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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, 2016, 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 contained within the Corporation’s public disclosure documents on file with Canadian Securities regulatory authorities, and in particular, within MEG’s most recently filed annual information form (the “AIF”). MEG’s public disclosure documents, including the AIF, may be accessed through the SEDAR website (www.sedar.com), at MEG’s website (www.megenergy.com), or by contacting MEG’s investor relations department.

Anticipated netbacks are calculated by adding anticipated revenues and other income and subtracting anticipated royalties, operating costs, transportation costs and realized commodity risk management gains/(losses) from such amount.
Forward-Looking Information

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

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MEG Energy Corp.

Meeting Agenda

• Overview  
  - Sachin Bhardwaj

• Operations  
  - Bill Mazurek

• Water  
  - Scott Rayner

• Compliance & Environment  
  - Mike Robbins

• Geosciences  
  - Greg Helman

• Reservoir  
  - Kejia Xi

• Future Plans  
  - Sachin Bhardwaj
Christina Lake Regional Project

2016-2017 Operating Highlights

• 2016 bitumen production averaged 81,245 bpd

• Q1 2017 Bitumen Production of 77,309 bpd

• Q1 2017 Average Field-wide SOR of 2.36

• Expanded implementation of eMSAGP
### Active Development Area (ADA)

#### Drilled* SAGD Wells

<table>
<thead>
<tr>
<th>Pattern</th>
<th>SAGD Pairs</th>
<th>Infill Wells</th>
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<tbody>
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*As of April 30 2017

- **Pattern AP**: R6
- **Pattern AN**: R6
- **Pattern AQ**: R6
- **Pattern AQ South**: R6
- **Pattern T**: T77
- **Pattern V**: T77
- **Pattern H**: T77
- **Pattern P**: T77
- **Pattern G**: T77
- **Pattern M**: T77
- **Pattern N**: T77
- **Water Disposal**: T77
- **Water Source Pipeline**: T77

* As of April 30 2017
Operations
Additions/Modifications

• Second contactor train has been added to Sulphur Removal Unit to increase the gas handling hydraulic capacity
• Not expecting significant changes in sulphur rate into the plant
Facility Performance: Bitumen Treatment

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

Successes

• Produced water exchanger fouling – implemented alternate chemical treating formulation which has significantly reduced fouling in the produced water exchangers in all phases.
• Continue skimming and fluid management strategy to reduce trucking.

Issues Being Addressed

• Solids removal from Phase 2 oil treating vessels.
• Skim fluid management in Phase 2B.
Future Actions

• Continue optimization of chemical treatment program.
• Continue plant testing to establish ultimate capacity.
• Continued optimization of slop oil treating and reduction initiatives.
Facility Performance: Water Treatment

Successes
- Continue recycling high blowdown volumes.
- Use of Intermediate Casing Point (ICP) apparatus to track boiler ion transport and optimize boiler internal treatment chemical usage.

Issues Being Addressed
- Continue to monitor reliability of saline water system.
- Cleaning of blowdown pond and pond liner monitoring.
Future Actions

• Optimization of water treating chemical usage.
Facility Performance: Steam Generation

Actual Steam Rate/Plant Design Steam Rate

Phase 2B planned outage and SRU fire.

Steam P/L repair.
Facility Performance: Steam Generation

Successes
• Stable operation throughout the year
• Successfully completed tube repairs on Phase 2B HRSG

Issues Being Addressed
• Enhancing steam pipeline condensate removal facilities
• Steam pipeline repair
Future Actions

- Continue to implement overall HP steam distribution control philosophy.
- Continue monitoring of steam generator tube corrosion.
- Increasing focus on steam generator tracking to enhance reliability and efficiency.
*2016 had lowest water use intensity in CLRP operations history (0.23 for both source and disposal)
Water Recycle and D81 Limits

D81 Compliant in 2016

*2016 disposal limit/actual percentages are for the calendar year
**2017 disposal limit/actual percentages are YTD to April 30
Water Management - Summary

• 2016 had lowest water use intensity in CLRP operations history
• Saline water use (McMurray) ongoing since November 2013. MEG plans to continue to utilize saline water for make-up.
• Non-saline Clearwater A and Ethel Lake groundwater production and pressure monitored in accordance with *Water Act* licenses
• Ethel Lake, Clearwater and McMurray aquifers are responding to pumping as expected
• MEG continues to optimize blowdown recycle, adjusting to operational limitations
• Technology advancement to reduce SOR and increase overall water use efficiency
• Blowdown evaporator planned to further improve water recycle capabilities
Reporting Year Highlights

• In January 2017, MEG received a 10 year renewal of its EPEA approval
• Our Monitoring Approach
• Sulphur Production and Removal
• Greenhouse Gas Management
• Compliance Summary
• Reclamation
Sulphur Removal

SRU Incident

Quarterly Average Inlet Sulphur
Quarterly Average Recovery
SO$_2$ Emissions

SO$_2$ Emissions (t/d)

April-16 to May-17

SRU Incident Resolved

SRU Maintenance

New SRU Tie-in

EPEA Approval Limit
SO$_2$ Emissions
90-Day Rolling Average SO$_2$
• MEG CLRP continues to produce one of the lowest net GHG intensity barrels in the industry.

• GHG performance is attributed to reservoir performance (low SOR’s), use of co-generation technology for steam generation, and ongoing reservoir efficiency technologies (ie. eMSAGP).
Self-Disclosures & Non-Compliances

- February 18, 2016: Voluntary Self Disclosure - Phase 2 utility water tank containment
  - Utility water composition changed from original design. AER approved alternate storage approach without secondary containment.

- January 10, 2017: Cement Pit Low Risk Non-Compliance (FIS# 459985)
  - MEG was assessed a low risk noncompliance for “Failure to provide information to the AER when requested or required - Low Risk“.
  - The cement pit was closed, and brought into compliance. AER was notified of the pit closure on May 30th, 2017.
MEG reported 5 EPEA approval contraventions to the AER during the reporting period:

- **April 30, 2016**: Passive Sample Station Damage Contravention
  - Passive sampler was replaced May 8th, 2017.

- **June 15, 2016**: Phase 2B OTSG NOx Hourly Limit Exceedance
  - Firing mode were returned to ensure NOx mass emissions rate were below approval limits.

- **October 9, 2016**: - Phase 2B OTSG-A CEMS Unit Availability Contravention
  - Unit was repaired and met availability requirements (90% uptime).

- **November 29, 2016**: P2B OTSG CEMS Downtime.
  - Unit was repaired and met availability requirements (90% uptime).

- **January 2017**: Passive Sample Station – Missing Passive H2S Sampler
  - Missing sampler was replaced.

- **January 18, 2017**: S8 Clearwater Well - Brackish Water Backflow
  - Checkvalve was repaired and well was flushed.
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.
Geosciences
Over the 2017 reporting period
• 23 coreholes were drilled.
• No special core analysis was done.
• No GeoMechanical analysis was done.
• No reservoir Fracture pressure or Caprock Integrity tests were done.
CLRP Active Development Area (ADA)

369 horizontal wells 
(SAGD & Infill wells)
CLRP: OBIP Approved Development Areas

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

T77
- min contour =10m
- contour interval = 5 m

Note: Figure represents MEG Energy volumetric estimates, not independent estimates from GLJ Petroleum Consultants.
## Well Spacing

<table>
<thead>
<tr>
<th>Pattern</th>
<th>Operating Wellpairs</th>
<th>Average Spacing Between SAGD Pairs (m)</th>
<th>Average Spacing Between SAGD Pair to Infill (m)</th>
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CLR Pattern Layout

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<td>AN</td>
<td>8</td>
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<tr>
<td>AP</td>
<td>13</td>
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</tbody>
</table>

Total: 143 57
CLRP Reservoir Performance

• First steam into Phase 1 (3 WPs) effectively started in March 2008
• First steam into Phase 2 wells started in August 2009
• First steam into Phase 2B wells started in Q3 2013
• Wells were started up in stages, dictated by steam availability
• The combined bitumen production from Phases 1 and 2 reached the original design capacity of 3,975 m³/d (25,000 bopd) by late April 2010.
• Phase 2B production ramp-up bettered Phase 2. Total production reached 11,340 m³/d (71,300 bopd) in Q2 2014, far exceeded the combined original design capacity of 9,539 m³/d (60,000 bpd).
• Production averaged 81,245 bopd in 2016. In Q1 2017, MEG achieved quarterly production of 77,309 bopd, a period which included some unplanned down time. April production averaged 78,245 bpd.
• The SOR of CLRP has ranged from 2.2 to 2.5 over the last 12 months and averaged 2.3 with new well start-ups.
• Current steam chamber pressure is between 2,160 and 2,350 kPag for Phases 1 and 2, between 2,300 and 3,450 kPag for Phase 2B. The steam chamber pressure is close to the initial pressure in the basal water zone where bottom water is present.
CLRP Production Performance

Scheduled Plant Turnaround

Rate (m$^3$/day)

- Steam
- Bitumen
- Water

Phase 1+2 Original Design Capacity

Phase 1+2+2B Original Design Capacity
CLRP Performance – SOR of All Patterns

- Phase 2 Start-up
- Phase 2B Start-up
CLRP Performance – Pattern A

- eMSAGP Pilot Start
- A7 and A8 on production
- eMSAGP in A4, A5 and A6 Start

Graph showing rates (m3/day, e4m3/month) with SOR on the y-axis and timeline from Jan-08 to Jan-18.
Low Performance Pad: Due primarily to injectors being drilled lower than planned making it difficult to control vapor production near heel. Well work-over to isolate the heel section of one injector resulted in better performance is expected following similar upcoming work-overs.
Medium Performance Pad: SAGD pay is under an associated gas cap and above bottom water. There has been no particular challenge in operating this pad to date.
High Performance Pad: High production associated with good reservoir quality and no impairments. There has been no particular challenge in operating this pad to date.
OBB1 Logging Results

Before NCG Co-injection
~3.5 years SAGD

After NCG Co-injection
~4.1 years eMSAGP

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

Sandy IHS
<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>Average Oil Saturation</th>
<th>SAGDable BIP (m³)</th>
<th>Ultimate Recovery (m³)</th>
<th>Cumulative Production (m³)</th>
<th>Recovery to Date (%SAGDable)</th>
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<td>14</td>
<td>759</td>
<td>0.33</td>
<td>0.71</td>
<td>1,025,000</td>
<td>563,750</td>
<td>215,974</td>
<td>21.1%</td>
</tr>
<tr>
<td>H*</td>
<td>3</td>
<td>12</td>
<td>692</td>
<td>0.32</td>
<td>0.74</td>
<td>598,000</td>
<td>328,900</td>
<td>92,362</td>
<td>15.4%</td>
</tr>
<tr>
<td>J</td>
<td>8</td>
<td>18</td>
<td>986</td>
<td>0.33</td>
<td>0.76</td>
<td>3,592,000</td>
<td>1,975,600</td>
<td>571,574</td>
<td>15.9%</td>
</tr>
<tr>
<td>K</td>
<td>7</td>
<td>18</td>
<td>955</td>
<td>0.33</td>
<td>0.75</td>
<td>2,966,000</td>
<td>1,647,800</td>
<td>617,918</td>
<td>20.6%</td>
</tr>
<tr>
<td>M</td>
<td>10</td>
<td>27</td>
<td>998</td>
<td>0.32</td>
<td>0.75</td>
<td>6,469,000</td>
<td>3,557,950</td>
<td>1,674,717</td>
<td>25.9%</td>
</tr>
<tr>
<td>N</td>
<td>9</td>
<td>23</td>
<td>1054</td>
<td>0.33</td>
<td>0.81</td>
<td>5,887,000</td>
<td>3,237,850</td>
<td>1,200,709</td>
<td>20.4%</td>
</tr>
<tr>
<td>T*</td>
<td>8</td>
<td>13</td>
<td>980</td>
<td>0.31</td>
<td>0.81</td>
<td>2,570,000</td>
<td>1,413,500</td>
<td>462,955</td>
<td>18.0%</td>
</tr>
<tr>
<td>U</td>
<td>6</td>
<td>16</td>
<td>882</td>
<td>0.3</td>
<td>0.8</td>
<td>2,033,000</td>
<td>1,118,150</td>
<td>437,826</td>
<td>21.5%</td>
</tr>
<tr>
<td>AP West*</td>
<td>10</td>
<td>27</td>
<td>918</td>
<td>0.33</td>
<td>0.83</td>
<td>6,813,000</td>
<td>3,747,150</td>
<td>1,962,269</td>
<td>28.8%</td>
</tr>
<tr>
<td>AP South**</td>
<td>3</td>
<td>21</td>
<td>727</td>
<td>0.33</td>
<td>0.79</td>
<td>1,356,000</td>
<td>745,800</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>AF</td>
<td>5</td>
<td>18</td>
<td>972</td>
<td>0.32</td>
<td>0.82</td>
<td>2,278,000</td>
<td>1,252,900</td>
<td>467,782</td>
<td>20.5%</td>
</tr>
<tr>
<td>AG*</td>
<td>5</td>
<td>20</td>
<td>836</td>
<td>0.33</td>
<td>0.77</td>
<td>2,095,000</td>
<td>1,152,250</td>
<td>249,785</td>
<td>11.9%</td>
</tr>
<tr>
<td>AN</td>
<td>8</td>
<td>23</td>
<td>870</td>
<td>0.32</td>
<td>0.83</td>
<td>4,187,000</td>
<td>2,302,850</td>
<td>1,054,568</td>
<td>25.2%</td>
</tr>
<tr>
<td>P**</td>
<td>10</td>
<td>20</td>
<td>957</td>
<td>0.32</td>
<td>0.76</td>
<td>4,655,000</td>
<td>2,560,250</td>
<td>430,395</td>
<td>9.2%</td>
</tr>
<tr>
<td>Total</td>
<td>143</td>
<td></td>
<td>67,862,000</td>
<td></td>
<td></td>
<td>37,324,100</td>
<td>21,763,464</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Cumulative production to April, 2017
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 2017
** New 2017

Note: Resource estimates in this table are based on MEG Energy volumetric calculations, and are not in accordance with National Instrument 51-101 guidelines. They are provided solely for the purpose of complying with Alberta regulatory requirements.
Enhanced Modified Steam and Gas Push
Phase 1 and Phase 2 Pad Layout

- Pad B (B1-B6): Feb. 2013  30% R.F.
- Pad C (C1-C6, D6): July 2013  46% R.F.
- Pad D (D1-D5): Aug. 2013  33% R.F.
- Pad E (E1-E6, F1): Jan. 2014  31% R.F.
- Pad F (F2-F6): Jan. 2014  36% R.F.
- Rest of Pad A (A4-A6):  April 2014  30% R.F.
- Wells (A7, A8, B7, B8, D7): July 2016 46% R.F.
- Pad V (V1-V6): July 2016 24% R.F.
Bitumen Rates for Phases 1 and 2

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

Recovery to date:
- 67% SOIP
- 69% SOIP
Steam Rates for Phases 1 and 2

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

eMSAGP Start
SOR for Phases 1 and 2

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

eMSAGP Start
In 5.5 years of eMSAGP (9+ years total), the pilot demonstrated consistent and very satisfactory performance. Higher bitumen production and recovery were achieved at a much lower SOR, averaging 0.60 over the period. Recovery to April 2017 was 69% of the revised SAGDable OOIP.

From the initiation of B Pattern eMSAGP in Feb 2013, Phase 2 eMSAGP showed repeatable performance. ISOR over the reporting period was 1.09. Bitumen recovery reached 67% of the revised SAGDable OOIP.

After several years of operation, eMSAGP has demonstrated better performance than SAGD: better recoveries with significant SOR reductions.

Steam freed up from eMSAGP process has been redeployed to new SAGD wells to increase overall production beyond original nameplate capacity without installing additional steam capacity.

Opportunities exist to optimize the timing of eMSAGP implementation and the rate of steam reduction.
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 265 e6m3 (~9.4 BCF), with an average injection rate of 70 e3m3/day (~2.5 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 & P) was about 2,000 kPag, about the same level as the initial gas cap pressure
- Performance to date indicates faster pressure increase over the active SAGD area which allows for a lower gas injection rate and volume to maintain gas cap pressure
- Plan is to maintain the current pressure on top of the active SAGD area and monitor pressures in gas and SAGD zones closely
- Thief zone effect of the gas cap has not been observed to date
CLRP Gas Cap Re-pressure (Patterns M, N & P)

Observation Wells
R5W4

102/13-03
103/05-03
100/08-03

102/06-03

T76

T77

† Gas injection wells
△ Gas injection wells (future)
--- Gas pipeline
---- Gas pipeline (future)

Mcmurray Channel Gas Pool in direct and indirect contact with SAGD interval
○ Observation Wells

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

- **Rate** (e3m³/cd)
- **Cumulative Gas** (e6m³)

Graph showing the rate and cumulative gas injection from July 2013 to July 2017.

- The rate graph fluctuates significantly from 2013 to 2015, peaking over 500 e3m³/cd.
- Cumulative gas injection shows a steady increase, reaching just below 250 e6m³ by July 2017.
Observation Well Pressure Readings

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

- Pilot project to proceed with the injection of unresolved emulsion into an active steam chamber limited to well pair V6
  - Plan would result in significant annual cost savings
  - Reduced truck traffic and emissions
  - Utilizing an existing wellpad (no additional surface disturbances)

- Unresolved emulsion is a mixture of produced water, oil & fine clay particles which cannot be treated with the processing trains currently in use at the CLRP
  - In 2015, 774 round trips were made to ship the unresolved emulsion to approved third party processing facilities (>850 km round trip per load)
  - The fluid is loaded into a vacuum truck at the CPF from storage tanks and a surface loading station located at the wellhead is used to pump fluid downhole

- V6I selected because of low oil production rate and poor reservoir quality, which limits the risk of any potential production impacts
  - Downhole temperatures into V6I are hot, which will aid in separating the unresolved emulsion
  - Located at the edge of the Pattern, limiting the potential impact to other producers

- Scheme Amendment Approved on September 26, 2016
• Date of first injection: December 15, 2016

• Average monthly volumes injected:
  - December 2016 = 52 m³ (includes 10 m³ hot water for flushing)
  - January 2017 = 187 m³ (includes 22 m³ hot water for flushing)
  - February 2017 = 0 m³
  - March 2017 = 0 m³
  - April 2017 = 44 m³ (includes 14 m³ hot water for flushing)

• Total volume injected to date = 283 m³ (includes 46 m³ hot water for flushing; 237 m³ unresolved emulsion)
  - Successfully pumped 237 m³ unresolved emulsion into V6I
  - April injection commingled with steam down short tubing string
  - Demonstrated improved bottom hole pressure response due to better viscosity (higher bottom hole temperatures)

• Routine Intermediate Casing Point (ICP) water analysis
  - Pre-job vs. 3 separate post job samples 3 hr, 6 hr, 48 hr
  - Showed no changes indicating no cross flow of fluids from V6I to V6P

• MEG plans to continue injecting unresolved emulsion into V6I as required
  - V6P and V6N continue to trend on previous decline curve projections
April 2016 - April 2017

- Various Directive 56 licenses and amendments for well pads and field facilities
- Sub-surface reconfiguration scheme amendments for patterns AQ, AT, L, and DB
- Expansion of NCG Co-Injection (eMSAGP) for patterns G, H, J, K, T, U, AF, AG, M, N, AP, AN, and P
- Unresolved emulsion injection project on well pair V6

April 2017 - April 2018

- Scheme amendment applications for sustaining patterns including AH, DC, and DD.
- New Pattern application for DG
- Scheme amendment application for gas cap repressurization
CLRP Future Development

CLRP Project Area
Approved SAGD Patterns
Patterns in progress (currently being drilled)
Planned Pattern Additions
Central Plant
2018 Core hole focus areas
Access pipeline
Environment and Regulatory

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