PetroChina Canada

2021 Performance Presentation

MacKay River Commercial Project

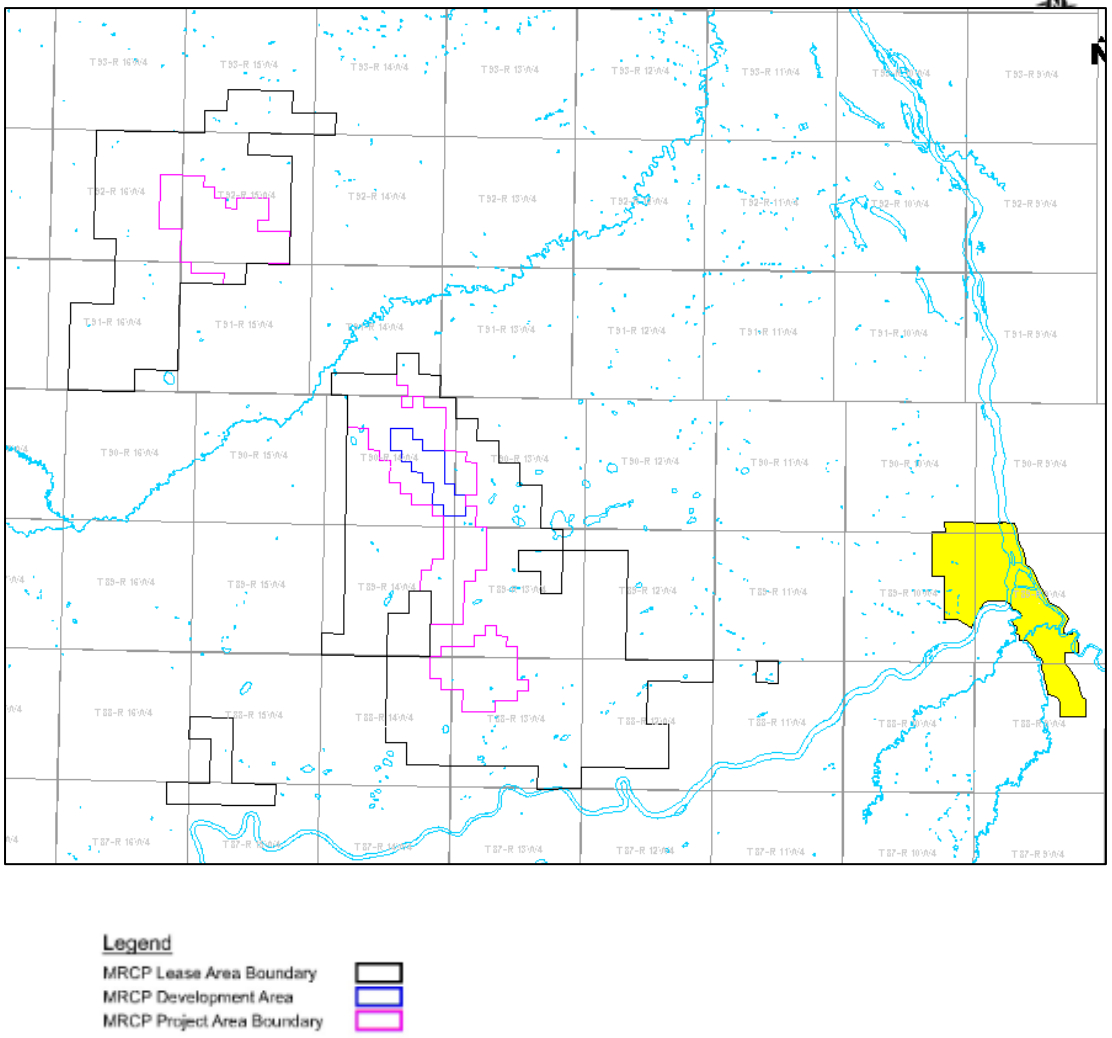
AER Scheme Approval No. 11715

January to December 2021

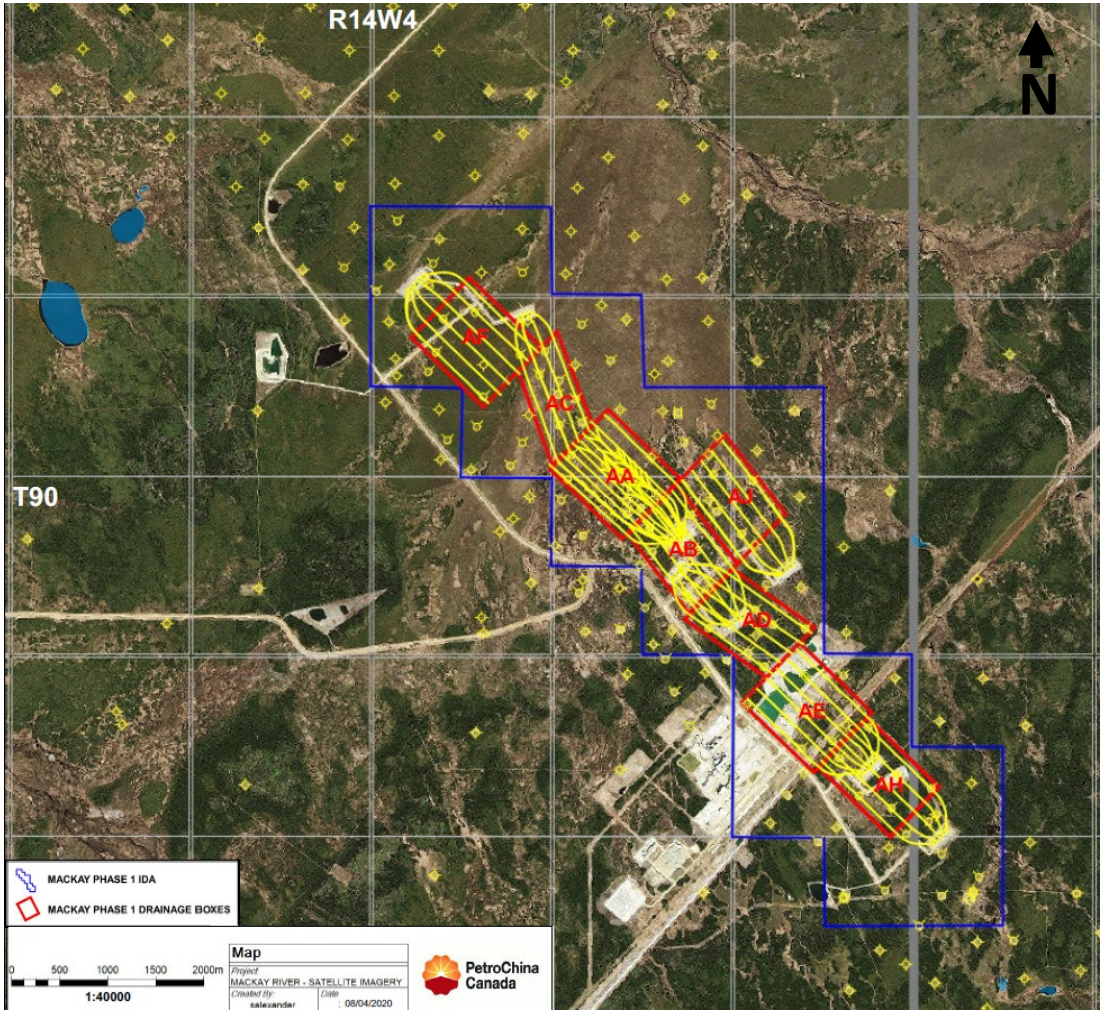
4.1 Introduction

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, with a Phase 1 capacity of 35,000 bbl/d of bitumen



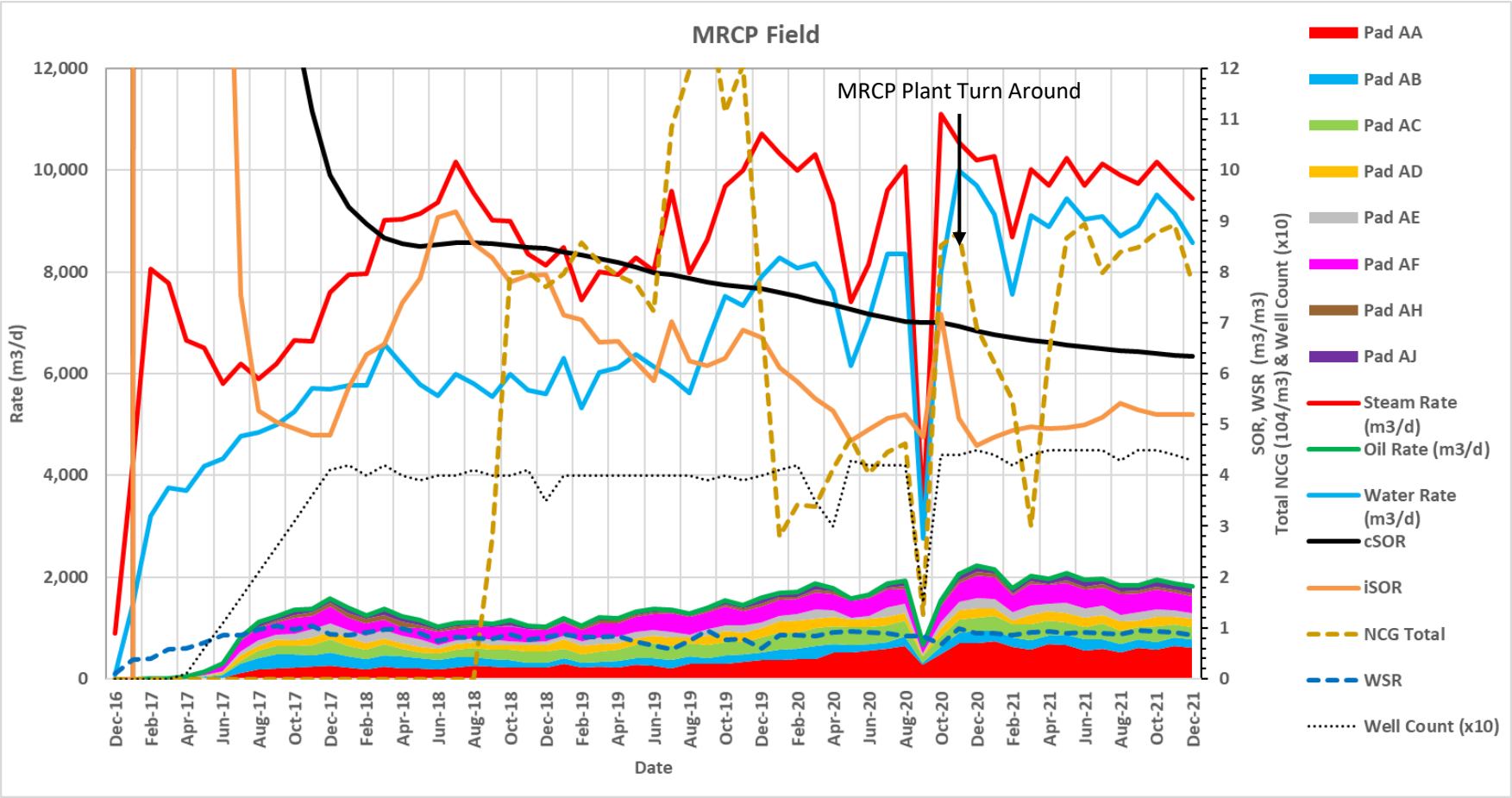
MRCP Phase 1 Overview



- 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
    - 850 m long horizontals
    - 125 m well spacing
  - 4 Horizontal infill well pairs (PAD AA)
    - 850 m long horizontals
    - Producer and/or injector uptracks
    - 62.5 m well spacing
  - The Central Processing Facility (“CPF”)
  - Water source wells and associated pipelines
  - Observation wells
  - Borrow areas
  - Access roads
  - Camps

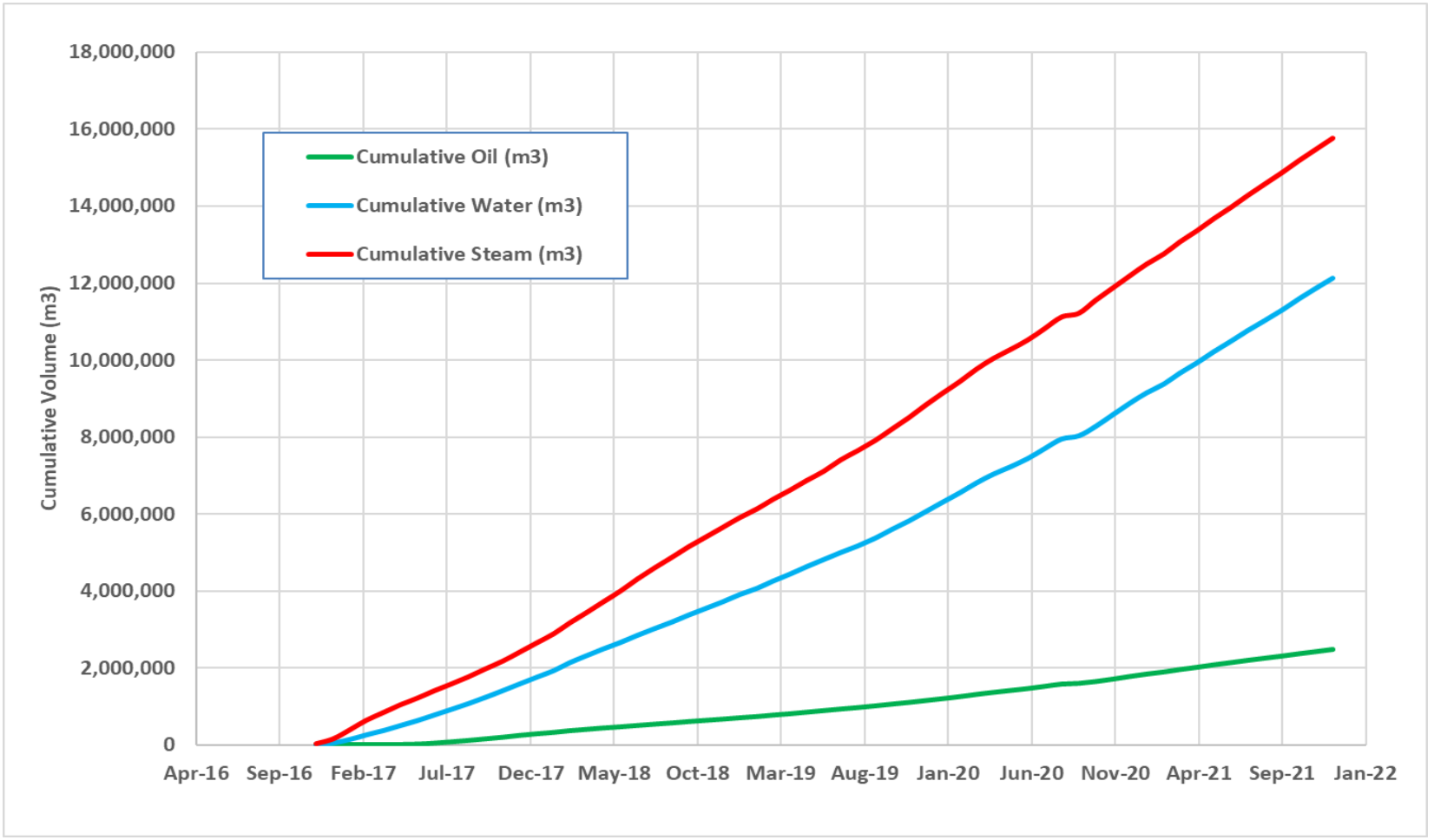
4.2 SUBSURFACE

MRCP – Field Performance



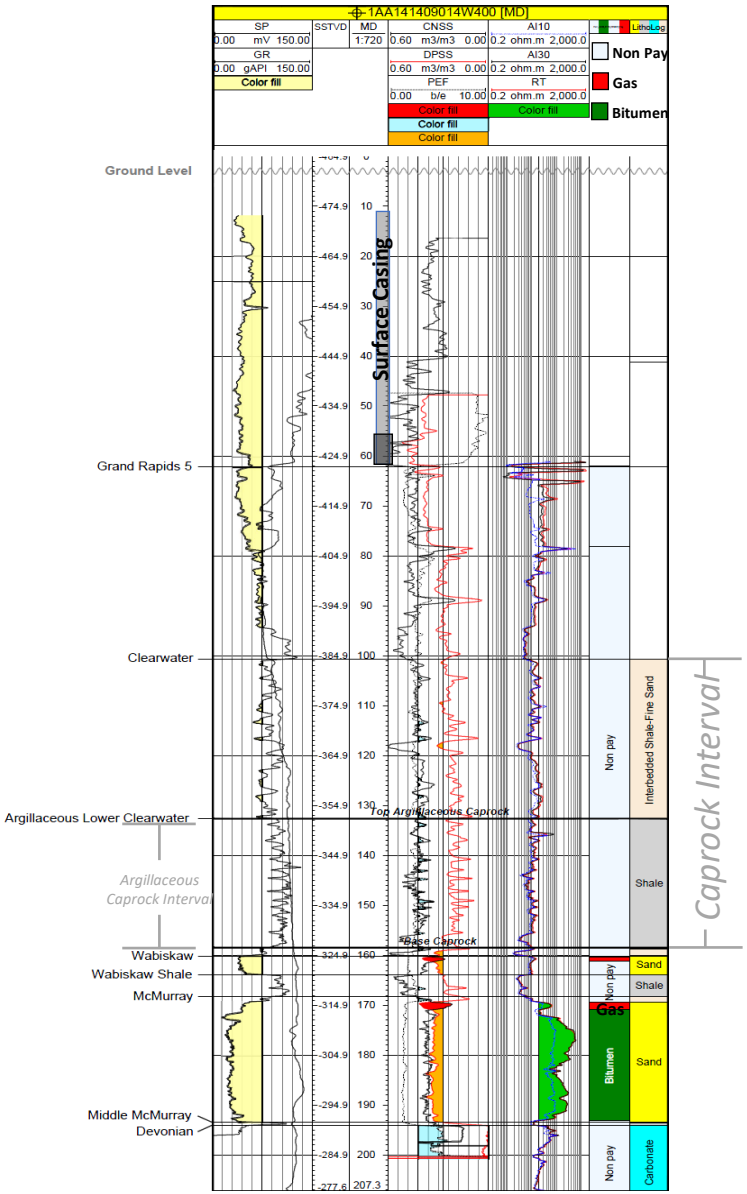
- Throughout 2021, MRCP achieved steady production, reaching a production average of 12,190 bbl/d. The 2021 monthly exit oil rate was 1,819 cubic metres per day (m3/d; 11,440 bbl/d). Steam to Oil Ratio (SOR) was stable and averaged 5.07 throughout the year
- PCC Continued field operation optimizations: Planning of infill wells; One Turbine Inflow Control Device (TICD) and Electric Submersible Pump (ESP) conversion in 2021 (AE02); and Drilling began on producer sidetrack wells at on AC04 and AF05.
- Non-Condensible Gas (NCG) co-injection in selected well pairs continued in 2021. PCC also maintained NCG injection in one vertical injection well.

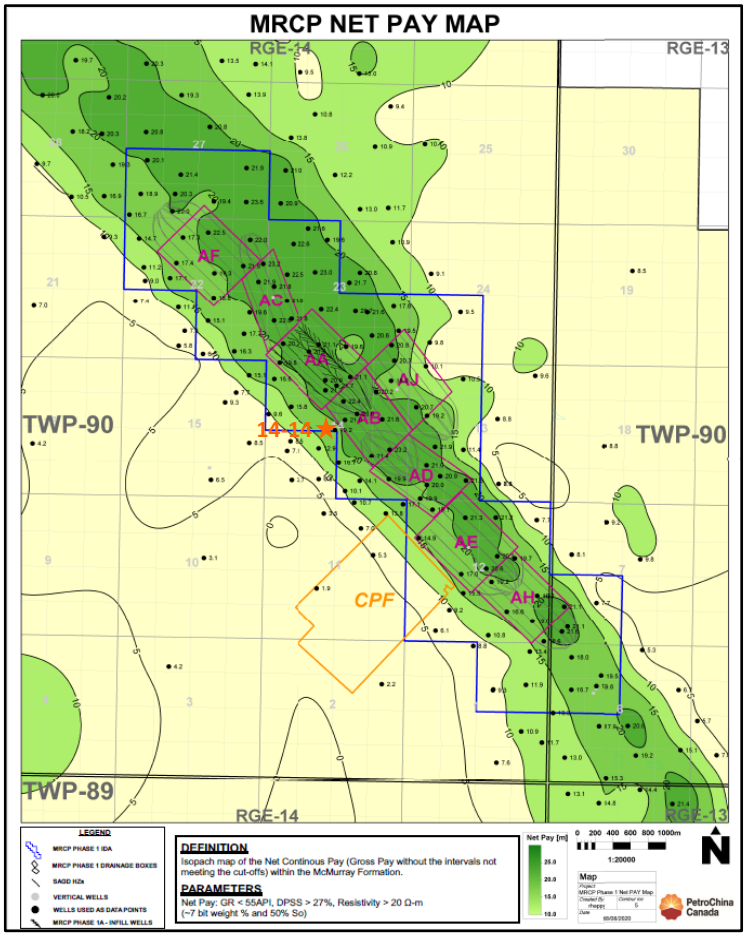
MRCP – Cumulative Fluid Volumes



- Performance is impacted by the presence of top gas/top lean zones, areas of thicker lower transition zone, and the presence of geological baffles (zones of higher mud bed frequency) affecting chamber growth
  - In certain areas, steam chamber interactions with top gas and losses to the lower transition zone has resulted in higher water retention by the reservoir
  - Mitigation strategies implemented includes, gas cap pressurization (NCG injection and co-injection), and balancing operating pressures with multiple thief zones. These strategies have significantly helped reduce water retention and steam losses

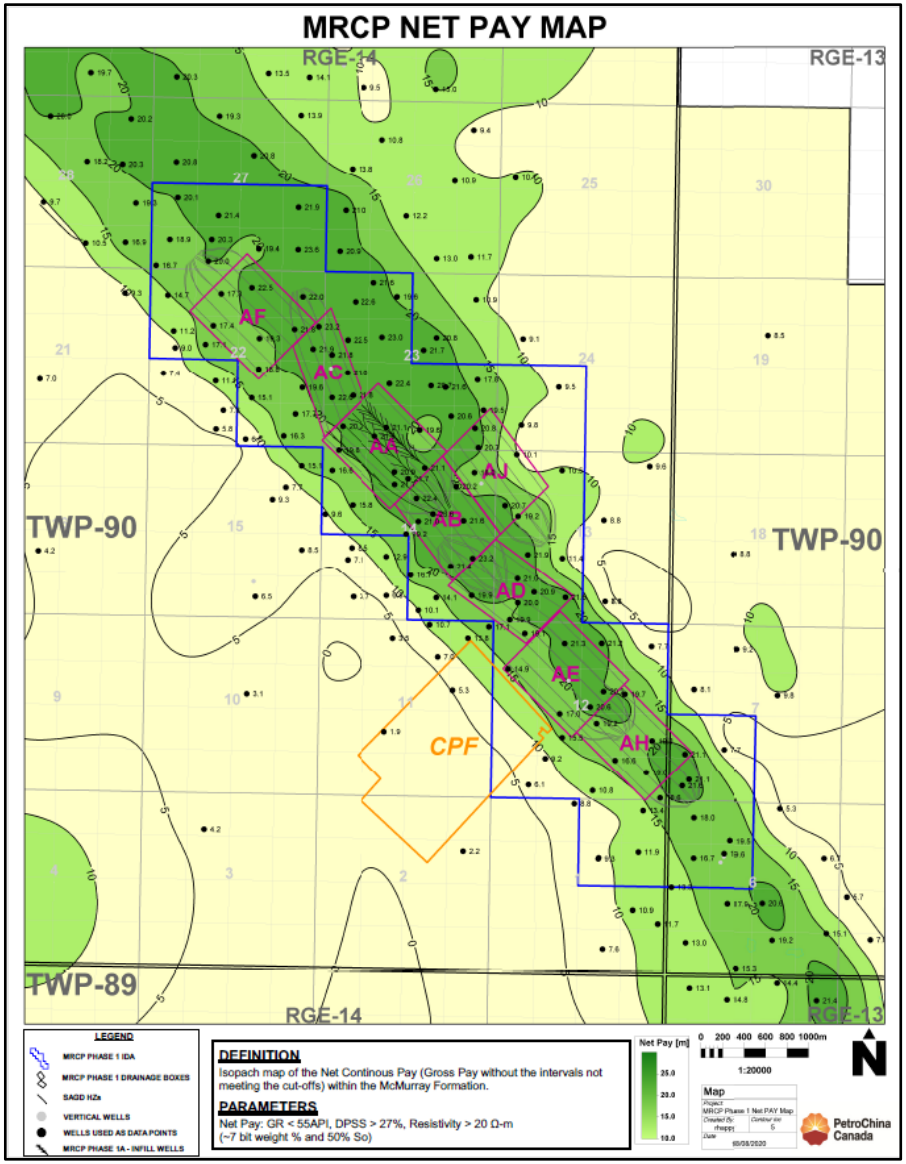
MacKay River Stratigraphy





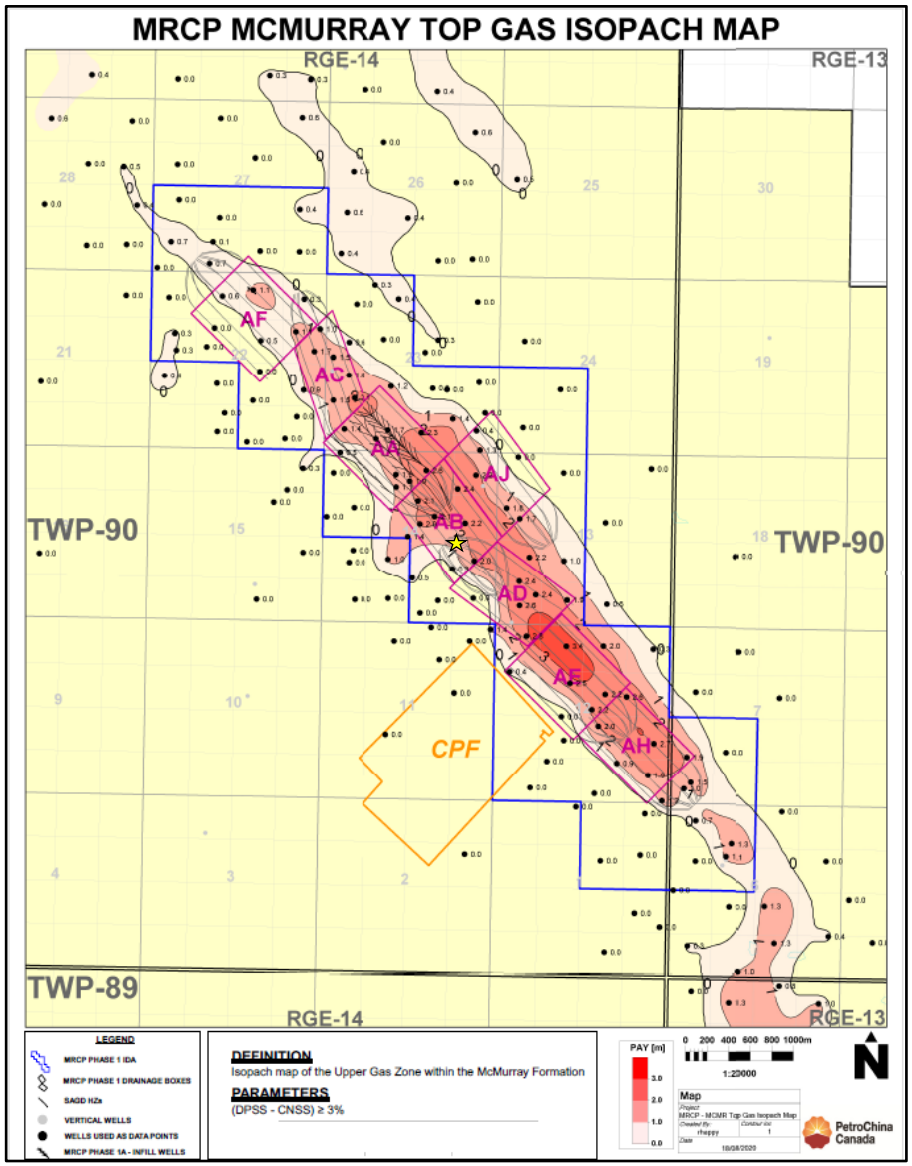
- Caprock is Argillaceous Lower Clearwater
- Wabiskaw sand above McMurray across the DA
- Target reservoir is Upper McMurray

Bitumen Net Pay Map – Development Area

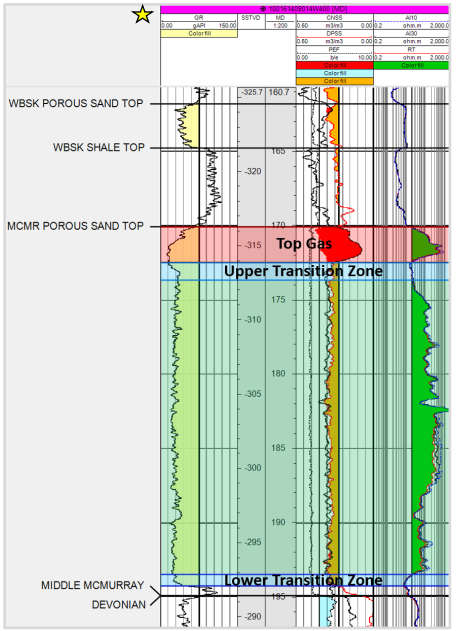


- Net pay cut-off at ≥10m
- Thickness ranges from 10 to25 m in the DA
- Upper McMurray reservoir shows strong NW to SE trend
- Central processing facility located Southwest of development area
- Majority of 8 drainage boxes are in >15 m bitumen pay

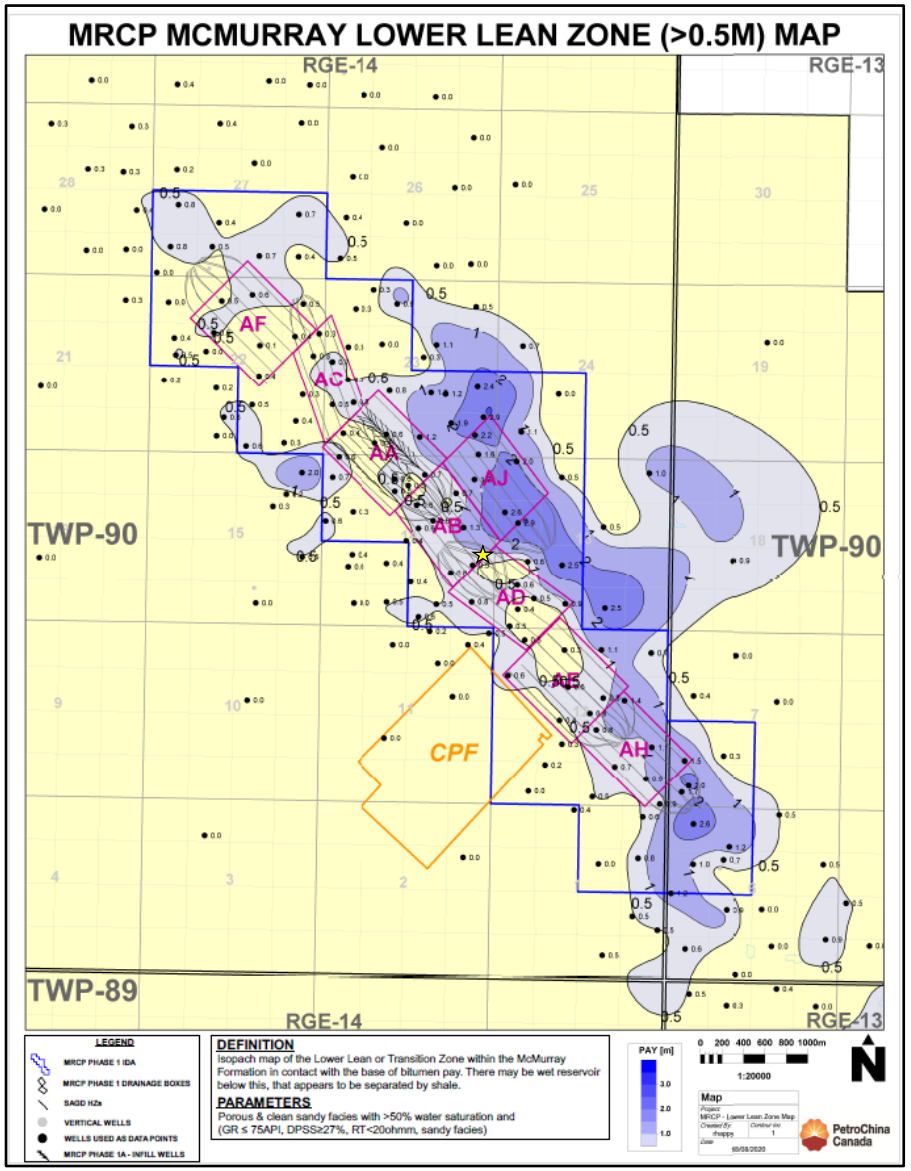
MCMR Top Gas Isopach Map



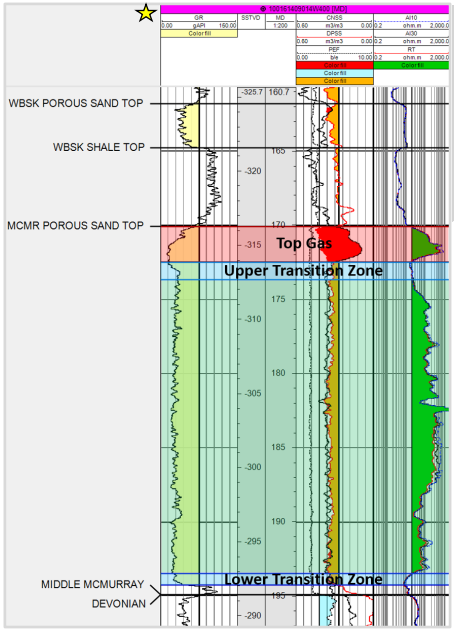
- Top gas zone present in the upper McMurray over the DA
- Ranges in thickness from approximately 0 to 3 m



Lower Transition Zone Map

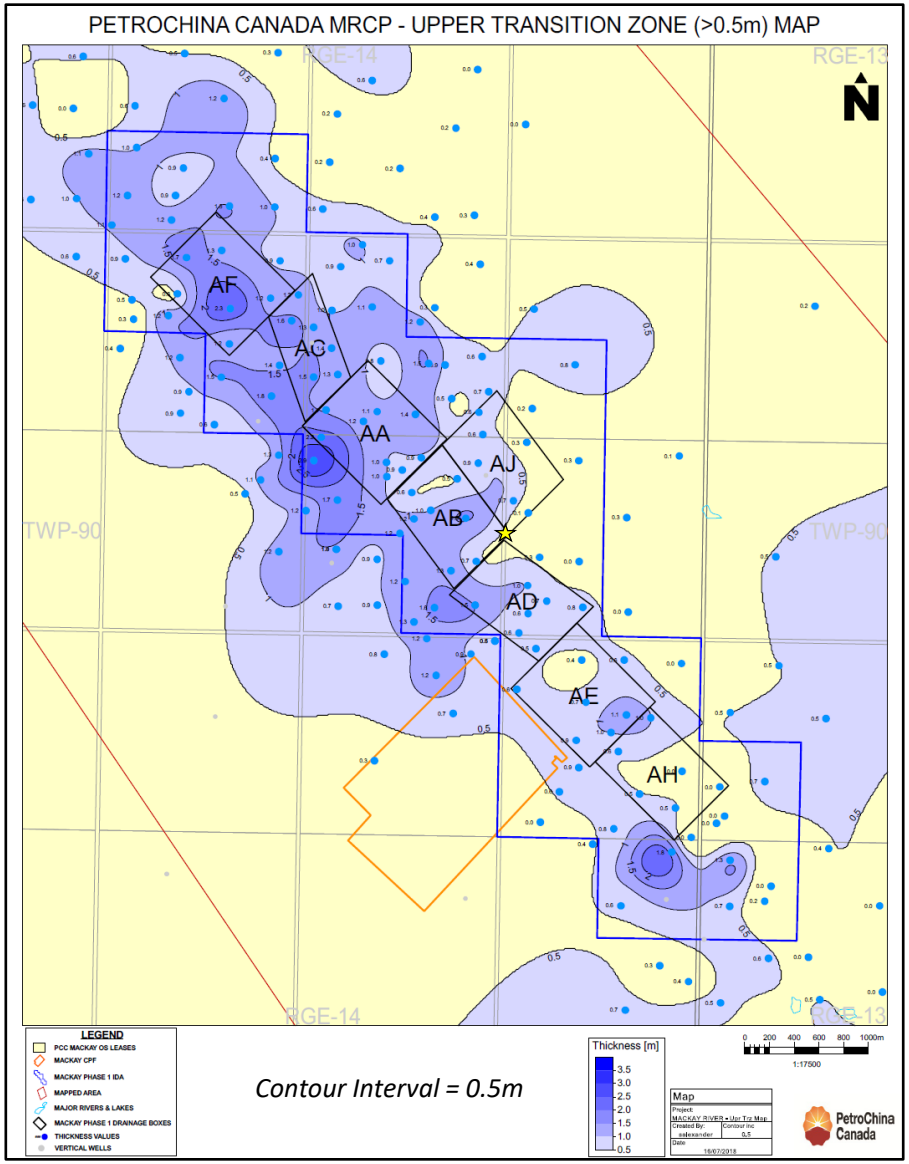


- Criteria:
  - Porous & clean sandy facies with >50% water saturation (GR ≤ 75 API, DPSS≥27%, RT<20 ohmm, sandy facies)
  - In communication with and below pay zone
- Characteristics:
  - Thin: <1.0 m over most of the Phase 1 drainage boxes
  - Limited Lateral Extent

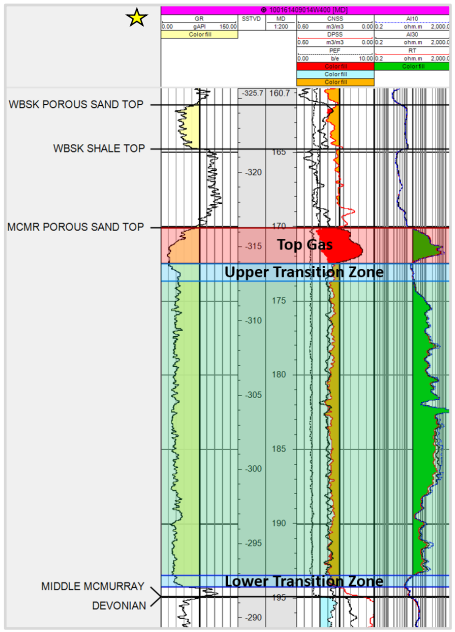


Lower Transition Zone Properties	
Parameter	**Average**
Total Water Saturation	70%
Total Porosity	33%
Horizontal Permeability (Core)	3300 mD
Vertical Permeability (Core)	2400 mD

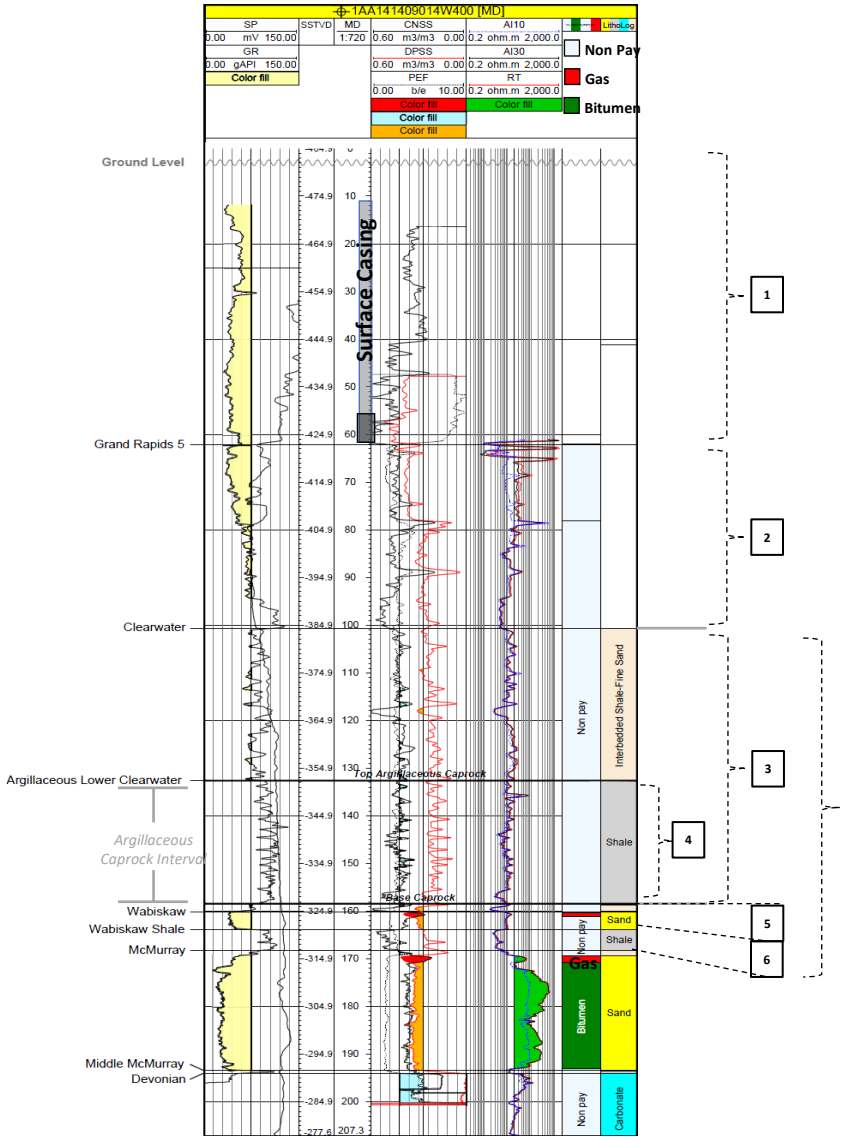
Upper Transition Zone Map



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



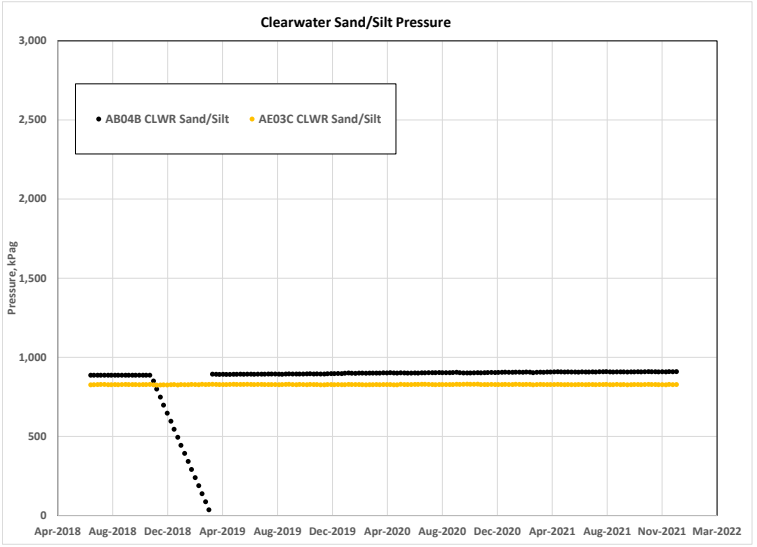
Caprock Monitoring: Overburden & Cap Rock Intervals



- Quaternary Sediments: from surface to the Grand Rapids
- Grand Rapids, overlies Clearwater
- Clearwater Formation, which is the gross caprock
- Argillaceous interval of Clearwater is the primary caprock for MRCP. It is present across the MRCP DA, it's 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 the casing of observation wells to monitor the sandier Clearwater intervals above the Argillageous caprock.
- Wabiskaw sand is the first known horizontal pathway on top of the reservoir. It is the main target for reservoir containment assurance and/or caprock integrity monitoring, early warning for pressure buildup.
- Wabiskaw shale lies above the McMurray reservoir and is the lower-most interval included within the overburden monitoring strategy.

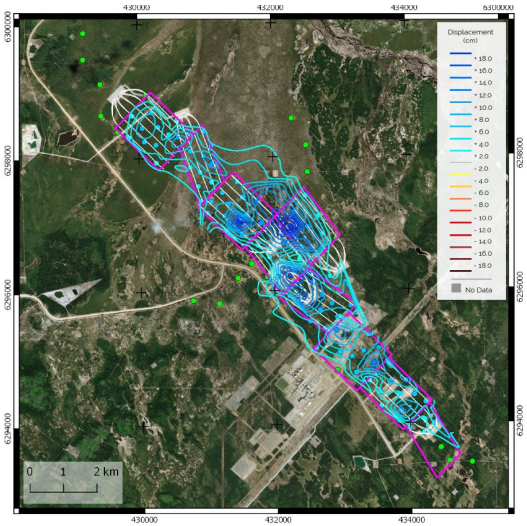
Caprock & Surface: Clearwater & Heave Monitoring

- Overburden surveillance above MRCP caprock (Clearwater Argillageous)
  - Clearwater sand/silt is above the MRCP caprock
  - Pressure range in 2021: 828 to 907 kPag (initial range: 826 to 896 kPag), Remains at virgin conditions, as expected
  - Temperature: range 4 to 5° C (initial range: 4 to 5° C)
  - Pressure and temperature expected to remain steady as this interval is immediately above the caprock

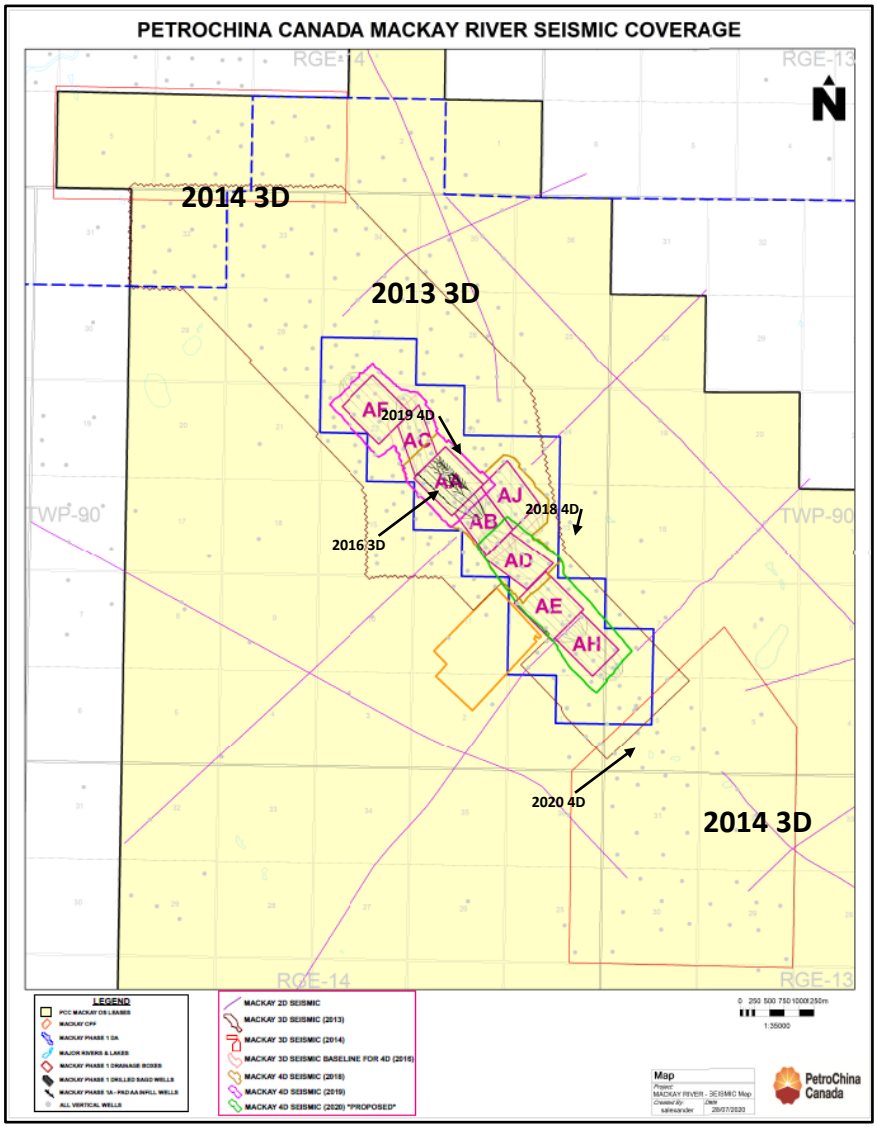


- Surface Displacement Monitoring
  - PCC implemented ground displacement monitoring using 104 corner reflectors over MRCP using Synthetic-aperture Radar Interferometry (InSAR) technology.
  - Heave is the dominant ground displacement effect registered in 2021
  - Cumulative heave up to 24 cm has been recorded in all MRCP pads (MAX in pad AJ)
  - Cumulative displacement per pad, Sep 2014 to Mar 2021 is shown in the adjacent table
  - The displacement measured during the period 2020 to 2021 is shown on the map as isolines

Pad	Cumulative Heave 2014-2021 (cm)	
	Ave	Max
AF	6.1	10.2
AC	6.3	10.5
AA	9.3	19.0
AB	9.1	17.7
AJ	11.3	24.0
AD	9.4	15.6
AE	7.4	12.7
AH	6.6	10.7



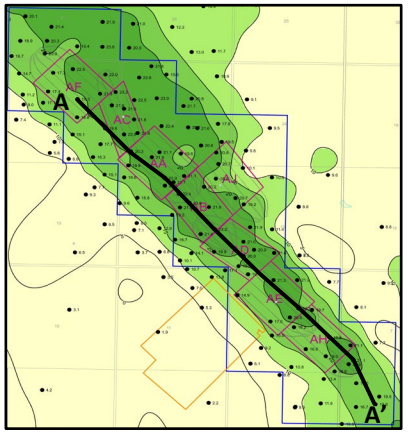
MRCP Seismic



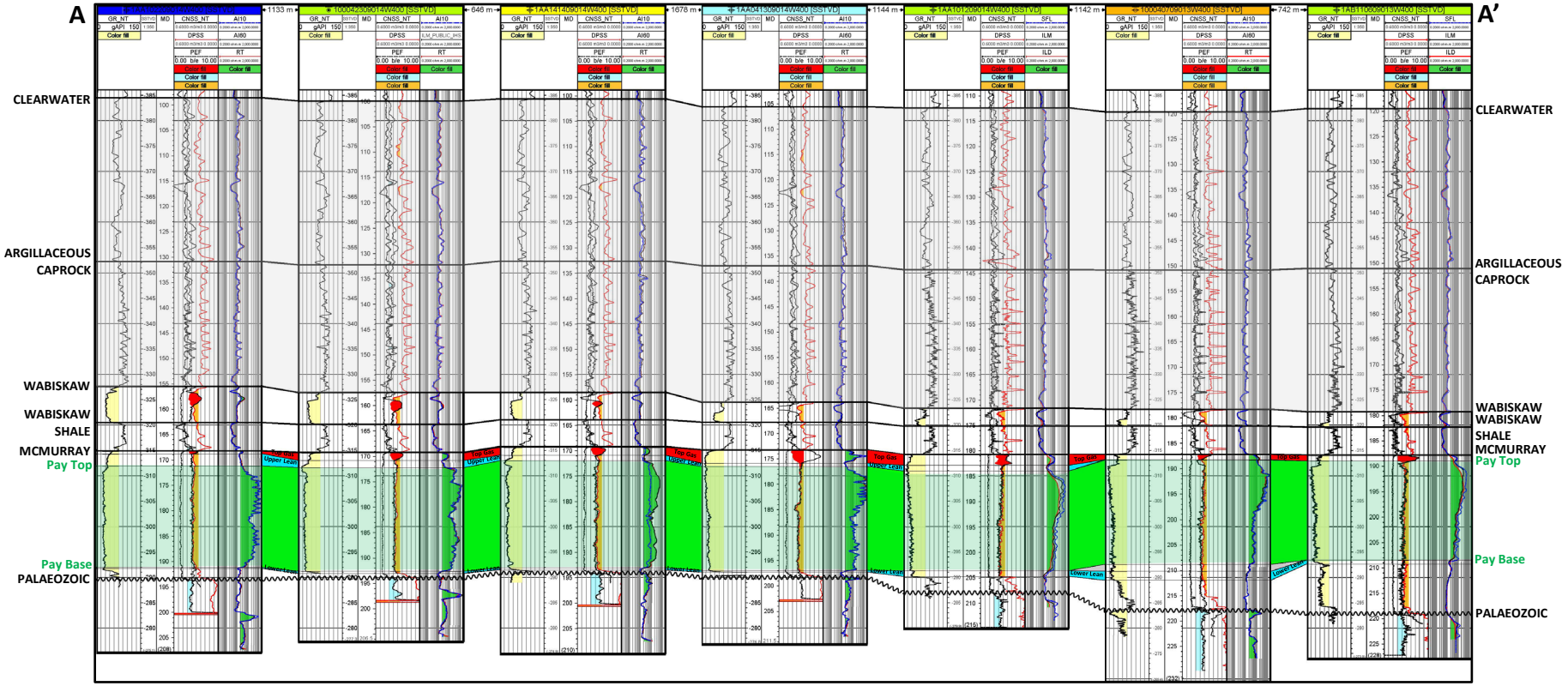
- Coverage Across MRCP includes:
  - ~96 km of 2D
  - ~58.4 km^2 of 3D
  - ~3.9 km^2 of 3D baseline for 4D
  - ~3.5 km^2 of 4D in 2018 - Interpreted
  - ~3.0 km^2 of 4D in 2019 – Interpreted
  - ~2.9 km^2 of 4D in 2020 – Interpreted
- 3D acquired in MRCP to help:
  - Assess Caprock
  - Plan/drill horizontal well trajectories
  - Assess McMurray reservoir
- 4D seismic surveys acquired at MRCP in 2018, 2019 & 2020
  - Used to monitor steam chamber growth
  - 2018: Pads AA, AB, AJ, AD
  - 2019: Pads AF, AC, AA
  - 2020: Pads AD, AE, AH

No Seismic exploration activities took place in 2021.

Structural Cross-Section across MRCP



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



Geologic and Reservoir Properties – OBIP For Operating Area

Drainage Box	# Well Pairs	Drainage Box Area (m^2)	Average S_o (frac)	Average Φ (frac)	Average K_h (D)	Average K_v (D)	Average Bitumen Pay Thickness (m)	Drainage Box OBIP (m3)	Estimated RF (%)	Estimated Drainage Box RBIP (m3)
AA	10	698,200	0.83	0.34	2.7	1.1	21.3	4,197,138	54	2,273,450
AB	5	562,600	0.8	0.34	2.7	1.1	22.6	3,465,819	57	1,971,383
AC	4	418,700	0.85	0.34	2.6	1	21.9	2,655,008	63	1,669,316
AD	5	560,100	0.77	0.33	2.6	1	20.8	2,957,075	54	1,605,723
AE	6	674,700	0.76	0.33	2.2	0.9	20.8	3,513,514	53	1,860,095
AF	6	675,400	0.82	0.34	2.6	1	22	4,149,444	62	2,575,517
AH	5	594,300	0.77	0.34	2.6	1	20.4	3,179,650	48	1,526,232
AJ	5	562,300	0.75	0.34	2.5	0.9	20.5	2,941,176	57	1,669,316
Total	*46*	*4,746,300*	*0.79*	*0.34*	*2.6*	*1*	*21.3*	*27,058,824*	*56*	*15,151,033*

OBIP = (NRV x PORT x SO)

- 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)
- RBIP = Recoverable Bitumen in Place

Geologic and Reservoir Properties – Original Bitumen In-Place

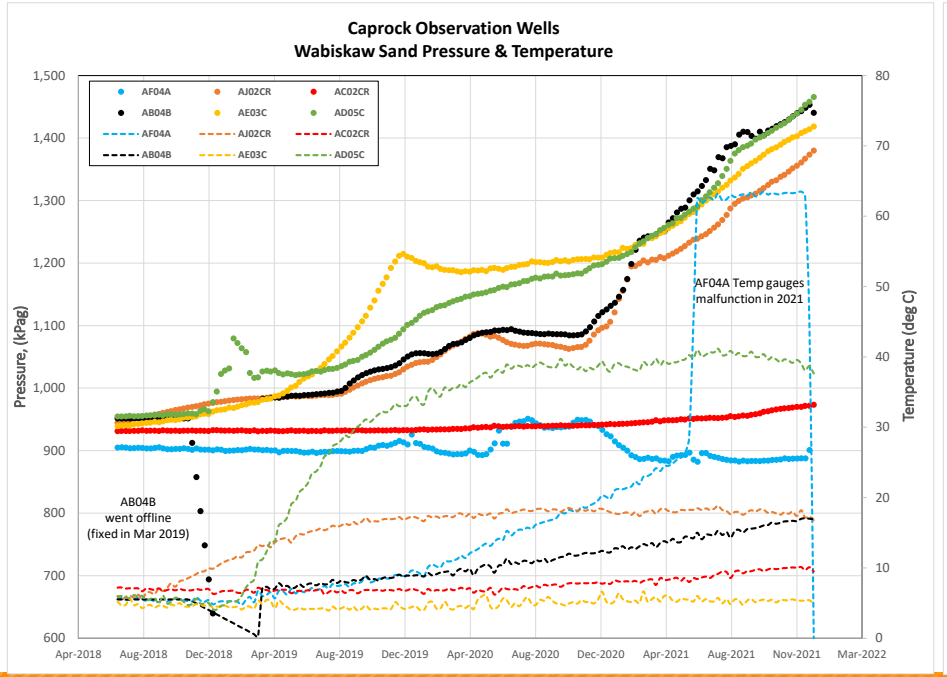
Parameters	Development Area	Project Area
Top of Reservoir Depth (mTVD)	176	175
Top of Reservoir Depth (TVD masl)	315	311
Base of Reservoir Depth (mTVD)	197	193
Base of Reservoir Depth (TVD masl)	294	293
Net Pay Thickness (m)	21.3	12.8
Porosity (frac)	0.34	0.33
Bitumen Saturation (frac)	0.79	0.75
OBIP (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 (°C)	6	6*

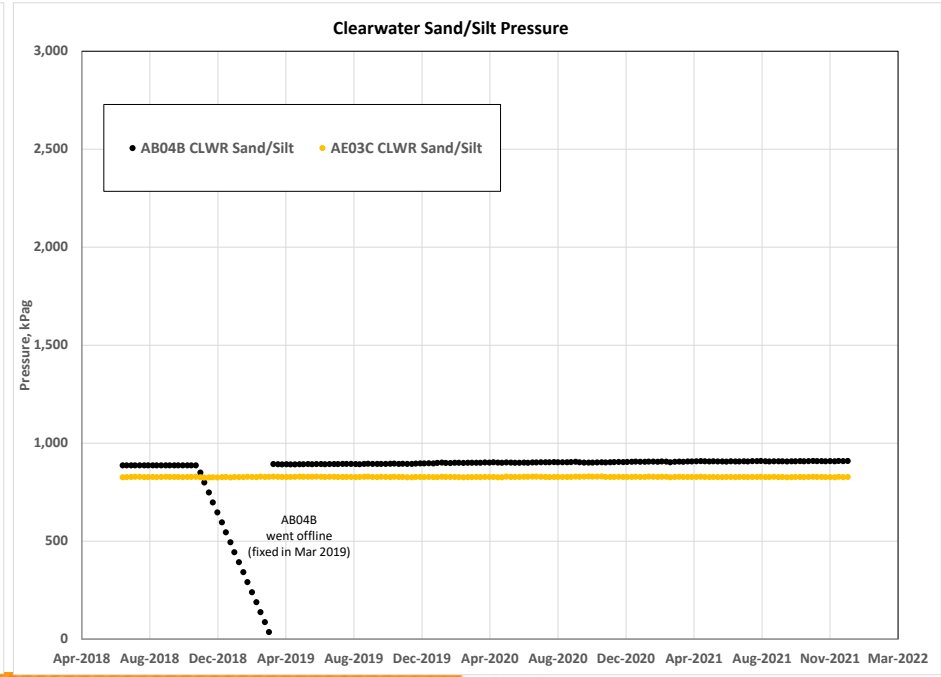
**Extrapolated from operating area*

Caprock Monitoring: P & T Wabiskaw and Clearwater Sands

- Wabiskaw Sand (above reservoir, below caprock):
  - Pressure: Average 1,183 kPag, range from 889 to 1,338 kPag (initial range: 900 to 950 kPag)
  - Temperature: Average 19 °C, range from 6 to 40 °C (initial range: 5 to 7 °C)
  - All pressure and temperature trends were considered normal in 2021 and attributed to thermal operations in the McMurray reservoir

- Clearwater sand/silt is above of MRCP caprock
  - Pressure: range from 828 to 907 kPag (initial range: 826 to 896 kPag), Remains at virgin conditions as expected
  - Temperature: range from 4 to 5 °C, (initial range: 4 to 5 °C)
  - Pressure and temperature expected to remain steady as this interval is immediately above the caprock





MRCP – Performance Indicators by Pad

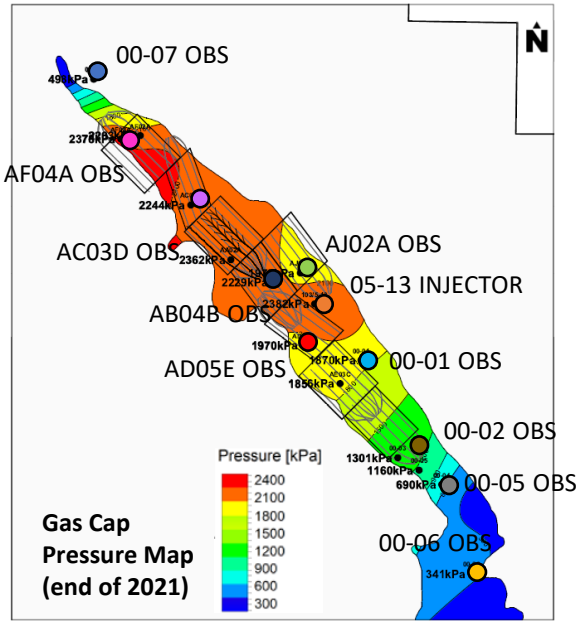
Pad	OBIP (m^3)	Cum. Oil to December 2021 (m^3)	Recovery to December 2021 (%)	Cumulative SOR by Dec 2021	Instantaneous SOR by Dec 2021	Ultimate Recovery (%)
AA	4,197,138	629,577	15.00%	4.8	4.3	54%
AB	3,465,819	288,265	8.32%	6.8	5.6	57%
AC	2,655,008	392,047	14.77%	4.0	3.2	63%
AD	2,957,075	244,570	8.27%	7.5	7.7	54%
AE	3,513,514	207,561	5.91%	9.3	9.4	53%
AF	4,149,444	503,448	12.13%	4.6	4.0	62%
AH	3,179,650	77,748	2.45%	17.3	9.4	48%
AJ	2,941,176	143,497	4.88%	12.1	6.2	57%
Total	27,058,824	2,486,711	9.19%	6.3	5.2	56%

- Higher SORs experienced on AE, AH, AJ and AD pads are primarily due to gas cap contact and/or slightly larger lower transition zone leak off.

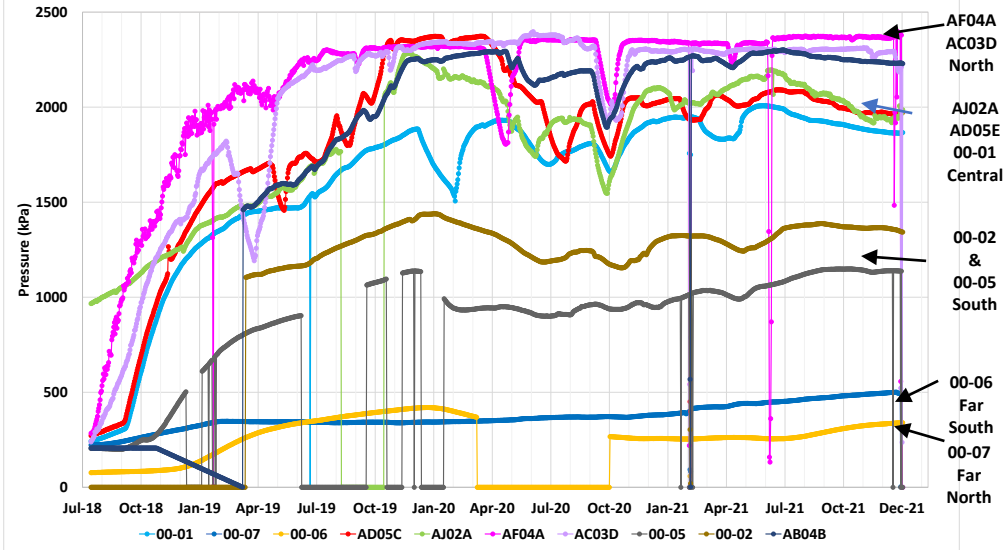
- Mitigations:
  - Operating pressure is balanced accordingly with the thief zones pressure
  - Gas cap pressurization with natural gas started in Sep 2018 in vertical well 05-13 (central DA). In 2021, the injector was S/I for repairs in Feb-Mar, injection resumed in Apr and continued during the year.
  - Gas co-injection started in well pairs of pads AH, AE, AD in Jan 2019 and it is expected to continue to support gas cap pressurization in the Southern DA during 2022

Gas Cap Pressurization: NCG Injection

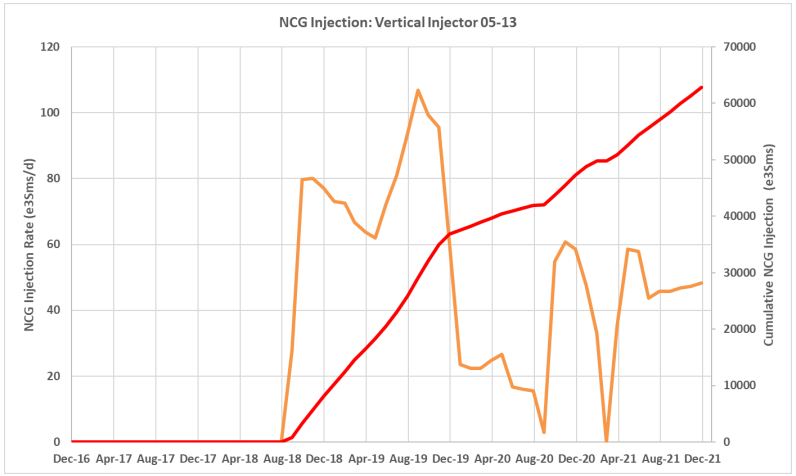
- The purpose of gas cap pressurization at MRCP is to increase the pressure in the gas cap to operate at a more favourable pressure balance between steam chambers and top thief zones to minimize steam losses.
  - Initial gas cap pressure of 200 kPag, presented a challenge to SAGD operation pressure balance
  - 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. By Q3, 2019 injection reached a maximum of 106,000 Sm^3/d (max approved by AER is 120,000 Sm^3/d per injector).
  - Injection suspended from Dec 2019 to Oct 2020. PCC reactivated NCG injection to continue support field pressure ramp up. Injector was S/I for repair in Feb-Mar 2021, injection resumed in Apr 2021
  - By Dec 2021, cumulative NCG injection was approximately 62,800 e^3Sm^3, the average injection rate in 2021 was 42,500 Sm^3/d (as per chart below, right)
  - The gas cap pressurization process has helped reduced SOR and maintain stable operation and production of wells affected by gas cap contact



Observation Wells Pressure Responses in Gas Cap

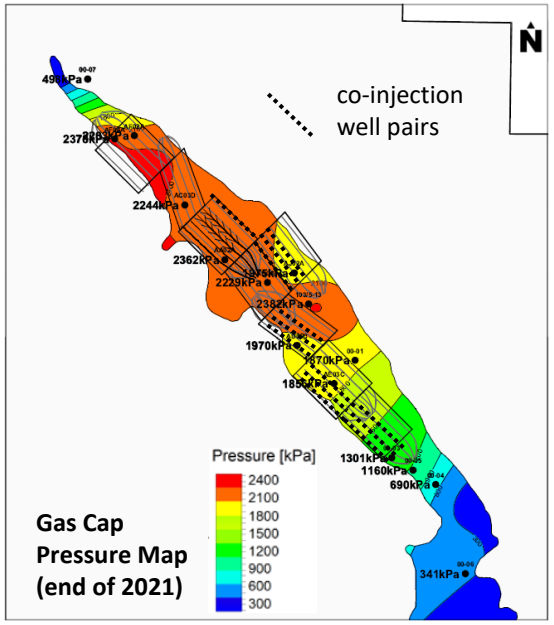


NCG Injection: Vertical Injector Well

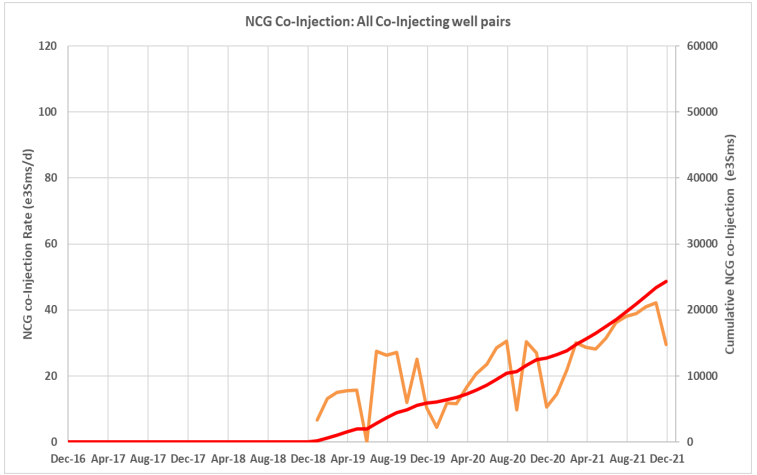


Gas Cap Pressurization: NCG Co-Injection

- NCG co-injection supports the gas cap pressurization at MRCP
  - Gas co-injection was implemented in January 2019, to support gas cap pressurization in areas distanced from vertical injector 05-13
  - Natural gas (Methane) is used for NCG Co-injection. It is expected that the co-injected gas remains in the gas cap once reaching the top of the reservoir, contributing to gas cap pressurization. No co-injected gas is expected to be recovered.
  - Typical co-injection rates range from 2,400 to 4,200 Sm^3/d per well (the maximum rate approved by AER is 5,000 Sm^3/d per well). The cumulative volume of NCG co-injection was approximately 24,300 e^3Sm^3 (as per chart below, right) by December 2021
  - Typical mole fractions (concentration) range between 0.5 and 2.0%
  - NCG co-injection parameters are evaluated weekly: Co-injection rates are adjusted within the permitted range based on each well pair response. Wells could be on and off co-injection depending on SOR and TFSR evaluation
  - PCC has identified and used NCG co-injection at 13 wells (shown in map), as of December 2021:
    - AA06
    - AB05
    - AJ01, AJ02
    - AD03, AD04, AD05
    - AE01, AE02, AE03
    - AH01, AH02, AH03
  - Pressure monitoring of the gas cap indicates that co-injected NCG reaches the top of the reservoir, providing pressure support, preventing excessive steam losses and supporting SAGD operation
  - No wellbore integrity issues have been identified
  - PCC continues to use gas co-injection to support pressurization of the gas cap



NCG co-Injection: Several Well Pairs

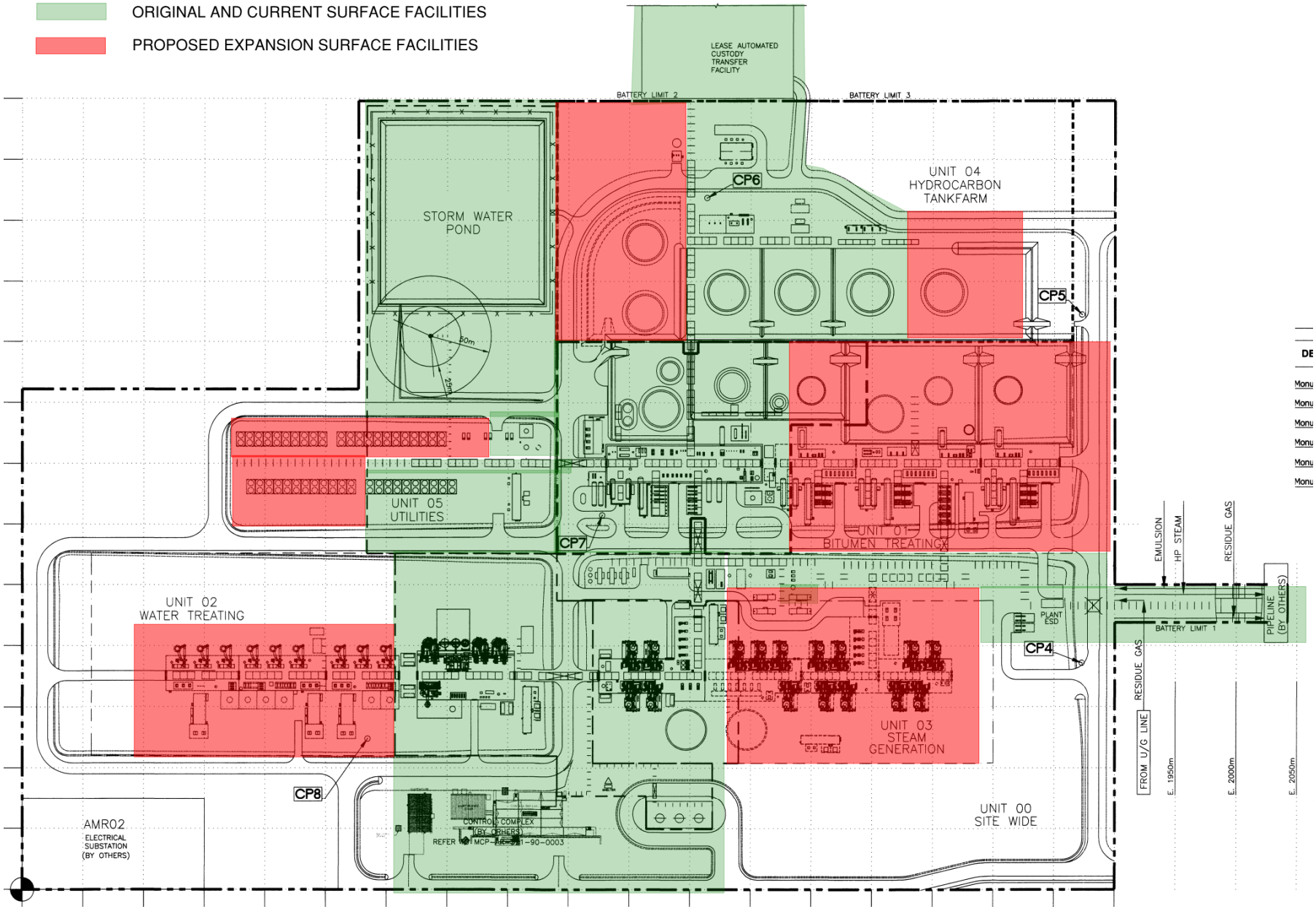


4.3 SURFACE

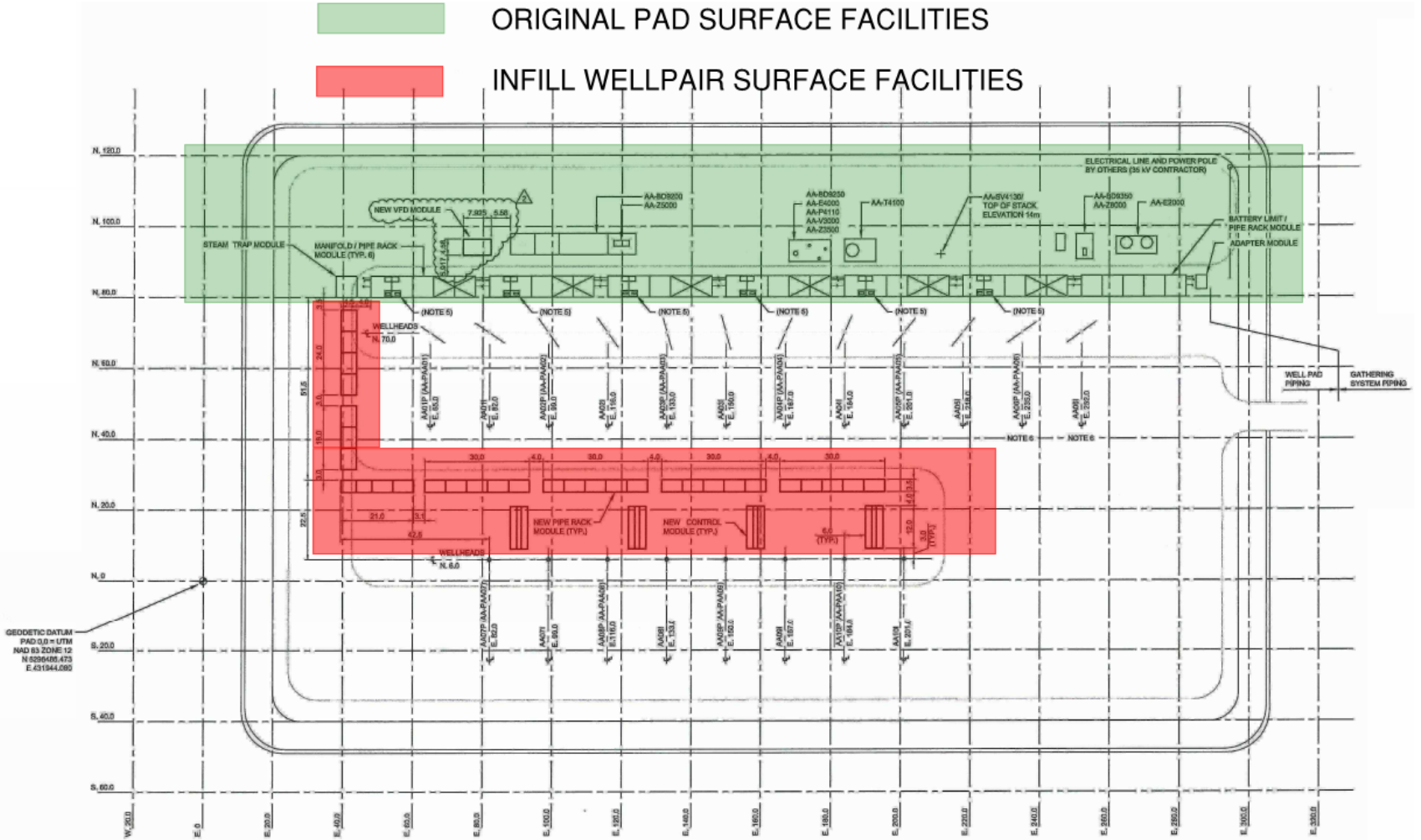
Central Processing Facility Development

ORIGINAL AND CURRENT SURFACE FACILITIES

PROPOSED EXPANSION SURFACE FACILITIES



Pad AA Surface Facility Development



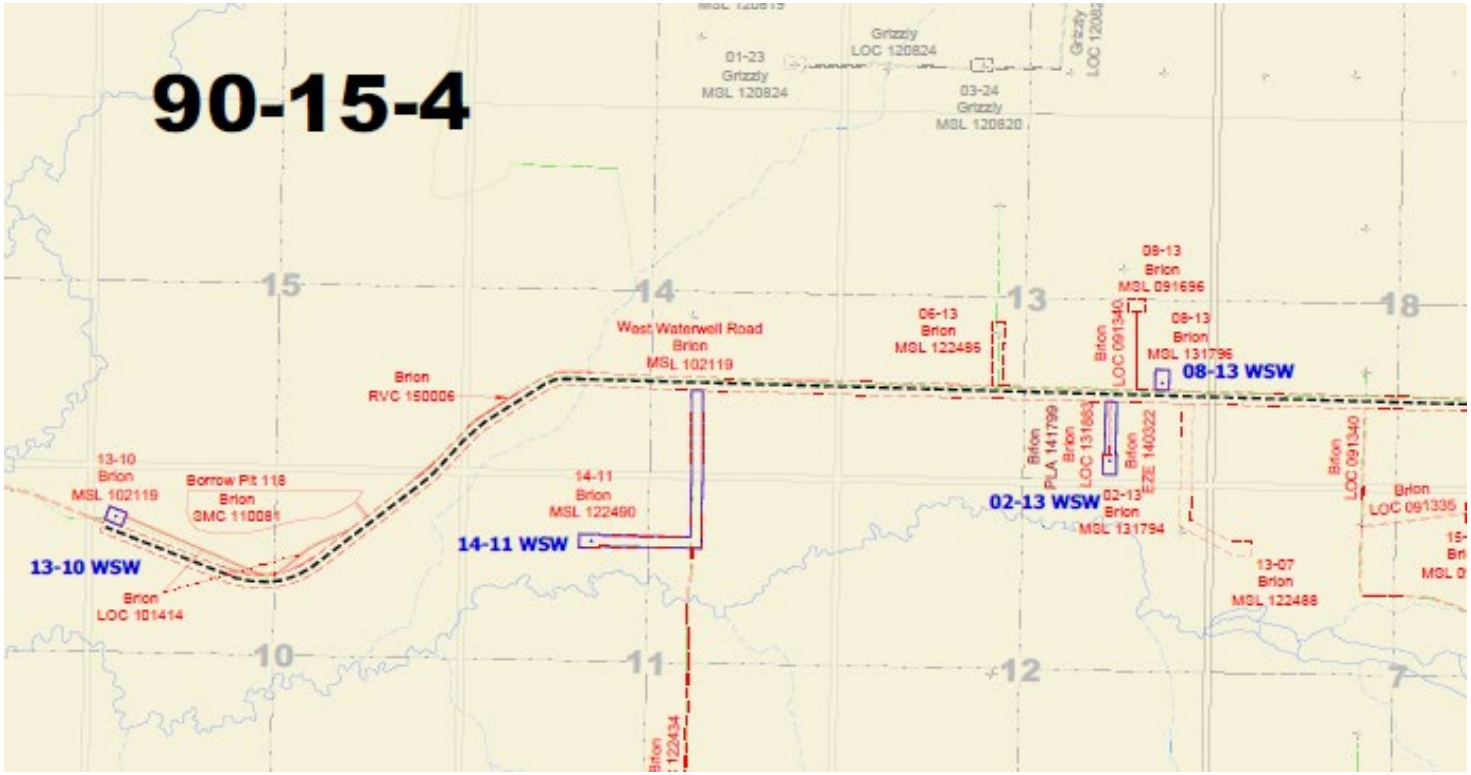
EQUIPMENT LIST

AA01I	INJECTION WELL	AA05P	PRODUCTION WELL	AA-PAA03	DOWNHOLE PUMP	AA07I	INJECTION WELL (NEW)	AA-PAA07	DOWNHOLE PUMP (NEW)
AA02I	INJECTION WELL	AA06P	PRODUCTION WELL	AA-PAA04	DOWNHOLE PUMP	AA08I	INJECTION WELL (NEW)	AA-PAA08	DOWNHOLE PUMP (NEW)
AA03I	INJECTION WELL	AA-BD9200	MCC / AIR COMPRESSOR BUILDING	AA-PAA05	DOWNHOLE PUMP	AA09I	INJECTION WELL (NEW)	AA-PAA09	DOWNHOLE PUMP (NEW)
AA04I	INJECTION WELL	AA-BD9250	TEST SEPARATOR BUILDING	AA-PAA06	DOWNHOLE PUMP	AA10I	INJECTION WELL (NEW)	AA-PAA10	DOWNHOLE PUMP (NEW)
AA05I	INJECTION WELL	AA-BD9350	START-UP PRODUCTION / ANNULUS GAS PUMP BUILDING	AA-T4100	POP TANK				
AA06I	INJECTION WELL	AA-E2000	START-UP PRODUCTION AERIAL COOLER	AA-V3000	TEST SEPARATOR	AA07P	PRODUCTION WELL (NEW)		
AA01P	PRODUCTION WELL	AA-E4000	PAD RESIDUE GAS HEATER	AA-Z5500	SAMPLE PACKAGE	AA08P	PRODUCTION WELL (NEW)		
AA02P	PRODUCTION WELL	AA-P4110	POP TANK PUMP	AA-Z6000	PAD INSTRUMENT AIR PACKAGE	AA09P	PRODUCTION WELL (NEW)		
AA03P	PRODUCTION WELL	AA-PAA01	DOWNHOLE PUMP	AA-Z8020	START UP / ANNULUS GAS PUMP PACKAGE	AA10P	PRODUCTION WELL (NEW)		
AA04P	PRODUCTION WELL	AA-PAA02	DOWNHOLE PUMP	AA-SV4130	VENT STACK				

Built and Planned Water Infrastructure

Water Act Licence No. 00266369-01-03:

- Approved Annual Withdrawal Volume = 2,116,964 m^3/year from the Empress Channel Aquifer
  - 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



Operational Comparison to Design Throughputs

4.4 Historical and Upcoming Activity

Historical and Upcoming Activity

- Summary of suspension and abandonment activity within 2021
  - There were no suspension or abandonment activities in 2021

2021 Regulatory and Operational Changes

Amendments to Scheme Approval No. 11715			
Amendment No.	**Application No.**	**Description**	**Approval Date**
11715S	1934017	Blanket Steam Push Well Treatments	16-Sep-2021

- PCC modified seven well pads to re-direct steam condensate from a Pop tank on each well pad to the emulsion line. This change was made to improve energy efficiency and allow for the Pop tanks to be decommissioned
- There were no modifications to the Central Processing Facility throughout 2021 that required AER approval
- There were no phase expansions, change in injection strategy, or infrastructure changes throughout 2021 that materially affected scheme performance or energy material balances

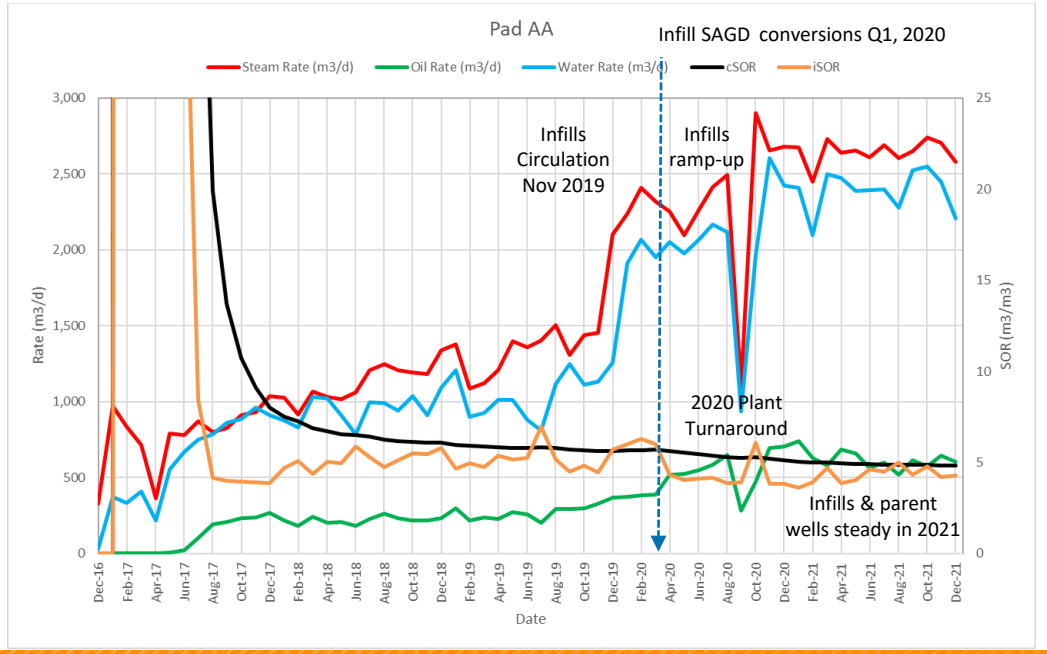
Key Learnings To-Date

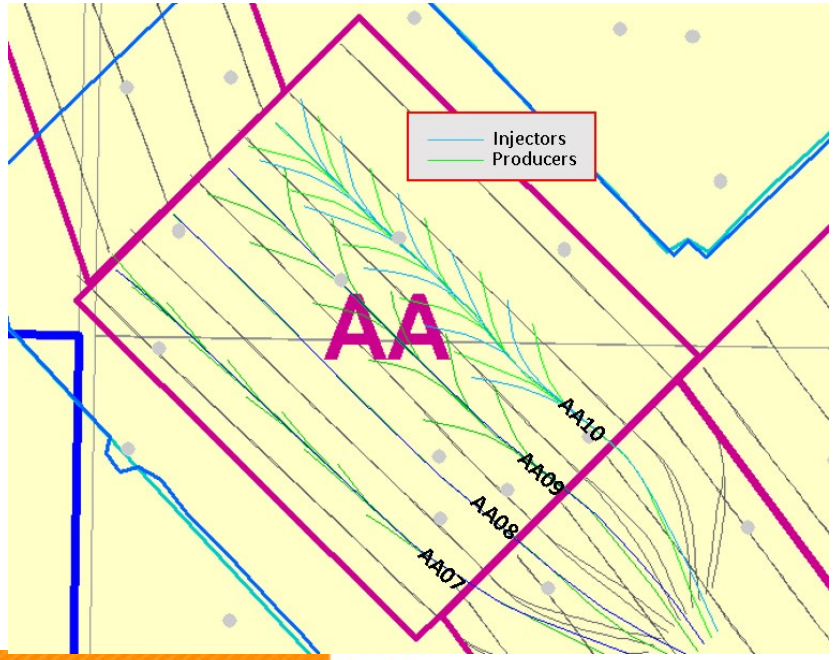
- Continuing to ramp-up production through optimization efforts and mitigating the effects of:
  - Top gas and thicker lower transition zones
  - Operational pressure strategies tied to “thief” zones
  - Effects of baffles and barriers
  - Fines migration
- The implementation of infill wells in pad AA has resulted in a positive experience. Key learnings in well/facilities planning, drilling, completion and operation are considered for future developments at MRCP
- ESP conversions continue to meet run-life expectations and are in-line with industry averages.
- The use of fiber optic temperature coils has proven to be a valuable tool to diagnose downhole issues and survey the conformance along the horizontal section.
- For wells that have been worked over with Tubing Deployed Inflow Control Devices (TDICD), continuous fiber optic temperature coils have left out of the completion to minimize pressure drop inside the liner.

Well Pad AA Infill Wells

- Steam circulation began late Nov 2019
- SAGD conversion between Mar-Apr 2020
- Infill wells performance to-date represents a clear improvement over their parent (original) wells
- Multilaterals showing communication with adjacent steam chambers. PCC continues to develop strategies to promote steam chamber development in heterogeneous reservoir
- Reservoir Conditions (heterogeneities, quality) are variable along the pad. Generally improving in the NE to SW direction. No direct comparison of infills performance is possible as each infill (as well as original wells) deals with different reservoir qualities.
- Main learnings:
  - Conventional infill well pair (no multilateral) with completion enhancements in cleaner reservoir outperforms parent wells
  - Multilateral wells are more adequate to lower quality reservoir to help promote steam chamber growth and reach out to interbedded sands. They also outperform parent wells
  - Technology adaptation to reservoir quality
- Infill Wells proposed for Pad AF will capture learnings from AA Pad infills

- AA07:
  - Casing Inflow Control Device in producer, PPS liner
  - Uptrack laterals
  - Vacuum Insulated Tubing
- AA08:
  - Casing Inflow Control Device in producer
  - Base Pair (conventional well pair, enhanced design with learning from first 42 well pairs), PPS liner.
- AA09:
  - Casing Inflow Control Device in producer,
  - Producer multilaterals to adjacent steam chamber
- AA10:
  - Casing Inflow Control Device in producer,
  - Producer and injector multilaterals to adjacent steam chamber





2021 Compliance Summary

Event Description and AER Reference Number (if applicable)	Event Details	Event Reason (if applicable)	Plan to Resolution
Directive 087 Voluntary Self Disclosure (2093485)	A non-routine casing repair conducted prior to obtaining AER approval as per the Directive.	Planning for casing repair did not account for the Non-routine casing repair approval.	PCC is now aware of this requirement and will account for it during future repairs.
Pipeline Rules Inspection Follow up (510201 and 510204)	AER requested additional information in relation to inspections that took place in 2018, that PCC had not responded to.	PCC was not able to provide the requested data to AER in a timely manner.	PCC contracted AER to resolve the matter and satisfy follow up questions.
Late Casing Repairs under Directive 087 (No reference number provided)	PCC received a Notification from AER that four wells were out of compliance with Sections 5.1 and 5.2 of Directive 087 in relation to the notification and repair of casing failures.	PCC had not tracked the repair timing requirements.	PCC Submitted a request to extend the timing to complete the repair timeline and completed repairs in November 2021. Tracking processes have been improved to prevent a reoccurrence of a similar incident.

Future Initiatives - 2022

- Winter Appraisal Program:
  - No new delineation wells
  - No seismic survey planned

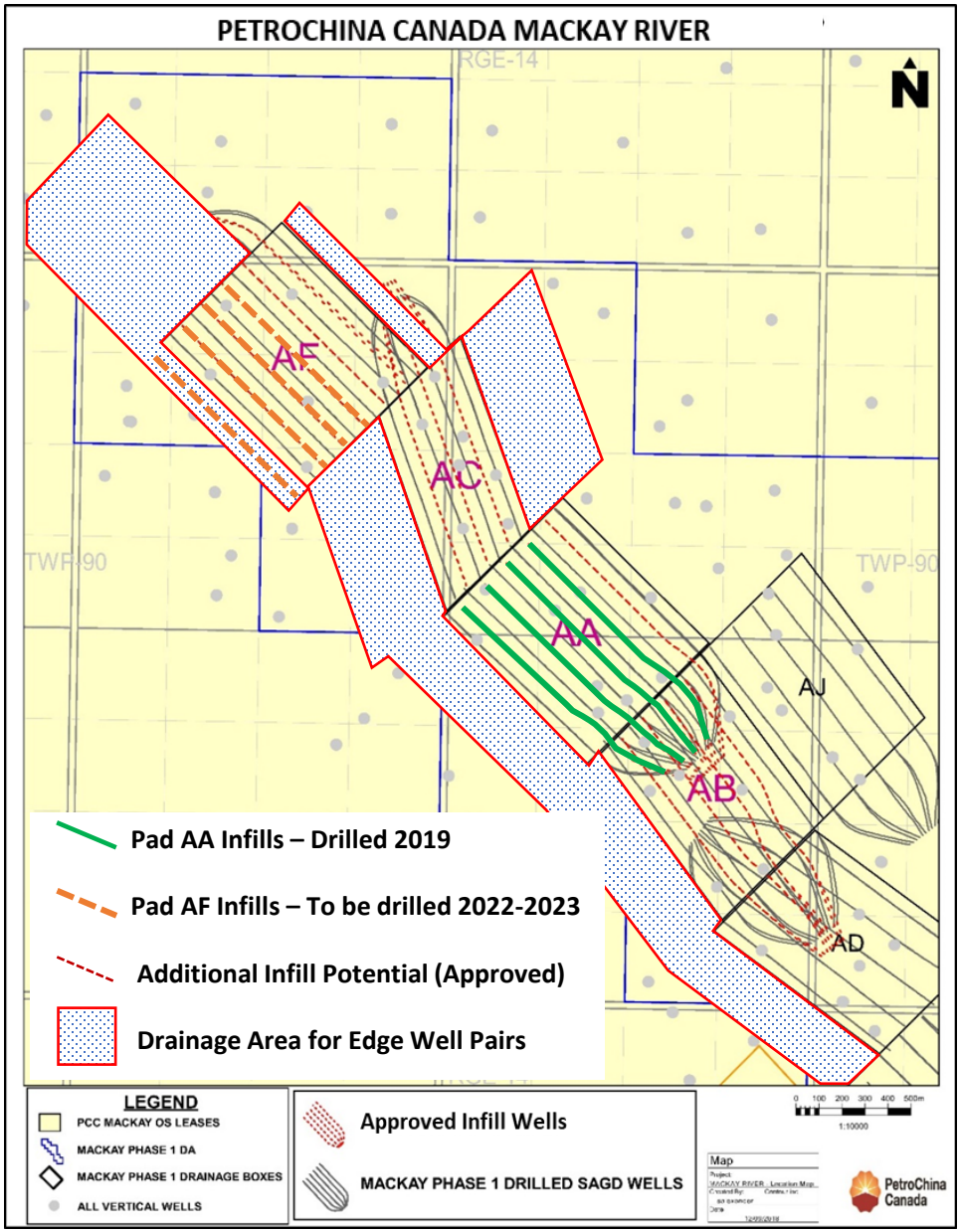
- Potential Commercial Amendment Applications:
  - Pressure maintenance in bottom transition zone continue to be investigated
  - Use of polymers to mitigate bottom transition zone continue to be investigated

- New Developments:
  - Bringing sidetrack wells on AC04 and AF05 into operation.
  - Infill wells approved by AER
    - Four new infill wells in Pad AF by end of 2022

- Other initiatives:
  - Producer sidetrack in selected wells pairs
  - Continue improving technology implementations (tubing deployed inflow control devices and other remedial pilot technologies for casing/liner improvement)

Future Initiatives

- PCC long range planning is ongoing and subject to change
  - No new delineation wells are planned
    - Sufficient delineation exist in near term (approximately 5 years)
  - 4D seismic
    - As needed basis to monitor and manage reservoir
    - Opportunistically cycle through the drainage areas
- Potential Amendment Applications:
  - Application for additional future sustaining well pairs
- Future Development Potential
  - Four new Pad AF wells in the short term
  - Medium- to long-term plan for additional sidetrack and edge wells is under development.



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