This presentation contains information in compliance with:

*AER Directive 054 - Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes*

*Section 3.1.1 Subsurface Issues Related to Resource Evaluation and Recovery*
Advisory

This document contains forward-looking information prepared and submitted pursuant to Alberta regulatory requirements and is not intended to be relied upon for the purpose of making investment decisions, including without limitation, to purchase, hold or sell any securities of Cenovus Energy Inc. The resources estimates contained herein are not reported in accordance with National Instrument 51-101 and are provided solely for the purpose of complying with Alberta regulatory requirements.

Additional information regarding Cenovus Energy Inc. is available at cenovus.com.
Current project status

Subsection 3.1.1 – 1)
Strong integrated oil portfolio

**TSX, NYSE | CVE**

<table>
<thead>
<tr>
<th>Enterprise value</th>
<th>C$29 billion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shares outstanding</td>
<td>757 MM</td>
</tr>
</tbody>
</table>

2014F production

| Oil & NGLs | 199 Mbbls/d |
| Natural gas | 470 MMcf/d |

2013 proved & probable reserves

| 3.2 BBOE |

Bitumen

| Economic contingent resources* | 9.8 Bbbls |
| Discovered bitumen initially in place* | 93 Bbbls |
| Lease rights** | 1.5 MM net acres |

P&NG rights

| 5.9 MM net acres |

Refining capacity

| 230 Mbbls/d |

Values are approximate. Forecast production based on the midpoints of the February 13, 2014 guidance document. Cenovus land at December 31, 2013. *See advisory. **Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignee’s behalf.
Foster Creek – current project status

- Phase A - 20k bbls/d on October 2001 (3,180 m³/d)
- 80 MW Cogen on Q1 2003
- Phase B - 30k bbls/d (4,770 m³/d)
- Phase C - 60k bbls/d complete 2006 (9,534 m³/d)
- Phases D & E - 120k bbls/d complete 2009 (19,078 m³/d)
- Water treating debottleneck and cooling loop complete 2010
- Q1 2014 oil production 109,412 bbls/d (17,395 m³/d)
- Record oil production day 130,580 bbl (20,761 m³)
- Approved for Phases A – H, capacity 240k bbls/d (38,271 m³/d)

Note that production volumes refer to total cumulative production capacity

Aerial shot of Foster Creek facility, and steam and emulsion lines

Subsection 3.1.1 – 1)

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Project status – phase D and E update

Main Plant:
• 120,000 bbls/d (19,078 m³/d) oil treating design capacity commissioned in 2009
• Debottleneck on water treating capacity complete in 2010
  – 2013 annualized average was 106,414 bbls/d (16,909 m³/d)
  – 2013 exit rate, Dec 2013, was 114,685 bbls/d (18,223 m³/d)
  – 2014 Q1 average rate was 109,412 bbls/d (17,177 m³/d)

Phases A - E well update:
• E08 Pad (WP 5-10) on production in October 2013
• E12 Wedge Well™ pad on production in November 2013
Construction ongoing for phases F, G and H with the following design capacities:

- Phase F – 30k bbls/d oil, first production target 2014
- Phase G – 30k bbls/d oil, first production target 2015
- Phase H – 30k bbls/d oil, first production target 2016
Current project status – SAGD resource

Subsection 3.1.1 – 2, a)

Development Boundary
Project Boundary

2,827 MMBbls OBIP (449 MMm³)
3,764 MMBbls OBIP (578 MMm³)

*OBIP calculation methodology available in subsequent slides
# Reservoir characteristics

<table>
<thead>
<tr>
<th>Reservoir Characteristic</th>
<th>West Area</th>
<th>Central Area</th>
<th>East Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (m subsea)</td>
<td>180 – 225</td>
<td>180 – 225</td>
<td>180 – 225</td>
</tr>
<tr>
<td>Thickness (m)</td>
<td>Up to 30+</td>
<td>Up to 30+</td>
<td>Up to 30+</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>34%</td>
<td>34%</td>
<td>32%</td>
</tr>
<tr>
<td>Horizontal Permeability (D)</td>
<td>Up to 10 D</td>
<td>Up to 10 D</td>
<td>Up to 8 D</td>
</tr>
<tr>
<td>Vertical Permeability (D)</td>
<td>Up to 8 D</td>
<td>Up to 8 D</td>
<td>Up to 6 D</td>
</tr>
<tr>
<td>Oil Saturation</td>
<td>~0.85 (0.50 in transition)</td>
<td>~0.85 (0.50 in transition)</td>
<td>~0.85 (0.50 in transition)</td>
</tr>
<tr>
<td>Water Saturation</td>
<td>~0.15 (0.50 in transition)</td>
<td>~0.15 (0.50 in transition)</td>
<td>~0.15 (0.50 in transition)</td>
</tr>
<tr>
<td>Original Pressure (kPa)</td>
<td>~2700</td>
<td>~2700</td>
<td>~2700</td>
</tr>
<tr>
<td>Original Temperature (ºC)</td>
<td>12 ºC</td>
<td>12 ºC</td>
<td>12 ºC</td>
</tr>
</tbody>
</table>

Subsection 3.1.1 – 2, b)
Composite type log: central wells

- Pervasive basal mud defines base
- Basal mud is discontinuous and ranges from 0-4 metres in thickness
- Provides a good marker during SAGD operations

Location: 11-19-70-4W4

Subsection 3.1.1 – 2, e)
Pervasive basal mud defines base

Basal mud is discontinuous and ranges from 0-4 metres in thickness

Provides a good marker during SAGD operations

Location: 2-21-70-3W4

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Maps and core

Subsection 3.1.1 – 2, c,d & f)
2013 SAGD Pay Isopach (2014 Strats)

- Development Boundary
- Project Boundary
  - 96 Strat Wells

2,827 MMBbls OBIP (449 MMm³)
3,764 MMBbls OBIP (578 MMm³)

*OBIP calculation methodology available in subsequent slides

Subsection 3.1.1 – 2, c)
McMurray to Paleozoic isopach

Subsection 3.1.1 – 2, c)
Paleozoic structure

Subsection 3.1.1 – 2, d)
SAGD top pay structure

Subsection 3.1.1 – 2, d)
Cored locations (2014)

Subsection 3.1.1 – 2, f)
## Post-steam core locations

### Table: Post-steam core locations

<table>
<thead>
<tr>
<th>Post-steam Core</th>
<th>Year Cored</th>
<th>Associated Well Pair</th>
<th>Distance from Well Pair</th>
<th>% So Clean Sand (from Dean Stark)</th>
<th>%So IHS</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Pre</td>
<td>Post</td>
</tr>
<tr>
<td>3A5-22-70-4</td>
<td>2005</td>
<td>A3</td>
<td>10</td>
<td>92</td>
<td>11-26%</td>
</tr>
<tr>
<td>2D2-22-70-4</td>
<td>2010</td>
<td>D21</td>
<td>27</td>
<td>90</td>
<td>1-21%</td>
</tr>
<tr>
<td>5-22-70-4</td>
<td>2011</td>
<td>A3</td>
<td>17</td>
<td>88</td>
<td>3-20%</td>
</tr>
<tr>
<td>2B9-15-70-4</td>
<td>2012</td>
<td>FP4</td>
<td>32</td>
<td>90</td>
<td>2-34%</td>
</tr>
<tr>
<td>D14-18-70-3</td>
<td>2013</td>
<td>E0306</td>
<td>21</td>
<td>N/A</td>
<td>2-26%</td>
</tr>
</tbody>
</table>

*Post-steam core locations diagram with labels A Pad, D Pad, F Pad, E03 Pad.*
Cross-sections

Subsection 3.1.1 – 2, i)
Representative structural cross-section over central area

Subsection 3.1.1 – 2, i)
Representative structural cross-section over East area

Subsection 3.1.1 – 2, i)
Representative structural cross-section over North area

Subsection 3.1.1 – 2, i)
Representative structural cross-section over West area

Subsection 3.1.1 – 2, i)
Geo-mechanical data

Subsection 3.1.1 – 2, j)
Geomechanical data

Caprock studies continue on Colorado Shale cores 104132107004W400 (JP09), 1021417003W400 (E12W8) and 105112107004W400

Mechanical testing of T31 Shale being carried out by Professor Chalaturnyk at University of Alberta on 1AA080807006W400
Surface monitoring
2013 surface heave

Subsection 3.1.1 – 2, k)
Caprock integrity

Subsection 3.1.1 – 2, m)

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Minimum in-situ stress values in the caprock vary across the project.
Smallest minimum in-situ stress values in each sub-area are shown in the above map.

Subsection 3.1.1 – 2, m)
Criteria for determining caprock integrity

Cenovus determines the minimum in-situ stress of the caprock over the project area through mini frac testing and seismic mapping.

Current approved MOP is 6.5 Mpag

Minimum in-situ stresses have shown variability across our development area:
- four different sub-areas have been proposed for the purposes of determining MOP
- an application was submitted in Q1 2014 to accommodate for higher MOP values based on 80% of the smallest caprock minimum in-situ stress in each sub-area

Operating pressures in the project vary through the various well stages:
- steam stimulation/circulation: (5.5 – 6.5 MPa)*
- ramp-up: (3.5 – 5.5 MPa)
- normal operating conditions: (2.0 – 3.5 MPa)

* - Note that this upper limit may be adjusted on a well by well basis following the approval of application 1790408
Drilling and completions
Steam requirements:
- The drilling program has been moderate since the startup of Phases D&E, majority of wells drilled in 2013/2014 Q1 are for phase F startup in 2014
- New wells on production in 2013/2014 Q1 did not increase steam demand significantly (E12 wedges, E08 pad)
- Cenovus does not anticipate that future wells drilled with Wedge Well™ technology will impact steam to pads

Subsection 3.1.1 – 3 a)
### Re-drills and re-entries

#### List of re-drill and re-entry wells in Foster Creek since January 1, 2013

<table>
<thead>
<tr>
<th>Pad</th>
<th>Type</th>
<th>Drill start</th>
<th>Drill end</th>
<th>Reason for remediation</th>
</tr>
</thead>
<tbody>
<tr>
<td>DP17</td>
<td>Re-entry</td>
<td>06-Feb-13</td>
<td>18-Feb-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>E16P06-2</td>
<td>Re-entry</td>
<td>23-Feb-13</td>
<td>05-Mar-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>W01P08</td>
<td>Re-entry</td>
<td>10-Mar-13</td>
<td>22-Mar-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>JP04</td>
<td>Re-entry</td>
<td>27-Mar-13</td>
<td>04-Apr-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>MP09</td>
<td>Re-entry</td>
<td>02-Apr-13</td>
<td>08-Apr-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>E10P04</td>
<td>Re-entry</td>
<td>09-Apr-13</td>
<td>17-Apr-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>E21P04</td>
<td>Re-entry</td>
<td>13-Apr-13</td>
<td>20-Apr-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>E20P08-1</td>
<td>Step-out</td>
<td>22-Apr-13</td>
<td>12-May-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>W02P02-1</td>
<td>Step-out</td>
<td>17-May-13</td>
<td>24-May-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>W02P03</td>
<td>Re-entry</td>
<td>11-Jun-13</td>
<td>17-Jun-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>E02P02</td>
<td>Re-entry</td>
<td>24-Jun-13</td>
<td>30-Jun-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>E19P13</td>
<td>Re-entry</td>
<td>05-Jul-13</td>
<td>22-Jul-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>DP22-1</td>
<td>Re-entry</td>
<td>27-Jul-13</td>
<td>02-Aug-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>FWW-1</td>
<td>Re-entry</td>
<td>06-Aug-13</td>
<td>15-Aug-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>E10P05</td>
<td>Re-entry</td>
<td>20-Aug-13</td>
<td>06-Sep-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>E24P04-2</td>
<td>Step-out</td>
<td>22-Aug-13</td>
<td>10-Sep-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>MP01</td>
<td>Re-entry</td>
<td>05-Sep-13</td>
<td>15-Sep-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
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<tr>
<td>E19P10</td>
<td>Re-entry</td>
<td>11-Sep-13</td>
<td>18-Sep-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>E20P05-1</td>
<td>Step-out</td>
<td>23-Sep-13</td>
<td>05-Oct-13</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>W02P05-1</td>
<td>Step-out</td>
<td>12-Mar-14</td>
<td>27-Mar-14</td>
<td>Primary Liner failure in the Hz slotted section of the well</td>
</tr>
<tr>
<td>GP05-1</td>
<td>Step-out</td>
<td>31-Jan-14</td>
<td>07-Mar-14</td>
<td>Drilling extension of existing well to access new reserves</td>
</tr>
</tbody>
</table>

Subsection 3.1.1 – 3 a)
Standard injector completion

Subsection 3.1.1 – 3 c)

- 339.7 mm 81.105 kg/m J-55 ST&C Surface Casing
- 244.5 mm 59.527 kg/m L-80 QB2 Production casing
- 139.7mm VIT tubing
- 114.3mm TKC4040 tubing
  - 4 holes x 10 mm Splitter
  - 8 holes x 10 mm Splitter
  - 16 holes x 10 mm Splitter
  - 32 holes x 10 mm Splitter
- 177.8mm Liner Details:
  - 177.8 mm 34.23 / 38.69 kg/m L80 QB2
Standard producer ESP completion

- 339.7 mm 71.40 kg/m H40 ST&C Surface Casing
- 244.5 mm 59.53 kg/m L80 QB2 Production casing
- 1/2” Capline for bubble tube and thermocouple
- Production Tubing: 88.9 mm tubing w/ ESP landed ~5m above primary liner hanger
- 31.75 mm DTS coiled tubing
- Slotted Liner: 177.8 mm, 38.69 kg/m L-80 QB2
Standard Wedge Well™ completion

298.4 mm 62.503 kg/m
H-40 ST&C Surface Casing

177.8 mm 34.228 kg/m
L80 QB2 Production casing

88.9mm EUE tubing w/ ESP landed ~5m above primary liner hanger

½” Capline for bubble tube and thermocouple

114.3mm 17.26 kg/m
L80 Slotted Liner
Artificial lift

ESPs (electric submersible pumps)
- all operating SAGD pairs (~ 170 producers) are currently equipped with ESPs. Rod pumps were used previously for wells with difficult start-up.

Rod pumps
- 30/66 operating wells utilizing Wedge Well™ technology are equipped with rod pumps
- rod pumps at Foster Creek can range from about 0 – 350 m³/d

<table>
<thead>
<tr>
<th></th>
<th>ESPs</th>
<th>Rod pumps</th>
</tr>
</thead>
<tbody>
<tr>
<td>Turn down (m³/d)</td>
<td>120</td>
<td>0</td>
</tr>
<tr>
<td>Max. rate (m³/d)</td>
<td>1200</td>
<td>350</td>
</tr>
<tr>
<td>Max. operating temp (°C)</td>
<td>218</td>
<td>200+</td>
</tr>
<tr>
<td>Number of pumps</td>
<td>173</td>
<td>43</td>
</tr>
<tr>
<td>Average run life (months)</td>
<td>15.9</td>
<td>4.9</td>
</tr>
</tbody>
</table>
Artificial lift new technology

ESPs
- higher temperature pumps are available and will be trialed at Foster Creek where appropriate
- current ESP technology will apply to the majority of Foster Creek wells (218°C).

Rod pumps
- previously used on wedge wells
- surface metering can be an issue, looking for better measurement
- higher maintenance pump than ESPs, have had problems with sand bridging and can result in slower ramp up to peak production
- currently moving toward changing Rod pumps to ESP where applicable and all go forward wells are ESP from the start

PCPs (progressive cavity pumps)
- lower bottom-hole temperature ratings than ESPs
- have trialed three types of elastomer PCP pump in KWW’s as well as a metal-on-metal PCP
- all PCPs have been removed and converted to ESP as a result of high maintenance costs and lower well productivity
Instrumentation in wells

Subsection 3.1.1 – 5)
Piezometer details

Three installation types:

Cemented tubing - vibrating wire piezometers mounted on tubulars and cemented in place (14 wells)

Hanging wire – pressure / temperature gauges hung from the wellhead to about 10-15m above perforations (9 wells)

Cemented casing – High temperature Optical pressure sensors strapped and cemented to the production casing (10 wells)

Eight new McMurray piezometers installed in Q1 2014
Foster Creek temperature data

43 observation wells logged to acquire temperature data
21 observation wells logged to acquire RST data
Instrumentation in SAGD wells

SAGD steam injector
- blanket gas for pressure measurement

SAGD producer
- ½” capline strapped to tubing for bubble tubes and single point thermocouple
- trialing distributed temperature sensing (DTS) strings in all new wells

SAGD using our patented Wedge Well™ technology
- no downhole instrumentation with rod pumps
- new wells with ESPs to be equipped with ½” capline strapped to production tubing string to measure pressure and temperature
- plan to equip 7” liner wells with instrumentation similar to SAGD producers

* Schematics can be seen in subsection 3.1.1 – 3 c)
Requirements under Subsection 3.1.1 5c) and d) are located in the Appendix
Wellbore integrity update
2013 well integrity

Intermediate casing deformation

- Deformations have been identified in the Colorado Shale Group
- Current Colorado Shale investigations include:
  - core sampling and lab testing
  - strain monitoring wells installation to occur in 2014/2015
  - calipers and scraper/gauge ring runs used to early indications of deformations
  - University of Alberta geomechanics CRD approved by NSERC and proceeding
Well integrity continued

Ovality-type casing deformations concentrate within the Joli Fu but have been noted elsewhere in the Colorado Shale Group. Varying degrees of these deformations have been noted in wells throughout Foster Creek:

- work is ongoing to identify common characteristics between affected wells
- E12P04 and E12P06 had deformations that resulted in failed pressure tests
Intermediate well integrity

No significant change on B, E and D pads
Identified casing impairments on E12 pad
  • two wells failed pressure test – abandoned
  • monitoring program frequency increased on this pad
D pad wellbore repairs on hold awaiting higher temp ECP
JIPs ongoing:
  • connection testing protocol
  • thermal/mechanical loading and corrosion synergistic effects
  • University of Alberta Geomechanical CRD
Well remediation work

SCVF issues after drilling
  • AP2-2, CP33, E12P03, and E24P06
Second White Specs (SWS) suspected as a source in all wells
  • indicated as source on hydrolog for CP33 and E12P03
  • perforated AP2-2 and confirmed with a static gradient
Successfully squeezed SWS in AP2-2 with a micro fine cement

Attempting to intersect the flow on CP33
  • squeeze with thermal micro fine cement
  • monitoring vent

E12P03 repaired with a SWS squeeze and patch

E24P06 still under investigation
  • required to monitor until July 2014
D pad wellbore integrity update  
Changes from 2013 – Q1 2014

<table>
<thead>
<tr>
<th>Well</th>
<th>Repair/Remediation</th>
</tr>
</thead>
<tbody>
<tr>
<td>DI17</td>
<td>Slimholed, Injecting</td>
</tr>
<tr>
<td>DP17</td>
<td>Slimholed, Re-entered</td>
</tr>
<tr>
<td>DI18</td>
<td>Abandoned</td>
</tr>
<tr>
<td>DP18</td>
<td>Abandoned</td>
</tr>
<tr>
<td>DI19</td>
<td>Slimholed, Injecting</td>
</tr>
<tr>
<td>DP19</td>
<td>Slimholed, Failed liner. Evaluating remedial options</td>
</tr>
<tr>
<td>DI20</td>
<td>Slimholed (low cement top), Monitoring for corrosion, Currently injecting</td>
</tr>
<tr>
<td>DI21</td>
<td>Downhole abandoned, currently working on SCVF issues.</td>
</tr>
<tr>
<td>DP21</td>
<td>Casing Patch installed, passed annual P-test.</td>
</tr>
</tbody>
</table>
Surface casing corrosion

Have wrapped/repaired 101 wells
- majority were wrapped on initial completion as a preventative measure
- go-forward coating has been identified for initial completion

Sample set of wells will be excavated in summer 2014
- coating will be examined for deterioration and signs of corrosion

Full field inspection of near-surface region has been performed
- surface casing, intermediate casing, packoff, SCVs
- inspection frequency outlined by WIM and managed by field operators
- results are documented and exceptions are put in the maintenance or well servicing queue to be fixed
B and E pads - surface casing vent flow issues

5 high TDS wells - EI27, EI28, EI29, EP25 and BI5 (identified in 2011)

- detailed shallow groundwater monitoring indicated anomalous organics found in Bonnyville aquifer close to SAGD wells

AITF work started in the 2012 calendar year, work is ongoing

- geochemical and additional isotopic analyses conducted in 2013
- isotopic assessments indicate source is Cretaceous and concentrations highly influenced by evaporation and water/rock (cement) interactions
- geochemical analyses show that organics detected in Quaternary not from vent but likely from organics naturally present in the Bonnyville
- shallow groundwater monitoring is ongoing

All five wells to have vent flows repaired and will be abandoned

- second White Specs squeezed off
- retest vent in May 2014 to confirm flow is shut off
B and E pads - surface casing vent flow issues

Two wells with gas flow and \( \text{H}_2\text{S} \) only when steaming

- BI6 and BI7 (currently shut in)
- AER approval to inject in 2014 to gather more samples.
- To date gas sampling and isotope analysis provided inconclusive results
  - evaluating the test procedure for retest in May 2014
- Vents are sweet when well is cold
  - working to identify source
G pad monitoring well locations
2013 G pad monitoring

Monitoring of four sets of groundwater wells continued in 2013

Groundwater movement is generally to the west-southwest in the upper aquifer, west-northwest in the intermediate aquifer and west in the lower aquifer

Currently, no thermal impacts from the injectors has been detected in monitoring wells that are >10 m from the injectors

- CVE is in the process of developing a program to delineate the plume at Pad G
4D seismic

Subsection 3.1.1 – 6)
3D seismic within project area

Subsection 3.1.1 – 6 a)

line ID: year of acquisition

Project boundary
4D seismic within project area

Subsection 3.1.1 – 6 b)
Subsection 3.1.1 – 6 b)
Scheme performance

Subsection 3.1.1 – 7 a)
Scheme performance prediction

Predict well pair performance based on modified Butler’s equation

Predict well pair CSOR using published CSOR correlations (Edmunds & Chhina 2002)

Generate overall scheme production performance by adding individual well forecasts over time to honour predicted steam capacity and water treating availability

Subsection 3.1.1 – 7a, i)
Subsection 3.1.1 – 7a, ii)
Central - cumulative % recovery SOIP

*Note – A35, AINF-6 & AINF-7 volumes included in E Pad
*Note that SOIP calculation methodology is available in subsequent slides

Subsection 3.1.1 – 7a, ii)
East - cumulative % recovery SOIP

Foster Creek - East Pads
Cumulative % Recovery SOIP

*Note that SOIP calculation methodology is available in subsequent slides

Subsection 3.1.1 – 7a, ii)
West - cumulative % recovery SOIP

Foster Creek - West Pads
Cumulative % Recovery SOIP

*Note that SOIP calculation methodology is available in subsequent slides

Subsection 3.1.1 – 7a, ii)
Cumulative steam oil ratio – central pads

B / L and EXP / M Pad SORs high due to shut-in periods of wells on pad that were affected by the Colorado Shale issue

D, C, A, F and G pads have superior SORs as a result of wells drilled utilizing our patented Wedge Well™ technology

D, C and A pad also have started methane co-injection

*Note – A35, AINF-6 & AINF-7 volumes included in E Pad
Cumulative steam oil ratio – east pads

E02 & E03 pads - geology in this area is more heterogeneous than in most areas at Foster Creek and start-up was difficult, requiring several steam stimulations, resulting in a higher CSOR.

E24, E16, E19, E20 and E12 pads - all very good geology and well performance, thus, low SORs.

E10 & E11 pads have seen some water influx in a couple of wells.

Subsection 3.1.1 – 7a, ii)
Cumulative steam oil ratio – west pads

Foster Creek - West Pads
Cumulative Steam Oil Ratio

Subsection 3.1.1 – 7a, ii)
Foster Creek has met the target rate in Phase A, Phase B, Phase C and Phase D&E applications

- Phase D&E (Pads J, E04, E08, E11, E15, E16, E19, E20, E21, E25, W01, W02, H) – 120,000 bbl/d (19,080 m³/d)
- Debottleneck added in 2010 to help maximize production as we underestimated our water production forecast (PWSR > 1)
- Anticipate daily production between 105,000 – 130,000 bbl/d throughout the remainder of the year
- Phase F coming on stream in Q3 2014

* Wells drilled utilizing Wedge Well™ technology have been drilled and are on production

Note that production volumes refer to cumulative production capacity on a total production basis

Subsection 3.1.1 – 7a, iii)
Steam chamber development

Subsection 3.1.1 – 7 b)
Methods for monitoring chamber development

Cenovus uses the following methods for monitoring chamber development:

- Observation wells
- Specialized logging and coring
- Seismic
- Volumetrics
Foster Creek temperature and RST data

43 observation wells logged to acquire temperature data
21 observation wells logged to acquire RST data
Foster Creek temperature wells

B6-22

- TSAT 218°C
- 206°C
- 10m offset C11 Well Pair

Subsection 3.1.1 – 7 b)

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Foster Creek temperature wells

Subsection 3.1.1 – 7 b)

D2-20

- 5m from E24W05 wedge well and 30m away from E24-03 well pair
Foster Creek temperature wells

Subsection 3.1.1 – 7 b)

- 9m away from E12-02 well pair

TSAT 226°C

230°C
East 4D seismic (2013)

East 4D acquired in 2013 processed and interpreted

Subsection 3.1.1 – 7 b)
Time-lapse seismic: E25 pair 06

Subsection 3.1.1 – 7 b)
Time-lapse seismic: E20 Pair 02

Subsection 3.1.1 – 7 b)
Time-lapse seismic: E15 Pair 5

Subsection 3.1.1 – 7 b)
Subsection 3.1.1 – 7 c)

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Two types of Oil in Place (OIP) are provided:

- SAGDable OIP and Productive OIP

**SAGDable OIP defined as:**

- $(\text{Planned Length}) \times (\text{Spacing}) \times (\text{Net SAGD Pay: Base to Top SAGD}) \times (S_o) \times (\phi)$
  - used drilled length for existing well pairs but will use planned length for all future pairs
  - a “before-drilling” OOIP, used during planning phase
  - doesn’t change after well pair plans finalized
  - used to plan additional wells (Wedge Well™, bypassed pay producers, re-drills, new pairs)
  - this is essentially a “planned” OOIP, as we would aim to drill the full planned length (typically 800m), and drill the producer well as low as possible in relation to Base SAGD

**Productive OIP defined as:**

- $(\text{Effective Length}) \times (\text{Spacing}) \times (\text{Effective Pay: Producer to Top SAGD}) \times (S_o) \times (\phi)$
  - an “after-drilling” OOIP, based on well pair potential
  - changes with time and interpretation (obs. wells, 4D seismic, MWD error, etc.)
  - used to plan blowdown strategy
  - this reflects actual well pair performance
    - incorporates actual overlapping slotted liner lengths initially (including blank sections <100m)
    - incorporates actual location of the producing well

**Productive OIP almost always < SAGDable OIP**

Internally updated reserves definitions and methodology in 2010 and review annually. Change in various pads SOIP and POIP values from year to year to better reflect well lengths, placement, recovery factors and production performance.
SOIP and POIP intervals

Wabiskaw Marker

McMurray Top

SAGD Pay Top

Transition

SAGD Pay Base

Paleozoic

**Cutoffs:**
- Gama: <60 API
- Porosity: >27% D
- Rt: >20 ohm-m (equates to 50% So)
- Facies: sand, sand-mud clasts, & sand-mud drapes.
- <1m mud interval

Subsection 3.1.1 – 7 c)
OIP – location of areas

Central: 10 pads
East: 14 pads
West: 2 pads

Subsection 3.1.1 – 7c, i,ii)
Ultimate recoveries in the central area are now forecasted higher than originally expected due to:
  • Wells drilled utilizing our patented Wedge Well™ technology have been successful
  • Indications of lower residual oil than originally expected

C, D & G Pads – currently re-evaluating SOIP, POIP and ultimate recoveries, expectation is that these volumes will increase

<table>
<thead>
<tr>
<th>PAD</th>
<th>SOIP Mm³</th>
<th>POIP Mm³</th>
<th>Cum Oil Mm³ (to Mar 31, 2014)</th>
<th>Recovery % SOIP</th>
<th>Recovery % POIP</th>
<th>Expected Ultimate Recovery Mm³</th>
<th>Ultimate Recovery as % of SOIP</th>
</tr>
</thead>
<tbody>
<tr>
<td>A PAD*--**</td>
<td>3,228</td>
<td>2,952</td>
<td>2,490</td>
<td>77</td>
<td>84</td>
<td>2,627</td>
<td>81%</td>
</tr>
<tr>
<td>B_L PAD</td>
<td>4,330</td>
<td>3,274</td>
<td>1,991</td>
<td>46</td>
<td>61</td>
<td>2,446</td>
<td>57%</td>
</tr>
<tr>
<td>C PAD**</td>
<td>4,592</td>
<td>3,957</td>
<td>3,631</td>
<td>79</td>
<td>92</td>
<td>3,700</td>
<td>81%</td>
</tr>
<tr>
<td>D PAD**</td>
<td>4,695</td>
<td>4,198</td>
<td>4,276</td>
<td>91</td>
<td>102</td>
<td>4,300</td>
<td>92%</td>
</tr>
<tr>
<td>E_K PAD*</td>
<td>4,625</td>
<td>3,820</td>
<td>3,035</td>
<td>66</td>
<td>79</td>
<td>3,251</td>
<td>70%</td>
</tr>
<tr>
<td>EXP_M PAD</td>
<td>4,156</td>
<td>3,110</td>
<td>1,640</td>
<td>39</td>
<td>53</td>
<td>2,593</td>
<td>62%</td>
</tr>
<tr>
<td>F PAD**</td>
<td>4,211</td>
<td>3,541</td>
<td>2,969</td>
<td>71</td>
<td>84</td>
<td>3,056</td>
<td>73%</td>
</tr>
<tr>
<td>G PAD**</td>
<td>3,265</td>
<td>2,274</td>
<td>2,383</td>
<td>73</td>
<td>105</td>
<td>2,500</td>
<td>77%</td>
</tr>
<tr>
<td>H PAD</td>
<td>721</td>
<td>504</td>
<td>74</td>
<td>10</td>
<td>15</td>
<td>420</td>
<td>58%</td>
</tr>
<tr>
<td>J PAD</td>
<td>4,170</td>
<td>3,118</td>
<td>1,058</td>
<td>25</td>
<td>34</td>
<td>2,227</td>
<td>53%</td>
</tr>
<tr>
<td>Total Central</td>
<td>37,994</td>
<td>30,748</td>
<td>23,546</td>
<td>62</td>
<td>77</td>
<td>27,121</td>
<td>71%</td>
</tr>
<tr>
<td>Total FC</td>
<td>107,114</td>
<td>86,502</td>
<td>45,215</td>
<td>42</td>
<td>52</td>
<td>71,744</td>
<td>67%</td>
</tr>
</tbody>
</table>

*Note - A35, AINF-6, 7 AINF-7 excluded from A pad volume and recovery and included in E_K pad.
**Note – includes wells drilled utilizing Wedge Well™ technology
Pad, area, and Foster Creek totals based on sum of wells

To Mar 31, 2014

Subsection 3.1.1 – 7c, i,ii)
OIP and percent recovery - east

Ultimate recovery includes only existing wells. Cenovus anticipates infill drilling on most pads that will significantly increase the ultimate recovery, but has not quantified these increases at this time.

<table>
<thead>
<tr>
<th>PAD</th>
<th>SOIP Mm³</th>
<th>POIP Mm³</th>
<th>Cum Oil Mm³ (to Mar 31, 2014)</th>
<th>Recovery % SOIP</th>
<th>Recovery % POIP</th>
<th>Expected Ultimate Recovery Mm³</th>
<th>Ultimate Recovery as % of SOIP</th>
</tr>
</thead>
<tbody>
<tr>
<td>E02 PAD</td>
<td>2,993</td>
<td>2,051</td>
<td>991</td>
<td>33</td>
<td>48</td>
<td>1,641</td>
<td>55%</td>
</tr>
<tr>
<td>E03 PAD</td>
<td>3,042</td>
<td>2,079</td>
<td>967</td>
<td>32</td>
<td>46</td>
<td>1,663</td>
<td>55%</td>
</tr>
<tr>
<td>E04 PAD</td>
<td>3,568</td>
<td>2,407</td>
<td>527</td>
<td>15</td>
<td>22</td>
<td>1,925</td>
<td>54%</td>
</tr>
<tr>
<td>E08 PAD</td>
<td>4,676</td>
<td>4,049</td>
<td>35</td>
<td>1</td>
<td>1</td>
<td>3,239</td>
<td>69%</td>
</tr>
<tr>
<td>E10 PAD</td>
<td>2,061</td>
<td>1,492</td>
<td>331</td>
<td>16</td>
<td>22</td>
<td>1,194</td>
<td>58%</td>
</tr>
<tr>
<td>E11 PAD</td>
<td>3,912</td>
<td>3,409</td>
<td>1431</td>
<td>37</td>
<td>42</td>
<td>2,727</td>
<td>70%</td>
</tr>
<tr>
<td>E12 PAD</td>
<td>7,023</td>
<td>4,831</td>
<td>3120</td>
<td>44</td>
<td>65</td>
<td>3,865</td>
<td>55%</td>
</tr>
<tr>
<td>E15 PAD</td>
<td>7,397</td>
<td>5,646</td>
<td>2042</td>
<td>28</td>
<td>36</td>
<td>4,517</td>
<td>61%</td>
</tr>
<tr>
<td>E16 PAD</td>
<td>3,486</td>
<td>3,119</td>
<td>1513</td>
<td>43</td>
<td>48</td>
<td>2,512</td>
<td>72%</td>
</tr>
<tr>
<td>E19 PAD</td>
<td>6,307</td>
<td>5,850</td>
<td>2499</td>
<td>40</td>
<td>43</td>
<td>4,680</td>
<td>74%</td>
</tr>
<tr>
<td>E20 PAD</td>
<td>5,882</td>
<td>4,909</td>
<td>2303</td>
<td>39</td>
<td>47</td>
<td>4,022</td>
<td>68%</td>
</tr>
<tr>
<td>E21 PAD</td>
<td>3,930</td>
<td>2,863</td>
<td>990</td>
<td>25</td>
<td>35</td>
<td>2,291</td>
<td>58%</td>
</tr>
<tr>
<td>E24 PAD</td>
<td>5,256</td>
<td>4,931</td>
<td>2830</td>
<td>54</td>
<td>57</td>
<td>4,008</td>
<td>76%</td>
</tr>
<tr>
<td>E25 PAD</td>
<td>4,137</td>
<td>3,390</td>
<td>1123</td>
<td>27</td>
<td>33</td>
<td>2,712</td>
<td>66%</td>
</tr>
<tr>
<td>Total East</td>
<td>63,671</td>
<td>51,027</td>
<td>20,701</td>
<td>33</td>
<td>41</td>
<td>40,996</td>
<td>64%</td>
</tr>
<tr>
<td>Total FC</td>
<td>107,114</td>
<td>86,502</td>
<td>45,215</td>
<td>42</td>
<td>52</td>
<td>70,625</td>
<td>66%</td>
</tr>
</tbody>
</table>

Pad, area, and Foster Creek totals based on sum of wells

To March 31, 2014
W01 & W02 pads came online in late 2011

<table>
<thead>
<tr>
<th>PAD</th>
<th>SOIP Mm³</th>
<th>POIP Mm³</th>
<th>Cum Oil Mm³ (to Mar 31, 2014)</th>
<th>Recovery % SOIP</th>
<th>Recovery % POIP</th>
<th>Expected Ultimate Recovery Mm³</th>
<th>Ultimate Recovery as % of SOIP</th>
</tr>
</thead>
<tbody>
<tr>
<td>W01</td>
<td>3,697</td>
<td>3,224</td>
<td>731</td>
<td>20</td>
<td>23</td>
<td>2,402</td>
<td>65%</td>
</tr>
<tr>
<td>W02</td>
<td>1,753</td>
<td>1,503</td>
<td>237</td>
<td>13</td>
<td>16</td>
<td>1,226</td>
<td>70%</td>
</tr>
<tr>
<td>Total West</td>
<td>5,450</td>
<td>4,727</td>
<td>968</td>
<td>18</td>
<td>20</td>
<td>3,628</td>
<td>67%</td>
</tr>
<tr>
<td>Total FC</td>
<td>107,114</td>
<td>86,502</td>
<td>45,215</td>
<td>42</td>
<td>52</td>
<td>70,625</td>
<td>66%</td>
</tr>
</tbody>
</table>

Pad, area, and Foster Creek totals based on sum of wells

Subsection 3.1.1 – 7c, i,ii)

To March 31, 2014
Recovery examples

W02 pad low ultimate recovery example with focus on W02-03 well pair

E16 pad medium ultimate recovery example with focus on E16-02 well pair

G pad high ultimate recovery example with focus on GP01 well pair
Current % Recovery of SOIP
Pad Totals

Foster Creek - % Recovery of SOIP per Pad (Mar 31, 2014)

Subsection 3.1.1 – 7c, iii)
OBIP – low example
W02 pad

Subsection 3.1.1 – 7 c, iii)
W02 pad overview

W02 pad began production in September 2011 (five pairs)

Generally good quality geology on the edge of the valley, some small variations in SAGD base between well pairs

Pad started up using ESPs, steam stimulations were successful on every well

Initial operating pressures ~3 Mpa until pad started communicating with rest of central pad

Remedial work on P02, P03, and P05 in 2013 - Q1 2014

Currently at ~11% recovery of POIP

CSOR is currently 3.3, expected to drop as pad is in early life

Next step will be drilling wells utilizing Wedge Well™ technology
W02 pad SAGD pay

Production date: September 2011
Standoff: 0 – 3 m
# pairs: 5 drilled
Pay trend: moderate to thin, with clast zones
W02 pad - extent of chamber development

<table>
<thead>
<tr>
<th>PAD</th>
<th>PAIR</th>
<th>SOIP Mm3</th>
<th>POIP Mm3</th>
<th>Cum Oil Mm3</th>
<th>% Recovery SOIP</th>
<th>% Recovery POIP</th>
</tr>
</thead>
<tbody>
<tr>
<td>W02 PAD</td>
<td>W02-01</td>
<td>443</td>
<td>355</td>
<td>49</td>
<td>11</td>
<td>14</td>
</tr>
<tr>
<td>W02 PAD</td>
<td>W02-02</td>
<td>348</td>
<td>301</td>
<td>32</td>
<td>9</td>
<td>11</td>
</tr>
<tr>
<td>W02 PAD</td>
<td>W02-03</td>
<td>450</td>
<td>395</td>
<td>59</td>
<td>13</td>
<td>15</td>
</tr>
<tr>
<td>W02 PAD</td>
<td>W02-04</td>
<td>389</td>
<td>360</td>
<td>61</td>
<td>16</td>
<td>17</td>
</tr>
<tr>
<td>W02 PAD</td>
<td>W02-05</td>
<td>124</td>
<td>92</td>
<td>36</td>
<td>29</td>
<td>39</td>
</tr>
<tr>
<td>Total</td>
<td>W02 PAD</td>
<td>1,753</td>
<td>1,503</td>
<td>237</td>
<td>13</td>
<td>16</td>
</tr>
</tbody>
</table>

Expected ultimate recovery (82% of POIP) = 1,226 Mm3

To March 31, 2014
Subsection 3.1.1 – 7c, iii)
Pad recovery expected to be ~81% of POIP
Pad is merged with central pod
Optimization of pad underway after remedial work
Currently at 11% recovery of POIP
Expecting continued improved of CSOR (current 3.3) after remedial work and pad optimization
OBIP – medium example
E16 pad
E16 pad overview

E16 pad began production in August 2008 (six pairs)
Steam stimulation start-up method was successful for all pairs
Geology consists of thick to moderately thick channel sands that are fairly consistent throughout, pay trend and thickness slopes down dip to the east
Expected ultimate recovery of this pad is high at about 82% of SOIP or about 87% or POIP
Overall performance is very good to date, with a CSOR of 2.4
Wells utilizing our patented Wedge Well™ technology were drilled in Q4 of 2013

Subsection 3.1.1 – 7c, iii)
E16 pad SAGD pay

Production date: October 2008
Standoff: 0 – 5 m
# pairs: 6 drilled
Pay trend: thick to variable
### E16 pad - extent of chamber development

<table>
<thead>
<tr>
<th>PAD</th>
<th>PAIR</th>
<th>SOIP  Mm³</th>
<th>POIP  Mm³</th>
<th>Cum Oil Mm³</th>
<th>% Recovery SOIP</th>
<th>% Recovery POIP</th>
</tr>
</thead>
<tbody>
<tr>
<td>E16 PAD</td>
<td>E16-01</td>
<td>515</td>
<td>490</td>
<td>291</td>
<td>57</td>
<td>59</td>
</tr>
<tr>
<td>E16 PAD</td>
<td>E16-02</td>
<td>689</td>
<td>659</td>
<td>363</td>
<td>53</td>
<td>55</td>
</tr>
<tr>
<td>E16 PAD</td>
<td>E16-03</td>
<td>696</td>
<td>575</td>
<td>293</td>
<td>42</td>
<td>51</td>
</tr>
<tr>
<td>E16 PAD</td>
<td>E16-04</td>
<td>586</td>
<td>527</td>
<td>235</td>
<td>40</td>
<td>45</td>
</tr>
<tr>
<td>E16 PAD</td>
<td>E16-05</td>
<td>508</td>
<td>442</td>
<td>159</td>
<td>31</td>
<td>36</td>
</tr>
<tr>
<td>E16 PAD</td>
<td>E16-06</td>
<td>492</td>
<td>426</td>
<td>172</td>
<td>35</td>
<td>40</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>E16 PAD</strong></td>
<td><strong>3,486</strong></td>
<td><strong>3,119</strong></td>
<td><strong>1,513</strong></td>
<td><strong>43</strong></td>
<td><strong>48</strong></td>
</tr>
</tbody>
</table>

Expected ultimate recovery (81% of POIP) = 2,512 Mm³

To March 31, 2014
E16 & E20 4D seismic (2012)

Subsection 3.1.1 – 7c, iii)
E16 pad temperatures

12m away from E16-02 well pair
D12-15

37m away from E16-03 well pair
A12-15

Tsat 233°C

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E16 pad performance

Subsection 3.1.1 – 7c, iii)

FOSTER CREEK
E16 Pad Performance

CSOR: 2.36

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E16-02 geological profile

Subsection 3.1.1 – 7c, iii)
Time-lapse seismic: E16 pair 2

Subsection 3.1.1 – 7c, iii)
E16-02 well pair performance

Subsection 3.1.1 – 7c, iii)

E16-02 Well Pair Performance

- Total Oil Rate (m³/d)
- Total Water Rate (m³/d)
- Total Steam Inj Rate (m³/d)
- Cum SOR
- Inst SOR

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E16 pad conclusions

Ultimate recovery is based on 87% of POIP

Differences between POIP and SOIP are primarily due to standoff from SAGD base

Ramp up took approximately 20 months to hit peak rates

4D seismic was shot in 2012, showing good chamber growth along pairs 1 – 4; remedial work was performed on pairs 5/6 which were redrilled to improve conformance and chamber growth

Wells utilizing our patented Wedge Well™ technology were drilled in Q4 of 2013

Will continue to use observation wells to help determine changes to steam chamber growth in the future

Subsection 3.1.1 – 7c, iii)
OBIP – high example

G pad
G pad overview

G pad began production in October 2005 (six pairs)

Thick and high quality geology with slight variation in the depth of the SAGD base and a relatively lower SAGD top at the heel of all the wells

All wedges were started in Q4 of 2009 and Q1 of 2010

Wedge Well™ startups required steam stimulations for each well
  - Edge well (GW07) had sufficient heat from a single well pair to start

Steam decline in mid 2010 to operate pad at central pod pressure, pad production performance as expected

Currently total recovery is 74% of SOIP

Next phase of SAGD is ramp down
### G pad - extent of chamber development

<table>
<thead>
<tr>
<th>PAD</th>
<th>PAIR</th>
<th>SOIP Mm3</th>
<th>POIP Mm3</th>
<th>Cum Oil Mm3</th>
<th>% Recovery SOIP</th>
<th>% Recovery POIP</th>
</tr>
</thead>
<tbody>
<tr>
<td>G PAD</td>
<td>GW01</td>
<td>0</td>
<td>0</td>
<td>94</td>
<td></td>
<td></td>
</tr>
<tr>
<td>G PAD</td>
<td>G1</td>
<td>580</td>
<td>422</td>
<td>308</td>
<td>67</td>
<td>92</td>
</tr>
<tr>
<td>G PAD</td>
<td>GW02</td>
<td>0</td>
<td>0</td>
<td>64</td>
<td></td>
<td></td>
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<td>3,265</td>
<td>2,274</td>
<td>2,430</td>
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<td>107</td>
</tr>
</tbody>
</table>

POIP recoveries over 100%

* - only ½ of the cum production from GW01 is shown, the other ½ is allocated to G Pad

To March 31, 2014

Subsection 3.1.1 – 7c, iii)
G pad SAGD pay

Production date: October 2005
Standoff: 2 – 6 m
# pairs: 6 drilled
# wedge wells: 7
Pay trend: thick to variable

Subsection 3.1.1 – 7c, iii)
G pad 4D seismic (2009)

Subsection 3.1.1 – 7c, iii)
G pad temperatures

10m away from G-01 well pair
B10-15

42m away from G-01/02 well pair
D10-15

Subsection 3.1.1 – 7c, iii)
G pad performance

FOSTER CREEK
G PAD & G Wedge Wells™ Performance

- Total Oil Rate (m³/d)
- Total Water Rate (m³/d)
- Total Steam Inj Rate (m³/d)
- Cum SOR
- Inst SOR
- Wells On Prod

Wedges on production
CSOR: 2.66

Subsection 3.1.1 – 7c, iii)
G-01 geological profile

Subsection 3.1.1 – 7c, iii)
Time-lapse seismic: GP1 (2009)

SEG standard convention: peak=increase in impedance

Subsection 3.1.1 – 7c, iii)
G-01 well pair performance

Subsection 3.1.1 – 7c, iii)
G pad conclusions

Pad recovery is greater than 100% of POIP

Currently reviewing SOIP, POIP and ultimate recoveries
  • expectation is that reserves will increase

Higher than anticipated recovery a result of:
  • wells drilled utilizing our patented Wedge Well™ technology have been successful
  • lower than anticipated residual oil saturations (15% vs. less than 10%)

G pad expansion, scheduled drilling of two new well pairs in 2014 at 80 m spacing to capture the heat under K pad heels and to the west of G pad

Have applied for steam ramp down (Q2 2013)

Following steam ramp down (following regulatory approvals), expectation is that CSOR will continue to drop below the current value of 3.6
Pad abandonments

Subsection 3.1.1 – 7 c, iv)
Pad abandonments

No pad abandonments are currently planned at Foster Creek in the next 5 years.

Subsection 3.1.1 – 7c, iv)
Steam quality
Steam quality

Steam quality will be impacted by pipeline size and distance

Currently at Foster Creek the steam qualities under normal operation conditions are as follows:

- central > 95%
- east > 94% (furthest pad)
- west - Designed to be > 95% as development continues

Steam is delivered to pads at approximately 7000 – 9000 kPa

There is some gain in quality due to pressure at each specific well pad and injection well

Steam quality is not expected to impact well performance at this time
Injected fluids
Injected fluids

Non-condensable gas
- steam rampdown for D pad started in Q3 2010, for C pad in Q4 2011 and for A Pad in Q1 2012

Acid treatments
- wells occasionally treated with HCl to minimize skin

Solvent
- have used solvent in start-up work-overs and have approval to use this as a potential start-up process

CO₂
- injected in E03I05 and E03I06
- pilot concluded in Q4 2013
Solvent start-ups

- Volumes typically range from 20 – 25 m³ per well
- Every well was treated with xylene
- List of wells:
  
  E07I03 / E07P03
  E07I05 / E07P05
  E07I06 / E07P06
  E07I07 / E07P07
  E08P02
  E08P04
  E08P07
  E08P10

Subsection 3.1.1 – 7 e)
2013 key learnings
E12I03 injector recompletion results

E12P03
Shut In DTS Data

Significant improvement in temperature profile

Subsection 3.1.1 – 7 f)
E1203 performance

Did wellpair performance improve with recompletion?

Ave emulsion rate ~340

Close steam sub to resolve hot spot

Begin pressuring up pad

Begin recompletion

P3 back online mid Dec 2012 after 2 years off.
Flush production

Pressure (kPag)

Pro. Dly Oil (m3/d)
Pro. Dly Stm (m3/d)
Pro_Dly Wtr (m3/d)
Emulsion
Pressure (kPag)

Ave emulsion rate ~390

Hot spot resolved, steady state production

wedge wells brought online

Recompletion

Flush production

Subsection 3.1.1 – 7 f)
C pad blowdown

C Pad Pad Monthly Rates

Start Rampdown
Full Blowdown

Subsection 3.1.1 – 7 f)
C Pad blowdown

Rampdown started with methane injection in Nov 2011

Full blowdown began in Mar 2013

Continue to balance pressure with methane injection

Production declines have been close to what was forecasted
Drawdown reduction through well treatments

FC Liner Drawdown Distributions Over Time

Liner Drawdown (kpa)

Distribution

December 1st, 2012
June 9th, 2013
November 4th, 2013
DO cut-off
February 11th, 2014

Subsection 3.1.1 – 7 f)
CO₂ injection pilot – update

CO₂ injection on E03I05 and E03I06: November 2011 - October 2013

Ramped up CO₂ injection rates in stages (1, 5, 10%)

Several non-CO₂ related production issues delayed the pilot

Pilot was concluded when it was determined that CO₂ was migrating into a neighboring pad (E04)

CO₂ injection has had a similar impact on the SOR as other non-condensable gases

  • require less steam injection to maintain target pressures

No solvent effect realized on oil rates
Wedge Well™ update

Wells drilled with Wedge Well™ technology

<table>
<thead>
<tr>
<th>Wells</th>
<th>On Production Date</th>
<th># Wells</th>
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<tbody>
<tr>
<td>A Pad</td>
<td>July 2005</td>
<td>7</td>
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<tr>
<td>B / L Pad</td>
<td>September 2011</td>
<td>5</td>
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<td>C Pad</td>
<td>May 2009</td>
<td>8</td>
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<td>D Pad</td>
<td>January 2008</td>
<td>6</td>
</tr>
<tr>
<td>E / K Pad</td>
<td>November 2010</td>
<td>5</td>
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<tr>
<td>Exp / M Pad</td>
<td>November 2011</td>
<td>5</td>
</tr>
<tr>
<td>F Pad</td>
<td>November 2009</td>
<td>6</td>
</tr>
<tr>
<td>G Pad</td>
<td>November 2009</td>
<td>7</td>
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<td>E24 Pad</td>
<td>October 2012</td>
<td>10</td>
</tr>
<tr>
<td>E12 Pad</td>
<td>October 2013</td>
<td>9</td>
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Subsection 3.1.1 – 7 f)
Pad performance plots
Requirements under Subsection 3.1.1 7 h) are located in the Appendix
Future plans
2013 – 2014 initiatives
Steam rampdown

C Pad on blowdown Q1 2013

A and D pads continue with rampdown

F and G pads are targeted next for rampdown

Subsection 3.1.1 – 8 a)
Plan to start up all new well pairs with steam circulation as geology permits
Upcoming pads in east development area are E08 (four WPs), E14, E42 and E07
Pressure sink project

- Reduce the pressure in the bottom water zone to provide flexibility in SAGD chamber operating pressure.
- Pull water from the MCM water sand and dispose of it into the LGR water sand

Subsection 3.1.1 – 8 a)
2014-2015 initiatives

Alternate liner trials continue on various pads
Liner and tubing deployed ICDs
Regional McMurray opportunity evaluation continues (one well coming on-line in Q2 2014)
Lower Grand Rapids disposal (Q3 2014)

Co-injection
- methane
- air
- surfactant
- solvent

Dilation

Insulated tubing
2014 – 2015 drilling plans

Subsection 3.1.1 – 8 b)

East Pads:
- E11 wedges, E15 wedges, E21 wedges, E25 wedges, E22, E28

Central Pads:
- Gexp, J wedges

West Pads:
- W15, W18, W19, W20, W23
2013 – 2014 steam strategy plans

Cenovus generally allocates steam to maintain targeted steam chamber operating pressures from pad to pad.

As steam rampdown progresses on A and D pads, steam demand for the project will be reduced, allowing the startup of new pads F and G. Pad steam rampdown will complement this strategy.

In 2014 Cenovus will be increasing steam generating capacity through the addition of Phase F. New steam will be allocated to Phase F pads.

Some steam from the existing A-E facility may be used to initiate steam simulation immediately prior to receiving incremental steam from Phase F.
Future projects

Current capacity is 120,000 bbls/d (19,080 m³/d), expectations for Phases F, G and H to peak at 240,000 bbls/d (38,271 m³/d). Evaluating opportunities to increase capacity.

Currently scoping plant optimization opportunities for Phases A-E

Phases F, G and H update

- New steam generation and production treating facilities being constructed next to the existing plant
- Phase F: 30,000 bbls/d, Phase G: 30,000 bbls/d, Phase H: 30,000 bbls/d, for total new capacity of 90,000 bbls/d (4,770 m³/d + 4,770 m³/d + 4,770 m³/d = 14,310 m³/d)
- Potential for another 35,000 bbls/d of optimization work
- The majority of new expansion is planned to be drilled west of the plant

Note that production volumes refer to production capacity on an incremental basis.
Future projects continued

Current success in SOR & WOR, and increased efficiencies in plant operations at Foster Creek indicates that Phases A – H may be capable of production greater than 240,000 bbls/d

Upcoming regulatory applications

- currently evaluating opportunities to increase project capacity to 300,000 bbl/d (47,696 m³/d)
- additional wells to recover un-swept reserves including injector-producer well pairs and single well producers
- continued exit strategies for mature pads
- future phase & sustaining development well pads

Currently drilling, completing and performing facilities work for sustaining and Phase F and G wells in 2014 through 2015

Note that production volumes refer to production capacity on an incremental basis.
End
Cenovus Foster Creek in-situ oil sands scheme (8623) update for 2013

Surface | Calgary | May 28, 2014
Foster Creek in-situ oil sands scheme

This presentation contains information in compliance with:

AER Directive 054 - Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

Section 3.1.2 Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery
Advisory

This document contains forward-looking information prepared and submitted pursuant to Alberta regulatory requirements and is not intended to be relied upon for the purpose of making investment decisions, including without limitation, to purchase, hold or sell any securities of Cenovus Energy Inc. Additional information regarding Cenovus Energy Inc. is available at cenovus.com
**Strong integrated oil portfolio**

### TSX, NYSE | CVE

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<th>Category</th>
<th>Value</th>
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<td>Shares outstanding</td>
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<tr>
<td>2014F production</td>
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<tr>
<td>Oil &amp; NGLs</td>
<td>199 Mbbls/d</td>
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<td>Natural gas</td>
<td>470 MMcf/d</td>
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<td>2013 proved &amp; probable reserves</td>
<td>3.2 BBOE</td>
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<td>Discovered bitumen initially in place*</td>
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<td>Refining capacity</td>
<td>230 Mbbls/d</td>
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*See advisory. **Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignee’s behalf.

© 2014 Cenovus Energy Inc.
Foster Creek – current project status

- Phase A - 20k bbls/d on October 2001 (3,180 m³/d)
- 80 MW Cogen on Q1 2003
- Phase B - 30k bbls/d (4,770 m³/d)
- Phase C - 60k bbls/d complete 2006 (9,534 m³/d)
- Phases D & E - 120k bbls/d complete 2009 (19,078 m³/d)
- Water treating debottleneck and cooling loop complete 2010
- Q1 2014 oil production 109,412 bbls/d (17,395 m³/d)
- Record oil production day 130,580 bbl (20,761 m³)
- Approved for Phases A – H, capacity 240k bbls/d (38,271 m³/d)

Note that production volumes refer to total cumulative production capacity.
Simplified process schematic for A/E

Subsection 3.1.2 – 1b)
Foster Creek plot plan
Phases F, G & H

- **Engineering & Procurement**
  - 99% complete on Phase F
  - 95% complete on Phase G
  - 80% complete on Phase H

- **Construction**
  - 89% complete on Phase F
    - field piping, electrical and instrumentation, insulation and pre-commissioning
  - 43% complete on Phase G
    - major equipment set, field piping starting
  - 5% complete on Phase H
    - concrete works, pile cutting and capping
Phase F commissioning

- **Area 05 – Utilities**
  - commissioning complete: glycol heaters, HP/LP flare, air, nitrogen and methanol system
  - fuel gas system purged and commissioned up to OTSG skid limit

- **Area 02 – Steam Generation**
  - BFW flush and flooding of piping completed
  - steam header warm-up completed
  - OTSG Start-up delayed due to vendor deficiencies – target start-up TBD
Phases F, G & H

Construction – east
Phases F, G & H

Construction – west

Subsection 3.1.2 – 1b)
Phases F, G, & H

Phase G OTSGs

Subsection 3.1.2 – 1b)
Osprey pilot (Clearwater formation)

Location: 11-02-70-4W4M

Facilities:
• 2 horizontal wells
• Multiphase pump
• 2 BFW tanks
• 1 OTSG & steam separator
• Commissioning December 2013
• First steam injection expected Q2 2014

Operations:
• Low pressure CSS pilot
• Emulsion ties into F Pad
• Fuel gas comes from F Pad
• Water source for steam is from blowdown disposal line
• Disposal ties in to 11-2 pad

Cold Production Result:
• Bitumen 24 m³
• Water 156 m³
• Results as expected
Osprey pilot

Subsection 3.1.2 – 1b)
Facility performance
Plant performance

Foster Creek Performance

- Bitumen
- SOR

Turnaround

Subsection 3.1.2 – 2a)
Area 3: Emulsion treatment

- Two inlet degassers (A/E & FGH)

- Five process trains (A/F), one FWKO + two treaters per train

- Two flash treaters (out of service)
  - the units have been taken out of service, drained, flushed and locked out
  - slop and de-sand fluids are treated in the tricanter unit

- Two Sulphur Removal Units (A/E & FGH) for sweetening produced and recovered gas
Area 03: Emulsion treatment

- Continued work to mitigation or reduce gas slugs to inlet degasser
  - Gas slug severity have been reduced by implemented slight back pressure on the main emulsion line
- Commissioned High-Integrity Pressure Protection System (HIPPS) at inlet of the degasser and reroute relief to a flare system
Area 07: Produced water de-oiling
Area 07: Produced water de-oiling

- Five de-oiling trains (A/F)
  - First train
    - one skim tank, one ISF and three ORFs
  - Second train
    - one skim tank, one smaller ISF and three ORFs
    - ISF capacity is 250 m³/hr. Some flow bypasses ISF.
  - Third - fifth trains
    - one skim tank, two ISFs and four ORFs
    - ISF capacity (375 m³/hr per unit)
Area 07: Produced water de-oiling

- Skim tanks
  - designed for < 4 hours retention time based on nominal capacity. Actual retention time is much lower.
  - improper oil skimming (XV valve & gravity flow out of tank)
  - there is no solid removal mechanism. Only few nozzles around the perimeter of the tank.
  - currently no chemical is added to skim tanks

- ISFs
  - vertical units with about 5-6 minutes of retention time
  - flocculent injected at inlet
  - two units are modified with microbubbler pumps instead of eductors
Area 07: Produced water de-oiling

- Oil removal filters (ORF) walnut shell media
- De-oiled produced water oil treatment
  - January 2013 to March 2014 performance:
    » skim tanks inlet average <150 ppm
    » ISFs inlet average 137 ppm
    » ORFs inlet average 45 ppm
    » ORFs outlet average 4-9 ppm
Area 07: Produced water de-oiling

- PW inlet flow to the facility is increasing. Started steam circulation before Phase F processing is ready.
- PW system capacity was found to be hydraulically constrained.
- System capacity increased from 1700 to 2090 sm³/hr by upsizing control valves, flow meters and twining piping from north de-oiling tanks to WLSs.
Area 08: Water water treatment

Subsection 3.1.2 – 2b)
Area 08: Produced water treatment

- Two Eimco units tested to 1000 m$^3$/hr
- One Densadeg designed for 500 m$^3$/hr
- Modifying Magox and Lime feed system to improve measurement and control
- Lime softener filters (LSF) – walnut shell media
- SAC followed by WAC ion exchange units
- 2013 Average BFW quality
  - silica < 30 ppm
  - TDS < 3000 ppm
  - hardness < 0.05 ppm
  - iron < 0.30 ppm
Area 08: Brackish water

- Continued brackish water piping replacement with duplex SS
- *Directive 081* project will take over a portion of this piping to convert it to glycol service
- Continue with corrosion monitoring
**Directive 081 update**

- Completed Pre-Feed study to determine plant modifications required to meet *Directive 081*
- Heat integration modification project IFA completed April 2014
- Increased produced water from de-oiling to water treatment by twinning piping from north de-oiling tanks to WLSs
- Continue to test and evaluate ways to reduce disposal volumes
- Compliance Assurance Plan was submitted to AER on May 21, 2014
Area 02 / 12: Steam generation

- Two cogen units (40 MW each)
- Five OTSGs 180 MM btu/hr
  - re-rated BFW flow rate from 83.3 to 95 m³/hr in 2014
- Fourteen OTSGs 250 MM btu/hr in AF
  - increased firing rate on 10 steam generators from 250 to 275 MMBtu/hr in 2013
- Continuous Emission Monitoring Systems (CEMS)
  - installed on two OTSGs (B-206 & B-210)
- Operating two OTSGs at higher quality since April 2014
  - increased steam quality from 82 to 85%
Area 02: Second stage OTSG

• One 180 MM Btu/hr OTSG configured to use blowdown (BD) from other OTSGs and HRSGs and ability to mix BFW as feed

• First test
  – 14 months operation with BFW
  – 87 days at 60 m³/hr feed (100% BD), 65% steam quality
  – OTSG was pigged
  – no concerns from inspection findings

• Second test
  – 18 months operation with BFW
  – 88 days at 87.5 m³/hr feed (~60% BD & 40% BFW), 75% quality
  – tube failure on January 4, 2013 in radiant section
  – caused by scale build-up which led to localized over-heating of the tube wall
Area 02: Second stage OTSG

- **Third test**
  - 93 days at 87.5 m$^3$/h feed (65% BD, 35% BFW), 70% quality
  - trial stopped due to BD pump maintenance
  - OTSG was pigged in May 2013

- **Fourth test**
  - 116 days at 87.5 m$^3$/hr feed 100% BFW, 80% quality.
  - then 156 days at 87.5 m$^3$/hr feed (65% BD, 35% BFW), 70% quality
  - OTSG was pigged in January 2014

- **Path forward**
  - will be using all of the BD in Phase F OTSGs
  - B-0205 will be kept as back-up if needed
Area 02: Second stage OTSG challenges

- BD pump operation, control and corrosion
- Corrosion and erosion in steam generator tubes
- Inaccurate and inconsistent water testing results
  - second Stage OTSG blowdown is very dark
  - titrations using color change as endpoint difficult to interpret
- Inconclusive pigging data
- Feed water quality
  - minor excursion in BFW to 1st stage is magnified
  - high in chlorides, silicon, iron and hardness
  - second stage OTSG BD has high pH, ~ 12.5
Power generation

Average Intensity:
2.64 MW/1000 m³ bitumen

Subsection 3.1.2 – 2d)
Gas usage

Gas Consumption: 0.20 e3m3/m3 bitumen
Solution Gas Recovery = 99.5%

Subsection 3.1.2 – 2e)
2013 flared gas volume (e³m³/month)

- 2013 total flared gas 716.1 e³m³, (2 e³m³/d), 0.12 m³/m³ oil, compared to 3523 e³m³ in 2012

- July 2013 volume high due to high off-spec volumes (unable to treat flow-back from acidized wells); had to cut back or shut-in inlet production to reduce off-spec flaring resulting from plant start-ups and ramp-ups.

- October 2013 volume high due to turnaround
Greenhouse gas emissions

Subsection 3.1.2 – 2f)
Emissions

• 2013 GHG emissions including CoGen 2.193 MM tonnes CO₂e (2.170 MM tonnes in 2012)
  – total annual emissions (tonnes CO₂e) less Deemed GHG Emissions from Electricity Generation 1.954 MM tonnes or reported emissions intensity 0.3167 tonnes CO₂e/m³ bitumen

• Fugitive emissions 291.7 tonnes (547t in 2012)
  – fugitive emissions include unintentional equipment leaks such as loose flanges, PSVs not sealing properly, equipment wear, etc. Does not include equipment vents that are intentionally designed to vent.
  – using Target Emissions Services to monitor FEMs with LDAR camera to detect leaks which are then repaired
Area 04: Vapor Recovery Unit (VRU)

- One screw compressor + eight liquid ring compressors

- Engineering in progress for addition of a new screw compressor in 2015

- Engineering in progress for de-bottlenecking the VRU header piping from tanks. The major parameters manipulated were:
  - skim tank temperature
  - Sales oil tank temperature
  - Treating temperature and pressure

- Started testing three phase separator to reroute lighter diluent to LACT
Area 04: Slop handling

• four slop tanks each about 870 m$^3$
• tricanter to treat slop fluid
  – processing 200 to 250 m$^3$/d of slop fluid
  – water and oil on spec and returned to facility
  – investigating what other fluids could be treated with this system
Measurement and reporting
MARP approvals

- FGH MARP was approved in April 2011
- Salt caverns are separated from the rest of the plant for production reporting
Methods for estimating injection and production volumes

Production well metering/estimates:

- Wellhead meters are quadrant edge orifice plate meters
- Mostly manual BS&W samples
- Some test vessels with mass-flow meters and in-line BS&W monitoring
  - central pads high maintenance, over designed for current rates, not frequently used
  - two MPFMs being piloted in the east (AGARs not very consistently reliable)
  - plan to test NMR (nuclear magnetic resonance) technology for BS&W and a new proportional sampler (bench test)
- Wells are sampled once a week for BS&W
Methods for estimating injection and production volumes

Production is prorated to plant volumes:

- oil: sales – diluent +/- inventories
- water: water entering battery and transferred to the IF (sum of the ORFS +/- inventories + transfers)

Steam injection meters:

- injection well head meters are nozzle-style
- steam is measured at each injector
- steam leaving the plant is calculated using the sum of the boiler feedwater meters minus the blowdown water meters. The plant steam is then prorated to each well.
Proration factors

- oil and water estimates are obtained from the wellhead meters and manual samples
- oil and water production is calculated from meters at the plant
- proration factors are found by dividing the actual production by the estimated
- gas allocated to each well is determined by GOR for the battery
2013 oil and water proration factors

Subsection 3.1.2 – 3b)
2013 steam proration factors

2013 steam proration

Plant Steam/Field Steam

Subsection 3.1.2 – 3b)
Optimization of test durations

- wellhead flow meters are used to measure the flow rate of existing wells at Foster Creek
- this variance from standard testing duration was granted by exemption letter because the wells all have individual flow meters so flow is continuously measured
- Quadrant edge orifice meters have been proven to compare well to coriolus meters
- starting with our west pad development for Phase F (wellpad W08), test separators will be installed on future pads
Description of water production, injection and uses
Current brackish source network

Legend
- Drilled Deviated Water Source Well
- Drilled Vertical Water Source Well
- Grand Rapids Source Well
- McMurray Source Well
- Grand Rapids Piezometer
- McMurray Piezometer

LGR Wells:
- 1F2/08-29-070-03W4
- 1F2/12-28-070-03W4
- 1F1/02-28-070-03W4
- 1F1/05-28-070-03W4
- 1F1/05-27-070-03W4
- 1F1/04-27-070-03W4
- 1F2/03-27-070-03W4
- 1F1/13-14-070-03W4
- 1F2/03-27-070-03W4
- 1F2/01-23-070-03W4
- 1F1/13-13-070-03W4
- 1F2/13-14-070-03W4
- 1F1/12-14-070-03W4
- 1F1/15-09-070-03W4
- 1F1/14-09-070-03W4

McM Wells:
- 1F1/08-23-070-03W4
- 1F2/01-23-070-03W4
- 1F1/13-13-070-03W4

Subsection 3.1.2 – 4a)
Fresh source wells

Subsection 3.1.2 – 4a)
saline water use during 2013 was 3,641,661.4 m$^3$ (0.59 m$^3$/m$^3$ oil)

saline water use during Q1 2014 was 992,380 m$^3$ (0.62 m$^3$/m$^3$ oil)

2013 Saline Source/Use:
- 70% Grand Rapids (SAGD)
- 30% McMurray (SAGD)

saline water used for cooling and makeup

Subsection 3.1.2 – 4b)
2013 monthly fresh water use (m$^3$)

- Fresh water used during 2013 was 283787.5 m$^3$ (.046 m$^3$/m$^3$ bitumen) compared to 156,201 m$^3$ in 2012.
- Fresh water used during Q1 2014 was 127174.1 m$^3$ (0.08 m$^3$/m$^3$ oil).
- Fresh water used for utilities and makeup.

[Bar chart showing water usage by quarter with Q2 and Q4 highlighted.]
Produced water

Lightning storm triggered islanding and load shed procedure. Lots of offspec produced.

Subsection 3.1.2 – 4c)
Steam generation

Monthly Steam Volumes

Lightning storm triggered islanding and load shed procedure. Lots of offspec

Subsection 3.1.2 – 4d)
Water Recycle Ratio

Approval 90%
2013 Avg 91.4%
Q1 2014 Avg 94.3%

PWR %

Jan/13  Feb/13  Mar/13  Apr/13  May/13  Jun/13  Jul/13  Aug/13  Sep/13  Oct/13  Nov/13  Dec/13  Jan/14  Feb/14  Mar/14

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## Water quality parameters

<table>
<thead>
<tr>
<th>Mg/L</th>
<th>McMurray</th>
<th>Grand Rapids</th>
<th>Produced</th>
<th>Boiler feed water</th>
<th>Boiler blowdown</th>
</tr>
</thead>
<tbody>
<tr>
<td>TDS</td>
<td>9400</td>
<td>5800</td>
<td>2000</td>
<td>3200</td>
<td>19000</td>
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<tr>
<td>SiO2</td>
<td>8.6</td>
<td>8.5</td>
<td>124</td>
<td>15.4</td>
<td>70</td>
</tr>
<tr>
<td>CL</td>
<td>5200</td>
<td>3600</td>
<td>861</td>
<td>1330</td>
<td>4500</td>
</tr>
<tr>
<td>Na</td>
<td>3500</td>
<td>2100</td>
<td>700</td>
<td>1010</td>
<td>4800</td>
</tr>
<tr>
<td>K</td>
<td>12</td>
<td>7.6</td>
<td>21</td>
<td>18</td>
<td>365</td>
</tr>
<tr>
<td>Ca</td>
<td>35</td>
<td>20</td>
<td>13</td>
<td>&lt;1</td>
<td>1</td>
</tr>
<tr>
<td>Alkalinity (as CaCO3)</td>
<td>1200</td>
<td>300</td>
<td>355</td>
<td>350</td>
<td>1800</td>
</tr>
<tr>
<td>pH</td>
<td>8.15</td>
<td>8.25</td>
<td>7.58</td>
<td>9.43</td>
<td>11.95</td>
</tr>
<tr>
<td>Fe</td>
<td>2.6</td>
<td>0.6</td>
<td>0.5</td>
<td>&lt;0.02</td>
<td>3</td>
</tr>
</tbody>
</table>

*Subsection 3.1.2 – 4)*
Foster Creek McMurray water disposal

- Class 1B (18 wells) approval 11351E, Class II (1 well) Approval 11059A
- Nine additional wells drilled on ED3 pad in December 2011 – D65/D51 application submitted and waiting for approval
- Water disposal includes water from operations (produced, regens, blowdown) and brines from cavern washing and displacements
- Regens are performed using softened water (brackish + produced, no fresh water) and combined with produced water for disposal
- Well workovers include coil cleanouts and acid stimulations
- Volumes are measured on each individual well by turbine or mag meters and pressure is measured at common headers located at the disposal pads
### Foster Creek McMurray water disposal wells

<table>
<thead>
<tr>
<th>UWI</th>
<th>Approval No.</th>
<th>Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>102/02-02-070-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>100/03-02-070-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>100/08-02-070-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>103/10-02-070-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>104/11-02-070-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>105/11-02-070-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>104/10-02-070-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>100/02-02-070-04W4 (LGR)</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>102/10-02-070-04W4</td>
<td>11059C</td>
<td>Class II</td>
</tr>
<tr>
<td>102/11-34-069-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>100/12-34-069-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>102/12-34-069-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>103/11-34-069-04W4</td>
<td>11351E</td>
<td>Class IB</td>
</tr>
<tr>
<td>100/16-19-069-03W4</td>
<td>11315E</td>
<td>Class 1B</td>
</tr>
</tbody>
</table>

**Subsection 3.1.2 – 4g)**
Current disposal well locations

Subsection 3.1.2 – 4g)

ED1 Pad

ED2 Pad

ED3 Pad

Legend

Disposal Wells:

ED1 Pad:
WDHZ 1 – 100/03-02-070-04W4
WDHZ 2 – 100/02-02-070-04W4
WDHZ 3 – 102/02-02-070-04W4
WDHZ 4 – 100/08-02-070-04W4
WD6 – 104/11-02-070-03W4
WD7 – 105/11-02-070-03W4
WD8 – 104/10-02-070-03W4
WD9 – 102/10-02-070-03W4
WD10 – 103/10-02-070-03W4

ED2 Pad:
WD11 – 102/11-34-069-04W4
WD12 – 100/12-34-069-04W4
WD13 – 103/11-34-069-04W4
WD14 – 102/12-34-069-04W4
WD15 – 100/06-34-069-04W4
WD16 – 100/05-34-069-04W4
WD17 – 102/06-34-069-04W4
WD18 – 102/05-34-069-04W4
WD19 – 100/03-34-069-04W4
WD20 – 100/04-34-069-04W4

ED3 Pad:
WD21 – 100/02-30-069-03W4
WD22 – 100/03-30-069-03W4
WD23 – 100/16-19-069-03W4
WD24 – 100/14-19-069-03W4
WD25 – 100/16-19-069-03W4
WD26 – 102/14-19-069-03W4
WD27 – 100/09-19-069-03W4
WD28 – 100/11-19-069-03W4
WD29 – 100/10-19-069-03W4
WD30 – 102/11-19-069-03W4

Abandoned Disposal well:
WD5 – 103/11-02-070-03W4

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McMurray class 1B approval

No. 11351E MWHIP 6,250 kPag

Avg. Operating Temp
55-60°C

Subsection 3.1.2 – 4h)
McMurray class II approval

No. 11059A MWHIP 6,255 kPa

Avg. Operating Temp
40-50°C

Subsection 3.1.2 – 4h)
Waste disposal

<table>
<thead>
<tr>
<th>Foster Creek Waste Streams</th>
<th>2013 Volume (m³)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slop oil</td>
<td>47,740</td>
<td>NewAlta Elk Point/Newalta Hughendon/Tervita Lindbergh Cavern</td>
</tr>
<tr>
<td>Drilling waste</td>
<td>44,256</td>
<td>Newalta Elk Point/Tervita Lindbergh Cavern/Tervita Bonnyville Landfill</td>
</tr>
<tr>
<td>Lime sludge</td>
<td>22,993</td>
<td>Newalta Elk Point/Tervita Lindbergh Cavern/Tervita Bonnyville Landfill</td>
</tr>
<tr>
<td>Contaminated soils</td>
<td>604</td>
<td>Newalta Elk Point/Tervita Lindbergh Cavern/Tervita Bonnyville Landfill</td>
</tr>
<tr>
<td>Sweetening liquids/sludge</td>
<td>6,683</td>
<td>Absolute Environmental Class 1a Disposal Well/Cancen New Sarepta/Newalta Elk Point/Tervita Lindbergh Cavern</td>
</tr>
<tr>
<td>Acid Workover Program</td>
<td>11,701</td>
<td>Newalta Elk Point/Tervita Lindbergh Cavern</td>
</tr>
</tbody>
</table>
Sulphur production
Sulphur recovery overview

- Central facility non-regenerative sweetening unit (NRSU) has been used since April 2007 to meet sulphur recovery requirements
  - second unit added in 2010 – can be used in parallel or for backup
  - high operating costs for chemical and disposal
  - balance recoveries on a daily/monthly basis

- Sulphur recovery – Q1 2013: 72.2%, Q2 2013: 70.6%, Q3 2013: 71.6%, Q4 2013: 72.0%, Q1 2014 70.0%
## Sulphur recovery

<table>
<thead>
<tr>
<th></th>
<th>Total Sulphur tonnes</th>
<th>Recovered Sulphur tonnes</th>
<th>Emissions tonnes</th>
<th>Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan 2013</td>
<td>117.3</td>
<td>98.4</td>
<td>18.9</td>
<td>83.85</td>
</tr>
<tr>
<td>Feb 2013</td>
<td>101.5</td>
<td>82.8</td>
<td>18.7</td>
<td>81.63</td>
</tr>
<tr>
<td>Mar 2013</td>
<td>116.62</td>
<td>76.64</td>
<td>39.98</td>
<td>67.99</td>
</tr>
<tr>
<td>Apr 2013</td>
<td>120.31</td>
<td>85.17</td>
<td>35.13</td>
<td>70.72</td>
</tr>
<tr>
<td>May 2013</td>
<td>41.36</td>
<td>30.84</td>
<td>10.53</td>
<td>72.39</td>
</tr>
<tr>
<td>Jun 2013</td>
<td>108.32</td>
<td>76.41</td>
<td>31.91</td>
<td>70.42</td>
</tr>
<tr>
<td>Jul 2013</td>
<td>144.62</td>
<td>80.56</td>
<td>64.06</td>
<td>55.78</td>
</tr>
<tr>
<td>Aug 2013</td>
<td>129.45</td>
<td>114.32</td>
<td>15.13</td>
<td>88.53</td>
</tr>
<tr>
<td>Sep 2013</td>
<td>131.72</td>
<td>91.84</td>
<td>39.89</td>
<td>70.16</td>
</tr>
<tr>
<td>Oct 2013</td>
<td>141.53</td>
<td>100.13</td>
<td>41.40</td>
<td>70.76</td>
</tr>
<tr>
<td>Nov 2013</td>
<td>116.77</td>
<td>87.79</td>
<td>28.98</td>
<td>75.12</td>
</tr>
<tr>
<td>Dec 2013</td>
<td>144.48</td>
<td>100.87</td>
<td>43.61</td>
<td>69.87</td>
</tr>
</tbody>
</table>
## Sulphur recovery

<table>
<thead>
<tr>
<th></th>
<th>Total Sulphur tonnes</th>
<th>Recovered Sulphur tonnes</th>
<th>Emissions tonnes</th>
<th>Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan 2014</td>
<td>101.1</td>
<td>80.3</td>
<td>20.8</td>
<td>79.4</td>
</tr>
<tr>
<td>Feb 2014</td>
<td>82.5</td>
<td>63.9</td>
<td>18.6</td>
<td>77.5</td>
</tr>
<tr>
<td>Mar 2014</td>
<td>100.3</td>
<td>55.2</td>
<td>45.1</td>
<td>55.3</td>
</tr>
</tbody>
</table>
SO$_2$ emissions (tonnes per day)

Subsection 5.1.2 – 6c)
Environmental issues summary
Environmental non-compliance 2013

AESRD Air related: Nox limit exceedance
- April 30 – Cogen 1201
- August 13 & 27 – Cogen 1201 & 1202

Land related:
- twenty-four environmental spills were reported and remedial action taken

AESRD Water Related:
- nine 7-day letters submitted
- non-compliance to license approval conditions (7), discharge criteria (1) or hydrocarbon/BTEX limit (1)

Federal
- no non-compliance events
## AER scheme applications – filed in 2013, approval received

<table>
<thead>
<tr>
<th>Application</th>
<th>Filing Date</th>
<th>Approval</th>
</tr>
</thead>
<tbody>
<tr>
<td>West Phase Pads and DA Expansion</td>
<td>June 3, 2013</td>
<td>December 12, 2013</td>
</tr>
<tr>
<td>W06 &amp; E21 Additional Well Pairs</td>
<td>August 9, 2013</td>
<td>January 7, 2014</td>
</tr>
<tr>
<td>GP05 Redrill and Extention</td>
<td>September 9, 2013</td>
<td>September 27, 2013</td>
</tr>
<tr>
<td>Regional McMurray Well Update LW06</td>
<td>November 26, 2013</td>
<td>December 12, 2013</td>
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</tbody>
</table>
AER scheme applications – filed in 2013, approval received continued

<table>
<thead>
<tr>
<th>Application</th>
<th>Filing Date</th>
<th>Approval</th>
</tr>
</thead>
<tbody>
<tr>
<td>F &amp; G Rampdown and Air Injection</td>
<td>April 26, 2013</td>
<td>June 8, 2014</td>
</tr>
<tr>
<td>Class 1B disposal ED3</td>
<td>December 19, 2013</td>
<td>May 9, 2014</td>
</tr>
</tbody>
</table>

Subsection 3.1.2 – 6b)
AER scheme applications – filed in 2013, approval pending

<table>
<thead>
<tr>
<th>Application</th>
<th>Filing Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase J Expansion</td>
<td>February 27, 2013</td>
</tr>
</tbody>
</table>

Subsection 3.1.2 – 6b)
• **Addition of flare stacks S-0504 and S-0505**
  approved April 26, 2013 (68492-01-01)

• **Kodiak Den wastewater treatment plant**
  approved June 26, 2013 (68492-01-02)
Annual reporting - 2013

The following reports were submitted March 2013 as per EPEA Approval 00068492-01-02:

• annual groundwater report
• annual C&R plan
• annual air monitoring report
• annual industrial runoff report
Cenovus is required to implement the following monitoring programs as part of EPEA Approval 00068492-01-02:

<table>
<thead>
<tr>
<th>EPEA Requirement</th>
<th>Report Name</th>
<th>Due Date</th>
<th>Status</th>
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</thead>
<tbody>
<tr>
<td>Schedule VIII, Condition 4</td>
<td>Wildlife Mitigation Program</td>
<td>October 31, 2012</td>
<td>Implemented</td>
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<tr>
<td>Schedule VIII, Condition 13</td>
<td>Wildlife Monitoring Program</td>
<td>October 31, 2012</td>
<td>Implemented</td>
</tr>
<tr>
<td>Schedule VIII, Condition 9</td>
<td>Woodland Caribou Mitigation and Monitoring Plan</td>
<td>January 31, 2013</td>
<td>Implemented</td>
</tr>
<tr>
<td>Schedule IX, Condition 41</td>
<td>Wetland Reclamation Trial Program</td>
<td>June 28, 2013</td>
<td>Submitted to ESRD, SIR responses submitted to AER</td>
</tr>
<tr>
<td>Schedule IX, Condition 47</td>
<td>Reclamation Monitoring Program</td>
<td>July 31, 2013 (submission extension)</td>
<td>Submitted to ESRD, SIR responses to be submitted to AER Q2 2014</td>
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<tr>
<td>Schedule XI, Condition 2</td>
<td>Wetland Monitoring Program</td>
<td>June 28, 2013</td>
<td>Authorized</td>
</tr>
<tr>
<td>Schedule VII, Condition 1</td>
<td>Soil Monitoring Programs</td>
<td>February 1, 2014 February 1, 2019</td>
<td>Submitted</td>
</tr>
<tr>
<td>Schedule IX, Condition 28</td>
<td>Project-Level Conservation, Reclamation and Closure Plan</td>
<td>June 30, 2016 (industry-wide extension granted)</td>
<td>Not due yet</td>
</tr>
<tr>
<td>Schedule IX, Condition 17</td>
<td>Decommissioning Plan and Land Reclamation Plan</td>
<td>Within six months of the plant ceasing operation</td>
<td>Not due yet</td>
</tr>
</tbody>
</table>
Goals of monitoring programs

Wildlife and Caribou Mitigation and Monitoring:

• The monitoring programs propose mitigation and monitoring objectives, metrics and targets

• Monitoring and mitigation is based on an outcomes based approach to facilitate continuous improvement

• Mitigation measures are designed in relation to project-related issues that have the potential to affect:
  • wildlife habitat availability and use, including noise and other sensory disturbance
  • wildlife mortality
  • obstruction of movement
Goals of monitoring continued

Wetland monitoring:

• Objective is to assess and quantify potential impacts of project infrastructure on surrounding wetlands using selected metrics and targets

• Effects of roads, well pads, borrow pits and CPFs will be monitored throughout the life of the project by assessing key parameters including water quality, water levels, vegetation species composition, cover and vigour
Co-operative initiatives

Cenovus participates in various co-operative efforts to address industry issues:

- Regional environmental monitoring
- Environmental research
- Stakeholder consultation
- Innovation and continuous improvement
Cooperative initiatives - Examples

• Canada’s Oil Sands Innovation Alliance (COSIA)

• Contributed to over thirty projects including: Wildwatch, LiDEA, Fladry, Geodesign, Functional Quality Land Metric, etc.

• Support for three chairs at the University of Alberta

• Contributor to the Joint Canada-Alberta Oil Sands Monitoring (JOSM)

• Lakeland Industry and Community Association (LICA)
  • Airshed Monitoring
  • Beaver River Watershed Alliance
Cooperative initiatives continued

- Regional Industry Caribou Collaboration project
- Alberta Chamber of Resources (ARC)
  - chair of the caribou committee
- Ecological Monitoring Committee for the Lower Athabasca (EMCLA)
- CAPP Environment Committee
Reclamation

• The Reclamation Monitoring Program proposal was submitted to ESRD in July 2013, SIRs for the program to be submitted Q2 2014

• Final reclamation activities have been initiated and/or completed on small portions of the commercial footprint (remote from the CPF) that are no longer required (~6 ha in 2013)

• Interim reclamation is present on approximately 30% of the commercial footprint not currently being used in construction or operations

• Stockpiles and associated vegetation growth were reviewed in 2013, and 24 stockpiles were planted with > 8,000 trees and/or woody shrubs

• There is currently no facility abandonment scheduled, consequently no well pad reclamation has commenced
Restoration of legacy 2D seismic footprints was initiated in 2012 and continued in 2013:

- TWP 72 & 73, RGE 1 & 2, W4M
- Objective is successional advancement, increasing the growth and abundance of conifers and course wood on linear features, reducing trafficability
- Treatments employed on linear features include mounding, stand modification and tree planting
- Treatment progress to-date has covered 193 km of a total potential 235 km in the treatment area (82% complete)
Statement of Compliance
Cenovus maintains and tracks compliance through the CenTrac conditions/commitment database, Incident Management System (IMS), routine inspections, and dedicated regulatory and environmental staff.

Cenovus believes its operations are in compliance with AER approvals and regulatory requirements.
Non-compliance events

AER enforcement action:

October 25, 2013

• High risk and low risk enforcement as a result of rig inspection at 16-19-70-4W4
• Non-compliance to Directive 036 (diverter line non-compliance)

Corrective action

• Cenovus corrected immediately by engaging contractor
Self-disclosures

September 24, 2013

- Clay liner in Area 1 tank farm had insufficient hydraulic conductivity as required by *Directive 055*

Corrective action

- Cenovus shut-in equipment and submitted repair plan to AER which was approved in Q4
Self-disclosures continued

Sept 26, 2013

- Continuous vent source on facility (tricanting centrifuge) found to be non-compliant with current facility license

Corrective action

- Equipment was shut-in. Cenovus working with vendor to engineer solution.
Self-disclosures continued

January 6, 2014

• Administrative review determined that non-steam pipeline segments had been constructed prior to issue of facility license. License applications were closed due to complications with ABSA registration.

Corrective action

• Licenses were issued in September 2013; further licensing not required
• Further training sessions were held outlining Directive 056 requirements
Self-disclosures continued

January 23, 2014

• Over-pressure on pipeline @ 6-34-69-4W4 due to dislodged fuse on XV

Corrective action

• Contractor was retrained on procedure for working with live circuits
• Pipeline was inspected; no damage occurred and the incident did not result in a release
Self-disclosures continued

January 31, 2014

- Incorrect licensing of pumps and compressors at FC main plant

Corrective action

- Updated facility license was filed, issued May 5, 2014
Future plans
Future projects

- Current capacity is 120,000 bbls/d, expectations for Phases F, G & H to peak at 240,000 bbls/d. Evaluating opportunities to increase capacity.

- Currently scoping plant optimization opportunities for Phases A-E

- Phases F, G & H update
  - New steam generation and production treating facilities being constructed next to the existing plant
  - Phase F: 30,000 bbls/d, Phase G: 30,000 bbls/d, Phase H: 30,000 bbls/d, for total new capacity of 90,000 bbls/d ($4,770 \text{ m}^3/\text{d} + 4,770 \text{ m}^3/\text{d} + 4,770 \text{ m}^3/\text{d} = 14,310 \text{ m}^3/\text{d})$
  - Potential for another 35,000 bbls/d of optimization work
  - The majority of new expansion is planned to be drilled west of the plant

Note that production volumes refer to production capacity on an incremental basis
Future projects continued

• Current success in SOR & WOR, and increased efficiencies in plant operations at Foster Creek indicates that Phases A – H may be capable of production greater than 240,000 bbls/d

• Upcoming regulatory applications
  • Currently evaluating opportunities to increase project capacity to 300,000 bbl/d (47,696 m³/d)
  • Additional wells to recover un-swept reserves including injector-producer well pairs and single well producers
  • Continued exit strategies for mature pads
  • Future phase & sustaining development well pads

• Currently drilling, completing and performing facilities work for sustaining and Phase F and G wells in 2014 through 2015

Note that production volumes refer to production capacity on an incremental basis
End
Advisory

This document contains forward-looking information prepared and submitted pursuant to Alberta regulatory requirements and is not intended to be relied upon for the purpose of making investment decisions, including without limitation, to purchase, hold or sell any securities of Cenovus Energy Inc. Additional information regarding Cenovus Energy Inc. is available at www.cenovus.com.
Agenda

- Foster Creek is our 50/50 joint venture with ConocoPhillips in which Cenovus is the operator
- Pad Updates (C, D, A)
  - Operational review
  - Temperature monitoring
  - Fluid saturation updates
  - Compositional analysis
- Next steps
  - A, C, & D Pad
Rate calculation error (wrong orifice plate size in DCS) under reported previous methane volumes from Mar 2012 – Jan 2014.
Corrected Injected Methane Rates

Rate calculation error (wrong orifice plate size in DCS) under reported previous methane volumes from Oct 2012 – Feb 2014.
Corrected Injected Methane Rates

Rate calculation error (wrong orifice plate size in DCS) under reported previous methane volumes from May 2012 – Feb 2014.
C Pad – Update

- Pad update – C pad
  - Operational review
  - Temperature monitoring
  - Fluid Saturation updates
  - Compositional analysis
23) The operator shall conduct the ramping down and ceasing of steam injection, and injecting of non-condensible gas, at well pads A, C, D subject to the following conditions:

a) The non-condensible gas injected will only be methane (fuel gas)
C Pad – Operational Overview

Injectors:
- CI11, CI12, CI13, CI14, CI15, and CI16 equipped and operational for methane injection
  - CI33 requires commissioning
- Methane injection started in November 2011
  - Full blowdown March 4, 2013
- Pad cum injection of 64,912 Se$^3$m$^3$ of methane to April 30, 2014
  - Rate calculation error (wrong orifice plate size in DCS) under reported previous methane volumes

Producers:
- CP11, CP13, CP14, and CP15 are currently shut-in
  - CP12 (offline)
  - CP16 (offline)
  - CP33-1 abandoned
- 7 wells utilizing Wedge Well™ technology are in operation
  - CW07 (offline)
### C Pad – Injection Summary

<table>
<thead>
<tr>
<th>Injector</th>
<th>Methane Injection Start Date</th>
<th>Cum gas injected to Apr 30, 2014 (Sm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CI11</td>
<td>Nov 2011</td>
<td>10,812</td>
</tr>
<tr>
<td>CI12</td>
<td>Feb 2012</td>
<td>13,346</td>
</tr>
<tr>
<td>CI13</td>
<td>Feb 2012</td>
<td>11,285</td>
</tr>
<tr>
<td>CI14</td>
<td>Nov 2011</td>
<td>7,749</td>
</tr>
<tr>
<td>CI15</td>
<td>Mar 2012</td>
<td>11,551</td>
</tr>
<tr>
<td>CI16</td>
<td>Feb 2012</td>
<td>10,168</td>
</tr>
<tr>
<td>CI33</td>
<td>Nov 2012</td>
<td>2</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>64,912</td>
</tr>
</tbody>
</table>

Cum gas since November 2011.

Rate calculation error (wrong orifice plate size in DCS) under reported previous methane volumes.

---

Well pairs

Wells utilizing Wedge Well™ technology
C Pad – Oil Voidage

- Percentage gas injected volume per oil produced

**Gas - Chamber Conditions**

- 64,912 Se3m3, Methane Injected (Std Conditions)
- 14,469 Se3m3, Methane Produced, excluding solution gas (Std Conditions)
- 50,443 Se3m3, Net Methane Injected (Std Conditions)

8.648 kg/m3, Density of Methane in Chamber

- 3,849,820 m3, Net Methane Injected at Reservoir Conditions

**% Gas Volume Injected vs Oil Voidage**

Since Start of C Pad Production, 2001

- 3,849,820 m3 of net methane injected (reservoir conditions)
- 3,682,540 m3 of oil produced (as of Nov 30, 2013)

104.5% oil voidage displaced by injected methane
C Pad – Injection Strategy

Phase 5: March 2013 onwards

- Pad steam injection shut-in, full pad blowdown
- Methane gas volumes adjusted to maintain reservoir pressure / balance with offset pads
- Currently shut-in well pair producers to evaluate impact on oil and methane production
WOR has remained relatively consistent since start of rampdown.
Temperature Logs & Fluid Saturation

23) b) Temperature measurement must be conducted a minimum of twice each calendar year at the designated observation wells listed below and the observation well referred in subclause (e). A suitable baseline temperature measurement must be available or obtained at each designated observation well listed below and the observation well referred to in subclause (e) prior to commencement of steam ramp down at each pad.

23) c) Fluid saturation measurements must be conducted a minimum of once every calendar year using well logging at a minimum of one observation well at each well pad. A suitable baseline fluid saturation measurement must be available or obtained at a minimum of one observation well at each well pad prior to the commencement of steam ramp down at each well pad.
C Pad: Temperature & Fluid Monitoring

- C Pad Logging History

<table>
<thead>
<tr>
<th>Target Steam</th>
<th>Temperature Log</th>
<th>RST Log</th>
</tr>
</thead>
<tbody>
<tr>
<td>100%</td>
<td>Jan 2012</td>
<td>Dec 2011</td>
</tr>
<tr>
<td>50%</td>
<td>Aug 2012</td>
<td>Aug 2012</td>
</tr>
<tr>
<td>30%</td>
<td>Dec 2012</td>
<td></td>
</tr>
<tr>
<td>0%</td>
<td>March 2013</td>
<td>Mar 2013</td>
</tr>
<tr>
<td>0%</td>
<td>Dec 2013</td>
<td>Dec 2013</td>
</tr>
<tr>
<td>0%</td>
<td>March 2014</td>
<td></td>
</tr>
</tbody>
</table>
• 3m offset C15 Well Pair
• Dec 2013 and Mar 2014 temperature curves are comparable.
• Current logged temperature is 192 deg C
• Temperatures before steam ramp down were 210 degC (below calculated TSAT).
• RST log shows a relative increase in gas saturation above the injector well
• RST So implies continued oil drainage from the lateral accretion beds and from within the steam chamber.
C Pad – B6-22

- 10m offset C11 Well Pair

- recent temperature curves are comparable, and very similar to pre-ramp down temperatures (205 deg C).

- RST curves imply continued oil drainage from the pay zone.
## C Pad Summary

### A7-22-70-4

<table>
<thead>
<tr>
<th></th>
<th>Phase 3: 50% Target Steam</th>
<th>Phase 4: 0% Target Steam</th>
<th>Phase 4: 0% Target Steam</th>
<th>% Change from Mar-2013 to Dec 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Aug-2012</td>
<td>Mar-2013</td>
<td>Dec-2013</td>
<td></td>
</tr>
<tr>
<td>$S_o$ ave in Steam Chamber</td>
<td>7.5%</td>
<td>7.4%</td>
<td>6.7%</td>
<td>-0.7%</td>
</tr>
<tr>
<td>$S_g$ ave in Steam Chamber</td>
<td>58%</td>
<td>63%</td>
<td>66%</td>
<td>2.5%</td>
</tr>
</tbody>
</table>

### B6-22-70-4

<table>
<thead>
<tr>
<th></th>
<th>Phase 3: 50% Target Steam</th>
<th>Phase 4: 0% Target Steam</th>
<th>Phase 4: 0% Target Steam</th>
<th>% Change from Mar-2013 to Dec 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Aug-2012</td>
<td>Mar-2013</td>
<td>Dec-2013</td>
<td></td>
</tr>
<tr>
<td>$S_o$ ave in Steam Chamber</td>
<td>9.3%</td>
<td>6.7%</td>
<td>6.9%</td>
<td>0.2%</td>
</tr>
<tr>
<td>$S_g$ ave in Steam Chamber</td>
<td>65%</td>
<td>67%</td>
<td>67%</td>
<td>0.1%</td>
</tr>
</tbody>
</table>
23) d) Compositional analysis of the casing gas at the AP4, CP16, DP20 wells and compositional analyses of the produced gas on a group basis for each well pad must be obtained monthly, commencing prior to the start of steam ramp down at each well pad.
D Pad – Update

• Pad Update – D Pad
  • Operational review
  • Temperature monitoring
  • Fluid saturation updates
  • Compositional analysis
Methane Injection

23) The operator shall conduct the ramping down and ceasing of steam injection, and injecting of non-condensible gas, at Well Pads A, C, D subject to the following conditions:

a) The non-condensible gas injected will only be methane (fuel gas)
D Pad – Operational Overview

Injectors:
- DI17, DI19, DI20, DI22 and DI34 equipped and operational for methane injection
  - DI18 – Abandoned well
  - DI21 - Abandoned well
  - DI34 - steam shut-in as of Dec 10, 2012
  - Methane injection initially started in August 2010 at low rates
  - Pad cumulative injection of 15,095 Se³m³ of methane to April 30, 2014
    - Rate calculation error (wrong orifice plate size in DCS) slightly under reported previous methane volumes

Producers:
- Production maintained on DP17, DP20, DP21, DP22, DF-1, & DP34
  - DP18 - Abandoned well
  - DP19 - Production issues, well not producing

All 6 wells drilled using our Wedge Well™ technology operational
## D Pad – Injection Summary

<table>
<thead>
<tr>
<th>Injector</th>
<th>Methane Injection Start Date</th>
<th>Cum gas injected to Apr 30, 2014 (Se3m3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DI17</td>
<td>May 2012</td>
<td>268</td>
</tr>
<tr>
<td>DI19</td>
<td>Aug 2010</td>
<td>2,172</td>
</tr>
<tr>
<td>DI20</td>
<td>Aug 2010</td>
<td>1,737</td>
</tr>
<tr>
<td>DI21</td>
<td>Aug 2010</td>
<td>267</td>
</tr>
<tr>
<td>DI22</td>
<td>Aug 2010</td>
<td>1,389</td>
</tr>
<tr>
<td>DI34</td>
<td>April 2012</td>
<td>9,262</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>15,095</strong></td>
</tr>
</tbody>
</table>

Cum gas since Aug 2010.

Rate calculation error (wrong orifice plate size in DCS) under reported previous methane volumes.

---

Well pairs

Wells utilizing Wedge Well™ technology
D Pad – All Wells Production and Injection
No plans for rampdown, plan to continue steaming as per Aug, 2012 amendment and Approval 8623HH.
Steam shut off in Dec, 2012 as per Aug, 2012 amendment and Approval 8623HH.
Numerous operational issues delayed rampdown on D Pad. First steam cuts occurred in late December 2013.
D Pad – Oil Voidage

- Percentage gas injected volume per oil produced

**Gas - Chamber Conditions**

15,095 m³, Methane Injected (Std Conditions)
4,275 m³, Methane Produced, excluding solution gas (Std Conditions)
10,820 m³, Net Methane Injected (Std Conditions)

8.648 kg/m³, Density of Methane in Chamber

825,803 m³, Net Methane Injected at Reservoir Conditions

**% Gas Volume Injected vs Oil Voidage**

_Since Start of D Pad Production, 2001_

825,803 m³ of net methane injected (reservoir conditions)
4,289,082 m³ of oil produced (as of April 30, 2014)

19.3% oil voidage displaced by injected methane
D Pad – Current Injection Strategy

Phase 1: Aug 2010 through Dec 2012
- Attempt to stabilize steam injection and commence low gas injection rates
- Blowdown on DI34 commencing in Dec 2012

Phase 2: Dec 2012 to Dec 2013
- Steam injection adjusted to maintain target pressures
- Blowdown on DI34 commenced in Dec 2012
- DI17 back online in Mar 2013
- Full steam injection on DI17 (methane shut-off)

Phase 3: Dec 2013
- Monitor A and C Pads and apply learnings
- Cut steam injection to ~85% of original target
- Methane gas volumes adjusted to maintain reservoir pressure / balance with offset pads
- Achieve stable injection rates and pressures prior to next cut
- Methane only injection on DI34; continued steaming DI17

Phase 4: Dec 2013 to Oct 2014
- Monitor A and C Pads and apply learnings
- Achieve stable injection rates and pressures (~1-4 months) prior to steam cuts (10-25%)
- Methane gas volumes adjusted to maintain reservoir pressure / balance with offset pads
- Methane only injection on DI34; continued steaming DI17

Phase 5: Oct 2014 onwards
- Steam cut to all wells except DI17
- Methane gas volumes adjusted to maintain reservoir pressure / balance with offset pads
D Pad – Predictive Forecast

DI17 remains on steam
23) b) Temperature measurement must be conducted a minimum of twice each calendar year at the designated observation wells listed below and the observation well referred in subclause (e). A suitable baseline temperature measurement must be available or obtained at each designated observation well listed below and the observation well referred to in subclause (e) prior to commencement of steam ramp down at each pad.

23) c) Fluid saturation measurements must be conducted a minimum of once every calendar year using well logging at a minimum of one observation well at each well pad. A suitable baseline fluid saturation measurement must be available or obtained at a minimum of one observation well at each well pad prior to the commencement of steam ramp down at each well pad.
D Pad: Temperature & Fluid Monitoring

- D Pad Logging History

<table>
<thead>
<tr>
<th>Target Steam</th>
<th>Temperature Log</th>
<th>Rst Log</th>
</tr>
</thead>
<tbody>
<tr>
<td>100%</td>
<td>Dec 2011</td>
<td>Dec 2011</td>
</tr>
<tr>
<td>100%</td>
<td>March 2012</td>
<td></td>
</tr>
<tr>
<td>100%</td>
<td>Dec 2012</td>
<td>Dec 2012</td>
</tr>
<tr>
<td>100%</td>
<td>March 2013</td>
<td></td>
</tr>
<tr>
<td>90%</td>
<td>Dec 2013</td>
<td>Dec 2013</td>
</tr>
<tr>
<td>80%</td>
<td>March 2014</td>
<td></td>
</tr>
</tbody>
</table>
D Pad – D2-22

- 20m offset D21 Well Pair

TSAT ~216°C

225°C
D Pad - D16-15

• 10m offset D22 Well Pair

TSAT ~216°C

220°C
D Pad – C13-14

- 9m offset D21 Well Pair

TSAT ~216°C

223°C
D Pad – B4-23

- 4m offset D19 Well Pair

TSAT ~216°C

193°C
D Pad – C16-15

- 19m offset D34 Well Pair

227°C

TSAT ~216°C
## D Pad Summary

<table>
<thead>
<tr>
<th></th>
<th>D16-15-70-4</th>
<th></th>
<th>B4-23</th>
<th></th>
<th>C13-14</th>
<th></th>
<th>D2-22</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Phase 1: 100% Target Steam</td>
<td>Phase 1: 100% Target Steam</td>
<td>Phase 3: 90% Target Steam</td>
<td></td>
<td>Phase 1: 100% Target Steam</td>
<td>Phase 1: 100% Target Steam</td>
<td>Phase 3: 90% Target Steam</td>
<td></td>
</tr>
<tr>
<td>$S_o$ ave in Steam Chamber</td>
<td>11.0%</td>
<td>7.0%</td>
<td>4.7%</td>
<td>-2.3%</td>
<td>9.0%</td>
<td>8.0%</td>
<td>5.9%</td>
<td>-2.1%</td>
</tr>
<tr>
<td>$S_g$ ave in Steam Chamber</td>
<td>59%</td>
<td>65%</td>
<td>74%</td>
<td>8.7%</td>
<td>68%</td>
<td>72%</td>
<td>73%</td>
<td>1.0%</td>
</tr>
<tr>
<td>$S_o$ ave in Steam Chamber</td>
<td>8.0%</td>
<td>6.0%</td>
<td>4.3%</td>
<td>-1.7%</td>
<td>66%</td>
<td>62%</td>
<td>69%</td>
<td>6.5%</td>
</tr>
</tbody>
</table>
23) d) Compositional analysis of the casing gas at the AP4, CP16, DP20 wells and compositional analyses of the produced gas on a group basis for each well pad must be obtained monthly, commencing prior to the start of steam ramp down at each well pad.
D Pad – Methane C1 Mole Composition

Methane Injection Start

Mole Fraction Air Free As Rec'd

Jan-09 Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15

Group Separator DP17 DP20 DP21 DP22 DP34

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A Pad – Update

- Pad update – A pad
  - Operational review
  - Temperature monitoring
  - Fluid saturation updates
  - Compositional analysis
23) The operator shall conduct the ramping down and ceasing of steam injection, and injecting of non-condensible gas, at Well Pads A, C, D subject to the following conditions:

a) The non-condensible gas injected will only be methane (fuel gas)
A Pad – Operational Overview

Injectors:
- AI1, AI4 and AI32 equipped and operational for methane injection
- AI2 and AI3 abandoned
- Methane injection started in March 2012
- Pad cum injection of 11,379 Se$^3$m$^3$ of methane to April 30, 2014
  - Rate calculation error (wrong orifice plate size in DCS) slightly over reported previous methane volumes.

Producers:
- AP1, AP2, AP3, and AP32 are operational
  - AP4 (offline)
- All 5 wells utilizing Wedge Well™ technology are in operation
A Pad – Injection Summary

<table>
<thead>
<tr>
<th>Injector</th>
<th>Methane Injection Start Date</th>
<th>Cum gas injected to Apr 30, 2014 (Sm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AI1</td>
<td>Mar 2012</td>
<td>4,282</td>
</tr>
<tr>
<td>AI4</td>
<td>Apr 2012</td>
<td>3,180</td>
</tr>
<tr>
<td>AI32</td>
<td>Mar 2012</td>
<td>3,917</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>11,379</td>
</tr>
</tbody>
</table>

Cum gas since March 2012.

Rate calculation error (wrong orifice plate size in DCS) slightly over reported previous methane volumes.

Well pairs

Wells utilizing Wedge Well™ technology
A Pad – Oil Voidage

• % Gas Injected Volume per Oil Produced

**Gas - Chamber Conditions**

11,379 Se3m³, Methane Injected (Std Conditions)
8,383 Se3m³, Methane Produced, excluding solution gas (Std Conditions)
2,996 Se3m³, Net Methane Injected (Std Conditions)

8.648 kg/m³, Density of Methane in Chamber

228,647 m³, Net Methane Injected at Reservoir Conditions

**% Gas Volume Injected vs Oil Voidage**

Since Start of A Pad Production, 1997

228,647 m³ of net methane injected (reservoir conditions)
2,521,600 m³ of oil produced (as of Apr 30, 2014)

9.07% oil voidage displaced by injected methane
A Pad – Injection Strategy

Phase 1: March to September 2012
- Commenced methane injection on a pad basis
- AI1, AI4 and AI32 to inject at 5 Se³m³/d each, pad total target 15 Se³m³/d
- Steam injection to remain unchanged

Phase 2: September 2012 to July 2013
- Steam injection cut to ~70% of original steam target
- Methane gas volumes adjusted to maintain reservoir pressure / balance with offset pads
- Achieve stable injection rates and pressures

Phase 3: December 2013
- Monitor C Pad and apply learnings
- Cut steam injection to ~60% of original steam target
- Methane gas volumes adjusted to maintain reservoir pressure / balance with offset pads
- Achieve stable injection rates and pressures prior to next cut

Phase 4: December 2013 to Oct 2014
- Monitor C Pad and apply learnings
- Achieve stable injection rates and pressures (~1-2 months) prior to steam cuts
- Methane gas volumes adjusted to maintain reservoir pressure / balance with offset pads

Phase 5: Oct 2014 onwards
- Steam injection stopped, blowdown
- Methane gas volumes adjusted to maintain reservoir pressure / balance with offset pads
A Pad – Predictive Forecast

The graph shows the predictive forecast for a pad, with actuals and forecast data presented over time. The chart compares various indicators including steam, oil, water rates, and methane production, with specific annotations for actuals and forecast periods. The data is presented in a timeline format from January 2011 to January 2016, highlighting the production and forecast trends.© 2013 Cenovus Energy Inc
Temperature Logs & Fluid Saturation

23) b) Temperature measurement must be conducted a minimum of twice each calendar year at the designated observation wells listed below and the observation well referred in subclause (e). A suitable baseline temperature measurement must be available or obtained at each designated observation well listed below and the observation well referred to in subclause (e) prior to commencement of steam ramp down at each pad.

23) c) Fluid saturation measurements must be conducted a minimum of once every calendar year using well logging at a minimum of one observation well at each well pad. A suitable baseline fluid saturation measurement must be available or obtained at a minimum of one observation well at each well pad prior to the commencement of steam ramp down at each well pad.
### A Pad Logging History

<table>
<thead>
<tr>
<th>Target Steam</th>
<th>Temperature Log</th>
<th>Rst Log</th>
</tr>
</thead>
<tbody>
<tr>
<td>100%</td>
<td>Jan 2012</td>
<td>Feb 2012</td>
</tr>
<tr>
<td>70%</td>
<td>Dec 2012</td>
<td></td>
</tr>
<tr>
<td>70%</td>
<td>Mar 2013</td>
<td>Mar 2013</td>
</tr>
<tr>
<td>60%</td>
<td>Dec 2013</td>
<td>Dec 2013</td>
</tr>
<tr>
<td>45%</td>
<td>Mar 2014</td>
<td></td>
</tr>
</tbody>
</table>
A Pad – C12-22

- 16m offset to A4 Well Pair
- Temperature curves remain consistent while ramping steam down to 45%.
- Dec 2013 curve shows a decrease in RST gas, but no change in temperature.

This may be due to curve error or temporary Injector well shut in. The next RST log will help verify this result.
A Pad – 5-22

- 3m offset to A3 Well Pair

TSAT ~216°C

170°C
# A Pad Summary

<table>
<thead>
<tr>
<th>5-22_5-22</th>
<th>Phase 2: 75% Target Steam</th>
<th>Phase 2: 75% Target Steam</th>
<th>Phase 3: 60% Target Steam</th>
<th>% Change from Mar-2013 to Dec 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Dec-2012</td>
<td>Mar-2013</td>
<td>Dec-2013</td>
<td></td>
</tr>
<tr>
<td>$S_o$ ave in Steam Chamber</td>
<td>3.9%</td>
<td>2.0%</td>
<td>1.6%</td>
<td>-0.4%</td>
</tr>
<tr>
<td>$S_g$ in Steam Chamber</td>
<td>71%</td>
<td>74%</td>
<td>78%</td>
<td>3.6%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>C12-22</th>
<th>Phase 2: 75% Target Steam</th>
<th>Phase 2: 75% Target Steam</th>
<th>Phase 3: 60% Target Steam</th>
<th>% Change from Mar-2013 to Dec 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Dec-2012</td>
<td>Mar-2013</td>
<td>Dec-2013</td>
<td></td>
</tr>
<tr>
<td>$S_o$ ave in Steam Chamber</td>
<td>13.0%</td>
<td>10.5%</td>
<td>10.6%</td>
<td>0.1%</td>
</tr>
<tr>
<td>$S_g$ in Steam Chamber</td>
<td>67%</td>
<td>68%</td>
<td>50%</td>
<td>-17.6%</td>
</tr>
</tbody>
</table>
23) d) Compositional analysis of the casing gas at the AP4, CP16, DP20 wells and compositional analyses of the produced gas on a group basis for each well pad must be obtained monthly, commencing prior to the start of steam ramp down at each well pad.
A Pad – Methane C1 Mole Composition

A Pad - Gas Composition

Methane Inj Start

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Next Steps

- C Pad in full blowdown
- D Pad in phase 4 – working towards full blowdown in Q3-Q4 2014
- A Pad in phase 4 – working towards full blowdown in Q3-Q4 2014
- Continue temperature and fluid saturation measurement testing
- Continue gas compositional sampling on all pads
- Further evaluation of methane injection effects
- F & G Pads approved
Questions?
## Table of contents

<table>
<thead>
<tr>
<th>Item</th>
<th>Page(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pad plots</td>
<td>3-32</td>
</tr>
<tr>
<td>Pressure data</td>
<td>33-47</td>
</tr>
<tr>
<td>Fibre temperature data</td>
<td>48-102</td>
</tr>
</tbody>
</table>
Pad plots

Subsection 3.1.1 – 7 h)
Foster Creek central

Central Area

Well Pairs
Wedge Wells

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FOSTER CREEK
G PAD & G Wedge Wells™ Performance

<table>
<thead>
<tr>
<th>Total Oil Rate (m³/d)</th>
<th>Total Water Rate (m³/d)</th>
<th>Total Steam Inj Rate (m³/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **Cum SOR**
- **Inst SOR**
- **Wells On Prod**

- **Rate (m³/day)**
- **Steam Oil Ratio (SOR)/Wells On Prod**

- **Axes:**
  - X-axis: Jan/13 to Mar/14
  - Y-axis: 0 to 2500

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FOSTER CREEK
H Pad Performance

Legend:
- Green line: Total Oil Rate (m3/d)
- Blue line: Total Water Rate (m3/d)
- Red line: Total Steam Inj Rate (m3/d)
- Black line: Cum SOR
- Yellow stars: Inst SOR
- Brown dots: Wells On Prod

Graph X-axis: Jan/13 to Mar/14
Graph Y-axis: Rate (m3/day) and Steam Oil Ratio (SOR)/Wells On Prod

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Foster Creek east area
FOSTER CREEK
E21 Pad Performance

- Total Oil Rate (m3/d)
- Total Water Rate (m3/d)
- Total Steam Inj Rate (m3/d)
- Cum SOR
- Inst SOR
- Wells On Prod

Rate (m3/day)

Steam Oil Ratio (SOR)/Wells On Prod

Jan/13, Feb/13, Mar/13, Apr/13, May/13, Jun/13, Jul/13, Aug/13, Sep/13, Oct/13, Nov/13, Dec/13, Jan/14, Feb/14, Mar/14

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Instrumentation in wells

Subsection 3.1.1 – 5 c, d)
Piezometer data
Foster Creek piezometer locations

Subsection 3.1.1 – 5 b)
Piezometer details

Three installation types:

Cemented tubing - vibrating wire piezometers mounted on tubulars and cemented in place (14 wells)

Hanging wire – pressure / temperature gauges hung from the wellhead to about 10-15m above perforations (9 wells)

Cemented casing – High temperature Optical pressure sensors strapped and cemented to the production casing (10 wells)

8 new McMurray piezometers installed in Q1 2014
## Piezometer details

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<th>UWI</th>
<th>Fluids / Zones</th>
<th>TVD (m KB)</th>
<th>MD (mKB)</th>
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Temperature data
Foster Creek temperature data

43 observation wells logged to acquire temperature data
21 observation wells logged to acquire RST data

- Wells selected for Temperature logging
- Wells selected for RST logging
43 observation wells were logged with temperature fiber in the winter drilling season of 2013.

Some wells were logged twice in 2013.
Foster Creek Obs Well Temperature Data
E03 Pad D16 FISHER 16-12-70-4 Jan-29-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
E11 Pad B16 FISHER 16-7-70-3 Jan-28-2013

Temperature (deg C)

Depth (m)

- 8:47:54
- 8:58:34
- 9:08:04
- 9:18:04
Foster Creek Obs Well Temperature Data
E12 Pad B6 FISHER 6-17-70-3 Jan-25-2013
Foster Creek Obs Well Temperature Data
E12 Pad B7 FISHER 7-17-70-3 Jan-26-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
E12 Pad C11 FISHER 11-17-70-3 Jan-27-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
G Pad B10 FISHER 10-15-70-4 Jan-22-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
G Pad C10 FISHER 10-15-70-4 Jan-22-2013

Temperature (deg C)

 Depth (m)

13:16:57
13:26:57
13:36:57
13:46:57
Foster Creek Obs Well Temperature Data
K Pad C13 FISHER 13-15-70-4 Jan-21-2013
Foster Creek Obs Well Temperature Data
E15 Pad C8 FISHER 8-16-70-3 Feb-4-2013

Temperature (deg C)

Depth (m)

- 9:06:20
- 9:15:50
- 9:25:50
- 9:36:20
Foster Creek Obs Well Temperature Data
E19 Pad B8 FISHER 8-21-70-3 Feb-2-2013
Foster Creek Obs Well Temperature Data
E20 Pad C2 FISHER 2-22-70-3 Feb-5-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
E20 Pad FISHER 3-22-70-3 Feb-4-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
E21 Pad A7 FISHER 7-21-70-3 Feb-2-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
E21 Pad D3 FISHER 3-21-70-3 Feb-2-2013

Temperature (deg C)

Depth (m)

12:22:23
12:31:53
12:41:53
12:51:53
Foster Creek Obs Well Temperature Data
E24 Pad D2 FISHER 2-20-70-3 Feb-1-2013

Temperature (deg C)

Depth (m)

- 11:25:45
- 11:35:55
- 11:46:25
- 11:55:55
Foster Creek Obs Well Temperature Data
E25 Pad A16 FISHER 16-20-70-3 Feb-1-2013

Temperature (deg C) vs Depth (m)
Foster Creek Obs Well Temperature Data
A Pad 5-22 FISHER 5-22-70-4 Mar-16-2013
Foster Creek Obs Well Temperature Data
C Pad A7 FISHER 7-22-70-4 Mar-17-2013

Temperature (deg C)
Depth (m)
Foster Creek Obs Well Temperature Data
C Pad B6 FISHER 6-22-70-4 Mar-16-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
D Pad C16 FISHER 16-15-70-4 Mar-14-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
D Pad D1 FISHER 1-22-70-4 Mar-15-2013

Time (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
D Pad D16 FISHER 16-15-70-4 Mar-14-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
G Pad B9 FISHER 9-15-70-4 Mar-16-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
D Pad B4 FISHER 4-23-70-4 Dec-10-2013

Temperature (deg C)

Depth (m)
Foster Creek Obs Well Temperature Data
D Pad D16 FISHER 16-15-70-4 Dec-10-2013

Temperature (deg C)

Depth (m)