Christina Lake Regional Project

2018/2019 Performance Presentation
Commercial Scheme Approval No. 10773

July 18, 2019
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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 m³/d or 3,000 bpd
- Sustained steaming commenced March 2008

Phase 2
- Approved in March 2007 for total production of 3,975 m³/d or 25,000 bpd
- First steam Q3 2009

Phase 2B
- Approved in March 2009 for total production of 9,540 m³/d or 60,000 bpd
- First steam Q3 2013

Phases 3A/B/C/D
- Approved in February 2012 for total production of 33,390 m³/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

Phase 2/2B CPF Approved Development Area

- R7 R6 R5
- T76
- T77
- T78

- R4W4

- Phase 2/2B CPF
- Approved Development Area
Active Development Area (ADA)

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

Drilled* SAGD Wells

* 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
Wabiskaw / McMurray Cores

- 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

[Map showing CLRP Project Area, 3D Seismic, Time Lapse 3D (2014), Time Lapse 3D (2016)]
**Active Development Area (ADA)**

- **526* horizontal wells** (SAGD and infill wells)
- *Does not include the incomplete Pairs of AH and DE patterns*
Wabiskaw/McMurray Stratigraphy

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

McMurray stratigraphy after ERCB RGS 2003
Wabiskaw / McMurray Reference Well

1AE/06-18-77-05W400

Cap Rock

Clearwater C

Wabiskaw C

Wabiskaw D

McMurray

Producer

Injector

SAGD Interval

B/W

BHL

<table>
<thead>
<tr>
<th></th>
<th>McMurray</th>
<th>SAGD</th>
</tr>
</thead>
<tbody>
<tr>
<td>h (m)</td>
<td>47.6</td>
<td>28.9</td>
</tr>
<tr>
<td>avg @</td>
<td>0.311</td>
<td>0.314</td>
</tr>
<tr>
<td>avg Sₚ</td>
<td>0.770</td>
<td>0.794</td>
</tr>
<tr>
<td>BMO (calc)</td>
<td>0.114</td>
<td>0.120</td>
</tr>
</tbody>
</table>

McMurray Pay >6wt% BMO
McMurray SAGD Pay Parameters

**SAGD Pay**

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

\[ R_t = \text{Deep Induction} \]

\[ \phi_{\text{density}} \geq 25\% \]

\[ S_o \text{ (bitumen saturation)} \geq 50\% \]

Gas and coal excluded

parameters for \( S_o \) calculation
## McMurray Reservoir Properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Pay (m)</td>
<td>18.7</td>
</tr>
<tr>
<td>Average Depth to reservoir top (mTVD)</td>
<td>359</td>
</tr>
<tr>
<td>Porosity range (Frac)</td>
<td>0.30-0.36</td>
</tr>
<tr>
<td>Water Saturation Range (frac)</td>
<td>0.15-0.30</td>
</tr>
<tr>
<td>Average $K_h$ (Darcies)</td>
<td>5,000</td>
</tr>
<tr>
<td>Average $K_v$ (Darcies)</td>
<td>2,500</td>
</tr>
<tr>
<td>Initial Reservoir Pressure (Kpag)</td>
<td>2,100</td>
</tr>
<tr>
<td>Reservoir temperature (°C)</td>
<td>13</td>
</tr>
</tbody>
</table>

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
Contour interval = 5 m
Cross Sections for Scheme Area

- Patterns B-F
- Pattern A
- Pattern V
- Pattern U
- Pattern T
- Pattern G
- Pattern H
- Pattern M
- Pattern N
- Pattern P
- Pattern AT
- Pattern L
- Pattern DB
- Pattern DC

Project Area

- T77
- T76

AH is in progress

AH North

AH East

F Expansion

AH West

AN North

AN South

R4

R5W4

R6

CLRP

SAGD

Patterns
Structural Cross Section A-A’

Stacked Pattern Development (Multiple Pay Intervals)
Structural Cross Section B-B’

- Clearwater C
- Wabiskaw C
- McMurray Formation
- Top McMurray
- Wabiskaw Marker
- Wabiskaw C Sand
- SAGD pay
- Top McMurray
- non-reservoir lithofacies
- Water Sand
- Cap Rock

Legend:
- Red: Injector
- Green: Producer

MEG Energy
Structural Cross Section D-D’

D  1AA/11-07-77-05W4  100/02-07-77-05W4  D’

- Clearwater C
- Cap Rock
- Wabiskaw C
- Wabiskaw Marker
- Top McMurray
- non-reservoir lithofacies
- SAGD pay
- Water Sand
- Producer
- Injector

MEG Energy
Structural Cross Section E-E’
Structural Cross Section F-F’

- McMurray Formation
- Clearwater C
- Wabiskaw Marker
- Wabiskaw C Sand
- Wabiskaw D Valley Fill
- non-reservoir lithofacies
- Top McMurray
- SAGD pay
- Water Sand
- Cap Rock
- Wabiskaw C
- Wabiskaw D

Legend:
- Red: Injector
- Green: Producer

MEG Energy
Structural Cross Section G-G’

T pattern
1AC/13-18-77-05W4

U pattern
1AE/06-18-77-05W4

A pattern
100/04-18-76-05W4

Clearwater C
Cap Rock
Wabiskaw C
Wabiskaw D

McMurray Formation

Producer
Injector

Reservoir currently unexploited
non-reservoir lithofacies
SAGD pay
Water Sand

Top McMurray
non-reservoir lithofacies

Structural Cross Section G-G’
Structural Cross Section H-H’

McMurray Formation

Clearwater C

Cap Rock

Wabiskaw Marker

Wabiskaw C Sand

SAGD pay

Top McMurray

non-reservoir lithofacies

Water Sand

HH’

Producer

Injector

McMurray Formation

Wabiskaw C

Wabiskaw D

HH’
Structural Cross Section I-I’

- 1AB/10-15-077-05W4
- 1AA/11-14-077-05W4
- 1AA/05-13-077-05W4

- McMurray Formation
- Clearwater C
- Wabiskaw Marker
- Wabiskaw C Sand
- SAGD pay
- Top McMurray
- Gassy Bitumen
- McM Ch Gas (associated)
- Water Sand
- non-reservoir lithofacies

Legend:
- Red: Injector
- Green: Producer
Structural Cross Section J-J’

- 102/05-12-077-05W4
- 100/16-12-077-05W4
- 100/04-18-077-04W4

- McMurray Formation
- Clearwater C
- Cap Rock
- Wabiskaw C Sand
- Wabiskaw Marker
- Wabiskaw D
- McM Ch Gas (associated)
- SAGD pay
- Water Sand
- Gassy Bitumen
- non-reservoir lithofacies
- non-reservoir lithofacies
- non-reservoir lithofacies

- 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
  - WBSK D Shale

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

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

Contour Interval = 5 m

- CLRP
  - Project Area
- Drilled SAGD
  - Patterns

Patterns:
- Pattern A
- Pattern AP
- Pattern AN
- Pattern V
- Pattern U
- Pattern T
- Pattern G
- Pattern H
- Pattern M
- Pattern N
- Pattern P
- Pattern AT

Locations:
- T77
- T76

Drilled SAGD Patterns:
- AH East
- AH North
- AH West
- AP South
- Pattern A
- Pattern AP
- Pattern U
- Pattern T
- Pattern G
- Pattern H
- Pattern M
- Pattern N
- Pattern P
- Pattern AT
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

- MEG OSL
- Approved Development Area
- Instrumented OB Wells
- Non-Instrumented OB wells

Map showing T77 and T76 areas with grid references R6, R5W4, and R4.
## Well Spacing

<table>
<thead>
<tr>
<th>Pattern</th>
<th>Operating Wellpairs</th>
<th>Average Spacing Between SAGD Pairs (m)</th>
<th>Average Spacing Between SAGD Pair to Infill (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>8</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>B</td>
<td>2</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>BB+D7</td>
<td>7</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>C+D8</td>
<td>7</td>
<td>110</td>
<td>55</td>
</tr>
<tr>
<td>D-D6-D7</td>
<td>5</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>E+F1</td>
<td>7</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>F+F1</td>
<td>5</td>
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<tr>
<td>V</td>
<td>6</td>
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<td>G</td>
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</tr>
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<td>U</td>
<td>6</td>
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<tr>
<td>AP West</td>
<td>10</td>
<td>100</td>
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<td>AP South</td>
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<td>100</td>
<td>50</td>
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<tr>
<td>AQ North</td>
<td>4</td>
<td>105</td>
<td>NA</td>
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<td>AQ South</td>
<td>4</td>
<td>120</td>
<td>NA</td>
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<tr>
<td>L</td>
<td>9</td>
<td>100</td>
<td>NA</td>
</tr>
<tr>
<td>AT</td>
<td>8</td>
<td>106</td>
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<tr>
<td>P Expansion</td>
<td>3</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>DB</td>
<td>11</td>
<td>100</td>
<td>NA</td>
</tr>
<tr>
<td>Total</td>
<td>182</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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
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
Well Completions – SAGD Injector

- Steam injected into both long tubing and short tubing
- Blanket gas on annulus
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.
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.
• 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
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 it is economically appropriate.
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)
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

- 13 3/8” Surface Casing
- 9 5/8” Production Casing
- 4 1/2” Production Tubing
- ESP
- 5 1/2” Wire Wrap Screen
Water Disposal Wells

- 13 3/8” Surface Casing
- 9 5/8” Production Casing
- 7” Production Tubing
- Isolation Packer
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
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
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
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
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 wellsites 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 m³/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 m³/d
Flow Control Devices (FCDs) or Inflow Control Devices (ICDs) used typically consist of an inflow ports and a sliding sleeve used to block or unblock these ports.

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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 m³/d (25,000 bpd) by late April 2010
- Phase 2B production ramp-up improved Phase 2. Total production reached 11,340 m³/d (71,300 bpd) in Q2 2014, far exceeded the combined original design capacity of 9,539 m³/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

Scheduled Plant Turnaround

Phase 1+2+2B Original Design Capacity
Phase 1+2 Original Design Capacity

Rate (m³/day)

Jan-08 Jan-10 Jan-12 Jan-14 Jan-16 Jan-18 Jan-20

Steam
Bitumen
Water
Performance – SOR of All Patterns

Phase 2 Start-up

Phase 2B Start-up
Pattern A Performance

Rate (m³/day, e4m³/month)

- Steam
- NCG Inj
- Bitumen
- Water
- SOR

Key Events:
- eMSAGP Pilot Start
- eMSAGP in A4, A5 and A6 Start
- A7 and A8 on production
Pattern B Performance

![Graph showing rate (m3/day, e4m3/month) from Jan-09 to Jan-21 with eMSAGP Start indicated.](image)

- **Rate (m3/day, e4m3/month)**
- **X-axis**: Jan-09 to Jan-21
- **Y-axis**: 0 to 1,000
- Lines representing:
  - **Steam** (red)
  - **NCG Inj** (orange)
  - **Bitumen** (green)
  - **Water** (blue)
  - **SOR** (black)

**Legend**

- Red: Steam
- Orange: NCG Inj
- Green: Bitumen
- Blue: Water
- Black: SOR
Pattern BB Performance

- **Rate (m³/day, e⁴m³/month)**
- **SOR**

Graph showing performance over time with details on eMSAGP of B3 - B6 start and B7 and B8 on production.
Pattern D Performance

![Graph showing Pattern D Performance with various data points and lines representing different categories such as Steam, NCG Inj, Bitumen, Water, and SOR. The graph includes a note labeling the 'eMSAGP Start' and the data range from Jan-09 to Jan-21.]
Pattern E Performance

![Graph showing the performance of different fluids over time.

- **Rate (m3/day, e4m3/month)**
- **SOR**

The graph displays the rate and SOR for different fluids starting from Jan-09 to Jan-21. Key points include:

- **eMSAGP Start**

Legend:

- Red: Steam
- Orange: NCG Inj
- Green: Bitumen
- Blue: Water
- Black: SOR
Pattern F Performance

![Graph showing production rates over time for different fluids and SOR. The graph includes lines for Steam, NCG Inj, Bitumen, Water, and SOR, with a notable eMSAGP start marked.]
Pattern V Performance

![Pattern V Performance Graph](image)

- **Rate (m³/day, e4m³/month)**
- **SOR**

Legend:
- **Steam**
- **NCG Inj**
- **Bitumen**
- **Water**
- **SOR**

- **eMSAGP Start**

Graph shows performance data from Jan-12 to Jan-20.
Pattern G Performance

MSAGP Start

- **Rate (m³/day, e⁴m³/month)**
- **SOR**

Legend:
- **Red** Steam
- **Orange** NCD Inj
- **Green** Bitumen
- **Blue** Water
- **Black** SOR
Pattern H Performance

![Graph showing the performance of Pattern H with different rates and SOR over time.]

- **Rate (m3/day)**
- **SOR**

Legend:
- Red: Steam
- Green: Bitumen
- Blue: Water
- Black: SOR

Time Period:
- Jan-13 to Jan-20
Low Performance Pad: Issues are suspected to be related to potential scale formation and aggravated by exposure to bottom water.
Pattern K Performance

The graph illustrates the performance of Pattern K with different fluid injections and rates over time. The x-axis represents the years from January 2013 to January 2020, and the y-axis shows the rate in m³/day, e4m³/month. The graph includes lines for steam, NCG injection, bitumen, water, and SOR (Solution Gas Oil Ratio). Notable events include the MSAGP Start and eMSAGP Start, indicated by red arrows on the graph.
Pattern M Performance

- Steam
- NCG Inj
- Bitumen
- Water
- SOR

Rate (m³/day, e4m³/month)

Jan-13 to Jan-20

eMSAGP Start
Pattern N Performance

*eMSAGP Start*

![Graph showing rates and SOR over time]

- **Rate (m³/day, e⁴m³/month)**
  - Steam
  - NCG Inj
  - Bitumen
  - Water
  - SOR

- **Time Periods:** Jan-13 to Jan-20
**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

[Graph showing the performance of different fluids over time, with markers for MSAGP Start and SOR.]

Rate (m³/day, 10⁴ m³/month)

MSAGP Start

Jan-13 Jan-14 Jan-15 Jan-16 Jan-17 Jan-18 Jan-19 Jan-20

Steam  NCG Inj  Bitumen  Water  SOR

Legend:
Pattern AP South Performance

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

![Chart showing the performance of different fluids (Steam, NCG Inj, Bitumen, Water, SOR) over time from Jan-14 to Jan-20. The chart highlights the eMSAGP Start with an arrow at the appropriate point on the x-axis.]

- **Rate (m3/day, e4m3/month)**
- **SOR**

Legend:
- Red: Steam
- Orange: NCG Inj
- Green: Bitumen
- Blue: Water
- Black: SOR

- **Jan-14**
- **Jan-15**
- **Jan-16**
- **Jan-17**
- **Jan-18**
- **Jan-19**
- **Jan-20**
Pattern AN Performance

![Graph showing rate (m³/day, e4m³/month) over time from January 2014 to January 2020. The graph includes lines for Steam, NCG Inj, Bitumen, Water, and SOR. The eMSAGP Start is indicated on the graph.](image-url)
Pattern P Performance

The graph below illustrates the performance of Pattern P, showing the rates (in m^3/day) for Steam, Bitumen, Water, and SOR from January 2015 to January 2020. The Infill Well Start is indicated by an arrow on the graph.

- **Steam**: Represented by red line, showing fluctuations in rate over the years.
- **Bitumen**: Represented by green line, with a steady increase in rate.
- **Water**: Represented by blue line, showing a moderate increase in rate.
- **SOR**: Represented by black line, with significant changes noted particularly after the Infill Well Start.
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

![Graph showing the performance of Pattern L with various rates and SOR values over time from Jan-18 to Jul-19. The graph includes lines for Steam, Bitumen, Water, and SOR, with rate in m³/day and SOR on the y-axis, and time in months on the x-axis.]
OBK3 Logging Results

Vertical chamber growth observed through IHS
**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

<table>
<thead>
<tr>
<th>Pattern</th>
<th>Operating WellPairs</th>
<th>Pattern Area (m²)</th>
<th>Average h (m)</th>
<th>Average Porosity</th>
<th>Average Oil Saturation</th>
<th>OBIP (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>8</td>
<td>698,812</td>
<td>22</td>
<td>0.33</td>
<td>0.76</td>
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<tr>
<td>B</td>
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<tr>
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<tr>
<td>C+D6</td>
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<td>0.75</td>
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</tr>
<tr>
<td>D-D6-D7</td>
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<td>0.81</td>
<td>1,952,000</td>
</tr>
<tr>
<td>E+F1</td>
<td>7</td>
<td>606,356</td>
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<td>0.33</td>
<td>0.77</td>
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<tr>
<td>F-F1</td>
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<td>2,148,000</td>
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<tr>
<td>V</td>
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<tr>
<td>G</td>
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<tr>
<td>H</td>
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<td>839,000</td>
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<tr>
<td>J</td>
<td>8</td>
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<td>0.74</td>
<td>3,999,000</td>
</tr>
<tr>
<td>K</td>
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<td>3,000,000</td>
</tr>
<tr>
<td>M</td>
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<td>970,951</td>
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</tr>
<tr>
<td>T</td>
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<td>779,449</td>
<td>15</td>
<td>0.32</td>
<td>0.82</td>
<td>2,970,000</td>
</tr>
<tr>
<td>U</td>
<td>6</td>
<td>521,939</td>
<td>19</td>
<td>0.30</td>
<td>0.80</td>
<td>2,414,000</td>
</tr>
<tr>
<td>AP West</td>
<td>10</td>
<td>912,982</td>
<td>31</td>
<td>0.34</td>
<td>0.82</td>
<td>7,760,000</td>
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<tr>
<td>AP South</td>
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<td>246,044</td>
<td>23</td>
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<td>0.79</td>
<td>1,485,000</td>
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<tr>
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<td>498,601</td>
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<td>2,609,000</td>
</tr>
<tr>
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<td>0.81</td>
<td>4,744,000</td>
</tr>
<tr>
<td>P*</td>
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<td>1,269,292</td>
<td>20</td>
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<td>5,802,000</td>
</tr>
<tr>
<td>AQ</td>
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<td>856,060</td>
<td>19</td>
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<td>0.80</td>
<td>4,404,000</td>
</tr>
<tr>
<td>AT*</td>
<td>8</td>
<td>972,328</td>
<td>22</td>
<td>0.31</td>
<td>0.78</td>
<td>5,188,000</td>
</tr>
<tr>
<td>L*</td>
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<td>946,760</td>
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<td>0.73</td>
<td>4,859,000</td>
</tr>
<tr>
<td>DB*</td>
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<td>21</td>
<td>0.33</td>
<td>0.68</td>
<td>5,777,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>184</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>96,795,000</strong></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Pattern</th>
<th>Operating WellPairs</th>
<th>Area (m²)</th>
<th>Average h (m)</th>
<th>Average Porosity</th>
<th>Average Oil Saturation</th>
<th>SAGDable BIP (m³)</th>
<th>Cumulative Production (m³)</th>
<th>Recovery to Date (% SADable)</th>
<th>Estimated Final Recovery (% SAGDable)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>8</td>
<td>698,812</td>
<td>20</td>
<td>0.32</td>
<td>0.76</td>
<td>3,501,000</td>
<td>2,124,079</td>
<td>61%</td>
<td>62%</td>
</tr>
<tr>
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<td>0.33</td>
<td>0.84</td>
<td>1,078,000</td>
<td>843,753</td>
<td>78%</td>
<td>83%</td>
</tr>
<tr>
<td>BB+D7</td>
<td>7</td>
<td>565,648</td>
<td>18</td>
<td>0.32</td>
<td>0.82</td>
<td>2,681,000</td>
<td>1,596,689</td>
<td>60%</td>
<td>60%</td>
</tr>
<tr>
<td>C+D6</td>
<td>7</td>
<td>647,762</td>
<td>26</td>
<td>0.33</td>
<td>0.76</td>
<td>4,090,000</td>
<td>3,319,528</td>
<td>81%</td>
<td>83%</td>
</tr>
<tr>
<td>D-D6-D7</td>
<td>5</td>
<td>339,069</td>
<td>18</td>
<td>0.34</td>
<td>0.81</td>
<td>1,686,000</td>
<td>1,150,007</td>
<td>68%</td>
<td>72%</td>
</tr>
<tr>
<td>E+F1</td>
<td>7</td>
<td>606,356</td>
<td>19</td>
<td>0.33</td>
<td>0.77</td>
<td>2,940,000</td>
<td>2,123,719</td>
<td>72%</td>
<td>75%</td>
</tr>
<tr>
<td>F-F1</td>
<td>5</td>
<td>382,821</td>
<td>19</td>
<td>0.33</td>
<td>0.78</td>
<td>1,867,000</td>
<td>1,181,771</td>
<td>63%</td>
<td>65%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
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<td><strong>12,339,546</strong></td>
<td><strong>69%</strong></td>
<td><strong>71%</strong></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Pattern</th>
<th>Operating WellPairs</th>
<th>Area (m²)</th>
<th>Average h (m)</th>
<th>Average Porosity</th>
<th>Average Oil Saturation</th>
<th>SAGDable BIP (m³)</th>
<th>Cumulative Production (m³)</th>
<th>Recovery to Date (% SADable)</th>
</tr>
</thead>
<tbody>
<tr>
<td>V</td>
<td>6</td>
<td>650,137</td>
<td>24</td>
<td>0.31</td>
<td>0.73</td>
<td>3,479,000</td>
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<tr>
<td>G</td>
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<td>0.74</td>
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<td>0.74</td>
<td>599,000</td>
<td>129,659</td>
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</tr>
<tr>
<td>J</td>
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<td>0.75</td>
<td>3,653,000</td>
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<tr>
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<td>0.74</td>
<td>2,783,000</td>
<td>1,109,889</td>
<td>40%</td>
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<tr>
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<td>0.79</td>
<td>6,965,000</td>
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<tr>
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<td>22</td>
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<td>0.80</td>
<td>5,657,000</td>
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<tr>
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<td>0.81</td>
<td>2,550,000</td>
<td>849,627</td>
<td>33%</td>
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<tr>
<td>U</td>
<td>6</td>
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<td>0.30</td>
<td>0.80</td>
<td>2,033,000</td>
<td>782,758</td>
<td>39%</td>
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<tr>
<td>AP West</td>
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<td>912,982</td>
<td>27</td>
<td>0.33</td>
<td>0.83</td>
<td>6,813,000</td>
<td>See Note**</td>
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<td>0.82</td>
<td>2,110,000</td>
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<td>0.77</td>
<td>2,095,000</td>
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<tr>
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<td>0.79</td>
<td>4,512,000</td>
<td>323,693</td>
<td>7%</td>
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<tr>
<td>L*</td>
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<td>0.73</td>
<td>4,165,000</td>
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<td>0.68</td>
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<td></td>
<td>67,574,000</td>
<td>16,285,564</td>
</tr>
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Note: Cumulative Production to April 2019  
*New pads or pads with wells added since May 2018  
**Covered under Experimental Scheme No. 12528B  

*New pads or pads with wells added since May 2018  
**Covered under Experimental Scheme No. 12528B
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
Phase 1 and Phase 2 Pad Layout

**eMSAGP Rollout:**
- 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
- 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

- Phase 1 SAGD (left axis)
- Phase 1 eMSAGP (left axis)
- Phase 2 SAGD (right axis)
- Phase 2 eMSAGP (right axis)

- Recovery to date: 72 %SOIP
- eMSAGP Start

- Phase 1 Bitumen (bpcd)
- Phase 2 Bitumen (bpcd)

Years
Steam Rates for Phases 1 and 2

- Phase 1 SAGD (left axis)
- Phase 1 eMSAGP (left axis)
- Phase 2 SAGD (right axis)
- Phase 2 eMSAGP (right axis)

Years

Phase 1 Steam (tpcd)

Phase 2 Steam (tpcd)
SOR for Phases 1 and 2

- Phase 1 SAGD
- Phase 1 eMSAGP
- Phase 2 SAGD
- Phase 2 eMSAGP

Years
0 1 2 3 4 5 6 7 8 9 10 11 12

ISOR
0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0

eMSAGP Start
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
Gas Cap
Re-Pressuring
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 mmmscf/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)

- Observation Wells
- 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 (Patterns M, N, & P)

![Graph showing cumulative gas injection rates and cumulative volumes from January 2013 to January 2020. The graph includes two lines: one representing injection rate and the other representing cumulative volume. The injection rate line shows fluctuations, while the cumulative volume line shows a steady increase.](image-url)
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)

Map showing gas injection wells, gas pipelines, observation wells, and McMurray Channel Gas Pool in direct and indirect contact with SAGD interval. Note: Not all SAGD intervals in the pool wells are directly connected to associated gas.
Observation Well Pressures (Pattern L)

Pressure (kPag)

Injection Start

Jan-18  Jul-18  Jan-19  Jul-19

100/12-14 (346.6 mKB)
100/12-14 (349.0 mKB)
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
  - V6 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
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

Water Make-up and Disposal Rate / Bitumen Rate

- Total Water Make-up/Bitumen
- Disposal Water/Bitumen
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
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

**Actual Steam Rate/Plant Design Steam Rate**

- **Steep/Design Steam (tonne/tonne)**
- **Month** (Jan-18, Feb-18, Mar-18, Apr-18, May-18, Jun-18, Jul-18, Aug-18, Sep-18, Oct-18, Nov-18, Dec-18, Jan-19, Feb-19, Mar-19, Apr-19)

- **Peak** in Aug-18 with a value of 1.20
- **Lowest** value in Jun-18 with a value of 0.70
- **Phase 2B planned maintenance** indicated by a peak in Jun-18

Graph indicates fluctuations in steam rate over time, with notable changes in Jun-18.
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
Future Actions

- Review use of thermal imaging to predict steam generator tube condition.
Facility Performance: Power Generation

Power Generated/Consumed

- Phase 2B planned maintenance.
- Phase 2 planned maintenance.
Facility Performance: Power Generation

Actual Power Generated / Design Generation

- Phase 2B planned maintenance.
- Phase 2B planned maintenance.
Facility Performance: Power Generation

Successes
• Stable operation throughout the year

Issues Being Addressed
• No significant issues
Facility Performance: Gas Usage

Gas Consumption

Phase 2B planned maintenance.
Facility Performance: Gas Usage

![Graph showing Total Gas Consumed / Bitumen from January 2018 to April 2019. The graph displays the gas consumption in terms of gas/bitumen (sm³/m³) over the specified period, with a peak in November 2018 and a decline towards April 2019.](image-url)
• 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
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 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
Water Overview

- Water Use and Recycle
- Source Water
- Disposal
- Monitoring
• 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
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
Source Water Well Locations

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

- 5 active McMurray disposal wells

ERCB Approval No. 10659
Maximum WHIP 4,230 kPag
Disposal Summary

Calendar Year (1.16 MM m³)

Reporting Year (1.24 MM m³)

Monthly Volume (m³)


100/07-16 077-05W4/00 100/09-29-077-05W4/00 103/10-29-077-05W4/00 102/10-29-077-05W4/00 100/11-29-077-05W4/00
Wellhead Injection Pressures

Increased disposal rates due to Boiler Feedwater excursion
Injection Temperatures
Basal McMurray Water Sand Pressure Monitoring

Graph showing pressure data over time with various markers indicating different wells and pressure levels.
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
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

<table>
<thead>
<tr>
<th><strong>Air</strong></th>
<th><strong>Soil</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemical analysis and flow rates for all fuel streams and stack emissions. We also monitor ambient air quality around our facilities.</td>
<td>Soil analysis and laboratory testing for any chemical changes or contaminations</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Groundwater</strong></th>
<th><strong>Surface Water/Wetlands</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>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.</td>
<td>Monitor surface water quantity and quality in nearby water bodies and watercourses</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Regional Monitoring</strong></th>
<th><strong>Wildlife</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>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.</td>
<td>Winter tracking, monitoring wildlife corridors using remote cameras, and employee wildlife sighting cards</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>Vegetation</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Monitor species composition and abundance</td>
</tr>
</tbody>
</table>
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 \( \text{H}_2\text{S} \) and \( \text{SO}_2 \) with readings taken on a monthly basis

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

SO2 Passive Monitoring Results

H2S Passive Monitoring Results
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
Sulphur Removal

- **Inlet Sulphur (t/d)** range from 0.00 to 2.00
- **Recovery (%)** range from 0 to 100

- **Quarterly Average Inlet Sulphur**
- **Quarterly Average Recovery**
Produced Gas Rates and H₂S Concentration
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.

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</tr>
</thead>
<tbody>
<tr>
<td>Oct-18</td>
<td>23</td>
<td>37</td>
<td>109</td>
<td>130</td>
<td>430</td>
<td>0</td>
<td>4</td>
</tr>
</tbody>
</table>
SO$_2$ Emissions

- SRU Maintenance
- ID2001-3 Variance for 2019
- Plant Upset

Graph showing SO$_2$ Emissions from April 18 to April 19, with EPEA Approval Limit, SO$_2$ Emissions, and 90-Day Rolling Average SO$_2$.
• **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 11\(^{th}\) 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
• 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).

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
## Audit/Inspection Summary

<table>
<thead>
<tr>
<th>Date</th>
<th>Audit/Inspection</th>
<th>Area</th>
<th>Result</th>
</tr>
</thead>
<tbody>
<tr>
<td>February 20, 2018</td>
<td>AER Pipeline Inspection (ID 471573)</td>
<td>Wildlife Crossing Compliance</td>
<td>Satisfactory</td>
</tr>
<tr>
<td>March 21, 2018</td>
<td>AER Drilling Waste Inspection (ID 472313)</td>
<td>Waste Handling and Storage</td>
<td>Satisfactory</td>
</tr>
<tr>
<td>April 2, 2018</td>
<td>AER Drilling Waste Audit (DD5649017)</td>
<td>Drilling Waste Management and Documentation</td>
<td>Satisfactory</td>
</tr>
<tr>
<td>August 1, 2018</td>
<td>AER Public Lands Act Inspection (ID477723)</td>
<td>Erosion and Sedimentation MEG Hardy 6-33-76-5 W4M</td>
<td>Unsatisfactory – Closed Corrective Action Complete</td>
</tr>
<tr>
<td>September 18, 2018</td>
<td>AER Manual 001 (ID479315)</td>
<td>Central Plant SAGD Facility and AP Pad</td>
<td>Satisfactory</td>
</tr>
<tr>
<td>September 18, 2018</td>
<td>AER Manual 001 (ID 479326)</td>
<td>MEG S2 Hardy 3-16-77-5 W4M Clearwater Source Well</td>
<td>Satisfactory</td>
</tr>
<tr>
<td>September 18, 2018</td>
<td>AER Manual 001 (ID 479327)</td>
<td>MEG S3 Hardy 8-16-77-5 W4M Clearwater Source Well</td>
<td>Satisfactory</td>
</tr>
<tr>
<td>September 18, 2018</td>
<td>AER Manual 001 (ID 479330)</td>
<td>MEG Hardy 7-16-77-5 W4M Regen Waste Disposal Well</td>
<td>Unsatisfactory – Closed Corrective Action Complete</td>
</tr>
</tbody>
</table>
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
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
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
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

- CLRP Project Area
- Approved SAGD Patterns
- Patterns in progress (currently being drilled)
- Planned Pattern Additions
- Central Plant
- 2019 Core hole focus areas
Environment and Regulatory

Sachin Bhardwaj
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