INTRODUCTION

SUBSURFACE

- Project Description & Status
- Geoscience
- 4-D Seismic & Monitoring
- Well Design & Instrumentation
  - Drilling & Completions
  - Artificial Lift
  - Instrumentation
  - Scheme Performance
- Pilots
- Future Plans

SURFACE OPERATIONS & COMPLIANCE

- Facilities
- Measurement & Reporting
- Water Production, Injection & Uses
- Sulphur Production
- Compliance
- Future Plans
SUBSURFACE GEOLOGY OVERVIEW
The Leismer Project currently includes a Central Processing Facility (CPF) and six well pads, with 35 well pairs and 9 producing infill wells.

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**LEISMER DEVELOPMENT AREA (LDA): WELL COUNT**

The Leismer Project currently includes a Central Processing Facility (CPF) and six well pads, with 35 well pairs and 9 producing infill wells.
• No new cores were obtained or analyzed in 2017 within the LDA

• No petrographic analyses were conducted in 2017

• No geomechanical analyses were conducted in 2017

• No reservoir fracture pressure and caprock integrity tests were conducted in 2017
GROSS BITUMEN IN PLACE (GBIP)

- Represents the total package that may be accessible via SAGD
- Petrophysical criteria:
  - Gamma Ray (GR) <= 75 API
  - Resistivity (RT) >= 40 ohm-m
  - Porosity (DPSS) >= 27%

DEVELOPABLE BITUMEN IN PLACE (DBIP)

- A more conservative definition used for planning well pair placement
- Same petrophysical criteria as GBIP
BOTH GBIP AND DBIP ARE RESTRICTED BY LITHOFACIES ENCOUNTERED IN CORE AND IMAGE LOGS:

- DBIP is restricted to higher quality lithofacies:
  - \( F1 \): Shale-Clast Breccia (if <5m)
  - \( F2 \): Trough Cross-Bedded Sand
  - \( F3 \): Current-Ripple Laminated Sand
  - \( F4A-B \): Sand with 5–10% Mud Interbeds

- GBIP includes DBIP lithofacies, and:
  - \( F4C-D \): Sand with 10–30% Mud Interbeds
  - \( F5A-B \): Sand with 30–70% Mud Interbeds

- Non-reservoir lithofacies (\( F6–F7 \)) are not included if they are greater than 2m in thickness
### LEISMER RESERVOIR PROPERTIES

<table>
<thead>
<tr>
<th>Well Pad</th>
<th>Area (10^3 m²)</th>
<th>Avg. DBIP Thickness (m)</th>
<th>Avg. GBIP Thickness (m)</th>
<th>Avg. Porosity (%)</th>
<th>Avg. Oil Saturation (%)</th>
<th>DBIP (10^3 m³)</th>
<th>GBIP (10^3 m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>L1</td>
<td>526</td>
<td>22.5</td>
<td>26.7</td>
<td>33</td>
<td>89</td>
<td>3,467</td>
<td>3,914</td>
</tr>
<tr>
<td>L2</td>
<td>498</td>
<td>19.2</td>
<td>24.5</td>
<td>32</td>
<td>86</td>
<td>2,821</td>
<td>3,344</td>
</tr>
<tr>
<td>L3</td>
<td>411</td>
<td>23.6</td>
<td>29.1</td>
<td>34</td>
<td>87</td>
<td>3,003</td>
<td>3,443</td>
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<tr>
<td>L4</td>
<td>389</td>
<td>19.6</td>
<td>22.4</td>
<td>33</td>
<td>87</td>
<td>2,236</td>
<td>2,433</td>
</tr>
<tr>
<td>L5</td>
<td>708</td>
<td>17.6</td>
<td>24</td>
<td>33</td>
<td>86</td>
<td>3,477</td>
<td>4,479</td>
</tr>
<tr>
<td>L6</td>
<td>571</td>
<td>25.3</td>
<td>28.9</td>
<td>33</td>
<td>87</td>
<td>3,471</td>
<td>3,836</td>
</tr>
<tr>
<td>Total/Avg.</td>
<td>3,103</td>
<td>21.3</td>
<td>25.9</td>
<td>33</td>
<td>87</td>
<td>18,475</td>
<td>21,449</td>
</tr>
<tr>
<td>LDA Total</td>
<td>24,166</td>
<td>15.5</td>
<td>17.3</td>
<td>32</td>
<td>85</td>
<td>116,054</td>
<td>144,403</td>
</tr>
</tbody>
</table>

* DBIP VALUES SHOWN

- Original Reservoir Pressure: 2,300 to 2,600 kPa
- Original Reservoir Temperature: 14°C
- Average Horizontal Permeability: 5 to 6 D
- Average Vertical Permeability: 4 to 5 D
- Depth: 410 to 444 m TVD (-230 to -216 m subsea)
- Variations in GBIP Volumes have occurred due to changes in the methodology in averaging porosity, oil saturation and drainage area boxes
GBIP THICKNESS MAP
DIRECT CONTACT TOP GAS THICKNESS MAP

Direct Contact = Gas in direct connection to the bitumen column
LDA PAD L4 EXAMPLE: 100/16-28-078-10W4/0

Well: 100/16-28-078-10W400

- Top Wabiskaw Member
- Top McMurray Formation
- A2 Mudstone
- Top GBIP
- Top DBIP
- Base GBIP Oil-Water Contact
- Top Devonian

Volumetrics:
- Yellow: Sand
- Green: Bitumen
- Gray: VSH Mud (Silt and Shale)
- Blue: Residual Water
- Cyan: Free Water
- Yellow: PHIT Mud (Silt and Shale)
WEST TO EAST PETROPHYSICAL LOG CROSS-SECTION: L1 TO L6 AREA
WEST TO EAST PETROPHYSICAL LOG CROSS-SECTION: L5 AREA
SAGD WELL PLACEMENT STRATEGY

- The vertical offset between the SAGD producer wells and bottom water is 3 m to 5 m
  - *The infill wells were placed at the same elevation as the SAGD producer wells*

- The vertical offset between the producer and injector well is 5 m
2017

No new mini-frac testing conducted in 2017

HISTORICAL MINI-FRAC TESTS (2010)

Caprock at Leismer is defined as the Clearwater Formation including regionally continuous shale of the Wabiskaw Member

- 6 tests at 01-04-079-10 W4
- 7 tests at 01-28-078-10 W4
MINI-FRAC RESULTS

2017

o No new caprock core, mini-frac or triaxial testing conducted in 2017
o Current SAGD operating pressure range 2,500 - 4,500 kPa

HISTORICAL

o Interpreted fracture closure pressure within the Wabiskaw Member at 386 m (TVD) of 7,350 – 7,520 kPa
o Approved Maximum Operating Pressure (MOP) is 5,500 kPa
o Results included in Leismer MOP Application (No. 1732216) submitted to ERCB July 2012
INSAR CUMULATIVE SURFACE HEAVE: L1 TO L4

2017

- No Interferometric Synthetic Aperture Radar (InSAR) data collected in 2017

HISTORICAL

- Satellite-based radar technique used for mapping surface changes
- InSAR deformation monitoring commenced in April of 2011
  - 89 corner reflectors (with supplemental natural points) installed for Pads L1 to L4 and primary steam pipelines
  - 5 corner reflectors (with supplemental natural points) installed for Pad L5
- Results on Pads L1–L4 to December 27th, 2014 show minimal surface heave (Maximum = 65 mm, Mean = 28.5 mm)
2017
- No new acquisition in 2017

HISTORICAL
- Q1 2016: 2.0 km² first 4D survey for Pad L5
- Q1 2015: 9.0 km² 3D survey
  - Third 4D repeat survey (2.2 km² of active SAGD Pads L1 and L2)
  - Repeat 3D seismic for higher resolution data
- Q1 2014: 2.1 km² 4D survey (active SAGD Pads L3 and L4)
- Q1 2013: 4.5 km² 3D survey
  - Second repeat survey (4.9 km² of active SAGD Pads L1–L4)
- Q1 2012: 8.6 km² 3D survey
  - First 4D survey (4.9 km² of active SAGD Pads L1–L4)
  - New baseline survey for Pads L5 and L6 (3.7 km²)
- Q1 2009: 4.9 km² baseline survey acquired (pre-steam) over Pads L1–L4
4D SEISMIC RESULTS

PADS L1–L4: ACQUIRED 2014 & 2015

- Pads L1–L4: No new 4D seismic data acquired
- 2014–2015 data shows high degree of conformance along SAGD well pairs

PAD L5: ACQUIRED 2016

- Pad L5: First 4D data acquired (2 years after start-up)
- 4D seismic anomalies indicate high degree of conformance along SAGD well pairs
- Irregularities are attributed to reservoir heterogeneity and well placement
4D SEISMIC RESULTS

- Western well pairs have increasing amounts of Breccia within the Injector-Producer Elevation
- This decreasing reservoir quality explains the lower conformance within the toes in L5P5–L5P7
HISTORICAL

- The Leismer Project includes a Central Processing Facility (CPF) and six well pads, with 35 well pairs and 9 producing infill producing wells.
## WELL PAIR SPACING

<table>
<thead>
<tr>
<th>Pad</th>
<th>Wells</th>
<th>Spacing (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>L1</td>
<td>P1–P1</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>P2–P3</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>P3–P4</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>P4–P5</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>P5–P6</td>
<td>100</td>
</tr>
<tr>
<td>L1L2</td>
<td>L2P6–L1P1</td>
<td>100</td>
</tr>
<tr>
<td>L2</td>
<td>P1–P2</td>
<td>100–110</td>
</tr>
<tr>
<td></td>
<td>P2–P3</td>
<td>100</td>
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<tr>
<td></td>
<td>P3–P4</td>
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<tr>
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<td>P5–P6</td>
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<td>L3</td>
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<td>75</td>
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<td>P3–P4</td>
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<td>P4–P5</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>P5–P6</td>
<td>100</td>
</tr>
<tr>
<td>L4</td>
<td>L3P6–L4P1</td>
<td>85–95</td>
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<tr>
<td></td>
<td>P1–P2</td>
<td>110</td>
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<tr>
<td></td>
<td>P2–P3</td>
<td>100</td>
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<tr>
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<td>P3–P4</td>
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<td></td>
<td>P4–P5</td>
<td>85</td>
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<tr>
<td>L5</td>
<td>P1–P2</td>
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<tr>
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<td>P2–P3</td>
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<td>P4–P5</td>
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<tr>
<td></td>
<td>P5–P6</td>
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<tr>
<td>L6</td>
<td>P2–P3</td>
<td>100</td>
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<tr>
<td></td>
<td>P3–P4</td>
<td>100</td>
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<tr>
<td></td>
<td>P4–P5</td>
<td>100</td>
</tr>
<tr>
<td></td>
<td>P5–P6</td>
<td>100</td>
</tr>
</tbody>
</table>
## COMPLETIONS OVERVIEW: TUBING & LINER CONFIGURATION

<table>
<thead>
<tr>
<th>Pad</th>
<th>Year Drilled</th>
<th>Number of Wells</th>
<th>Injector Sand Control</th>
<th>Injector Tubing</th>
<th>Producer Sand Control</th>
<th>Flow Control Devices (FCD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>L1</td>
<td>2009</td>
<td>6 well pairs</td>
<td>8-5/8” slotted</td>
<td>Parallel</td>
<td>7” or 8-5/8” slotted or wire-wrap screen</td>
<td>None</td>
</tr>
<tr>
<td>L2</td>
<td>2009</td>
<td>6 well pairs</td>
<td>8-5/8” slotted</td>
<td>Parallel</td>
<td>7” or 8-5/8” slotted or wire-wrap screen</td>
<td>None</td>
</tr>
<tr>
<td>L3</td>
<td>2009</td>
<td>6 well pairs</td>
<td>8-5/8” slotted</td>
<td>Parallel</td>
<td>7” slotted</td>
<td>2 producers (on tubing)</td>
</tr>
<tr>
<td>L4</td>
<td>2009</td>
<td>5 well pairs</td>
<td>8-5/8” slotted</td>
<td>Parallel</td>
<td>7” or 8-5/8” slotted or wire-wrap screen</td>
<td>1 injector (on tubing)</td>
</tr>
<tr>
<td>L5</td>
<td>2013</td>
<td>7 well pairs</td>
<td>7” slotted</td>
<td>Concentric</td>
<td>6-5/8” or 7” wire-wrap screen</td>
<td>2 injectors (on liner) 4 producers (on liner)</td>
</tr>
<tr>
<td>L6</td>
<td>2014</td>
<td>5 well pairs</td>
<td>7” slotted</td>
<td>Concentric</td>
<td>6-5/8” or 7” wire-wrap screen</td>
<td>3 injectors (on tubing) 3 producers (on liner)</td>
</tr>
<tr>
<td>L2</td>
<td>2014</td>
<td>2 infills</td>
<td>n/a</td>
<td>n/a</td>
<td>7” wire-wrap screen</td>
<td>None</td>
</tr>
<tr>
<td>L1,L2</td>
<td>2015</td>
<td>7 infills</td>
<td>n/a</td>
<td>n/a</td>
<td>7” wire-wrap screen</td>
<td>1 producer (on tubing)</td>
</tr>
<tr>
<td>L5</td>
<td>2016</td>
<td>4 infills</td>
<td>n/a</td>
<td>n/a</td>
<td>7” wire-wrap screen</td>
<td>None</td>
</tr>
</tbody>
</table>

Indicates change in 2017
Producer wells are initially completed with parallel tubing for the circulation phase.

Producer wells are recompleted to Electric Submersible Pump (ESP) after circulation.

Injector wells are not recompleted after circulation and remain in their initial parallel or concentric tubing configuration.
- Injectors completed with parallel tubing
- Instrumentation carried inside 1.75” coiled tubing
TYPICAL WELL COMPLETION DURING PRODUCTION PHASE: PADS L5–L6

- Injectors completed with concentric tubing
- Instrumentation carried inside 1.5” coiled tubing. Coil runs inside 2-3/8” guide string.
- 5 of 7 injectors on Pad L5 completed with Vacuum Insulated Tubing (VIT) on long tubing
TYPICAL WELL COMPLETION DURING START-UP PHASE: INFILL WELL

- Sliding sleeves were open for circulation and closed during production phase
- Allowed for circulation past the ESP during warm-up phase
- Instrumentation carried inside 1/4” capillary. Capillary tube run inside 2-3/8” X 3-1/2” guide string
- Single point pressure and temperature gauge at the toe
- Other infill designs are similar but without the sliding sleeve option and completed with either ESP or Progressive Cavity Pump (PCP)
FLOW CONTROL DEVICES (FCD)

2017

- Installed 3 retro-fitted tubing deployed FCDs on production wells

HISTORICAL

- Liner-deployed FCDs installed on 7 producer wells and 2 injector wells
  - *Installed prior to first steam*
- Tubing-deployed FCDs installed on 3 injector wells
  - *Pad 6 start-up was accelerated by exploiting producer FCDs*
  - *FCDs on injector wells have resulted in more uniform subcool conformance in the corresponding producer well*
- Tubing-deployed FCD installed on 1 producer well
ARTIFICIAL LIFT

ELECTRICAL SUBMERSIBLE PUMP (ESP)

- 42 ESPs running
  - 27 month mean time to failure (MTTF) since field start-up
  - 21 month average run life (2 year window)
- ESP sizes allow for rates 200–1,200 m³/d
- Intake conditions:
  - 180–235°C
  - 2,500–3,300 kPag

PROGRESSING CAVITY PUMP (PCP)

- 1 PCP running
  - Planning conversion to ESP
  - Longest running PCP >580 days
- PCP sizes allow for rates 90–400 m³/d
- Intake conditions:
  - 180–235°C
  - 2,500–3,300 kPag
<table>
<thead>
<tr>
<th>Pad</th>
<th>Number of Wells</th>
<th>Wellbore Instrumentation</th>
<th>Additional Instrumentation</th>
</tr>
</thead>
<tbody>
<tr>
<td>L1</td>
<td>6 well pairs</td>
<td>10 thermocouples in horizontal 3 bubble tubes (pump, heel, toe) Blanket gas in injector well</td>
<td>L1P3, L1P4, L1P5: distributed temperature sensing (DTS) fibre L1I3: 5 thermocouples + 2 piezos + bubble tubes</td>
</tr>
<tr>
<td>L2</td>
<td>6 well pairs</td>
<td>10 thermocouples in horizontal 3 bubble tubes (pump, heel, toe) Blanket gas in injector well</td>
<td>L2P2: DTS fibre L2I3: 6 thermocouples + bubble tubes</td>
</tr>
<tr>
<td>L3</td>
<td>6 well pairs</td>
<td>10 thermocouples in horizontal 3 bubble tubes (pump, heel, toe) Blanket gas in injector well</td>
<td>L3P1, L3P2, L3P3: 40 point fibre L3I3: 6 thermocouples + bubble tubes L3P3: fibre pressure gauge L3P4, L3P6: 40 point fiber &amp; toe pressure</td>
</tr>
<tr>
<td>L4</td>
<td>5 well pairs</td>
<td>10 thermocouples in horizontal 3 bubble tubes (pump, heel, toe) Blanket gas in injector well</td>
<td>L4P4: 2 thermocouples</td>
</tr>
<tr>
<td>L5</td>
<td>7 well pairs</td>
<td>10 thermocouples in horizontal 2 bubble tubes (heel, toe) Blanket gas in injector well</td>
<td>L5P7, L5I1: fibre pressure gauge (heel) L5I5, L5P5, L5I7, L5P7: 3 thermocouples on sfc. csg. L5P5: 40 point fiber &amp; toe pressure</td>
</tr>
<tr>
<td>L6</td>
<td>5 well pairs</td>
<td>10 thermocouples in horizontal 2 bubble tubes (heel, toe) Blanket gas in injector well</td>
<td>L6I2, L6I4, L6I6: DTS fibre</td>
</tr>
<tr>
<td>L2</td>
<td>2 infills</td>
<td>40 point fibre 2 fibre pressure gauges (heel, toe)</td>
<td>None</td>
</tr>
<tr>
<td>L1</td>
<td>7 infills</td>
<td>40 point fibre 1 fibre pressure gauge (toe)</td>
<td>L1N1: fibre pressure gauge heel</td>
</tr>
</tbody>
</table>

Indicates change in 2017
INSTRUMENTATION: OBSERVATION (OBS)

WELLS

- 30 thermocouples, spaced at 1 m above, below, and within SAGD pay
- 10 thermocouple bundles installed in wells previously equipped with fibre optics (DTS) in February 2018
- 3 to 4 piezometers in bitumen, bottom water, and top lean/gas zone
- 90% thermocouples and 70% piezometers are in working condition, and reading temperature and pressure properly
LEISMER PRODUCTION PERFORMANCE

- 2017 Average production 3,301 m³/d (20,763 bbl/d)
  - *Highest oil and steam annual average production in Leismer history*
- Production increase in 2017 supported by implementation of 3 flow control device installations and 3 infill well liner plug backs
 Injector blanket gas pressure from all SAGD Injectors

- Approved maximum operating pressure (MOP) is 5,500 kPag
- All injectors are operating around 3,200 kPag
### PAD RECOVERIES

<table>
<thead>
<tr>
<th>Well Pad</th>
<th>DBIP (10³ m³)</th>
<th>GBIP (10³ m³)</th>
<th>Cumulative Production (10³ m³)</th>
<th>DBIP Recovery to Date</th>
<th>GBIP Recovery to date</th>
<th>Predicted Recovery after 15 years (DBIP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>L1</td>
<td>3,467</td>
<td>3,914</td>
<td>1,862</td>
<td>54%</td>
<td>48%</td>
<td>65–75%</td>
</tr>
<tr>
<td>L2</td>
<td>2,821</td>
<td>3,344</td>
<td>1,465</td>
<td>52%</td>
<td>44%</td>
<td>65–75%</td>
</tr>
<tr>
<td>L3</td>
<td>3,003</td>
<td>3,443</td>
<td>1,514</td>
<td>51%</td>
<td>44%</td>
<td>50–60%</td>
</tr>
<tr>
<td>L4</td>
<td>2,236</td>
<td>2,433</td>
<td>1,033</td>
<td>46%</td>
<td>42.5%</td>
<td>50–60%</td>
</tr>
<tr>
<td>L5</td>
<td>3,477</td>
<td>4,479</td>
<td>761</td>
<td>22%</td>
<td>17%</td>
<td>50–60%</td>
</tr>
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<td>L6</td>
<td>3,471</td>
<td>3,836</td>
<td>439</td>
<td>13%</td>
<td>11.5%</td>
<td>65–75%</td>
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<tr>
<td>Total</td>
<td>18,475</td>
<td>21,449</td>
<td>7,075</td>
<td>38%</td>
<td>33%</td>
<td>~65%</td>
</tr>
</tbody>
</table>

- DBIP, Cumulative Production, and Recovery Factor valid as of February 28th, 2018
- Predicted Recovery Factor is based on 2D volumetric and simulations
2017 PAD PERFORMANCE: PERFORMANCE SELECTION

- 2017 Peak oil rate 366 – 816 m³/d (2,300–5,130 bbl/d)
- 2017 iSOR: 2.2 – 4.5
- Selection of High/Mid/Low cases based on Oil Rate and iSOR

**2017 PAD PERFORMANCE:**

**PERFORMANCE SELECTION**

- **HIGH:** Pad L1
- **MID:** Pad L3
- **LOW:** Pad L4

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**Graph:**

- **Oil Rate (m³/d):**
  - Production Range
  - Pad L1
  - Pad L2
  - Pad L3
  - Pad L4
  - Pad L5
  - Pad L6

- **iSOR:**
  - Production Range
  - Pad L1
  - Pad L2
  - Pad L3
  - Pad L4
  - Pad L5
  - Pad L6

**Legend:**

- HIGH
- MID
- LOW
PAD PERFORMANCE - HIGH: PAD L1

PAD L1 GEOLOGY

- Pad L1 has a consistent, thick net pay in both the GBIP and the DBIP
- Has highest oil saturation (89%) and above average permeability (Kh 5.6D)

<table>
<thead>
<tr>
<th>Well Pad</th>
<th>Area ($10^3$ m$^2$)</th>
<th>Avg. DBIP Thickness (m)</th>
<th>Avg. GBIP Thickness (m)</th>
<th>Avg. Porosity * (%)</th>
<th>Avg. Oil Saturation* (%)</th>
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</tr>
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<td>L2</td>
<td>498</td>
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</tr>
<tr>
<td>Total/Avg.</td>
<td>3,103</td>
<td>21.3</td>
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<tr>
<td>LDA Total</td>
<td>24,166</td>
<td>15.5</td>
<td>17.3</td>
<td>32</td>
<td>85</td>
</tr>
</tbody>
</table>
2017 PAD PERFORMANCE – HIGH: PAD L1

- SAGD well pairs on production in 2010
  - *Infill wells drilled in 2015 and started in 2016*
- 2017 Peak bitumen rate ~ 822 m³/d (5,170 bbl/d)
- 2017 iSOR: 1.9 – 2.6
- Pad L1 continues to be a high performing pad
  - *Infill wells contribute ~45% of total pad production i.e. ~320–400 m³/d (2,000–2,500 bbl/d)*
  - *Infill wells have provided significant oil rates and reductions in SOR on the pad*
PLUG BACKS

- In 2017 three infill wells were plugged back to isolate thermally hot regions.
- The infill system deliverability improved despite shortening of horizontal well length by ~25%.
  - The infill system is defined as the infill well plus 50% production from the adjacent SAGD pairs.
- TFSR and reservoir retention targets are based off the infill well system emulsion and steam.

**L1N5 well schematic and temperature profile before and after plug back**

**L1N5 infill system production uplift**

- Improved temperature profile post plug back.
- Improved oil rates post plug back.
OBSERVATION WELL AND SEISMIC DATA

- 2015 4D seismic in Pad L1 showed the steam chamber was fully developed in the toe region
- 2018 saturation logs demonstrate the positive impacts of the 2017 plug back initiatives
  - 100/08-28 shows drainage from top of the reservoir
  - 102/05-27 and 100/5-27
    - Shows full steam chamber development and conductive heating drainage
    - Steam chamber drawn down below infill well elevation
PAD L3 GEOLOGY

- Pad L3 has a consistent, thick GBIP with thinning DBIP and heterogeneity to the east
- Has average oil saturation (87%) and high permeability (Kh 6.4D)
- No infill wells on this pad

<table>
<thead>
<tr>
<th>Well Pad</th>
<th>Area ($10^3$ m$^2$)</th>
<th>Avg. DBIP Thickness (m)</th>
<th>Avg. GBIP Thickness (m)</th>
<th>Avg. Porosity (%)</th>
<th>Avg. Oil Saturation (%)</th>
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</tr>
</tbody>
</table>
2017 PAD PERFORMANCE – MID: PAD L3

- SAGD well pairs on production in 2010
- 2017 Peak bitumen rate ~ 540 m3/d (3,400 bbl/d)
- 2017 iSOR: 2.8 – 4.4
- In 2017 installed FCDs in L3P4 and L3P6
  - *Pad L3 oil production improved by 36% and SOR reduced by 27%*
FLOW CONTROL DEVICES (FCDs)

- Q4-2017 installed 2 FCDs in Pad L3
- The FCDs improved the well performance
  - Oil uplift: >250 bbl/d per well

Improved temperature profile post FCD installation

Improved oil rates post FCD installation
OBSERVATION WELL AND SEISMIC DATA

- 2014 4D seismic showed good conformance along the well trajectory
  - \textit{L3P1 and P2 lower conformance in the toe region is influenced by reservoir quality}
- Q4-2017 installed flow control devices to achieve better temperature conformance
- 2018 saturation logs show the steam chamber has grown vertically and demonstrates drainage from the conductive heating interval
**PAD L4 GEOLOGY**

- Pad L4 has thickest GBIP/DBIP to the East
- Has average oil saturation (87%) and slightly below average permeability (Kh 5.2 D)
- No infill wells on this pad

<table>
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2017 PAD PERFORMANCE – LOW: PAD L4

- 2017 Peak bitumen rate ~ 370 m³/d (2,330 bbl/d)
  - *Performance indicative of the historical steam reductions on the pad*

- 2017 iSOR: 3.1 – 4.5
  - *Expanded NCG co-injection to remaining three well pairs on this pad in 2017*
OBSERVATION WELL AND SEISMIC DATA

- 2014 4D seismic showed good conformance along the well pairs
- The steam chambers have developed to the top of DBIP in 100/16-28 and 100/09-28
  - *All wells show a well developed steam chamber at the top of DBIP and up to 7m of reservoir still to drain via conductive heating*
- The saturation logs confirm the opportunity to draw down the steam chamber

PADS L3-L4 4D: ACQUIRED 2014

4D Anomaly Thickness (m)

- 10
- 15
- 20
- 25
- 30
Source water is extracted from the Grand Rapids Fm and Clearwater B

Steam is injected into the McMurray Fm

Disposal water is also injected into the McMurray Fm

Leismer’s bottom water pressure rise can largely attributed to this net addition of water/mass into the McMurray Fm
Initial bottom water pressure was approximately 2,300 kPa.

Bottom water pressure rose rapidly once Pads L1 - L4 were started.

Strong bottom water pressure communication is observed between pads.

Throughout 2017, bottom water pressure reduced by ~70 kPa by steam re-allocation efforts and source water management across the field.
FIELD PRESSURE STRATEGY

- Moving towards an even pressure across the field as Pad L1-L4 and L6 are in coalescence
- In order to minimize bottom-water influx, need to operate the wells with a positive dP between producer well and bottom-water
- Stabilize the bottom-water pressure across the field by controlling source and disposal rates
Source water and retention are managed to minimize bottom water pressure variations.

Currently managing the reservoir pressure and steam allocation across the field to achieve a more balanced reservoir retention.
STEAM PRESSURE
- Steam is delivered to pads at about 7,000–9,000 kPa
- Steam pressure dropped to 5,000–6,000 kPa at the pad

TYPICAL STEAM QUALITY
- Steam quality decreases during transportation to well pads due to heat losses
  - Estimated at 95% at Pads L1–L4
  - Estimated at 90% at Pad L5 due to longer, larger diameter pipe line

STEAM QUALITY VARIATIONS
- Steam quality varies as steam rates are increased/decreased
- Most consistent at Pads L1–4 due to shared trunk line
- Most variable at Pad L5 due to additional 4 km steam line off main trunk line
SURFACE CASING VENT FLOW (SCVF)

CURRENT STATUS

Most SAGD wells have steam vent flow while producing or injecting
  o Steam vent is considered non-serious in accordance with AER Interim Directive ID 2003-01
  o Steam vent is present all times of the year
  o Steam vent disappears when the wells are shutdown
  o Steam vent does not contain $\text{H}_2\text{S}$

MONITORING

  o No liner or casing failures occurred during the reporting period
  o Steam vent is checked monthly
    • Regular monitoring of temperature, flow estimation, presence of bubbles & $\text{H}_2\text{S}$
    • Changes are reported as per ID 2003-01
  o Future SCVF is prevented through thermal cementing during drilling where the cement is circulated until there is a full density return to surface
SUBSURFACE PILOTS
NON-CONDENSABLE GAS (NCG) PILOT

Initially the NCG Co-Injection Pilot was conducted on two well pairs on Pad L4

- NCG Co-Injection helped reduce the steam oil ratio (SOR)

Based on positive results from the initial two well pairs in 2017, NCG Co-Injection was expanded to an additional three well pairs on Pad L4

- Five OBS wells (★) in the Pad L4 were repurposed with new thermocouple strings in Q1 2018
  - Temperature data will help to evaluate and optimize the NCG Co-Injection performance

- The evaluation is ongoing, with continued monitoring and optimization of the NCG Co-Injection well performance
2018 SUBSURFACE DEVELOPMENT PLANS

- Continue evaluating NCG co-injection on Pad L4
- Evaluate the feasibility of NCG co-injection on Pads L1, L2 and L3
- Conduct Pad L5 infill well completions (4 wells)
  - Potential start-up Q3 2018
  - 2 wells will be completed with rod pumps
  - 2 wells will be completed with ESPs
- Continue Pad L2 expansion design / planning

PAD ABANDONMENTS

- No pad abandonments anticipated at Leismer within next five years
SURFACE OPERATIONS
FACILITIES
2017 OVERVIEW

- Degasser Project design completed and site installation commenced in 2017
- 5th OTSG project sanctioned and site preparation started in Q4-2017
- Earthwork and construction of surface facilities completed for pad 5 infill wells

2017 OPERATIONS

- Successfully completed chemical trials for water and oil processing
- Significantly reduced slop volumes throughout the year
- Preparations and planning commenced for upcoming 2018 turnaround (Q2-2018)
SIMPLIFIED SCHEMATIC
CERAMIC MEMBRANE PILOT

Design Capacity: 75 tonnes/hour
Total Membranes: 44 (4 banks of 11 membranes)
Feed Streams: Skim Tank Outlet, IGF outlet, De-oiled Water
Design Flux: 160 LMH

- Field testing of ceramic membrane pilot project completed in Q1-2017
- ROSS™ system was installed for simultaneous removal of oil and silica from produced water
- System was tested at flow rates from 30 – 75 t/h
- Technical evaluation and technology report was completed in 2017
- Membrane system successfully removed oil and silica. Water quality exceeded conventional treatment (de-oiling and WLS)
- Overall design throughput was not achieved on consistent basis
- Further field testing is not planned at this time

ROSS™ = Removal of Oil and Silica Simultaneously
SURFACE OPERATIONS

FACILITY PERFORMANCE
FACILITY PERFORMANCE

SITE RELIABILITY HAS REMAINED HIGH (~97%)

- Based on steam performance
- Facility operating near or at maximum design capacity

MAJOR ACTIVITIES

- Pigged steam generators in August 2017 and January 2018
- Replaced burner shield on one steam generator in January 2018
- Replaced section of steam outlet piping and check valve on one OTSG with upgraded material
- Completed chemical trials for water and oil treating processes and switched chemical provider in Q3-2018
- Inspected and conducted integrity digs on sales and diluent pipelines in February 2018
CHALLENGES

- Corrosion on steam outlet piping currently being monitored with some piping sections scheduled to be upgraded in 2018 turnaround
- Failure of fresh water pipeline in November 2017
- Increased pigging frequency due to moderate fouling on OTSGs

OPPORTUNITIES

- Degasser Project initiated to handle lower density diluent supply and reduce losses
- Chemical trials showing promise for improved oil treatment and reduced slop generation
2017 Total Bitumen Production: 1,204,933 m³

2017 Total Electrical Load: 84,790 MWh
2017 Total Purchased Gas: 231,242 x 10^3 m^3

2017 Total Produced Gas: 17,274 x 10^3 m^3
2017 Total Vented Gas from Raw Water Tank (Based on Gas/Water Ratio - GWR): $9.0 \times 10^3 \text{m}^3$

2017 Total Carbon Dioxide Equivalent: 535,000t

Raw Water Vented Gas (Se$^3$m$^3$)


CO$_2$ Equivalent (tonne)
2017 Total HP Flare: 10.3 x10^3 m^3
2017 Total LP Flare: 11.9 x10^3 m^3
Solution Gas Recovery for the Year: 99.9%
SURFACE MEASUREMENT, ACCOUNTING AND REPORTING PLAN (MARP)
WELL TESTING

- Well tests used to calculate daily bitumen and water production
- Six hour test with 1 hour purge utilized to improve accuracy of oil calculation
- Pads L1, L3, L5 and L6 are equipped with full test headers and test separators
- Pad L4 equipped with full test header and Multi-Phase Flow Meters (MPFM)
- MPFM installed on Pad L2 in late 2016 and verified with the existing water cut meter in 2017. MPFM now utilized for Pad L2 well testing data
- Auto samplers installed at the pads in 2017 to improve accuracy and consistency of water cut samples used for meter calibrations
2017 Proration Improvement

- AGAR meter re-calibration
- Corrected well test data to standard conditions
LEISMER WATER NETWORK

- 5 Wells completed in Lower Grand Rapids Formation
- 1 Brackish water well in Clearwater B formation

LEISMER DISPOSAL WELLS

- 2 Disposal wells in the Basal McMurray; one operating, one standby
- Both wells are Class 1b (Disposal Approval No. 11479)
Pressure and temperature monitoring

OBS well 1F1/14-28-078-10W4/0 offline since July 2017

Proposed 100/10-33-078-10W4/0 to replace 14-28 for disposal well monitoring
CPF WATER USES

WATER DIVERSION LICENCE (WDL) 00239880 FOR 317,915 m³/y (871 m³/d)

- Total non-saline water pumped from source wells at Leismer in 2017 was 252,000 m³ (690 m³/d) or 79% of allowable WDL amount
  - ~ 98.5% went to Leismer CPF for process use
  - ~ 1.5% for domestic use at CPF

SOURCE WATER MINIMIZED BY OPERATING AT BALANCED RESERVOIR RETENTION

- Source water intensity was 0.21 bbl-water/bbl-bitumen in 2017
- Higher source volumes required in March – May 2017 due to increased steam retention
- Based on reservoir conditions with WSR > 1 for the majority of the year, source water requirements remained low and required mainly used for CPF utility requirements
- High blowdown recycle rates have been maintained
FLOW FROM GRAND RAPIDS

2017 Annual Non-Saline Diversion: 252,407 m³
Annual Non-Saline Water Diversion Licence Limit: 317,915 m³
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Brackish Water</th>
<th>Non-saline Water</th>
<th>Produced Water</th>
<th>Disposal Water</th>
</tr>
</thead>
<tbody>
<tr>
<td>TDS [mg/L]</td>
<td>5,700</td>
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<td>2,300</td>
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<td>pH [-]</td>
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<tr>
<td>Hardness [mg/L as CaCO₃]</td>
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<tr>
<td>Cl [mg/L]</td>
<td>2,800</td>
<td>230</td>
<td>925</td>
<td>12,500</td>
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</table>
2017 Annual Steam Production: 3,814,000 m³
2017 Total Produced Water: 4,082,000 m³
2017 Total Disposal Water: 326,600 m³
2017 Total D81 Disposal Limit: 415,700 m³
DISPOSAL WATER PRESSURE & TEMPERATURE

13-33-078-10W4 WHP (kPag) vs. Disposal Water Temp. (°C)
12-33-078-10W4 WHP (kPag) vs. Disposal Wellhead Pressure (kPag)
WHP Limit (kPag)

Disposal Temperature (°C)
Disposal Wellhead Pressure (kPag)
2017 Blowdown Recycle Rate: 70%

2017 Total Off-Site Slop Production: 6,500 m³
SLOP HANDLING:
- 4,300 m³ of water was trucked off site within slop volume
- Water volume disposed in 2017 was 40% lower than previous year

SOLIDS DISPOSAL:
- Water treatment related solids (lime softening sludge) is allowed to settle in the sludge pond at site and is removed periodically
- No sludge was disposed from the pond in 2017
SURFACE SULPHUR PRODUCTION

ATHABASCA OIL CORPORATION
Leismer average daily sulphur dioxide (SO$_2$) emissions in 2017 was 1.17 t/d in 2017 (59% of approval limit)

- *Note: EPEA approval limit for the Leismer Project is 2.0 t/d of SO$_2$ emissions*

- Total annual SO$_2$ emissions for 2017 was 428 tonnes

- Leismer currently does not have sulphur recovery facilities
DAILY & QUARTERLY SULPHUR EMISSIONS

- Quarterly Emissions Avg. (t/d)
- Daily Sulphur Dioxide Emissions (t/d)
- EPEA Sulphur Dioxide Limit (t/d)
OTSG NOX EMISSIONS

Approval Limit 13.0 kg/hr

kg/hr

Jan-17 Feb-17 Mar-17 Apr-17 May-17 Jun-17 Jul-17 Aug-17 Sep-17 Oct-17 Nov-17 Dec-17
AMBIENT AIR QUALITY MONITORING RESULTS

ALBERTA ENERGY REGULATOR APPROVAL LIMITS BASED ON ALBERTA AMBIENT AIR QUALITY OBJECTIVES AND GUIDELINES:

- SO₂ (1-hour average): 172 ppbv
- H₂S (1-hour average): 310 ppbv
- NO₂ (1-hour average): 300 ppbv

<table>
<thead>
<tr>
<th>Month</th>
<th>Peak SO₂ (ppb)</th>
<th>Peak H₂S (ppb)</th>
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</thead>
<tbody>
<tr>
<td>January</td>
<td>1.3</td>
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<td>December</td>
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<td>October</td>
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<td>November</td>
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<th>Operational Time SO₂ (%)</th>
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<th>December</th>
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SURFACE ENVIRONMENTAL ISSUES
ATHABASCA OIL CORPORATION BELIEVES IT IS IN COMPLIANCE WITH THE AER SCHEME APPROVAL AND REGULATORY REQUIREMENTS

For the period of March 1, 2017 to February 28, 2018, AOC has no unaddressed non-compliant events
## APPROVALS AND AMENDMENTS

<table>
<thead>
<tr>
<th>Date</th>
<th>Approval Summary</th>
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<tbody>
<tr>
<td>July 24, 2017</td>
<td>Directive 56 Facility Licence amendment for continuous sulphur emission rate</td>
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<tr>
<td>September 1, 2017</td>
<td>Commercial Scheme amendment for L2 Expansion reduced well length (10935U)</td>
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<tr>
<td>December 20, 2017</td>
<td>Class II Disposal Well Approval for disposing produced water into the Clearwater formation (11874A)</td>
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</tbody>
</table>
EPEA APPROVAL REPORTS & PROPOSALS SUBMITTED

- Monthly Air Reports
- Soil Management Program Report – February 8, 2018
- Annual Groundwater Monitoring Report – March 27, 2018
- Annual Conservation and Reclamation Report – March 23, 2018
- Annual Air Report – March 23, 2018
- Annual Industrial Wastewater Report – March 28, 2018
- Annual Industrial Runoff Report – March 28, 2018
- Annual Wetland Monitoring Report – March 28, 2018

WATER ACT REPORTS

- WDL: Monthly use reporting
- Annual Water Use Report – February 20, 2018
PARTICIPATION IN MULTI-STAKEHOLDER REGIONAL INITIATIVES:

- Oil Sands Monitoring (OSM)
- Wood Buffalo Environmental Association (WBEA)
- Regional Industry Caribou Collaboration (RICC)
SURFACE
NON-COMPLIANCE EVENTS
The following list summarizes non-compliance events for the period of March 2017 to February 2018.

For all events, corrective actions were identified and tracked to completion.

<table>
<thead>
<tr>
<th>Event</th>
<th>Corrective Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>November 22, 2017: Source water pipeline failed</td>
<td>Heat trace controller settings verified on other pipelines. Verification of heat trace set points were included in annual inspection criteria</td>
</tr>
</tbody>
</table>
MAJOR ACTIVITIES & TARGET DATES

CPF DEGASSER PROJECT AND NORLITE DILUENT SUPPLY
- Construction to be completed mid 2018 and start up scheduled for Q2-2018
- Degasser start up in conjunction with new diluent supply
- New diluent supply from Enbridge Norlite pipeline to be connected to Leismer in Q2-2018

PAD L5 INFILL WELLS
- Earthworks and facility construction completed with start-up scheduled for Q3-2018

PAD L2 EXPANSION
- Continue Pad L2 expansion design / planning

5TH OTSG ADDITION
- Start up scheduled for Q4-2018