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

Subsurface
June 15, 2016

cenovus ENERGY

# Oil & gas and financial information

Oil & gas information

The estimates of reserves and contingent resources were prepared effective December 31, 2015 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, 2015 and in our Statement of Contingent and Prospective Resources for the year ended December 31, 2015, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

There is uncertainty 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.

<u>Total bitumen initially-in-place (BIIP) estimates</u>, 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. <u>Petroleum initially-in-place (PIIP) estimates for Pelican Lake</u> 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 presentation contains information in compliance with:

*AER Directive 054 - Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes*

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. The 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., including information regarding contingent resources, is available in our Annual Information Form for the year ended December 31, 2015 and in our Statement of Contingent and Prospective Resources for the year ended December 31, 2015 at cenovus.com.

# Subsection 3.1.1-1)
# Brief background

cenovus ENERGY

# About Cenovus

**TSX, NYSE | CVE**

| | |
|---|---|
| Enterprise value | C$18 billion |
| Shares outstanding | 833 million |
| 2016F production | |
| Oil sands | 151 Mbbls/d |
| Conventional | 54 Mbbls/d |
| Total liquids | 205 Mbbls/d |
| Natural gas | 385 MMcf/d |
| **Total production** | **269 MBOE/d** |
| 2015 proved & probable reserves | 3.8 BBOE |
| Bitumen | |
| Economic contingent resources* | 9.3 Bbbls |
| Lease rights** | 2.0 MM net acres |
| P&NG rights | 4.1 MM net acres |
| Refining capacity | 230 Mbbls/d net |

Values are approximate. Forecast production based on February 11, 2016 guidance.
*See advisory. **Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignee's behalf.

# 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

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

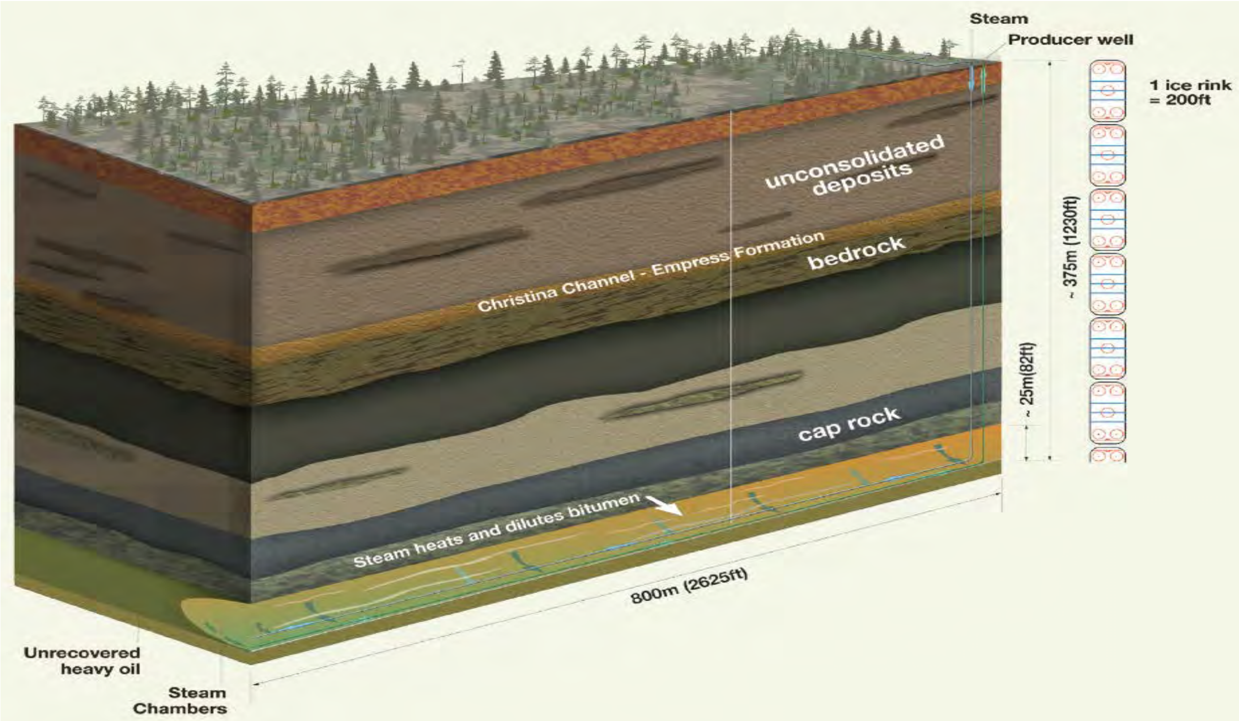
Q4 2013 CDE Debottleneck amendment

Q4 2015 Approval of phase H and eastern expansion amendment

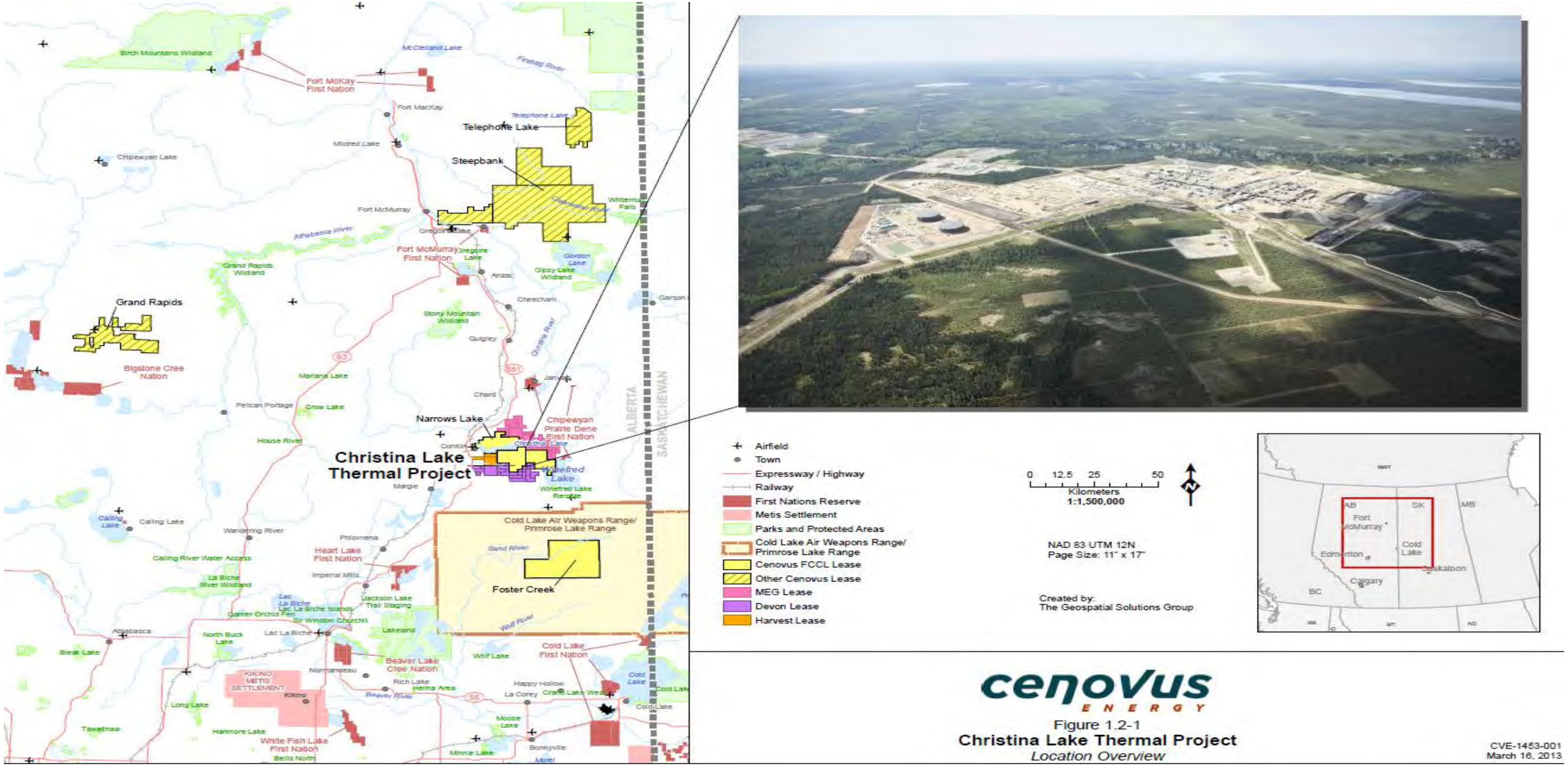
Q4 2015 CDE Debottleneck first steam

# Recovery process

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

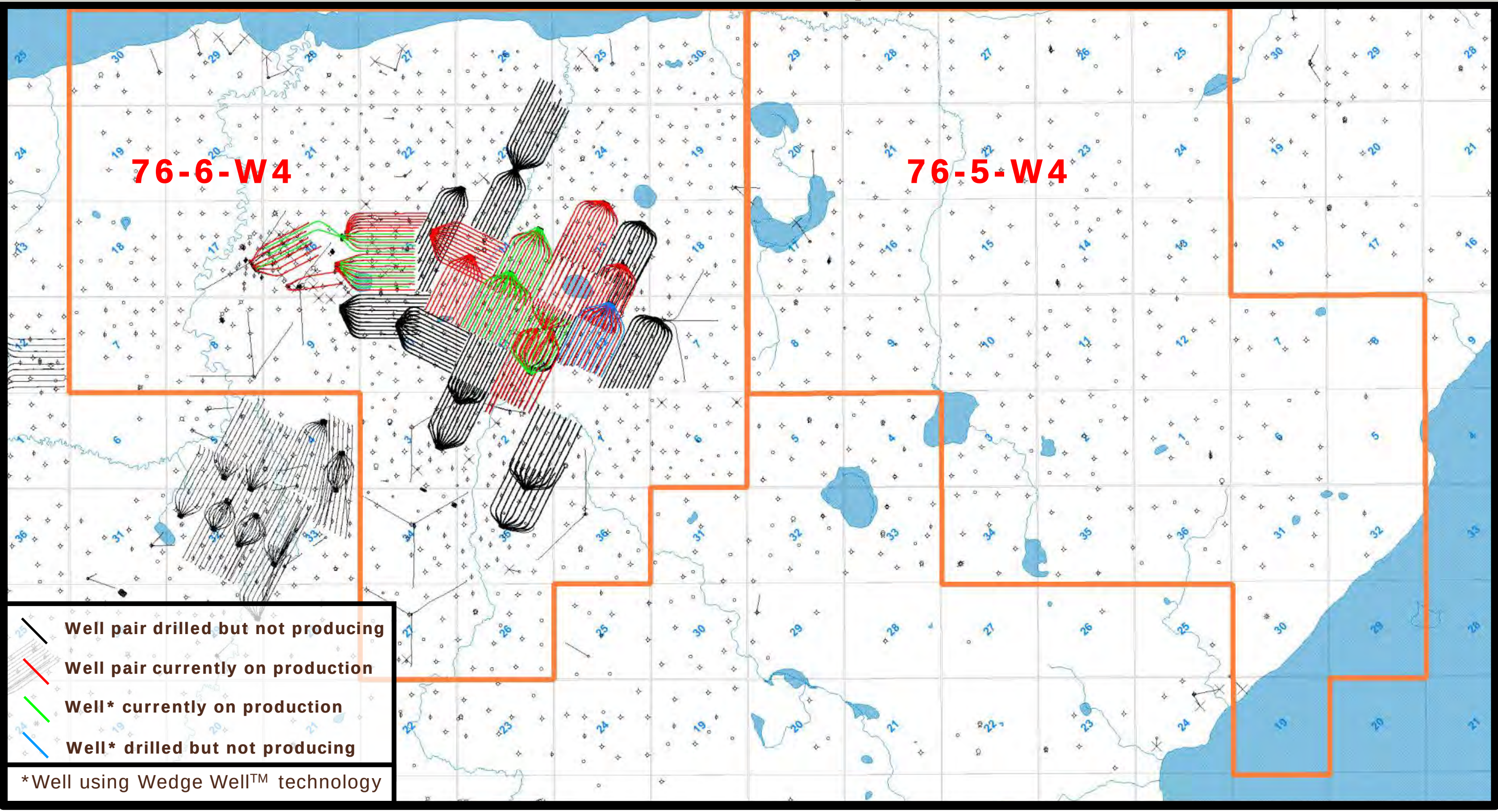


# Area Map



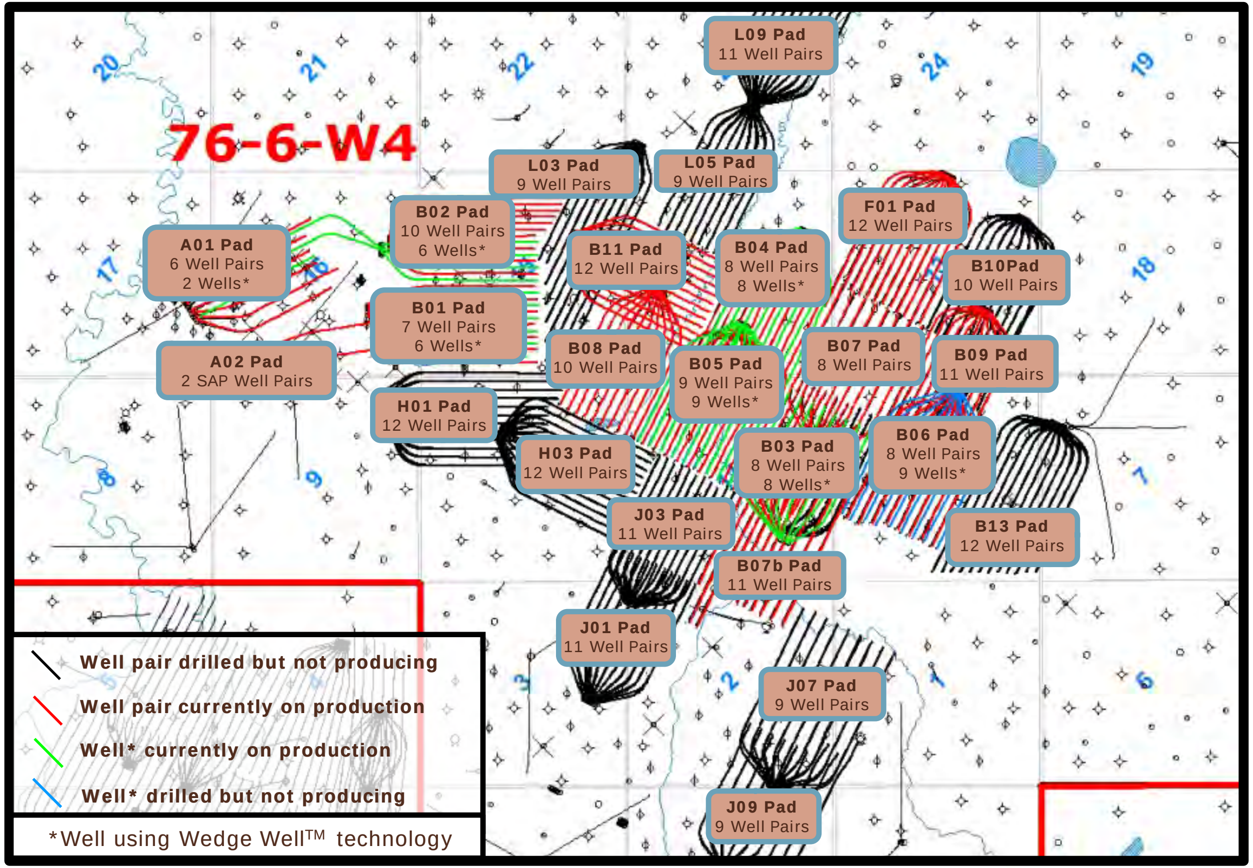
Birch Mountains Wildland
Fort McKay First Nation
McClelland Lake
Firebag River
Fort MacKay
Telephone Lake
Mildred Lake
Chipewyan Lake
Steepbank
Fort McMurray
Athabasca River
Fort McMurray First Nation
Gregoire Lake
Grand Rapids Wildland
Gipsy Lake Wildland
Anzac
Cheecham
Grand Rapids
Stony Mountain Wildland
Bigstone Cree Nation
Mariana Lake
Pelican Portage
Crow Lake
Narrows Lake
Chipewyan Prairie Dene First Nation
House River
Christina Lake Thermal Project
Margie
Winefred Lake
Calling Lake
Wandering River
Cold Lake Air Weapons Range/ Primrose Lake Range
Heart Lake First Nation
Calling River Water Access
Foster Creek
Athabasca
Lac La Biche
Beaver Lake Cree Nation
Cold Lake First Nation
Kikino Metis Settlement
White Fish Lake First Nation
Cold Lake
Bonnyville
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
1:1,500,000
NAD 83 UTM 12N
Page Size: 11" x 17"
Created by:
The Geospatial Solutions Group
AB
SK
MB
Fort McMurray
Cold Lake
Edmonton
Calgary
Saskatoon
BC
cenovus ENERGY
Figure 1.2-1
Christina Lake Thermal Project
Location Overview
CVE-1453-001
March 16, 2013

# Scheme Map

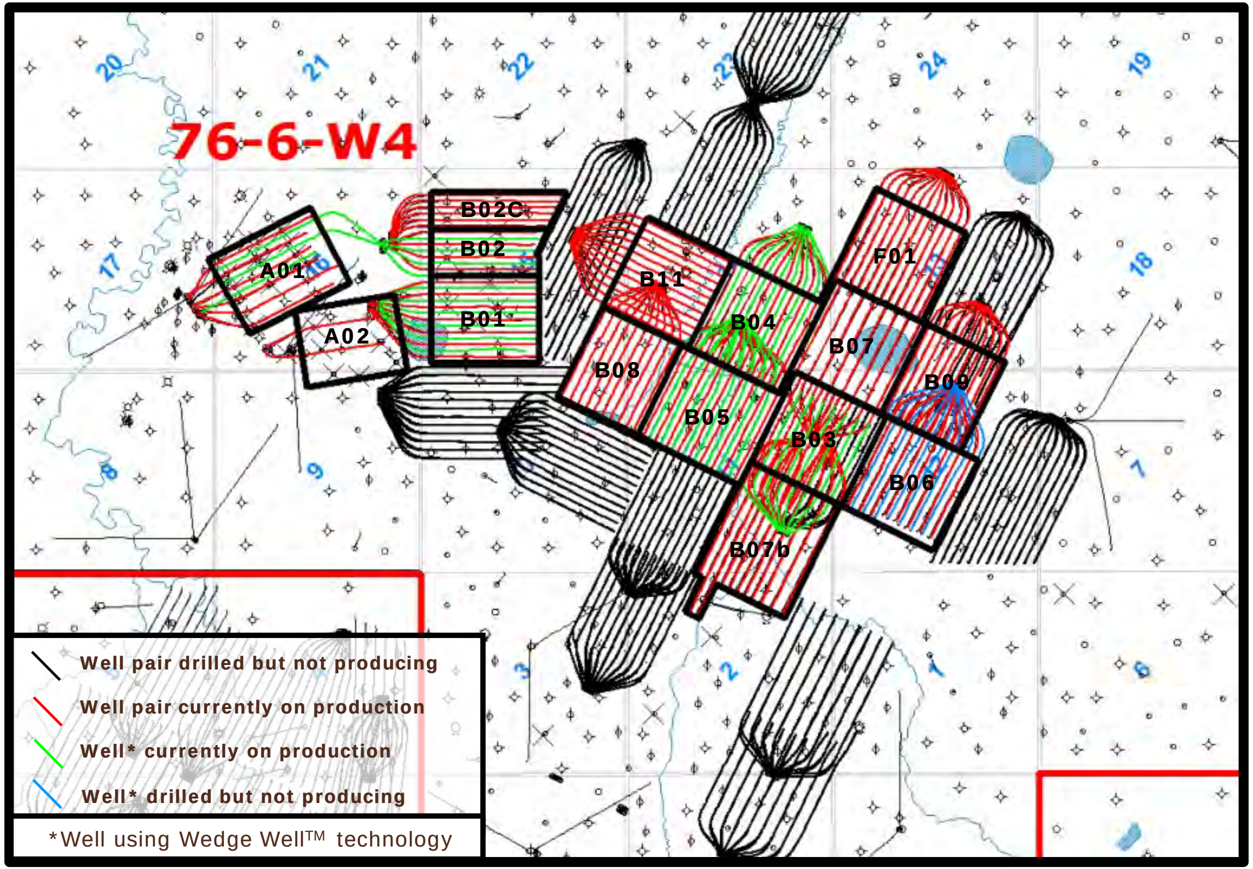


76-6-W4
76-5-W4
Well pair drilled but not producing
Well pair currently on production
Well* currently on production
Well* drilled but not producing
*Well using Wedge Well™ technology

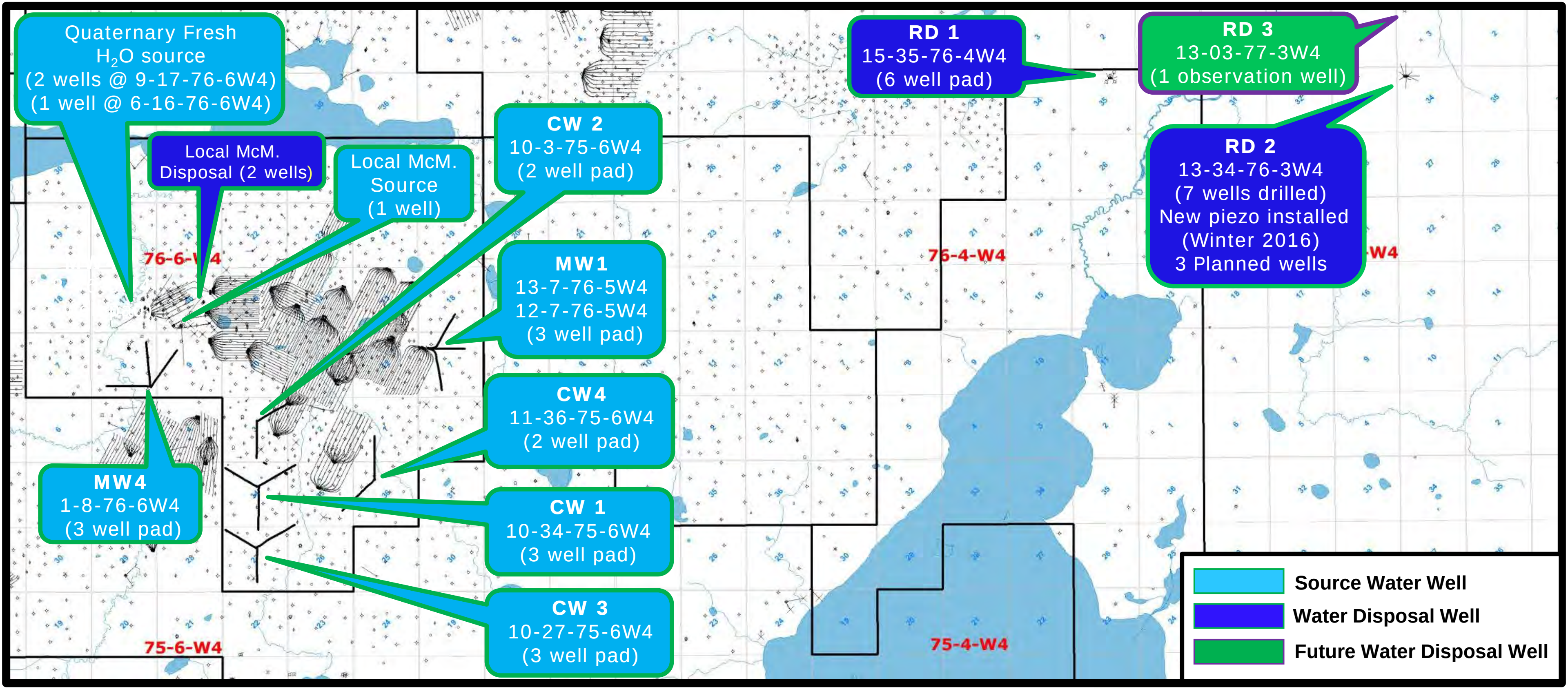
# Drilled SAGD Wells as of March 31, 2016



# Commercial SAGD Wells as of March 31, 2016



# Source and Disposal Wells as of March 31, 2016




Note: MW1 & MW4 are not in use yet, but will be by year end for Phase F

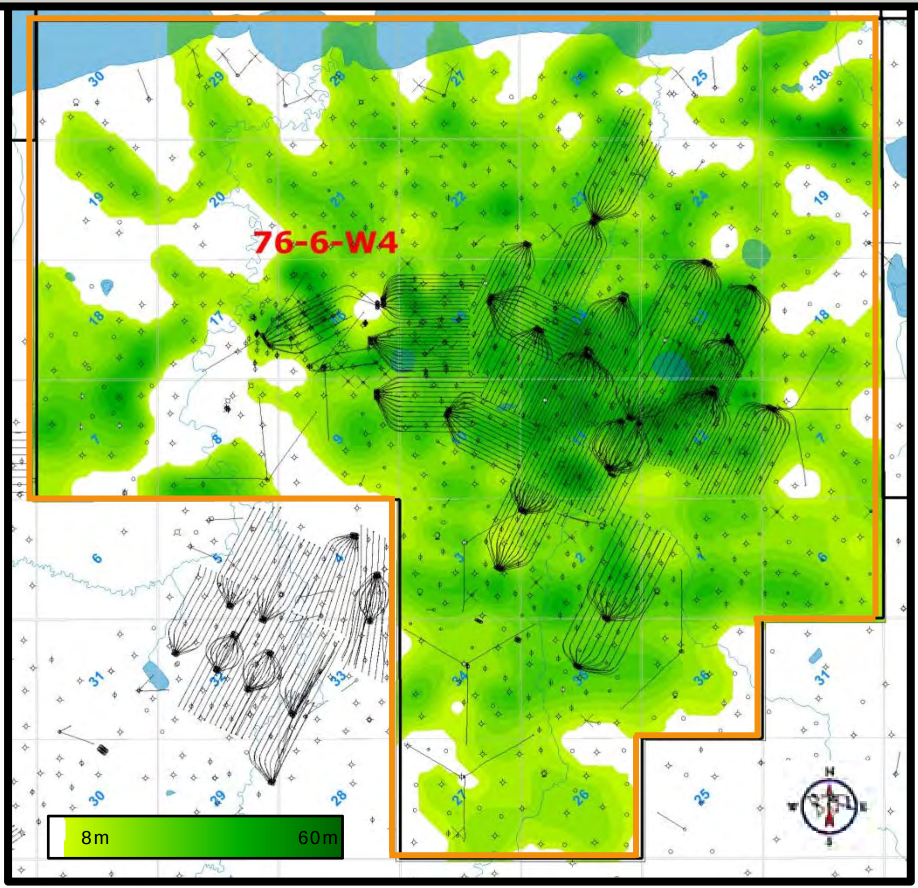
# Subsection 3.1.1 – 2) Geology and Geoscience

Brant Skibsted

Geologist

cenovus ENERGY

### SAGD Pay Iso- CHLK Proper




# AER Approved Project Area

## *Reservoir Properties (project area)*

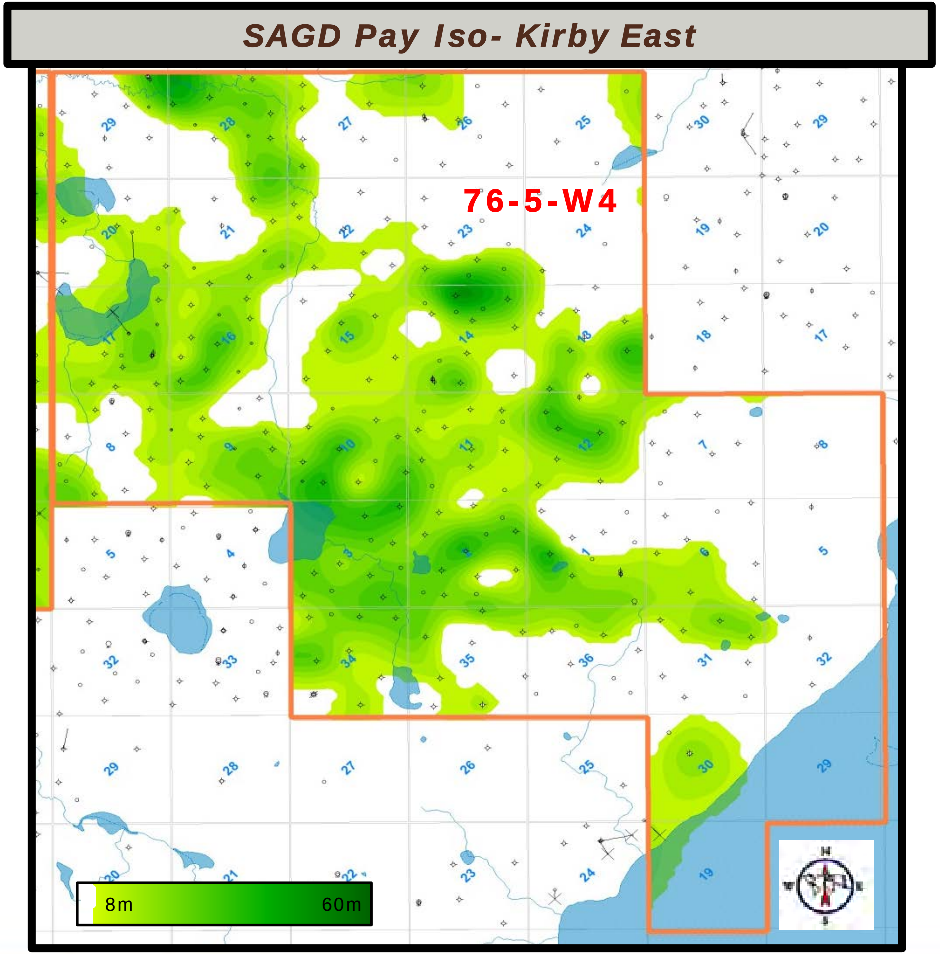
| | |
|---|---|
| **Reservoir depth:** | **350m TVD** |
| **Original reservoir pressure:** | **2500 kPa** |
| **Original reservoir temperature:** | **12°C** |
| **Average Vertical permeability:** | **4.2 Darcies** |
| **Average Horizontal permeability:** | **7.0 Darcies** |
| **Average SAGD pay:** | **21 meters** |
| **Average porosity (Ø):** | **33%** |
| **Average oil saturation:** | **80%** |

***Rock Volume:* 1,925 x $10^6$ m$^3$**

***SOIP:* 508 x $10^6$ m$^3$**

**Note: CVE Volumetric Estimates, not IQRE estimates**

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




# AER Approved Project Area

## Reservoir Properties (project area)

| | |
|---|---|
| Reservoir depth: | 350m TVD |
| Original reservoir pressure: | 2500 kPa |
| Original reservoir temperature: | 12°C |
| Average Vertical permeability: | 4.2 Darcies |
| Average Horizontal permeability: | 7.0 Darcies |
| Average SAGD pay: | 21 meters |
| Average porosity (Ø): | 32% |
| Average oil saturation: | 70% |

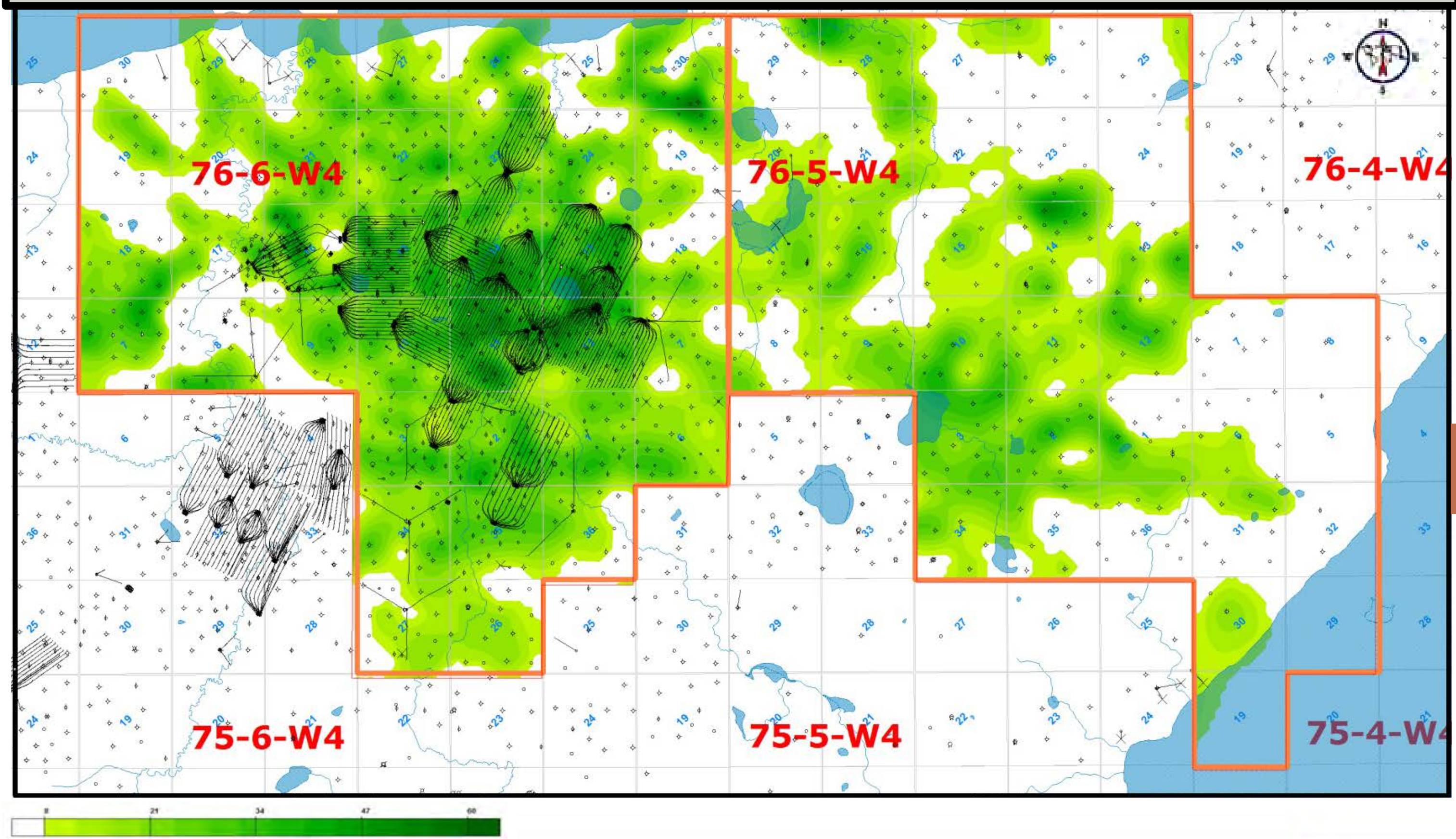
*Rock Volume: **875 x $10^6$*** m$^3$

*SOIP: **196 x $10^6$*** m$^3$

**Note: CVE Volumetric Estimates, not IQRE estimates**

**SOIP = Rock Volume in Project area x phi (.32) x So (.70)**

# SAGD Pay Iso




*Rock Volume:*

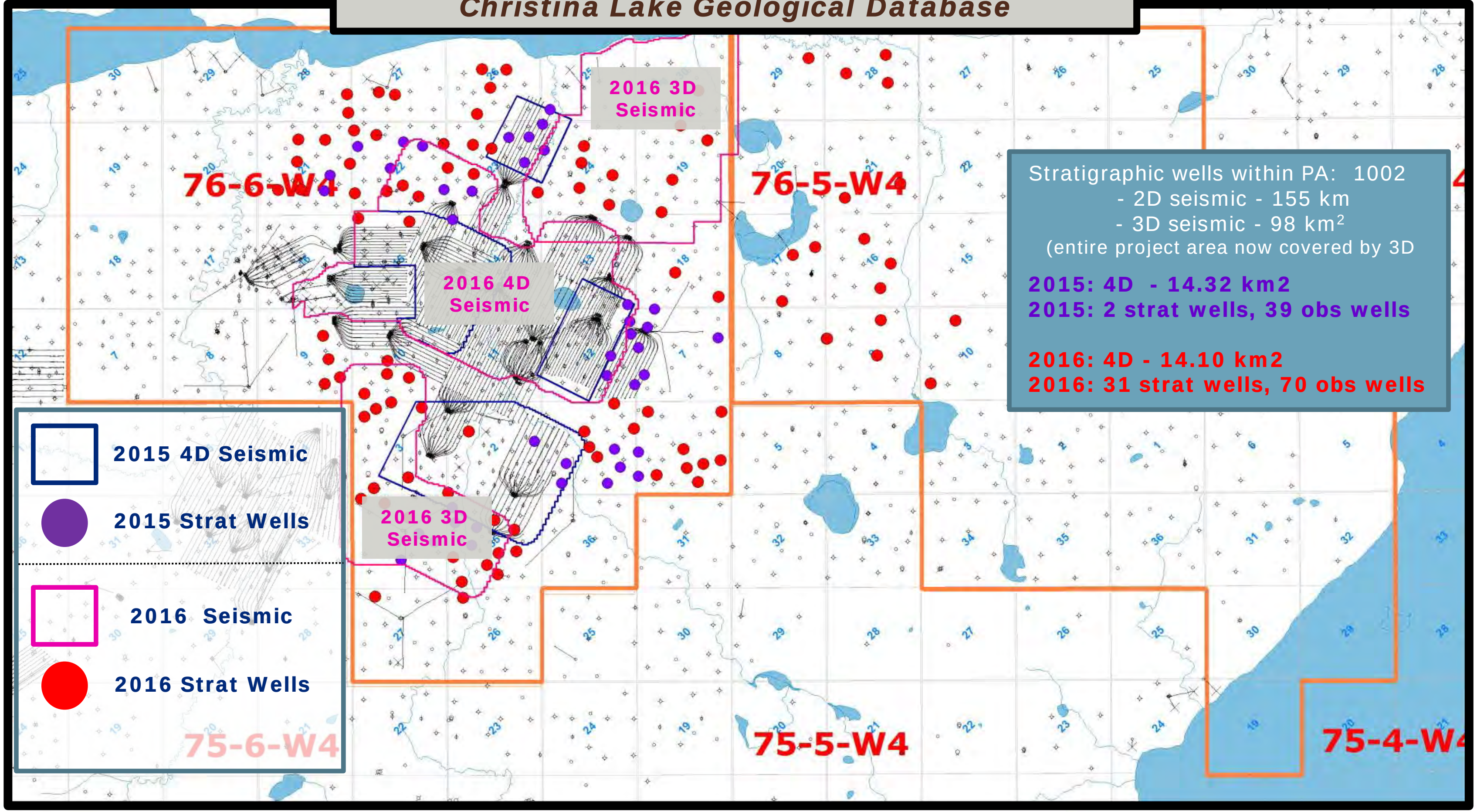
**2,801 x10$^6$ m$^3$**

*SOIP:*

**704 x 10$^6$ m$^3$**

**Note: CVE Volumetric Estimates, not IQRE estimates**

# Christina Lake Geological Database

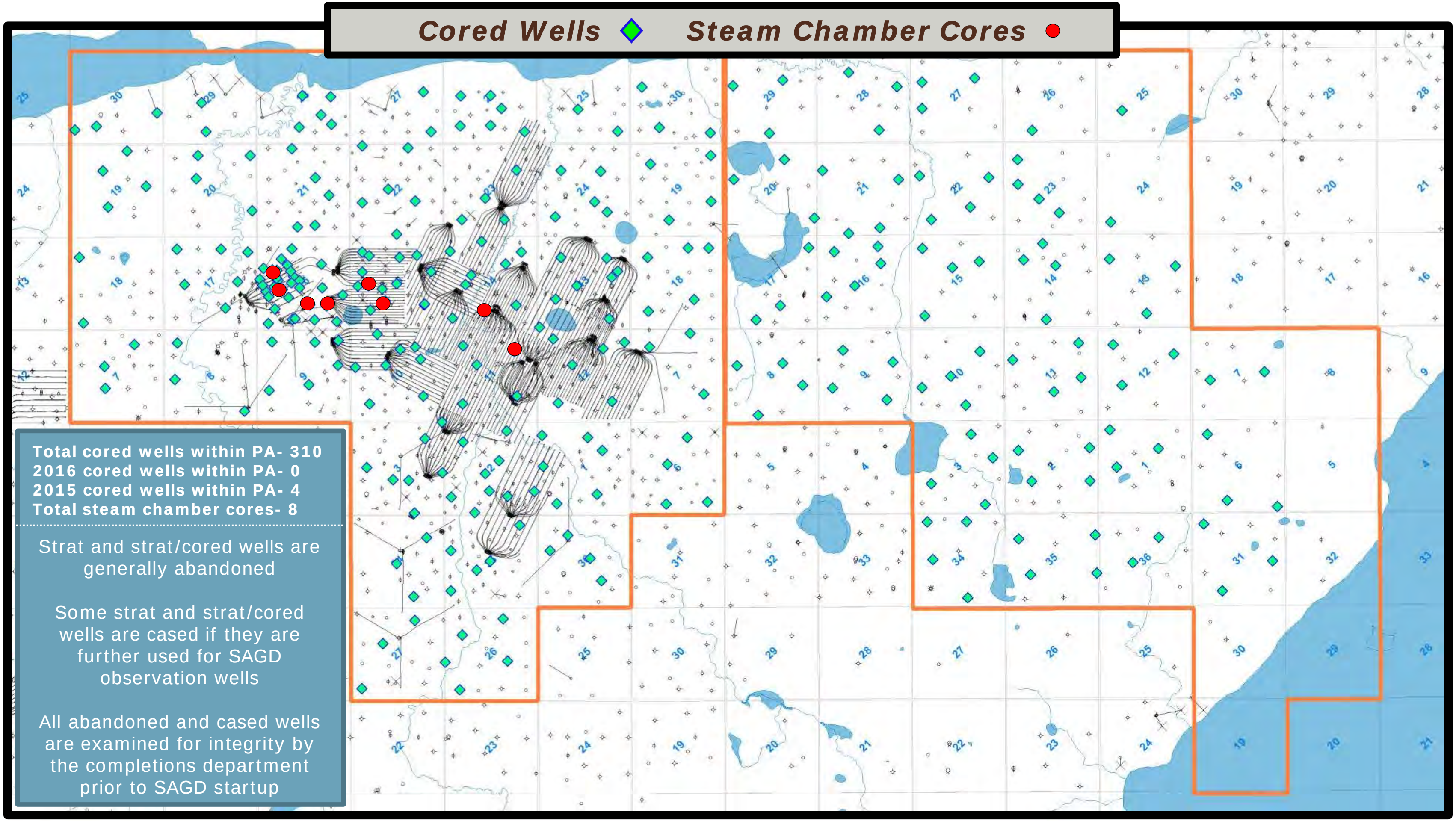



Stratigraphic wells within PA: 1002
- 2D seismic - 155 km
- 3D seismic - 98 km²

(entire project area now covered by 3D

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

**2016: 4D - 14.10 km2**
**2016: 31 strat wells, 70 obs wells**




**Total cored wells within PA- 310**
**2016 cored wells within PA- 0**
**2015 cored wells within PA- 4**
**Total steam chamber cores- 8**

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

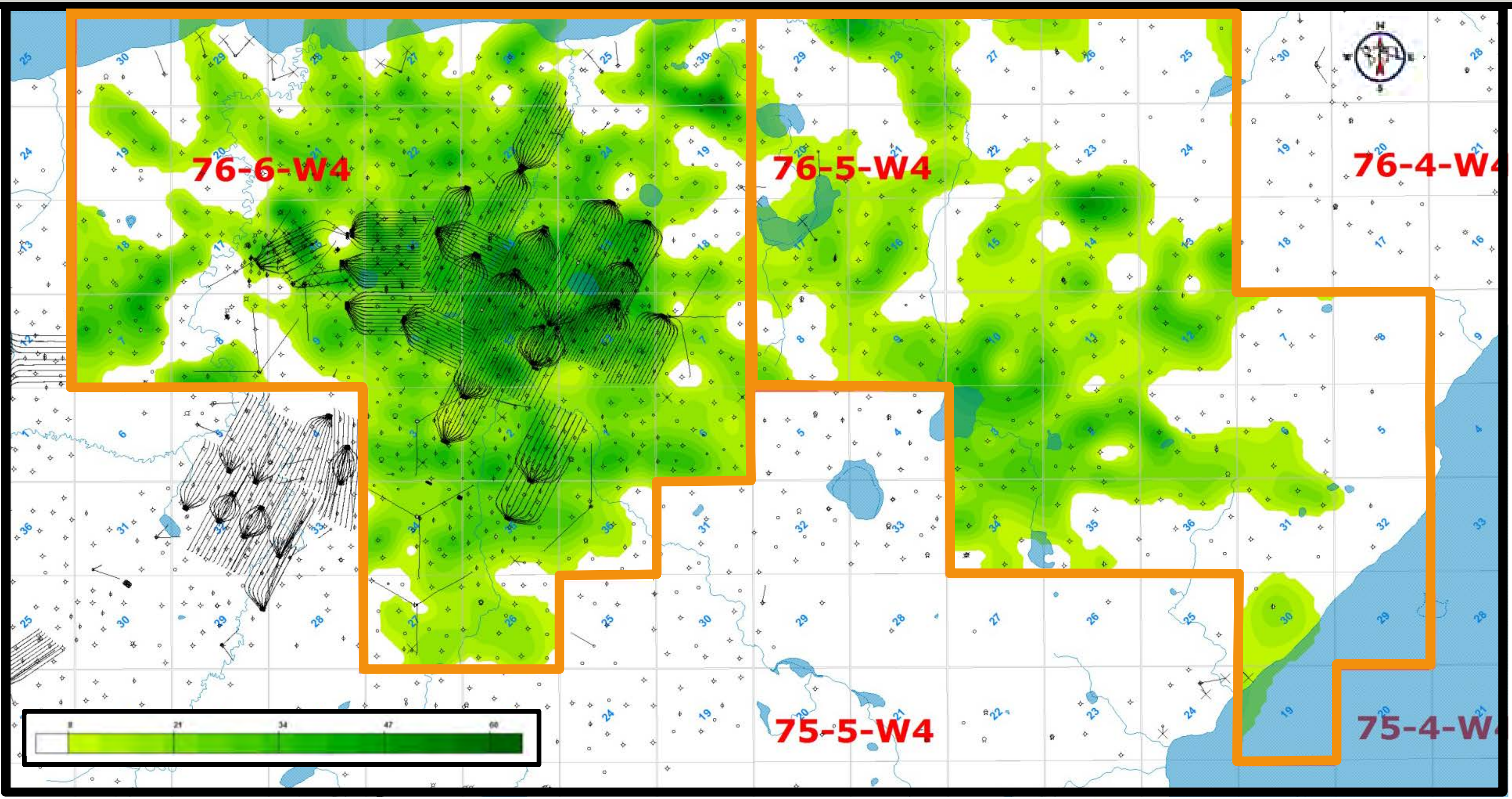
All abandoned and cased wells are examined for integrity by the completions department prior to SAGD startup

**Analysis:**

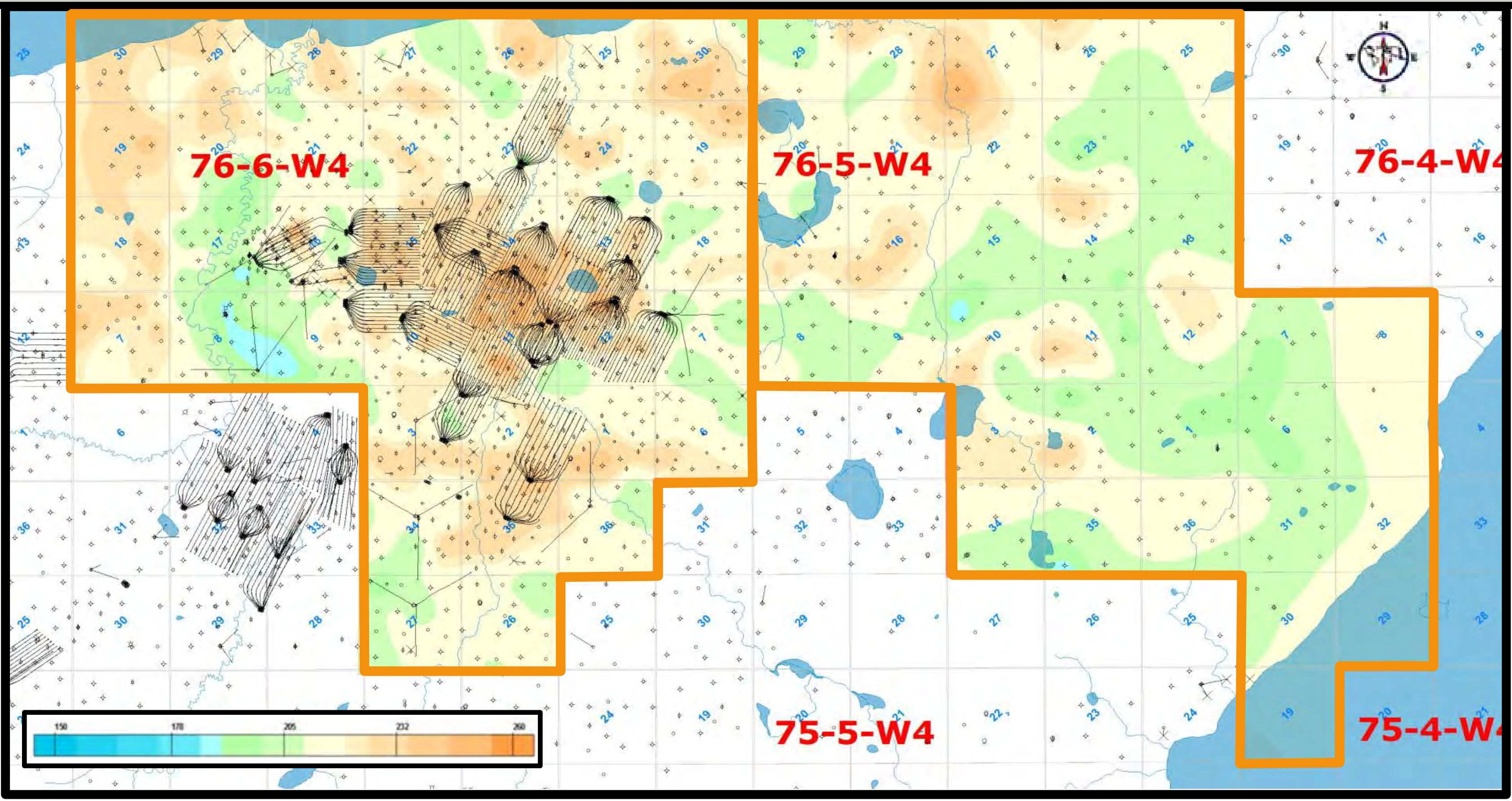
- ✓ Routine core analysis
- ✓ Photos

# Geological Maps

# SAGD Pay Iso: SAGD Pay Top – SAGD Base



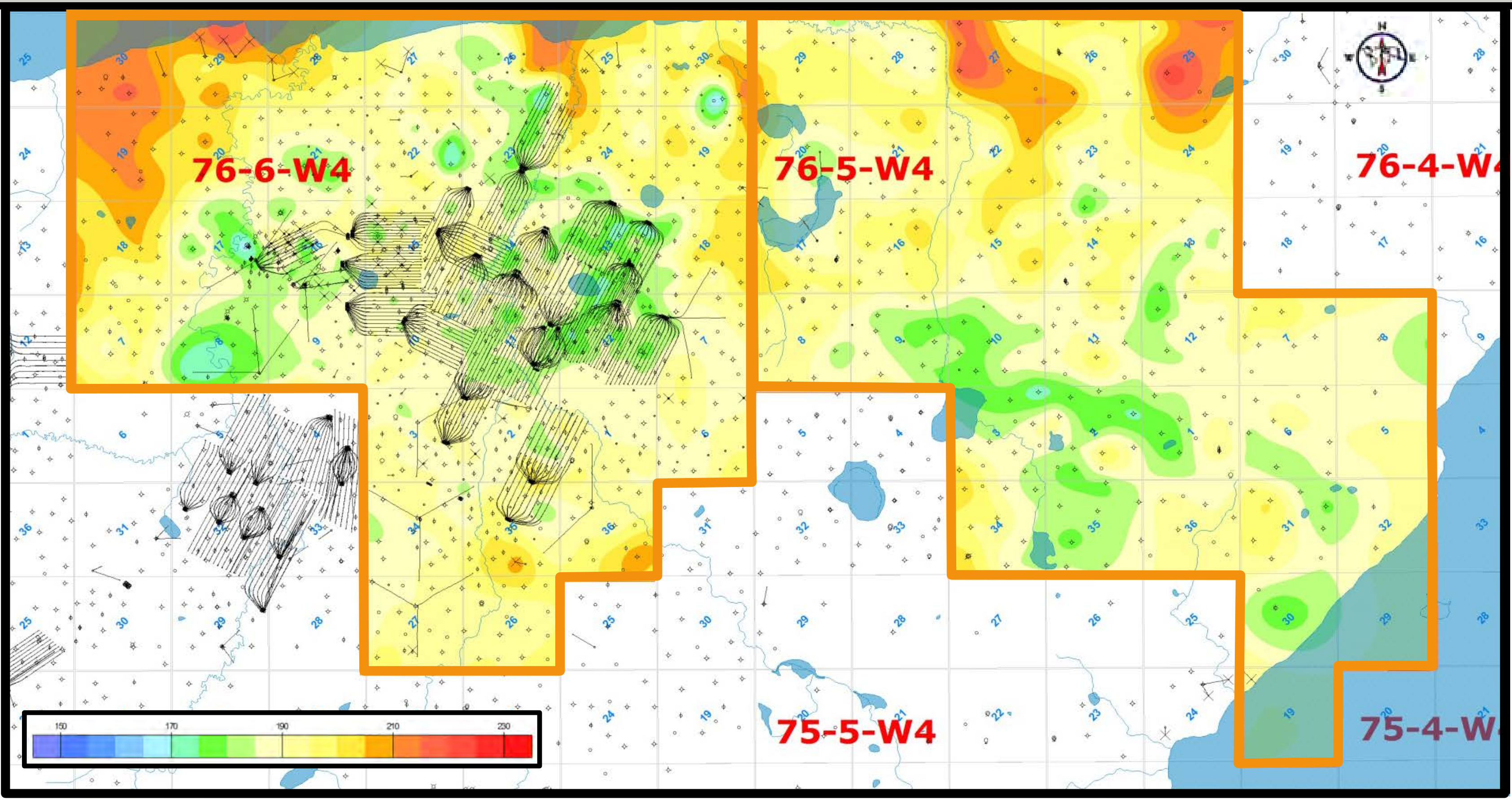
# SAGD Top Structure, SSTVD






June 15, 2016

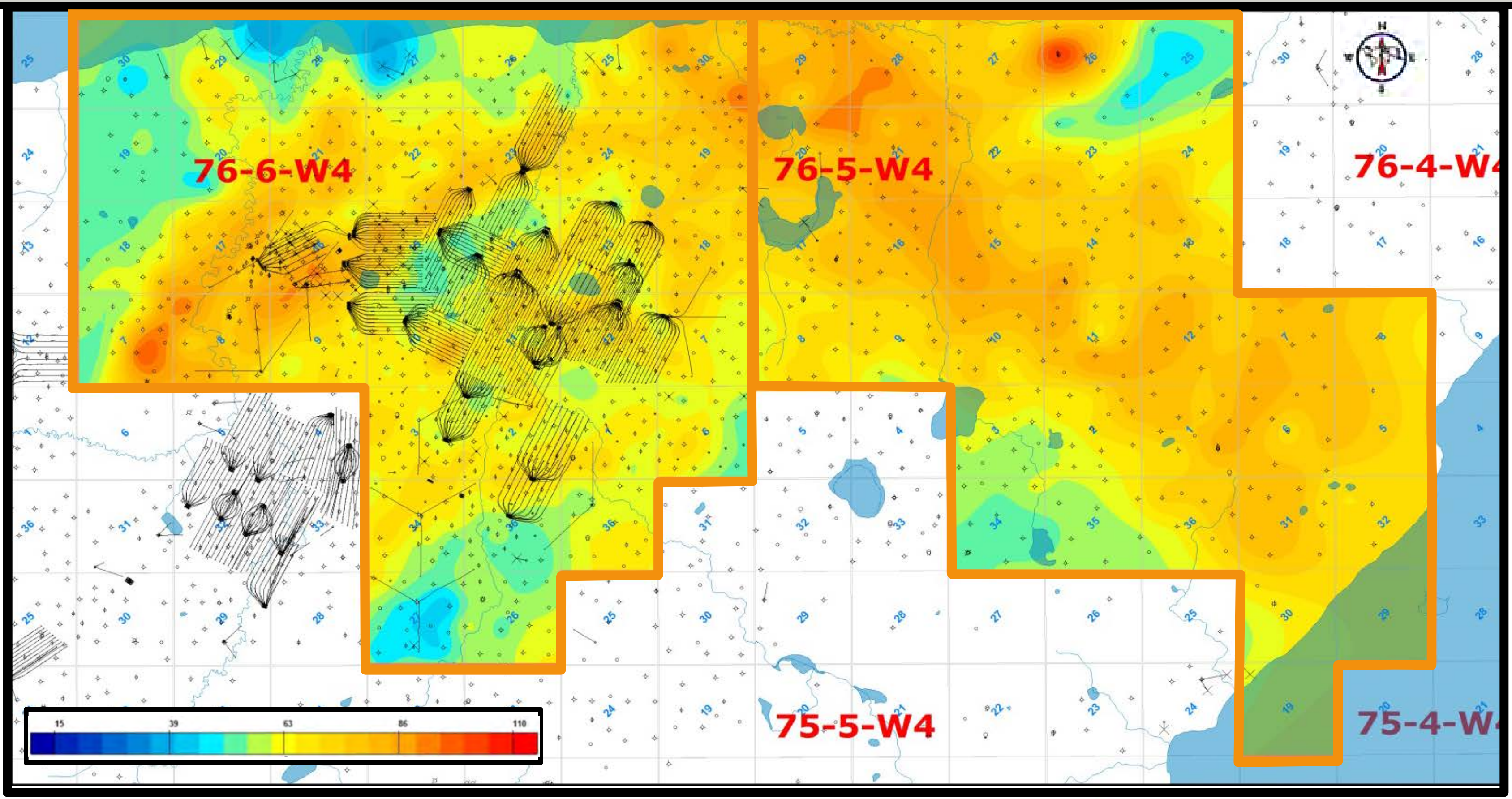
# SAGD Base Structure, SSTVD



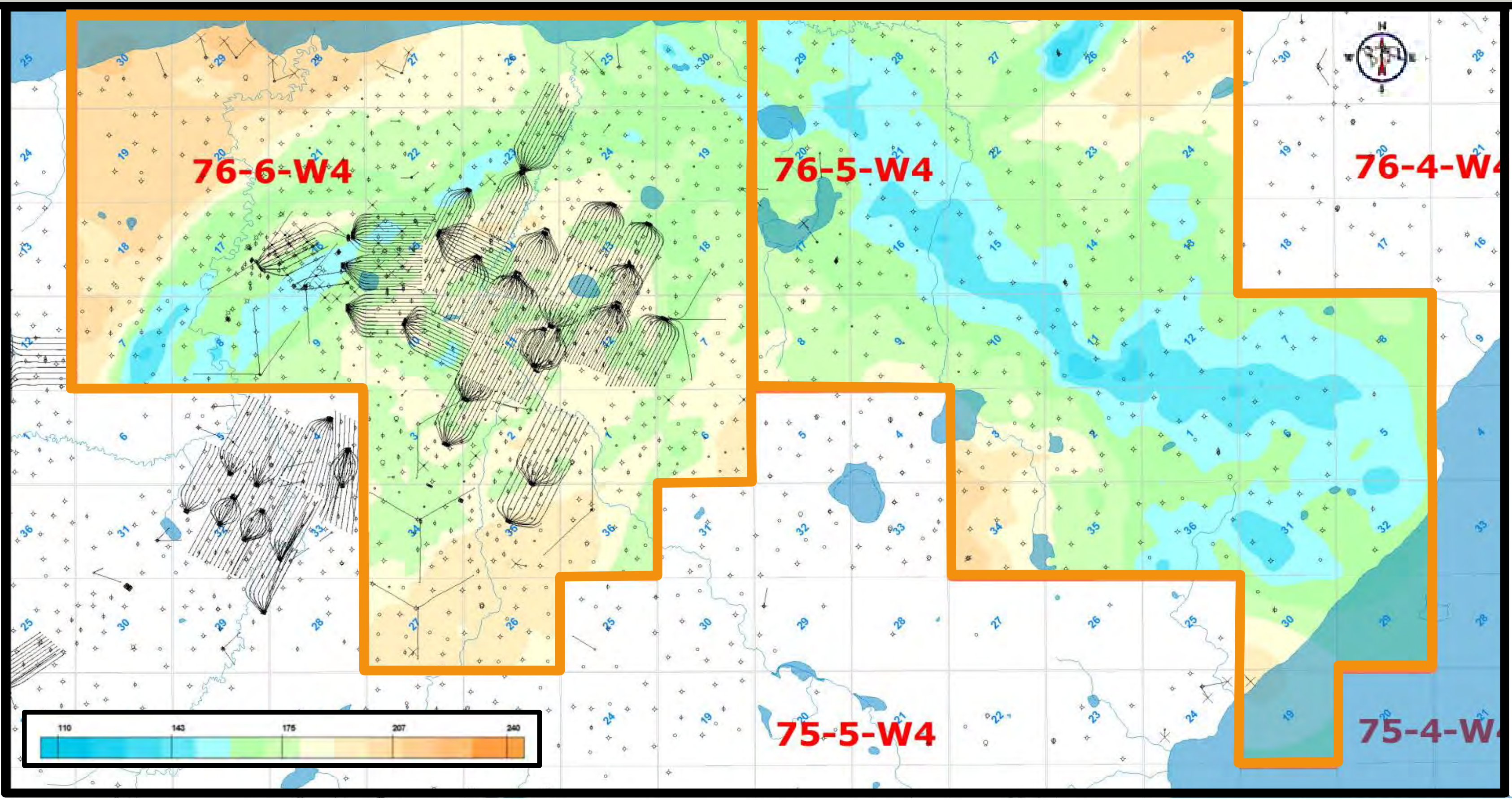

cenovus ENERGY


June 15, 2016

# McMurray Iso, McM. - Paleo

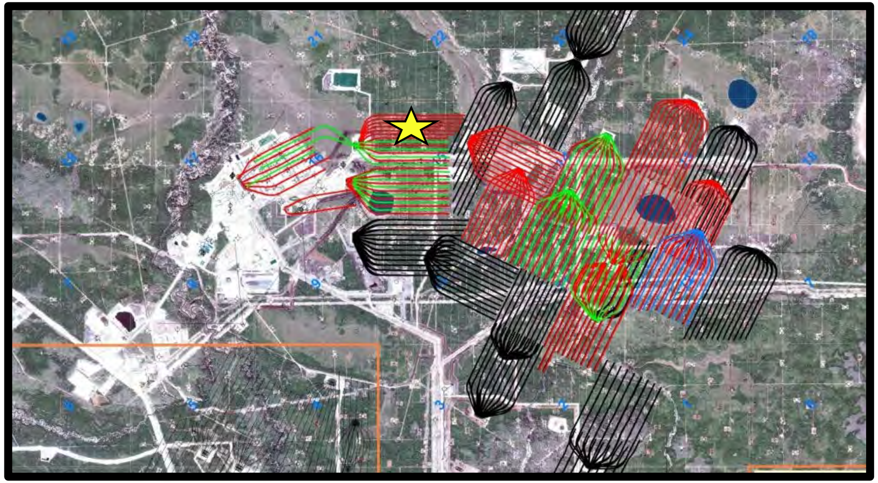


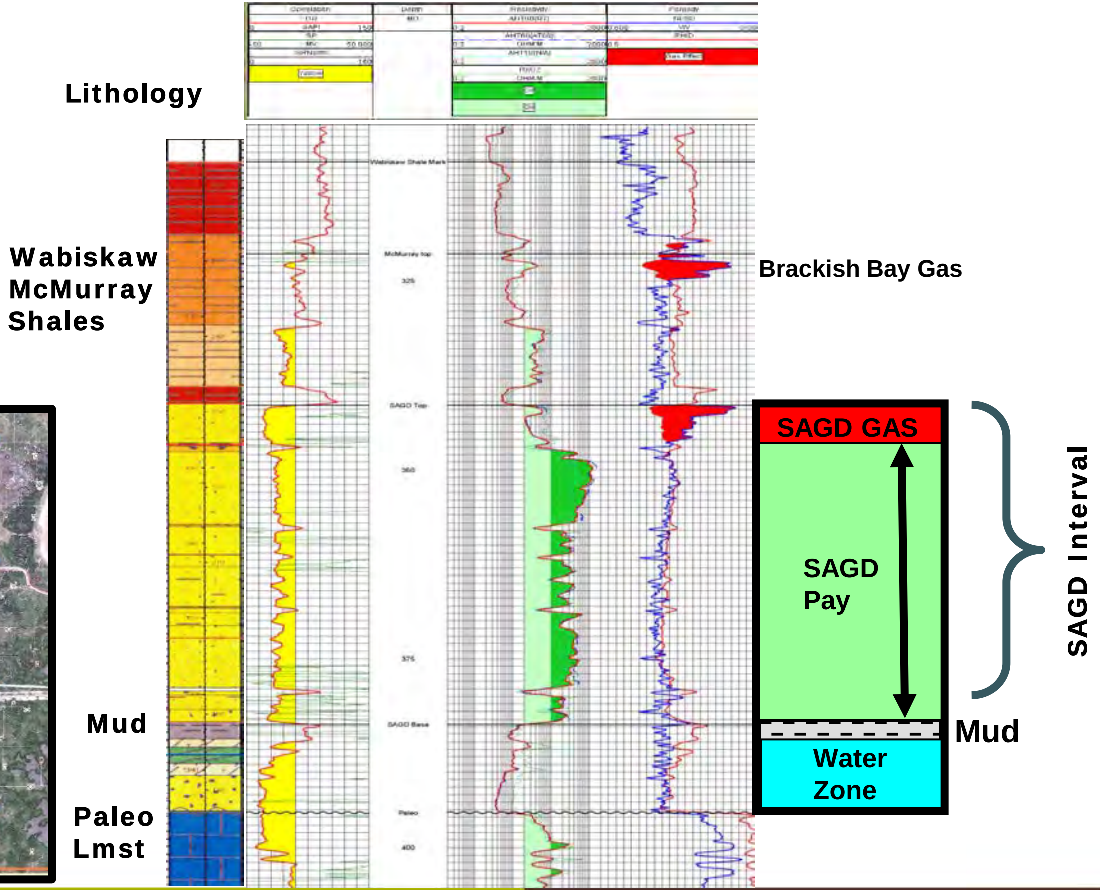
# *Paleozoic Structure, SSTVD*



# Composite type log: Phase B

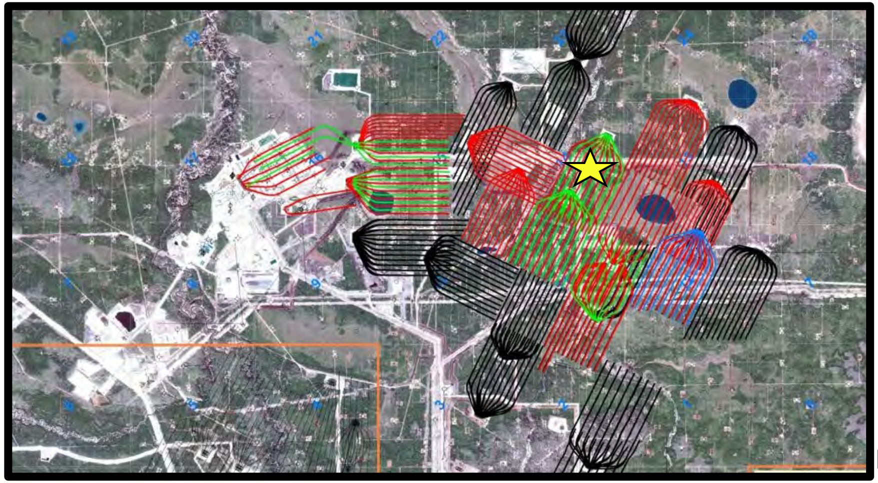
- Pervasive basal mud layer often separates bitumen and McMurray water
- Basal mud is discontinuous and ranges from 0-4 metres in thickness
- Provides a good marker during SAGD operations





# Composite type log: Phase CDE

- 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

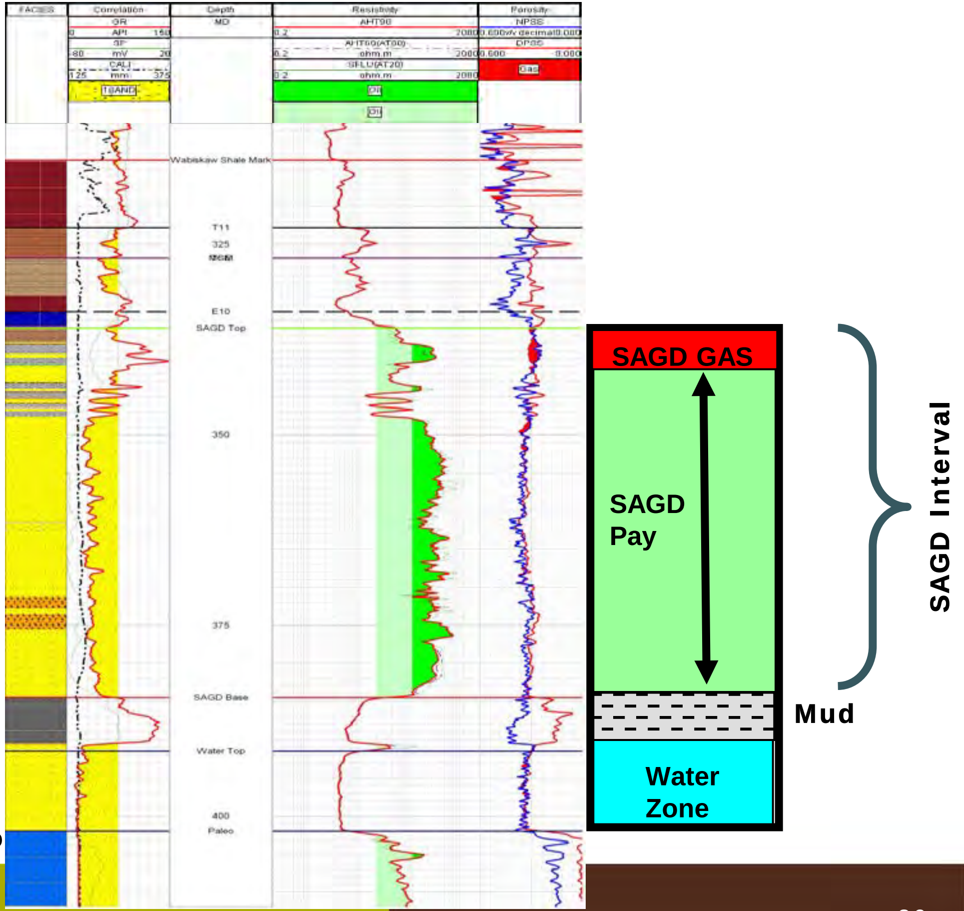


Lithology

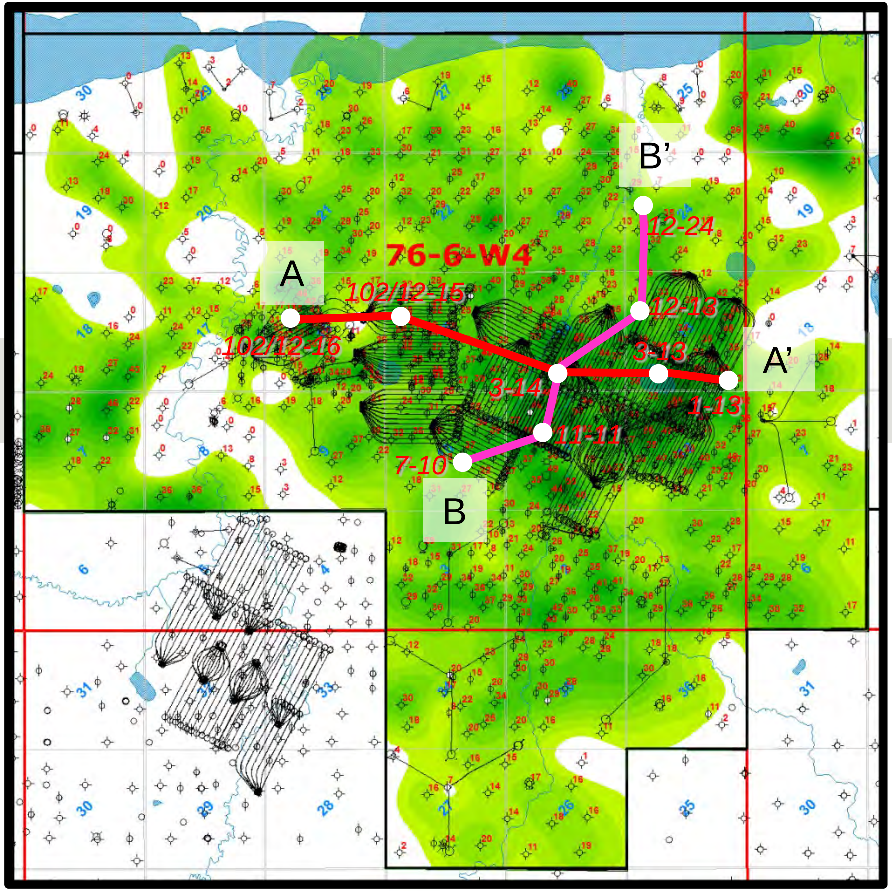
Wabiskaw McMurray Shales

Mud

Paleo



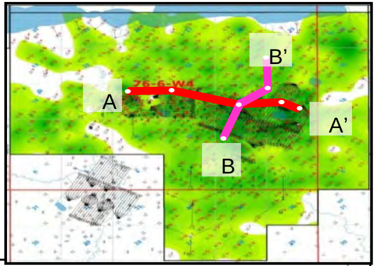
## Representative Cross Sections

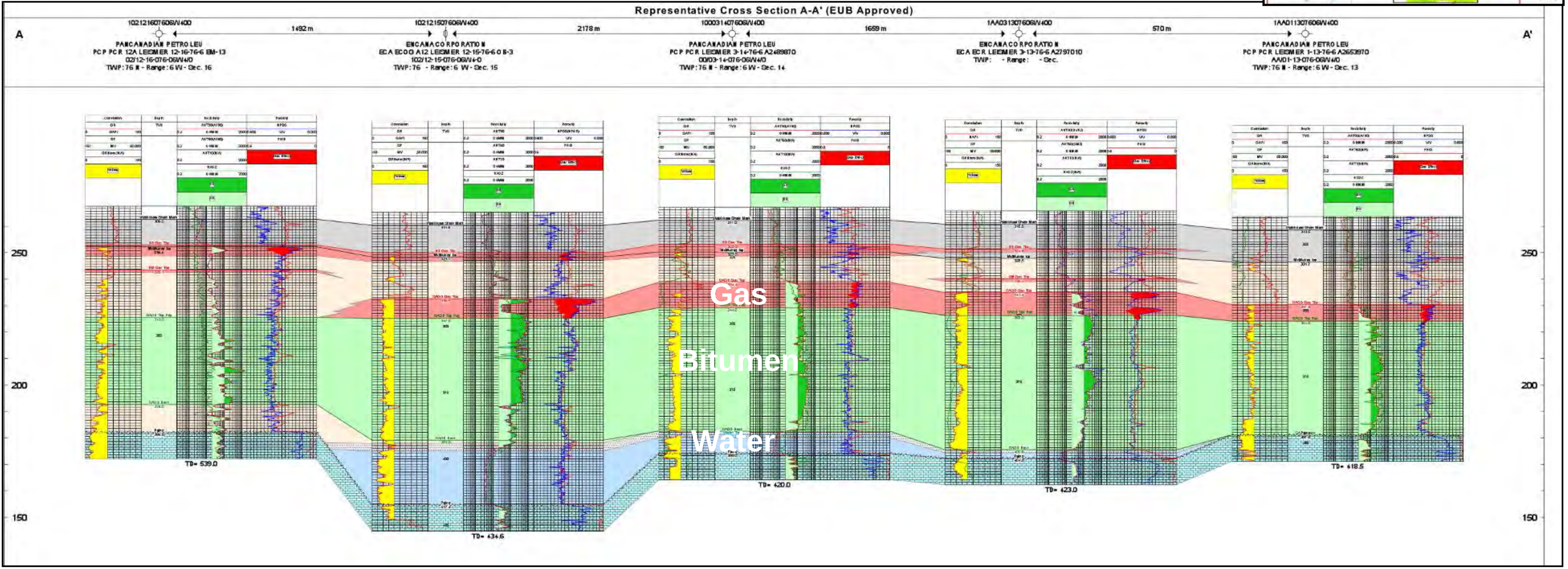



cenovus ENERGY

June 15, 2016

# Cross section A-A' (saturation)



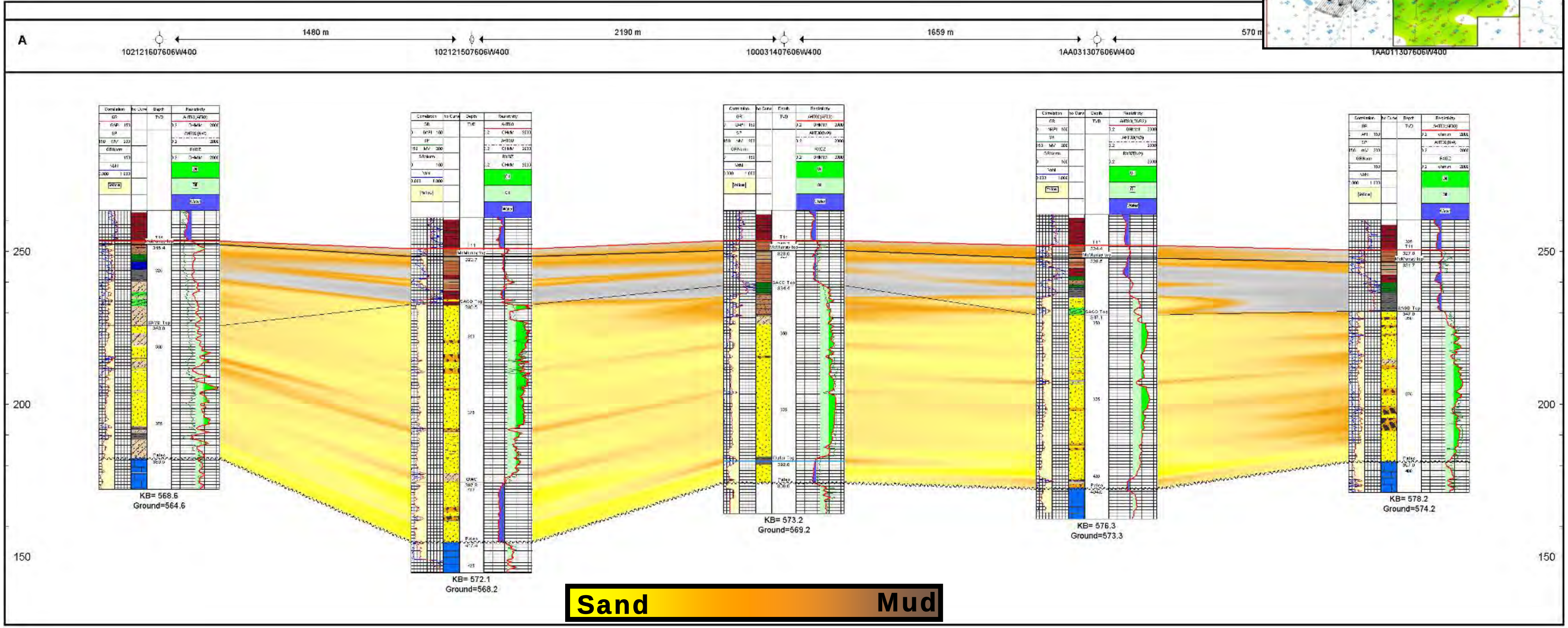



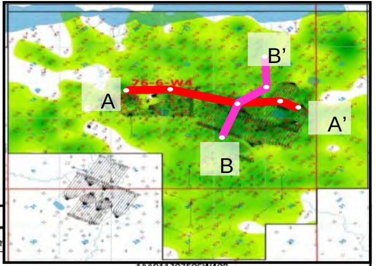




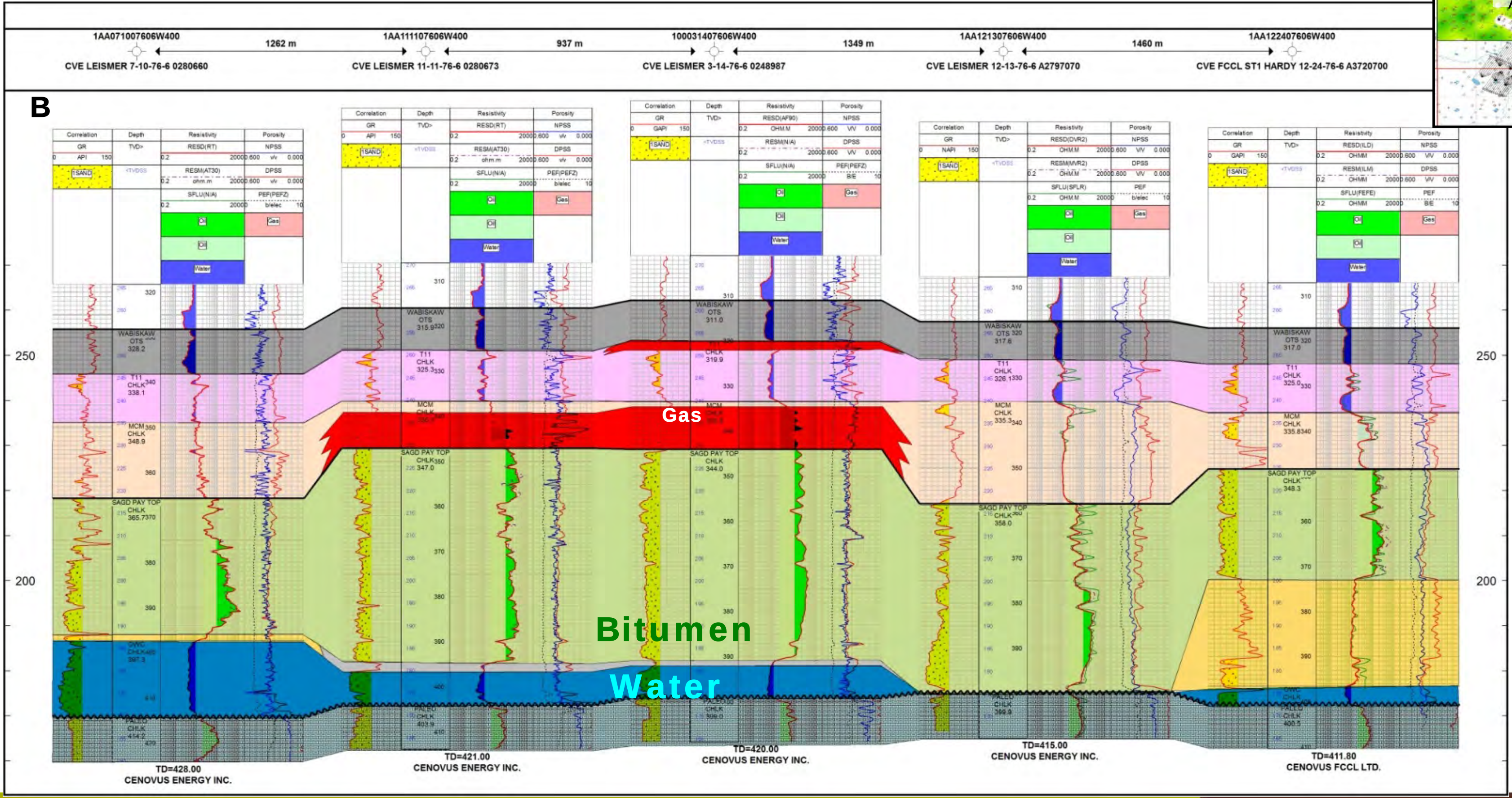
June 15, 2016

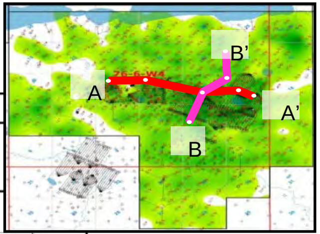
# Cross section A-A' (lithology)



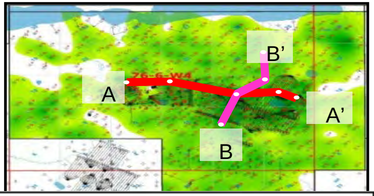



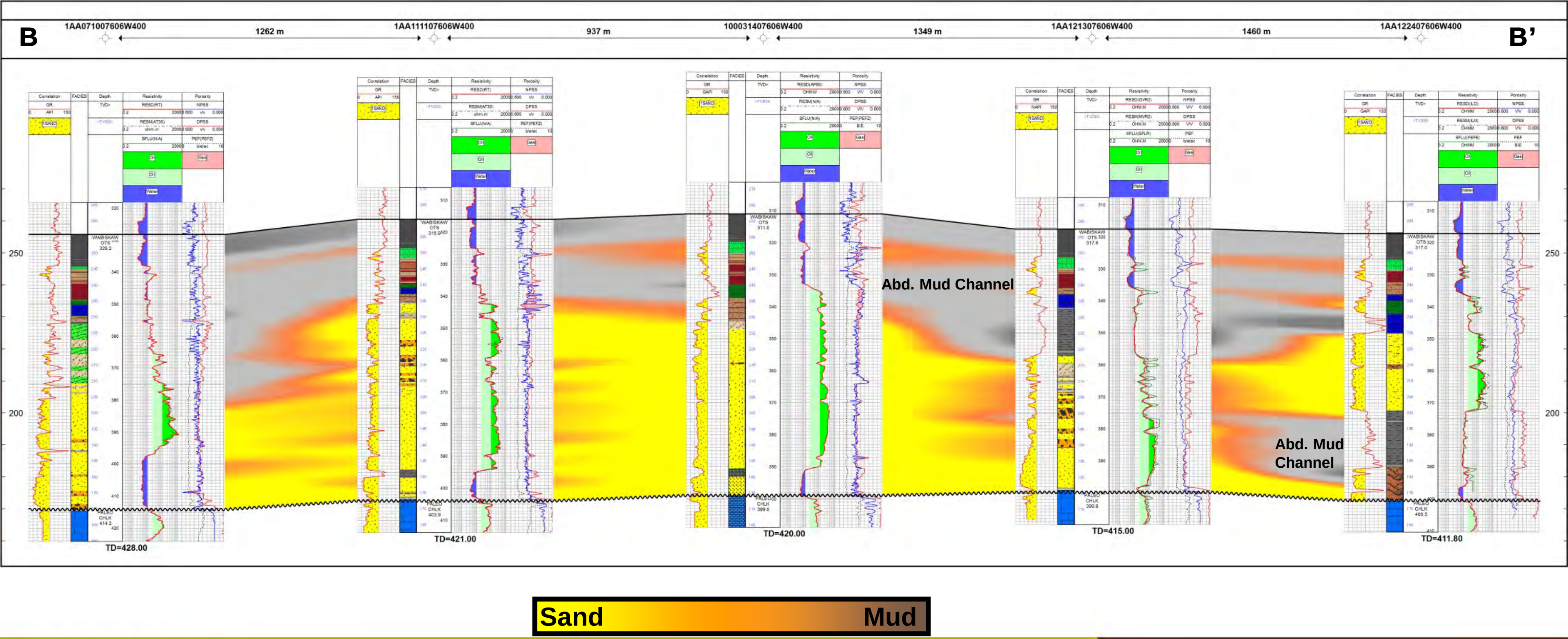
# Cross section B-B' (saturation)



# Cross section B-B’ (lithology)



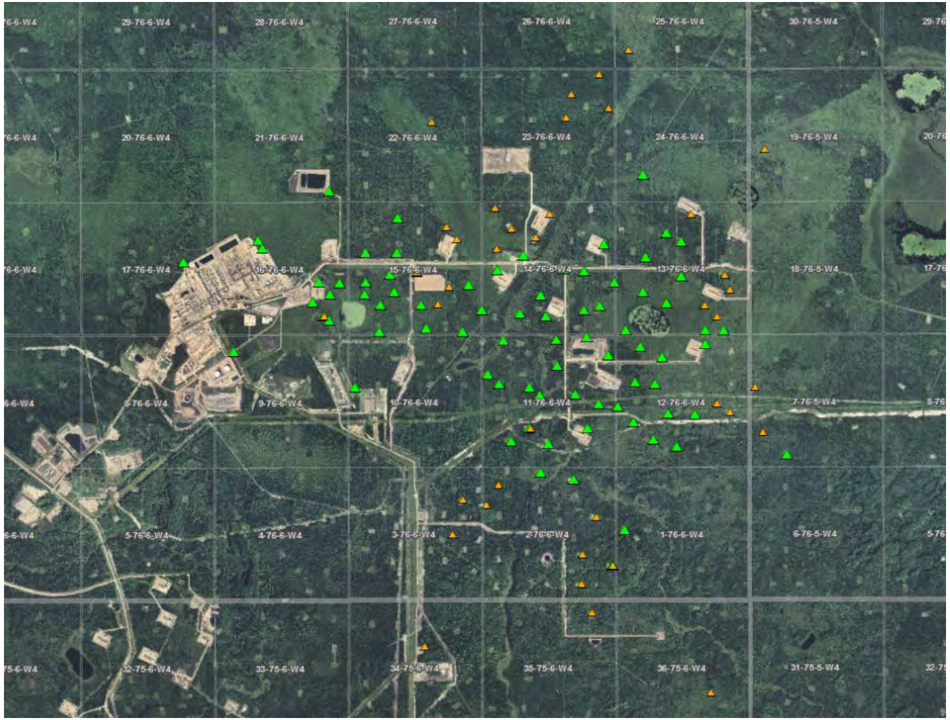



# Geomechanical and surface heave

- Integrated InSAR (Synthetic Aperture Radar) Land Deformation Monitoring took place between October 2014 – October 2015 by MDA Geospatial Services Inc.
- The measurements were successfully made on 98 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 directly with pad, pipeline and plant structures

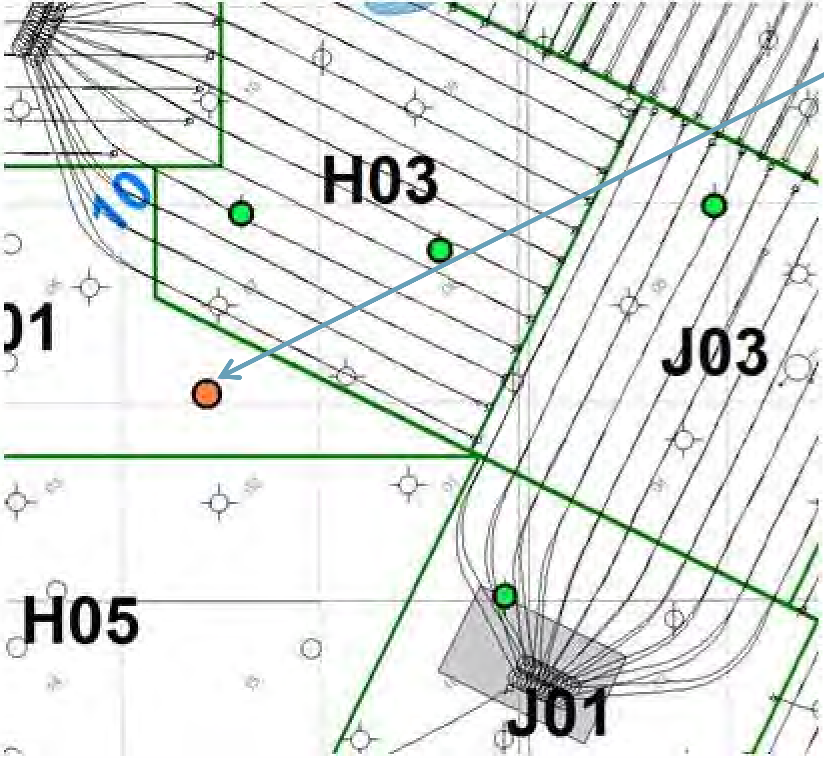
**Refer to Appendix 1 for detailed heave data**

# Corner reflector (CR) locations:




Current Corner Reflectors: 98
Current Reference Corner Reflectors: 11
New Installs: 39 (orange)

# Strain Monitoring




1AC/07-10-076-06W4
~250 m (185-435 m TVD)

- Strain monitoring gauges were installed winter 2016. No data has been acquired yet, but a baseline will be conducted prior to first steam on H03 Pad.
- The strain monitoring data gathered will be used in models and simulations that will improve our understanding of mechanisms that cause casing impairments.

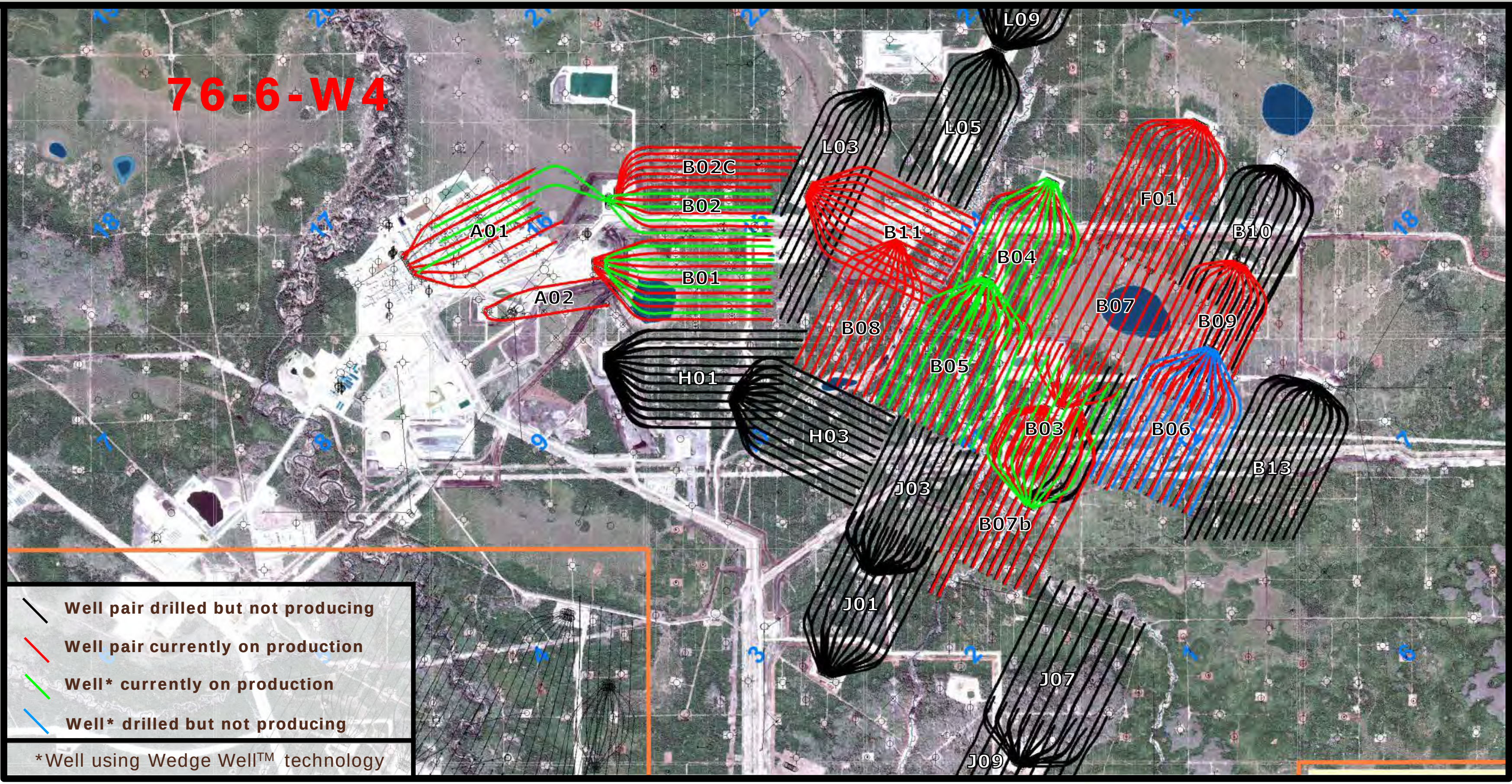
# Subsection 3.1.1 – 3) Drilling and Completions

Mike Ellis

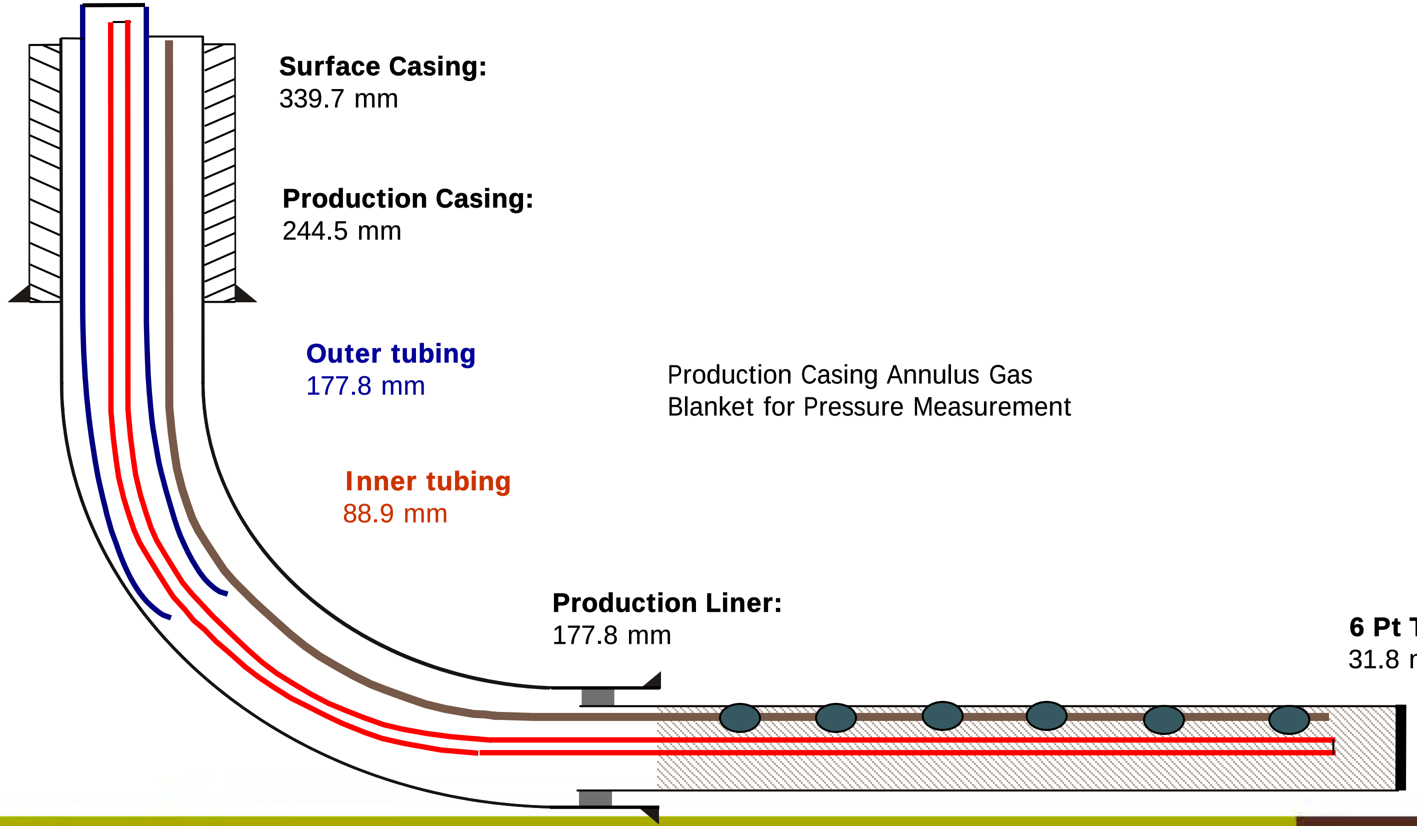
Production Engineer

cenovus ENERGY

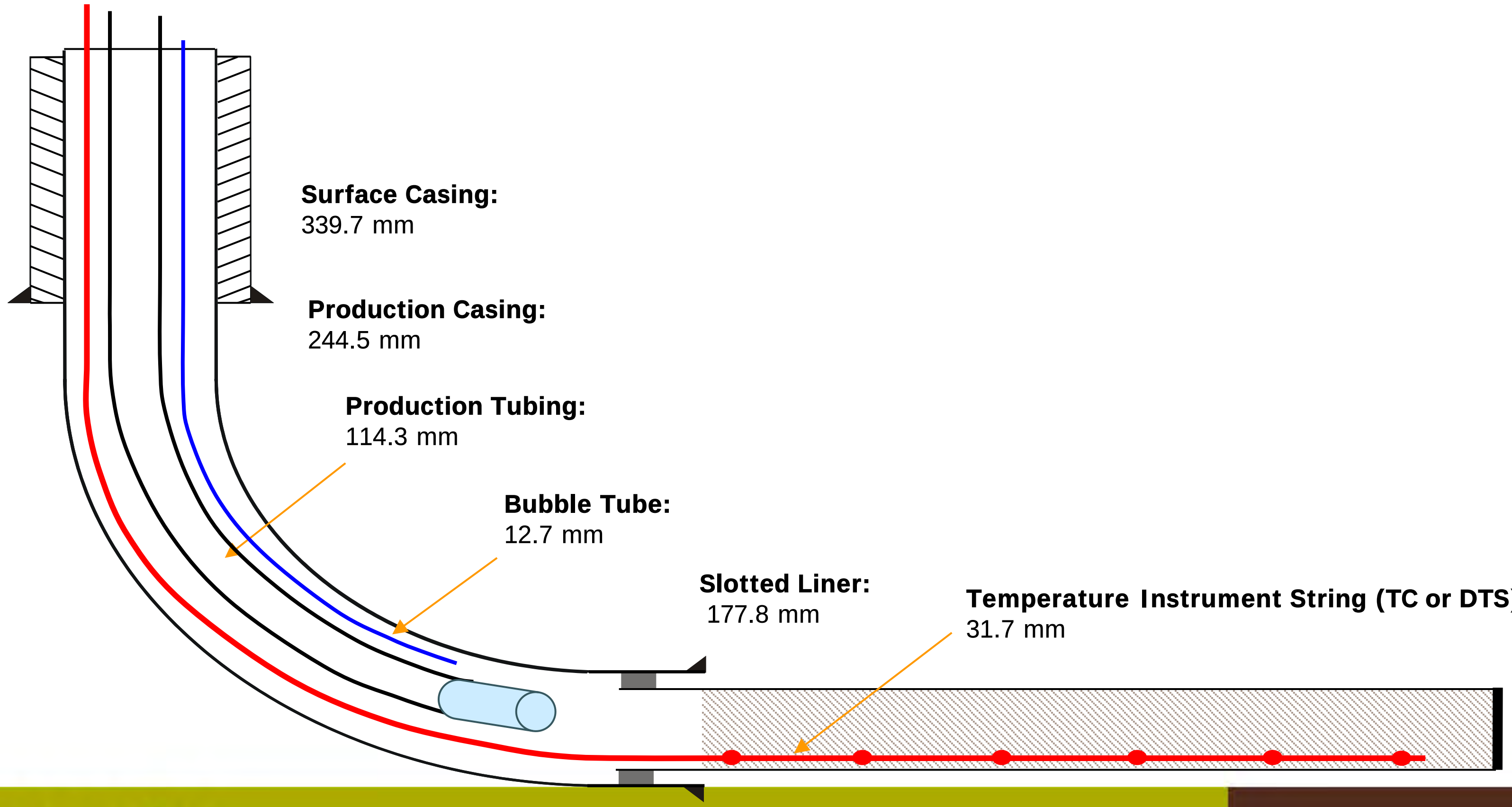
# SAGD Summary to Date



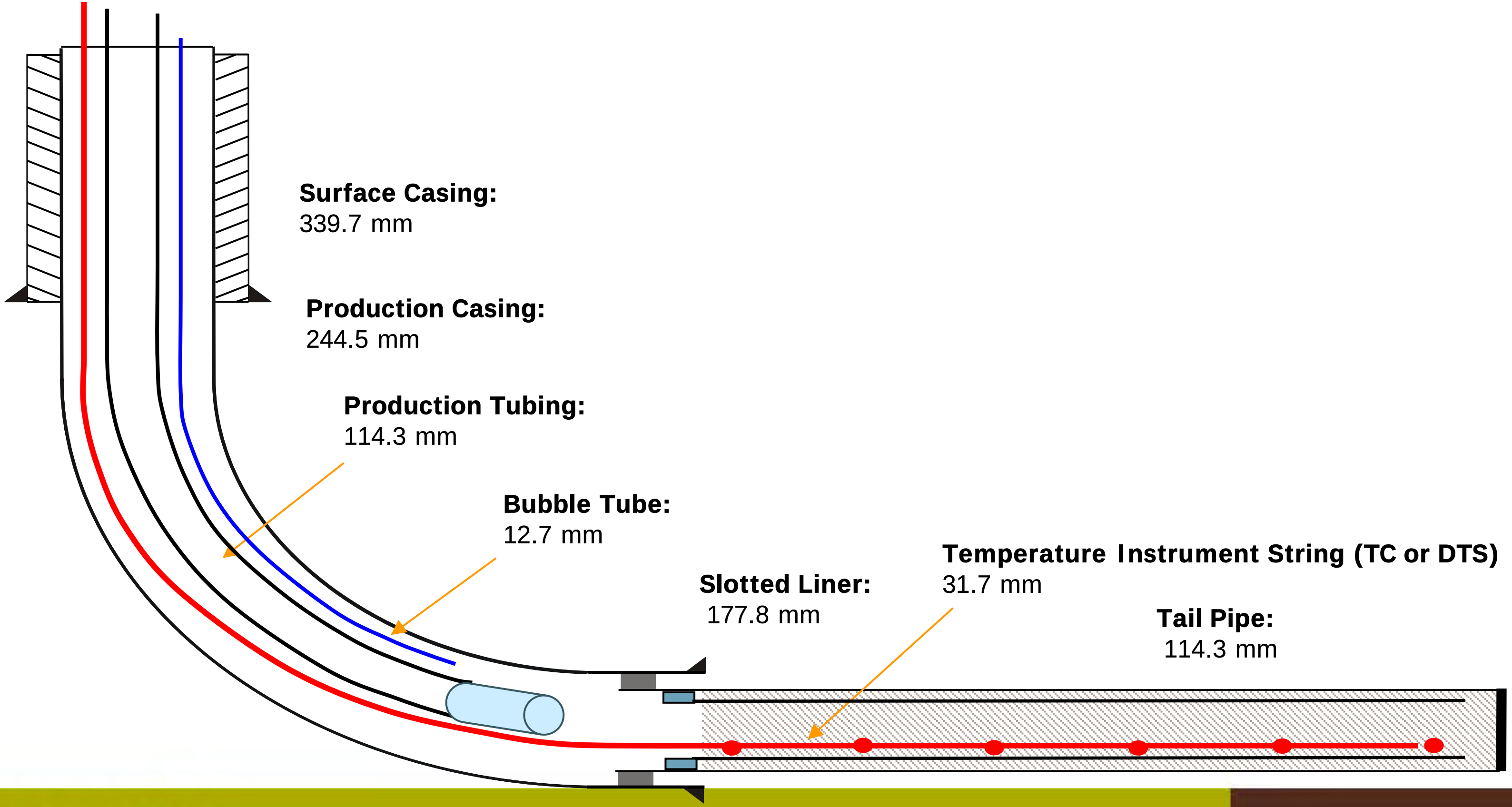
# Sample Producer Circulation Completion



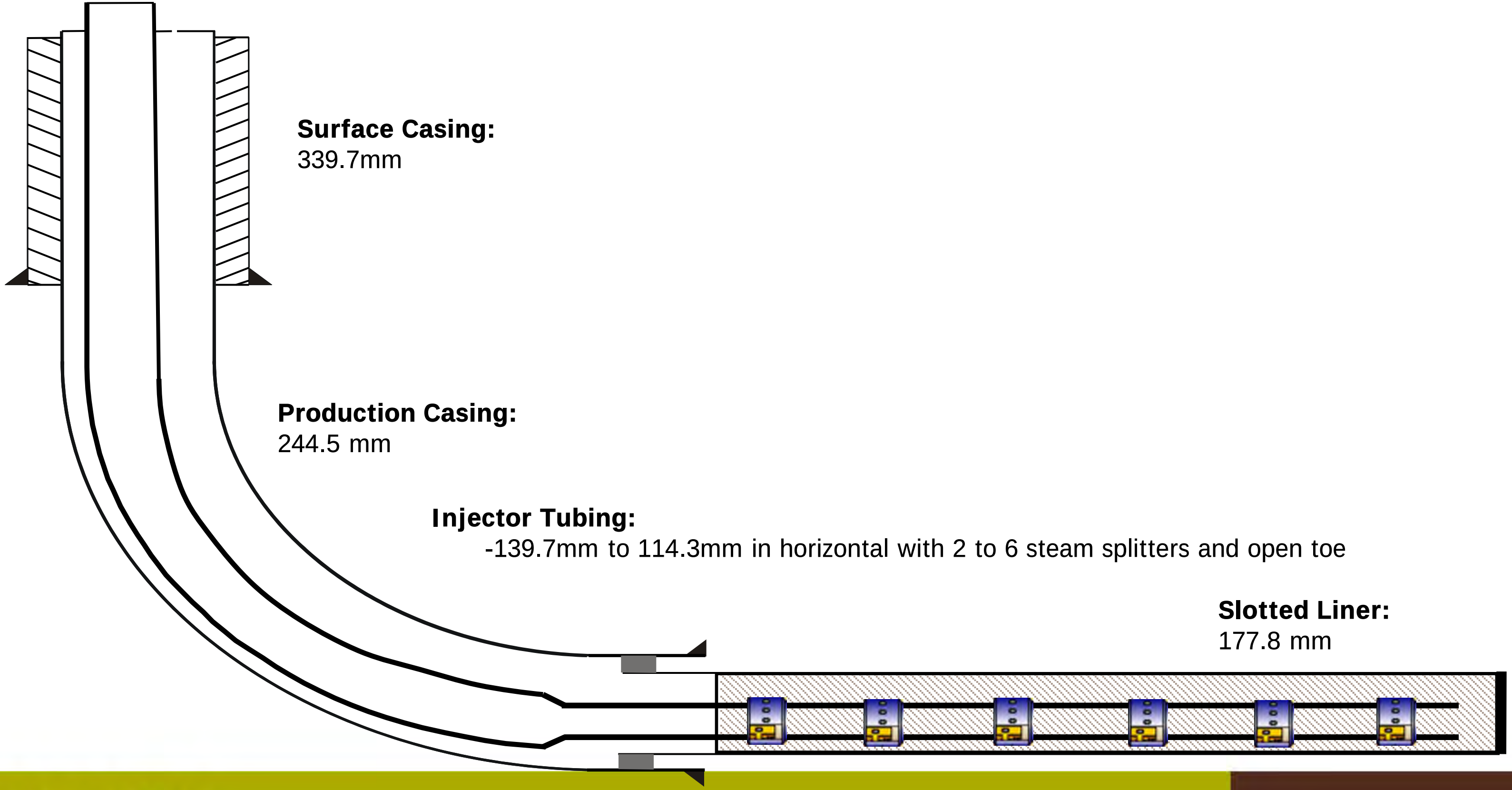
# Sample ESP Producer Completion



# Sample ESP Producer Completion w/ Tailpipe



# Sample Injector Completion



# Flow Control Devices

- **Currently testing 3 flow control devices**
  - 1 liner deployed ICDs
  - 2 tubing deployed ICDs
- **Production from wells commenced in 2015**
- **ICD effectiveness review ongoing**

| Well Name | Well Type | Production Date | Deployment |
|---|---|---|---|
| F01P08 | Producer | 08/09/2015 | Tubing Deployed |
| F01P10 | Producer | 08/03/2015 | Tubing Deployed |
| B07P10 | Producer | 12/10/2015 | Liner Deployed |

# 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 | 2 | 0 | 2 | 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 | 18 | 0 | 9 | 9 |
| B06 Pad | 2012 | 8 | 0 | 8 | 0 |
| B07 Pad | 2012 | 8 | 0 | 8 | 0 |
| B07b Pad | 2015 | 11 | 0 | 11 | 0 |
| B08 Pad | 2013 | 10 | 0 | 10 | 0 |
| B09 Pad | 2014 | 11 | 0 | 11 | 0 |
| B11 Pad | 2013 | 12 | 0 | 12 | 0 |
| F01 Pad | 2015 | 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 (150 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

# SAGD Well Pressure Instrumentation

At Christina Lake all production 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 and to accommodate encapsulated thermocouples, where desired.

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

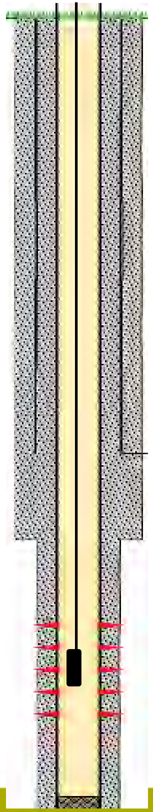
**At Christina Lake, production wells currently use 1 of 2 technologies to measure downhole temperatures.**

- **Type ‘K’ Thermocouples**
  - Single point installed at the heel
  - 6 point that is installed along the producer horizontal

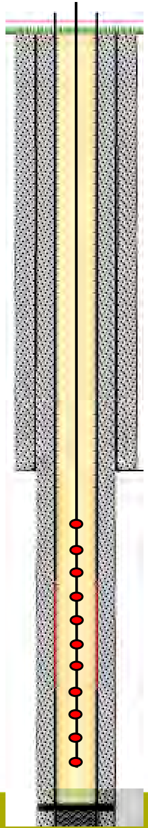
- **Distributed Temperature Sensing (DTS)**
  - fiber optic instrumentation provides temperature measurement at any point from surface to the toe of the producer horizontal section

# Instrumentation in Observation Wells (typical completions)

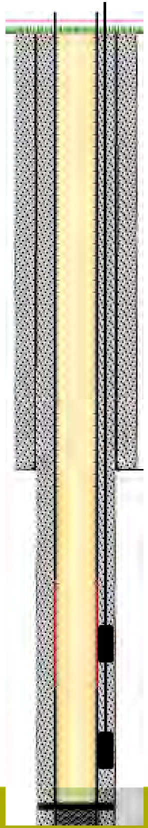
Hanging Piezometer



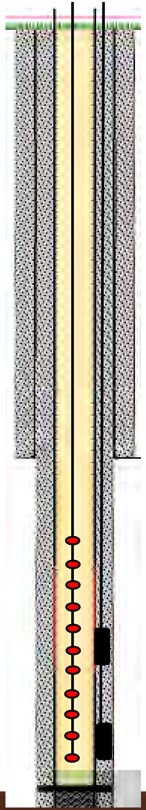
Hanging Thermocouples



Cemented Piezometers



Cemented Piezometers and Hanging Thermocouples



# 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.

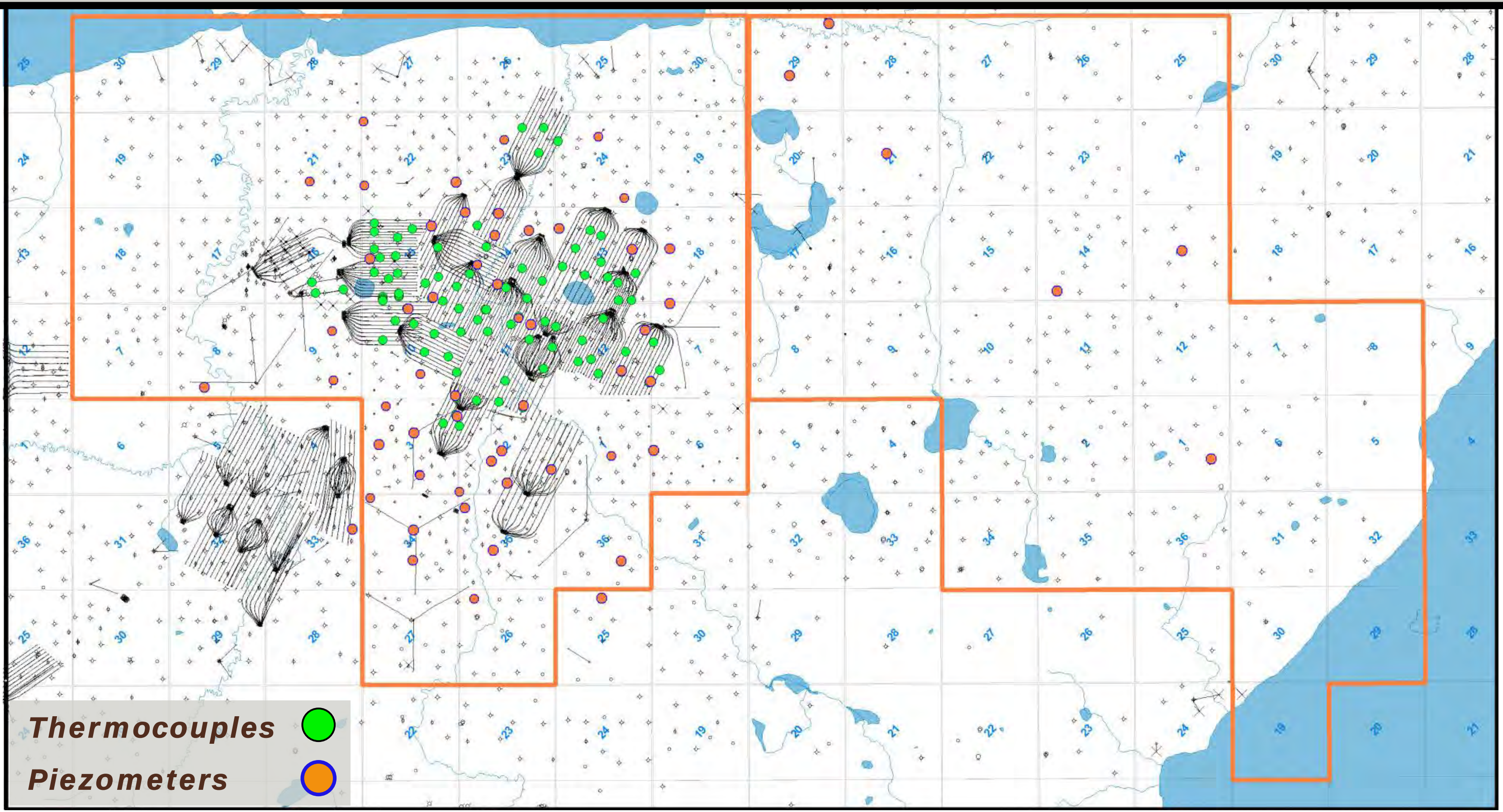
**Piezometers**

- Reliability has been good since 2013 when the switch was made to high temperature vibrating wire piezometers rated to 250ºC
- Cemented piezometers are impossible to replace in kind. Need to install hanging piezometer to replace
- Have seen failures as a result of improper installation and well securement issues

**Communications**

- Migration to a new radio network has increased reliability substantially
- Ongoing upgrades to SCADA equipment increases dependability and lowers future maintenance costs

# Observation Wells



# Subsection 3.1.1–5c) & d) instrumentation data

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

cenovus ENERGY

# Subsection 3.1.1 – 6)
# 4D Seismic


Amin Fardi

Reservoir Engineer

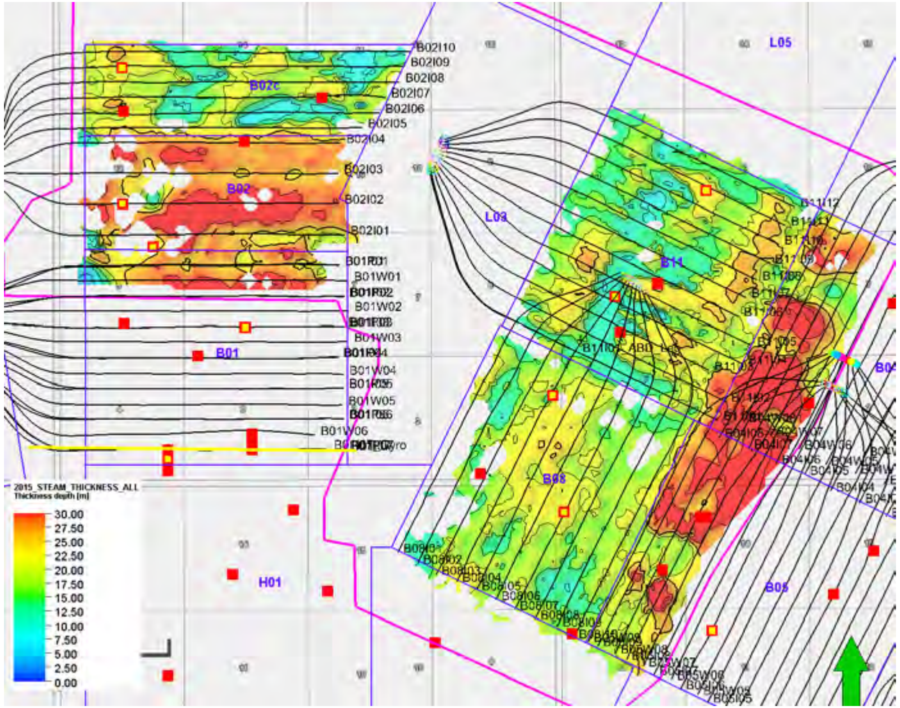

cenovus ENERGY

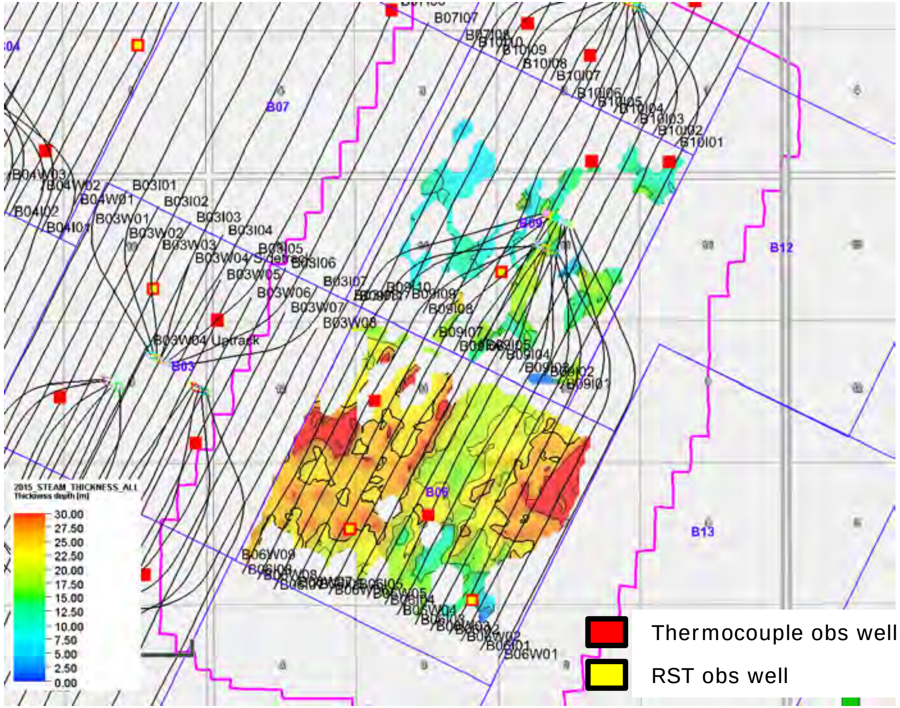
# Subsection 3.1.1 – 6) a)


2015
4D
seismic
outlines

a) seismic lines location map

# Subsection 3.1.1 – 6) b)




b) Interpreted steam-affected chamber thickness

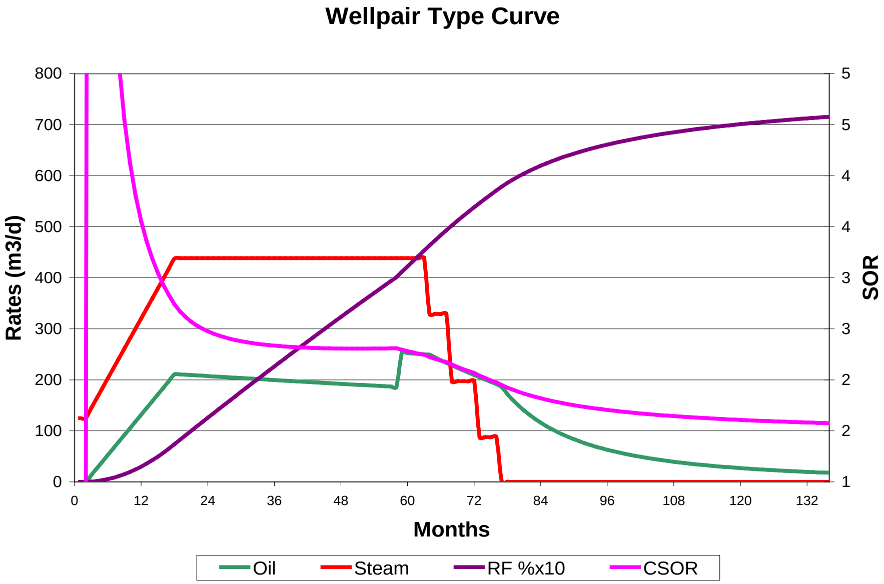
# Subsection 3.1.1 – 7) Scheme performance

Amin Fardi

Reservoir Engineer

# Scheme performance prediction

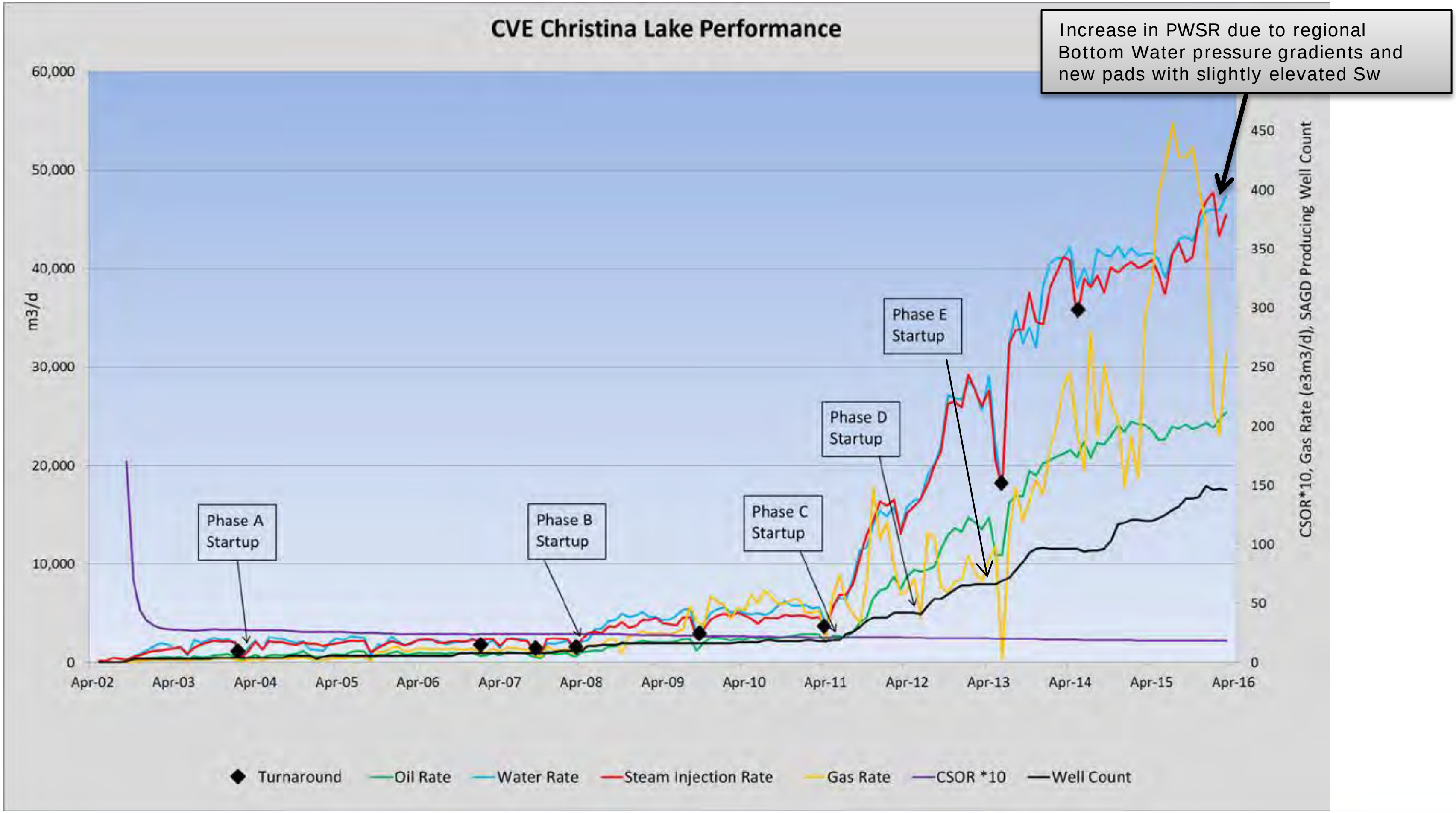
- Predict well pair performance based on modified Butler's equation
- Predict well pair CSOR using published CSOR correlations (Edmunds & Chhina 2002)
- Generate overall scheme production performance by adding individual well forecasts over time to honor predicted steam capacity and water treating availability

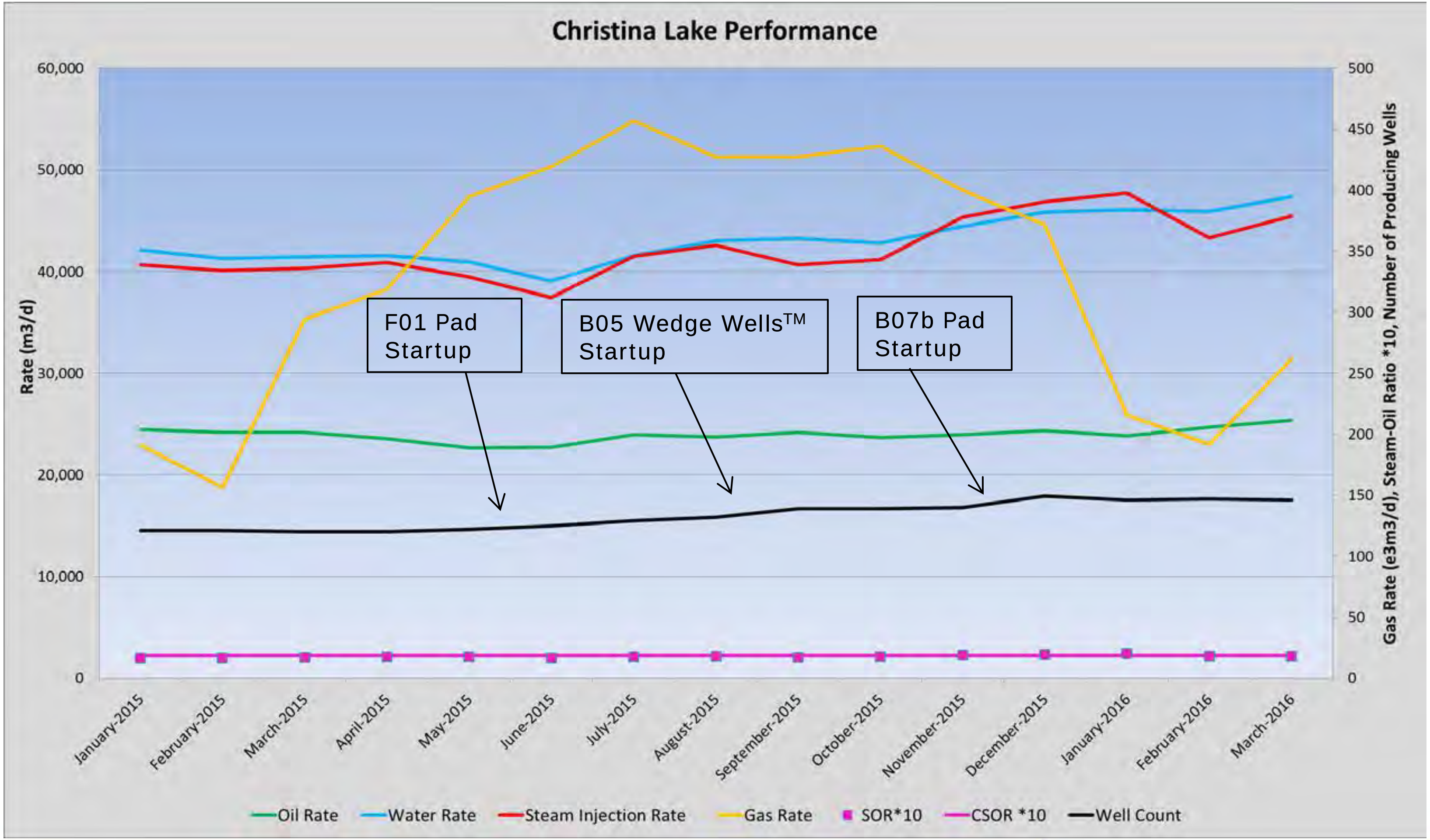


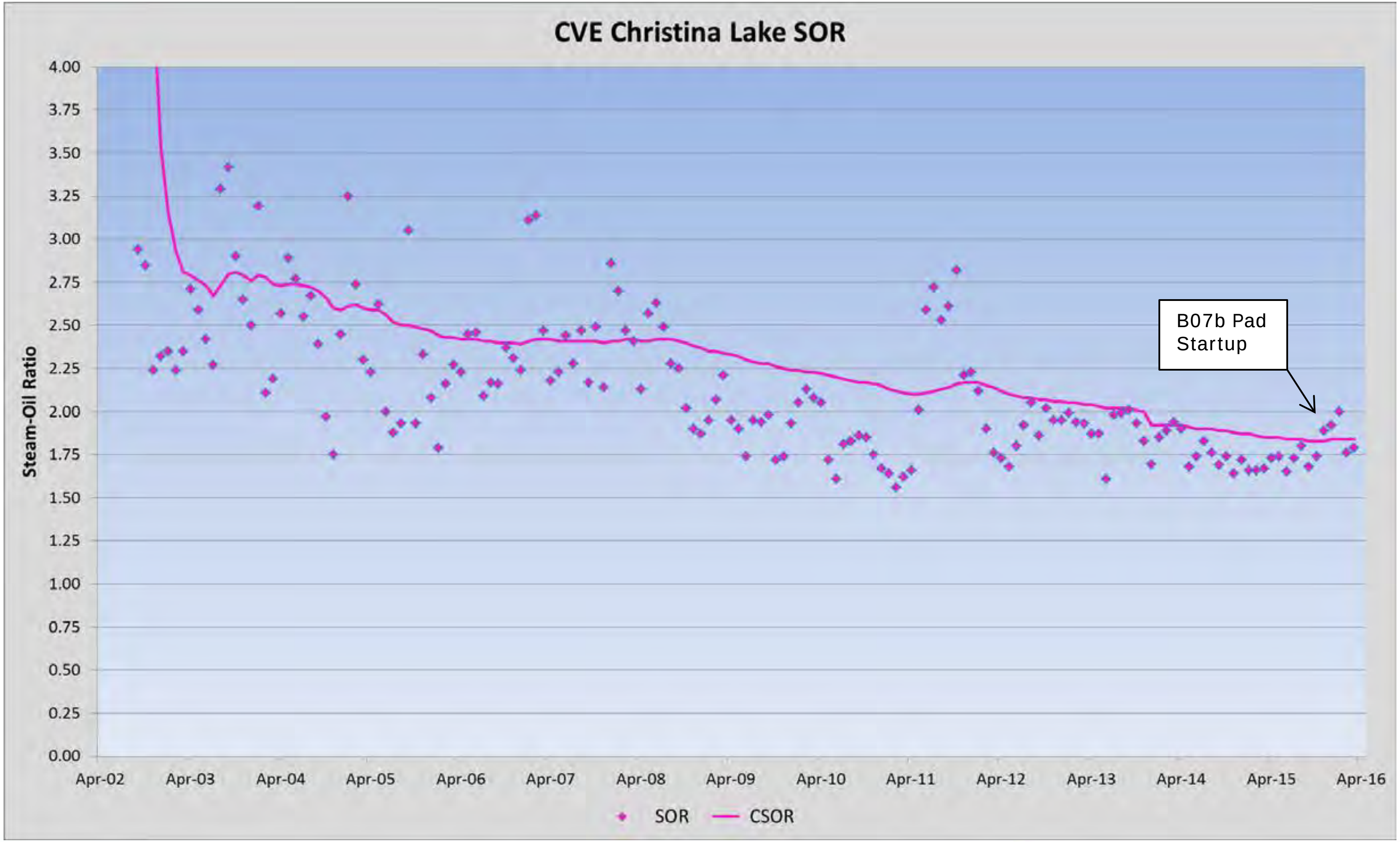
# SAGD summary to date

**161 total production wells in operation to date:**

- 122 standard well pairs
  - all on ESP, no gas lift
- one offset toe producer well
  - ESP
  - increase recovery from A01-3 well pair
- 38 wells using patented Wedge Well$^{TM}$ 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
  - 9 located in B05 pad


CVE Christina Lake Performance
Increase in PWSR due to regional Bottom Water pressure gradients and new pads with slightly elevated Sw
60,000
50,000
40,000
30,000
20,000
10,000
0
m3/d
450
400
350
300
250
200
150
100
50
0
CSOR*10, Gas Rate (e3m3/d), SAGD Producing Well Count
Phase A Startup
Phase B Startup
Phase C Startup
Phase D Startup
Phase E Startup
Apr-02
Apr-03
Apr-04
Apr-05
Apr-06
Apr-07
Apr-08
Apr-09
Apr-10
Apr-11
Apr-12
Apr-13
Apr-14
Apr-15
Apr-16
Turnaround
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
CSOR *10
Well Count


Christina Lake Performance
Rate (m3/d)
60,000
50,000
40,000
30,000
20,000
10,000
0
500
450
400
350
300
250
200
150
100
50
0
Gas Rate (e3m3/d), Steam-Oil Ratio *10, Number of Producing Wells
F01 Pad Startup
B05 Wedge Wells™ Startup
B07b Pad Startup
January-2015
February-2015
March-2015
April-2015
May-2015
June-2015
July-2015
August-2015
September-2015
October-2015
November-2015
December-2015
January-2016
February-2016
March-2016
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
SOR*10
CSOR *10
Well Count


CVE Christina Lake SOR
Steam-Oil Ratio
4.00
3.75
3.50
3.25
3.00
2.75
2.50
2.25
2.00
1.75
1.50
1.25
1.00
0.75
0.50
0.25
0.00
Apr-02
Apr-03
Apr-04
Apr-05
Apr-06
Apr-07
Apr-08
Apr-09
Apr-10
Apr-11
Apr-12
Apr-13
Apr-14
Apr-15
Apr-16
B07b Pad Startup
SOR
CSOR

# 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: ***Base*** *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

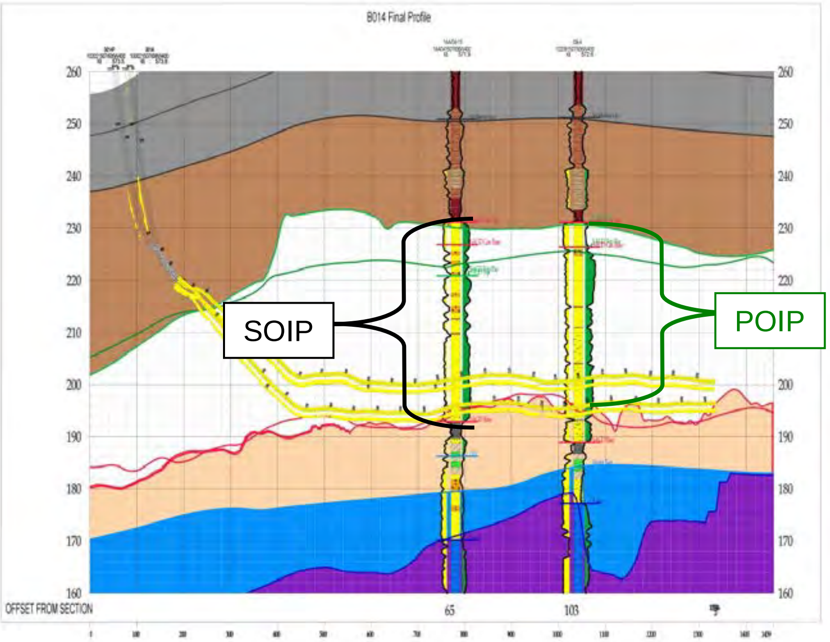
## We define producible OIP as:

- (**Effective length**) x (Spacing) x (Effective pay: ***Producer*** *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

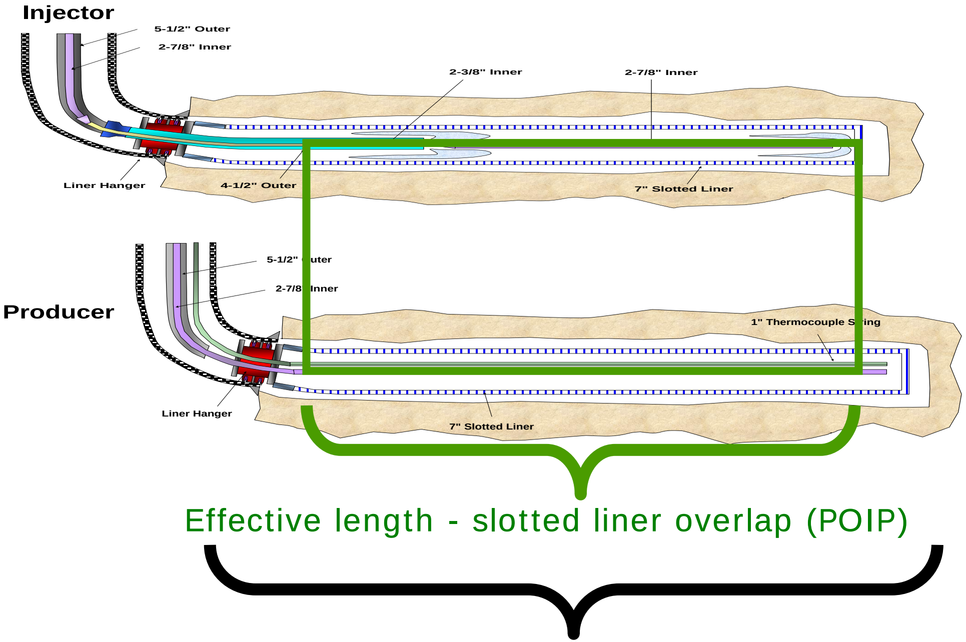
## Producible OIP is always < SAGDable OIP

# SAGDable vs. producible OIP (definition)

Vertical




Horizontal



# OIP and RF per pad

| Oil in Place (OIP) and % Recovery | | | | | | |
|---|---|---|---|---|---|---|
| Pad | Cumulative Oil Production ($Mm^3$)* | SOIP ($Mm^3$) | SOIP Recovery* | POIP ($Mm^3$) | POIP Recovery* | Ultimate Recovery |
| A | 2,198 | 5,054 | 43.5% | 4,332 | 50.7% | 60-85% |
| A02 | 373 | 4,056 | 9.2% | 3,583 | 10.4% | 60-85% |
| B01 | 3,323 | 5,830 | 57.0% | 4,817 | 69.0% | 60-85% |
| B02 | 2,256 | 3,081 | 73.2% | 2,694 | 83.8% | 60-85% |
| B02C | 1,229 | 2,461 | 49.9% | 1,851 | 66.4% | 60-85% |
| B03 | 3,857 | 7,296 | 52.9% | 5,742 | 67.2% | 60-85% |
| B04 | 4,347 | 7,369 | 59.0% | 6,295 | 69.1% | 60-85% |
| B05 | 3,359 | 8,325 | 40.3% | 7,080 | 47.4% | 60-85% |
| B06 | 2,638 | 5,694 | 46.3% | 4,522 | 58.3% | 60-85% |
| B07 | 3,590 | 6,929 | 51.8% | 6,043 | 59.4% | 60-85% |
| B07b | 166 | 6,528 | 2.5% | 5,275 | 3.1% | 60-85% |
| B08 Pad | 1,751 | 5,593 | 31.3% | 4,603 | 38.0% | 60-85% |
| B09 Pad | 1,207 | 7,063 | 17.1% | 5,999 | 20.1% | 60-85% |
| B11 Pad | 2,639 | 5,887 | 44.8% | 5,266 | 50.1% | 60-85% |
| F01 Pad | 447 | 5,954 | 7.5% | 4,668 | 9.6% | 60-85% |

*As of March 31, 2016*

***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.***

Expect to recover 60-85% of oil in place (OIP) depending on the quality of pay. OIP volumes increased by 10% in 2015 compared to previous year's estimates. In certain cases significant non-rich pay was added, which has a lower expected ultimate recovery than the original highly rich pay, thus lowering overall expected ultimate recovery.

A02 OIP volumes encompass the entire standard size drainage box intended for 8-12 SAGD production well pairs. Currently only two producing well pairs.

# Average Reservoir Parameters

| Pad | Well Spacing (m) | Net SAGD Pay (m) | Pad Area | Average (ø) | Average ($S_o$) |
|---|---|---|---|---|---|
| A | 116 | 32 | 800m x 800m | 0.31 | 0.76 |
| A02 | 100 | 31 | 800m x 800m | 0.31 | 0.80 |
| B01 | 100 | 37 | 700m x 850m | 0.32 | 0.80 |
| B02 | 100 | 37 | 375m x 850m | 0.32 | 0.84 |
| B02C | 50 | 28 | 300m x 1000m | 0.32 | 0.83 |
| B03 | 100 | 43 | 800m x 800m | 0.32 | 0.84 |
| B04 | 100 | 43 | 800m x 800m | 0.31 | 0.81 |
| B05 | 100 | 42 | 800m x 800m | 0.31 | 0.78 |
| B06 | 100 | 35 | 800m x 800m | 0.31 | 0.80 |
| B07 | 100 | 40 | 800m x 800m | 0.31 | 0.81 |
| B07b | 67* | 29 | 800m x 800m | 0.30 | 0.75 |
| B08 Pad | 67 | 33 | 800m x 800m | 0.34 | 0.83 |
| B09 Pad | 67 | 47 | 800m x 800m | 0.31 | 0.83 |
| B11 Pad | 67 | 39 | 800m x 800m | 0.30 | 0.82 |
| F01 Pad | 67 | 35 | 800m x 800m | 0.30 | 0.75 |

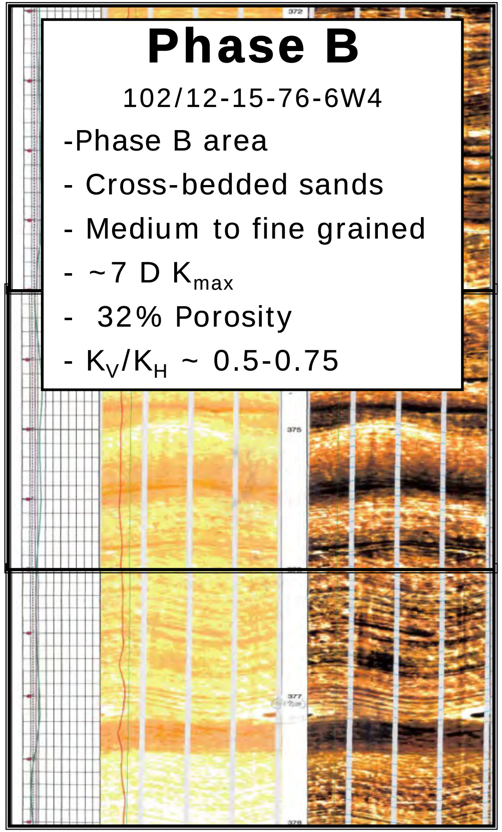
* Pairs 17-19 drilled at 100 m spacing

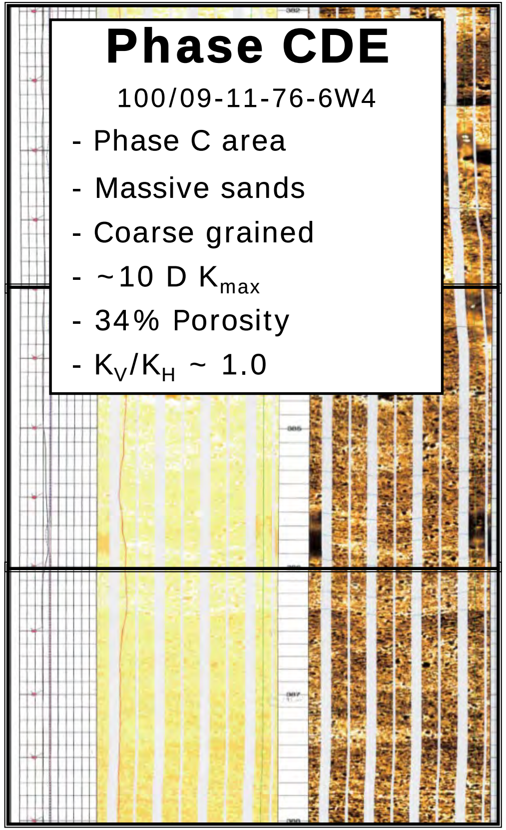
# Varying Reservoir Quality Pad Patterns

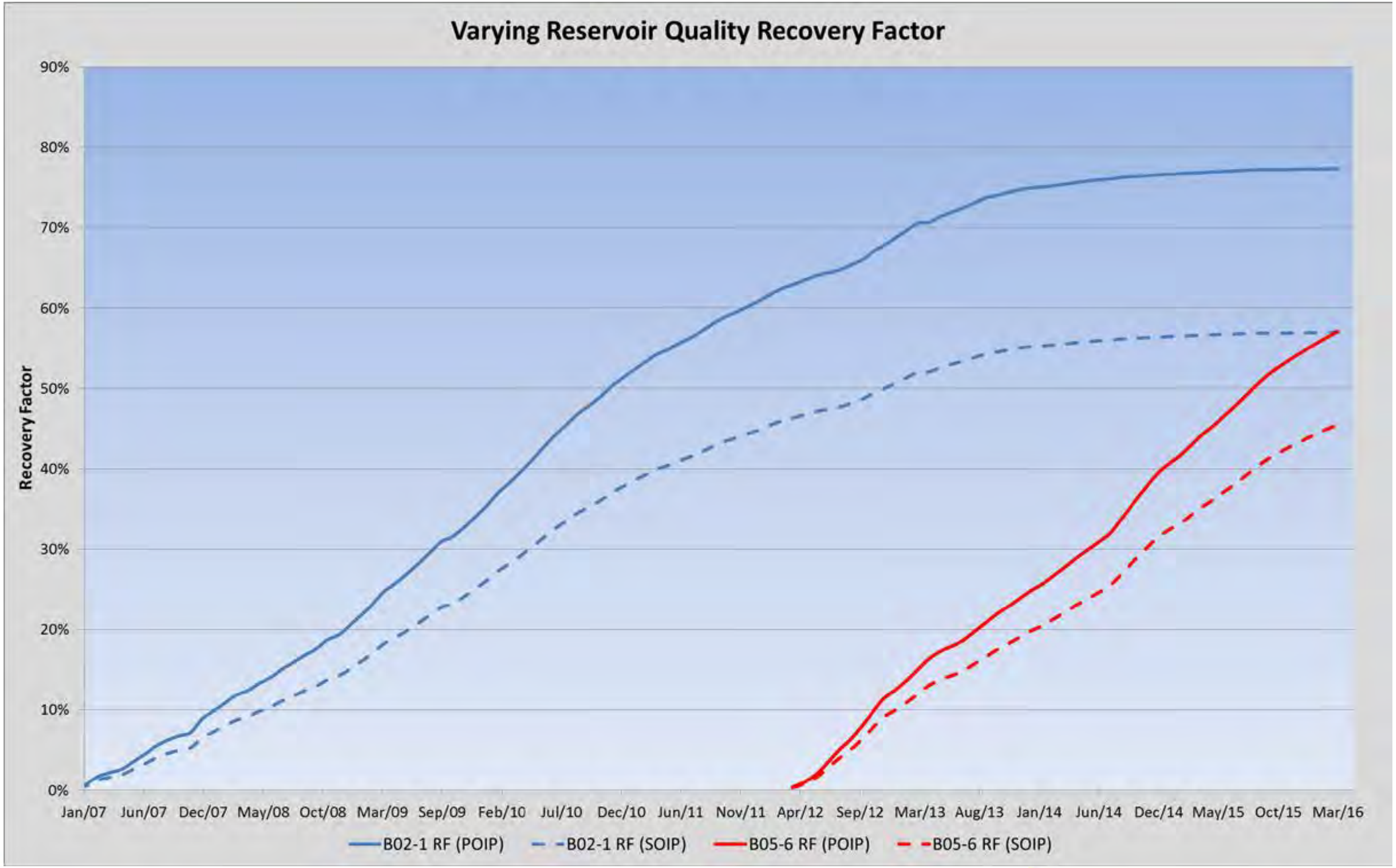
**Two example well pairs provided in Subsection 3.1.1 – 7b) illustrate:**

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

Variation in well performance is the result of several years of operational learnings between pad start dates.

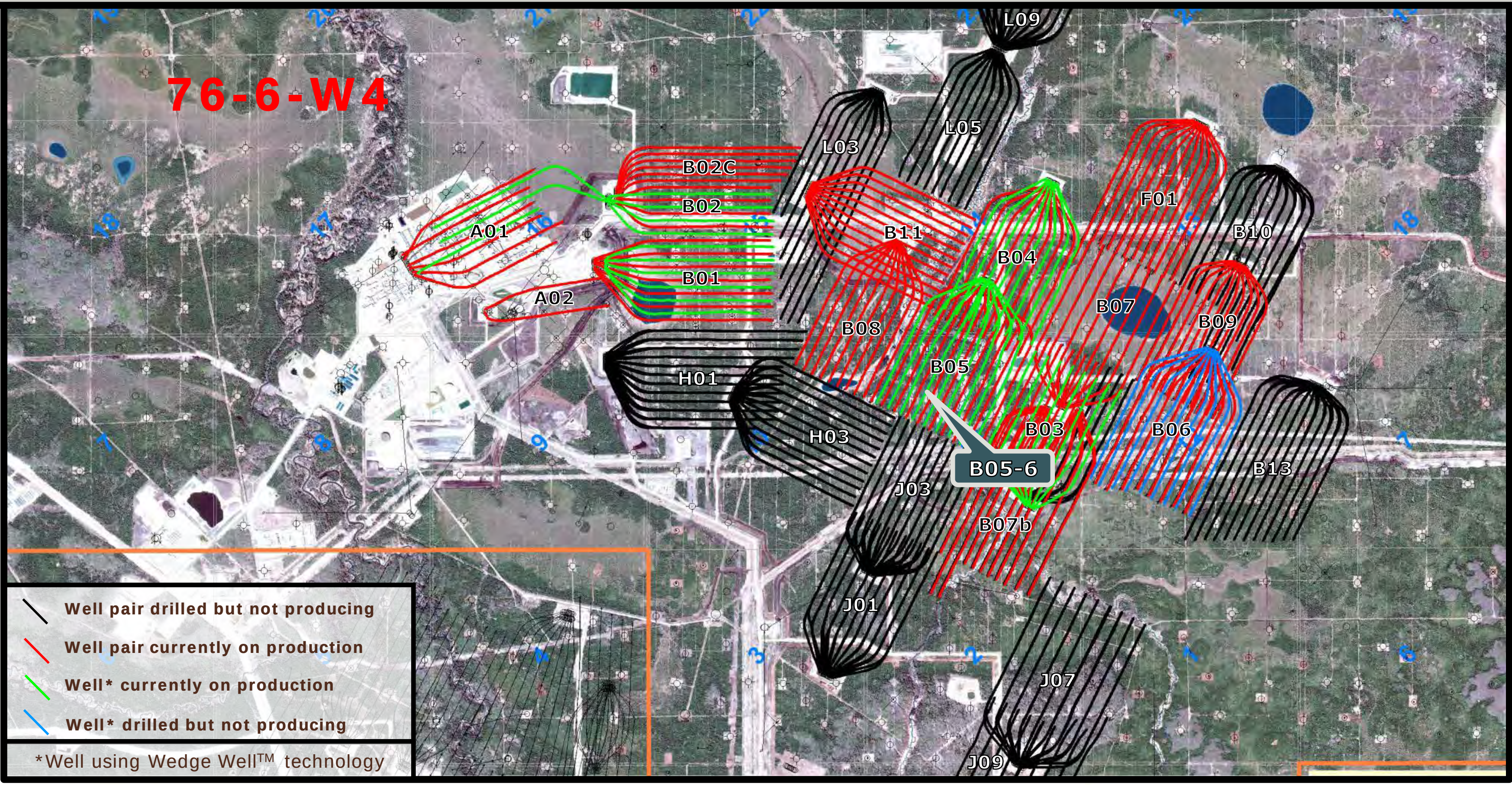


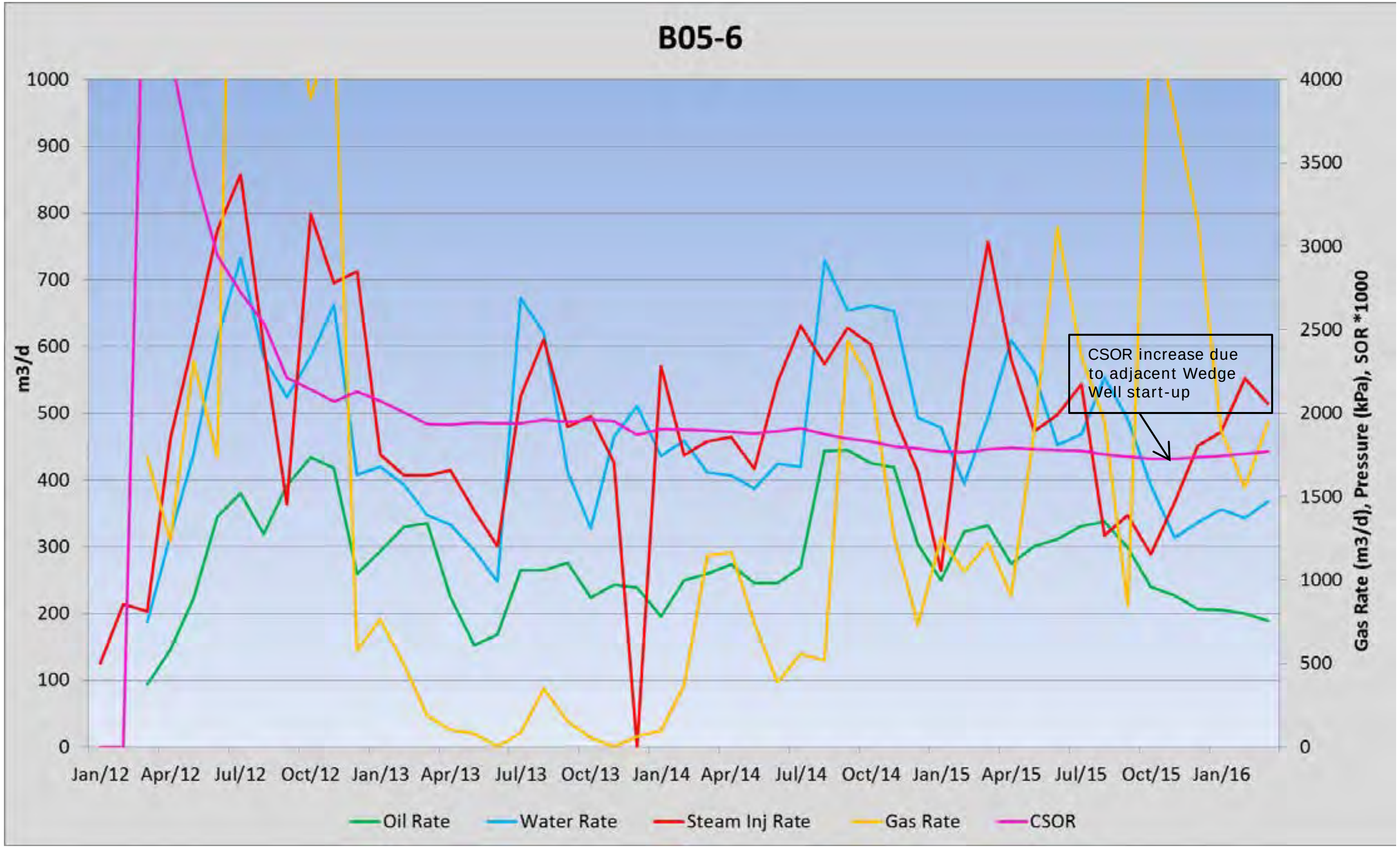


Varying Reservoir Quality Recovery Factor
Recovery Factor
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Jan/07 Jun/07 Dec/07 May/08 Oct/08 Mar/09 Sep/09 Feb/10 Jul/10 Dec/10 Jun/11 Nov/11 Apr/12 Sep/12 Mar/13 Aug/13 Jan/14 Jun/14 Dec/14 May/15 Oct/15 Mar/16
B02-1 RF (POIP)
B02-1 RF (SOIP)
B05-6 RF (POIP)
B05-6 RF (SOIP)

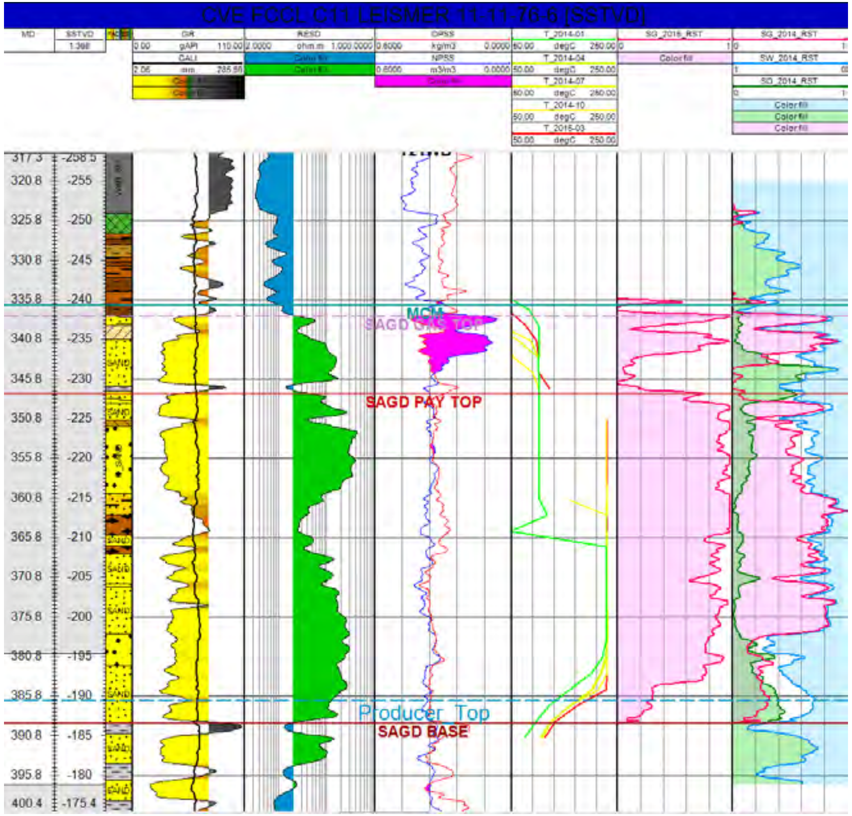
# B05-6 Well Pair




cenovus ENERGY

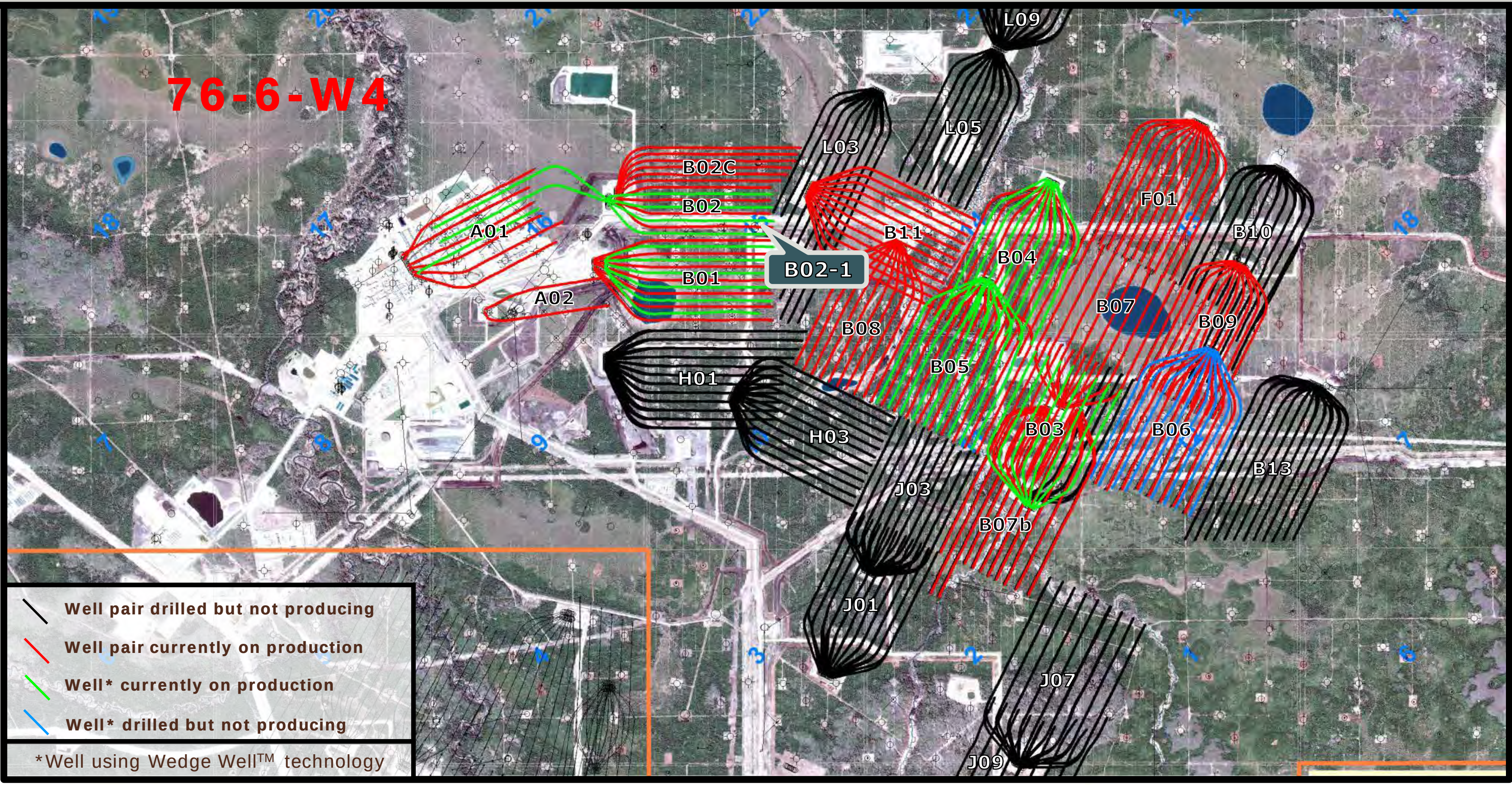

B05-6
m3/d
Gas Rate (m3/d), Pressure (kPa), SOR *1000
1000
900
800
700
600
500
400
300
200
100
0
4000
3500
3000
2500
2000
1500
1000
500
0
Jan/12 Apr/12 Jul/12 Oct/12 Jan/13 Apr/13 Jul/13 Oct/13 Jan/14 Apr/14 Jul/14 Oct/14 Jan/15 Apr/15 Jul/15 Oct/15 Jan/16
Oil Rate
Water Rate
Steam Inj Rate
Gas Rate
CSOR
CSOR increase due to adjacent Wedge Well start-up

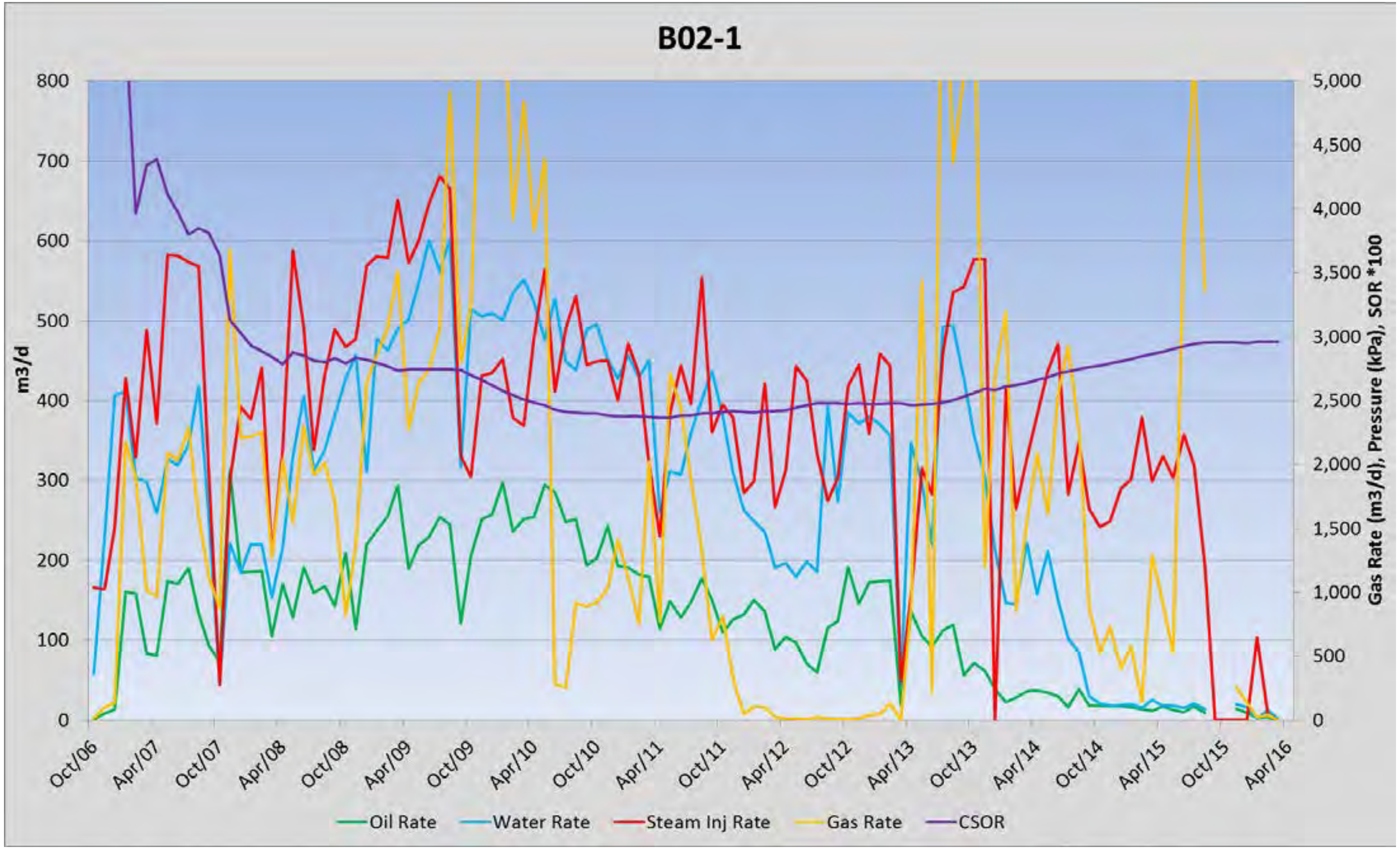
# B05-6 Toe



CVE FCCL C11 LEISMER 11-11-76-6 (SSTVD)
MCM
SAGD GAS TOP
SAGD PAY TOP
Producer_Top
SAGD BASE

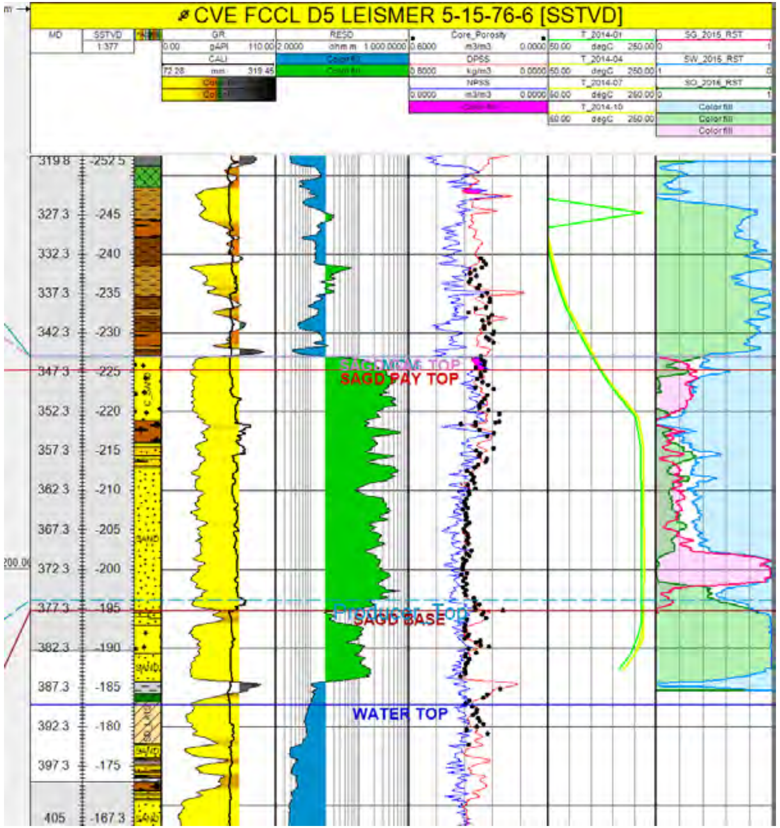
# B02-1 Well Pair






*Rampdown trial at B02-1 interrupted by VFD failure in late 2015, causing steam to be shut-off prematurely.

# B02-1 Mid




No baseline data for this well – high water saturations in the pay zone are steam

# 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 $MPa_g$ 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

# Full-blowdown on A01 pad

- **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 ~ 2,000 $kPa_g$
    - no negative impact has been observed with the pad operations as a result of full methane injection.
    - average concentration for Jan 2015 - March 2016
      - average methane injection rate 40 e3m3/d
      - CSOR has been maintained at 2.50

# B01/B02 pad rampdown/blowdown pilot

## Temporary wind-down test on B01 and B02 pads started June 2015

- timeframe: 1 year
- well pairs: B01-1 to B01-4 including WWs 01-03; B02-1 to B02-4 included.
- steam will be brought back on after test is complete

## B01-1 to B01-4: Blowdown test (6 month test, extended to 1 year in Jan 2016)

- shut-in steam on all four wells
    - using gas cap (top down blowdown) to maintain pressure
- CSOR has been maintained at 1.67

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

- cut steam by 25% every 3 months (75%, 50%, 25%, 0%)
- CSOR has been maintained at 1.92

## Key learnings thus far:

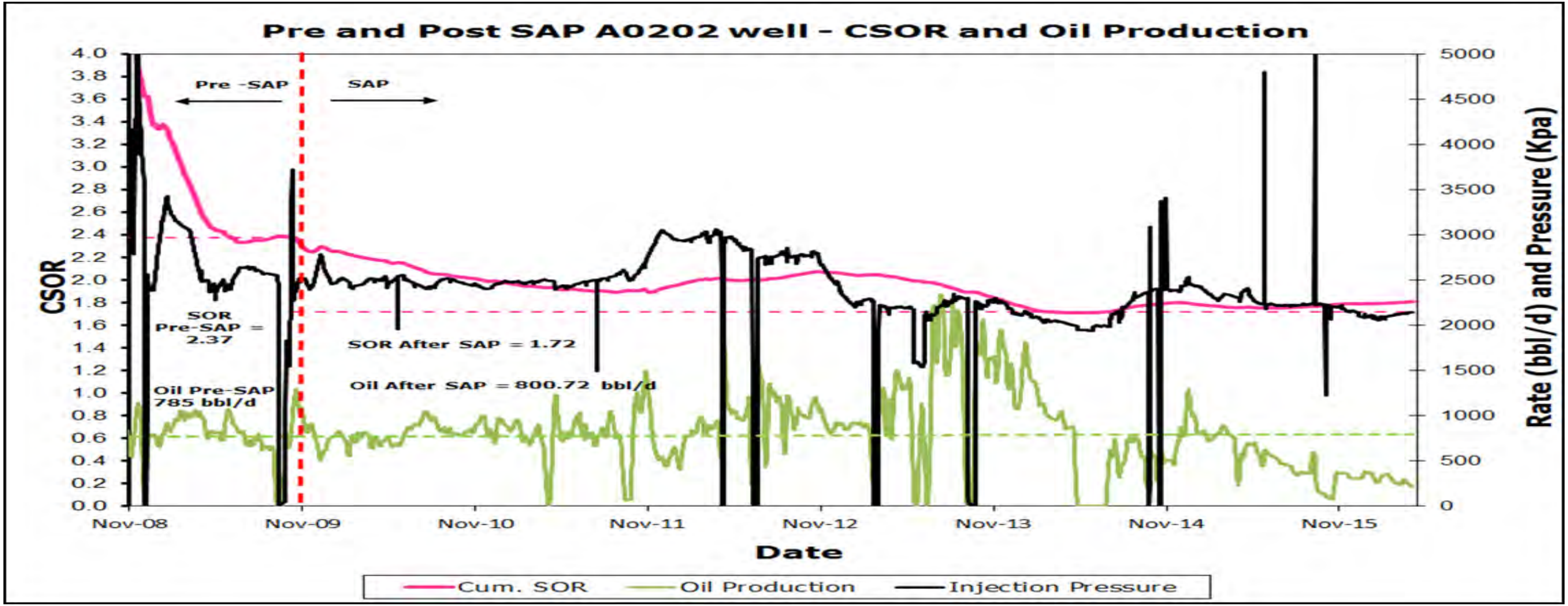
- Increased gas production observed during blowdown
- Neighboring SAGD pads appear unaffected by blowdown at this time

# Subsection 3.1.1 – 7e) Injected fluids

A02-2 SAP Project

cenovus ENERGY

# A0202 SAP



Pre and Post SAP A0202 well - CSOR and Oil Production
Pre -SAP
SAP
SOR Pre-SAP = 2.37
SOR After SAP = 1.72
Oil Pre-SAP 785 bbl/d
Oil After SAP = 800.72 bbl/d
CSOR
4.0
3.8
3.6
3.4
3.2
3.0
2.8
2.6
2.4
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
Rate (bbl/d) and Pressure (Kpa)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Nov-08
Nov-09
Nov-10
Nov-11
Nov-12
Nov-13
Nov-14
Nov-15
Date
Cum. SOR
Oil Production
Injection Pressure

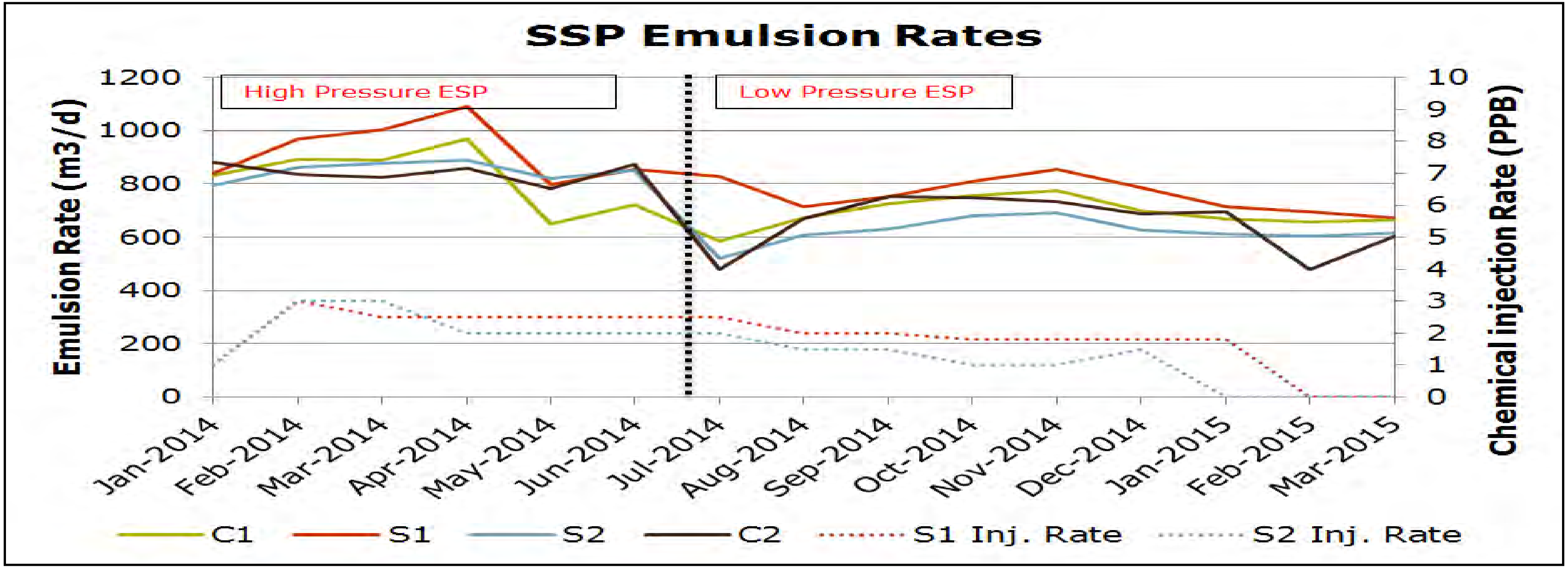
# A0202 SAP (solvent aided process)

- **Started butane co-injection in November 2009**
- **Cumulative SOR of 1.81**
- **Cumulative solvent recovery factor of 70.6%**
- **SAP has shown benefit of oil uplift and reducing SOR**
- **Acid job on producer well in September 2015**
- **Planning to stop butane co-injection and operate A0202 on steam in Q2 2016**
- **Planning to commence NCG co-injection (25 wt.%) in Q3 2016**
- **A0201 Early SAP injection (planning to inject butane in Q2/Q3 2016)**

# Subsection 3.1.1 – 7e)
# Injected fluids

## Surfactant Steam Process (SSP) pilot

# SSP (Surfactant Steam Process)




**C1 → B11P09 (control well 1) S1 → B11P10 (surfactant 1) S2 → B11P11 (surfactant 2) C2 → B11P12 (control well 2)**

# SSP

- **Four wells in SSP trial**
- **Two wells with different surfactants and two control wells**
- **First steam in July 2013**
- **High pressure ESP operation (4000 kPa BHP) in November 2013**
- **First surfactant co-injection in January 2014**
- **Low pressure ESP operation (2800 kPa BHP) in June 2014**
- **Stopped injecting surfactant in Jan/Feb 2015**
- **Results are inconclusive due to communication with neighboring wells and thief zones**

# Subsection 3.1.1 – 7f)
# 2015 key learnings

## Operating SAGD with Top Gas, Bottom Water

# Operations at Christina Lake

## Thief zones:

- B01 to B11 pad are operating under a gas cap
- A01, B01 to B11 and F01 Pads have areas where Regional Bottom Water (BW) present with no shale break separating oil and BW

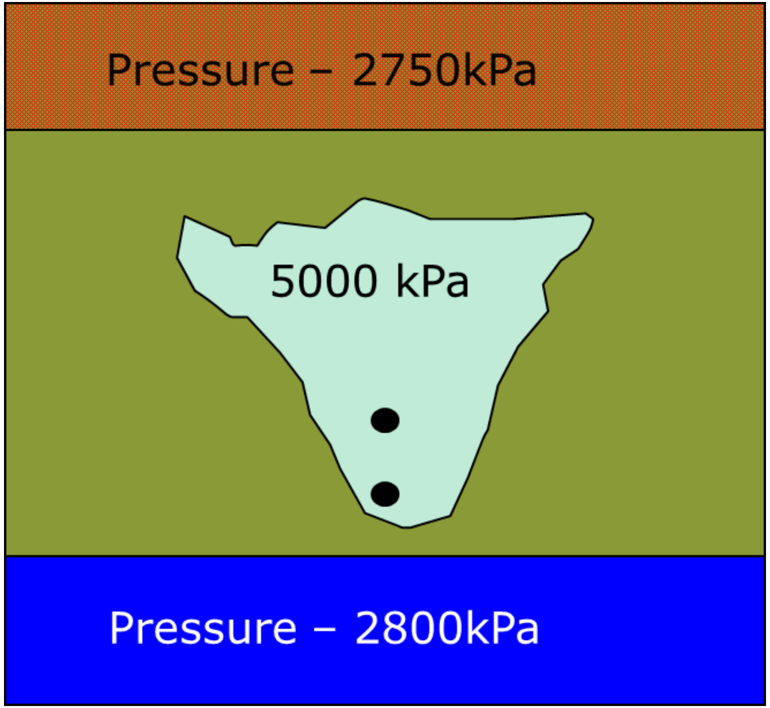
## Well performance of these two situations will be discussed:

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

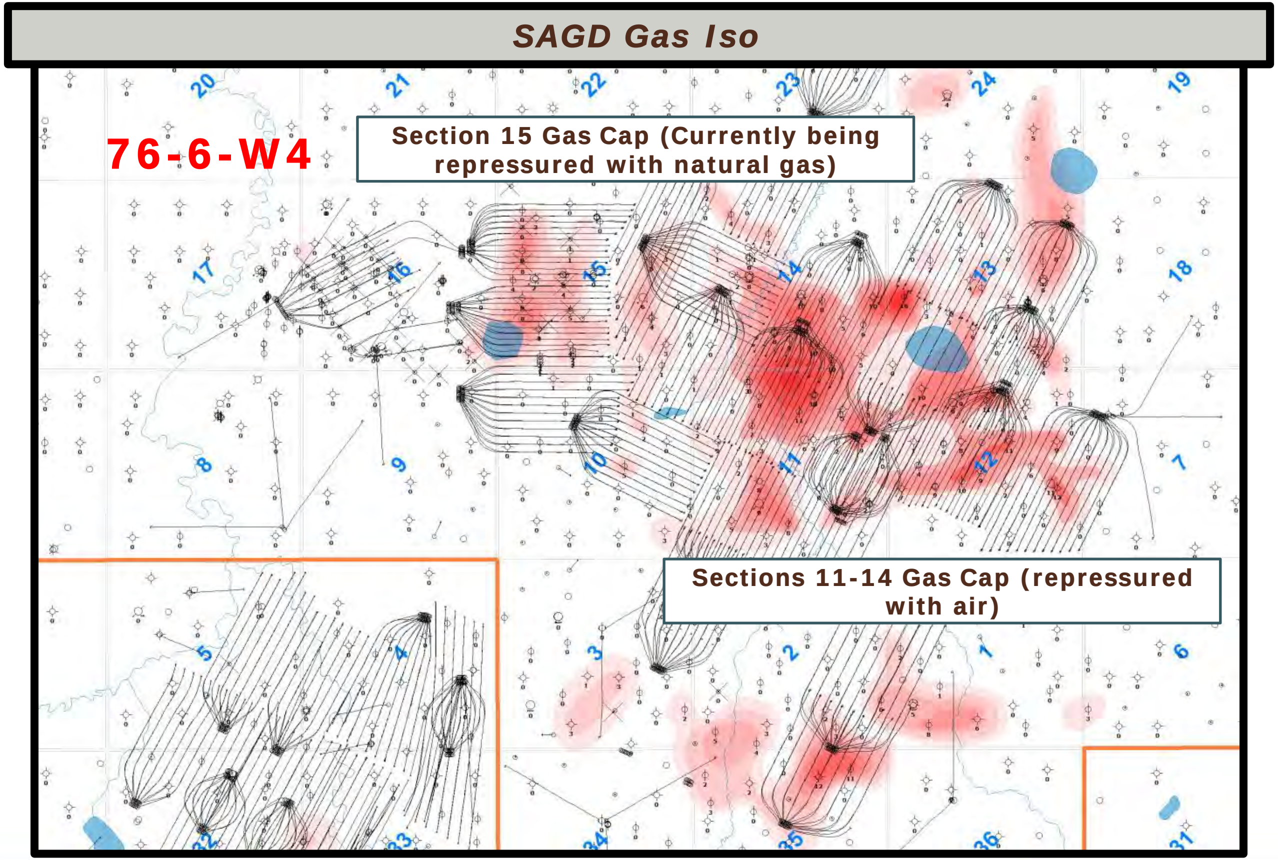
# High pressure operations

**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

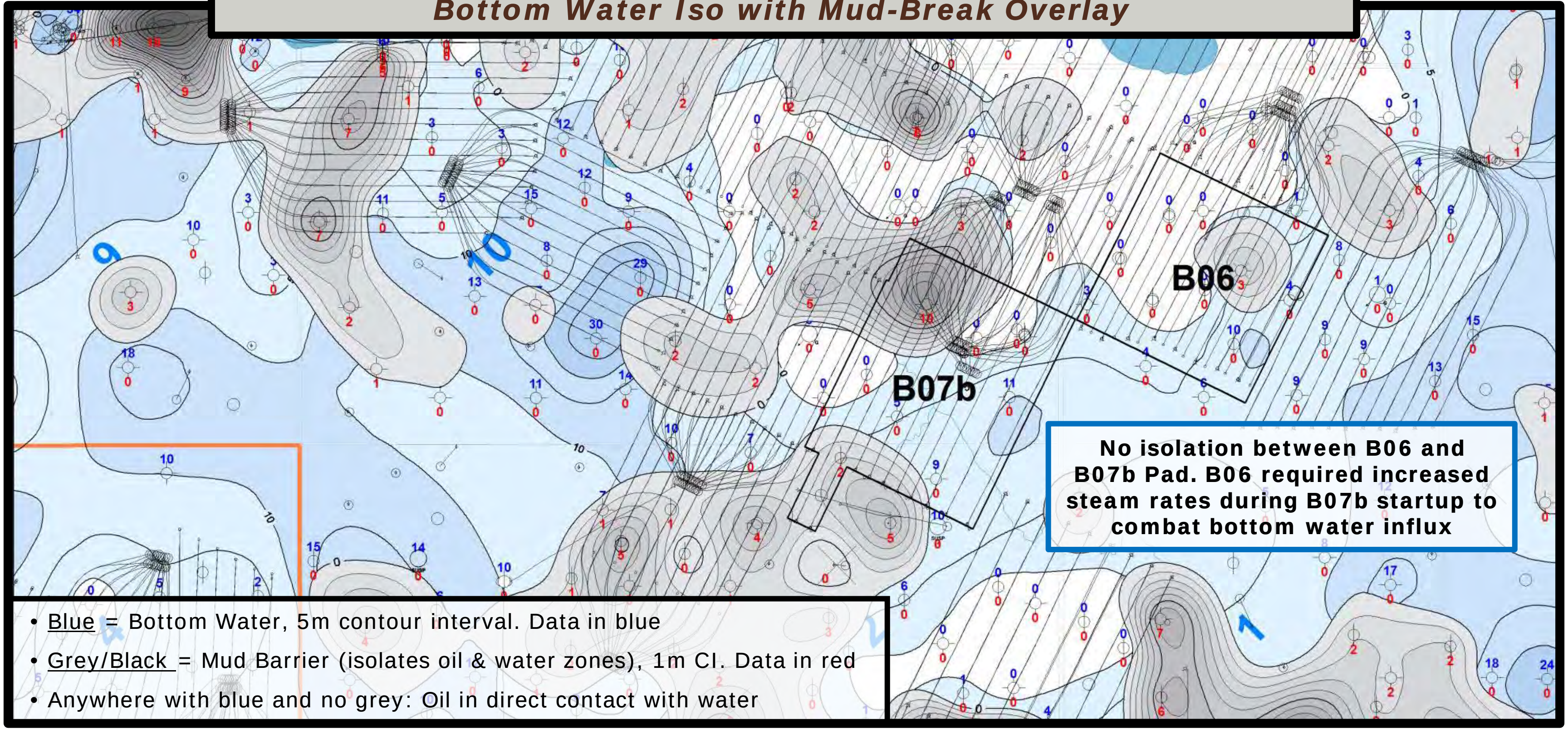


# B05-3 Gas Cap Communication


Gas influx into the steam chamber as evidence from cooling on thermocouples in adjacent monitoring wells. Effects of gas influx into the steam chamber are reversible.

# Bottom Water With No Isolation

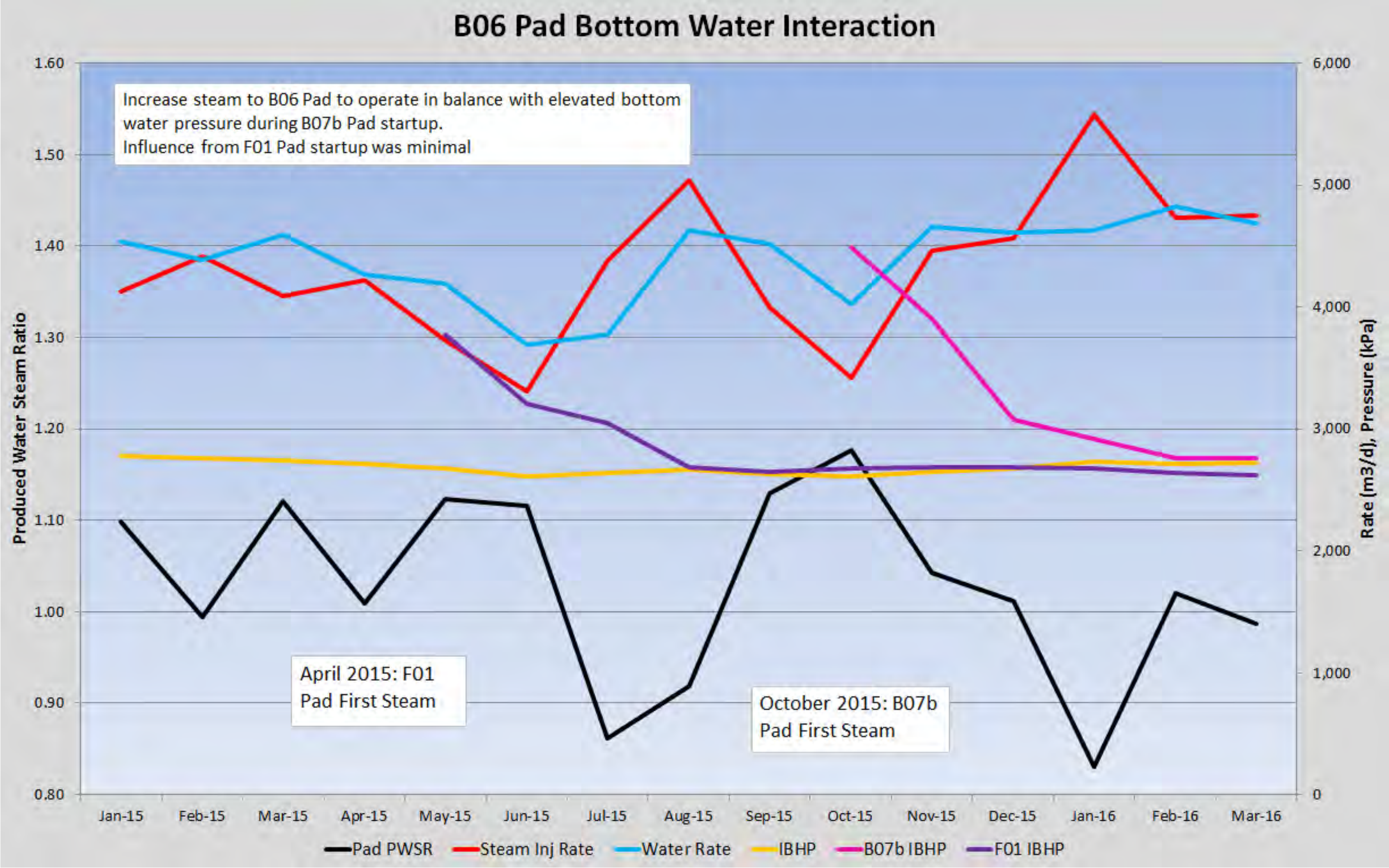
## *Bottom Water Iso with Mud-Break Overlay*




**No isolation between B06 and B07b Pad. B06 required increased steam rates during B07b startup to combat bottom water influx**

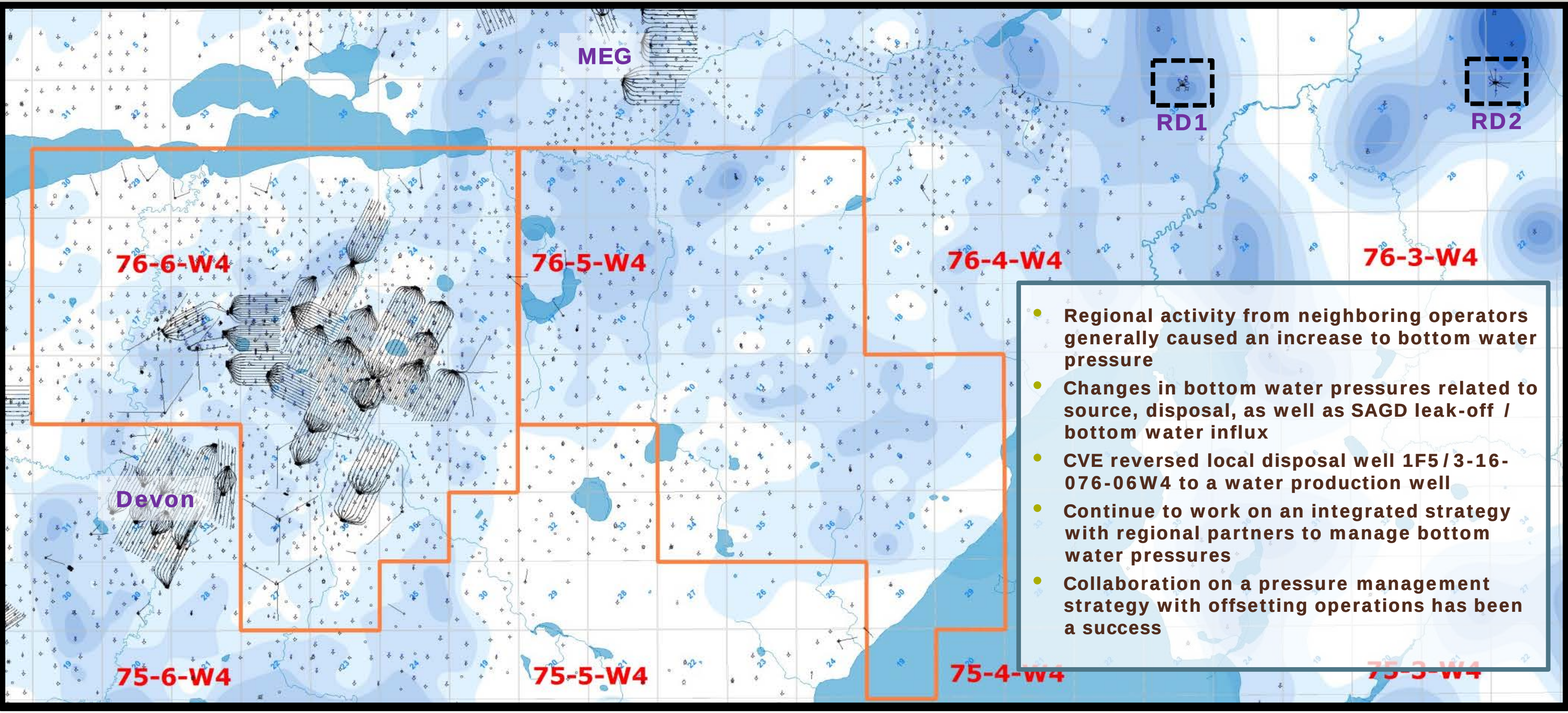
- Blue = Bottom Water, 5m contour interval. Data in blue
- Grey/Black = Mud Barrier (isolates oil & water zones), 1m CI. Data in red
- Anywhere with blue and no grey: Oil in direct contact with water


June 15, 2016


B06 Pad Bottom Water Interaction
Increase steam to B06 Pad to operate in balance with elevated bottom water pressure during B07b Pad startup.
Influence from F01 Pad startup was minimal
April 2015: F01 Pad First Steam
October 2015: B07b Pad First Steam
Produced Water Steam Ratio
Rate (m3/d), Pressure (kPa)
1.60
1.50
1.40
1.30
1.20
1.10
1.00
0.90
0.80
6,000
5,000
4,000
3,000
2,000
1,000
0
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Pad PWSR
Steam Inj Rate
Water Rate
IBHP
B07b IBHP
F01 IBHP

# Regional Bottom Water Pressure Influence

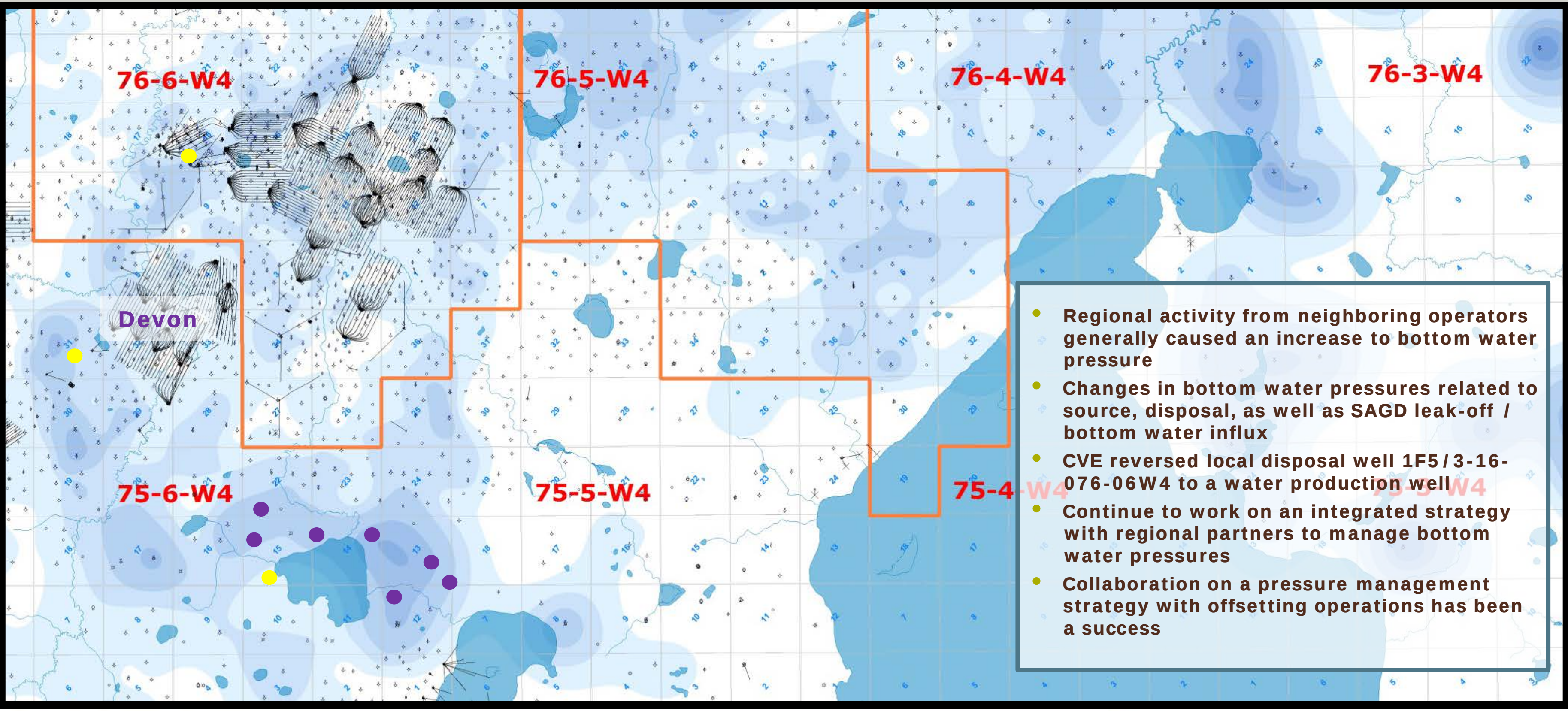
## Bottom Water Iso




- Regional activity from neighboring operators generally caused an increase to bottom water pressure
- Changes in bottom water pressures related to source, disposal, as well as SAGD leak-off / bottom water influx
- CVE reversed local disposal well 1F5/3-16-076-06W4 to a water production well
- Continue to work on an integrated strategy with regional partners to manage bottom water pressures
- Collaboration on a pressure management strategy with offsetting operations has been a success

# Regional Bottom Water Pressure Influence

## *Bottom Water Iso*



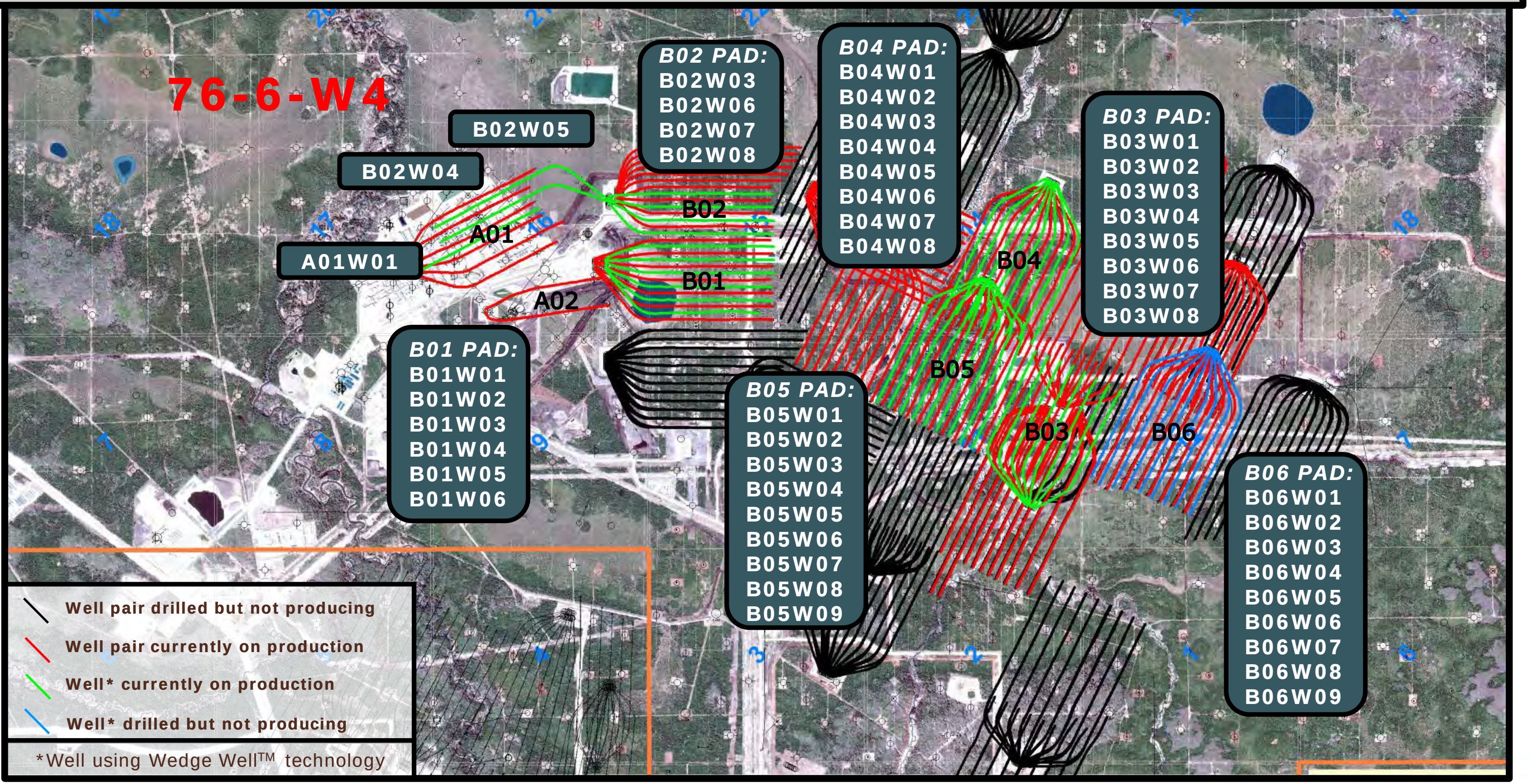

- Regional activity from neighboring operators generally caused an increase to bottom water pressure
- Changes in bottom water pressures related to source, disposal, as well as SAGD leak-off / bottom water influx
- CVE reversed local disposal well 1F5/3-16-076-06W4 to a water production well
- Continue to work on an integrated strategy with regional partners to manage bottom water pressures
- Collaboration on a pressure management strategy with offsetting operations has been a success

Source Well
Disposal Well

# Subsection 3.1.1 – 7f)
# 2015 key learnings

## Patented Wedge Well™ technology

# Patented Wedge Well™ Technology Locations



# Wedge Well™ Learnings

- Better parent well pair operation has reduced the necessity of wells using the Wedge Well™ technology.
- Wedge Well™ technology use may still be justified given the right conditions and will be evaluated on an individual pad basis going forward.
- Wedge Well™ vertical offset in relation to neighboring producers is determined by balancing the accessible incremental oil that can be recovered by the Wedge Well™ with the extent of conductive heating from the existing producing pairs.

# Subsection 3.1.1 – 7f) 2015 key learnings

## Wabiskaw Zone at Christina Lake

# Background

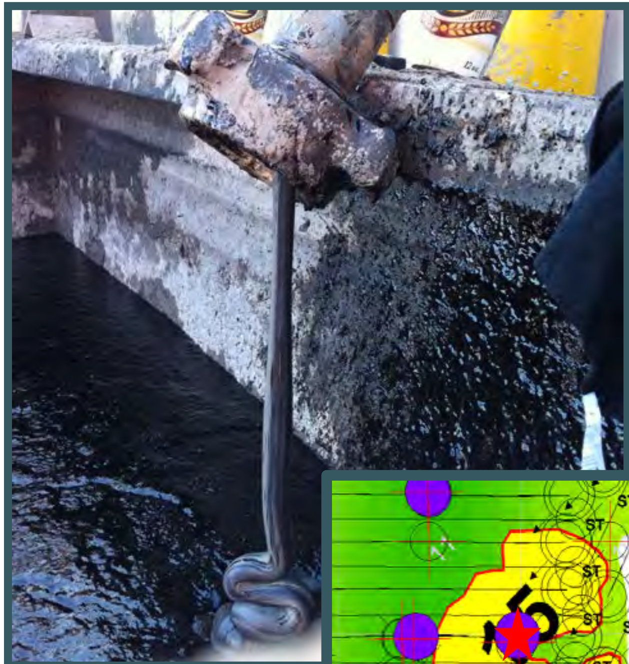
**Unexpected Discovery:**
steam-core drill in April 2013

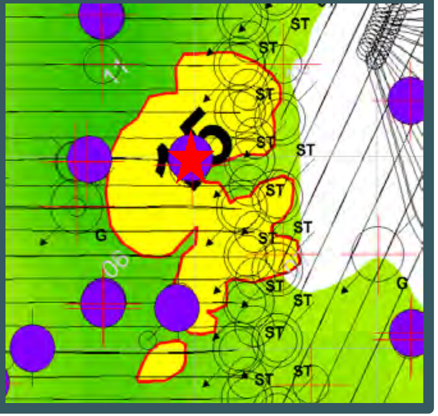
**6,500kPa Overpressure:**
conductive thermal expansion in WBSK
(above 5,400kPa MOP)

**4D Seismic Identification**

**WBSK Producer:**
107/06-15, 8,600m$^3$ oil, depressurization

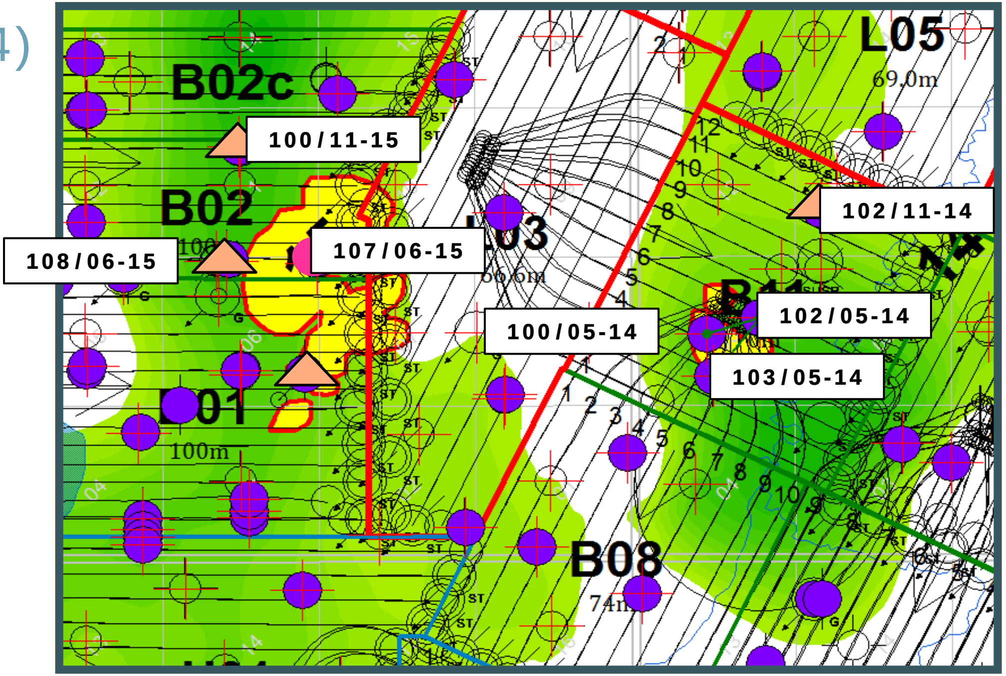
**Monitoring:**
enhanced observation capabilities in the area





# 2015-2016 Monitoring Enhancements

- Installed piezometer (00/05-14)
  - 4D seismic anomaly NOT overpressure
- Fixed broken thermocouples (03/05-14)
- Fixed broken piezometer (08/06-15)
- Added WBSK thermocouples (02/11-14)
- Shot 4D seismic in Q1 2016



# Conclusion

- None of the Wabiskaw is currently observed to be over MOP.
- Monitoring is in place to detect any future over pressuring before it reaches MOP.
- Potential overpressure in 4D seismic in Zone 2 proved to be low pressure, hints at gas accumulation and McMurray/Wabiskaw communication in this area, which reduces overpressure risk.
- Mitigation plans are in place if pressures climb towards MOP.

# Subsection 3.1.1 – 7g) Information requests

# Information Requests

**No Information requests for 2015**

# Subsection 3.1.1 – 7h)
# Pad production plots

cenovus ENERGY

# Pad production plots

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

# Subsection 3.1.1 – 8) Future plans

Amin Fardi

Reservoir Engineer

# Resource recovery strategy

## Well/pad placement:

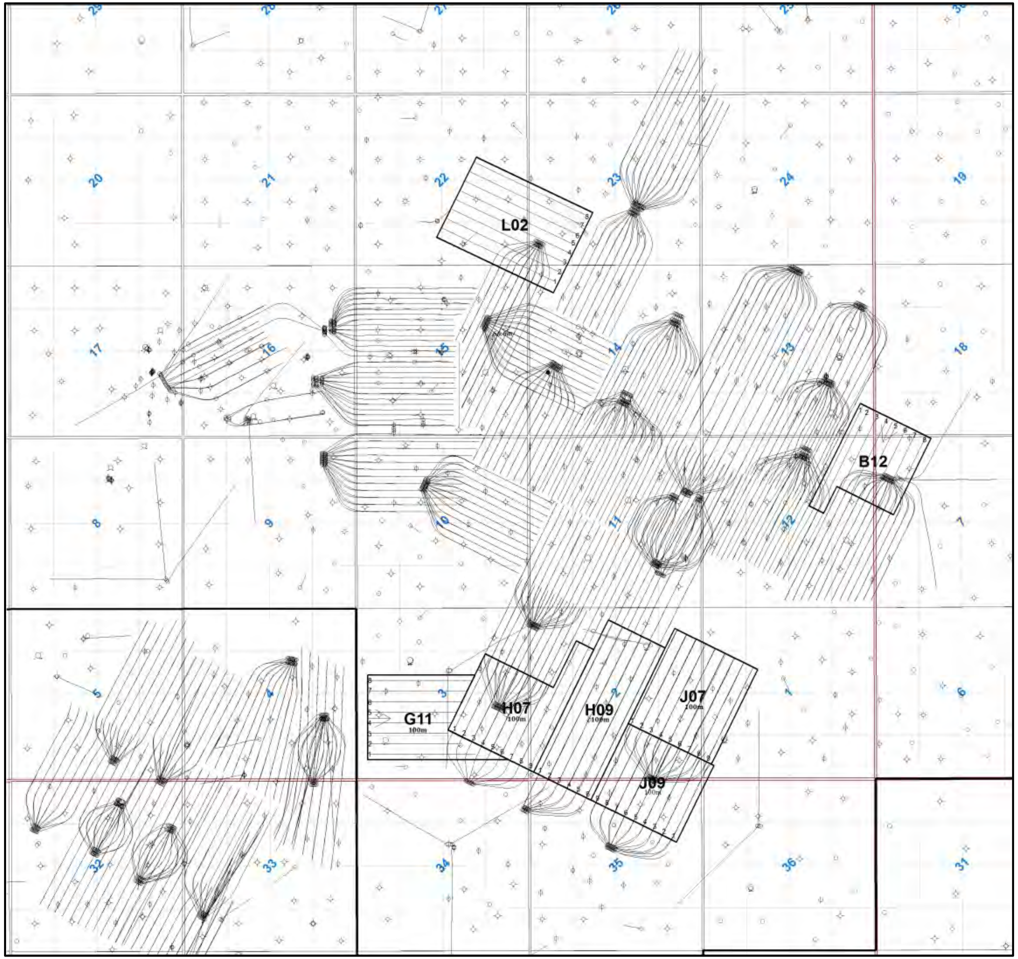
- 2016/2017 well pairs will be drilled as per the existing (or future) applications and approvals
- Well spacing/trajectories planned to be submitted for approval prior to construction/drilling

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

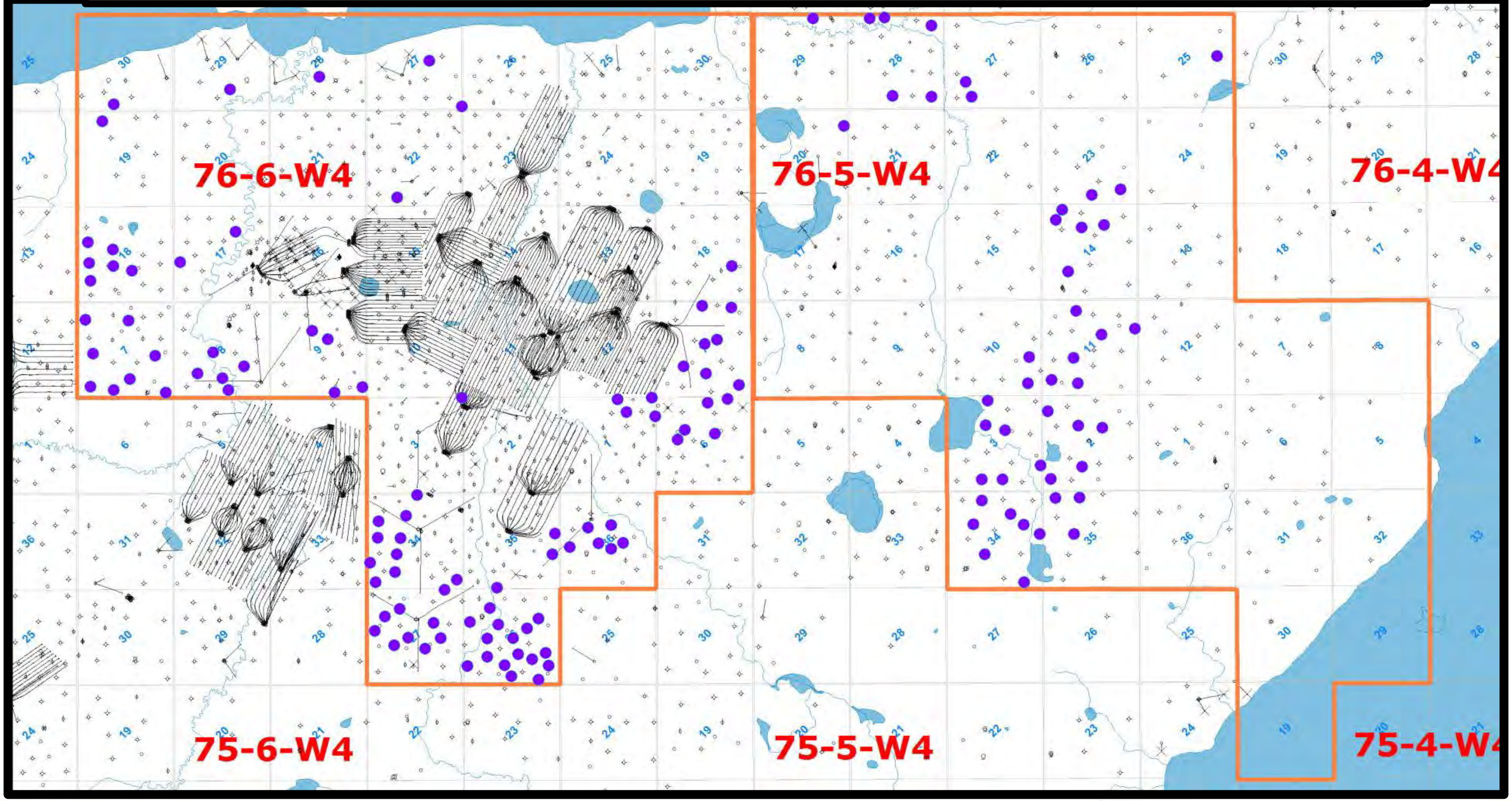
**Any deviations will be applied for as future amendments**

# SAGD Drilling Plans 2016/2017

| Pad | Pad type | Well count | Timing |
|---|---|---|---|
| J07 | Production | 9 well pairs | Q1 2016 |
| J09 | Production | 9 well pairs | Q1 2016 |
| H09 | Production | 6 well pairs | Q2 2016 |
| H07 | Production | 9 well pairs | Q4 2016 |
| L02 | Production | 8 well pairs | Q2 2017 |
| B12 | Production | 8 well pairs | Q3 2017 |
| G11 | Production | 8 well pairs | Q4 2017 |



# Planned Strat Wells for 2016/17



# Steam strategy 2016

- Phase F OTSG adding ~15,000 $m^3$/d incremental capacity. 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: B06 Wedge Well™ technology, B10, L03, J03, L05, L09, J01, B13
- total of 93 well pairs and 12 wells using Wedge Well™ technology
- Rampdown/blowdown/co-injection operations:
  - plan to continue blowdown at A01 pad
  - plan to continue at blowdown on B01-1 to B01-4 and rampdown on B02-1 to B02-4
  - Finalize co-injection/blowdown timing on B03, B04, B07 pad
- No steam shortages expected on existing pads

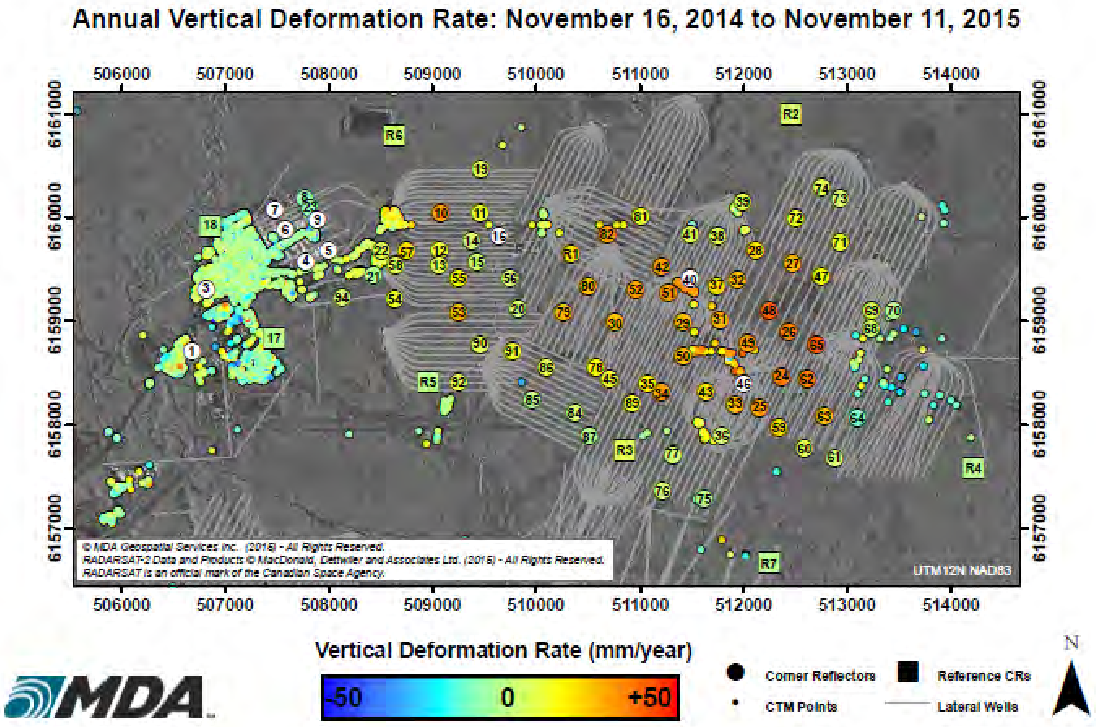
# Steam strategy 2017

- The following pads are planned to start up for sustaining production: J09, J07, H09
- total of 24 well pairs
- Blowdown operations:
  - planned to continue at A01 pad
  - Return steam to B01 and B02 and study reversibility following blowdown/rampdown test
  - Commence co-injection/blowdown on mature pads
- No steam shortages expected on existing pads

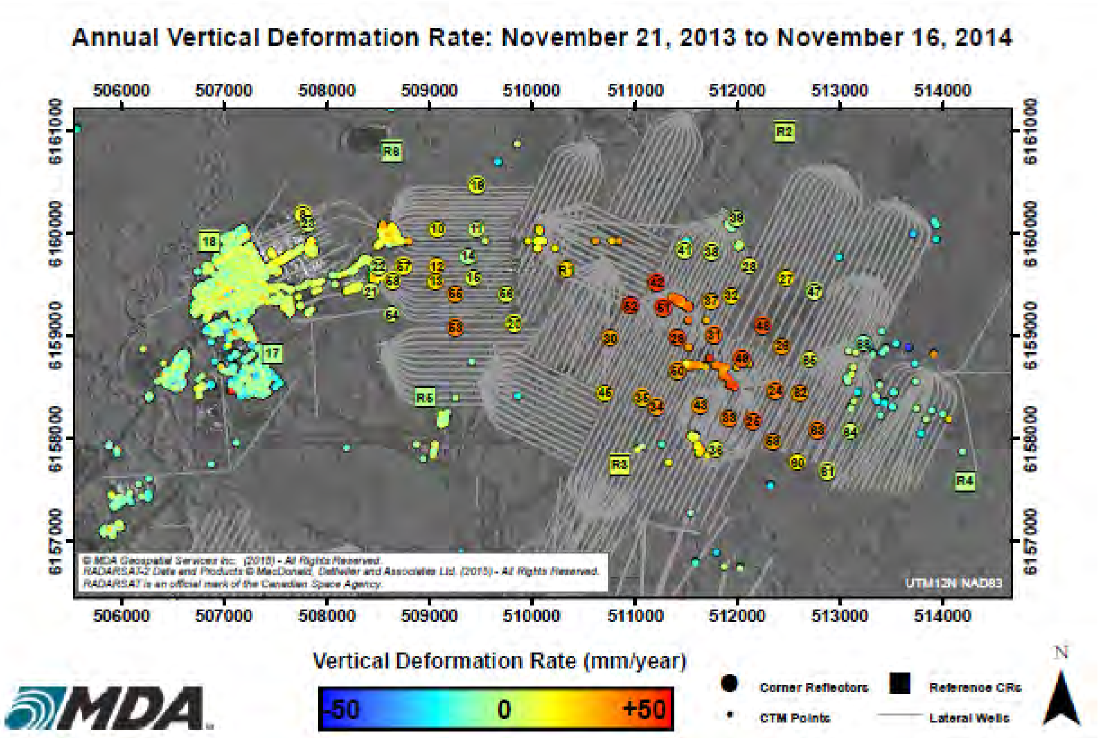
# Appendix 1
# Subsection 3.1.1 – 2)
# Heave data

# Annual vertical deformation rates:

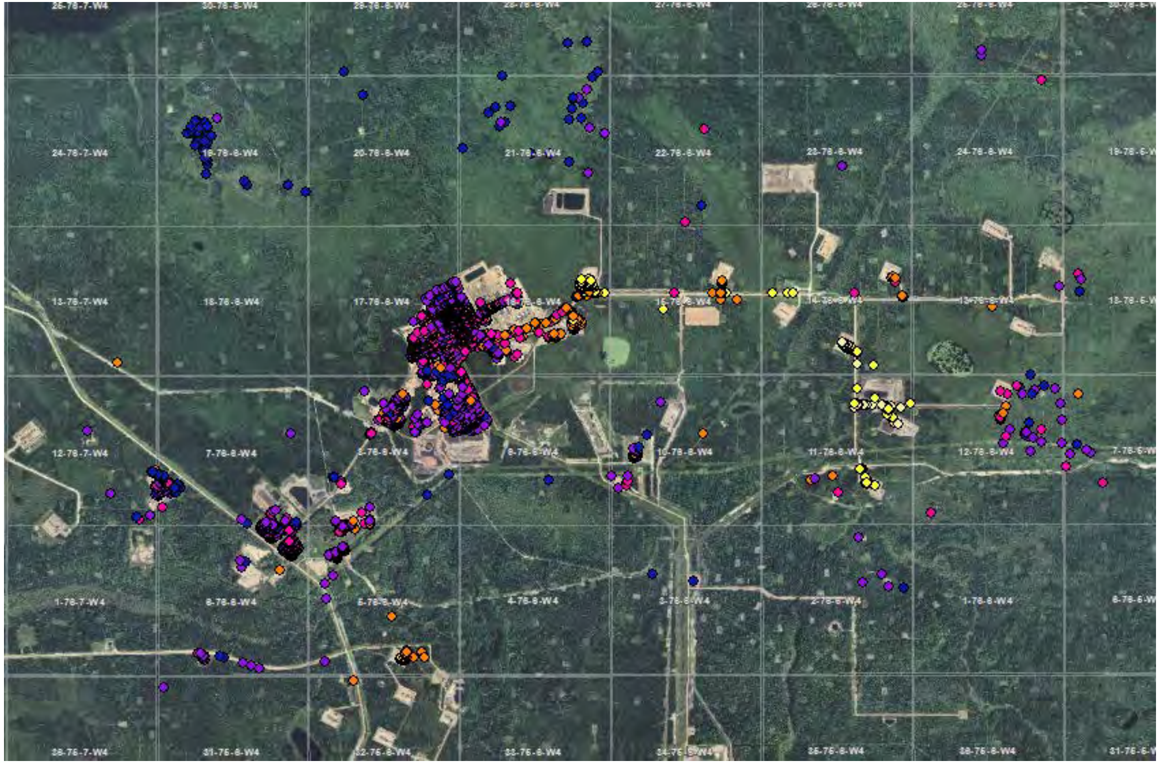
## November 16, 2014 – November 11, 2015 (1 year)



# Previous Annual vertical deformation rates:
November 21, 2014 – November 16, 2016

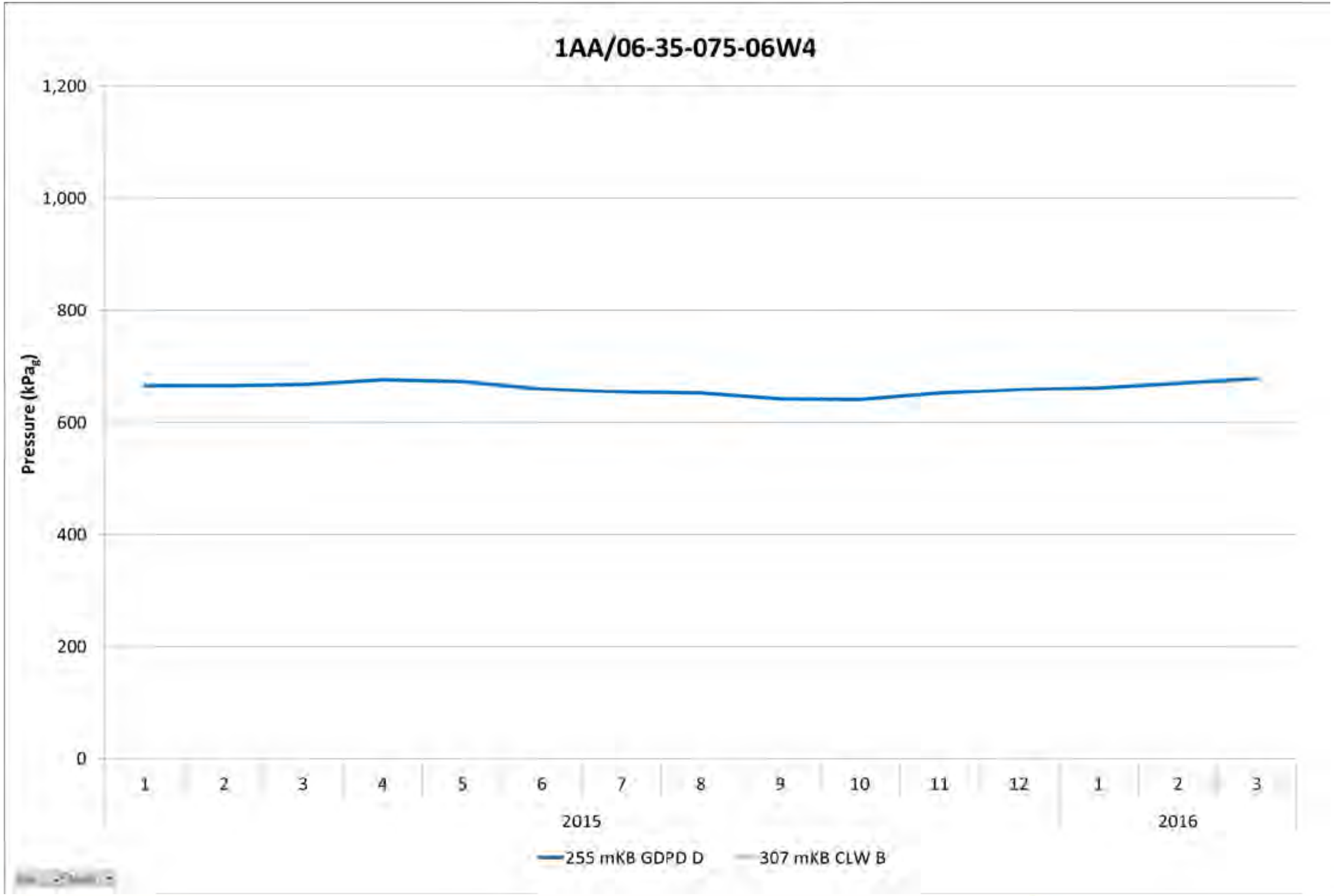


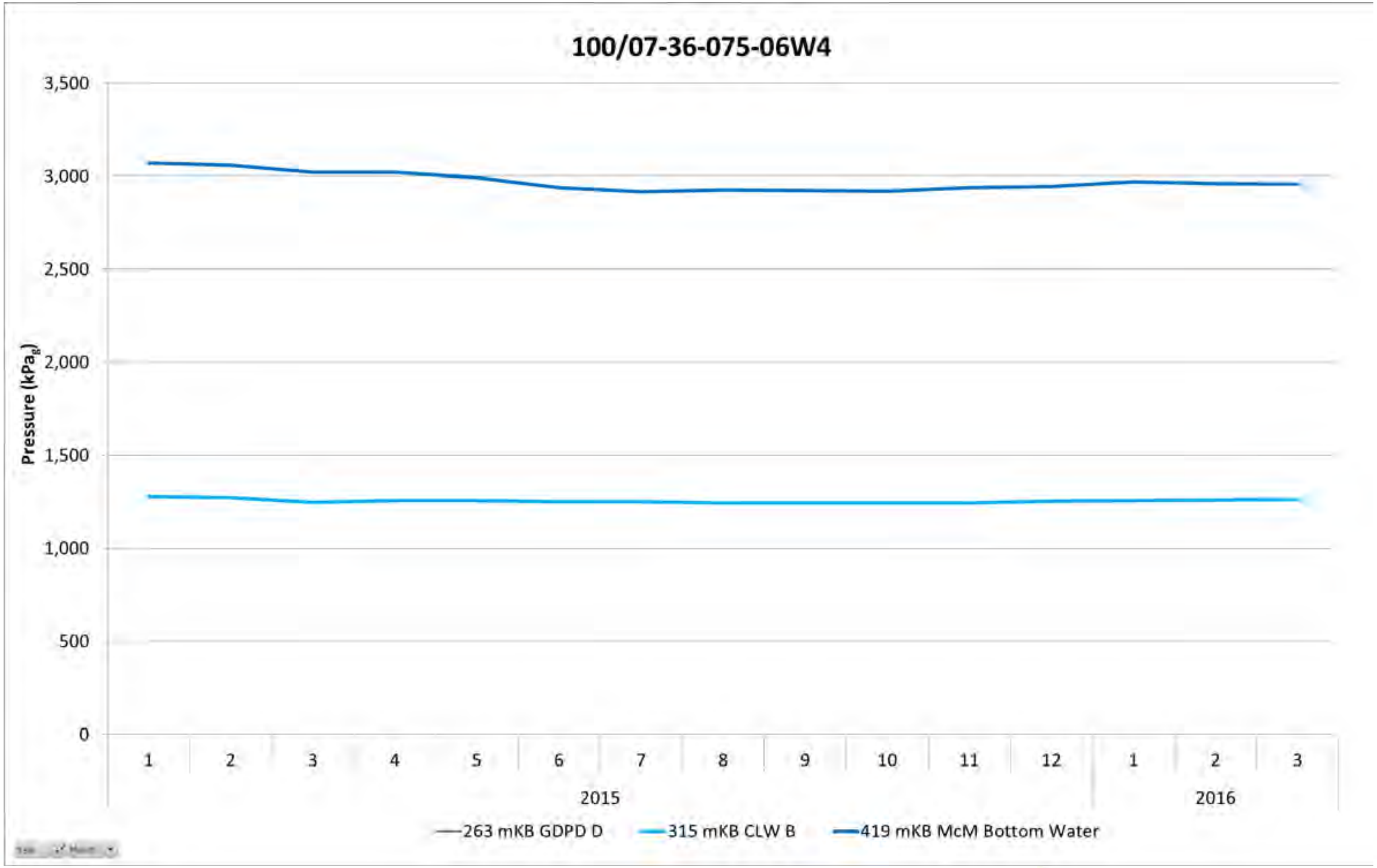
# Geomechanical and surface heave (Coherent Targets)



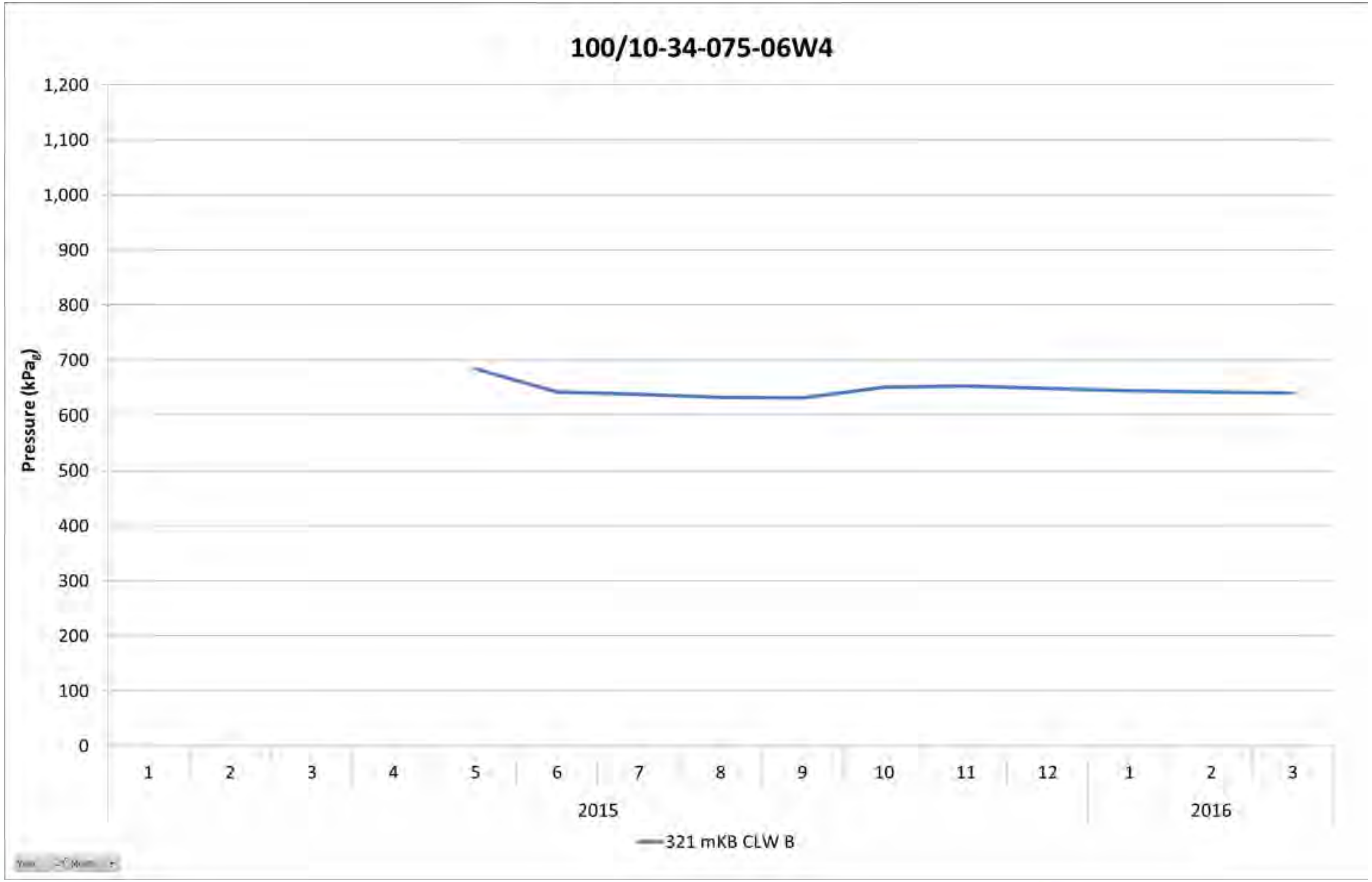
# Appendix 2
# Subsection 3.1.1 – 5d)
# Piezometer data

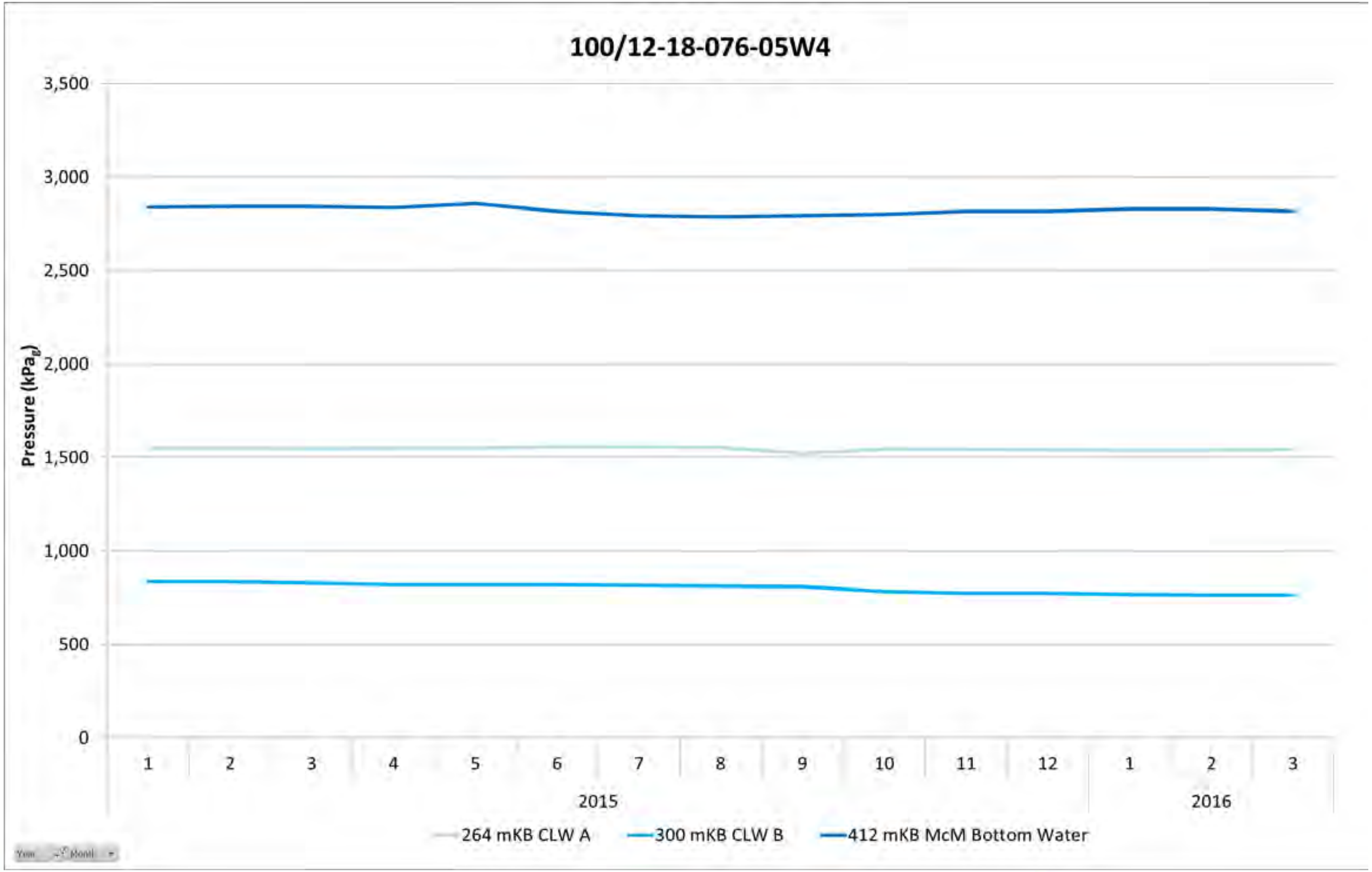
cenovus ENERGY


1AA/06-35-075-06W4
1,200
1,000
800
600
400
200
0
Pressure (kPag)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
255 mKB GDPD D
307 mKB CLW B

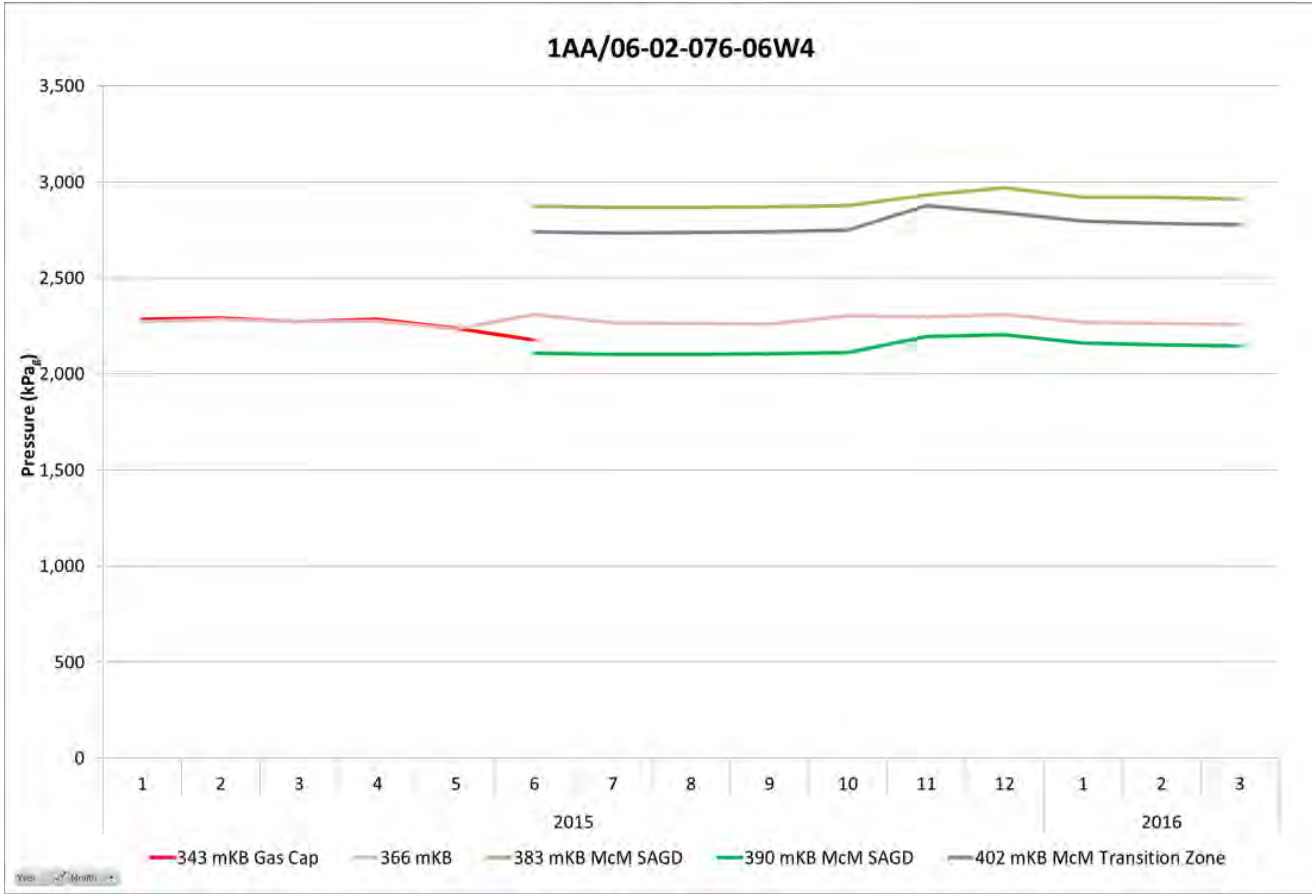


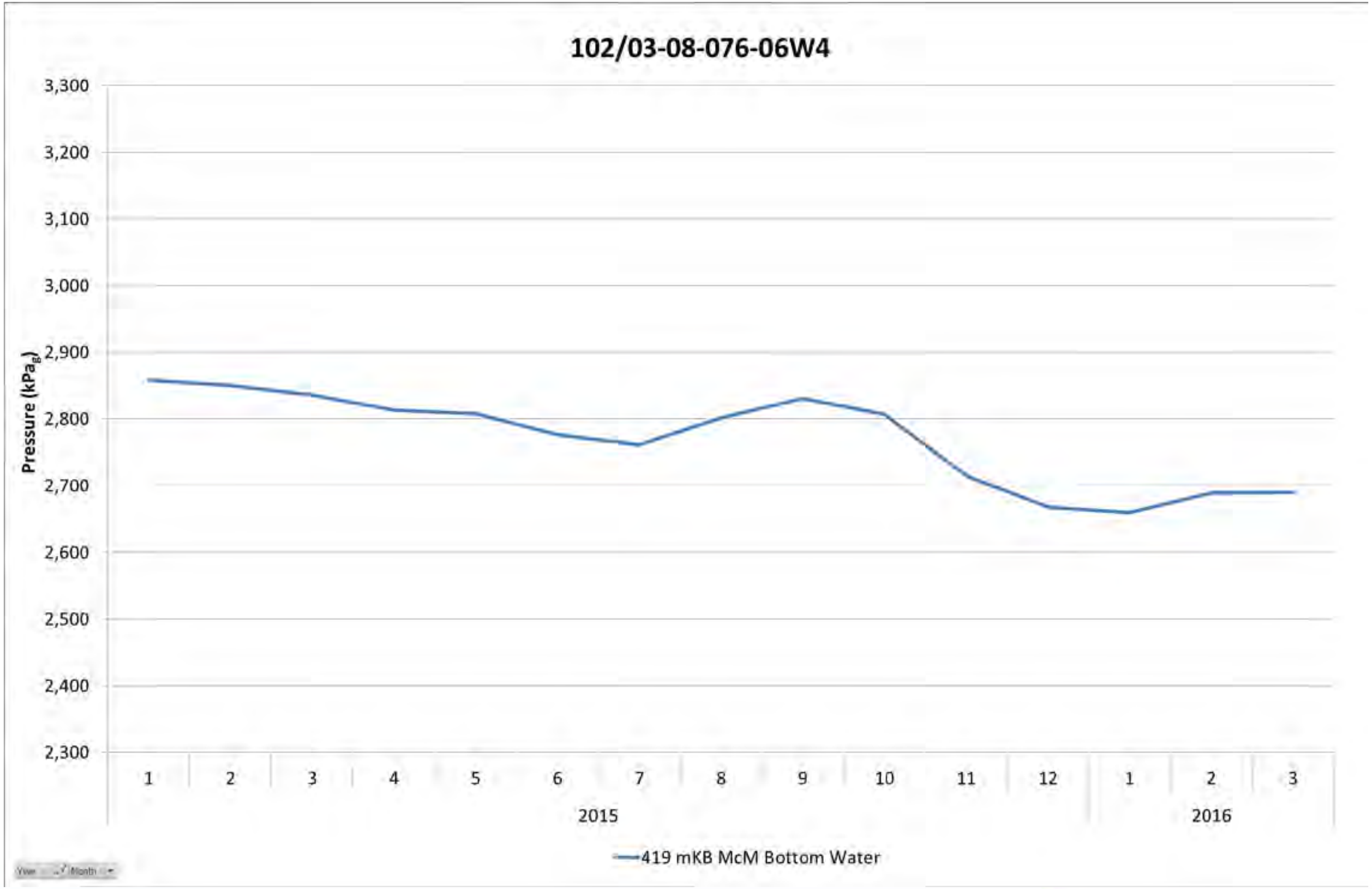
100/07-36-075-06W4
Pressure (kPag)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
263 mKB GDPD D
315 mKB CLW B
419 mKB McM Bottom Water


100/10-34-075-06W4
Pressure (kPag)
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
321 mKB CLW B



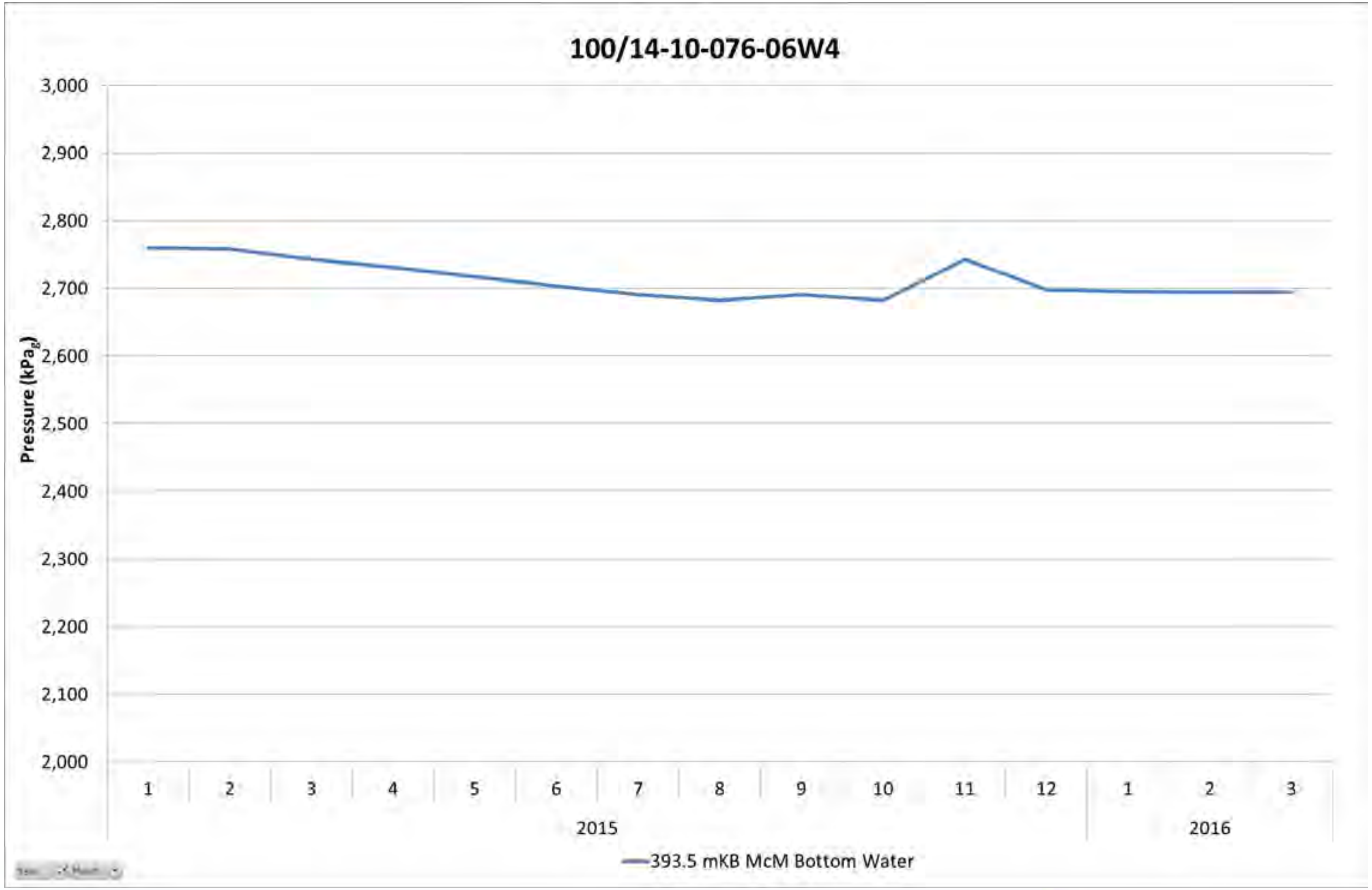
100/12-18-076-05W4
Pressure (kPag)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
264 mKB CLW A
300 mKB CLW B
412 mKB McM Bottom Water


1AA/06-02-076-06W4
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPag)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
343 mKB Gas Cap
366 mKB
383 mKB McM SAGD
390 mKB McM SAGD
402 mKB McM Transition Zone


102/03-08-076-06W4
3,300
3,200
3,100
3,000
2,900
2,800
2,700
2,600
2,500
2,400
2,300
Pressure ($kPa_g$)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
419 mKB McM Bottom Water

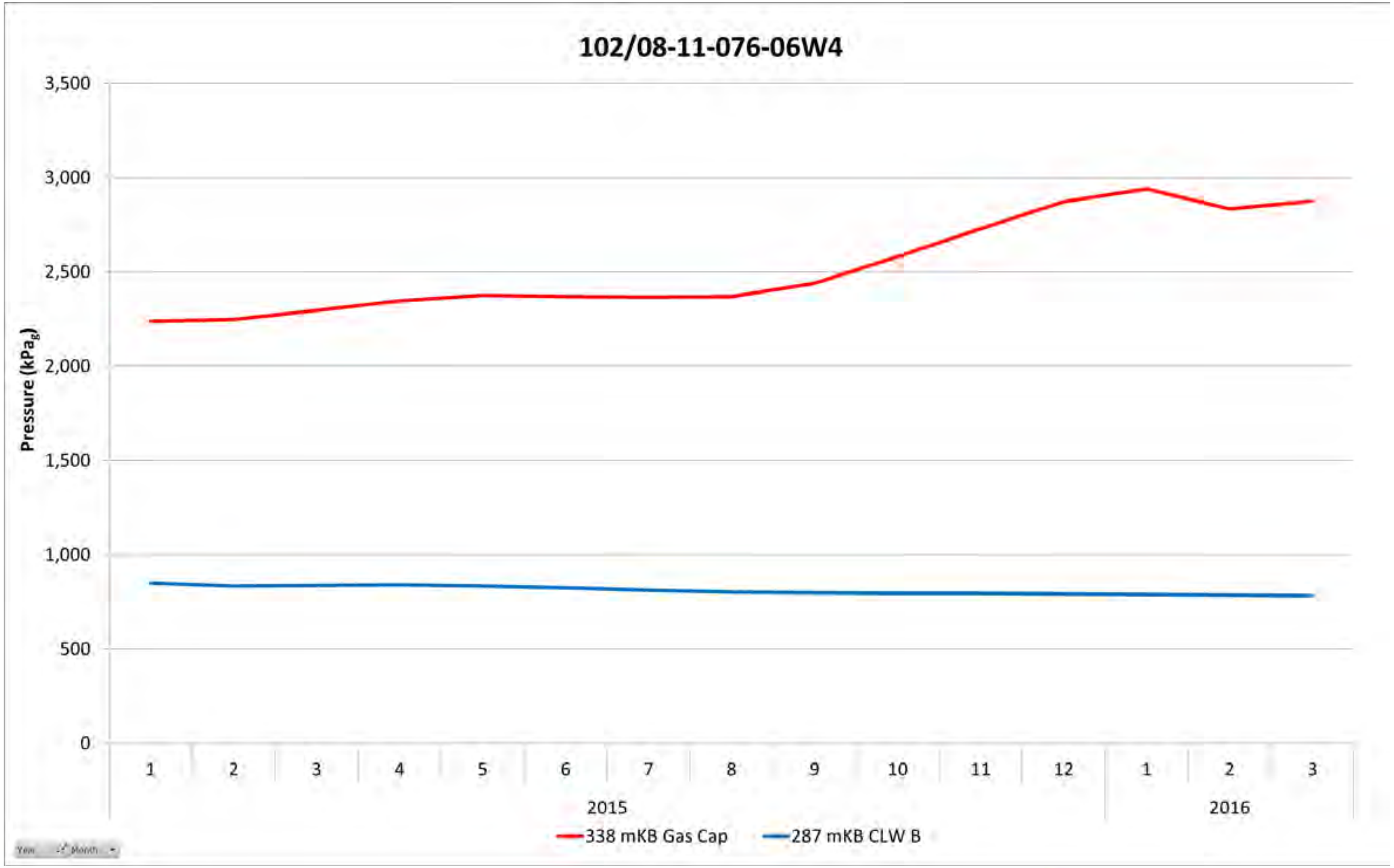
# 100/07-10-076-06W4

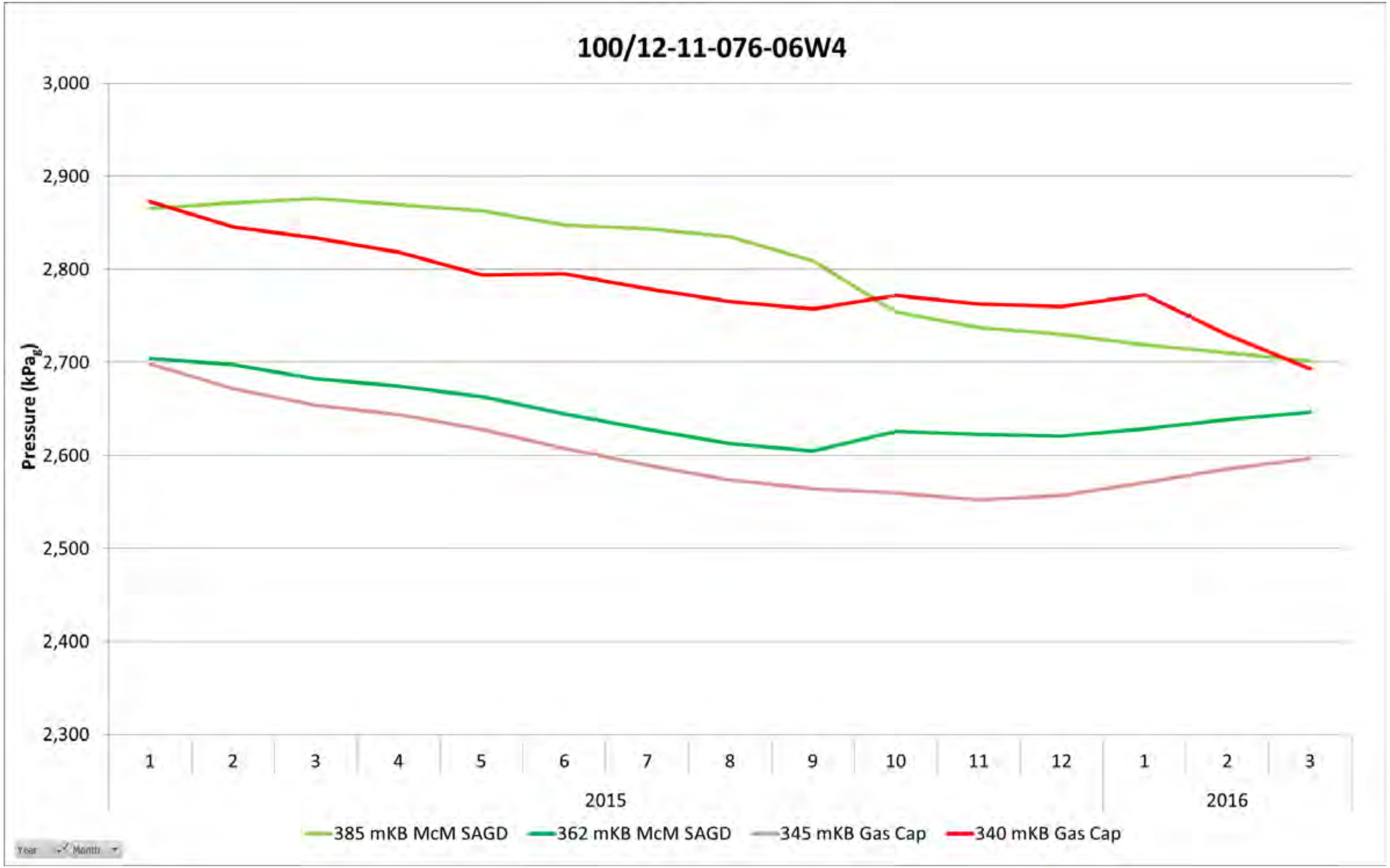
## Broken Downhole

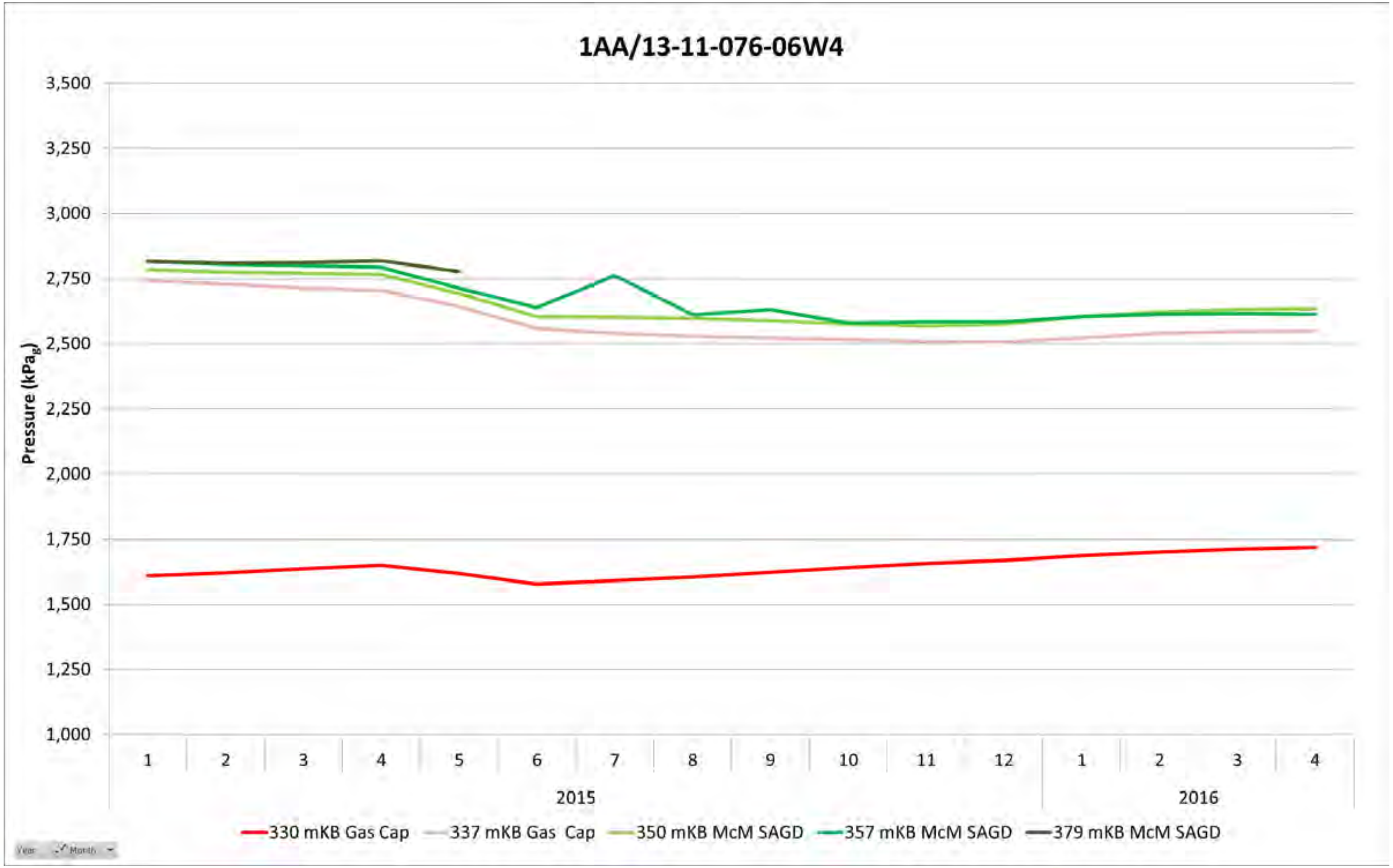



cenovus ENERGY

June 15, 2016


102/08-11-076-06W4
Pressure (kPag)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
338 mKB Gas Cap
287 mKB CLW B


100/12-11-076-06W4
Pressure (kPag)
3,000
2,900
2,800
2,700
2,600
2,500
2,400
2,300
1 2 3 4 5 6 7 8 9 10 11 12 1 2 3
2015
2016
385 mKB McM SAGD
362 mKB McM SAGD
345 mKB Gas Cap
340 mKB Gas Cap
Year
Month

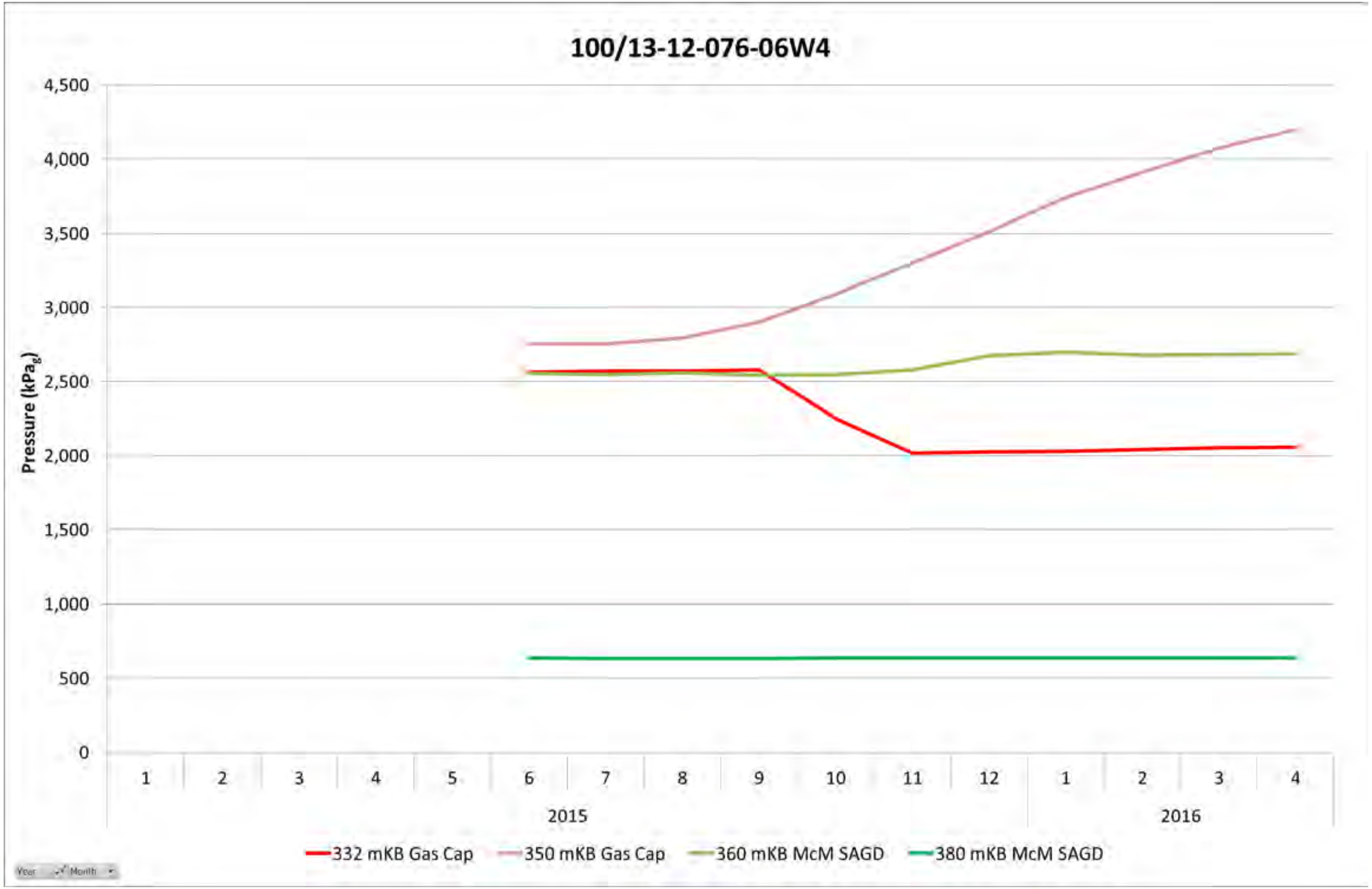

1AA/13-11-076-06W4
3,500
3,250
3,000
2,750
2,500
2,250
2,000
1,750
1,500
1,250
1,000
Pressure (kPag)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
4
2015
2016
330 mKB Gas Cap
337 mKB Gas Cap
350 mKB McM SAGD
357 mKB McM SAGD
379 mKB McM SAGD

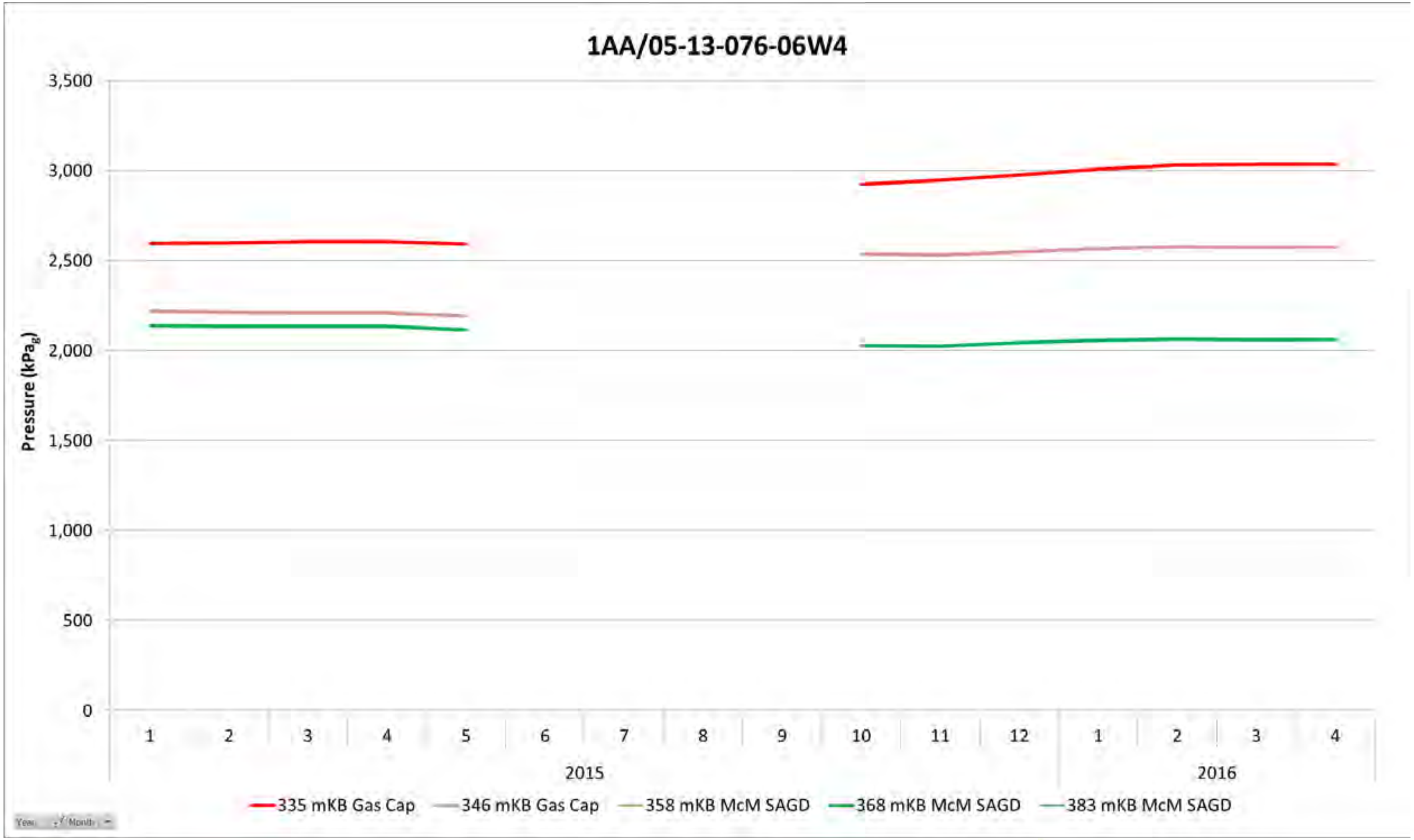
# 100/15-11-076-06W4

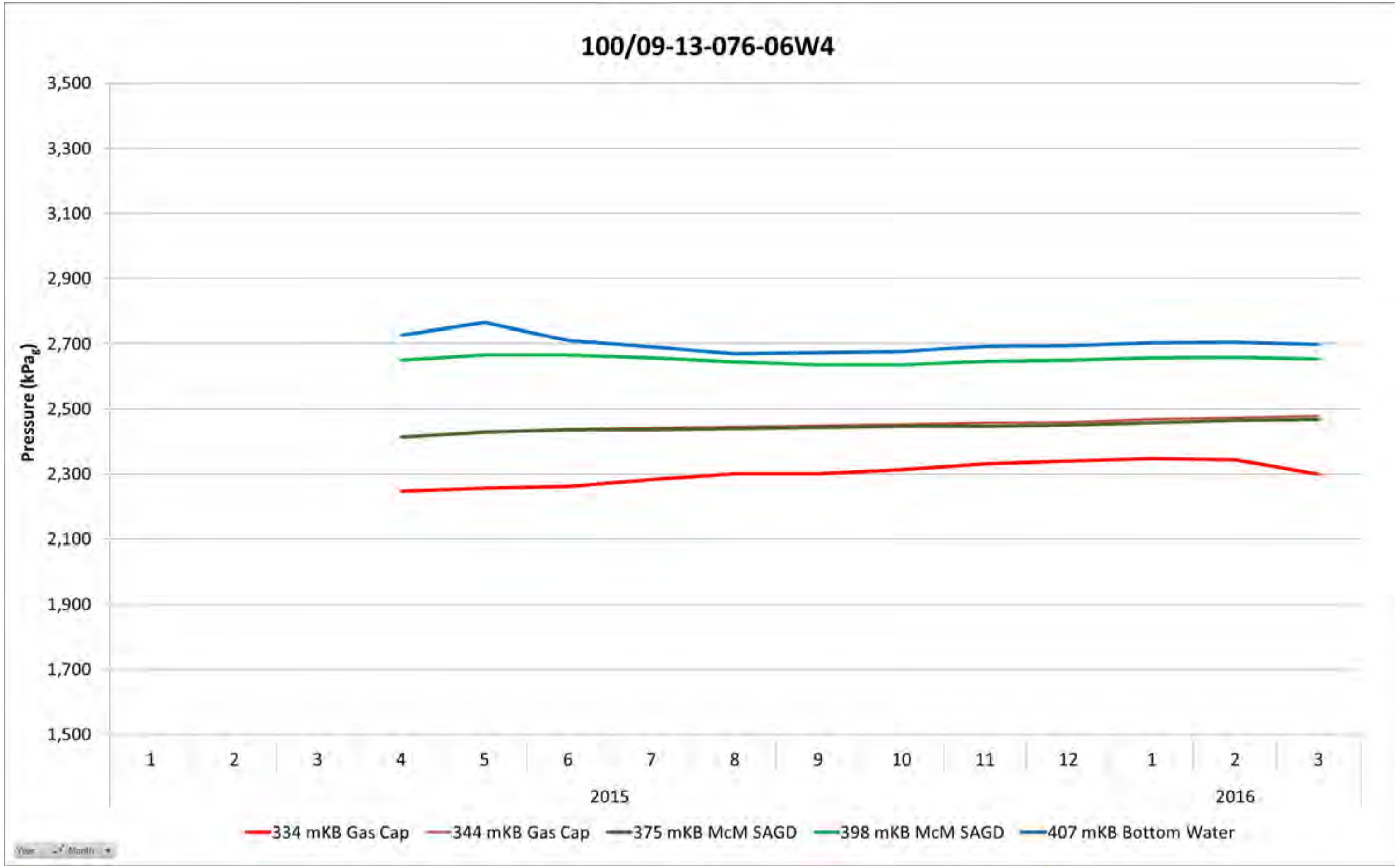
**Broken Downhole**

# 102/06-12-076-06W4

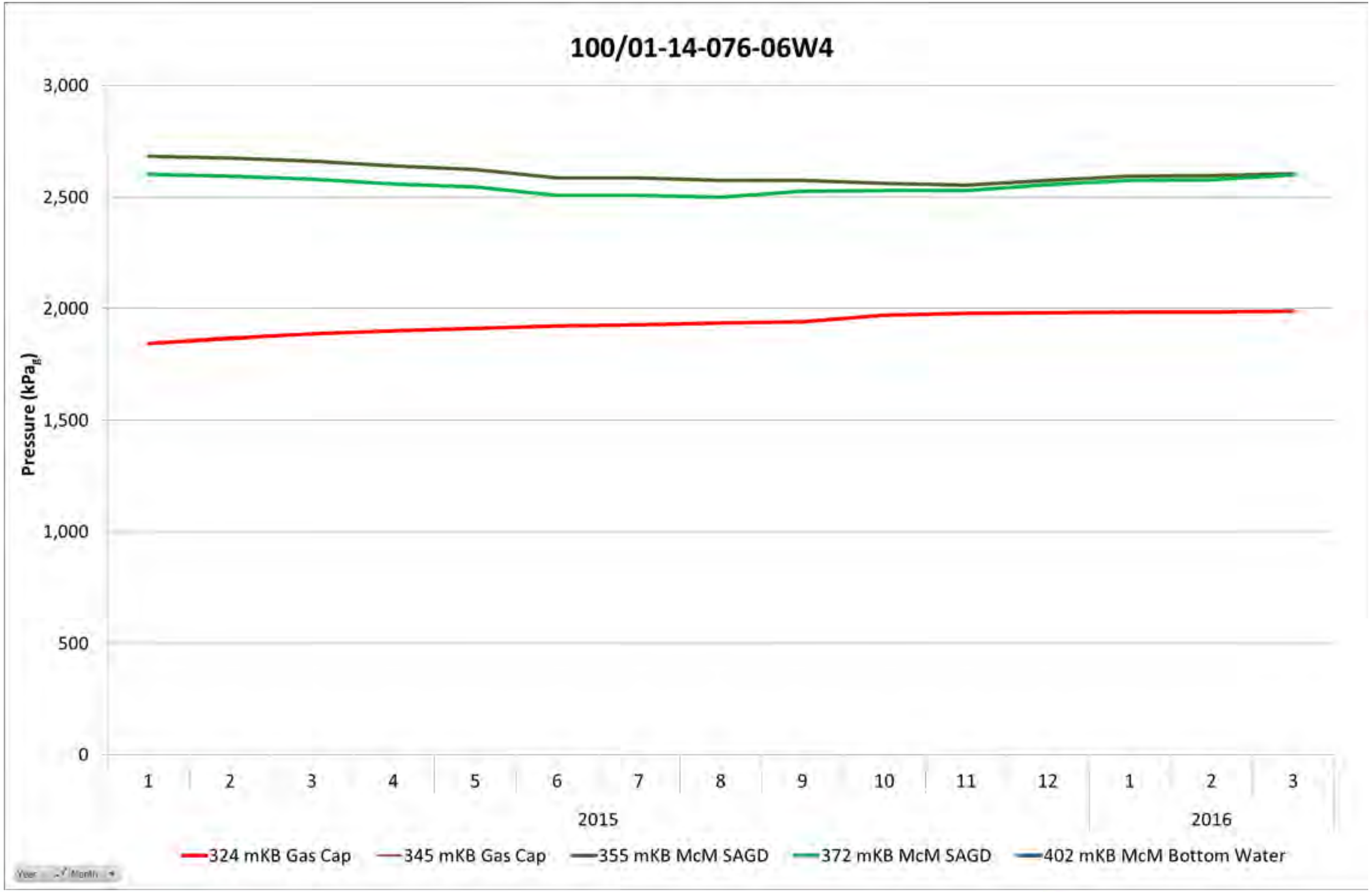
**Broken Downhole**


100/13-12-076-06W4
Pressure (kPag)
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4
2015
2016
332 mKB Gas Cap
350 mKB Gas Cap
360 mKB McM SAGD
380 mKB McM SAGD


1AA/05-13-076-06W4
Pressure (kPag)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
4
2015
2016
335 mKB Gas Cap
346 mKB Gas Cap
358 mKB McM SAGD
368 mKB McM SAGD
383 mKB McM SAGD



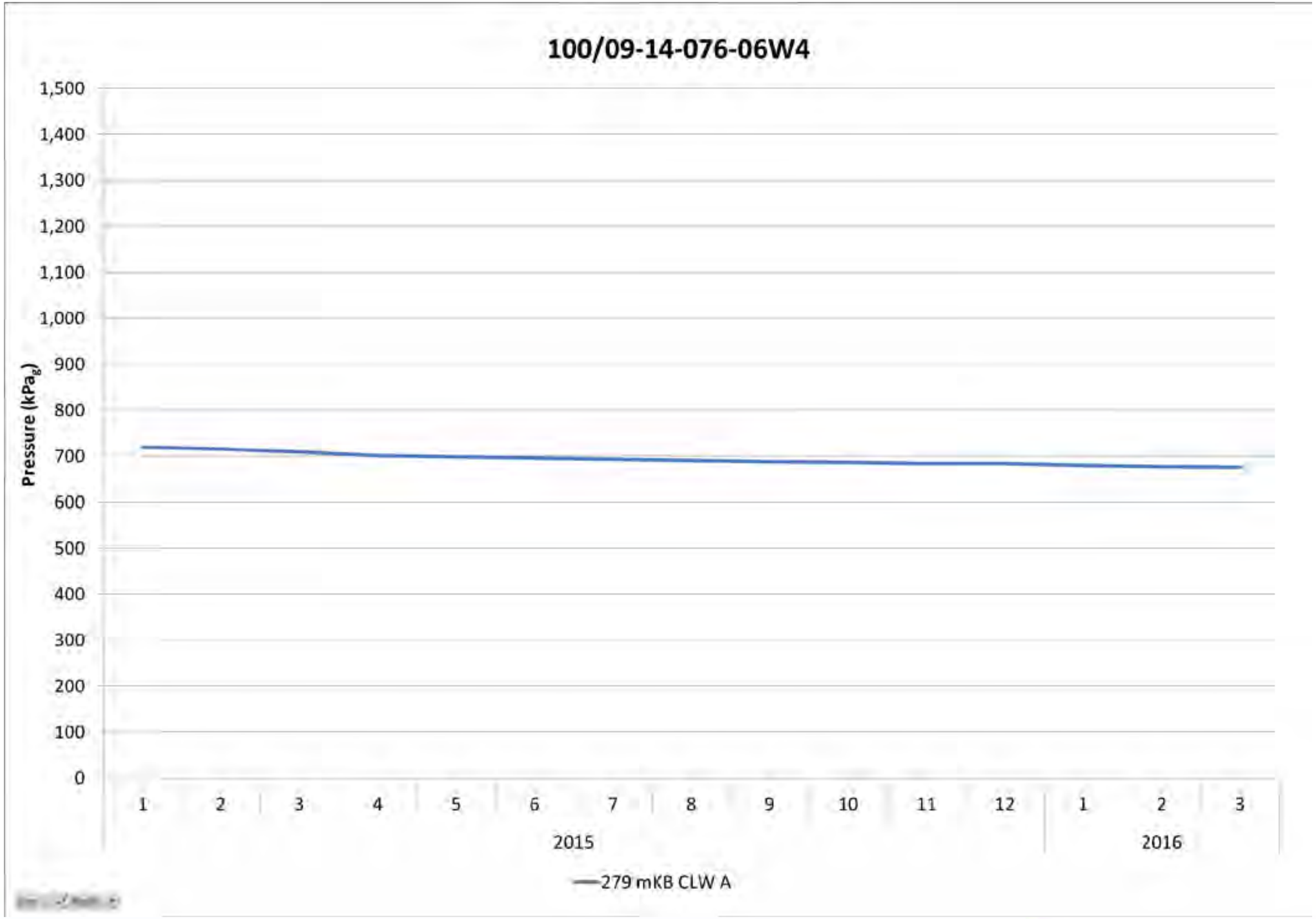
100/09-13-076-06W4
Pressure (kPag)
3,500
3,300
3,100
2,900
2,700
2,500
2,300
2,100
1,900
1,700
1,500
1 2 3 4 5 6 7 8 9 10 11 12 1 2 3
2015
2016
334 mKB Gas Cap
344 mKB Gas Cap
375 mKB McM SAGD
398 mKB McM SAGD
407 mKB Bottom Water

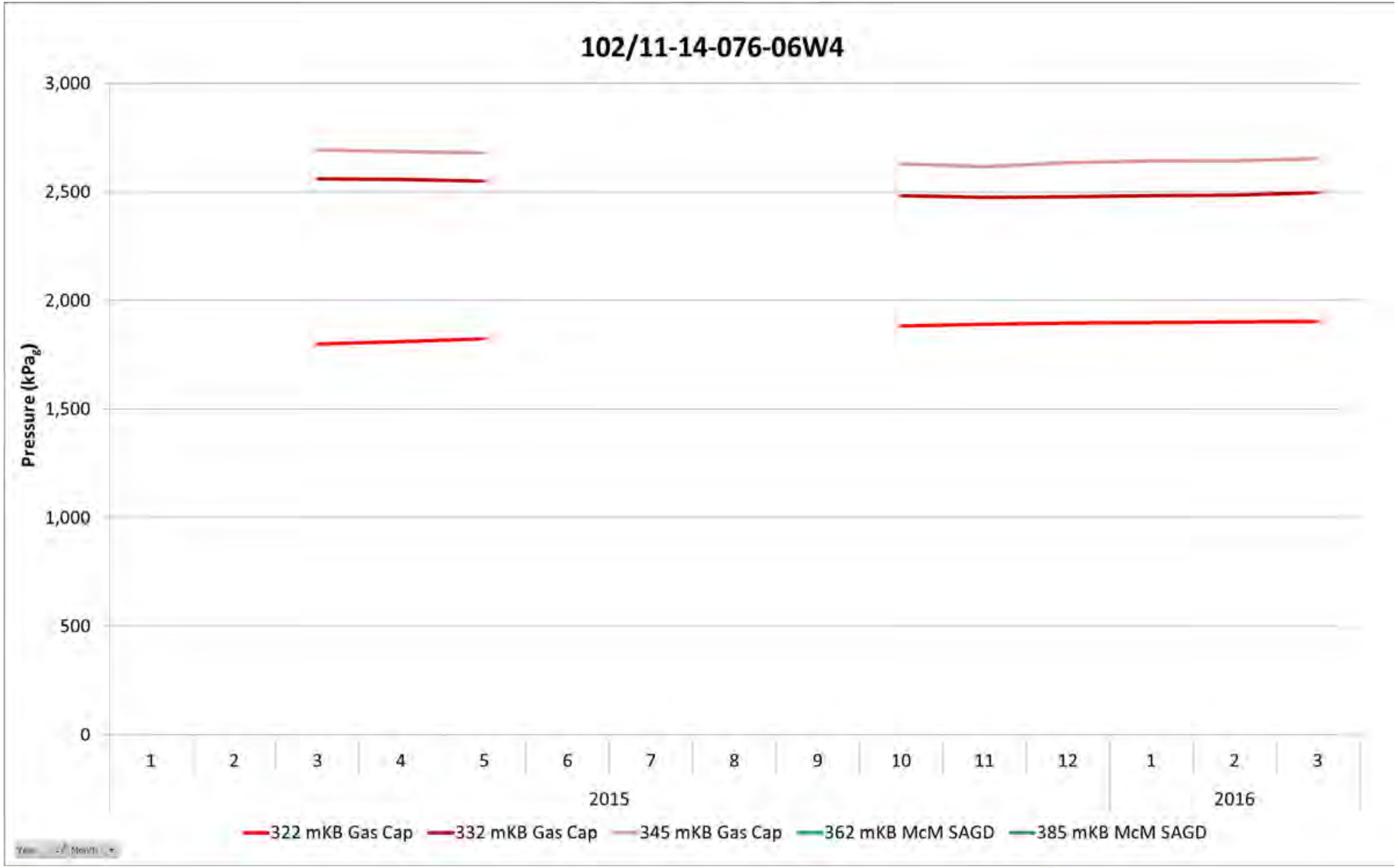


100/01-14-076-06W4
Pressure (kPag)
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
324 mKB Gas Cap
345 mKB Gas Cap
355 mKB McM SAGD
372 mKB McM SAGD
402 mKB McM Bottom Water

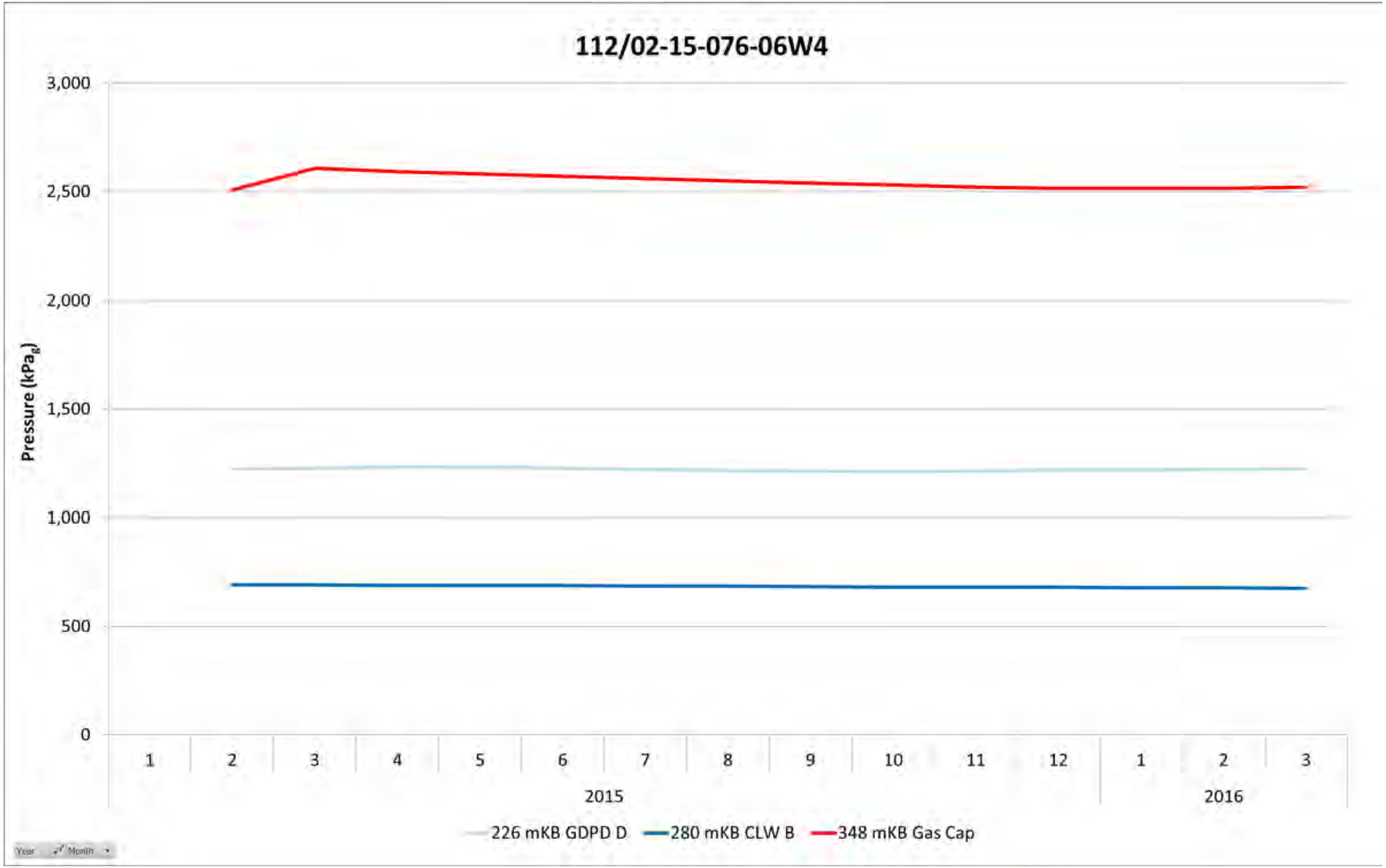
# 102/05-14-076-06W4

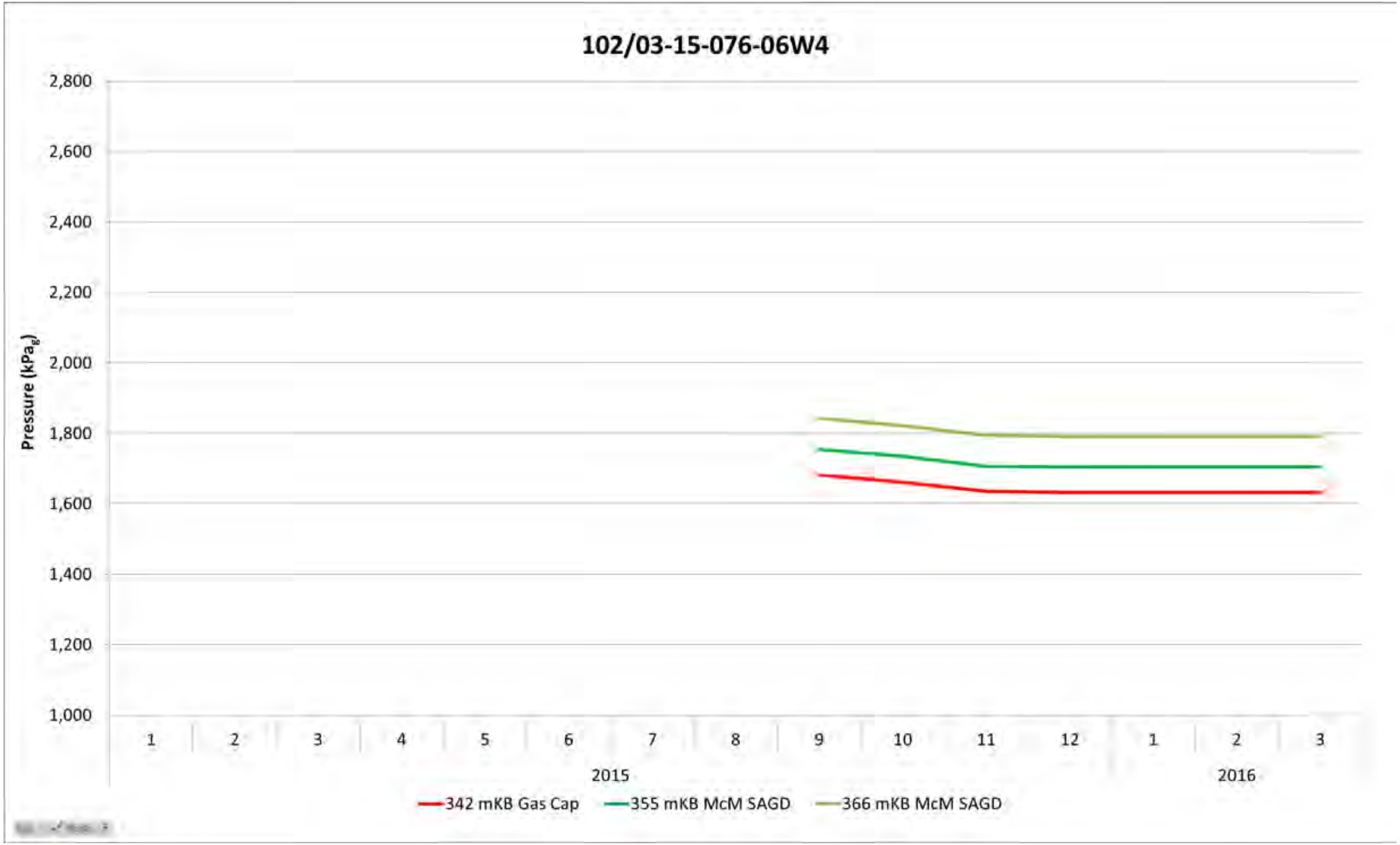
## Broken Downhole


100/09-14-076-06W4
Pressure (kPag)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
279 mKB CLW A

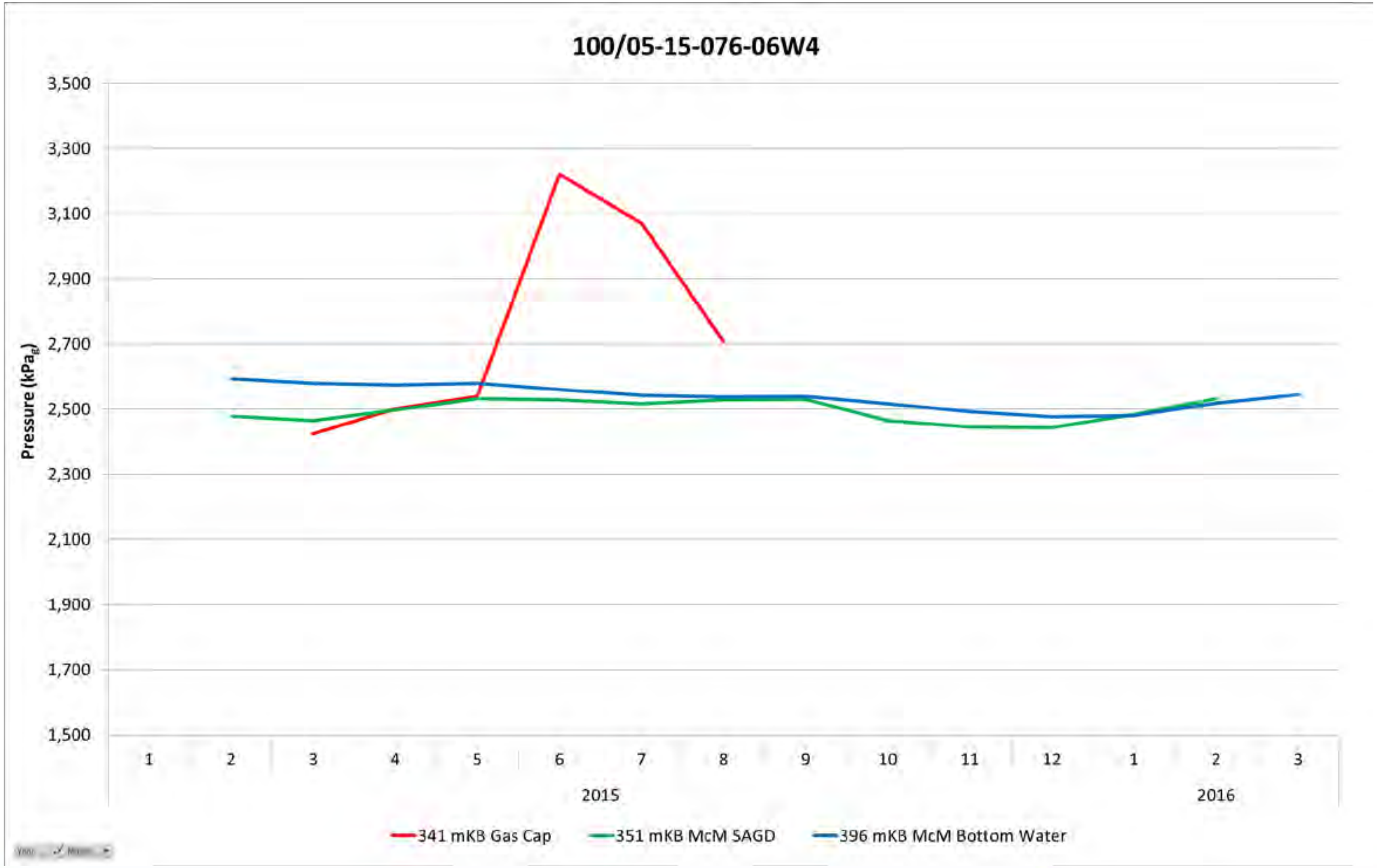


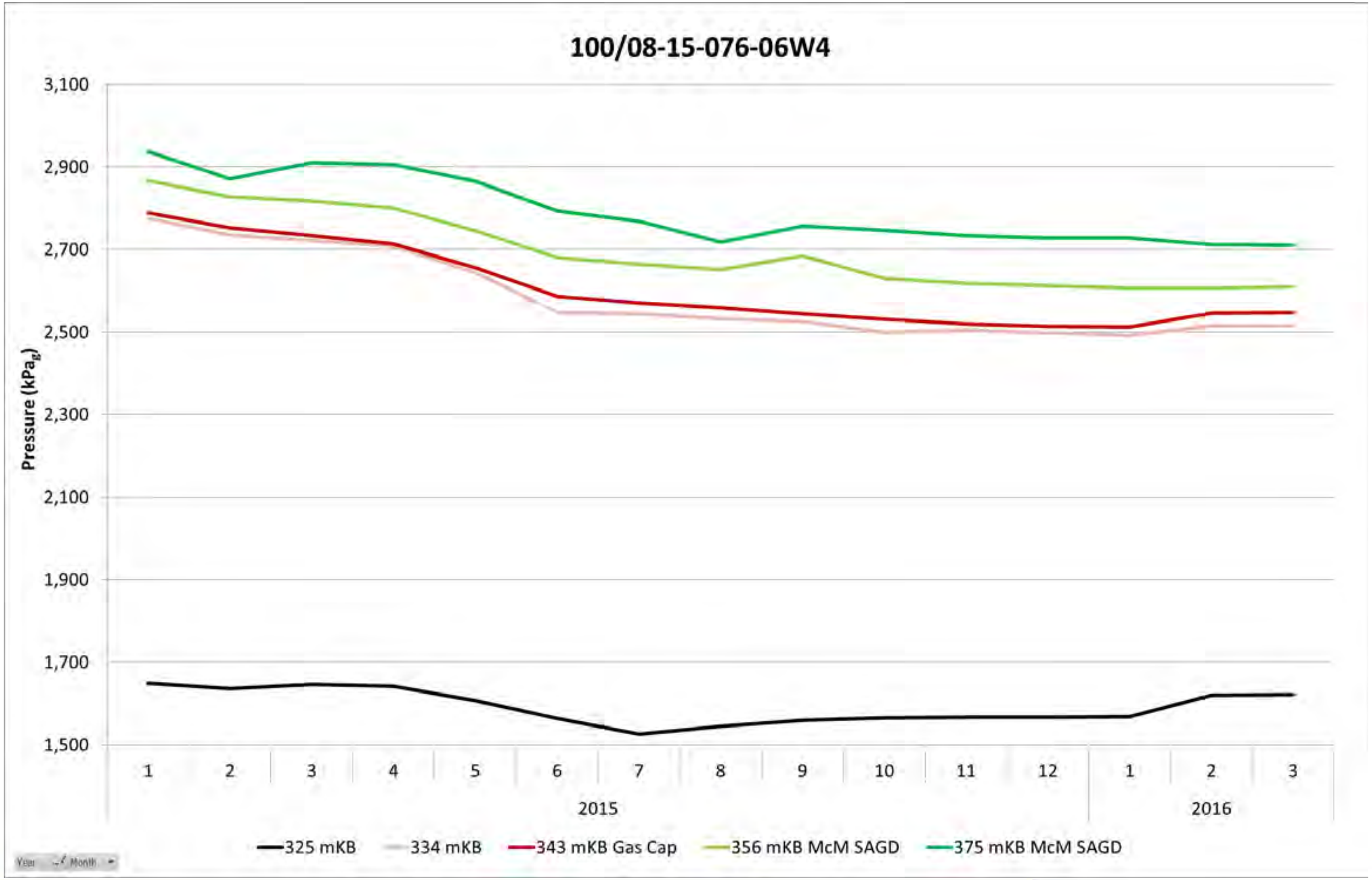
102/11-14-076-06W4
Pressure (kPag)
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
322 mKB Gas Cap
332 mKB Gas Cap
345 mKB Gas Cap
362 mKB McM SAGD
385 mKB McM SAGD

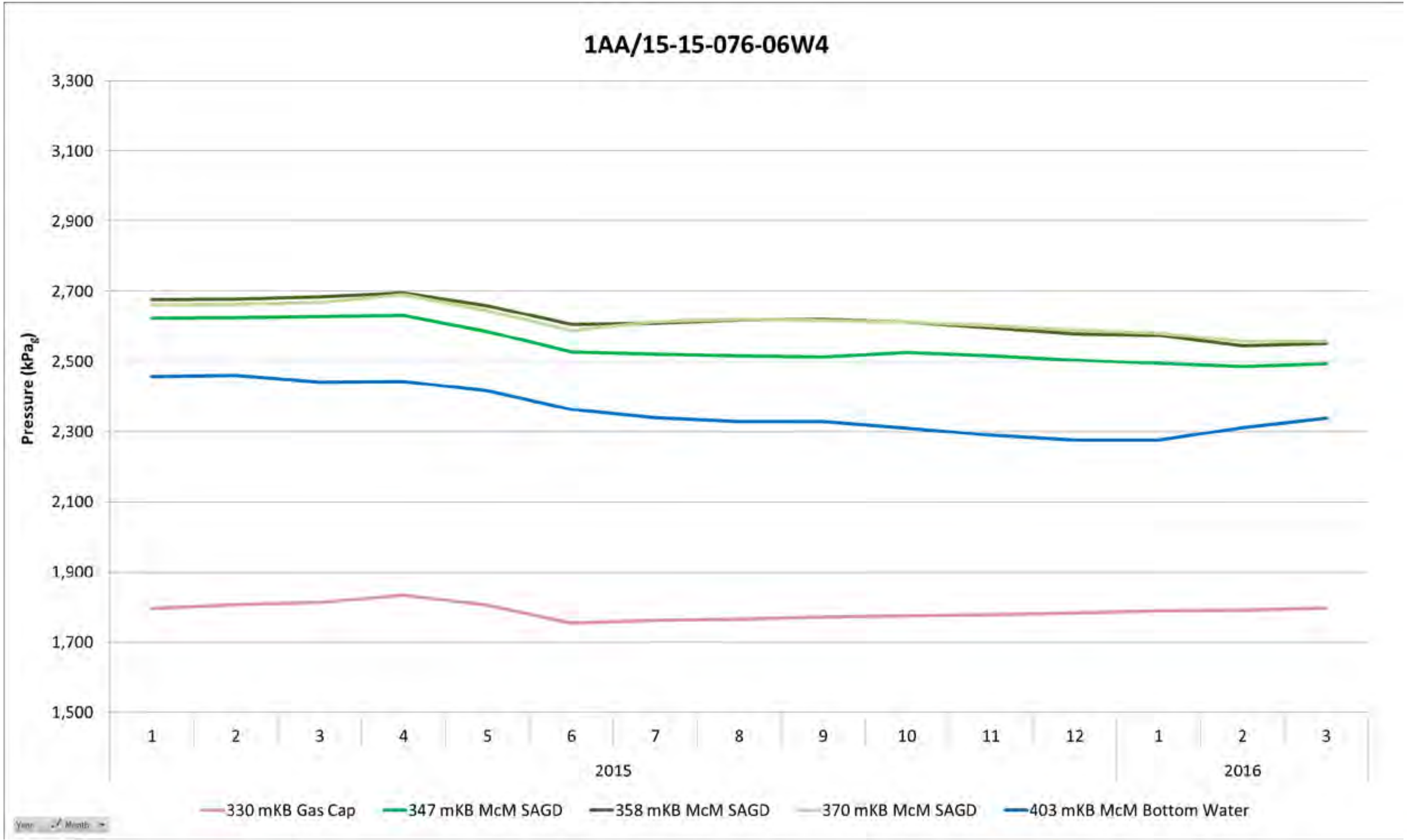

112/02-15-076-06W4
Pressure (kPa$_g$)
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
226 mKB GDPD D
280 mKB CLW B
348 mKB Gas Cap


102/03-15-076-06W4
Pressure (kPag)
2,800
2,600
2,400
2,200
2,000
1,800
1,600
1,400
1,200
1,000
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
342 mKB Gas Cap
355 mKB McM SAGD
366 mKB McM SAGD

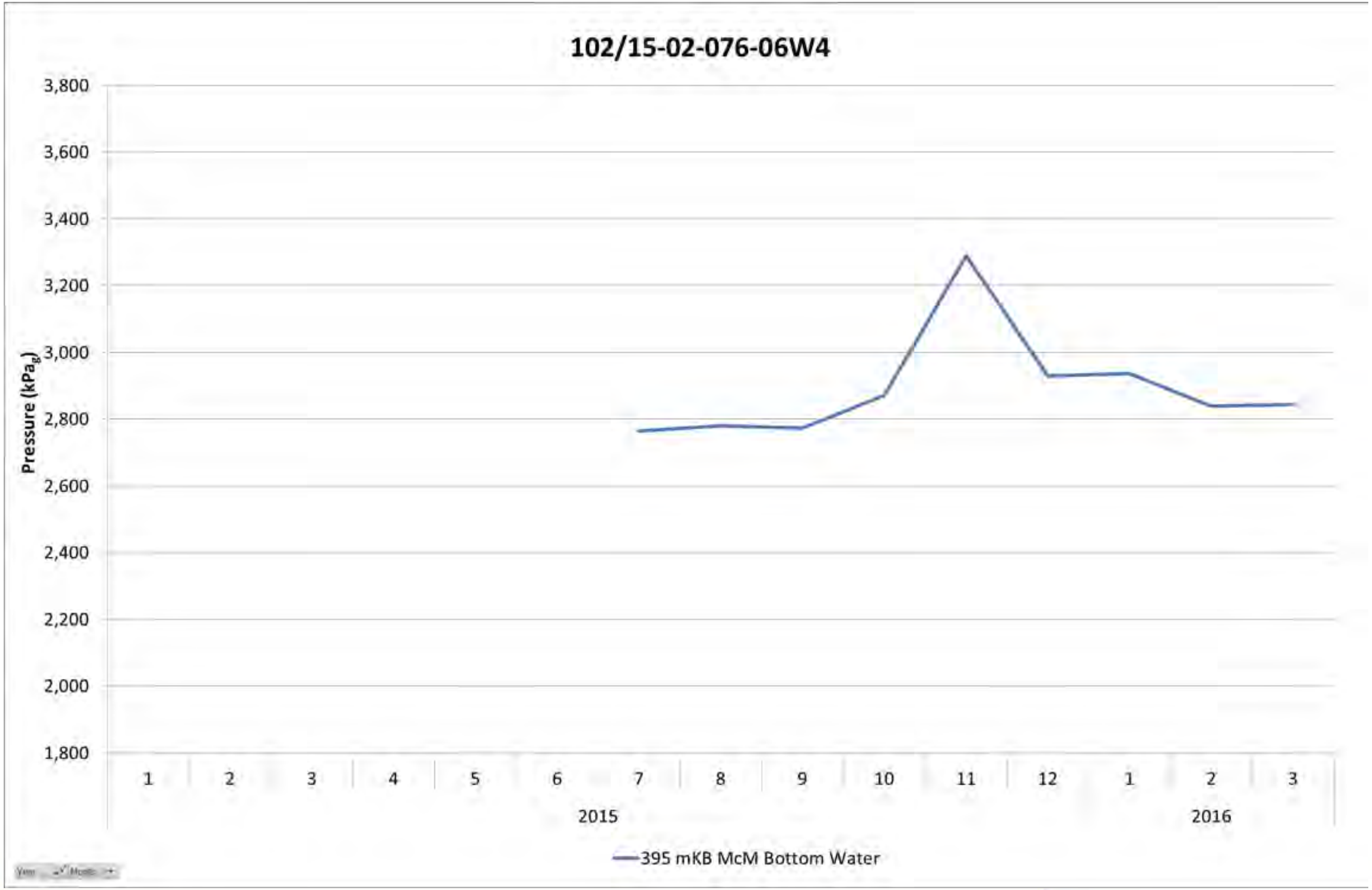

100/04-15-076-06W4
2,700
2,500
2,300
2,100
1,900
1,700
1,500
Pressure (kPag)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
352 mKB McM SAGD
364 mKB McM SAGD


100/05-15-076-06W4
Pressure (kPag)
3,500
3,300
3,100
2,900
2,700
2,500
2,300
2,100
1,900
1,700
1,500
1 2 3 4 5 6 7 8 9 10 11 12 1 2 3
2015
2016
341 mKB Gas Cap
351 mKB McM SAGD
396 mKB McM Bottom Water


100/08-15-076-06W4
Pressure (kPa$_g$)
3,100
2,900
2,700
2,500
2,300
2,100
1,900
1,700
1,500
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
325 mKB
334 mKB
343 mKB Gas Cap
356 mKB McM SAGD
375 mKB McM SAGD



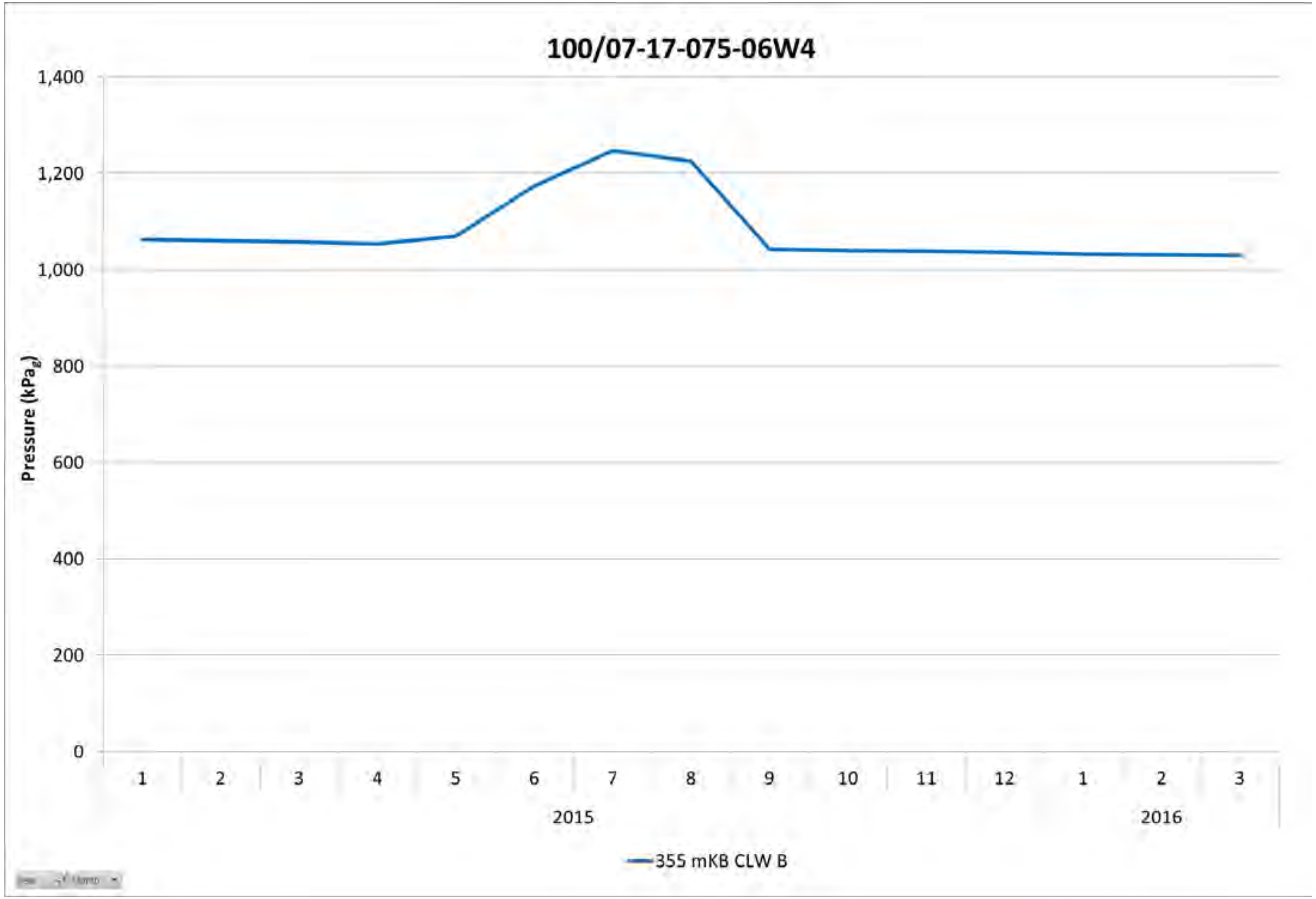
1AA/15-15-076-06W4
3,300
3,100
2,900
2,700
2,500
2,300
2,100
1,900
1,700
1,500
Pressure (kPag)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
330 mKB Gas Cap
347 mKB McM SAGD
358 mKB McM SAGD
370 mKB McM SAGD
403 mKB McM Bottom Water

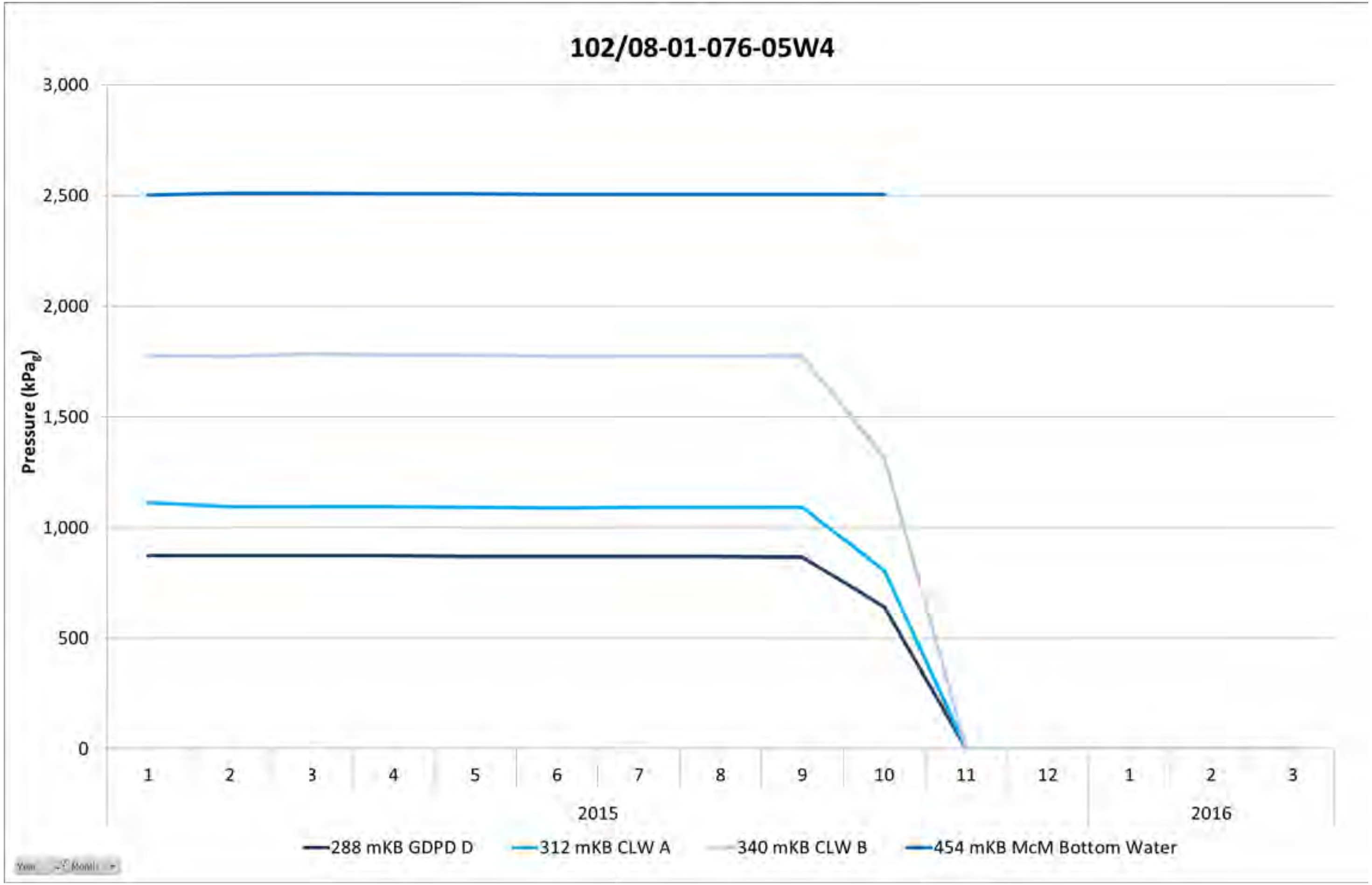


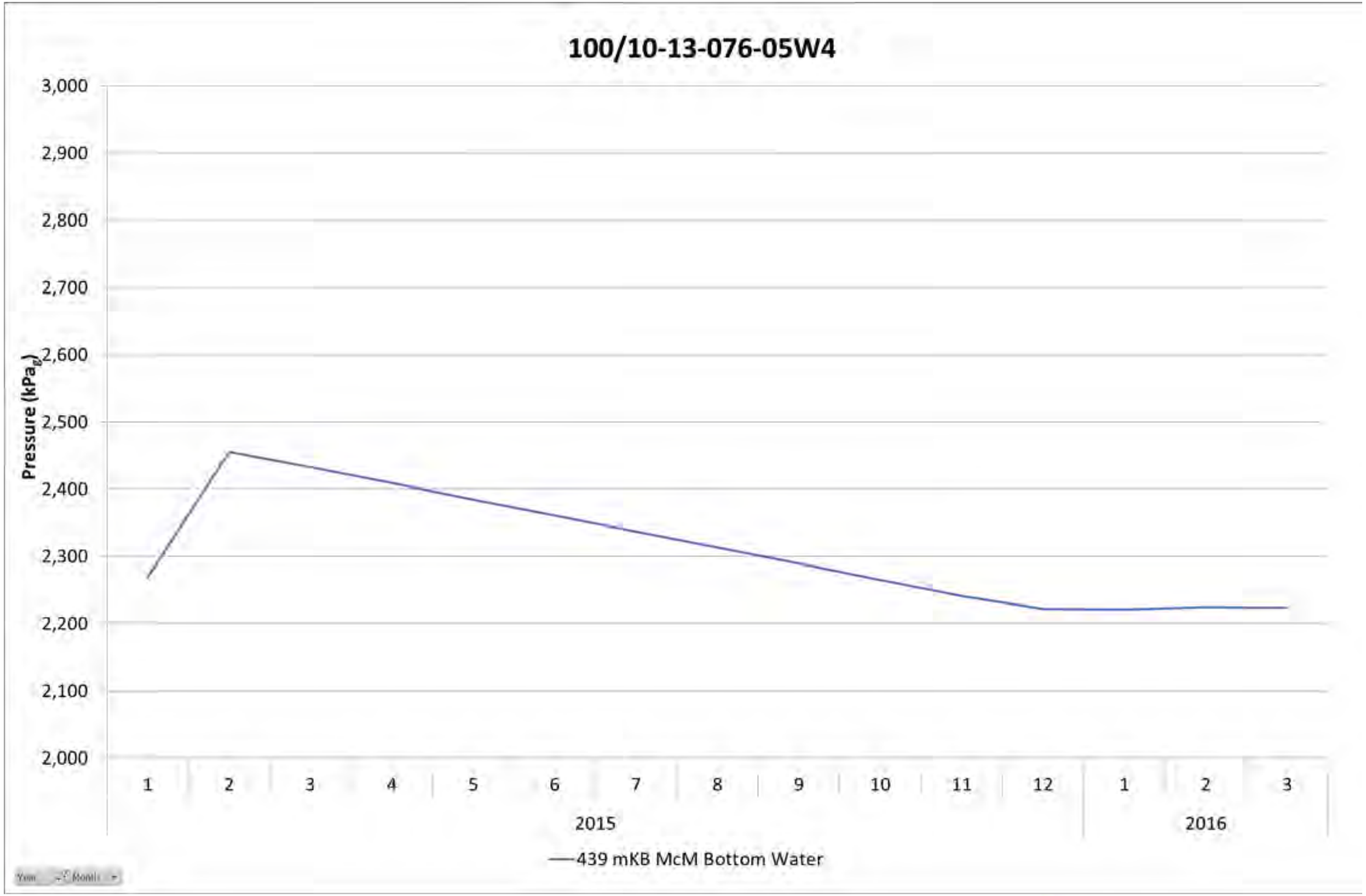
102/15-02-076-06W4
Pressure (kPa$_g$)
3,800
3,600
3,400
3,200
3,000
2,800
2,600
2,400
2,200
2,000
1,800
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
395 mKB McM Bottom Water

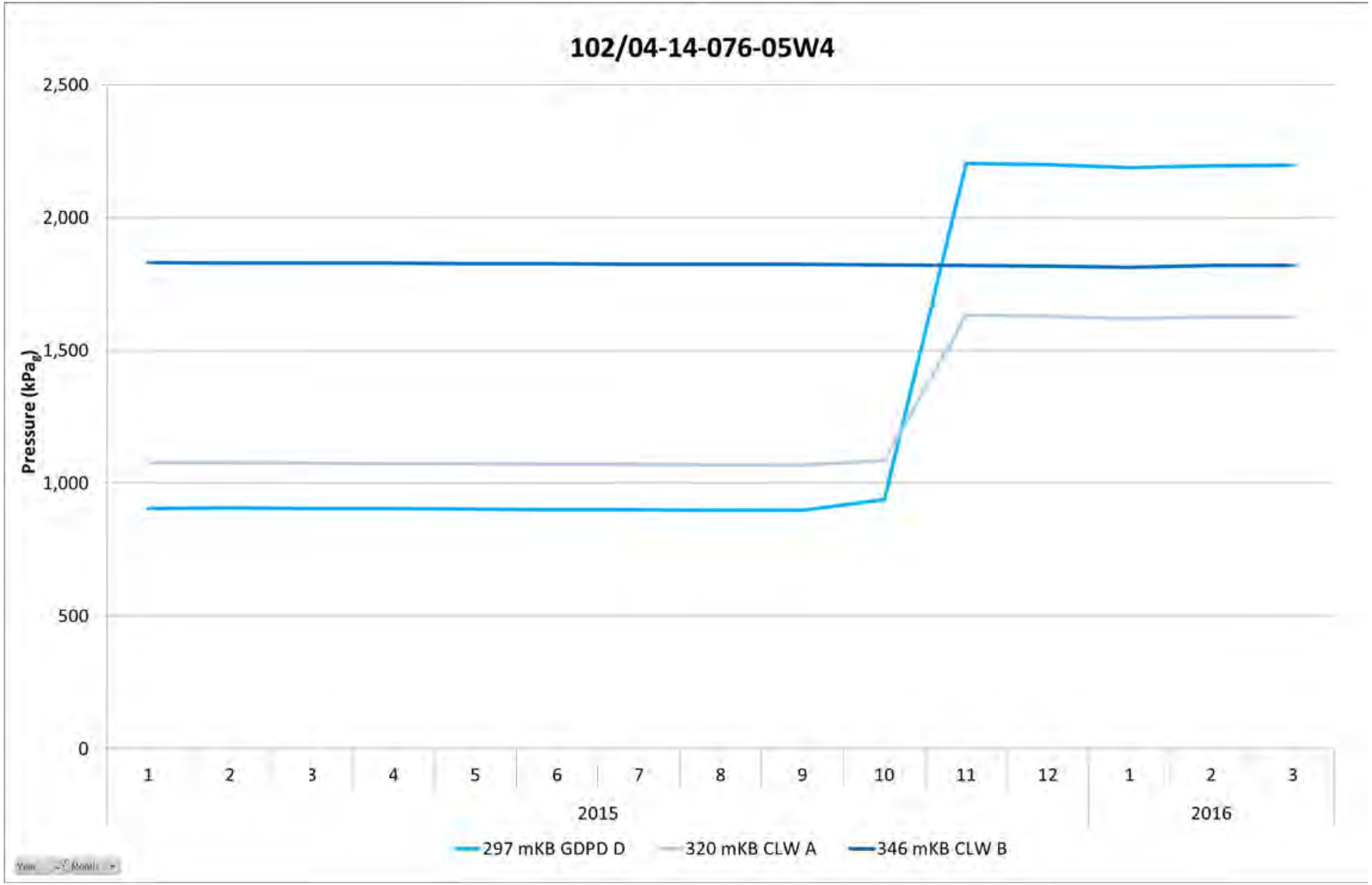
# 100/09-15-076-06W4

**Broken Downhole**

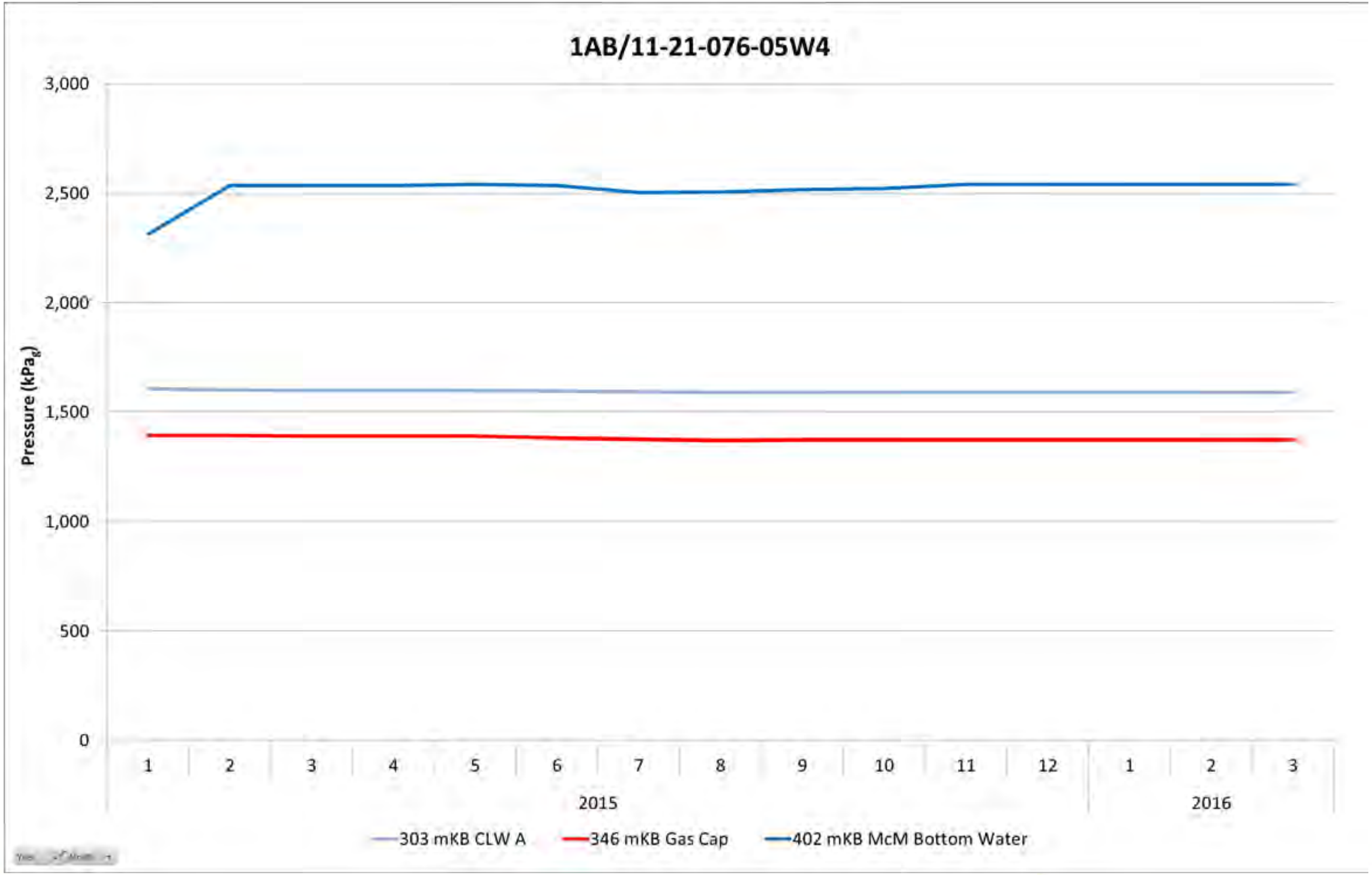

100/07-17-075-06W4
Pressure (kPag)
1,400
1,200
1,000
800
600
400
200
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
355 mKB CLW B

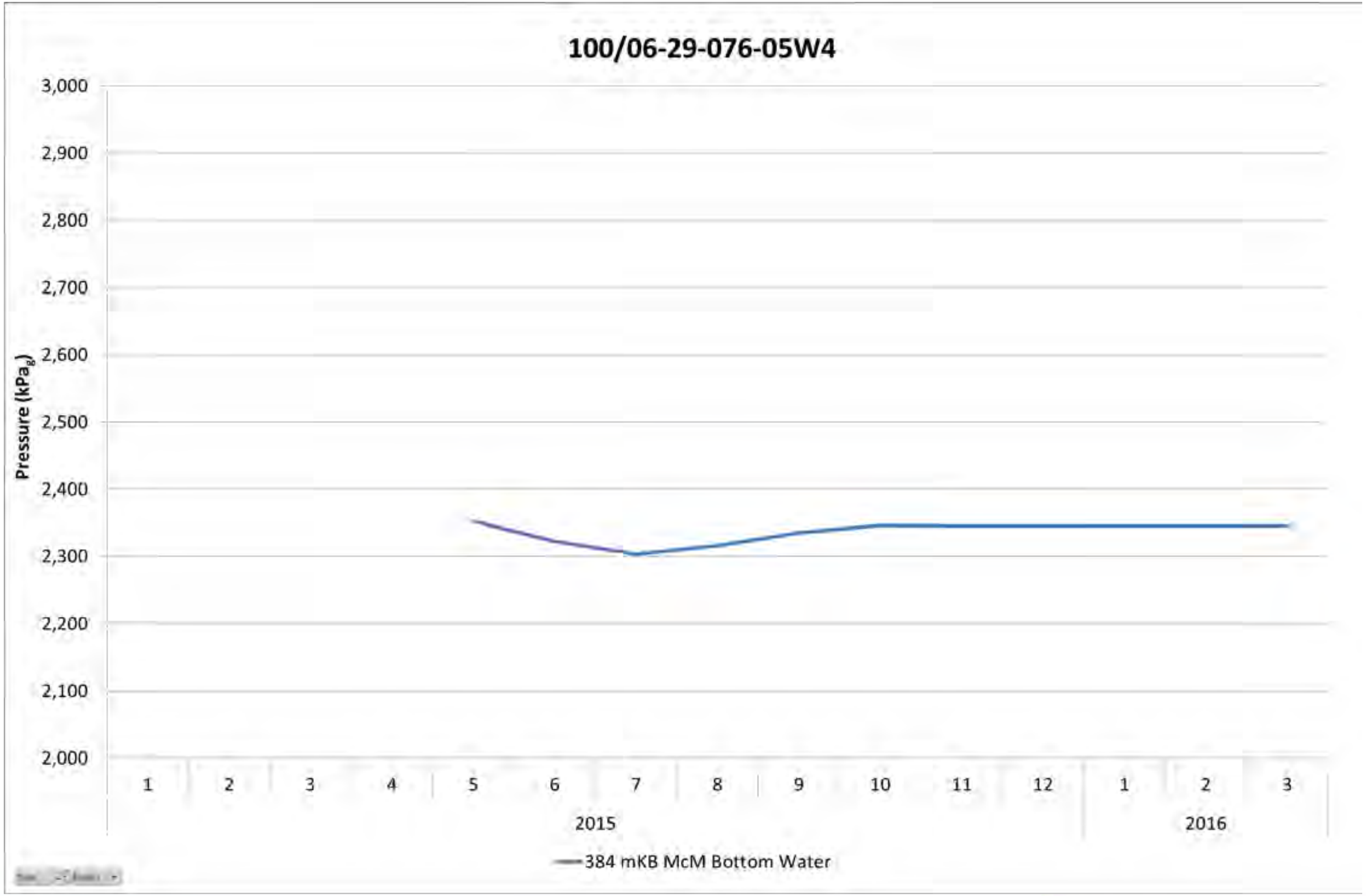

102/08-01-076-05W4
Pressure (kPag)
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
288 mKB GDPD D
312 mKB CLW A
340 mKB CLW B
454 mKB McM Bottom Water

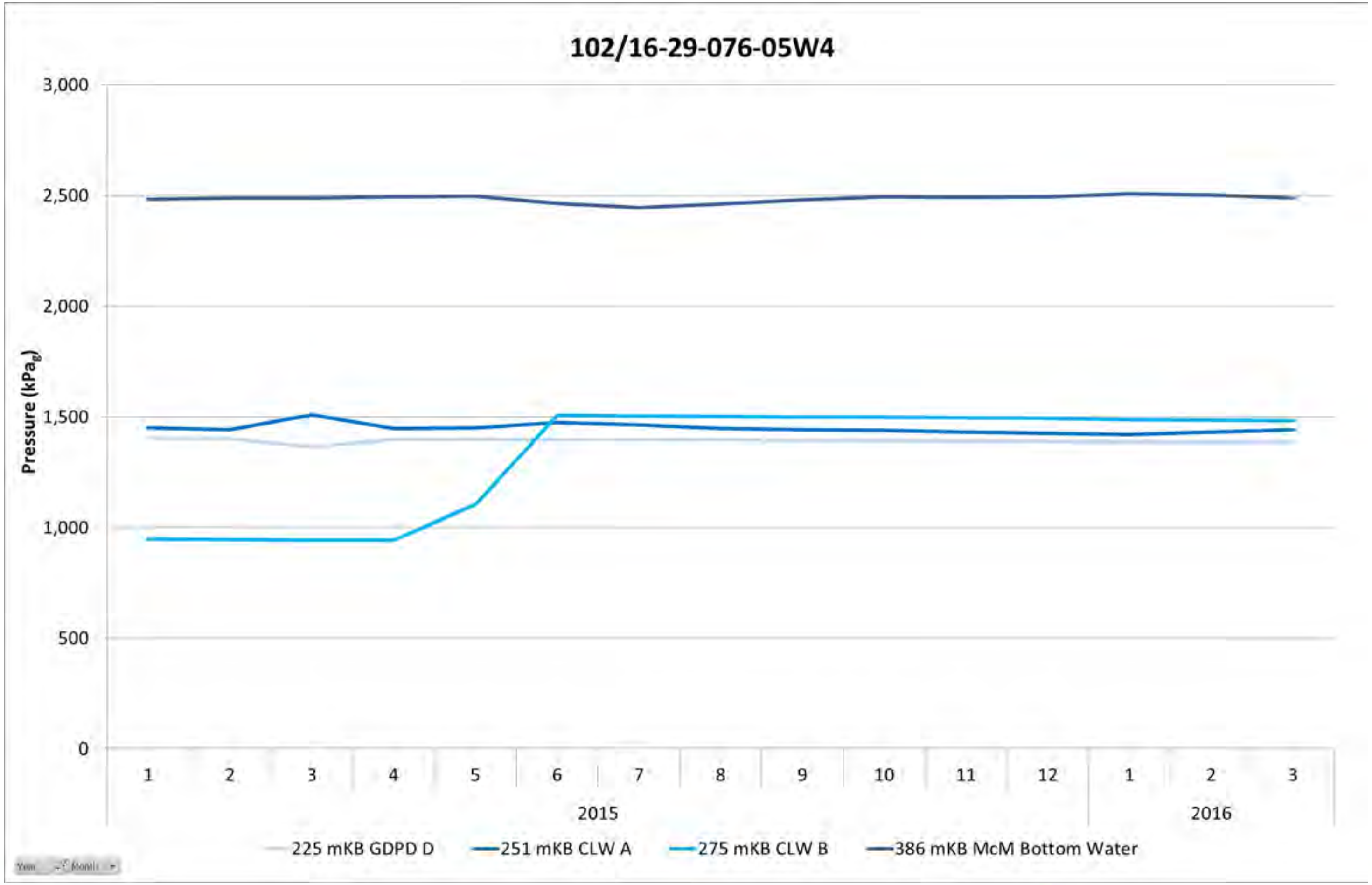

100/10-13-076-05W4
Pressure (kPag)
3,000
2,900
2,800
2,700
2,600
2,500
2,400
2,300
2,200
2,100
2,000
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
439 mKB McM Bottom Water



102/04-14-076-05W4
Pressure (kPag)
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
297 mKB GDPD D
320 mKB CLW A
346 mKB CLW B


1AB/11-21-076-05W4
Pressure (kPa$_g$)
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
303 mKB CLW A
346 mKB Gas Cap
402 mKB McM Bottom Water

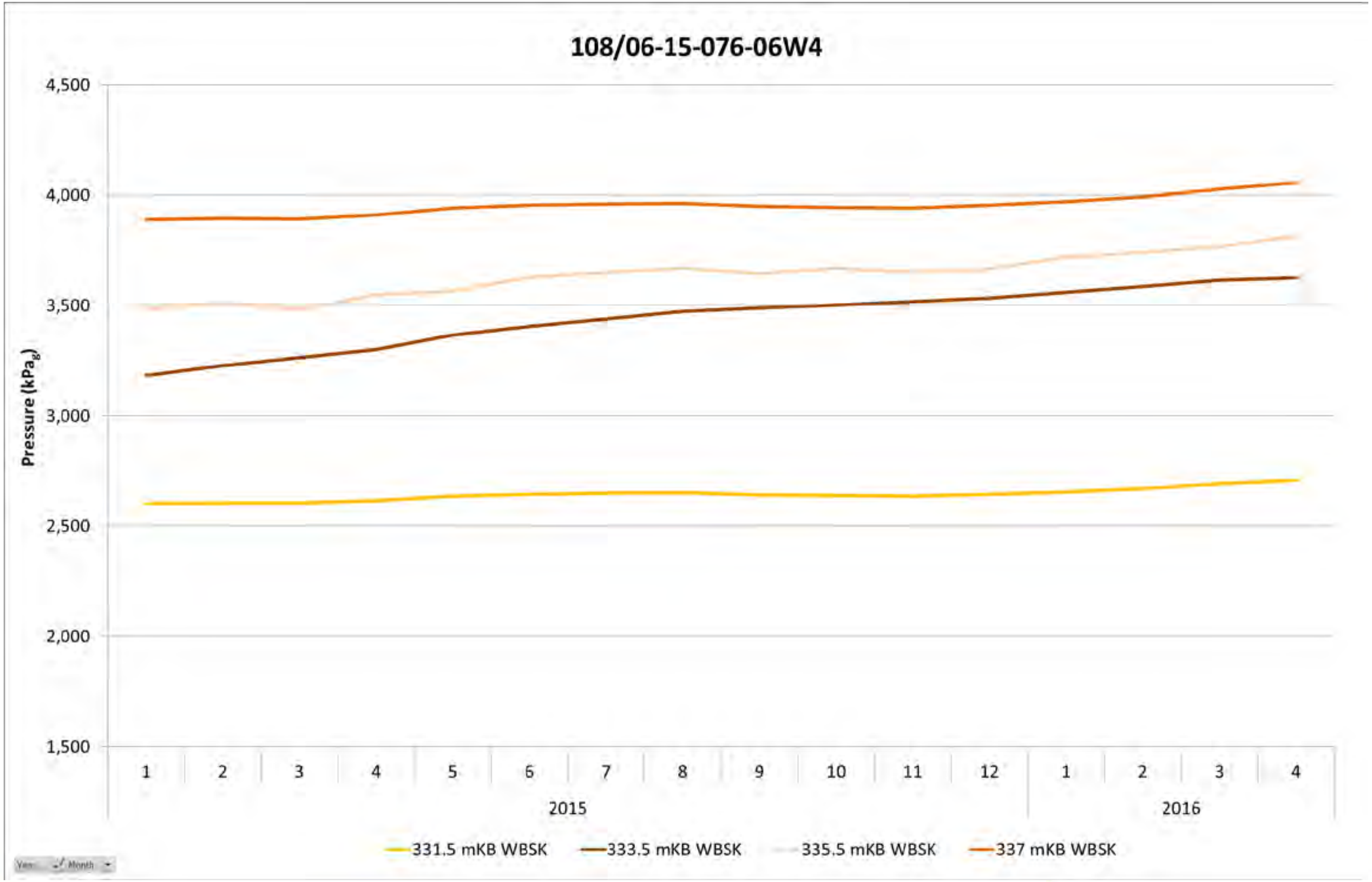

100/06-29-076-05W4
Pressure (kPag)
3,000
2,900
2,800
2,700
2,600
2,500
2,400
2,300
2,200
2,100
2,000
1 2 3 4 5 6 7 8 9 10 11 12 1 2 3
2015
2016
384 mKB McM Bottom Water



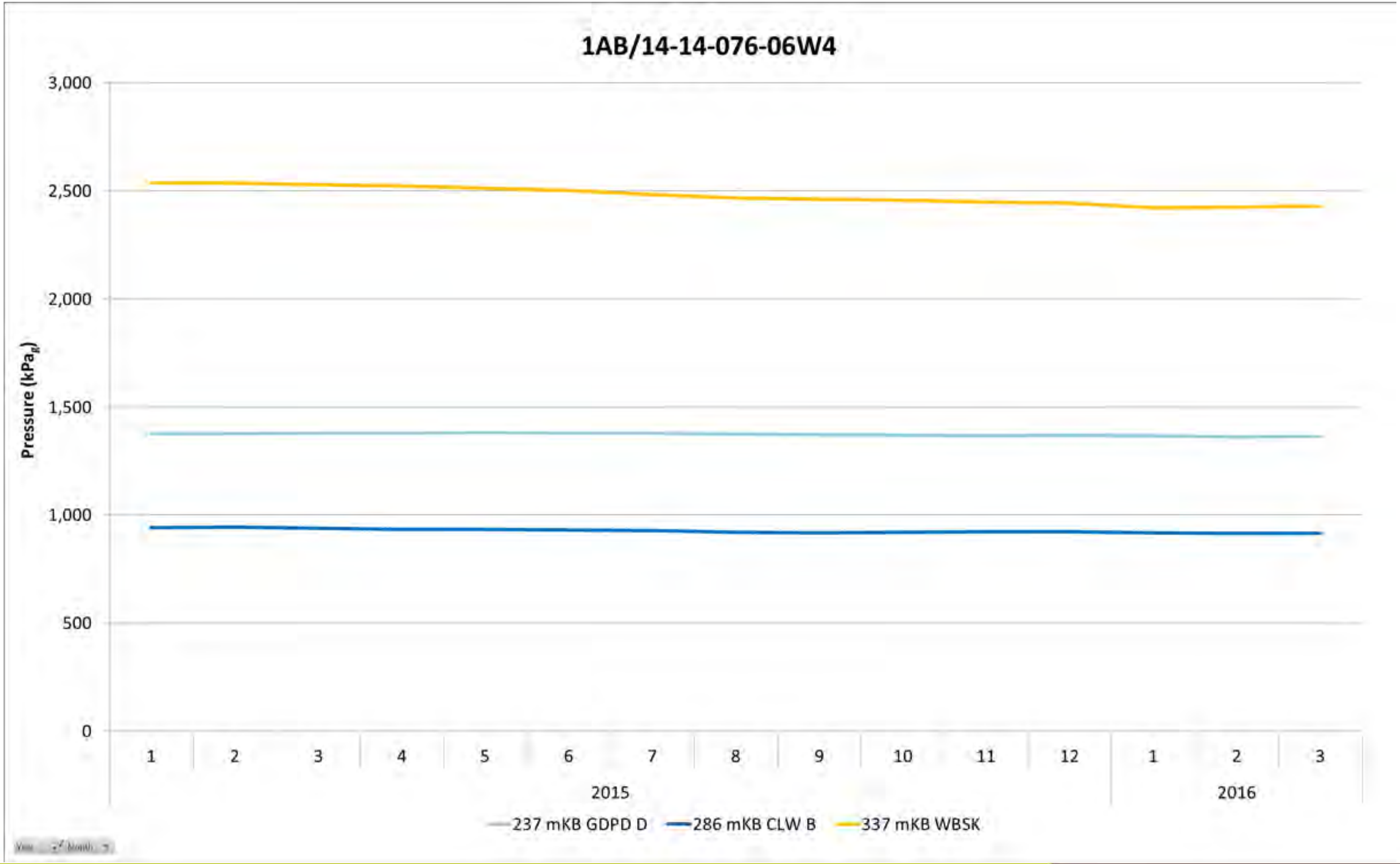
102/16-29-076-05W4
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPa$_g$)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
225 mKB GDPD D
251 mKB CLW A
275 mKB CLW B
386 mKB McM Bottom Water

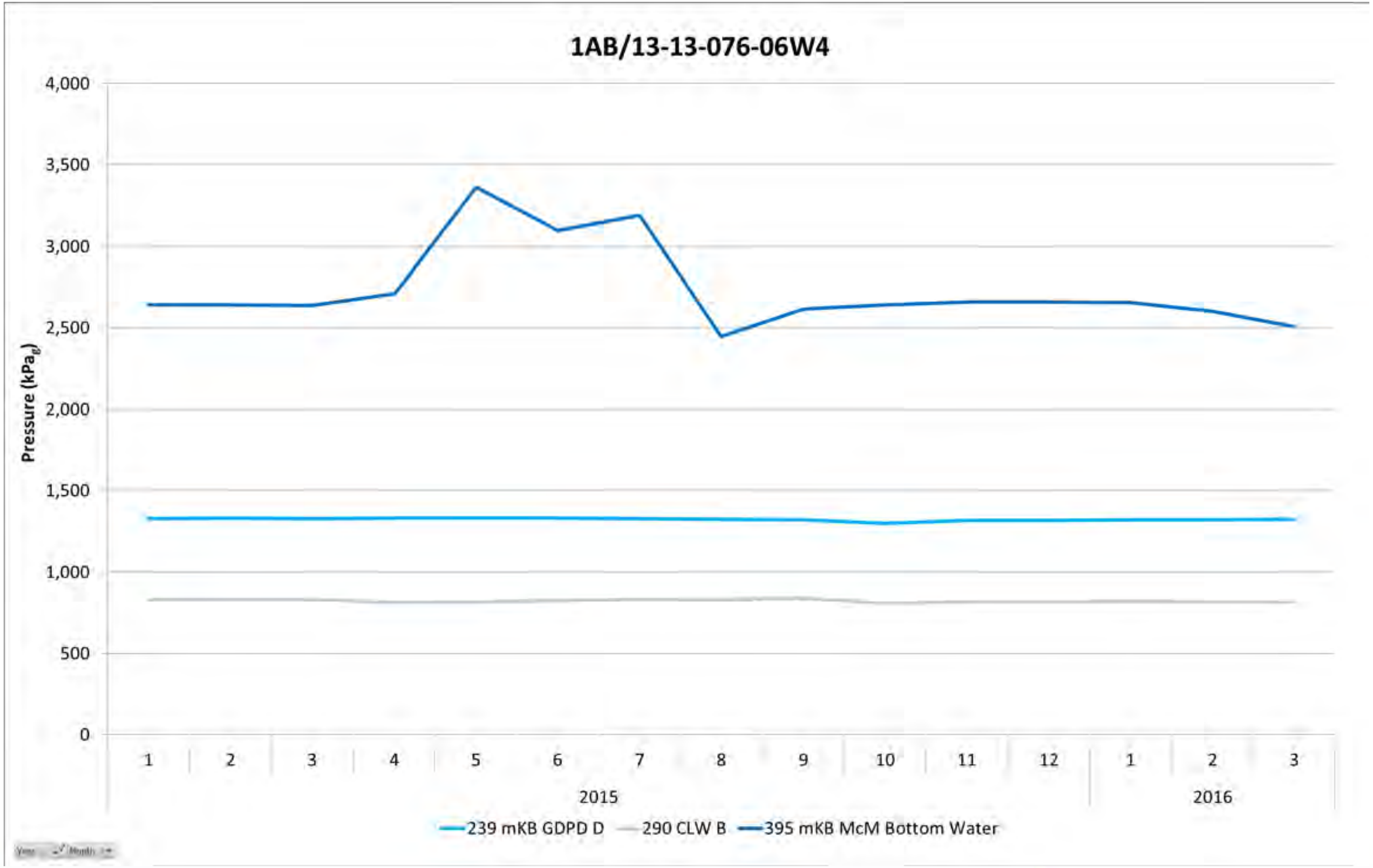
# 100/10-03-076-06W4

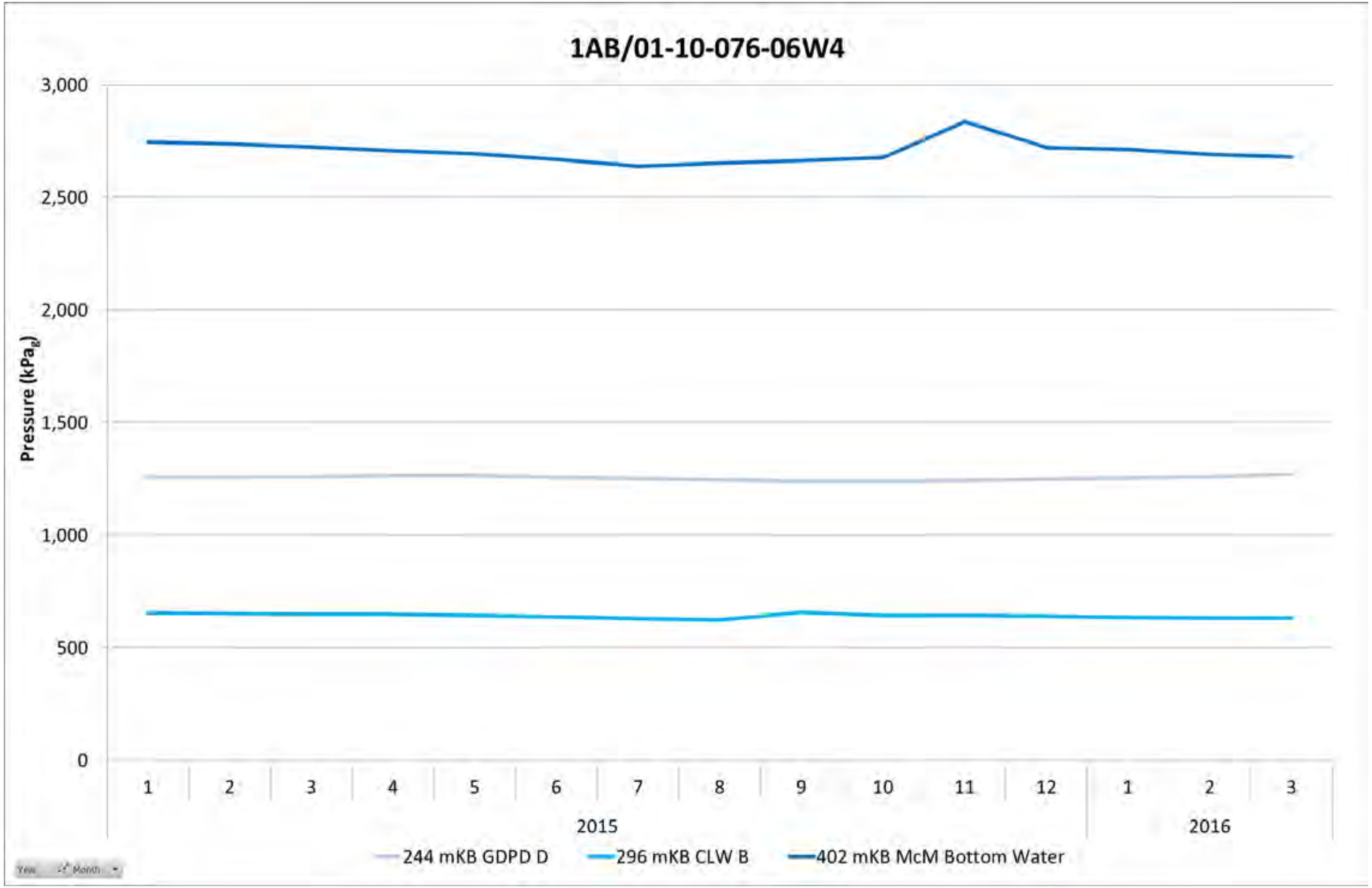
## Broken Downhole

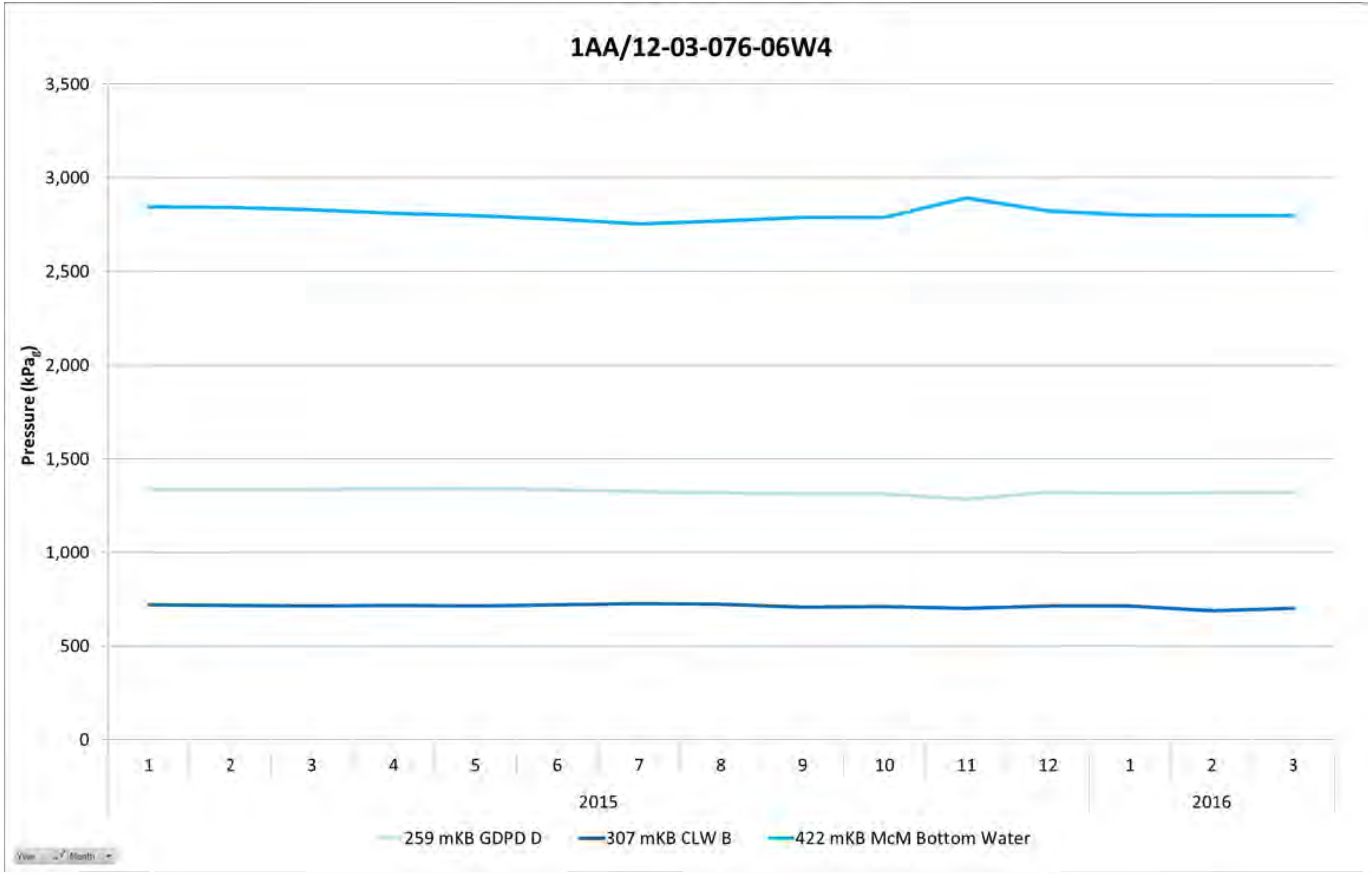


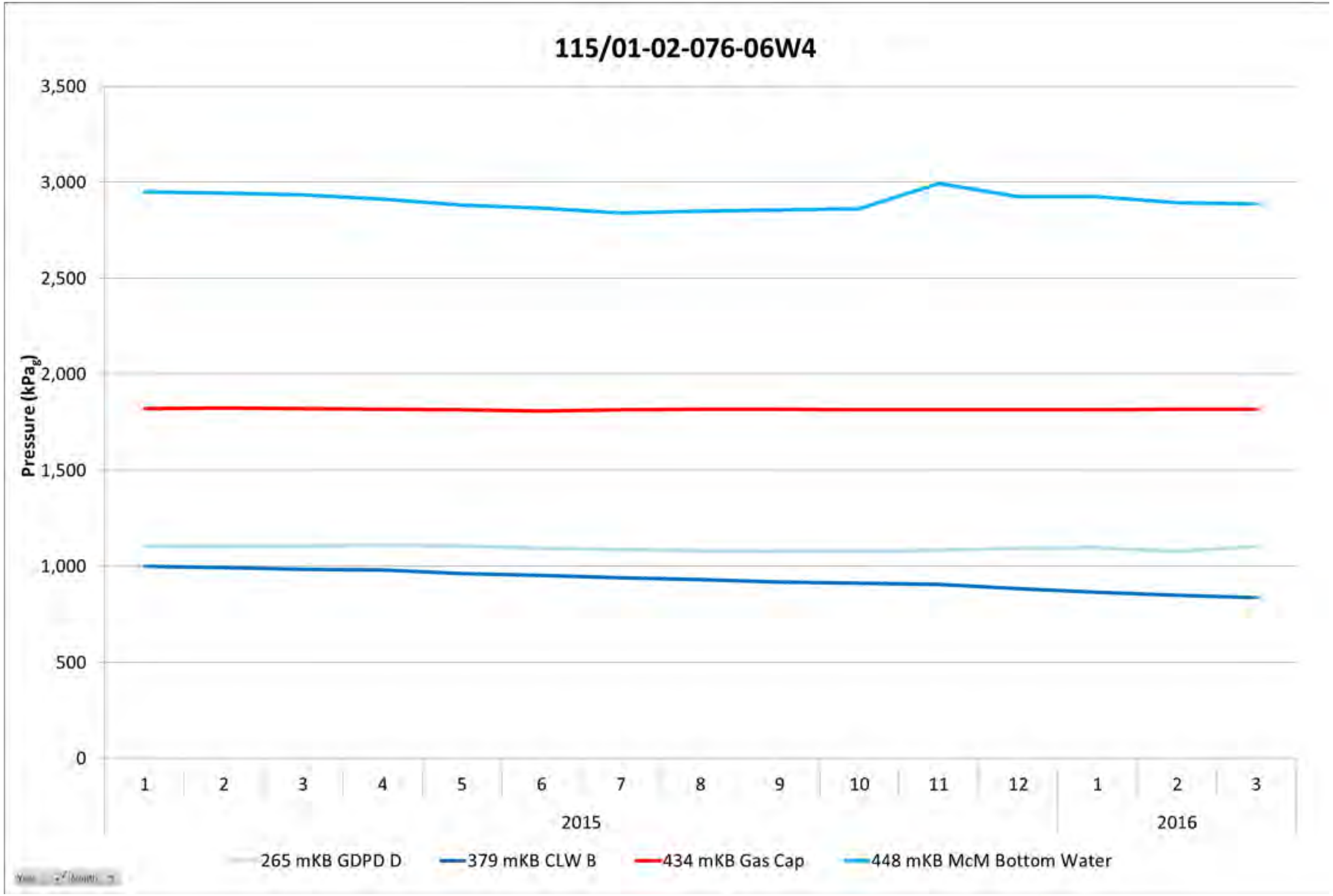
108/06-15-076-06W4
4,500
4,000
3,500
3,000
2,500
2,000
1,500
Pressure (kPag)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
4
2015
2016
331.5 mKB WBSK
333.5 mKB WBSK
335.5 mKB WBSK
337 mKB WBSK

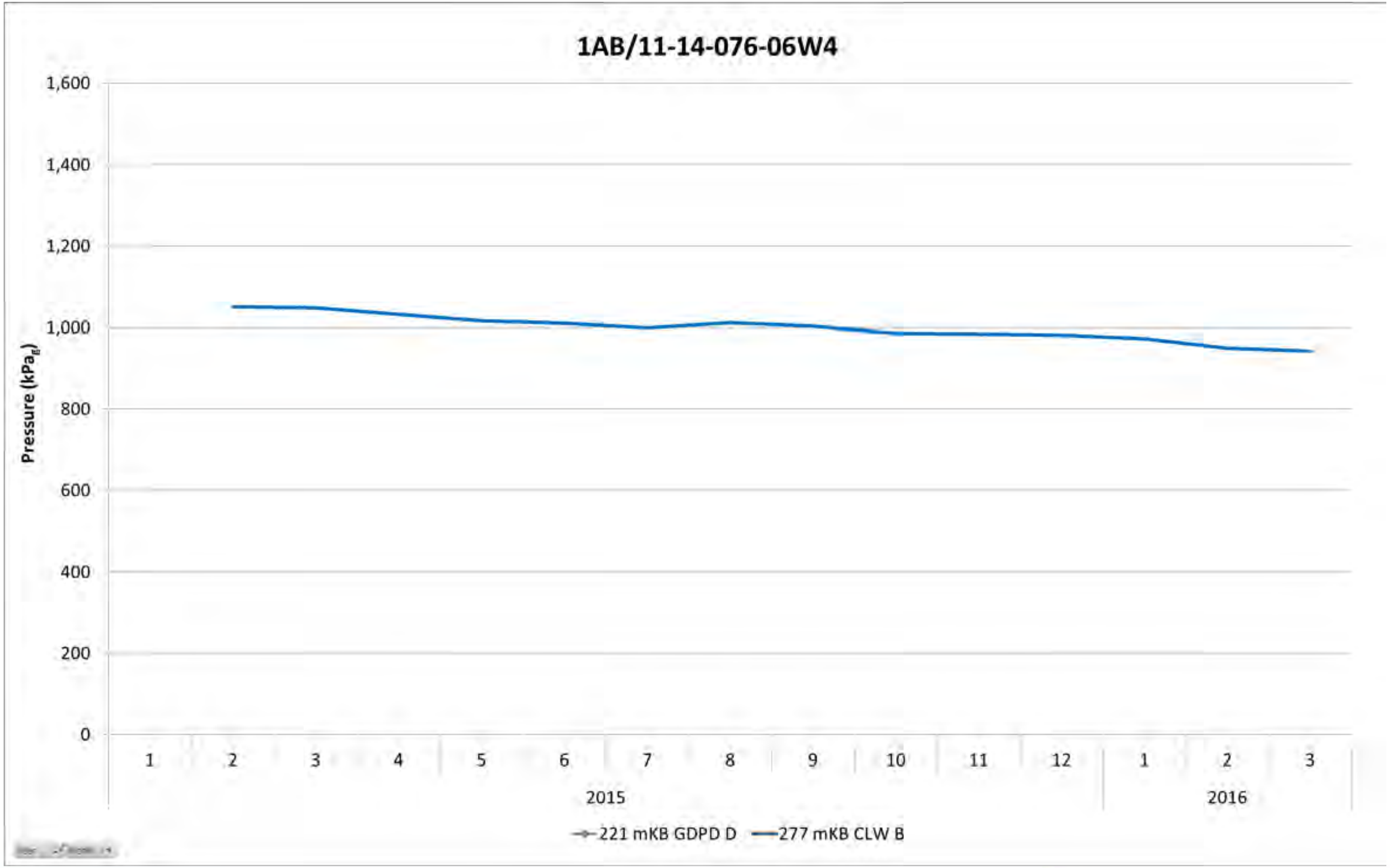

1AB/14-14-076-06W4
3,000
2,500
2,000
1,500
1,000
500
0
Pressure (kPag)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
237 mKB GDPD D
286 mKB CLW B
337 mKB WBSK

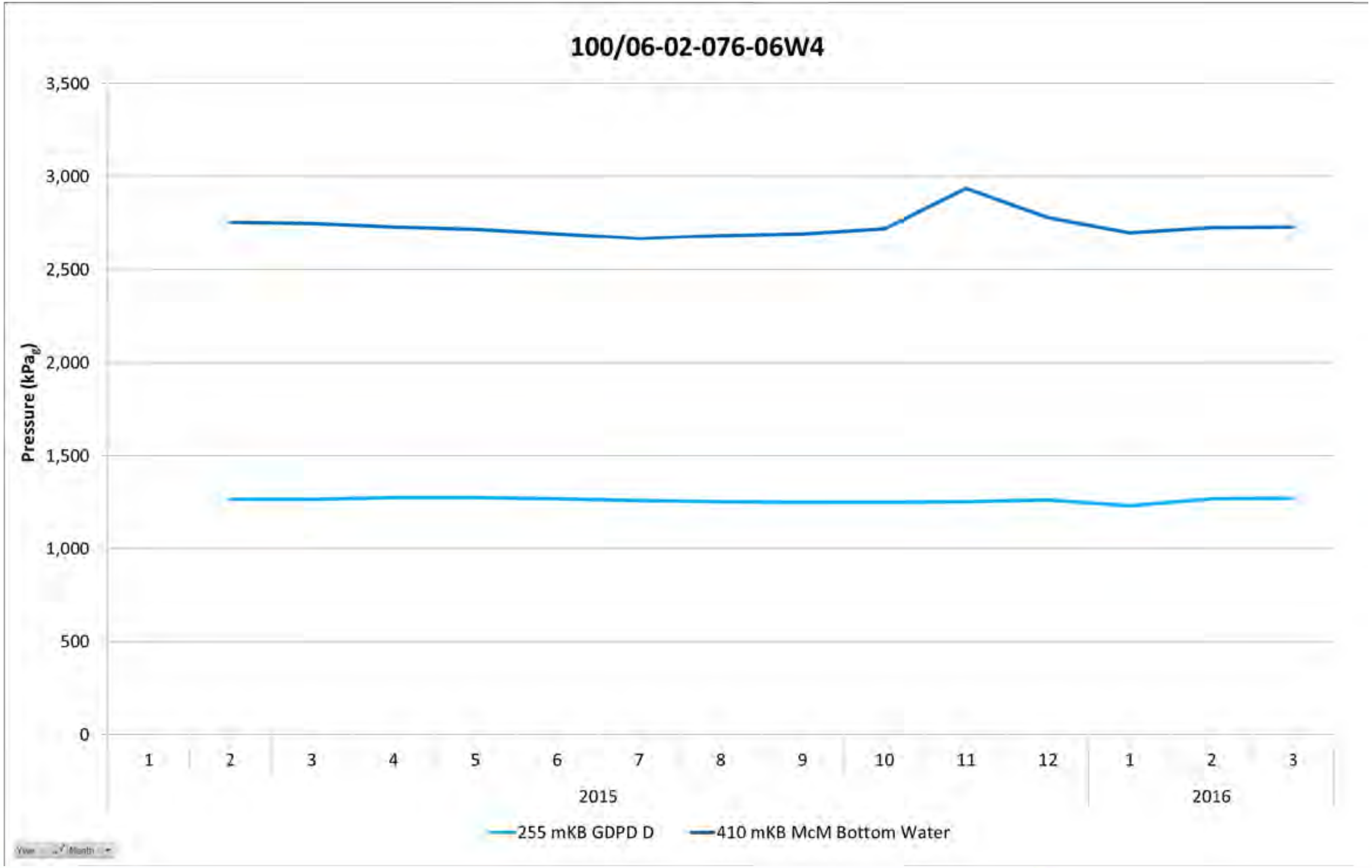

1AB/13-13-076-06W4
Pressure (kPag)
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
239 mKB GDPD D
290 CLW B
395 mKB McM Bottom Water

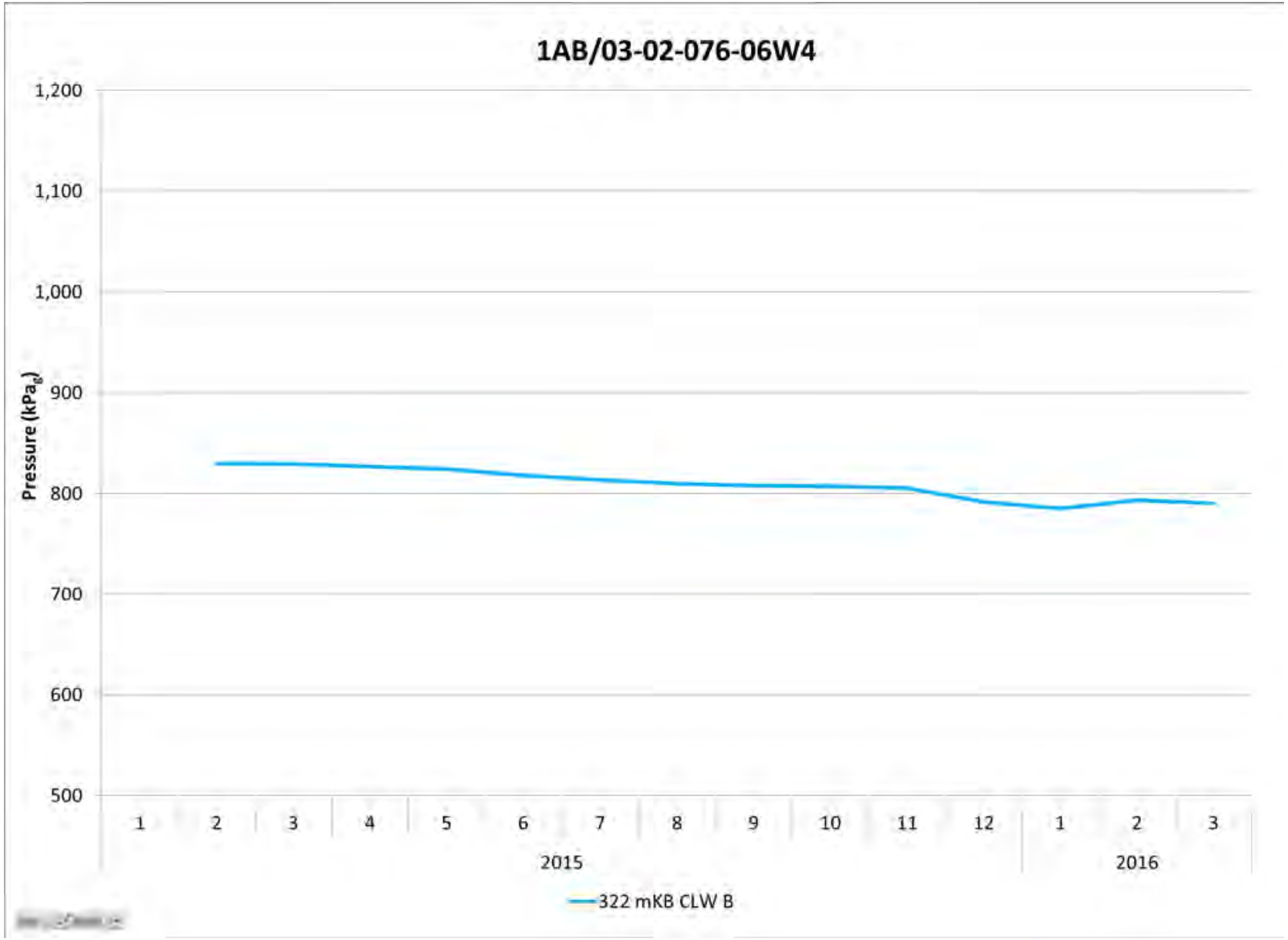

1AB/01-10-076-06W4
Pressure (kPa$_g$)
3,000
2,500
2,000
1,500
1,000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 1 2 3
2015
2016
244 mKB GDPD D
296 mKB CLW B
402 mKB McM Bottom Water


1AA/12-03-076-06W4
Pressure (kPag)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
259 mKB GDPD D
307 mKB CLW B
422 mKB McM Bottom Water

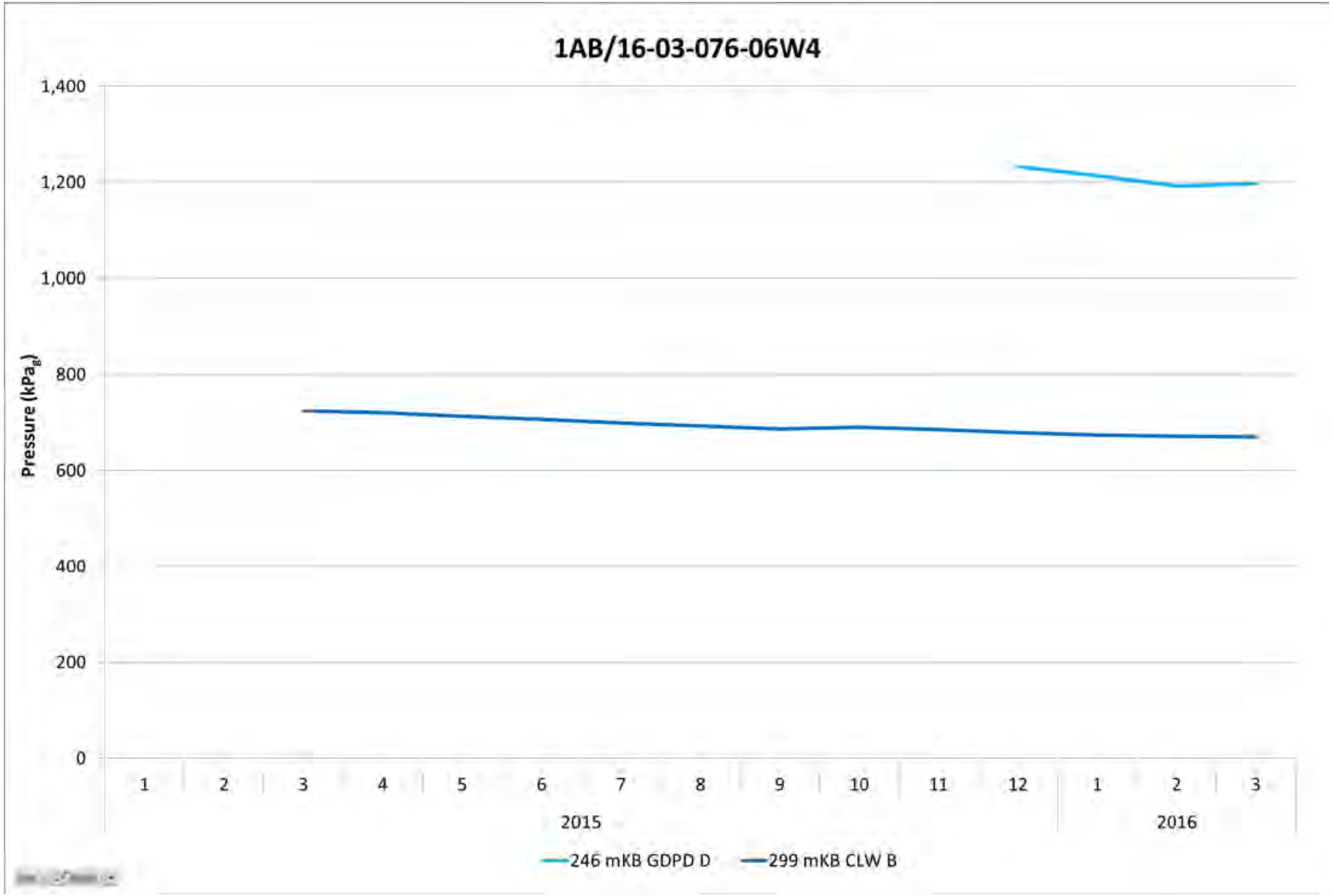

115/01-02-076-06W4
Pressure (kPag)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
265 mKB GDPD D
379 mKB CLW B
434 mKB Gas Cap
448 mKB McM Bottom Water

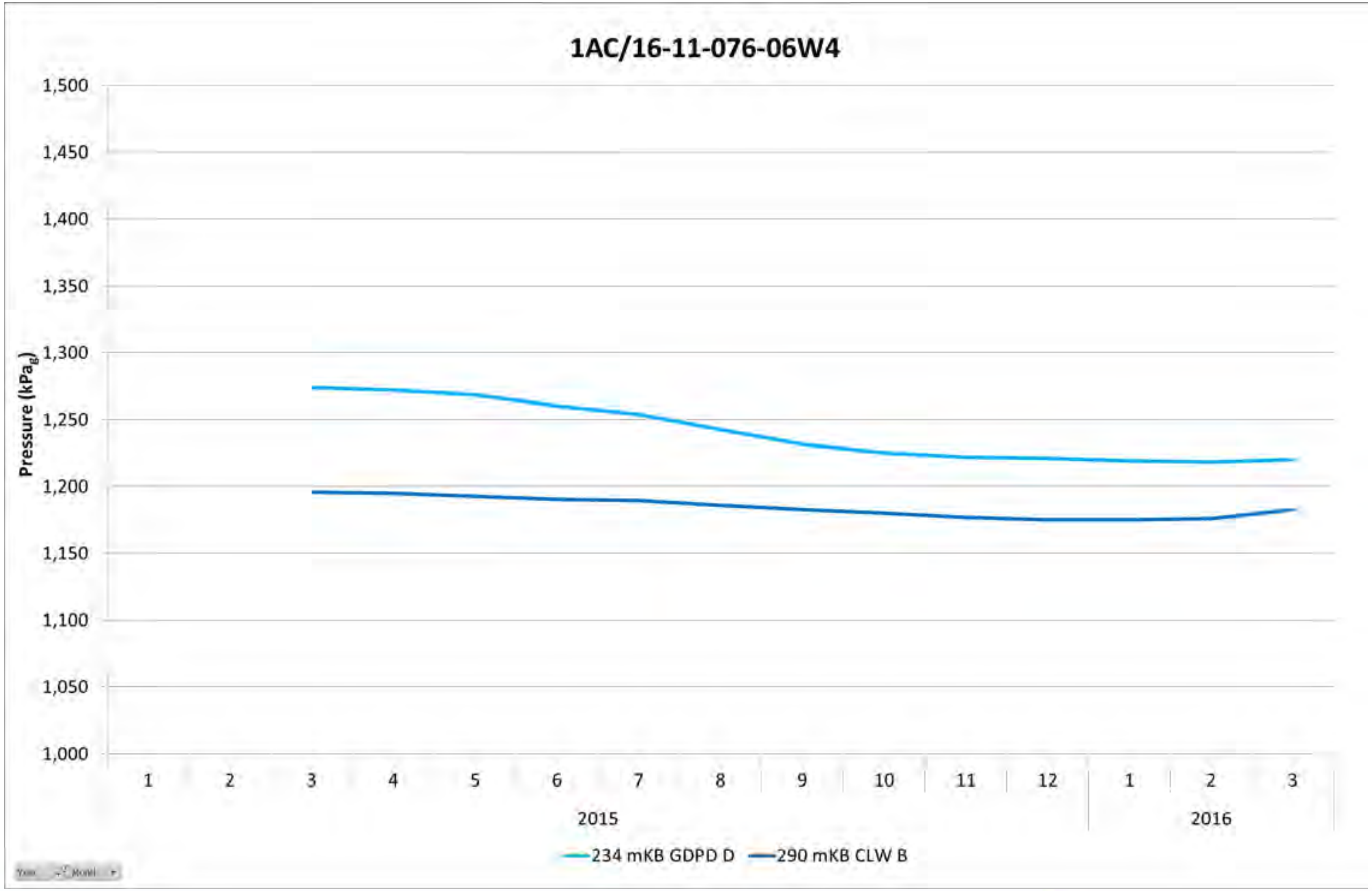

1AB/11-14-076-06W4
Pressure (kPag)
1,600
1,400
1,200
1,000
800
600
400
200
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
221 mKB GDPD D
277 mKB CLW B

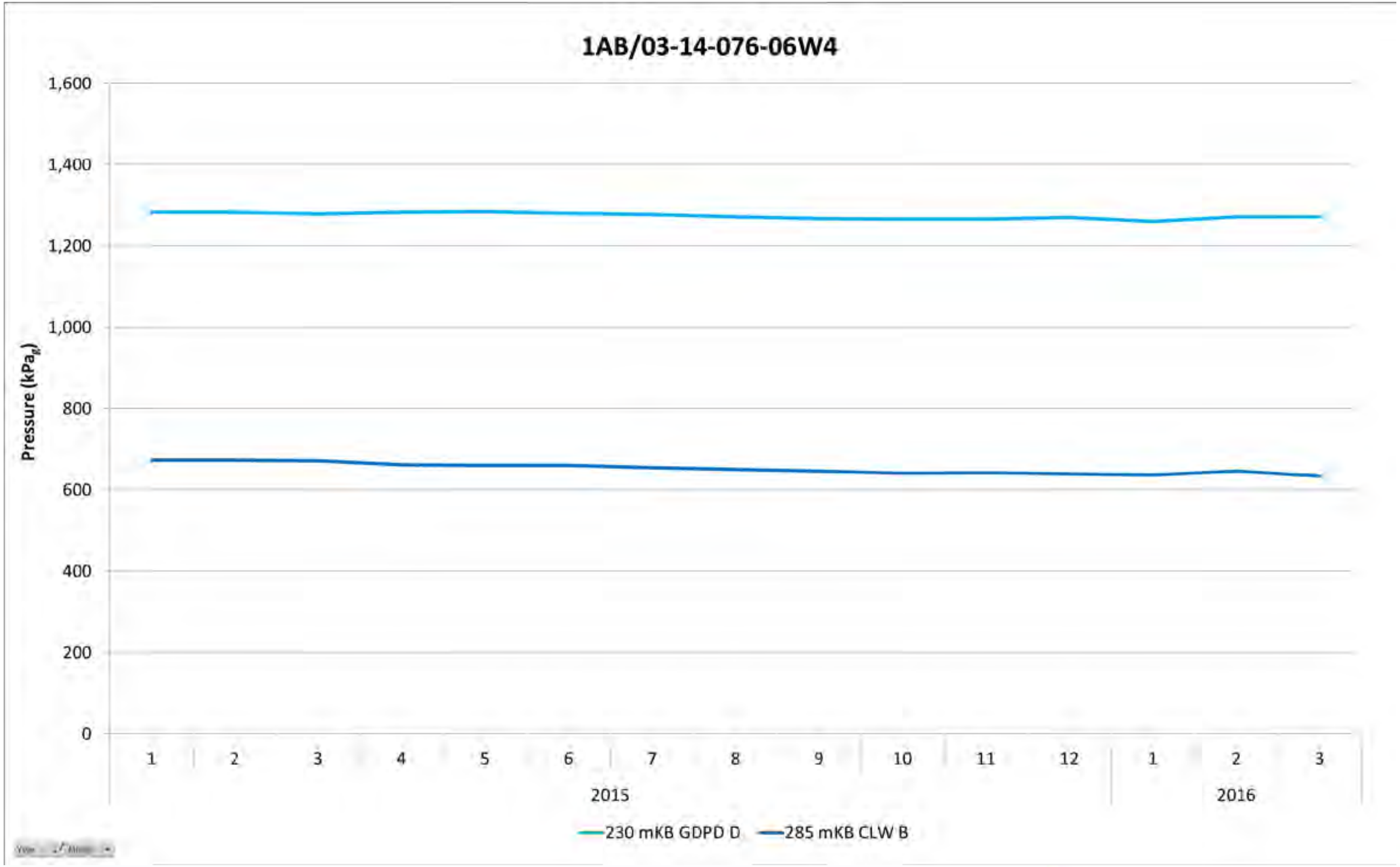

100/06-02-076-06W4
Pressure (kPag)
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
255 mKB GDPD D
410 mKB McM Bottom Water



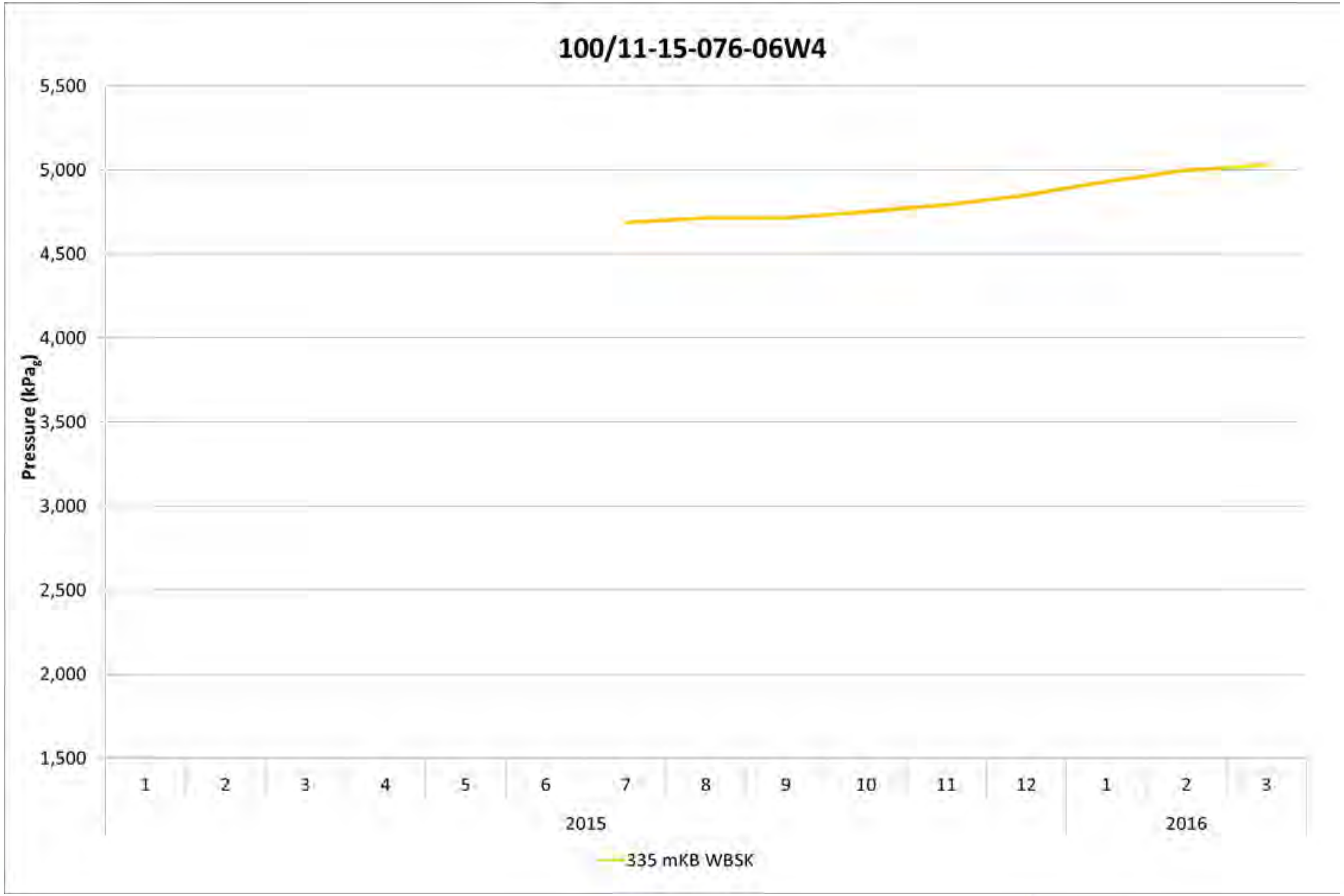
1AB/03-02-076-06W4
Pressure (kPag)
1,200
1,100
1,000
900
800
700
600
500
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
322 mKB CLW B


1AB/16-03-076-06W4
Pressure ($kPa_g$)
1,400
1,200
1,000
800
600
400
200
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
246 mKB GDPD D
299 mKB CLW B


1AC/16-11-076-06W4
1,500
1,450
1,400
1,350
1,300
1,250
1,200
1,150
1,100
1,050
1,000
Pressure ($kPa_g$)
1 2 3 4 5 6 7 8 9 10 11 12 1 2 3
2015
2016
234 mKB GDPD D
290 mKB CLW B

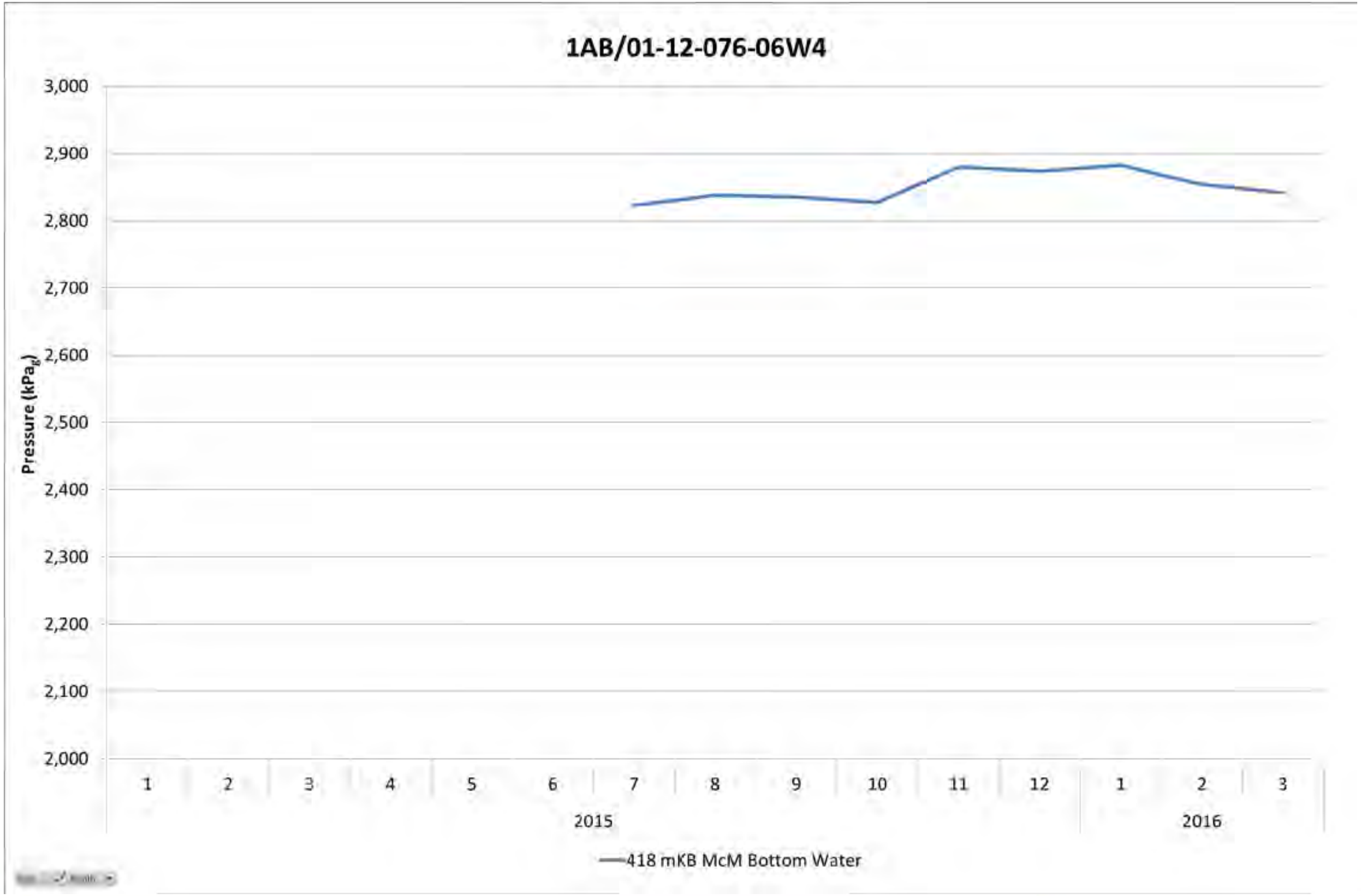


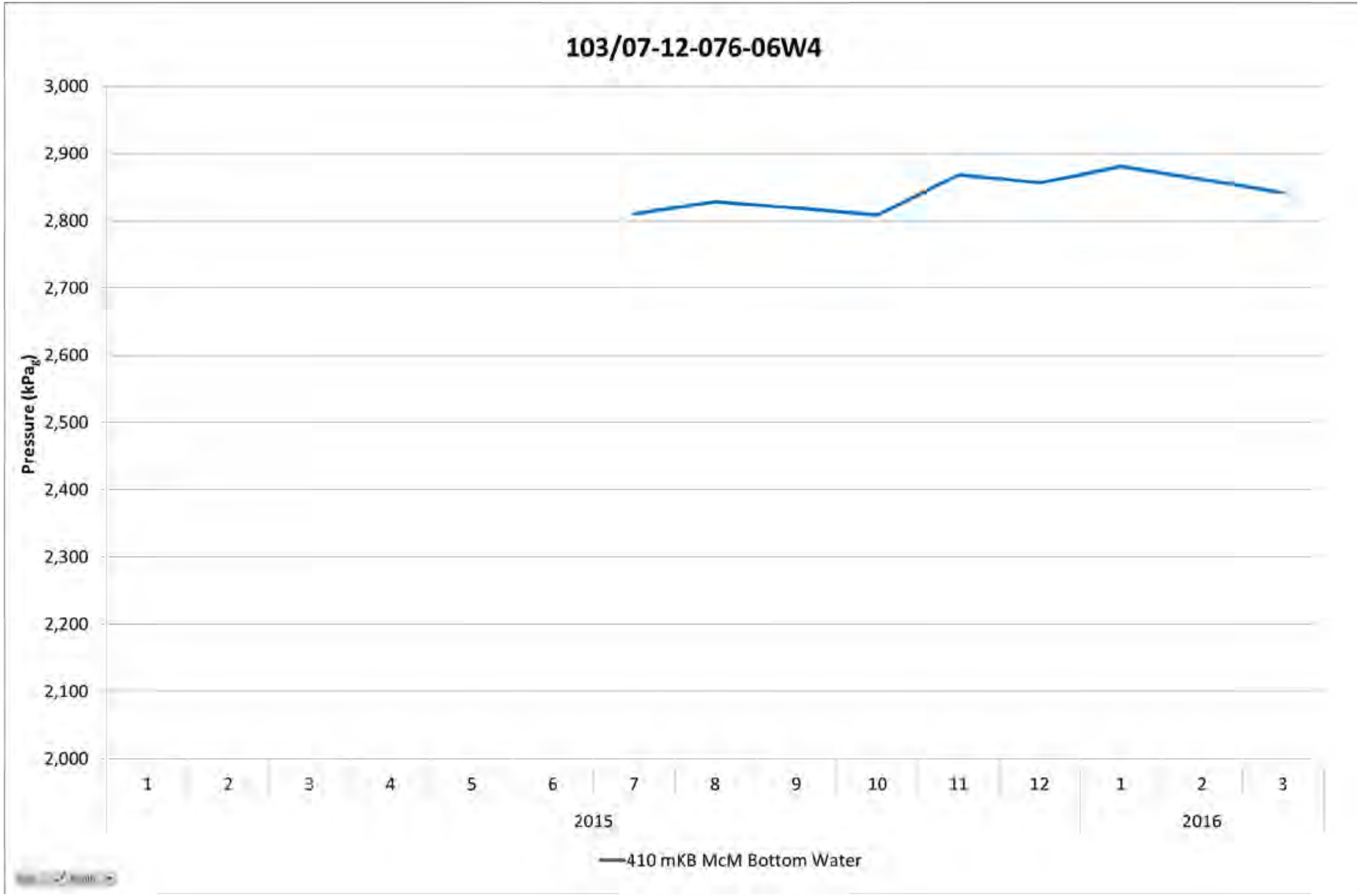

cenovus ENERGY

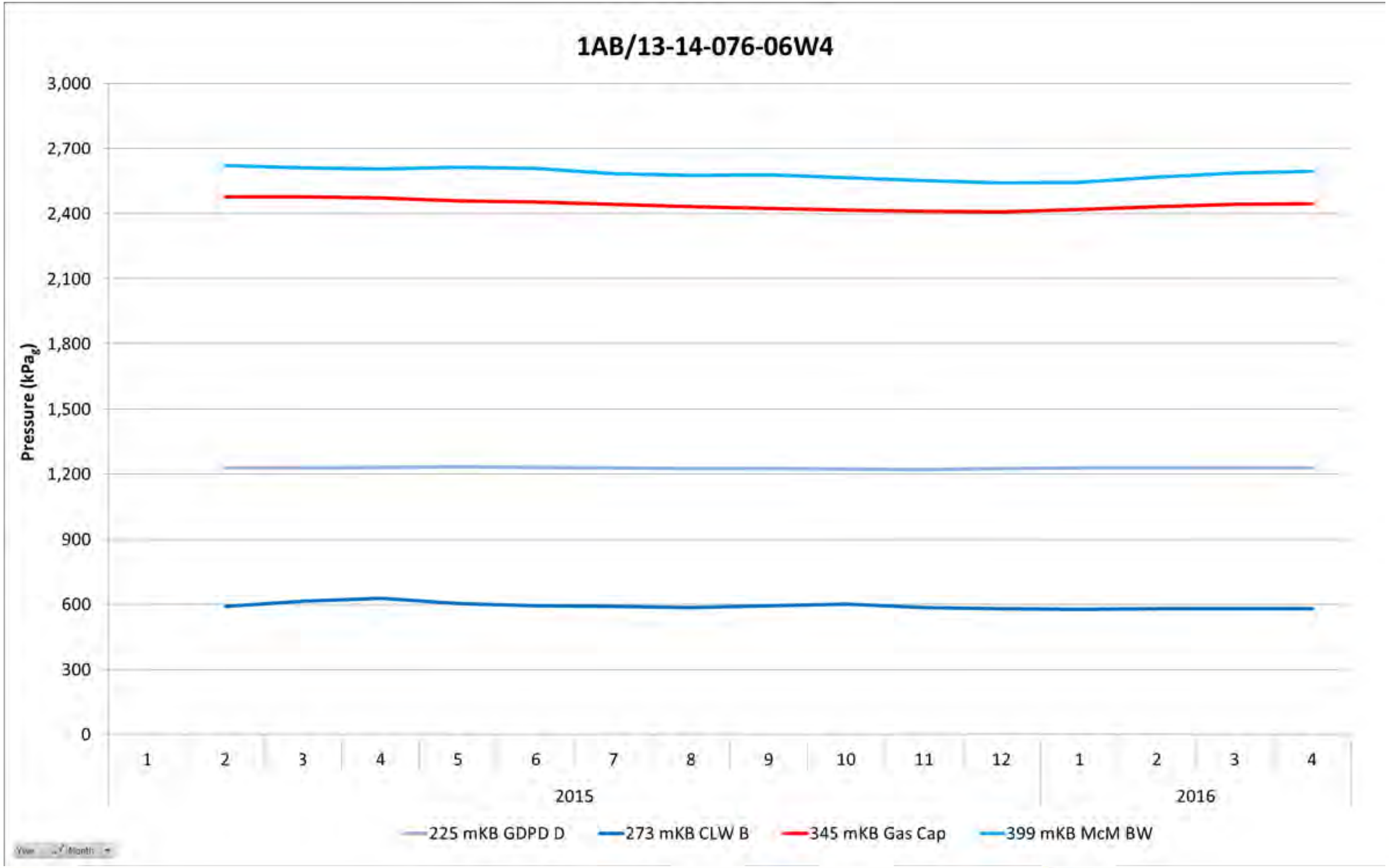


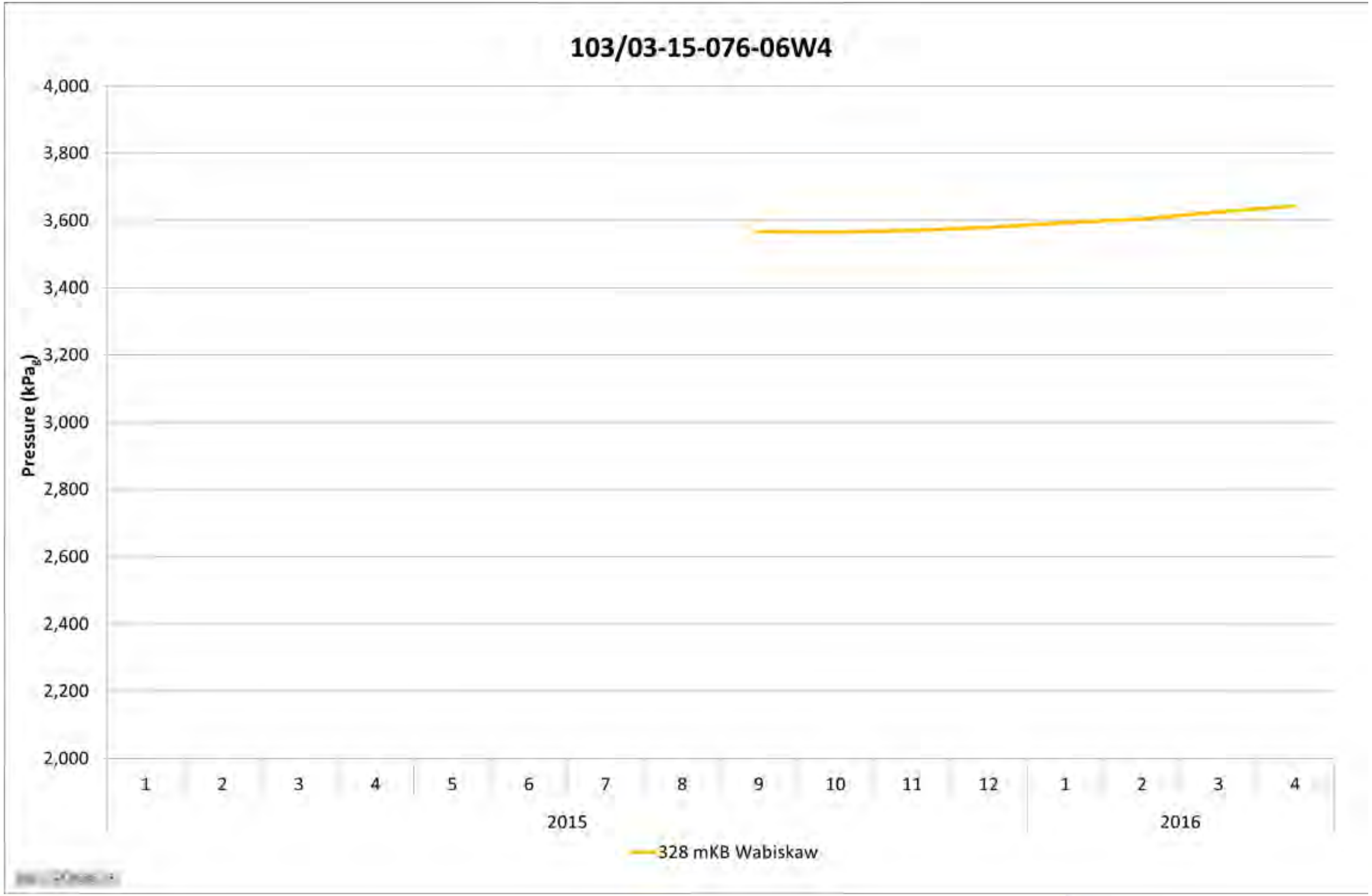

cenovus ENERGY

June 15, 2016

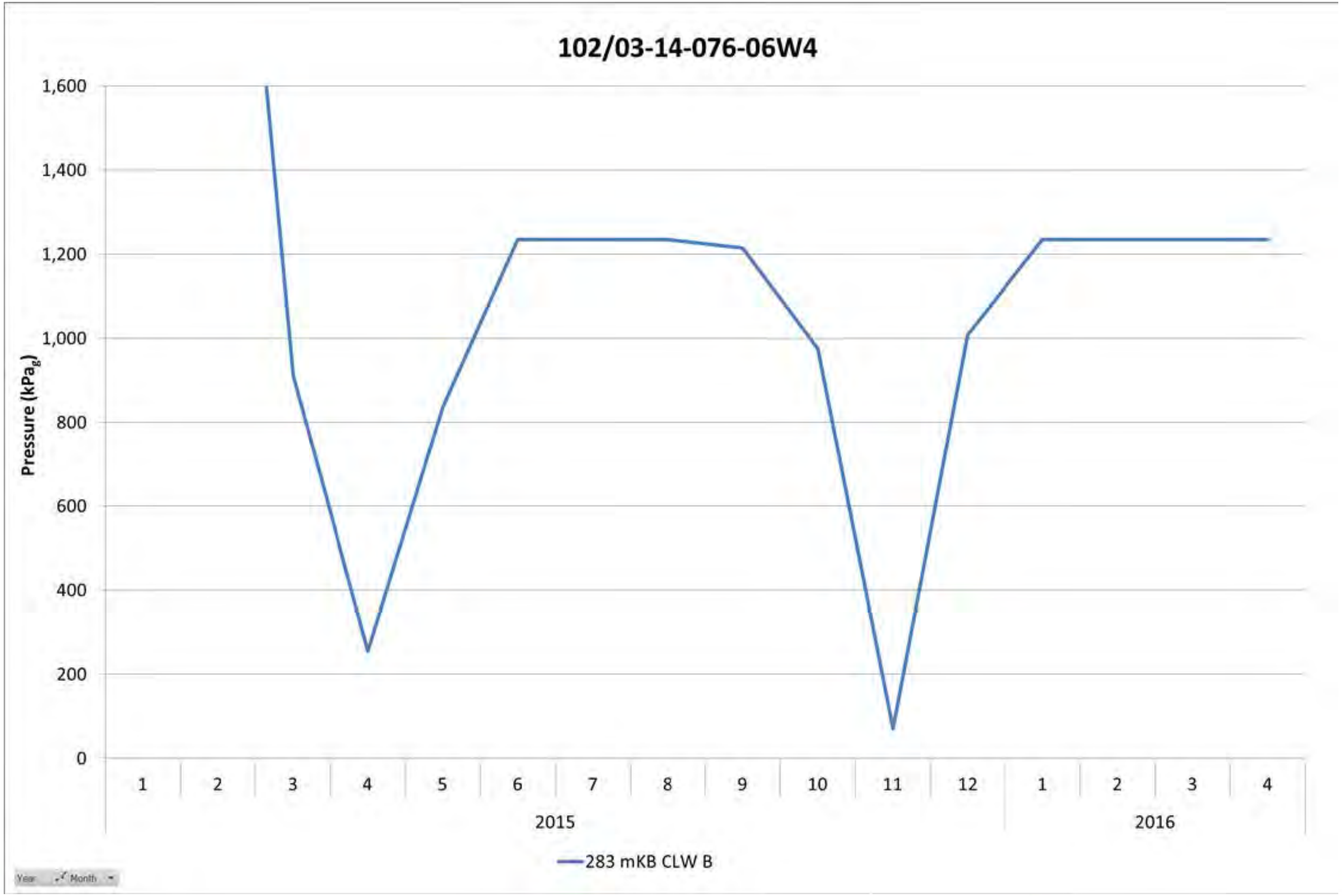

1AB/01-12-076-06W4
3,000
2,900
2,800
2,700
2,600
2,500
2,400
2,300
2,200
2,100
2,000
Pressure (kPag)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
418 mKB McM Bottom Water


103/07-12-076-06W4
Pressure (kPag)
3,000
2,900
2,800
2,700
2,600
2,500
2,400
2,300
2,200
2,100
2,000
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
2015
2016
410 mKB McM Bottom Water

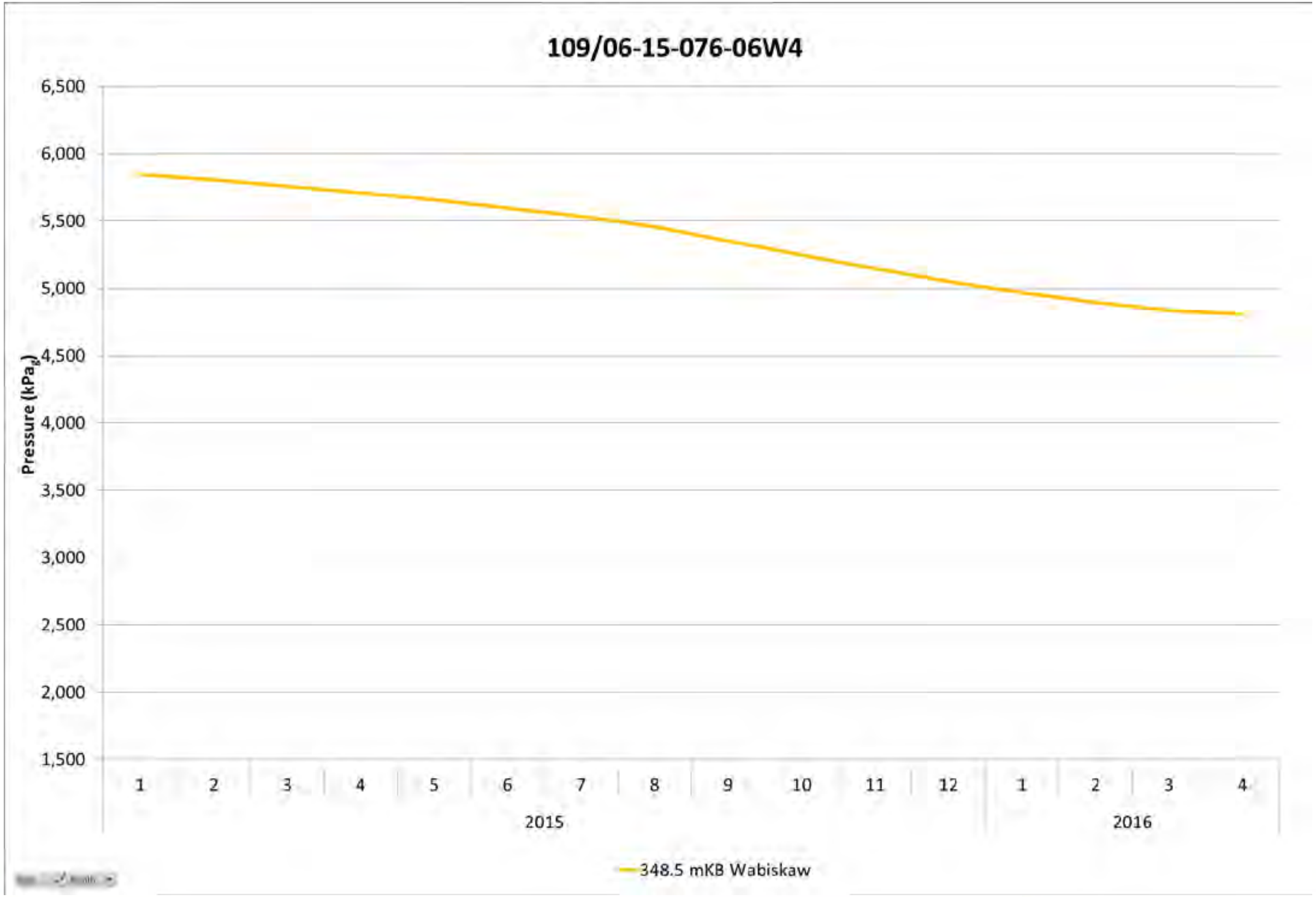

1AB/13-14-076-06W4
Pressure (kPa$_g$)
3,000
2,700
2,400
2,100
1,800
1,500
1,200
900
600
300
0
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
4
2015
2016
225 mKB GDPD D
273 mKB CLW B
345 mKB Gas Cap
399 mKB McM BW



103/03-15-076-06W4
Pressure (kPag)
4,000
3,800
3,600
3,400
3,200
3,000
2,800
2,600
2,400
2,200
2,000
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
4
2015
2016
328 mKB Wabiskaw



102/03-14-076-06W4
1,600
1,400
1,200
1,000
800
600
400
200
0
Pressure (kPa$_g$)
1
2
3
4
5
6
7
8
9
10
11
12
1
2
3
4
2015
2016
283 mKB CLW B
Year
Month

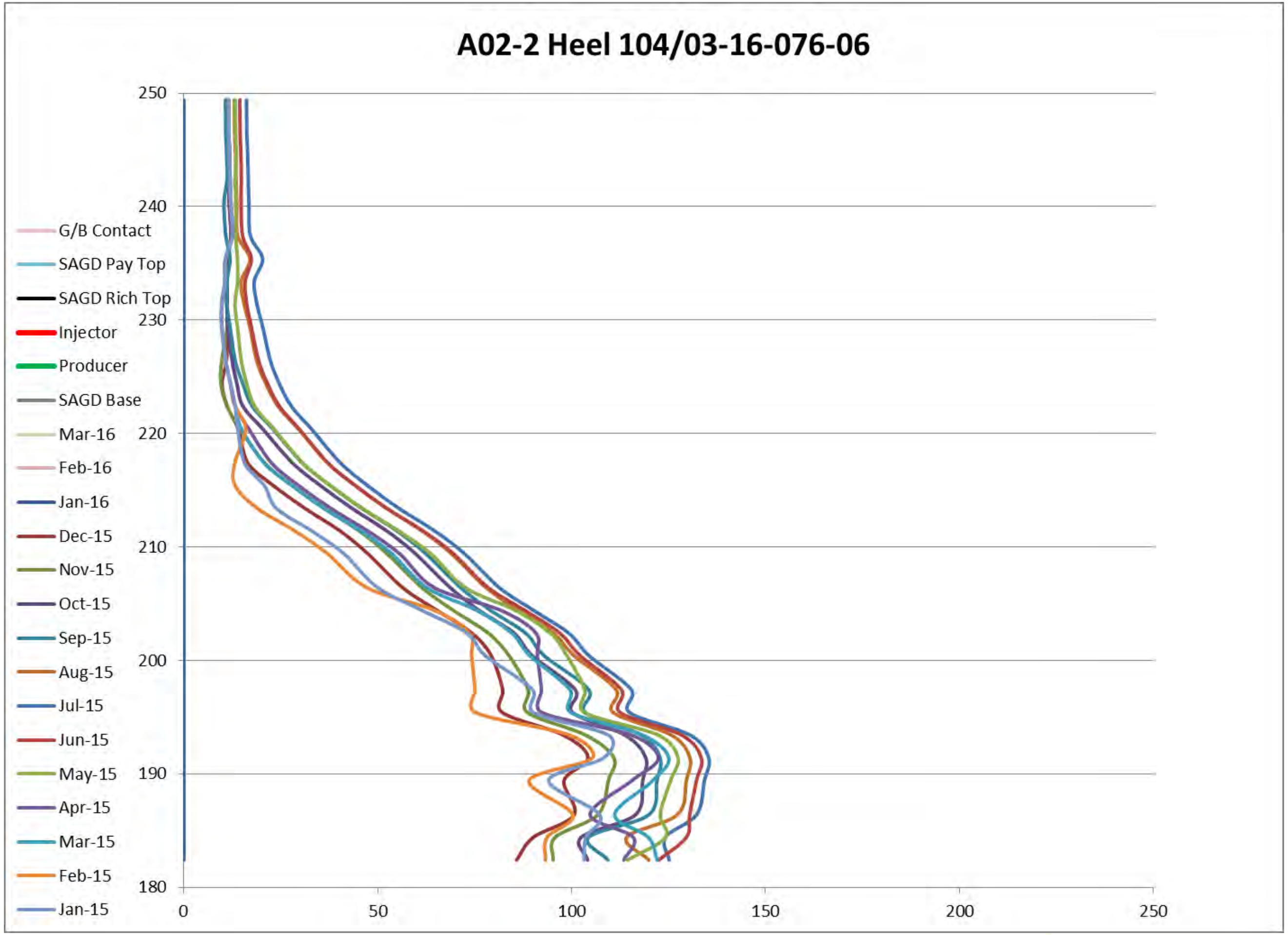


109/06-15-076-06W4
Pressure (kPa)
6,500
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4
2015
2016
348.5 mKB Wabiskaw

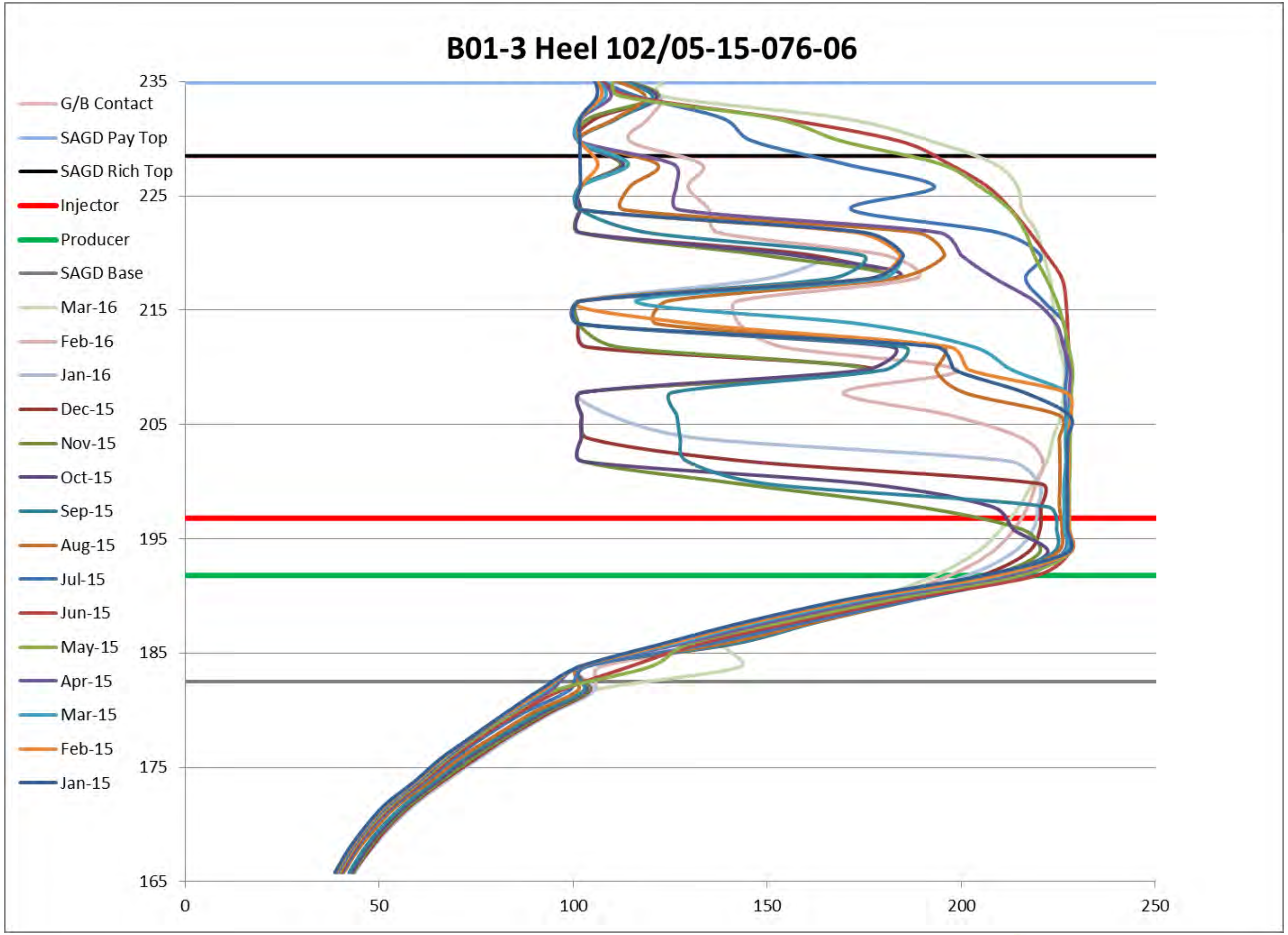
# Appendix 3
# Subsection 3.1.1 – 5d)

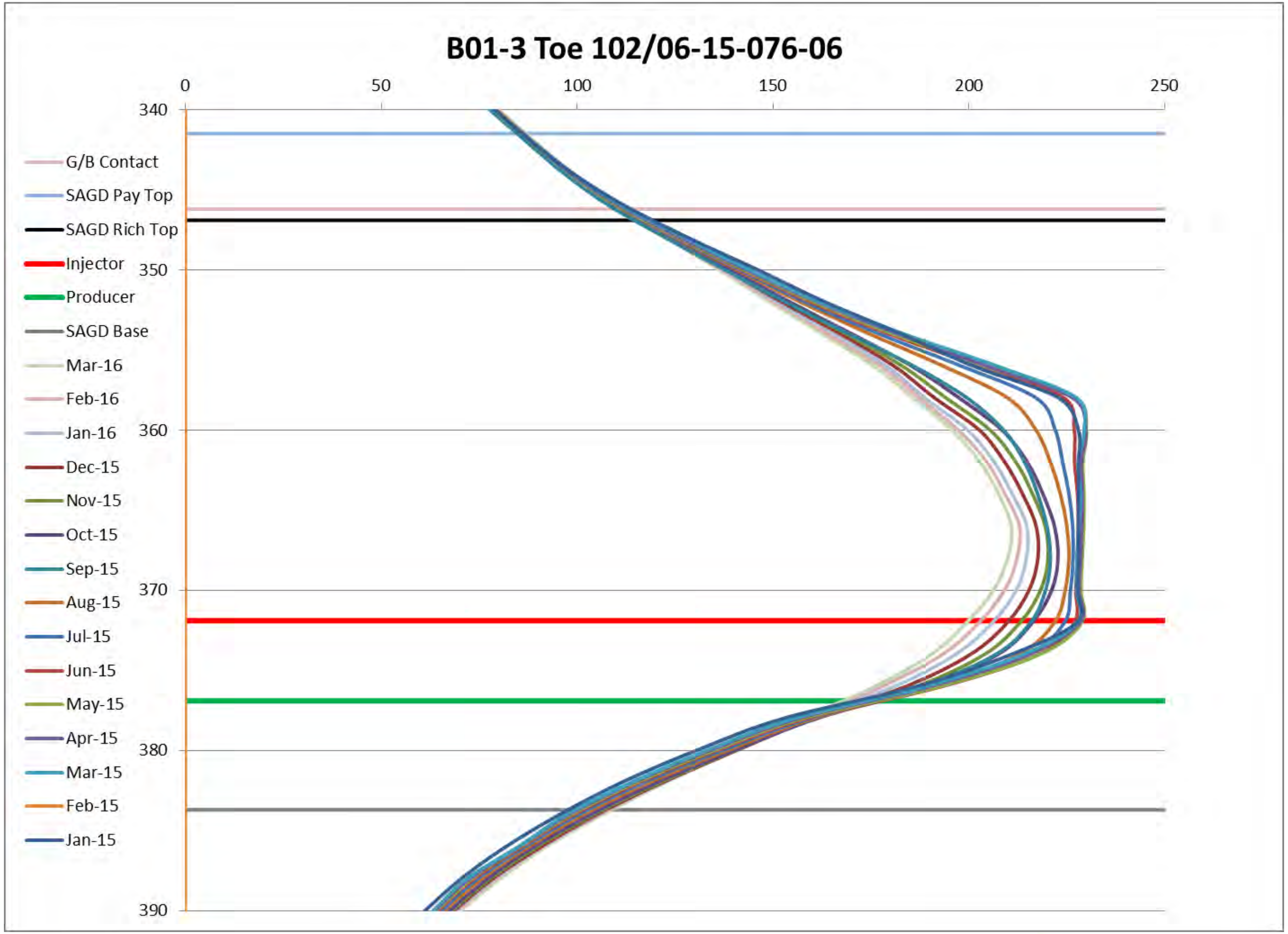
# Observation Well Temperature Data

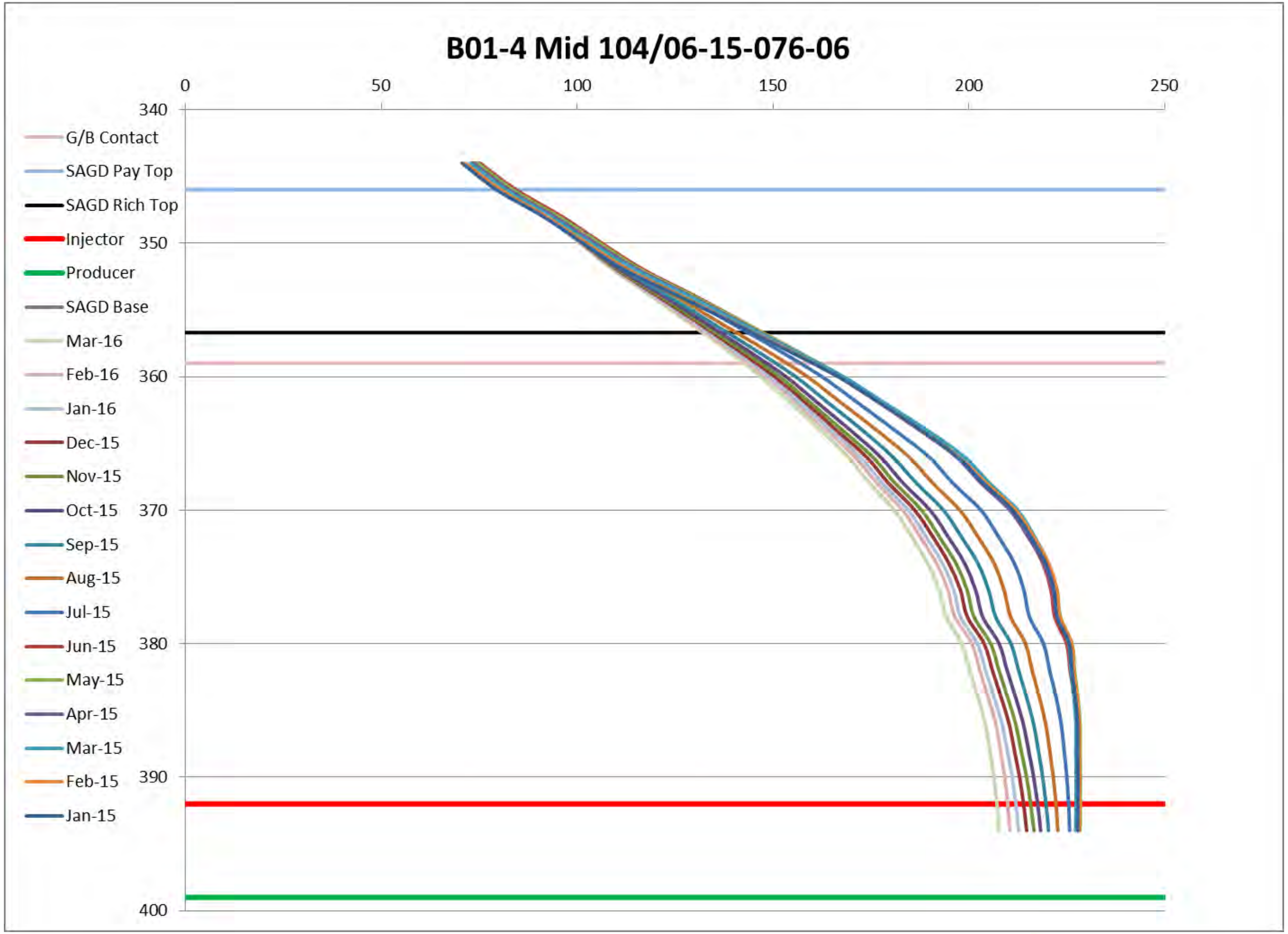
cenovus ENERGY



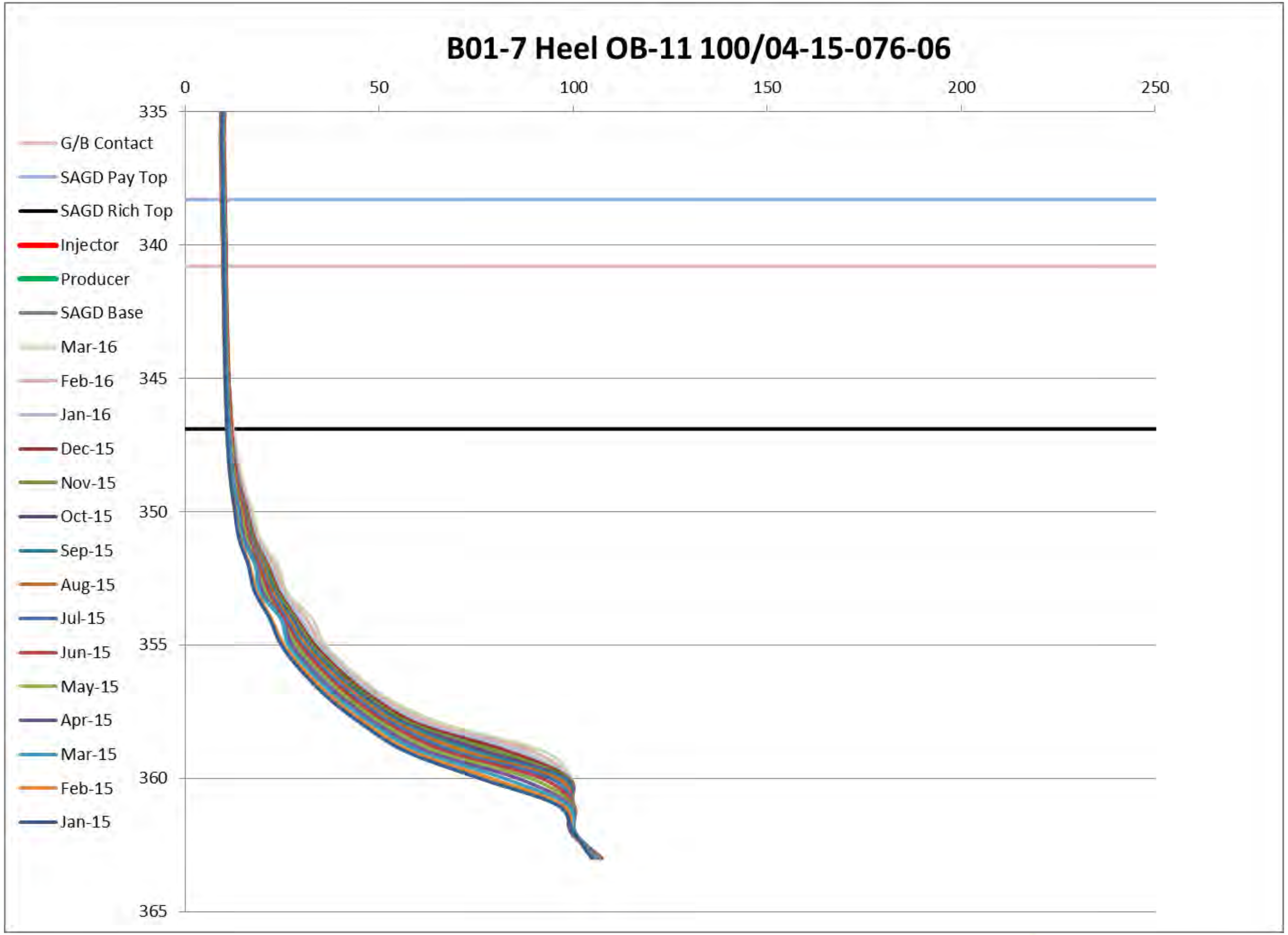
A02-2 Heel 104/03-16-076-06
250
240
230
220
210
200
190
180
0
50
100
150
200
250
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

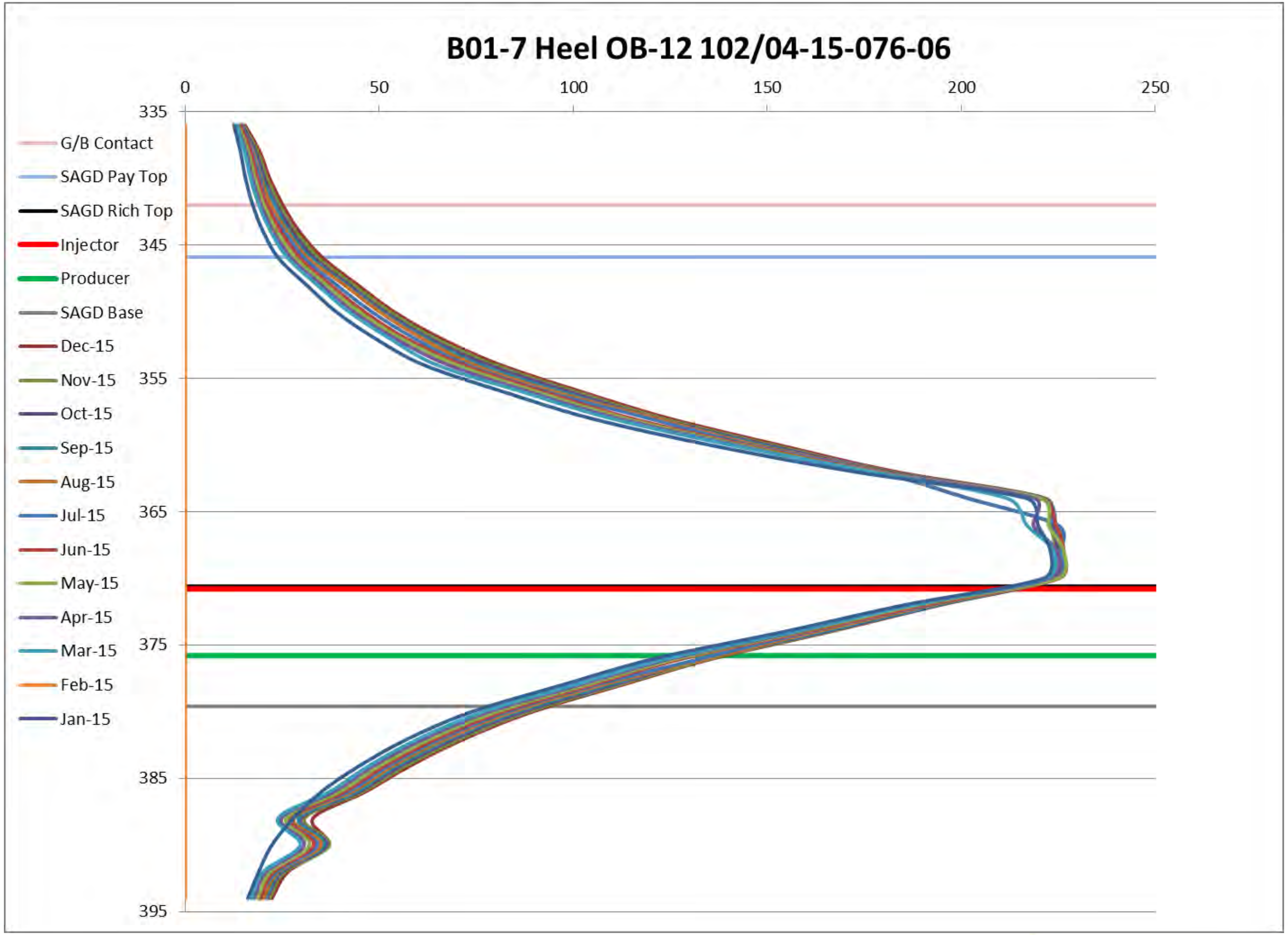

B01-3 Heel 102/05-15-076-06
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15
235
225
215
205
195
185
175
165
0
50
100
150
200
250

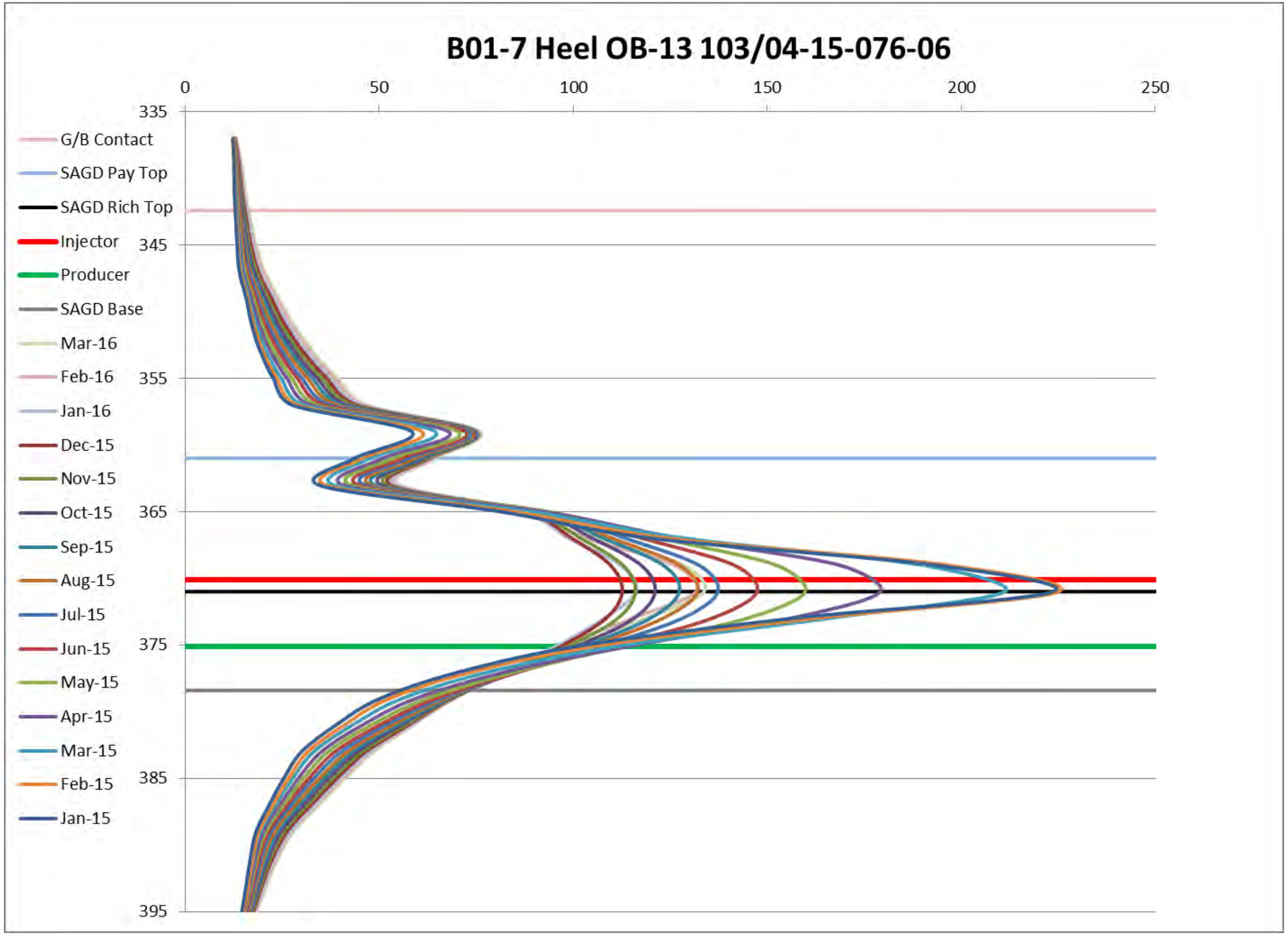

B01-3 Toe 102/06-15-076-06
0
50
100
150
200
250
340
350
360
370
380
390
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15



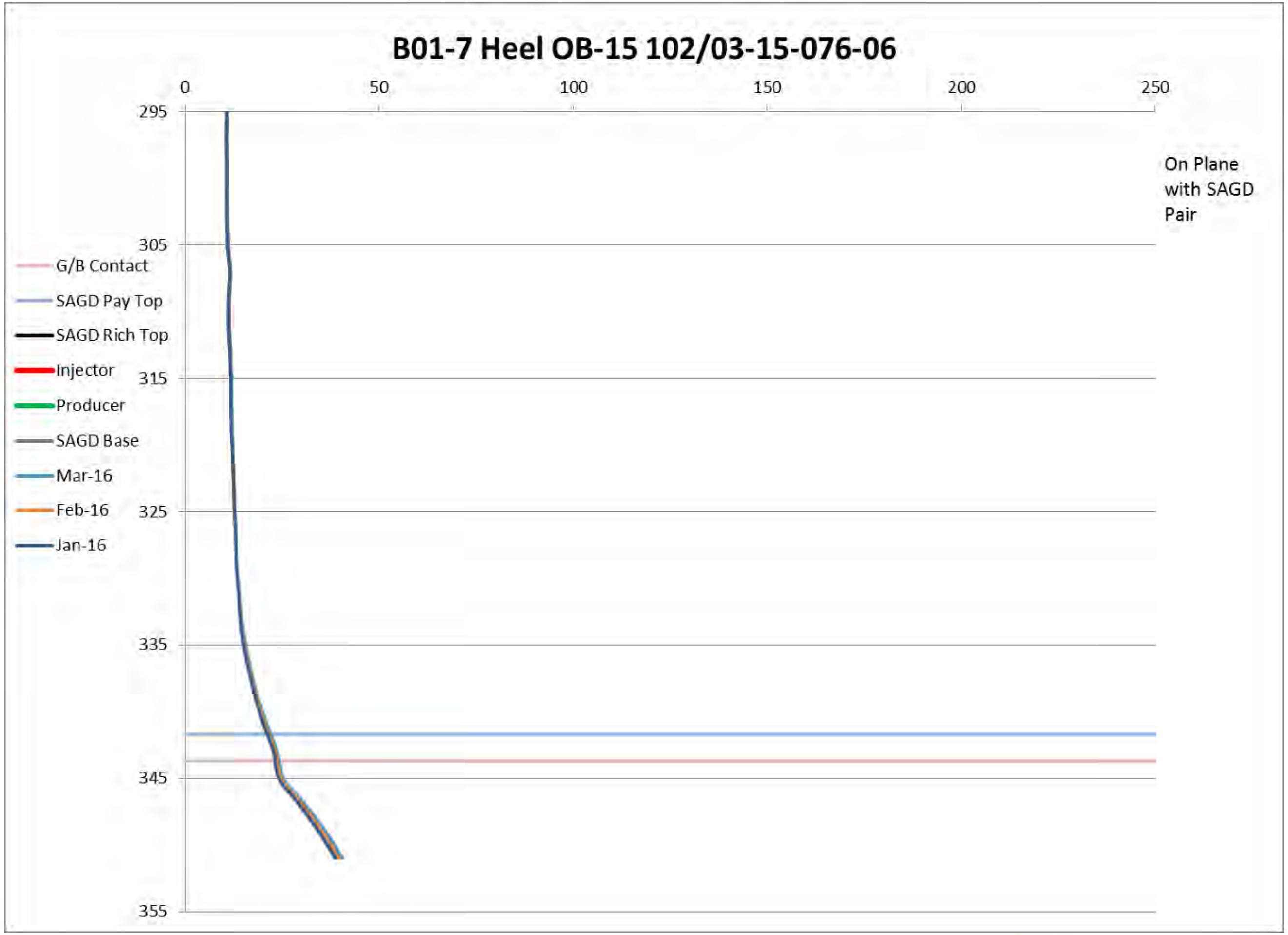
B01-4 Mid 104/06-15-076-06
0
50
100
150
200
250
340
350
360
370
380
390
400
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15


B01-7 Heel OB-11 100/04-15-076-06
0
50
100
150
200
250
335
340
345
350
355
360
365
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

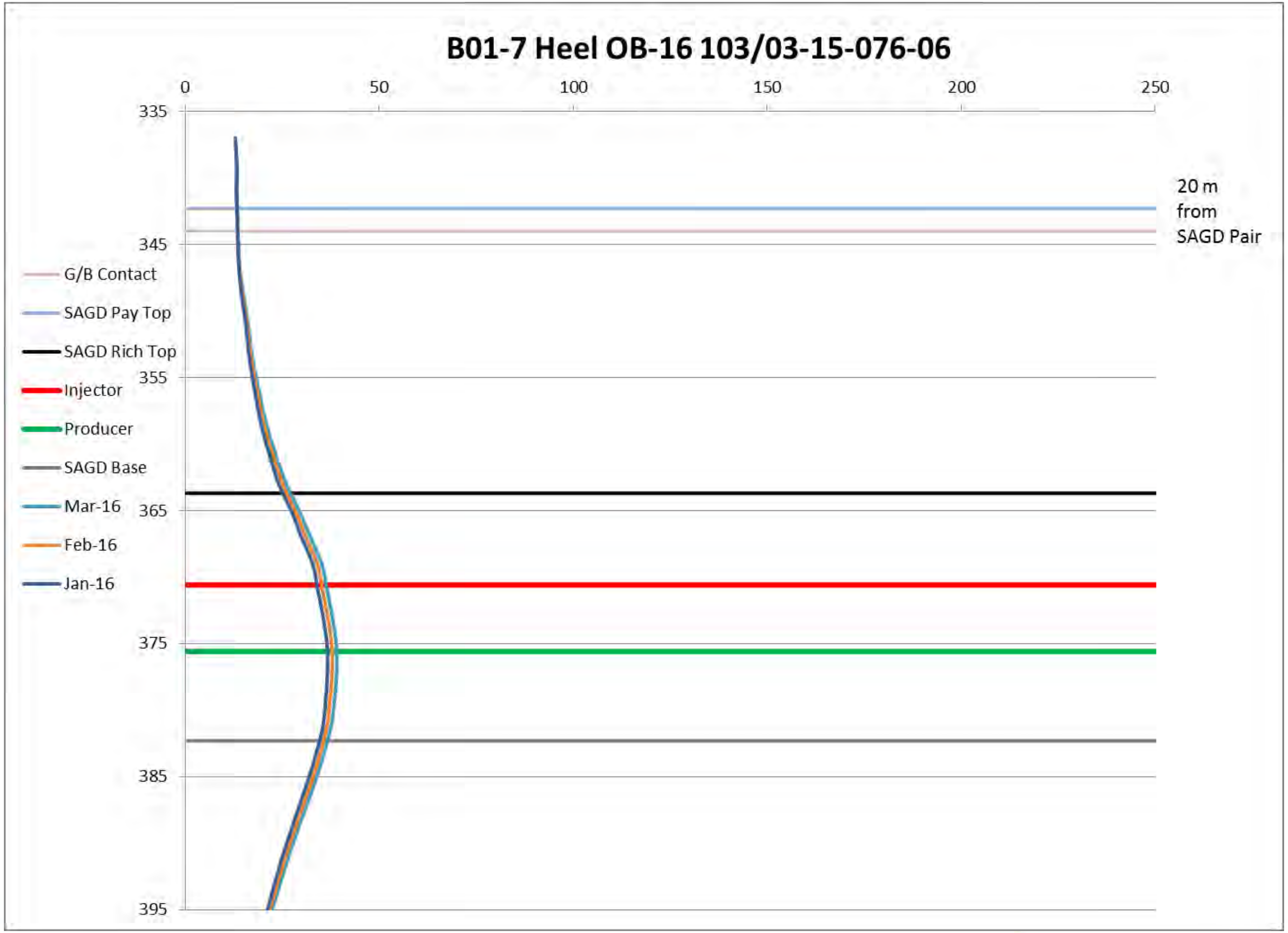

B01-7 Heel OB-12 102/04-15-076-06
0
50
100
150
200
250
335
345
355
365
375
385
395
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

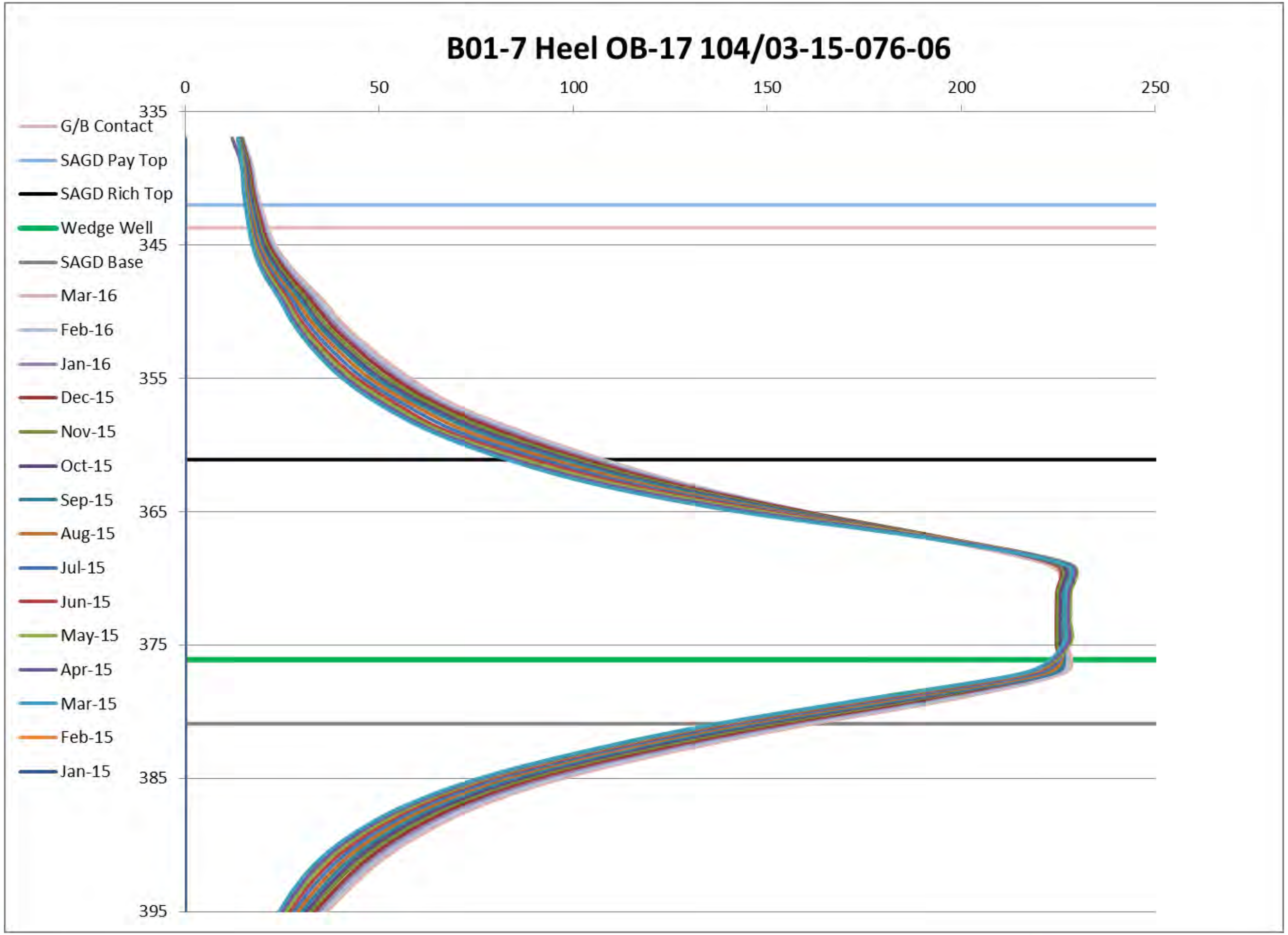


B01-7 Heel OB-13 103/04-15-076-06
0
50
100
150
200
250
335
345
355
365
375
385
395
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15



B01-7 Heel OB-15 102/03-15-076-06
0
50
100
150
200
250
295
305
315
325
335
345
355
On Plane with SAGD Pair
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16

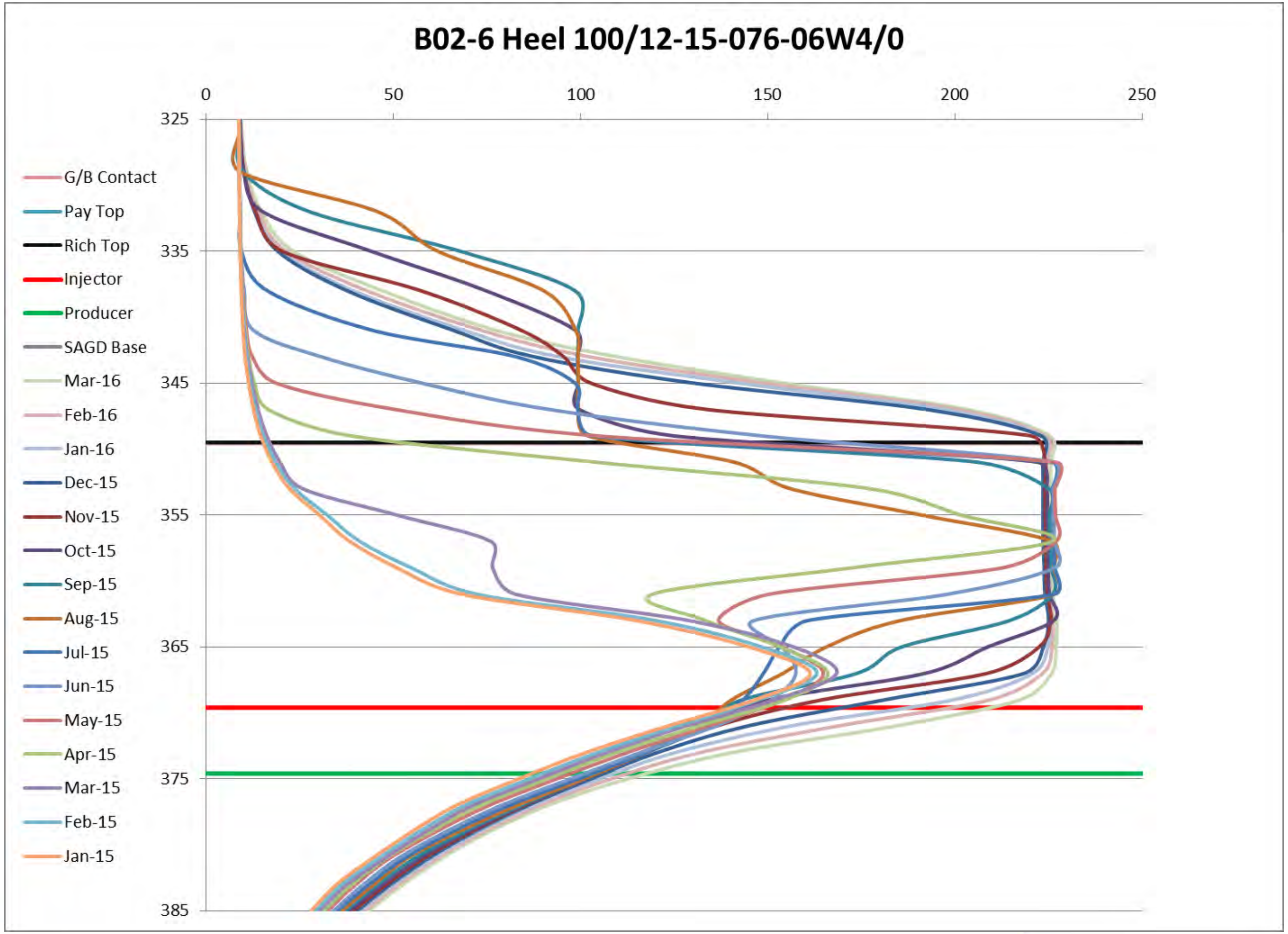

B01-7 Heel OB-16 103/03-15-076-06
0
50
100
150
200
250
335
345
355
365
375
385
395
20 m
from
SAGD Pair
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16



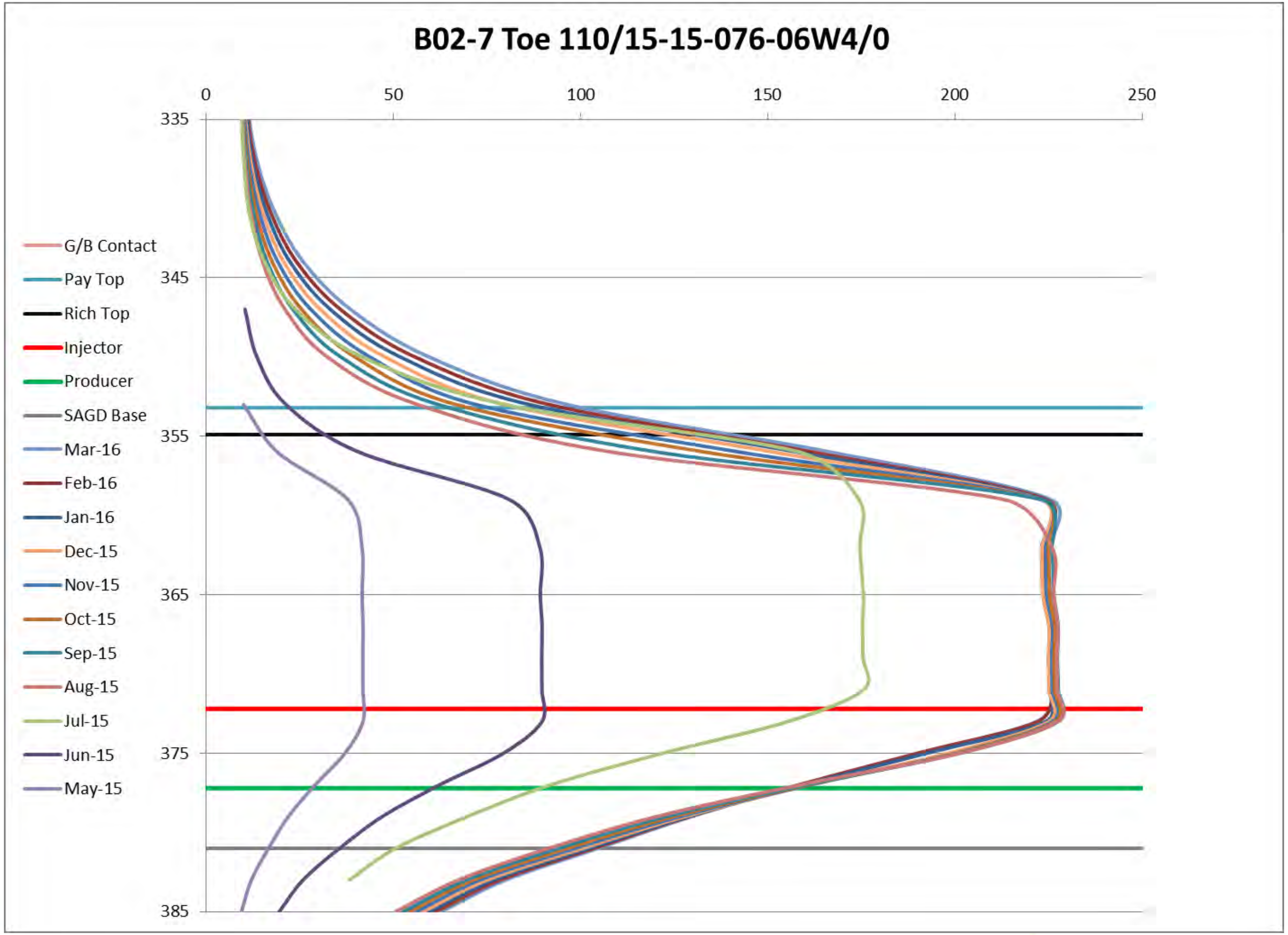

cenovus ENERGY

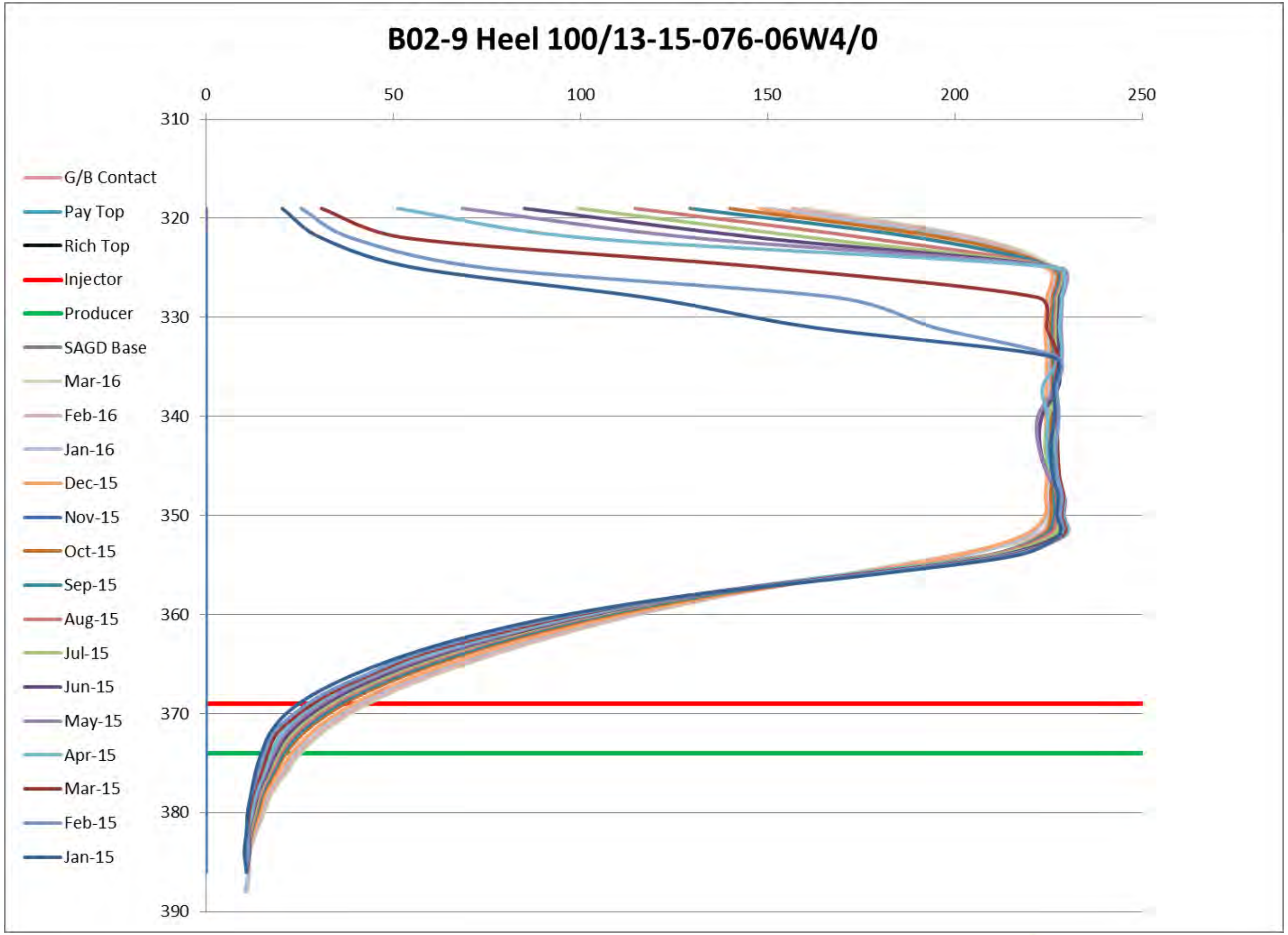
June 15, 2016

B02-2 Heel 102/12-15-076-06
0
50
100
150
200
250
270
280
290
300
310
320
330
340
350
360
370
380
390
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

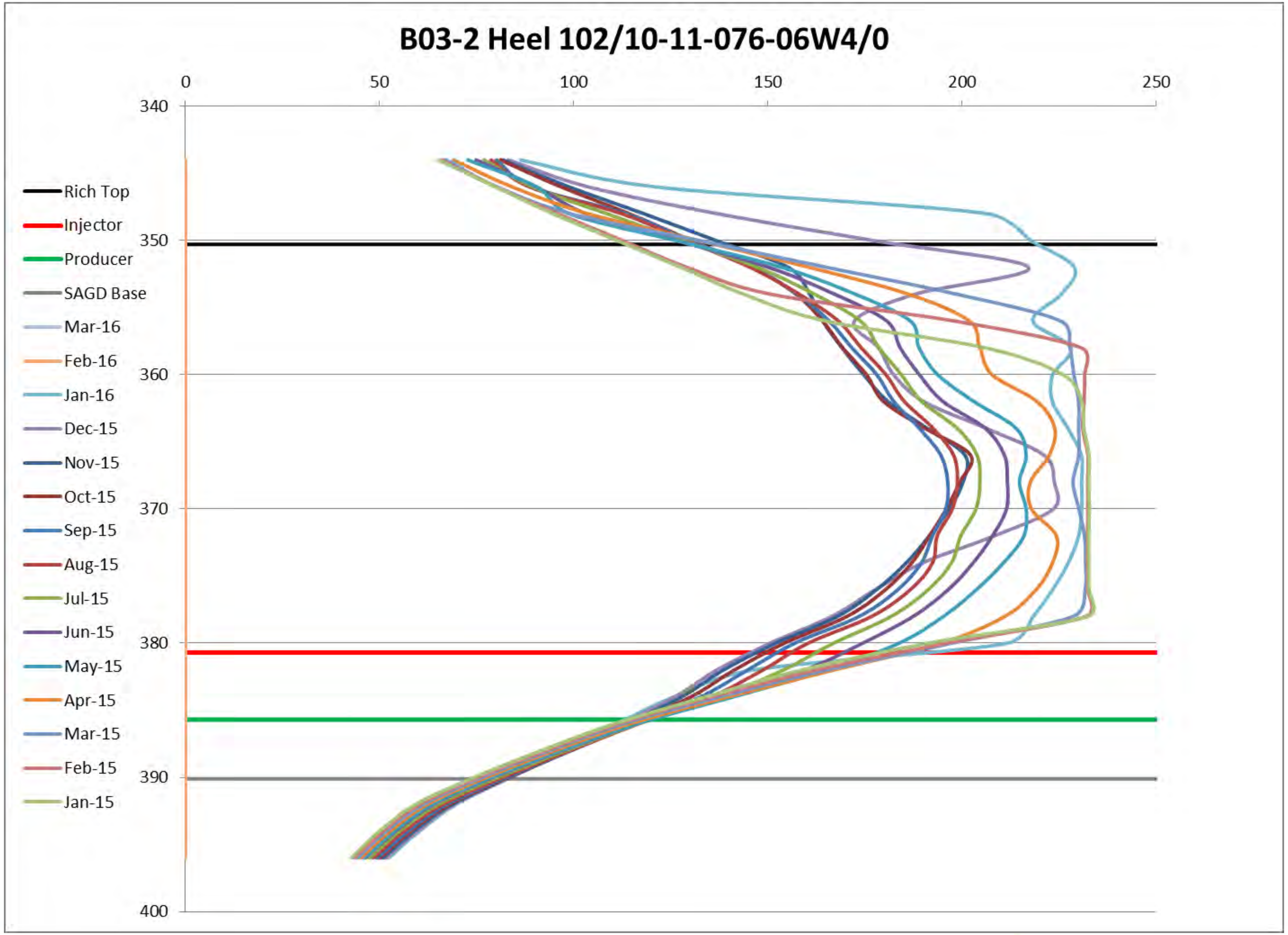


B02-6 Heel 100/12-15-076-06W4/0
0
50
100
150
200
250
325
335
345
355
365
375
385
G/B Contact
Pay Top
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15


B02-7 Toe 110/15-15-076-06W4/0
0
50
100
150
200
250
335
345
355
365
375
385
G/B Contact
Pay Top
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15

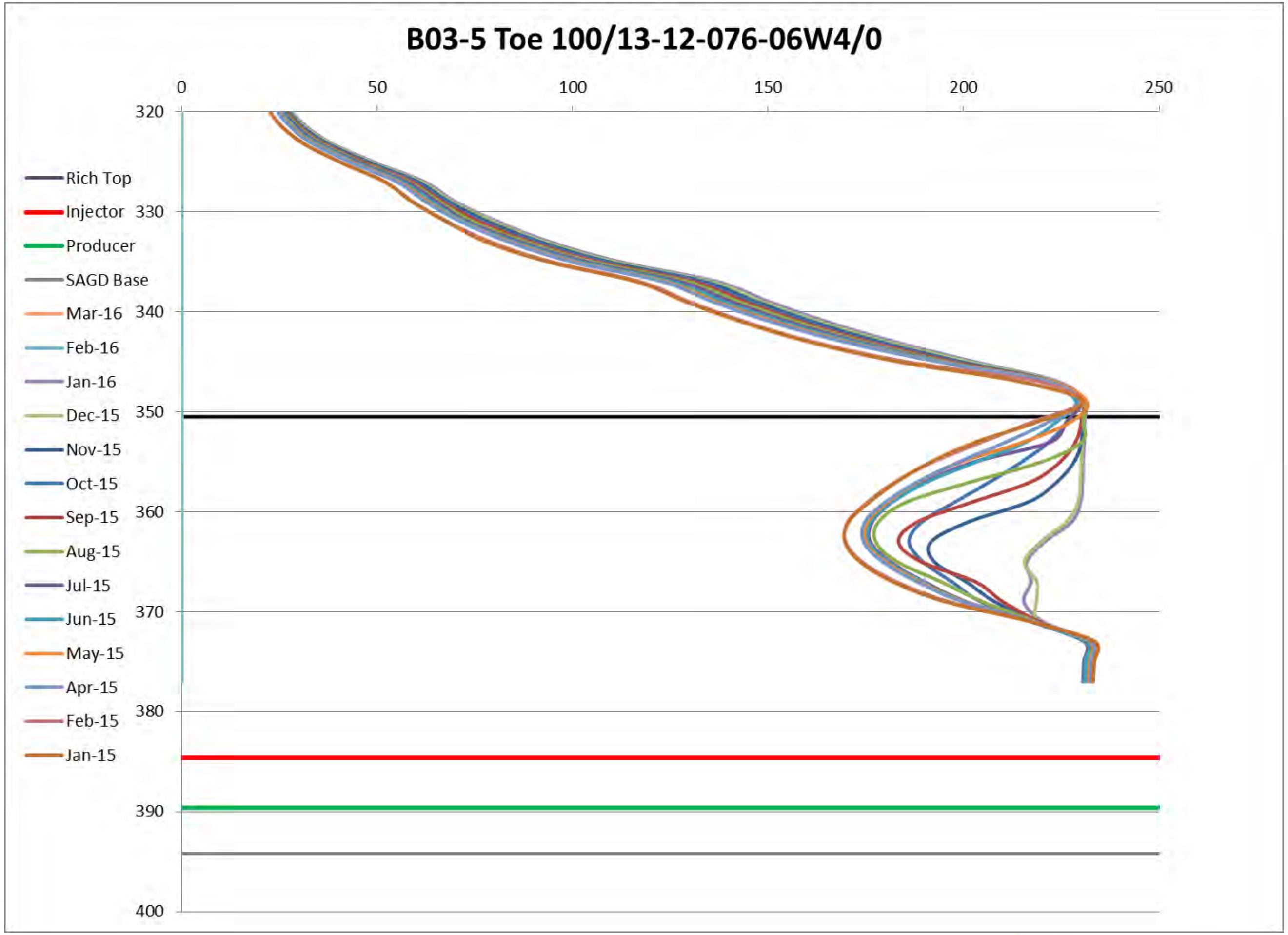


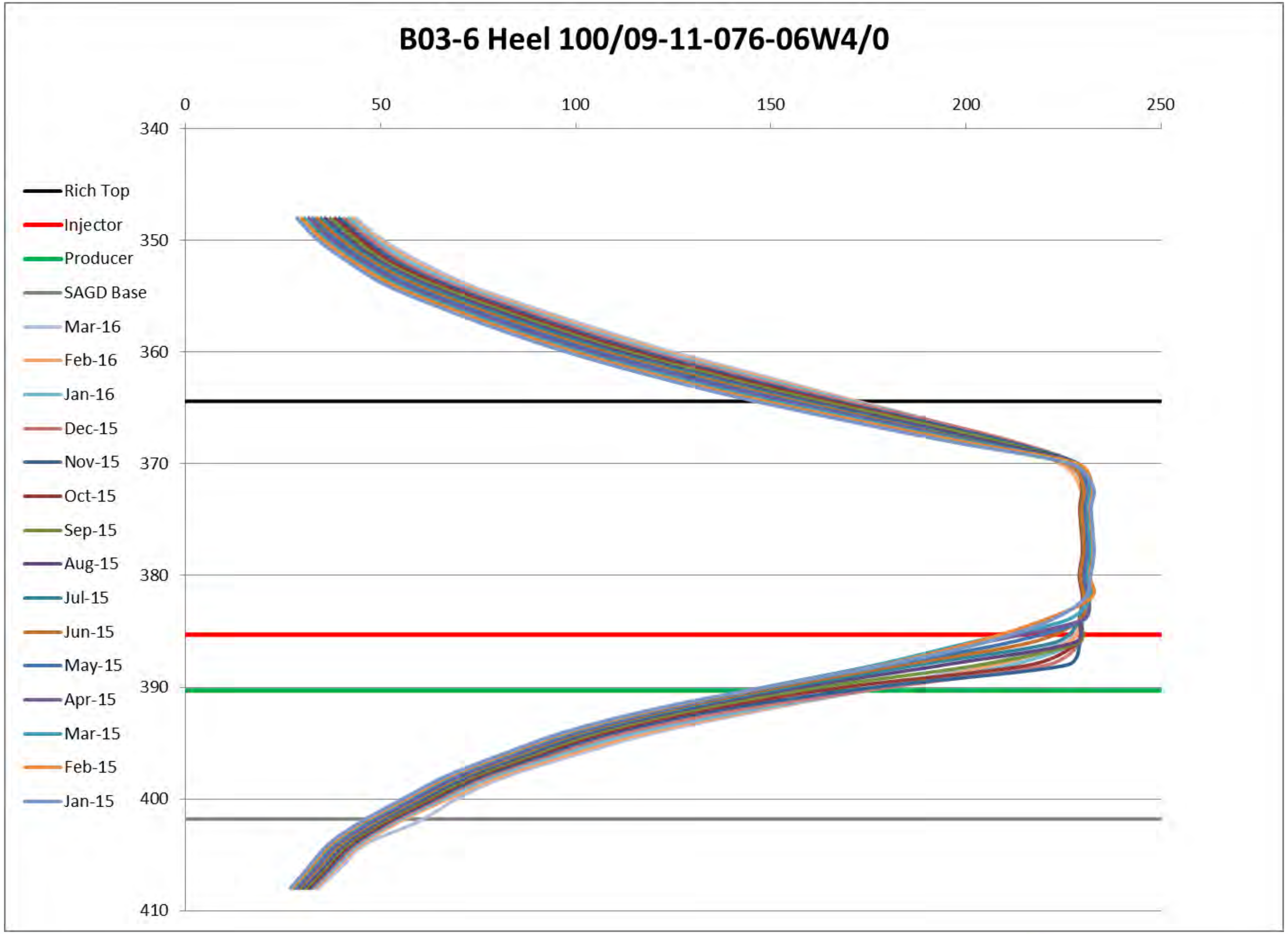
B02-9 Heel 100/13-15-076-06W4/0
0
50
100
150
200
250
310
320
330
340
350
360
370
380
390
G/B Contact
Pay Top
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

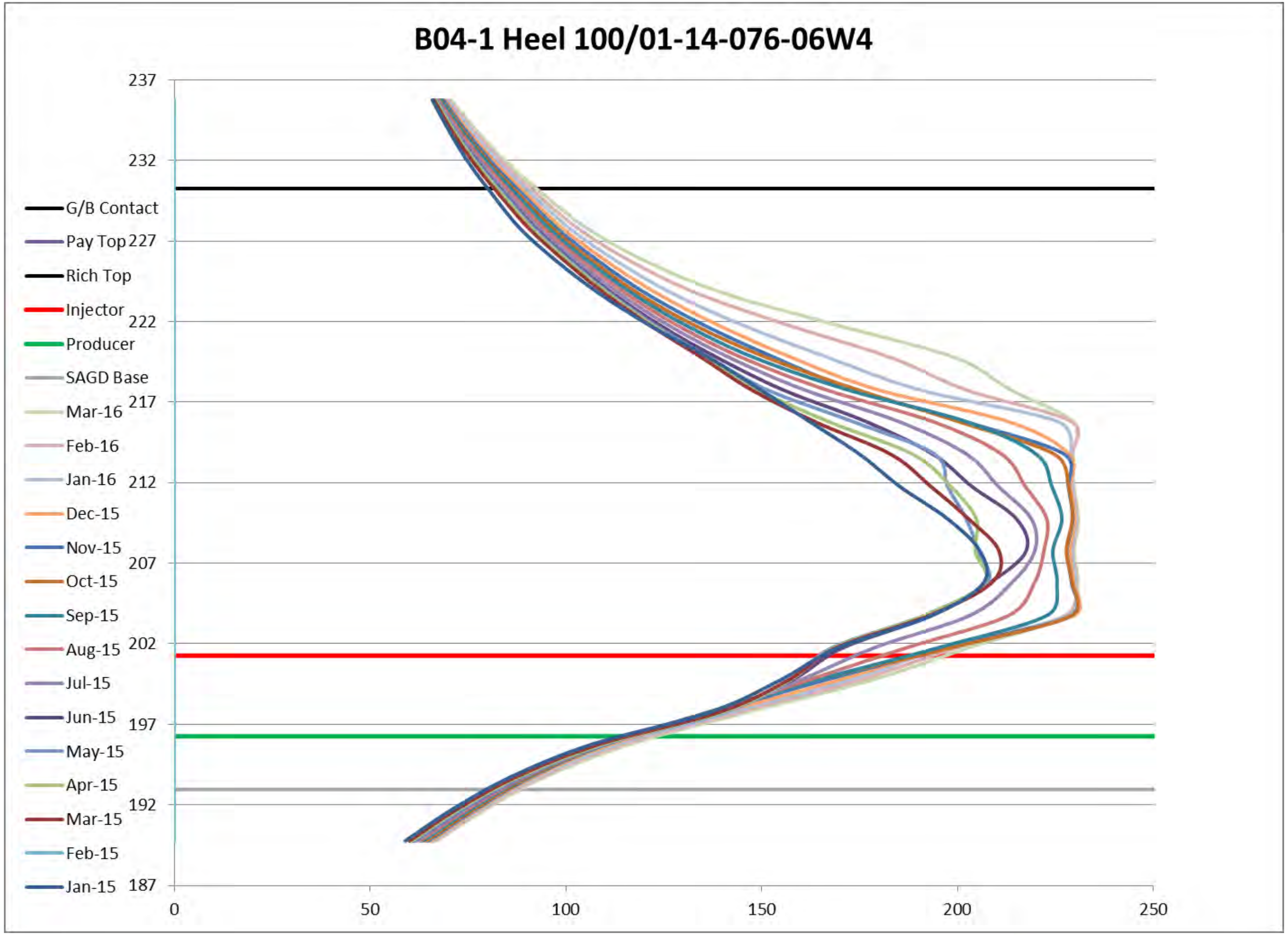


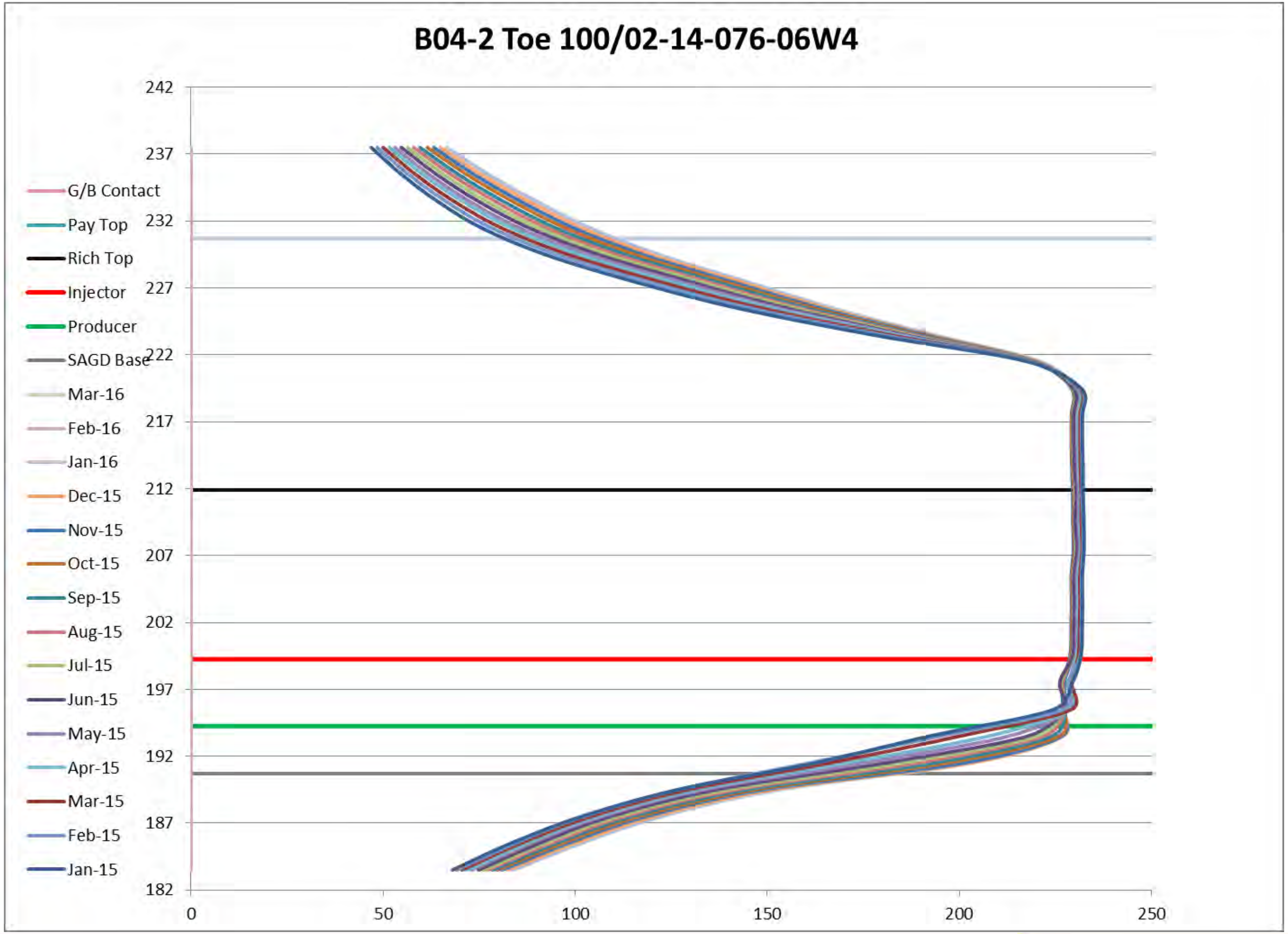
B03-2 Heel 102/10-11-076-06W4/0
0
50
100
150
200
250
340
350
360
370
380
390
400
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

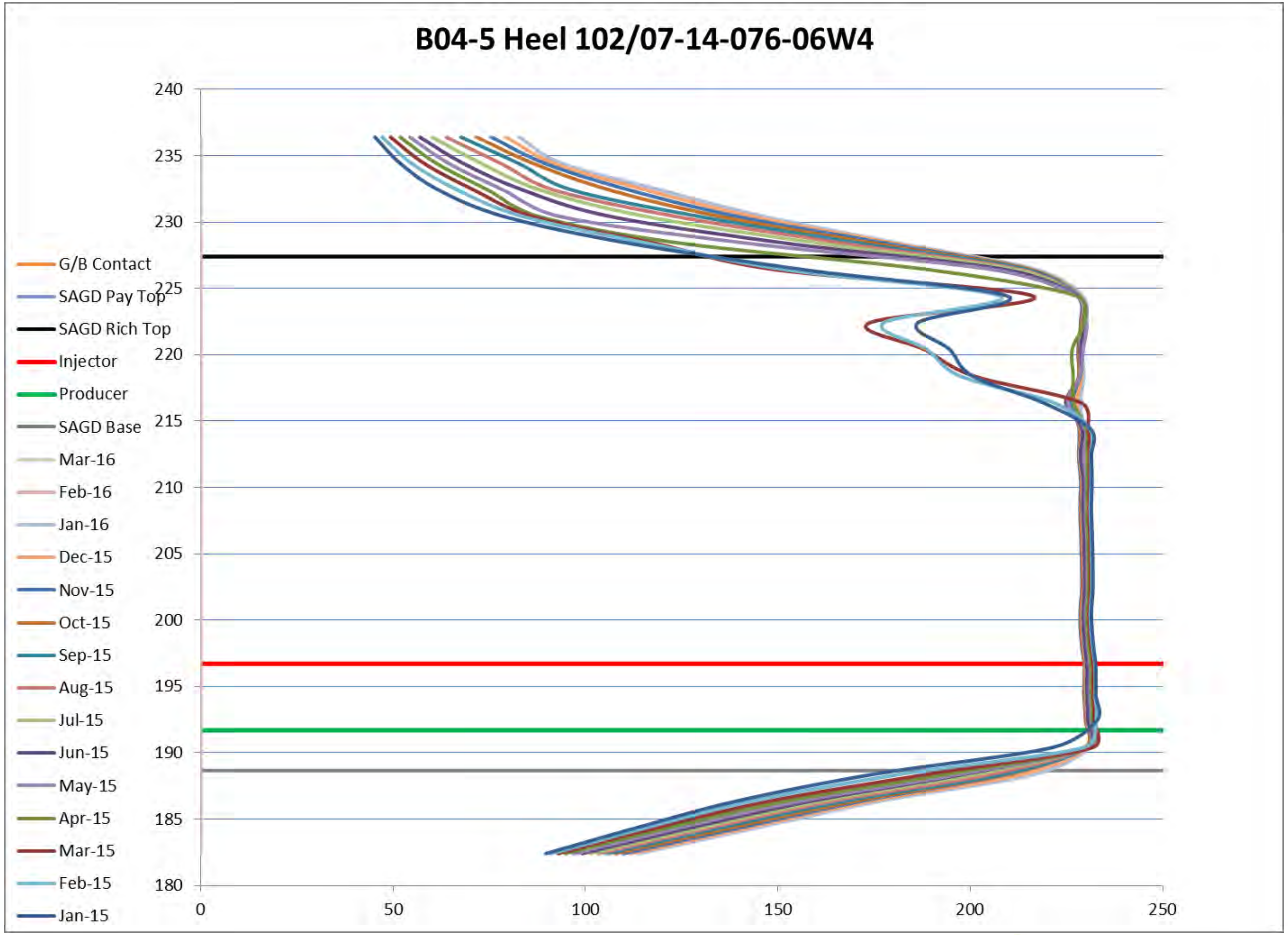

B03-3 Toe 100/16-11-076-06W4/0
0
50
100
150
200
250
340
350
360
370
380
390
400
410
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Jan-15


B03-5 Toe 100/13-12-076-06W4/0
0
50
100
150
200
250
320
330
340
350
360
370
380
390
400
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Feb-15
Jan-15

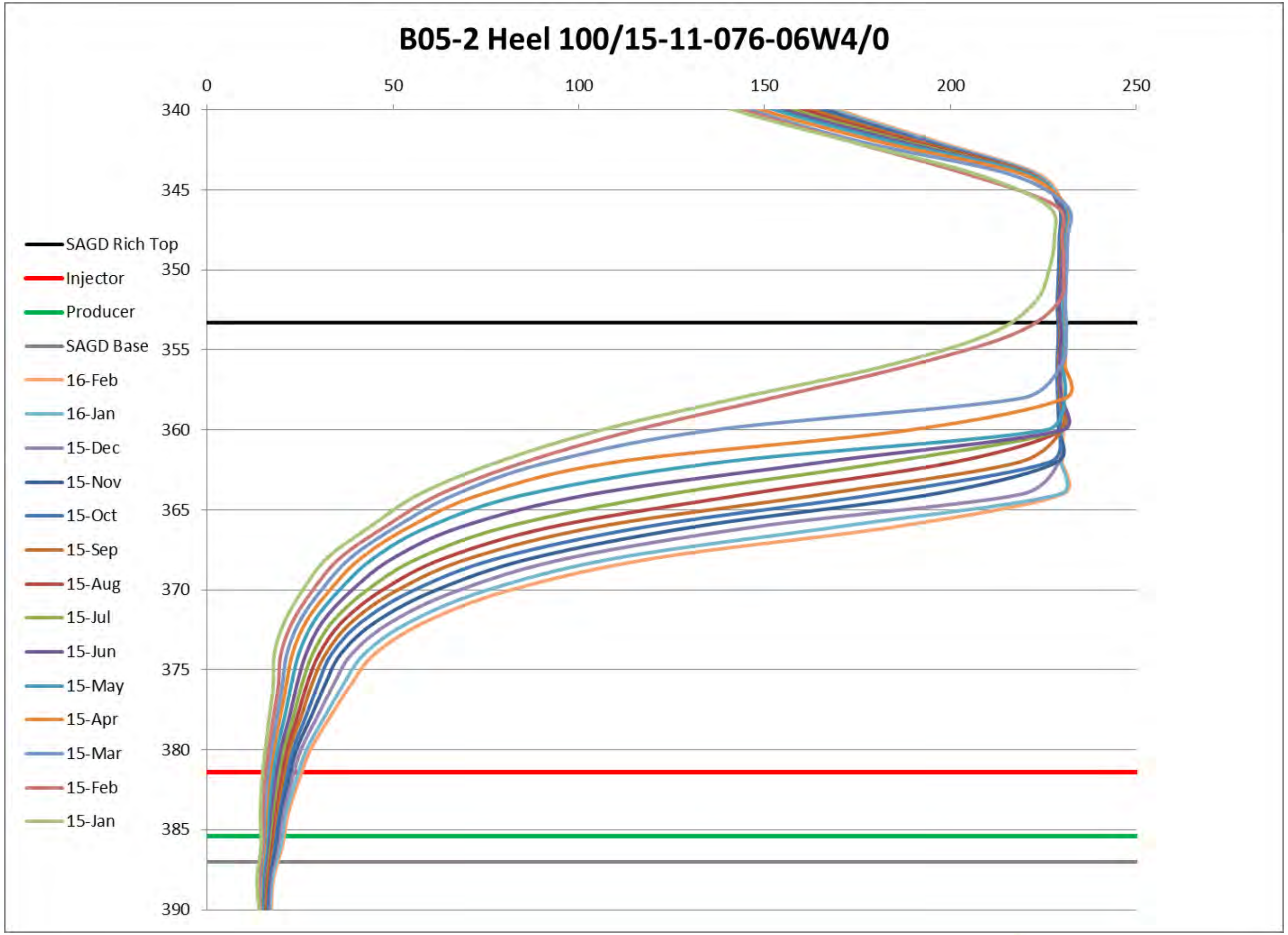

B03-6 Heel 100/09-11-076-06W4/0
0
50
100
150
200
250
340
350
360
370
380
390
400
410
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15


B04-1 Heel 100/01-14-076-06W4
237
232
227
222
217
212
207
202
197
192
187
0
50
100
150
200
250
G/B Contact
Pay Top
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

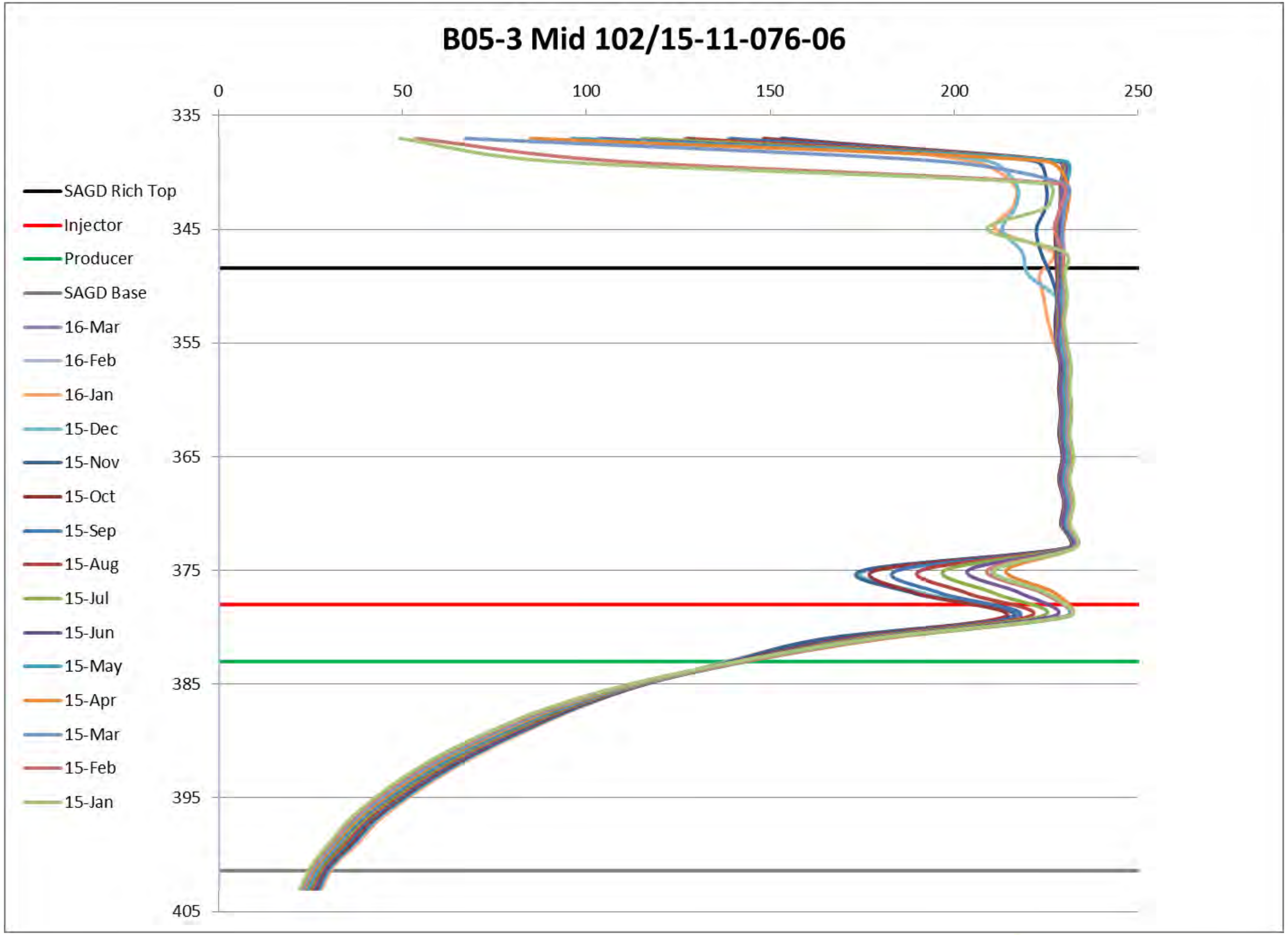

B04-2 Toe 100/02-14-076-06W4
G/B Contact
Pay Top
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15
242
237
232
227
222
217
212
207
202
197
192
187
182
0
50
100
150
200
250

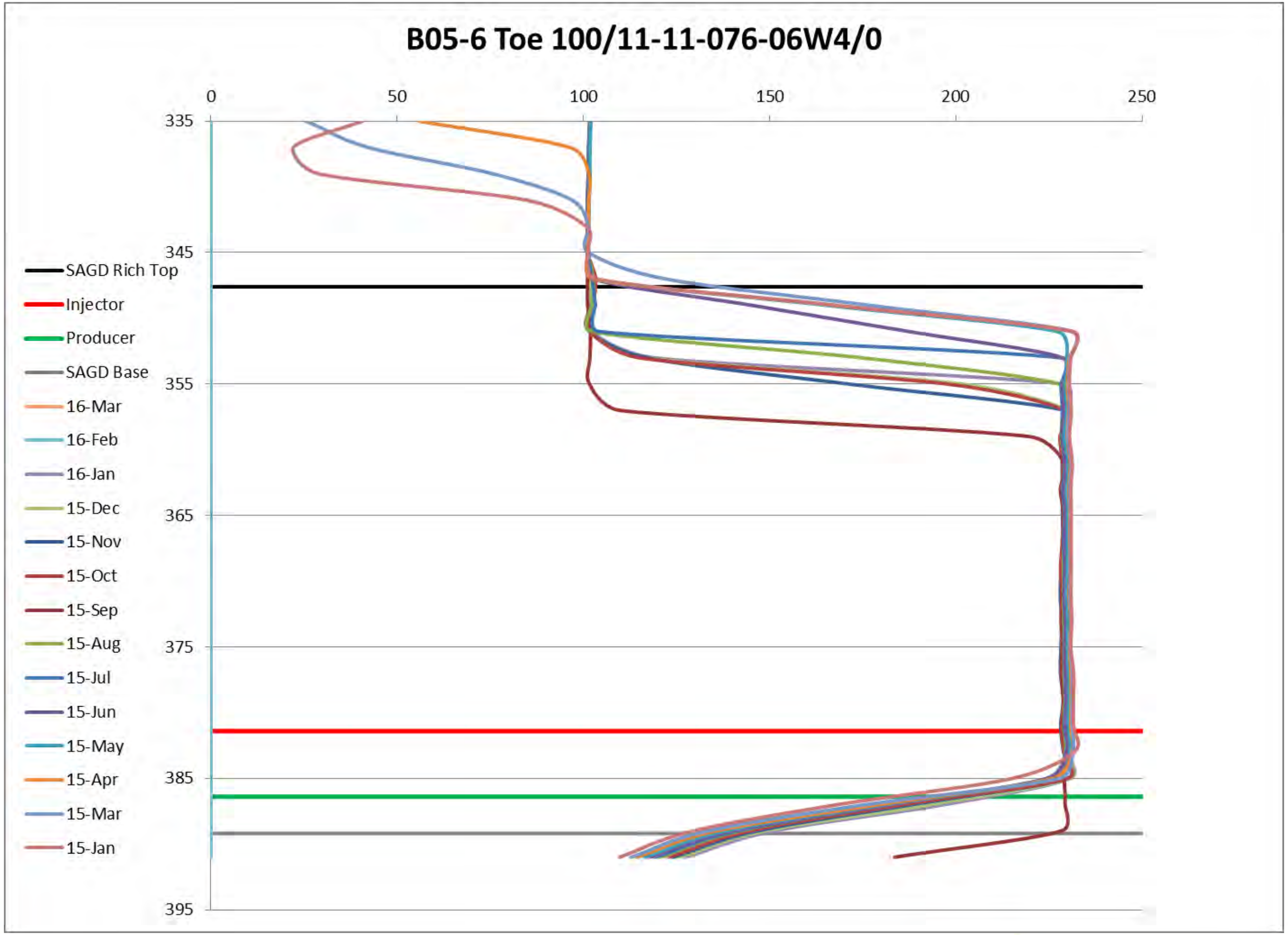


B04-5 Heel 102/07-14-076-06W4
240
235
230
225
220
215
210
205
200
195
190
185
180
0
50
100
150
200
250
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

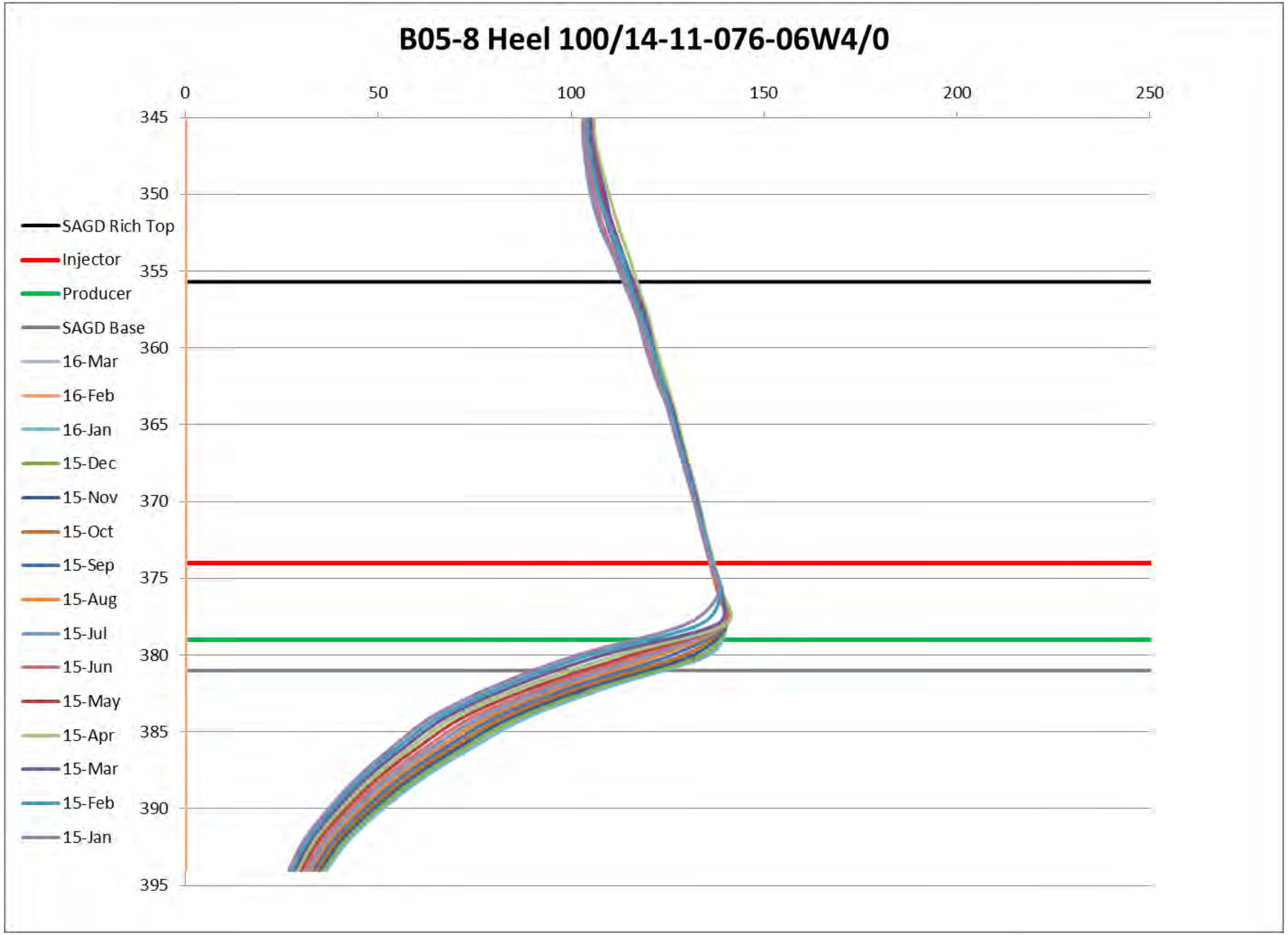


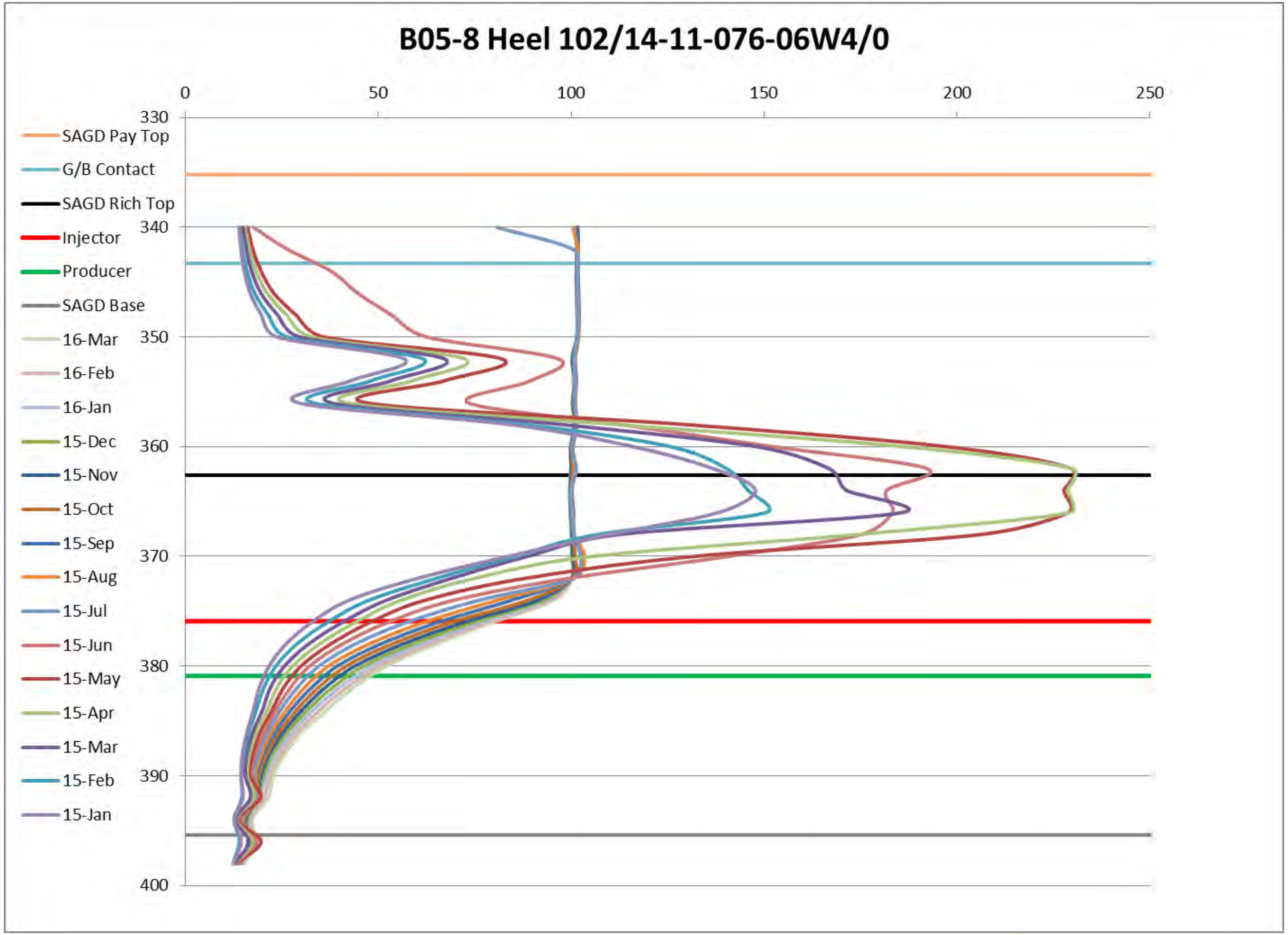

cenovus ENERGY


B05-3 Mid 102/15-11-076-06
0
50
100
150
200
250
335
345
355
365
375
385
395
405
SAGD Rich Top
Injector
Producer
SAGD Base
16-Mar
16-Feb
16-Jan
15-Dec
15-Nov
15-Oct
15-Sep
15-Aug
15-Jul
15-Jun
15-May
15-Apr
15-Mar
15-Feb
15-Jan

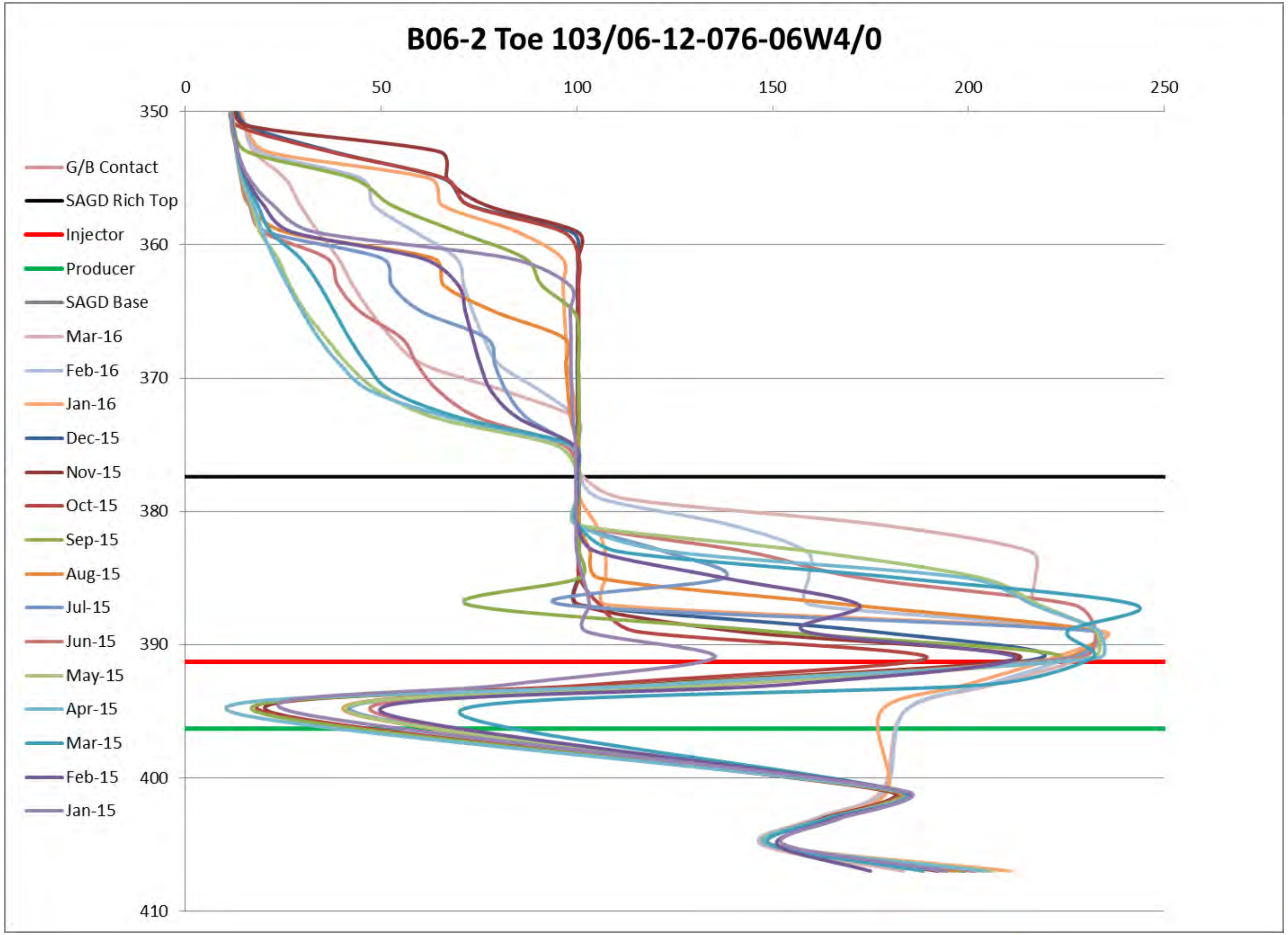


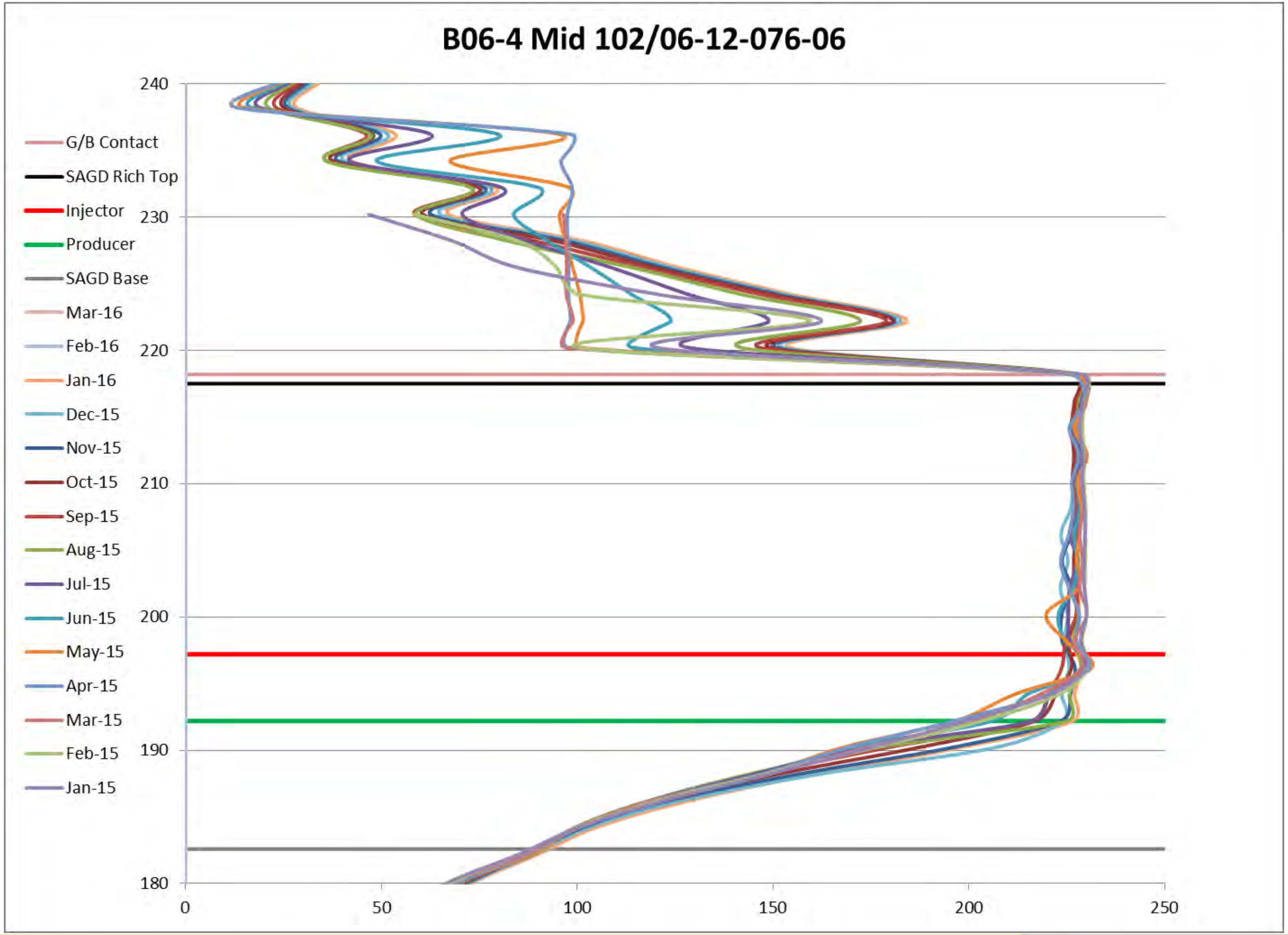
B05-6 Toe 100/11-11-076-06W4/0
0
50
100
150
200
250
335
345
355
365
375
385
395
SAGD Rich Top
Injector
Producer
SAGD Base
16-Mar
16-Feb
16-Jan
15-Dec
15-Nov
15-Oct
15-Sep
15-Aug
15-Jul
15-Jun
15-May
15-Apr
15-Mar
15-Jan

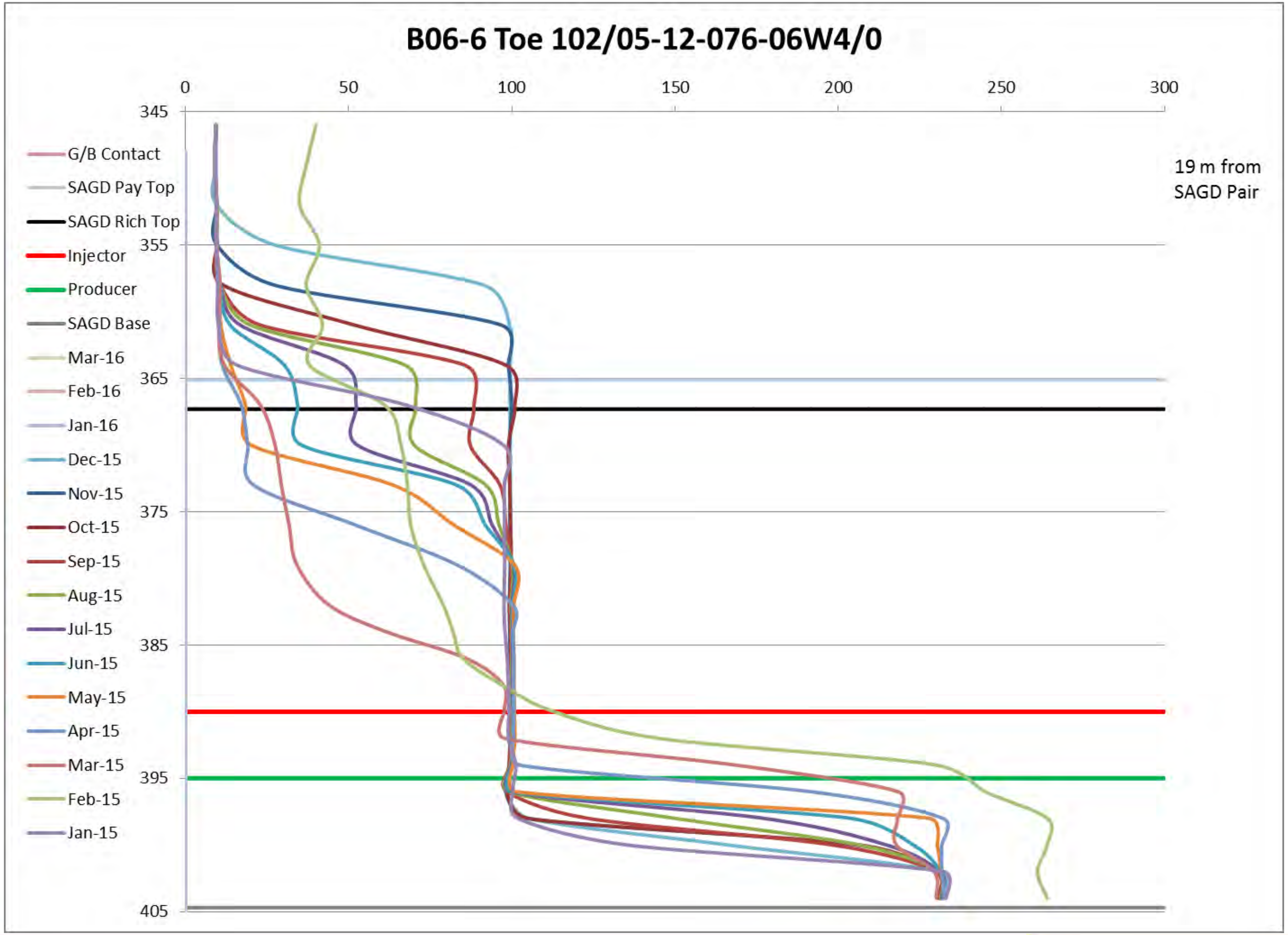

B05-8 Heel 100/14-11-076-06W4/0
0
50
100
150
200
250
345
350
355
360
365
370
375
380
385
390
395
SAGD Rich Top
Injector
Producer
SAGD Base
16-Mar
16-Feb
16-Jan
15-Dec
15-Nov
15-Oct
15-Sep
15-Aug
15-Jul
15-Jun
15-May
15-Apr
15-Mar
15-Feb
15-Jan

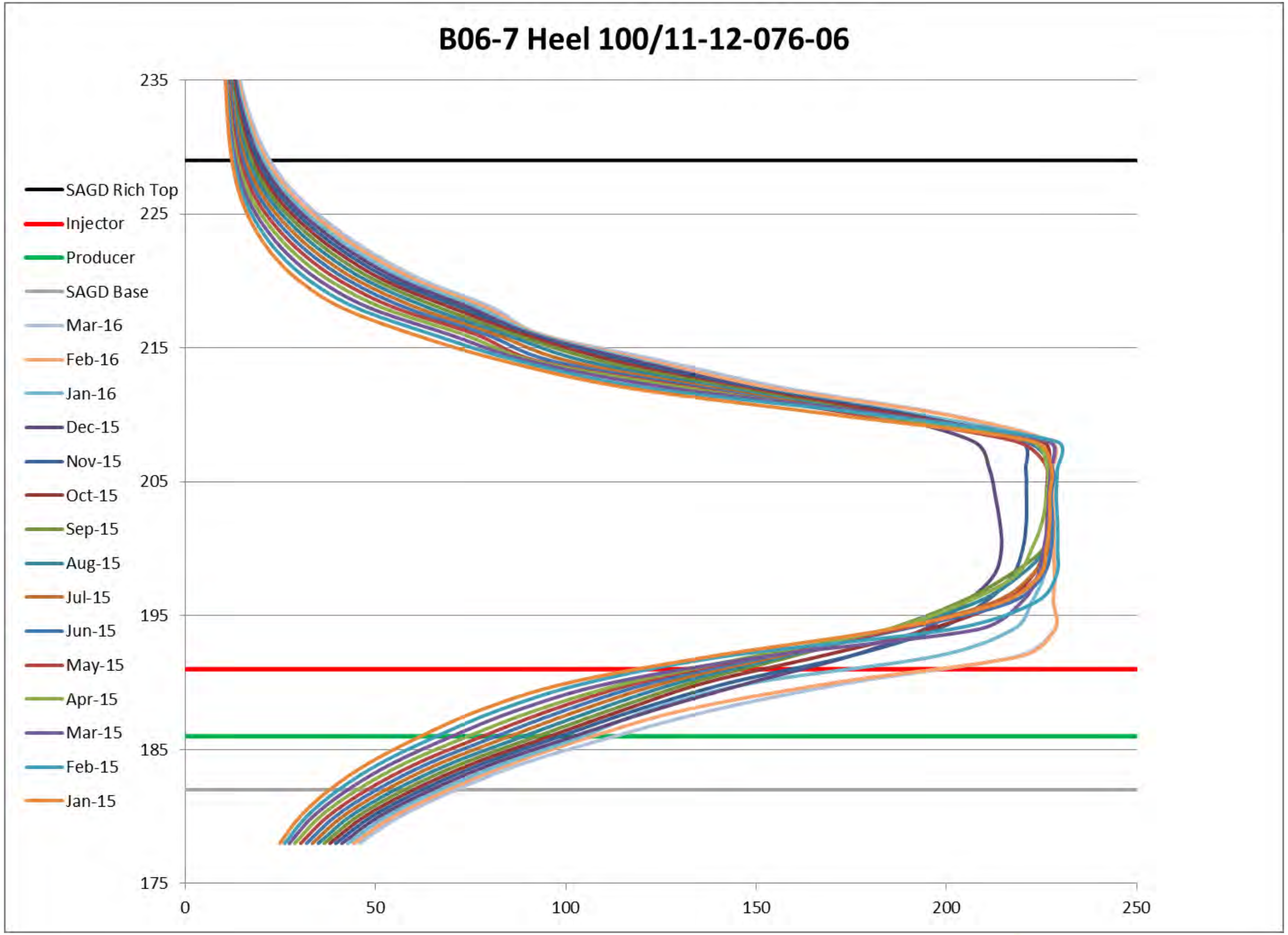


B05-8 Heel 102/14-11-076-06W4/0
0
50
100
150
200
250
330
340
350
360
370
380
390
400
SAGD Pay Top
G/B Contact
SAGD Rich Top
Injector
Producer
SAGD Base
16-Mar
16-Feb
16-Jan
15-Dec
15-Nov
15-Oct
15-Sep
15-Aug
15-Jul
15-Jun
15-May
15-Apr
15-Mar
15-Feb
15-Jan

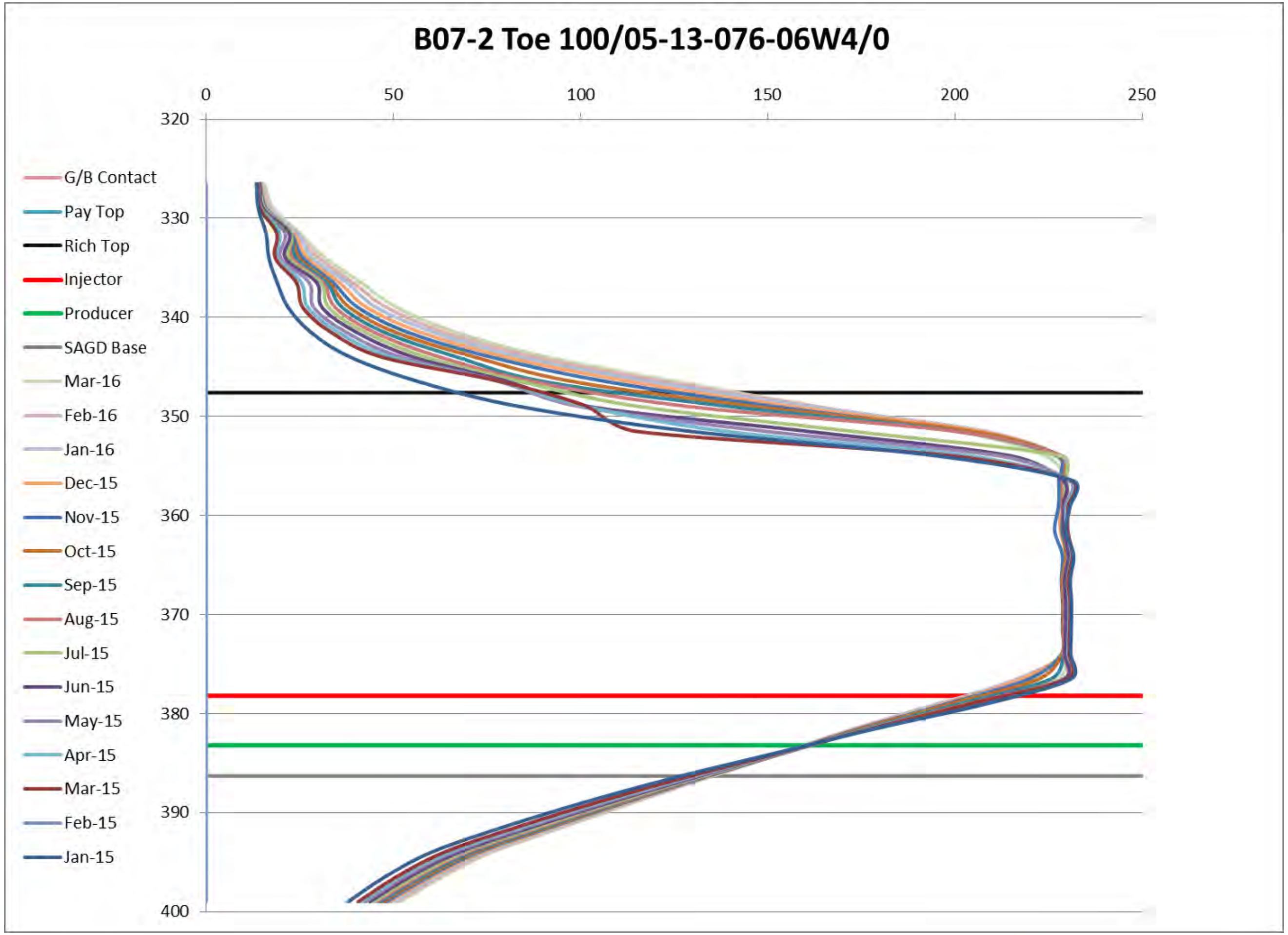

B06-2 Toe 103/06-12-076-06W4/0
0
50
100
150
200
250
350
360
370
380
390
400
410
G/B Contact
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15


B06-4 Mid 102/06-12-076-06
G/B Contact
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15
240
230
220
210
200
190
180
0
50
100
150
200
250

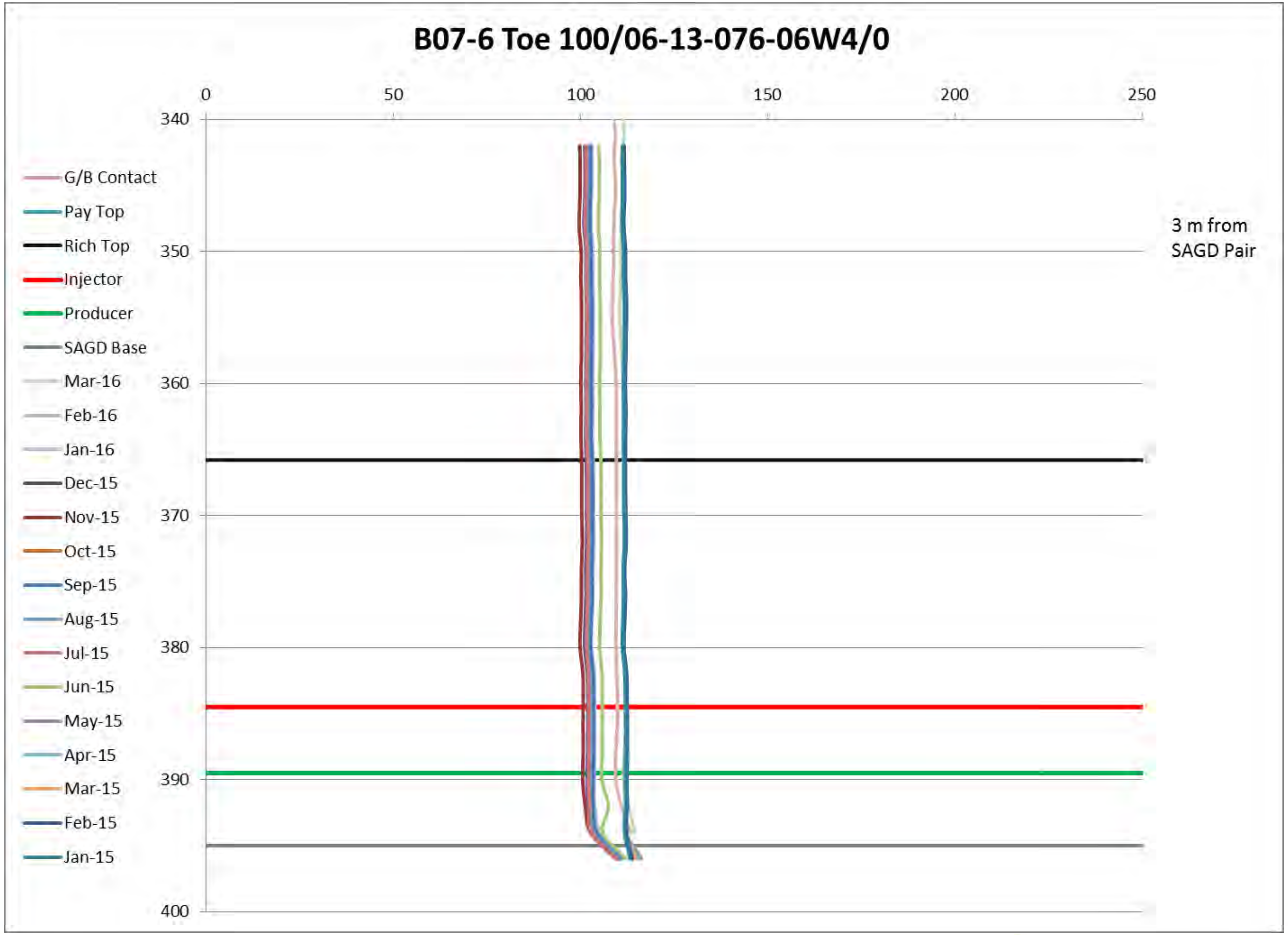

B06-6 Toe 102/05-12-076-06W4/0
0
50
100
150
200
250
300
345
355
365
375
385
395
405
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15
19 m from
SAGD Pair



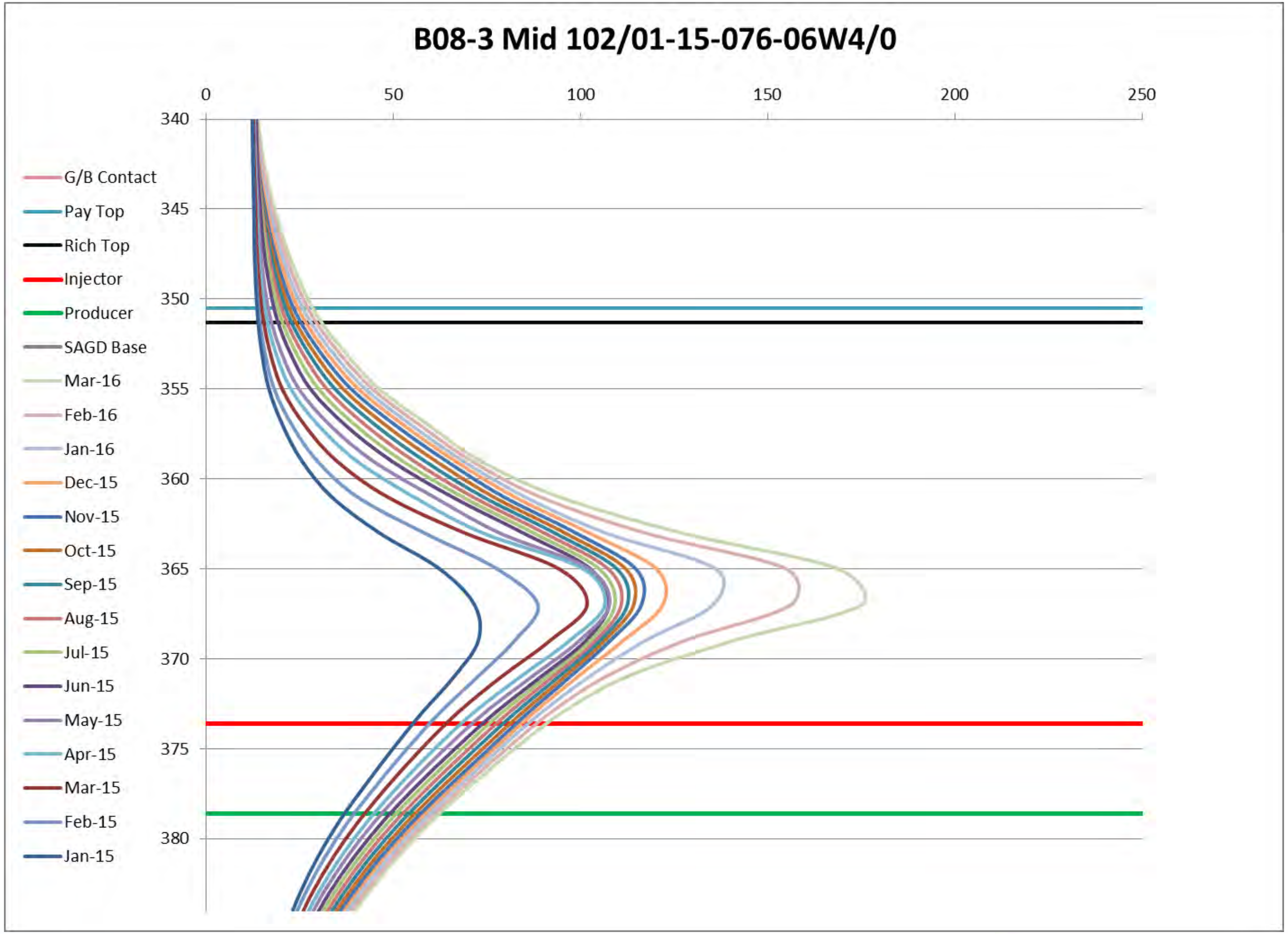
B06-7 Heel 100/11-12-076-06
235
225
215
205
195
185
175
0
50
100
150
200
250
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15



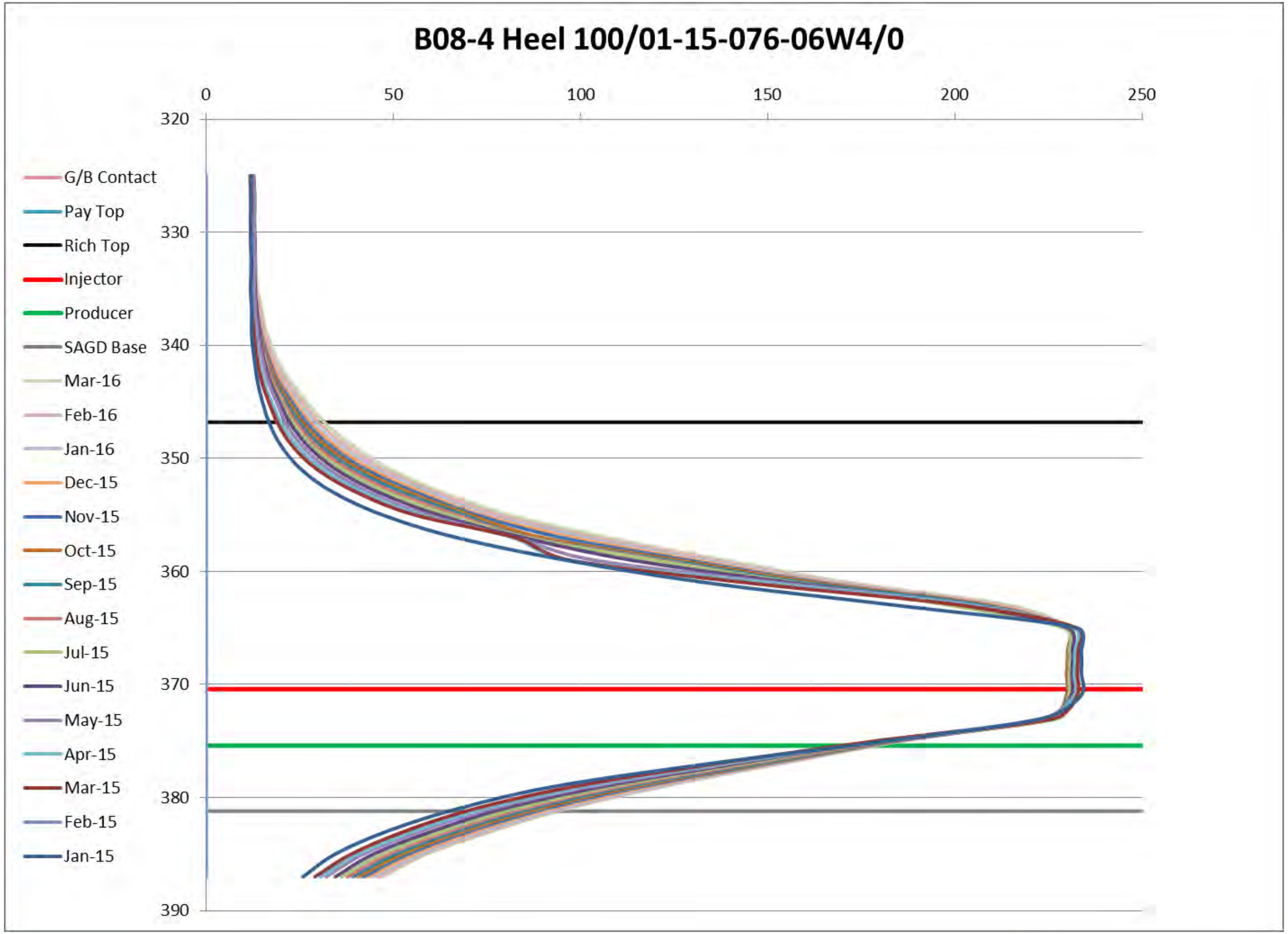

cenovus ENERGY


B07-6 Toe 100/06-13-076-06W4/0
0
50
100
150
200
250
340
350
360
370
380
390
400
G/B Contact
Pay Top
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15
3 m from
SAGD Pair

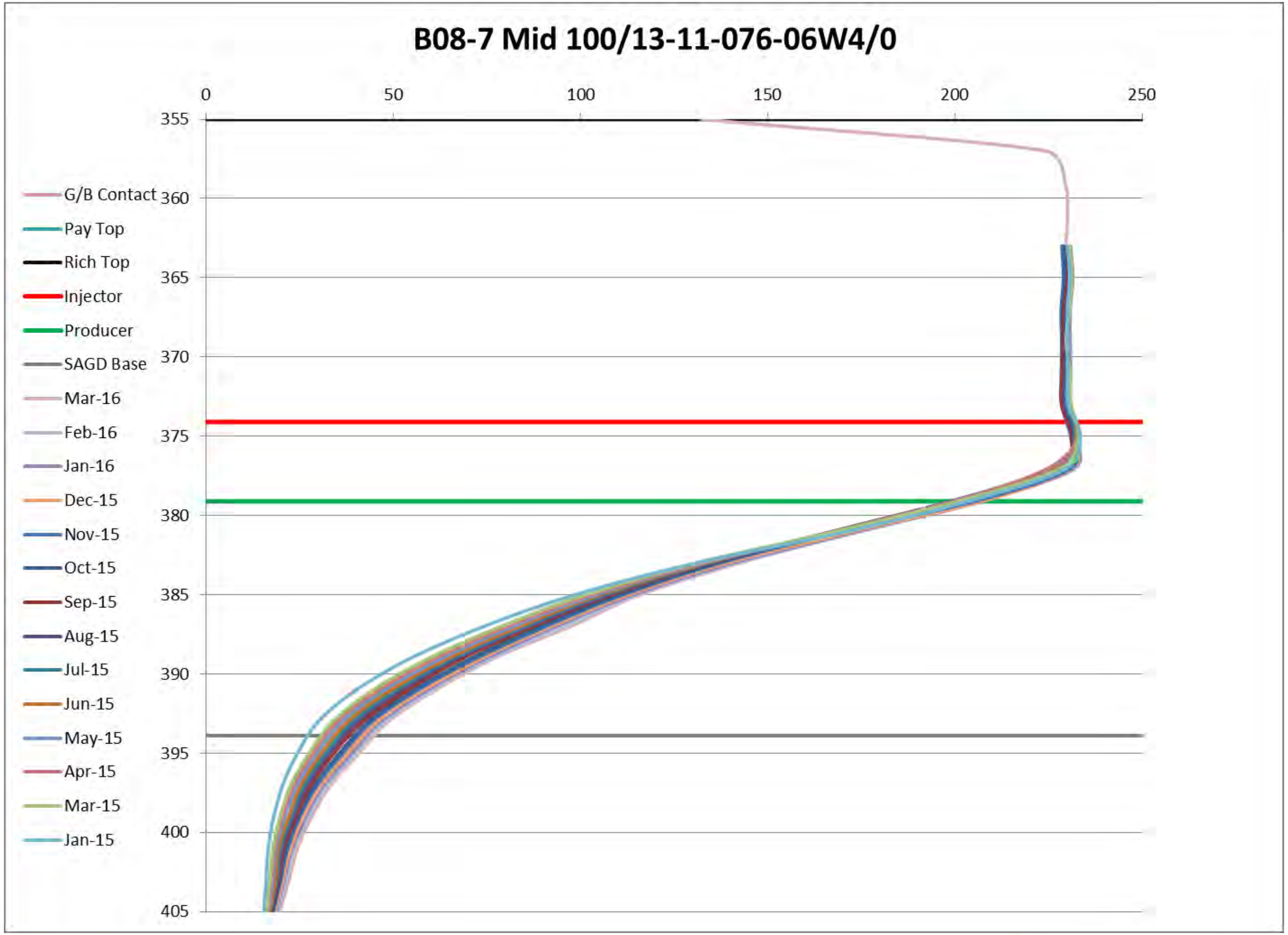

B07-10 Mid 100/03-11-076-06W4
0
50
100
150
200
250
340
345
350
355
360
365
370
375
380
385
390
395
400
Producer
Injector
Mar-16
Feb-16
Jan-16



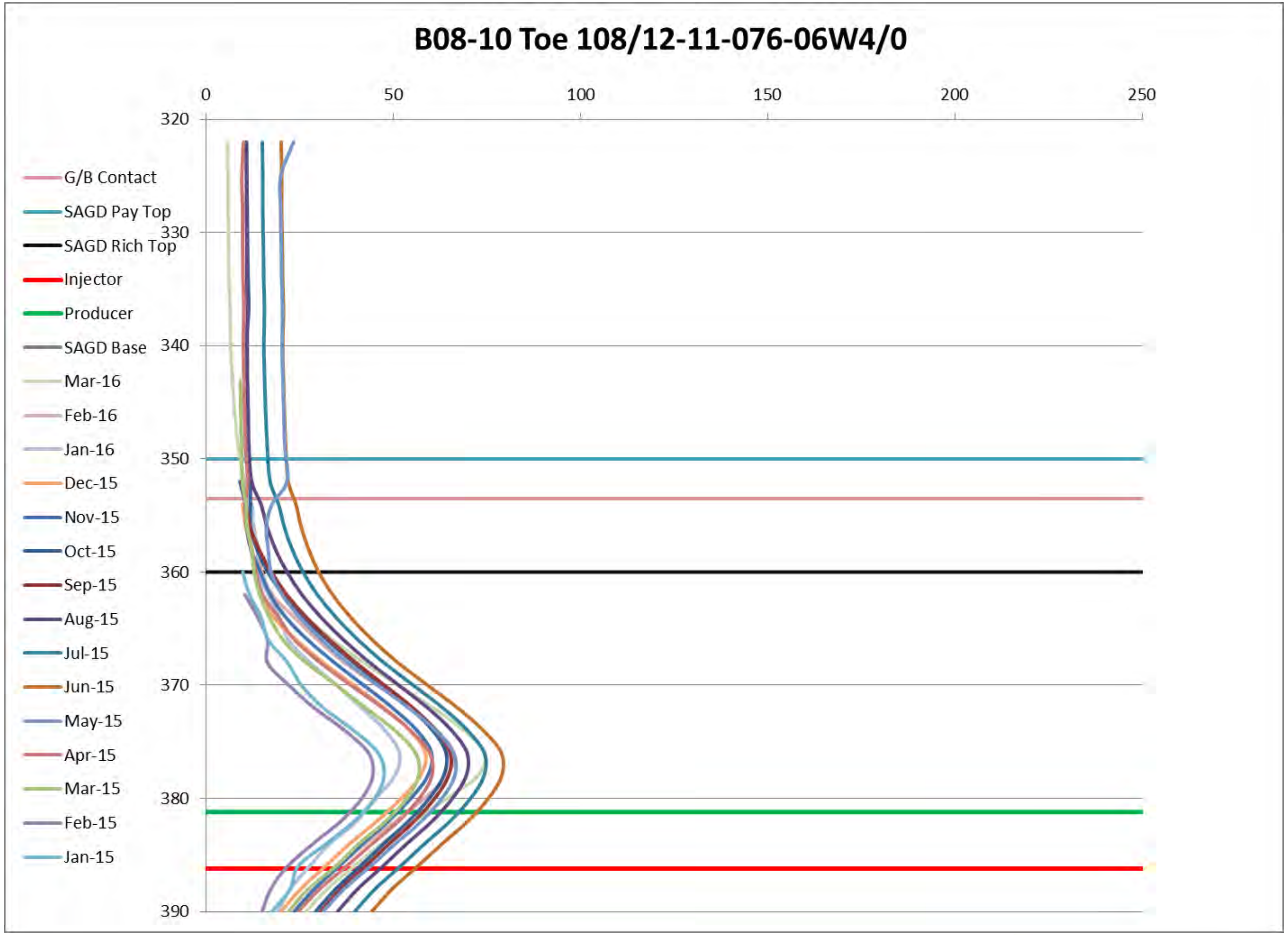
B08-3 Mid 102/01-15-076-06W4/0
0
50
100
150
200
250
340
345
350
355
360
365
370
375
380
G/B Contact
Pay Top
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15



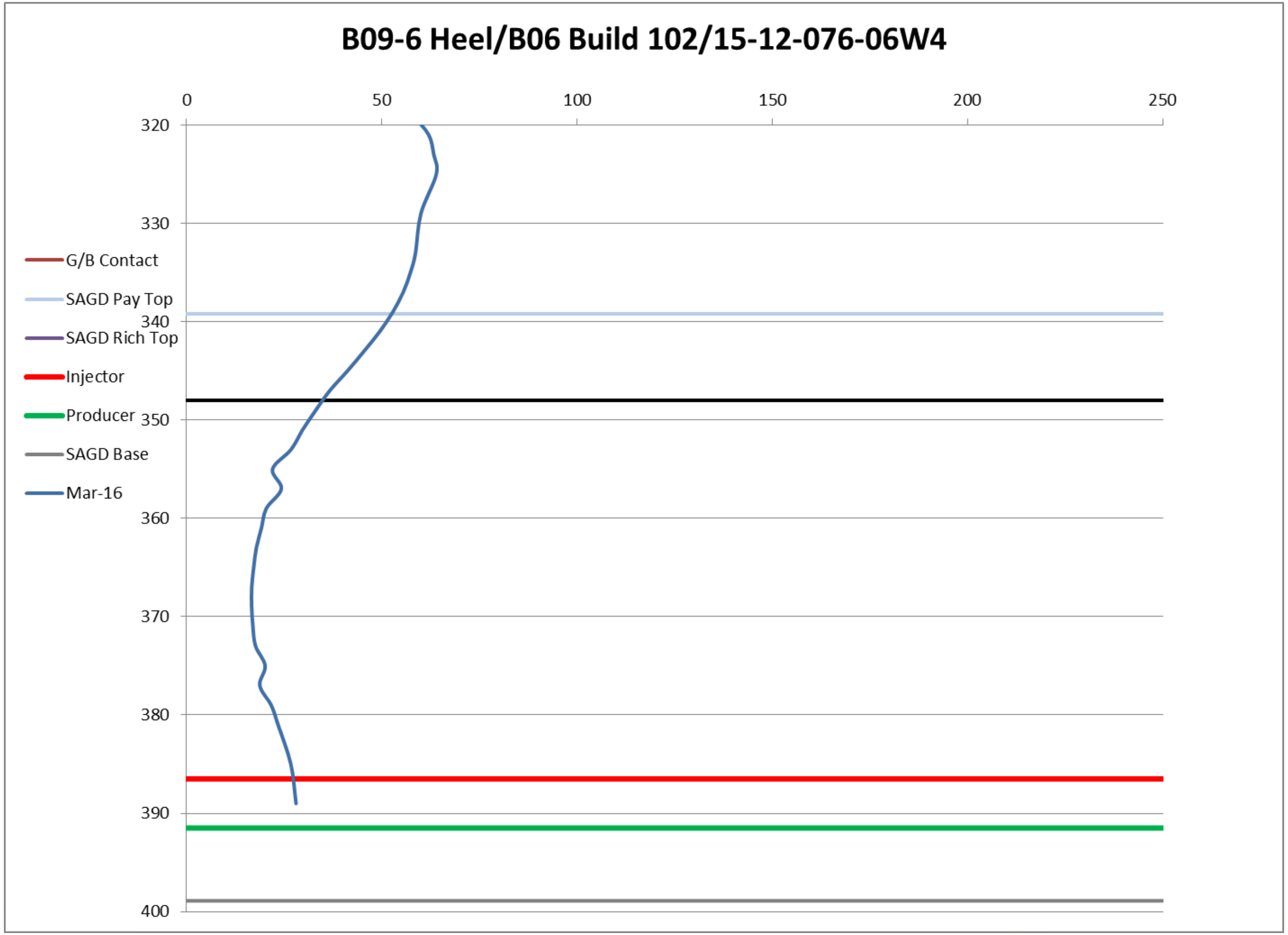
B08-4 Heel 100/01-15-076-06W4/0
0
50
100
150
200
250
320
330
340
350
360
370
380
390
G/B Contact
Pay Top
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

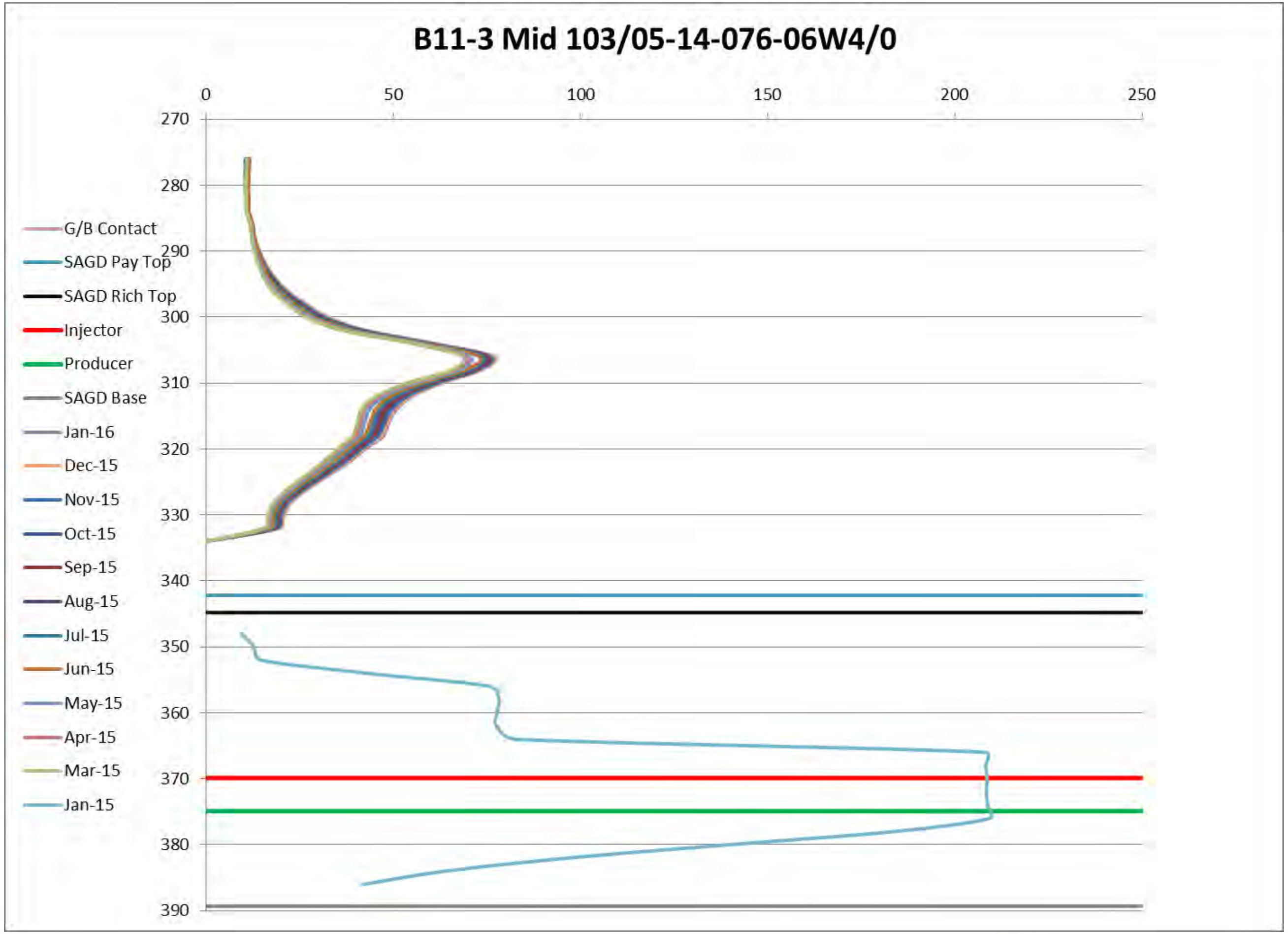


B08-7 Mid 100/13-11-076-06W4/0
0
50
100
150
200
250
355
360
365
370
375
380
385
390
395
400
405
G/B Contact
Pay Top
Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Jan-15



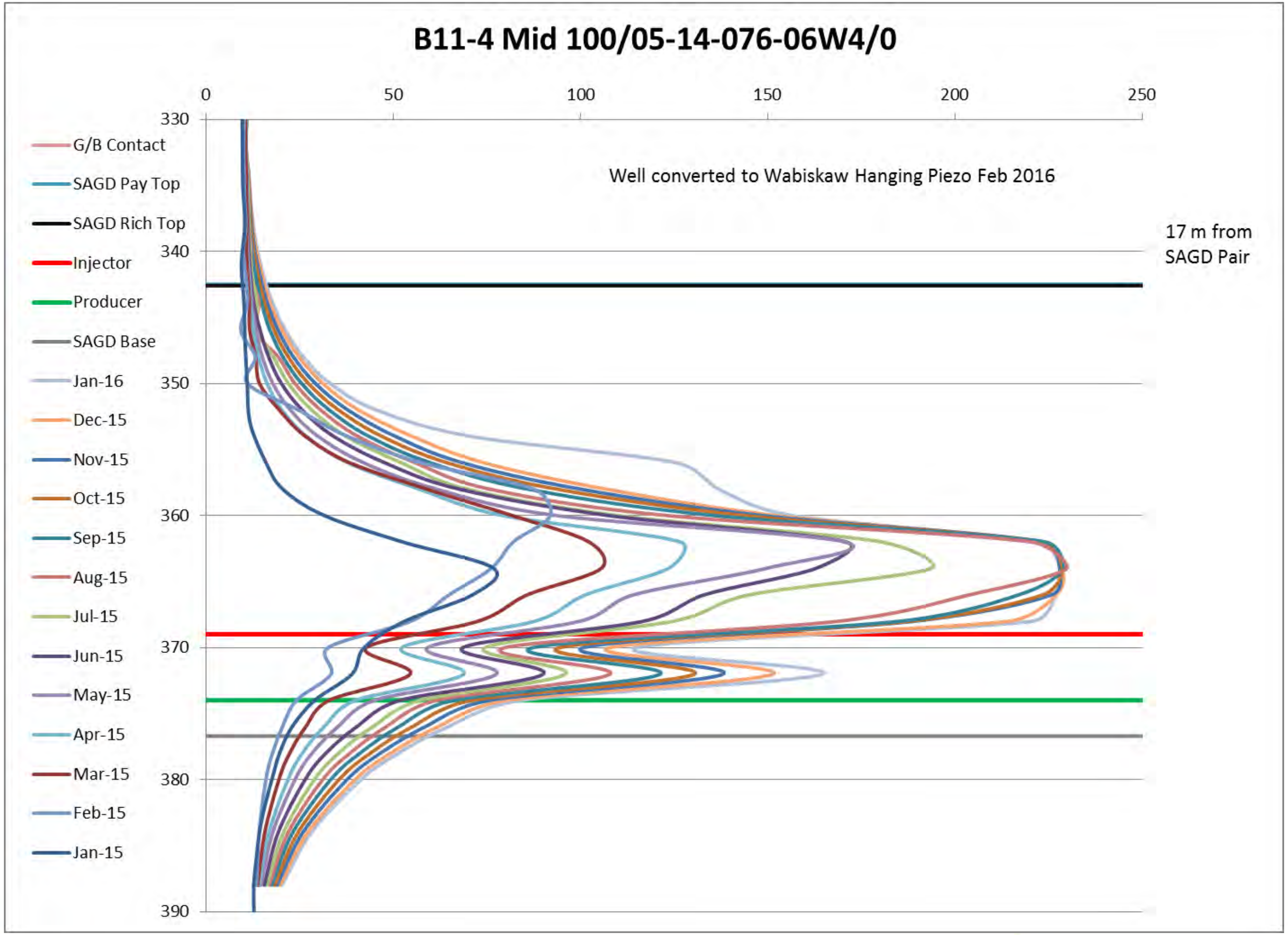
B08-10 Toe 108/12-11-076-06W4/0
0
50
100
150
200
250
320
330
340
350
360
370
380
390
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Feb-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15


B09-6 Heel/B06 Build 102/15-12-076-06W4
0
50
100
150
200
250
320
330
340
350
360
370
380
390
400
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16

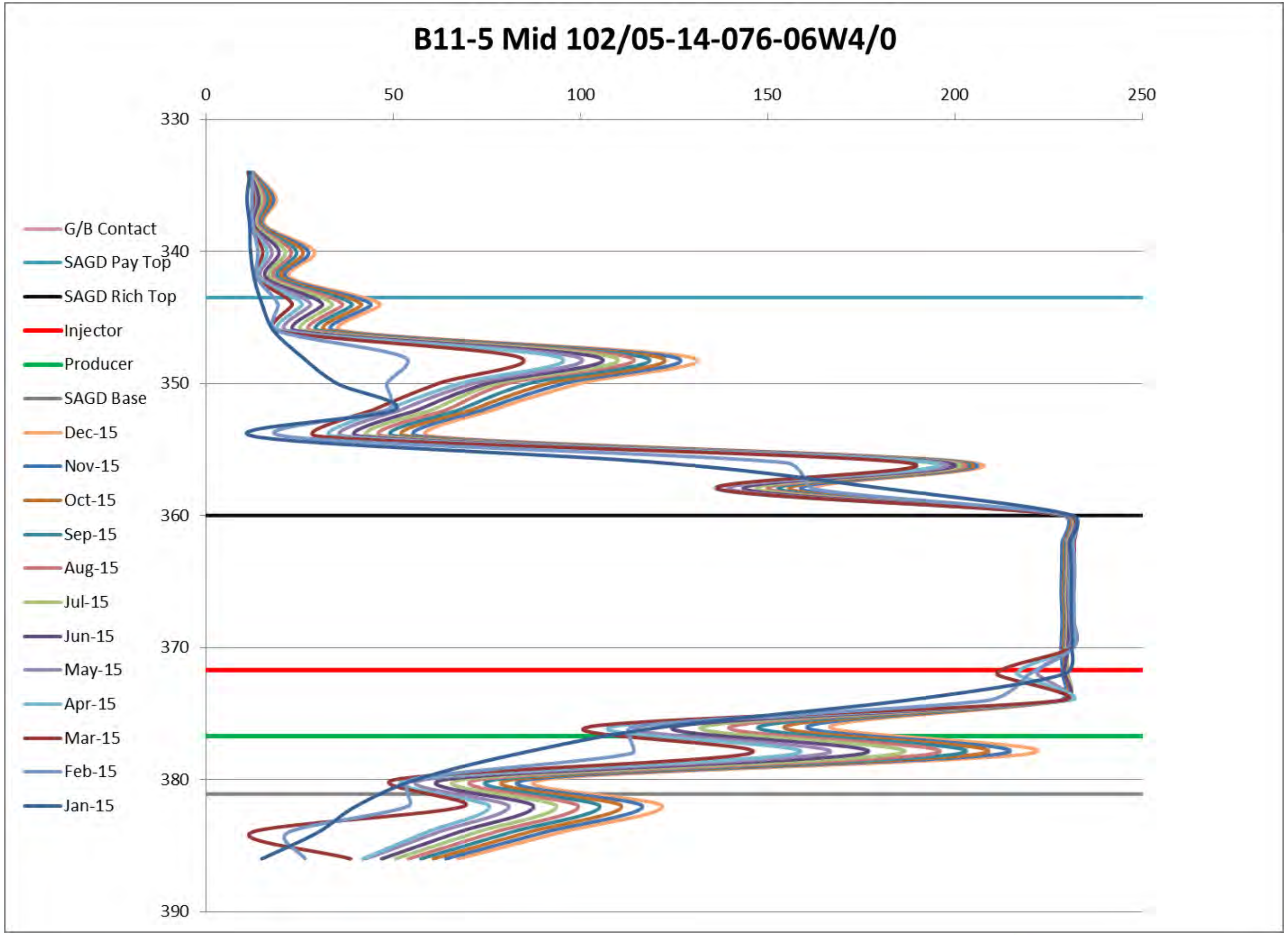


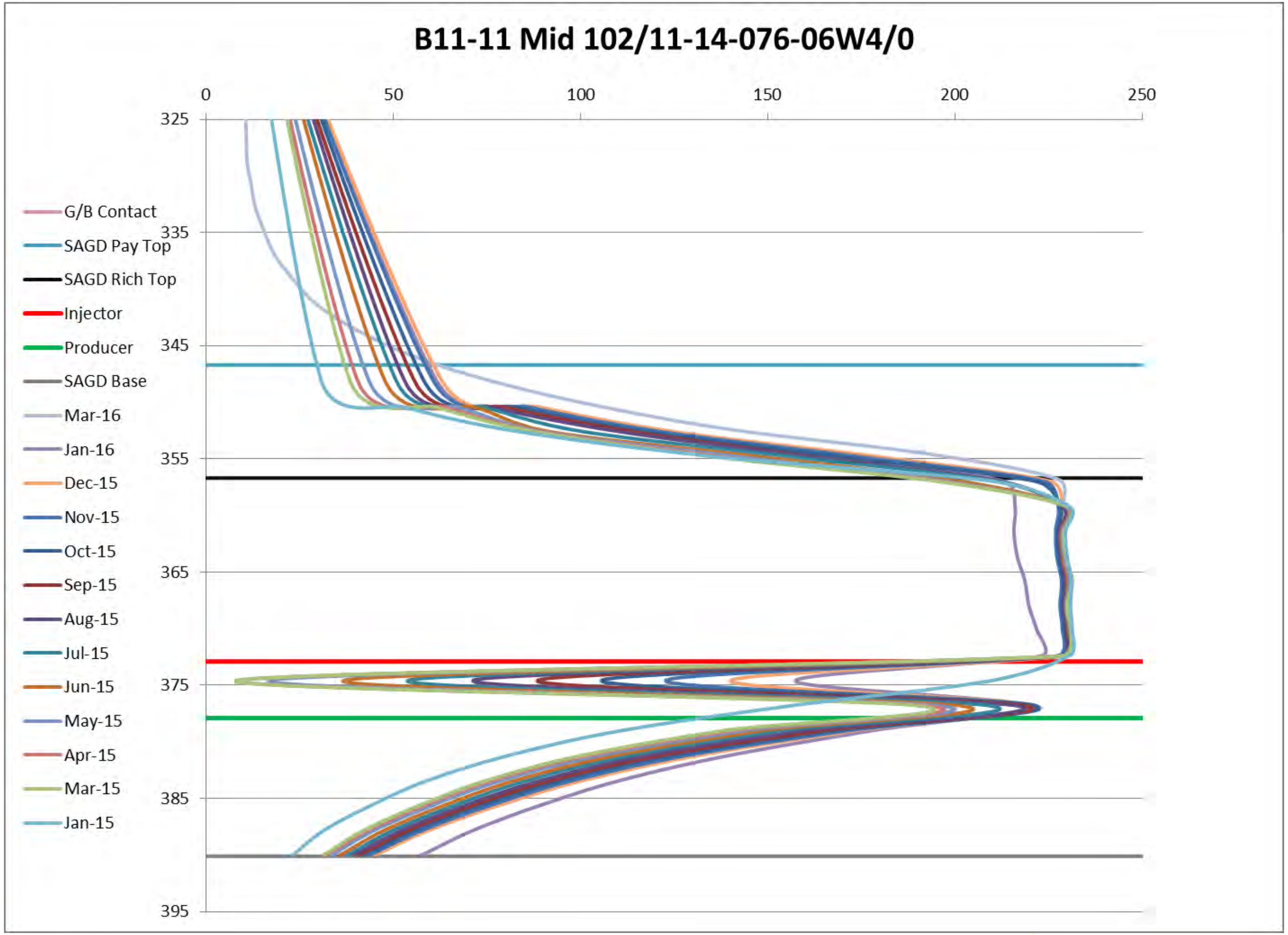

cenovus ENERGY

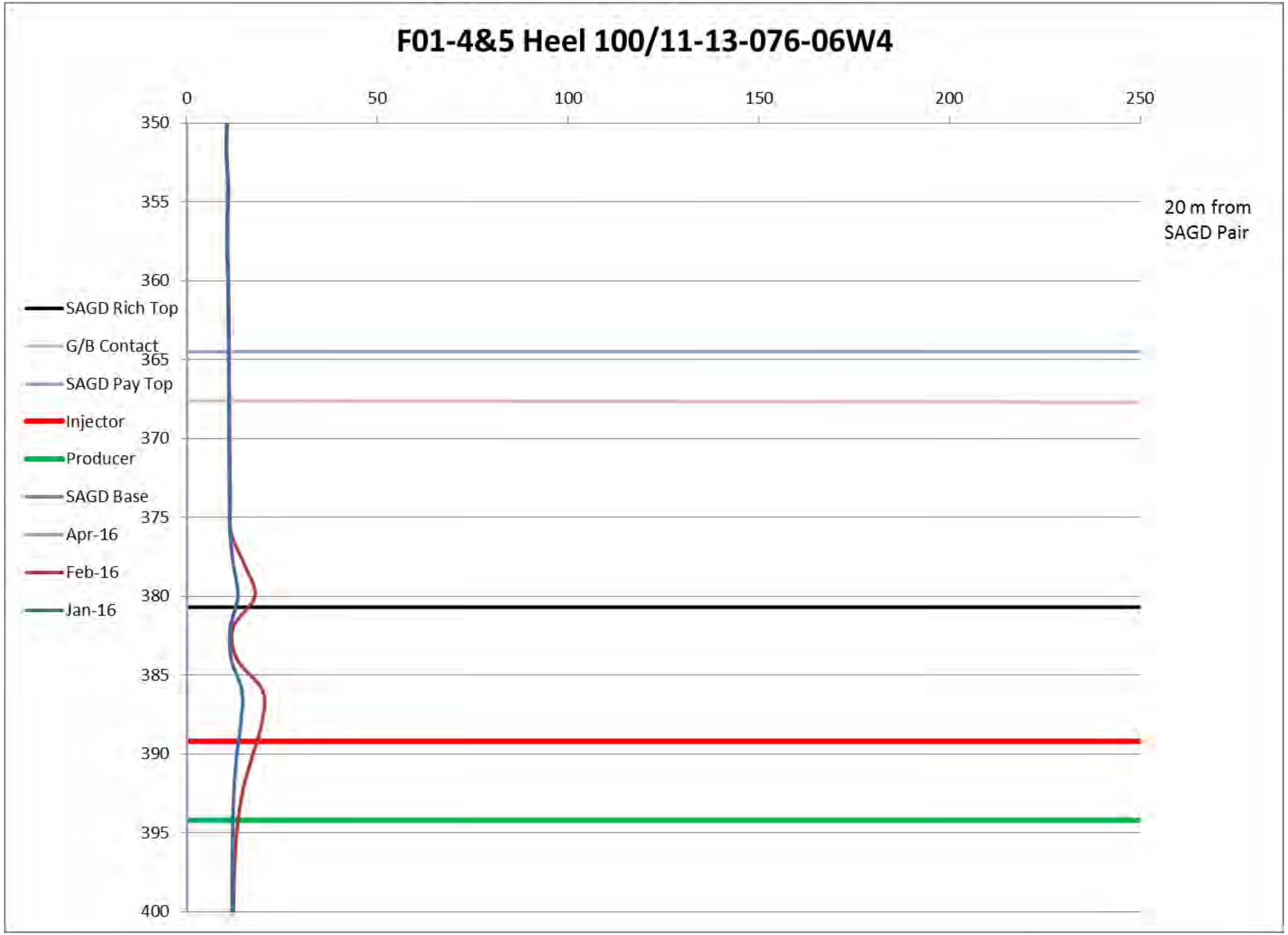
June 15, 2016



B11-4 Mid 100/05-14-076-06W4/0
Well converted to Wabiskaw Hanging Piezo Feb 2016
17 m from SAGD Pair
0
50
100
150
200
250
330
340
350
360
370
380
390
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

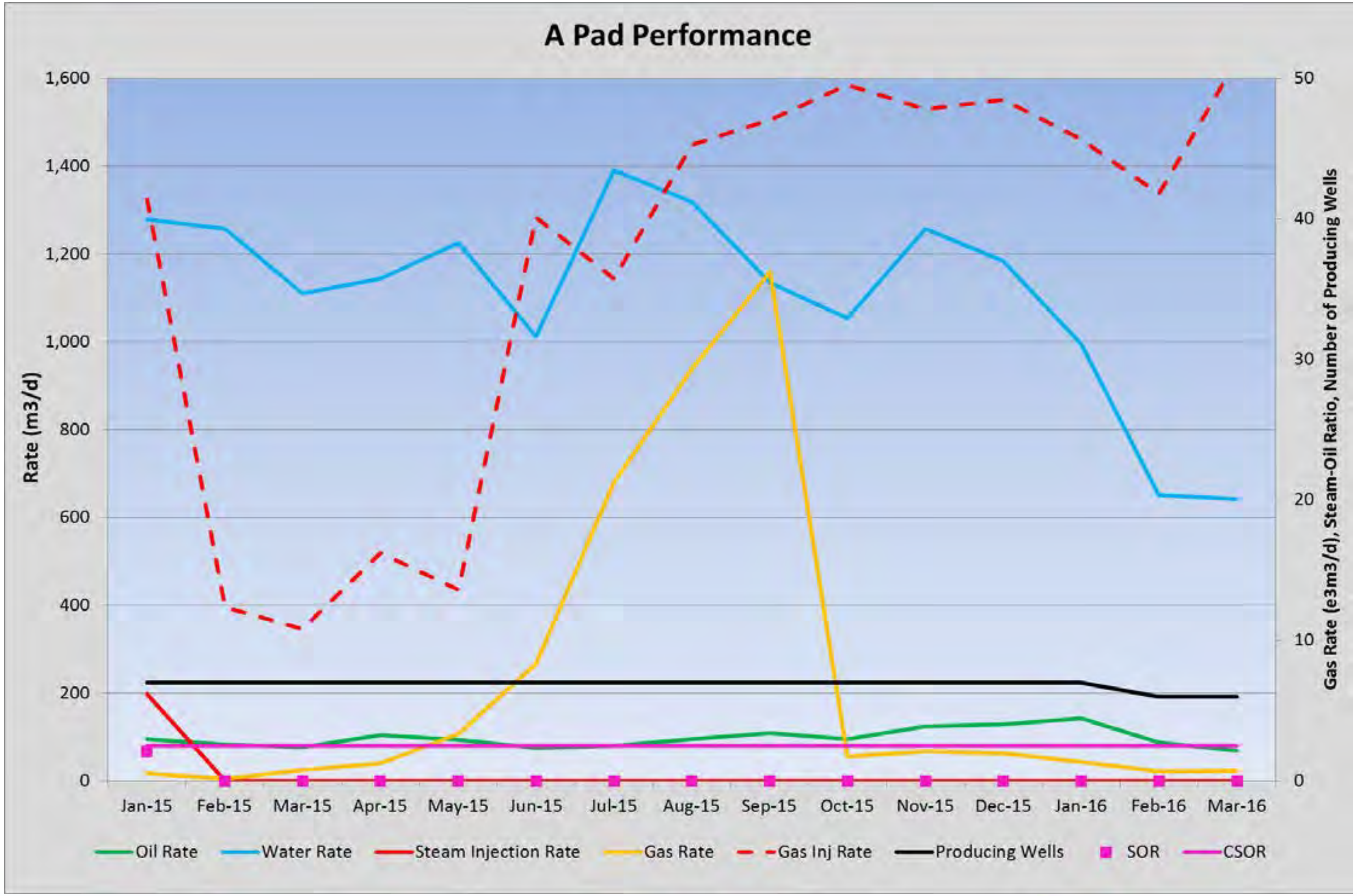

B11-5 Mid 102/05-14-076-06W4/0
0
50
100
150
200
250
330
340
350
360
370
380
390
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Feb-15
Jan-15

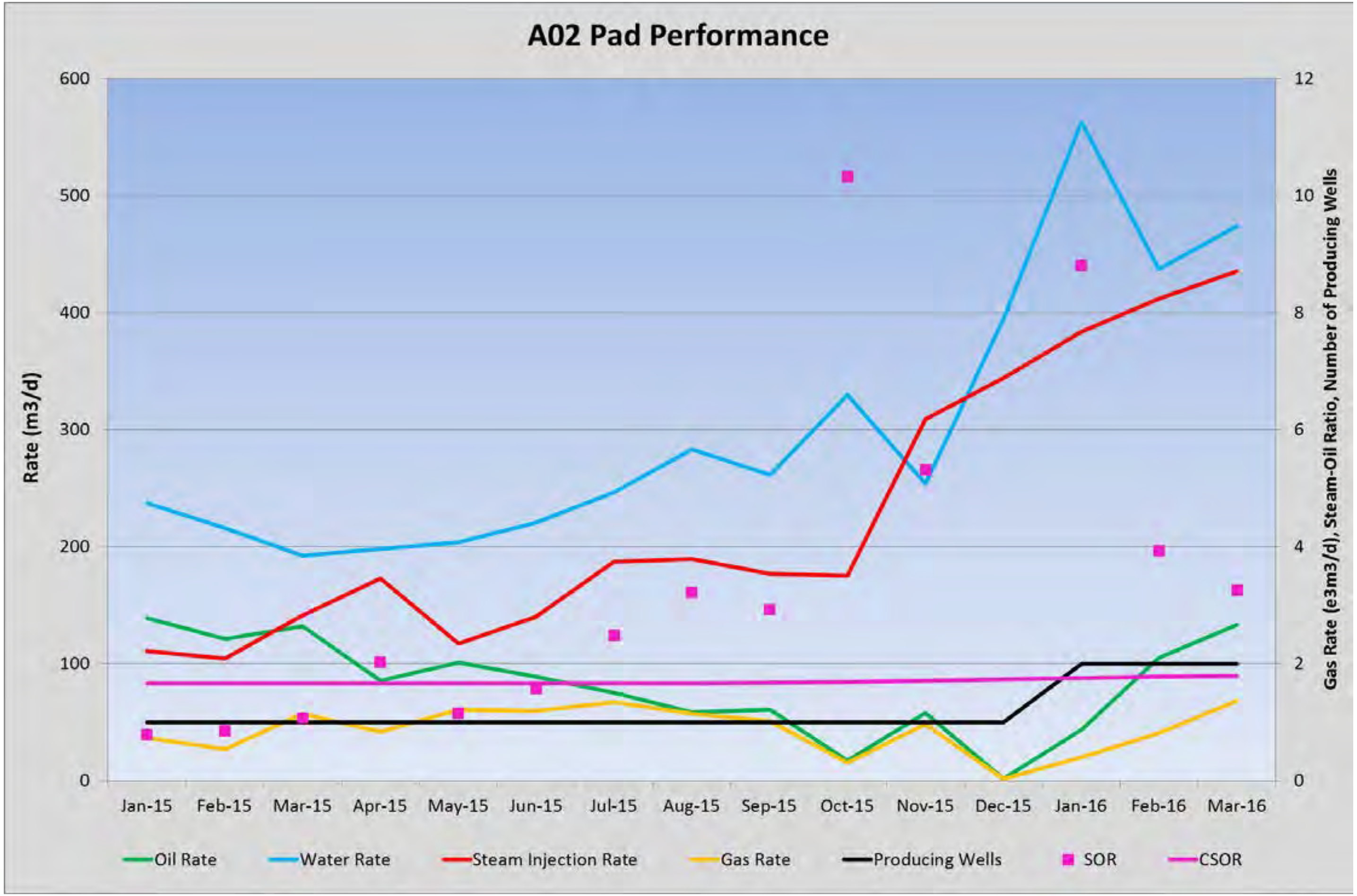

B11-11 Mid 102/11-14-076-06W4/0
0
50
100
150
200
250
325
335
345
355
365
375
385
395
G/B Contact
SAGD Pay Top
SAGD Rich Top
Injector
Producer
SAGD Base
Mar-16
Jan-16
Dec-15
Nov-15
Oct-15
Sep-15
Aug-15
Jul-15
Jun-15
May-15
Apr-15
Mar-15
Jan-15


F01-4&5 Heel 100/11-13-076-06W4
0
50
100
150
200
250
350
355
360
365
370
375
380
385
390
395
400
20 m from
SAGD Pair
SAGD Rich Top
G/B Contact
SAGD Pay Top
Injector
Producer
SAGD Base
Apr-16
Feb-16
Jan-16

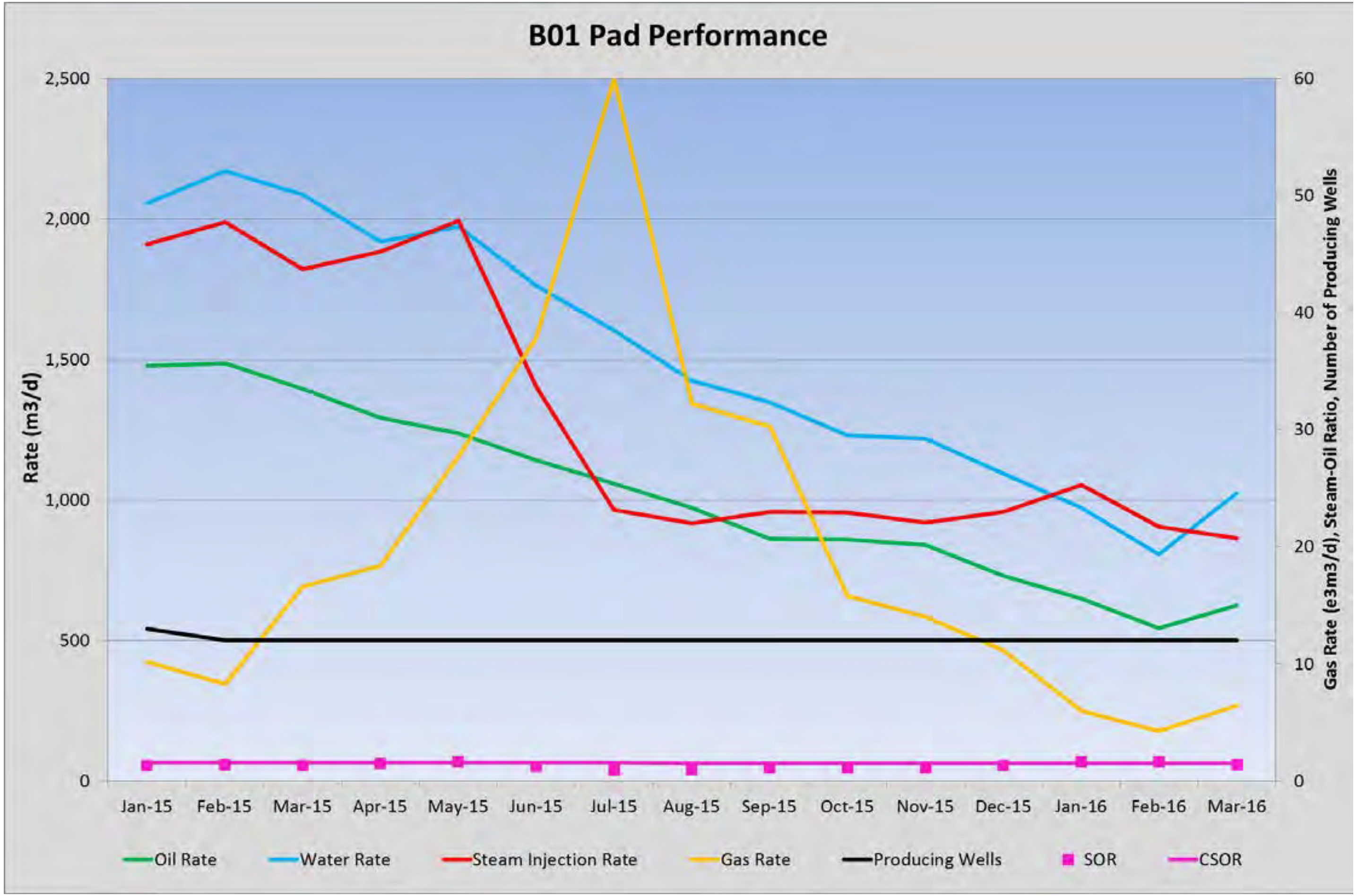
# Appendix 4
# Subsection 3.1.1 – 7h)
## Pad Production Data

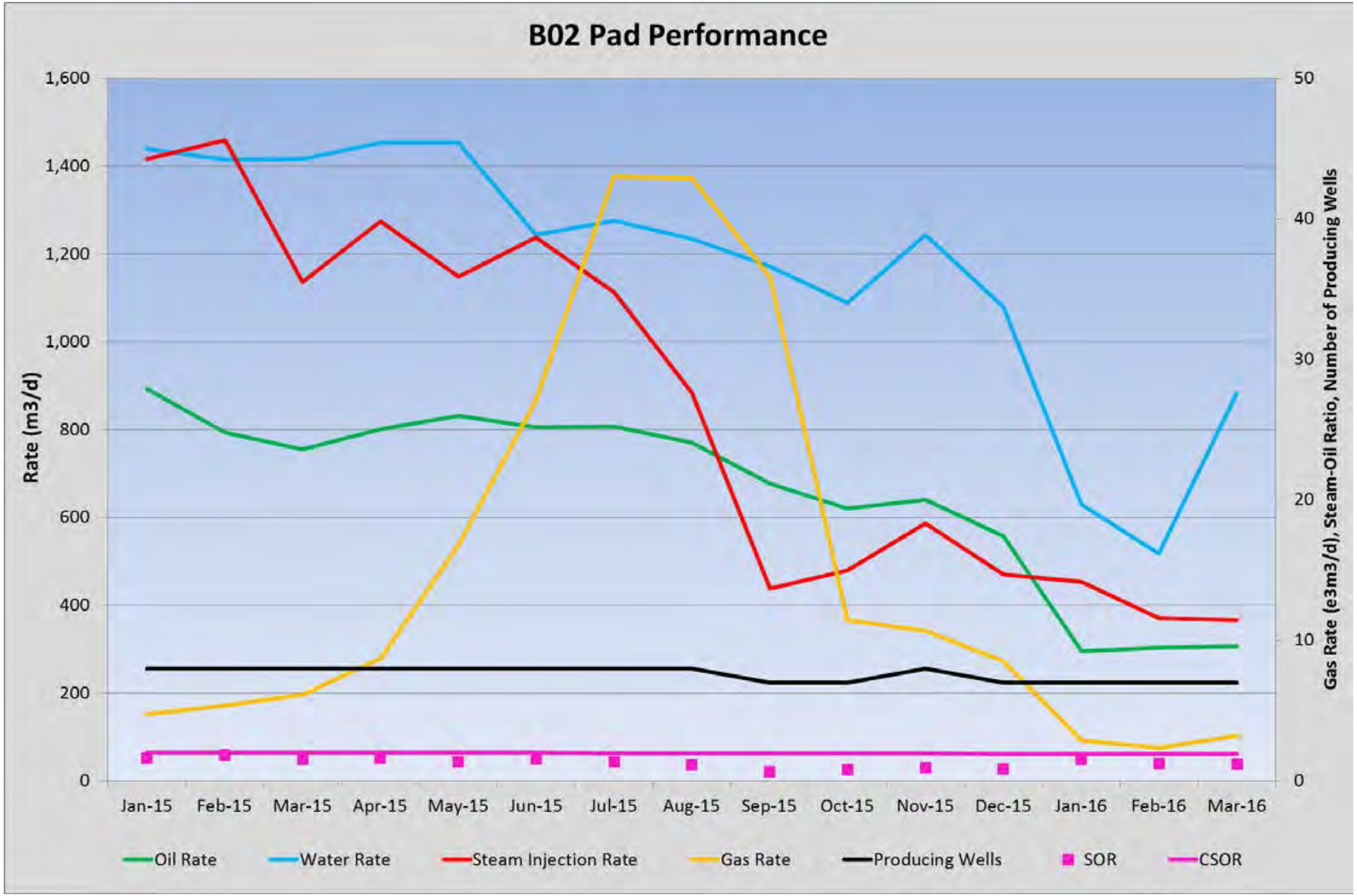
cenovus ENERGY


A Pad Performance
Rate (m3/d)
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
1,600
1,400
1,200
1,000
800
600
400
200
0
50
40
30
20
10
0
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Gas Inj Rate
Producing Wells
SOR
CSOR

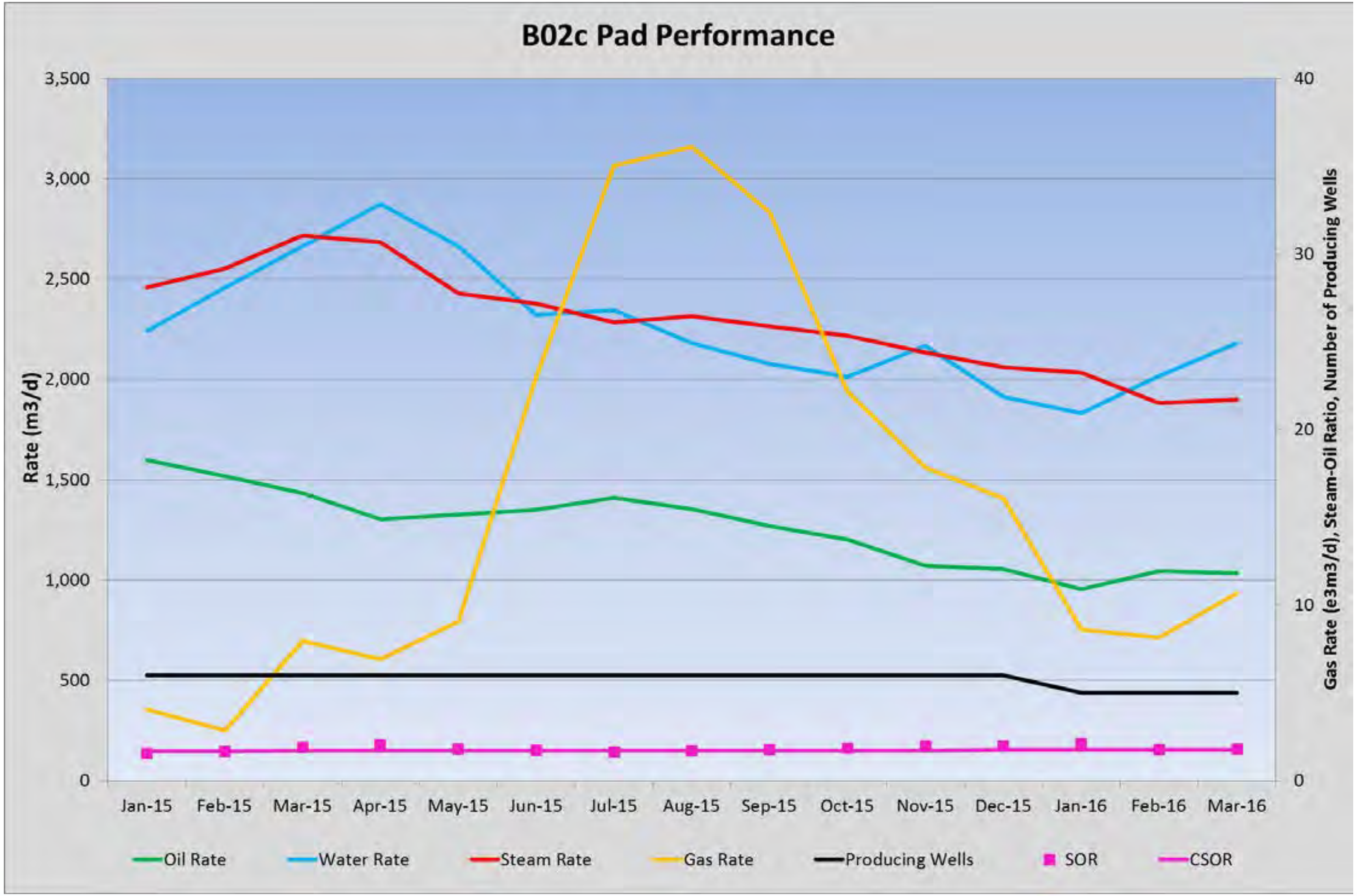


A02 Pad Performance
Rate (m3/d)
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
600
500
400
300
200
100
0
12
10
8
6
4
2
0
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Producing Wells
SOR
CSOR


B01 Pad Performance
Rate (m3/d)
2,500
2,000
1,500
1,000
500
0
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
60
50
40
30
20
10
0
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Producing Wells
SOR
CSOR

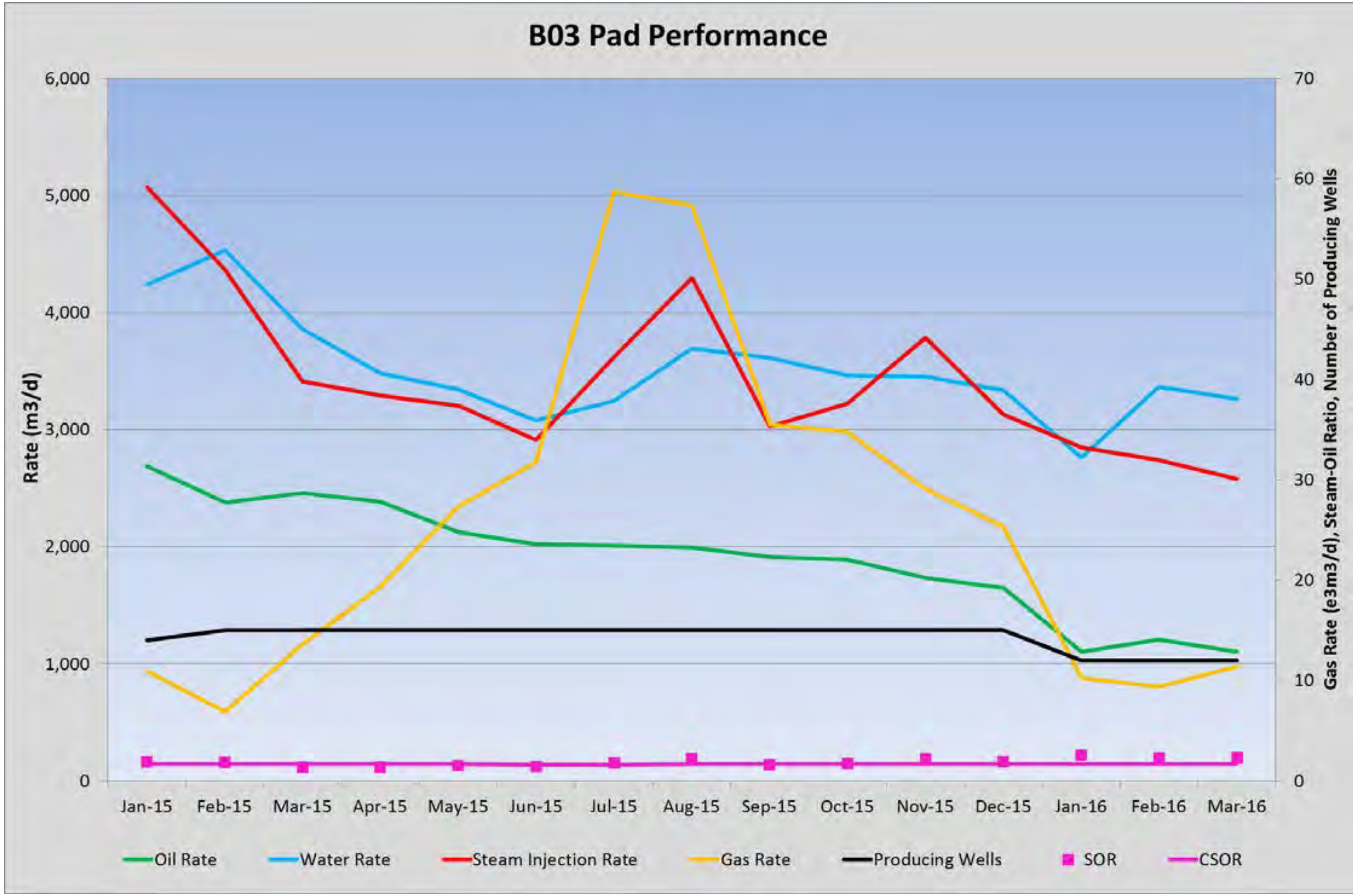


B02 Pad Performance
Rate (m3/d)
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
1,600
1,400
1,200
1,000
800
600
400
200
0
50
40
30
20
10
0
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Producing Wells
SOR
CSOR

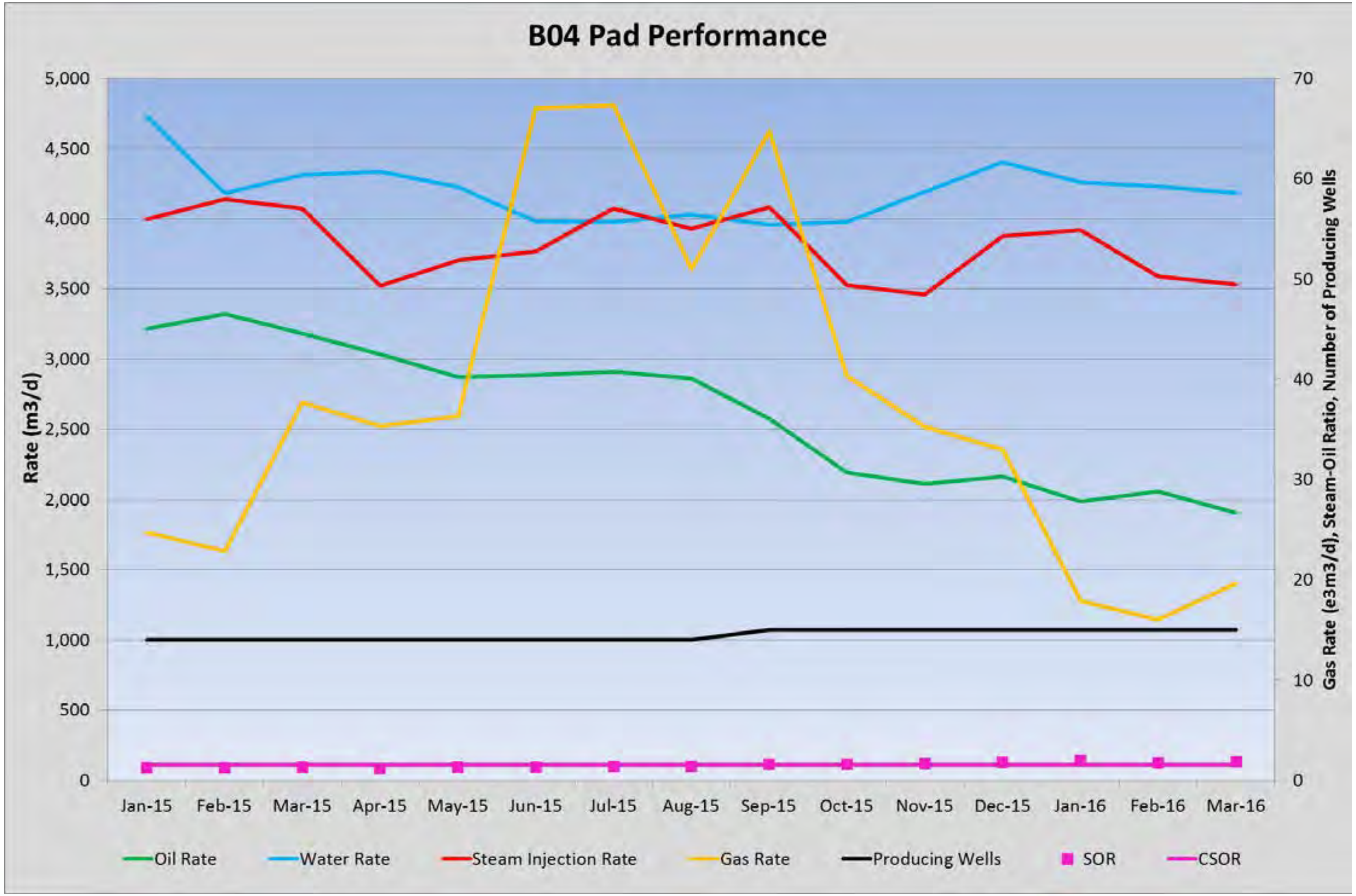


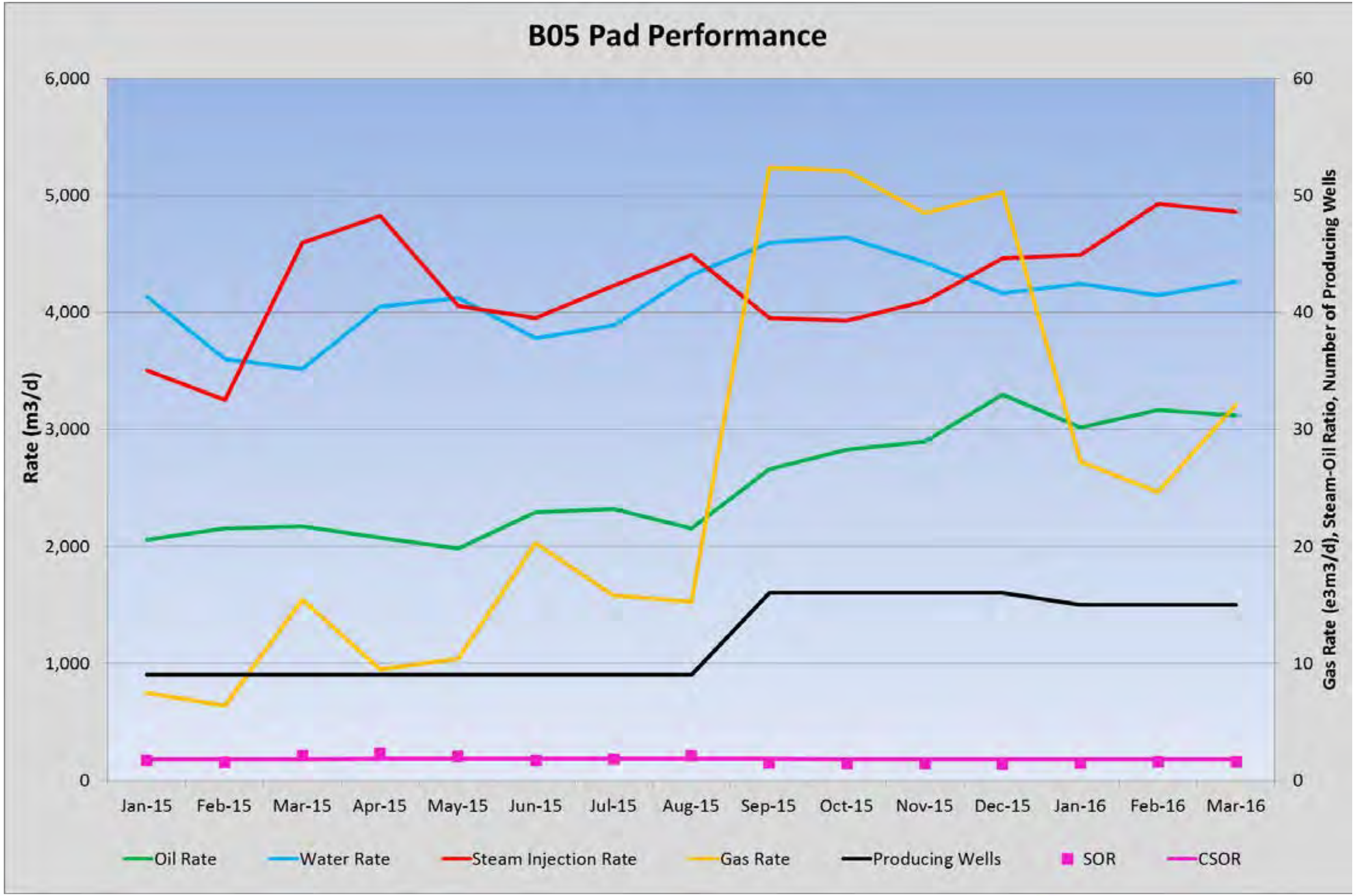

cenovus ENERGY

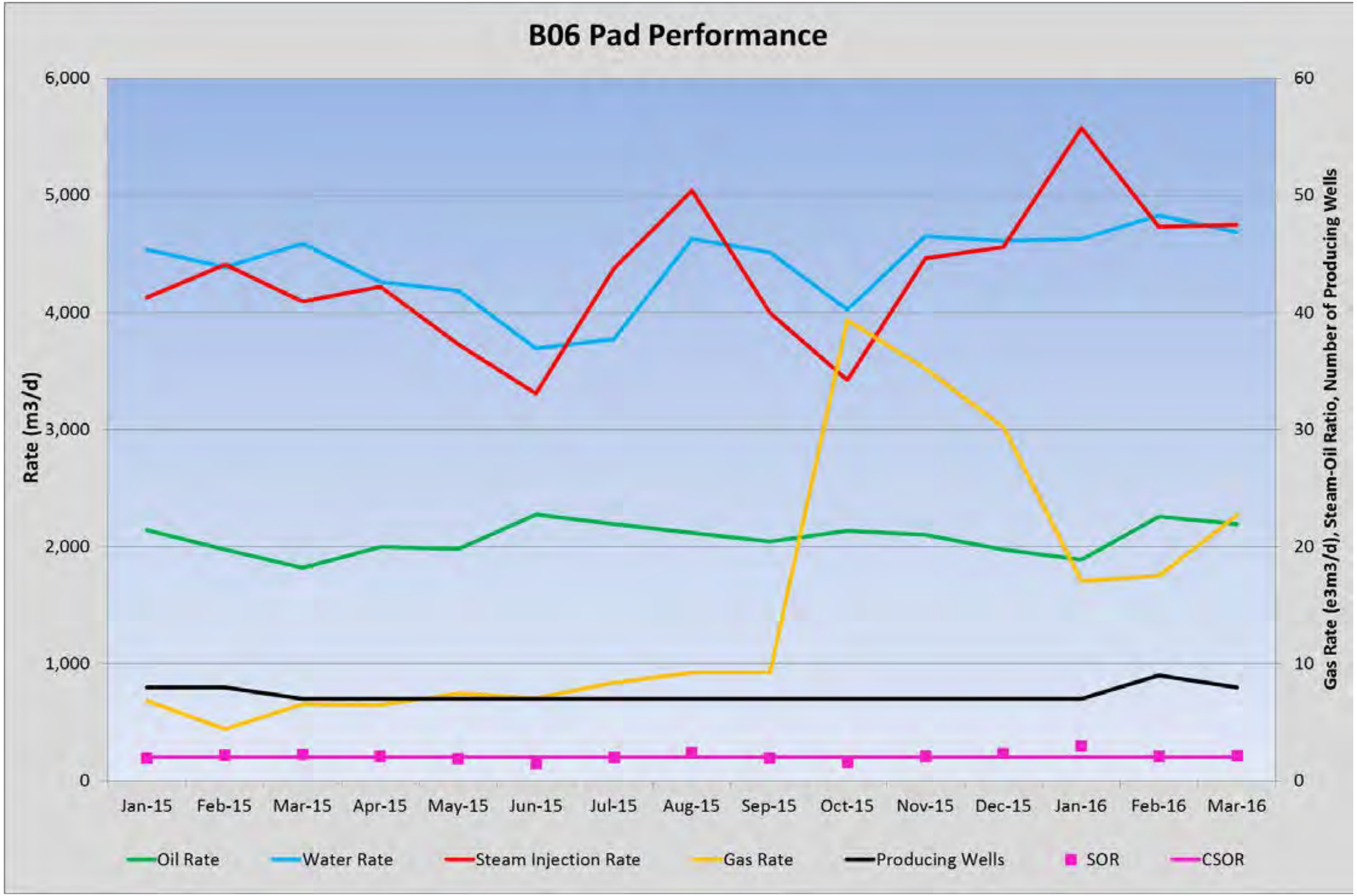
June 15, 2016

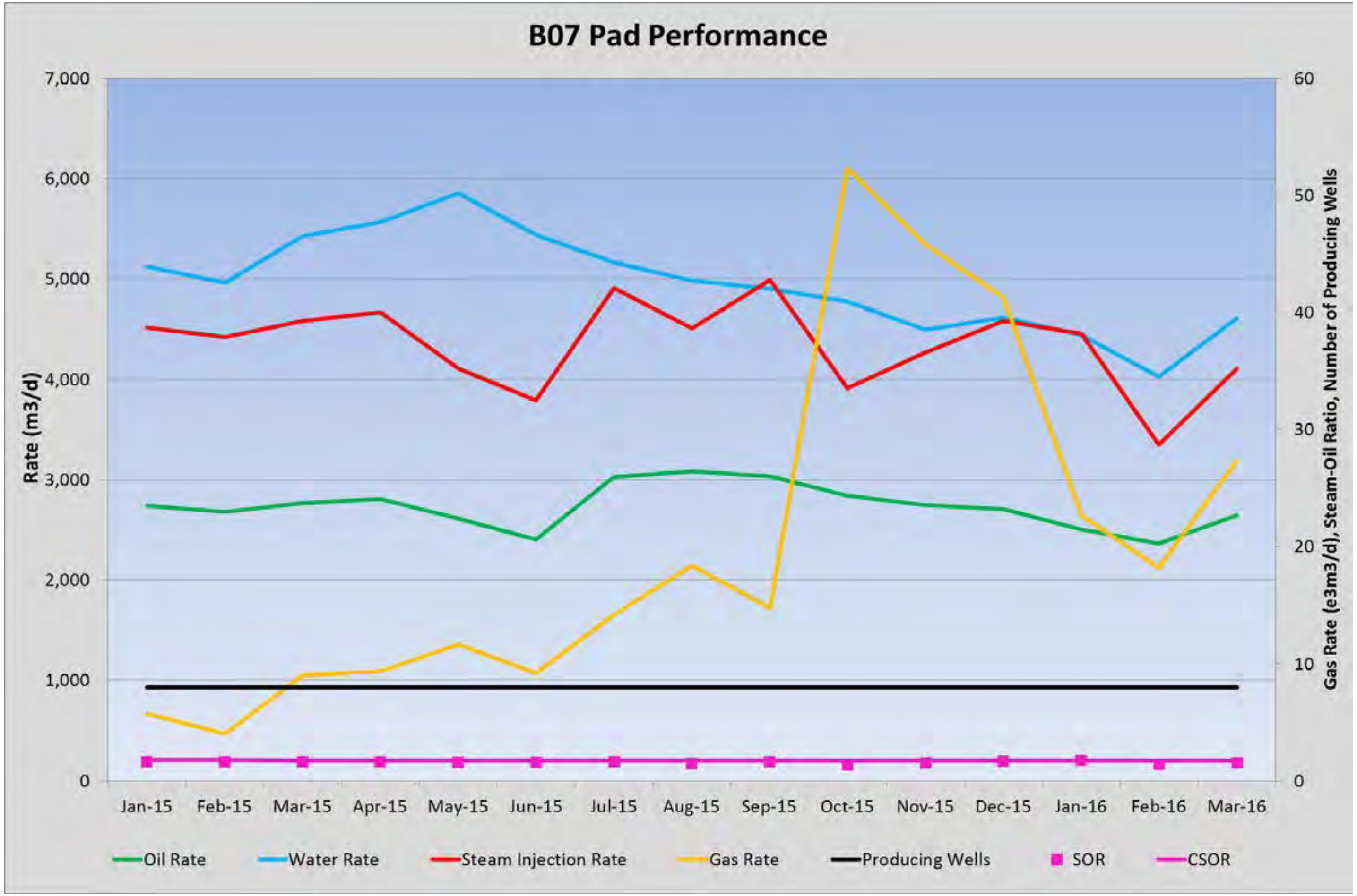


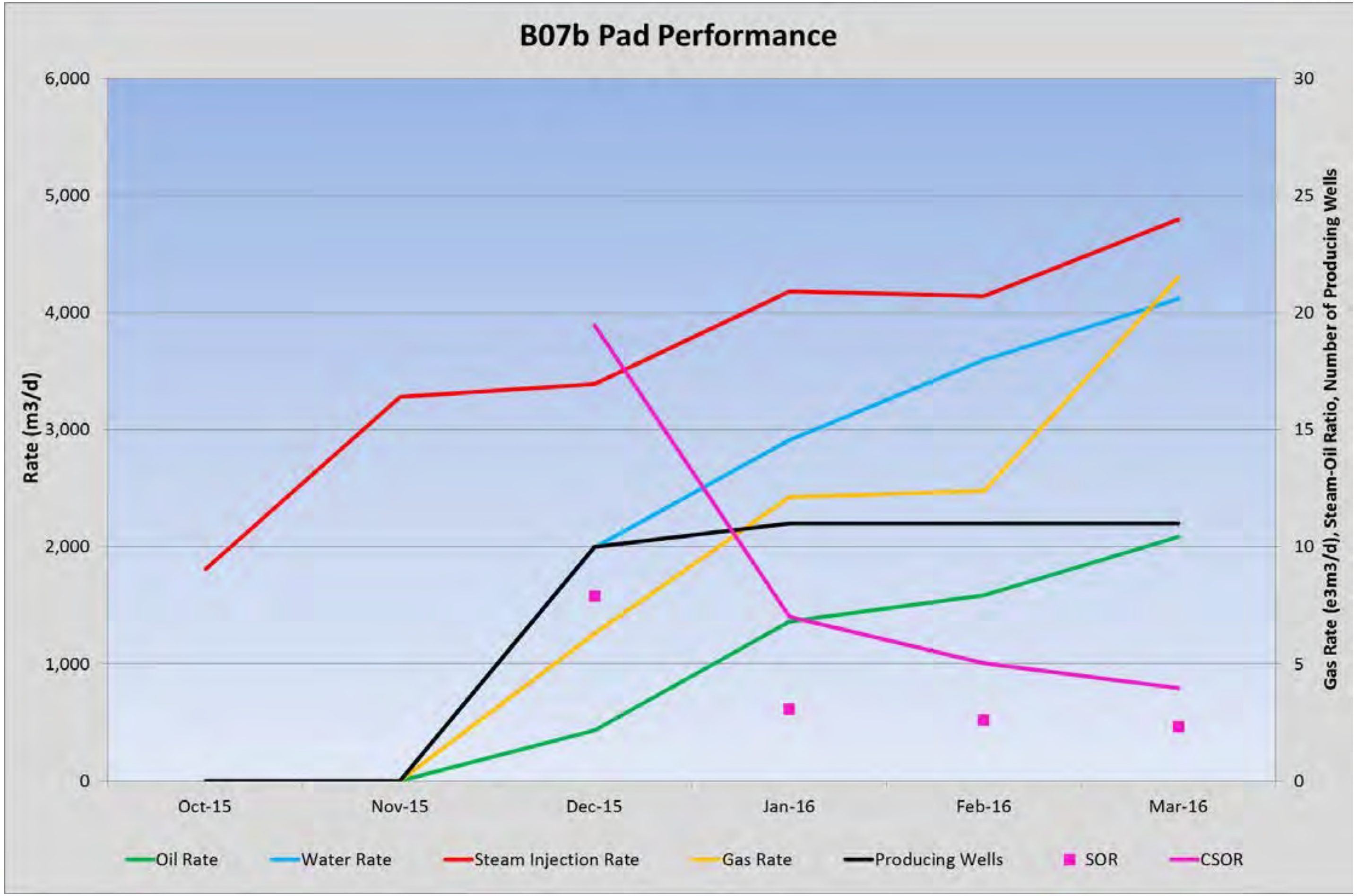
B03 Pad Performance
6,000
5,000
4,000
3,000
2,000
1,000
0
Rate (m3/d)
70
60
50
40
30
20
10
0
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Producing Wells
SOR
CSOR

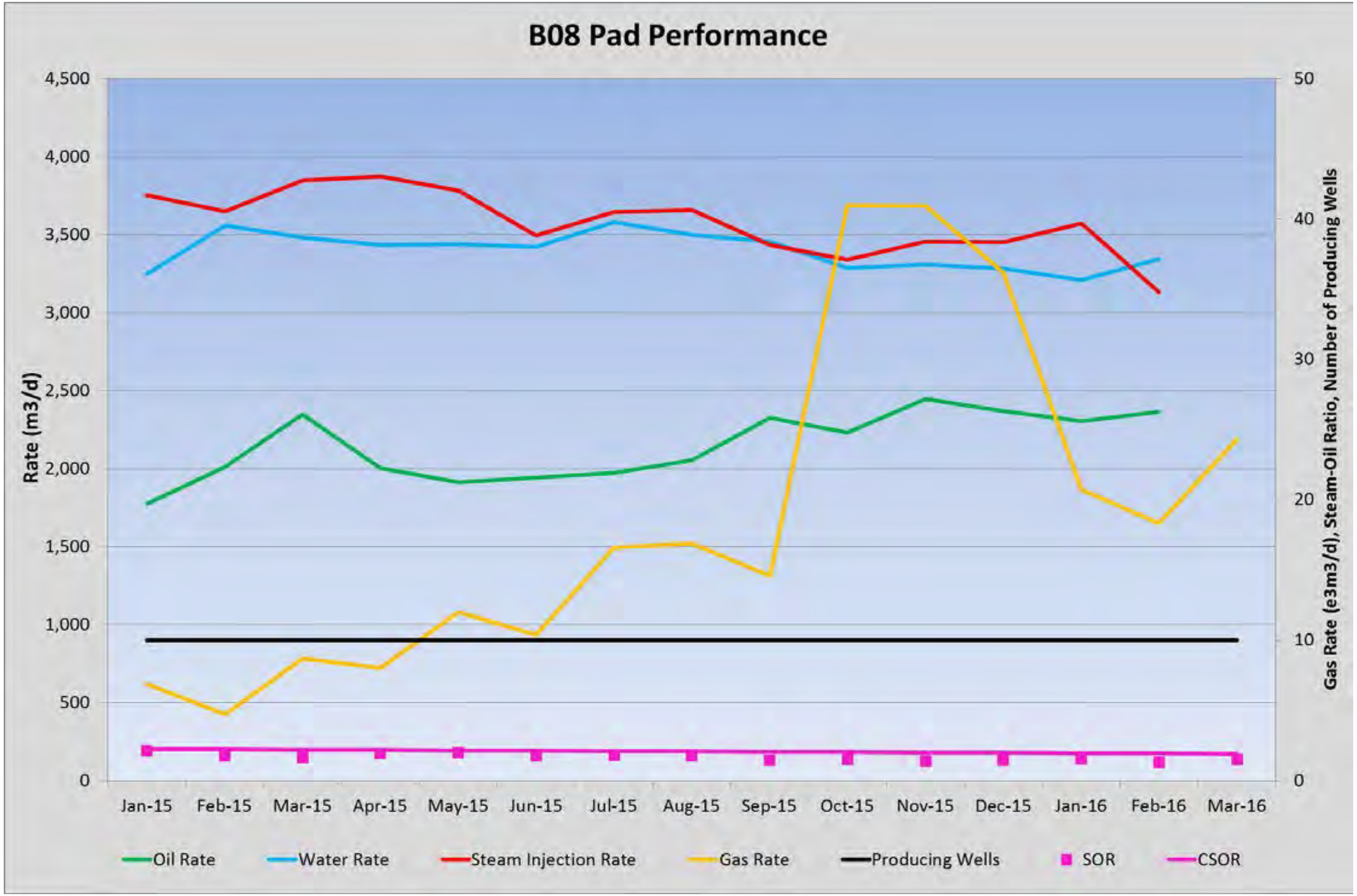

B04 Pad Performance
Rate (m3/d)
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
70
60
50
40
30
20
10
0
Jan-15 Feb-15 Mar-15 Apr-15 May-15 Jun-15 Jul-15 Aug-15 Sep-15 Oct-15 Nov-15 Dec-15 Jan-16 Feb-16 Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Producing Wells
SOR
CSOR

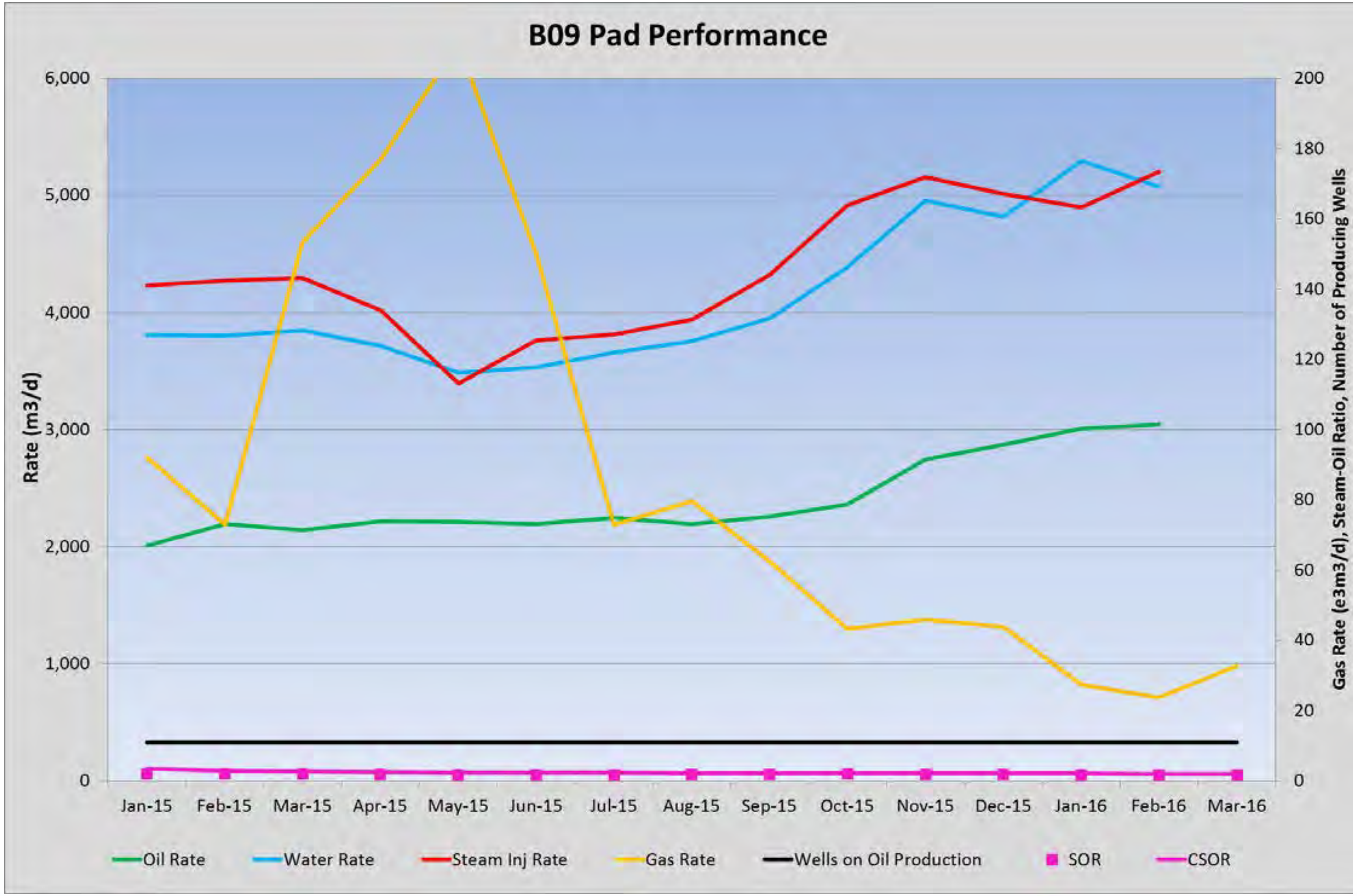

B05 Pad Performance
6,000
5,000
4,000
3,000
2,000
1,000
0
Rate (m3/d)
60
50
40
30
20
10
0
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Producing Wells
SOR
CSOR

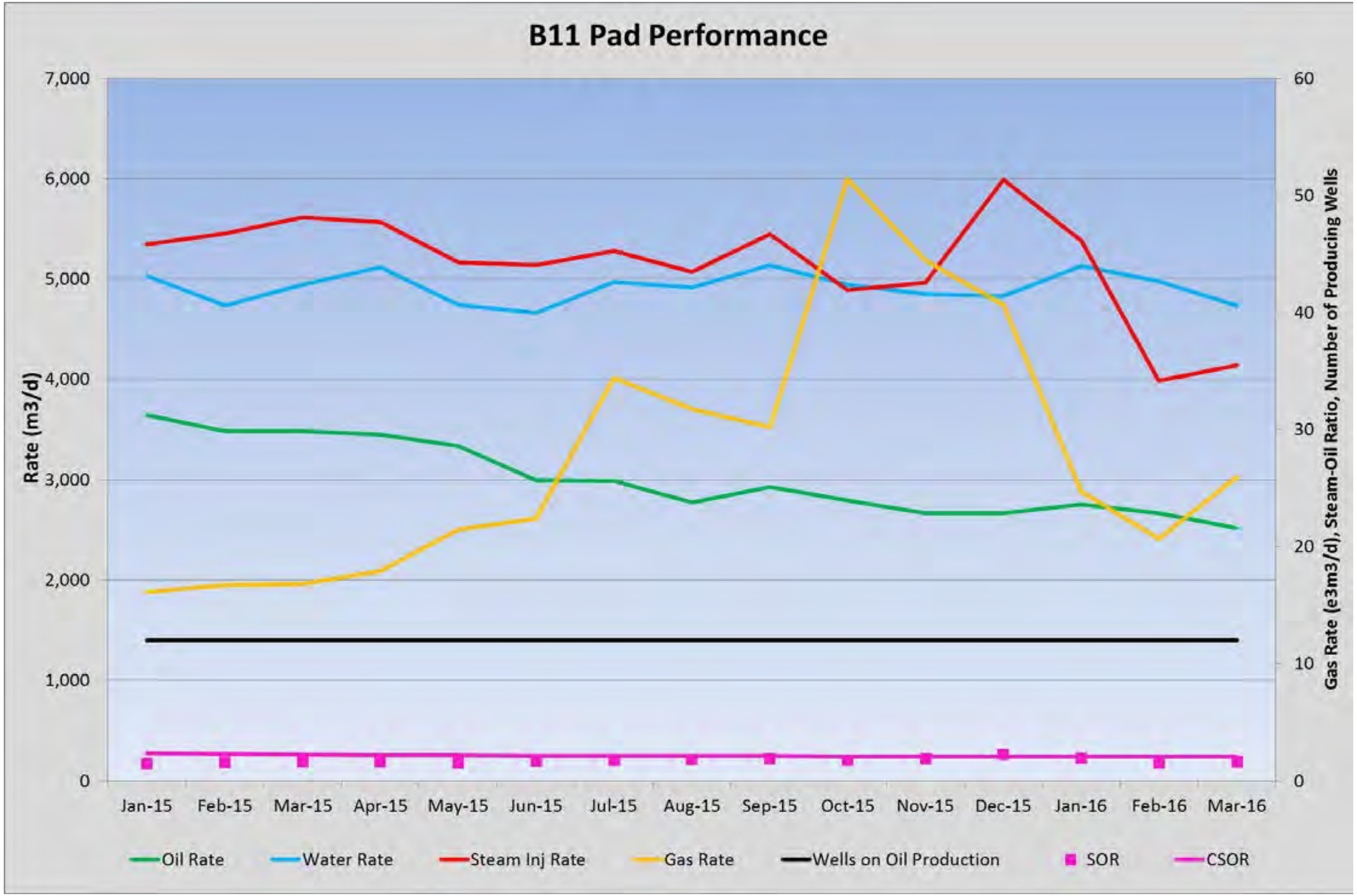

B06 Pad Performance
Rate (m3/d)
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
6,000
5,000
4,000
3,000
2,000
1,000
0
60
50
40
30
20
10
0
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Producing Wells
SOR
CSOR


B07 Pad Performance
Rate (m3/d)
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
60
50
40
30
20
10
0
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Producing Wells
SOR
CSOR

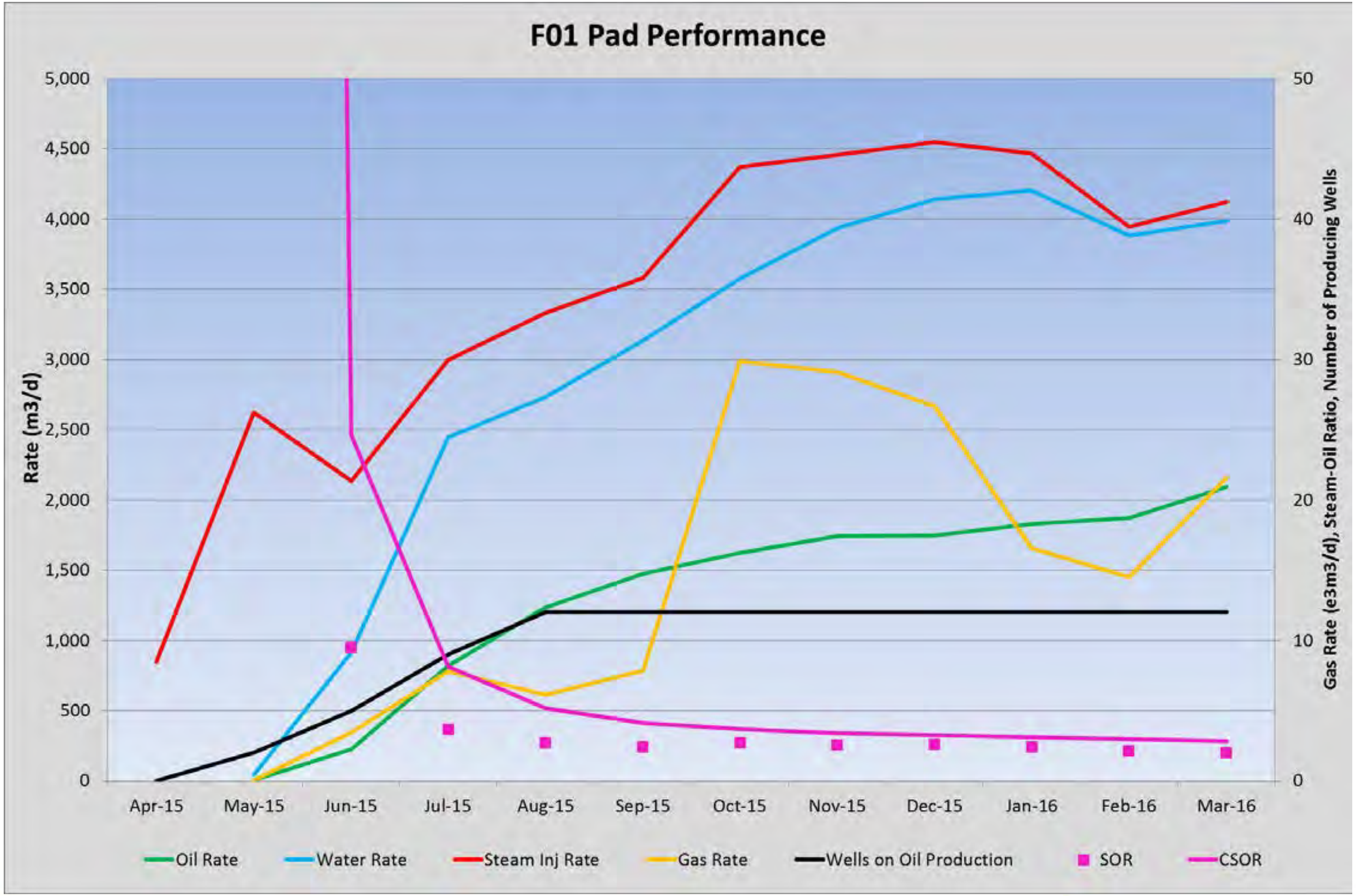

B07b Pad Performance
Rate (m3/d)
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
6,000
5,000
4,000
3,000
2,000
1,000
0
30
25
20
15
10
5
0
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Producing Wells
SOR
CSOR


B08 Pad Performance
Rate (m3/d)
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
50
40
30
20
10
0
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Injection Rate
Gas Rate
Producing Wells
SOR
CSOR


B09 Pad Performance
Rate (m3/d)
6,000
5,000
4,000
3,000
2,000
1,000
0
200
180
160
140
120
100
80
60
40
20
0
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Inj Rate
Gas Rate
Wells on Oil Production
SOR
CSOR



B11 Pad Performance
Rate (m3/d)
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
60
50
40
30
20
10
0
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Inj Rate
Gas Rate
Wells on Oil Production
SOR
CSOR


F01 Pad Performance
Rate (m3/d)
Gas Rate (e3m3/d), Steam-Oil Ratio, Number of Producing Wells
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
50
40
30
20
10
0
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
Mar-16
Oil Rate
Water Rate
Steam Inj Rate
Gas Rate
Wells on Oil Production
SOR
CSOR

# Cenovus Christina Lake In-situ Oil Sands Scheme 8591 2015 Update

Surface

June 16, 2016

cenovus ENERGY

# Oil & gas and financial information

Oil & gas information

The estimates of reserves and contingent resources were prepared effective December 31, 2015 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, 2015 and in our Statement of Contingent and Prospective Resources for the year ended December 31, 2015, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

There is uncertainty 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 presentation contains information in compliance with:

*AER Directive 054 - Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes*

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. The 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., including information regarding contingent resources, is available in our Annual Information Form for the year ended December 31, 2015 and in our Statement of Contingent and Prospective Resources for the year ended December 31, 2015 at cenovus.com.

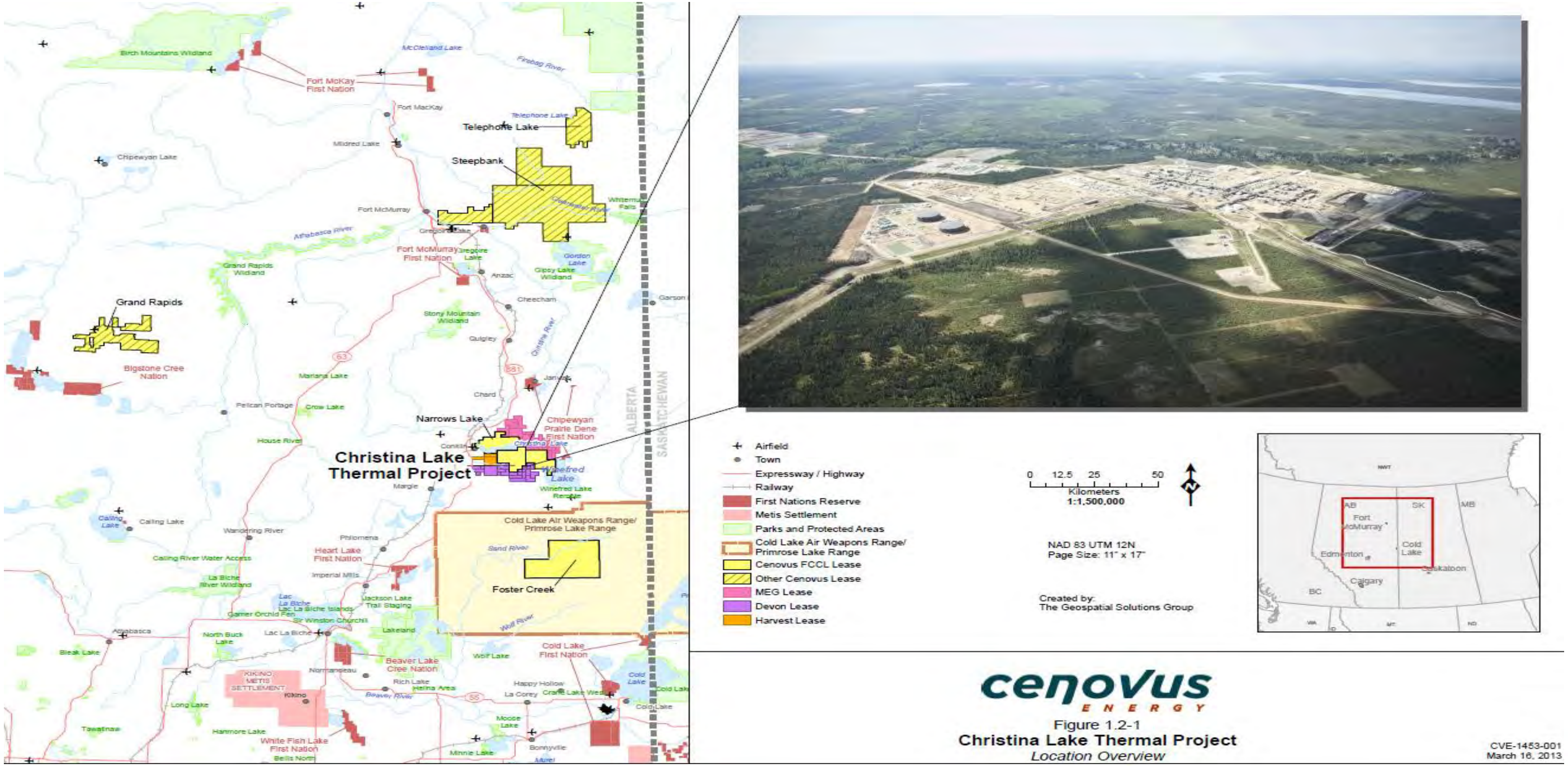
# About Cenovus

**TSX, NYSE | CVE**

| | |
|---|---|
| Enterprise value | C$18 billion |
| Shares outstanding | 833 million |
| 2016F production | |
| Oil sands | 151 Mbbls/d |
| Conventional | 54 Mbbls/d |
| Total liquids | 205 Mbbls/d |
| Natural gas | 385 MMcf/d |
| **Total production** | **269 MBOE/d** |
| 2015 proved & probable reserves | 3.8 BBOE |
| Bitumen | |
| Economic contingent resources* | 9.3 Bbbls |
| Lease rights** | 2.0 MM net acres |
| P&NG rights | 4.1 MM net acres |
| Refining capacity | 230 Mbbls/d net |

Values are approximate. Forecast production based on February 11, 2016 guidance.
*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
Fort McKay First Nation
McClelland Lake
Firebag River
Fort MacKay
Telephone Lake
Telephone Lake
Mildred Lake
Chipewyan Lake
Steepbank
Fort McMurray
Athabasca River
Gregoire Lake
Fort McMurray First Nation
Gregoire Lake
Grand Rapids Wildland
Gordon Lake
Gipsy Lake Wildland
Anzac
Grand Rapids
Cheecham
Garson
Stony Mountain Wildland
Christina River
Bigstone Cree Nation
Quigley
Mariana Lake
Janvier
Chard
Pelican Portage
Crow Lake
Narrows Lake
Chipewyan Prairie Dene First Nation
House River
Christina Lake
Conklin
Christina Lake Thermal Project
Winefred Lake
Margie
Winefred Lake Reserve
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
La Biche River Wildland
Foster Creek
Jackson Lake Trail Staging
Lac La Biche
Lac La Biche Islands
Garner Orchid Fen
Sir Winston Churchill
Wolf River
Lakeland
Athabasca
North Buck Lake
Lac La Biche
Cold Lake First Nation
Bleak Lake
Beaver Lake Cree Nation
Wolf Lake
KIKINO METIS SETTLEMENT
Normandeau
Kikino
Rich Lake
Happy Hollow
Cold Lake
Helina Area
La Corey
Crane Lake West
Cold Lake
Beaver River
Cold Lake
Long Lake
Moose Lake
Tawatinaw
Hanmore Lake
White Fish Lake First Nation
Bonnyville
Bells North
Minnie Lake
Muriel
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
NWT
AB
SK
MB
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

Mandy Chen

Sr. Process Engineer

cenovus ENERGY

# Facility Summary

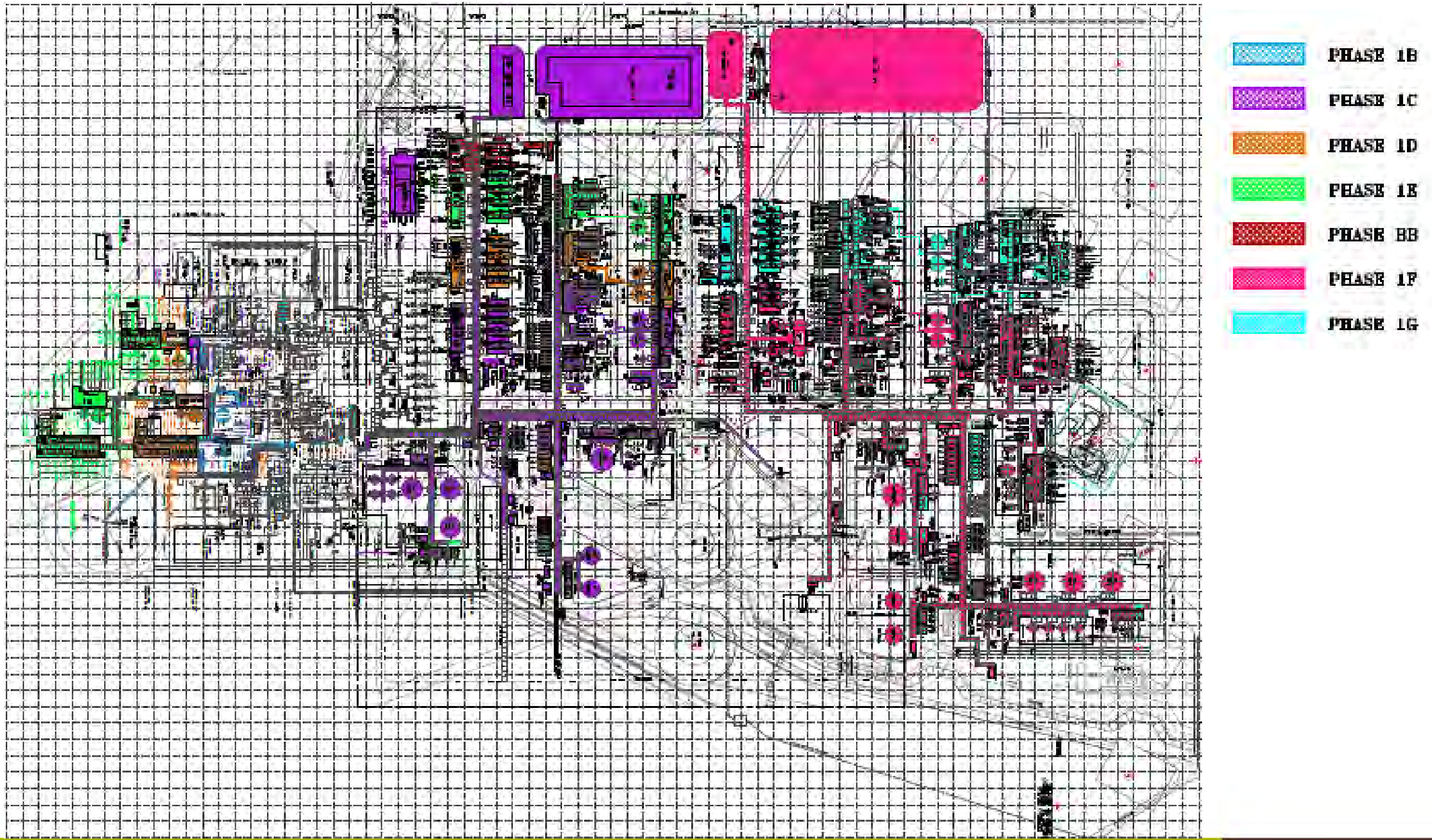
## 2nd Stage Blowdown Boiler Start-Up

- Two blowdown boilers were commissioned in September 2015
- Increase steam capacity by 7,280 t/d and minimize blowdown disposal
- Operated on 100% blowdown as feed water

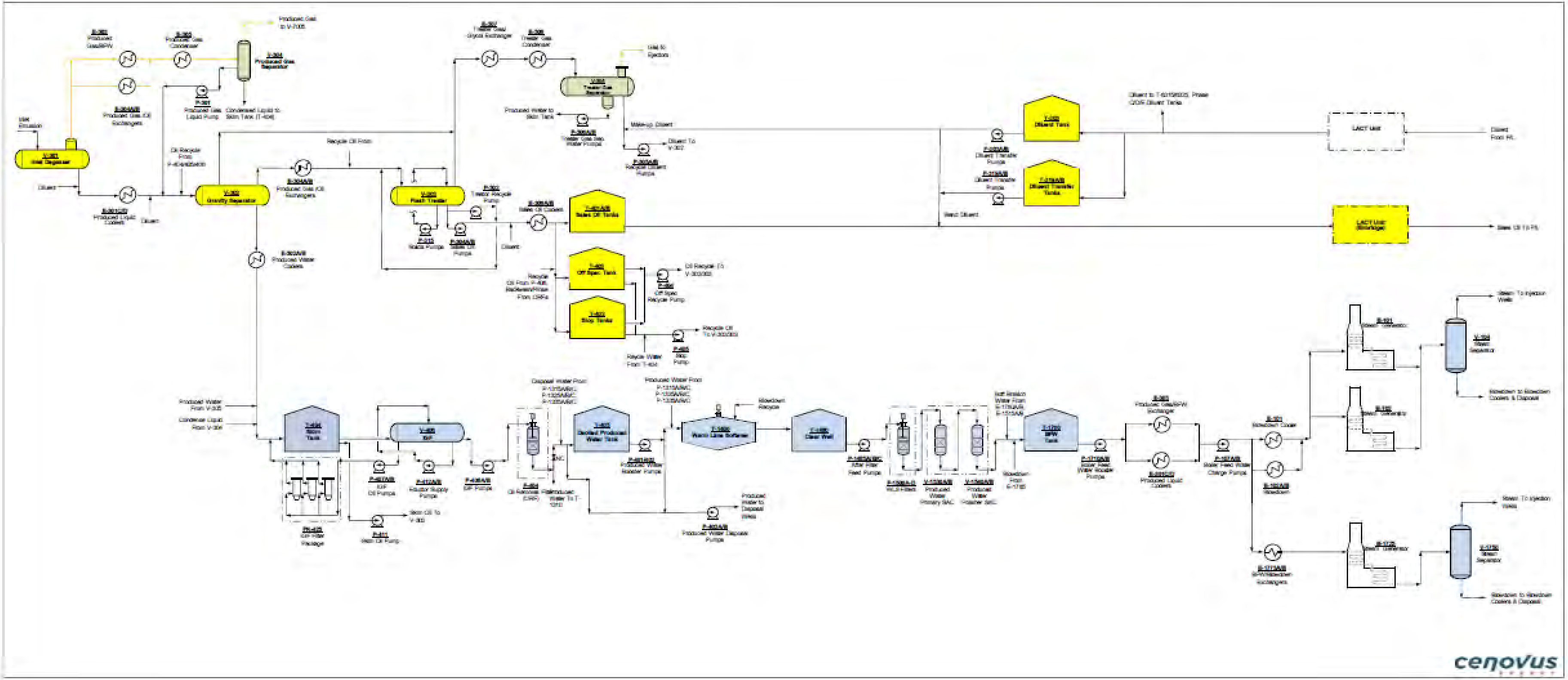
## Addition of Heat Exchangers

- Nine heat exchangers were added in August 2015
- Increased cooling capacity by ~3,180 $m^3$/d

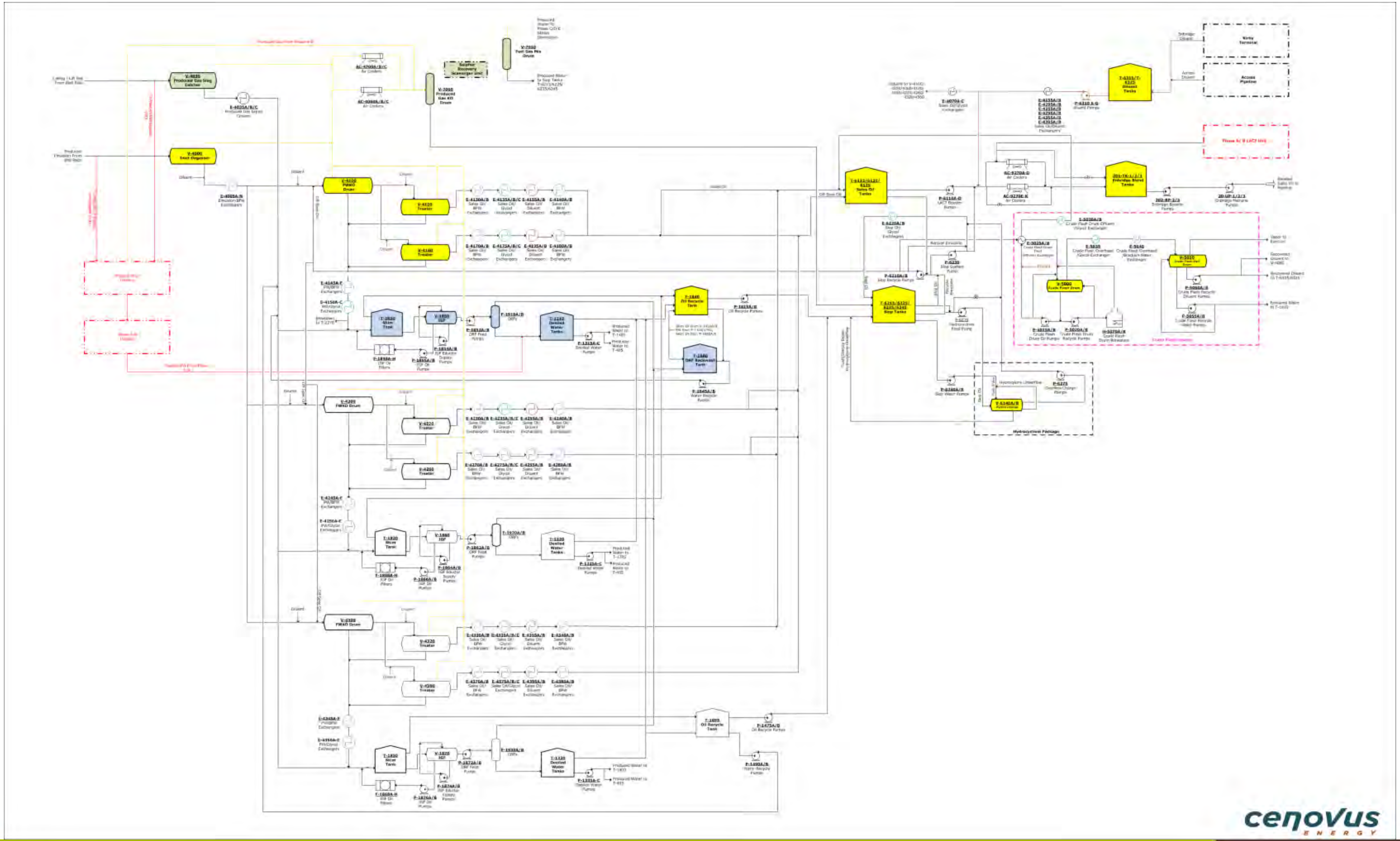
# Overall Plot Plan – Existing Plant Plus Phase F/G



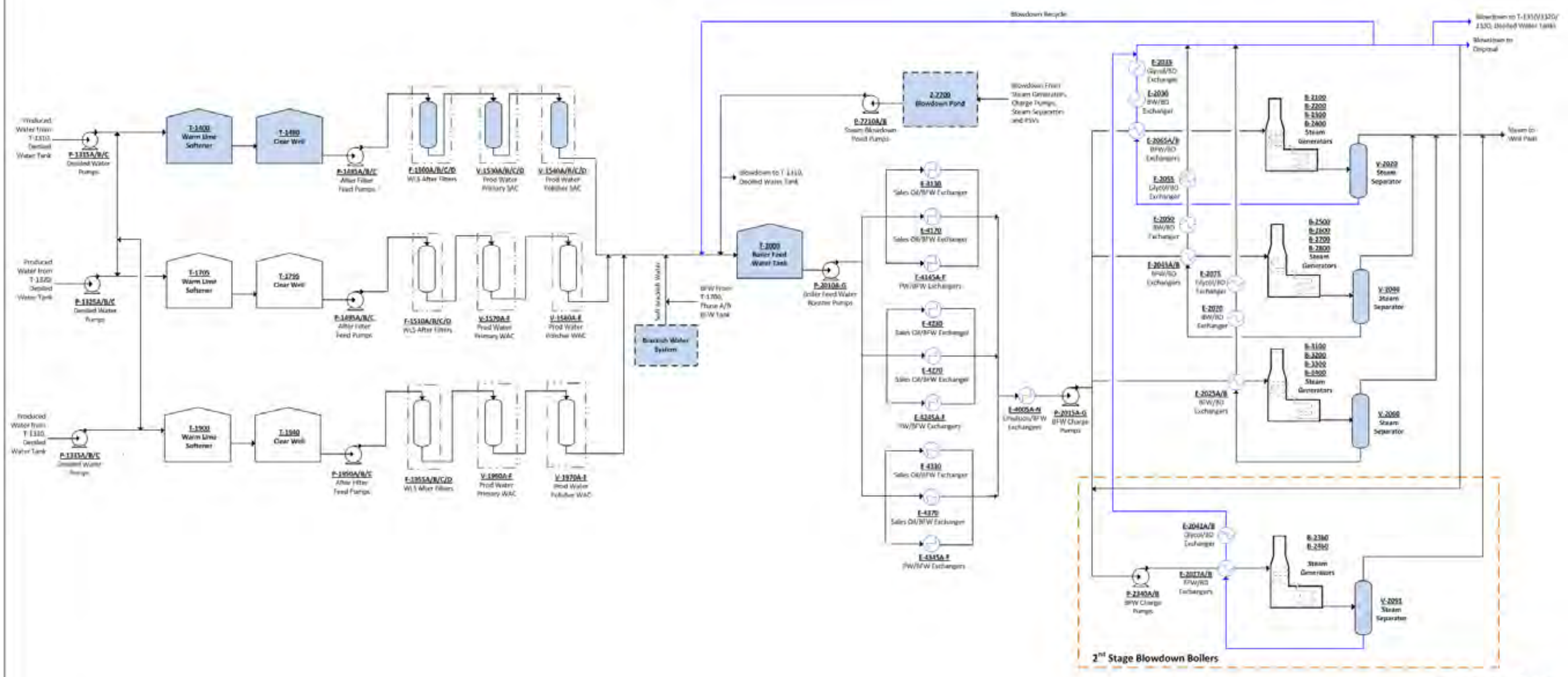
# Phase A/B Process De-oiling, Steam & Water System



# Phase C / D / E Process De-oiling



# Phase C/D/E Steam & Water System




cenovus ENERGY

# Facility Modifications

- No additional major modifications made to Phase A-E outside of Phase C/D/E optimization already mentioned

- Commissioning of Produced Water / Boiler Feed Water crossover line to enable water sharing across Phase A-E and Phase F expected May 2016

- Commissioning of CL1F expansion expected in August 2016
  - Includes addition of cogeneration

- Addition of three blend coolers and commissioning expected in June 2016

# Subsection 3.1.2 – 2) Facility performance

Bailey Gould

Process Engineer

# Plant performance

## Exceeded design performance:

- Steam plant has achieved higher rates than nameplate design (103%, 50,000 t/d vs nameplate 48,400 t/d)
- Oil treating has achieved higher rates than nameplate design (101%, 25,755 $m^3$/d vs 25,437 $m^3$/d)

## Debottlenecking Completed:

- Successful commissioning and start up of CDE Optimization project
- Debottleneck included 2 x OTSGs and additional cooling equipment

# Bitumen treatment

## Process

- Capacity of 25,437 $m^3$/d, consistently achieving nameplate production in Q1 2016 as new pads ramp up
- Have reduced issues with treating and water quality due to:
  - Further improvements to chemical treating program
  - Improved operating procedures and monitoring programs
  - Modifications to control logic and increased automation
- Continued success of treating program to minimize slop production
- Slop handling is internalized within the facility, with little to no offsite management

# 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

## Water treatment

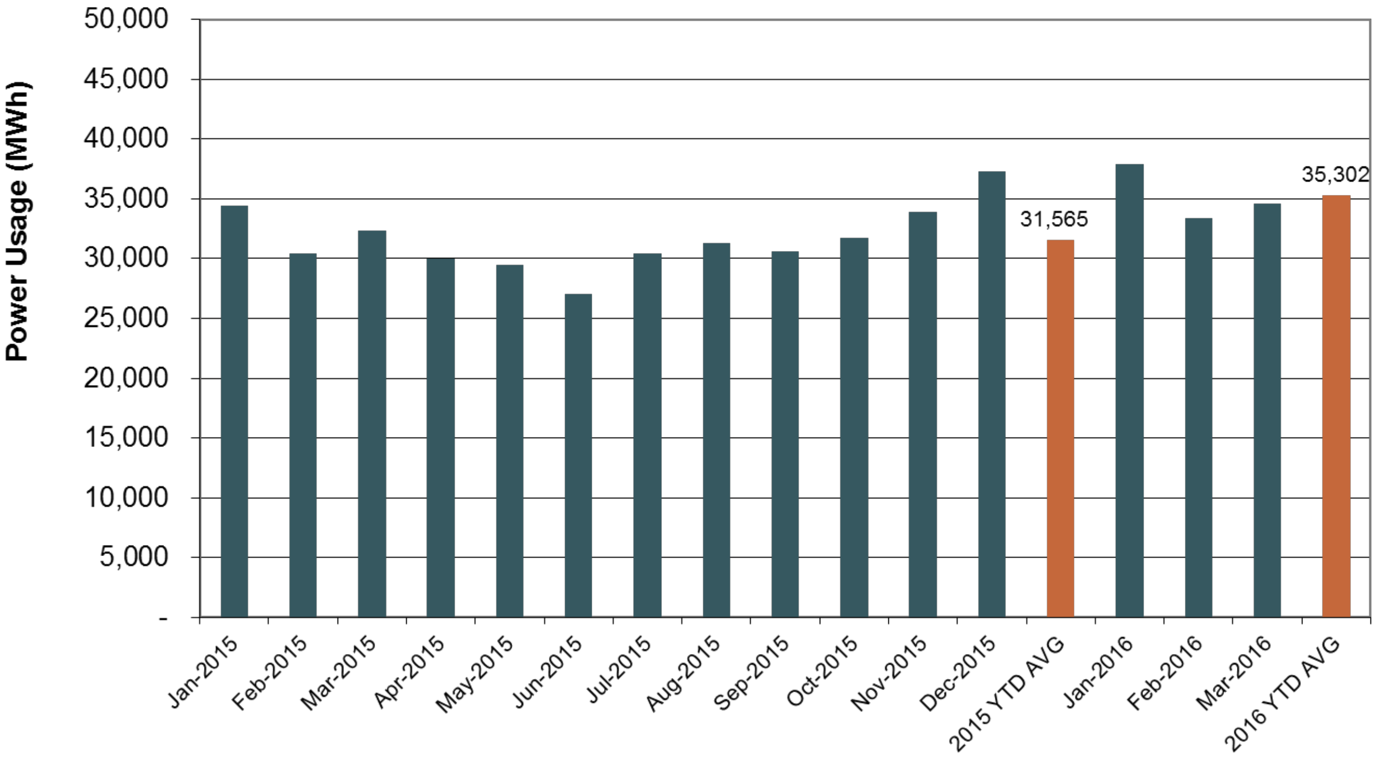
- Blowdown recycle into the produced water treatment trains and boiler feed water tank with no adverse impacts up to 50% of total blowdown volumes produced
- Chemical optimization continues to be a focus in water treatment

# Steam generation

## Steam generation via 17 OTSGs

- Original design capacity of 48,400 $m^3$/d CWE dry steam
- Re-rated design capacity of 50,800 $m^3$/d CWE dry steam
- Have achieved rates in excess of 50,000 $m^3$/d CWE dry steam
- Typical operation: 82% quality
  - Worked with vendor to re-rate CDE OTSGs
  - Rigorous monitoring program including continuous boiler performance monitoring
  - 2 x OTSGs were operated on 100% blowdown as feed water and 75% steam quality for 2 months with slightly higher scaling rate in the radiant section observed

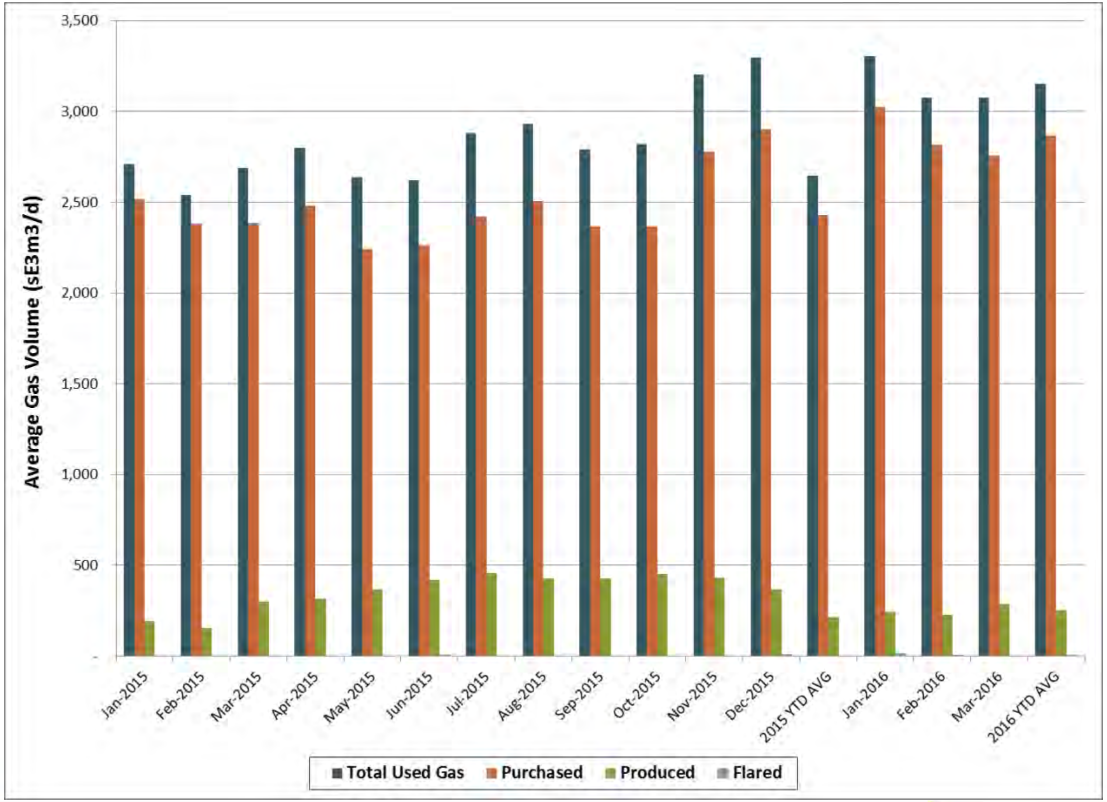
# Power usage




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

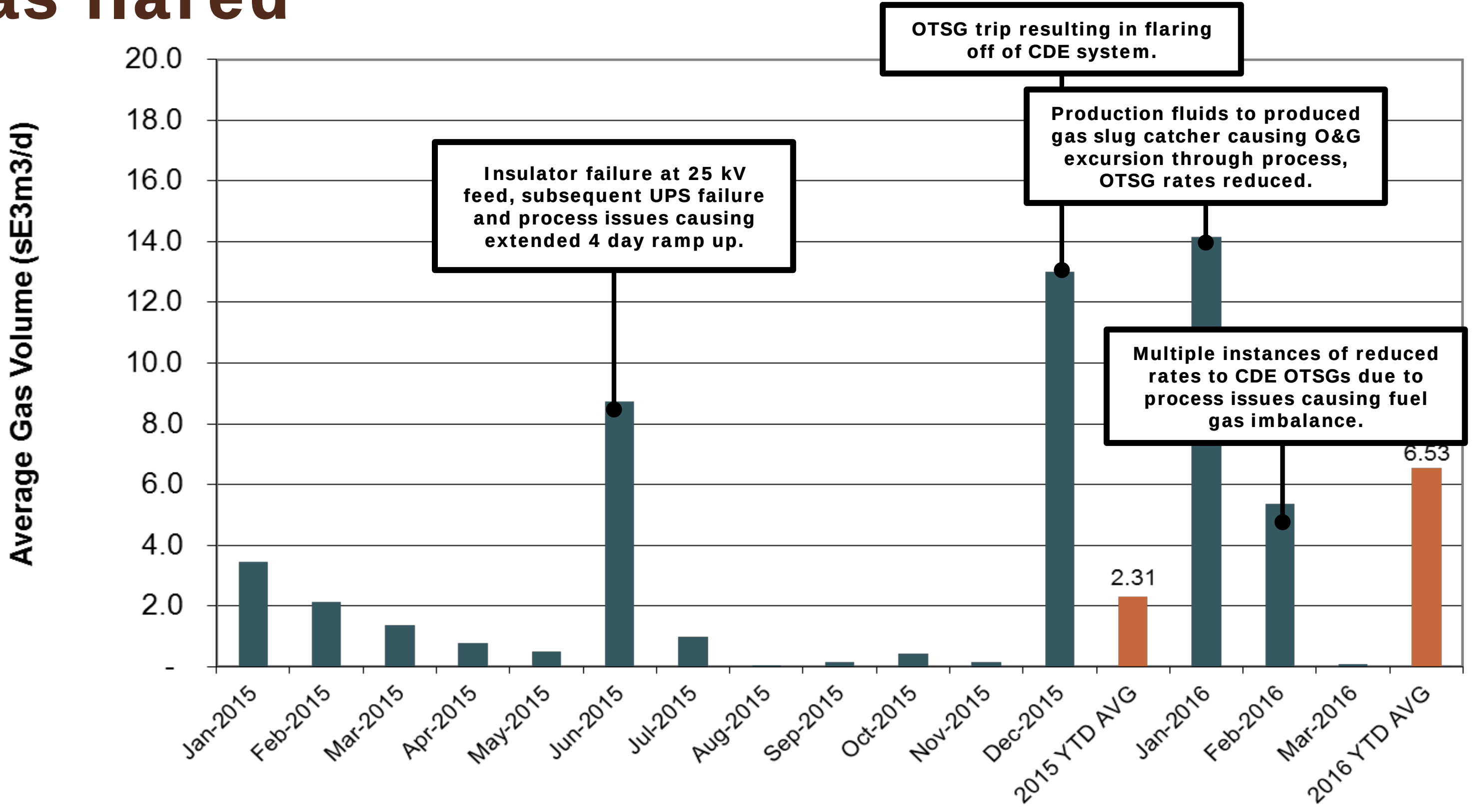
cenovus ENERGY

# Gas usage



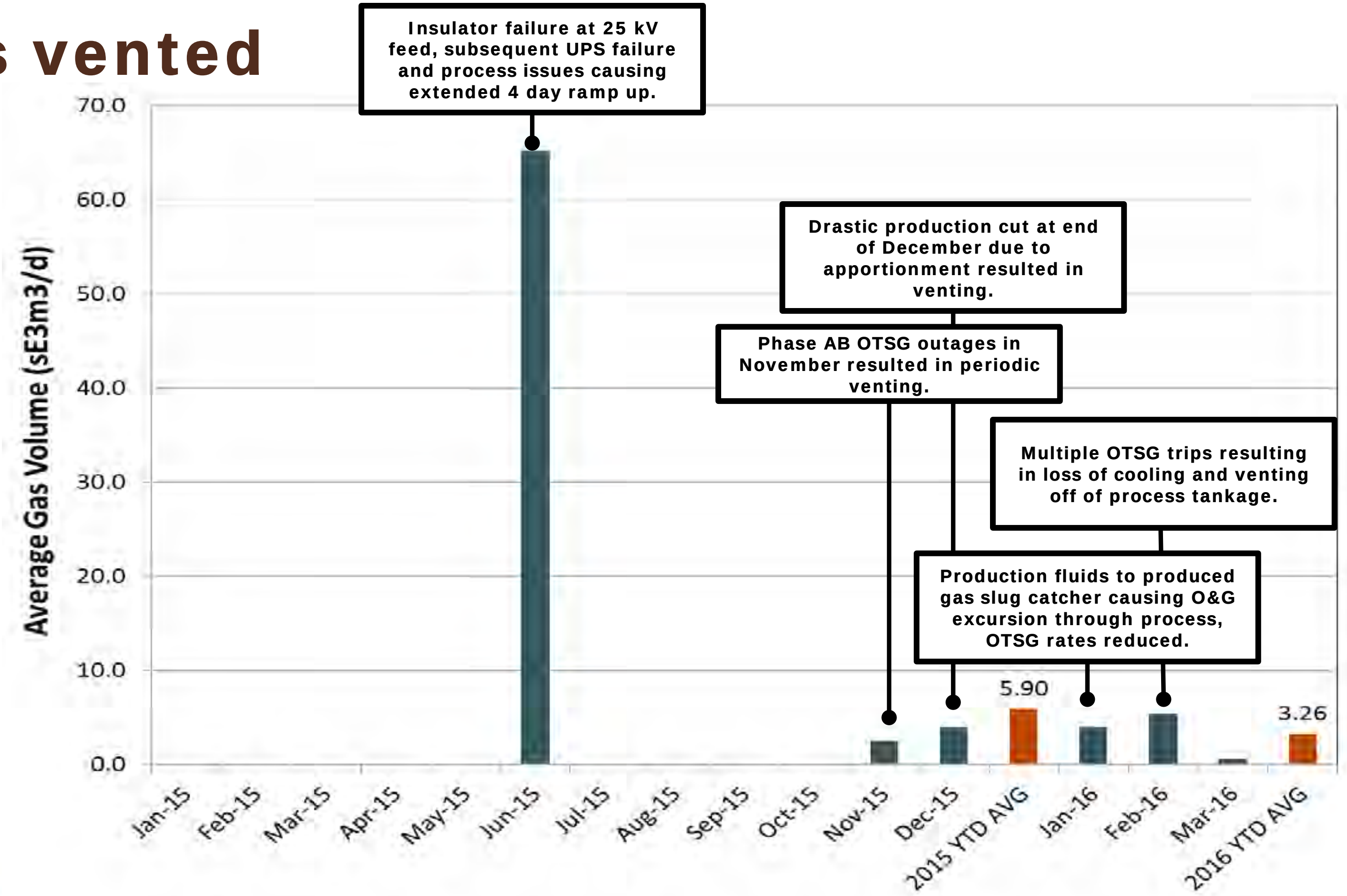
Average Gas Volume (sE3m3/d)
3,500
3,000
2,500
2,000
1,500
1,000
500
-
Jan-2015
Feb-2015
Mar-2015
Apr-2015
May-2015
Jun-2015
Jul-2015
Aug-2015
Sep-2015
Oct-2015
Nov-2015
Dec-2015
2015 YTD AVG
Jan-2016
Feb-2016
Mar-2016
2016 YTD AVG
Total Used Gas
Purchased
Produced
Flared

# Gas flared



Average Gas Volume (sE3m3/d)
20.0
18.0
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
-
Jan-2015
Feb-2015
Mar-2015
Apr-2015
May-2015
Jun-2015
Jul-2015
Aug-2015
Sep-2015
Oct-2015
Nov-2015
Dec-2015
2015 YTD AVG
Jan-2016
Feb-2016
Mar-2016
2016 YTD AVG
2.31
6.53
Insulator failure at 25 kV feed, subsequent UPS failure and process issues causing extended 4 day ramp up.
OTSG trip resulting in flaring off of CDE system.
Production fluids to produced gas slug catcher causing O&G excursion through process, OTSG rates reduced.
Multiple instances of reduced rates to CDE OTSGs due to process issues causing fuel gas imbalance.

# Gas vented



Insulator failure at 25 kV feed, subsequent UPS failure and process issues causing extended 4 day ramp up.
Drastic production cut at end of December due to apportionment resulted in venting.
Phase AB OTSG outages in November resulted in periodic venting.
Multiple OTSG trips resulting in loss of cooling and venting off of process tankage.
Production fluids to produced gas slug catcher causing O&G excursion through process, OTSG rates reduced.
Average Gas Volume (sE3m3/d)
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
5.90
3.26
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
2015 YTD AVG
Jan-16
Feb-16
Mar-16
2016 YTD AVG

# Greenhouse gas emissions

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

- Q1 2016 total direct emissions by gas type
  - $CO_2$ – 548,976 tonnes $CO_2e$
  - $CH_4$ – 5,907 tonnes $CO_2e$
  - $N_2O$ – 905 tonnes $CO_2e$

- 2015 total direct emissions by gas type
  - $CO_2$ –1,968,254 tonnes $CO_2e$
  - $CH_4$ – 29,843 tonnes $CO_2e$
  - $N_2O$ – 3,164 tonnes $CO_2e$

*Note – Only the 2015 GHGs have been verified and submitted, the 2016 numbers are preliminary.

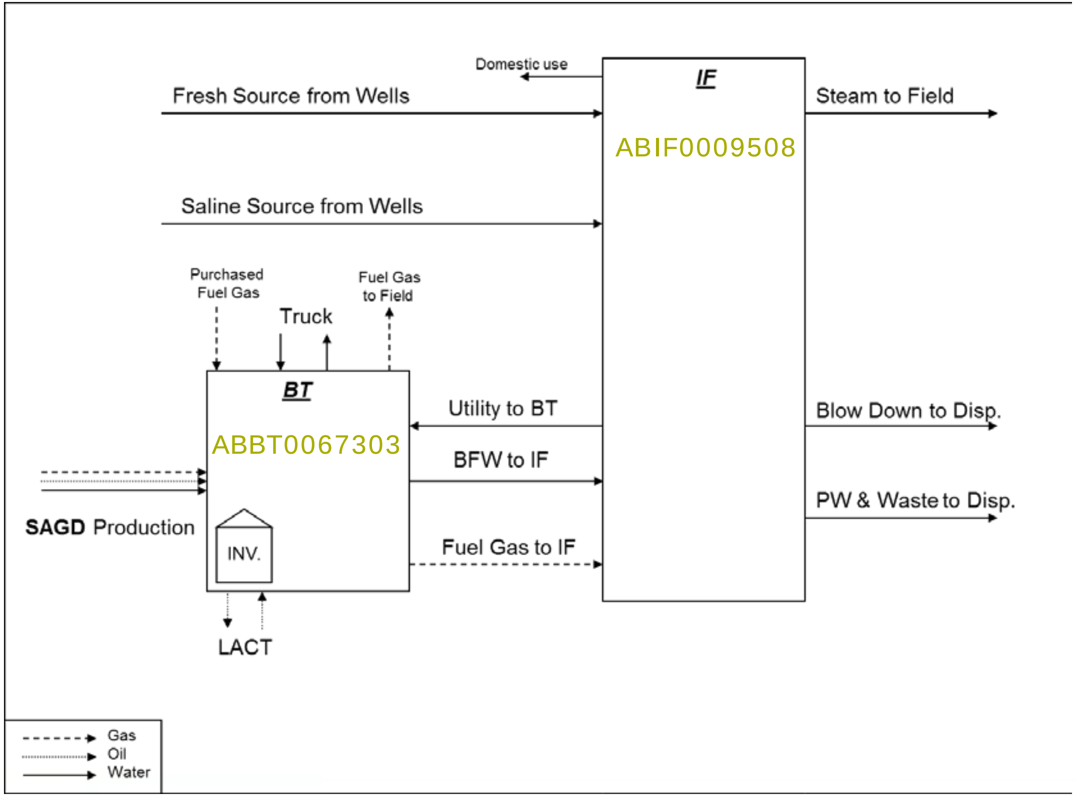
# Subsection 3.1.2 – 3)
# Measurement and reporting (MARP)

Mandy Chen

Sr. Process Engineer

cenovus ENERGY

# Simplified MARP schematic



# Production Volumes

## Bitumen Production

- Estimate by well tests (2 phase test separators with BSW%)
    - 8-12 wells per separator
    - ~10 hour cycles + purges
    - 1 hour of testing for every 40 hours of well operations, or about 2 x 10 hour tests per month

## Gas Production

- The produced gas is "measured by difference" based on the gas balance.

- This "measured by difference" monthly volume is used to calculate the facility gas-to-oil ratio (GOR) and then be used to estimate gas production from each well since October 2015.

# Injection Volumes

## Steam Injection

- Steam to wells measured by nozzles or V-cone
- Prorate well steam to plant steam metered by flow nozzle off steam separators

## Gas Co-Injection

- Co-injected gas monitored and reported on a well basis

# Water Balance

- Two RD1 disposal water meters were found to be inaccurate due to improper meter configurations in the Distributed Control System (DCS).

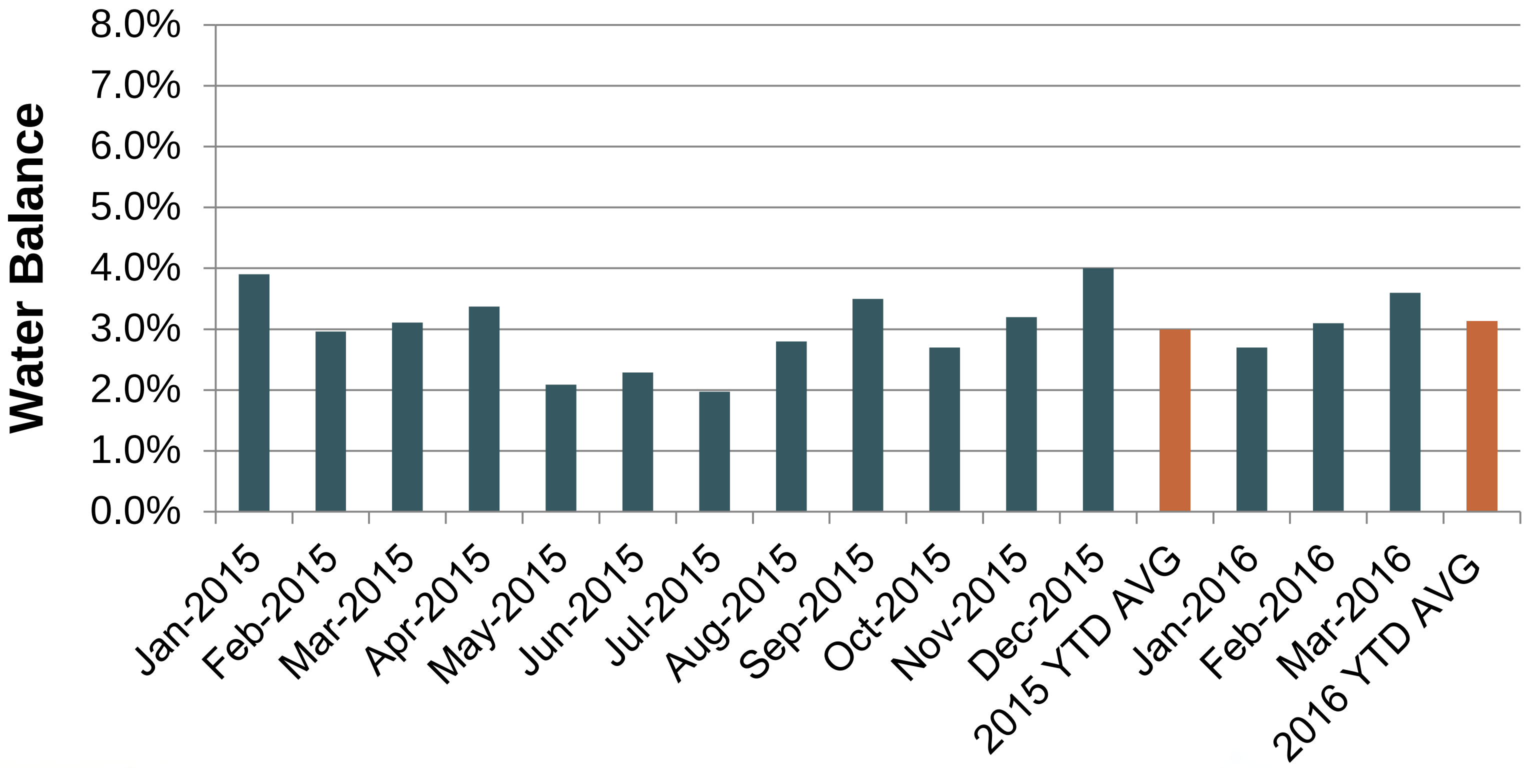
- This measurement issue was addressed after the problem was found in December 2014.

- Overall water balance had been improved in 2015. The average monthly water imbalance is 2.99%.

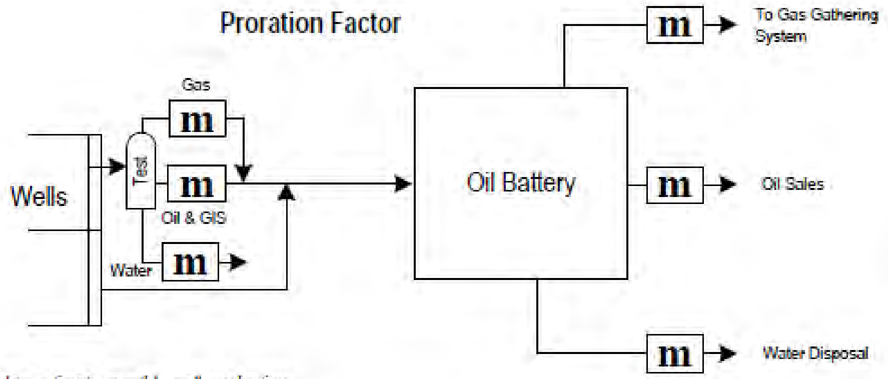
Note:

- Correction factors were applied to disposal volumes reported by the MARP meters. A letter of self disclosure for the water imbalance was submitted to AER in February 2015.

# Water Balance



# Proration factors




Test rates are used to estimate monthly well production volumes of each product.

Estimated monthly battery production of each product is determined by totalling all wells' estimated production.

Actual monthly battery production volume of each product is determined by measured delivery and inventory changes.

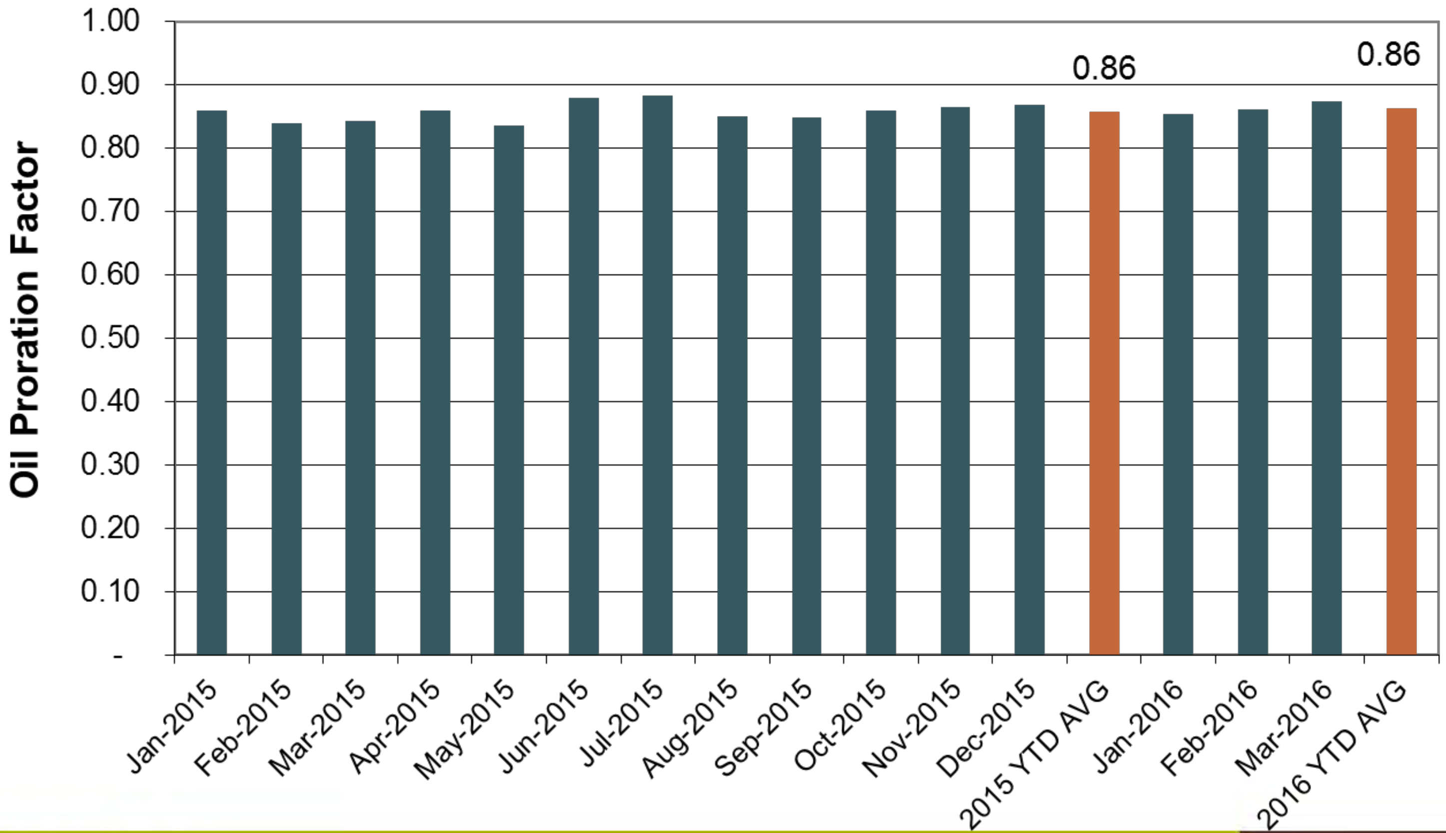
For each product,
Proration Factor = Actual Battery Production / Estimated Battery Production

For each product for each well,
Actual Monthly Well Production = Estimated Monthly Well Production x Proration Factor

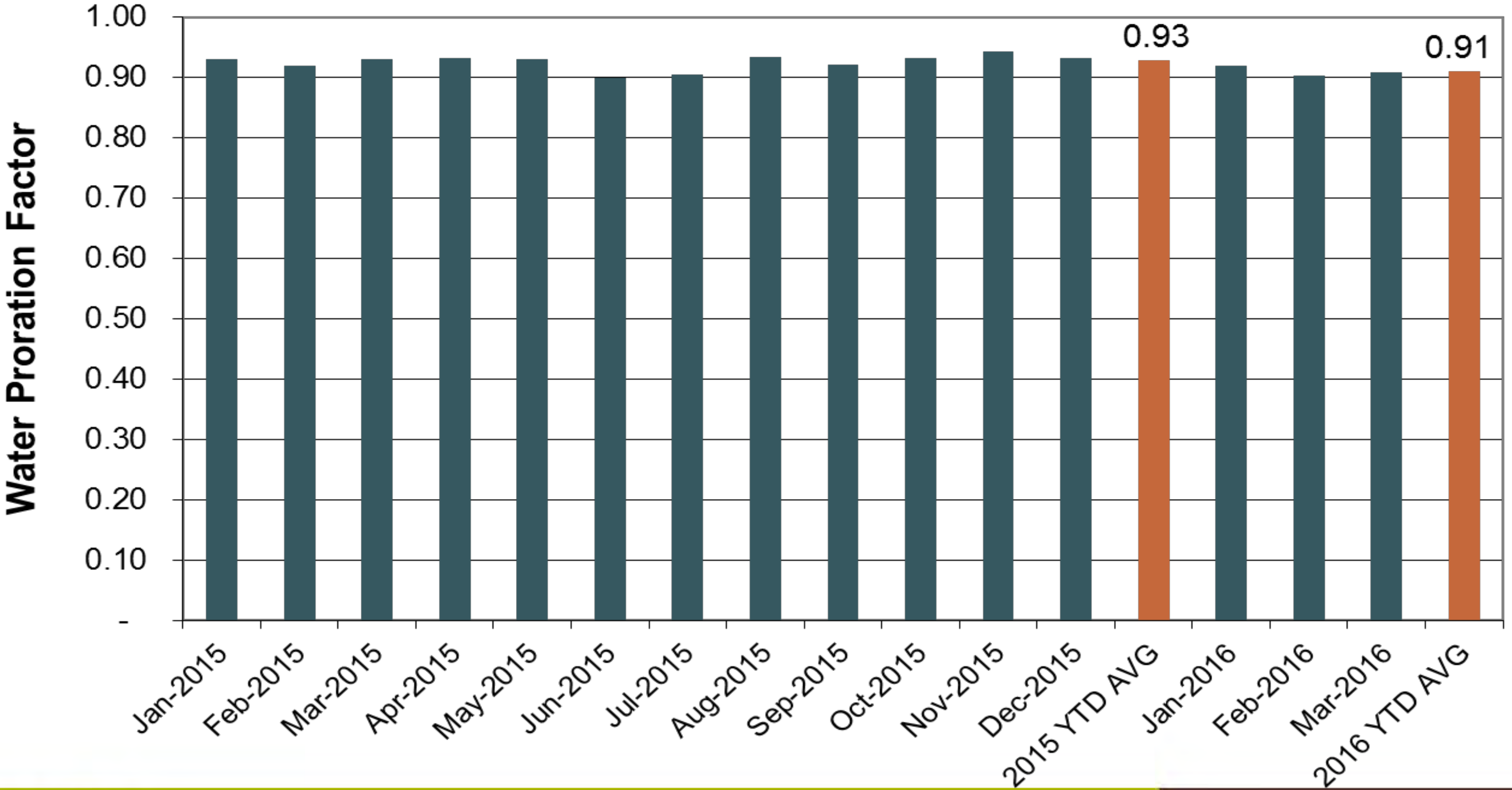
**m** = Measurement Point

*Courtesy of AER*

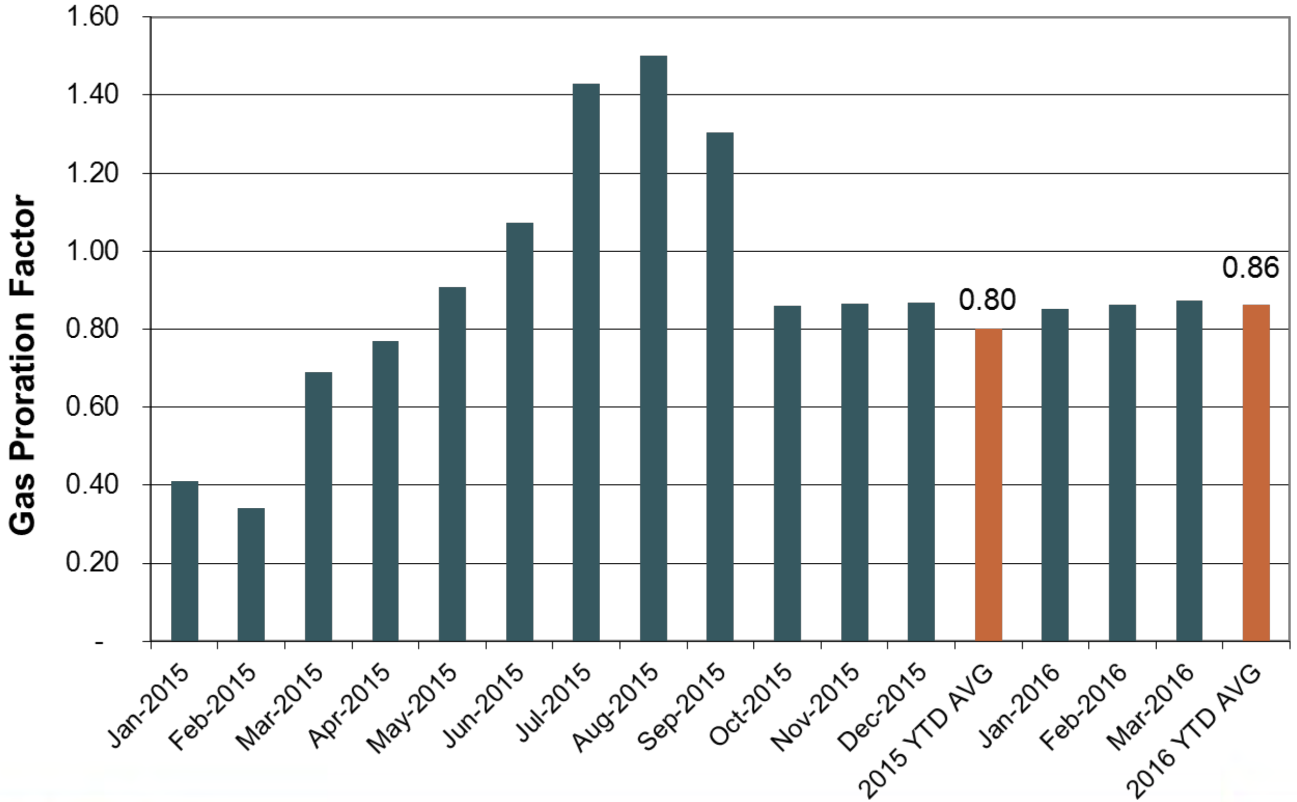
# Oil Proration Factor



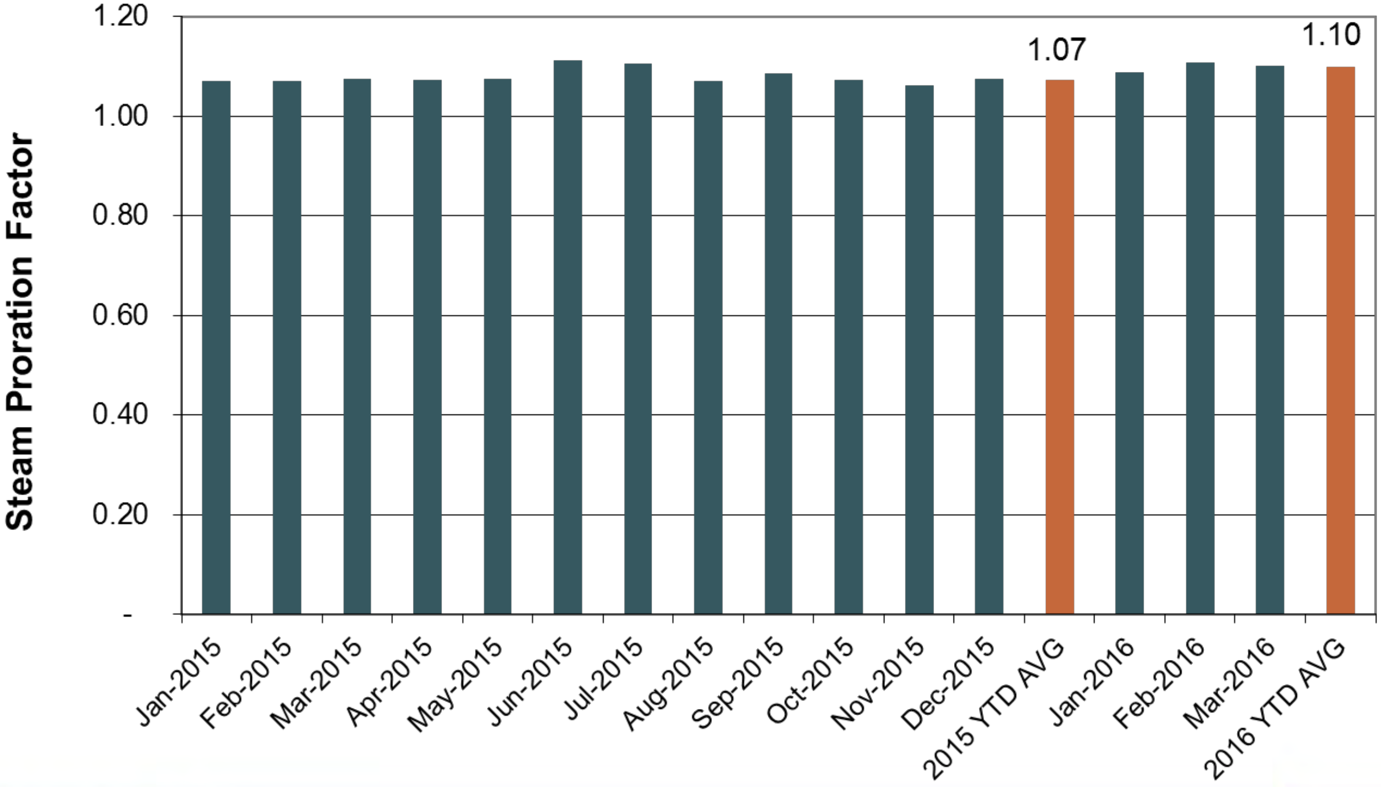
# Water Proration Factor



# Gas Proration Factor



# Steam Proration Factor



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

Bailey Gould

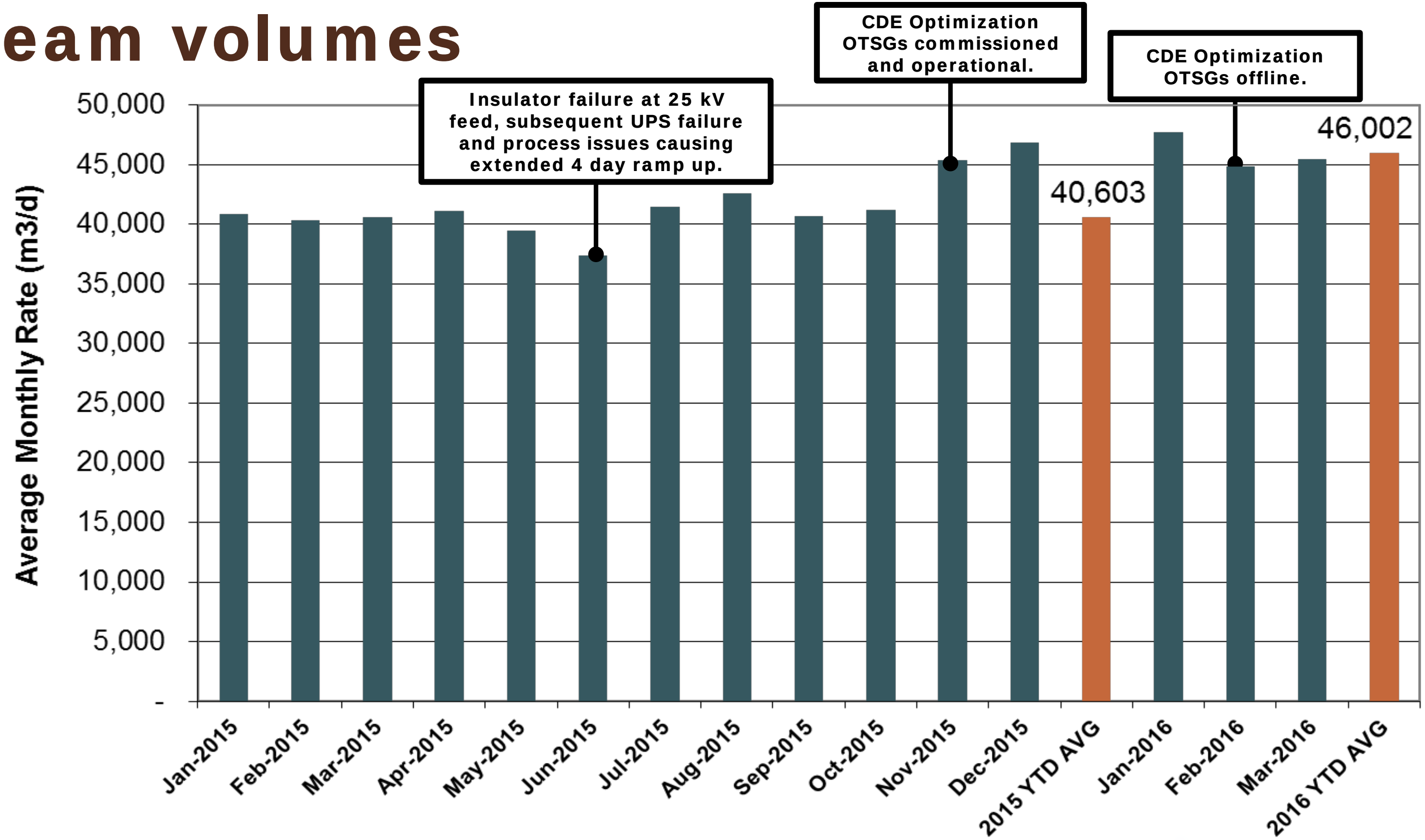
Process Engineer

Kayley Moule

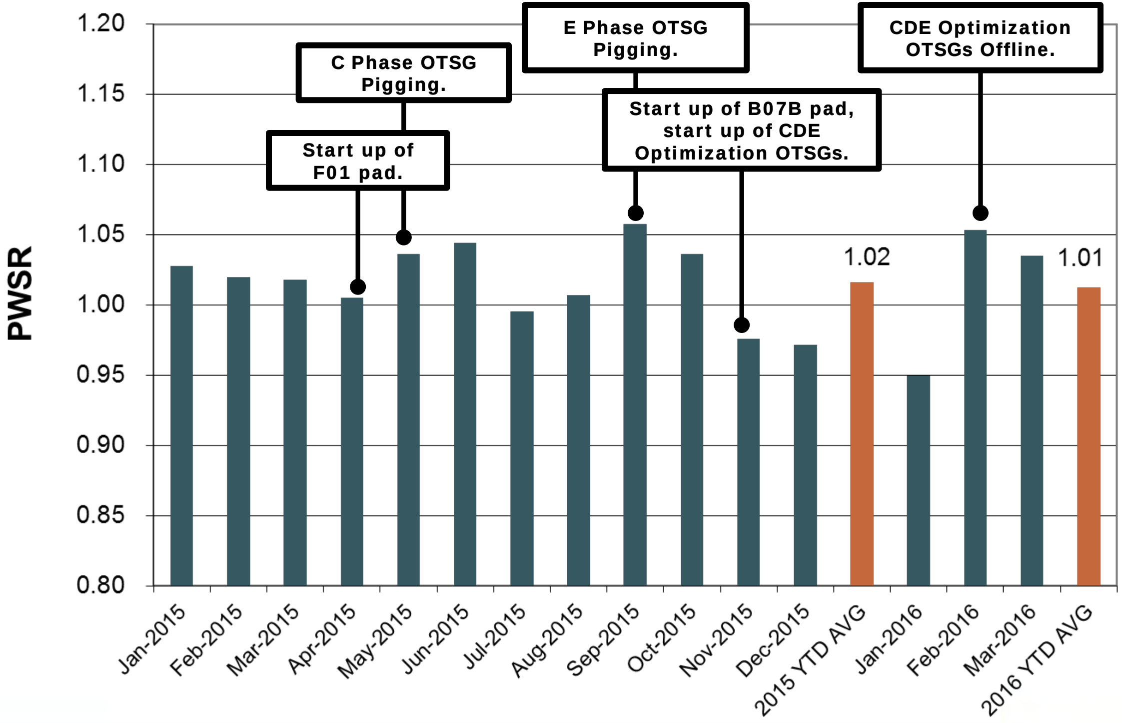
Production Engineer

cenovus ENERGY

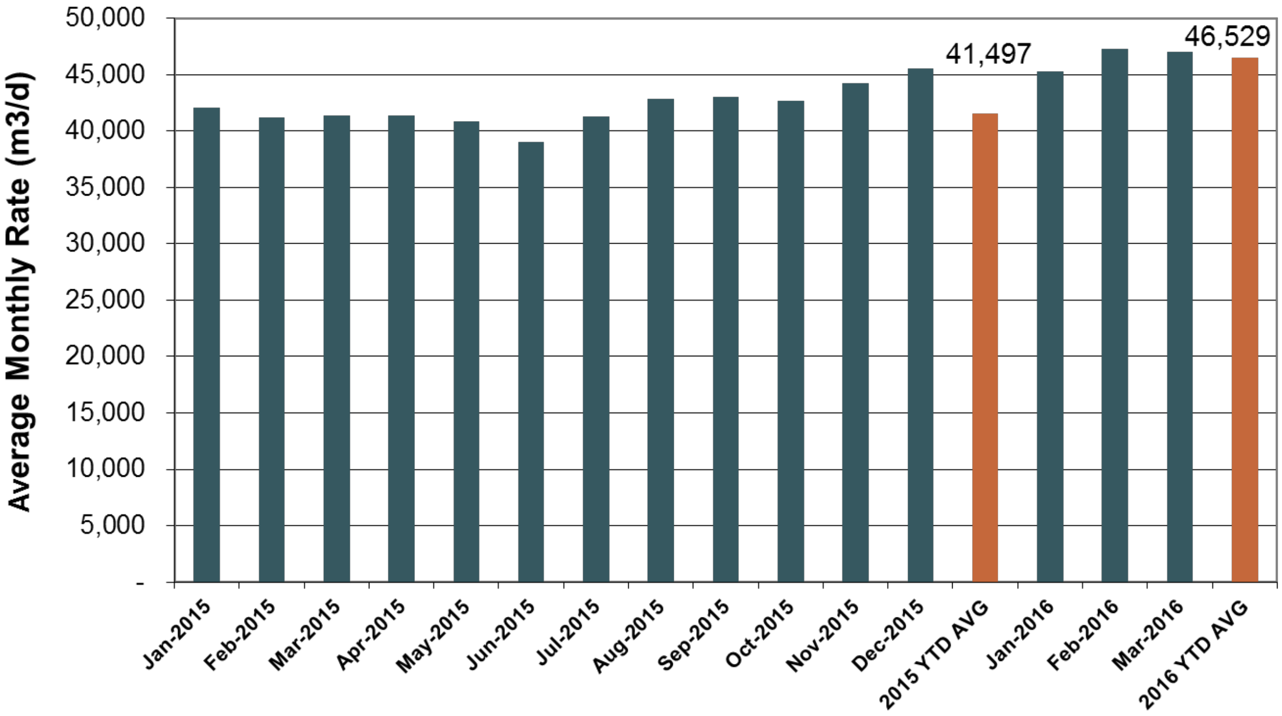
# Steam volumes



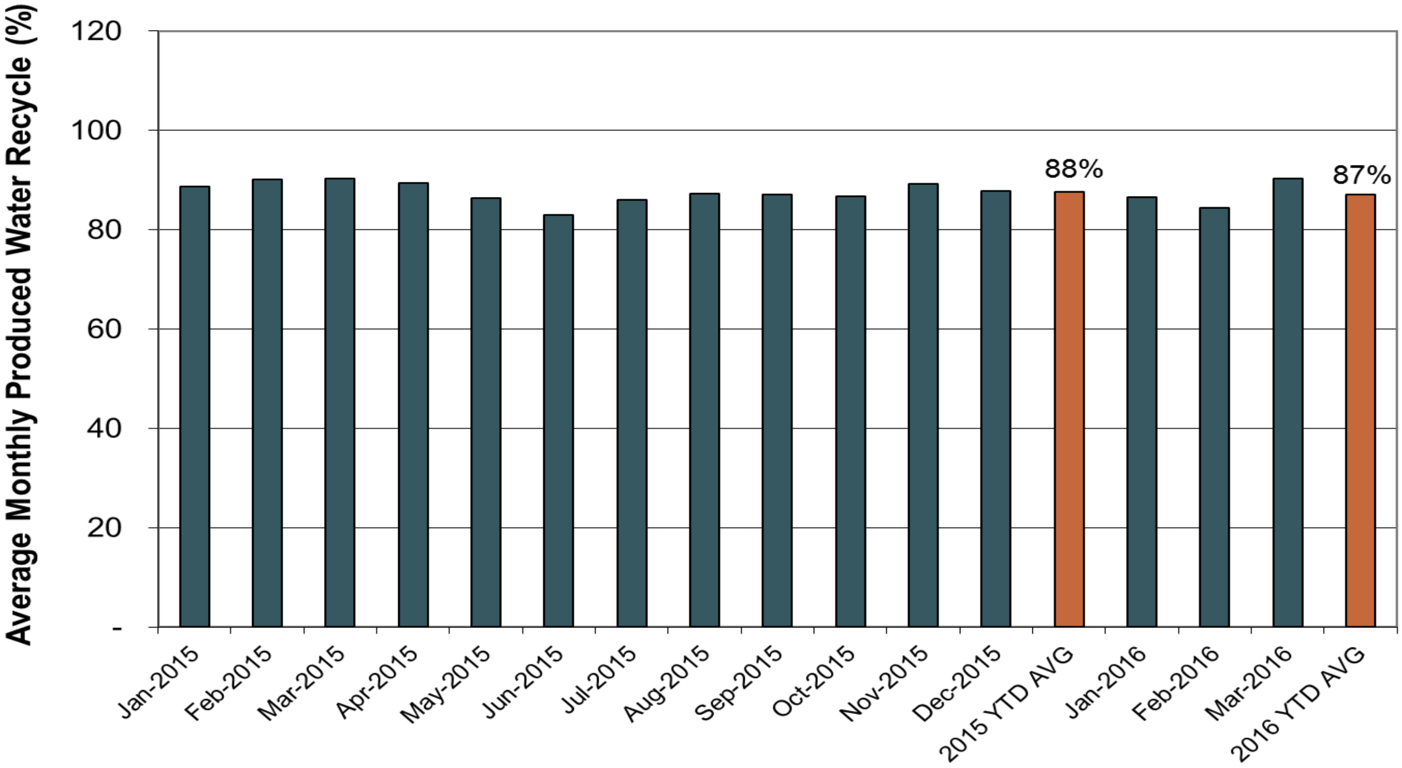
# Produced water to steam ratio



# Produced water volumes



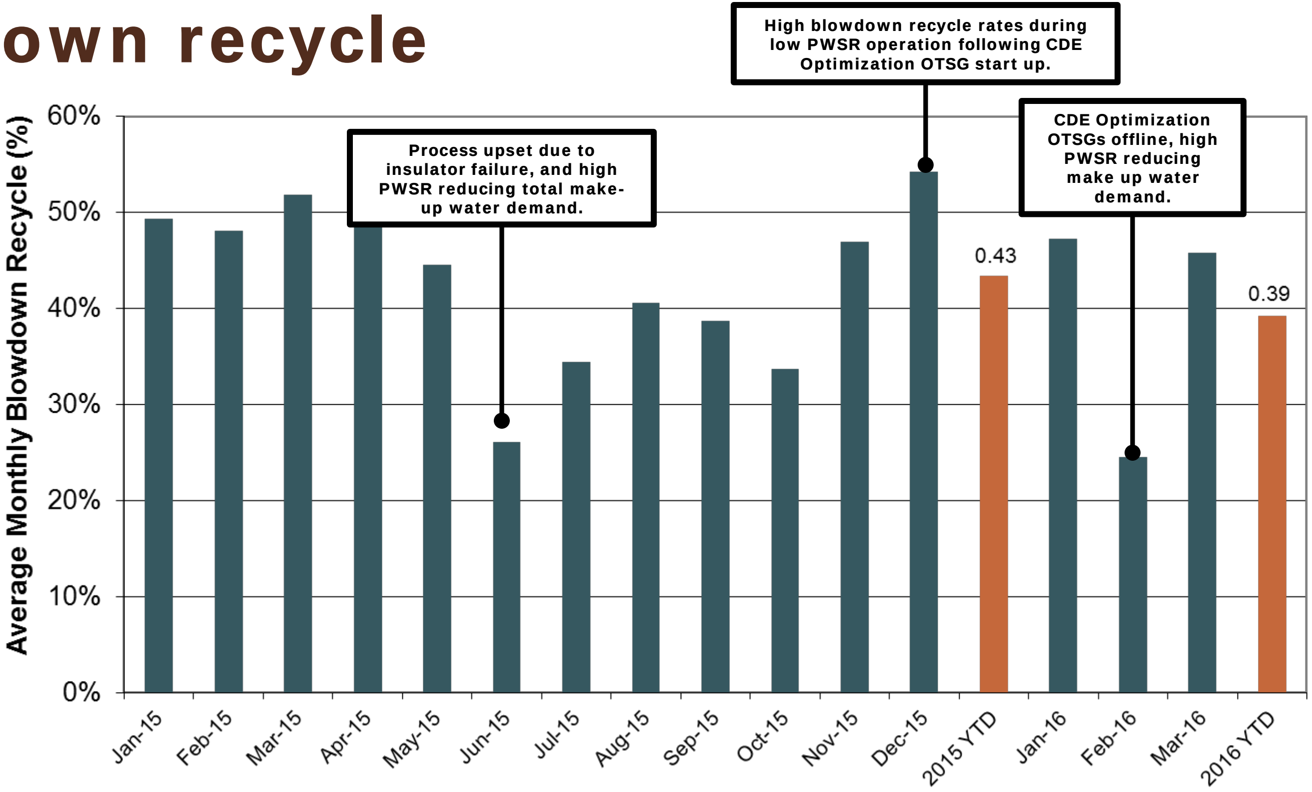
# Water recycle ratio




**Produced-Water Recycle (%) = [(Produced Water In – Disposal Total) / (Produced Water In)] x 100**

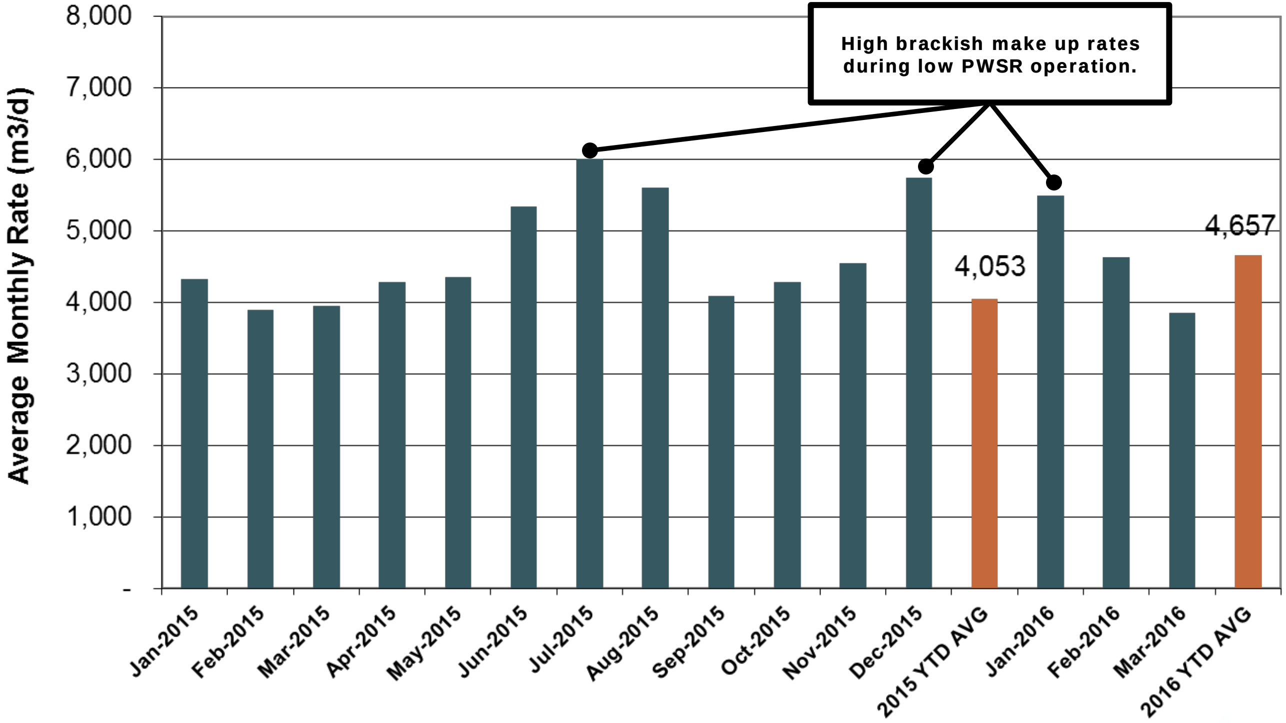
cenovus ENERGY

# Blowdown recycle




**Note:** Blowdown recycle rates vary depending on Produced Water:Steam ratio and make-up water demand, in addition to BFW quality.

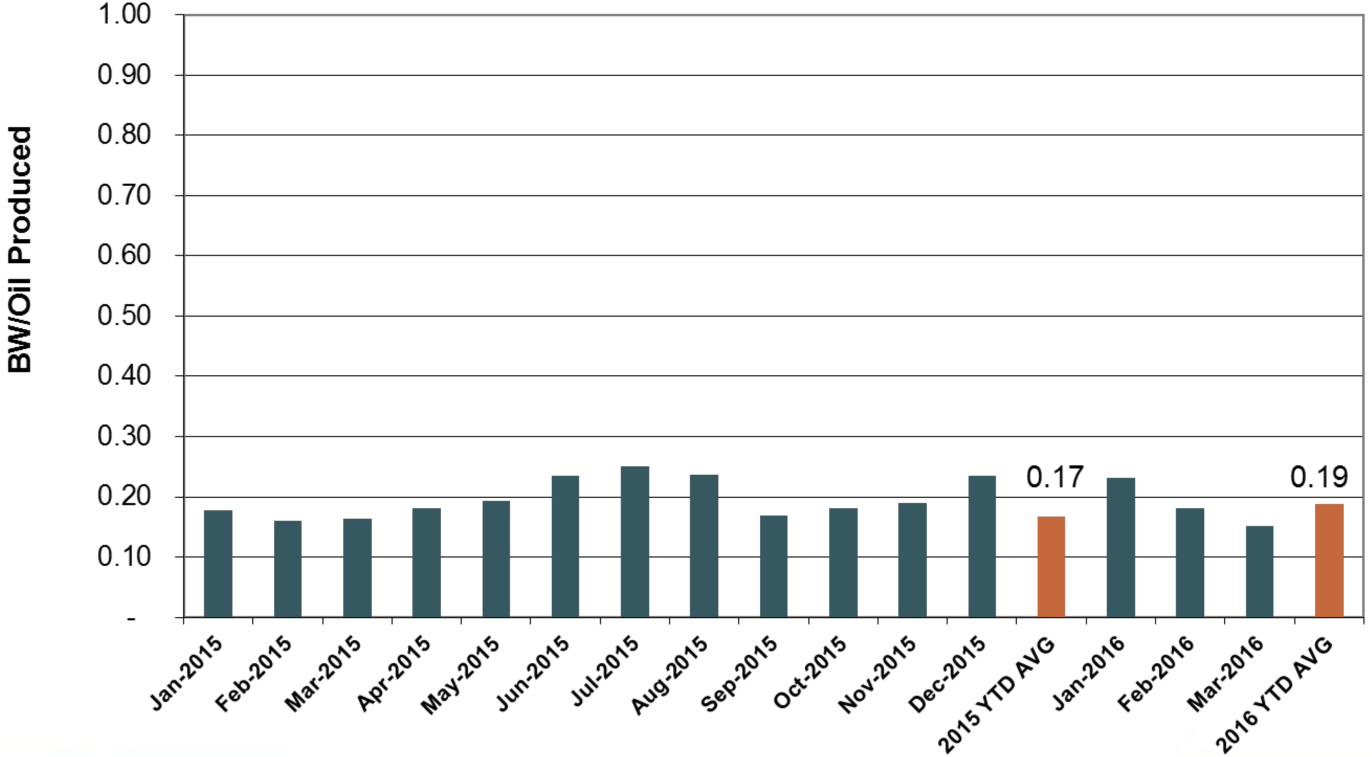
# Brackish water use



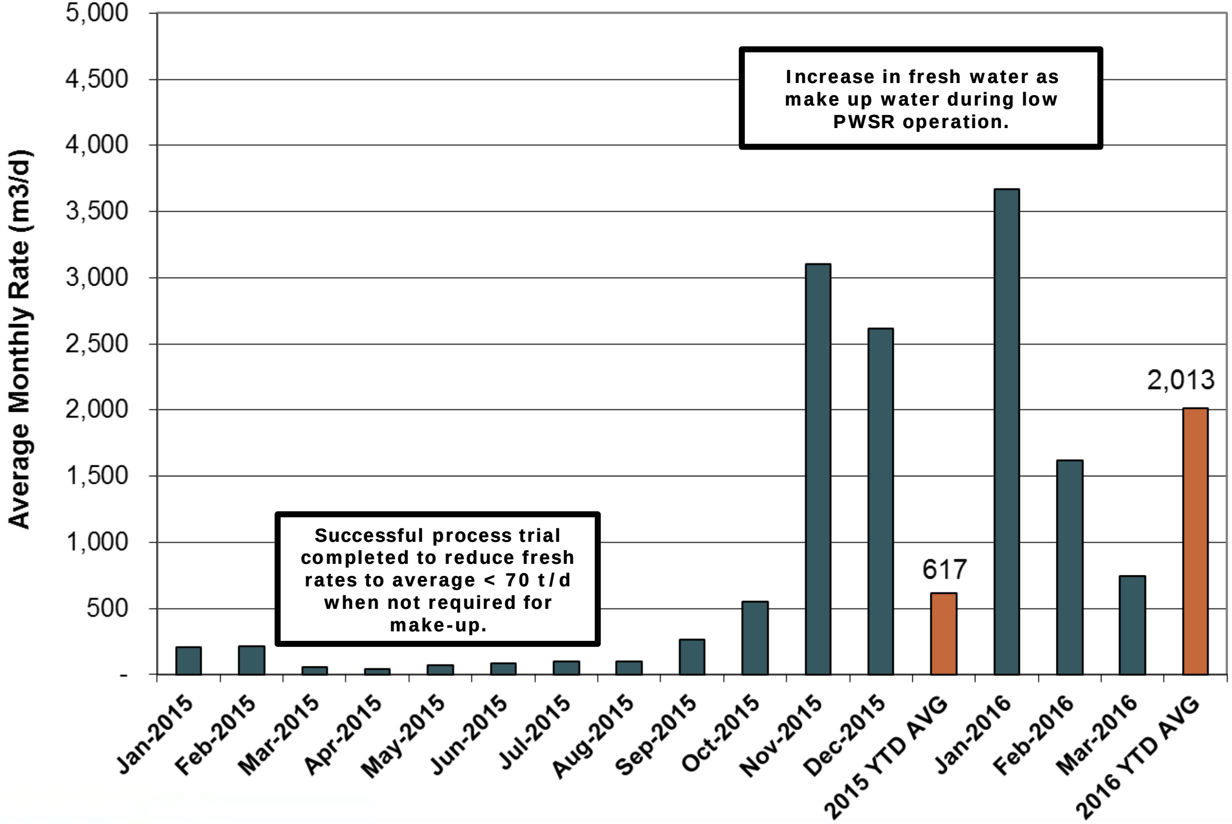

Uses:

- Make-up water for steam generation
- Produced water and produced emulsion cooling in Phase ABCDE
- Softened water used for slurry make-up, seal flushes etc.

# Brackish water intensity



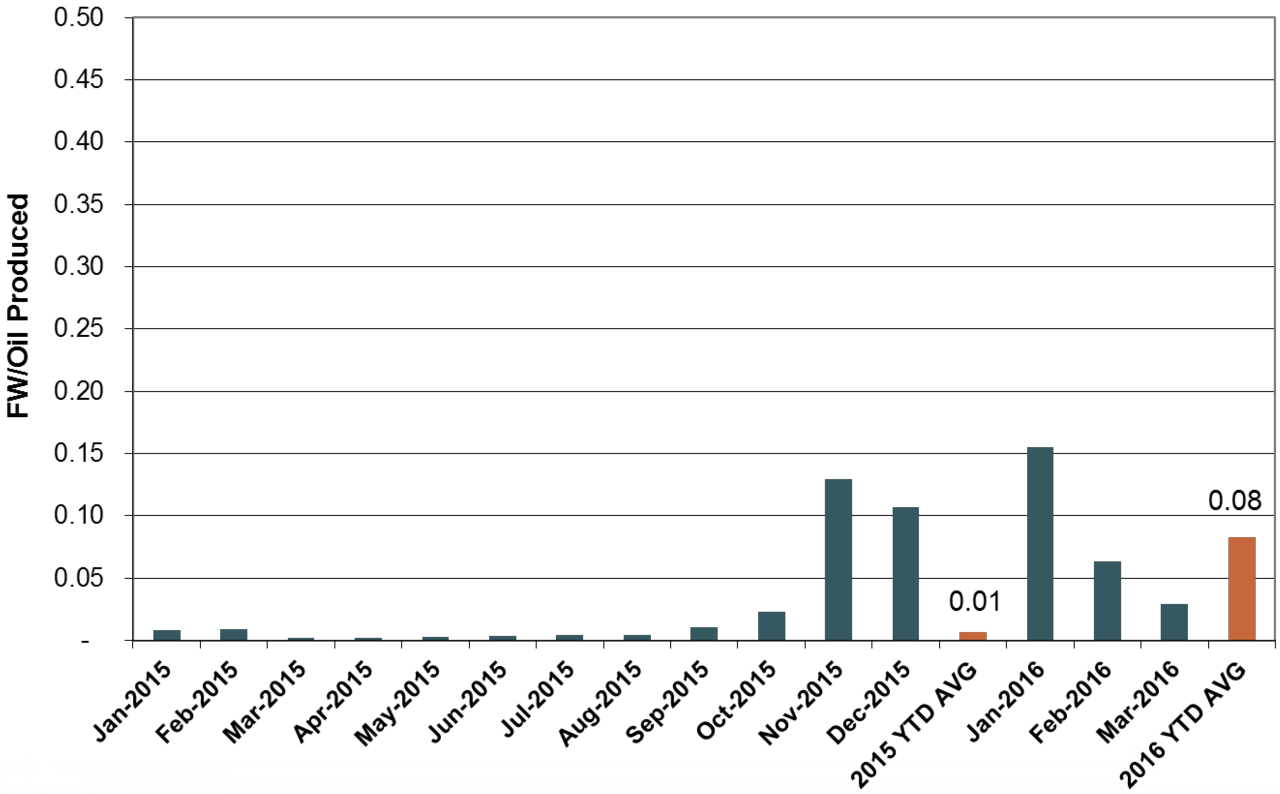
# Fresh water use



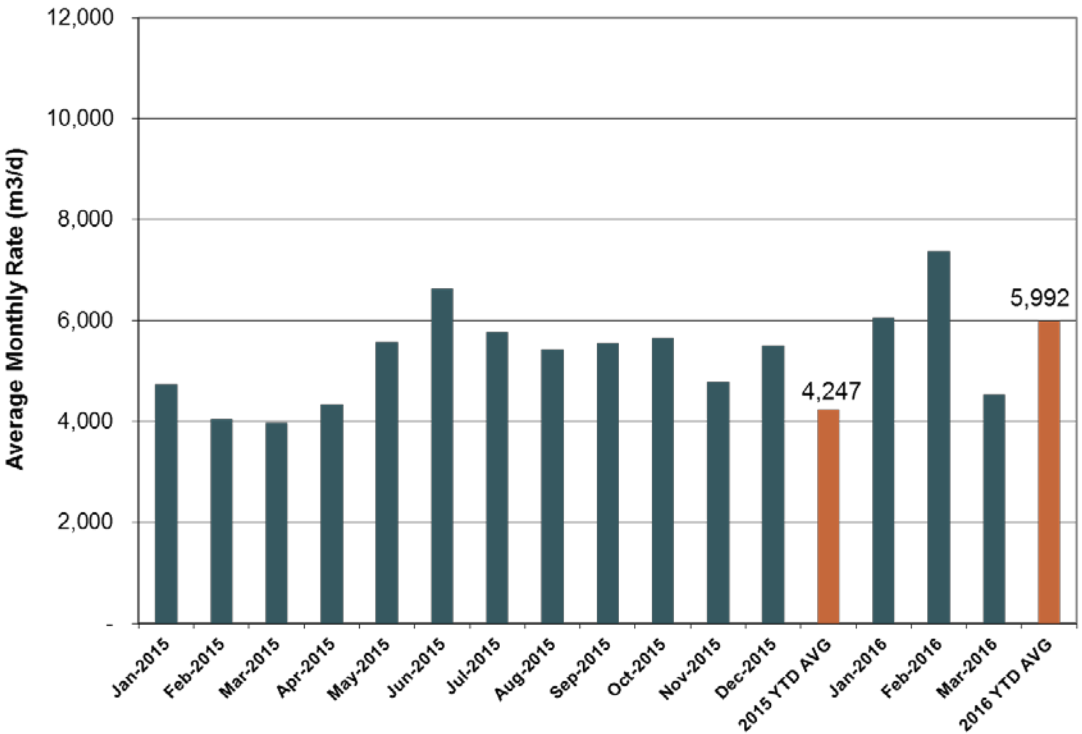

Uses:

- Was used for make-up water for steam generation during commissioning and start up of CDE Optimization OTSGs.
- Includes camp and domestic use, utilities, etc.  All attempts are made to minimize fresh water usage when not required as make-up water.

# Fresh water intensity

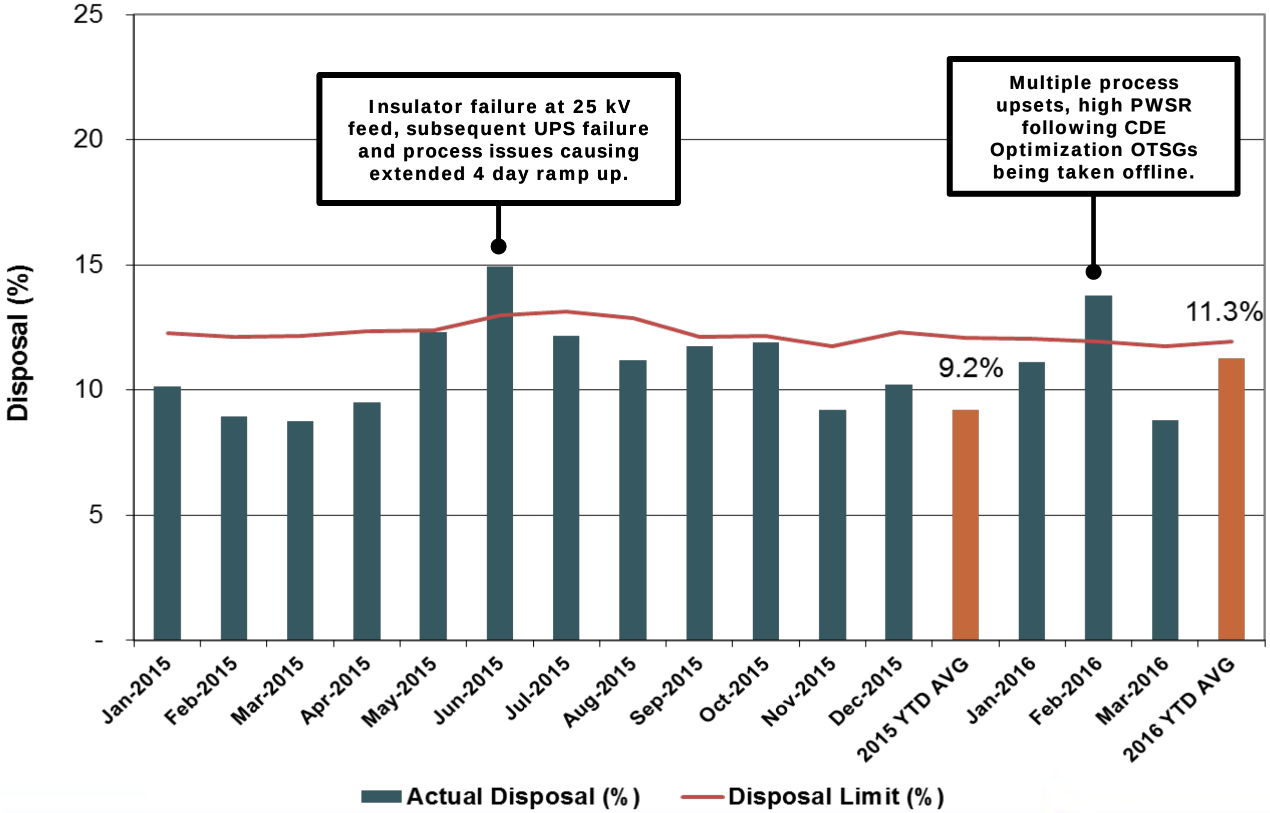


# Total disposal volumes (PW, RW, BD)

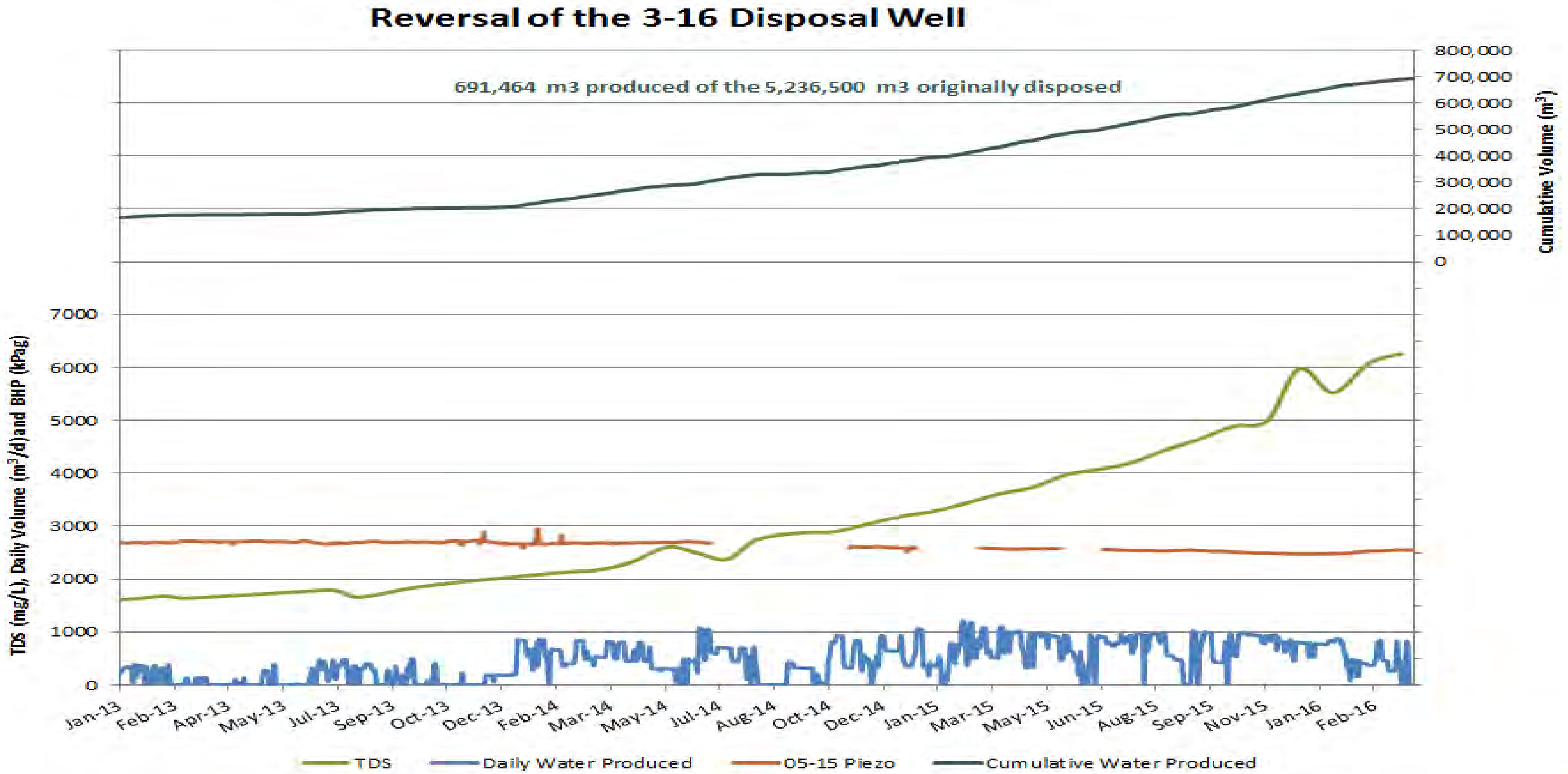



Notes: Operating philosophy is to minimize disposal volumes at all times and maximize produced water re-use. Specifically, blowdown recycle, regeneration optimization, and minimizing brackish make-up requirements have been areas of focus to reduce disposal.

# Directive 081 disposal limit



# 3-16 well reversal



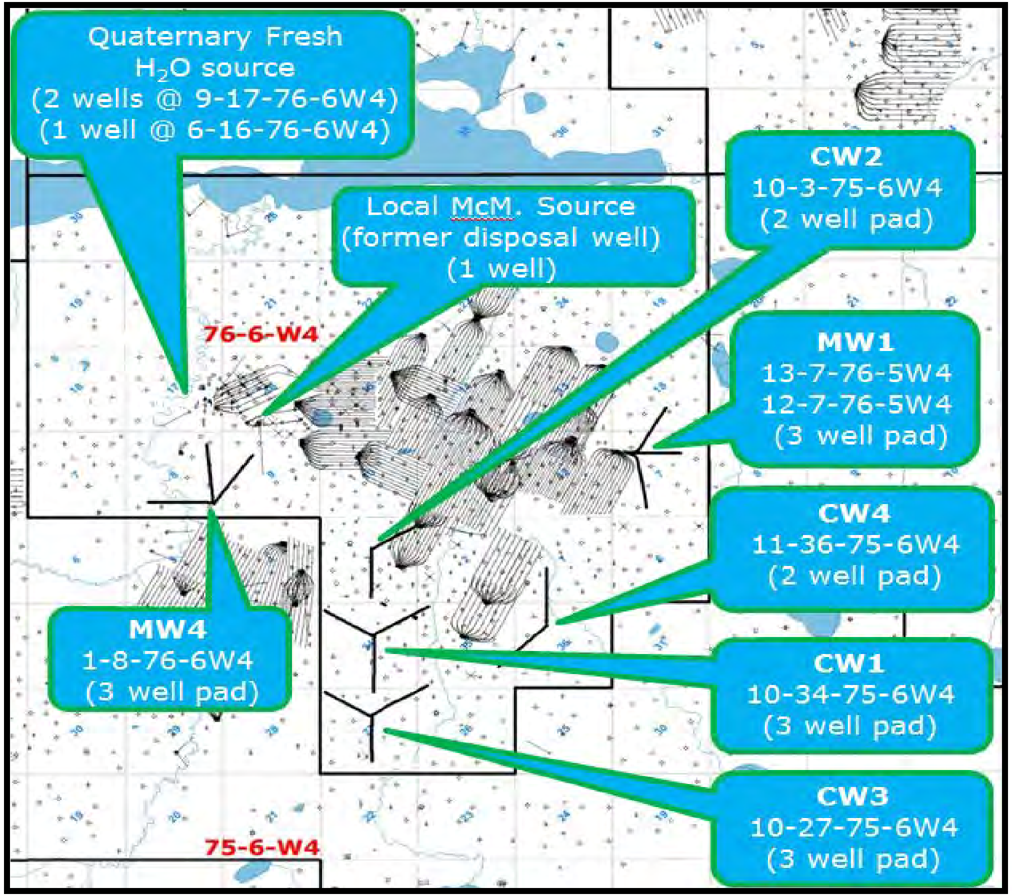
# Fresh and brackish sources

## 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
- 1 Quaternary well (Empress Formation) at 06-16-076-06W4M with TDL of 20,000 m3 for Feb-Sept 2016

## 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= 5,070 mg/L
- 10-34C 1F1/15-27-075-06W4/00 TDS= 7,780 mg/L
- 10-3A 1F1/16-03-076-06W4/00 TDS= 4,600 mg/L
- 10-3B 1F1/02-03-076-06W4/00 TDS= 5,580 mg/L
- 10-27A 100/04-35-075-06W4/00 TDS= 9,730 mg/L
- 10-27B 100/13-27-075-06W4/00 TDS= 8,900 mg/L
- 10-27C 100/02-27-075-06W4/00 TDS= 11,700 mg/L
- **Disposal reversal well**
- 3-16 1F5/03-16-076-06W4/00 TDS= 6,6200 mg/L
- **2013**
- CW4-A 1F1/01-35-075-06W4 TDS= 13,200 mg/L
- CW4-B 1F1/06-01-076-06W4 TDS= 8,800 mg/L
- **New in 2015 (MW1 and MW4 wells-not used until Phase F startup)**
- MW1-A 1F1/07-18-076-05W4 TDS=16,880mg/L
- MW1-B 1F1/03-07-076-05W4 TDS=16,520mg/L
- MW1-C 1F1/09-07-076-05W4 TDS=16,420mg/L
- MW4-A 1F3/11-09-076-06W4 Not sampled yet-expected TDS=>12,000mg/L
- MW4-B 1F1/04-08-076-06W4 Not sampled yet-expected TDS=>12,000mg/L
- MW4-C 1F1/16-08-076-06W4 Not sampled yet-expected TDS=>12,000mg/L



# Water disposal operations

**Injecting into McMurray water sands at 13-34 since April 2015**

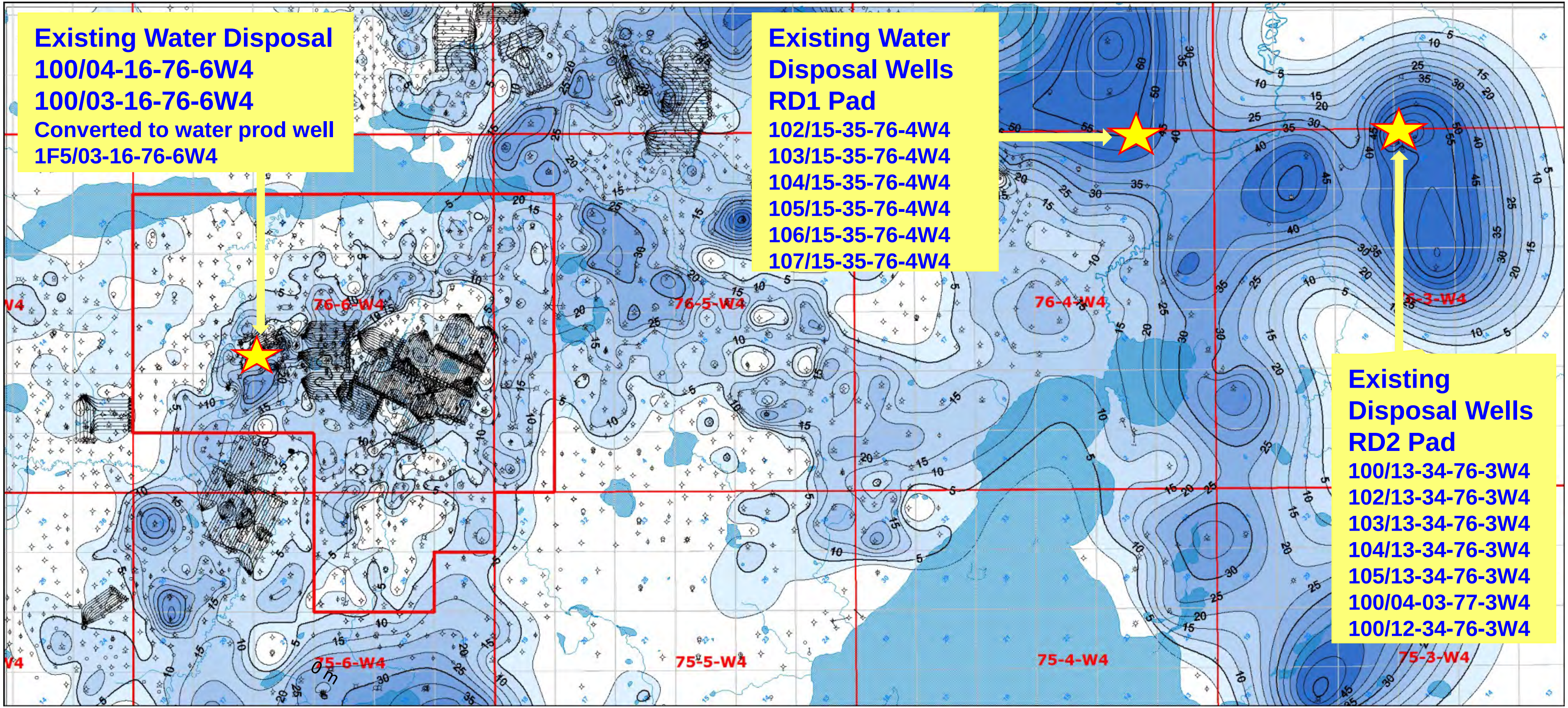
**Approval No. 9712, 10627C and 10627D (Class 1b Disposal)**

**Sixteen disposal wells (all Class 1b)**

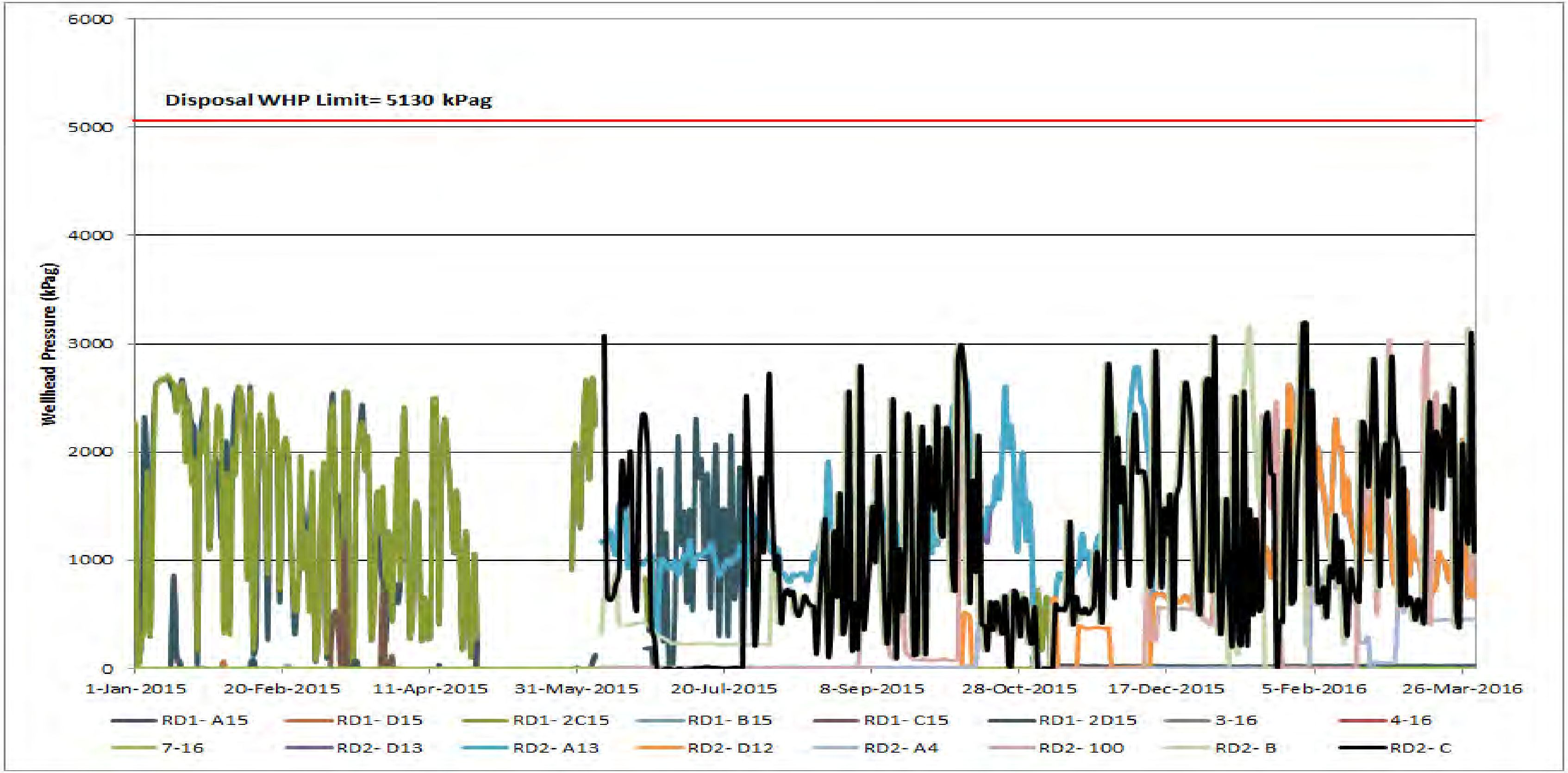
- Three disposal wells located near the facility 3-16-1, 4-16, and 7-16 (now abandoned)
- One well located near the facility (3-16-2) has been converted for disposal reversal
- Six disposal wells located at 15-35 utilized for upset scenarios
- Seven disposal wells in service located at 13-34

**13-34 disposal is main disposal location with 15-35 and local wells used as back-up**

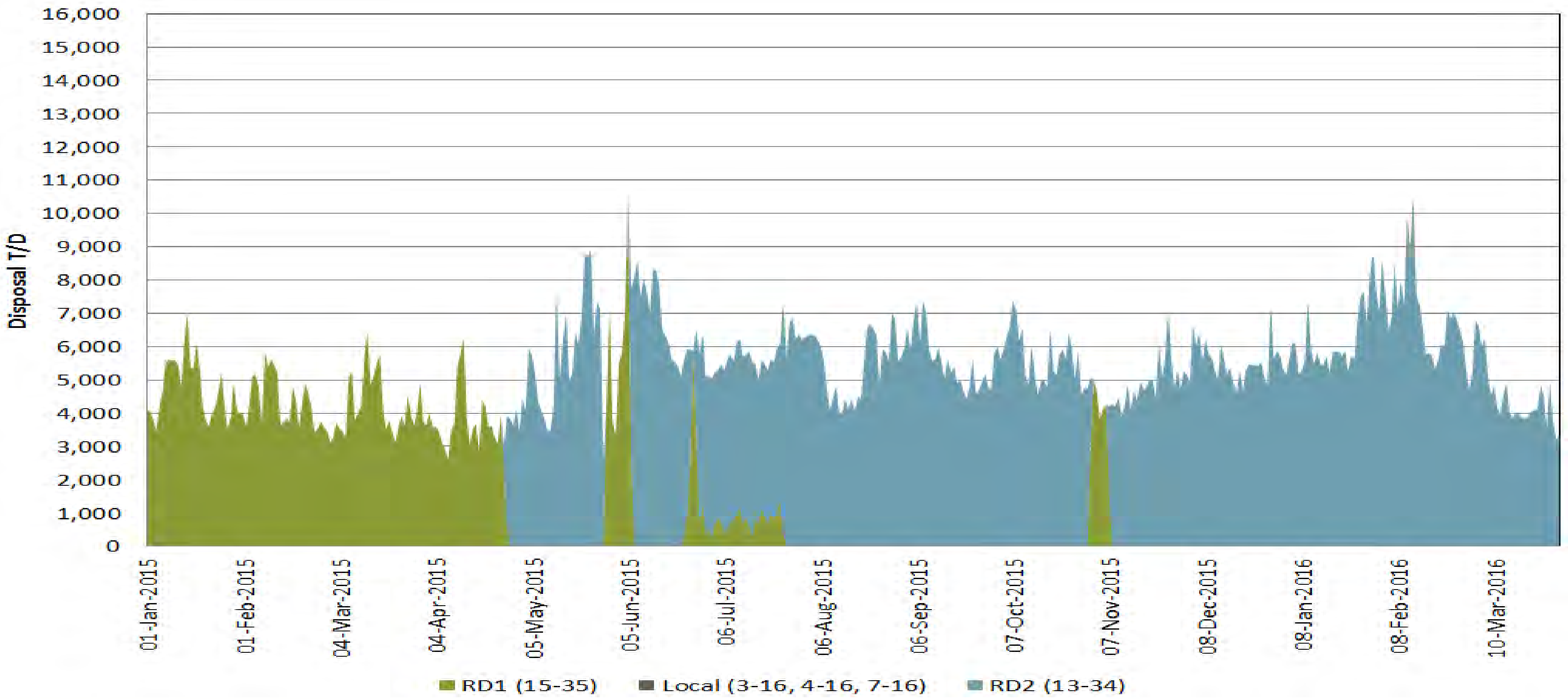
# McMurray water disposal wells



# Disposal well head pressures

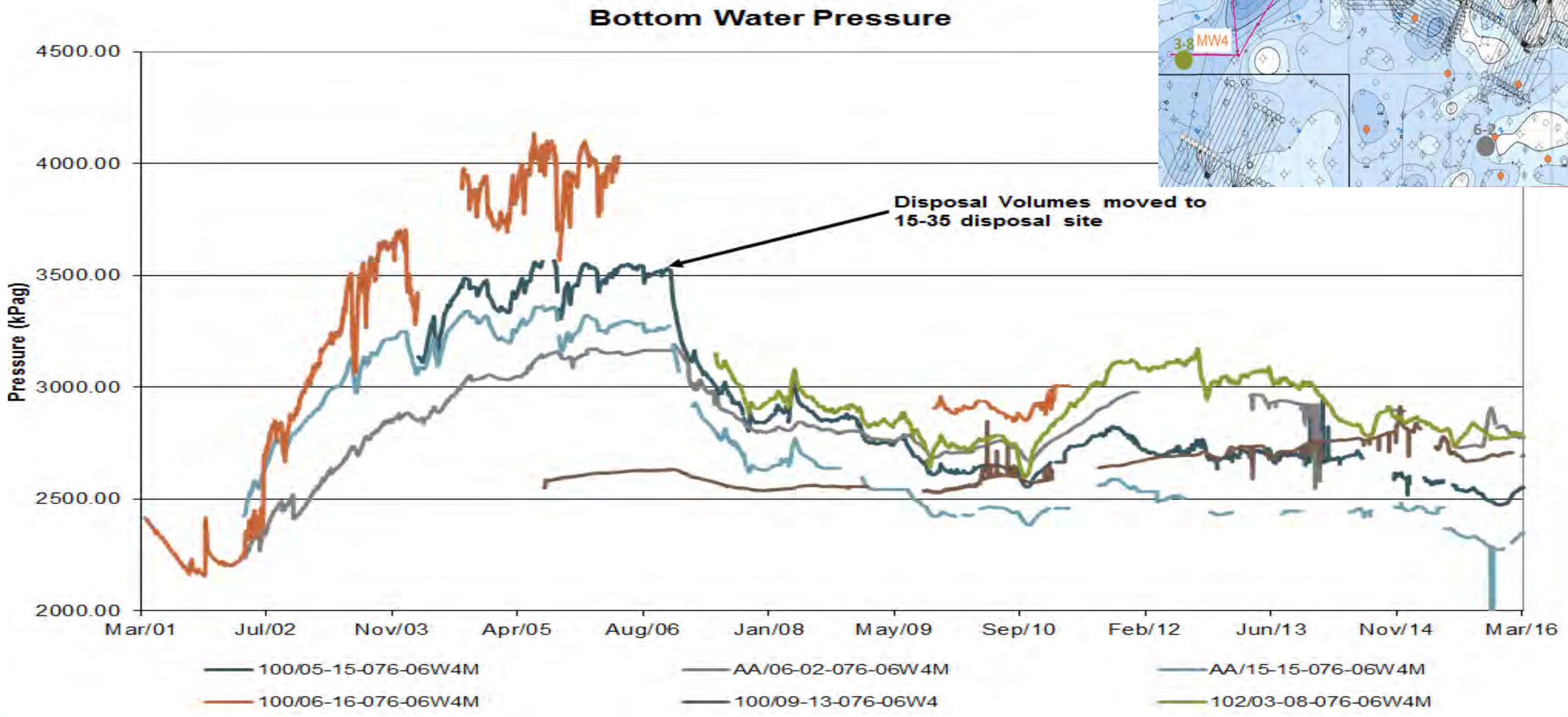


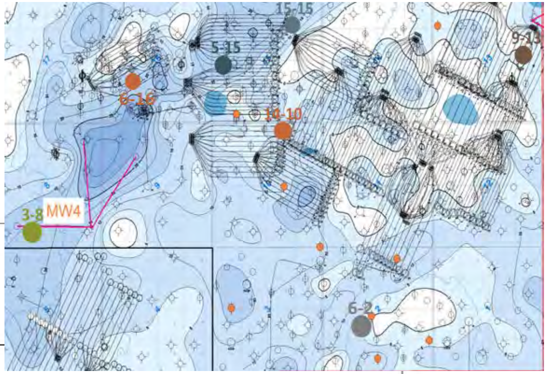
# Christina Lake Disposal Totals



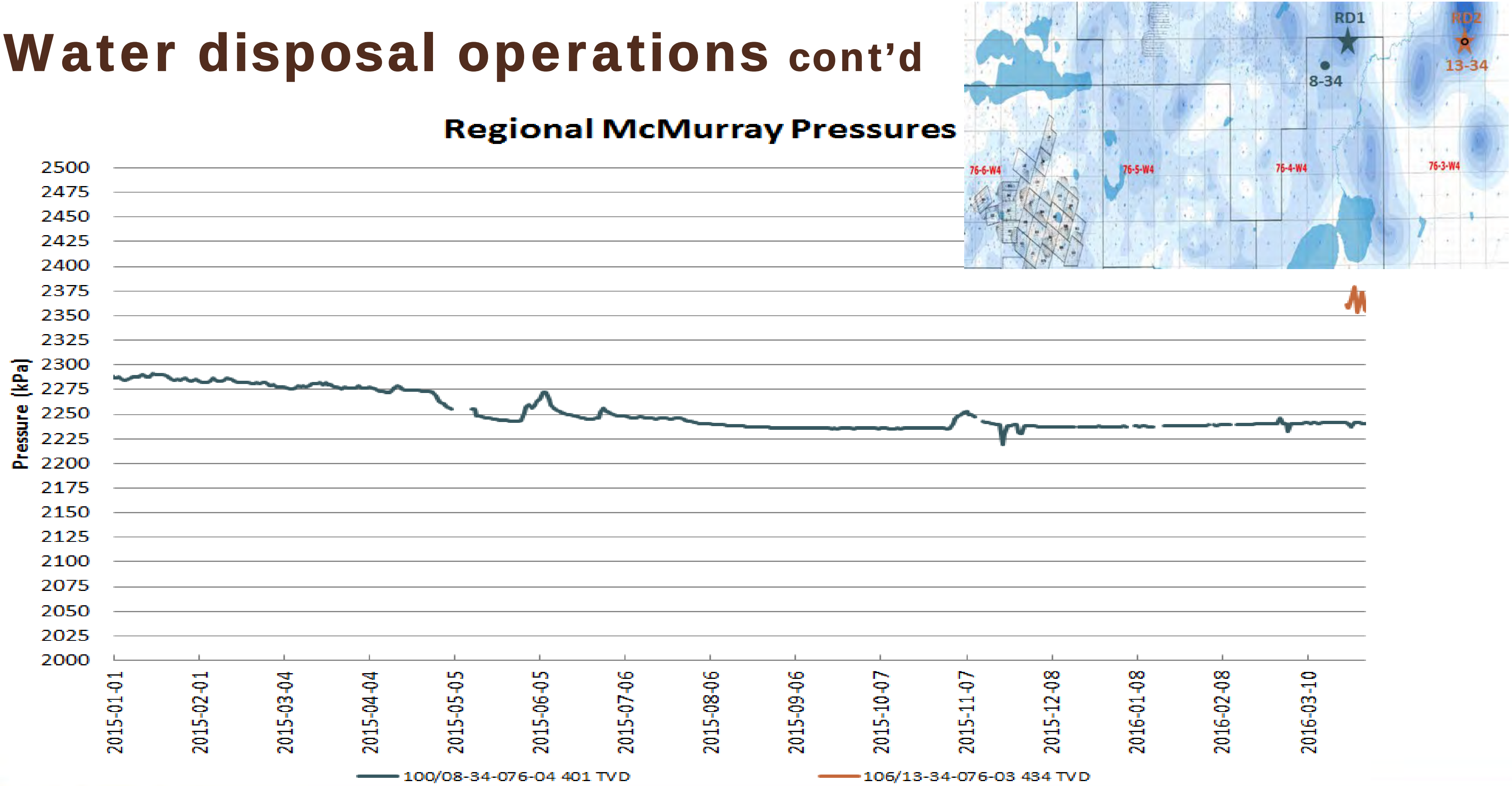

Note: No local disposal occurred in 2015 / Q1 2016

# Water Disposal Operations



# Water disposal operations cont'd



# Waste disposal volumes

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

| | 2015 | 2014 | 2013 |
|---|---|---|---|
| Slop Oil / Production Fluids ($m^3$) | 31,518 | 82,241 | 157,155 |
| Drilling Waste ($m^3$) | 63,664 | 56,260 | 37,086 |
| Lime Sludge ($m^3$) | 16,179 | 15,279 | 23,759 |
| Contaminated Soils ($m^3$) | 159 | 187 | 310 |
| Spent Scavenger ($m^3$) | 6,613 | 5,346 | 2,975 |
| **Total** | **118,113** | **159,313** | **221,285** |

# Waste disposal sites 2015

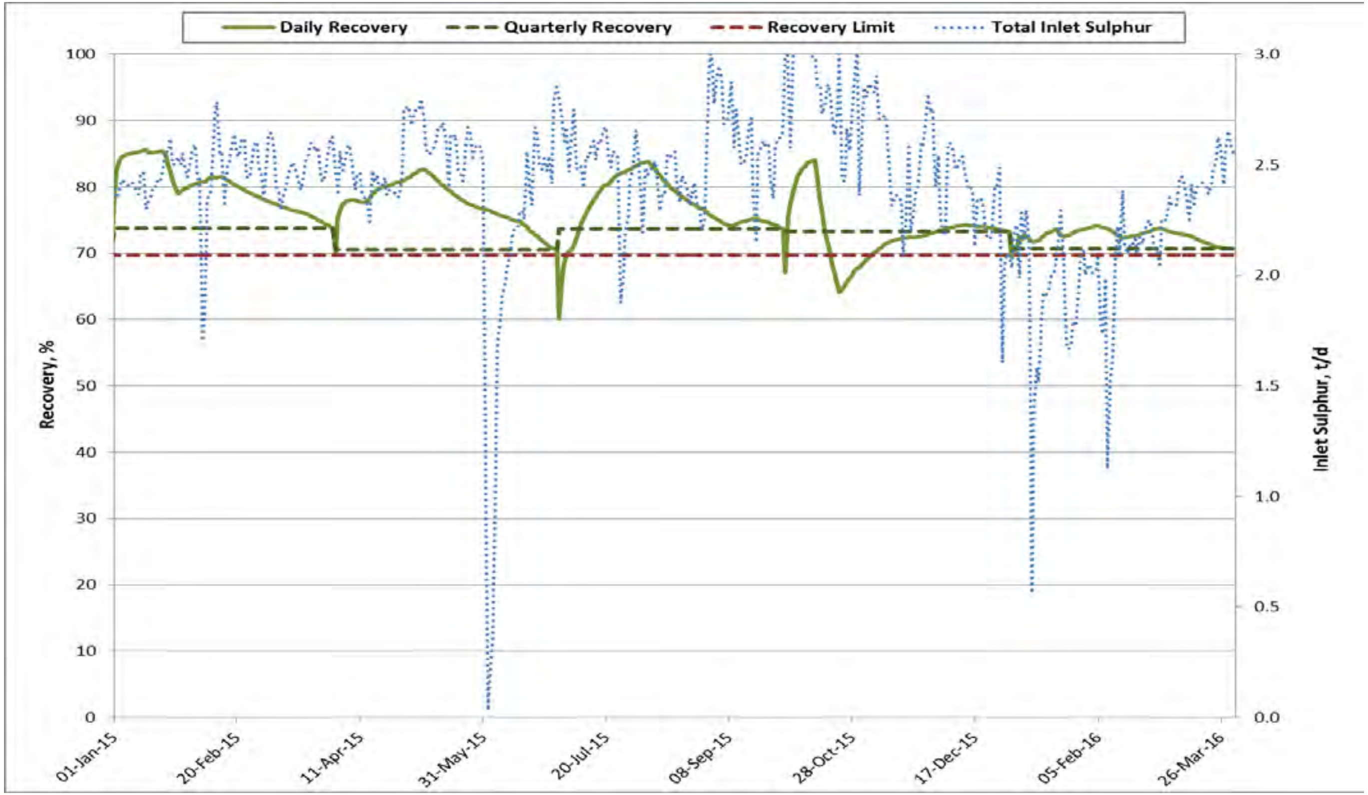
| Facility | Total ($m^3$) |
|---|---|
| Tervita Janvier Landfill | 66,951 |
| Tervita Lindbergh Cavern | 20,254 |
| Cancen New Sarepta Disposal Well | 19,382 |
| Tervita Bonnyville Landfill | 8,051 |
| Newalta Elk Point | 2,317 |
| Newalta Fort McMurray | 2,180 |
| R.B.W. Edmonton | 998 |
| **TOTAL ($m^3$)** | **120,132** |

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

# Subsection 3.1.2 – 5) Sulphur production

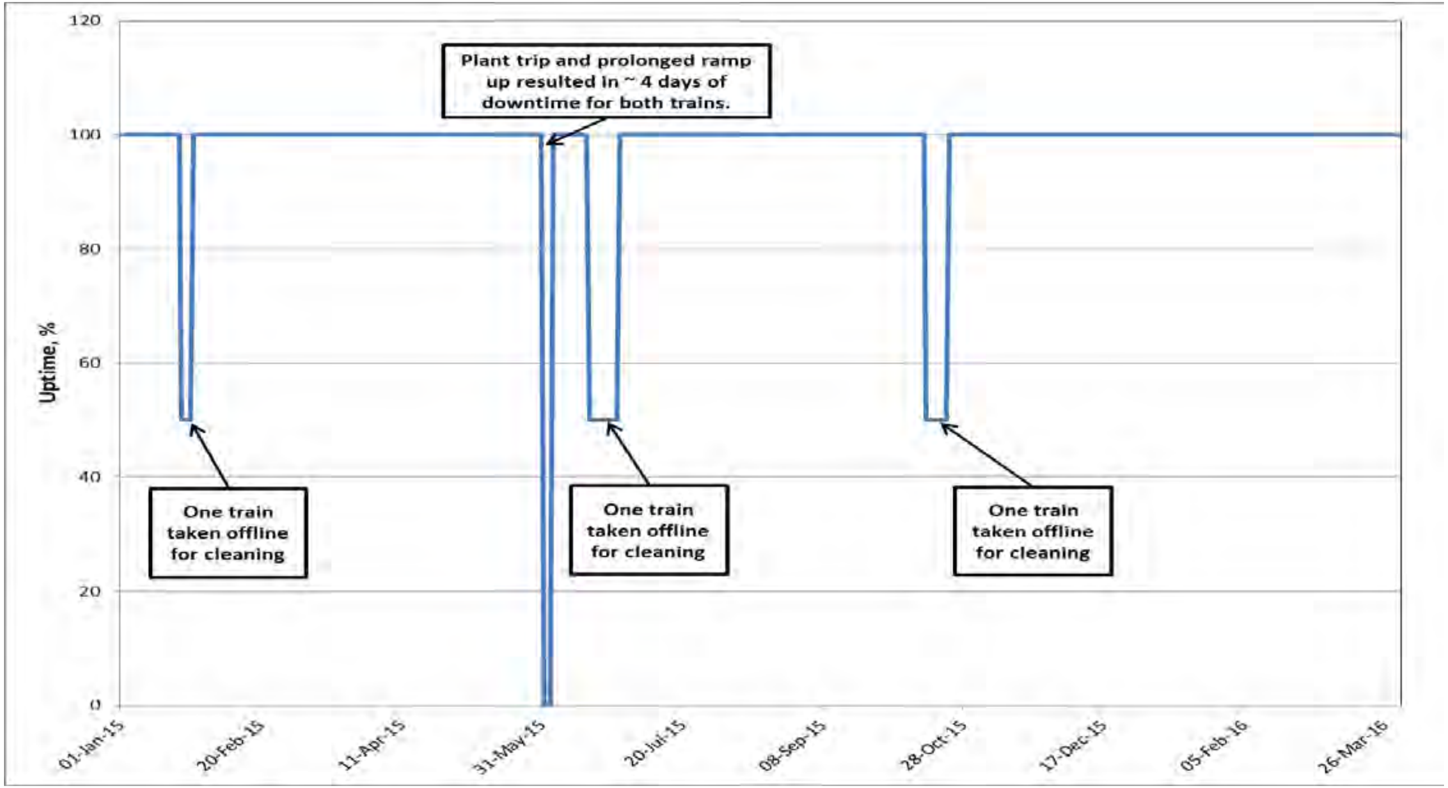
Bailey Gould
Process Engineer

# Scavenger recovery details




| Quarter | Recovery |
|---|---|
| Q1 2015 | 73.8% |
| Q2 2015 | 70.5% |
| Q3 2015 | 73.7% |
| Q4 2015 | 73.3% |
| Q1 2016 | 70.6% |

# Scavenger uptime details

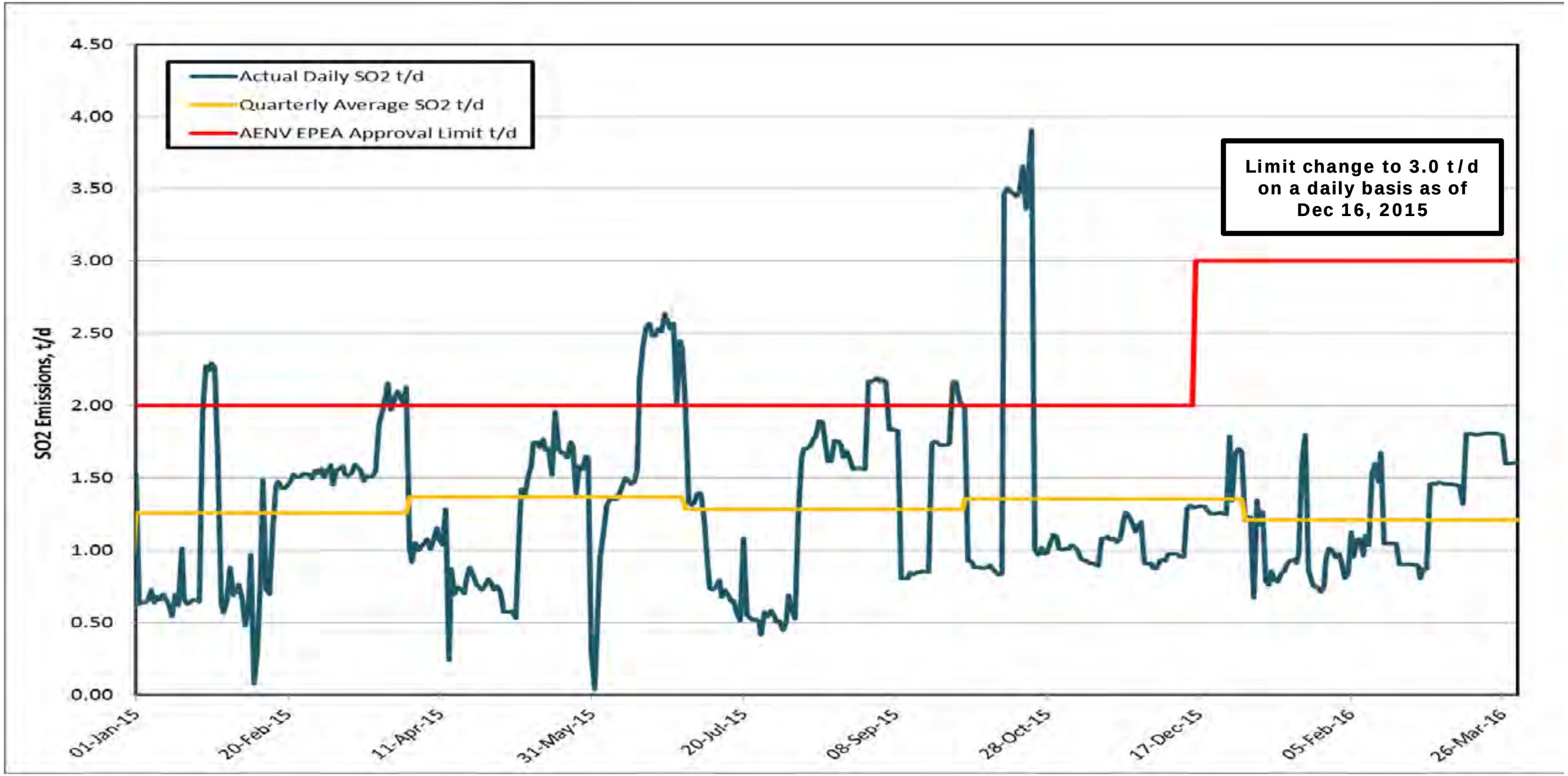


# Sulphur recovery operation

## 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 has been postponed following change in $SO_2$ emissions limit to daily rather than calendar quarter year average as of Dec 16, 2015.
  - Require Phase F SRU to be operable before a train can be taken down for cleaning to prevent exceeding daily limit.
- Cleaning frequency determined based on process monitoring (pressure drop, spent chemical quality, gas temperature)

# $SO_2$ emissions



# Ambient air quality monitoring

## Passive exposure monitoring

As per the Approval (Table 3.3), Christina Lake is required to maintain a network of twelve passive monitoring exposure stations to obtain monthly static exposures of $H_2S$ and $SO_2$.

The passive monitoring results in 2015 did not identify any significant air quality issues related to Plant operations.

## Continuous air quality monitoring

CLTP 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.

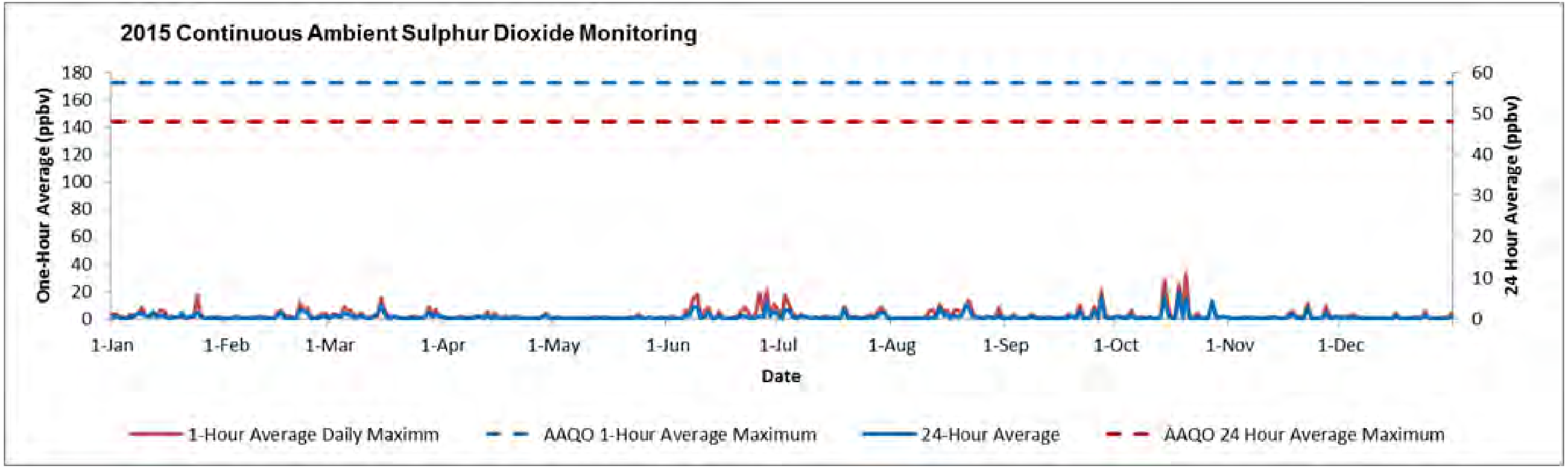
In 2015, continuous air quality monitoring was conducted from Jan 1 to December 31 by Maxxam Analytics. The continuous ambient air monitoring station is located at 03-16-076-06-W4M. This location is the same as the passive monitoring station C10.

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

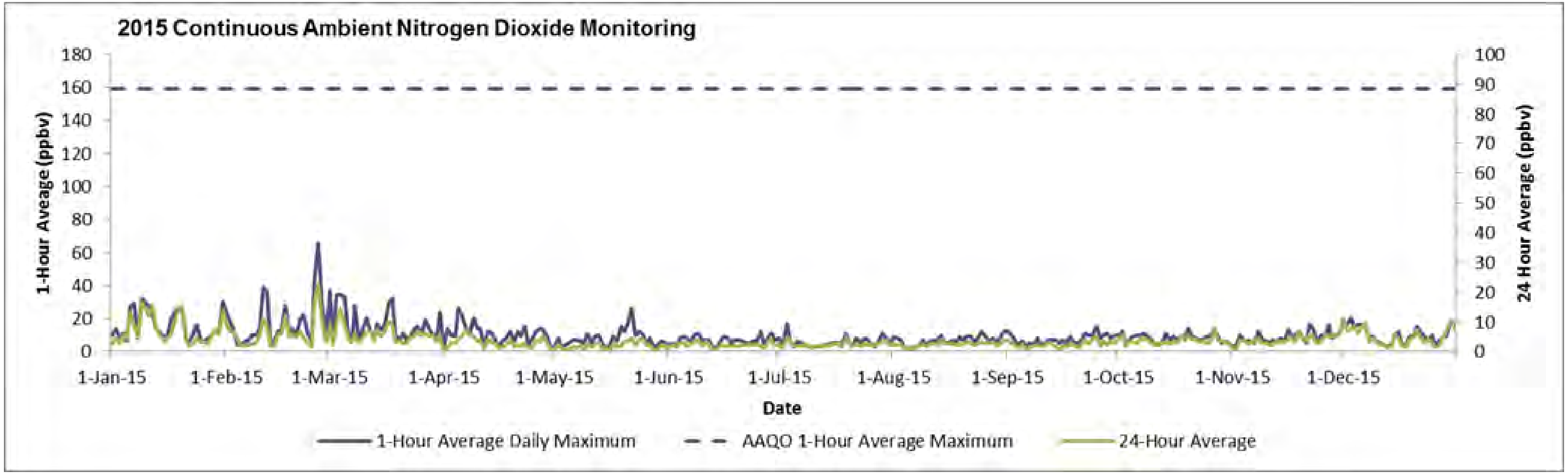
The continuous ambient air quality monitoring in 2015 did not identify any significant air quality issues related to Plant operations.

## No criteria exceedances were noted in either monitoring program

# Ambient air monitoring results - sulphur dioxide



# Ambient air monitoring results – nitrogen dioxide



# Subsection 3.1.2 – 6) Environmental issues

Jesse Wong

Environmental Advisor

cenovus ENERGY

# 2015 Compliance issues and amendments

| Approval number | Amendments | Compliance issues |
|---|---|---|
| EPEA Approval 00048522-01-06&07 | 06 - Phase H approval issued December 16, 2015.<br>07 – Clerical amendment | No |
| EPEA Approval 00298224-00-00 | No | No |
| Water Act Approval 00265924-00-02 | 02 – Surface Water Run-off Ponds amended to 1:10 yr./24hr duration storm event | No |
| Water Act License 00267617-00-02 | No | No |
| Water Act License 00343057-00-01 | Expiry amended to December 12, 2016 | No |
| Water Act License 00293633-00-00 | Water level cut-off elevations modified March 3, 2016 | No |

cenovus ENERGY

# Monitoring programs

| Monitoring program | Progress and results |
|---|---|
| Air quality monitoring | Air emissions increased slightly in 2015 due to the commissioning of the blowdown boilers. No significant trends in ambient air monitoring observed. |
| Groundwater monitoring | Monitoring Program to be updated to include Phase H. |
| Thermal metal mobilization monitoring | Small temperature changes (up to 2C) detected in the deeper Empress and the Ethel Lake formations in 2015. Groundwater chemistry has been consistent since the start of steaming. |
| Soil monitoring program | Soil Monitoring Program Proposal authorized April 23, 2014. Monitoring and reporting completed. |
| Wildlife and caribou mitigation and monitoring programs | 3 Year comprehensive report completed and sent to AER on May 15th, 2015. Proposed changes to programs being discussed with the AER. |
| Wetland monitoring program | Minor changes to program were approved by the AER in April 2016. |

# Monitoring programs continued

| Monitoring program | Progress and results |
|---|---|
| Reclamation monitoring Program | 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 | To be submitted in October 2017, as per Specific Enactment Direction 001 issued March 1, 2016 |

# Environmental initiatives

The regional multi-stakeholder forums that Cenovus was involved with in 2015 include:

- Canadian Oil Sands Innovation Alliance (COSIA): Linear Deactivation Program (LiDEA)

- Alberta Environmental Monitoring, Evaluation and Reporting Agency (AMERA)
  - 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 – 7) Statement of compliance

Brent Mitchell

Specialist, Regulatory Applications

# 2015 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 – 8)
# Statement of non-compliance

Brent Mitchell

Specialist, Regulatory Applications

cenovus ENERGY

# 2015 Non-compliance summary – AER

| Date | Non compliance / self-disclosure | Follow-up |
|---|---|---|
| 2015-02-03 | Unsatisfactory High Risk Drilling Waste Inspection @ 11-22-76-6W4 W0471662 | Compliance achieved on Feb 4, 2015 |
| 2015-02-13 | Disposal water balance exceedance Approval No. 8591 | Compliance achieved on Jul 30, 2015 |
| 2015-03-19 | A01 MARP Meters (FIT-226A, 226B, 226C, 226D, 227E, 227F) Approval No. 8591 | Compliance achieved on Jun 24, 2015 |
| 2015-07-15 | Notice of Noncompliance - Outstanding Non-Abandoned OSE Wells (57 CL wells) | Compliance achieved on Sep 14, 2015 |
| 2016-01-13 | Unsatisfactory Low Risk Oil Facility Inspection @ 8-17-76-6W4 F27189 | Compliance achieved on Jan 22, 2016 |

# Subsection 3.1.2 – 9)
Future plans

# Major activities and target dates

| Phase | Regulatory | | | Production capacity ($m^3/d$) | |
|---|---|---|---|---|---|
| | Filing | Approval | First steam | Incremental | Total |
| A | Q1 1998 | Q1 2000 | Q2 2002 | 1,590 | 1,590 |
| B | Q2 2005 | Q4 2005 | Q2 2008 | 1,400 | 2,990 |
| C | Q3 2007 | Q2 2008 | Q2 2011 | 6,360 | 9,350 |
| D | Q3 2007 | Q2 2008 | Q2 2012 | 6,360 | 15,710 |
| E | Q3 2009 | Q2 2011 | Q3 2013 | 6,360 | 22,070 |
| F | Q3 2009 | Q2 2011 | 2016 | 6,360 | 28,430 |
| G | Q3 2009 | Q2 2011 | | 6,360 | 34,790 |
| FG Amendment | Q4 2012 | Q4 2012 | | 3,180 | 37,970 |
| CDE 2nd Stage OTSG | Q4 2012 | Q3 2013 | 2015 | 3,370 | 41,340 |
| H | Q1 2013 | Q4 2015 | | 7,950 | 49,290 |