MEG ENERGY

Christina Lake Regional Project

2015/2016 Performance Presentation Commercial Scheme Approval No. 10773

September 6, 2016

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MEG Energy Corp.

Meeting Agenda

• **Overview**	Simon Geoghegan
• **Geosciences**	Greg Helman
• **Reservoir**	John Kelly
• **Operations**	Bill Mazurek
• **Water**	Scott Rayner
• **Compliance & Environment**	Mike Robbins
• **Future Plans**	Sachin Bhardwaj

MEG Energy Corp.

Who We Are

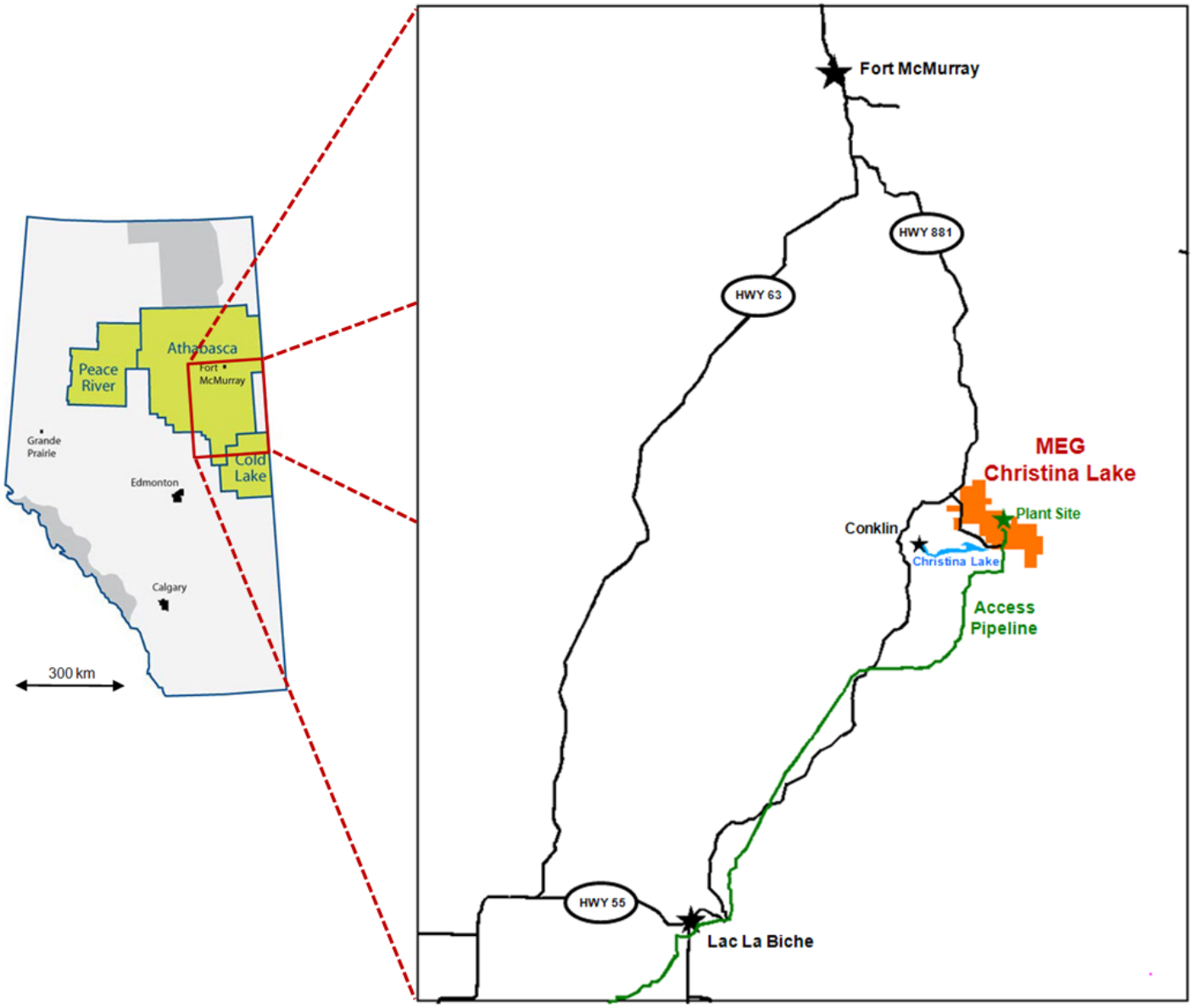
MEG Energy Corp. (MEG) is a public Calgary-based energy company focused on the development and recovery of bitumen and the generation of power in northeast Alberta.

MEG Energy Corp.

Who We Are

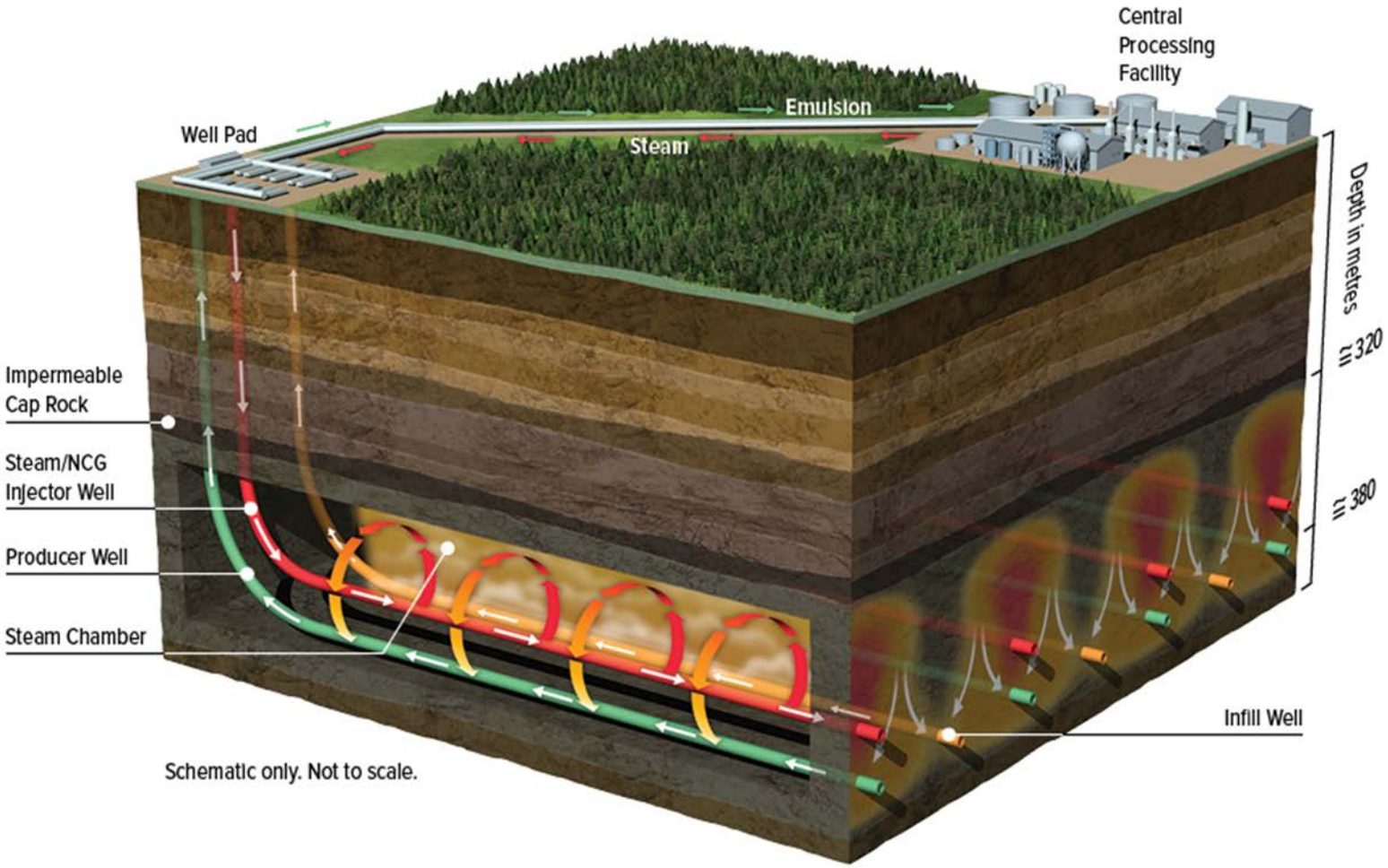
- Established in 1999
- Utilize steam-assisted gravity drainage (SAGD) technology to extract bitumen from the oil sands
- Operating Area– Christina Lake Project Phases 2 (includes Phase 1) and 2B
- 50%-ownership of the Access Pipeline

Christina Lake Regional Project (CLRP)



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 (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 (incremental 3,523 m^3/d or 22,000 bpd)
- First steam Q3 2009
- Phase 1/2 pads: A, B, C, D, E, F, V

Phase 2B

- Approved plant expansion to 9,540 m^3/d or 60,000 bpd (incremental 5,540 m^3/d or 35,000 bpd)
- First steam Q3 2013
- Phase 2B pads: M, N, J, K, G, H, P, T, U, AP, AF, AG, AN

Phase 3

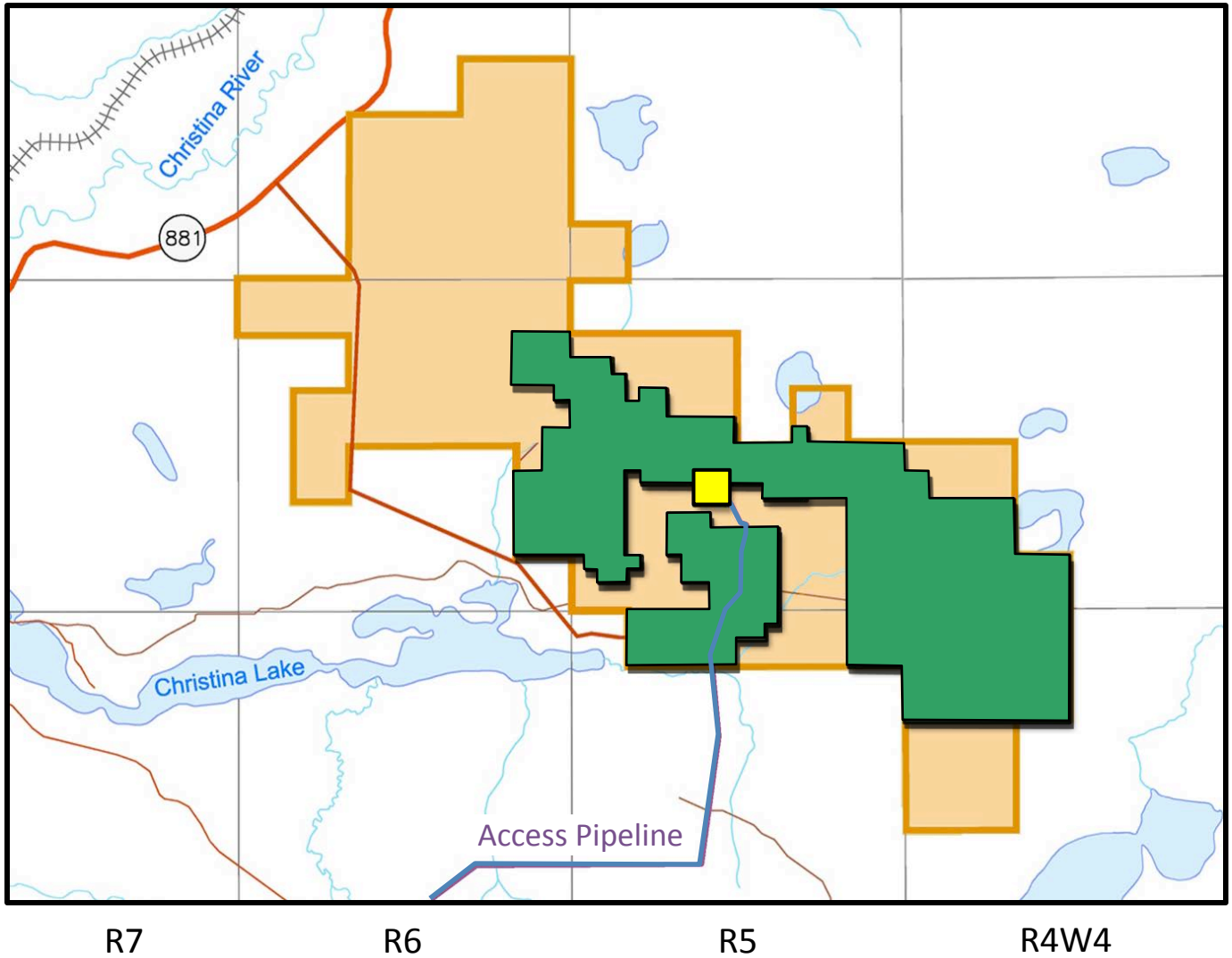
- Approval granted January 2012, expansion to 33,390 m^3/d or 210,000 bpd

Christina Lake Regional Project

2015-2016 Operating Highlights

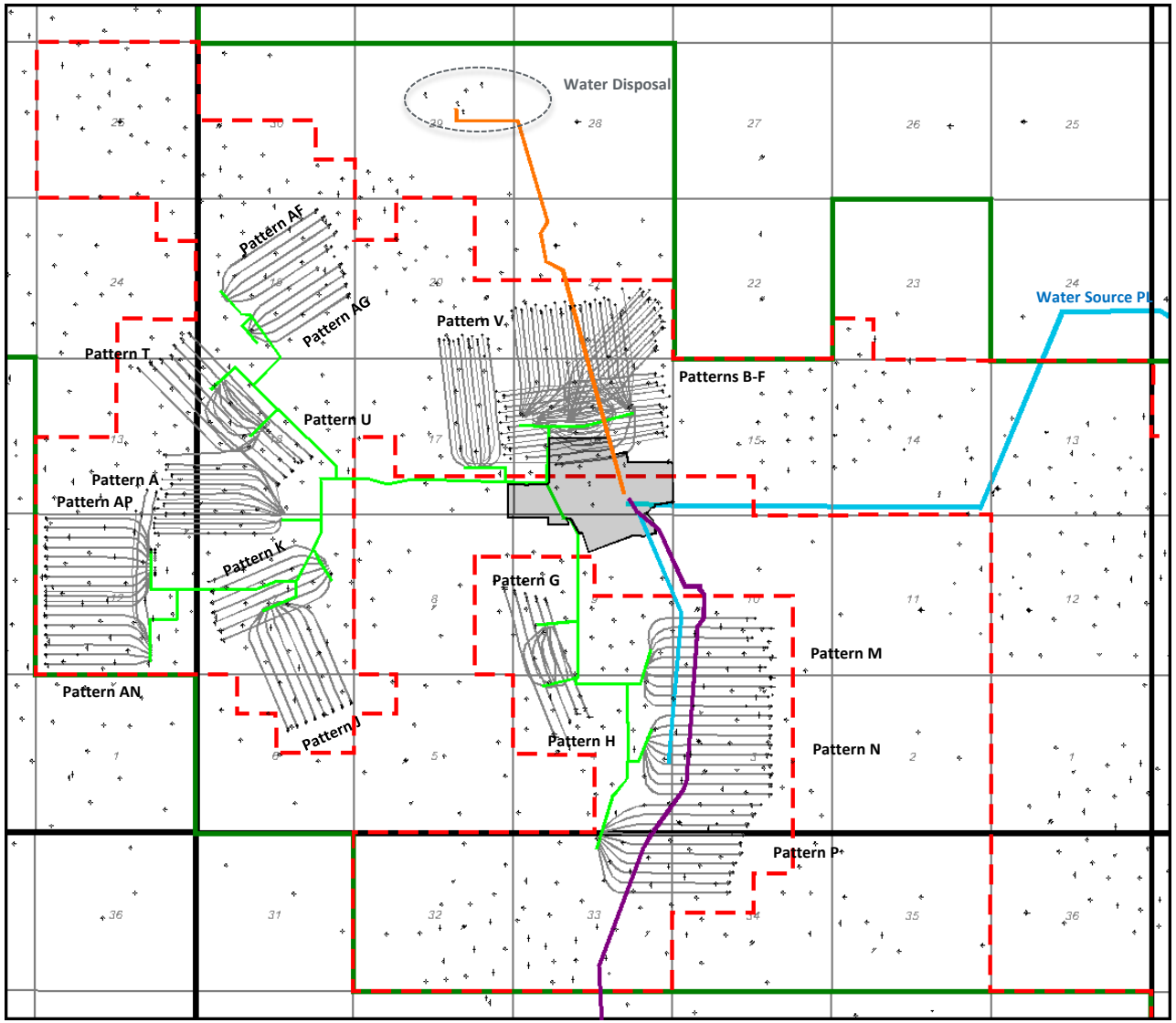
- 2015 bitumen production from both Phase 2 and 2B facilities averaged 80,025 bpd
- Q1 2016 bitumen production of 76,640 bpd including scheduled plant turnaround
- Fieldwide SOR of 2.4
- Expanded implementation of eMSAGP

Christina Lake Regional Project (CLRP)



Phase 2/2B CPF **Approved Development Area**

CLRP Active Development Area (ADA)



MEG OSL
Approved Development Area
Central Plant
Access Pipeline
Emulsion Pipeline
Disposal Pipeline
Water source Pipeline

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	7	0
M	10	0
N	9	0
P	10	0
T	8	0
U	6	0
V	6	6
AF	5	0
AG	5	0
AN	8	1
AP	10	2
Total	143	48

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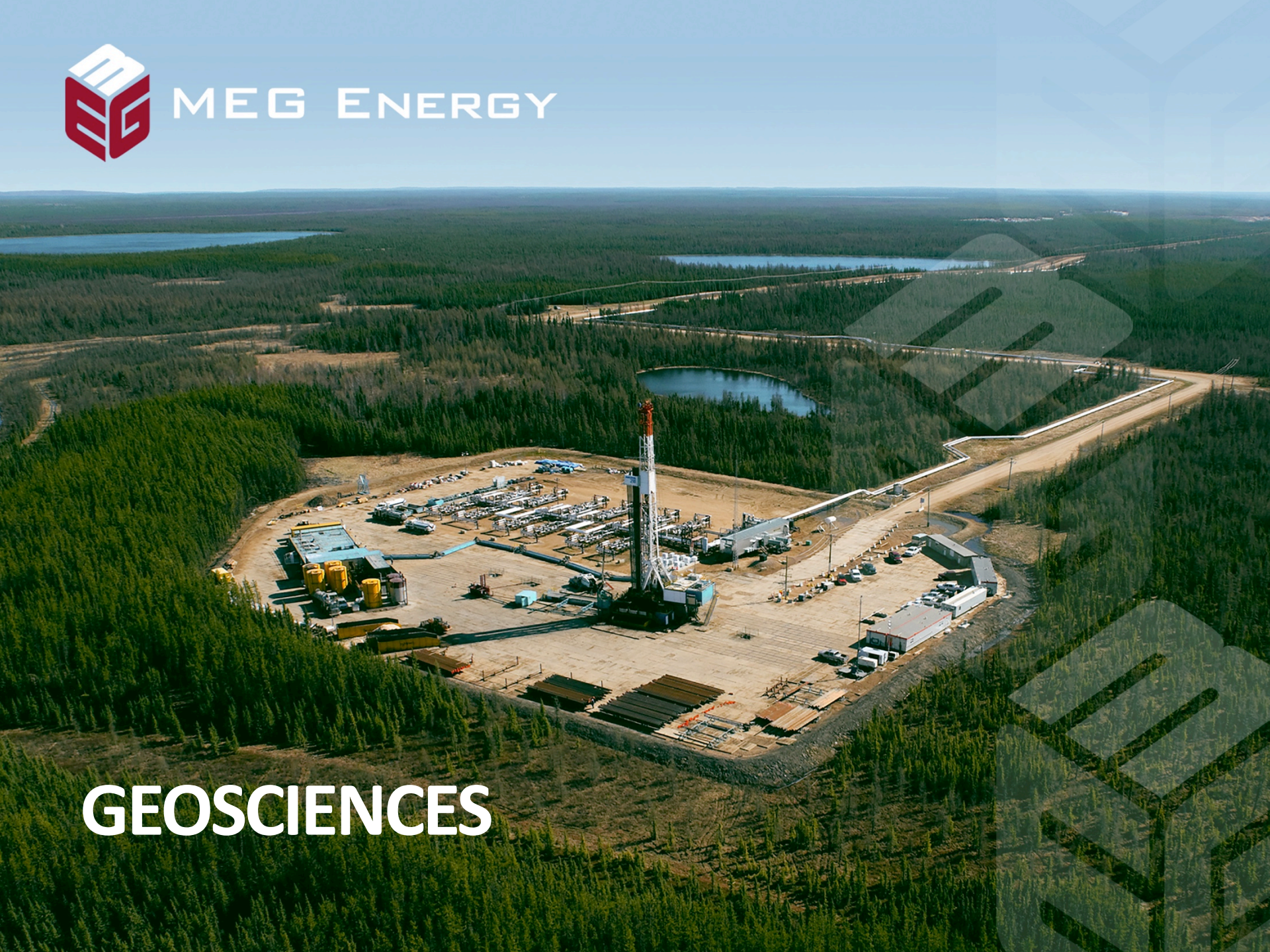
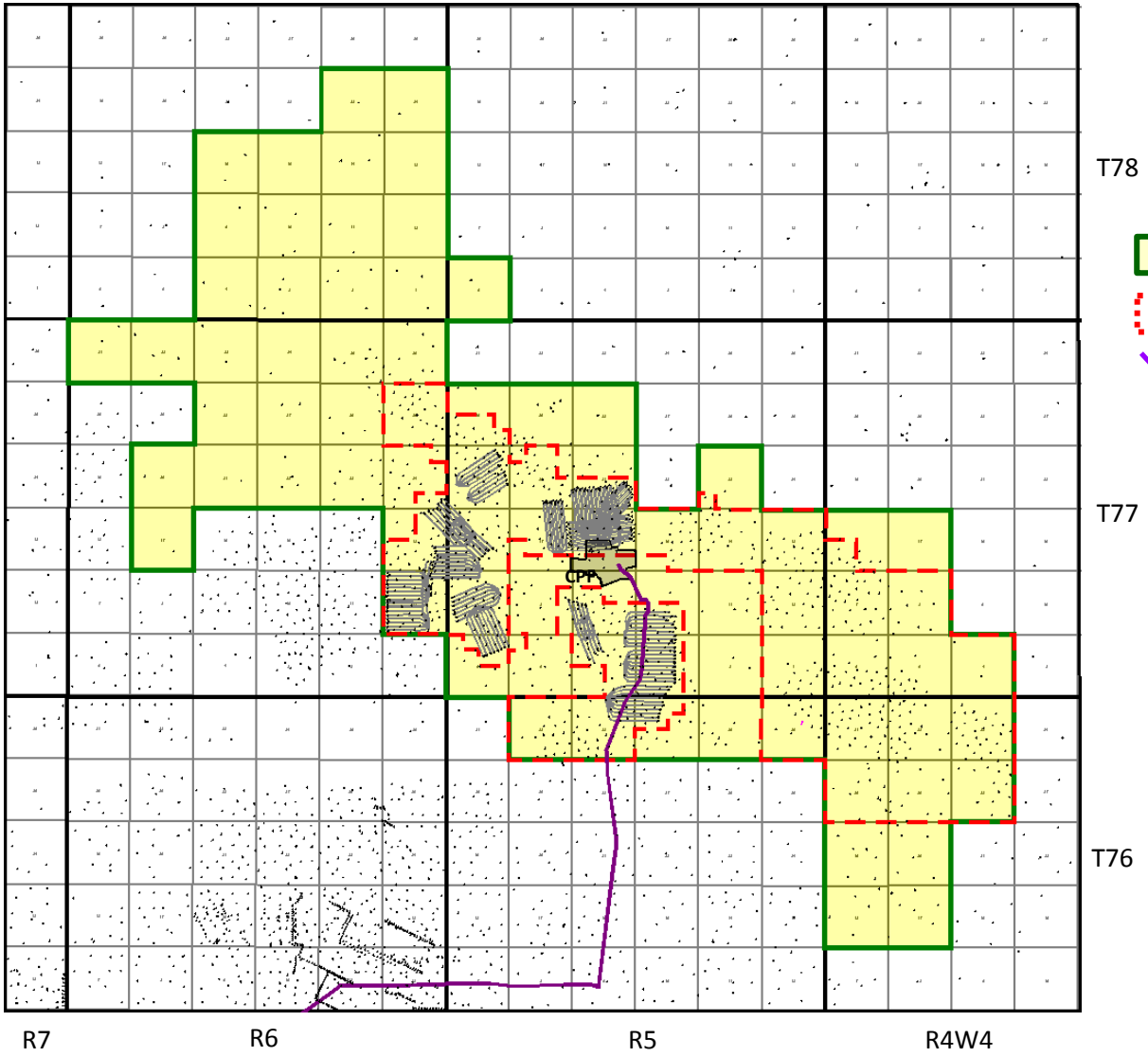


GEOSCIENCES

CLRP Geoscience Review

- Well and Seismic Data
  - Core hole update
  - 4-D Seismic Update
  - SAGD Drilling update
- Stratigraphic Framework
  - Geologic Overview
  - Type log
- Reservoir and Pay Parameters
- Active Development Area Bitumen Pay
  - Developable pay Isopach map
    - Approved undrilled pattern volumetrics
  - 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

Christina Lake Regional Project (CLRP)



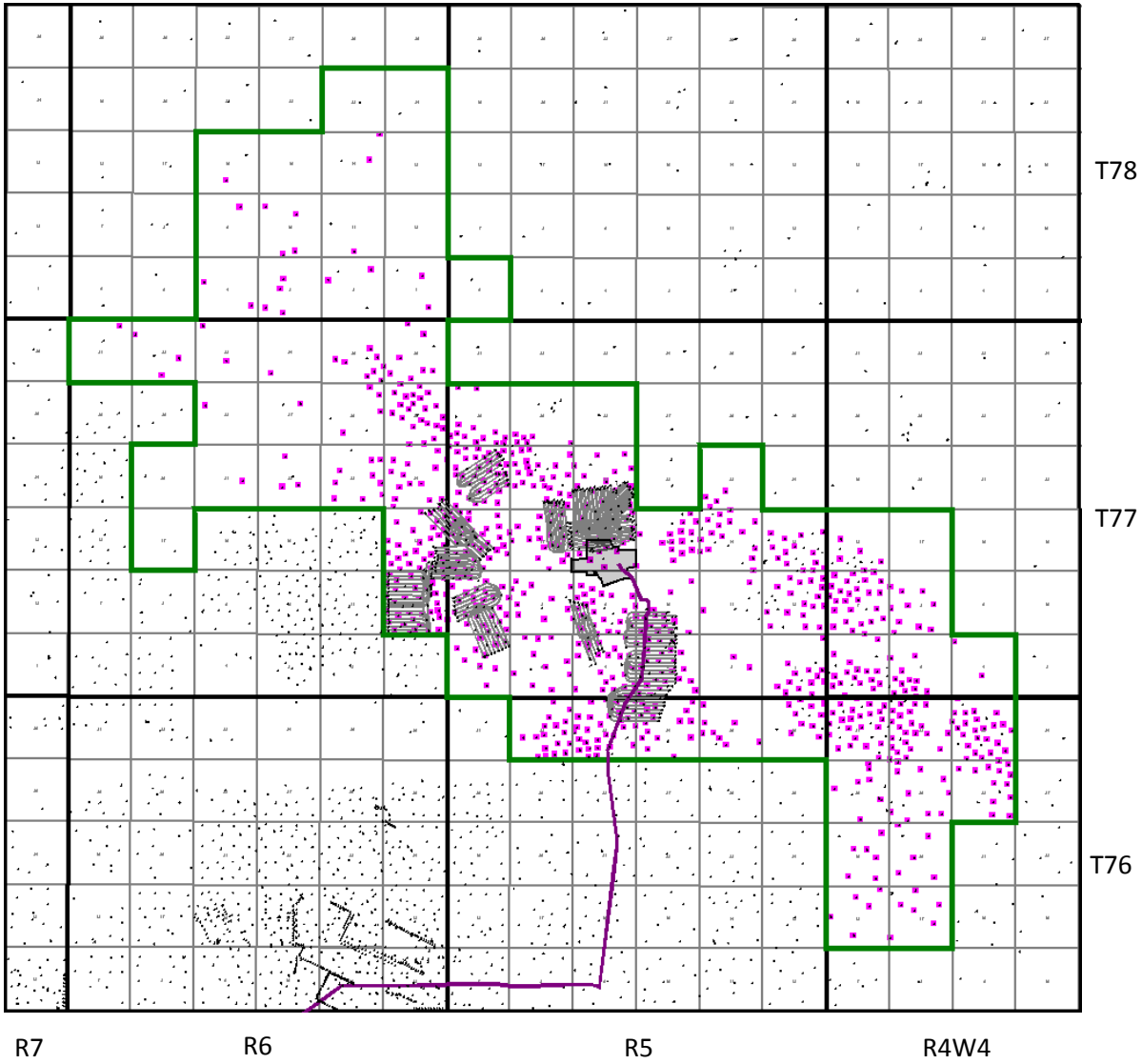
CLRP Project Area

Approved Development Areas

Access Pipeline

CPF = Central Plant Facility

CLRP Wabiskaw / McMurray Cores

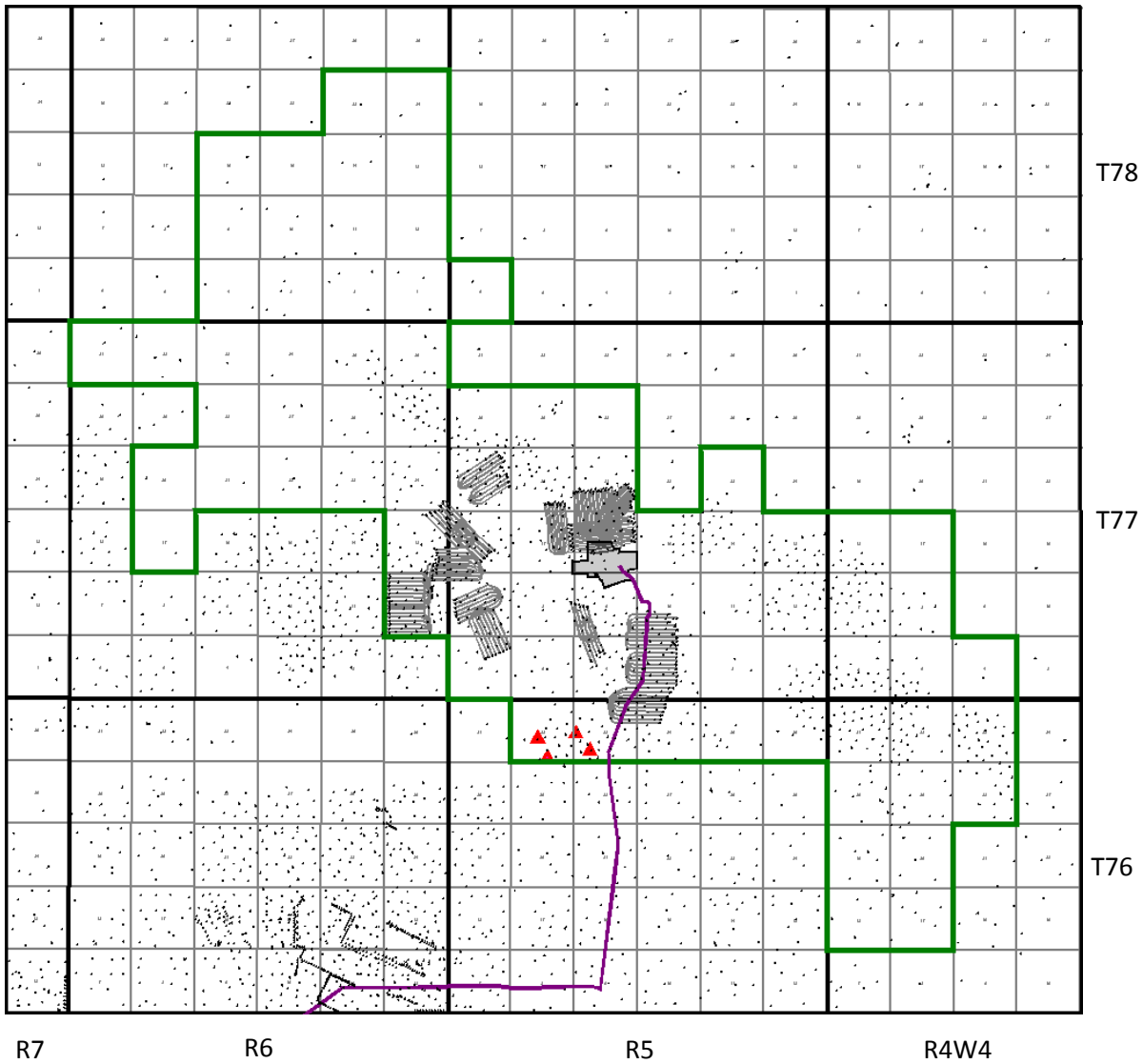


CLRP Project Area

Wabiskaw / McMurray Core

- 835 cored wells
- 86% of all wells are cored

CLRP 2016 Stratigraphic Test Wells



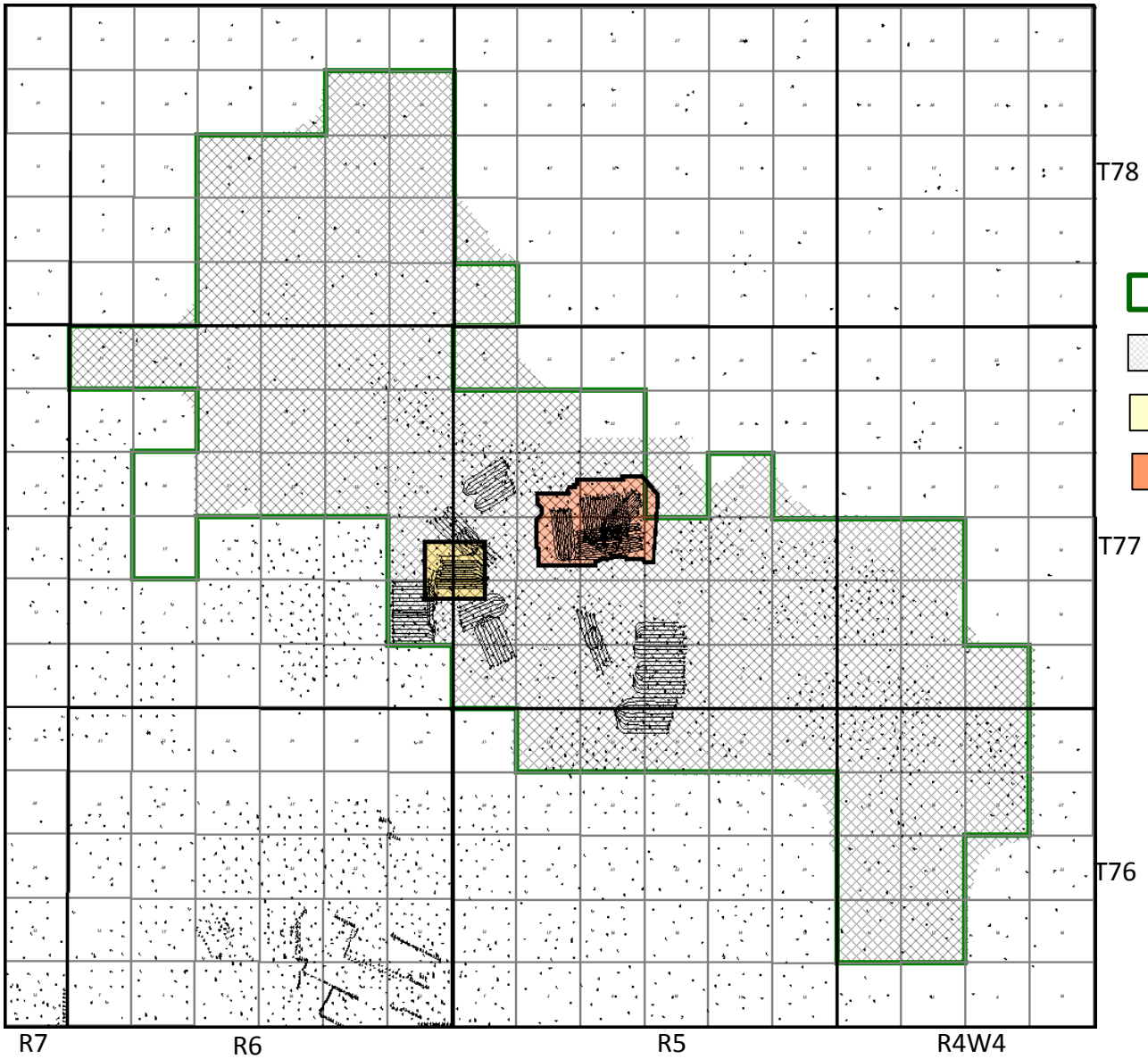
CLRP Project Area

2016 Wells

Over the 2016 reporting period

- 4 coreholes were drilled.
- No special core analysis was done.
- No GeoMechanical analysis was done.
- No reservoir Fracture pressure or Caprock Integrity tests were done.

CLRP 3D Seismic



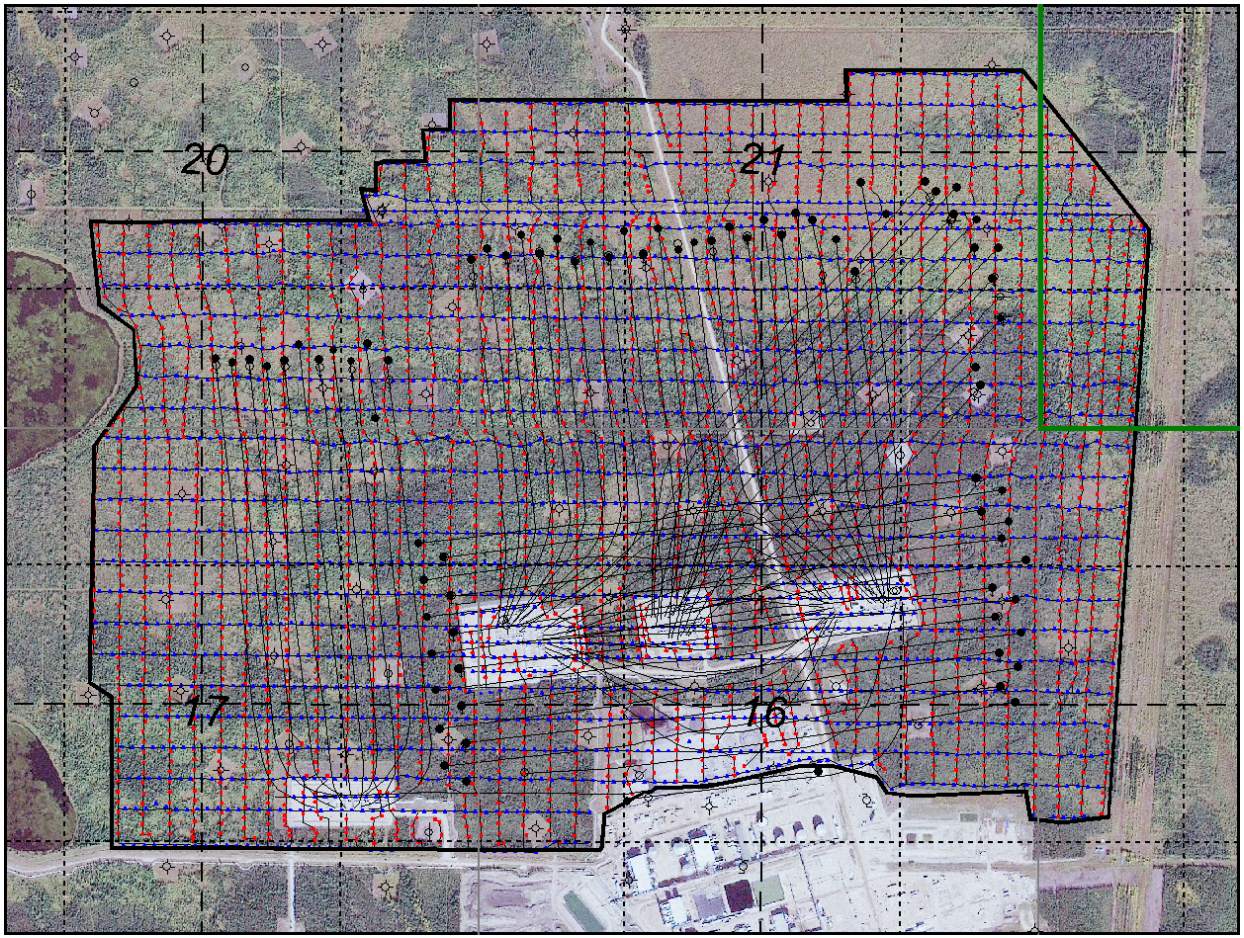
CLRP Project Area

3D Seismic

Time Lapse 3D (2014)

Time Lapse 3D (2016)

CLRP 4D Seismic



R5W4

MEG OSL

Time Lapse 3D (2016)

Shot Point

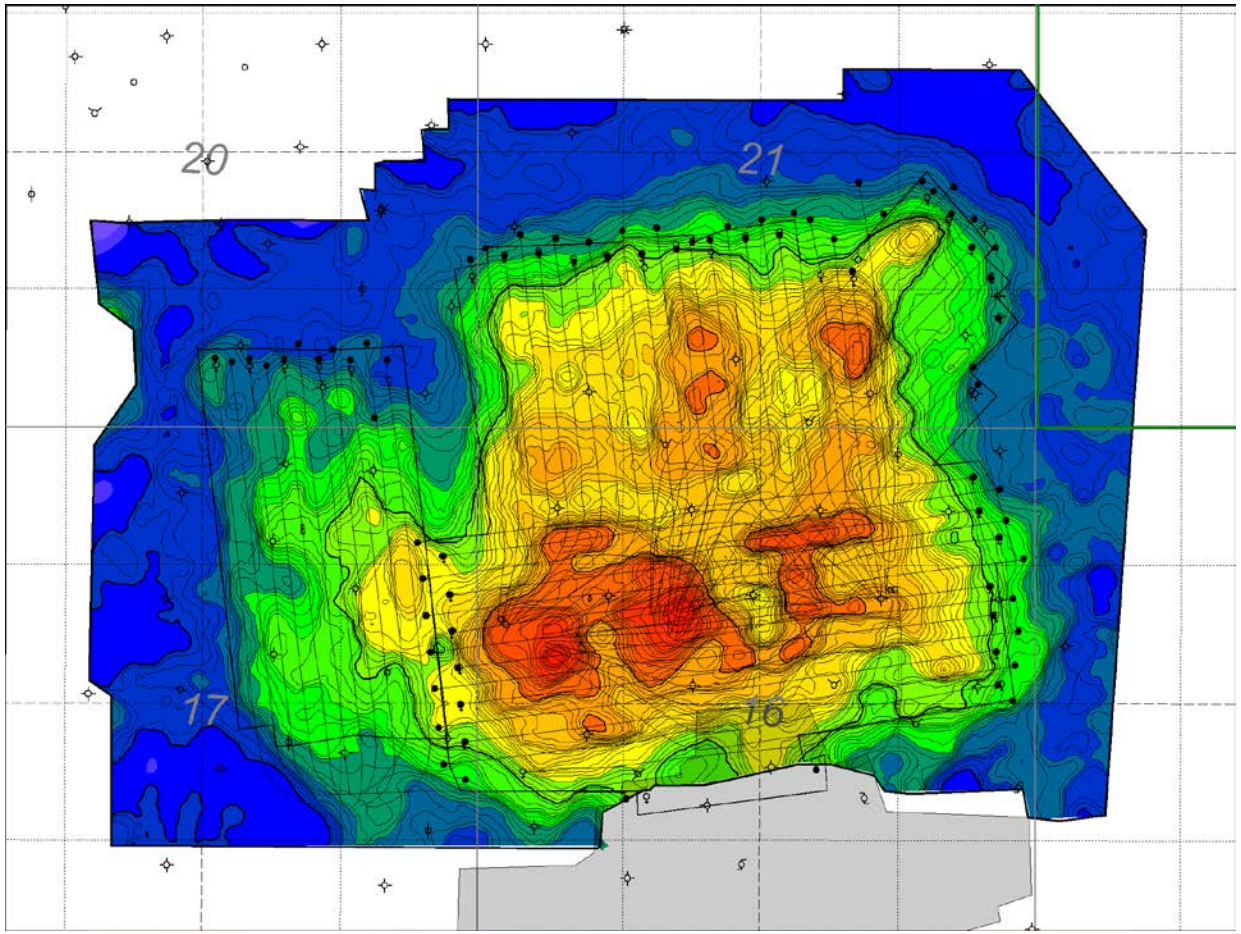
Receivers

T77

- Seismic was shot in January-February 2016 over a period of 7days.
- The shooting parameters involved 70m x 90m shot-receiver line spacing and 30m receiver and shot intervals.
- On the active surface pads, Vibroseis was used in lieu of the standard Dynamite source.

4D Seismic Survey

Paleozoic Time Delay Map



MEG OSL

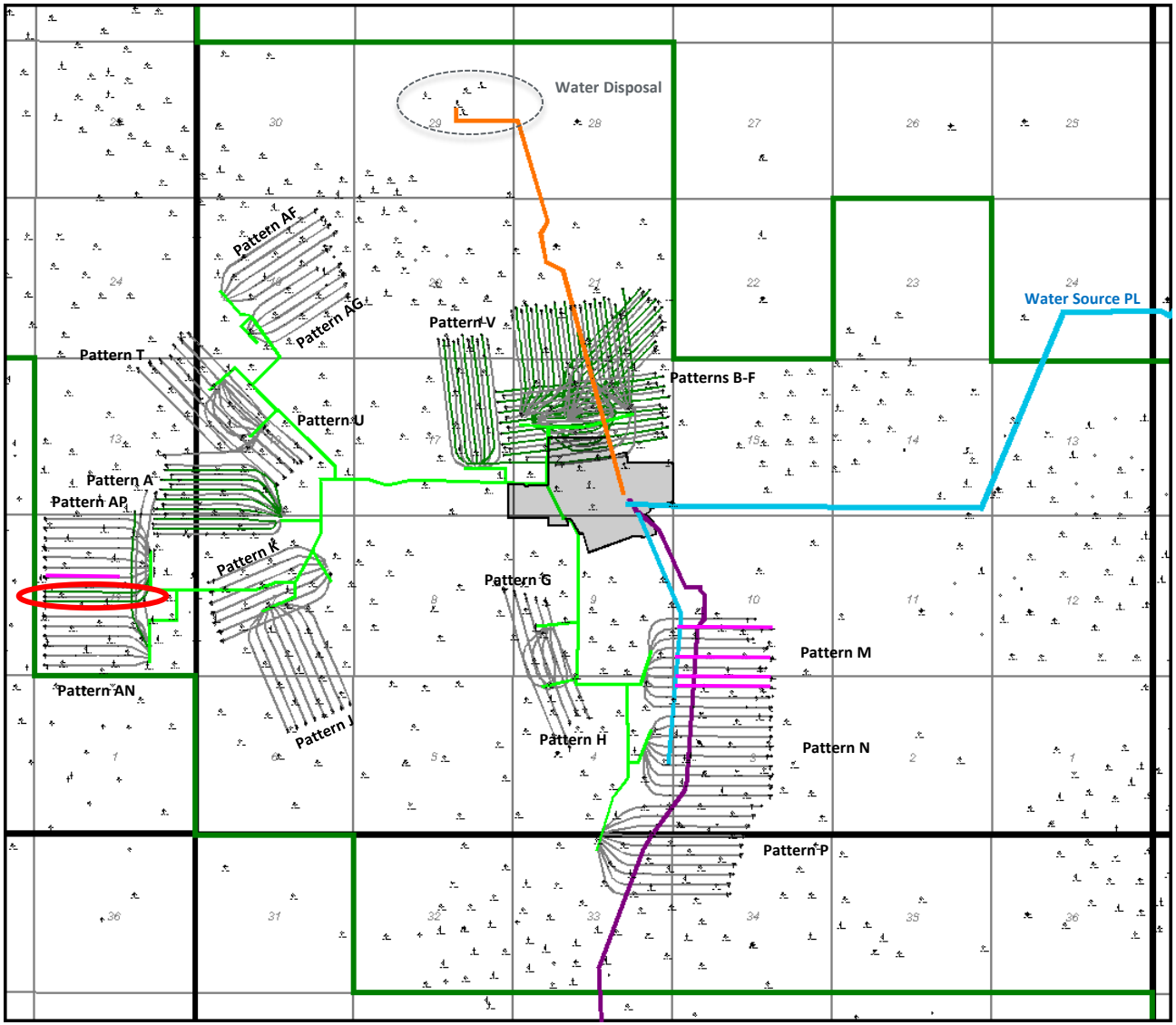
Central Plant

- Time delay of the Paleozoic time structure from Seismic shot before production (2007) and seismic shot in January 2016
- Time Delay is directly related to the level of steam chamber development

High

Low

CLRP Active Development Area (ADA)

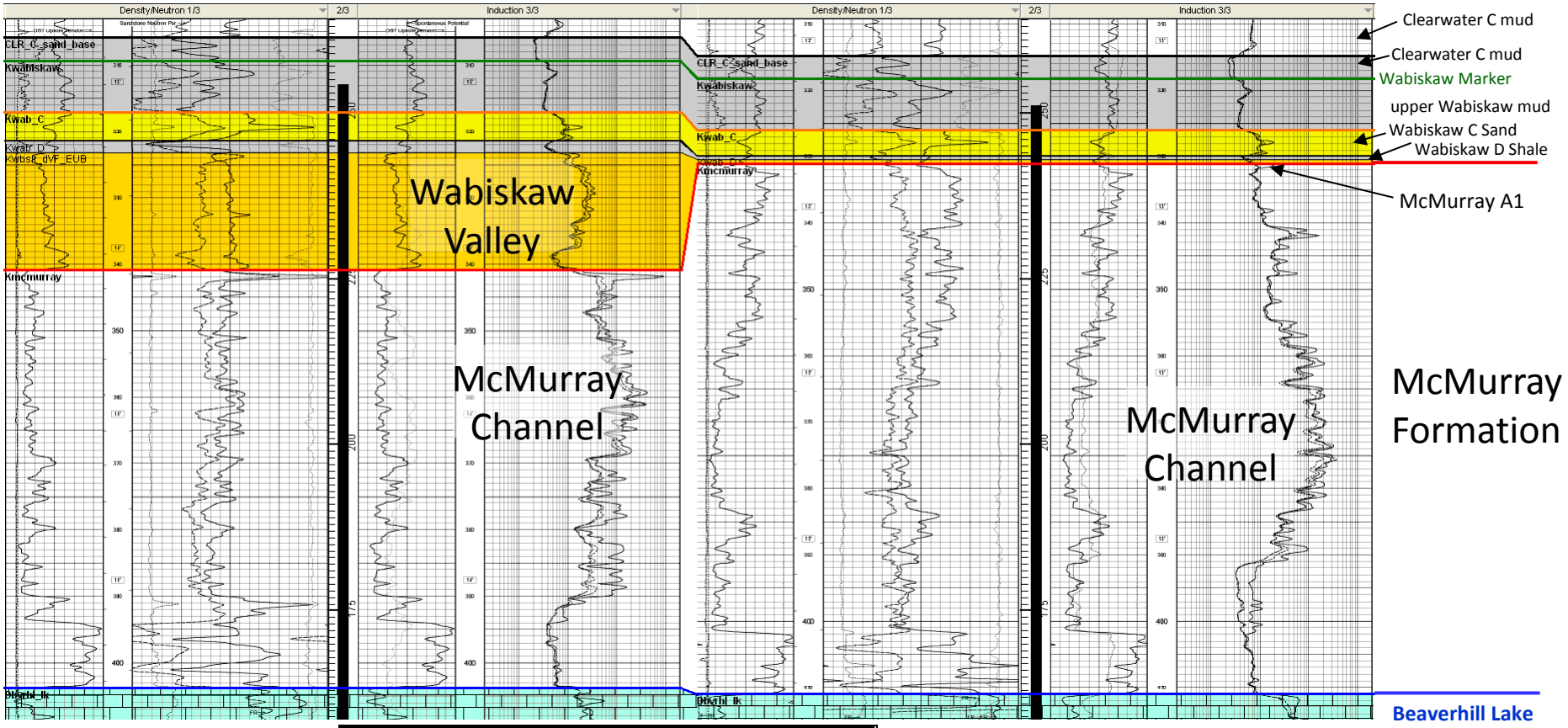


- MEG OSL
- Approved Development Area
- Central Plant
- Access Pipeline
- Emulsion Pipeline
- Disposal Pipeline
- **Water source Pipeline**
- **Recent Infill Drilling**
- **Recent SAGD Redrills**

334 horizontal wells
(SAGD & Infill wells)

CLRP: Wabiskaw/McMurray Stratigraphy

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

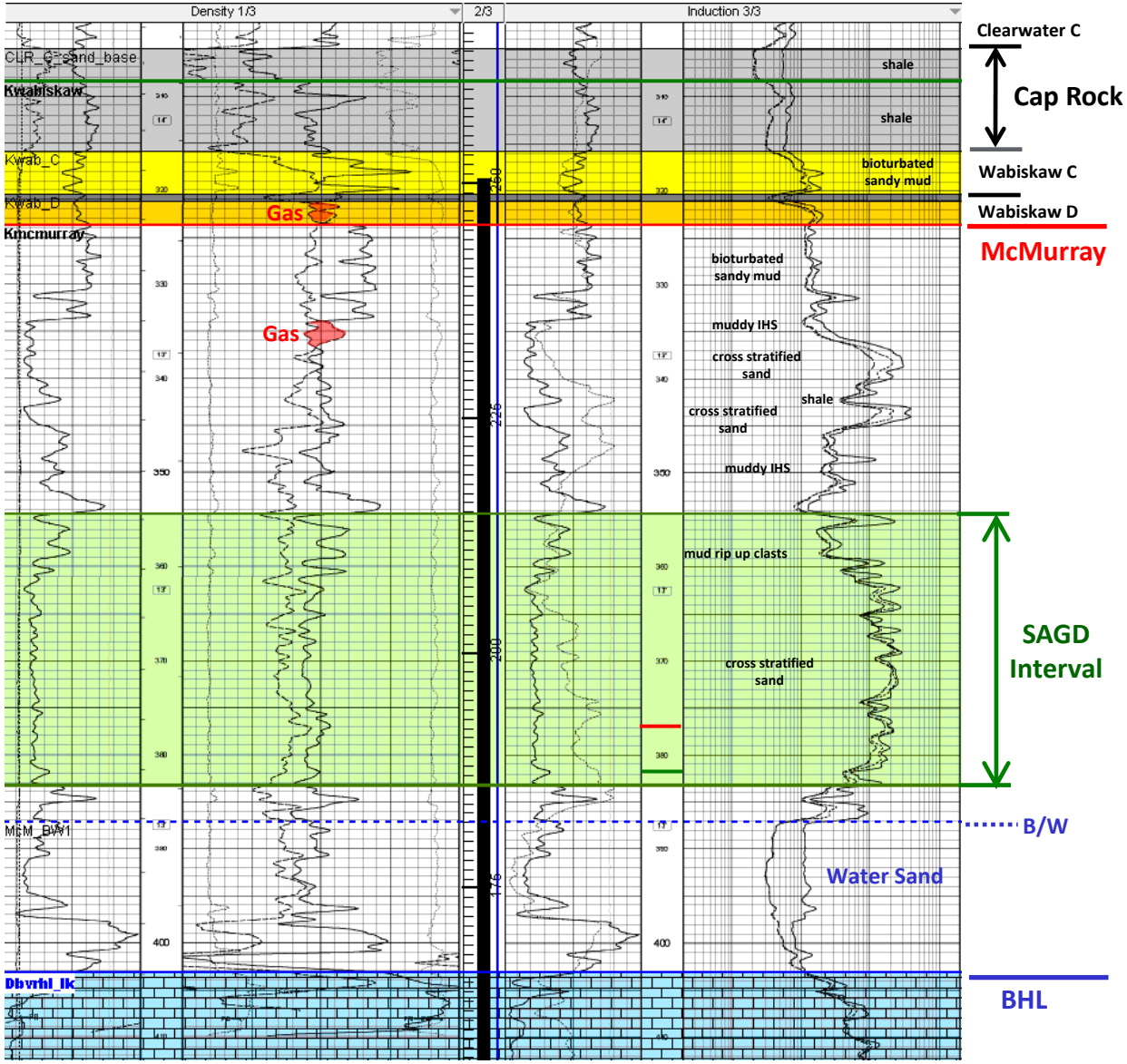


Stratigraphic Unit	Facies Association
lower Clearwater C	offshore mud
upper Wabiskaw	offshore / lower shoreface mud
Wabiskaw C	shoreface sand
Wabiskaw D Shale	bay mud
Wabiskaw D Valley	bay sand and mud
McMurray A1	shoreface sand / coal
upper McMurray Channel	tidal flat / creek sand and mud
lower McMurray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

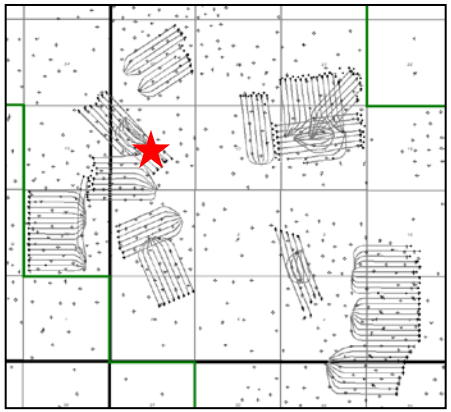
McMurray stratigraphy after ERCB RGS 2003

CLRP: 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

CLRP: 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

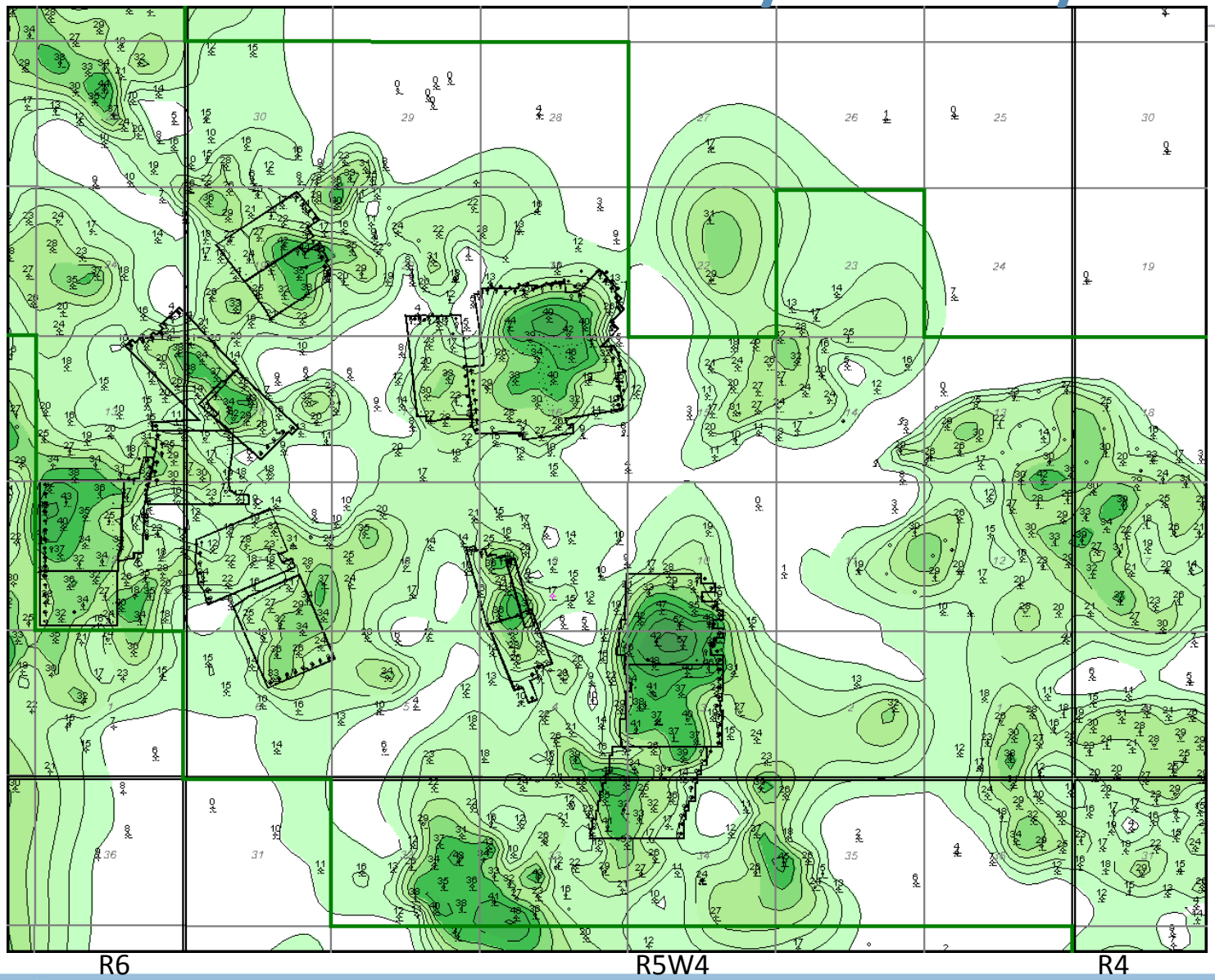
S_o (bitumen saturation) ≥ 50%

gas and coal excluded

CLRP: Average McMurray Reservoir Properties

Average pay (m)	18.7
Average depth to reservoir top (m TVD)	359
Average porosity (frac)	0.32
Average Sw (frac)	0.25
Average K_h (Darcies)	5,000
Average K_v (Darcies)	2,500
Initial reservoir pressure (kPag)	2,100
Reservoir temperature (°c)	13

CLRP ADA Total McMurray SAGD Pay ≥ 10 m



CLRP Project Area

SAGD Patterns

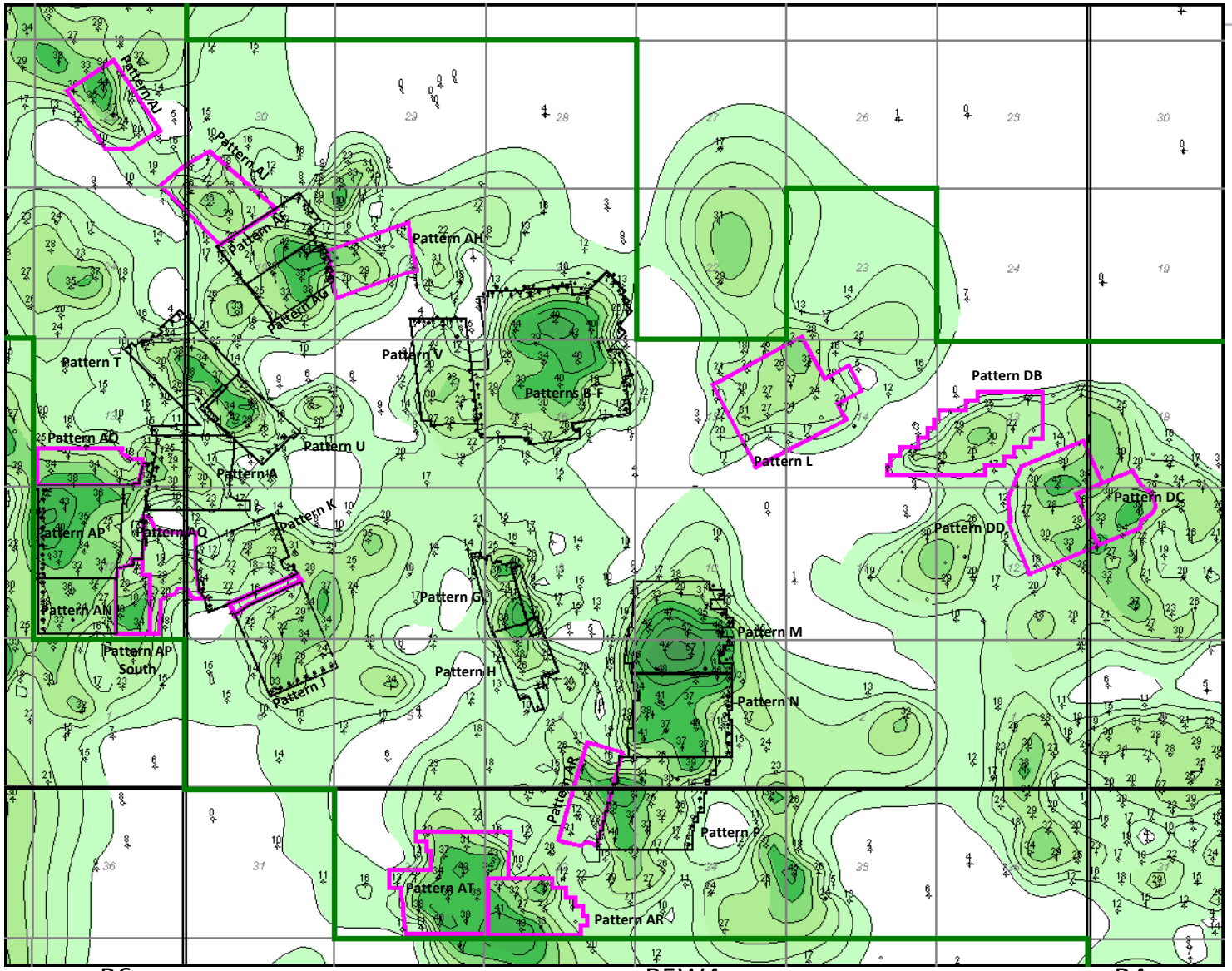
SAGD Pay Cutoffs:

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

min contour =10m

contour interval = 5 m

CLRP: OBIP Approved Development Areas



R6 R5W4 R4

CLRP Project Area

SAGD Patterns

Approved Patterns

T77

SAGD Pay Cutoffs:

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

T76

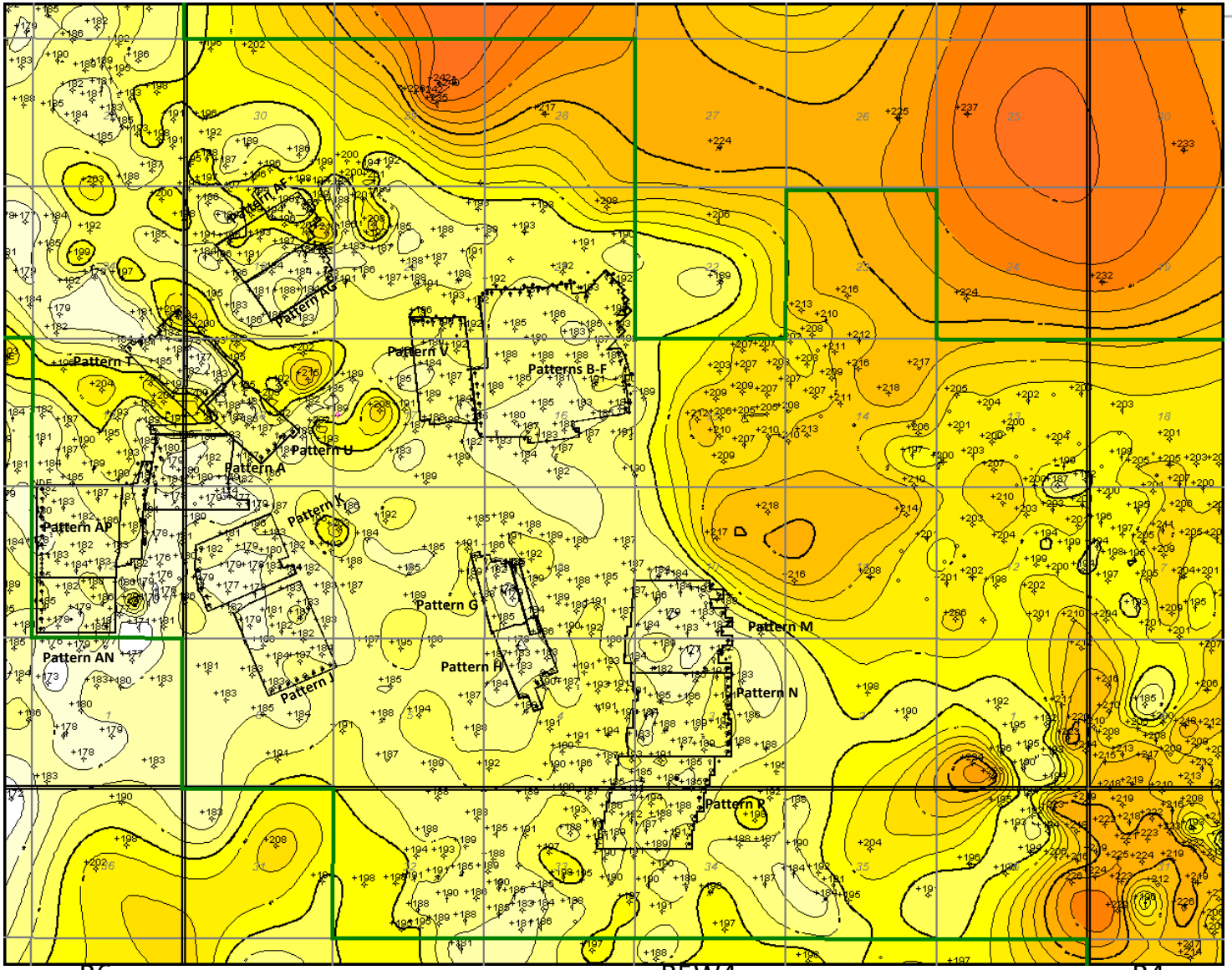
min contour =10m

contour interval = 5 m

CLRP: OBIP Approved Development Areas

OBIP Volumetrics for approved undrilled pads				
Pattern	Avg H	Avg Ø	Avg S_o	OBIP (bbl)
AQ North	25.9	33.3%	82.0%	18,683,000
AQ South	16.9	33.7%	79.0%	12,652,000
AP South	21.6	33.5%	80.5%	9,088,000
AJ North	216	32.6%	79.1%	18,393,000
AJ South	18.8	31.9%	81.3%	17,480,000
AH	19.6	31.8%	73.1%	13,600,000
K	15.6	32.6%	69.6%	1,679,000
AT	20.8	31.6%	78.4%	29,531,000
AR South	22.5	31.3%	76.1%	17,805,000
AR North	18	30.7%	73.7%	11,007,000
L	22	32.7%	76.1%	39,644,000
DB	23.7	32.8%	68.8%	31,789,000
DD	27.1	32.7%	72.4%	37,731,000
DC	29.7	32.7%	72.6%	18,626,000

CLRP ADA Base SAGD Pay Structure



CLRP Project Area

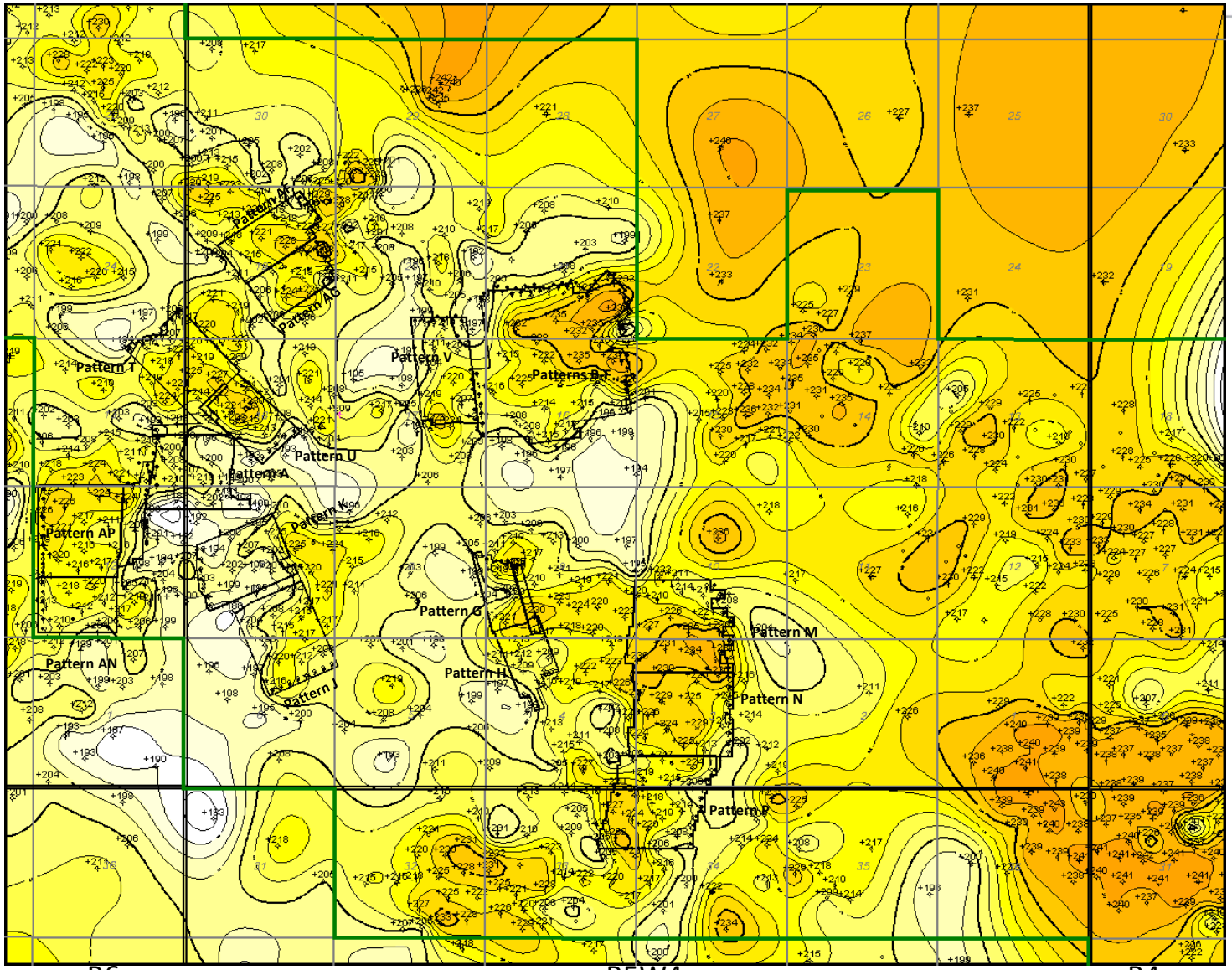
SAGD Patterns

T77

T76

contour interval = 5 m

CLRP ADA Top SAGD Pay Structure



CLRP Project Area

SAGD Patterns

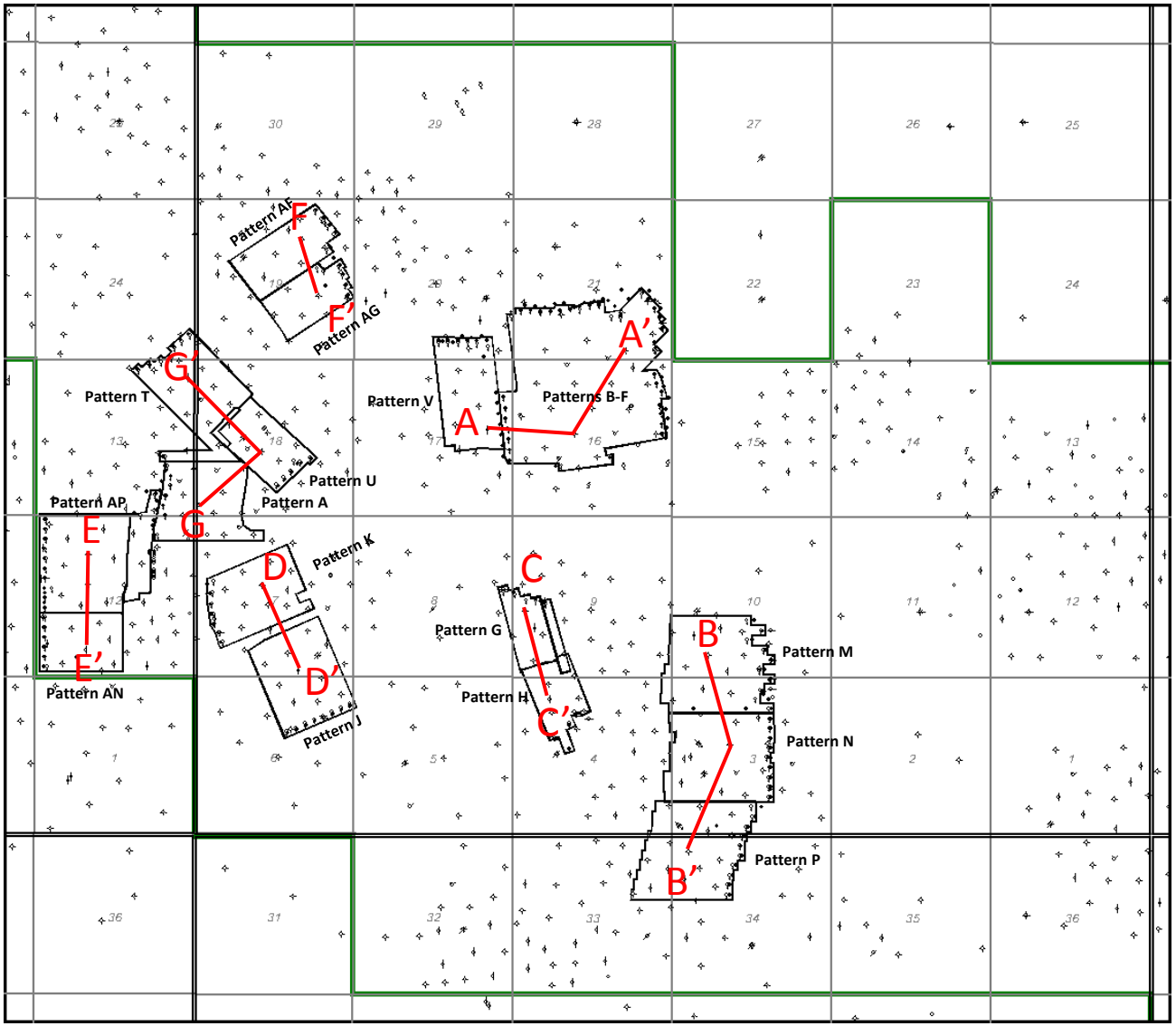
T77

contour interval = 5 m

T76

R6 R5W4 R4

CLRP: Cross Sections for scheme area



CLRP Project Area

SAGD Patterns

CLRP: Structural Cross Section A-A’

A

111/09-17-77-05W4

1AB/11-16-77-05W4

1AA/02-21-77-05W4

A’

Clearwater C

Cap Rock

Wabiskaw C

Wabiskaw Marker

Wabiskaw C Sand

Top McMurray

non-reservoir lithofacies

SAGD pay

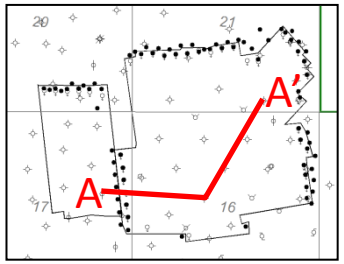
Water Sand

McMurray Formation

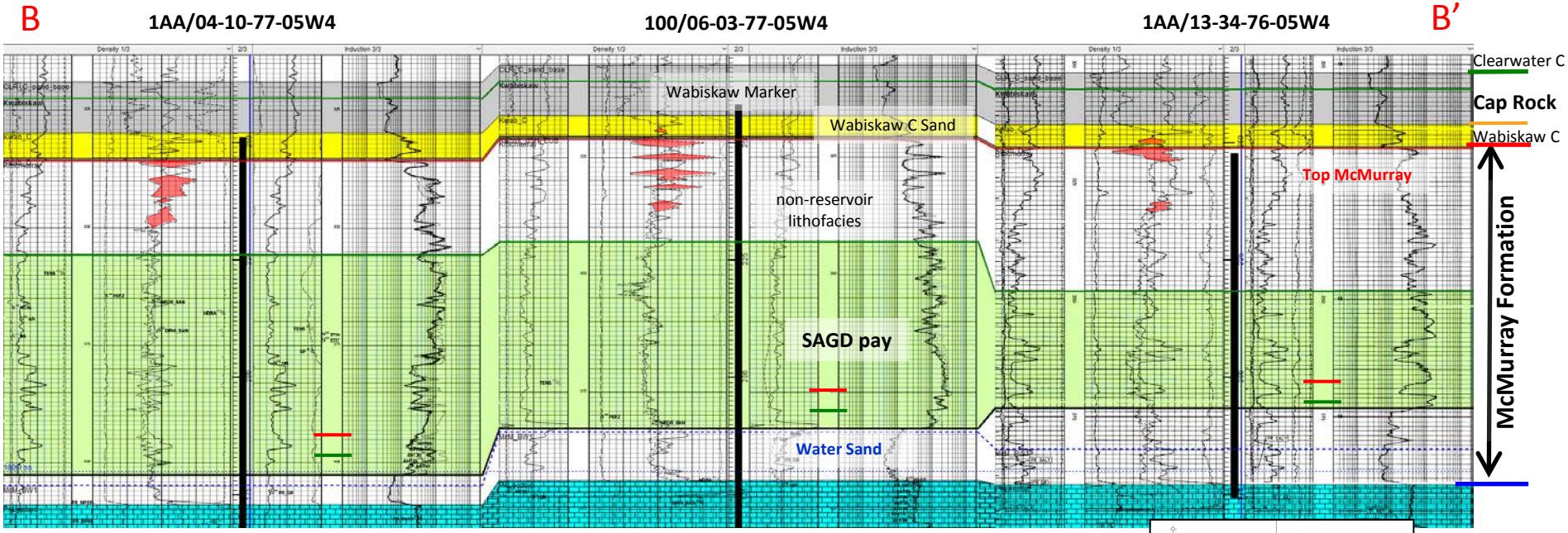
Injector

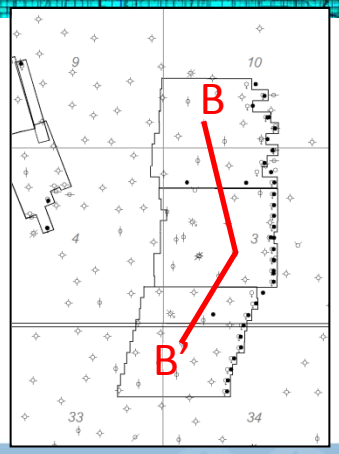
Producer

Stacked Pattern Development (Multiple Pay Intervals)



CLRP: Structural Cross Section B-B’

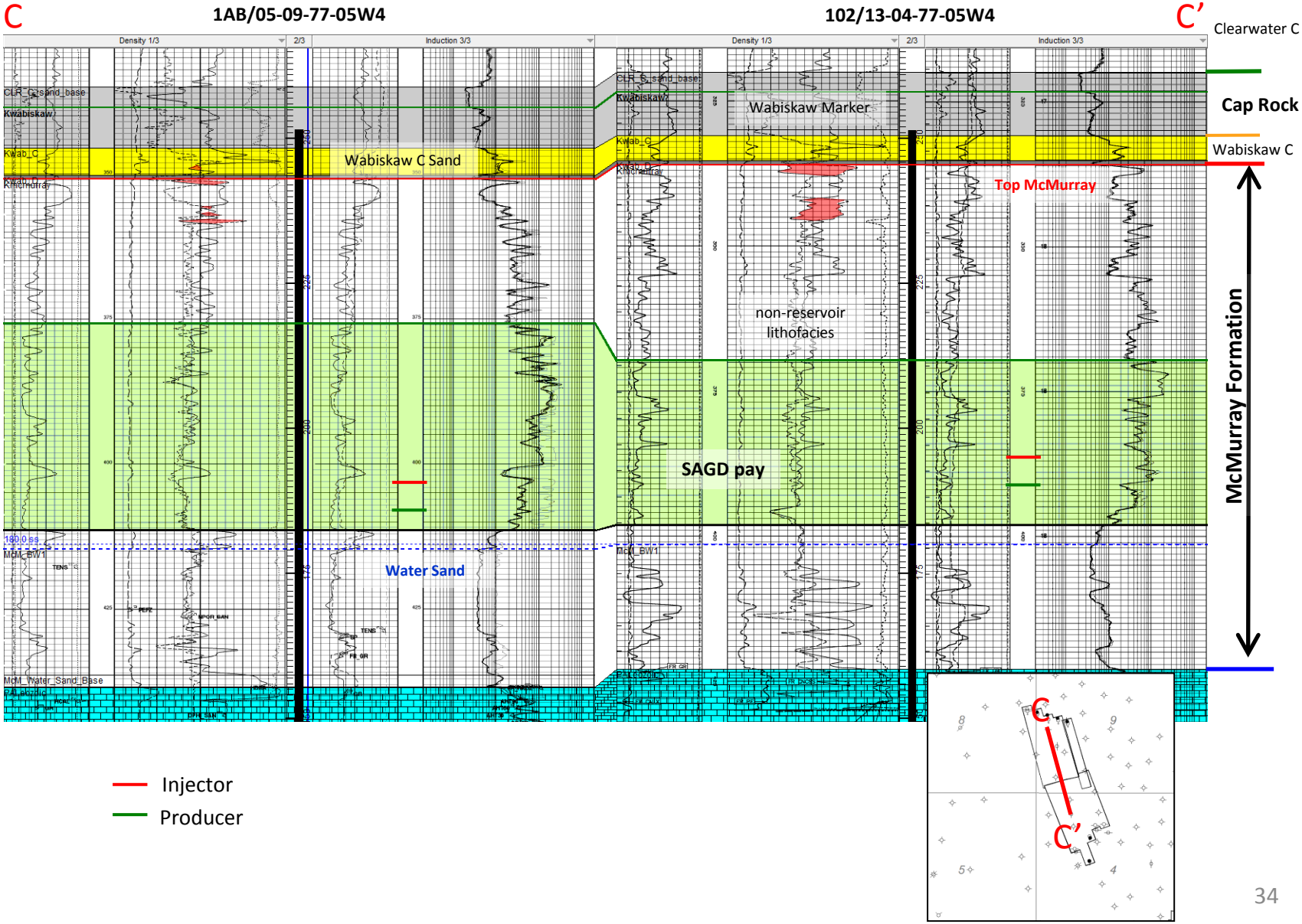




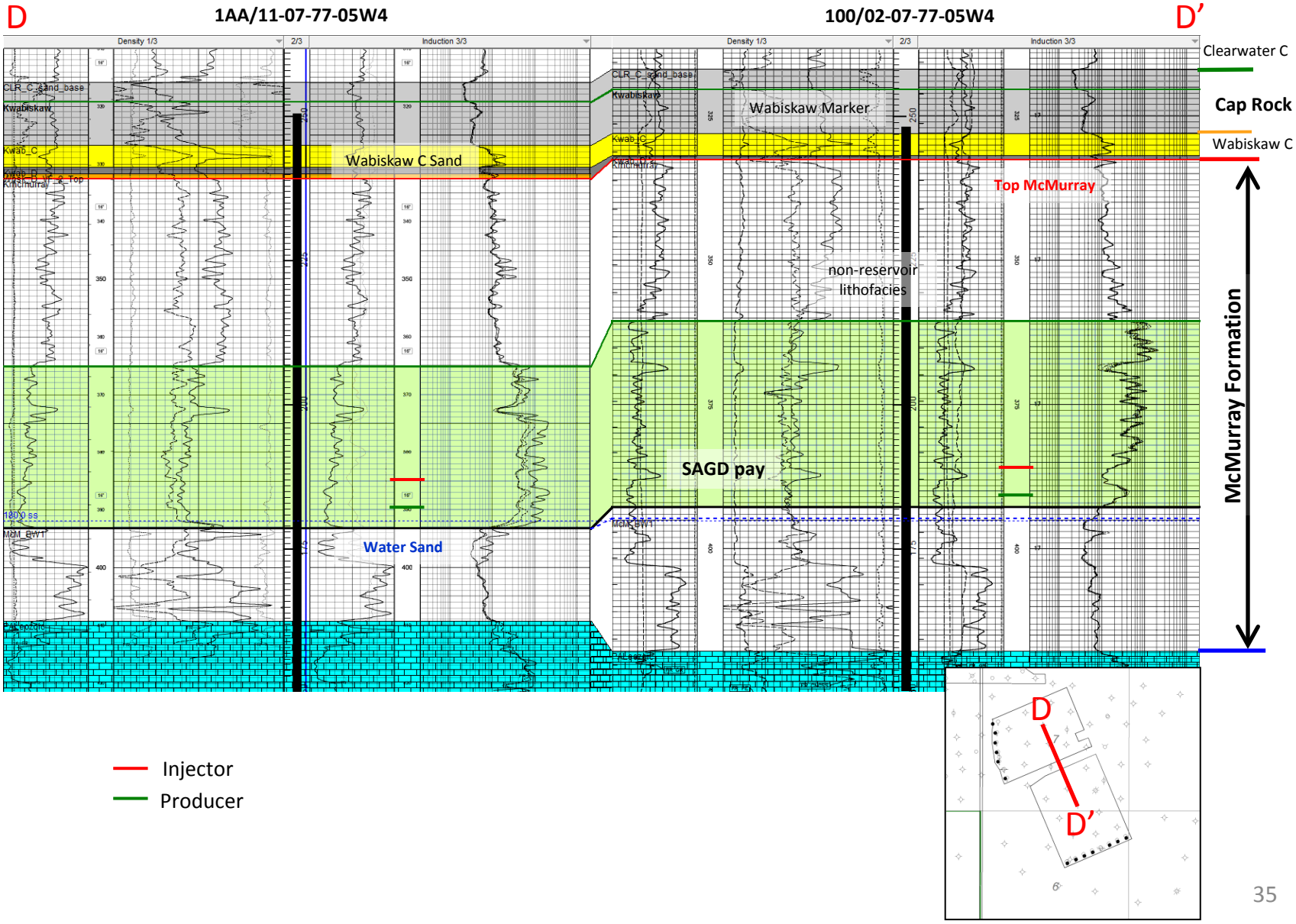
Injector

Producer

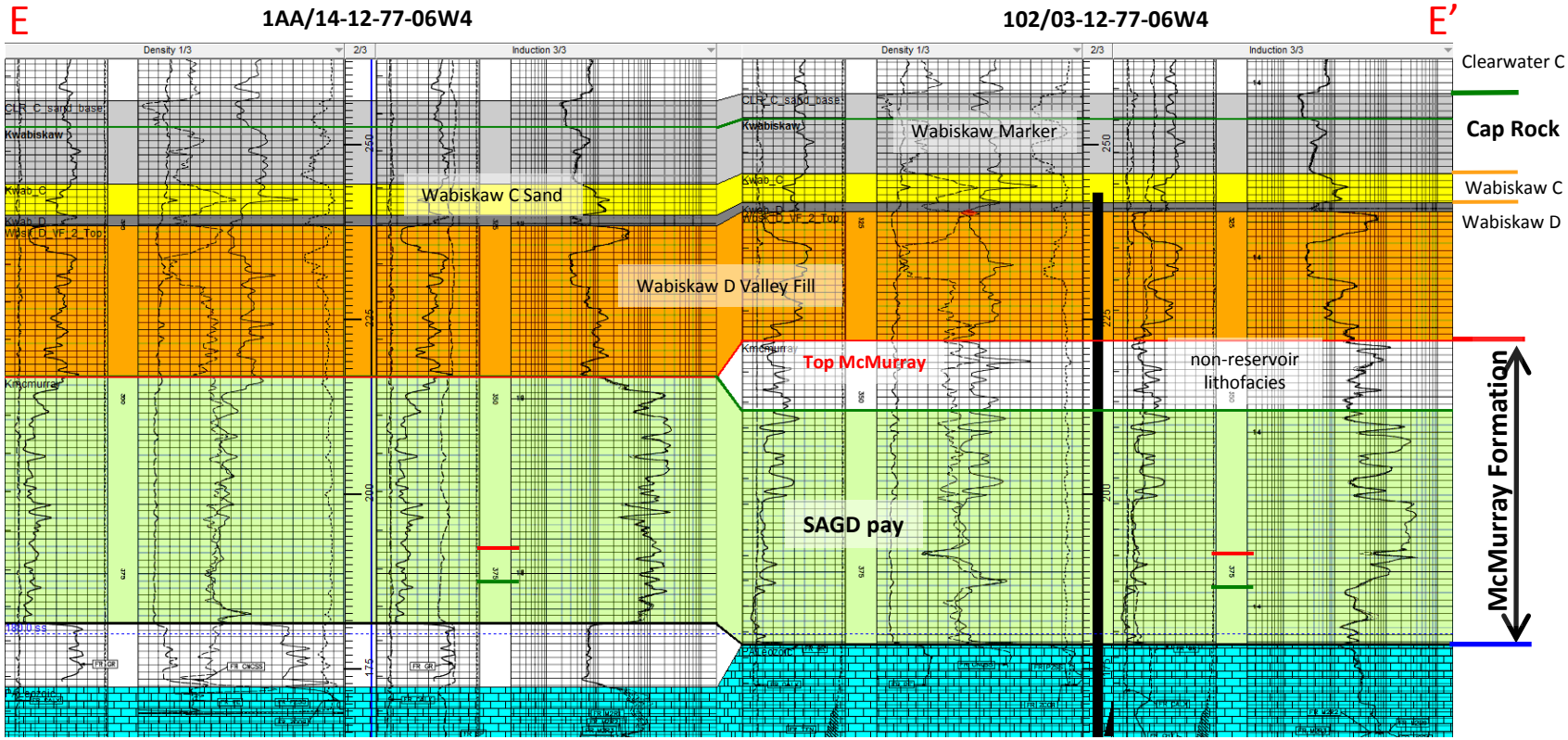
CLRP: Structural Cross Section C-C’

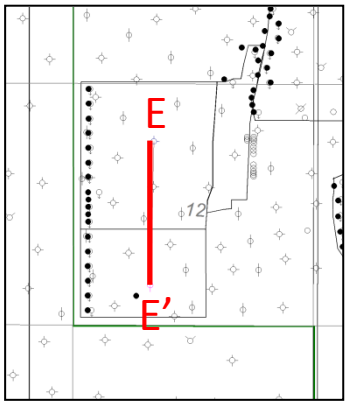


CLRP: Structural Cross Section D-D’



CLRP: Structural Cross Section E-E’

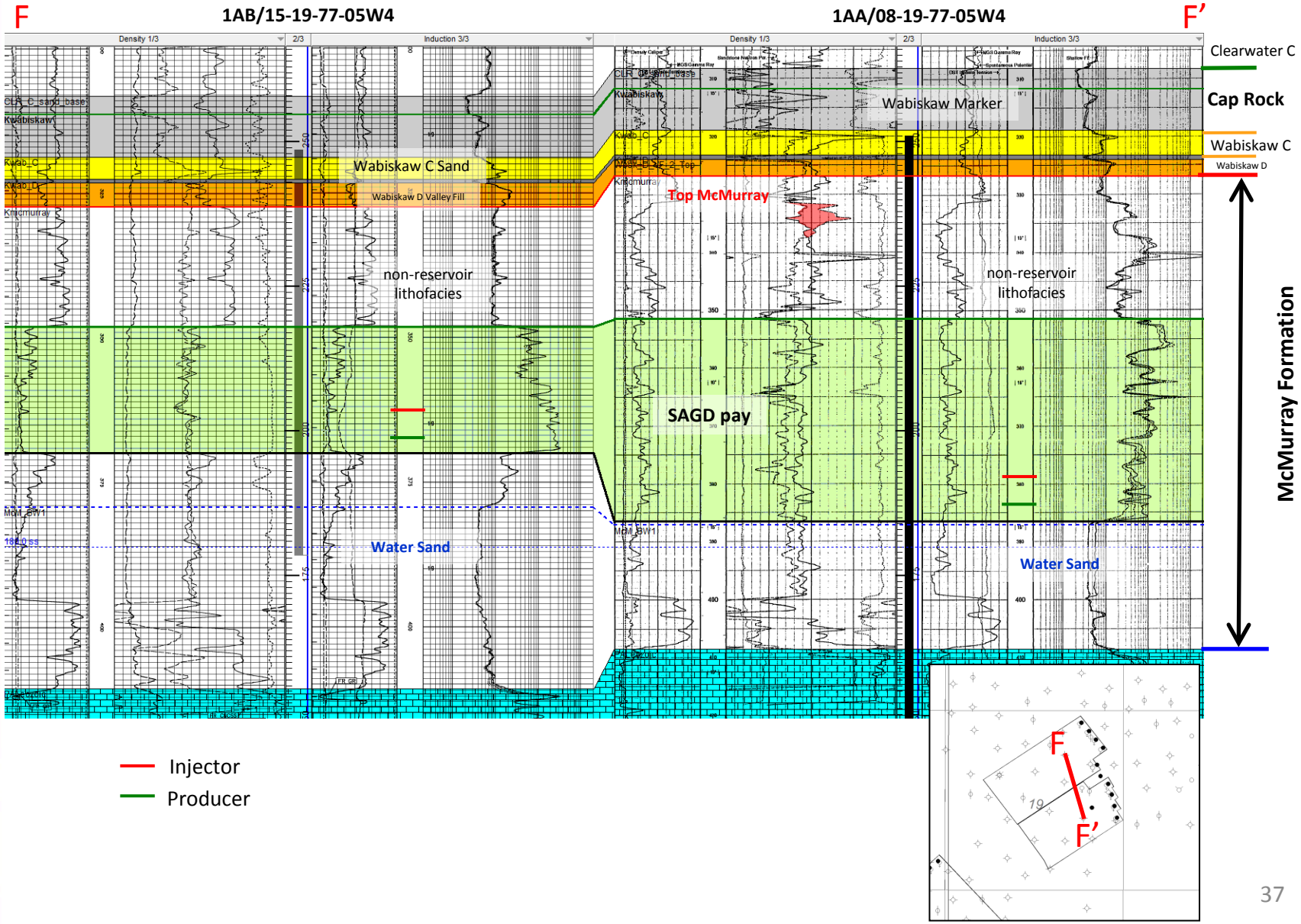




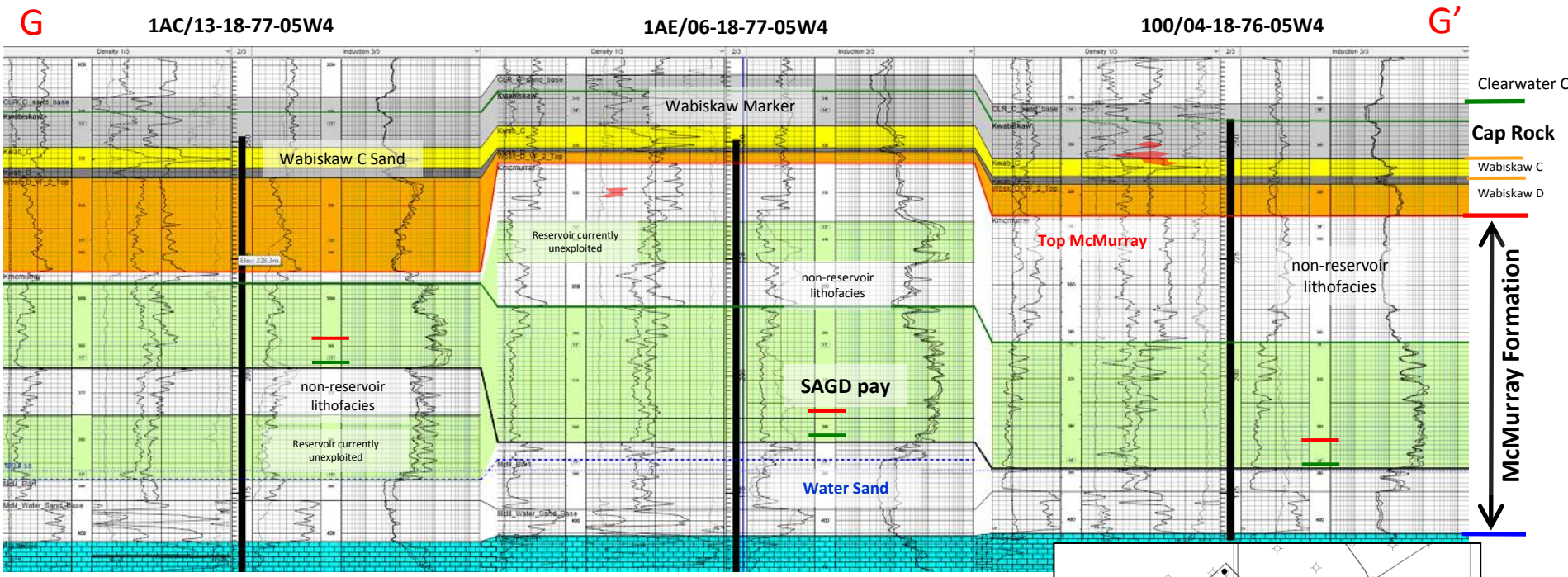
Injector

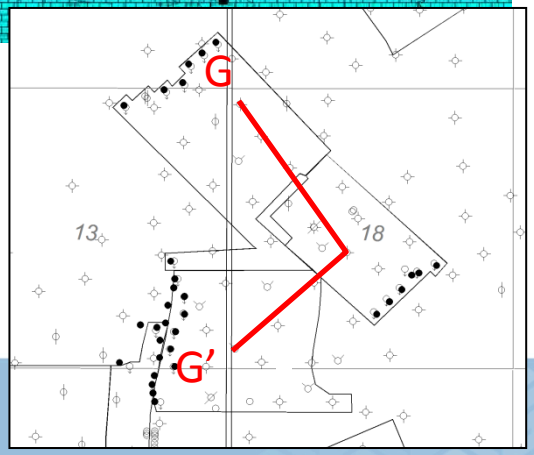
Producer

CLRP: Structural Cross Section F-F’



CLRP: Structural Cross Section G-G’



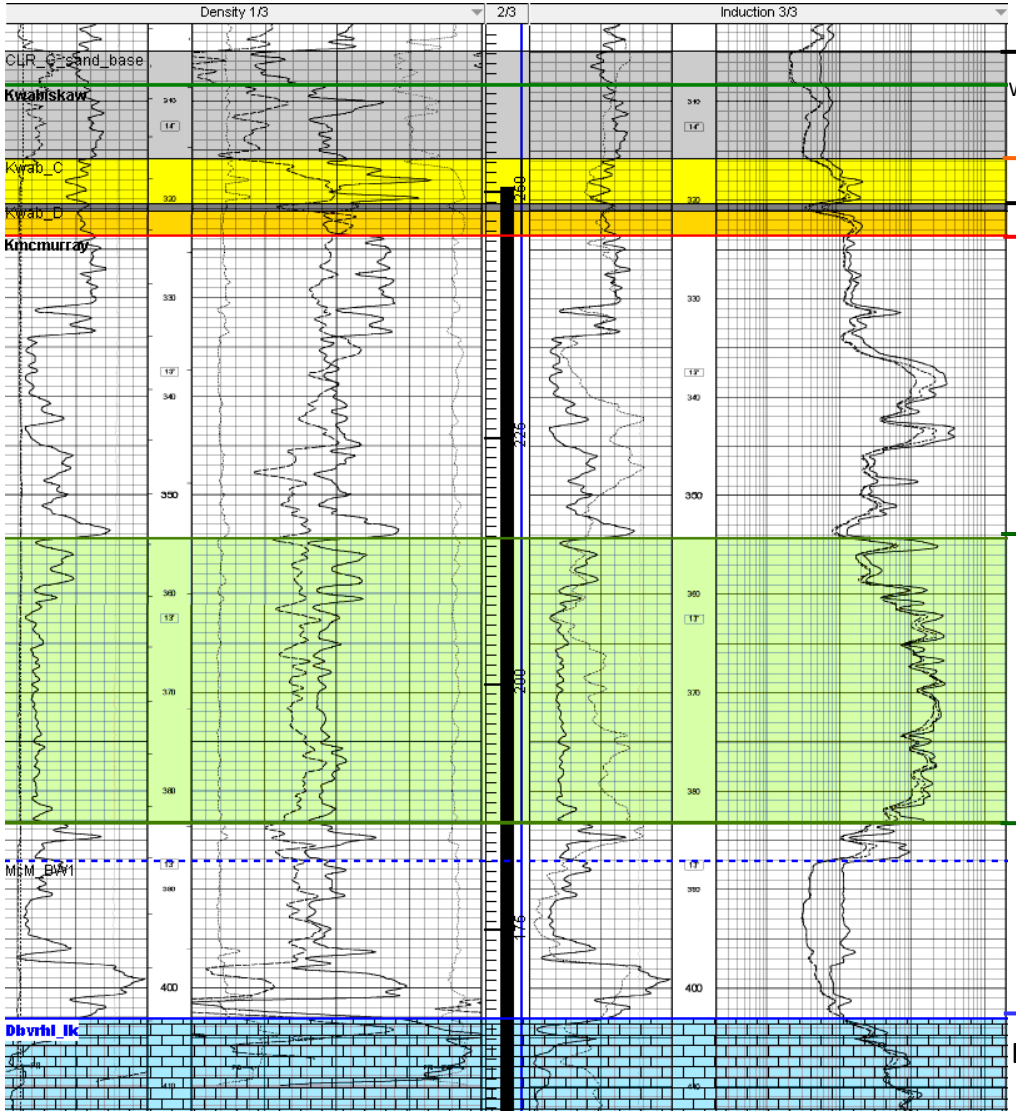


Injector

Producer

CLRP 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

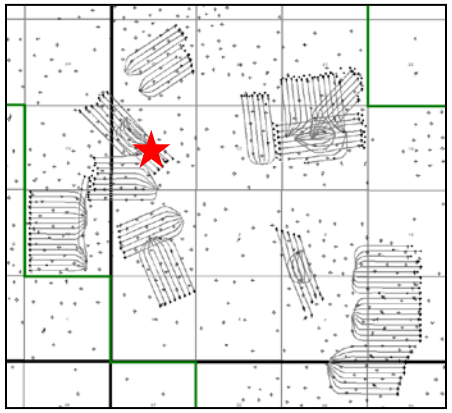
Lower Clearwater Cap Rock = 10.9 m thick

SAGD Pay

Bitumen / Water Contact

Water Sand

Beaverhill Lake



CLRP ADA Lower Clearwater Cap Rock

CLRP Project Area

Drilled SAGD Patterns

T77

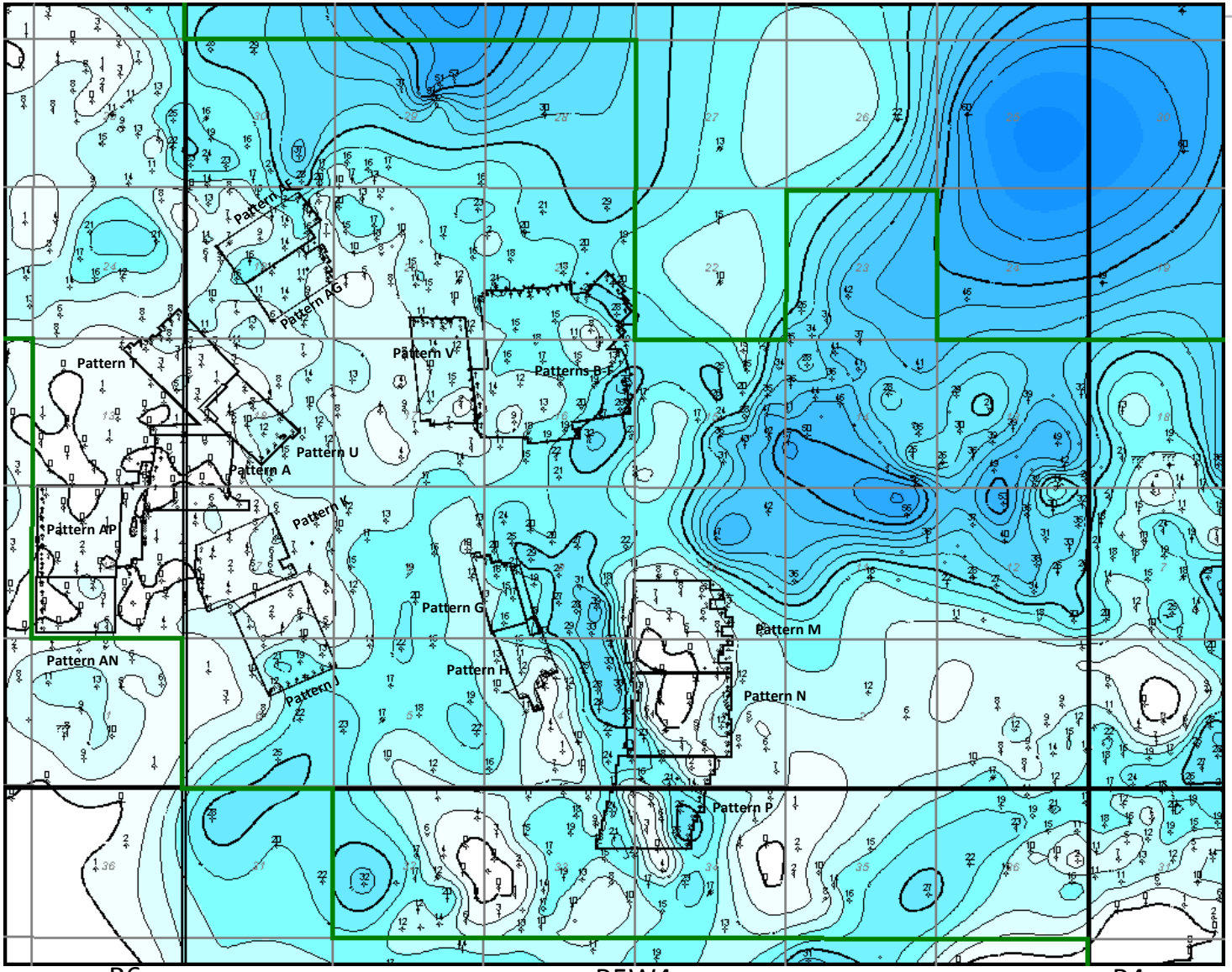
Active Development Area
Average Cap rock Thickness = 10.7 m
Minimum Thickness = 8.5 m
Maximum Thickness = 12.3 m

Thickness in Metres

T76

R6 R5W4 R4

CLRP ADA Basal McMurray Net Water Isopach



CLRP Project Area

Drilled SAGD Patterns

T77

T76

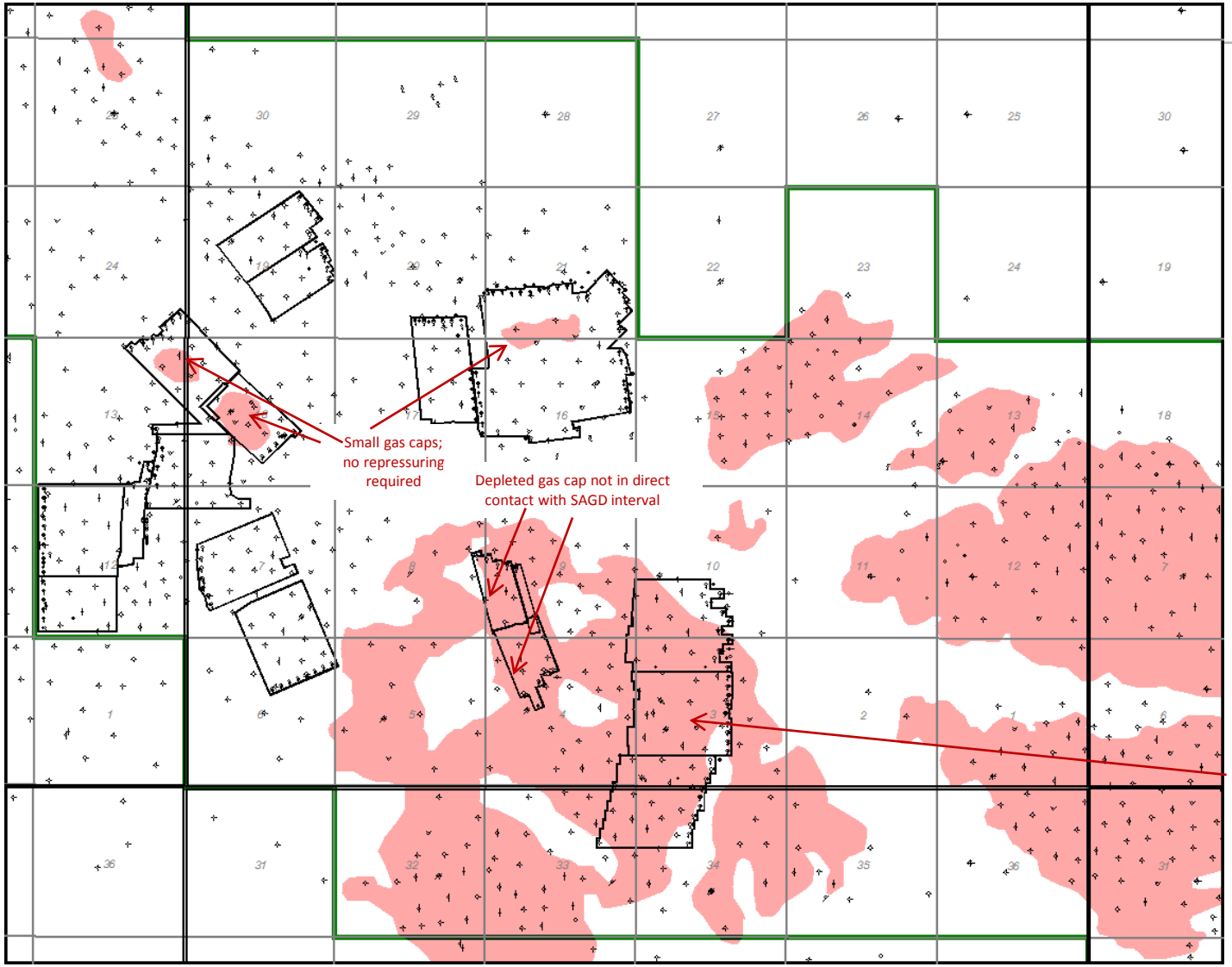
Contour Interval = 5 m

R6

R5W4

R4

CLRP ADA Associated McMurray Gas Pools



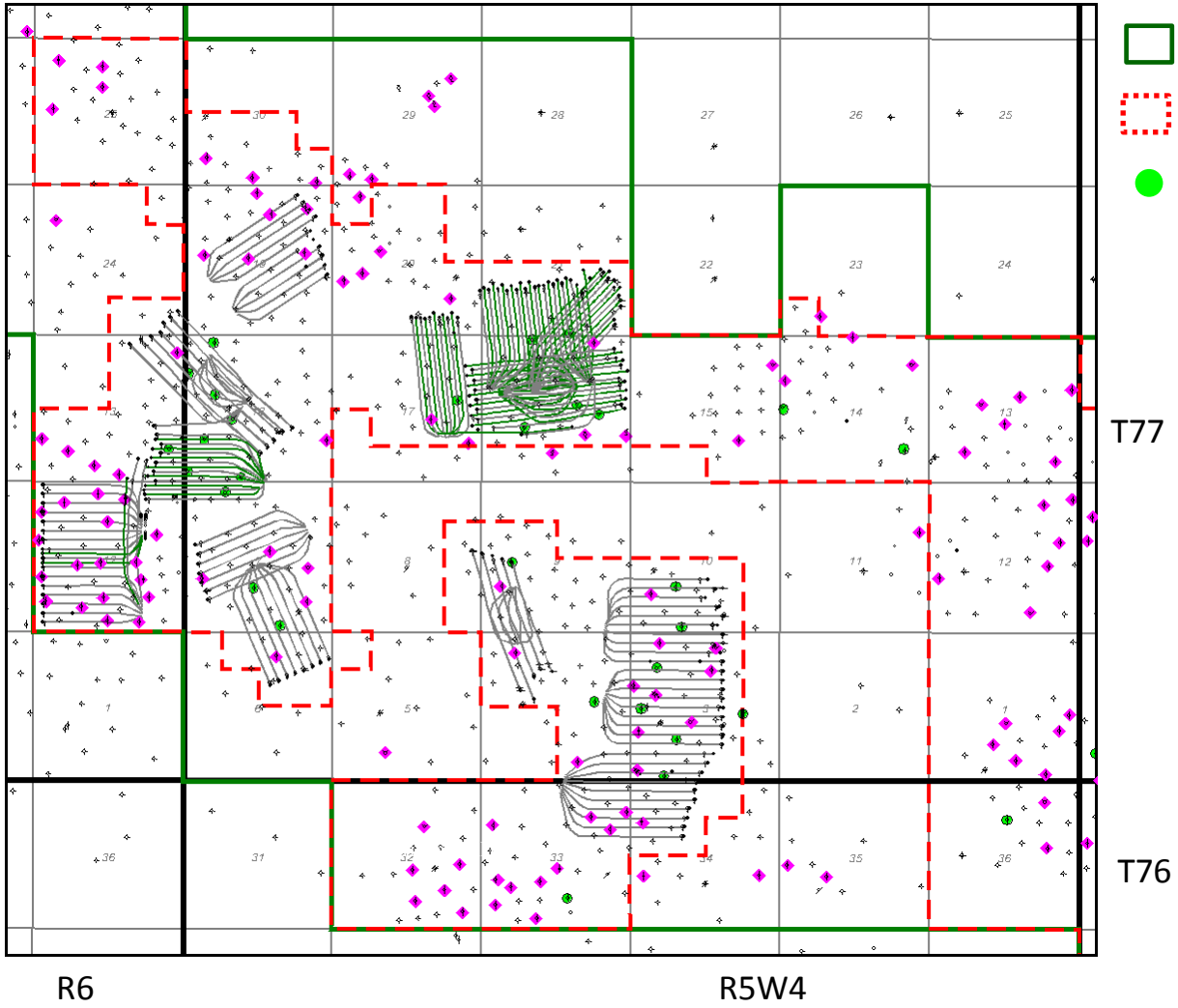
MEG OSL

Drilled SAGD Patterns

Gas Pool in direct or indirect contact with SAGD interval

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

CLRP ADA OB and Cased Wells



MEG OSL

Approved Development Area

Instrumented OB Wells

Non-Instrumented OB 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	2	100	NA
J	8	100	NA
K	7	100	NA
M	10	100	NA
N	9	100	NA
T	7	100	NA
U	6	100	NA
AP	10	100	50
AF	5	100	NA
AG	4	100	NA
AN	8	100	50
P	10	100	NA
TOTAL	**137**		

MEG ENERGY

RESERVOIR

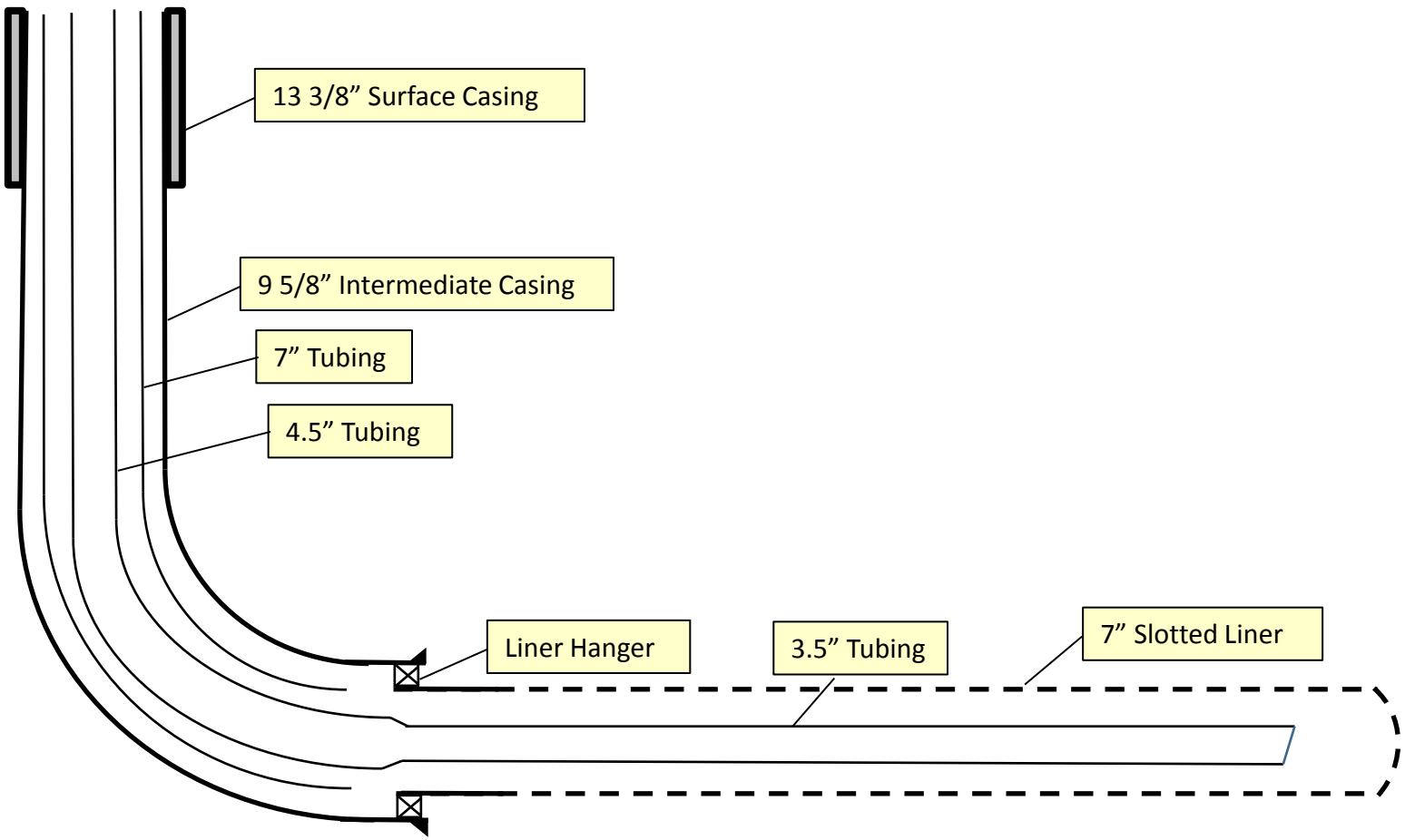
CLRP Reservoir Review

- Wells
  - Schematics
  - Well Integrity Management
  - Workovers
  - Artificial Lift
- Current Performance
  - Field performance
  - Pattern performance
  - Cased hole logs
  - eMSAGP update
- Associated gas cap re-pressuring

MEG ENERGY

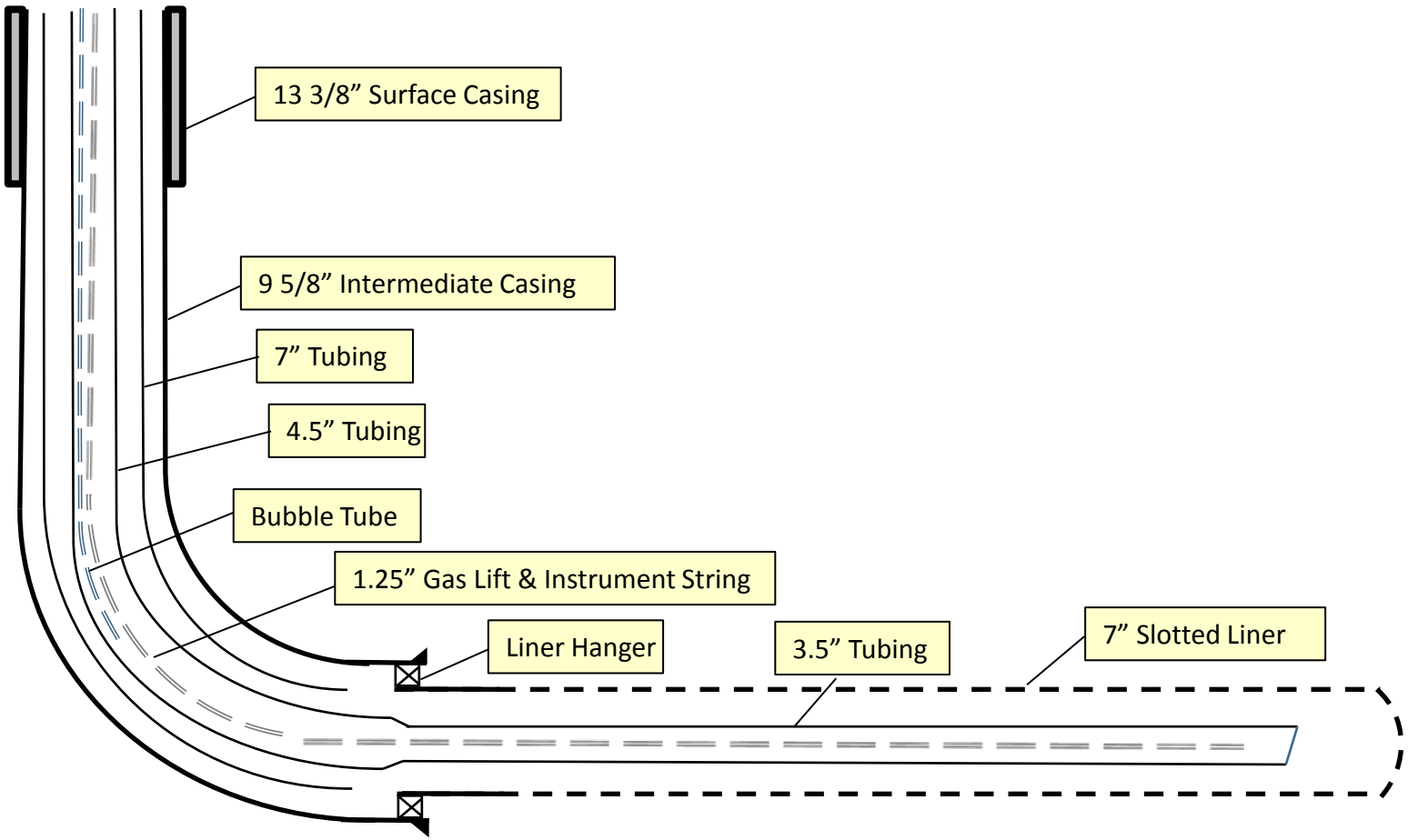
WELLS

Well Completions – SAGD Injector



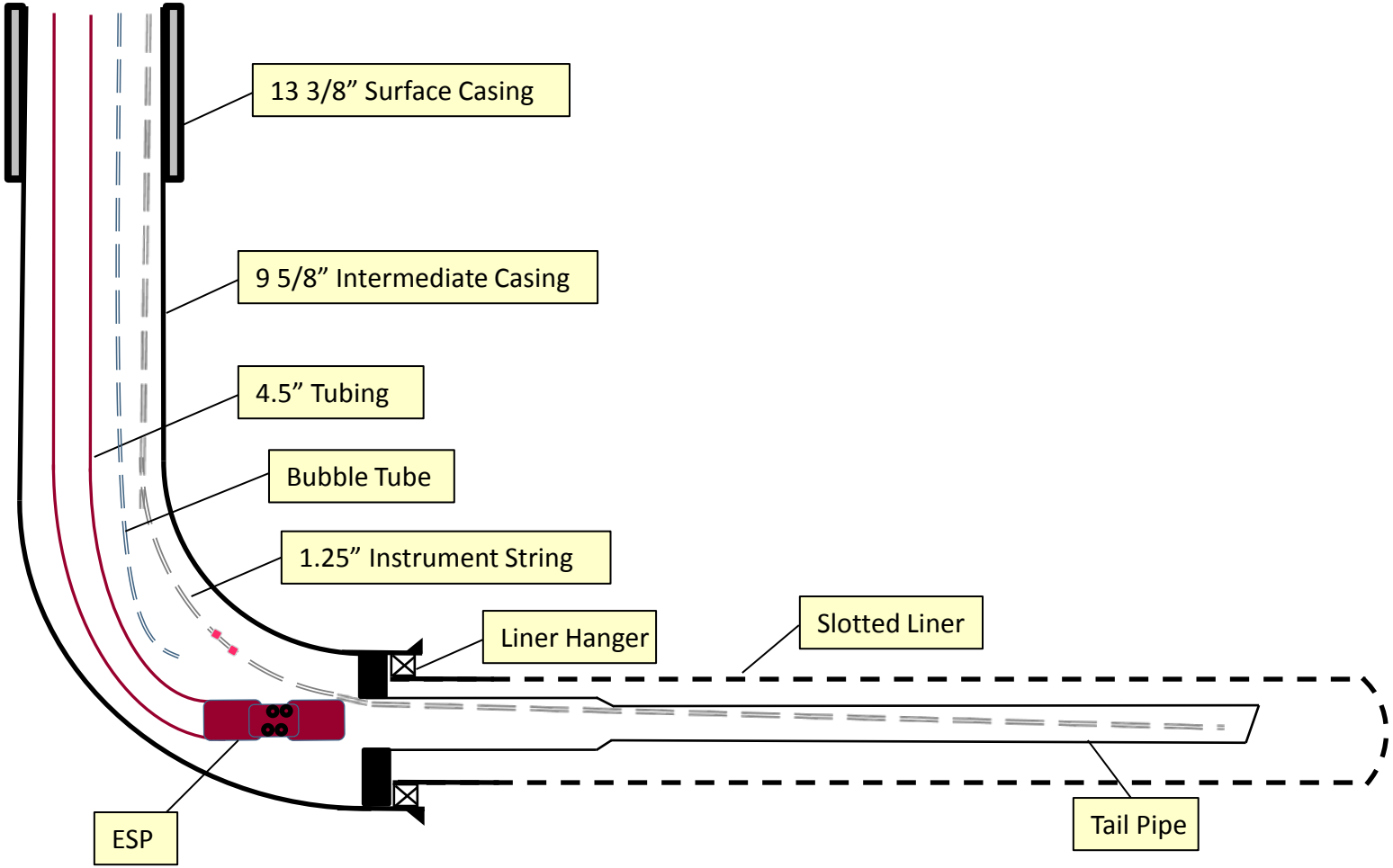
- Steam injected into both long tubing and short tubing
- Blanket gas on annulus

Well Completions – SAGD Producer (Gas Lift)



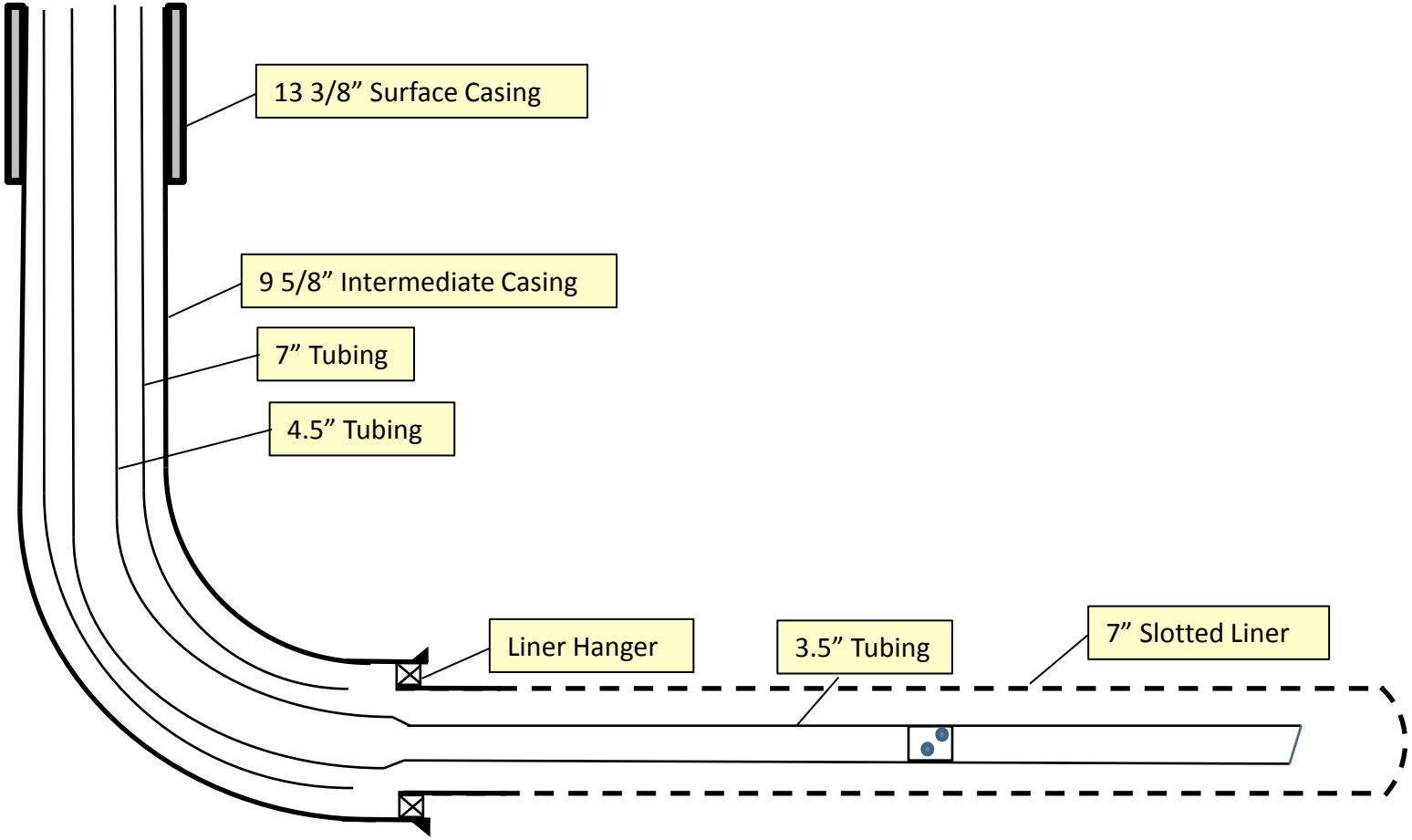
- Thermocouples are inside the instrument string to provide temperature measurements at selected locations
- Bubble tube landed near bottom of well to provide pressure measurement

Well Completions – SAGD Producers (ESP)



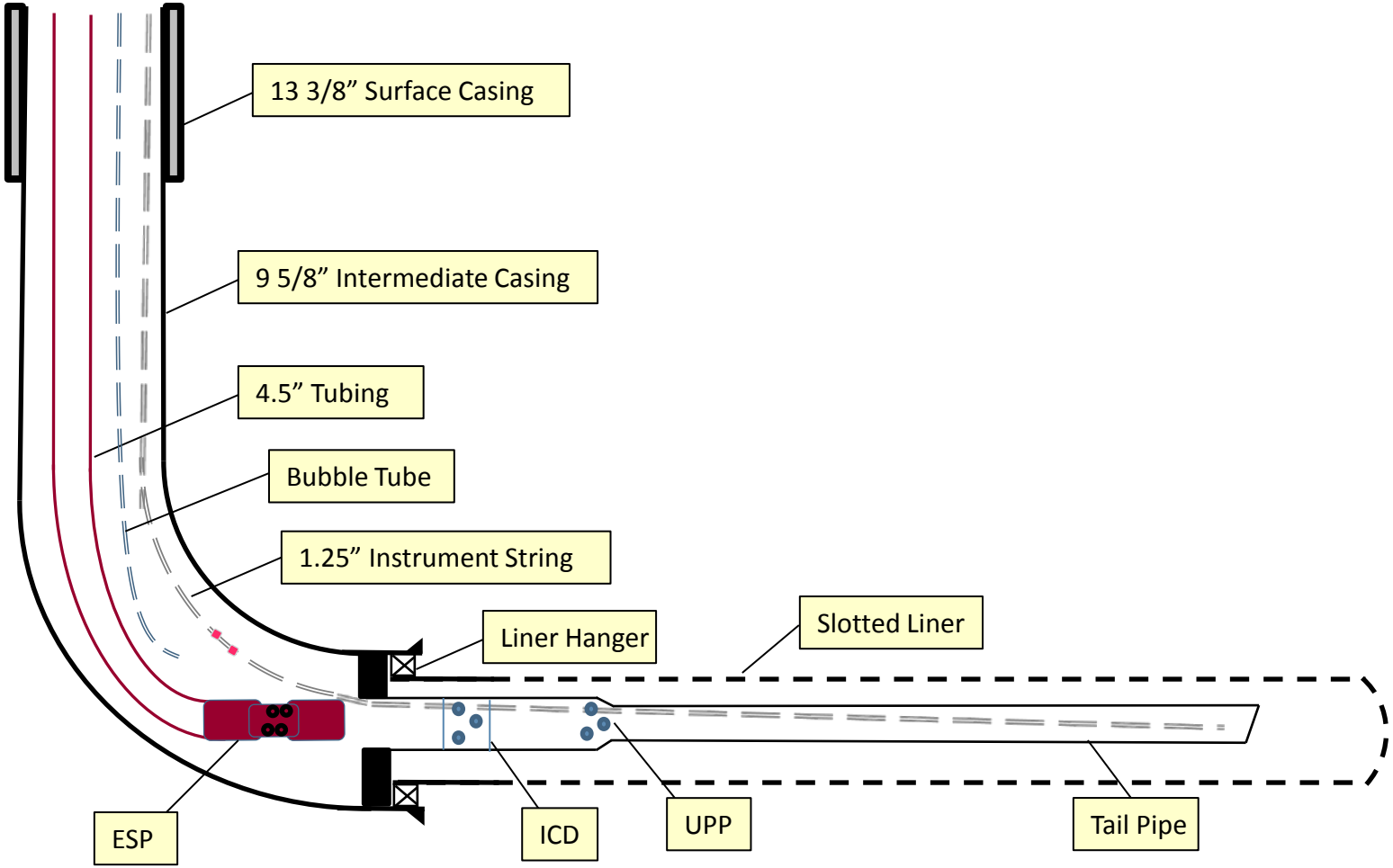
- Thermocouples or thermal fibre are inside the instrument string to provide temperature measurements at selected locations
- Bubble tube is landed near ESP to provide pressure measurement for SAGD producer

Well Completions – Outflow Control Devices



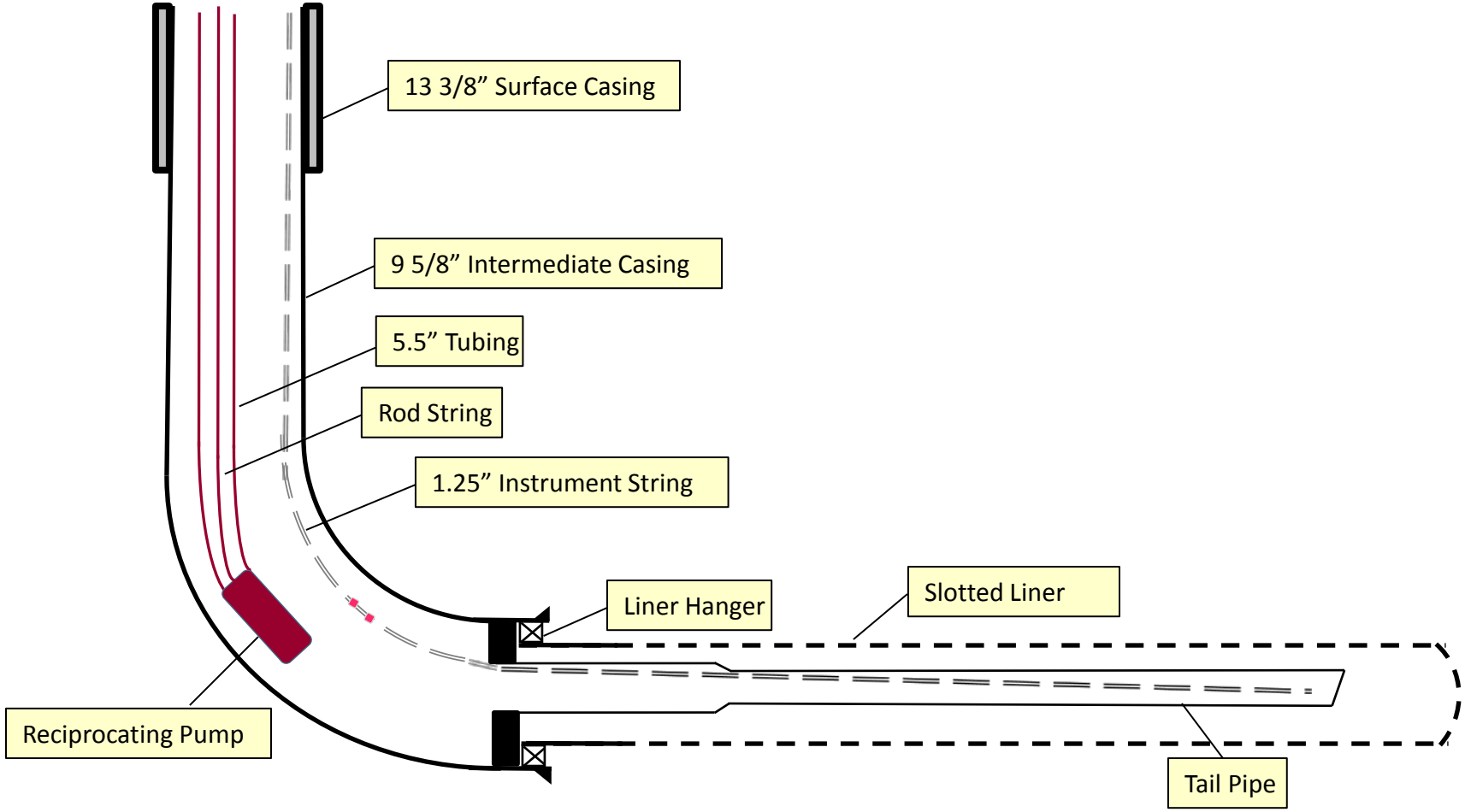
- Consists of several holes placed mid-way of the long tubing to distribute steam at the middle of the well in addition to the heel and toe
- Current installation are V1I and M4I and results to date have been positive

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
- To date, MEG has only utilized ICDs in the production tubing and not on the liner

Well Completions – Infill Producers

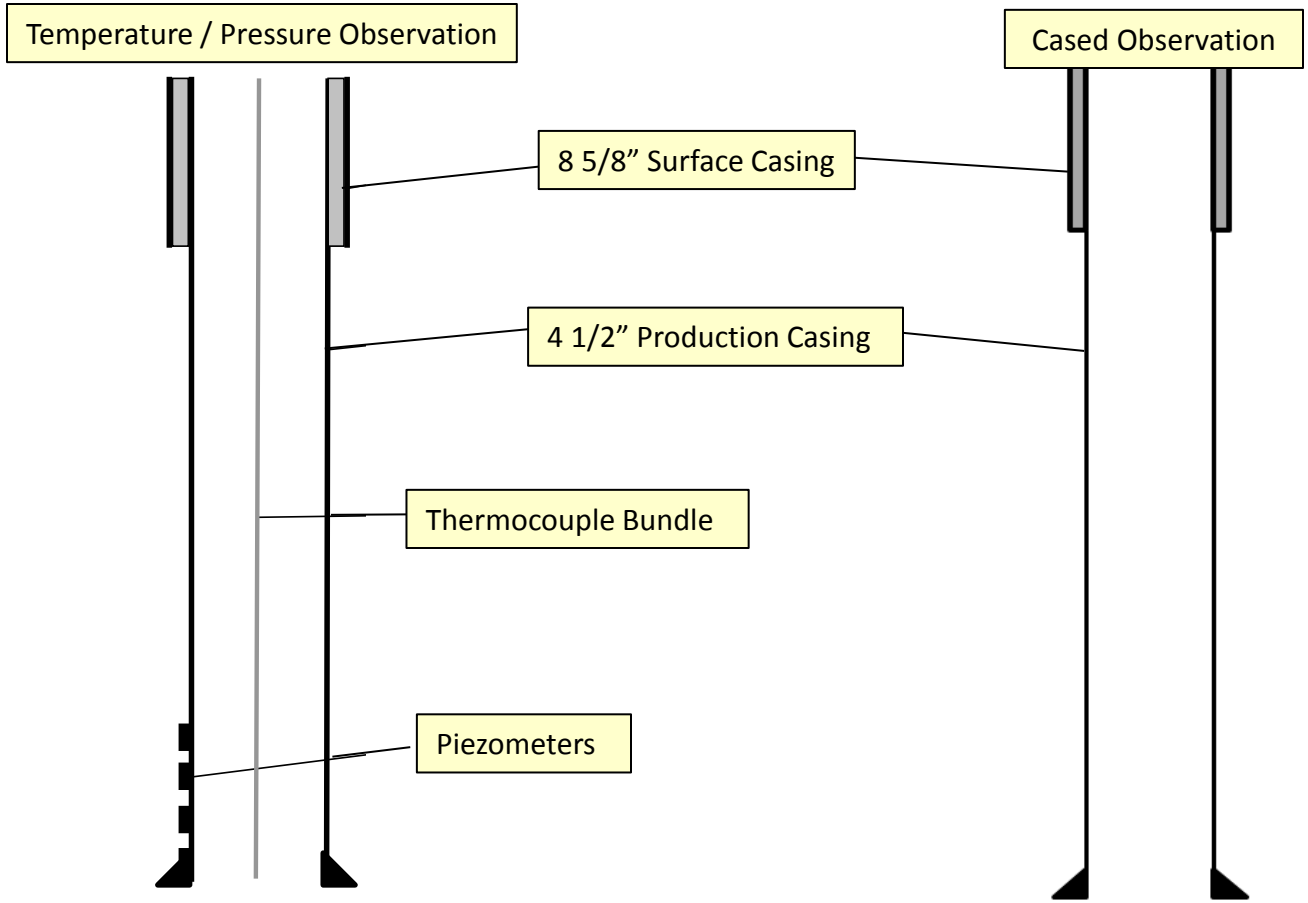


- Thermocouples or thermal fibre are inside the instrument string to provide temperature measurements at selected locations
- Bottom hole pressure is estimated from fluid level measurement

Temperature Measurement

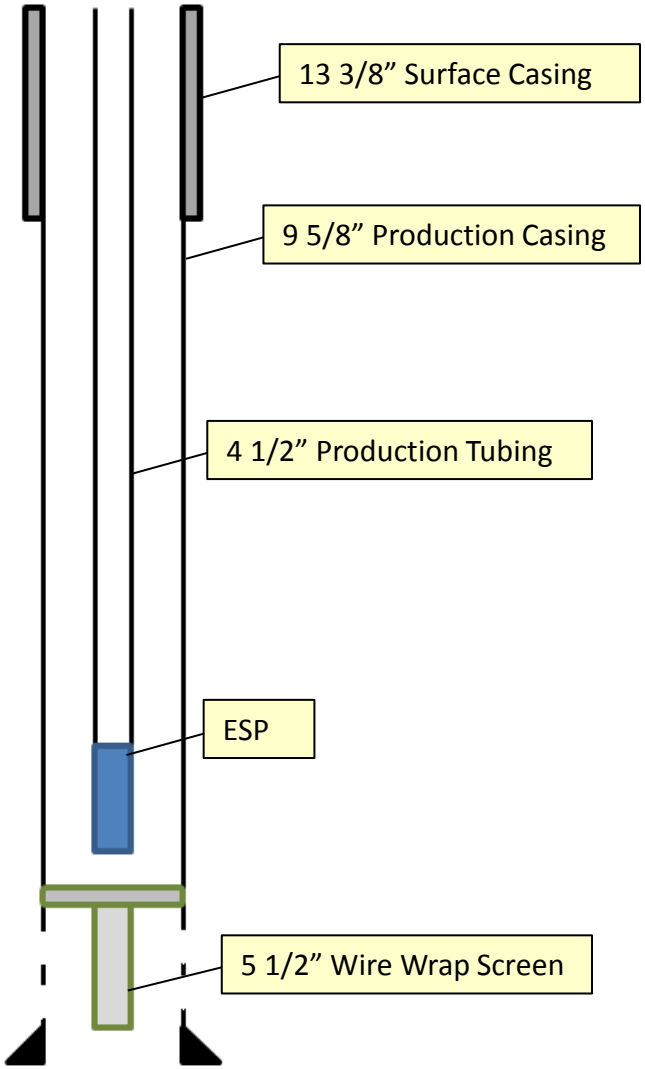
- Have historically relied on four-point thermocouple strings in all SAGD and infill wells due to proven accuracy
- Currently have installed thermal fibre on V, AP and AN infill wells, AF and P Pad SAGD producers, and recent re-drills on AP and M Pads (AP4P, M3P, M4P, M6P, M9P)
- Recent fibre installations have demonstrated improved data quality, reliability, and cost, and thermal fibre is expected to be the technology for future pads

Observation Wells

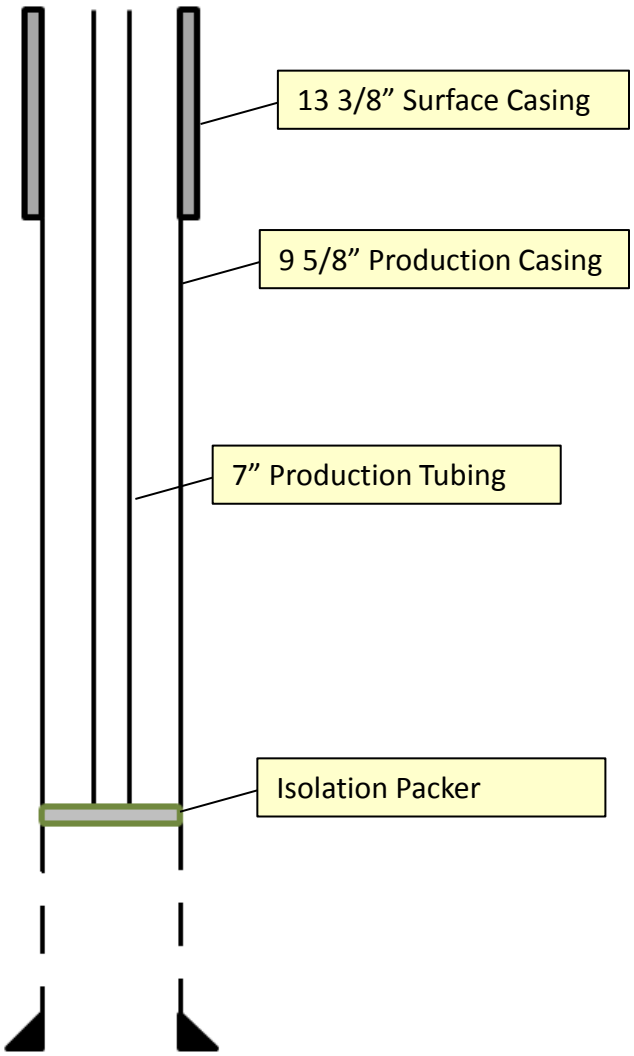


- Thermocouples are landed over expected steam zone
- Piezometers are placed in areas of geological interest (gas, bitumen, water zones and potential pay breaks)

Water Source Wells



Water Disposal Wells



CLRP Well Integrity Management

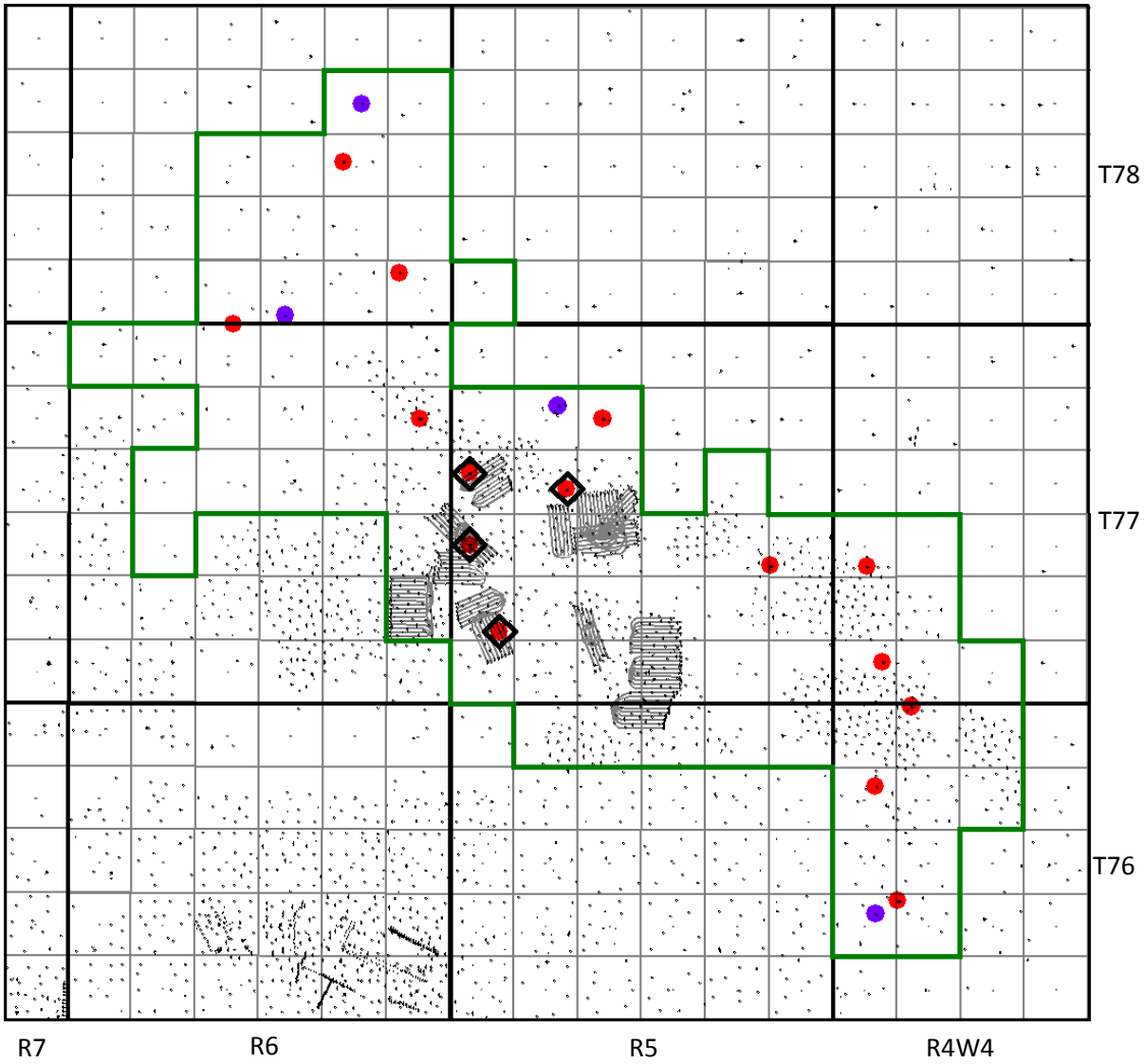
Well Integrity Program for CLRP

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

The Well Integrity Program includes:

- Well Integrity Management System (well tracking and monitoring)
- Targeted selection casing integrity checks and Well Servicing support
- Casing design and failure mechanism identification
- Compliance assurance, AER commitments and reporting
- Inactive Well Compliance Program management

CLRP 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 D-20 abandonment applications have been filed and approved for requisite wells within the ADA
- 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

CLRP Well Workovers – Re-drills

Issue

- In-zone isolated liner impairment on AP4P SAGD producer well identified in 2015

Highlights

- The impairment occurred during the production ramp up following an ESP replacement combined with opening an ICD
- Four-point thermocouple data did not show that steam temperature was reached, however sand production and damaged instrumentation string occurred
- Well was successfully re-drilled and put on production

Outcomes and Lessons Learned

- Improved processes implemented for future production ramp up following pump replacements, especially when combined with opening of an ICD as inflow characteristics of the wells may change
- Well was completed with thermal fibre to improve temperature data resolution

CLRP Artificial Lift

- **135 Electric submersible pumps (ESP) in operation**
  - Approximately 55% ESPs rated to 250°C and 45% rated to 220°C
  - Operating pressures range from 2,100-3,200kPag
  - Design fluid rates 200-1200m^3/d
  - Run-time between pulls is 785-800 days Run-time improvements have been realized by utilizing higher quality equipment where required

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

CLRP Well Workovers – Re-drills

Issue

- Suspected liner plugging identified on wells at M Pad, leading to the re-drilling of 4 SAGD producers

Highlights

- Wells exhibited high pressure drop across the liner and much lower production rates for the quality of pay
- All 4 wells were successfully re-drilled and placed on production, and demonstrated significantly improved rates and pressure drop
- Producer laterals were drilled to improve overall trajectories and were on average approximately 0.5m to 1.5m higher TVD than the original wells
- At the time of the project, commercially available stimulation fluids did not demonstrate a probability of success and would still require significant expenditure
- Perforation of plugged slotted liner was estimated to have similar cost to re-drilling but without the high certainty of restoring productivity

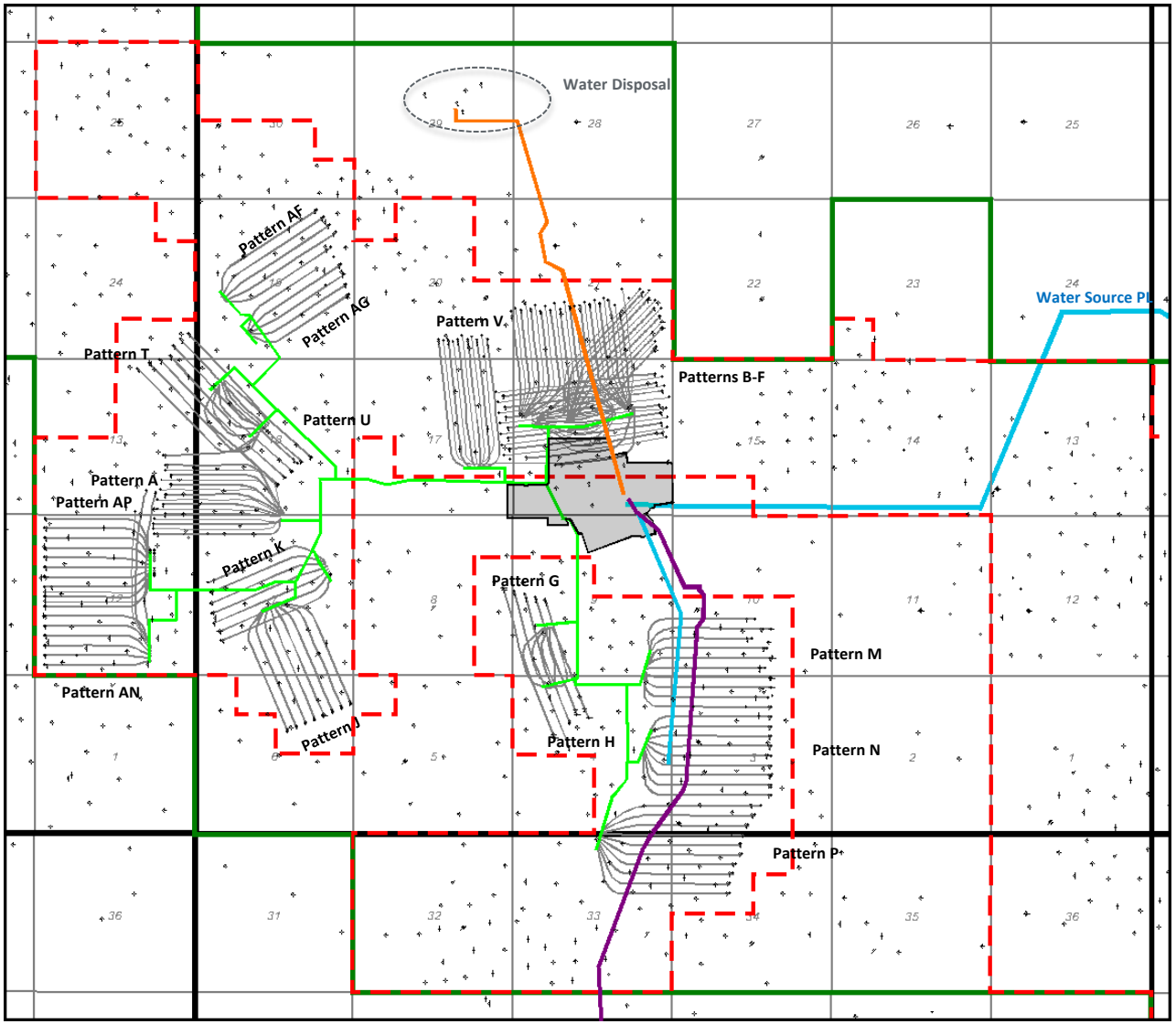
Outcomes and Lessons Learned

- Changes made to well cleanout and fluids used during drilling and completions
- Assessing other underperforming wells with similar characteristics to identify candidates for re-drill or stimulation

MEG ENERGY

SCHEME PERFORMANCE

CLRP Pattern Layout



MEG OSL
Approved Development Area
Central Plant
Access Pipeline
Emulsion Pipeline
Disposal Pipeline
Water source Pipeline

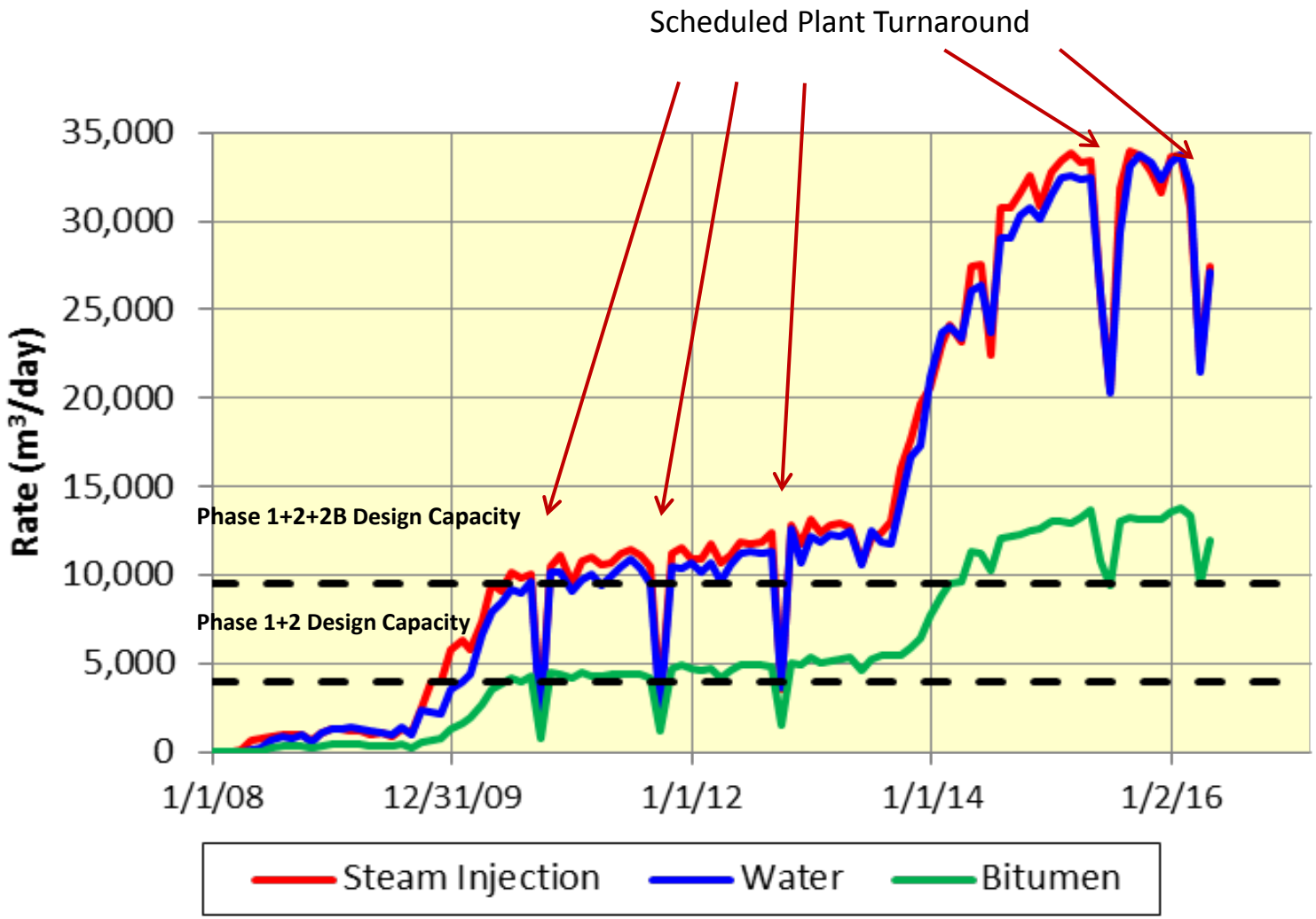
Drilled SAGD Wells

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	7	0
M	10	0
N	9	0
P	10	0
T	8	0
U	6	0
V	6	6
AF	5	0
AG	5	0
AN	8	1
AP	10	2
Total	143	48

CLRP 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 design capacity of 3,975 m^3/d (25,000 bopd) by late April 2010.
- Phase 2B production ramp-up bettered that of Phase 2. Total production from all phases reached 11,340 m^3/d (71,300 bopd) in Q2 2014, exceeded the combined initial design capacity of 9,539 m^3/d (60,000 bopd).
- Production averaged 80,033 bopd in 2015
- In Q1 2016, MEG achieved quarterly production of 76,640 bopd, a period which included a scheduled plant turnaround. April production averaged over 75,000 bopd.

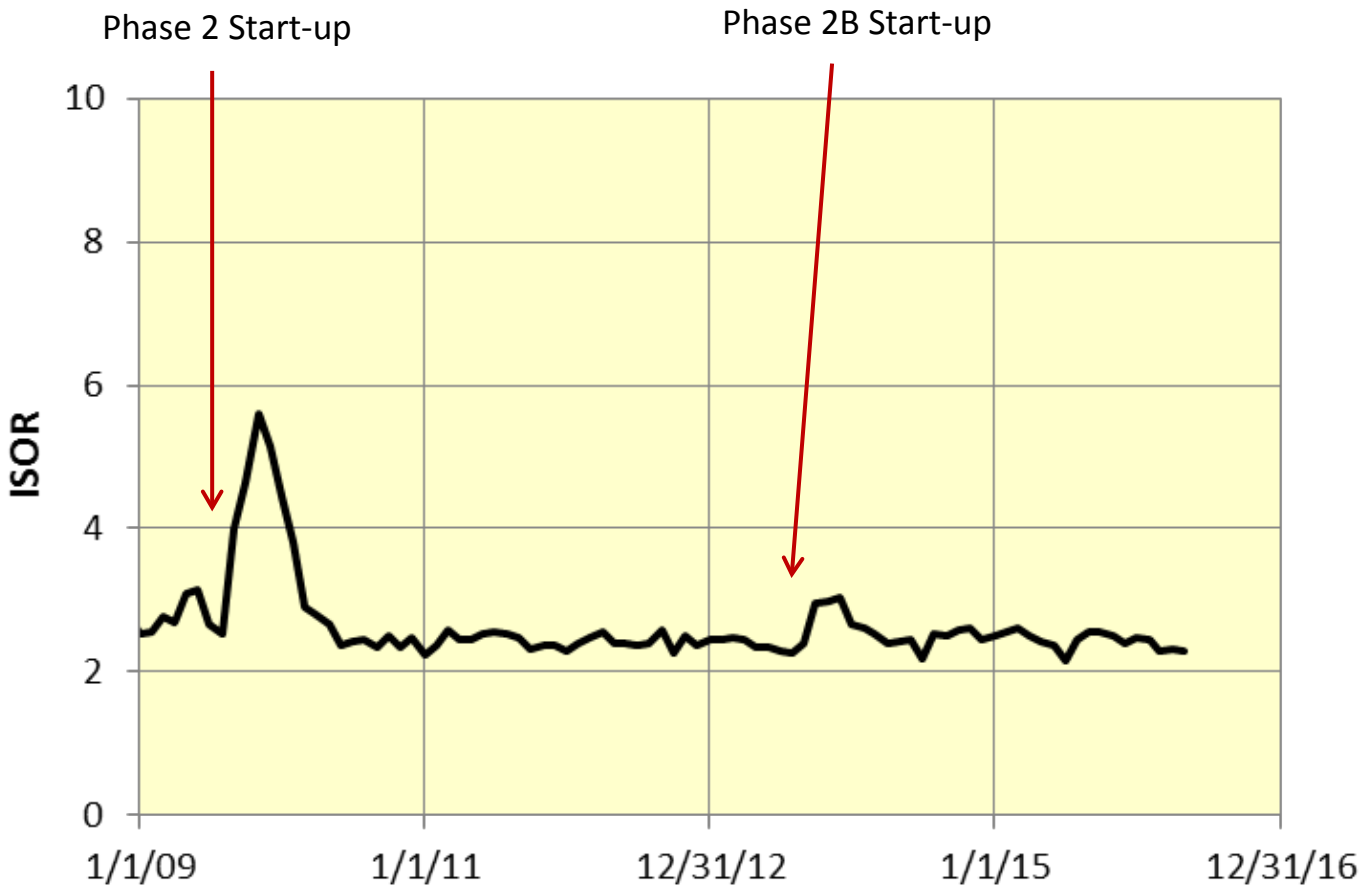
CLRP Production Performance



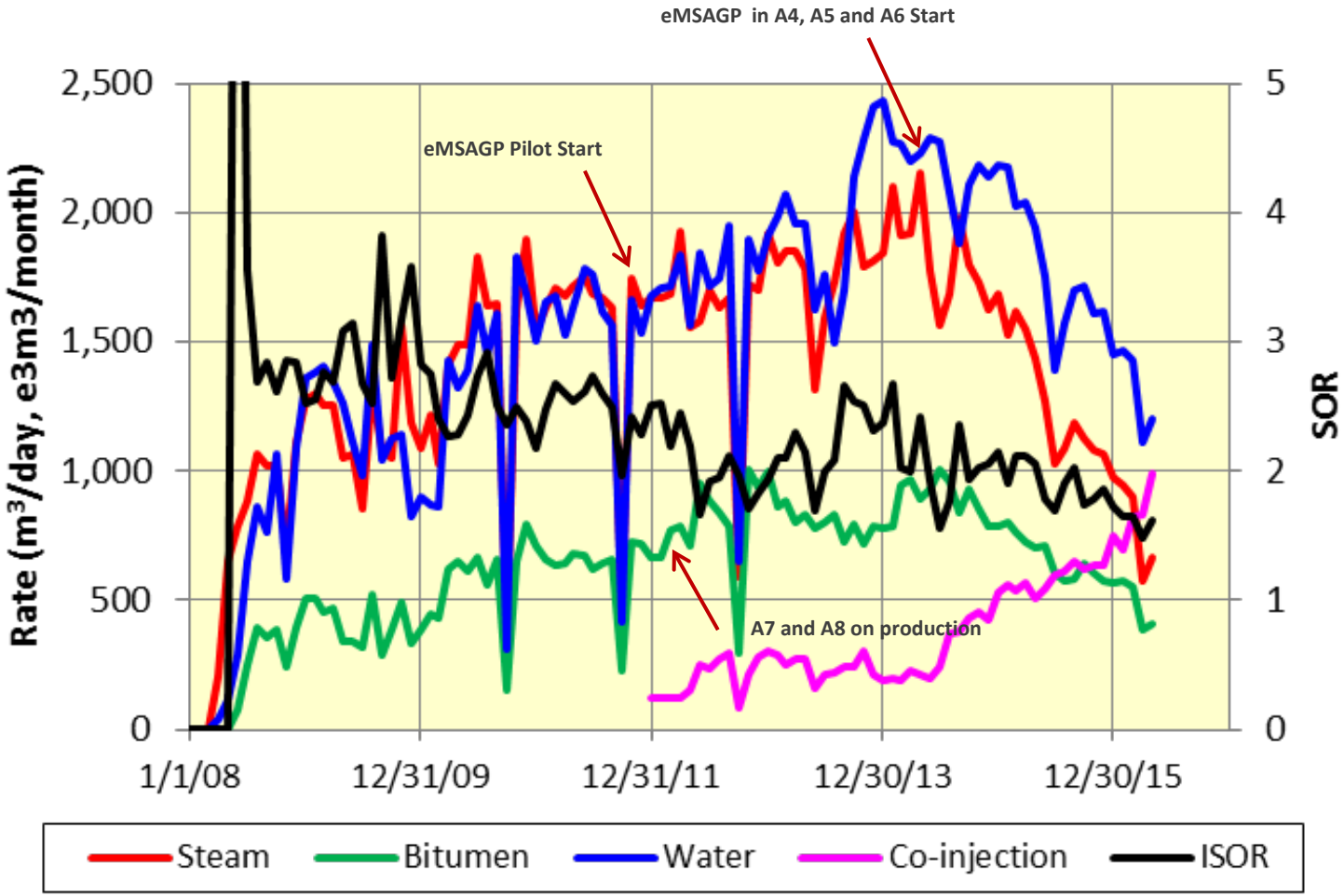
CLRP Reservoir Performance (continued)

- Current steam chamber pressure is between 2,000 and 2,700 kPag for Phases 1 and 2, between 2,100 and 3,450 kPag for Phase 2B. The steam chamber pressure is close to the initial pressure in the basal water zone where bottom water is present.
- The Phase 1 eMSAGP pilot was initiated in December 2011, which showed very successful results. In 2013 eMSAGP was expanded to wells A4, A5, A6 and patterns B, C, D, E and F, and has demonstrated the process to be repeatable on a commercial scale.
- The SOR of the eMSAGP wells (36 SAGD WP's and 37 infill wells) averaged 1.8 relative to the SAGD design level of 2.8 in the period, which allowed MEG to utilize the freed up steam to bring more SAGD wells on production. The SOR of eMSAGP wells has continued to improve year over year.
- The SOR of CLRP has ranged from 2.2 to 2.6 over the last 12 months and averaged 2.4 with new well start-ups.

CLRP Performance – SOR of All Patterns

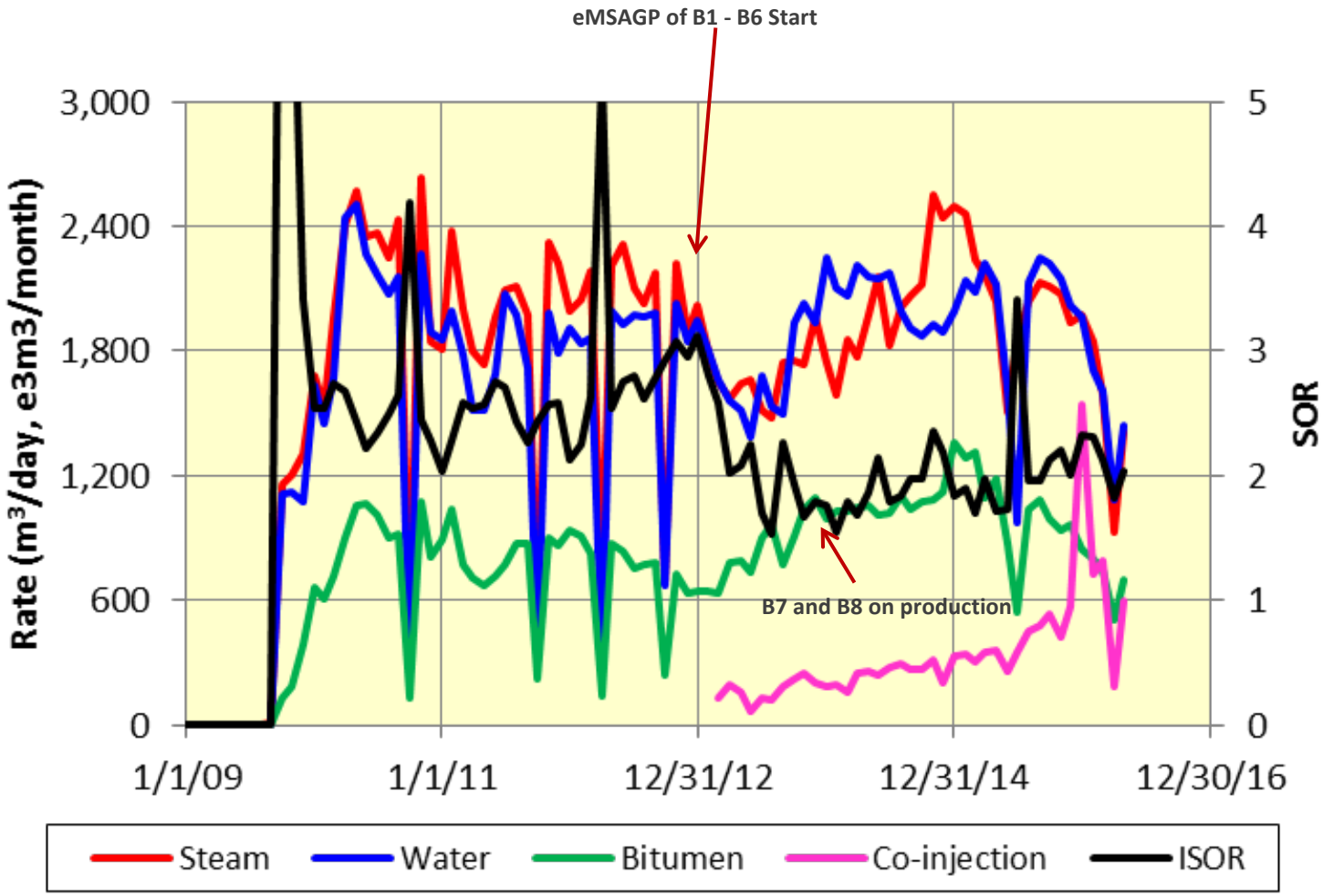


CLRP Performance – Pattern A

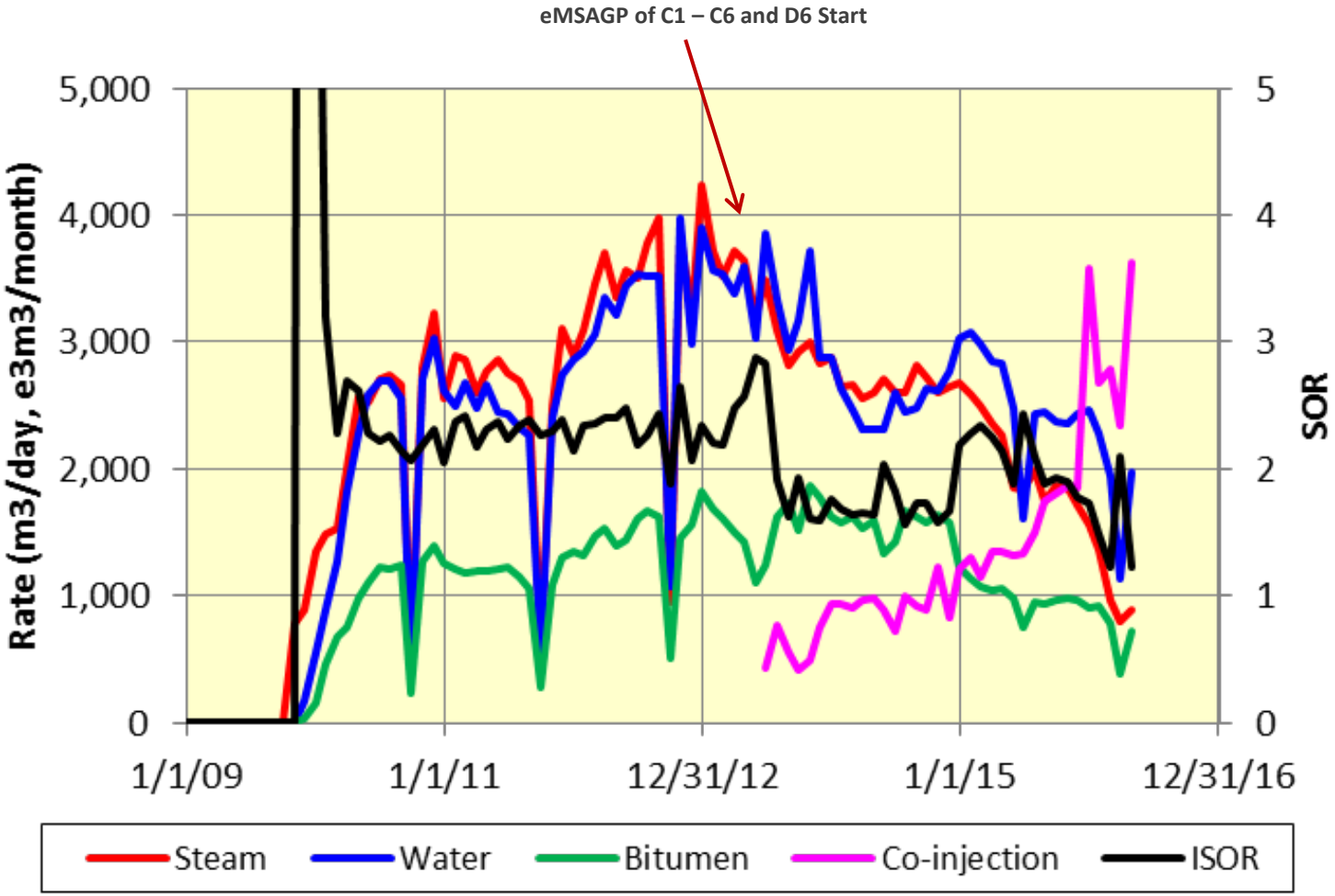


Increased water to steam ratio noted recently was mostly from two edge SAGD well pairs (A6 and A8), a result of edge or bottom water incursion

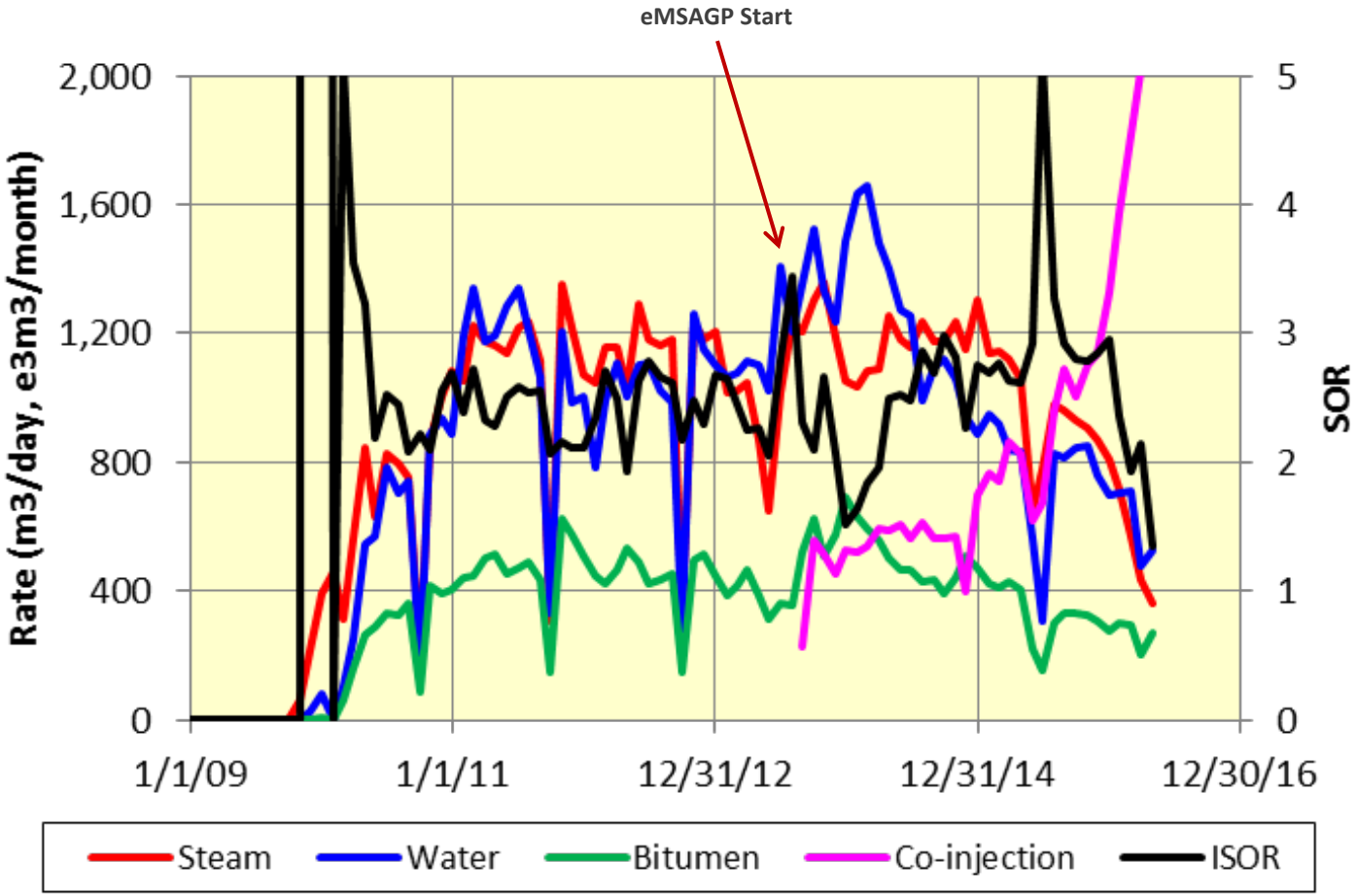
CLRP Performance – Pattern B



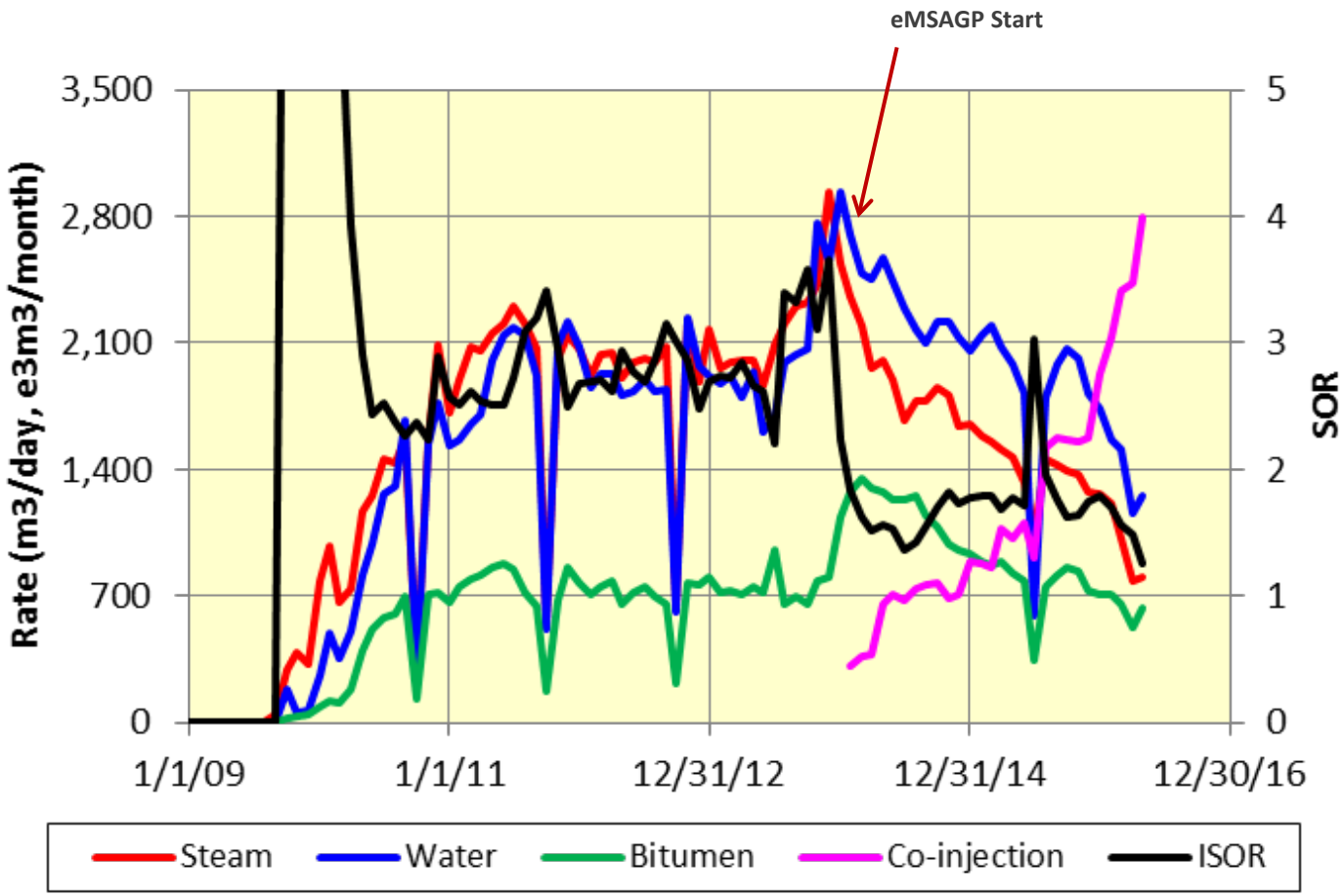
CLRP Performance – Pattern C



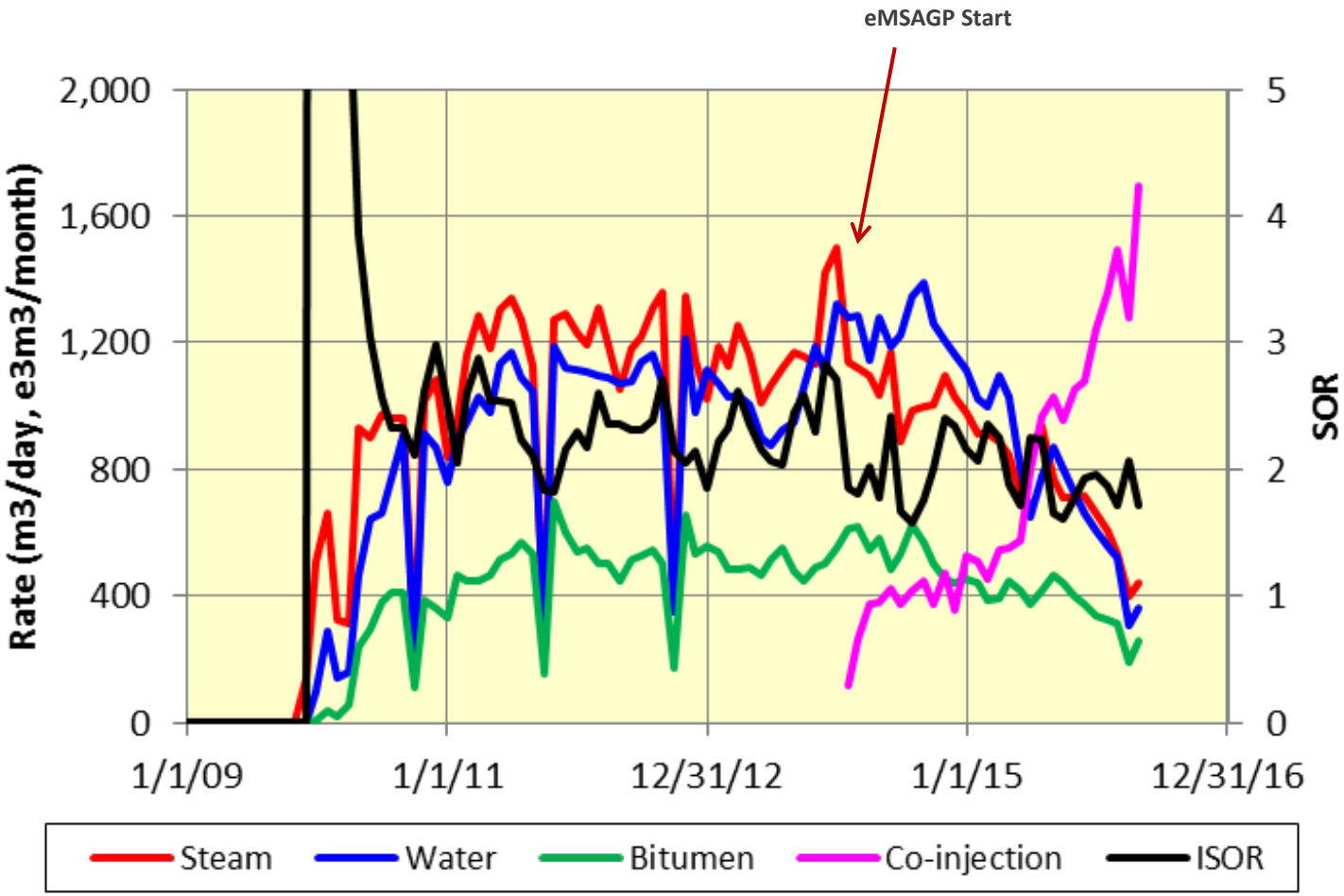
CLRP Performance – Pattern D



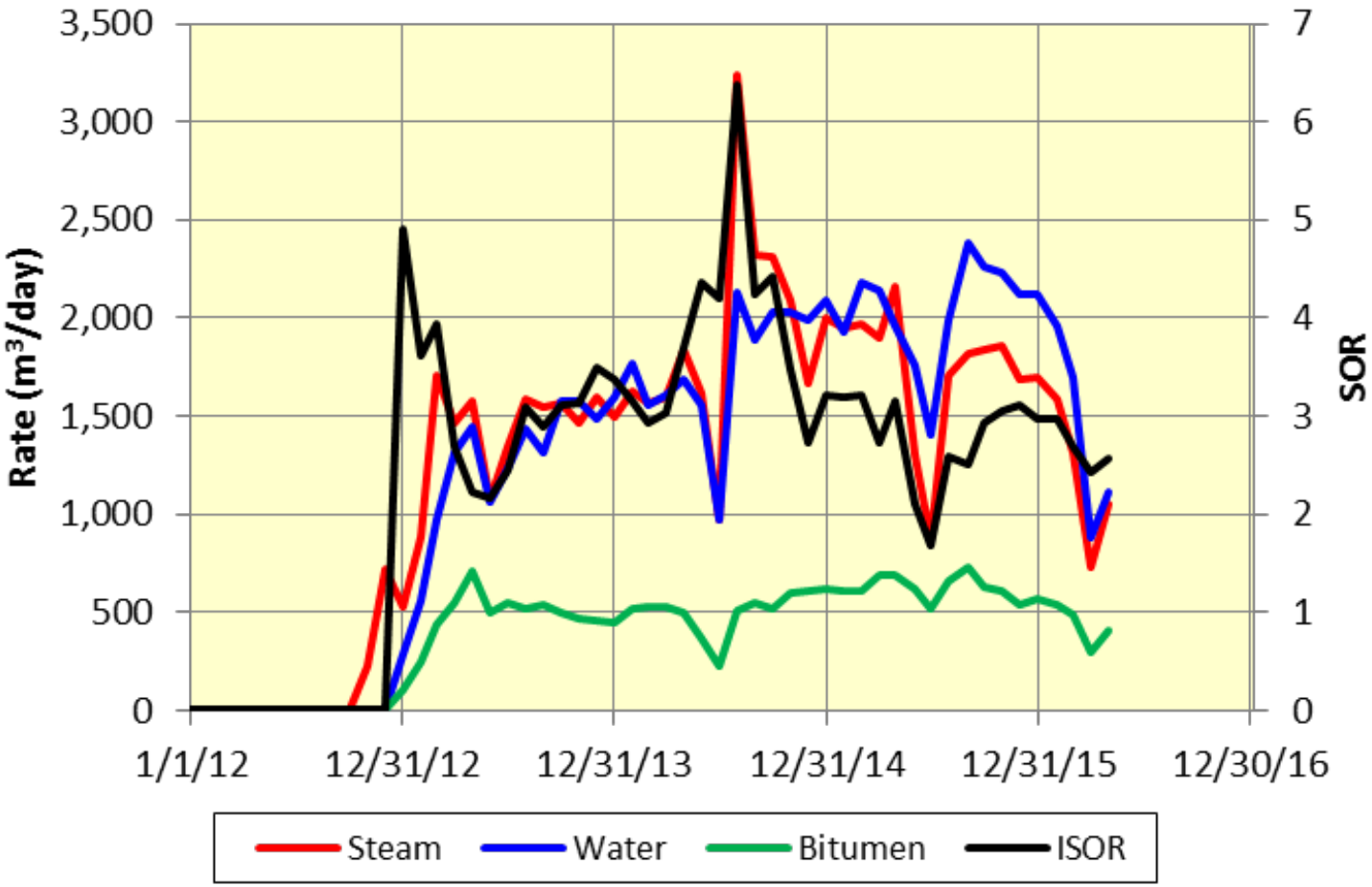
CLRP Performance – Pattern E



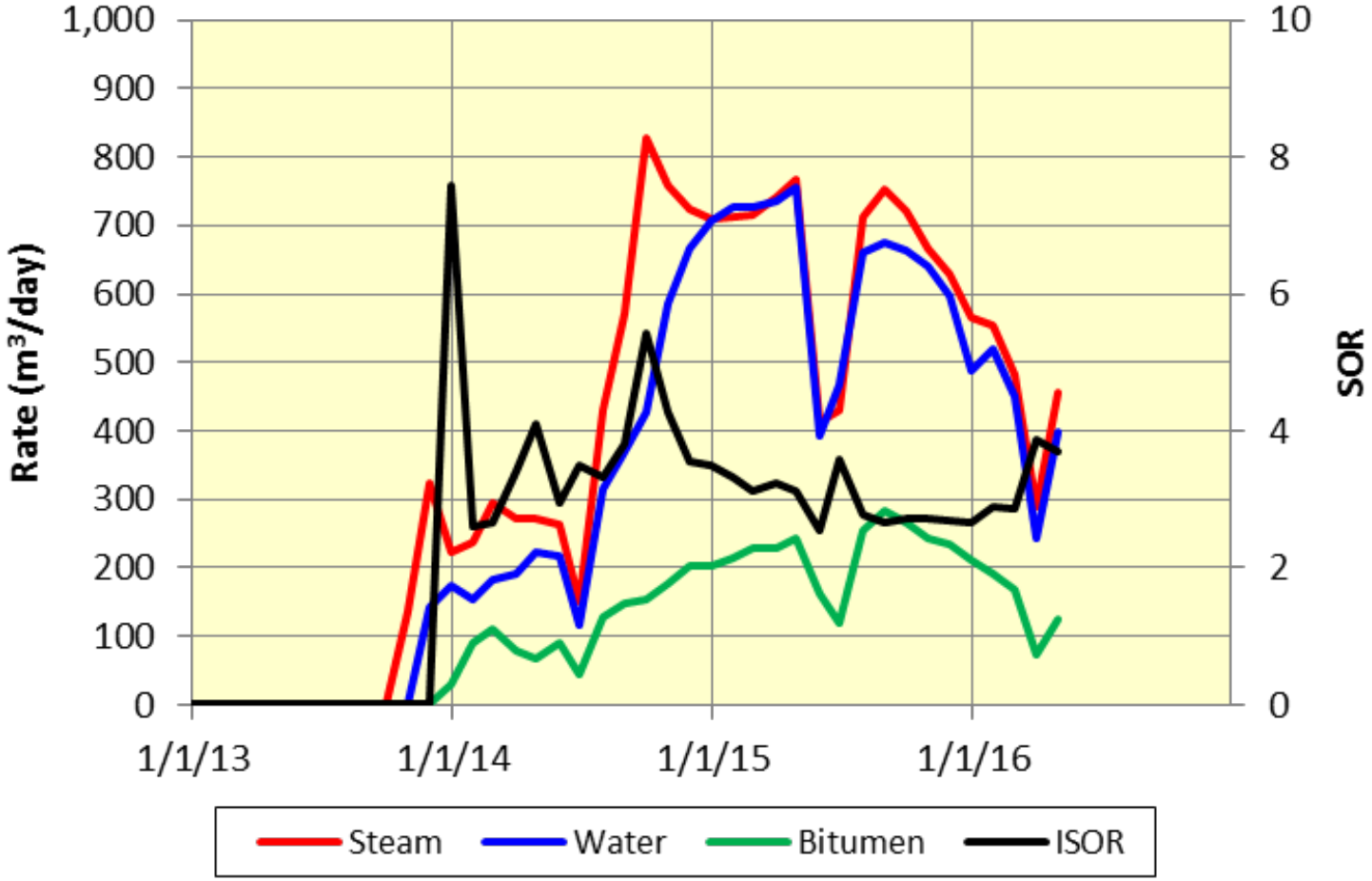
CLRP Performance – Pattern F



CLRP Performance – Pattern V

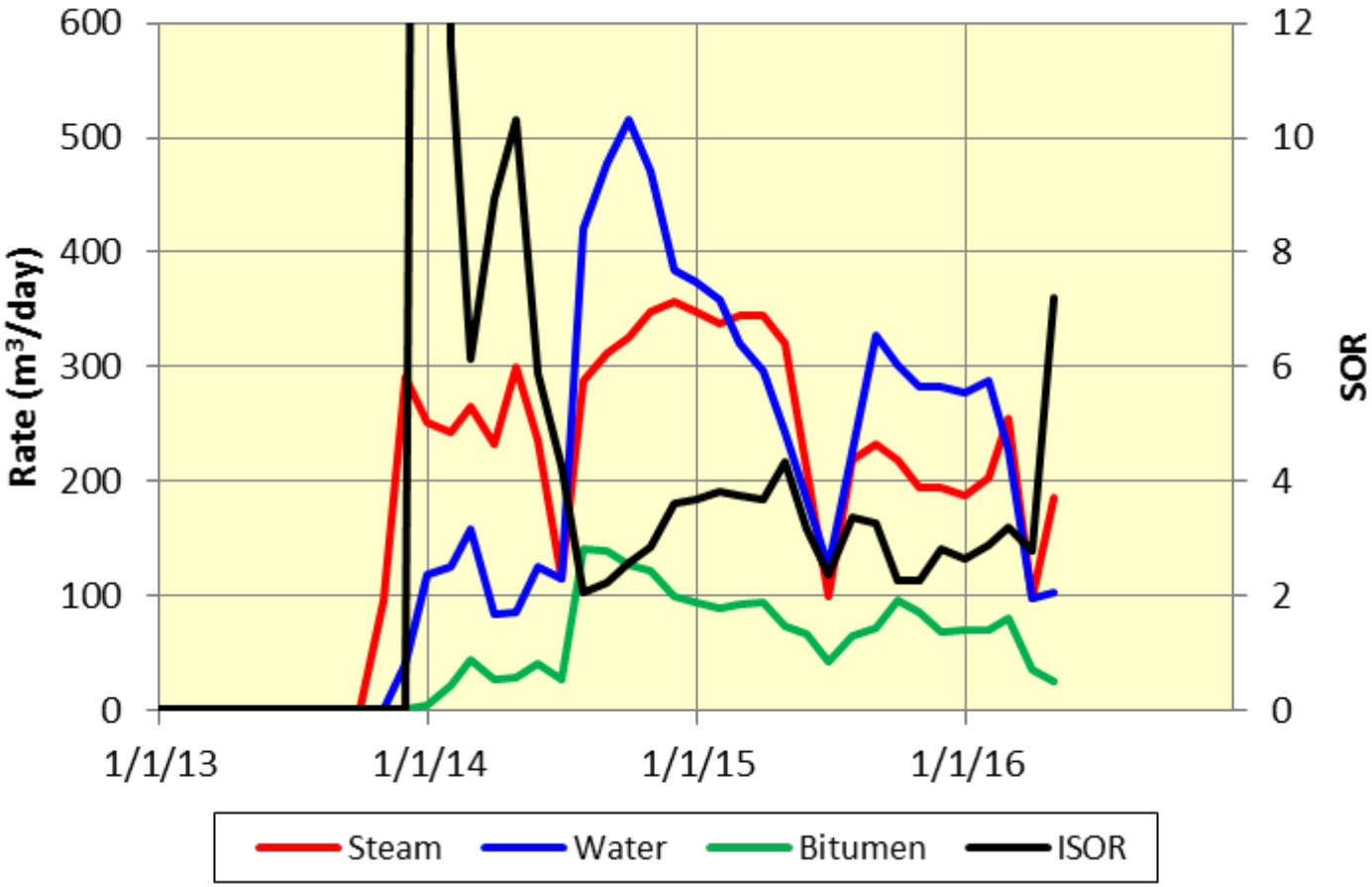


CLRP Performance – Pattern G

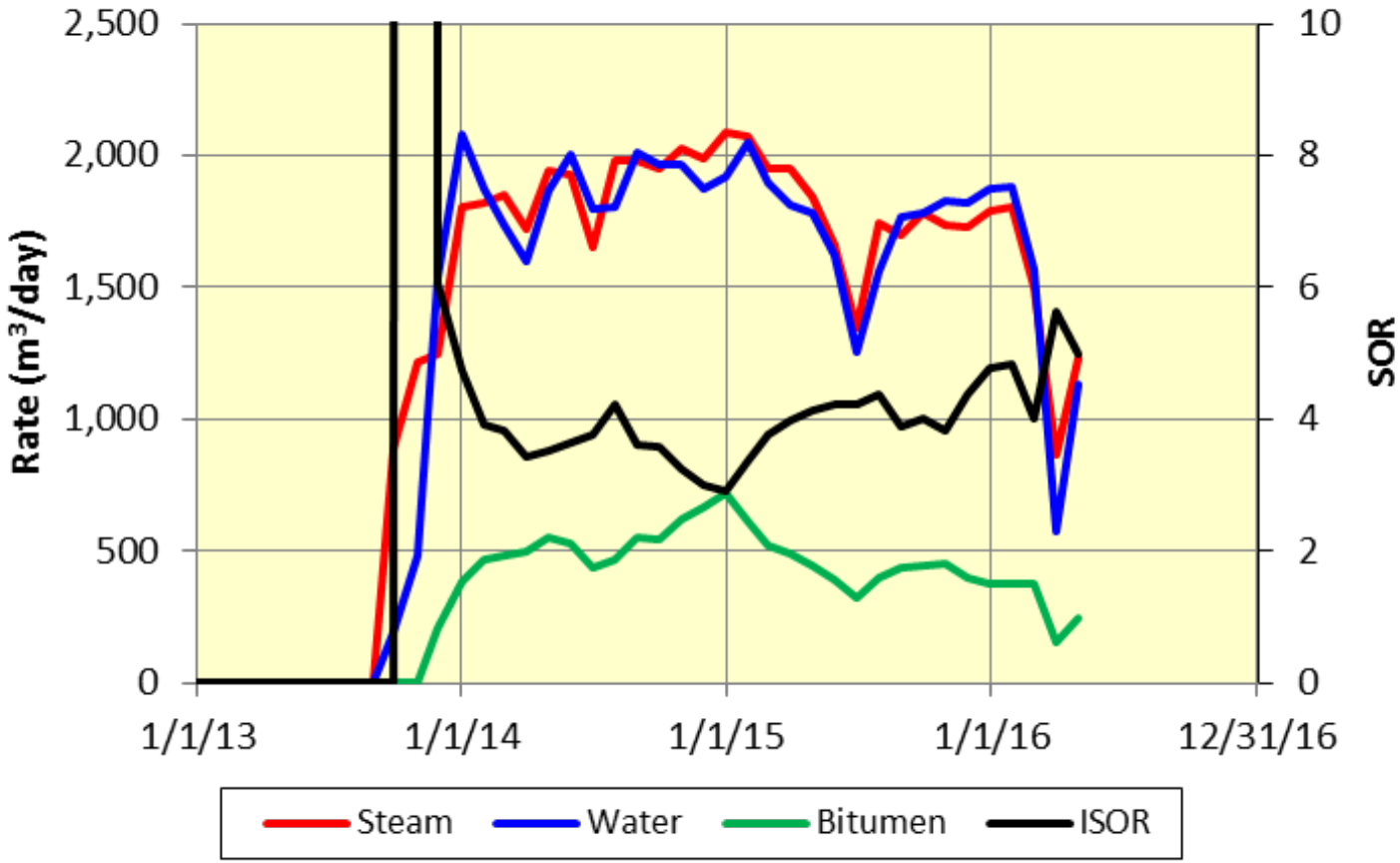


Drop in production in 2015 largely due to liner impairment on G4

CLRP Performance – Pattern H

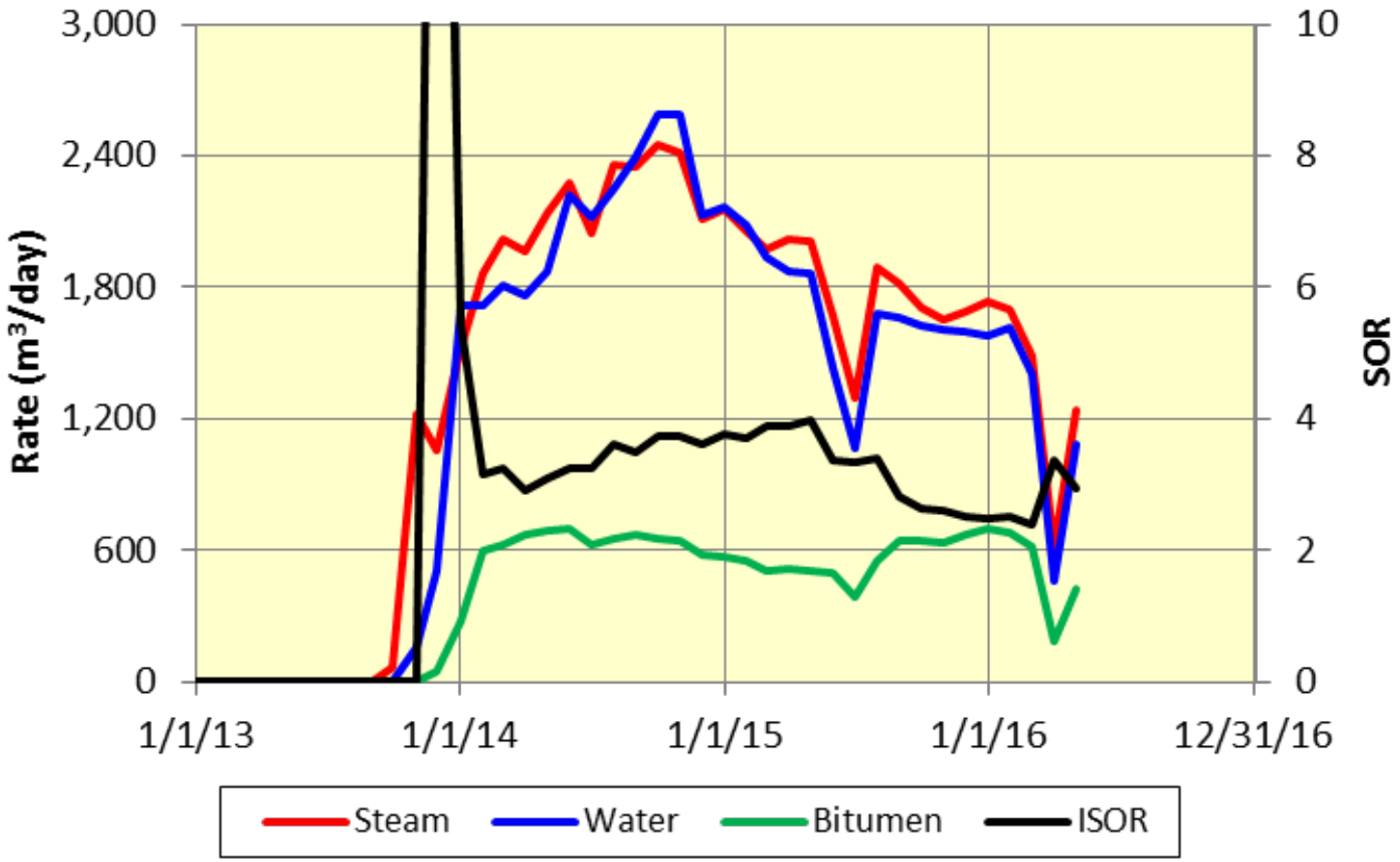


CLRP Performance – Pattern J

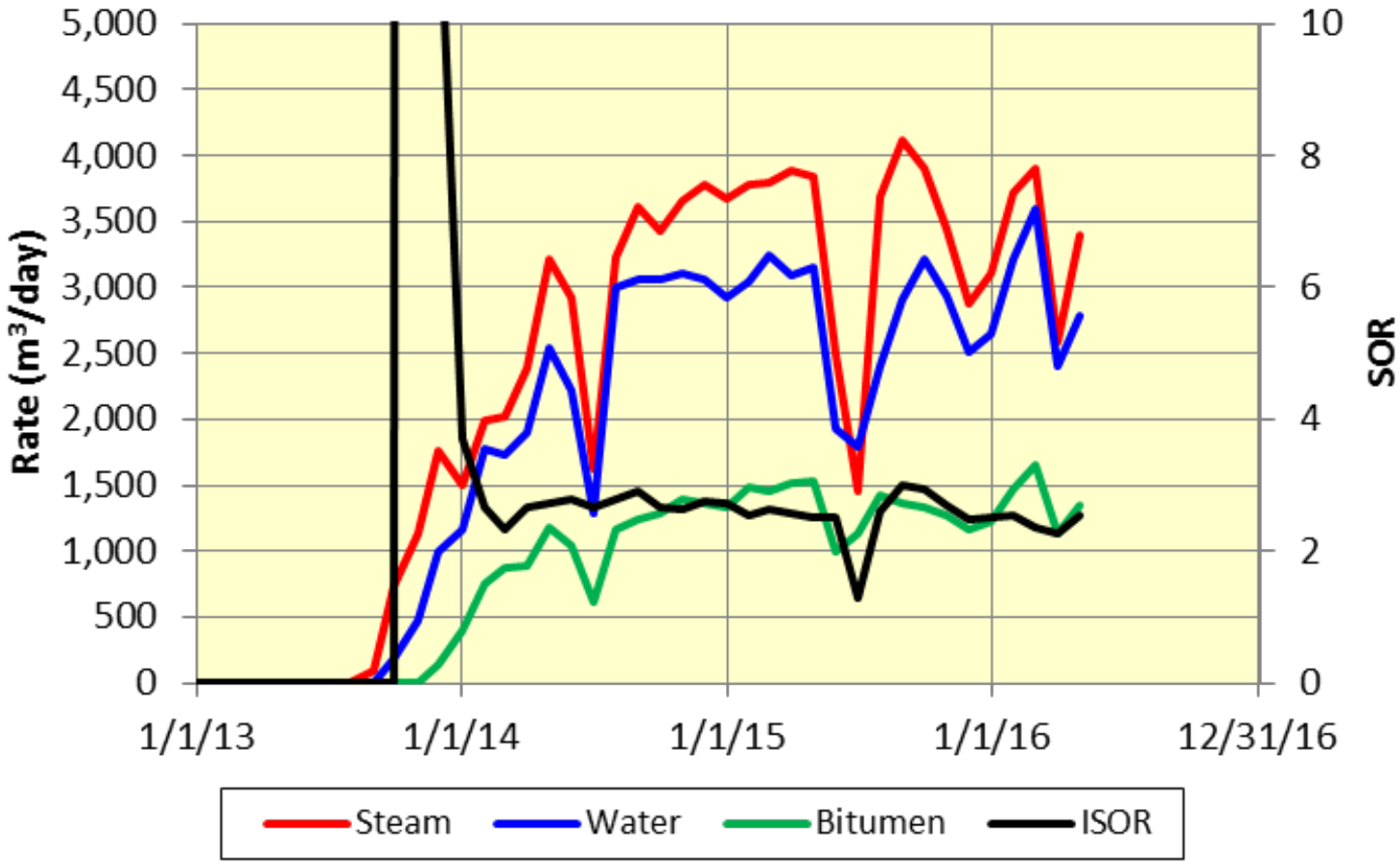


Drop in production in 2015 largely due to liner impairment on J4

CLRP Performance – Pattern K

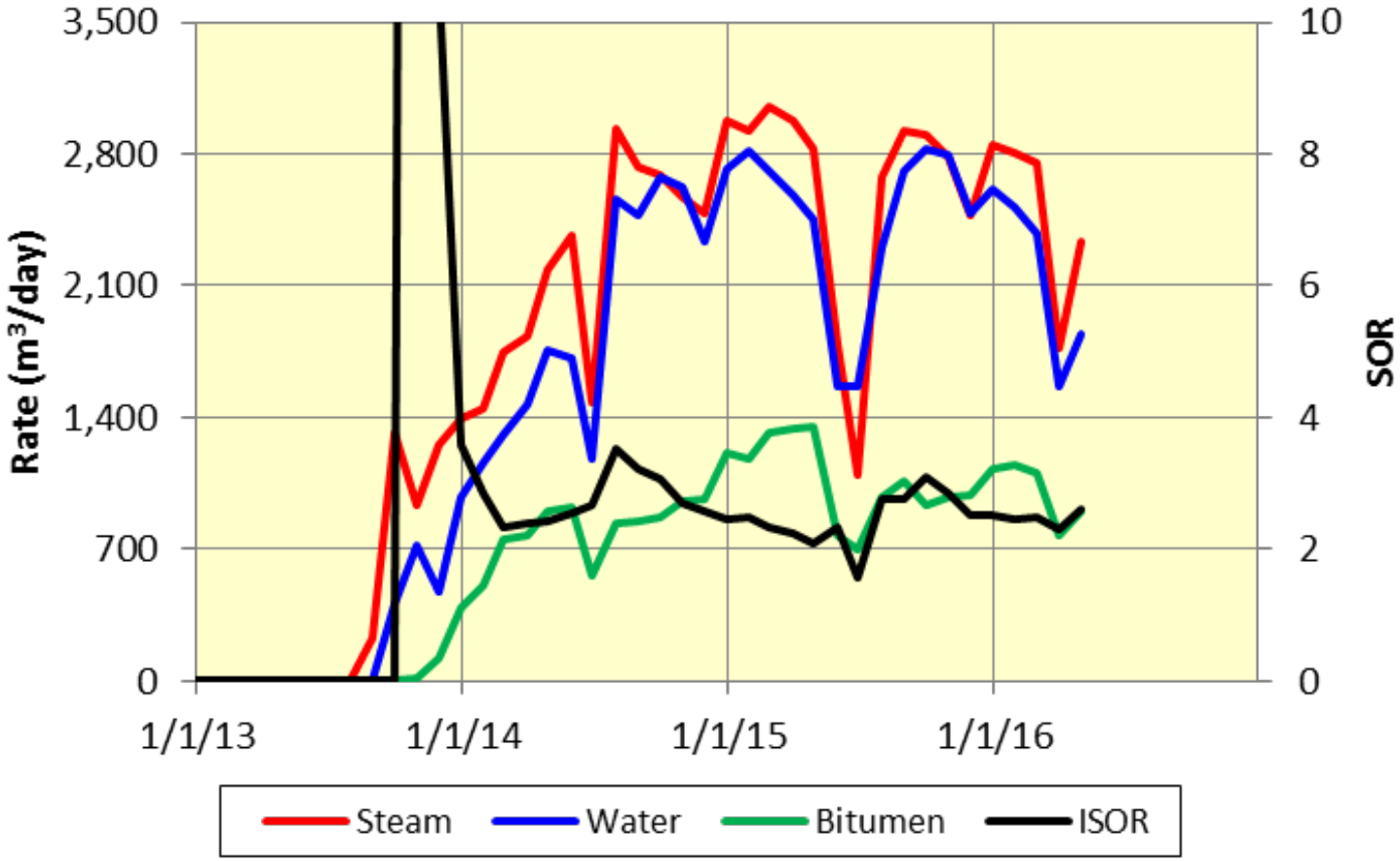


CLRP Performance – Pattern M

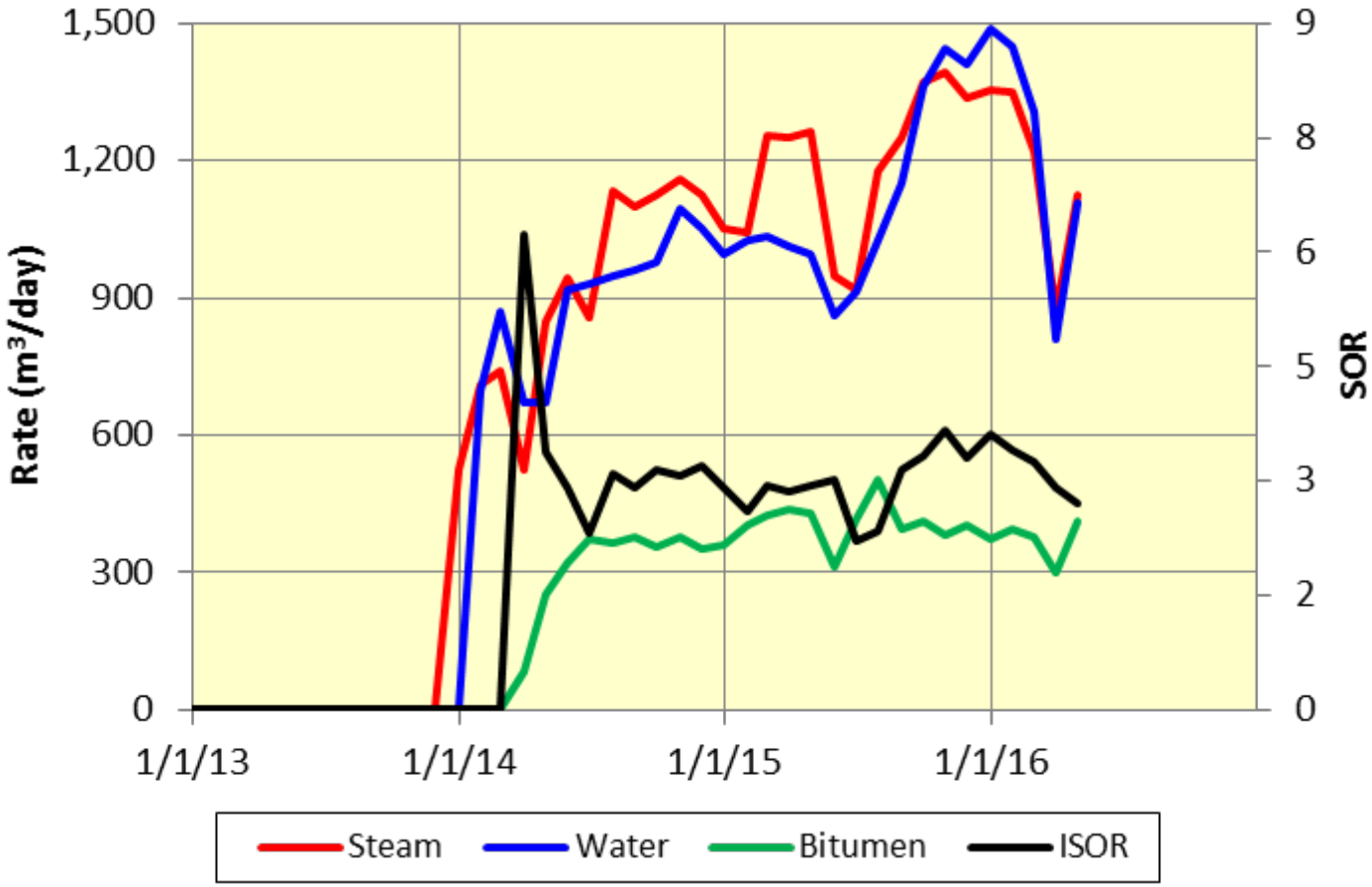


- M9P and M10P have very low production due to poor producer inflow, lowering the overall WSR. Both wellpairs operate at low pressure so steam is not considered lost to thief zones
- 4 producers were redrilled and exhibit improved fluid rates and water recovery, consistent with lower water recovery being a result of poor inflow rather than steam loss to thief zones

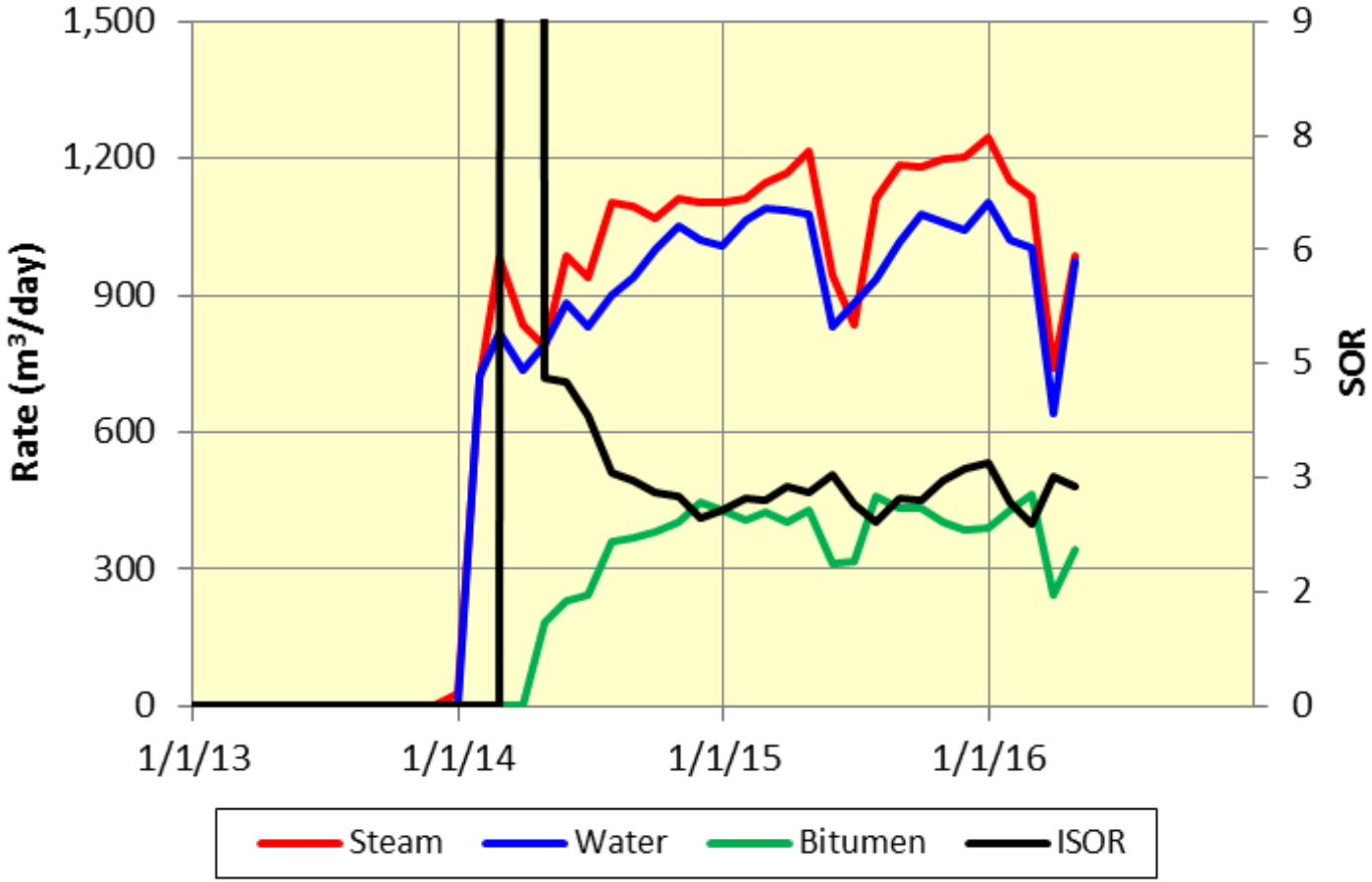
CLRP Performance – Pattern N



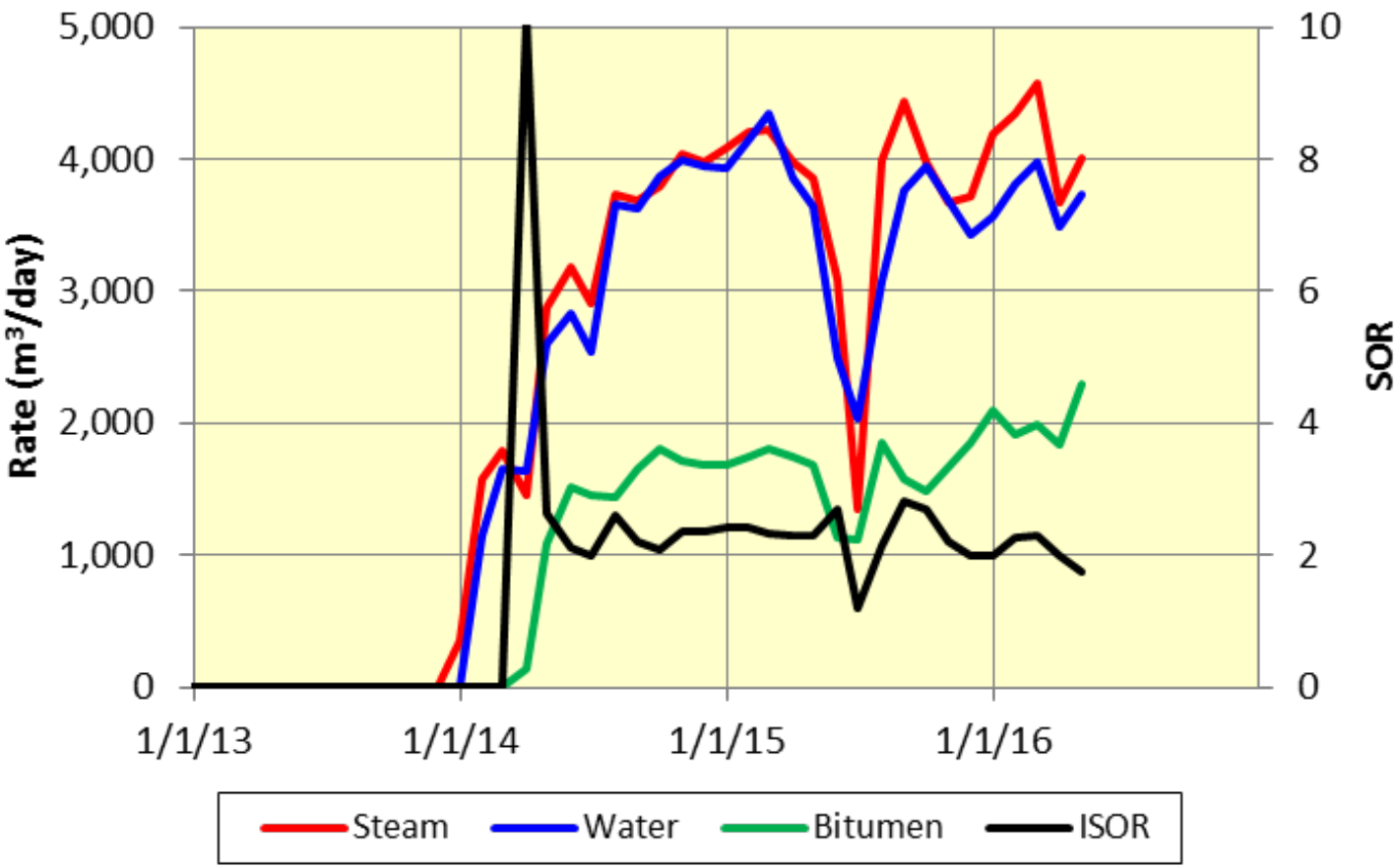
CLRP Performance – Pattern T



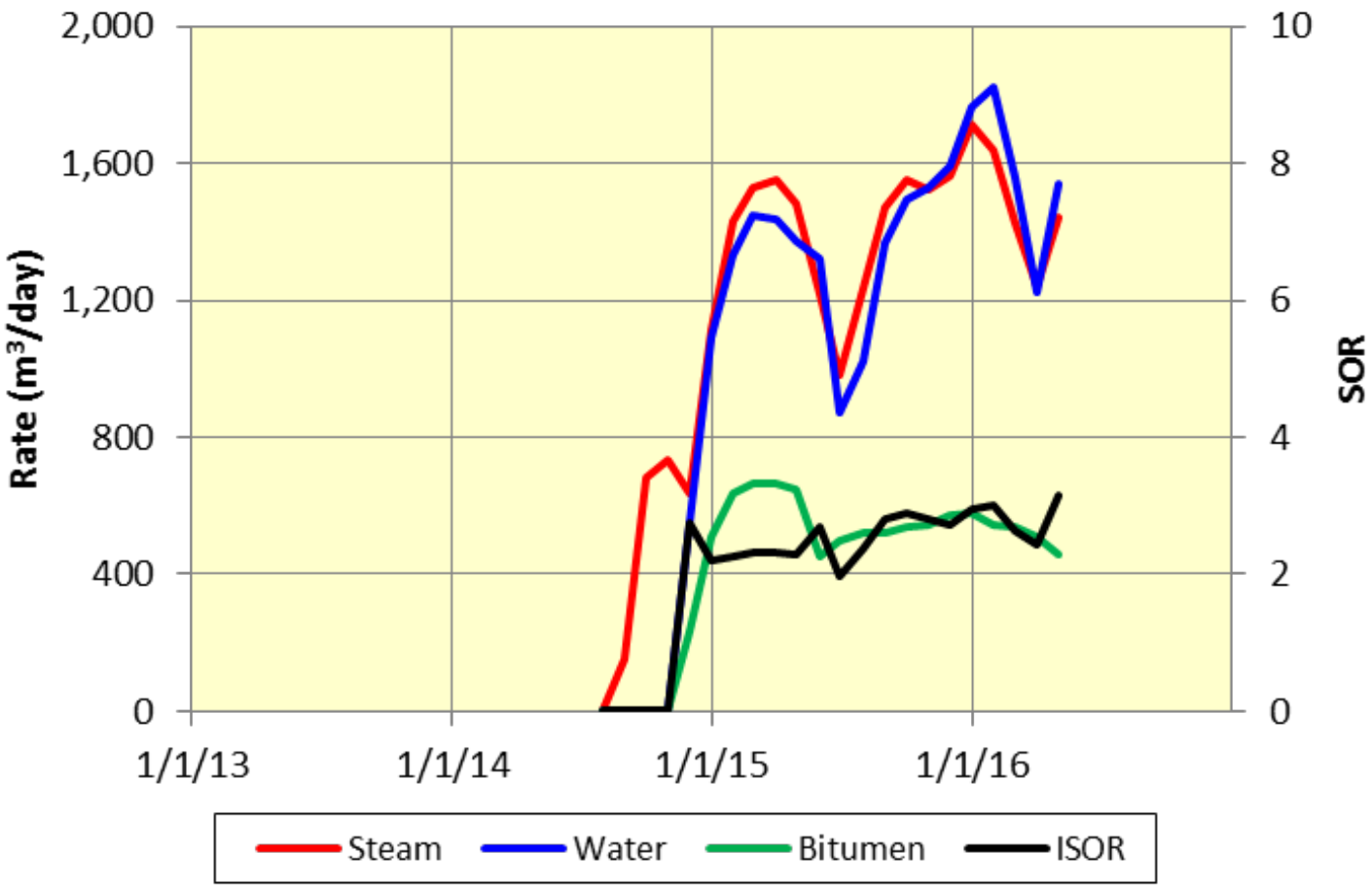
CLRP Performance – Pattern U



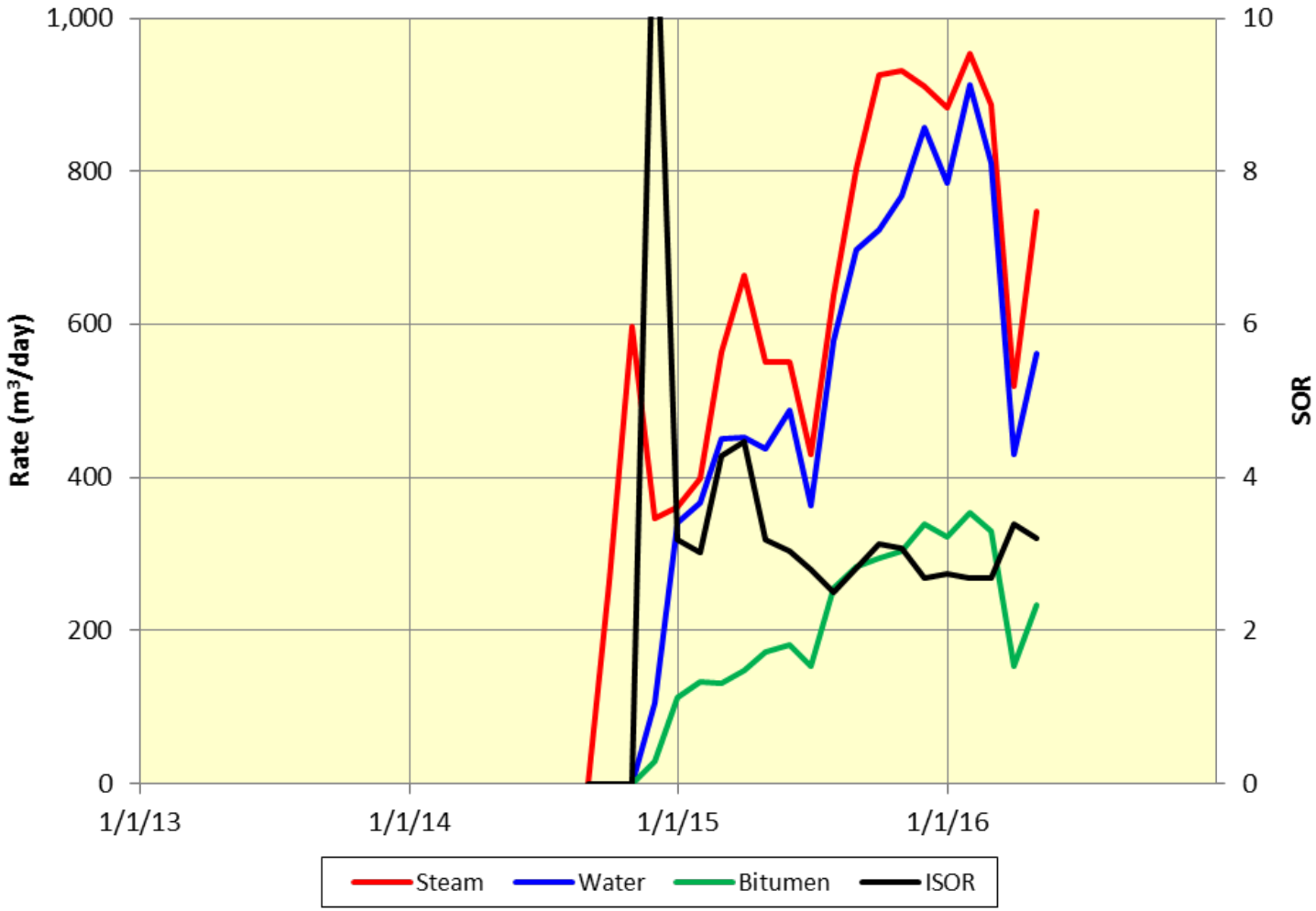
CLRP Performance – Pattern AP



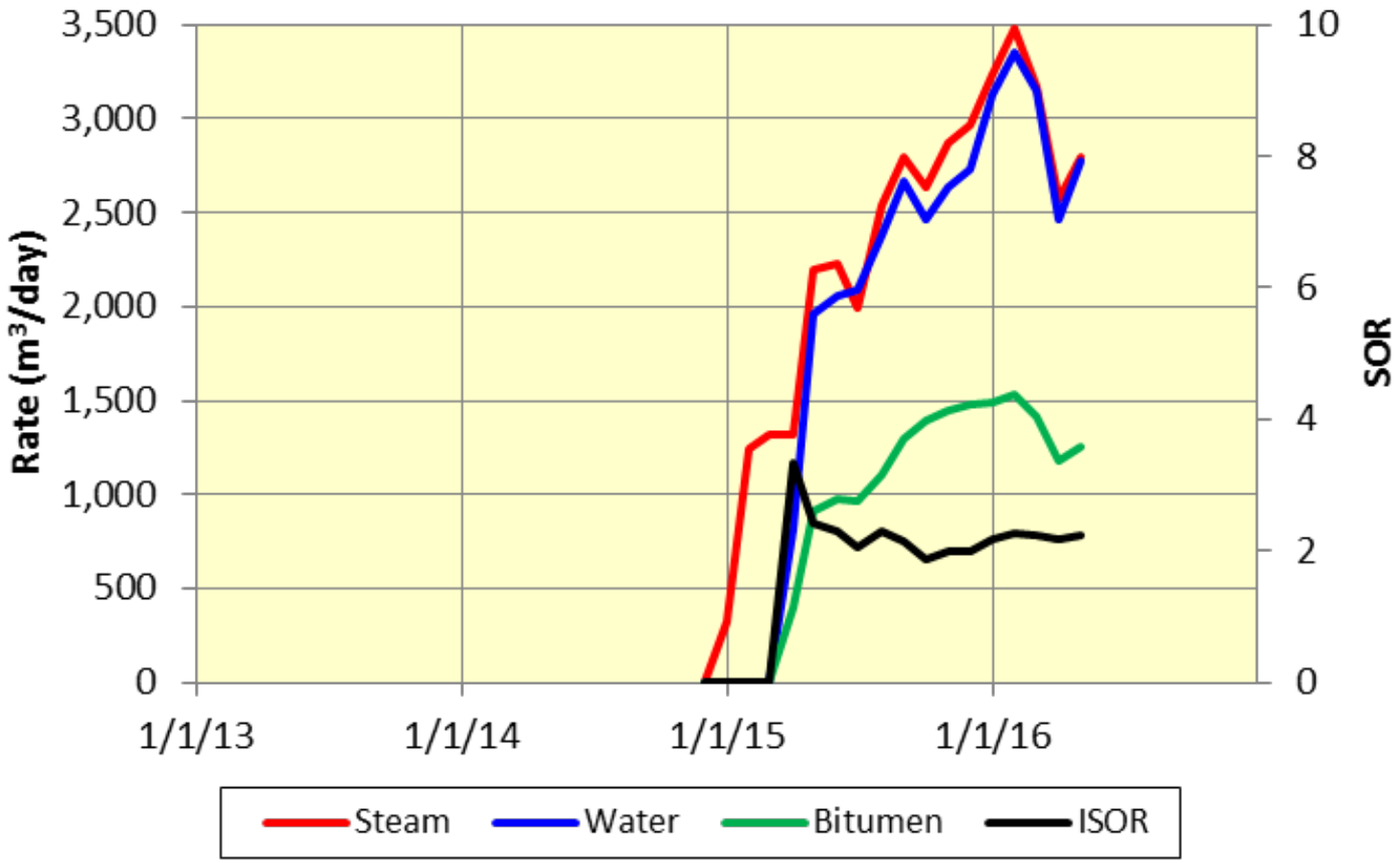
CLRP Performance – Pattern AF



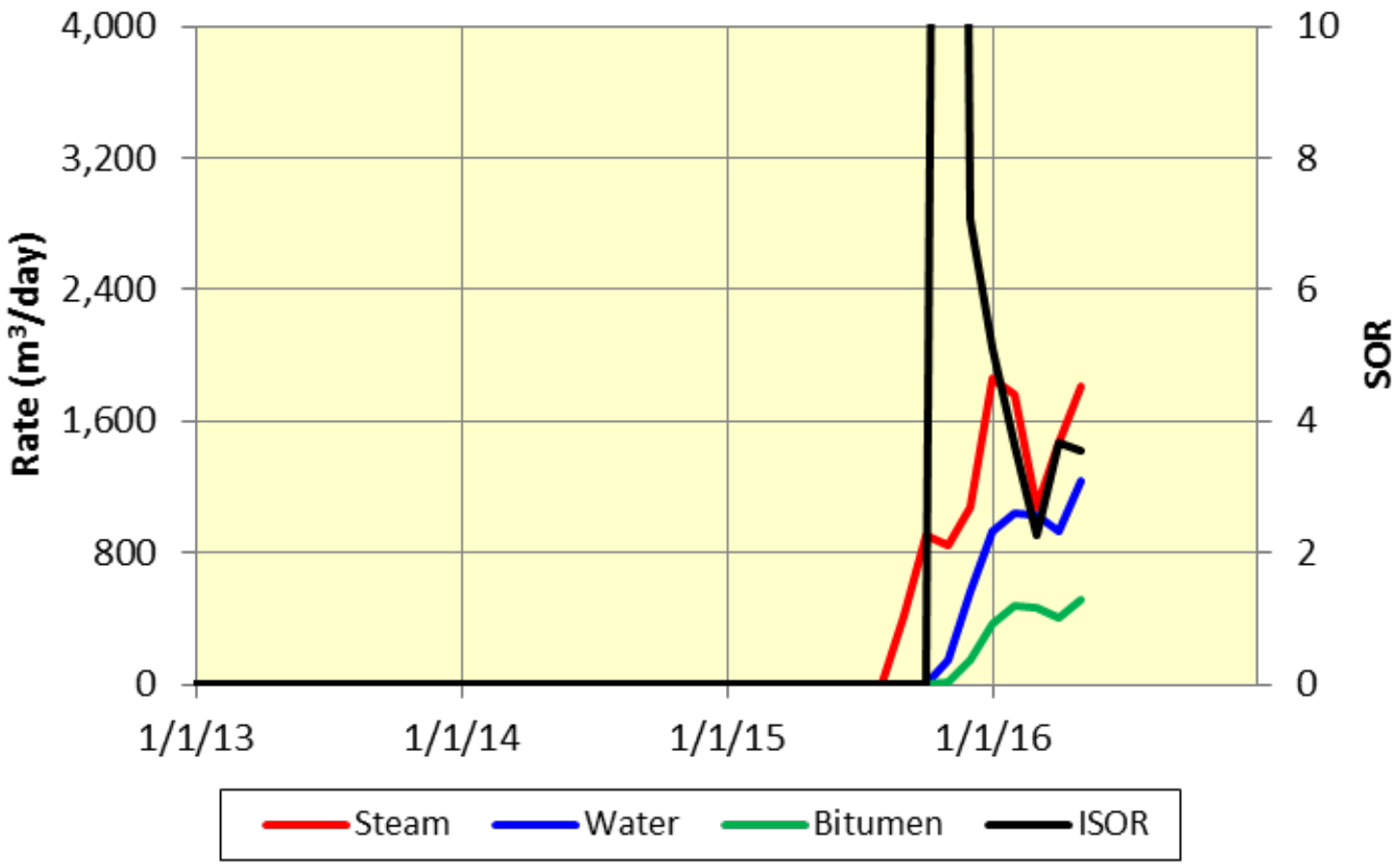
CLRP Performance – Pattern AG



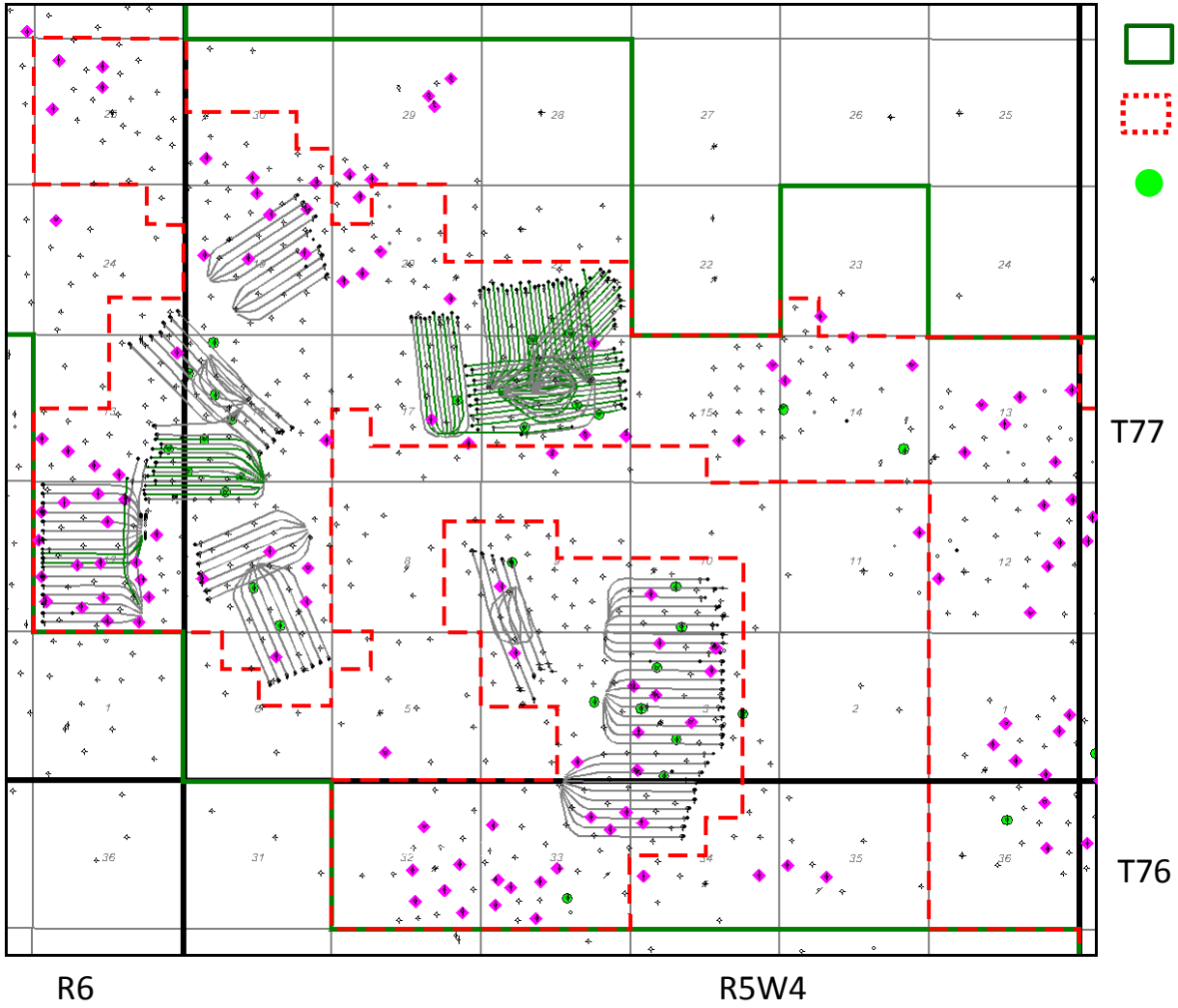
CLRP Performance – Pattern AN



CLRP Performance – Pattern P



CLRP ADA OB and Cased Wells



MEG OSL

Approved Development Area

Instrumented OB Wells

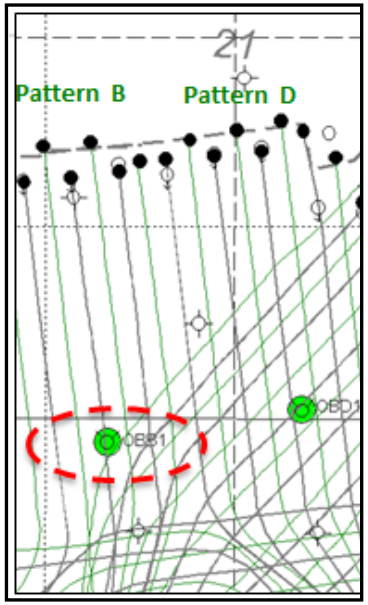
Non-Instrumented OB wells

OBB1 Logging Results

Sandy IHS

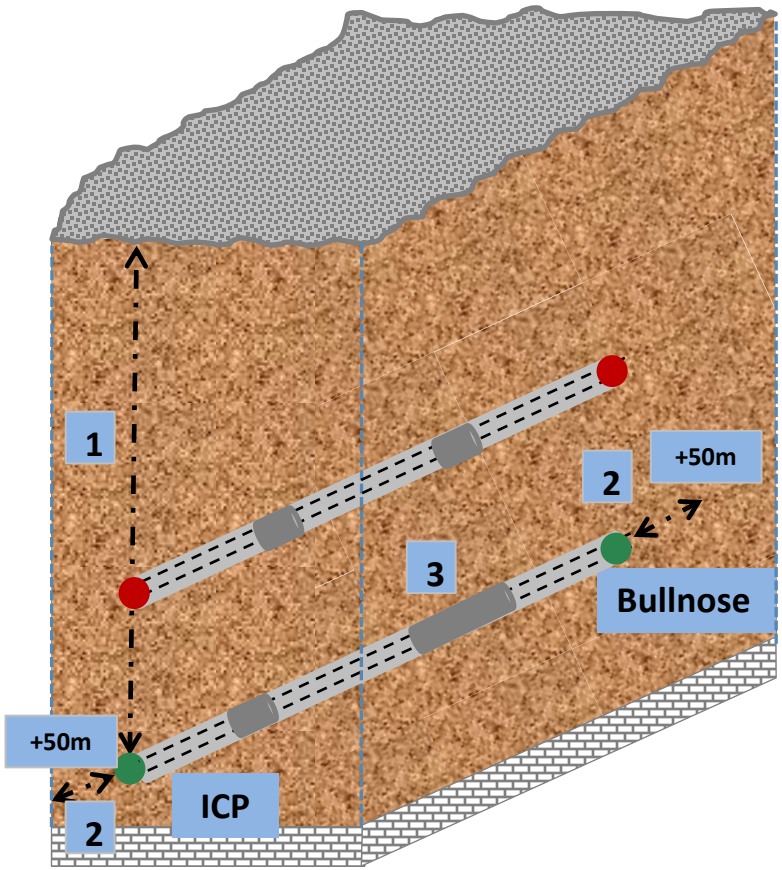
Before NCG Co-injection
~3 years SAGD

After NCG Co-injection
~3 years eMSAGP



Vertical chamber growth through IHS is observed after co-injection of NCG

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.

3 For blank sections >100m, only include 100m for effective length. Expect to access 50m from either side.

- **Total Bitumen In Place**

Use full pay height

Total Bitumen in Place

Pattern	Operating Wellpairs	Average h (m)	Average L (m)	Average Porosity	Average Oil Saturation	OBIP (m^3)
A	8	22	889	34%	72%	3,815,000
B	2	33	745	34%	82%	1,371,000
BB + D7	7	20	846	33%	83%	3,199,000
C + D6	7	27	803	34%	75%	3,889,000
D-D6-D7	5	21	680	34%	78%	1,847,000
E + F1	7	23	819	33%	77%	3,278,000
F - F1	5	22	776	33%	78%	2,148,000
V	6	21	1139	33%	72%	3,464,000
G	4	17	759	33%	71%	1,237,000
H	2	16	832	33%	72%	1,237,000
J	8	21	986	33%	76%	4,191,000
K	7	21	955	33%	75%	3,496,000
M	10	30	998	32%	75%	7,185,000
N	9	26	1054	33%	80%	6,634,000
T	7	19	952	32%	81%	3,325,000
U	6	19	882	30%	80%	2,414,000
AP	10	33	832	33%	83%	7,393,000
AF	5	23	972	32%	82%	2,862,000
AG	4	22	835	33%	77%	1,872,000
AN	8	27	870	32%	83%	4,940,000
P	10	20	957	32%	76%	4,655,000
TOTAL	**137**					**74,452,000**

Note: h is net Pay: SAGD base to SAGD Top
L is Liner length (including blanks) with 50m added to each end (100m total)

Bitumen Recovery

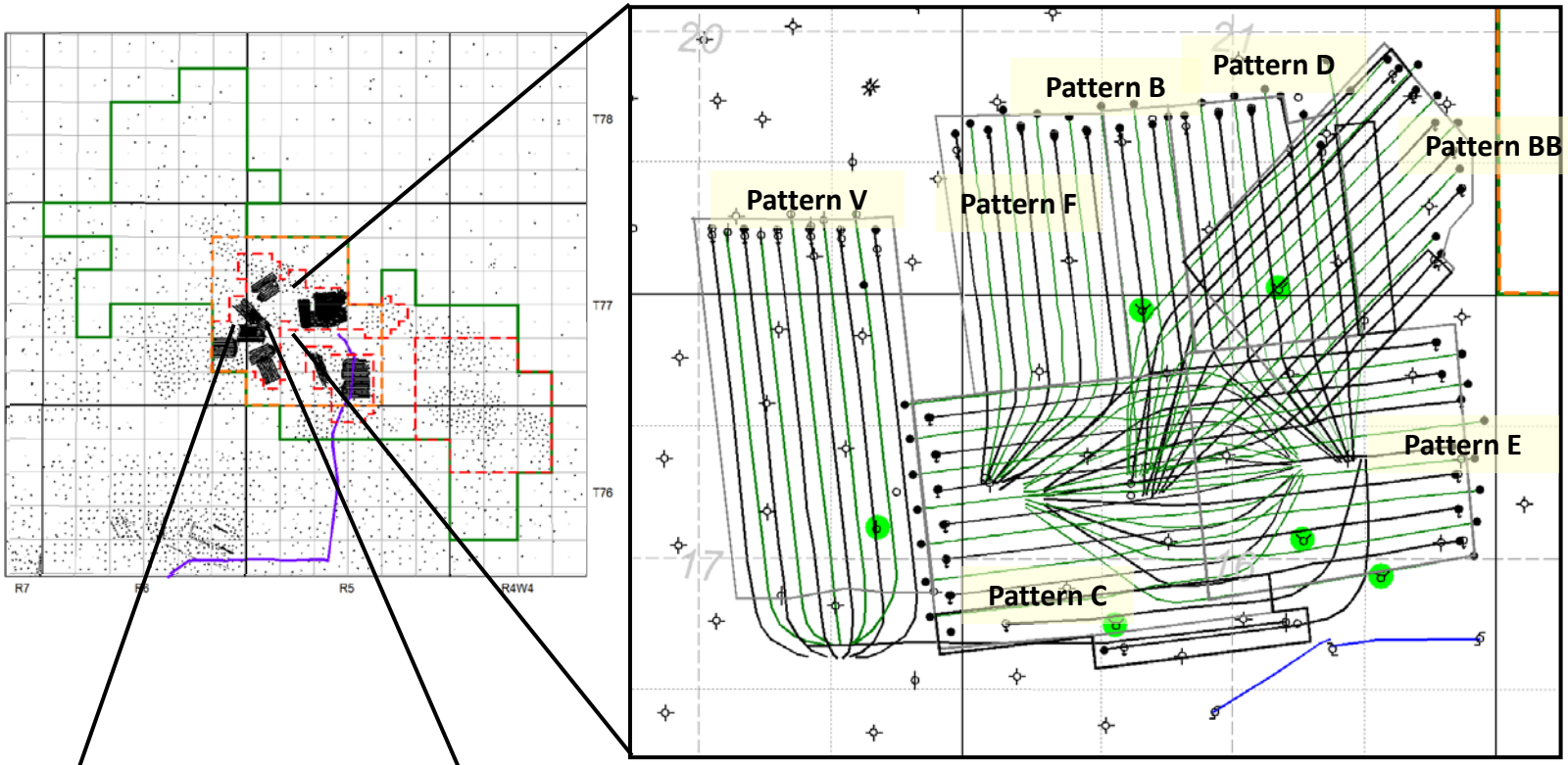
Pattern	Operating Wellpairs	Average h (m)	Average L (m)	Average Porosity	Average Oil Saturation	SAGDable BIP (m^3)	Ultimate Recovery (m^3)	Cumulative Production (m^3)	Recovery (% SAGDable)
A	8	19	889	34%	72%	3,296,000	1,812,800	1,873,905	56.9%
B	2	30	745	34%	82%	1,246,000	685,300	666,086	53.5%
BB + D7	7	17	846	33%	83%	2,714,000	1,492,700	1,374,947	50.7%
C + D6	7	24	803	34%	75%	3,453,000	1,899,150	2,877,355	83.3%
D-D6-D7	5	18	680	34%	78%	1,622,000	892,100	927,685	57.2%
E + F1	7	20	819	33%	77%	2,915,000	1,603,250	1,760,001	60.4%
F - F1	5	19	776	33%	78%	1,867,000	1,026,850	1,018,645	54.6%
V	6	18	1139	33%	72%	2,970,000	1,633,500	647,699	21.8%
G	4	14	759	33%	71%	1,025,000	563,750	145,239	14.2%
H	2	13	832	33%	72%	509,000	279,950	62,014	12.2%
J	8	18	986	33%	76%	3,592,000	1,975,600	412,233	11.5%
K	7	18	955	33%	75%	2,996,000	1,647,800	509,194	17.0%
M	10	27	998	32%	75%	6,469,000	3,557,950	1,069,190	16.5%
N	9	23	1054	33%	81%	5,887,000	3,237,850	828,576	14.1%
T	7	16	952	32%	81%	2,803,000	1,541,650	292,137	10.4%
U	6	16	882	30%	80%	2,033,000	1,118,150	284,154	14.0%
AP	10	28	832	33%	83%	6,439,000	3,541,450	1,278,313	19.9%
AF	5	18	972	32%	82%	2,278,000	1,252,900	292,580	12.8%
AG	4	20	835	33%	77%	1,701,000	935,550	119,673	7.0%
AN	8	23	870	32%	83%	4,187,000	2,302,850	512,957	12.3%
P	10	20	957	32%	76%	4,655,000	2,560,250	72,864	1.6%
TOTAL	**137**					**60,002,000**	**33,001,100**	**17,025,446**	28.4%

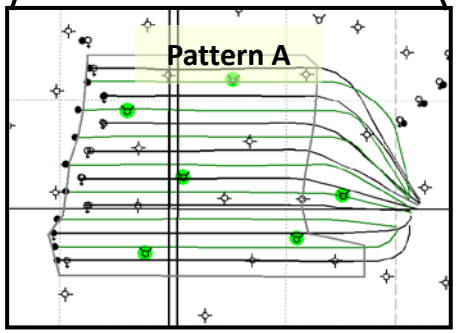
Note: Production volume and number of operating wellpairs are as of April 2016
h is net pay above the producer
L is Liner length (including blanks) with 50m added to each end (100m total)
Cumulative production includes associated infill wells

MEG ENERGY

Update on Enhanced Modified Steam and Gas Push (eMSAGP)

Phase 1 and Phase 2 Pad Layout





eMSAGP Rollout:

- ✓ Pad A Pilot (A1-A3): Dec. 2011 35% R.F.
- ✓ Pad B (B1-B6): Feb. 2013 30% R.F.
- ✓ Pad C (C1-C6, D6): July 2013 46% R.F.
- ✓ Pad D (D1-D5): Aug. 2013 33% R.F.
- ✓ Pad E (E1-E6, F1): Jan. 2014 31% R.F.
- ✓ Pad F (F2-F6): Jan. 2014 36% R.F.
- ✓ Rest of Pad A (A4-A6): April 2014 30% R.F.

Phase 1 eMSAGP (Pilot)

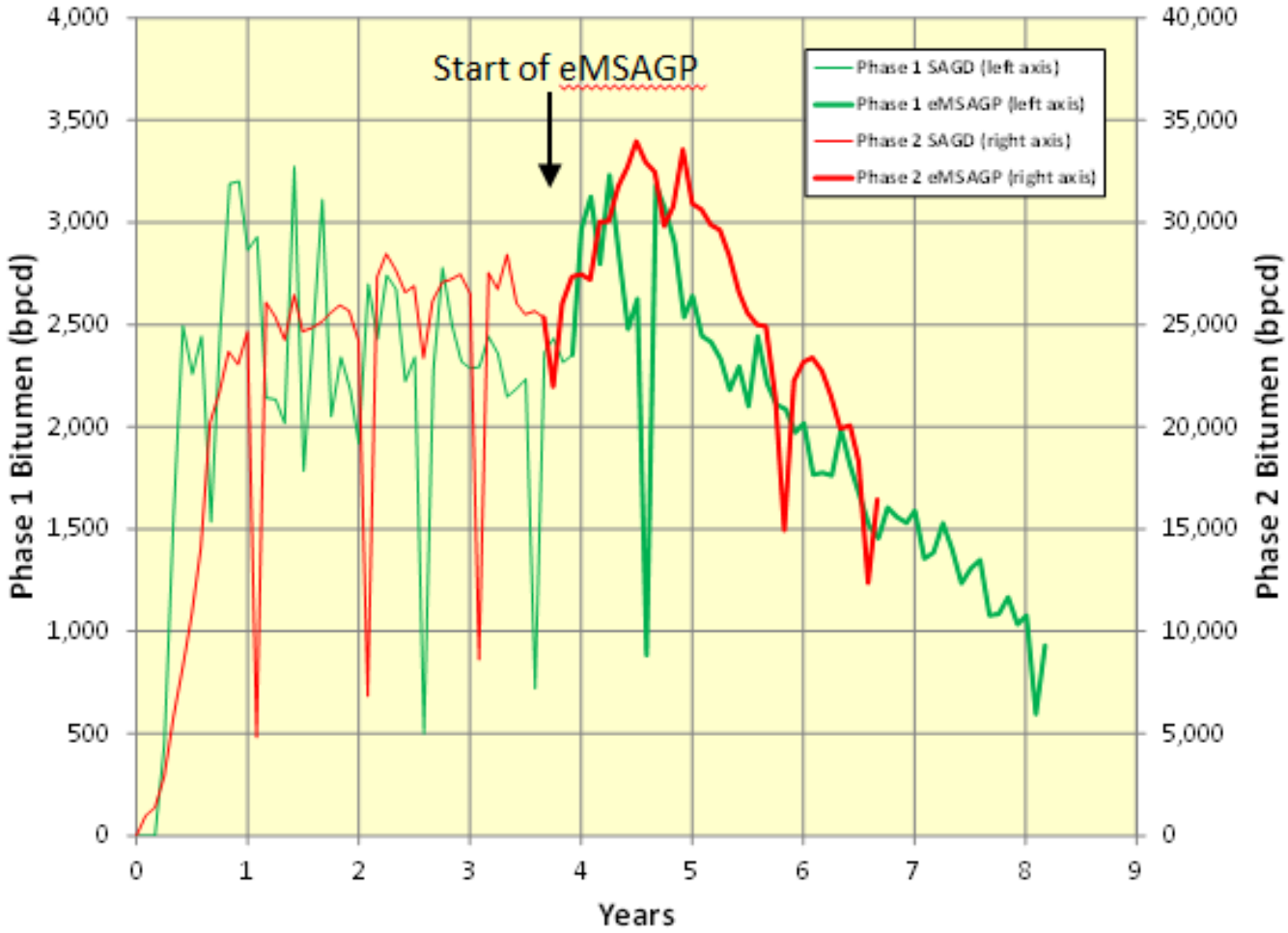
Recovery Phase	SAGD	eMSAGP
Bitumen Production (bbl)	3,048,000	3,065,000
Recovery of SAGDable OOIP (%)	35	35
SOR in the Phase	2.64	1.31

Note:

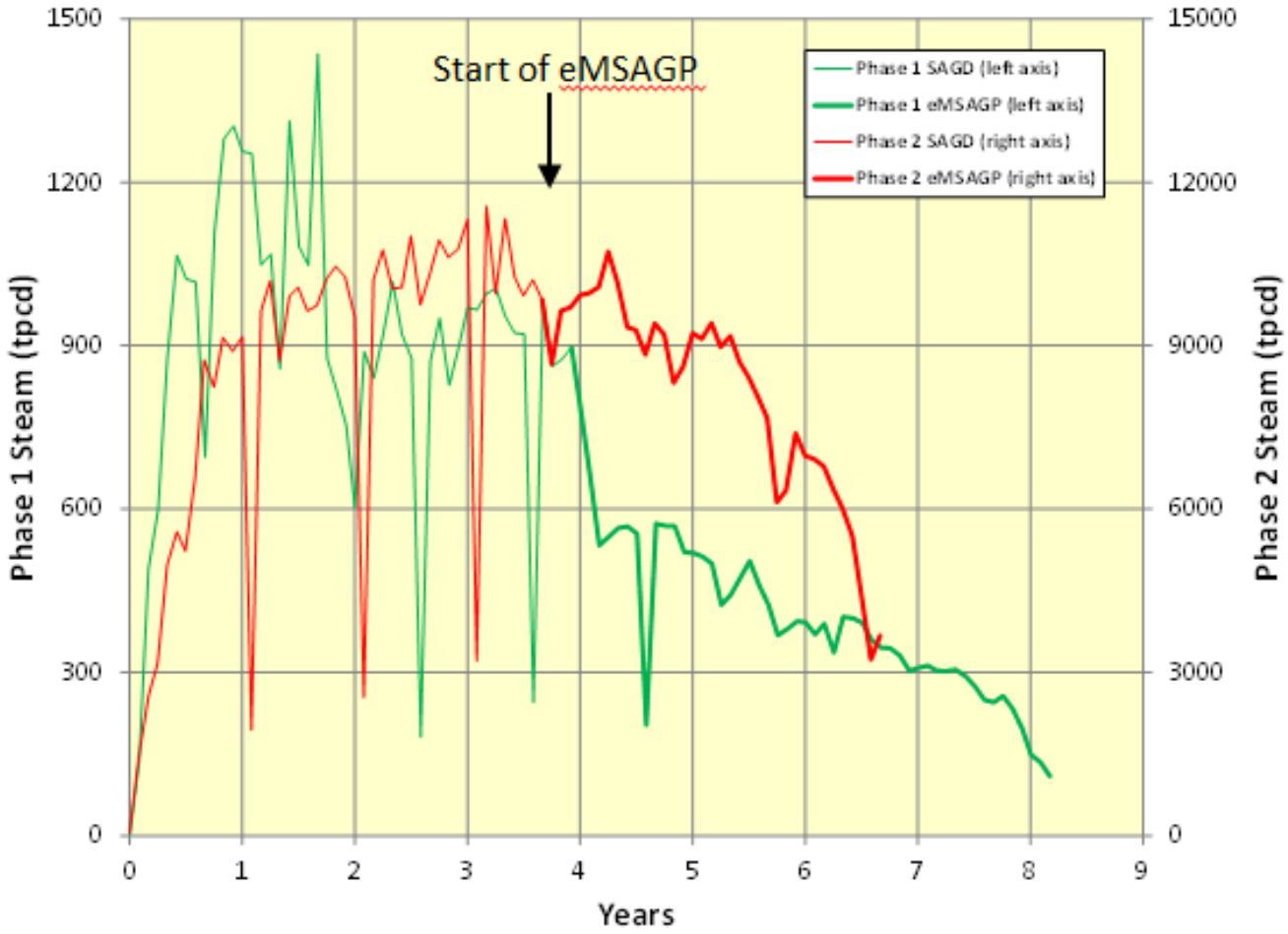
SAGDable OOIP = 8,799,000 bbls

Production of the eMSAGP phase was to April 30, 2016.

Bitumen Rates for Phases 1 and 2



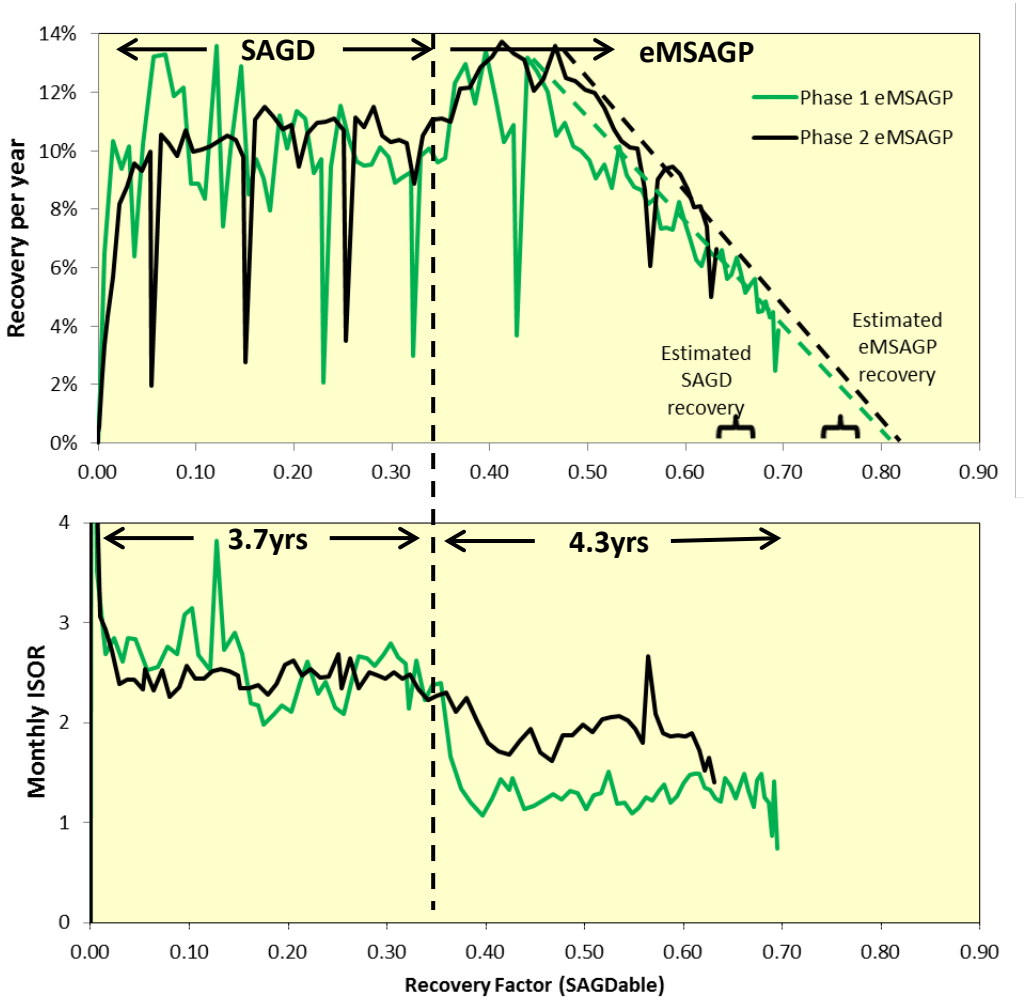
Steam Rates for Phases 1 and 2



Performance Comparison of Phases 1 and 2

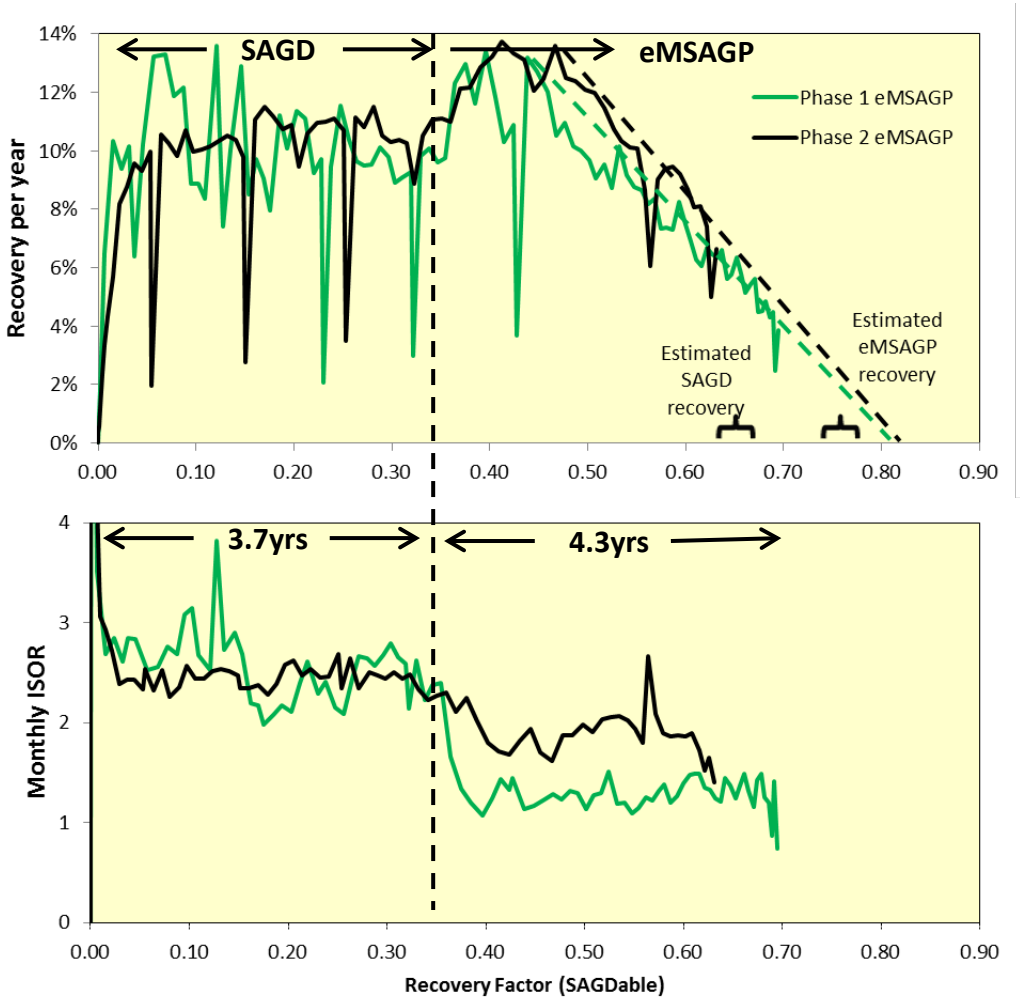
- Comparison is facilitated by introducing normalized bitumen production
- Normalized bitumen rate = bitumen rate / SOIP, where SOIP is SAGDable Oil In Place
- The normalized rates have the dimension of time^{-1} and can therefore be compared for projects having different number of wells.
  - Normalized rates are expressed as recovery rates per year

Performance Comparison of Phases 1 and 2



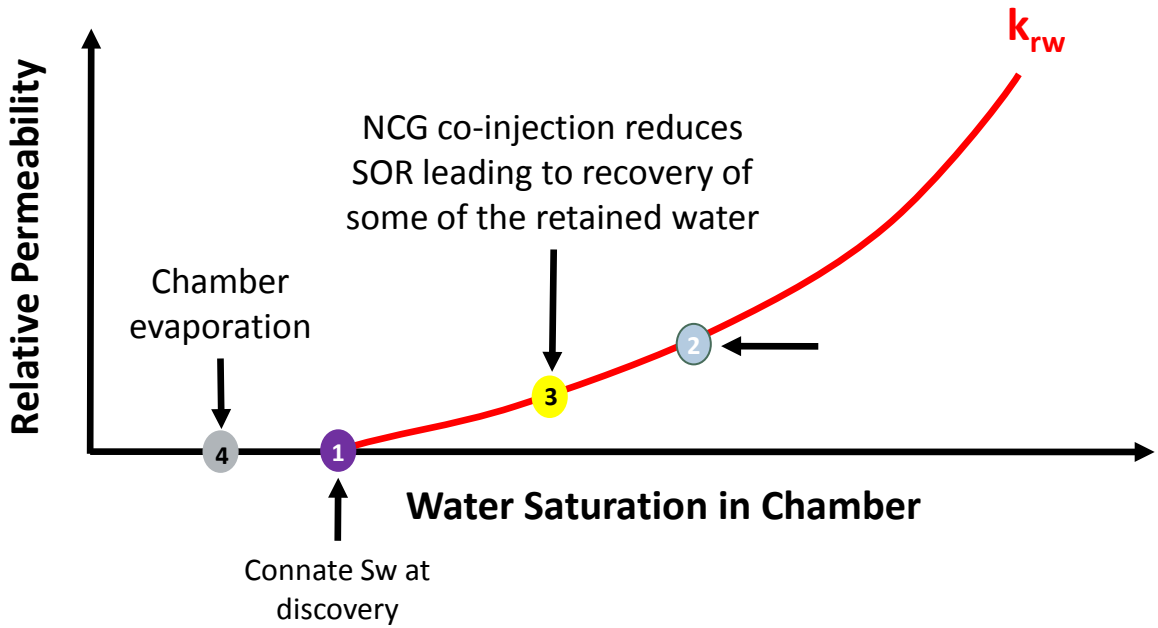
- The normalized bitumen rates plotted against SAGDable recovery indicate a similar ultimate eMSAGP bitumen recovery for Phases 1 and 2
- eMSAGP suggests an additional recovery of ~10-12% over SAGD (without infill wells) with a significant reduction in SOR

Performance Comparison of Phases 1 and 2



- The normalized bitumen rates plotted against SAGDable recovery indicate a similar ultimate eMSAGP bitumen recovery for Phases 1 and 2
- eMSAGP suggests an additional recovery of ~10-12% over SAGD with an significant reduction in SOR

eMSAGP Produced Water to Steam Ratio (WSR)



- During SAGD operation, a part of the injected water (condensed steam) is retained in the reservoir as chamber develops (point 1 to point 2). WSR is expected to be <1
- When the recovery process is transitioned from SAGD to eMSAGP, the NCG co-injection reduces the SOR recovering some of the retained water (point 2 to point 3)
- Partial pressure of steam starts to drop (while total pressure stays constant) and the temperature of the chamber falls. The stored heat is recovered by evaporating the water surrounding the hot reservoir rocks. Chamber becomes progressively drier and water saturation inside the chamber could go below initial connate water saturation (point 3 to point 4). WSR is expected to be >1
- For pads that are connected bottom water, it is possible that WSR can be further increased due to bottom water production. Production practice has been put in place to minimize bottom water intrusion by monitoring produced water chemistry

Conclusions

- eMSAGP has been successfully implemented to Phases 1 and 2
  - After several years of operation, eMSAGP has demonstrated better performance than SAGD: better recoveries (~10%-12% higher) with significant SOR reductions (~30-50% lower)
  - Steam freed up from eMSAGP process has been redeployed to new SAGD wells to increase overall production beyond nameplate capacity without installing any new additional steam capacity
- It appears that further enhancements to eMSAGP is possible
  - Normalized rate plot for Phases 1 and 2 shows that the bitumen rates and recoveries are trending to the same levels, although steam reductions were more conservative on Phase 2
  - Given the similarity of Phase 2 and Phase 1 bitumen production, it appears that there is room for further steam optimization and reduction of ISOR in eMSAGP

Conclusions

- From experience at Phase 2, it appears that optimal timing can differ depending on resource
  - For pay that is not encumbered by thief zones (bottom water), the greatest benefit in production and cumulative SOR could be realized by implementing eMSAGP at or before 30% recovery

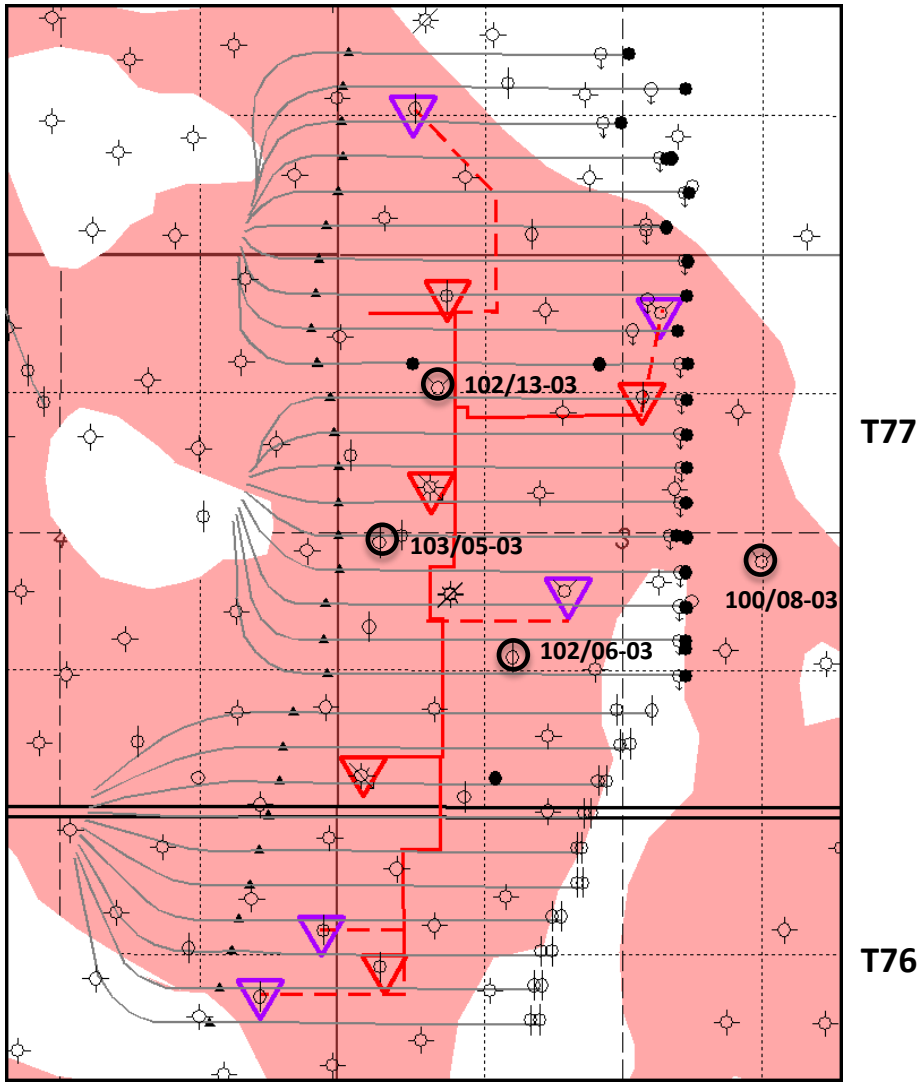
MEG ENERGY

CLRP Gas Cap Re-pressuring

Gas Cap Re-pressuring Project Update

- The AER approval was granted in November 2012
- Natural gas injection into 5 wells commenced in June 2013
- Total injection to date was 246 e6m3 (~8.7 BCF), with an average injection rate of 104 e3m3/day (~3.7mmscf/day) over the period
- Pressure responses have been observed in all 5 monitoring wells
- Estimated gas zone pressure above the active SAGD patterns (M & N) 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
- Plan is to maintain the current pressure on top of the active SAGD area and monitor pressures in gas and SAGD zones closely

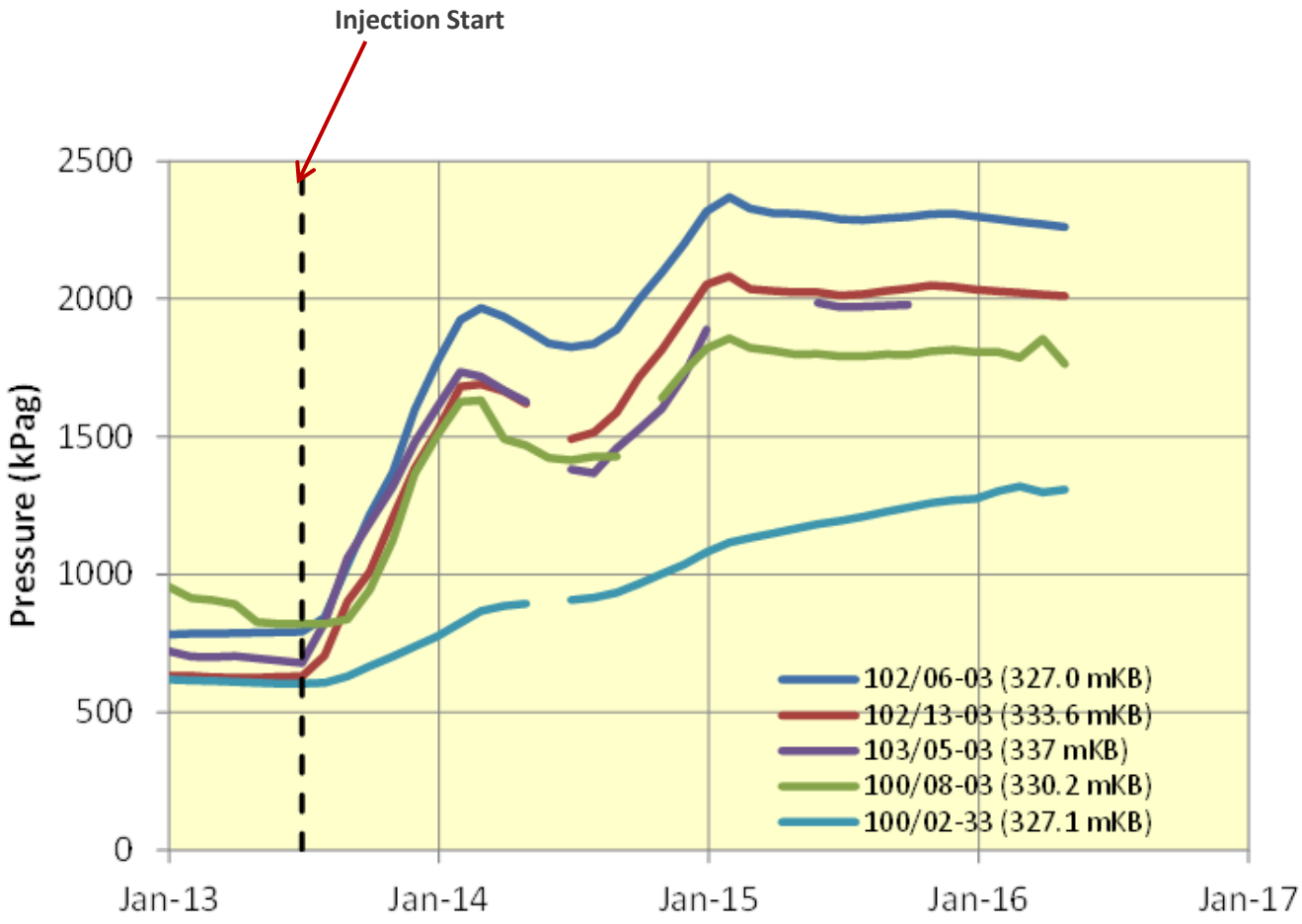
CLRP Gas Cap Re-pressure Scheme (Patterns M & N)



- 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**

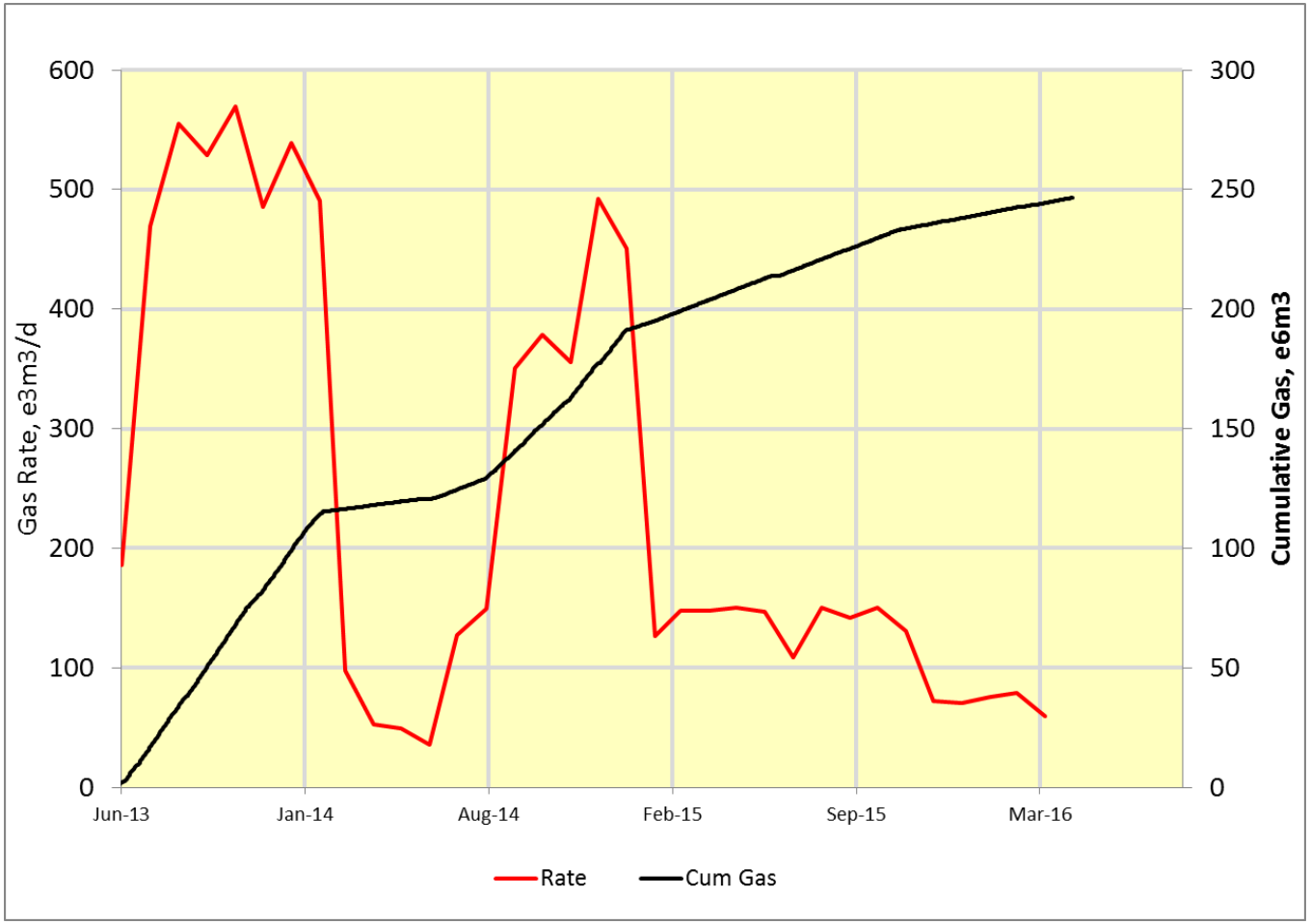
Note:
Not all SAGD intervals in the pool wells are directly connected to associated gas

Observation Well Pressure Readings



The 100/02-33 well is roughly 1,600 meters away from the active injection/SAGD area

Gas Injection



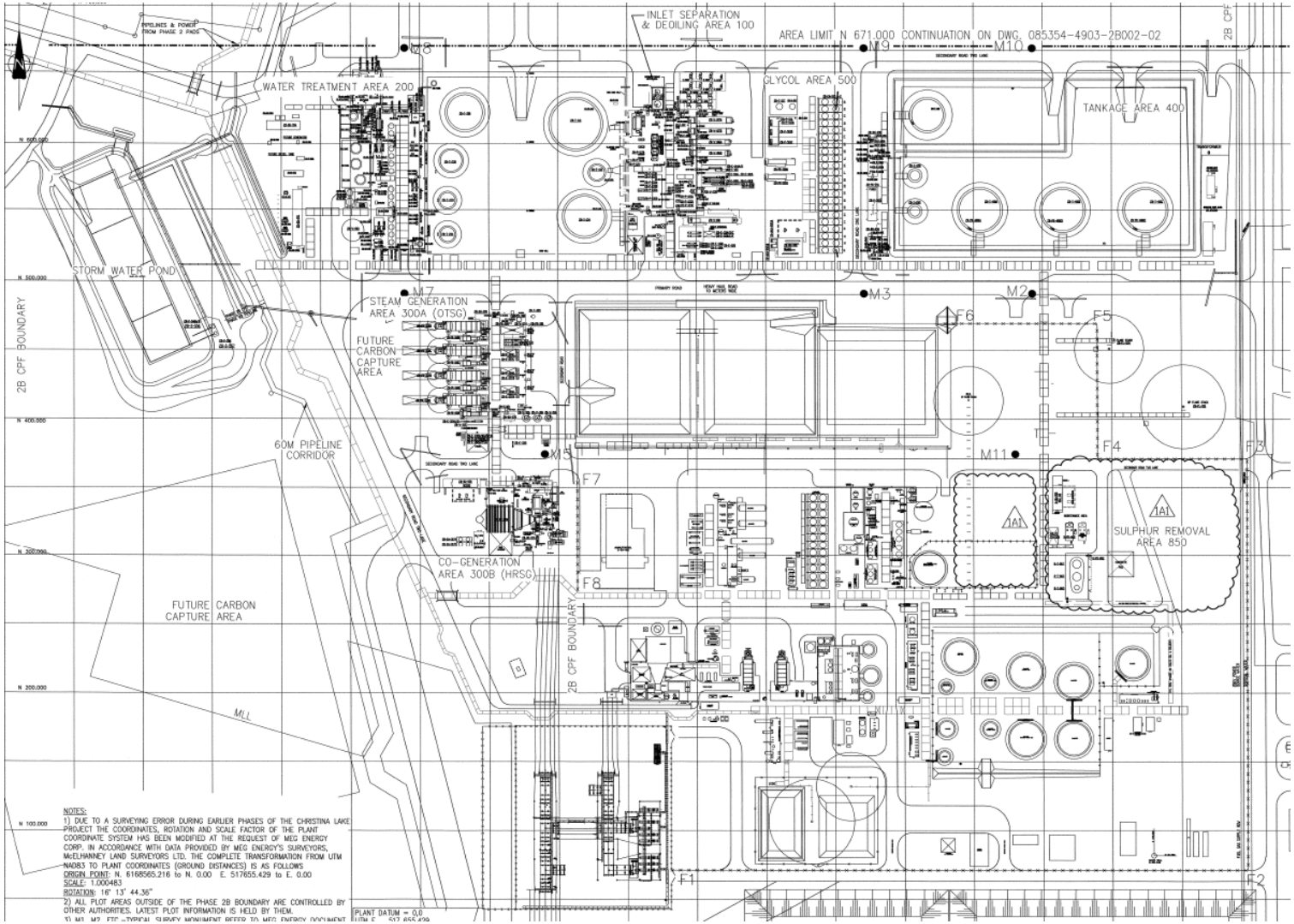
MEG ENERGY

OPERATIONS

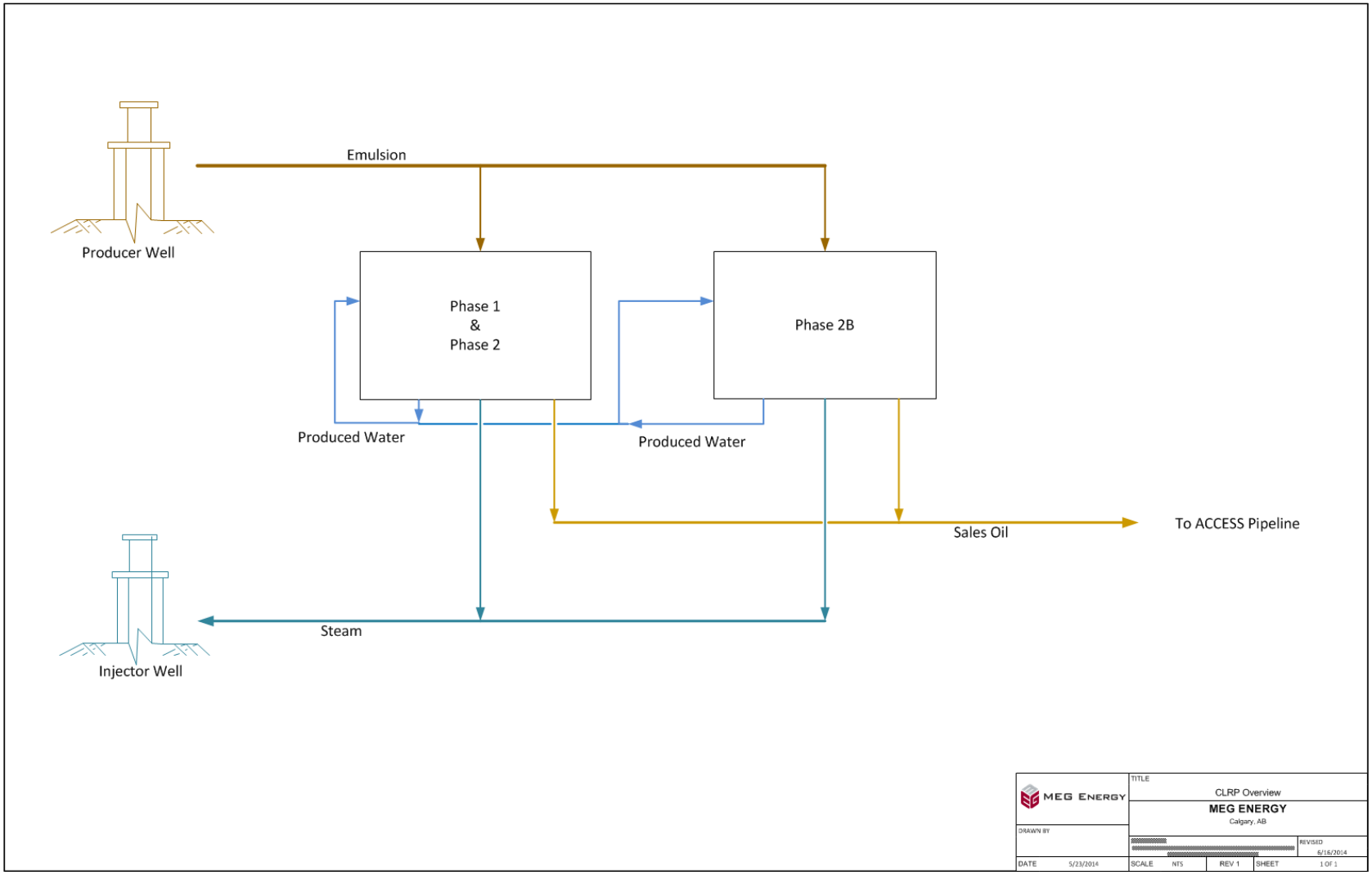
Operations Overview

- Operation Overview
- sulphur Recovery Unit Incident
- Bitumen Treatment
- Water Treatment
- Steam Generation
- Power Generation
- Gas Usage

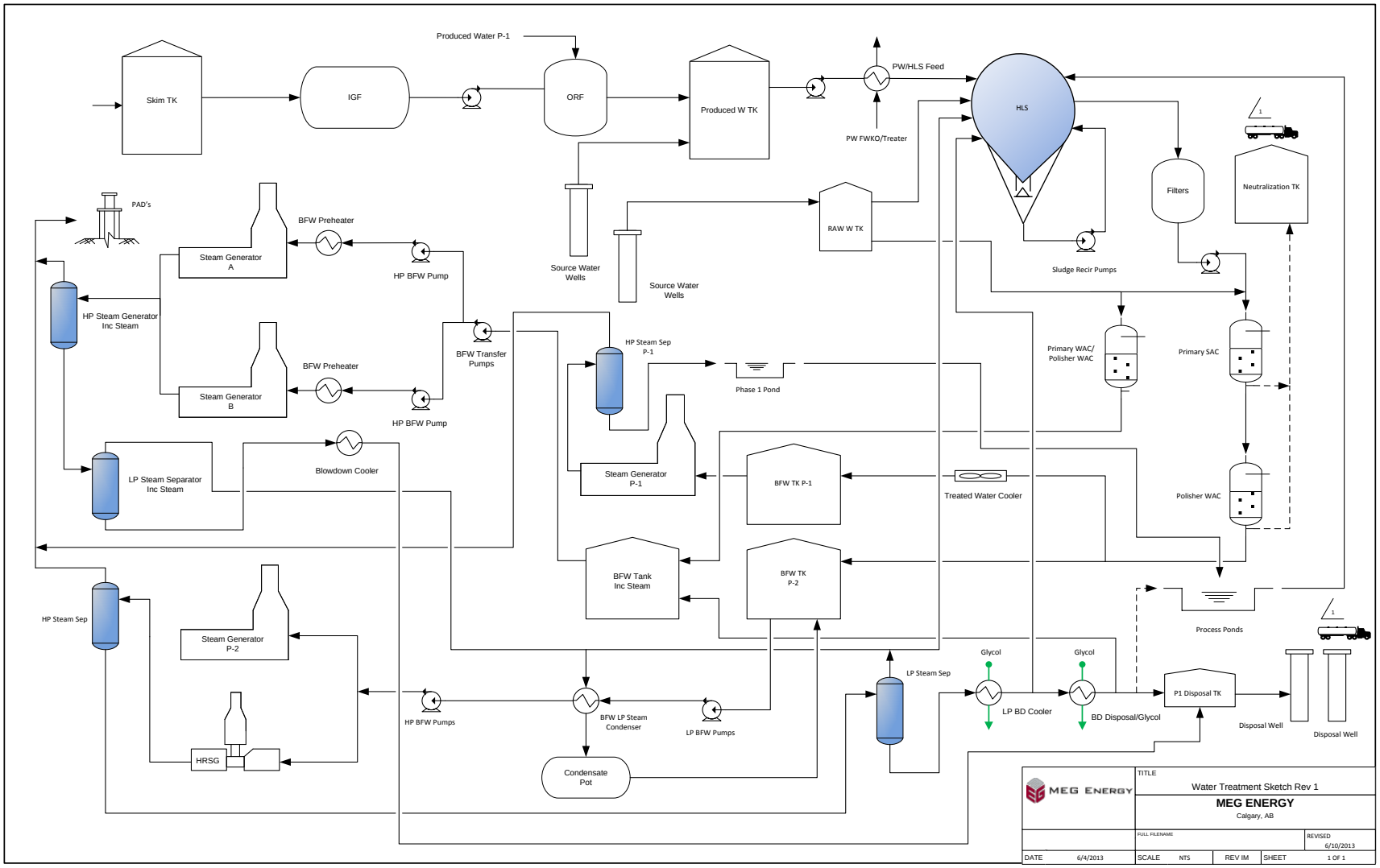
CPF Site Plan



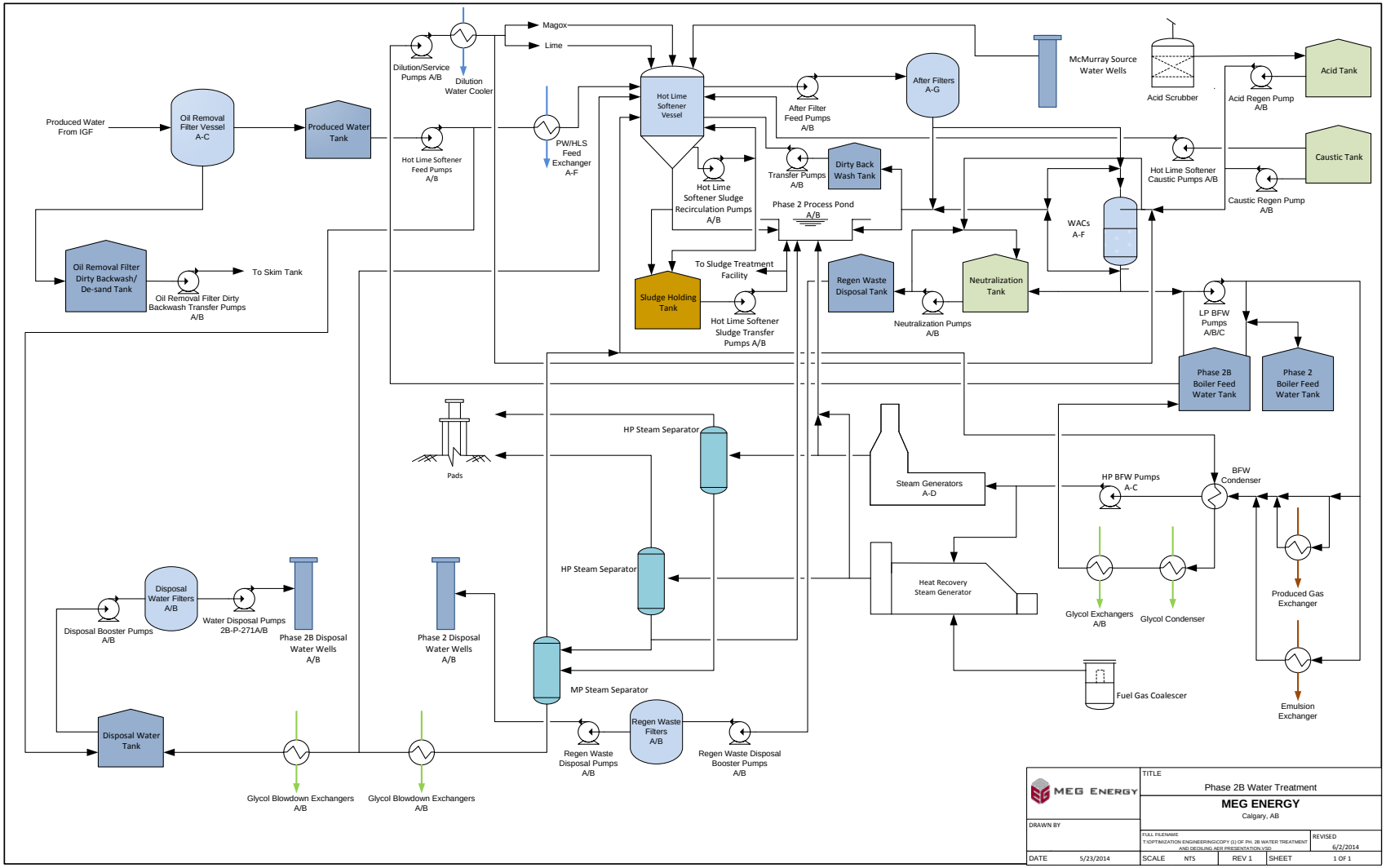
Integrated Distribution/Gathering System



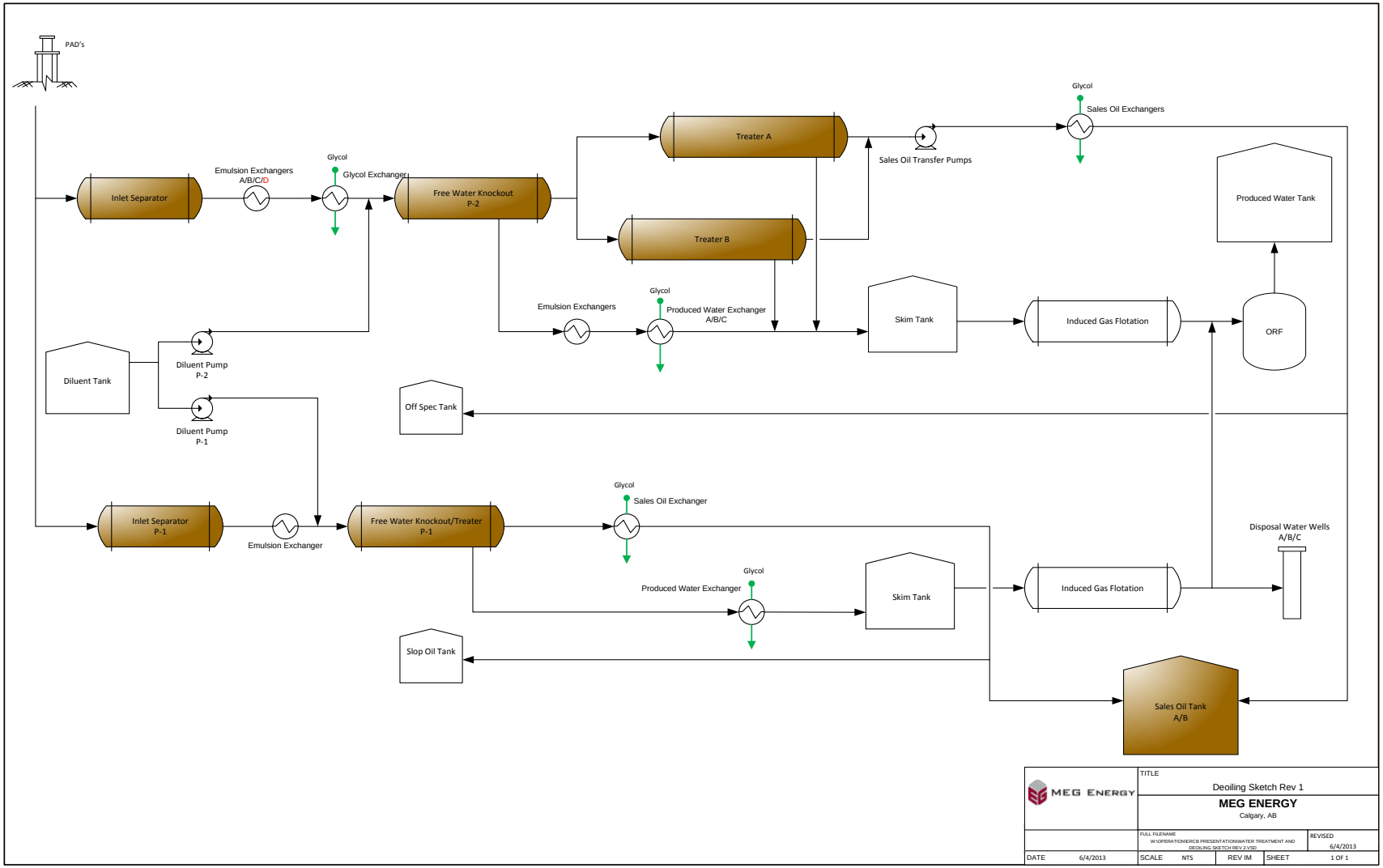
Water and Steam Process Overview Phase 1 and 2



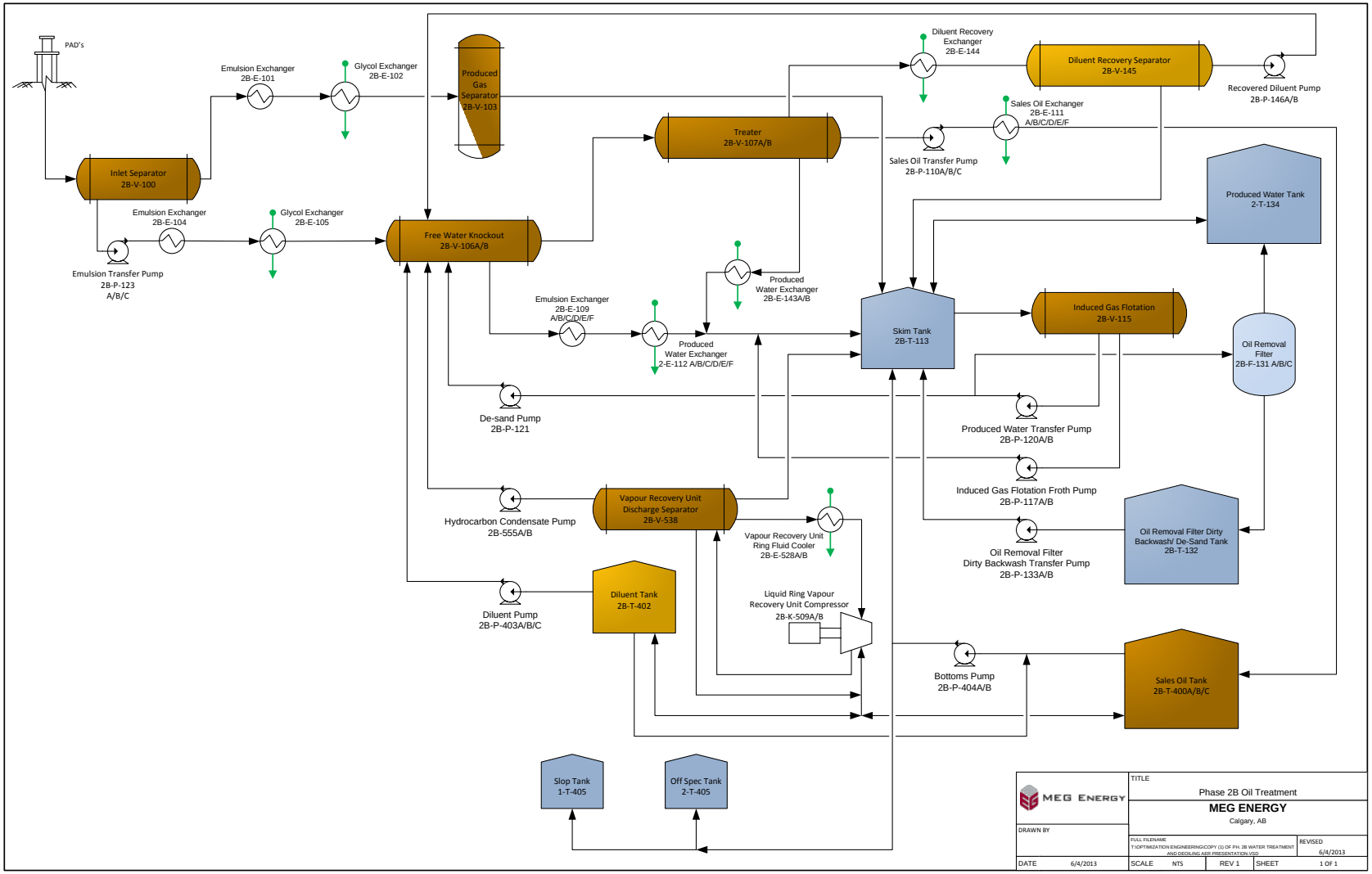
Water and Steam Process Overview Phase 2B



Oil Treatment Overview Phase 1 and 2



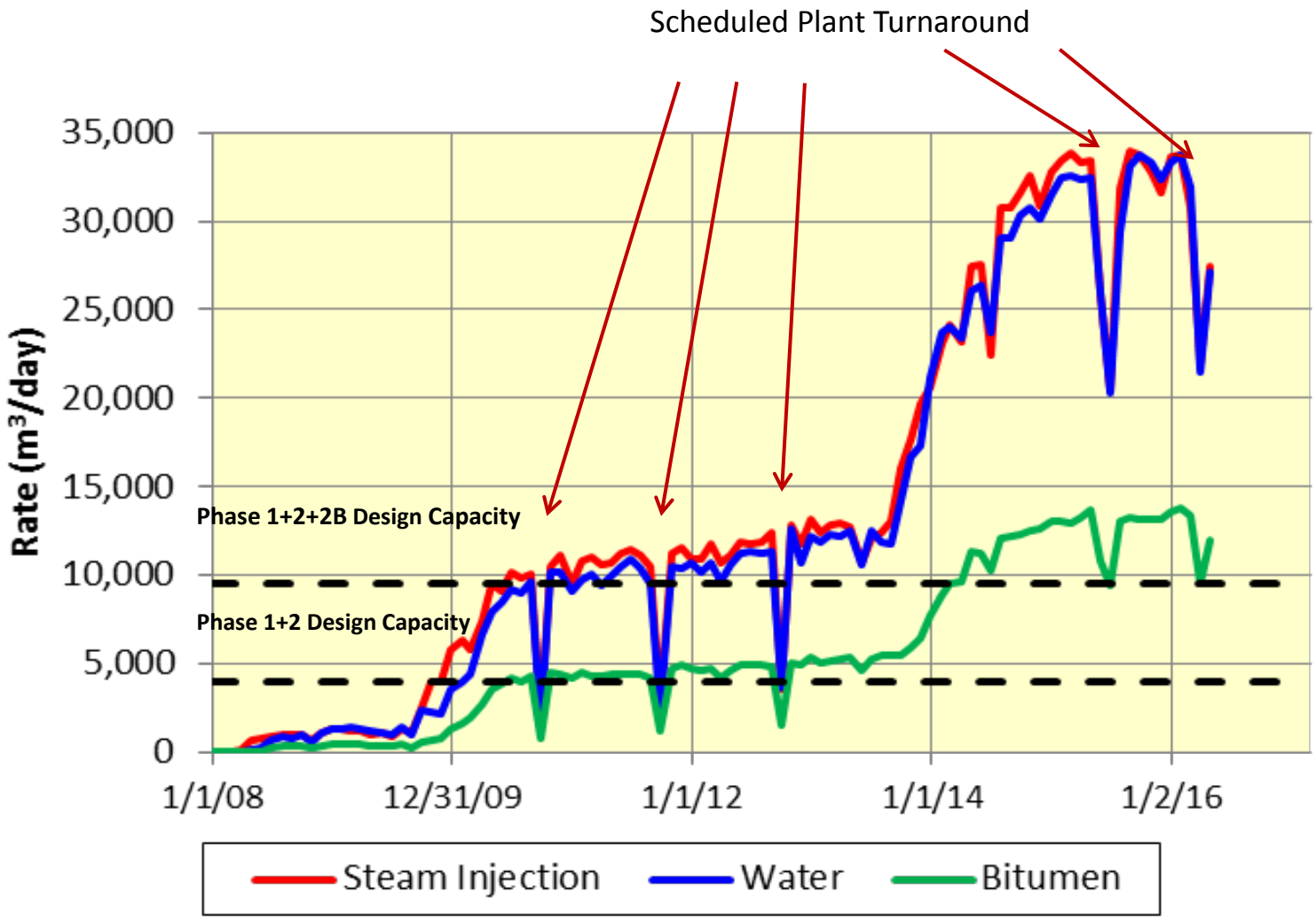
Oil Treatment Overview Phase 2B



Additions/Modifications

- No significant additions or modifications have been made in 2015.

CLRP Production Performance



Facility Performance: Sulphur Recovery Unit

Incident Summary

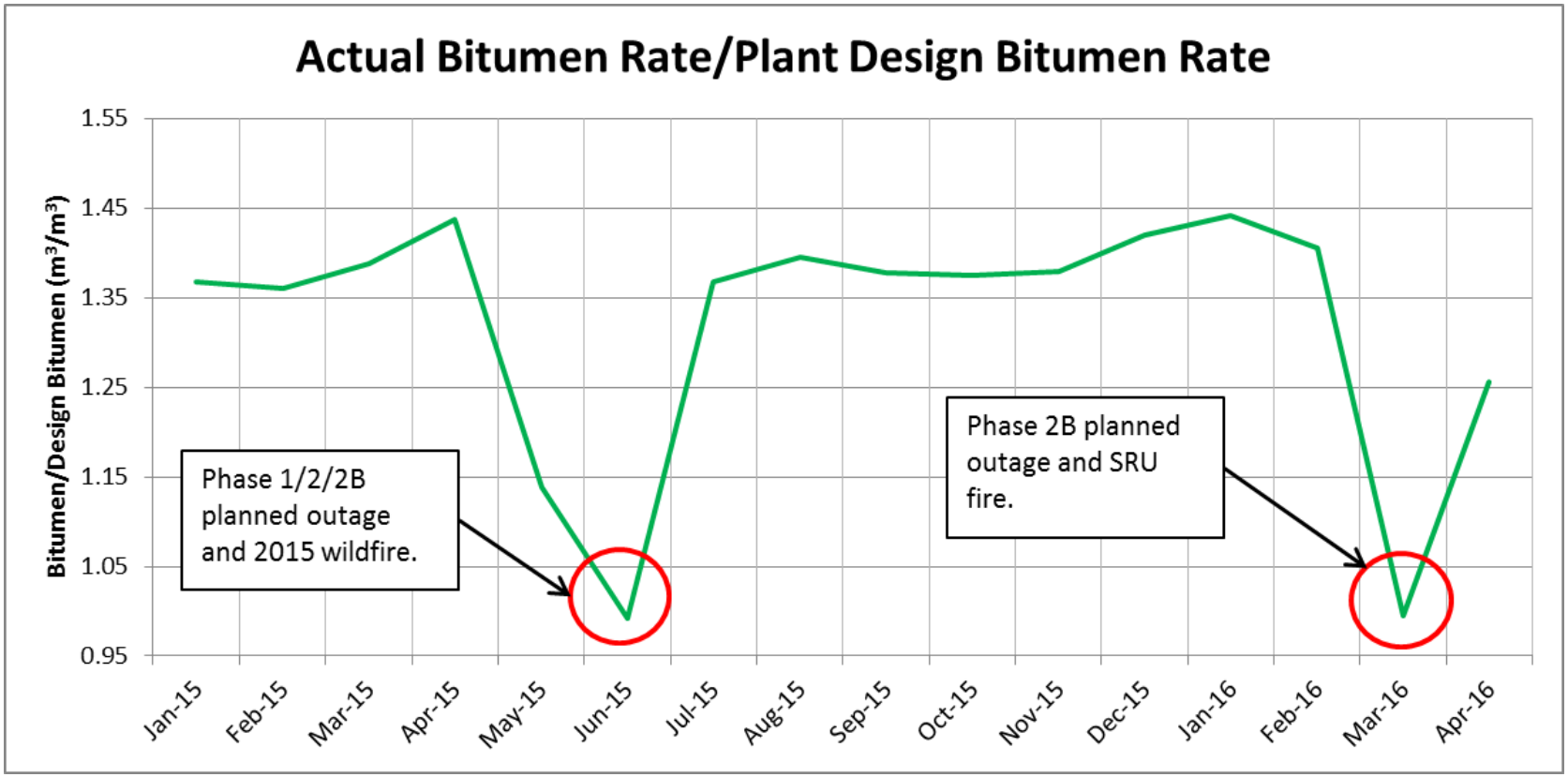
- Liquid level in the spent scavenger tank was lowered below the electric immersion heater during a routine tank offloading operation.
- The immersion heater coils rapidly heated to above the auto ignition temperature of the tank contents resulting in an internal fire and explosion.
- Unit was offline for approximately seven weeks for investigation and repair.
- Sulphur recovery rate was ramped back to 70% and the unit was tested at various flows and pressures.

Facility Performance: Sulphur Recovery Unit

Incident Summary (continued)

- A number of changes were made to the design including:
  - Installation of a nitrogen blanketing system.
  - Change to an external source of heat (tank tracing).
  - Installation of a flame arrestor on the tank vent.
  - Addition of low level alarms/trips.
- MEG is completing a root cause analysis with the engineering contractor and implementing changes to the design process to reduce the likelihood of similar issues.
- For more details, refer to AER Incident Investigation FIS# 20160647.

Facility Performance: Bitumen Treatment



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

Facility Performance: Bitumen Treatment

Successes

- Implemented various debottlenecking projects to increase capacity and enhance the reliability of the Phase 2B plant.
- Performed capacity testing in both Phase 2 and Phase 2B to establish plant capacity and identify bottlenecks.
- Continue skimming and fluid management strategy to reduce trucking.

Issues Being Addressed

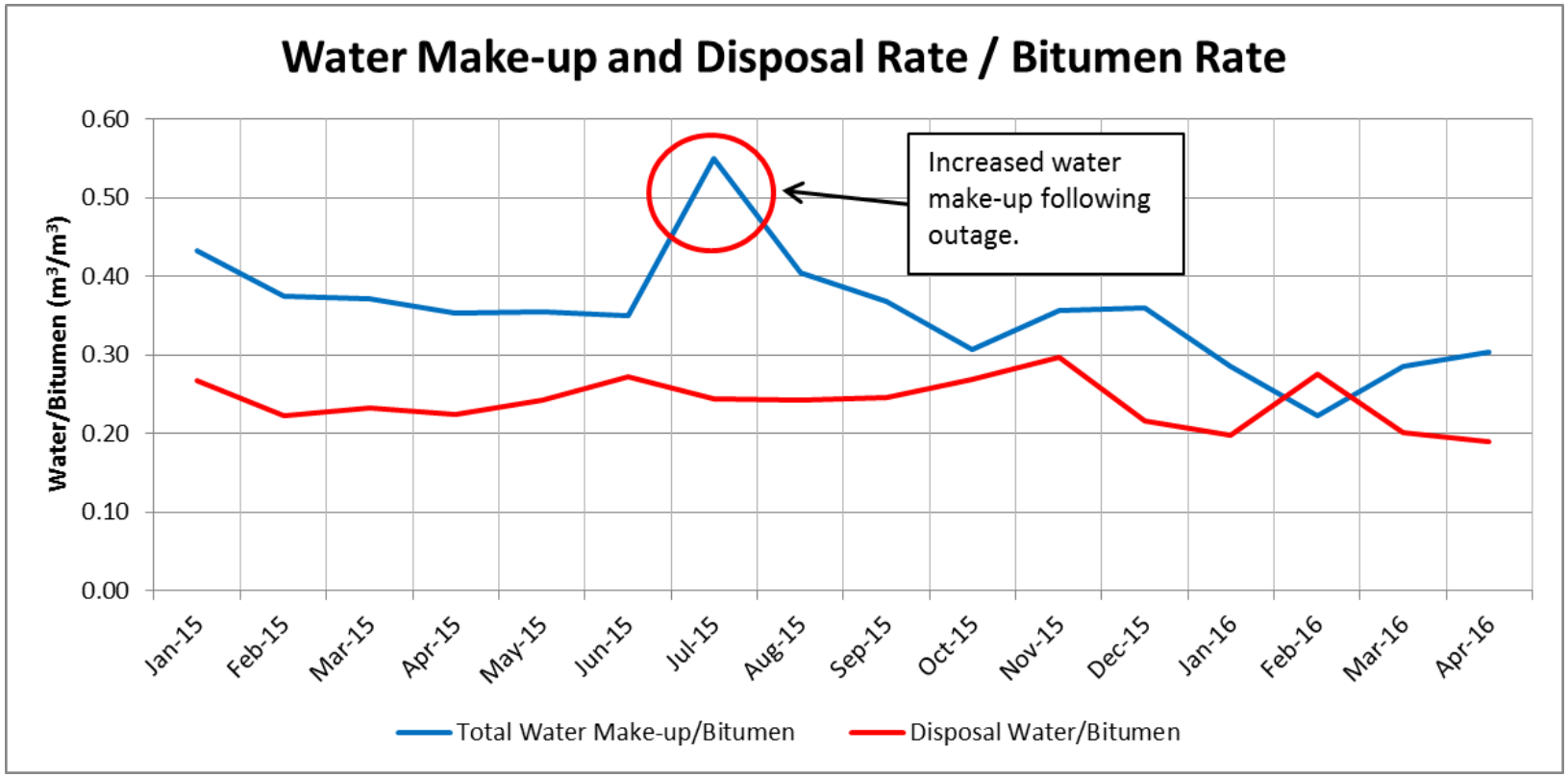
- Produced water exchanger fouling.
- Skim fluid management in Phase 2B.

Facility Performance: Bitumen Treatment

Future Actions

- Continue to implement plant capacity testing for possible future operating scenarios.
- Continued optimization of slop oil treating and reduction initiatives.

Facility Performance: Water Treatment



Facility Performance: Water Treatment

Successes

- Continue recycling high blowdown volumes.
- Saline water use.
- Implemented alternate steam generator internal treatment chemical.
- Mono media in after filters.

Issues Being Addressed

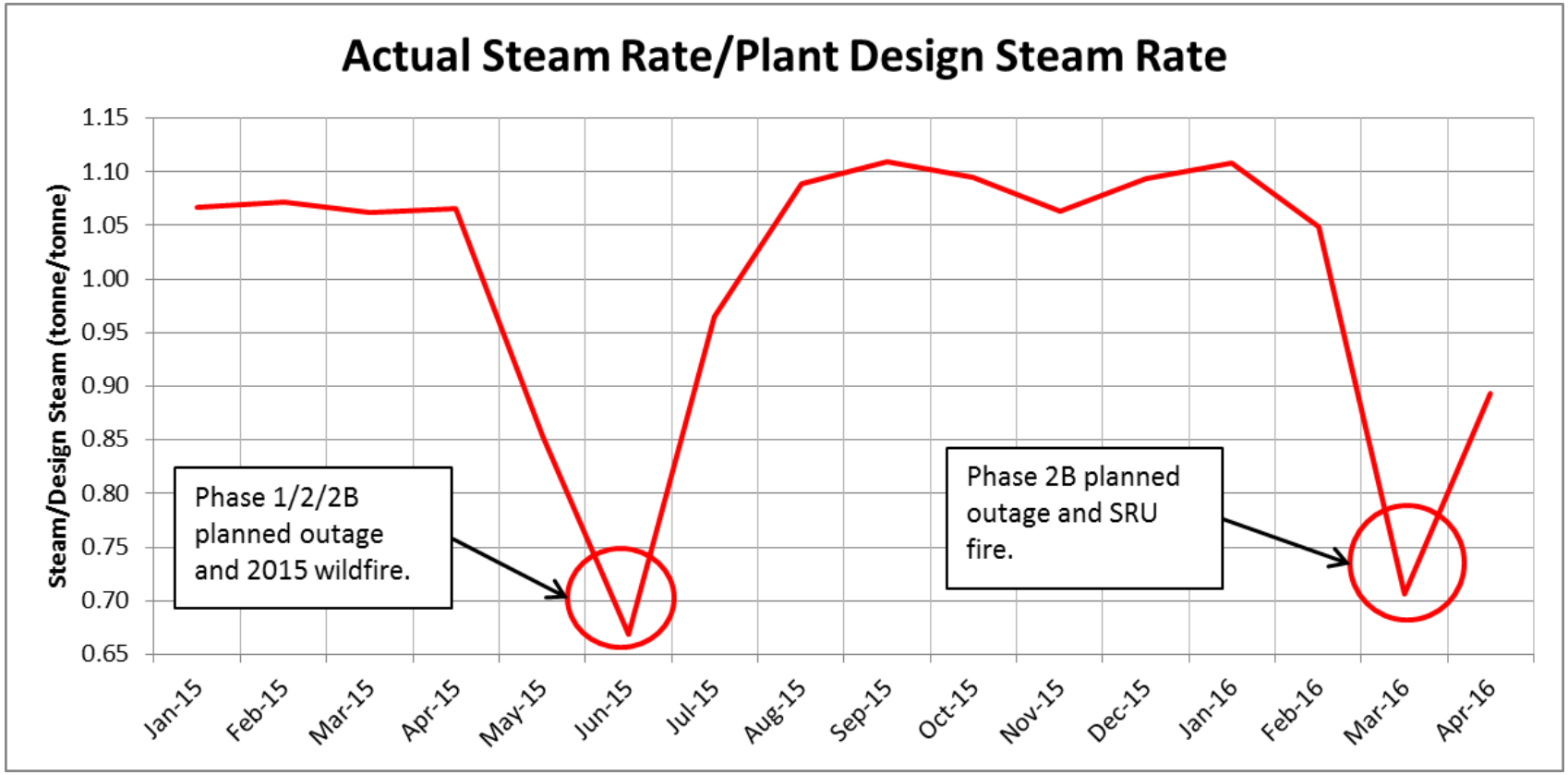
- Examining impact of boiler feed water quality parameters on steam generator reliability.
- Optimization of water treating chemical usage.
- pH trials in HLS to minimize free OH concentration.
- Saline water system corrosion in plant – being addressed with monitoring and alternate materials.

Facility Performance: Water Treatment

Future Actions

- Optimize the use of blowdown recycle with saline water usage to reduce contaminant recycle to BFW.
- Examine alternate methods of monitoring HLS pH.

Facility Performance: Steam Generation



Facility Performance: Steam Generation

Successes

- Stable operation throughout the year
- Successfully completed tube repairs on both Phase 2 and Phase 2B HRSGs.
- Implemented more detailed steam generator availability and utilization tracking.
- Addressed root cause of HRSG relief valve leaking.

Issues Being Addressed

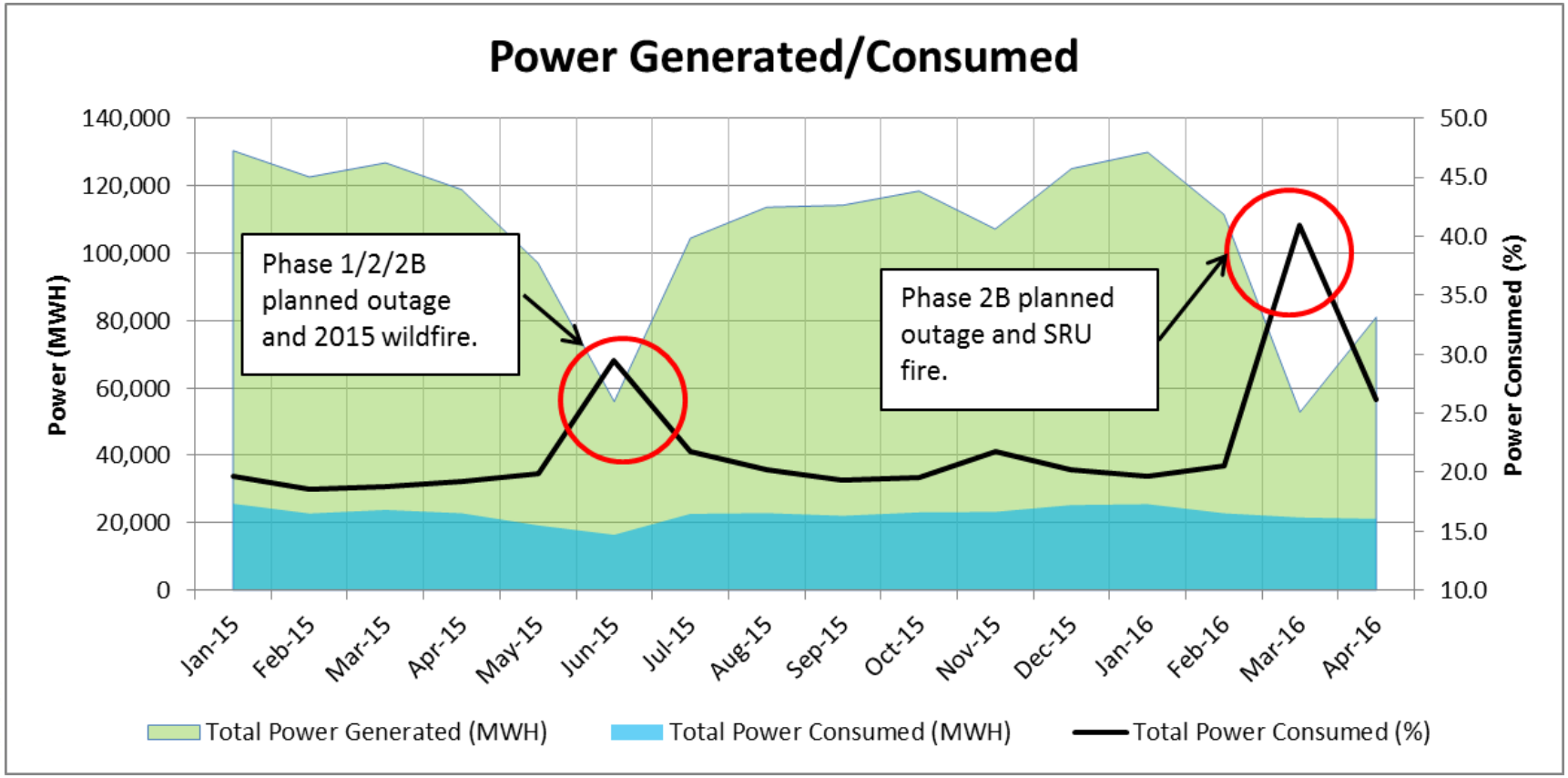
- Testing overall HP steam system control philosophy.
- Tube corrosion issues in Phase 2 and Phase 2B HRSGs.

Facility Operations: Steam Generation

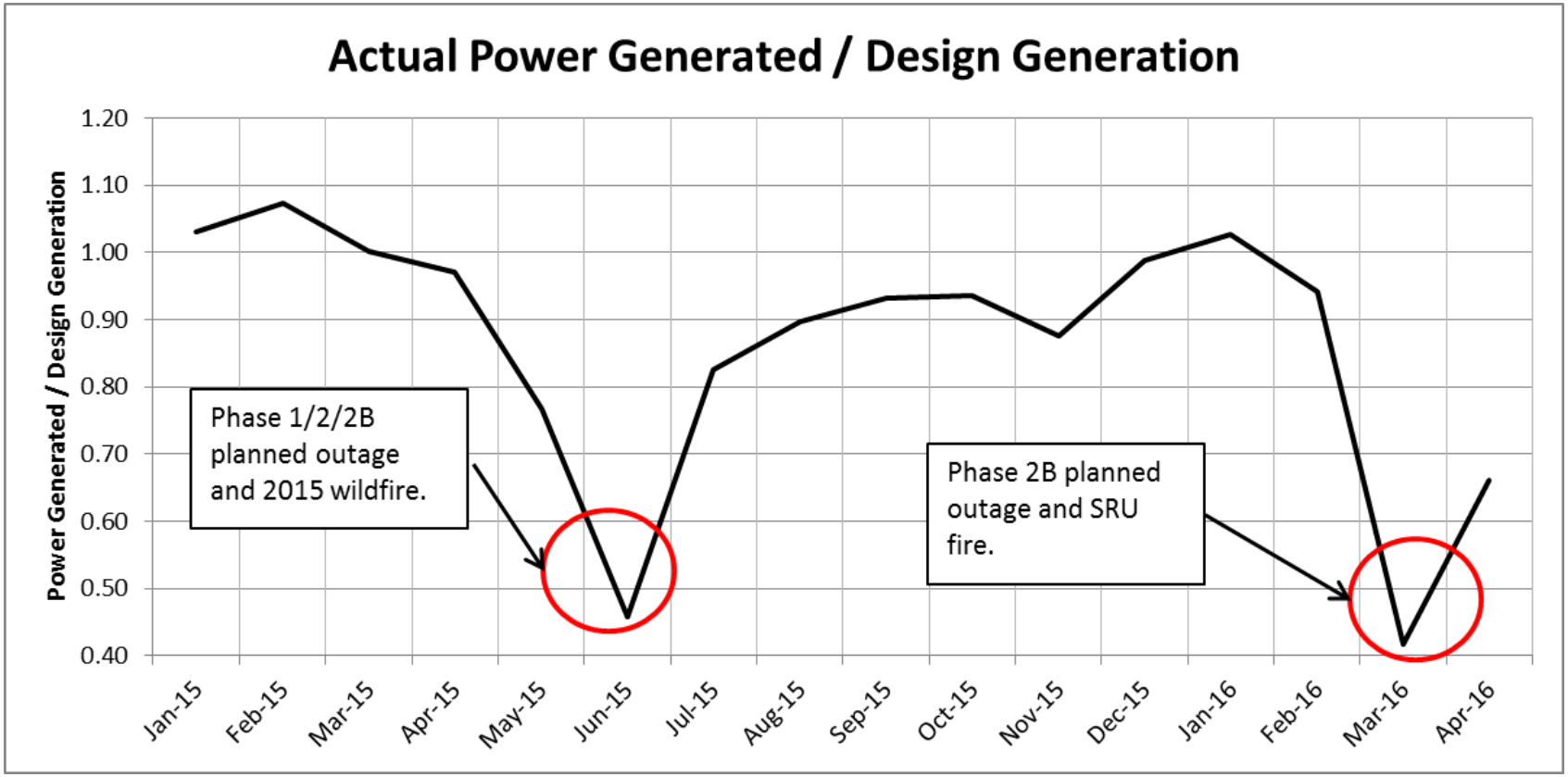
Future Actions

- ICP (Inductively Coupled Plasma) testing used to track ion transport through the steam generators.
- Continue to implement overall HP steam distribution control philosophy.
- Continue monitoring of steam generator tube corrosion.
- Examine methods for online cleaning of steam generators.

Facility Performance: Power Generation



Facility Performance: Power Generation



Facility Performance: Power Generation

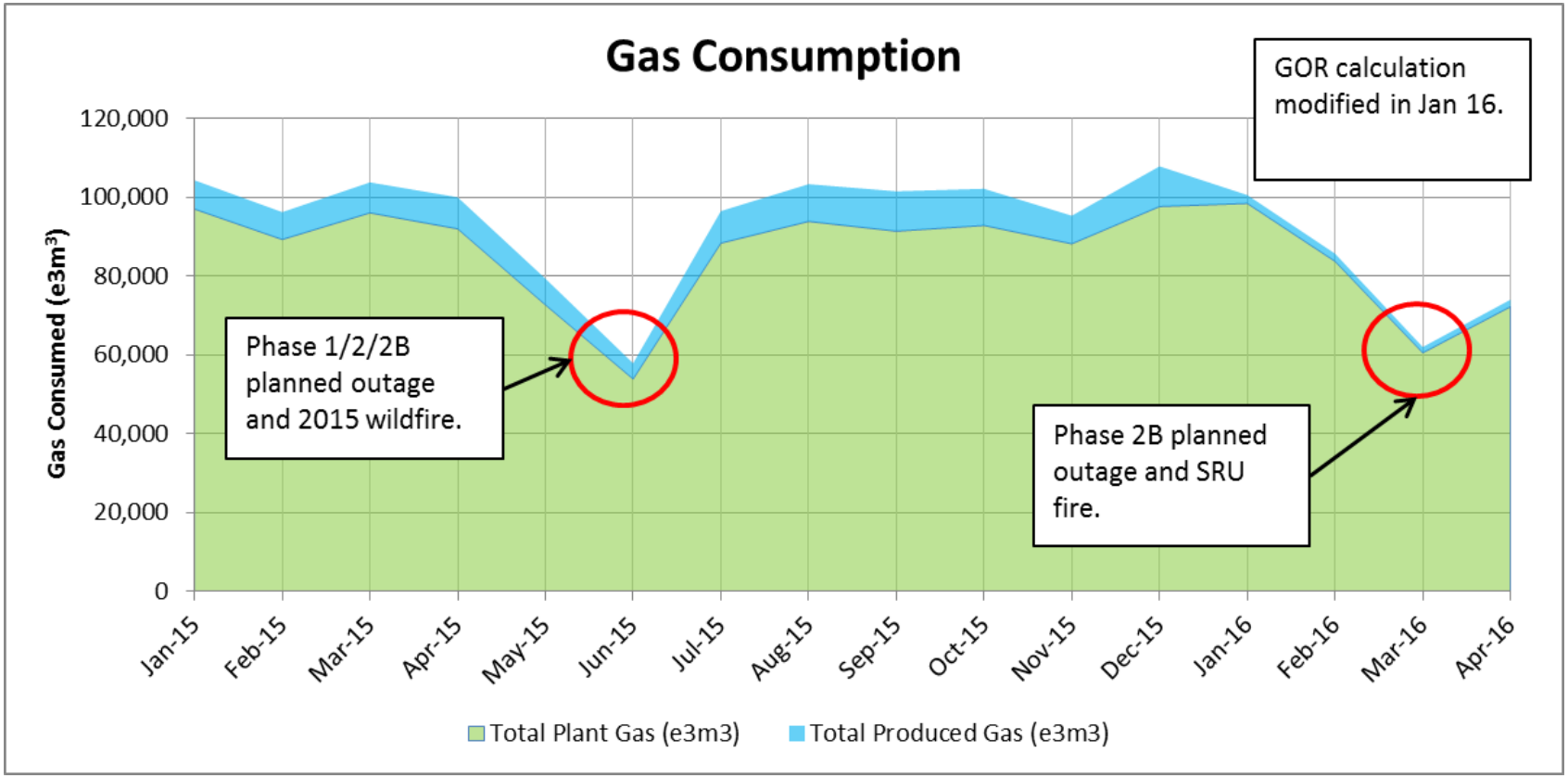
Successes

- Stable operation throughout the year.
- Testing completed on Phase 2B emergency generator.

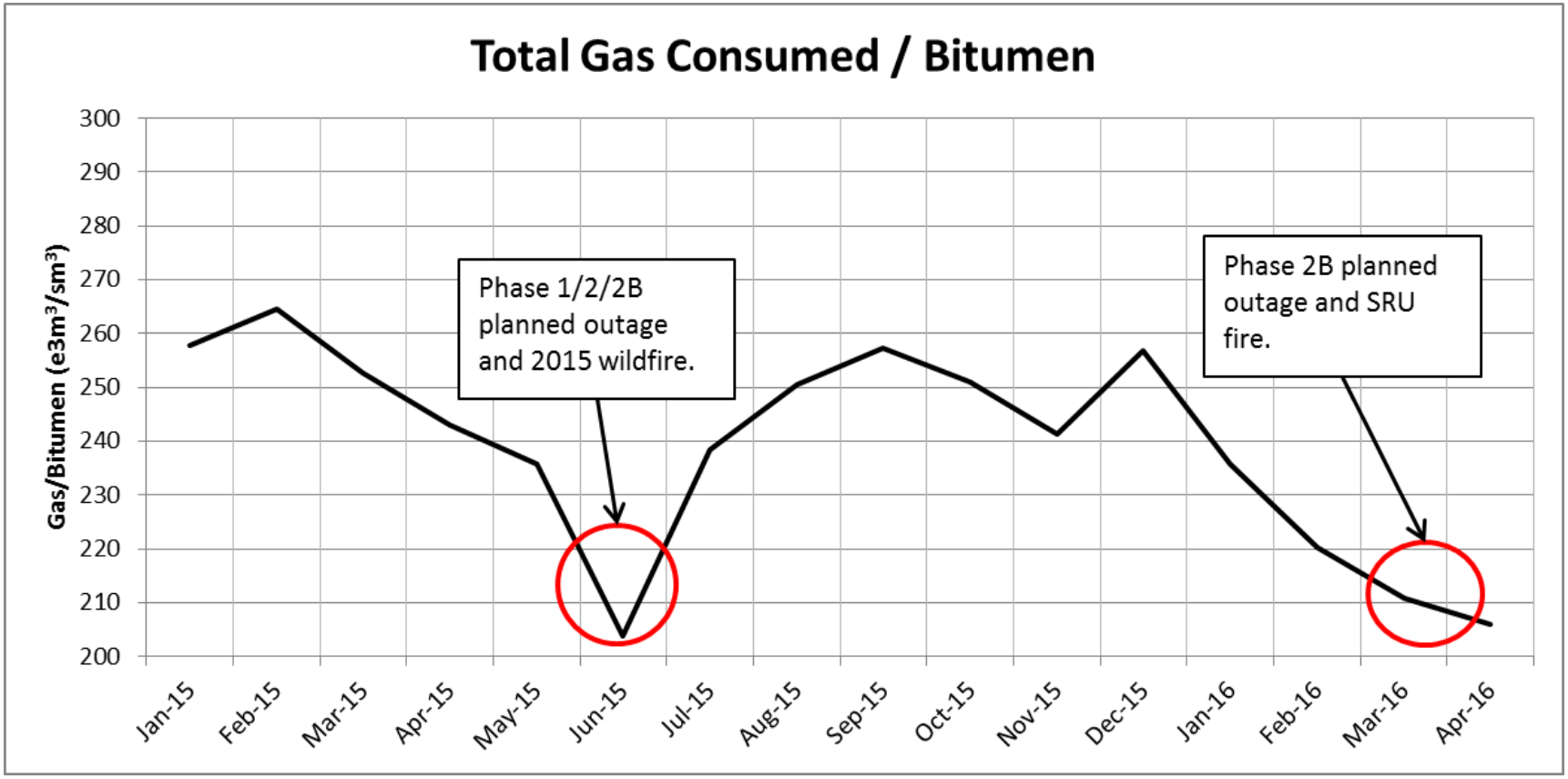
Issues Being Addressed

- No significant issues.

Facility Performance: Gas Usage



Facility Performance: Gas Usage



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
  - Examining 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

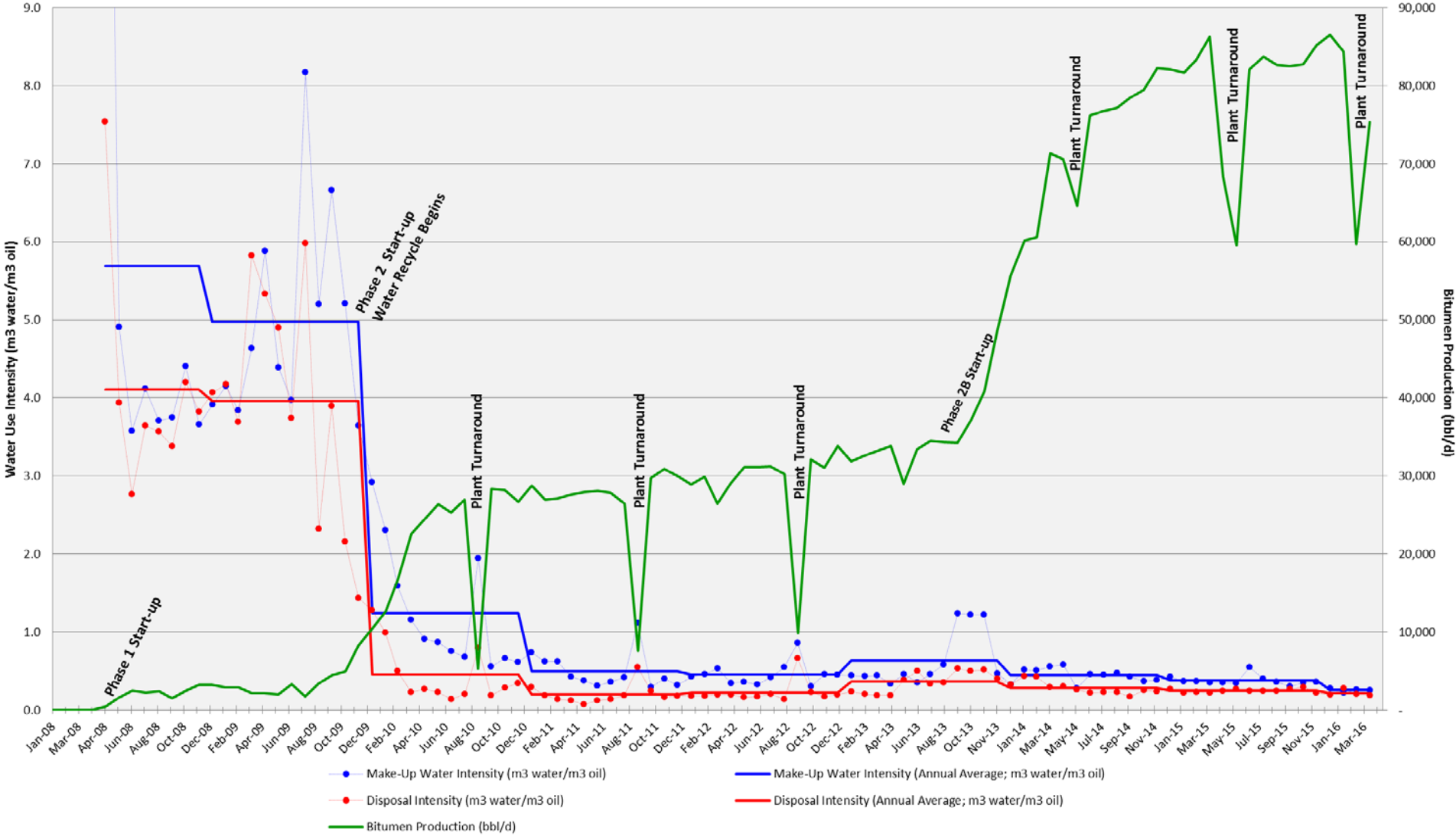
MEG ENERGY

WATER

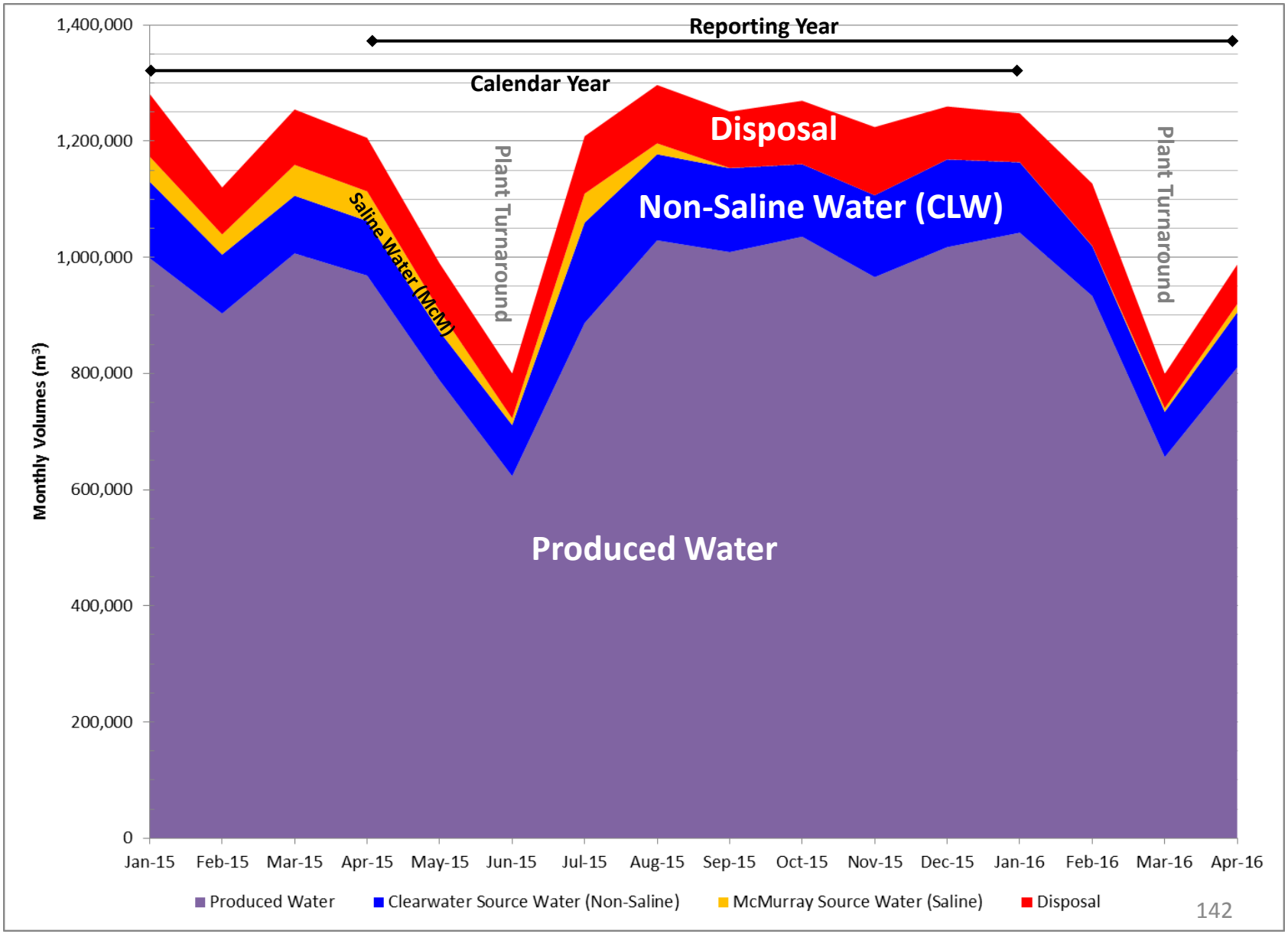
Water Management

- Water Use Intensity, Volumes and Recycle
- Water Source
- Water Disposal
- Water Use Optimization

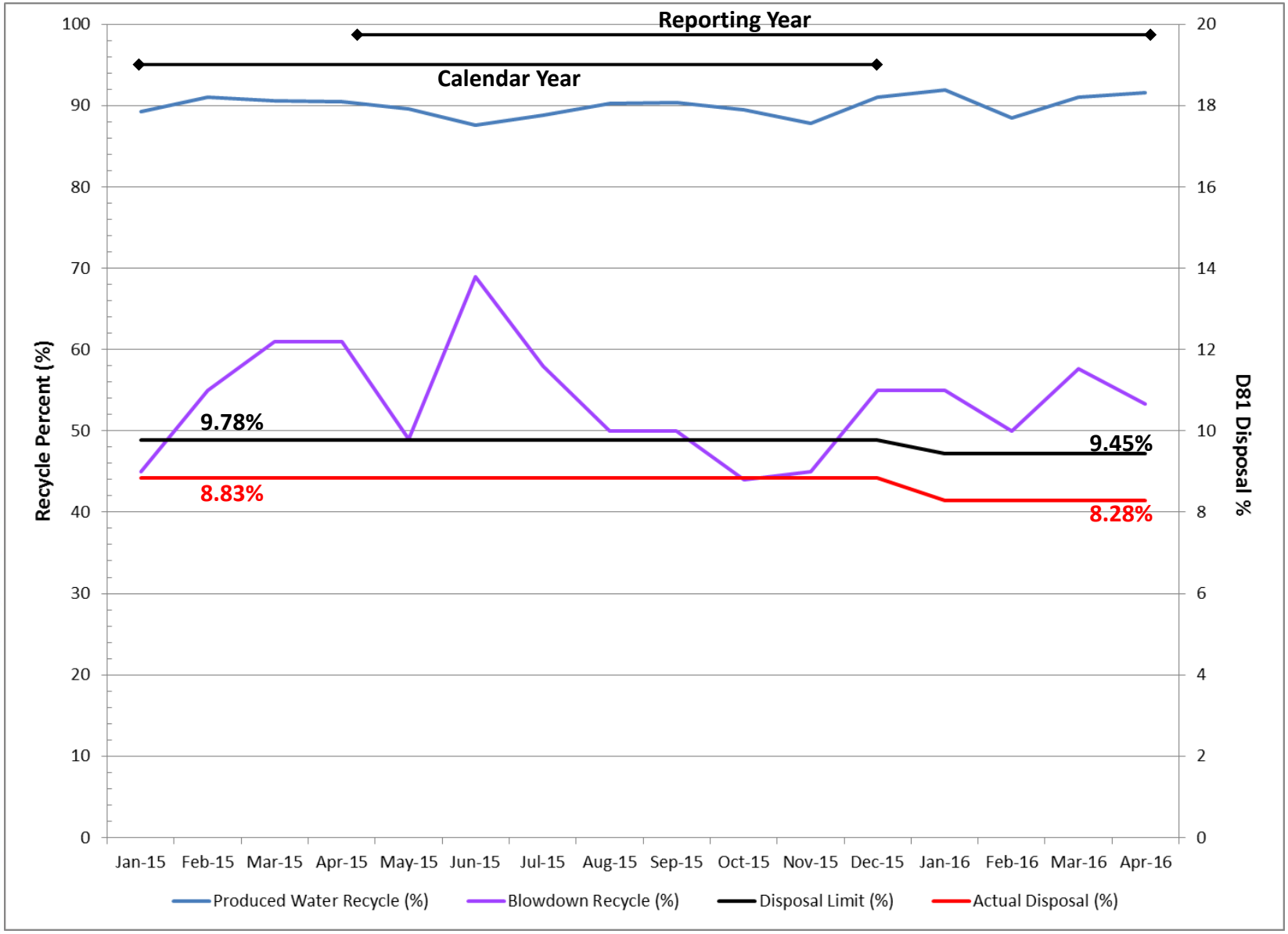
CLRP Water Use Intensity



Monthly Water Volumes

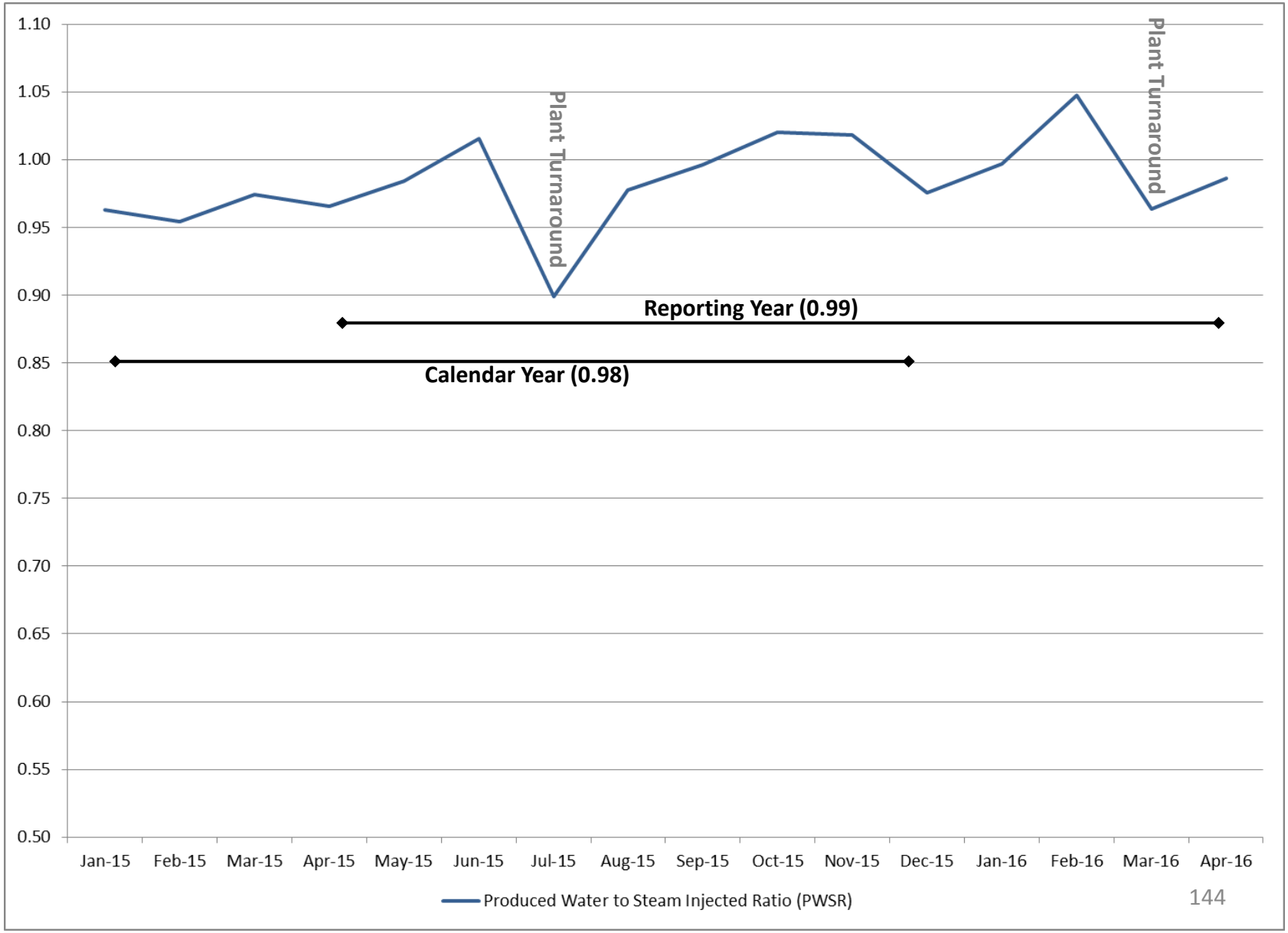


Water Recycle and D81 Limits

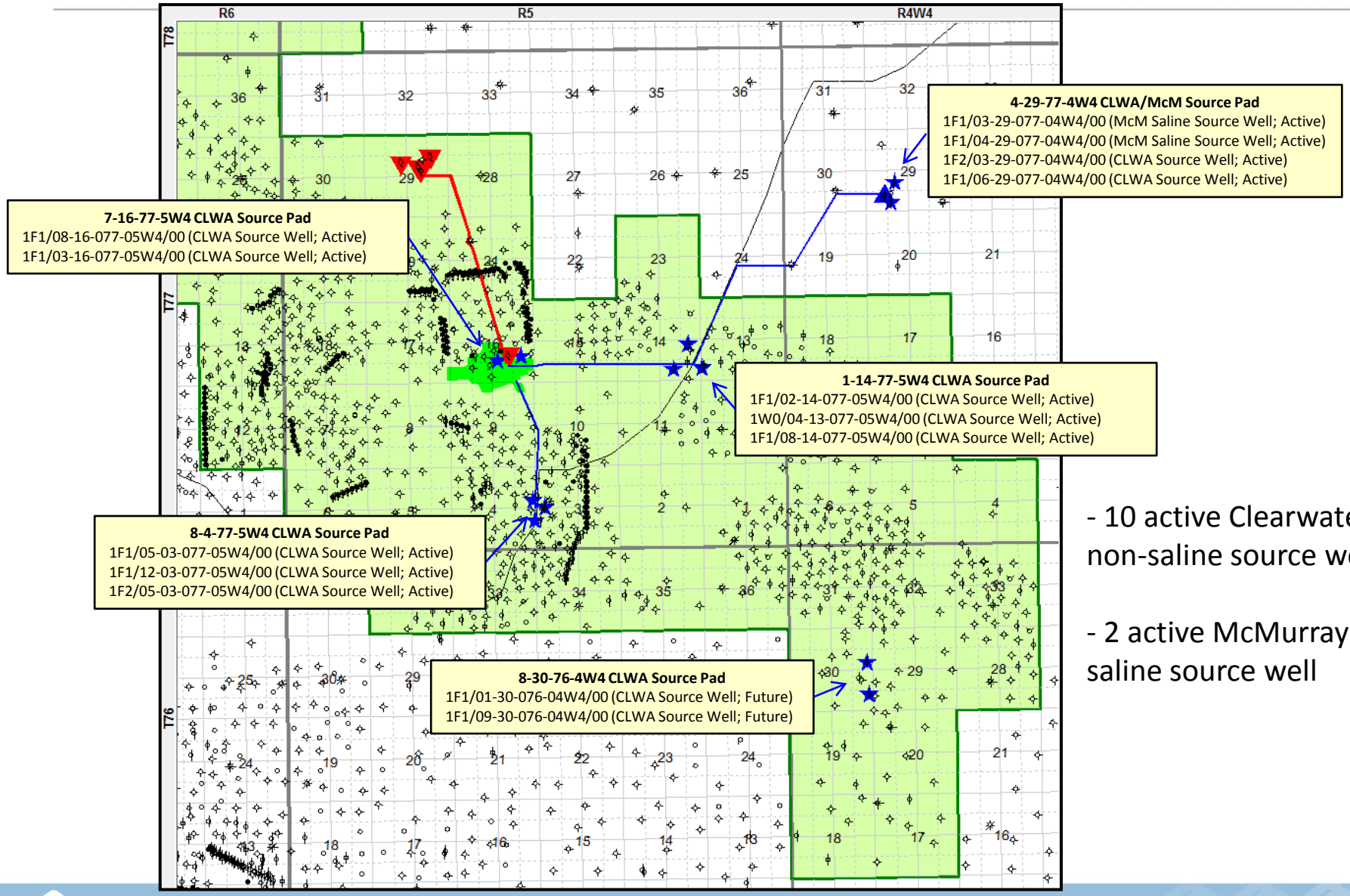


D81 Compliant in 2015

Produced Water to Steam Injected Ratio



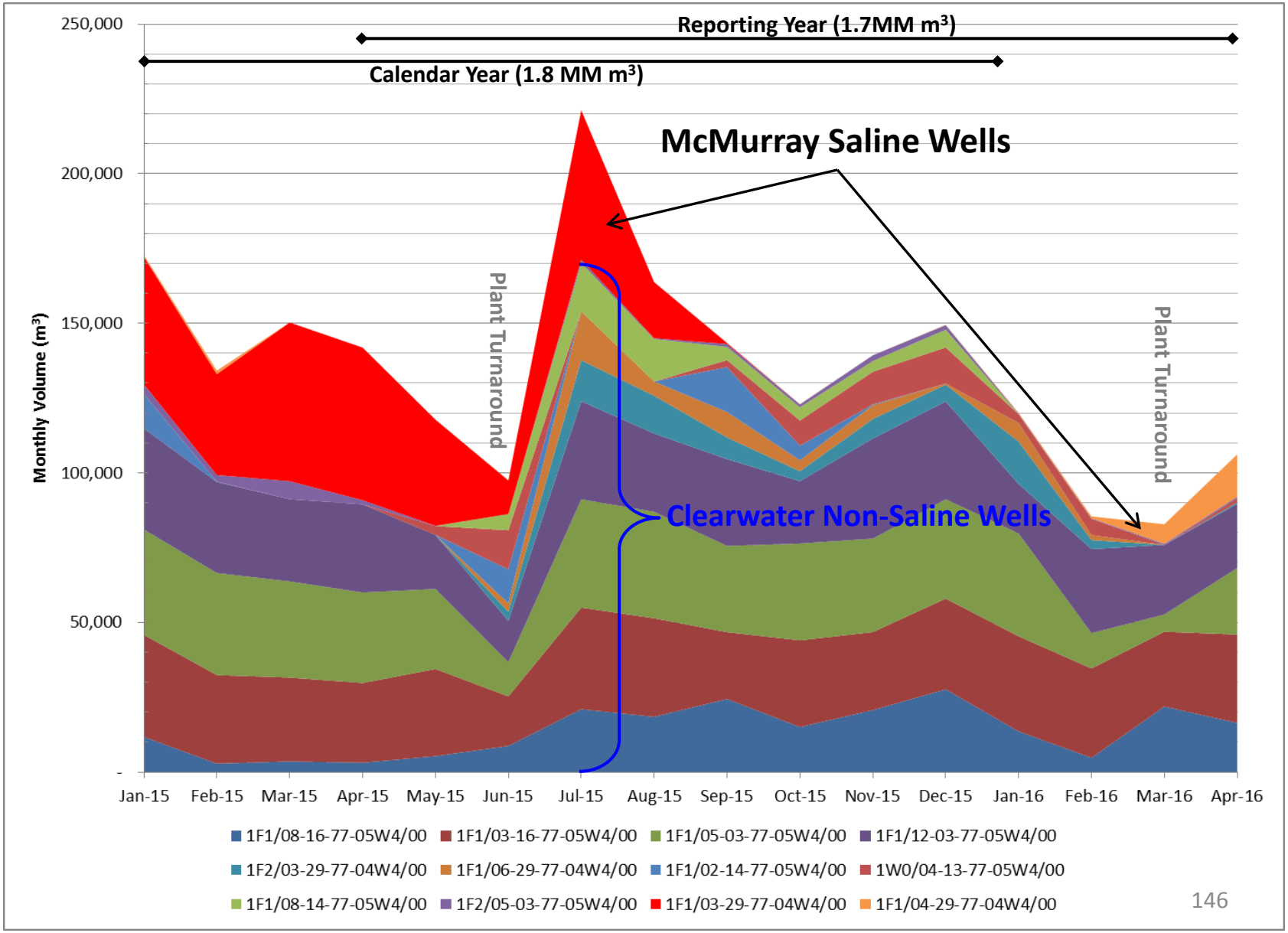
CLRP Source Water Well Locations



- 10 active Clearwater non-saline source wells

- 2 active McMurray saline source well

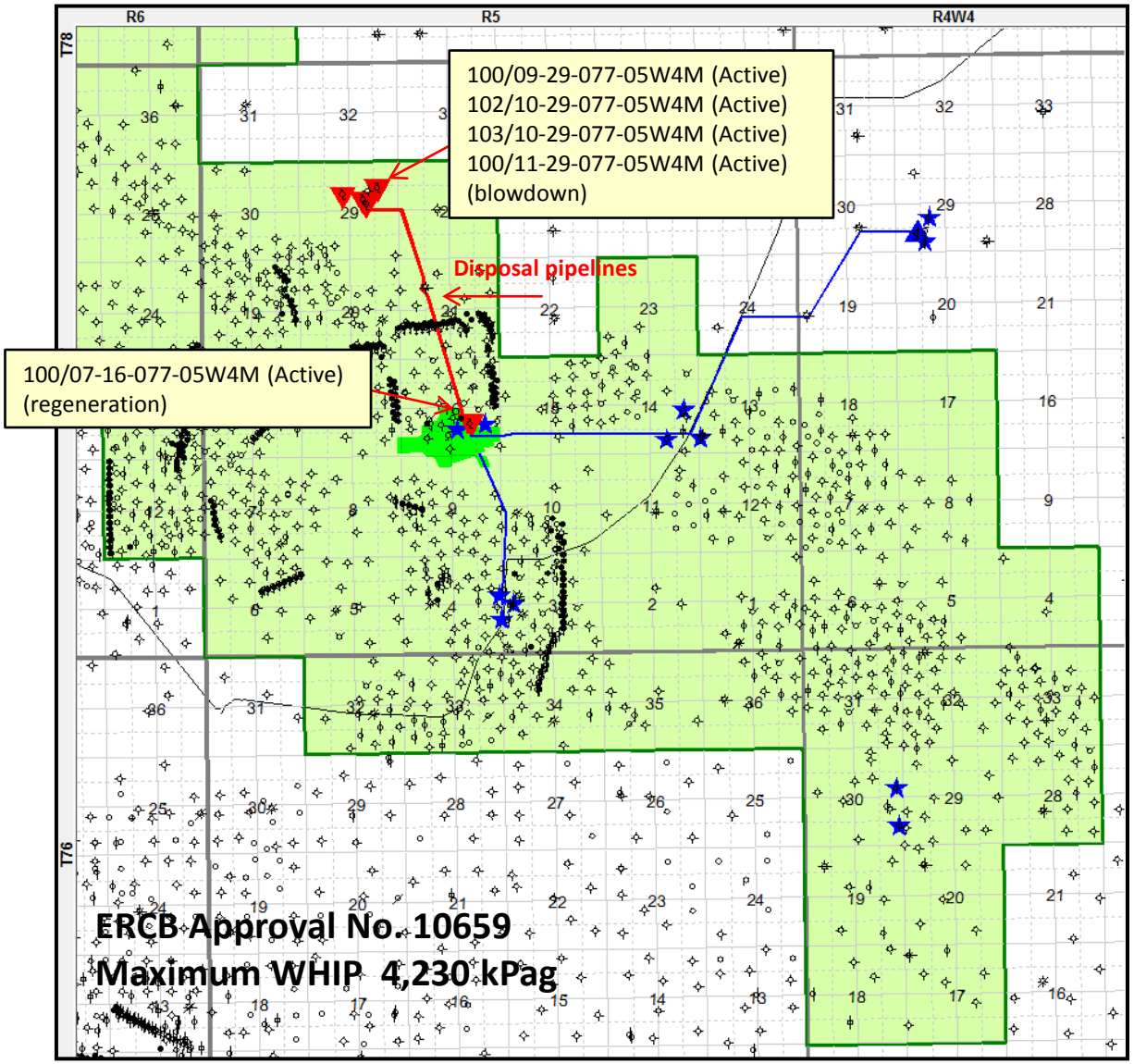
Source Well Production



Source Water Management

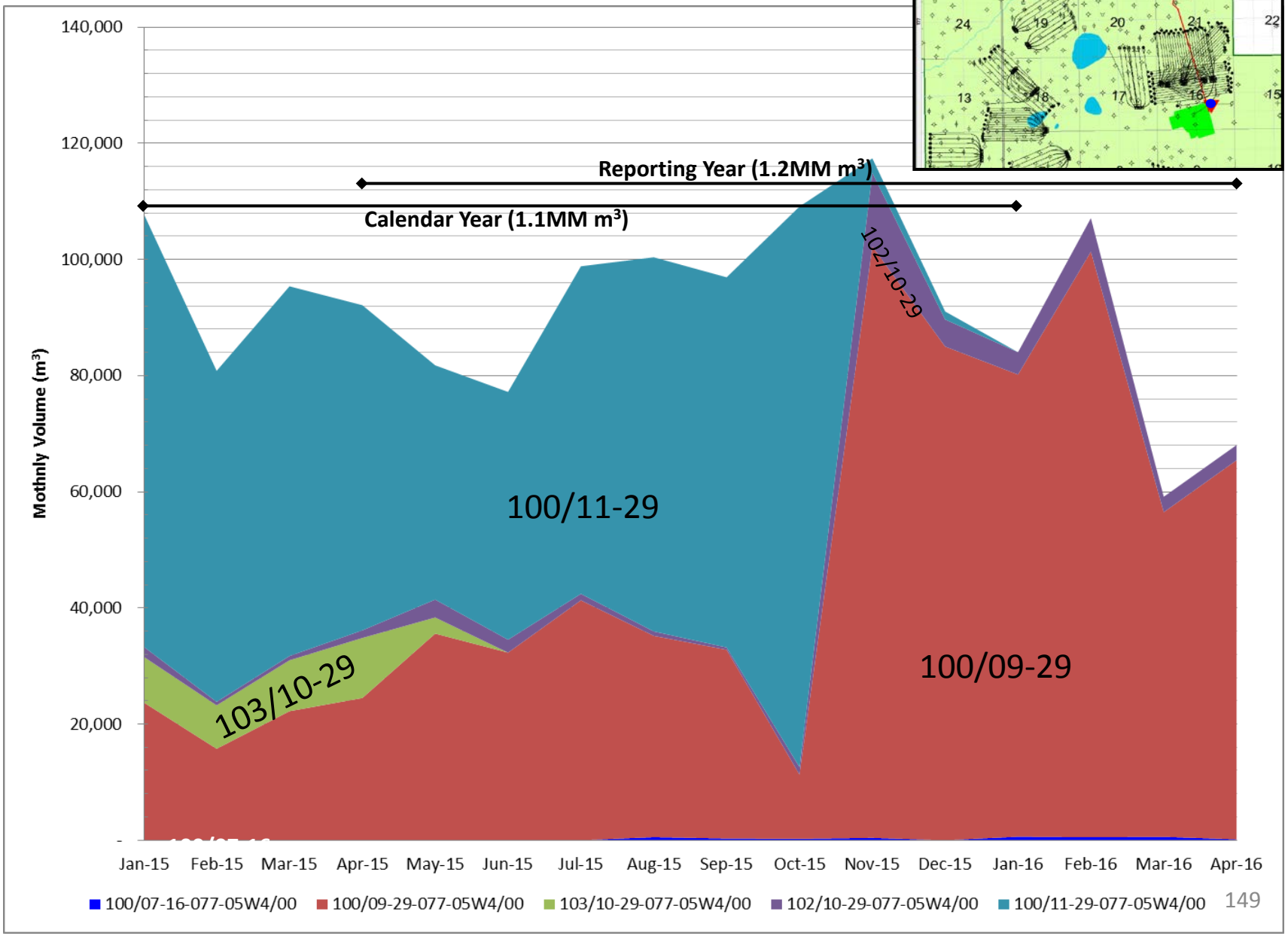
- Saline McMurray groundwater production ongoing since November 2013
  - System outage between August 2015 and February 2016 due to aqueous CO_2 corrosion. System back on-line.
- Non-saline Clearwater A and Ethel Lake groundwater production and pressure monitored in accordance with *Water Act* licenses
- Ethel Lake, Clearwater and McMurray aquifers are responding to pumping as expected

CLRP McMurray Disposal Wells

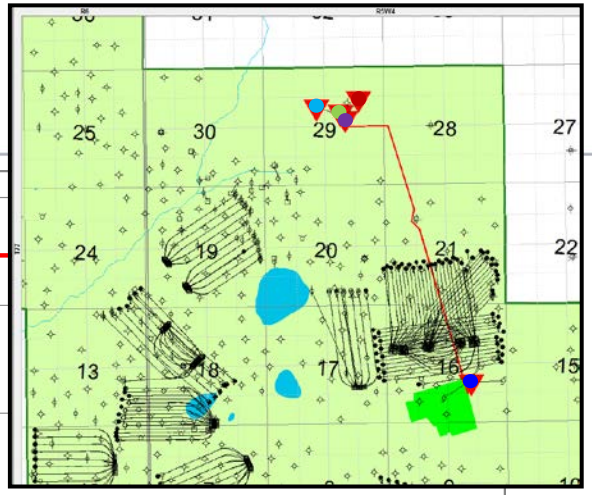


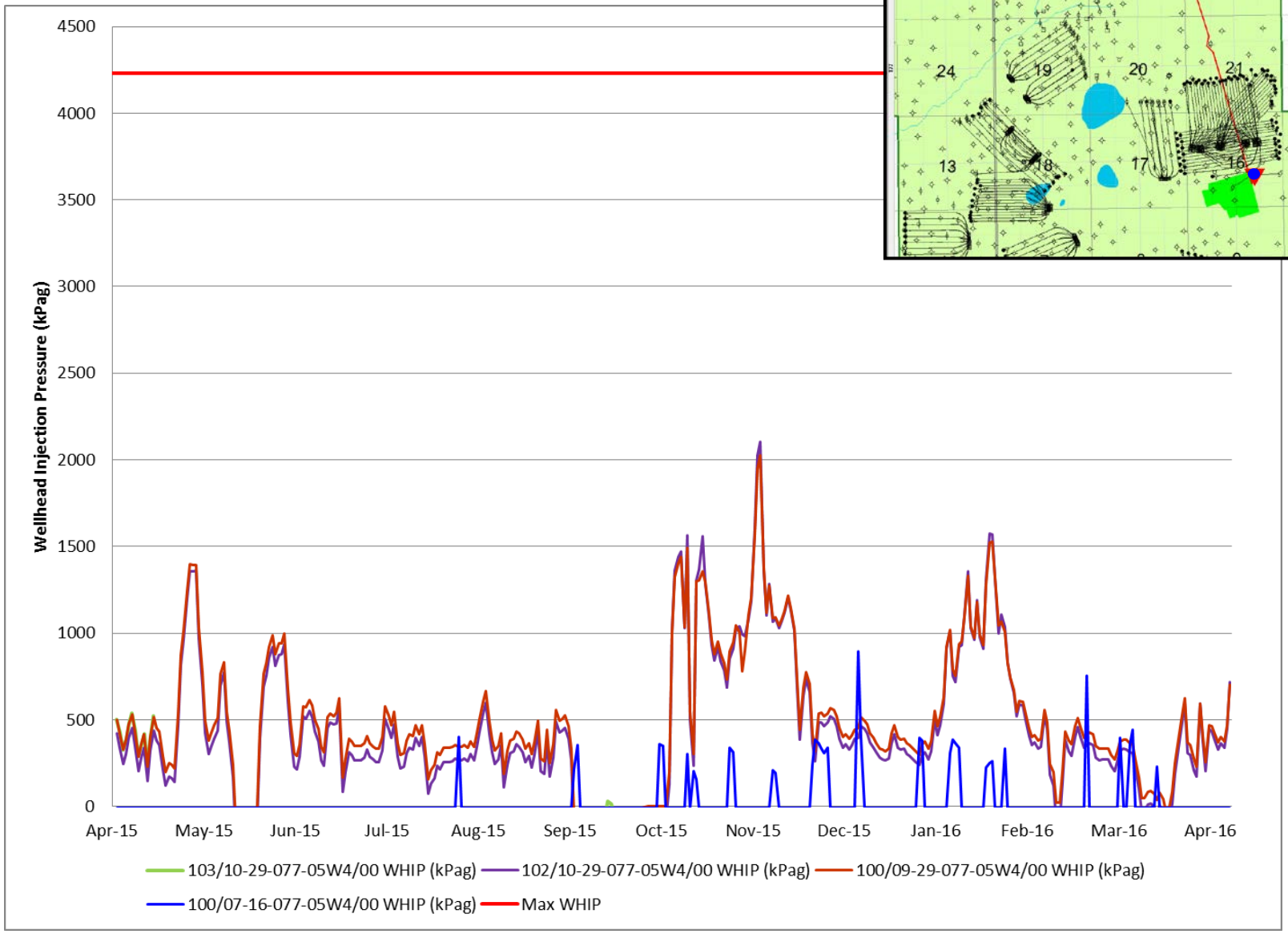
- 5 active McMurray disposal wells

Disposal Summary



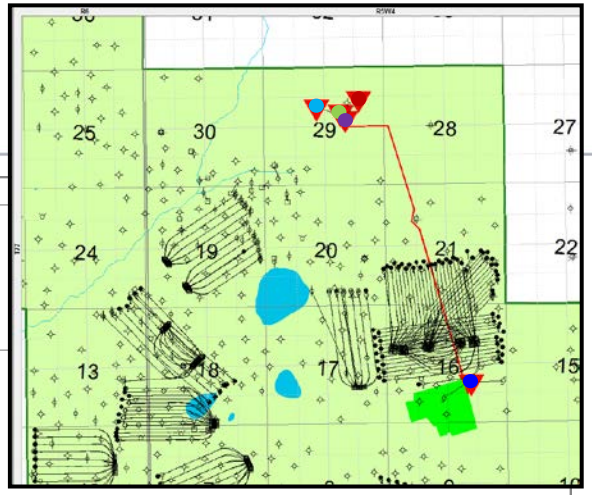
Wellhead Injection Pressures





*100/11-29-077-05W4/00 well on vacuum during operation

Disposal Temperatures



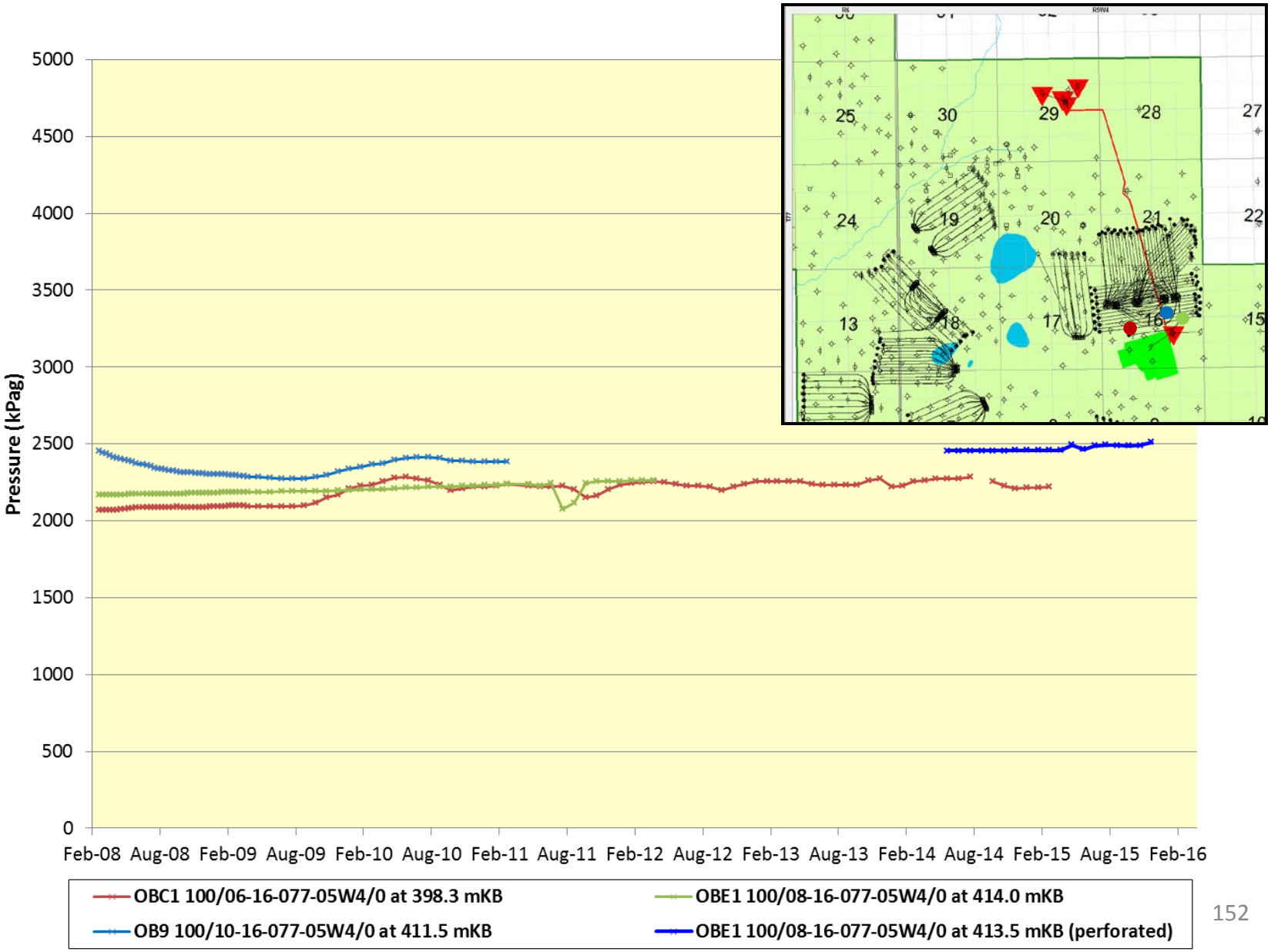
Wellhead Temperature (deg C)

70
60
50
40
30
20
10
0

Apr-15 May-15 Jun-15 Jul-15 Aug-15 Sep-15 Oct-15 Nov-15 Dec-15 Jan-16 Feb-16 Mar-16 Apr-16

103/10-29-077-05W4/00Temp (deg. C)
102/10-29-077-05W4/00 Temp (deg. C)
100/09-29-077-05W4/00 Temp (deg. C)
100/07-16-077-05W4/00 Temp (deg. C)
100/11-29-077-05W4/00 Temp (deg. C)

Basal McMurray Water Sand Pressure Monitoring



Water Use Optimization

- MEG continues to optimize blowdown recycle (exceeding design and adjusting to operational limitations)
- Saline water use (McMurray) ongoing since November 2013. MEG plans to continue to utilize saline water for make-up.
- Technology advancement to reduce SOR (eMSAGP)
- Blowdown evaporator planned to further improve water recycle capabilities

MEG ENERGY

COMPLIANCE & ENVIRONMENT

Compliance & Environment

Reporting Year Highlights

- Our Monitoring Approach
- Sulphur Production and Removal
- Greenhouse Gas Management
- Compliance Summary
- Reclamation

MEG's Extensive Monitoring

Detecting any 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 the Alberta Biodiversity Monitoring Institute, the Wood Buffalo Environmental Association, and the new Alberta, Canada, 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

Other Environmental Initiatives

MEG also 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. This program is a multi-pronged strategy comprised of 4 pillars: (i) research on caribou, predators and their habitats, (ii) coordinated footprint management, (iii) site-specific assessment of wildlife and vegetation responses to reclamation treatments on linear features, and (iv) broad-scaled, active adaptive management study design (treatment vs control) across large areas.

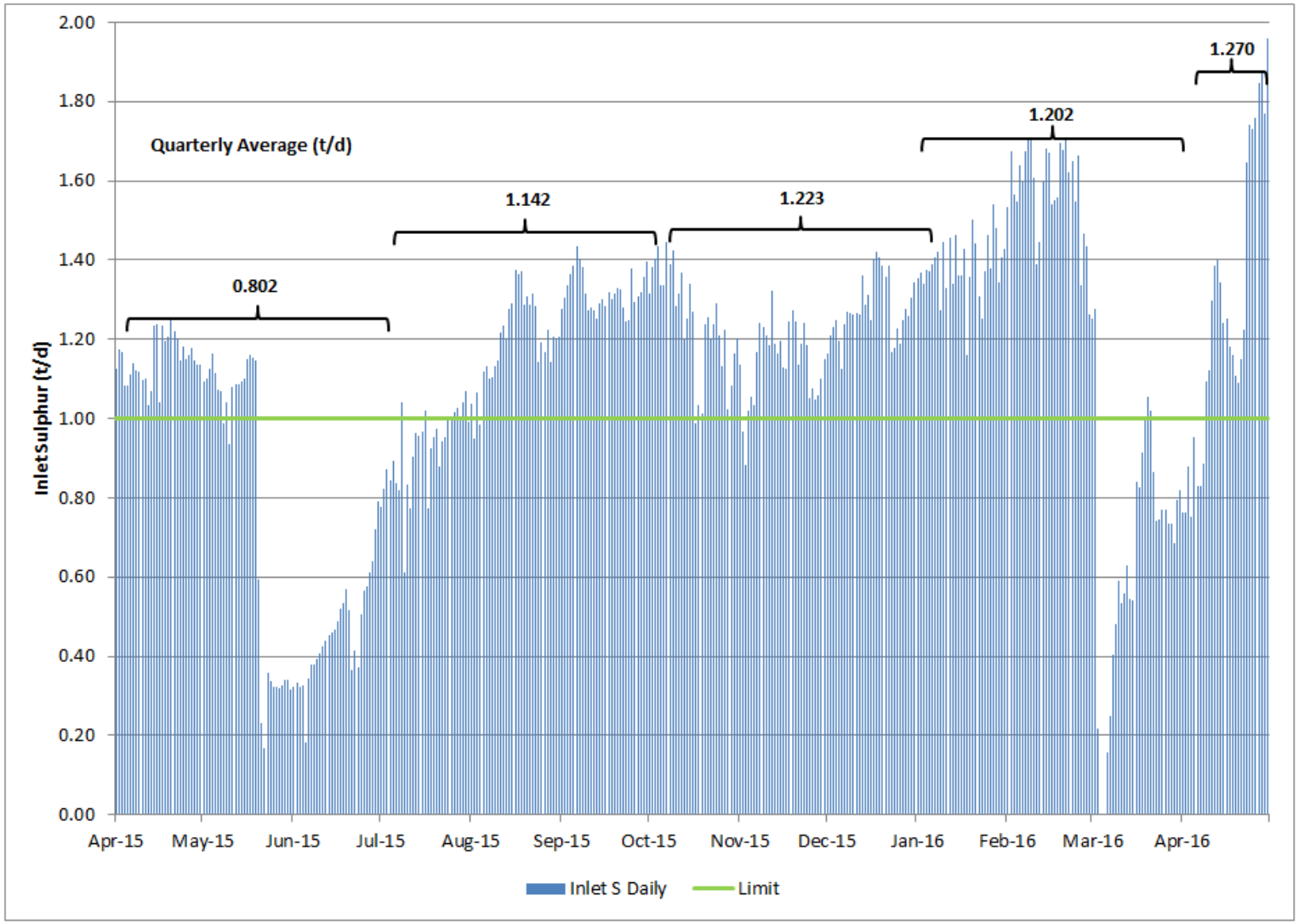
- **Faster Forests (COSIA)-** The Faster Forests program is a reclamation research collaboration amongst seven oil & gas operators designed to identify reclamation techniques which can accelerate re-vegetation of sites disturbed by industry exploration activity.

- **Wood Buffalo Environmental Association (WBEA)-** WBEA monitors the environment of the Regional Municipality of Wood Buffalo in north-eastern Alberta

Sulphur Production and Removal

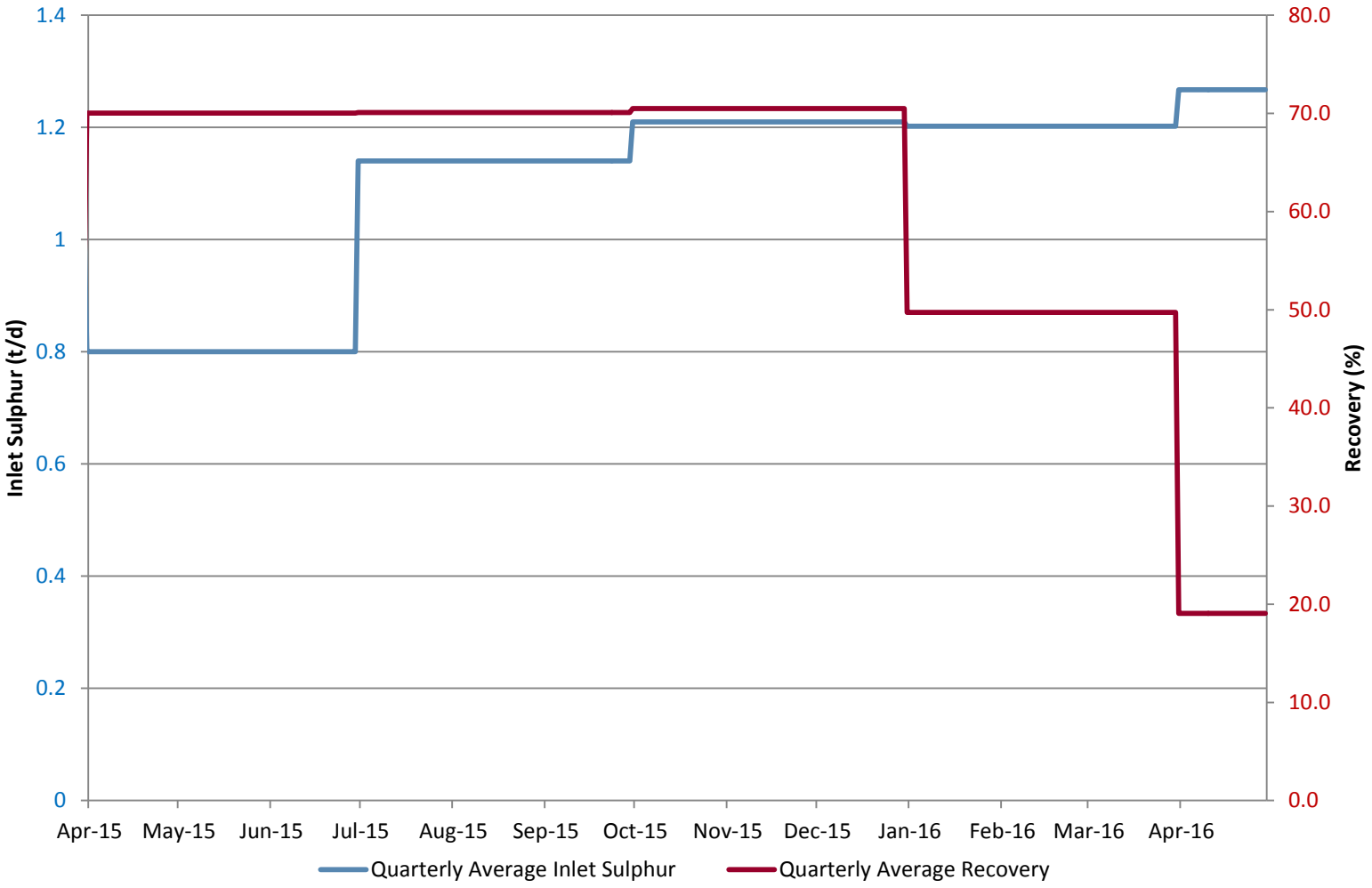
- **Sulphur Recovery Unit (SRU) Scavenger Tank Incident**
  - Incident occurred in a tank associated with CLRP SRU on March 3 leaving the SRU non-operational for approximately 7 weeks.
  - AER issued an Enforcement Order requiring MEG to submit a repair and interim operating plan.
  - Resulted in <70% recovery for Q1 2016.
  - SRU start up occurred on April 21.
  - Alberta Ambient Air Quality Objectives (AAAQO) and Lower Athabasca Regional Plan (LARP) levels were not exceeded during the interim operating period.
  - AER Incident investigation closed on April 15, 2016.
  - Final incident report submitted Q3 2016.

Daily Inlet Sulphur

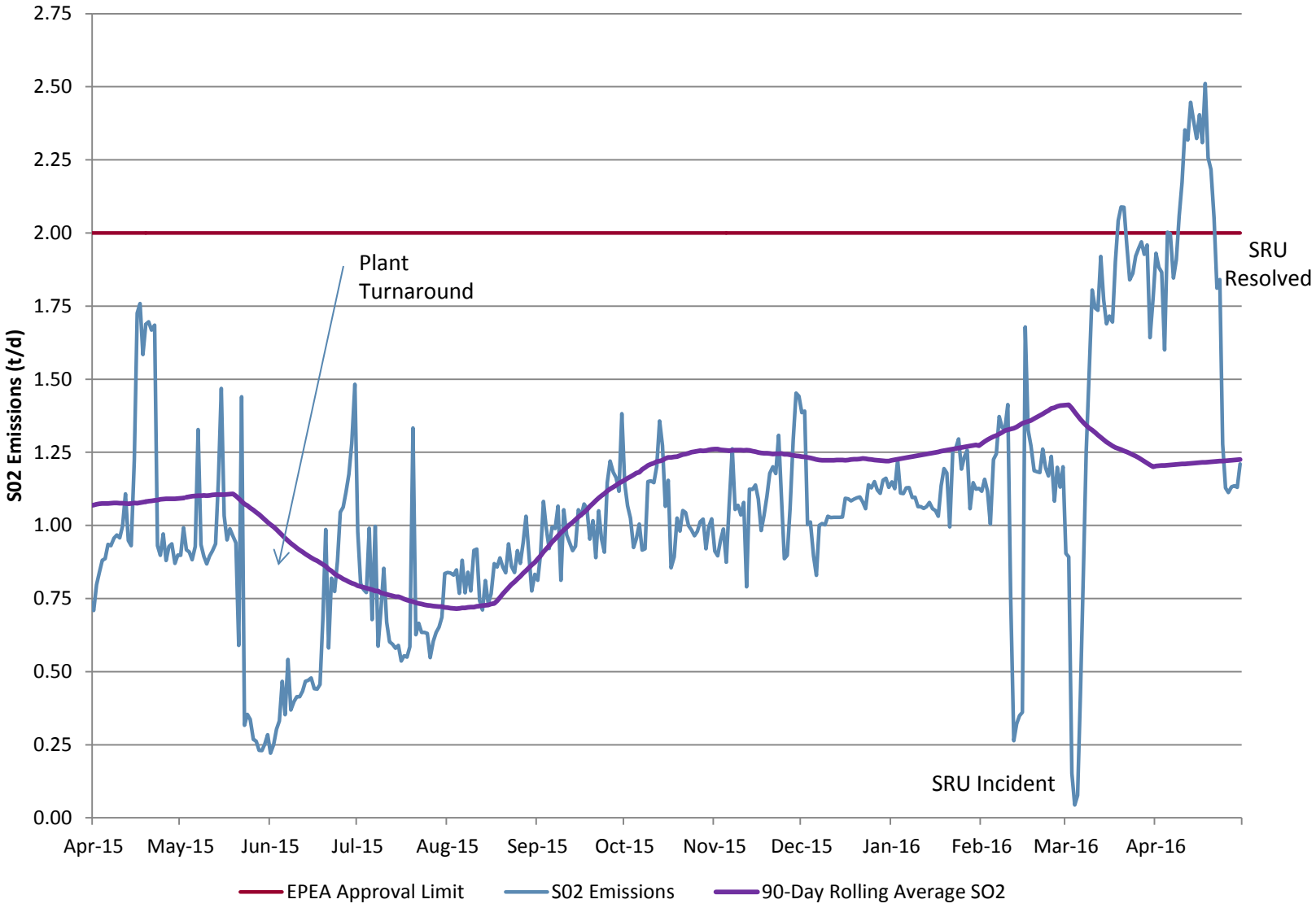


Average inlet sulphur surpassed 1 t/d in 2014 triggering scheme sulphur recovery requirements

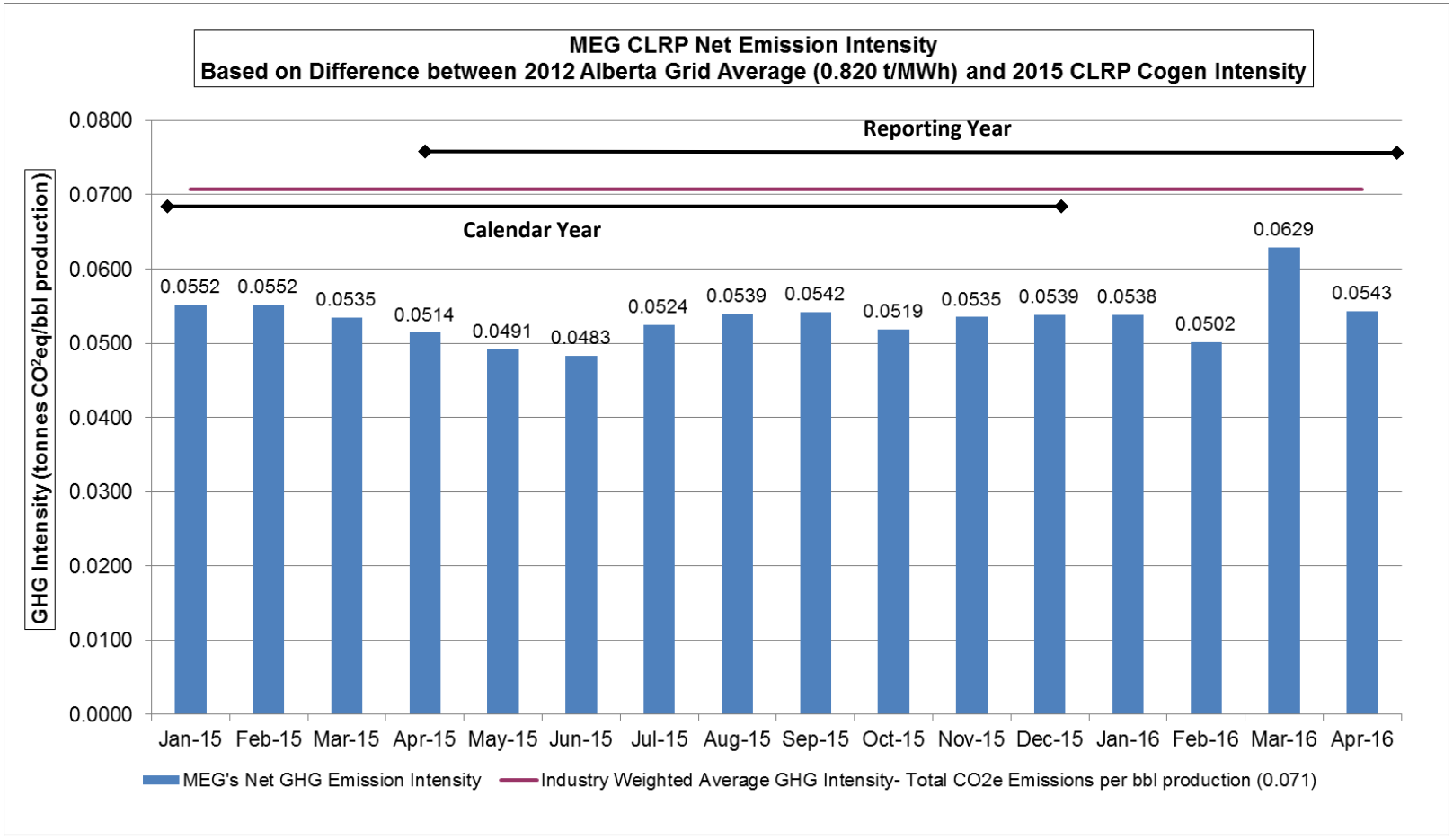
Sulphur Removal



SO_2 Emissions



Greenhouse Gas (GHG) Management



- MEG CLRP continues to produce one of the lowest net GHG intensity barrels in the industry.
- GHG performance is attributed to reservoir performance (low SOR's), use of co-generation technology for steam generation, and ongoing reservoir efficiency technologies (ie. eMSAGP).

Compliance Summary

Regulatory Inspections and Audits

- Two satisfactory AER drilling inspections occurred on January 7, 2015 and January 25, 2015 to ensure compliance with Directive 037.
- Satisfactory pipeline inspection on January 14, 2015
- Satisfactory AER Manual 001 facility inspection at CLRP on February 24, 2015
- AER Inspection and site tour of CLRP project on July 22, 2015 to ensure compliance with soil conservation and reclamation requirements of aspects of EPEA approval.
- Satisfactory AER Manual 001 inspection of SAGD Facility and wellpads February 24, 2016.
- Satisfactory inspection of SRU facility, reconstruction and remediation May 29, 2016.

Compliance Summary

Self-Disclosures & Non-Compliances

MEG reported 3 scheme related self-disclosures to the AER during the reporting period:

- February 15, 2016: Process fluid leak into Storm Pond.
- February 18, 2016: Phase 2 utility water tank containment deficiency.
- March 3, 2016: SRU spent scavenger storage tank fire.

- On April 1, 2016 MEG received an Enforcement Order under EPEA related to March 3 SRU tank fire.
- The AER issued an Enforcement Order acknowledging the SRU outage and, as a result, potential for daily emissions limit exceedances. The order required MEG to submit an Interim Operating and Repair Plan for operation and repair of the facility. The AER temporarily suspended the daily sulphur emission limit of 2.0 t/day during the period of the enforcement order.
- During the repair period, there were no exceedances of Alberta Ambient Air Quality Objectives or LARP air quality management triggers.
- MEG has a robust process for monitoring and internally reporting its inlet sulphur rates, sulphur recovery rates and SO_2 emissions. MEG will continue to refine this system to ensure compliance with its EPEA limits.
- MEG is currently working to expand sulphur capacity to provide additional operating flexibility in the event of an outage.

Compliance Summary

MEG reported 5 EPEA approval contraventions to the AER during the reporting period:

- August 20, 2015: Continuous Emissions Monitoring System (CEMS) Non-Compliance
  - Missed 90% uptime requirement
- September 20, 2015: Flare Outage Non-Compliance
  - Phase 2 HP flare outage.
- October 4, 2015: Continuous Emissions Monitoring System (CEMS) Non-Compliance
  - Late submission of the August 2015 electronic CEMS data file
- March 19-21, 2016: Daily sulphur dioxide limit Non-Compliance
  - Exceedance of the daily sulphur dioxide limit on 3 days.

Ambient Air Quality Monitoring

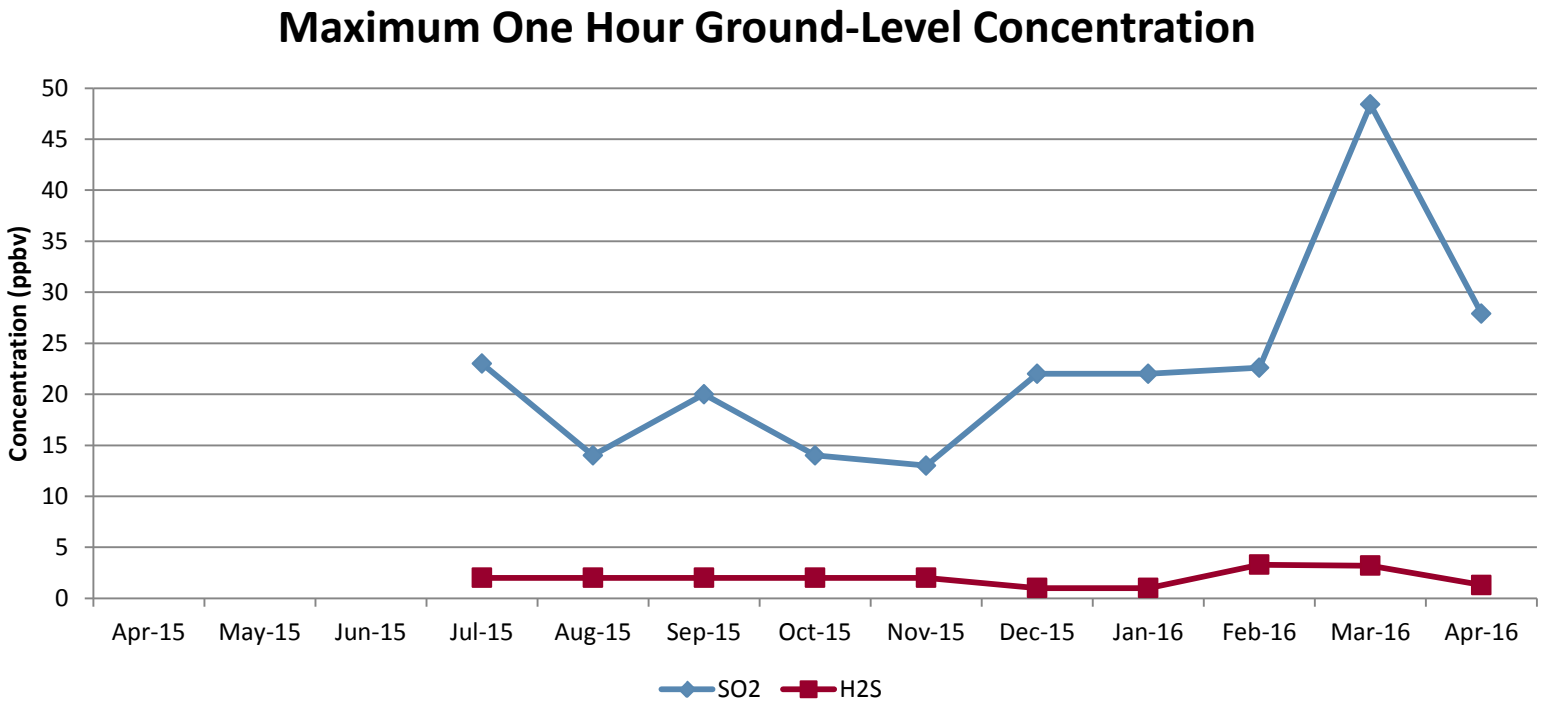
Continuous Ambient Air Monitoring Trailer and Passive Sampling

- MEG employed the use of a continuous ambient air monitoring trailer from July to December 2015 for phases 1, 2 and 2B as required by our 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.
- No ambient air contraventions were reported in 2015.
- Two reported exceedances of EPEA sulphur emissions limits in March 2016 related to SRU fire.

Ambient Air Quality Monitoring

Continuous Monitoring Results

	Maximum Reading (ppbv)	Month of Maximum Reading	Limit (ppbv)
SO2	48.4	March 2016	172
H2S	3.3	February 2016	10

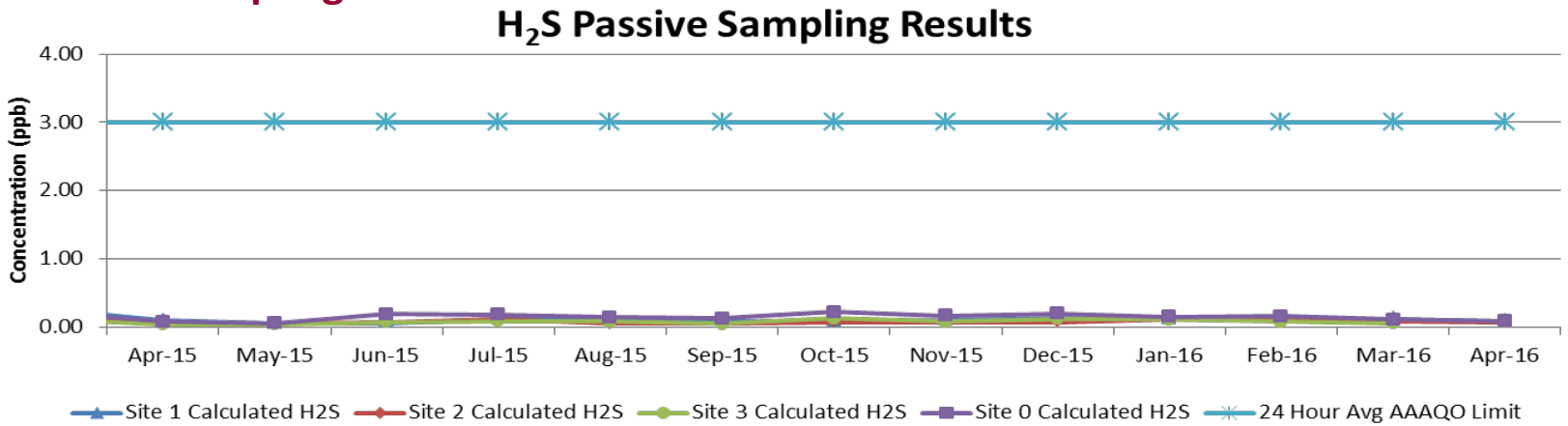


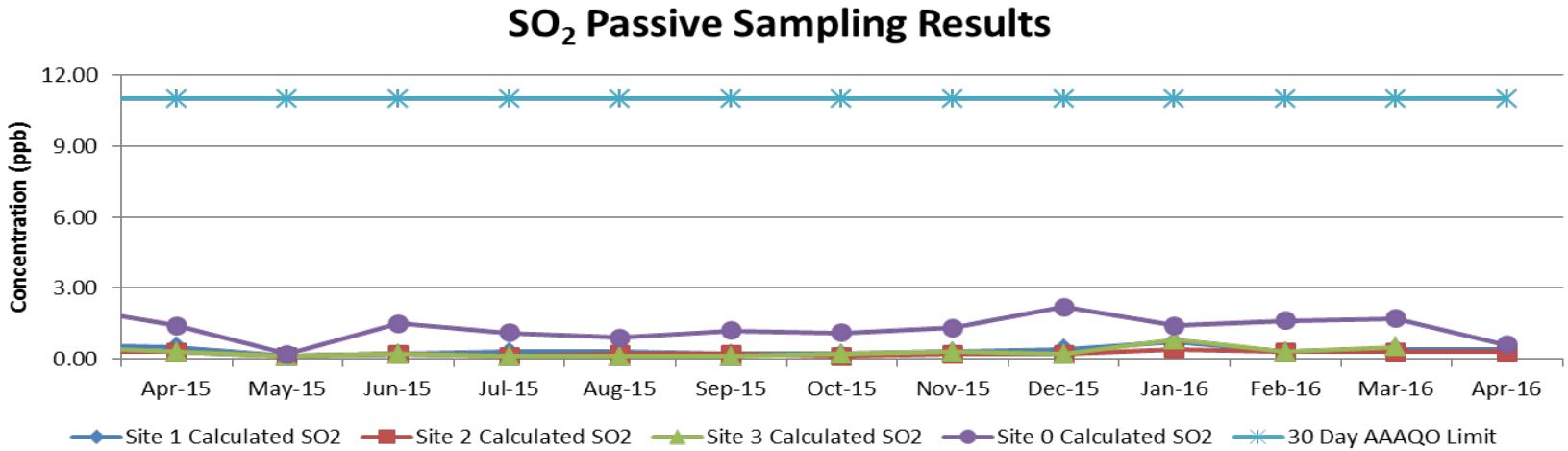
There were no exceedances of Ambient Air Quality Objectives during the reporting period.

As required by the terms and conditions of the EPEA approval, MEG is required to assess ambient air quality with a continuous monitoring station for six months per year. MEG had a 3rd party operated continuous monitoring station at the facility at the time of the SRU incident and for the duration of the SRU outage. In addition, MEG was assessing potential impacts to regional air quality using available data from the Wood Buffalo Environmental Association (WBEA) trailer at Conklin Lookout. During this period, no exceedances of AAAQO or LARP regional management triggers were recorded at either monitoring location.

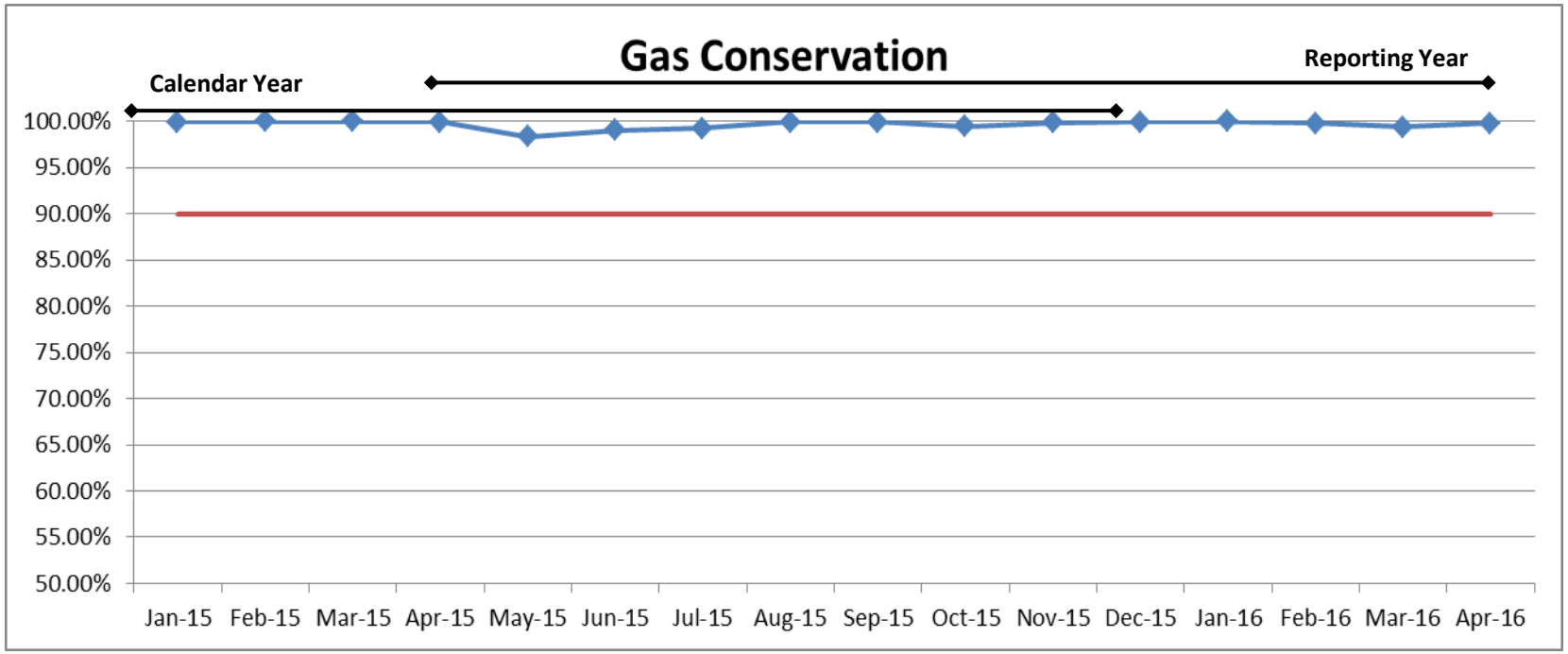
Ambient Air Quality Monitoring

Passives Sampling Results





Gas Usage



- Overall gas conservation >99%
- MEG reported 26 flaring and 0 venting notifications to the AER from April to December 2015 including exceedances and outages.
- MEG reported 8 flaring and 0 venting notifications to the AER from January to April in 2016 including exceedances and outages.

Conservation & Reclamation

Reporting Year Highlights

- Wetland Reclamation Trial Program
  - Completed planting of the trial site.
  - Completed first vegetation survey of site.
- Borrow Pit 31
  - Completed planting of Northern portion of borrow pit to prepare for closure and reclamation certification.
- Ongoing OSE Reclamation and Assessment Program
- Ongoing research and monitoring programs
  - Woodland Caribou Mitigation and Monitoring Program
  - Canadian Oil Sands Innovation Alliance Faster Forest Program
  - Rare Plant Mitigation and Monitoring

OSE Reclamation

Summary

January to December 2015:

- Reclamation Certificates Submitted for:
  - CLRP 50040
  - CLRP 60068
  - CLRP 70107
  - Jackfish 70079
  - Kirby 100067
  - Thornbury 70077
- Reclamation Certificates Received:
  - May River 070069
  - May River 060066
  - Jackfish 060065

January to April 2016:

- Reclamation Certificates Submitted for:
  - CLRP 090055
  - Duncan 100059
  - May River 090043
  - May River 100068

Conservation & Reclamation

Linear Disturbance Deactivation

- As required by MEG's EPEA Caribou Mitigation and Monitoring Plan, MEG initiated a project to perform linear restoration activities in townships 077-03 and 077-04 W4M in the winter of 2016.
- The work was completed in partnership with the Regional Industry Caribou Collaboration (RICC).
- The project occurred from February 10 – 28, 2016 and a total of 12.7 km of linear features were treated. The resulting total habitat restored, accounting for the 500 meter buffer, is about 600 hectares.

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.

MEG ENERGY

CLRP
FUTURE PLANS

Regulatory Activity

April 2015 - April 2016

- Various Directive 56 licenses and amendments for well pads and field facilities
- Scheme pattern amendments for pads AR, AT, L
- Expansion of NCG Co-Injection on Pads A through F and V

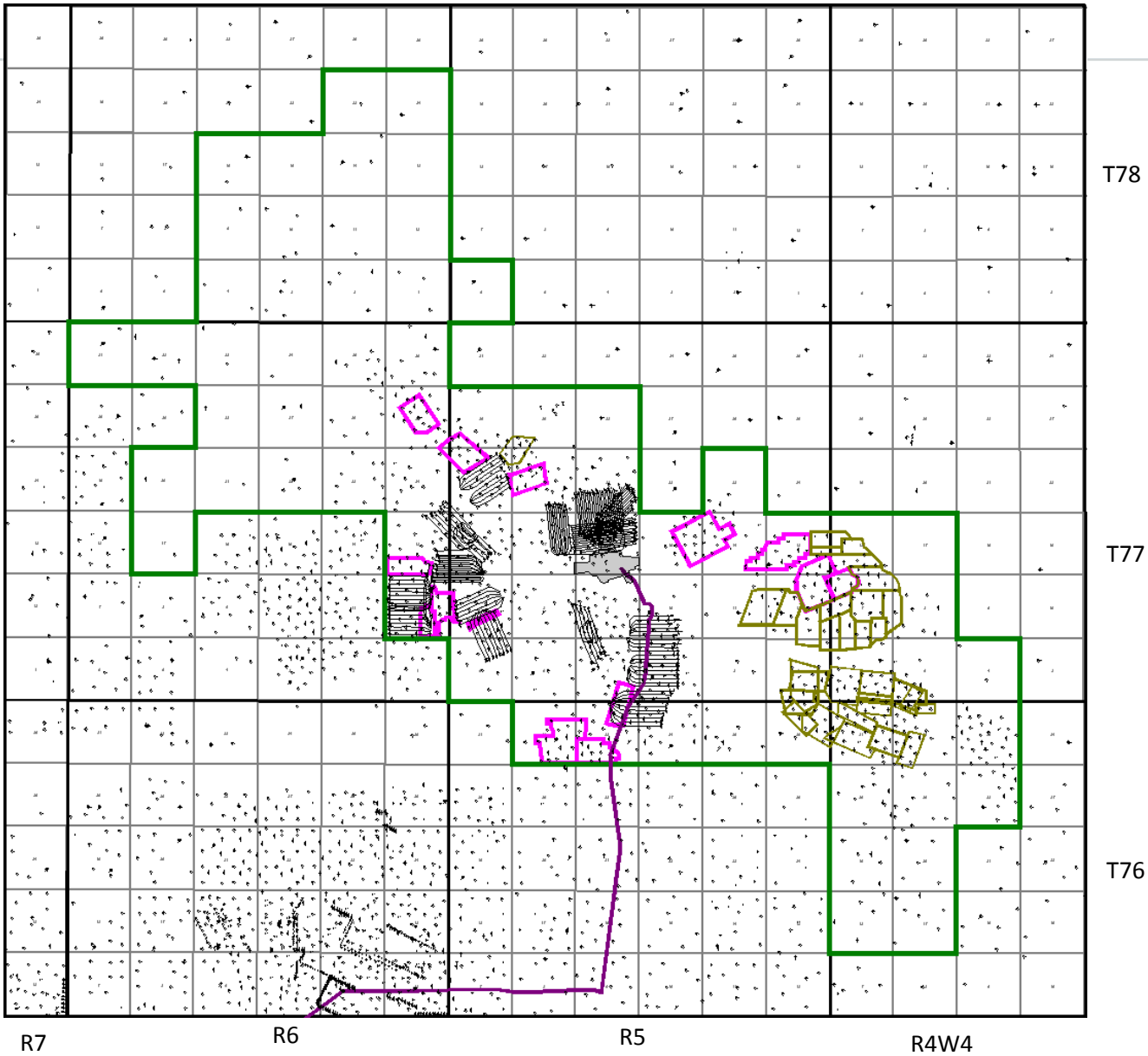
April 2016 - April 2017

- eMSAGP applications for G, H, J, K, T, U, AF and AG patterns
- Application for eMVAPEX pilot in June 2016
- Off-spec fluid injection project Q3 2016

CLRP Future Plans

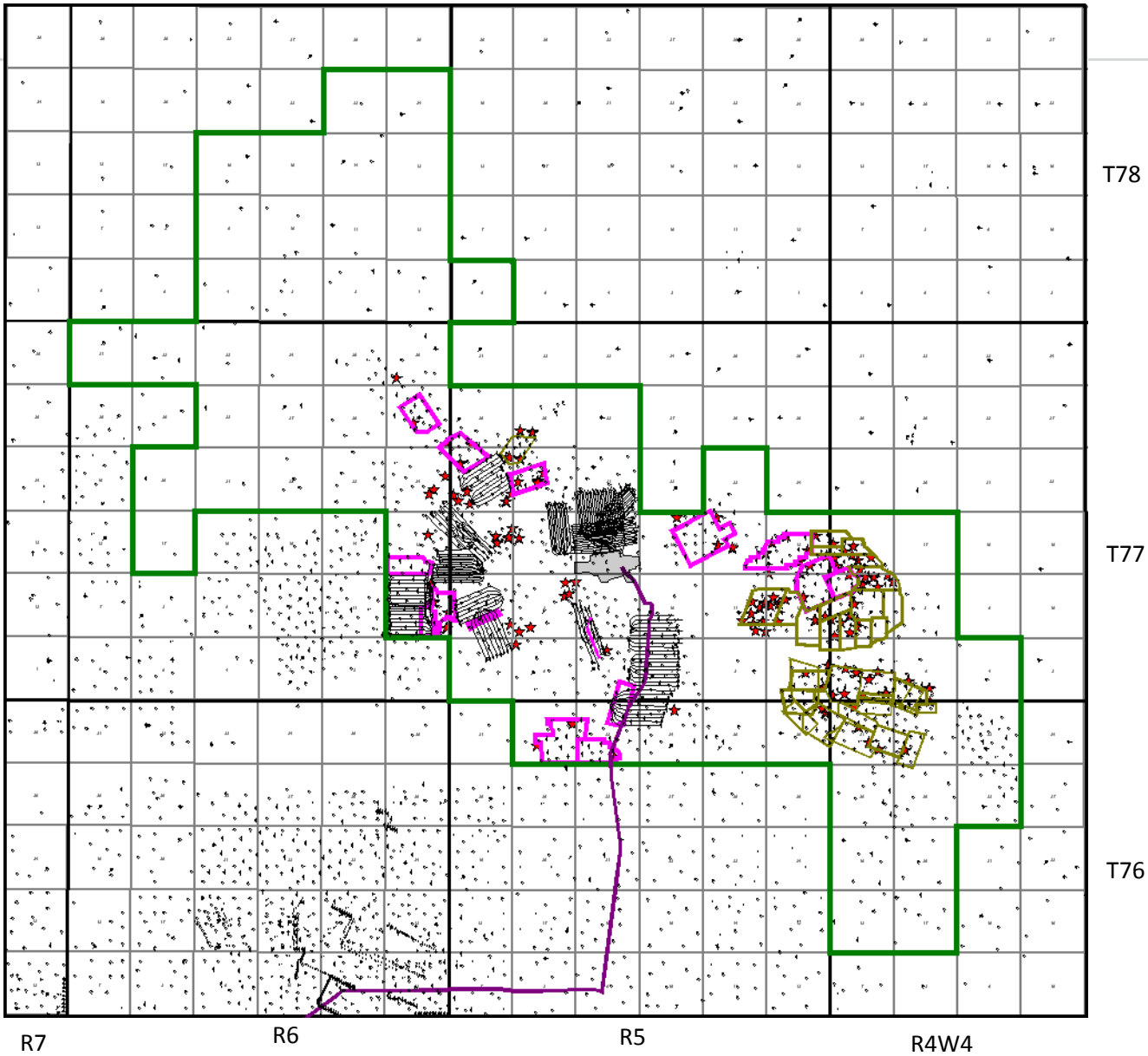
- Continued development of eMSAGP within Active Development Area
- Ongoing progress of brownfield development within existing facility footprint
- Ongoing pattern addition within CLRP development area
- Ongoing resource assessment

CLRP Future Development



- CLRP Project Area
- Approved SAGD Patterns
- Planned Pattern Additions
- Central Plant
- Access pipeline

CLRP Future Development



- CLRP Project Area
- Approved SAGD Patterns
- Planned Pattern Additions
- Central plant
- 2017-2019 Core locations
- Access pipeline

MEG ENERGY

Questions and Comments