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The information concerning petroleum reserves and resources appearing in this document was derived from a report of GLJ Petroleum Consultants Ltd. dated effective as of December 31, 2013, which has been prepared in accordance with the Canadian Securities Administrators National Instrument 51-101 entitled Standards of Disclosure for Oil and Gas Activities ("NI 51-101") at that time. The standards of NI 51-101 differ from the standards of the SEC. The SEC generally permits U.S. reporting oil and gas companies in their filings with the SEC, to disclose only proved, probable and possible reserves, net of royalties and interests of others. NI 51-101, meanwhile, permits disclosure of estimates of contingent resources and reserves on a gross basis. As a consequence, information included in this presentation concerning our reserves and resources may not be comparable to information made by public issuers subject to the reporting and disclosure requirements of the SEC.

There are significant differences in the criteria associated with the classification of reserves and contingent resources. Contingent resource estimates involve additional risk, specifically the risk of not achieving commerciality, not applicable to reserves estimates. There is no certainty that it will be commercially viable to produce any portion of the resources. The estimates of reserves, resources and future net revenue from individual properties may not reflect the same confidence level as estimates of reserves, resources and future net revenue for all properties, due to the effects of aggregation. Further information regarding the estimates and classification of MEG’s reserves and resources is available by contacting MEG’s investor relations department.

Anticipated netbacks are calculated by adding anticipated revenues and other income and subtracting anticipated royalties, operating costs and transportation costs from such amount.
Disclosure Advisories

Forward-Looking Information

Certain statements contained in this presentation constitute forward-looking statements. These statements relate to future events or MEG’s future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words “anticipate”, “plan”, “contemplate”, “continue”, “estimate”, “expect”, “intend”, “propose”, “might”, “may”, “will”, “shall”, “project”, “should”, “could”, “would”, “believe”, “predict”, “forecast”, “pursue”, “potential” and “capable” and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this presentation should not be unduly relied upon. These statements speak only as of the date of this presentation. In addition, this presentation may contain forward-looking statements and forward-looking information attributed to third party industry sources.

In particular, this presentation contains forward-looking statements pertaining to the following: the reserve and resource potential of MEG’s assets; the bitumen production and production capacity of MEG’s assets; MEG’s growth strategy and opportunities; MEG’s capital expenditure programs and future capital requirements; the estimated quantity of MEG’s proved reserves, probable reserves and contingent resources; MEG’s projections of commodity prices, costs and netbacks; MEG’s estimates of future interest and foreign exchange rates; MEG’s environmental considerations, including water usage and greenhouse gas emissions; MEG’s blending capability for its bitumen diluent blend; the timing and size of certain of MEG’s operations and phases, including its planned bitumen development projects, and the levels of anticipated production; supply and demand fundamentals for crude oil, bitumen blend, natural gas, condensate and other diluents; MEG’s access to adequate pipeline capacity; MEG’s access to third-party infrastructure; industry conditions including with respect to project development; potential future markets for MEG’s products; the planned construction of MEG’s facilities, including the Stonefell Terminal and the Access Pipeline expansion; MEG’s drilling plans; MEG’s plans for, and results of, exploration and development activities; the use of the proceeds of the public offering; the expected application timeframe for the Surmont Project and for the Growth Properties; the timing for receipt of various regulatory approvals, including receipt of various regulatory approvals for the Christina Lake Project, Surmont Project and Growth Properties; MEG’s treatment under governmental regulatory and royalty regimes and tax laws; and MEG’s future general and administrative expenses.

The forward-looking statements contained in this presentation are based on certain assumptions including: future crude oil, bitumen blend, natural gas, condensate and other diluent prices; MEG’s ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which MEG conducts and will conduct its business; MEG’s ability to market production of bitumen blend successfully to customers; MEG’s future production levels; the applicability of technologies for the recovery and production of MEG’s reserves and resources; the recoverability of MEG’s reserves and resources; operating costs; future capital expenditures to be made by MEG; future sources of funding for MEG’s capital programs; MEG’s future debt levels; geological and engineering estimates in respect of MEG’s reserves and resources; the geography of the areas in which MEG is conducting exploration and development activities; the impact of increasing competition on MEG; and MEG’s ability to obtain financing on acceptable terms.

In addition, information and statements in this presentation relating to “reserves” and “resources” are deemed to be forward-looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future.

The forward-looking statements included in this presentation are expressly qualified by this cautionary statement and are made as of the date of this presentation. MEG does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws. For more information regarding forward-looking statements, please see “Risk Factors” and “Regulatory Matters” within the AIF.
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  Simon Geoghegan
MEG Energy Corp.

Who We Are

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

Who We Are

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

An Efficient Technology
Christina Lake Regional Project

Project history

Phase 1
• Approved in February 2005 for bitumen production of 477 m$^3$/d (3,000 bpd)
• Sustained steaming commenced March 2008

Phase 2
• Approved in March 2007 for total production of 3,975 m$^3$/d or 25,000 bpd (incremental 3,523 m$^3$/d or 22,000 bpd)
• First steam Q3 2009
• Phase 1/2 pads: A, B, C, D, E, F, V

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

Phase 3
• Approval granted January 2012, expansion to 33,390 m$^3$/d or 210,000 bpd
Christina Lake Regional Project

2014-2015 Operating Highlights

• 2014 bitumen production from both Phase 2 and 2B facilities averaged 71,186 bpd

• Q1 2015 bitumen production of 82,398 bpd and field wide SOR of 2.6

• Expanded implementation of eMSAGP
Christina Lake Regional Project (CLRP)

Phase 2/2B CPF
Approved Development Area

Access Pipeline

Phase 2/2B CPF
Approved Development Area
Geosciences
CLRP Geoscience Review

- Well and Seismic Data
- Stratigraphic Framework
- Reservoir and Pay Parameters
- Active Development Area Bitumen Pay
- SAGD Patterns
  - New SAGD Patterns for 2014
- McMurray Water Resources
- Cap Rock Geology
- Active Development Area Associated Gas Resources
- Legacy Wells
Christina Lake Regional Project (CLRPG)

- CPF = Central Plant Facility
- Approved Development Areas
- Access Pipeline

CLRP Project Area

- T78
- T77
- T76

- R7
- R6
- R5
- R4W4
CLRP Wabiskaw / McMurray Cores

- 827 cored wells
- 85% of all wells are cored
CLRP 3D Seismic

CLRP Project Area
3D Seismic
Time Lapse 3D (2014)
CLRP Active Development Area (ADA)

332 horizontal wells
(SAGD & Infill wells)
CLRPM: Wabiskaw/McMurray Stratigraphy

Beaverhill Lake

McMurray Channel

Wabiskaw Valley

McMurray Formation

Beaverhill Lake carbonate mudstone

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

<table>
<thead>
<tr>
<th></th>
<th>McMurray</th>
<th>SAGD</th>
</tr>
</thead>
<tbody>
<tr>
<td>h (m)</td>
<td>47.6</td>
<td>30.3</td>
</tr>
<tr>
<td>avg Ø</td>
<td>0.311</td>
<td>0.314</td>
</tr>
<tr>
<td>Avg S₀</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 ≥ 6 wt% BMO
SAGD Pay

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

\( R_t = \text{Deep Induction} \)

\( \varnothing_{\text{density}} \geq 25\% \)

\( S_o \) (bitumen saturation) \( \geq 50\% \)

gas and coal excluded

parameters for \( S_o \) calculation
### CLRP: Average 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>Average porosity (frac)</td>
<td>0.32</td>
</tr>
<tr>
<td>Average $S_w$ (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

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

contour interval = 5 m
CLRP ADA Base SAGD Pay Structure

contour interval = 5 m

CLRP Project Area
SAGD Patterns

T77

R6
R5W4
CLRP ADA Top SAGD Pay Structure

Contour interval = 5 m
CLRP Pattern A SAGD Development

[Diagram showing geological layers and well sections with labels such as Wabiskaw Marker, Wabiskaw C Sand, Wabiskaw D valley fill, Cap Rock, McMurray Formation, SAGD pay, non-reservoir lithofacies, mud, limestone, and well markers like 1AC/01-13-77-06W4, 1AB/04-18-77-05W4, 1AA/03-18-77-05W4.]
CLRP Phase 2 SAGD and Infill Wells Map View

- SAGD Well Pair
- Infill Well
- SAGD Drainage
- Legacy Gas Well
- OB Well Instrumented
- OB Well
- WSW

800 m

MEG Energy
CLRP Stacked SAGD Pay

100/14-16-77-05W4 OBB1

100/02-21-77-05W4 OBD1

Single Pattern Development (Single Pay Interval)

Stacked Pattern Development (Multiple Pay Intervals)

Piezometers

Non-Reservoir Lithofacies

SAGD Pay

Water Sand

Bitumen / Water Contact

Clearwater C

Cap Rock

Wabiskaw C

McMurray

Devonian

MEG Energy
CLRP Pattern B SAGD Development

1AA/06-21-77-05W4

100/14-16-77-05W4 OBB1

- Clearwater C
- Cap Rock
- Wabiskaw C

- McMurray
- Devonian

Non-Reservoir Lithofacies

SAGD Pay

Water Sand

Bitumen / Water Contact

Gas

Non-Reservoir Lithofacies

Piezometers
CLR P Pattern BB SAGD Development

100/02-21-77-05W4 OBD1

1AB/01-21-77-05W4

Clearwater C

Cap Rock

Wabiskaw C

McMurray

Devonian

Piezometers

Non-Reservoir Lithofacies

SAGD Pay

SAGD Pay

Bitumen / Water Contact

Water Sand

Gas
CLRP Pattern C SAGD Development

1AB/12-16-77-05W4

1AA/12-16-77-05W4

Clearwater C

Cap Rock

Wabiskaw C

McMurray

Devonian

Non-Reservoir Lithofacies

SAGD Pay

Gas

Non-Reservoir Lithofacies

SAGD Pay

Water Sand

Bitumen / Water Contact

Water Sand
"Tiger Stripes" = interbedded water sand and bitumen sand

Piezometers
"Tiger Stripes" = interbedded water sand and bitumen sand
CLRPM Pattern D6/D7 SAGD Development

100/06-16-77-05W4 OBC1

1AA/07-16-77-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

Non-Reservoir Lithofacies

Water Sand

Bitumen / Water Contact

SAGD Pay

SAGD PP

Non-Reservoir Lithofacies

MEG Energy
CLRP Pattern V SAGD Development
CLRP G & H SAGD Development
CLRP Pattern G SAGD Development

1AB/05-09-77-05W4

1AA/04-09-77-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

SAGD Pay

Non-Reservoir Lithofacies

Gas

Non-Reservoir Lithofacies

SAGD Pay

Water Sand

Bitumen / Water Contact

Water Sand
1AA/13-04-77-05W4
1AB/13-04-77-05W4

Cap Rock
Wabiskaw C
McMurray
Devonian

Gas
Non-Reservoir Lithofacies
SAGD Pay
Water Sand
Bitumen / Water Contact

SAGD Pay
Non-Reservoir Lithofacies

MEG Energy
CLRP J & K SAGD Development

T77

- SAGD Well Pair
- SAGD Prod ICP
- SAGD Drainage
- Type 2A Legacy Well
- OB Well Instrumented
- OB Well
CLRPM Pattern J SAGD Development

1AA/02-07-77-05W4
1AA/16-06-77-05W4

Cap Rock
Wabiskaw C
McMurray

Non-Reservoir Lithofacies
Devonian

SAGD Pay
Gas
Water
Sand
Bitumen / Water Contact
CLR P Pattern K SAGD Development

1AF/06-07-77-05W4

1AD/10-7-77-05W4
CLRP M & N SAGD Development

Pattern M

Pattern N

Pattern P

400 m

R5W4

T77

SAGD Well Pair

SAGD Prod ICP

SAGD Drainage

Legacy Gas Well

OBS Well Instrumented

OBS Well

MEG Energy
CLRP Pattern M SAGD Development

1AA/04-10-77-05W4

1AA/03-10-77-05W4
CLRPG Pattern N SAGD Development

100/12-03-77-05W4
1AC/10-03-77-05W4

Cap Rock
Wabiskaw C
McMurray
Devonian

Gas
SAGD Pay
SAGD Pay
SAGD Pay
SAGD Pay
SAGD Pay
SAGD Pay
SAGD Pay
SAGD Pay

Bitumen / Water Contact
Water sand
CLRP T & U SAGD Development

Pattern T
Pattern U
Pattern A

SAGD Well Pair
△ SAGD Prod ICP
SAGD Drainage
∙ OB Well Instrumented
∙ OB Well

400 m

R6

R5W4
Lower sands to be developed at a later date
CLRP Pattern U SAGD Development

102/12-18-77-05W4

1AA/07-18-77-05W4

Cap Rock

Wabiskaw C

Wabiskaw D

McMurray

Gas

SAGD Pay

Non-Reservoir Lithofacies

Water Sand

Devonian

Bitumen / Water Contact
CLRP Pattern AF SAGD Development

1AB/11-19-77-05W4

1AB/15-19-77-05W4

Cap Rock

Wabiskaw C

Wabiskaw D

McMurray

Devonian

SAGD Pay

Bitumen / Water Contact

SAGD Pay

McMurray

Wabiskaw C

Wabiskaw D

Cap Rock

SAGD Pay

Bitumen / Water Contact

SAGD Pay
CLRP Pattern AG SAGD Development

1AB/06-19-77-05W4

1AA/08-19-77-05W4

Cap Rock

Wabiskaw C

Wabiskaw D

McMurray

Devonian

SAGD Pay

Gas

Bitumen / Water Contact

Water Sand

SAGD Pay

Gas
CLRP AP SAGD Development

SAGD Well Pair

SAGD Prod ICP

SAGD Drainage

OB Well

Pattern AP

Pattern AN

OSL Boundary

400 m

R6W4
CLRP Pattern AP SAGD Development

1AB/12-12-77-06W4

100/11-12-77-06W4

Cap Rock

Wabiskaw C

Wabiskaw D

McMurray

Devonian

SAGD Pay

Bitumen / Water Contact

Water Sand

SAGD Pay

Cap Rock
CLRP AN SAGD Development

- SAGD Well Pair
- Infill Well
- SAGD Prod ICP
- SAGD Drainage
- OB Well

Pattern AP
Pattern AN

AN1
AN2
AN3
AN8
AN1N

T77

400 m

R6W4

OSL Boundary

MAG ENERGY
CLRPA Pattern AN SAGD Development

Beaverhill Lake

Wabiskaw Member

Wabiskaw D Valley-Fill

McMurray Formation

SAGD Pay

non-reservoir lithofacies

Cap rock

Wabiskaw D Valley-Fill

non-reservoir lithofacies

SAGD Pay

Cap rock

water sand

McMurray Formation

Beaverhill Lake

Wabiskaw D Valley-Fill

non-reservoir lithofacies

SAGD Pay

Cap rock

Wabiskaw Member

non-reservoir lithofacies

SAGD Pay

Cap rock
CLR Pattern AN SAGD Development

100/04-12-77-06W4

Wabiskaw Member

Wabiskaw D Valley-Fill

McMurray Formation

Beaverhill Lake

Cap rock

non-reservoir lithofacies

SAGD Pay

water sand

bitumen / water contact

non-reservoir lithofacies

100/03-12-77-06W4

Cap rock

non-reservoir lithofacies

SAGD Pay

water sand

non-reservoir lithofacies
CLRP P SAGD Development

- Pattern N
- Pattern P
- SAGD Well Pair
- SAGD Prod ICP
- SAGD Drainage
- Legacy Gas Well
- OB Well Instrumented
- OB Well

R5W4

400 m
CLRP Pattern P SAGD Development

1AB/16-33-76-05W4

1AA/14-34-76-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

Gas

SAGD Pay

non-reservoir lithofacies

Water Sand

Bitumen / Water Contact
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
## CLR Lower Clearwater Cap Rock

### 1AE/06-18-77-05W4

<table>
<thead>
<tr>
<th>Depth</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>10.9 m</td>
<td>Lower Clearwater Cap Rock</td>
</tr>
<tr>
<td>62</td>
<td>SAGD Pay</td>
</tr>
<tr>
<td>Bitumen / Water Contact</td>
<td>Water Sand</td>
</tr>
<tr>
<td>WBSK C</td>
<td>WBSK D Shale</td>
</tr>
<tr>
<td>WBSK D</td>
<td>WBSK C</td>
</tr>
<tr>
<td>WBSK Mkr</td>
<td>mud</td>
</tr>
</tbody>
</table>

**Clearwater C**

**McMurray**

**non-reservoir lithofacies**

**Lower Clearwater Cap Rock = 10.9 m thick**
CLRP ADA Lower Clearwater Cap Rock

Active Development Area
Average Cap rock Thickness = 10.8 m
Minimum Thickness = 8.6 m
Maximum Thickness = 13.1 m

Thickness in Metres
The measured minimum *in situ* principal stress gradient in the Clearwater cap rock is approximately 20 kPa/m. This gradient coincides with the weight of the overburden as derived from density logs indicating the minimum principal stress is in the vertical direction, i.e., if fracturing were to occur, it is likely in the horizontal direction.

For a typical cap rock depth of 320 m in the CLRP area, the minimum principal stress is 6,400 kPa. This is more than twice the anticipated steady state SAGD operating pressure.

The measured minimum *in situ* principal stress gradient in the McMurray oil sands is slightly lower at approximately 18 kPa/m. This indicates the minimum principal stress is likely in the horizontal direction, i.e., if fracturing were to occur, it is likely in the vertical direction.

Quote from BitCan Geosciences & Engineering Inc.:

“...if a vertical fracture inadvertently propagated out of the payzone into the cap rock, it would eventually turn horizontal. This is due to the in-situ stress regime in the caprock favoring horizontal fractures. Therefore, the vertical fracture extending upwards from the payzone is arrested in the caprock and does not propagate further upwards, i.e., it cannot form the hydraulic conduit connecting the payzone and aquifers.”

MEG’s measurements are consistent with other operators’ mini-frac results in the Christina Lake area.
Regional Cap Rock Mini-Frac Test Results

- CVE Christina Lake data: Christina Lake Annual Update to AER, June 2010; Application for the Christina Lake Thermal Project Phase H and Eastern Expansion, March 2013
- CVE Narrows Lake data: Narrows Lake Application to AER, Appendix 1-VII (Cap Rock Study), June 2010
- Harvest BlackGold data: Application for Approval of the BlackGold Expansion Project, Volume 1, December 2009
- Devon Jackfish data: 2011 Devon Jackfish ERCB Annual Update, October 2011
- Devon Pike data: Application for Approval of the Pike 1 Project Volume 1, June 2012

XX.X Measured in situ minimum principal stress gradient (kPa/m)
CLAIP ADA OB and Cased Wells

- MEG OSL
- Approved IDA
- Instrumented OB Wells
- Non-Instrumented OB wells

Diagram showing CLRP ADA OB and Cased Wells with various symbols representing different types of wells.
CLRP Reservoir Review

- Wells
  - Schematics
  - Well Integrity Management
  - Work overs
  - Artificial Lift

- Current Performance
  - Field performance
  - Pattern performance
  - eMSAGP update

- Associated gas cap re-pressuring
Wells
- Steam injected into both long tubing and short tubing
- Blanket gas on annulus
- 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 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 – Infill Producers

- Thermocouples 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 Pad infill wells (V2N – V7N) and AF SAGD producers (AF1P – AF5P)
• Thermocouples, while accurate, provide far fewer points of measurement and require a well intervention to replace. In the event of thermocouple failure the replacement could be delayed to coincide with an ESP replacement.
• Early experience with thermal fibre implementation required efforts to ensure accurate calibration, reliability, and data system integration. Increased coverage of temperature profile and ease of replacement can provide better well optimization and protection of slotted liner.
• P Pad, newest SAGD pad scheduled for steam-in Q3 2015, has fibre installed as part of an ongoing evaluation of performance and costs which will determine the choice of technology for future pads
• Upset production port (UPP) typically consists of 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
ICD Lessons Learned

Early Lessons
• 10 wells have had ICDs opened as wells reach maturity
• Most have shown an improved rate and good conformance, enabling higher peak production rates without requiring more expensive workovers
• Low cost of initial installation, and flexibility in choosing if or when to open, has led to many new installations while earlier results are being evaluated

Wells with ICDs Installed
• 38 wells have ICDs installed
• T8P
• U2P, U3P
• AG1P, AG2P, AG3P
• AN1P, AN2P, AN3P, AN4P, AN5P, AN6P, AN7P, AN8P
• 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

Water Disposal Wells
Developing Well Integrity Best Practices for CLRP

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

The Well Integrity Program includes:

- Risk management – Well health matrix
- Well Integrity Management System (well tracking and monitoring)
- Targeted selection casing integrity checks and Well Servicing support
- Casing design and failure mechanism identification
- AER commitments and reporting
- Inactive Well Compliance Program management
CLRPL Legacy Wells

MEG OSL

Existing SAGD patterns

Type 1B wells (D&A)

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

Type 2B wells

zone abandoned

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

Type 2B: D&C with non-thermal cement
Legacy Well Thermal Compatibility

- Thermal compatibility addressed on a pad by pad basis in conjunction with IDA amendment applications
- Specific D-20 abandonment applications have been filed and approved for requisite wells within the ADA
- MEG has developed a thermal compatibility program which has been reviewed by AER staff. The program includes:
  - A detailed assessment of compatibility of existing all wellbores within the CLRP project area
  - General abandonment strategies to ensure well integrity thermal development areas
  - Monitoring and surveillance plans
CLRP Well Workovers – BB6I

Issue

• Surface Casing Vent Flow (SCVF) on SAGD injector
• Cement micro-annulus has formed behind the 7” slimhole casing, source is inside the well below the slimhole casing shoe

Implications

• Identified a casing gas vent flow through the slimhole cement while the well was operating
• Confirmed that original intermediate casing breach which caused the well to be slimholed is not the SCVF source
• Proved the slimhole casing integrity through pressure testing

Actions

• Set a wireline retrievable bridge plug in the well for suspension which has isolated the SCVF source
• Successfully continuing to operate BB6 producer without support from BB6 injector
Issue

• In-zone isolated liner impairments on 4 SAGD producer wells identified in 2013: V3P, N2P, N3P, and M7P

Highlights

• All 4 wells were successfully re-drilled utilizing the existing intermediate section and have since resumed SAGD operation with no issues
• The impairments developed during circulation and were not production induced
• These wells had an average lateral length of about 1000 metres

Optimization

• Analysis has suggested the impairments may be a result of thermal induced deformation in longer lateral wells
• Slotted liner design has been adjusted on re-drills and subsequent wells and there have been no further liner issues
• All MEG SAGD well pairs are initially completed with gas lift capabilities

• 125 Electric submersible pumps (ESP) in operation
  – Approximately 55% ESPs rated to 220°C and 45% rated to 250°C
  – Operating pressures range from 2,100-3,200kPag
  – Design fluid rates 200-1200m³/d
  – Run-time between pulls is 625-675 days
  – Run-time improvements have been realized by utilizing higher quality equipment where required

• 45 rod pumps installed in the infill wells
  – Operating pressures range from 2,000-2,500kPag
  – Design fluid rates 100-500m³/d
Scheme Performance
CLRP Pattern Layout

Pattern A
Pattern AP
Pattern AN
Pattern T
Pattern G
Pattern H
Pattern M
Pattern N
Pattern P

Water Disposal

Water Source PL

Development Area
Central Plant
Access Pipeline
Emulsion Pipeline
Disposal Pipeline
Water source Pipeline

April 2015 Wells
SAGD Well Pairs:
Operating: 126
Circulating: 1
Standing: 15
Total: 142

Infill:
Operating: 45
Standing: 1
Total: 46
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
- Current steam chamber pressure is between 2,000 and 2,900 kPag for Phases 1 and 2, between 2,300 and 3,400 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 combined bitumen production from Phases 1 and 2 reached the design capacity of 3,975 m$^3$/d (25,000 bopd) by late April 2010.
- Phase 2B production ramp-up bettered that of Phase 2. Total production from all phases reached 11,340 m$^3$/d (71,300 bopd) in Q2 2014, exceeded the combined initial design capacity of 9,539 m$^3$/d (60,000 bopd).
• The SOR of CLRP has ranged from 2.2 to 2.6 over the last 12 months and averaged 2.5 with new well start-ups.

• The Phase 1 eMSAGP pilot was initiated in December 2011, which showed very successful results. Commercial eMSAGP was expanded to wells A4, A5, A6 and patterns B, C, D, E and F in 2013.

• The SOR of the eMSAGP wells (36 SAGD WP’s and 37 infill wells) averaged 1.9 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.

• In Q1 2015, MEG achieved record quarterly production of 82,398 bopd, an increase of 41% over the same period of 2014. April production averaged over 86,280 bopd.
CLRP Production Performance

Scheduled Plant Turnaround

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

- Steam Injection
- Water
- Bitumen

Rate (m$^3$/day)

1/1/08 12/31/09 12/31/11 12/30/13 12/30/15
CLRP Performance – SOR of All Patterns

Phase 2 Start-up

Phase 2B Start-up

ISOR

1/1/09 1/1/10 1/1/11 1/1/12 12/31/12 1/1/14 1/1/15 1/1/16
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.
Increased steam injection rate was to increase the steam chamber pressure in two SAGD well pairs (B1 and B2) that have bottom water.
Bitumen production drop in December 2014 was partially due to measurement calibration.
CLRP Performance – Pattern D

![Graph showing performance trends over time with labels for rates in m^3/day and e^3 m^3/month with different colors representing Steam, Water, Bitumen, Co-injection, and ISOR. A red arrow indicates eMSAGP Start on a specific date.]
CLRP Performance – Pattern E

- Steam
- Water
- Bitumen
- Co-injection
- ISOR

Rate (m3/day, e3m3/month)

CLRP Performance – Pattern E

- eMSAGP Start

Rate (m3/day, e3m3/month)

1/1/09 1/1/11 12/31/12 12/31/14

SOR
CLRP Performance – Pattern V

![Graph showing SOR (Steam Oil Ratio) rates for different fluids over time: Steam, Water, Bitumen, ISOR. The x-axis represents dates from 1/1/12 to 12/31/15, and the y-axis represents rates in m³/day, ranging from 0 to 3,600.]
CLRP Performance – Pattern G

![Graph showing CLRP Performance for Pattern G]

- **SOR Rate (m³/day)**: The graph displays the SOR rate for different fluids over time, with peaks and troughs indicating variations in production.
- **Steam**, **Water**, **Bitumen**, and **ISOR** are represented by different colors,
- The x-axis represents dates ranging from 1/1/13 to 1/1/16,
- The y-axis represents rate in m³/day,
- The graph illustrates the performance trend over the specified period.
In mid-2014 workovers were performed on H4I, H4P, and H3P which led to a large surge in production but do not reflect sustainable rates.
CLRP Performance – Pattern J

![Graph showing CLRP Performance for Pattern J](image-url)

- SOR Rate (m³/day)
- Steam
- Water
- Bitumen
- ISOR

Graph illustrates the performance of CLRP for Pattern J over the years from 1/1/13 to 1/1/16.
CLRP Performance – Pattern K

The graph shows the rate (m³/day) of steam, water, bitumen, and ISOR from 1/1/13 to 1/1/16. The rate increases sharply around 1/1/14 and then stabilizes over the next few years.
M9P and M10P have low TFSR due to poor producer inflow, lowering the overall WSR. Both wellpairs operate at low pressure so steam is not considered lost to thief zones. Temporary steam reduction due to pipeline construction activity in mid-2014.
For the Phase 2 wells, eMSAGP was implemented near 30% recovery of pay above the producer, with individual pattern recoveries ranging from about 30% to 46%.

The patterns which experienced the greatest increase in rate of recovery had eMSAGP initiated earlier, suggesting that implementation at advanced stages of recovery is sub-optimal.
CLRP Performance – Pattern T

- SOR Rate (m$^3$/day)
- Steam, Water, Bitumen, ISOR

Graph showing the performance of CLRP Pattern T with data from 1/1/13 to 1/1/16.
CLRP Performance – Pattern U

![Graph showing CLRP Performance Pattern U]

- **SOR Rate (m³/day)**
- **Date**:
  - 1/1/13
  - 1/1/14
  - 1/1/15
  - 1/1/16
- **Graph Legend**:
  - **Red**: Steam
  - **Blue**: Water
  - **Green**: Bitumen
  - **Black**: ISOR

The graph illustrates the performance of different fluids (Steam, Water, Bitumen) and ISOR over time from 1/1/13 to 1/1/16.
CLRP Performance – Pattern AF
CLRP Performance – Pattern AG

![Graph showing performance of CLRP Pattern AG](image-url)

- **Rate (m³/day)**
- **SOR**
- **Steam**
- **Water**
- **Bitumen**
- **ISOR**
CLRP Performance – Pattern AN

Rate (m³/day)

SOR

1/1/13 1/1/14 1/1/15 1/1/16

Steam Water Bitumen ISOR
## Original Oil in Place

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<thead>
<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>OOIP (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)  
* Updated in May 2015
## Oil Recovery

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<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>
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Note: Production volume and number of operating wellpairs are as of April 2015
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
* Updated in May 2015
Update on enhanced Modified Steam and Gas Push (eMSAGP)
Phase 1 and Phase 2 Pad Layout

eMSAGP Rollout:

- Pad B (B1-B6): Feb. 2013
- Pad C (C1-C6, D6): July 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): April 2014
The eMSAGP pilot involves 3 SAGD well pairs (A1, A2 and A3) and 3 infill wells (initially A1N and A2N, later also 0.5*A3N and 0.5*A7N). Non-condensable gas (NCG) and steam are injected into SAGD injectors; production is through SAGD producers and infill wells.

Co-injection commenced in December 2011. The first two infill wells were brought on production in January 2012 after steam stimulation. A3N and A7N were put on production in January 2014.

Over ~3.5 years, steam injection has been reduced by about 63%.
- NCG injection reduces steam requirement while maintaining steam chamber pressure.
- Combined bitumen production is consistently better than that expected from SAGD alone.
- SOR has dropped from ~2.5 to ~1.2, resulting in more wells being brought on and proportionally lower emissions and water usage.

To-date, pilot performance has been very satisfactory.
Performance of eMSAGP Pilot

The graph shows the performance of an eMSAGP Pilot over time. The x-axis represents dates from January 1, 2010, to January 1, 2016, with specific dates marked: January 1, 2010, January 1, 2011, January 1, 2012, December 31, 2012, December 31, 2013, January 1, 2015, and January 1, 2016. The y-axis represents rate (m³/day) and co-injection (e³m³/day). The graph plots the rate of steam, bitumen, and NCG co-injection over these dates.

The rate and co-injection are depicted with different line colors: red for steam, green for bitumen, and purple for NCG co-injection. There is a notable increase in the rate and co-injection after the start date of the pilot on January 1, 2012.
Performance of eMSAGP Pilot

![Graph showing performance metrics over time, with phases labeled for Pilot Start and Recovery Above Producer vs. ISOR.](graph_image)
Performance of eMSAGP Wells

Pilot Start  Commercial Start

Co-injection Rate (e3m³/day)

Rate (m³/day)

Steam Injection  Bitumen  NCG Co-injection
SOR of eMSAGP Wells

The graph shows the SOR (Stoichiometric Oxygen Requirement) data for eMSAGP Wells over time. The x-axis represents dates from January 1, 2010, to January 1, 2016, while the y-axis represents SOR values ranging from 0.0 to 5.0.

- **Pilot Start**: January 1, 2010
- **Commercial Start**: December 31, 2012

Two lines are plotted on the graph:
- **ISOR** (red line) indicates the initial SOR values.
- **CSOR** (black line) shows the corrected SOR values.

The SOR values decrease over time, with fluctuations observed especially after the commercial start date. The ISOR line starts at a higher value compared to the CSOR line, showing the impact of corrections on the SOR values.
After 3.5 years, the eMSAGP pilot has demonstrated consistent and very satisfactory performance. Higher bitumen production rate was achieved at a much lower SOR, averaging 1.2 over the period.

Following the success of the pilot, commercial application of eMSAGP has been implemented in patterns B, C, D, E, F and 3 more wells in Pattern A (A4 to A6).

Performance to date strongly suggests repeatable performances from pattern to pattern.

Freed up steam has been redeployed to start new SAGD and infill wells.

Since the initiation of B Pattern eMSAGP in Feb 2013, the bitumen production rate for Phases 1 and 2 has increased and ISOR has come down from 2.4 to 1.9. Total reduction is steam injection was about 27% to April 2015.
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 201 e6m³ (~7.1 BCF), with an average injection rate of 242 e3m³/day (8.7 mmscf/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
- Plan is to maintain the current pressure on top of the active SAGD area and monitor pressures in gas and SAGD zones closely
Gas Injection

Rate (e3m3/cd)
Cumulative (e6m3)

0
50
100
150
200
250
300
0
100
200
300
400
500
600
7/1/13 12/30/13 7/1/14 12/30/14 7/1/15 12/30/15

Rate Cum Gas

124
The 100/02-33 well is roughly 1,600 meters away from the active injection/SAGD area.
CLRP Gas Cap Re-pressure Scheme (Patterns M & N)

Observation Wells

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
Operations
Operations Overview

• Operation Overview
• Bitumen Treatment
• Water Treatment
• Steam Generation
• Power Generation
• Gas Usage
• Measurement and Reporting
Integrated Distribution/Gathering System
Water and Steam Process Overview Phase 1 and 2

Diagram of water and steam process flow for Phase 1 and 2.
Water and Steam Process Overview Phase 2B
Oil Treatment Overview Phase 1 and 2
Additions/Modifications

• Sulfur Removal Unit completed and started up in August 2014.
  • Allowed MEG to continue to meet EPEA and Interim Directive 2001-3 commitments.
CLRP Production Performance

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

Graph showing production performance with the following data points:
- **Rate (m³/day)**
  - 0
  - 5,000
  - 10,000
  - 15,000
  - 20,000
  - 25,000
  - 30,000
  - 35,000

**Dates**:
- 1/1/08
- 12/31/09
- 12/31/11
- 12/30/13
- 12/30/15

**Legend**:
- Red: Steam Injection
- Blue: Water
- Green: Bitumen
MEG’s Phase 2 and Phase 2B FWKOs and Treaters were designed using a range of diluents with densities ranging from synthetic crude to naphtha.

Since plant commissioning, MEG has been using a naphtha based diluent. Since less naphtha diluent than synthetic crude diluent is required to meet the target dilbit density, the dilbit contains a higher percentage of bitumen. This increases the overall oil capacity of an oil processing plant.

In addition to the above, MEG’s equipment design has a designated residence time. In actual operation, a lower residence time than the original design has been required to achieve satisfactory oil-water separation. This has allowed the overall capacity of the plant to be increased.
Facility Performance: Bitumen Treatment

Successes

• Implemented various small projects to increase capacity of Phase 2B plant.
• Implemented skimming and fluid management strategy to reduce trucking.
• Produced gas routed to Sulfur Removal Unit for treatment.
• Implemented load shedding scheme to mitigate impact of plant or well pad trips on emulsion gathering system.
• Cleaned glycol coolers for improved cooling capacity.

Issues Being Addressed

• Produced water exchanger fouling
• Phase 2 glycol cooling system is limited during summer months.
Future Actions

• As production is ramped up, optimizing recovery of heat from emulsion to BFW pre-heat.

• Managing operation of PW exchangers to maximize recovery of heat into the HLS feed.

• Continued optimization of slop oil treating and reduction initiatives.
Facility Performance: Water Treatment

Water Make-up and Disposal Rate / Bitumen Rate

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

Phase 1/2 planned outage.
Facility Performance: Water Treatment

Successes

- Continue recycling high blowdown volumes.
- Continuous use of saline water.
- New liner installed in west pond

Issues Being Addressed

- After-filter media carryover.
- Phase 2B magnesium oxide feeding issues.
- Leaking around penetration point in west pond.
Facility Performance: Water Treatment

Future Actions

• West pond liner penetration being removed.
• Testing mono-media in after-filters.
• Continuing testing of magnesium oxide feeding options.
Phase 2 TDS Boiler Feed Water

Phase 2 HLS Outlet TDS

TDS ppm

Phase 2 TDS
Proration Factors

Bitumen Proration Factor

Jan-14, Feb-14, Mar-14, Apr-14, May-14, Jun-14, Jul-14, Aug-14, Sep-14, Oct-14, Nov-14, Dec-14, Jan-15, Feb-15, Mar-15, Apr-15
Proration Factors

Water Proration Factor

- Jan-14
- Feb-14
- Mar-14
- Apr-14
- May-14
- Jun-14
- Jul-14
- Aug-14
- Sep-14
- Oct-14
- Nov-14
- Dec-14
- Jan-15
- Feb-15
- Mar-15
- Apr-15
Facility Performance: Steam Generation

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

- **Phase 1/2 planned outage.**
- **Incremental steam generator and P2 HRSG PSV issues.**

- Graph shows the comparison between actual steam rate and plant design steam rate from April 2014 to April 2015.
Facility Performance: Steam Generation

Successes

- Stable operation throughout the year
- Took advantage of lower operating pressures in the Phase 2B HRSG and OTSGs to increase steaming capacity.
- Increased steam quality in the Phase 1/2/2B OTSGs from 78% to 80% (design quality).
- Planned Phase 1/2 plant outage – completed combustion inspection on Phase 2 GTG and pigged Phase 2 HRSG and Phase 1/2 OTSGs.
- Wind fence trial at pond to reduce blowdown plume appears successful – looking at expanding.
- Successfully implemented steam balance as secondary measurement.

Issues Being Addressed

- Tube corrosion issues in two 50 MMBtu/hr boilers.
- Relief valve leaking on Phase 2 HRSG
Future Actions

• Continue optimizing steam generator discharge quality while implementing enhanced monitoring program.
• Implement overall HP steam distribution control philosophy.
• Implement more detailed steam generator availability and utilization tracking.
Facility Performance: Power Generation

Power Generated/Consumed

- Phase 1/2 planned outage.
Facility Performance: Power Generation

Actual Power Generated / Design Generation

Phase 1/2 planned outage.
Facility Performance: Power Generation

Successes
- Stable operation throughout the year

Issues Being Addressed
- No significant issues.
Facility Performance: Gas Usage

Gas Consumption

- Total Purchased Gas (e3m3)
- Total Produced Gas (e3m3)

Phase 1/2 planned outage.
CLRP Gas Balance
Facility Performance: Gas Usage

Total Gas Consumed / Bitumen

Gas/Bitumen (m^3/m^3)

- Well steam circulation.
- Phase 1/2 planned outage.

Facility Performance: Measurement

- AGAR BS&W meters commissioned and calibrated for all operational pads in 2014.
  - Full PM cycle and annual calibration approximately 75% complete for 2015.
- Successfully completed three years of testing of P1/2 water wells and one year of well tests on the new P2B water wells.
  - No significant gas detected via third party well testing.
- Implemented engineering calculation for secondary steam measurement for Phase 2B HP steam to well pads.
Yearly comparison of “Sum of HP steam to well pads” and “Sum of well pad steam meters” returned a yearly average of 1.6%.

![Graph: Sum of HP Steam to Pads Vs. Sum of Well Steam Meters]

- EC data Sum of steam to pads
- Tons
- Month/day
- 03/07 04/26 06/15 08/04 09/23 11/12 01/01 02/20 04/11 05/31
Water
Water Management

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

D81 Compliant in 2014
Produced Water to Steam Injected Ratio

Reporting Year (0.96)

Calendar Year (0.97)

Produced Water to Steam Injected Ratio (PWSR)
- 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 (1.7MM m³)**
- **Reporting Year (2.0MM m³)**

- Monthly Volume (m³)

- Data for wells with different codes:
  - 1F1/08-16-77-05W4/00
  - 1F1/03-16-77-05W4/00
  - 1F1/05-03-77-05W4/00
  - 1F1/12-03-77-05W4/00
  - 1F2/03-29-77-04W4/00
  - 1F1/06-29-77-04W4/00
  - 1F1/02-14-77-05W4/00
  - 1W0/04-13-77-05W4/00
  - 1F1/08-14-77-05W4/00
  - 1F2/05-03-77-05W4/00
  - 1F1/03-29-77-04W4/00
  - 1F1/04-29-77-04W4/00
Source Water Management

- Saline McMurray groundwater production ongoing since November 2013
- 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

*100/07-16-077-05W4/00 well on vacuum during operation
Basal McMurray Water Sand Pressure Monitoring

Graph showing pressure over time with annotations for different locations and their corresponding pressures.

- 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
Compliance & Environment
Compliance & Environment

Reporting Year Highlights

• Our Monitoring Approach
• Sulphur Production and Removal
• Greenhouse Gas Management
• Compliance Summary
• Reclamation
MEG’s Extensive Monitoring

Detecting any changes that may occur due to our developments

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

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

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

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

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

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

**Vegetation**
Monitor species composition and abundance.
- Sulphur Removal Unit completed and started up in August 2014.
  - Allows MEG to meet EPEA and Interim Directive 2001-3 limits
  - Continuous monitoring of produced gas $H_2S$ concentrations for system control

- Average 1 tonne/day inlet sulphur reached in Q1-2015
  - Operating challenges resulted in <70% recovery for calendar quarter
  - SRU maintenance and modifications undertaken in Q1 to improve operability
  - Compliant with approval requirements in Q2-2015
Daily Inlet Sulphur

Quarterly Average (t/d)

- 0.838
- 0.930
- 0.911
- 1.068
- 1.149

Date

- Inlet Sulphur
- Limit
Sulphur Removal

- **Inlet Sulphur (t/d):**
  - 1-Apr-14 to 22-Jul-14: 0.8
  - 22-Jul-14 to 17-Sep-14: 0.9
  - 17-Sep-14 to 8-Jan-15: 1.0
  - 8-Jan-15 to 5-Mar-15: 1.1
  - 5-Mar-15 to 30-Apr-15: 1.2

- **Recovery (%):**
  - 1-Apr-14 to 22-Jul-14: 0.0
  - 22-Jul-14 to 17-Sep-14: 10.0
  - 17-Sep-14 to 8-Jan-15: 20.0
  - 8-Jan-15 to 5-Mar-15: 30.0
  - 5-Mar-15 to 30-Apr-15: 40.0

- **Legend:**
  - Blue line: Quarterly Average Inlet Sulphur
  - Red line: Quarterly Average Recovery

**Date:**
- 1-Apr-14
- 27-May-14
- 22-Jul-14
- 17-Sep-14
- 12-Nov-14
- 8-Jan-15
- 5-Mar-15
- 30-Apr-15
SO₂ Emissions
MEG CLRP continues to produce one of the lowest net GHG intensity barrels in the industry.

Q1 2015 performance of ~0.0526 T/bbl CO$_2$e vs an industry average of 0.071T/bbl CO$_2$e.

GHG performance is attributed to reservoir performance (low SOR’s), use of co-generation technology for steam generation, and ongoing reservoir efficiency technologies (ie. eMSAGP).
Compliance Summary

Inspections

- An inspection was conducted March 2015, which was deemed satisfactory

Site Visit

- Senior staff from the AER Bonnyville Field Office visited the CLRP for a site tour September 30, 2014
Self-Disclosures

MEG reported 5 self-disclosures to the AER during the reporting period:

• April 28, 2014: License Amendments from Oil Sands Evaluation to Observation wells
• August 11, 2014: Pad P Construction Soil Salvage Non-Compliance
• January 29, 2015: Well Test Frequency Non-Compliance
• March 18, 2105: Long Term Water Diversion Licence Annual Reports Late Submission
• March 7, 2015: Failure to Meet Calendar Quarter-Year Sulphur Removal Efficiency
MEG reported 5 incidents to the AER during the reporting period:

- **April 13, 2014: Ambient Air Monitoring Trailer H₂S Hourly Exceedance**
  - 31 minutes exceedance, data validity suspect

- **June 28, 2014: Passive Air Sampler Failure**
  - Sample cartridge found on ground, data compromised

- **September 8, 2014: Continuous Emissions Monitoring System (CEMS) Non-Compliance**
  - Missed 90% uptime requirement, due to equipment malfunction

- **February 10, 2015: Wastewater Treatment Plant**
  - Missing sampling parameters specified in new EPEA approval for pending equipment

- **March 16, 2015: Oilfield Drilling Waste Reporting Delay**
  - Missed reporting timeline
Spills

- 12 reportable spills occurred at MEG from April 2014 to April 2015. All reports were filed with the AER and remediation has been completed. MEG’s 2014/15 spill intensity ranks well below industry average (CAPP, 2012).
2012 Temporary Diversion Licence Exceedance

- **February 6th, 2015:** MEG received an Administrative Penalty of $30,500 related to 2012 exceedances of withdrawal limits related to four Temporary Water Diversion Licences. MEG originally self-reported this matter in accordance with its *Water Act* approvals. As part of our commitment to continuous improvement, MEG has implemented improved training, monitoring and internal reporting processes. The AER has reviewed MEG’s corrective actions and commended MEG regarding the success of these initiatives.
Continuous Ambient Air Monitoring Trailer and Passive Sampling

- MEG employed the use of a continuous ambient air monitoring trailer from January to June 2014 for phases 1, 2 and 2B as required by our approval.
- Additional monitoring was completed through August and September, prior to and during the start-up of the SRU.
- 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.
- Two ambient air contraventions were reported in 2014.
## Continuous Monitoring Results

<table>
<thead>
<tr>
<th>Maximum Reading for 2014 (ppbv)</th>
<th>Month of Maximum Reading in 2014</th>
<th>Limit (ppbv)</th>
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<tbody>
<tr>
<td>SO2 60</td>
<td>January</td>
<td>172</td>
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<tr>
<td>H2S 19</td>
<td>April</td>
<td>10</td>
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### Maximum 1 Hour Ground-Level Concentration

![Graph showing SO2 and H2S concentrations from January to December 2014](image-url)
Ambient Air Quality Monitoring

Passives Sampling Results

**H₂S Passive Sampling Results**

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**SO₂ Passive Sampling Results**

|---------------------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|--------|
- Overall gas conservation >99%
- MEG reported 16 flaring and 2 venting notifications to the AER including exceedances and outages.
Conservation & Reclamation

Reporting Year Highlights

• Wetland Reclamation Trial Program
  • Ongoing reclamation of two borrow pits for the purpose of permanent reclamation.

• Caribou Habitat Reclamation Trial

• Oil Sands Exploration (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

• Reclamation Certificates are being submitted immediately for:
  - CLRP 050040
  - CLRP 060068
  - CLRP 070107
  - May River 060066
  - May River 070069

• Reclamation Certificates to be submitted spring 2015:
  - Jackfish 060065
  - Jackfish 070079
  - Thornbury 070077

• Reclamation Certificates to be submitted fall 2015:
  - CLRP 090055
  - Duncan 100059
  - May River 090043
• 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.
CLRP
Future Plans
Regulatory Amendments

Amendments approved April 2014 - April 2015

- Phase 2B4X facilities relocation amendment approval received
- Expand IDA to include 6 new subsurface patterns
- Various amendments to pad orientation
- Expansion of NCG Co-Injection on Pads A through F
CLRP Future Development

- CLRP Project Area
- Approved SAGD Patterns
- Future SAGD Patterns
- Central Plant
- Access pipeline
• Ongoing de-bottlenecking of Phase 2B facilities
• Ongoing pattern addition within CLRP development area
• Continued development of eMSAGP within Active Development Area
• Ongoing resource assessment
Questions and Comments