KIRBY IN SITU OIL SANDS EXPANSION PROJECT
AER DIRECTIVE 54 ANNUAL PERFORMANCE PRESENTATION

October 2014
## Outline - Subsurface

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# Outline - Surface

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Background

Location of Kirby Expansion Project
• Recovery Process: Steam Assisted Gravity Drainage (SAGD)
Directive 54 Section 3.1.1
Subsurface Issues Related to Resource Evaluation and Recovery
Geology
Project Area SAGD Pay Isopach
### Geology

**Project Area Volumetrics**

<table>
<thead>
<tr>
<th></th>
<th>Average Pay Thickness (m)</th>
<th>Average Oil Saturation (%)</th>
<th>Average Porosity (%)</th>
<th>OBIP (e$^3$ m$^3$)</th>
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<tr>
<td>Kirby Expansion Approved Project Area</td>
<td>14.8</td>
<td>78.4</td>
<td>32.7</td>
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</table>

- Volumetric calculation (for >10m contour):
  - Area above 10m of pay $\times$ Pay Thickness $\times$ Oil Sat. $\times$ Porosity
Geology
Kirby South Type Log
Geology
Kirby South Structural Cross-Section
Geology
Kirby South Development Area

- Recovery Process: Steam Assisted Gravity Drainage (SAGD)
### Geology
**Kirby South Development Area Volumetrics**

<table>
<thead>
<tr>
<th></th>
<th>Average Pay Thickness (m)</th>
<th>Average Oil Saturation (%)</th>
<th>Average Porosity (%)</th>
<th>OBIP (E³m³)</th>
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<tbody>
<tr>
<td>Kirby South Approved Development Area</td>
<td>19.7</td>
<td>76.3</td>
<td>33.2</td>
<td>55,000</td>
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- Volumetric calculation (for >10m contour):
  - Area above 10m of pay $\times$ Pay Thickness $\times$ Oil Sat. $\times$ Porosity
<table>
<thead>
<tr>
<th>Drainage Area</th>
<th>Area (m²)</th>
<th>Oil Saturation (%)</th>
<th>Porosity (%)</th>
<th>Pay Thickness (m)</th>
<th>OBIP (E³m³)</th>
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<td>A</td>
<td>600,017</td>
<td>67.9%</td>
<td>33.3%</td>
<td>28.9</td>
<td>3,920</td>
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<td>B</td>
<td>669,345</td>
<td>75.4%</td>
<td>32.8%</td>
<td>23.45</td>
<td>3,880</td>
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<td>C</td>
<td>629,989</td>
<td>78.3%</td>
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<td>25.36</td>
<td>4,180</td>
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<tr>
<td>D</td>
<td>792,398</td>
<td>79.5%</td>
<td>33.3%</td>
<td>26.27</td>
<td>5,510</td>
</tr>
<tr>
<td>E</td>
<td>502,828</td>
<td>75.5%</td>
<td>34.2%</td>
<td>23.08</td>
<td>3,000</td>
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<tr>
<td>F</td>
<td>462,018</td>
<td>77.6%</td>
<td>33.3%</td>
<td>21.03</td>
<td>2,510</td>
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<tr>
<td>G</td>
<td>654,516</td>
<td>82.9%</td>
<td>33.2%</td>
<td>25.17</td>
<td>4,530</td>
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# Geology
## Average Reservoir Properties

<table>
<thead>
<tr>
<th></th>
<th>Initial Reservoir Pressure (Kpa)</th>
<th>Initial Reservoir Temperature (°C)</th>
<th>Average Depth of Reservoir, McMR SAGD Pay Top (mTVD)</th>
<th>Average Pay Thickness (m)</th>
<th>Average Porosity, Φ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kirby South Operating Area</td>
<td>~2600</td>
<td>10 to 15</td>
<td>530</td>
<td>21.9</td>
<td>33.2</td>
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<td>490</td>
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<td>32.7</td>
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<table>
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<tr>
<th></th>
<th>Average Oil Saturation (%)</th>
<th>Average Water Saturation (%)</th>
<th>Average Horizontal Permeability from OB plugs, Kh (mD)</th>
<th>Average Vertical Permeability from OB plugs, Kv (mD)</th>
<th>Kv/Kh Ratio</th>
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<tr>
<td>Kirby South Operating Area</td>
<td>74.8</td>
<td>25.2</td>
<td>6410</td>
<td>5260</td>
<td>0.82</td>
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<tr>
<td>Kirby Expansion Approved Project Area</td>
<td>78.4</td>
<td>21.6</td>
<td>6560</td>
<td>5510</td>
<td>0.84</td>
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</table>
Geology
Kirby South SAGD Pay Top Structure

Polygon Legend
- Kirby Expansion Project Area
- Approved Development Area(s)
- Drainage Boxes (Existing & Pending)

Canadian Natural
Kirby Expansion Project
Kirby South Development Area
Structure - McMurray SAGD Pay Top (mSS)

2014 DRILLED STRATS
Geology
Kirby South SAGD Pay Base Structure
Geology
Kirby South Net Water Sand Isopach
• No special core analysis was performed on 2014 Kirby South cores
Geology
Kirby North Type Log

Clearwater A Shale
Wabiskaw
Wabiskaw B
Wabiskaw D
McMurray

Paleozoic Unconformity
Cap Rock Interval
Wabiskaw D SAGD Pay
McMurray SAGD Pay
McMurray Basal Water Sand
Geology
Kirby North Structural Cross Section

- Clearwater A Shale
- Wabiskaw B
- Wabiskaw D
- McMurray
- Paleozoic Unconformity

- Cap Rock Interval
- McMurray SAGD Pay
- McMurray Basal Water Sand
Geology
Kirby North SAGD Pay Isopach
• No special core analysis performed on Kirby North cores in 2014
## Geology
### Kirby North Development Area Volumetrics

<table>
<thead>
<tr>
<th></th>
<th>Average Pay Thickness (m)</th>
<th>Average Oil Saturation (%)</th>
<th>Average Porosity (%)</th>
<th>OBIP (e³m³)</th>
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<tbody>
<tr>
<td>Wabiskaw D Reservoir</td>
<td>15.6</td>
<td>77.5</td>
<td>32.8</td>
<td>43,691</td>
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<tr>
<td>McMurray Reservoir</td>
<td>18.2</td>
<td>80.0</td>
<td>32.3</td>
<td>78,237</td>
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<td>Kirby North Approved Development Area</td>
<td></td>
<td></td>
<td></td>
<td>121,928</td>
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- **Volumetric calculation (for >10m contour):**
  - Area above 10m of pay $\times$ Pay Thickness $\times$ Oil Sat. $\times$ Porosity

---

**CNQ**

Slide 26
<table>
<thead>
<tr>
<th>Drainage Area</th>
<th>Area (m²)</th>
<th>Oil Saturation (%)</th>
<th>Porosity (%)</th>
<th>Pay Thickness (m)</th>
<th>OBIP (e³m³)</th>
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<tbody>
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<td>KN01</td>
<td>763,120</td>
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<td>KN02</td>
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<tr>
<td>KN03</td>
<td>763,033</td>
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<td>KN04</td>
<td>763,316</td>
<td>83.8</td>
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<td>4,900</td>
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<td>KN05</td>
<td>443,723</td>
<td>81.6</td>
<td>33.5</td>
<td>20.8</td>
<td>2,530</td>
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Geology
Kirby North Wabiskaw D SAGD Pay Top Structure
Geology
Kirby North McMurray SAGD Pay Top Structure
Geology
Kirby North McMurray SAGD Pay Base Structure

Kirby Expansion Project
Kirby North Development Area
Structure - McMurray Base SAGD Pay

Polygon Legend
- Kirby Expansion Project Area
- Approved Development Area(s)
- Drainage Boxes (Existing & Pending)

075-08W4
Geology
Kirby North McMurray Net Bottom Water Isopach
Geology
3D Seismic Coverage
Cap Rock interval varies in thickness from 9-22m over development areas

- 1AA/09-06-075-08W4 Mini-Frac location (2012)
- 100/13-20-073-07W4 Mini-Frac location (2011)
Cap Rock
Mini Frac Results

<table>
<thead>
<tr>
<th></th>
<th>AA/09-06-075-08W4</th>
<th>100/13-20-073-07W4</th>
</tr>
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<tbody>
<tr>
<td>TVD(m)</td>
<td>Minimum Stress (Mpa)</td>
<td>Minimum Stress (Kpa/m)</td>
</tr>
<tr>
<td>Clearwater Cap Rock</td>
<td>451.5 7.61 16.9</td>
<td>Clearwater Cap Rock 473 7.67 16.2</td>
</tr>
</tbody>
</table>

MOP for Kirby South Pads A to G and Kirby North proposed Pads KN01-KN05 is 7 MPa.

7.61 Mpa

7.67 Mpa
Subsurface Schematic
Majority of wells are equipped with ESPs.

As of Aug. 20, no rod pumps operating. Strategy is to install them periodically due to low production rates / suspected sand production.

- Range of lift capacity
  - Rod Pump: 0-300m3/d
  - ESP: 150-1000m3/d

- Operating Temperature
  - Less than 250°C for both rod pumps and ESPs

Completion is continually being optimized as required

- Steam splitters are installed to improve steam distribution in the injector
- Scab liners are installed to enhance toe production in the producer
- Tubing deployed inflow and outflow control devices are presently deployed in the following well pairs:
  - Steam splitters: C2, C3, E1, F2, F4, G1 - G3
  - Scab liners: B3 - B6, D1, D2, E3 - E5, F1 - F7, G1 – G4
Instrumentation Summary

- Blanket gas pressures are used to monitor bottom hole pressures for SAGD injection wells.

- SAGD producers are equipped with temperature monitoring (DTS) along the lateral and bubble tubes with surface measurement for the toe pressure.

- Observation wells gather multiple temperatures and pressures at various elevations.
Well Schematics
Injection Well (Dual String)

- 339.7 mm (13 3/8”) Surface Casing set @ ~ 200.0 mKB
- 244.5 mm (9 5/8”) Casing set @ ~ 750.0 mKB
- 88.9 mm (3 1/2”) short tubing (Heel) @ ~ 750.0 mKB
- 88.9 mm (3 1/2”) Long Tubing (Toe) @ ~ 1700.0 mKB
- Liner Hanger ~20 m behind ICP
- Slotted Liner 177.8 mm (7”)
- 600-1000 m Hz sections
Well Schematics
Injection Well (Single String)

- 339.7 mm (13 3/8\”) Surface Casing set @ ~ 200.0 mKB
- 244.5 mm (9 5/8\”) Casing set @ ~ 750.0 mKB
- 114.3 mm (3 1/2\”) Long Tubing @ ~ 1700.0 mKB
- Liner Hanger ~20 m behind ICP
- 2 - 114.3 (4 1/2”) Steam Splitters
- Slotted Liner 177.8 mm (7\”)
- 600-1000 m Hz sections
Well Schematics
Production Well

- 339.7 mm (13 3/8") Surface Casing set @ ~ 200.0 mKB
- 244.5 mm (9 5/8") Casing set @ ~ 750.0 mKB
- 88.9mm (3 ½") tubing to Pump landed ~50 m behind Liner Hanger
- Liner Hanger ~20 m behind ICP
- Slotted Liner 177.8 mm (7")
- 600-1000 m Hz sections
- 48 mm (1.9") guide string with DTS fibre instrumentation
Well Schematics
Production Well (Scab Liner)

- 339.7 mm (13 3/8”) Surface Casing set @ ~ 200.0 mKB
- 244.5 mm (9 5/8”) Casing set @ ~ 750.0 mKB
- 88.9mm (3 ½”) tubing to Pump landed ~50 m behind Liner Hanger
- Liner Hanger ~20 m behind ICP
- 48 mm (1.9”) guide string with DTS fibre instrumentation
- Pump
- Slotted Liner 177.8 mm (7”)
- 600-1000 m Hz sections
Well Schematics
Observation Well

Note: Shows a plan for 2011-2013 drilled observation wells, as previous wells don’t have external casing transmitters.
Well Schematics
Disposition Well

- 244.5 mm SURFACE CASING, SET BETWEEN 25 m & 150 m CEMENTED FULL LENGTH
- 177.8 mm PRODUCTION CASING THERMALLY CEMENTED TO SURFACE
- 88.9 mm TUBING
- ANNULUS FILLED WITH INHIBITED WATER
- INJECTION ISOLATION PACKER
- PERFORATIONS OR SCREEN
- McMURRAY BASAL AQUIFER (~550 m)
- McMURRAY TOP
- WOC
Operational Strategy
Start-up

• Average circulation rates were 200-320 m$^3$/d/pair
  - Higher rates required due to depths and plant back pressure
• Circulation pressure was balanced with bottom water pressure to minimize fluid losses
  - Bottomhole Pressures (BHP) ranged between 2.5 to 3.5 MPa in areas influenced by bottom water and increased up to 5 MPa in areas without bottom water
• Circulated wells for 2 to 4 months
  - Duration determined by temperature and performance observations
  - Duration also extended in case of re-drills where inter-pair spacing exceeds 5 metres
• For both wells of SAGD pair
  - Inject steam down tbg. string to toe
  - Produce water and steam via 2$^{nd}$ tbg. string from heel
Operational Strategy
SAGD

- Inject steam down short and long string in injector
- Pump fluid from producer using artificial lift
- Operate wells based on a target steam chamber pressure and target subcool
- Steam chamber pressure is measured by blanket gas pressure in the injector and is controlled by the steam injection rate
  - Target pressure chosen to balance bottom water where it exists, typically 2.5 MPa to 3.5 Mpa (Pads A to F)
  - For pads without bottom water influence, pressures may increase up to 5 Mpa (Pad G)
• Subcool is determined based on the difference between the saturated temperature producer pressure and the highest temperature along the producer lateral
  - Target chosen to maximize production and minimize live steam production

• To optimize the pressure and subcool target a combination of parameters are monitored including:
  - Water retention in reservoir
  - Chlorides concentration in produced water
  - SOR
  - Well bottomhole pressures
Kirby South Performance
Kirby South Pad Map
Kirby South
SAGD Well Spacing

- Original well spacing on Pads A, B, & C were 100m.
- Well spacing was optimized from 100m to 80m to achieve improved CDOR, SOR and recovery factors for wells with less bottom water influence.
- F Pad spacing was decreased to 50m where thicker bottom water exists to lessen the slumping of oil and therefore improve CDOR, SOR and recovery factor.

<table>
<thead>
<tr>
<th>Pad</th>
<th>Number of Well Pairs</th>
<th>Inter well Spacing (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>6</td>
<td>100</td>
</tr>
<tr>
<td>B</td>
<td>7</td>
<td>100</td>
</tr>
<tr>
<td>C</td>
<td>7</td>
<td>100</td>
</tr>
<tr>
<td>D</td>
<td>8</td>
<td>80</td>
</tr>
<tr>
<td>E</td>
<td>6</td>
<td>80</td>
</tr>
<tr>
<td>F</td>
<td>7</td>
<td>50</td>
</tr>
<tr>
<td>G</td>
<td>8</td>
<td>80</td>
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## Kirby South Performance Pad Recoveries

<table>
<thead>
<tr>
<th>Pad</th>
<th>OBIP (E3m3)</th>
<th>Ult. Recovery (E3m3)</th>
<th>Cum Oil (E3m3)</th>
<th>RF</th>
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<tr>
<td>A</td>
<td>3,920</td>
<td>2,352</td>
<td>55</td>
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<tr>
<td>B</td>
<td>3,880</td>
<td>2,328</td>
<td>96</td>
<td>2.5%</td>
</tr>
<tr>
<td>C</td>
<td>4,180</td>
<td>2,508</td>
<td>132</td>
<td>3.2%</td>
</tr>
<tr>
<td>D</td>
<td>5,510</td>
<td>3,306</td>
<td>56</td>
<td>1.0%</td>
</tr>
<tr>
<td>E</td>
<td>3,000</td>
<td>1,800</td>
<td>92</td>
<td>3.1%</td>
</tr>
<tr>
<td>F</td>
<td>2,510</td>
<td>1,506</td>
<td>36</td>
<td>1.4%</td>
</tr>
<tr>
<td>G</td>
<td>4,530</td>
<td>2,718</td>
<td>22</td>
<td>0.5%</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>27,530</strong></td>
<td><strong>16,518</strong></td>
<td><strong>489</strong></td>
<td><strong>1.8%</strong></td>
</tr>
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</table>

*Recovery as of August 20, 2014*
Note: Well count includes all wells post cure-out, excluding liner failures waiting for repair and re-steam
Kirby South Performance Summary

- Started circulating first well pair in Sept. 2013
  - Order of pad circulation: C, B, D, A, E, F, G
- First SAGD well converted Jan. 2014
- 4 liner failures thus far (B2, D3, D7, D8); 3 D pad well pairs already re-drilled
- Peak oil production reached ~4000m3/d
- 9 well pairs yet to be converted to SAGD
- Reservoir performance is similar to expectations, awaiting plant optimization
Kirby South Performance
Pad A

- SAGD well pair: 6
- Completed drilling: July 2011
- First steam: Oct. 2013
- Inter-well pair spacing: 100m
- Avg. net pay: 29m
- Avg. So: 68%
- Avg. porosity: 33%
- Current RF: 1.4%
Kirby South Well Pair A6

- Steam Injection
- Oil Production
- Water Production
- ISOR
- CSOR

Rate (m³/d)

SOR (m³/m³)

Kirby South Performance
Pad A Obs Well – 26 metres from A4
- BW pressure changes as pad pressures are increased / decreased

- McMurray pressure fairly constant due to distance from steam chamber (26m from A4)

- Clearwater gauge landed in impermeable shale

- Clearwater declining pressure result of gauge effects and does not indicate change in cap rock properties
Kirby South Performance
Pad A Key Learnings

- Pad A performance has been somewhat delayed due to plant capacity restrictions
- To date, Pad A has performed below reservoir expectations
- Specifically, A1-A3 have performed poorer than expected
  - Evaluating potential re-drill for A1-A3
  - Wells have poor conformance with cold toes and hot spots in the first half of the well
- A1-A4 producers communicate with bottom water
  - Balance pressures with bottom water
  - To date bottom water does not seem to be influencing performance
Kirby South Performance
Pad D

- SAGD well pair: 8
- Completed drilling: July 2012
- First steam: Oct. 2013
- Inter-well pair spacing: 80m
- Avg. net pay: 26m
- Avg. So: 80%
- Avg. porosity: 33%
- Current RF: 1.0% (3 well pairs not yet on SAGD)
Kirby South Performance
Pad D Production

Kirby South Pad D

- Steam Injection
- Oil Production
- Water Production
- ISOR
- CSOR
- Well Count

Graph showing the performance of Kirby South Pad D from October 2013 to August 2014, with data points for monthly rates in m³/d and SOR (m³/m³) per well count.
Kirby South Performance
High Recovery Pad D Well Pair

Kirby South Well Pair D4

- Steam Injection
- Oil Production
- Water Production
- ISOR
- CSOR

Rate (m³/d)

SOR (m³/m³)


0 50 100 150 200 250 300 350 400 450 500

0 1 2 3 4 5 6 7 8 9 10
Horizontal DTS data shows steam movement through the reservoir.

C2I pressure increase

Horizontal DTS data shows steam movement through the reservoir

D1I pressure increase

D4I pressure increase
Kirby South Performance
Pad D Obs Well Pressures

- Pad D Obs wells show good pressure sensitivities to changes in SAGD operations

**Figure: Pad D Obs. Well Datum Pressure vs Time**

- D5 significant pressure increase
- Plant cuts
- D1/D2 ramp up resulting in reduced pressures
Kirby South Performance
Pad D Obs Well – 5m From D2
Kirby South Performance
Pad D Obs Well – 5.5m From D2

OB2B – 102/10-20-073-07W4

Temperature Sensor

0 20 40 60 80 100 120
Temperature (deg C)

460
480
500
520
540
560
Depth (mK8)

15-Aug-13 00:00:00
14-Sep-13 00:00:00
12-Dec-13 23:00:00
11-Jan-14 23:00:00
10-Feb-14 23:00:00
13-Mar-14 00:00:00
12-Apr-14 00:00:00
12-May-14 00:00:00
11-Jun-14 00:00:00
11-Jul-14 00:00:00
10-Aug-14 00:00:00
D3, D7, & D8 liner failures occurred during circulation

Potential reasons for well failures:
- Liner may have been damaged while running in due to lost circulation
- Higher fines percentage in D7 & D8 geology
- Operational upsets led to heating and cooling cycles

Completed sidetracks on D3P, D7I, D7P, D8I, & D8P 5m laterally and at the same depth as existing wells pairs

New lateral are completed with FascRite liner on D3 and MeshRite liner on D7 & D8 to ensure better liner integrity

Estimate to start steaming Nov. 2014.
Kirby South Performance
Pad D Key Learnings

- Pad D performance has been somewhat delayed due to plant capacity restrictions
- Pad production has been reduced due to liner failures; however reservoir performance is meeting expectations
- Karst features across pad have not influenced performance
- Known communication through old RAX SAGD pilot
  - To date no performance issues due to RAX pilot to date
  - Long term strategy to balance pressures between C & D pad
  - Continually monitor RAX pressure and temperatures
- Scab liners have been installed on D1 & D2 to improve temperature conformance
Kirby South Performance
Pad C – High Recovery Pad

- SAGD well pair: 7
- Completed drilling: Nov. 2011
- First steam: Sept. 2013
- Inter-well pair spacing: 100m
- Avg. net pay: 25m
- Avg. So: 78%
- Avg. porosity: 33%
- Current RF: 3.2%
Kirby South Performance
Pad C Production

Kirby South Pad C

- Steam Injection
- Oil Production
- Water Production
- ISOR
- CSOR
- Well Count

Rate [m³/d]

SOR [m³/m³]

Well Count

Kirby South Performance
High Recovery Pad C Well Pair
Kirby South Performance
Low Recovery Pad C Well Pair

Kirby South Well Pair C6

- Steam Injection
- Oil Production
- Water Production
- ISOR
- CSOR

Rate (m³/d) vs. Time (Sep-2013 to Aug-2014)

Canadian Natural
Kirby South Performance
Pad C Key Learnings

- Pad C performance has been somewhat delayed due to plant capacity restrictions
- Reservoir performance is meeting expectations
- Producers communicate with transition zone
  - To date no performance issues due to bottom water
  - Balance pressures with bottom water
- Similar to Pad D, long term strategy is to balance pressures for wells in close proximity to RAX wells
Kirby South Performance
5 Year Outlook – Pad Abandonments

• No expected pad abandonments in the next 5 years
Kirby South Performance
Wellhead Steam Quality

• During steady operations, wellhead quality should be 95% or greater

• There is some evidence that certain pads and wells have experienced slightly lower quality during start-up
  – This is not expected to have an impact on recovery

• No other fluids are injected with the steam
Kirby South Observation Well Results
100/10-28-073-07W4 – 4m From G3

Colony gas well to evaluate the ability of non-thermal cement to maintain hydraulic isolation in a thermal environment

No data prior to Apr-2014
Some pressure gauges do not seem to be connected to the reservoir

- Can address this in existing wells by perforating the well and running a gauge inside the casing
- Evaluating other completion options for future Observation Wells
Bottom water gauge not reading accurately as it was pressuring up prior to March 2014. Zone was perforated March 2014. Believe to be reading accurately now.
• Seeing temperatures heat up in the Wabiskaw formation due to proximity to A5P build section (~5m).
• Very localized and isolated temperature increase.
Future Plans – Subsurface Summary

• Area steam plans
  – Continue to optimize SAGD pairs
  – Circulate and convert B1 & G5-G8
  – Steam to be directed to D Pad re-drilled pairs (D3, D7, D8)
• Re-drill B2 in Q1 2015 due to liner failure in producer
• F pad step outs (F8, F9, F10) planned to be drilled Q1 2015
• Preparing Scheme Amendment applications (H & I Pads – Section 23) to be submitted in 2015.
• Kirby North initial development
  – Changes in drainage box location and associated surface infrastructure for first five approved SAGD well pads.

<table>
<thead>
<tr>
<th>Proposed Kirby North Schedule Pads KN01-KN05</th>
</tr>
</thead>
<tbody>
<tr>
<td>Scheme Amendment Application</td>
</tr>
<tr>
<td>Public Lands Act Applications</td>
</tr>
<tr>
<td>Routine D56 Applications</td>
</tr>
<tr>
<td>Commence Tree Clearing and Construction</td>
</tr>
<tr>
<td>Commence Drilling and Completions</td>
</tr>
<tr>
<td>Steam – in</td>
</tr>
</tbody>
</table>
Directive 54 Section 3.1.2
Surface Operations, Compliance and Issues Not Related to Resource Evaluation and Recovery
Surface Facilities Overview
Plot Plans

• Detailed Site Plot Plans:
  – Kirby SAGD Production Pad Plot Plan
    ▪ Dwg No. KBF-G-210-0001
  – Kirby South Central Plant Plot Plan
    ▪ Dwg No. KBP-00-210-0002
  – Kirby North Central Plant Plot Plan
    ▪ Dwg No. KNP-100-210-0001 R1

• Simplified Schematic:
  – Kirby In-Situ Oil Sands Project Simplified Schematic
Surface Facilities Overview
Kirby Simplified Schematic
Surface Facilities Overview
Kirby South Modifications

• Summary of Modifications since August 2013
  – Slop oil recycle injection location modifications (enhanced integration to process train)
  – Centrifuge process upgrades (facilitate enhanced separation, reliability and uptime)
  – Various oil and water treating chemical injection location modifications
  – Installation of various vessel instruments (improve interface and level control, enhanced data gathering for process optimizations)
  – Piping modifications in the Evaps to facilitate cleaning
  – D pad redrill and piping modifications to allow circulation to Annulus Gas line
  – Plant inlet ESD valve addition to address SIL concerns with ABSA
Kirby South Facility Performance
Oil Treating/Produced Water Deoiling Area

- Overall water quality and oil treating targets have been generally met
  - Experienced some treating challenges due to low rates/low inlet temperature during early circulation
  - Continue dealing with periodic oil treating upsets during the ramp up phase as production rates hit new highs
    - Several optimizations to the chemical treating program, vessel operation, and instrumentation have been made to resolve the issues
    - Plans in place to continue optimizing/removing issues as rates increase to full design
  - Several PW de-oiling upsets have led to short-term restrictions for evaporator cleaning and protection
    - Several changes to operating parameters and the chemical treating program have been made to resolve the issues
    - Plans in place to continue optimizing/removing issues as rates increase to full design
  - Early challenges in keeping up with slop generation
    - Improvements made to slop handling flexibility (recycle, trucking)
    - Work continues to address slop oil centrifuge design deficiencies
Kirby South Facility Performance
Water Treatment Area

- In general good performance in the evaporators - meeting design expectations

- Water upsets have affected evaporator performance periodically due to excess oil being sent to the evaporators. This has affected steam availability
  - Oil-in-water excursion response protocol updated based on operating data
  - Chemical cleaning procedures in place and optimized to address the issue and quickly restore evaporator capacity after an upset
  - Plans in place to further streamline upset response and cleaning procedures

- Water treatment pH adjustment method has been changed to amine instead of caustic to reduce the iron and OH alkalinity in the BFW
Boilers

• Boiler recirculation pumps have experienced seal failures – causing steam impacts in late 2013
  – The failures were due to improper o-ring material and improper seal plan for the high temperature service
  – Issue has been addressed with a new seal and seal flush design

• Boiler failures (periodic steam impacts in 2014)
  – Tube header failures discovered in April 2014
    ▪ The failures were due to localized wall thinning in the furnace tube collection headers
    ▪ Tubes were replaced and refractory was installed on the collection headers in all boilers to eliminate future failures
• Tube wall loss has since been discovered in other parts of the furnace
  – Steaming was reduced to protect the operating boilers and begin inspection and repairs
  – An engineering solution has been developed and is being implemented on a boiler-by-boiler basis as they are repaired
  – Plans in place to further optimize the solution based on inspection/performance of the repaired and upgraded boilers in order to meet increasing well steam demand into 2015
Kirby South Facility Performance Utilities

• Possible cooling limitation in the glycol system predicted at full rates in summer months
  – Temporary solutions developed to minimize the chances of a production impact
  – Long-term solutions being evaluated based on actual performance

• Full plant outage Oct 23rd – 26th 2013 due to a glycol system header flange failure
  – Control system changes made to the glycol system to prevent reoccurrence

• Oil found in the glycol system on Nov 21st due to a heat exchanger tube failure
  – No production impact
  – Oil was removed from the glycol system on-line with a chemical wash
Kirby South Facility Performance
Salt Caverns

• In general the caverns have been able to manage evaporator blowdown solids
• Some optimization ongoing to cavern return filtration
• Currently preparing Cavern 2 for MIT test
Kirby South Facility Performance
Power Consumption

- Power Consumption on a monthly basis

<table>
<thead>
<tr>
<th>Month</th>
<th>Total Power Consumption (kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sep -13</td>
<td>9,005,979</td>
</tr>
<tr>
<td>Oct -13</td>
<td>11,894,391</td>
</tr>
<tr>
<td>Nov -13</td>
<td>13,930,247</td>
</tr>
<tr>
<td>Dec -13</td>
<td>15,011,255</td>
</tr>
<tr>
<td>Jan -14</td>
<td>15,572,903</td>
</tr>
<tr>
<td>Feb -14</td>
<td>12,792,768</td>
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<tr>
<td>Mar -14</td>
<td>15,886,276</td>
</tr>
<tr>
<td>Apr -14</td>
<td>15,180,438</td>
</tr>
<tr>
<td>May -14</td>
<td>14,154,162</td>
</tr>
<tr>
<td>Jun -14</td>
<td>15,750,211</td>
</tr>
<tr>
<td>Jul -14</td>
<td>14,099,425</td>
</tr>
<tr>
<td>Aug-14</td>
<td>15,086,360</td>
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</table>
Kirby South Facility Performance
Gas Usage

- Gas Usage on a monthly basis

<table>
<thead>
<tr>
<th>Month</th>
<th>Total Purchased Gas e3m3</th>
<th>Total Gas Produced e3m3</th>
<th>Total Gas Vented e3m3</th>
<th>Total Solution Gas to Flare e3m3</th>
<th>Solution Gas Recovered %</th>
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</thead>
<tbody>
<tr>
<td>Sep -13</td>
<td>4,500</td>
<td>0</td>
<td>-</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>Oct -13</td>
<td>12,768</td>
<td>0</td>
<td>-</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>Nov -13</td>
<td>16,392</td>
<td>36</td>
<td>-</td>
<td>18</td>
<td>50%</td>
</tr>
<tr>
<td>Dec -13</td>
<td>15,267</td>
<td>32</td>
<td>-</td>
<td>12</td>
<td>62%</td>
</tr>
<tr>
<td>Jan -14</td>
<td>15,891</td>
<td>58</td>
<td>-</td>
<td>22</td>
<td>62%</td>
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<tr>
<td>Feb -14</td>
<td>12,258</td>
<td>167</td>
<td>-</td>
<td>117</td>
<td>30%</td>
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<tr>
<td>Mar -14</td>
<td>17,635</td>
<td>508</td>
<td>-</td>
<td>26</td>
<td>95%</td>
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<td>Apr -14</td>
<td>16,492</td>
<td>99</td>
<td>-</td>
<td>4</td>
<td>96%</td>
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<td>May -14</td>
<td>15,701</td>
<td>144</td>
<td>-</td>
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<td>100%</td>
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<td>Jun -14</td>
<td>17,872</td>
<td>352</td>
<td>-</td>
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<td>Jul -14</td>
<td>13,974</td>
<td>373</td>
<td>-</td>
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<td>100%</td>
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<td>Aug-14</td>
<td>15,036</td>
<td>295</td>
<td>-</td>
<td>0</td>
<td>100%</td>
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</tbody>
</table>
Kirby South Facility Performance Emissions

- Kirby Greenhouse Gas Emissions
  - Currently establishing baseline in accordance with the Specified Gas Emitters Regulation (SGER).

- Kirby Sulphur Emissions
  - No exceedance of the EPEA daily SO2 emissions limit of 2.0 t/d
  - No exceedance of the AER D56 calendar quarterly sulphur limit of 1 t/d
  - No plans for sulphur recovery installation at this time, as Canadian Natural anticipates sulphur emissions to be less than 1 t/d sulphur
  - Contingency plan is to reduce production if the sulphur emission rate approaches the EPEA or D56 limit
Kirby South Facility Performance
Sulphur Emissions

Kirby South Year 1 Sulphur Emissions

- EPEA Daily Limit / D54 Quarterly Limit
- Sulphur
- Calendar Quarter Sulphur
Kirby South Facility Performance
Ambient Air Quality Results

- During the monitoring periods, there were no ambient SO2, H2S or NO2 readings above the Alberta Ambient Air Quality Objective (AAAQO).
- During the month of December 2013, the NOX, NO, NO2, and SO2 analyzers failed to meet the required 90% uptime for that calendar month.
Measurement and Reporting Summary

• MARP approved in October 2011 and last updated in April 2014
  – All were minor changes (typos on drawings, inconsistencies between what is on the drawings and on the measurement list)

• Methods for estimating well production and injection volumes:
  – Produced emulsion from the scheme will be commingled at the battery. Bitumen and water production from the battery will be prorated to each well using monthly proration test data and proration factors
    ▪ Total Battery Oil (Water) / Total Test Oil (Water) at Wells = Oil (Water) Proration Factor
    ▪ Oil (Water) Proration Factor * Each Well Test Oil (Water) Volume = Oil (Water) Allocated to Each Well
  – Gas will be allocated to each well using a battery GOR
    ▪ Total Solution Gas Produced / Total Battery Oil = Gas Oil Ratio
    ▪ Gas Oil Ratio * Oil Allocated to Each Well = Gas Allocated to Each Well
  – Injected steam volumes will be continuously measured at the wellhead and prorated to the total steam leaving the injection facility

• Test Durations
  – Most wells will have 4-hour proration test durations but some wells may be tested from 1 to 6 hours, depending on their unique conditions and maturity
Measurement and Reporting
Proration Factors

Sep 2013 – March 2014 high profacs – plant metering issues and non-design operation at very low rates/early circulation
Well testing could not be properly calibrated until most of the wells were on SAGD. Well tests during circulation are less accurate
Continuing to improve calibration techniques to further improve profacs
Future Plans – Surface
Kirby South Planned 2014 – 2015 Activities

• Central Plant
  – Continue troubleshooting the oil train to optimize the process and improve overall performance, including
    ▪ Diluent to bitumen optimization (rates and location)
    ▪ Separation chemical additions (rates and location) / testing will continue with new chemicals
    ▪ Possible oil treating and/or PW de-oling equipment addition/modifications to improve reliability and performance

• Pads
  – Metering changes to improve measurement of utility gas
  – Piping modifications on B pad relate to re-drill
  – Potential piping modifications on A pad relate to re-drill
  – Possible piping addition on G pad to be able to circulate the remaining wells to be converted to SAGD
  – Project in place to start adding more wells on pad F
Kirby North Site Activities
Summary

• Central Plant
  – Drilling substantially complete for salt cavern wells
  – Major project infrastructure in progress including temporary power, roads, etc.
  – Piling substantially complete
  – Field civil work for equipment/building foundations progressing
  – Module setting complete for salt cavern development phase
  – Field mechanical and electrical installation in progress
  – Tank erection field contractor mobilizing
  – Temporary construction offices in place for field contractors. Construction Management office construction commencing

• Pads & Pipelines
  – Temporary gas pipeline in place for plant and camp
  – Engineering in progress for facilities and pipelines

• Steam-in date planned for Q4 2016
Kirby North Site Activities
Central Plant – Q3 2014
Kirby North Site Activities
Salt Cavern Module Setting Q3 2014
• Mechanical Vapor Compression (MVC) evaporators selected for BFW treatment
  – Treatment of both recycled produced water and makeup water
  – Evaporator blow down solids disposal to on-site salt cavern
  – Silica Sorption process selected vs. high pH process from application
Mechanical Vapor Compression Evaporator:
Kirby South Water Usage
Produced and Make-up Water Usage

Water Sources
Saline
- McMurray Fm
  - TDS = 14,500 ppm
  - Pressure balancing, make-up and cavern wash water
- Grand Rapids
  - TDS 4,500 ppm (tested frequently)
  - Make-up and cavern wash water

Non-Saline
- Grand Rapids
  - TDS 2,450 ppm
  - Make-up and wash water
- Empress Fm
  - TDS = 550 ppm
  - Make-up and utility water
## Kirby South Water Usage
### Produced and Make-up Water Usage

<table>
<thead>
<tr>
<th>Month</th>
<th>Non-saline Volume</th>
<th>Saline Volume</th>
<th>Non Saline Make-Up Percentage</th>
<th>Injection</th>
<th>Produced</th>
<th>PWR</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>m$^3$</td>
<td>m$^3$</td>
<td>%</td>
<td>m$^3$</td>
<td>m$^3$</td>
<td>%</td>
</tr>
<tr>
<td>Sep-13</td>
<td>48,855</td>
<td>24,260</td>
<td>67</td>
<td>38,937</td>
<td>14,792</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Start-Up Mode</td>
</tr>
<tr>
<td>Oct-13</td>
<td>30,132</td>
<td>8,457</td>
<td>78</td>
<td>23,805</td>
<td>108,364</td>
<td>78</td>
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<tr>
<td>Nov-13</td>
<td>39,575</td>
<td>5,010</td>
<td>89</td>
<td>16,386</td>
<td>196,494</td>
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<tr>
<td>Dec-13</td>
<td>37,114</td>
<td>17,321</td>
<td>68</td>
<td>29,216</td>
<td>214,129</td>
<td>86</td>
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<tr>
<td>Jan-14</td>
<td>45,075</td>
<td>11,779</td>
<td>79</td>
<td>28,165</td>
<td>204,284</td>
<td>86</td>
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<td>Feb-14</td>
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<td>95</td>
<td>17,678</td>
<td>125,906</td>
<td>86</td>
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<tr>
<td>Mar-14</td>
<td>21,120</td>
<td>32,762</td>
<td>39</td>
<td>26,929</td>
<td>242,489</td>
<td>89</td>
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<tr>
<td>Apr-14</td>
<td>9,839</td>
<td>33,029</td>
<td>23</td>
<td>20,855</td>
<td>250,890</td>
<td>92</td>
</tr>
<tr>
<td>May-14</td>
<td>10,369</td>
<td>26,154</td>
<td>28</td>
<td>22,007</td>
<td>220,676</td>
<td>90</td>
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<tr>
<td>Jun-14</td>
<td>6,452</td>
<td>32,318</td>
<td>17</td>
<td>22,731</td>
<td>268,756</td>
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<tr>
<td>Jul-14</td>
<td>7,407</td>
<td>36,027</td>
<td>17</td>
<td>16,938</td>
<td>191,446</td>
<td>91</td>
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<tr>
<td>Aug-14</td>
<td>7,397</td>
<td>19,259</td>
<td>28</td>
<td>25,427</td>
<td>238,668</td>
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<tr>
<td>1st Year Totals</td>
<td>312,028</td>
<td>248,744</td>
<td>56</td>
<td>289,074</td>
<td>2,276,893</td>
<td>89</td>
</tr>
</tbody>
</table>

- Non-saline volumes declined and saline volumes increased
- Directive 81 Disposal Limit = 11%, Actual Disposal = 10% for the first year of operations
- Produced Water Recycle also increased after first 6 months
- Also used a total of 50,567 m$^3$ of non-saline/potable water to supply camps and office complex during first year of operations
Kirby South Water Usage
Source and Disposal Well Map

- WSW and WDW
# Kirby South Water Usage Source Wells - Saline

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Use</th>
<th>Unique Well Identifier</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>McMurray Source Wells</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CNRL WSW01 Kirby 14-30-73-7</td>
<td>Make-up Source (not used)</td>
<td>1F1/14-30-73-7W4M</td>
</tr>
<tr>
<td>CNRL WSW MC01 Kirby 10-33-73-8</td>
<td>Make-up Source</td>
<td>1F1/10-33-73-8 W4M</td>
</tr>
<tr>
<td>CNRL WSW MC02 Kirby 10-33-73-8</td>
<td>Make-up Source</td>
<td>1F2/10-33-73-8 W4M</td>
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<tr>
<td><strong>McMurray Off-Lease Saline Source Evaluation Well</strong></td>
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<tr>
<td>CNRL WSW MC03 Kirby 11-13-73-6</td>
<td>Make-up Source</td>
<td>1F1/11-13-73-06W4M</td>
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<tr>
<td><strong>Grand Rapids Source Well</strong></td>
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<tr>
<td>CNRL WSW GR01 Kirby 13-21-73-7</td>
<td>Make-up Source</td>
<td>1F3/13-21-073-07W4M</td>
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</table>
## Kirby South Water Usage

### Source Wells – Non-Saline

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Use</th>
<th>Unique Well Identifier</th>
</tr>
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<tr>
<td><strong>GRAND RAPIDS Formation</strong></td>
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</tr>
<tr>
<td>Grand Rapids Source Wells</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CNRL WSW02 Kirby 14-30-73-7</td>
<td>Make-up Source</td>
<td>1F2/14-30-73-8W4M</td>
</tr>
<tr>
<td><strong>EMPRESS Formation Source Wells</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CNRL WSW Kirby 13-21-73-7</td>
<td>Utility Source</td>
<td>1F2/13-21-73-07W4M</td>
</tr>
<tr>
<td>CNRL WSW EMP03 12-21-73-7</td>
<td>Utility Source</td>
<td>1F1/12-21-73-07W4M</td>
</tr>
<tr>
<td><strong>MURIEL LAKE Formation - Source Wells</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CNRL WSW ML03 Kirby 13-21-73-7</td>
<td>Domestic Source</td>
<td>1F4/13-21-73-7W4M</td>
</tr>
<tr>
<td><strong>ETHEL LAKE Formation - Source and Standby Wells</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CNRL WSW EL01 Kirby 16-29-73-7</td>
<td>Domestic Source</td>
<td>1F1/16-29-73-7W4M</td>
</tr>
<tr>
<td>CNRL WSW EL02 Kirby 15-29-73-7</td>
<td>Domestic Source</td>
<td>No UWI</td>
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<td>No license required</td>
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### Kirby South Water Usage

#### Disposal Wells

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<th>Well Name</th>
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<tr>
<td><strong>McMurray Disposal Wells</strong></td>
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<td></td>
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<tr>
<td>RAX Kirby 9-34-73-8</td>
<td>Disposal (not currently used)</td>
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<tr>
<td>CNRL WDW01 Kirby 8-17-74-8</td>
<td>Disposal</td>
<td>00/08-17-74-08W4M</td>
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<tr>
<td>CNRL WDW02 Kirby 10-17-74-8</td>
<td>Disposal</td>
<td>02/10-17-74-08W4M</td>
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<tr>
<td>CNRL WDW03 Kirby 15-17-74-8</td>
<td>Disposal</td>
<td>00/15-17-74-08W4M</td>
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| **Salt Cavern Wells**              |                            |                            |
| CNRL CAVERN VERT KIRBY 13-21-73-7  | Lotsburg                   | 100/13-21-73-07W4M         |
| CNRL CAVERN DD KIRBY 4-28-73-7     | Prairie Evaporate          | 102/4-28-073-07W4M         |
### Kirby South Water Usage Disposal Wells

<table>
<thead>
<tr>
<th>Month</th>
<th>Wellhead Temperature Daily Average</th>
<th>Wellhead Pressure Daily Average</th>
<th>Cumulative Volume</th>
<th>Wellhead Temperature Daily Average</th>
<th>Wellhead Pressure Daily Average</th>
<th>Cumulative Volume</th>
<th>Wellhead Temperature Daily Average</th>
<th>Wellhead Pressure Daily Average</th>
<th>Cumulative Volume</th>
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<tr>
<td>Sep-13</td>
<td>0</td>
<td>2506</td>
<td>4210</td>
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<td>13</td>
<td>1375</td>
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<td>9</td>
<td>1356</td>
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<td>Dec-13</td>
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<td>17585</td>
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<td>1647</td>
<td>0</td>
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<td>1649</td>
<td>650</td>
<td>8</td>
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<td>Mar-14</td>
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<td>4833</td>
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<tr>
<td>May-14</td>
<td>12</td>
<td>1903</td>
<td>0</td>
<td>11</td>
<td>1903</td>
<td>3515</td>
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<td>1857</td>
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<td>Jun-14</td>
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<td>8225</td>
<td>17</td>
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<td>Jul-14</td>
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<td>17</td>
<td>1875</td>
<td>1890</td>
<td>14</td>
<td>1853</td>
<td>11584</td>
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<td>Aug-14</td>
<td>20</td>
<td>0</td>
<td>0</td>
<td>21</td>
<td>2594</td>
<td>9481</td>
<td>21</td>
<td>2557</td>
<td>15321</td>
</tr>
</tbody>
</table>

**Note:** Wellhead Daily Average Temperatures and Pressures presented here are from data recorded on the 20th day of every month.
Pressures in McMurray Fm Basal Aquifer being monitored daily within McMurray Fm Basal Aquifer at monitoring wells listed in Commercial Scheme Approval 11475.
Kirby South Pressure Balance Scheme Update

- Most observation well pressures are now at or near static pressure (2550 kPa)
  - Injection at disposal wells and production at source wells both affect bottom water pressure under reservoir
  - Can control bottom water pressure by adjusting production at source wells

Kirby South - McMurray Formation
Source Well and Observation Monitoring

* Static pressure for F Pad 12-20 = 2621.6 kPa (March 2011)
Kirby South Pressure Balance Scheme Update

- McMurray Fm Basal Aquifer pressure near 10-17-74-8 disposal area
  - Pressure increased in aquifer early on during cavern washing, but is now decreasing mainly because of decreased rates of injection
  - Obtained chemistry sample at 1-17 obs well in March, 2014, TDS ~12,500, which is background concentration
Kirby South Pressure Balance Scheme Update

- Reservoir at disposal area cannot accommodate high disposal rates (> 1,500 m$^3$/d) in the long-term
  - Currently below 1,500 m$^3$/d, but this will grow as more pads added, also need to account for potential increased disposal rate due to plant upset
    - Installation of disposal well at 100/10-19-073-08W4/00 in Q3-Q4 2014
      - Increases disposal capacity and is connected to 10-33 source area (pressure balance)
Water Sources and Wastewater Disposal

- Salt caverns to treat water and drop out particulates in the Prairie Evaporite and the Lotsburg Formation

- McMurray Formation Basal Aquifer – Primary Wastewater Disposal Zone
  - Pressure balanced with source wells, water used for cavern wash and make-up
    - Used learnings from Kirby South to locate wells

- Clearwater Formation B Aquifer - Saline water source
  - Cavern wash and make-up water

- Empress Formation Terrace Aquifer - Non-Saline water source
  - Cavern wash, peak make-up, and utility
Kirby South Waste Disposal Summary

- Beaver Regional Municipal Landfill
  - 2310 kg sludge and debris

- Clean Harbors Ryley Landfill
  - 217,963 kg leachable waste solids

- Secure Pembina Landfill
  - 56,981 kg leachable waste solids

- Tervita Janvier Landfill
  - 1,205,410 kg sludge

- Tervita Metals Recycling
  - 25,381 kg metal

- Van Brabant Oil
  - 2,390 kg flammable liquid

- Wood Buffalo Landfill
  - 149,660 kg domestic waste
Environmental Summary
Monitoring Programs

- Wildlife Mitigation Plan and Monitoring Program
  - Monitoring mitigation efficacy (above ground pipelines, barriers to wildlife movement, effects of human presence)
    - Remote camera monitoring began fall 2012
  - Monitoring distribution and abundance of listed species at the local scale
  - Techniques and procedures to facilitate return of disturbed lands to pre-disturbance wildlife habitat capacity
  - Winter track count surveys every 3 years (began winter 2011/2012)
  - Breeding bird surveys every 3 years (beginning June 2014)
  - Marsh bird surveys every 3 years (began June 2013)
  - Wildlife sighting cards provided to workers and compiled information reported to ESRD through the Fish and Wildlife Management Information System
Environmental Summary
Monitoring Programs

• Wetland Monitoring Program
  – Culvert inspection program identified corrective action required on culverts.
  – Data on near-surface water level in wetlands contribute to an understanding of hydrologic conditions. No indication of Project effects on wetland hydrology is apparent to date.
  – Runoff events and evaporative drawdown apparent drivers of temporal variability in surface water elevation. Further monitoring required to determine extent of variability.
  – Few surface water quality exceedances; substances that are naturally present. Further monitoring required to determine conclusions.
Environmental Summary
Monitoring Programs

• Groundwater Monitoring Program
  – Well pad monitoring program to monitor potential effect of steam injection on mineral solubility and mobilization of trace elements
    ▪ 1 monitoring well on each Pad B, Pad D, Pad F
  – Central Plant monitoring program monitors groundwater conditions within shallow sediments
    ▪ 17 groundwater monitoring wells at CPF
  – Sub-regional monitoring program to monitor conditions in regionally extensive non-saline Tertiary/Quaternary aquifers
    ▪ 12 sub-regional monitoring wells
  – Compliance monitoring and sampling began October 2013. Parameters that were identified above comparative guidelines were not considered impacts to the groundwater quality as the parameters were most likely naturally occurring.
Environmental Summary

Reclamation Activities

• Reclamation Activities
  – Soil placement in four borrow areas

• Reclamation Monitoring
  – Objectives are to ensure:
    ▪ land is reclaimed to an equivalent land capability
    ▪ appropriate replacement of all salvaged topsoil on recontoured areas
    ▪ sustainable, diverse vegetation growth on all disturbed areas
    ▪ pre-disturbance wildlife carrying capacities are obtained
  – Regular site monitoring throughout reclaimed areas within the Project Area
Environmental Summary
Provincial/Federal Programs

• Canadian Oil Sands Innovation Alliance (COSIA)

• Lower Athabasca Regional Plan (LARP)
  – Participation in the South Athabasca Oil Sands (SAOS) area for Groundwater Management

• Joint Canada/Alberta Implementation Plan for Oil Sands Environmental Monitoring
  – Participation in the implementation of the program. Technical information and site access provided as necessary.

• Provincial and Federal Woodland Caribou Policies
  – Participating in the implementation of habitat restoration work on Canadian Natural project lands as part of a coordinated industry effort
  – Participating in the upcoming GOA process to develop and implement range-level restoration plans

• Base Level Industrial Emissions Requirements (BLIERs)
  – Providing feedback through CAPP on Multi-sector Air Pollutants Regulations (MSAPR) which includes BLIERs for Reciprocating Engines and Boilers & Heaters
## Approvals

### Commercial Oil Sands Scheme

<table>
<thead>
<tr>
<th>Date</th>
<th>Approval Date</th>
<th>Description</th>
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<tbody>
<tr>
<td>11475</td>
<td>September 2010</td>
<td>Commercial Oil Sands Scheme Approval</td>
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<tr>
<td>11475A</td>
<td>November 2010</td>
<td>Revise initial development Pads A to G</td>
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<tr>
<td>11475B</td>
<td>November 2011</td>
<td>Change inter-well spacing Drainage Area D</td>
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<td>11475C</td>
<td>December 2011</td>
<td>Change inter-well spacing in Drainage Area B</td>
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<tr>
<td>11475D</td>
<td>May 2012</td>
<td>Change inter-well spacing in Drainage Area E</td>
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<tr>
<td>11475E</td>
<td>June 2012</td>
<td>Evaluation of on-lease McMurray brackish water</td>
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<td>11475F</td>
<td>August 2012</td>
<td>Change inter-well spacing in Drainage Area G</td>
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<tr>
<td>11475G</td>
<td>September 2012</td>
<td>Change inter-well spacing in Drainage Area F Addition to Drainage Area D</td>
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<td>11475H</td>
<td>April 2013</td>
<td>Evaluation of off-lease Clearwater brackish water</td>
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<tr>
<td>11475I</td>
<td>January 2014</td>
<td>Operational Strategy amendment</td>
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<tr>
<td>11475J</td>
<td>March 2014</td>
<td>Trajectory and lateral length modifications in Drainage Area G</td>
</tr>
<tr>
<td>11475K</td>
<td>May 2014</td>
<td>Approval of Kirby In Situ Oil Sands Expansion Project</td>
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In Compliance
## Approvals Disposal

### Class 1b Cavern Disposal

<table>
<thead>
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<tr>
<td>11716</td>
<td>November 2011</td>
<td>Cavern Solution Mining</td>
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<td>11716A</td>
<td>July 2013</td>
<td>Class 1b Cavern Disposal</td>
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<td></td>
<td>- Prairie Evaporites formation through well 00/13-21-073-07W4</td>
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<tr>
<td></td>
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<td>- Lotsberg formation through well 00/04-28-073-07W4</td>
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### In Compliance

### Class Ib Disposal

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<td>11761A</td>
<td>April 2013</td>
<td>Modify pH requirements</td>
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<td>11761B</td>
<td>March 2014</td>
<td>Amend MWHIP</td>
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### In Compliance
### Approvals Disposal (continued) and Facility License

#### Class II Disposal

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<td>• 00/08-22-074-10W4/0</td>
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<td>September 2003</td>
<td>Transferred to Canadian Natural from Rio Alto Exploration</td>
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<td>9594A</td>
<td>December 2011</td>
<td>Approval of Kirby In Situ Oil Sands Project</td>
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<td>9594B</td>
<td>May 2014</td>
<td>Approval of Kirby In Situ Oil Sands Expansion Project</td>
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#### In Compliance

#### Facility License

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<td>F42290</td>
<td>October 2010</td>
<td>Kirby South Phase 1 Central Processing Facility</td>
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<td>F42290</td>
<td>July 2013</td>
<td>Amended for KS1 CPF to reflect stream day rates and number of compressors and pumps</td>
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<td>F44051</td>
<td>July 2014</td>
<td>Kirby North Phase 1 Central Processing Facility</td>
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#### In Compliance
## Approvals

### EPEA and Water Act

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<td>237382-00-00</td>
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<td>237382-00-01</td>
<td>July 2014</td>
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<td>00334375-00-00</td>
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<td>Groundwater diversion license, Empress Unit 1 and Grand Rapids Formation</td>
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<td>00288494-00-00</td>
<td>April 2011</td>
<td>Groundwater diversion license, Ethel Lake Formation</td>
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<td>00327156-00-00</td>
<td>August 2013</td>
<td>Industrial surface runoff diversion license</td>
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<td>00303825-00-00</td>
<td>July 2014</td>
<td>Preliminary Certificate groundwater diversion, Empress Terrace Formation</td>
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<tr>
<td>00303820-00-00</td>
<td>September 2014</td>
<td>Industrial surface runoff diversion license</td>
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**In Compliance**
• Reportable Spills
  – 7 reportable spills on-lease, including 4 oil/water, 1 produced water/magnesium oxides, 1 glycol and 1 brackish water

• EPEA Contraventions
  – Ambient Air Monitoring Trailer, less than 90% total run time August 2013
  – Continuous Air Monitoring Trailer, less than 90% total run time December 2013
  – Ambient H2S hourly average exceedance June 2014. Not attributed to Central Process Facilities.
  – CEMS malfunction, less than 90% total run time July 2014

• All compliance items reported to ESRD/AER as required.
Forward Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the “Company”) in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as “forward-looking statements”) within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words “believe”, “anticipate”, “expect”, “plan”, “estimate”, “target”, “continue”, “could”, “intend”, “may”, “potential”, “predict”, “should”, “will”, “objective”, “project”, “forecast”, “goal”, “guidance”, “outlook”, “effort”, “seeks”, “schedule”, “proposed” or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses, and other guidance provided throughout this presentation constitute forward-looking statements. Disclosure of plans relating to exploration and expected results of existing and future developments and acquisitions is subject to forward-looking statements. The Kirby Thermal Oil Sands operations and future expansion, Septimus, Phmro thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf coast, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, the proposed Energy East pipeline from Hardisty to Eastern Canada, the construction and future operations of the North West Redwater bitumen upgrader and refinery and disclosures relating to the Devon Canada Asset acquisition also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to “reserves” are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas and natural gas liquids (NGLs”) reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company’s products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company’s current guidance is based; the Company’s ability to maintain its operating capacity, including with respect to the operation of its pipelines and refineries; the Company’s ability to implement its business strategy, including exploration and development activities; impact of competition; the Company’s defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company’s and its subsidiaries’ ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company’s bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labor required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company’s bitumen products; availability and cost of financing; the Company’s and its subsidiaries’ success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil; operating, transportation, tax and other costs and expenses; size, location and condition of the Company’s assets, liabilities, and reserves; ability of the Company to raise capital; ability to benefit from recent acquisitions; ability to maintain relationships with government agencies; ability to maintain insurance coverage at reasonable costs and adequate levels; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; and the Company’s defense of lawsuits; the environmental and operating hazards of its operations; the Company’s ability to obtain required permits; the adequacy of the Company’s reserves for taxes; and other circumstances affecting revenues and expenses. The Company’s operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company’s assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the “Risks Factors” section of the AIF. Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the factors affecting the information, should circumstances or Management’s estimates or opinions change.
Reporting Disclosures

Special Note Regarding Currency, Production and Reserves

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are presented on a before royalties basis unless otherwise stated. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent (“BOE”). A BOE is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6Mcfe:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6Mcfe:1bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6Mcfe:1bbl conversion ratio may be misleading as an indication of value.

This document, herein incorporated by reference, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2013 the Company retained Independent Qualified Reserves Evaluators (“Evaluators”), Sproule Associates Limited and Sproule International Limited (together as “Sproule”) and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company’s proved and proved plus probable reserves with an effective date of December 31, 2013 and a preparation date of February 3, 2014. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission ("SEC") requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2011 and 2012 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 “Extractive Activities - Oil and Gas” in the Company’s Form 40-F filed with the SEC in the “Supplementary Oil and Gas Information” section of the Company’s Annual Report targeted to be released in late March 2013.

Resources Other Than Reserves

The contingent resources other than reserves (“resources”) estimates provided in this presentation are internally evaluated by qualified reserves evaluators in accordance with the COGE Handbook as directed by NI 51-101. No independent third party evaluation or audit was completed. Resources provided are best estimates as of December 31, 2012. The resources are evaluated using deterministic methods which represent the expected outcome with no optimism or conservatism.

Resources, as per the COGE Handbook definition, are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered commercially viable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of these resources.

Due to the inherent differences in standards and requirements employed in the evaluation of reserves and contingent resources, the total volumes of reserves or resources are not to be considered indicative of total volumes that may actually be recovered and are provided for illustrative purposes only.

Crude oil, bitumen or natural gas initially-in-place volumes provided are discovered resources which include production, reserves, contingent resources and unrecoverable volumes.

Special Note Regarding non-GAAP Financial Measures

This document includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, cash production costs and net asset value. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to, or more meaningful than, net earnings, as determined in accordance with IFRS, as an indication of the Company’s performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the “Financial Highlights” section of the Company’s MD&A. The derivation of cash production costs is included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of the Company’s MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of the Company’s MD&A.

Volumes shown are Company share before royalties unless otherwise stated.
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