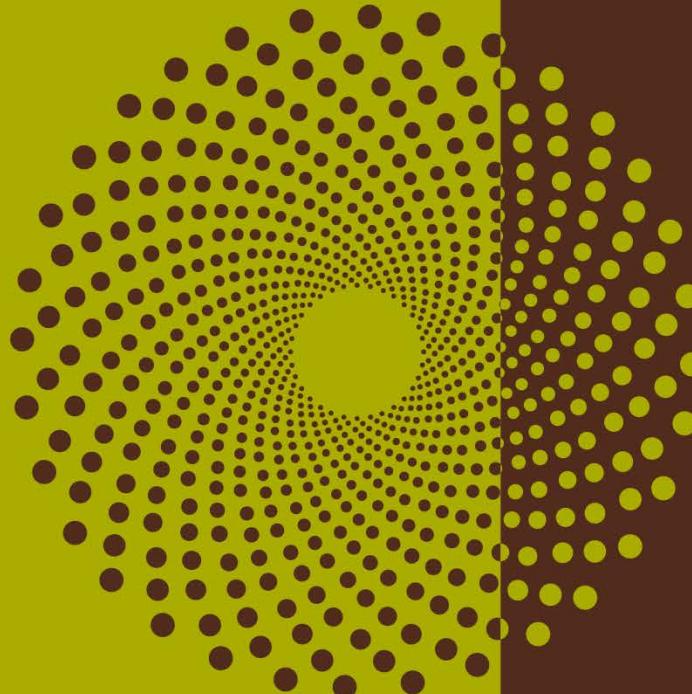


Cenovus FCCL Ltd.  
Foster Creek In situ Progress Report  
Scheme 8623  
2016 Update

Subsurface Presentation  
May 30, 2017



# Oil & gas and financial information

## Oil & gas information

The estimates of reserves and contingent resources were prepared effective December 31, 2016 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 *Standards of Disclosure for Oil and Gas Activities*. 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, 2016 and in our Statement of Contingent and Prospective Resources for the year ended December 31, 2016, available on SEDAR at [www.sedar.com](http://www.sedar.com), EDGAR at [www.sec.gov](http://www.sec.gov) and on our website at [cenovus.com](http://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.

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.

<sup>TM</sup> denotes a trademark of Cenovus Energy Inc.

© 2017 Cenovus Energy Inc.

# Advisory

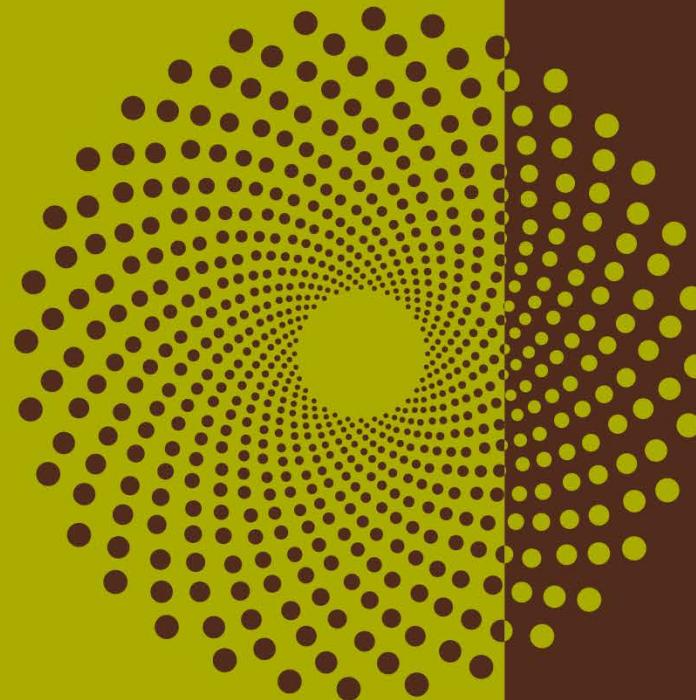
This presentation contains information in compliance with:

*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.

# Brief background

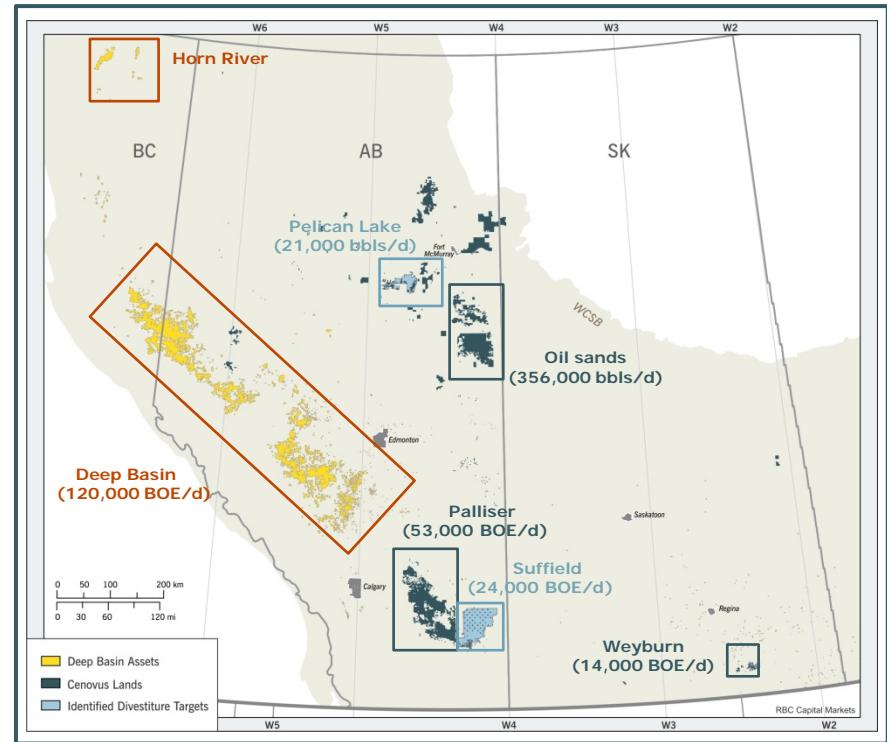
Subsection 3.1.1-1)



# About Cenovus

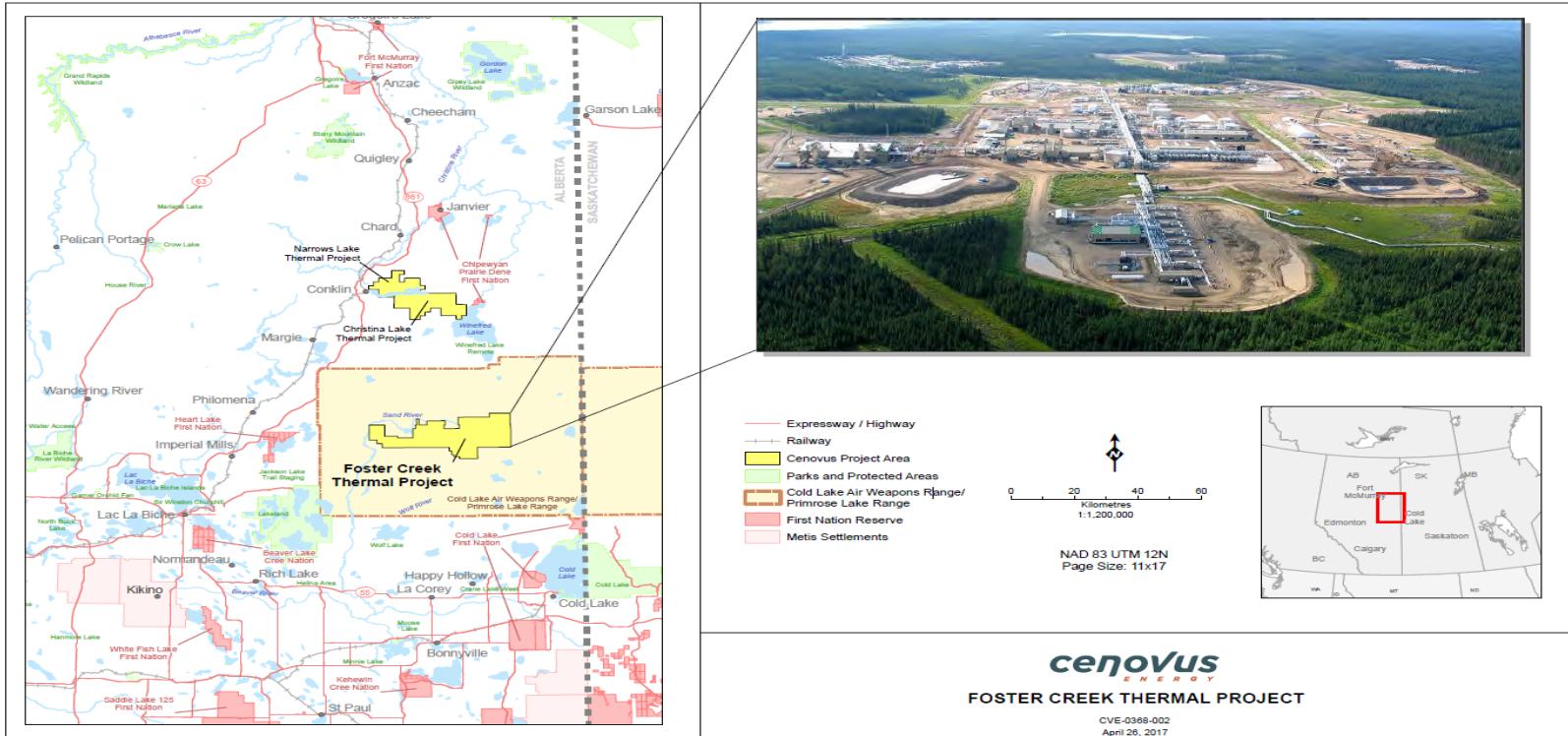
TSX, NYSE | CVE

Enterprise value	C\$29 billion
Shares outstanding	1,229 million
2017F production <sup>(1)</sup>	
Oil sands	178 Mbbls/d
Conventional	54 Mbbls/d
Total liquids	232 Mbbls/d
Natural gas	350 MMcf/d
Acquired assets	
Oil sands	178 Mbbls/d <sup>(1)</sup>
Deep Basin	120 MBOE/d <sup>(1)</sup>
<b>Total production</b>	<b>588 MBOE/d<sup>(1)</sup></b>
2016 proved & probable reserves	7.8 BBOE
Bitumen	
Economic contingent resources	10.7 Bbbls
Lease rights*	5.0 MM net acres
P&NG rights	7.0 MM net acres
Refining capacity	230 Mbbls/d net



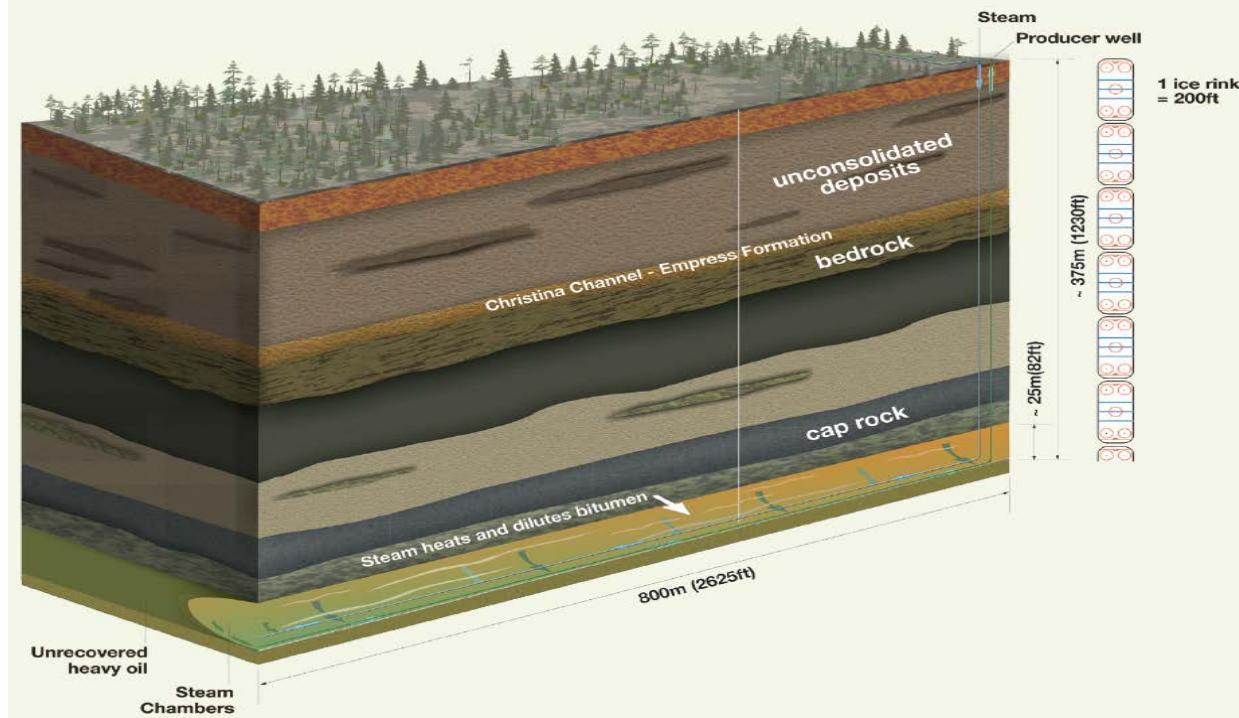
Values are approximate. <sup>(1)</sup> Forecast production based on December 8, 2016 guidance and reflects 2017 forecast production for the acquired assets as though the acquisition closed on January 1, 2017 and full year volumes were contributed; acquisition closed on May 17, 2017 and pro rata volumes will be reflected in reported results. \*Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignee's behalf.

# Area map

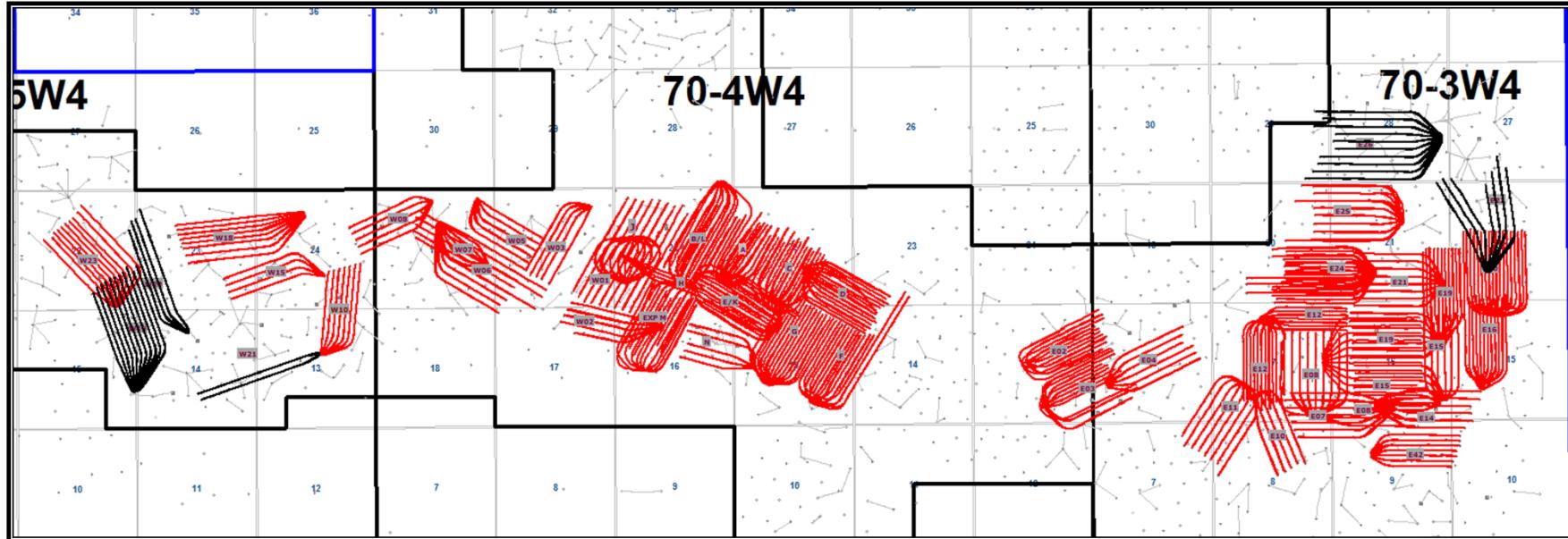


# Recovery process

- The Foster Creek 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



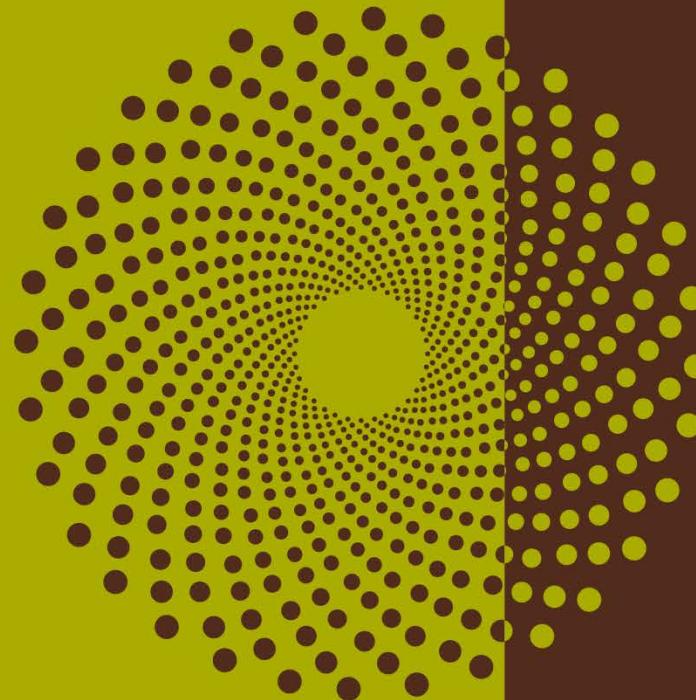
## Scheme map



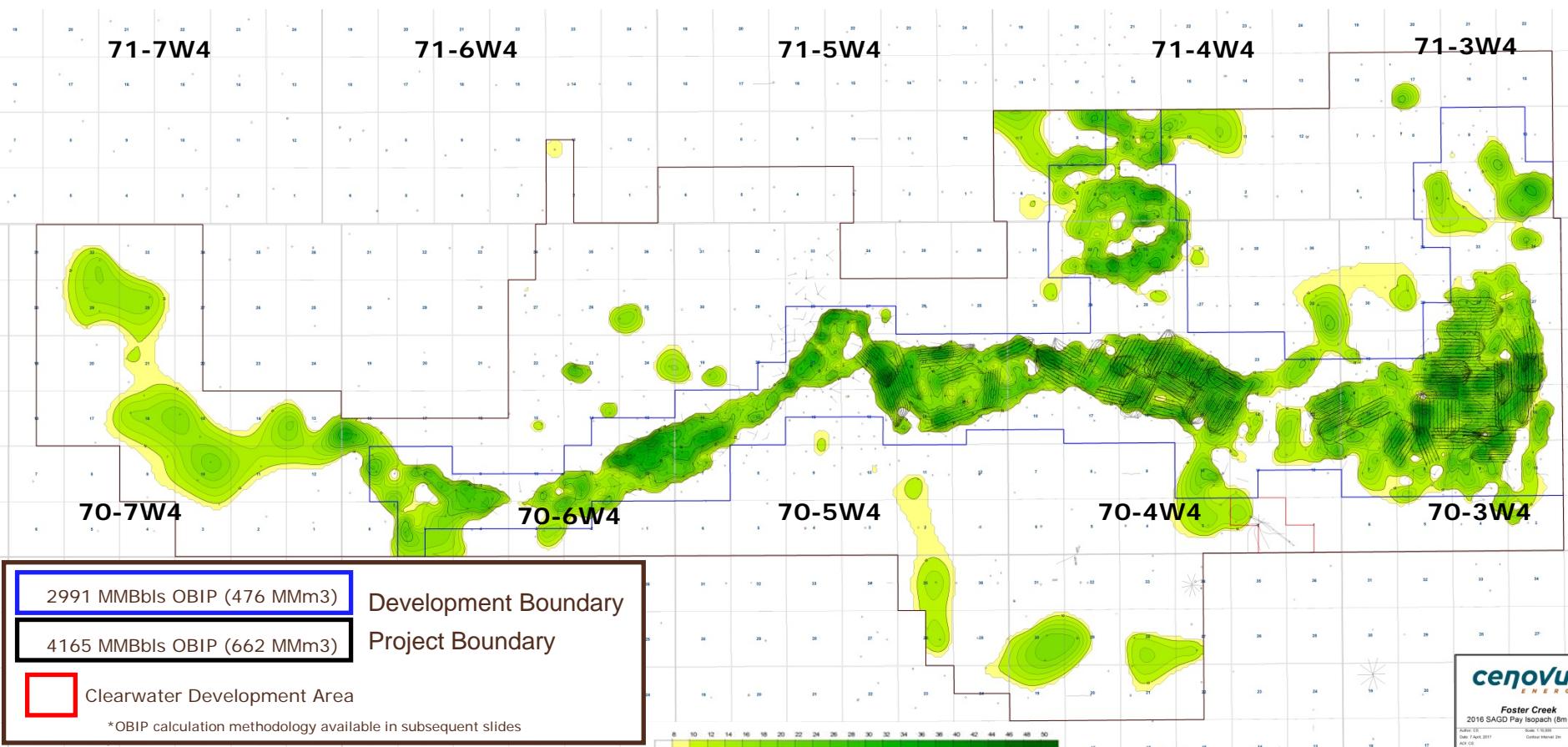
- / Well Pairs on Production
- \ Well Pairs Drilled Not Producing

# Geology and Geoscience

Subsection 3.1.1 – 2)



# Current Project Status – SAGD Resource



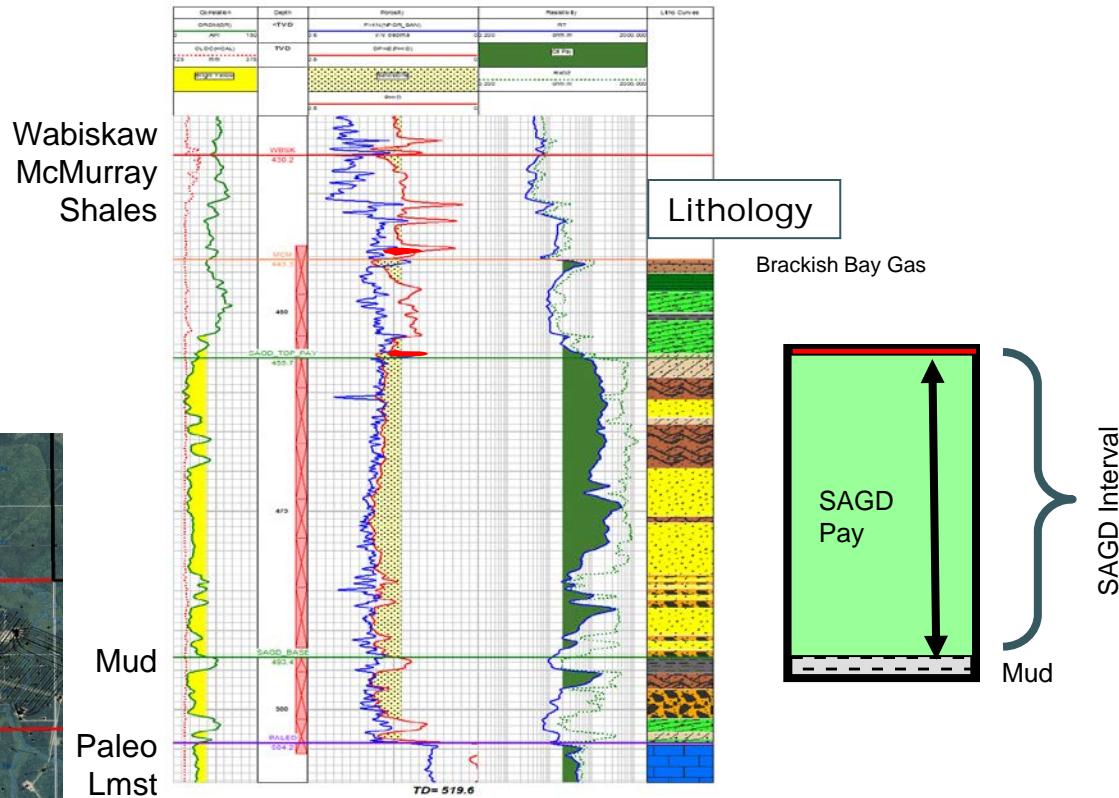
# Reservoir characteristics

<b>Reservoir Characteristic</b>	<b>West Area</b>	<b>Central Area</b>	<b>East Area</b>
Depth (m subsea)	180 – 225	180 – 225	180 – 225
Thickness (m)	Up to 30+	Up to 30+	Up to 30+
Porosity (%)	34%	34%	32%
Horizontal Permeability (D)	Up to 10 D	Up to 10 D	Up to 8 D
Vertical Permeability (D)	Up to 8 D	Up to 8 D	Up to 6 D
Oil Saturation	~0.85 (0.50 in transition)	~0.85 (0.50 in transition)	~0.85 (0.50 in transition)
Water Saturation	~0.15 (0.50 in transition)	~0.15 (0.50 in transition)	~0.15 (0.50 in transition)
Original Pressure (kPa)	~2700	~2700	~2700
Original Temperature (°C)	12 °C	12 °C	12 °C

# Composite type log: central wells

- Basal mud defines base of pay
- Basal mud is discontinuous and ranges from 0-4 metres in thickness
- Provides a good marker during SAGD operations

Location: 11-19-70-4W4



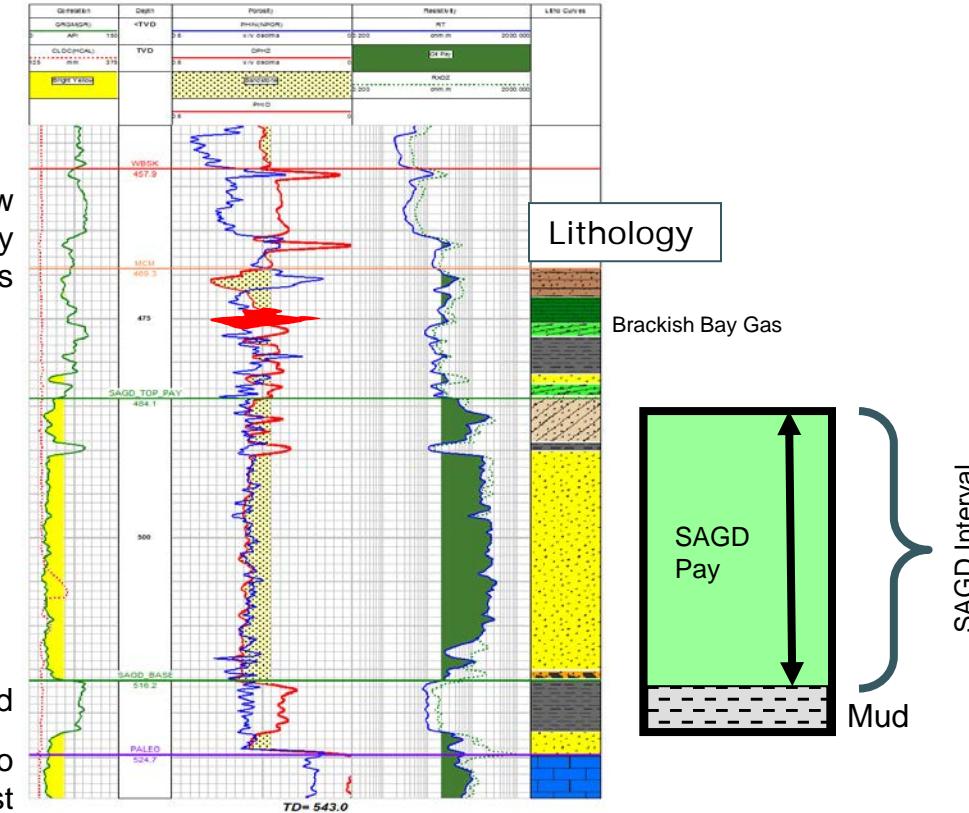
# Composite type log: east wells

- Basal mud defines base of pay
  - Basal mud is discontinuous and ranges from 0-4 metres in thickness
  - Provides a good marker during SAGD operations

Location: 2-21-70-3W4



Wabiskaw  
McMurray  
Shales



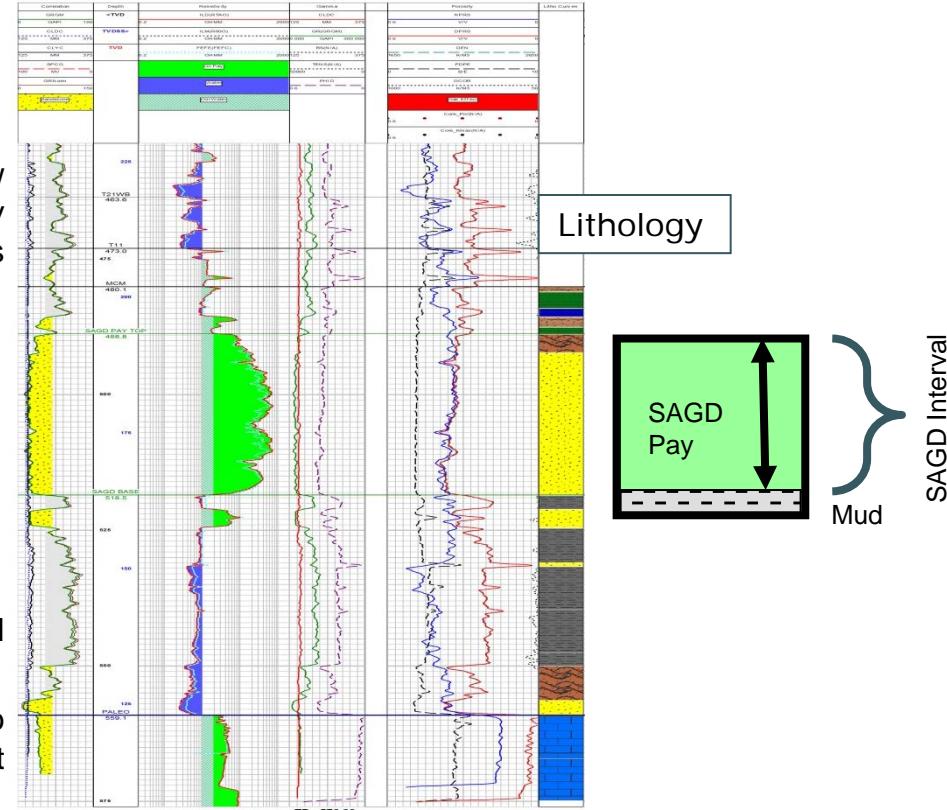
# Composite type log: west wells

- Basal mud defines base of pay
- Basal mud is discontinuous and ranges from 0-4 metres in thickness
- Provides a good marker during SAGD operations

Location: 16-12-70-6W4

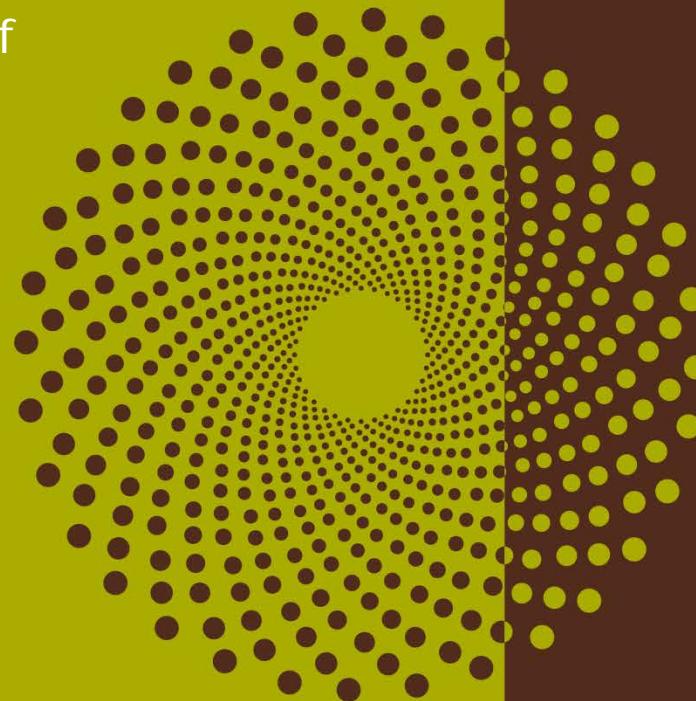


Wabiskaw  
McMurray  
Shales

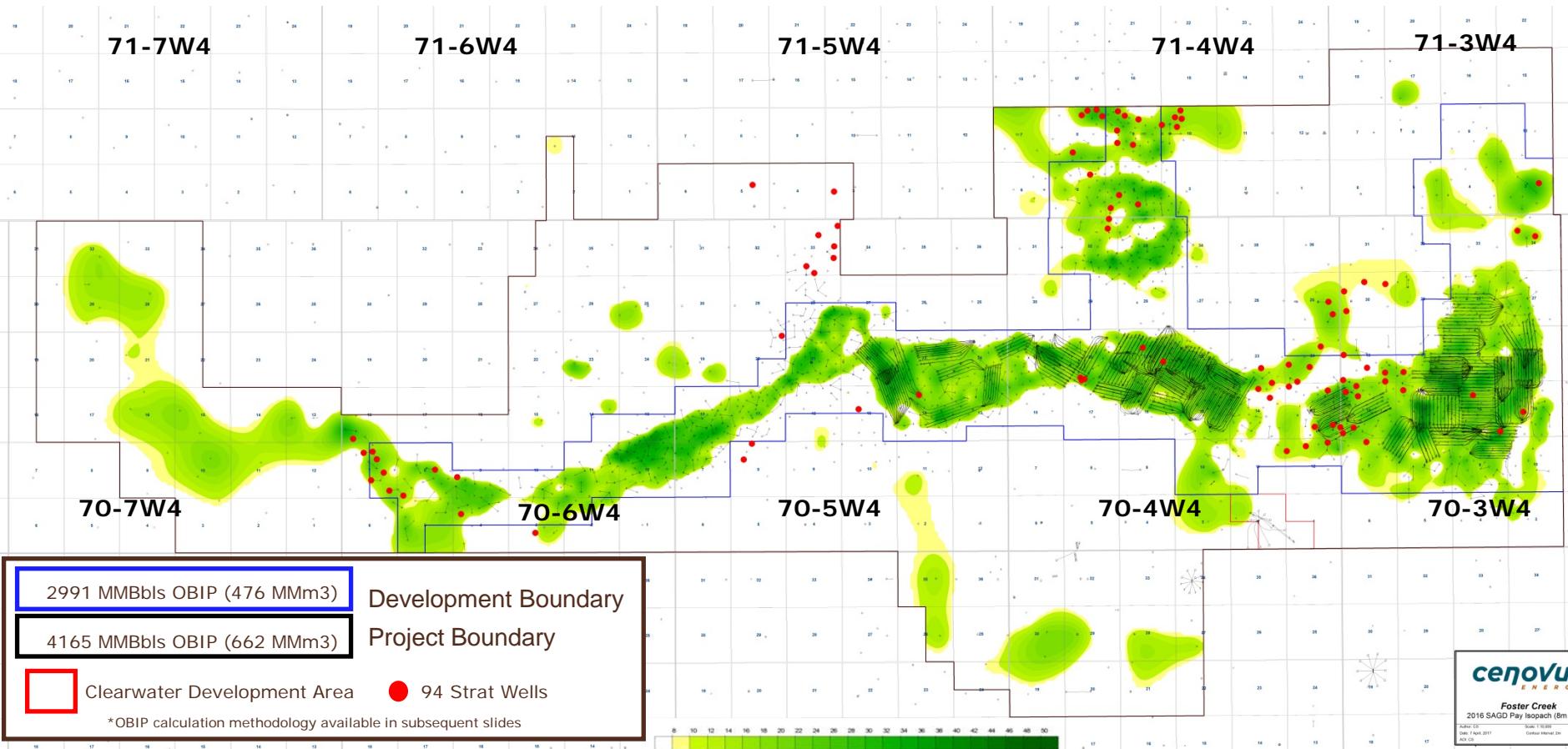


# Maps and Core

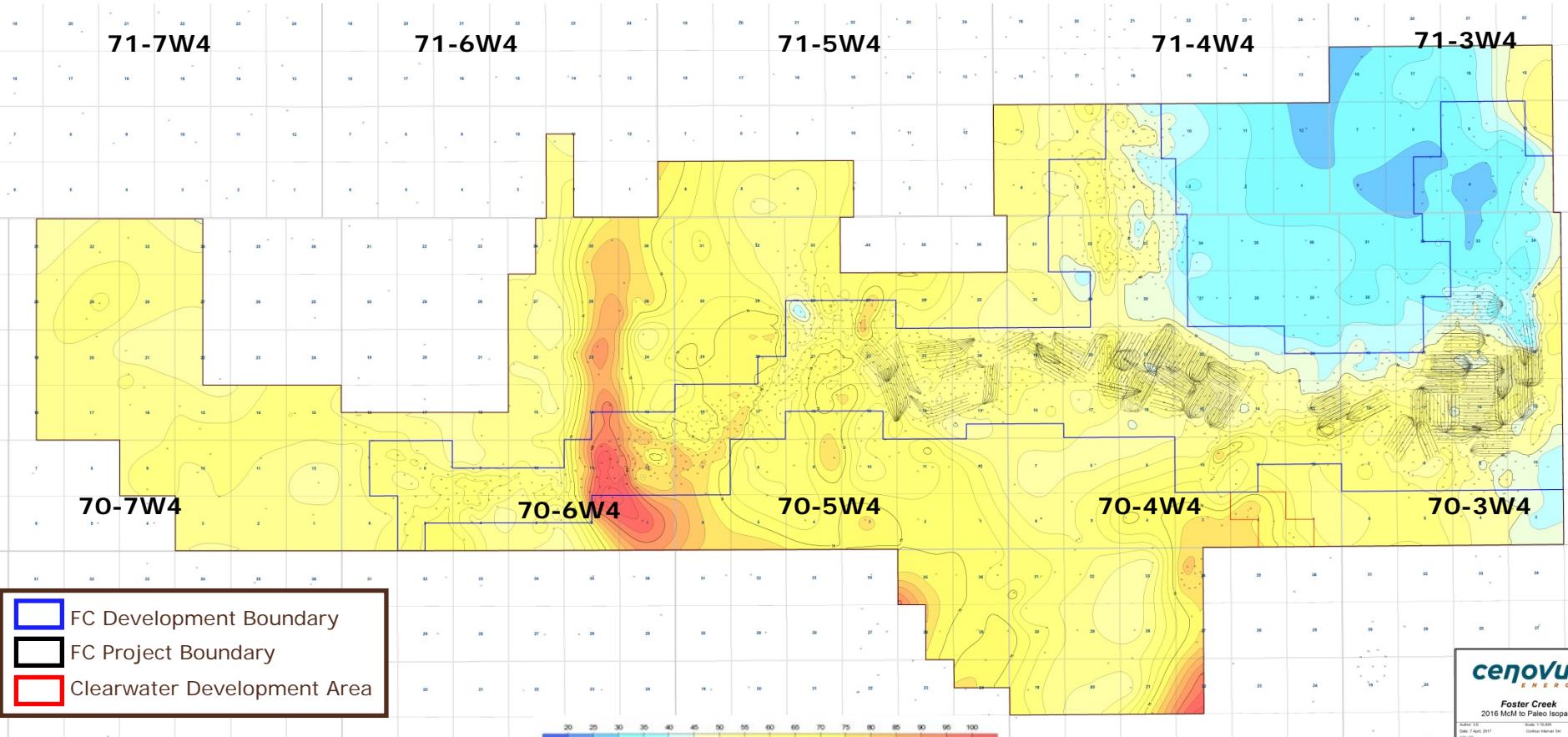
Subsections 3.1.1 – 2) b-d and f



# 2016 SAGD pay isopach (2017 Strats)

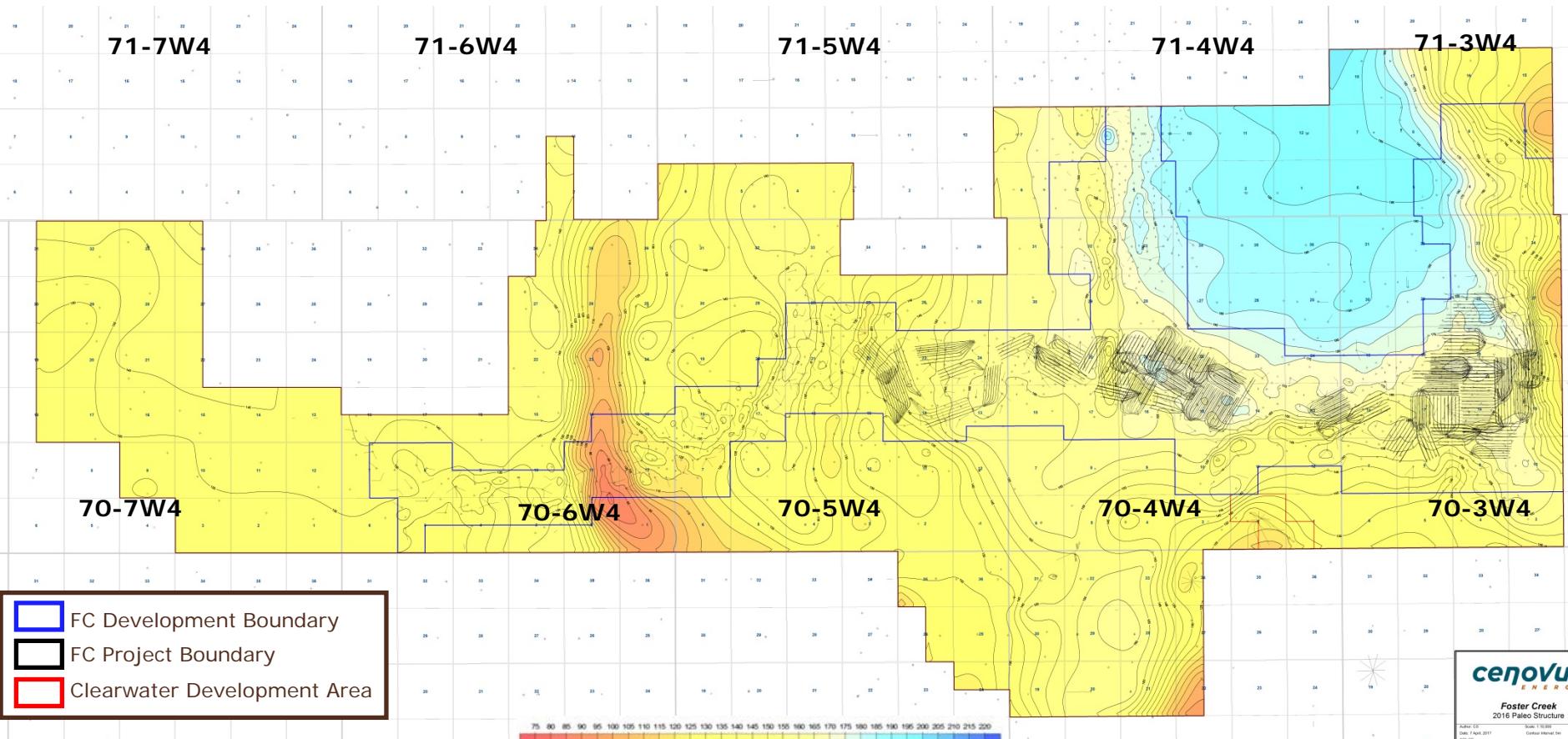


# McMurray to Paleozoic Isopach

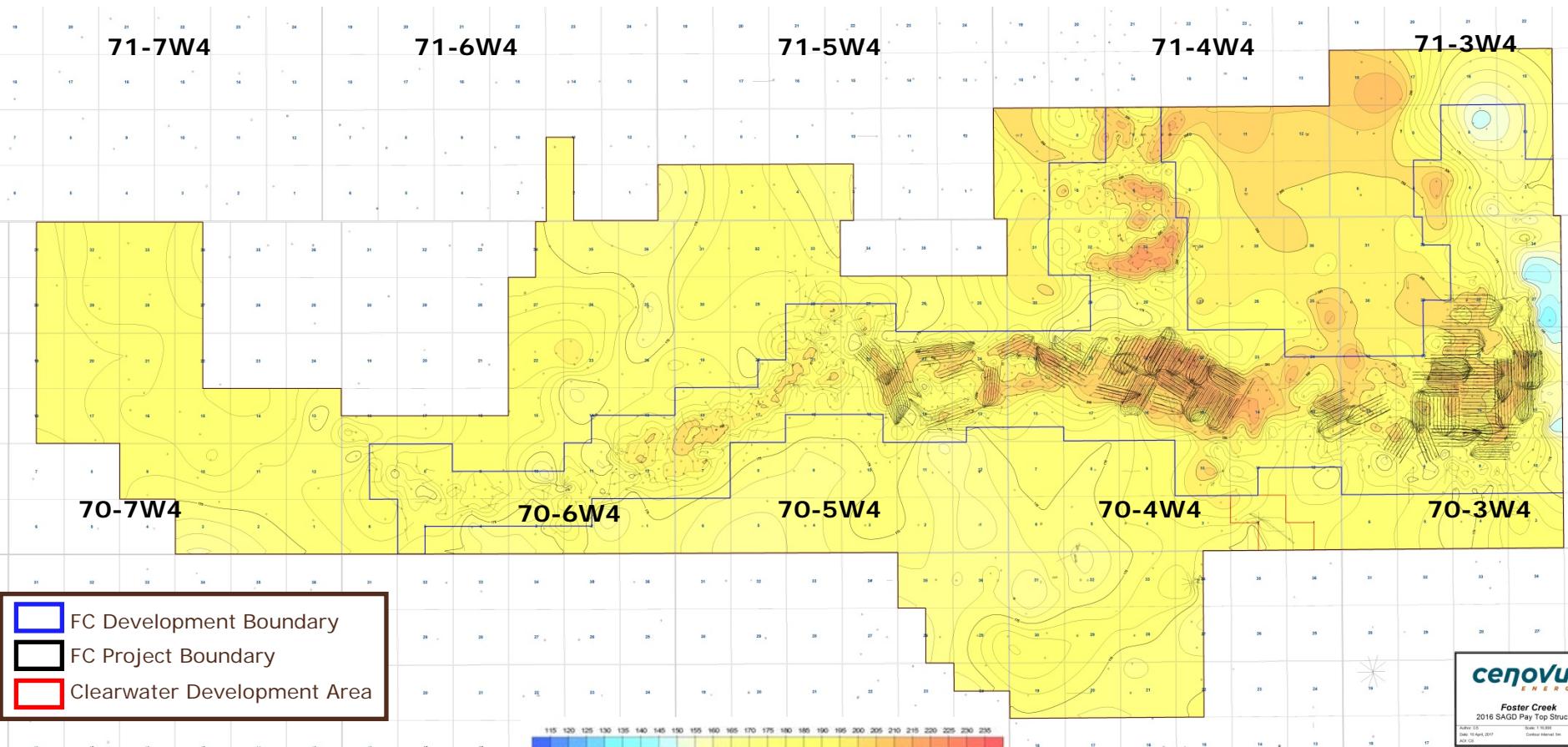


- FC Development Boundary
- FC Project Boundary
- Clearwater Development Area

# Paleozoic Structure

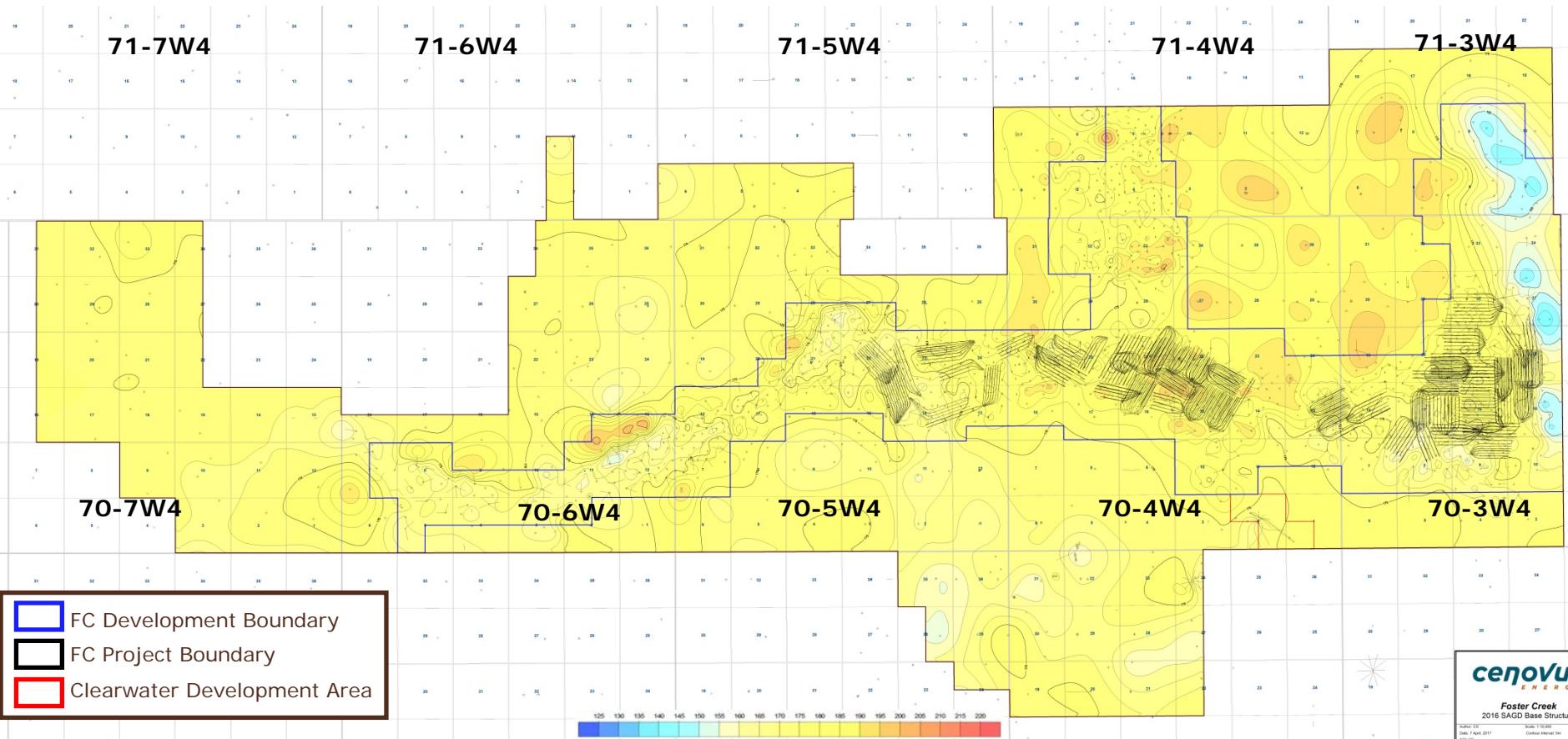


# SAGD Pay Top Structure

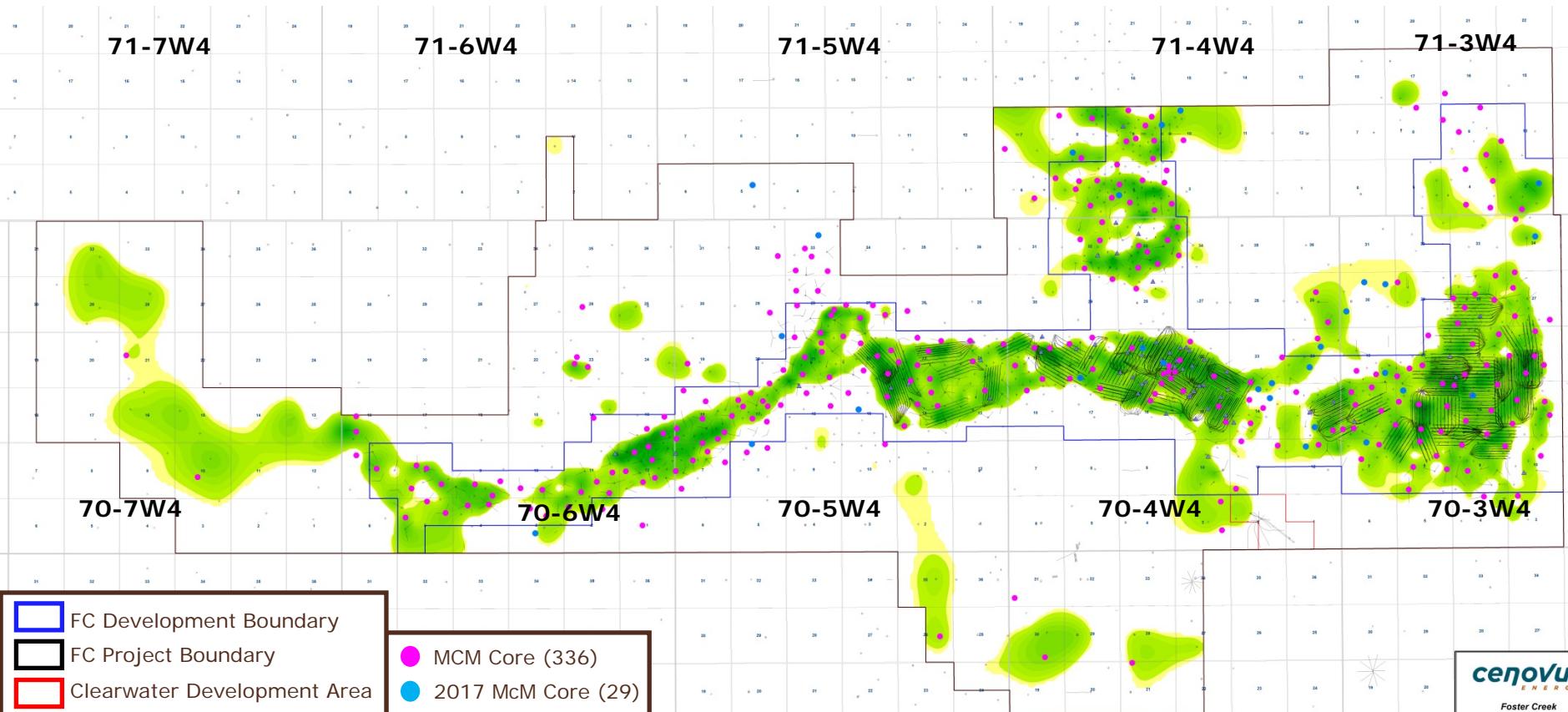


- FC Development Boundary
- FC Project Boundary
- Clearwater Development Area

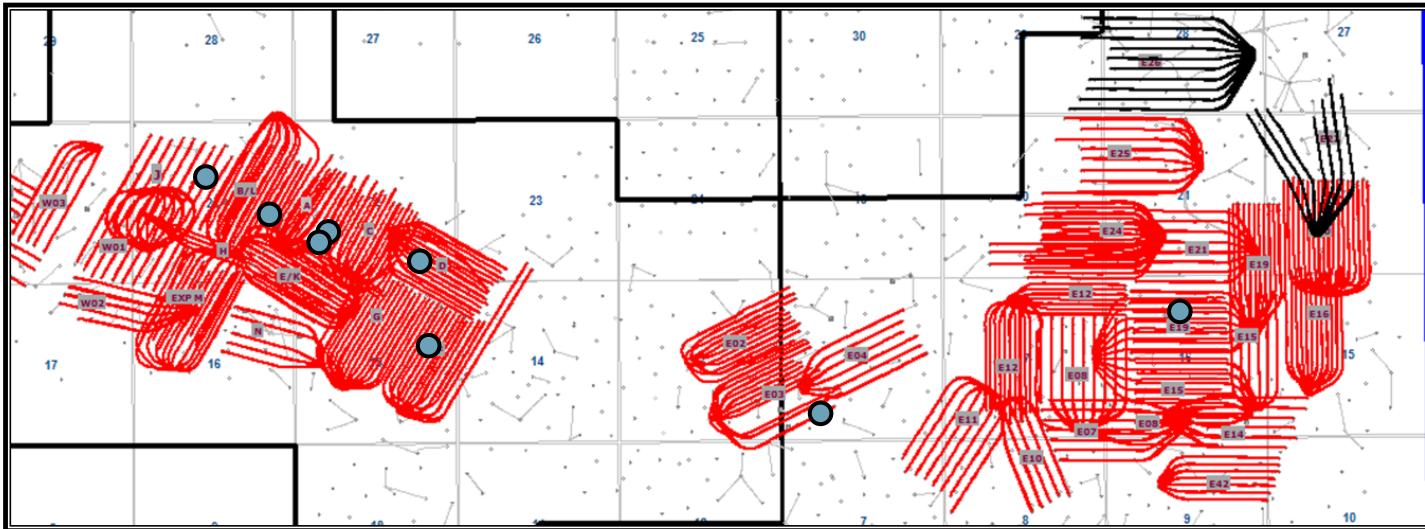
# SAGD Base Structure



# Cored Locations (2017)



# Post-steam core locations



● Post-steam core locations

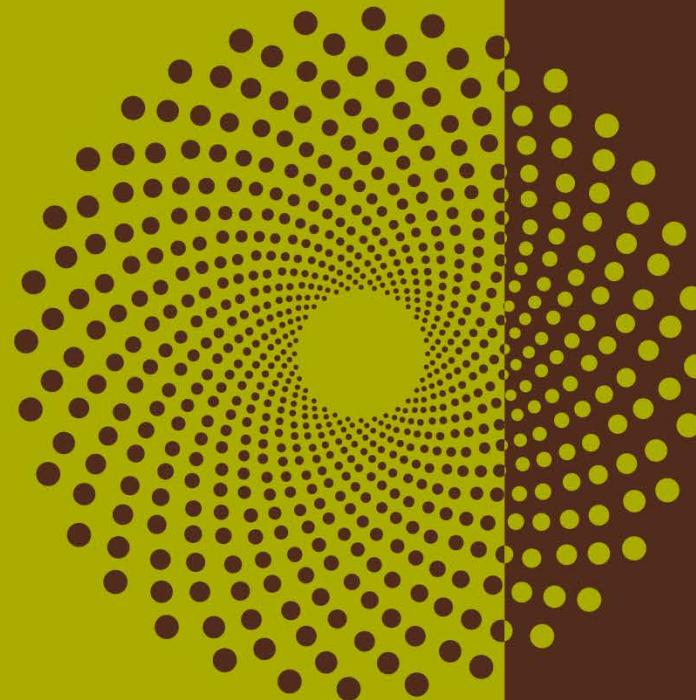
— Well Pairs on Production

/ Well Pairs Drilled Not Producing

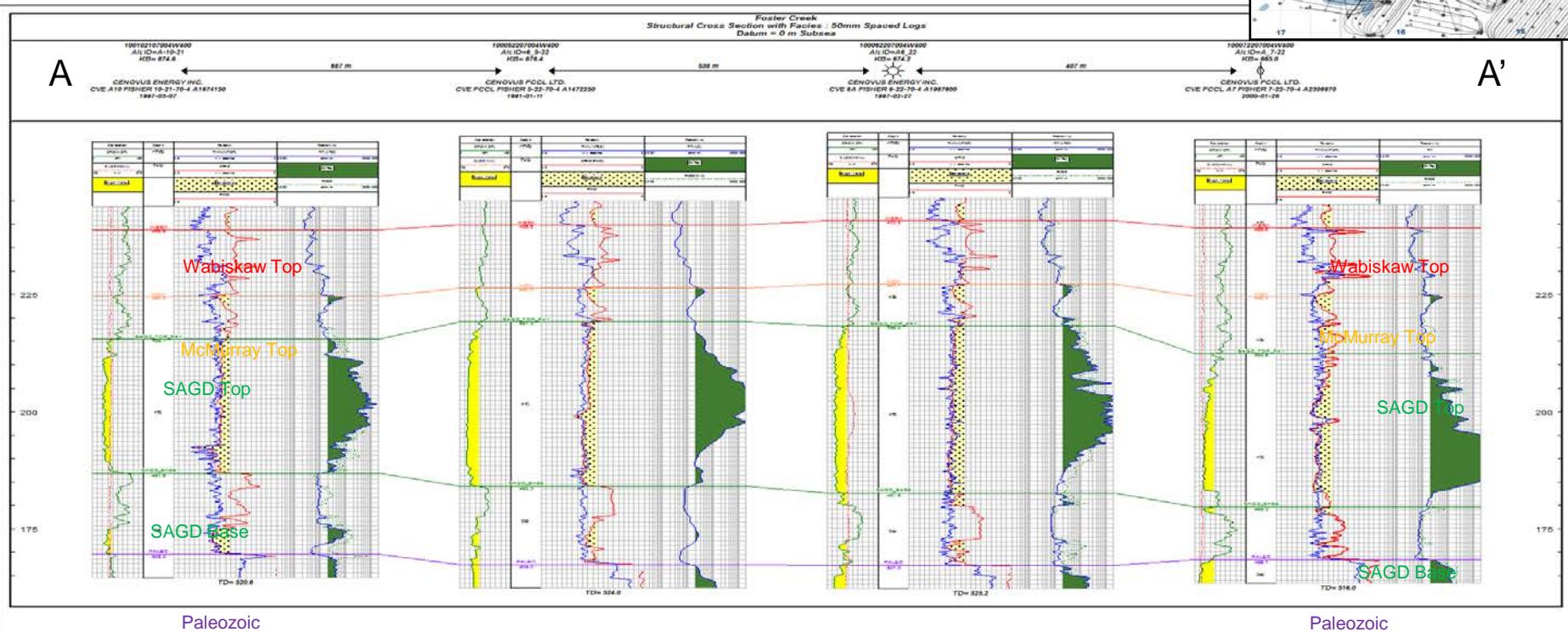
WELL NAME	TYPE	YEAR	ASSOC WP	DISTANCE FROM WP (M)	% SO Clean sand (from Dean Stark)		% So IHS	
					Pre	Post	Pre	Post
CVE 3A5-22 FISHER 5-22-70-4	SCC	2005	A3	10	92	11-26	no lats	no lats
CVE FCCL 2D2 FISHER 2-22-70-4	SCC	2010	D21	27	90	1-21	65-83	14-60
CVE FCCL 5-22 FISHER 5-22-70-4	SCC	2010	A3	17	88	3-20	no lats	no lats
CVE FCCL 2B9 FISHER 9-15-70-4	SCC	2012	FP4	32	90	2-34	no lats	no lats
CVE FCCL D4 FISHER 4-18-70-3	SCC	2012	E03P06	21	N/A	2-26	N/A	8-80
CVE FCCL 2B14-16 A FISHER 14-16-70-3	SCC	2017	E19P09	18	85	1-16	60	16-28
CVE FCCL 2C8-21 C8 FISHER 8-21-70-4	SCC	2017	LW2	19	80	not available	60	not available
CVE FCCL 3D11-21 D FISHER 11-21-70-4	SCC	2017	JWP2	42	N/A	not available	N/A	not available

# Cross Sections

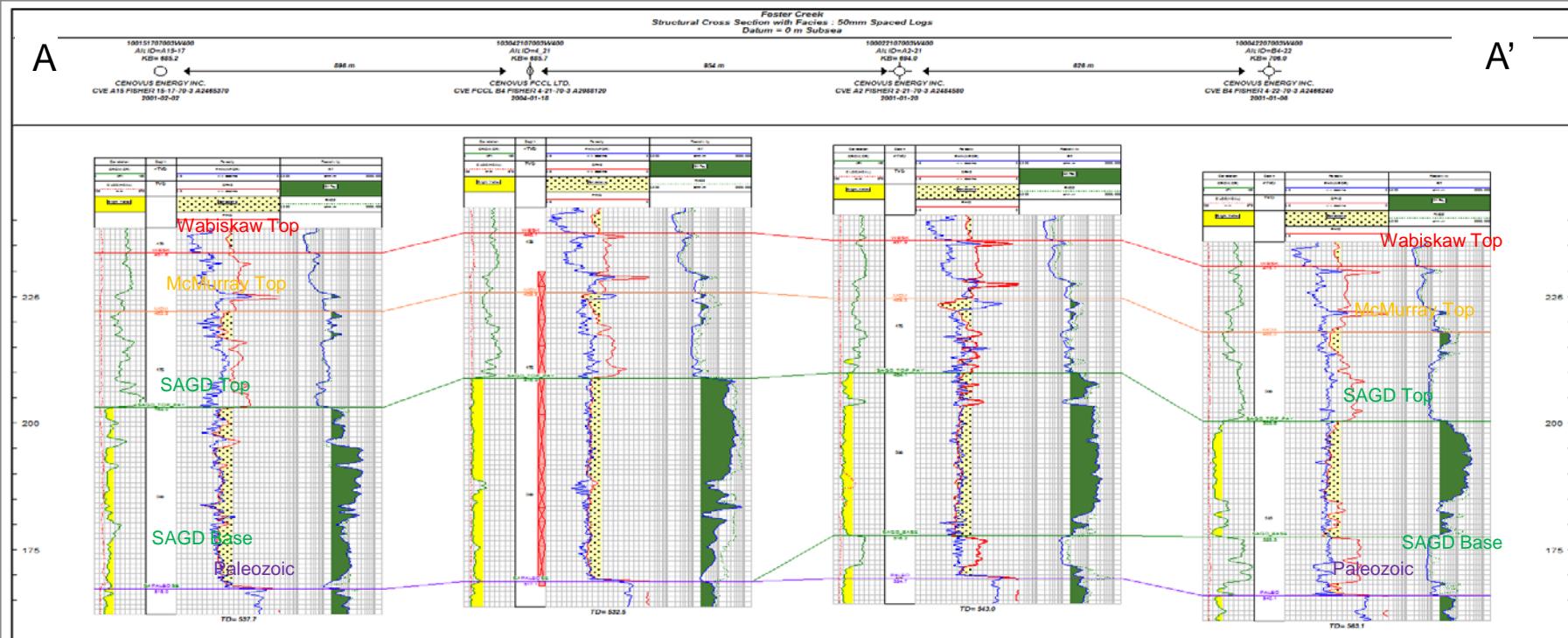
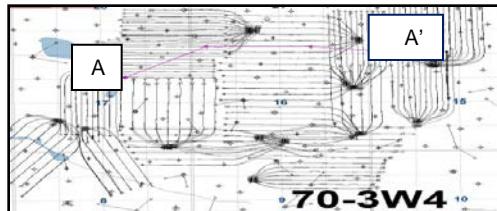
Subsections 3.1.1-2e) i-iii and f



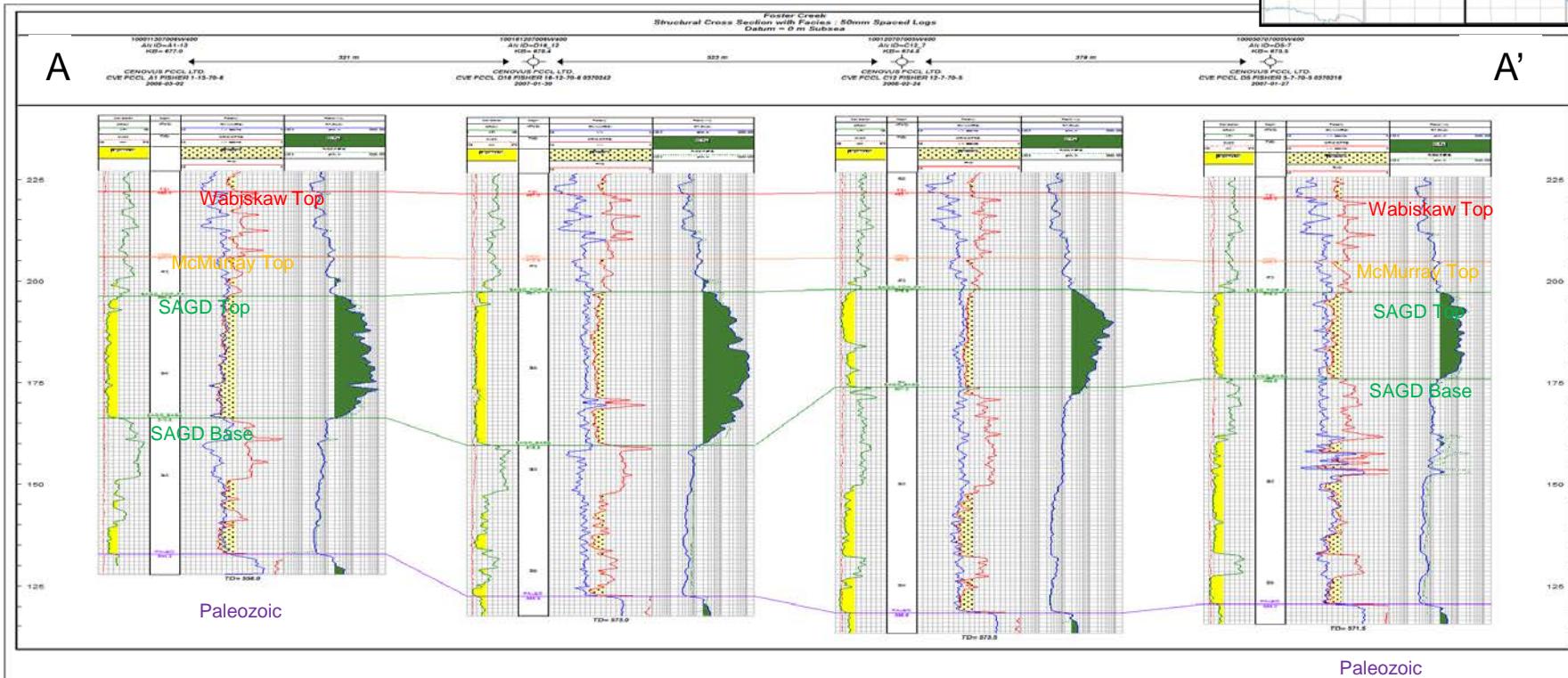
# Representative structural cross-section over Central area



# Representative structural cross-section over East area



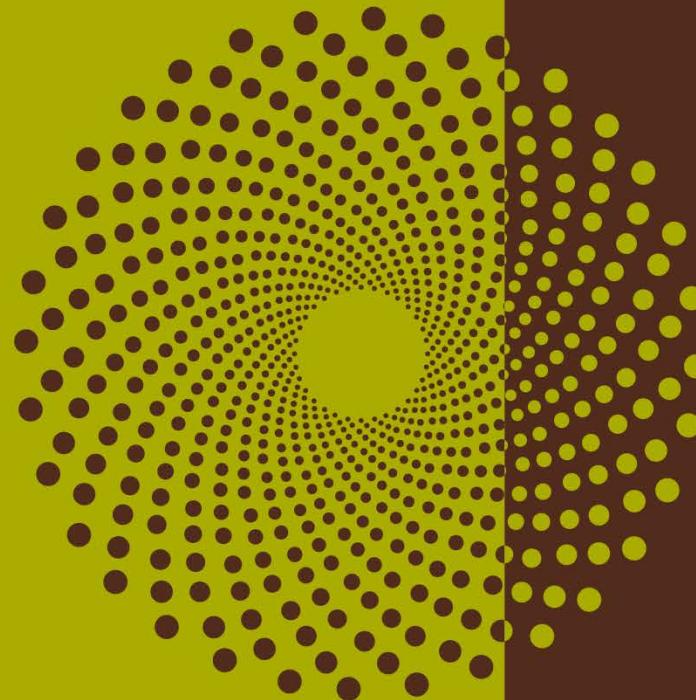
# Representative structural cross-section over West area



© 2017 Cenovus Energy Inc.  
May 30, 2017  
3.1.1-2e i-iii and f

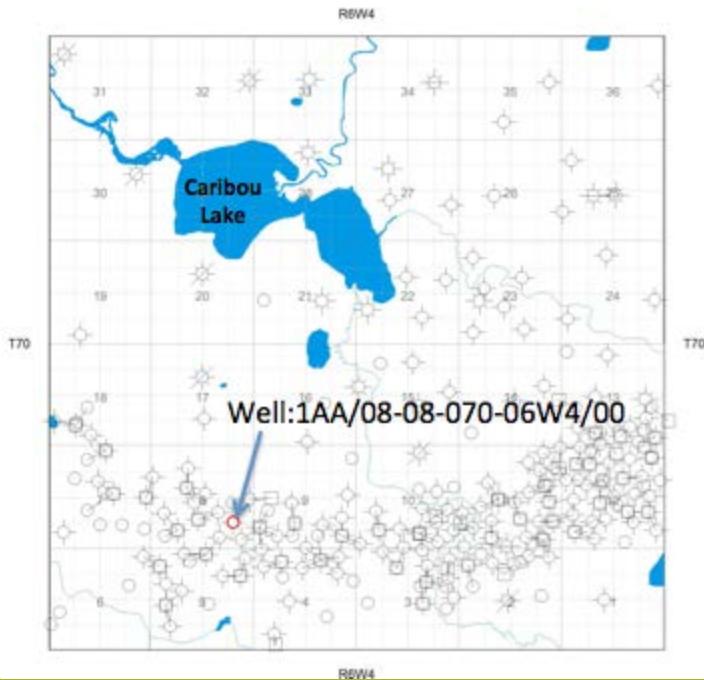
# Geo-mechanical Data

## Subsection 3.1.1-2) j



# Geomechanical data

## Sample from Well 1AA/08-08-070-6W4



Formation Interval	Depth (m)	Bulk Modulus, K (MPa)	Young's Modulus, E* (MPa)	c' <sub>peak</sub> (MPa)	ϕ' <sub>peak</sub>
T21(CEUDX2)	459.7	213	256	0	30°
T21(CEUDX1)	459.8	178	214	0	17°
T21(CEUDX3 & 4)	460.2	482	578	1.5	25°

\* Assumes v=0.3. K = E/3(1-2v)

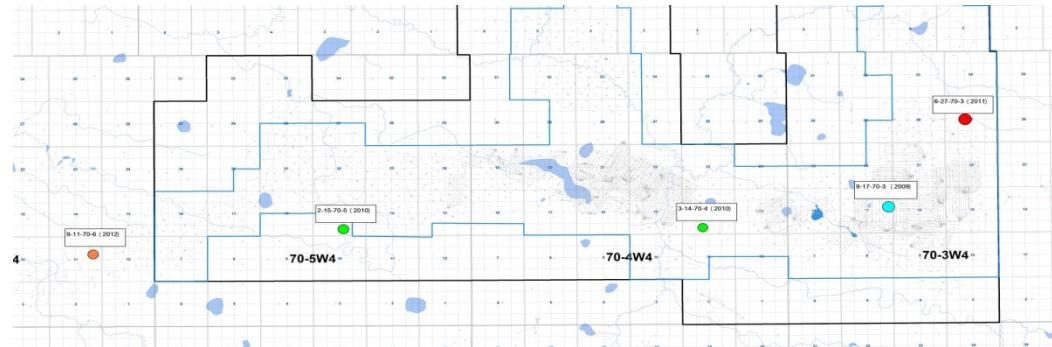
Formation Interval	Depth (m)	Bulk Modulus, K (MPa)	Young's Modulus, E* (MPa)	c' <sub>peak</sub> (MPa)	ϕ' <sub>peak</sub>
T11 (CEUDX5, 6 & 7)	466.6	482	578	0.4	32°

\* Assumes v=0.3. K = E/3(1-2v)

# Mini-frac wells

- We recognize that tensile and shear failure are two possible ways for integrity to be compromised
- Mini-frac data are related to the tensile failure ONLY

**9-17-70-3 (2009)**  
**2-15-70-5 (2010)**  
**3-14-70-4 (2010)**  
**6-27-70-3 (2011)**  
**9-11-70-6 (2012)**

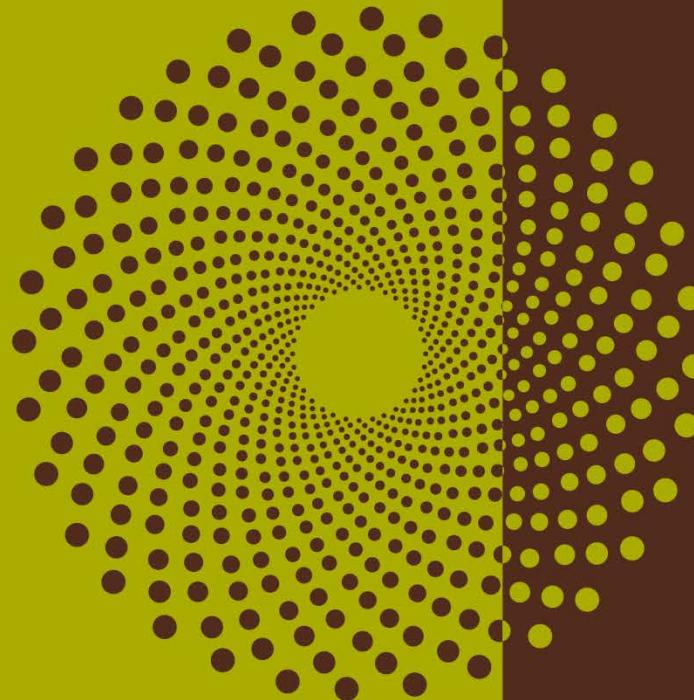


# Summary of Mini-frac test results

Test date	UWI	Zone	TVD (m)	Measured Closure Pressure (kPa/m)
2009	9-17-70-3	McMurray Sand	500.3	12.49
2010	2-15-70-5	Westgate Shale	280.3	21.79
2010	2-15-70-5	Grand Rapids Shale	360.8	17.55
2010	2-15-70-5	Clearwater Shale Caprock	421.3	20.98
2010	2-15-70-5	T31 (Clearwater Shale) Caprock	437.5	22.24
2010	2-15-70-5	Clearwater Sand	447.3	14.09
2010	2-15-70-5	Clearwater Sand	455.8	14.88
2010	2-15-70-5	Wabiskaw Shale (T11) Caprock	477.8	18.13
2010	3-14-70-4	Westgate Shale	260.3	21.67
2010	3-14-70-4	Grand Rapids Shale	344.3	16.91
2010	3-14-70-4	T31 (Clearwater Shale) Caprock	416.5	21.25
2010	3-14-70-4	Wabiskaw Shale (T11) Caprock	447.3	20.00
2010	3-14-70-4	McMurray Mudstone	459.3	19.29
2011	6-27-70-3	Westgate Shale	270.3	21.05
2011	6-27-70-3	Joli Fou Shale	330.3	23.69
2011	6-27-70-3	Grand Rapids Shale	395.8	17.22
2011	6-27-70-3	T31 (Clearwater Shale) Caprock	470.0	21.08
2011	6-27-70-3	T21 (Clearwater Shale) Caprock	493.3	22.91
2011	6-27-70-3	McMurray Sand	532.3	12.56
2012	9-11-70-6	Joli Fou Shale	313.7	23.46
2012	9-11-70-6	Clearwater Shale Caprock	434.0	19.94
2012	9-11-70-6	T31 (Clearwater Shale) Caprock	449.5	20.41
2012	9-11-70-6	T21 (Clearwater Shale) Caprock	471.5	21.55
2012	9-11-70-6	McMurray Sand	525.5	11.73

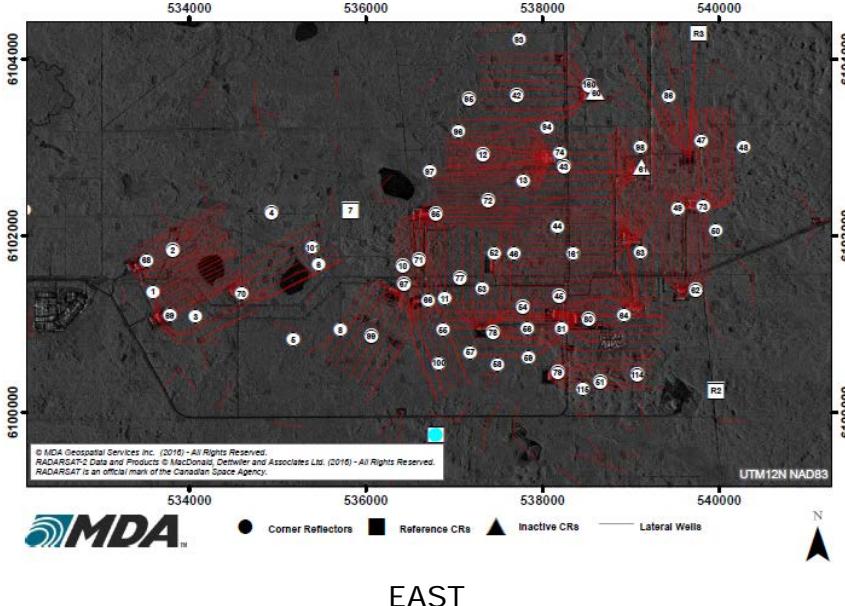
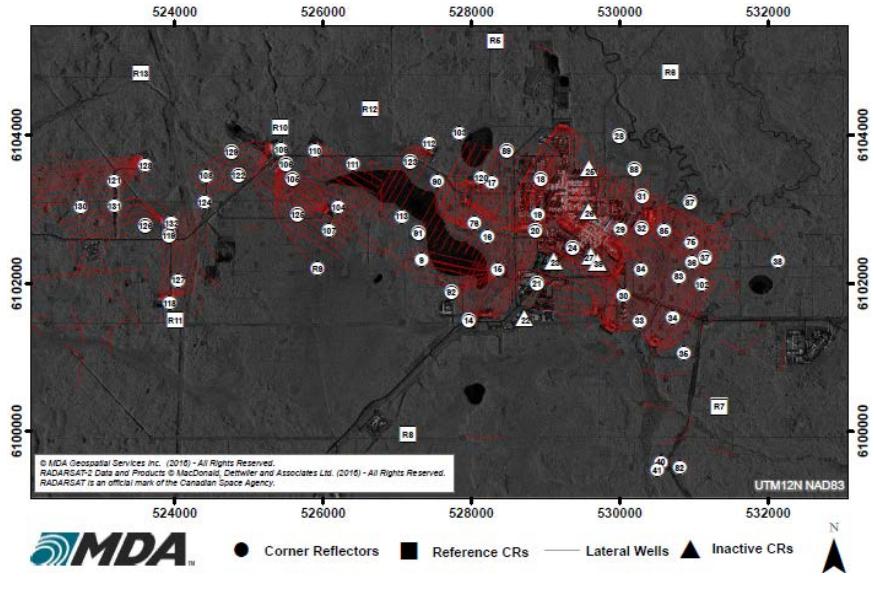
# Surface Monitoring

## Subsection 3.1.1 – 2) k



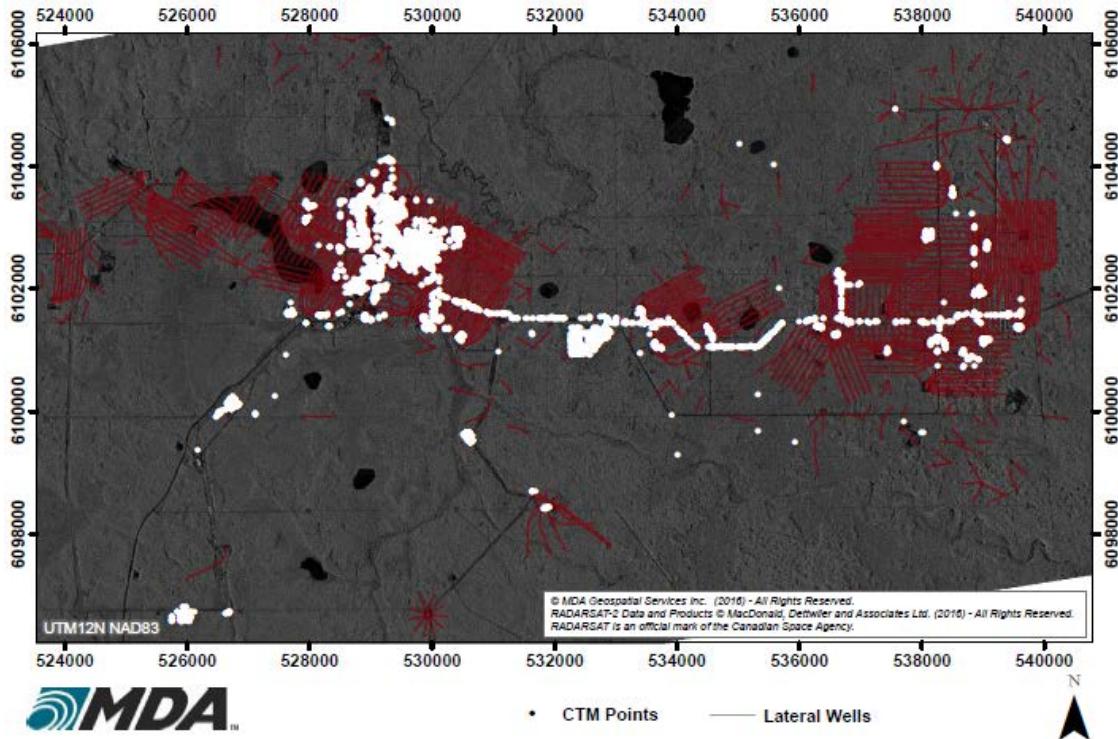
# 2016 ground heave monitoring

Active CRs: 136



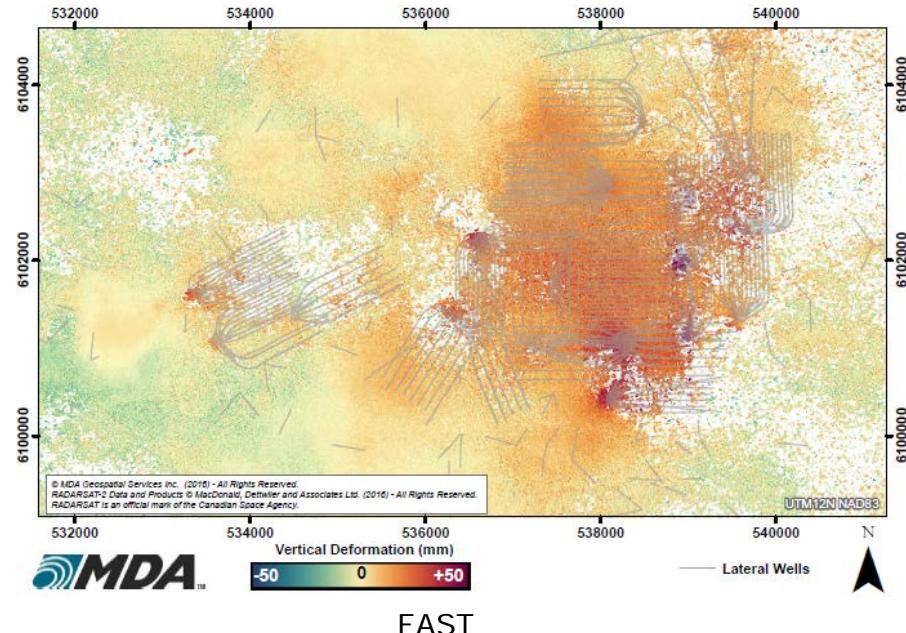
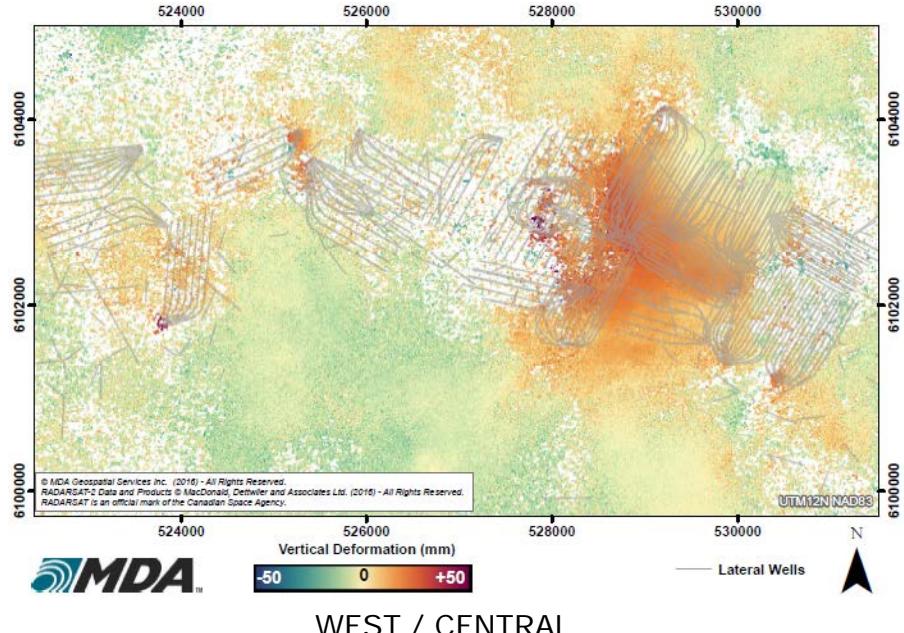
# 2016 ground heave monitoring

CTM Points: 22,083

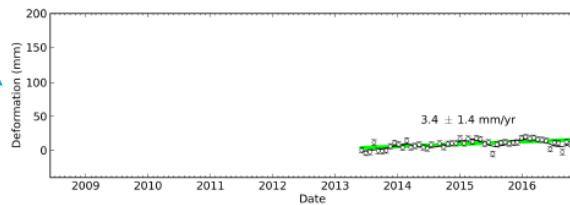
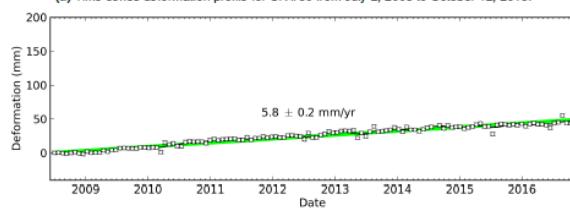
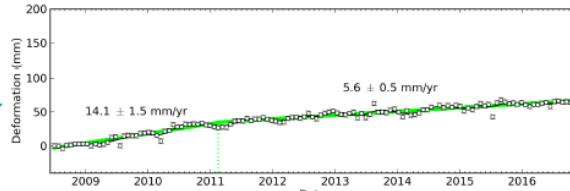
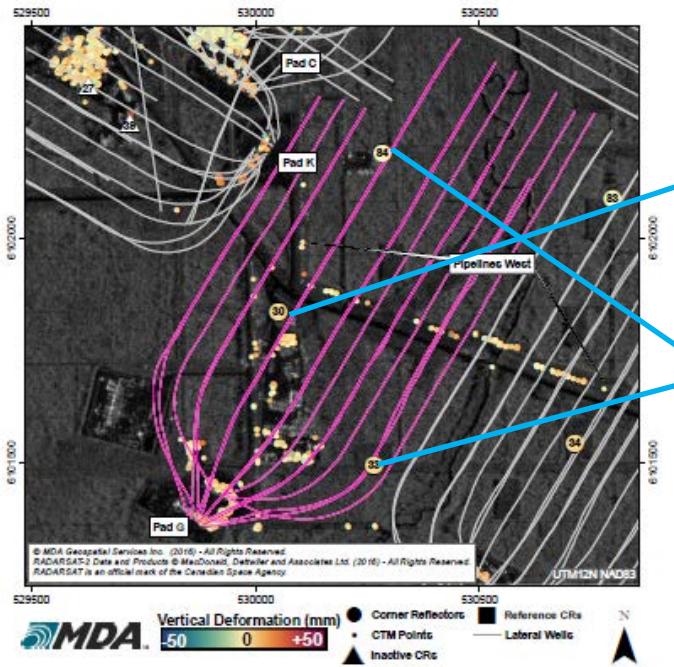


# 2016 ground heave monitoring

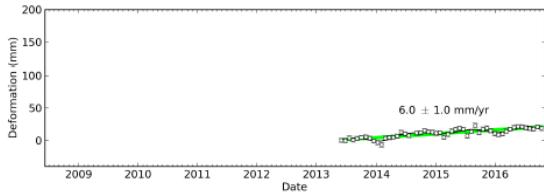
Deformation Map



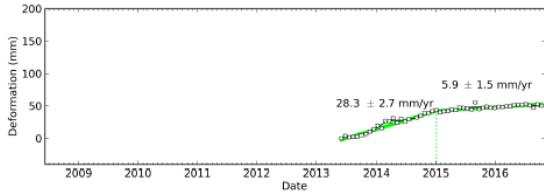
# Corner reflectors: G pad



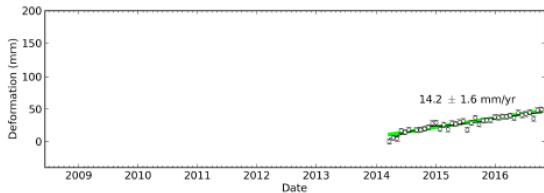
# Corner reflectors: W01 pad



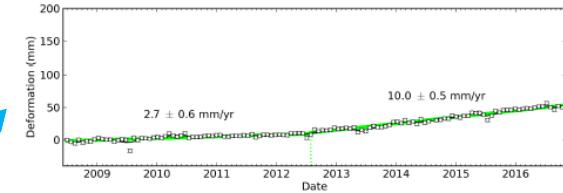
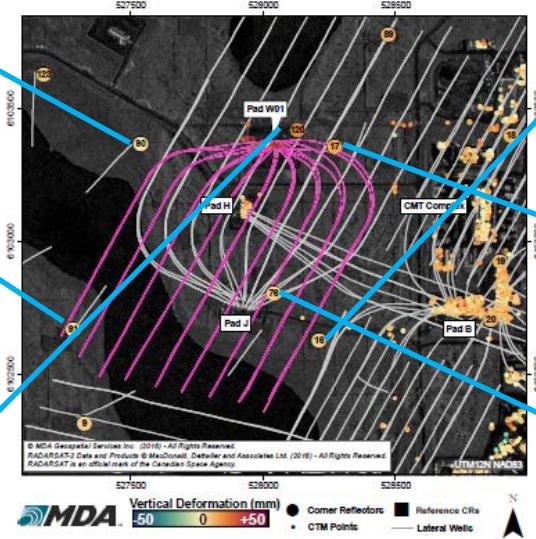
(a) Time series deformation profile for CR #90 from June 6, 2013 to October 12, 2016.



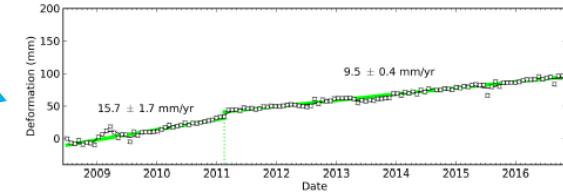
(b) Time series deformation profile for CR #91 from June 6, 2013 to October 12, 2016.



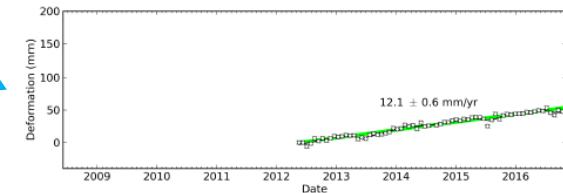
(c) Time series deformation profile for CR #120 from March 21, 2014 to October 12, 2016.



(a) Time series deformation profile for CR #16 from July 2, 2008 to October 12, 2016.

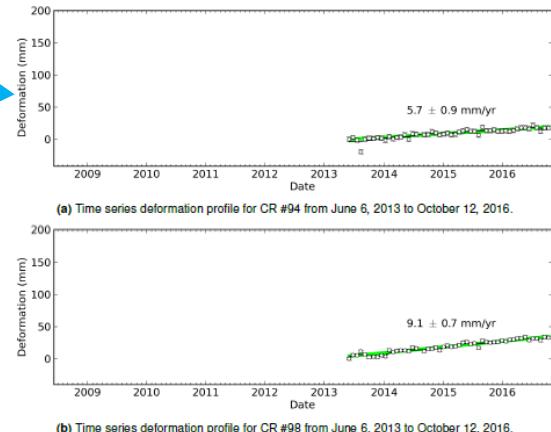
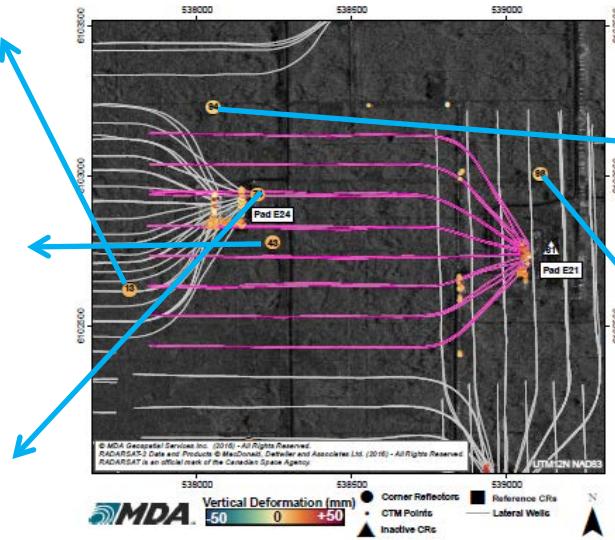
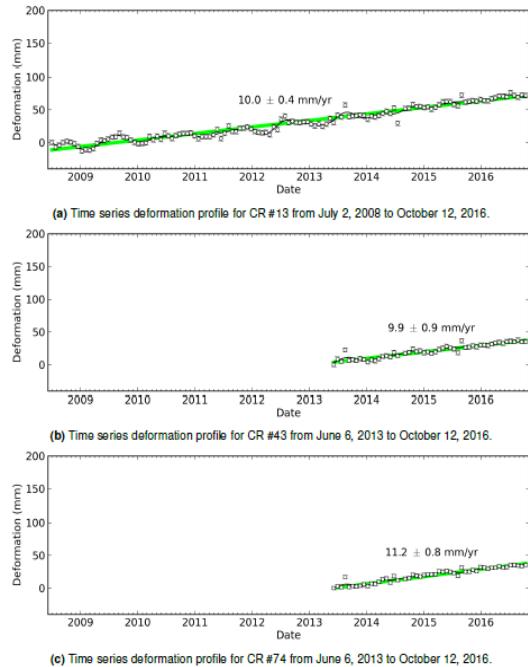


(b) Time series deformation profile for CR #17 from July 2, 2008 to October 12, 2016.



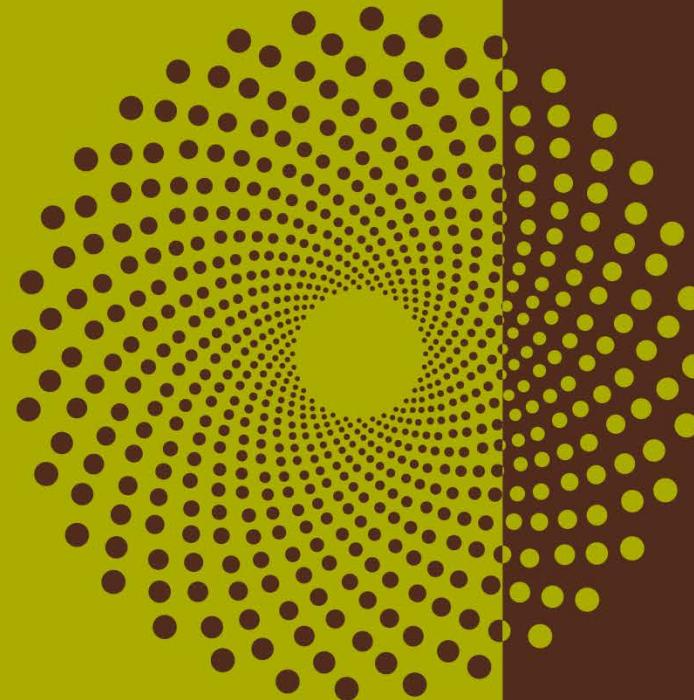
(c) Time series deformation profile for CR #76 from May 18, 2012 to October 12, 2016.

# Corner reflectors: E21 pad



# Caprock Integrity

Subsection 3.1.1 – 2) m

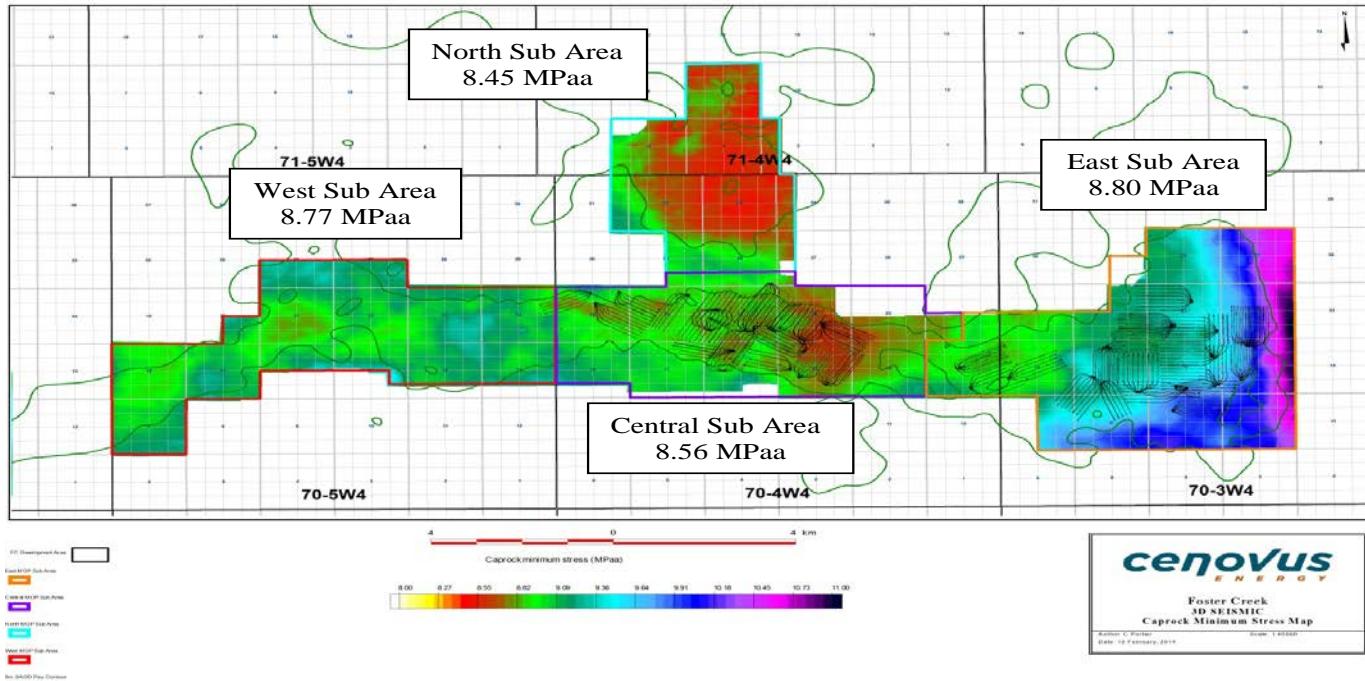


# Caprock monitoring plans

Cenovus monitors caprock integrity through:

- 1. SAGD injection pressure monitoring**
- 2. Piezometer monitoring in the T31 caprock**
  - Previously 3 locations
  - Added an additional 3 locations in 2015
- 3. Heave monitoring**
- 4. 4D seismic monitoring**

# Caprock minimum in-situ stress



Minimum in-situ stress values in the caprock vary across the project  
Smallest minimum in-situ stress values in each sub-area are shown in the above map

# Criteria for determining caprock integrity

Cenovus determines the minimum in-situ stress of the caprock over the project area through mini-frac testing and seismic mapping

Minimum in-situ stresses have shown variability across our development area

Current project contains four regions with different approved MOP values

- North – 6.6 MPag
- Central – 6.7 MPag
- West – 6.9 MPag
- East – 6.9 MPag

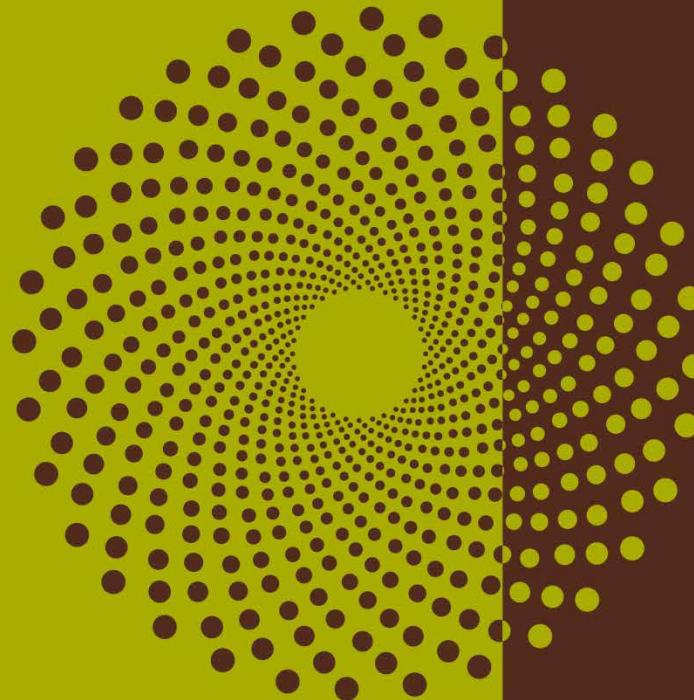
Operating pressures in the project vary through the various well stages

- steam stimulation/circulation: (5.5 – 6.6 MPa)\*
- ramp-up: (3.5 – 5.5 MPa)
- normal operating conditions: (2.0 – 3.5 MPa)

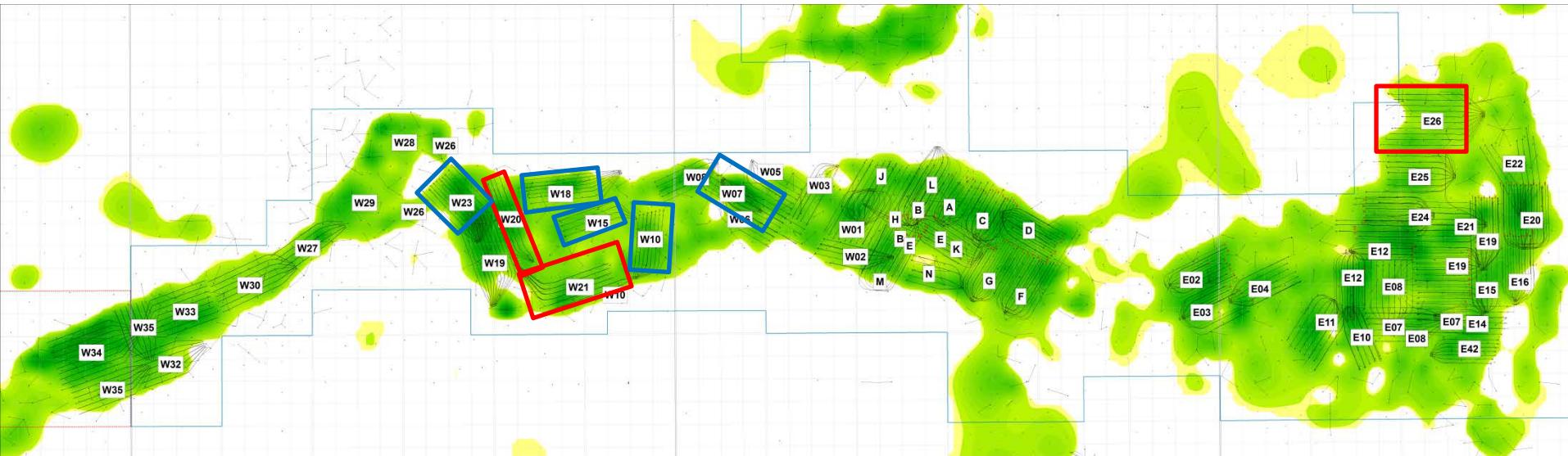
\* Note that this upper limit is specific to the MOP of each region

# Drilling and Completions

Subsection 3.1.1 – 3)



# March 2016 - March 2017 new SAGD well pairs drilling



## East Pads:

- E26
- W21, W20
- W07, W10, W15, W18, W19, W23

Mar 2016 - Mar 2017 Drilling  
 2016 Production

# Re-drills and re-entries

## List of re-drill and re-entry wells in Foster Creek since January 1, 2016

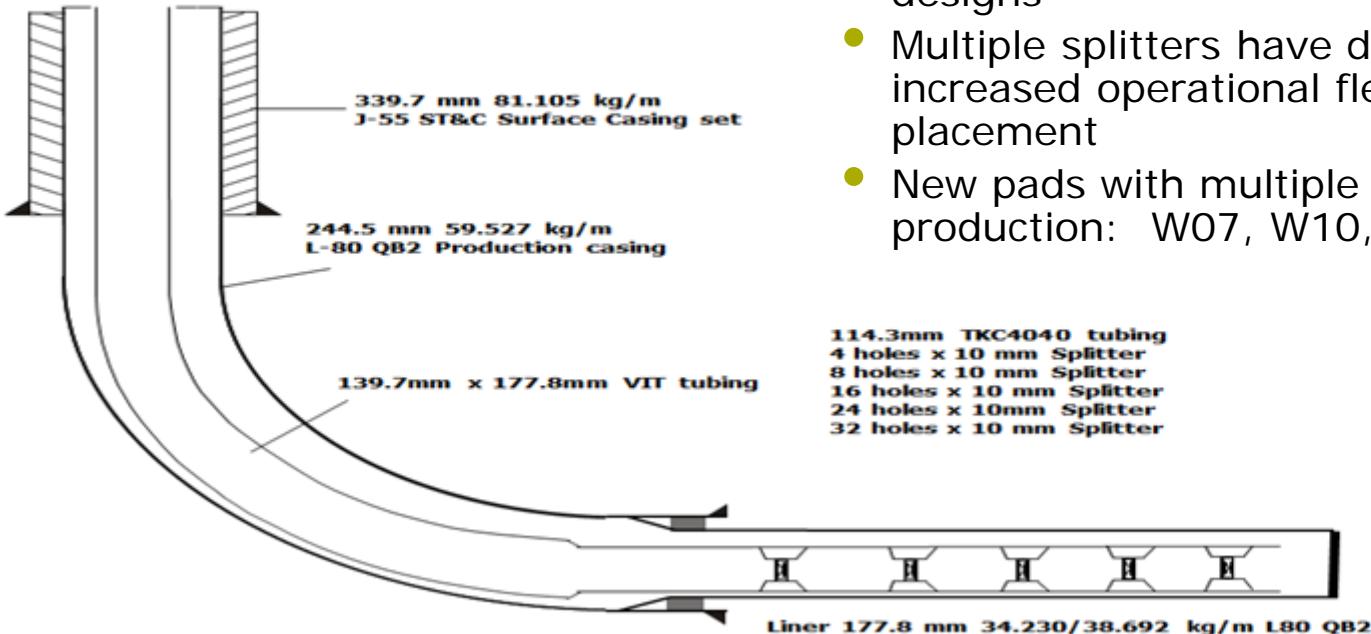
Well	Type	Drill Start Date	Comment / Status
LP03	Producer	02-Feb	Drilled
E25P08-1	Producer	08-Feb	Drilled
E08P05	Producer	15-Feb	Drilled
E03P04-1	Producer	22-Feb	Drilled
AP35	Producer	28-Feb	Drilled
E19P12-1	Producer	04-Mar	Drilled.
E19P03-1	Producer	10-Mar	Drilled
JP08-1	Producer	16-Mar	Drilled
LP05	Producer	21-Mar	Drilled.
W03P03	Producer	25-Mar	Drilled.
E04P08-1	Producer	29-Mar	Drilled.
E03P02-1	Producer	05-Apr	Drilled
W01P02-1	Producer	13-Apr	Drilled
JP02	Producer	24-Apr	Drilled
JP03-1	Producer	30-Apr	Drilled
E19P05-1	Producer	08-May	Drilled
W06I03	Injector	16-May	Drilled
W06P05-1	Producer	22-May	Drilled
E16P04	Producer	30-May	Drilled
E16IW06-1	Injector	05-Jun	Drilled
E20IW08-1	Injector	21-Jun	Drilled

Well	Type	Drill Start Date	Comment / Status
FWW6-1	Producer	14-Apr	Drilled
FP08 (FP03)	Producer	20-Apr	Drilled
FP07 (FP05)	Producer	27-Apr	Drilled
FI07 (FI05)	Injector	04-May	Drilled
FI08 (FI03)	Injector	12-May	Drilled
E24P08-1	Producer	21-May	Drilled.
E24I07-1	Injector	28-May	Drilled.
E24P03-1	Producer	03-Jun	Drilled.
E24P04-3	Producer	15-Jun	Drilled.
E24P02-1	Producer	20-Jun	Drilled.
E15P03-1	Producer	25-Jun	Drilled.
E15P02-1	Producer	02-Jul	Drilled
E15P01-1	Producer	09-Jul	Drilled
W02P01-1	Producer	14-Jul	Drilled
E24P07-1	Producer	21-Jul	Drilled
E24I08-1	Injector	28-Jul	Drilled
E24I04-1	Injector	03-Aug	Drilled
E24I03-1	Injector	09-Aug	Drilled
E24I02-1	Injector	17-Aug	Drilled
W06P02	Producer	25-Aug	Drilled
W06I02	Injector	29-Aug	Drilled

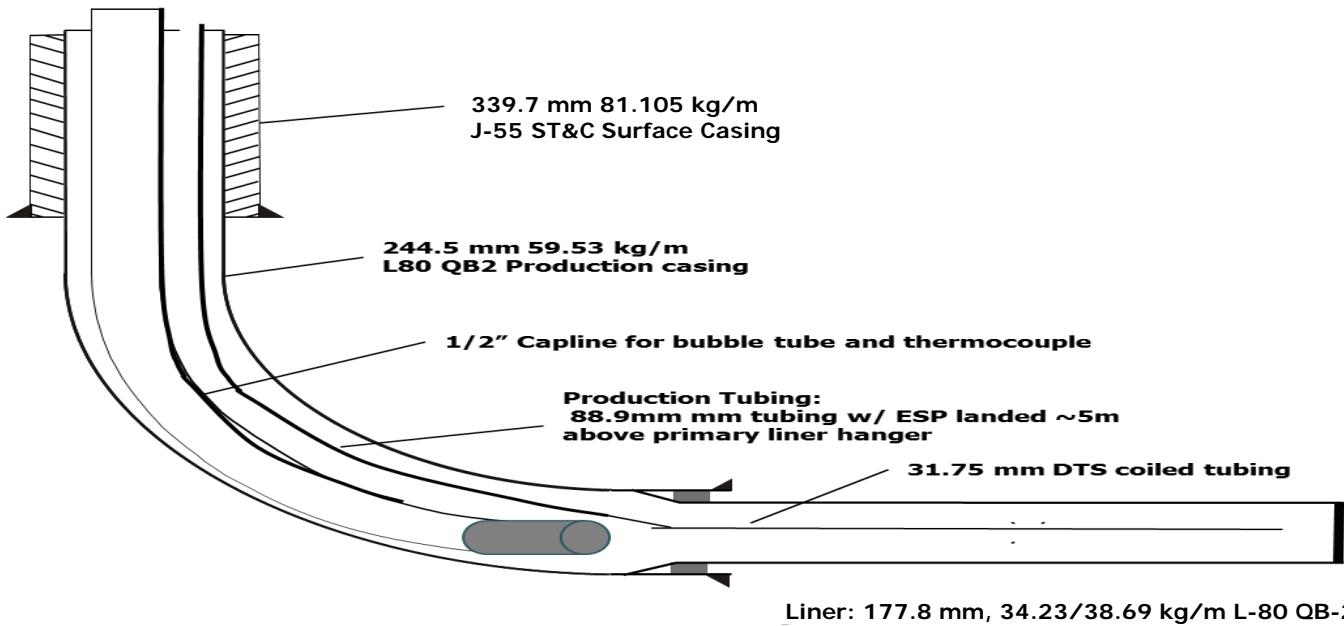
Well	Type	Drill Start Date	Comment / Status
W06I05-1	Injector	02-Sep	Drilled
W10P04-1	Producer	07-Sep	Drilled
W10P08	Producer	14-Sep	Drilled
W10P09	Producer	19-Sep	Drilled
W10I08	Injector	24-Sep	Drilled
W10I09	Injector	29-Sep	Drilled
E19I06-1	Injector	04-Oct	Drilled
E15P11-2	Producer	11-Oct	Drilled
E11P06-1	Producer	17-Oct	Drilled
GP06-1	Producer	23-Oct	Drilled
E20P04-1	Producer	29-Oct	Drilled
E08P06	Producer	09-Nov	Drilled
E25P06-1	Producer	14-Nov	Drilled.
GP02-1	Producer	24-Nov	Drilled
E12P07-2	Producer	30-Nov	Drilled.
E25P06-1	Producer	30-Aug	Drilled
E21P03-1	Producer	06-Sep	Drilled
E21P04-1	Producer	14-Sep	Drilled
E21P09	Producer	21-Sep	Drilled
E21I09	Injector	28-Sep	Drilled
NP04	Producer	06-Oct	Drilled

# Standard injector completion

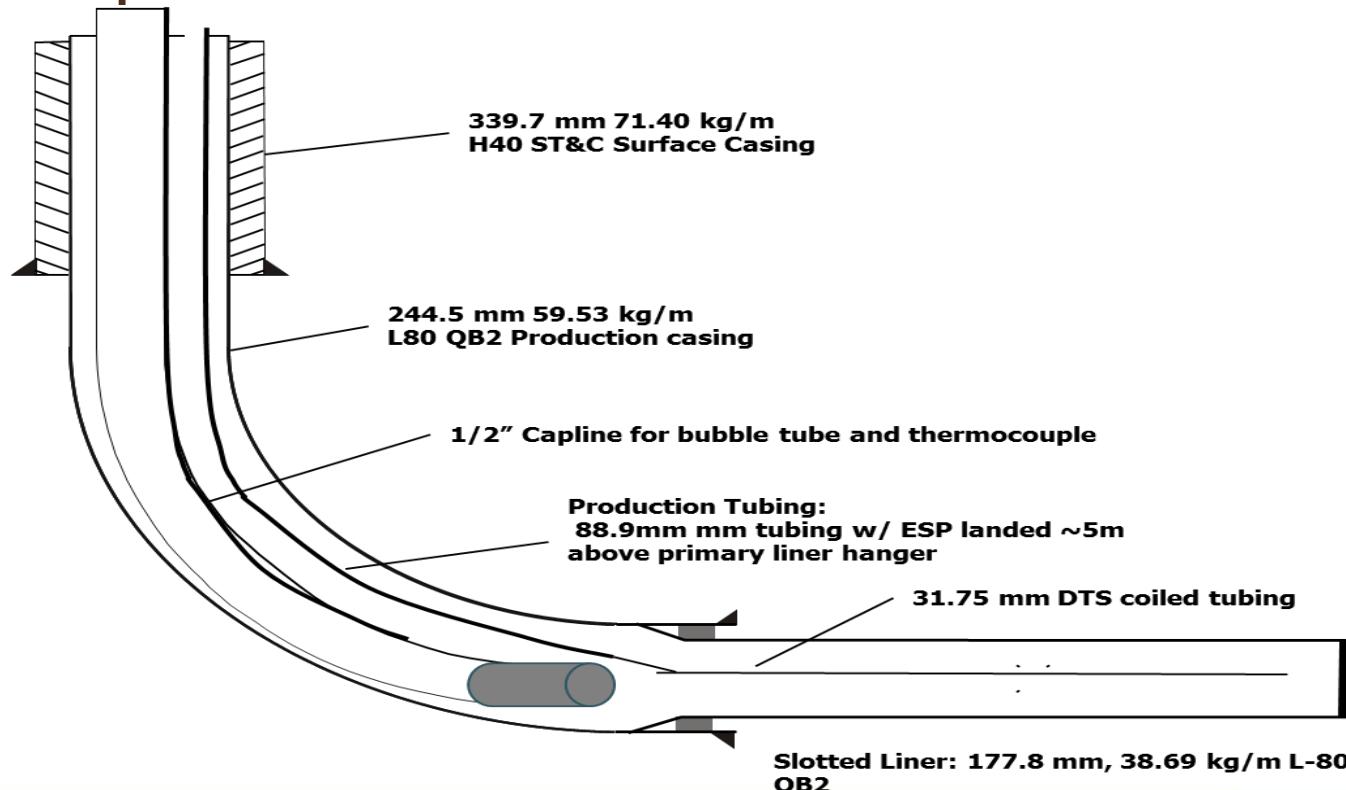
- Majority of well pairs at Foster Creek have been started up with single splitter injector designs
- Multiple splitters have demonstrated increased operational flexibility with steam placement
- New pads with multiple splitter designs on production: W07, W10, W18



# Standard producer Electric Submersible Pump (ESP) completion

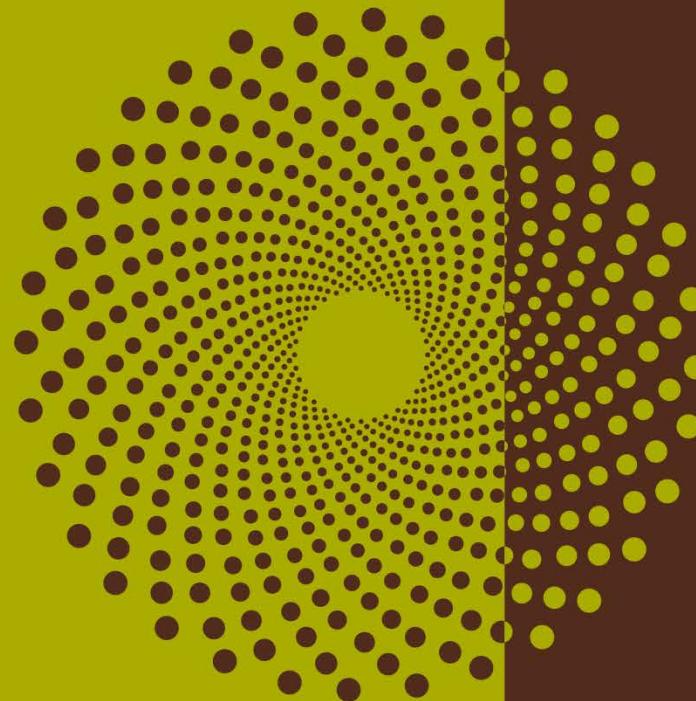


# Standard Wedge Well™ technology completion



# Artificial lift

Subsection 3.1.1 – 4)



# Artificial lift

## Electric submersible pumps (ESPs)

- all operating SAGD pairs (~264 producers) are currently equipped with ESPs

## Rod pumps

- 33/97 operating wells utilizing Wedge Well™ technology are equipped with rod pumps
- rod pumps at Foster Creek can range from about 0 – 350 m<sup>3</sup>/d

	ESPs	Rod pumps
Turn down (m <sup>3</sup> /d)	72	0
Max. rate (m <sup>3</sup> /d)	1200	350
Max. operating temp (°C)	250	200+
Number of pumps	264	33
Average run life (months)	11	5.0

# Artificial lift – continued

## ESPs

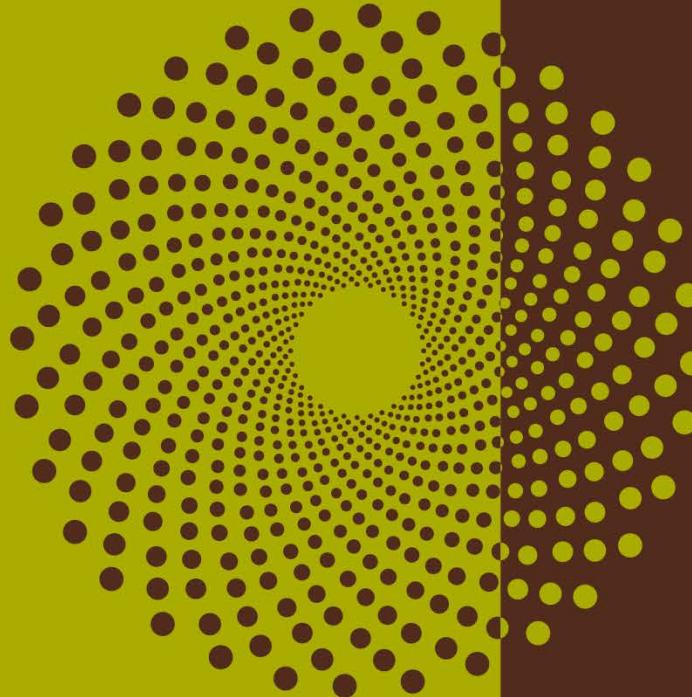
- Working with vendors to increase runtime

## Rod pumps

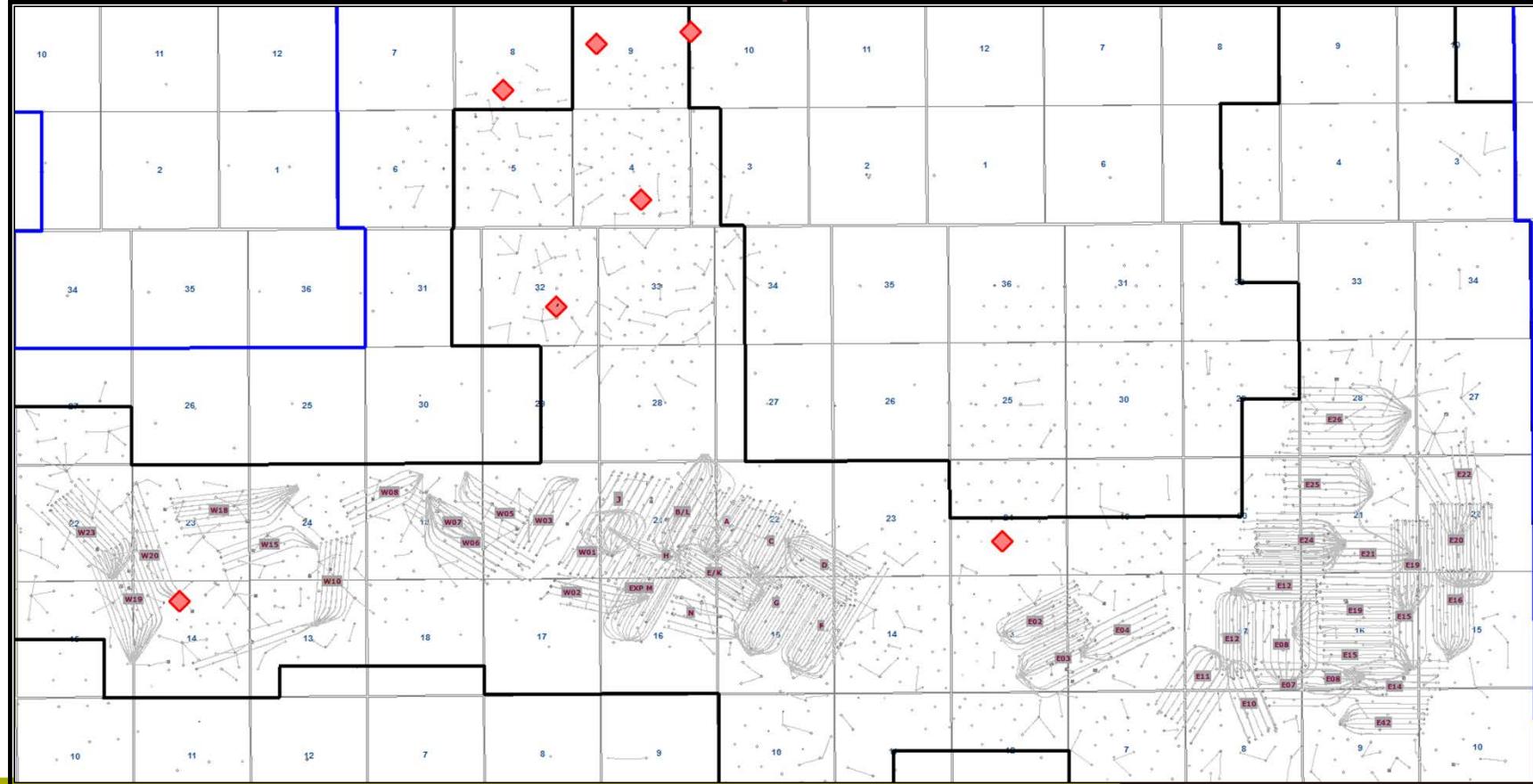
- Previously utilizing Wedge Well™ technology

# Instrumentation in wells

Subsection 3.1.1 – 5)



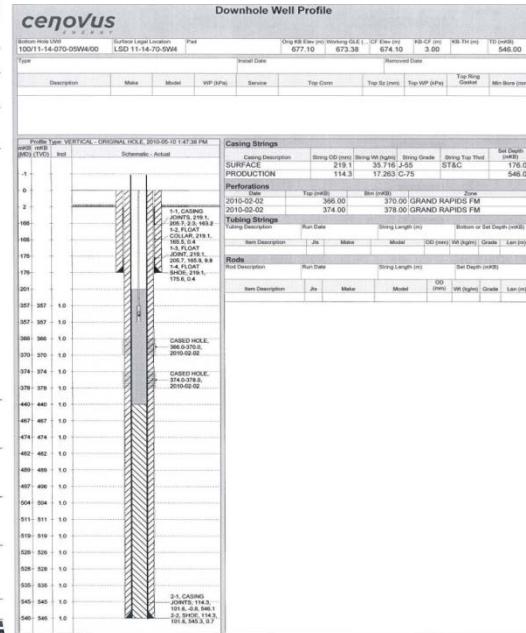
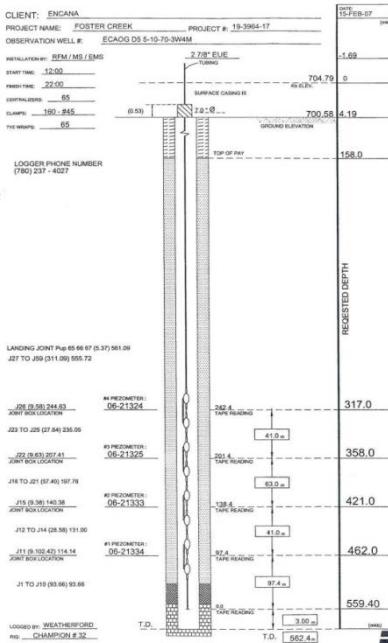
# Foster Creek 2017 piezometer locations



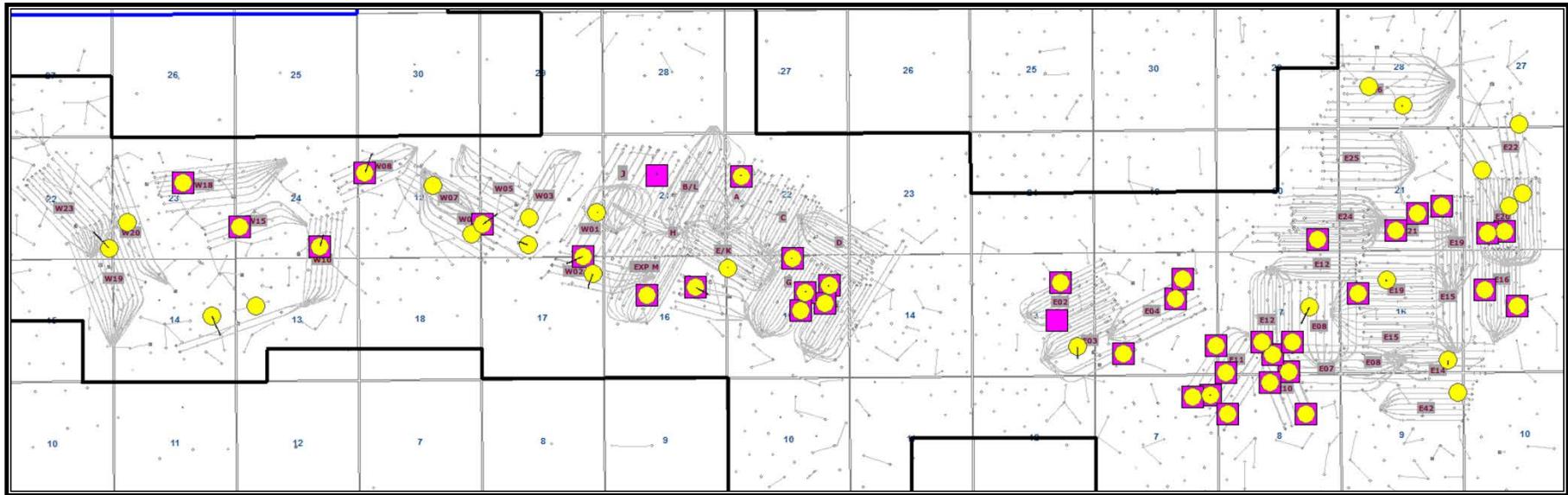
# Piezometer details

## Three installation types:

- Cemented tubing - vibrating wire piezometers mounted on tubulars and cemented in place (14 wells)
  - Hanging wire – pressure / temperature gauges hung from the wellhead to about 10-15m above perforations (10 wells)
  - Cemented casing – High temperature Optical pressure sensors strapped and cemented to the production casing (39 wells)
  - Seven new McMurray piezometers installed



# Foster Creek temperature and RST data - 2017



2017 RST logging (62)

2017 Temperature logging (37)

# Instrumentation in SAGD wells

## SAGD steam injector

- blanket gas for pressure measurement

## SAGD producer

- $\frac{1}{2}$ " capline strapped to tubing for bubble tubes and single point thermocouple
- distributed temperature sensing (DTS) strings installed in majority of new wells

## SAGD using our patented Wedge Well™ technology

- no downhole instrumentation with rod pumps
- new wells with ESPs to be equipped with  $\frac{1}{2}$ " capline strapped to production tubing string to measure pressure and temperature

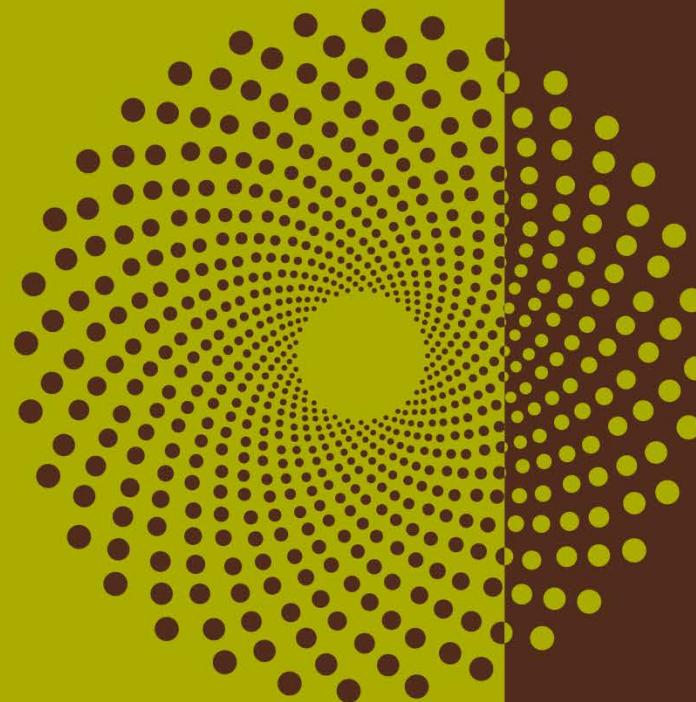
\* Schematics can be referenced in subsection 3.1.1 – 3 c)

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

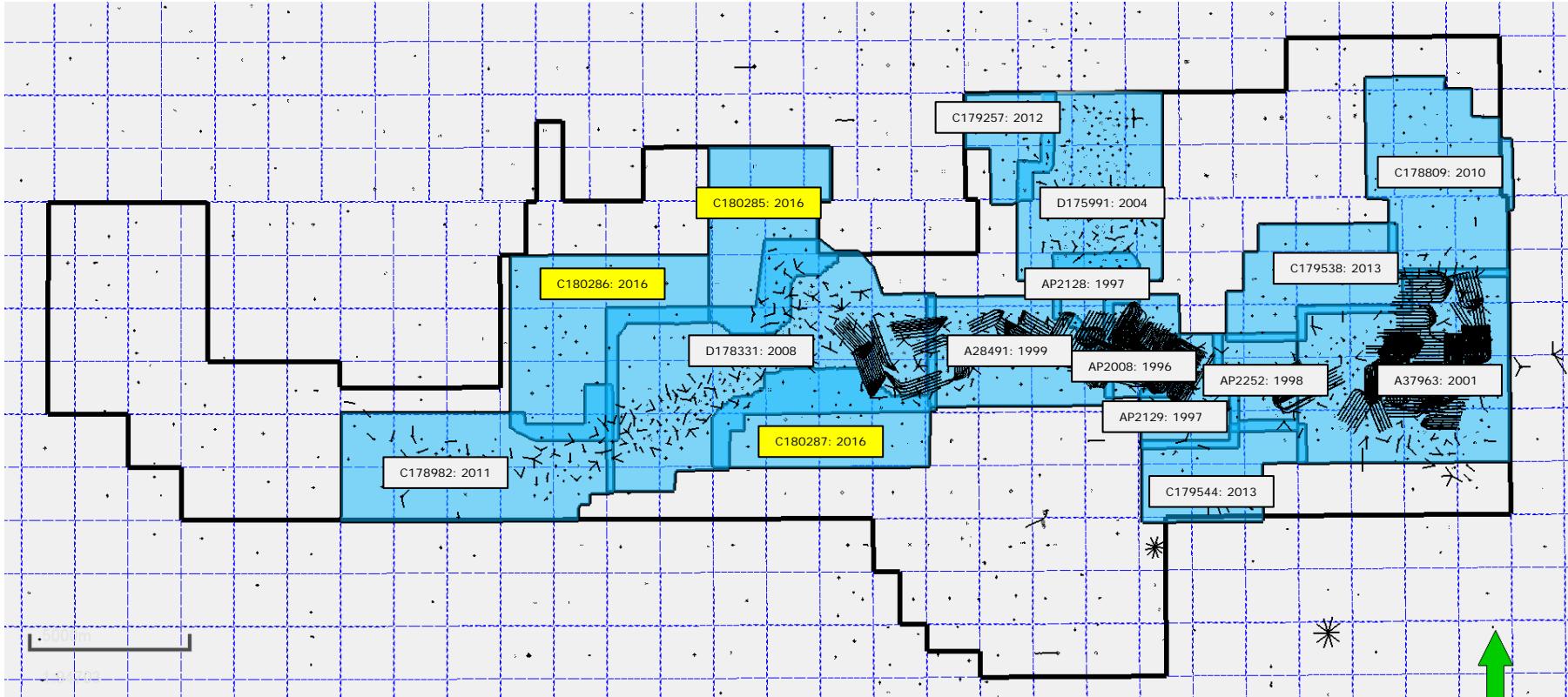
**Requirements under Subsection 3.1.1 5c) and d) are located in the Appendix**

# 4D seismic

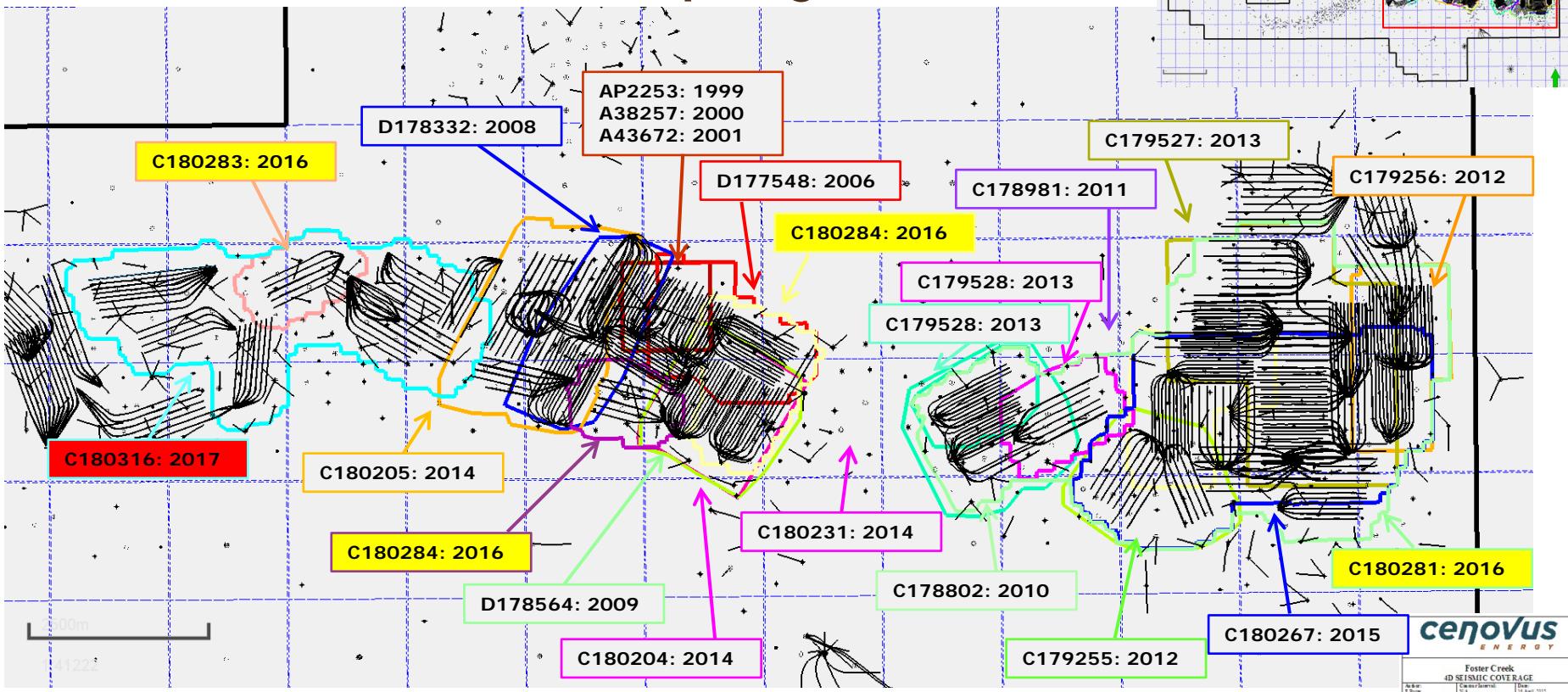
Subsection 3.1.1 – 6)



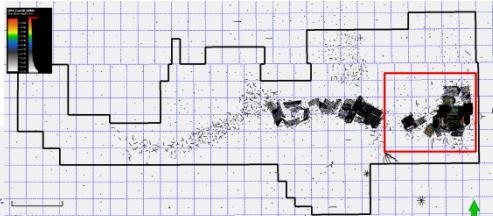
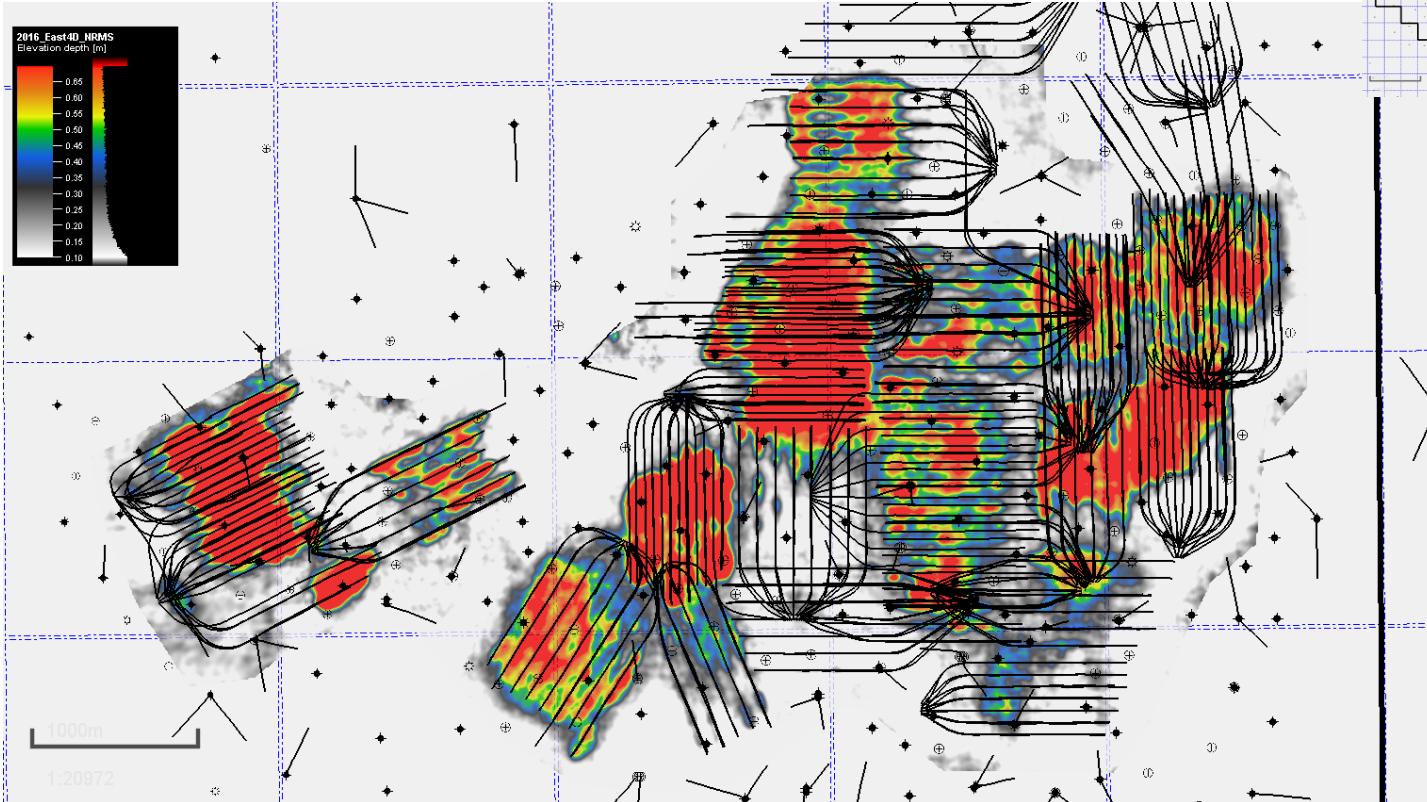
# 3D seismic within Project Area



# 4D seismic within project area



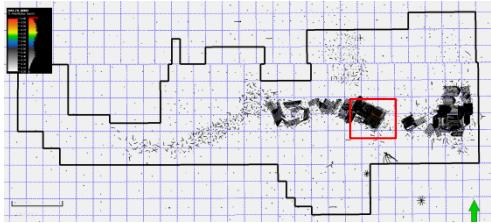
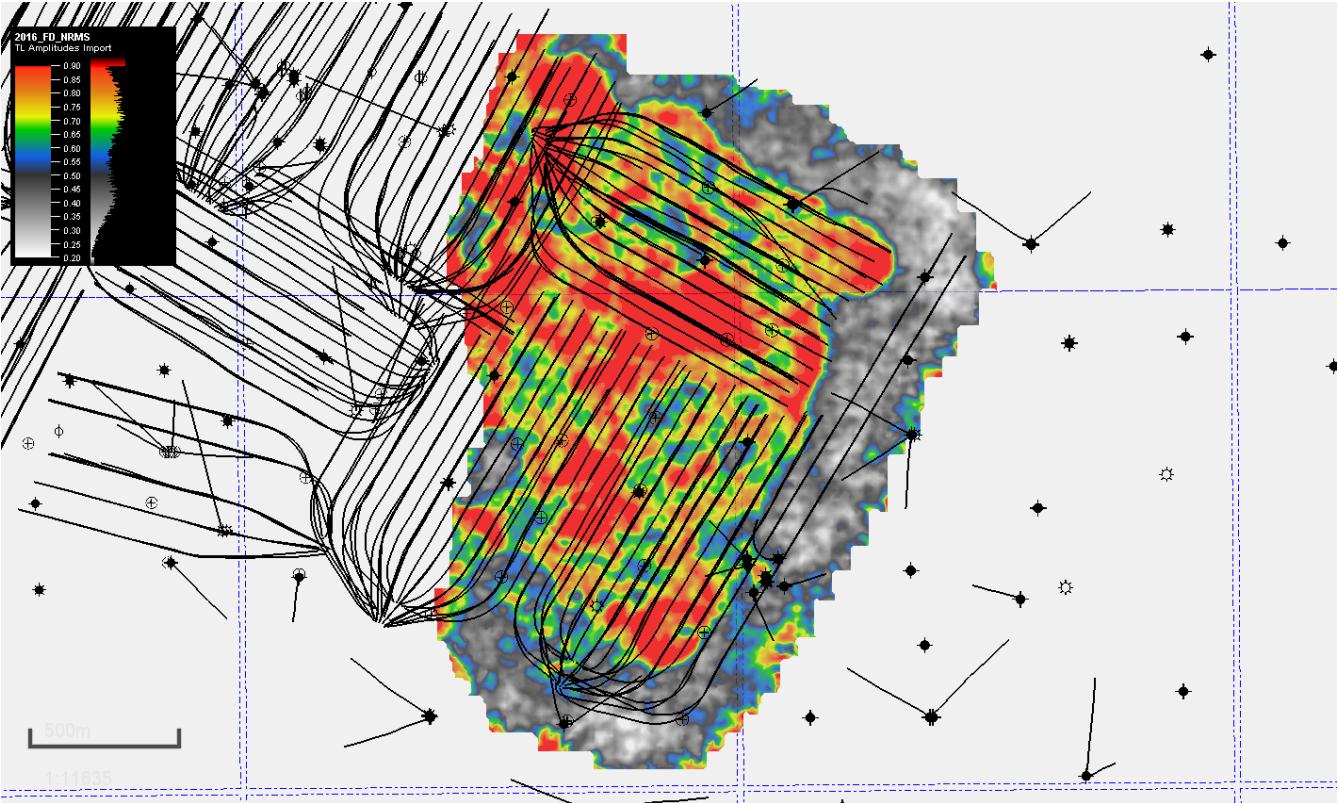
# 2016 East 4D seismic



## 4D NRMS

Normalized Root Mean Square is a measure of repeatability between the baseline and monitor surveys. Higher values indicate less repeatability and heated reservoir

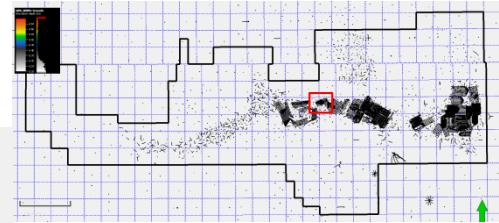
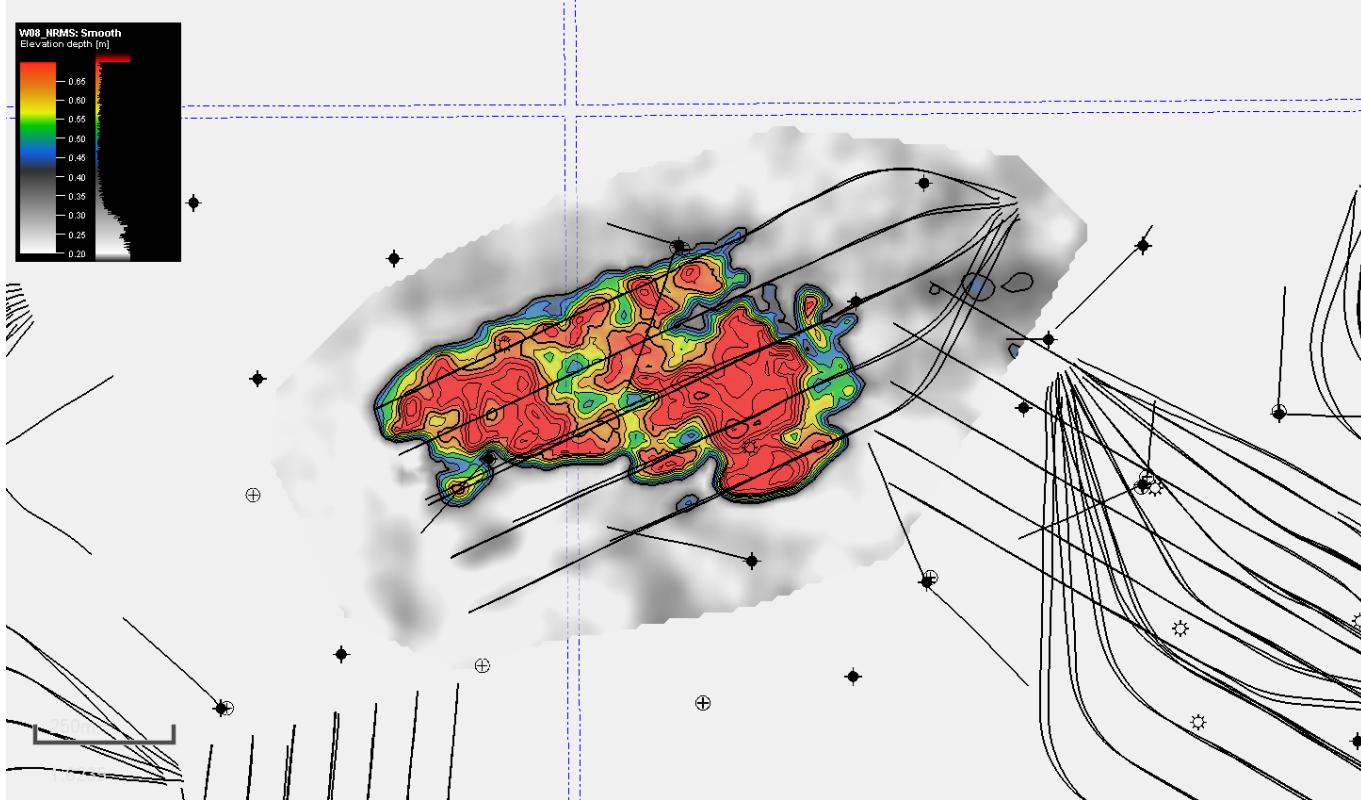
# 2016 FD 4D Seismic



## 4D NRMS

Normalized Root Mean Square is a measure of repeatability between the baseline and monitor surveys. Higher values indicate less repeatability and heated reservoir.

# 2016 W08 4D seismic

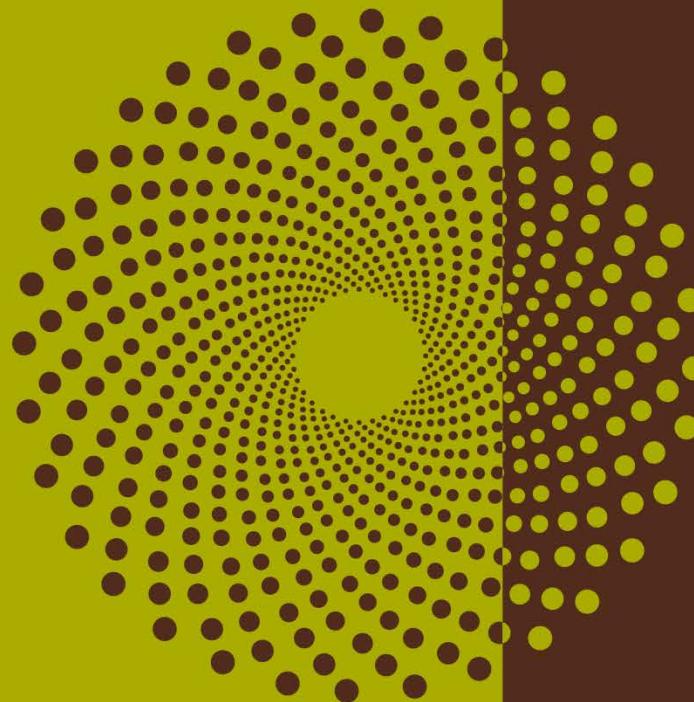


## 4D NRMS

Normalized Root Mean Square is a measure of repeatability between the baseline and monitor surveys. Higher values indicate less repeatability and heated reservoir.

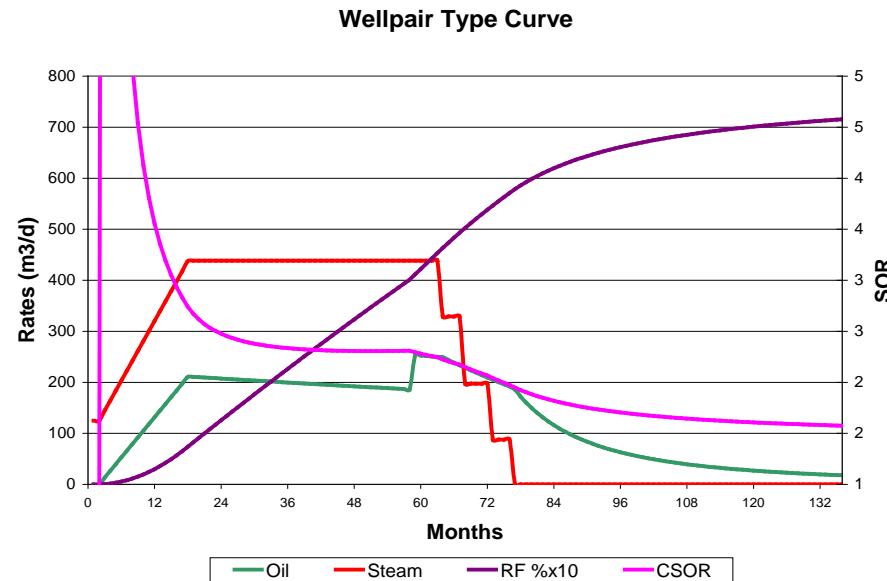
# Scheme performance

Subsection 3.1.1 – 7 a)

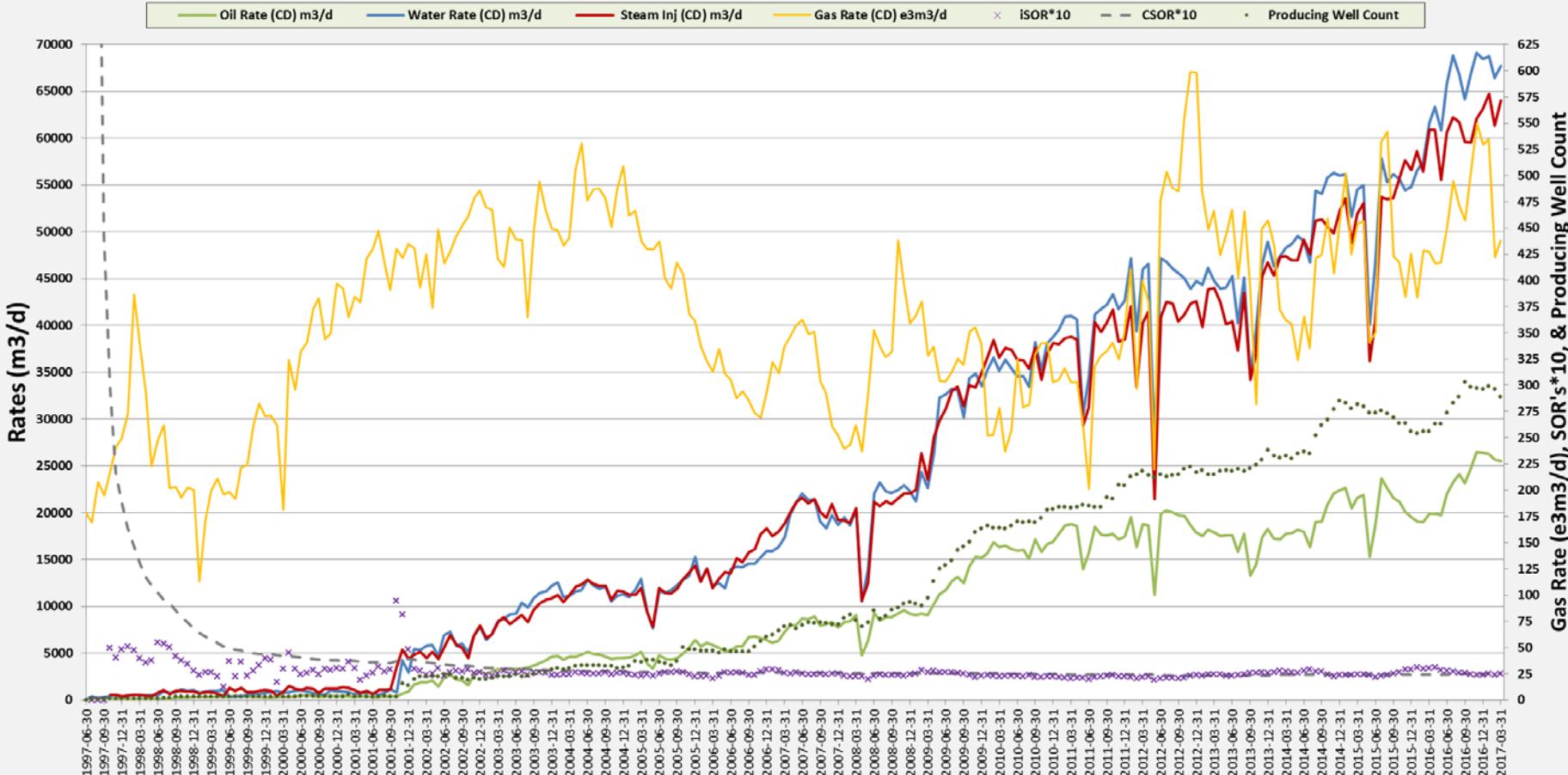


# Scheme performance prediction

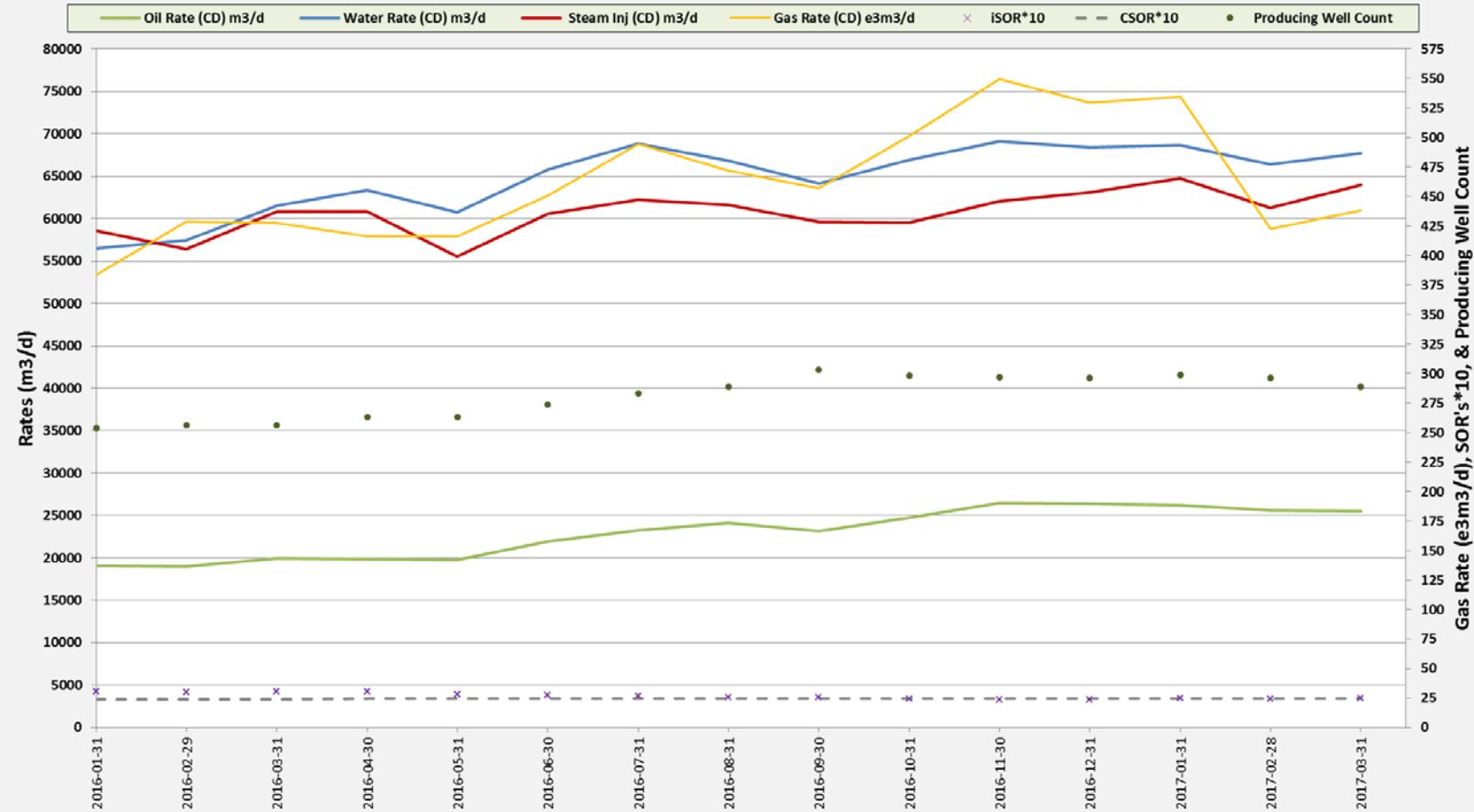
- Predict well pair performance based on modified Butler's equation
- Predict well pair CSOR using published CSOR correlations (*Edmunds & Chhina 2002*)
- Generate overall scheme production performance by adding individual well forecasts over time to honour predicted steam capacity and water treating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



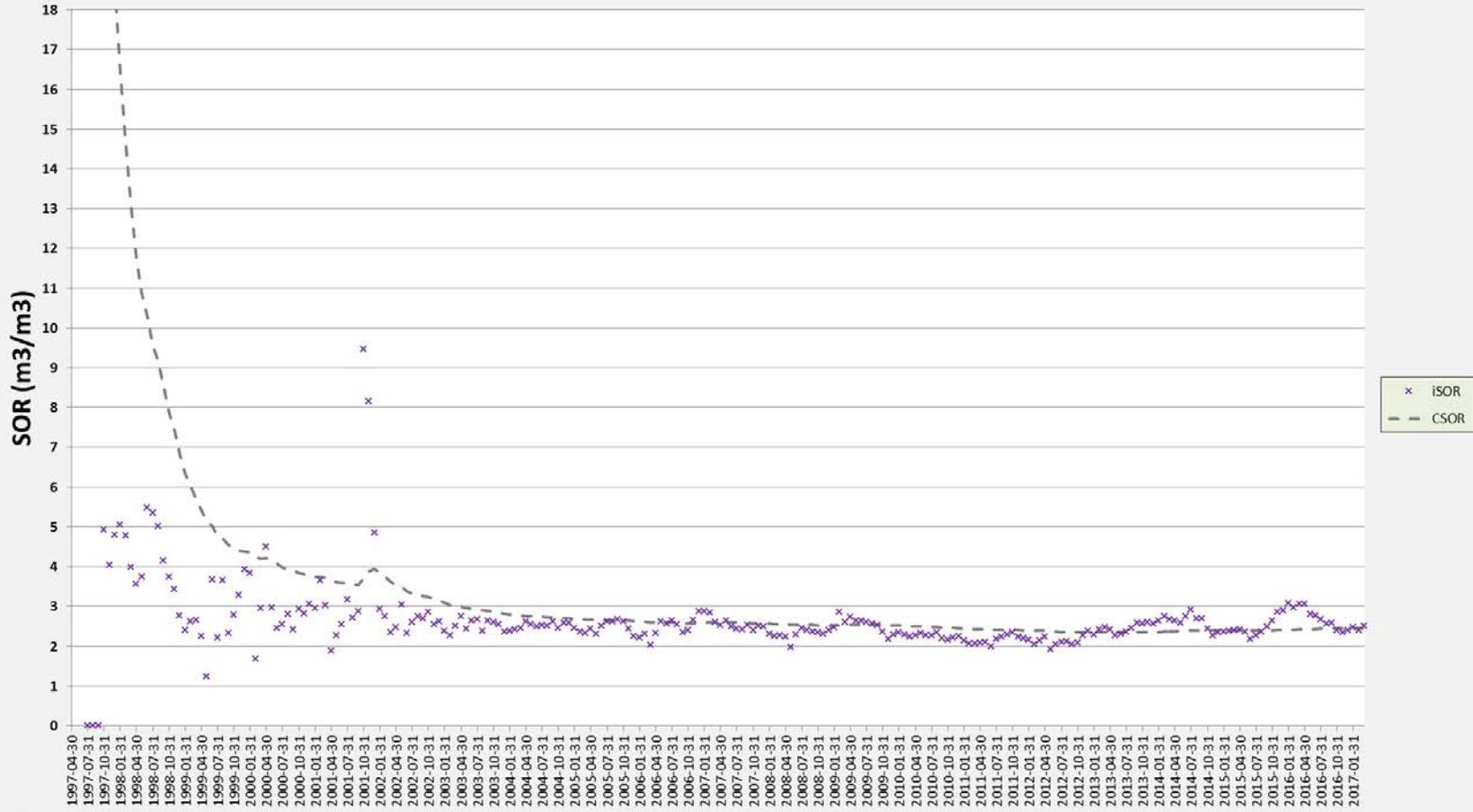
# Foster Creek Performance



## Foster Creek Performance



## Foster Creek SOR



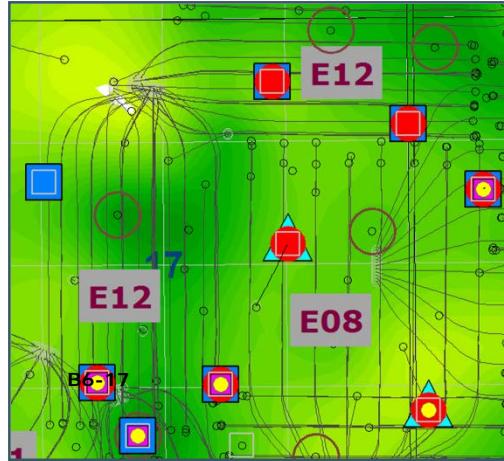
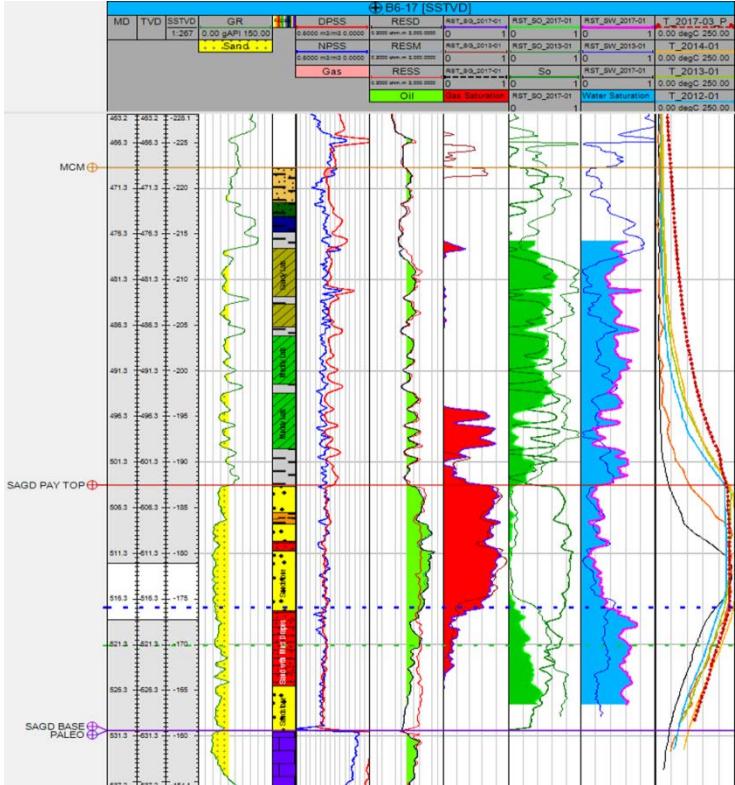
# Methods for monitoring chamber development

**Cenovus uses the following methods for monitoring chamber development:**

- Observation wells
- Specialized logging and coring
- Seismic
- Volumetrics

# Foster Creek temperature wells

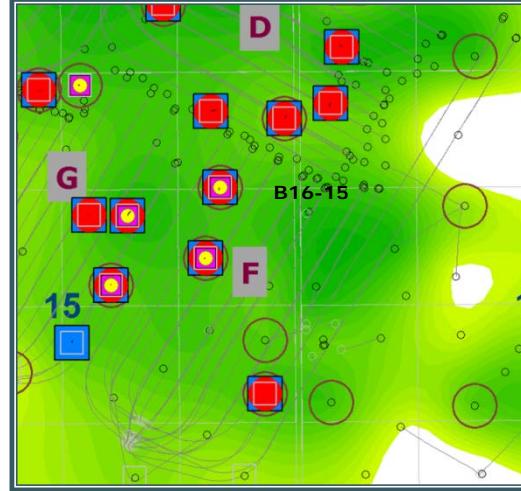
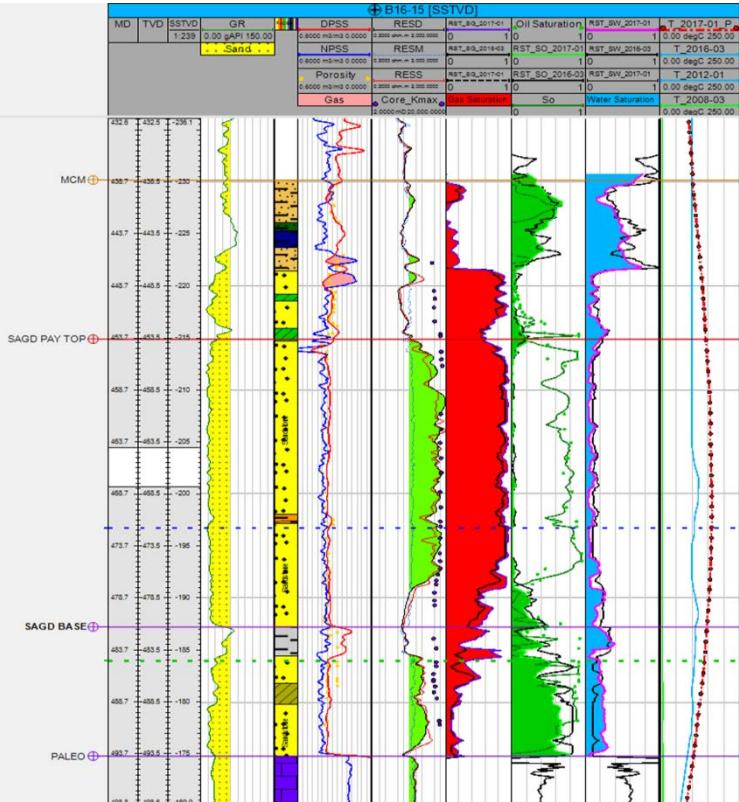
B6-17



8m offsite E12P02

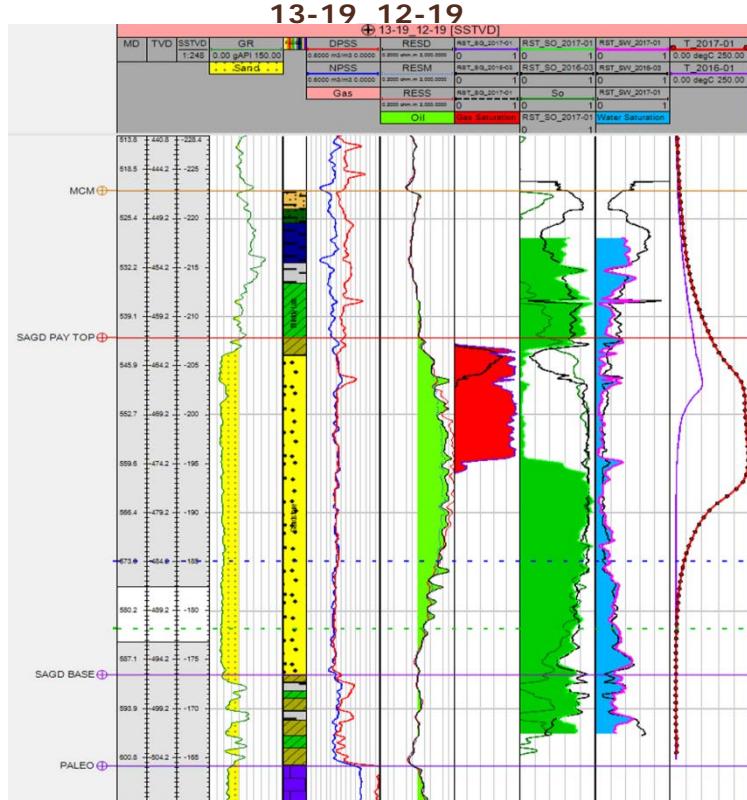
# Foster Creek temperature wells

B16-15



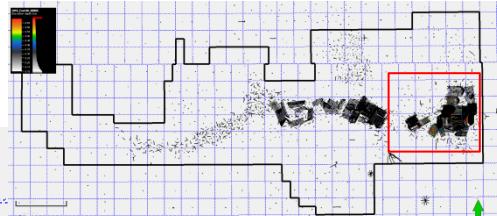
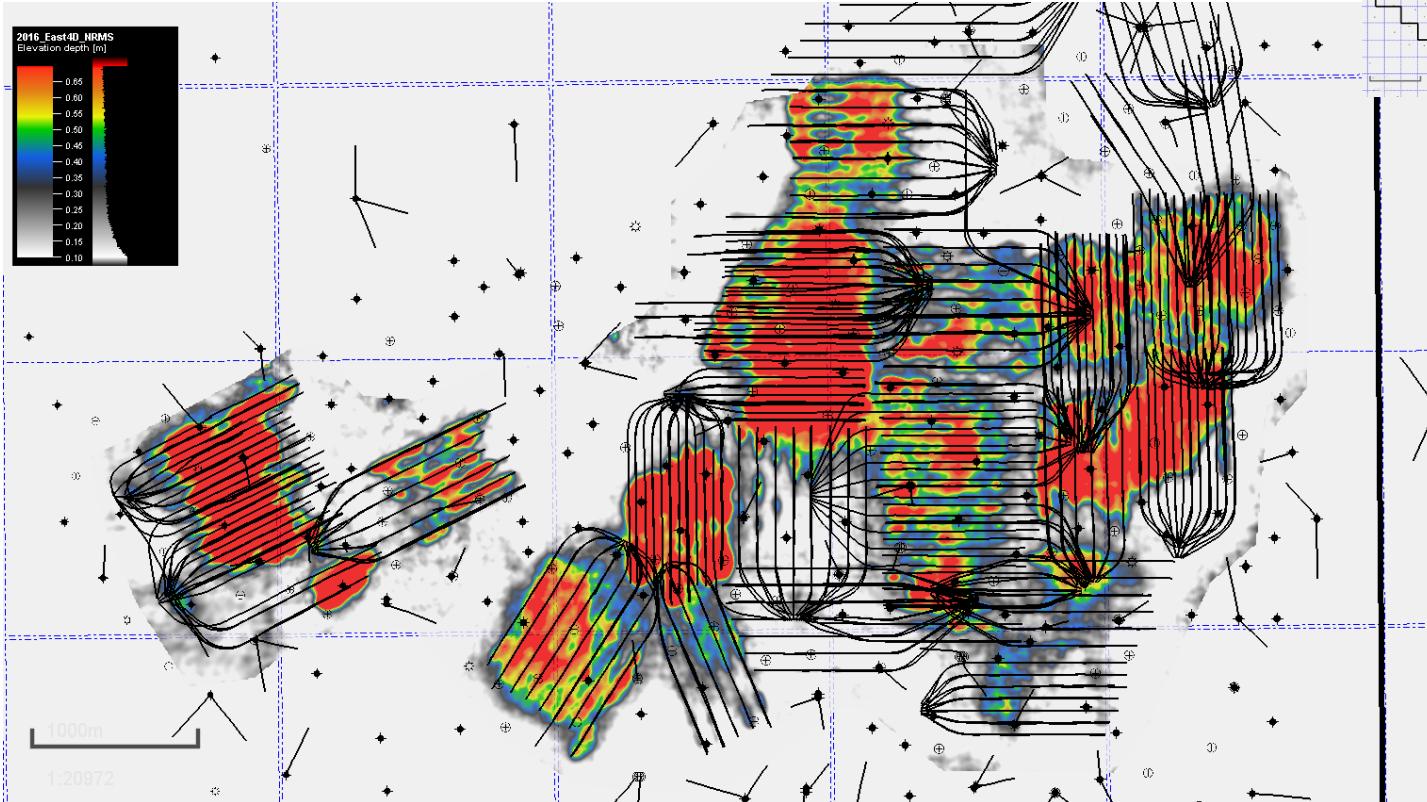
17m away from FP5 well pair

# Foster Creek temperature wells



## 44m offset W08P03 well pair

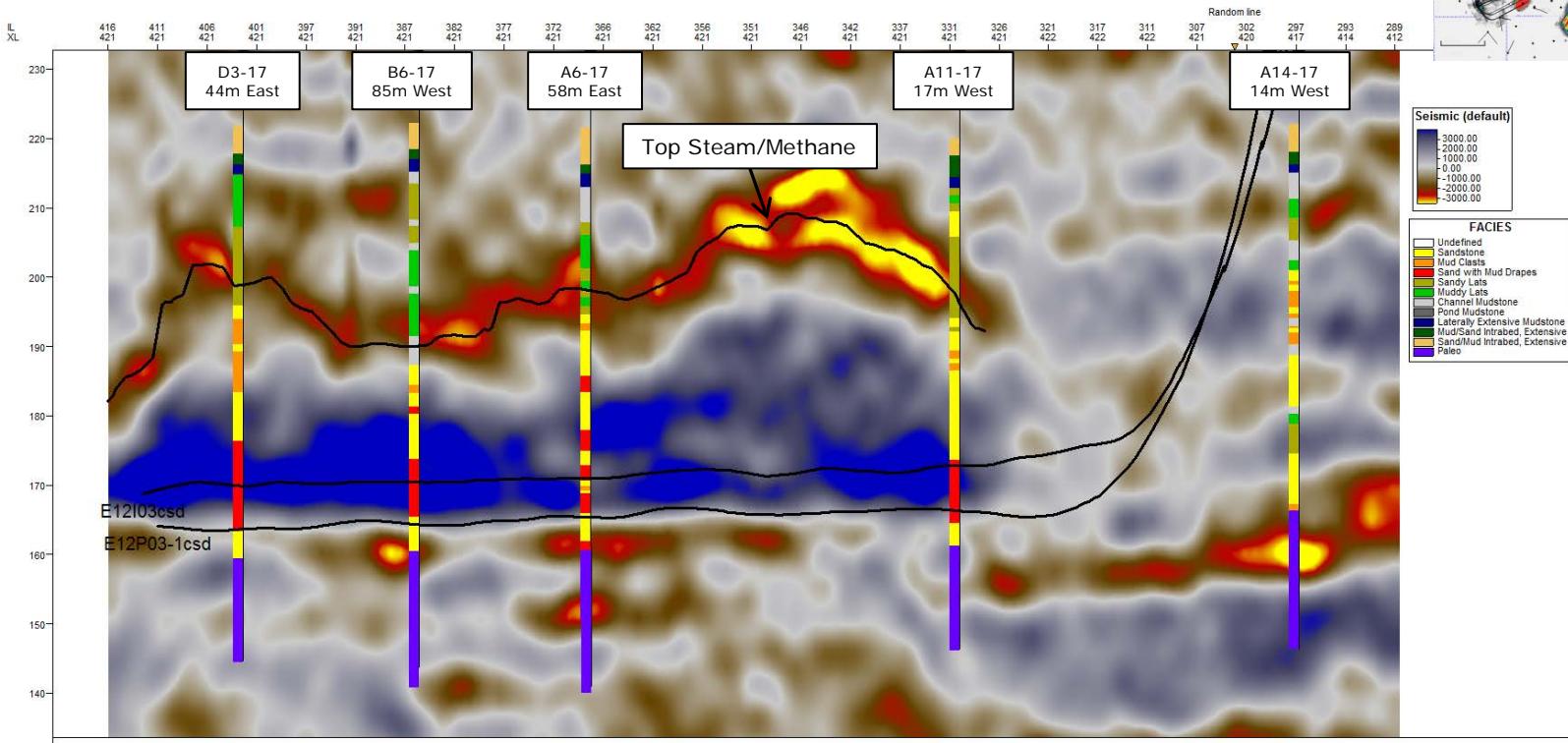
# 2016 East 4D seismic



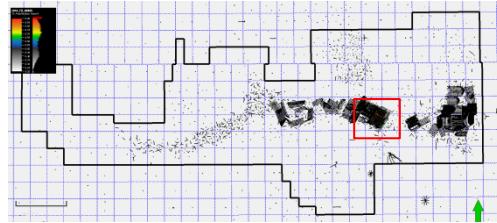
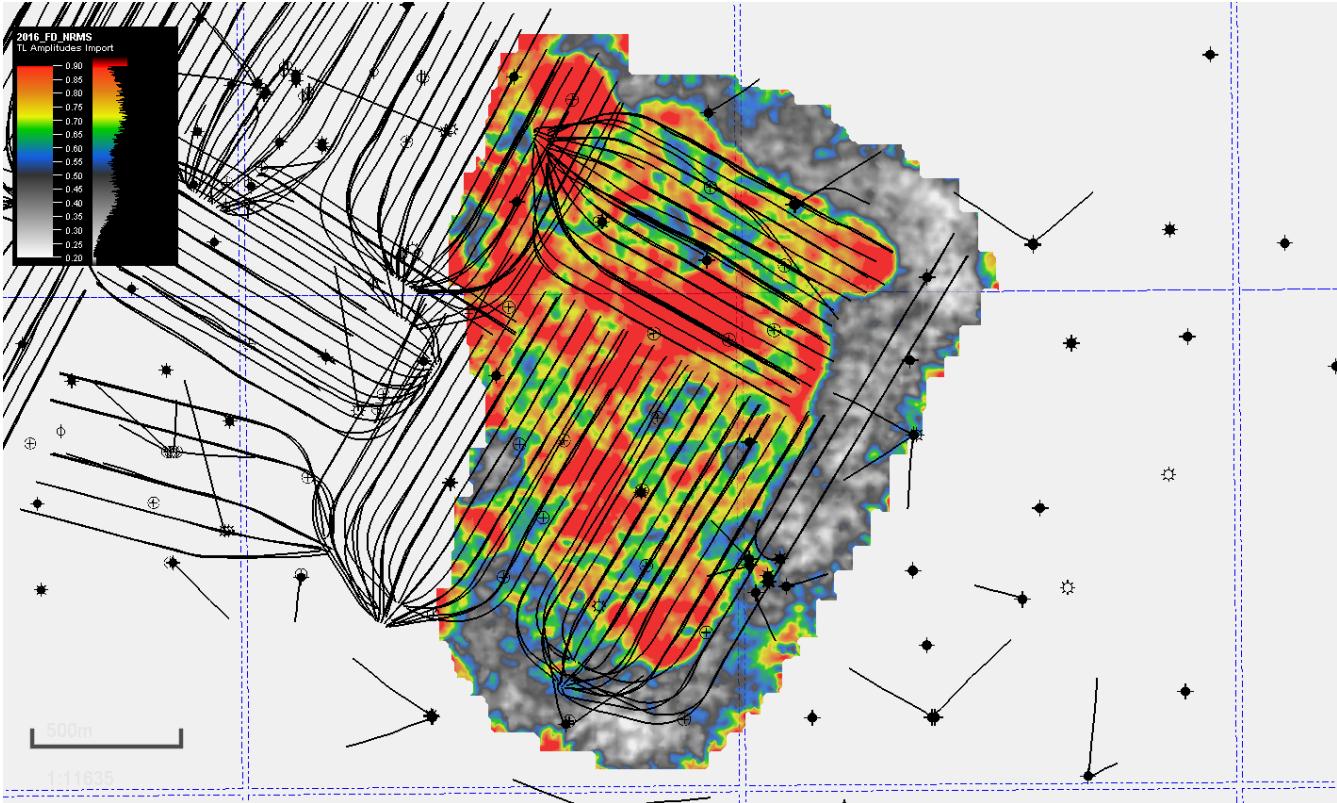
## 4D NRMS

Normalized Root Mean Square is a measure of repeatability between the baseline and monitor surveys. Higher values indicate less repeatability and heated reservoir

# Time-lapse seismic: E12 pair 03



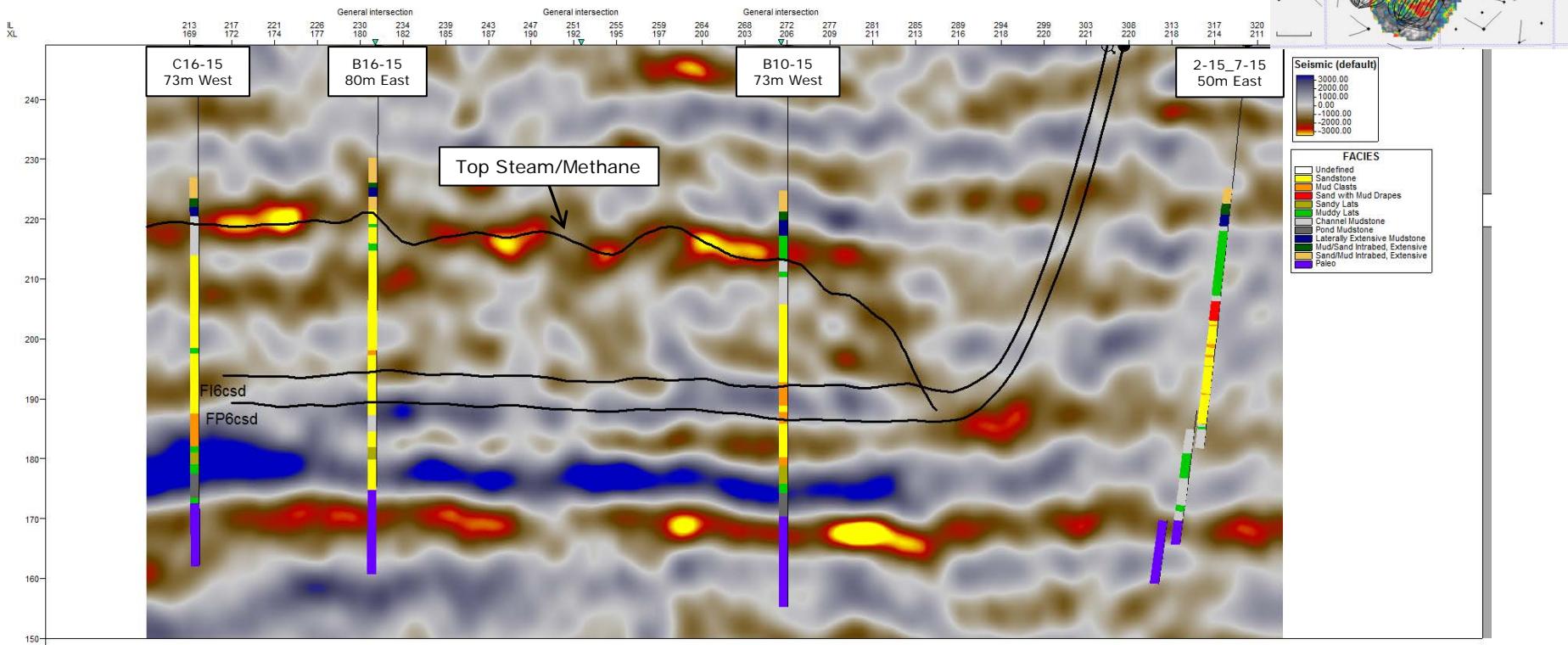
# 2016 FD 4D seismic



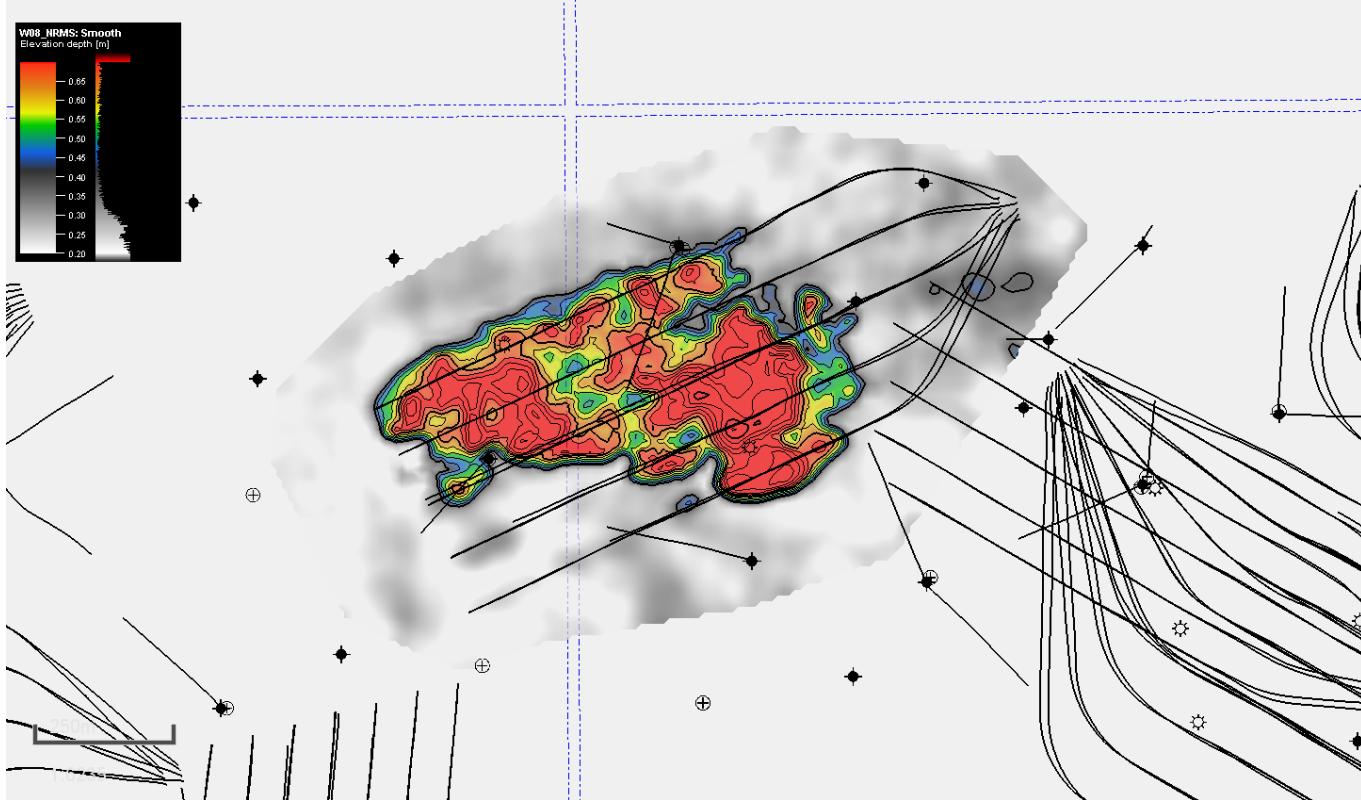
## 4D NRMS

Normalized Root Mean Square is a measure of repeatability between the baseline and monitor surveys. Higher values indicate less repeatability and heated reservoir

# Time-lapse seismic: F pad pair 06



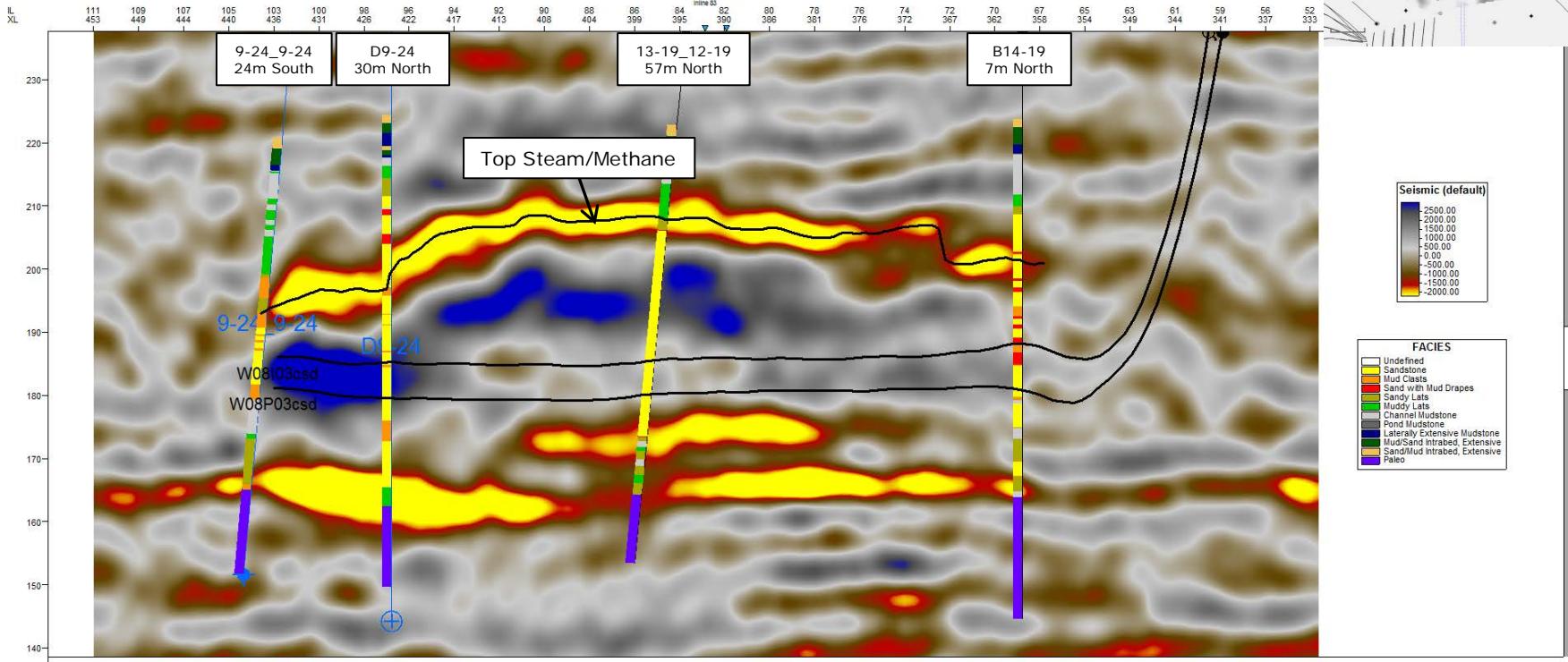
# 2016 W08 4D seismic



## 4D NRMS

Normalized Root Mean Square is a measure of repeatability between the baseline and monitor surveys. Higher values indicate less repeatability and heated reservoir

# Time-lapse seismic: W08 pair 03



# Oil in Place definitions

## SAGD-able Oil In Place (SOIP) Quantification

- Oil volume within a drainage box area between the SAGD base surface to SAGD Pay Top surface
- Drainage box area = drainage box length x wellpair spacing
- Default drainage box length is the length of overlapping injector/producer slots + 50m heel/toe extension
- Modified to account for well to well interactions and surveillance data
- The porosity and oil saturation within this volume are generated from stratigraphic wireline log data

## Estimated Ultimate Recovery

- Cum oil produced to date + forecasted production

All oil in place quantities and estimated ultimate recovery quantities are internal estimates. There is no certainty that any portion of such quantities will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such quantities.

# OIP & percent recovery – central

PAD	Average Well Spacing (m)	Area (m <sup>2</sup> )	Height (m)	$\Phi$ (%)	S. (%)	SOIP (Mm <sup>3</sup> )	Cum Oil Mm <sup>3</sup> (to Mar 31, 2017)	Recovery % SOIP	Estimated Ultimate Recovery (Mm <sup>3</sup> )	Ultimate Recovery as % of SOIP
A	117	543,506	28	33%	81%	4,086	3,524	86%	3,813	93%
B_L	103	605,382	24	35%	79%	4,029	2,478	62%	2,694	67%
C	105	541,344	29	35%	82%	4,656	3,763	81%	3,770	81%
D	100	676,265	28	32%	81%	4,821	4,534	94%	4,604	96%
E_K	89	576,134	22	35%	80%	3,518	2,966	84%	3,032	86%
EXP_M	106	640,418	25	34%	81%	4,459	2,412	54%	2,822	63%
F	98	817,054	26	34%	79%	5,689	3,448	61%	3,946	69%
G	96	596,677	25	34%	80%	3,918	2,761	70%	2,971	76%
H	113	139,402	20	34%	74%	672	145	22%	226	34%
J	99	722,666	22	33%	76%	4,125	1,535	37%	2,450	59%
N	100	322,899	19	34%	82%	1,690	53	3%	784	46%
<b>Total Central</b>						<b>41,664</b>	<b>27,619</b>	<b>66%</b>	<b>31,112</b>	<b>75%</b>
<b>Total FC</b>						<b>155,654</b>	<b>68,578</b>	<b>44%</b>	<b>94,625</b>	<b>61%</b>

To Mar 31, 2017

# OIP and percent recovery - east

PAD	Average Well Spacing (m)	Area (m <sup>2</sup> )	Height (m)	Φ (%)	S. (%)	SOIP (Mm <sup>3</sup> )	Cum Oil Mm <sup>3</sup> (to Mar 31, 2017)	Recovery % SOIP	Estimated Ultimate Recovery [Mm <sup>3</sup> ]	Ultimate Recovery as % of SOIP
E02	106	401,512	30	33%	74%	2,963	1,371	46%	1,594	54%
E03	112	400,335	34	33%	71%	3,228	1,351	42%	1,548	48%
E04	100	522,570	26	34%	79%	3,658	907	25%	1,345	37%
E07	100	584,261	16	28%	73%	1,989	111	6%	417	21%
E08	104	811,692	24	31%	77%	4,637	943	20%	2,957	64%
E10	100	417,700	22	32%	74%	2,073	708	34%	1,563	75%
E11	100	706,863	29	32%	75%	5,004	2,593	52%	3,195	64%
E12	103	878,701	32	35%	79%	7,849	4,627	59%	5,534	71%
E14	100	436,503	22	33%	81%	2,407	619	26%	1,347	56%
E15	96	1,082,645	25	33%	81%	7,207	3,343	46%	4,823	67%
E16	93	536,177	24	34%	78%	3,680	2,406	65%	2,696	73%
E19	102	1,134,109	26	34%	80%	7,886	4,494	57%	4,761	60%
E20	90	779,459	27	34%	83%	6,253	3,781	60%	4,470	71%
E21	100	712,643	24	32%	79%	4,221	1,589	38%	2,320	55%
E24	100	921,568	26	35%	85%	6,994	3,642	52%	4,272	61%
E42	74	381,823	21	31%	77%	2,012	518	26%	1,134	56%
E25	104	813,888	24	32%	81%	4,930	2,159	44%	2,701	55%
<b>Total East</b>						<b>76,990</b>	<b>35,161</b>	<b>46%</b>	<b>46,676</b>	<b>61%</b>
<b>Total FC</b>						<b>155,654</b>	<b>68,578</b>	<b>44%</b>	<b>94,625</b>	<b>61%</b>

To March 31, 2017

# OIP and percent recovery – west

PAD	Average Well Spacing (m)	Area (m <sup>2</sup> )	Height (m)	Φ (%)	S. (%)	SOIP (Mm <sup>3</sup> )	Cum Oil Mm <sup>3</sup> (to Mar 31, 2017)	Recovery % SOIP	Estimated Ultimate Recovery (Mm <sup>3</sup> )	Ultimate Recovery as % of SOIP
W01	100	676,167	23	34%	79%	4,281	1,889	44%	2,493	58%
W02	97	376,851	19	33%	85%	2,070	520	25%	725	35%
W03	92	421,984	24	32%	74%	2,493	235	9%	1,077	43%
W05	98	341,146	22	31%	75%	1,710	100	6%	789	46%
W06	99	758,366	25	31%	81%	4,793	464	10%	669	14%
W07	87	334,674	30	33%	78%	2,787	241	9%	1,544	55%
W08	100	428,285	28	32%	78%	2,899	689	24%	1,522	52%
W10	75	467,500	26	31%	82%	3,056	473	15%	1,483	49%
W15	100	379,950	23	31%	86%	2,268	91	4%	1,025	45%
W18	78	676,409	25	32%	89%	4,689	630	13%	2,532	54%
W23	79	777,376	28	33%	85%	5,955	468	8%	2,978	50%
<b>Total West</b>						<b>37,000</b>	<b>5,798</b>	<b>16%</b>	<b>16,837</b>	<b>46%</b>
<b>Total FC</b>						<b>155,654</b>	<b>68,578</b>	<b>44%</b>	<b>94,625</b>	<b>61%</b>

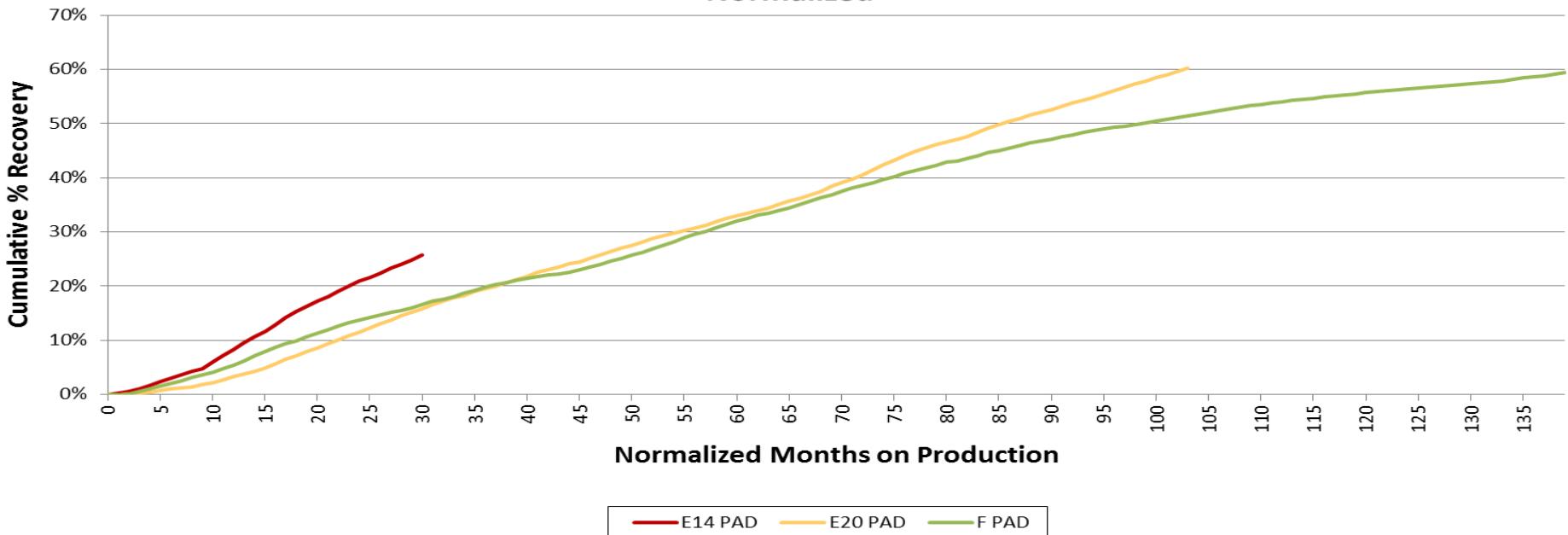
To March 31, 2017

# Recovery examples

- E14 pad low ultimate recovery example with focus on E14-01 well pair
- E20 pad medium ultimate recovery example with focus on E20-01 well pair
- F pad high ultimate recovery example with focus on F-01 well pair

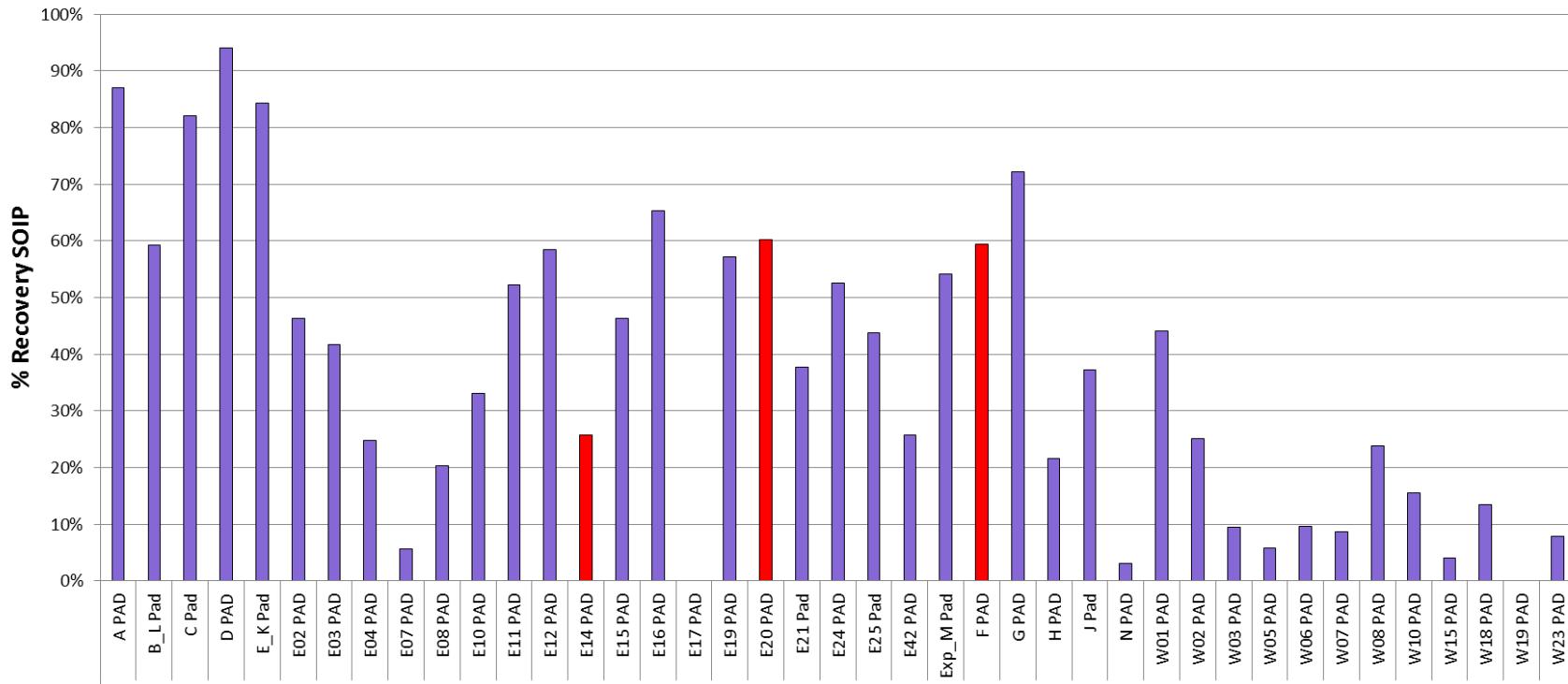
# Recovery examples cumulative percent recovery SOIP

Foster Creek - E14, E20 & F Pads  
Cumulative % Recovery SOIP  
Normalized



# Current percent recovery of SOIP: pad totals

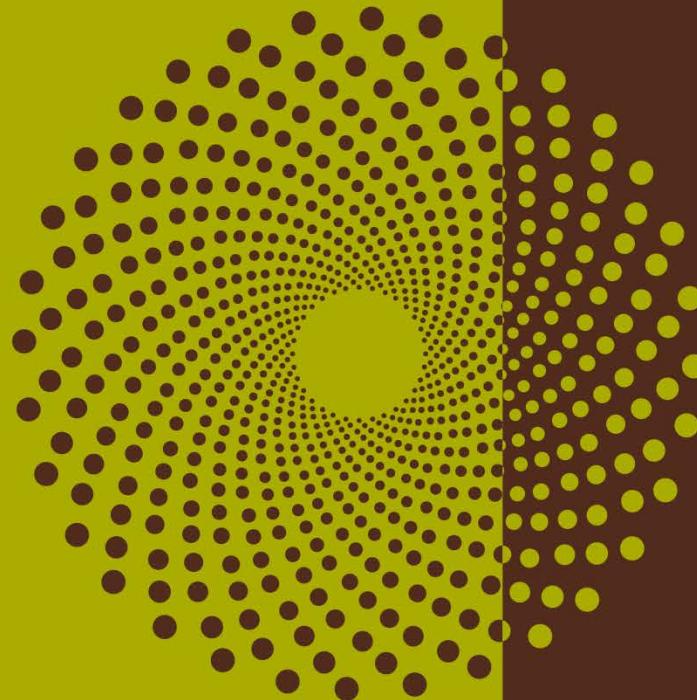
Foster Creek - % Recovery of SOIP per Pad (Mar31, 2017)



# OBIP – low example

## E14 pad

Subsection 3.1.1 – 7 c) iii



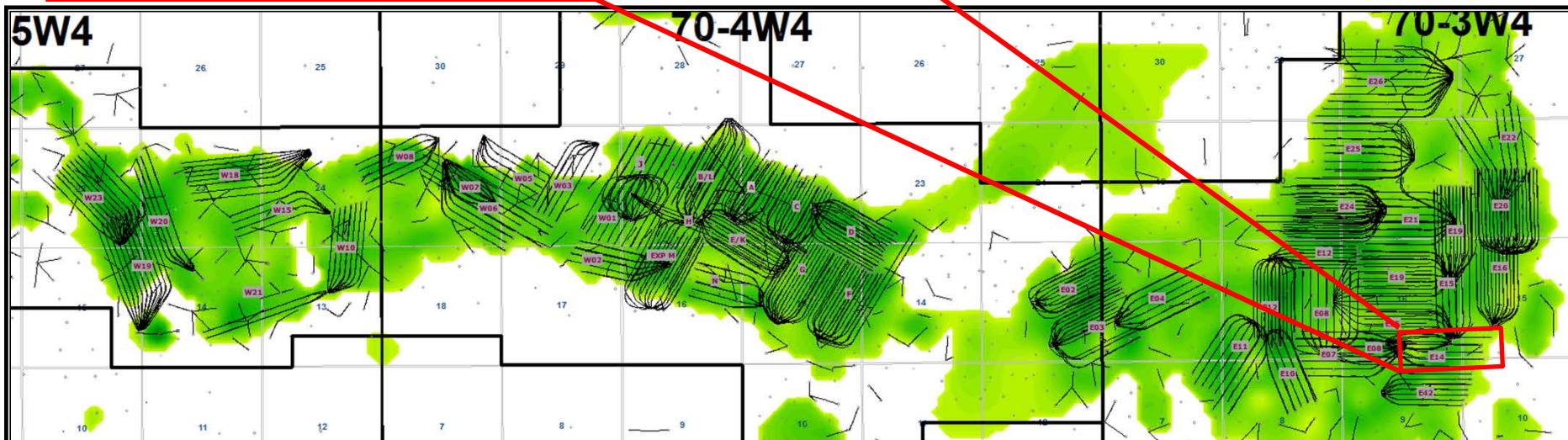
# E14 pad overview

- E14 pad started production in September 2011 (six pairs)
- Heterogeneous quality geology, some small variations in SAGD base between well pairs
- Poor conformance
- P03/P05/P06 with lower recovery
- Initial operating pressures ~4.5 Mpa, currently producing ~2800 kPa
- Currently at ~26% recovery of SOIP, slightly behind its recovery curve in relation to the age of the pad
- CSOR is currently 2.60

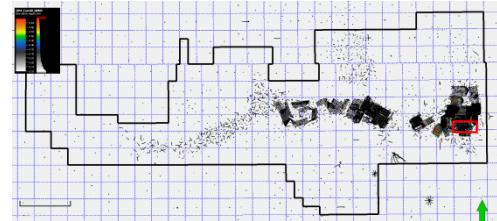
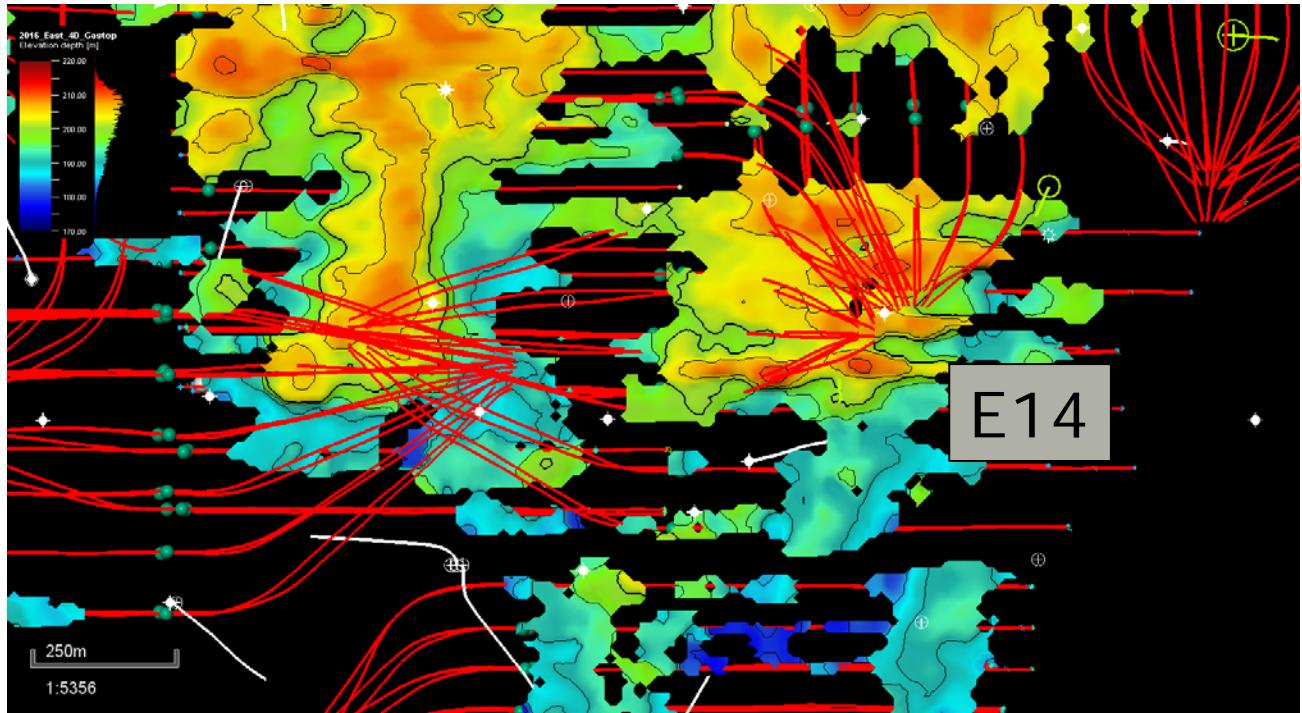
# E14 pad SAGD pay



Production Date: October 2014  
# pairs: 6 drilled



# E14 4D seismic



Interpreted top of steam elevation

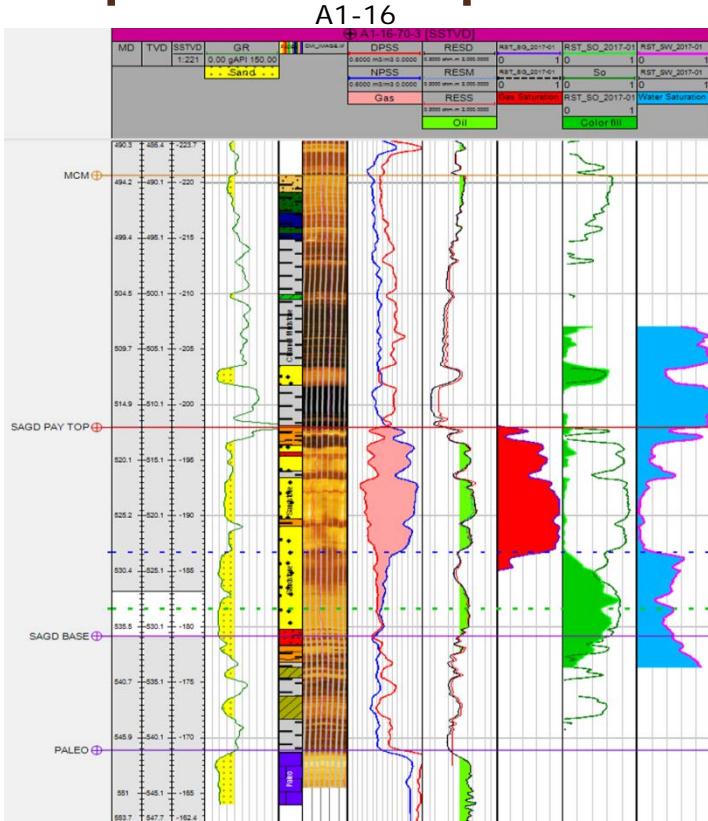
# E14 pad - extent of chamber development

PAD	PAIR	SOIP (Mm3)	Cum Oil Mm3 (to Mar 31, 2017)	Recovery % SOIP
E14 PAD	E14P01	489	166	34%
E14 PAD	E14P02	452	120	27%
E14 PAD	E14P03	395	72	18%
E14 PAD	E14P04	392	136	35%
E14 PAD	E14P05	401	67	17%
E14 PAD	E14P06	279	60	21%
Total	E14 PAD	2,407	619	26%

Expected ultimate recovery (56% of SOIP) = 1,347 Mm3

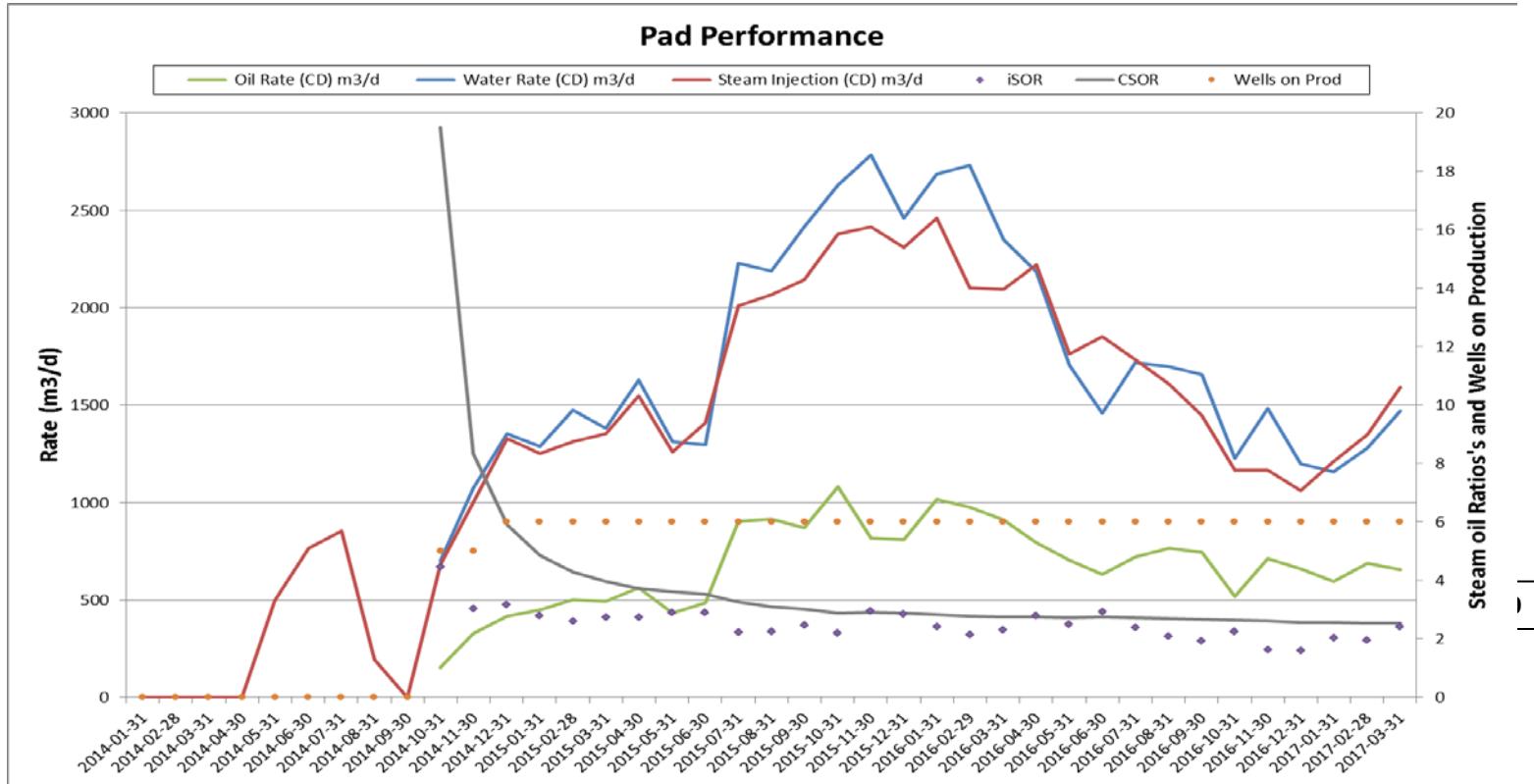
To March 31, 2017

# E14 pad temperatures

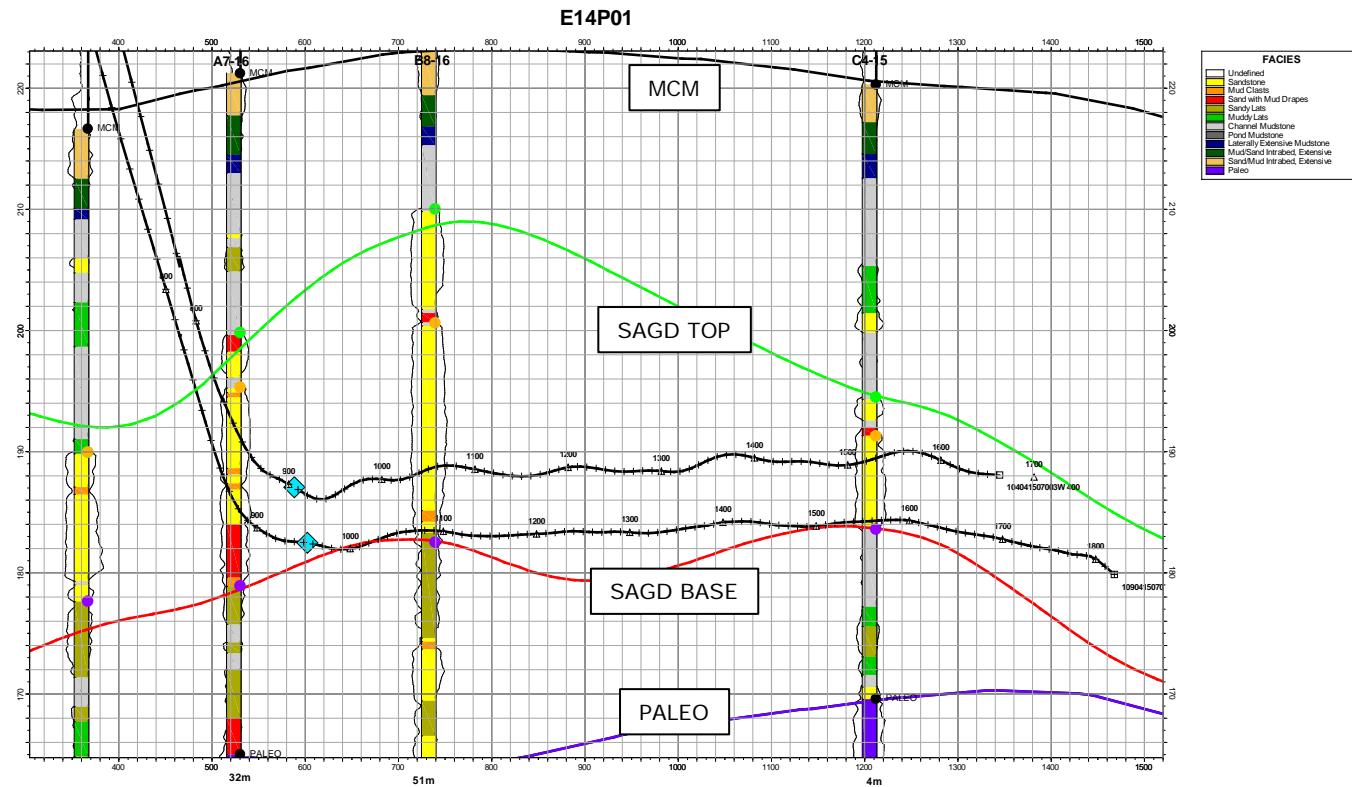


44m offset E14-03 well pair

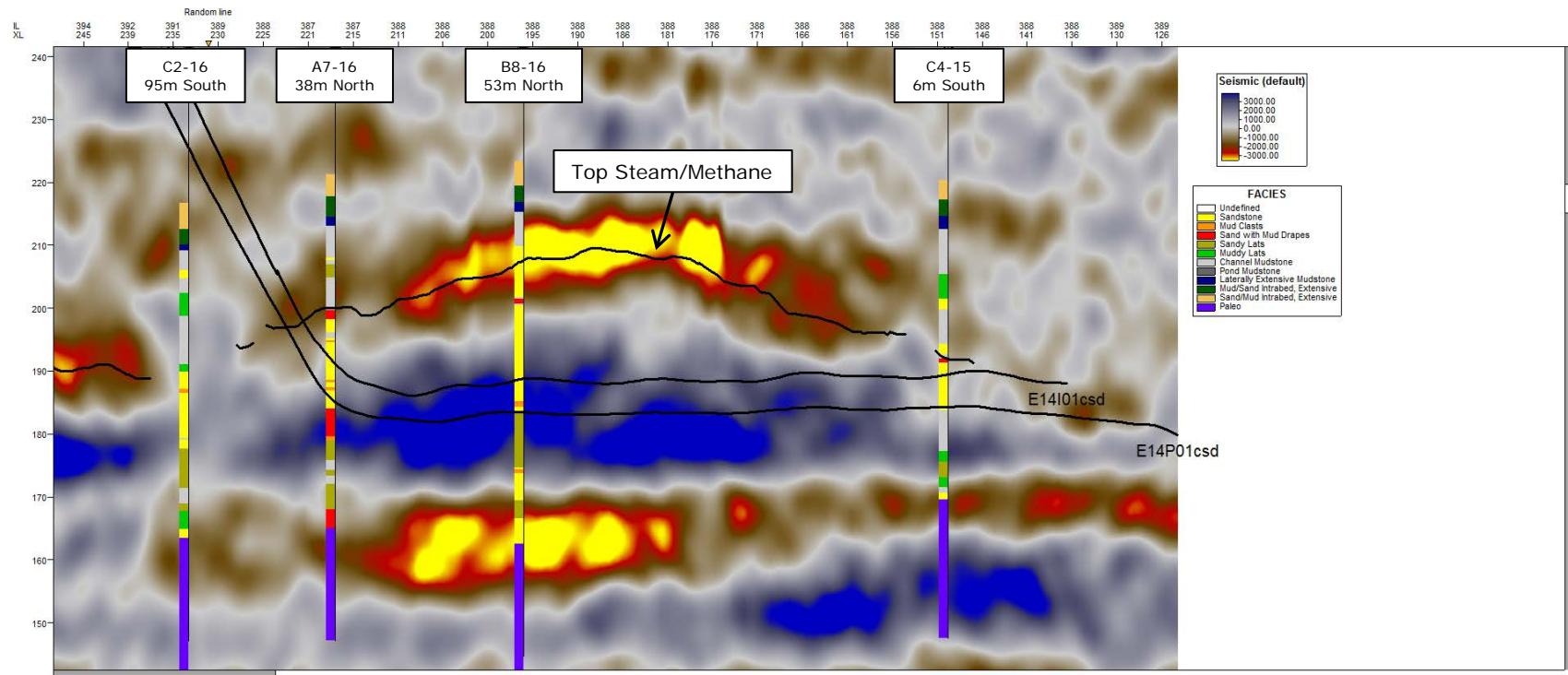
# E14 pad performance



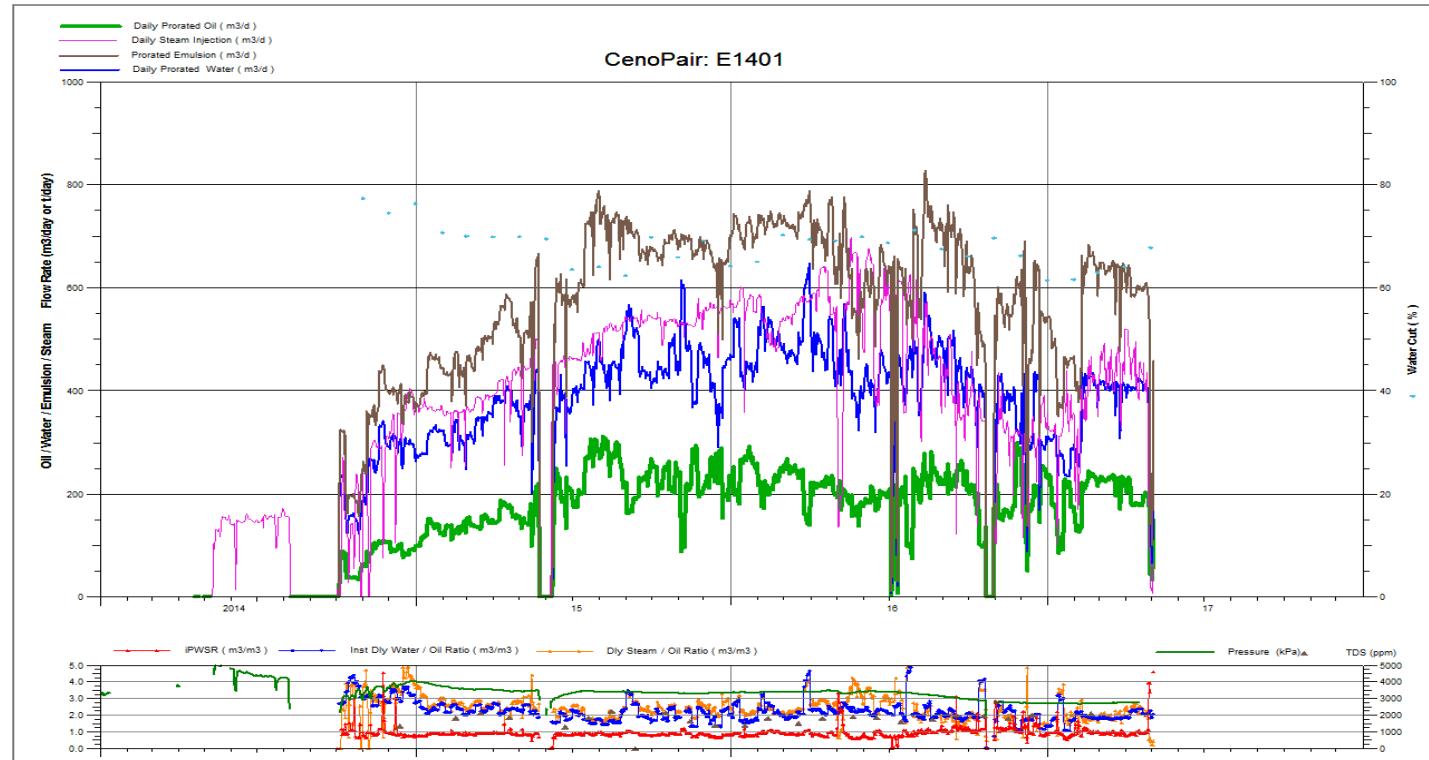
# E14-01 geological profile



# Time-lapse seismic: E14 pair 1



# E14-01 well pair performance

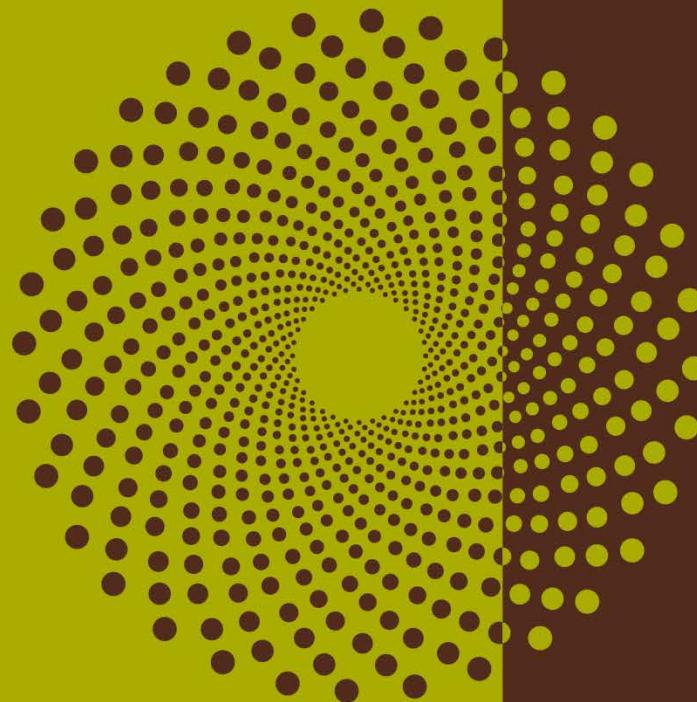


# E14 pad conclusions

- Currently at ~26% recovery of SOIP
- Optimization of pad underway after remedial work
- Recently drilled TC well between P3 & P4
- Balance reservoir pressures with E15 and E08 pads

# OBIP – medium example E20 pad

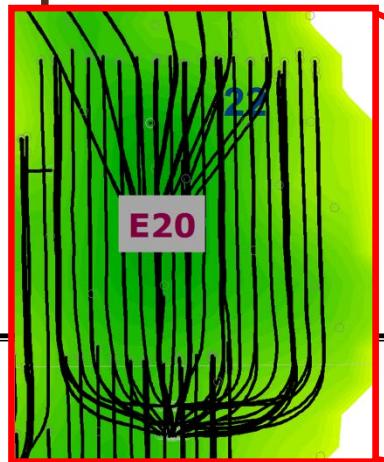
Subsection 3.1.1 – 7 c) iii



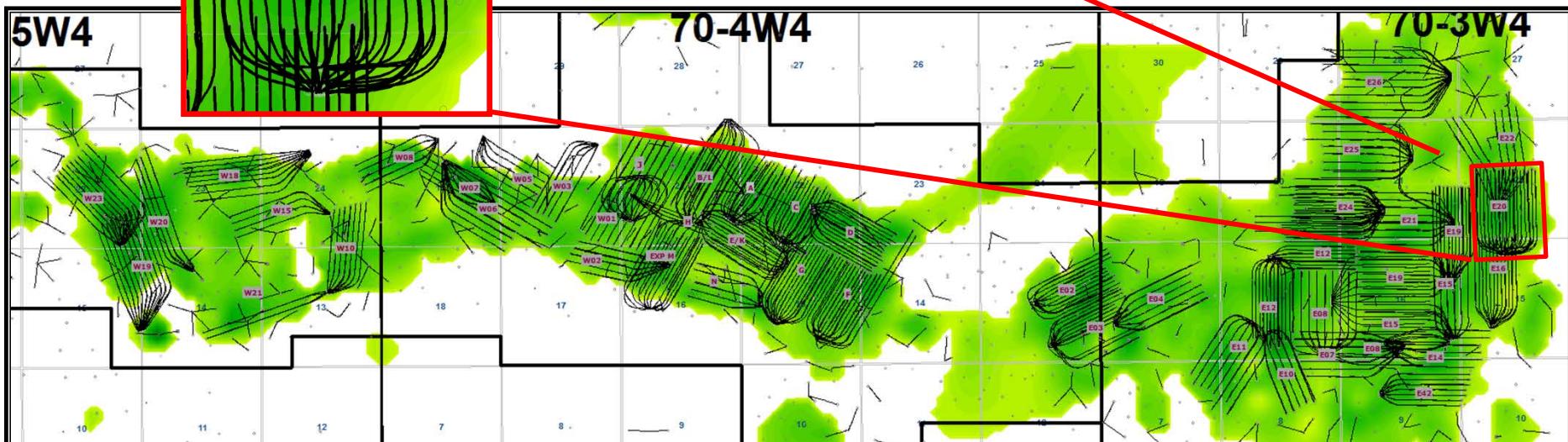
# E20 pad overview

- **E20 pad started production in July 2008, wells utilizing Wedge Well™ technology online Aug 2014**
  - 9 WP's, 8 wells utilizing Wedge Well™ technology
  - E20W7 re-drilled over W08 for steam support
  - E20P04 re-drilled deeper
  - E20P09 schedule for re-drill
- **Clean injector geology pair 1-7, Heterogeneous producer geology**
- **SAGD base sloping to the east (P09)**
- **Initial operating pressures ~3.1 Mpa, currently producing ~2800 kPa**
- **Currently at ~60% recovery of SOIP**
- **CSOR is currently ~2.49**

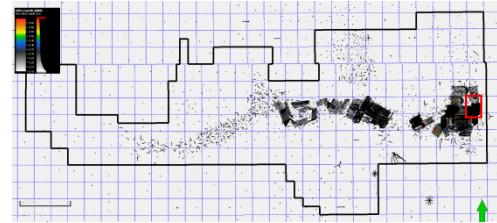
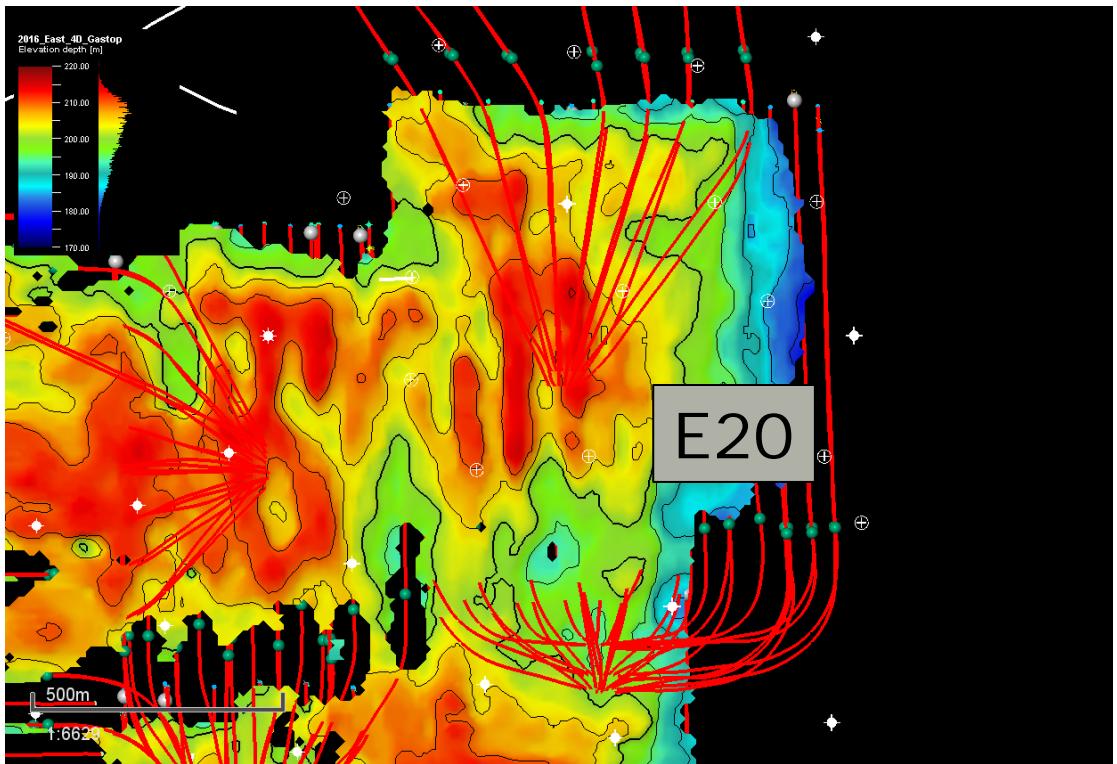
# E20 pad SAGD pay



Production Date: September 2008  
# pairs: 9 drilled  
# ww: 8 drilled



# E20 4D seismic



Interpreted top of steam elevation

# E20 pad - extent of chamber development

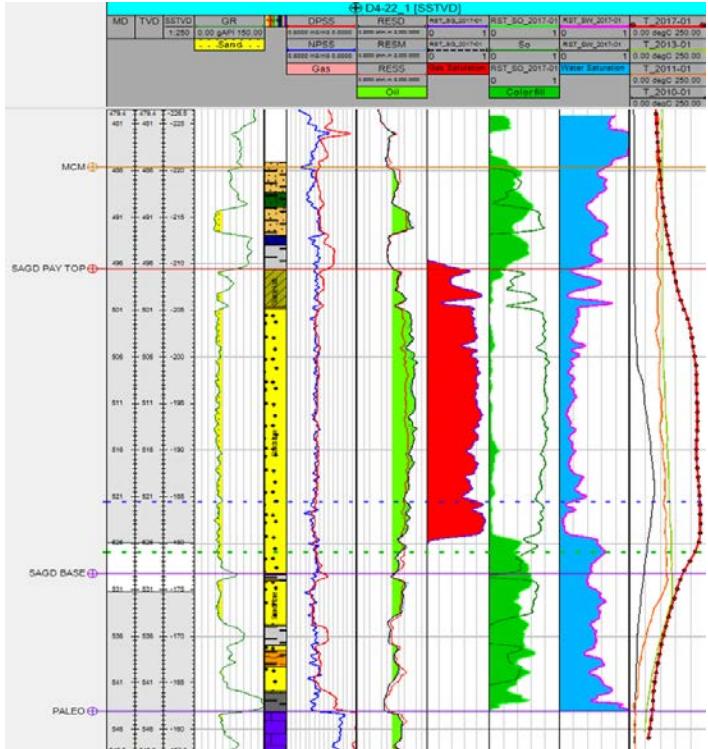
PAD	PAIR	SOIP (Mm3)	Cum Oil Mm3 (to Mar 31, 2017)	Recovery % SOIP
E20 PAD	E20P01	615	446	72%
E20 PAD	E20P02	747	431	58%
E20 PAD	E20P03	850	494	58%
E20 PAD	E20P04	906	460	51%
E20 PAD	E20P05	906	565	62%
E20 PAD	E20P06	822	619	75%
E20 PAD	E20P07	640	487	76%
E20 PAD	E20P08	333	277	83%
E20 PAD	E20P09	233	0	0%
E20 PAD	E20W08	201	1	0%
Total	E20 PAD	6,253	3,781	60%

Expected ultimate recovery (71% of SOIP) = 4,470 Mm3

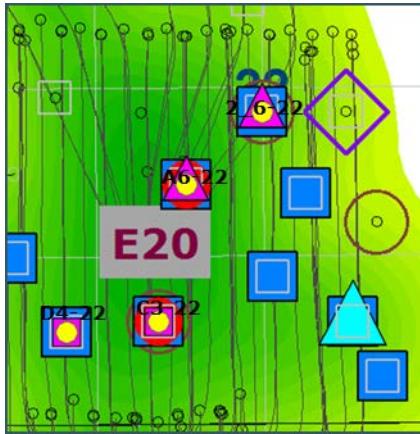
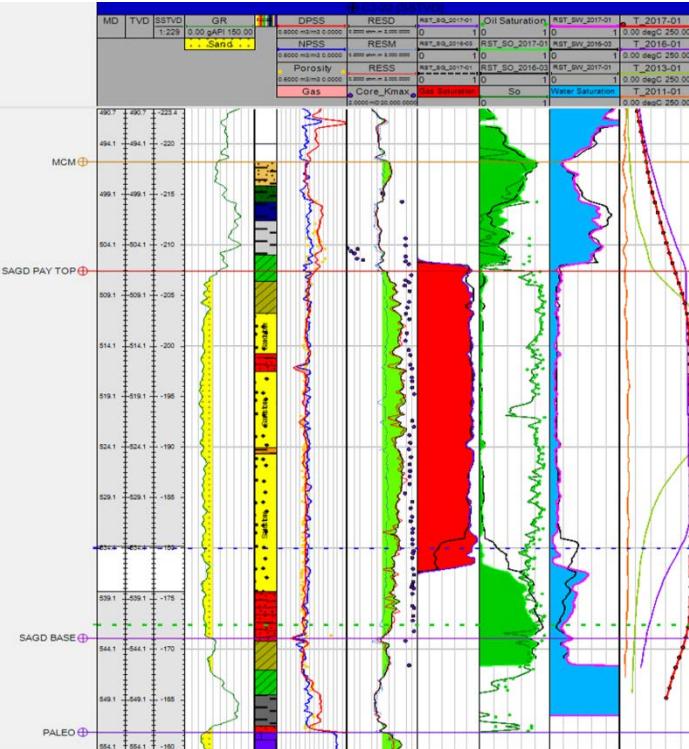
To March 31, 2017

# E20 Pad Temperatures

D4-22 8m away from E20-02 well pair

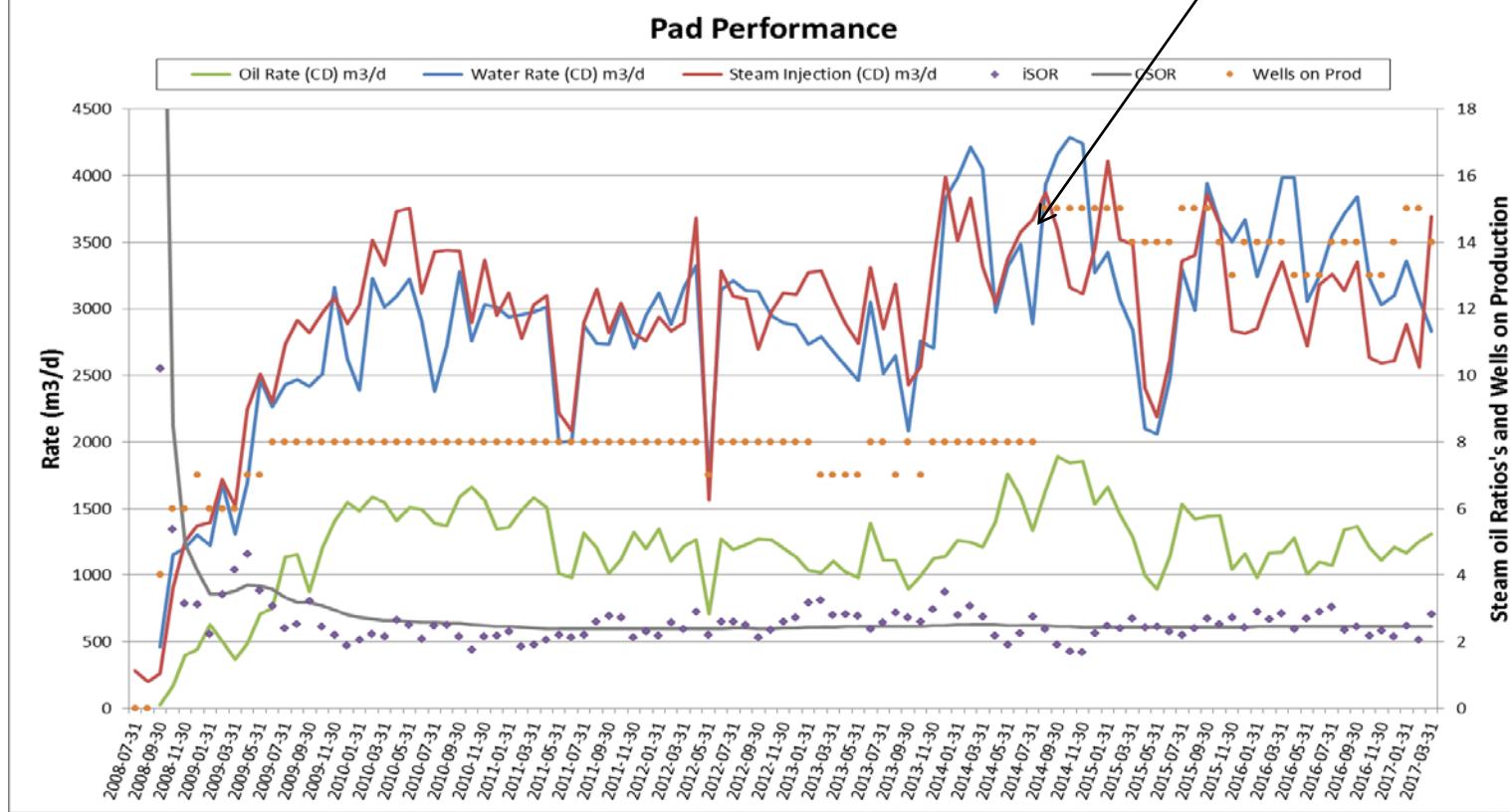


C3-22 25m away from E20-04 well pair

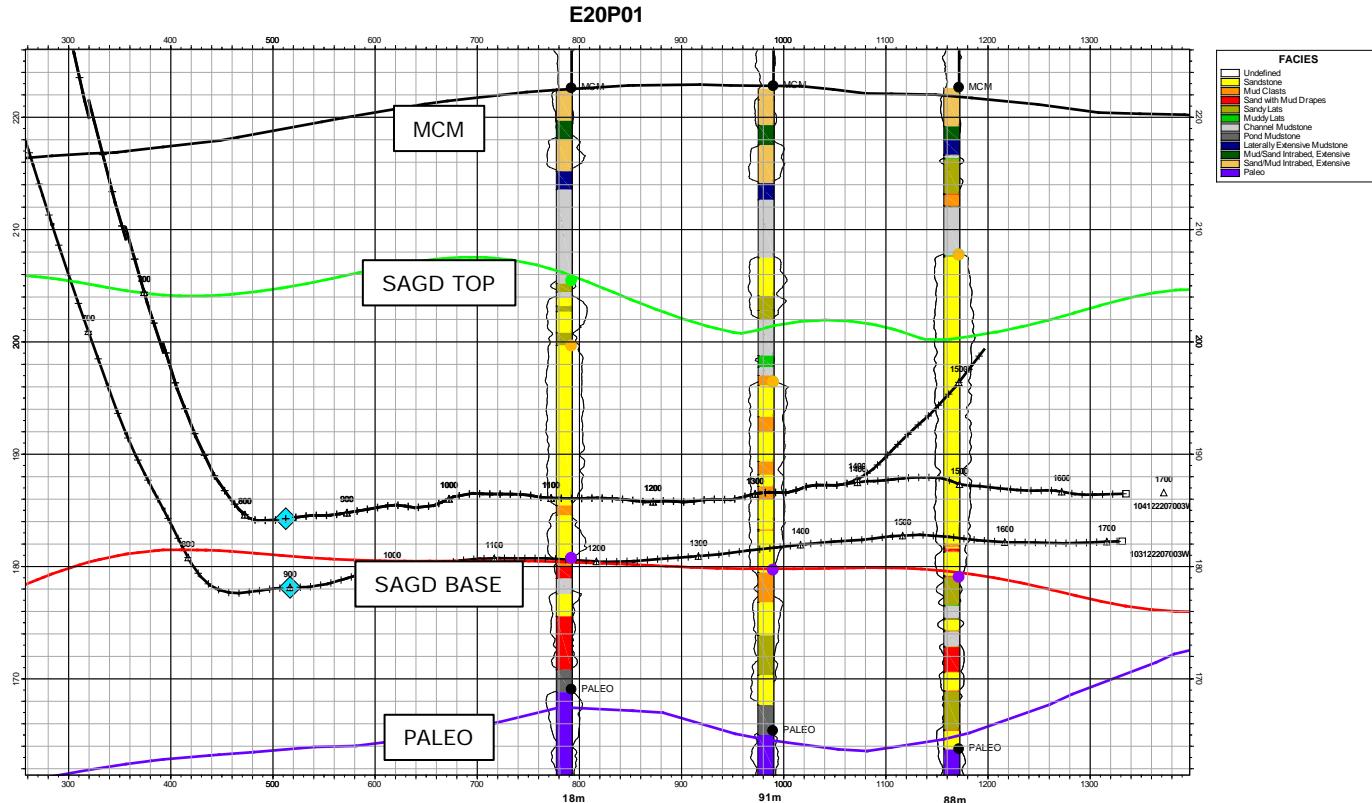


# E20 pad performance

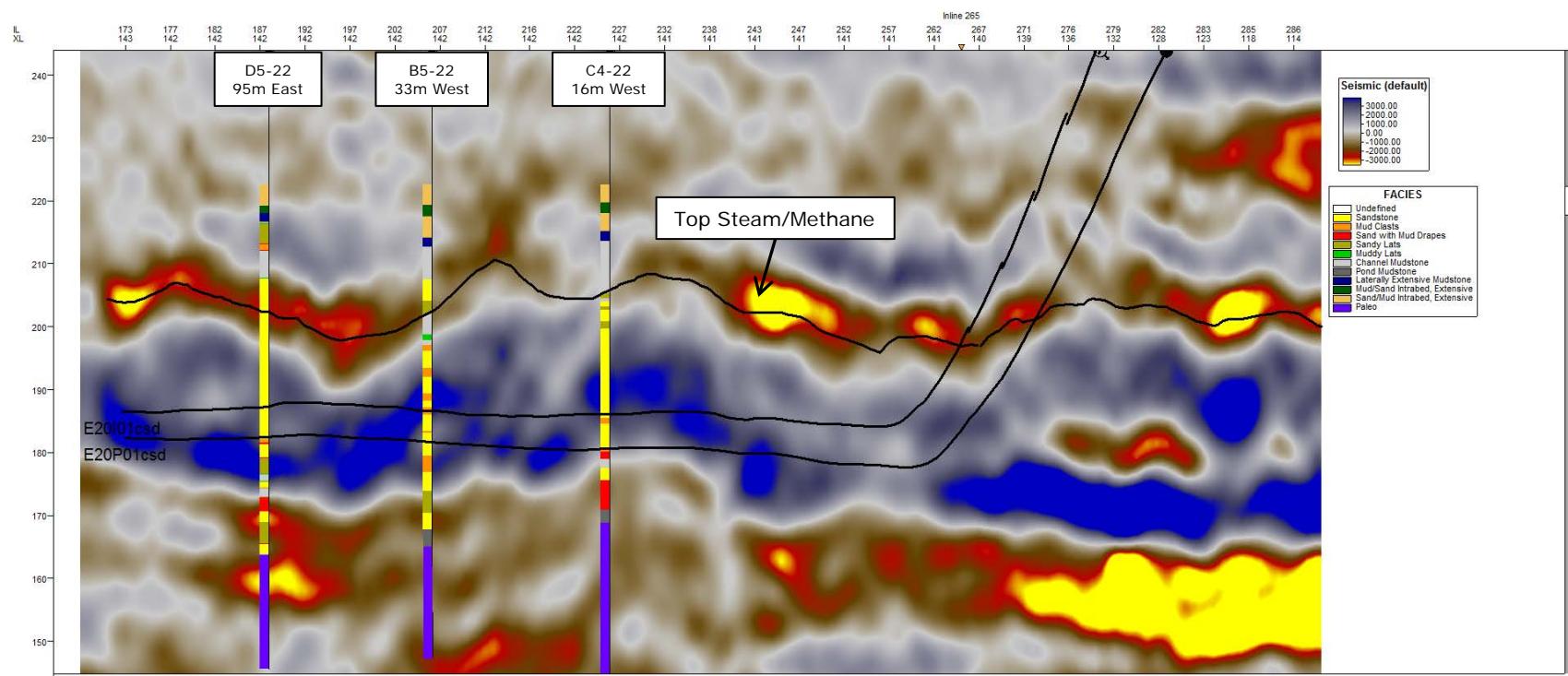
**Wedge Well™  
online**



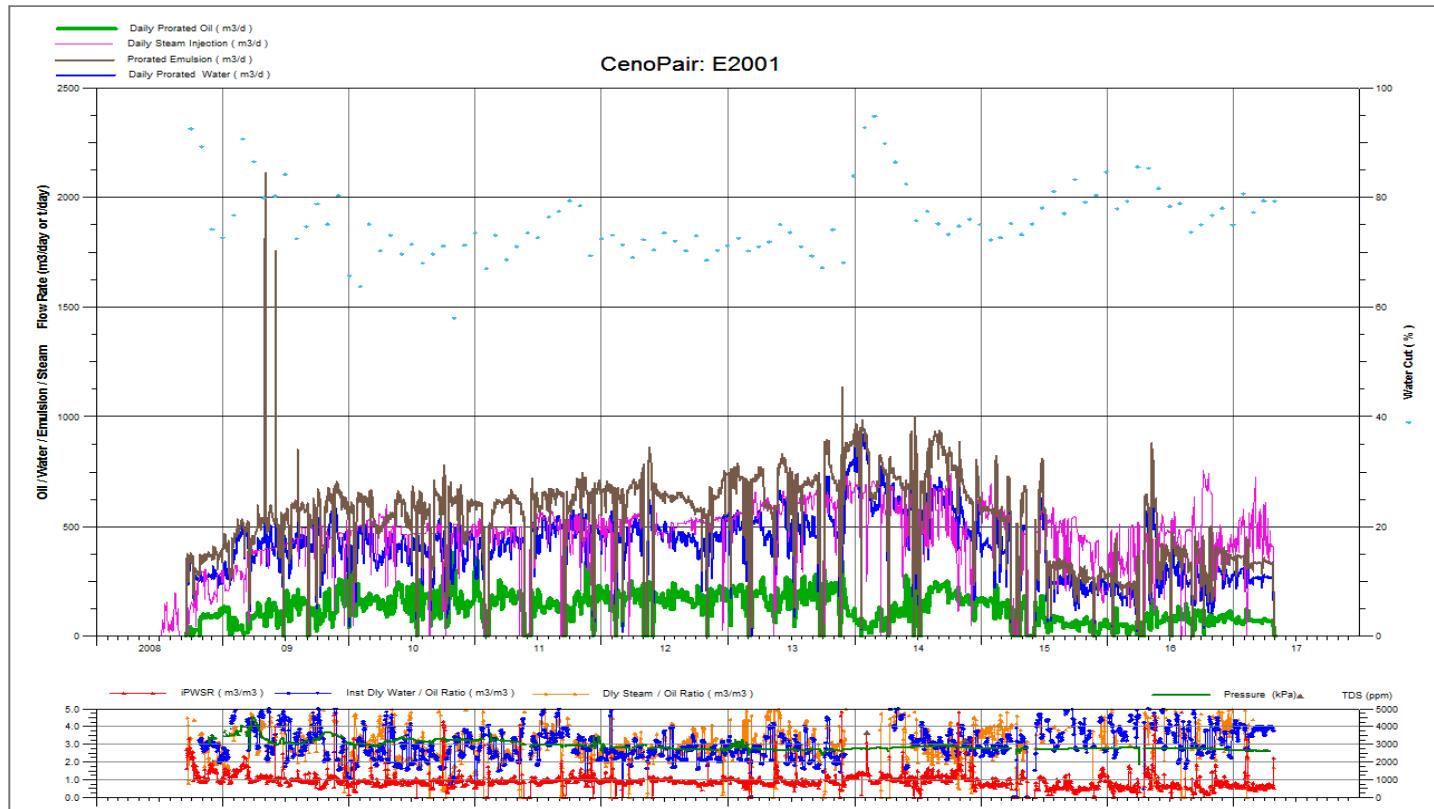
# E20-01 geological profile



# Time-lapse seismic: E20 pair 1



# E20-01 well pair performance



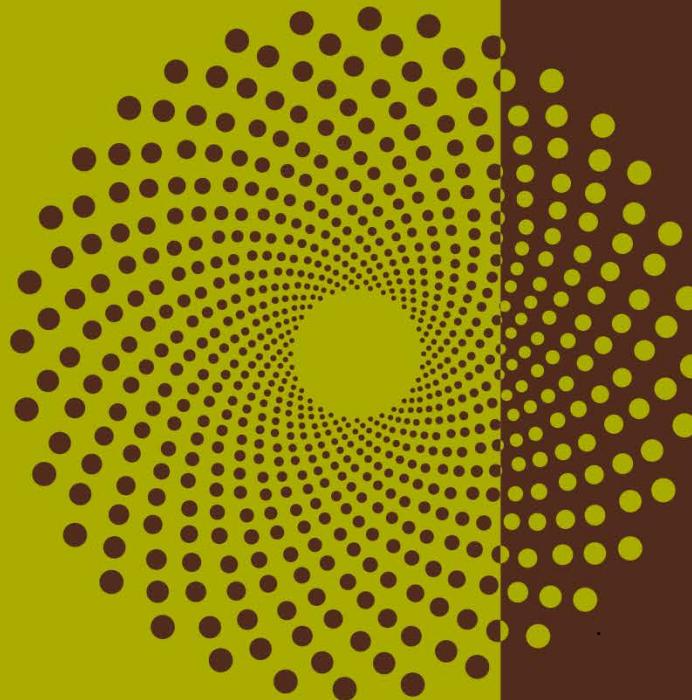
# E20 pad conclusions

- E20 Pad steam chamber is merged with E16 and E21
- Optimization of pad underway after remedial work
- E20P07 re-drill is in the schedule for 2017
- E20P09 re-drill is in the schedule for 2017
- Currently at ~60% recovery of SOIP

# OBIP – high example

## F pad

Subsection 3.1.1. – 7 c) iii

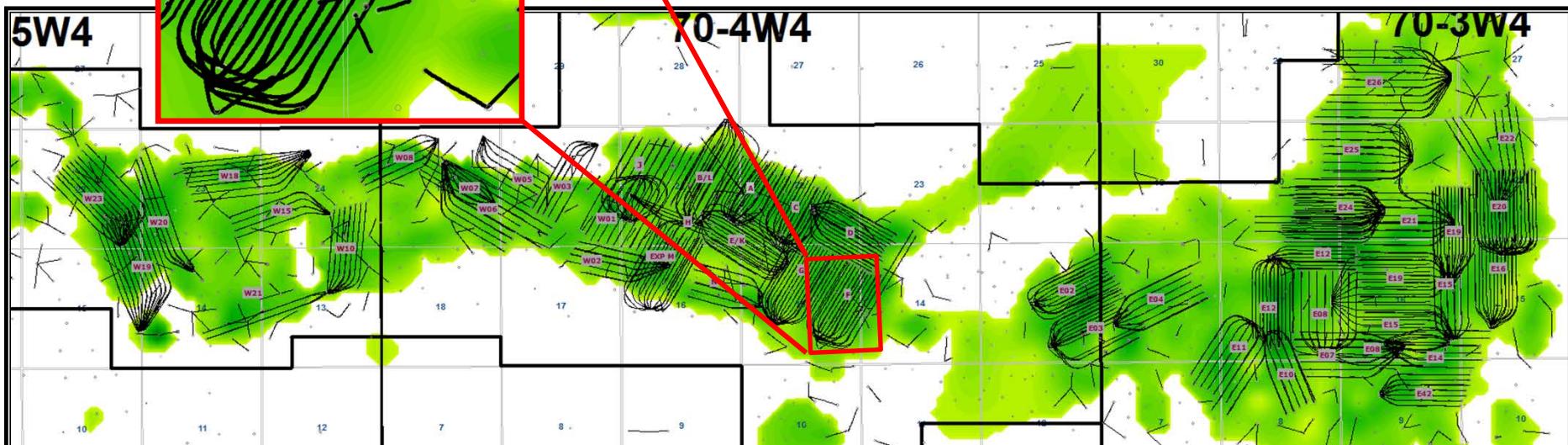


# F pad overview

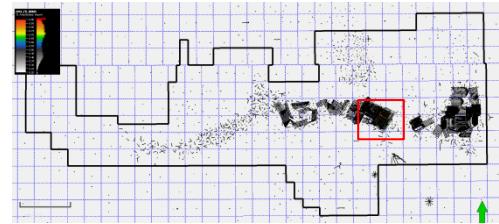
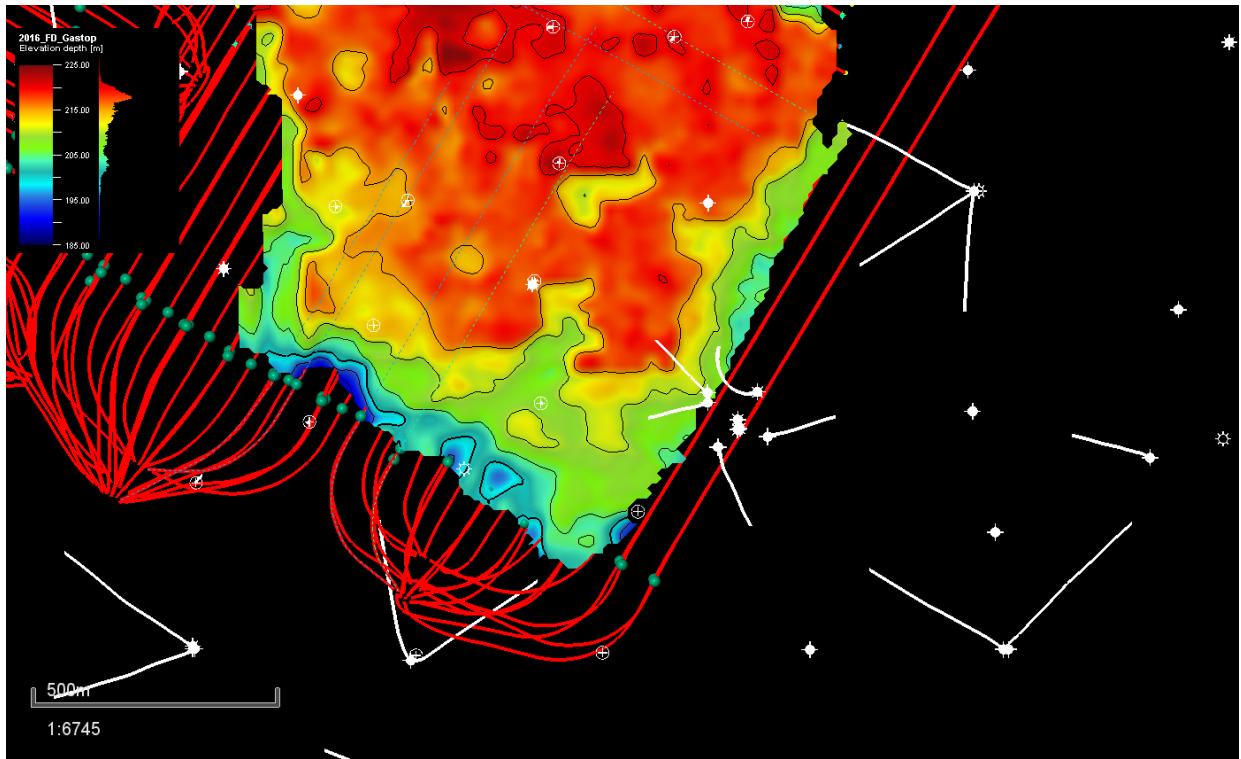
- F Pad started production in September 2005 (six pairs, 6 wells utilizing Wedge Well™ technology)
  - F7 and F8 pair drilled 2016 on east end of pad, FW6 re-drilled deeper
- Heterogeneous quality geology, some small variations in SAGD base between well pairs
- Bullhead steam stimulations were successful on every well
- Initial operating pressures ~3 Mpa, currently producing ~2125 kPa.
- Currently at ~81% recovery of SOIP (F1 – F6)
- CSOR is currently 2.75

# F pad SAGD pay

Production Date: September 2005  
# pairs: 8 drilled  
# ww: 6 drilled



# F pad 4D seismic



Interpreted top of  
steam elevation

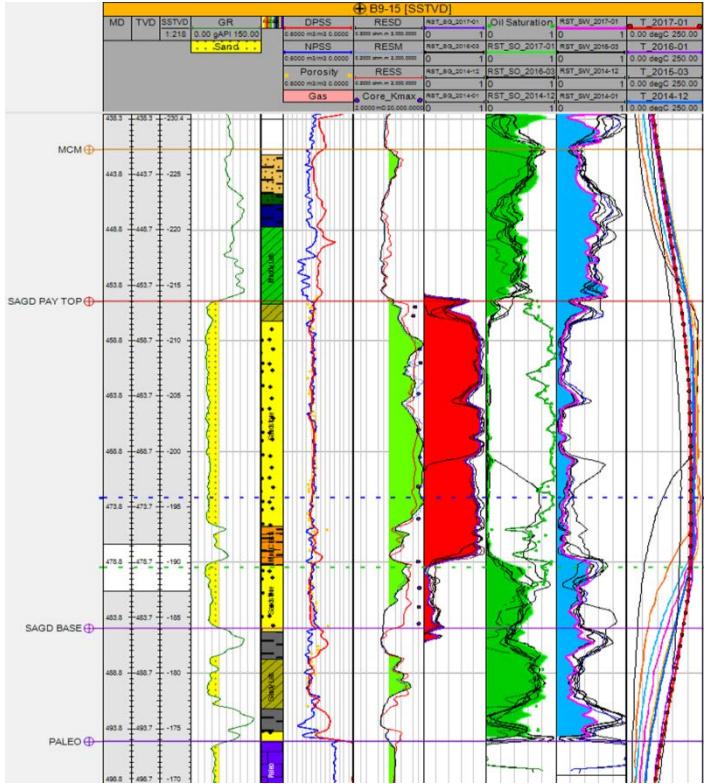
# F pad - extent of chamber development

PAD	PAIR	SOIP (Mm3)	Cum Oil Mm3 (to Mar 31, 2017)	Recovery % SOIP
F PAD	FP01	865	619	72%
F PAD	FP02	643	464	72%
F PAD	FP03	681	578	85%
F PAD	FP04	685	588	86%
F PAD	FP05	663	573	86%
F PAD	FP06	658	595	90%
F PAD	FP07	763	13	2%
F PAD	FP08	731	19	3%
Total	F PAD	5,689	3,448	61%

Expected ultimate recovery (69% of SOIP) = 3,946 Mm3

To March 31, 2017

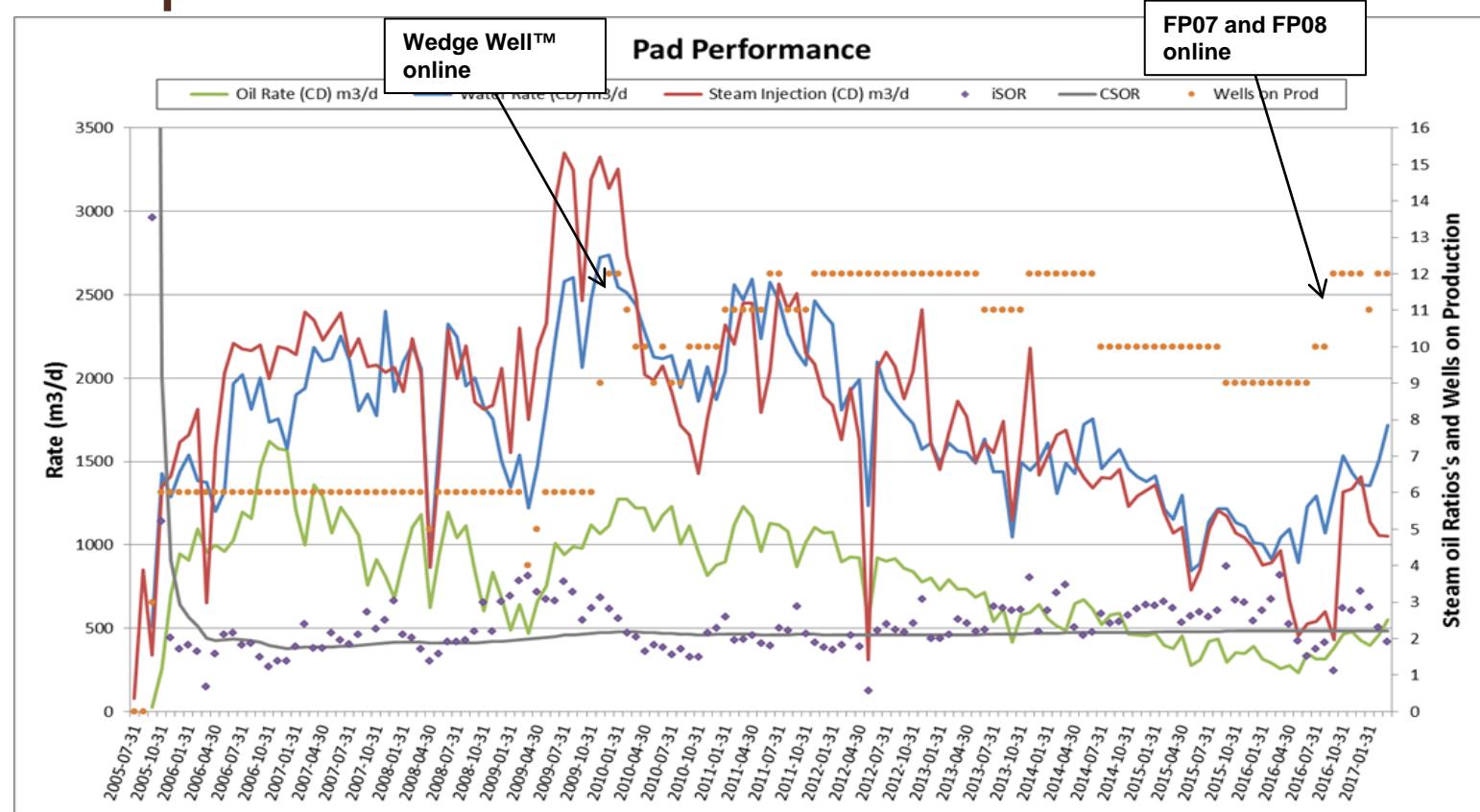
# F pad temperatures



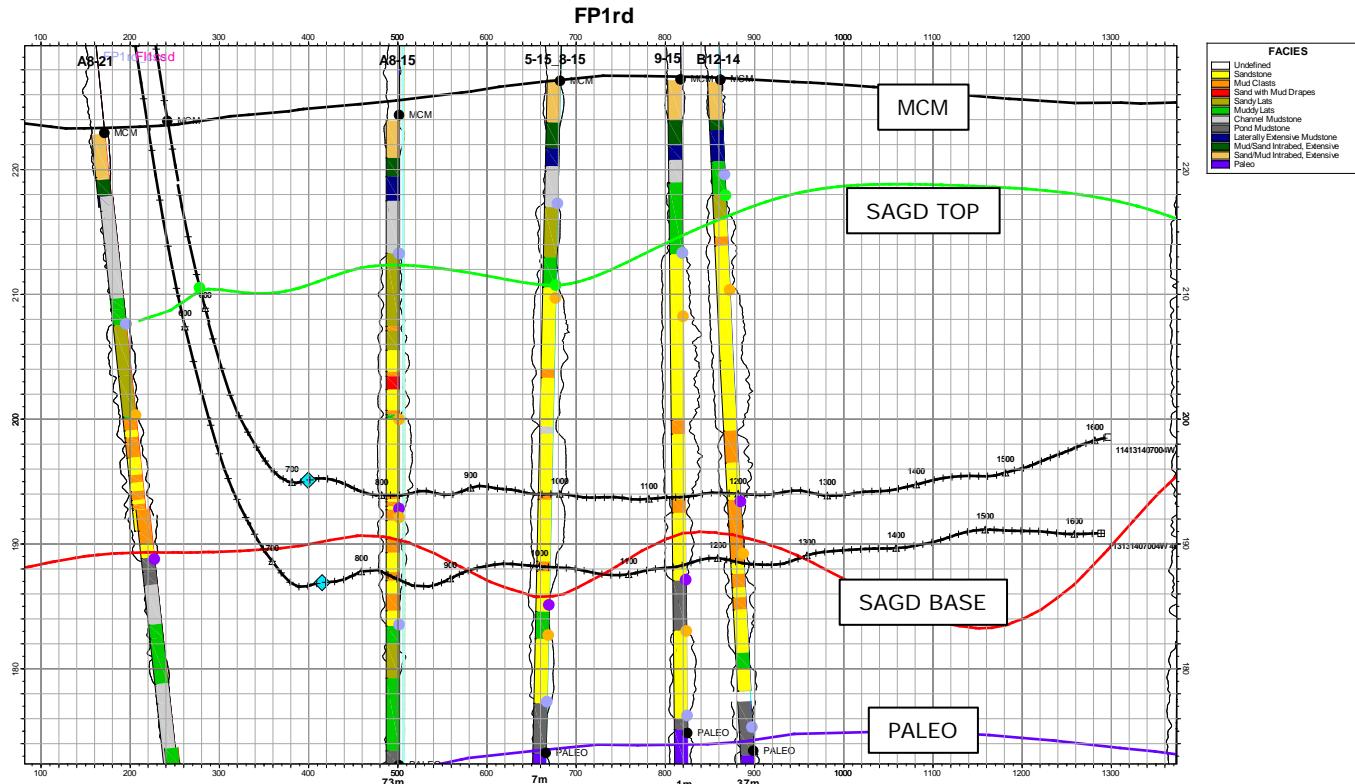
13m away from FWW5 well pair



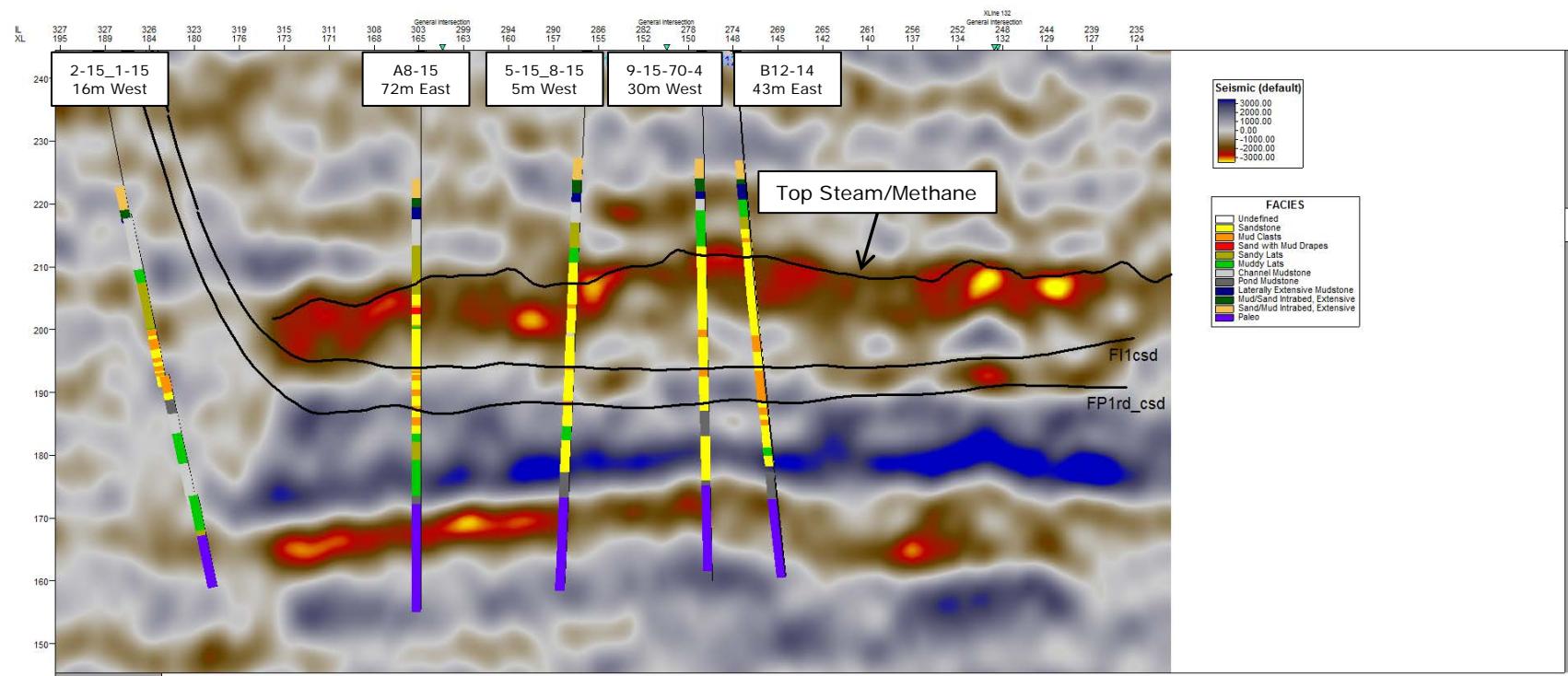
# F pad performance



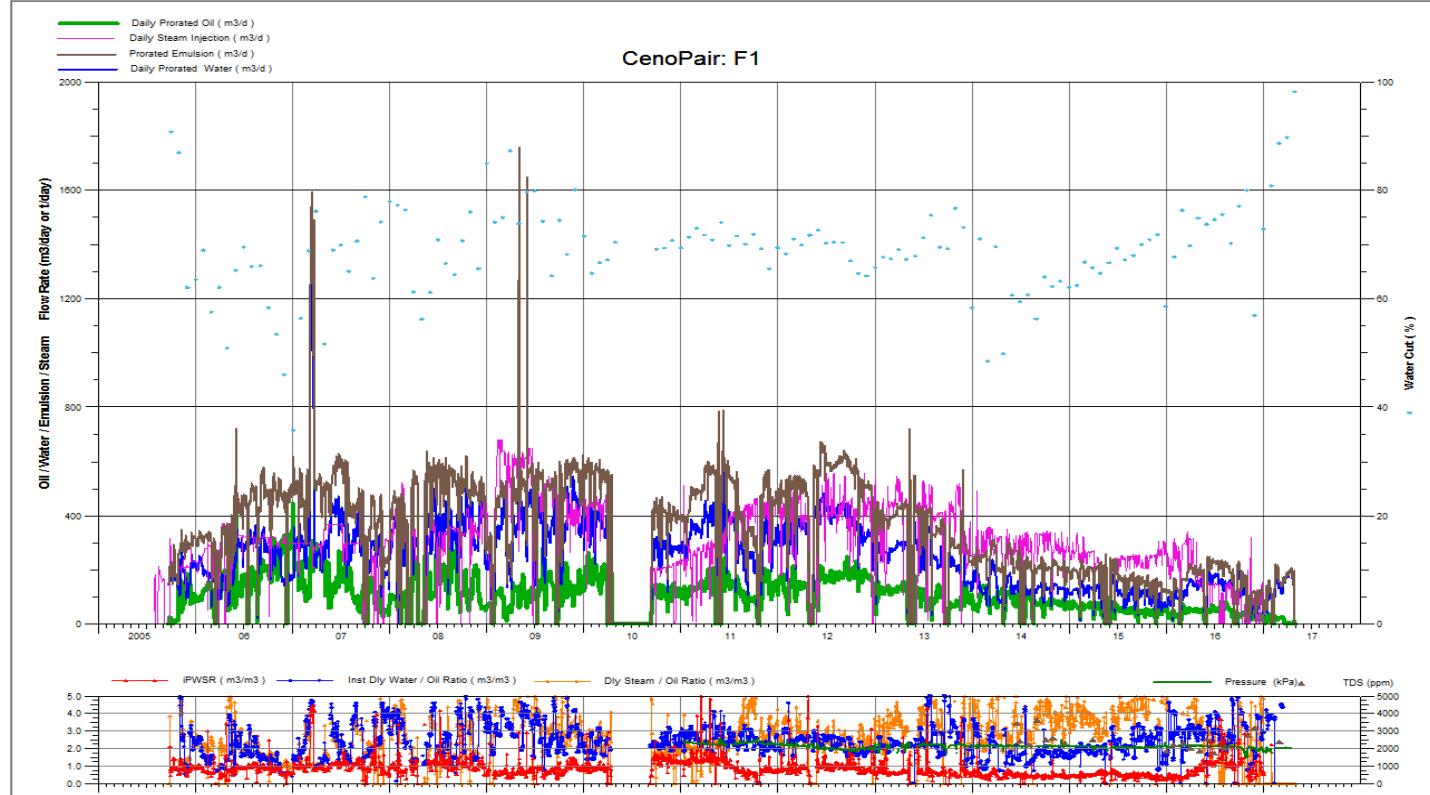
# F-01 geological profile



# Time-lapse seismic: F pair 1



# F-01 well pair performance



# F pad conclusions

- Pad is merged with central pod
- F1-F6 is on full blowdown, F7 and F8 are on SAGD operation
- Currently at ~81% recovery of SOIP (F1 – F6)
- Monitor conformance on F7 and F8

# Pad abandonments

- No pad abandonments are currently planned at Foster Creek in the next 5 years

# Steam quality

- Steam quality will be impacted by pipeline size and distance
- Currently at Foster Creek the steam qualities under normal operation conditions are as follows:
  - central ~ 95%
  - east ~ 94%
  - west ~ 95%
- Steam is delivered to pads at approximately 7000 – 9000 kPa
- Steam quality is not expected to impact well performance at this time

# Injected fluids

## Non-condensable gas

- NCG currently injected on A, C, D, F, G, M\_Exp, B/L, E/K, E02, E03, and E04 pads

## Acid treatments

- wells occasionally treated with HCl and Thermosolv to minimize skin

## Solvent

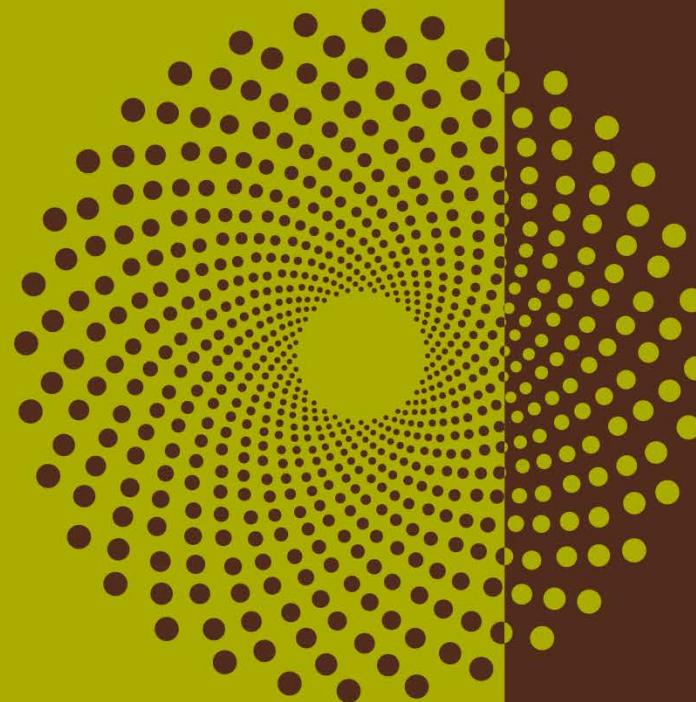
- have used solvent in start-up work-overs and have approval to use this as a potential start-up process

## CO<sub>2</sub>

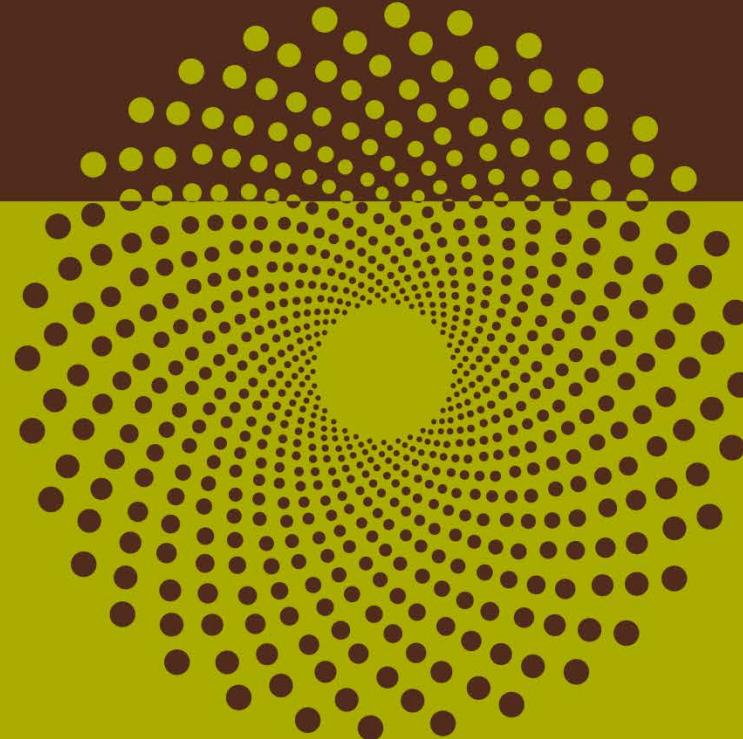
- injected in E03I05 and E03I06
- pilot concluded in Q4 2013

# 2016 key learnings

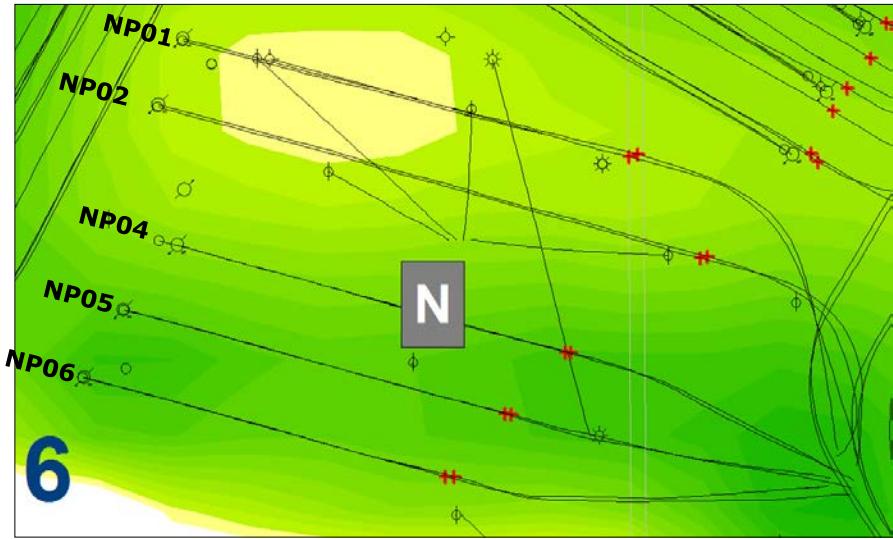
Subsection 3.1.1 – 7 f)



# N-Pad Pilot Update



# N pad overview



- NP01/NP02 are thin pay pilot wells
- NP04→NP06 are propane SAP pilot wells
- NP03 was not drilled to maintain isolation between the two pilots
- SAGD startup in Q2 2016

# Thin pay pilot overview

- Pilot goal is to prove that Cenovus can produce and operate thin pay reservoirs
- NP01 and NP02 drilled 6 & 7m from the SAGD TOP
- NI01 and NI02: drilled 4m high and 3m laterally from producer

Vertical ranging from observation wells was used to verify drilling depths and correct MWD uncertainties to ensure accurate thin pay for pilot wells (N01-N02)

- Circulation startup since wells were drilled off SAGD base

Wells drilled above the transition zone present in FC Central

# SAP Pilot Overview

**Pilot goal is to increase our understanding of propane SAP  
Propane (C3) SAP pilot is located at NP04-NP06**

- 160m development gap between NP02 and NP04
- Delay startup of NP05 to maintain isolation in NP04 and NP06 for SAP trial
- Wells are short to maintain 150m offset to E pad (West)
  - ~500-550m

**Wells have rich pay thickness ~12-16m**

**~1 year SAGD baseline prior to C3 injection**

# Ongoing work

- **Methods of injection**
  - Reduced number of injectors on a pad
  - Centralized injection (utilizing central pad for injection to support multiple pads)

# Well Integrity Update



# Well integrity - casing

## 2016 Intermediate Casing Failures

- Ongoing monitoring and inspection program to assess casing condition and repair as required

## Casing Corrosion

Corrosion Location	Status
Surface Casing Exterior	Mitigation program in place
Surface Casing Interior / Intermediate Casing Exterior	Investigation on-going
Pack-Off	Investigation on-going

# Well Integrity - SCVF

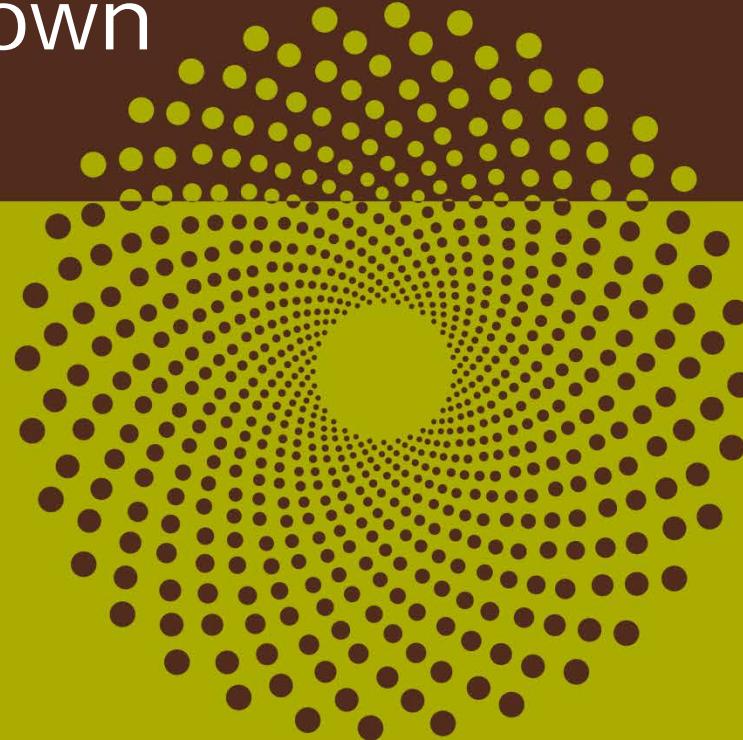
- Cenovus complies with all regulations and when a surface casing vent flow is identified, Cenovus reports non-serious and serious surface casing vent flows into the DDS system per ID 2003-01
- Cenovus engages with the AER to discuss appropriate strategies related to managing SCVFs
- Cenovus communicates with the AER regularly on the status of the vents and presents an annual update on activities executed to manage surface casing vent flows

# Well integrity – strain monitoring

## Strain monitoring wells installed

- Baseline data in non-thermally affected zones in laterals
  - 1AB/03-23-070-05W4/00 (FC W20 Pad)
  - 1AD/05-23-070-05W4/00 (FC W20 Pad)
  - 100/05-28-070-03W4/00 (FC E26 Pad)
  - 100/14-14-070-05W4/00 (FC W20 Pad)
- Field measurements scheduled relative to milestone dates

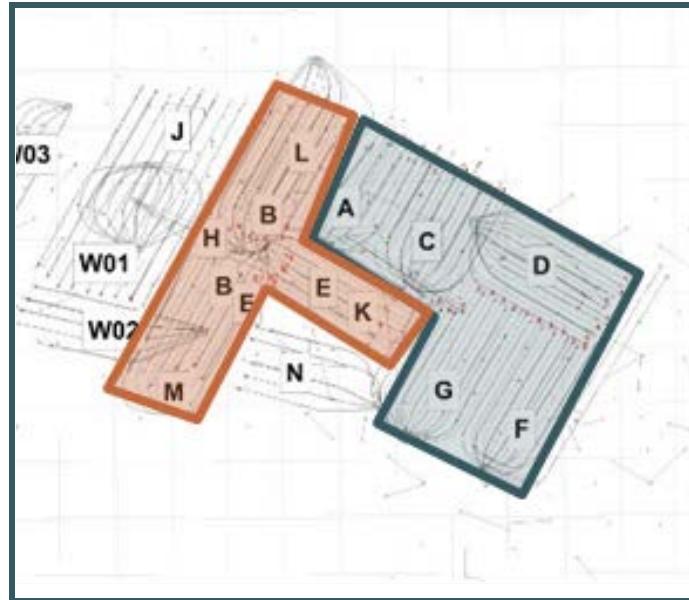
# Rampdown/Blowdown Update



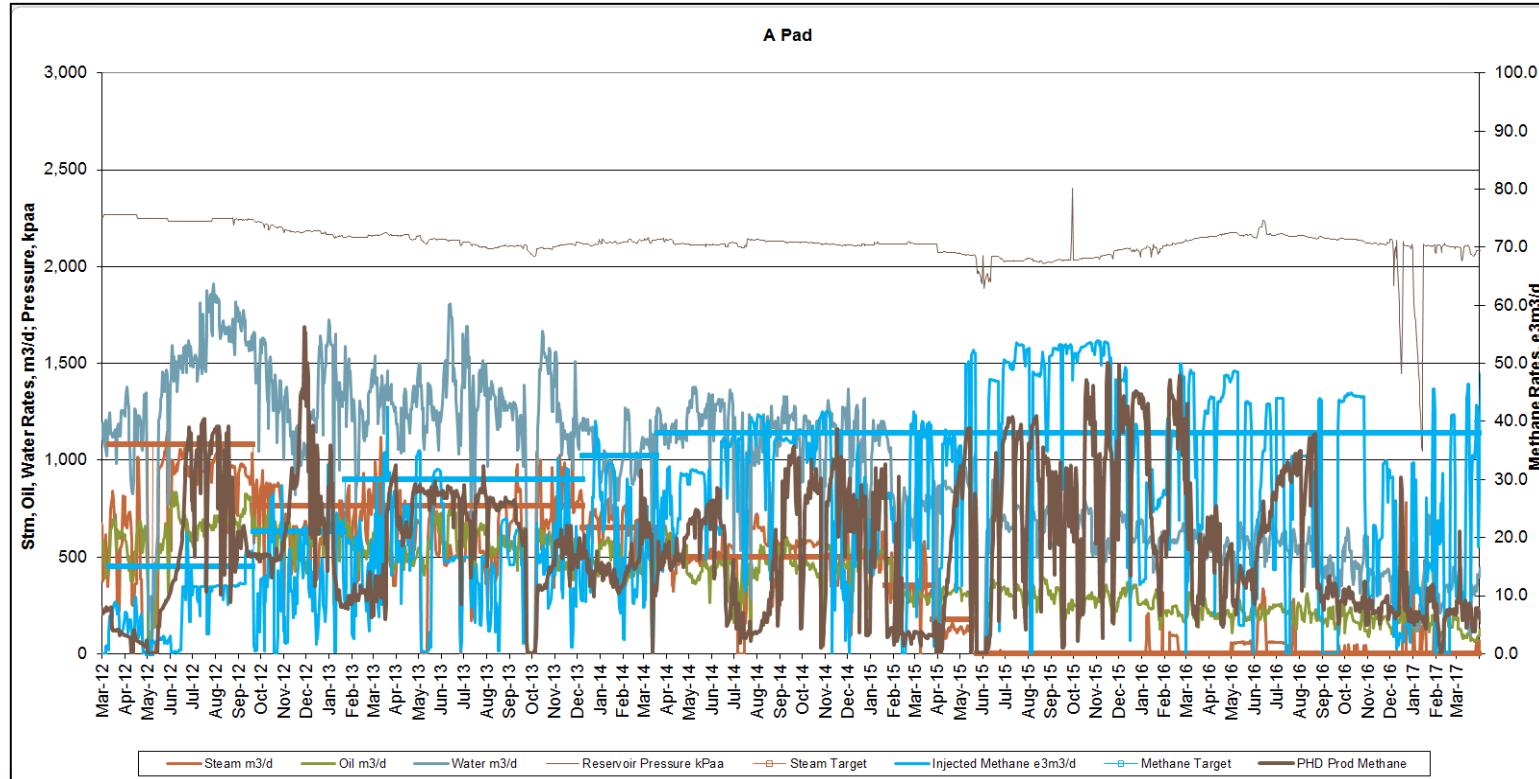
# Current rampdown/blowdown

Pad Name	Methane Inj Start Date	Blowdown Start Date
Pad A	Mar 2012	May 2015
Pad C	Nov 2011	Mar 2013
Pad D	Aug 2010	Mar 2015*
Pad F	May 2014	TBD
Pad G	May 2014	TBD
E/K	Nov 2016	TBD
B/L	Nov 2016	TBD
Exp/M	Nov 2016	TBD

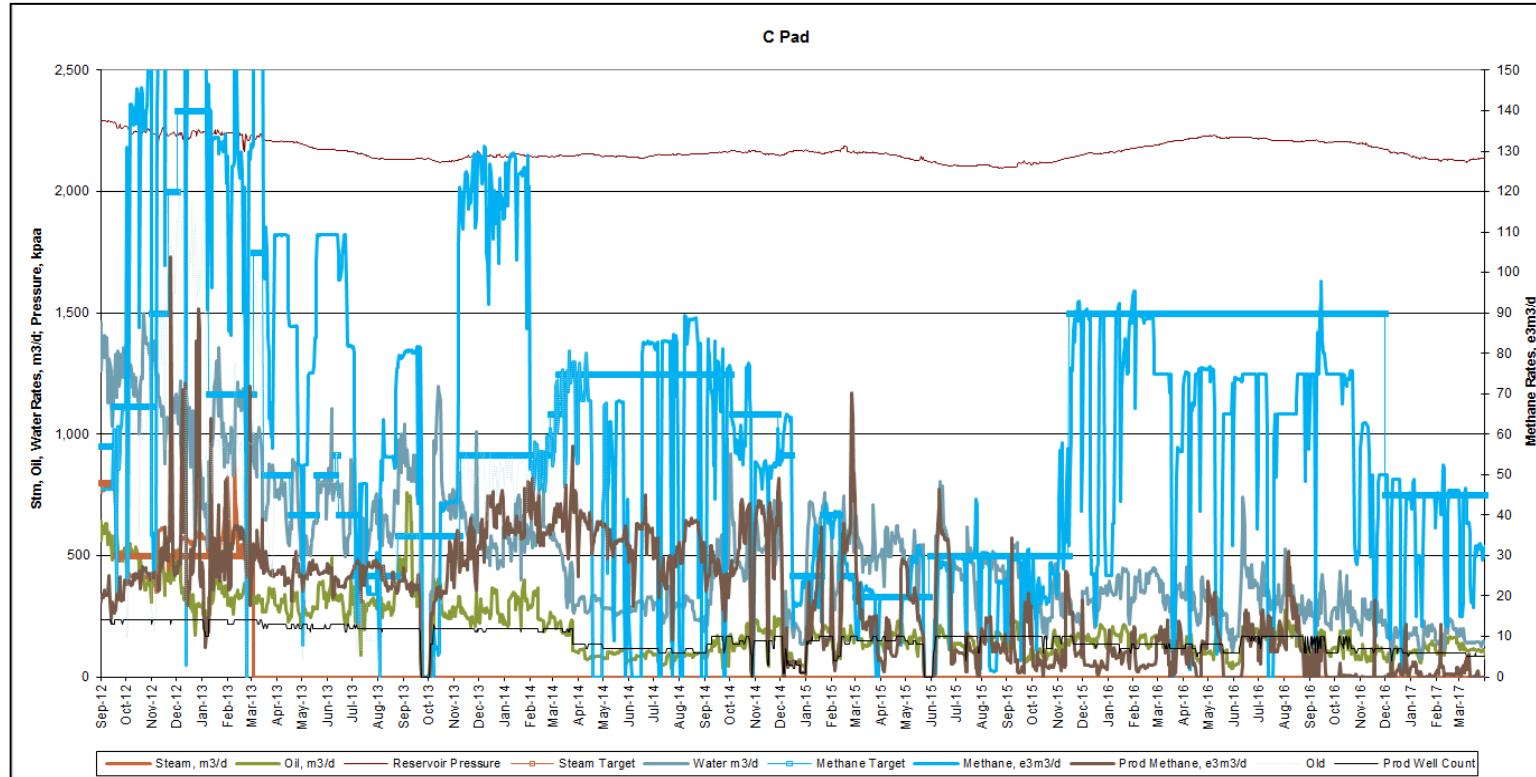
\*Excludes D17, full pad blowdown was May 2015 including D17



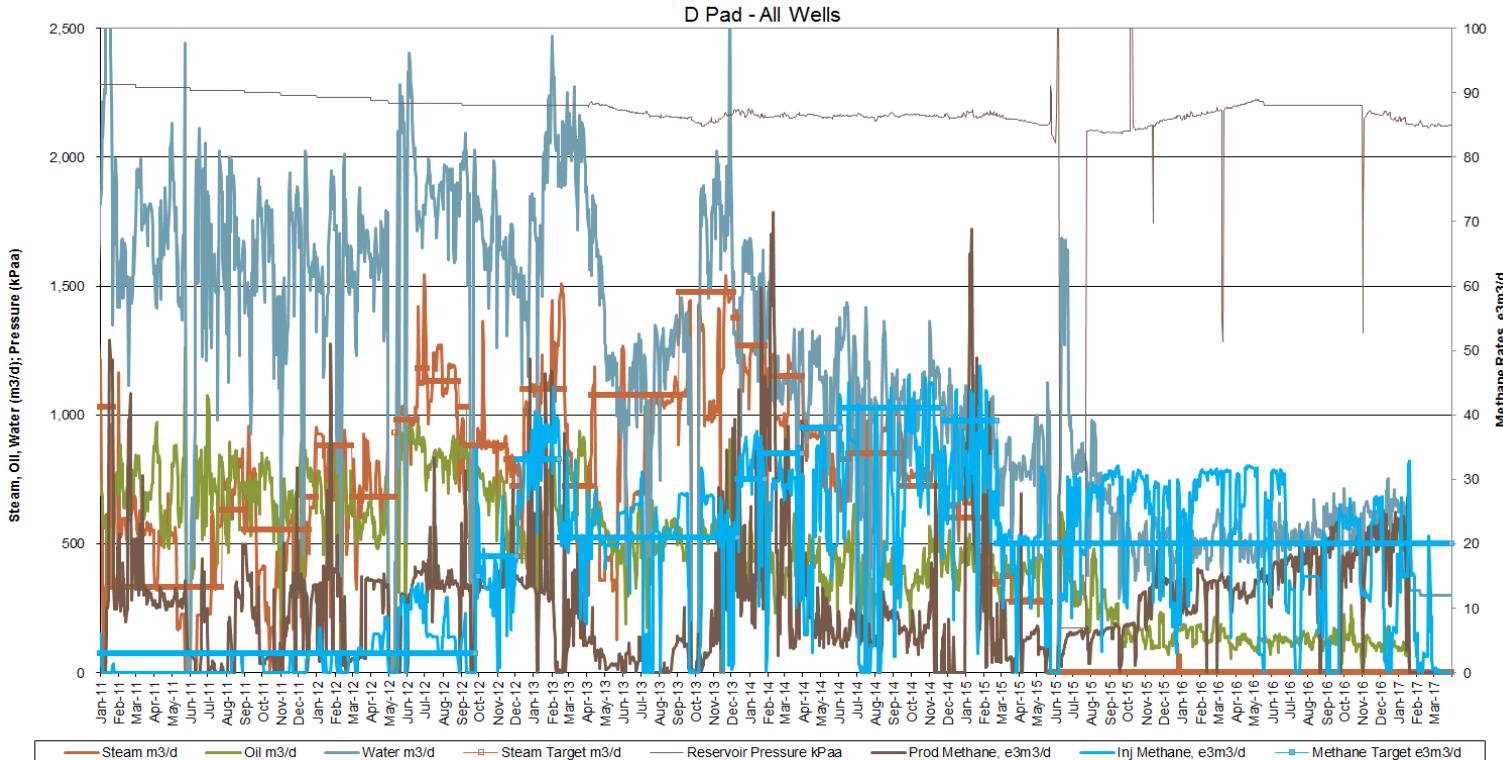
# Pad A – production & injection



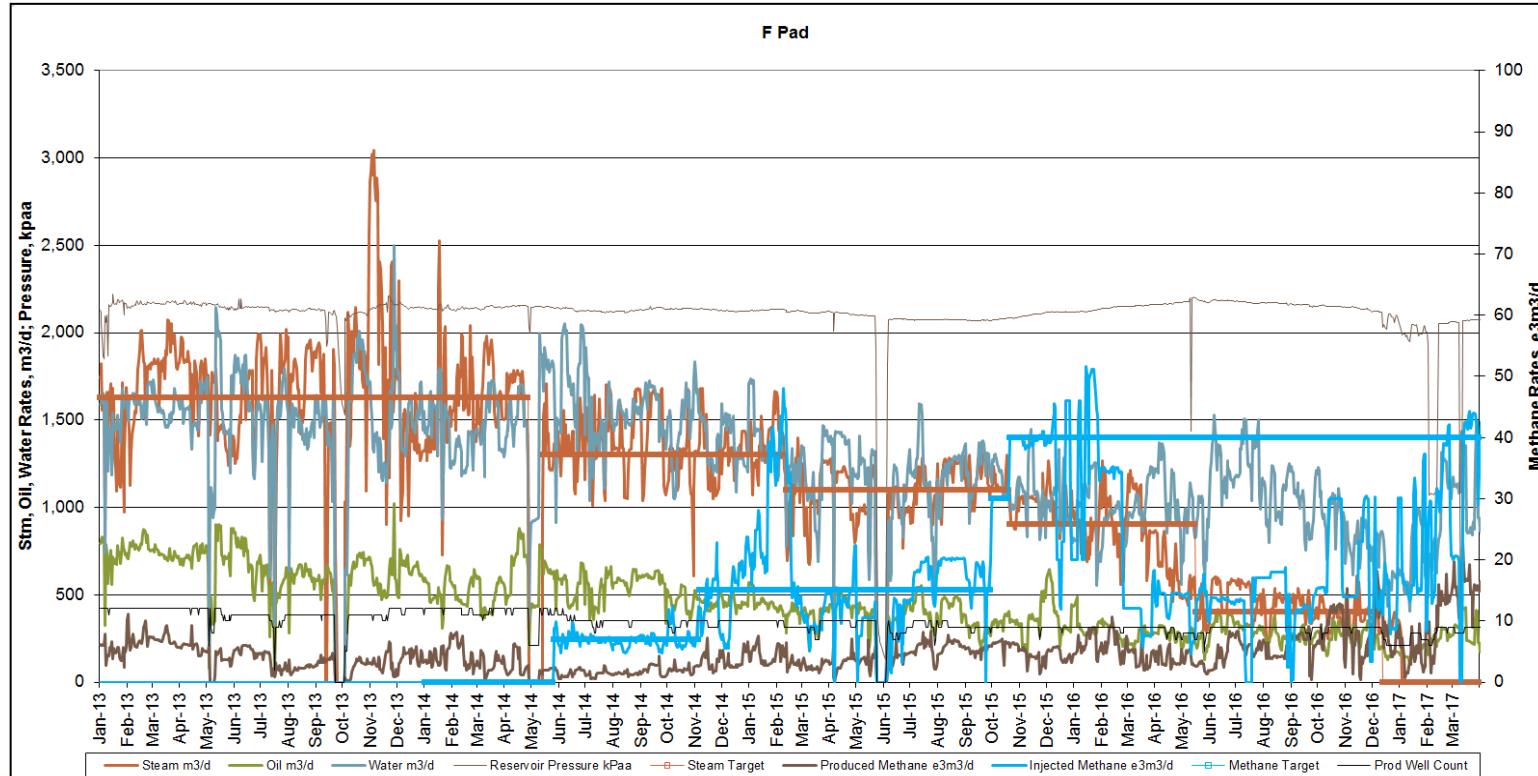
# Pad C – production & injection



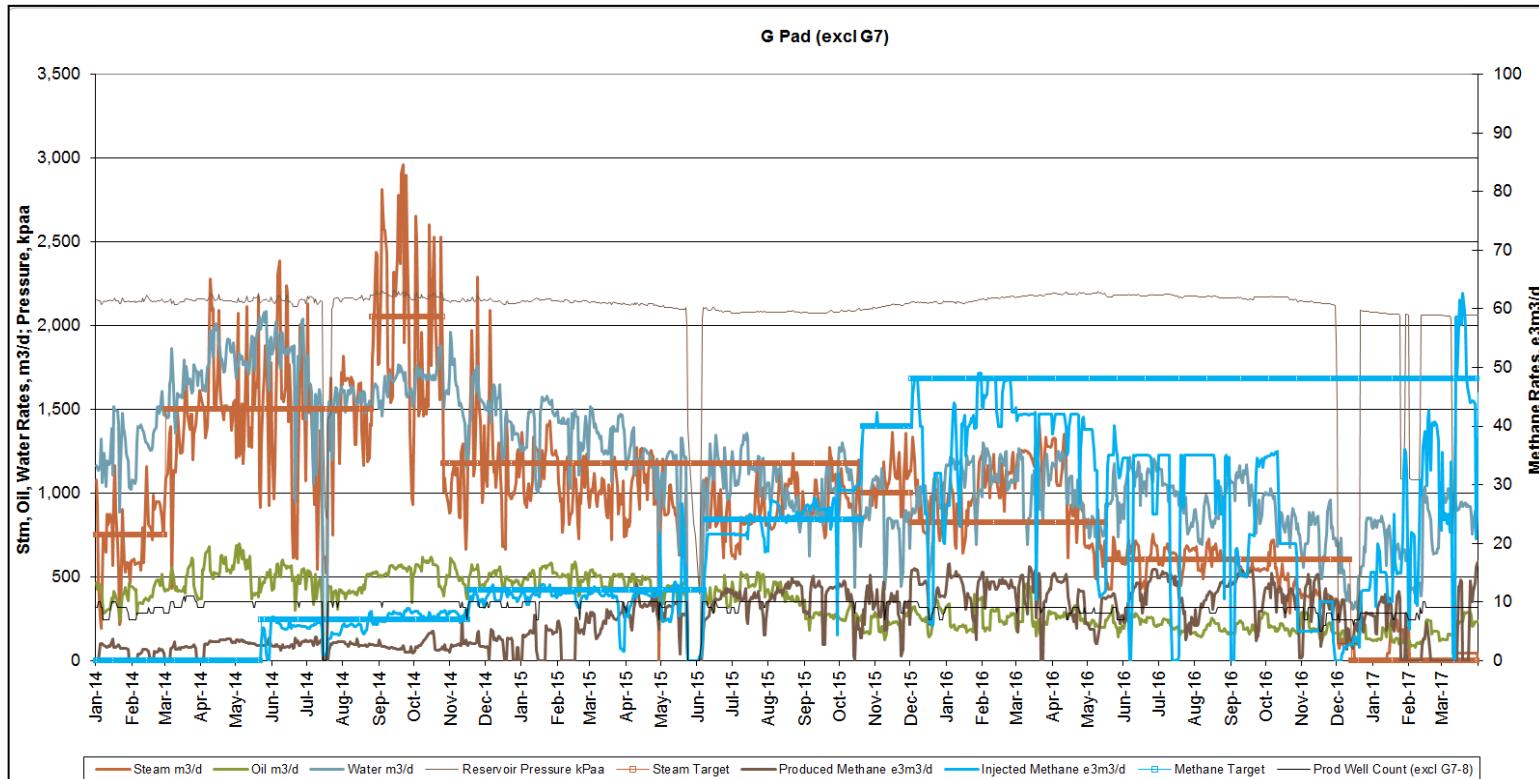
# Pad D – production & injection



# Pad F – production & injection



# Pad G – production & injection



# Ongoing work

## Methods of injection

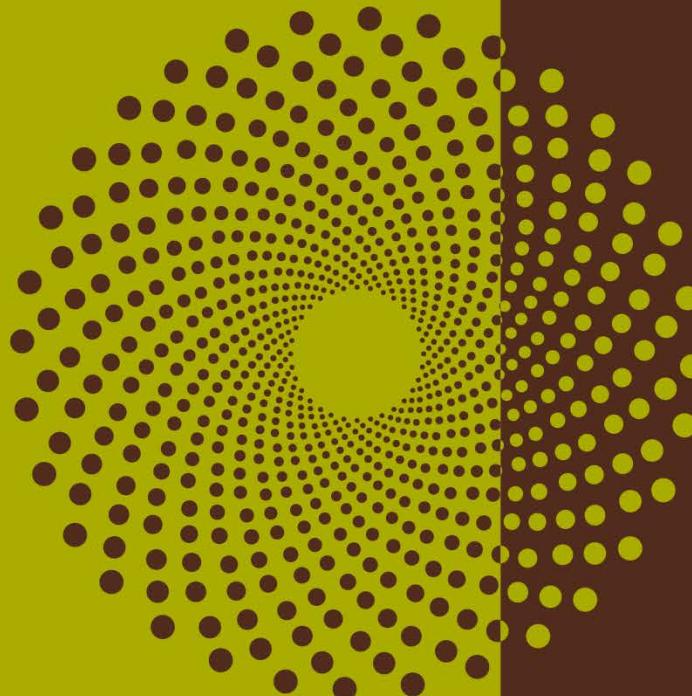
- Reduced number of injectors on a pad
- Centralized injection (utilizing central pad for injection to support multiple pads)
- Learnings on current rampdown/blowdown pads remain consistent with past performance
- Pads E19, E20, and E12 to be converted to rampdown/blowdown in 2017

# Subsection 3.1.1 – 7 h) – pad performance plots

- Requirements under Subsection 3.1.1 7 h) are located in the Appendix

# Future plans 2017 initiatives

Subsection 3.1.1 – 8



# Steam rampdown/blowdown

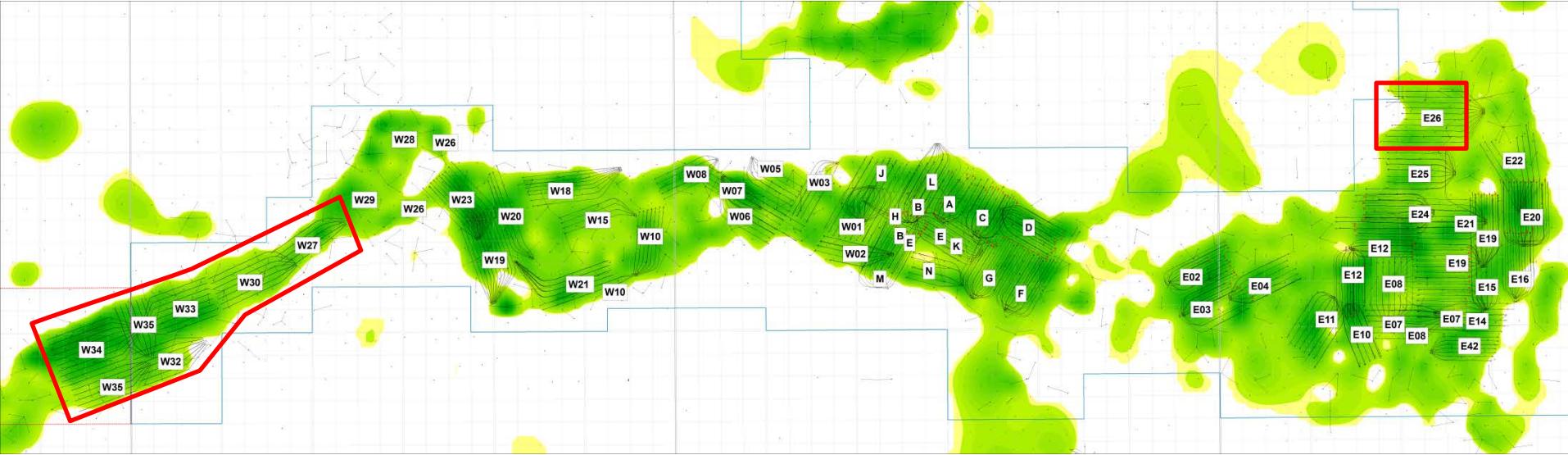
- A, C, D pads continuing on blowdown
- F & G pads started blowdown Q4 2016
- B/L, E/K, M Exp pads started rampdown Q4 2016
- E02, E03, E04 pads started co-injection Q3 2016

# 2017 initiatives

- Alternate liner trials continue on various pads
- Liner and tubing deployed FCDs
- Co-injection
  - solvent
- Insulated tubing
  - Commercialized VIT in injectors
- N pad Trials
  - Thin pay pilot
  - Propane SAP pilot

<u>Well</u>	<u>FCD</u>
W05P05	ICD
W08P01	ICD
GP5-1	ICD
DF1	ICD
E15P11-1	ICD
E16P06	ICD
FP2-1	ICD
E12P07-1	ICD
FP07	ICD
FI07	OCD
GP6-1	ICD
E15P02-1	ICD
W21P04	ICD

# 2017 new SAGD well pairs drilling plans



## West Pads:

- W27, W30, W32  
W33, W34, W35

 Mar 2016 - Mar 2017 Drilling  
 2016 Production

# 2017-2018 steam strategy plans

- Cenovus allocates steam to maintain targeted steam chamber operating pressures from pad to pad
- Steam rampdown is used to optimize steam allocation across the field by freeing up steam to be used in starting up new pads
- Overall strategy is to optimize field SOR

# Thank you