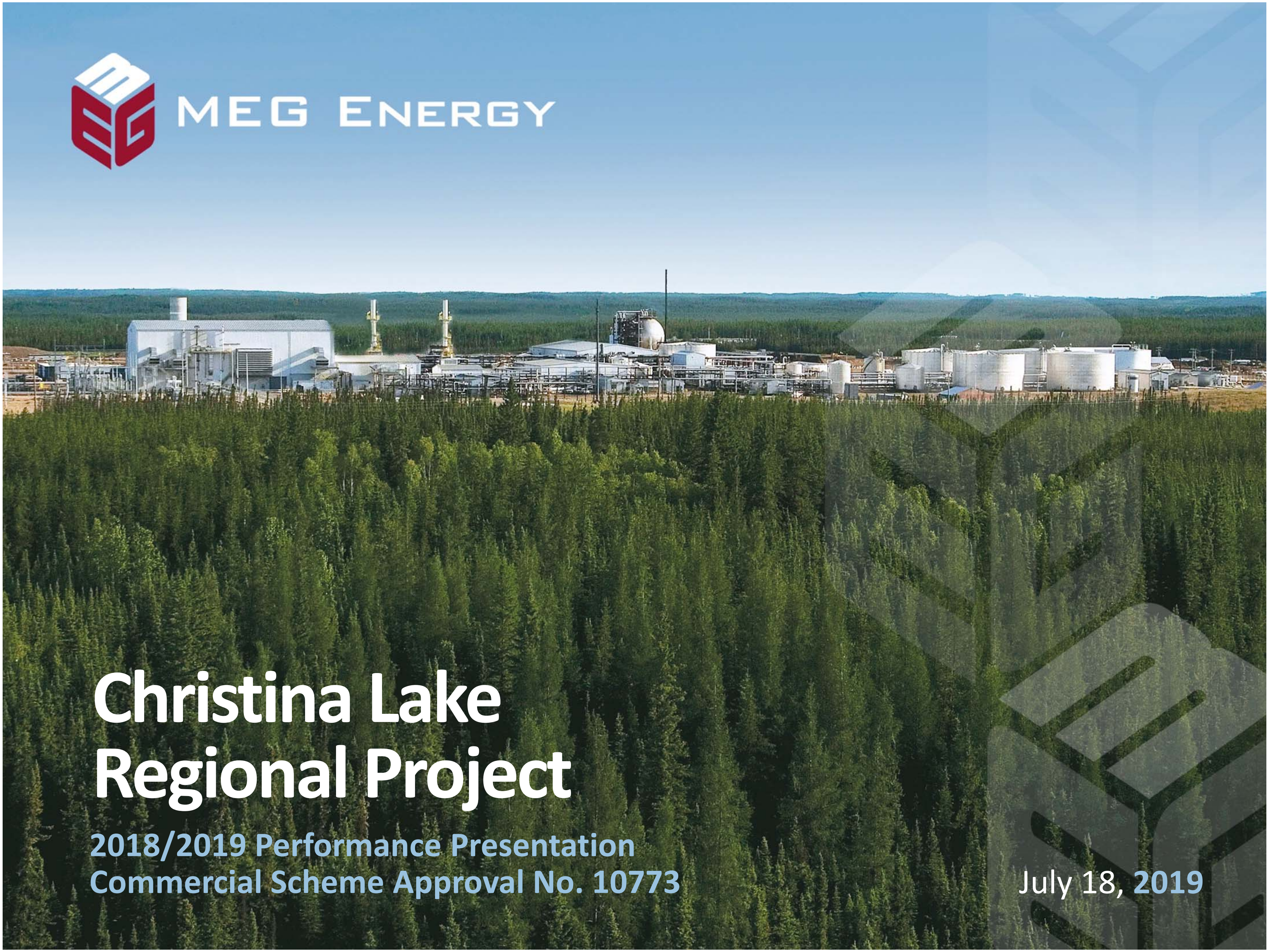


MEG ENERGY

Christina Lake Regional Project

2018/2019 Performance Presentation
Commercial Scheme Approval No. 10773

July 18, 2019

Disclaimer

This presentation is not, and under no circumstances is to be construed to be a prospectus, offering memorandum, advertisement or public offering of any securities of MEG Energy Corp. (“MEG”). Neither the United States Securities and Exchange Commission (the “SEC”) nor any other state securities regulator nor any securities regulatory authority in Canada or elsewhere has assessed the merits of MEG’s securities or has reviewed or made any determination as to the truthfulness or completeness of the disclosure in this document. Any representation to the contrary is an offence.

Recipients of this presentation are not to construe the contents of this presentation as legal, tax or investment advice and recipients should consult their own advisors in this regard.

MEG has not registered (and has no current intention to register) its securities under the United States Securities Act of 1933, as amended (the “U.S. Securities Act”), or any state securities or “blue sky” laws and MEG is not registered under the United States Investment Act of 1940, as amended. The securities of MEG may not be offered or sold in the United States or to U.S. persons unless registered under the U.S. Securities Act and applicable state securities laws or an exemption from such registration is available. Without limiting the foregoing, please be advised that certain financial information relating to MEG contained in this presentation was prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, which differs from generally accepted accounting principles in the United States and elsewhere. Accordingly, financial information included in this document may not be comparable to financial information of United States issuers.

The information concerning petroleum reserves and resources appearing in this document was derived from a report of GLJ Petroleum Consultants Ltd. dated effective as of December 31, 2017, which has been prepared in accordance with the Canadian Securities Administrators National Instrument 51-101 entitled Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) at that time. The standards of NI 51-101 differ from the standards of the SEC. The SEC generally permits U.S. reporting oil and gas companies in their filings with the SEC, to disclose only proved, probable and possible reserves, net of royalties and interests of others. NI 51-101, meanwhile, permits disclosure of estimates of contingent resources and reserves on a gross basis. As a consequence, information included in this presentation concerning our reserves and resources may not be comparable to information made by public issuers subject to the reporting and disclosure requirements of the SEC.

There are significant differences in the criteria associated with the classification of reserves and contingent resources. Contingent resource estimates involve additional risk, specifically the risk of not achieving commerciality, not applicable to reserves estimates. There is no certainty that it will be commercially viable to produce any portion of the resources. The estimates of reserves, resources and future net revenue from individual properties may not reflect the same confidence level as estimates of reserves, resources and future net revenue for all properties, due to the effects of aggregation. Further information regarding the estimates and classification of MEG’s reserves and resources is contained within the Corporation’s public disclosure documents on file with Canadian Securities regulatory authorities, and in particular, within MEG’s most recently filed annual information form (the “AIF”). MEG’s public disclosure documents, including the AIF, may be accessed through the SEDAR website (www.sedar.com), at MEG’s website (www.megenergy.com), or by contacting MEG’s investor relations department.

Anticipated netbacks are calculated by adding anticipated revenues and other income and subtracting anticipated royalties, operating costs, transportation costs and realized commodity risk management gains(losses) from such amount.

Disclosure Advisories

Forward-Looking Information

This document may contain forward-looking information including but not limited to: expectations of future production, revenues, expenses, cash flow, operating costs, steam-oil ratios, regulatory approvals, pricing differentials, reliability, profitability, emission intensity and capital investments; estimates of reserves and resources; the anticipated reductions in operating costs as a result of optimization and scalability of certain operations; and the anticipated sources of funding for operations and capital investments. Such forward-looking information is based on management's expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures, plans for and results of drilling activity, environmental matters, regulatory processes, business prospects and opportunities.

By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: risks associated with the oil and gas industry, for example, the securing of adequate supplies and access to markets and transportation infrastructure; the availability of capacity on the electricity transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and revenues; health, safety and environmental risks; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws; assumptions regarding and the volatility of commodity prices, interest rates and foreign exchange rates, and, risks and uncertainties related to commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that MEG may enter into from time to time to manage its risk related to such prices and rates; risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with MEG's future phases and the expansion and/or operation of MEG's projects; risks and uncertainties related to the timing of completion, commissioning, and start-up, of MEG's future phases, expansions and projects; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with MEG's projects; and uncertainties arising in connection with any future disposition of assets.

Although MEG believes that the assumptions used in such forward-looking information are reasonable, there can be no assurance that such assumptions will be correct. Accordingly, readers are cautioned that the actual results achieved may vary from the forward-looking information provided herein and that the variations may be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive.

Further information regarding the assumptions and risks inherent in the making of forward-looking statements can be found in MEG's most recently filed AIF, along with MEG's other public disclosure documents. Copies of the AIF and MEG's other public disclosure documents are available through the SEDAR website which is available at www.sedar.com.

The forward-looking information included in this document is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this document is made as of the date of this document and MEG assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

Disclosure Advisories

Market Data

This presentation contains statistical data, market research and industry forecasts that were obtained from government or other industry publications and reports or based on estimates derived from such publications and reports and management's knowledge of, and experience in, the markets in which MEG operates. Government and industry publications and reports generally indicate that they have obtained their information from sources believed to be reliable, but do not guarantee the accuracy and completeness of their information. Often, such information is provided subject to specific terms and conditions limiting the liability of the provider, disclaiming any responsibility for such information, and/or limiting a third party's ability to rely on such information. None of the authors of such publications and reports has provided any form of consultation, advice or counsel regarding any aspect of, or is in any way whatsoever associated with, MEG. Further, certain of these organizations are advisors to participants in the oil sands industry, and they may present information in a manner that is more favourable to that industry than would be presented by an independent source. Actual outcomes may vary materially from those forecast in such reports or publications, and the prospect for material variation can be expected to increase as the length of the forecast period increases. While management believes this data to be reliable, market and industry data is subject to variations and cannot be verified due to limits on the availability and reliability of data inputs, the voluntary nature of the data gathering process and other limitations and uncertainties inherent in any market or other survey. Accordingly, the accuracy, currency and completeness of this information cannot be guaranteed. None of MEG, its affiliates or the underwriters has independently verified any of the data from third party sources referred to in this presentation or ascertained the underlying assumptions relied upon by such sources.

MEG Energy Corp.

Who We Are

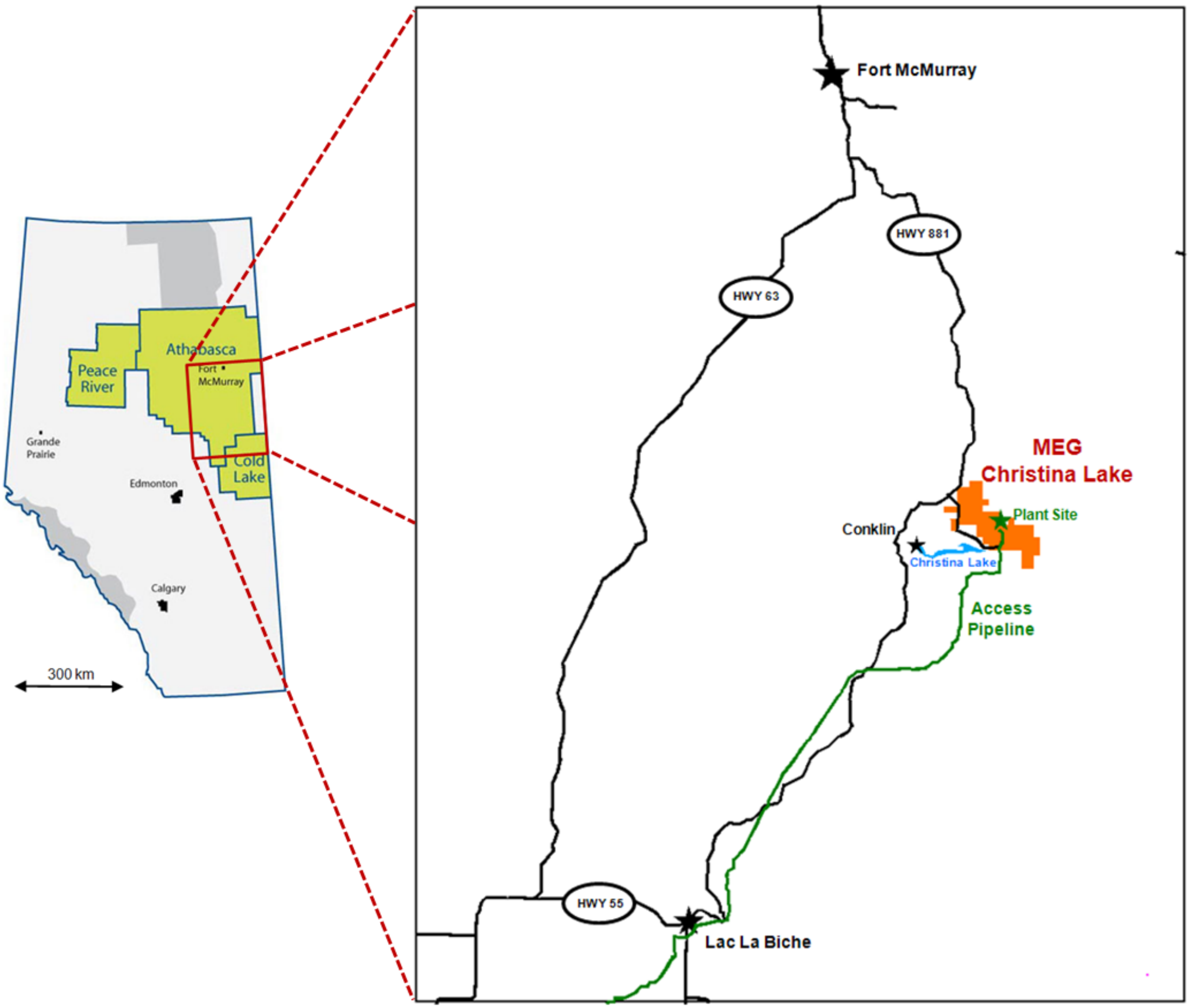
MEG Energy Corp. (MEG) is a public Calgary-based energy company focused on the development and recovery of bitumen and the generation of power in northeast Alberta

MEG Energy Corp.

Who We Are

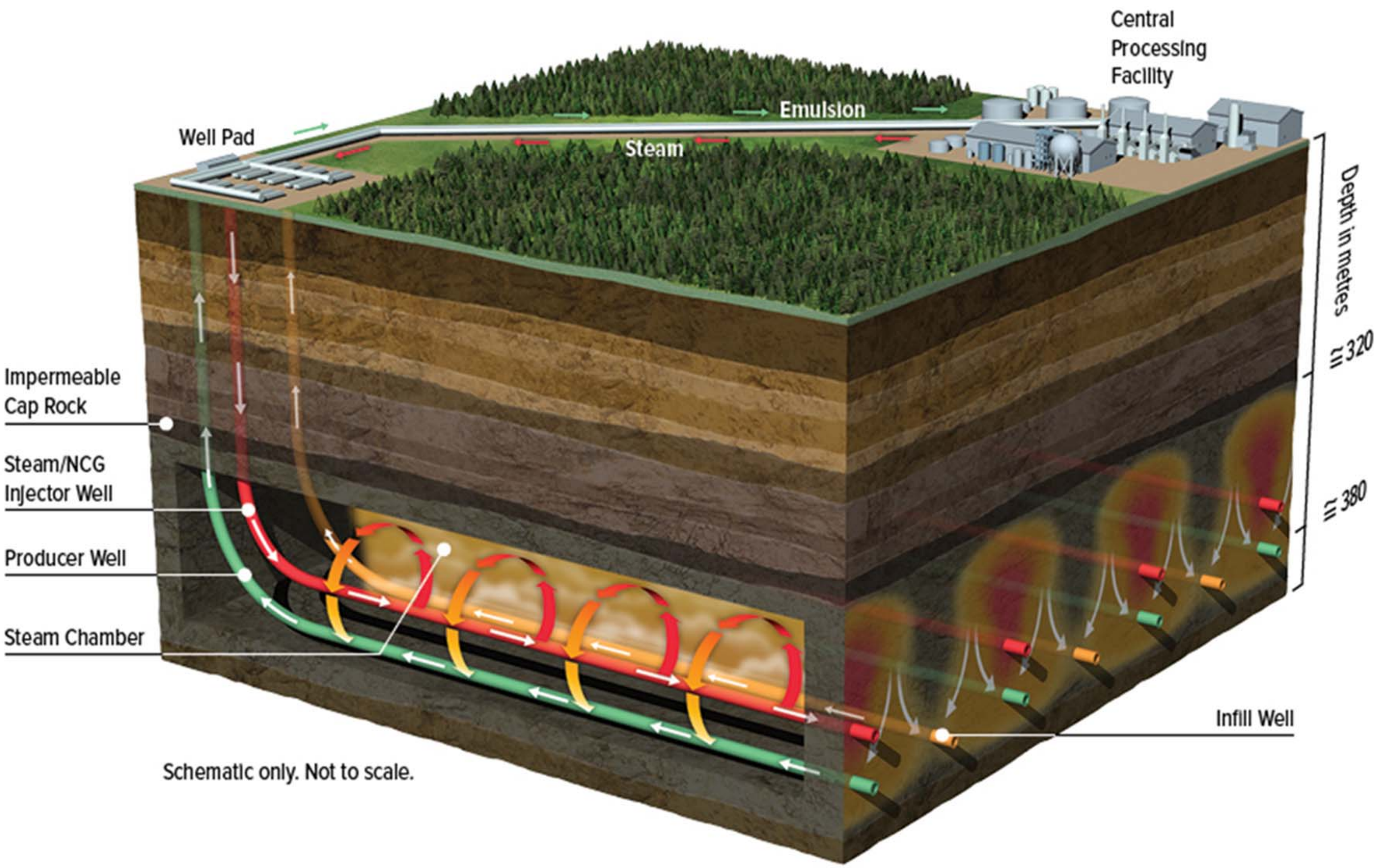
- Established in 1999
- Use steam-assisted gravity drainage (SAGD) technology to extract bitumen from the oil sands
- Operating Christina Lake Project Phases 2 (includes Phase 1) and 2B

Christina Lake Regional Project



Steam-Assisted Gravity Drainage (SAGD)

An Efficient Technology



Christina Lake Regional Project

Project History

Phase 1

- Approved in February 2005 for bitumen production of 477 m^3/d or 3,000 bpd
- Sustained steaming commenced March 2008

Phase 2

- Approved in March 2007 for total production of 3,975 m^3/d or 25,000 bpd
- First steam Q3 2009

Phase 2B

- Approved in March 2009 for total production of 9,540 m^3/d or 60,000 bpd
- First steam Q3 2013

Phases 3A/B/C/D

- Approved in February 2012 for total production of 33,390 m^3/d or 210,000 bpd

Phase 2B4X

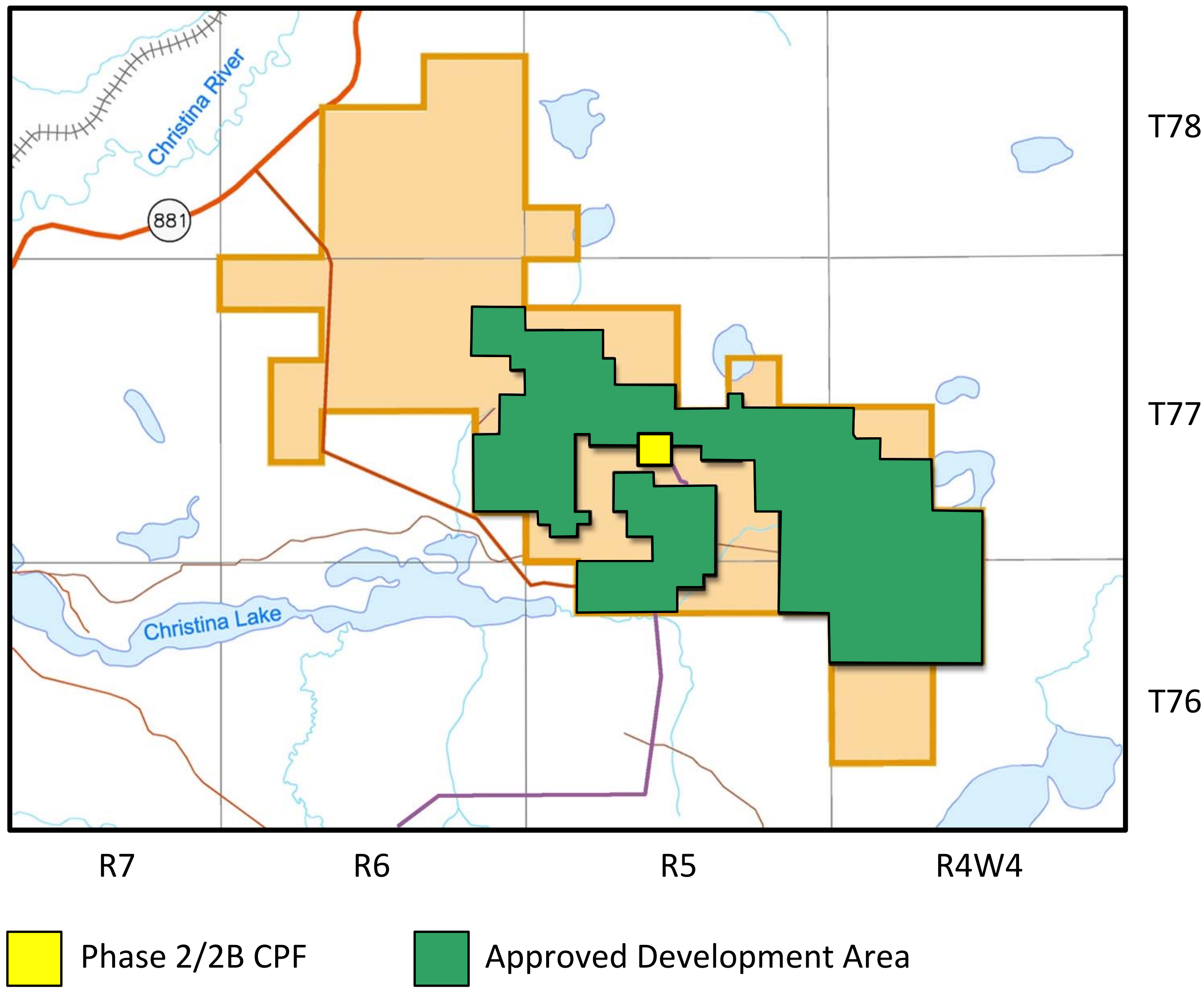
- Approved in June 2014 to re-locate Phase 3B to Phase 2/2B CPF

Christina Lake Regional Project

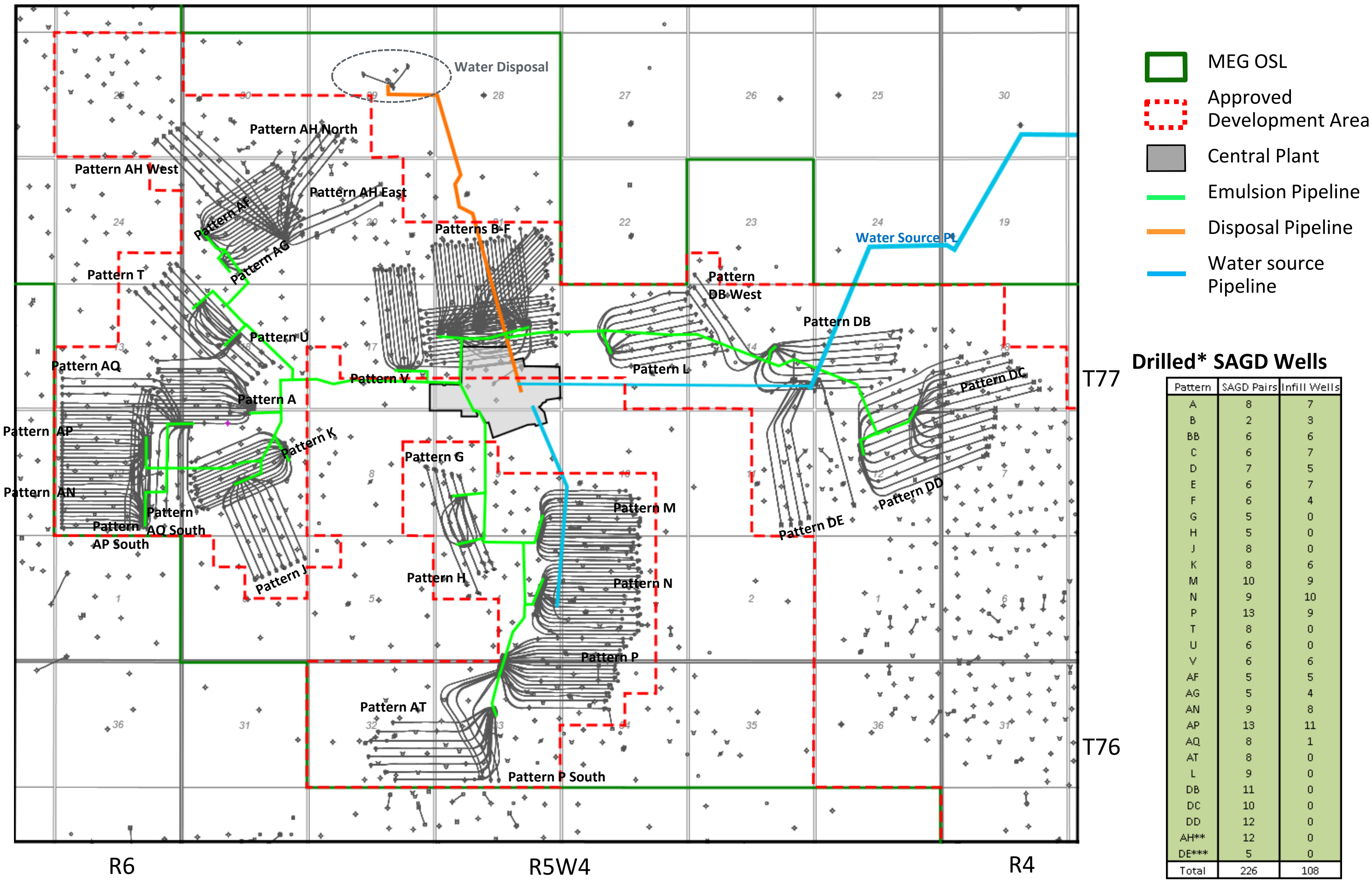
2018-2019 Operating Highlights

- 2018 Bitumen Production Averaged 87,731 bpd
- Q1 2019 Bitumen Production of 87,113 bpd
- Q1 2019 Average Field-wide SOR of 2.20
- Expanded Implementation of eMSAGP

Christina Lake Regional Project



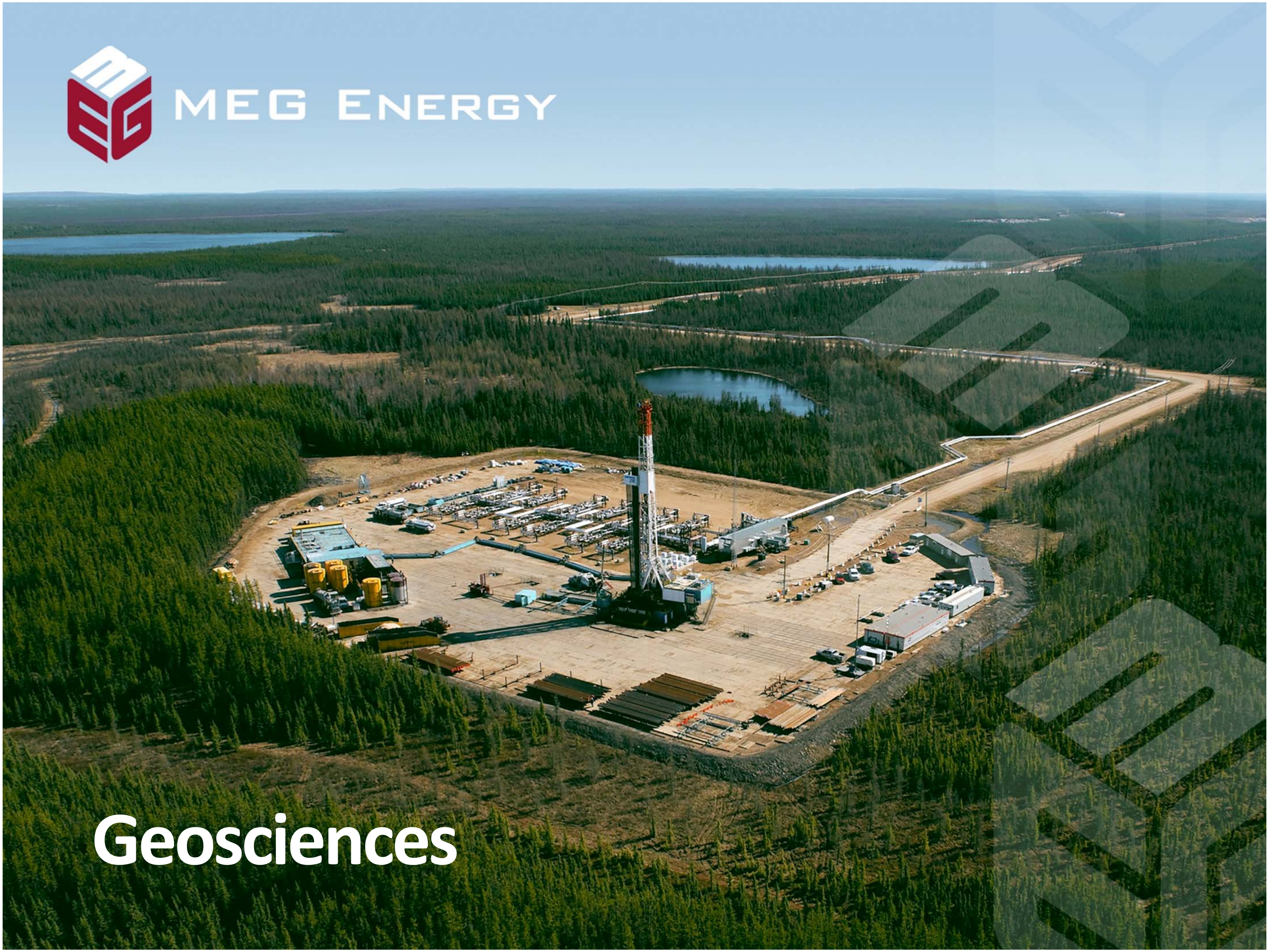
Active Development Area (ADA)



Drilled* SAGD Wells

Pattern	SAGD Pairs	Infill Wells
A	8	7
B	2	3
BB	6	6
C	6	7
D	7	5
E	6	7
F	6	4
G	5	0
H	5	0
J	8	0
K	8	6
M	10	9
N	9	10
P	13	9
T	8	0
U	6	0
V	6	6
AF	5	5
AG	5	4
AN	9	8
AP	13	11
AQ	8	1
AT	8	0
L	9	0
DB	11	0
DC	10	0
DD	12	0
AH**	12	0
DE***	5	0
Total	226	108

*** As of April 30 2019**
**** AH has 12/12 producers drilled with no Injectors yet completed**
*****DE has 5 of 11 producers drilled with no Injectors yet completed**

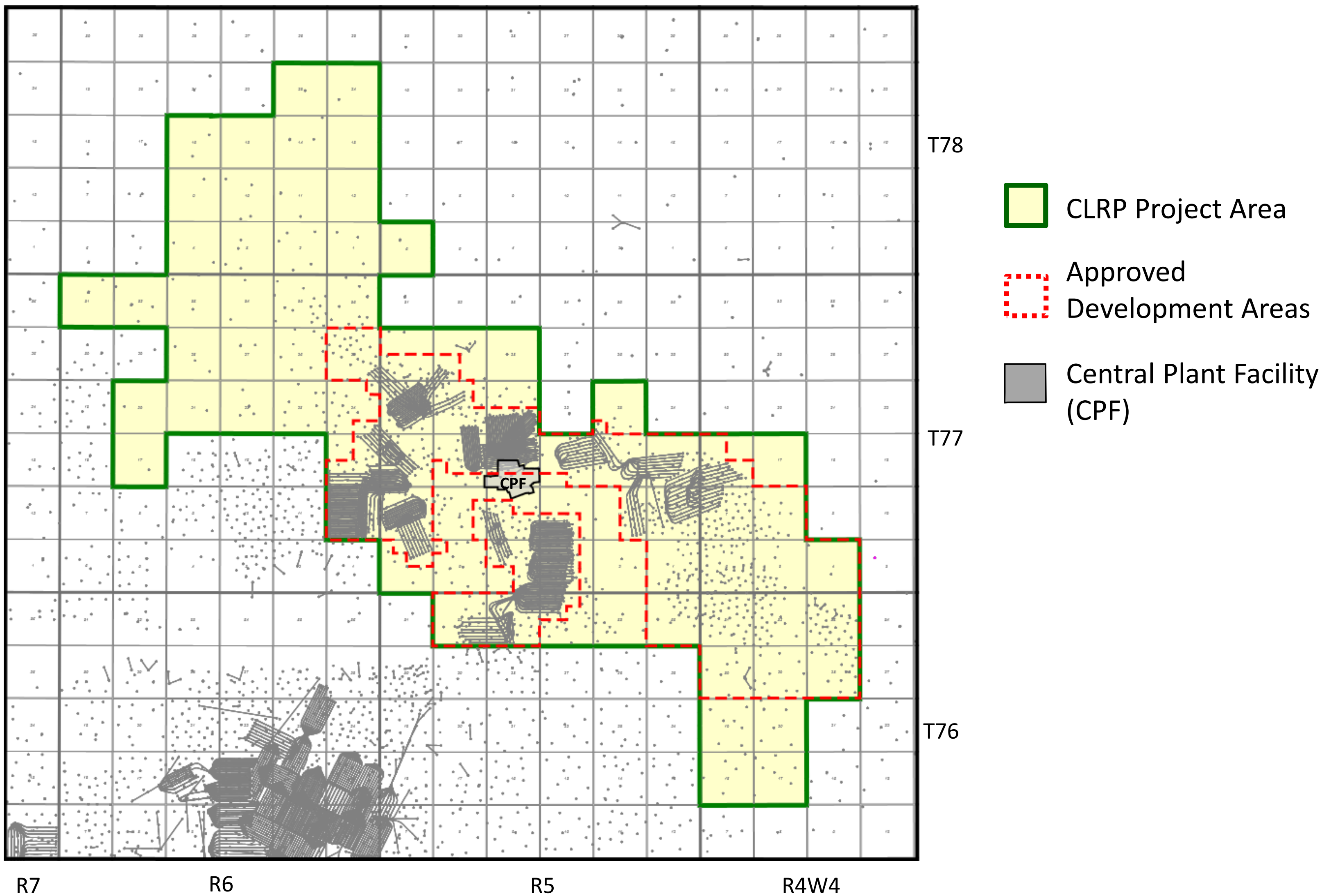


Geosciences

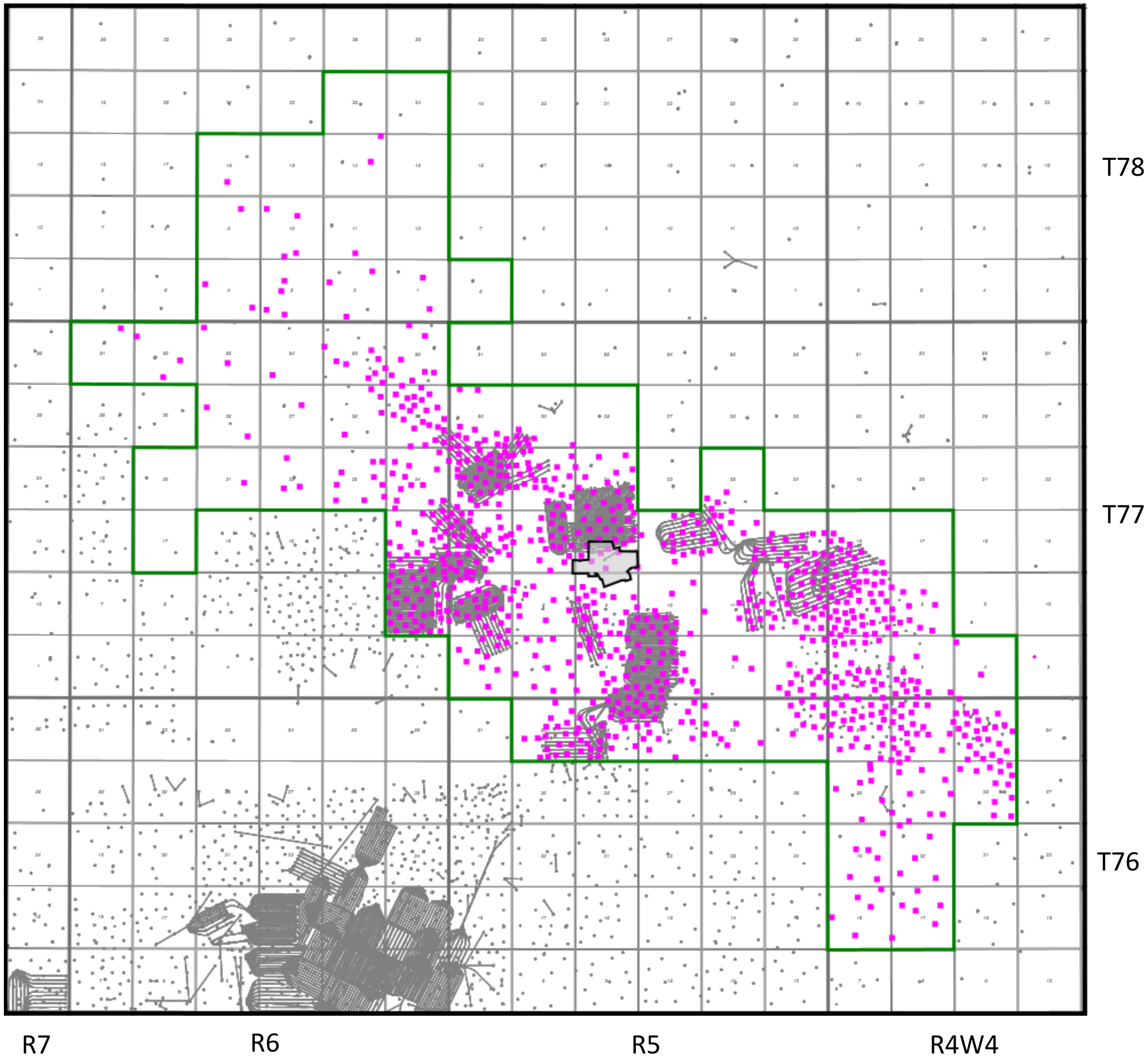
Geoscience Review

- Well and Seismic Data
  - Core hole update
  - SAGD Drilling update
- Stratigraphic Framework
  - Geologic Overview
  - Type log
- Reservoir and Pay Parameters
- Active Development Area Bitumen Pay
  - Developable pay Isopach map
  - Top and Base pay Structure maps
  - Structure Sections over exploited area
- Cap Rock Geology
- Basal Aquifer Net sand Isopach
- Active Development Area Associated Gas Resources
- Observation Wells
- SAGD Well Spacing

Christina Lake Regional Project (CLRP)



Wabiskaw / McMurray Cores

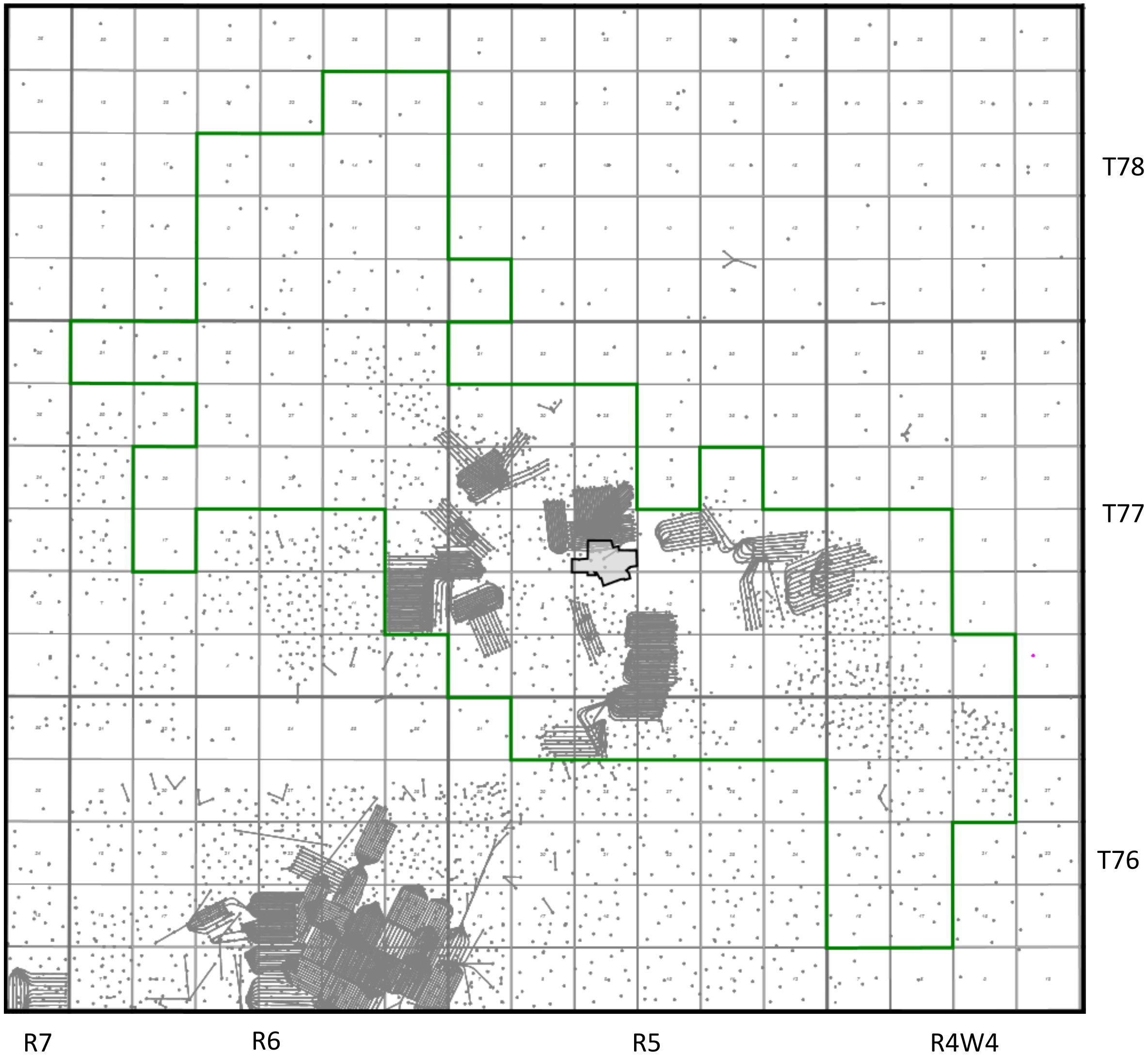


CLRP Project Area

Wabiskaw / McMurray Core

- 910 cored wells
- 87% of all wells are cored

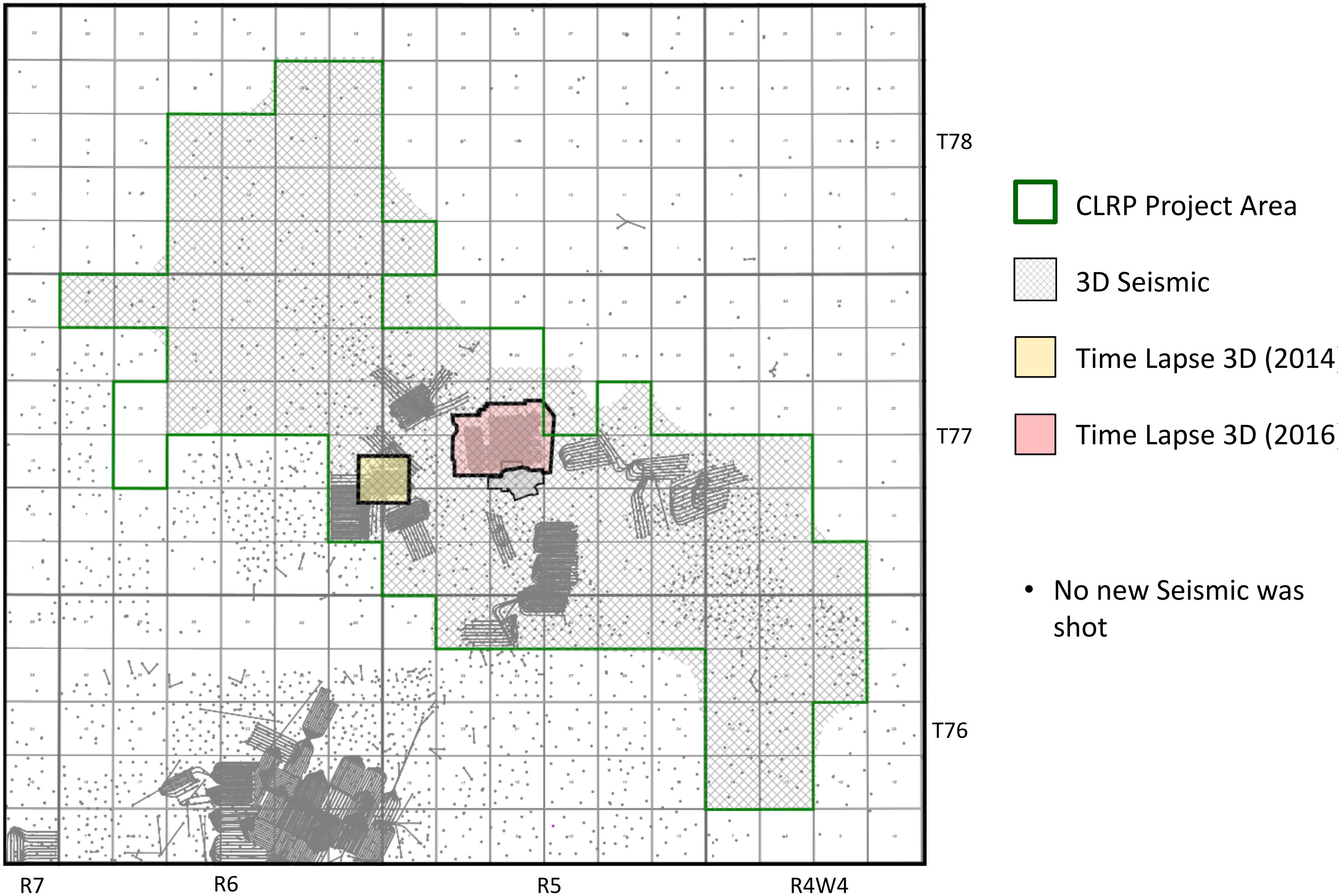
2019 Stratigraphic Test Wells



Over the 2019 reporting period

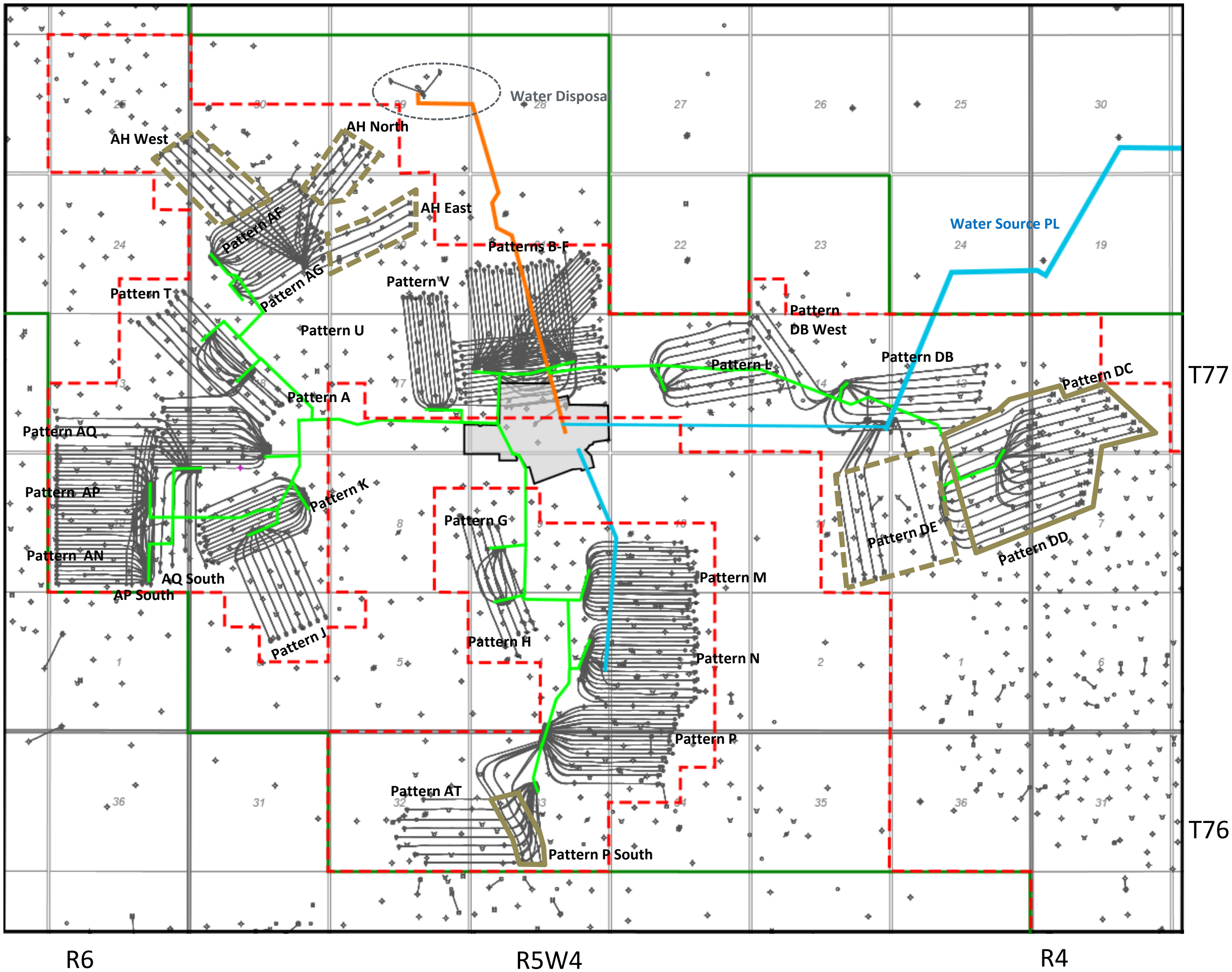
- No delineation wells were drilled
- No GeoMechanical analysis was done
- No reservoir Fracture Pressure or Caprock Integrity tests were done

3D Seismic



- No new Seismic was shot

Active Development Area (ADA)



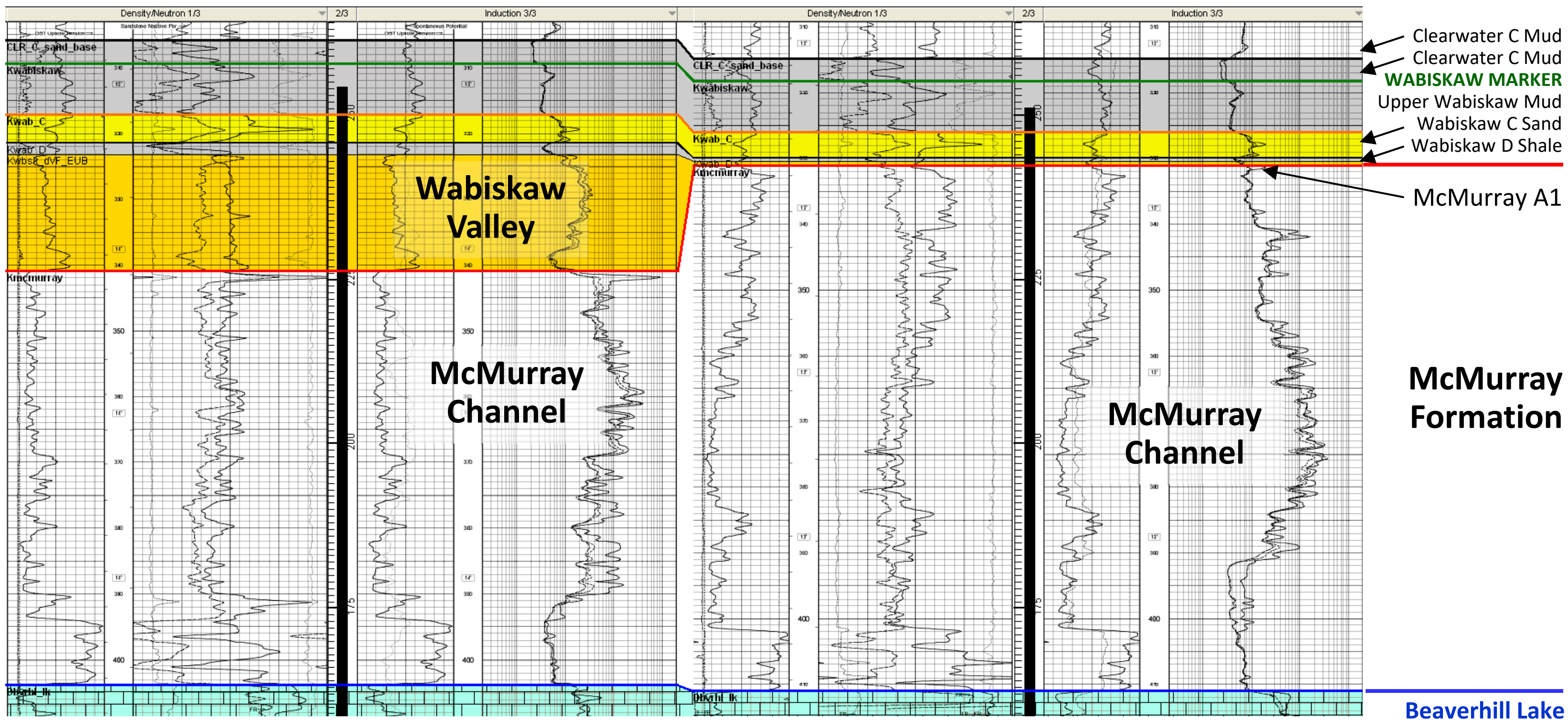
MEG OSL
Approved Development Area
Central Plant
Emulsion Pipeline
Disposal Pipeline
Water Source Pipeline
Recent SAGD Patterns
Recent SAGD Patterns (in progress)

526* horizontal wells
(SAGD and infill wells)

***Does not include the incomplete Pairs of AH and DE patterns**

Wabiskaw/McMurray Stratigraphy

1AA/13-18-77-05W4 **1AC/10-07-77-05W4**

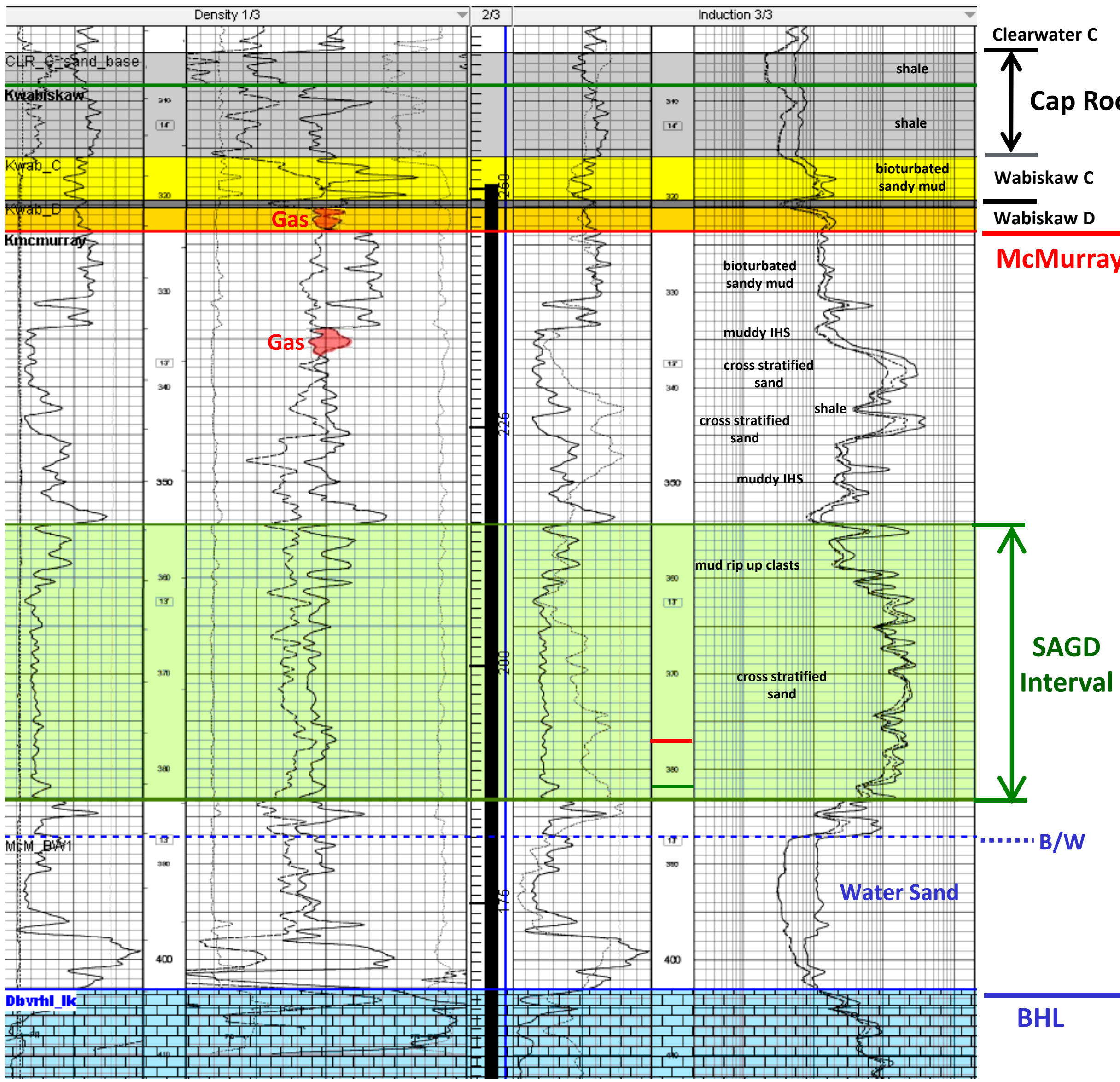


Stratigraphic Unit	Facies Association
lower Clearwater C	offshore mud
upper Wabiskaw	offshore / lower shoreface mud
Wabiskaw C	shoreface sand
Wabiskaw D Shale	bay mud
Wabiskaw D Valley	bay sand and mud
McMurray A1	shoreface sand / coal
upper McMurray Channel	tidal flat / creek sand and mud
lower McMurray Channel	fluvial / estuarine channel sand and mud
Beaverhill Lake	carbonate mudstone

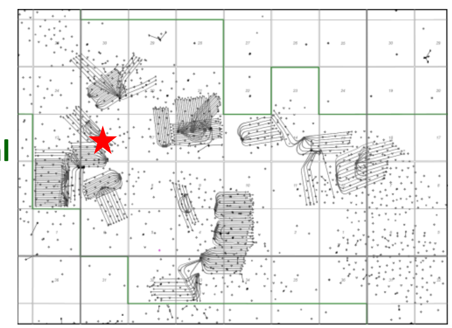
McMurray stratigraphy after ERCB RGS 2003

Wabiskaw / McMurray Reference Well

1AE/06-18-77-05W400



	McMurray	SAGD
h (m)	47.6	28.9
avg ø	0.311	0.314
avg S_o	0.770	0.794
BMO (calc)	0.114	0.120
McMurray Pay >6wt% BMO		



Injector
Producer

McMurray SAGD Pay Parameters

SAGD Pay

≥ 10 m continuous pay (defined from cores, images and well logs)

R_t = Deep Induction

$Ø_{density}$ ≥ 25%

parameters for S_o calculation

S_o (bitumen saturation) ≥ 50%

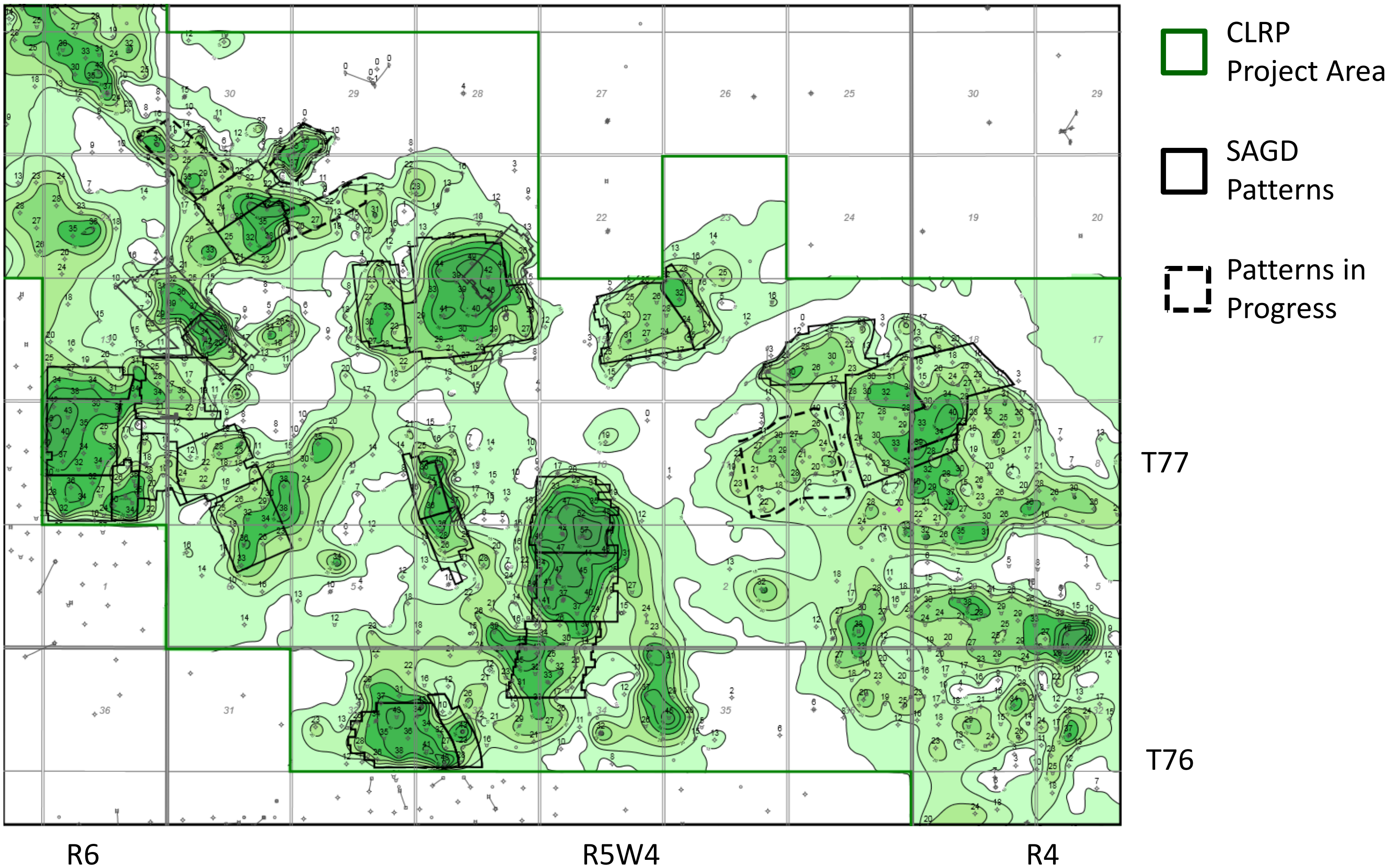
Gas and coal excluded

McMurray Reservoir Properties

Average Pay (m)	18.7
Average Depth to reservoir top (mTVD)	359
Porosity range (Frac)	0.30-0.36
Water Saturation Range (frac)	0.15-0.30
Average K_h (Darcies)	5,000
Average K_v (Darcies)	2,500
Initial Reservoir Pressure (Kpag)	2,100
Reservoir temperature (°C)	13

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

ADA Total McMurray SAGD Pay ≥ 10 m

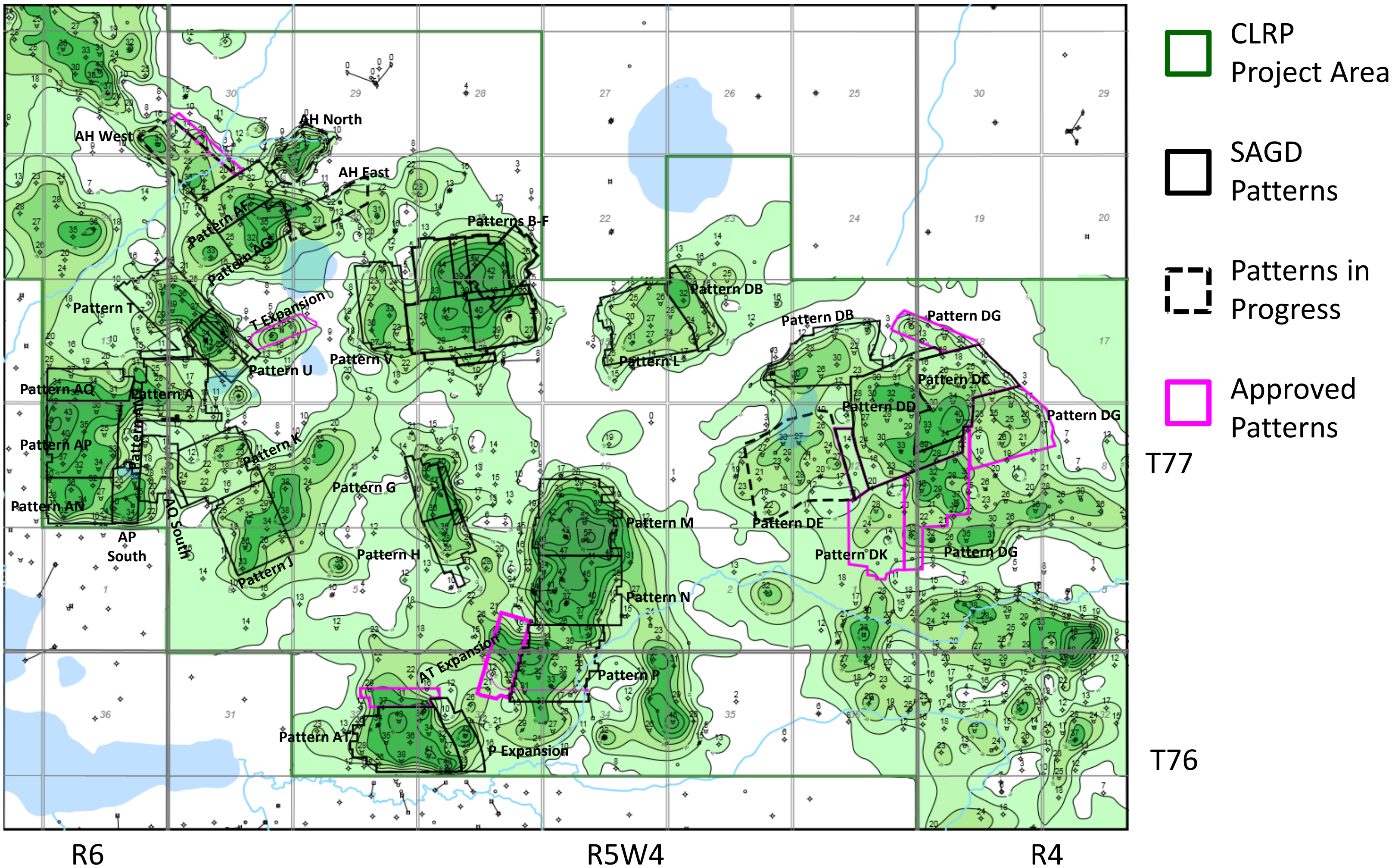


SAGD Pay Cutoffs:

- Continuous bitumen pay ≥ 10 m (defined by logs, images and core)
- So ≥ 50% (~6 wt% bulk mass oil);
- Porosity (density) ≥ 25%;

Min contour = 10 m
Contour interval = 5 m

OBIP Approved Development Areas

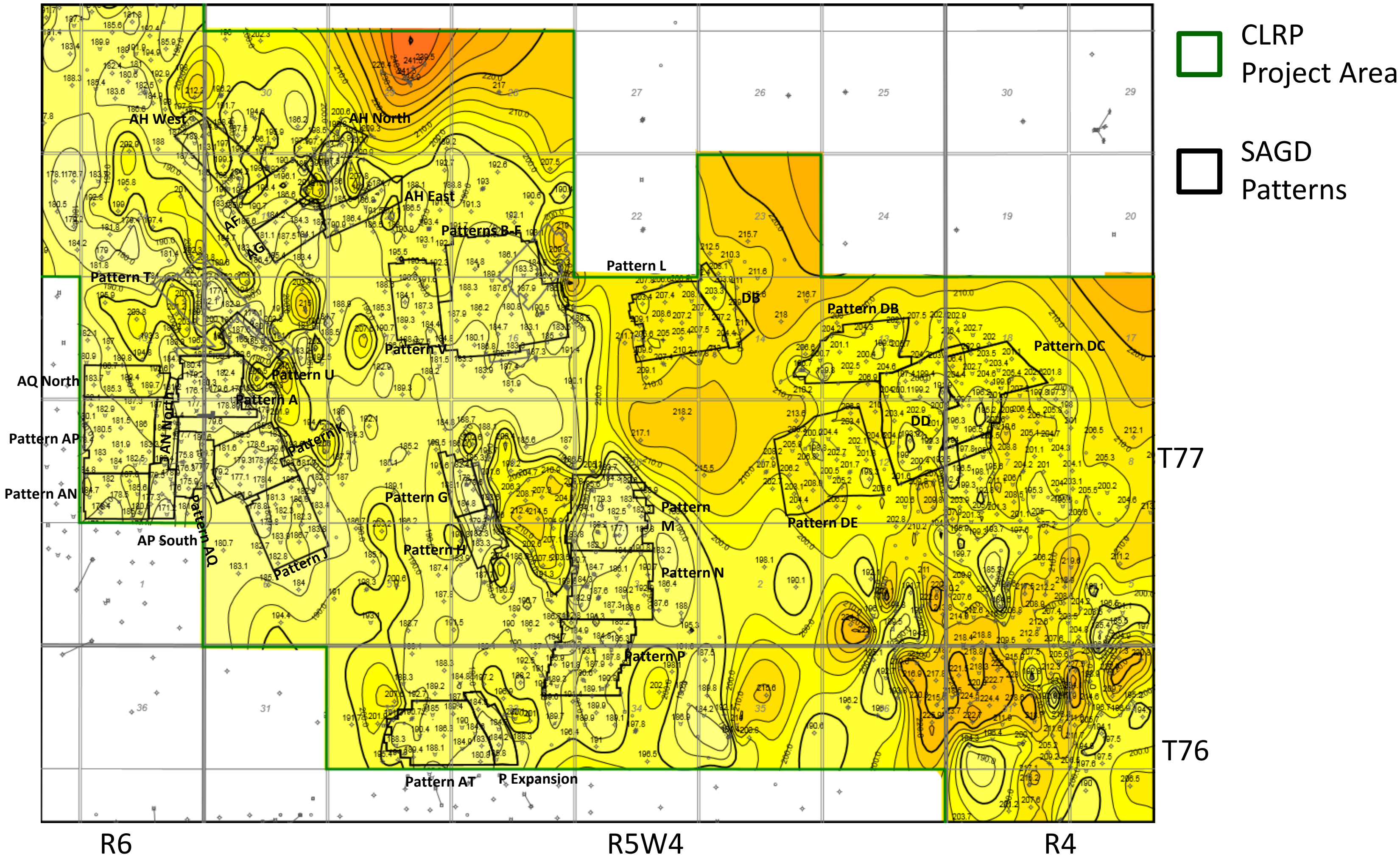


SAGD Pay Cutoffs:

- Continuous bitumen pay ≥ 10 m (defined by logs, images and core)
- So ≥ 50% (~6 wt% bulk mass oil);
- Porosity (density) ≥ 25%;

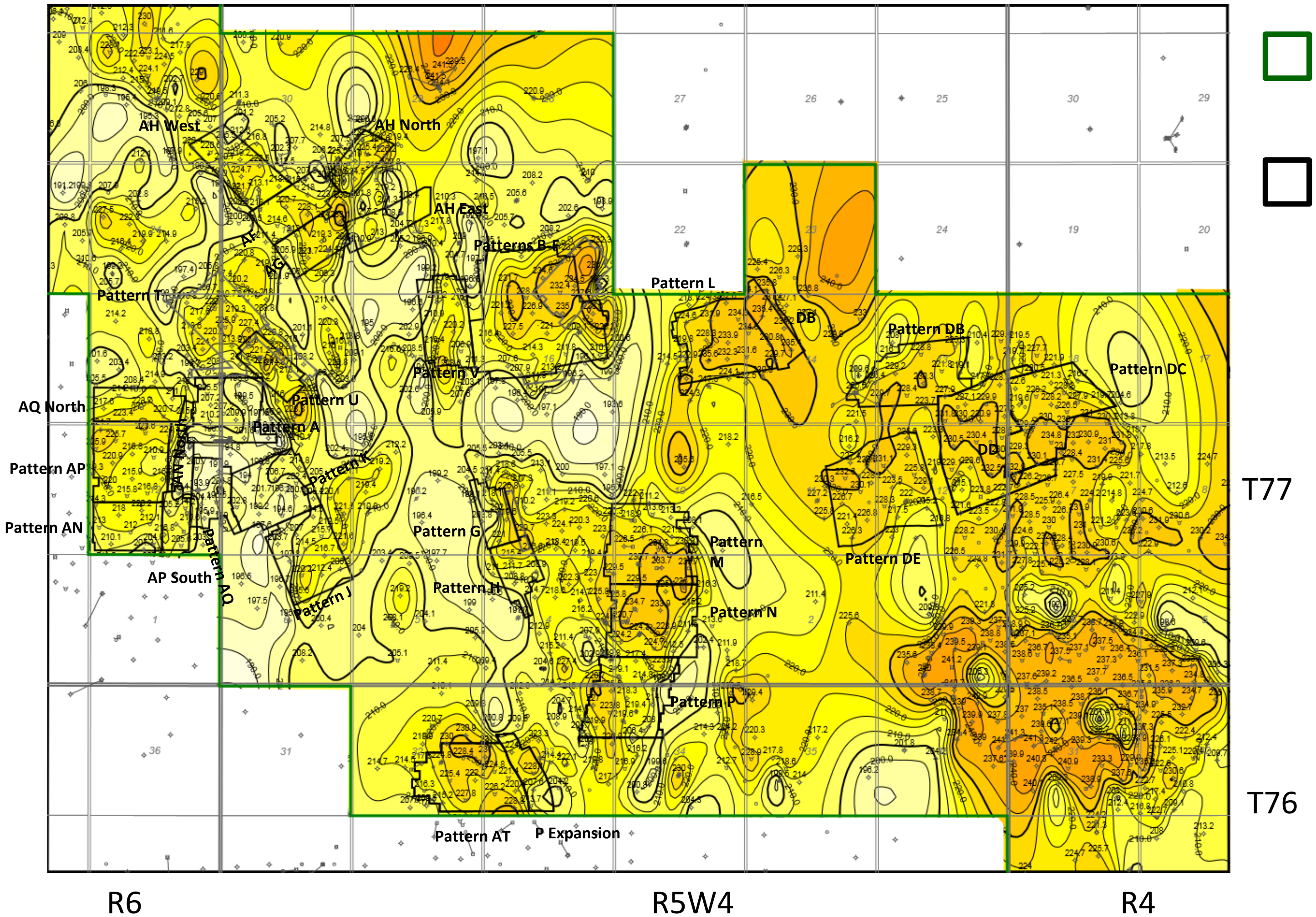
Min contour = 10 m
Contour interval = 5 m

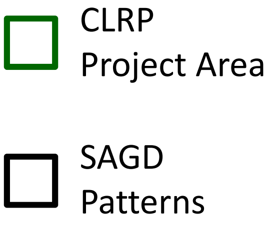
ADA Base SAGD Pay Structure



Contour interval = 5 m

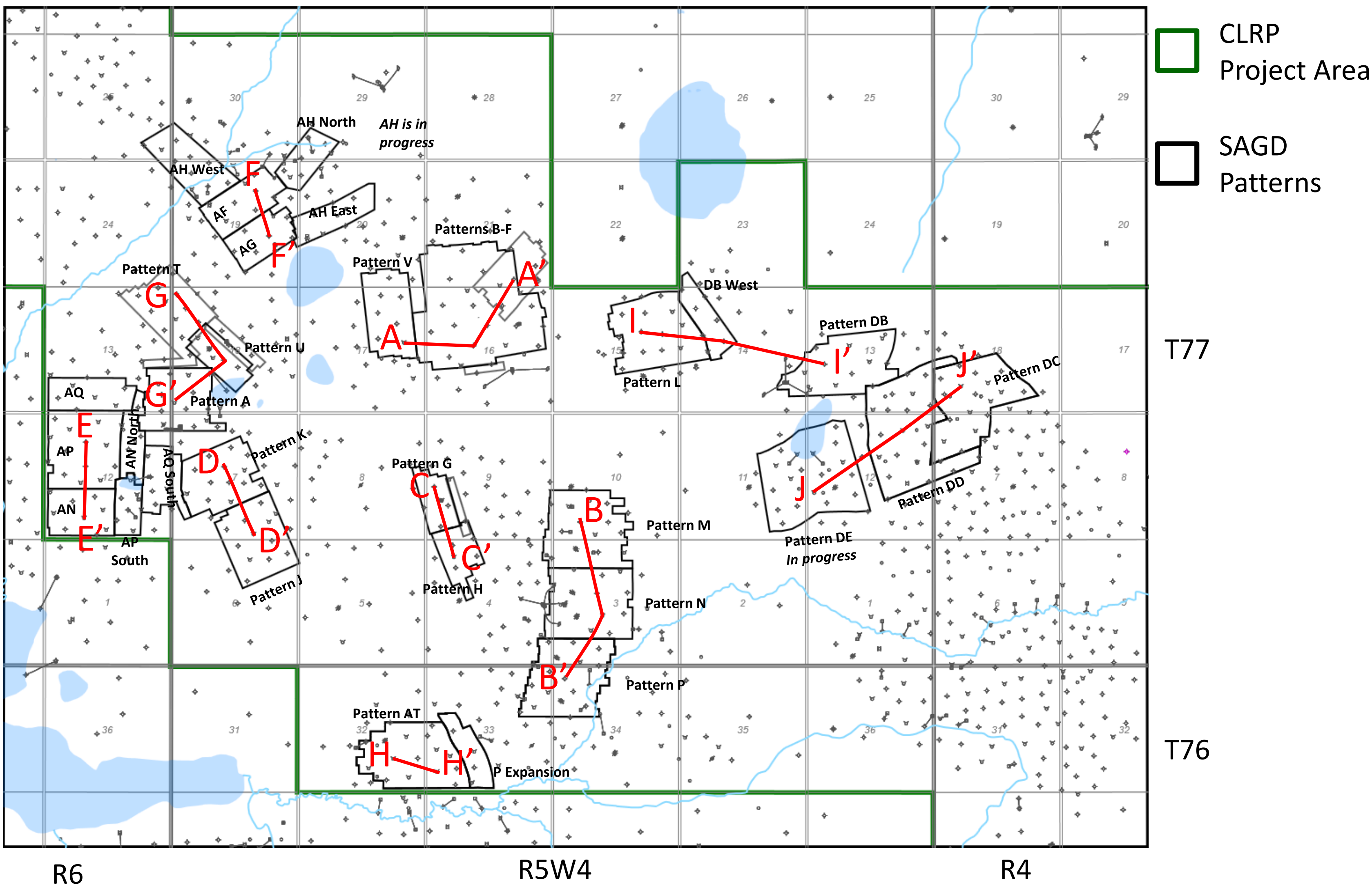
ADA Top SAGD Pay Structure



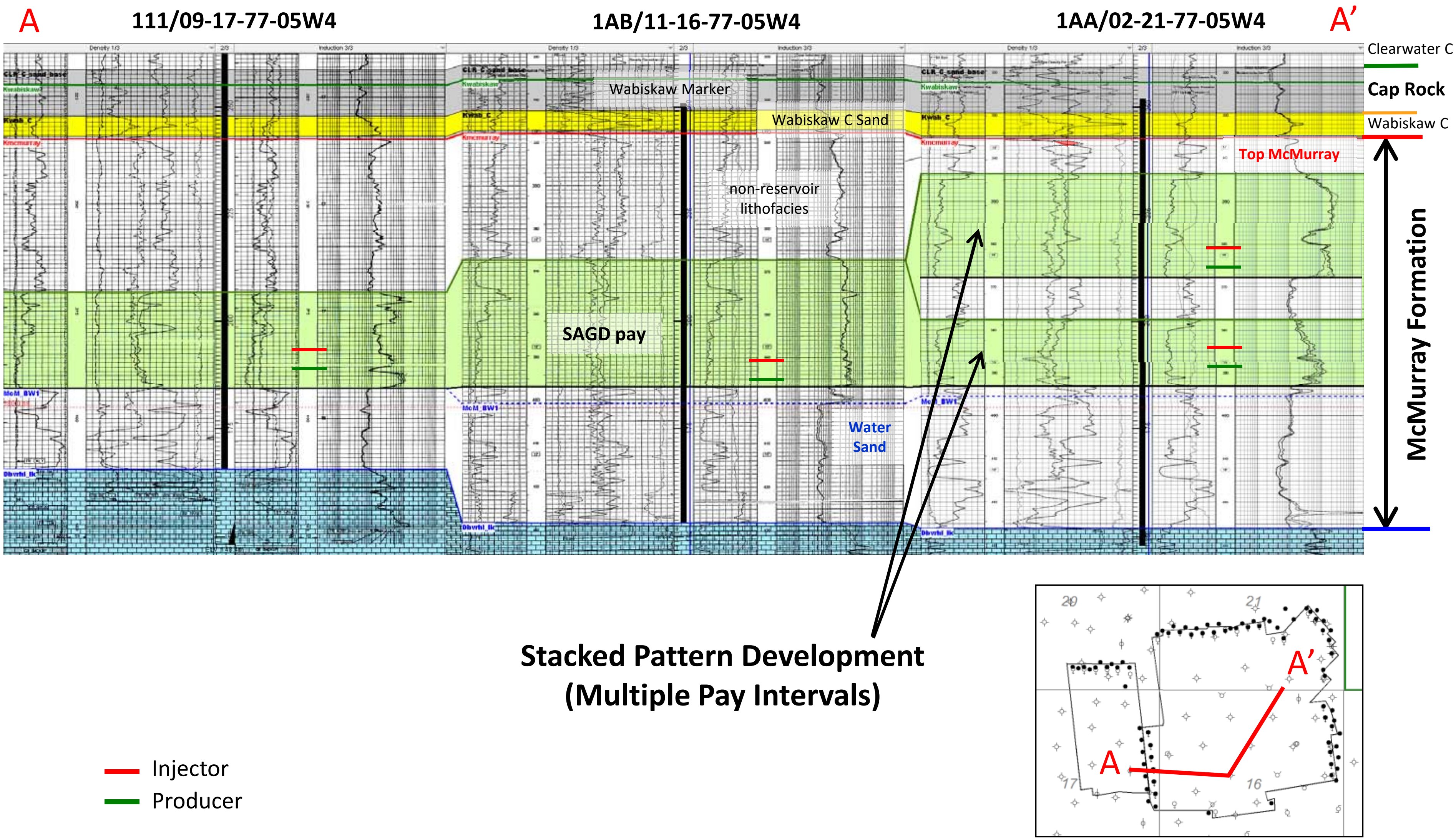


Contour interval = 5 m

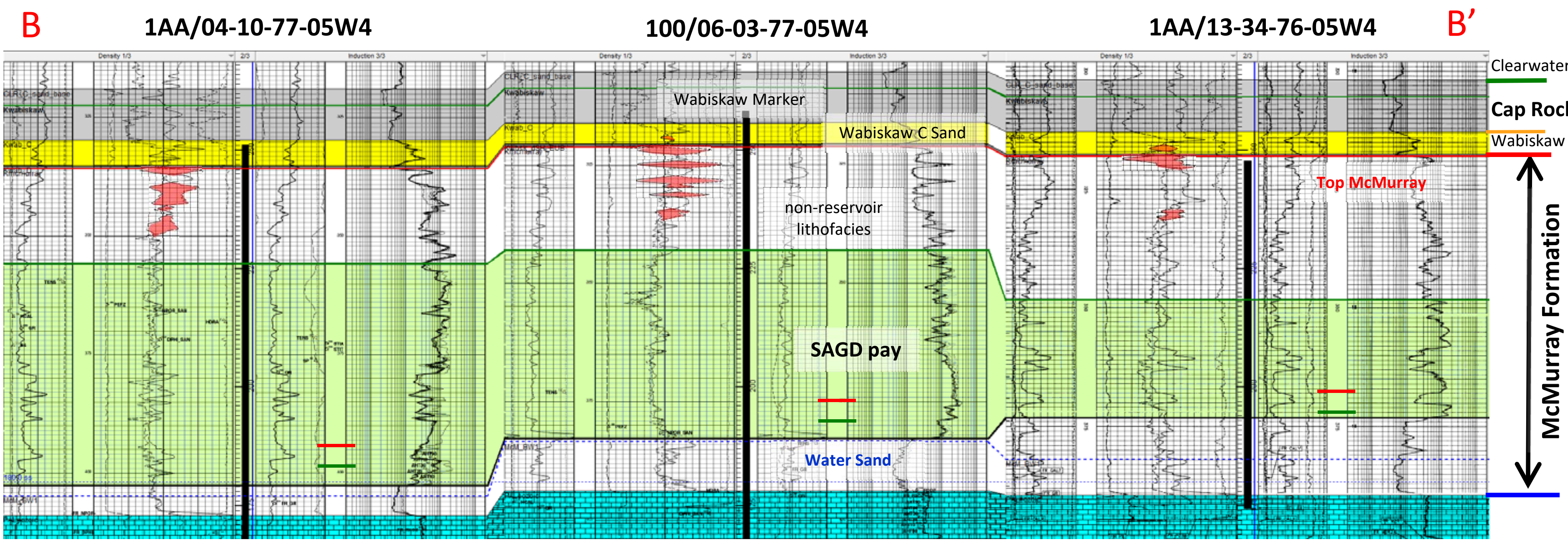
Cross Sections for Scheme Area

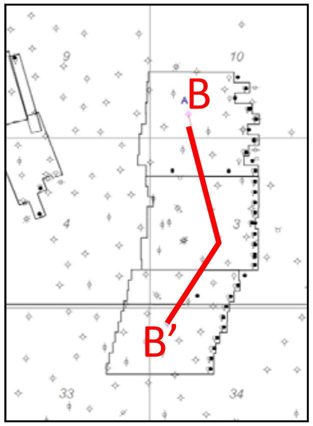


Structural Cross Section A-A’



Structural Cross Section B-B’

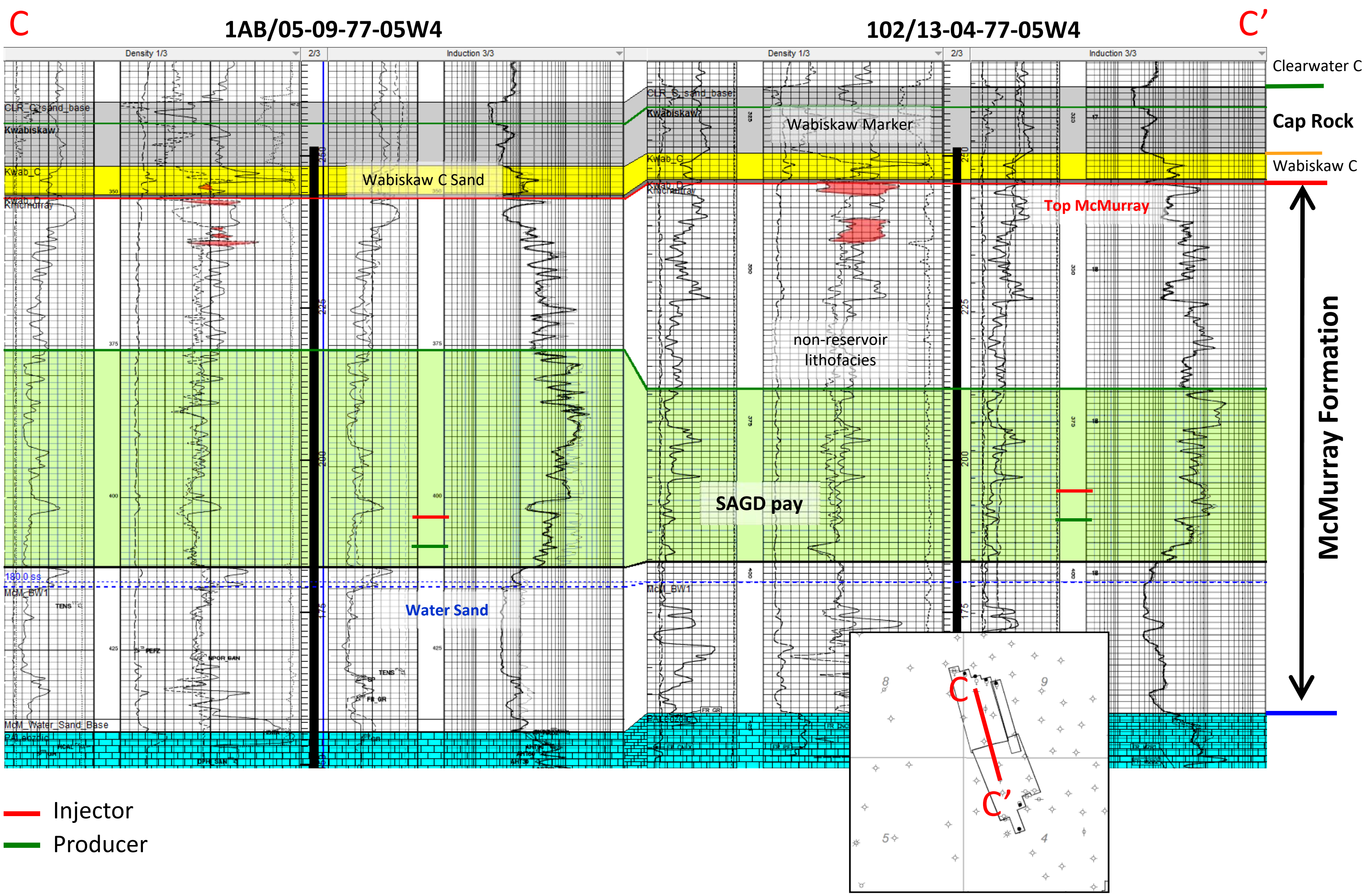




Injector

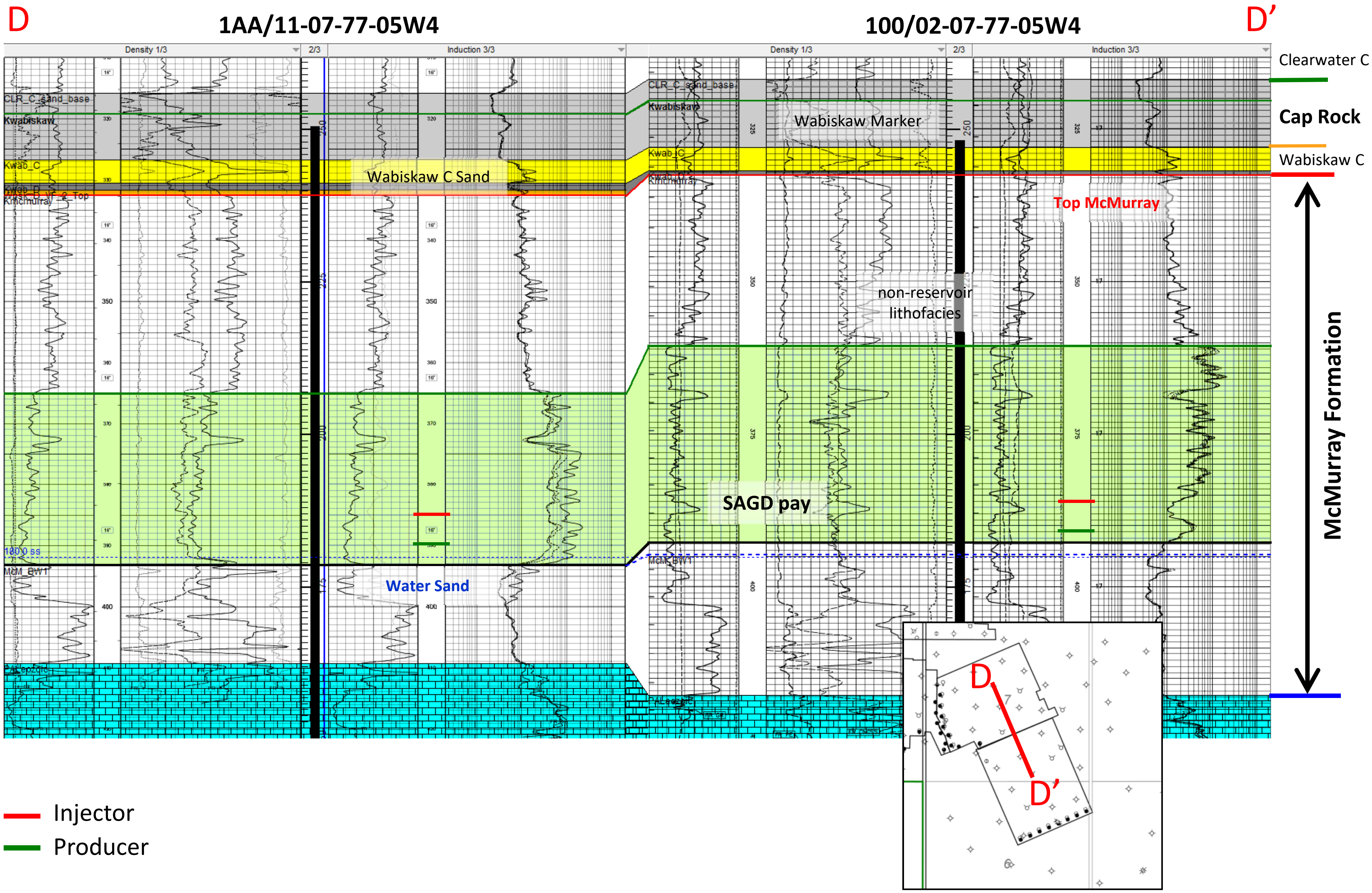
Producer

Structural Cross Section C-C’



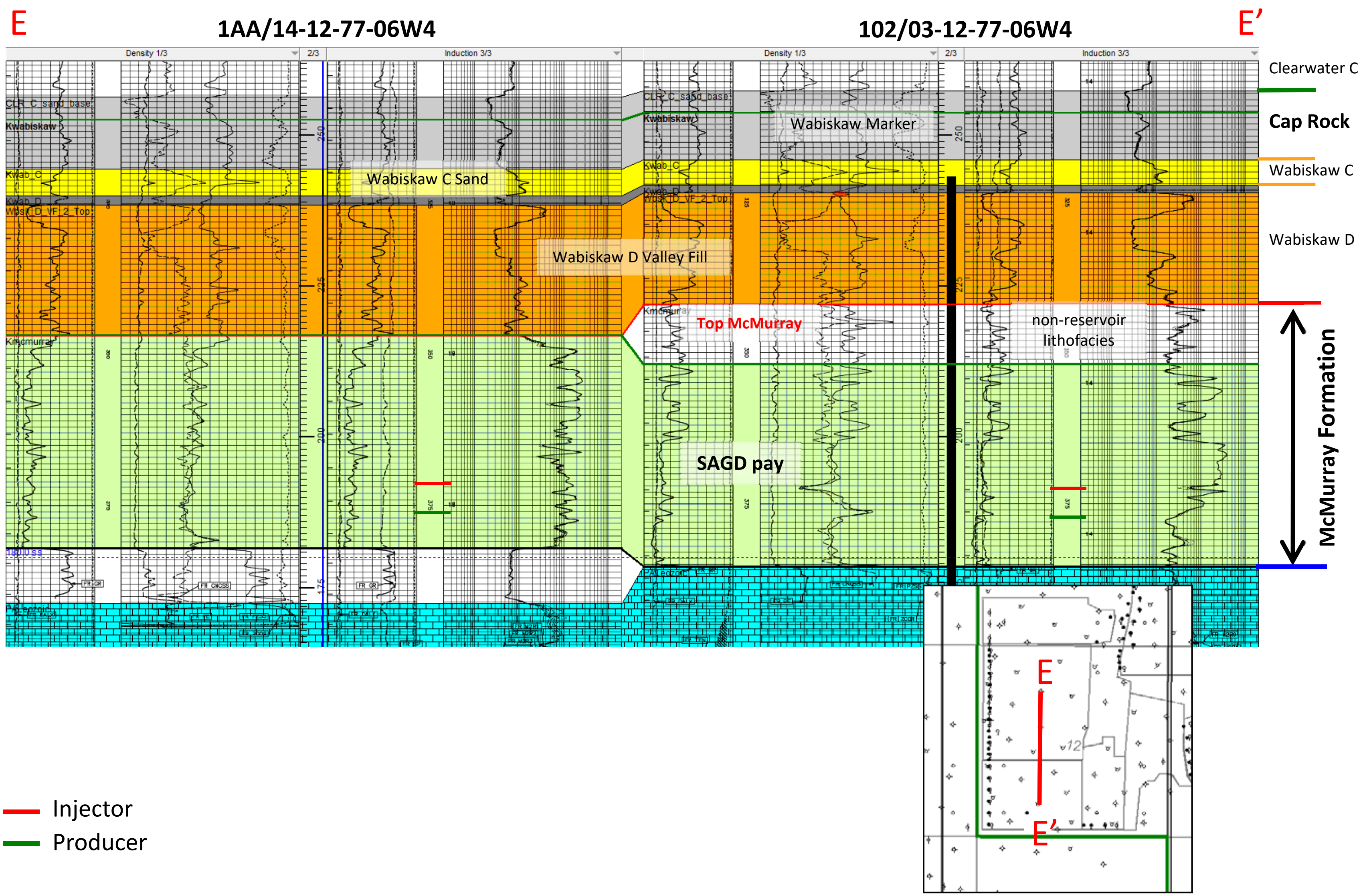
Injector
Producer

Structural Cross Section D-D'



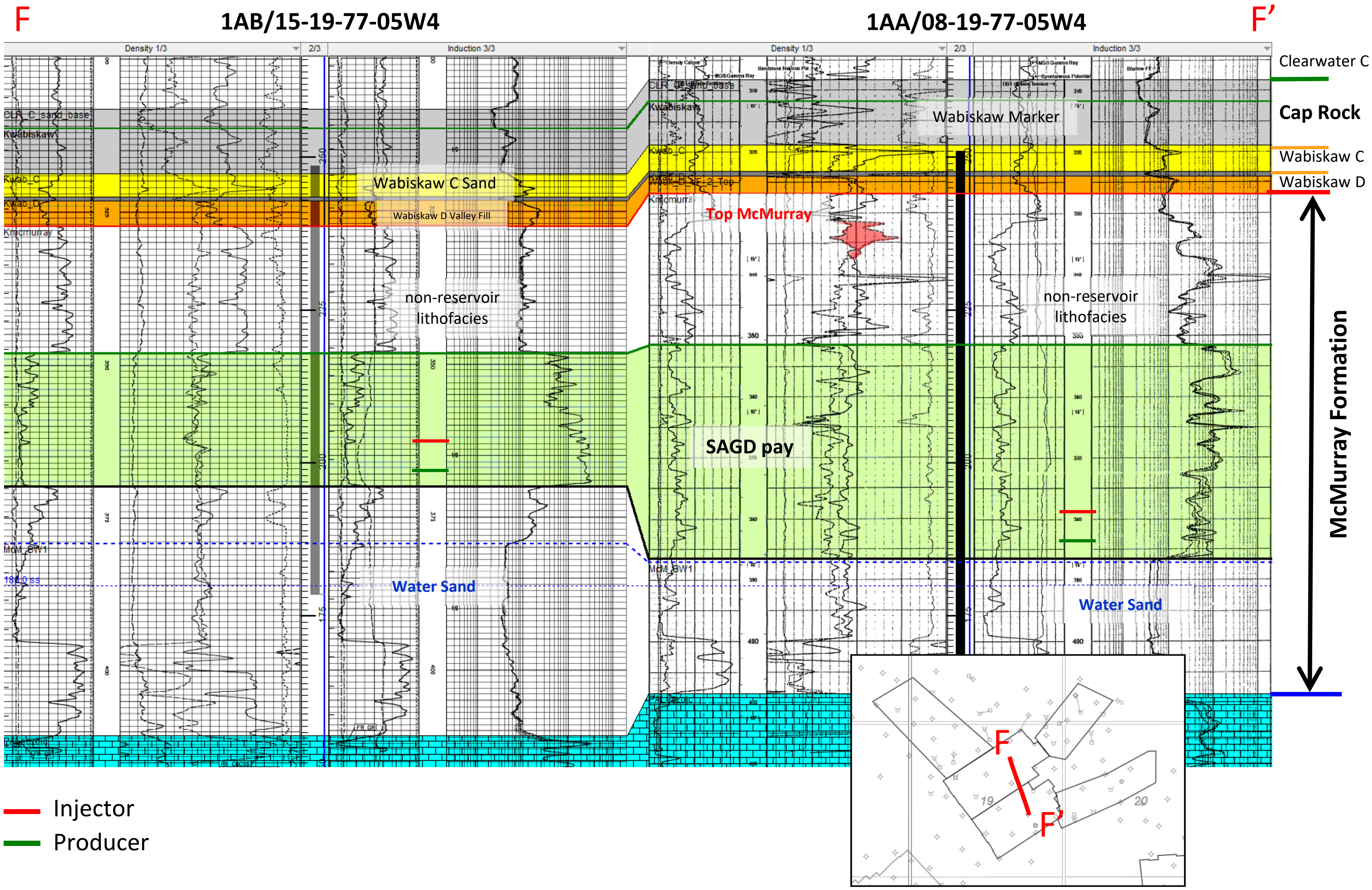
Injector
Producer

Structural Cross Section E-E’



Injector
Producer

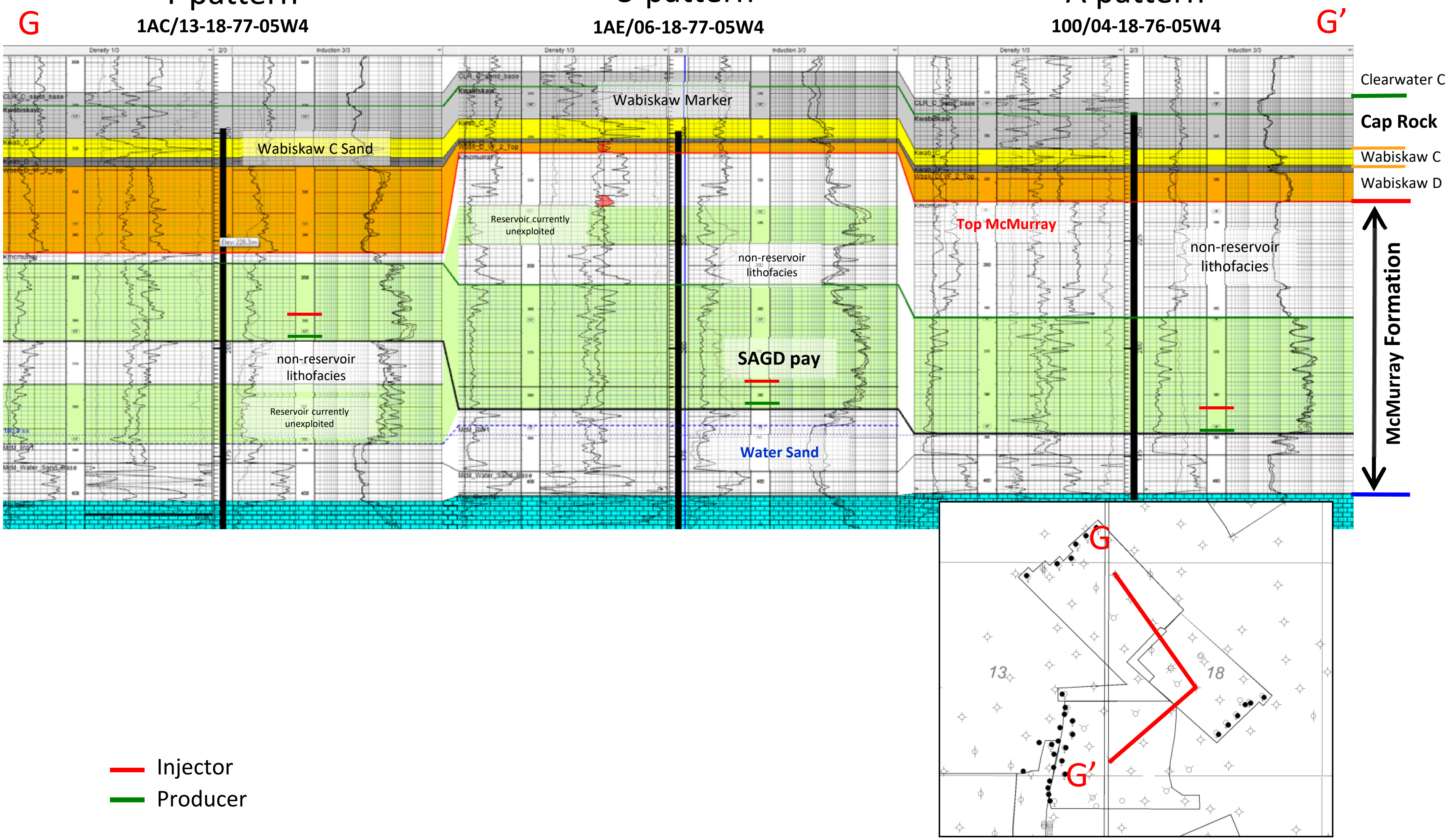
Structural Cross Section F-F’



Injector

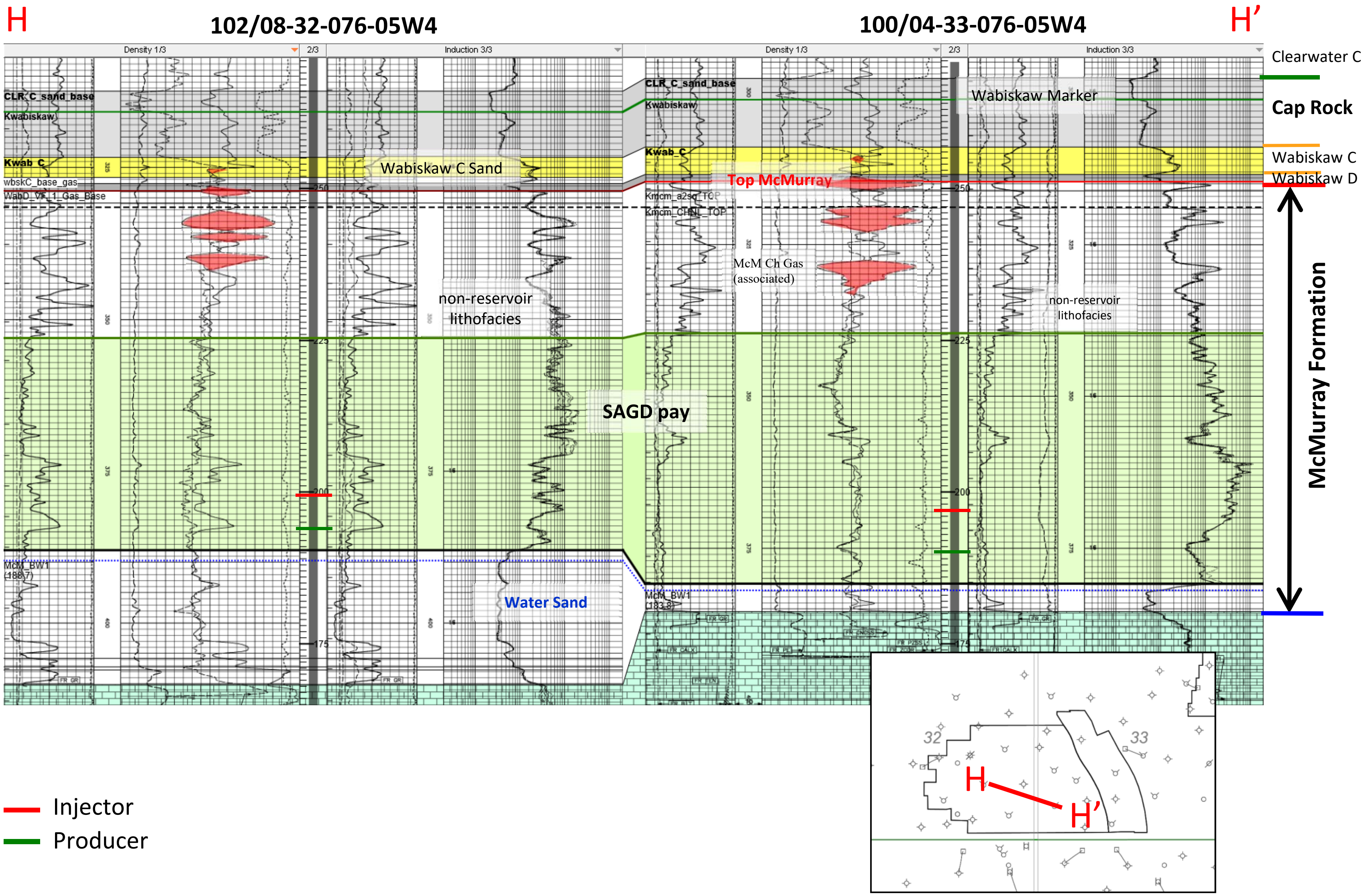
Producer

Structural Cross Section G-G’



Injector
Producer

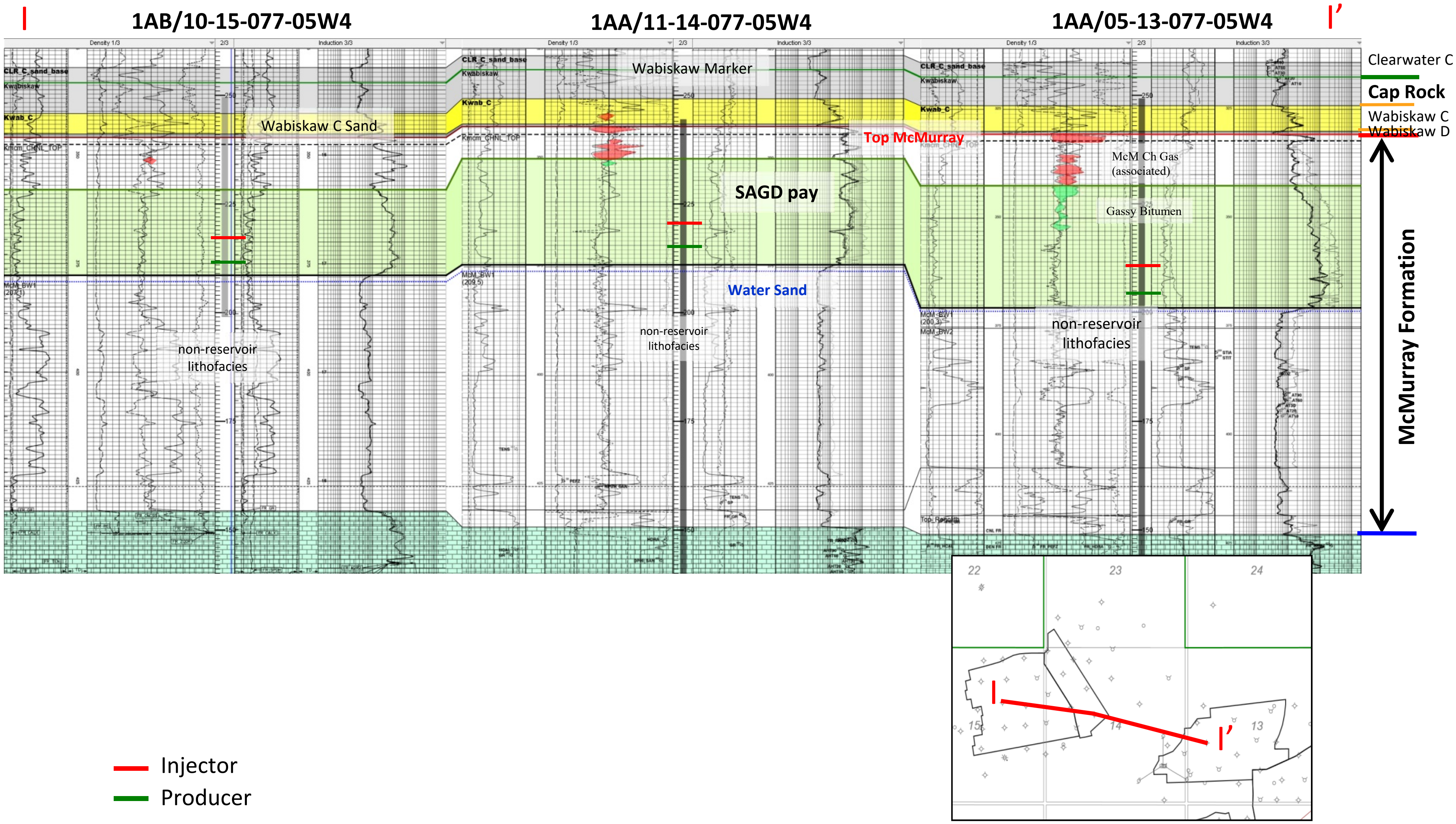
Structural Cross Section H-H’



Injector

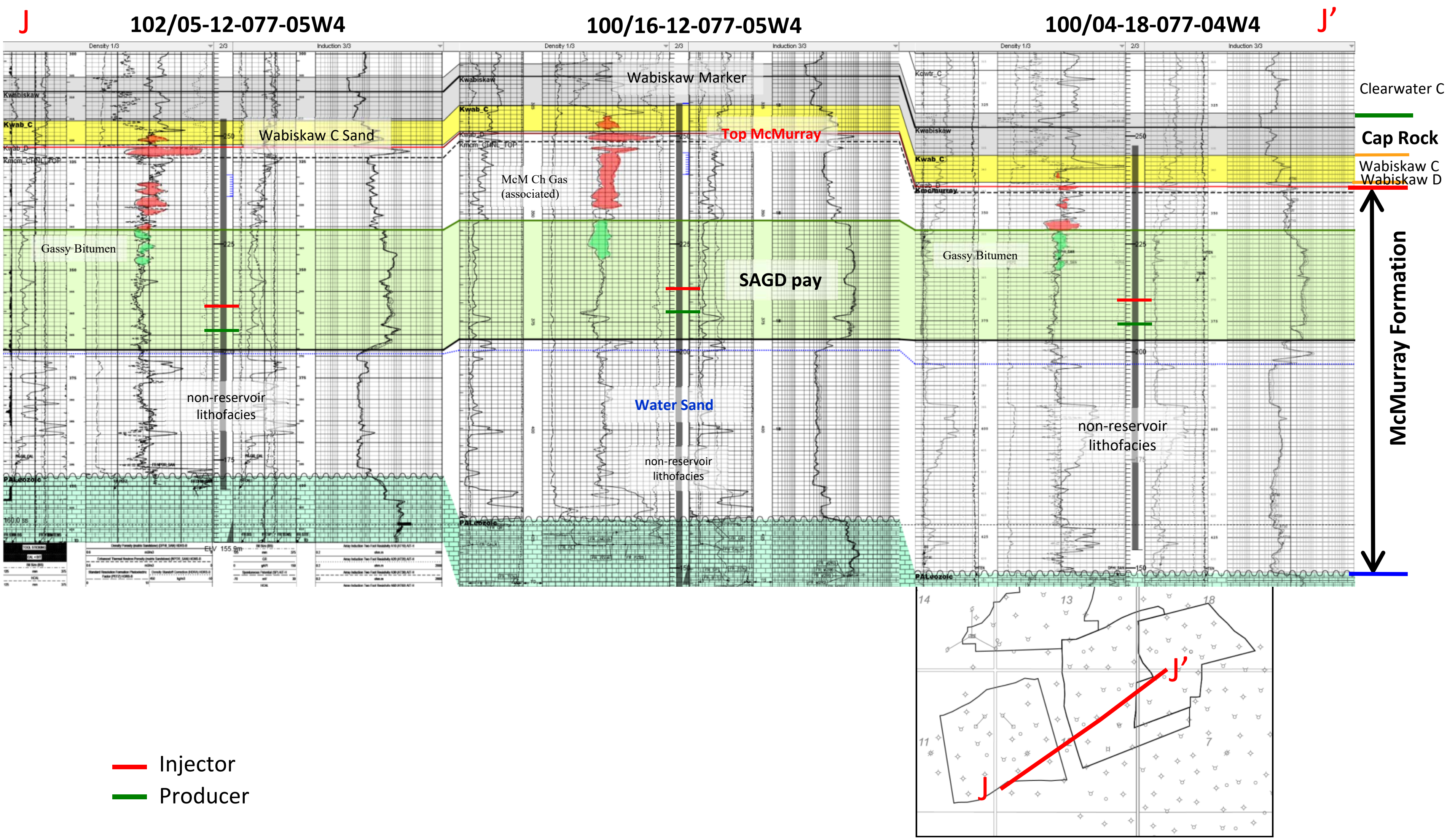
Producer

Structural Cross Section I-I’



Injector
Producer

Structural Cross Section J-J’

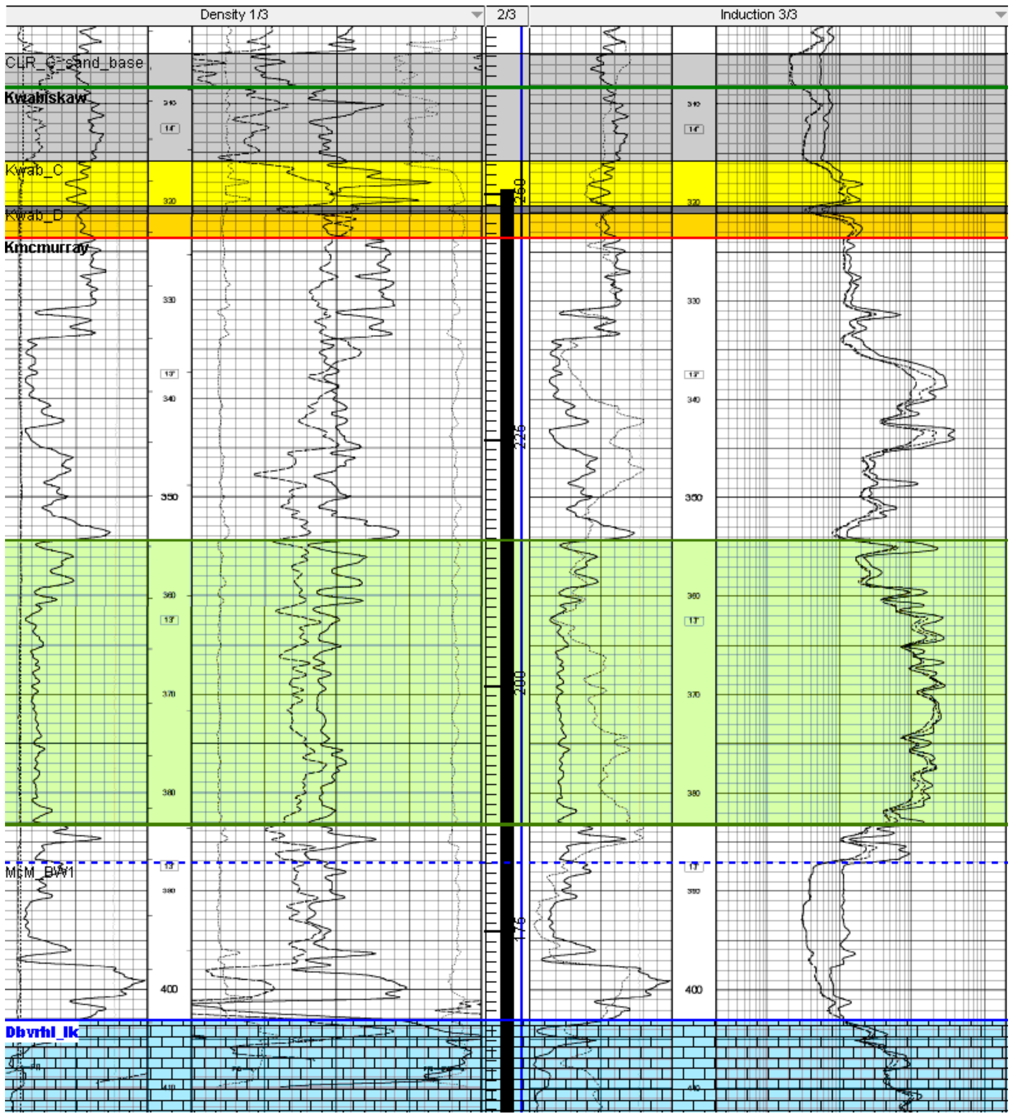


Injector

Producer

Lower Clearwater Cap Rock

1AE/06-18-77-05W4



Clearwater C

mud
WBSK Mkr
mud

Lower Clearwater Cap Rock

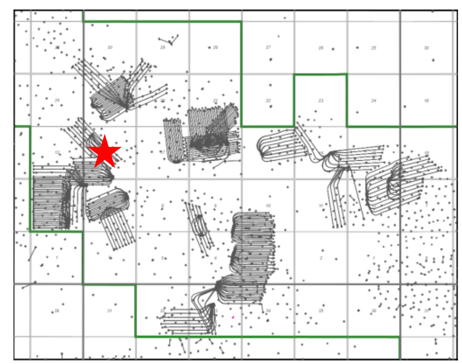
WBSK C
WBSK D Shale
WBSK D

McMurray

non-reservoir lithofacies

Lower Clearwater Cap Rock = 10.9 m thick

SAGD Pay

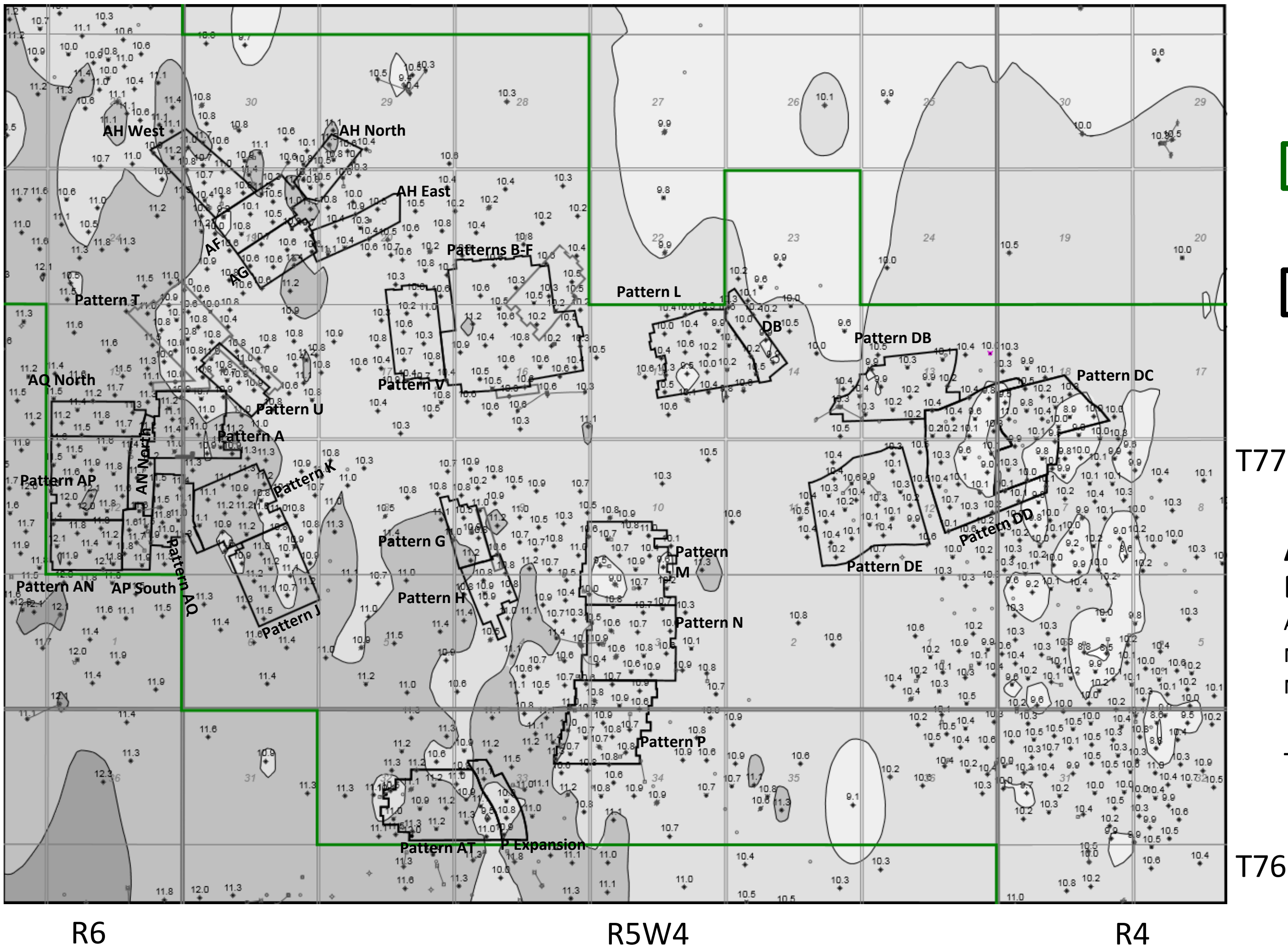


Bitumen / Water Contact

Water Sand

Beaverhill Lake

ADA Lower Clearwater Cap Rock



CLRP Project Area

Drilled SAGD Patterns

Active Development Area

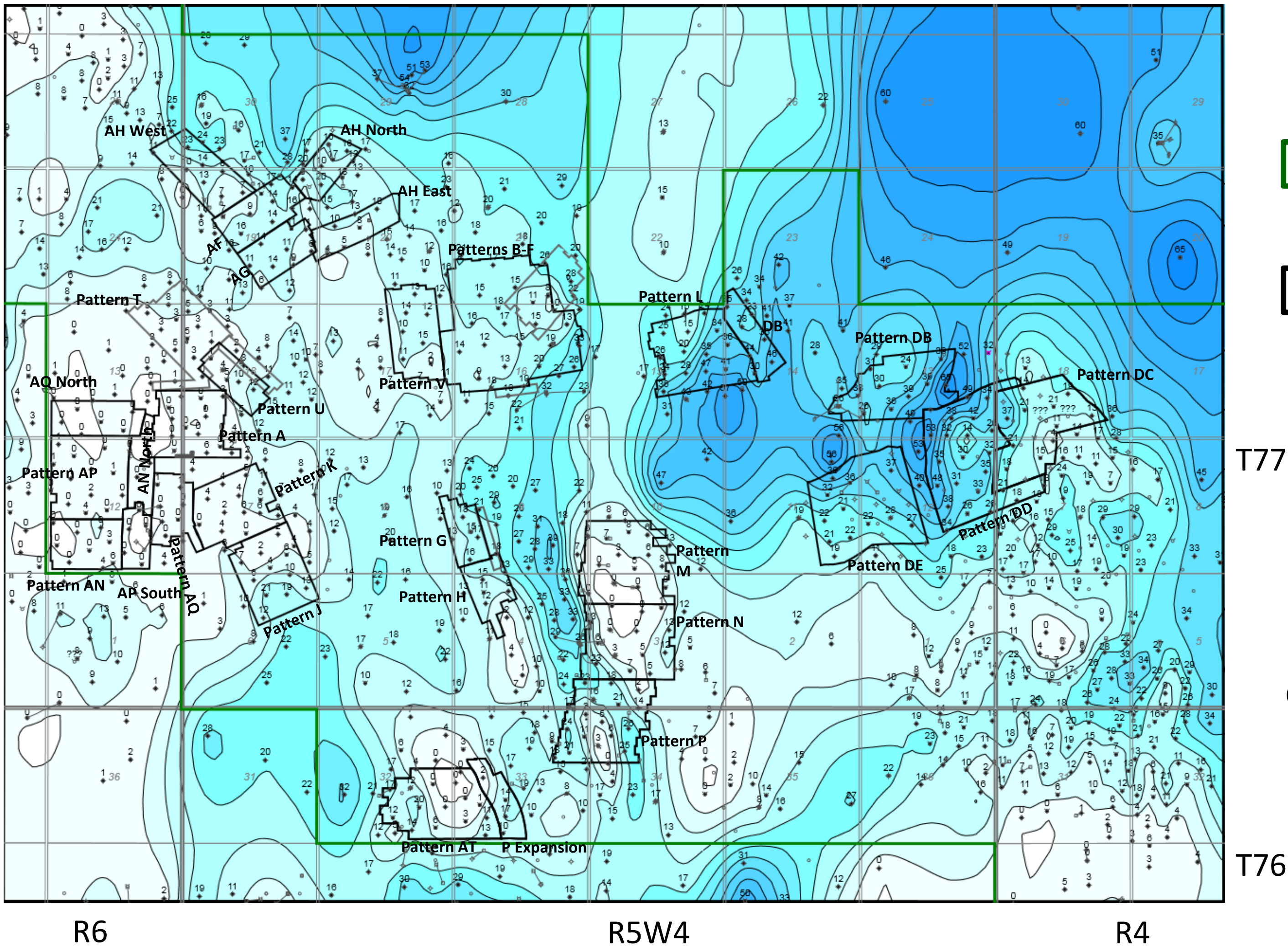
Average Cap rock Thickness = 10.7 m

Minimum Thickness = 8.5 m

Maximum Thickness = 12.3 m

Thickness in Metres

ADA Basal McMurray Net Water Isopach

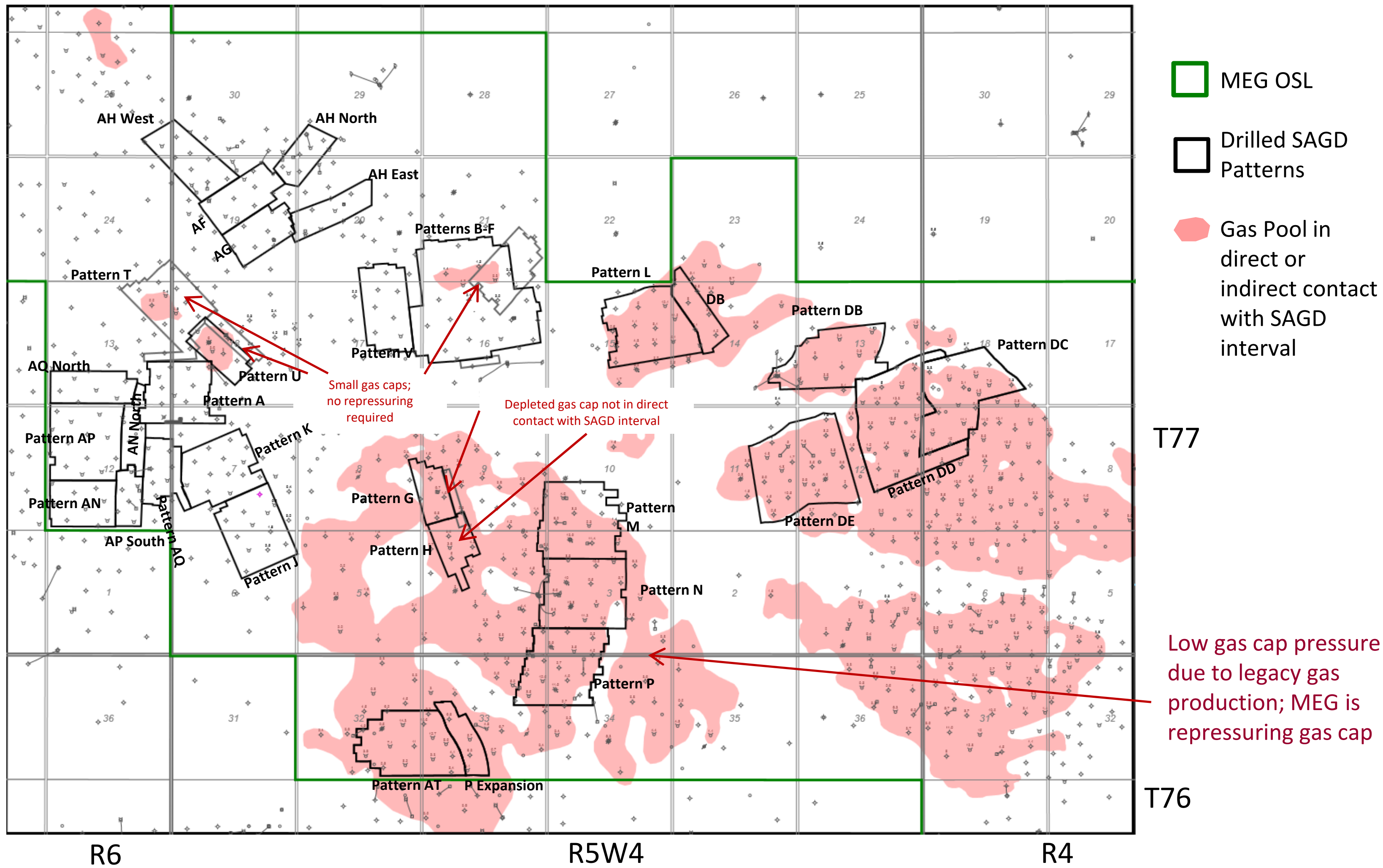


CLRP Project Area

Drilled SAGD Patterns

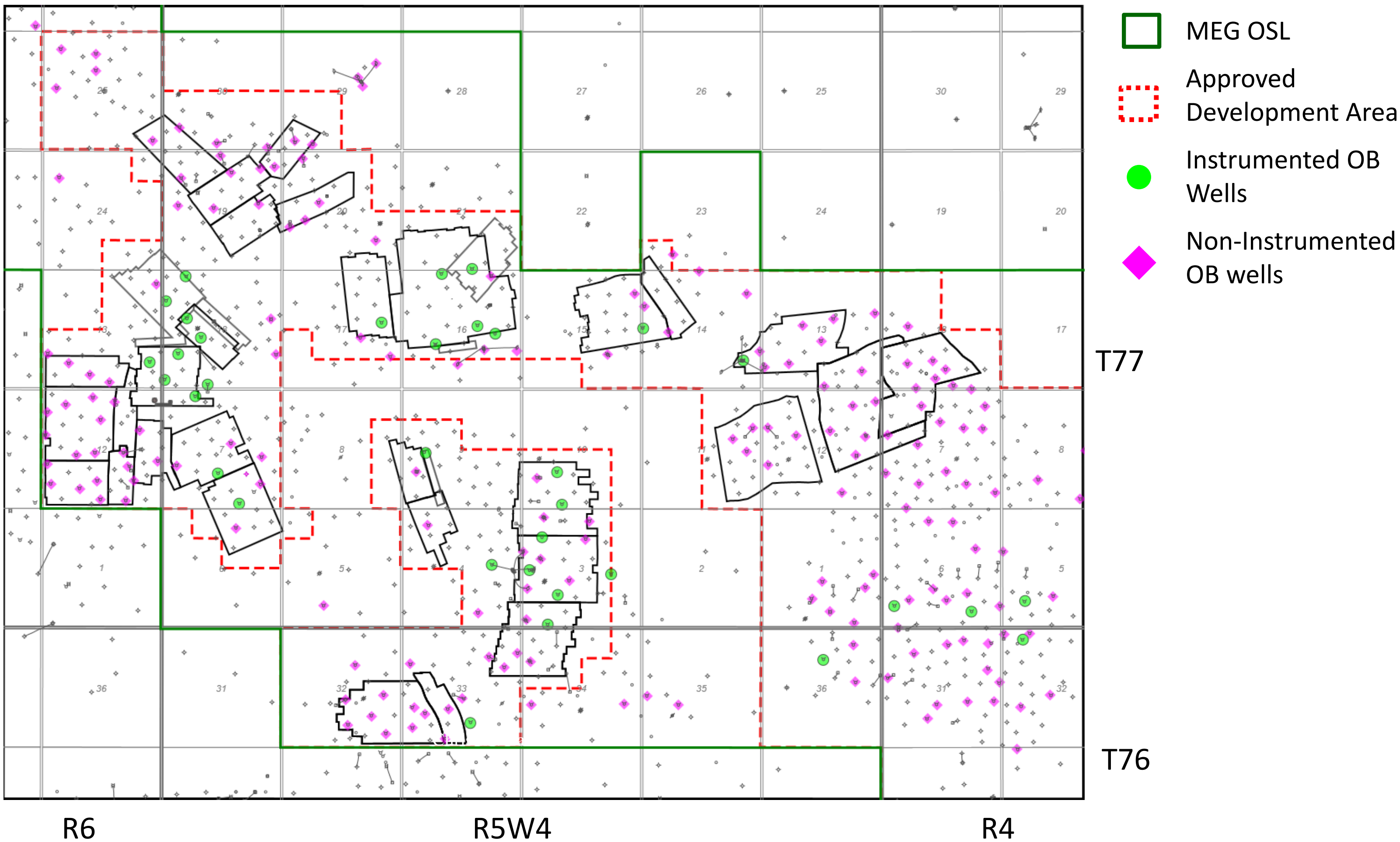
Contour Interval = 5 m

ADA Associated McMurray Gas Pools



Note: Not all SAGD intervals in the pool wells are directly connected to associated gas

ADA OB and Cased Wells



Well Spacing

Pattern	Operating Wellpairs	Average Spacing Between SAGD Pairs (m)	Average Spacing Between SAGD Pair to Infill (m)
A	8	100	50
B	2	100	50
BB+D7	7	100	50
C+D6	7	110	55
D-D6-D7	5	100	50
E+F1	7	100	50
F-F1	5	100	50
V	6	100	50
G	4	100	NA
H	3	100	NA
J	8	100	NA
K	7	100	50
M	10	100	50
N	9	100	50
T	8	100	NA
U	6	100	NA
AP West	10	100	50
AP South	3	112	65
AF	5	100	50
AG	5	100	50
AN	8	100	50
P	10	100	50
AQ North	4	105	NA
AQ South	4	120	NA
L	9	100	NA
AT	8	106	NA
P Expansion	3	100	50
DB	11	100	NA
Total	182		

Geoscience Summary

- No 2019 Winter core program
- Continued success drilling longer wells, (in reference to both distance to ICP and Lateral length)
  - MEG's success in extending drill lengths has allowed for more pay trends to be reached from individual surface pads
- SAGD well spacing becoming further optimized

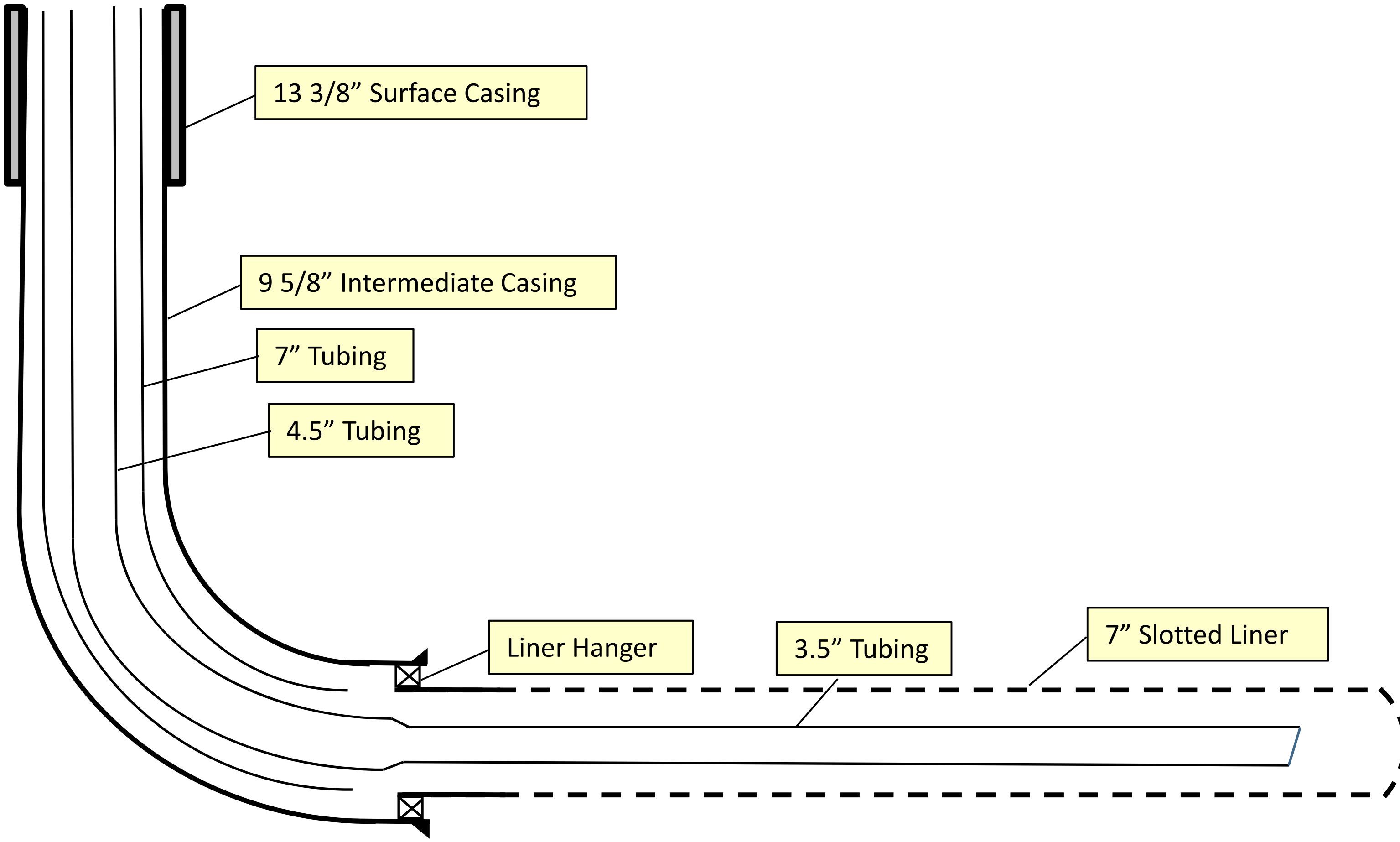

MEG ENERGY
Reservoir

Reservoir Review

- Wells
  - Schematics
  - Well Integrity Management
  - Artificial Lift
- Scheme Performance
  - Field performance
  - Pattern performance
  - Cased hole logs
- eMSAGP Update
- Gas Cap Re-Pressuring
- Unresolved Emulsion Injection

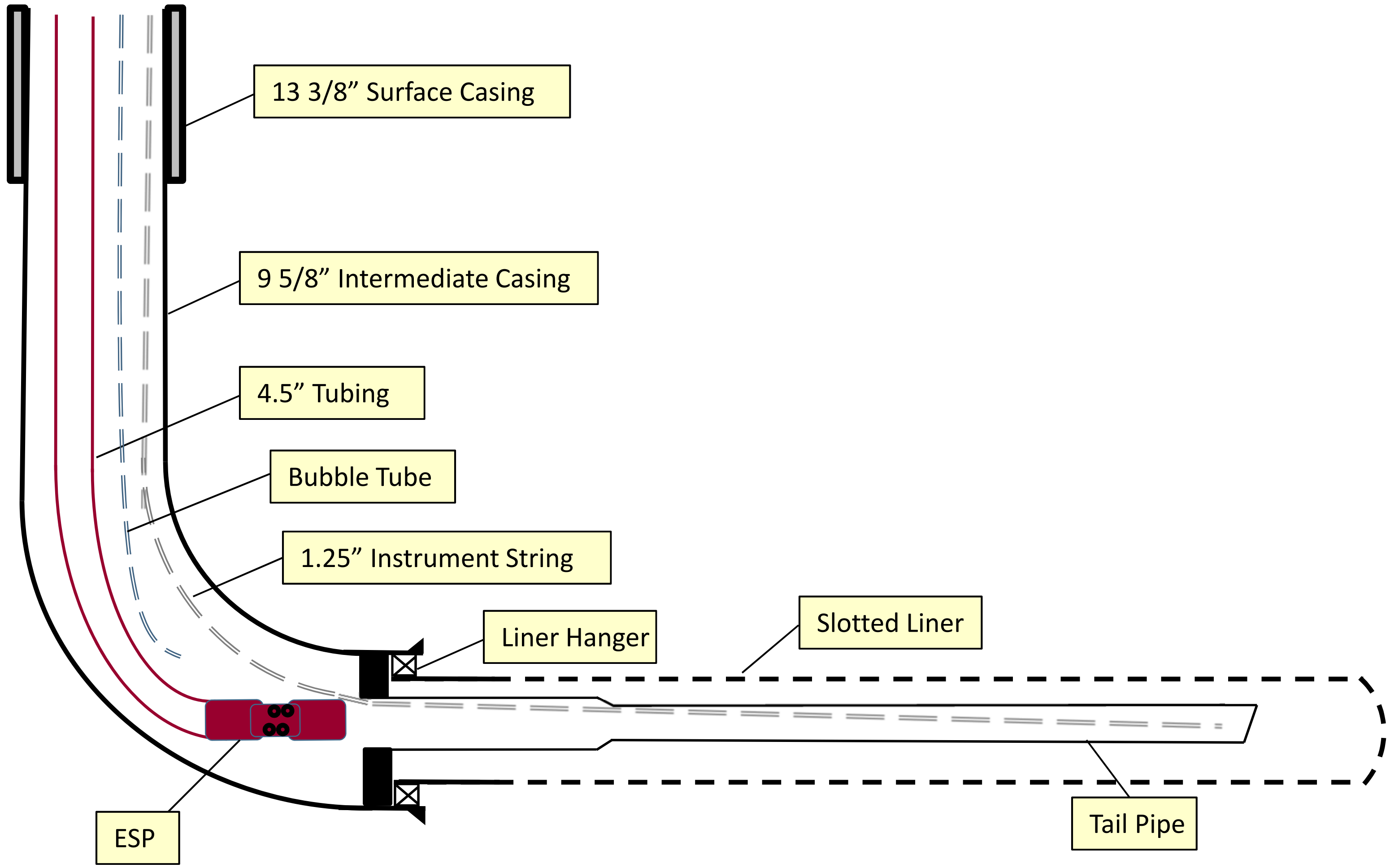
Wells

Well Completions – SAGD Injector



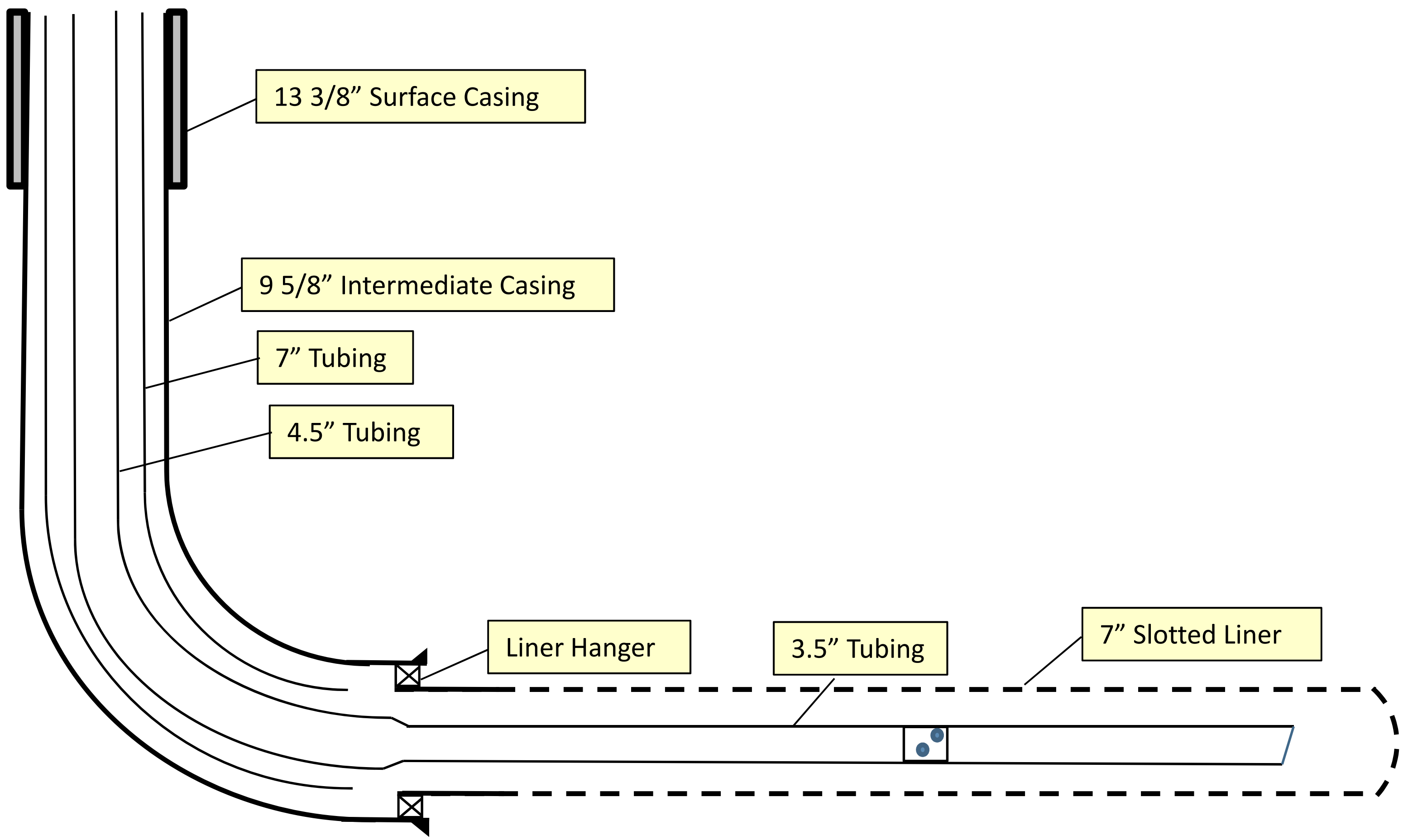
- Steam injected into both long tubing and short tubing
- Blanket gas on annulus

Well Completions – SAGD Producers (ESP)



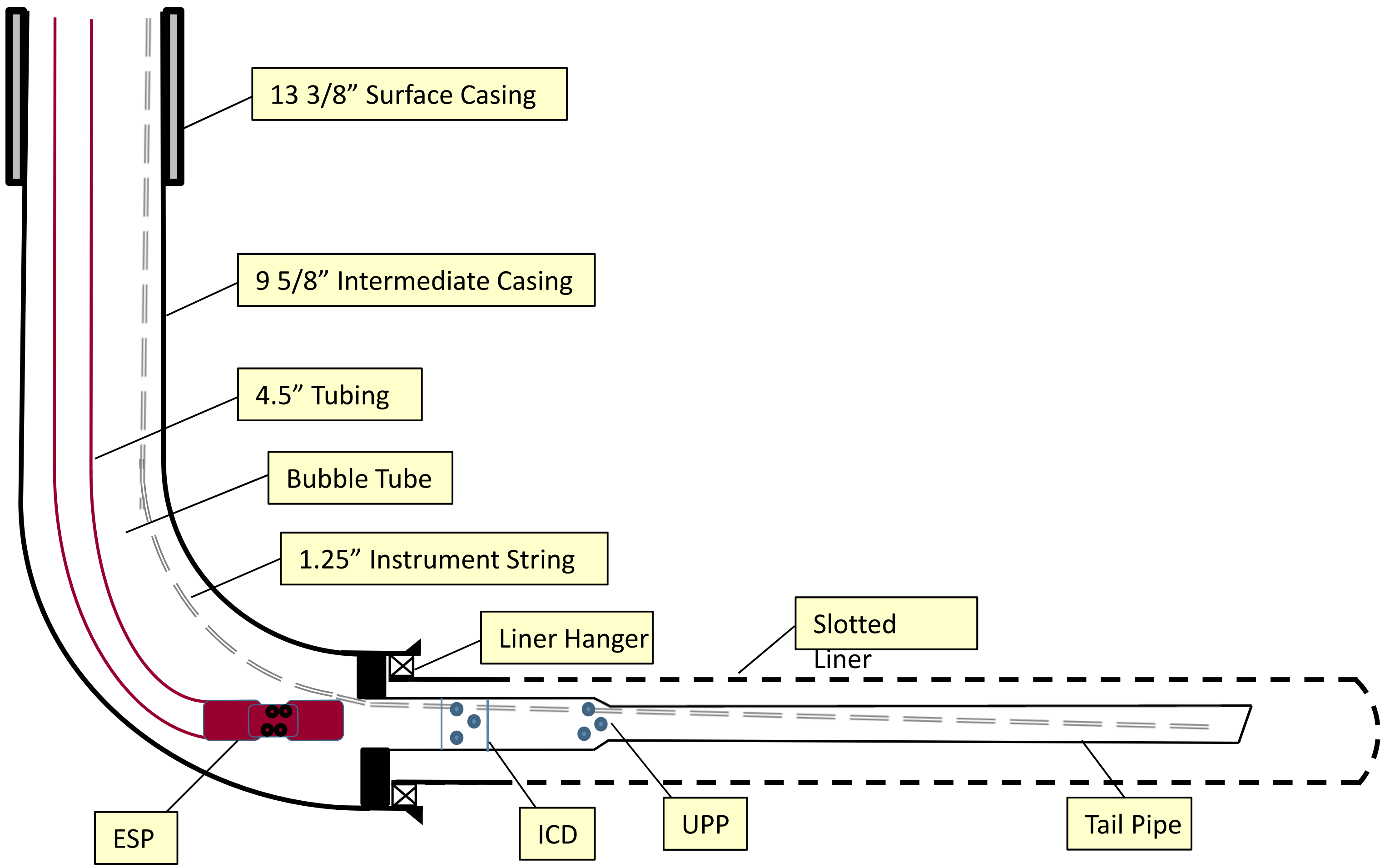
- Thermocouples or thermal fiber are inside the instrument string to provide temperature measurements at selected locations
- Bubble tube is landed near ESP to provide pressure measurement for SAGD producer

Well Completions – Outflow Control Devices



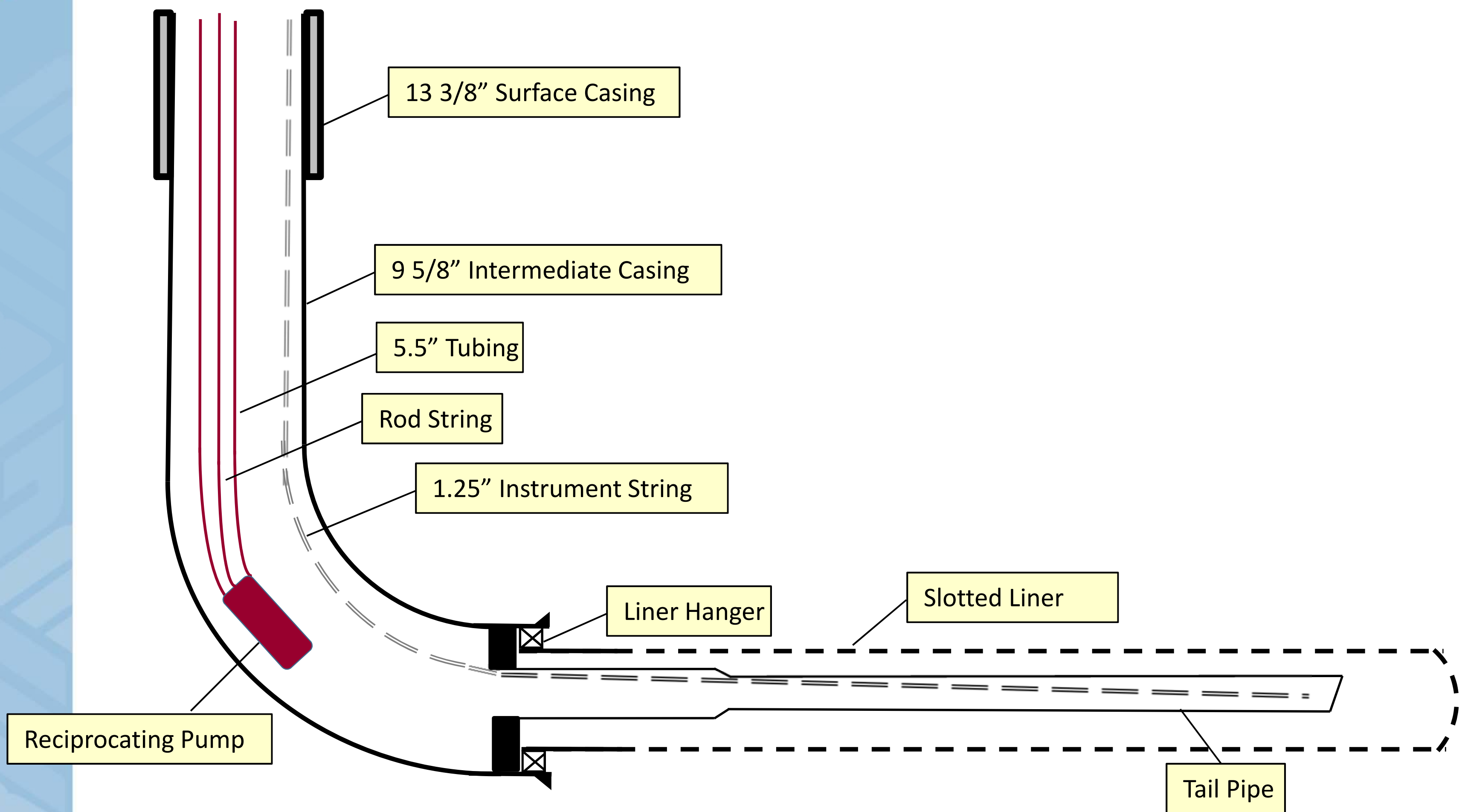
- Consists of several holes placed mid-way of the long tubing to distribute steam at the middle of the well in addition to the heel and toe

Well Completions – Inflow Control Devices



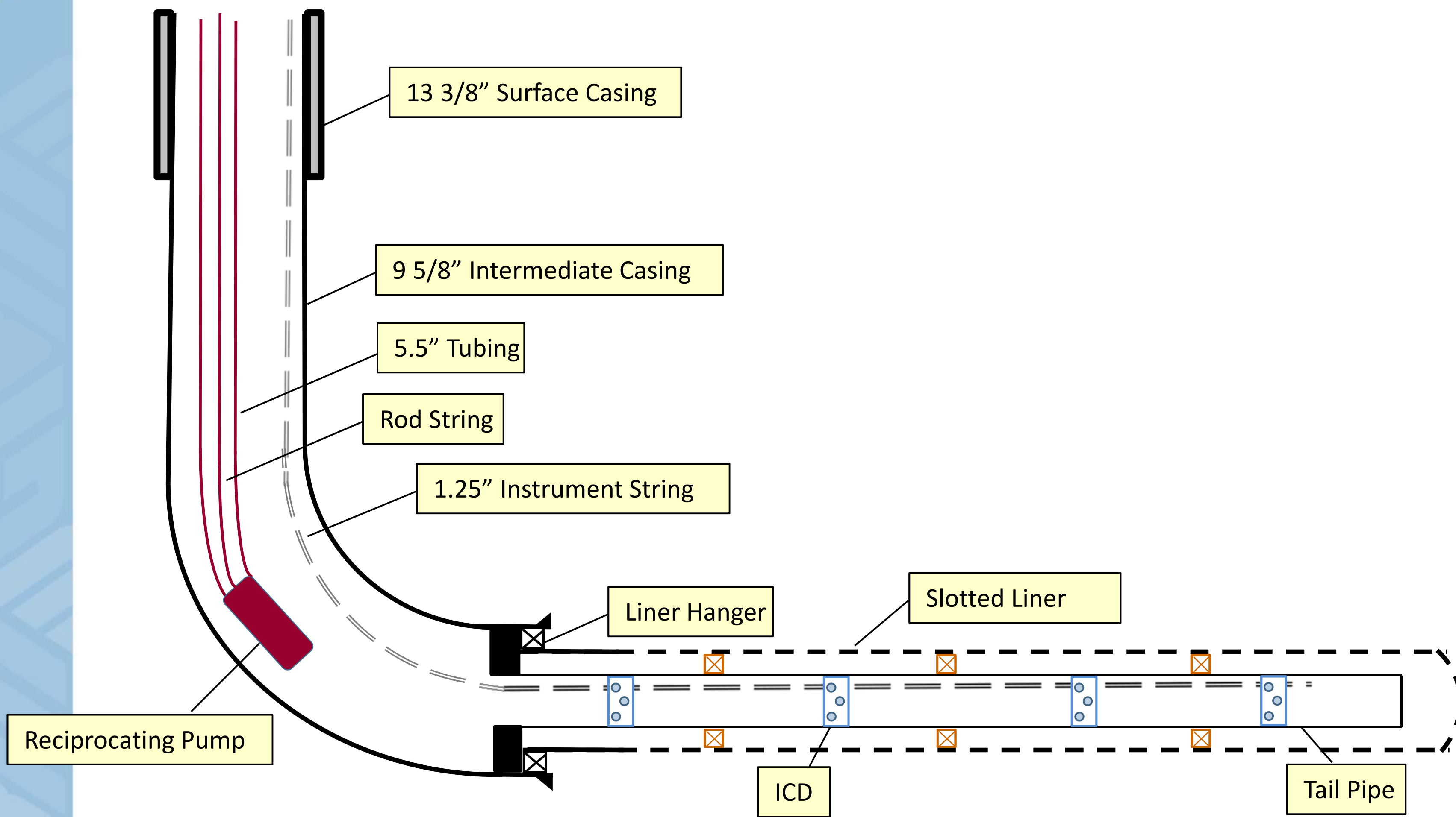
- Upset production port (UPP) typically consists of holes located at the crossover from 4.5" to 3.5" tubing and is always open
- Inflow control device typically consists of a sliding sleeve with holes that is initially closed and later opened when the well is mature
- UPP/ICD locations and tubing dimensions are based on well-bore hydraulic calculations. Crossovers are typically utilized as UPP joints as dictated by the results of the hydraulic design

Well Completions – Infill Producers



- Thermocouples or thermal fiber are inside the instrument string to provide temperature measurements at selected locations
- Reciprocating pumps are selected for use in infill producers based on economic analysis and technical limitations of ESPs (i.e. temperature limitations of ESPs). ESPs have been implemented in wells when the it is economically appropriate.

Well Completions – Segmented Infill Producers

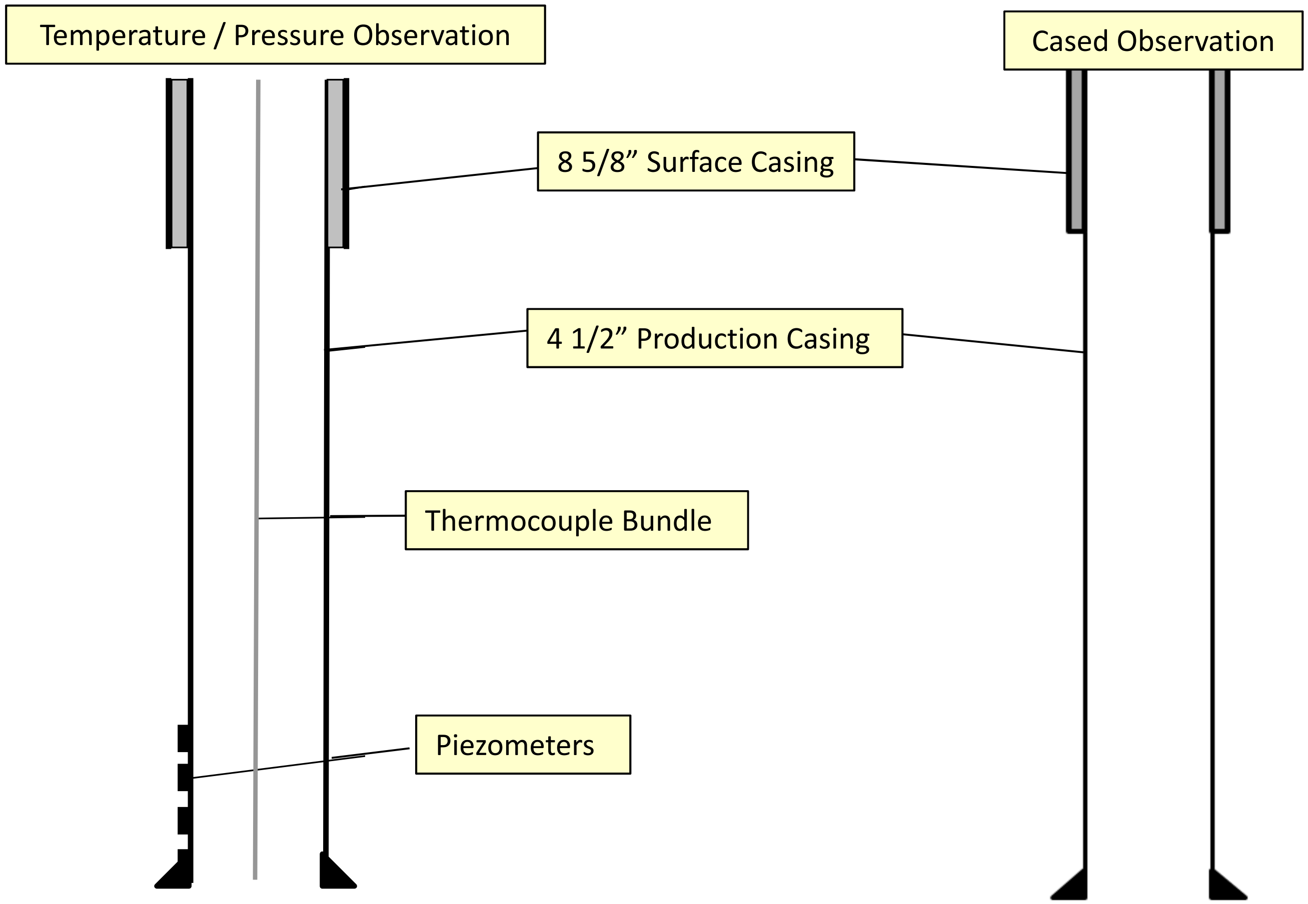


- Flow control device typically consists of a sliding sleeve with holes to allow for zone isolation
- Reciprocating pumps are selected for use in infill producers based on economic analysis and technical limitations of ESPs (i.e. temperature limitations of ESPs). ESPs have been implemented in wells when the it is economically appropriate.

Temperature Measurement

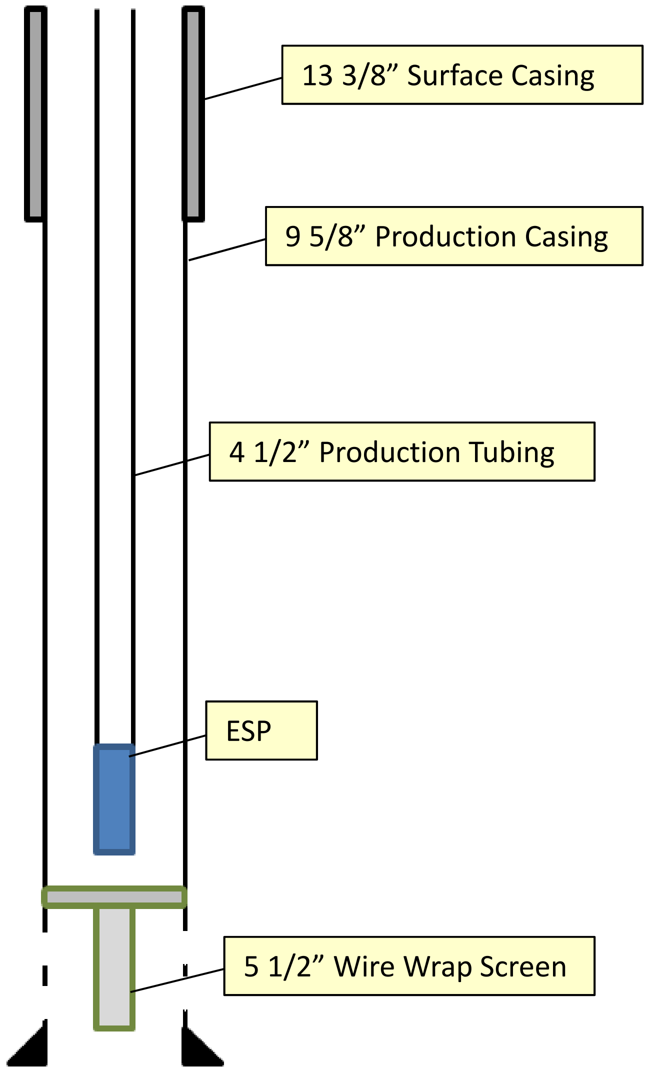
- Have historically relied on six/four-point thermocouple strings in all SAGD and infill wells due to proven accuracy
- Thermal fiber installations have demonstrated improved data quality, reliability, and cost, and fiber is planned to be used on future pads
- Currently have installed thermal fiber on
  - AF, AG, AP, AN, AQ, K, M, N, P and V Pad infill wells
  - AF, AQ, AT, DB, L, P Pad SAGD producers
  - AP and AN Expansion SAGD Producers (AP11P, AP12P, AP13P and AN9P)
  - Re-drills on AP and M Pads (AP4P, M3P, M4P, M6P, M9P)

Observation Wells

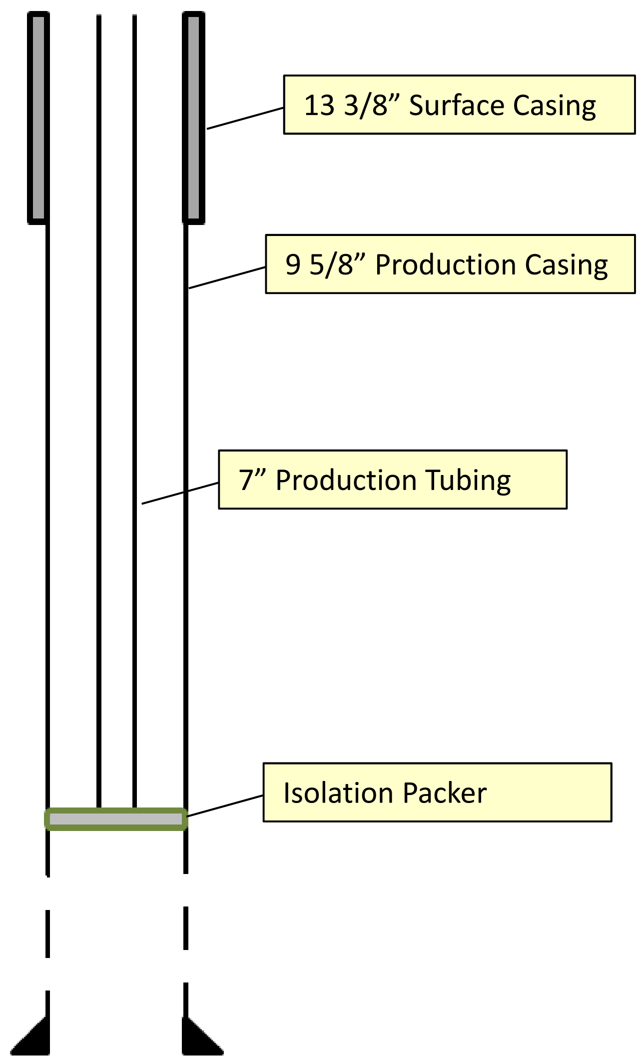


- Thermocouples are landed over expected steam zone
- Piezometers are placed in areas of geological interest (gas, bitumen, water zones and potential pay breaks)

Water Source Wells



Water Disposal Wells



Well Integrity Management

Well Integrity Program for CLRP

- Includes: SAGD, Infill, Observation, Gas Injection, Core-Holes, Legacy Gas, Source and Disposal Wells

The Well Integrity Program includes:

- Well Integrity Management System (well tracking and monitoring)
- Targeted proactive casing integrity checks and well servicing support
- Casing design
- Compliance assurance, AER commitments and reporting
- Directive 013 and Inactive Well Compliance Program management

Formation Integrity Monitoring

- As operating reservoir pressures are well below the MOP limit, there are no passive seismic or geo-mechanical monitoring systems in place at Christina Lake.

Well Integrity Management System

Highlights

- Select and prioritize SAGD wells for intermediate casing integrity inspections based on risk based evaluation criteria
- Conduct follow-up inspections as needed
- Incorporate learnings from the Well Integrity Management model into well design

CLRP Well Suspensions

- 7 SAGD well pairs are suspended on Pads G, H, J and K
    - 3 pairs are suspended due to high production of fine sand
    - 1 pair suspended after operating issues (poor injector – producer communication)
    - 3 pairs have not yet started on production
- Suspended 1 infill well on Pad B due to high production of fine sand
- Suspended 8 SAGD producer wells on Pads B, K, M, N and AP that have been re-drilled. All re-drills are now the active producers.
    - 4 due to liner plugging issues (high pressure drop)
    - 2 due to high production of fine sand
    - 2 due to liner impairments (2011 and 2016)
- Suspended 1 SAGD producer well on Pad K due to high production of fine sand
    - Candidate to re-drill this well

CLRP Well Integrity – Liners

K8N has not produced since July 2018 due to suspected liner integrity concerns

Issue

- Suspect in-zone liner impairment after tubing string became stuck and had to be cut out

Implications

- Fish top of remaining tubing string is at heel portion of liner and inhibits further investigation
- Attempted to produce well but replacement pumps filled up with fine sand

Actions

- Analysis of pressure and temperature history does not point to a clear event or indication of when impairment formed
- Candidate for re-drill or re-entry
- Liner design will be adjusted on future wells for improved strength and sand control

CLRP Well Integrity – Liners

J6P has not produced since March 2018 due to liner integrity issue

Issue

- Suspected subcool event occurred in horizontal liner causing loss of sand control

Implications

- High amount of sand discovered during pump replacement and perforated secondary liner inhibits further investigation

Actions

- Analysis of pressure and temperature history points to a subcool event in 2017 as the cause of the liner issue
- Candidate for re-drill or re-entry

CLRP Well Integrity – Liners

K3N has not produced since January 2018 due to sand control concerns

Issue

- Loss of sand control within horizontal liner

Implications

- Attempted to produce well but replacement pumps filled up with fine sand
- Liner cleanout indicated high amounts of sand coming in at mid-point of horizontal liner.
    - All produced sand is finer than liner slot size
    - No structural damage to liner encountered during cleanout

Actions

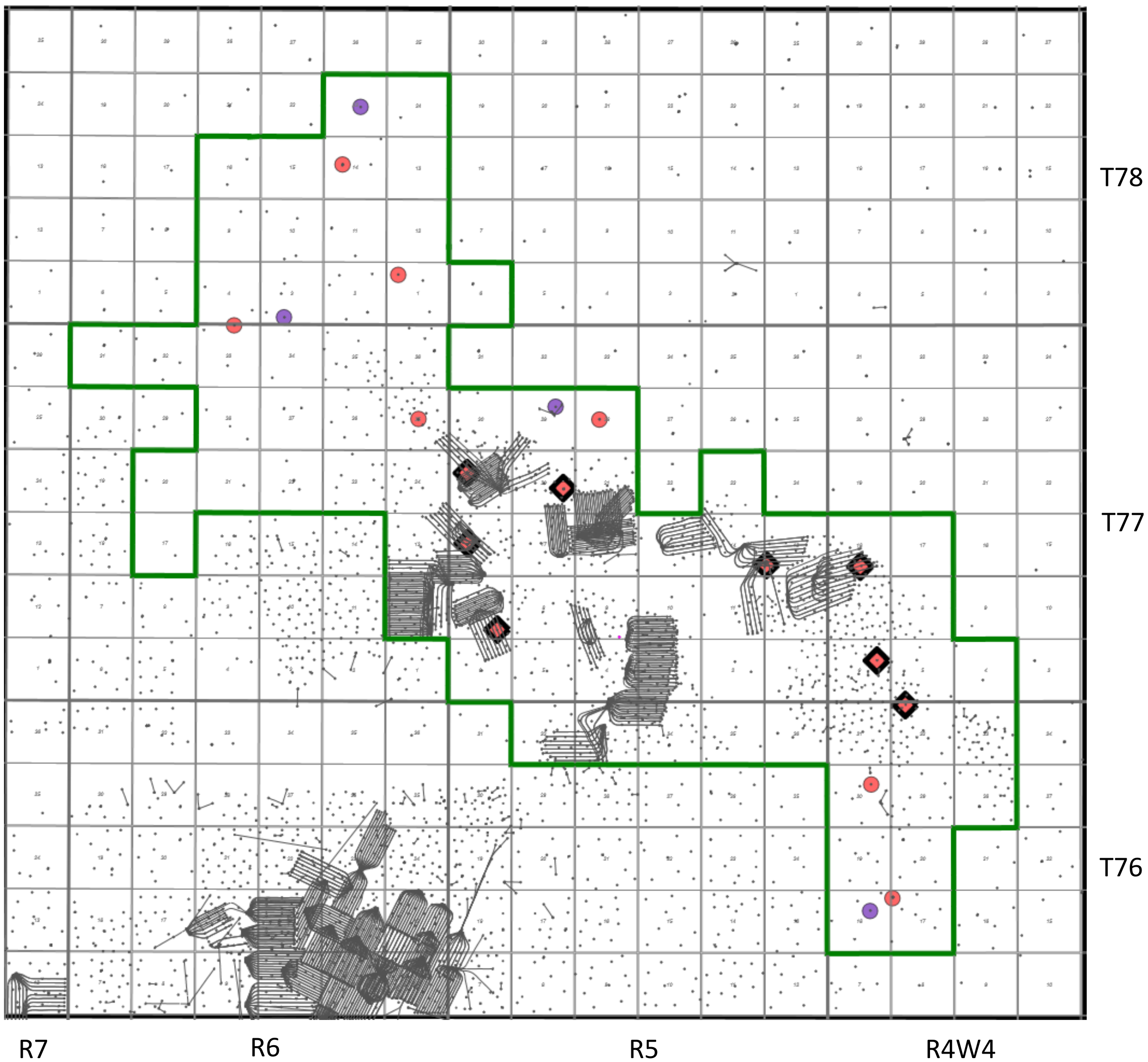
- Candidate for re-drill or re-entry
- Liner design will be adjusted on future wells for improved strength and sand control

Directive 013 and IWCP

Program Highlights

- MEG has opted into the AER's Area Based Closure (ABC) Program and aims to meet the ABC spent target by the end of the 2019 calendar year
  - Proposed and confirmed ABC plans have been entered into the OneStop system
  - Q1 spend has included the abandonment of an observation well (100/13-07-77-04W4/00) and caribou restoration applied to two LOC's associated with the abandoned 10-20 wellsite in 77-03W4
  - Remainder of the year spend will focus on facility abandonment, borrow pit reclamation, and OSE reclamation
- As per the Directive 013 waiver MEG received when opting into ABC, MEG will be executing annual inspections on all Medium Risk Type 6 wells to maintain compliance

Legacy Wells



MEG OSL

Existing SAGD patterns

Type 1B wells (D&A)

Type 2B wells (D&C, DC&A)

Type 2B wells zone abandoned

Type 1B: D&A with non-thermal cement

Type 2B: D&C with non-thermal cement

Legacy Well Thermal Compatibility

- Thermal compatibility addressed on a pad by pad basis in conjunction with IDA amendment applications
- Specific Directive 20 abandonment applications have been filed and approved for requisite wells within the Approved Development Area
- MEG has developed a thermal compatibility program which has been reviewed by AER staff. The program includes:
  - A detailed assessment of compatibility of existing wellbores within the CLRP project area
  - General abandonment strategies to ensure well integrity thermal development areas
  - Monitoring and surveillance plans

Artificial Lift

- **177 electric submersible pumps (ESP) in operation**
  - Approximately 72% ESPs rated to 250°C and 28% rated to 220°C
  - Operating pressures range from 2,100-3,450 kPag
  - Design fluid rates 200-1200 m^3/d
  - Run-time between pulls is approximately 920 days and improvements have been made by utilizing higher temperature rated equipment, as required

- **95 rod pumps installed in the infill wells**
  - Operating pressures range from 2,000-2,500 kPag
  - Design fluid rates 100-500 m^3/d

Inflow / Flow Control Devices

- Flow Control Devices (FCDs) or Inflow Control Devices (ICDs) used typically consist of a inflow ports and a sliding sleeve used to block or unblock these ports.

Pad	Well Name	API/UWI	Date FCD/ICDs Ran	Number of FCD/ICDs
AF	AF2N	112/09-19-077-05W4/00	10/2/2018	2
	AF3N	113/09-19-077-05W4/00	11/15/2018	5
	AF4N	114/09-19-077-05W4/00	5/10/2019	3
	AF5N	115/09-19-077-05W4/00	8/21/2018	3
	AF8N	111/16-19-077-05W4/00	4/4/2018	1
	AF9N	112/16-19-077-05W4/00	7/19/2018	4
AG	AG1P	103/09-19-077-05W4/00	11/19/2014	1
	AG2P	104/09-19-077-05W4/00	11/14/2014	1
	AG3P	105/08-19-077-05W4/00	11/19/2014	1
AN	AN1P	117/01-13-077-06W4/00	3/13/2015	1
	AN2P	104/02-13-077-06W4/00	3/23/2015	1
	AN3P	108/05-12-077-06W4/00	3/9/2015	1
	AN4N	113/05-12-077-06W4/00	12/10/2017	1
	AN4P	109/05-12-077-06W4/00	3/19/2015	1
	AN5P	106/04-12-077-06W4/00	3/8/2015	1
	AN6P	107/04-12-077-06W4/00	3/12/2015	1
	AN7N	111/04-12-077-06W4/00	5/26/2019	3
	AN7P	103/03-12-077-06W4/00	3/5/2015	1
	AN8N	112/04-12-077-06W4/00	12/13/2017	1
	AN8P	109/04-12-077-06W4/00	3/16/2015	1
	AN9P	108/16-12-077-06W4/00	10/9/2017	3
AP	AP10P	109-13-12-077-06W4/00	3/28/2014	1
	AP11P	120/02-12-077-06W4/00	6/20/2017	1
	AP12P	121/02-12-077-06W4/00	4/20/2017	1
	AP13P	117/02-12-077-06W4/00	6/15/2017	1
	AP1N	112/05-12-077-06W4/00	3/19/2018	2
	AP1P	103/05-12-077-06W4/00	3/15/2014	1
	AP2N	115/12-12-077-06W4/00	5/31/2017	1
	AP2P	104/05-12-077-06W4/00	3/31/2014	1
	AP3N	116/12-12-077-06W4/00	8/6/2018	2
	AP4I	102/12-12-077-06W4/00	6/11/2018	1
	AP4P	106/12-12-077-06W4/00	3/27/2014	1
	AP5P	107/12-12-077-06W4/00	3/18/2014	1
	AP6P	108/12-12-077-06W4/00	3/23/2014	1
	AP7N	116/13-12-077-06W4/00	10/29/2017	1
	AP7P	106/13-12-077-06W4/00	3/25/2014	1
	AP8P	107/13-12-077-06W4/00	3/21/2014	1
	AP9N	118/13-12-077-06W4/00	11/2/2017	1
	AP9P	108/13-12-077-06W4/00	3/18/2014	1

Pad	Well Name	API/UWI	Date FCD/ICDs Ran	Number of FCD/ICDs
AQ	AQ1N	120/04-13-077-06W4/00	3/1/2018	1
	AQ1P	116/04-13-077-06W4/00	11/8/2017	1
	AQ2P	117/04-13-077-06W4/00	11/23/2017	1
	AQ7P	104/08-12-077-06W4/00	11/26/2017	1
	AQ8P	104/04-07-077-05W4/00	11/23/2017	2
AT	AT3I	104/06-32-076-05W4/00	1/22/2018	1
	AT4I	107/07-32-076-05W4/00	1/24/2018	1
	AT5I	102/06-32-076-05W4/00	1/12/2018	1
	AT6I	102/03-32-076-05W4/00	1/15/2018	1
	AT7I	106/02-32-076-05W4/00	1/17/2018	1
	AT8I	107/02-32-076-05W4/00	1/19/2018	1
DB	DB10I	103/10-13-077-05W4/00	5/15/2018	1
	DB10P	106/10-13-077-05W4/00	11/30/2018	1
	DB11I	104/10-13-077-05W4/00	5/16/2018	1
	DB11P	107/10-13-077-05W4/00	3/15/2019	1
	DB1I	1W4/13-14-077-05W4/00	5/12/2018	1
	DB2I	116/13-14-077-05W4/00	5/18/2018	1
	DB2P	118/13-14-077-05W4/00	12/7/2018	1
	DB3I	100/04-23-077-05W4/0	5/13/2018	1
	DB3P	102/04-23-077-05W4/00	2/5/2019	1
	DB4I	102/03-13-077-05W4/0	5/16/2018	1
	DB4P	100/03-13-077-05W4/00	11/15/2018	1
	DB5I	100/07-13-077-05W4/00	5/10/2018	2
	DB5P	106/07-13-077-05W4/00	1/22/2019	1
	DB6I	102/07-13-077-05W4/00	5/17/2018	2
	DB6P	107/07-13-077-05W4/00	1/30/2019	2
	DB7I	103/07-13-077-05W4/00	5/11/2018	1
	DB7P	108/07-13-077-05W4/00	1/26/2019	1
	DB8I	104/07-13-077-05W4/00	4/21/2019	3
	DB9I	102/10-13-077-05W4/00	5/14/2018	1
DC	DC10I	108/07-18-077-04W4/00	10/19/2018	1
	DC1I	103/14-07-077-04W4/00	10/27/2018	1
	DC2I	104/14-07-077-04W4/00	10/25/2018	1
	DC3I	102/14-07-077-04W4/00	10/24/2018	1
	DC4I	104/03-18-077-04W4/00	10/21/2018	1
	DC5I	102/01-18-077-04W4/00	10/13/2018	1
	DC6I	104/01-18-077-04W4/00	10/15/2018	1
	DC7I	100/07-18-077-04W4/00	10/16/2018	1
	DC8I	102/07-18-077-04W4/00	10/17/2018	1
	DC9I	103/07-18-077-04W4/00	10/18/2018	1

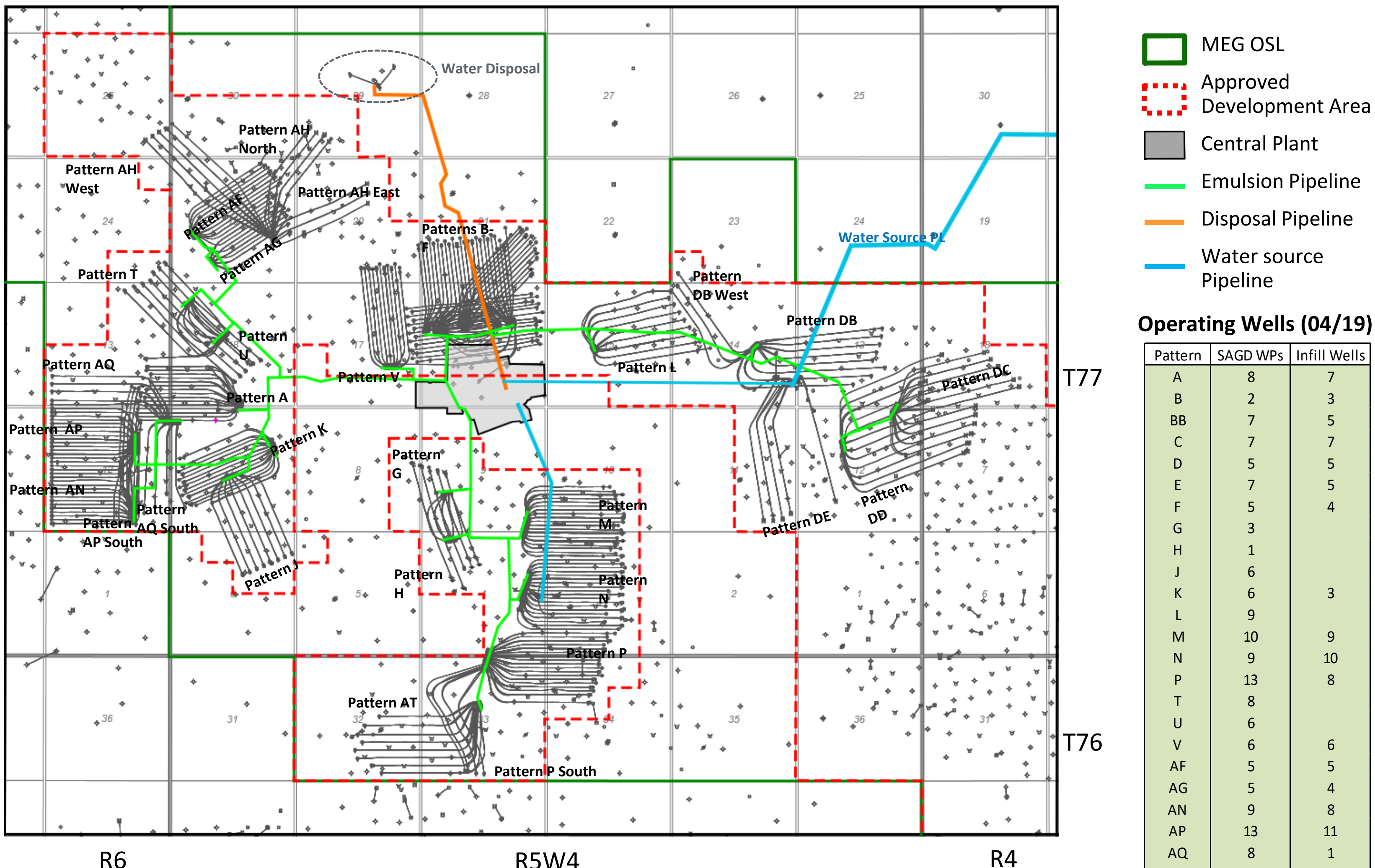
Inflow / Flow Control Devices – cont'd

Pad	Well Name	API/UWI	Date FCD/ICDs Ran	Number of FCD/ICDs
DD	DD2I	1W0/05-18-077-04W4/00	10/28/2018	1
	DD3I	102/01-13-077-05W4/00	10/9/2018	1
	DD4I	103/01-13-077-05W4/00	10/8/2018	1
	DD5I	103/04-18-077-04W4/00	10/7/2018	1
	DD6I	102/13-07-077-04W4/00	10/4/2018	1
	DD7I	104/16-12-077-05W4/00	10/3/2018	1
	DD8I	1W0/13-07-077-04W4/00	10/2/2018	1
J	J5I	102/09-06-077-05W4/00	6/16/2019	3
K	K4N	112/05-07-077-05W4/00	4/2/2019	3
	K5N	113/05-07-077-05W4/00	4/5/2019	3
	K6N	114/05-07-077-05W4/00	5/5/2019	3
	K6PR	117/05-07-077-05W4/00	8/26/2017	1
	K8P	100/03-07-077-05W4/02	11/18/2017	1
L	L1I	1W2/13-14-077-05W4/00	12/16/2017	1
	L2I	105/16-15-077-05W4/00	12/18/2017	1
	L3I	113/13-14-077-05W4/00	12/20/2017	1
	L4I	114/13-14-077-05W4/00	12/22/2017	1
	L5I	107/12-14-077-05W4/00	12/31/2017	1
	L5P	103/12-14-077-05W4/00	10/19/2018	2
	L6I	108/12-14-077-05W4/00	12/16/2017	1
	L7I	109/12-14-077-05W4/00	12/17/2017	1
	L8I	110/12-14-077-05W4/00	12/19/2017	1
	L9I	102/05-14-077-05W4/00	12/21/2017	1
M	M1N	114/15-03-077-05W4/00	3/28/2018	1
	M1P	103/15-03-077-05W4/03	12/13/2013	1
	M2P	107/15-03-077-05W4/0	12/9/2013	1
	M3P	108/15-03-077-05W4/0	1/10/2014	2
	M4I	106/15-03-077-05W4/0	5/29/2016	1
	M4P	109/15-03-077-05W4/0	10/28/2013	2
	M5N	112/02-10-077-05W4/00	2/10/2018	1
	M5P	105-02-10-077-05W4/0	12/13/2013	1
	M6P	106/02-10-077-05W4/0	12/19/2013	1
	M7P	107/02-10-077-05W4/02	7/7/2014	1
	M9P	103/07-10-077-05W4/00	11/3/2013	1

Pad	Well Name	API/UWI	Date FCD/ICDs Ran	Number of FCD/ICDs
N	N10N	117/15-03-077-05W4/00	11/5/2018	3
	N2N	106/06-03-077-05W4/00	4/9/2018	4
	N2P	108/07-03-077-05W4/02	8/4/2014	2
	N4N	108/06-03-077-05W4/00	8/19/2018	3
	N4P	105/07-03-077-05W4/00	1/10/2014	1
	N5N	107/06-03-077-05W4/00	6/19/2019	3
	N5P	106/07-03-077-05W4/02	12/16/2013	1
	N6N	100/11-03-077-05W4/00	5/29/2018	5
	N6P	107/10-03-077-05W4/00	11/18/2013	1
	N7N	115/10-03-077-05W4/00	6/22/2019	3
	N8N	116/10-03-077-05W4/00	4/8/2018	5
	N8P	109/10-03-077-05W4/00	11/29/2013	1
	N9P	102/10-03-077-05W4/00	11/25/2013	1
P	P11P	103/03-33-076-05W4/00	1/17/2019	1
	P12P	105/03-33-076-05W4/00	1/13/2019	1
	P13P	103/02-33-076-05W4/00	11/20/2018	1
	P1N	110/03-03-077-05W4/00	6/7/2018	4
	P2N	115/12-12-077-06W4/00	6/11/2018	4
	P2P	106/02-03-077-05W4/00	10/21/2015	1
	P3N	109/03-03-077-05W4/00	6/15/2018	4
	P3P	104/03-03-077-05W4/02	10/18/2015	1
	P4N	111/14-34-076-05W4/00	6/2/2018	4
	P5N	112/14-34-076-05W4/00	6/16/2018	4
	P6N	113/14-34-076-05W4/00	6/14/2018	4
	P7N	114/14-34-076-05W4/00	6/5/2018	4
	P8N	105/11-34-076-05W4/00	6/9/2018	4
T	T7P	103/15-13-077-06W4/00	11/19/2016	1
	T8P	104/15-13-077-06W4/00	5/9/2015	1
U	U3P	108/07-18-077-05W4/00	3/30/2014	1
V	V1I	104/01-20-077-05W4/00	10/8/2013	1
	V4N	112/02-20-077-05W4/00	6/27/2018	5
	V6P	110/02-20-077-05W4/00	11/2/2014	1

Scheme Performance

Pattern Layout



Operating Wells (04/19)

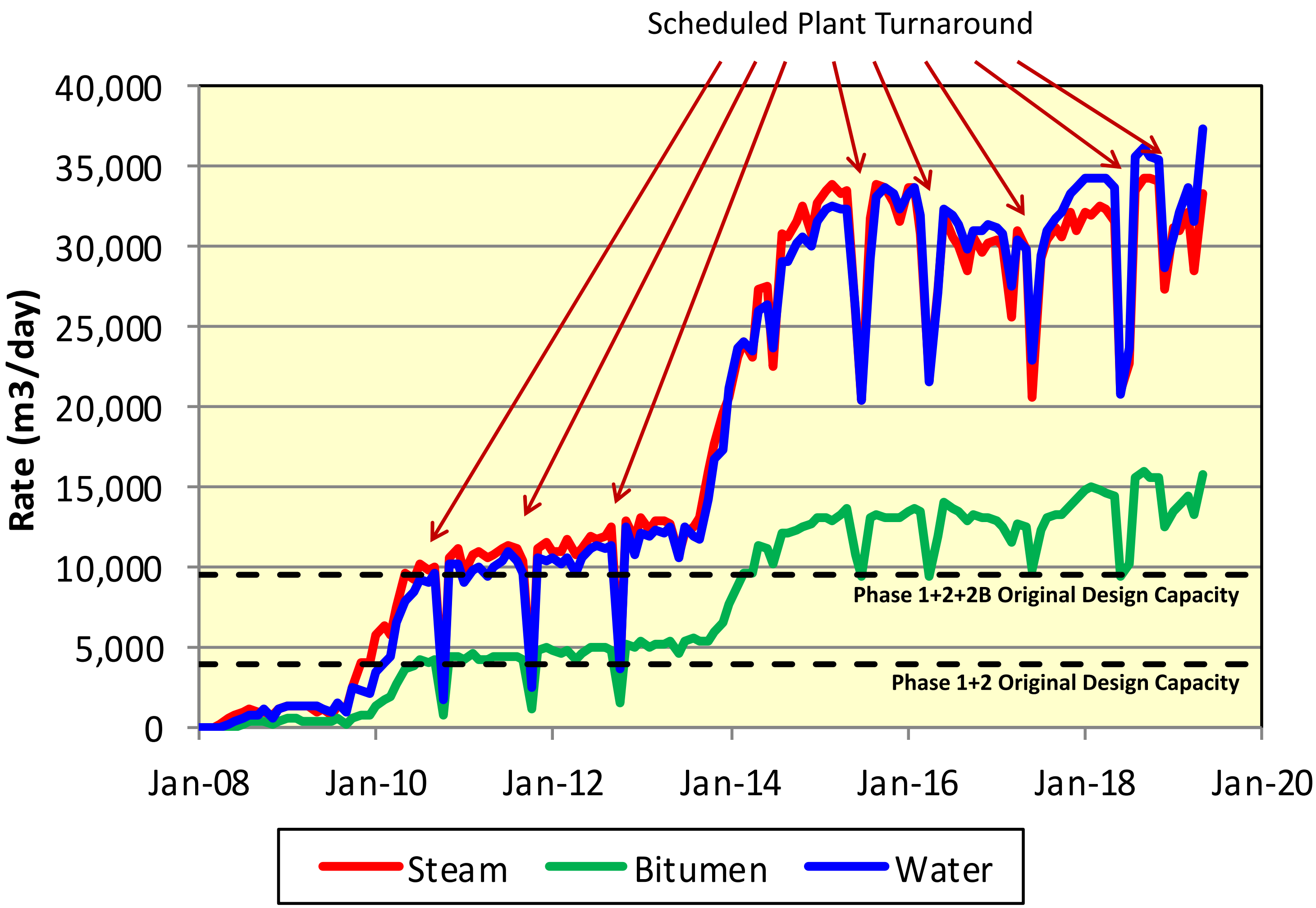
Pattern	SAGD WPs	Infill Wells
A	8	7
B	2	3
BB	7	5
C	7	7
D	5	5
E	7	5
F	5	4
G	3	
H	1	
J	6	
K	6	3
L	9	
M	10	9
N	9	10
P	13	8
T	8	
U	6	
V	6	6
AF	5	5
AG	5	4
AN	9	8
AP	13	11
AQ	8	1
AT	8	
DB	11	
Total	177	101

*** As of April 30 2019**

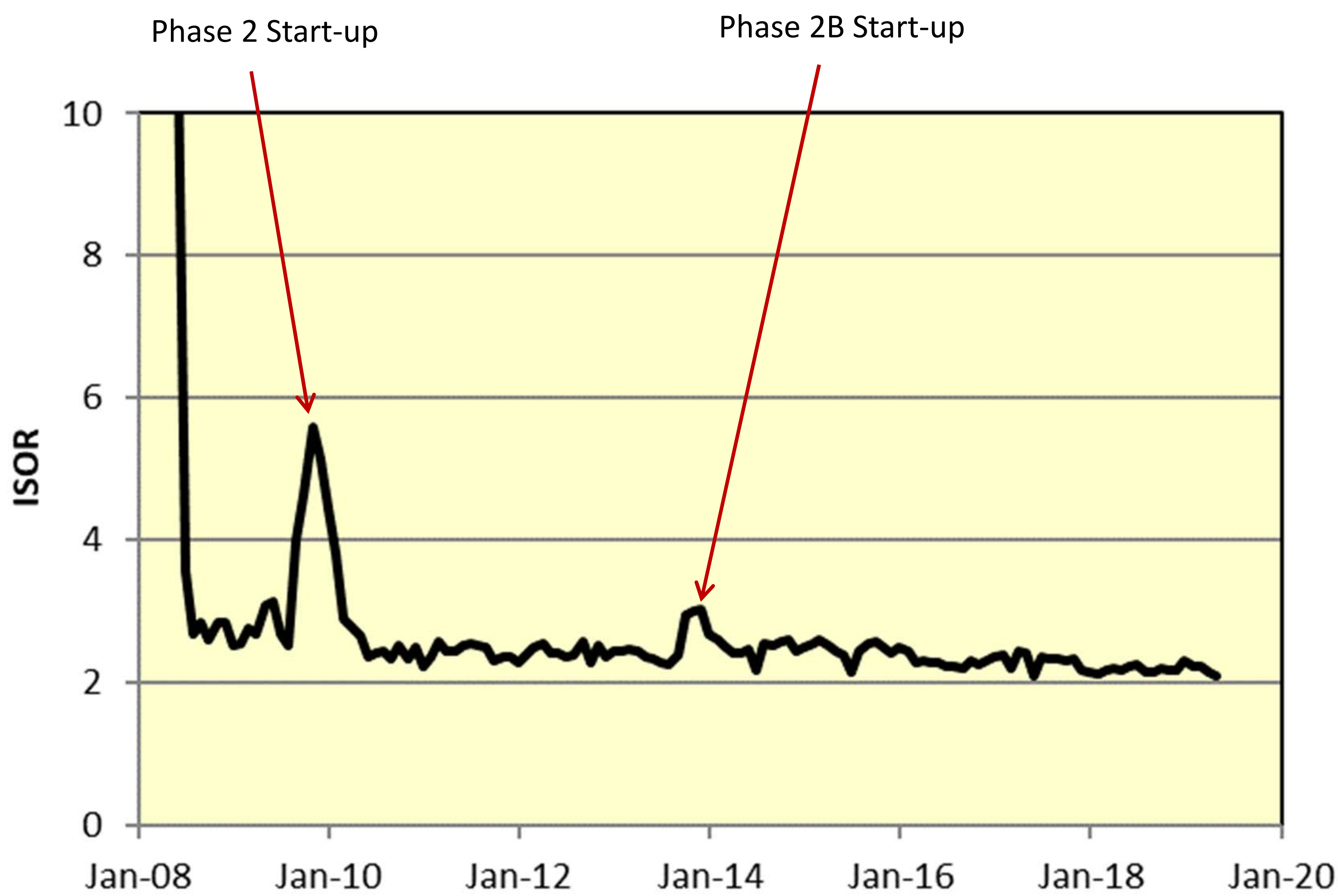
Reservoir Performance

- First steam into Phase 1 (3 WPs) effectively started in March 2008
- First steam into Phase 2 wells started in August 2009
- First steam into Phase 2B wells started in Q3 2013
- Wells were started up in stages, dictated by steam availability
- The combined bitumen production from Phases 1 and 2 reached the original design capacity of 3,975 m^3/d (25,000 bpd) by late April 2010
- Phase 2B production ramp-up improved Phase 2. Total production reached 11,340 m^3/d (71,300 bpd) in Q2 2014, far exceeded the combined original design capacity of 9,539 m^3/d (60,000 bpd)
- Production averaged 87,731 bpd in 2018. In Q1 2019, MEG achieved quarterly production of 87,113 bpd, partially impacted by government production limits. April production averaged 99,347 bpd
- The SOR of CLRP has ranged from 2.1 to 2.3 over the last 12 months. Government production limitations resulted in increased steam generation management operational challenges
- Current steam chamber pressure is between 2,190 and 2,445 kPag for Phases 1 and 2, between 2,215 and 2,565 kPag for Phase 2B. The steam chamber pressure is close to the initial pressure in the basal water zone where bottom water is present

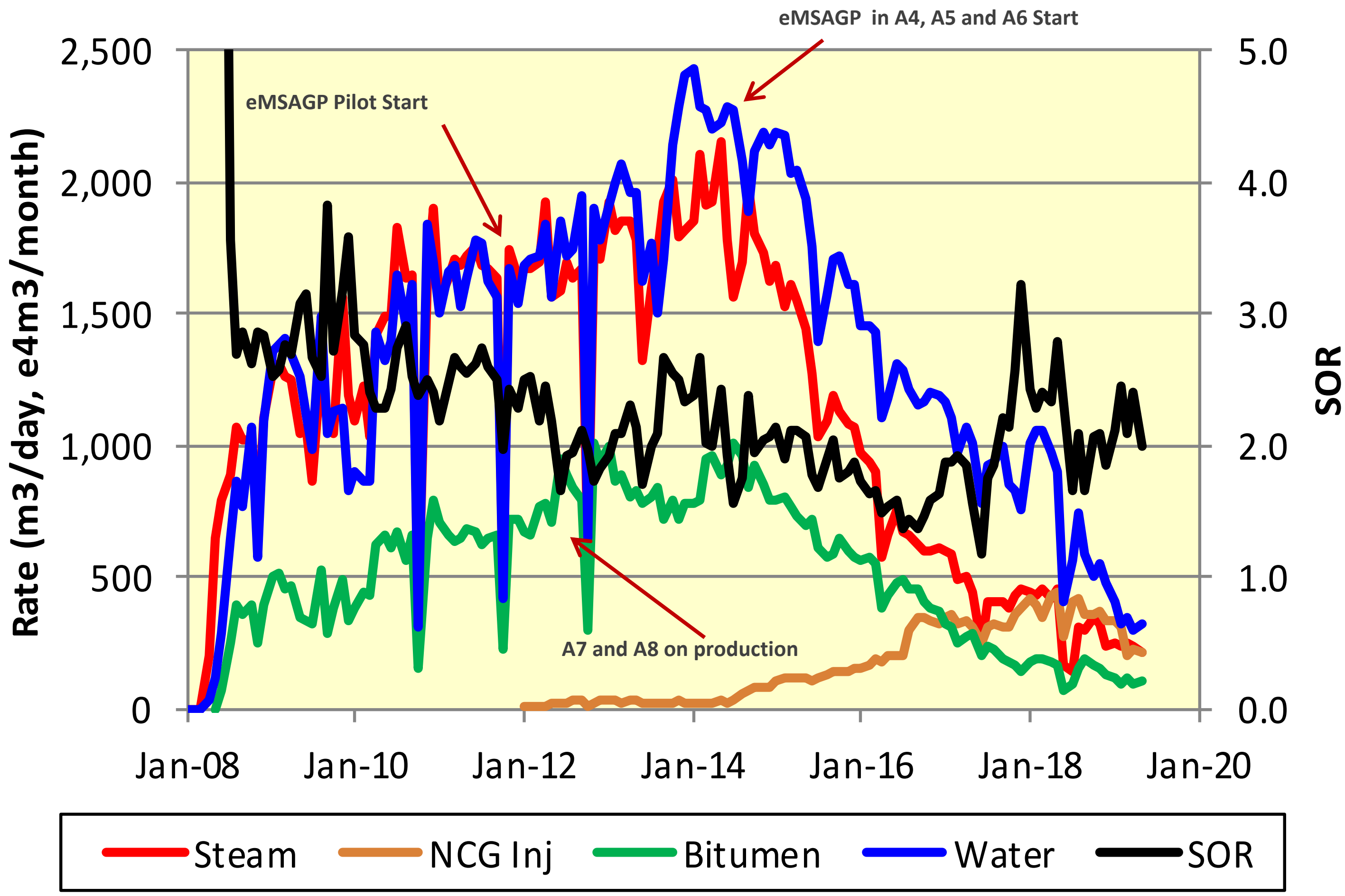
Production Performance



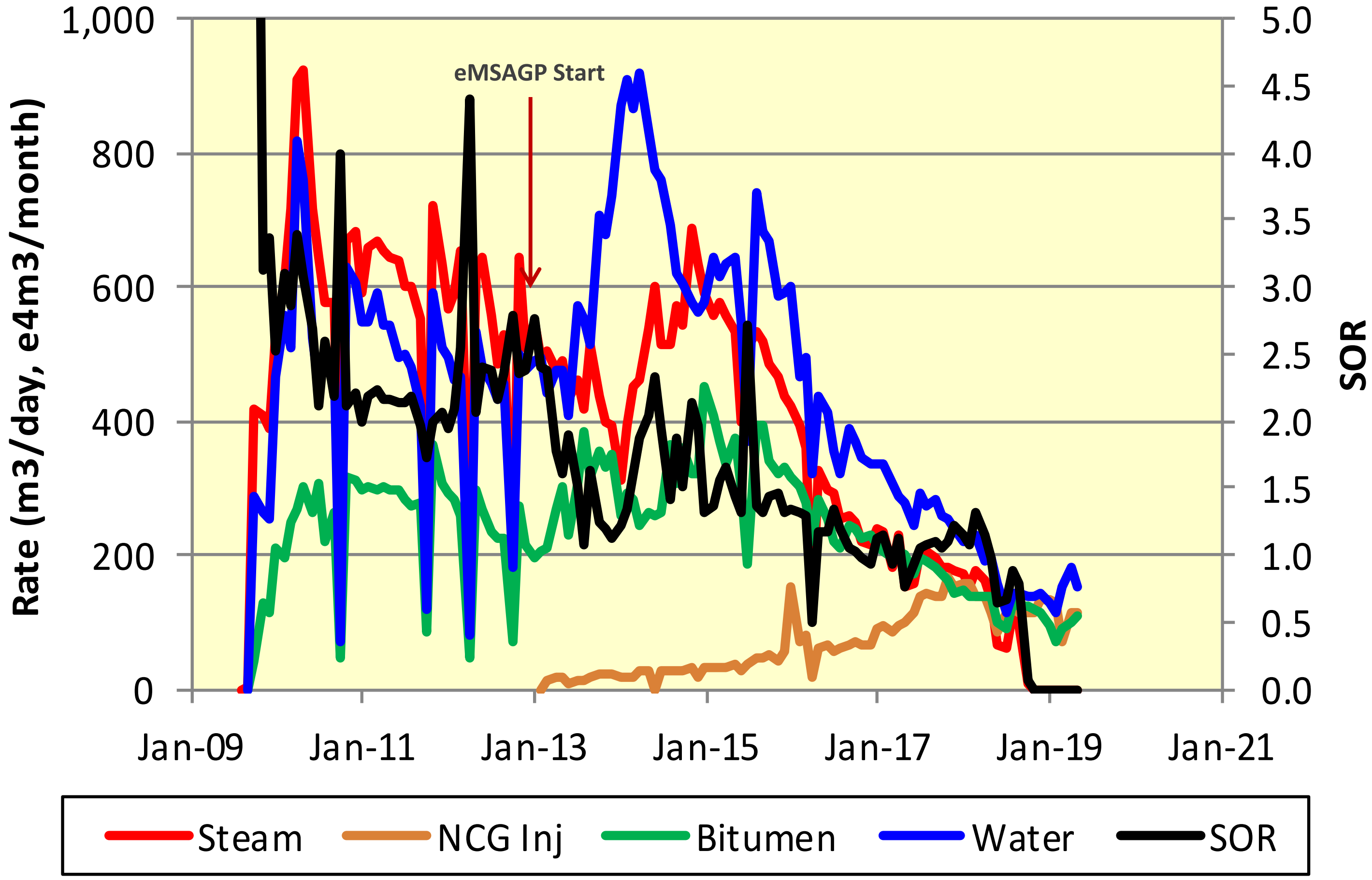
Performance – SOR of All Patterns



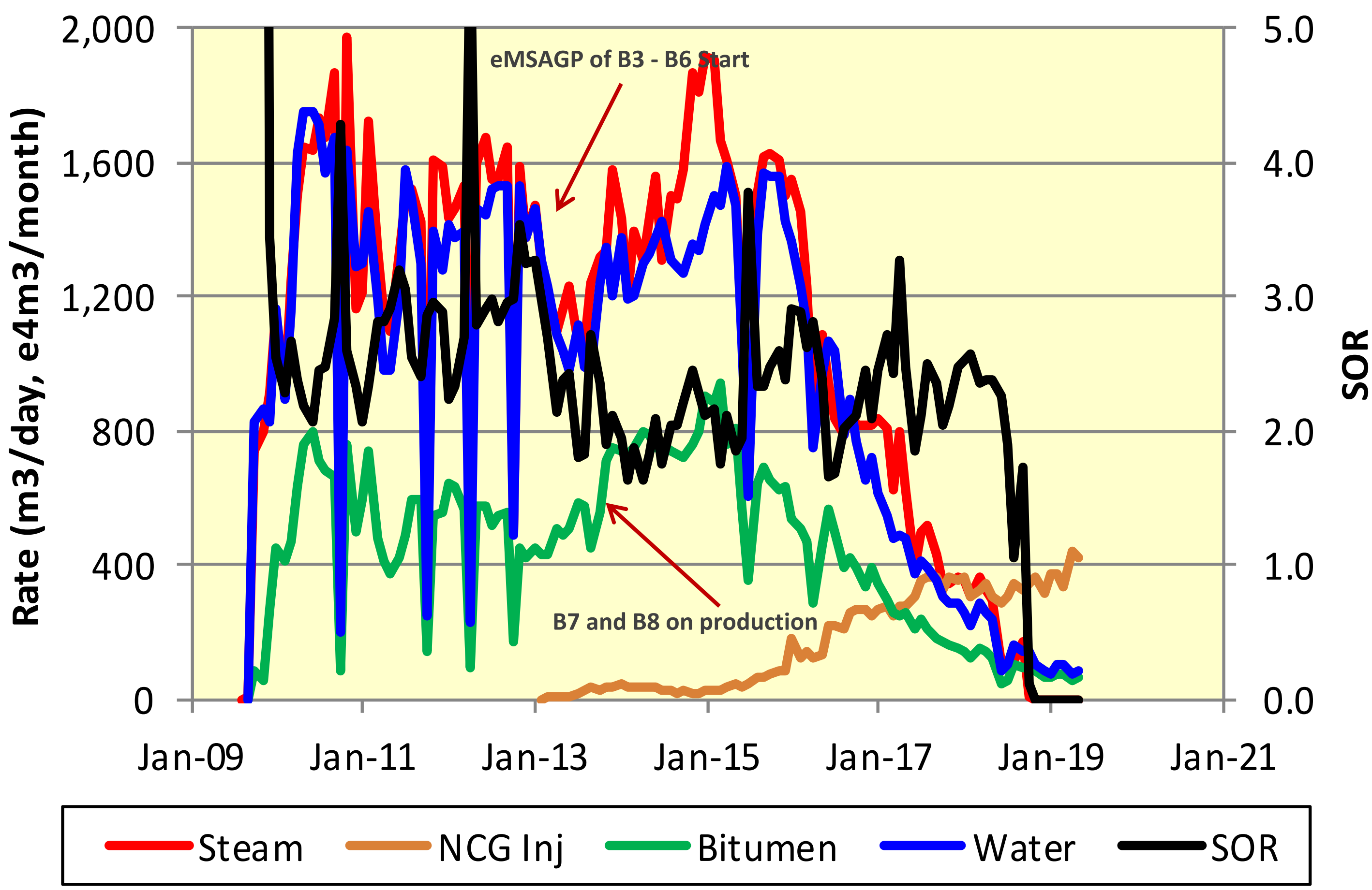
Pattern A Performance



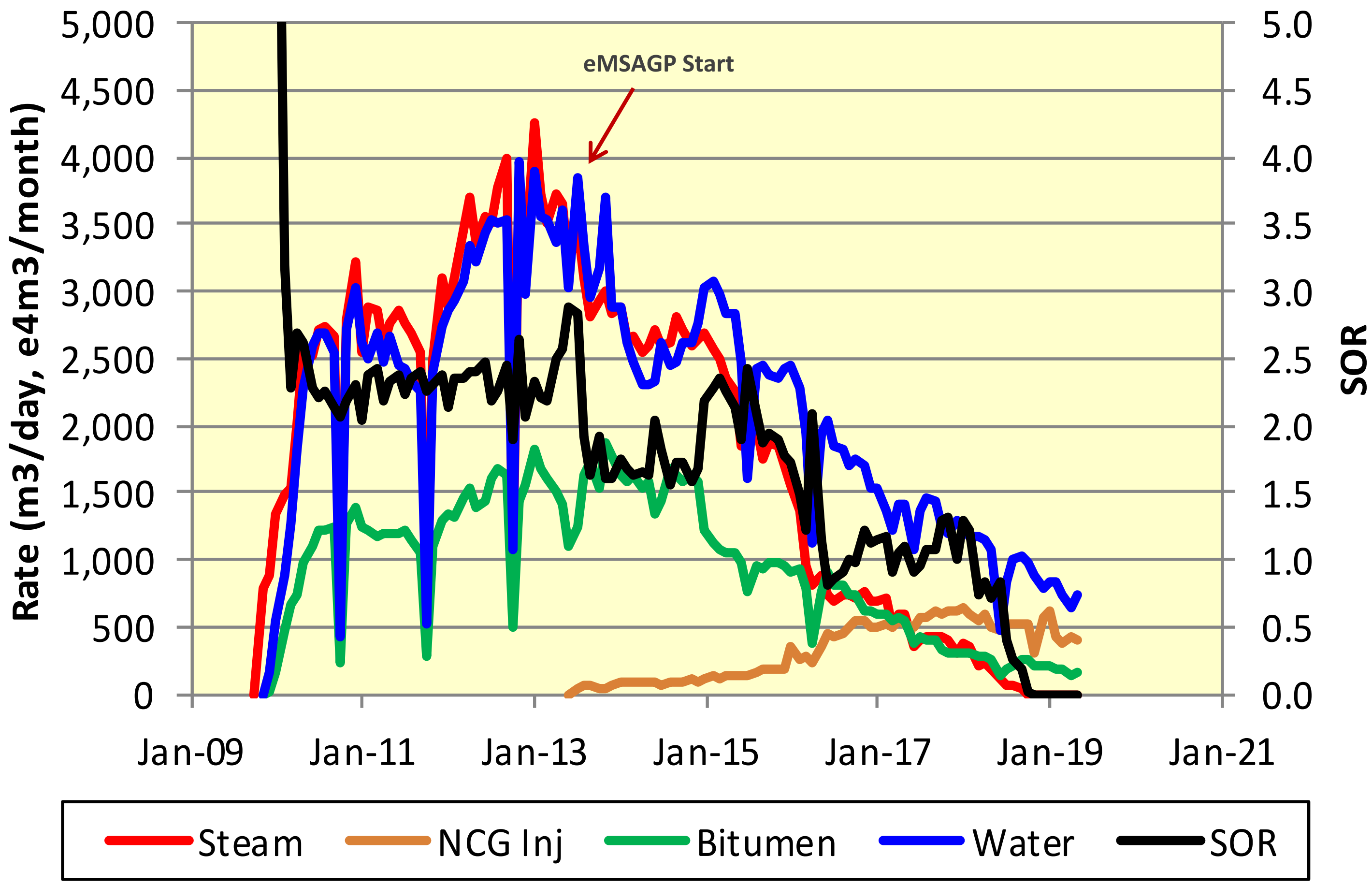
Pattern B Performance



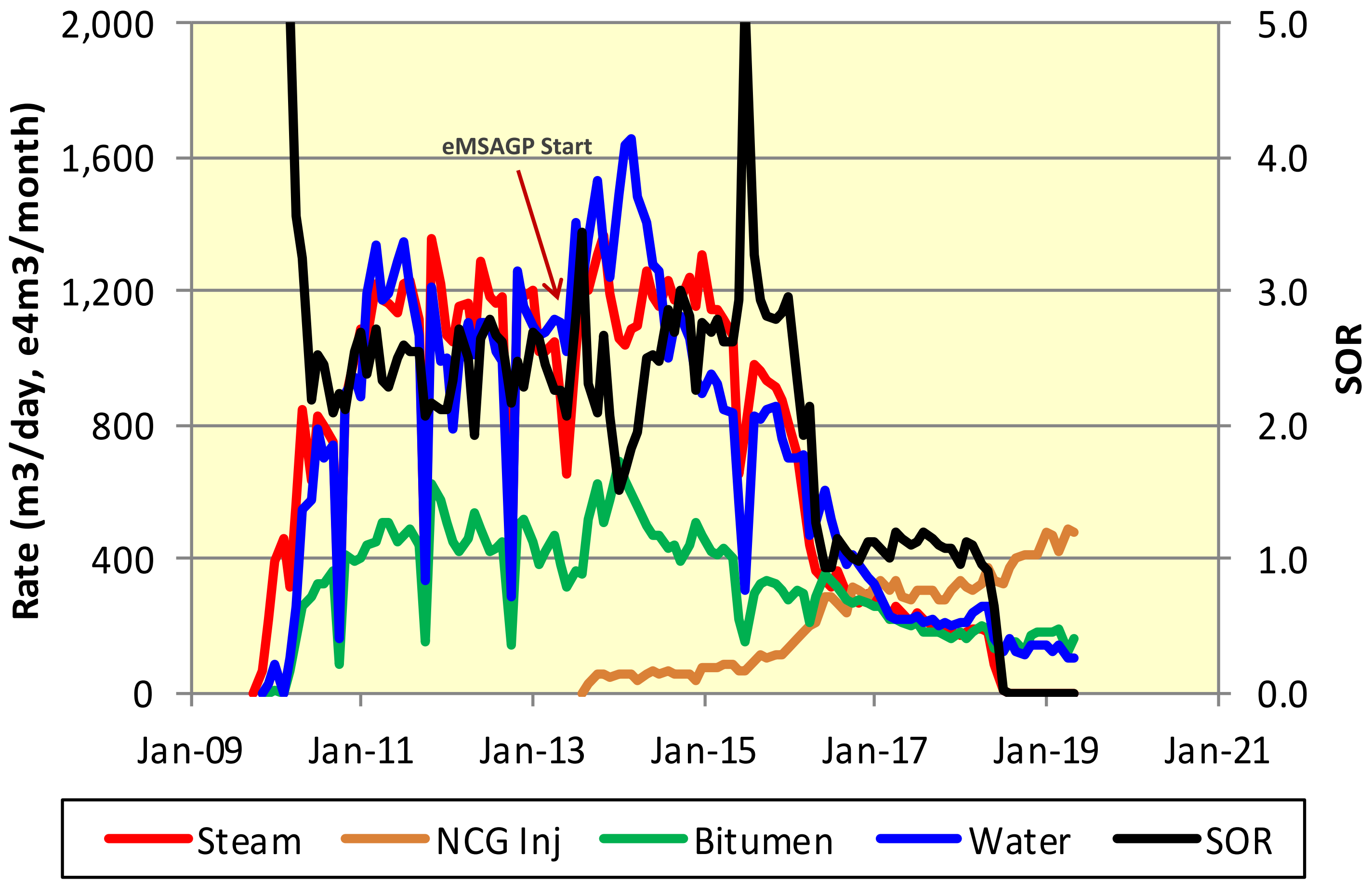
Pattern BB Performance



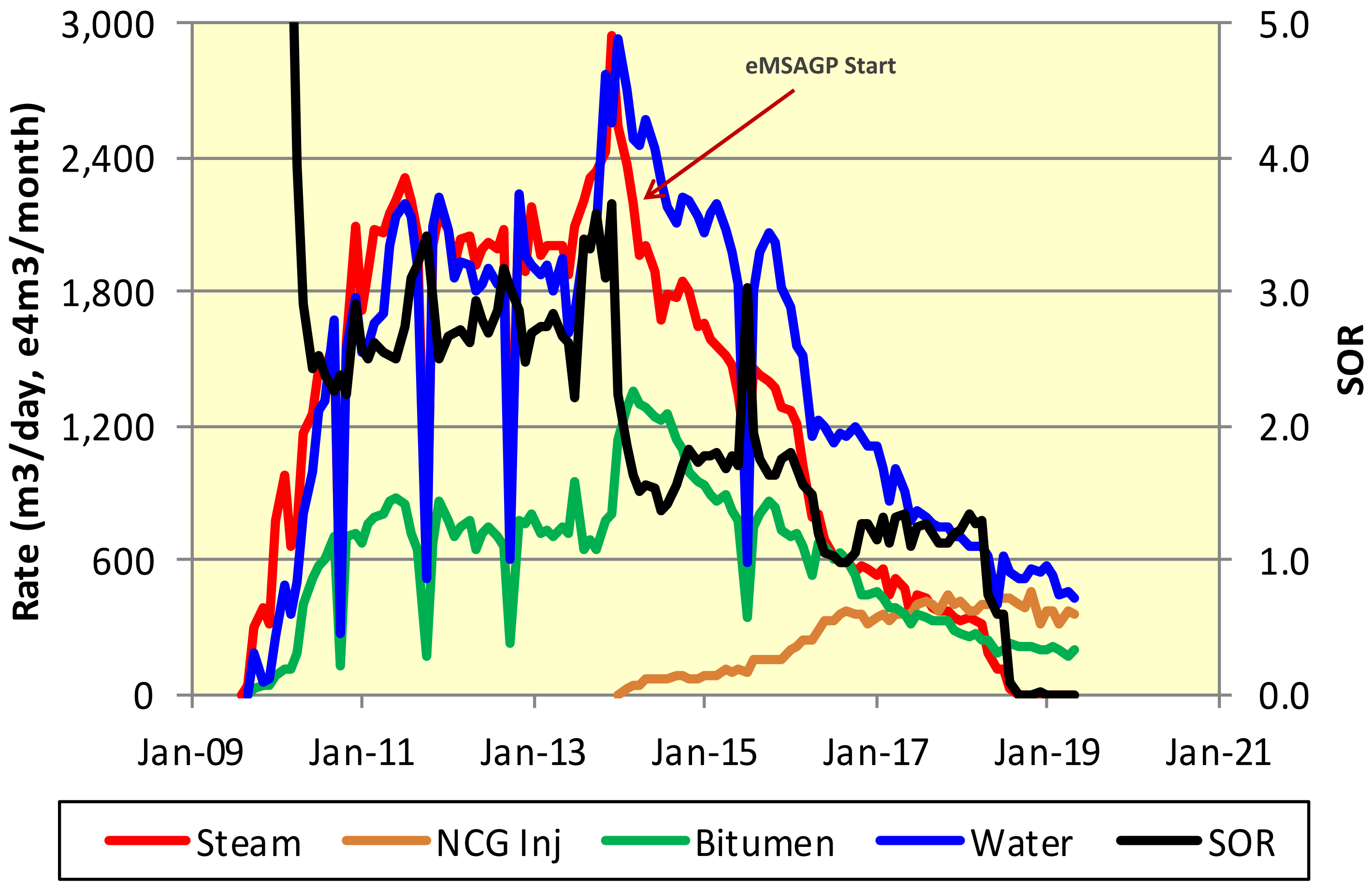
Pattern C Performance



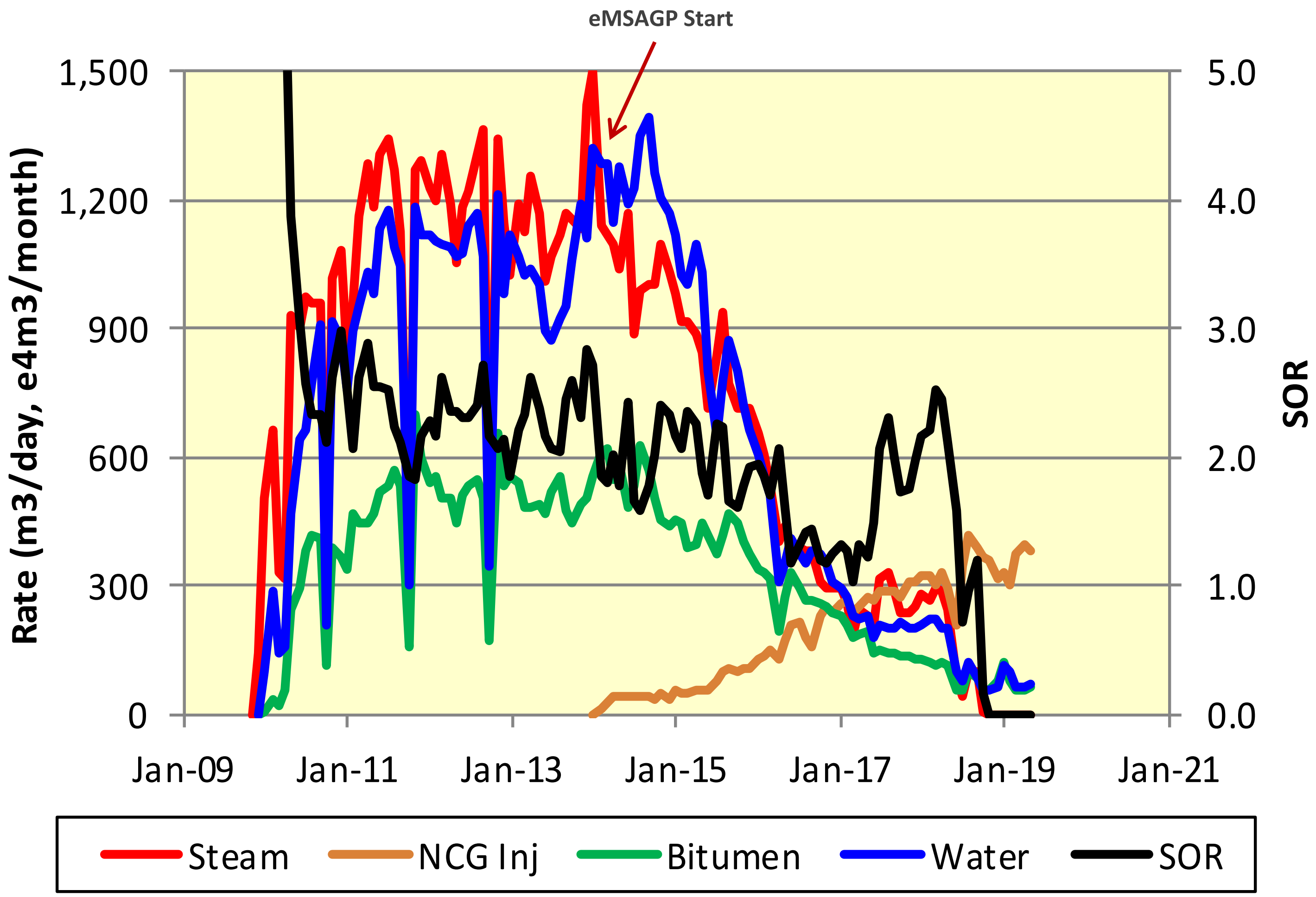
Pattern D Performance



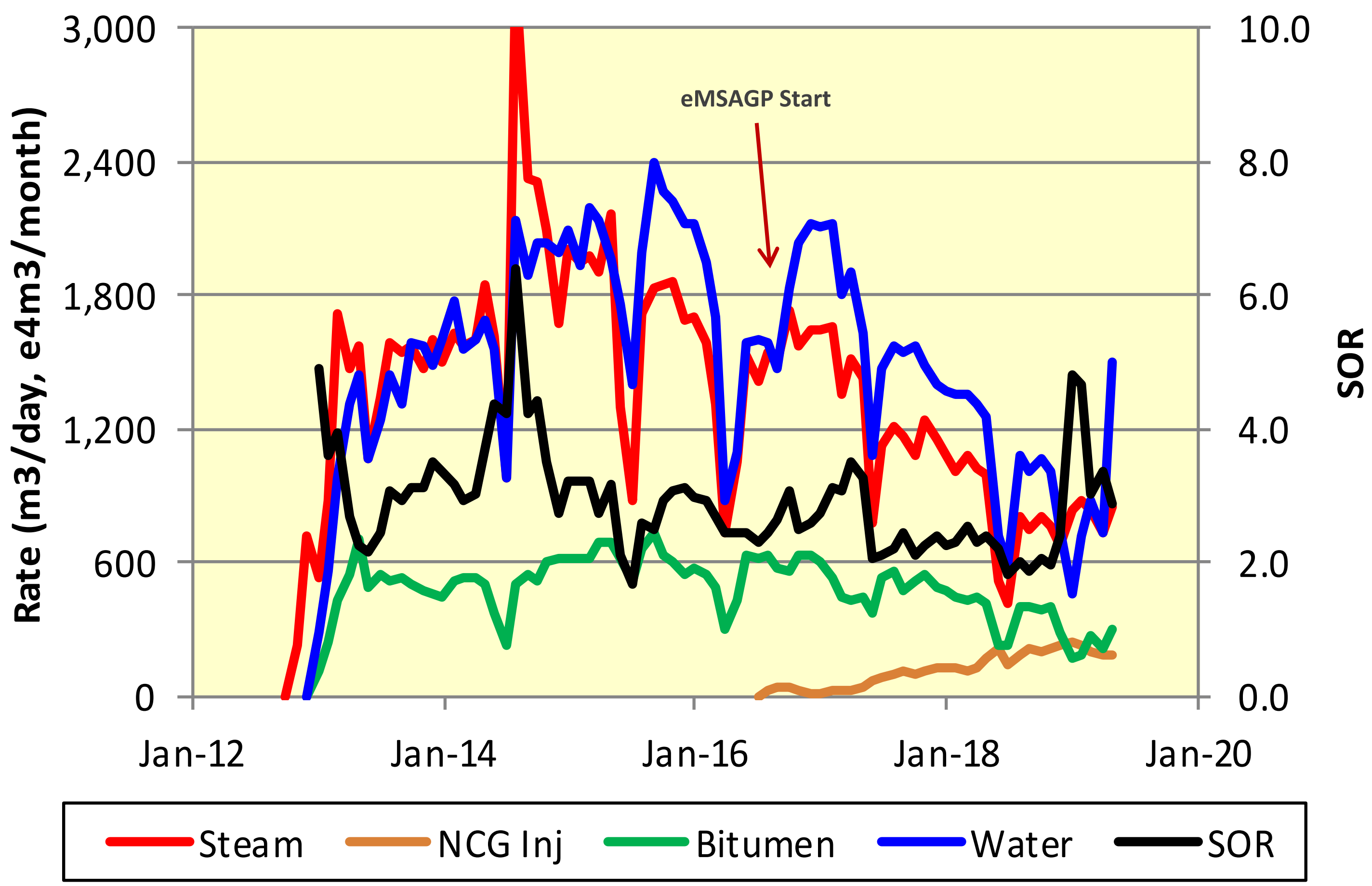
Pattern E Performance



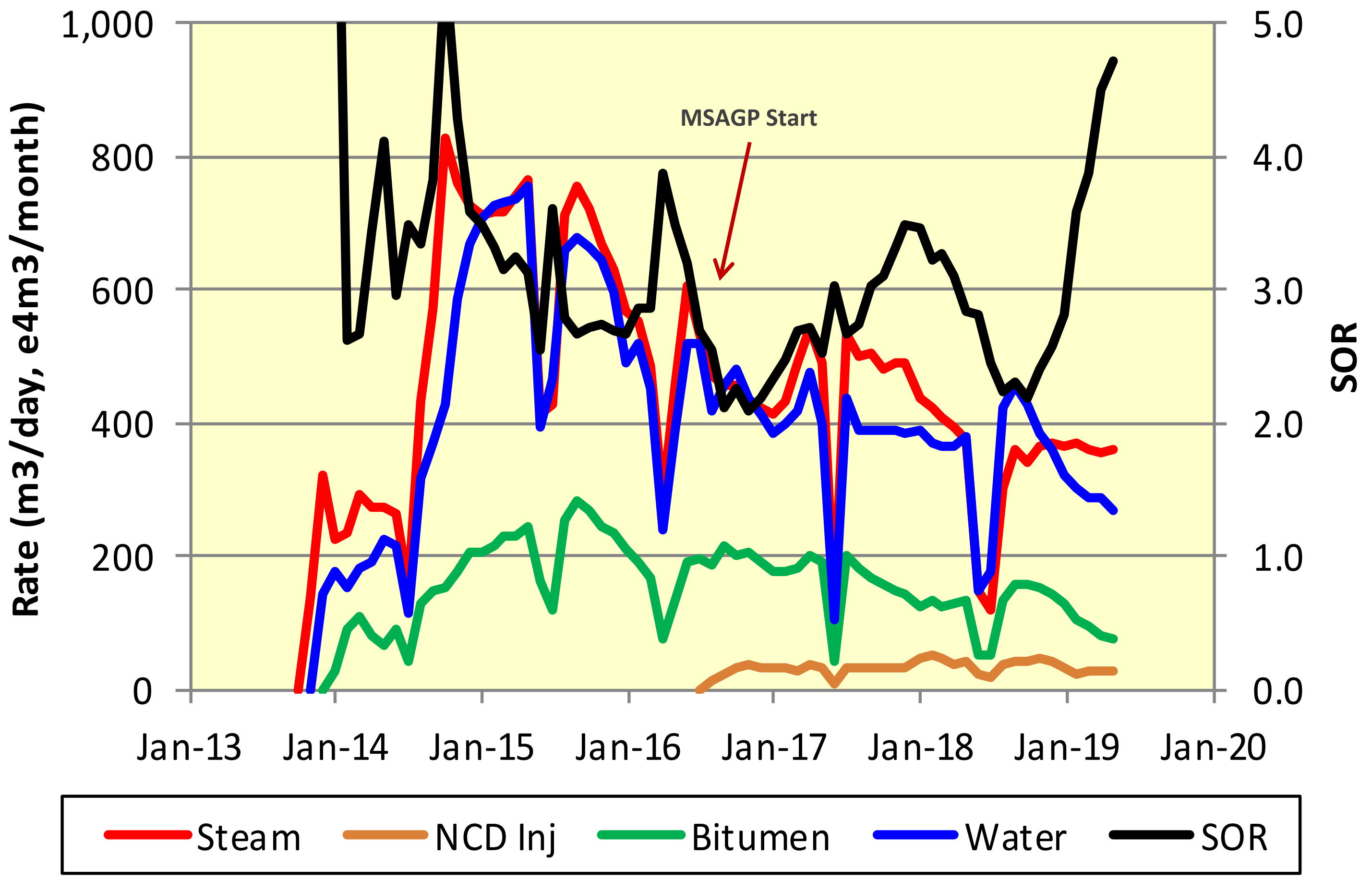
Pattern F Performance



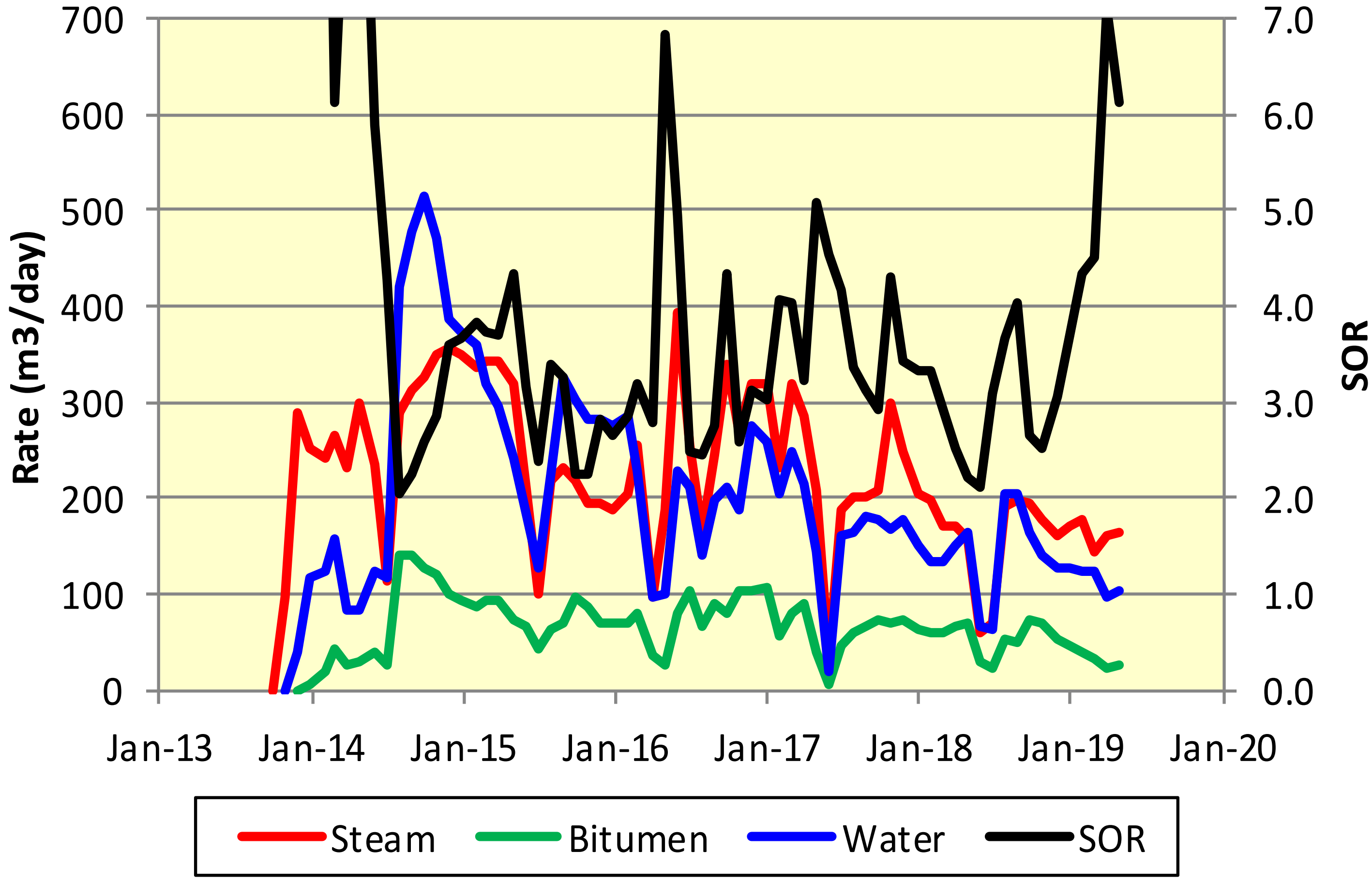
Pattern V Performance



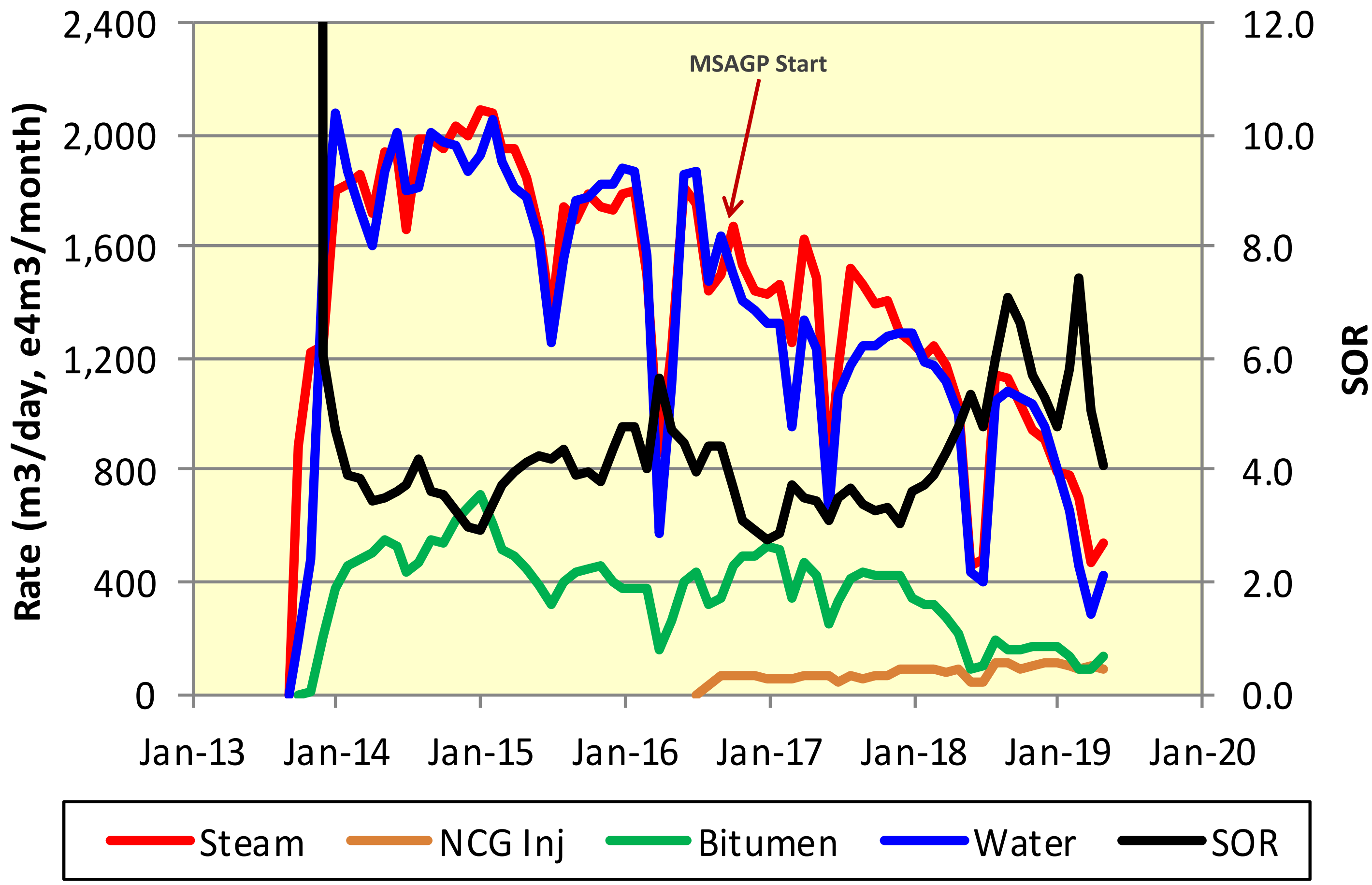
Pattern G Performance



Pattern H Performance

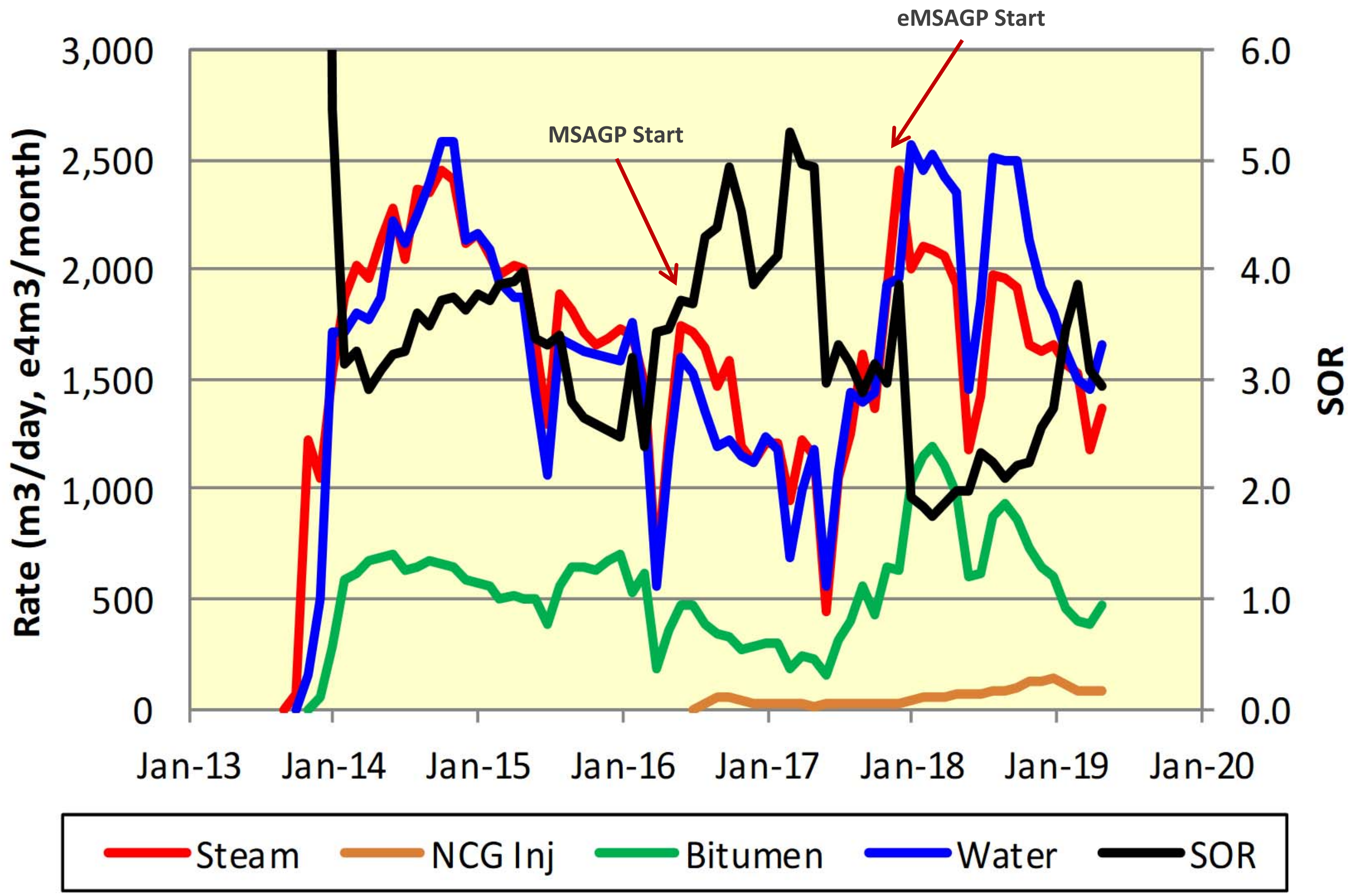


Pattern J Performance

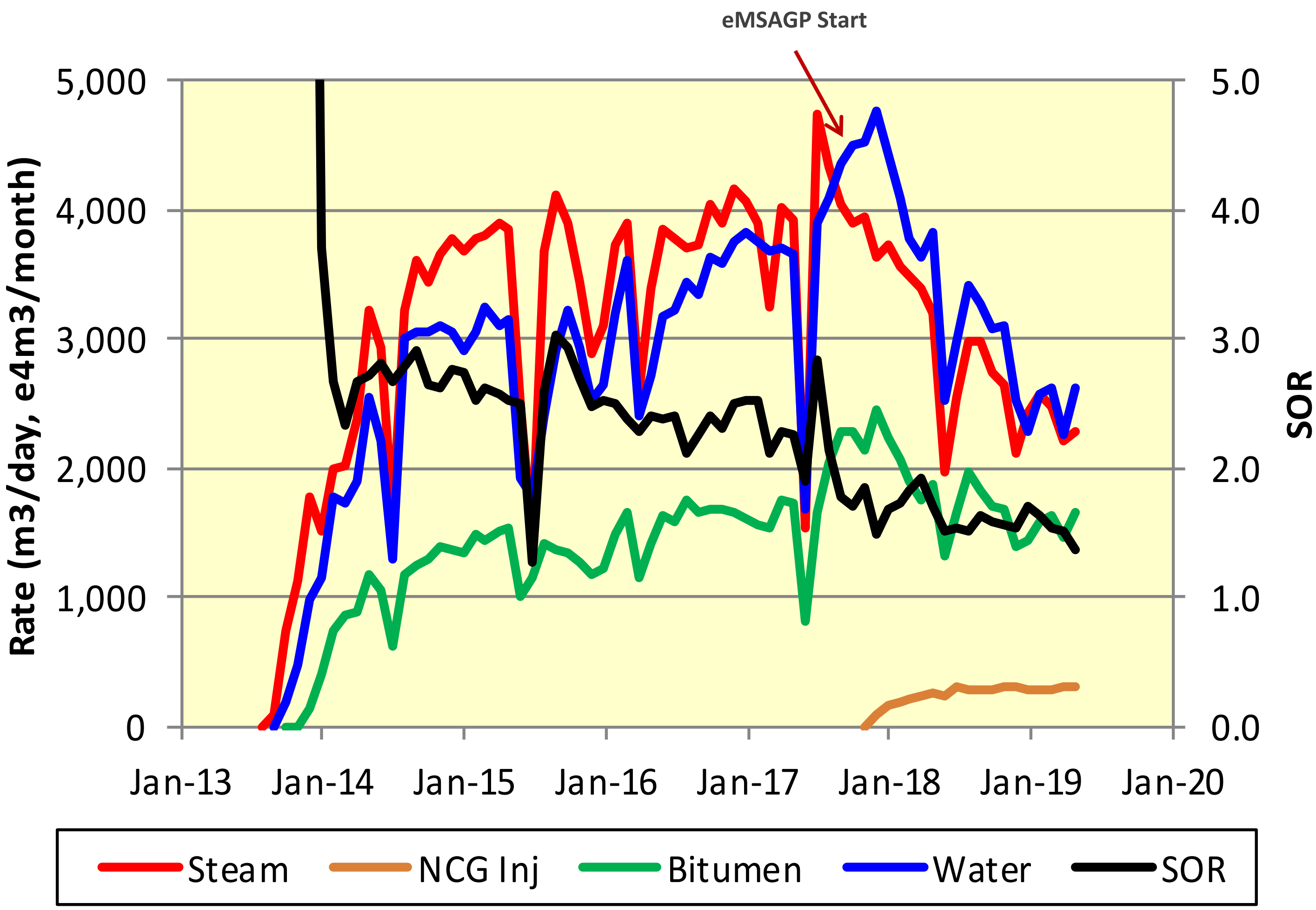


Low Performance Pad: Issues are suspected to be related to potential scale formation and aggravated by exposure to bottom water.

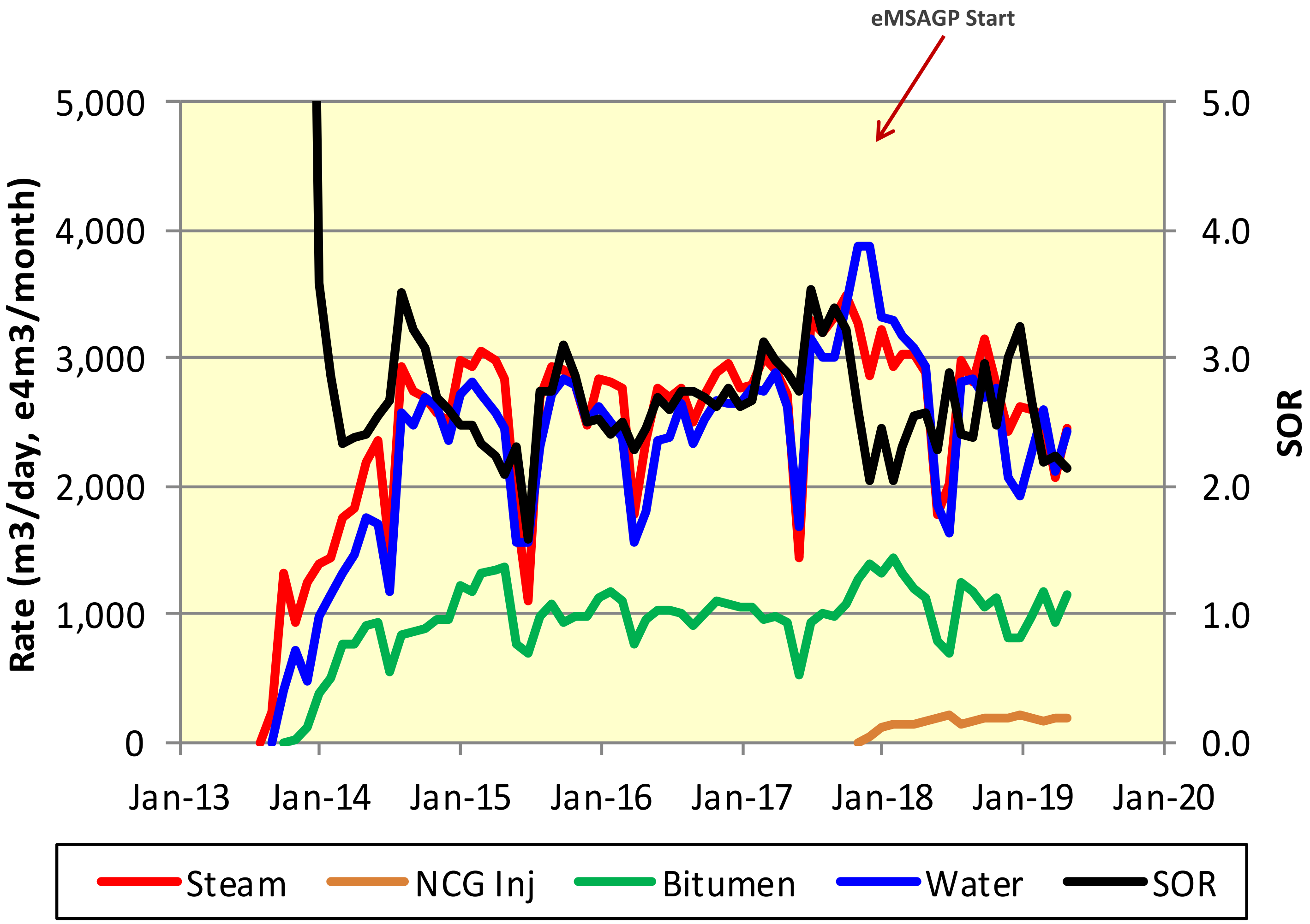
Pattern K Performance



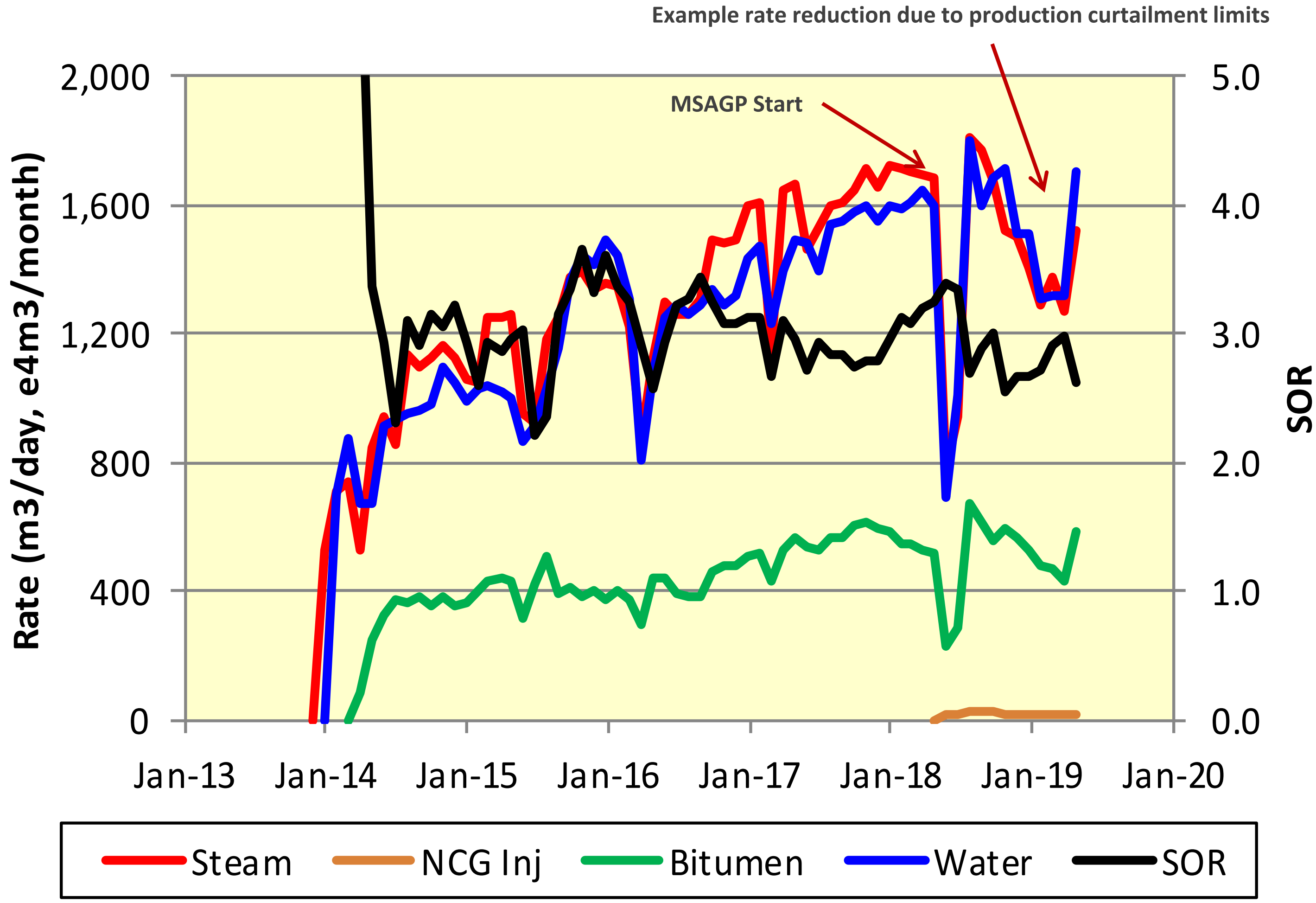
Pattern M Performance



Pattern N Performance

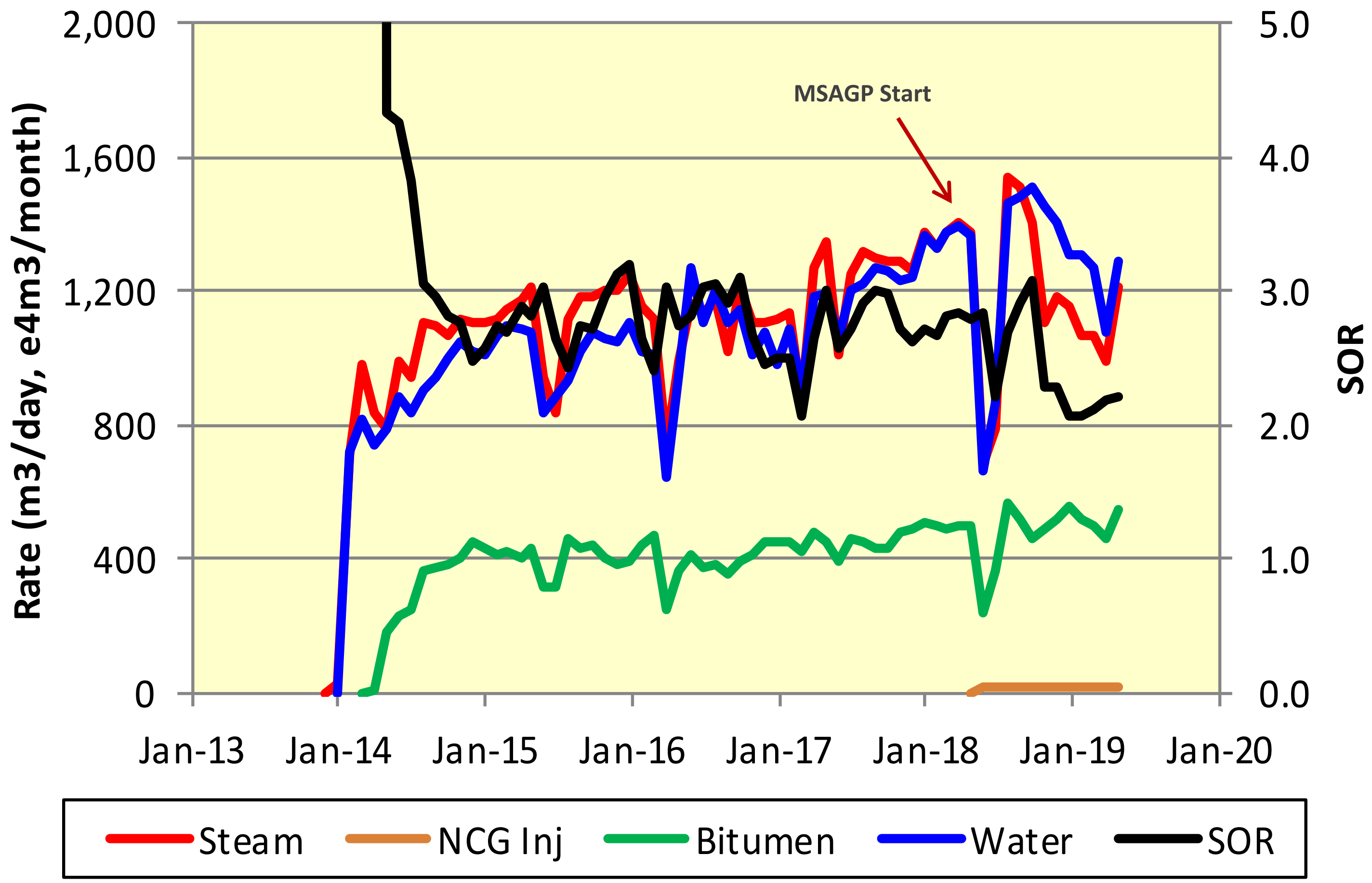


Pattern T Performance

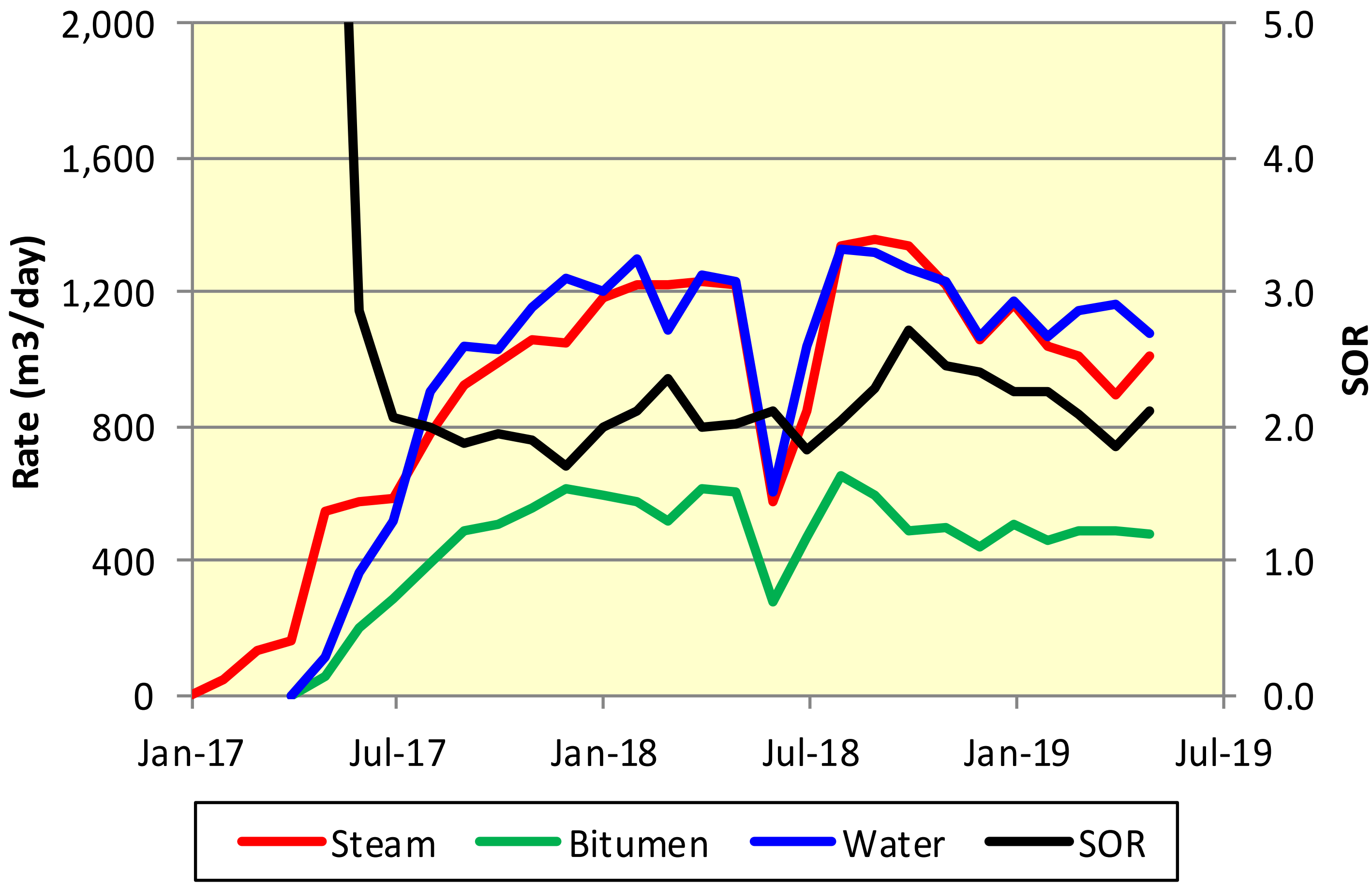


Medium Performance Pad: Production rate and pad performance has continued develop. There has been no particular challenge in operating this pad to date.

Pattern U Performance

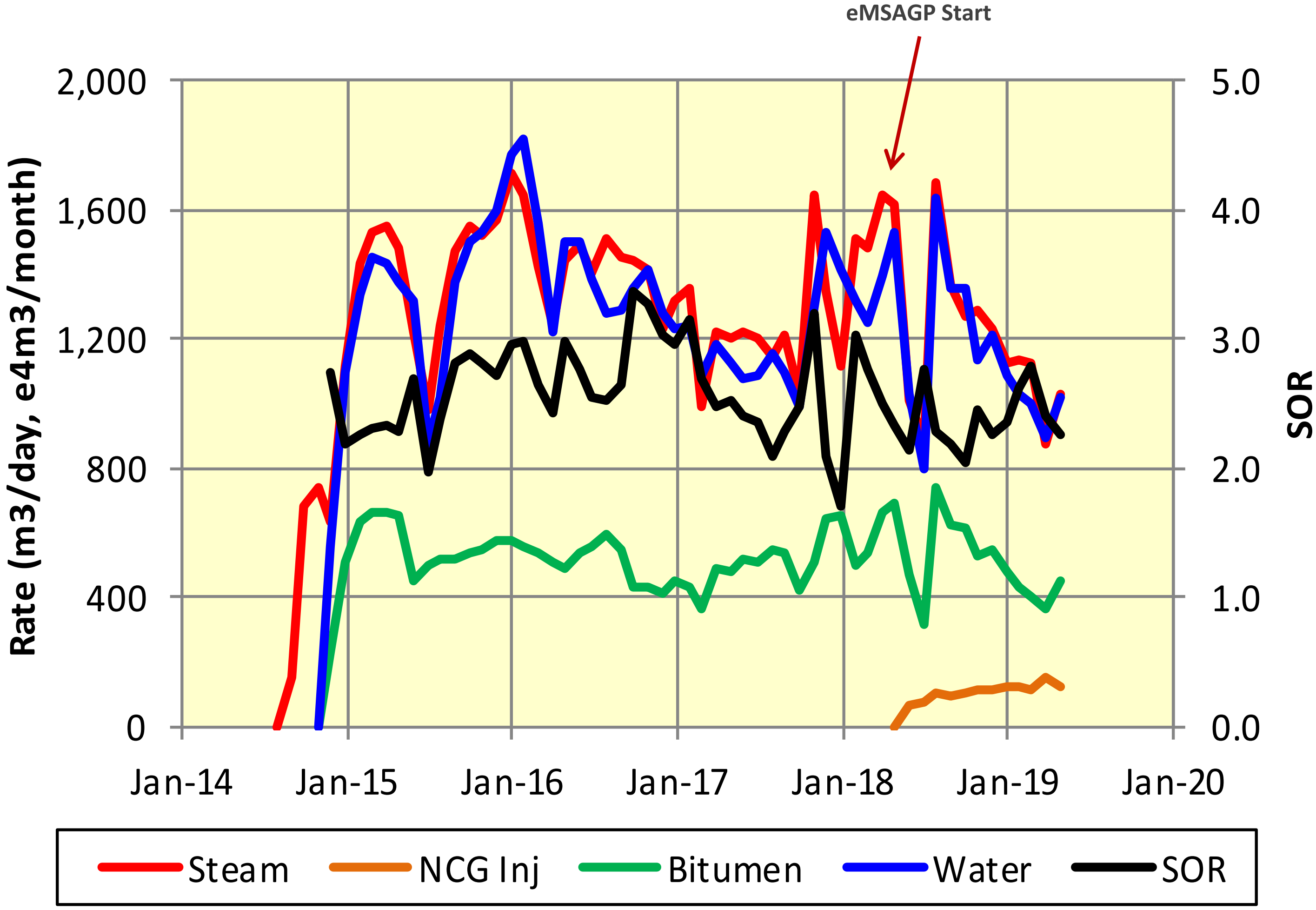


Pattern AP South Performance

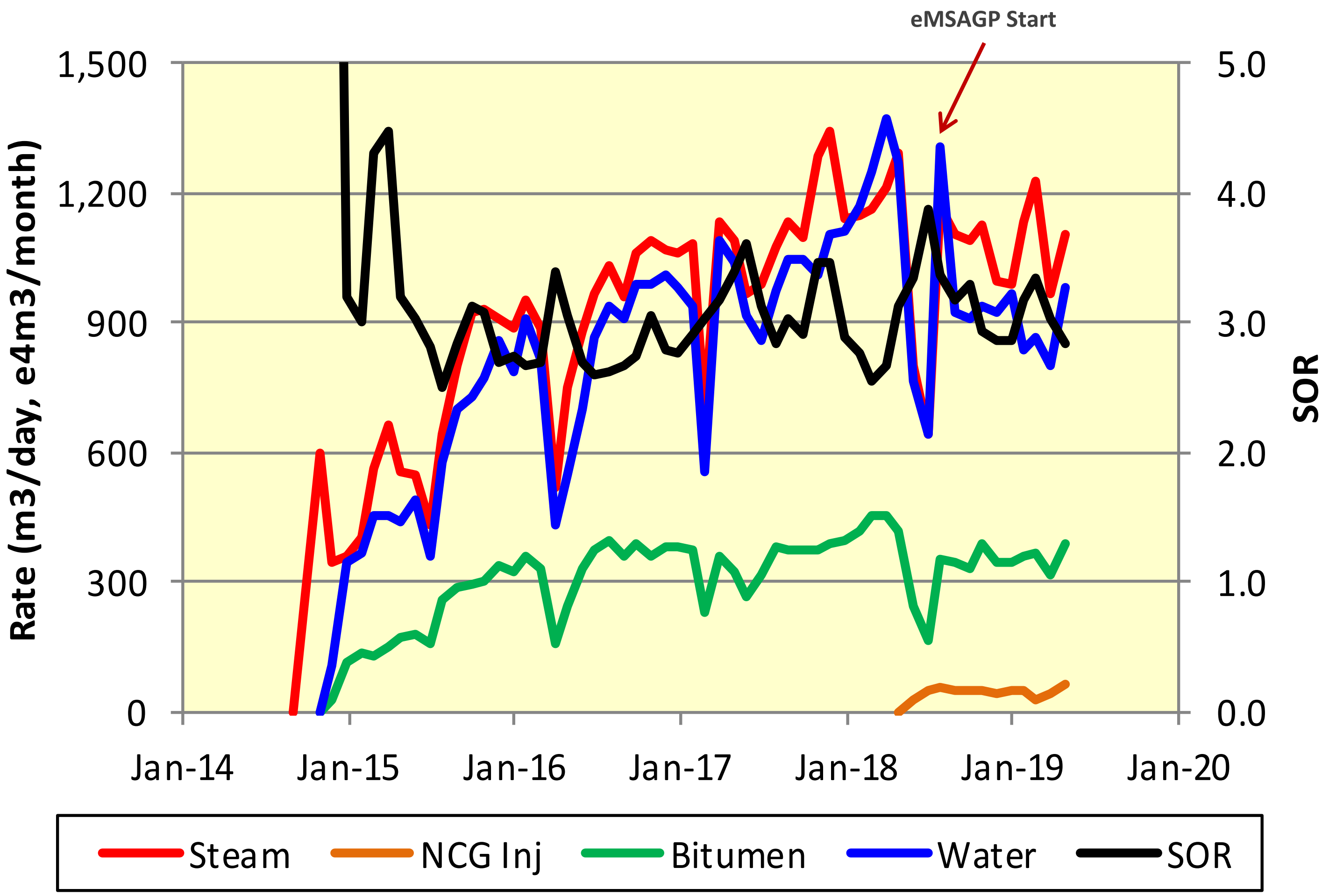


Note: AP West wells covered under Experimental Scheme No. 12528B

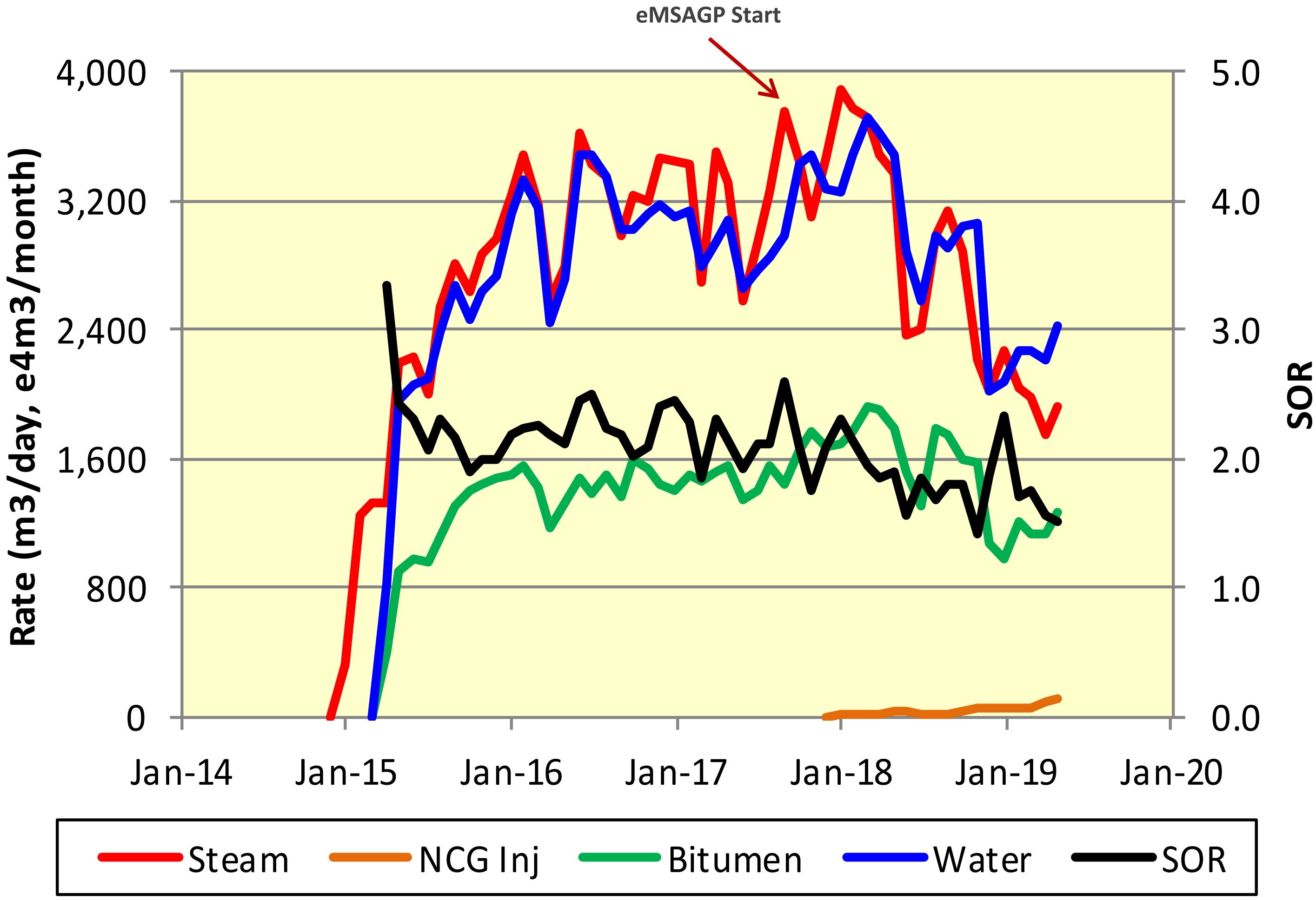
Pattern AF Performance



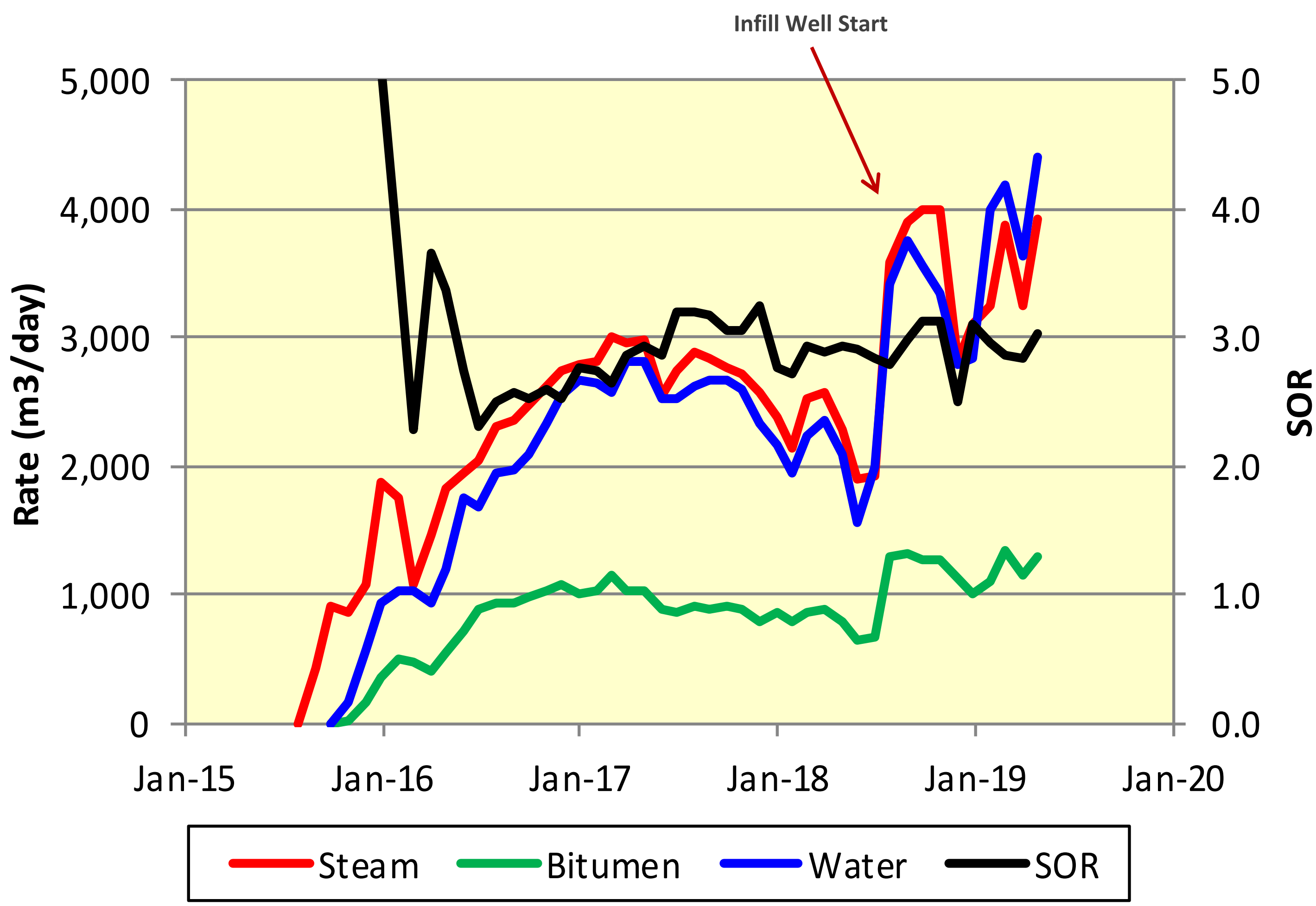
Pattern AG Performance



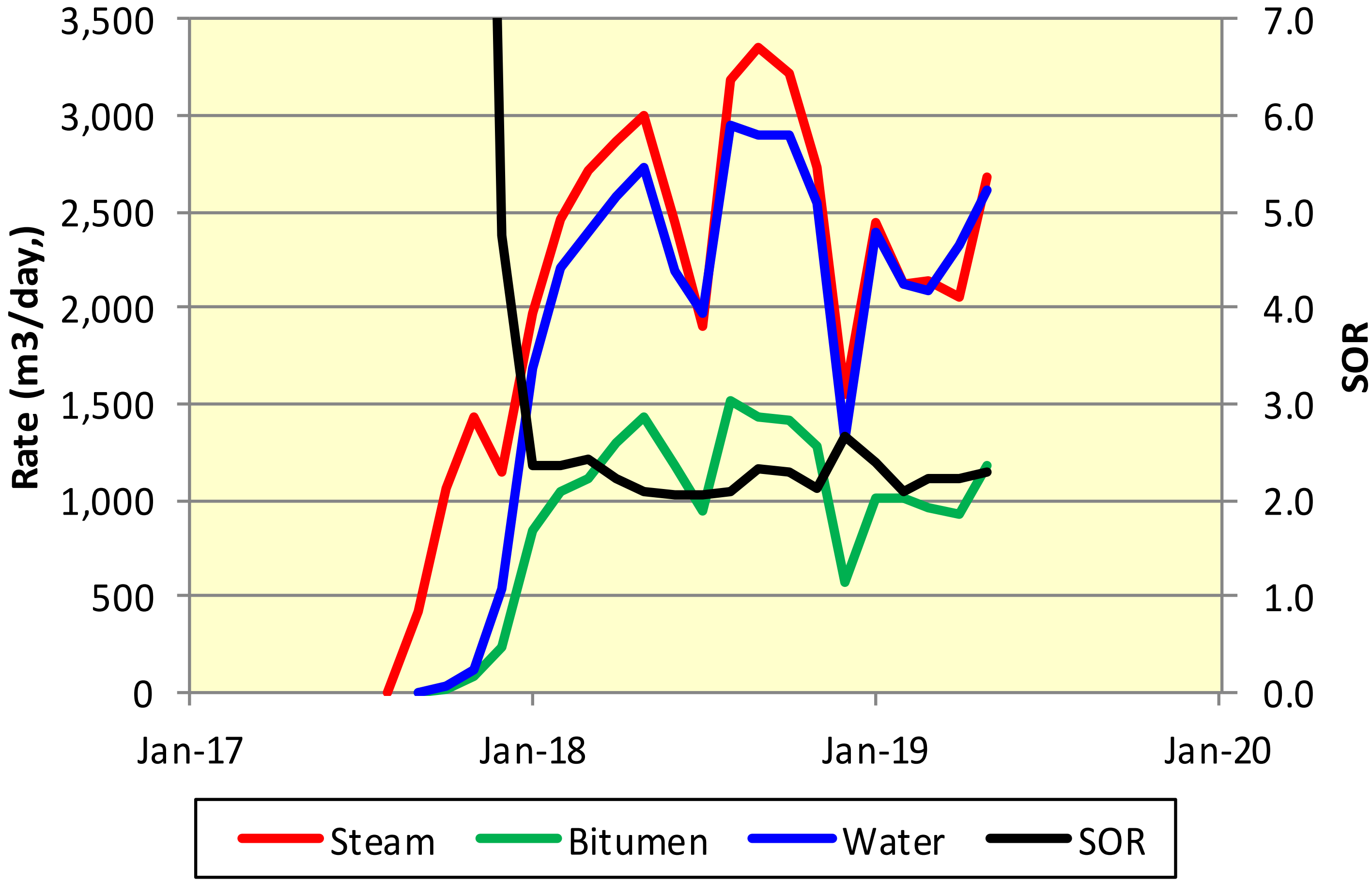
Pattern AN Performance



Pattern P Performance

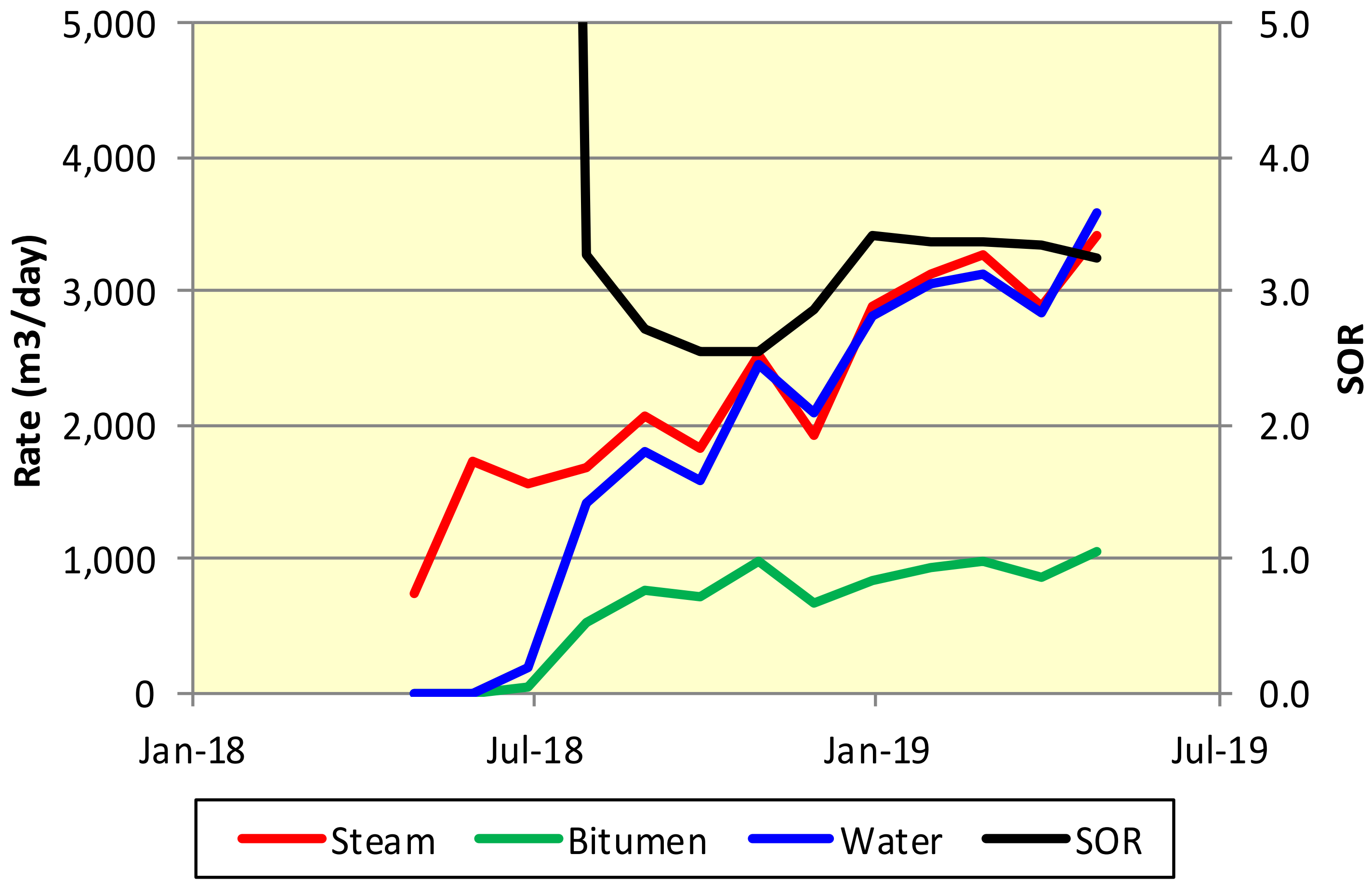


Pattern AQ Performance

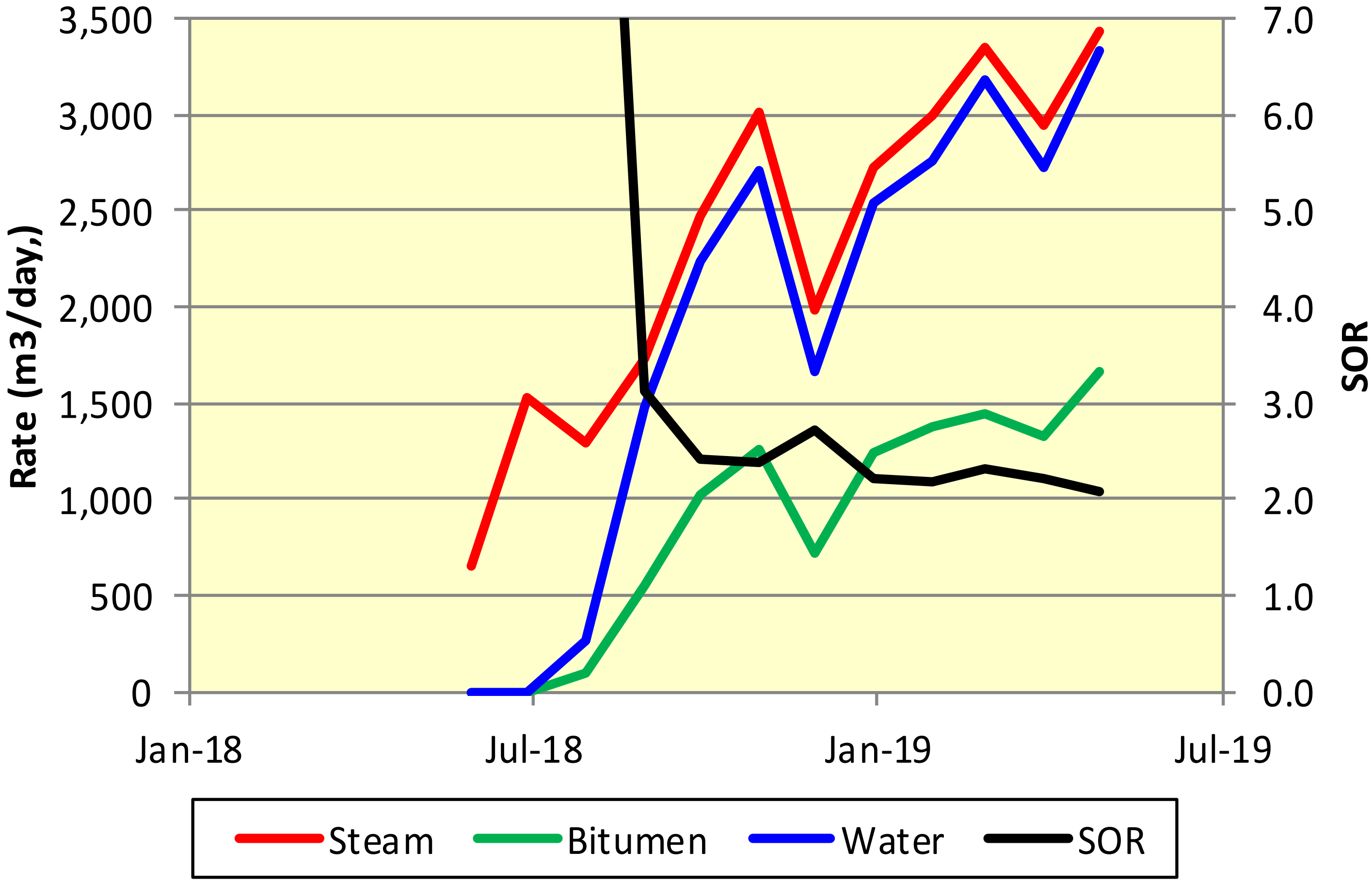


High Performance Pad: High production associated with good reservoir quality and no impairments. There has been no particular challenge in operating this pad to date.

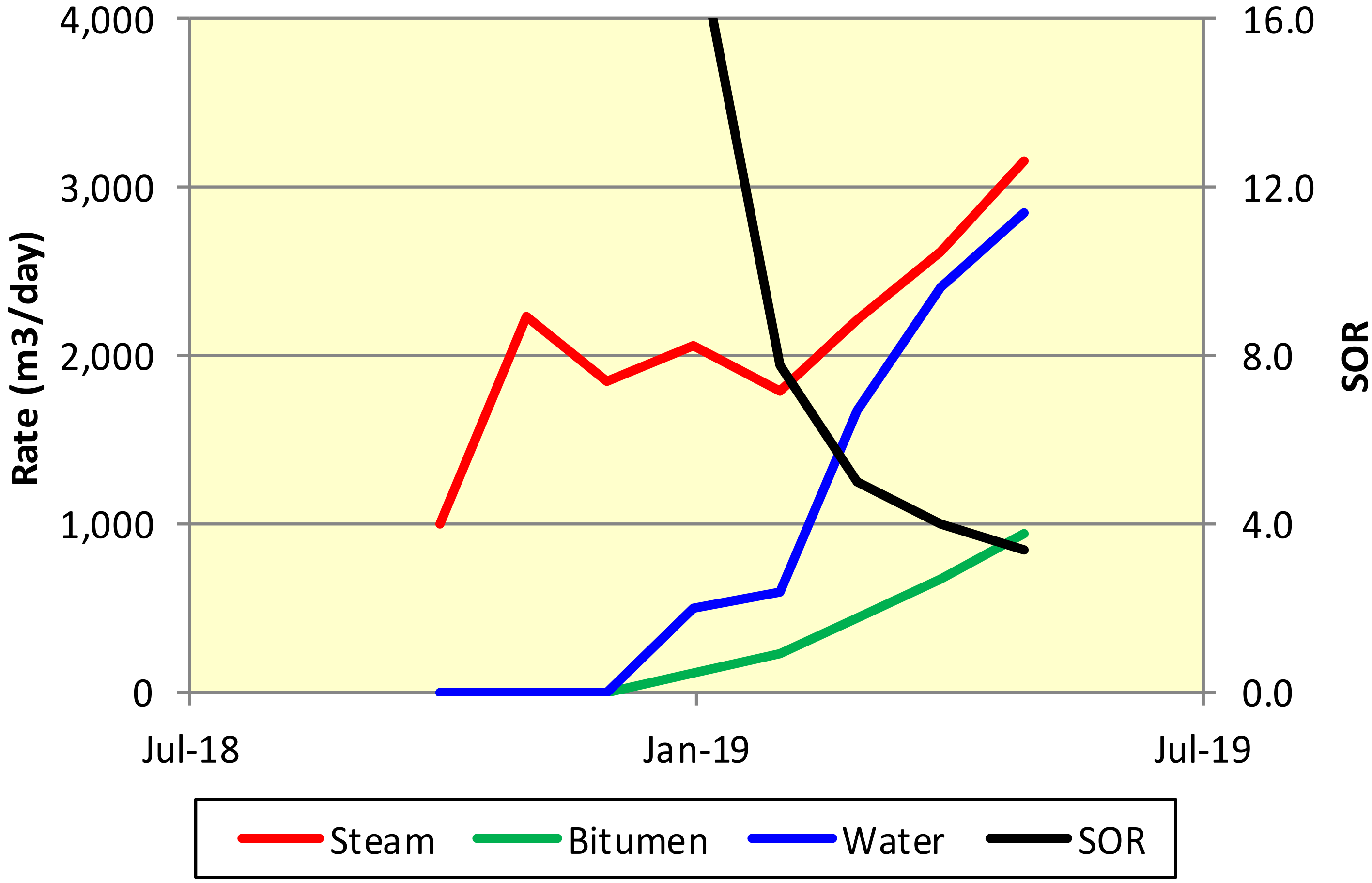
Pattern L Performance



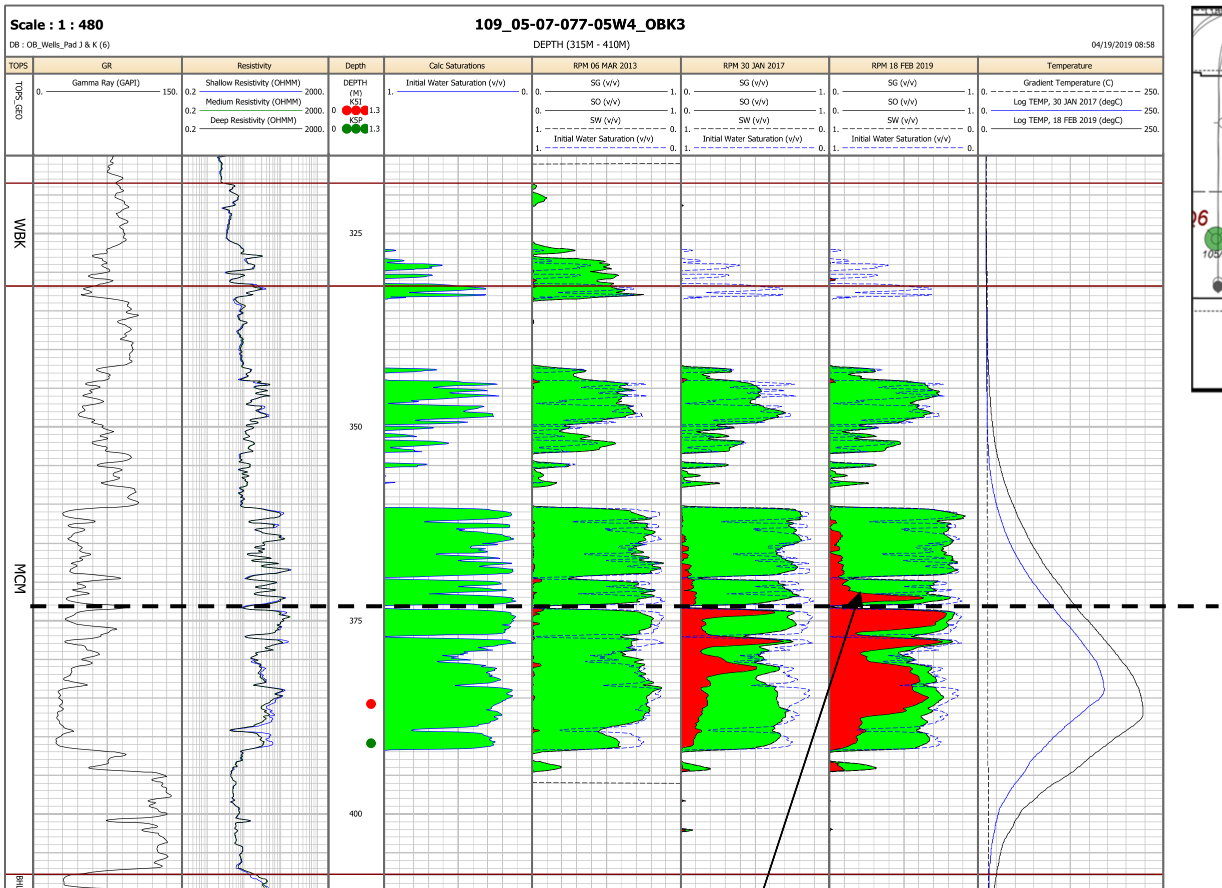
Pattern AT Performance

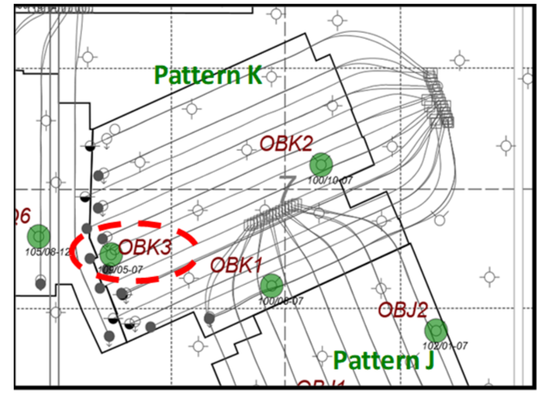


Pattern DB Performance



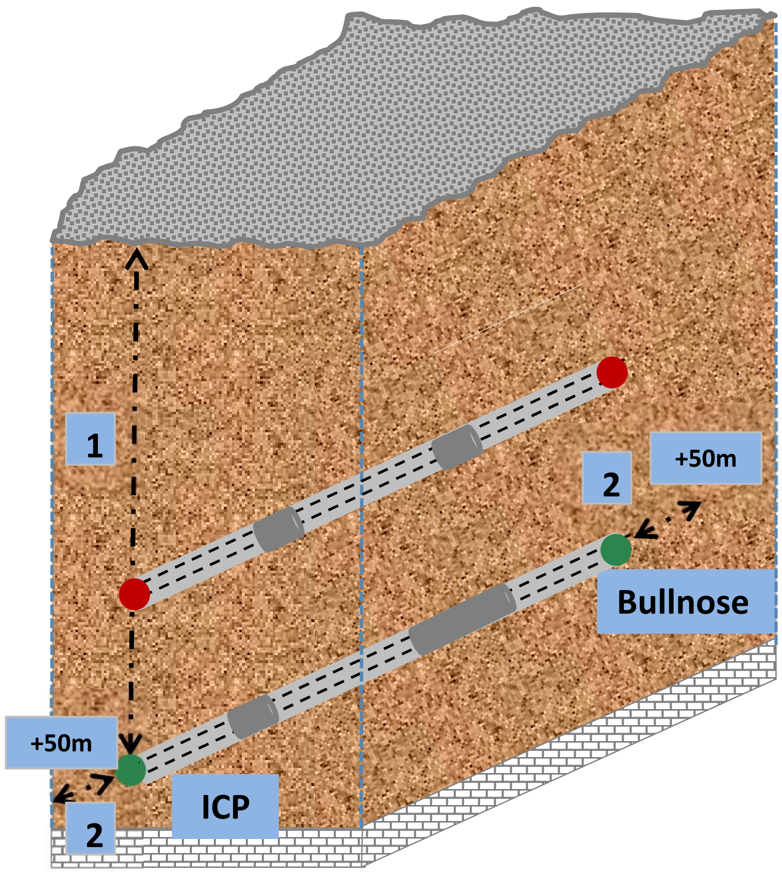
OBK3 Logging Results





Vertical chamber growth observed through IHS

Original Bitumen in Place



- **SAGDable Bitumen In Place**

1 Calculate pay height above producer.

2 Add 50m effective drainage length past first and last slots, unless poor reservoir is encountered.

- **Total Bitumen In Place**

Use full pay height

Total Bitumen in Place

Pattern	Operating WellPairs	Pattern Area (m^2)	Average h (m)	Average Porosity	Average Oil Saturation	OBIP (m^3)
A	8	698,812	22	0.33	0.76	3,752,000
B	2	148,878	32	0.33	0.83	1,300,000
BB+D7	7	565,648	20	0.32	0.83	3,006,000
C+D6	7	647,762	30	0.33	0.75	4,687,000
D-D6-D7	5	339,069	21	0.34	0.81	1,952,000
E+F1	7	606,356	23	0.33	0.77	3,520,000
F-F1	5	382,821	22	0.33	0.78	2,148,000
V	6	650,137	26	0.32	0.74	3,926,000
G	4	294,951	18	0.32	0.72	1,184,000
H	3	214,415	17	0.33	0.72	839,000
J	8	781,677	21	0.33	0.74	3,999,000
K	8	754,663	16	0.33	0.74	3,000,000
M	10	978,051	29	0.32	0.79	7,226,000
N	9	970,951	24	0.33	0.80	6,009,000
T	8	779,449	15	0.32	0.82	2,970,000
U	6	521,939	19	0.30	0.80	2,414,000
AP West	10	912,982	31	0.34	0.82	7,760,000
AP South	3	246,044	23	0.33	0.79	1,485,000
AF	5	498,601	20	0.32	0.81	2,609,000
AG	5	414,226	22	0.33	0.77	2,235,000
AN	9	792,929	23	0.33	0.81	4,744,000
P*	13	1,269,292	20	0.31	0.75	5,802,000
AQ	8	856,060	19	0.33	0.80	4,404,000
AT*	8	972,328	22	0.31	0.78	5,188,000
L*	9	946,760	21	0.33	0.73	4,859,000
DB*	11	1,218,688	21	0.33	0.68	5,777,000
Total	**184**					**96,795,000**

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

Note: h is net pay from SAGD top- SAGD Base

The area reflects the drainage box which is generally 50m from the edge pairs and 50m beyond and behind the first and last slots where appropriate

*New pads or pads with wells added since May 2018

Bitumen Recovery – Mature Patterns

Pattern	Operating WellPairs	Area (m^2)	Average h (m)	Average Porosity	Average Oil Saturation	SAGDable BIP(m^3)	Cumulative Production (m^3)	Recovery to Date (% SADable)	Estimated Final Recovery (% SAGDable)
A	8	698,812	20	0.32	0.76	3,501,000	2,124,079	61%	62%
B	2	148,878	26	0.33	0.84	1,078,000	843,753	78%	83%
BB+D7	7	565,648	18	0.32	0.82	2,681,000	1,596,689	60%	60%
C+D6	7	647,762	26	0.33	0.76	4,090,000	3,319,528	81%	83%
D-D6-D7	5	339,069	18	0.34	0.81	1,686,000	1,150,007	68%	72%
E+F1	7	606,356	19	0.33	0.77	2,940,000	2,123,719	72%	75%
F-F1	5	382,821	19	0.33	0.78	1,867,000	1,181,771	63%	65%
Total	**41**					**17,843,000**	**12,339,546**	**69%**	**71%**

Note: Cumulative Production to April 2019

h is net pay: SAGD Top- producer

The area reflects the drainage box which is generally 50m from the edge pairs and 50m beyond and behind the first and last slots where appropriate

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

Bitumen Recovery – New Patterns

Pattern	Operating WellPairs	Area (m^2)	Average h (m)	Average Porosity	Average Oil Saturation	SAGDable BIP(m^3)	Cumulative Production (m^3)	Recovery to Date (% SADable)
V	6	650,137	24	0.31	0.73	3,479,000	1,131,944	33%
G	4	294,951	16	0.32	0.74	1,116,000	307,329	28%
H	3	214,415	12	0.32	0.74	599,000	129,659	22%
J	8	781,677	19	0.32	0.75	3,653,000	749,337	21%
K	8	754,663	15	0.33	0.74	2,783,000	1,109,889	40%
M	10	978,051	28	0.32	0.79	6,965,000	2,975,026	43%
N	9	970,951	22	0.33	0.80	5,657,000	1,975,619	35%
T	8	779,449	13	0.31	0.81	2,550,000	849,627	33%
U	6	521,939	16	0.30	0.80	2,033,000	782,758	39%
AP West	10	912,982	27	0.33	0.83	6,813,000	See Note**	
AP South	3	246,044	21	0.33	0.79	1,362,000	360,470	26%
AF	5	498,601	16	0.32	0.82	2,110,000	854,207	40%
AG	5	414,226	20	0.33	0.77	2,095,000	509,536	24%
AN	9	792,929	20	0.33	0.82	4,165,000	2,154,852	52%
P*	13	1,269,292	16	0.32	0.75	4,864,000	1,153,542	24%
AQ	8	856,060	17	0.33	0.80	3,935,000	592,959	15%
AT*	8	972,328	19	0.31	0.79	4,512,000	323,693	7%
L*	9	946,760	18	0.33	0.73	4,165,000	253,334	6%
DB*	11	1,218,688	17	0.33	0.68	4,718,000	71,783	2%
Total	**143**					**67,574,000**	**16,285,564**	**24%**

Note: Cumulative Production to April 2019
h is net pay: SAGD Top- producer
The area reflects the drainage box which is generally 50m from the edge pairs and 50m beyond and behind the 1st and last slots where appropriate
*New pads or pads with wells added since May 2018
**Covered under Experimental Scheme No. 12528B

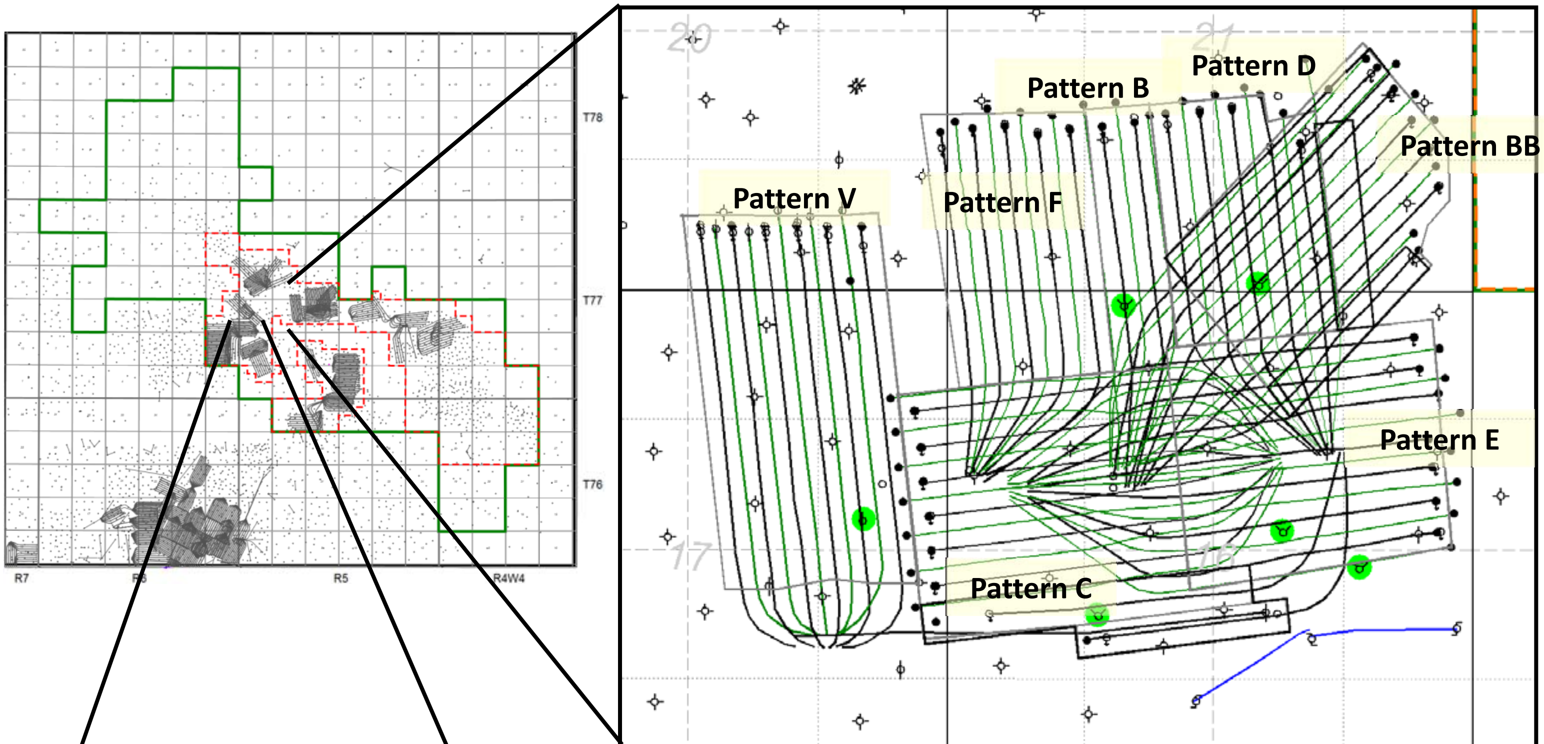
Note: Resource estimates in this table are based on MEG Energy volumetric calculations, and are not in accordance with National Instrument 51-101 guidelines. They are provided solely for the purpose of complying with Alberta regulatory requirements.

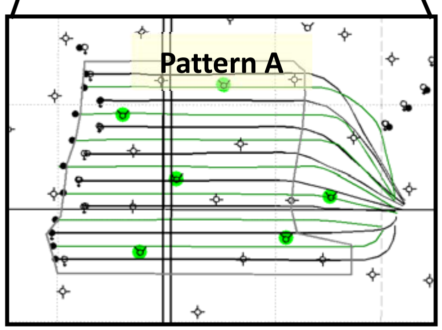
Pad Abandonment

- The following mature patterns are anticipated to require pad abandonments within the next five years
  - A Pad
  - B Pad
  - C Pad
  - D Pad
  - E Pad
  - F Pad

Enhanced Modified Steam and Gas Push

Phase 1 and Phase 2 Pad Layout

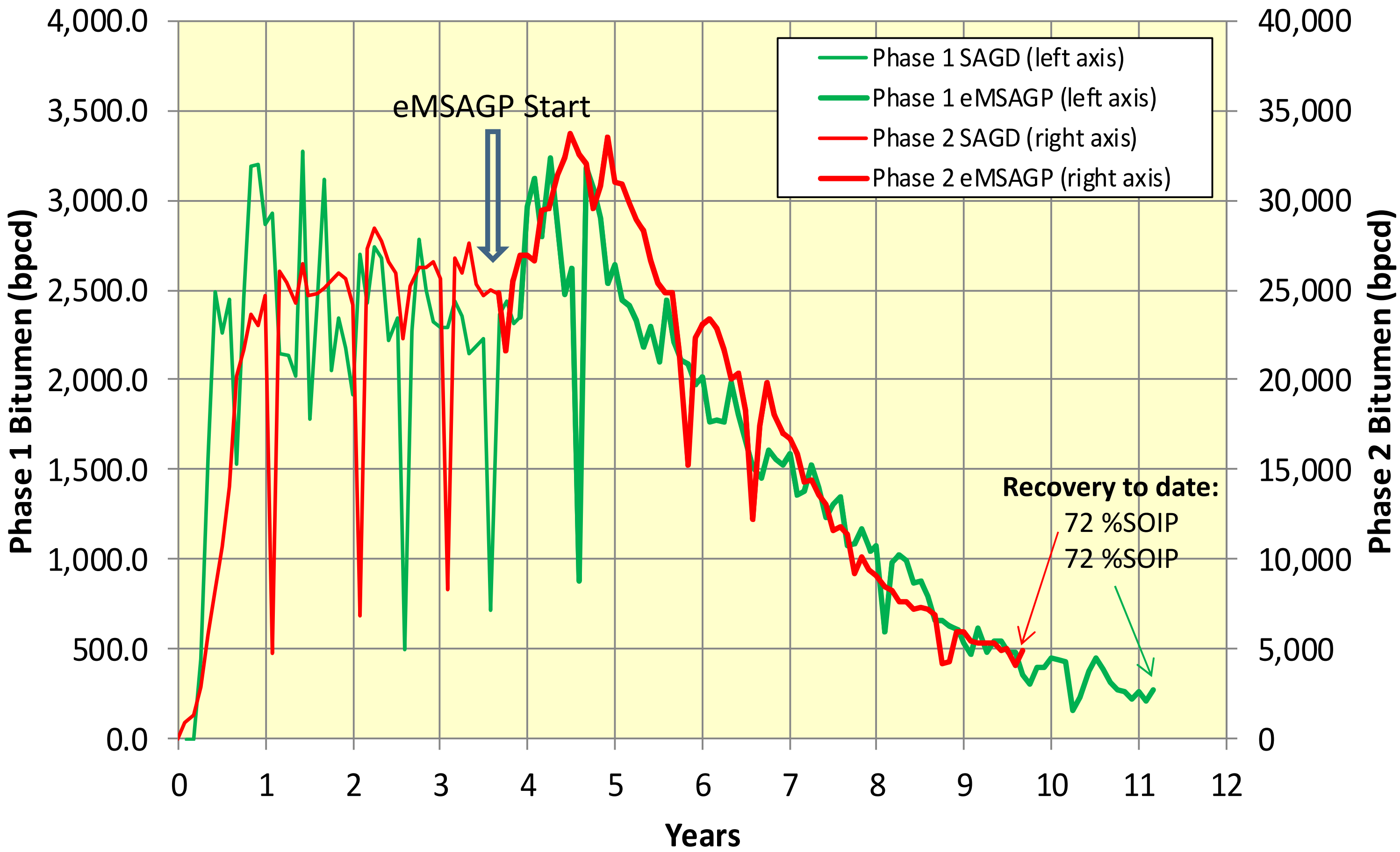




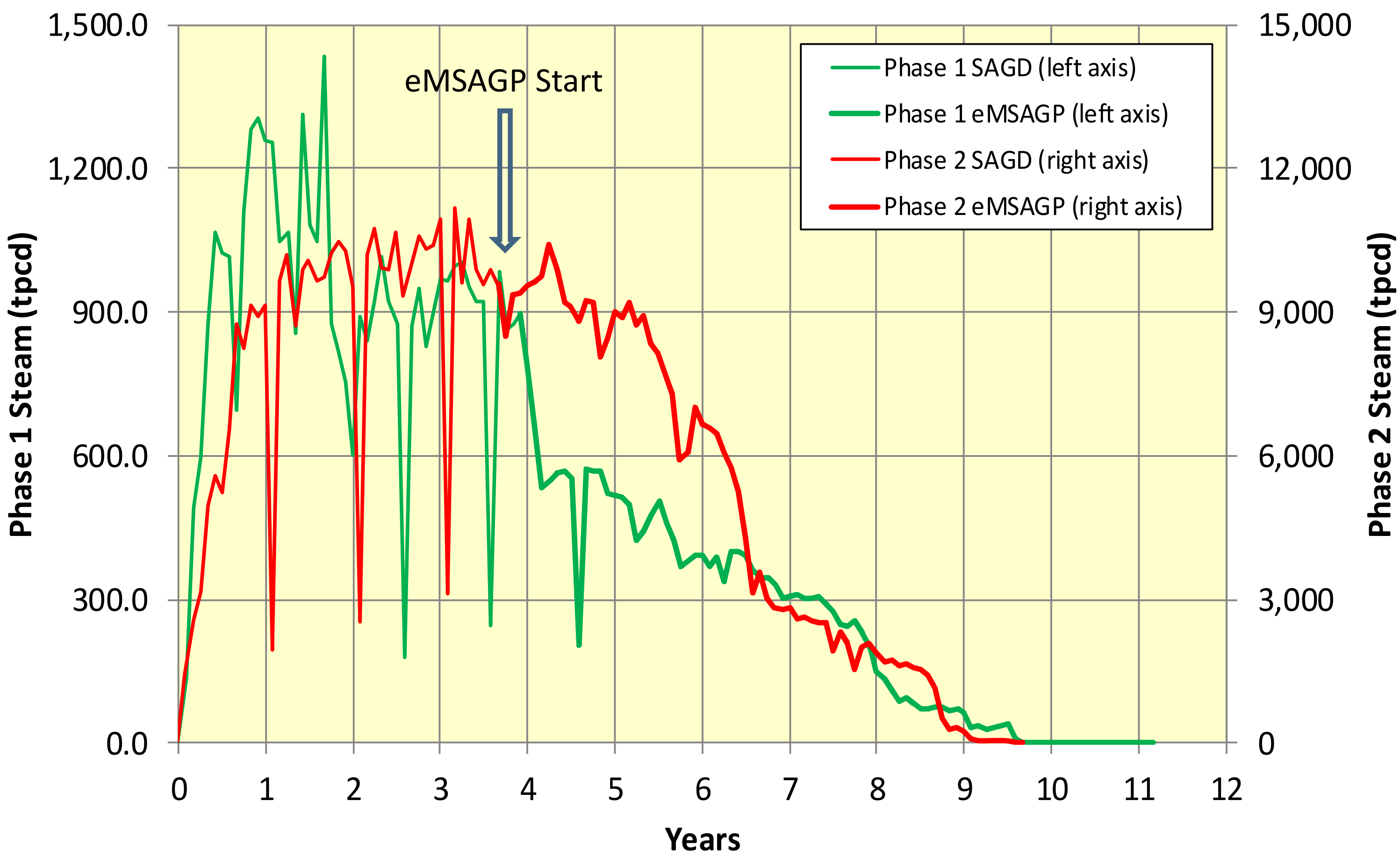
eMSAGP Rollout:

- Pad A Pilot (A1-A3): Dec. 2011
- Pad B (B1-B6): Feb. 2013
- Pad C (C1-C6, D6): Jul. 2013
- Pad D (D1-D5): Aug. 2013
- Pad E (E1-E6, F1): Jan. 2014
- Pad F (F2-F6): Jan. 2014
- Rest of Pad A (A4-A6): Apr. 2014
- Wells (A7, A8, B7, B8, D7): Jul. 2016
- Pad V (V1-V6): Jul. 2016
- Pad K (K2-K7): Oct. 2017
- Pad M (M1-M10): Nov. 2017
- Pad N (N1-N9): Nov. 2017
- Pad AN (AN1-AN8): Dec. 2017
- Pad AF (AF1-AF5): May 2018
- Pad AG (AG1-AG4): May 2018

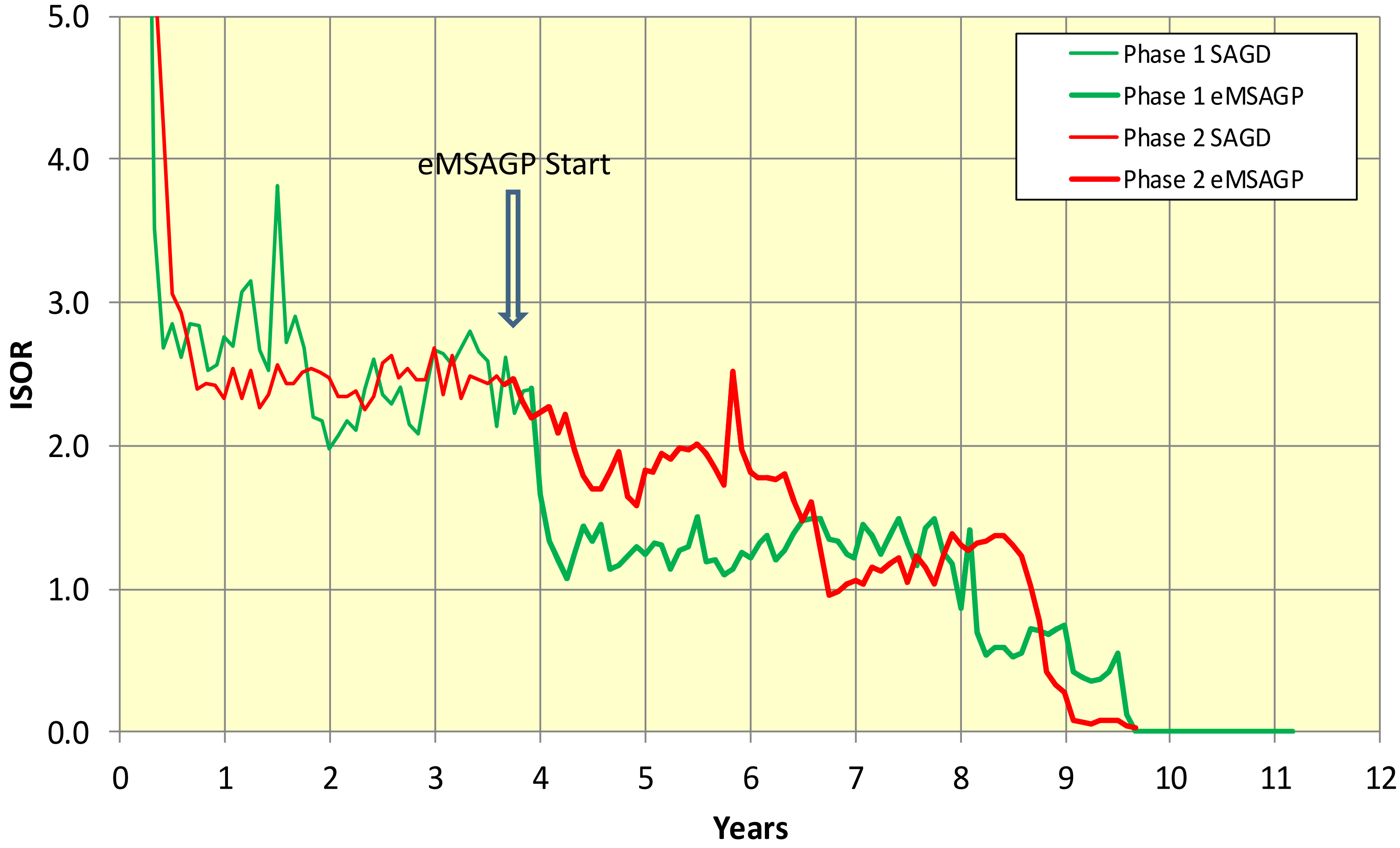
Bitumen Rates for Phases 1 and 2



Steam Rates for Phases 1 and 2



SOR for Phases 1 and 2



Summary of eMSAGP Development

- In 7.5 years of eMSAGP (11 years total), the Pad A pilot demonstrated consistent and very satisfactory performance
  - Higher bitumen production and recovery were achieved at a much lower SOR, with no steam injection over the reporting period
  - Recovery to April 2019 was 72% of SAGDable OOIP
- From the initiation of B Pattern eMSAGP in Feb 2013, Phase 2 eMSAGP showed repeatable performance
  - ISOR over the reporting period was 0.19
  - Recovery to April 2019 was 72% of SAGDable OOIP
- Overall, eMSAGP has demonstrated better performance than SAGD with Higher recoveries with significant SOR reductions
  - Infill wells are drilled at a pattern recovery of about 30%SOIP.
  - NCG co-injection starts when infill wells demonstrate steady production and pattern pressure is about the original formation pressure
  - Steam freed up from eMSAGP process has been redeployed to new SAGD wells to increase overall production beyond original nameplate capacity
- eMSAGP has been initiated on Phase 2B Pads AN, AF, AG, K, M and N

MEG Energy

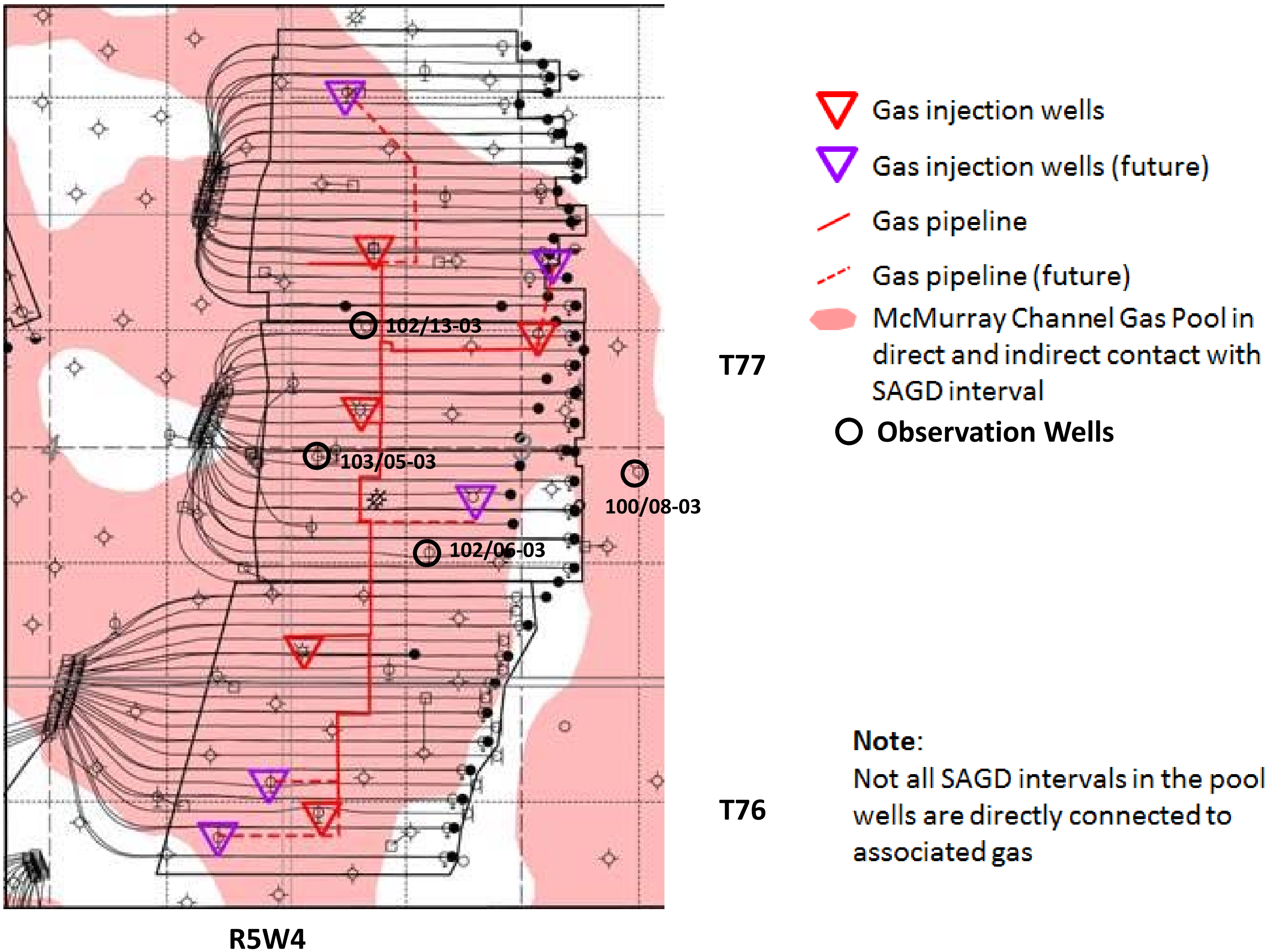
Gas Cap Re-Pressuring

Gas Cap Re-Pressuring Project Update

M, N, and P Patterns

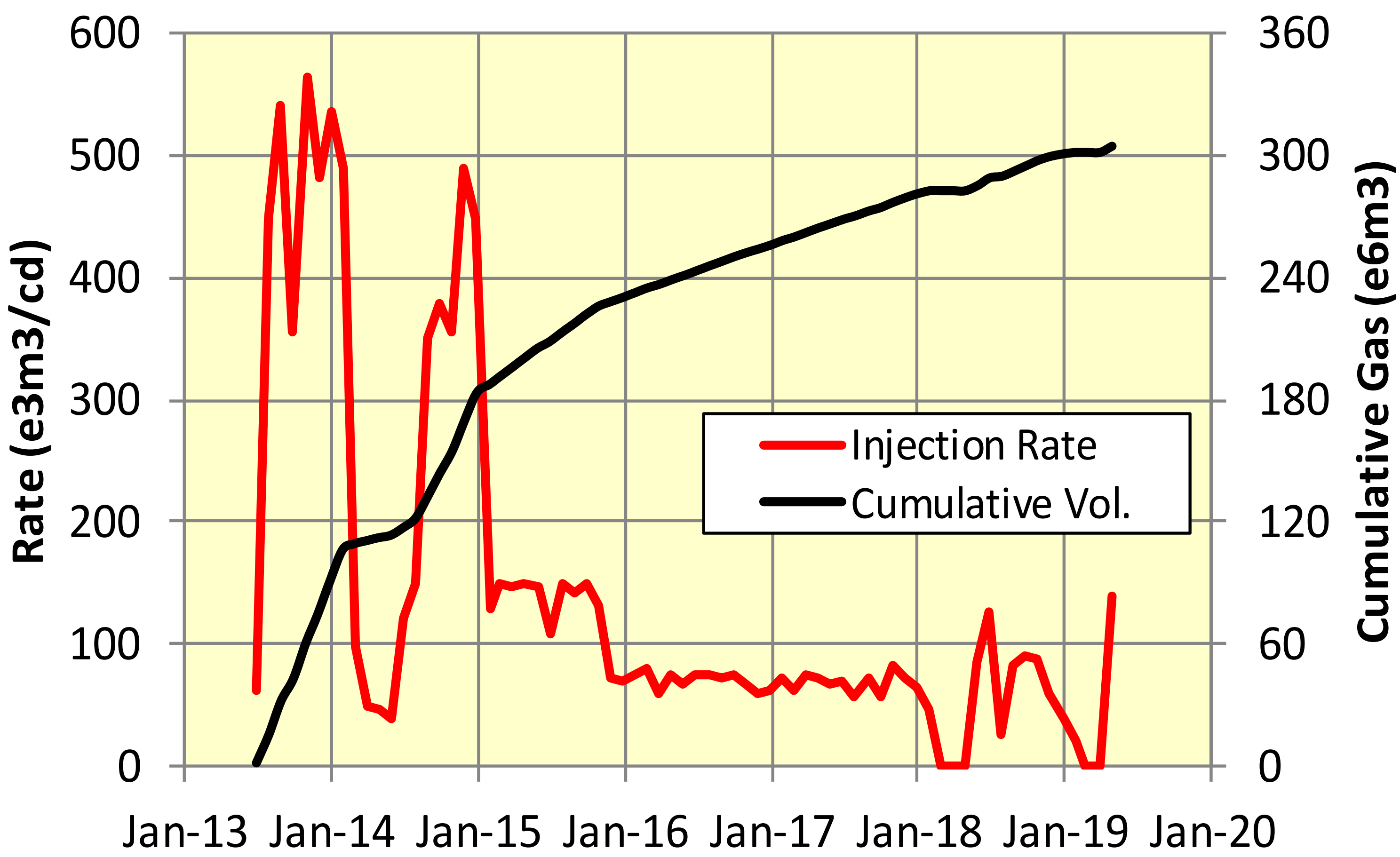
- The AER approval was granted in November 2012
- Natural gas injection into 5 wells commenced in June 2013
- Total injection to date was 305 e6m3 (~10.8 BCF), with an average injection rate of 63 e3m3/day (~2.1 mmscf/day) over the last year
- Pressure responses have been observed in all 5 monitoring wells
- Estimated gas zone pressure above the active SAGD patterns (M, N & P) was about 2,000 kPag, about the same level as the initial gas cap pressure
- Performance to date indicates faster pressure increase over the active SAGD area which allows for a lower gas injection rate and volume to maintain gas cap pressure
- Plan is to maintain the current pressure on top of the active SAGD area and monitor pressures in gas and SAGD zones closely
- Negative thief zone effect of the gas cap has not been observed to date

Gas Cap Re-Pressure (Pattern M, N & P)

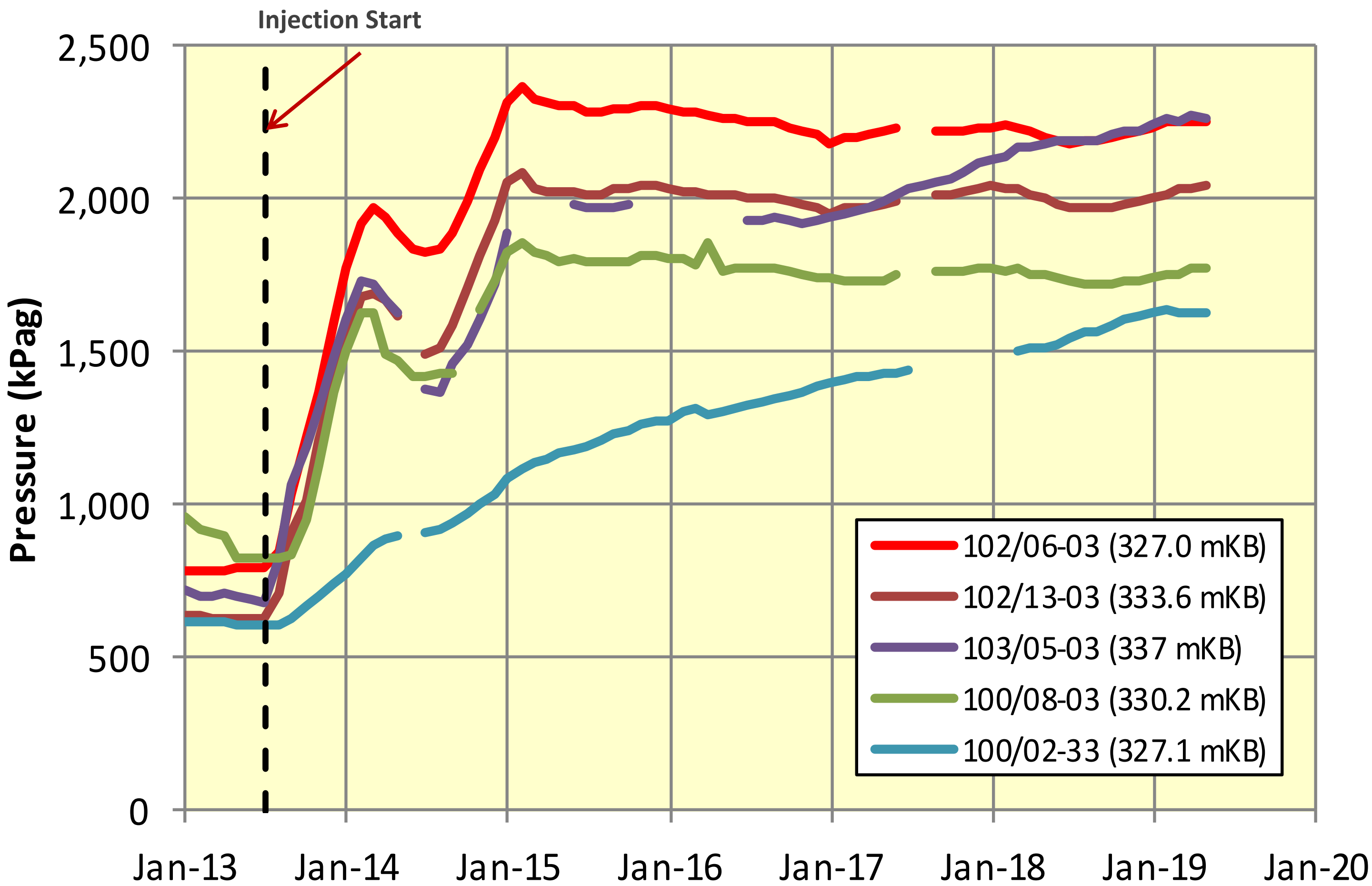


Note:
Not all SAGD intervals in the pool wells are directly connected to associated gas

Total Gas Injection (Patterns M, N, & P)



Observation Well Pressures (Patterns M, N & P)



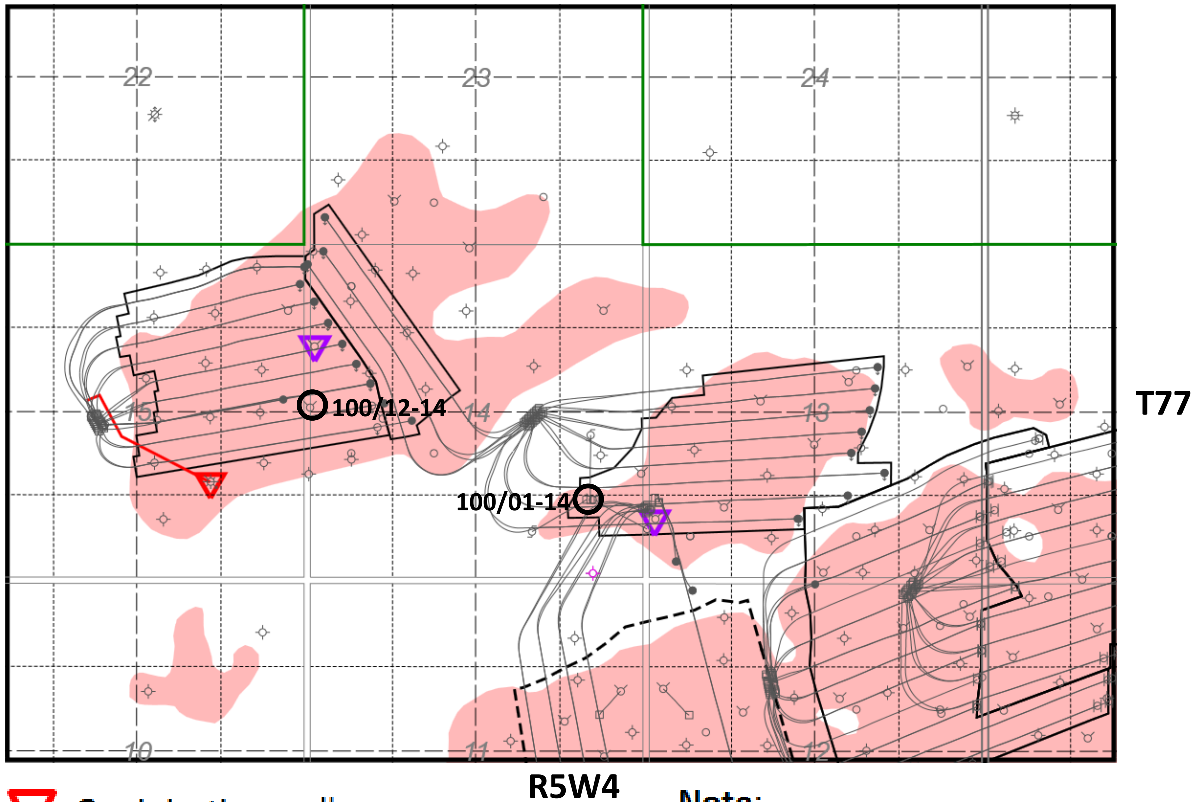
The 100/02-33 well is roughly 600 meters away from the active injection/SAGD area

Gas Cap Re-Pressuring Project Update

L & DB Patterns

- The AER approval was amended on Mar. 5, 2018 (Approval No. 10733TT) to include new development area including L SAGD patterns
- Natural gas injection into 1 well commenced in April 2018
- Total injection to date was 10 e6m3 (~0.36 BCF), with an average injection rate of 28 e3m3/day (~1.0 mmscf/day) over the last year
- Estimated gas zone pressure above the active L SAGD patterns is about 1,980 kPag, about the same level as the initial gas cap pressure
- Plan is to maintain the current pressure on top of the active SAGD area and monitor pressures in gas and SAGD zones closely.
- Minimal injection volumes are anticipated to maintain the pressure over the L SAGD Pattern
- Negative thief zone effect of the gas cap has not been observed to date
- Injection into the gas cap over up-coming DC and DD patterns is anticipated to begin in mid 2019

Gas Cap Re-Pressure (Patterns L & DB)



Gas injection wells

Gas injection wells (future)

Gas pipeline

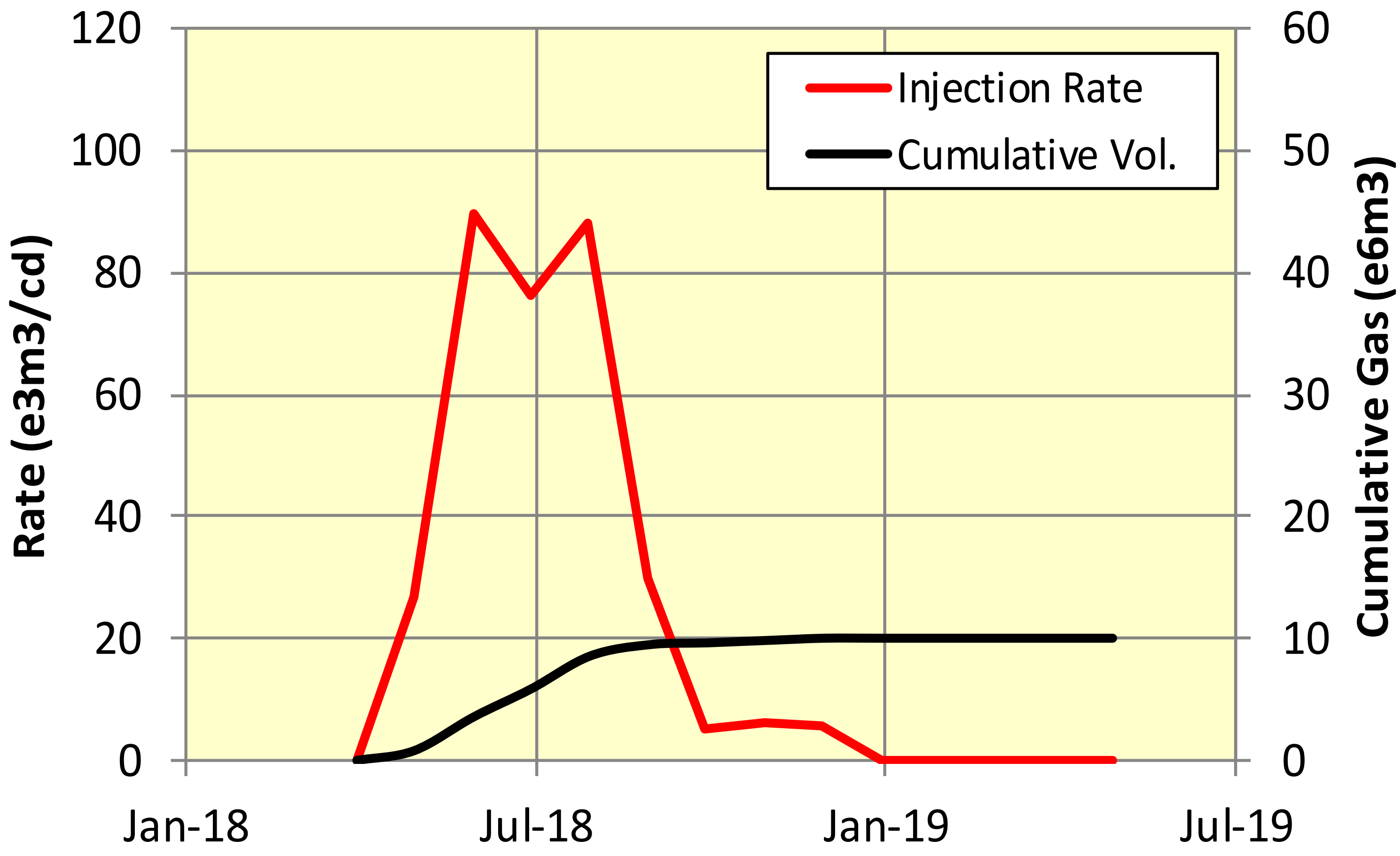
Gas pipeline (future)

McMurray Channel Gas Pool in direct and indirect contact with SAGD interval

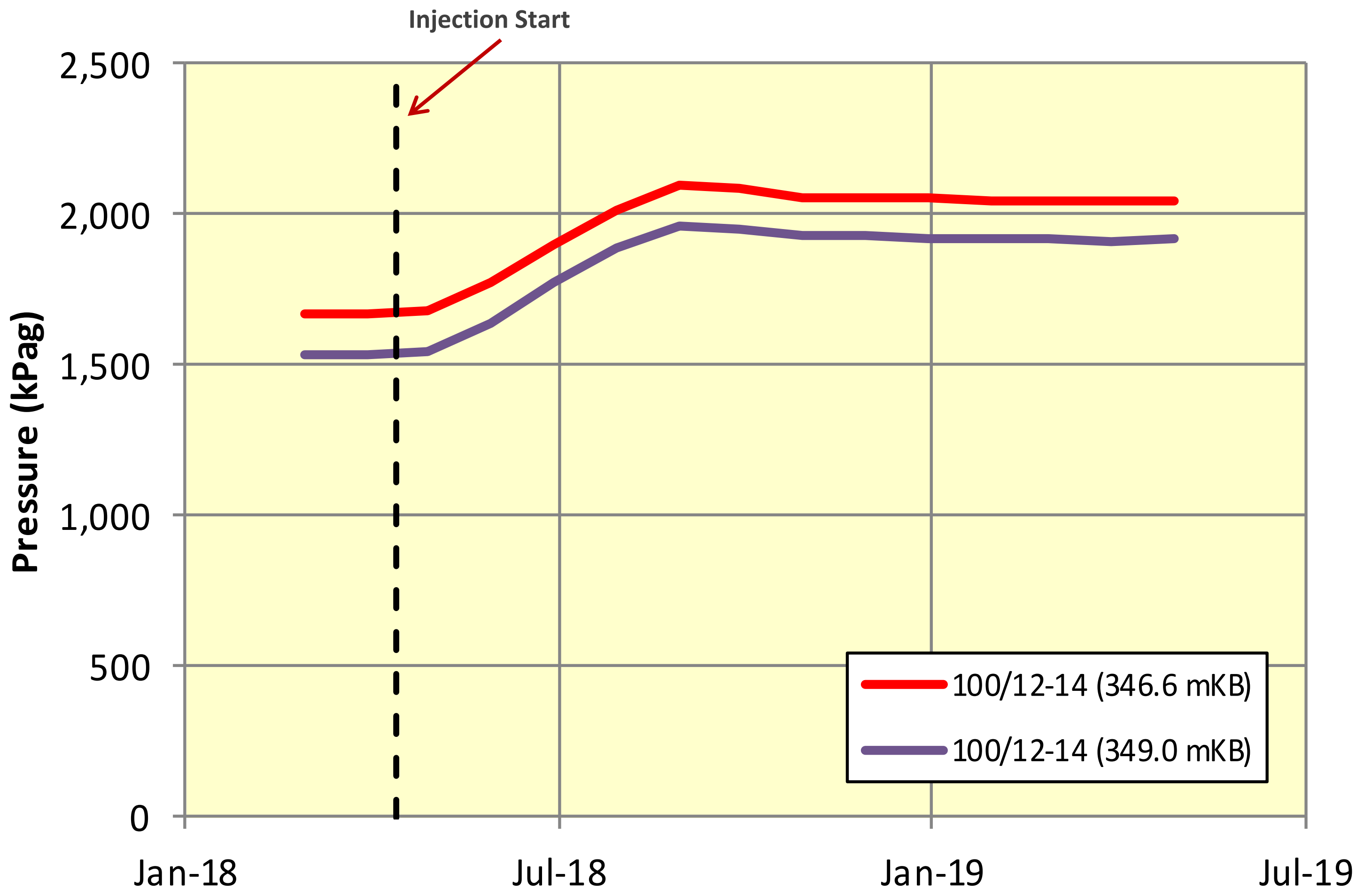
Observation Wells

Note:
Not all SAGD intervals in the pool wells are directly connected to associated gas

Total Gas Injection (Pattern L)



Observation Well Pressures (Pattern L)



MEG ENERGY

Unresolved Emulsion Injection

Unresolved Emulsion Overview

- Pilot project extended on September 26, 2018 (Approval No. 10773WW) until September 30, 2019
  - Approval allows for the injection of unresolved emulsion into an active steam chamber limited to well pair V6
  - Unresolved emulsion is a mixture of produced water, oil & fine clay particles which cannot be treated with the processing trains currently in use at the CLRP
  - V6I selected because of low oil production rate and poor reservoir quality, which limits the risk of any potential production impacts
- Rates of unresolved emulsion at CLRP have been reduced resulting in the trial being put on hold
  - Largely due to better processing efficiency at the CPF
  - No unresolved emulsion has been injected to the reservoir since April 2017
  - No current plans to re-start injection of unresolved emulsion

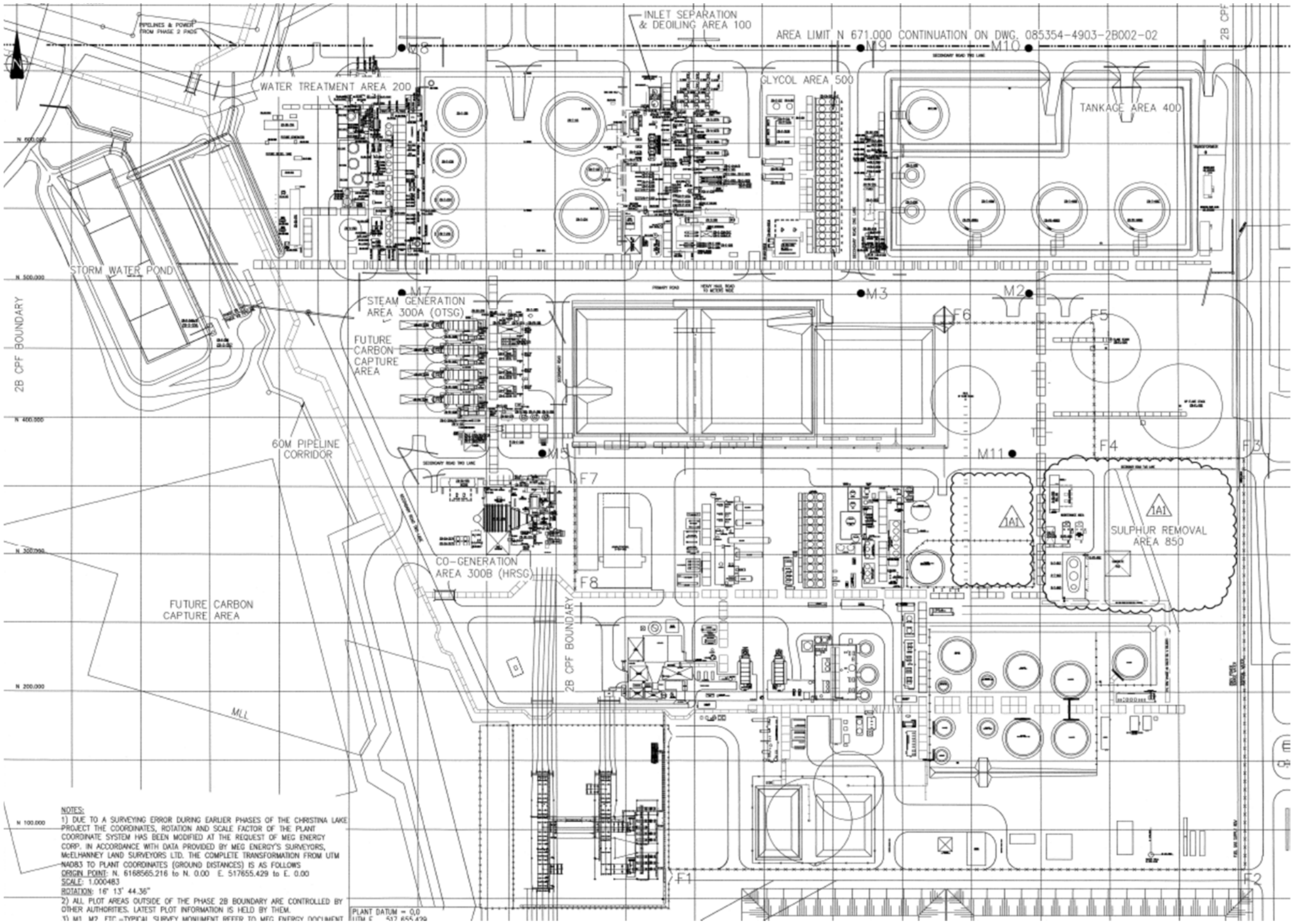
MEG Energy

Operations

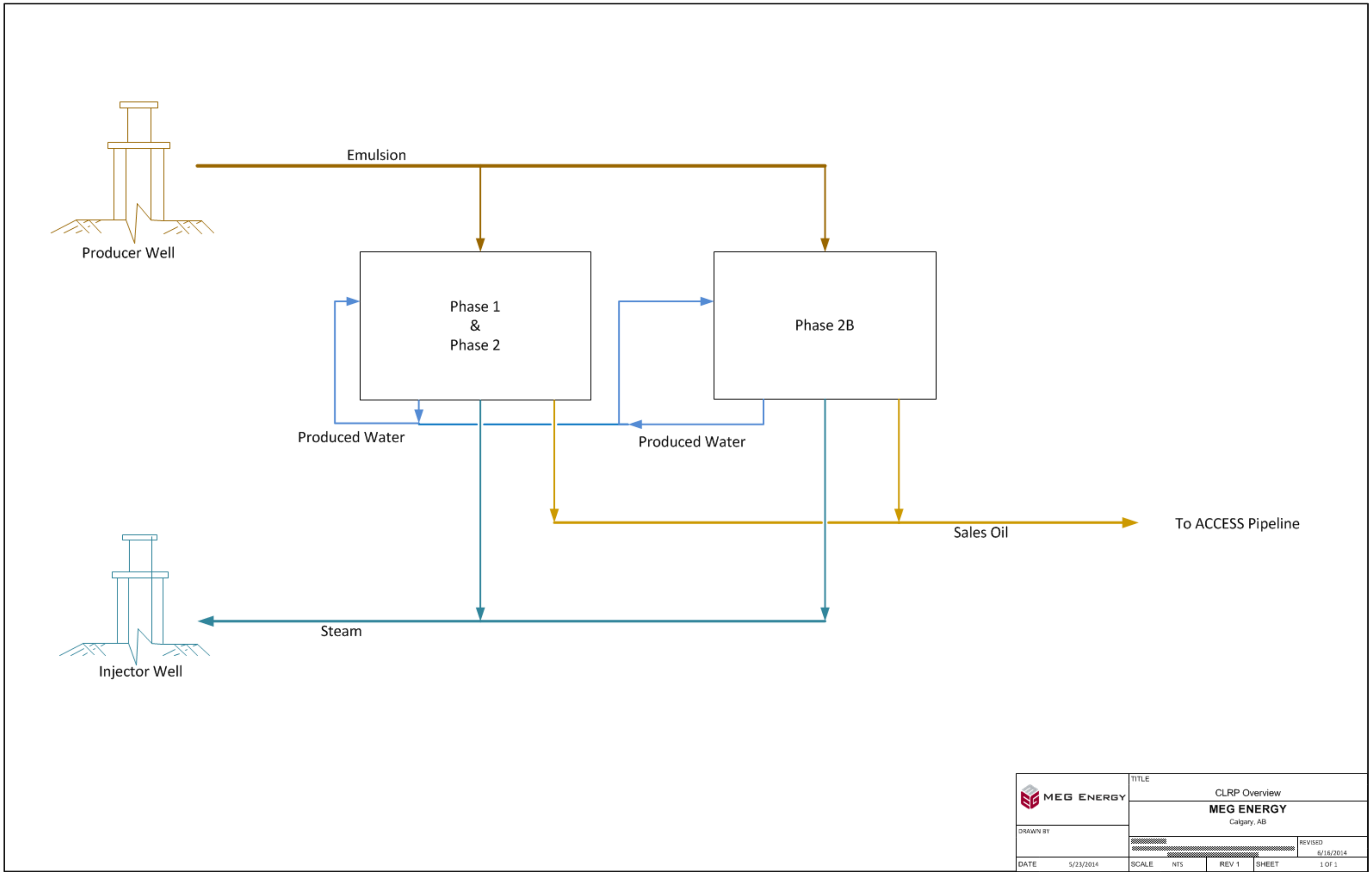
Operations Overview

- Operation Overview
- Bitumen Treatment
- Water Treatment
- Steam Generation
- Power Generation
- Gas Usage
- Facility Measurement

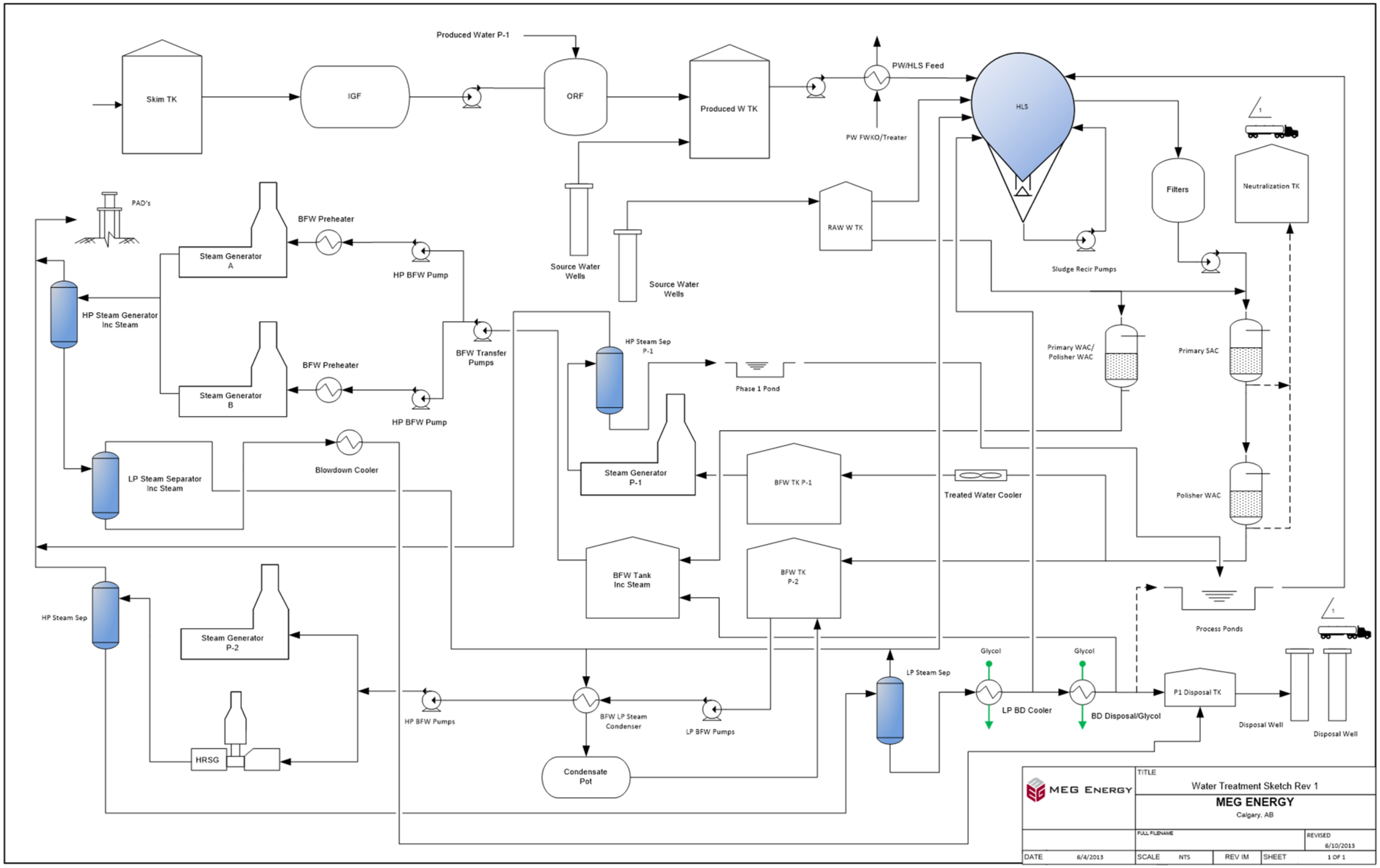
CPF Site Plan



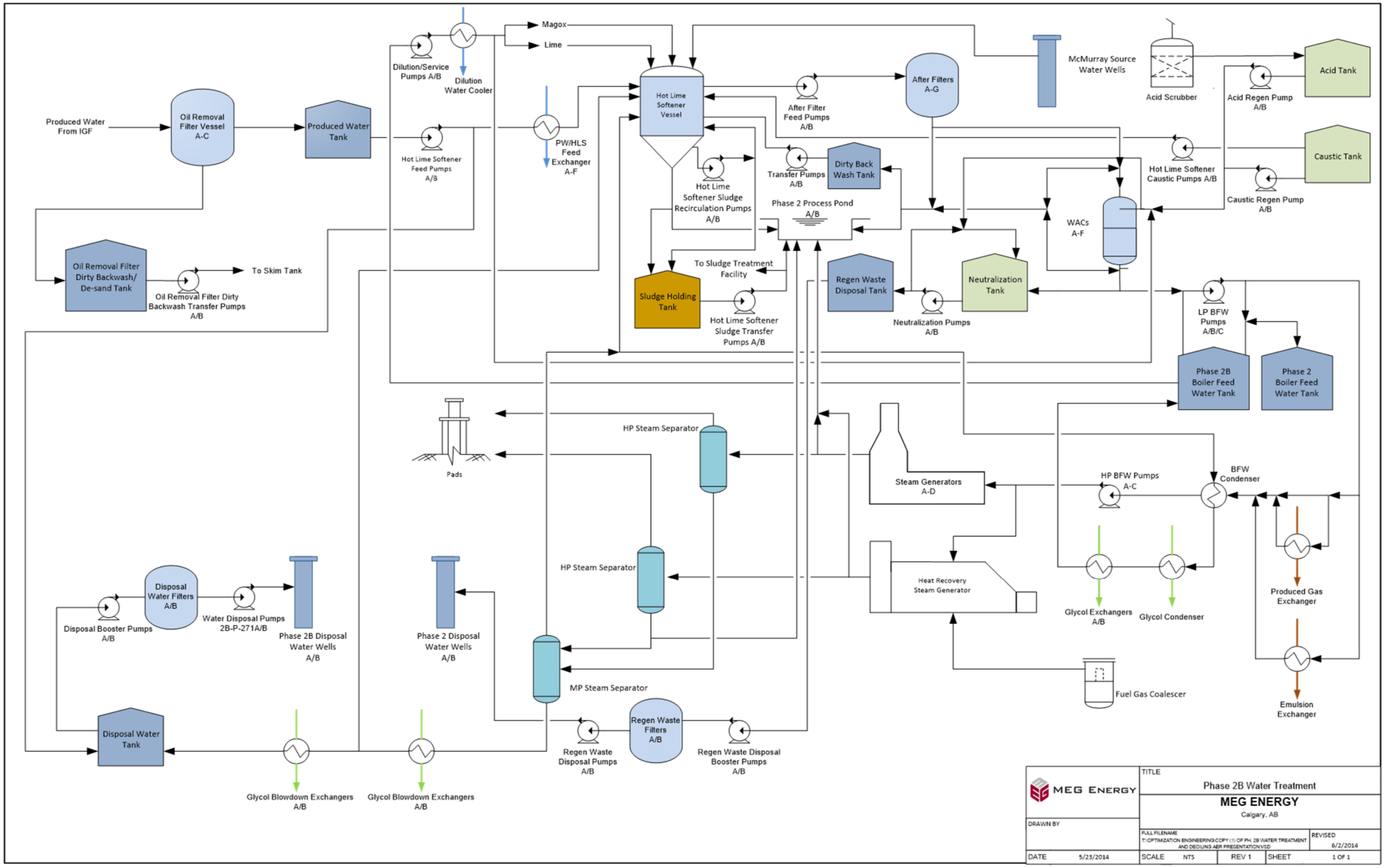
Integrated Distribution/Gathering System



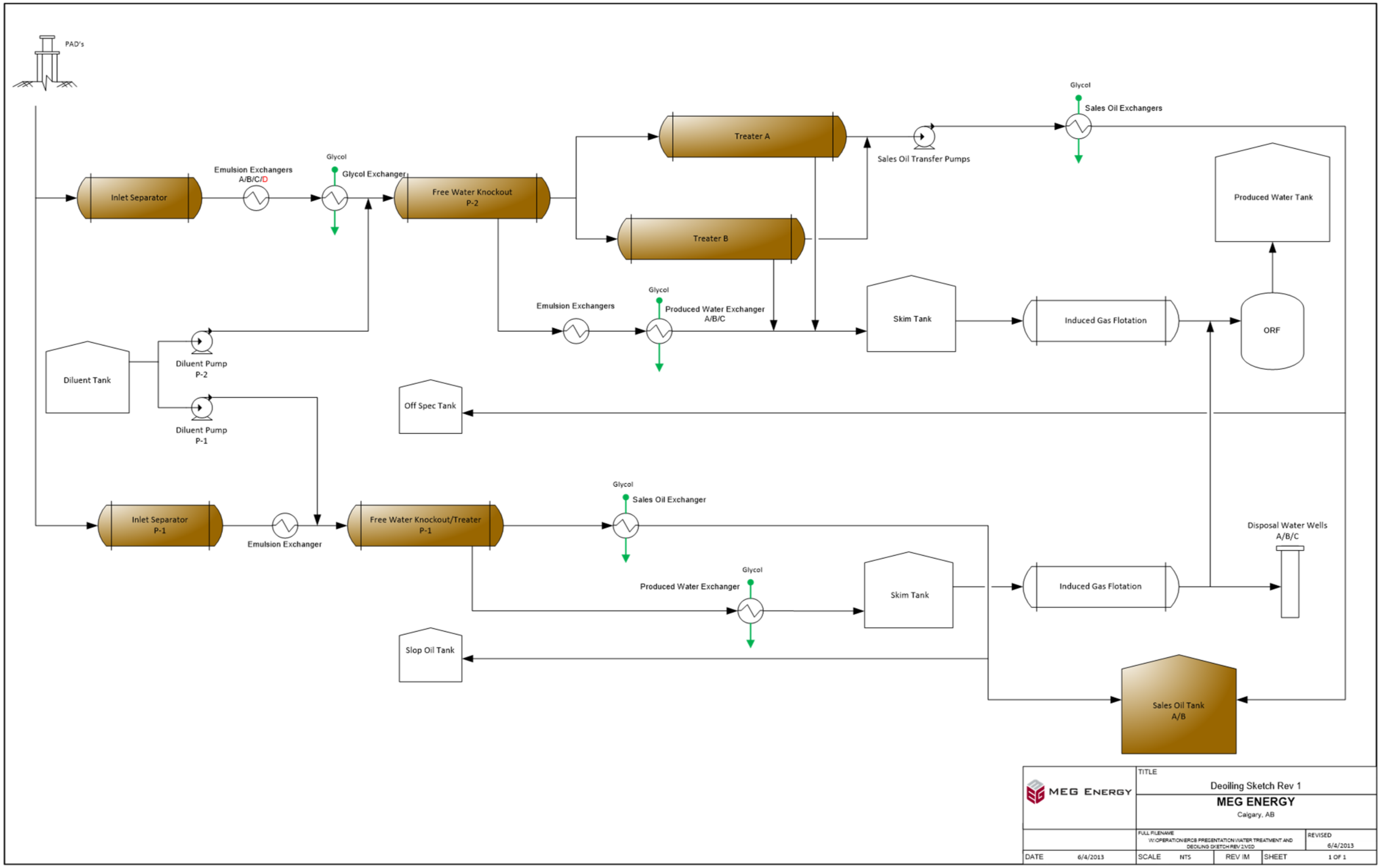
Water and Steam Process Overview Phase 1 and 2



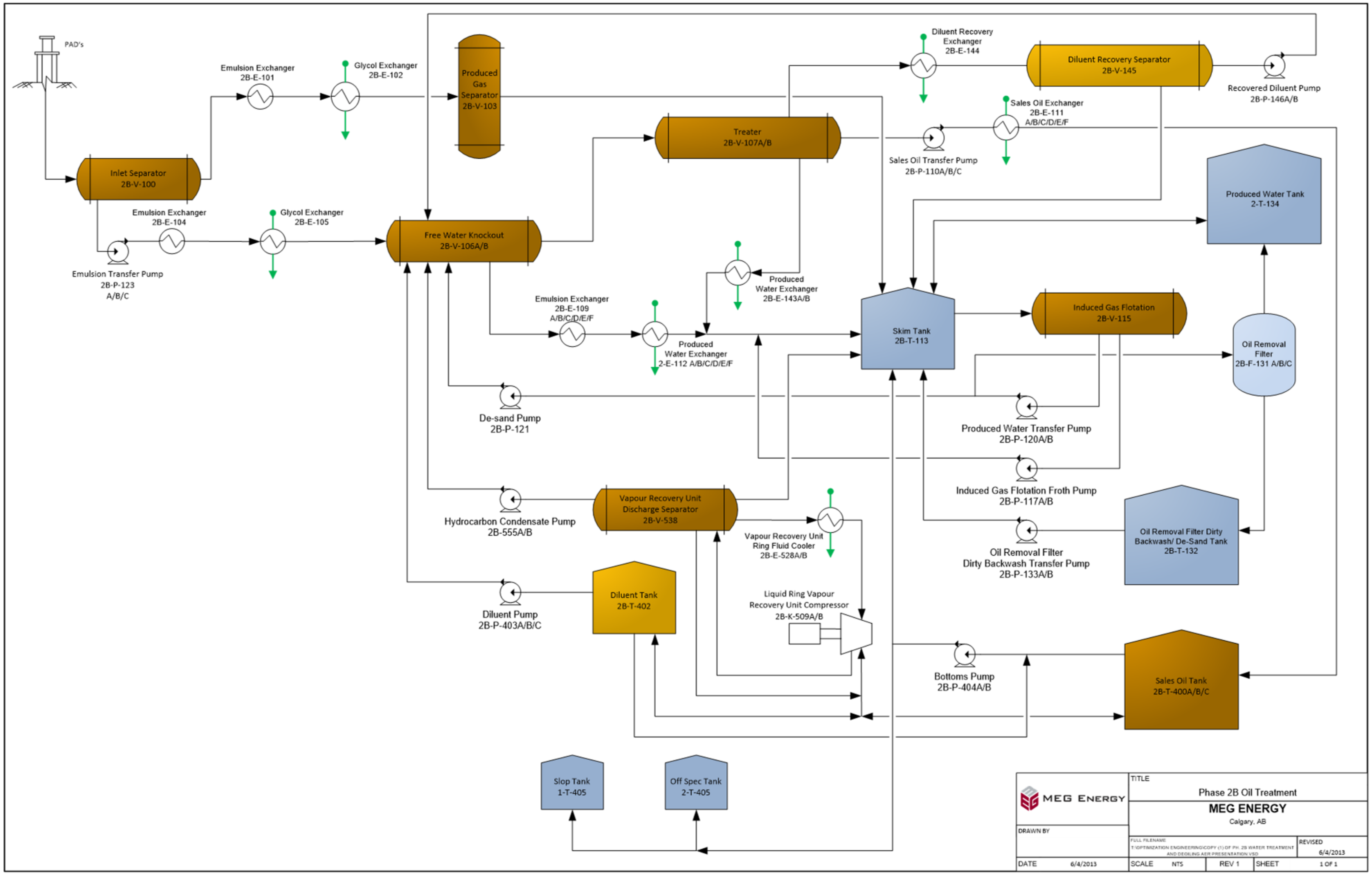
Water and Steam Process Overview Phase 2B



Oil Treatment Overview Phase 1 and 2



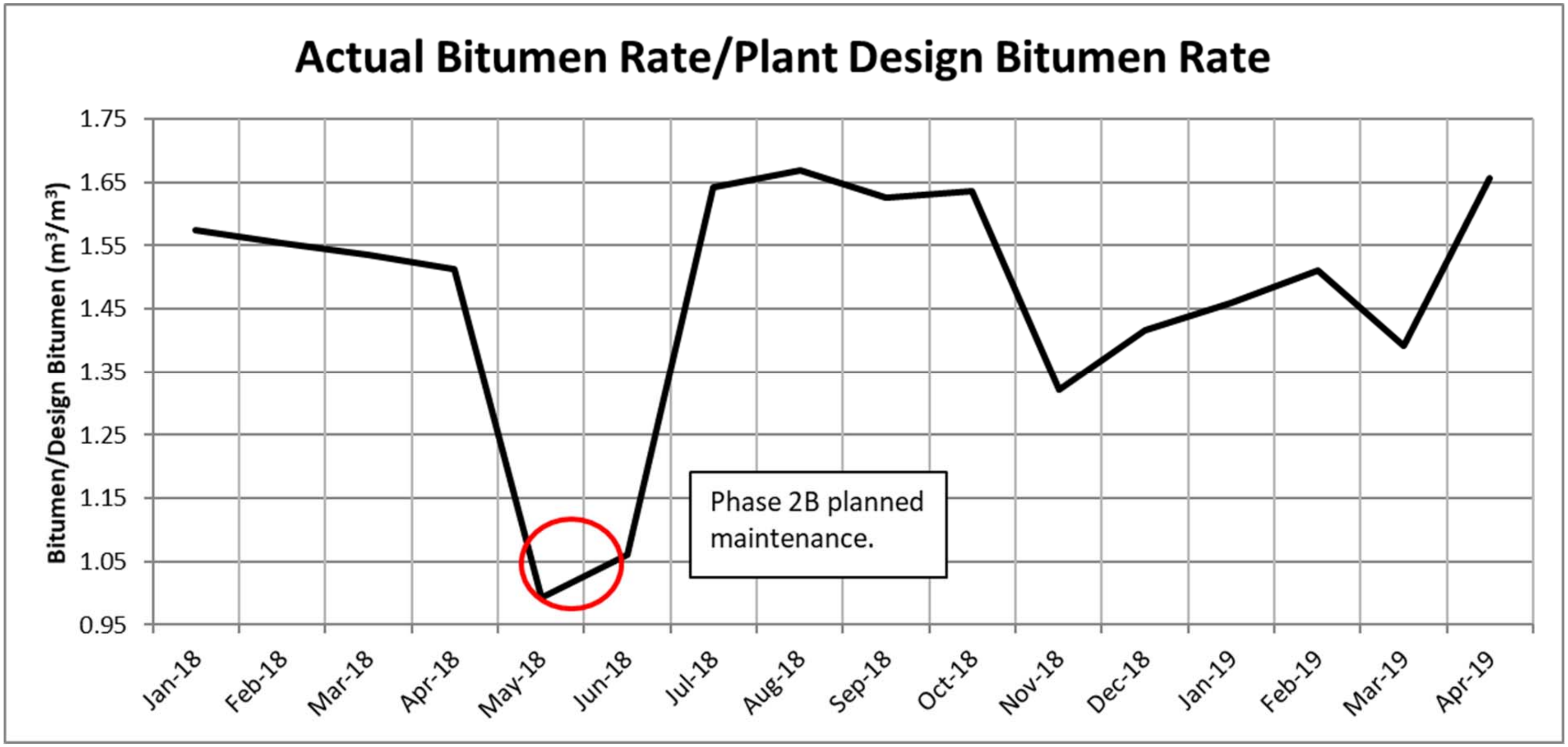
Oil Treatment Overview Phase 2B



Additions/Modifications

- The Produced Gas Recycle Project was commissioned in October 2018 to manage increased produced gas returns to the Central Processing Facility
  - Approved under EPEA Application No. 011-216466 and OSCA Application No. 1907055
- Minor debottlenecking projects are in the planning process
  - Any required regulatory applications will be submitted prior to execution of debottlenecking projects

Facility Performance: Bitumen Treatment



- Performance over original design primarily due to operation with naphtha diluent and equipment design factors.

Facility Performance: Bitumen Treatment

Successes

- Modified Phase 2B diluent tank inlet to promote mixing of tank contents to reduce the impact of daily variations in diluent composition on the sale oil storage tanks
- Enhanced control programming on the Phase 2B sales oil tank farm VRU to reduce pressure fluctuation experienced with changes in diluent composition
- Installation of enhanced interface level measurement in Phase 2B FWKOs and Treaters
- Modifications completed to Phase 2B FWKO and Treater internal baffle design
- Various minor plant debottlenecking projects in Phase 2B

Issues Being Addressed

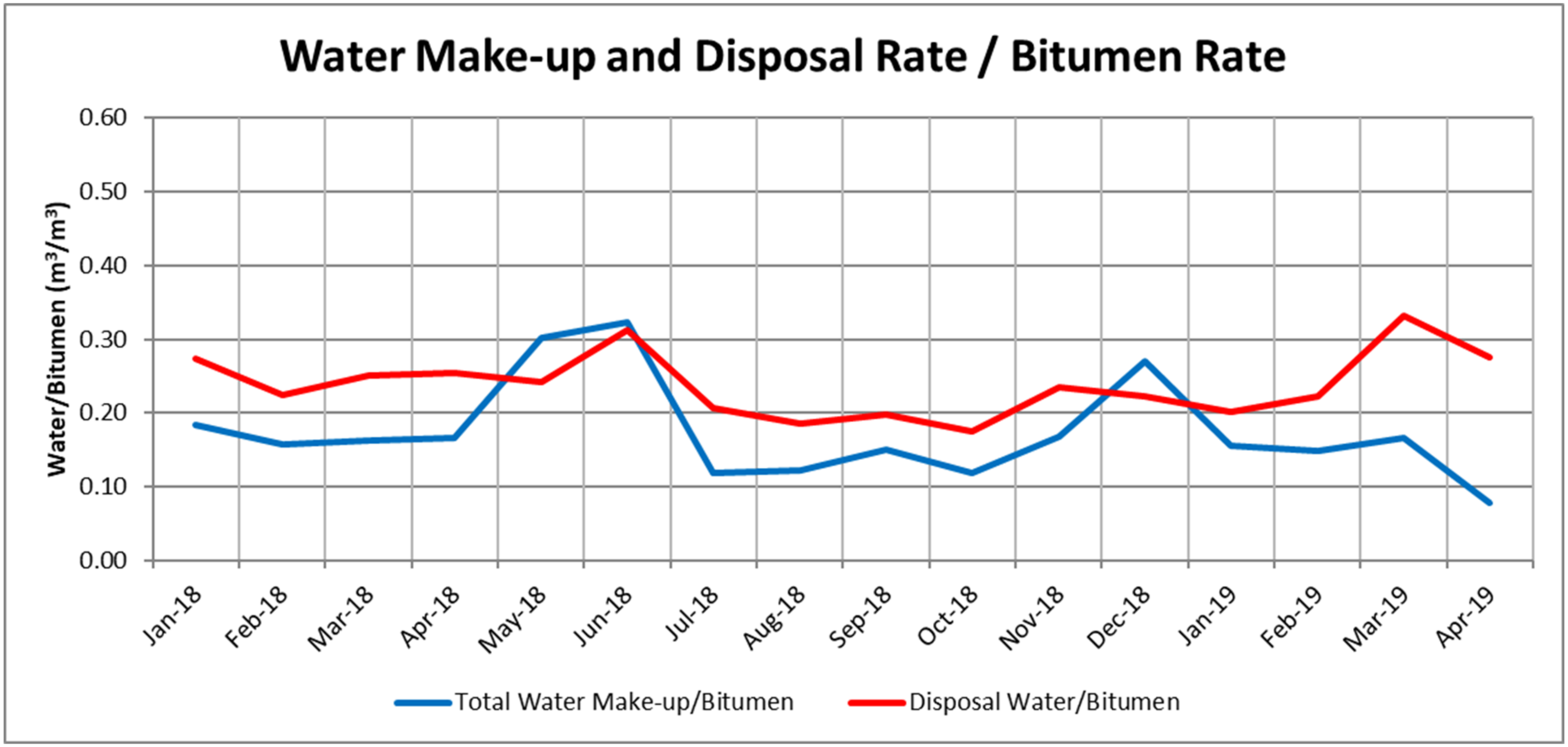
- Flow variations in the Phase 2 oil treating equipment
- Continue to work to mitigate impact of diluent composition changes

Facility Performance: Bitumen Treatment

Future Actions

- Enhancements to Phase 2B slop handling equipment to reduce overall slop trucking volumes
- Continue optimization of chemical treatment program
- Continue plant testing to establish ultimate capacity as bottlenecks are eliminated

Facility Performance: Water Treatment



Facility Performance: Water Treatment

Successes

- Solidified sludge removed from the Phase 2B HLS resulting in improved operation and reliability
- Reduced fresh water makeup requirements via modification to Phase 2B back wash water supply system
- Dryness of processed HLS sludge from centrifuge increased by approximately 15%

Issues Being Addressed

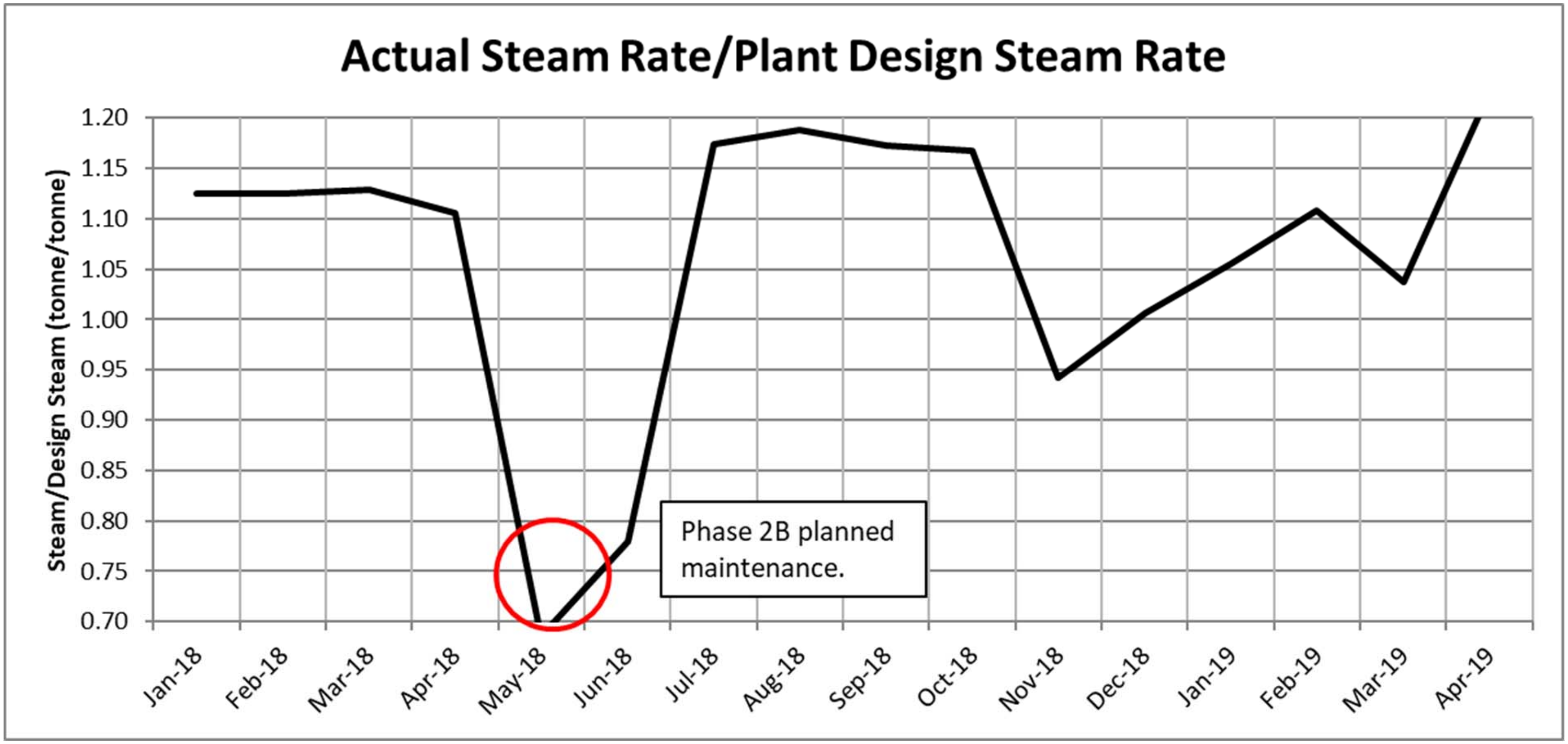
- Cleaning of accumulated sludge from process ponds
- Balance boiler blowdown recycle against produced water usage to optimize disposal water volume

Facility Performance: Water Treatment

Future Actions

- Reroute centrate from HLS sludge processing directly into Phase 2 HLS
- Plant testing to determine bottlenecks to future growth

Facility Performance: Steam Generation



Facility Performance: Steam Generation

Successes

- Stable operation throughout the year
- Review and modifications on the overall control and protection of the HP steam distribution system underway.
- Fuel gas heating value analyzer installed in Phase 2B to allow increased accuracy of steam generator efficiency tracking and optimization.
- Steam distribution condensate removal facilities continue to be implemented as steam distribution system is expanded.

Issues Being Addressed

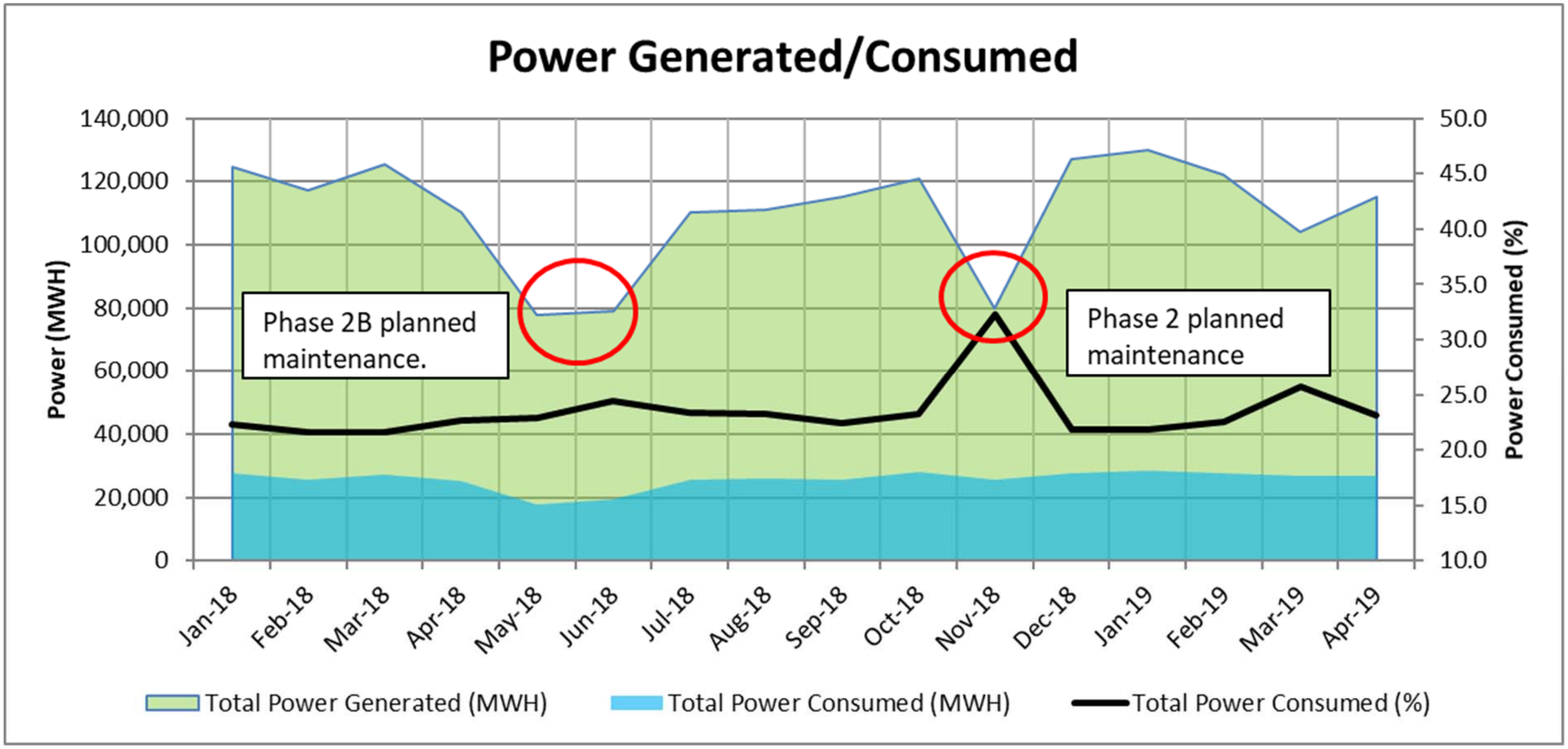
- Continue to implement improved steam pipeline condensate removal facilities at high value locations

Facility Operations: Steam Generation

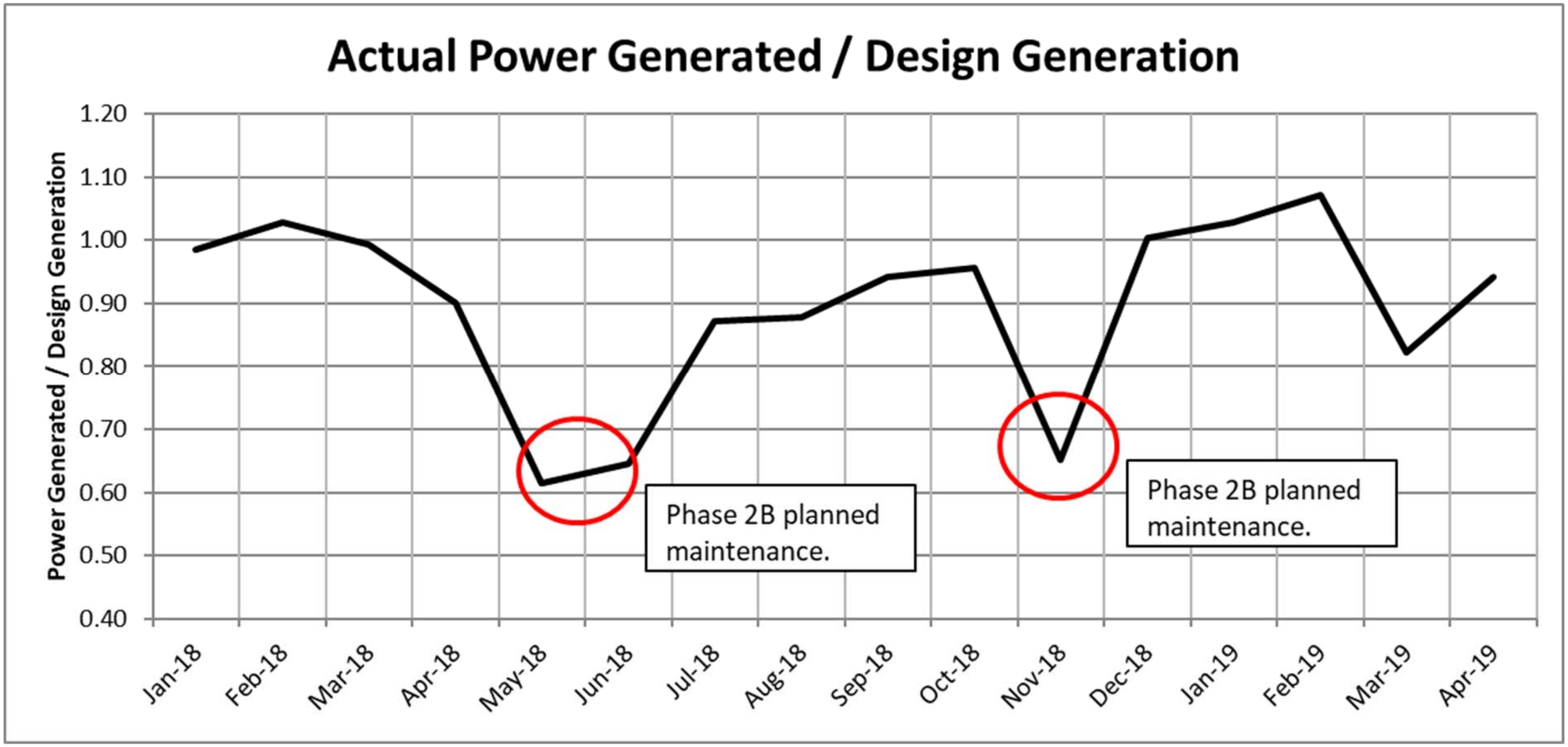
Future Actions

- Review use of thermal imaging to predict steam generator tube condition.

Facility Performance: Power Generation



Facility Performance: Power Generation



Facility Performance: Power Generation

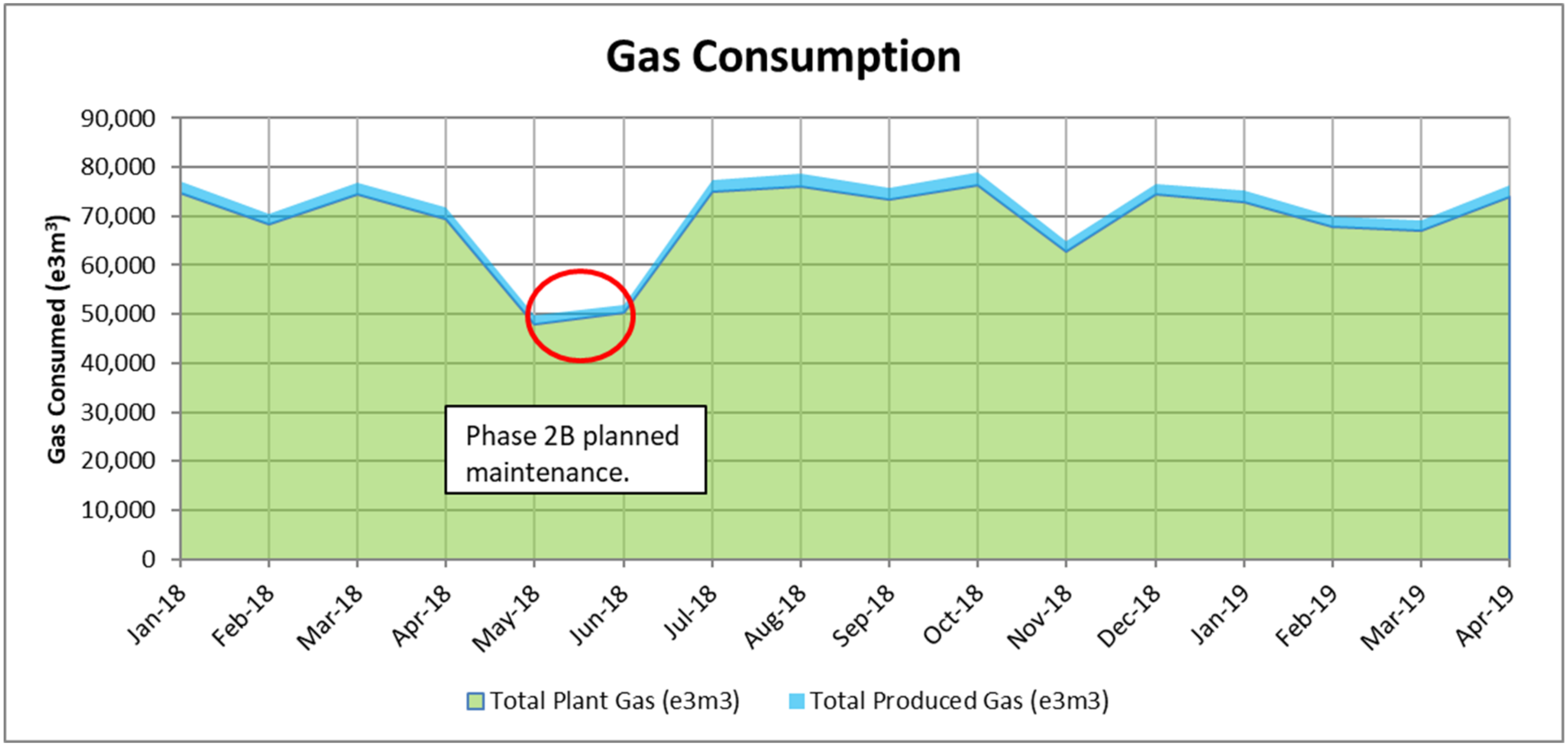
Successes

- Stable operation throughout the year

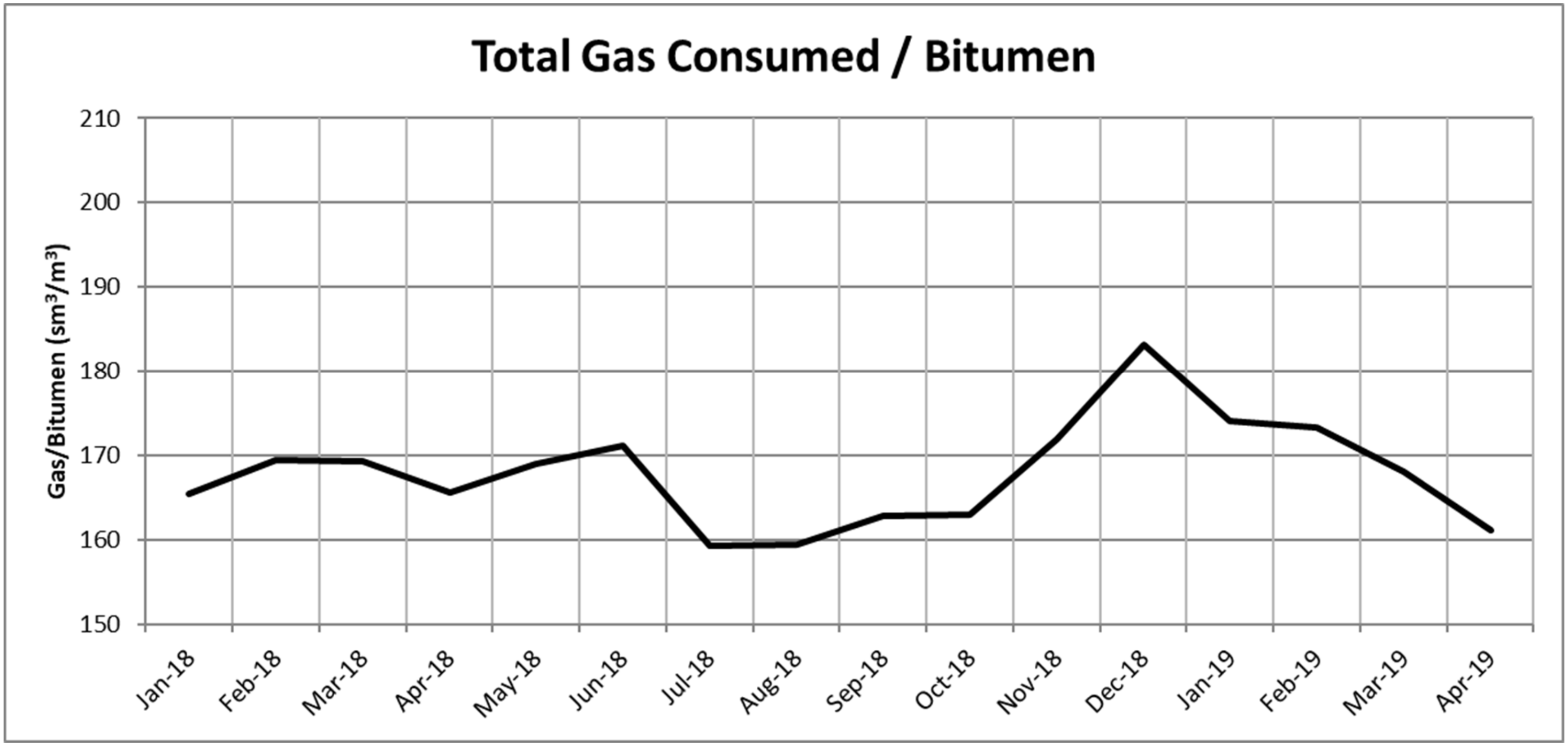
Issues Being Addressed

- No significant issues

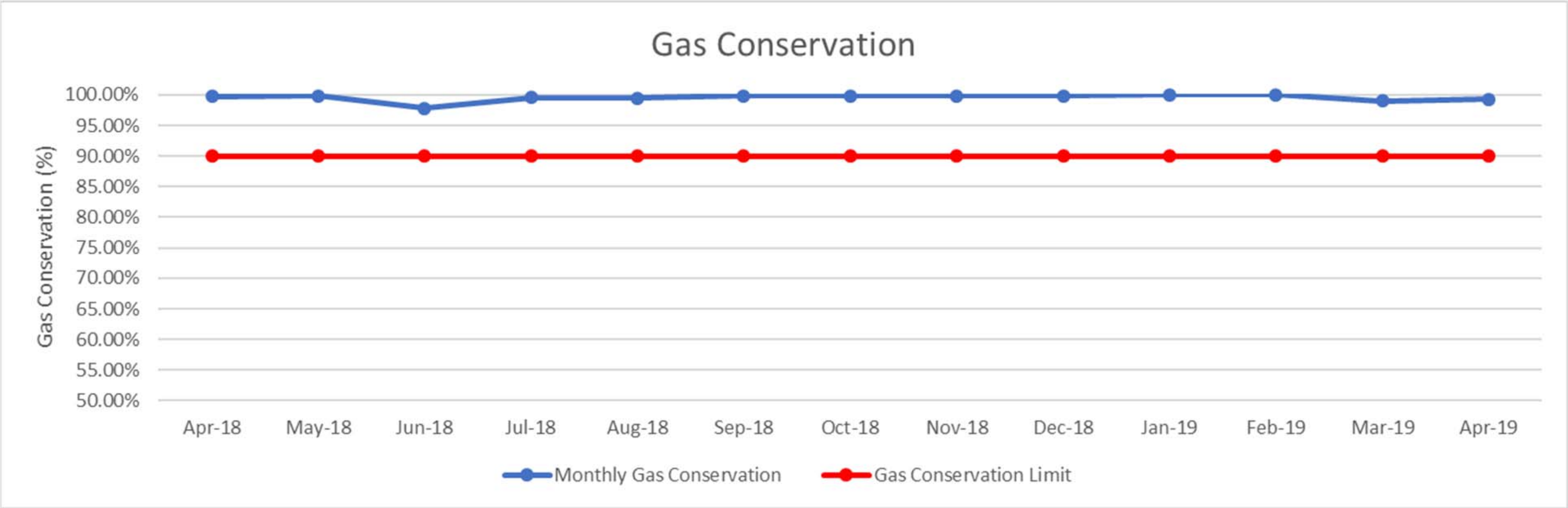
Facility Performance: Gas Usage



Facility Performance: Gas Usage



Gas Usage



- Overall gas conservation >95%
- MEG reported 12 flaring and 1 venting notifications to the AER from April to December 2018
- MEG reported 6 flaring and 0 venting notifications to the AER from January to April in 2019

Facility Measurement

Well Tests

- Well tests used to determine bitumen and water production rates for each well
  - Pads are equipped with test separators
  - Each production well receives 1 testing hour per 40 hours in operation
  - Test durations shall be optimized to obtain as many representative production well tests as possible for each month
  - Reservoir GOR = 5; Gas Proration Factor = 1
- Water cuts via in-line meters or spot samples with manual S&W measurement
  - Using alternative S&W method using emulsion density

Field Steam Measurement

- Electronic diagnostics on smart vortex steam meters (Rosemount 8800D) have improved safe operations and reduced O&M costs

Facility Measurement

Facility Gas Balance >5%

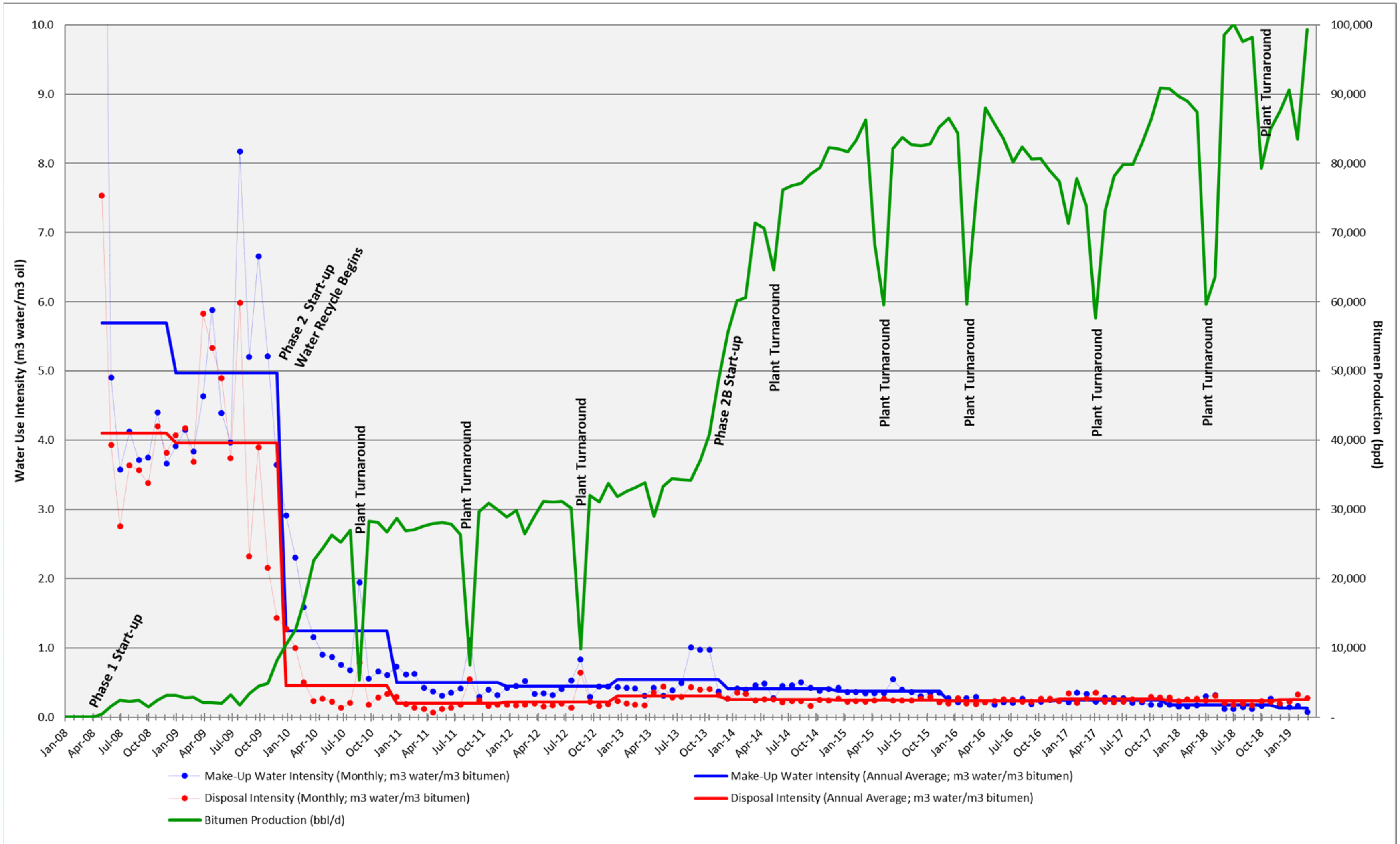
- Switch to Gas-Oil Ratio January 2016
- Improve accuracy of solution gas reporting to account for NCG returns
- Petrinex limitations to entering negative values and alerts on produced gas to flare
- Alternative method of reporting gas balances and solution gas to flare is being examined.
  - Achieve facility gas balance <5%
  - Accuracy of solution gas
  - Work within Petrinex


MEG ENERGY
Water

Water Overview

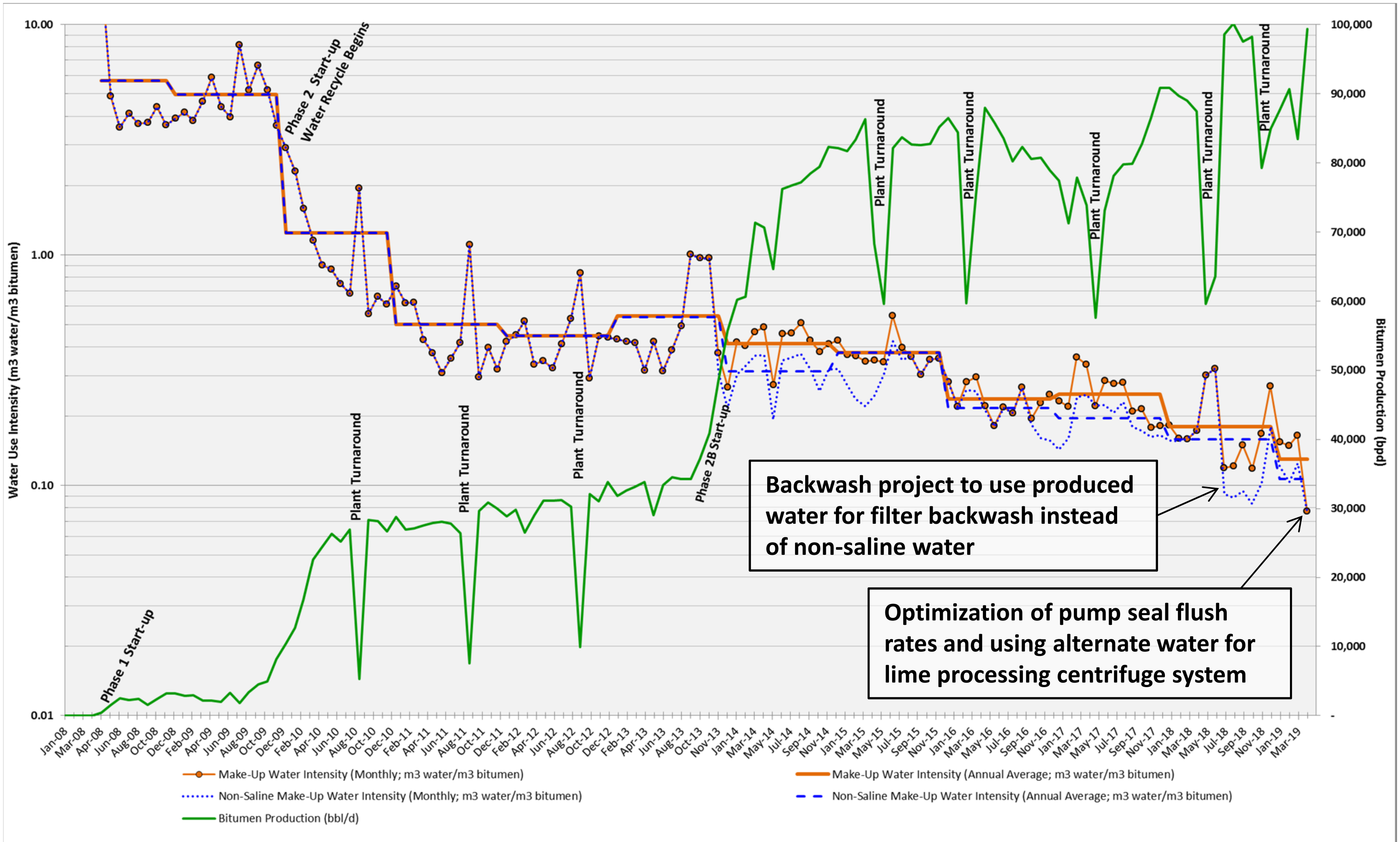
- Water Use and Recycle
- Source Water
- Disposal
- Monitoring

Water Use Intensity



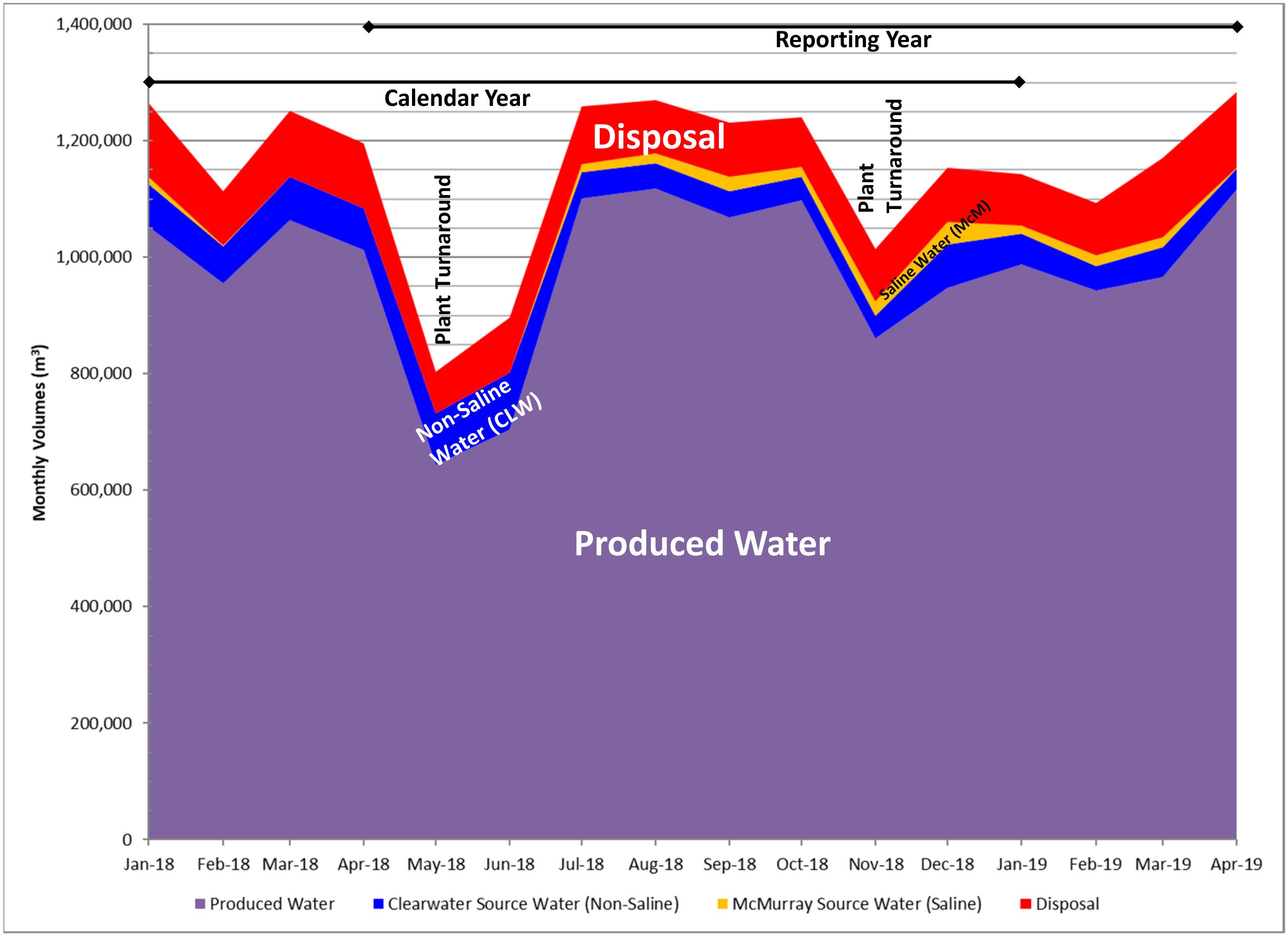
- 2018 total make-up water use intensity of 0.18
- 2019 YTD to end of April total make-up water use intensity of 0.13
- These are the lowest water use intensities in MEG operations history

Non-Saline Water Use Intensity

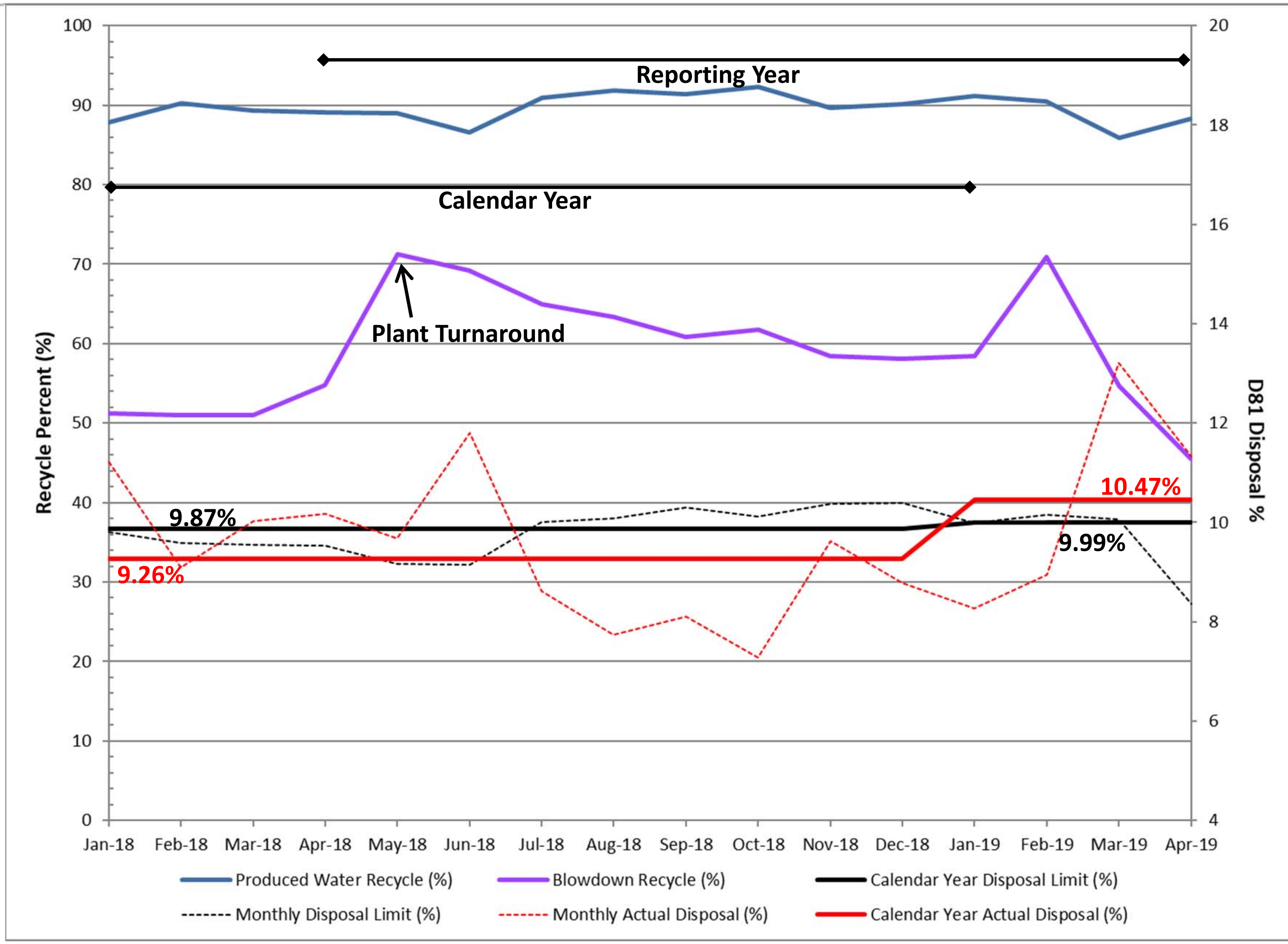


- 2018 had lowest non-saline water use intensity in CLRP operations history (0.16)
- 2019 YTD to the end of April non-saline water use intensity is 0.11

Monthly Water Volumes



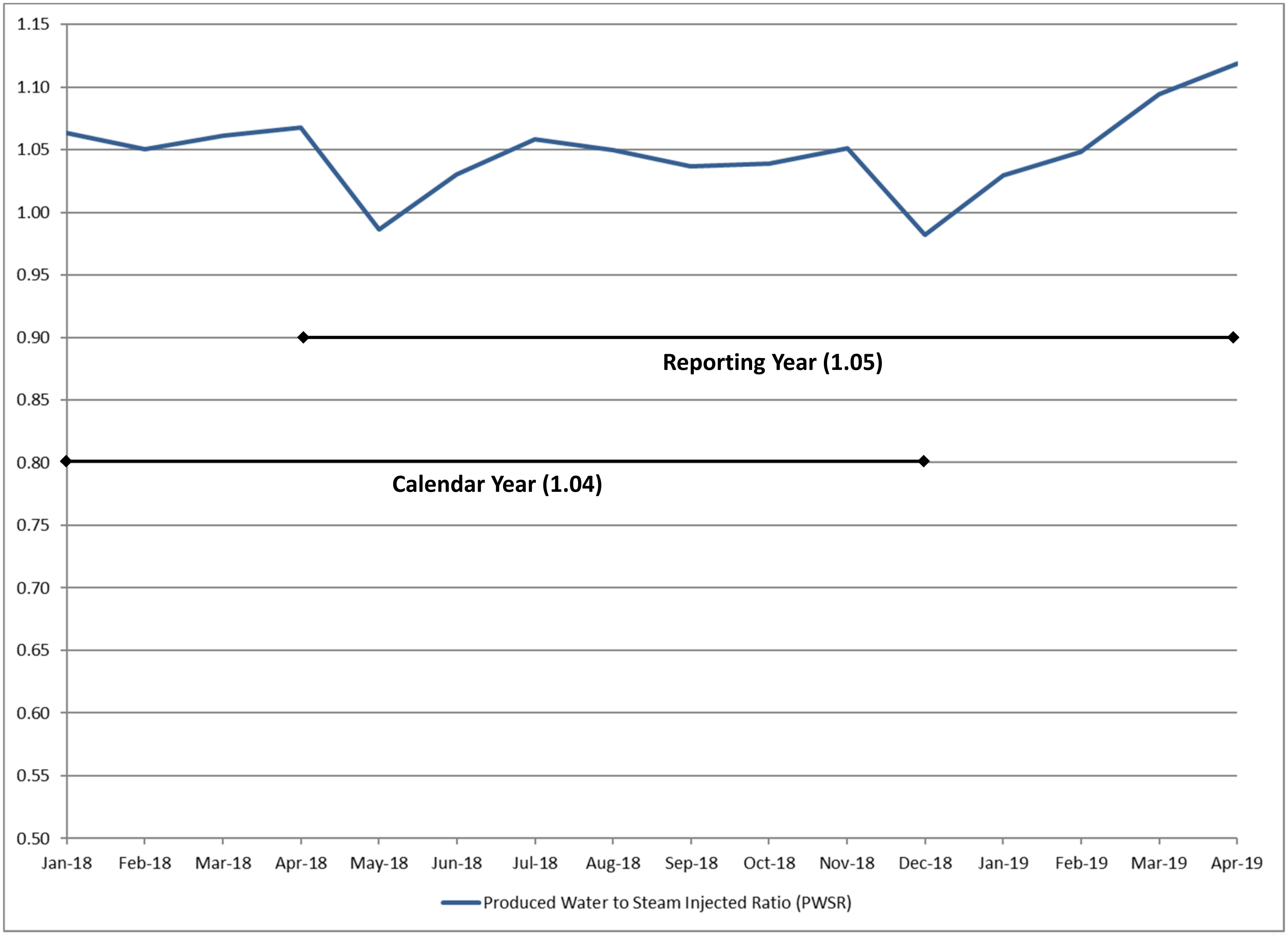
Water Recycle and D81 Limits



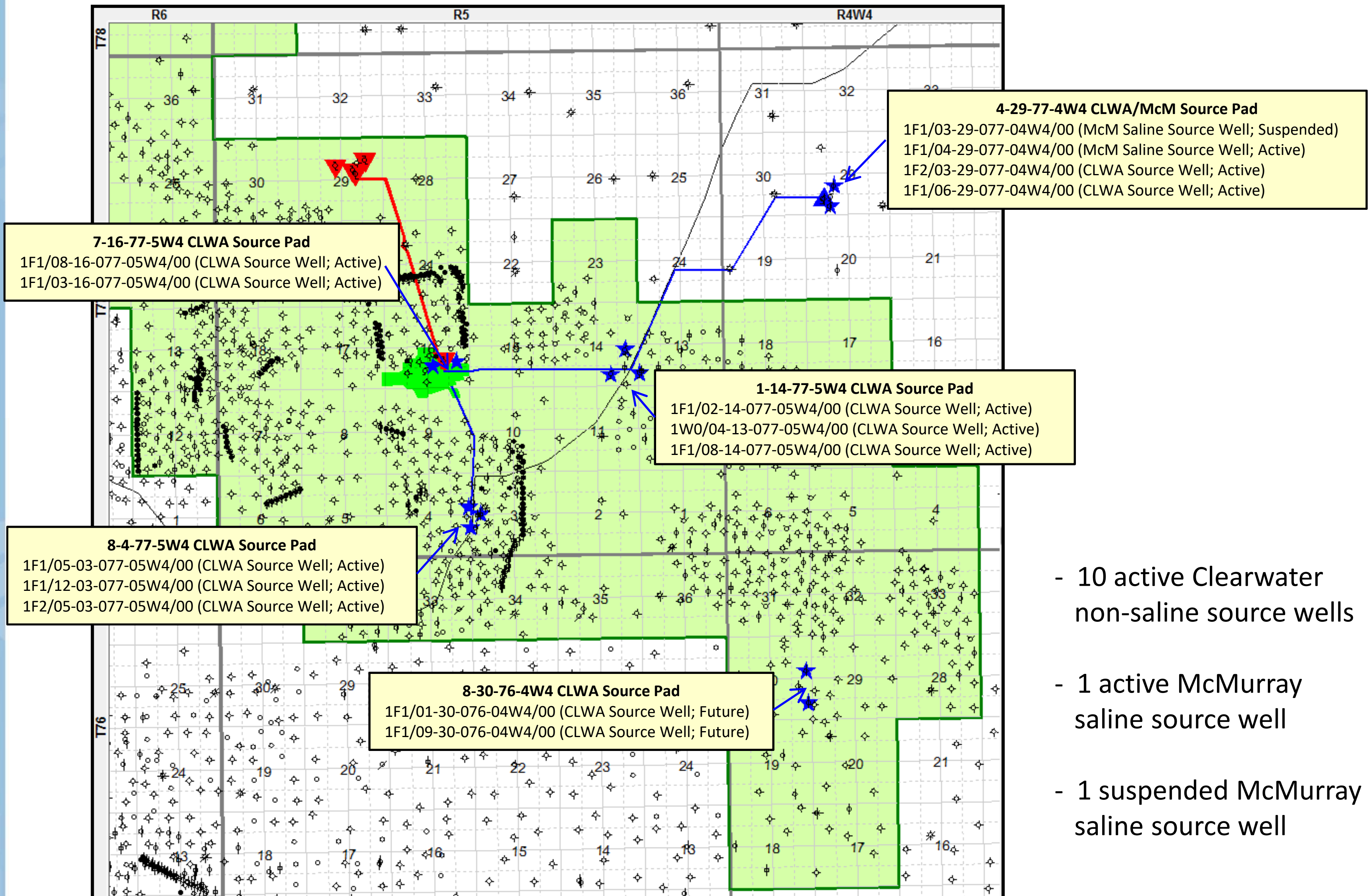
D81 Compliant in 2018

- 2019 calendar year disposal limit/actual percentages are YTD to April 30
- Actual disposal % in 2019 is high due to high PWSR (>1.05). MEG will continue to communicate with the AER regarding 2019 D81 compliance as the year progresses

Produced Water to Steam Injected Ratio

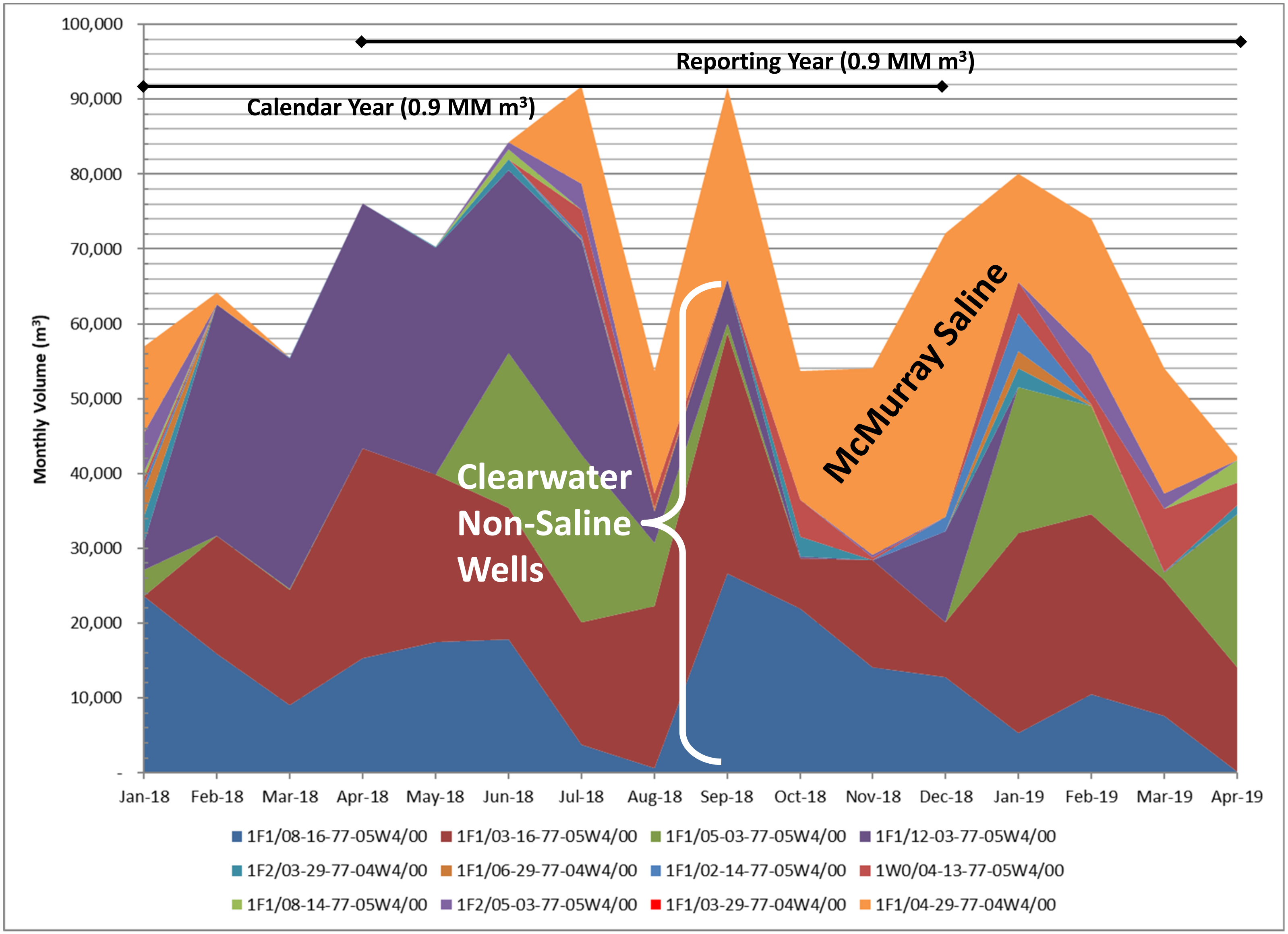


Source Water Well Locations

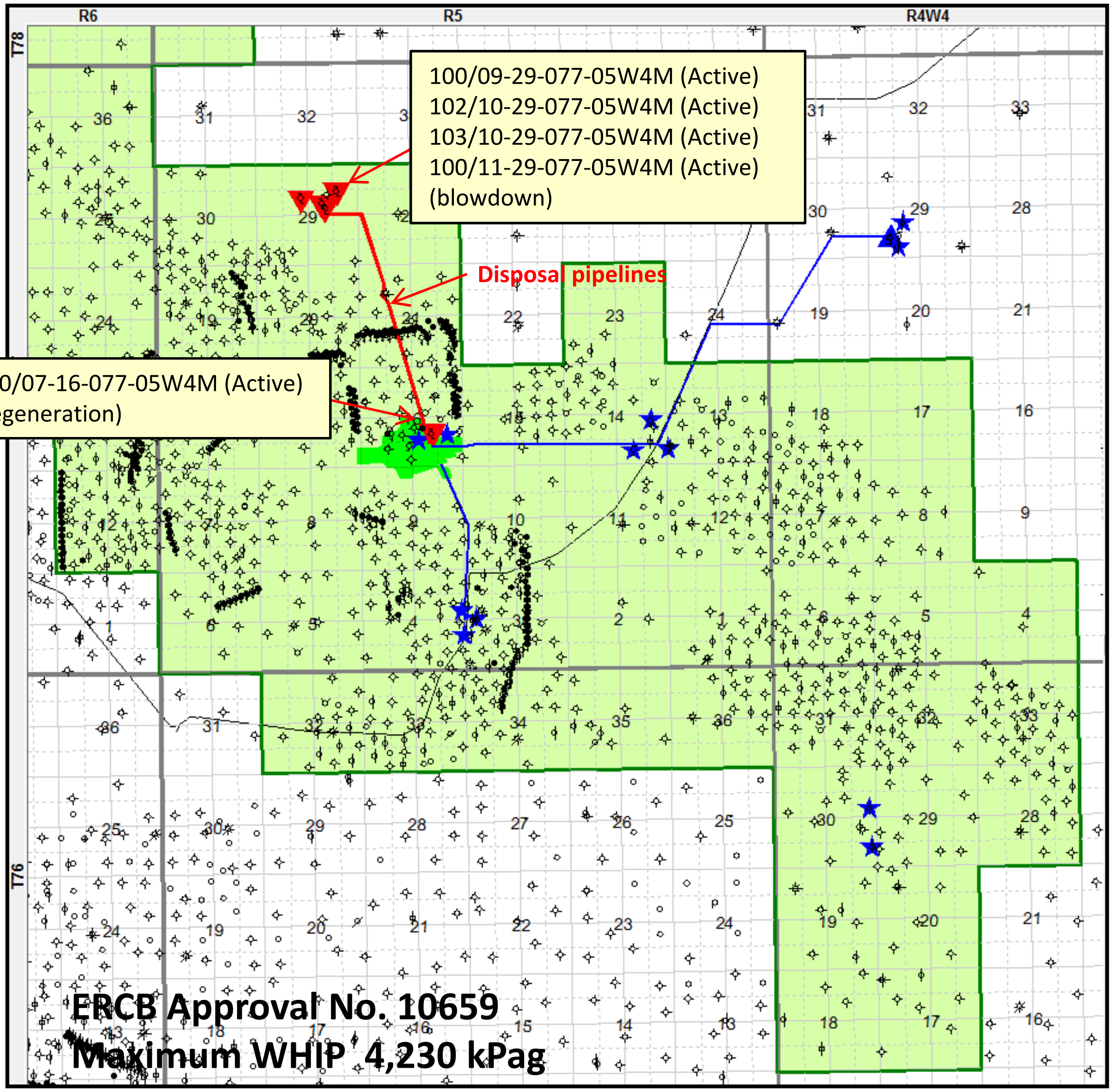


- 10 active Clearwater non-saline source wells
- 1 active McMurray saline source well
- 1 suspended McMurray saline source well

Source Water Well Production

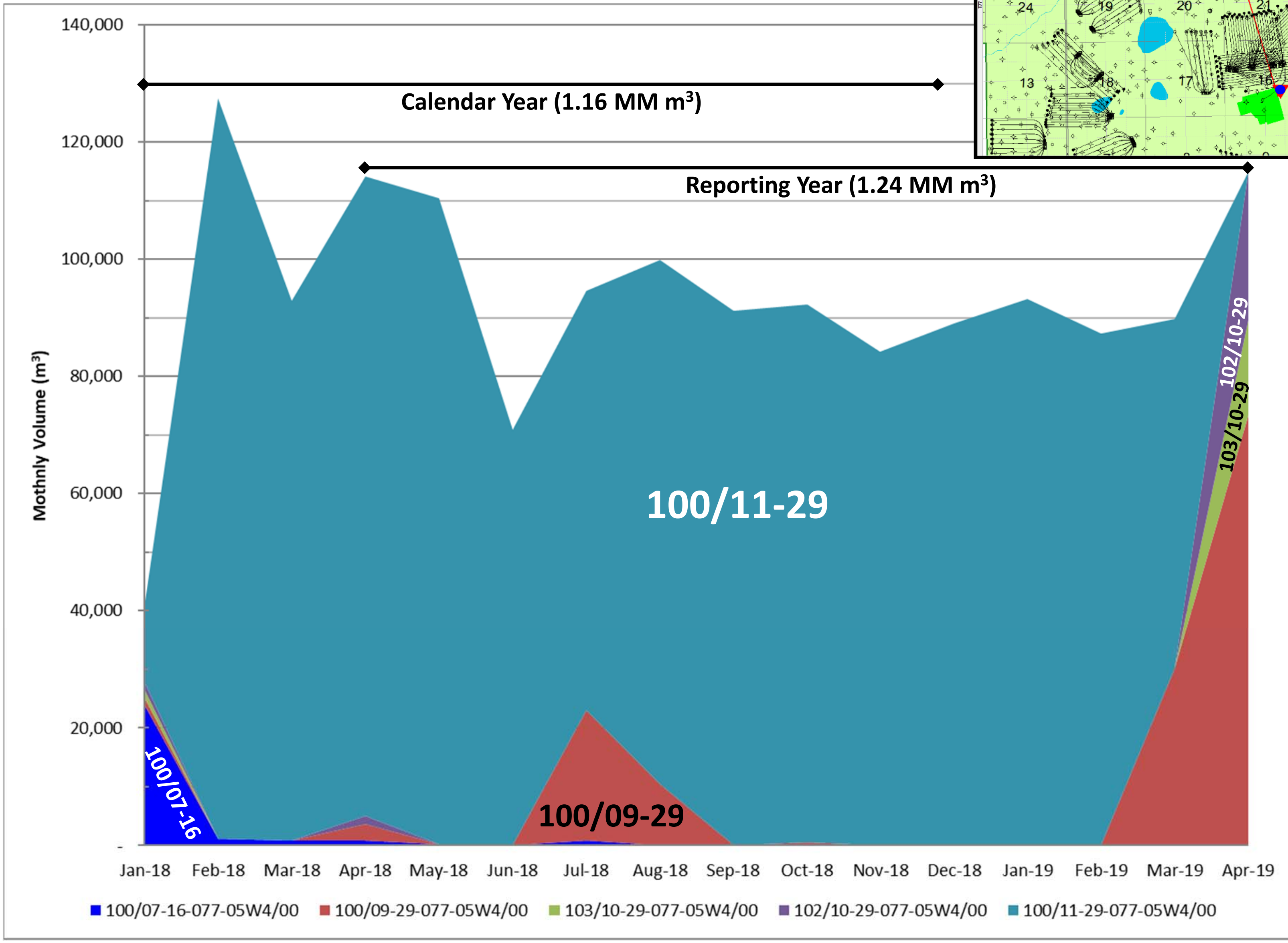


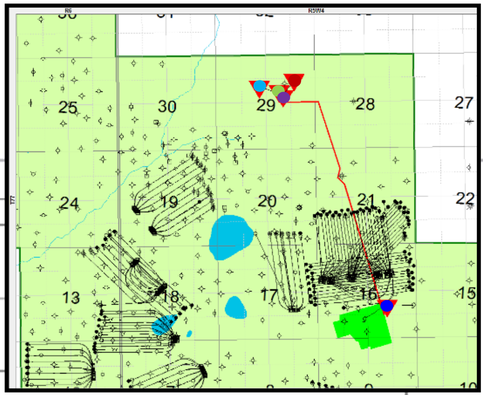
McMurray Disposal Wells



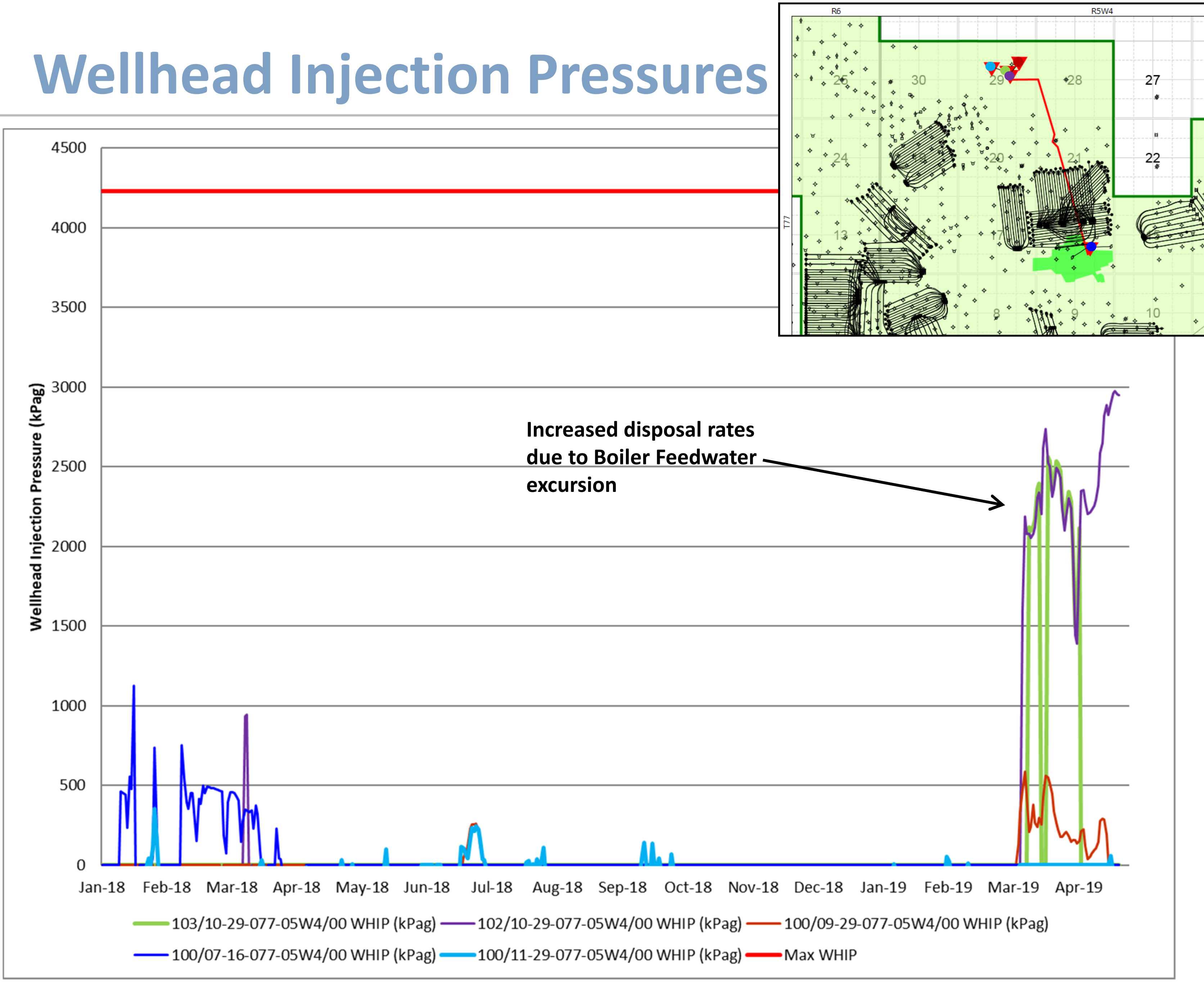
- 5 active McMurray disposal wells

Disposal Summary

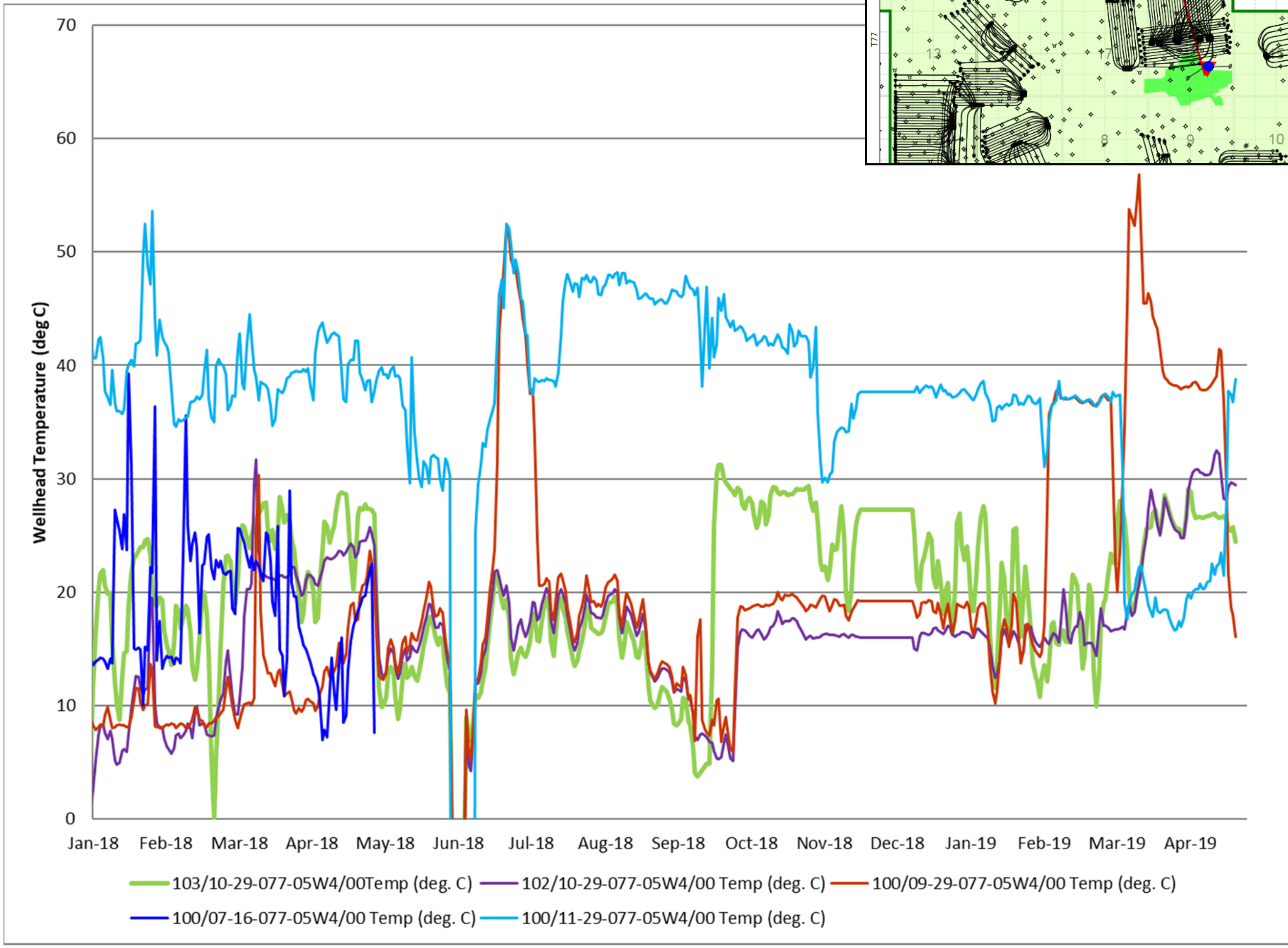


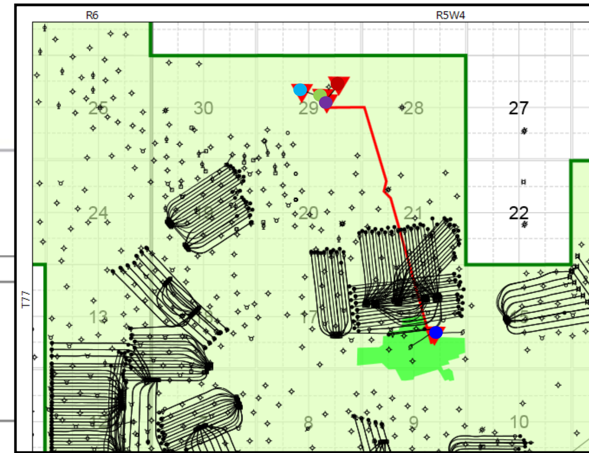


Wellhead Injection Pressures

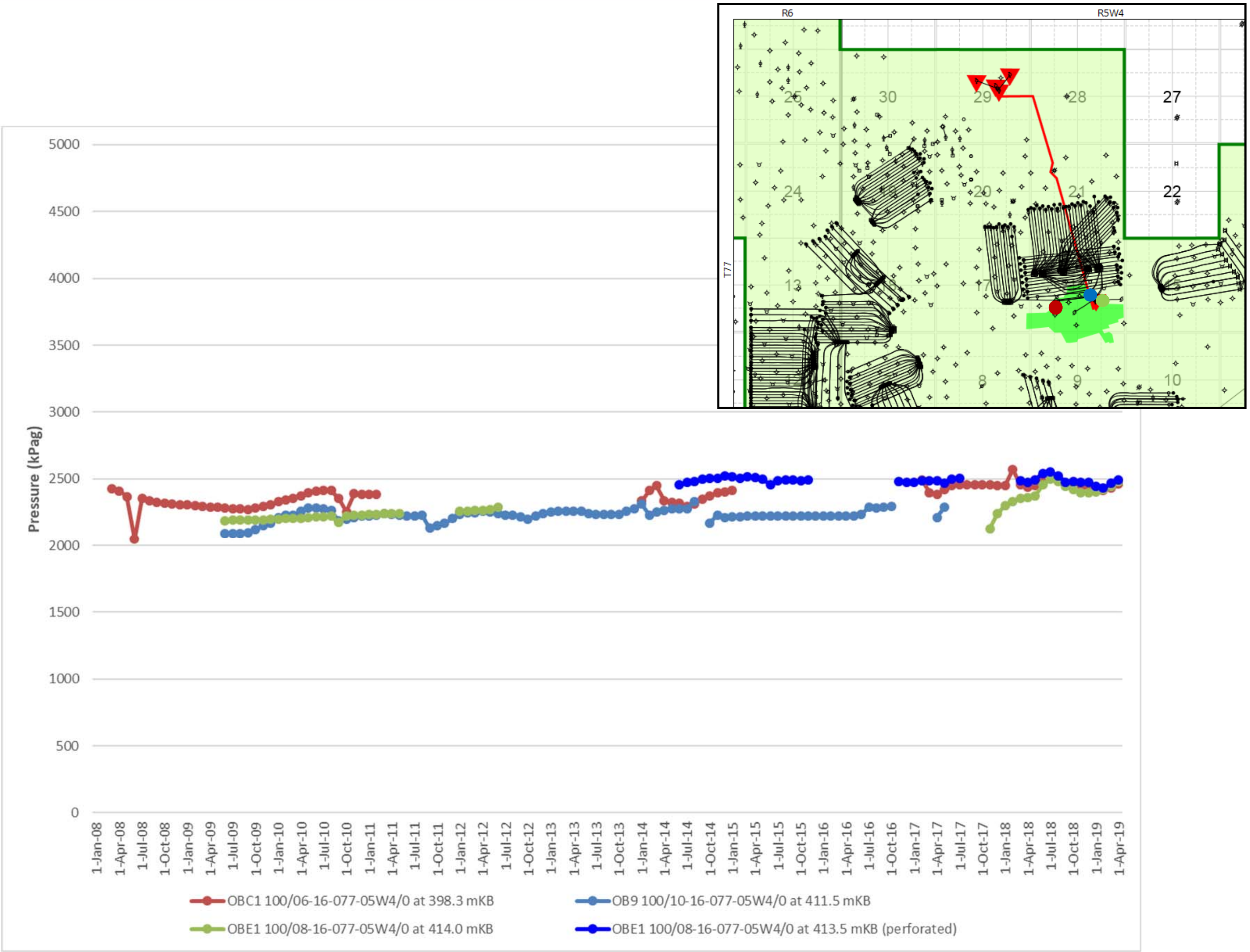


Injection Temperatures





Basal McMurray Water Sand Pressure Monitoring



Water Management Summary

- 2018 had lowest total make-up and non-saline make-up water use intensity in CLRP operations history
  - MEG executed a project to replace non-saline water for backwash with produced water. This has further decreased non-saline water use intensity.
- D81 compliant in 2018
- High produced water to steam ratios have increased 2019 year-to-date disposal rates. MEG will continue to communicate with the AER regarding 2019 D81 compliance as the year progresses.
- Saline water use (McMurray) ongoing since November 2013. MEG plans to continue to utilize saline water for steam generation make-up
- Non-saline Clearwater A and Ethel Lake groundwater production and pressure monitored in accordance with *Water Act* licenses
- Ethel Lake, Clearwater and McMurray aquifers are responding to pumping as expected
- Technology advancement to reduce SOR and increase overall water use efficiency
- Blowdown evaporator planned to be online in 2020 to further improve water recycle capabilities

MEG ENERGY

Compliance & Environment

Compliance & Environment

Reporting Year Highlights

- Monitoring Programs
- Environmental Initiatives
- Sulphur Production and Removal
- Greenhouse Gas Management
- Compliance Summary
- Reclamation

MEG's Extensive Monitoring

Detecting changes that may occur due to our developments

Air
Chemical analysis and flow rates for all fuel streams and stack emissions. We also monitor ambient air quality around our facilities.

Groundwater
Check water quantities and quality. This includes our groundwater use as well as leak detection systems for our recycling ponds, waste management facility and tank farms.

Regional Monitoring
MEG participates in a number of regional monitoring initiatives and groups such as: Alberta Biodiversity Monitoring Institute, Wood Buffalo Environmental Association and the Joint Oil Sands Monitoring program.

Soil
Soil analysis and laboratory testing for any chemical changes or contaminations

Surface Water/Wetlands
Monitor surface water quantity and quality in nearby water bodies and watercourses

Wildlife
Winter tracking, monitoring wildlife corridors using remote cameras, and employee wildlife sighting cards

Vegetation
Monitor species composition and abundance

Monitoring Program Updates

In compliance with EPEA Approval 216466-01-03, the following Monitoring Program Proposals were submitted to the AER

- No new Monitoring Program Proposals were submitted to the AER in 2018
- Approval of the updated Wetland and Waterbody Monitoring Proposal is underway:
  - Submitted to the AER on August 31, 2017
  - Finalizing supplemental information request responses related to impacts from elevated metal concentrations and the best course of action to ensure no increased risks to aquatic receptors
  - Taking some additional time to respond to ensure alignment with the *Assessment of Thermally-mobilized Constituents in Groundwater for Thermal In Situ Operations* (the Directive; GoA 2018)

Ambient Air Quality Monitoring

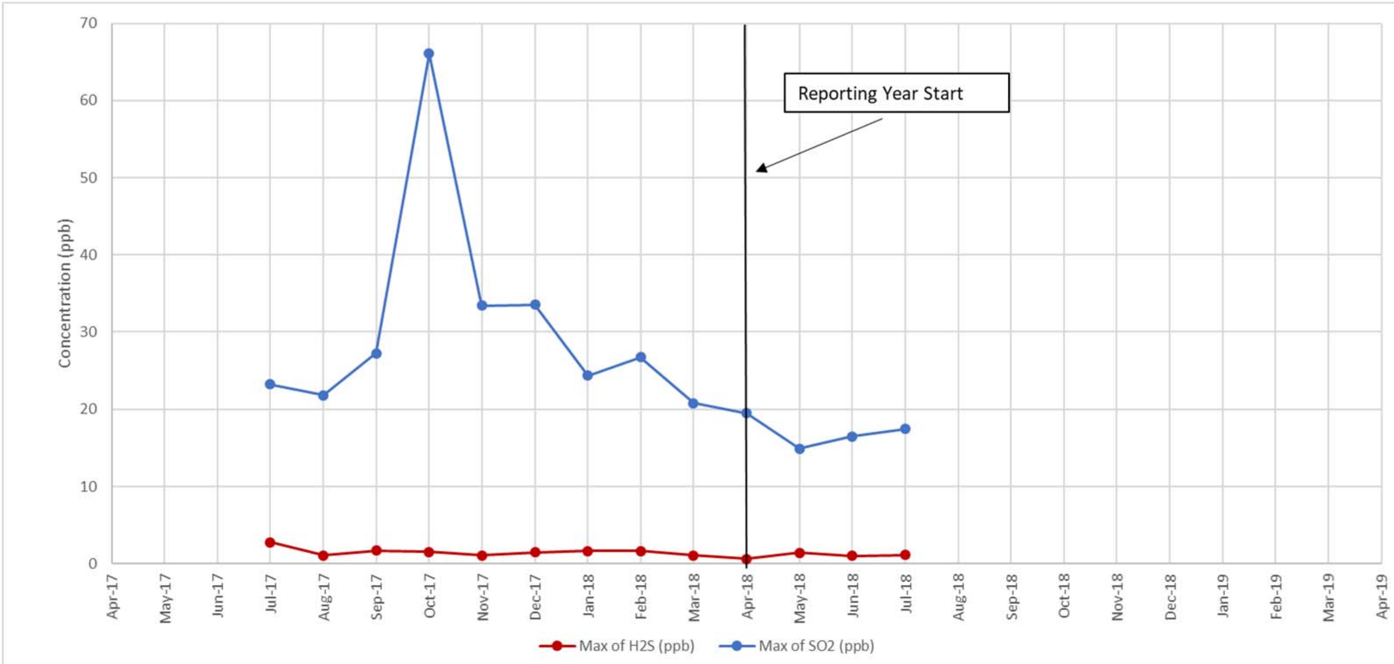
Continuous Ambient Air Monitoring Trailer and Passive Sampling

- MEG used continuous ambient air monitoring trailer from June 2017 to July 2018 for phases 1, 2 and 2B, as required by our EPEA approval
- Four passive monitors are installed around the CLRP site for the measurement of H_2S and SO_2 with readings taken on a monthly basis

MONITORING STATION	PARAMETER	MONITORING PERIOD	REPORTING FREQUENCY	
			MONTHLY	ANNUALLY
One continuous monitoring station for Phase 1/2/2B/2B4X as per *Air Monitoring Directive*	Sulphur dioxide concentrations, hydrogen sulphide concentrations, nitrogen dioxide concentrations, wind speed and wind direction	Six months per year	Yes	Yes
	Total hydrocarbons concentrations	Continuously for the first six months of operation of Phase 2, Phase 2B and Phase 2B4X		

Ambient Air Quality Monitoring

Continuous Monitoring Results



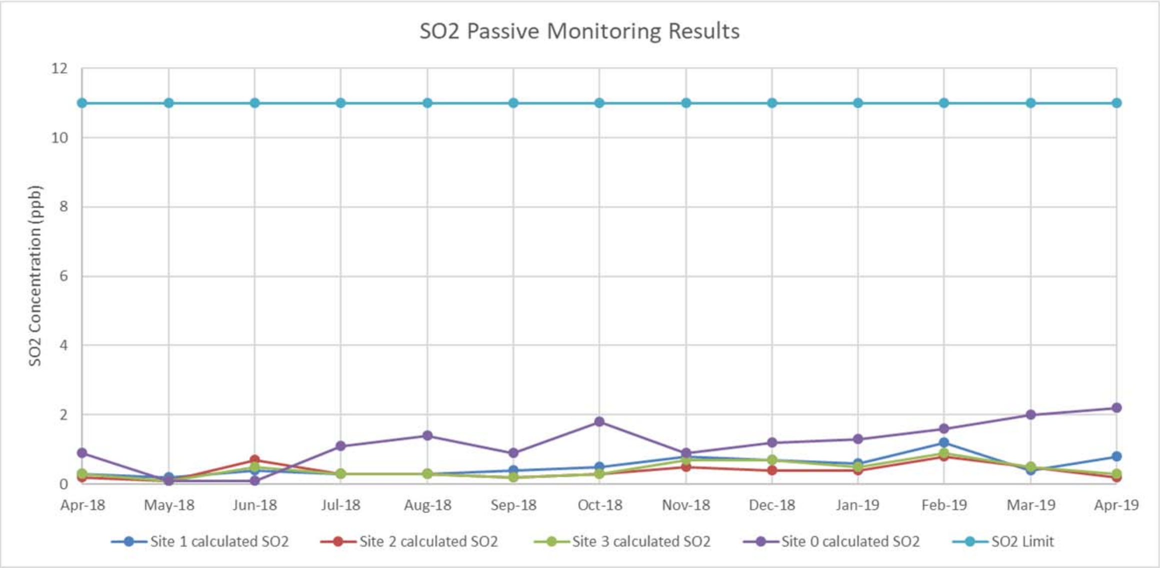
For the Reporting Year of April 2018 – April 2019	Maximum Concentration (ppbv)	Month of Maximum	AAAQO 1-hour Limit (ppbv)
SO2	19.51	April-18	172
H2S	1.41	May-18	10

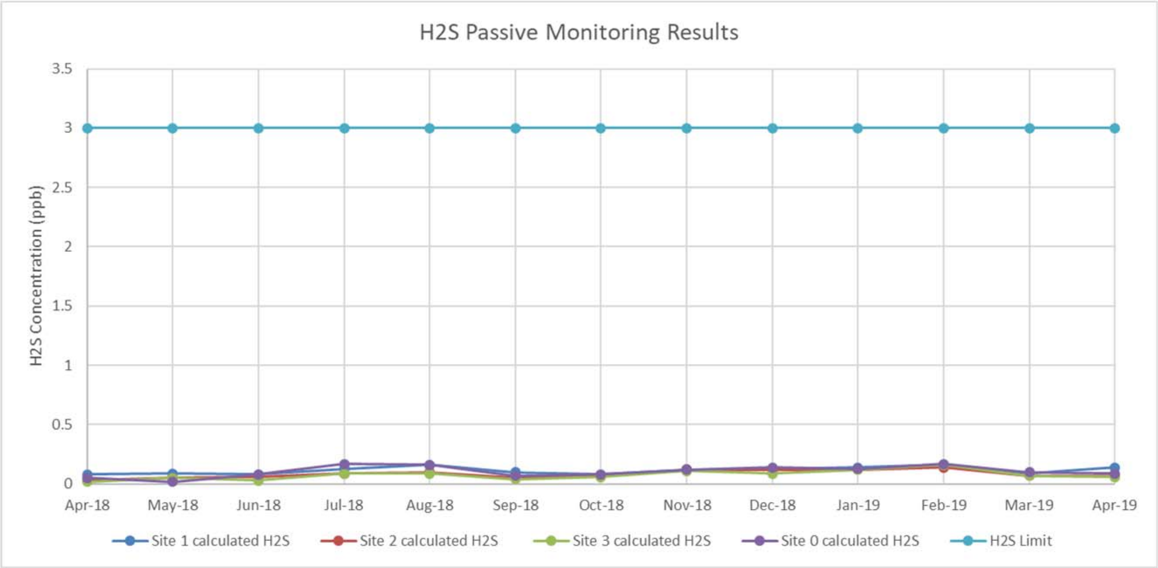
There were no exceedances of Ambient Air Quality Objectives during the reporting period.

MEG is required to have continuous ambient air monitoring for 6 months every year. The continuous ambient air monitoring was conducted in 2018 from January to July. The continuous ambient air monitoring trailer will return to MEG CLRP in June 2019.

Ambient Air Quality Monitoring

Passive Sampling Results



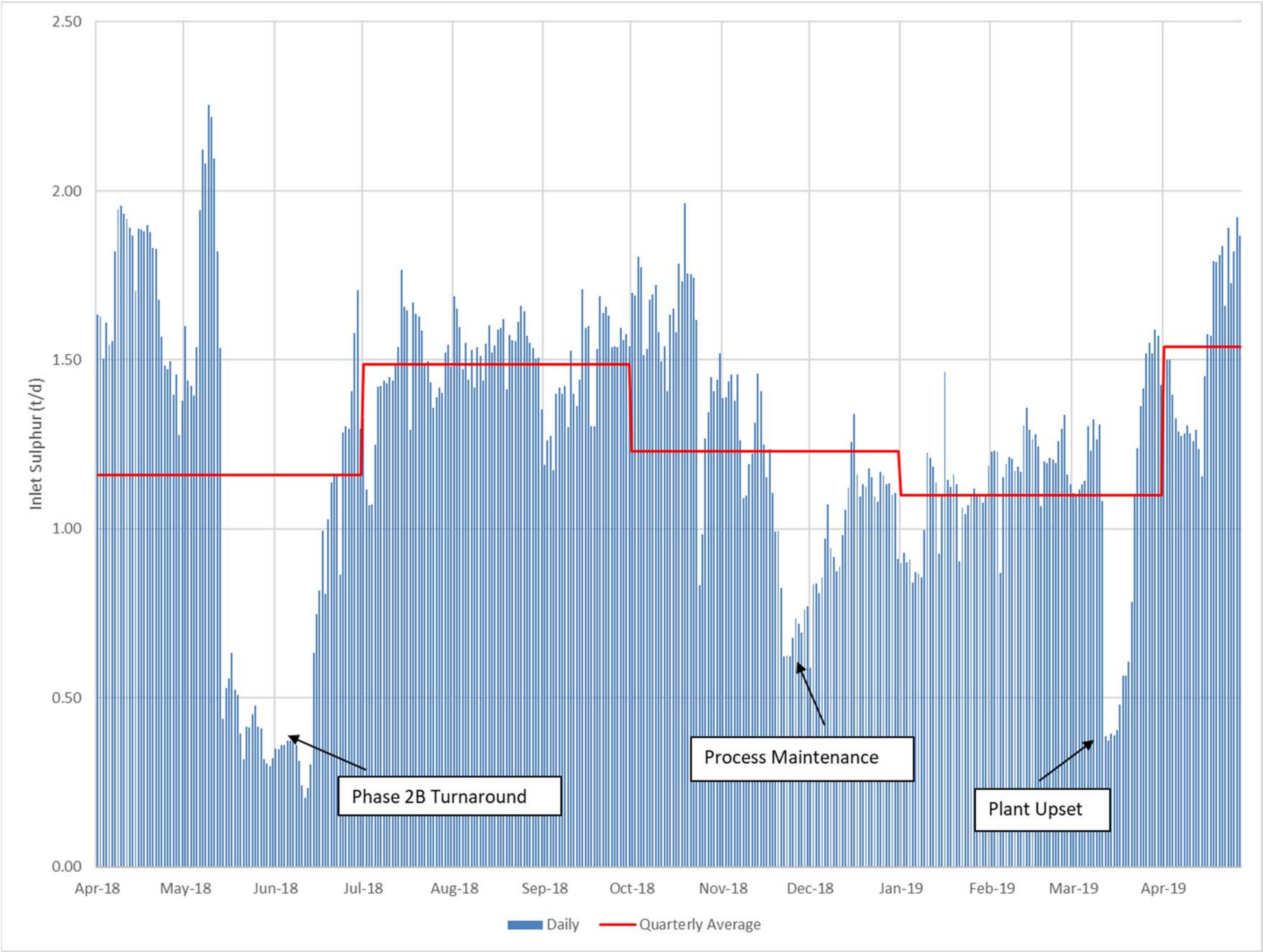


Environmental Initiatives

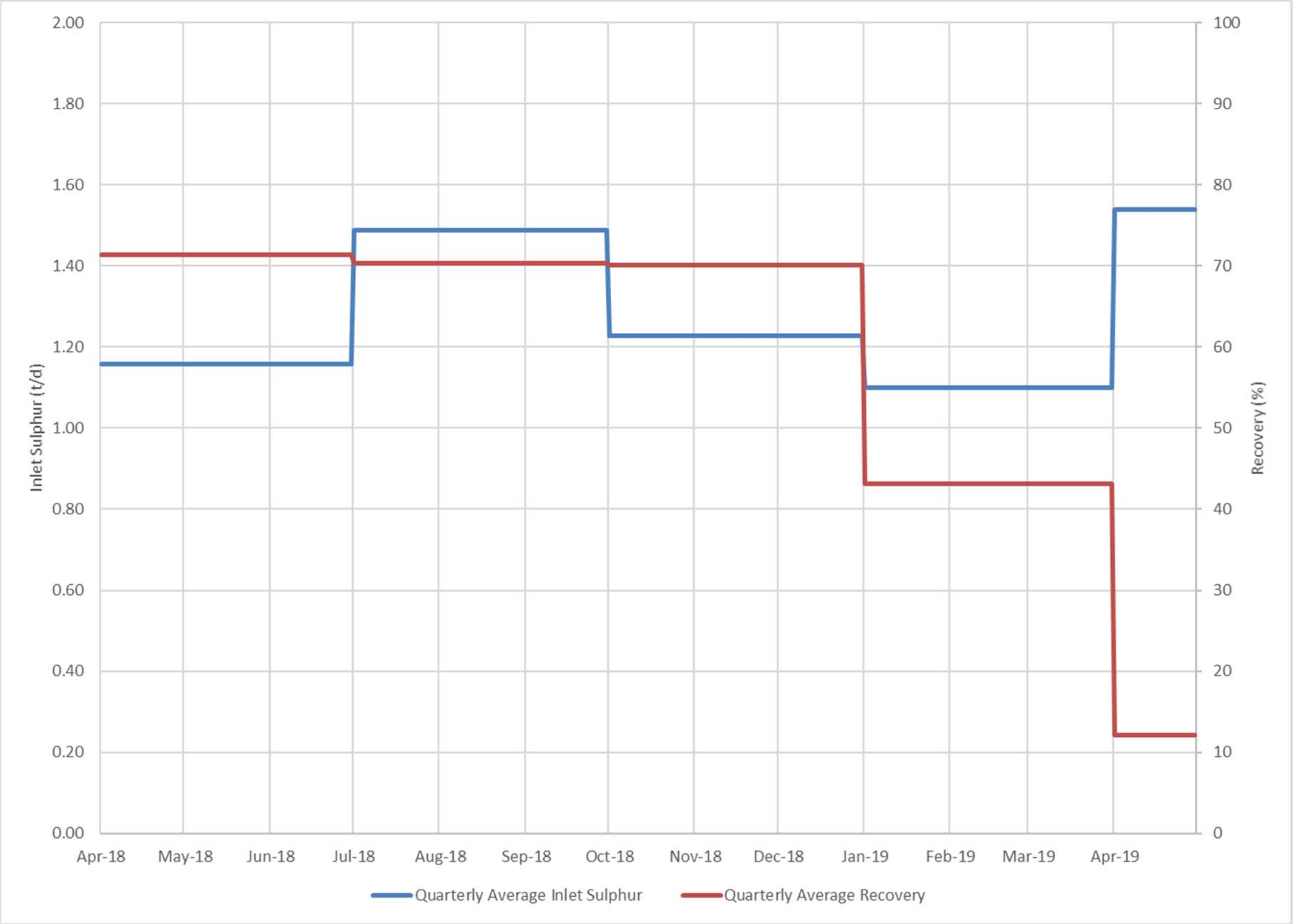
MEG participates in the following environmental initiatives:

- **Industrial Footprint Reduction Options Group (iFROG)**
  - University of Alberta led research collaboration focused on enhancing construction and wetlands reclamation practices in boreal Alberta
- **Regional Industry Caribou Collaboration (RICC/COSIA)**
  - A group of companies from the oil sands and forestry sectors collaborating with the Government of Alberta and other institutions to address caribou conservation and recovery in NE Alberta
- **Faster Forests (COSIA)**
  - The COSIA Faster Forests program is a reclamation research collaboration amongst seven oil & gas operators designed to identify reclamation techniques which can accelerate re-vegetation of sites disturbed by exploration activities
- **Wood Buffalo Environmental Association (WBEA)**
  - WBEA monitors the environment of the Regional Municipality of Wood Buffalo in north-eastern Alberta

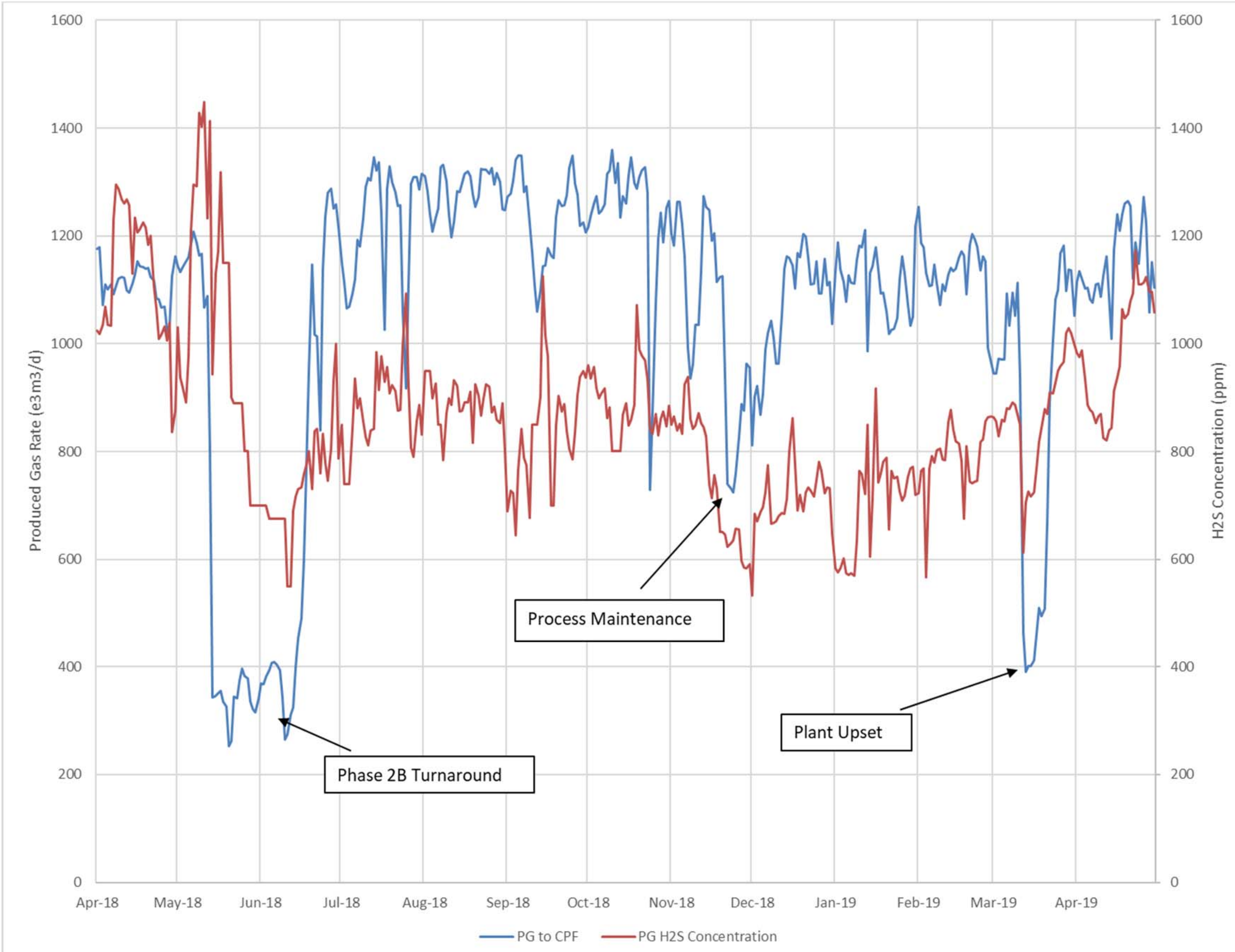
Inlet Sulphur



Sulphur Removal



Produced Gas Rates and H_2S Concentration

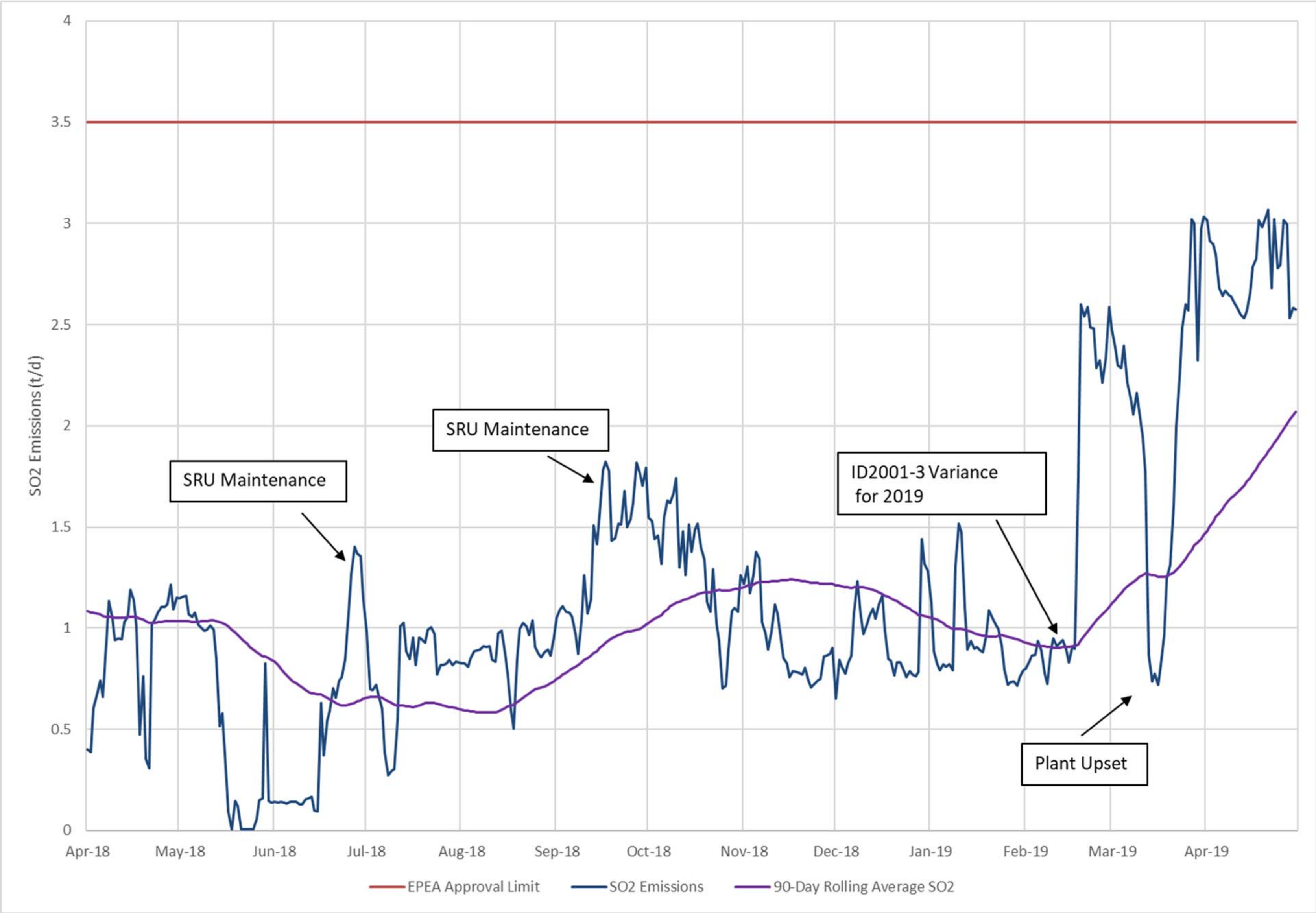


Produced Gas Recycle Project

- The permanent Produced Gas Recycle Project (PGRP) was commissioned in October 2018 to manage increased produced gas returns to the Central Processing Facility
- The PGRP is designed to receive sweetened gas from the Sulphur Removal Units to be compressed, dehydrated, and re-injected into the reservoir
- Due to reliability issues (instrumentation, o-ring seals, line freezing, reboiler tuning) the gas compressor and the glycol dehydrator featured in the PGRP has had limited uptime
- Produced gas rates have been managed in the field by turning off high-gas wells until consistent run-time of the PGRP can be maintained

	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
Produced Gas Recycle Project Runtime (hrs/month)	23	37	109	130	430	0	4

SO_2 Emissions

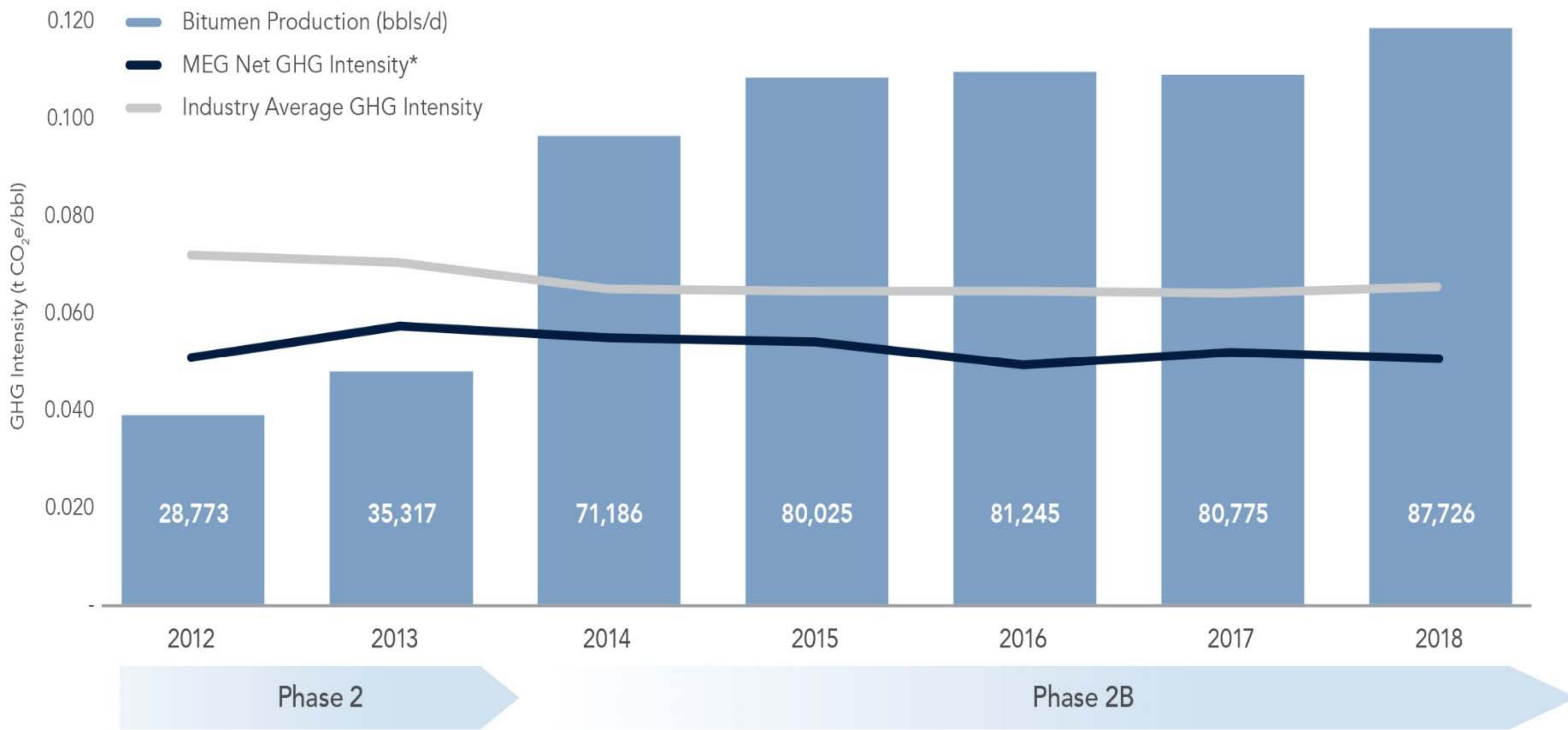


Sulphur Recovery Unit (SRU)

- **Sulphur Removal Train Maintenance** – One SRU train was removed from service for flushing maintenance in July 2018 and October 2018

- **Sulphur Recovery Guideline Variance** – On February 11th 2019, MEG was granted a temporary waiver from ID2001-03: Sulphur Recovery Guidelines for the Province of Alberta as written in MEG's Commercial Scheme Approval No. 10773ZZ
  - *"The Operator is temporarily exempt from meeting the recovery requirements as set out in Table 1 of AER Interim Directive (ID) 2001-03: Sulphur Recovery Guidelines for the Province of Alberta. This clause will expire on December 31, 2019."*
  - MEG remains committed to compliance with Alberta Ambient Air Quality Objectives limits and the EPEA daily SO2 emissions limit

Greenhouse Gas (GHG) Management



Sources: MEG's net GHG data from 2010-2018 has been third-party verified. In situ industry average estimate is calculated based on the most recent reported data to Environment Canada, Alberta Energy Regulator, and Alberta Electric System Operator.
* Net GHG intensity includes the associated benefits of cogeneration

- MEG CLRP continues to produce one of the lowest net GHG intensity barrels in the industry.
- GHG performance is attributed to reservoir performance (low SORs), use of cogeneration technology for steam generation, and ongoing reservoir efficiency technologies (i.e. eMSAGP).

Audit/Inspection Summary

Date	Audit/Inspection	Area	Result
February 20, 2018	AER Pipeline Inspection (ID 471573)	Wildlife Crossing Compliance	Satisfactory
March 21, 2018	AER Drilling Waste Inspection (ID 472313)	Waste Handling and Storage	Satisfactory
April 2, 2018	AER Drilling Waste Audit (DDS649017)	Drilling Waste Management and Documentation	Satisfactory
August 1, 2018	AER Public Lands Act Inspection (ID477723)	Erosion and Sedimentation MEG Hardy 6-33-76-5 W4M	Unsatisfactory – Closed Corrective Action Complete
September 18, 2018	AER Manual 001 (ID479315)	Central Plant SAGD Facility and AP Pad	Satisfactory
September 18, 2018	AER Manual 001 (ID 479326)	MEG S2 Hardy 3-16-77-5 W4M Clearwater Source Well	Satisfactory
September 18, 2018	AER Manual 001 (ID 479327)	MEG S3 Hardy 8-16-77-5 W4M Clearwater Source Well	Satisfactory
September 18, 2018	AER Manual 001 (ID 479330)	MEG Hardy 7-16-77-5 W4M Regen Waste Disposal Well	Unsatisfactory – Closed Corrective Action Complete

Compliance Summary

Self-Disclosures & Non-Compliances

- **Voluntary Self Disclosures:**
  - April 2018, the infill well, MEG N2N HARDY 106/06-03-077-05 W4/00 was deficient in test hours
  - June 2018, the infill well, MEG \B9N HARDY 114/08-21-077-05 W4/00 was deficient in test hours
  - August 2018 – Non-Conformances associated with MEG's 2017-2018 Oilsands Exploration (OSE) Program – Alternate access routes being used without a TFA
  - November 2018, producer well, MEG \E1P HARDY 105/09-16-077-05 W4/00 was deficient in test hours
- **Non-Compliances:**
  - 07-16-077-05 W4 (AER ID 479330) – Low Risk Notice – Disposal well SCVF assembly was not being vented to atmosphere but was venting inside wellhead shack – MEG submitted confirmation by Oct 18, 2018 corrective action was complete and SCVF assembly being vented outside
  - 06-33-076-05 W4 (AER ID 477723) – Low Risk Notice - Erosion occurring on the north side of LOC851438 causing sedimentation into the adjacent waterbody. No erosion controls measures noted during inspection, vegetation has not been re-established. MEG submitted confirmation by Sept 30, 2018 that erosion and sedimentation control measures implemented

Compliance Summary

MEG reported two EPEA approval contraventions to the AER during the reporting period:

- **06-15-077-05 W4 - L Pad berm breach (AER CIC#34021)** – On June 23, 2018 water levels increased on L pad due to heavy rains and began to overflow the north end of the pad berm. The industrial runoff water release was uncontrolled and sampling was not able to be completed before the release to confirm whether runoff water parameters met EPEA approval requirement. Samples were collected from remaining pooled water on pad and it met release criteria

- **02-16-077-05 W4 - CPF Runoff Release (AER CIC#343966)** – On September 14, 2018 Industrial run off water from the southwest corner of MEG's 2-16-77-5 W4M facility was released offsite without sampling from the central plant. The water was field tested during the run off event and test results were, pH 7.45, chlorides <20 mg/L, and no visible sheen observed

Compliance

- To the best of MEG's knowledge, the Christina Lake Regional Project is in compliance with all conditions and regulatory requirements related to Approval No. 10773.
  - For the period of April 1, 2018 to March 31, 2019, MEG Energy has no unaddressed non-compliant events

Conservation & Reclamation

Reporting Year Highlights

Borrow Pit Reclamation

- Borrow Pit 8
  - Herbaceous plant control occurred in Q2 2018 to reduce the proliferation of undesirable plants that pose a risk to the planted conifers
- Borrow Pit 4A
  - Erosion stabilization and vegetation applied to ameliorate slumping on southwestern edge of water body
- Borrow Pit 12
  - Recontouring, soil replacement and revegetation took place in Q2 2018
- Former Borrow Pit 3/Current Pad AT
  - The disturbed area surrounding the pad (once a part of the Borrow Pit 3 disposition) that had not been previously planted was revegetated in Q2 2018
- Borrow Pit 9
  - Recontouring and soil replacement occurred in Q2 2018
- Borrow Pit 23
  - Soil replacement undertaken in Q4 2018
- Borrow Pit 11
  - Detailed Site Assessment completed in Q3 2018 for Reclamation Certification Application

Conservation & Reclamation

Reporting Year Highlights

Wetland Reclamation Trial Program

- Completed fourth year of monitoring at Borrow Pit 7 WRT

Ongoing Research and Monitoring Programs

- MEG's Woodland Caribou Mitigation and Monitoring Program
- COSIA Faster Forest Program
- COSIA iFrog Program (Industrial Footprint Reduction Options Group)
- COSIA RICC Program (Regional Industry Caribou Collaboration)

Project Level Conservation, Reclamation, and Closure Plan

- PLCRCP SIRs were issued to MEG on June 27, 2018, following a response letter to AER on July 31, 2018. The PLCRCP was authorized on August 10, 2018

Linear Disturbance Deactivation/Caribou Habitat Restoration

- As required by MEG's EPEA Caribou Mitigation and Monitoring Plan, linear restoration activities continued in townships 077-03 and 077-04 W4M in the winter and spring of 2018
  - Phase I work was completed on 24.1 km of seismic line from February 1st to March 5th 2018
    - Mounding Treatment: 13.4 m, 8.7 ha
    - Ripping Only: 1 km, 0.6 ha
    - Hand Treatment: 4.5 km, 3.6 ha
    - Hand Fall: 3.4 km, 1.8 ha
    - Skips: 0.6 km, 0.4 ha
    - Natural regeneration identified during fieldwork: 1.2 km, 0.7 ha
  - Phase II of the project occurred from May 12 to May 18 2018
    - Planting: 2.7 km

OSE Reclamation

Reporting Year Highlights:

Ongoing OSE Reclamation, Assessments and Reclamation Certification

- **Annual Field Program executed, including:**
  - 2018 OSE Program Aerial Assessments
  - CLRP 110074 Ground-Truthing
  - CLRP 130056 Ground-Truthing
  - CLRP 130057 Ground-Truthing
  - CLRP 130058 Ground-Truthing
  - CLRP 140056 Aerial Assessment
  - CLRP 150022 Aerial Assessment
  - CLRP 160019 Aerial Assessment

- **OSE Wellsite Reclamation Certification received for:**
  - CLRP 100089
  - Thornbury 100070
  - Surmont 070004
  - Surmont 100069

- **OSE Program revegetation completed on 11 cut/fill locations**

MEG ENERGY

Future Plans

Future Plans

- Continued development of eMSAGP within Active Development Area
- Ongoing progress of brownfield development within existing facility footprint
- Ongoing pattern addition within CLRP development area
- Ongoing resource assessment

Regulatory Activity

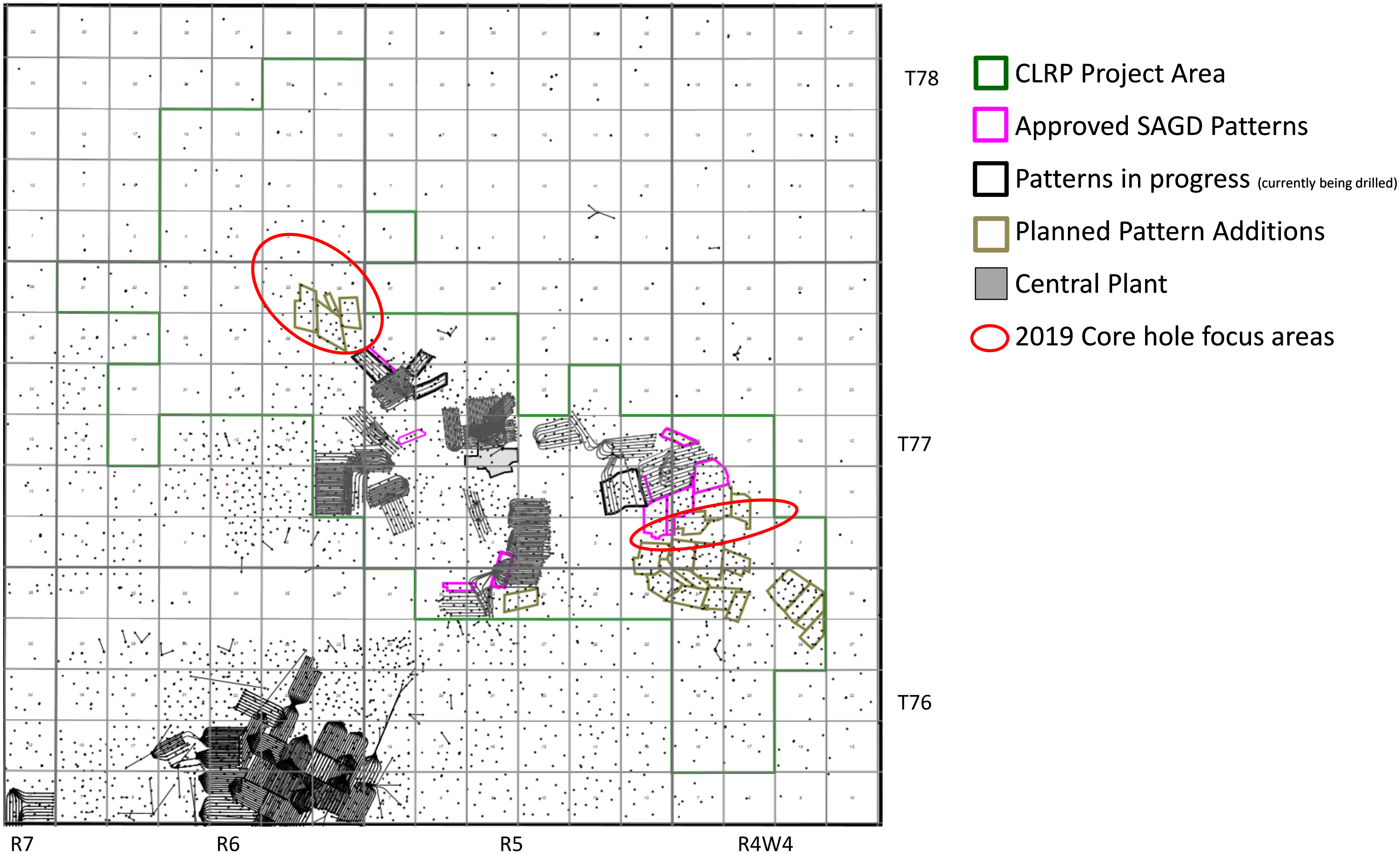
April 2017 - April 2018

- Directive 56 licenses and amendments for well pads and field facilities
- Sub-surface reconfiguration scheme amendments for patterns T, AH, DE, DG, & DK
- Field wide expansion of NCG Co-Injection (eMSAGP)
- Unresolved Emulsion Injection Pilot Extension
- Steam Heater Project Directive 17 Variance Request
- Renewal of groundwater diversion license 266479-01-00

April 2018 - April 2019

- Scheme amendment applications for sustaining patterns

Future Development



MEG ENERGY

Environment and Regulatory

Sachin Bhardwaj
Regulatory Team Lead
403-781-1027
Sachin.Bhardwaj@megenergy.com

Scott Rayner
Manager, Land, Environment & Regulatory
403-767-0532
Scott.Rayner@megenergy.com

www.megenergy.com