Disclaimer

Certain statements contained in this presentation constitute forward-looking information within the meaning of applicable securities laws. 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 information. In particular, this presentation may contain forward-looking information 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; the timing for construction of MEG's projects; the planned construction of and enhancements to MEG's facilities; MEG's drilling plans; MEG's plans for, and results of, exploration and development activities and recent initiatives such as the co-injection of non-condensable gas; the expected application timeframe for MEG's projects; and the timing associated with the application for and the receipt of various regulatory approvals.

The forward-looking information in this presentation is based on a number of factors, expectations and assumptions which may prove to be incorrect. In particular, assumptions have been made regarding 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 ability to export power to the electric transmission grid; 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.

No assurance can be given that such forward-looking information or the underlying assumptions will prove to be correct so the reader is cautioned not to unduly rely upon such information. Such forward-looking information also involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated by such forward-looking information. Further details regarding the assumptions and risks inherent in such forward-looking information can be found in MEG's annual information form dated February 27, 2013, which is available at www.sedar.com.

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Outline

• Overview  
  Simon Geoghegan

• Geosciences  
  Andrew Fox

• Reservoir  
  Jeremy Gizen/Kejia Xi

• Operations  
  Ted Lamb

• Water  
  Scott Rayner

• Compliance & Environment  
  Simon Geoghegan

• Future Plans  
  Simon Geoghegan
MEG Energy Corp.

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.
Christina Lake Regional Project (CLRP)
The SAGD Process
CLRP 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)
- Mechanical completion in August 2009
- Reached design name plate in April 2010

Phase 2B
- Plant expansion to 9,540 m$^3$/d or 60,000 bpd (incremental 5,540 m$^3$/d or 35,000 bpd)
- ERCB approval granted April 21, 2009
- Commissioning underway, first steam expected Q3/Q4 2013

Phase 3
- ERCB approval granted January 2012
- Construction commenced in Q1 2013
Christina Lake Regional Project (CLRP)

Phase 2 Development Area

Phase 3 Development Area

Proposed CPF

Christina Lake

Access Pipeline
MEG Energy – Christina Lake Regional Project

• Currently operating Phase 2 (includes Phase 1) of Christina Lake Regional Project (CLRPR) about 150 km south of Fort McMurray

• Designed capacity of 3,975 m³/d (25,000 bpd) and SOR of 2.8

• 2012 bitumen production averaged 28,773 bpd

• Q1 2013 bitumen production of 32,531 bpd and SOR of 2.5

• Phase 2B currently in commissioning phase, first steam expected Q3, with first oil commencing in Q4

• Phase 3 of CLRPR approved January 2012 (scheme expansion to 33,390 m³/d or 210,000 bpd). Site clearing and construction commenced in Q1 2013
Patterns A, B, C, D, E, F and V are producing.
Geosciences
CLRP Geoscience Review

- Well and Seismic Data
- Stratigraphic Framework
- Reservoir and Pay Parameters
- Active Development Area Bitumen Pay
- Phase 1 SAGD Pattern A
- Phase 2 SAGD Patterns
- Phase 2B Drilled SAGD Patterns
- Phase 3 Development
- McMurray Water Resources
- Cap Rock Geology
- Active Development Area Associated Gas Resources
- Thermal Compatibility
Christina Lake Regional Project (CLRDP)

Diagram showing:
- Approved Project Area
- Approved Development Areas
- Phase 2 Development
- Access Pipeline
CLRP Wabiskaw / McMurray Cores

- 745 cored wells
- 85% of all wells are cored

Approved Project Area

Wabiskaw / McMurray Core
CLRP 2013 Delineation, Water Source and Water Disposal Wells

115 of 135 Wells Cored (85%)

- CLR Project Area
- 2013* Delineation Well
- 2013* WSW
- 2013* WDW

* Includes wells drilled in Dec. 2012
CLRP 3D Seismic

No seismic recorded in 2013
CLRPM: Wabiskaw/McMurray Stratigraphy

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

Beaverhill Lake

**Wabiskaw Marker**

**Wabiskaw C Sand**

**McMurray A1**

**Wabiskaw D Shale**

**Clearwater C mud**

**upper Wabiskaw mud**

**Wabiskaw C Sand**

**McMurray Formation**

**Wabiskaw Valley**

**McMurray Channel**

**McMurray A1**

**Beaverhill Lake**

---

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

McMurray stratigraphy after ERCB RGS 2003
CLRP: Wabiskaw / McMurray Type Well

1AE/06-18-77-05W4

<table>
<thead>
<tr>
<th>McMurray</th>
<th>SAGD</th>
</tr>
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<tr>
<td>h (m)</td>
<td>47.6</td>
</tr>
<tr>
<td>avg $\Phi$</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 ≥ 6 wt% BMO
CLRP: McMurray SAGD Pay Parameters

**SAGD Pay**

\[ \geq 10 \text{ m continuous pay (defined from cores, images and well logs)} \]

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

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

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

gas and coal excluded
CLRP ADA: Total McMurray SAGD Pay $\geq 10$ m

SAGD Pay Cutoffs:
- continuous bitumen pay $\geq 10$ m (defined by logs, images and core)
- $S_o \geq 50\%$ (6 wt% bulk mass oil)
- Porosity (density) $\geq 25\%$

contour interval = 5 m

T77
SAGD Pay Cutoffs:
• continuous bitumen pay $\geq 10$ m (defined by logs and core)  
• $S_o \geq 50\%$ (~6 wt% bulk mass oil);  
• Porosity (density) $\geq 25\%$;
CLRP Pattern A Base SAGD Pay Structure

Contour Interval = 5 m
Posted values above sea level

Intermediate Casing Point (ICP)
CLRP Pattern A Top SAGD Pay Structure

Contour Interval = 5 m
Posted values above sea level

Intermediate Casing Point (ICP)
CLRP Pattern A SAGD (A1 well pair)

1AC/01-13-77-06W4  1AB/04-18-77-05W4  1AA/03-18-77-05W4

Wabiskaw D valley fill

Wabiskaw Marker

Wabiskaw C Sand

Top McMurray

mud

limestone

Cap Rock

Clearwater C

Wabiskaw

McMurray Formation

SAGD pay

non-reservoir lithofacies

Injector

Producer

MEG Energy
CLRP Phase 2 SAGD Well Pairs Map View

- Well pairs drilled from surface Pad D
- E Pattern includes F1 well pair

### Pattern SAGD Pairs

<table>
<thead>
<tr>
<th>Pattern</th>
<th>SAGD Pairs</th>
</tr>
</thead>
<tbody>
<tr>
<td>B</td>
<td>2</td>
</tr>
<tr>
<td>BB</td>
<td>6</td>
</tr>
<tr>
<td>C</td>
<td>6</td>
</tr>
<tr>
<td>C Expansion</td>
<td>2</td>
</tr>
<tr>
<td>D</td>
<td>5</td>
</tr>
<tr>
<td>E²</td>
<td>7</td>
</tr>
<tr>
<td>F</td>
<td>5</td>
</tr>
<tr>
<td>V</td>
<td>6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>39</strong></td>
</tr>
</tbody>
</table>

1. well pairs drilled from surface Pad D
2. E Pattern includes F1 well pair
CLRP Phase 2 SAGD and Infill Wells Map View

- MEG OSL Boundary
- SAGD Patterns
- Infill Wells
- OB Well (pressure and temperature)
- SAGD Producer ICP

<table>
<thead>
<tr>
<th>Pattern</th>
<th>SAGD Pairs</th>
<th>Infill Wells</th>
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</thead>
<tbody>
<tr>
<td>B</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>BB</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>C</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td>C Expansion¹</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>D</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>E²</td>
<td>7</td>
<td>6</td>
</tr>
<tr>
<td>F</td>
<td>5</td>
<td>4</td>
</tr>
<tr>
<td>V</td>
<td>6</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>39</strong></td>
<td><strong>31</strong></td>
</tr>
</tbody>
</table>

1. well pairs drilled from surface Pad D
2. E Pattern includes F1 well pair
CLRP Phase 2: Stacked SAGD Pay

100/14-16-77-05W4 OBB1
100/02-21-77-05W4 OBD1

Clearwater C
Cap Rock
Wabiskaw C
McMurray
Devonian

Single Pattern Development (Single Pay Interval)
Stacked Pattern Development (Multiple Pay Intervals)

Piezometers
Phase 2 Area Lower SAGD Pay ≥ 10 m

SAGD Pay Cutoffs:
• continuous bitumen pay ≥ 10 m (defined by logs and core)
• So ≥ 50% (~6 wt% BMO)
• Porosity (density) ≥ 25%;
Phase 2 Area Lower SAGD Pay $\geq 10$ m

SAGD Pay Cutoffs:
- continuous bitumen pay $\geq 10$ m (defined by logs and core)
- $So \geq 50\%$ (~6 wt% BMO)
- Porosity (density) $\geq 25\%$

Contour Interval = 5 m
Phase 2 Lower SAGD Development (Pattern B)

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

Non-Reservoir Lithofacies

Gas

Piezometers

MEG Energy
Phase 2 Lower SAGD Development (Pattern C)

1AB/12-16-77-05W4

1AA/12-16-77-05W4

Clearwater C
Cap Rock
Wabiskaw C

McMurray

Devonian

SAGD Pay
Non-Reservoir Lithofacies
Gas

Bitumen / Water Contact
Water Sand

Water Sand

MEG ENERGY
Phase 2 Lower SAGD Development (Pattern D)

“Tiger Stripes” = interbedded water sand and bitumen sand

Piezometers
Phase 2 Lower SAGD Development (Pattern E)

1AA/11-16-77-05W4

1AA/16-16-77-05W4

SAGD

Pay

Devonian

Cap Rock

Wabiskaw C

Clearwater C

Non-Reservoir Lithofacies

"Tiger Stripes" = interbedded water sand and bitumen sand
Phase 2 Lower SAGD Development (Pattern F)

1AA/05-21-77-05W4  1AA/13-16-77-05W4

- Clearwater C
- Cap Rock
- McMurray
- Devonian

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

- Water
- Sand
Phase 2 SAGD Development (Pattern D6/D7)

100/06-16-77-05W4 OBC1

1AA/07-16-77-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

Piezometers

Non-Reservoir Lithofacies

SAGD Pay

Water Sand

Bitumen / Water Contact

Non-Reservoir Lithofacies

SAGD Pay

Water Sand

D7

D6
Phase 2 Area SAGD Development (Pattern V)

1AA/10-17-77-05W4

1AA/15-17-77-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

SAGD Pay

Non-Reservoir Lithofacies

Gas

Water Sand

Bitumen / Water Contact

Water Sand
Phase 2 Area Base Lower SAGD Pay Structure

Contour Interval = 5 m
Posted values above sea level

CLRP Project Area
SAGD Patterns

T77

400 m  RSW4
Phase 2 Area Top Lower SAGD Pay Structure

Contour Interval = 5 m

Posted values above sea level
Phase 2 Area Upper SAGD Pay ≥ 10 m

SAGD Pay Cutoffs:
- continuous bitumen pay ≥ 10 m (defined by logs and core)
- So ≥ 50% (~6 wt% BMO)
- Porosity (density) ≥ 25%;

Contour Interval = 5 m
Phase 2 Area Upper SAGD Pay ≥ 10 m

Contour Interval = 5 m

SAGD Pay Cutoffs:
- continuous bitumen pay ≥ 10 m (defined by logs and core)
- So ≥ 50% (~6 wt% BMO)
- Porosity (density) ≥ 25%;
Phase 2 Upper SAGD Development (Pattern BB)

100/02-21-77-05W4 OBD1

1AB/01-21-77-05W4

Piezometers

Clearwater C
Cap Rock
Wabiskaw C
McMurray
Devonian

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

MEG Energy
Phase 2 Area Base Upper SAGD Pay Structure

Contour Interval = 5 m
Posted values above sea level
Phase 2 Area Top Upper SAGD Pay Structure

Contour Interval = 5 m
Posted values above sea level
CLRP ADA Additional Drilled SAGD Patterns

- Pattern A
- Pattern V
- Pattern M
- Pattern N
- Pattern P
- Pattern T
- Pattern U

CLRP Project Area
Approved IDA
Drilled, producing patterns
Drilled, non-producing patterns

T77
Phase 2 SAGD Development (Pattern G)

1AB/05-09-77-05W4 1AA/04-09-77-05W4
Phase 2 SAGD Development (Pattern H)

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

- Cap Rock
- Wabiskaw C
- McMurray
- Devonian

- SAGD Pay
- Gas
- Non-Reservoir Lithofacies
- Water Sand
- Bitumen / Water Contact
Phase 2 SAGD Development (Pattern J)

1AA/02-07-77-05W4

1AA/16-06-77-05W4

Cap Rock

Wabiskaw C

McMurray

Non-Reservoir Lithofacies

Non-Reservoir Lithofacies

Gas

SAGD Pay

Water Sand

Bitumen / Water Contact

Devonian

SAGD Pay
Phase 2 SAGD Development (Pattern K)

1AF/06-07-77-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

Non-Reservoir Lithofacies

Non-Reservoir Lithofacies

SAGD Pay

SAGD Pay

Water Sand

Water Sand

Bitumen / Water Contact

1AD/10-7-77-05W4
Phase 2 SAGD Development (Pattern M)

1AA/04-10-77-05W4

1AA/03-10-77-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

Gas

SAGD Pay

Non-Reservoir Lithofacies

Water Sand

Water Sand

Bitumen / Water Contact
Phase 2B SAGD Development (Pattern N)

1AA/12-03-77-05W4

1AC/10-03-77-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

Pattern N not tied in

Bitumen / Water Contact
Phase 2 SAGD Development (Pattern T)

Lower sands to be developed at a later date
Pattern T not currently producing
CLRP ADA Basal McMurray Net Water Isopach

Contour Interval = 5 m

CLRP Project Area
Phase 2 Project Area
Drilled SAGD Patterns

T77

R6
R5W4
Low gas cap pressure due to legacy gas production; MEG has approval to repressurize gas cap.

Small gas cap; no repressuring required.

Depleted gas cap not in direct contact with SAGD interval.

Local gas cap contact with SAGD interval; ~20% depletion from original pressure; no repressuring required.

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

Clearwater C

WBSK Mkr mud

Lower Clearwater Cap Rock

WBSK C

WBSK D Shale

McMurray

non-reservoir lithofacies

Lower Clearwater Cap Rock = 10.9 m thick

SAGD Pay

Bitumen / Water Contact

Water Sand

Beaverhill Lake
Phase 2 Development Area
Average Caprock Thickness = 10.8 m
Minimum Thickness = 8.5 m
Maximum Thickness = 12.1 m
CLRP Cap Rock Testing

• 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: 2010 CVE Christina Lake ERCB Annual Update, June 2010
- CVE Narrows Lake data: CVE Narrows Lake Application to ERCB, Appendix 1-VII (Cap Rock Study), June 2010
- KNOC 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
CLRP Legacy Wells

- Existing SAGD patterns
- Proposed 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
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
- A general thermal compatibility program has been drafted by MEG and reviewed by ERCB staff. Final submission planned for Q3 2013. The program includes:
  - A detailed assessment of compatibility of existing all wellbores within the CLRP project area
  - General abandonment approach
  - Monitoring plans
Reservoir
CLRP Reservoir Review

- Wells
  - Schematics
  - Work overs

- Current Performance
  - Field performance
  - Pattern performance
  - eMSAGP update
  - OB well cased-hole logging

- Associated gas cap re-pressuring

- Future production enhancement plans
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.
• Thermocouples are inside the instrument string to provide temperature measurements at selected locations
Thermocouples are inside the instrument string to provide temperature measurements at selected locations.
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

8 5/8” Production Casing

4 1/2” Production lubing

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


Issue

- Liner Impairment on V3P
- Identified while running the tail pipe for ESP Conversion February 2013

Implications

- The circulation tubing was pulled successfully but could not run in past the failure with the production tail pipe
- Identified impairment approximately at the halfway point of the horizontal
- Unable to run tail pipe to desired landing depth in horizontal

Actions

- Run compression block and camera log to confirm the break is impassable
- Pulled approximately 100m of liner to re-drill the horizontal section from the existing intermediate casing
- The intermediate section has been suspended with a wire line retrievable plug. The idle injector well has been confirmed in tact via tubing movement and has been purged with sweet dry fuel gas
- Planning the re-drill of a new horizontal from the existing intermediate section
CLRP Artificial Lift

• All MEG SAGD well pairs are initially completed with gas lift capabilities
• 44 Electric submersible pumps (ESP) in operation
  – Approximately 75% ESPs rated to 220°C and 25% rated to 250°C
  – Operating pressures range from 2,100-3,000kPag
  – Design fluid rates 200-1200m³/d
  – Mean run-time between pulls is 675 days

• Four reciprocating pumps installed in the infill wells
  – Three rod insert and one tubing pump
  – Operating pressures range from 2,000-2,500kPag
  – Design fluid rates 100-500m³/d
Scheme Performance
SAGD wells
SAGD: 44
Circulating: 0
Standing: 3
Total: 47

Infill wells
Operating: 5
Standing: 29
Total: 34
First steam into A1, A2 & A3 wells effectively occurred in March 2008

First steam into Phase 2 wells occurred in August 2009

Wells were started up in stages, dictated by steam availability

Typical preheat time was between 1 to 2 months due to the presence of bottom water, allowing rapid heating of the reservoir

Current reservoir operating pressure is between 2,100 and 3,000 kPag. The steam chamber pressure is similar to the basal water zone (~2,000 to 2,200 kPag) where SAGD wellpairs are underlain by bottom water

Phase 2 Production ramp-up was ahead of schedule
  – The combined bitumen production of Phase 1 and Phase 2 reached the design capacity of 3,975 m3/d (25,000 bpd) on an intermittent basis by late April 2010 – eight months after first steam

Bitumen production rates have been consistently above the design capacity since June 2010 with exceptions during planned outages
The SOR has averaged 2.4 over the last 12 months and has ranged from 2.3 to 2.6.

The improved SOR relative to the design level of 2.8, has allowed MEG to bring more well pairs onto production fully utilizing the excess steam:
- A8 well pair
- D7 well pair
- Pattern V, 5 well pairs
- Wells on production in April 2013 included 44 SAGD well pairs and 5 infill wells

The eMSAGP pilot in Phase 1 wells was initiated in December 2011. This project has demonstrated very encouraging results. Phase 2 eMSAGP expansion was started with the Pattern B wells in February 2013.

In the first quarter of 2013, MEG achieved record quarterly production of 32,500 barrels per day, a 14% increase for the same period in 2012. Current production is on a growing trend.
CLRP Production Performance

Rate (m³/day)

Scheduled Plant Turnaround

Design Capacity

0 2,000 4,000 6,000 8,000 10,000 12,000 14,000
1/1/08 12/31/08 12/31/09 12/31/10 12/31/11 12/31/12 12/31/13

Steam Injection
Water
Bitumen
CLRP Performance – Pattern SOR

![Graph showing ISOR performance over time with different patterns labeled A, B, BB, C, D, E, F, and V. The graph includes data from 1/1/08 to 12/31/13.]
A1 to A3 will be discussed under eMSAGP update
CLRP Performance – Pattern B

- Pad down due to OH&S incident
- eMSAGP start in the pattern

Graph showing the rate (m³/day) from 1/1/09 to 12/31/13 for Steam, Water, and Bitumen.
CLRP Performance – Pattern BB

Pad down due to OH&S incident

eMSAGP start in the pattern
CLRP Performance – Pattern C

- Steam
- Water
- Bitumen
Higher water production was a result of bottom water incursion and lower steam quality to the D5 well pair. New high pressure steam separator reducing condensate carry over to end well. Steam reduction for pad pressure adjustment.
CLRP Performance – Pattern F

Rate (m³/day)

1/1/09 1/1/10 1/1/11 1/1/12 12/31/12 12/31/13

Steam Water Bitumen

86
CLRP Performance – Pattern V

Production ramp up of 5 SAGD well pairs

Rate (m$^3$/day)

- Red: Steam
- Blue: Water
- Green: Bitumen

1/1/12 12/31/12 12/31/13
## SAGDable Oil-in-Place

<table>
<thead>
<tr>
<th>Pattern</th>
<th>Operating Wellpairs</th>
<th>Average h (m)</th>
<th>Average L (m)</th>
<th>Average Porosity</th>
<th>Oil Saturation</th>
<th>OOIP (m³)</th>
<th>Ultimate Recovery (m³)</th>
<th>Cumulative Production (m³)</th>
<th>Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>8</td>
<td>19</td>
<td>889</td>
<td>34%</td>
<td>72%</td>
<td>3,296,000</td>
<td>1,812,800</td>
<td>1,063,406</td>
<td>32%</td>
</tr>
<tr>
<td>B</td>
<td>2</td>
<td>30</td>
<td>745</td>
<td>34%</td>
<td>82%</td>
<td>1,246,000</td>
<td>685,300</td>
<td>319,195</td>
<td>26%</td>
</tr>
<tr>
<td>BB + D7</td>
<td>5</td>
<td>15</td>
<td>916</td>
<td>33%</td>
<td>85%</td>
<td>1,963,000</td>
<td>1,079,650</td>
<td>648,415</td>
<td>33%</td>
</tr>
<tr>
<td>C + D6</td>
<td>7</td>
<td>24</td>
<td>803</td>
<td>34%</td>
<td>75%</td>
<td>3,453,000</td>
<td>1,899,150</td>
<td>1,492,890</td>
<td>43%</td>
</tr>
<tr>
<td>D</td>
<td>5</td>
<td>18</td>
<td>680</td>
<td>34%</td>
<td>78%</td>
<td>1,622,000</td>
<td>892,100</td>
<td>476,375</td>
<td>29%</td>
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<tr>
<td>E + F1</td>
<td>7</td>
<td>20</td>
<td>819</td>
<td>33%</td>
<td>77%</td>
<td>2,915,000</td>
<td>1,603,250</td>
<td>779,201</td>
<td>27%</td>
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<tr>
<td>F - F1</td>
<td>5</td>
<td>19</td>
<td>776</td>
<td>33%</td>
<td>78%</td>
<td>1,867,000</td>
<td>1,026,850</td>
<td>518,857</td>
<td>28%</td>
</tr>
<tr>
<td>V</td>
<td>6</td>
<td>18</td>
<td>1139</td>
<td>33%</td>
<td>72%</td>
<td>2,970,000</td>
<td>1,633,500</td>
<td>61,261</td>
<td>2%</td>
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<tr>
<td>TOTAL</td>
<td>45</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>19,332,000</td>
<td>10,632,600</td>
<td>5,359,600</td>
<td>28%</td>
</tr>
</tbody>
</table>

Note: Production volume and number of operating wellpairs are as of April 2013

h is net pay above the producer
L is Liner length (including blanks) with 50m added to each end (100m total)

## Original Oil-in-Place

<table>
<thead>
<tr>
<th>Pattern</th>
<th>Operating Wellpairs</th>
<th>Average h (m)</th>
<th>Average L (m)</th>
<th>Average Porosity</th>
<th>Oil Saturation</th>
<th>OOIP (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>8</td>
<td>22</td>
<td>889</td>
<td>34%</td>
<td>72%</td>
<td>3,815,000</td>
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<tr>
<td>B</td>
<td>2</td>
<td>33</td>
<td>745</td>
<td>34%</td>
<td>82%</td>
<td>1,371,000</td>
</tr>
<tr>
<td>BB + D7</td>
<td>5</td>
<td>18</td>
<td>916</td>
<td>33%</td>
<td>83%</td>
<td>2,293,000</td>
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<tr>
<td>C + D6</td>
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<td>27</td>
<td>803</td>
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<td>75%</td>
<td>3,889,000</td>
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<tr>
<td>D</td>
<td>5</td>
<td>21</td>
<td>680</td>
<td>34%</td>
<td>78%</td>
<td>1,847,000</td>
</tr>
<tr>
<td>E + F1</td>
<td>7</td>
<td>23</td>
<td>819</td>
<td>33%</td>
<td>77%</td>
<td>3,278,000</td>
</tr>
<tr>
<td>F - F1</td>
<td>5</td>
<td>22</td>
<td>776</td>
<td>33%</td>
<td>78%</td>
<td>2,148,000</td>
</tr>
<tr>
<td>V</td>
<td>6</td>
<td>21</td>
<td>1139</td>
<td>33%</td>
<td>72%</td>
<td>3,464,000</td>
</tr>
<tr>
<td>TOTAL</td>
<td>45</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>22,105,000</td>
</tr>
</tbody>
</table>

Note: h is net Pay: SAGD base to SAGD Top
L is Liner length (including blanks) with 50m added to each end (100m total)
Update on enhanced Modified Steam and Gas Push (eMSAGP)
eMSAGP Pilot Wells

Pattern A

Infill wells
NCG/steam co-injection
A Summary of eMSAGP Pilot in Pattern A

- eMSAGP involves 3 SAGD well pairs (A1, A2 and A3) and 2 infill wells (A1N and A2N). Non-condensable gas (NCG) and steam are injected into SAGD injectors; production are through all 5 wells.

- Before NCG co-injection, steam chamber pressures were reduced to near original reservoir pressure to minimize gas leak-off.

- Co-injection commenced in December 2011. The infill wells were brought on production in January 2012 after steam stimulation.

- Over ~1.5 years, steam injection has been reduced by about 50%:
  - 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 ~1.3, resulting in more wells being brought on and less emissions and water usage.

- To-date, pilot performance is very encouraging.
Pattern A: Casing Wellhead Pressures
Pattern A eMSAGP Pilot Performance - Rates

[Graph showing performance rates for different fluids (Steam, Water, Bitumen, NCG) over time from 1/1/08 to 12/31/13. Key events include 3 SAGD WP’s and 3 WP’s + 2 Infill Wells.]
eMSAGP Pilot Pattern Performance

Repealable pattern

\[ A_2 + \frac{A_1 N + A_2 N}{2} \approx \text{Avg} (A_1, A_2, A_3) + \text{Avg} (A_1 N, A_2 N) \]

- **SAGD Simulation**
- **Average A1-A3**
- **Average A1-A3 + Average Infill**
- **Same recovery as SAGD**
Pattern A eMSAGP Pilot Performance - ISOR

- SOR
- 3 SAGD Wells
- 3 SAGD Wells + 2 Infill Wells
- eMSAGP Start
- 1/1/08 to 12/31/13
MEG is implementing eMSAGP in 3 more patterns as approved by the ERCB

- Pattern B and BB
  - 3 SAGD well pairs have started NCG co-injection. The pressures in 2 SAGD chambers are being reduced to get ready for NCG co-injection
  - 3 infill wells are on production after steam stimulation. Production rates are between 300 to 500 bpd similar to Pattern A infill wells

- Pattern C
  - 7 infill wells are being tied in
  - NCG co-injection may commence in June 2013

- Pattern D
  - 5 infill wells have been drilled, awaiting tie in
OB wells have pressure and temperature instrumentation.
**CLRP A Pattern OB6**

100/04-18-77-05W4 OB6

**Open Hole Logs**

<table>
<thead>
<tr>
<th>Date</th>
<th>Service Provider</th>
<th>Technology</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dec 2009</td>
<td>SLB</td>
<td>Open Hole Logs</td>
<td>Calculated $S_o$</td>
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<tr>
<td>Feb 2011</td>
<td>Baker</td>
<td>Cased Hole Log</td>
<td></td>
</tr>
<tr>
<td>Jan 2012</td>
<td>SLB</td>
<td>Cased Hole Log</td>
<td></td>
</tr>
<tr>
<td>Jan 2013</td>
<td>Baker</td>
<td>Cased Hole Log</td>
<td></td>
</tr>
</tbody>
</table>

**Cased Hole Log Service Provider**

- SLB = Schlumberger
- Baker = Baker Hughes

Cased hole saturation logs indicated increased gas saturation and reduced water saturation in the steam chamber.

Potential baffles and barriers:
- mud clasts
- 27 cm thick mud parting
- mud clasts
- >5 cm thick mud partings

OB6 is 2.5 m from the A2 SAGD well pair.

Approximate position of production and injection wells from directional surveys while drilling.

SLB SLB Baker

Cased Hole Log Service Provider

Approximate position of production and injection wells from directional surveys while drilling.
100/14-16-77-05W4 OBB1

Open Hole Logs

Cased Hole Log
Dec 2009
SLB
Cased Hole Log
Feb 2011
Baker
Cased Hole Log
Jan 2012
SLB
Cased Hole Log
Dec 2012
Baker

Temperature

Cased hole saturation logs and temperature surveys indicate bitumen production was mainly from the lower SAGD pay to date.

Approximate position of production and injection wells from directional surveys while drilling.

OBB1 is 1 m from B1
Approximate position of production and injection wells from directional surveys while drilling

Cased hole saturation logs and temperature surveys indicate steam chamber development in both upper and lower reservoirs.

OBD1 is 11 m from B4 and 17.5 m from D3.
Cased hole saturation logs and temperature surveys indicate lateral steam chamber development and an increase of bitumen saturation in the water zone that requires further study.

OB9 is approximately 30 m from the E2 SAGD well pair.
CLRP Gas Cap
Re-pressuring
The ERCB approval granted in November 2012

5 wells have been completed as initial natural gas injection wells

Anticipated commissioning / start-up is expected to be mid June as facilities work is being completed

Planned initial injection rate is expected to be up to 708 e3m3 (25 MMSCF) per day into a 600 kPa gas pool

Total required gas volume to restore reservoir pressure is estimated to be about 339,600 e3m3 (12 BCF). This volume can be smaller dependent on reservoir compartmentalization.

Initial focus will be on Pattern M and Pattern N where part of the bitumen pay is underlain by bottom water

Pressure monitoring will rely on observation wells and fall off tests if necessary. Current plan can be adjusted based on pressure response.
Note:
Not all SAGD intervals in the pool wells are directly connected to associated gas.
Future Production
Patterns A, B, C, D, E, F & V are producing
Patterns G, H, J, K, M, N & T to be brought on
CLRP ADA Future Development

- MEG OSL
- Approved Development Area
- Drilled, producing patterns
- Drilled, non-producing patterns
- Approved SAGD Patterns

T77
CLRP Phase 3A Future Development
Operations
Operations Overview

- Operation Overview
- Bitumen Treatment
- Vapour Recovery
- Water Treatment
- Steam Generation
- Power Generation
- Measurement and Reporting
- Future Activities
Oil Treatment Overview
MEG’s commercial operation continues to exceed expectations

Key accomplishments

- Consistently producing over the design name plate capacity
- Successful major turn around in 2012
- December 2012 was a 1st for MEG, producing over 1 Million bbls for the Month
- Reservoir Optimization initiatives allowing MEG to show continuous production growth
Facility Operations: Bitumen Treatment

**Successes**
- Oil processing on spec > 99% for the last year
- Zero BS&W excursions on the sales pipeline for the last year
- Plant capacity testing completed to identify bottlenecks
- De-bottlenecking work started in 1st Quarter 2013
- Consistently exceeding the design name plate
- Optimization initiatives have improved process and de-oiling efficiency

**Issues**
- Exchangers fouling
- Glycol cooling system is limited during summer months

- Produced Water/Bitumen (m3/m3)
- Make Up Water/Bitumen (m3/m3)
- Disposal Water/Bitumen (m3/m3)
• Vapour recovery compressor maintained a 97% availability
• **Reported produced gas rate variability in November and March is due to new wells starting up on Pad V**

**Issues**
• Communication failures between vapor recovery compressor and plant control system
• Control of the VRU suction header
• Aerial cooler tube failure in December resulted in extended outage of VRU

**Implications**
• Difficulty in trending VRU operating data and status
• Instability of vapor recovery compressor and minor flaring events especially during summer months

**Actions**
• Upgrades to communication link between vapor recovery compressor and plant control system
• Modifications to VRU suction piping and compressor suction pressure control have stabilized the vapor recovery header
VRU Availability

![Graph showing VRU Availability with a cooling tube failure at around Jan-13.](image-url)
Gas Conservation

Plant turnaround

Production slow down due to Enbridge pipeline capacity restriction
Successes

• Water treatment plant operating at 90% (April 1, 2012 – May 1, 2013) or 96.1% (Nov 1 – May 1) of current name plate
• Boiler feedwater on spec 99.7% (yearly average)
• 2013 YTD actual disposal  7.15% (Limit = 8.91%)
• Continue recycling high blowdown volumes (steam and liquid) >60%
• Completed the tie-in between Phase 1 and Phase 2 process ponds
• Continue managing 100% produced water in water treatment plant
• New oxygen analyzer in BFW showing reliable results
• New polymer make down system
• New coagulant tank (no totes at site for coag in water treatment)
• Plant trial of brackish water

Issues

• Process ponds liner – west pond complete, east pond liner repair in progress which will reduce storage capacity and may have short term impacts on disposal volumes
• WAC vessel down for 35 days due to internal repairs
• Dry chemicals (lime and magox) feeding issues
Facility Operations: Water Treatment (continued)

Implications

• Plant instability/control

Actions

• New high efficiency WAC resin installed in one vessel
• Trial scheduled for online HLS sludge dewatering
• Pond liner repair underway
Water Treatment – Quality Parameters

<table>
<thead>
<tr>
<th></th>
<th>Clearwater Well</th>
<th>Brackish Water</th>
<th>Produced Water</th>
<th>Boiler Feed Water</th>
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<tbody>
<tr>
<td>TDS (as mg/l)</td>
<td>2,010</td>
<td>13,000</td>
<td>1,525</td>
<td>4,850</td>
</tr>
<tr>
<td>SiO₂ (as mg/l)</td>
<td>8.9</td>
<td>12</td>
<td>210</td>
<td>28</td>
</tr>
<tr>
<td>Cl (as mg/l)</td>
<td>910</td>
<td>6,900</td>
<td>1,493</td>
<td>2,390</td>
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<tr>
<td>Na (as mg/l)</td>
<td>830</td>
<td>4,720</td>
<td>534</td>
<td>1,850</td>
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<tr>
<td>K (as mg/l)</td>
<td>3</td>
<td>34</td>
<td>19</td>
<td>52</td>
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<tr>
<td>Ca (as mg/l CaCO₃)</td>
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<td>75</td>
<td>4</td>
<td>0.2</td>
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<tr>
<td>Total Alkalinity (as mg/l CaCO₃)</td>
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<td>1,100</td>
<td>325</td>
<td>776</td>
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<tr>
<td>pH</td>
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<td>7.9</td>
<td>7.4</td>
<td>10.0</td>
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<td>Fe (as mg/l)</td>
<td>0.5</td>
<td>2</td>
<td>0.1</td>
<td>0.05</td>
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</table>

**Note:** Reporting period average (Apr 2012- Apr 2013)
BFW TDS

mg/L

4357  5636  5189  3938  4703  3279  5127  5488  5474  4504  5334  5287  4435

Apr-12  May-12  Jun-12  Jul-12  Aug-12  Sep-12  Oct-12  Nov-12  Dec-12  Jan-13  Feb-13  Mar-13  Apr-13
Boiler Availability

Month-year

Phase2 HRSG
Phase2 OTSG
Phase1 OTSG
Incremental Steam 1
Incremental Steam 2

Boiler Availability (%)
Monthly Steam Injection

![Graph showing monthly steam injection from Apr-12 to Mar-13. The graph indicates fluctuations in steam injection with notable peaks in Oct-12 and Aug-12, and a significant drop in Aug-12.](image_url)
Facility Operations: Power Generation

Successes

- Consistent GT operation (availability >98.5%)
- Generator protection system upgrade in 2012
- High efficiency HEPA inlet filtration added to reduce performance loss between blade washing
- Islanding functionality commissioned to allow facility operation when disconnected AESO grid
- HRSG firing rate increase with corresponding thermal and power output improvements
- 25% reduction in overall boiler and GT unit trips, 2011-2012
- Facility fire & gas voting head project completed. Eliminated random facility trips caused by false readings.
Facility Operations: Power Generation (continued)

Issues
• Instability during grid isolation

Implications
• Potential Impact on availability

Actions
• Regular preventative maintenance
• Inspection planned during scheduled and unscheduled outages
• Continued improvement of steam safety system related trips
* Generation and usage are estimates based on MEG metering
Energy Intensity

Excludes fuel usage for power generation
CoGen GTG/HRSG

GTG Availability (168 h/w)  HRSG Availability (168 h/w)
Facility Operations: Gas Usage

Successes
- High temperature blowdown exchanger replaced with steam condenser
- Gas usage intensities are within design

Issues
- No major issues

Implications
- Plant heat balance inefficiencies

Actions
- Plant heat optimization ongoing
Successes

• Received approval of 2013 MARP update
• The smaller produced gas meters have been working very well in the test separators
• The four well pads online water cut analyzers are working well with the existing SAGD wells
• New Coriolis meters installed in the four test separators are working well
• Two new ultrasonic steam meters have been commissioned and are providing very repeatable readings on the high pressure steam flows
• The new procedure to measure flare gas is working well
• Phase 2 HP Steam Separator is installed and the balance of BFW and blow down improved significantly
• 2012 EPAP was completed in December 2012 and submitted
• Source well gas testing conducted December 2012
Issues

• Water group source meter occasionally have higher than expected variability and well tests didn’t indicate excessive dissolved gas
• Deposits from steam injection and condensate carry over are creating build-up on the injection well steam vortex meters
• Use of a clamp-on ultrasonic gas meter allows us to start baseline comparison of existing gas meters

Implications

• Continuing to investigate source well gas production and pump performance
• Errors with steam allocation from well pad steam injection meters
• The gas clamp-on meter will allow us to compare performance of the in-line meters w/o a shutdown or bypass
Future Actions

• The ORF discharge to produced water tank meter will allow us to accurately calculate the make-up water. This project is in design.
• Evaluating replacing the wellhead vortex steam meters
• Planning to perform visual inspection of all the well steam meters
Well Testing and Measurement

- Existing design has 6 to 13 producing wells through a single test separator.
- Bitumen proration factors ranged from 0.86 – 1.05

- Conditioning orifice meters currently installed on A & B pads showing encouraging results as an alternate measurement approach and has improved efficiency of reservoir management.
Future Activities

• Ongoing plant de-bottleneck projects
• HLS sludge dewatering solution (centrifuges)
• Implementing and evaluating projects to further improve the water recycle rate
• Phase 2B ramp-up
• Phase 2B secondary steam measurement
Water Management
Water Management

- Water Source
- Water Disposal
- Water Use & Volumes
- Water Recycle
- Water Use Optimization
CLRP Source Water Well Locations

7-16-77-5W4 CLWA Source Pad
1F1/08-16-077-05W4/00 (CLWA Source Well; Active)
1F1/03-16-077-05W4/00 (CLWA Source Well; Active)

1-14-77-5W4 CLWA Source Pad
1F1/02-14-077-05W4/00 (CLWA Source Well; Future)
1F1/01-14-077-05W4/00 (CLWA Source Well; Future)
1F1/08-14-077-05W4/00 (CLWA Source Well; Future)

8-4-77-5W4 CLWA Source Pad
1F1/05-03-077-05W4/00 (CLWA Source Well; Active)
1F1/12-03-077-05W4/00 (CLWA Source Well; Active)
1F2/05-03-077-05W4/00 (CLWA Source Well; Future)

8-30-76-4W4 CLWA Source Pad
1F1/01-30-076-04W4/00 (CLWA Source Well; Future)
1F1/09-30-076-04W4/00 (CLWA Source Well; Future)

4-29-77-4W4 CLWA/McM Source Pad
1F1/03-29-077-04W4/00 (McM Saline Source Well; Active)
1F1/14-20-077-04W4/00 (CLWA Source Well; Future)
1F1/06-29-077-04W4/00 (CLWA Source Well; Future)
• Under licensed volume limits
• Average daily withdrawals range from 0 – 4700 m³/day
CLRP Clearwater Production and Pressure Monitoring

- Clearwater A water production and pressure (water levels) monitored in accordance with Water Act licenses
- Clearwater A water sand is responding to pumping as expected
- No exceedances of licensed allocations or drawdown limitations
CLRP McMurray Disposal Wells

Disposal pipelines

100/09-29-077-05W4M (Active)
102/10-29-077-05W4M (Active)
103/10-29-077-05W4M (Active) (blowdown)

100/07-16-077-05W4M (regeneration)

ERCB Approval No. 10659
Maximum WHIP 4,230 kPag
Disposal Well: 102/10-29-77-05W4

344,863 m$^3$ in 2012/2013 reporting year
Disposal Well: 100/09-29-77-05W4

25,271 m³ in 2012/2013 reporting year
Disposal Well: 103/10-29-77-05W4

2.5 m³ in 2012/2013 reporting year
Disposal Well: 100/07-16-77-05W4

1,180 m³ in 2012/2013 reporting year

*well on vacuum during disposal
Basal McMurray Water Sand Pressure Monitoring

![Graph showing water sand pressure monitoring over time]

- **OB1 100/06-16-077-05W4/0 at 398.3 mKB**
- **OB1 100/08-16-077-05W4/0 at 414.0 mKB**
- **OB9 100/10-16-077-05W4/0 at 411.5 mKB**
Monthly Water Rates

![Graph showing monthly water rates with a peak in October followed by a sharp drop in September, labeled as Plant turnaround.](image)
• On December 5, 2012, MEG requested that the new directive requirements take effect immediately to the Christina Lake Regional Project
• YTD disposal has averaged 19.8% below D81 disposal limit
• Produced water recycle rate YTD is 91.5%
Produced Water to Steam Injected Ratio

- 2012 WSR = 93%
- YTD WSR = 95%
Water Use Optimization

• MEG continues to optimize blowdown recycle (exceeding design and adjusting to operational limitations) >60%

• Modification made to the pilot CPF in 2013 to reduce disposal
  – Installation of line to transfer pilot process pond water to Phase 2 process ponds

• Conducted testing of saline water (McMurray) in Q3, 2012. Saline water use planned for Phase 2B operation within next reporting year

• Ongoing trial of incremental steam generators (2 x 50 MMBTU/h) utilizing blowdown make-up stream

• MEG expects challenges with disposal (D81) limits in 2013, related to Phase 2B facility commissioning and start-up

• MEG planning installation of a blowdown evaporator planned for 2015 to further improve water recycle capabilities
Compliance and Environment
Compliance & Environment

- Flaring/Gas Conservation
- Sulphur Production and Emissions
- Greenhouse Gas Management
- Compliance
• Overall gas conservation >99%

• April 2013 replacement of Phase 1 HP Flare expected to further reduce flaring events
Sulphur Production and Emissions

- MEG is conducting active monitoring of produced gas H₂S concentrations on a weekly basis

- EPEA SO₂ emissions limit for CLRP is 2.0 t/d, daily SO₂ emissions have averaged 0.370 t/d (April 1, 2012 to April 30, 2013)

- Peak SO₂ emissions to date is 0.746 t/d (occurred during a Jan 2013 plant trip and HP flare event)

- No significant changes in sulphur production have been observed over past year of production

- Sulphur capture currently planned for Phase 2B, using a liquid scavenger process
SO$_2$ Emissions

- SO$_2$ production remains stable and well below limits
• MEG CLRP continues to produce one of the lowest net GHG intensity barrels in the *in situ* industry

• Q1 2013 performance of ~0.045T/bbl CO$_2$e vs an industry average of 0.071T/bbl CO$_2$e

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

Inspections

- 9 ERCB inspections were conducted from April 2012 to April 2013, all of which were satisfactory
  - 3 pipeline inspections
  - 2 well inspections
  - 4 facility inspections
Self-Disclosures

MEG reported 8 self-disclosures to the ERCB during the reporting period:

• **July 19, 2012: Corehole Conversions- Late Submission**
  – Non-conformance related to late notification of corehole conversions to observation wells.

• **August 3, 2012: Water Measurement Potential Non-Compliance**
  – Potential non-conformance with water measurement requirements as outlined in ERCB Directive 017. MEG investigated of water balance, water meter accuracy and consistency in volumetric reporting to the Petroleum Registry. A follow-up report was submitted in December 2012.

• **October 25, 2012: Well Test Frequency Non-Compliance**
  – Non-compliance on well testing requirements during a turnaround period as prescribed in Directive 17. Testing was compliant following the turnaround.

• **November 13, 2012: Secondary Containment Capacity Deficiency**
  – Potential inadequate secondary containment for various tanks at the Christina Lake Regional Project. An engineering solution has been proposed and follow up with the ERCB is ongoing.
Self-Disclosures (continued)

- **February 15, 2013: LP Flare Reliability**
  - MEG submitted a Corrective Action Plan to address ongoing Phase 1 Low Pressure Flare outages. The plan includes installation of a permanent pilot and wind shielding. The work outlined in the plan was completed in April 2013.

- **March 15, 2013: Well Re-Entry Without Submission of Well Licence Re-Entry/Resumption Application**
  - Non-compliance on work during March, 2013, where MEG re-entered three abandoned wells in preparation of non-routine abandonment and for the purpose of assessment of the well bores. MEG failed to submit the well license re-entry prior to entering the abandoned well bores as per Directive 56 and his since completed proper license requests.

- **April 18, 2013: Steam Injection Rate Reduction**
  - Non-compliance on reduction in the steam injection rate to one injector well that exceeded the 30% threshold stated in scheme approval 10773. The injection rate was reduced due to limited capacity of a common steam line. Future occurrences of the non-compliance are not anticipated as the common line now has adequate capacity.
Compliance Reporting

Flaring & Venting

• MEG reported 22 flaring/venting notifications to the ERCB including exceedances and outages.
• 6 were planned and 16 were unplanned
• Installation of new equipment of Phase 1 HP flare is expected to result in increased reliability moving forward

Incident Reporting

• March 14, 2013 – Pipeline Coating Damage & Repair
  – Damaged coating on abandoned gas lines consistent with initial installation or backfill. No release of gas or fluids associated with the incident. Issue rectified with sleeve repair.
Spills

- 12 spills occurred at MEG from April 2011 to April 2012 that met the ERCB reporting requirements. All reports were filed with ERCB and remediation has or is being completed. 2012/13 spill intensity ranks well below CAPP industry average.
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.
CLRP
Future Plans
Regulatory Amendments

Amendments approved April 2012 - April 2013

• Phase 2 infill wells
• Gas cap re-pressuring within Phase 2 (Active Development Area)
• AF, AG, AH, AP, AQ & AN pads
• NCG co-injection pilot at Pads B, C & D
• Facilities changes at Phase 2B and Phase 3 plants (includes addition of blowdown evaporators, reduction in total # of OTSG’s, installation of co-generation facilities)

• Additional McMurray disposal well at 100/11-29-77-5W4/00
LRP ADA Future Development

- MEG OSL
- Approved Development Area
- Drilled, producing patterns
- Drilled, non-producing patterns
- Approved SAGD Patterns

T77

R6

R5W4
CLRP Phase 3A Future Development

- CLRP Project Area
- Approved Development Area
- Proposed patterns

Diagram showing the project area with different sections labeled T77, T76, R5, R4W4.
Phase 2B first steam scheduled for Q3/Q4 2013
- Ongoing de-bottlenecking of Phase 2 facilities
- Ongoing construction of Phase 3A facilities
- Ongoing pattern additions within Phase 2 and 3 areas
- Finalization and submission of thermal compatibility program
- Continued development of eMSAGP within Active Development Area
- Ongoing resource assessment
Questions & Comments