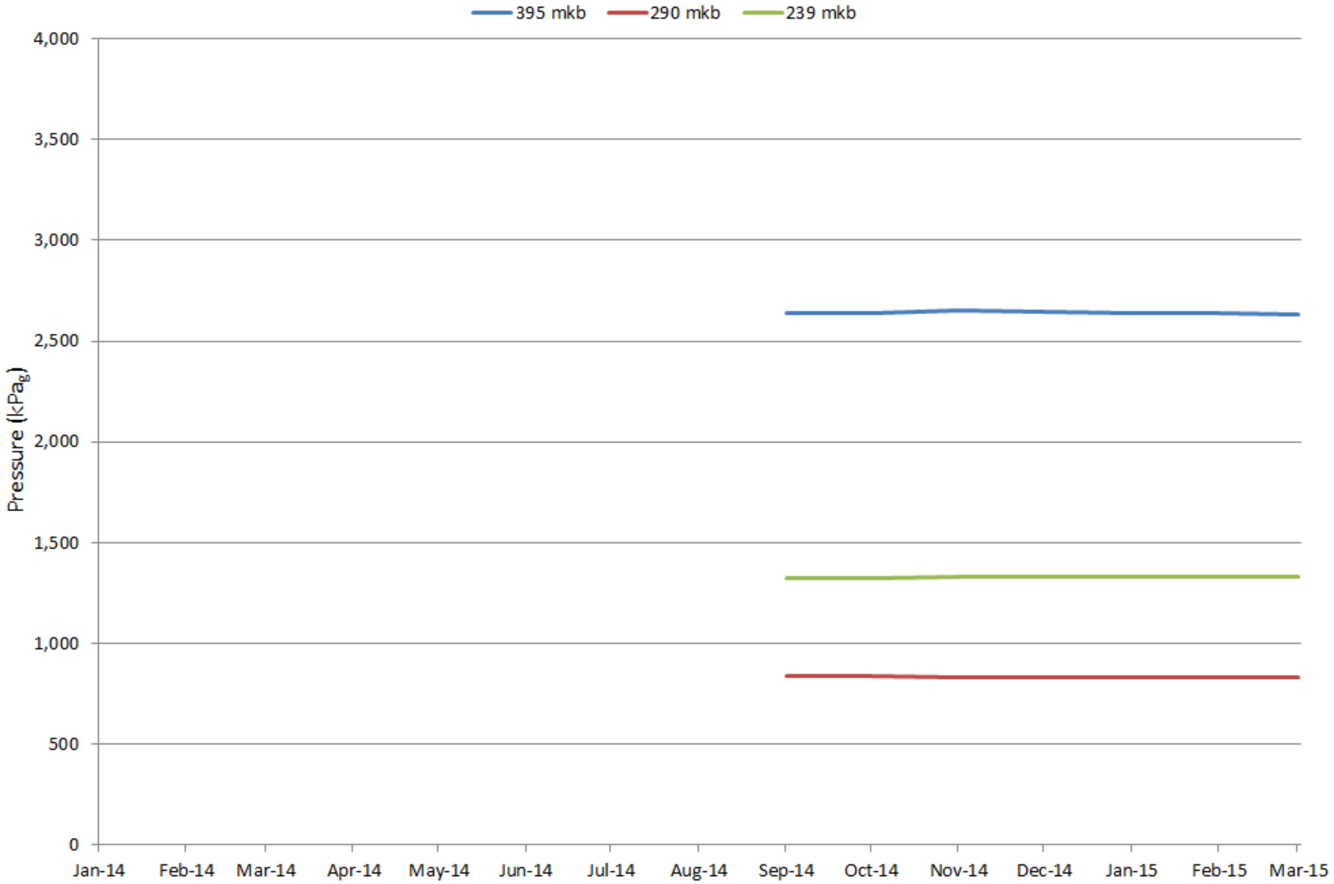
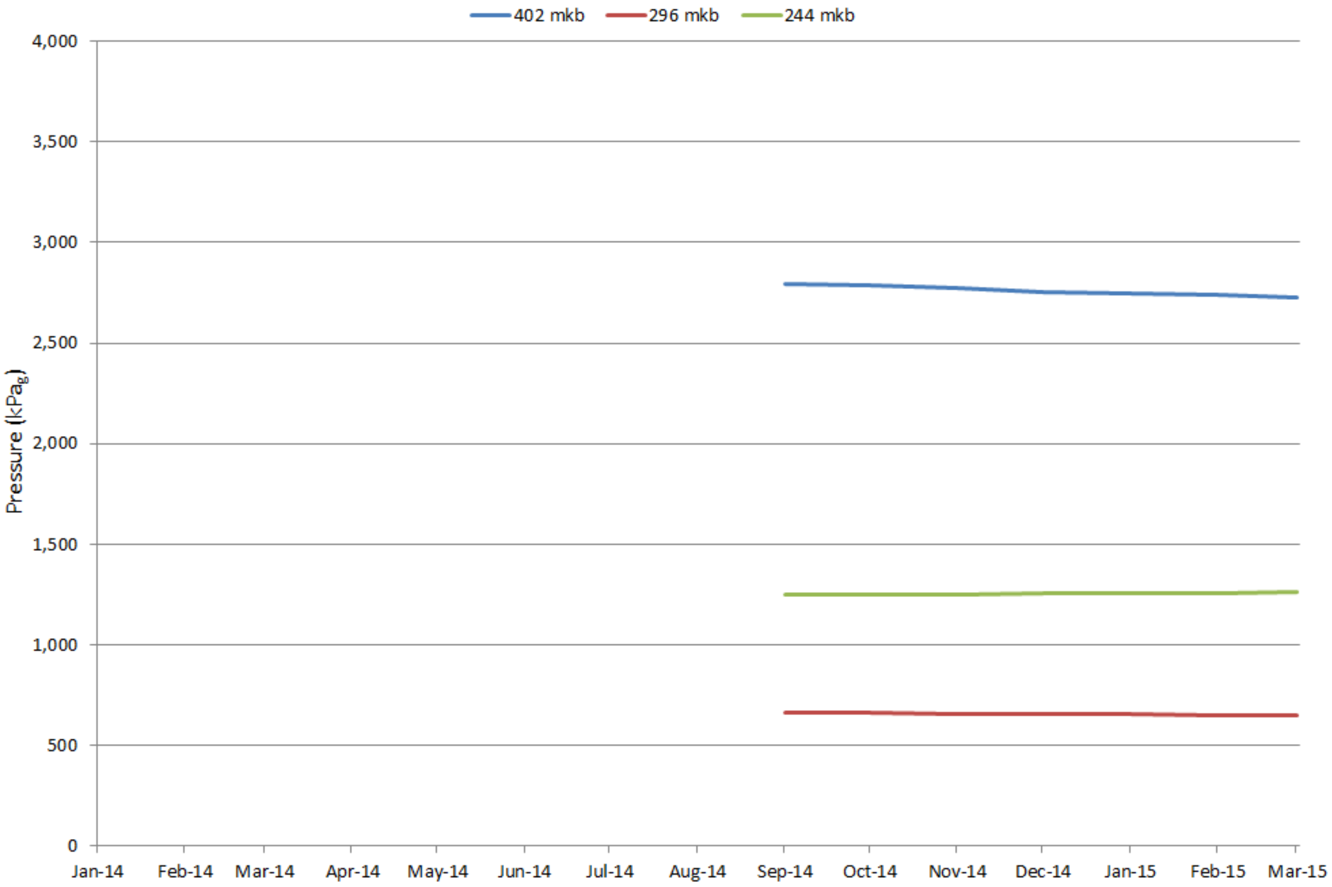
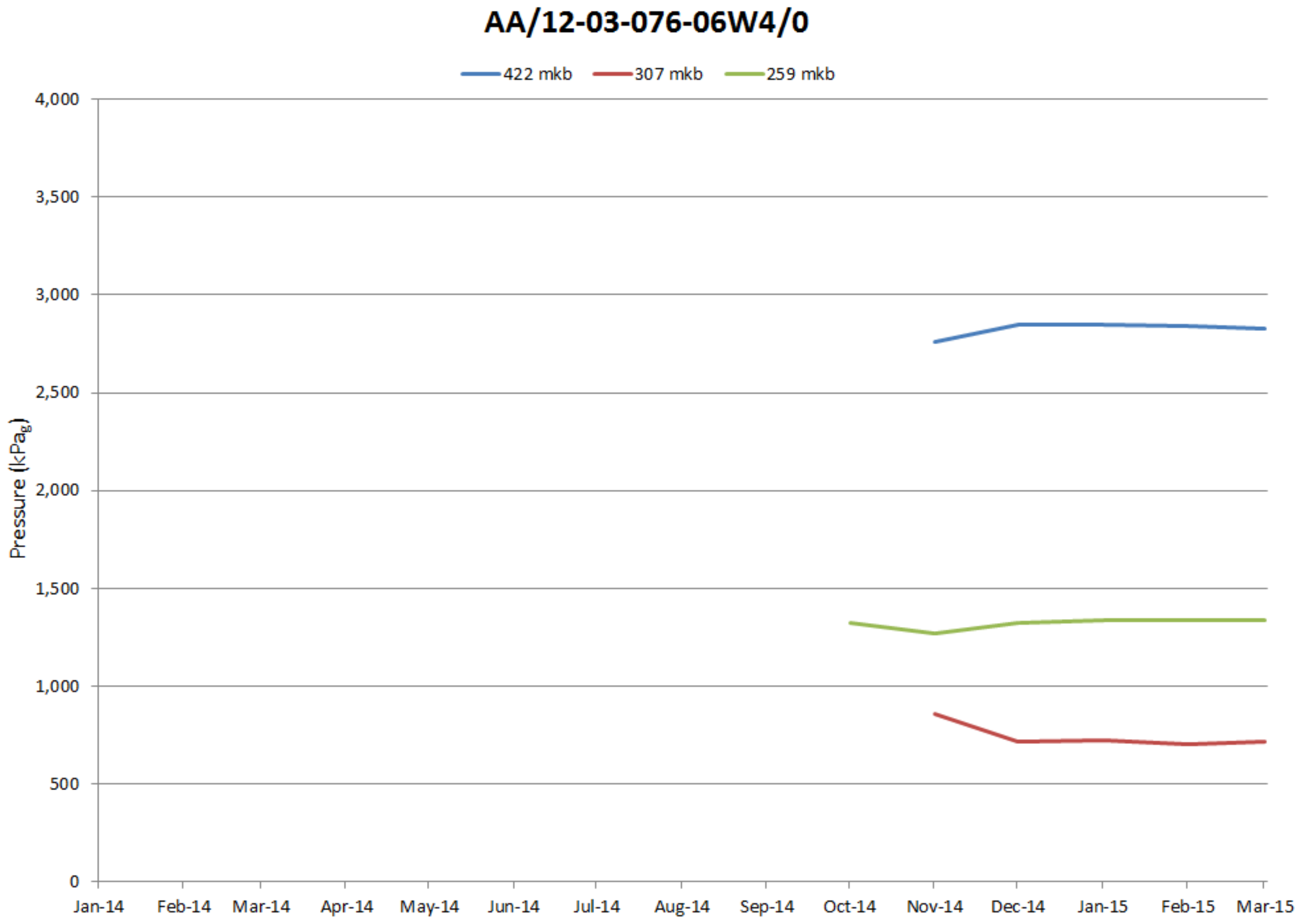
AB/13-13-076-06W4/0

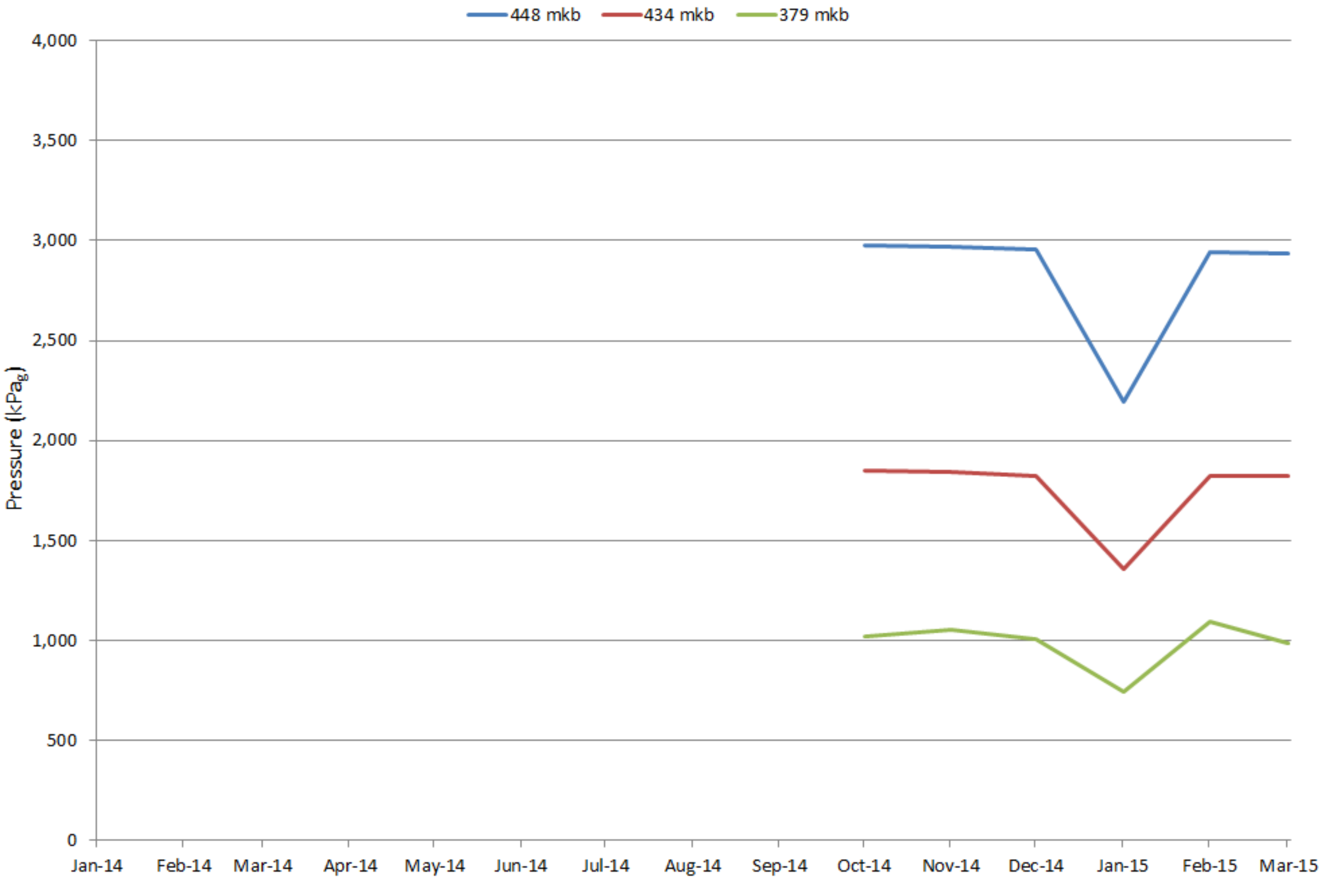


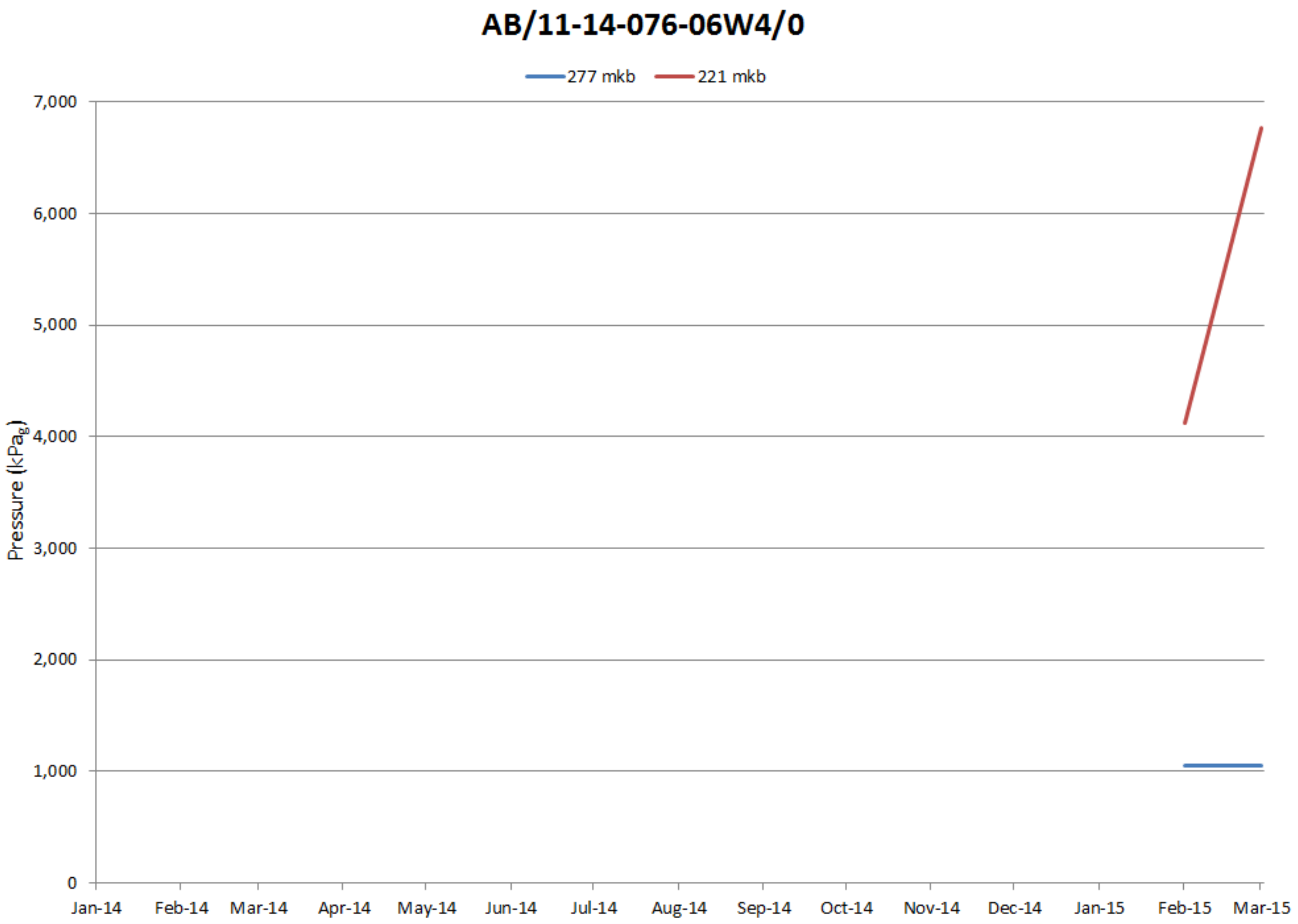
AB/01-10-076-06W4/0

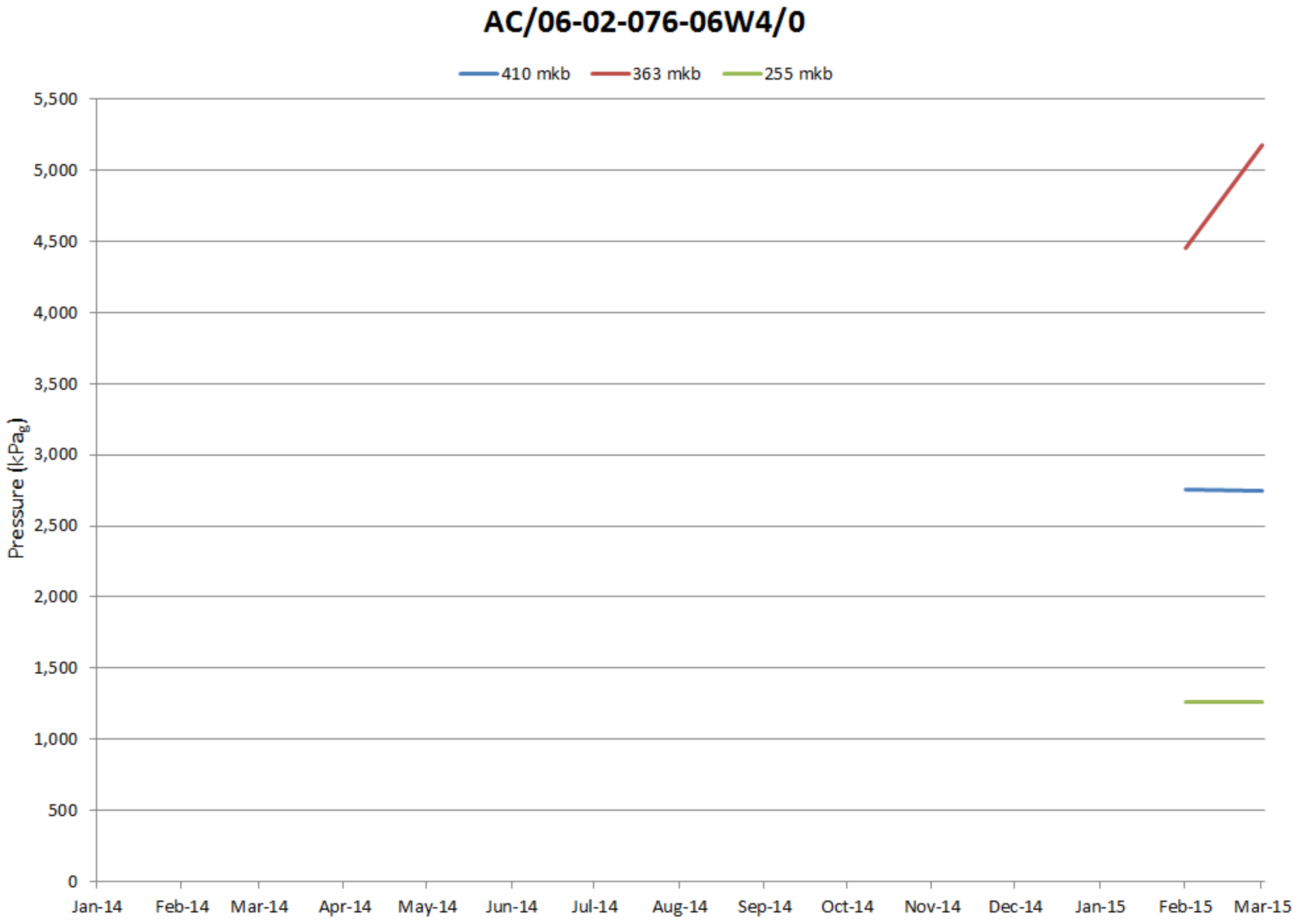


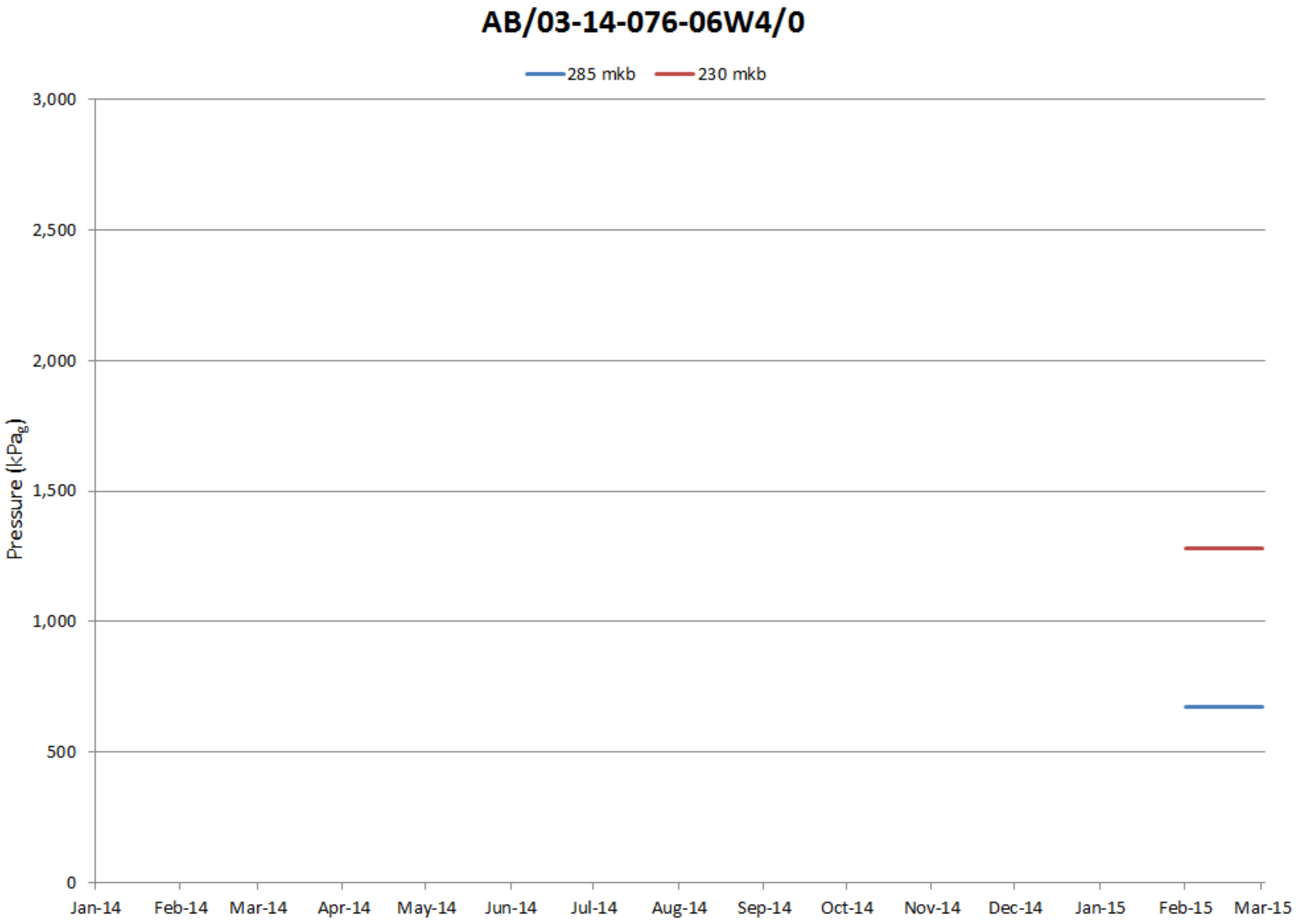

AA/12-03-076-06W4/0
422 mkb
307 mkb
259 mkb
Pressure (kPa_g)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

AB/01-02-076-06W4/0

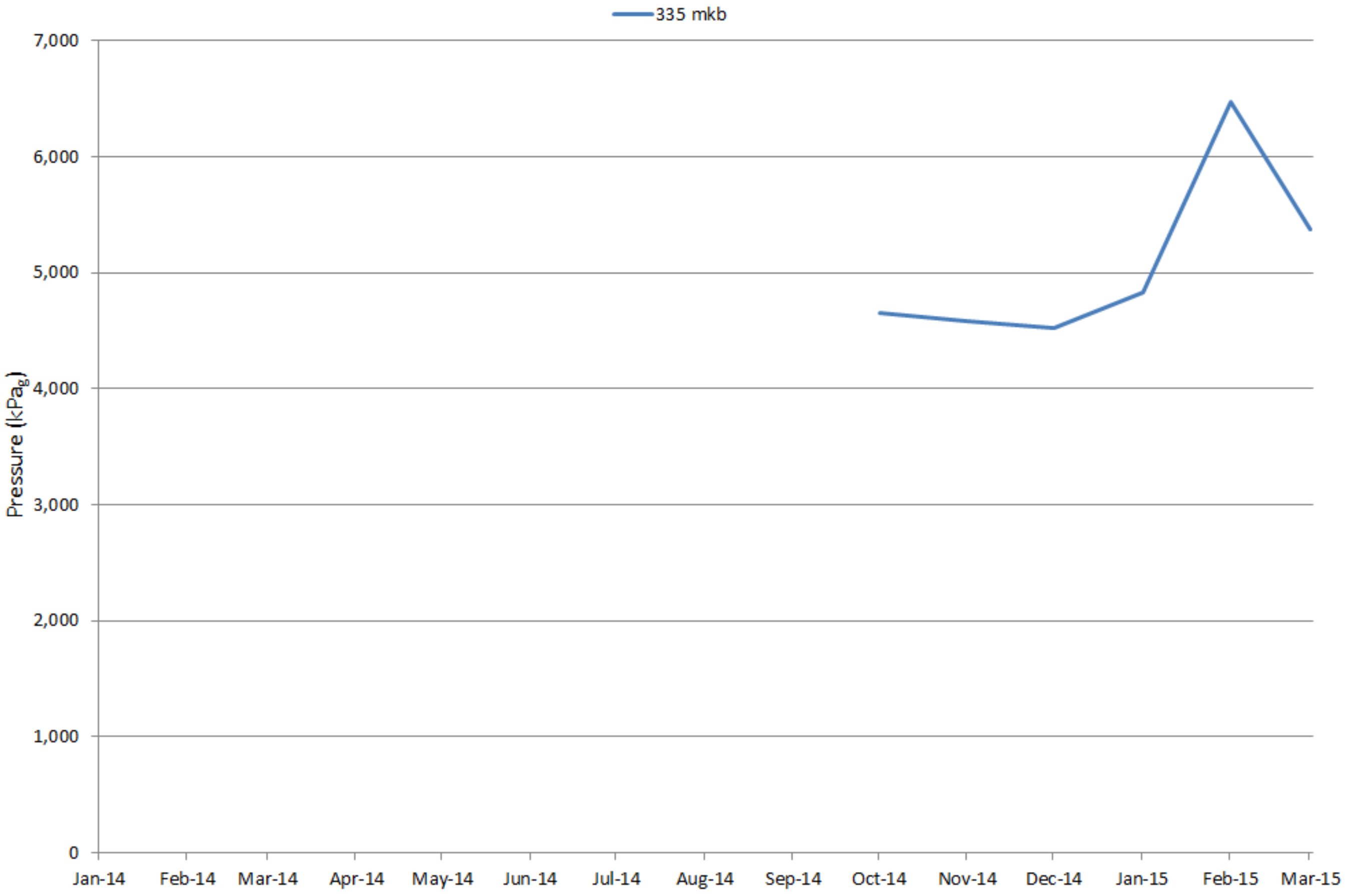


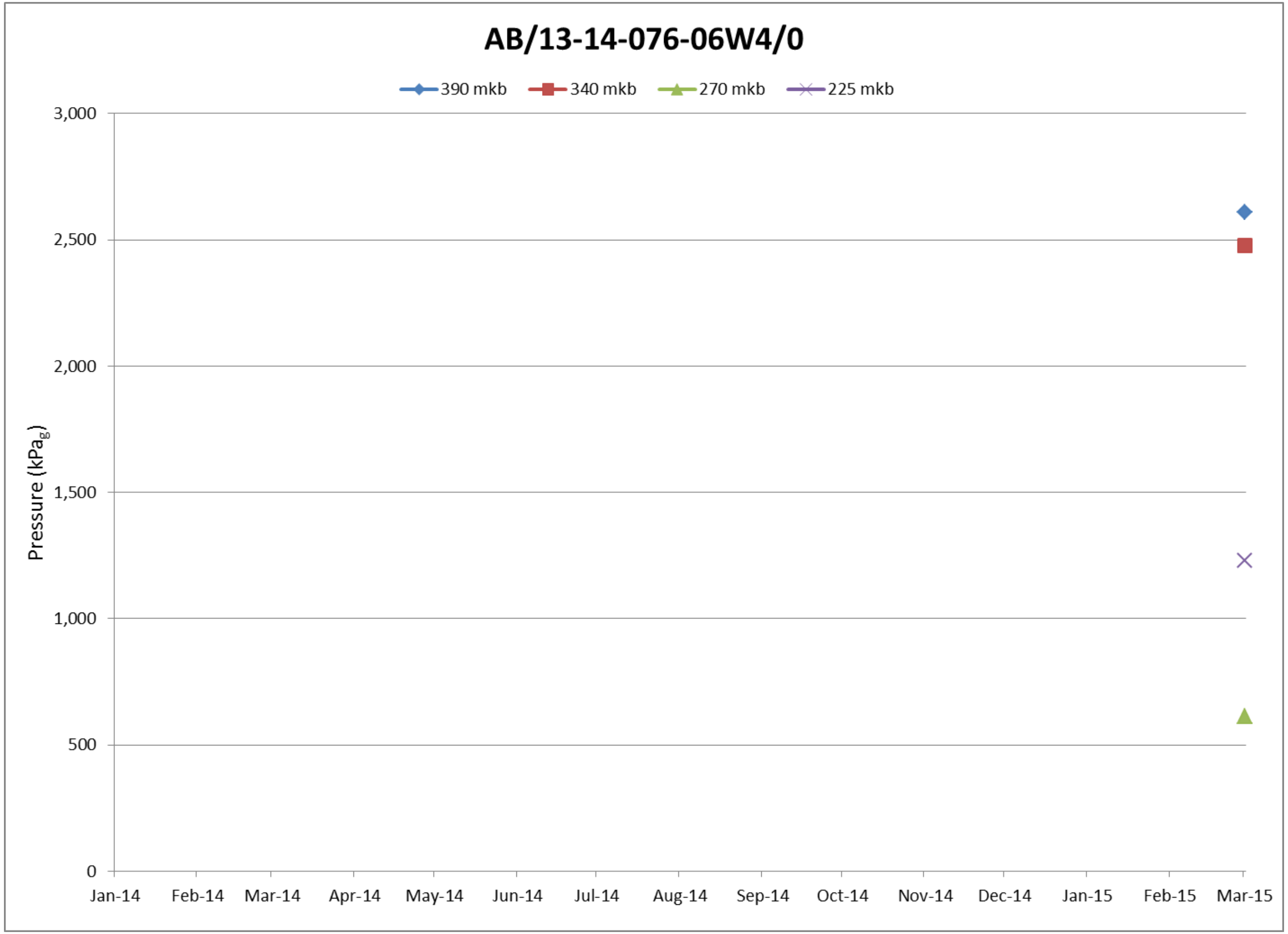

AB/11-14-076-06W4/0
277 mkb
221 mkb
Pressure (kPa$_g$)
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

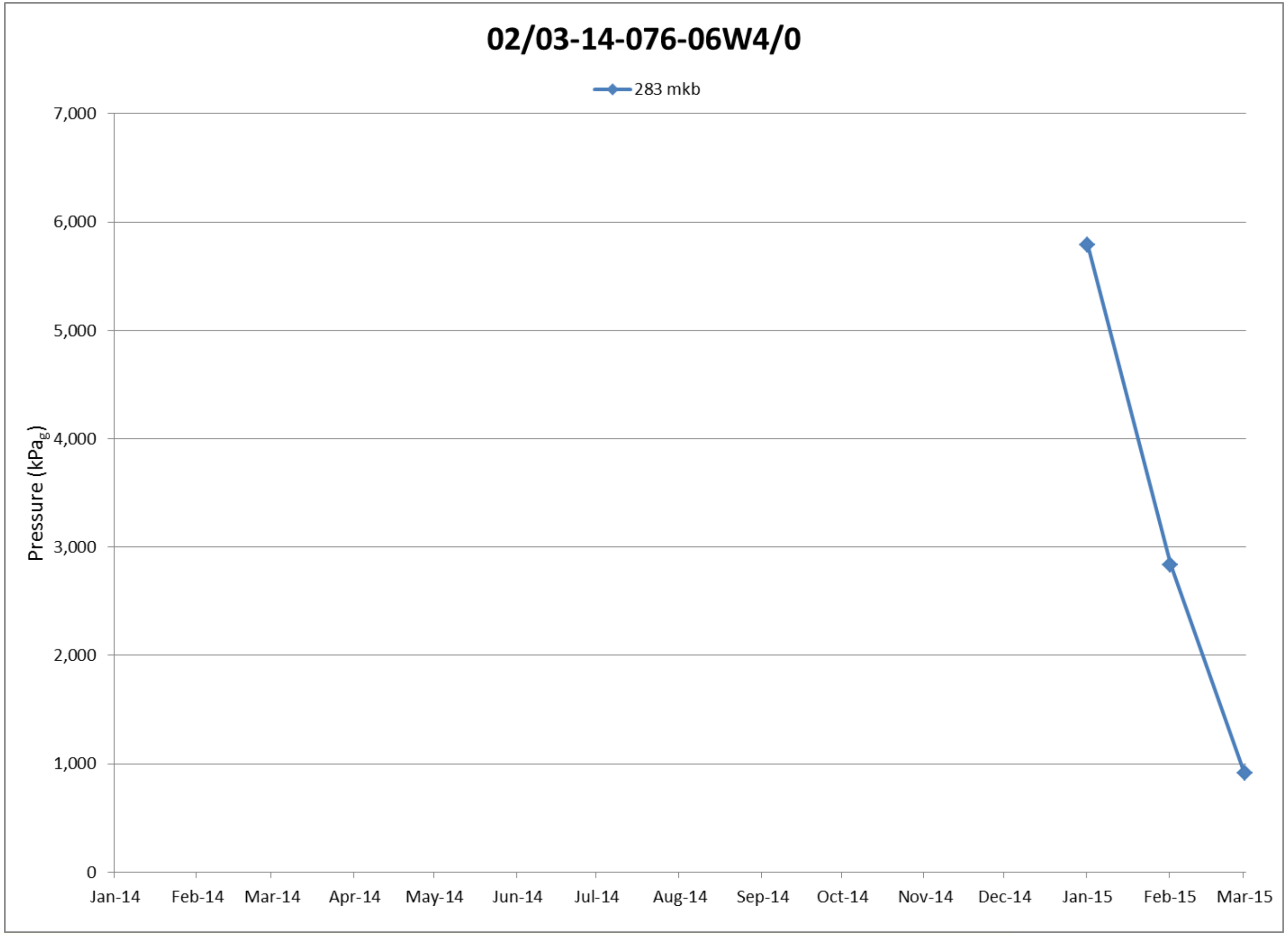

AC/06-02-076-06W4/0
410 mkb
363 mkb
255 mkb
Pressure (kPag)
5,500
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

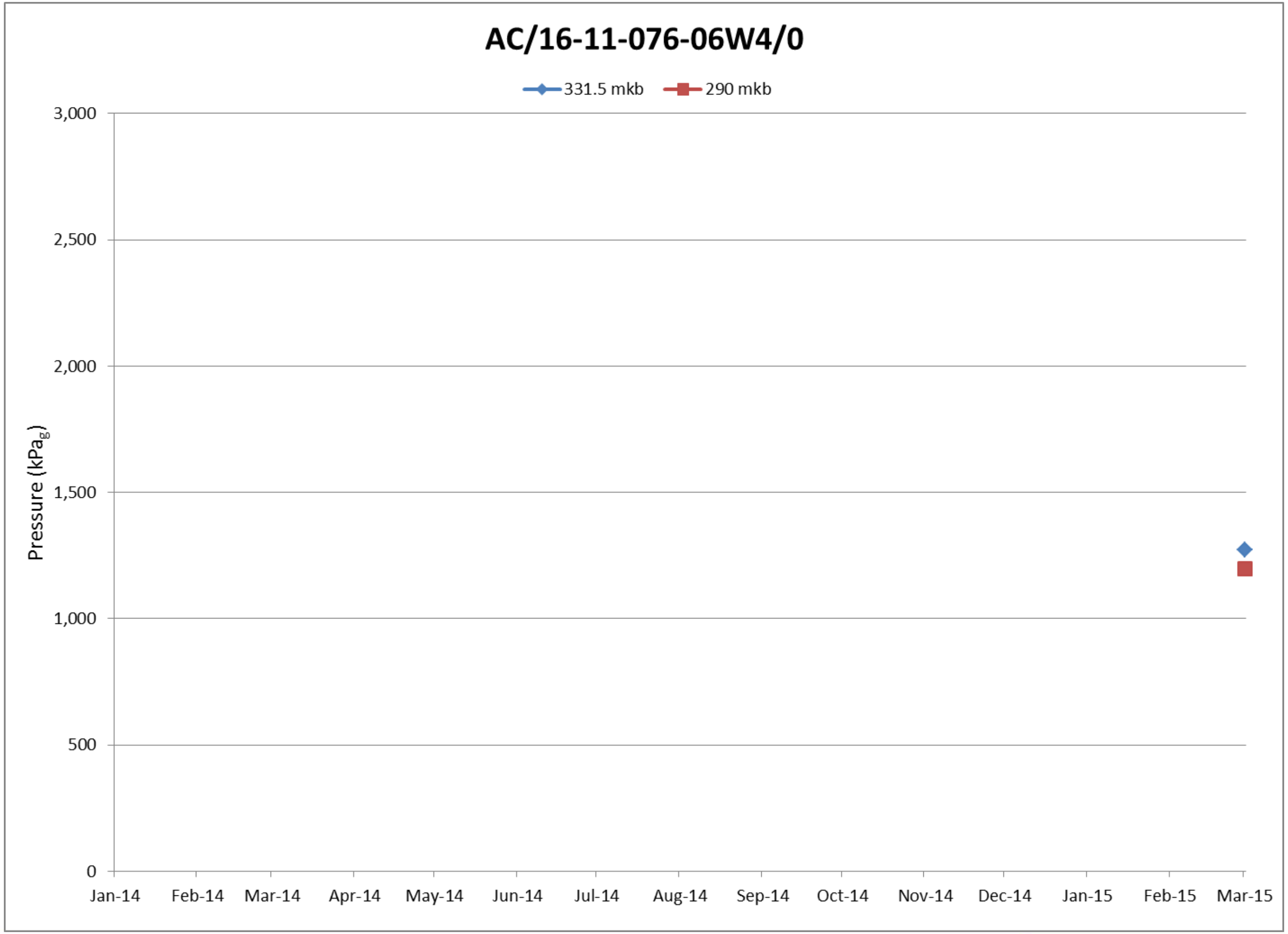

AB/03-14-076-06W4/0
285 mkb
230 mkb
Pressure (kPa$_g$)
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

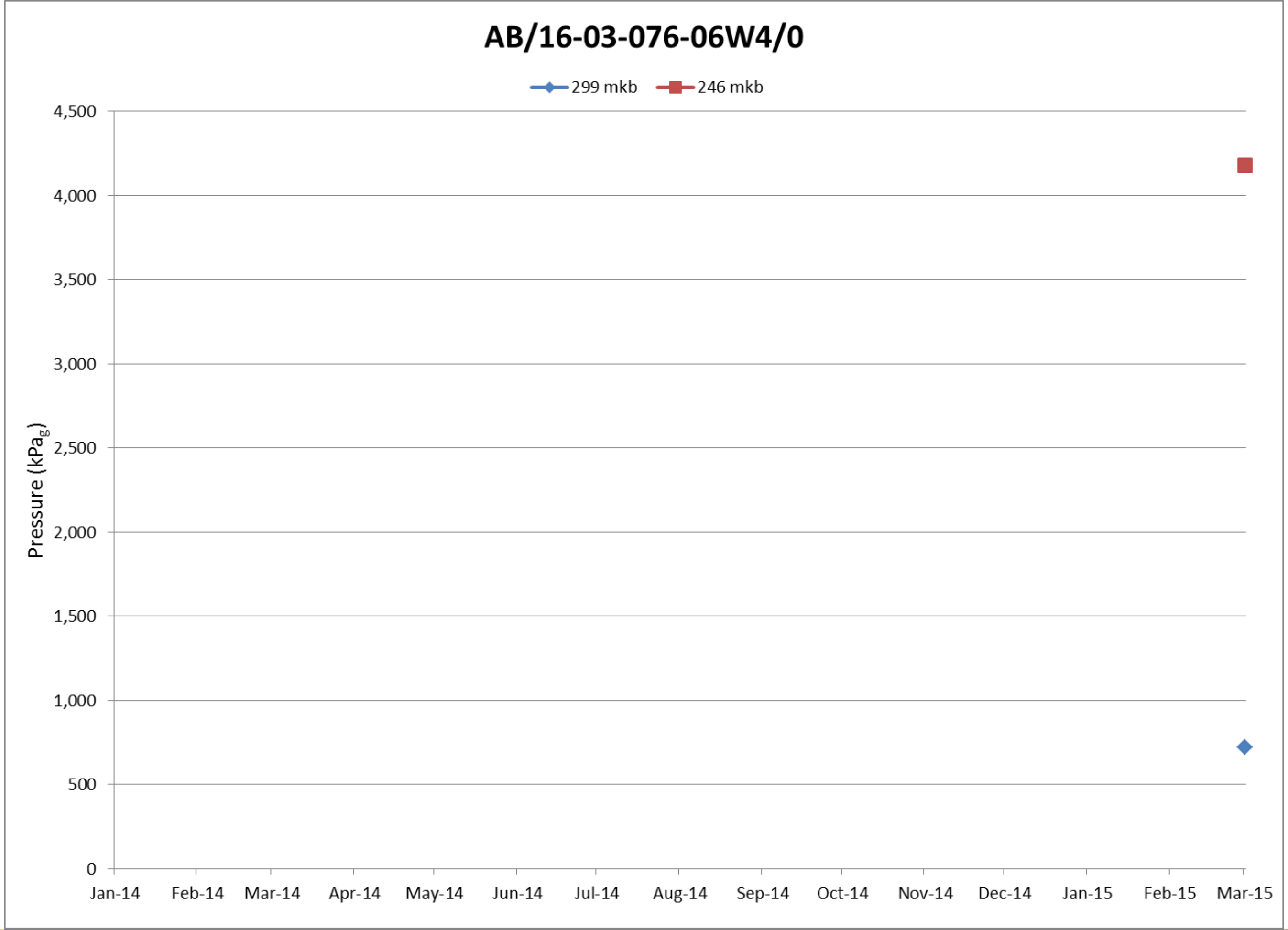
00/11-15-076-06W4/0

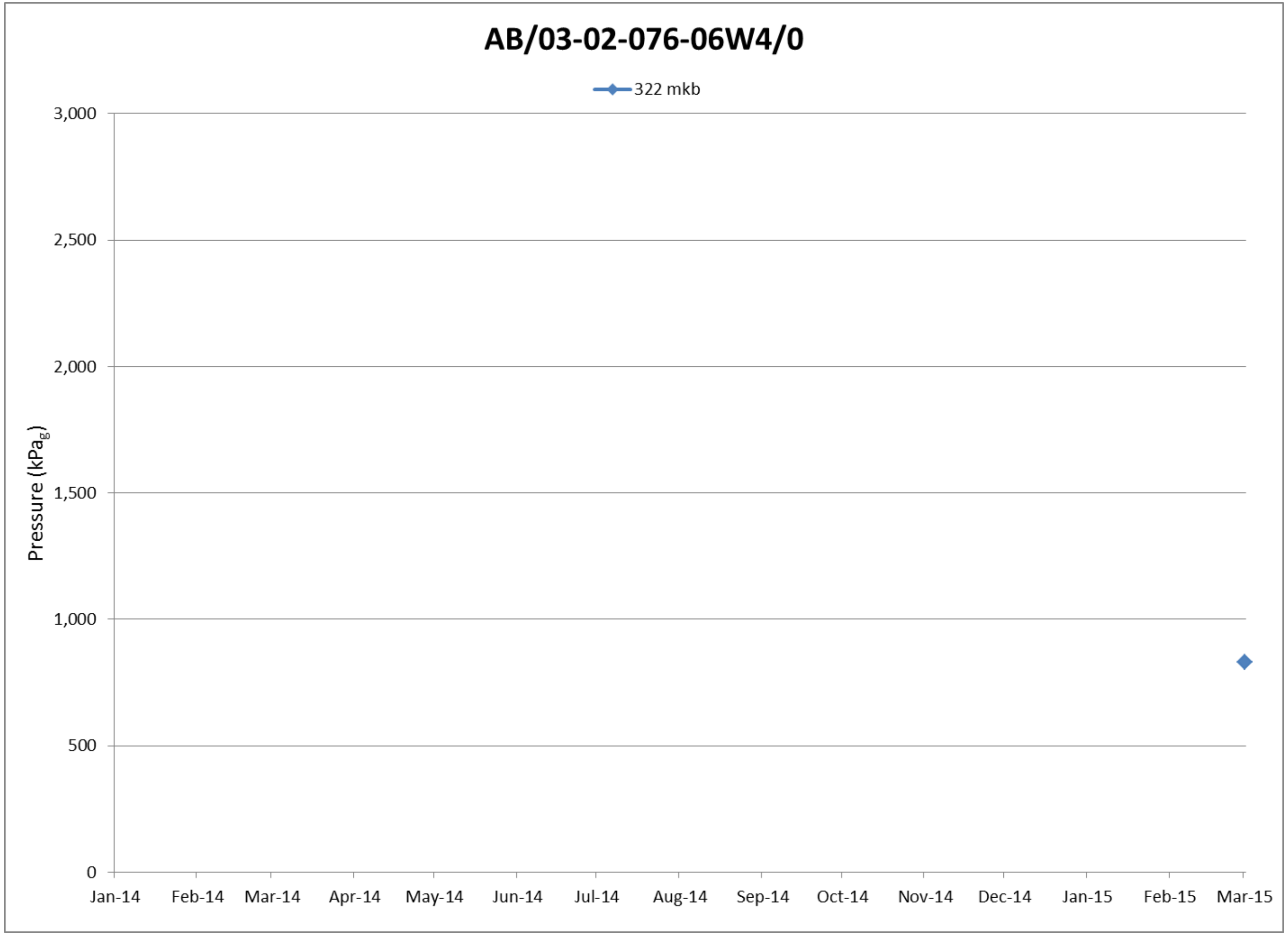


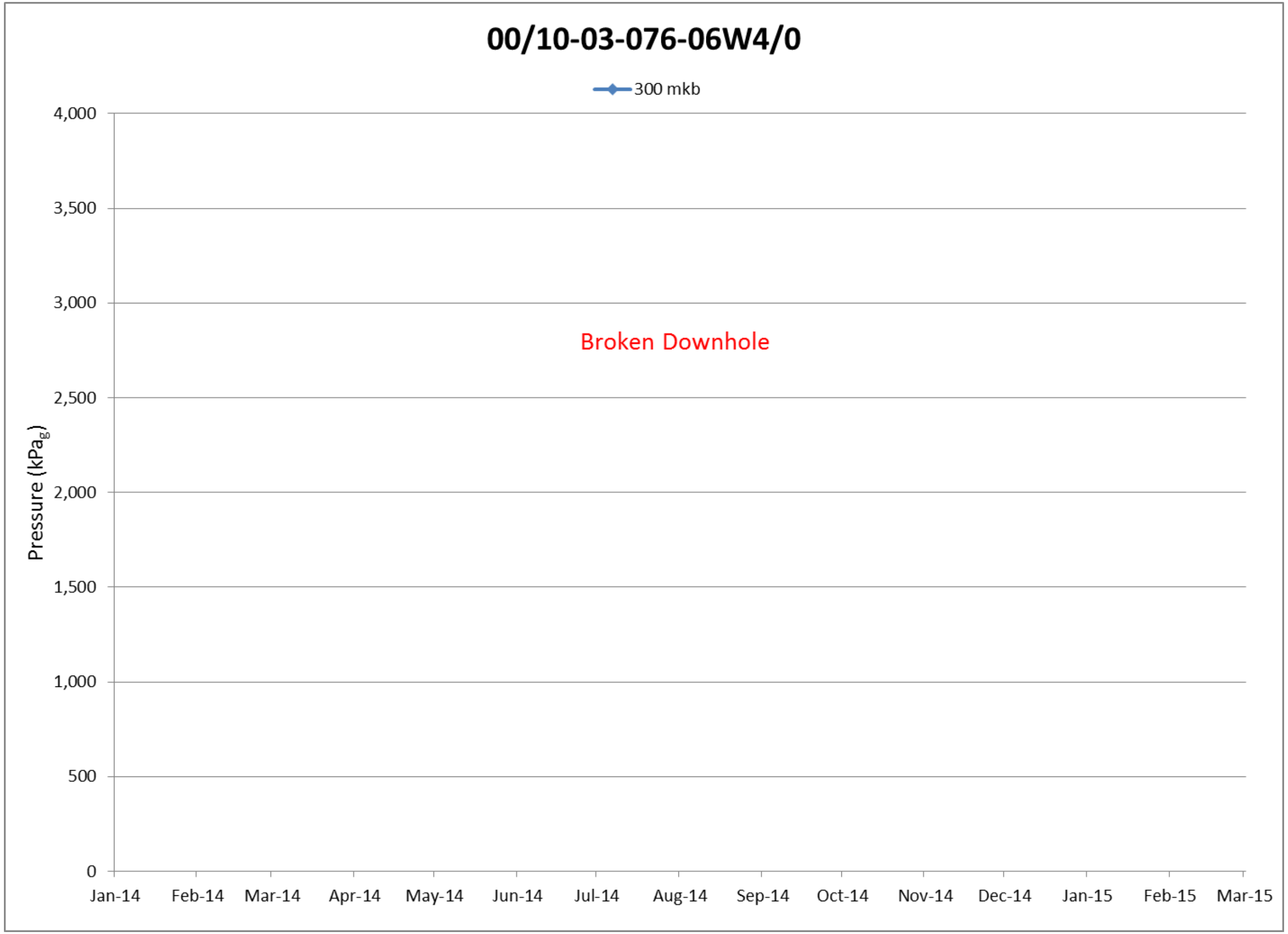

AB/13-14-076-06W4/0
390 mkb
340 mkb
270 mkb
225 mkb
Pressure (kPag)
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

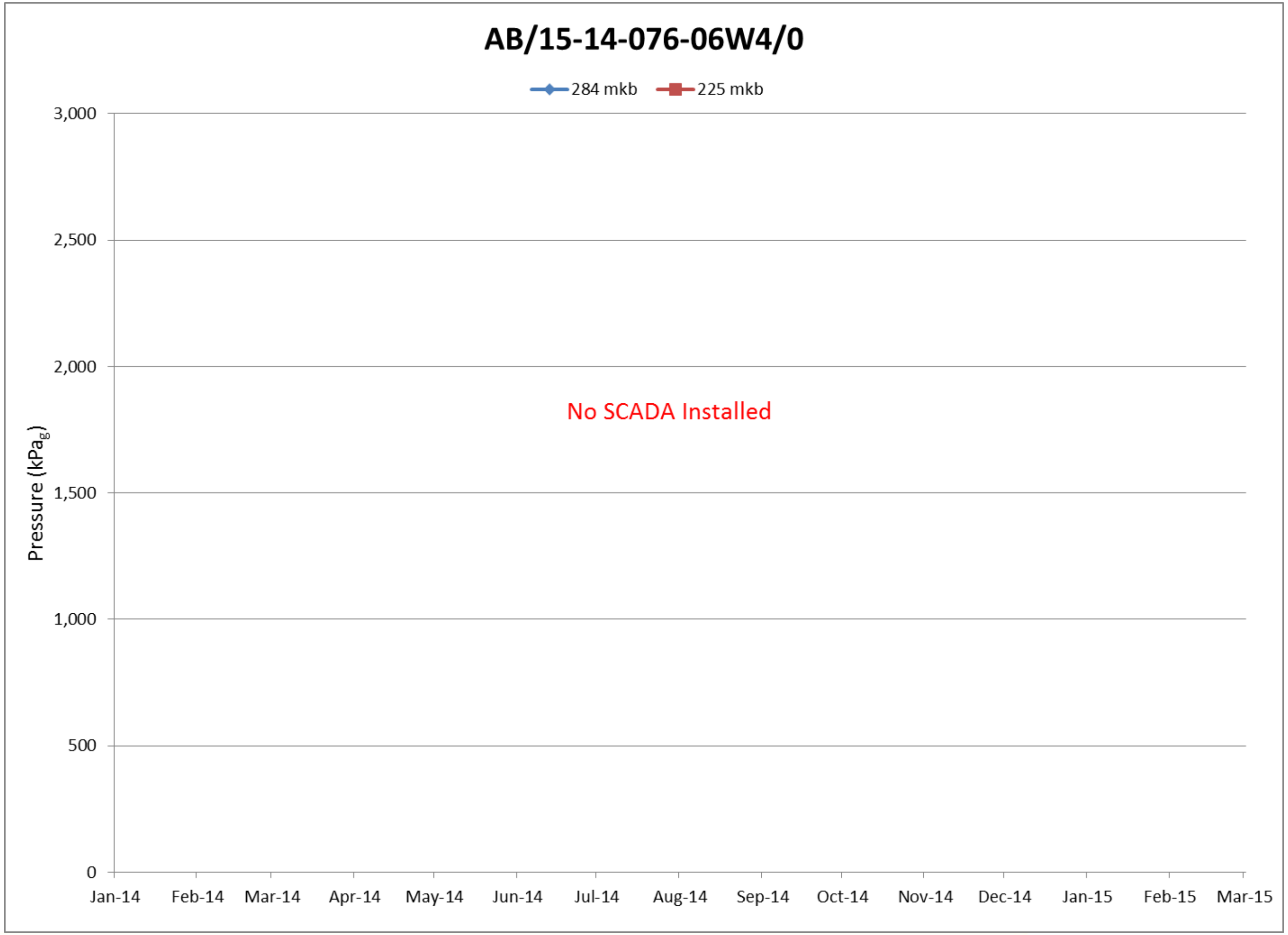

02/03-14-076-06W4/0
283 mkb
Pressure (kPag)
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15


AC/16-11-076-06W4/0
331.5 mkb
290 mkb
Pressure (kPag)
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15


AB/16-03-076-06W4/0
299 mkb
246 mkb
Pressure (kPa$_g$)
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15


AB/03-02-076-06W4/0
322 mkb
Pressure (kPa$_g$)
3,000
2,500
2,000
1,500
1,000
500
0
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15


00/10-03-076-06W4/0
300 mkb
Pressure (kPa_g)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Broken Downhole
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15


AB/15-14-076-06W4/0
284 mkb
225 mkb
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPa$_g$)
No SCADA Installed
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

Appendix 3
Subsection 3.1.1 – 5d)

RST & observation temperature data

Thermocouples in observation wells

Well UWI	Top T/C Depth (MD)	Bottom T/C Depth (MD)	# Points	Well Observed	Observed Well Section	Needs Work	Instrumentation TVD of SAGD Producer (mKb)	Instrumentation TVD of SAGD Injector (mKb)	Lateral Offset to SAGD Producer (m)	Lateral Offset to SAGD Injector (m)
104/03-16-076-06W4	319	390	32	A022	Heel	N	389	384	4	4
102/05-15-076-06W4	334	406	36	B013	Heel	N	380	374	15	15
102/06-15-076-06W4	340	390	26	B013	Toe	N	385	381	3	3
104/06-15-076-6W4	344	394	26	B014	Middle	N	378	372	0	0
103/05-15-076-6W4	323	385	32	B021	Mid	N	377	371	39	39
102/12-15-076-6W4	344	406	32	B022	Heel	N	382	377	2	2
100/11-15-076-6W4	350	400	26	B024	Toe	N	381	376	5	5
102/10-11-076-6W4	346	396	27	B032	Heel	N	387	383	0	0
100/16-11-076-6W4	347	407	30	B033	Toe	N	389	384	0	0
100/13-12-076-6W4	344	406	30	B035	Toe	N	391	386	0	0
100/09-11-076-6W4	350	408	31	B036	Heel	N	390	385	0	0
100/01-14-076-6W4	341	387	24	B041	Heel	N	382	379	0	0
100/02-14-076-6W4	340	394	28	B042	Toe	Y	384	379	0	0
102/07-14-076-6W4	337	391	28	B045	Heel	N	385	380	0	0
102/03-14-076-6W4	336	390	28	B046	Toe	N	386	381	0	0
100/15-11-076-6W4	338	390	27	B052	Heel	N	385	380	44	44
102/15-11-076-6W4	335	403	34	B053	Mid	N	384	378	0	0
100/11-11-076-6W4	335	391	29	B056	Toe	Y	389	385	0	0
100/14-11-076-6W4	340	394	28	B058	Heel	N	384	379	0	0
100/05-13-076-6W4	321.5	394	30	B072	Toe	N	388	384	0	0
100/06-13-076-6W4	342	396	27	B076	Toe	Y	395	390	0	0
102/03-15-076-6W4	293	351	30	B017	Toe	N	377	372	0	0
103/03-15-076-6W4	337	395	30	B017	Toe	N	377	372	20	20
104/03-15-076-6W4	337	395	30	B017	Toe	N	377	372	50	50
100/04-15-076-6W4	333	363	30	B017	Heel	N	377	372	0	0
102/04-15-076-6W4	334	394	30	B017	Heel	N	377	372	30	30
103/04-15-076-6W4	335	395	30	B017	Heel	N	377	372	50	50
104/04-15-076-6W4	336	396	30	B017	Heel	N	377	372	70	70

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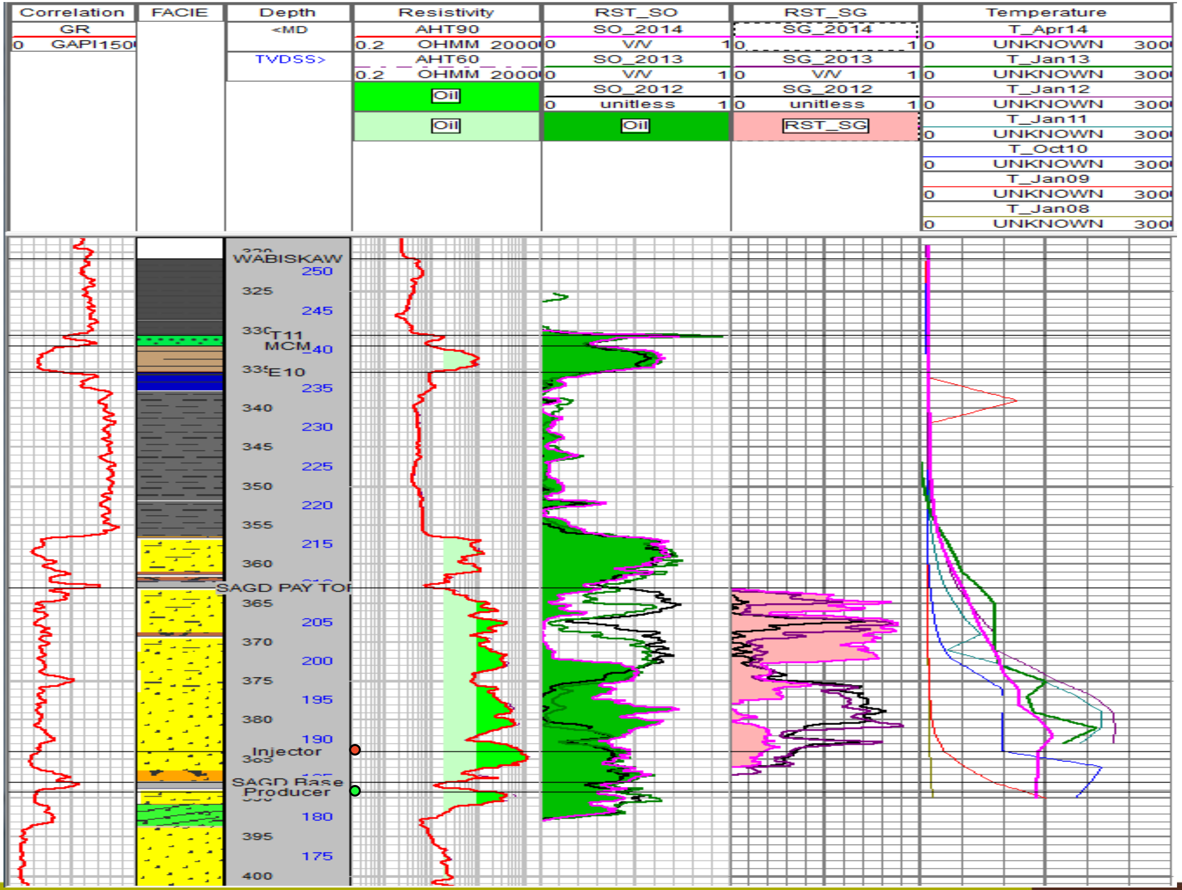
June 24, 2015

Thermocouples in observation wells

Well UWI	Top T/C Depth (MD)	Bottom T/C Depth (MD)	# Points	Well Observed	Observed Well Section	Needs Work	Instrumentation TVD of SAGD Producer (mKb)	Instrumentation TVD of SAGD Injector (mKb)	Lateral Offset to SAGD Producer (m)	Lateral Offset to SAGD Injector (m)
100/12-15-076-6W4	329	385	29	B026	Heel	N	380	375	6	6
1AA/15-15-076-6W4	329	385	23	B027	Toe	N	380	375	1	1
100/13-15-076-6W4	327	385	24	B029	Heel	N	374	368	6	6
1AA/13-11-076-6W4	330	394	32	B058	Mid	Y	380	375	33	33
102/14-11-076-6W4	340	398	30	B058	Heel	N	384	379	20	20
103/06-12-76-6W4	349	407	28	B062	Toe	Y	391	386	0	0
102/06-12-76-6W4	345	407	27	B064	Mid	N	391	386	15	15
102/05-12-76-6W4	348	402	24	B066	Toe	Y	395	390	0	0
100/11-12-76-6W4	345	403	30	B067	Heel	N	397	392	0	0
102/11-14-76-6W4	344	392	40	B11-7	Mid	Y	377	372	18	18
102/05-14-76-6W4	334	386	27	B11-5	Mid	Y	377	372	17	17
100/05-14-76-6W4	329	390	27	B11-4	Mid	N	375	369	18	18
103/05-14-76-6W4	332	390	25	B11-3	Mid	N	375	370	14	14
100/01-15-76-6W4	325	387	32	B08-4	Heel	Y	375	370	0	0
102/01-15-76-6W4	323	385	32	B08-3	Mid	N	378	372	20	20
100/13-11-76-6W4	344	394	26	B08-7	Mid	N	379	374	0	0
108/12-11-76-6W4	332	390	30	B08-10	Toe	N	382	376	0	0
102/11-14-76-6W4	260	305	20	B11-11	Mid	Y	378	373	18	18
100/12-13-76-6W4	350	400	25	F01-9	Mid	Y	394	385	14	14
100/14-13-76-6W4	340	394	27	F01-7 F01-8	Heel	N	391	384	43	43
100/11-13-76-6W4	350	400	25	F01-4 F01-5	Heel	N	384	388	35	35
108/06-13-76-6W4	340	393	28	F01-1 F01-2	Mid	Y	390	385	40	40
102/15-12-76-6W4	270	310	26	B06	Build	N	333	328	5	5
102/15-12-76-6W4	313	390	14	B09-6	Mid		392	387	12	12
102/01-13-76-6W4	340	390	25	B09-1	Heel	Y	390	385	20	20
100/02-13-76-6W4	340	395	28	B09-4 B09-5	Heel	Y	387	382	32	32
102/02-13-76-6W4	350	400	26	B09-6 B09-7	Build	Y	373	368	30	30
100/07-13-76-6W4	350	395	24	B09-10	Build	N	380	375	16	16
100/02-16-076-06W4	400	330	30	A02-4	Heel	N	387	382	17	17
100/01-16-076-06W4	395	325	30	A02-4	Toe	N	385	380	10	10

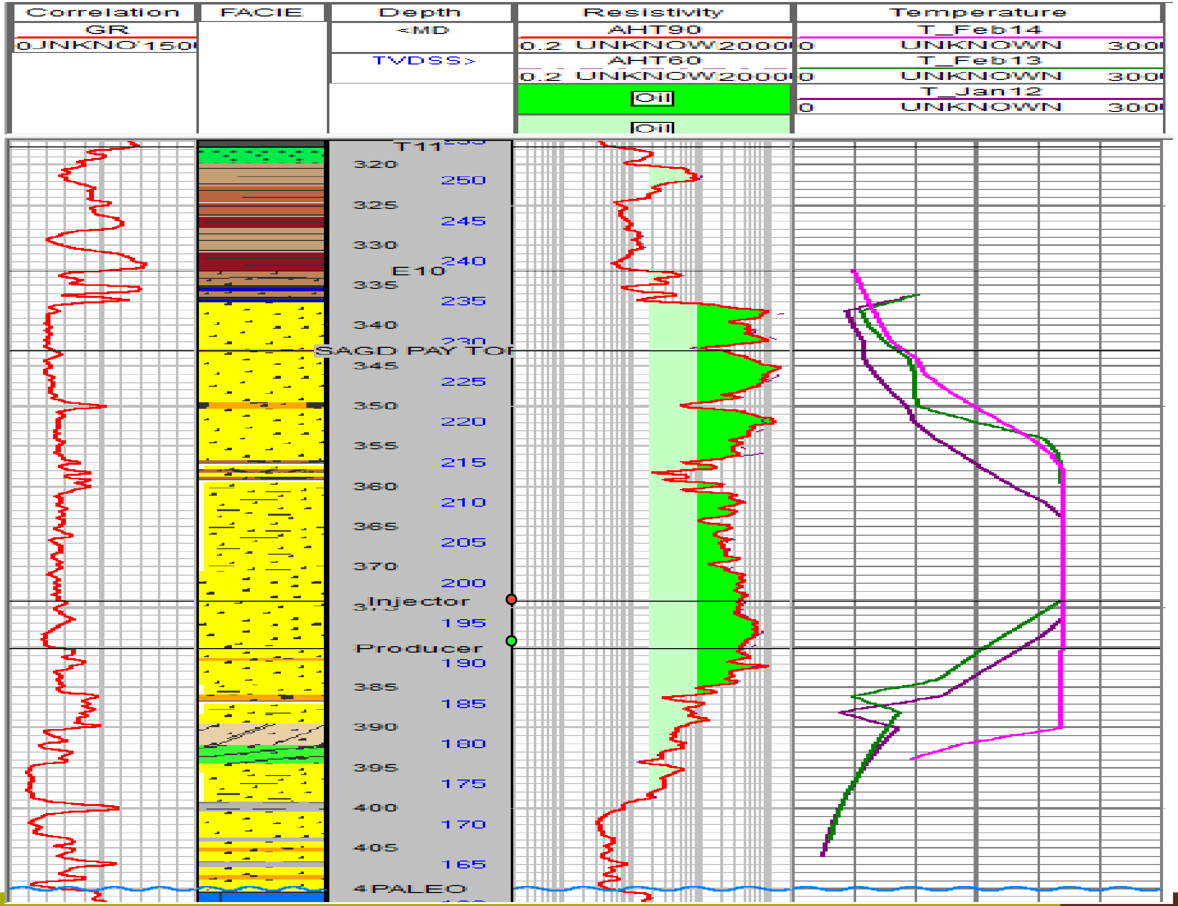
RST logs
A022 pad

TO-33 (A022_HEEL) 104031607606W400

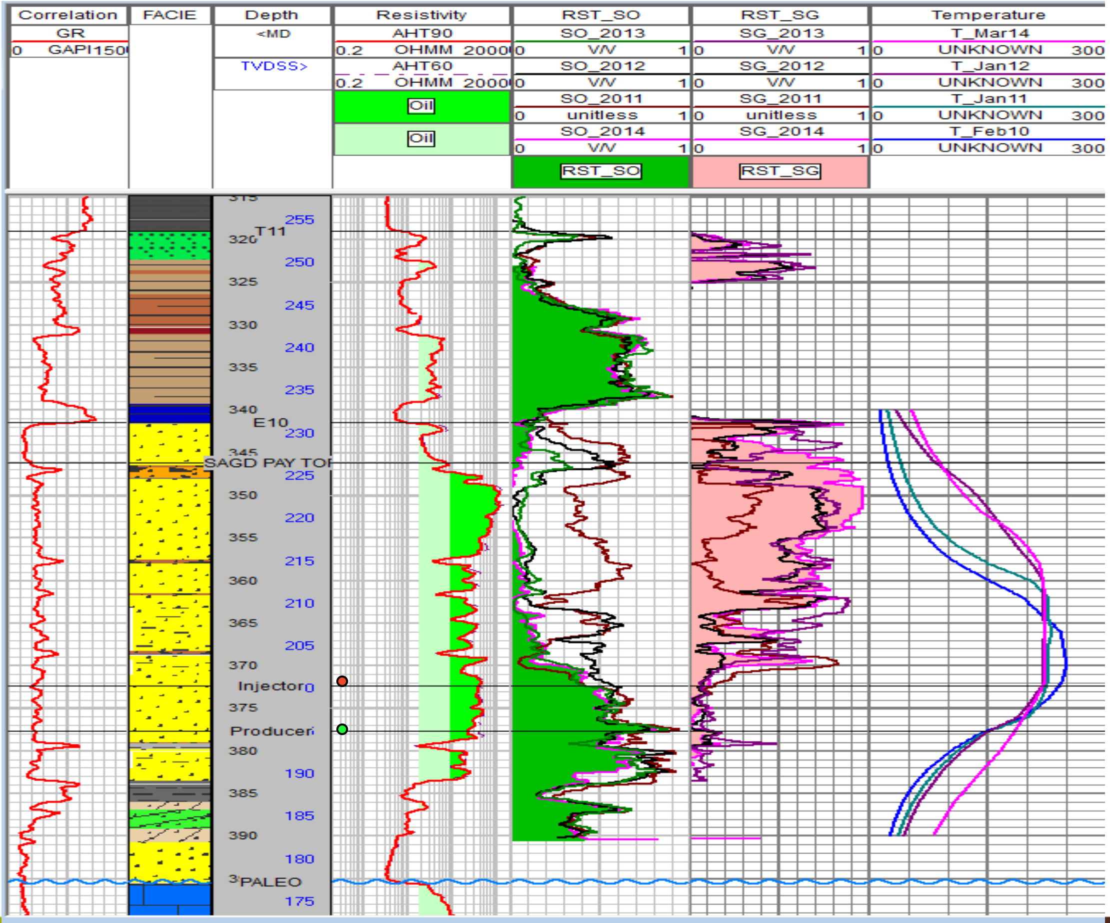


RST logs
B01 pad

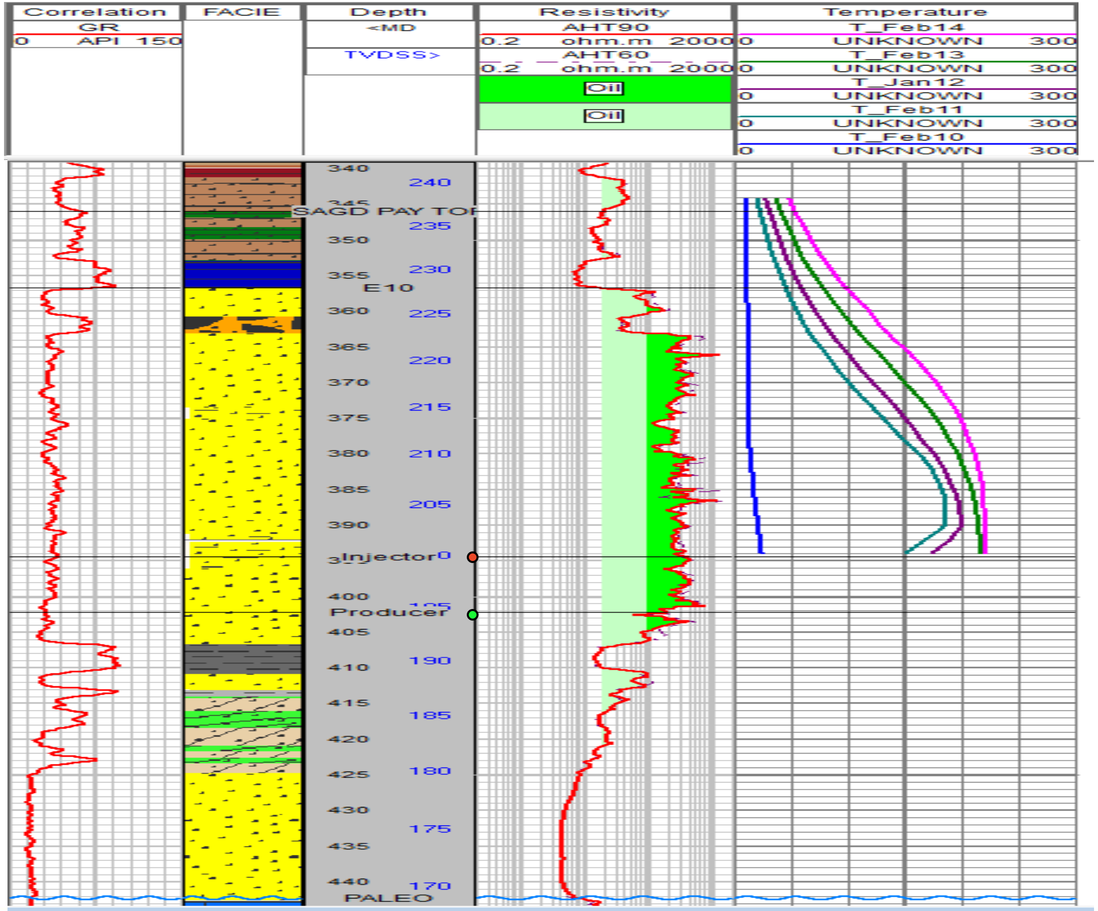
OB-5 (B0103 HEEL) 102051507606W400



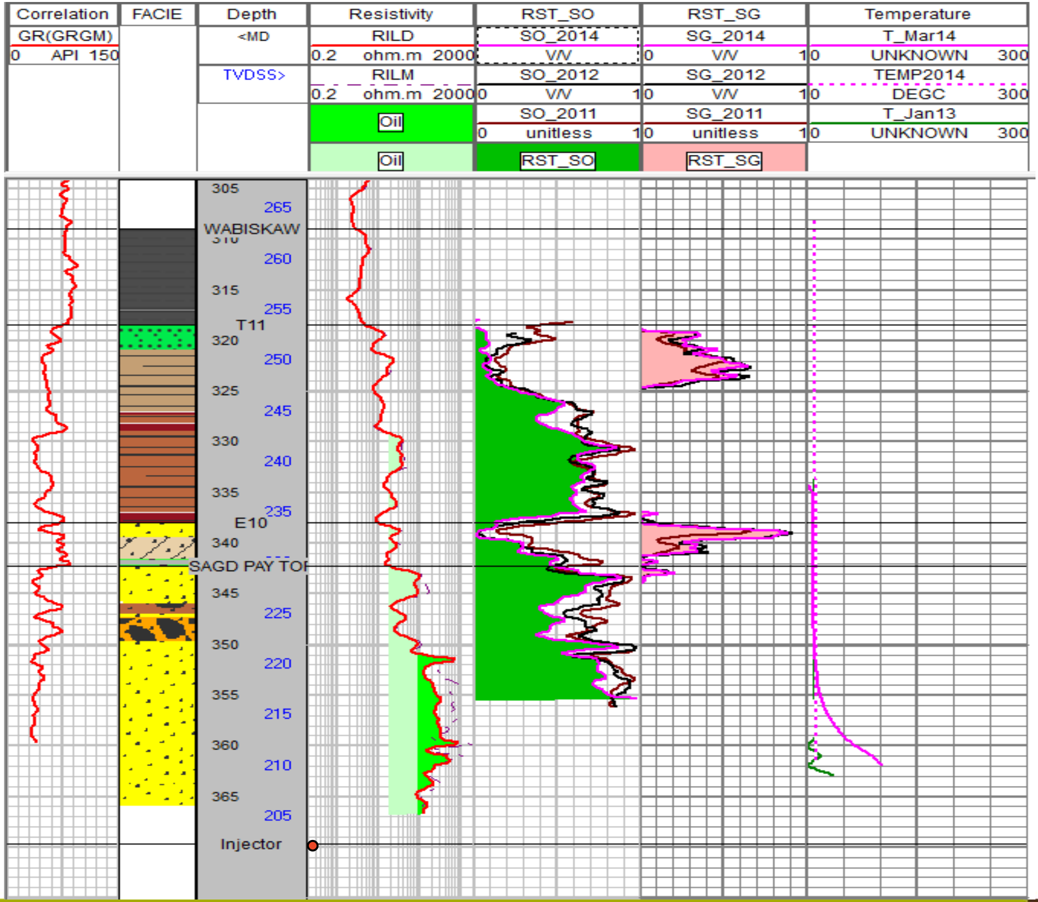
OB-4 (B0103 TOE) 102061507606W400



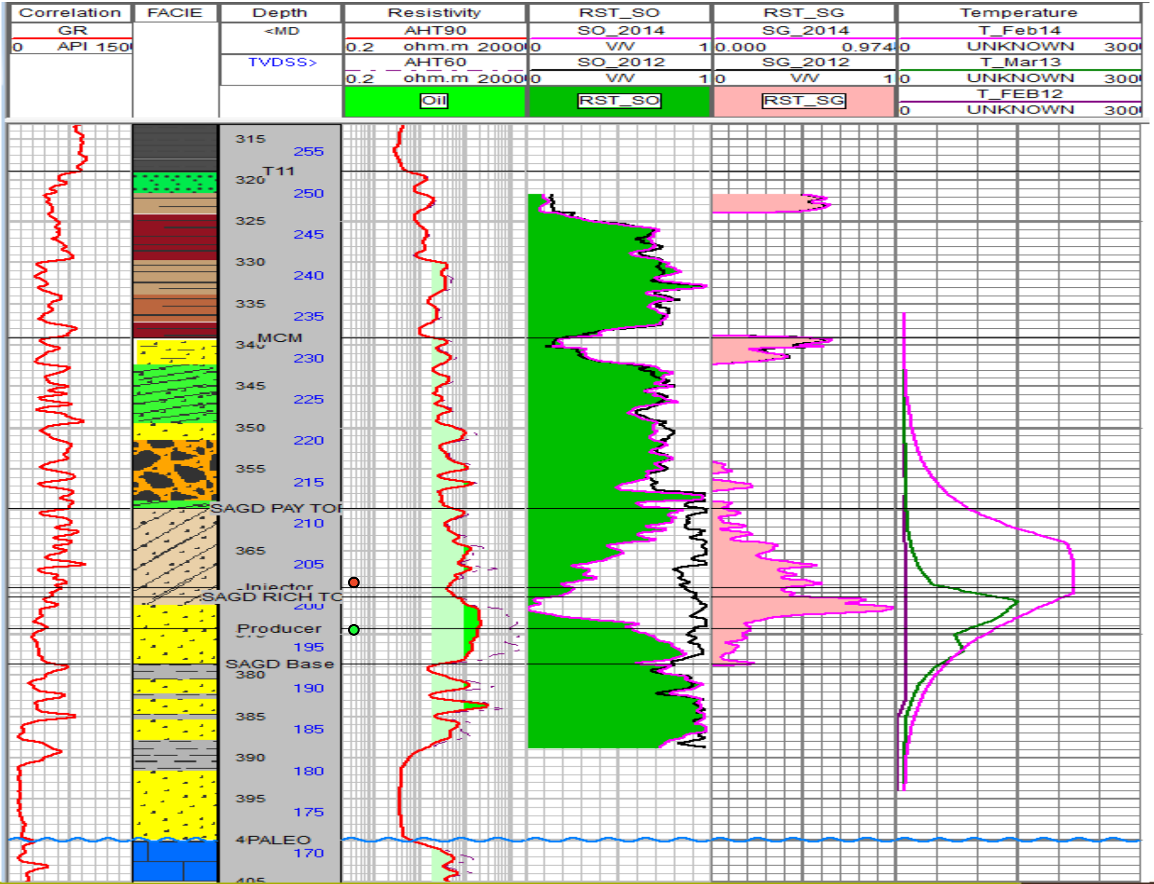
OB-6 (B0104 MID 104061507606W400)



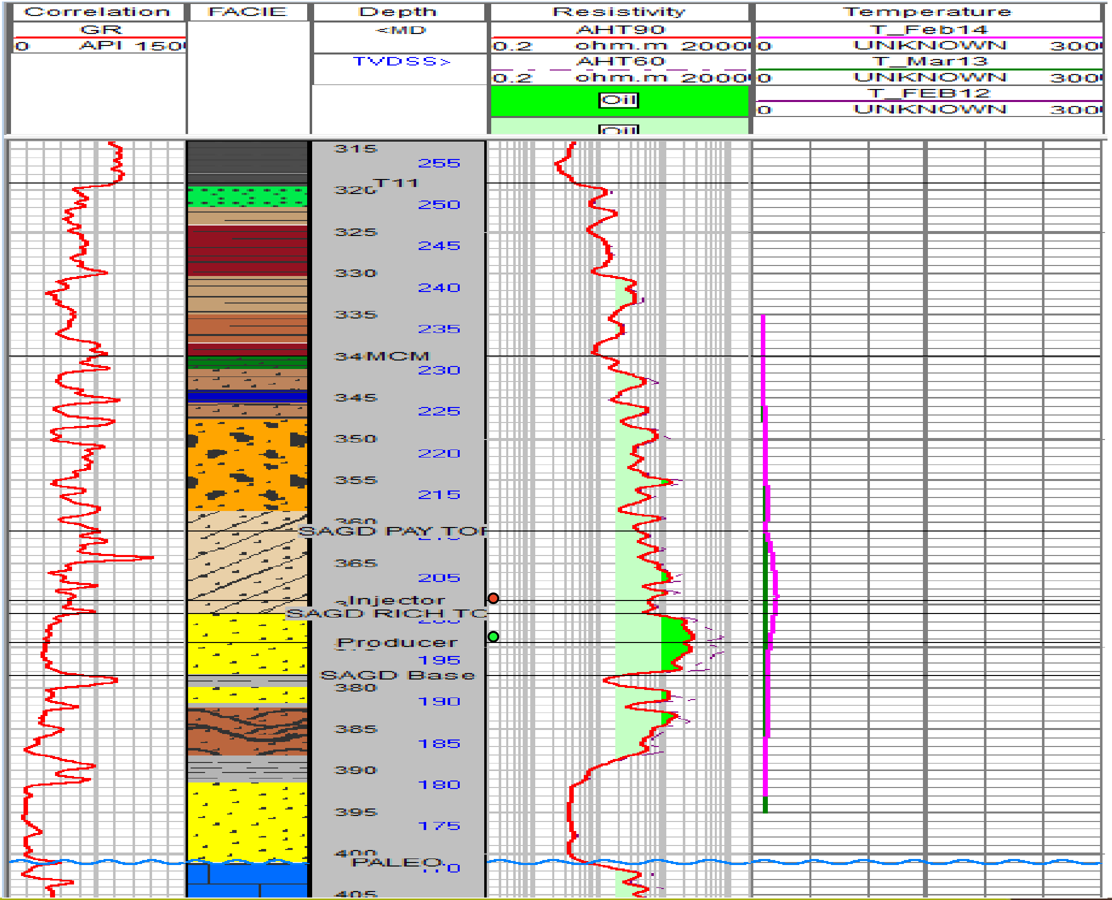
OB-11 (B017 Heel) 100041507606W400



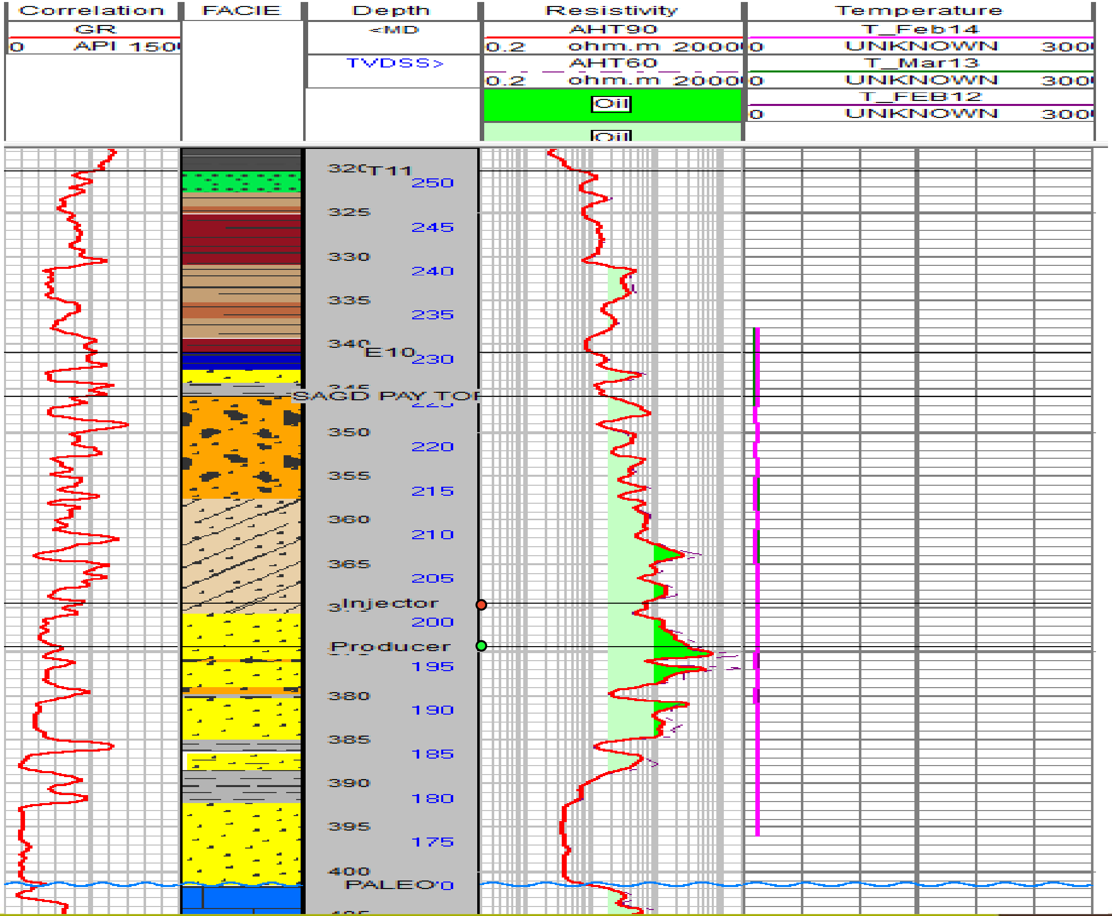
OB-12 (B017 Heel) 102041507606W400



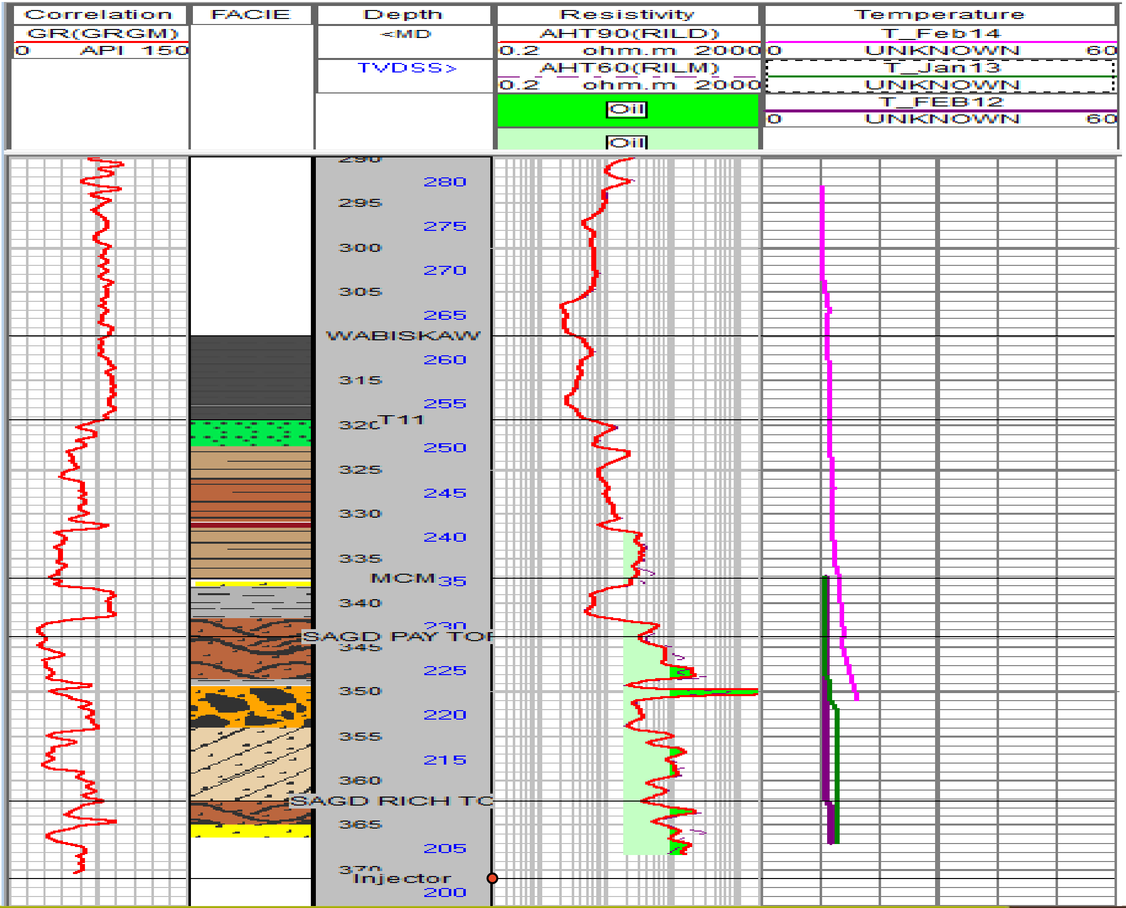
OB-13 (B017 Heel) 103041507606W400



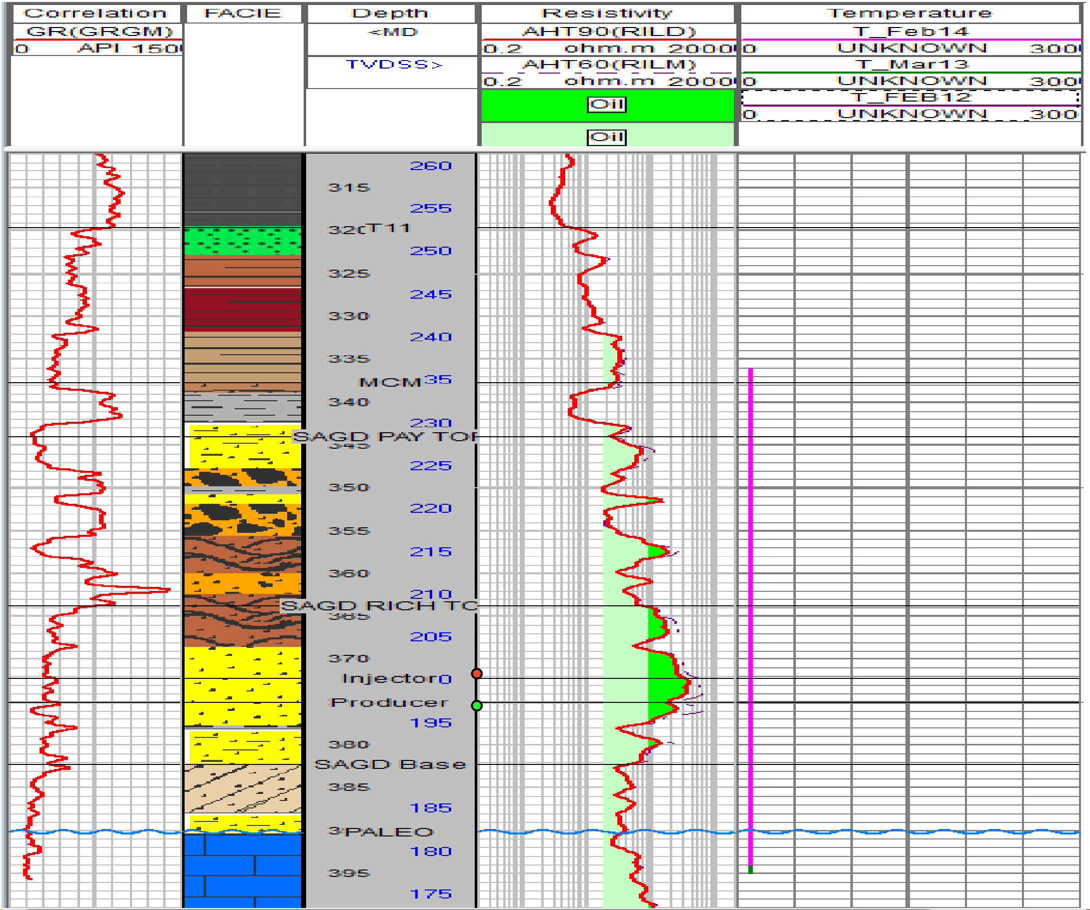
OB-14 (B017 Heel) 104041507606W400



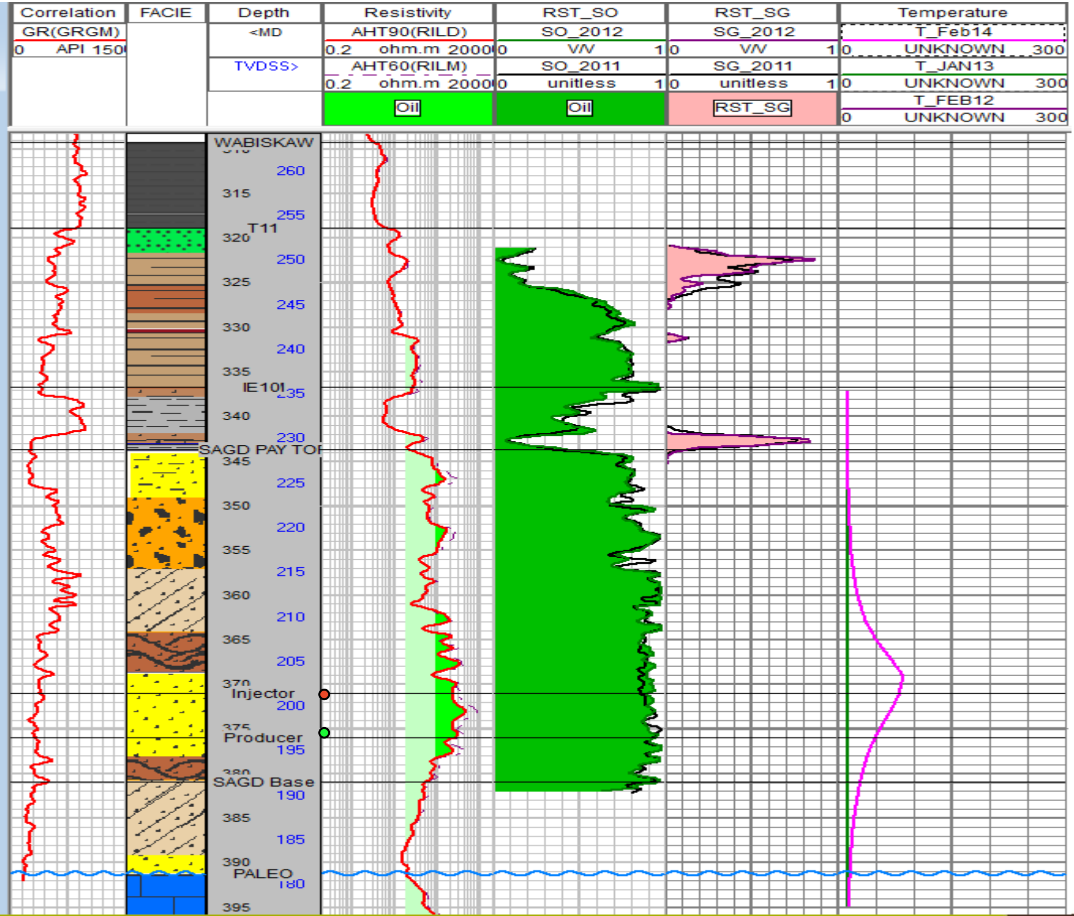
OB-15 (B017 Heel) 102031507606W400



OB-16 (B017 Heel) 103031507606W400

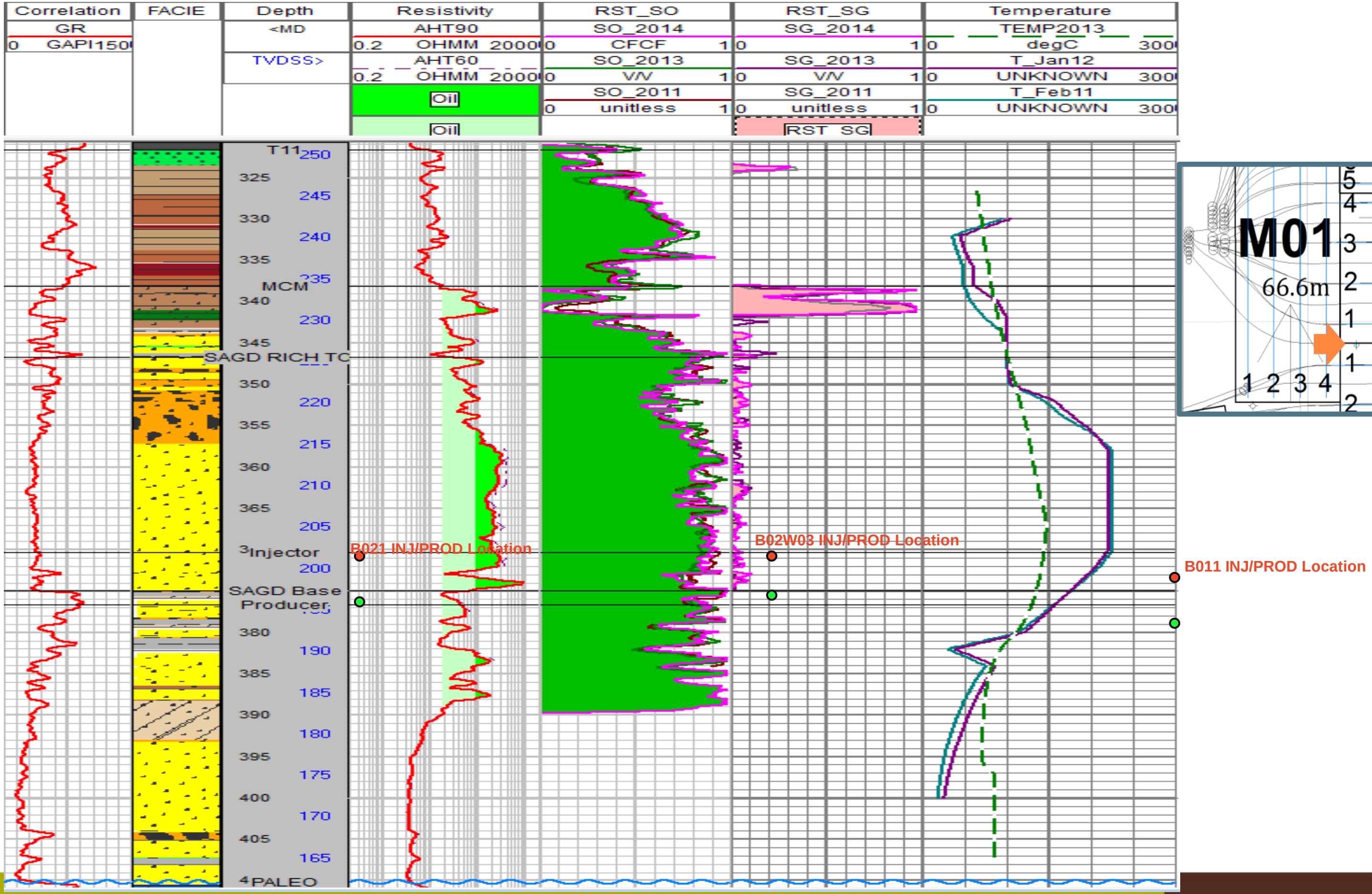


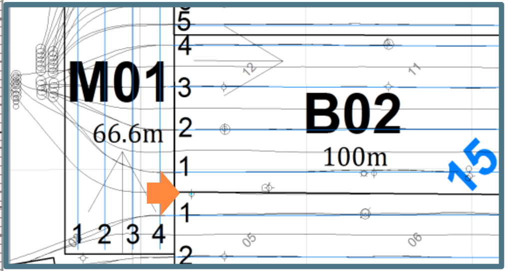
OB-17 (B017 TOE) 104031507606W400



RST logs
B02 pad

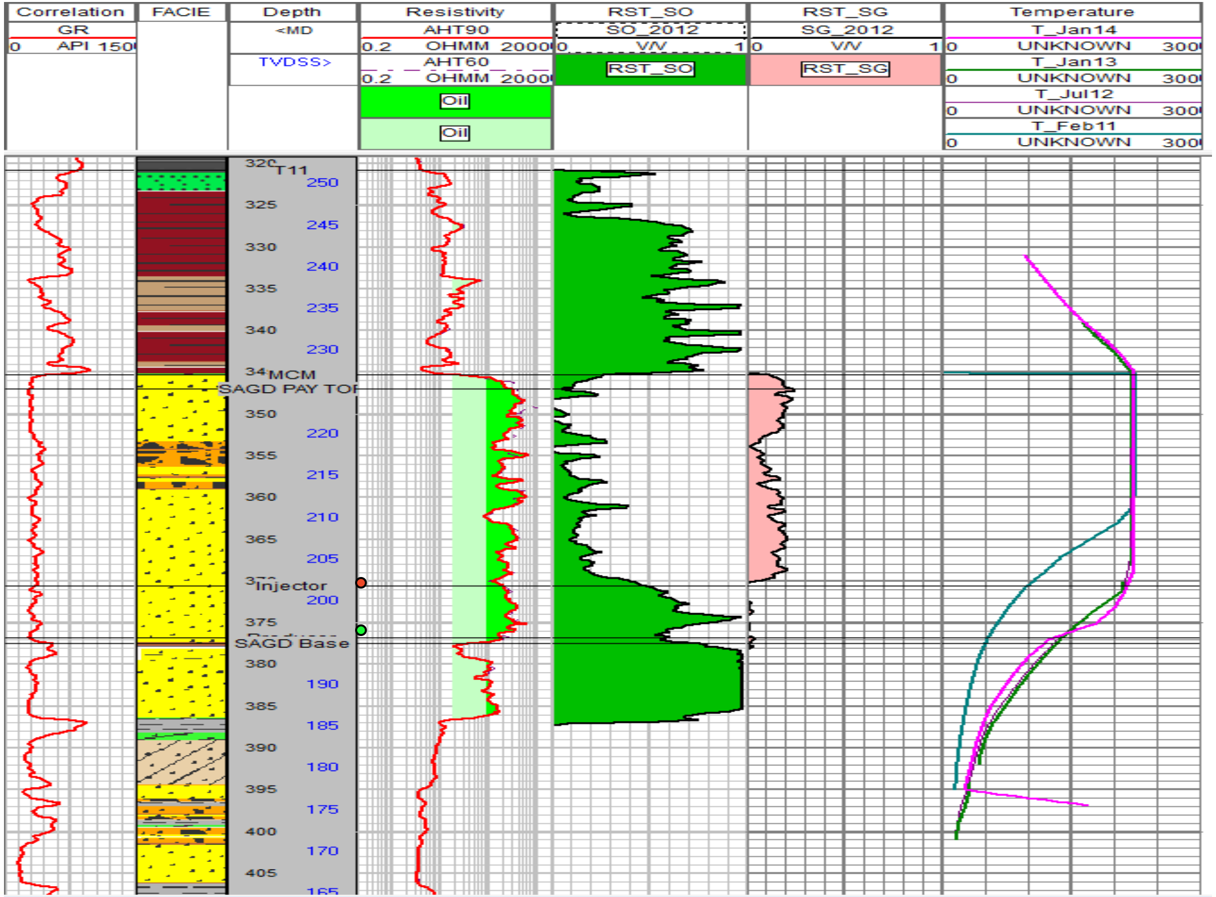
(Btw half B021-11) 100051507606W400



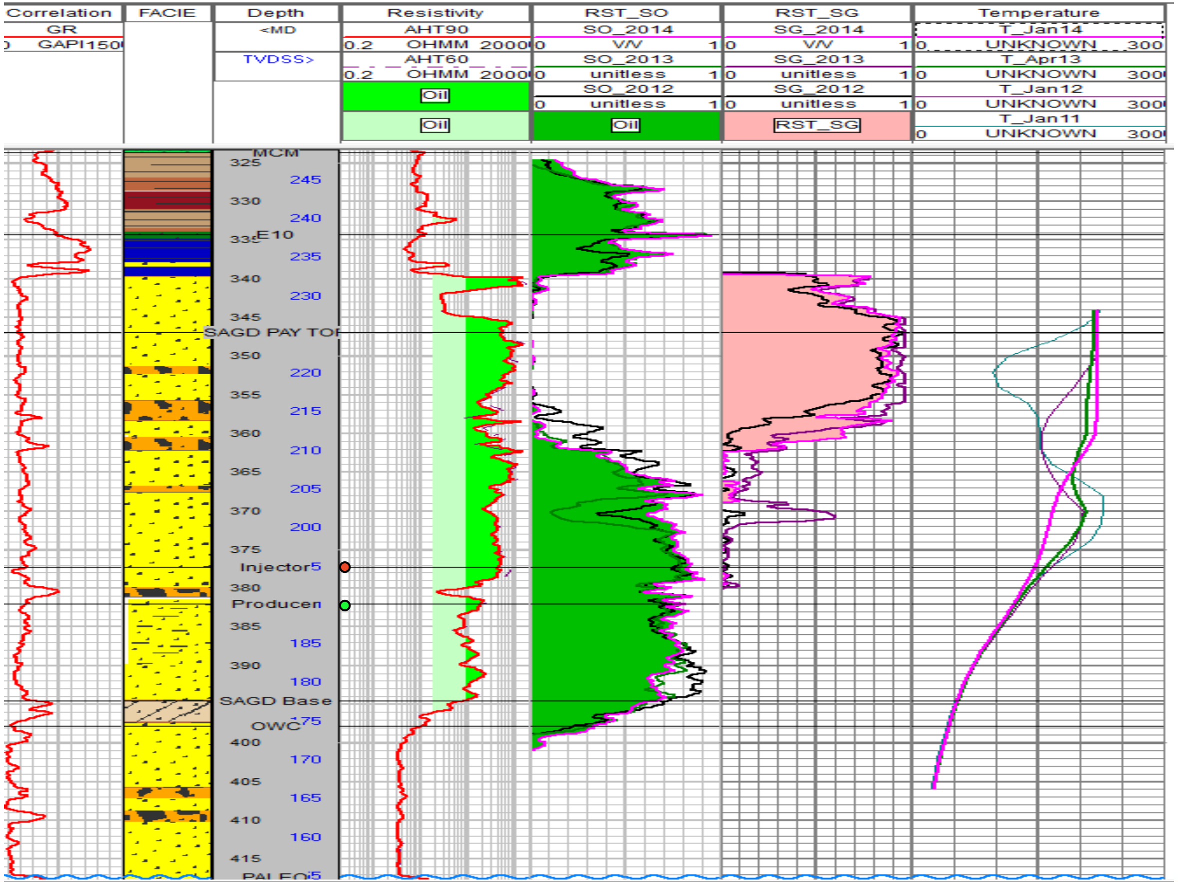


B011 INJ/PROD location(SS): 199.1/193.1
B02W03 INJ/PROD location(SS): 196/201
B021 INJ/PROD location(SS): 201.9/195.6

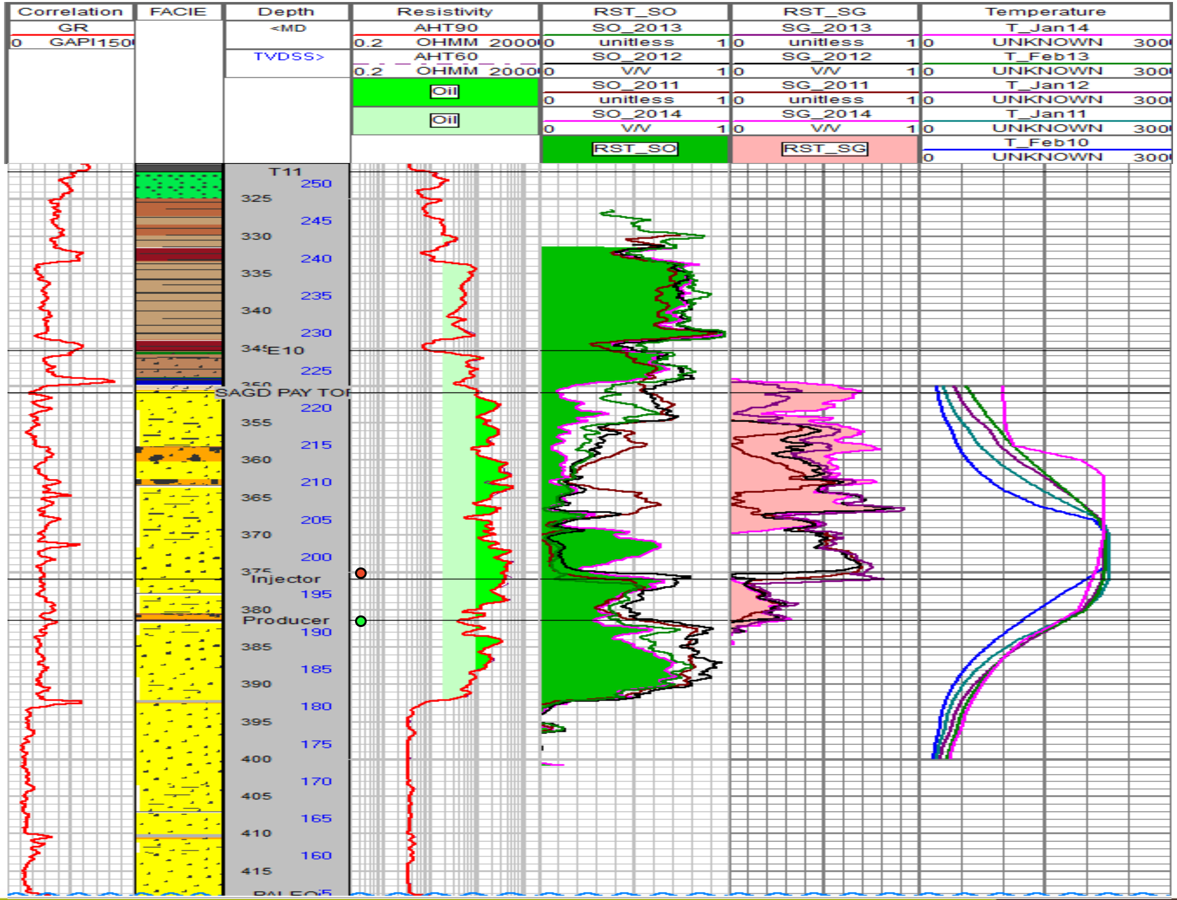
GP-5 (B0201 MID) 103051507606W400



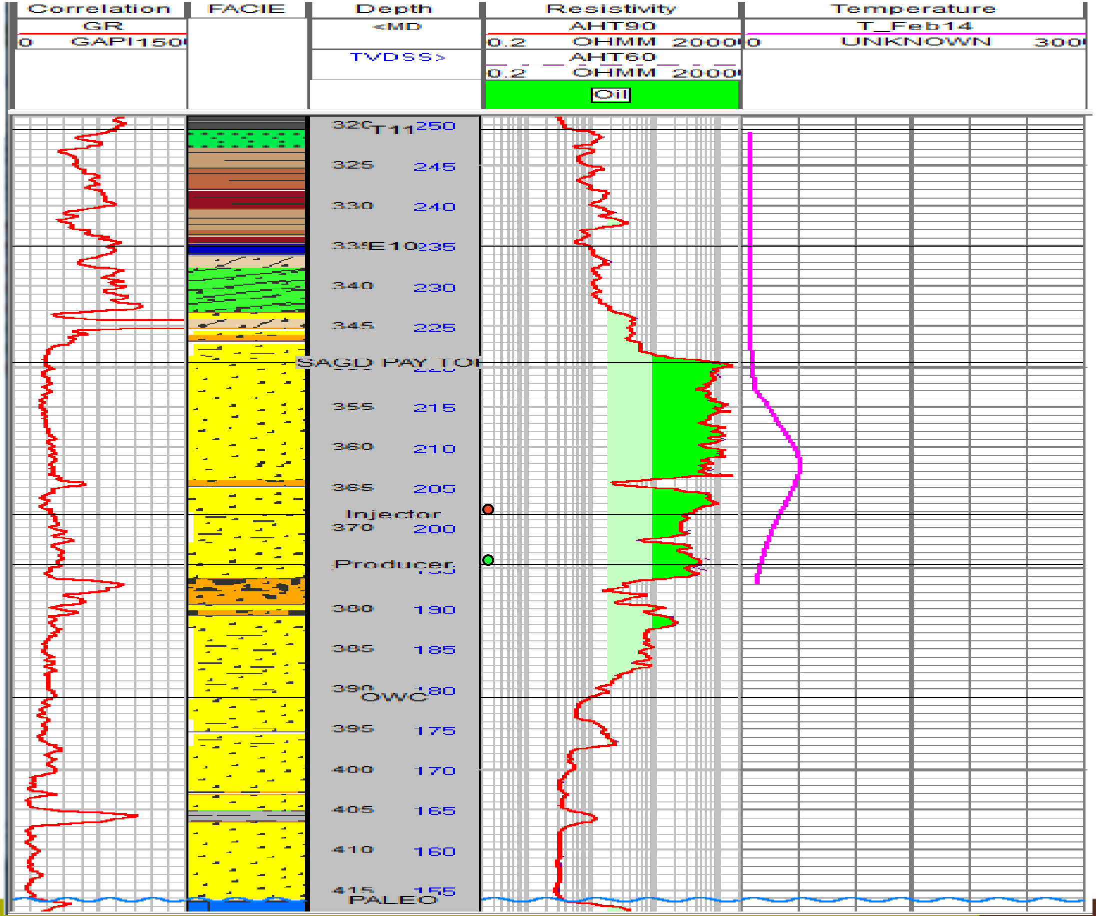
OB-3 (B0202 HEEL) 102121507606W400



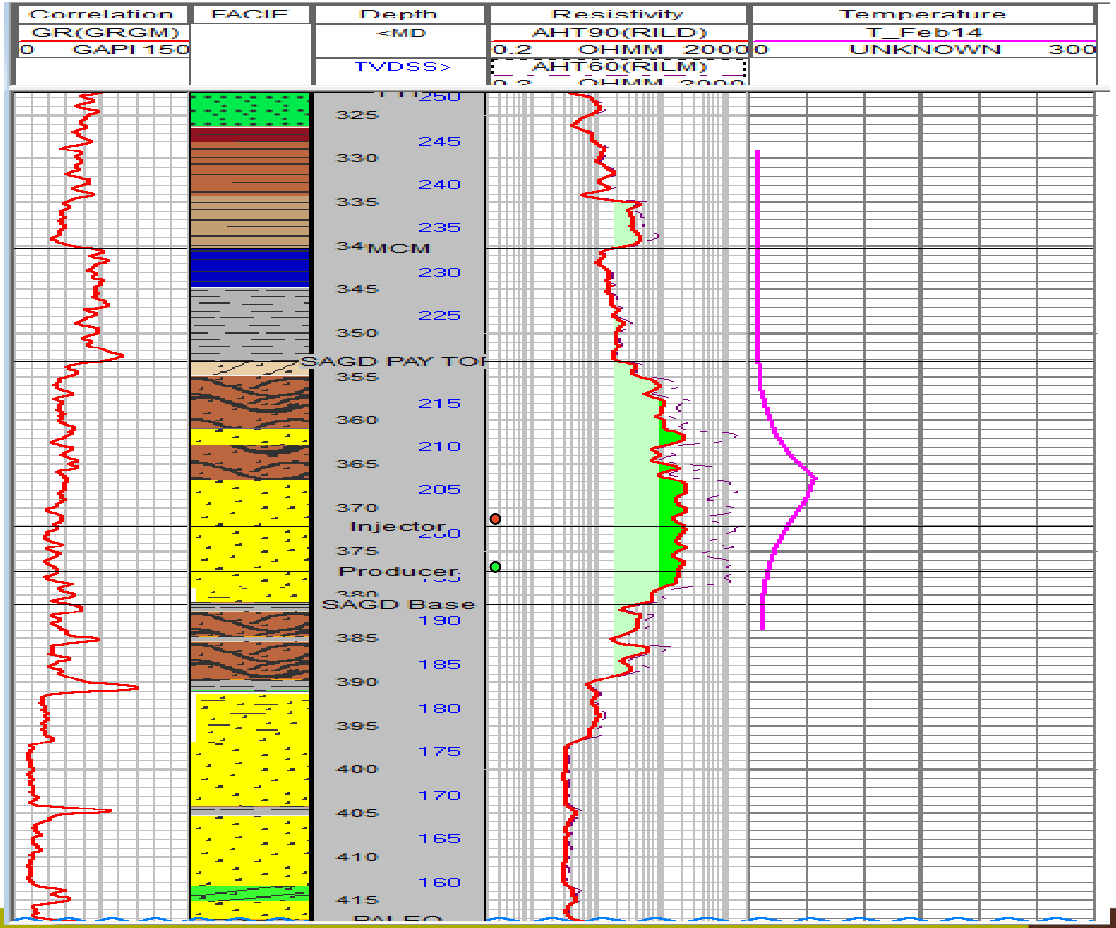
OB-2 (B0204 TOE) 100111507606W400



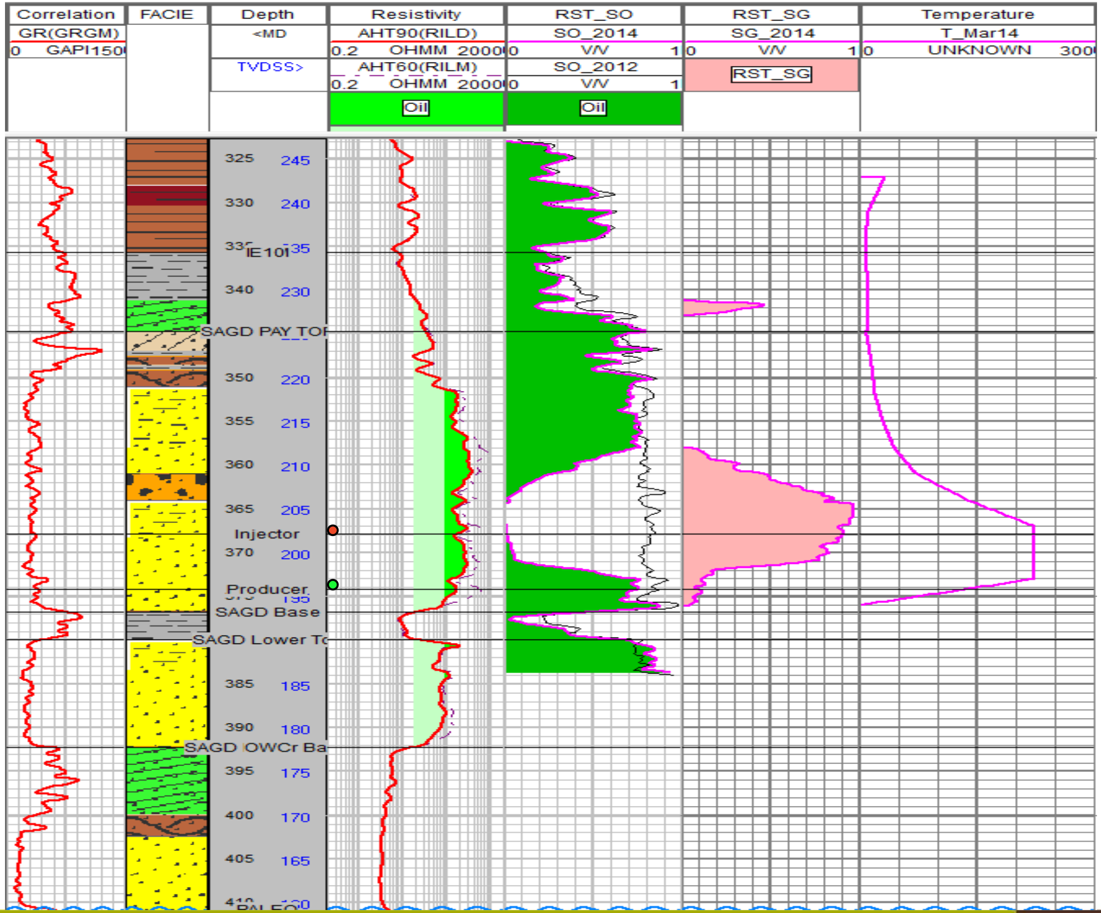
B026H (B0206 HEEL) 100121507606W400



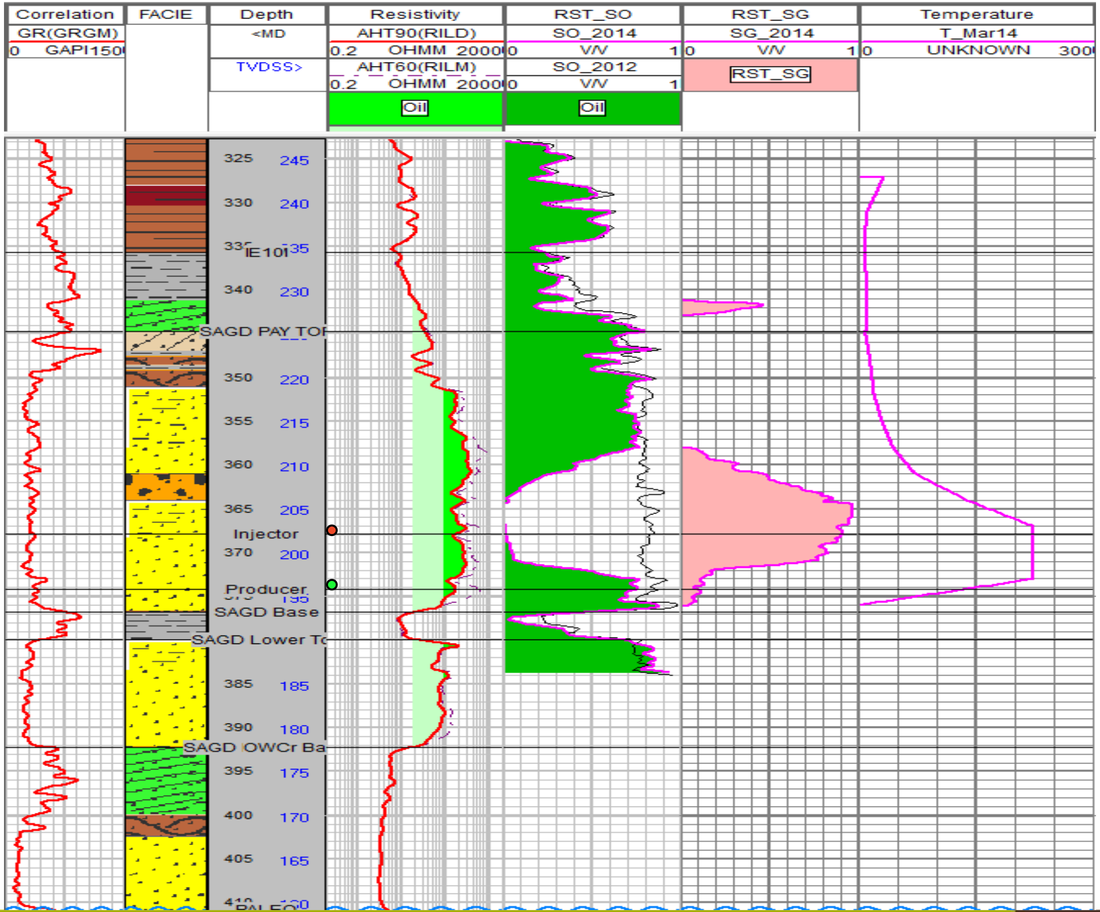
B027T (B0207 TOE) 110151507606W400



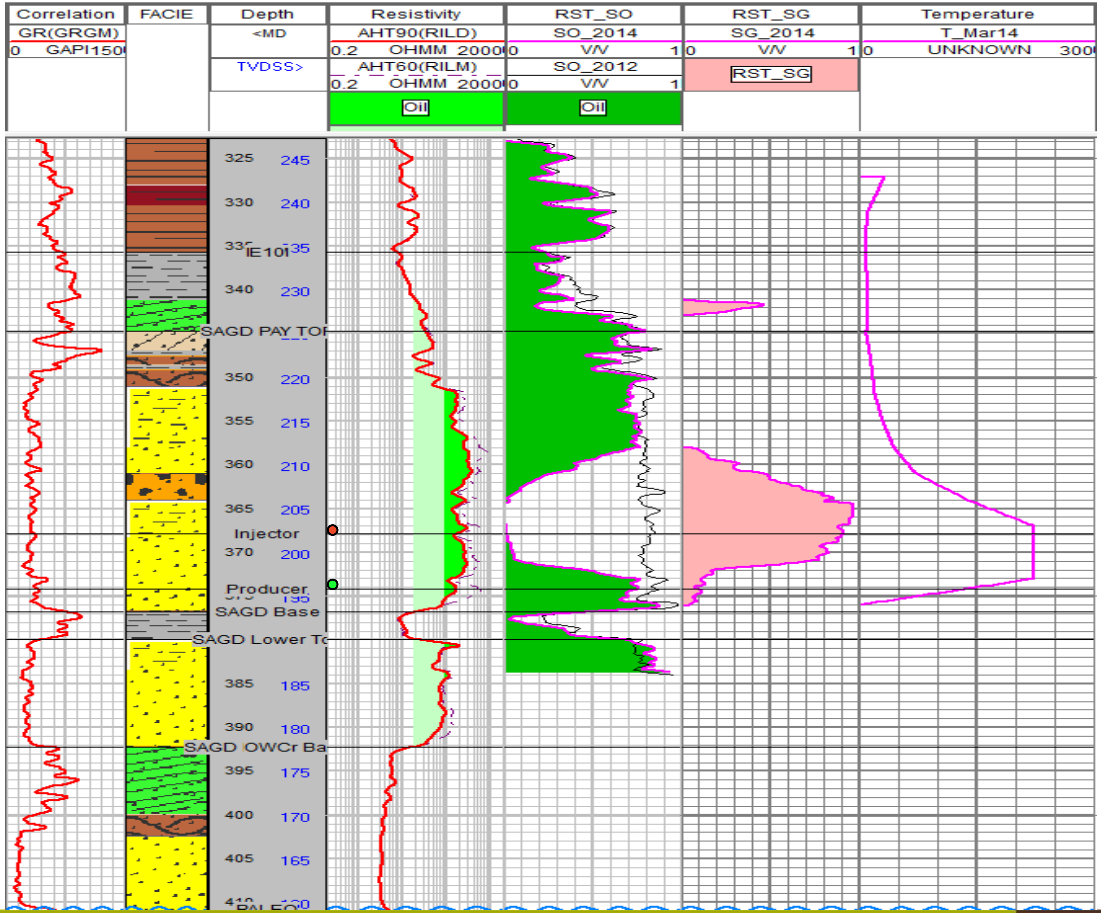
B029H (B0209 HEEL) 100131507606W400



B029H (B0209 HEEL) 100131507606W400



B029H (B0209 HEEL) 100131507606W400



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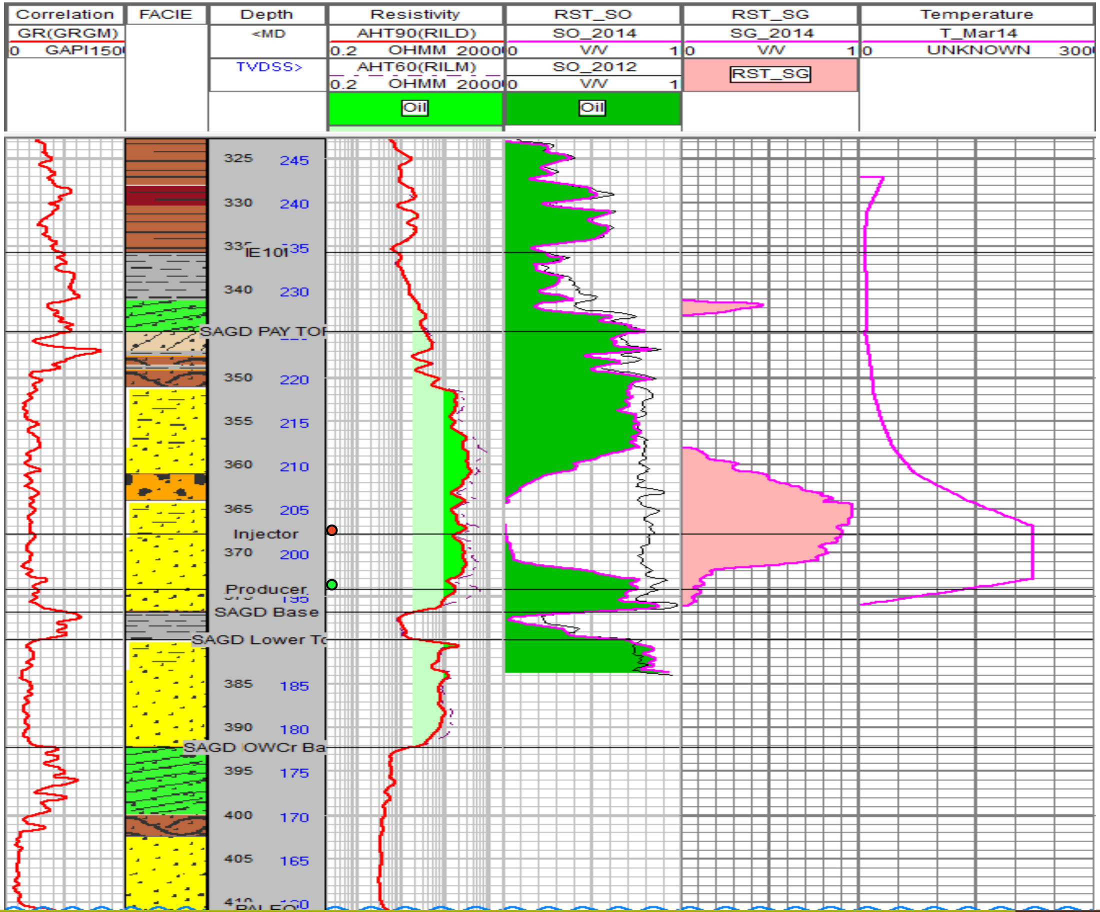
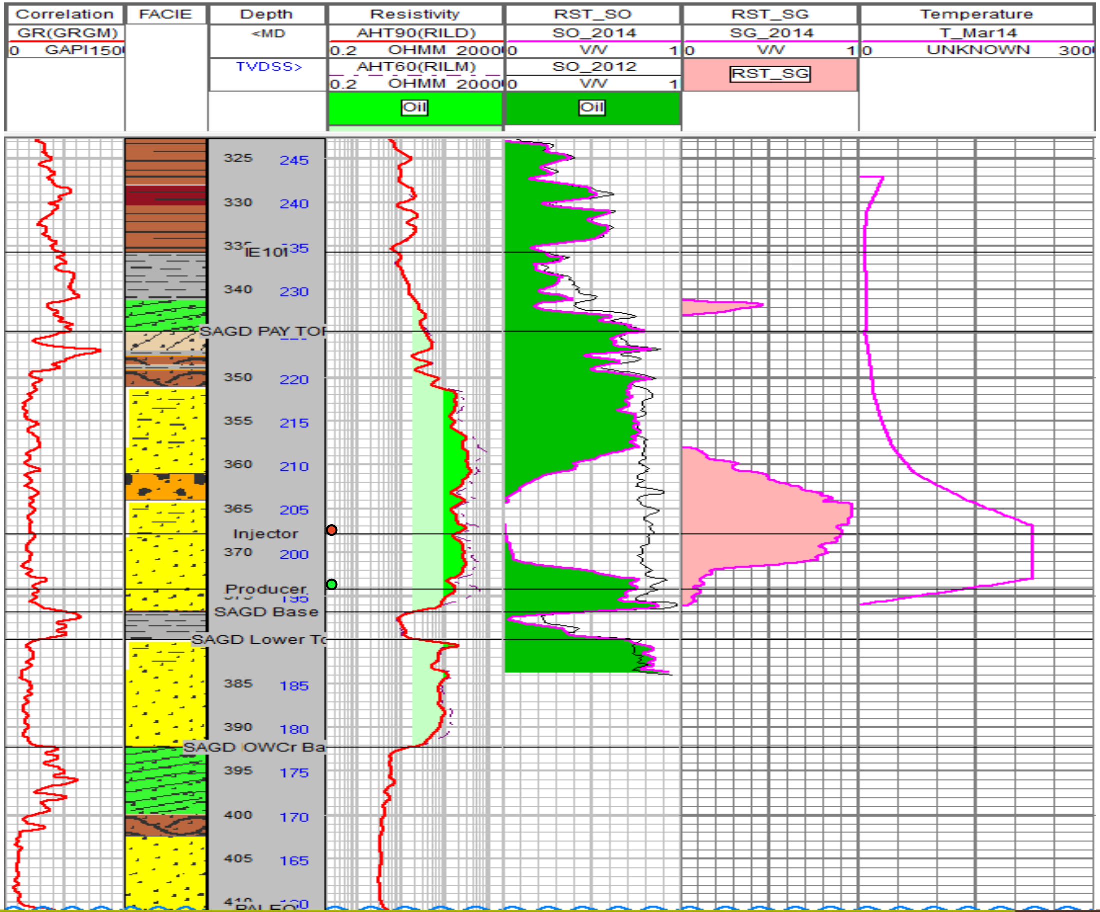
B029H (B0209 HEEL) 100131507606W400

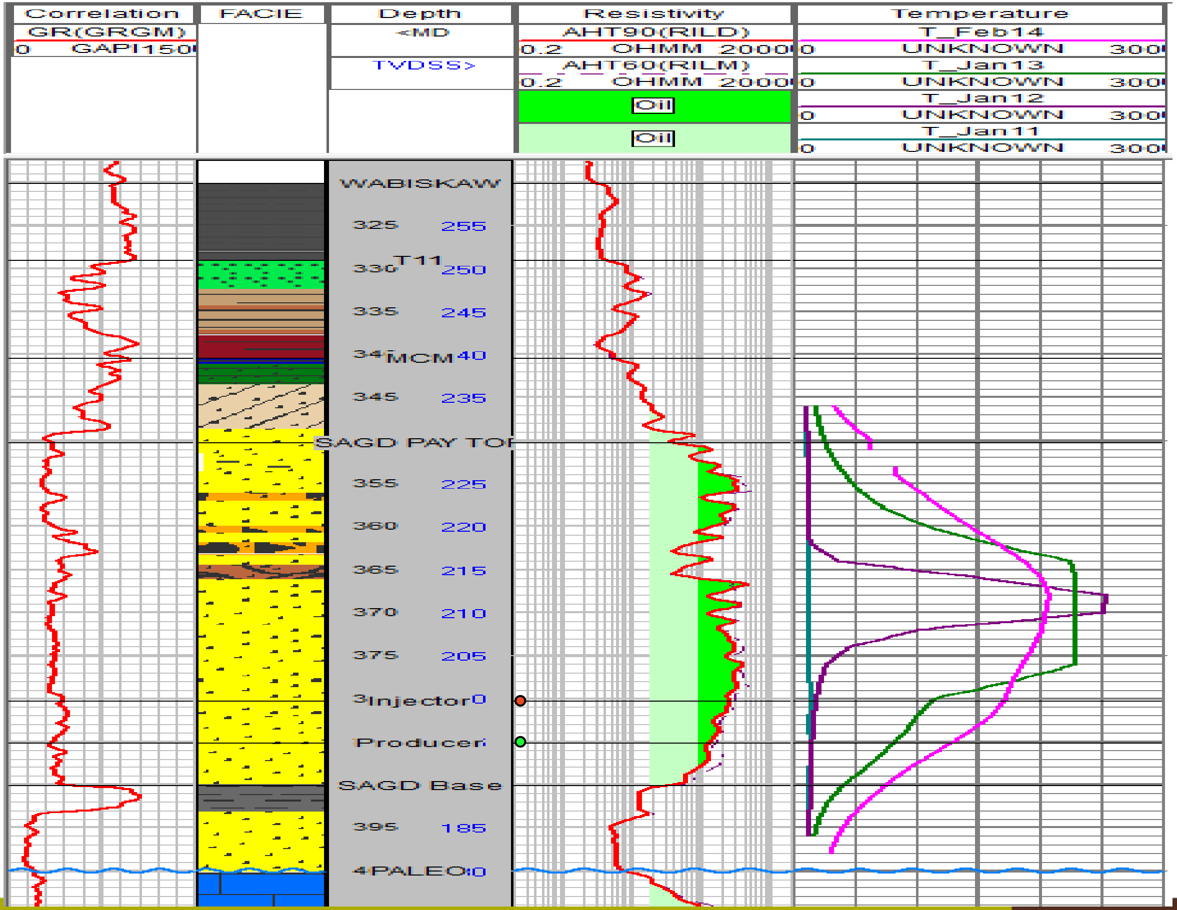


B029H (B0209 HEEL) 100131507606W400



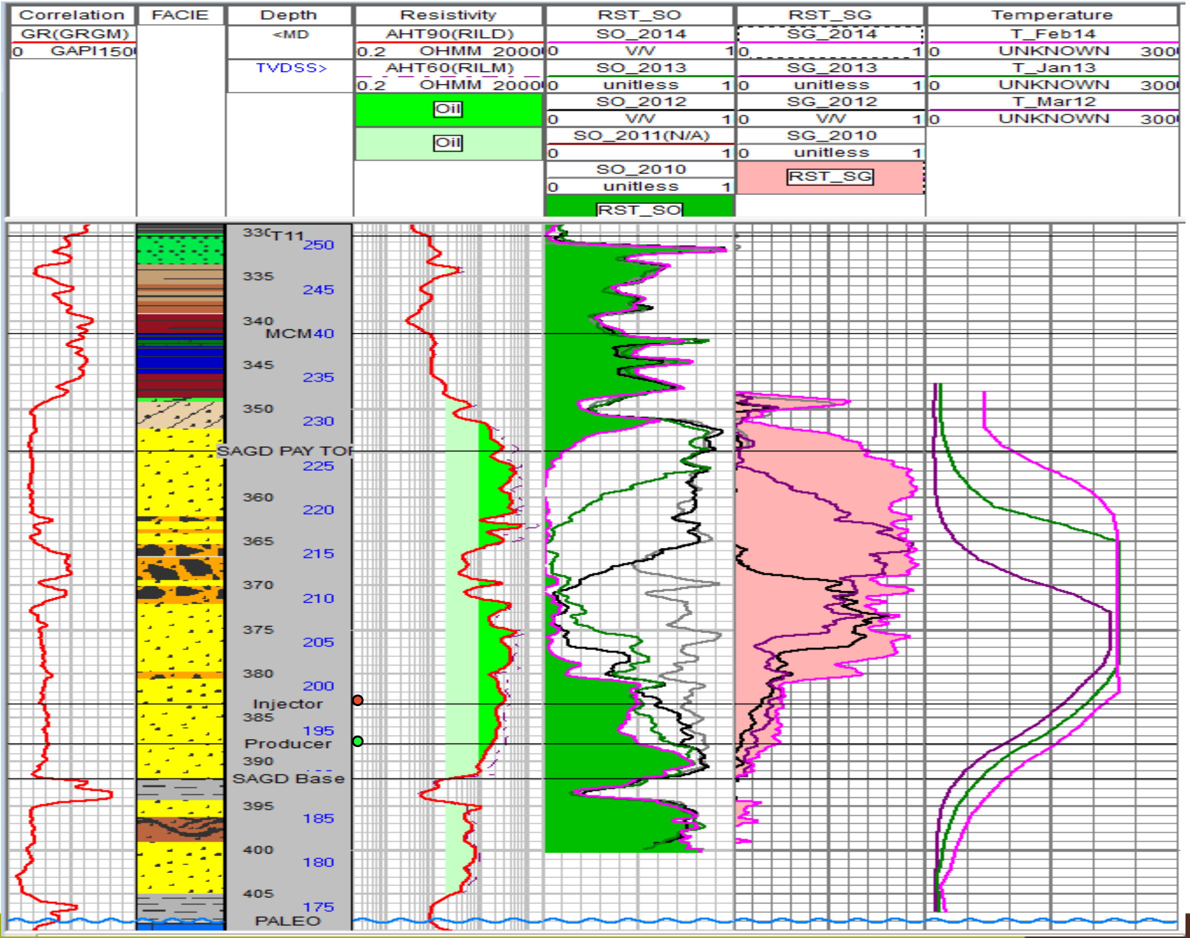
RST Logs
B03Pad

B32H (B0302 HEEL) 102101107606W400

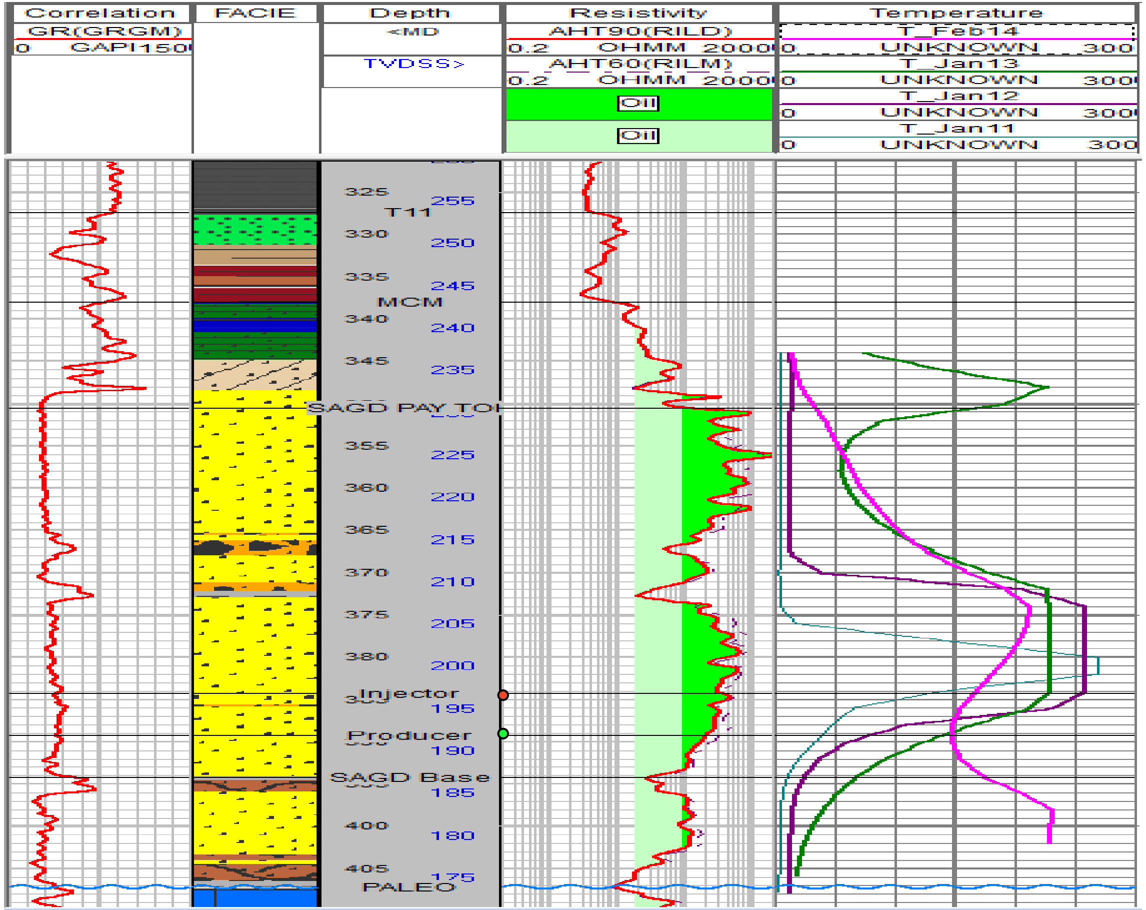


cenovus ENERGY

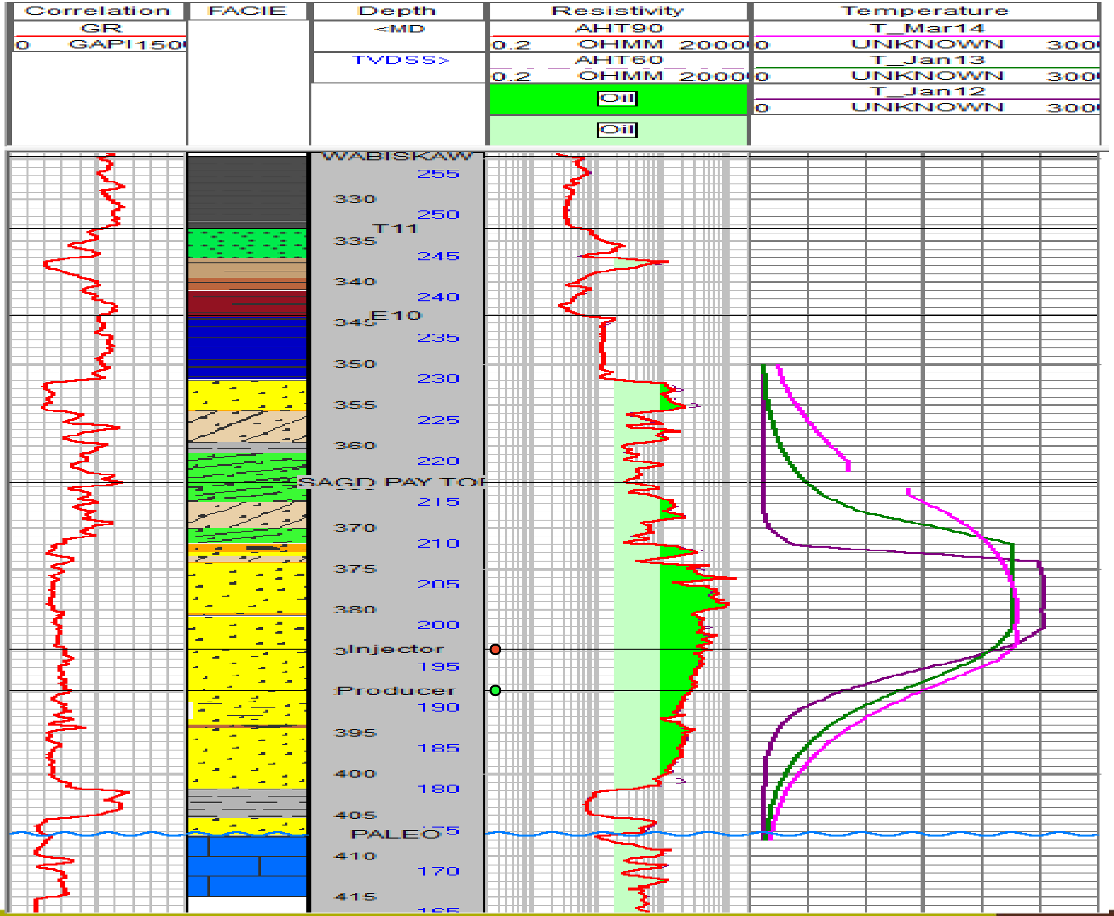
B33T (B033 TOE) 100161107606W400



B35T (B035 TOE) 100131207606W400



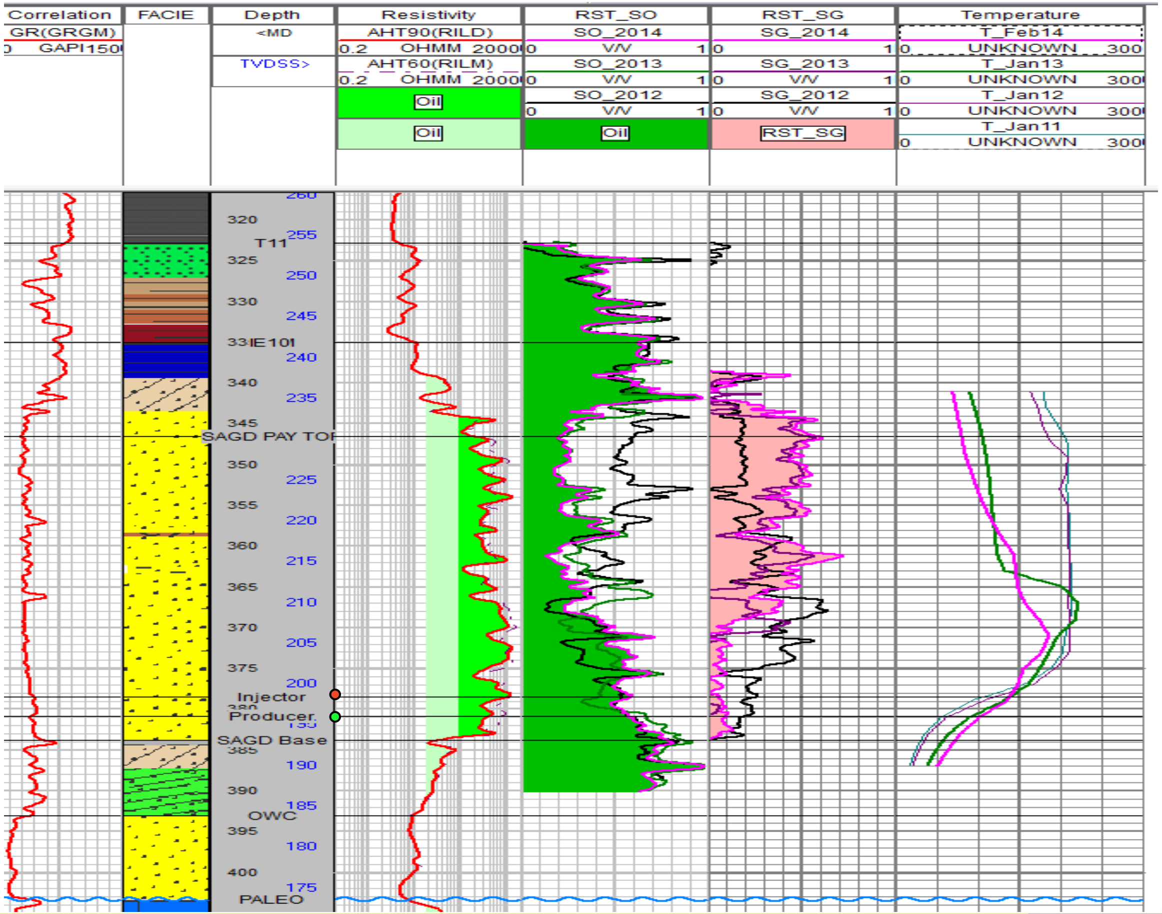
B36H (B036 HEEL) 100091107606W400



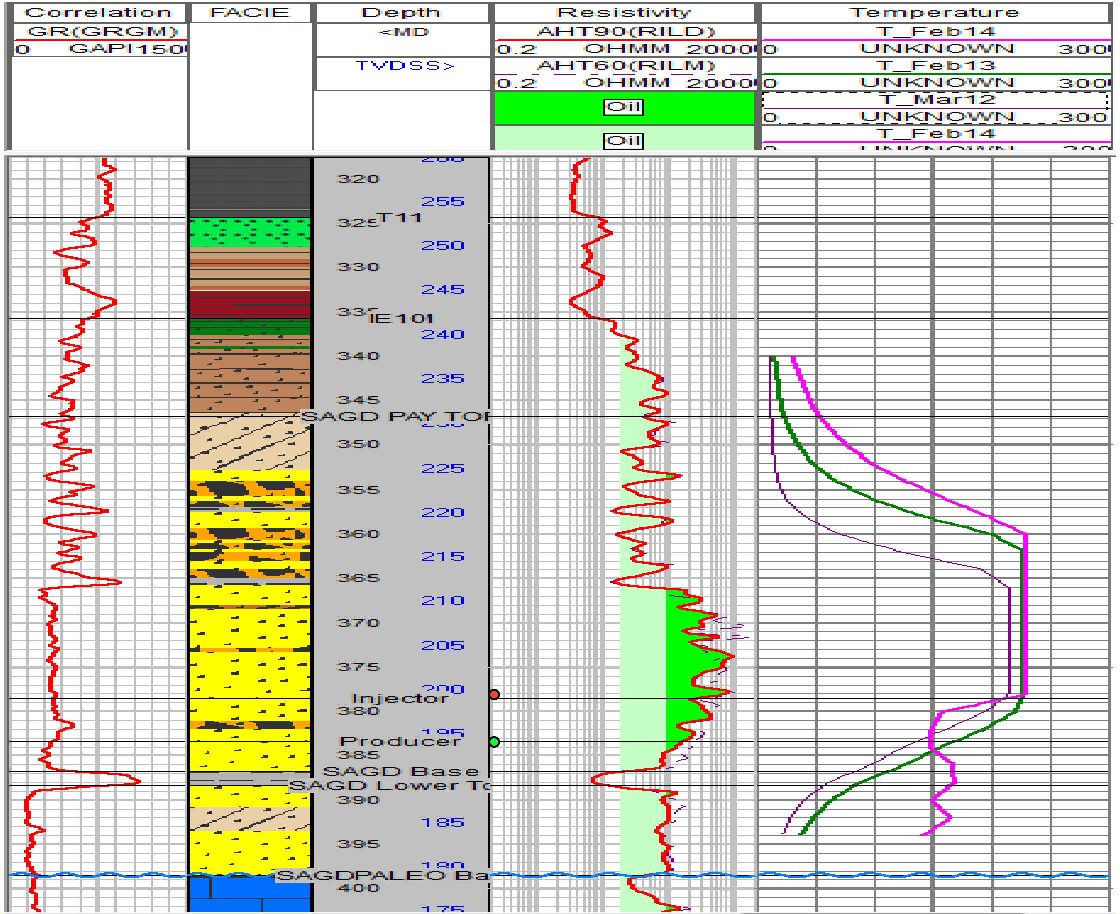
RST logs
B04 pad

cenovus ENERGY

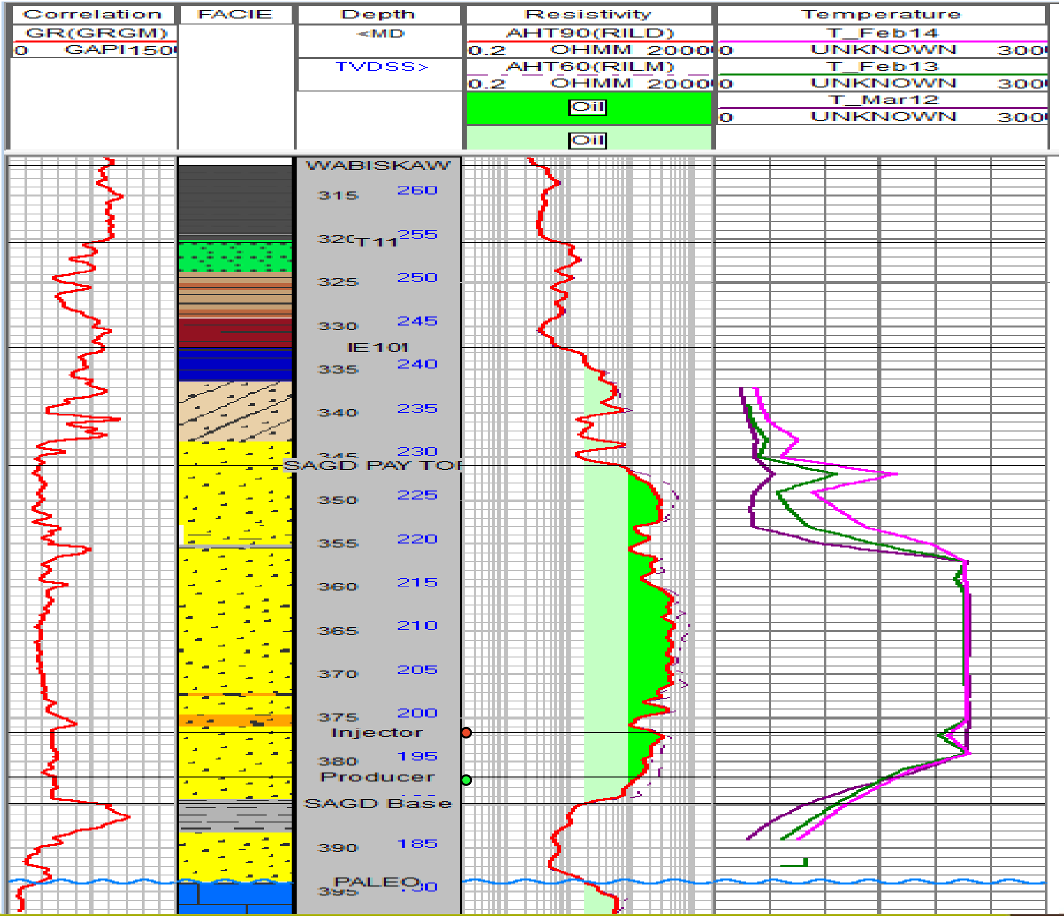
B41H (B041 HEEL) 100011407606W400



B42T (B042 TOE) 100021407606W400

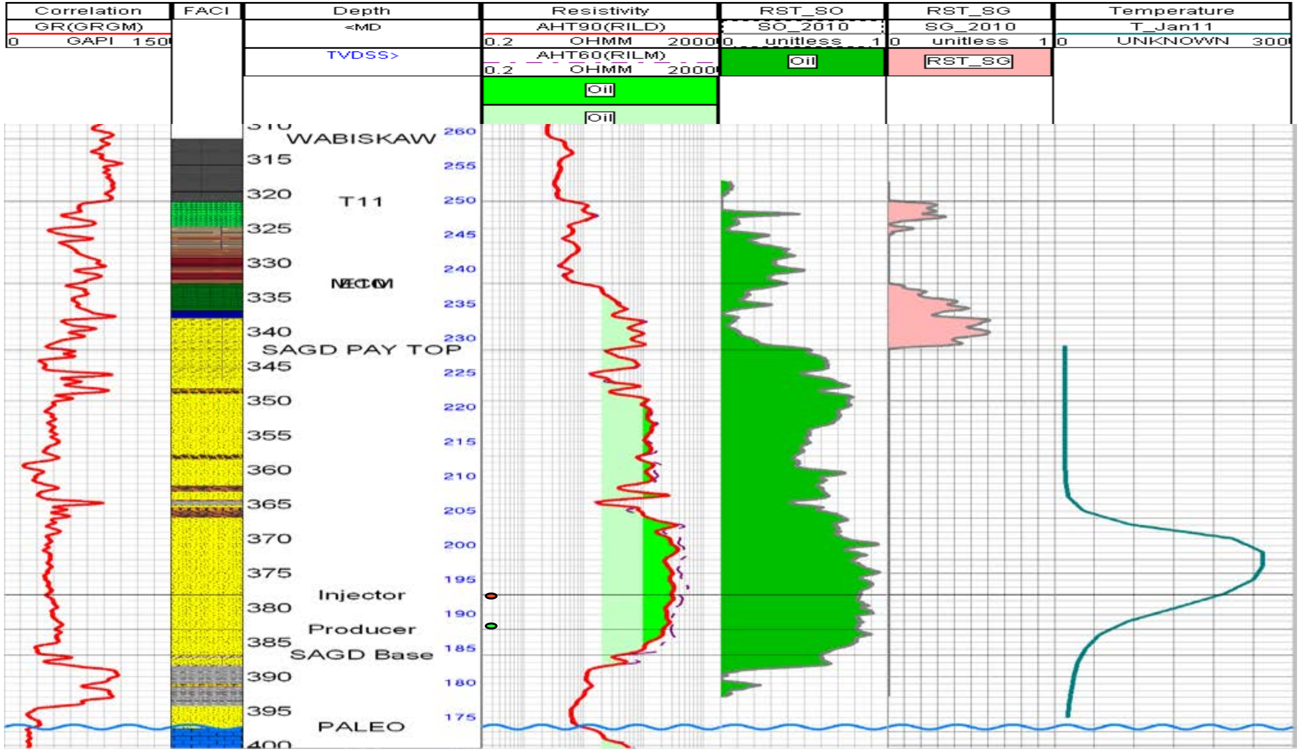


B45H (B045 HEEL) 102071407606W400



No themo data or RST after 2012

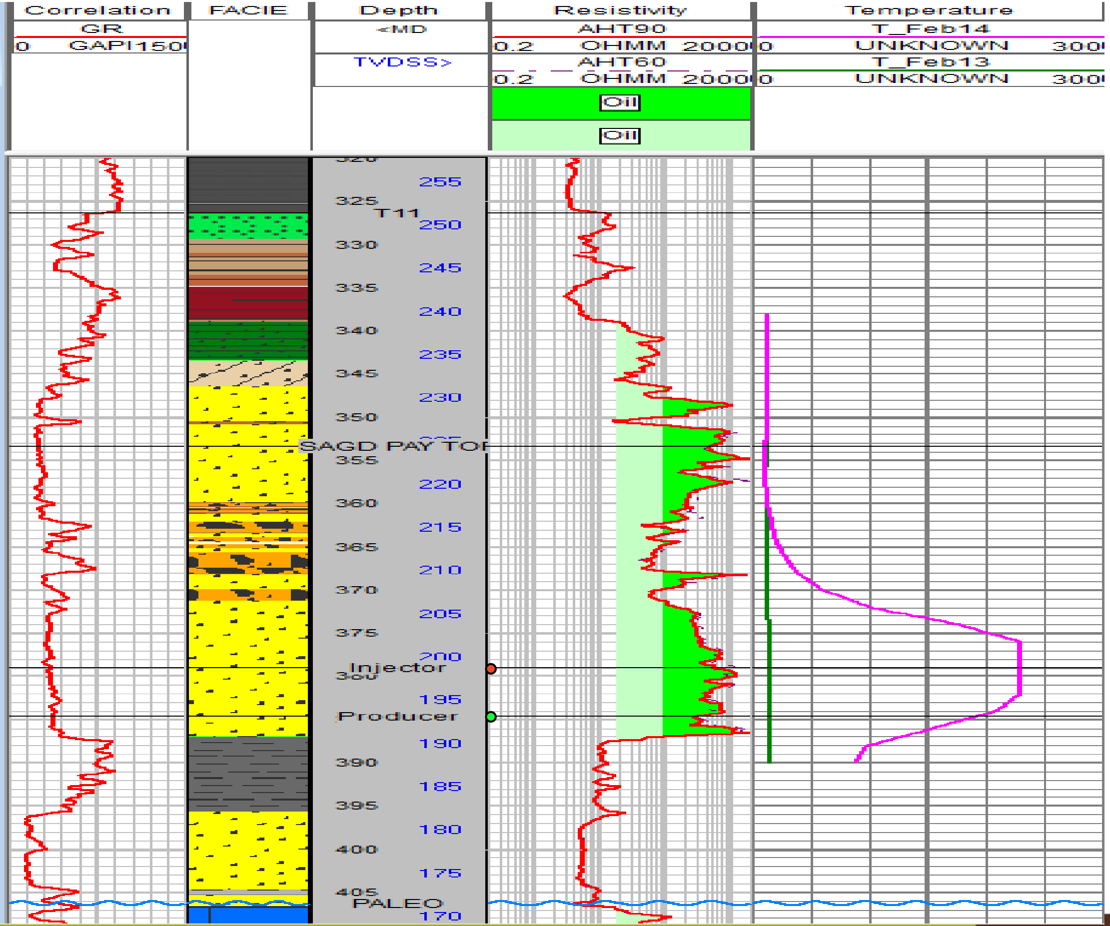
B46T (B0406 TOE) 102031407606W400



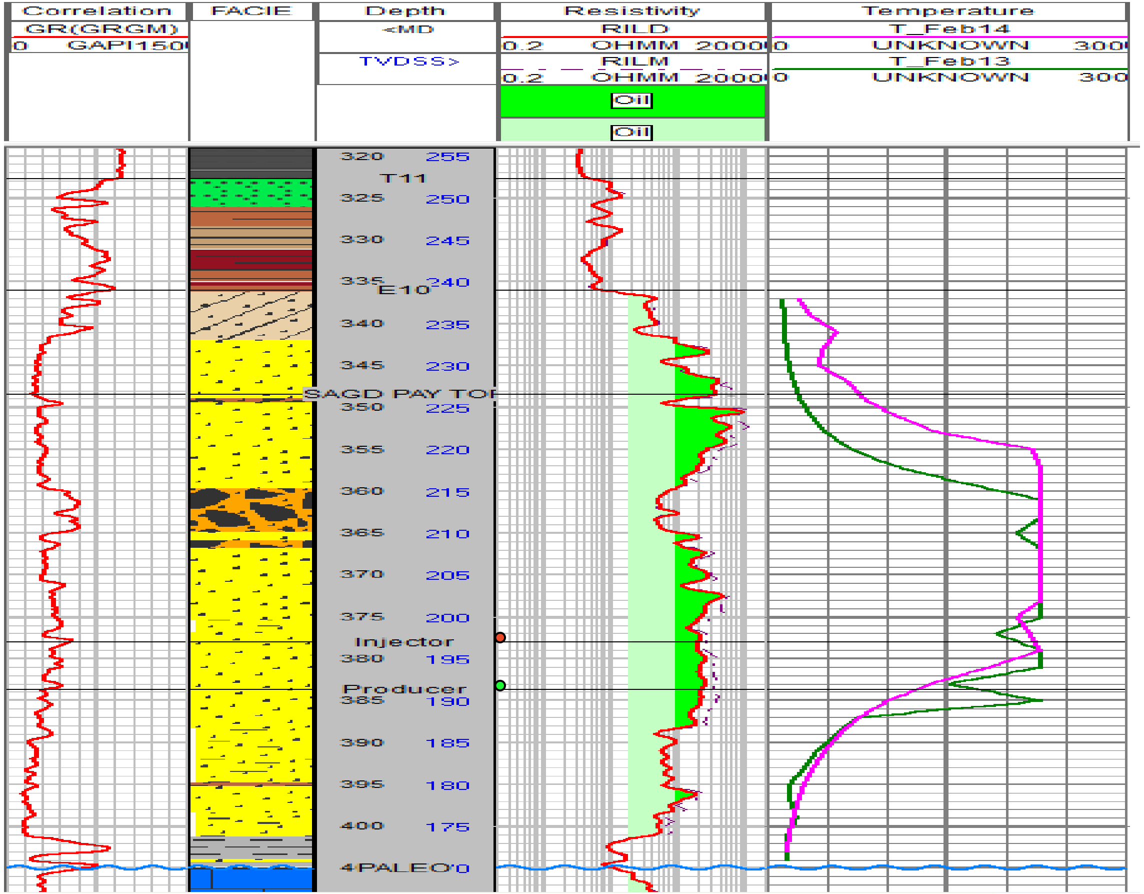
RST logs
B05 pad

cenovus ENERGY

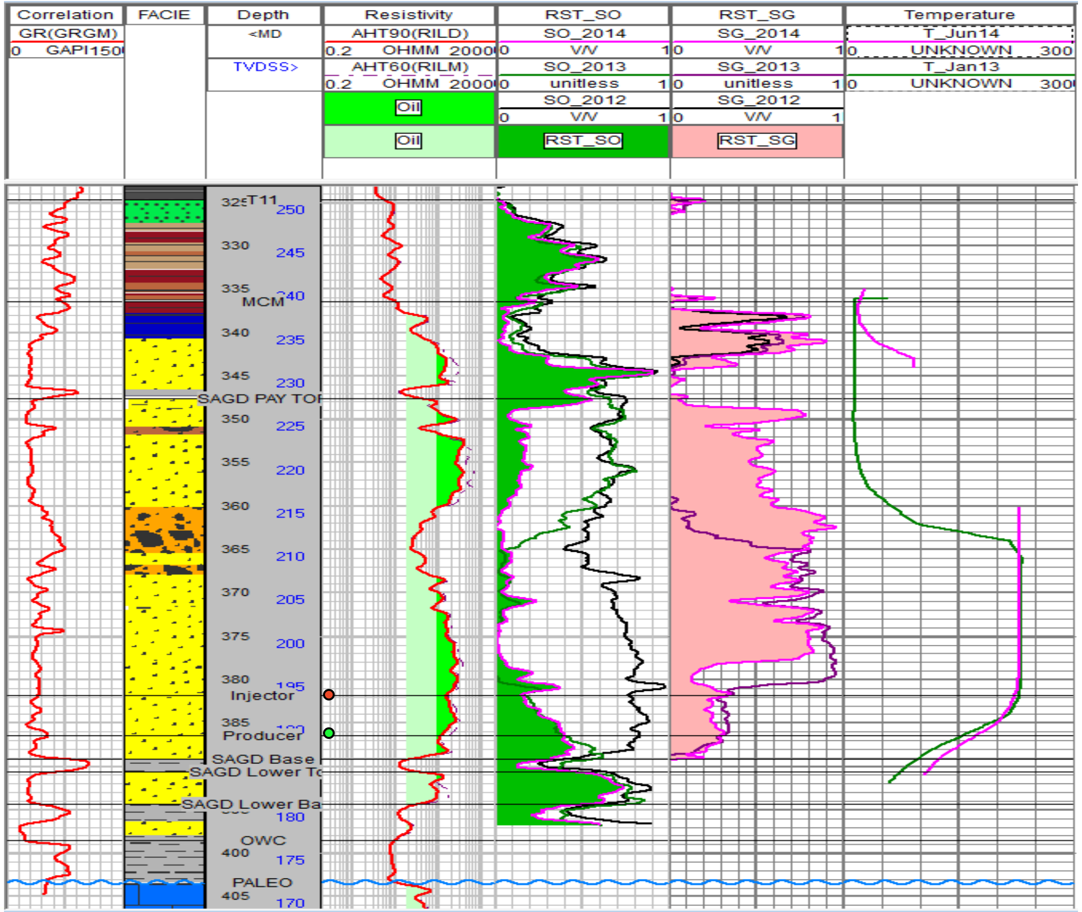
B52H (B052 HEEL) 100151107606W400



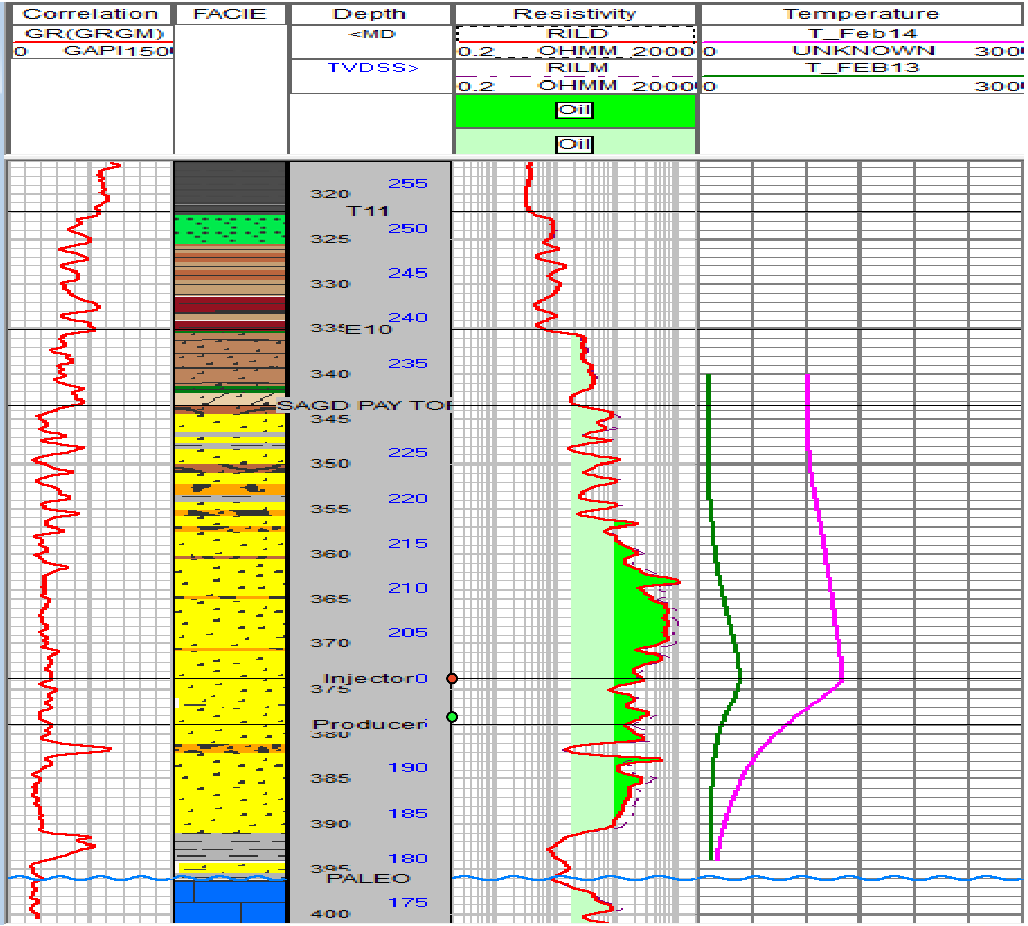
B53M (B053 MIDDLE) 102151107606W400



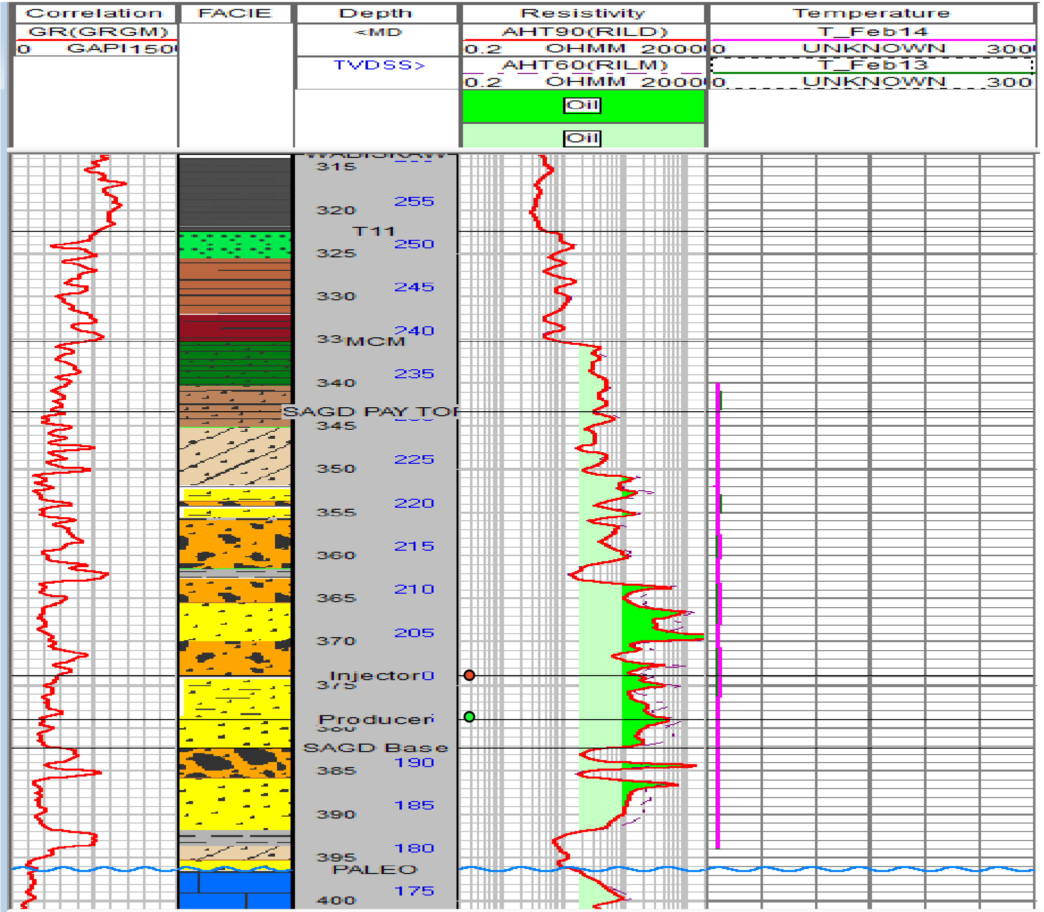
B56T (B056 TOE) 100111107606W400



B58H(1) (B058 HEEL) 100141107606W400

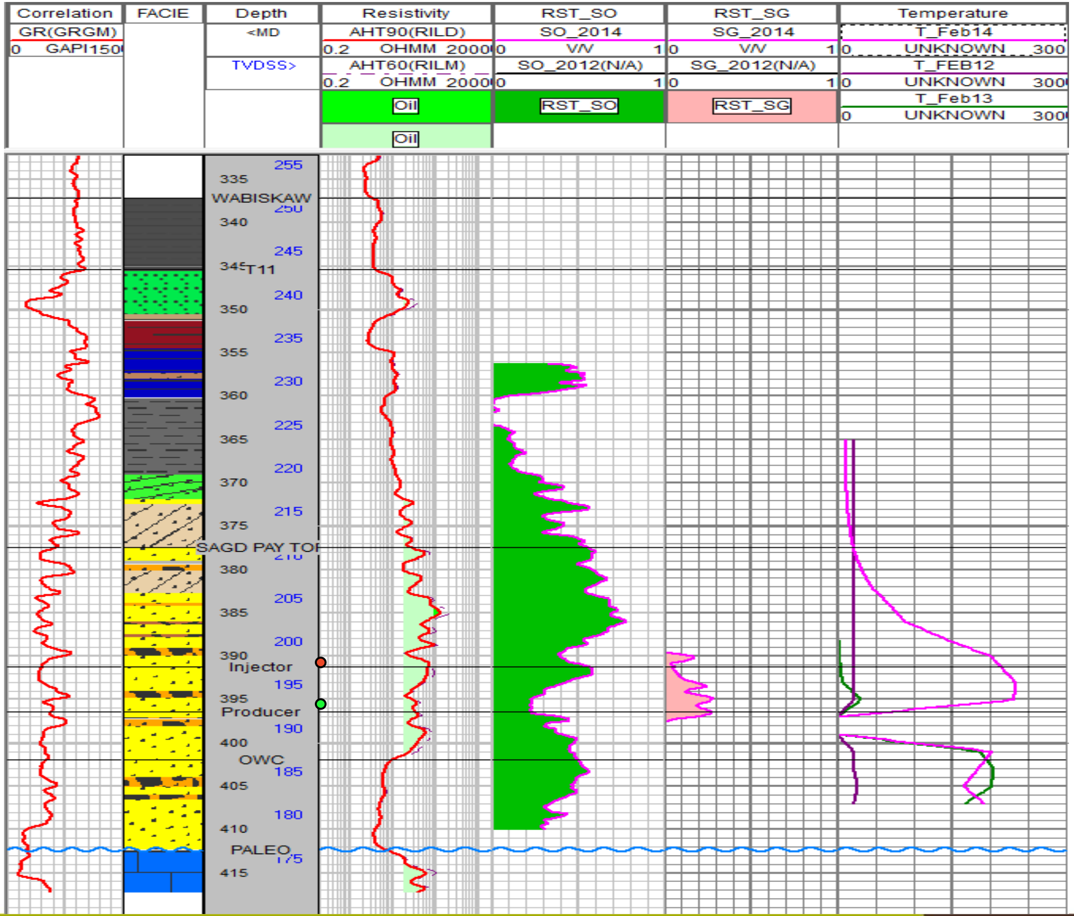


B58H(2) (B058 HEEL) 102141107606W400

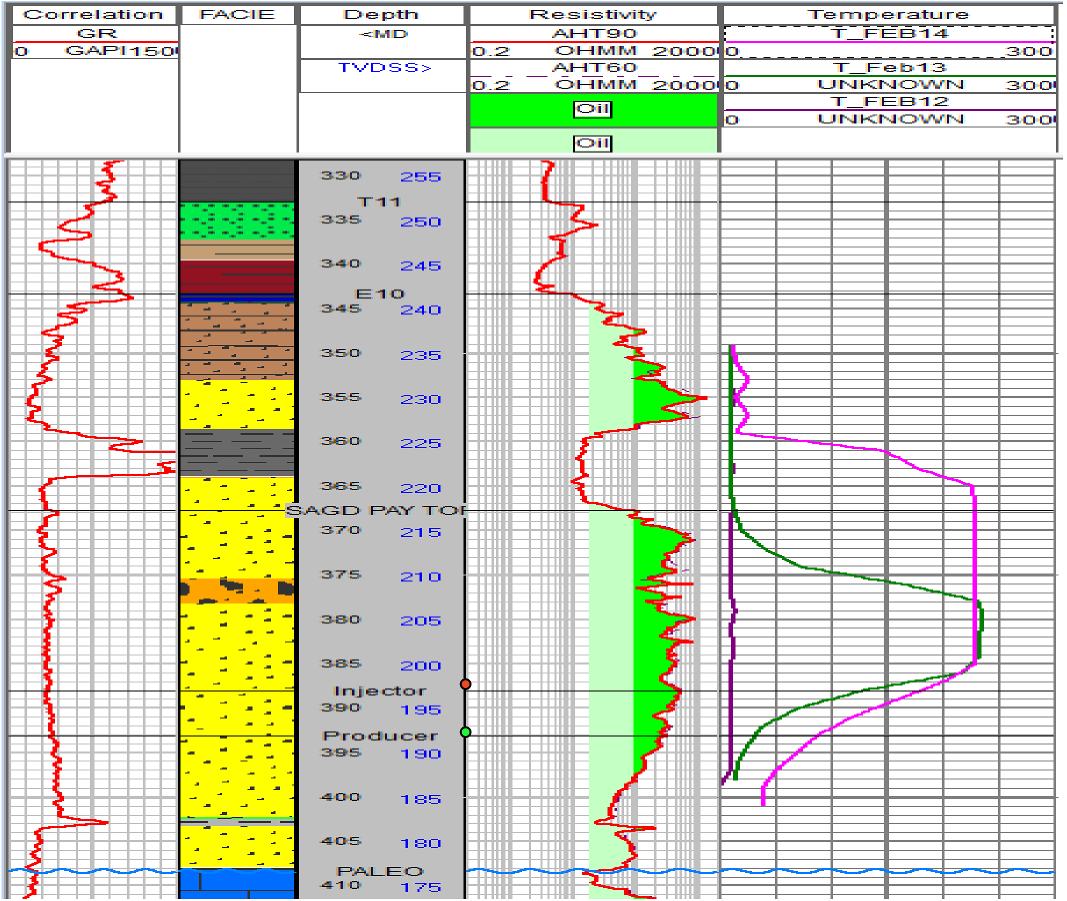


RST logs
B06 pad

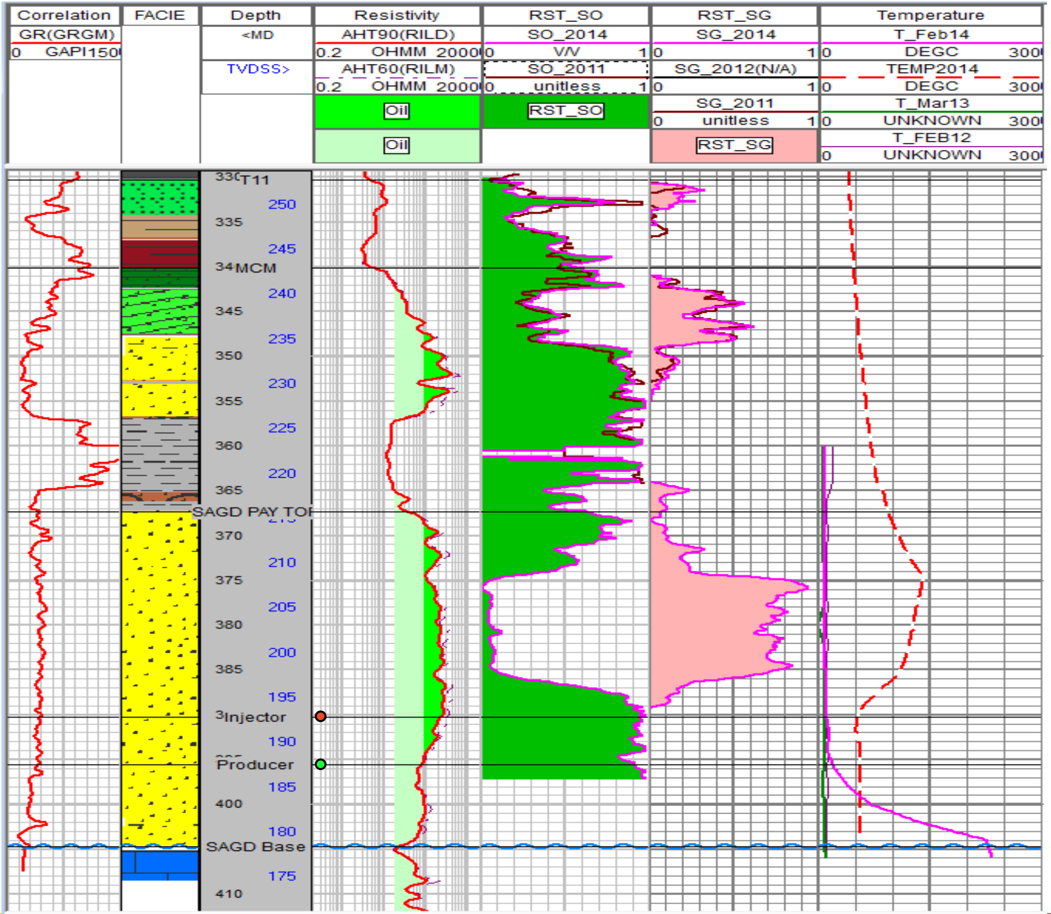
B62T (B062 TOE) 103061207606W400



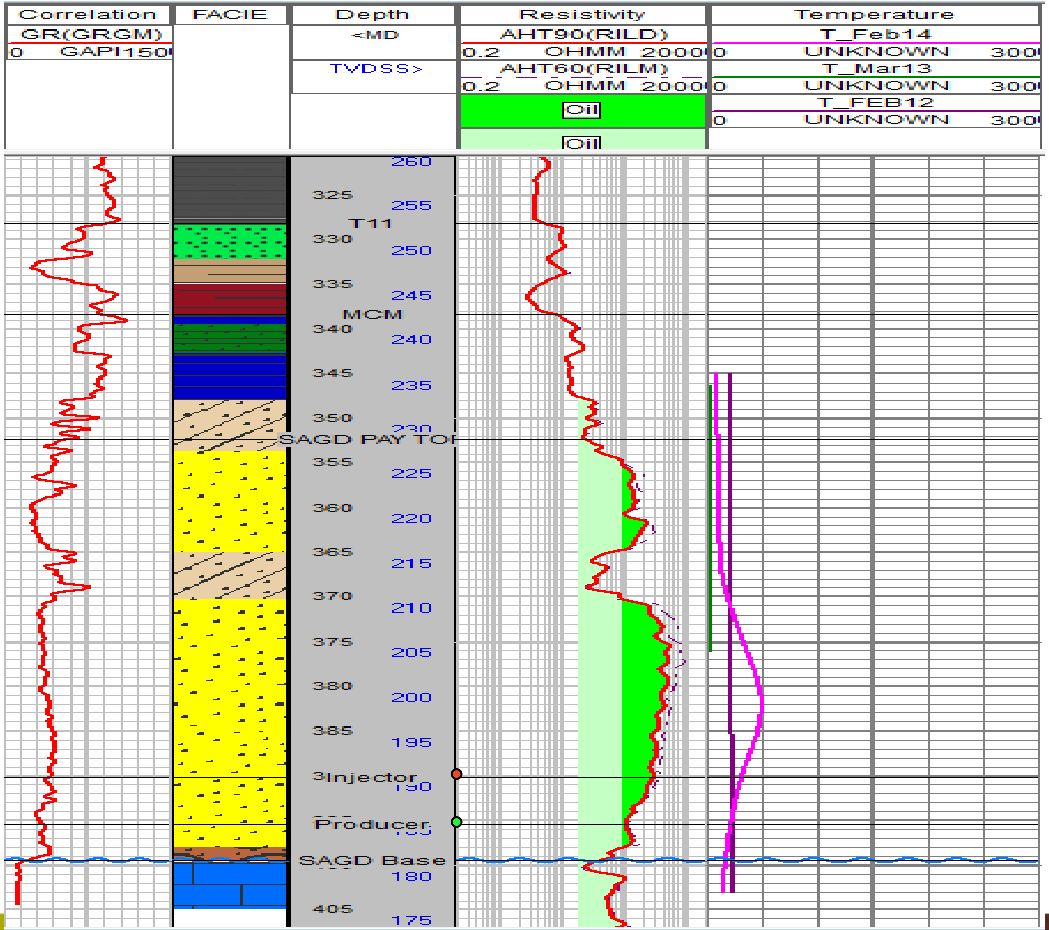
B064 (B064 Middle) 102061207606W400



B66T (B06_6 Toe) 102051207606W400

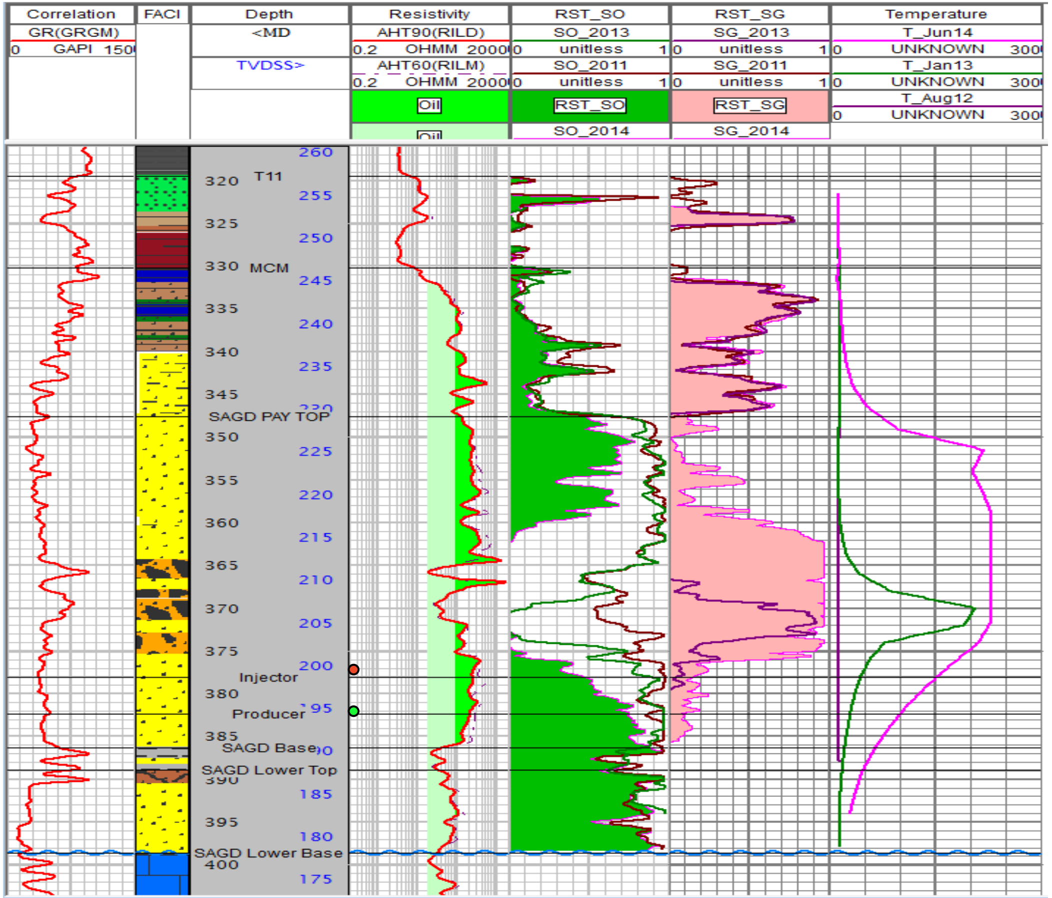


B67H (B06_7 Heel) 100111207606W400

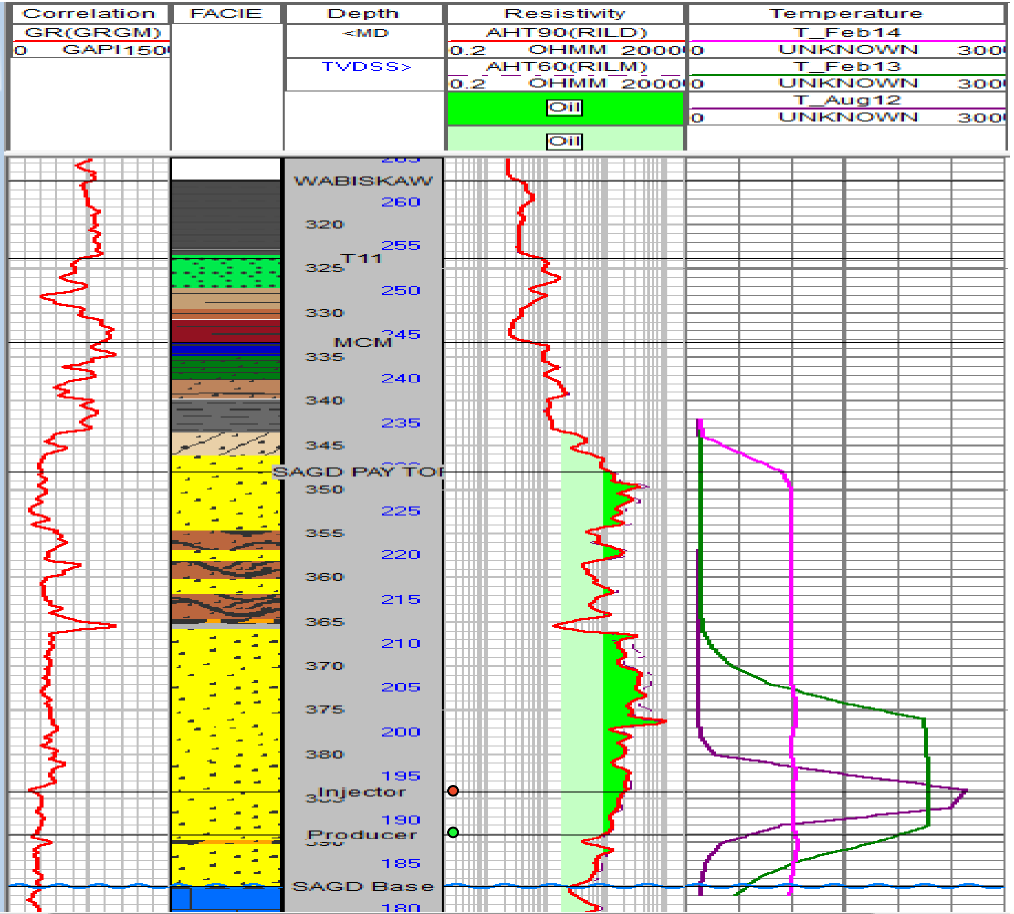


RST logs
B07 pad

B72T (B07_2 Toe) 100051307606W400

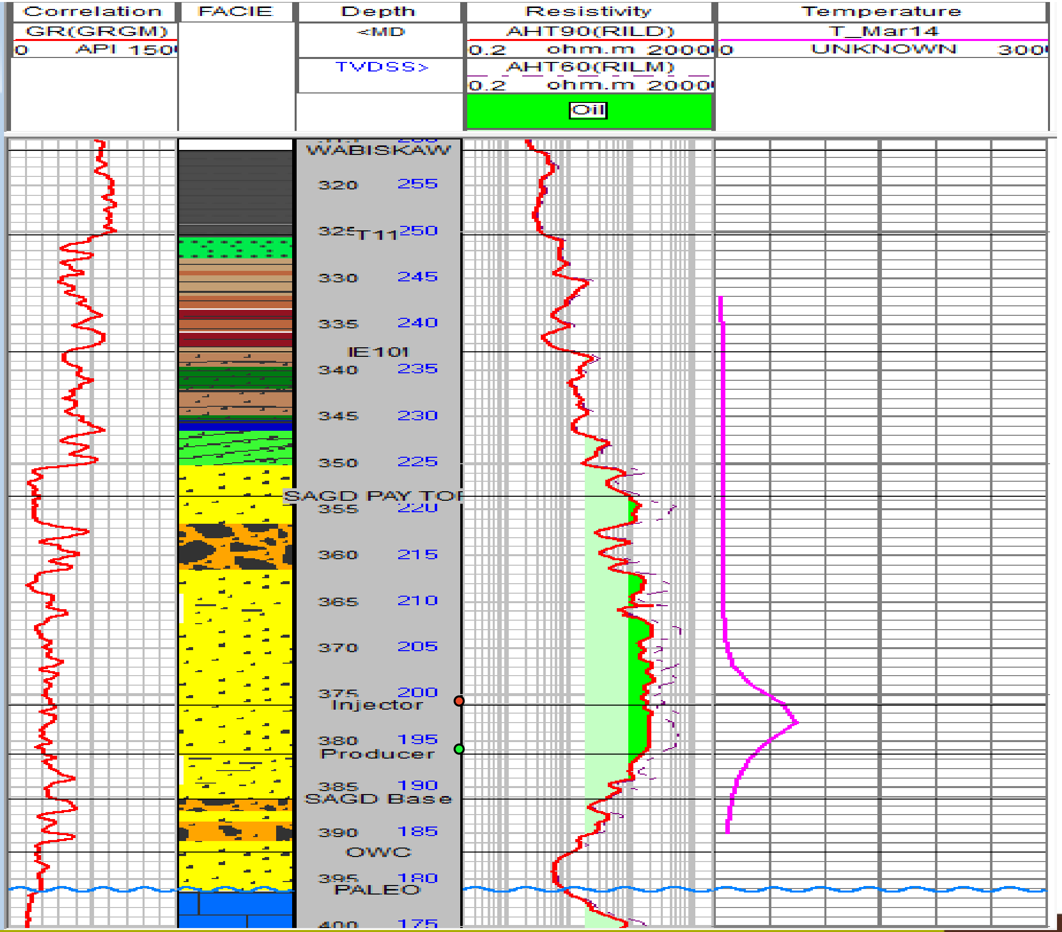


B76T (B07_6 Toe) 100061307606W400

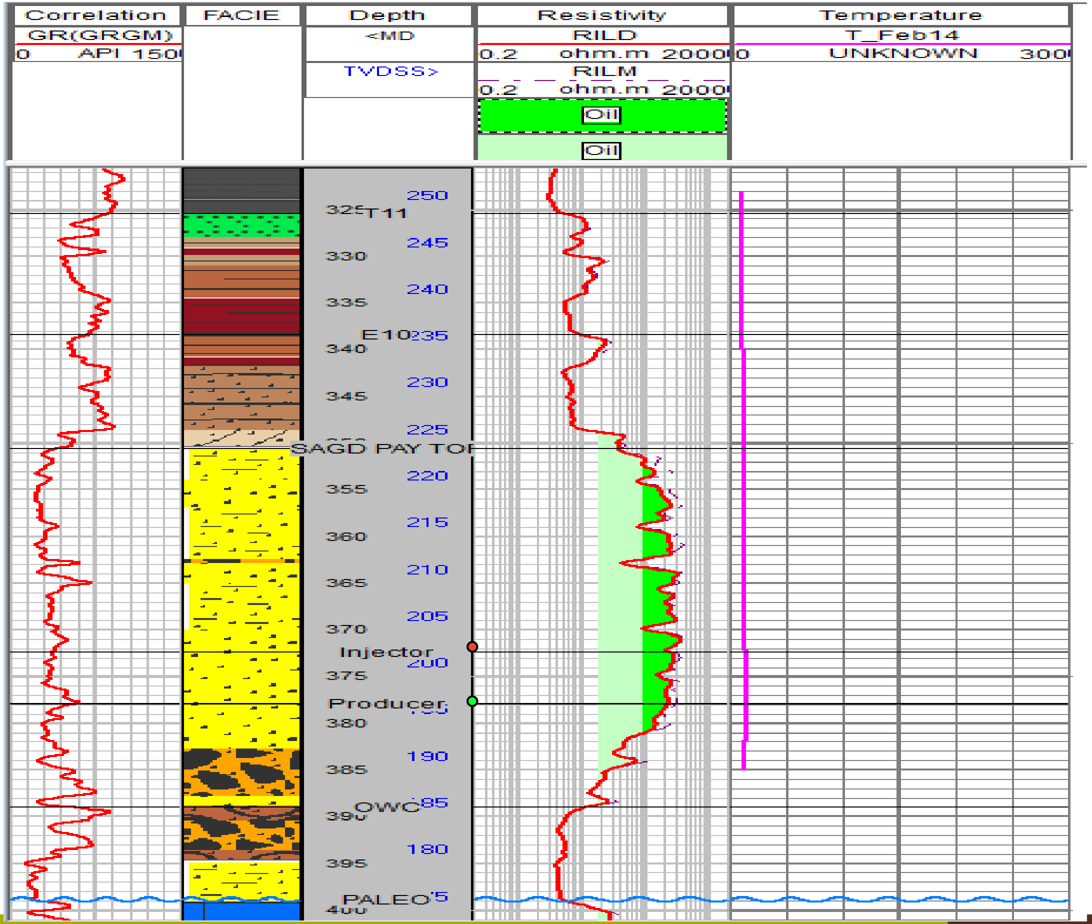


RST logs
B08 pad

B0810T (B0810 TOE) 108121107606W400



B083M (B0803 MID) 102011507606W400



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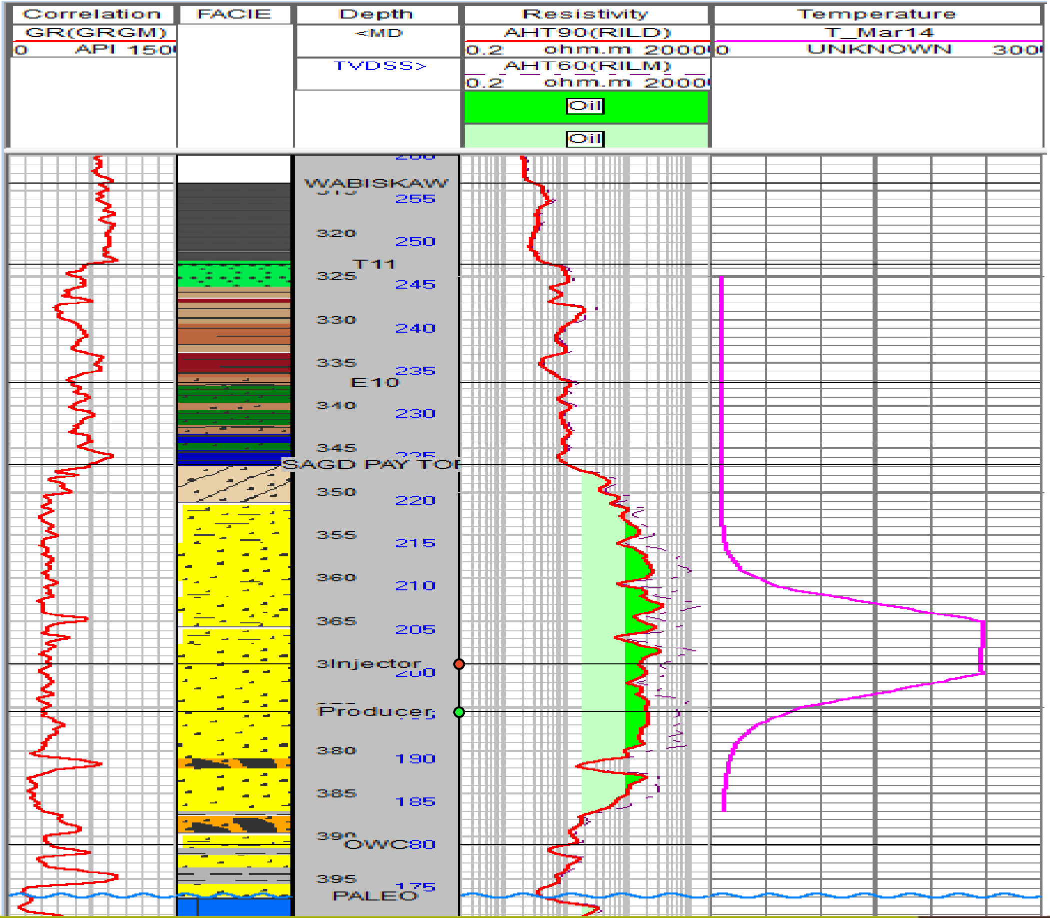
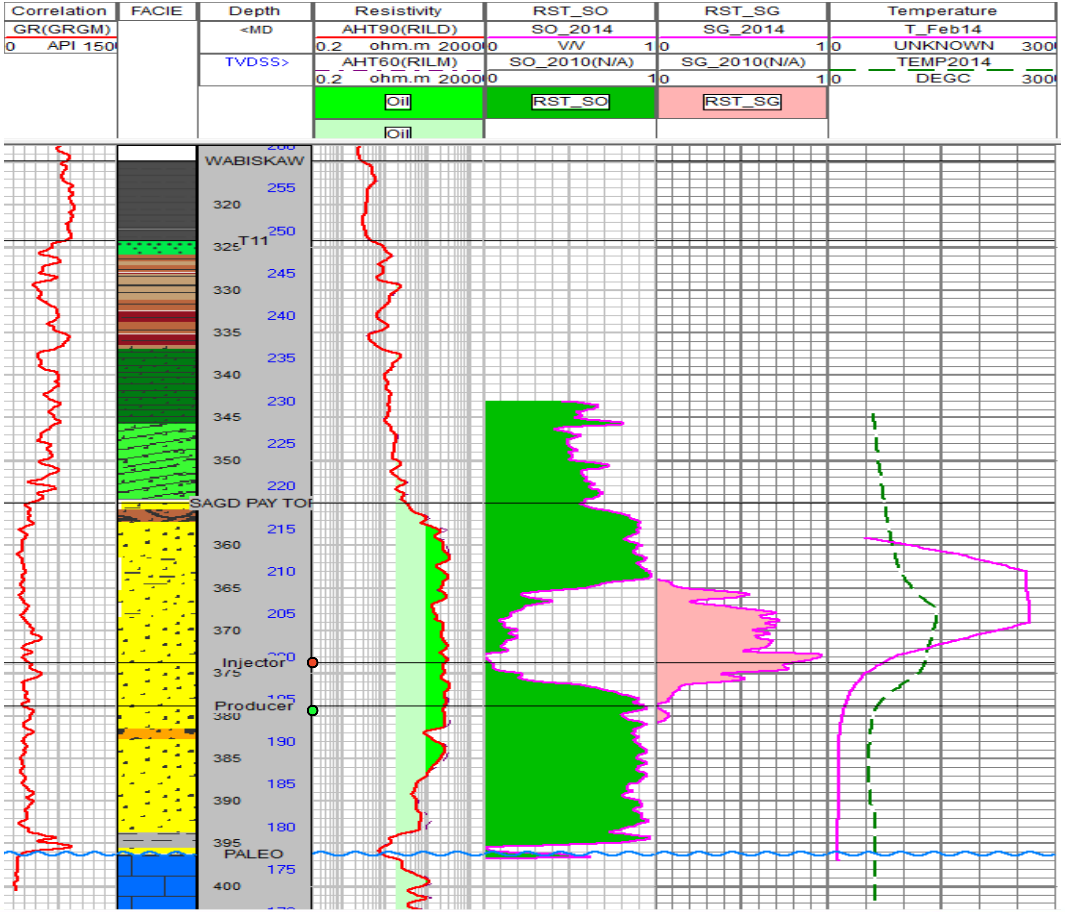
B084H (B0804 HEEL) 100011507606W400



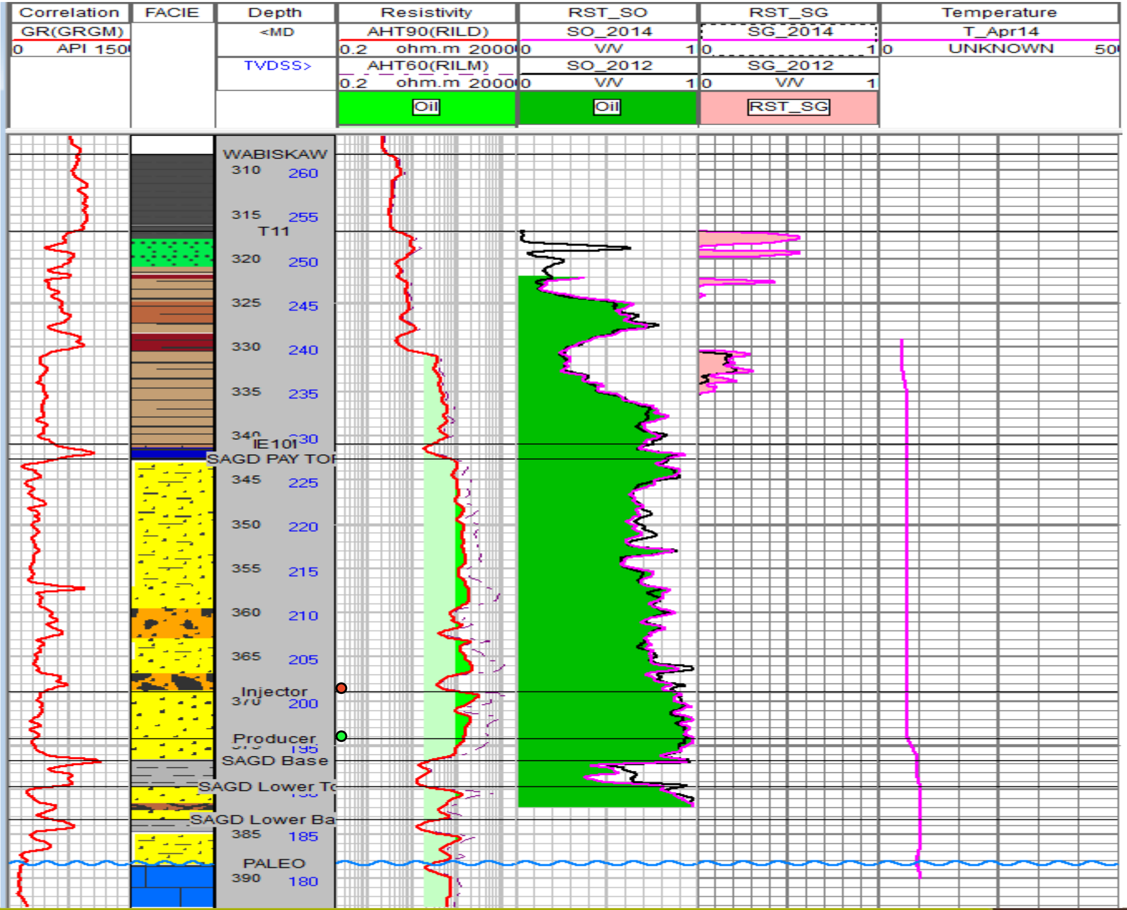
B087M (B0807 MID) 100131107606W400



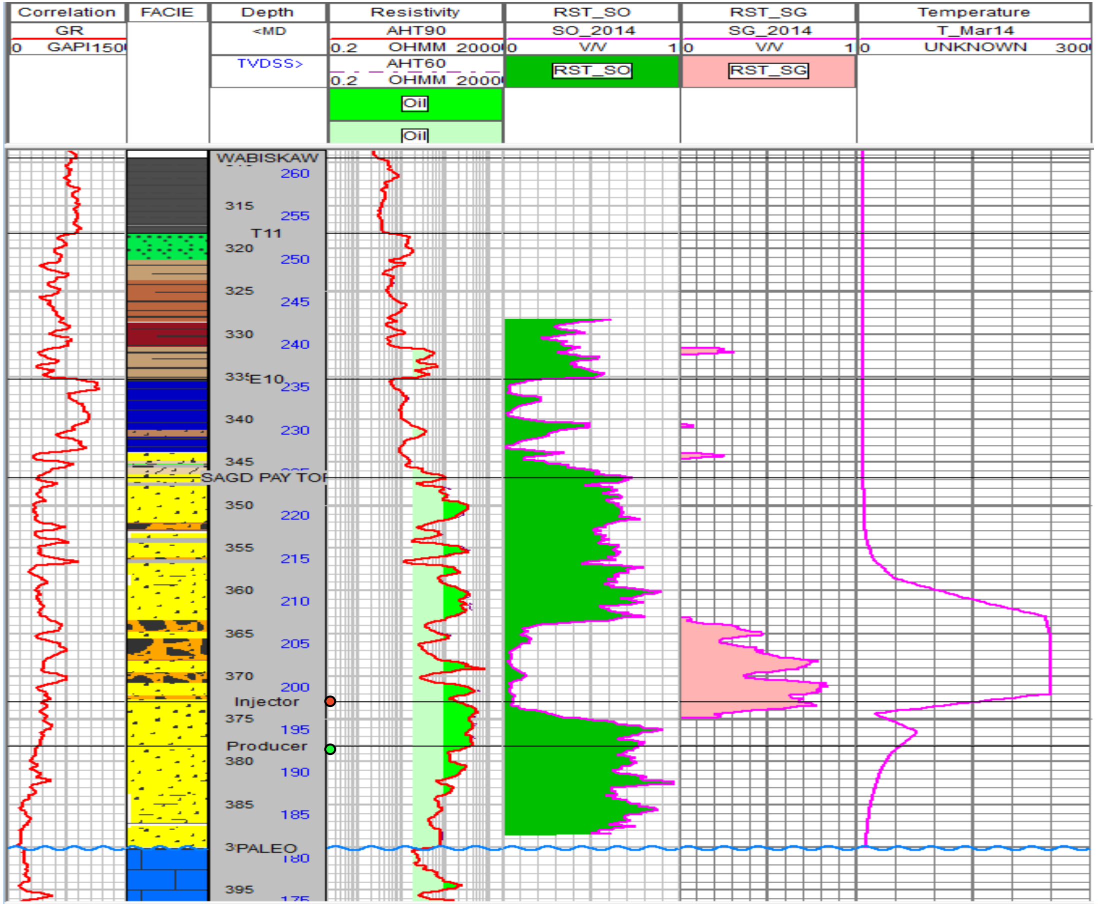
RST logs
B11 pad

cenovus ENERGY

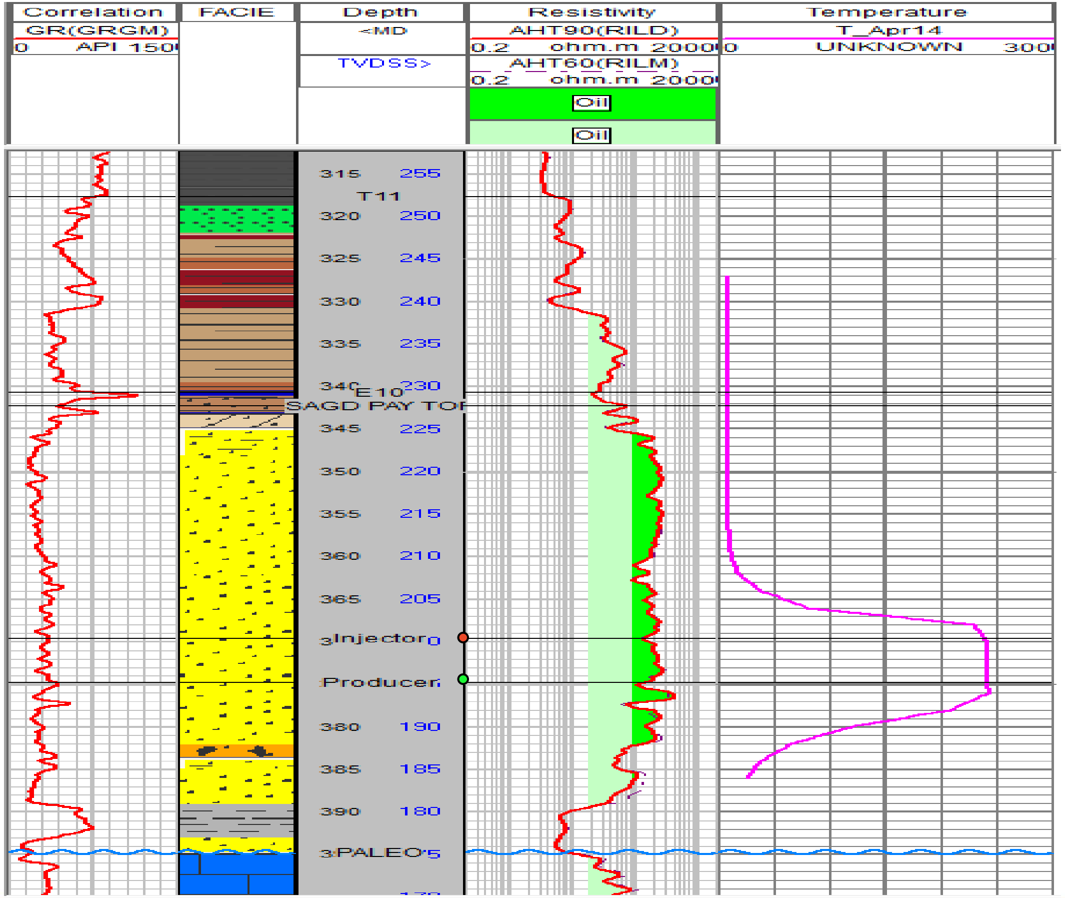
B11_04 MID 100051407606W400



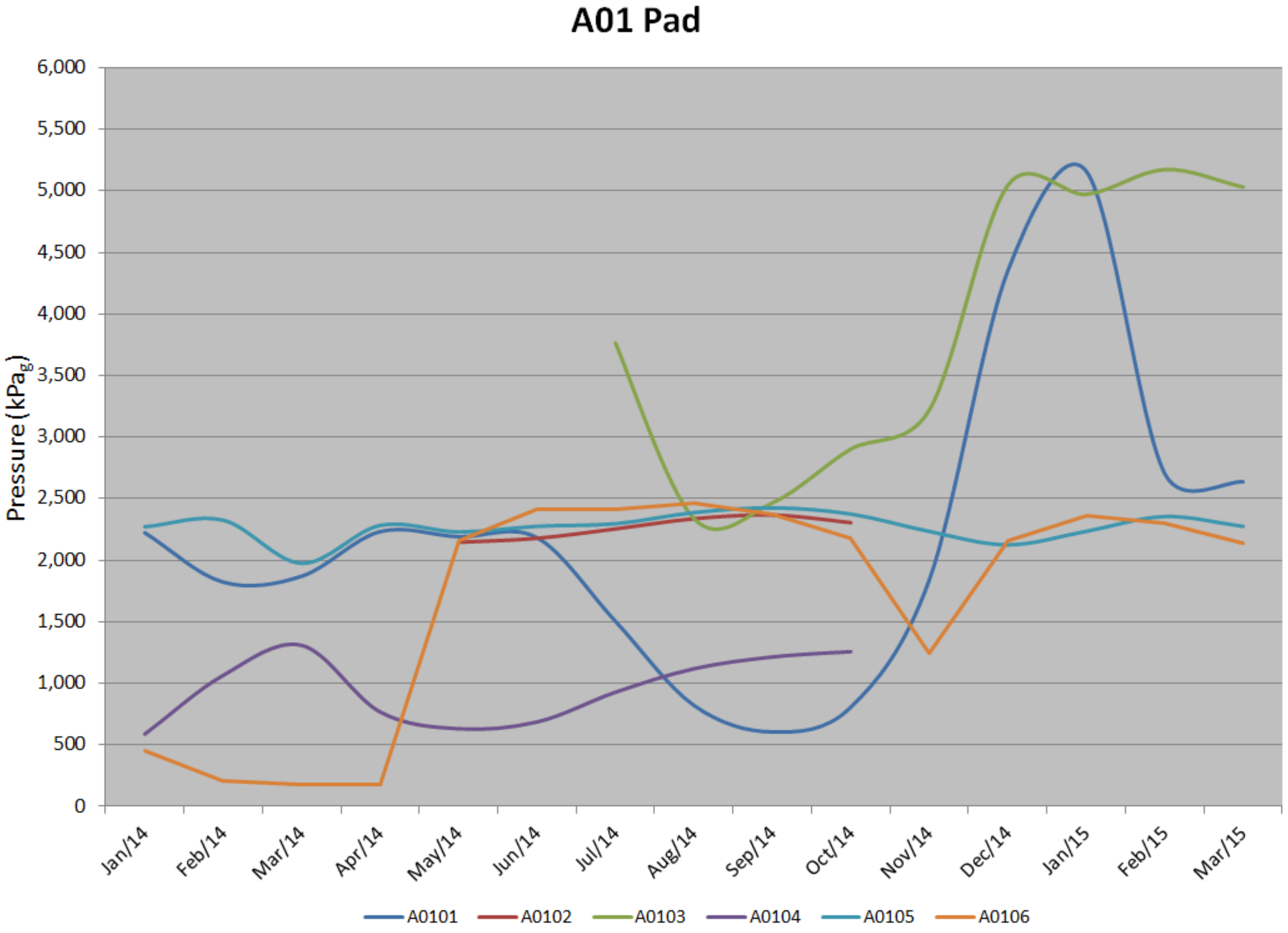
B11_11 MID 102111407606W400



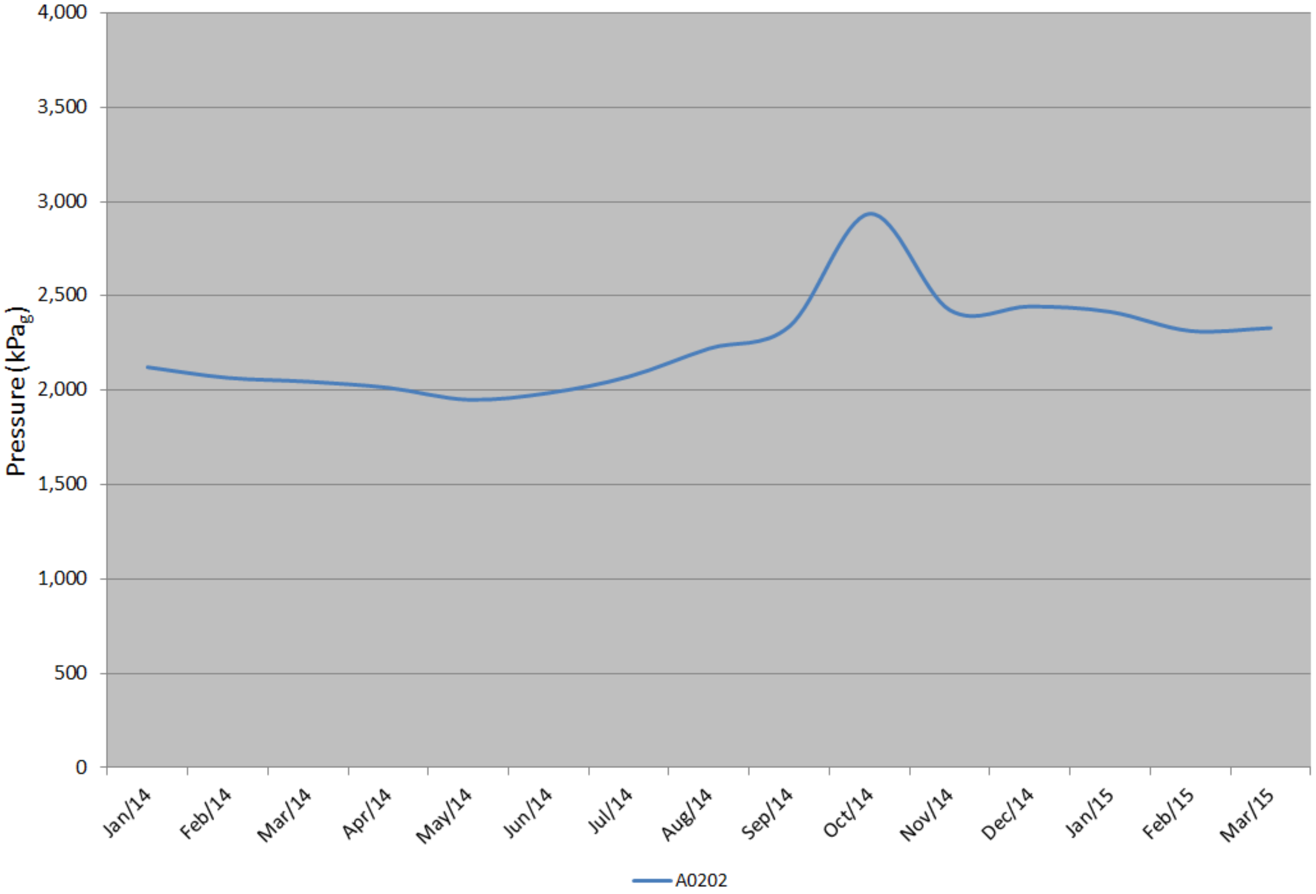
B11_03 MID 103051407606W400



Appendix 4
Subsection 3.1.1 – 5d)
Injection pressures

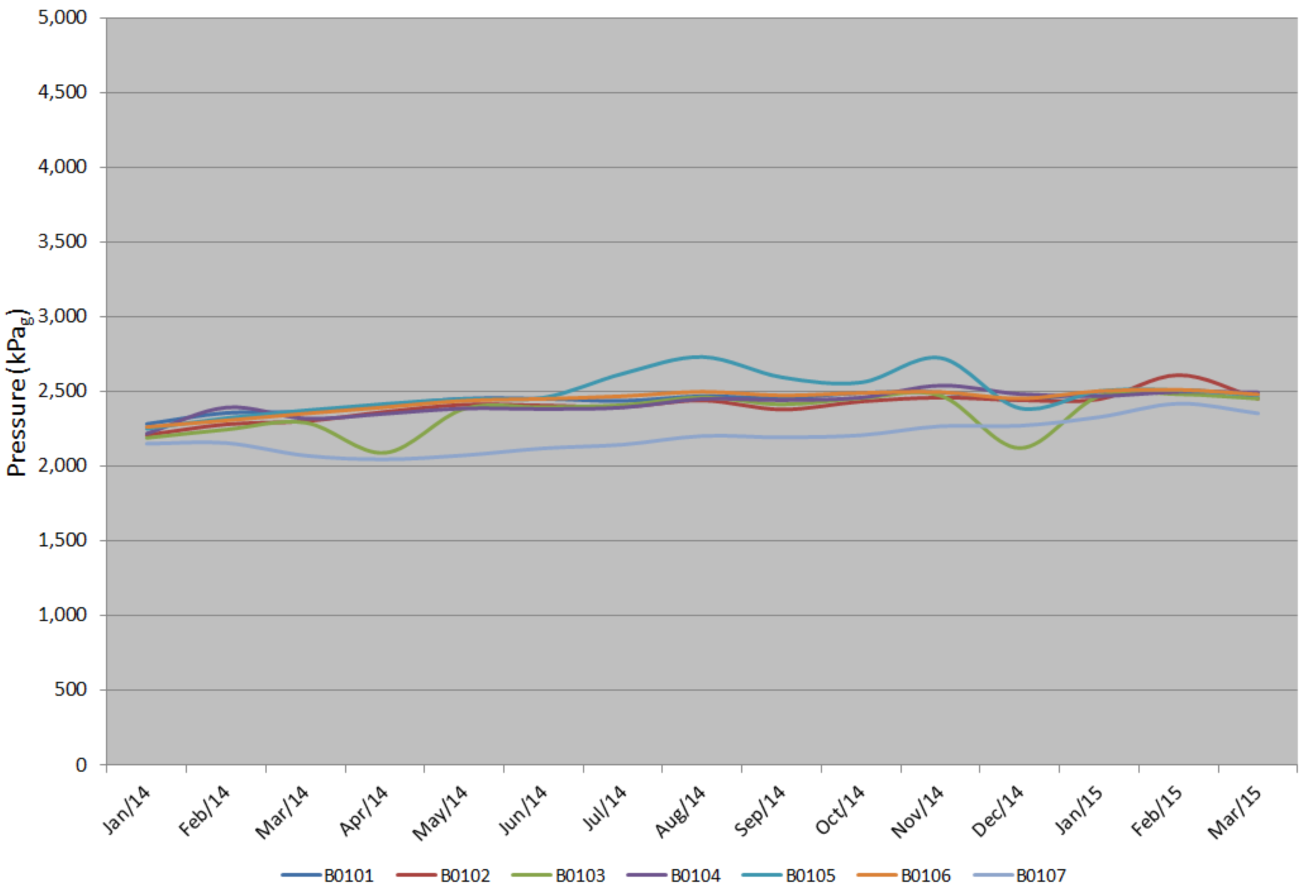

A01 Pad
Pressure (kPa$_g$)
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
A0101
A0102
A0103
A0104
A0105
A0106

A02 Pad



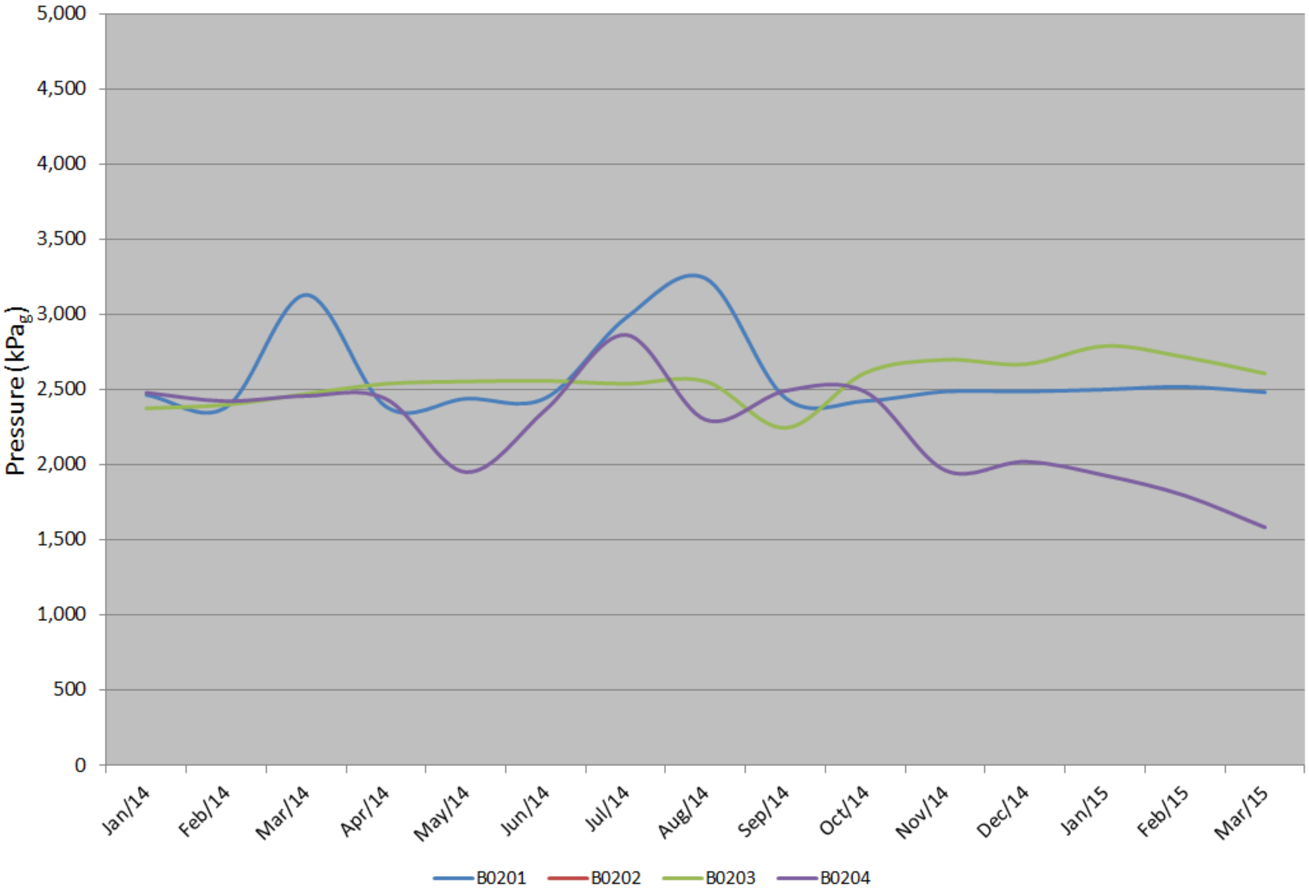
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPag)
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
A0202

B01 Pad

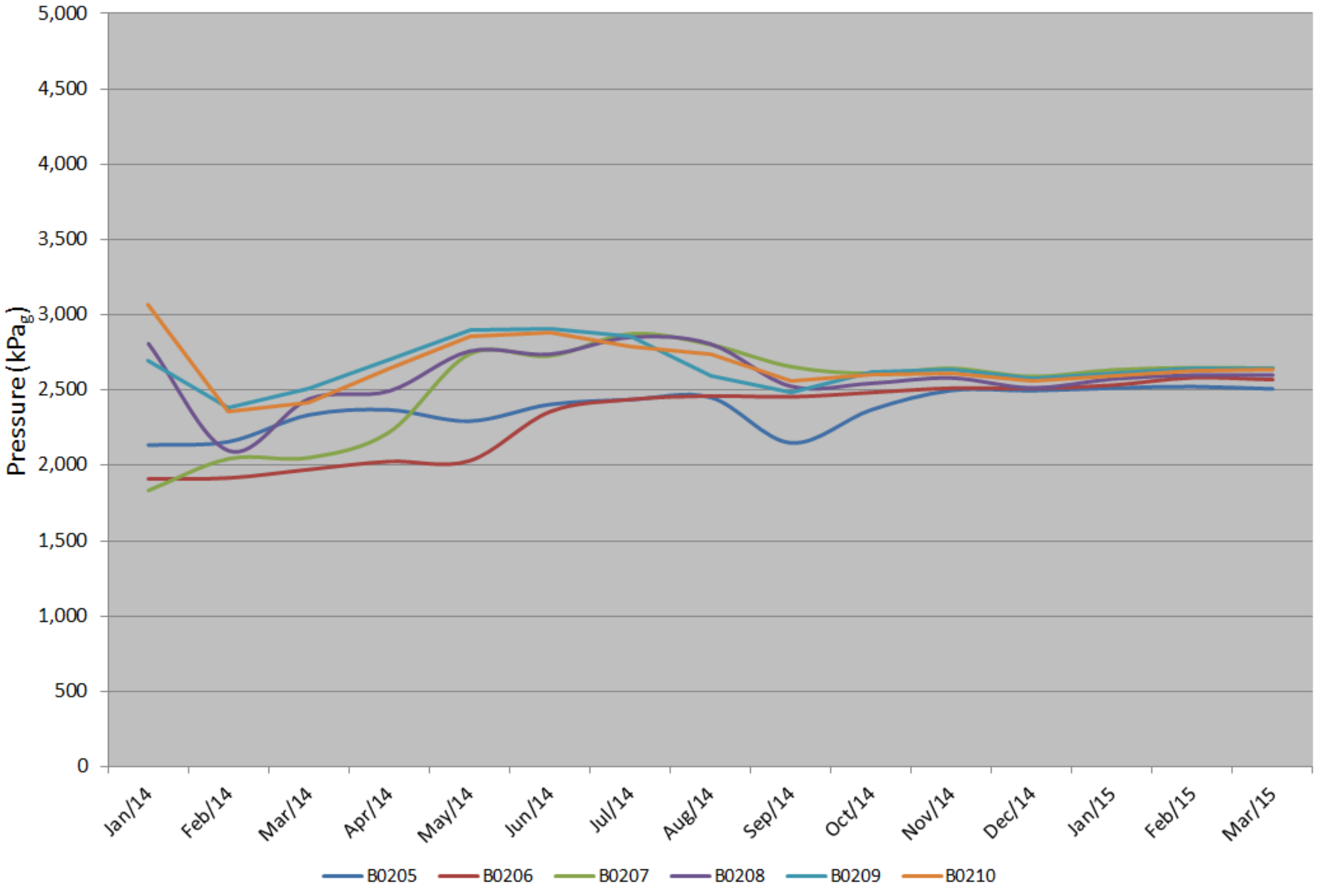


5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPag)
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
B0101
B0102
B0103
B0104
B0105
B0106
B0107

B02 Pad

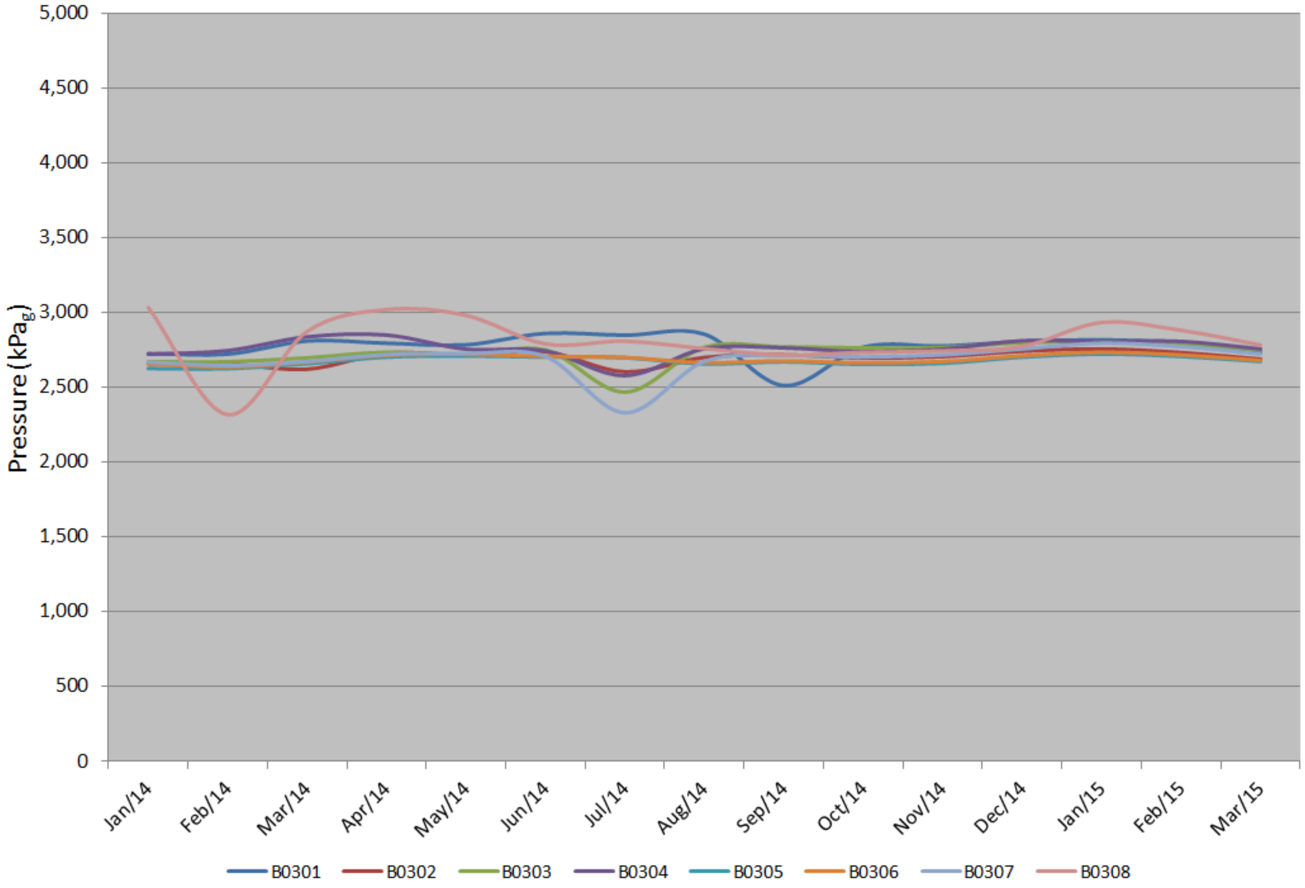

5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPag)
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
B0201
B0202
B0203
B0204

B02C Pad



Pressure (kPag)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
B0205
B0206
B0207
B0208
B0209
B0210

B03 Pad



5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPag)
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
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Mar/15
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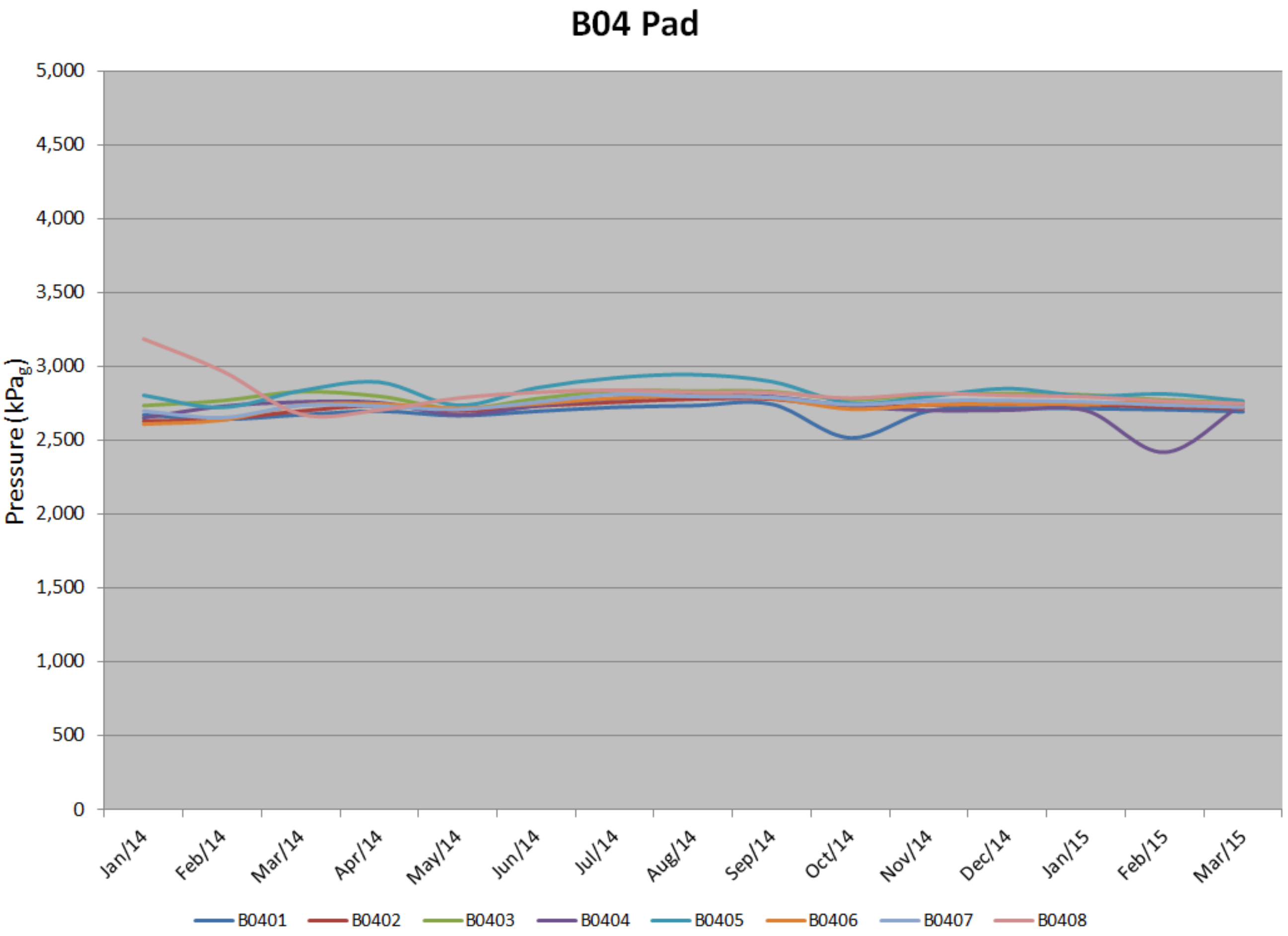
B0306
B0307
B0308



B04 Pad
Pressure (kPag)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
B0401
B0402
B0403
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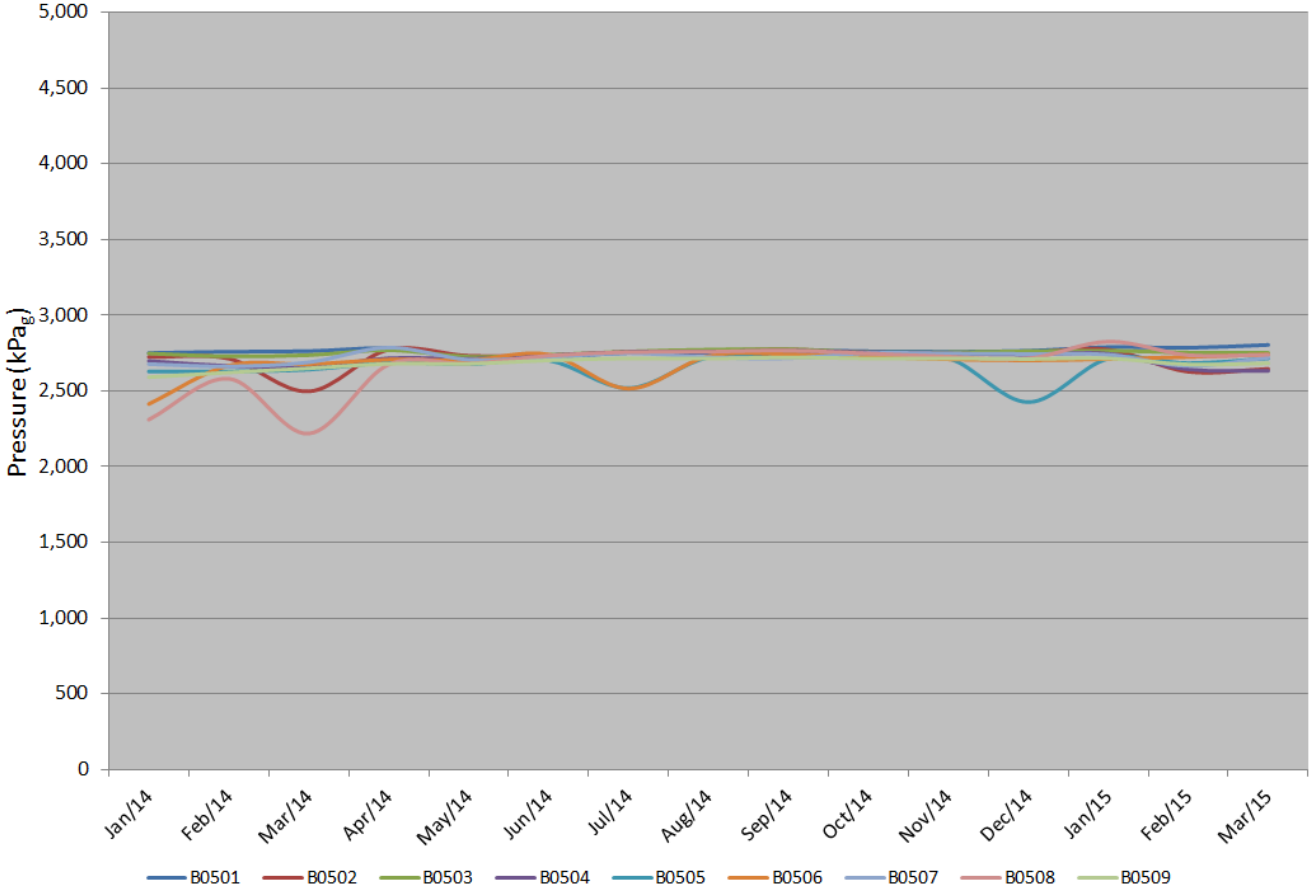
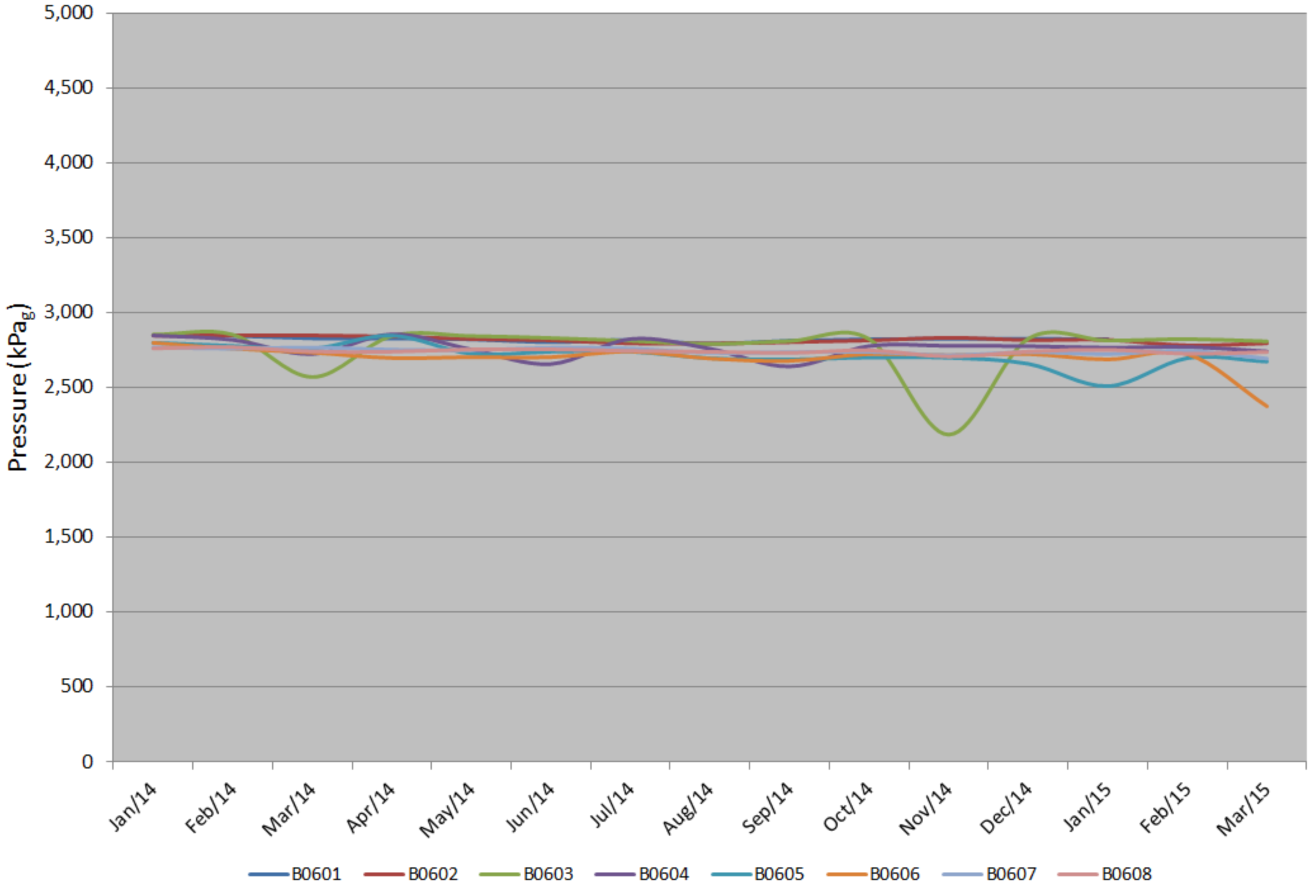
B0406
B0407
B0408

B05 Pad

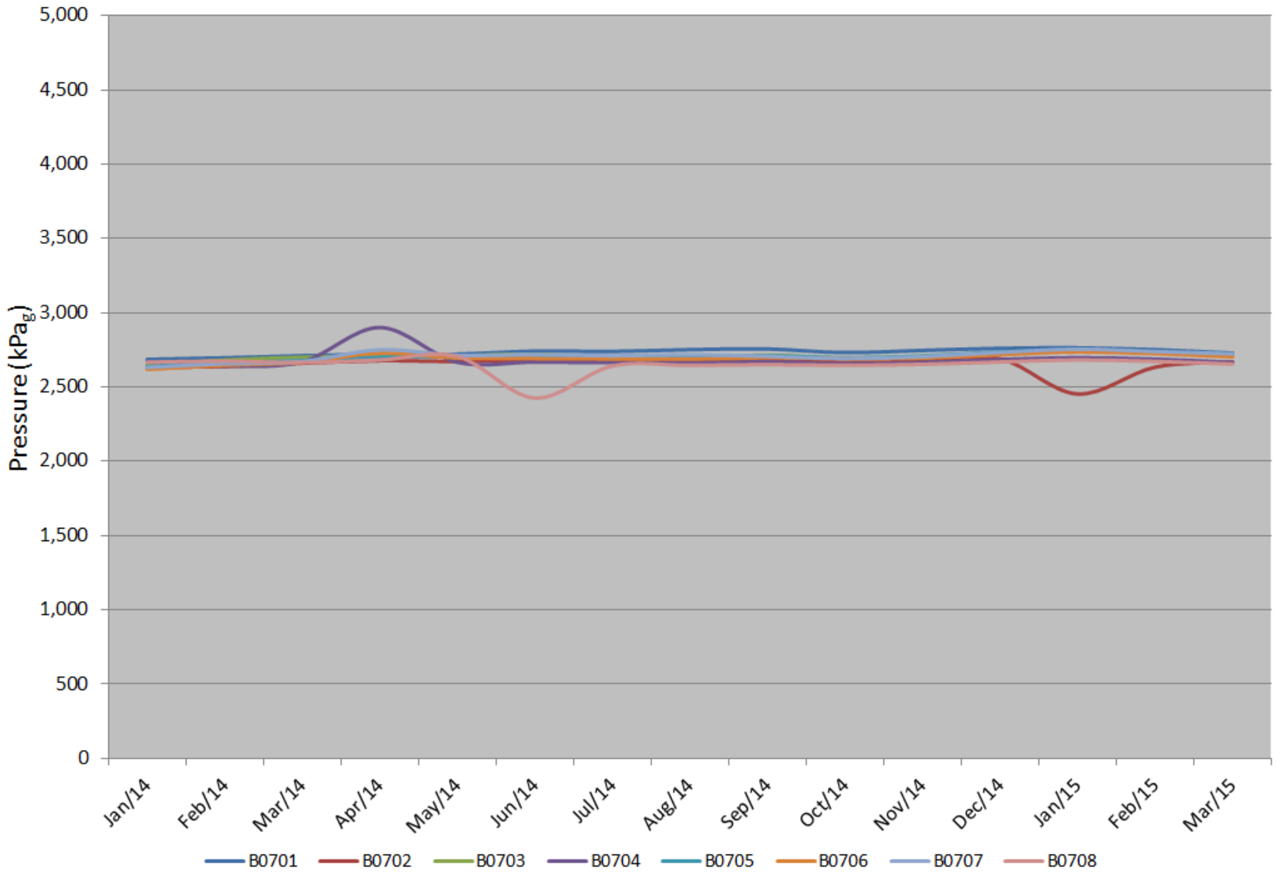

Pressure (kPa$_g$)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
B0501
B0502
B0503
B0504
B0505
B0506
B0507
B0508
B0509

B06 Pad



Pressure (kPag)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
B0601
B0602
B0603
B0604
B0605
B0606
B0607
B0608

B07 Pad



5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPag)
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
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Mar/15
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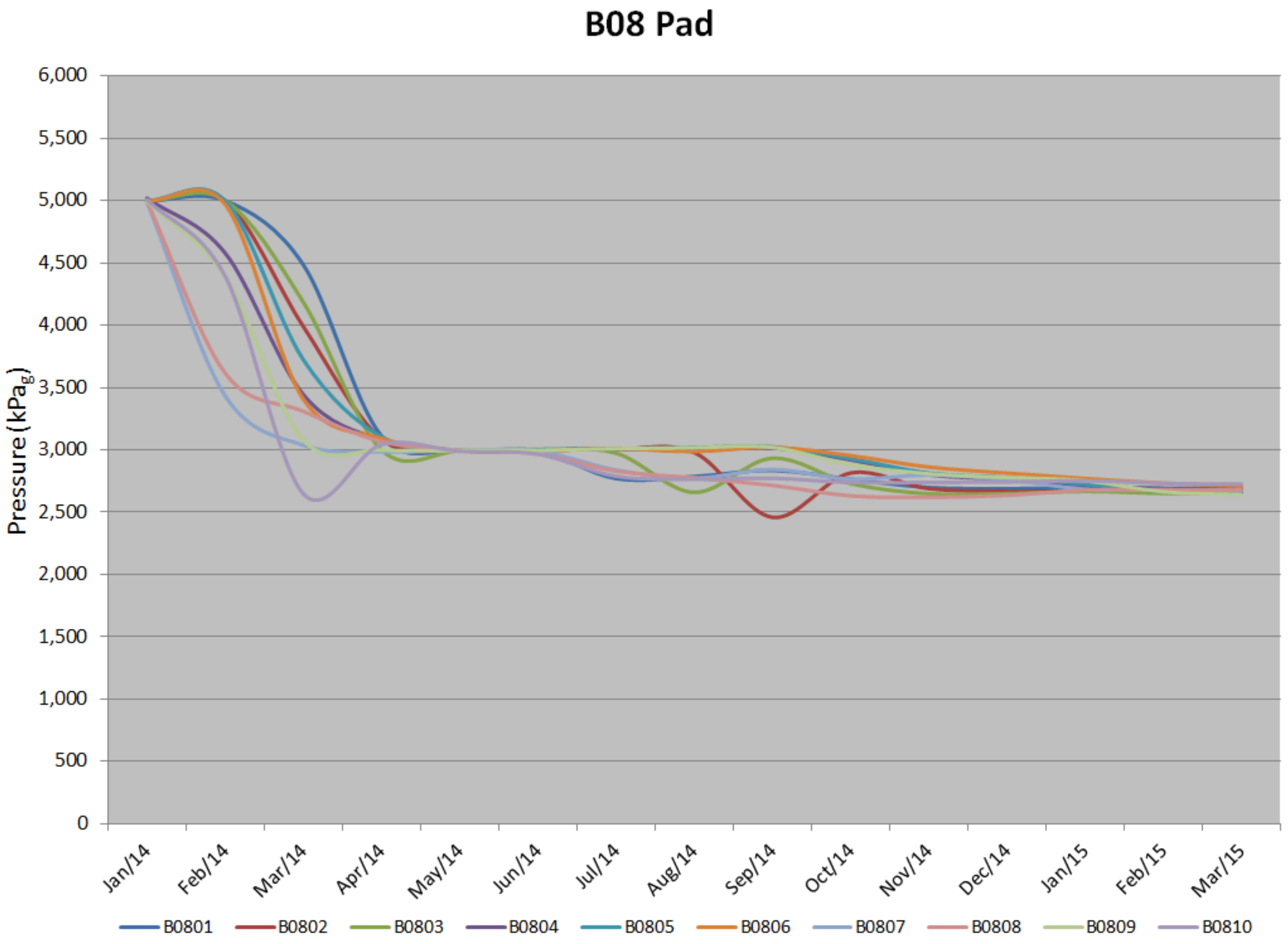
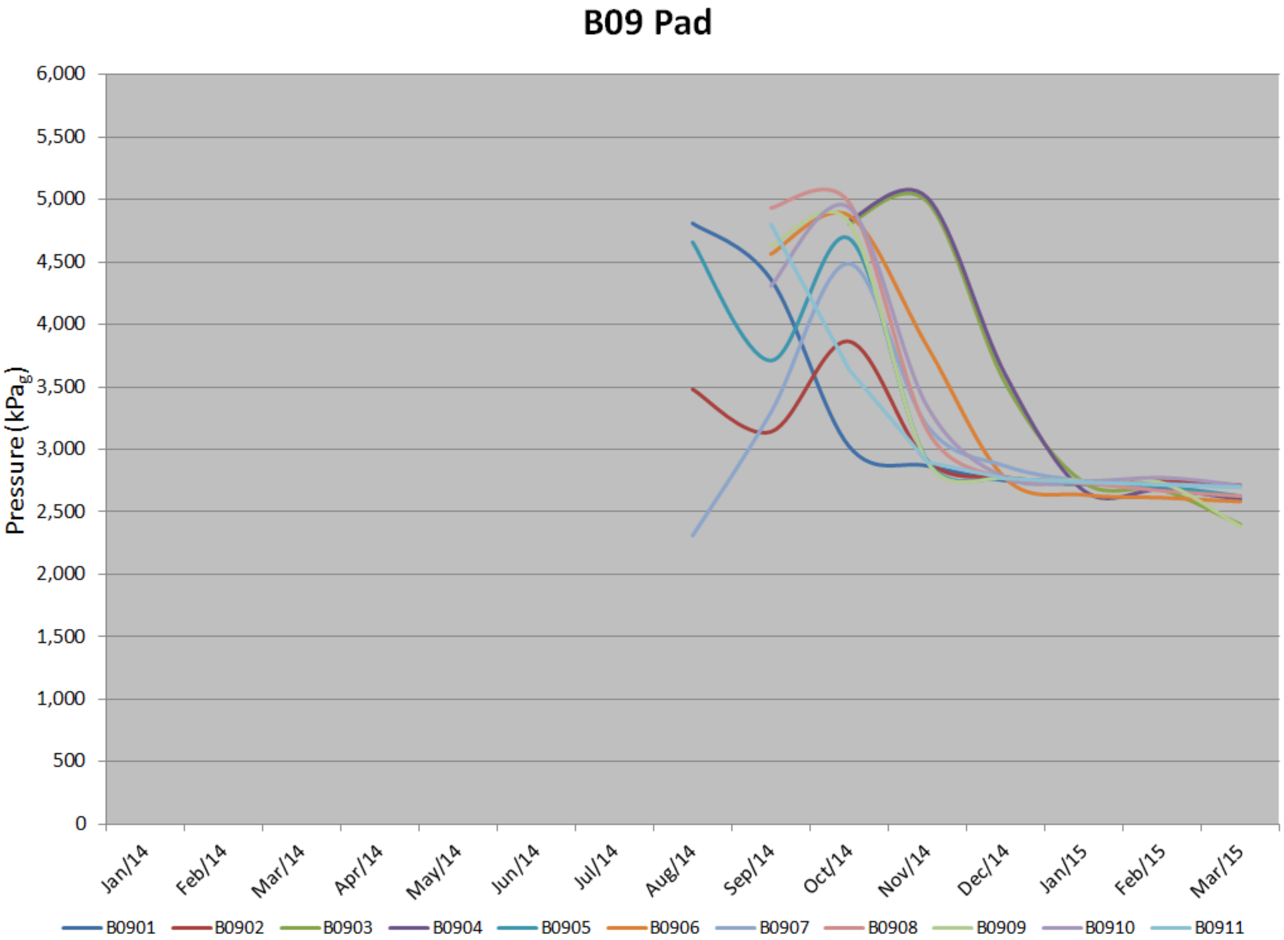
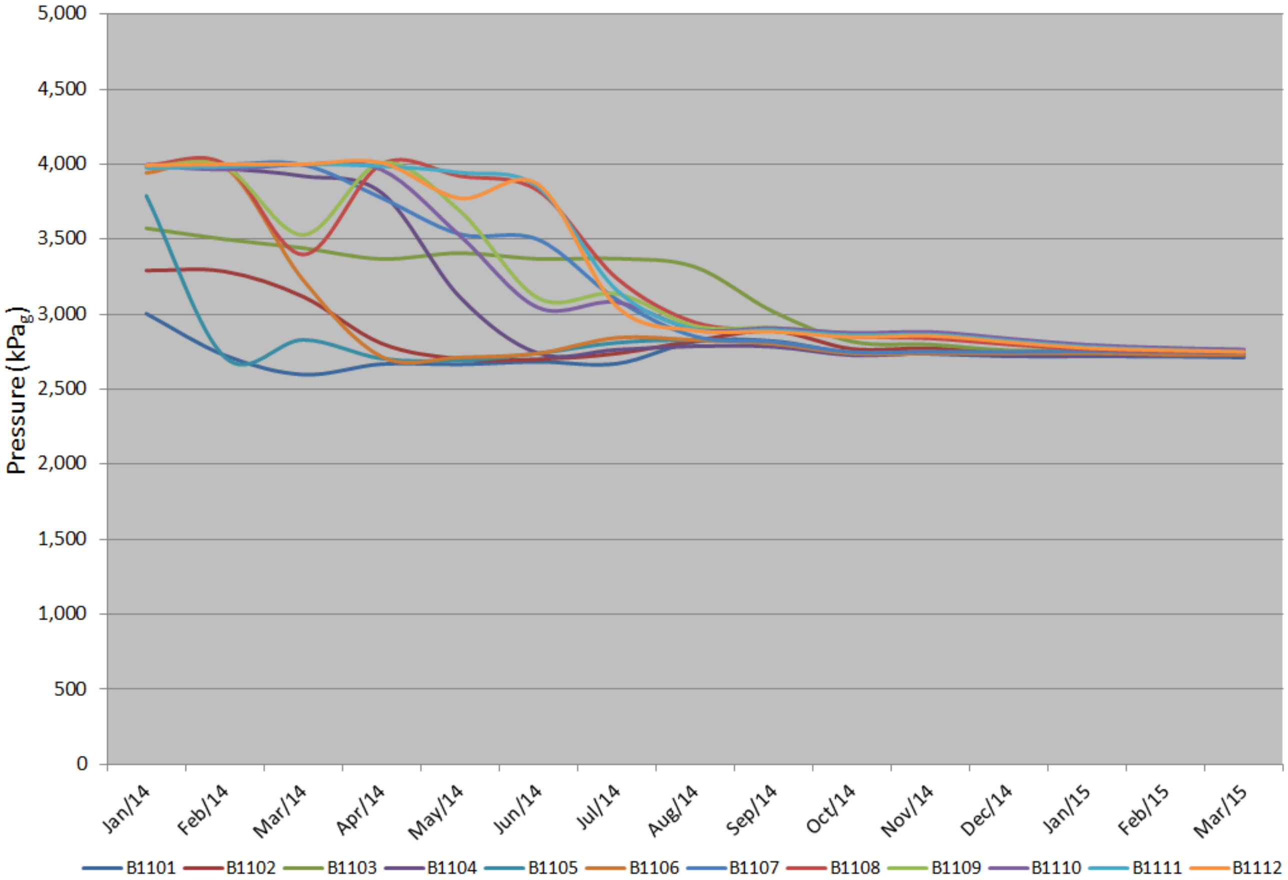
B0702
B0703
B0704
B0705
B0706
B0707
B0708


B08 Pad
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPa$_g$)
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
B0801
B0802
B0803
B0804
B0805
B0806
B0807
B0808
B0809
B0810


B09 Pad
Pressure (kPag)
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
B0901
B0902
B0903
B0904
B0905
B0906
B0907
B0908
B0909
B0910
B0911

B11 Pad



Pressure (kPa$_g$)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15
B1101
B1102
B1103
B1104
B1105
B1106
B1107
B1108
B1109
B1110
B1111
B1112

Appendix 5
Subsection 3.1.1 – 7h)
Pad production data

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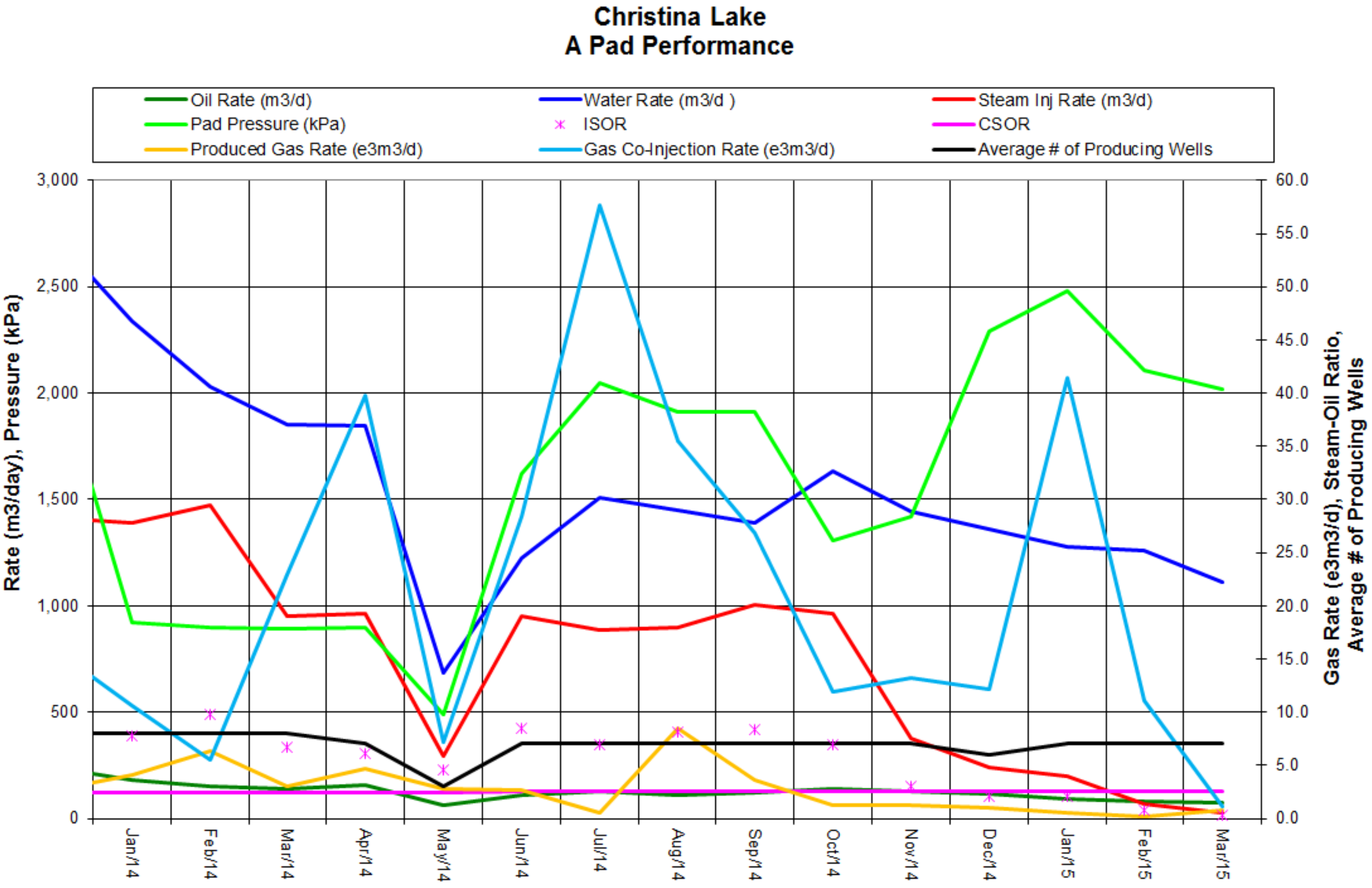
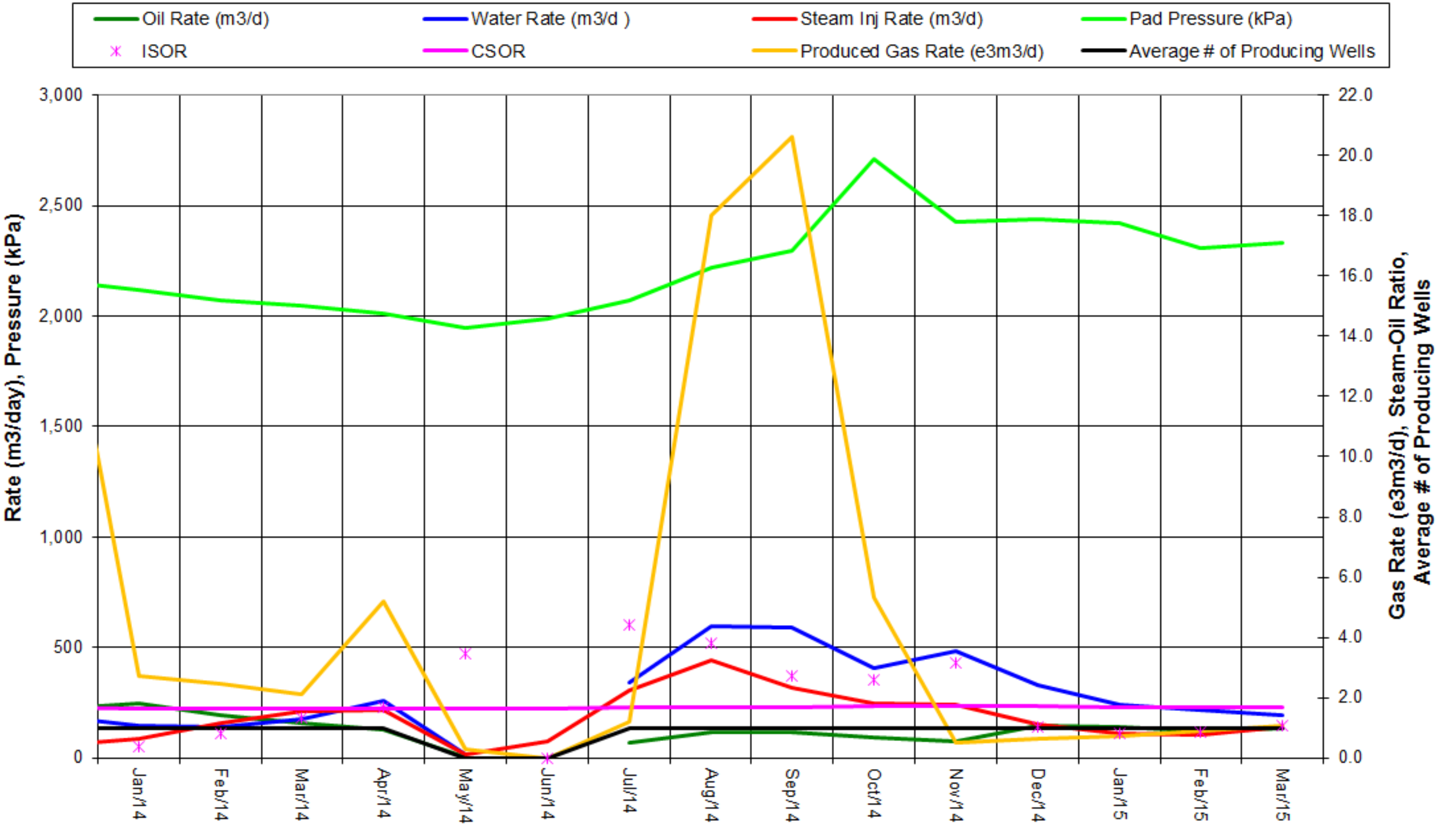
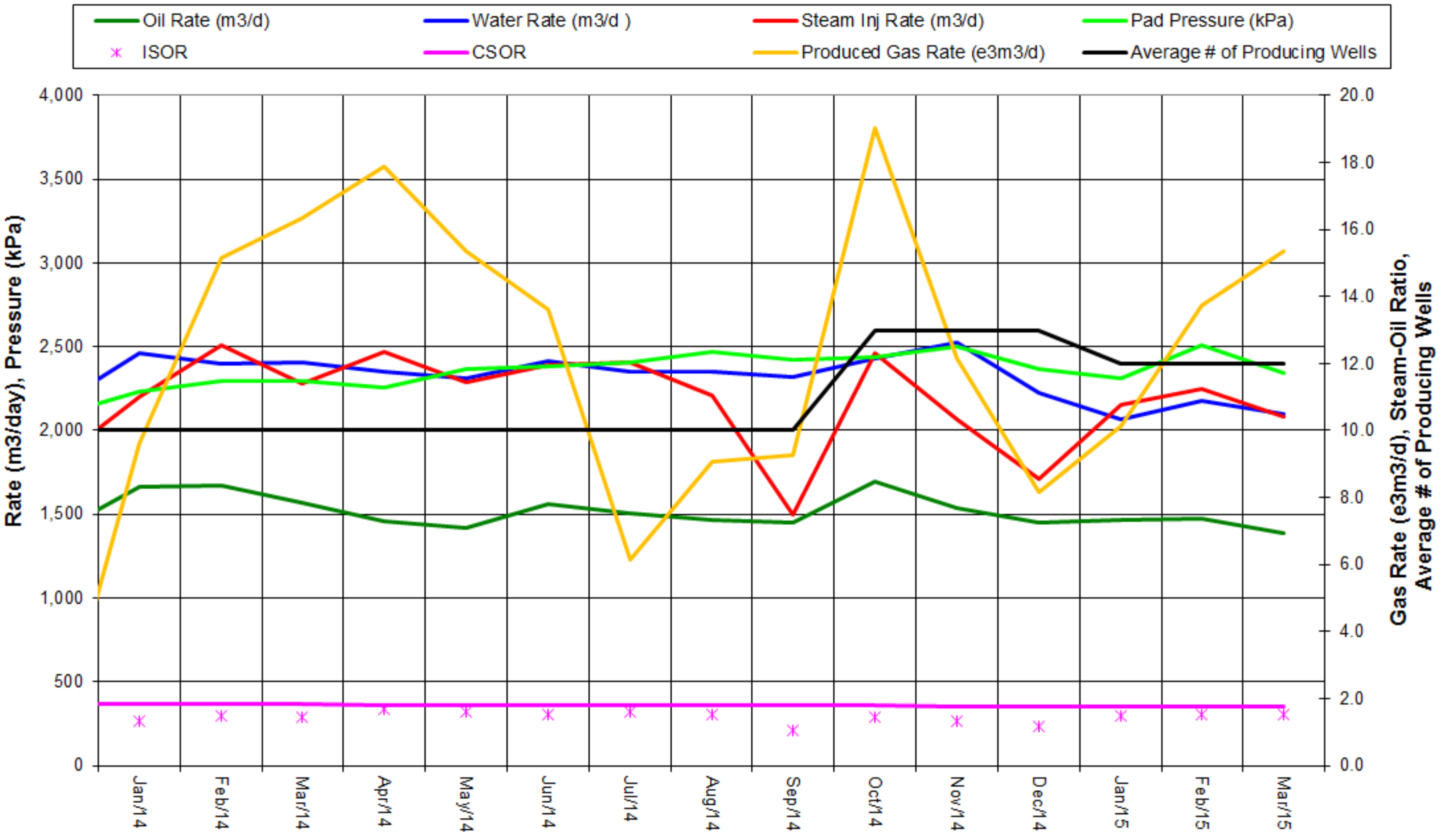


Christina Lake
A Pad Performance
Oil Rate (m3/d)
Water Rate (m3/d)
Steam Inj Rate (m3/d)
Pad Pressure (kPa)
ISOR
CSOR
Produced Gas Rate (e3m3/d)
Gas Co-Injection Rate (e3m3/d)
Average # of Producing Wells
Rate (m3/day), Pressure (kPa)
Gas Rate (e3m3/d), Steam-Oil Ratio, Average # of Producing Wells
3,000
2,500
2,000
1,500
1,000
500
0
60.0
55.0
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15

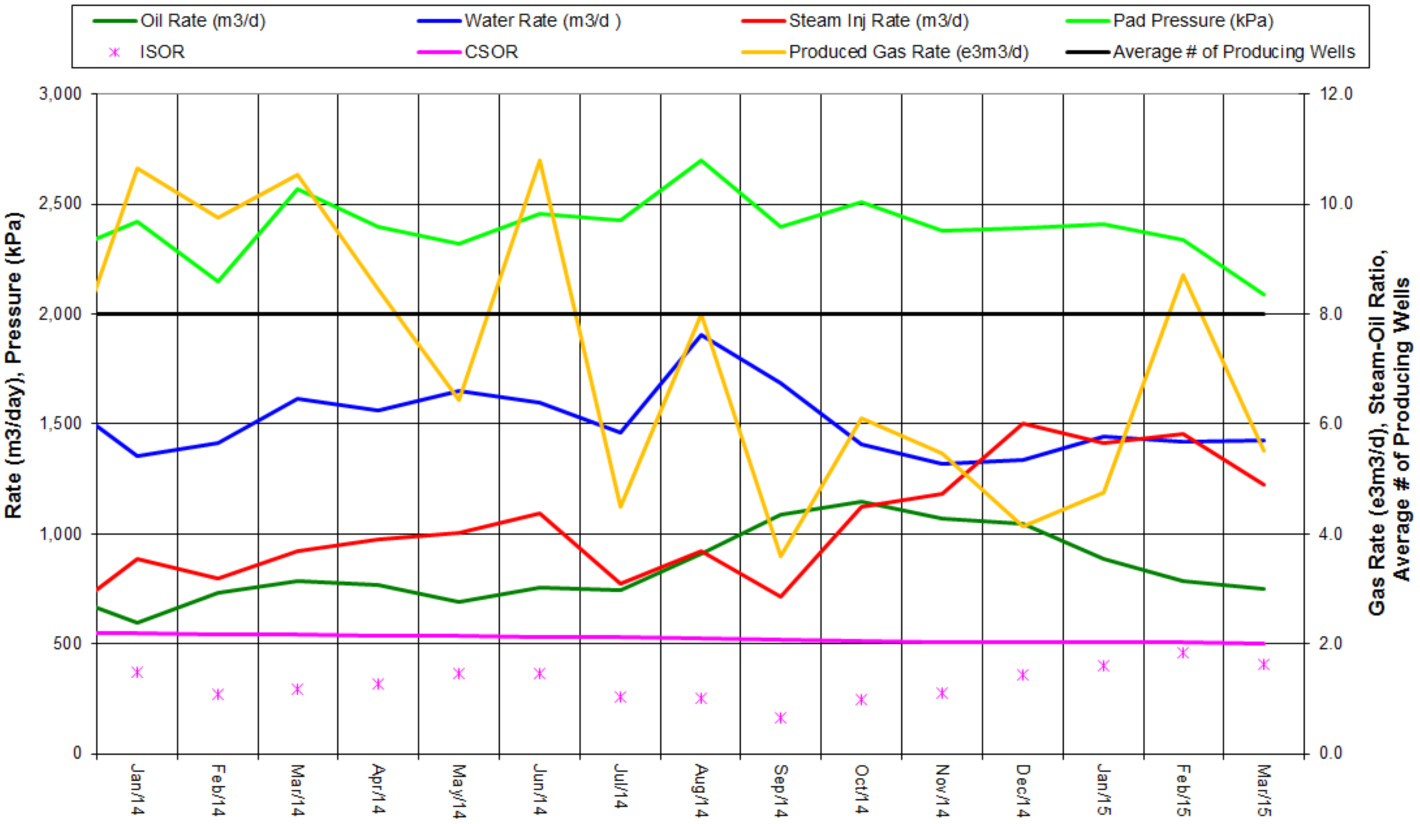
Christina Lake
A02 Pad Performance



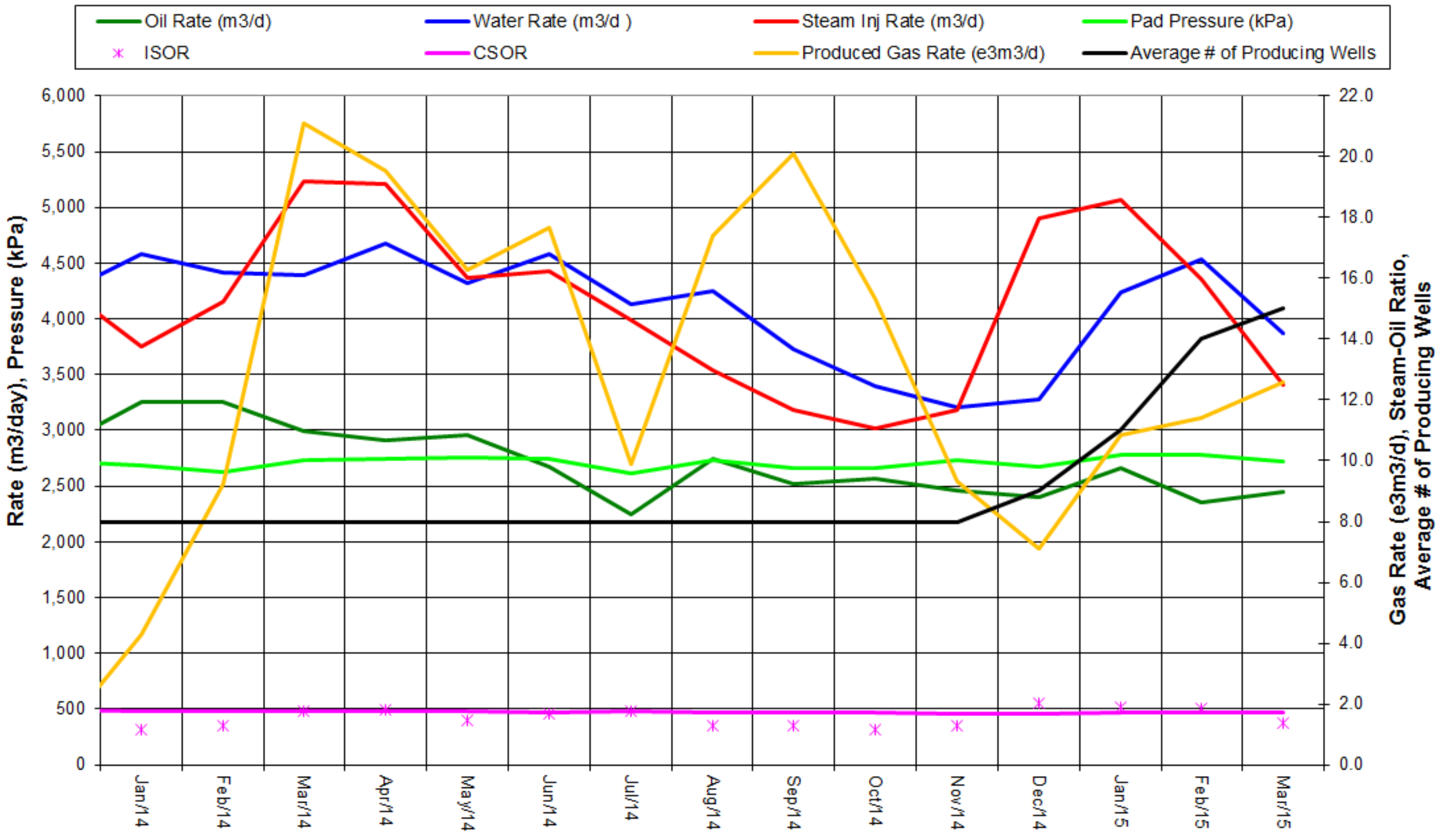
Christina Lake
B01 Pad Performance



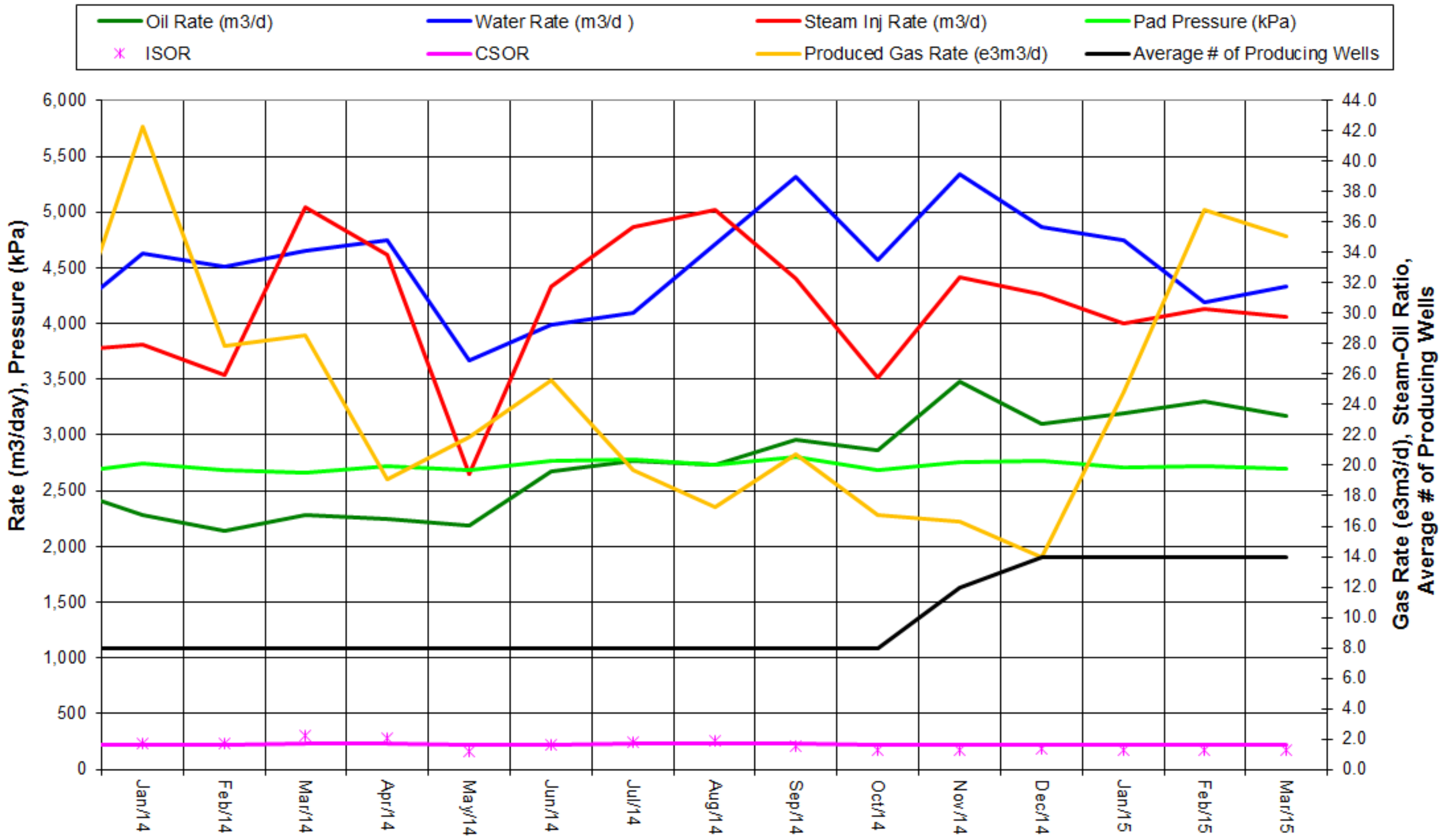
Christina Lake
B02 Pad Performance

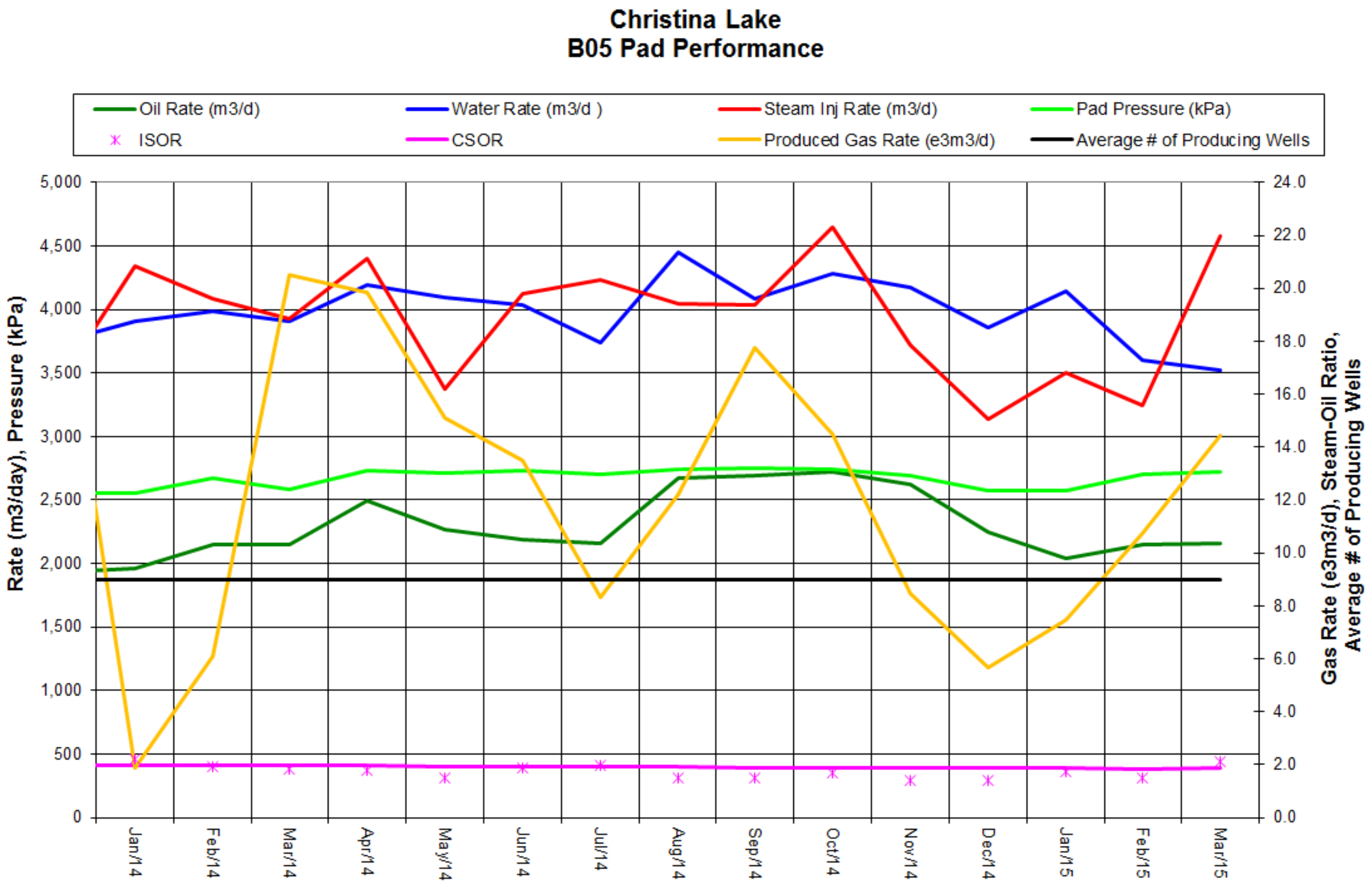


Christina Lake
B03 Pad Performance

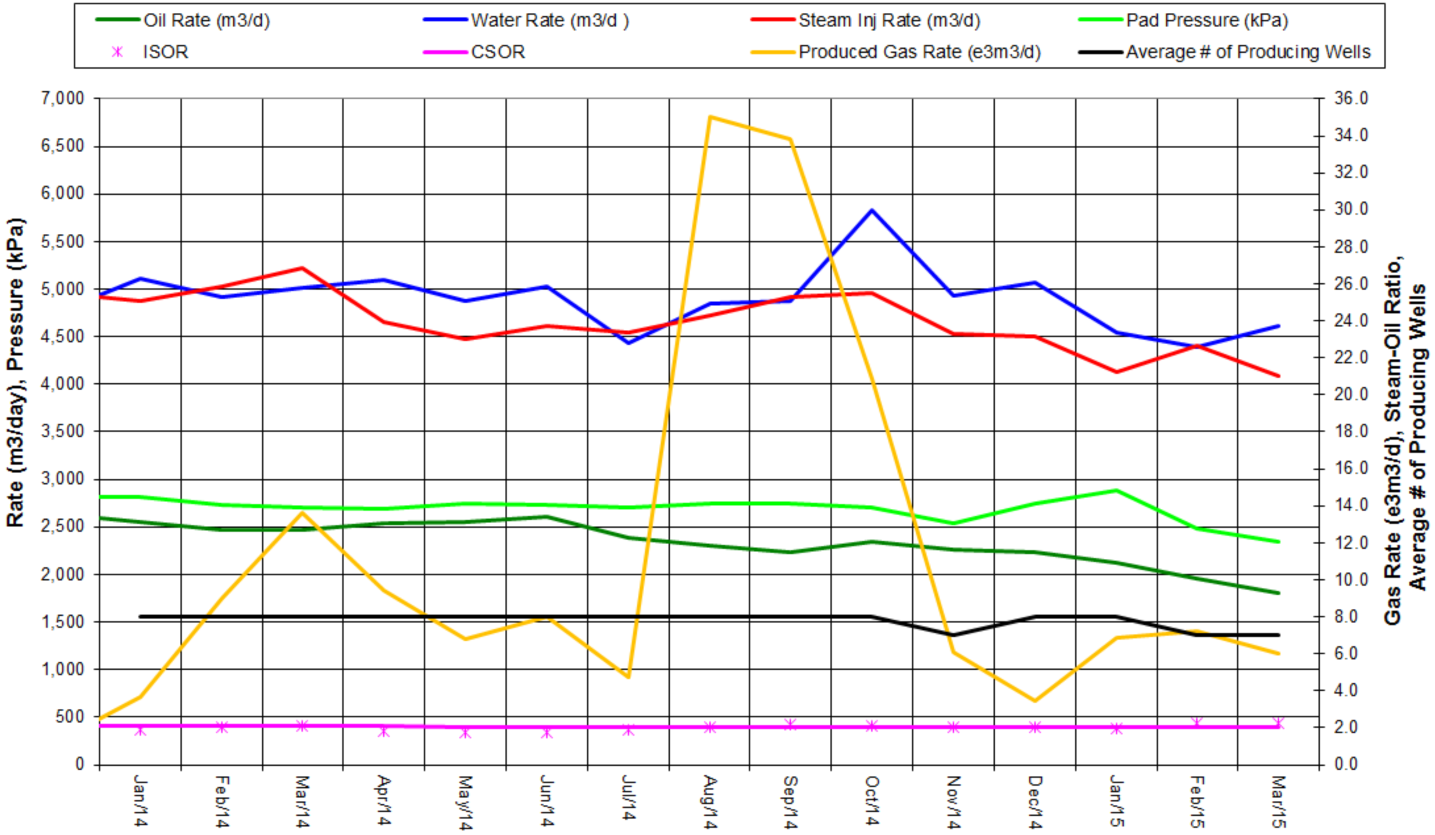


Christina Lake
B04 Pad Performance

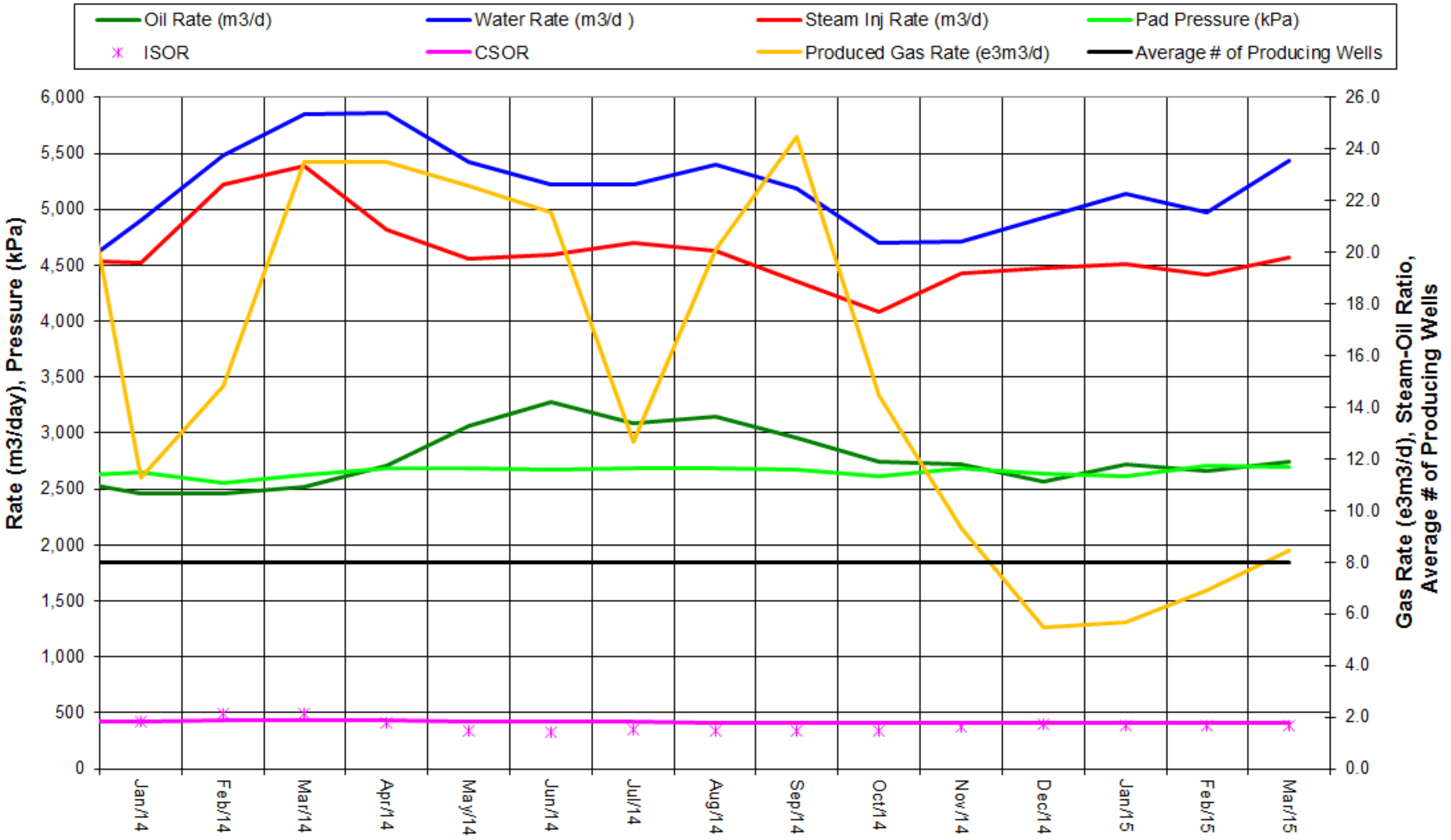



Christina Lake
B05 Pad Performance
Oil Rate (m3/d)
Water Rate (m3/d)
Steam Inj Rate (m3/d)
Pad Pressure (kPa)
ISOR
CSOR
Produced Gas Rate (e3m3/d)
Average # of Producing Wells
Rate (m3/day), Pressure (kPa)
Gas Rate (e3m3/d), Steam-Oil Ratio, Average # of Producing Wells
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
24.0
22.0
20.0
18.0
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
Jan/14
Feb/14
Mar/14
Apr/14
May/14
Jun/14
Jul/14
Aug/14
Sep/14
Oct/14
Nov/14
Dec/14
Jan/15
Feb/15
Mar/15

Christina Lake
B06 Pad Performance



Christina Lake
B07 Pad Performance



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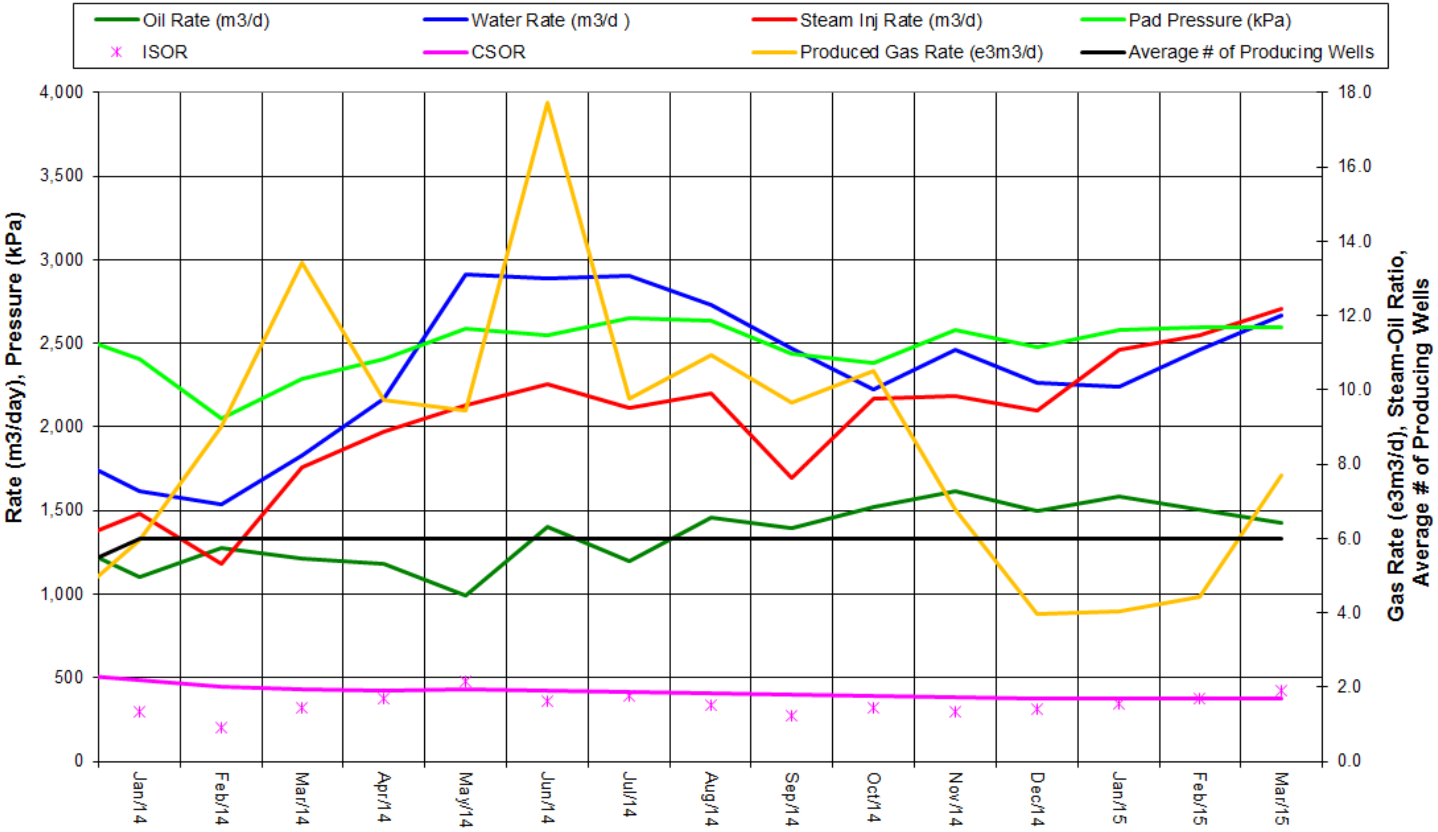
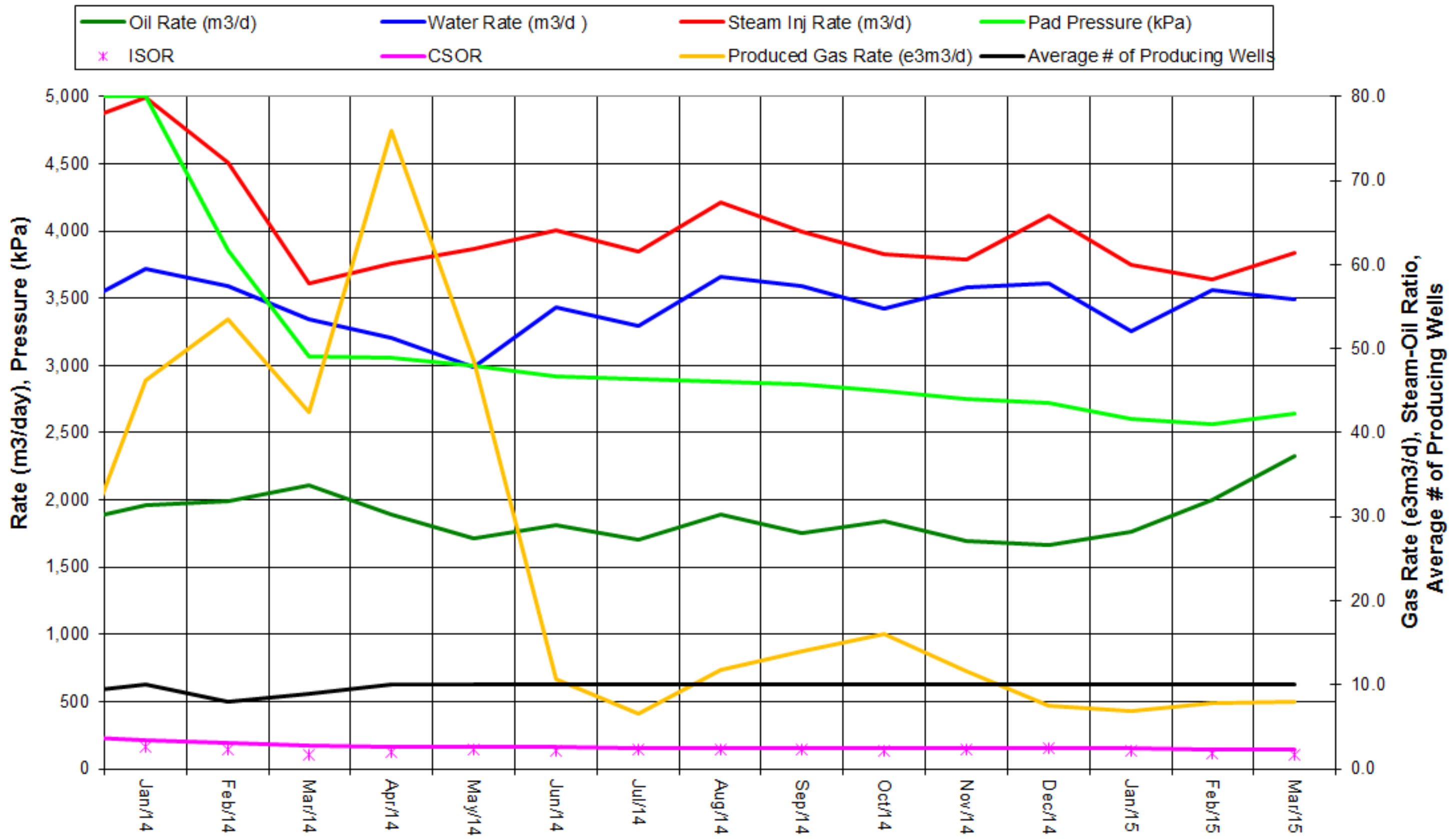
June 24, 2015

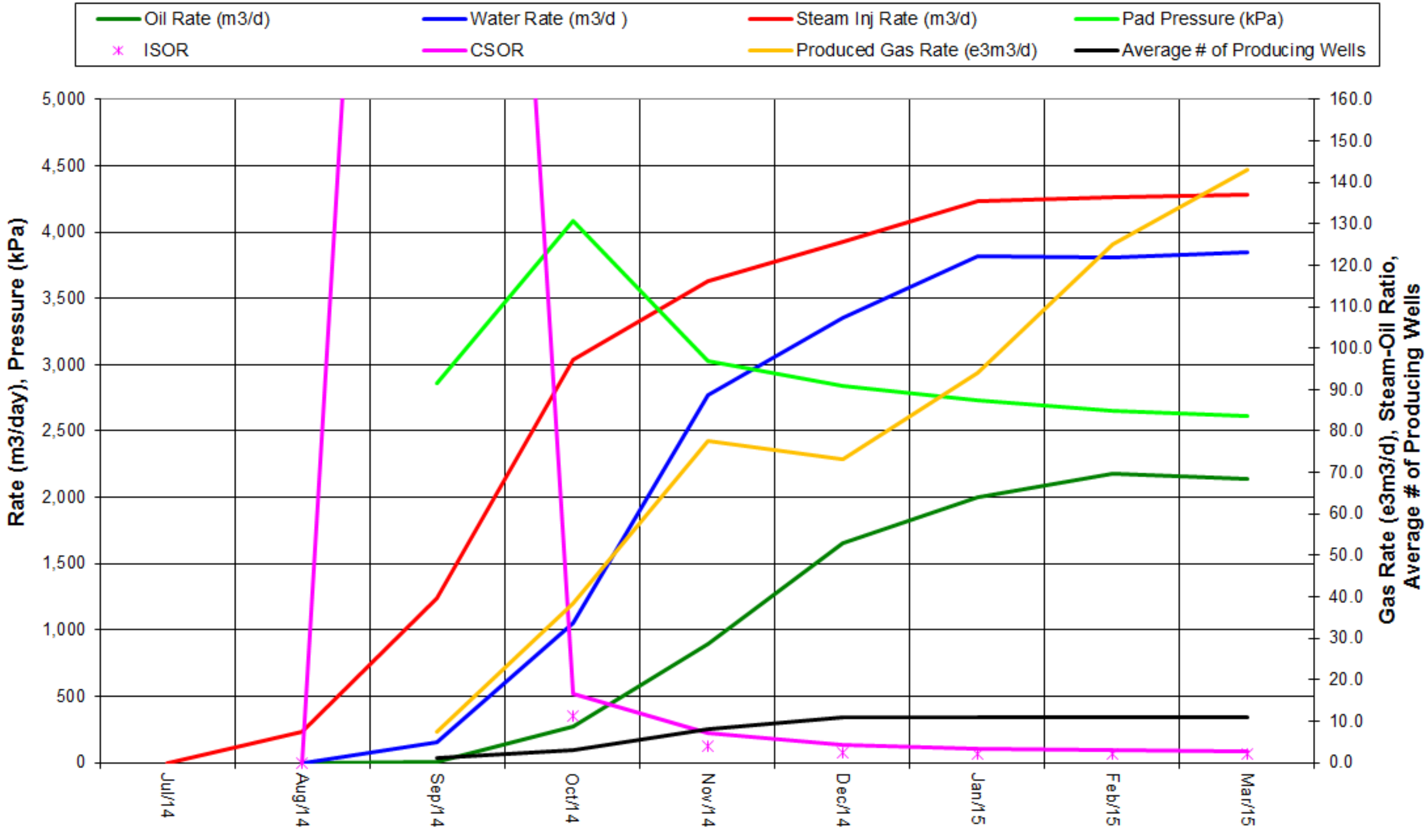
Christina Lake
B02C Pad Performance



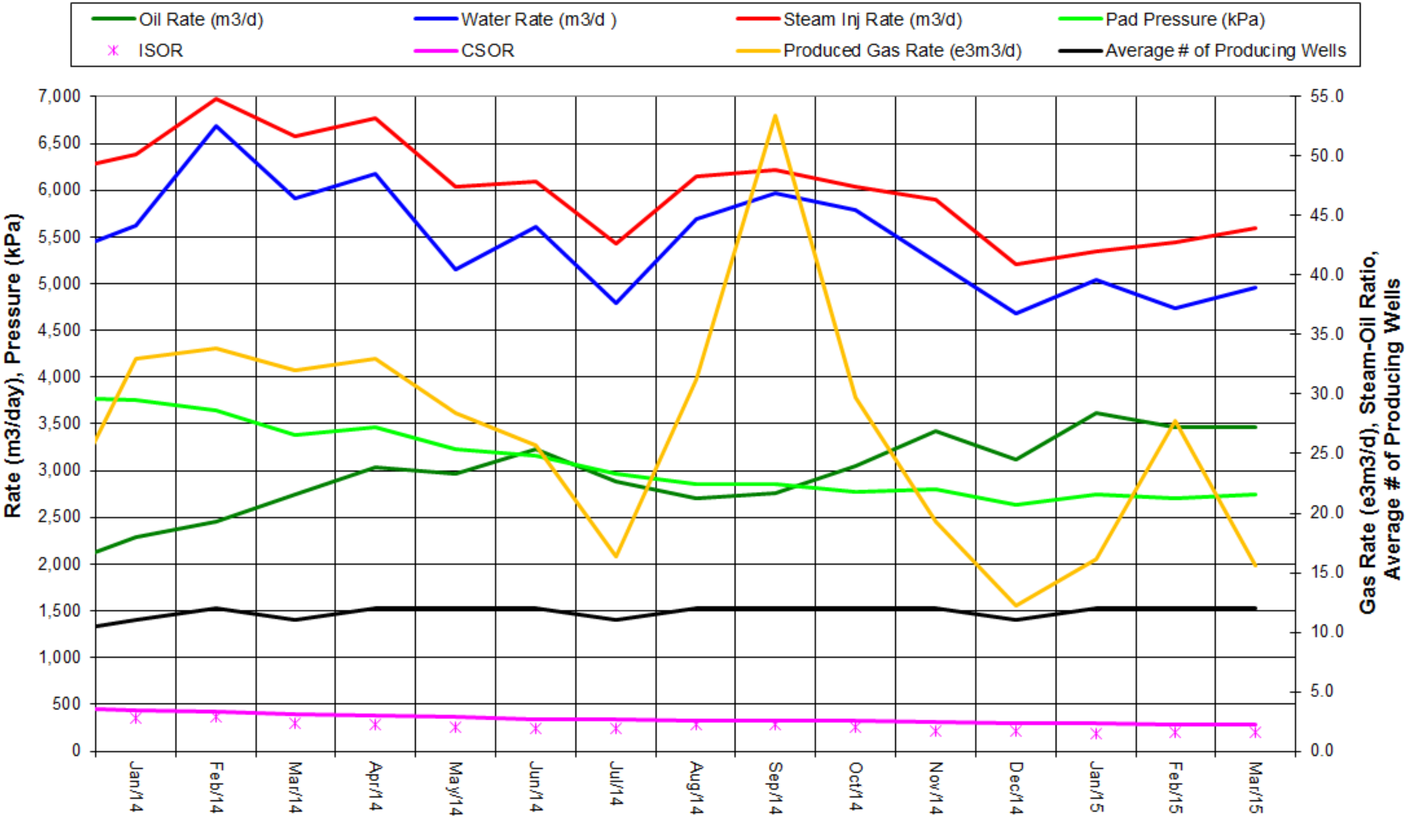
Christina Lake
B08 Pad Performance



Christina Lake
B09 Pad Performance



Christina Lake
B11 Pad Performance



Cenovus Christina Lake
In-situ Oil Sands Scheme 8591
2014 Update

Surface
June 25, 2015

cenovus ENERGY

Oil & gas and financial information

Oil & gas information

The estimates of reserves and contingent resources were prepared effective December 31, 2014 and the estimates of bitumen initially-in-place were prepared effective December 31, 2012. All estimates were prepared by independent qualified reserves evaluators, based on definitions contained in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101. Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates, is contained in our AIF and Form 40-F for the year ended December 31, 2014, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of those resources. Actual resources may be greater than or less than the estimates provided.

Total bitumen initially-in-place (BIIP) estimates, and all subcategories thereof, including the definitions associated with the categories and estimates, are disclosed and discussed in our July 24, 2013 news release, available on SEDAR at sedar.com and at cenovus.com. BIIP estimates include unrecoverable volumes and are not an estimate of the volume of the substances that will ultimately be recovered. Cumulative production, reserves and contingent resources are disclosed on a before royalties basis. All estimates are best estimate, billion barrels (Bbbls). *Total BIIP* (143 Bbbls); *discovered BIIP* (93 Bbbls); *commercial discovered BIIP* equals the *cumulative production* (0.1 Bbbls) plus *reserves* (2.4 Bbbls); *sub-commercial discovered BIIP* equals *economic contingent resources* (9.6 Bbbls) plus the *unrecoverable portion of discovered BIIP* (81 Bbbls); *undiscovered BIIP* (50 Bbbls); *prospective resources* (8.5 Bbbls); *unrecoverable portion of undiscovered BIIP* (42 Bbbls). Any contingent resources as at December 31, 2012 that are sub-economic or that are classified as being subject to technology under development have been grouped into the unrecoverable portion of discovered BIIP. Petroleum initially-in-place (PIIP) estimates for Pelican Lake are effective December 31, 2012 and were prepared by McDaniel. All estimates are best estimate discovered PIIP volumes as follows: *Mobile Wabiskaw* total PIIP (2.11 Bbbls); discovered PIIP (2.11 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0.03 Bbbls); unrecoverable discovered PIIP (1.72 Bbbls); undiscovered PIIP (0 Bbbls). *Mobile Wabiskaw development area* total PIIP (1.62 Bbbls); discovered PIIP (1.62 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.26 Bbbls); undiscovered PIIP (0 Bbbls). *Immobile Wabiskaw* total PIIP (1.33 Bbbls); discovered PIIP (1.33 Bbbls); cumulative production (0 Bbbls); reserves (0 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.33 Bbbls); undiscovered PIIP (0 Bbbls).

Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

Non-GAAP measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS such as, Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Readers are encouraged to review our most recent Management's Discussion and Analysis, available at cenovus.com for a full discussion of the use of each measure.

Advisory

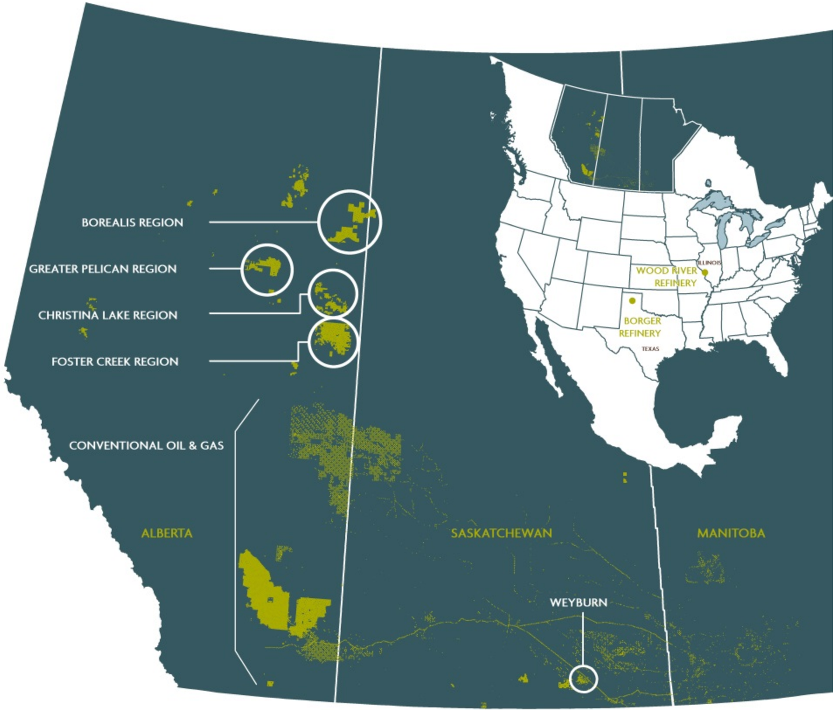
This document contains forward-looking information prepared and submitted pursuant to Alberta regulatory requirements and is not intended to be relied upon for the purpose of making investment decisions, including without limitation, to purchase, hold or sell any securities of Cenovus Energy Inc. Certain resources estimates contained herein are not reported in accordance with National Instrument 51-101 and are provided solely for the purpose of complying with Alberta regulatory requirements.

Additional information regarding Cenovus Energy Inc. is available at cenovus.com

Strong integrated portfolio

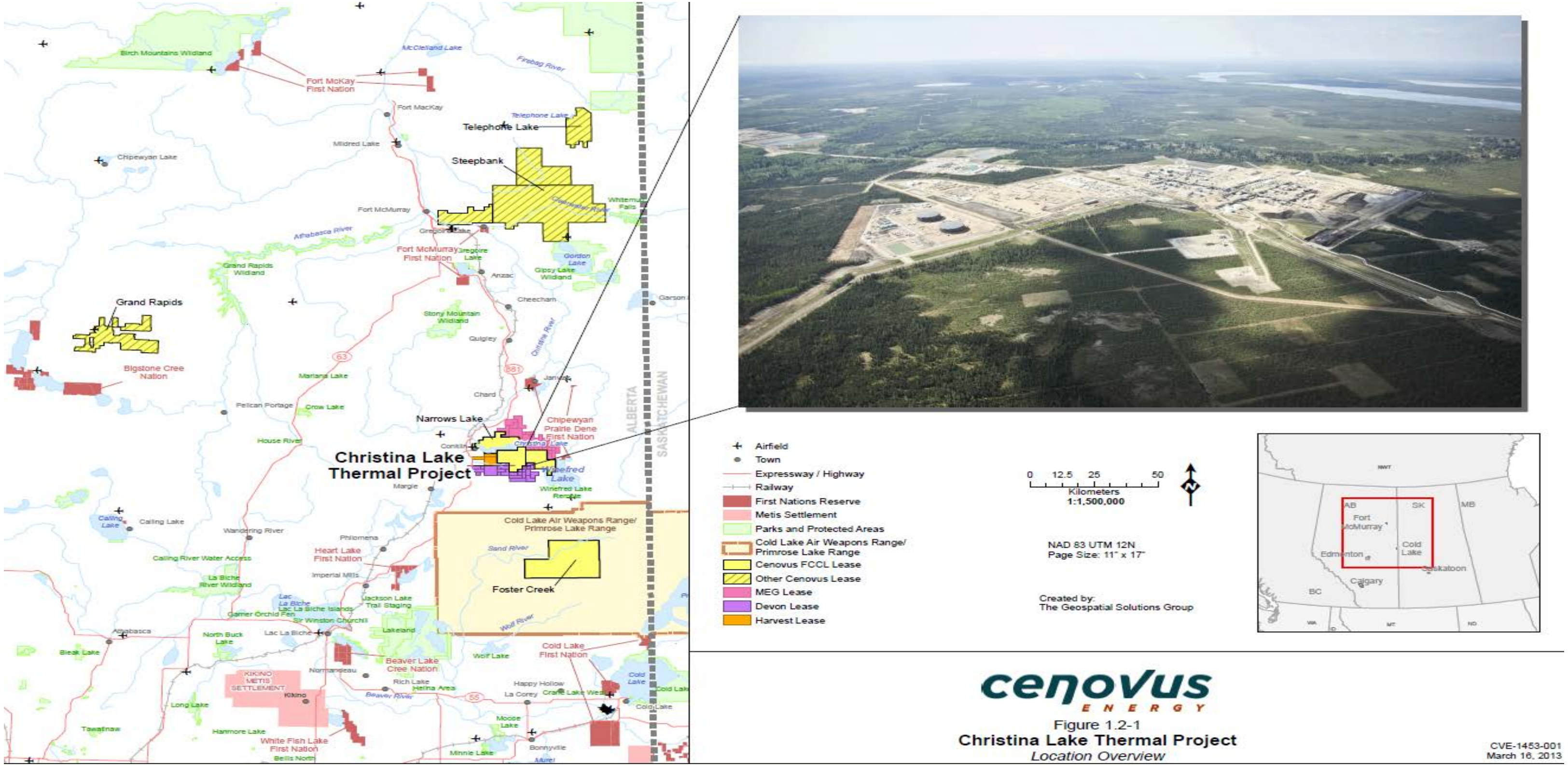
TSX, NYSE | CVE

Enterprise value	C$25 billion
Shares outstanding	829 MM
2015F production	
Oil & NGLs	204 Mbbls/d
Natural gas	438 MMcf/d
2014 proved & probable reserves	3.9 BBOE
Bitumen	
Economic contingent resources*	9.3 Bbbls
Discovered bitumen initially in place*	93 Bbbls
Lease rights**	1.5 MM net acres
P&NG rights	5.6 MM net acres
Refining capacity	230 Mbbls/d net



Values are approximate. Forecast production based on midpoints of January 28, 2015 guidance. Cenovus land at December 31, 2014. *See advisory. **Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignee's behalf.

Area Map



Birch Mountains Wildland
McClelland Lake
Firebag River
Fort McKay First Nation
Fort MacKay
Telephone Lake
Telephone Lake
Mildred Lake
Chipewyan Lake
Steepbank
Fort McMurray
Athabasca River
Fort McMurray First Nation
Gregoire Lake
Grand Rapids Wildland
Gordon Lake
Gipsy Lake Wildland
Anzac
Cheecham
Grand Rapids
Stony Mountain Wildland
Quigley
Bigstone Cree Nation
Mariana Lake
Janvier
Chard
Pelican Portage
Crow Lake
Narrows Lake
Chipewyan Prairie Dene First Nation
House River
Christina Lake
Christina Lake Thermal Project
Winefred Lake
Winefred Lake Reserve
Margie
ALBERTA
SASKATCHEWAN
Calling Lake
Calling Lake
Wandering River
Cold Lake Air Weapons Range/ Primrose Lake Range
Philomena
Heart Lake First Nation
Sand River
Calling River Water Access
Imperial Mills
Foster Creek
La Biche River Wildland
Lac La Biche
Jackson Lake Trail Staging
Garner Orchid Fen
Sir Winston Churchill
Lac La Biche Islands
Athabasca
North Buck Lake
Lac La Biche
Lakeland
Wolf River
Bleak Lake
Cold Lake First Nation
Wolf Lake
Beaver Lake Cree Nation
Kikino Metis Settlement
Kikino
Normandeau
Rich Lake
Helina Area
Happy Hollow
La Corey
Crane Lake West
Cold Lake
Cold Lake
Long Lake
Beaver River
Tawatinaw
Harmore Lake
White Fish Lake First Nation
Moose Lake
Bonnyville
Minnie Lake
Bellis North
Airfield
Town
Expressway / Highway
Railway
First Nations Reserve
Metis Settlement
Parks and Protected Areas
Cold Lake Air Weapons Range/ Primrose Lake Range
Cenovus FCCL Lease
Other Cenovus Lease
MEG Lease
Devon Lease
Harvest Lease
0 12.5 25 50
Kilometers
1:1,500,000
NAD 83 UTM 12N
Page Size: 11" x 17"
Created by:
The Geospatial Solutions Group
AB
SK
MB
NWT
Fort McMurray
Cold Lake
Edmonton
Saskatoon
Calgary
BC
cenovus
ENERGY
Figure 1.2-1
Christina Lake Thermal Project
Location Overview
CVE-1453-001
March 16, 2013

Subsection 3.1.2 – 1) Facilities

Ben Lee

Process Engineer

Facility summary

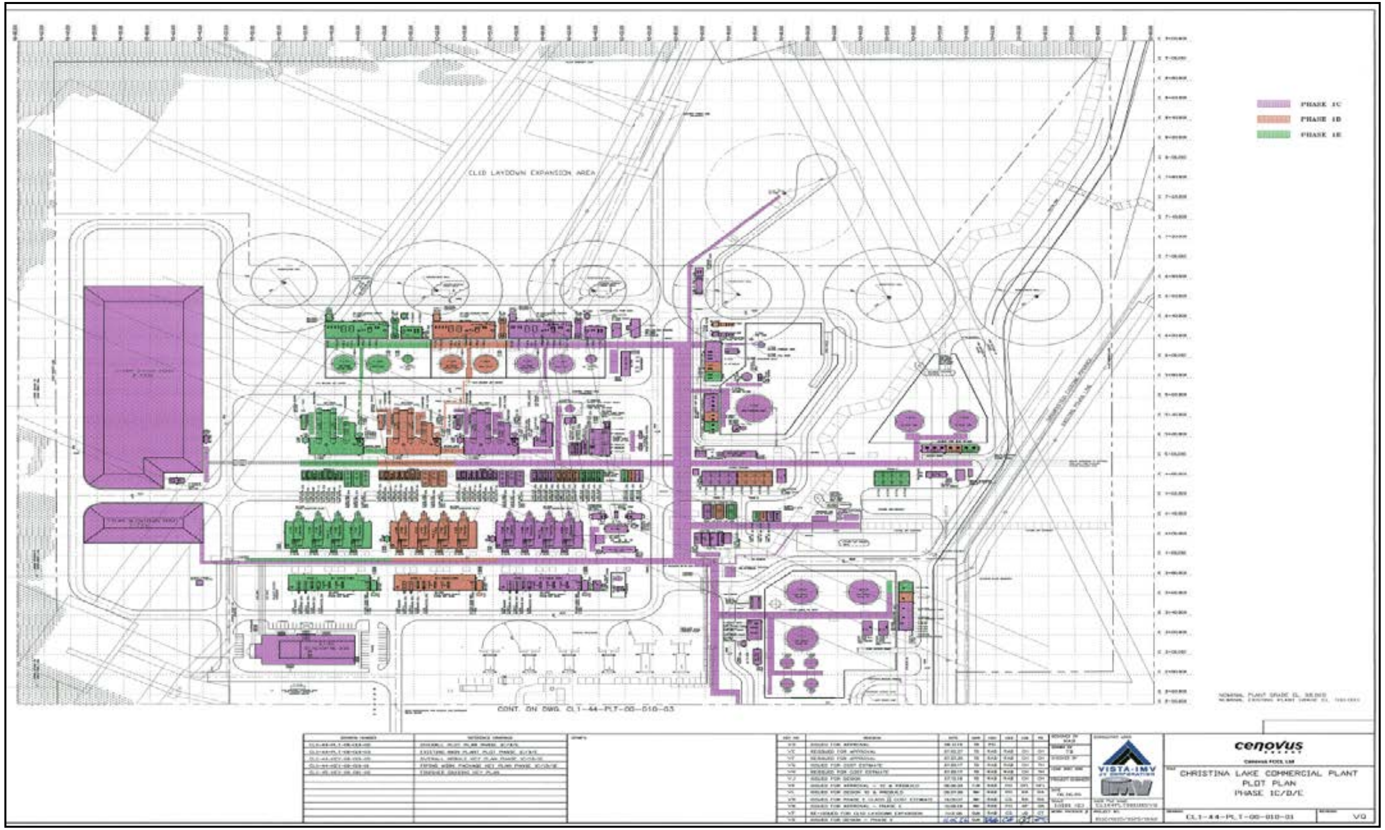
Inter Pipeline Polaris operational

- New diluent pipeline for shipments to both Foster Creek (FC) and Christina Lake (CL)
- Began accepting deliveries at CL in October
- More stable supply and quality
- Will eventually support the entire facility in five years

Phase A/B turnaround completed

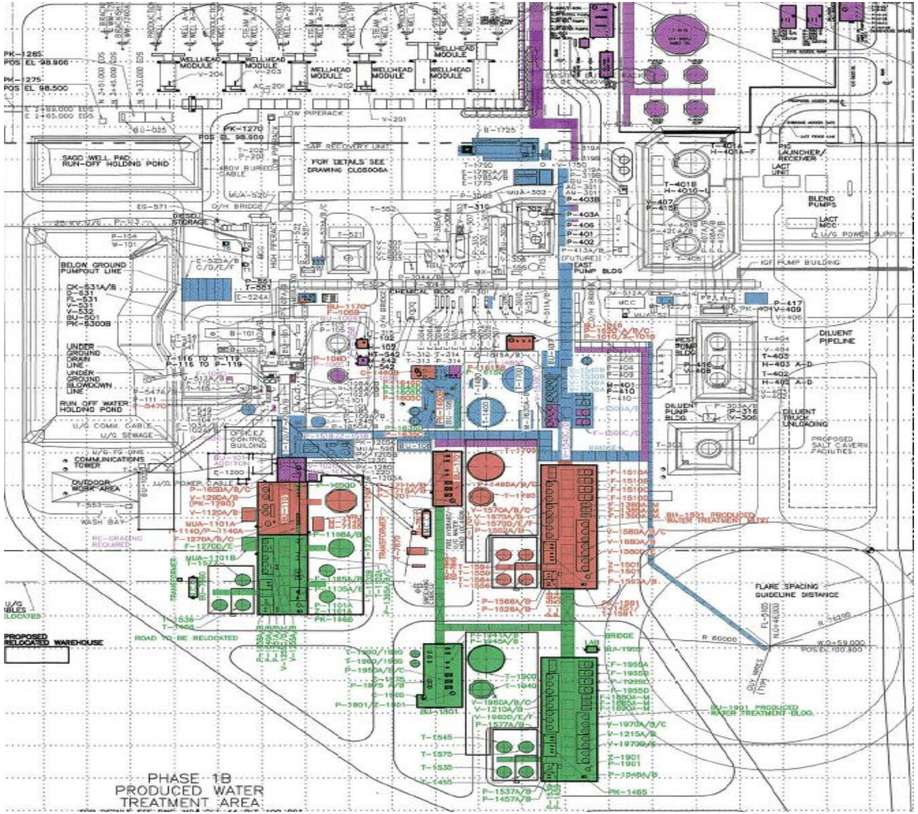
- Took place from May 3 to May 19 including ramp down/up
- Focus on OTSGs, Process area, and Flare Header
- Managed to offload emulsion into CDE facility to reduce impact to production
    - Only lost ~25,000 bbls due to TA

Detailed plot plan – Phase C/D/E

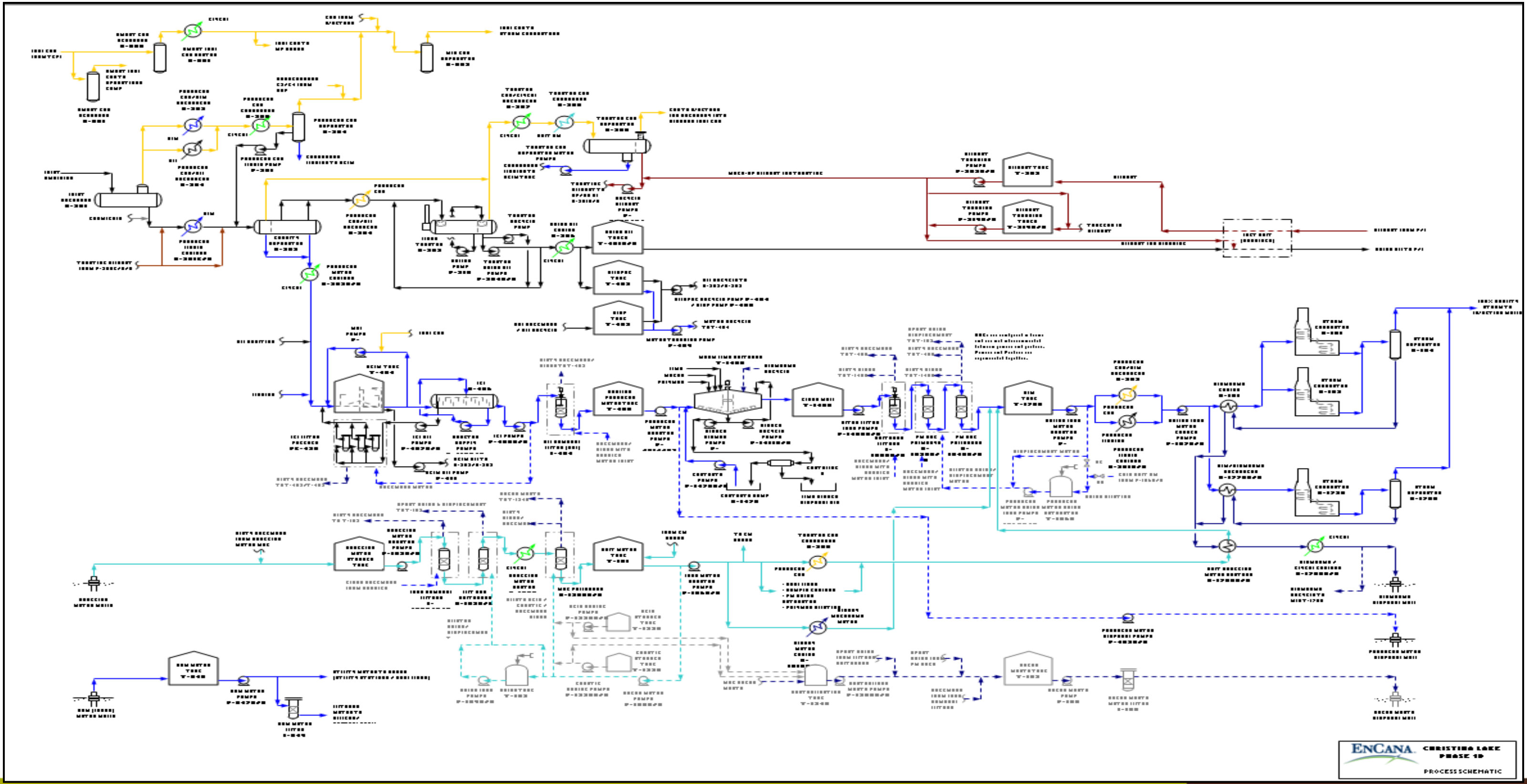


Subsection 3.1.2-1a)
June 25, 2015

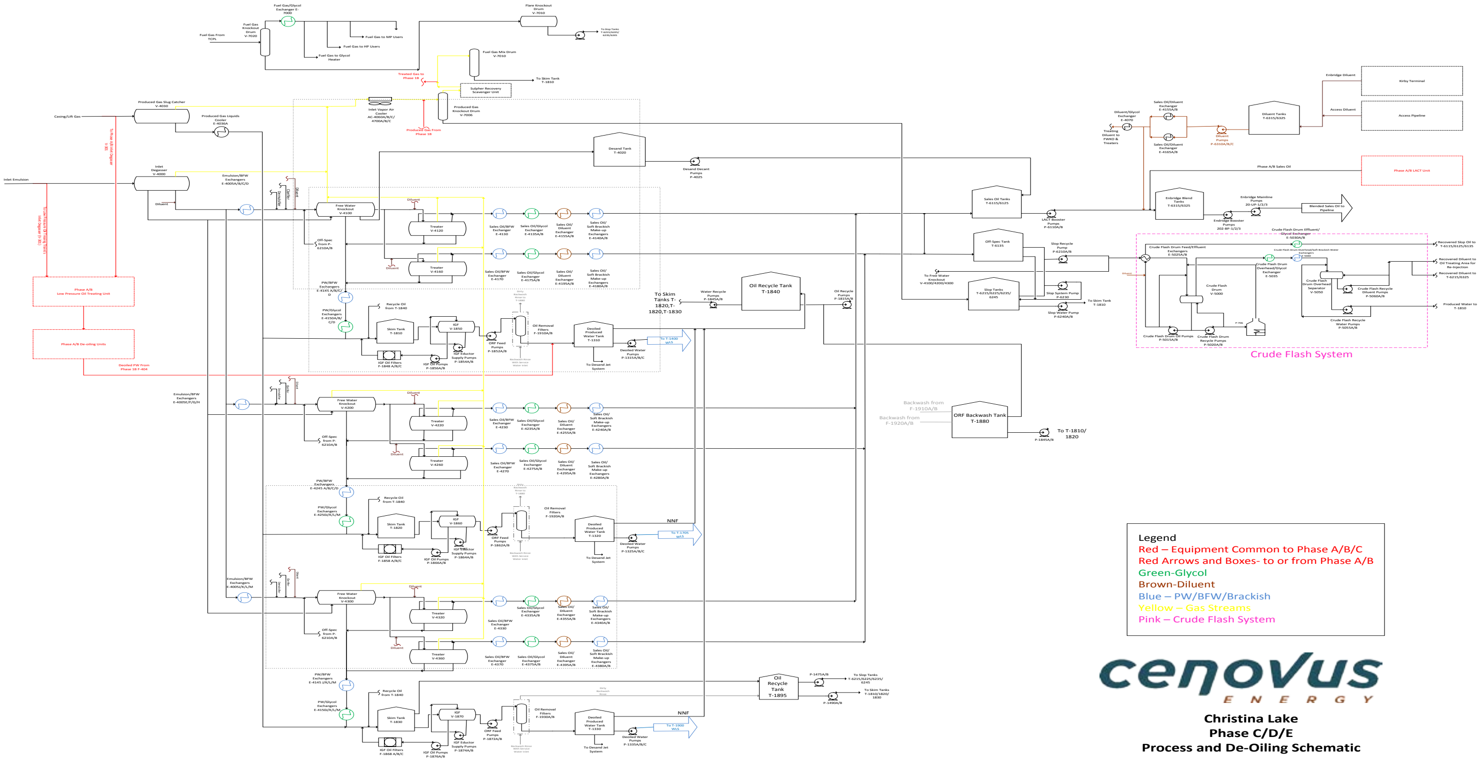
Detailed plot plan – Phase A/B and C/D/E water treatment



Process schematic – Phase A/B

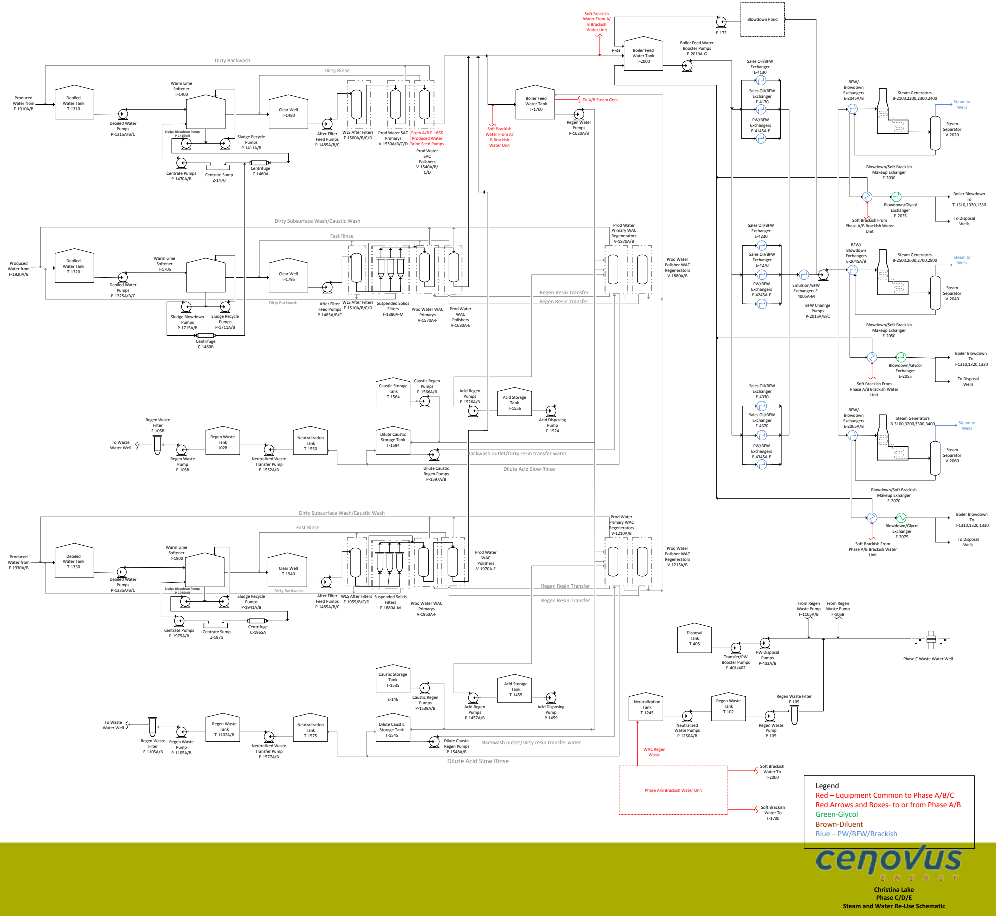


Process schematic – Phase C/D/E

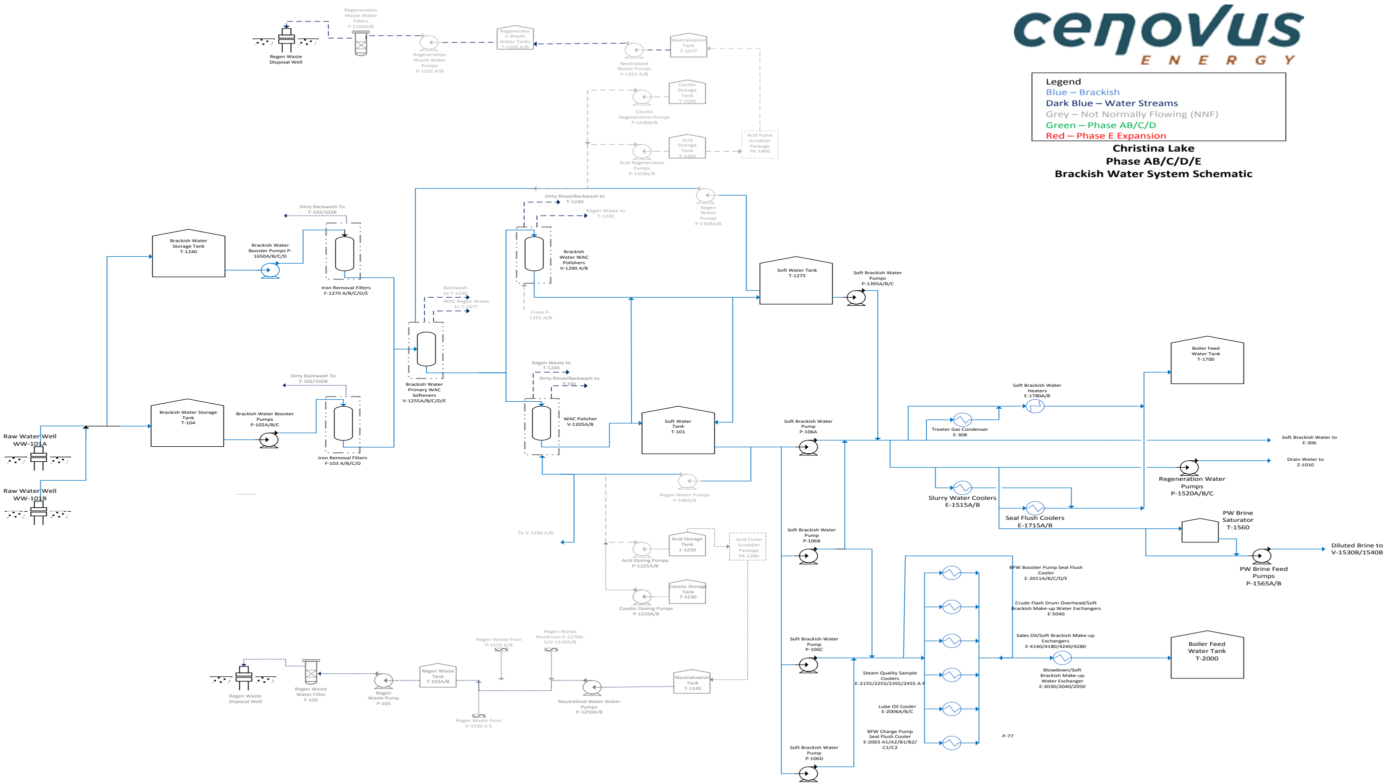


Subsection 3.1.2-1b)
June 25, 2015

Process schematic – Phase C/D/E



Process schematic – Phase C/D/E



Facility modifications

No major modifications made to Phase A/B/C/D/E

- Blowdown boiler addition expected in 2015
- CL1F expansion expected in 2016

Subsection 3.1.2 – 2)
Facility performance

Ben Lee

Process Engineer

cenovus ENERGY

Plant performance

Exceeded design performance:

- Steam plant has achieved higher rates than nameplate design
  (106%, 42,000 t/d vs nameplate 39,523 t/d)
- Water treatment (de-oiling) has achieved higher rates than nameplate design through each individual train
  (104%, 51,032 t/d vs nameplate 49,146 t/d)
- Oil treating has achieved higher rates than nameplate design
  (115%, 159,540 bbls/d vs 138,800 bbls/d)

Issues:

- Emulsion chemical treating program required optimization

Plant performance

Treating success

- Slop generation was one of major plant concerns in previous years, compounded by increased production
- Changes to chemical injection program in March 2014 improved oil treating performance while significantly reducing slop generated
- Slop handling is now completely internalized within the facility, with little to no offsite management

Bitumen treatment

Process

- Capacity of 138,800 bbls/d
- Have consistently achieved rates of 138,800 bopd (high of 159,540 bbls or 115% of design achieved)
- Have reduced issues with treating and water quality due to:
  - Optimized chemical treating
  - Improving operating procedures
  - Modifications to control logic
- Completed trial to examine maximum throughput capabilities of CDE process trains and determine what are constraints
- Implemented new diluent injection logic to more accurately control density throughout process trains

Water treatment

De-oiling

- Capacity of 49,146 t/d of water
- Flowed up to 51,032 t/d of water
- Issues in de-oiling are:
  - Water cooling at high flow rates
  - Fouling of heat exchangers
  - Deoiling efficiency at higher throughputs

Water treatment

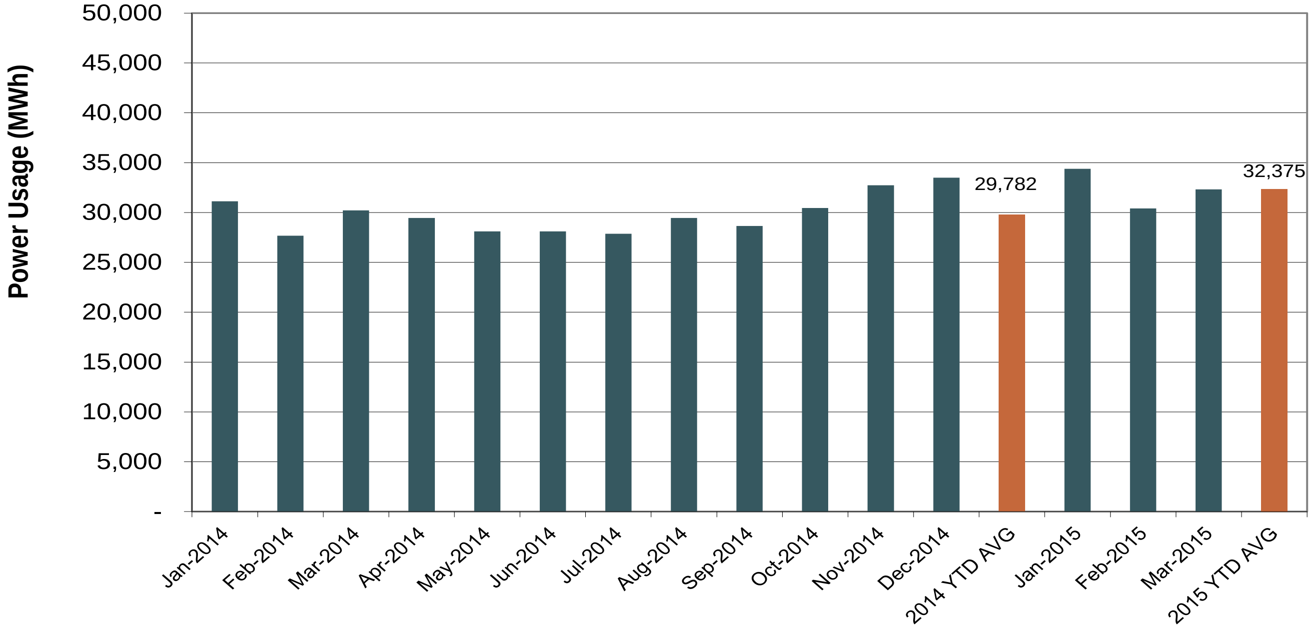
- Blowdown recycle into the produced water treatment trains and BFW tank with no adverse impacts up to 54% of total blowdown volumes produced
- No major issues to report

Steam generation

Steam generation via 15 OTSGs

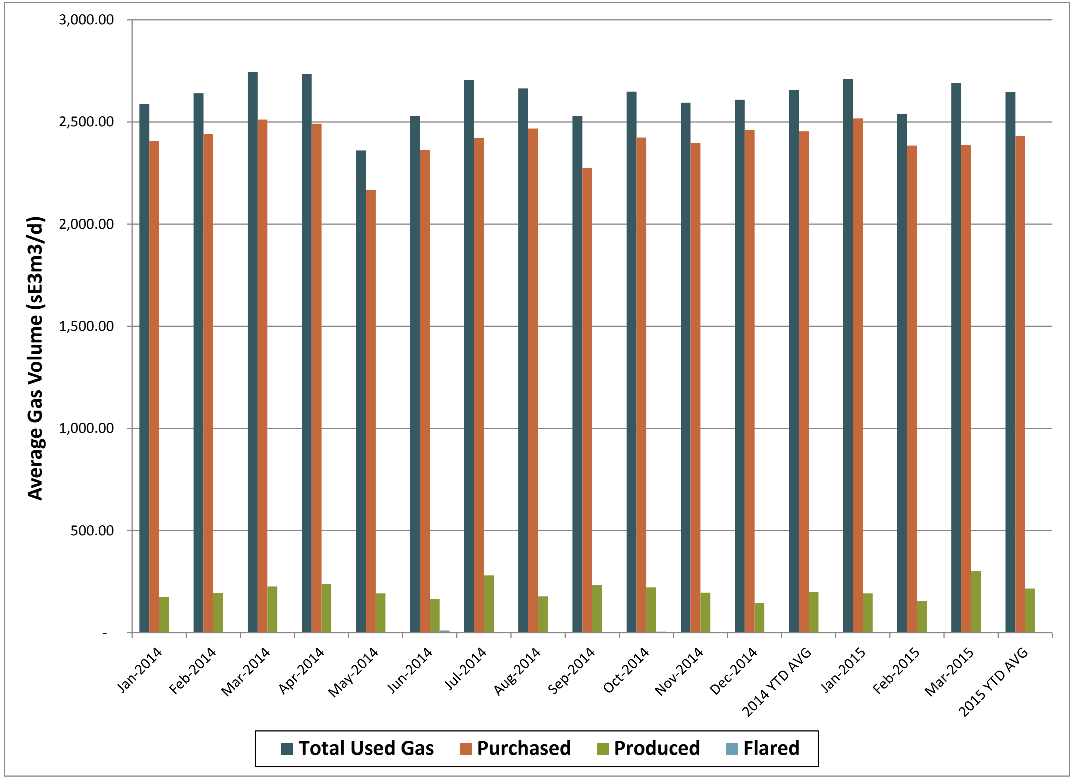
- Design capacity of 39,523 m^3/d CWE dry steam
- Have achieved rates in excess of 42,000 m^3/d CWE dry steam
- Typical operation: 82% quality
  - Tested operation of four OTSGs at 85% quality while maintaining blowdown recycle
  - Observed accelerated fouling rate compared to baseline OTSGs operating at 82%
  - Rigorous monitoring program including NDT, DT, and continuous boiler performance monitoring in place

Power usage



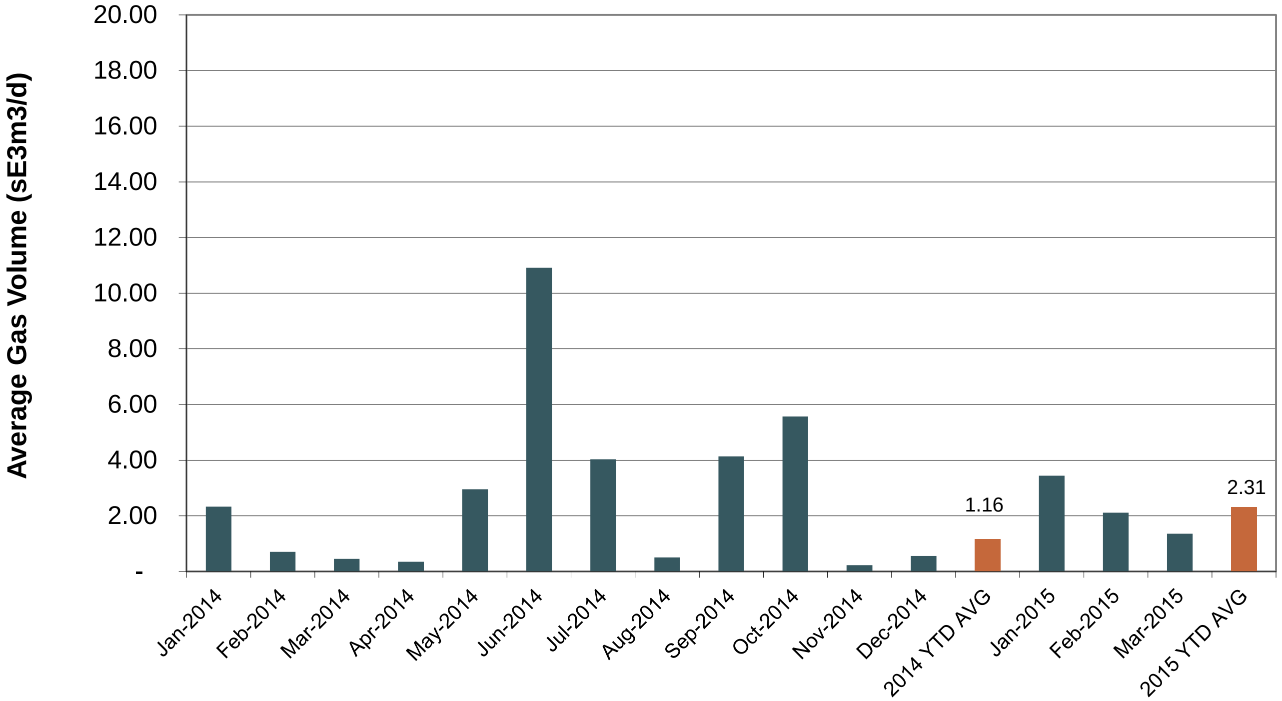
*Note – Plot represents monthly power imports. No operating power generation facilities at Christina Lake

Gas usage



3,000.00
2,500.00
2,000.00
1,500.00
1,000.00
500.00
-
Average Gas Volume (sE3m3/d)
Jan-2014
Feb-2014
Mar-2014
Apr-2014
May-2014
Jun-2014
Jul-2014
Aug-2014
Sep-2014
Oct-2014
Nov-2014
Dec-2014
2014 YTD AVG
Jan-2015
Feb-2015
Mar-2015
2015 YTD AVG
Total Used Gas
Purchased
Produced
Flared

Gas flared



Average Gas Volume (sE3m3/d)
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
-
1.16
2.31
Jan-2014
Feb-2014
Mar-2014
Apr-2014
May-2014
Jun-2014
Jul-2014
Aug-2014
Sep-2014
Oct-2014
Nov-2014
Dec-2014
2014 YTD AVG
Jan-2015
Feb-2015
Mar-2015
2015 YTD AVG

Greenhouse gas emissions

Greenhouse gas emissions are reported to AER on yearly basis for review

- Q1 2015 total total direct emissions by gas type
  - CO_2 – 458,443 tonnes CO_2e
  - CH_4 – 450 tonnes CO_2e
  - N_2O – 727 tonnes CO_2e

- 2014 total direct emissions by gas type
  - CO_2 –1,824,438 tonnes CO_2e
  - CH_4 – 3,805 tonnes CO_2e
  - N_2O – 2,903 tonnes CO_2e

*Note – Only the 2014 GHGs have been verified and submitted, the 2015 numbers are still preliminary.

Subsection 3.1.2 – 3)
Measurement and reporting (MARP)

Colin Read
Production Engineer

cenovus ENERGY

Measurement, Accounting & Reporting Plan (MARP) (Directive 042)

Water imbalance exceedance

- Correction factors were applied to disposal volumes reported by the MARP meters as a result of inconsistencies between installed orifice plates, data sheets, and DCS calibration factors for the months of January to November, 2014.
- A letter of self disclosure for the water imbalance was submitted to AER on February 13, 2015.

2014 MARP SIRs addressed:

- 2014 SIRS addressed. Majority of SIRs and responses addressed metering discrepancies between the MARP document and schematic.
- Future phase meters clearly labeled for 2015 submission
- Updated tank lists and process schematics to reflect current information

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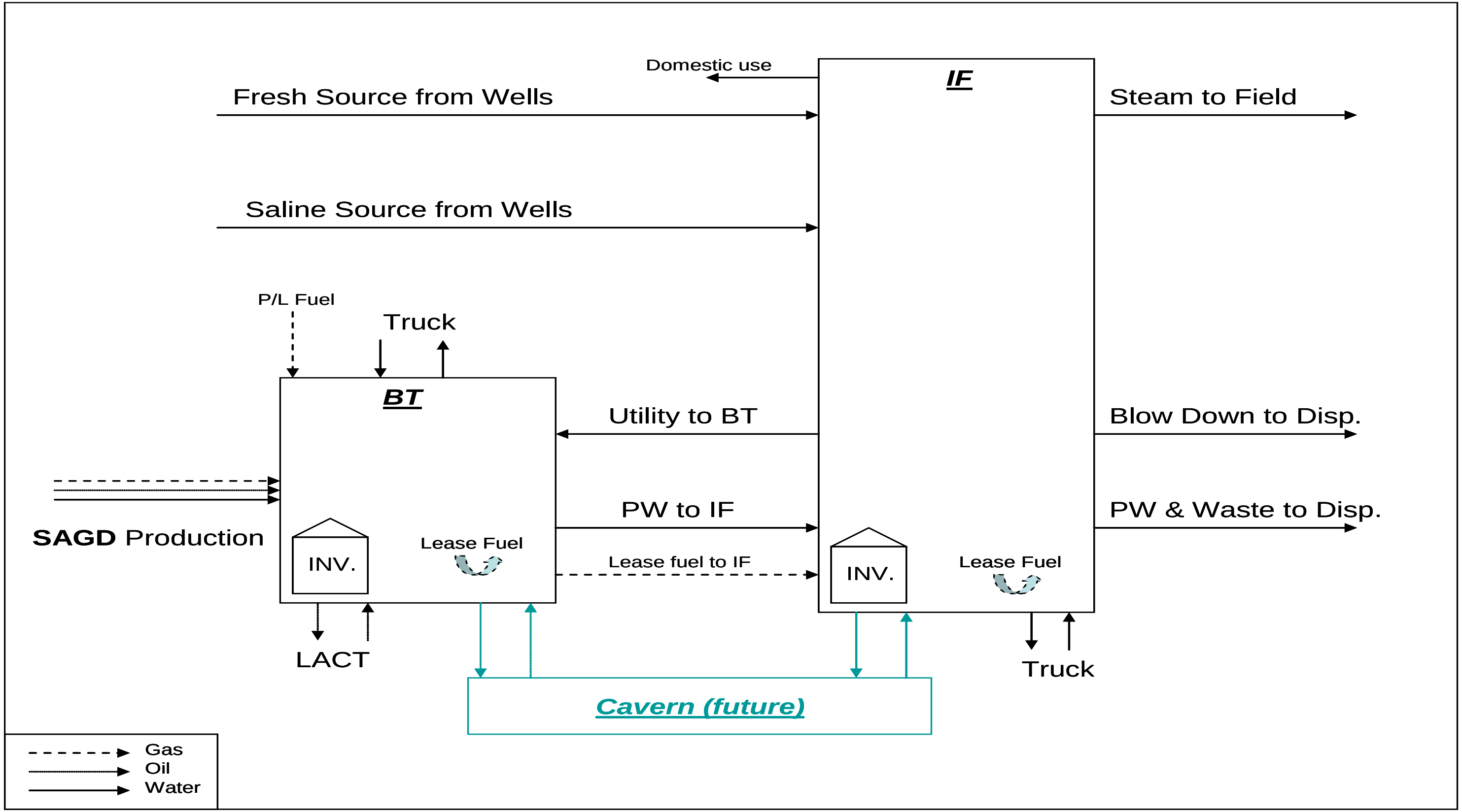
Simplified MARP schematic



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Injection volumes

Steam injection

- Steam to wells measured by nozzles or V-cone (>95% quality)

- Prorate well steam to plant steam (metered by flow nozzle off steam seps, checked by BFW- BD)

Production and injection volumes

Measured plant bitumen

- Blend (API 12.3) and bitumen inventory and trucking
- Incorporated diluent loss/bitumen gain in to production calculation
- Estimate by well tests (2 phase test separators with BSW%)
    - 8-12 wells per separator (maximum 12 wells per separator)
    - ~10 hour cycles + purges
    - 1 hour of testing for every 20 hours of well operations, or about 4 x 10 hour tests per month

Gas production

- Plant measurement by balance
- Measuring well GOR based off well test and prorate to plant measurement
- Co-injected gas monitored and reported on a well basis

Proration factors

Overall water balance closure monitored on a monthly basis (< 5%)

Oil proration

- Typically 10%
- Some months have higher proration error due to facility turnaround, process upsets, BSW meter drift, and phase ramp up

Water proration

- Typically < 10%
- Some months have higher proration error due to facility turnaround, process upsets

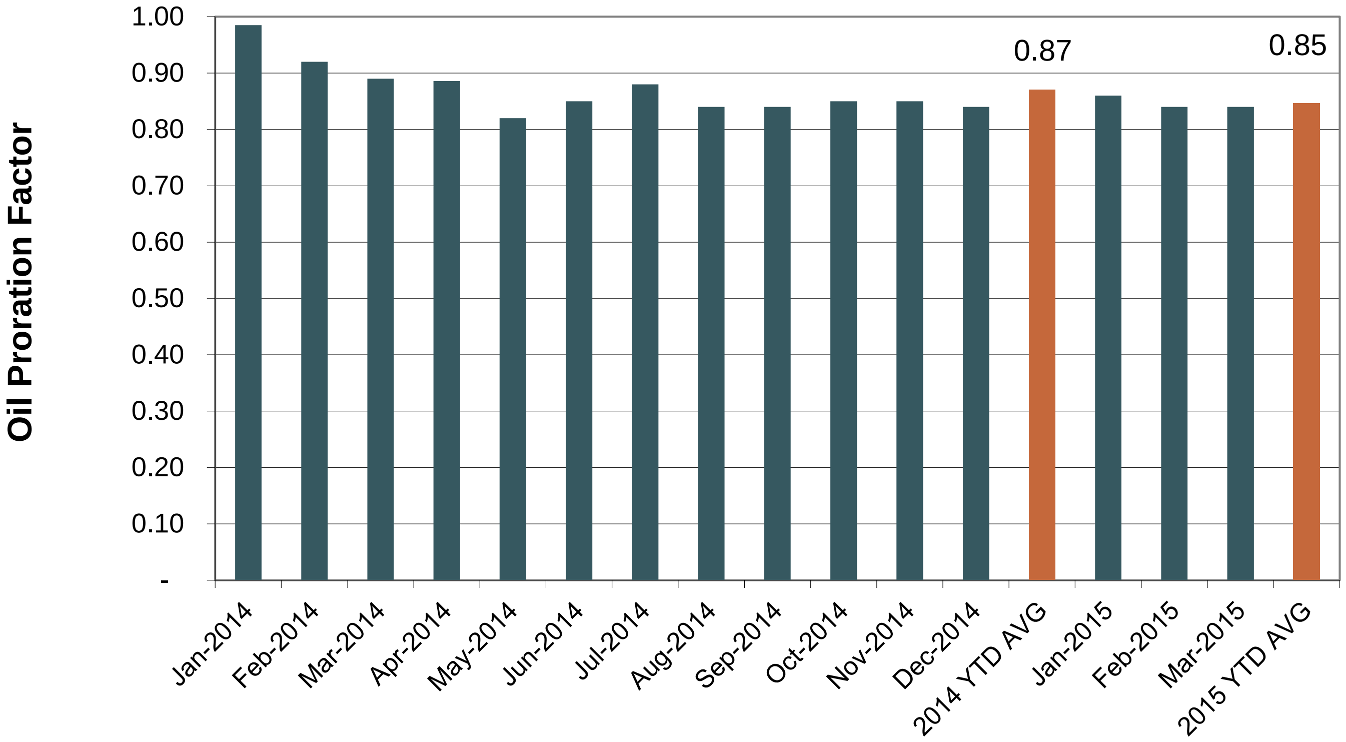
Gas proration

- Variable and sometimes greater than 50%
- Variable due to:
  - Proration based from individual well tests (not facility GOR)

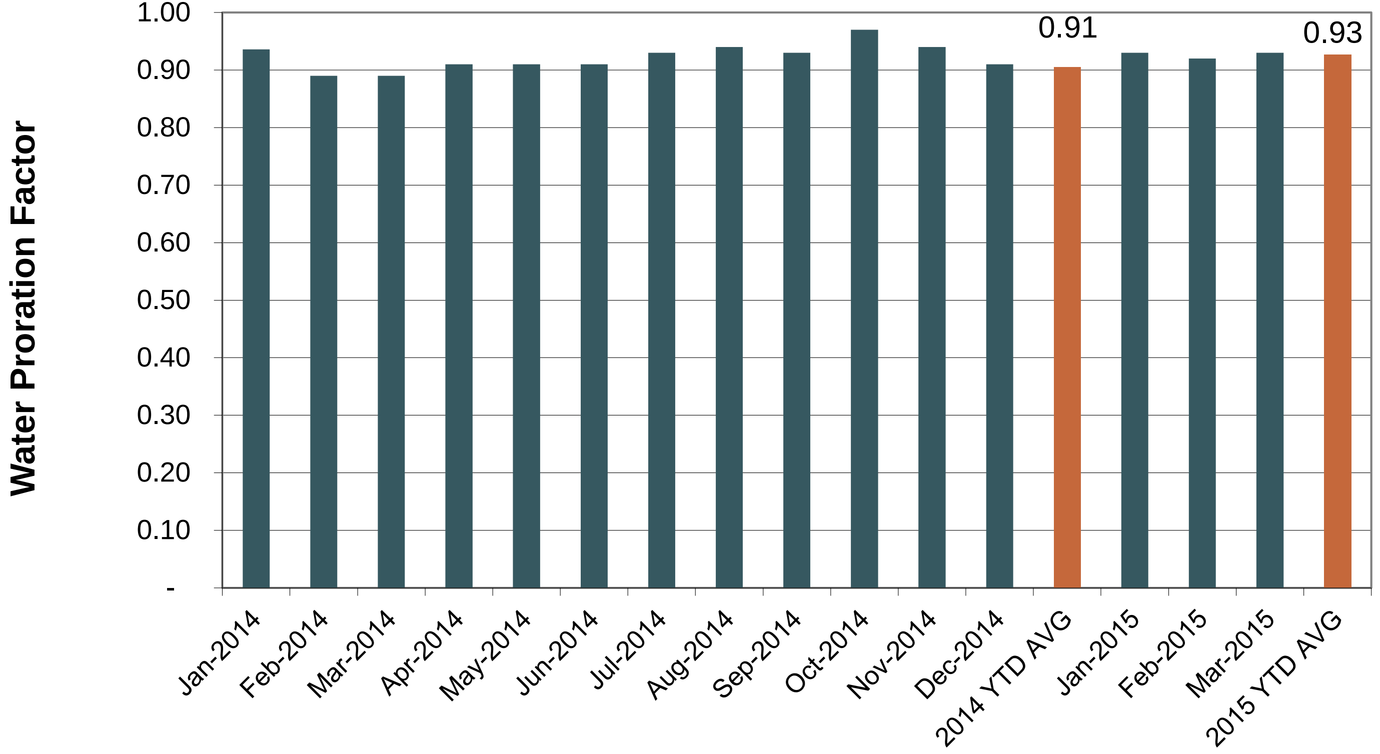
Steam proration

- Typically < 8%
- Some higher proration error occurred after start-up/commissioning and during plant upsets

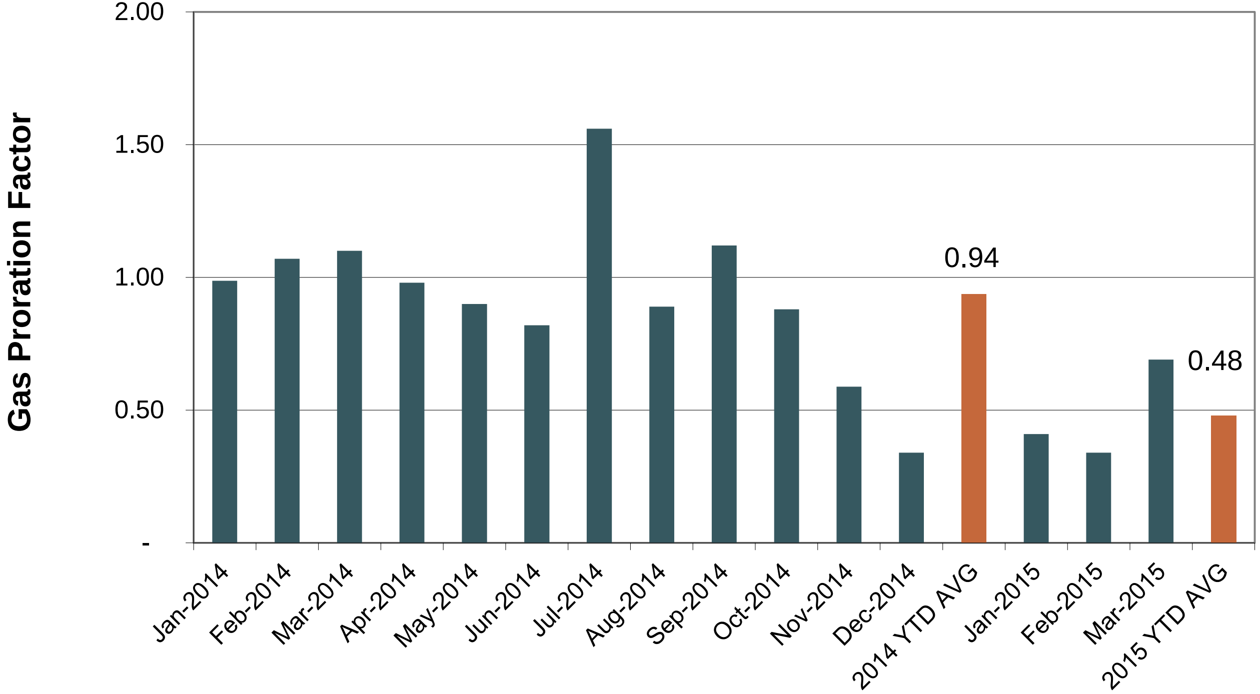
Proration factors



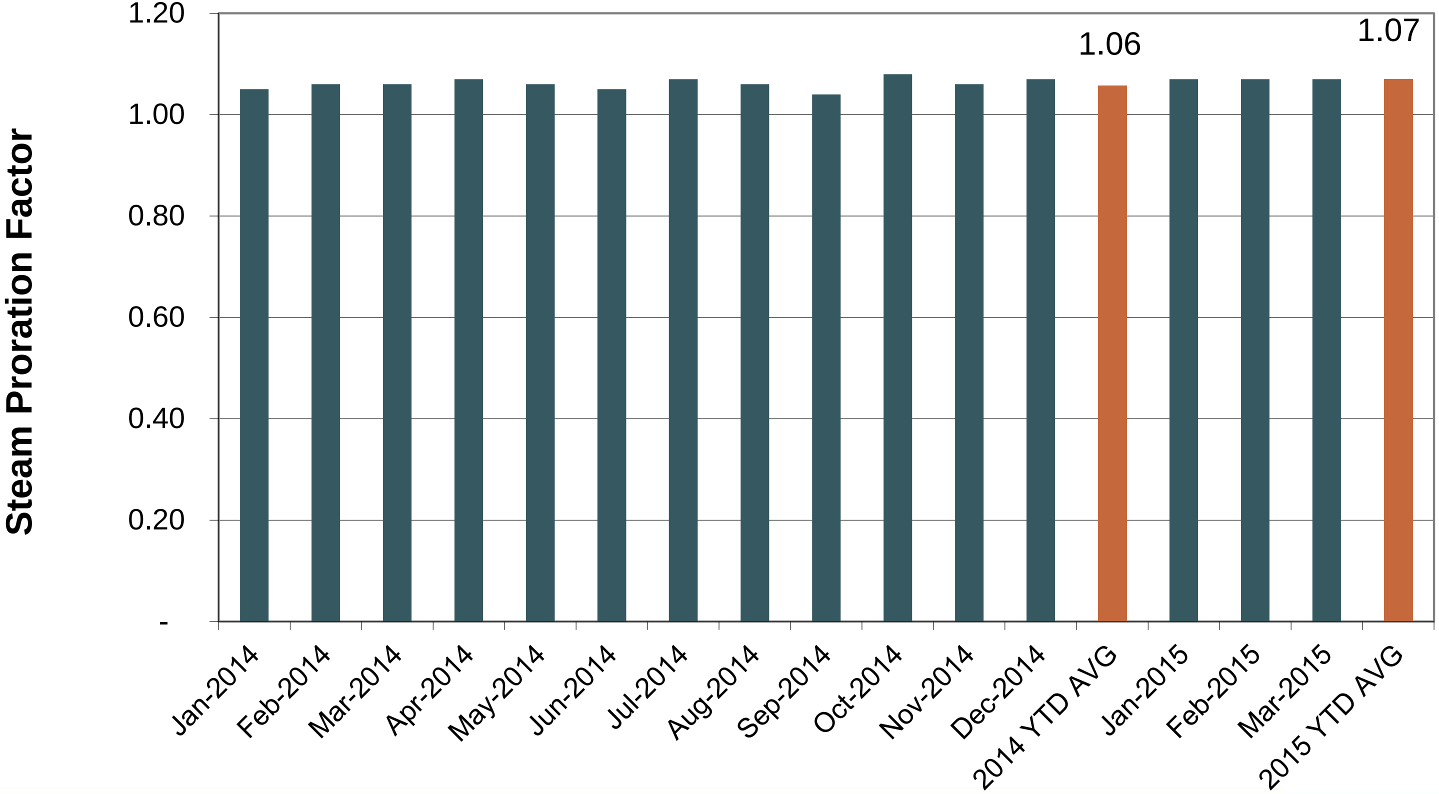
Proration factors



Proration factors



Proration factors



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MARP – New measurement technology

Cenovus continually focuses on evaluating new meter technologies

Water cut meters:

- Completed initial investigation and presented first results of water cut analysis by Delta C capacitance probe in the field. Further testing in store
- Investigating Weatherford's Red Eye as alternative to AGAR Corporation
- Investigating water cut via density differential by coriolis meter using known density curves at T & P for water and bitumen

Subsection 3.1.2 – 4) Water production (injection and uses)

Ben Lee

Process Engineer

Fresh and brackish sources

Fresh wells:

- •Two Quaternary wells (Empress Formation) at 09-17-076-06W4M
- •ESRD - Licensed for up to 5,000 m^3/day
- •TDS = 500-600 mg/L

Brackish water source wells:

•Historical

- •10-34A 1F1/13-35-075-06W4/00 TDS= 7,400 mg/L
- •10-34B 1F1/13-34-075-06W4/00 TDS= 7,200 mg/L
- •10-34C 1F1/15-27-075-06W4/00 TDS= 7,200 mg/L
- •10-3A 1F1/16-03-076-06W4/00 TDS= 4,600 mg/L
- •10-3B 1F1/02-03-076-06W4/00 TDS= 5,700 mg/L
- •10-27A 100/04-35-075-06W4/00 TDS= 11,600 mg/L
- •10-27B 100/13-27-075-06W4/00 TDS= 8,700 mg/L
- •10-27C 100/02-27-075-06W4/00 TDS= 12,100 mg/L

•Disposal reversal well

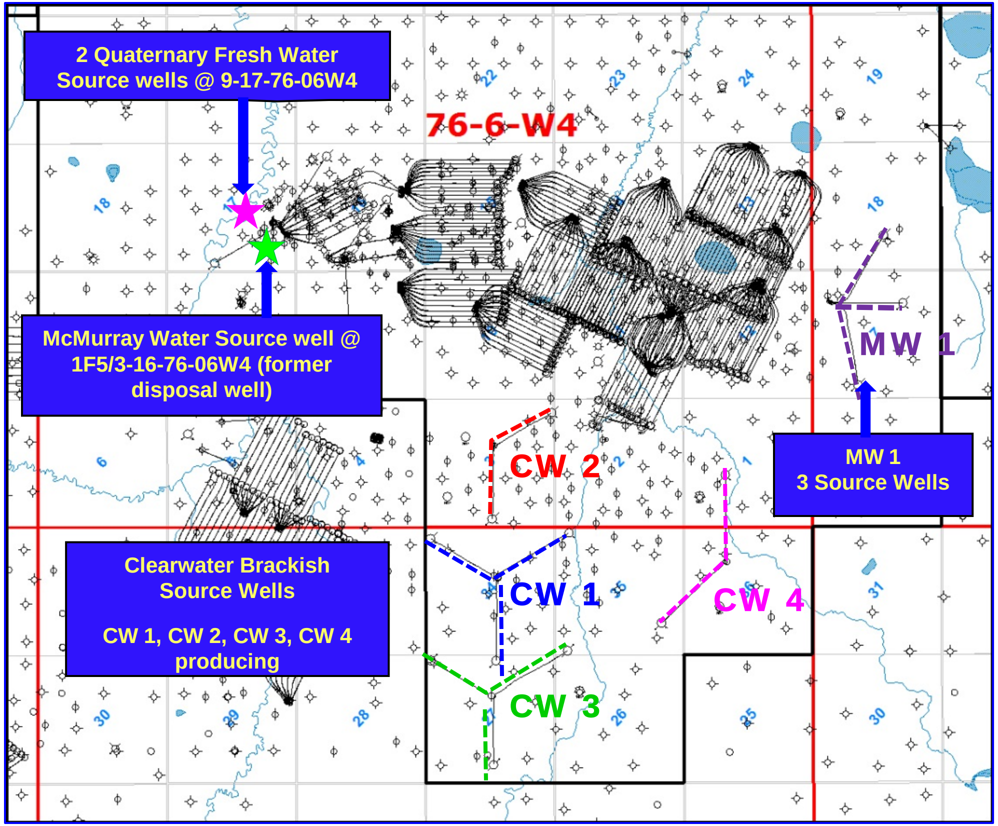
- •3-16 1F5/03-16-076-06W4/00 TDS= 2,300 mg/L

•2013

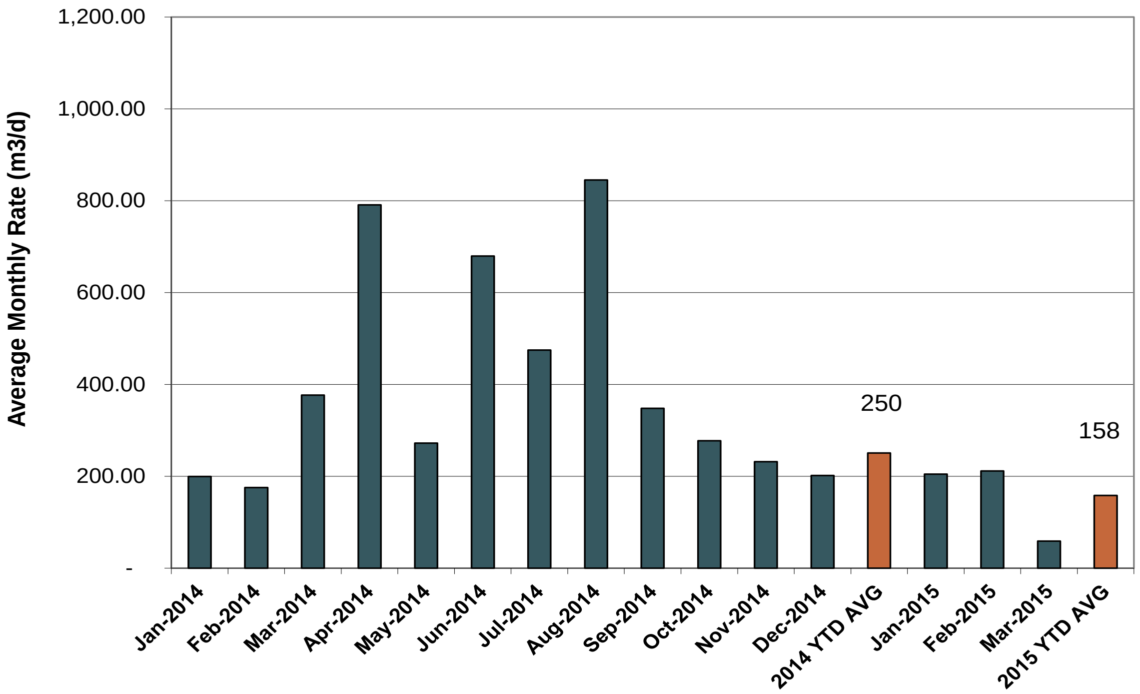
- •CW4-A 1F1/01-35-075-06W4 TDS= 13,400 mg/L
- •CW4-B 1F1/06-01-076-06W4 TDS= 9,400 mg/L

•New in 2014 (MW 1 wells-not used until Phase F startup)

- •1F1/07-18-076-05W4 Not sampled yet-expected TDS=>12,000mg/L
- •1F1/09-07-076-05W4 Not sampled yet-expected TDS=>12,000mg/L
- •1F1/03-07-076-05W4 Not sampled yet-expected TDS=>12,000mg/L



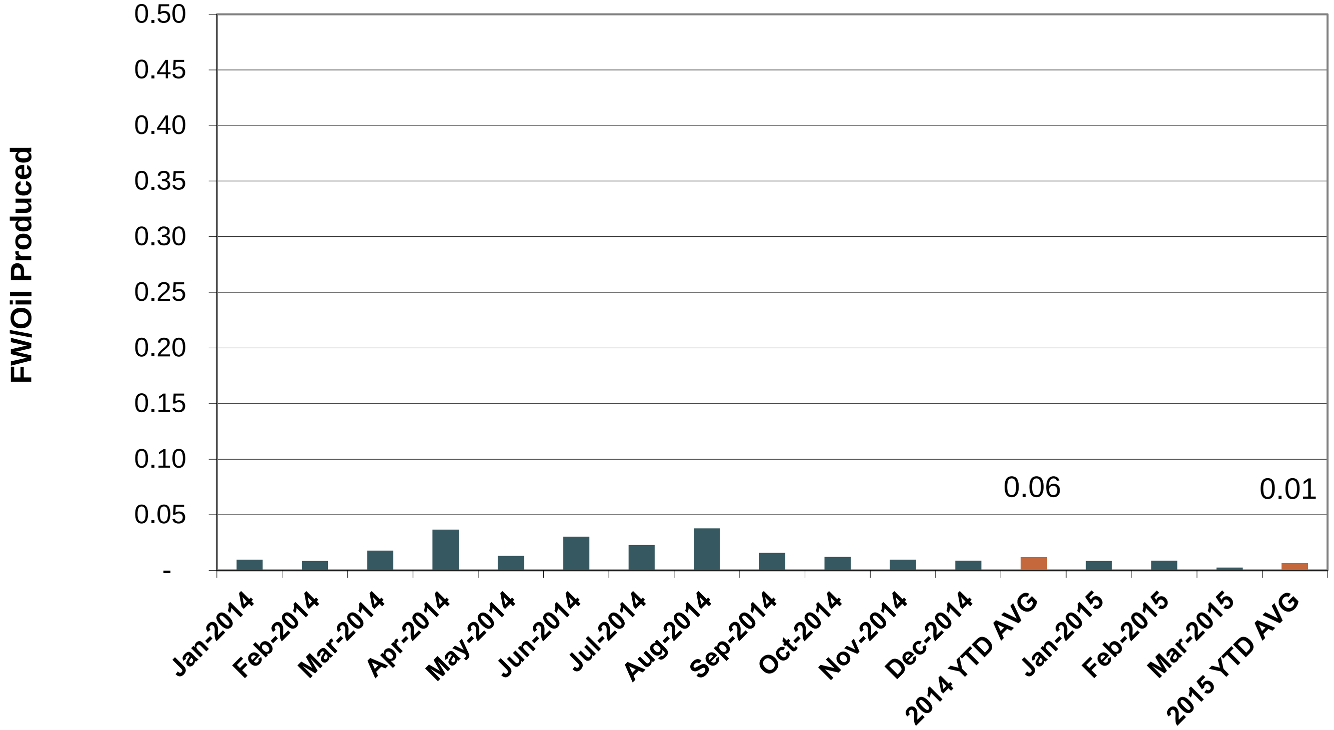
Fresh water use



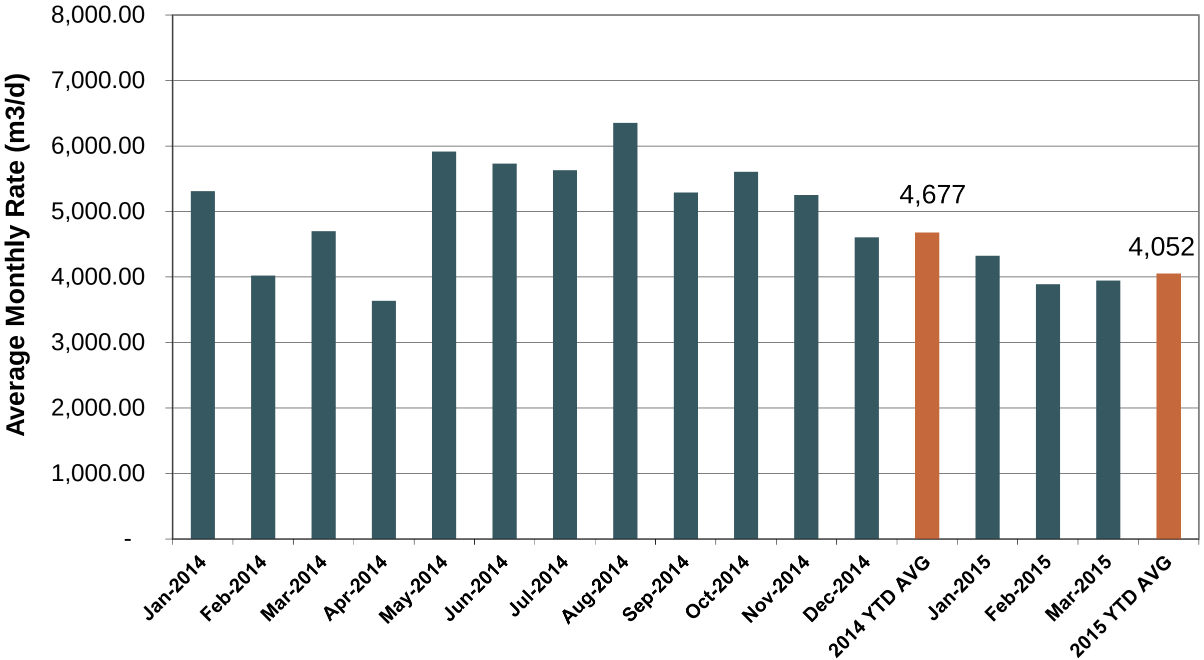
Uses:

- Includes camp and domestic use, utilities, seal flushes, etc. All attempts are made to minimize fresh water usage.
- Was used for make-up water for steam during commissioning and start up

Fresh water intensity



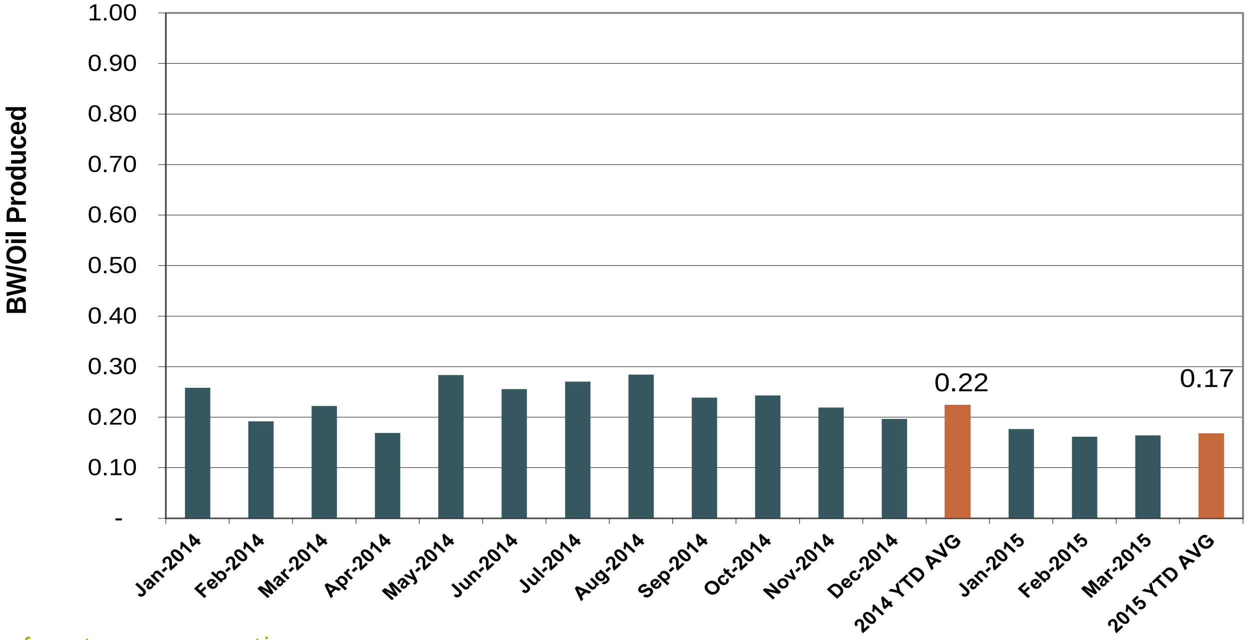
Brackish water use



Uses:

- Make-up water for steam generation
- Softened water used for slurry make-up, seal flushes etc.

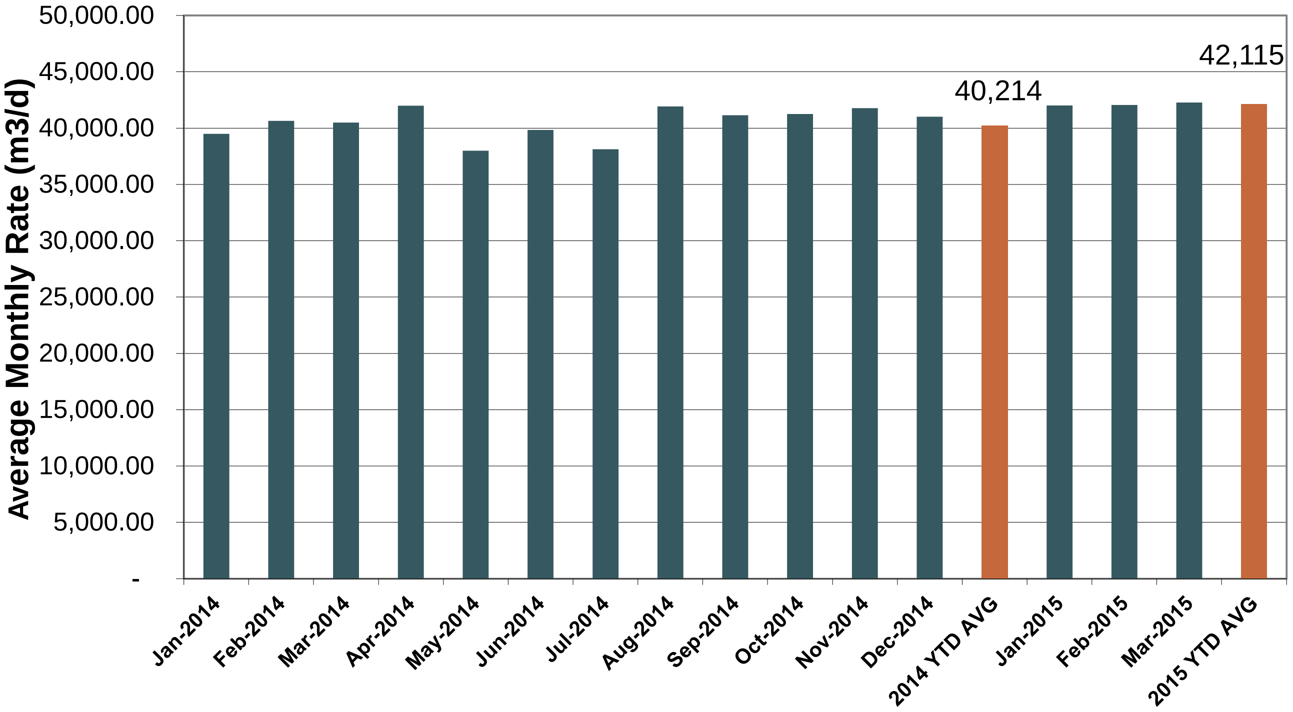
Brackish water intensity



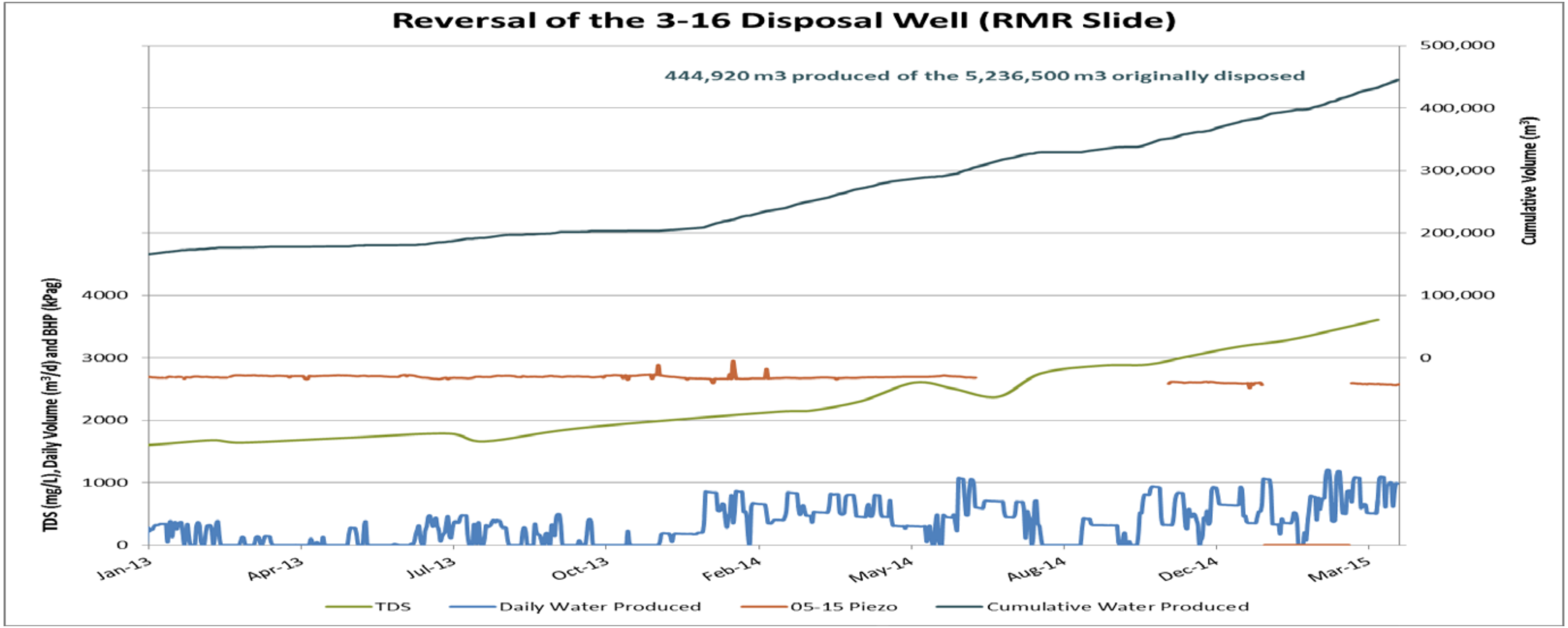
Uses:

- Make-up water for steam generation
- Softened water used for slurry make-up, seal flushes etc.

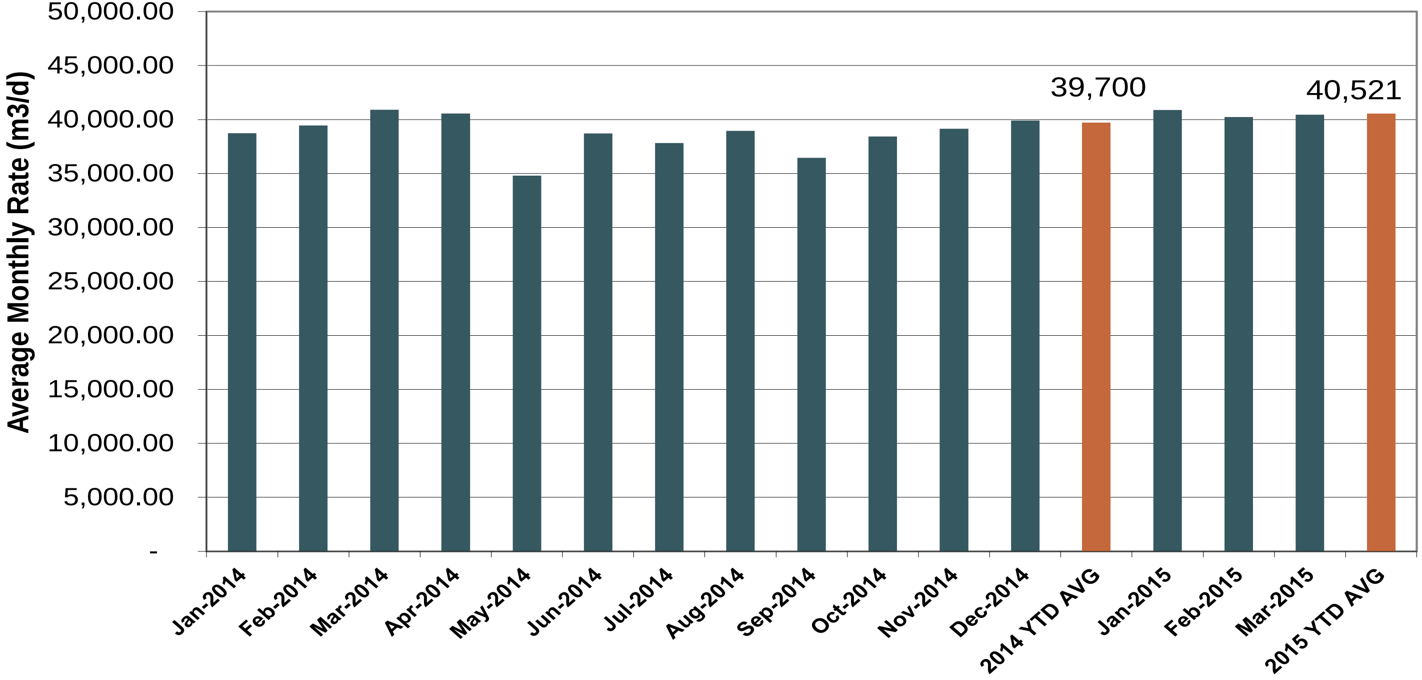
Produced water volumes



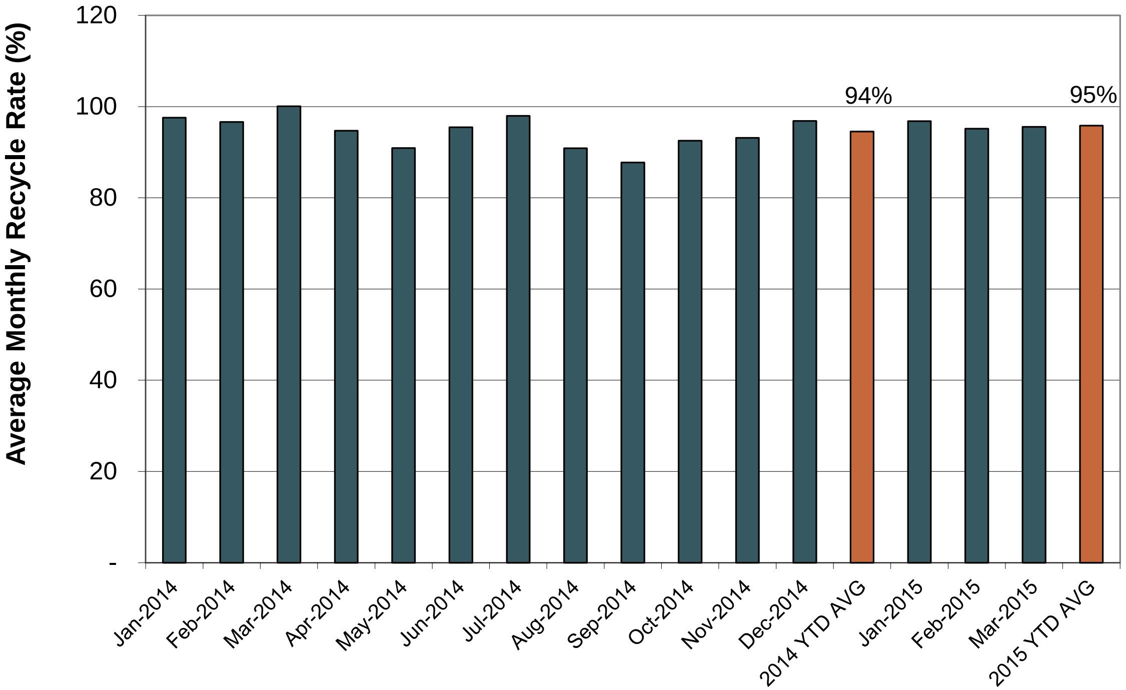
3-16 well reversal



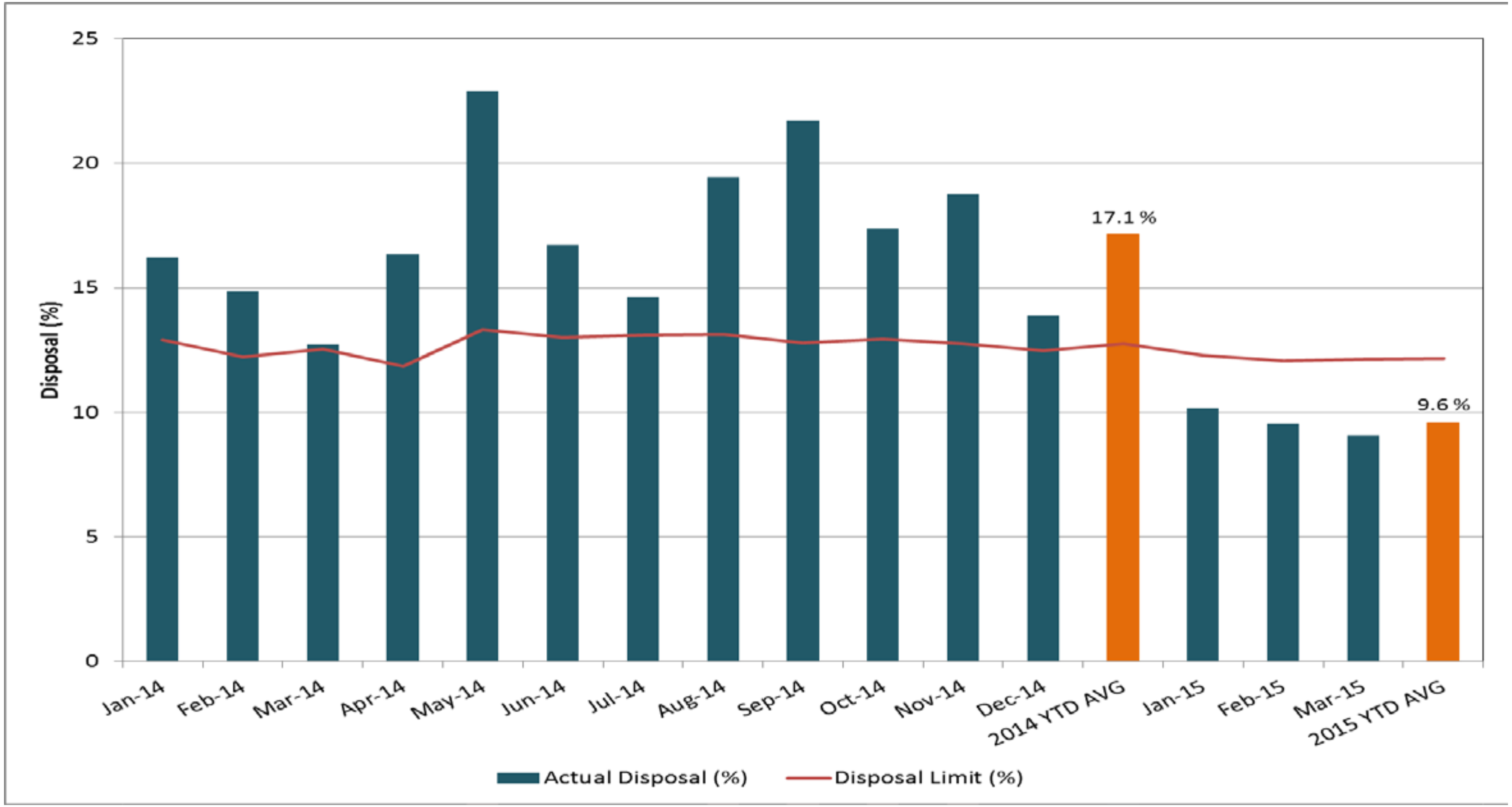
Steam volumes



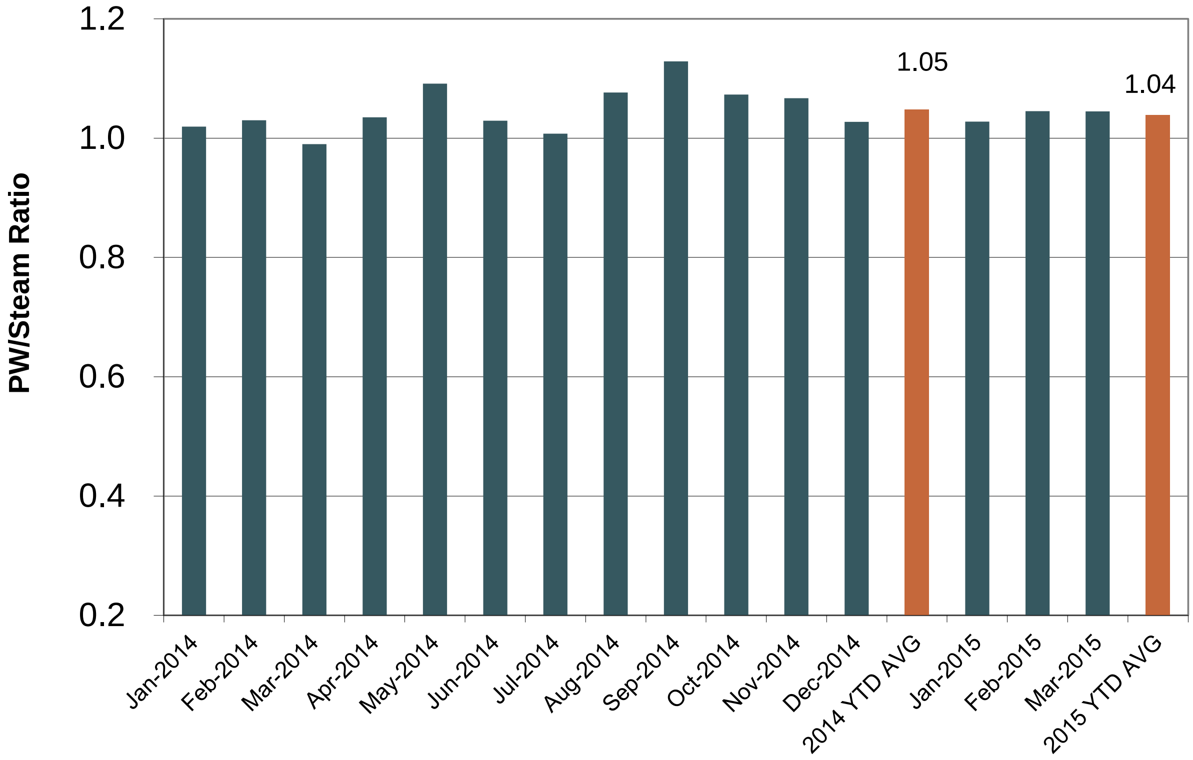
Water recycle ratio



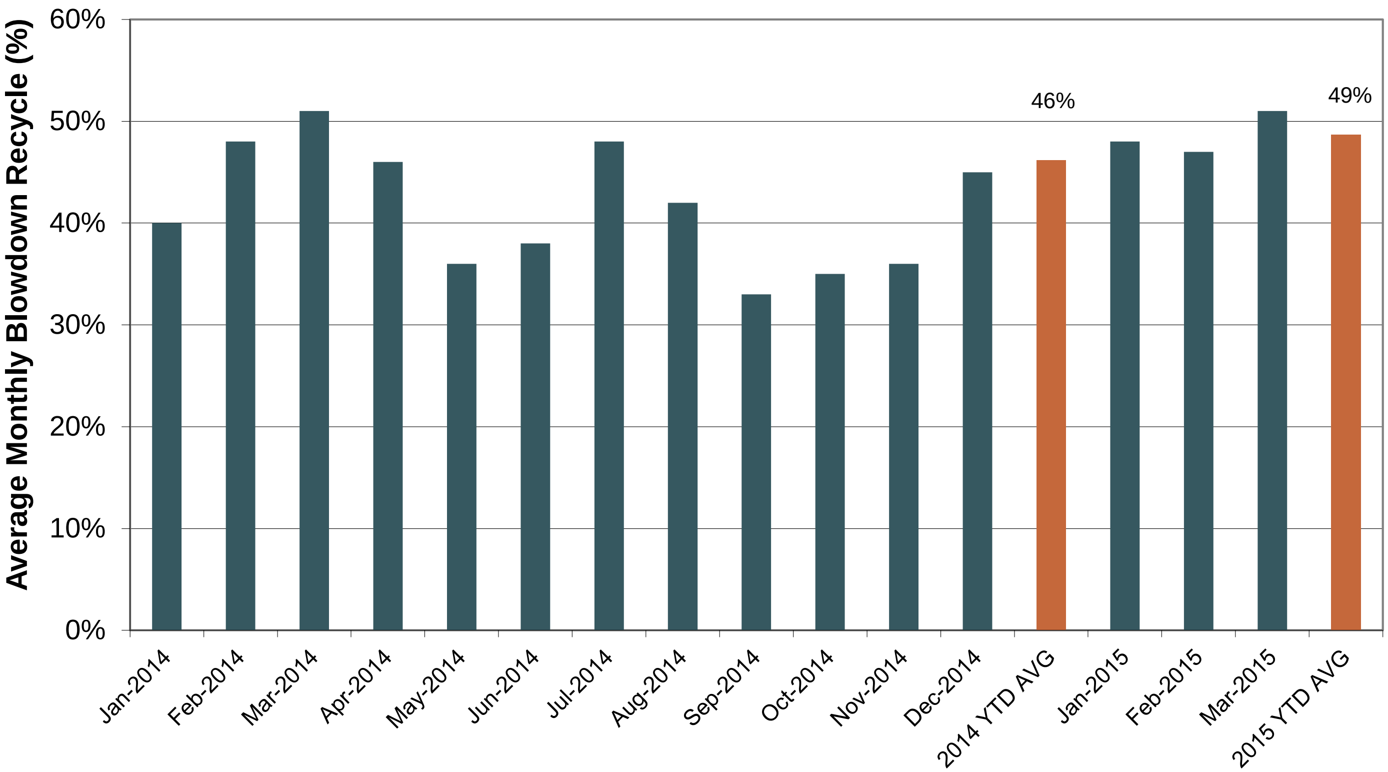
Directive 081 disposal limit



Produced water to steam ratio



Blowdown recycle



NOTE: BD Recycle volumes very dependent of PW: Steam ratio

Water disposal operations

Continue to inject into McMurray water sands at 15-35

Approval No. 9712 and 10627 (Class 1b Disposal)

Nine disposal wells (all Class 1b)

- Three disposal wells located near the facility (3-16-1, 4-16, and 7-16 – now abandoned);
- One well located near the facility (3-16-2) has been converted for disposal reversal
- Six disposal wells in service located at 15-35

15-35 disposal is main disposal location with local wells used as back-up

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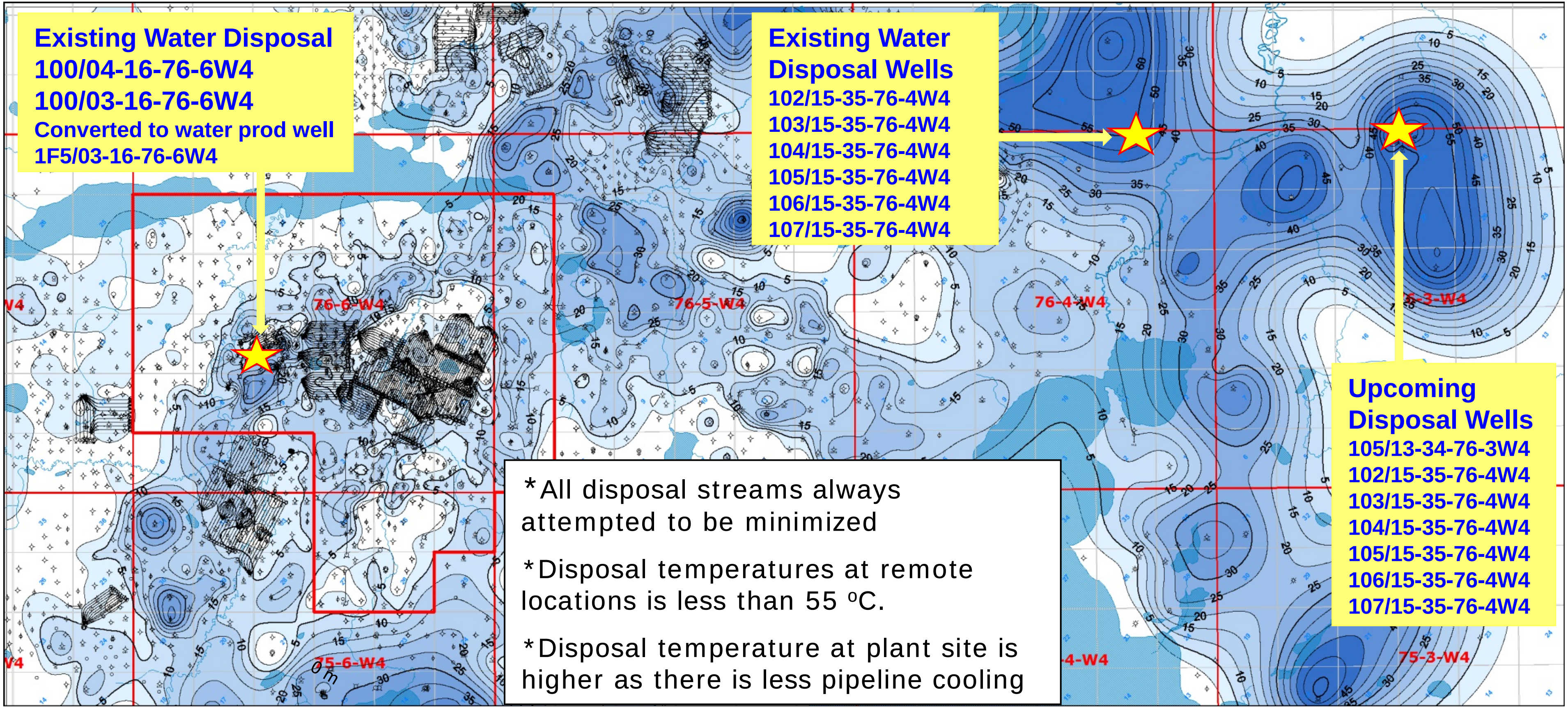
McMurray water disposal wells

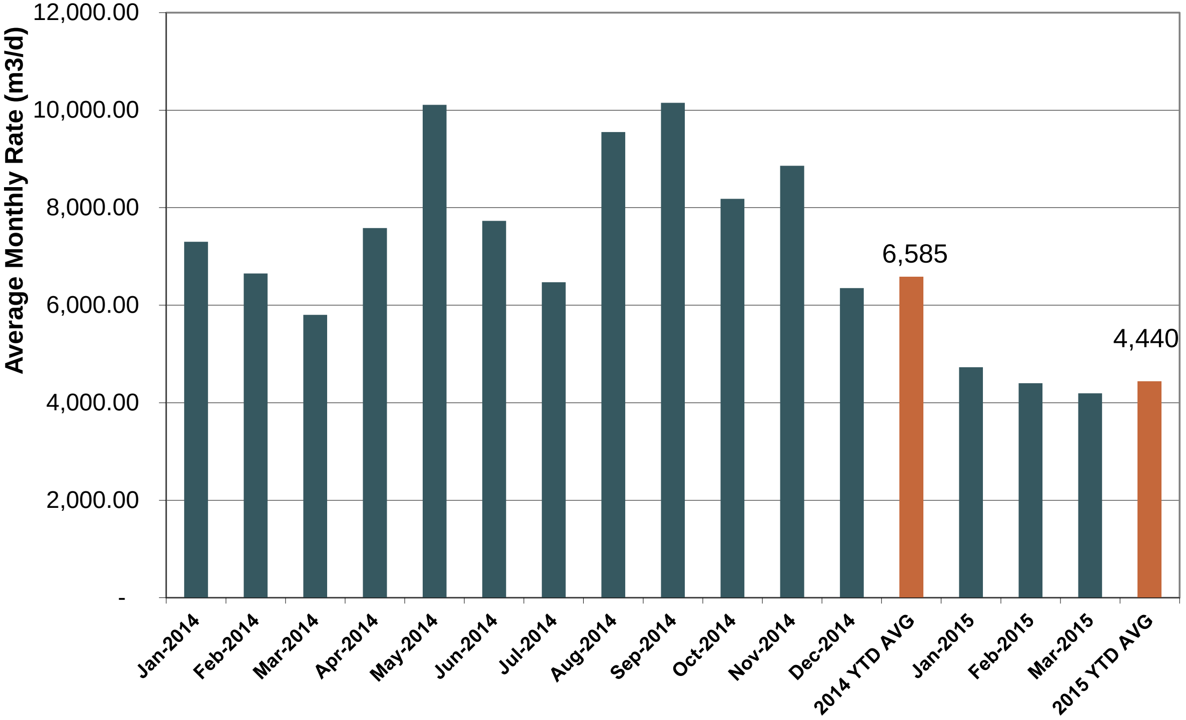


*All disposal streams always attempted to be minimized

*Disposal temperatures at remote locations is less than 55 ºC.

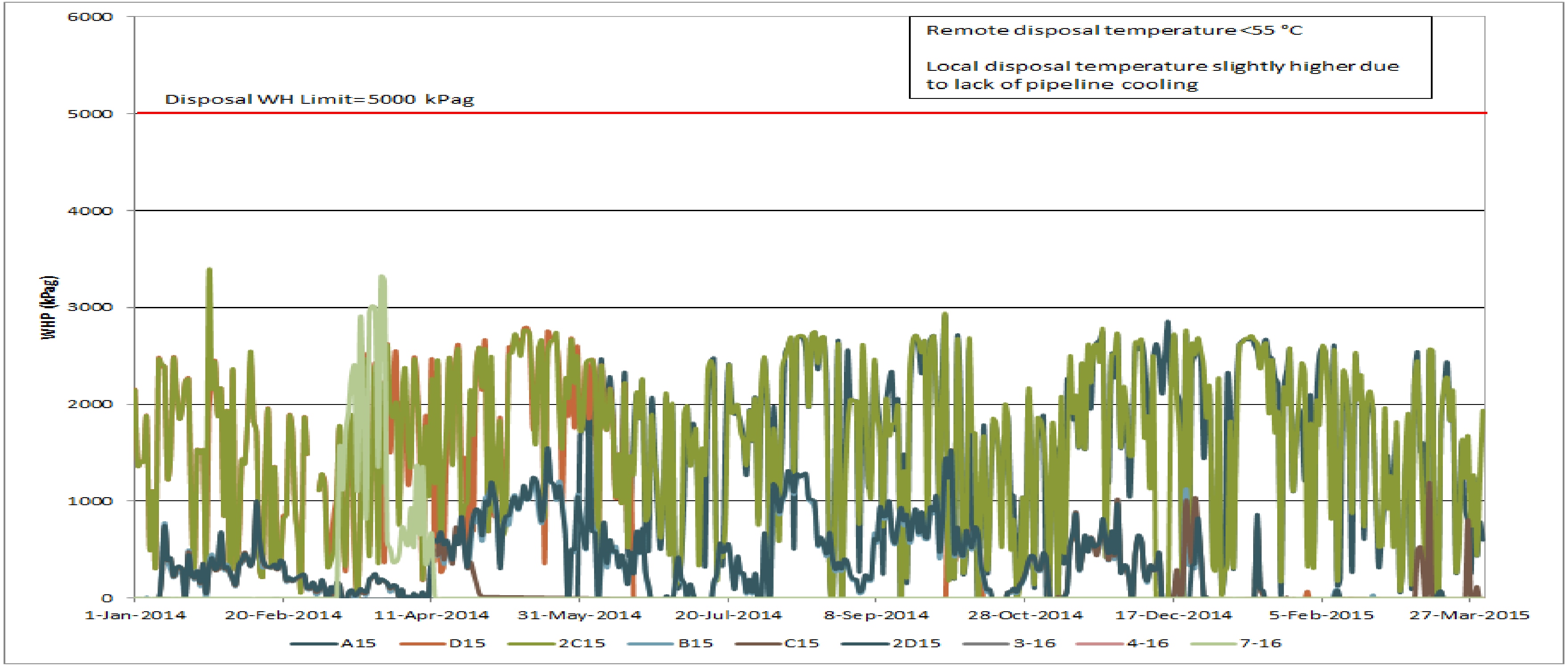
*Disposal temperature at plant site is higher as there is less pipeline cooling

Total disposal volumes (PW, RW, BD)

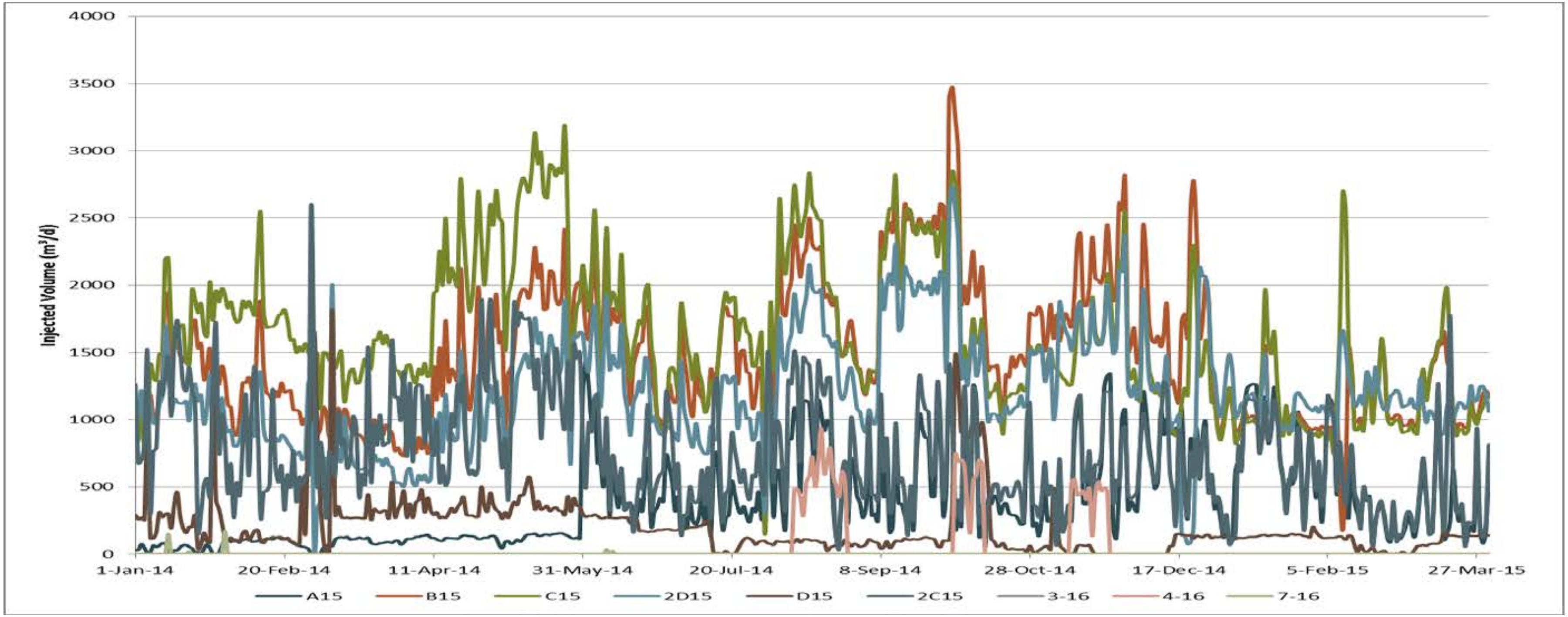


Notes: All disposal stream always attempted to be minimized. Specifically, blowdown recycle, regeneration optimization, and minimizing brackish makeup requirements to ensure the maximum amount of produced water can be used.

Disposal well head pressures



Disposal injection volume



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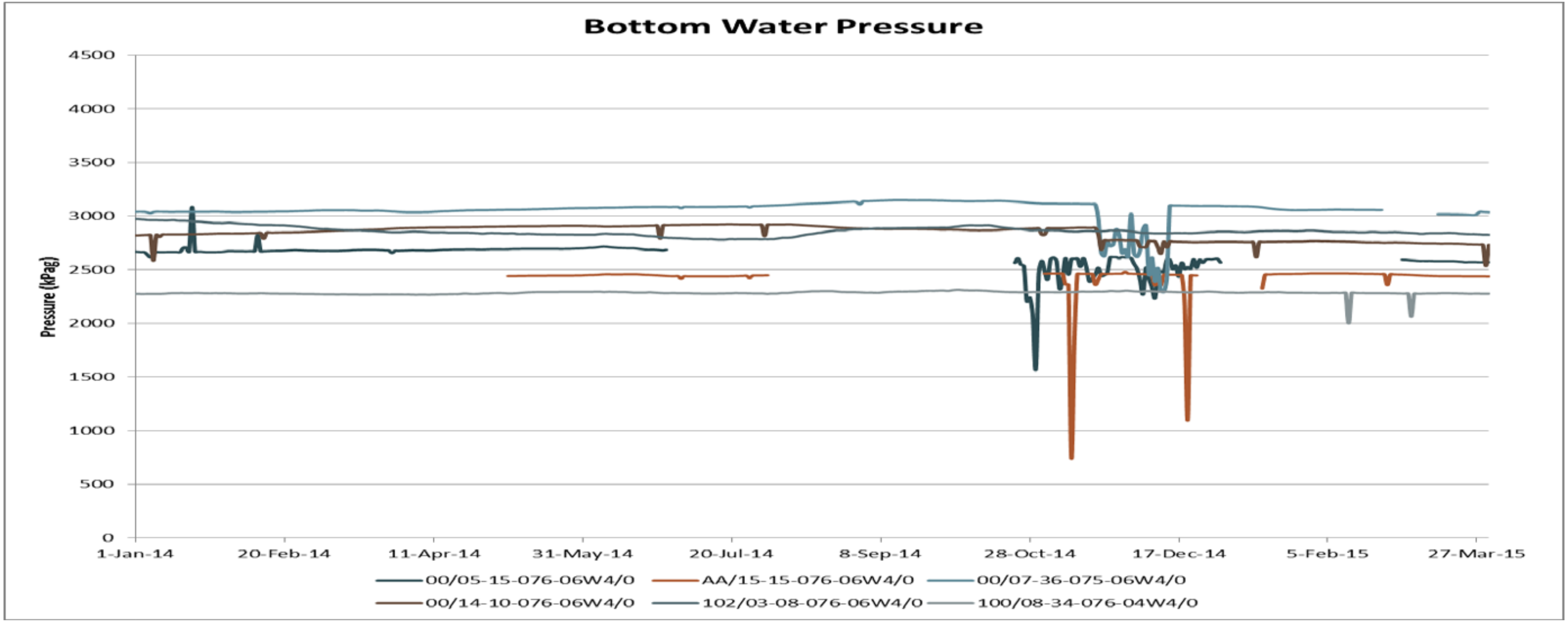
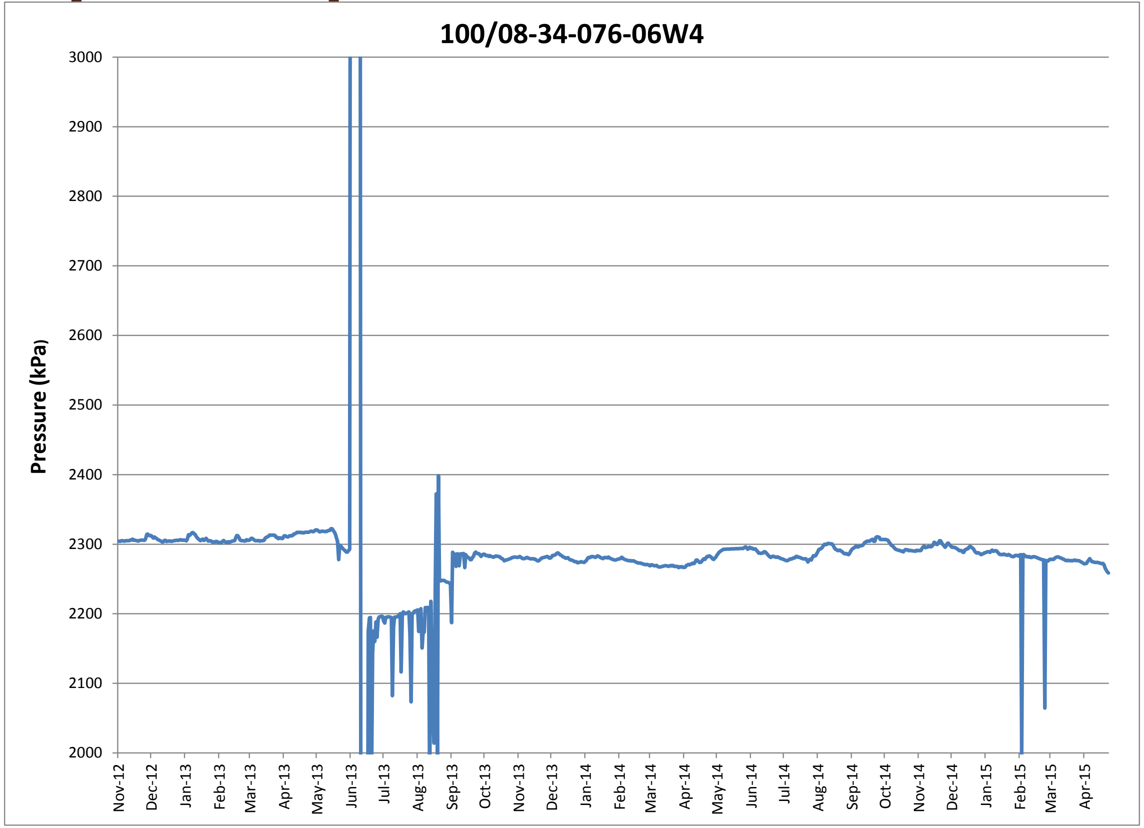
Water disposal operations



Water disposal operations cont'd



Waste disposal volumes

Reduced slop oil volume due to treating improvements with chemical optimization.

	2014	2013	2012
Slop Oil / Production Fluids (m^3)	82,241	157,155	74,262
Drilling Waste (m^3)	56,260	37,086	27,796
Lime Sludge (m^3)	15,279	23,759	10,437
Contaminated Soils (m^3)	187	310	1,511
Spent Scavenger (m^3)	5,346	2,975	1,932
Total	**159,313**	**221,285**	**115,938**

Waste disposal sites 2014

Facility	Total (m^3)
Absolute Env. Class Ia Disposal Well	1,063
Cancen New Sarepta Disposal Well	4,417
Newalta Elk Point	31,861
Newalta Hughendon	729
R.B.W. Edmonton	999
Tervita Bonnyville Landfill	986
Tervita Janvier Landfill	59,445
Tervita Lindbergh Cavern	67,350
Tervita Mitsue	274
Tervita Unity, SK Cavern	311
TOTAL (m^3)	**167,434**

Cenovus Christina Lake trucks all disposal waste to licensed third party facilities

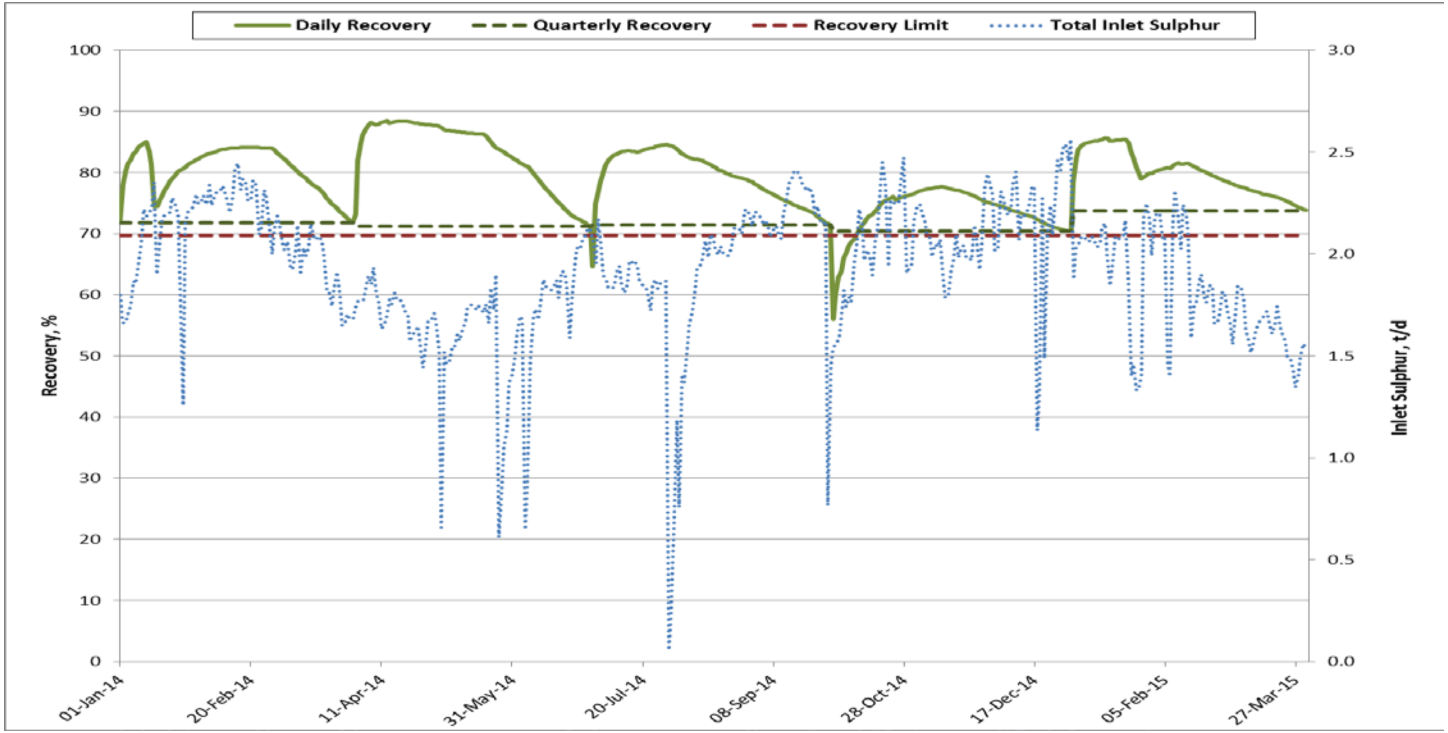
Subsection 3.1.2 – 5) Sulphur production

Ben Lee

Process Engineer

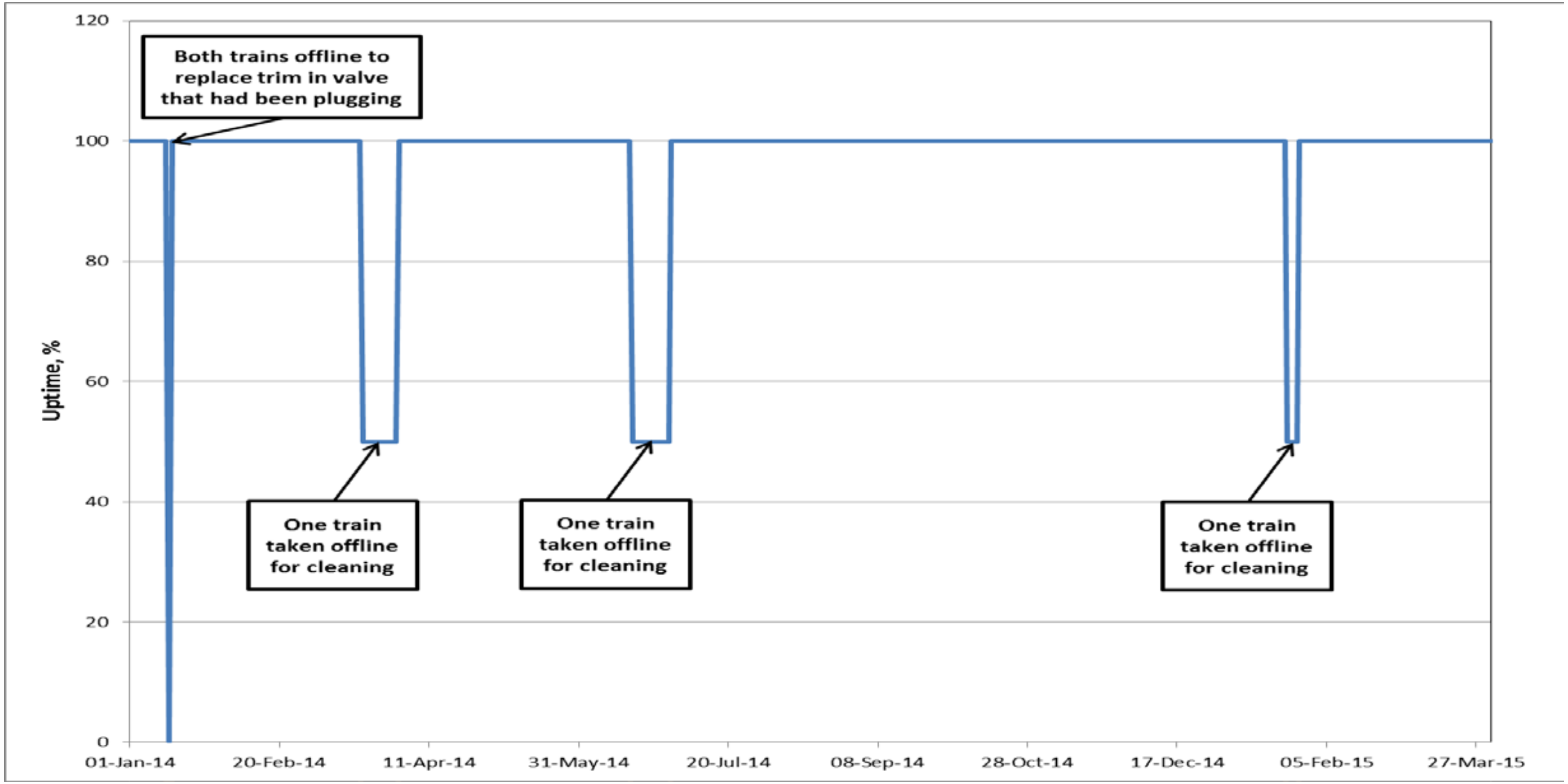
cenovus ENERGY

Scavenger recovery details



Quarter	Recovery
Q1 2014	71.8%
Q2 2014	71.2%
Q3 2014	71.4%
Q4 2014	70.4%
Q1 2015	73.8%

Scavenger uptime details

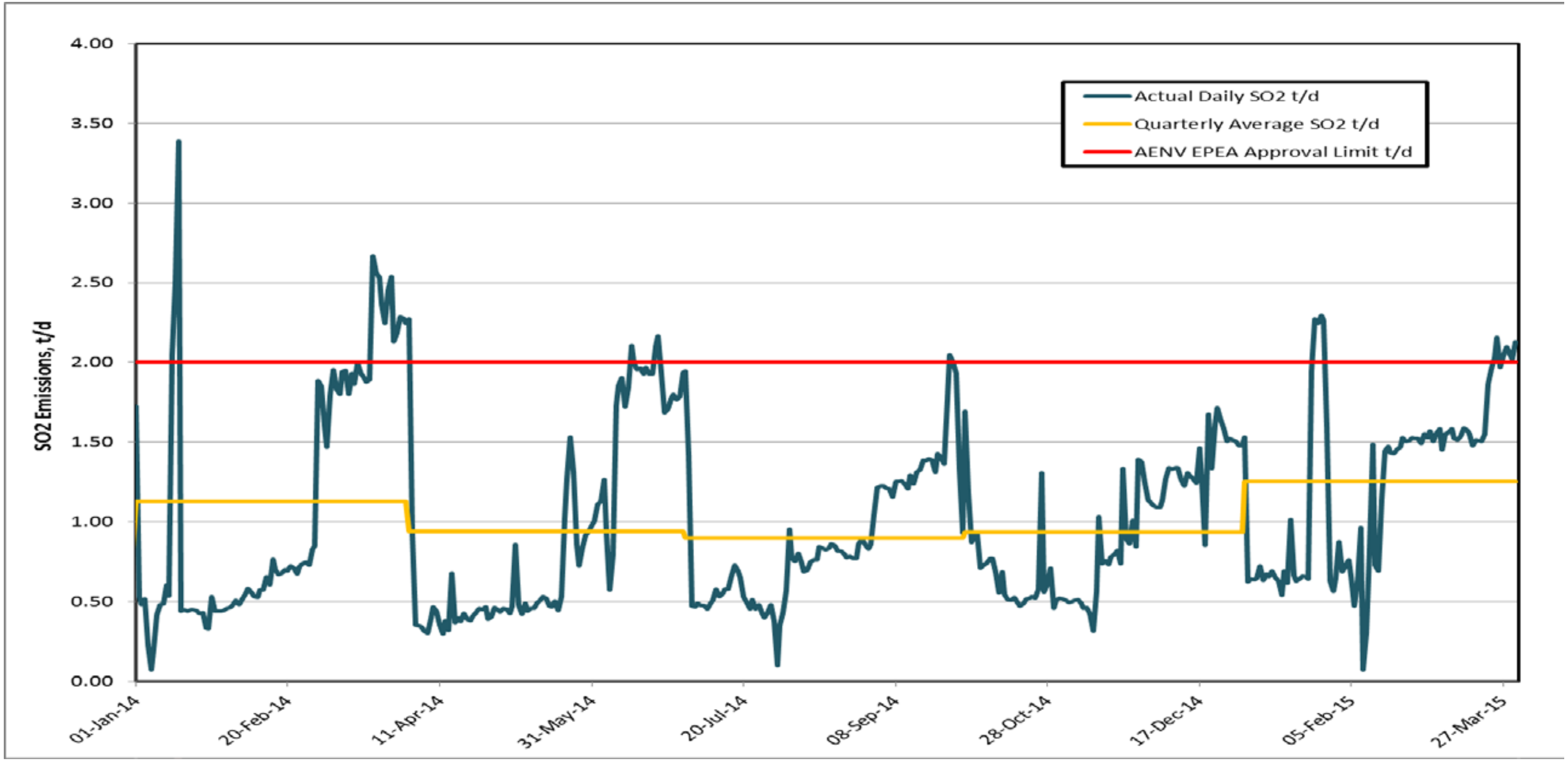


Sulphur recovery operation

Preventative measures

- Chemical injection continues to be operated in counter current configuration
- Each train is on a 6-12 month PM to be cleaned (contactor, internal distributor, outlet separator demister inspected)
- Cleaning frequency determined based on process monitoring (pressure drop, spent chemical quality, gas temperature)

SO_2 emissions



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Subsection 3.1.2-5c)
June 25, 2015

Ambient air quality monitoring

Passive exposure monitoring

As per the Approval (Table 3.3), prior to commencing operation of Phase E, Christina Lake was required to maintain a network of four passive monitoring exposure stations to obtain monthly static exposures of H2S and SO2. After Phase E commenced operation, i.e., in June 2013, 12 passive monitoring exposure stations must be maintained.

Passive exposure monitoring was conducted for SO2 and H2S at the AESRD approved passive monitoring locations from January through December, 2014.

The passive monitoring results in 2014 did not identify any significant air quality issues related to Plant operations.

Continuous air quality monitoring

CLSF is required in the Approval (Table 3.3) to maintain one continuous ambient air monitoring station 12 months per year to measure ambient levels of SO_2, H_2S, and NO_2 concentrations in addition to wind speed and wind direction.

In 2014, continuous air quality monitoring was conducted from Jan 1 to December 31 by Maxxam Analytics. The continuous ambient air monitoring station is located approximately at 03-16-076-06-W4M. This location is the same as the passive monitoring station C10. Parameters measured were SO_2, H_2S, NO_2, wind speed and direction.

There were no operational issues relating to the ambient air monitoring equipment during the monitoring period.

The continuous ambient air quality monitoring in 2014 did not identify any significant air quality issues related to Plant operations.

No criteria exceedances were noted in either monitoring program

Ambient monitoring trailer for 2014 monthly summary results

	Parameter	Maximum Reading for 2014 (ppbv)	Date of Maximum Reading in 2014	Limit (ppbv)
SO_2	1 hr average	20	June 30	172
	24 hr average	3.3	Jan. 15, Oct. 2	48
H_2S	1 hr average	3	Oct. 22, Dec. 11	10
	24 hr average	1.4	Dec. 11	3
NO_2	1 hr average	58	Dec. 3	159

- As was noted for the period 2010 to 2013, in 2014, there were no ambient NO_X, SO_2 or H_2S readings above the Alberta Ambient Air Quality Objective (AAAQO).
- Maximum 1 hour and 24 hour average values for SO_2, H_2S, and NO_2 for 2014 are listed above.

Subsection 3.1.2 – 7) Environmental issues

Michelle Camilleri

Sr. Environmental Advisor

2014 Compliance issues and amendments

Approval number	Amendments	Compliance issues
EPEA Approval 00048522-00-05	"Plant" definition amended to include TWP 75	No
EPEA Approval 00298224-00-00	No	No
Water Act Approval 00265924-00-01	No	No
Water Act License 00267617-00-02	No	No
Water Act License 00285141-00-01	No	No
Water Act License 00082524-00-06	Amended to include additional water source uses	No
Water Act License 00343057-00-00	No	No
Water Act License 00293633-00-00	No	No

Monitoring programs

Monitoring program	Progress and results
Air quality monitoring	Air emissions increased in 2014. This was a direct result of Phase E operating at full capacity for the full calendar year.
Groundwater monitoring	No material changes in 2014
Thermal metal mobilization monitoring	Well chemistry showed the influence of cement infiltration, wells were cleaned out Q3 2014. No chemical or temperature impacts related to thermal effects were detected in 2014.
Soil monitoring program	Soil Monitoring Program Proposal authorized April 23, 2014 and second monitoring event completed.
Wildlife and caribou mitigation and monitoring programs	AGP Monitoring, Winter Track and Remote Cameras, Amphibian and Breeding Bird Community Response to Development monitoring completed in 2014. Three Year comprehensive report due May 15th, 2015.
Wetland monitoring program	No material changes in 2014

Monitoring programs continued

Monitoring program	Progress and results
Reclamation monitoring Ppogram	Deferred until December 31, 2016. No permanent reclamation has occurred to date, however Cenovus continues to evaluate opportunities for permanent reclamation at the Project, including well pads.
Wetland reclamation trial program	Deferred until a candidate site becomes available
Project level conservation, reclamation and closure plan	Deferred until December 31, 2016

Environmental initiatives

The regional multi-stakeholder forums that Cenovus was involved with in 2014 include:

- Cumulative Effects Management Association (CEMA) Land Working Group
- Canadian Oil Sands Innovation Alliance (COSIA): Linear Deactivation Program (LiDEA)
- Joint Canada-Alberta Oil Sands Monitoring (JOSM)
  - Wood Buffalo Environmental Association (WBEA)
  - Alberta Biodiversity Monitoring Institute (ABMI)
  - Regional Aquatics Monitoring Program (RAMP)
- Industrial Footprint Reduction Options Group (iFROG)

Subsection 3.1.2 – 8)
Statement of compliance

Chris Grant

Specialist

(Regulatory Audit & Compliance)

2014 Compliance status

Maintain and track compliance

- Incident Management System (IMS)
- Centrac Database for commitment management
- Internal Regulatory Compliance Audit Team
- Dedicated onsite Environmental Monitoring and Stewardship Advisors
- Routine inspections and audits
- Raise awareness through training
- Establish consistent management processes

Cenovus FCCL Ltd. believes existing CLTP operations are in compliance with AER approvals and regulatory requirements.

Subsection 3.1.2 – 9)
Statement of non-compliance

Chris Grant

Specialist

(Regulatory audit & compliance)

2014 Non-compliances – AER / AESRD

Date	Non compliance / self-disclosure	Follow-up
2014-04-03	Notice of Low Risk Noncompliance - Commencement of Drilling without Notice @ 10/4-2-76-6W4 W0461895	Compliance achieved on May 1, 2014
2014-04-01	Unsatisfactory Low Risk Drilling Operations @ 9-11-76-6W4 - Notification of Commencement of Drilling (Spud) - Cenovus FCCL did not notify the appropriate Field Center within 12 hours of the commencement of the drilling of a well.	Compliance achieved on April 11, 2014
2014-03-15	Drilling Mud Releases to Surface during Utility Corridor Directional Drilling Project (SE-17-076-06W4M)	Clean-up complete
2014-01-10	Unsatisfactory Low Risk Drilling Operations @ 9-3-76-6W4 - At the time of the inspection, the shop certifications for the spool in use were not pressure tested in accordance with Appendix 5 of Directive 36.	Compliance achieved on February 3, 2014
2014-01-10	2.5m^3 spill of floc water (01-11-076-06W4)	Clean-up Complete
2014-01-08	Trespass of the 1AA/12-13-76-5W4 well whereby the well was drilled 1.1m beyond the allowable 15m overhole.	Compliance achieved on 30-Jan-2014
2014-01-07	Release of 3m^3 of strip water at strip water site (NE-06-076-06-W4M)	Clean-up Complete

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2014 Non-compliances – AER / AESRD Con’t

Date	Non-compliance / self-disclosure	Follow-up
2014-12-22	Site entry to conduct hill cut without AER Approval (2-25-76-6W4)	Compliance achieved
2014-11-13	5.3 m^3 of Propylene Glycol Spill	Clean-up complete
2014-11-08	1.5m^3 of clay material placed off disposition (07-17-076-06 W4M)	Clean-up complete
2014-09-11	Packer Testing @ 102/7-16-76-6W4 W0249293 - Failure to complete necessary reporting of required packer testing by September 1 of each year	Compliance achieved on December 11, 2014
2014-07-03	Trespass @ 6-2-76-6W4 0450645	Compliance achieved on December 23, 2014
2014-06-8	Fresh water release from hydrotest of pipeline	Clean-Up complete
2014-04-27	Sedimentation released off disposition (06-15-076-06W4M)	Clean-up complete
2014-04-06	Surface water and sedimentation released off disposition (SE-14-076-06W4M)	Clean-up complete

Subsection 3.1.2 – 9)
Future plans

Major activities and target dates

Phase	Regulatory			Production capacity (bbl/d)	
	Filing	Approval	First steam	Incremental	Total
A	Q1 1998	Q1 2000	Q2 2002	10,000	10,000
B	Q2 2005	Q4 2005	Q2 2008	8,800	18,800
C	Q3 2007	Q2 2008	Q2 2011	40,000	58,800
D	Q3 2007	Q2 2008	Q2 2012	40,000	98,800
E	Q3 2009	Q2 2011	Q3 2013	40,000	138,800
F	Q3 2009	Q2 2011	2016	40,000	178,800
G	Q3 2009	Q2 2011		40,000	218,800
FG Amendment	Q4 2012	Q4 2012		20,000	238,800
CDE 2nd Stage OTSG	Q4 2012	Q3 2013	2015	21,200	260,000
H	Q1 2013	2015		50,000	310,000

Filed applications

Category	Application	Date filed
3	Phase H and eastern expansion	March, 2013
1	Emulsion circulation during unscheduled plant shutdown	April, 2014
2	B01/B02 rampdown/blowdown pilot	April, 2014
1	Phase D aerial cooler equipment change	June, 2014
2	Casing gas re-injection B03-7	March, 2014
2	Air co-injection trial B05-8	July, 2014
2	L pad trajectory amendment	June, 2014
2	Producer well length extension (B10-1 to B10-5)	May, 2014
2	A01 permanent blowdown	August, 2014
2	A02-2 SAP methane injection to demonstrate butane recovery	August, 2014
2	B13 well length extension	December, 2014

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Filed applications

Category	Application	Date filed
1	Phase CDE oil debottleneck	Feb, 2015
1	Multi directional wells SAGD enhanced lengths	March, 2015
2	Non-condensable gas ventilation well (B08 or H01)	March, 2015
2	L09, J07, L07 well length extension	March, 2015

Potential future applications

Category	Application	Planned filing date
2	Sustaining pad trajectory amendment	Q3 2015
2	B03/B04 methane co-injection	Q3 2015
3	Development area expansion	Q4 2015

Changes to plant design or water treatment strategy

Current plans are consistent with existing approvals

Any future changes will be communicated via notifications or amendments as required

Phases F and G amendment incorporates “cogeneration” into the CLTP

- Power generated will supply onsite operations

The following applications will have the potential to improve CLTP current water metrics

- CDE 2nd Stage OTSGs project
- Phase H project application