2018 Performance Presentation

MacKay River Commercial Project

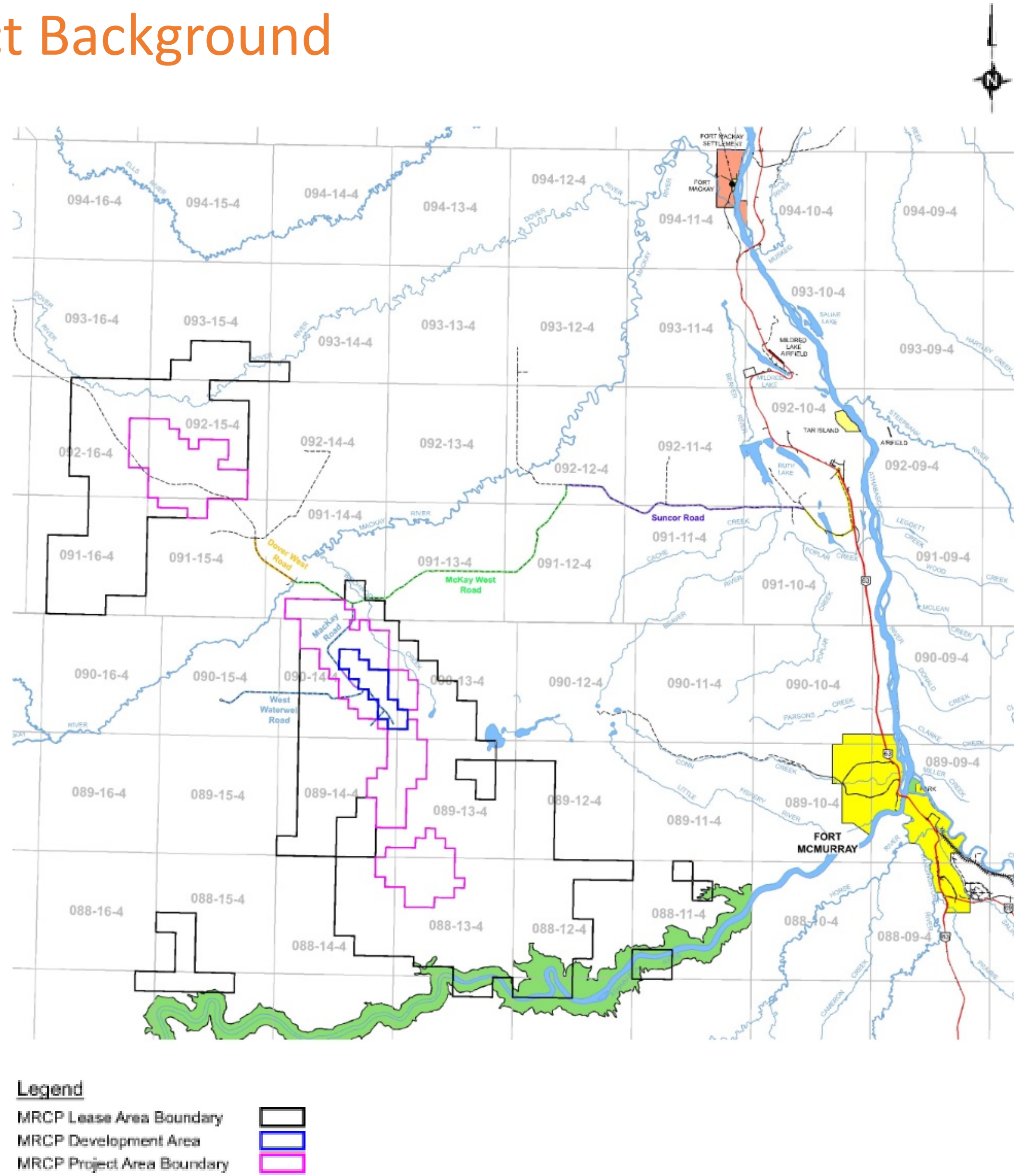
AER Scheme Approval No. 11715

April 1, 2018 to March 31, 2019

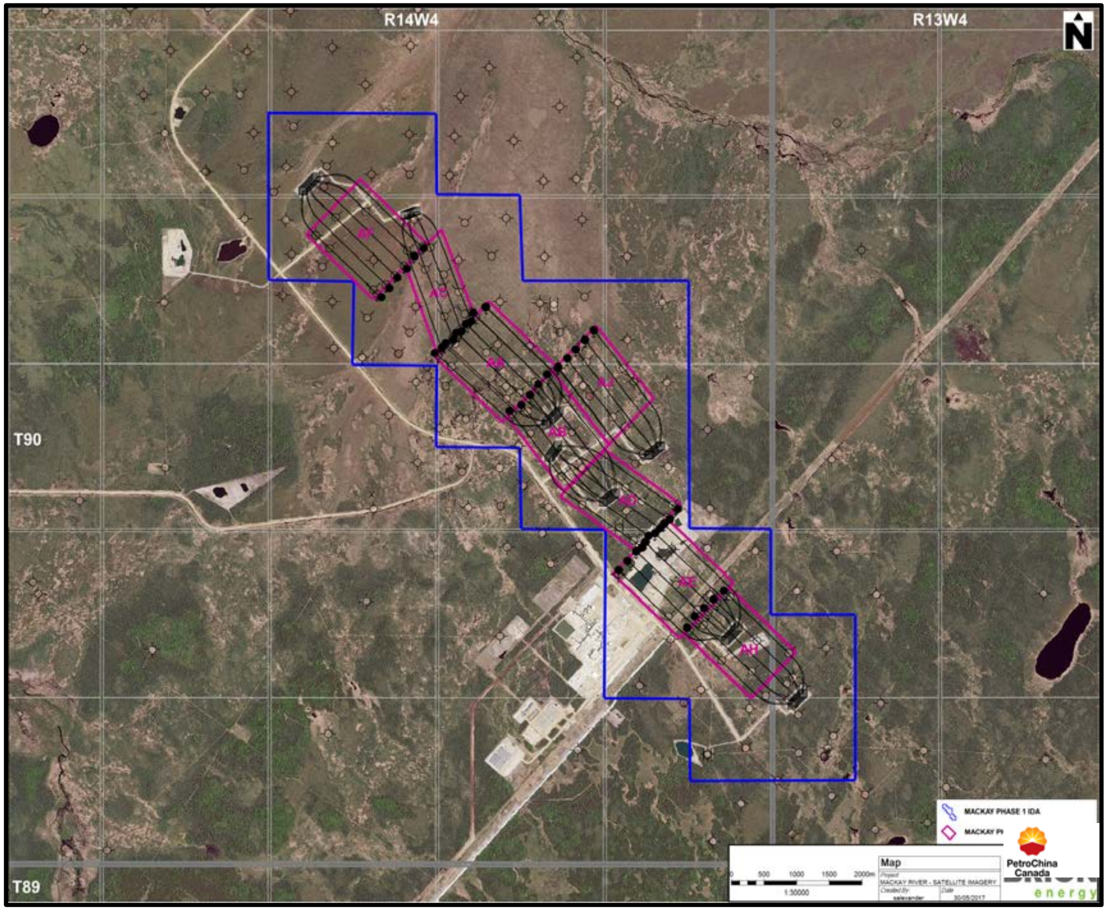
PCC-RA-PA-00003

Project Background

- PetroChina Canada ("PCC") owns and operates the MacKay River Commercial Project ("MRCP")
- The MRCP is a bitumen recovery project located within the Regional Municipality of Wood Buffalo ("RMWB") in northeast Alberta; approximately 30 km northwest of Fort McMurray
- The MRCP utilizes steam-assisted gravity drainage (SAGD) technology
- The MRCP is planned for phased development to peak capacity of 150,000bbl/d bitumen



MRCP Phase 1 Overview



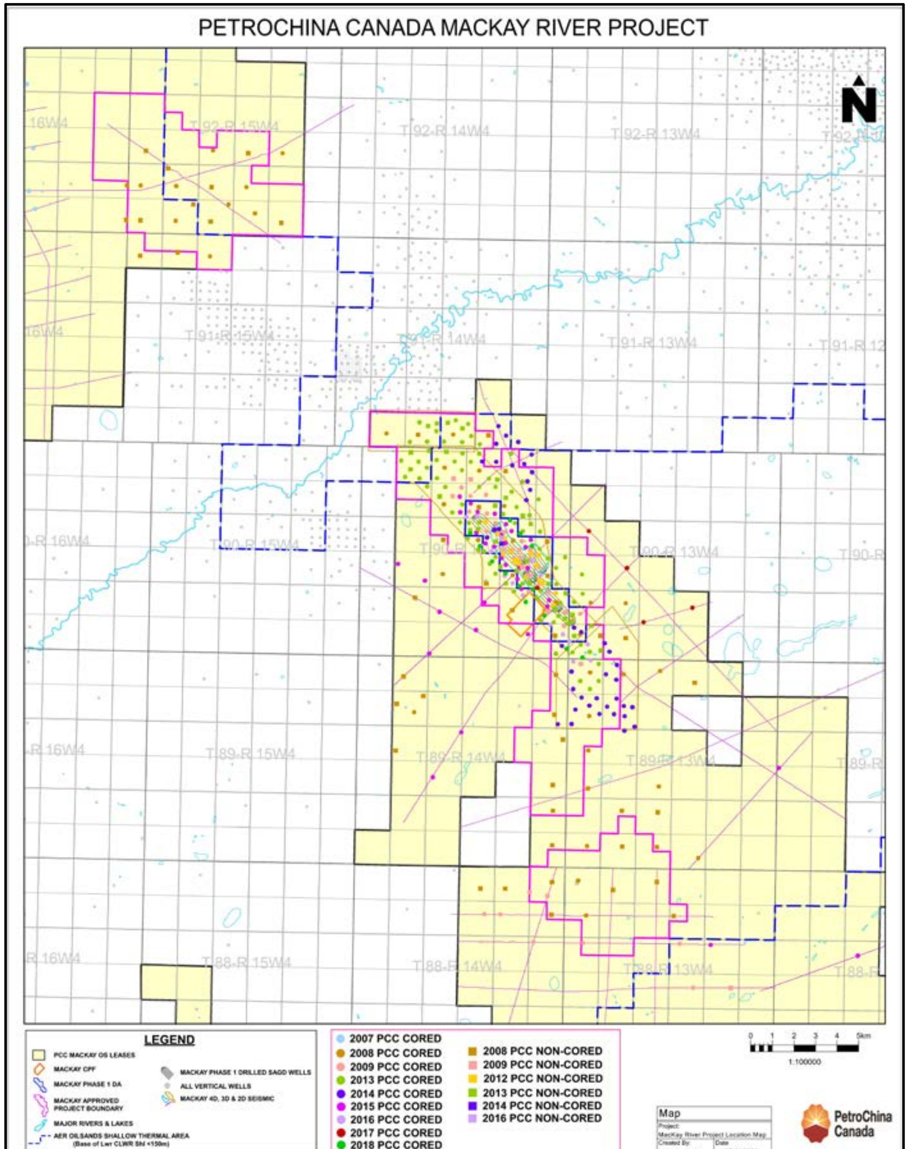
- Phase 1 has a bitumen capacity of 35,000 bpd
- The Phase 1 development area (DA) includes:
  - 8 SAGD surface well pads and associated subsurface drainage patterns
  - 42 SAGD Horizontal well pairs
  - 850m long horizontals
  - 125m well spacing
  - The Central Processing Facility ("CPF")
  - Water source wells and associated pipelines
  - Observation wells
  - Borrow areas
  - Access roads
  - Camps

Directive 078 - Scheme Approval Amendments

Amendments to Scheme Approval No. 11715		
Amendment No.	**Purpose**	**Approval Date**
11715A	Drainage patterns AF and AG were combined into a single subsurface drainage pattern (AF)	12-Jun-2012
11715B	Equipment reconciliation and design changes at the MRCP CPF	5-Sep-2013
11715C	Amalgamation of MacKay Operating Corporation and Brion Energy Corporation into a single corporate entity.	15-Sep-2015
11715D	Addition of 17 down-spaced well pairs in four subsurface drainage patterns (AA, AB, AC and AF) and deferral of the development of AI drainage pattern.	9-Nov-2015
NA	Approval to temporarily exceed the maximum operating pressure for 42 well pairs at MRCP.	21-Dec-2016
11715E	FUSE^{TM} polymer fluid dilation process	03-March-2017
11715F	Update for Corporate Name Change from Brion Energy Corporation to PetroChina Canada Ltd.	20-Oct-2017
11715G	Application to Update the MOP at the MRCP	25-May-2018
11715H	Application for the Steam Stimulation Process (AJ-05 Only)	31-May-2018
11715 I and J	Application for Gas Cap Pressurization	08-June-2018
11715K	Application for the Steam Stimulation Process (AF-05 Only)	23-Oct-2018
11715L	Well Design Enhancements	14-Nov-2018
11715M	Producer Re-Entries and Sidetrack; Co-Injection for Gas Cap Pressurization; Four Injector Re-Drills	7-Dec-2018
11715N	Bottom Transition Zone Treatment	18-Dec-2018
11715O	Polymer Treatment	22-Mar-2019
11715P	Wellbore Conditioning and Stabilization	Pending

3.1.1 SUBSURFACE ISSUES RELATED TO RESOURCE EVALUATION AND RECOVERY

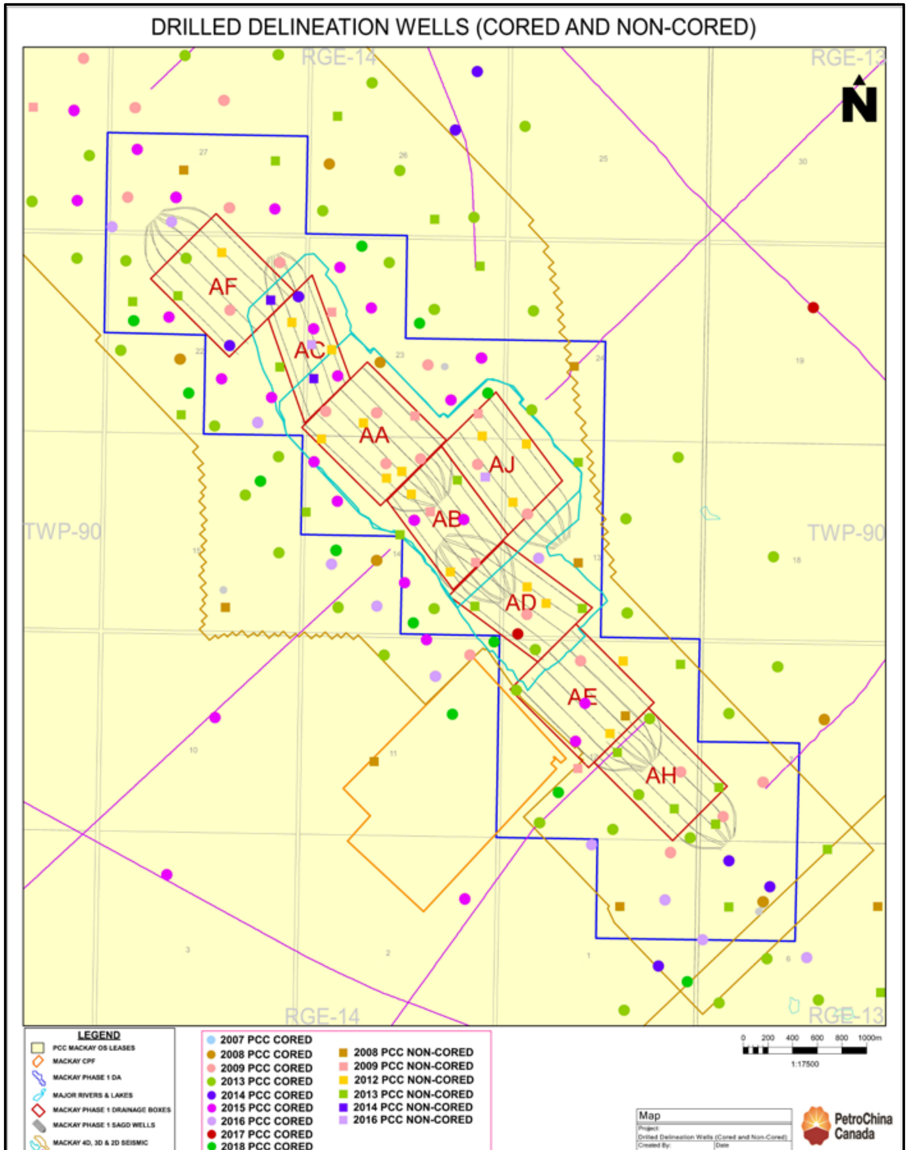
Scheme Approval Area Overview



PetroChina Canada MacKay River								
	MRCP Project Area				MRCP Phase 1 DA			
	Total Wells	Cored Wells	Speciality Logged	Petrographically Analysed	Total Wells	Cored Wells	Speciality Logged	Petrographically Analysed
2013 & Prior	206	119	55	17	76	33	17	11
2014 - 2017	68	64	58	18	33	29	28	15
2018	13	13	13	0	5	5	5	0
TOTAL	**287**	**196**	**126**	**35**	**114**	**67**	**50**	**26**

- 287 total vertical wells in the MRCP Project Area ("PA")

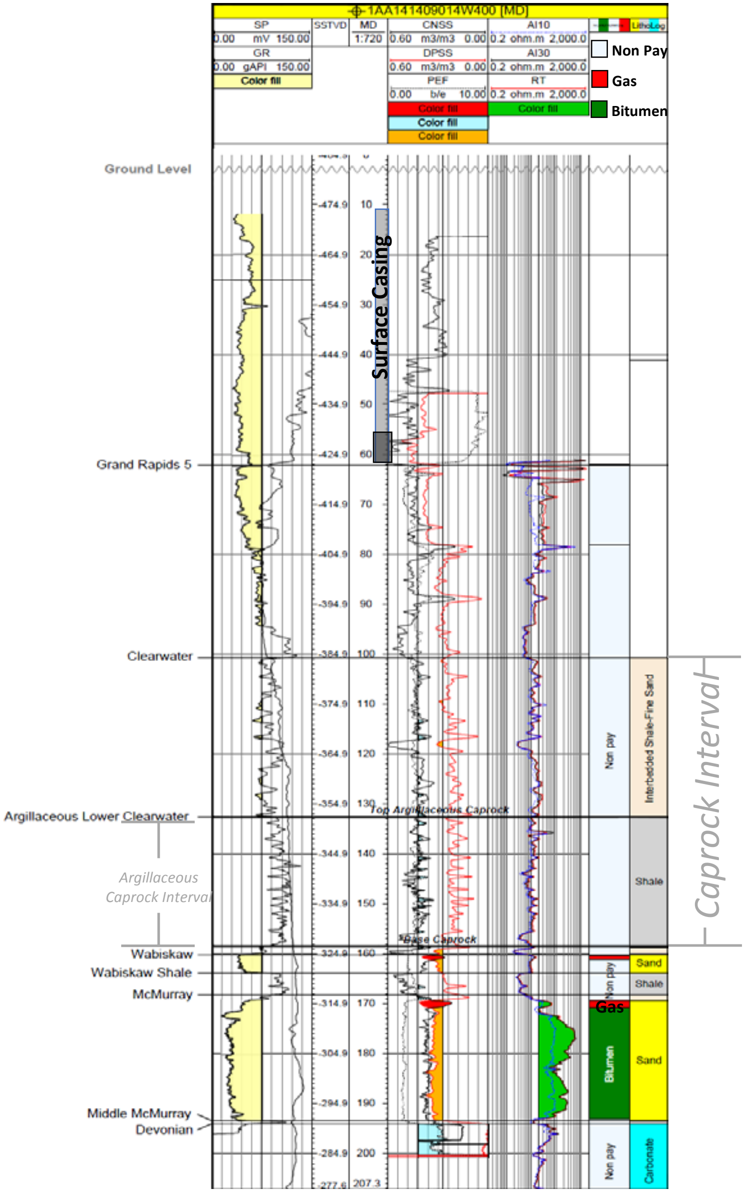
MRCP1 Wells – Vertical & SAGD

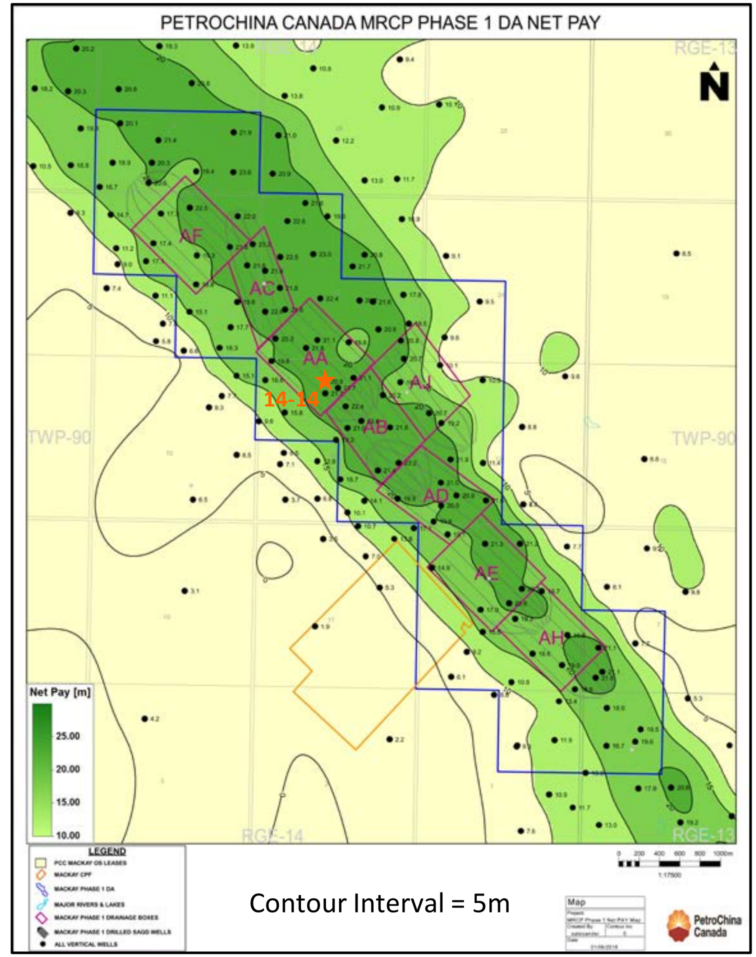


PetroChina Canada MacKay River				
	MRCP Phase 1 DA			
	Total Wells	***Cored Wells***	***Speciality Logged***	***Petrographically Analysed***
2008	7	2	0	1
2009	23	17	11	5
2010	1	1	1	0
2011	0	0	0	0
2012	16	0	0	0
2013	29	13	5	5
2014	6	4	2	3
2015	19	19	18	12
2016	7	5	7	0
2017	1	1	1	0
2018	5	5	5	0
TOTAL	**114**	**67**	**50**	**26**

- 114 vertical wells in MRCP Development Area (“DA”)
- 42 horizontal well pairs in MRCP DA

MacKay River Stratigraphy





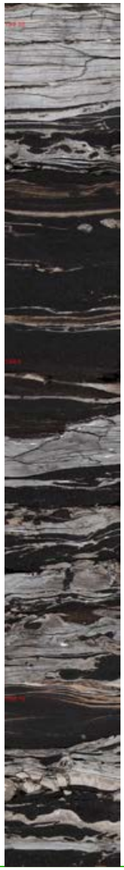
- Caprock is Argillaceous Lower Clearwater
- Wabiskaw sand above McMurray across DA
- Target reservoir is Upper McMurray

Oil Sands Pay Facies

MRCP Upper McMurray Facies

F8b:Bioturbated Heterolithic Sands with Continuous Mud Beds (Core Scale)

15-70% Vsh
over 50cm interval



F8a: Bioturbated Herolithic Sands with Discontinuous Mud Beds

15-30% Vsh
over 50cm interval

F9: Bioturbated Wavy-Bedded Sands

<15% Vsh
over 50cm interval

F10: Ripple Cross-Laminated to Cross-Bedded Sands

<5% Vsh
over 50cm interval

F11: Cross-Bedded Sands

<5% Vsh
over 50cm interval

F12: Bioturbated Hummocky Cross-Stratified Sands (Lam-Scram)

5-15% Vsh
over 50cm interval

F13: Bioturbated Muddy Sands

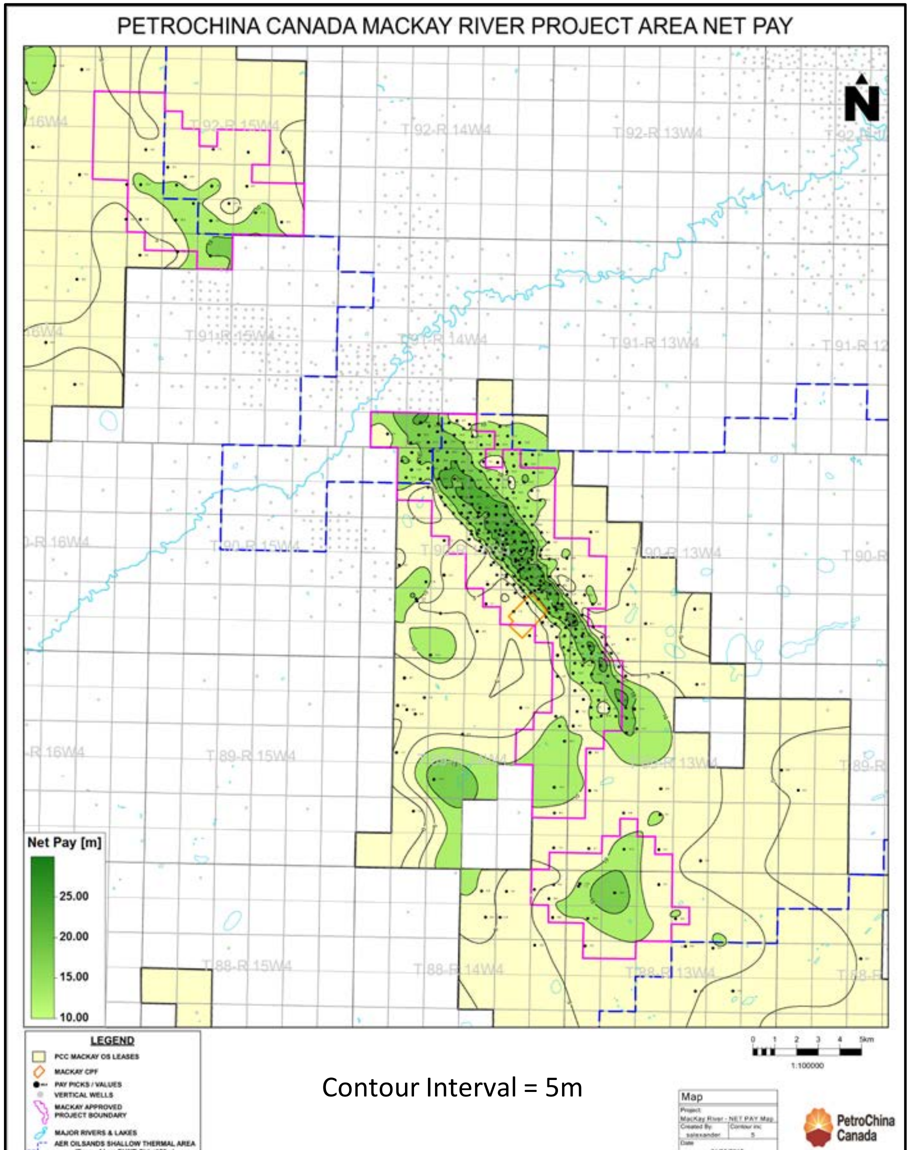
>15% Vsh
over 50cm interval

PAY FACIES

Pay Facies:

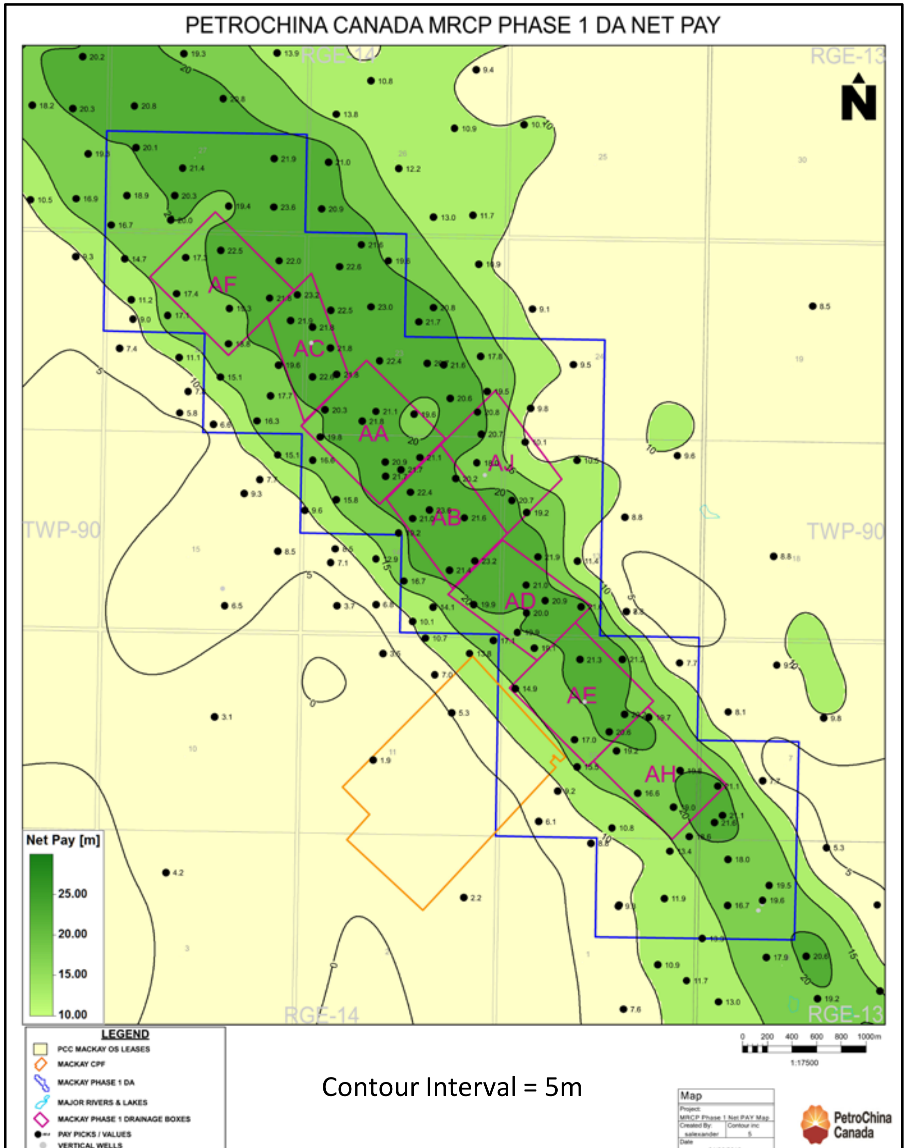
- Includes Facies F8a, F9, F10, F11, F12
- Typically >30% Porosity
- Weight percent bitumen >8%
- Permeability ~0.9-2.7 Darcy's

Bitumen Net Pay Map – Project Area



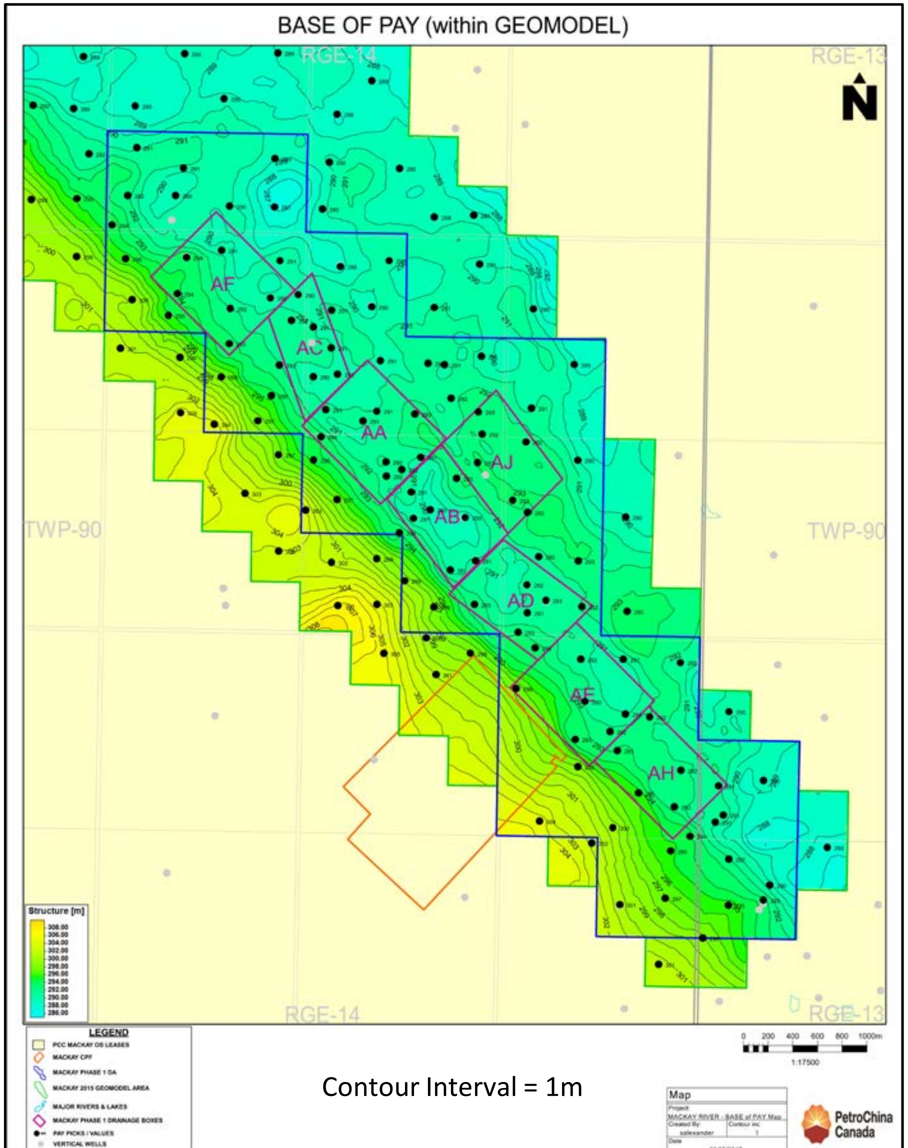
- Net pay cut-off at ≥10m
- Thickness ranges from 10-25m in the DA
- Upper McMurray reservoir shows strong NW-SE trend
- DA lies 2km South of AER Oil Sands Shallow Thermal Area

Bitumen Net Pay Map – Development Area



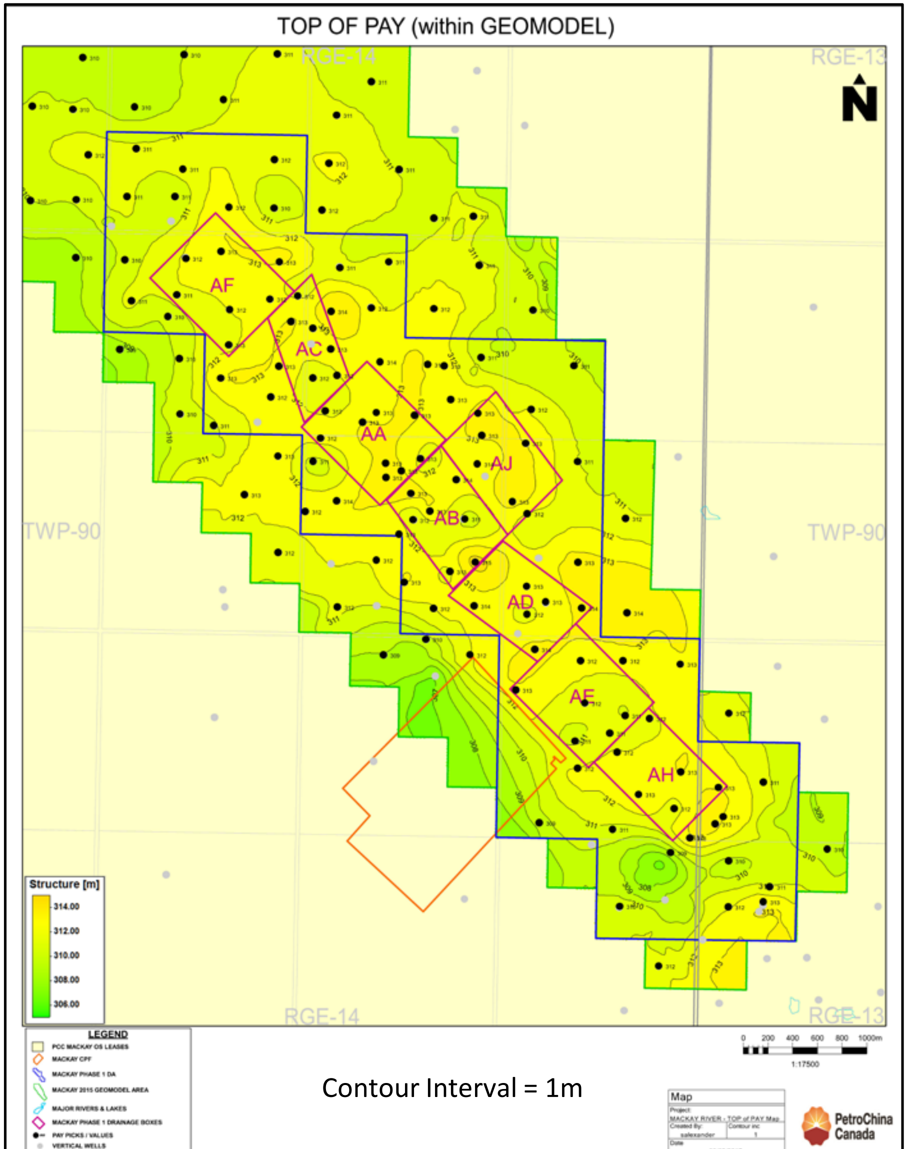
- Net pay cut-off at ≥10m
- Thickness ranges from 10-25m in the DA
- Upper McMurray reservoir shows strong NW-SE trend
- Central processing facility located Southwest of development area
- Majority of 8 drainage boxes are in >15m bitumen pay

Base of Pay Structure Map



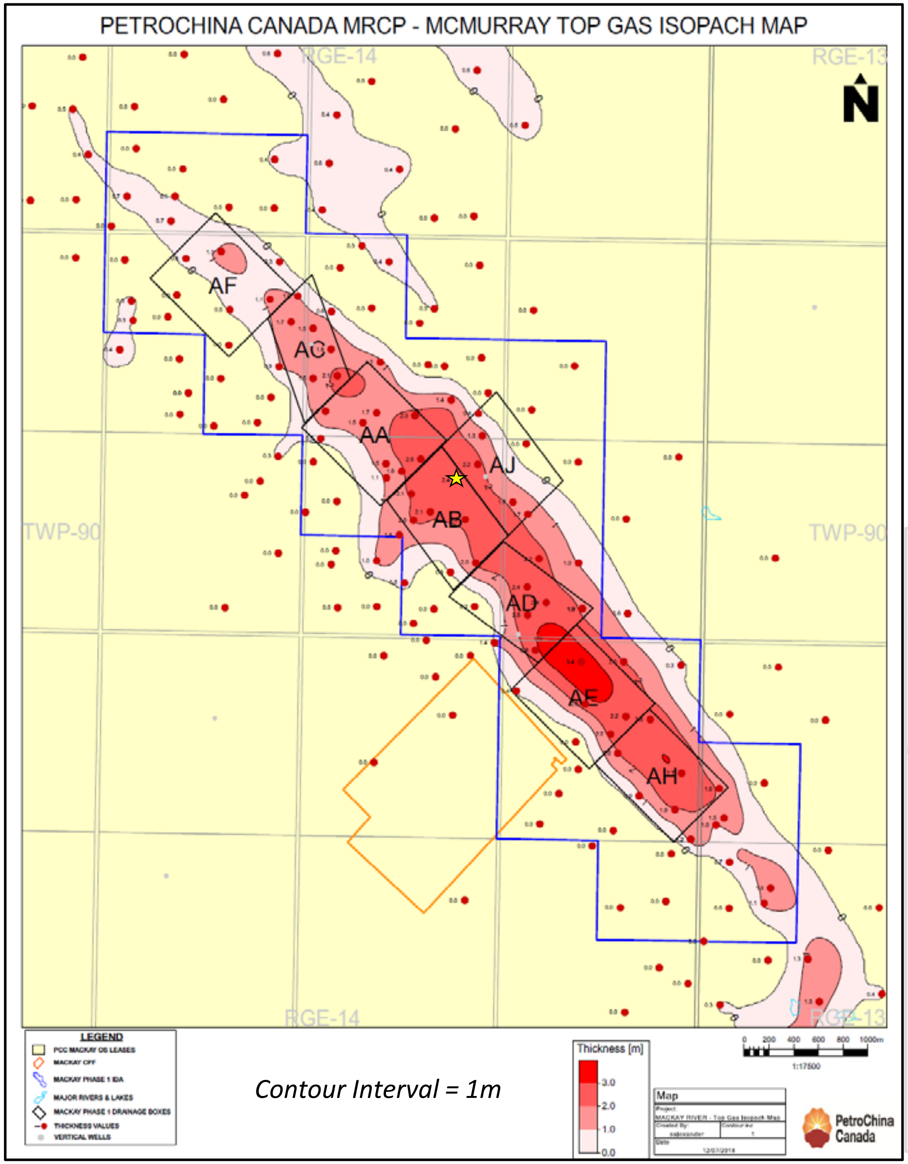
- Base of pay is reasonably flat across existing 8 drainage boxes
- Base of pay elevation rises on Southwest side of DA

Top of Pay Structure Map

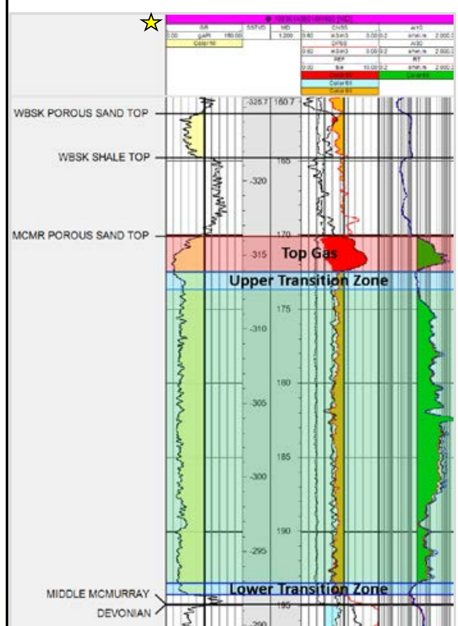


- Top of Pay is relatively consistent over the 8 drainage boxes in the DA
- The Top of Pay fluctuates only ~6m between 308-314m SS across the entire DA

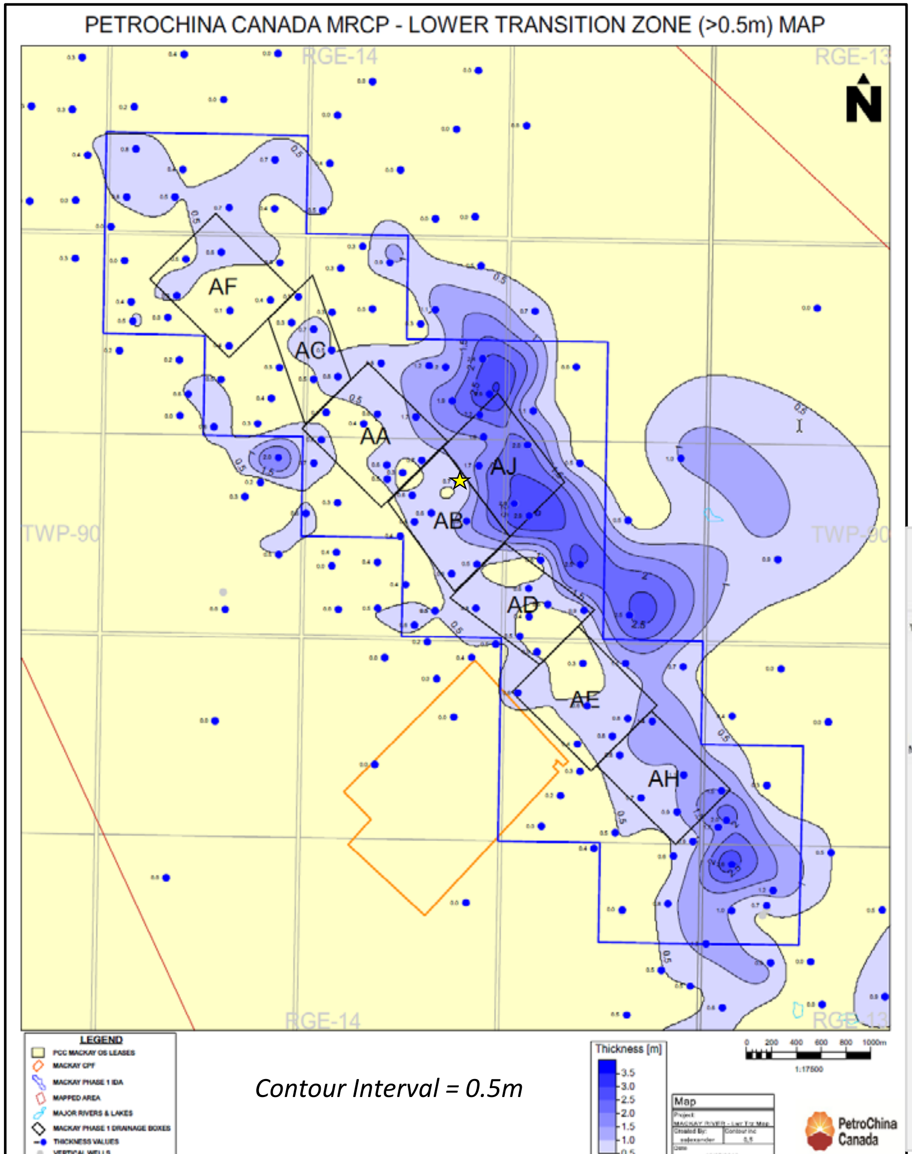
MCMR Top Gas Isopach Map



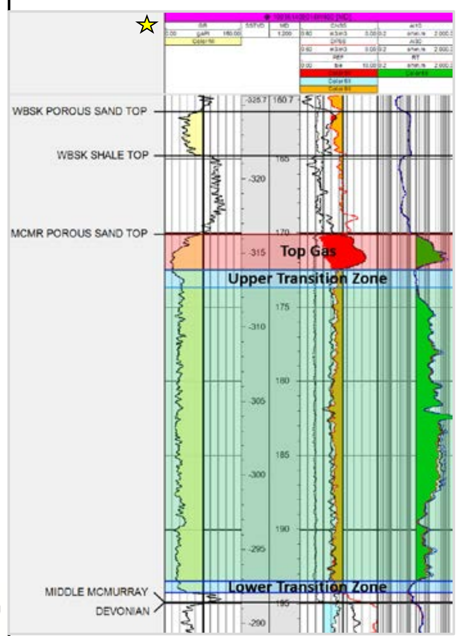
- Top gas zone present in the upper McMurray over the DA
- Ranges in thickness from approximately 0 to 3 meters



Lower Transition Zone Map



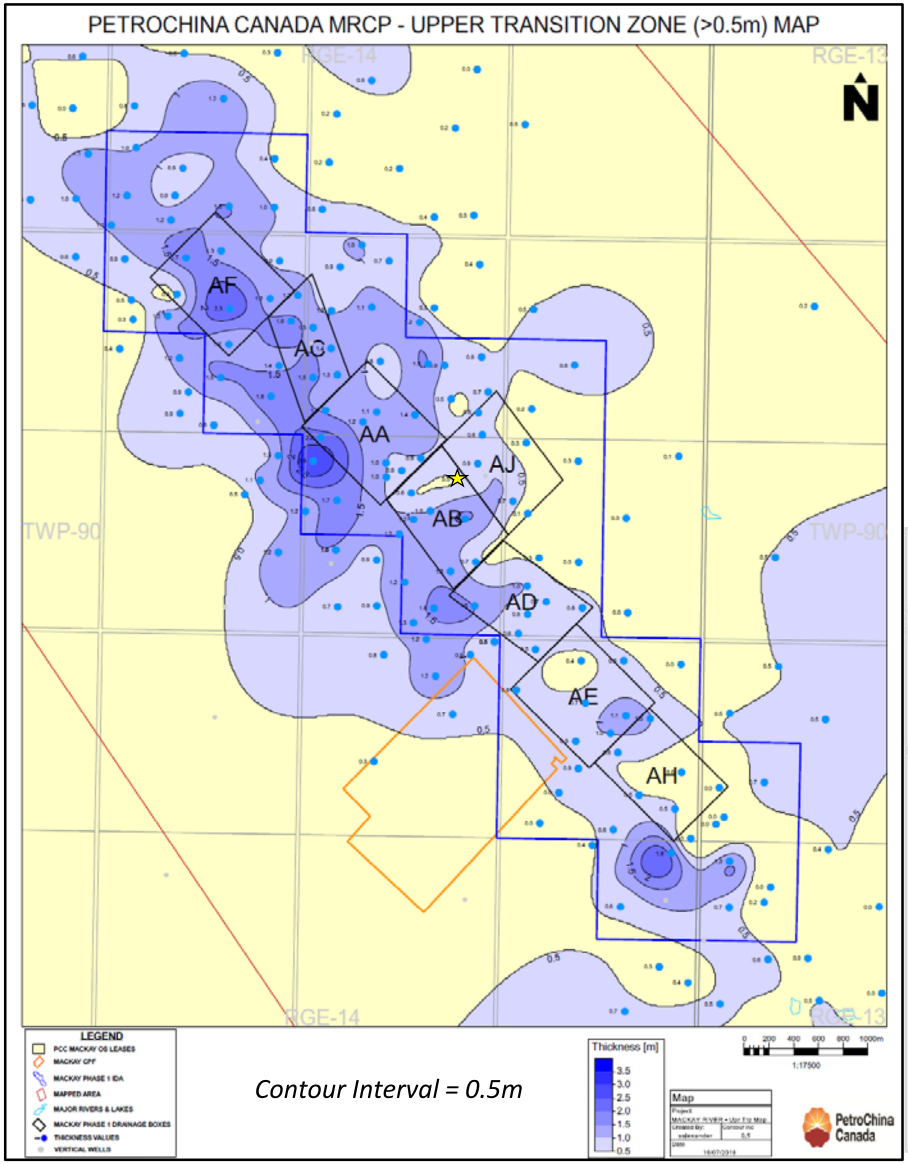
- Criteria:
  - Porous & clean sandy facies with >50% water saturation (GR ≤ 75API, DPSS≥27%, RT<20ohmm, sandy facies)
  - In communication with and below pay zone
- Characteristics:
  - Thin: <1.0m over most of the Phase 1 drainage boxes
  - Limited Lateral Extent



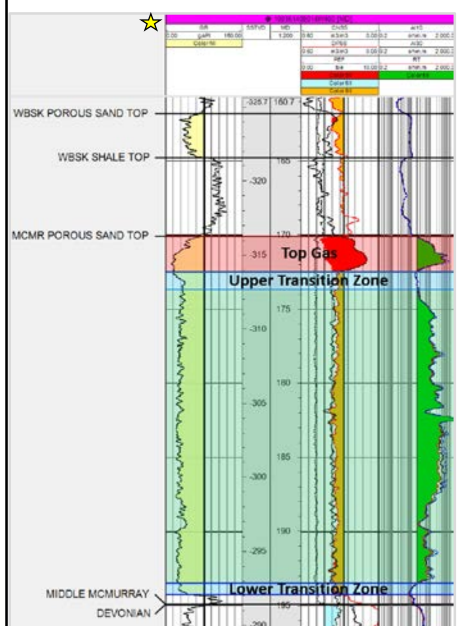
Lower Transition Zone Properties

Parameter	Average
Total Water Saturation	70%
Total Porosity	33%
Horizontal Permeability (Core)	3300 mD
Vertical Permeability (Core)	2400 mD

Upper Transition Zone Map



- Criteria:
  - Porous & clean sandy facies with >50% water saturation (GR ≤ 75API, DPSS≥27%, RT<20ohmm, sandy facies)
  - In communication with and above pay zone
- Characteristics:
  - Thin: <1.5m over most of the Phase 1 drainage boxes
  - Limited Lateral Extent



Geologic and Reservoir Properties – OBIP FOR OPERATING AREA

Drainage Box	# Well Pairs	Drainage Box Area (m^2)	Average S_o (frac)	Average Φ (frac)	Reservoir Model Average K_h (D)	Reservoir Model Average K_v (D)	Average Bitumen Pay Thickness (m)	Drainage Box OBIP (10^6 bbl)	Estimated RF (%)*	Estimated Drainage Box RBIP (10^6 bbl)*
AA	6	698,200	0.83	0.34	2.7	1.1	21.3	26.4	54	14.3
AB	5	562,600	0.8	0.34	2.7	1.1	22.6	21.8	57	12.4
AC	4	418,700	0.85	0.34	2.6	1	21.9	16.7	63	10.5
AD	5	560,100	0.77	0.33	2.6	1	20.8	18.6	54	10.1
AE	6	674,700	0.76	0.33	2.2	0.9	20.8	22.1	53	11.7
AF	6	675,400	0.82	0.34	2.6	1	22	26.1	62	16.2
AH	5	594,300	0.77	0.34	2.6	1	20.4	20	48	9.6
AJ	5	562,300	0.75	0.34	2.5	0.9	20.5	18.5	57	10.5
Total	*42*	*4,746,300*	*0.79*	*0.34*	*2.6*	*1*	*21.3*	*170.2*	*56*	*11.9*

OBIP = Original Bitumen In-Place and measured in $10^6 m^3$ units and converted to 10^6 barrels using conversion factor of 6.2898

NRV = Net Rock Volume in $10^6 m^3$ derived from deterministic mapping of SAGDable
net pay, or from geomodel calculations

SO = Average bitumen saturation from the SAGD exploitable reservoir interval
generated from 1-SWT (in fractions)

PORT = Average porosity from the SAGD exploitable reservoir interval generated from PORT (in fractions)

OBIP = (NRV x PORT x SO)

Note:

1. *Reservoir Model Average permeability is extracted from history matched reservoir model and may change year to year*
2. *Core based permeability analysis of reservoir sands within DA*
   - *Avg Kh = 4,400mD (Range = 500mD – 12,000mD+)*
   - *Avg Kv = 3,770mD (Range = 200mD – 10,000mD+)*

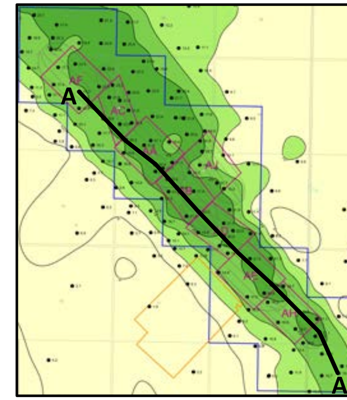
Geologic and Reservoir Properties – OBIP

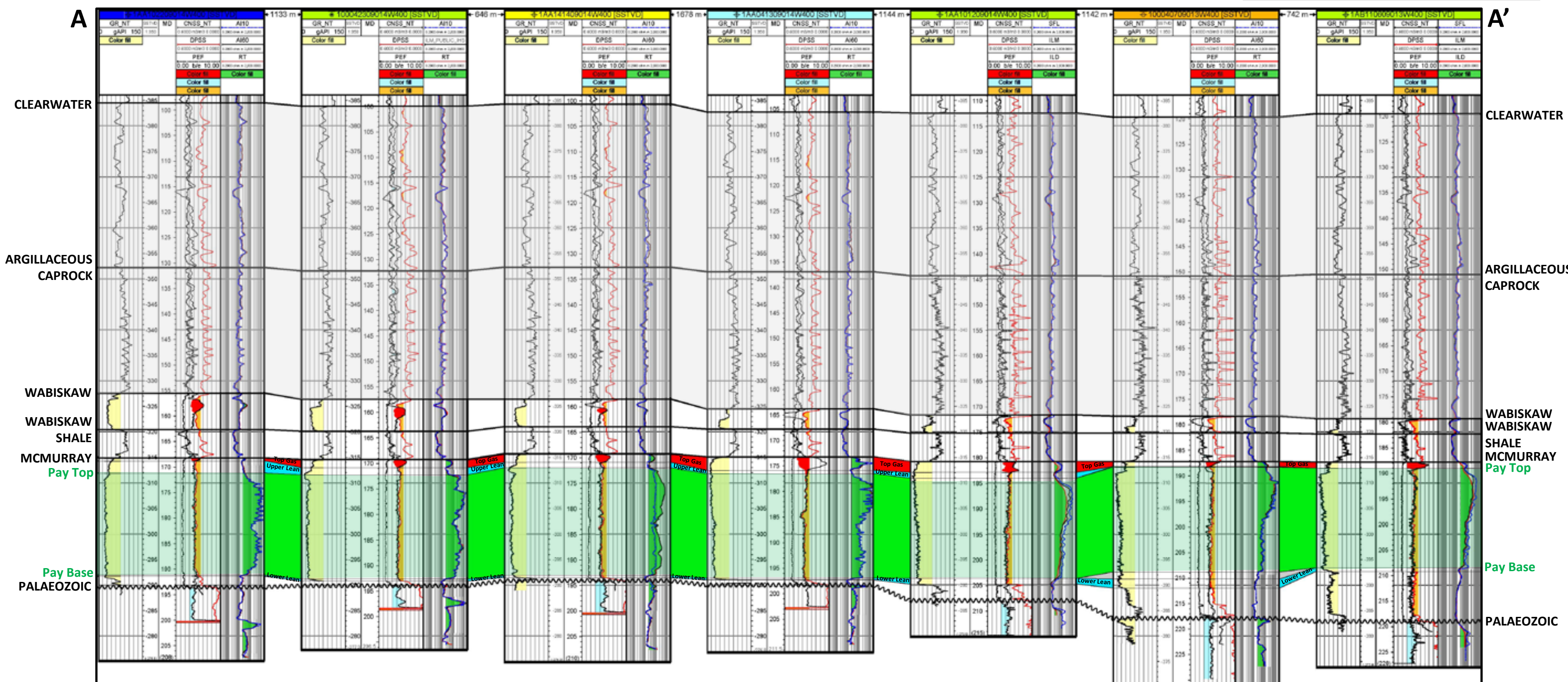
Parameters	Development Area	Project Area
Top of Reservoir Depth (mTVD)	176	175
Top of Reservoir Depth (TVD masl)	315	311
Base of Reservoir Depth (mTVD)	197	193
Base of Reservoir Depth (TVD masl)	294	293
Net Pay Thickness (m)	21.3	12.8
Porosity (frac)	0.34	0.33
Bitumen Saturation (frac)	0.79	0.75
OBIP (10^6 bbl)	170.2	2890.8
OBIP (10^6 m^3)	27.1	459.6
Initial Pressure (kPaa)	220 (top) – 400 (bottom)	220 (top) – 400 (bottom)*
Original Reservoir Temperature (^oC)	6	6*

*** *Extrapolated from operating area***

Structural Cross-Section across MRCP

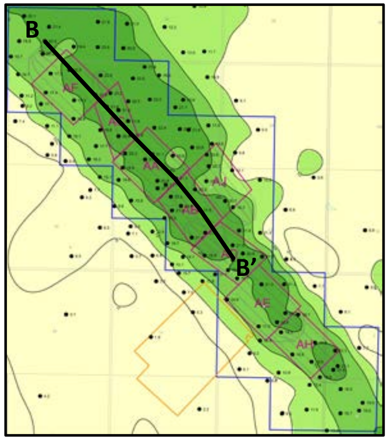
- Good reservoir quality with continuity along Development Area
- Minor structural variation at base of pay
- Thick and laterally continuous caprock with consistent lithology

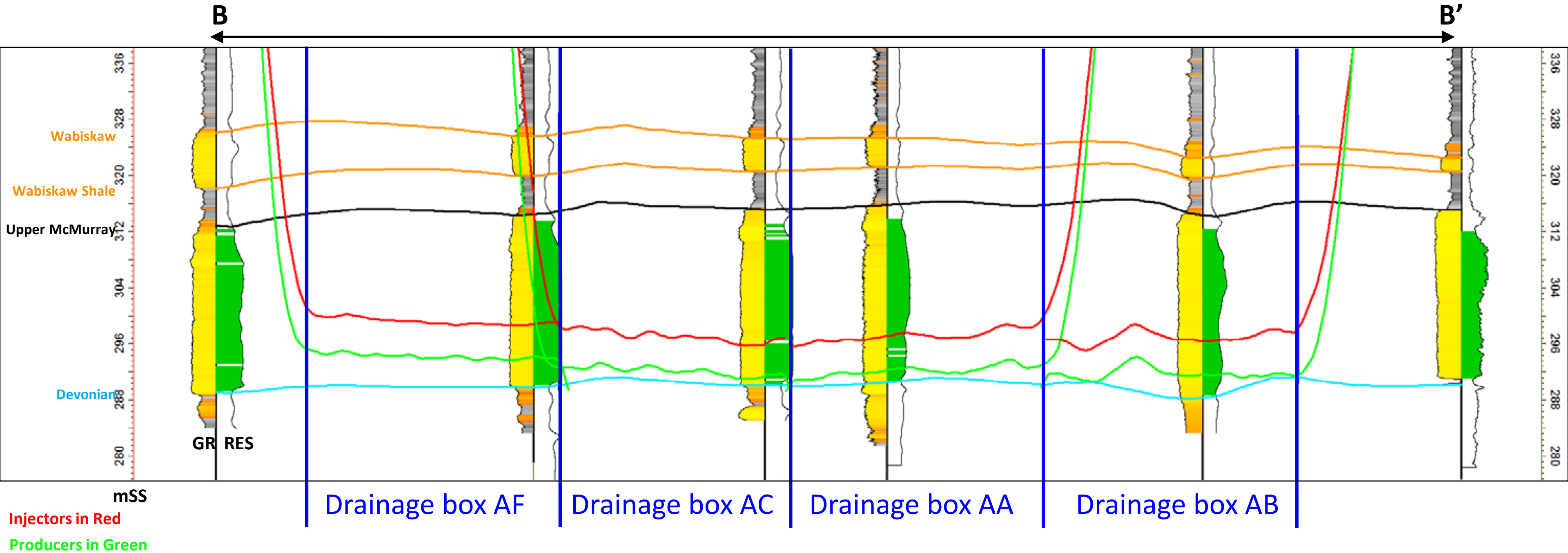




NW–SE Structural Cross-Section: Drainage boxes: AF, AC, AA, AB

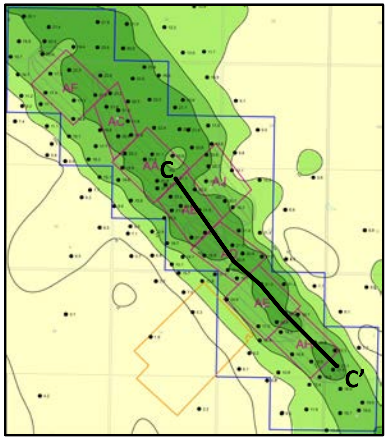
- Clean and consistent reservoir thickness over the 4 drainage boxes
- Bitumen thickness ranges from 15 to 20+m
- Producer wells placed 1m from base of pay
- Injector wells placed 5m above producer

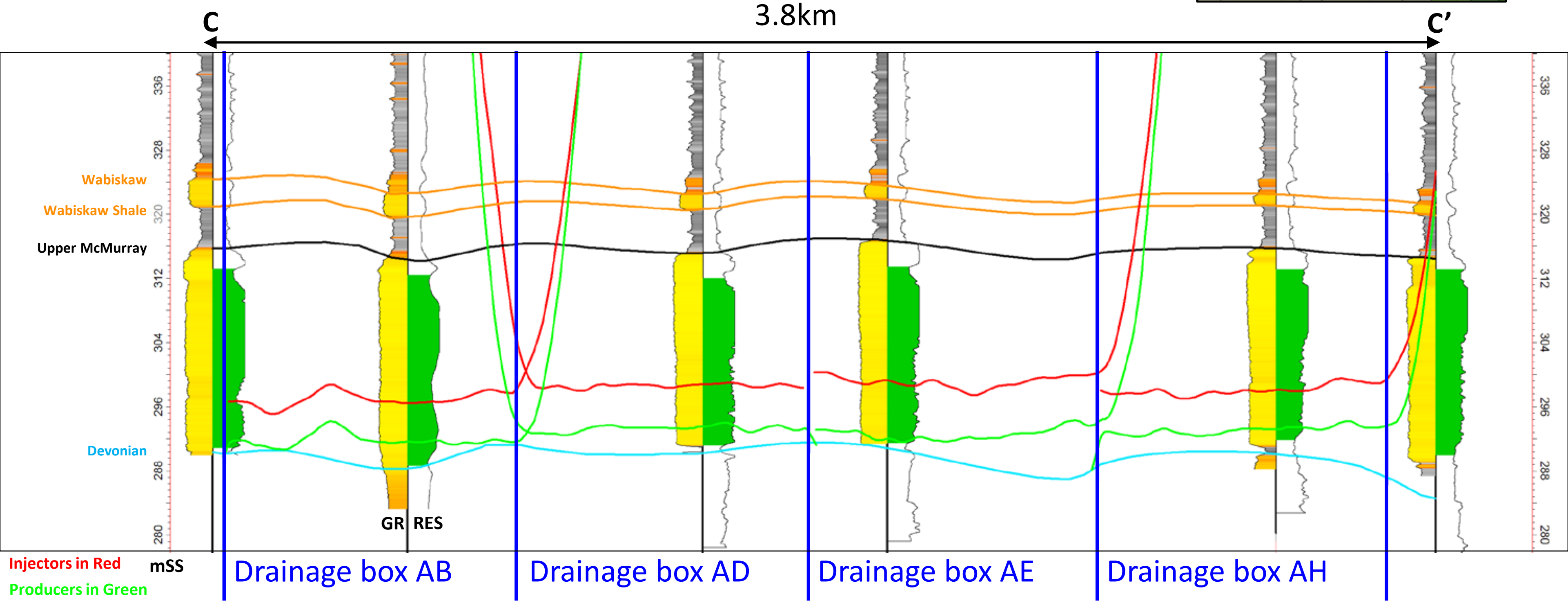




NW–SE Structural Cross-Section: Drainage boxes: AB, AD, AE, AH

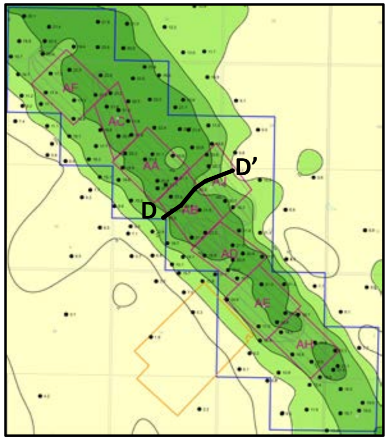
- Clean and consistent reservoir thickness over the 4 drainage boxes
- Bitumen thickness ranges from 15 to 20+m
- Producer wells placed 1m from base of pay
- Injector wells placed 5m above producer

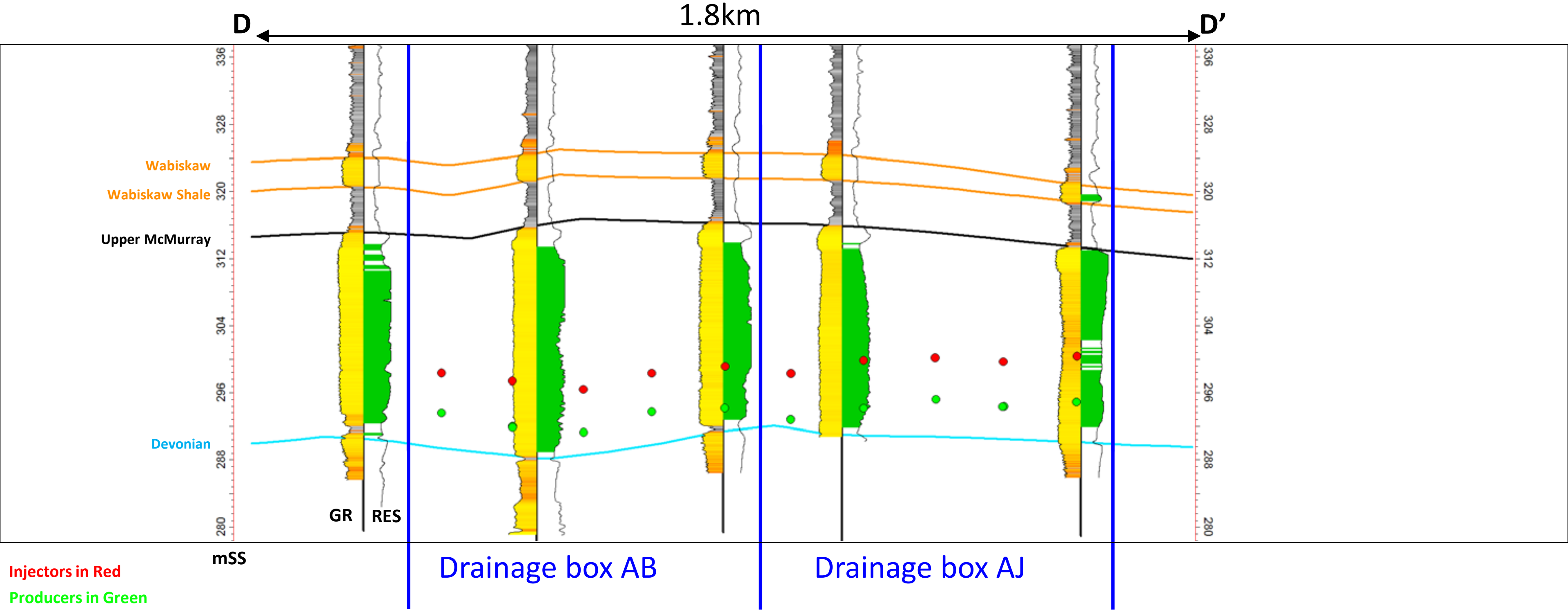




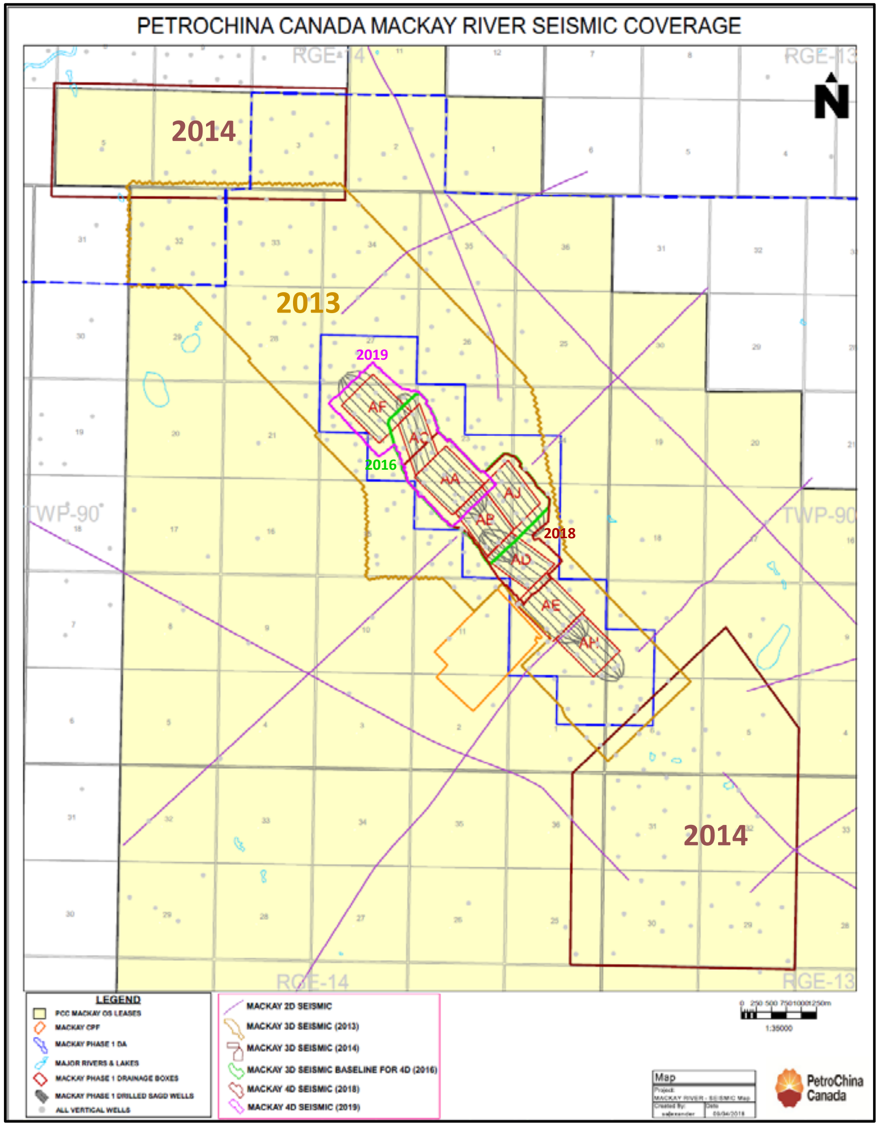
W–E Structural Cross-Section: Drainage boxes: AB, AJ

- Bitumen thickness ranges from 10 to 20+m
- Producer wells placed 1m from base of pay
- Injector wells placed 5m above producer





MRCP Seismic



Coverage Across MRCP includes:

- ~96 km of 2D
- ~58.4 km^2 of 3D
- ~3.9 km^2 of 3D baseline for 4D
- ~3.5 km^2 of 4D in 2018 - Interpreted
- ~3.0 km^2 of 4D in 2019 – Processing

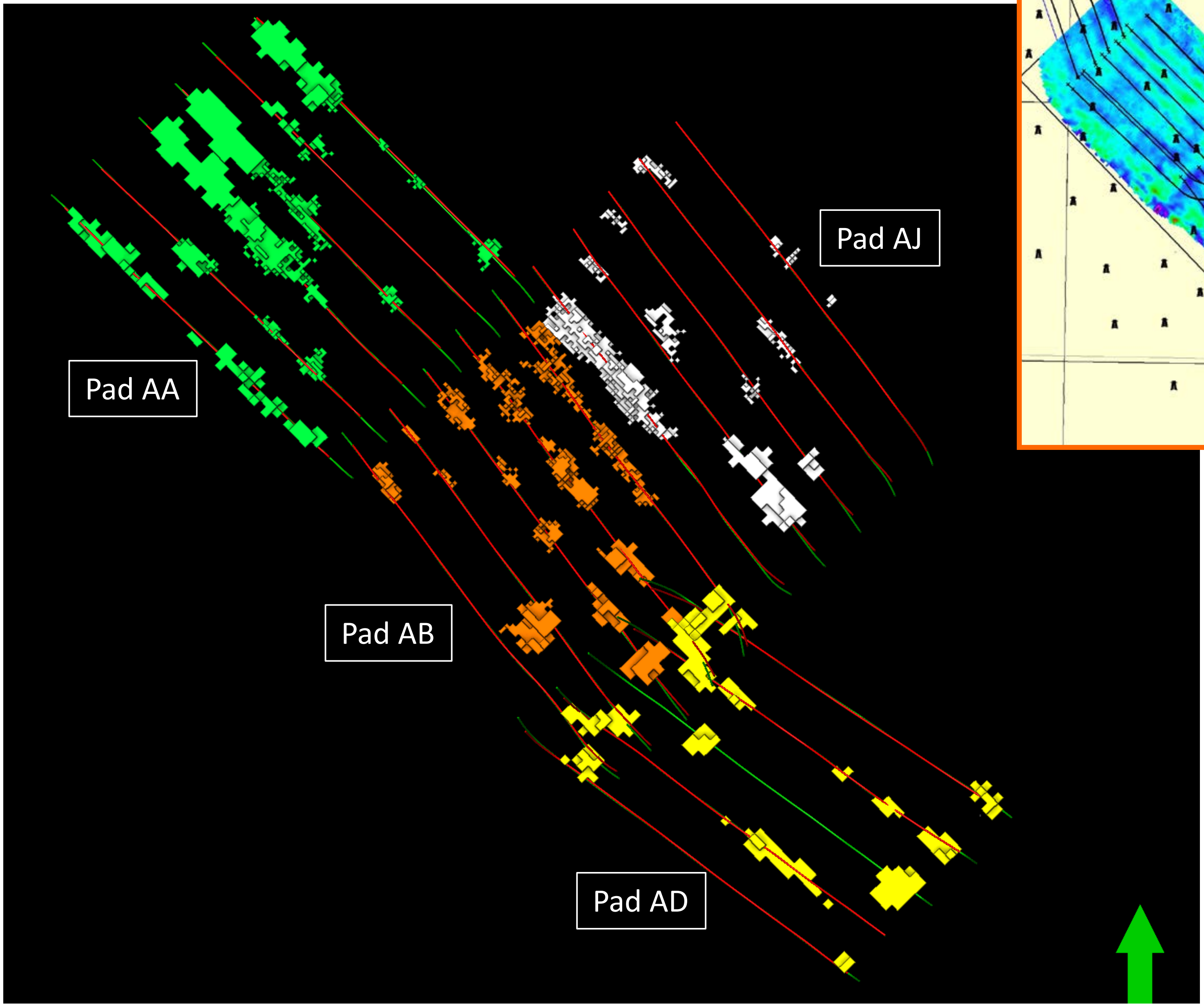
3D acquired in MRCP to help:

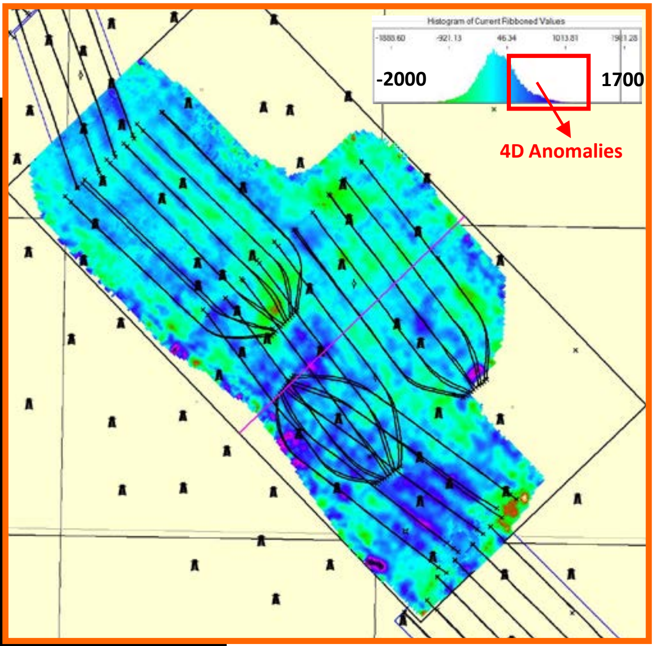
- Assess Caprock
- Plan/drill horizontal well trajectories
- Assess McMurray reservoir

4D seismic survey acquired at MRCP in 2019

- Will monitor steam chamber growth
- Updated 4D coverage 2019 acquisition

4D-Derived Steam Chambers from 2018 4D



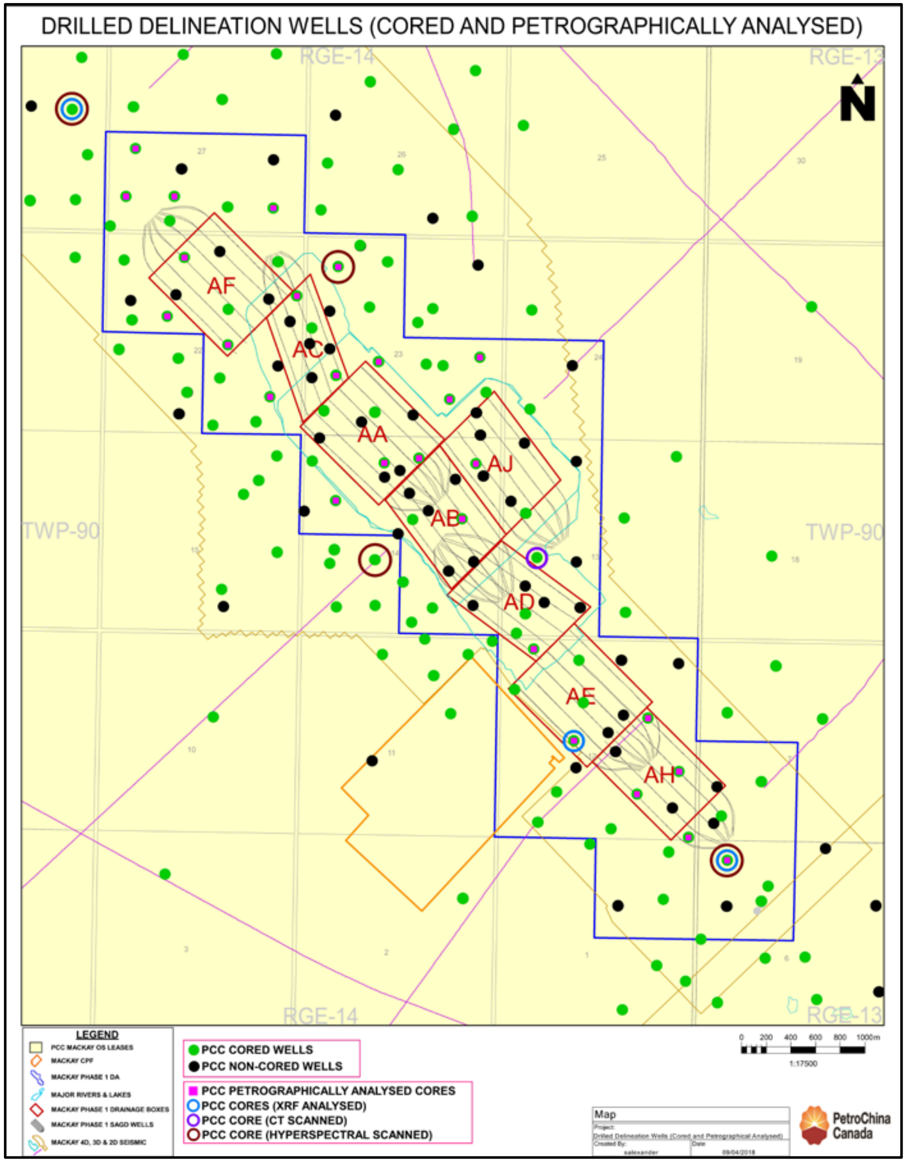


4D RMS Amplitude Differences

Interpreted Steam Chamber Bodies

4D Inversion

Special Core Analysis – Petrographic Analysis

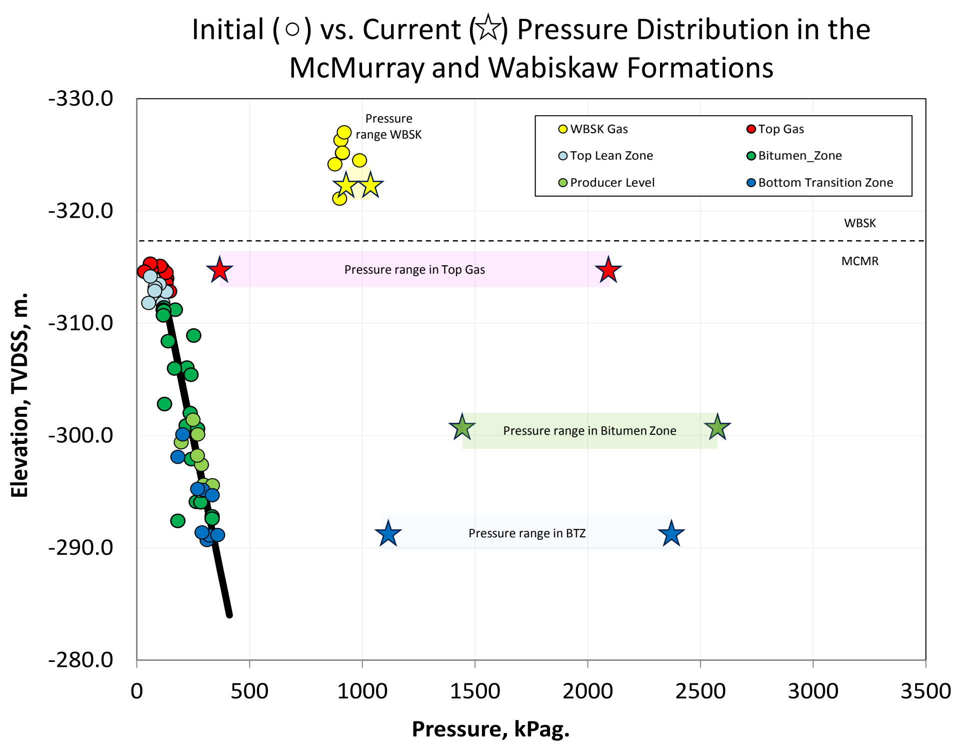


- PCC has conducted a combination of different studies on 26 cored wells in the initial Development Area.
- Studies done on highlighted wells include:
  - CT Scan - 1
  - XRF - 3
  - SEM - 17
  - XRD - 26
  - Thin sections - 24
  - Grain size analysis – 24
  - Hyperspectral Imaged – 4

Reservoir Pressure Update

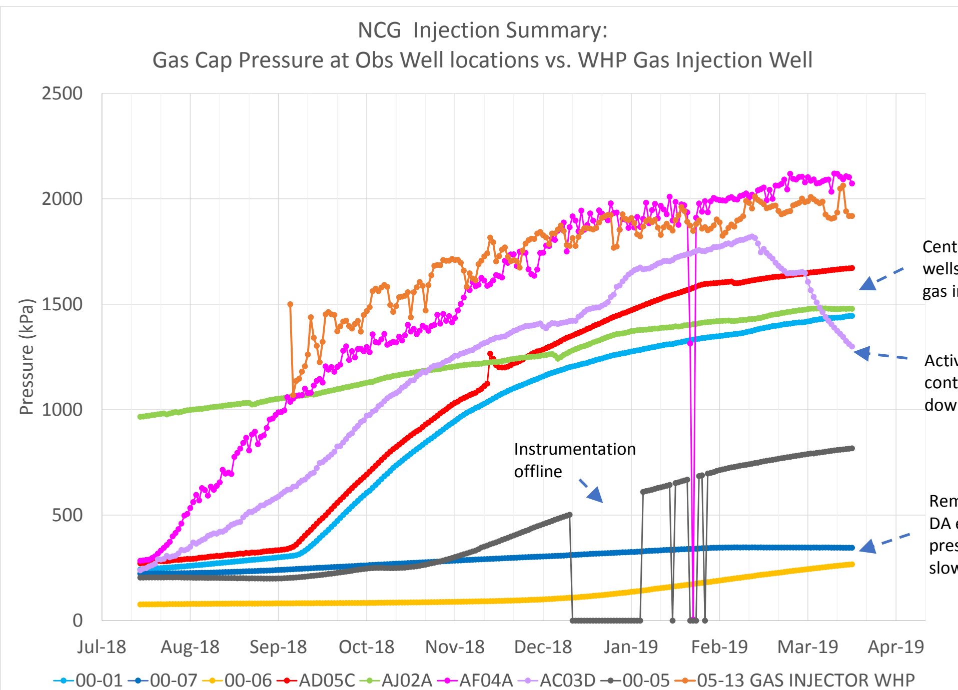
- MRCP reservoir was initially at low pressure:
  - Initial pressure of 100 – 200 kPag at the top of McMurray Formation reservoir
  - Initial pressure of 300 - 400 kPag at the base of McMurray Formation reservoir and the Bottom Transition Zone
  - Pressure of 900 to 1,000 kPag in Wabiskaw sand above reservoir indicates competent isolation from the McMurray

- MRCP Pressure Update:
  - In May 2018, PCC received AER approval to increase the Maximum Operating Pressure (MOP) to 2,594 kPag at MRCP (set point 2,525 kPag)
  - Since project start-up the pressure build-up and pressure distribution in the various zones in the reservoir has been closely monitored by PCC through its observation wells network.
    - Operating Pressure within the approved range is applied in SAGD well pairs in the field on a case by case basis. Current range is from 2,525 kPag in North DA to 1,450 kPag in South DA.
    - Gas cap pressurization started in Sep 2018, pressure ranges from ~2,000 kPag in Central and North areas of DA (influenced by SAGD activity & gas injection) to ~300 kPag in outer areas of DA under surveillance
    - Bottom Transition Zone pressure has also increased, ranging from 2,400 kPag in North DA (thinner BTZ) to 1,100 kPag in South DA (thicker BTZ)
    - Wabiskaw sand remains at ~1,000 kPag



Gas Cap Pressurization

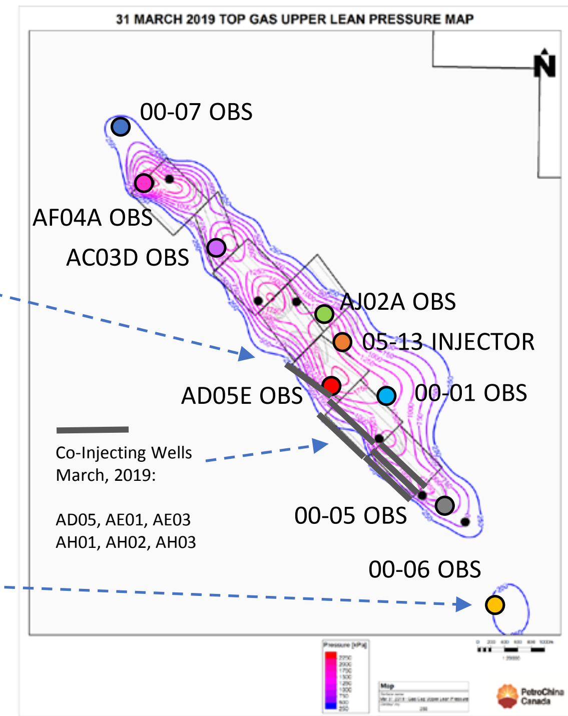
- Purpose of gas cap pressurization at MRCP is to increase the pressure in the gas cap to operate at a more favourable pressure balance between steam chambers and top thieve zones to minimize steam losses
  - Initial gas cap pressure of 200 kPag, presented a challenge to SAGD operation pressure balance
  - Evidence of steam chamber communication to the gas cap since early 2018
  - The pressurization process started in Sep 2018. Natural gas is injected in the vertical well 103/05-13-090-14W4-00, at rates close to the approved limit of 80,000 Sm3/d
  - PCC is monitoring the pressurization process through the pressure gauges installed at the gas cap level in observation wells. Permanent evaluation of the reservoir performance and response to injection will determine optimum pressure target
  - Gas co-injection started in Jan 2019, mainly in South DA to support gas cap pressurization in areas distanced from injector 05-13, typical co-injection rates ranges from 2,400 to 4, 200 Sm3/d (approved 5,000 Sm3/d)



Central DA obs wells response to gas injection

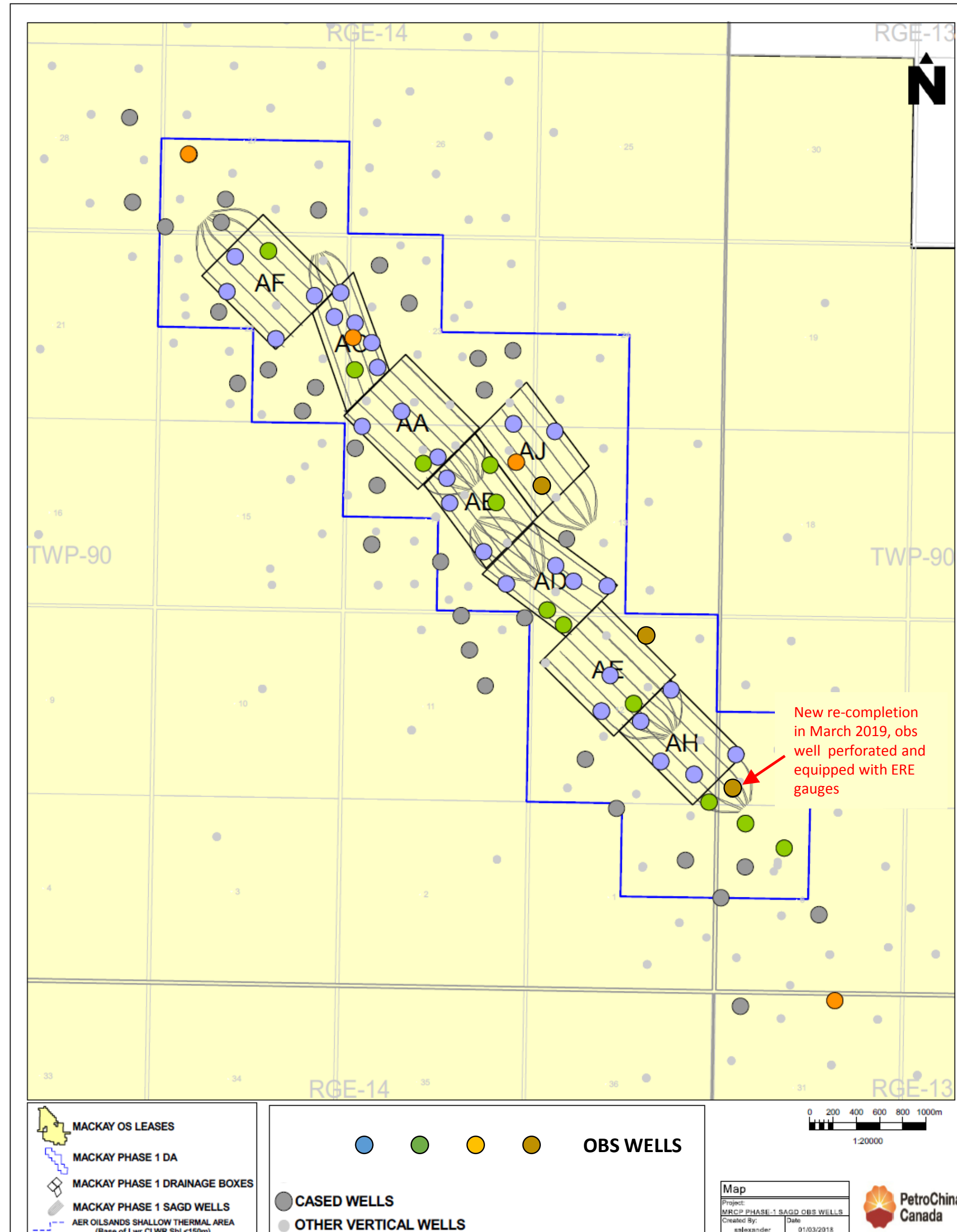
Active gas cap contact: AC03 down for WO

Remote areas of DA experiencing pressurization at slower pace



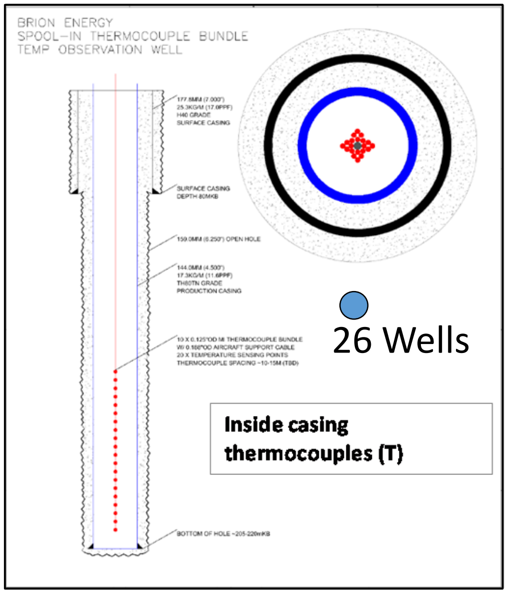
Observation Well Overview

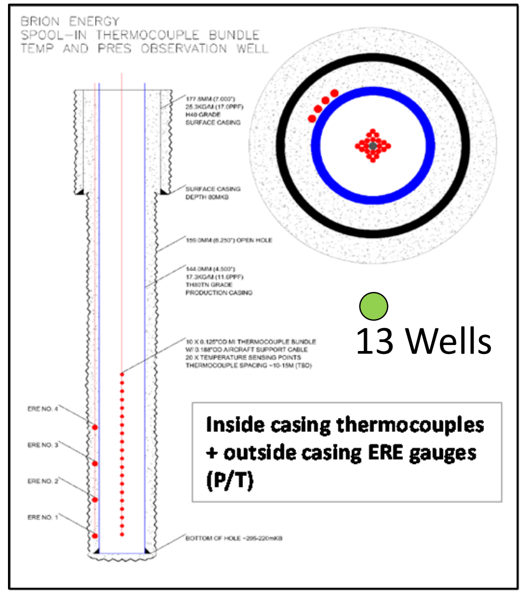
- Total of 46 observation wells for MRCP
  - o One additional observation well conversion: North West of Pad AF
- This network has been designed to monitor the following themes:
  - o Caprock Monitoring
  - o Reservoir Top Gas
  - o Bottom Transition Zone
  - o Baffles/barriers above injector
  - o Baffles/barriers between producer/injector
  - o History Match / Chamber Development
    - ▪ Early Stage (< 10 m)
    - ▪ Late Stage (> 10 m)
  - o Lateral/Regional Monitoring (> 100m)
- According to their design, they are classified as:
  - o Obs Wells w/ just Thermocouples
  - o Obs Wells w/ Thermocouples and EREs
  - o Perforated Obs Wells w/ Thermocouples and/or EREs (Single Zone)
  - o Perforated Obs Wells w/ Thermocouples and/or EREs (Multi Zone)

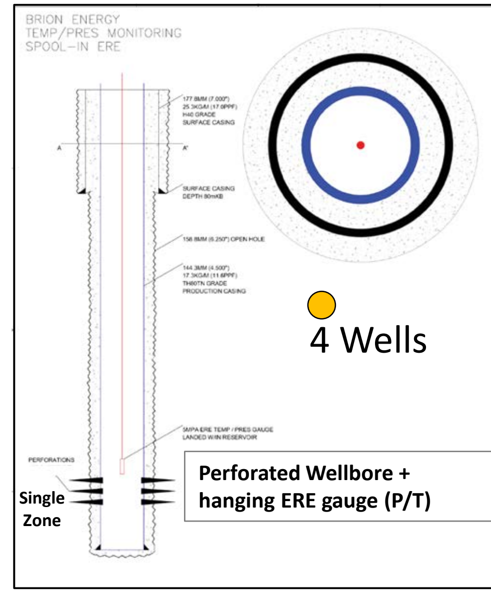


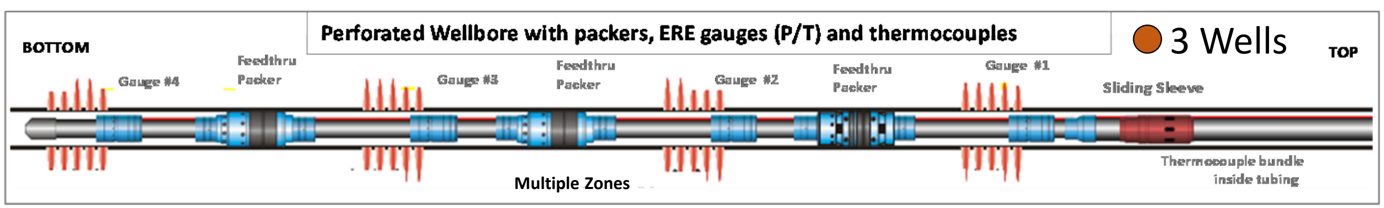
Typical Observation Well Design

- Example of the types of observation well design and instrumentation configurations at MRCP:









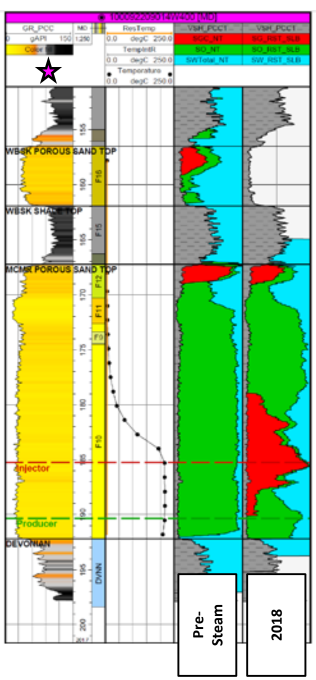
Type of gauge reading:
- (T) Only temperature
- (P/T) Temperature & Pressure

Vendor provided diagrams: Petrospec Engineering Ltd. and Packers Plus

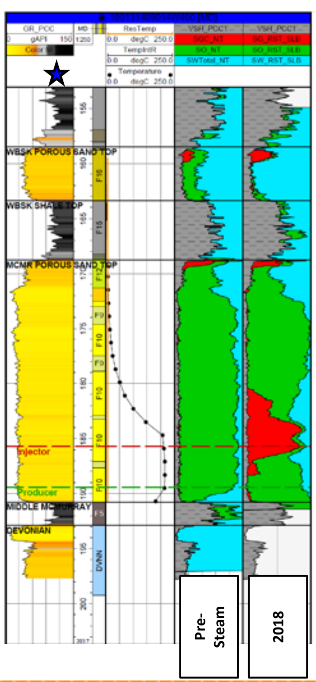
Observation Well RST

- Reservoir Saturation Tool (RST) is used to track steam chamber development over time
- MRCP DA RST Logging:
  - Two RST logs run in 2017 to calibrate pre-steam baseline
  - Nine RST logs run in 2018 (~6-8 months of SAGD production) distributed across most pads
  - No RST logging in 2019
  - PPC is evaluating the time for next round of RST logging
  - Examples:

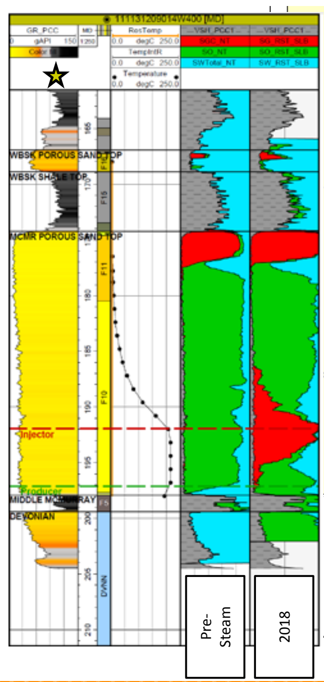
AC03A: 1m from Producer AC03 (heel)

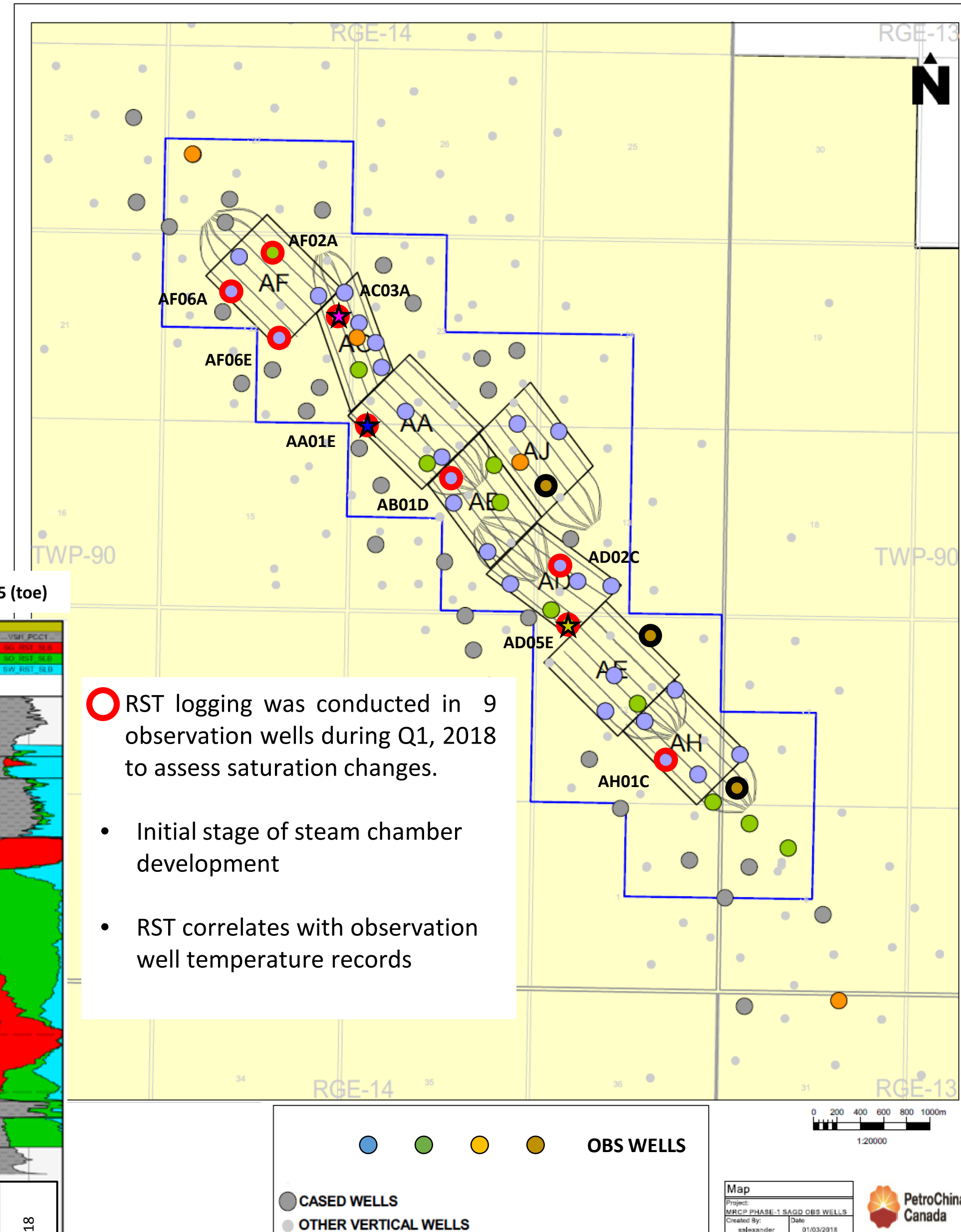


AA01E: 3m from Producer AA01 (toe)

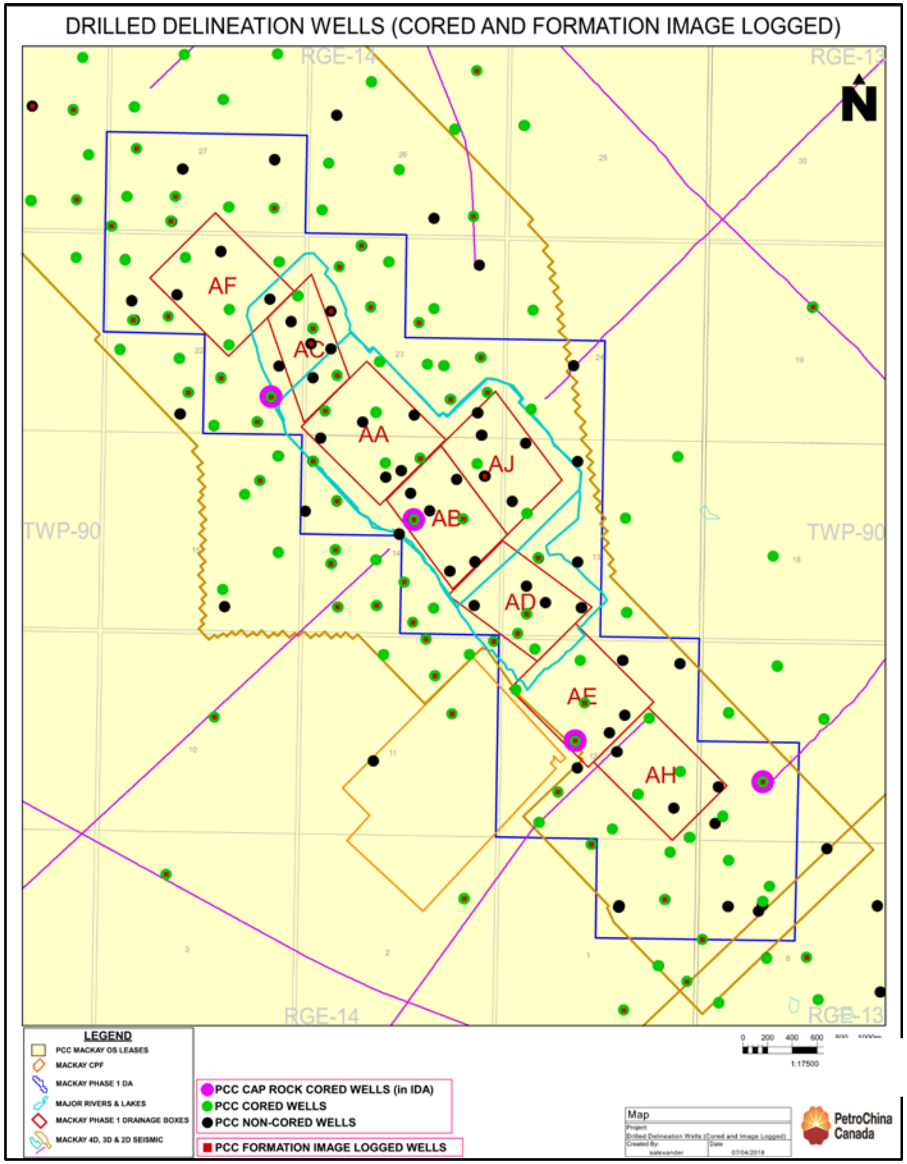


AD05E: 3m from Producer AD05 (toe)





Characterization of Caprock



PCC has collected the following dataset for caprock characterization from delineation and coreholes within the DA:

- Formation Image logs for 37 wells
- Cored 67 wells
- 4 Caprock core

MRCP Geomechanics: Mini-frac tests

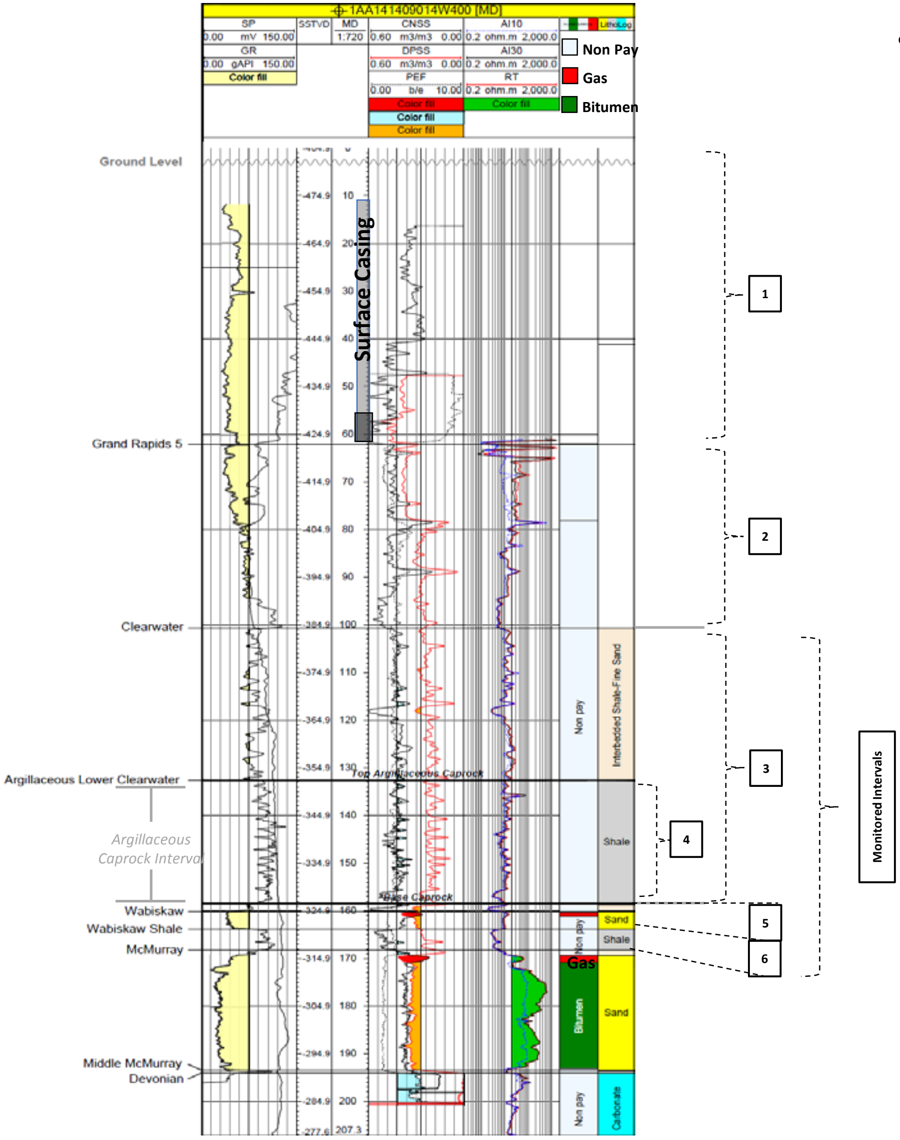
- Mini-frac tests were conducted between 2009-2016, no new test since 2016
- The results are in agreement with local and regional trends
- The average caprock fracture gradient measured for the MRCP region within the argillaceous Clearwater is 21.59 kPag/m
- Approved maximum operating pressure (MOP):
  - In 2018, PCC obtained approval to increase its MOP to 2,594 kPag calculated from base of Clearwater caprock in Phase 1 area of 150.2 mTVD and a gradient of 14.7 kPag/m. PCC has chosen to set SAGD operating pressure at 2,525 kPag (injection pressure set point)

Well	Year	Formation	Fracture Gradient (kPag/m)
100/04-23-90-14W4M	2009	McMurray Oil Sand	16.7
1AA/06-07-90-13W4M	2009	Clearwater Caprock	21.5
1AA/14-28-90-14W4M	2013	McMurray Oil Sand	14.9
		Clearwater Caprock	20.6
		Wabiskaw shale	21.3
100/03-14-090-15W4	2016	McMurray Oil Sand	16.9
		Clearwater Caprock	22.3
		Wabiskaw shale	18.8

MRCP Geomechanics

- Caprock integrity testing and geomechanics
  - Caprock core testing was completed in well 1AA/06-07-090-13W4: tri-axial laboratory testing, and X-ray diffraction analysis.
  - Field measured in-situ stress conditions and fracture criteria were also inputs to the geomechanical model, minifrac: 1AA/06-07-090-13W4 / 100/04-23-90-14W4M
  - Geomechanical simulations using ABAQUS, a commercial finite element stress analysis software, ran by BitCan were conducted to provide confirmation that SAGD operations at MRCP will not pose any risk to the caprock integrity.
  - Additional studies were conducted by CGG GeoConsulting for PCC in 2018 to support MOP increase application, main conclusion indicated that an increased MOP of 2,594 kPag is safe and does not present a significant risk of shear failure of the caprock.

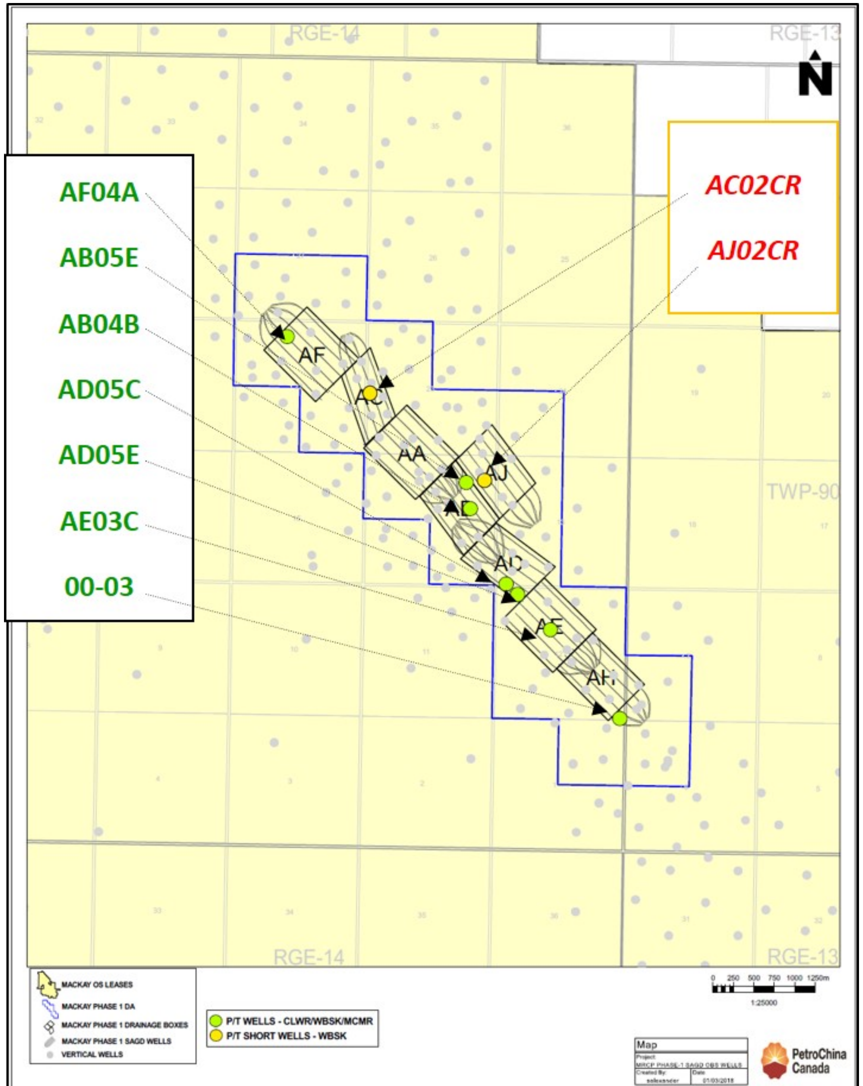
Caprock Monitoring: Overburden & Cap Rock Intervals



- **Overburden intervals:**
  1. Quaternary Sediments: from surface to the Grand Rapids
  2. Grand Rapids, overlies Clearwater
  3. Clearwater Formation, which is the gross caprock
  4. Argillaceous interval of Clearwater, primary caprock for MRCP. It is present across the MRCP DA, is a thick (>21 m), and laterally continuous, consistent, clay-rich caprock, free of influence of any vertical pore pressure transmission pathways.

     Some instrumentation is set outside casing of observation wells to monitor the Clearwater intervals
  5. Wabiskaw sand, which is the first known horizontal pathway on top of the reservoir. Main target for reservoir containment assurance and/or caprock integrity monitoring, early warning for pressure buildup.
  6. Wabiskaw shale lies above the McMurray reservoir, and this is the lower-most interval included within the overburden monitoring strategy.

Caprock Monitoring: Observation Wells

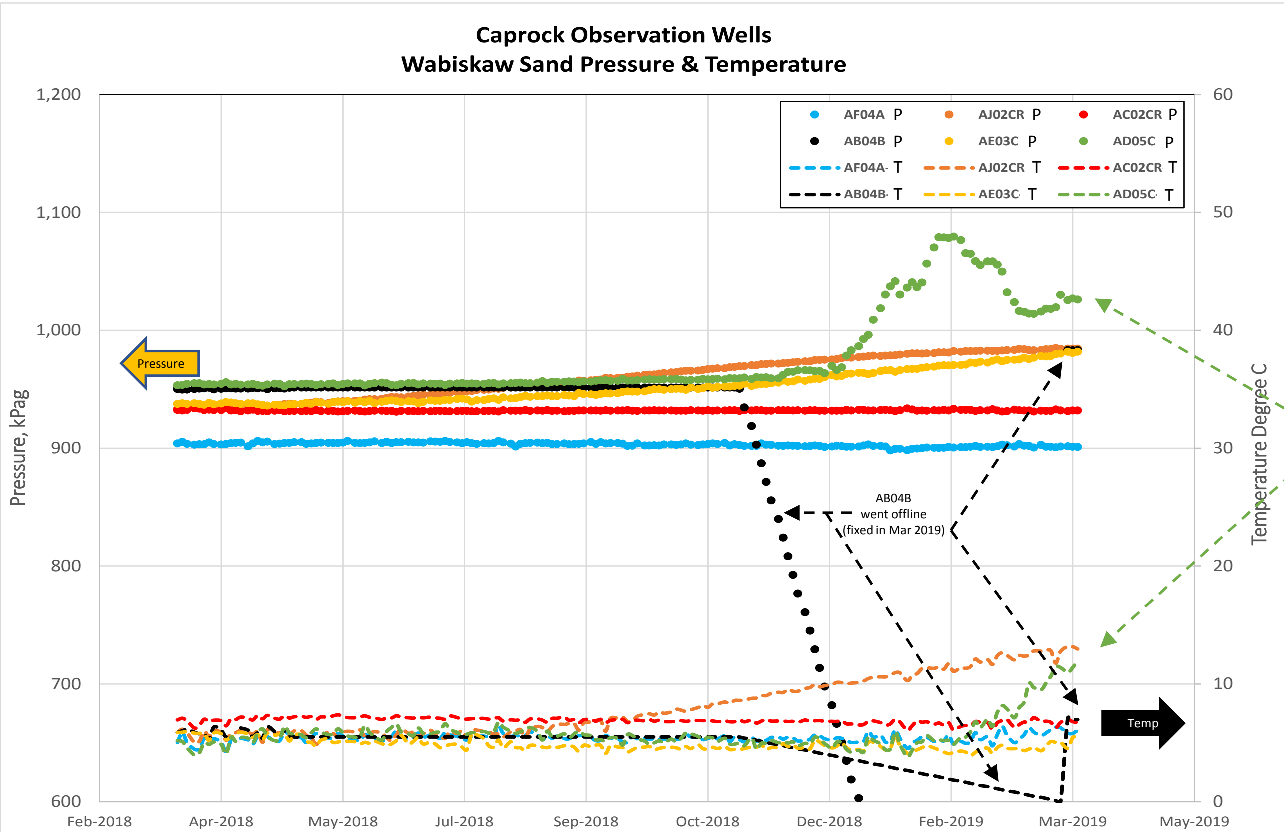


- Monitoring caprock pressure and temperature in 9 vertical wells
- Electromagnetic Resonating Element (ERE) gauges for pressure and temperature on exterior of production casing or interior with perforation.
- Wabiskaw Sand Monitoring:
  - 2 vertical wells drilled to base Wabiskaw (isolated from McMurray reservoir): AJ02CR and AC02CR
  - Equipped with interior pressure/temperature ERE
- Caprock Monitoring – Wabiskaw and Clearwater:
  - 7 vertical wells drilled to the base of the McMurray Formation: AB05E, AD05E, AF04A, 00-03, AB04B, AE03C and AD05C.
  - Pressure and temperature in one to four layers within the caprock intervals on the exterior of production casing.

Caprock Monitoring: Pressure and Temperature in Wabiskaw Sand

Wabiskaw sand is the first line of defense of MRCP caprock

- Wabiskaw average pressures and temperatures:
  - o Pressure 900 – 992 kPag (initial range: 900 - 950 kPag)
  - o Temperature 6-14 °C (initial range: 5-7 °C)
  - o Pressure and temperature changes since mid July. Slow pressure and temperature build-up expected.
- Caprock observation well data pressure and temperature is reviewed bi-weekly.



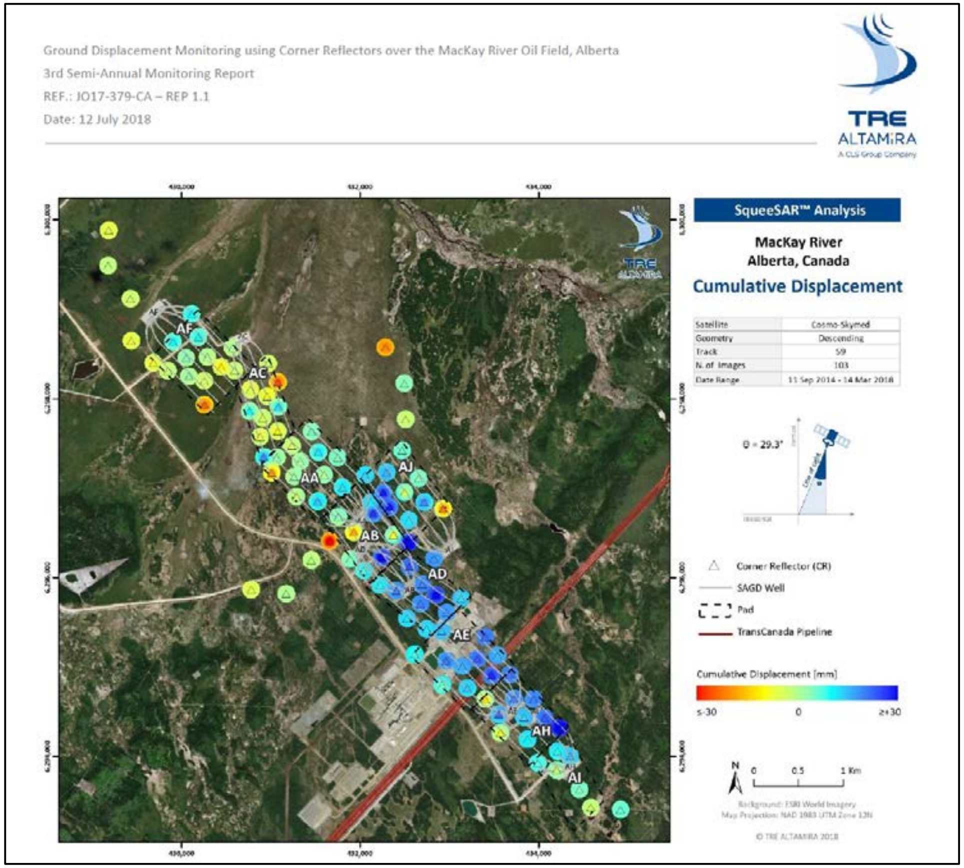
ERE gauge in obs well AD05C (@ **Wabiskaw sand)** has been identified as having communication through the cement with the lower part of the well (see slide No. 57 for more information)

- Off trend Pressure and temperature build-up
  - o 1,022 kPa & 12°C @ Mar 2019
- PCC is closely monitoring this well and will execute remedial actions in 2019-2020

Surface Displacement Monitoring

- PCC has an extensive network of corner reflectors installed for surface displacement and heave monitoring
  - PCC implemented ground displacement monitoring using 104 corner reflectors over MRCP using Synthetic-aperture Radar Interferometry (InSAR) technology.
  - The total amount of displacement measured from September 2014 to March 2018 is shown in the map
  - Subsidence more dominant in Northern Pads AF, AC & AA
  - Other areas of localized subsidence were identified off pad
  - Subsidence coincide with Muskeg areas
  - Central and southern pads AJ, AB, AD, AE and AH show heave
  - Maximum and minimum values of cumulative displacement per pad, Sep 2014 – Mar 2018 are shown in the following table:

Pad	September 2014 to March 2018 Cumulative Displacement (mm)			
	Minimum		Maximum	
AF	-24.0	T4	+10.8	H2
AC	-26.4	H11	+19.2	T8
AA	-20.2	H26	+15.2	H34
AB	-18.4	H36	+35.2	H37
AJ	-22.1	T15	+43.3	H39
AD	+9.7	H45	+32.5	H47
AE	+5.2	T16	+28.2	H59
AH	-13.7	H61	+36.7	T18
AI	-3.8	R9	+15.5	H70
Off-pad	-36.9	R6	+18.6	H38



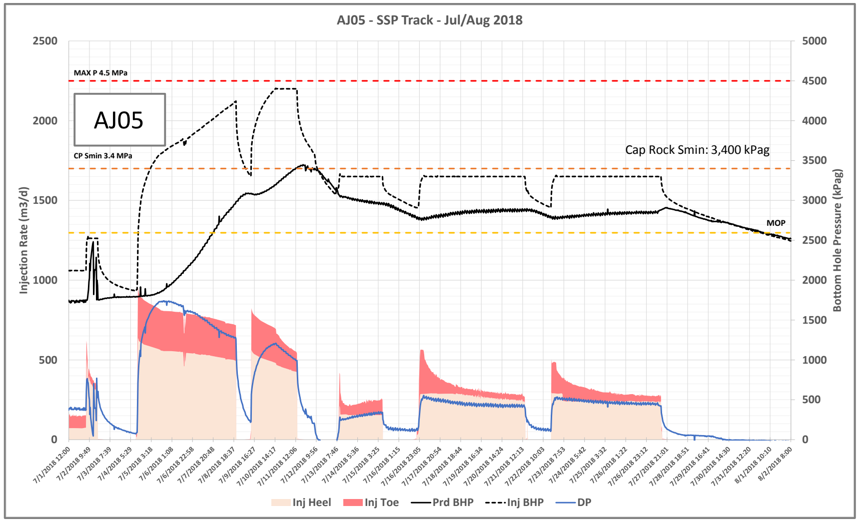
SSP – Field Test

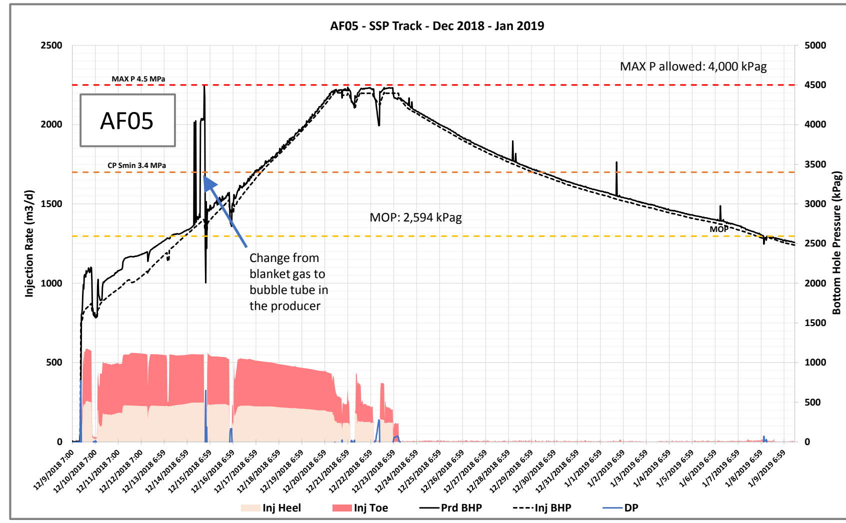
- Steam Stimulation Process (SSP): injection of a limited amount of steam at high pressure to create a dilation of the reservoir rock surrounding the selected SAGD well pair. During the SSP steam is injected in a SAGD well pair in order to cause the rock matrix around the wellbore to dilate and increase porosity and permeability, improving fluid mobility through mud laminations or low permeability streaks.
- The objectives of the SSP are as follows:
    - Enhance communication between injector and producer wells following conversion to SAGD mode.
    - Enhance SAGD well productivity and overall bitumen recovery by increasing the porosity and permeability of the reservoir around the wellbore.
    - Evaluate the applicability of this technology for use in future well pair additions to the MRCP and other PCC oil sands projects.
- During the reporting period, 2 SSP tests were conducted at MRCP:
    - AJ05 (Jul-Aug, 2018)
    - AF05 (Dec, 2018 – Jan, 2019)

AF05 SSP execution

SSP – Field Test

- Summary of SSP execution: AJ05 & AF05





- SSP safely executed
- All observation wells pressure gauges and adjacent SAGD well pairs steady
- No interference observed, no alarms triggered
- Reported to AER:
    - No improvement after SSP – Challenging Reservoir Conditions
    - Requested approval for testing SSP in other candidates
    - Requested flexibility on time constrains for future tests

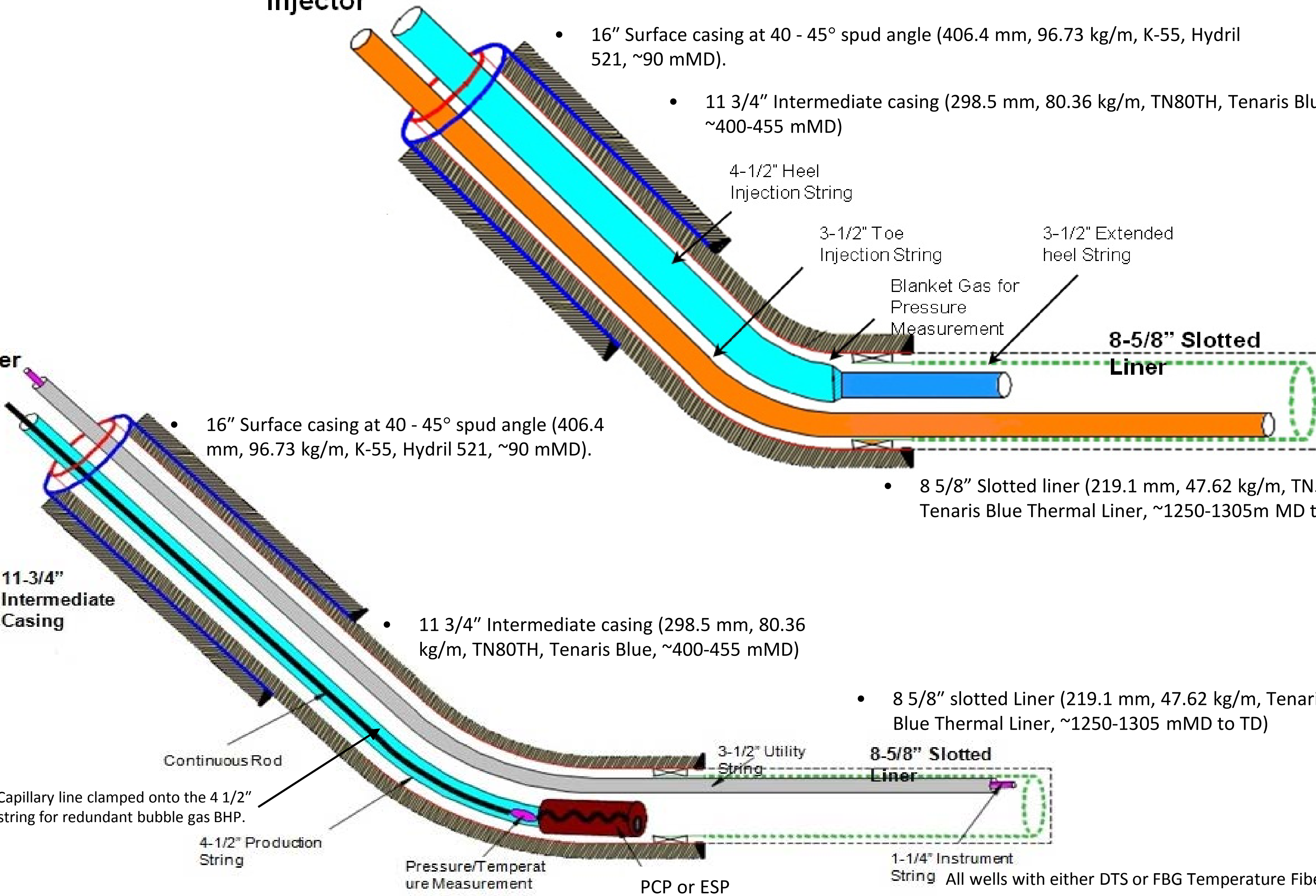
- SSP safely executed
- All observation wells pressure gauges and adjacent SAGD well pairs steady
- No interference observed, no alarms triggered
- Reported to AER:
    - Some improvement observed after SSP
    - PCC is currently evaluating post-test performance
    - Results of evaluation will determine future applicability of the technique

Summary of SSP - Time and Volume Constraints vs. Test Actuals

	Max Press (kPag)	Days injecting at Max Press	Days injecting above 3,400 kPag	Volume injected above 3,400 kPag (m3)	Max Days operating above MOP	Max injected Volume above MOP (m3)
Authorized by AER	4,500	2	7	6,000	30	16,000
AJ05 Actuals	4,400	0	7.1 *	4,335	27.5	8,423
AF05 Actuals	4,400	0	6.2	2,262.1 (+125)**	25.8	4,022.5 (+125)**

* Time exceedance (2h; 22m) during final depressurization stage, timely communicated to AER by PCC
** Additional volume due to passing valves identified after steam S/I, timely communicated to AER by PCC

MRCP Standard Completion Schematic



- 16" Surface casing at 40 - 45° spud angle (406.4 mm, 96.73 kg/m, K-55, Hydril 521, ~90 mMD).
- 11 3/4" Intermediate casing (298.5 mm, 80.36 kg/m, TN80TH, Tenaris Blue, ~400-455 mMD)
- 8 5/8" Slotted liner (219.1 mm, 47.62 kg/m, TN55TH, Tenaris Blue Thermal Liner, ~1250-1305m MD to TD)
- 16" Surface casing at 40 - 45° spud angle (406.4 mm, 96.73 kg/m, K-55, Hydril 521, ~90 mMD).
- 11 3/4" Intermediate casing (298.5 mm, 80.36 kg/m, TN80TH, Tenaris Blue, ~400-455 mMD)
- 8 5/8" slotted Liner (219.1 mm, 47.62 kg/m, Tenaris Blue Thermal Liner, ~1250-1305 mMD to TD)
- 1/4" Capillary line clamped onto the 4 1/2" Heel string for redundant bubble gas BHP.

All wells with either DTS or FBG Temperature Fiber

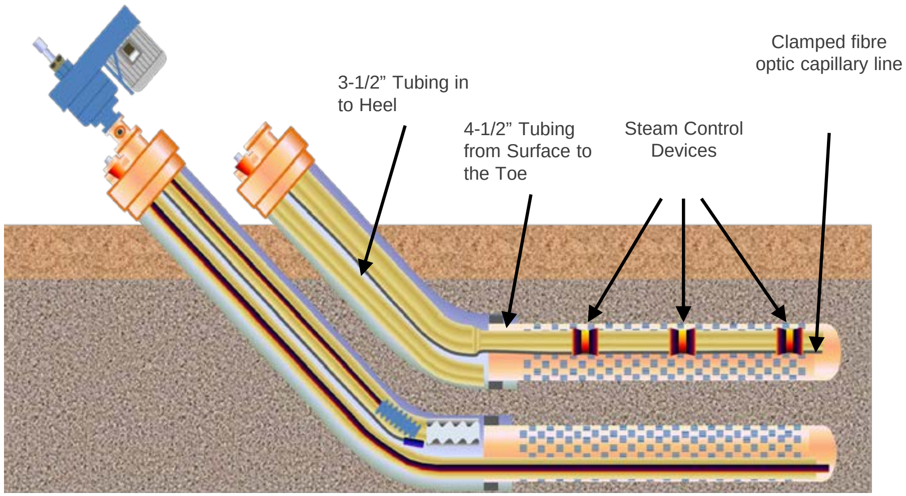
Summary of Alternate Completions

System	Principle	Use in
Steam distribution control devices	Reduction of pressure gradient in the liner- better distribution of steam	AA02I, AB02I and AD02I
Inflow control devices Liner Based	Reservoir inflow equalization	AC01P and AD02P
Alternative sand control using Wire Wrap Screens (WWS)	Maximization of opened flow area to reduce completion drawdown	AE03P
Alternative sand control using Precision Punched Screens (PPS)	Improved filter media resistance to wearing using: better metallurgy and change of fluid momentum. Reduced tendency to plugging minimizing the thickness of the slots.	AH04P and AF02P
Tubing Deployed Inflow Control Devices (TDICD)	Adds back-pressure to regions of the well, at or near steam breakthrough conditions	AD03, and AA05

Trial status to-date (March 2019):

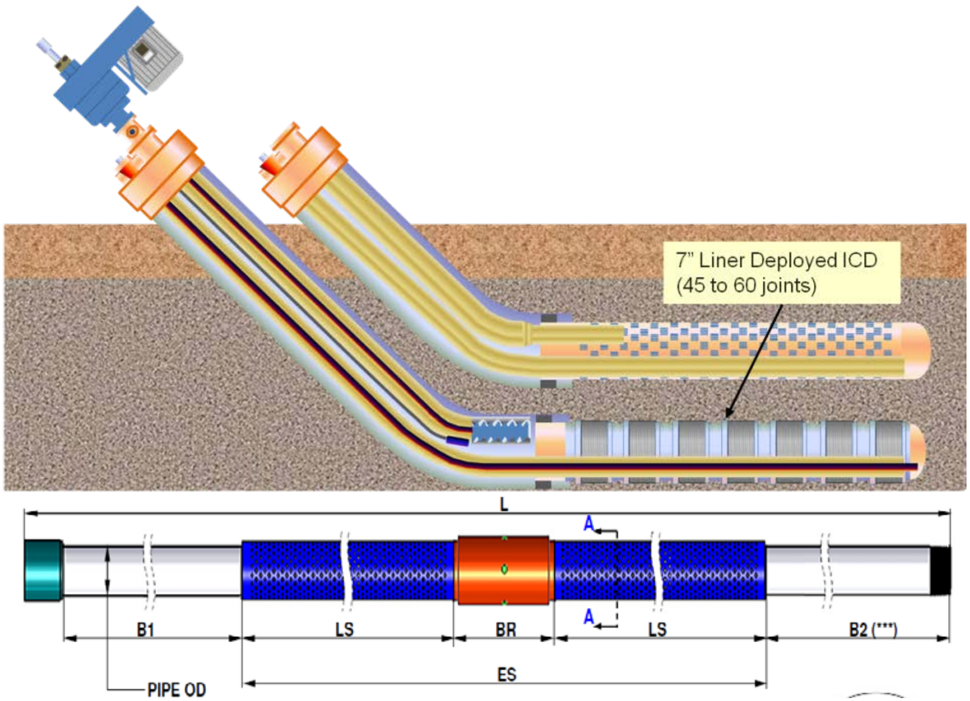
- No specific advantages of using WWS on AE03P or PPS on AH04P have been observed thus far
- On the contrary, AF02P equipped with PPS has shown very good performance after conversion to SAGD
    - Constantly low drawdown (DP) of ~100 kPa (the lowest on the pad)
    - Highest normalized emulsion production rate on the pad
    - Highest normalized cumulative emulsion production on the pad
- The use of TDICDs is being trialed on wells with low liner drawdown, and where one or more controlling hot-spots limits the production from the well. Evaluation of this application is ongoing.

Steam Control Devices Test



- The injector wells that have steam control devices installed are: AA02I, AD02I and AB02I.
- These wells have a full fibre optic temperature sensor in the injector to allow better monitoring of the steam chamber growth.

Inflow Control Devices Test



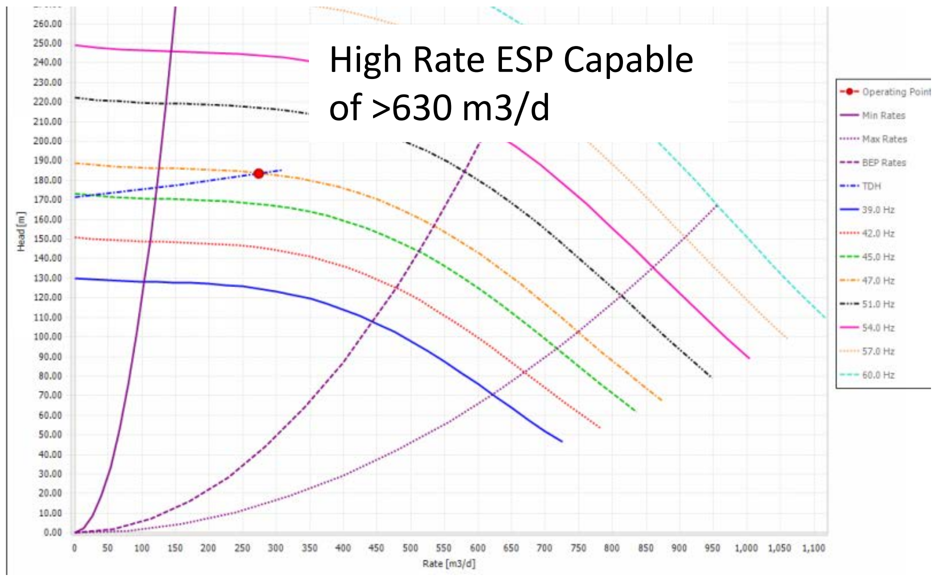
- The liner deployed ICDs on AD02P and AC01P have performed well, yielding good overall conformance and production.
- Application of ICDs has been expanded to include tubing deployed systems. TDICDs have been installed at AD03P and AA05P, and are currently being evaluated.

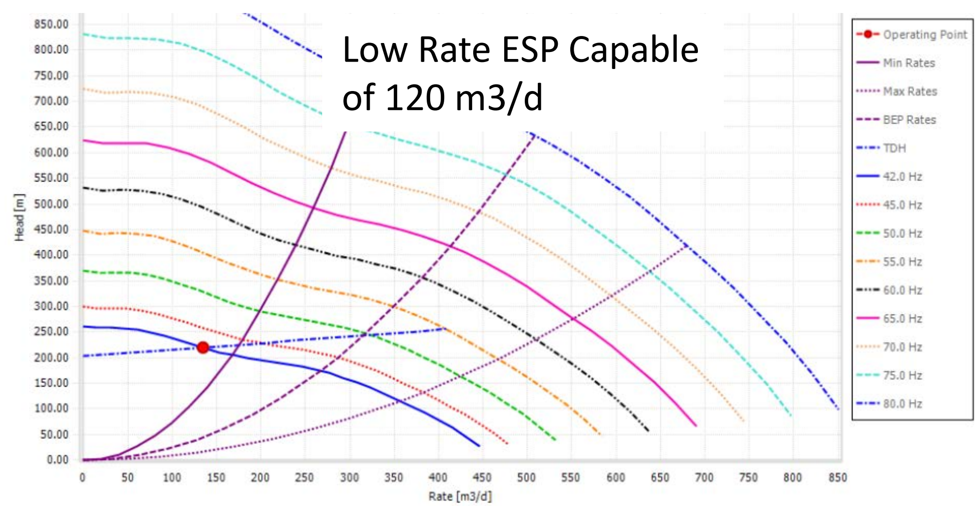
Artificial Lift - Performance

- **General ESP Designs:**
  - I. Emulsion flow: 120 m3/d – 600+ m3/d
  - II. Max temp: 250 C (Typically operated <200C)
  - III. Max head: 600 m (surface pipe pressure rating limitation)
  - IV. GOR: 2 – 8 m3/m3
  - V. MTTF expectation: 24 mo. (min).
  - VI. Current PCC MTTF not representative, since only 1 failure realized to date (18 mo. Run time).

- **General PCP Designs:**
  - I. Emulsion flow: 70 m3/d – 260+ m3/d
  - II. Max temp: 300 C (Typically operated <200C)
  - III. Max head: N/A (surface pipe protections in place)
  - IV. Average 40% volume efficiency after 6 months of operation
  - V. GOR: 2 – 8 m3/m3
  - VI. MTTF: 16.4 mo. (includes DH mechanical failures)

Average PBHP – 1750 kPag,





Artificial Lift – Distribution of Lift Types

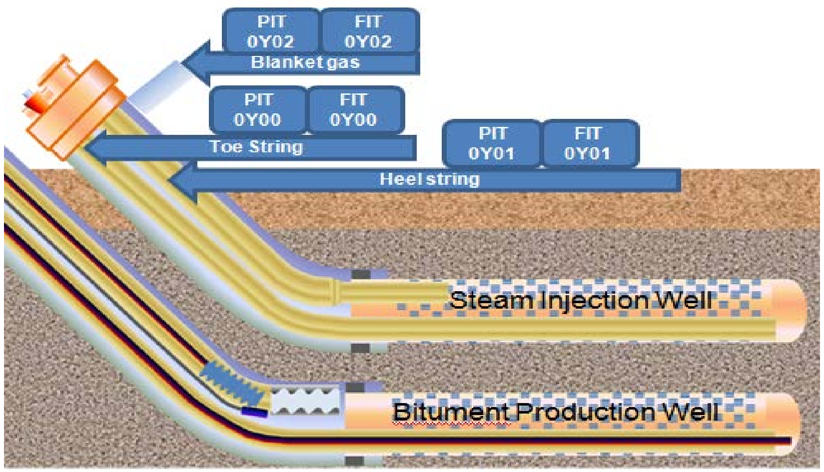
Artificial Lift Distribution		
AA PAD		AE PAD
AA01 (ESP)		AE01
AA02 (ESP)		AE02
AA03		AE03 (ESP)
AA04 (ESP)		AE04
AA05 (ESP)		AE05
AA06 (ESP)		AE06
AB PAD		AF PAD
AB01		AF01 (ESP)
AB02 (ESP)		AF02 (ESP)
AB03 (ESP)		AF03
AB04 (ESP)		AF04 (ESP)
AB05		AF05 (ESP)
AC PAD		AF06 (ESP)
AC01 (ESP)		AH PAD
AC02 (ESP)		AH01 (ESP)
AC03 (ESP)		AH02
AC04 (ESP)		AH03 (ESP)
AD PAD		AH04
AD01		AH05
AD02 (ESP)		AJ PAD
AD03 (ESP)		AJ01 (ESP)
AD04 (ESP)		AJ02
AD05		AJ03
		AJ04
		AJ05
Wells not indicating ESP lift, utilize Metal-Metal PCPs		

General Comments

- All 42 wellpairs utilize artifical lift for SAGD production.
- Two artificial lift types are utilized at MRCP: ESP and PCP.
- 16 ESP conversion were completed in the past year.
- Of the remaining 42 wellpairs 18 wells continue to utilize metal-metal PCPs.
- Conversion of wells from PCP lift to ESP is evaluated on an opportunity basis, when PCPs fail/lose lift capability, or when the well is worked over for other reasons.

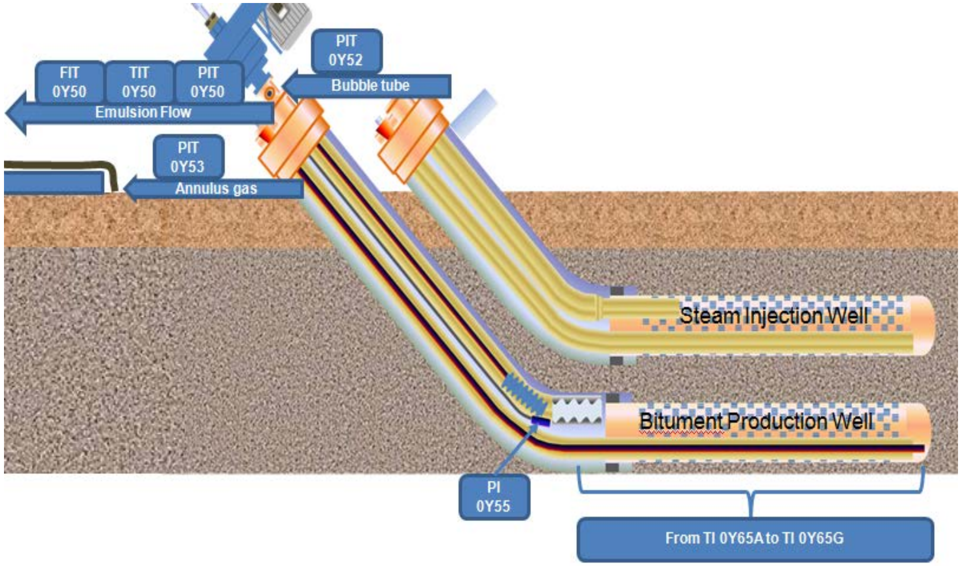
Summary of Downhole Instrumentation

Injection Well Instrumentation



Variable	Type of Instrument
Down hole pressure	Blanket gas / Pressure Transmitter
Blanket gas injection rate	Coriolis meter
Toe string steam injection rate	Vortex meter
Toe string well head pressure	Pressure transmitter
Heel string steam injection rate	Vortex meter
Toe string well head pressure	Pressure transmitter

Producer Well Instrumentation



Variable	Type of instrument
Down hole pressure	Optic pressure sensor (phasing out)
Down hole pressure	Bubble Tube / Pressure transmitter
Blanket gas injection rate (Circ)	Coriolis meter
Toe string steam rate (Circ)	Vortex meter
Toe string well head pressure (Circ)	Pressure transmitter
Well bore temperature	DTS or FBG fibre optic system
Return well head pressure	Pressure transmitter
Return well head temperature	Temperature transmitters
Return rate	Coriolis meter

Summary of Additional Downhole Instrumentation

System	Type	Use in
Pressure and temperature sensor at the heel Pressure and Temperature sensor at heel Heel Thermocouple	Optic sensor Piezo meter Thermocouple	Few optical sensors remain in service. A bubble tube is the primary heel pressure measurement. Installed with ESPs on AC . 3 systems (1 failed). Heel thermocouple is being trialed on AF06, as a backup to FBG/DTS measurement.
DTS well bore temperature sensing system	Fibre optic DTS	Installed in every producer on PADs: AA, AD, AF, AJ and AH. Installed on injectors: AA02I, AA03I, AD02I, AJ02I and AJ03I.
LxData well bore temperature sensing system	Fibre optic FBG	Installed in every producer on PADs: AB, AC and AE. Installed on injector AB02I.
Pressure sensor at the toe of the well	Fibre optic FBG	On AB02P, AC01P, and AE04P

Well Production Testing

- Well production and injection volumes are estimated by the use of Coriolis meters (emulsion) and vortex meters (injection) for each well as the raw data check for the well tests

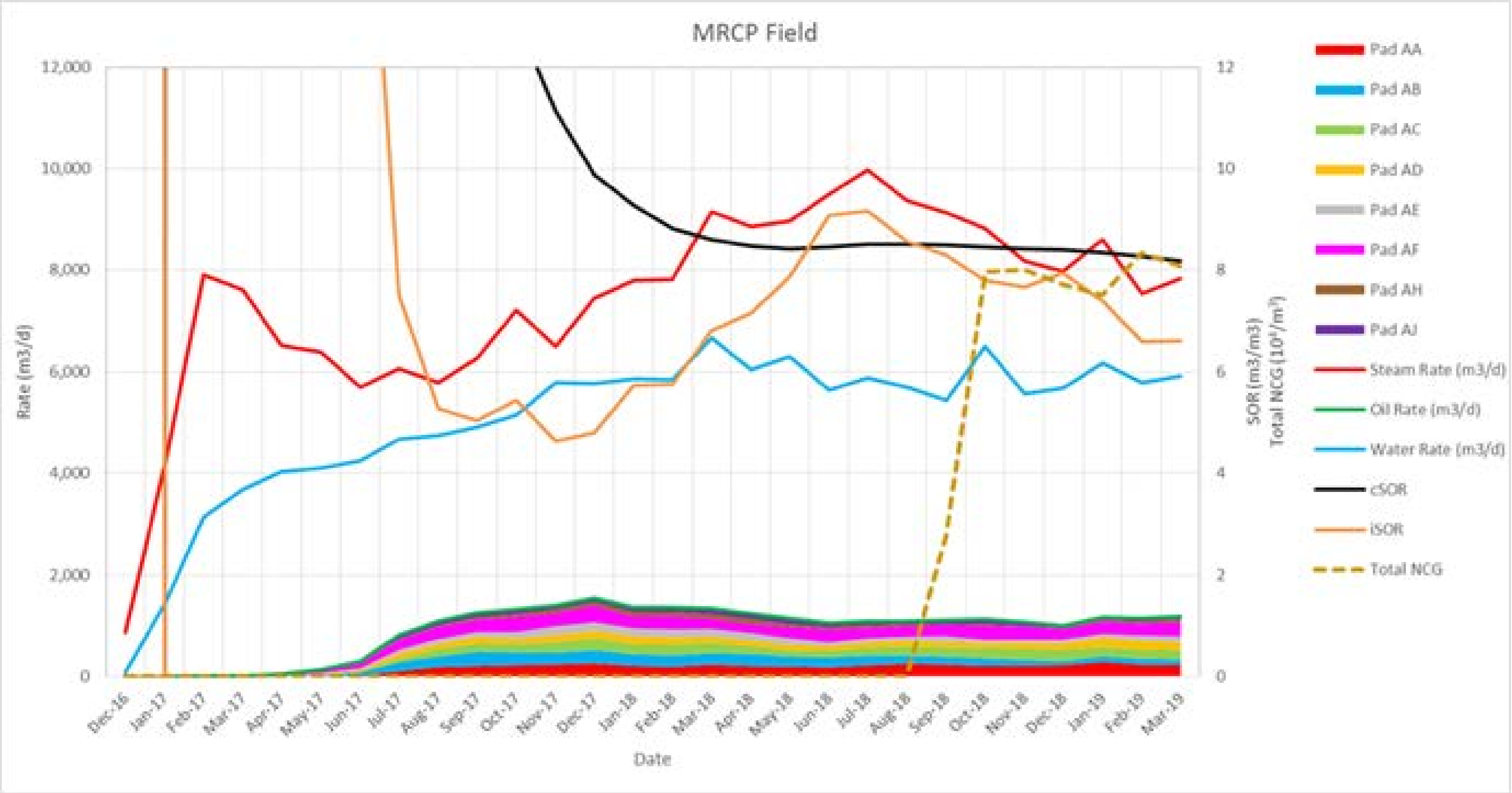
- MRCP utilizes one test separator per pad that automatically cycles through each well on the pad every 24 hours.
  - Typically each well will be in test for at least 120 hours per month
  - Well testing validations are completed once per week per pad within the Energy Components software

- This data is rolled up and balanced with the facility production and injection volumes to determine month end pro-rations prior to submission to Petrinex

MRCP – Update on Performance Prediction Methodology

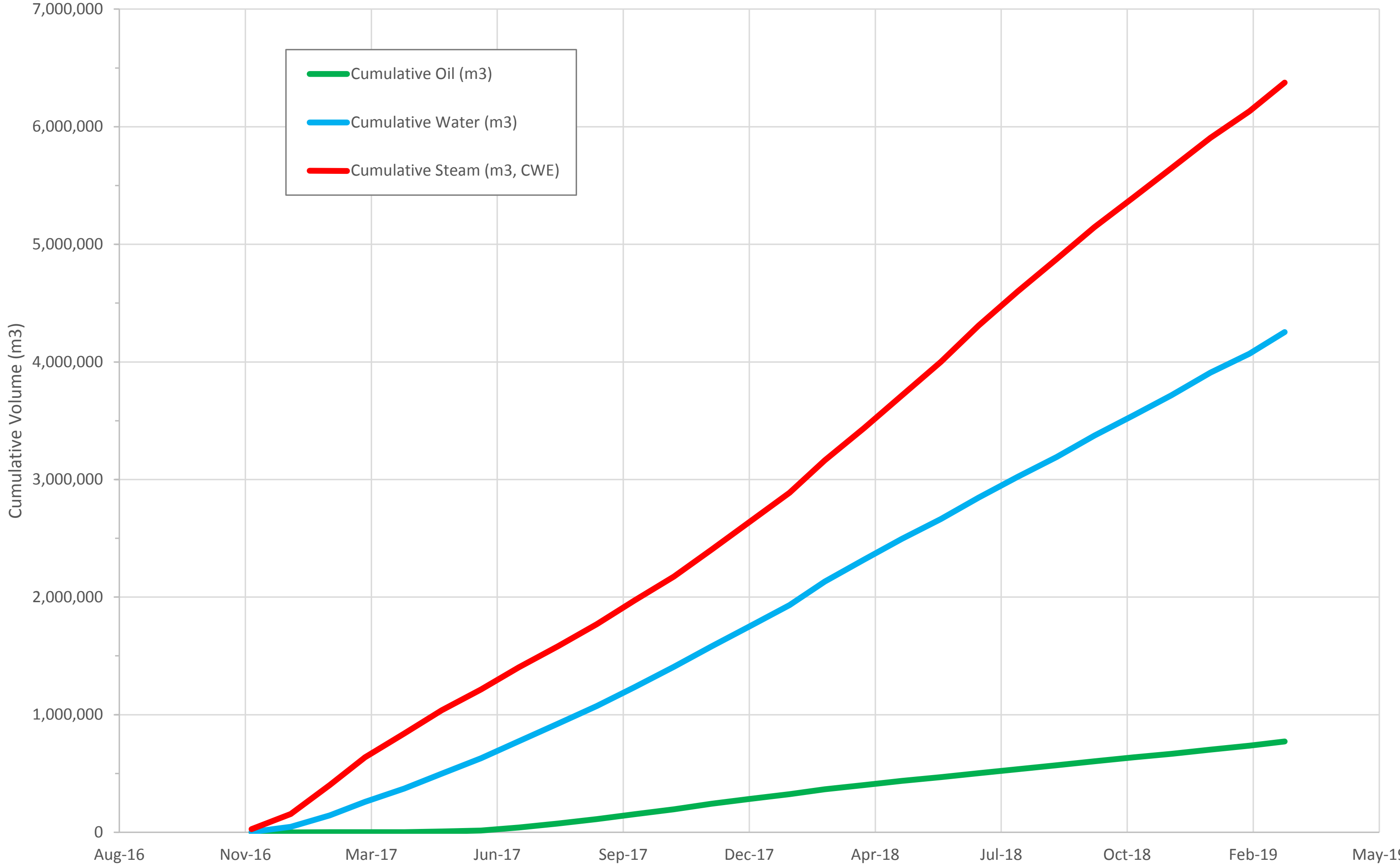
- Actual performance has deviated from pre-steam forecasted performance
- Geological and reservoir models have been updated since first steam
- PCC has reviewed analog field performance and has developed its own methodology for performance predictions
    - Reservoir simulations are used to history match well pair, pad and field performance. The forecast is based on a history matched model of:
        - steam injection
        - produced oil and water
        - historical pressures

MRCP – Field Performance



- MRCP is continuing to ramp up production
- Steam and thus SOR impacted by top gas zone effects and areas of thicker lower transition zone
- Geological baffles (zones of higher mud bed frequency) impacting chamber growth and performance in areas of the reservoir
- 2018 monthly exit rate (1000 m3/d)
- Late 2018 production primarily impacted by workovers, well testing and infill drilling activity
- NCG Injection at 103/05-13 was started in September followed by additional co-injection in approved wells

MRCP – Cumulative Fluid Volumes



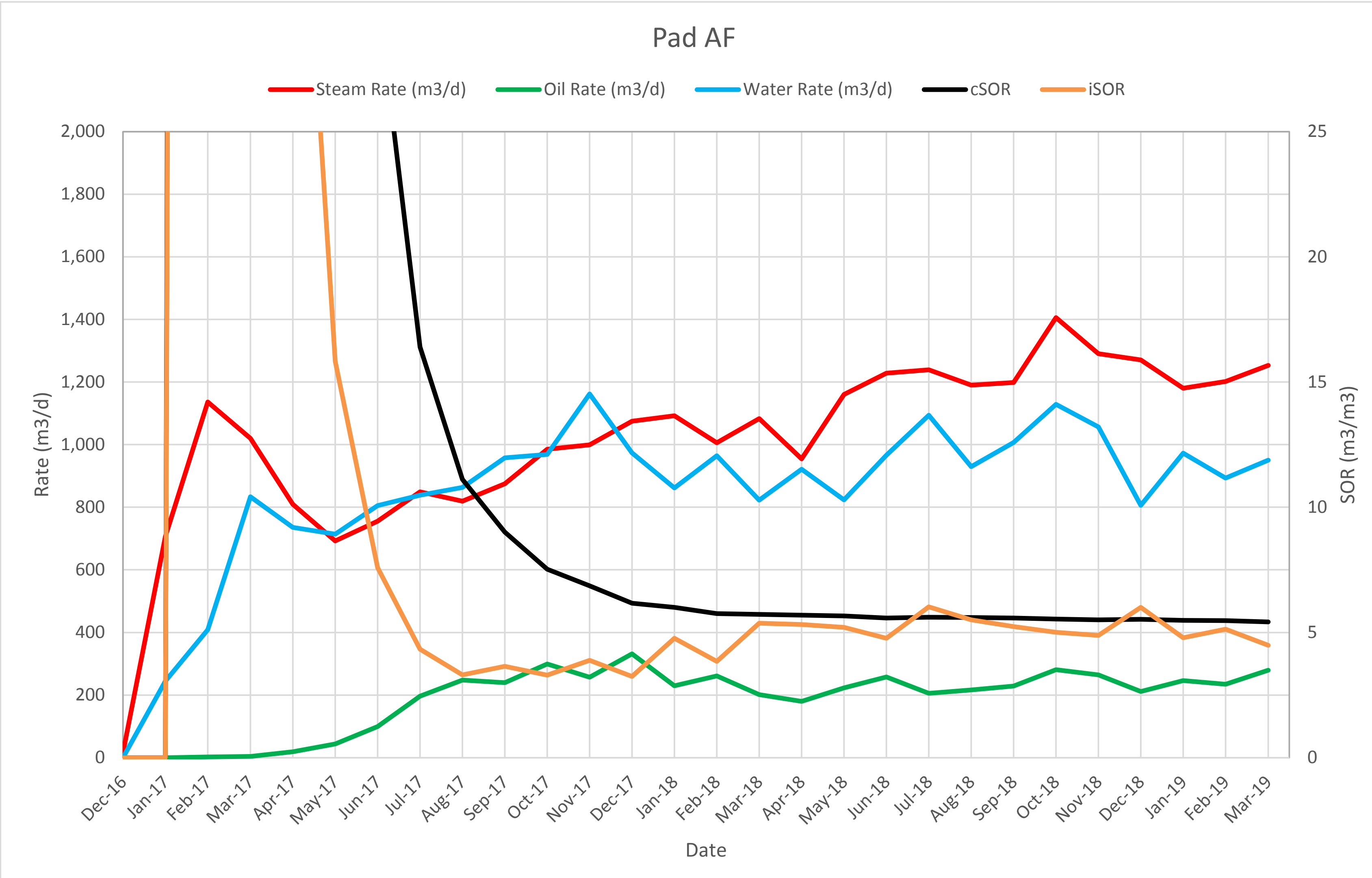
- In a few areas, steam chamber interactions with top gas and losses to the lower transition zone has resulted in higher retention by the reservoir.
- Mitigation strategies in execution include gas cap pressurization (gas injection and co-injection), balancing operating pressures with multiple thief zones

MRCP – Performance Indicators by Pad

Pad	OBIP (m^3)	Cum. Oil to March 31 2018 (m^3)	Recovery to March 31 2018 (%)	CSOR	ISOR	Ultimate Recovery (%)
AA	4,197,138	141,169	3.36	5.9	4.7	54
AB	3,465,819	119,350	3.44	7.5	9.2	57
AC	2,655,008	114,765	4.32	4.9	4.5	63
AD	2,957,075	81,757	2.76	9.2	7.4	54
AE	3,513,514	71,111	2.02	11.3	9.6	53
AF	4,149,444	160,052	3.86	5.4	4.5	62
AH	3,179,650	31,335	0.99	24.2	12.2	48
AJ	2,941,176	52,901	1.80	17.1	13.3	57
Total	**27,058,824**	**772,440**	**2.85**	**8.3**	**6.6**	**56**

- Higher SORs experienced on AE, AH, AJ and AB pads primarily due to gas cap contact and slightly larger lower transition zone leak off.
- Mitigations:
  - Operating pressure is balanced accordingly with the thief zones pressure
  - Gas cap pressurization with natural gas started in Sep 2018 in vertical well 05-13 (central DA)
  - Gas co-injection started in well pairs of pads AH, AE, AD in Jan 2019 to support gas cap pressurization in the Southern DA

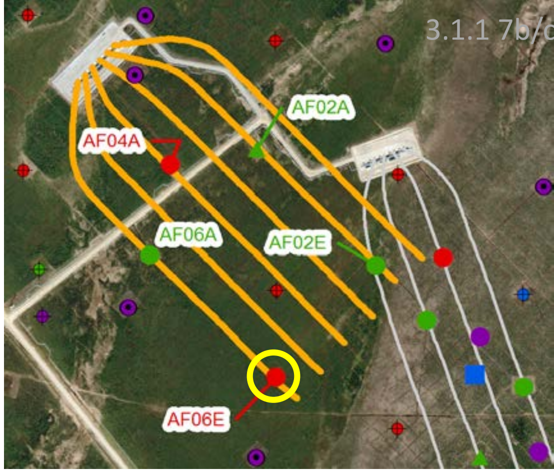
MRCP – Pad AF: High Performance Example



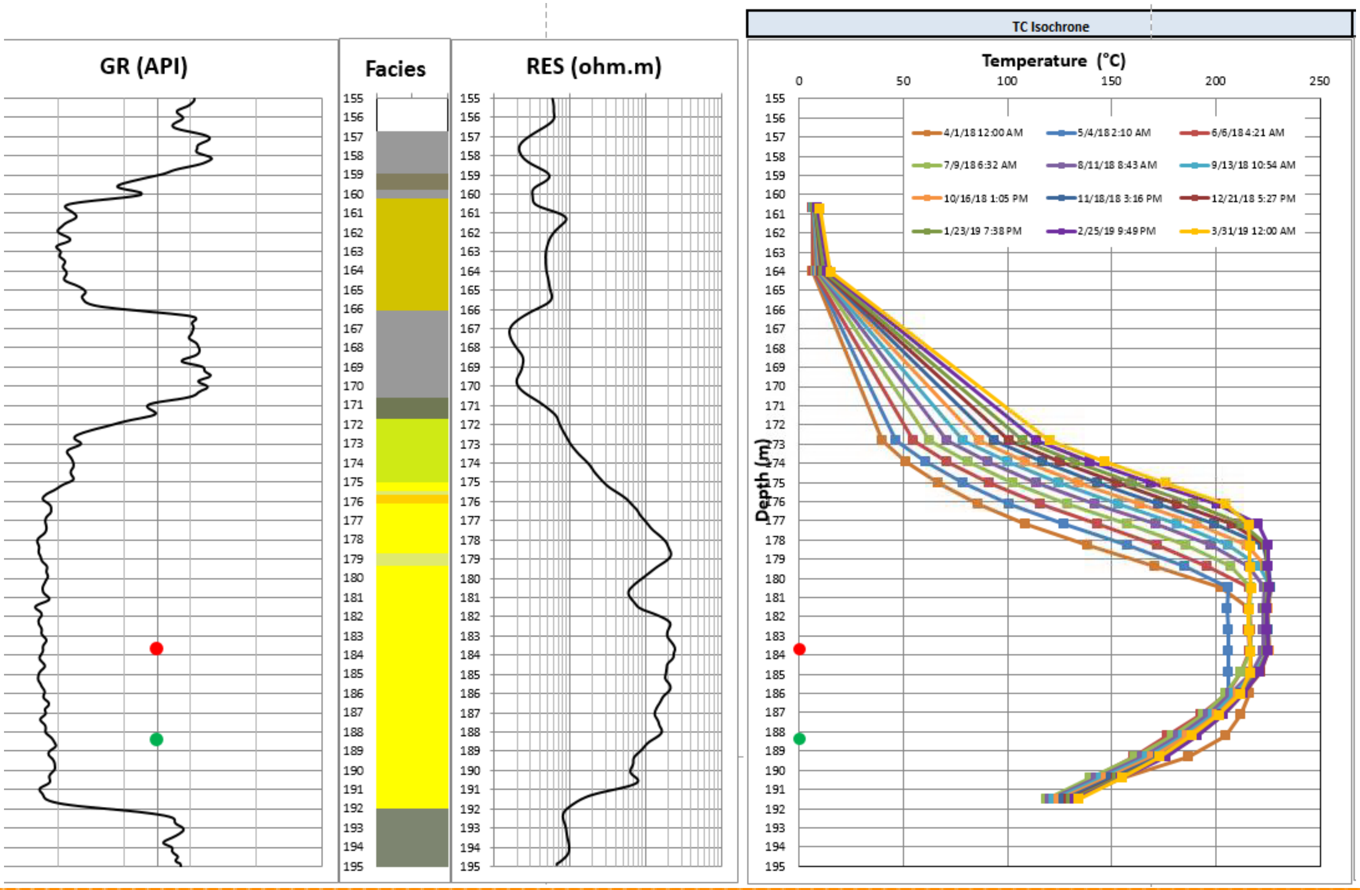
MRCP – Observation Well Examples: Pad AF

5 Observation Wells in the Pad for steam chamber monitoring:

- Example: AF06E – 2.3 m from toe of AF06
- Design: Obs Well w/ thermocouples
- Steam Chamber conditions seen since 07/2017
- Sustained steam chamber growth observed during reporting period



- ERE and Image
- ERE, Image and Core
- Thermocouple
- Thermocouple and Core
- Thermocouple, Image and COre
- Thermocouple and ERE
- Thermocouple, ERE and Core
- Thermocouple, ERE, Image and Core



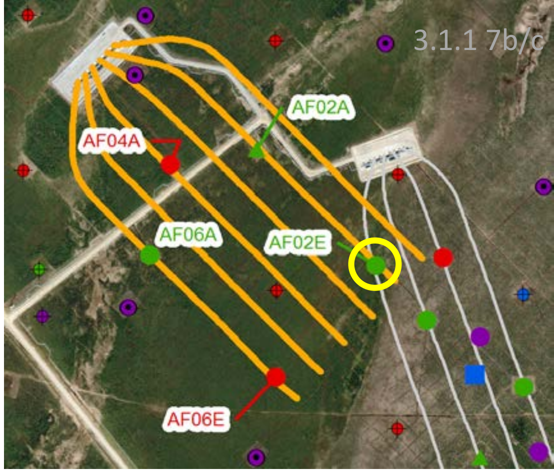
Sustained steam chamber growth above injector level

MAX temp reflects operational pressure changes

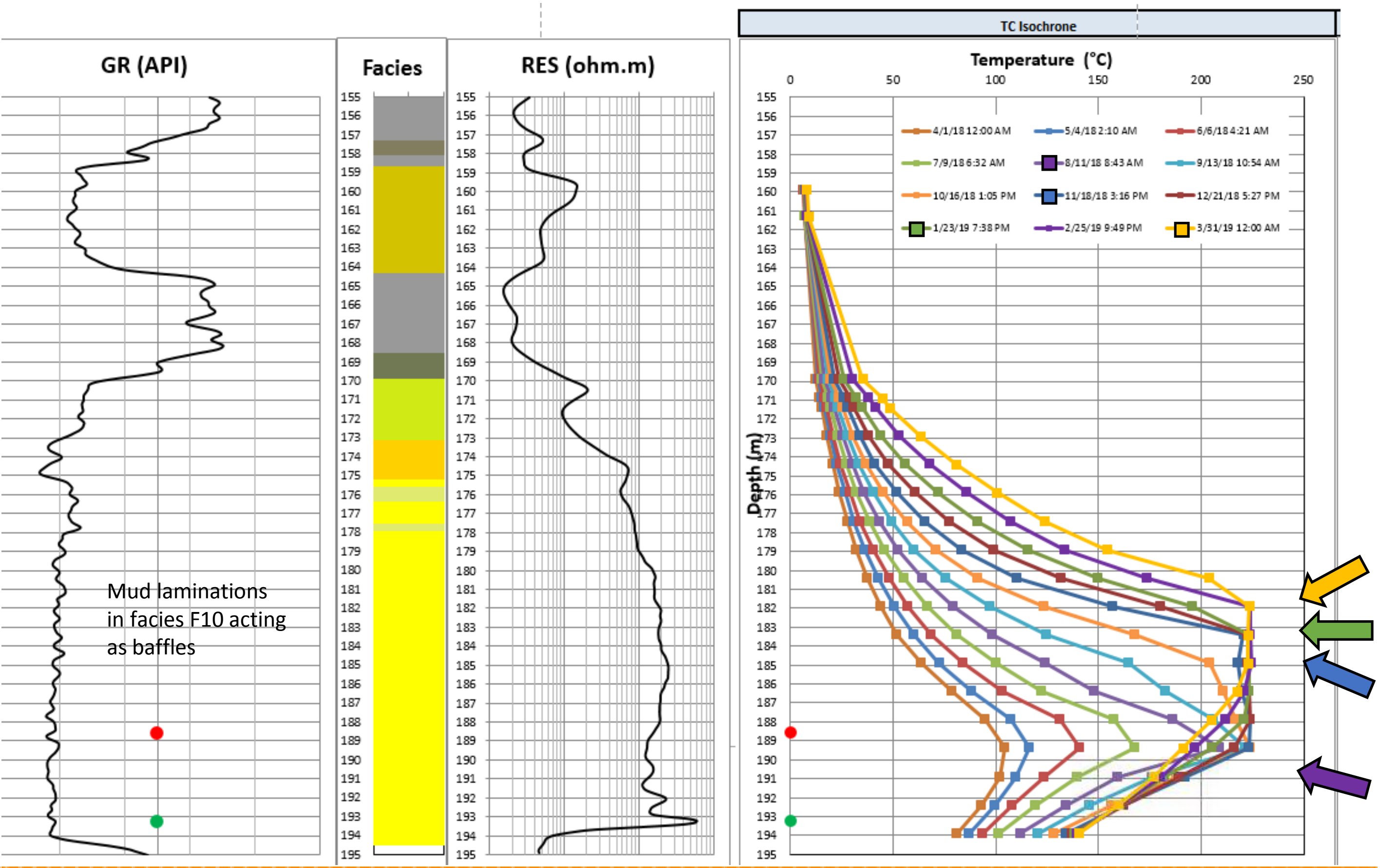
MRCP – Observation Well Examples: Pad AF

5 Observation Wells in the Pad for steam chamber monitoring:

- Example: AF02E – 9.7 m from toe of AF02
- Design: Obs Well w/ thermocouples
- Steam Chamber conditions seen since 08/2018
- Steam chamber slowed down by geological baffles



ERE and Image
ERE, Image and Core
Thermocouple
Thermocouple and Core
Thermocouple, Image and COre
Thermocouple and ERE
Thermocouple, ERE and Core
Thermocouple, ERE, Image and Core



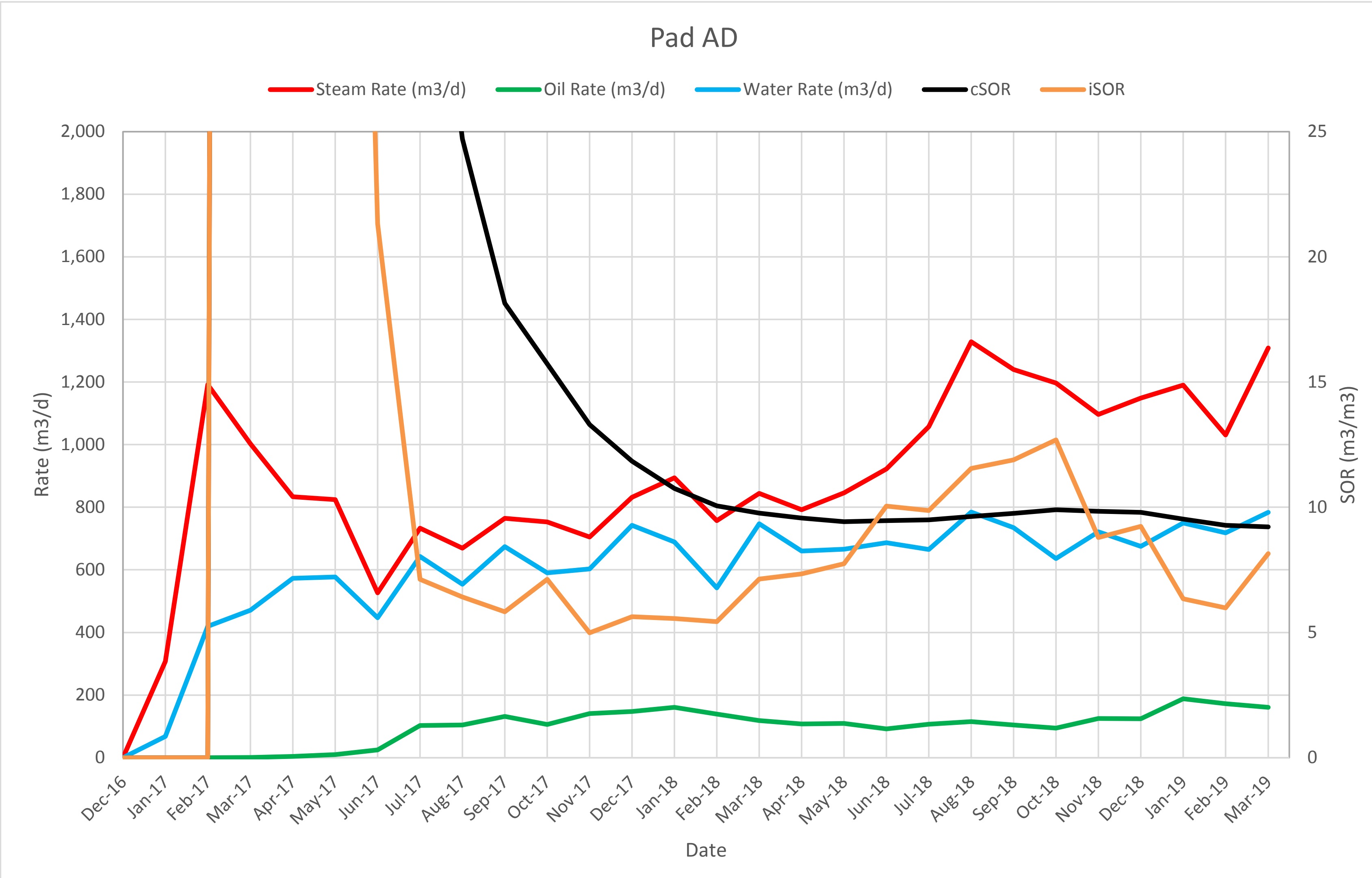
Moved 1m Feb to early Mar 2019 @182m

Stalled @183m Nov 2018 – Jan 2019

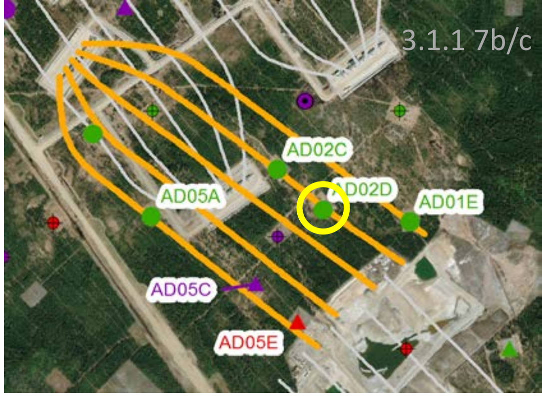
Moved 6m up Aug to Nov 2018 (1.5m/month)

First steam @189m in Aug 2018

MRCP – Pad AD: Medium Performance Example



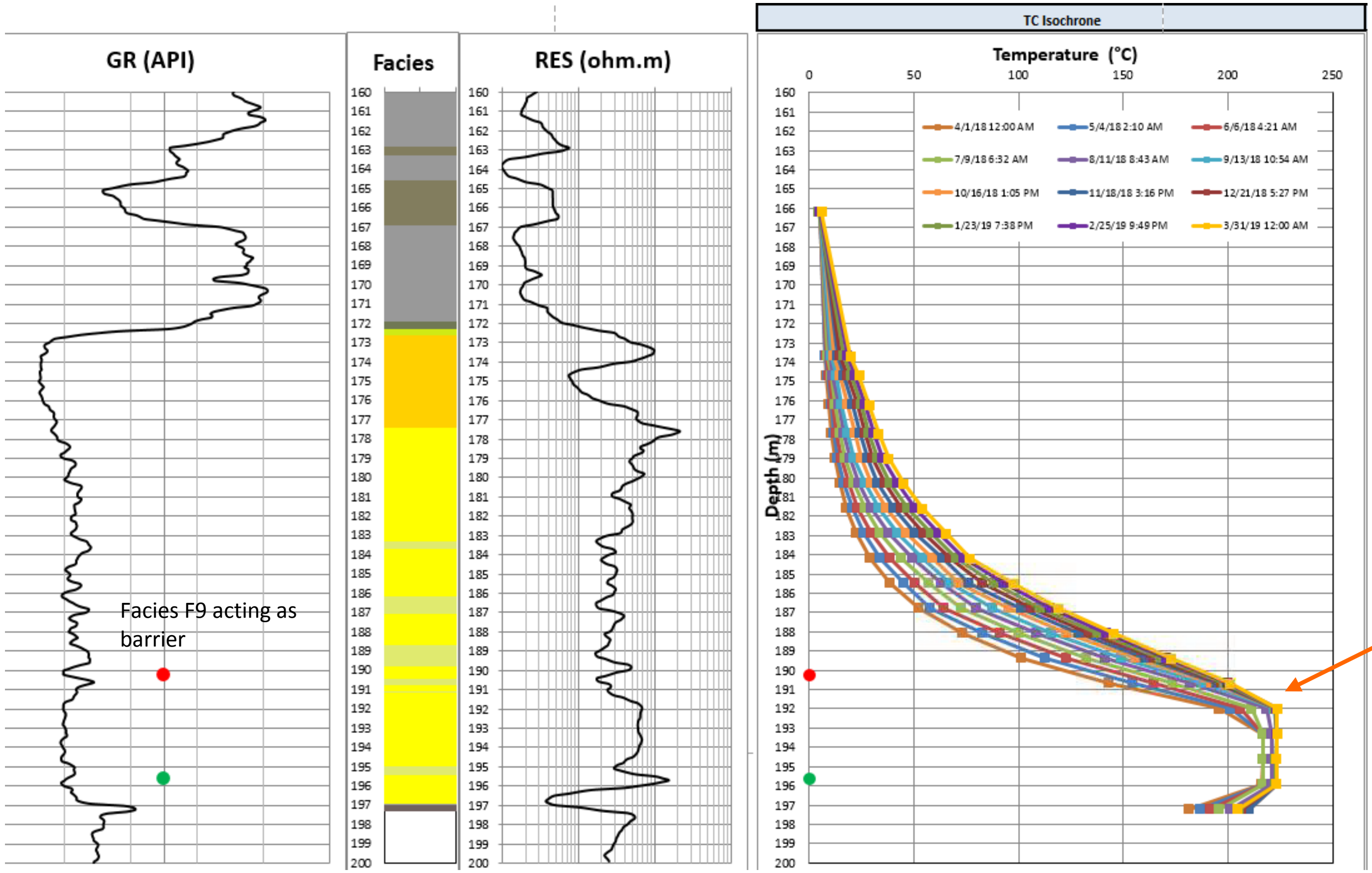
MRCP – Observation Well Examples: Pad AD



- ERE and Image
- ERE, Image and Core
- Thermocouple
- Thermocouple and Core
- Thermocouple, Image and COre
- Thermocouple and ERE
- Thermocouple, ERE and Core
- Thermocouple, ERE, Image and Core

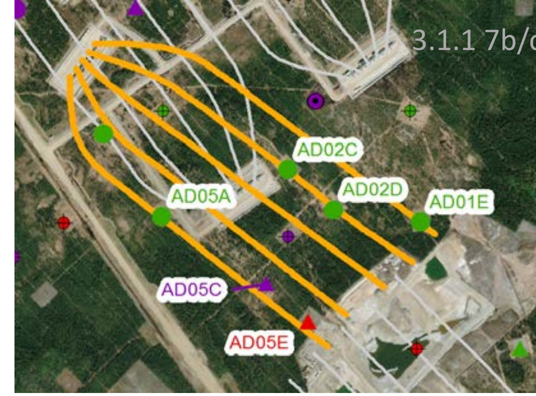
6 Observation Wells in the Pad for steam chamber monitoring:

- Example: AD02D – 5.59 m from toe of AD02
- Design: Obs Well w/ thermocouples
- Steam Chamber conditions seen since 11/2017
- Relevant geological baffles & barriers affecting steam chamber in this location



Steam Chamber stalled between injector and producer

Influenced by mud baffles & barriers present between injector and producer



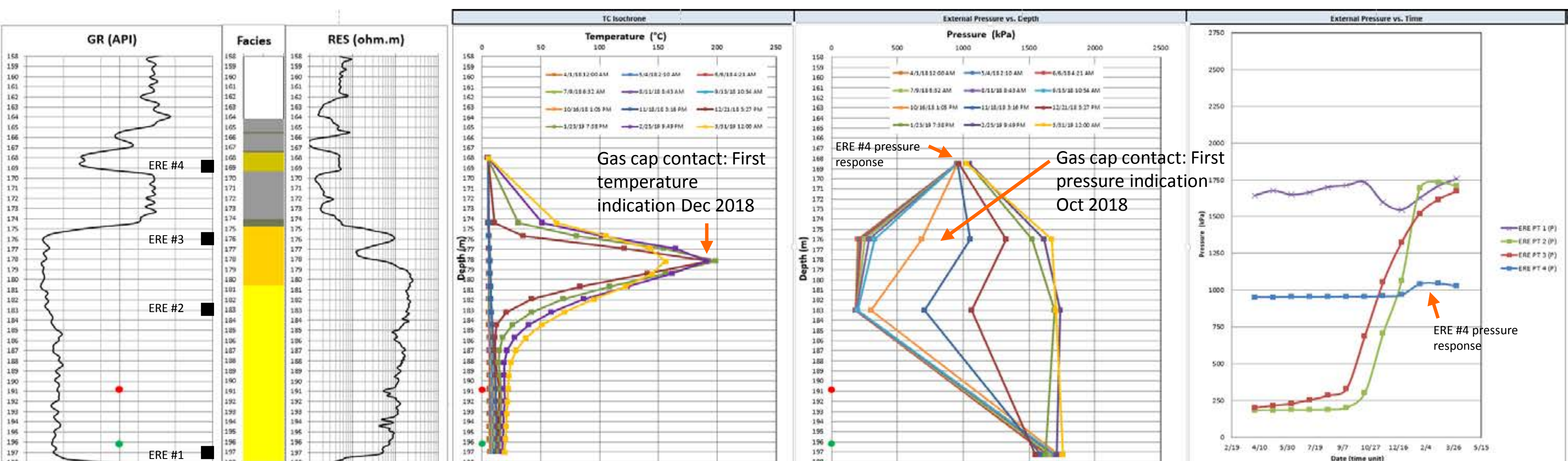
MRCP – Observation Well Examples: Pad AD

6 Observation Wells in the Pad for steam chamber monitoring:

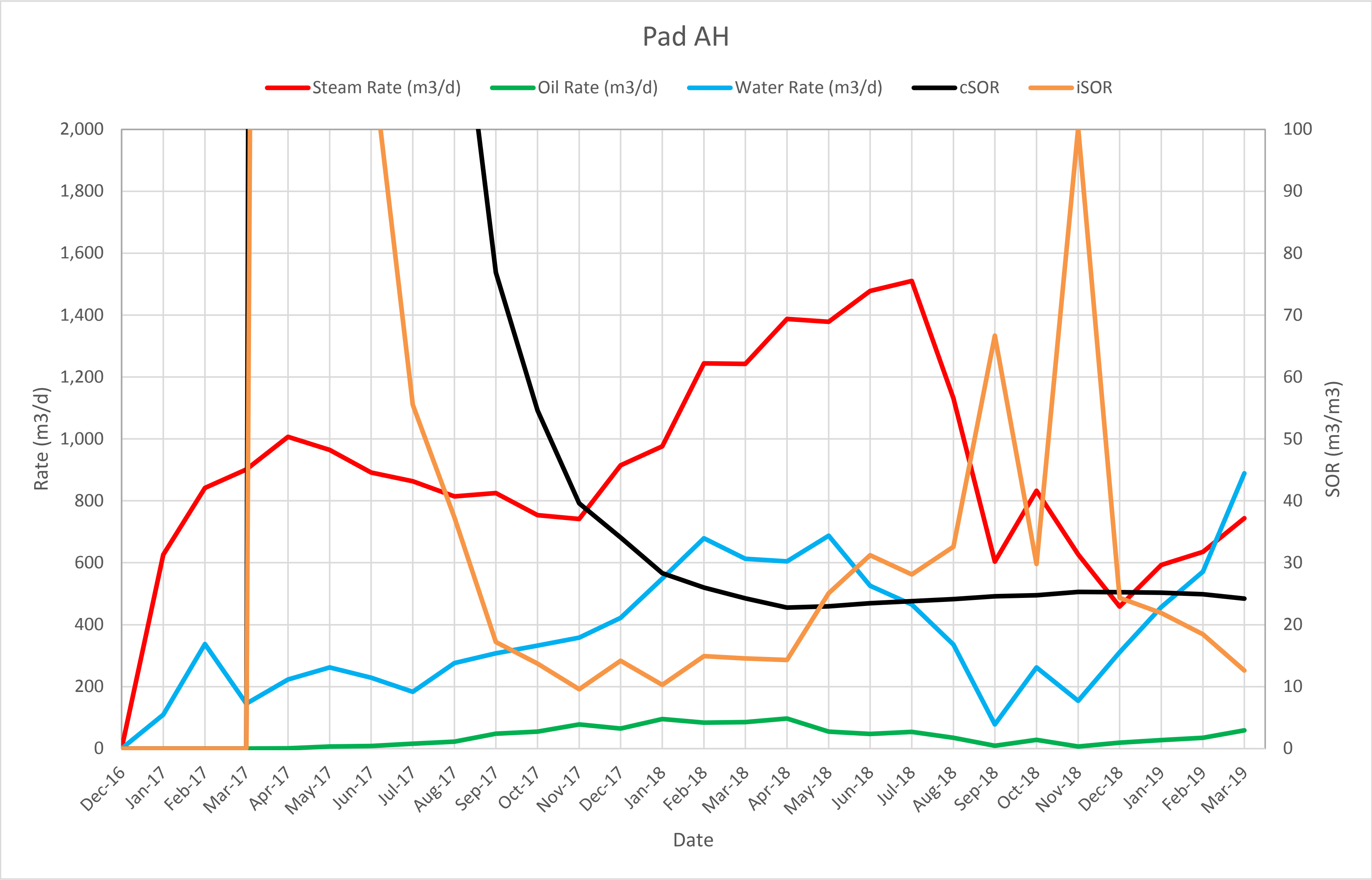
- Example: AD05C – 38.8 m from mid section of AD05
- Design: Obs Well w/ Thermocouples and external ERE pressure gauges
- Identified lateral event related to steam chamber contacting gas cap in AD05 and AD04
- ERE gauge #4 trend (WBSK) changed abruptly in mid Dec 2018
  - Pressure: reached 1,080 kPag (peak) before declining to ~1,022 kPag
  - Temperature: ERE temp increased to 12ºC in Mar 2019

Actions: Though minor concern, PCC is seriously following this type of case:

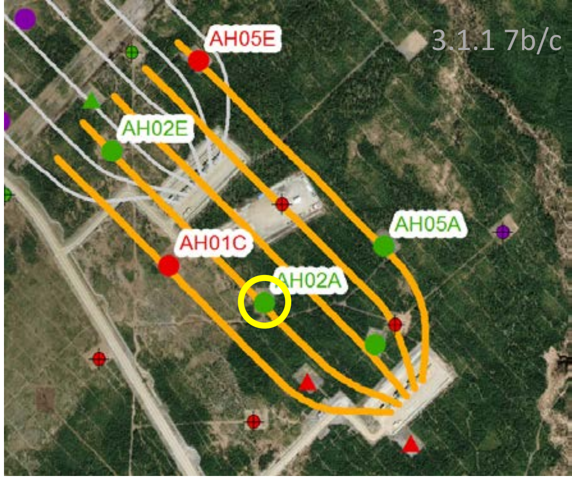
- D&C:
  - CBL/VDL check OK, cement looks normal.
  - Surface casing vent inspection was conducted. Good test, no bubbling detected.
- Reservoir:
  - Confirmed gauges consistency, no drifting, good match between external T ERE and thermocouples.
  - Permanent monitoring, temperature increase confirms the gauge has communicated with lower zone.
  - Preparing for remedial intervention in winter of 2019-2020



MRCP – Pad AH: Low Performance Example

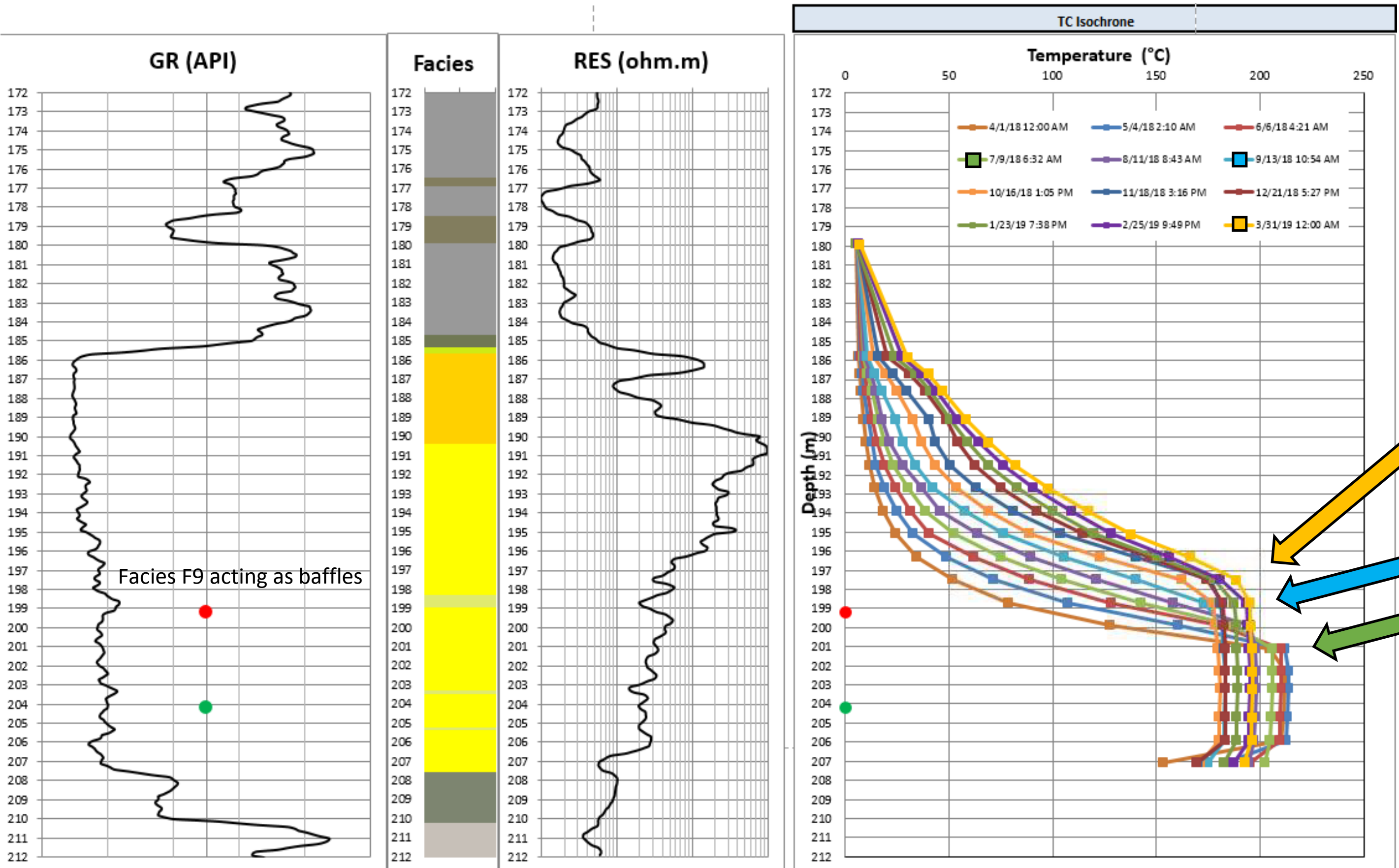


MRCP – Observation Well Examples: Pad AH



5 Observation Wells in the Pad for steam chamber monitoring:

- Example: AH02A – 8.36 m from mid-section of AH02
- Design: Obs Well w/ thermocouples
- Steam Chamber conditions seen since 02/2018
- Competent F9 baffle halted steam chamber



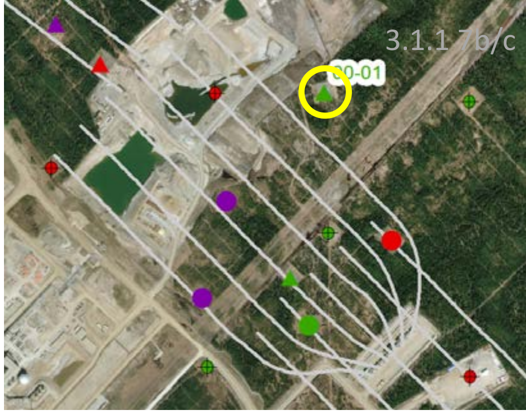
Steam chamber stalled by F9 mud beds since Sep 2018

Moved just above injector level until Sep 2018

Steam Chamber between injector and producer until Jul 2018

Steam chamber development is influenced by mud baffles present between injector and producer and higher Sw to the bottom of the reservoir

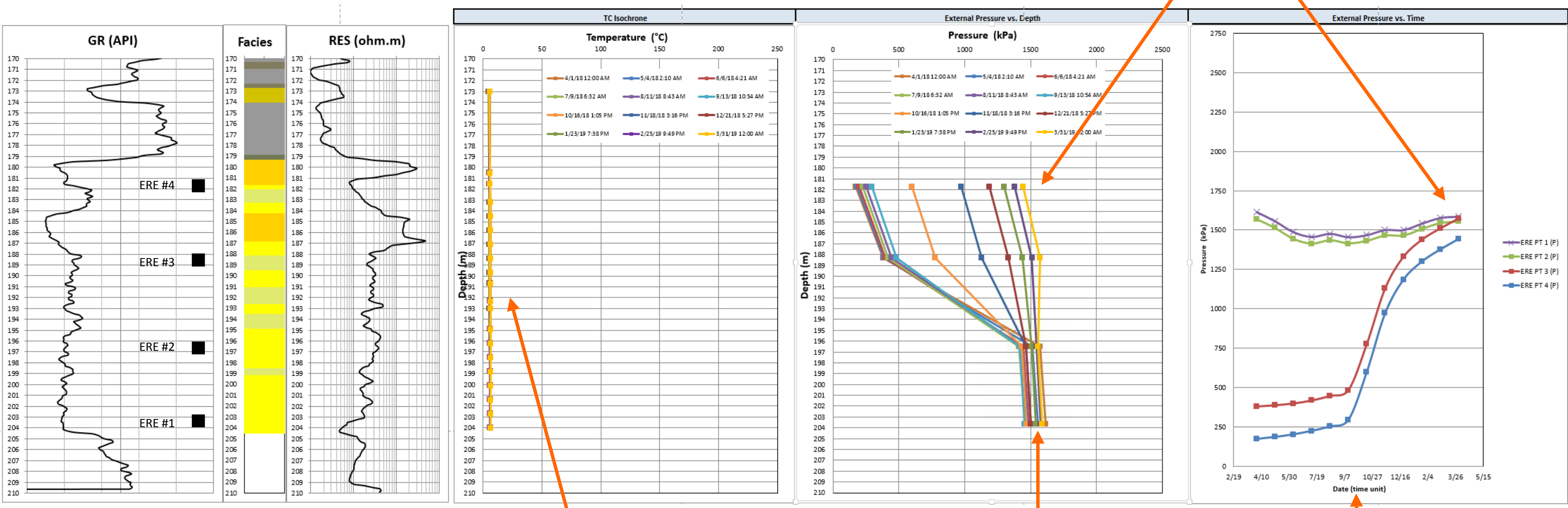
MRCP – Observation Well Examples: Off-Pad



7 Observation Wells are located outside the DA, far from direct influence of well pairs to monitor regional trends

- Example: 00-01 – 125 m from AE06
- Design: Perforated Obs Well w/ Thermocouples and ERE pressure gauges (Multi Zone)
- Temperature response: Virgin reservoir temperature, as expected
- This well has been instrumental in understanding regional pressure trends of the top gas and bottom transition zone
    - Pressure build up first observed in the BTZ as start-up and ramp-up of SAGD wells influenced the pressure in the bottom of the reservoir
    - Pressure response in the top gas shown from Q3, 2018 as the top gas is pressurized by gas injection and interactions with steam chambers

Pressure in Top Gas increasing (accelerated after gas injection started in 05-13)

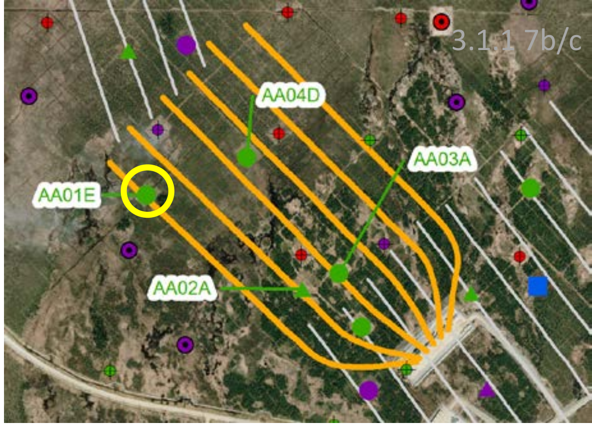


No TEMP response

Pressure in BTZ indicating ~ 1500 kpag

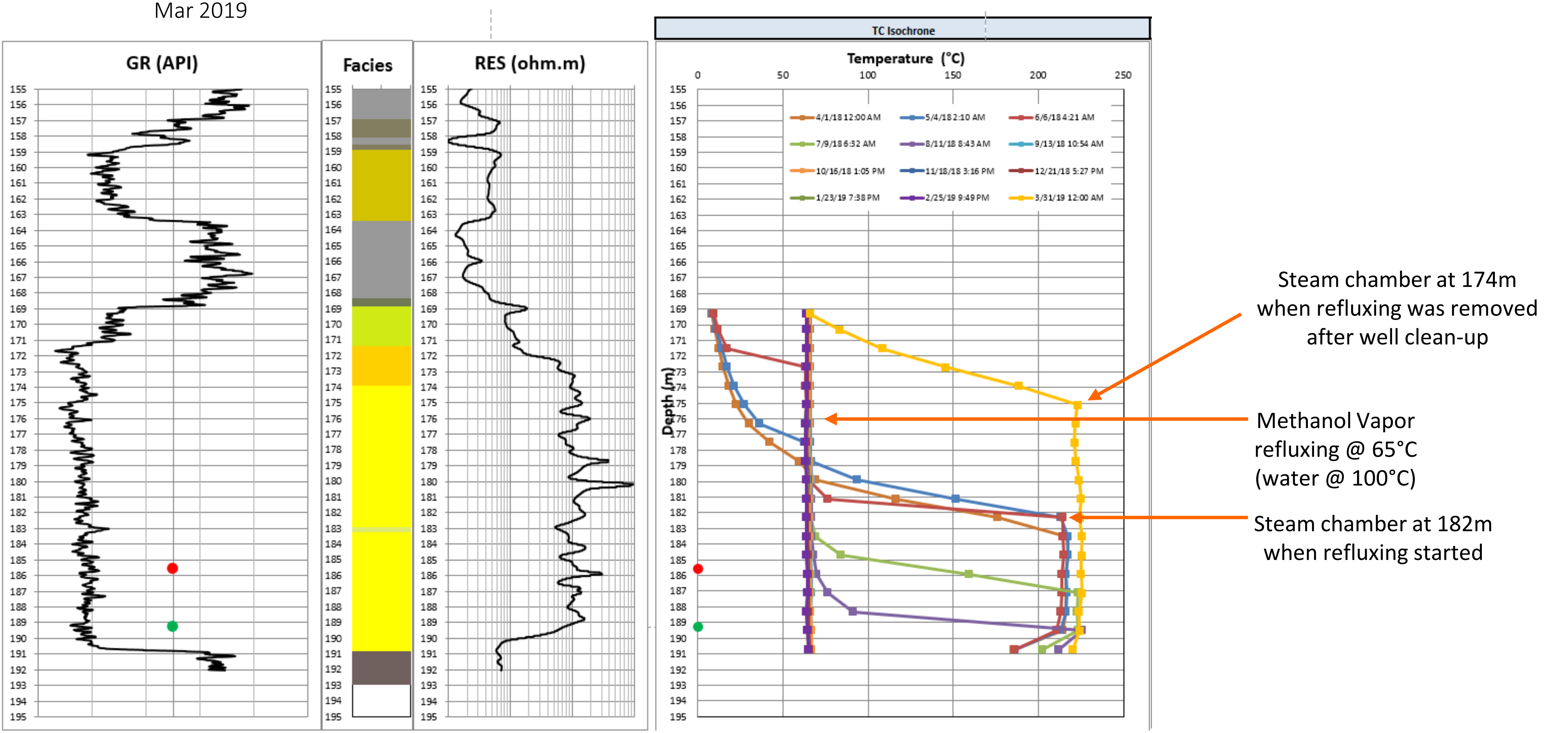
05-13 started gas injection in late Sep 2018

MRCP – Observation Well Examples: Pad AA



4 Observation Wells experienced water or methanol vapor refluxing in 2018 and were repaired in Mar 2019

- Example: AA01E – 3.1 m from AA01 toe
- Design: Obs Well w/ thermocouples
- Temperature response: Steam chamber being tracked since Dec 2017
- Temperature alignment caused by presence of methanol (or water) inside wellbores.
  - Methanol refluxing showed up in May 2018, prevented valid temperature record until Mar 2019



Key Learnings To-Date

- SAGD
  - Continuing to ramp-up production through optimization efforts and mitigating the effects of:
    - Top gas and thicker lower transition zones
    - Operational pressure strategies tied to “thief” zones
    - Effects of baffles and barriers
    - Fines migration
  - The use of PCP was the best low cost conversion solution
    - Some design considerations need optimization to extend run life
  - Differences in wellbore horizontal temperature fibre vendors are evident in data accuracy
    - Observations indicate that FBG may show signs of degrade

Future Initiatives

- Winter Appraisal Program:
  - Annually review MLE requirements
  - Plan to shoot a 4D seismic monitor survey in 2019/2020

- Potential Commercial Amendment Applications in 2019/2020:
  - Steam Stimulation Process – additional wells may be requested
  - Pressure maintenance in bottom transition zone is being investigated
  - Solvent co-injection or solvent soaking under consideration

- Infill Well Project:
  - MacKay Phase 1A – down spaced 17 well pairs utilizing well design enhancements approved:
    - Drilling 4 well pairs on Pad AA – steam to start Q4 2019
    - Drilling of the remaining 13 well pairs will follow a staged approach to incorporate learnings from initial infill well pairs

- Sustaining Wells
  - Continue the internal project development process for the first group of sustaining well pairs
  - Potentially submit an application in early 2020

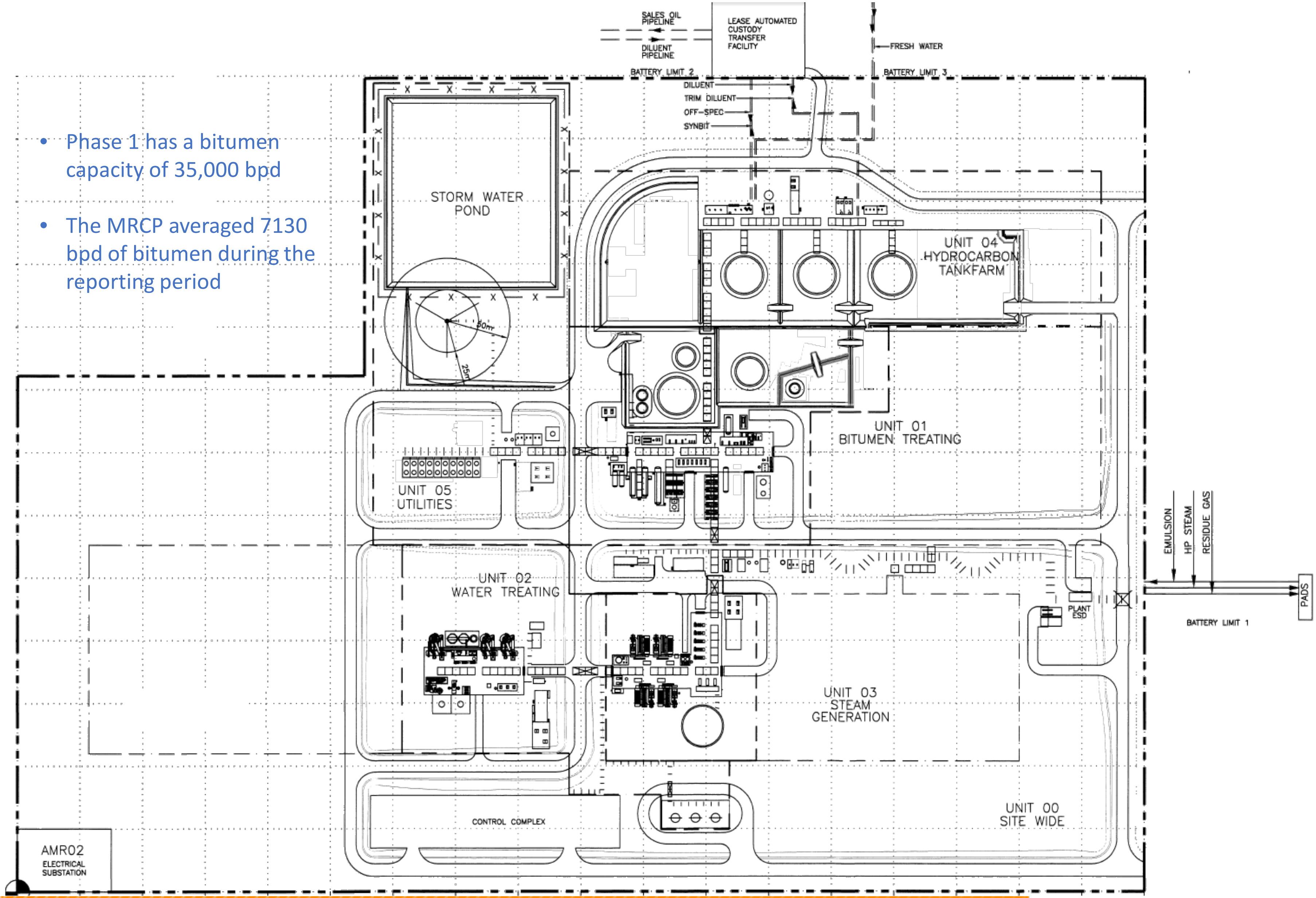
- Pad/Well Abandonments:
  - There are no pad or well abandonments planned in the next reporting cycle

3.1.2 SURFACE OPERATIONS, COMPLIANCE AND ISSUES NOT RELATED TO RESOURCE EVALUATION

Facility Performance, measurement and reporting
Parts (1), (2), (3)

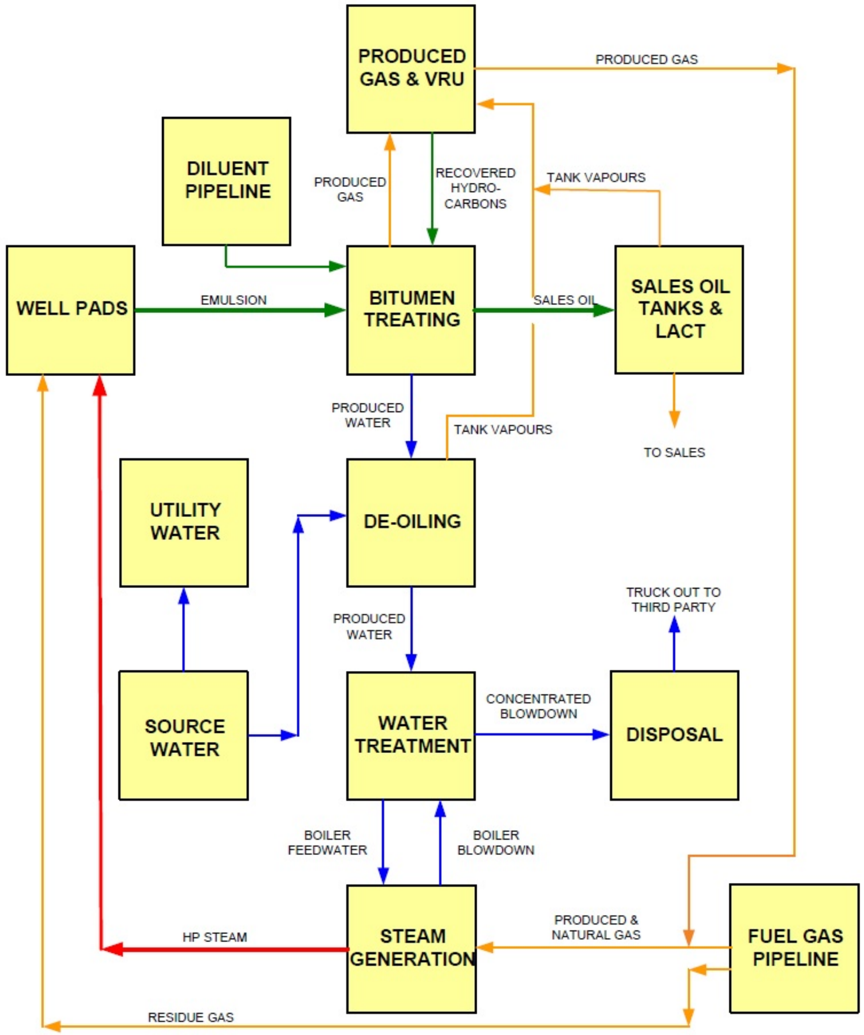
MRCP Central Processing Facility Phase 1 Plot Plan

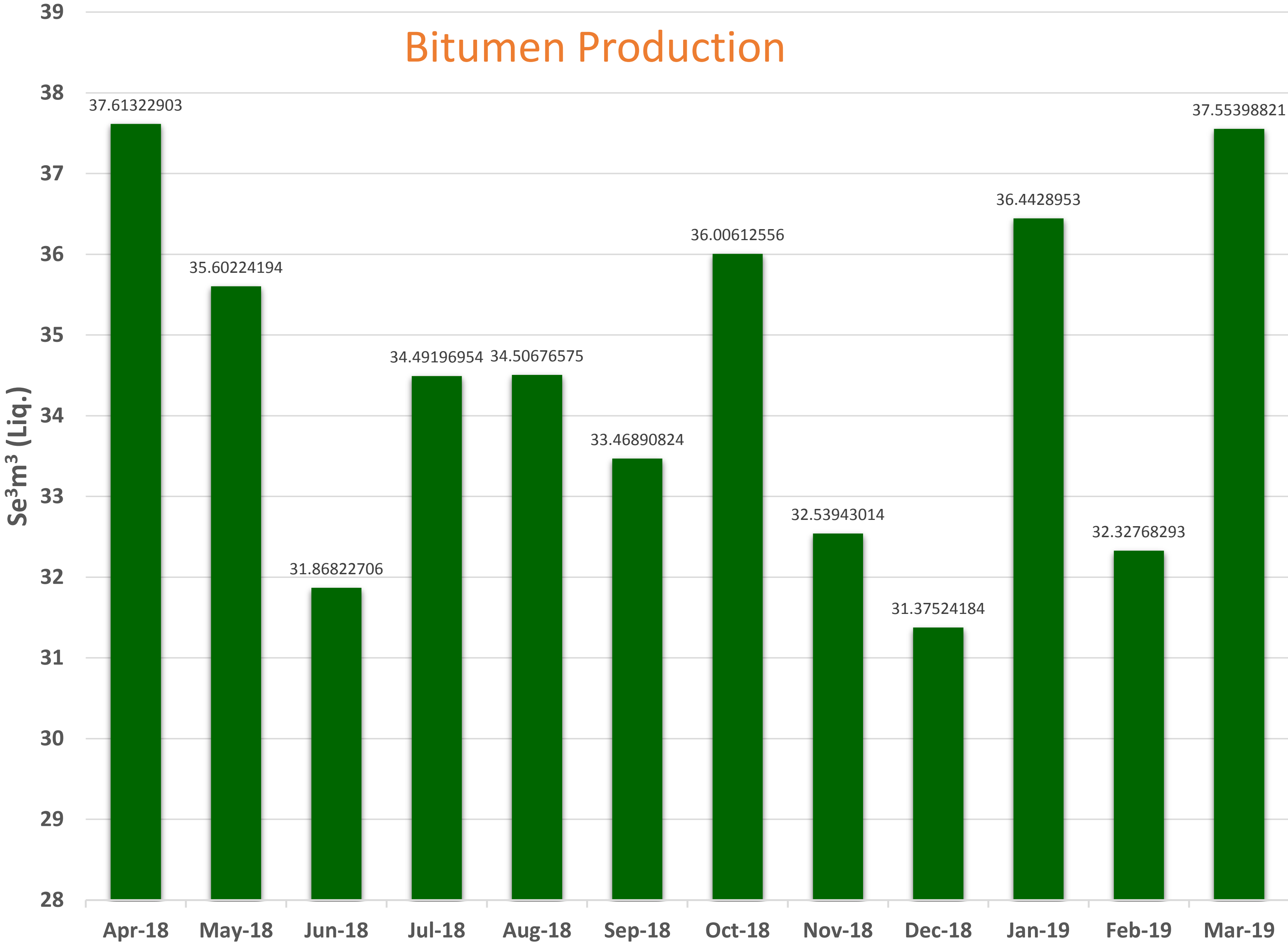
- Phase 1 has a bitumen capacity of 35,000 bpd
- The MRCP averaged 7130 bpd of bitumen during the reporting period



MRCP Central Processing Facility – Aerial View

MRCP CPF General Block Flow Diagram




Bitumen Production
Se3m3 (Liq.)
39
38
37
36
35
34
33
32
31
30
29
28
37.61322903
35.60224194
31.86822706
34.49196954
34.50676575
33.46890824
36.00612556
32.53943014
31.37524184
36.4428953
32.32768293
37.55398821
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
Nov-18
Dec-18
Jan-19
Feb-19
Mar-19

Water Treatment Technology

- High pH Vertical Tube Falling Film Mechanical Vapor Compression (MVC) Evaporators for produced water treating:
  - First Stage Evaporators x (2)
  - Second Stage Evaporator x (1)

- Forced Circulation MVC driven Concentrator for further concentrating of evaporator blowdown to Reduced Liquid Discharge (RLD)

Water Treatment Successes and Challenges

- Successes:
  - The performance of evaporators and concentrator are meeting design expectations in general

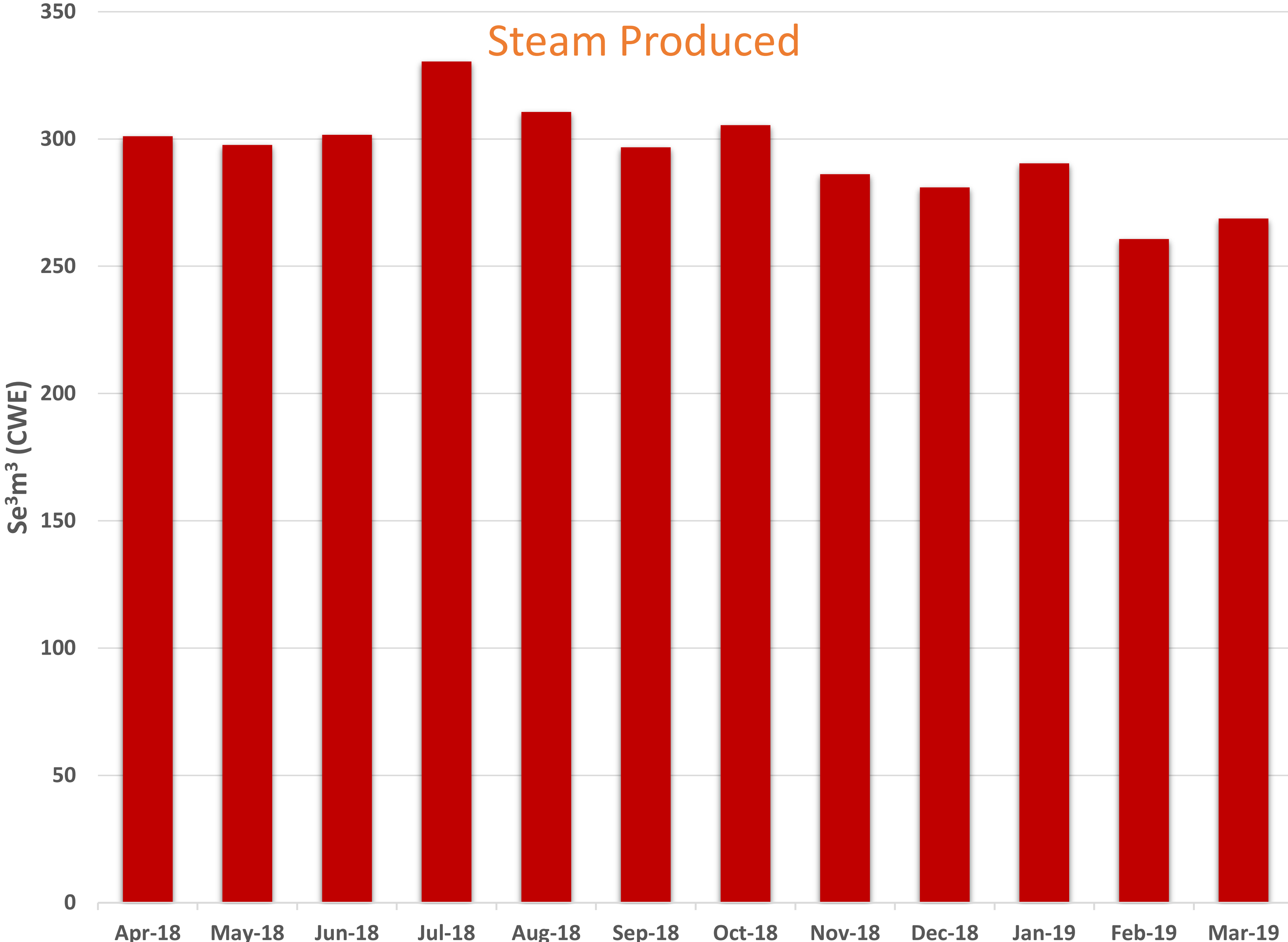
- Challenges:
  - Equipment scaling due to hard non saline water as service water, plan in place to mitigate.
  - H_2S unexpectedly concentrating in water treatment foul gas (see slide No. 87 for future plans regarding sulphur recovery).

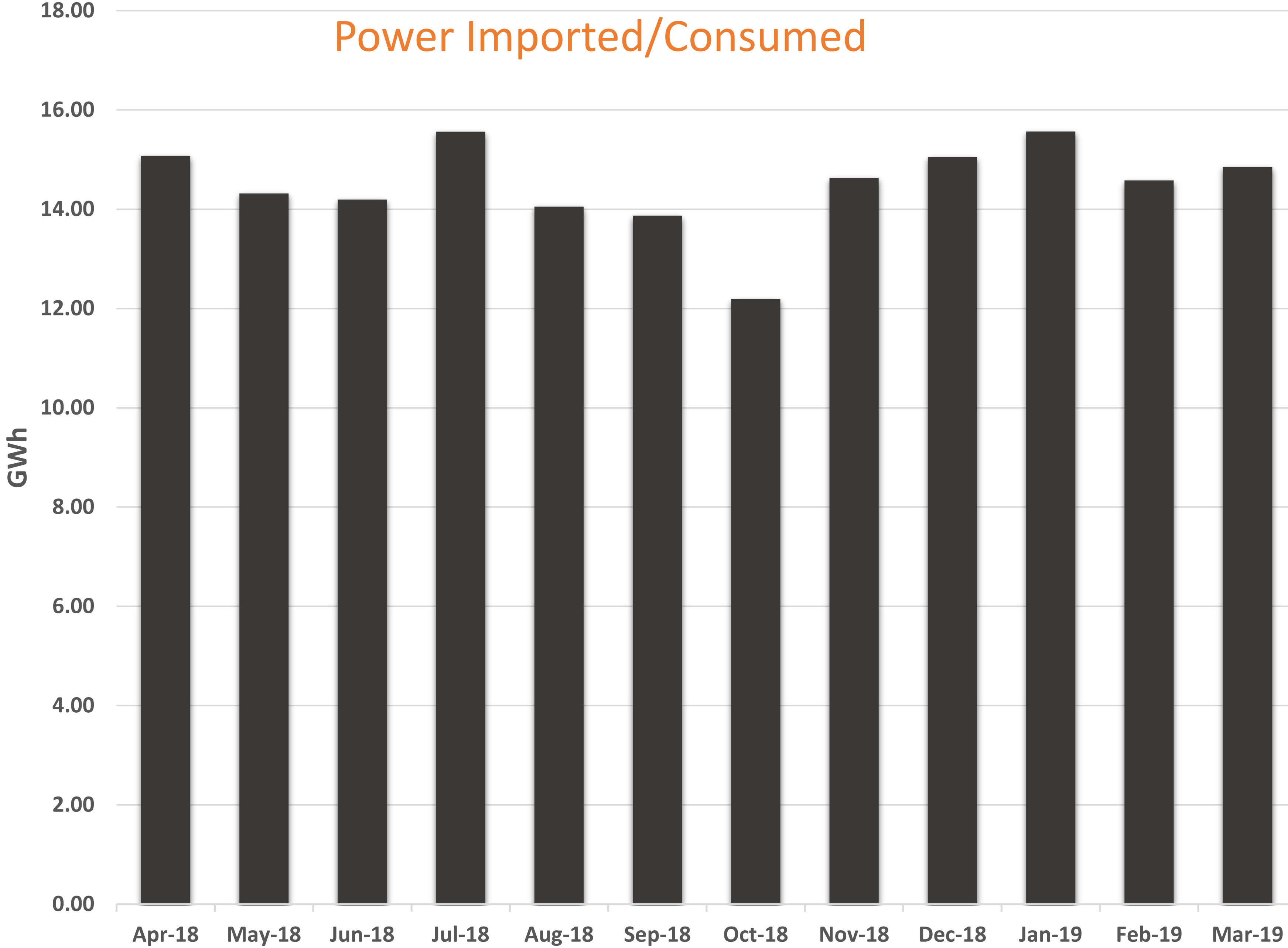
Steam Generation Technology

- Natural circulation elevated drum steam generators designed for sub-ASME feed water quality
  - (4) x steam generators
  - Low NOx combustion system

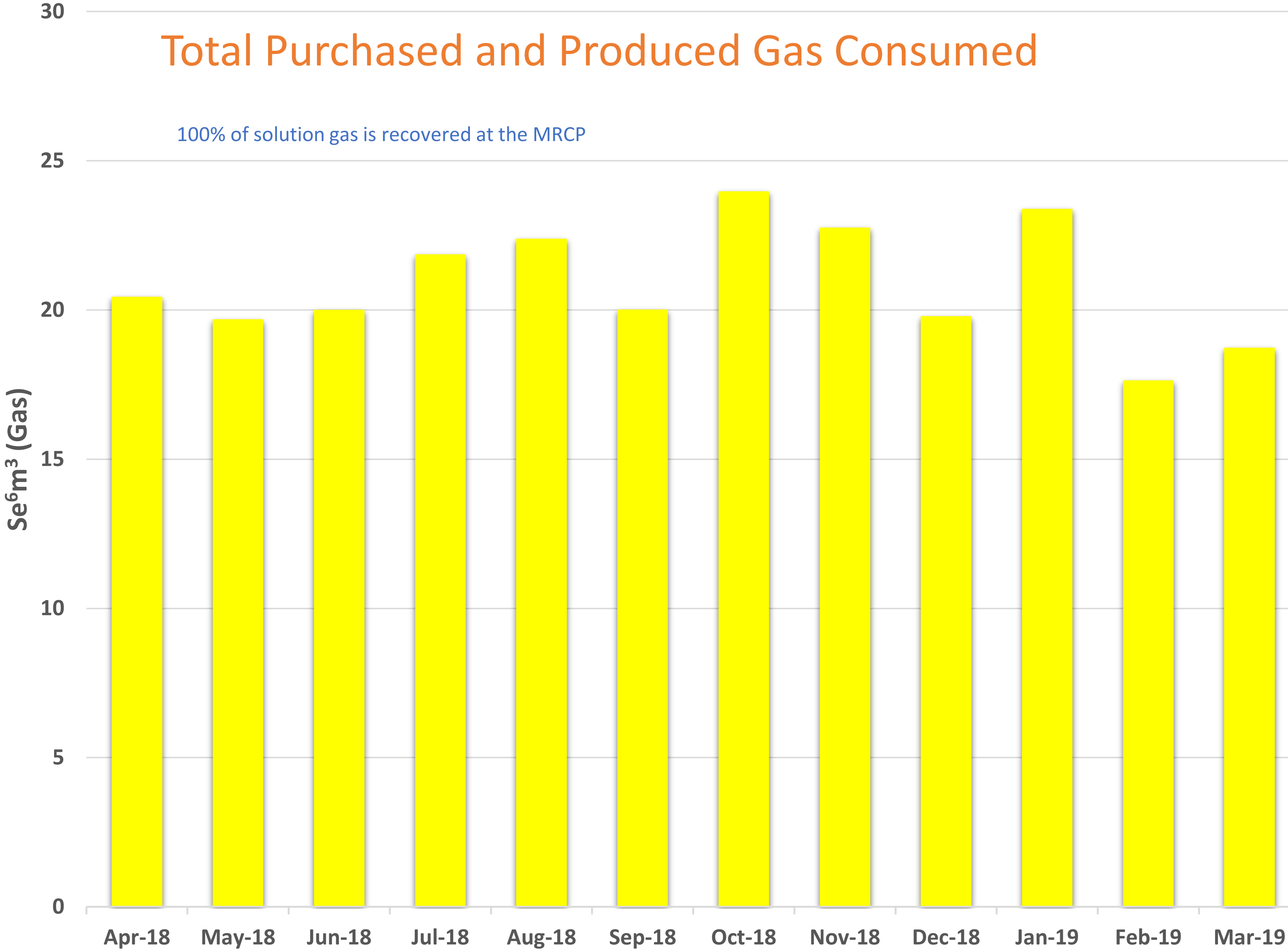
- Steam Generation Success:
  - Boilers are successfully commissioned and operating. The steam generated is meeting the field steam demands.

- Steam Generation Challenge:
  - Low produced water return rate from field forced high rate of cold source water as make-up. As a result, boiler feed water temperatures are low which condenses Sulphur compounds on the boiler economizers.


Steam Produced
Se³m³ (CWE)
350
300
250
200
150
100
50
0
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
Nov-18
Dec-18
Jan-19
Feb-19
Mar-19

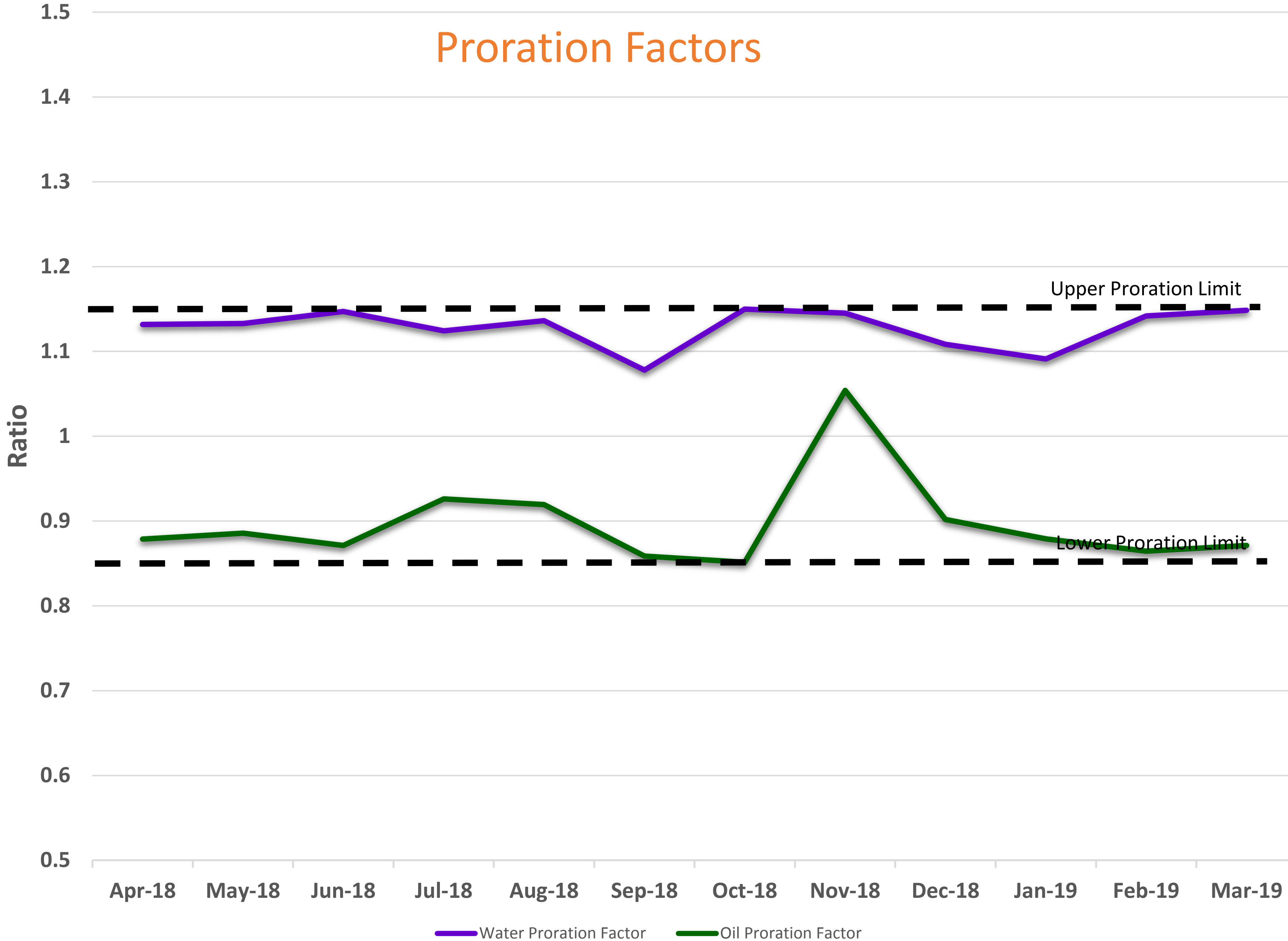

Power Imported/Consumed
GWh
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
Nov-18
Dec-18
Jan-19
Feb-19
Mar-19

Total Purchased and Produced Gas Consumed



Measurement Accounting & Reporting Plan (MARP)

- Mackay River Report Codes:
  - Production Battery AB BT 0142085
  - Injection Facility AB IF 0142086
  - Meter Station (Fuel Gas) AB MS 0136386
  - Custody Transfer Point (Diluent) AB PL 0142114
  - Custody Transfer Point (Product) AB PL 0144307


Proration Factors
Ratio
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
Upper Proration Limit
Lower Proration Limit
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
Nov-18
Dec-18
Jan-19
Feb-19
Mar-19
Water Proration Factor
Oil Proration Factor

3.1.2 SURFACE OPERATIONS, COMPLIANCE AND ISSUES NOT RELATED TO RESOURCE EVALUATION

DISCUSSION OF WATER PRODUCTION, INJECTION, AND USES
Part (4)

Non-Saline Water

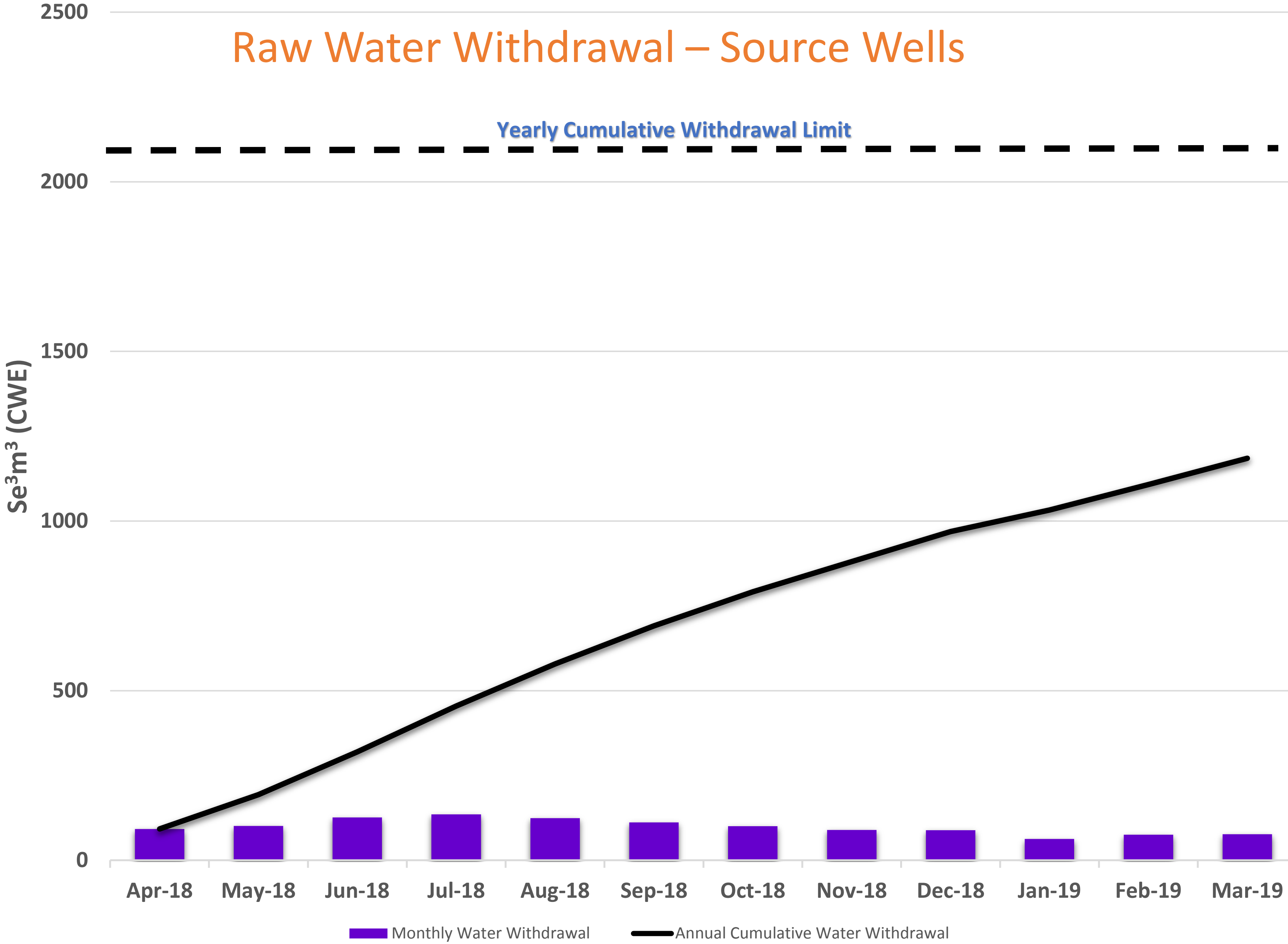
Source Water Wells

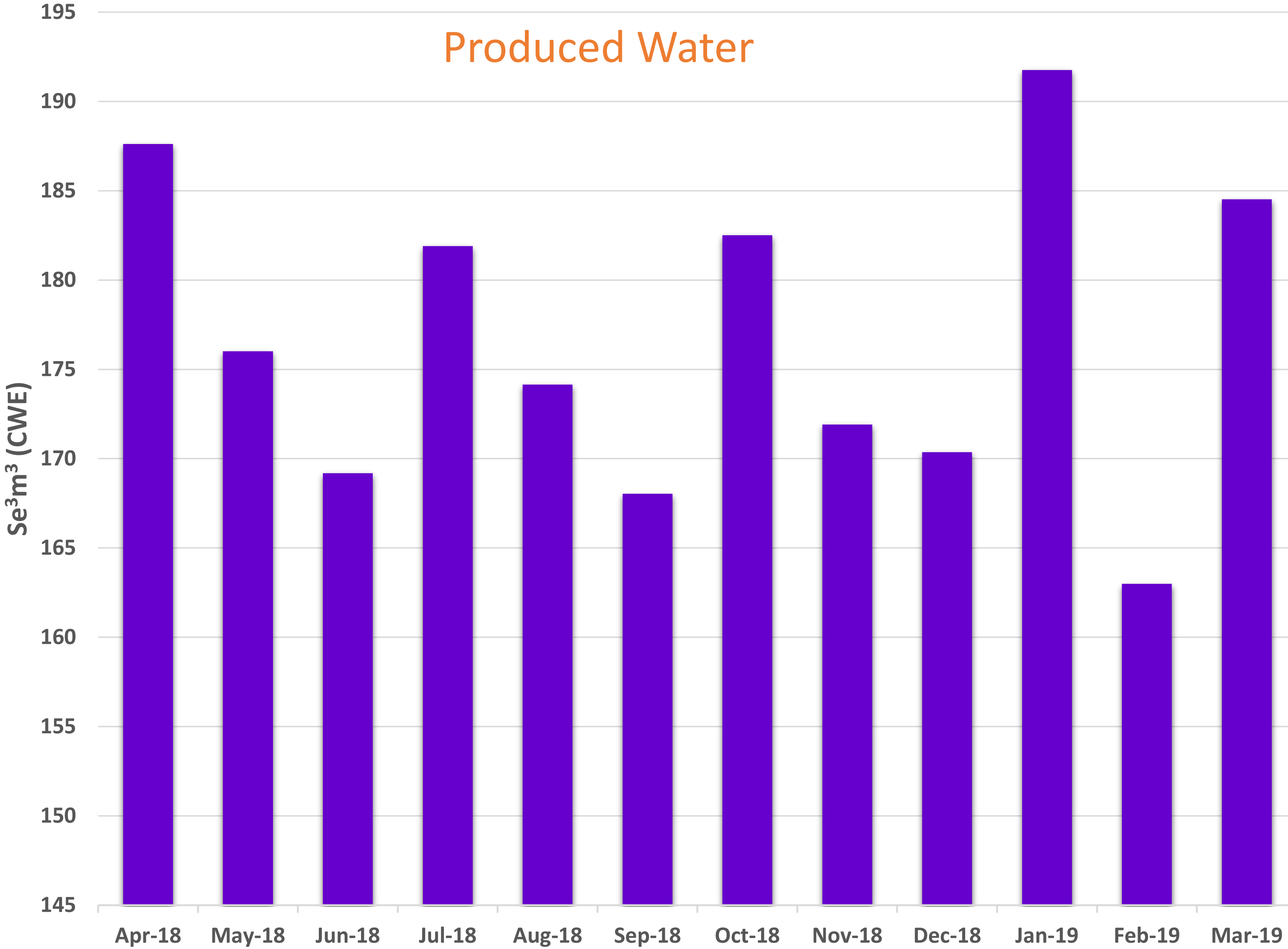
- Water Act Licence No. 00266369-01-03:
  - Approved Annual Withdrawal Volume = 2,116,964 m^3/year from the Empress Channel
    - 13-10-90-15W4, max rate 2,930 m^3/d
    - 14-11-90-15W4M, max rate 3,000 m^3/d
    - 02-13-90-15W4M, max rate 2,900 m^3/d
    - 08-13-90-15W4M, max rate 3,100 m^3/d

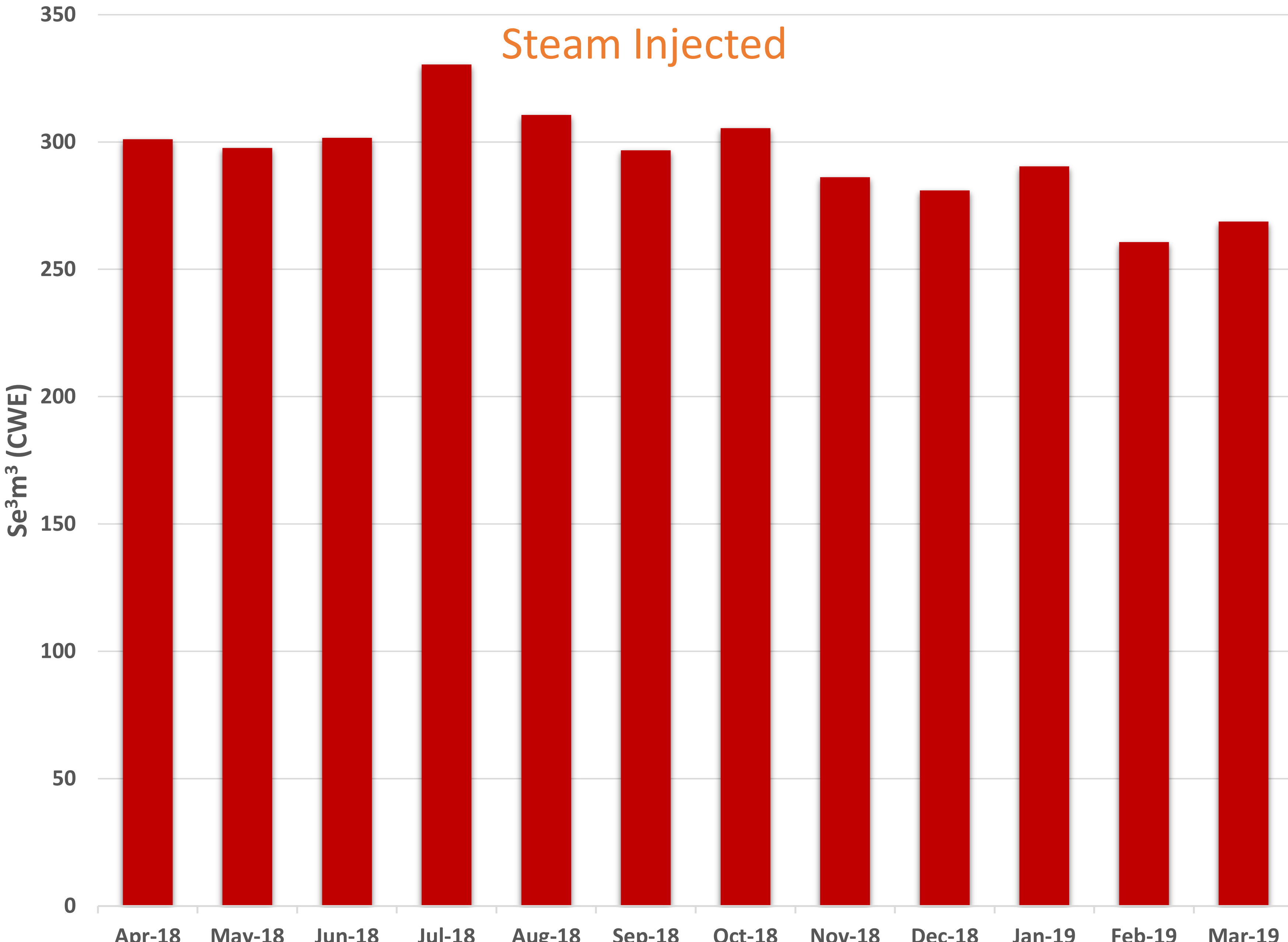
Domestic Water Wells

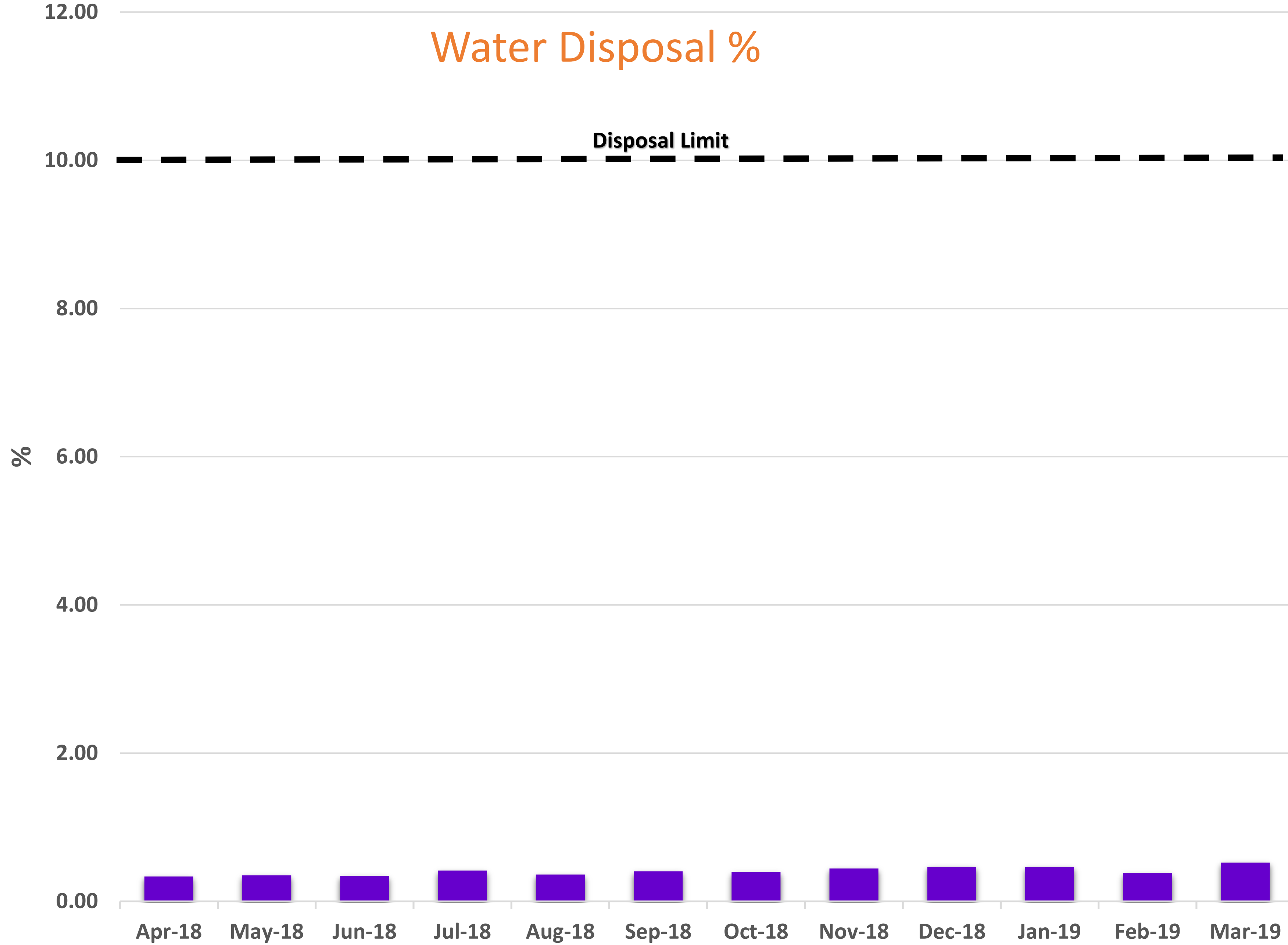
- Water Act Licence No. 00316276-00-00:
  - Approved Annual Withdrawal Volume = 82,125 m^3/yr from the Grand Rapids 4
    - 16-02-90-14W4M North, max rate 400 m^3/d
    - 16-02-90-14W4M South, max rate 360 m^3/d

Raw Water Withdrawal – Source Wells




Produced Water
Se³m³ (CWE)
195
190
185
180
175
170
165
160
155
150
145
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
Nov-18
Dec-18
Jan-19
Feb-19
Mar-19


Steam Injected
Se³m³ (CWE)
350
300
250
200
150
100
50
0
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
Nov-18
Dec-18
Jan-19
Feb-19
Mar-19


Water Disposal %
Disposal Limit
%
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
Nov-18
Dec-18
Jan-19
Feb-19
Mar-19

Blowdown, Waste and Disposal Wells

Blowdown Recycle

- Continuous blowdown from boilers is injected into the HP steam line.
- Intermittent blowdown from boilers is recycled to Water Treatment.

Waste and Disposal Wells

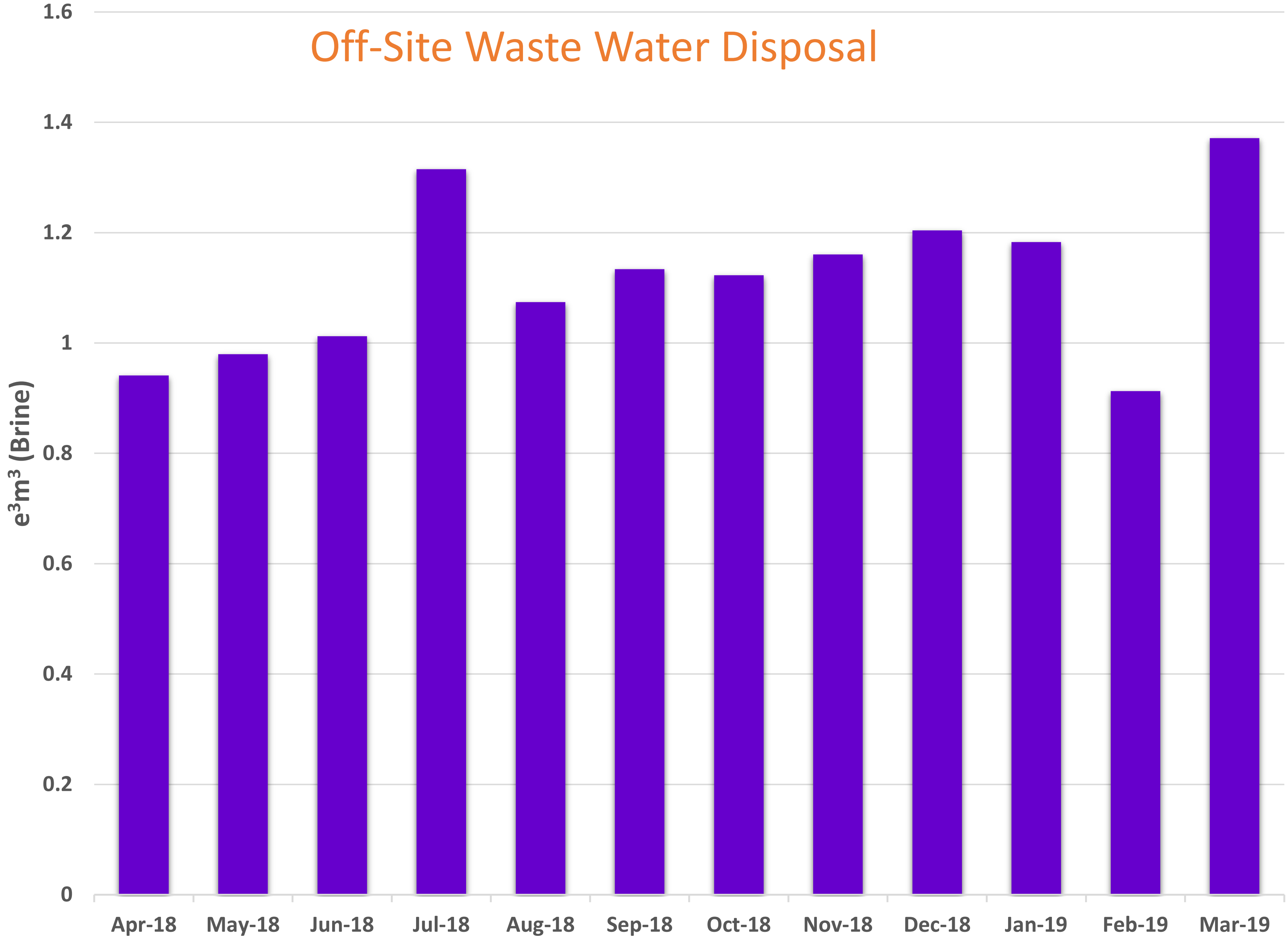
- Waste Tracker software and AER manifests are used to track and submit data to AER.
- No disposal wells are associated with MRCP Phase 1.

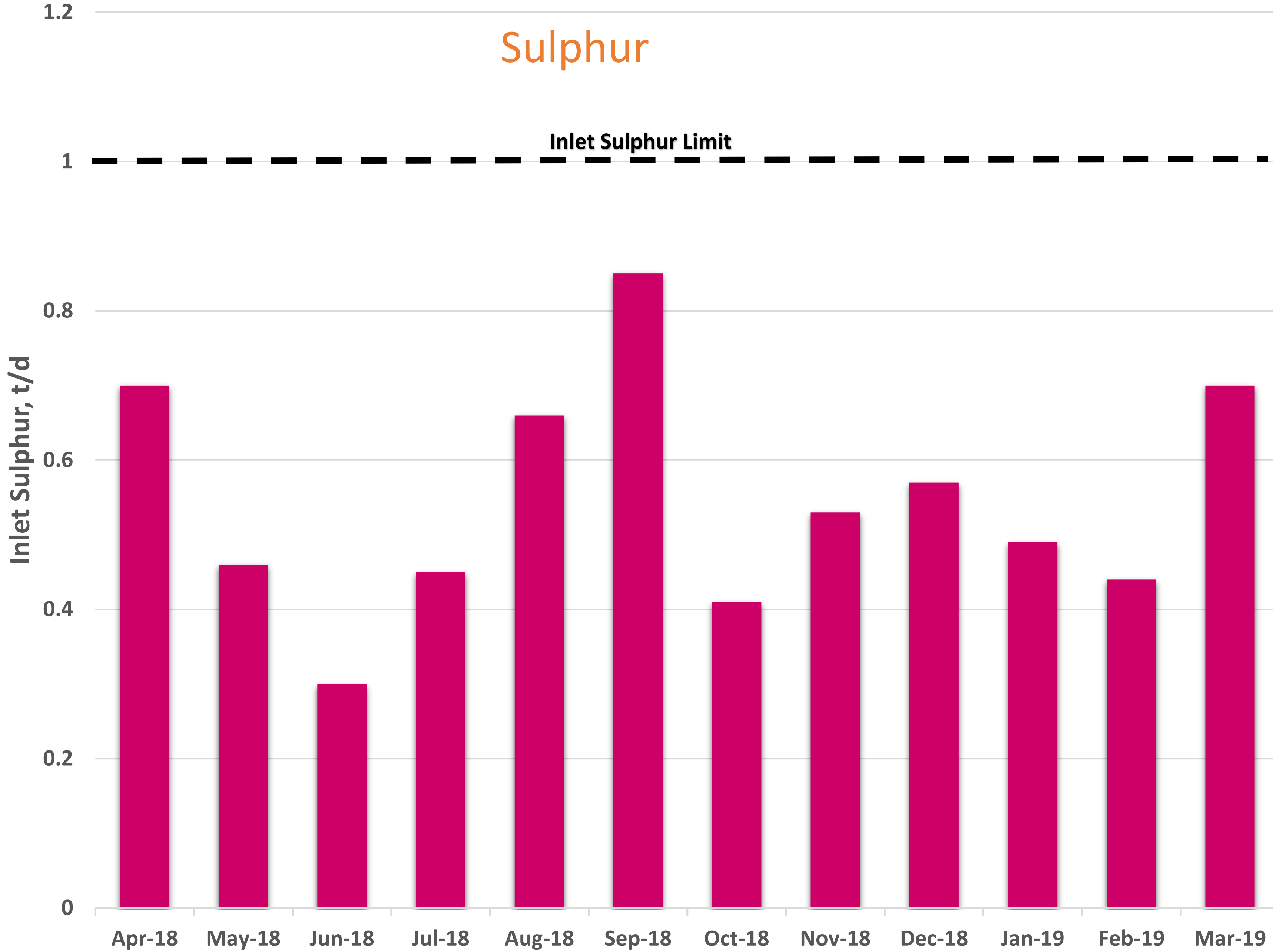
Off-Site Waste Water Disposal

- Concentrated brine reject, emulsified slop oil, and desand slurry water streams are disposed of off-site.

- Location of disposal sites:
  - Tervita Lindbergh – AB WP 0000557 (For evaporator/concentrator brine water)
  - Tervita Fort McMurray - AB WP 0133414 (For emulsified slop oil water and de-sand slurry water)
  - Secure Energy Tulliby Lake– AB IF 0139713 (For emulsified slop oil water and de-sand slurry water)

- Sources of disposal water:
  - Evaporator Waste Water Tanks
  - Concentrator Feed/Waste Tanks
  - Slop Oil and Desand/Decant Tanks


Off-Site Waste Water Disposal
e3m3 (Brine)
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
Nov-18
Dec-18
Jan-19
Feb-19
Mar-19


Sulphur
Inlet Sulphur Limit
Inlet Sulphur, t/d
1.2
1
0.8
0.6
0.4
0.2
0
Apr-18
May-18
Jun-18
Jul-18
Aug-18
Sep-18
Oct-18
Nov-18
Dec-18
Jan-19
Feb-19
Mar-19

Future Plans – Sulphur Recovery

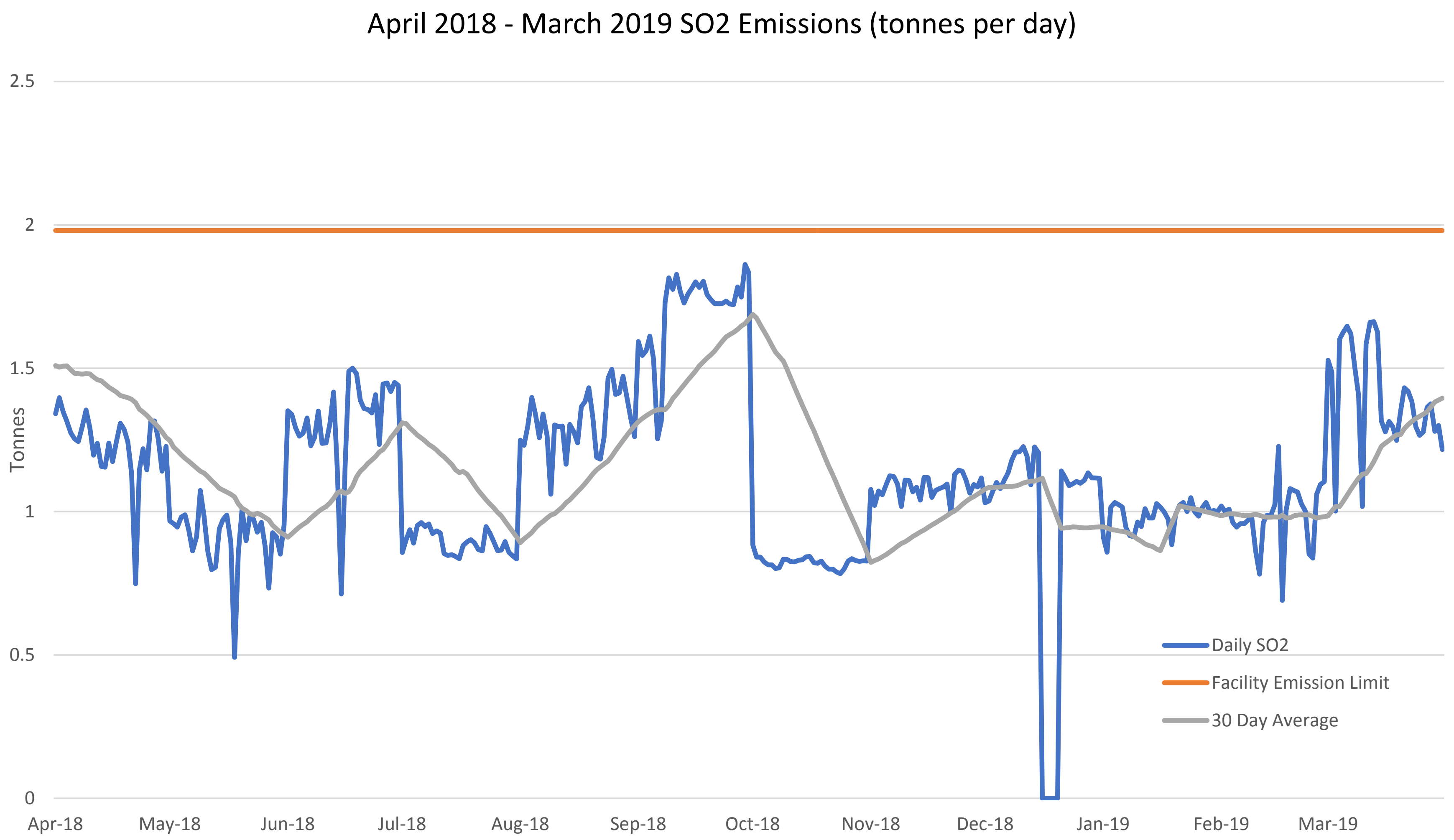
- PCC's initial sulphur recovery design will focus on sequestration of the sulphur within the caustic waste brine destined for disposal. Since the majority of the hydrogen sulphide is concentrating preferentially in the foul vent system of the water treatment plant, this highly concentrated/low flow stream can easily be sequestered by means of injecting additional caustic into the produced water (upstream of de-aeration) whereby the acidic sulphur species can be quickly sequestered in bisulphide format.

Summary of actual calendar quarter-year sulphur emissions

Overview of peak and average sulphur emissions

	Sulphur Emissions (tonnes)	Peak Daily Sulphur Emission (tonnes)	Average Daily Sulphur Emissions (tonnes)
2018 Q2	52.44	0.75	0.58
2018 Q3	59.7	0.93	0.65
2018 Q4	43.74	0.61	0.48
2019 Q1	50.72	0.83	0.56

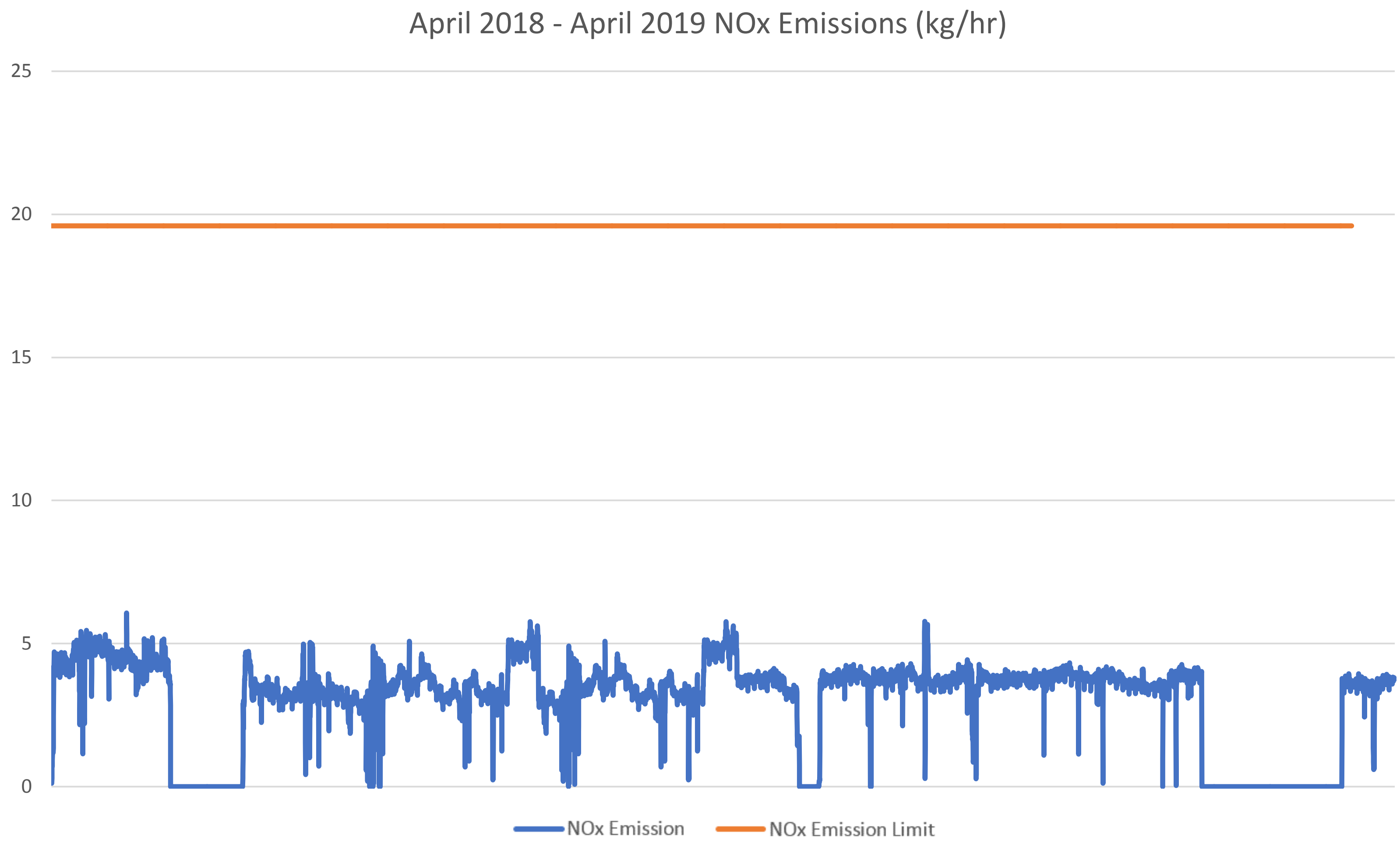
Comparison of actual peak daily and rolling average sulphur dioxide (SO_2) emissions with conditions of Alberta EPEA approvals



Sulphur / SO2 emission compared to limits

Month	Total Daily Average (Sulphur t)	Calendar Quarter Average (Sulphur t) Limit 1 tonne	Combined Sources Daily Maximum (SO2) Limit 1.98 tonne
April	0.617	0.587	1.233
May	0.455		0.910
June	0.661		1.322
July	0.446	0.651	0.892
August	0.657		1.313
September	0.851		1.702
October	0.412	0.476	0.823
November	0.543		1.087
December	0.473		0.947
January	0.492	0.561	0.985
February	0.492		0.983
March	0.700		1.399

NOx Emission Rate – Continuous Emission Monitoring System



Regulatory Compliance

Notification Date	Non-Compliance	Description	Resolution
25-Jul-18	Noncompliance with clause 16e of scheme approval 11715J	SSP duration of injection above limit	Incorporate learnings into potential future tests
4-Sep-18	Directive 017 s. 12.3.9: Well production Measurement	In July 2018, no valid well tests were completed for production well AE06. The reason was that the flow was too low and therefore directed to the multiphase pump package (MPP) to increase pressure differential in order to lift more fluid	An alternative measurement method allowed collection of necessary data in July. For production measurement, AE-FIT-0650 flow was used. Bottom Sediment and Water was assumed from last sample June 18, 2018
19-Oct-18	Wells have been operating since approximately December 2016 under a "suspended" well status	Wells were suspended due to delayed construction schedule however we never activated once operation started	All wells have been re-activated
8-Jan-19	Noncompliance with clause 16e of scheme approval 11715J	Despite the DCS showing the valves as closed, some of the valves were passing. This resulted approximately 1.0 m3/ hr of steam being injected during the pressure falloff portion of the test, when there should have been no injection.	The steam control valve had an actuator that was out of spec and may not have had the ability to fully close. The actuator was replaced at the end of January, 2019
12-Dec-2018	EPEA	Voluntary Self-Disclosure - Equipment Failure Installation leak resulting in steam release	Repair plan put in place
14-Dec-2018	EPEA	Release Report - Equipment Failure – Valve leak resulting in steam condensate release	Condensate was vacuumed up. Procedures modified to incorporate inspections prior to returning wellheads to service
21-Dec-2018	Water Act	Voluntary Self-Disclosure (x2) Missed WURS data submission deadlines	Closed gaps in reporting process
22-Jan-2019	EPEA	Voluntary Self-Disclosure – Diesel spill at well pad AI	Site cleaned up with vacuum truck
27-Feb-2019	EPEA	Steam release at well AJ05I	Implementation of a check program at all shut in wells to assure winterization has occurred

AER release reporting requirements were followed for all EPEA non-compliances

Industrial Wastewater and Industrial Runoff Management and Disposal

- Between April 1 2018 and March 31 2019:
  - A total of 17,240 m^3 of wastewater and waste emulsion was trucked off-site for disposal;
  - 397,368 m^3 of industrial runoff was released from the storm water pond of the Industrial Runoff Control System;
  - 45,735 m^3 of industrial runoff was released from the eight SAGD well pads

- Summary of Non-Compliances:
  - In 2018, pre-release testing and volume measurement was not obtained for six storm water pond release dates and eight well pad release dates. Discharge analysis was not obtained for one storm water pond discharge and two well pad discharges.
  - In 2019 volume measurements and discharge testing was not obtained for nine well pad release dates. All releases had pre-release analysis conducted.

- **Contravention report was submitted for all non-compliances related to industrial runoff**

EPEA and Water Act Amendments

- There have been no amendments to EPEA approval No. 254465-00-02 since the last performance presentation.
- Water Act approval No. 00266369-01-04 was amended to reflect the corporate name change from Brion Energy Corporation to PetroChina Canada Ltd. It is now approval No. 00266369-01-05.

Compliance Statement

To the best of our knowledge, PCC's MRCP is compliant with all conditions of its approvals and associated regulations with the exception of items disclosed in previous slides.

EPEA Monitoring Programs

Monitoring Programs Required under EPEA Approval	
Program	**Progress and Results**
Groundwater Monitoring	• Groundwater monitoring was conducted in June and October 2018 at the MCP and Pad AJ, and in October at Pad AH. • Groundwater quality in the shallow glacial till and Grand Rapids 4 and 5 aquifers were relatively stable in 2018 and consistent with historical conditions • Thermal effects are being monitored and will be compared to the Thermal Directive
Wetland Monitoring	• The comprehensive wetland monitoring report was submitted to the AER on September 27, 2018 • Based on data collected from focal plots, there were no definitive impacts from the MRCP activities on surrounding wetlands identified in the five years of monitoring data.
Annual Conservation and Reclamation Report	• Schedule II, Condition 7, and Schedule IX, Conditions 52 and 53 of the EPEA Approval require PCC to prepare an Annual Conservation and Reclamation Report (Annual C&R Report) for submission to the Alberta Energy Regulator. • The approved Wetland Reclamation Trial Program prepared by Acden Navus Limited Partnership (2014a) contained two trials: Small-Scale Trial #1: Alternative Storage Technique of Peat Material and Peatland Reclamation of a Borrow Area and Small-Scale Trial #2: Effects of Padding over Reclamation Material (hereafter referred to as “Trial #2”). • Trial #2 involved collection of samples from the unsalvaged soil beneath the pad, stockpiled soil and undisturbed soil and comparing properties of these soils at 2, 3, 5, 10 and 20 years post construction of Pad AH. Samples have been collected for years 2 (2015), 3 (2016) and 5 (2018). • After five years, placement of fill material (padded) over unsalvaged organic and transitional soils has not resulted in a greater loss of soil quality in comparison to salvaging and stockpiling soil. • Reclamation Monitoring Program currently being implemented on reclaimed portions of Borrow Areas 12, 38, and 118. Monitoring will continue until the AER issues the requisite reclamation certificates
2019 Operational Soil Monitoring Program Proposal	• The Operational Soil Monitoring Program will be implemented following authorization in writing by the Director per Schedule VII(4) of the EPEA Approval with the Soil Monitoring Program report submitted on or before January 31, 2020, contingent upon receiving approval prior to winter 2019 (frozen conditions). • The Program Proposal was approved by the AER on March 26, 2019.
Wildlife and Woodland Caribou Monitoring	• The comprehensive wildlife report was submitted to the AER on May 30, 2018 • A large component of the mitigation monitoring plan was the implementation and monitoring of caribou habitat restoration treatments and access management trials. Preliminarily results indicate some success of restoration trials, particularly in supporting the establishment and growth of planted black spruce, and naturally established tamarack seedlings. • For the most part, monitoring results were similar to those observed during baseline surveys, and in some cases winter track count densities recorded during monitoring surveys were higher than those recorded during baseline. Monitoring results appear to be in line with impact predictions from the EIA.
Annual Air Emission Summary and Evaluation Report-	• No issues with operations or pollution control equipment where identified in 2018. • In 2018 there were no expansions or modifications to the operations at the Mackay River Commercial Project that would affect atmospheric emissions from this facility. • In 2018 there were no changes to monitoring methods.
Annual Industrial Wastewater and Industrial Runoff Report-	• A total of 17,408.10 m3 of wastewater was removed from site • 359,928 m3 of industrial runoff was released from the Storm Water Pond of the MCP Industrial Runoff Control System • 29,251 m3 of industrial runoff was released from the eight SAGD well pads

Summary of ambient air quality monitoring results required under EPEA approvals

2018 Q2 1-hour Averages				
	H_2S (ppb)	NO_2 (ppb)	SO_2 (ppb)	THC (ppm)
Maximum	5	22.6	18	2.7
Average	0.13	1.45	0.54	2.2
AAAQO Limit	10	159	172	N/A

2018 Q3 1-hour Averages				
	H_2S (ppb)	NO_2 (ppb)	SO_2 (ppb)	THC (ppm)
Maximum	21	25.5	16	2.8
Average	0.06	1.22	0.46	2.17
AAAQO Limit	10	159	172	N/A

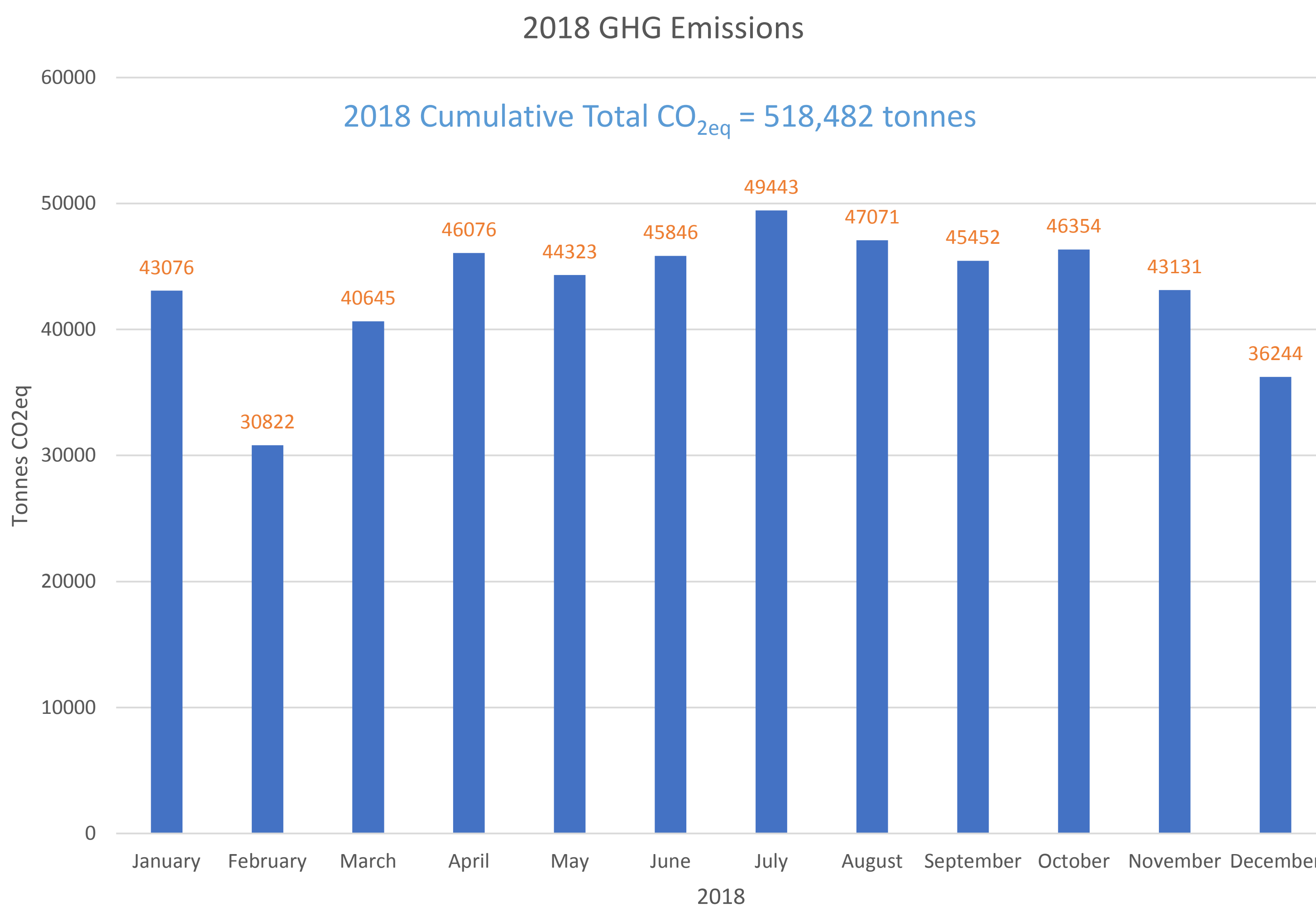
2018 Q4 1-hour Averages				
	H_2S (ppb)	NO_2 (ppb)	SO_2 (ppb)	THC (ppm)
Maximum	2	82.1	34	3.5
Average	0.05	3.99	0.60	2.25
AAAQO Limit	10	159	172	N/A

2019 Q1 1-hour Averages				
	H_2S (ppb)	NO_2 (ppb)	SO_2 (ppb)	THC (ppm)
Maximum	2	72.7	25	3.3
Average	0.06	4.89	0.87	2.28
AAAQO Limit	10	159	172	N/A

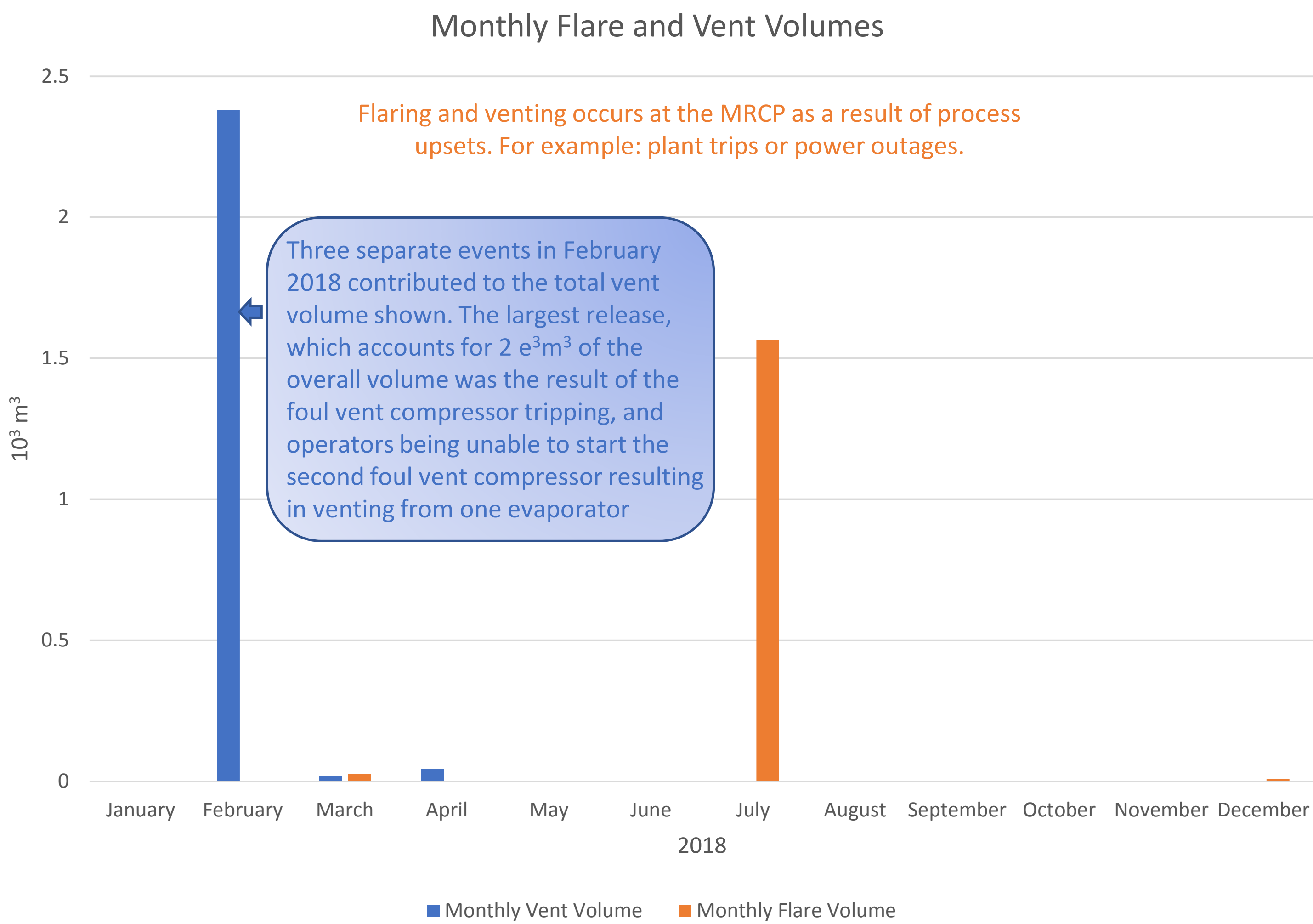
Progress and results of reclamation programs

- Reclamation continues at Borrow Pits 12, 38 and 118.
- Borrow Pit is 118 nearly reclaimed and PPC could potentially apply for a reclamation certificate fall 2019.
- PCC is evaluating future reclamation candidates.

Greenhouse Gas Emissions



Flaring and Venting at the MRCP



Regional Monitoring and Initiatives

PCC continues to participate in and/or fund the following initiatives:

- Oil Sands Environmental Monitoring Program (OSEMP)
- Canada's Oil Sands innovation Alliance (COSIA) Monitoring Working Group
- Wood Buffalo Environmental Association (WBEA)
- Alberta Biodiversity Monitoring Institute (ABMI)
- Black Bear Partnership Project
- Alberta Upstream Petroleum Research Fund (AUPRF)

Future Plans – Surface Facilities and Regulatory Applications

- No additional EPEA or Water Act Licence amendments are proposed for the remainder of 2019
- Currently focused on optimization and efficiency gains to support further production growth. No major changes to surface facilities are proposed at this time.
  - Routine maintenance may require temporary shutdowns of equipment.
- Infill Well Project:
  - Drilling 4 well pairs on Pad AA – steam to start Q4 2019
  - Next 13 well pairs are under internal review – design may depends on results of the AA wells
- Sustaining Well Pairs
  - Continue the internal project development process for the first group of sustaining well pairs
  - Potentially submit an application in early 2020

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