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Anticipated netbacks are calculated by adding anticipated revenues and other income and subtracting anticipated royalties, operating costs and transportation costs from such amount.
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This document may contain forward-looking information including but not limited to: expectations of future production, revenues, expenses, cash flow, operating costs, steam-oil ratios, pricing differentials, reliability, profitability and capital investments; estimates of reserves and resources; the anticipated reductions in operating costs as a result of optimization and scalability of certain operations; and the anticipated sources of funding for operations and capital investments. Such forward-looking information is based on management’s expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures, plans for and results of drilling activity, environmental matters, business prospects and opportunities.

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

Access Pipeline
CLRP Active Development Area (ADA)

Drilled SAGD Wells

<table>
<thead>
<tr>
<th>Pattern</th>
<th>SAGD Pairs</th>
<th>Infill Wells</th>
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<td>A</td>
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<td>B5</td>
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<td>C</td>
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<td>E</td>
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<td>1</td>
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<tr>
<td>AP</td>
<td>10</td>
<td>2</td>
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</table>

Total 143 48
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 (CLRDP)

- **CLRDP Project Area**
- **Approved Development Areas**
- **Access Pipeline**

**CPF = Central Plant Facility**
CLRP Wabiskaw / McMurray Cores

- 835 cored wells
- 86% of all wells are cored
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)
Seismic was shot in January-February 2016 over a period of 7 days.

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

- 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

• MEG OSL
  Central Plant

High
Low
CLRP Active Development Area (ADA)

- 334 horizontal wells (SAGD & Infill wells)

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

Water disposal

Water Source PL

Recent Infill Drilling

Recent SAGD Redrills
CLRP: Wabiskaw/McMurray Stratigraphy

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

**Clearwater C**

- Cap Rock
- Wabiskaw C
- Wabiskaw D
- McMurray

<table>
<thead>
<tr>
<th>McMurray</th>
<th>SAGD</th>
</tr>
</thead>
<tbody>
<tr>
<td>h (m)</td>
<td>47.6</td>
</tr>
<tr>
<td>avg ø</td>
<td>0.311</td>
</tr>
<tr>
<td>avg S_o</td>
<td>0.770</td>
</tr>
<tr>
<td>BMO (calc)</td>
<td>0.114</td>
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</table>

McMurray Pay >6wt% BMO

**SAGD Interval**

- Water Sand
- B/W
- BHL

**Gas**

- cross stratified sand
- muddy IHS
- bioturbated sandy mud
- bioturbated sandy mud
- bioturbated sandy mud
- muddy IHS
- cross stratified sand
- cross stratified sand
- mud rip up clasts

**Producers**

- Injector
- Producer
SAGD Pay

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

$R_t$ = Deep Induction

$\phi_{\text{density}} \geq 25\%$

$S_o$ (bitumen saturation) ≥ 50%

gas and coal excluded
CLRP: Average McMurray Reservoir Properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
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</thead>
<tbody>
<tr>
<td>Average pay (m)</td>
<td>18.7</td>
</tr>
<tr>
<td>Average depth to reservoir top (m TVD)</td>
<td>359</td>
</tr>
<tr>
<td>Average porosity (frac)</td>
<td>0.32</td>
</tr>
<tr>
<td>Average Sw (frac)</td>
<td>0.25</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 ($^\circ$C)</td>
<td>13</td>
</tr>
</tbody>
</table>
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
SAGD Pay Cutoffs:
- continuous bitumen pay $\geq 10 \text{ m}$ (defined by logs, images and core)
- $S_o \geq 50\%$ ($\sim 6 \text{ wt\% bulk mass oil}$)
- Porosity (density) $\geq 25\%$

Minimum contour = 10 m
Contour interval = 5 m
## OBIP Volumetrics for approved undrilled pads

<table>
<thead>
<tr>
<th>Pattern</th>
<th>Avg H</th>
<th>Avg $\phi$</th>
<th>Avg $S_o$</th>
<th>OBIP (bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AQ North</td>
<td>25.9</td>
<td>33.3%</td>
<td>82.0%</td>
<td>18,683,000</td>
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<tr>
<td>AQ South</td>
<td>16.9</td>
<td>33.7%</td>
<td>79.0%</td>
<td>12,652,000</td>
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<tr>
<td>AP South</td>
<td>21.6</td>
<td>33.5%</td>
<td>80.5%</td>
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<td>AJ North</td>
<td>216</td>
<td>32.6%</td>
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<tr>
<td>AJ South</td>
<td>18.8</td>
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<td>81.3%</td>
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<td>AH</td>
<td>19.6</td>
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<td>73.1%</td>
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<td>K</td>
<td>15.6</td>
<td>32.6%</td>
<td>69.6%</td>
<td>1,679,000</td>
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<tr>
<td>AT</td>
<td>20.8</td>
<td>31.6%</td>
<td>78.4%</td>
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<td>AR South</td>
<td>22.5</td>
<td>31.3%</td>
<td>76.1%</td>
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<td>AR North</td>
<td>18</td>
<td>30.7%</td>
<td>73.7%</td>
<td>11,007,000</td>
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<td>L</td>
<td>22</td>
<td>32.7%</td>
<td>76.1%</td>
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<td>32.8%</td>
<td>68.8%</td>
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<td>DD</td>
<td>27.1</td>
<td>32.7%</td>
<td>72.4%</td>
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<td>DC</td>
<td>29.7</td>
<td>32.7%</td>
<td>72.6%</td>
<td>18,626,000</td>
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</table>
CLRP ADA Base SAGD Pay Structure

- Contour interval = 5 m

CLRP Project Area
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
CLRFP ADA Top SAGD Pay Structure

contour interval = 5 m

T77

T76

CLRFP Project Area
SAGD Patterns

Pattern A
Pattern AP
Pattern AN
Pattern V
Pattern U
Pattern T
Pattern G
Pattern H
Pattern M
Pattern N
Pattern P
CLRP: Cross Sections for scheme area

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

SAGD Patterns

CLR Project Area

Grid Layout:
- T77
- T76
- R6
- RSW4
CLRP: Structural Cross Section A-A’

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

- **1AA/04-10-77-05W4**
- **100/06-03-77-05W4**
- **1AA/13-34-76-05W4**

**Key Features:**
- **Wabiskaw Marker**
- **Wabiskaw C Sand**
- **SAGD pay**
- **Non-reservoir lithofacies**
- **Water Sand**
- **Top McMurray**
- **Cap Rock**
- **Clearwater C**

**Legend:**
- **Red** = Injector
- **Green** = Producer
CLRP: Structural Cross Section C-C’

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

- Producer
- Injector
CLRP: Structural Cross Section D-D’

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

Diagram details:
- Producer
- Injector
CLRP: Structural Cross Section E-E’

- **E**
  - 1AA/14-12-77-06W4
  - Wabiskaw C Sand
  - Wabiskaw D Valley Fill
  - Top McMurray
  - SAGD pay
  - Producer
  - Injector

- **E’**
  - 102/03-12-77-06W4
  - Wabiskaw Marker
  - Non-reservoir lithofacies
  - McMurray Formation
  - Cap Rock

Key features:
- **McMurray Formation**
- **Cap Rock**
- **Wabiskaw C and D**
- **SAGD pay**

Legend:
- Red: Injector
- Green: Producer
CLRP: Structural Cross Section F-F’

F

1AB/15-19-77-05W4

Wabiskaw C Sand

non-reservoir lithofacies

Top McMurray

SAGD pay

Water Sand

F’

1AA/08-19-77-05W4

Wabiskaw Marker

non-reservoir lithofacies

McMurray Formation

Clearwater C

Cap Rock

Wabiskaw C

Wabiskaw D Valley Fill

Producer

Injector
CLRP: Structural Cross Section G-G’
CLR P Lower Clearwater Cap Rock

1AE/06-18-77-05W4

Clearwater C
mud
WBSK Mkr
mud

Lower Clearwater Cap Rock

WBSK C
WBSK D Shale

McMurray

non-reservoir lithofacies

SAGD Pay

Bitumen / Water Contact

Water Sand

Beaverhill Lake

Lower Clearwater Cap Rock = 10.9 m thick
CLR Project Area

Drilled SAGD Patterns

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

Thickness in Metres

CLR Project Area

Drilled SAGD Patterns
Contour Interval = 5 m

CLRP Project Area

Drilled SAGD Patterns

T77

T76

Contour Interval = 5 m
Low gas cap pressure due to legacy gas production; MEG is repressuring gas cap

Small gas caps; no repressuring required

Depleted gas cap not in direct 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

R6

R5W4
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>
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</thead>
<tbody>
<tr>
<td>A</td>
<td>8</td>
<td>100</td>
<td>50</td>
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<tr>
<td>B</td>
<td>2</td>
<td>100</td>
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<tr>
<td>BB + D7</td>
<td>7</td>
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<td>50</td>
</tr>
<tr>
<td>C + D6</td>
<td>7</td>
<td>110</td>
<td>55</td>
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<tr>
<td>D-D6-D7</td>
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<td>100</td>
<td>50</td>
</tr>
<tr>
<td>E + F1</td>
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<td>50</td>
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<td>F - F1</td>
<td>5</td>
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</tbody>
</table>
- **Wells**
  - Schematics
  - Well Integrity Management
  - Workovers
  - Artificial Lift

- **Current Performance**
  - Field performance
  - Pattern performance
  - Cased hole logs
  - eMSAGP update

- Associated gas cap re-pressuring
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
• 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
- 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

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-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
MEG OSL

Existing SAGD patterns

Type 1B wells (D&A)

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

Type 1B: D&A with non-thermal cement
Type 2B: D&C with non-thermal cement

zone abandoned

CLRNP Legacy Wells

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
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 200-1200m³/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 100-500m³/d
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
SCHEME PERFORMANCE
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 m³/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 m³/d (71,300 bopd) in Q2 2014, exceeded the combined initial design capacity of 9,539 m³/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

- Phase 1+2 Design Capacity
- Scheduled Plant Turnaround
- Phase 1+2+2B Design Capacity
- Phase 1+2 Design Capacity

Graph showing rates in m³/day from 1/1/08 to 1/2/16:
- Steam Injection
- Water
- Bitumen
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

Phase 2 Start-up

Phase 2B Start-up

ISOR

1/1/09 1/1/11 12/31/12 1/1/15 12/31/16

0 1 2 3 4 5 6 7 8 9 10
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

eMSAGP of B1 - B6 Start

B7 and B8 on production

Rate (m³/day, e³m³/month)

SOR

1/1/09 1/1/11 12/31/12 12/31/14 12/30/16

Steam Water Bitumen Co-injection ISOR
CLRP Performance – Pattern D

![Graph showing CLRP performance with various parameters over time. The graph includes lines for Steam, Water, Bitumen, Co-injection, and ISOR, with a notable eMSAGP Start event.]
CLRP Performance – Pattern E

![Graph showing rate and SOR over time with markers for specific events like eMSAGP Start.]

Legend:
- **Steam**
- **Water**
- **Bitumen**
- **Co-injection**
- **ISOR**

- **Rate (m3/day, e3m3/month)**
- **SOR**

Key dates and events:
- 1/1/09
- 1/1/11
- 12/31/12
- 12/31/14
- 12/30/16

Marker: eMSAGP Start
CLRP Performance – Pattern V

![Graph showing CLRP Performance Pattern V](image)
Drop in production in 2015 largely due to liner impairment on G4
CLRP Performance – Pattern H
Drop in production in 2015 largely due to liner impairment on J4
CLRP Performance – Pattern K

![Graph showing performance rates and SOR over time for Steam, Water, Bitumen, and ISOR.](image)
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 U
CLRP Performance – Pattern AP

![Graph showing CLRP Performance Pattern AP with data points for different parameters such as Rate (m³/day) and SOR over time from 1/1/13 to 1/1/16. The graph includes lines for Steam, Water, Bitumen, and ISOR.]
CLRP Performance – Pattern AF

The graph shows the performance of CLRP with different patterns over time. The x-axis represents time from 1/1/13 to 1/1/16, while the y-axis represents the rate in m³/day. The graph includes lines for Steam, Water, Bitumen, and ISOR, each with a distinct color.
CLRP Performance – Pattern AN

- **Rate (m³/day)**
- **SOR**

- **Steam** (red line)
- **Water** (blue line)
- **Bitumen** (green line)
- **ISOR** (black line)
CLRP Performance – Pattern P
CLRP ADA OB and Cased Wells

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

Diagram showing well locations in T77 and T76, with R6 and R5W4 grid lines.
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

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<tr>
<th>Pattern</th>
<th>Operating Wellpairs</th>
<th>Average h (m)</th>
<th>Average L (m)</th>
<th>Average Porosity</th>
<th>Average Oil Saturation</th>
<th>OBIP (m³)</th>
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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

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*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*
Update on Enhanced Modified Steam and Gas Push (eMSAGP)
Phase 1 and Phase 2 Pad Layout

eMSAGP Rollout:
- 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)

<table>
<thead>
<tr>
<th>Recovery Phase</th>
<th>SAGD</th>
<th>eMSAGP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bitumen Production (bbl)</td>
<td>3,048,000</td>
<td>3,065,000</td>
</tr>
<tr>
<td>Recovery of SAGDable OOIP (%)</td>
<td>35</td>
<td>35</td>
</tr>
<tr>
<td>SOR in the Phase</td>
<td>2.64</td>
<td>1.31</td>
</tr>
</tbody>
</table>

Note:

- SAGDable OOIP = 8,799,000 bbls
- Production of the eMSAGP phase was to April 30, 2016.
Bitumen Rates for Phases 1 and 2

Start of eMSAGP
Steam Rates for Phases 1 and 2

Start of eMSAGP
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
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 a 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
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)

- **Observation Wells**
  - R5W4
  - T76
  - T77
  - 102/13-03
  - 103/05-03
  - 100/08-03
  - 102/06-03

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

OPERATIONS
Operations Overview

- Operation Overview
- sulphur Recovery Unit Incident
- Bitumen Treatment
- Water Treatment
- Steam Generation
- Power Generation
- Gas Usage
Water and Steam Process Overview Phase 1 and 2
Water and Steam Process Overview Phase 2B

- Oil Removal Filter
- Produced Water Tank
- Hot Lime Softener
- Feed Pumps A/B
- PW/HLS Feed Exchanger A-F
- Membrane/Service Pumps A/B
- Oil Removal Filter Vessel A-C
- Produced Water From IGF
- Produced Water
- Hot Lime Softener Vessel
- After Filters A/B
- Hot Lime Softener Sludge Recirculation Pumps A/B
- Hot Lime Softener
- Recirculation Pumps A/B
- Sludge Holding Tank
- Oil Removal Filter Dirty Backwash/De-sand Tank
- Oil Removal Filter Dirty Backwash Transfer Pumps A/B
- Produced Gas Exchanger
- Emulsion Exchanger
- Hot Lime Softener Vessel
- Dirty Backwash Tank
- To Sludge Treatment Facility
- Regen Waste Disposal Tank
- Neutralization Tank
- Regen Waste Disposal Pumps A/B
- Regen Waste Disposal Booster Pumps A/B
- Regen Waste Disposal Filters A/B
- Regen Waste Disposal Booster Pump A/B
- Disposal Water Tanks
- Phase 2 Disposal Water Wells A/B
- HP BFW Pumps A-C
- LP BFW Pumps A/B
- Glycol Blowdown Exchangers A/B
- Glycol Blowdown Exchangers A/B
- Glycol Exchangers A/B
- Fuel Gas Coalescer
- Produced Gas Exchanger
- Condenser
- Heater Recovery Steam Generator
- HP Steam Separator
- HP Steam Separators
- MP Steam Separators
- Neutralization Pumps A/B
- Sludge Transfer Pumps A/B
- To Sludge Treatment Facility
- Regen Waste
- Disposal Tank
- Regen Waste Disposal Tank
- Disposal Booster Pumps A/B
- Water Disposal Pumps 20-P-271A/B
- Phase 2B Disposal Water Wells A/B
- Disposal Water Filters A/B
- Disposal Water Filter A/B
- Disposal Water Filter A/B
- Produced Water
- Produced Water
- Produced Gas
- Produced Gas
- Hot Lime Softener
- Hot Lime Softener
- Acid Tank
- Acid Tank
- Regen Waste Filters A/B
- Regen Waste Filters A/B
- Caustic Tank
- Caustic Tank
- Neutralization Tank
- Neutralization Tank
- Neutralization Tank
- Acid Regen Pump A/B
- Acid Regen Pump A/B
- Hot Lime Softener Caustic Pumps A/B
- Hot Lime Softener Caustic Pumps A/B
- Acid Scrubber
- Acid Scrubber
- WACs A-F
- Phase 2B Boiler Feed Water Tank
- Phase 2B Boiler Feed Water Tank
- MILFurnance Source Water Wells
- MILFurnace Source Water Wells
- Acid Tank
- Acid Tank
- Phase 2B Water Treatment
- Phase 2B Water Treatment
- MEG ENERGY
- Calgary, AB
- MEG ENERGY
- Calgary, AB
- Scale
- Title
- Project
- Notes
- Final
- Title
- Notes
- Final
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

Scheduled Plant Turnaround

Phase 1+2+2B Design Capacity

Phase 1+2 Design Capacity

Rate (m³/day)

- Steam Injection
- Water
- Bitumen

[Graph showing production rates over time with key events marked]
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.
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.

Actual Bitumen Rate/Plant Design Bitumen Rate

- Phase 1/2/2B planned outage and 2015 wildfire.
- Phase 2B planned outage and SRU fire.
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

**Water Make-up and Disposal Rate / Bitumen Rate**

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

- Increased water make-up following outage.
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.
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

Actual Steam Rate/Plant Design Steam Rate

Steam/Design Steam (tonne/tonne)

Phase 1/2/2B planned outage and 2015 wildfire.

Phase 2B planned outage and SRU fire.
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.
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

Power Generated/Consumed

- Phase 1/2/2B planned outage and 2015 wildfire.
- Phase 2B planned outage and SRU fire.

Legend:
- Green: Total Power Generated (MWH)
- Blue: Total Power Consumed (MWH)
- Black: Total Power Consumed (%)

Months: Jan-15 to Apr-16
Facility Performance: Power Generation

Actual Power Generated / Design Generation

Phase 1/2/2B planned outage and 2015 wildfire.

Phase 2B planned outage and SRU fire.
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

Gas Consumption

- Phase 1/2/2B planned outage and 2015 wildfire.
- Phase 2B planned outage and SRU fire.

GOR calculation modified in Jan 16.
Facility Performance: Gas Usage

Total Gas Consumed / Bitumen

Phase 1/2/2B planned outage and 2015 wildfire.

Phase 2B planned outage and SRU fire.
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 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
Water Management

- Water Use Intensity, Volumes and Recycle
- Water Source
- Water Disposal
- Water Use Optimization
Water Recycle and D81 Limits

D81 Compliant in 2015
Produced Water to Steam Injected Ratio

- Calendar Year (0.98)
- Reporting Year (0.99)
- Plant Turnaround
- 10 active Clearwater non-saline source wells
- 2 active McMurray saline source well
Source Well Production

- McMurray Saline Wells
- Clearwater Non-Saline Wells

Calendar Year (1.8 MM m³)
Reporting Year (1.7MM m³)
Saline McMurray groundwater production ongoing since November 2013
  • System outage between August 2015 and February 2016 due to aqueous CO₂ 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

ERCB Approval No. 10659
Maximum WHIP 4,230 kPag
Wellhead Injection Pressures

*100/11-29-077-05W4/00 well on vacuum during operation
Basal McMurray Water Sand Pressure Monitoring

- OBC1 100/06-16-077-05W4/0 at 398.3 mKB
- OBE1 100/08-16-077-05W4/0 at 414.0 mKB
- OB9 100/10-16-077-05W4/0 at 411.5 mKB
- OBE1 100/08-16-077-05W4/0 at 413.5 mKB (perforated)
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
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
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 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.
Average inlet sulphur surpassed 1 t/d in 2014 triggering scheme sulphur recovery requirements.
SO$_2$ Emissions

<table>
<thead>
<tr>
<th>Plant Turnaround</th>
</tr>
</thead>
<tbody>
<tr>
<td>SRU Incident</td>
</tr>
<tr>
<td>SRU Resolved</td>
</tr>
</tbody>
</table>

- EPEA Approval Limit
- S02 Emissions
- 90-Day Rolling Average SO2

<table>
<thead>
<tr>
<th>Period</th>
<th>SO2 Emissions (t/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Apr-15</td>
<td>0.00</td>
</tr>
<tr>
<td>May-15</td>
<td>0.25</td>
</tr>
<tr>
<td>Jun-15</td>
<td>0.50</td>
</tr>
<tr>
<td>Jul-15</td>
<td>0.75</td>
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<tr>
<td>Aug-15</td>
<td>1.00</td>
</tr>
<tr>
<td>Sep-15</td>
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<td>Jan-16</td>
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<tr>
<td>Feb-16</td>
<td>2.50</td>
</tr>
<tr>
<td>Mar-16</td>
<td>2.75</td>
</tr>
<tr>
<td>Apr-16</td>
<td>3.00</td>
</tr>
</tbody>
</table>

- Graph showing SO$_2$ emissions over time with specific events marked.

- Graph labels:
  - X-axis: Month
  - Y-axis: SO$_2$ Emissions (t/d)
  - Line colors:
    - Red: EPEA Approval Limit
    - Blue: S02 Emissions
    - Purple: 90-Day Rolling Average SO2
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).
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 inspection of SRU facility, reconstruction and remediation May 29, 2016.
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 SO₂ 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.
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.
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 H₂S and SO₂ 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.
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

**H₂S Passive Sampling Results**

- Concentration (ppb)
- X-axis: Months from Apr-15 to Apr-16
- Legends:
  - Site 1 Calculated H₂S
  - Site 2 Calculated H₂S
  - Site 3 Calculated H₂S
  - Site 0 Calculated H₂S
  - 24 Hour Avg AAAQO Limit

**SO₂ Passive Sampling Results**

- Concentration (ppb)
- X-axis: Months from Apr-15 to Apr-16
- Legends:
  - Site 1 Calculated SO₂
  - Site 2 Calculated SO₂
  - Site 3 Calculated SO₂
  - Site 0 Calculated SO₂
  - 30 Day AAAQO Limit
- 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.
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
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.
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 eMVAPLEX 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
- 2017-2019 Core locations
- Access pipeline

CLRP Future Development

[Map with grid and markers indicating project areas and patterns]
Questions and Comments