Long Lake – Annual Performance Presentation
in accordance with Directive 054
(Subsurface)

April 8, 2015
Overview

• Overview
• Geology and Geosciences
  – Slides 8 to 66
• Kinosis Geology and Geosciences
  – Slides 67 to 89
• Drilling and Completions
  – Slides 90 to 105
• Scheme and Pad Performance
  – Slides 106 to 124
• Learnings, Trials, and Pilots (Slides 125 to 142)
  – Liners – Redrill and Repairs
  – Infill Projects – Learnings and Future Plans
• Observation Wells
  – Slides 143-146
• Future Plans
Purpose

This presentation contains information to comply with Alberta Energy Regulator’s Directive 054 – Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes.
Corporate Ownership

- Nexen Energy ULC is an upstream oil and gas company responsibly developing energy resources in the UK North Sea, offshore West Africa, the United States and Western Canada.

- In February 2013, Nexen became a wholly-owned subsidiary of Chinese National Offshore Oil Company (CNOOC) Limited.

- Nexen has three principal businesses: conventional oil and gas, oil sands and shale gas.
Nexen Oil Sands Leases
# Chronology of Oil Sands Operations

<table>
<thead>
<tr>
<th>Year</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>EIA and regulatory submissions for the commercial Long Lake Facility</td>
</tr>
<tr>
<td>2003</td>
<td>Regulatory approvals for the commercial Long Lake Facility</td>
</tr>
<tr>
<td>2003 - 2007</td>
<td>Production at the Long Lake SAGD Pilot Plant</td>
</tr>
<tr>
<td>2004</td>
<td>Construction begins for the commercial Long Lake Facility</td>
</tr>
<tr>
<td>2006</td>
<td>Regulatory amendments, including Pad 11</td>
</tr>
<tr>
<td>2007</td>
<td>Start of commercial bitumen production for the Long Lake Facility</td>
</tr>
<tr>
<td>2007</td>
<td>Regulatory submissions for Long Lake South (development of Knosis lease)</td>
</tr>
<tr>
<td>2009</td>
<td>Regulatory approvals issued for Long Lake South</td>
</tr>
<tr>
<td>2009</td>
<td>Start of operation of the Long Lake Upgrader</td>
</tr>
<tr>
<td>2010</td>
<td>Regulatory approvals for Pads 12 and 13</td>
</tr>
<tr>
<td>2012</td>
<td>First production from Pads 12 and 13</td>
</tr>
<tr>
<td>2012</td>
<td>Major turnaround for maintenance at CPF and Upgrader</td>
</tr>
<tr>
<td>2012</td>
<td>Regulatory approvals for Pads 14 and 15 and K1A (formerly Long Lake South)</td>
</tr>
<tr>
<td>2012</td>
<td>Construction begins for K1A and Pads 14 and 15</td>
</tr>
<tr>
<td>2013</td>
<td>Increased production from Long Lake well pads, begin circulation at Pad 14</td>
</tr>
<tr>
<td>2014</td>
<td>K1A and Pads 14 and 15 started production</td>
</tr>
</tbody>
</table>
2014 Summary

• Most successful year at Long Lake
  – Best ever safety record
  – Record production (42,900 bpd average) and significant increase over 2013
    • Improved plant reliability
    • Optimization of existing wells
    • Pads 14/15 ramping up above expectation
  – K1A completion and start-up
  – Completion and start-up of first Long Lake infill wells
Stratigraphy

Reservoir: McMurray Fm.

Cap rock: Wabiskaw & Clearwater Fm.
Nexen’s Facies Code

- **Sandstone**: Facies 1:
  - clean crossbedded sandstone
  - VSH 0 - 10%
  - estuarine sands

- **Sandy IHS**: Facies 2:
  - inclined interbedded sandstone, and mudstone
  - VSH 10 - 30%
  - point bar facies

- **Breccia**: Facies 3:
  - mud clast breccia
  - sand supported and mud clast supported
  - channel base facies

- **Muddy IHS**: Facies 4:
  - inclined interbedded sandstone, and mudstone
  - VSH 30 - 80%
  - point bar facies

- **Mudplug**: Facies 5:
  - muds and silts
  - abandoned channel muds
  - point bar facies

- **Mudstone**: Facies 6:
  - flood plain deposits

- **Limestone**: Facies 7:
  - Devonian carbonates
Nexen’s Regional Model

- Multiple valleys
  - C & D valleys (oldest)
  - A valley (youngest)
- In terms of sequence stratigraphy, it was a low-accommodation setting
- Compound incised-valley system hung from several surfaces in the McMurray
Regional Depositional Model

- Tidal-Fluvial/Estuarine Complexes
  - Stacked channel systems including:
    - Mid-channel bars
    - Channel-tidal shoal complexes
    - Channel-point bar complexes
    - Mud plugs

- Estuarine/brackish water environment
McMurray Geological Model and Reservoir Facies

<table>
<thead>
<tr>
<th>MCB = mid-channel bar</th>
<th>Facies 1 &amp; Facies 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>LPB = lower point bar</td>
<td>Facies 1 &amp; Facies 3</td>
</tr>
<tr>
<td>IHS = inclined heterolithic stratification</td>
<td>Facies 2, Facies 3, &amp; Facies 4</td>
</tr>
</tbody>
</table>
Devonian Structure with Karst and Salt Dissolution Features

MAP DATA
- ZERO EDGE
- DEVONIAN STRUCTURE CONTOURS (C.I.=10m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM
- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE: NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

STRUCTURE EVENTS OVERLAY
- MULTI STAGE COLLAPSE
- PRE McMURRAY COLLAPSE
- POST McMURRAY COLLAPSE

DEVONIAN STRUCTURE RASTER
- High : 267.8
- Low : 139.3m
Devonian Structure with Karst and Salt Dissolution Features

- Relatively flat below current SAGD development areas.
- Lows related to collapse features (karst and dissolution) and erosion.
Long Lake
McMurray Structure

MAP DATA
- ZERO EDGE
- McMURRAY STRUCTURE CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM
- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

McMURRAY STRUCTURE RASTER
- High : 334.2
- Low : 245.1 m
• Relatively flat
• Blue-shaded areas are lows related to salt dissolution
• Subtle structural influences related to karsting, erosion on Devonian and differential compaction over muddier McMurray deposits
• Relatively consistent isopach (50-70m)
• Thick areas associated with Devonian lows
Pay and Exploitable Bitumen-in-Place Mapping Methodology
Pay and Exploitable Bitumen-in-Place Mapping Methodology

- **Pay cut-offs:**
  - Top of pay interval is a 2m shale with \( >30\% V_{\text{shale}} \)
  - Focus on low \( V_{\text{shale}} \) intervals with thinner and fewer shale beds
  - Account for standoff from bottom water or non-reservoir

- **Top of EBIP Pay Interval:**
  - Single shale interval (\( > 30\% V_{\text{shale}} \)) of 2m
  - Cumulative shale interval (\( > 30\% V_{\text{shale}} \)) of 4m

- **Base of EBIP Pay Interval:**
  - Depth of an existing or planned horizontal well pair (EBIP pay base = producer well depth)
  - Stand-off from bitumen/water contact or non-reservoir

- **Gas Interval(s) Associated with EBIP Pay Interval**
  - Gas identified by neutron/density crossover

- **High Water Saturation Interval(s) Associated with EBIP Pay Interval**
  - \( > 50\% \text{ Swe} \) (effective water saturation) and \( < 30\% V_{\text{shale}} \)

- **EBIP will be calculated from a hydrocarbon pore volume height (HPVH) map**

### Reservoir Rock
- Sand
- Breccia
- IHS with \( < 30\% V_{\text{shale}} \)

### High Water Saturation Interval
- \( > 50\% \text{ Swe} \) (effective water saturation) and \( < 30\% V_{\text{shale}} \)

### Minimum EBIP HPVH and Pay Interval Contour
- \( 3 \text{ m}^3/\text{m}^2 \text{ EBIP HPVH} = 12 \text{m EBIP Pay Interval} \)
Pay and Exploitable Bitumen-in-Place Mapping Methodology

EBIP Pay Interval
- < 30% $V_{\text{shale}}$
- < 50% $S_{\text{we}}$
- may have associated
  - gas interval(s)
  - high water saturation interval(s)

Primary zone defined as the thickest pay interval unless:
- an existing (or planned) hz well pair is within an interval
- geologists have interpreted continuity of an interval across an area
Pay and Exploitable Bitumen-in-Place Mapping Methodology

- **Base of EBIP Pay Interval**
  - Depth of an existing or planned hz well pair (EBIP Pay Interval base = producer well depth)
  - 3m stand-off if no bottom water (minimum shale of 2m thickness)
  - 5m stand-off if in contact with bottom water (minimum bottom water thickness of 2m)
Base of EBIP Pay Interval

• In areas where reserves are mapped but future well pairs have not been laid out, a 3m or 5m stand-off from the mapped base of the reservoir is applied when estimating EBIP.

• Applying these stand-offs attempts to account for the volume of resource that may not be recoverable by future SAGD producer wells due to the following assumptions:
  – Wells will be placed at elevations that optimize the well pair extent through high quality reservoir.
  – Maintaining a flat trajectory.
  – Avoiding production risk due to bottom water where it occurs.

• **3m** stand-off is applied above the base-of-reservoir where the base of reservoir is in contact with non-reservoir strata.
  – Attempt to account for resource that will likely remain unproduced due to irregularities on the base-of-reservoir surface structure.

• Stand-off is increased to **5m** where the base of the reservoir is mapped as being in contact with bottom water.
  – “Contact” is considered to occur where there is less than a 2m shale interval between the top of bottom water and the base of the bitumen reservoir.

• **5m** stand-off from the bottom water contact attempts to mitigate the following concerns:
  – Maintain sufficient stand-off between the producer and the bottom water surface to avoid early communication.
  – Attempts to account for the uncertainty in the nature of the contact between the base-of-reservoir and bottom water.
  – Uncertainty in the elevation of the bottom water contact.
  – Allows steam chamber development along the entire length of the horizontal well pair during the early SAGD ramp up phase and should act as a baffle.

• Once a SAGD well pair location is proposed for an area, the actual elevation of the producer well will then define the EBIP base.
Considerations

• Target high quality resource - preferentially staying above mud clast breccia
• Plan horizontal well pair orientation so as to minimize stranded pay and/or preserve secondary development opportunities
• Maintain a flat trajectory as much as possible

Constraints

• Minimum of 5m stand-off from bottom water (if present) to minimize the risk of a pressure sink coming in contact with the higher pressure steam chamber
• Max. elevation change between horizontal wells 15 m/100 m
• 3 to 5 m vertical deviation from intermediate casing point (ICP)
• Approximate maximum rise or dip rate 1m/50m
Long Lake EBIP

(E^6 m^3)

330.65

Nexen Cutoffs: h > 12m or HPVH > 3 m

Hydrocarbon Pore Volume Height

$$HPVH = \sum (S_o \times \Phi)$$

Pay tp

Pay bs

Hydrocarbon Pore Volume Height (HPVH) is calculated from petrophysical logs calibrated to Dean Stark analysis.

Long Lake EBIP Average Reservoir Parameters

- Measured Depth (top) 200 m KB
- Thickness 22 m
- Effective Porosity 31.2 %
- $V_{shale}$ 10.1 %
- Permeability – Historical Plug Data
  - $K_{max}$ 5565 mD
  - $K_{vert}$ 4491 mD
- Effective Water Saturation 31.2 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure:
  ~1000 - 1100kPa @ 230m AMSL

Effective porosity, effective water saturation, and $V_{shale}$ are calculated every 10 cm over the EBIP interval, and the average is derived.
Long Lake
EBIP Pay Interval Isopach

MAP DATA
- ZERO EDGE
- EBIP ISOPACH (C.I.=2m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

EBIP ISOPACH RASTER
High : 72.2
Low : 12.0m

- Colour shading : >12m EBIP Interval
- Contours clipped to 3m³/m² HPVH EBIP contour
Long Lake
EBIP Pay Interval Isopach

MAP DATA
- ZERO EDGE
- EBIP ISOPACH (C.I.$=2m$)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

EBIP ISOPACH RASTER
- High : 72.2
- Low : 12.0m

- Colour shading : $>12m$ EBIP Interval

★ TYPE LOG
Type Log – 1AA/07-36-085-07W4

<table>
<thead>
<tr>
<th>Well: 1AA_07-36-085-07W4_0</th>
</tr>
</thead>
<tbody>
<tr>
<td>OPTI CANADA ET AL CHEECHAM 7-36-85-7</td>
</tr>
<tr>
<td>SURFACE ELEVATION: 494.10</td>
</tr>
<tr>
<td>RIG RELEASE: 03-MAR-2000</td>
</tr>
<tr>
<td>VERTICAL SCALE: 1:480</td>
</tr>
</tbody>
</table>

### Measurement Ref.: KB
- **Elevation Meas. Ref.:** 497.10
- **Drilled Depth:** 265.50
- **Measurement Ref.:** KB
  - Surface Elevation: 494.10

### Wire Measurements
1. **WIRE.BS:**
   - **Wire RMS:** 0.140 240
   - **Wire Cal.:** 0.140 240

2. **WIRE.RHB:**
   - **Wire RMS:** 0.2650 2650
   - **Wire DPSS:** 0.6 V/V 0
   - **Wire DRHO:** 0.6 V/V 0

3. **WIRE.NPSS:**
   - **Wire RMS:** 0.6 V/V 0
   - **Wire PEF:** 0.1 6

4. **WIRE.DT:**
   - **Wire RMS:** 0.6 V/V 0
   - **Wire DRHO:** 0.6 V/V 0

5. **WIRE.ILD:**
   - **Wire RMS:** 0.2 2000
   - **Wire ILM:** 0.2 2000

6. **WIRE.SFL:**
   - **Wire RMS:** 0.2 2000
   - **Wire SFL:** 0.2 2000

### Tidal-Fluvial Estuarine Complexes
- **Wabiskaw:**
- **Wabiskaw 'C':**
- **McMurray:**
- **McMurray A1:**

### EBIP Pay Interval
- **Top of Pay:**
- **Base of Pay:**

### Devonian

---

**29**
Long Lake
EBIP Pay Interval Base Structure

- Base of EBIP Pay Interval influenced by facies changes, karsting, erosion, salt dissolution, and bottom water
- Base EBIP is equal to the producer depth
Top of EBIP Pay Interval:
- base of 2m or thicker shale
- or cumulative 4m shale
- or base of top gas
- or base of top water
- or top of McMurray tidal-fluvial estuarine complexes

Bitumen in regional McMurray shorefaces and the McMurray A1 are not considered pay.
Long Lake
HPVH Isopach over EBIP Pay Interval

MAP DATA
- ZERO EDGE
- EBIP HPVH ISOPACH (C.I.=1m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM
- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEViated WELL PATH (DRILLED)

Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

EBIP HPVH ISOPACH RASTER
High : 15.5
Low : 3.0m

\[ \text{HPVH} = \sum_{\text{Min pay tp}} \left( S_0 \Phi \right) \]

- Colour shading : > 3m³/m² HPVH
Long Lake
HPVH Isopach Over EBIP Pay Interval

MAP DATA
- ZERO EDGE
- EBIP HPVH ISOPACH (C.I.=1m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM
- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

EBIP HPVH ISOPACH RASTER
- High : 15.5
- Low : 3.0m

\[ \text{Min pay to} \]
\[ \text{HPVH} = \sum \left( \text{So} \times \Phi \right) \]

- Colour shading : > 3m³/m² HPVH
Long Lake Total Gas: Gas Interval(s) within and in contact with EBIP Interval

- Gas identified by neutron/density crossover
- Gas associated with EBIP Interval
  - within EBIP Interval
  - directly in contact with top water or top of EBIP interval
  - contours clipped to 3m³/m² HPVH EBIP contour
• Gas identified by neutron/density crossover
• Gas associated with EBIP Interval
  - within EBIP Interval
  - directly in contact with top water or top of EBIP interval
  - contours clipped to 3m$^3$/m$^2$
• HPVH EBIP contour
# Type Log – 103/13-36-085-07W4

<table>
<thead>
<tr>
<th>Well: 103_13-36-085-07W4_0</th>
</tr>
</thead>
<tbody>
<tr>
<td>NEXEN OPTI NEWBY 13-36-85-7</td>
</tr>
<tr>
<td>MEASUREMENT REF.: KB</td>
</tr>
<tr>
<td>ELEVATION MEAS. REF.: 496.00</td>
</tr>
<tr>
<td>DRILLED DEPTH: 269.00</td>
</tr>
<tr>
<td>SURFACE ELEVATION: 492.30</td>
</tr>
<tr>
<td>RIG RELEASE: 06-FEB-2006</td>
</tr>
<tr>
<td>VERTICAL SCALE: 1:480</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Depth</th>
<th>Water</th>
<th>Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Depth</th>
<th>Devonian</th>
<th>McMurray</th>
<th>Wabiskaw 'C'</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Top of Pay</td>
<td>EBIP Pay interval</td>
<td>Base of Pay</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Depth</th>
<th>Depth</th>
<th>Wire</th>
<th>Wire</th>
<th>Wire</th>
<th>Wire</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Depth</th>
<th>Depth</th>
<th>Depth</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

## Tidal-Fluvial Estuarine Complexes

- Gas
- Water

## McMurrray

- Top of Pay
- EBIP Pay interval
- Base of Pay

## Wabiskaw

- Top of Pay
- EBIP Pay interval
- Base of Pay
Long Lake High Water Saturation Interval(s) in contact with Top EBIP Interval Isopach

- > 50% Swe and < 30% $V_{\text{shale}}$
- High water saturation intervals above and in contact with EBIP
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour
Long Lake  High Water Saturation Interval(s) in contact with Top EBIP Interval Isopach

- > 50% Swe and < 30% V_{shale}
- High water saturation intervals above and in contact with EBIP
- Contours clipped to 3m$^3$/m$^2$ HPVH EBIP contour
- > 50% Swe and < 30% $V_{\text{shale}}$
- Cumulative thickness of high water saturation interval(s) within EBIP interval
- Contours clipped to 3m$^3$/m$^2$ HPVH EBIP contour
Long Lake Cumulative Thickness of High Water Saturation Interval(s) within EBIP Interval

- > 50% Swe and < 30% \( V_{\text{shale}} \)
- Cumulative thickness of high water saturation interval(s) within EBIP interval
- Contours clipped to 3m\(^3\)/m\(^2\) HPVH EBIP contour

★ TYPE LOG
### Type Log – 100/05-32-085-06W4

**Well: 100_05-32-085-06W4_0**

**NEXEN OPTI OB1 B NEWBY 5-32-85-6**

**MEASUREMENT REF.: KB**

**ELEVATION MEAS. REF.: 472.20**

**DRILLED DEPTH: 248.80**

**SURFACE ELEVATION: 469.90**

**RIG RELEASE: 17-NOV-2002**

**VERTICAL SCALE: 1:480**

<table>
<thead>
<tr>
<th>Depth (m)</th>
<th>Wabiskaw 'C'</th>
<th>McMurray</th>
</tr>
</thead>
<tbody>
<tr>
<td>250</td>
<td></td>
<td></td>
</tr>
<tr>
<td>225</td>
<td></td>
<td></td>
</tr>
<tr>
<td>200</td>
<td></td>
<td></td>
</tr>
<tr>
<td>175</td>
<td></td>
<td></td>
</tr>
<tr>
<td>150</td>
<td></td>
<td></td>
</tr>
<tr>
<td>125</td>
<td></td>
<td></td>
</tr>
<tr>
<td>100</td>
<td></td>
<td></td>
</tr>
<tr>
<td>75</td>
<td></td>
<td></td>
</tr>
<tr>
<td>50</td>
<td></td>
<td></td>
</tr>
<tr>
<td>25</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**Devonian**

**EBIP Pay Interval**

- **Top of Pay**
- **Base of Pay**

**Wabiskaw**

- **Tidal-Fluvial Estuarine Complexes**
- **High Swe = 78%**
- **Depth**

**TVDSS METRES**

- **WIRE.RHOB_1**
- **K/M 2400**
- **WIRE.DPSS_1**
- **V/V 0.60**
- **WIRE.DT_1**
- **US/M 100**
- **WIRE.NPSS_1**
- **V/V 0.60**
- **WIRE.PEF_1**
- **B/E 16**
- **WIRE.DRHO_1**
- **K/M -400**

**SP_1**

- **MV 100**
- **400**

**GR_2**

- **GAPI 150**

**Type Log – 100/05-32-085-06W4**

- **McMurray Top of Pay**
- **Base of Pay**

- **Wabiskaw 'C'**

- **Devonian**

- **EBIP Pay Interval**

- **Tidal-Fluvial Estuarine Complexes**

- **High Swe = 78%**

- **Depth**
Long Lake
Bottom Water Associated with EBIP Interval

- > 50% Swe and < 30% $V_{\text{shale}}$
- Base of Bottom Water
  - top of a > 2m > 30% $V_{\text{shale}}$ shale interval
- Contours clipped to 3m$^3$/m$^2$ HPVH EBIP contour
Long Lake
Bottom Water Associated with EBIP Interval

- > 50% Swe and < 30% $V_{\text{shale}}$
- Base of Bottom Water
  - top of a > 2m > 30% $V_{\text{shale}}$ shale interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour
Representative structural cross-section of the East Side of Long Lake (South - North)
Representative structural cross-section of the East Side of Long Lake (West - East)
Representative structural cross-section of the West Side of Long Lake (South - North)

Well: 1AA_09-25-085-07W4_0

Well: 1AA_07-36-085-07W4_0

Well: 1AA_07-01-086-07W4_0
Representative structural cross-section of the West Side of Long Lake (West - East)
Representative structural cross-section of Pads 12 and 13

Well: 1AA_14-07-086-06W_0
SURFACE ELEVATION: 464.05
MEASUREMENT SET: K1
ELEVATION RANGE: 200-760
VERTICAL SOLID: 1 HEP

Well: 100_09-07-086-06W_0
SURFACE ELEVATION: 464.44
MEASUREMENT SET: K1
ELEVATION RANGE: 200-760
VERTICAL SOLID: 1 HEP

Well: 1AA_12-08-086-06W_0
SURFACE ELEVATION: 465.30
MEASUREMENT SET: K1
ELEVATION RANGE: 200-760
VERTICAL SOLID: 1 HEP

Wabiskaw 'C'
Top of Pay
Base of Pay
Devonian
McMurray
EBIP Pay Interval
Pad 12
Pad 13
Pad 15
Representative structural cross-section of Pads 14 and 15
Long Lake
Cap Rock Type Log

Cap rock defined as top of Clearwater B to top of Wabiskaw C sand.
Long Lake Cap Rock Evaluation - Pre-2014

MINI-FRACT LOCATION
10090708066W400
1AB08208506W400

TRIAXIAL STRENGTH & DIRECT SHEAR TESTING
1AB082908506W400

XRD, PETROGRAPHY, & GRAIN SIZE ANALYSIS
1AA083208506W400
1AA102708067W400
1AA122808506W400
1AA14208506W400
10053308506W400
105062808506W400
102092908506W400
100102908506W400
103142908506W400

CAPROCK CORE
10053308506W400
100082908506W400
10011080860W400
100132808506W400
10014080860W400
1AA012080506W400
1AA070208607W400
1AA07208506W400
1AB043208506W400
1AB082908506W400
1AC042808506W400
Long Lake Cap Rock Evaluation - 2014

**CAP ROCK EVALUATION**
- MINI FRAC
- PETROGRAPHY
- TRIAXIAL / CAPROCK CORE
- TRIAXIAL / CAPROCK CORE / XRD

**MINI-FRAC LOCATION**
- 100101308506W400

**TRIAXIAL STRENGTH & DIRECT SHEAR TESTING**
- 1AB061708506W400
- 100043308506W400

**XRD**
- 100043308506W400

**PETROGRAPHY**
- 1AA131308507W4/00

**CAPROCK CORE**
- 1AB061708506W400
- 100043308506W400
Long Lake
Cap Rock Evaluation Image Logs

**IMAGE LOGS**
- ▲ 2011 IMAGE LOGS
- ○ 2012 IMAGE LOGS
- ● 2013 IMAGE LOGS
- ▼ 2014 IMAGE LOGS
# Long Lake

Cap Rock Evaluation Image Logs

<table>
<thead>
<tr>
<th>UWI</th>
<th>WELL_NAME</th>
<th>Licence No.</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>103080708606W400</td>
<td>Nexen OPTI VWP Newby 8-7-86-6</td>
<td>0428037</td>
<td>2011</td>
</tr>
<tr>
<td>1AB520808506W400</td>
<td>Nexen OPTI Newby 5-28-85-6</td>
<td>0427602</td>
<td>2011</td>
</tr>
<tr>
<td>107033208506W400</td>
<td>Nexen OPTI OBS E Newby 5-32-85-6</td>
<td>0430940</td>
<td>2011</td>
</tr>
<tr>
<td>100140808606W400</td>
<td>Nexen OPTI VWP Newby 14-8-86-6</td>
<td>0429890</td>
<td>2011</td>
</tr>
<tr>
<td>1AB042108506W400</td>
<td>Nexen OPTI Newby 4-21-85-6</td>
<td>0427525</td>
<td>2011</td>
</tr>
<tr>
<td>117063208506W400</td>
<td>Nexen OPTI VWP E Newby 6-32-85-6</td>
<td>0428454</td>
<td>2011</td>
</tr>
<tr>
<td>1AA072008506W400</td>
<td>Nexen OPTI Newby 7-20-85-6</td>
<td>0427523</td>
<td>2011</td>
</tr>
<tr>
<td>1AB050108607W400</td>
<td>Nexen OPTI Newby 5-1-86-7</td>
<td>0426907</td>
<td>2011</td>
</tr>
<tr>
<td>1AB082908506W400</td>
<td>Nexen OPTI Newby 8-29-85-6</td>
<td>0427605</td>
<td>2011</td>
</tr>
<tr>
<td>1AB142108506W400</td>
<td>Nexen OPTI Newby 14-21-85-6</td>
<td>0427599</td>
<td>2011</td>
</tr>
<tr>
<td>100090708606W400</td>
<td>Nexen OPTI OBS Newby 9-7-86-6</td>
<td>0429878</td>
<td>2011</td>
</tr>
<tr>
<td>100110908606W400</td>
<td>Nexen OPTI VWP Newby 11-9-86-6</td>
<td>0429631</td>
<td>2011</td>
</tr>
<tr>
<td>1AB162908506W400</td>
<td>Nexen OPTI Newby 16-29-85-6</td>
<td>0427928</td>
<td>2011</td>
</tr>
<tr>
<td>1AA012008506W400</td>
<td>Nexen OPTI Newby 1-20-85-6</td>
<td>0427522</td>
<td>2011</td>
</tr>
<tr>
<td>1AC042808506W400</td>
<td>Nexen OPTI NE Newby 4-28-85-6</td>
<td>0427601</td>
<td>2011</td>
</tr>
<tr>
<td>106033208506W400</td>
<td>Nexen OPTI OBS W Newby 3-32-85-6</td>
<td>0429976</td>
<td>2011</td>
</tr>
<tr>
<td>10002908506W400</td>
<td>Nexen CNOOC OBS SW Newby 8-28-85-6</td>
<td>0443963</td>
<td>2012</td>
</tr>
<tr>
<td>100100708606W400</td>
<td>Nexen CNOOC OBS Newby 10-7-86-6</td>
<td>0443868</td>
<td>2012</td>
</tr>
<tr>
<td>109103608507W400</td>
<td>Nexen OPTI OBS Newby 10-36-85-7</td>
<td>0442823</td>
<td>2012</td>
</tr>
<tr>
<td>103093108506W400</td>
<td>Nexen CNOOC OBS E Newby 9-31-85-6</td>
<td>0444540</td>
<td>2012</td>
</tr>
<tr>
<td>1AD162908506W400</td>
<td>Nexen OPTI S Newby 16-29-85-6</td>
<td>0439561</td>
<td>2012</td>
</tr>
<tr>
<td>1AB101308507W400</td>
<td>Nexen OPTI SW Newy 10-13-85-7</td>
<td>0440277</td>
<td>2012</td>
</tr>
<tr>
<td>1AB161308507W400</td>
<td>Nexen OPTI SW Newy 16-13-85-7</td>
<td>0440283</td>
<td>2012</td>
</tr>
<tr>
<td>111150708606W400</td>
<td>Nexen CNOOC OBS Newby 15-7-86-6</td>
<td>0443869</td>
<td>2012</td>
</tr>
<tr>
<td>1AA052508607W400</td>
<td>Nexen OPTI Newby 5-25-86-7</td>
<td>0439592</td>
<td>2012</td>
</tr>
<tr>
<td>1AA091708606W400</td>
<td>Nexen OPTI Newby 9-17-86-6</td>
<td>0439575</td>
<td>2012</td>
</tr>
</tbody>
</table>
## Long Lake
### Cap Rock Evaluation Image Logs

<table>
<thead>
<tr>
<th>UWI</th>
<th>Well Name</th>
<th>Well License</th>
<th>Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>1AB121808506W400</td>
<td>Nexen CNOOC S Newby 12-18-85-6-4</td>
<td>452419</td>
<td>2013</td>
</tr>
<tr>
<td>1AE121808506W400</td>
<td>Nexen CNOOC W Newby 12-18-85-6-4</td>
<td>452786</td>
<td>2013</td>
</tr>
<tr>
<td>1AB071308507W400</td>
<td>Nexen CNOOC Newby 7-13-85-7-4</td>
<td>452444</td>
<td>2013</td>
</tr>
<tr>
<td>1AC081308507W400</td>
<td>Nexen CNOOC SW Newby 8-13-85-7-4</td>
<td>452446</td>
<td>2013</td>
</tr>
<tr>
<td>1AC091308507W400</td>
<td>Nexen CNOOC NW Newby 9-13-85-7-4</td>
<td>452447</td>
<td>2013</td>
</tr>
<tr>
<td>1AC161308507W400</td>
<td>Nexen CNOOC W Newby 16-13-85-7-4</td>
<td>452406</td>
<td>2013</td>
</tr>
<tr>
<td>1AB052408507W400</td>
<td>Nexen CNOOC SW Newby 5-24-85-7-4</td>
<td>452408</td>
<td>2013</td>
</tr>
<tr>
<td>1AA102408507W400</td>
<td>Nexen CNOOC Newby 10-24-85-7-4</td>
<td>452410</td>
<td>2013</td>
</tr>
<tr>
<td>1AD041308507W400</td>
<td>Nexen CNOOC DD E Newby 4-13-85-7-4</td>
<td>452682</td>
<td>2013</td>
</tr>
<tr>
<td>1AB051308507W400</td>
<td>Nexen CNOOC DD NW Newby 5-13-85-7-4</td>
<td>452683</td>
<td>2013</td>
</tr>
<tr>
<td>1AC051308507W400</td>
<td>Nexen CNOOC DD SE Newby 5-13-85-7-4</td>
<td>452872</td>
<td>2013</td>
</tr>
<tr>
<td>1AB111308507W400</td>
<td>Nexen CNOOC DD NW Newby 11-13-85-7-4</td>
<td>452685</td>
<td>2013</td>
</tr>
<tr>
<td>1AC012408507W400</td>
<td>Nexen CNOOC DD SE Newby 1-24-85-7-4</td>
<td>452686</td>
<td>2013</td>
</tr>
<tr>
<td>1AD012408507W400</td>
<td>Nexen CNOOC DD NE Newby 1-24-85-7-4</td>
<td>452873</td>
<td>2013</td>
</tr>
<tr>
<td>100101308507W400</td>
<td>Nexen CNOOC OBS Newby 10-13-85-7</td>
<td>453792</td>
<td>2013</td>
</tr>
<tr>
<td>102092508507W400</td>
<td>Nexen CNOOC OBS Newby 9-25-85-7</td>
<td>451050</td>
<td>2013</td>
</tr>
<tr>
<td>100053308506W400</td>
<td>Nexen OPTI OBS W Newby 5-33-85-6</td>
<td>444781</td>
<td>2013</td>
</tr>
<tr>
<td>105062808506W400</td>
<td>Nexen CNOOC OBS Newby 6-28-85-6</td>
<td>453531</td>
<td>2013</td>
</tr>
<tr>
<td>100102908506W400</td>
<td>Nexen CNOOC VWP S Newby 10-29-85-6</td>
<td>453585</td>
<td>2013</td>
</tr>
<tr>
<td>100011308507W400</td>
<td>Nexen CNOOC S Newby 1-13-85-7</td>
<td>0453603</td>
<td>2013</td>
</tr>
<tr>
<td>103061308507W400</td>
<td>Nexen CNOOC OBS SE Newby 6-13-85-7</td>
<td>0453571</td>
<td>2013</td>
</tr>
<tr>
<td>1AB031308507W400</td>
<td>Nexen CNOOC DD SE Newby 3-13-85-7</td>
<td>0452681</td>
<td>2013</td>
</tr>
<tr>
<td>1AB041808506W400</td>
<td>Nexen CNOOC NE Newby 4-18-85-6</td>
<td>0452427</td>
<td>2013</td>
</tr>
<tr>
<td>1AB121308507W400</td>
<td>Nexen CNOOC DD W Newby 12-13-85-7</td>
<td>0452684</td>
<td>2013</td>
</tr>
<tr>
<td>110133208506W400</td>
<td>Nexen CNOOC VWP SE Newby 13-32-85-6</td>
<td>0453560</td>
<td>2013</td>
</tr>
<tr>
<td>109133208506W400</td>
<td>Nexen CNOOC VWP W Newby 13-32-85-6</td>
<td>0453540</td>
<td>2013</td>
</tr>
<tr>
<td>103142908506W400</td>
<td>Nexen CNOOC VWP Newby 14-29-85-6</td>
<td>0453532</td>
<td>2013</td>
</tr>
<tr>
<td>102092908506W400</td>
<td>Nexen CNOOC OBS SW Newby 9-29-85-6</td>
<td>0453581</td>
<td>2013</td>
</tr>
<tr>
<td>1AB031908506W400</td>
<td>Nexen CNOOC NE Newby 3-19-85-6</td>
<td>0452424</td>
<td>2013</td>
</tr>
<tr>
<td>UWI</td>
<td>Well Name</td>
<td>Well Licence</td>
<td>Year</td>
</tr>
<tr>
<td>-------</td>
<td>--------------------------------</td>
<td>--------------</td>
<td>------</td>
</tr>
<tr>
<td>100042808506W400</td>
<td>NEU CNOOC VWP NEWBY 4-28-85-6</td>
<td>461719</td>
<td>2014</td>
</tr>
<tr>
<td>100043308506W400</td>
<td>NEU CNOOC VWP S NEWBY 4-33-85-6</td>
<td>461840</td>
<td>2014</td>
</tr>
<tr>
<td>100152908506W400</td>
<td>NEU CNOOC VWP NEWBY 15-29-85-6</td>
<td>462042</td>
<td>2014</td>
</tr>
<tr>
<td>103122808506W400</td>
<td>NEU CNOOC VWP NEWBY 12-28-85-6</td>
<td>461749</td>
<td>2014</td>
</tr>
<tr>
<td>1AA022608607W400</td>
<td>NEU CNOOC NE NEWBY 2-26-86-7</td>
<td>462081</td>
<td>2014</td>
</tr>
<tr>
<td>1AA102508607W400</td>
<td>NEU CNOOC NEWBY 10-25-86-7</td>
<td>461064</td>
<td>2014</td>
</tr>
<tr>
<td>1AA112608607W400</td>
<td>NEU CNOOC NEWBY 11-26-86-7</td>
<td>462083</td>
<td>2014</td>
</tr>
<tr>
<td>1AA152408607W400</td>
<td>NEU CNOOC NEWBY 15-24-86-7</td>
<td>461063</td>
<td>2014</td>
</tr>
<tr>
<td>1AA162208607W400</td>
<td>NEU CNOOC NEWBY 16-22-86-7</td>
<td>462076</td>
<td>2014</td>
</tr>
<tr>
<td>1AA162308607W400</td>
<td>NEU CNOOC NEWBY 16-23-86-7</td>
<td>462078</td>
<td>2014</td>
</tr>
<tr>
<td>1AB012008506W400</td>
<td>NEU CNOOC NEWBY 1-20-85-6</td>
<td>461037</td>
<td>2014</td>
</tr>
<tr>
<td>1AB051708506W400</td>
<td>NEU CNOOC NEWBY 5-17-85-6</td>
<td>461031</td>
<td>2014</td>
</tr>
<tr>
<td>1AB052108506W400</td>
<td>NEXEN CNOOC NEWBY 5-21-85-6</td>
<td>461083</td>
<td>2014</td>
</tr>
<tr>
<td>1AB061708506W400</td>
<td>NEU CNOOC NEWBY 6-17-85-6</td>
<td>461614</td>
<td>2014</td>
</tr>
<tr>
<td>1AB092008506W400</td>
<td>NEU CNOOC NW NEWBY 9-20-85-6</td>
<td>461079</td>
<td>2014</td>
</tr>
<tr>
<td>1AB101708506W400</td>
<td>NEU CNOOC DD NEWBY 10-17-85-6</td>
<td>461065</td>
<td>2014</td>
</tr>
<tr>
<td>1AB121708506W400</td>
<td>NEU CNOOC DD NEWBY 12-17-85-6</td>
<td>461066</td>
<td>2014</td>
</tr>
<tr>
<td>1AB122108506W400</td>
<td>NEU CNOOC NEWBY 12-21-85-6</td>
<td>461085</td>
<td>2014</td>
</tr>
<tr>
<td>1AB131708506W400</td>
<td>NEU CNOOC NEWBY 13-17-85-6</td>
<td>461034</td>
<td>2014</td>
</tr>
<tr>
<td>1AB161708506W400</td>
<td>NEU CNOOC NEWBY 16-17-85-6</td>
<td>461036</td>
<td>2014</td>
</tr>
<tr>
<td>1AB162008506W400</td>
<td>NEU CNOOC NEWBY 16-20-85-6</td>
<td>461081</td>
<td>2014</td>
</tr>
<tr>
<td>1AC042108506W400</td>
<td>NEU CNOOC NEWBY 4-21-85-6</td>
<td>461082</td>
<td>2014</td>
</tr>
<tr>
<td>1AC051708506W400</td>
<td>NEU CNOOC S NEWBY 5-17-85-6</td>
<td>461032</td>
<td>2014</td>
</tr>
<tr>
<td>1AC092008506W400</td>
<td>NEU CNOOC SW NEWBY 9-20-85-6</td>
<td>461080</td>
<td>2014</td>
</tr>
<tr>
<td>1AD092008506W400</td>
<td>NEU CNOOC SE Newby 9-20-85-6</td>
<td>461709</td>
<td>2014</td>
</tr>
</tbody>
</table>
Long Lake Seismic

- 3-D seismic as of 2014
- Pads 4 and 5 & Pads 12 and 13 4-D seismic acquired in 2014
Project Objectives and Expectations:

• Use 4D (time-lapse) seismic techniques to detect areas of the reservoir that have been influenced by steam injection

• Potential to monitor steam conformance along a well pair and image thief zones

Three different areas were examined in 2014

• 2014 4D survey covering Pads 1, 3, 5 and a portion of Pad 2NE

• 2014 4D survey covering Pads 12 and 13

• 2013 4D survey covering Pads 10W & 11
Time Delay anomalies are the difference between the Devonian surface on the 2002 baseline seismic survey and the monitor seismic surveys in 2011 and 2014.

These time delays generally represent steam chamber growth but also any changes in gas occurrence.
Time Delay anomalies are the difference between the Devonian surface on the 2002 baseline seismic survey and the monitor seismic surveys in 2013.

These time delays generally represent steam chamber growth but also any changes in gas occurrence.

This is the first monitor seismic survey that has been shot over these pads.
Long Lake
Seismic – Pad 10W & 11 Time Delay

Time Delay anomalies are the difference between the Devonian surface on the 2002 baseline seismic survey and the monitor seismic surveys in 2013.

These time delays generally represent steam chamber growth but also any changes in gas occurrence.

This is the first monitor seismic survey that has been shot over these pads.
Evaluation Wells Completed
- Cored Vertical Wells: 17
- Non-cored Vertical Wells: 17
- Non-cored Deviated Wells: 2
- Total = 36

Observation Wells
- 3 Water Monitoring Wells
- 4 Q-Channel Monitoring Wells
- 3 Pad 14/15 Wells
- Total = 10

Infill Wells
- 4 wells drilled on Pad 7

Re-Drills
- 3 wells re-drilled (03P05 & 03S05 & 11P10)

Total = 53 wells
# Long Lake 2014 Core Hole Program (17 Wells)

<table>
<thead>
<tr>
<th>UWI</th>
<th>Well Name</th>
<th>Well License #</th>
</tr>
</thead>
<tbody>
<tr>
<td>1AA151708506W400</td>
<td>NEU CNOOC NEWBY 15-17-85-6</td>
<td>461035</td>
</tr>
<tr>
<td>1AB071708506W400</td>
<td>NEU CNOOC NEWBY 7-17-85-6</td>
<td>461033</td>
</tr>
<tr>
<td>1AA062108506W400</td>
<td>NEU CNOOC NEWBY 6-21-85-6</td>
<td>461084</td>
</tr>
<tr>
<td>1AB122108506W400</td>
<td>NEU CNOOC NEWBY 12-21-85-6</td>
<td>461085</td>
</tr>
<tr>
<td>1AB061708506W400</td>
<td>NEU CNOOC NEWBY 6-17-85-6</td>
<td>461614</td>
</tr>
<tr>
<td>1AA012208607W400</td>
<td>NEU CNOOC NEWBY 1-22-86-7</td>
<td>462075</td>
</tr>
<tr>
<td>1AA082308607W400</td>
<td>NEU CNOOC NEWBY 8-23-86-7</td>
<td>462077</td>
</tr>
<tr>
<td>1AA092408607W400</td>
<td>NEU CNOOC NEWBY 9-24-86-7</td>
<td>462079</td>
</tr>
<tr>
<td>1AB112408607W400</td>
<td>NEU CNOOC NEWBY 11-24-86-7</td>
<td>462080</td>
</tr>
<tr>
<td>1AB022608607W400</td>
<td>NEU CNOOC SW NEWBY 2-26-86-7</td>
<td>462082</td>
</tr>
<tr>
<td>1AA142608607W400</td>
<td>NEU CNOOC NEWBY 14-26-86-7</td>
<td>462084</td>
</tr>
<tr>
<td>1AA012708607W400</td>
<td>NEU CNOOC NEWBY 1-27-86-7</td>
<td>462085</td>
</tr>
<tr>
<td>1AB041608606W400</td>
<td>NEU CNOOC NEWBY 4-16-86-6</td>
<td>461059</td>
</tr>
<tr>
<td>1AA121608606W400</td>
<td>NEU CNOOC NEWBY 12-16-86-6</td>
<td>461060</td>
</tr>
<tr>
<td>1AA101708606W400</td>
<td>NEU CNOOC NEWBY 10-17-86-6</td>
<td>461062</td>
</tr>
<tr>
<td>1AA021708606W400</td>
<td>NEU CNOOC NEWBY 2-17-86-6</td>
<td>461061</td>
</tr>
<tr>
<td>1AB060508606W400</td>
<td>NEU CNOOC NEWBY 6-5-86-6</td>
<td>461058</td>
</tr>
</tbody>
</table>
Long Lake 2014 Observation Well Program (10 Wells)

<table>
<thead>
<tr>
<th>UWI</th>
<th>Well Name</th>
<th>Well License #</th>
</tr>
</thead>
<tbody>
<tr>
<td>1WM043308506W400</td>
<td>NEU CNOOC VWP WM NEWBY 4-33-85-6</td>
<td>NL-00209</td>
</tr>
<tr>
<td>1WM133208506W400</td>
<td>NEU CNOOC WM G C NEWBY 13-32-85-6</td>
<td>NL-00208</td>
</tr>
<tr>
<td>112133208506W400</td>
<td>NEU CNOOC VWP N B NEWBY 13-32-85-6</td>
<td>463737</td>
</tr>
<tr>
<td>111133208506W400</td>
<td>NEU CNOOC WM N C NEWBY 13-32-85-6</td>
<td>463680</td>
</tr>
<tr>
<td>103122808506W400</td>
<td>NEU CNOOC VWP NEWBY 12-28-85-6</td>
<td>461749</td>
</tr>
<tr>
<td>100152908506W400</td>
<td>NEU CNOOC VWP NEWBY 15-29-85-6</td>
<td>462042</td>
</tr>
<tr>
<td>1WP152908506W400</td>
<td>NEU CNOOC VWP NEWBY 15-29-85-6 R</td>
<td>NL-00207</td>
</tr>
<tr>
<td>100042808506W400</td>
<td>NEU CNOOC VWP NEWBY 4-28-85-6</td>
<td>461719</td>
</tr>
<tr>
<td>100043308506W400</td>
<td>NEU CNOOC VWP S NEWBY 4-33-85-6</td>
<td>461840</td>
</tr>
<tr>
<td>104023208506W400</td>
<td>NEU CNOOC VWP SD NEWBY 2-32-85-6</td>
<td>461851</td>
</tr>
</tbody>
</table>
Kinosis
Geology and Geoscience
• Nexen’s Knosis property is located approximately 50km SE of Fort McMurray

• Located between Long Lake and ConocoPhillips Surmont

• ERCB Approval No. 9485F was granted in 2009 for development of Knosis in a portion of T84R7W4

• First steam achieved Aug 2014, first oil achieved Nov 2014

• Knosis 2 Gas Re-pressurization commenced
Kinosis – 2014 Activity and 3D Seismic Outline

- 5 OBS wells drilled in K1A
- 47 delineation wells drilled
- 27 West of HWY 881
- 20 East of HWY 881
Kinosis IDA EBIP and Average Reservoir Parameters

Kinosis IDA EBIP

EBIP \( (E^6m^3) \) 204

Nexen Cutoffs: \( h > 12m \) or HPVH > 3 m

Hydrocarbon Pore Volume Height

\[
\text{HPVH} = \sum_{\text{pay bs}} \left( S_o * \Phi \right)
\]

Hydrocarbon Pore Volume Height (HPVH) is calculated from petrophysical logs calibrated to Dean Stark analysis.

Pay Average Reservoir Parameters

- **Depth**: 280 m KB
- **Thickness**: 34 m
- **Effective Porosity**: 31%
- **Permeability From Core Plugs**
  - \( K_{\text{max}} \): 4030 mD
  - \( K_{\text{vert}} \): 2347 mD
- **Effective Water Saturation**: 26%
- **Temperature**: 6 – 8 °C
- **Initial Reservoir Pressure**
  - ~1100 - 1300 kPa

Effective porosity and effective water saturation are calculated every 10cm over the Pay interval, and the average is derived.
Structure controlled by Pre-Cretaceous erosion and dissolution of the Prairie Evaporite, Lotsberg and Cold Lake salts.

Has a significant effect on base of pay structure and bottom water contacts.

Timing of salt solutioning was pre-McMurray, syn-McMurray and post-McMurray.

Minor karsting on Devonian surface.
Devonian Structure with Karst and Salt Dissolution Features
Structure - Top of McMurray

- Influenced by depositional elements that results in differential compaction.
- Can determine timing of some dissolution features, areas of thick and thin sand sections.
Structure - EBIP Base Kinosis
Structure - EBIP Top Kinosis
HPVH Isopach over EBIP Interval
Kinosis
Example Log:

Kinosis KIA

EBIP Pay

Interval

Devonian

McMurray Fluvial Estuarine Complex top

Top Gas

EBIP Pay Interval

Pay Interval

Bottom Water

Note: Resistivity gradient is due to salinity changes. Core used to confirm oil saturations.
Representative structural cross-section of K1A
Cap Rock data collected in 2014
Top Water in the McMurray - Kinesis
Bottom Water in the McMurray - Kinsonis
Top Gas in the McMurray - Kinesis
Kinosis 2 Gas Re-pressurization Update

- Received approval in February 2014 to repressurize Kinosis 2 gas pool with natural gas

- Natural gas injection started in August 2014

- Total injected gas volume: 1.2 sBcf (~12% of total McMurray gas produced from Kinosis 2 gas pool)

- Average pressure within Kinosis 2 gas pool increased from 560 kPag to 615 kPag

- The minimum pressure target is 1100kPa to establish a pressure equilibrium within the system as bottom water pressure in the Kinosis 2 area is ~ 1100kPa
Nexen planning a multi-phased development of Kinosis IDA.

The first Phase is K1A – First Steam Achieved Aug 2014

- Project expectations
  - 15-25,000 b/d peak bitumen rates
  - SAGD drilling commenced in 2012, First Steam Aug 2014, First Oil Nov 2014
- Two wellpads (4 drainage areas) of 16 and 21 well pairs at 75m spacing
- Steam Generation Facility (4 OTSG’s)
- Pipelines connecting the facilities to Long Lake
  - Boiler feed water from Long Lake, emulsion to Long Lake
- Tie-ins and support infrastructure required at Long Lake
- Support utilities

Well Pad Layout

Facilities Schematic

K1A Scope (shaded area)
• First steam commenced Aug 2014
  – 8 wells on circulation first on Pad 1 – Drainage Area C, K1P01 to K1P08
  – 8 more wells placed on circulation over Aug to Nov 2014, Drainage Area A, K1P09 to K1P16 as room in start up circulation facilities allowed
  – 8 Wells on Pad 2 placed on circulation Oct 2014
    • Drainage Area B: K2P13 to K2P15
    • Drainage Area D: K2P18 to K2P22
• Well conversions from Circulation to SAGD Production with ESPs commenced in Nov 2014
  – 8 wells converted in Drainage Area C, K1P01 to K1P08
Kinosis 1A Observation Wells

- **2013:**
  - Installed eight (8) wells with VWP’s (vibrating wire piezometer)

- **2014:**
  - Installed five (5) wells with VWP’s
  - Installing 10 thermocouple strings for monitoring temperature

- **Purpose:**
  - Monitor temperature and steam chamber development and bottom water interaction (where applicable) over time
  - Monitor temperature and pressure for cap rock monitoring
K1A – 4D Seismic to be shot over 3 Drainage Areas (A, C and D).

- No 4D survey at Drainage Area B because of surface constraints of the Kinosis facilities (Pad 1, flowlines and roadway) preventing the placement of dynamite holes and/or buried geophones.
- The edges of the Drainage Areas A & C surveys overlap over Drainage B, however the data quality is low and likely not suitable for interpretation at Drainage B.

- 3 K1A OBS wells to have thermocouple strings installed, one well re-outfitted with new T/C string.
- 2 OBS wells drilled for water source and disposal monitoring purposes.

Future phases being evaluated—
- K1B regulatory applications submitted.
Drilling and Completions, Artificial Lift, and Instrumentation
Long Lake & Kinosis
Long Lake
Horizontal Well Locations

Inter-well Spacing

- Pad 1: 75m (with infill wells)
- Pad 2-6, Pads 8-10: 100m
- 6P11 to 6P12: 75m
- Pad 7N: 50m (with infill wells)
- 7P11 to 7P12: 200m
- Pad 11W (11P01 to P06): 40m
- Pad 11 E (11P07 to 11P10): 80m
- Pad 12-15: 75m
Long Lake Well Pair Completions Map through 2014

Objects are not representative of depth
Well Pair Completions Map through 2014

Objects are not representative of depth
Typical Injector Completion

Concentric

• Majority of Long Lake’s design
• 406.4mm (16”) surface casing
• 298.5mm (11 3/4”) or 244.5mm (9 5/8”) intermediate casing
• 219.1mm (8 5/8”) or 177.8mm (7”) slotted liner
• Injection Strings: 177.8mm (7”) and 114.3mm (4 ½”)
• All Kinosis wells, and a few Long Lake wells completed with steam splitters in long injection string
  - Results showing improved temperature conformance in Long Lake Wells
• All Kinosis wells, Long Lake Pads 12-15, 04S05 and 11S05 completed with Vacuum Insulated Tubing (VIT) in the long string
  - VIT is 139.7mm (5 ½”) or 114.3mm (4 ½”), usually installed to the ICP
Typical Injector Circulation

Injector Circulation

- Surface Casing: 339.9mm, 81.1kg/m
- Intermediate Casing: 298.5 mm, 80.36 kg/m, K-55, Tenaris Blue
- Heel Inj. String: 177.8mm, 34.2kg/m

269.9 mm Hz Hole

- Toe Inj. String: 114.3 x 68.9mm vacuum insulated tubing with steam splitters
- Injection Liner: 177.8mm, 34.2kg/m

9 5/8' production casing
7' tubing
4 1/2'' x 3 1/2'' ViT

blanket gas
steam injection
circulation returns
Typical Producer Completions – ESP

- Scab liners installed in many of the producing wells in an effort to achieve optimal temperature conformance across the wellbore.

Diagram:
- 340mm (13 3/8”) surface casing
- 88.9mm (3 ½”) tubing
- 244.5mm (9 5/8”) casing
- 52.4mm (2 1/16”) guide string
- 177.8mm (7”) slotted liner
- 38.1mm (1 ½”) instrument string
- Optional: 114.3mm (4 ½”) scab liner
Typical Producer Circulation

Producer Circulation

- 9 5/8" production casing
- 3 1/2" tubing
- 3 1/2" tubing
- 1 1/2" instrument coil

Surface Casing:
339.9mm, 81.1kg/m

Production String:
88.9mm, 13.7kg/m

Intermediate Casing:
244.5mm, 53.6kg/m

Thermal 40F Cement

Injection String:
88.9mm, 13.7kg/m

Production Liner:
177.8mm, 34.2kg/m, 4 thermo-couples

Instrumentation Coil:
38.1mm, 4 thermo-couples

Cement

blanket gas
steam injection
circulation returns
instrumentation string

NOT TO SCALE
Artificial Lift Performance

- Original gas lift completions have been converted to artificial lift via Electric Submersible Pumps (ESP) in most SAGD producers
  - 6 wells currently are on gas lift production
  - Conversions completed to allow production at lower steam chamber pressures (between 1400-2200 kPa)
- ESPs installed in 109 wells
  - Pump performance:
    - Average Run Time: 372 running days
    - Mean Failure Time: 682 running days
  - Operating temperatures have reached 215ºC
  - Pumps operate at pressures between 1000 and 1500 kPa (Producer)
  - Fluid production rates range from 75 - 1100 m³/d
- Active member of ESP Reliability Information and Failure Tracking System JIP
- Currently running 1 Progressive Cavity Pump (PCP) in 02P07
  - Kudu 1100-MET-750 metal stator and rotor installed Mar-2014 (continuous operations since)
- ESPs and PCP use Variable Frequency Drive (VFD) to control pump speed and production rates
SAGD Instrumentation

- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube
- 4-6 equally spaced thermocouples across the producer lateral
- Heel pressure measurement via blanket gas between the heel string and the intermediate casing
Alternate SAGD Instrumentation

- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

Wells with DTS Fiber
- K1P02
- K1P04
- K1P06
- K1P08
- K1P10
- K1P12
- K1P14
- K1P16

Heel pressure measurement via blanket gas between the heel string and the intermediate casing

Fiber Optic Distributed Temperature Sensing

Blanket Gas

Bubble tube
Typical Water Source Well

- ESP intake landed above the top of the water formation
- 18.3mm probe run through polytube and landed above the ESP
  - Monitors water level in casing

219.1mm (8 5/8“) Production Casing

25.4mm (1“) Polytube

88.9mm (3 1/2“) Tubing String

140mm (5 1/2“) Screen

ESP
Typical Observation Wells

- Vibrating wire piezometer sensors (green) are strapped outside the production casing providing pressure and temperature measurements
  - 2 and 3 string casing designs have been used
- Thermocouple strings (red) provide temperature measurements
Alternative Observation Well
Pads 14 & 15

- Thermal Cement from PBTD to the top of the McMurray
  - To prevent heating from McMurray
- Perforated Upper and Lower Cap Rock Intervals
  - Clearwater B
  - Wabiskaw C
- Full Bore Permanent Packer Between Perforations
- 1.5” Pressure/Temperature Coil String Stabbed Into Packer
  - Complete with 2 isolated pressure/temperature gauges monitoring each perforated cap rock zone
Scheme Performance
2014 Performance (Long Lake + K1A)
Performance

- Commercial Steam Assisted Gravity Drainage (SAGD)
- Downhole injection pressure varies throughout the field, ranges from 1,400 kPa to 2,400 kPa
- Converted remaining wells on Pad 15 from circulation to SAGD production with ESPs in April 2014
- Began circulating K1A well pairs in August 2014. 8 wells converted from circulation to SAGD production with ESPs in Nov 2014
- 17 pads and 153 well pairs, 119 producing wells at year end
  - Long Lake: 15 pads and 116 well pairs, 111 producing wells at year end
  - K1A: 2 pads and 37 well pairs, 8 producing wells at year end
- Reduced injection pressures on several pads throughout Long Lake
  - Material balance - Improved efficiency (lower SOR and/or higher WSR)
  - Trialing different strategies for pads with high water saturation intervals
  - Q-channel

<table>
<thead>
<tr>
<th></th>
<th>Design m³/d</th>
<th>Design bbl/d</th>
<th>Dec-2014 m³/d</th>
<th>Dec-2014 bbl/d</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bitumen</td>
<td>11,130</td>
<td>70,000</td>
<td>7,431</td>
<td>46,762</td>
</tr>
<tr>
<td>Steam</td>
<td>37,000</td>
<td>233,000</td>
<td>30,516</td>
<td>192,029</td>
</tr>
<tr>
<td>SOR</td>
<td>3.3</td>
<td></td>
<td>4.1</td>
<td></td>
</tr>
</tbody>
</table>
## Recoverable Bitumen

<table>
<thead>
<tr>
<th>Pad</th>
<th>Num Wells</th>
<th>EBIP $E^6 m^3$</th>
<th>Estimated Ultimate RF</th>
<th>Recoverable Bitumen $E^6 m^3$</th>
<th>Cum Production Dec. 2014 $E^3 m^3$</th>
<th>RF</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>5</td>
<td>2.1</td>
<td>60%</td>
<td>1.2</td>
<td>797</td>
<td>36%</td>
</tr>
<tr>
<td>2NE</td>
<td>6</td>
<td>2.4</td>
<td>51%</td>
<td>1.2</td>
<td>611</td>
<td>25%</td>
</tr>
<tr>
<td>2SE</td>
<td>5</td>
<td>1.0</td>
<td>33%</td>
<td>0.3</td>
<td>228</td>
<td>23%</td>
</tr>
<tr>
<td>3</td>
<td>5</td>
<td>2.4</td>
<td>60%</td>
<td>1.4</td>
<td>955</td>
<td>39%</td>
</tr>
<tr>
<td>4</td>
<td>2</td>
<td>0.2</td>
<td>66%</td>
<td>0.1</td>
<td>72</td>
<td>52%</td>
</tr>
<tr>
<td>5</td>
<td>5</td>
<td>3.2</td>
<td>60%</td>
<td>1.9</td>
<td>1082</td>
<td>34%</td>
</tr>
<tr>
<td>6N</td>
<td>6</td>
<td>2.7</td>
<td>48%</td>
<td>1.3</td>
<td>621</td>
<td>22%</td>
</tr>
<tr>
<td>6W</td>
<td>7</td>
<td>2.0</td>
<td>60%</td>
<td>1.2</td>
<td>683</td>
<td>36%</td>
</tr>
<tr>
<td>7E</td>
<td>7</td>
<td>1.3</td>
<td>69%</td>
<td>0.9</td>
<td>563</td>
<td>43%</td>
</tr>
<tr>
<td>7N*</td>
<td>5</td>
<td>3.1</td>
<td>66%</td>
<td>2.0</td>
<td>1383</td>
<td>46%</td>
</tr>
<tr>
<td>8</td>
<td>6</td>
<td>2.5</td>
<td>57%</td>
<td>1.4</td>
<td>844</td>
<td>34%</td>
</tr>
<tr>
<td>9NE</td>
<td>5</td>
<td>1.1</td>
<td>52%</td>
<td>0.6</td>
<td>192</td>
<td>17%</td>
</tr>
<tr>
<td>9W</td>
<td>5</td>
<td>1.5</td>
<td>50%</td>
<td>0.8</td>
<td>345</td>
<td>22%</td>
</tr>
<tr>
<td>10N</td>
<td>3</td>
<td>2.2</td>
<td>25%</td>
<td>0.5</td>
<td>150</td>
<td>14%</td>
</tr>
<tr>
<td>10W</td>
<td>5</td>
<td>2.2</td>
<td>57%</td>
<td>1.3</td>
<td>498</td>
<td>24%</td>
</tr>
<tr>
<td>11</td>
<td>10</td>
<td>2.2</td>
<td>62%</td>
<td>1.4</td>
<td>922</td>
<td>42%</td>
</tr>
<tr>
<td>12</td>
<td>9</td>
<td>3.4</td>
<td>55%</td>
<td>1.9</td>
<td>330</td>
<td>10%</td>
</tr>
<tr>
<td>13</td>
<td>9</td>
<td>3.2</td>
<td>54%</td>
<td>1.7</td>
<td>404</td>
<td>13%</td>
</tr>
<tr>
<td>14</td>
<td>6</td>
<td>1.8</td>
<td>49%</td>
<td>0.9</td>
<td>82</td>
<td>4%</td>
</tr>
<tr>
<td>15</td>
<td>5</td>
<td>1.3</td>
<td>53%</td>
<td>0.7</td>
<td>21</td>
<td>1%</td>
</tr>
<tr>
<td>K1A</td>
<td>37</td>
<td>19.9</td>
<td>53%</td>
<td>10.6</td>
<td>12</td>
<td>0%</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>153</strong></td>
<td><strong>61.6</strong></td>
<td><strong>54%</strong></td>
<td><strong>33.3</strong></td>
<td><strong>10795</strong></td>
<td><strong>18%</strong></td>
</tr>
</tbody>
</table>

* Pad 7N estimated ultimate RF and recoverable bitumen volumes do not include expected additional recovery from infill wells drilled in 2014
December 2014 Average Injection Pressures

<table>
<thead>
<tr>
<th>Drain Area/Pad</th>
<th>Average Injector Pressure (kPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>K1A-A</td>
<td>1828</td>
</tr>
<tr>
<td>K1A-B</td>
<td>2725</td>
</tr>
<tr>
<td>K1A-C</td>
<td>2549</td>
</tr>
<tr>
<td>K1A-D</td>
<td>2800</td>
</tr>
<tr>
<td>LL-001</td>
<td>1675</td>
</tr>
<tr>
<td>LL-002NE</td>
<td>1337</td>
</tr>
<tr>
<td>LL-002SE</td>
<td>1594</td>
</tr>
<tr>
<td>LL-003</td>
<td>1538</td>
</tr>
<tr>
<td>LL-004</td>
<td>1368</td>
</tr>
<tr>
<td>LL-005</td>
<td>1731</td>
</tr>
<tr>
<td>LL-006N</td>
<td>2018</td>
</tr>
<tr>
<td>LL-006W</td>
<td>1777</td>
</tr>
<tr>
<td>LL-007E</td>
<td>1905</td>
</tr>
<tr>
<td>LL-007N</td>
<td>2046</td>
</tr>
<tr>
<td>LL-008</td>
<td>1722</td>
</tr>
<tr>
<td>LL-009NE</td>
<td>1663</td>
</tr>
<tr>
<td>LL-009W</td>
<td>2098</td>
</tr>
<tr>
<td>LL-010N</td>
<td>1659</td>
</tr>
<tr>
<td>LL-010W</td>
<td>2036</td>
</tr>
<tr>
<td>LL-011</td>
<td>1867</td>
</tr>
<tr>
<td>LL-012</td>
<td>1606</td>
</tr>
<tr>
<td>LL-013</td>
<td>1836</td>
</tr>
<tr>
<td>LL-014</td>
<td>2325</td>
</tr>
<tr>
<td>LL-015</td>
<td>2280</td>
</tr>
</tbody>
</table>
PAD Performance

Examples of Low, Mid, High Recovery
Examples of Low, Mid, High Recovery

• Low Recovery
  – Pad 2NE

• Mid Recovery
  – Pad 8

• High Recovery
  – Pad 11
PAD 2NE Production Summary

- Steam SI to 02S04, 02S05 and 02S06 since Q1 2013 due to Q-channel
- Reduction in production rates due to less energy being injected into the system
- Short term steam reductions due to plant or surface constraints have lead to inconsistent production performance
- At YE, injection pressures were ~1,275 – 1,485 kPa
- Stepped pressure outwards from the shut in injectors to reduce cross-flow

<table>
<thead>
<tr>
<th>Well</th>
<th>EBIP (m3)</th>
<th>Dec 2014 Cumulative Bitumen (m3)</th>
<th>Dec 2014 RF (%)</th>
<th>Final EUR (m3)</th>
<th>Final RF (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>02P01</td>
<td>375</td>
<td>65</td>
<td>17%</td>
<td>225</td>
<td>60%</td>
</tr>
<tr>
<td>02P02</td>
<td>395</td>
<td>68</td>
<td>17%</td>
<td>237</td>
<td>60%</td>
</tr>
<tr>
<td>02P03</td>
<td>450</td>
<td>86</td>
<td>19%</td>
<td>270</td>
<td>60%</td>
</tr>
<tr>
<td>02P04</td>
<td>434</td>
<td>108</td>
<td>25%</td>
<td>174</td>
<td>40%</td>
</tr>
<tr>
<td>02P05</td>
<td>349</td>
<td>125</td>
<td>36%</td>
<td>139</td>
<td>40%</td>
</tr>
<tr>
<td>02P06</td>
<td>393</td>
<td>158</td>
<td>40%</td>
<td>177</td>
<td>45%</td>
</tr>
<tr>
<td>Pad 2NE</td>
<td>2396</td>
<td>611</td>
<td>25%</td>
<td>1222</td>
<td>51%</td>
</tr>
</tbody>
</table>
PAD 2NE - Geology

- Sand Facies
- EBIP Interval
PAD 2NE - Geology

- Cumulative “lean zone” within EBIP interval
- Top Water in contact with EBIP interval
PAD 8 Production Summary

- Oil cut dropping in late 2013 - changed production strategy to focus on increased emulsion rates
  - Improved oil cut – improved oil production
  - Improved temperature distribution along laterals
- Brought 08P01 & 08P02 online in February 2014 after being shut in since 2012

<table>
<thead>
<tr>
<th>Well</th>
<th>EBIP (m³)</th>
<th>Dec 2014 Cumulative Bitumen (m³)</th>
<th>Dec 2014 RF (%)</th>
<th>Final EUR (m³)</th>
<th>Final RF (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>08P01</td>
<td>302</td>
<td>41</td>
<td>14%</td>
<td>136</td>
<td>45%</td>
</tr>
<tr>
<td>08P02</td>
<td>183</td>
<td>61</td>
<td>33%</td>
<td>82</td>
<td>45%</td>
</tr>
<tr>
<td>08P03</td>
<td>429</td>
<td>98</td>
<td>23%</td>
<td>193</td>
<td>45%</td>
</tr>
<tr>
<td>08P04</td>
<td>488</td>
<td>160</td>
<td>33%</td>
<td>293</td>
<td>60%</td>
</tr>
<tr>
<td>08P05</td>
<td>516</td>
<td>260</td>
<td>50%</td>
<td>361</td>
<td>70%</td>
</tr>
<tr>
<td>08P06</td>
<td>555</td>
<td>223</td>
<td>40%</td>
<td>333</td>
<td>60%</td>
</tr>
<tr>
<td>Pad 8</td>
<td>2473</td>
<td>843</td>
<td>34%</td>
<td>1399</td>
<td>57%</td>
</tr>
</tbody>
</table>
PAD 8 – Geology

- Reservoir quality improves from east to west
PAD 8 – Geology

- Lean zones throughout pad
- Top water at toes connected to extensive top water body on Pad 10W and Pad 11
PAD 8 Performance

Some similar characteristics throughout pad:

• Large top water influence – high produced water volumes
  – Upsized pump capacity in late 2013 / early 2014 to produce higher volumes
• Limited seismic and core hole data due to lake covering pad area
• Large secondary zone above primary EBIP – separated by shale barrier
• Scab liners installed in several wells to encourage temperature development at the toes

Pad can be split into 2 groups:

• 08P01, 08P02, 08P03 – low recovery
  – Lower quality reservoir
  – Thin pay – dominated by mud plug

• 08P04, 08P05 & 08P06 – high recovery
  – High quality reservoir
  – Thicker pay
  – Increased emulsion production resulted in improved contribution from the toe sections
Continuing to investigate whether secondary zone has started contributing

- Potentially 8-12 m of pay
- Temperature profile on 100/14-25 obs well
- RST on 100/14-25 observation well in Q1 2015
- 4D seismic over Long Lake West in Q1 2015
- New observation well on Pad 6W in Q1 2015
PAD 8 – Restarting 08P01 & 08P02

- Producers shut in Q2 2012 due to high water cut
  - Question of whether 0% oil cut readings were accurate
- Injectors continued to get occasional steam when excess was available
- Successfully restarted ESPs in Q1 2014 without any issues
- Significant improvement in performance (rates below are combined for 08P01 & 08P02)

<table>
<thead>
<tr>
<th>Case</th>
<th>Oil Rate (m3/day)</th>
<th>Total Fluid Rate (m3/day)</th>
<th>Oil Cut (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>April 2011 Average</td>
<td>10</td>
<td>1200</td>
<td>&lt;1%</td>
</tr>
<tr>
<td>Dec 2014 Average</td>
<td>115</td>
<td>1250</td>
<td>9%</td>
</tr>
</tbody>
</table>

- Similar strategy to the rest of the pad– focus on withdrawing fluid
- Lower priority compared to higher performing wells in the field due to high water cut
  - inconsistent production & injection
- Temperatures along wellbores continuing to heat up
All 10 wells are on ESP
- Tighter well spacing on west side of pad (40m vs 80m)
- Thick, relatively clean sand package with top water
- 2013 4D has improved interpretation of IHS bedding and steam chamber development
- 11P10 re-drilled due to liner failure
- Decline in bitumen rates can be attributed to top water effect
- Reduced operation pressure from 2100 to 1850 kPa
- At YE, injection pressures were ~1,850–1,920 kPa
PAD 11 - Geology

HWS Interval above and in contact with EBIP – Top Water

Cumulative Thickness HWS Interval within the EBIP – lean zone
Combining production history with 4D data:

- 4D used to define IHS in top water not seen on logs or in core—changes interpretation of top water zones and operating strategy
- 4D anomalies confirmed by temperatures seen on Observation well
Learnings, Trials, and Pilot Projects
ICD Performance – PAD 13

• In-flow control devices were installed in the producer scab liners with the intent to promote “more even” production of fluid along the wellbore with the expected benefits:
  • Reduced pressure drop along the producer
  • Better conformance along the well
  • Allow more representative temperature measurement from down-hole thermocouples

• Majority of wells with ICDs have been consistent good producers since SAGD conversion and are meeting production expectations

• All ICDs remain in operation with no current plans to close, alter or remove the devices

• 11 producers have 2 fixed sleeve ICDs (4 and 8 or 3 and 9 ports) and 2 have 1 fixed sleeve ICD (7 ports) installed along the lateral

• Wells are showing good conformance
Pilot Projects Update

- **PAD 13 Solvent Co-Injection Pilot Test (2 years)**
  - Application approval 9485U was received in April, 2013.
  - Solvent co-injection started October, 2014 at 13S3 and 13S4.
  - Preliminary indications of production uplift seen despite lean zone impairment in the pilot area.
  - Solvent recovery in line with simulation prediction as of year end 2014.

- **PAD 7E NCG Pilot Test**
  - Application approval 9485R received in September, 2012.
  - Early indications of iSOR reduction however results not yet conclusive.
  - Gas injection stable at 10 E3M3/D with minimal operational issues. No detrimental impact seen on bitumen production.

- **PAD 7N NCG Pilot Test**
  - Application approval 9485CC received in May, 2014.
  - NCG co-injection in 5 well pairs planned.
  - Pilot start up planned for 2015.
Solvent Soak – Pad 12 & 13

- Solvent soaking in cold system prior to circulation was experimented with in several SAGD well pairs
- Production responses and observed circulation durations showed no measureable impact as a result of solvent soaking in the cold system

<table>
<thead>
<tr>
<th>Pad 12</th>
<th>Well Pair</th>
<th>Xylene Volume (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>12P01</td>
<td></td>
<td>57.6</td>
</tr>
<tr>
<td>12P02</td>
<td></td>
<td>58.8</td>
</tr>
<tr>
<td>12P03</td>
<td></td>
<td>59.2</td>
</tr>
<tr>
<td>12P04</td>
<td></td>
<td>58.4</td>
</tr>
<tr>
<td>12P05</td>
<td></td>
<td>0.0</td>
</tr>
<tr>
<td>12P06</td>
<td></td>
<td>57.8</td>
</tr>
<tr>
<td>12P07</td>
<td></td>
<td>59.4</td>
</tr>
<tr>
<td>12P08</td>
<td></td>
<td>0.0</td>
</tr>
<tr>
<td>12P09</td>
<td></td>
<td>57.4</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Pad 13</th>
<th>Well Pair</th>
<th>Xylene Volume (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13P01</td>
<td></td>
<td>60.7</td>
</tr>
<tr>
<td>13P02</td>
<td></td>
<td>30.2</td>
</tr>
<tr>
<td>13P03</td>
<td></td>
<td>30.1</td>
</tr>
<tr>
<td>13P04</td>
<td></td>
<td>60.0</td>
</tr>
<tr>
<td>13P05</td>
<td></td>
<td>60.1</td>
</tr>
<tr>
<td>13P06</td>
<td></td>
<td>60.3</td>
</tr>
<tr>
<td>13P07</td>
<td></td>
<td>0.0</td>
</tr>
<tr>
<td>13P08</td>
<td></td>
<td>61.0</td>
</tr>
<tr>
<td>13P09</td>
<td></td>
<td>62.9</td>
</tr>
</tbody>
</table>
Solvent Soak – Pad 12 & 13

- Xylene injection in a warm system was experimented with in 13P06 once the well pair demonstrated hydraulic communication after circulation of both injector and producer at balanced pressures.
- After xylene injection, the well was left to soak during turnaround and then circulation was resumed for 1 month.
  - Volume injected : 70m3
  - Wellbore temperature : 120 deg C
  - Time left shut in : 1 month

- The results show positive impact on production after conversion to SAGD
Liner Failures – Redrill and Repairs
2014 Liner Failures

- 9 liner failures in 2014
- Evaluated case by case to determine whether to repair, re-drill or shut in

**Wells Re-drilled**
- 3P05/03S05 - liner failure Q3 2013, first oil Q2 2014
- 11P10 - liner failure Q4 2013, first oil Q2 2014

**Wells Repaired**
- 6P04 - liner failure Q2, plugged back
- 6P10 - liner failure Q3, plugged back
- 7P11 - liner failure Q3, heel scab
- 7P12 - liner failure Q3, heel scab
- 10P04 - liner failure Q3, plugged back

**Wells Currently Shut In – Ongoing Evaluation**
- 6P12 – liner failure Q1
- 2P11 – liner failure Q2
2014 Liner Failures

- Trialing a different repair design on 2 well pairs (07P11, 07P12)
  - Straddle packer assembly with 2 packers and blank pipe
- Isolate damaged section of liner without losing access to the rest of lateral
- On production since Q3 2014 without issues
2014 Redrill Lookback– 11P10

- Suspected liner failure at ~600mKB
- Unsuccessfully attempted to clean out wellbore to verify failure location
- Could not use other repair options such as plug back due to location of failure and debris in the lateral
• Re-drilled in Q1 2014 – side track from original well
  – 6m offset
  – Shortened lateral to match plugged back depth of original producer
• Re-drilled well is performing well with higher water and total emulsion rates compared to prior to re-drill
2014 Redrill Lookback– 03P05

- Liner failure in both injector and producer
- New trajectories
  - Stayed 25m away from the previous failure area at the heel of the well
  - Increased well offset to 7m at the heel to limit risk or re-failing wells
  - Toe-up trajectories were drilled to avoid poor geology at the toes of the wells
  - Drilled a bit shorter to maintain 150m buffer with Q-Channel edge
• Improvement in production after re-drill
• Re-drilled in Q1 2014 – side track from original injector and producer
Infill Projects – Learnings and Future Plans
PAD 1 Infill Project Lookback

- 2 well pairs (injector + producer) drilled in 2012. Circulated for 3 months prior to starting SAGD in Q1 2013
- Original well pairs on Pad 1 had 150m well spacing
- Infill well pairs were placed in different sand packages to target undrained reserves
PAD 1 Infill Project Lookback

- Temperature survey after drilling infill wells showed inconsistent temperature development
  - Confirmed that injectors were required instead of only producer wells
- Infill wells have been successful in increasing both production and estimated recoverable reserves from Pad 1
PAD 7N Infill Project Summary

- Infill program of 4 producer wells in 7N, upgrading surface facilities in Pad 10.
  - ESP artificial lift
  - Drilling spud time in mid-August 2014
  - Small NCG modifications in surface facilities (PAD) 10, for future implementation of NCG.
  - 1st vertical spud in Long lake
    - Fastest well drilled was 10P17 (Vertical Spud)
    - Performance on 10P17 clearly shows that well design concept changes (e.g. vertical vs slant spud) has potential of reducing overall drilling costs/time.
- Early identification of Devonian risk collision in some wells
- First oil in Q1 2015
PAD 7N Infill Project Learnings

Drilling Trajectories:
- Used Temperature Fall off analysis to help guide well trajectories
- 10P15/10P17
  » to avoid collision with the existing OBS well \( \rightarrow 10P15 \)
  » get \( \sim 30 \) m closer to existing chamber
  » Observed higher temperature closer to the toes of the infill wells
- At YE, were evaluating 10P16 start up without pre-heating (estimated \( \sim 10\% \) likelihood of this happening in one well)
- Other 3 wells planned only steam injection (1-1.5 months) instead of 3 months
- Horizontal infill producer elevations were planned to be at the same TVD as the offsetting producer wells. However, due to unintended intersection of the Devonian, the elevation of three infill producers were adjusted, on average 5m upwards. As a result, these new infill producers are above the original producer wells.
PAD 7N Infill Project Learnings: Drilling Risks and Results

- Robust drilling risk assessment and implementation of risk mitigation options directly contributed to successful wells’ delivery

- Penetration into the Devonian strata occurred on 10P15
  - The primary cause of this unintended penetration was uncertainty in determining the elevation of the Devonian surface using 3D seismic in the vicinity of the well.
  - The Devonian was penetrated for 45 meters (MD) in the lateral section of the well.
  - Following communication DOE, the lateral section was subsequently plugged back with cement. As a result, there is no contact between the drilled Devonian section and any open wellbore.
  - The well was then sidetracked at a higher elevation and reached total depth (TD) entirely within the McMurray Formation

- Penetration into the Devonian strata occurred on 10P16
  - The primary cause of this unintended penetration was uncertainty in determining the elevation of the Devonian surface using 3D seismic in the vicinity of the well.
  - An additional factor was the narrow drilling window that was available for the well to avoid collision with existing suspended SAGD wells.
  - The Devonian was penetrated for 8 meters of measured depth (MD) in the build section of the well.
  - Following communication with the DOE, the proper corrective measures were taken
PAD 7N Infill Project Learnings: Drilling Risks and Mitigation

- Options for reducing risks of Devonian collision while maximizing pay, in future infills are being evaluated
  - Evaluate the benefit of acquiring seismic while drilling to identify Devonian surface and avoid trespass before the next well program
  - Try image Devonian under the lake using Refraction Statics
  - Integration of 4D (planned to be shot in 2015)
  - Further TVD uncertainty analysis in drilling depth during well planning
  - Work with survey vendor(s) to understand better ways of reducing TVD uncertainty: (Independent gyros, Ranging, re-processing of existing surveys, fluid pressure measurements, etc.)

- Despite these efforts, the risk of Devonian trespass cannot be eliminated
  - Limited seismic data quality and well data leading to uncertainty in seismic surface
  - Drilling uncertainty on depth
  - Continue to have early communication with DOE to explain potential issues prior to the program
Future Infill Project Opportunities

- Asset teams have identified opportunities for infill well locations throughout Long Lake

- Pads 3, 5, 6N, 6W, 8, and 10W

- Planning to continue evaluation of proposed locations throughout 2015 and submit corresponding approval applications
Observation Wells
Long Lake Well Pads and Observation Wells
## Observation Wells – Long Lake

N/A – Greater than 250m to Q-channel or closest well pair

<table>
<thead>
<tr>
<th>UW</th>
<th>Closest Wellpair</th>
<th>Distance to Wellpair (m)</th>
<th>Distance to Q channel (m)</th>
<th>Closest Distance to Wellpair (m)</th>
<th>Distance to Q channel (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>100010608060W400</td>
<td>LL-009-09</td>
<td>69</td>
<td>45</td>
<td>70</td>
<td>N/A</td>
</tr>
<tr>
<td>100013108060W400</td>
<td>LL-001-01</td>
<td>1</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100023208060W400</td>
<td>LL-005-04</td>
<td>51</td>
<td>29</td>
<td>44</td>
<td>N/A</td>
</tr>
<tr>
<td>100033108060W400</td>
<td>LL-005-04</td>
<td>7</td>
<td>103</td>
<td>120</td>
<td>N/A</td>
</tr>
<tr>
<td>100042808060W400</td>
<td>LL-014-03</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100043208060W400</td>
<td>LL-001-03</td>
<td>12</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100043308060W400</td>
<td>LL-014-07</td>
<td>219</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100050808060W400</td>
<td>LL-013-09</td>
<td>115</td>
<td>68</td>
<td>87</td>
<td>N/A</td>
</tr>
<tr>
<td>100052080806W400</td>
<td>LL-001-01</td>
<td>3</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100053080806W400</td>
<td>LL-014-07</td>
<td>109</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100060108067W400</td>
<td>LL-011-08</td>
<td>118</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100060708068W400</td>
<td>LL-012-01</td>
<td>67</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100060808068W400</td>
<td>LL-013-09</td>
<td>N/A</td>
<td>87</td>
<td>50</td>
<td>N/A</td>
</tr>
<tr>
<td>100052908060W400</td>
<td>LL-002-02</td>
<td>52</td>
<td>97</td>
<td>145</td>
<td>N/A</td>
</tr>
<tr>
<td>10006108060W400</td>
<td>LL-014-03</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100082080600W400</td>
<td>LL-015-04</td>
<td>128</td>
<td>236</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100092108607W400</td>
<td>LL-012-01</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100092808604W00</td>
<td>LL-015-04</td>
<td>10</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100093108607W400</td>
<td>LL-003-01</td>
<td>3</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100100708600W400</td>
<td>LL-012-05</td>
<td>5</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100102908600W400</td>
<td>LL-014-03</td>
<td>N/A</td>
<td>99</td>
<td>140</td>
<td>N/A</td>
</tr>
<tr>
<td>100103208600W400</td>
<td>LL-005-01</td>
<td>7</td>
<td>N/A</td>
<td>42</td>
<td>N/A</td>
</tr>
<tr>
<td>10011080860W400</td>
<td>LL-013-09</td>
<td>230</td>
<td>109</td>
<td>138</td>
<td>N/A</td>
</tr>
<tr>
<td>100113508070W400</td>
<td>LL-010-05</td>
<td>4</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100120808060W400</td>
<td>LL-013-09</td>
<td>132</td>
<td>179</td>
<td>213</td>
<td>N/A</td>
</tr>
<tr>
<td>100122808060W400</td>
<td>LL-014-01</td>
<td>32</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100132808060W400</td>
<td>LL-015-05</td>
<td>164</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100140808060W400</td>
<td>LL-013-09</td>
<td>N/A</td>
<td>23</td>
<td>33</td>
<td>N/A</td>
</tr>
<tr>
<td>100141708600W400</td>
<td>LL-013-09</td>
<td>N/A</td>
<td>41</td>
<td>8</td>
<td>N/A</td>
</tr>
<tr>
<td>100142508057W400</td>
<td>LL-008-06</td>
<td>28</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100143208057W400</td>
<td>LL-003-03</td>
<td>135</td>
<td>3</td>
<td>42</td>
<td>N/A</td>
</tr>
<tr>
<td>100152508057W400</td>
<td>LL-010-16</td>
<td>17</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100152908056W00</td>
<td>LL-014-05</td>
<td>203</td>
<td>100</td>
<td>113</td>
<td>N/A</td>
</tr>
<tr>
<td>100162908056W00</td>
<td>LL-014-06</td>
<td>18</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100163108056W00</td>
<td>LL-002-03</td>
<td>97</td>
<td>46</td>
<td>57</td>
<td>N/A</td>
</tr>
<tr>
<td>100206080600W400</td>
<td>LL-009-09</td>
<td>112</td>
<td>10</td>
<td>27</td>
<td>N/A</td>
</tr>
<tr>
<td>100211208600W400</td>
<td>LL-014-01</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100211308056W00</td>
<td>LL-013-01</td>
<td>1</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100223208060W400</td>
<td>LL-005-04</td>
<td>101</td>
<td>20</td>
<td>7</td>
<td>N/A</td>
</tr>
<tr>
<td>100242208060W400</td>
<td>LL-014-01</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100243208060W400</td>
<td>LL-001-03</td>
<td>4</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100250808060W400</td>
<td>LL-013-06</td>
<td>36</td>
<td>4</td>
<td>28</td>
<td>N/A</td>
</tr>
<tr>
<td>100252908060W400</td>
<td>LL-004-05</td>
<td>2</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>100253208060W400</td>
<td>LL-001-01</td>
<td>1</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>
## Pad 14/15 Obs Wells Baseline Values

### Pad 14 Baseline Values
(as of March 31, 2015)

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Sensor Depth (m)</th>
<th>Formation</th>
<th>Base Line Pressure kPa&lt;sub&gt;a&lt;/sub&gt;</th>
<th>Current Pressure kPa&lt;sub&gt;a&lt;/sub&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>04-28</td>
<td>126</td>
<td>CLWT A</td>
<td>TBD</td>
<td>1020</td>
</tr>
<tr>
<td>05-33</td>
<td>119</td>
<td>CLWT A</td>
<td>980</td>
<td>985</td>
</tr>
<tr>
<td>100_04-33</td>
<td>123.1</td>
<td>CLWT A</td>
<td>1110</td>
<td>Will be removed</td>
</tr>
<tr>
<td></td>
<td>126.1</td>
<td>CLWT A</td>
<td>1185</td>
<td></td>
</tr>
<tr>
<td>13-28</td>
<td>116</td>
<td>CLWT A</td>
<td>1000</td>
<td>1005</td>
</tr>
<tr>
<td>1WP_15-29</td>
<td>127</td>
<td>CLWT A</td>
<td>TBD</td>
<td>990</td>
</tr>
<tr>
<td>WM_04-33</td>
<td>115</td>
<td>CLWT A</td>
<td>970</td>
<td>960</td>
</tr>
<tr>
<td></td>
<td>115.5</td>
<td>CLWT A</td>
<td>980</td>
<td>975</td>
</tr>
</tbody>
</table>

### Pad 15 Baseline Values
(as of March 31, 2015)

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Sensor Depth (m)</th>
<th>Formation</th>
<th>Base Line Pressure kPa&lt;sub&gt;a&lt;/sub&gt;</th>
<th>Current Pressure kPa&lt;sub&gt;a&lt;/sub&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>105_06-28</td>
<td>122.5</td>
<td>CLWT A</td>
<td>1100</td>
<td>1105</td>
</tr>
<tr>
<td>08-29</td>
<td>118.5</td>
<td>CLWT A</td>
<td>930</td>
<td>925</td>
</tr>
<tr>
<td>102_09-29</td>
<td>126.5</td>
<td>CLWT A</td>
<td>1020</td>
<td>1020</td>
</tr>
<tr>
<td>103_12-28</td>
<td>121.5</td>
<td>CLWT A</td>
<td>TBD</td>
<td>1020</td>
</tr>
</tbody>
</table>

- DCS alarm is triggered +75kPa above baseline (Hi alarm) and DCS steam shut-in is triggered +100kPa (Hi-Hi alarm).
- Need to set baseline for 04-28, WP15-29, 03/13-28
Future Plans
Long Lake 2014/2015 Evaluation Program

- **Long Lake**
  - 4 observation wells drilled (2 cored); 3 for reservoir optimization and future infill placement and 1 for Q-Channel monitoring
  - 4D shot over Long Lake West

- **Kinosis**
  - 3 water wells (1 source and 2 monitoring)
  - baseline 3D seismic survey over K1A IDA
2015 Plans – Existing Pads

• Long Lake: continue to optimize wells and increase production
• K1A: continue with SAGD conversions and production ramp-up
• Assess Opportunities to apply enhanced SAGD technologies
  – Monitor NCG Co-injection trial at Pad 7E to assess capability to reduce steam requirements
  – Advance NCG Co-injection trial at Pad 7N, target implementation 2015
  – Monitor ES-SAGD solvent co-injection pilot at Pad 13 with respect to production uplift and solvent recovery and assess commercial feasibility of process
• Review opportunity for 5 additional well pairs on Pads 14 and 15
• Continue to evaluate infills at Long Lake
  – Monitor and optimize LL Pad 7N infills
  – Further evaluate infills in Long Lake area
  – Submit regulatory applications
2015 Plans – New Developments

• Long Lake
  – Long Lake SW (Pads 16 to 19)
    • Proceed with development planning at a reduced pace
    • Regulatory approval received for Pads 16 to 18; submitted Q4 2014 for Pad 19

• Kinosis
  – K1B
    • Proceed with development planning at a reduced pace
    • Regulatory application submitted in Q1 2015
  – K2
    • Evaluate results from gas re-pressurization

• Continue to assess the area for exploitation opportunities
Scheme Performance
Pad Level
PAD 1 Production Summary

- All 5 wells on ESP
- Stable operation and increased steam injection helped achieve higher production
  - 1S01 toe steam was restarted mid year
- At YE, injection pressures were ~1,600-1,750 kPa

- Five well pairs (01P01 to 01P03, 04P05 and 04P06)
- Cumulative production of 797 E3m³ (RF 36%)
PAD 2NE Production Summary

- All 6 wells on ESP
- Steam SI to 02S04, 02S05 and 02S06
- Short term steam reductions have lead to inconsistent production performance
- At YE, injection pressures were ~1,275 – 1,485 kPa

- Six well pairs (02P01 to 02P06)
- Cumulative production of 611 E^3m^3 (RF 25%)
PAD 2SE Production Summary

- 2P8 - 2P10 on ESP
- 2P07 on PCP
- 02Pair11 SI due to liner failure
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,350 – 1,900 kPa

Five well pairs (02P07 to 02P011)
Cumulative production of 228 E^3 m^3 (RF 23%)
PAD 3 Production Summary

- All 5 wells on ESP
- Short-term steam reductions to 03S01, 03S02, and 03S03
- 03PAIR05 ramping up after redrill
- At YE, injection pressures were ~1,285-1,800 kPa

- Five well pairs (03P01 to 03P05)
- Cumulative production of 955 E^3m^3 (RF 39%)
PAD 4 Production Summary

- All wells on ESP
- Stable operation helped maintain production
- At YE, injection pressures were ~1,260–1,515kPa

- Two well pairs (04P01 to 04P02)
- Cumulative production of 72 E³m³ (RF 52%)
PAD 5 Production Summary

- All 5 wells on ESP
- Stable operation and increased steam helped maintain production
  - 5S02 toe steam was restarted in Q3
- At YE, injection pressures were ~1,650–1,825kPa

- Five well pairs (05P01 to 05P05)
- Cumulative production of 1082 E^3m^3 (RF 34%)
PAD 6N Production Summary

- All wells on ESP
- Higher water production as a result of maximizing withdrawals
- 6P4 plugged back due to poor reservoir quality at toe
- At YE, injection pressures were ~1,750–1,850 kPa

- Six well pairs (06P01 to 06P05 plus 06P13)
- Cumulative production of 621 E^3m^3 (RF 22%)

---

**Graph:**
- Rate (m^3/d)
- SOR & Well Count
- Graph shows trends for Bitumen, Water, Steam, SOR, and Well Count over the years 2007 to 2014.
• Seven well pairs (06P06 to 06P12)
• Cumulative production of 683 E$^3$m$^3$ (RF 36%)

• All 7 wells on ESP
• Stable operation
• 6P12 shut in due to potential liner failure
• At YE, injection pressures were ~1,700–1,950 kPa
• All 7 wells on ESP
• Stable operation
• At YE, injection pressures were ~1,850–2,100 kPa
• NCG injection started October 2014 on 07P07, 07P08, 07P09
• Liner failures on 07P11 and 07P12 repaired with liner and packer assembly

- Seven well pairs (07P06 to 07P12)
- Cumulative production of 563 E³m³ (RF 43%)
• All 5 wells on ESP
• 07P01-07P03 in possible decline phase
• Proposed NCG pilot project
• Increased steam injection and maximized withdrawals helped achieve higher production
• 4 infill producer wells were drilled in 2014
• At YE, injection pressures were ~2,000 - 2,100 kPa

Five well pairs (07P01 to 07P05)
Cumulative production of 1383 E³m³ (RF 46%)
PAD 8 Production Summary

- All 6 wells on ESP
- Increased emulsion rates in late 2013 and saw improved performance
- Brought 08P01 & 08P02 online in February 2014 after being shut in since 2012
  - No issues re-starting ESPs
- At YE, injection pressures were ~1,850–2,100 kPa

- Six well pairs (08P01 to 08P06)
- Cumulative production of 844 E$^3$m$^3$ (RF 34%)
PAD 9NE Production Summary

- All 5 wells on ESP
- 9P07 plugged back at toe due to liner failure
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,350 – 1,900 kPa

- Five well pairs (09P06 to 09P10)
- Cumulative production of 192 E³m³ (RF 17%)
PAD 9W Production Summary

- 9P1-9P3 on gas lift
- 9P4 & 9P5 on ESP
- Stable operation
- 9P5 in possible decline phase
- At YE, injection pressures were ~2,000 - 2,100 kPa

- Five well pairs (09P01 to 09P05)
- Cumulative production of 345 E³m³ (RF 22%)

![Graph showing production rates and SOR & Well Count over time from 2007 to 2014.](image)
PAD 10N Production Summary

- All wells on gas lift
- Increased run time led to higher production and lower SOR
- At YE, injection pressures were \(~1,700 – 1,900\) kPa

- Three well pairs producing (10P10 to 10P12)
- Cumulative production of 150 E\(^3\)m\(^3\) (RF 14\%)
• Five well pairs (10P01 to 10P05)
• Cumulative production of 498 E3m3 (RF 24%)

• All 5 wells on ESP
• Stable operation
• Performance impacted by top water WSR > 1.0
• At YE, injection pressures were ~1,950–2,100 kPa
Ten well pairs (11P01 to 11P10)
Cumulative production of 922 E³m³ (RF 42%)

- All 10 wells are on ESP
- Pad in possible decline phase
- 11P10 re-drilled due to liner failure
- Decline in bitumen rates can be attributed to top water effect
- Reduced operation pressure from 2100 to 1850 kPa
- At YE, injection pressures were ~1,850–1,920 kPa
PAD 12 Production Summary

- Nine well pairs (12P01 to 12P09)
- Cumulative production of 330 E³m³ (RF 10%)
- All 9 wells are on ESP
- Flat bitumen rate attributed to lean zone
- Reduced pressure on west side of pad in attempt to promote water production
- Reduced operational pressure from 1,900 to 1,600 kPa
- At YE, injection pressures were ~1,300–1,875 kPa
PAD 13 Production Summary

- Nine well pairs (13P01 to 13P09)
- Cumulative production of 404 $E^3m^3$ (RF 13%)
- All 9 wells are on ESP
- Initiated ES-SAGD project at wells 13P3 and 13P4 in October
- Flat bitumen rate attributed to lean zone and facility constraints
- Reduced operational pressure from 1,975 to 1,825 kPa
- At YE, injection pressures were ~1,800–1,875 kPa
PAD 14 Production Summary

- All 6 wells on ESP
- SAGD conversion in Q2 2014
- All wells on ramp-up
- At YE, injection pressures were ~2,300 - 2,500kPa

- Six well pairs (14P01 to 14P03 and 14P05 to 14P07)
- Cumulative production of 82 E³m³ (RF 4%)
PAD 15 Production Summary

- All 5 wells on ESP
- Last well converted to SAGD in Q4 2014
- All wells on ramp-up
- At YE, injection pressures were ~ 2,300 - 2,500kPa

- Five well pairs (15P01 to 15P05)
- Cumulative production of 21 E^3m^3 (RF 1%)
**K1A-A Production Summary**

- **8 Pairs on circulation at YE**
  - K1P09 to K1P16
  - Circulation Pressures from 1200 to 2800 kPa
  - Leaky Wells circulated closer to bottom water pressure

- **Anticipate conversion to production in 2015**

- **Ten well pairs (K1P09 to K1P16 and K2P01 to K2P02)**

- **Cumulative production of 0 E^3m^3 (RF 0%)**

- **K2P01 & K2P02 scheduled for circulation start up in Q3 2015**
K1A-B Production Summary

- 3 of 8 pairs on circulation in Oct 2014
  - K2P13 - K2P15
  - Circulation Pressures of 2,500 to 2,800 kPag
- Anticipate conversion to production in 2015
- K2P09 – K2P12 & K2P16 scheduled for circulation start up through 2015
- Solvent Assisted start up trial on K2P14 – injected 38m³ Solvent (Diluent) in late Dec

- Eight well pairs (K2P09 to K2P16)
- Cumulative production of 0 E³m³ (RF 0%)
K1A-C Production Summary

- 8 of 8 pairs on circulation in Aug 2014
- Circulation Pressures from 2,500kPa to 2,800 KPa
- Conversion to Production Started in Nov 2015 through Dec 2014
- Operating Pressure of 2,500 to 2,800 kPa

- Eight well pairs (K1P01 to K1P08)
- Cumulative production of 12 E^3m^3 (RF 0.2%)
K1A-D Production Summary

- Eleven well pairs (K2P03 to K2P08 and K2P18 to K2P22)
- Cumulative production of 0 E³m³ (RF 0%)
- 5 of 11 pairs on circulation in Oct 2014
  - K2P18 - K2P22
  - Circulation Pressures of 2,800kPa
- Anticipate conversion to Production in 2015
- K2P03 – K2P08 scheduled for circulation start up through 2015
- Solvent Assisted start up trial on K2P19 – injected 38m³ Solvent (Diluent) in late Dec
Overview

- Overview
- Field Infrastructure and Inlet Treating
  - Slides 14-19
- Steam and Power Generation
  - Slides 20-30
- Water Treatment
  - Slides 31-38
- Volume Measurement and Reporting
  - Slides 39-42
- Water Production, Injection and Uses
  - Slides 43-57
- Sulphur Recovery
  - Slides 58-63
- Regulatory Compliance & Environmental Performance
  - Slides 64-83
- Future Plans
  - Slides 84-85
Purpose

This presentation contains information to comply with Alberta Energy Regulator’s Directive 054 – Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes.
Corporate Ownership

• Nexen Energy ULC is an upstream oil and gas company responsibly developing energy resources in the UK North Sea, offshore West Africa, the United States and Western Canada.

• In February 2013, Nexen became a wholly-owned subsidiary of Chinese National Offshore Oil Company (CNOOC) Limited.

• Nexen has three principal businesses: conventional oil and gas, oil sands and shale gas.
Nexen Oil Sands Leases
## Chronology of Oil Sands Operations

<table>
<thead>
<tr>
<th>Year</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>EIA and regulatory submissions for the commercial Long Lake Facility</td>
</tr>
<tr>
<td>2003</td>
<td>Regulatory approvals for the commercial Long Lake Facility</td>
</tr>
<tr>
<td>2003 - 2007</td>
<td>Production at the Long Lake SAGD Pilot Plant</td>
</tr>
<tr>
<td>2004</td>
<td>Construction begins for the commercial Long Lake Facility</td>
</tr>
<tr>
<td>2006</td>
<td>Regulatory amendments, including Pad 11</td>
</tr>
<tr>
<td>2007</td>
<td>Start of commercial bitumen production for the Long Lake Facility</td>
</tr>
<tr>
<td>2007</td>
<td>Regulatory submissions for Long Lake South (development of Kinson lease)</td>
</tr>
<tr>
<td>2009</td>
<td>Regulatory approvals issued for Long Lake South</td>
</tr>
<tr>
<td>2009</td>
<td>Start of operation of the Long Lake Upgrader</td>
</tr>
<tr>
<td>2010</td>
<td>Regulatory approvals for Pads 12 and 13</td>
</tr>
<tr>
<td>2012</td>
<td>First production from Pads 12 and 13</td>
</tr>
<tr>
<td>2012</td>
<td>Major turnaround for maintenance at CPF and Upgrader</td>
</tr>
<tr>
<td>2012</td>
<td>Regulatory approvals for Pads 14 and 15 and K1A (formerly Long Lake South)</td>
</tr>
<tr>
<td>2012</td>
<td>Construction begins for K1A and Pads 14 and 15</td>
</tr>
<tr>
<td>2013</td>
<td>Increased production from Long Lake well pads, begin circulation at Pad 14</td>
</tr>
<tr>
<td>2014</td>
<td>K1A and Pads 14 and 15 started production</td>
</tr>
</tbody>
</table>
2014 Summary

• Most successful year at Long Lake
  – Best ever safety record
  – Record production (42,900 bpd average) and significant increase over 2013
    • Improved plant reliability
    • Optimization of existing wells
    • Pads 14 & 15 ramping up above expectation
  – K1A completion and start-up
  – Completion and start-up of first Long Lake infill wells
Process Overview
Long Lake Plot Plan
Kinosis Phase 1A (K1A) Plot Plan
Long Lake overview with new DRU construction activities– October 22, 2014
Kinosis Phase 1 (K1A)

Aerial of Nexen’s K1A Steam Generation Facility with Well Pads 2 in background – October 15, 2014
Field and Inlet Treating

- Emulsion from Pads
  - FWKOS
  - Treaters
  - Flash
  - Upgrader
  - Tank Farm
  - Truck Terminal
  - Slop Tank
  - Skimmings Tank
  - Centrifuge
  - Skim Tank
  - IGF
  - ORF
  - De-oiling Tank
  - To HLS

Flow directions:
- Emulsion
- Oil
- Water
Field and Inlet Treating - Successes

• Chemical injection – re-location of chemical injection, upgraded pump with VFD control and bulk storage facilities
  – Existing chemicals continue to provide good performance with regular monitoring
  – The bulk storage project as part of K1A has been commissioned and supports CPF and is showing the efficiency improvements as expected. The new DMO trial was postponed in 2014 but is on target for early 2015.

• FWKO Desand Line Modification Project
  – Modified desand lines on the FWKO’s allow us to dump clean water from FWKO’s front end and route it through the Produced Water exchangers.

• Exchanger Performance
  – Nexen determined that the fully open desand lines on the FWKO were impacting fouling on the PW exchangers due to high throughput rates and oil carryover.
  – After blocking in the desands on the front end it was noticeable that the fouling frequency in the exchangers was dropping and allowing longer run times.
Field and Inlet Treating – Successes
Continued

• **Rag / Slop Management**
  – Brought in a second centrifuge to process slop which increased our capability from 200m3/day to approximately 800m3/day
  – Old philosophy of batching tanks or providing separation discarded for 100% slop processing which has yielded very good results and long haul truck hauling ceased
  – Slop recycle to front end FWKO stopped as not required with centrifuge capacity
  – Desand dumps on FWKO front end closed in to prevent excessive oil and water carryover into de-oiling system having a positive impact on rag formation
  – DMO trials planned to improve any rag formation tendencies by emulsion from K1A

• **K1A**
  – Production in 2014
  – Early performance shows it is exceeding expectations for production rates
High Exchanger Temperatures & Tank Pressures

- With higher production rates Nexen is experiencing higher Produced Oily Water (POW) and Produced Water (PW) temperatures that result in higher exchanger outlet temperatures and subsequently higher tank pressures.
- This places a higher load on the Vapor Recovery Compressors (VRU).
- The newly installed FWKO desand lines as well as increased throughput rates have allowed more oily water and solids to route through the exchangers causing increased fouling and subsequent higher frequency of chemical cleaning.
- Generally this is a steaming process followed by a caustic solution flush to remove heavy material.
- The additional load of bringing on K1A has had an extra burden.
- Although they have their own bank of exchangers the overall loading in the Inlet process has gone up and challenges have been encountered managing all the water.
- The exchanger design flow rates for PW is near or at the upper limit of 36,000m³.
• **Electrostatic Grids in Treaters**
  - The treaters are designed to remove residual water in the oil phase from the FWKOs utilizing electrostatic grids. The grids have not been as effective in removing water as expected. There was no change in 2014 and they were not in service.
  - It has been proposed to install sonar probes to establish proper levels to control PW injection properly and get the grids working. On hold as of December 2014.

• **VRU Performance and “Rapid Results Team”**
  - Since the tanks operate at only a slight positive pressure they cannot be connected to the flare system.
  - Vapor recovery system continues to offer us challenges due to capacity restrictions associated with piping configurations and size.
  - Rebuild of one complete unit with parts on hand already which has been completed.
  - Increased pressure on Flash Vessel and Diluent Condensate Separator resulting in VRU load reduction. Completed this with good results for 4 day period and unable to repeat due to other process factors.
  - ORC diluent stripper control improved to provide less light ends in diluent resulting in VRU load reduction
  - Any operational activity resulting in weeping/venting trigger a very high priority to resolve. All materials have been inventoried in stores and scaffolding for access remains in place. No change in 2014.
Steam and Power Generation
Steam and Power Generation - Successes

- **Steam Production**
  - The remainder of the ABSA requirements for the OTSG re-rates have been submitted for final approval. These re-rates allow for increased steam production.
    - Approval was received for the re-rate of the OTSG's
    - The TIWW PSV's were received
    - All six OTSG's are now re-rated to 154m3/h from 146 m3/h
  - No longer mixing Syngas and Natural gas
    - Fewer trips of the OTSG’s and HRSG’s, especially OTSG’s E and F that run on Natural gas only
    - Less complications from heating value fluctuation
  - More reliable steam production due to fewer trips results in improved bitumen production

- **Condensate Quality**
  - Continuing to use filming Amine injection for LP, MP and HP steam
Steam and Power Generation – Successes Continued

- **E-013 Exchangers**
  - 8400-E-013 A and C tube bundles have been replaced with bundles made of different metallurgy intended for longer life before failure

- **Automated Safe Park function on DCS**
  - Cuts qualities and fuel gas to OTSGs and HRSG’s and transitions GTG’s to Natgas from Syngas
  - Now automatically occurs during a PSA trip or a Gasifier train trip (Upgrader trips)

- **Procedure for use of HP Syngas**
  - Procedure for use of high pressure syngas in the GTGs was completed
  - HP Syngas is now successfully being used in the GTGs when available which offsets natural gas usage
Steam and Power Generation – Successes Continued

- **Duct Burner Fouling**
  - Procedure for purging and cleaning of HRSG duct burners completed February 2014
  - Operations can now complete cleaning of duct burners while unit is online which has increased syngas usage and steam output on an annual basis

- **Air Extraction Unit**
  - Commissioned and tested the Air Extraction Unit for GTGs, which will increase power output
  - More work required

- **Blowdown Tank**
  - No Blowdown Tank (8400-T-002) overflows
  - Improved procedure contributed to this milestone
  - Work on logic changes ongoing
Steam and Power Generation - Updates

• **Emergency Power Supply**
  – Total plant power outage determined weaknesses with SAGDs E-gen power supply
  – Team is working with the AIT group for re-design of the system to mitigate the risk to the operation

• **E-013 Exchangers**
  – 8400-E-013-B exchanger found internally leaking after only 6 months of operation, affecting site water balance
  – Changes to metallurgy is expected to extend life to two years
Steam and Power Generation – Updates
Continued

- **Duct Burner Fouling**
  - causing reduced steam production from HRSGs 1 and 2
    - Nitrogen purging effective but requires 6 hours and fouling returns quickly
    - Looking into different ways to clean the duct burners that do not require a full outage

- **PSA Reliability (Upgrader)**
  - Inconsistent Syngas pressure from the Upgrader causes OTSGs and HRSGs to trip when pressure swings are too large
  - Team has been established to review and correct PSA issues
Steam and Power Generation – Updates Continued

• **Fuel Gas Configurations**
  – OTSGs A-D and HRSGs 1 and 2 must run on the same fuel as per the current configuration
  – When Syngas supply from the Upgrader is low, these boilers must be run at lower rates, or the choice must be made to switch all over to natural gas
    • Natural gas tie-in to HRSG’s 1 and 2 design complete, and scheduled for June 2015
    • Will allow multiple options for utilizing available fuels on any steam generators
SAGD Energy Intensity

SAGD Fuel Intensity (GJ/m³)

Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec

Fuel Intensity for Steam (GJ/m³)  Fuel Intensity for Bitumen (GJ/m³)
SAGD Natural Gas and Syngas Usage

[Graph showing the usage of SAGD Gas, LP Syngas, and Natural Gas from January 2014 to December 2014. The graph indicates fluctuations in usage over the year.]
Total Power Usage

![Graph showing power usage over time.](image-url)
Greenhouse Gas Emissions

- Long Lake’s absolute GHG emissions have been rising with increasing production, but intensity is trending downwards

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kilotonnes (kT) CO₂e Emissions</td>
<td>3,229</td>
<td>3,191</td>
<td>3,613</td>
<td>4,139</td>
<td>4,758</td>
</tr>
<tr>
<td>GHG intensity (kg CO₂e/bbl bitumen produced)</td>
<td>361</td>
<td>307</td>
<td>317</td>
<td>310</td>
<td>304</td>
</tr>
</tbody>
</table>

- Nexen and the AESRD resolved negotiations around Long Lake’s baseline in July 2014, Long Lake now has an approved baseline based on 2010-12 performance
  - Long Lake’s GHG baseline is divided among the facility’s three major products – bitumen, PSC and electricity

- Long Lake’s compliance is being met through reducing Long Lake’s GHG intensity, the use of offsets from Nexen’s Soderglen wind farm asset, and contributions to the technology fund

- Current GHG regulations (known as SGER) are set to expire in June 2015
  - Nexen is monitoring the development of these regulations
Water Treatment
High Quality Water System
Water Treatment - Successes

• **After Filters**
  – After filters backwash sequence implemented
  – Backwash volume significantly reduced

• **Chemical injection modifications**
  – Chemical injection modifications for Produced Water (PW) were completed
    • Separate coagulant injection to HLSs A/B started up, allowing proper adjustment during upset conditions
    • New flocculant injection system installed (pumps and pre-mixer dilution drums)

• **Capacity Test**
  – SAGD Water Treatment Capacity test conducted
  – Throughput increased after HLS internal modifications completed on 2012-2013 and WAC primaries/polishers adjusted differential pressure within safe limit

• **E-013 Exchangers**
  – E-013 bundles replaced
  – Improvement of the LP condensate quality and recovery, increasing the usage as feed to HQWS and reducing fresh water requirements
• **High Quality Water System**
  
  – Fresh water heater E-002 bundle replaced
  – better control on the HQWS inlet temperature, allowing more stable temperature supply to ROs
  – Microfiltration membranes replaced in 2 of 3 trains, improving water feed quality to Reverse Osmosis Membranes (RO)
  – Mixed beds enhanced performance. Resin replaced and scour step added to improve separation and regeneration of the anion and cation resins
  – RO low fouling membranes trial was started to evaluate the impact of high TOC on low fouling membranes; this continued into 2015
  – Lime sludge from HLS blowdown is now being centrifuged and disposed of to landfill and water returned to the produced water system which will eliminate costly dredging and will contribute to pond integrity
  – More SAGD low pressure steam condensate into the HQWS feed, less fresh water use from source wells
Water Treatment - Updates

• **SAGD BFW treatment for hardness and silica**
  – Improvements required for the Lime/Magox systems
  – Brackish water used during K1A start up, difficult to treat
  – Higher Backwash and regeneration volumes for After filters and Weak Acid Cation Exchangers (WAC) required
  – High fouling rate with online pH meters, unreliable
  – WAC primary and polisher resin losses due to passing valves

• **Sludge carry over from HLSs**
  – Additional sludge taps on HLSs not preforming as designed
  – High fouling rate with online pH meters, unreliable
  – New pumps installed for better flocculent injection control
  – Periodical issues with HLS blowdown valves, doing manual blow downs

• **WAC primary and polisher resin fouling**
  – causing high differential pressures
  – Result of poor de-oiled water quality and over feeding chemicals
• **Difficulties in controlling De-Aerator compartment level for HLS restricting feed to HLS A/B**
  - WAC primary and polisher inlet valves not working
  - WAC feed pumps/recirculation valves fouling

• **High Quality Water System**
  - Mono media filters low run time
  - Rapid fouling on RO’s membranes
  - Trial with more foulant resistant membranes started

• **Fresh Water Leak**
  - Fresh Water leak at the common header from source wells to plant
  - Repair plan issued
  - A temporary repair has been completed with final repair to be completed during the 2015 Turnaround
• **Micro-Filtration**
  – Micro filtration unit performance issues
  – Membranes replaced in 2 of 3 trains in 2014
  – All are complete at time of report

• **Mixed Bed Polishers**
  – Mixed bed polishers internal damage on interface laterals causing resin losses
  – Temporary repair complete to reduce resin losses; project in progress to install new interface laterals for permanent fix during 2015 Turnaround

• **HQWS Analyzers**
  – Additional analyzers installed in HQWS to better control chemical injection and improve feed to RO
  – Commissioning and automation for the HQWS analyzers to be completed in future
Silica In Boiler Feed Water

![Graph showing silica concentration in boiler feed water over a year. The graph includes data for CPF BFW and DB BFW, with a target silica level indicated.]
pH for Boiler Feed Water

![Graph showing pH levels for Boiler Feed Water (CPF BFW and DB BFW) from January to December. The graph includes a lower limit at 9 and an upper limit at 10.5, with fluctuating data points throughout the year.](image_url)
Volume Measurement and Reporting
Produced Bitumen Measurement

- Ten two-phase test separators with up to 12 well pairs for Pads 1-10, 12 & 13.
  - Currently testing two wells per day per separator. 12 hour test duration, with a minimum of one test per week per well.
  - Wells with ESPs are equipped with wellhead coriolis meters for daily optimization, which allows the well test a longer duration for monitoring S&W profiles.
  - Bitumen cuts are based on an inline water cut analyzer (AGAR meter) and manual cuts are taken for confirmation.
- All ten wells on Pad 11 receive continuous well testing via individual coriolis flow measurement and AGAR water cut meters.
- Multiphase flow meters installed on Pads 14 & 15 and K1A.
- Bitumen samples collected from emulsion line are analyzed by Long Lake Lab and 3rd Party lab to determine density as requested by Department of Energy.
Steam Injection Measurement

- Steam injection is measured at the wellhead (estimating steam quality of 95% at the wellhead).
  - Nexen accurately measures the total steam at the individual well heads on each pad through the use of vortex meters and does not use a common meter to prorate HP steam to the wells. These vortex meters with a steam condensate trap upstream have given the most accurate trend of actual plant output. Through 2014 these meters were inspected, cleaned and calibrated. All wellhead meters have preventative maintenance schedule to maintain the accuracy as per MARP.
- Two V-cone meters were installed for steam measurement at CPF during 2012 turnaround (8400-FIT-510,8400-FIT-518).
Produced Bitumen and Water Measurement

### Proration Factors

<table>
<thead>
<tr>
<th>Month</th>
<th>OIL</th>
<th>GAS</th>
<th>WATER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>0.88862</td>
<td>6.11645</td>
<td>0.92670</td>
</tr>
<tr>
<td>Feb</td>
<td>0.92045</td>
<td>8.13304</td>
<td>0.88479</td>
</tr>
<tr>
<td>March</td>
<td>0.90985</td>
<td>6.42687</td>
<td>0.88804</td>
</tr>
<tr>
<td>April</td>
<td>0.87712</td>
<td>5.46922</td>
<td>0.90581</td>
</tr>
<tr>
<td>May</td>
<td>0.84712</td>
<td>5.57744</td>
<td>0.91318</td>
</tr>
<tr>
<td>June</td>
<td>0.87523</td>
<td>5.25845</td>
<td>0.94228</td>
</tr>
<tr>
<td>July</td>
<td>0.88836</td>
<td>5.69410</td>
<td>0.94814</td>
</tr>
<tr>
<td>August</td>
<td>0.85256</td>
<td>6.94934</td>
<td>0.90956</td>
</tr>
<tr>
<td>Sept</td>
<td>0.92527</td>
<td>7.15486</td>
<td>0.90103</td>
</tr>
<tr>
<td>October</td>
<td>0.88353</td>
<td>6.03378</td>
<td>0.97200</td>
</tr>
<tr>
<td>November</td>
<td>0.85216</td>
<td>3.13596</td>
<td>0.97422</td>
</tr>
<tr>
<td>December</td>
<td>0.85402</td>
<td>4.02812</td>
<td>1.01620</td>
</tr>
</tbody>
</table>
Water Production, Injection & Uses
Potable Well

Never been used for potable (used for SAGD drilling in 2014)

<table>
<thead>
<tr>
<th>Location</th>
<th>Total (m$^3$)</th>
<th>Annual avg. (m$^3$/cd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13-31-85-06W4M Q</td>
<td>201,639</td>
<td>552</td>
</tr>
</tbody>
</table>
No drilling of fresh source wells in 2014
## Freshwater Pipeline (CONT’D)

<table>
<thead>
<tr>
<th>Location</th>
<th>Formation</th>
<th>Fresh?</th>
<th>Total (m³)</th>
<th>Annual avg. (m³/cd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>01-21-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>125,729</td>
<td>344</td>
</tr>
<tr>
<td>01-27-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>207,022</td>
<td>567</td>
</tr>
<tr>
<td>01-34-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>117,392</td>
<td>322</td>
</tr>
<tr>
<td>02-12-86-07W4M Q</td>
<td>Quaternary</td>
<td>Y</td>
<td>315,144</td>
<td>863</td>
</tr>
<tr>
<td>02-32-85-06W4M QC</td>
<td>Gregoire Channel</td>
<td>Y</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>06-14-86-07W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>108,464</td>
<td>297</td>
</tr>
<tr>
<td>06-18-85-05W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>07-36-85-07W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>334,418</td>
<td>916</td>
</tr>
<tr>
<td>08-01-86-07W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>09-12-86-07W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>230,686</td>
<td>632</td>
</tr>
<tr>
<td>09-28-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>29,191</td>
<td>80</td>
</tr>
<tr>
<td>10-11-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>345,935</td>
<td>948</td>
</tr>
<tr>
<td>10-21-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>83,172</td>
<td>228</td>
</tr>
<tr>
<td>10-29-85-6W4M QC</td>
<td>Gregoire Channel</td>
<td>Y</td>
<td>35,873</td>
<td>98</td>
</tr>
<tr>
<td>12-19-85-05W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>165,898</td>
<td>455</td>
</tr>
<tr>
<td>13-31-85-06W4M Q</td>
<td>Quaternary</td>
<td>Y</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>15-28-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>159,211</td>
<td>436</td>
</tr>
<tr>
<td>16-33-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>53,124</td>
<td>146</td>
</tr>
</tbody>
</table>

**License Allocation 3,285,000 m³ (annual daily average of 9,000 m³/d)**

<p>| | | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>2,311,262</strong></td>
<td><strong>6,315</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- Total of 18 wells tied in.
- WS Q 13-31-085-06W4 also used for potable water.
No drilling of saline source wells in 2014
Saline Water Pipeline (CONT’D)

<table>
<thead>
<tr>
<th>Location</th>
<th>Formation</th>
<th>Saline?</th>
<th>Sample Date</th>
<th>Concentration (mg/L)</th>
<th>Total (m³)</th>
<th>Annual avg. (m³/cd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F2033008406W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>14,000</td>
<td>15,109</td>
<td>41</td>
</tr>
<tr>
<td>1F1053308406W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>7,800</td>
<td>8,584</td>
<td>24</td>
</tr>
<tr>
<td>1F1063108406W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>33,000</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>07-23-85-06W4 GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>09-Oct-14</td>
<td>16,900</td>
<td>6,825</td>
<td>19</td>
</tr>
<tr>
<td>1F1072608407W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>22,000</td>
<td>39,925</td>
<td>109</td>
</tr>
<tr>
<td>09-25-85-06W4 GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>09-Oct-14</td>
<td>5,130</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1101308505W400</td>
<td>McMurray</td>
<td>Y</td>
<td>18-Feb-07</td>
<td>38,200</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1112908406W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>8,000</td>
<td>11,264</td>
<td>31</td>
</tr>
<tr>
<td>11-29-84-06W4 GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>5,700</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1143508407W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>29,000</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1152808505W400</td>
<td>McMurray</td>
<td>Y</td>
<td>14-Feb-07</td>
<td>42,200</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1162708407W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>16-Oct-14</td>
<td>23,000</td>
<td>163</td>
<td>0</td>
</tr>
<tr>
<td>1F1162508407W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>15,000</td>
<td>1,388</td>
<td>4</td>
</tr>
<tr>
<td>1F1163008406W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>6,200</td>
<td>9,465</td>
<td>26</td>
</tr>
<tr>
<td>06-08-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>19-Dec-12</td>
<td>2,000</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1112808406W400</td>
<td>Clearwater</td>
<td>N</td>
<td>30-May-13</td>
<td>2,900</td>
<td>20</td>
<td>0</td>
</tr>
<tr>
<td>11-32-84-06W4M GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>09-Sept-14</td>
<td>4,360</td>
<td>1,095</td>
<td>3</td>
</tr>
<tr>
<td>16-25-84-07W4 GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>19-Dec-12</td>
<td>2,400</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>16-27-84-07W4 GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>07-Aug-14</td>
<td>1,940</td>
<td>2,288</td>
<td>6</td>
</tr>
</tbody>
</table>

**Subtotal Saline Diverted Volume**: 92,721 m³ / 253 m³/cd

<table>
<thead>
<tr>
<th>Location</th>
<th>Formation</th>
<th>Saline?</th>
<th>Sample Date</th>
<th>Concentration (mg/L)</th>
<th>Total (m³)</th>
<th>Annual avg. (m³/cd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>06-08-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>19-Dec-12</td>
<td>2,000</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1112808406W400</td>
<td>Clearwater</td>
<td>N</td>
<td>30-May-13</td>
<td>2,900</td>
<td>20</td>
<td>0</td>
</tr>
<tr>
<td>11-32-84-06W4M GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>09-Sept-14</td>
<td>4,360</td>
<td>1,095</td>
<td>3</td>
</tr>
<tr>
<td>16-25-84-07W4 GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>19-Dec-12</td>
<td>2,400</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>16-27-84-07W4 GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>07-Aug-14</td>
<td>1,940</td>
<td>2,288</td>
<td>6</td>
</tr>
</tbody>
</table>

**Subtotal Fresh Diverted Volume**: 3,403 m³ / 9 m³/cd

**TOTAL VOLUME DIVERTED**: 96,125 m³ / 263 m³/cd

- 19 wells tied in.
- 5 fresh wells tied into saline pipeline (SAGD startup, plant upsets, feed to HQWS).
- Isolation valves are installed on freshwater wells on the saline water pipeline.
Fresh Water Source Wells Water Quality TDS
Saline Source Wells Water Quality TDS

Saline wells sampled if diversion criteria are met: > 10,000 m³/year
Other Water Sources

• Surface runoff to lime sludge ponds (00247843-00-00)
  – 2014: 201,725 m³ (estimate)

• Corehole and SAGD drilling
  – Various TDLs: 102,128 m³ in 2014
    • Includes volumes from WS Q 03-36-084-07W4: 1,390 m³ in 2014
    • Estimate includes 100% of water used in 2014 calendar year
Water Make-up

- Use of freshwater make-up (in decreasing amounts)
  1. Demineralized water make-up (UPG and cogens)
  2. Utility and plant use (UPG and SAGD)
  3. SAGD steam make-up (HLS's)
  4. Potable
  5. Others (incl. drilling)

<table>
<thead>
<tr>
<th>Freshwater Uses in 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>total</td>
</tr>
<tr>
<td>---------</td>
</tr>
<tr>
<td>main groundwater license (235895)</td>
</tr>
<tr>
<td>Surface runoff to ponds</td>
</tr>
<tr>
<td>SAGD drilling</td>
</tr>
<tr>
<td>Winter drilling program (Long Lake and Kinosis)</td>
</tr>
<tr>
<td>Potable trucked to Long Lake</td>
</tr>
<tr>
<td>TOTAL</td>
</tr>
</tbody>
</table>

- Saline water make-up:
  99,777 m³ in 2014 for steam make-up (HLS's)
Water Management Metrics

**WATER RECYCLE**

- **RECYCLE %** \[
\frac{\text{[steam injection to the reservoir – freshwater portion of that steam injection]}}{\text{(produced water from the reservoir)}} \times 100
\]

- 2014 recycle rate: 76.4%

- Small amounts of freshwater to SAGD for steam generation.
- Continued implementation of water conservation practices.
- Reservoir gains correlate with recycle rate.
- Nexen is committed to prudent water use and to achieving the highest water recycle rate practical.

**WATER DISPOSAL**

- **Disposal limit (%)** \[
\frac{[(\text{Freshwater In} \times 0.03) + (\text{Brackish water In} \times 0.35) + (\text{Produced water In} \times 0.1)]}{\text{[(Freshwater In) + (Brackish water In) + (Produced water In)]}} \times 100
\]

- Disposal limit = 9%
- 2014 disposal rate = 10.4%
- Nexen’s disposal rate includes freshwater demand to the upgrader

**WATER TO STEAM RATIO (WSR)**

- 2014 WSR = 1.11; monthly WSR ranged from 1.06 to 1.16
Disposal Wells

Class 1b Wells (6)

Class 1a Wells (2) suspended in 2015

K1A McM disposal well 14-32 license approved

K1A McM disposal well 11-28 license approved (conditions)

LLK backup KR disposal well 9-28 license approved

McM disposal well 1-21 suspended

KR disposal well 11-28 license approved (conditions)

Kinosis KR disposal well drilled in 2014

Withdrawn
### Disposal Wells (CONT’D)

<table>
<thead>
<tr>
<th>Approval # 10023F</th>
<th>Class 1b</th>
<th>January - December 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disposal Well</td>
<td>Total (m³)</td>
<td>Annual avg. (m³/cd)</td>
</tr>
<tr>
<td>103/09-28-085-06W4 KR</td>
<td>Blowdown</td>
<td>682,411</td>
</tr>
<tr>
<td>100/09-28-085-06W4 McM</td>
<td>Blowdown</td>
<td>544,817</td>
</tr>
<tr>
<td>100/01-21-085-06W4 McM*</td>
<td>Blowdown</td>
<td>0</td>
</tr>
<tr>
<td>100/04-22-085-06W4 McM</td>
<td>Blowdown</td>
<td>25,531</td>
</tr>
<tr>
<td>100/11-32-084-06W4 McM</td>
<td>Blowdown</td>
<td>25,129</td>
</tr>
<tr>
<td>100/14-32-084-06W4 McM</td>
<td>Blowdown</td>
<td>0</td>
</tr>
<tr>
<td>100/11-28-084-06W4/00 KR</td>
<td>Drilling fluids</td>
<td>8,160</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td>1,286,048</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Approval # 11611</th>
<th>Class 1a</th>
<th>January - December 2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disposal Well</td>
<td>Total (m³)</td>
<td>Annual avg. (m³/cd)</td>
</tr>
<tr>
<td>100/06-16-085-06W4 KR**</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>100/05-16-085-06W4 McM**</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td>0</td>
</tr>
</tbody>
</table>

*Well is suspended
**Well is suspended in 2015

- Reservoirs (McMurray and Keg River) performing well
- Average temperature of disposal water is ~50°C
- All wells passed annulus pressure test
Disposal Well Volumes

Long Lake and K1A Class 1b - Daily Disposal Volumes

Increase in K1A circulation steam demand
Disposal Well - Well Head Pressures

AER maximum wellhead pressures (3000 - 3950 kPag)
Sulphur Recovery
• The Long Lake sour gas processing system is located in the Upgrader area but is an integrated facility for treating sour gas produced from both the SAGD CPF and Upgrader. There are six subsystems in this unit:

1. **Amine Regeneration Subsystem**
   • The Amine Regeneration Subsystem is designed to remove H2S and CO2 from rich amine and produce lean amine for re-use in the OrCrudeTM, Hydrocracker Unit, AGU, SRU Subsystem, and SAGD;

2. **Selexol Regeneration Subsystem**
   • The Selexol Regeneration Subsystem is designed to remove H2S and CO2 from rich Selexol and produce lean Selexol for re-use in the Selexol Absorbing System;

3. **Sour Water Stripping Subsystem**
   • The Sour Water Stripping Subsystem is designed to strip H2S and NH3 from sour water coming from the OrCrudeTM, Hydrocracker Unit, AGU, and the SRU Subsystem. Stripped water is returned to the SAGD CPF and Upgrader for re-use and the acid gas exiting this system flows to the SRU subsystem;
4. SRU Subsystem
   • The SRU Subsystem converts sulphur contaminants (mainly H2S) flowing from the Amine Regeneration, Selexol Regeneration, and Sour Water Stripping Subsystems into liquid sulphur. The subsystem is also designed to destroy ammonia;

5. Tail Gas Treating Unit (TGTU) Subsystem
   • The TGTU Subsystem is designed to convert any sulphur contaminants in the tail gas flowing from the SRU Subsystem back into H2S so that the H2S can be removed by amine solution in the TGTU Absorber. Any remaining sulphur contaminants in the tail gas are oxidized in the incinerator before it is released to atmosphere; and

6. Miscellaneous Utilities Subsystem
   • The Miscellaneous Utilities Subsystem contains the acid gas flare and associated equipment, a natural gas heater, and various condensate collection drums, condensate blowdowns, flash drums, etc., that are necessary for the operation of the sulphur recovery systems.
The sulphur recovery rate averaged 99.2% during 2014.
- Incinerator Stack Quarterly Average SO₂ Limit = 15.6 tonnes per day
- Plant Annual Average SO₂ Limit = 18.42 tonnes per day
- 2014 Average SO₂ well below limits

### 2014 SO₂ Emissions (tonnes)

<table>
<thead>
<tr>
<th></th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
<th>Sep</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>FLARE</strong> SAGD</td>
<td>0.160</td>
<td>0.086</td>
<td>0.125</td>
<td>0.200</td>
<td>0.098</td>
<td>0.106</td>
<td>0.100</td>
<td>0.113</td>
<td>0.048</td>
<td>0.027</td>
<td>0.271</td>
<td>0.198</td>
<td>1.532</td>
</tr>
<tr>
<td><strong>SRU Incinerator Stack</strong></td>
<td>40.570</td>
<td>28.810</td>
<td>58.120</td>
<td>64.850</td>
<td>22.320</td>
<td>35.910</td>
<td>75.920</td>
<td>42.310</td>
<td>58.530</td>
<td>26.670</td>
<td>24.530</td>
<td>72.370</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Total (tonnes)</th>
<th>Average (tonnes/day)</th>
<th>Limit (tonnes/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Plant Annual Average</strong></td>
<td>ALL</td>
<td>2329.264</td>
<td>6.382</td>
</tr>
<tr>
<td>1st</td>
<td>127.500</td>
<td>1.397</td>
<td></td>
</tr>
<tr>
<td>2nd</td>
<td>123.080</td>
<td>1.349</td>
<td></td>
</tr>
<tr>
<td>3rd</td>
<td>176.760</td>
<td>1.937</td>
<td></td>
</tr>
<tr>
<td>4th</td>
<td>123.570</td>
<td>1.354</td>
<td></td>
</tr>
<tr>
<td><strong>SRU Incinerator Stack</strong></td>
<td>15.6</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Grand Total: 261.300 146.536 314.635 127.253 83.478 118.654 622.590 117.934 93.328 71.767 142.671 229.118 2329.264
# Sulphur Recovery Rates and Unit Uptimes

<table>
<thead>
<tr>
<th>Items</th>
<th>Jan-14</th>
<th>Feb-14</th>
<th>Mar-14</th>
<th>Apr-14</th>
<th>May-14</th>
<th>Jun-14</th>
<th>Jul-14</th>
<th>Aug-14</th>
<th>Sep-14</th>
<th>Oct-14</th>
<th>Nov-14</th>
<th>Dec-14</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>Claus Units</td>
<td>% of Month Processing AG</td>
<td>90.6%</td>
<td>100.0%</td>
<td>80.8%</td>
<td>95.2%</td>
<td>100.0%</td>
<td>94.0%</td>
<td>92.2%</td>
<td>85.3%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>94.8%</td>
</tr>
<tr>
<td>Sulphur Recovery</td>
<td>Monthly Recovery Rate (%)</td>
<td>99.6%</td>
<td>99.9%</td>
<td>98.8%</td>
<td>99.7%</td>
<td>99.9%</td>
<td>99.8%</td>
<td>96.4%</td>
<td>99.6%</td>
<td>99.7%</td>
<td>99.9%</td>
<td>99.9%</td>
<td>99.4%</td>
</tr>
<tr>
<td></td>
<td>Quarterly Recovery Rate (%)</td>
<td>99.5%</td>
<td>99.8%</td>
<td>98.6%</td>
<td>99.8%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Average Inlet Sulphur (Tonnes/day)</td>
<td>286.8</td>
<td>415.2</td>
<td>283.3</td>
<td>382.8</td>
<td>396.9</td>
<td>374.4</td>
<td>253.8</td>
<td>241.7</td>
<td>318.5</td>
<td>381.4</td>
<td>371.1</td>
<td>367.9</td>
</tr>
<tr>
<td></td>
<td>Average Monthly Sulphur Production (Tonnes/day)</td>
<td>285.6</td>
<td>414.6</td>
<td>279.8</td>
<td>381.6</td>
<td>396.5</td>
<td>373.5</td>
<td>244.6</td>
<td>240.8</td>
<td>317.5</td>
<td>381.0</td>
<td>370.7</td>
<td>366.7</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Month</th>
<th>% Time TGTU in Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-14</td>
<td>90.4%</td>
</tr>
<tr>
<td>Feb-14</td>
<td>100.0%</td>
</tr>
<tr>
<td>Mar-14</td>
<td>80.1%</td>
</tr>
<tr>
<td>Apr-14</td>
<td>92.2%</td>
</tr>
<tr>
<td>May-14</td>
<td>100.0%</td>
</tr>
<tr>
<td>Jun-14</td>
<td>93.8%</td>
</tr>
<tr>
<td>Jul-14</td>
<td>89.6%</td>
</tr>
<tr>
<td>Aug-14</td>
<td>84.1%</td>
</tr>
<tr>
<td>Sep-14</td>
<td>100.0%</td>
</tr>
<tr>
<td>Oct-14</td>
<td>100.0%</td>
</tr>
<tr>
<td>Nov-14</td>
<td>100.0%</td>
</tr>
<tr>
<td>Dec-14</td>
<td>100.0%</td>
</tr>
</tbody>
</table>
Acid Gas Flare Events Summary

<table>
<thead>
<tr>
<th>Month</th>
<th>AG Sources</th>
<th>SWAG Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Duration (h)</td>
<td>Volume (Sm3)</td>
</tr>
<tr>
<td>January</td>
<td>72.1</td>
<td>9510</td>
</tr>
<tr>
<td>February</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>March</td>
<td>149.4</td>
<td>97454</td>
</tr>
<tr>
<td>April</td>
<td>35.7</td>
<td>3487</td>
</tr>
<tr>
<td>May</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>June</td>
<td>45.9</td>
<td>9623</td>
</tr>
<tr>
<td>July</td>
<td>71.6</td>
<td>25790</td>
</tr>
<tr>
<td>August</td>
<td>120.0</td>
<td>11808</td>
</tr>
<tr>
<td>September</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>October</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>November</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>December</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>2014 Total</td>
<td>494.6</td>
<td>157672</td>
</tr>
</tbody>
</table>

Note: SWAG - Sour Water Acid Gas
AG - Acid Gas

- Total SO₂ flaring for 2014 was 720.9 tonnes.
- Acid Gas Flaring Events are part of the monthly report submitted to Alberta Environment and Sustainable Resource Development (AESRD).
- The leading cause for the major flaring events in 2014 was due to unplanned Upgrader trips and restarts.
Regulatory Compliance and Environmental Performance
Regulatory Compliance

- **Inspections:**
  - February 13, 2014 Follow-up to the Pad 14/15 pipeline failure
  - March 5, 2014 Follow-up to a spill reported by Nexen in the DRU
  - March 5, 2014 Follow-up to a uncontrolled run-off spill and Pad 14 flow line
  - August 15, 2014 Follow-up to the Pad 14/15 pipeline failure
  - August 15, 2014 Follow-up to the Pad 14/15 pipeline failure subsequent spill
  - December 20, 2014 Follow-up inspection in response to odour complaints from Anzac
  - December 22, 2014 Follow-up inspection in response to a spill/release incident which occurred on November 24 (fresh water line failure)

- **Compliance Actions:**
  - No compliance actions in 2014
Compliance Continued

- **Voluntary Self Disclosures:**
  - **May 15, 2014**
    - Nexen did not complete a DDS notification 48 hours prior to hydrotesting two pipelines as part of the commissioning activities for the Kinosis lease. Corrective action – Nexen informed AER of the event prior to activity and conducted additional education for staff.
  - **June 1, 2014**
    - Nexen reported to the AER an incident in which a hydrostatic pressure test of a new 14" steam pipeline resulted in the release of water into a containment tray. No release into the environment.
  - **August 15, 2014**
    - Nexen notified the AER of a downhole pressure exceedance in the toe producer of 14P03. Corrective action – steam injection decreased, alarms set on production well pressure.
Compliance Continued

- **Voluntary Self Disclosures Continued**
  - September 2, 2014
    - Nexen notified the Alberta Department of Energy and the AER of a penetration of Devonian mineral rights that occurred during the 2014 infill drilling program while drilling well 102/15-25-085-07W4. Alberta Energy waived the fine for trespass on the basis of complex geology. AER confirmed the matter was brought into compliance.
  - September 9, 2014
    - Nexen notified the Alberta Department of Energy and the AER of a penetration of Devonian mineral rights that occurred during the 2014 infill drilling program while drilling well 104/15-25-085-07W4/0. Alberta Energy waived the fine for trespass on the basis of complex geology. AER confirmed the matter was brought into compliance.
  - December 4, 2014
    - Nexen notified the AER of a downhole pressure exceedance in 15P02 producer. Corrective action—new procedure to reduce freezing of pressure gauges, redundant alarms set on injection and producer pressures.
AER Scheme Approval

• **Amendments received in 2014:**
  – Pad 11 Producer 10 Wellbore Re-entry – approved January 17, 2014
  – Pad 14/15 Monitoring Program – approved January 23, 2014
  – Well compatibility Pad 1& 2 at K1A – approved January 23, 2014
  – Gas Re-Pressurization Project at K2 – approved February 25, 2014
  – Pads 16, 17 and 18 – approved March 12, 2014
  – Long Lake Pad 7N Infill – approved May 16, 2014
  – Field Trial Co-Injection of NCG with Steam at Pat 7N – approved May 29, 2014
  – Field Trial Co-Injection of NCG with Steam at Pat 11 – approved May 29, 2014
  – Kinosis Phase 1A - Well Compatibility Update – approved July 24, 2014
  – Trial Solvent Enhanced Circulation at Kinosis K1A – approved August 5, 2014
  – Long Lake Diluent Tank Project – approved October 21, 2014
  – Revised Gregoire Channel Edge Interpretation – approved February 26, 2014
  – Diluent Tank Project – approved October 21, 2014

• **Applications in review:**
  – Pad 19
Environmental Reportable Incidents

<table>
<thead>
<tr>
<th>PERMIT VIOLATIONS</th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
<th>Sep</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>3</td>
<td>4</td>
<td>6</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>5</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>33</td>
</tr>
<tr>
<td>Projects</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>2</td>
<td>0</td>
<td>0</td>
<td>4</td>
</tr>
<tr>
<td>Total</td>
<td>3</td>
<td>4</td>
<td>7</td>
<td>2</td>
<td>1</td>
<td>0</td>
<td>5</td>
<td>2</td>
<td>2</td>
<td>4</td>
<td>3</td>
<td>4</td>
<td>37</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>SPILLS</th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
<th>Sep</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>2</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>3</td>
<td>2</td>
<td>12</td>
</tr>
<tr>
<td>Projects</td>
<td>1</td>
<td>0</td>
<td>3</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>5</td>
</tr>
<tr>
<td>Total</td>
<td>2</td>
<td>0</td>
<td>4</td>
<td>0</td>
<td>0</td>
<td>2</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>2</td>
<td>17</td>
</tr>
</tbody>
</table>

- During 2014 Long Lake and K1A had a total of 37 permit violations and 17 reportable spills previously reported to the AER.
- There was a significant decline in 2014 (37) as compared to 2013 (97) for total permit violations and this is largely due to the creation of a tool for control room operators to identify any potential risk of violating the limits and make changes in the process to eliminate that risk.
<table>
<thead>
<tr>
<th>Material Released</th>
<th>Quantity (m3)</th>
<th>Brief Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water - Supernatant</td>
<td>3</td>
<td>Supernatant was spilled when the hose on the trash pump to the brackish header failed.</td>
</tr>
<tr>
<td>Magnesium Oxide</td>
<td>5</td>
<td>Faulty level transmitter caused Magox Slurry tank to overflow.</td>
</tr>
<tr>
<td>Diesel Fuel</td>
<td>1.2</td>
<td>400 bbl tank set up near Pad 10 had diesel soaking in the bottom of the tank, diesel leaked from a manway that was not secured properly resulting in diesel being spilled</td>
</tr>
<tr>
<td>Water - Boiler Feed</td>
<td>19</td>
<td>A Pressure Safety Valve related to two Boiler Feedwater Coolers (8300-E001-A/B) released 19m3 of boiler Feedwater. Approximately 17m3 overflowed secondary containment and was captured by the onsite collection system and diverted to the Lime Sludge Pond.</td>
</tr>
<tr>
<td>Oil &amp; Water Emulsion</td>
<td>3</td>
<td>Process Oily Water spill at Encanex centrifuge</td>
</tr>
<tr>
<td>Water - Boiler Feed</td>
<td>5</td>
<td>PSV on 8300-E-001 lifted and overflowed the containment, spilling boiler Feedwater on the ground</td>
</tr>
<tr>
<td>Water - Utility</td>
<td>17.1</td>
<td>WS-6-31 Brackish water well found with passing valve and leaking gasket on flange.</td>
</tr>
<tr>
<td>Diesel Fuel</td>
<td>0.513</td>
<td>Contractor forgot to close the air bleed valve of a fuel truck after purging the hose. When he resumed filling the second tank the diesel came out of the bleed line and flowed down the diesel tank.</td>
</tr>
<tr>
<td>Water - Boiler Feed</td>
<td>9.375</td>
<td>Heat tracing failure on HLS-C sample line caused the pipe to freeze and a gasket to leak.</td>
</tr>
<tr>
<td>Water - Boiler Feed</td>
<td>12</td>
<td>Overflow at Encanex centrifuge while worker was filling polymer mix tank.</td>
</tr>
<tr>
<td>Water - fresh groundwater</td>
<td>1425.6</td>
<td>Water was found bubbling up from the ground near water source well lines at plant boundary. Break was discovered after investigation.</td>
</tr>
<tr>
<td>Water - Produced</td>
<td>8</td>
<td>During a WAC Regen, water was found flowing out of the nitrogen vent.</td>
</tr>
</tbody>
</table>
# Reportable Spill Summary

## Project Development and Execution

<table>
<thead>
<tr>
<th>Material Released</th>
<th>Quantity (m3)</th>
<th>Brief Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil &amp; Water Emulsion</td>
<td>7</td>
<td>During steam heating of ruptured line, 7m3 of oily water was released to ground.</td>
</tr>
<tr>
<td>Propane</td>
<td>0.12</td>
<td>Propane tank shifted from thawing ground conditions and caused a supply line to crack and release approximately 120L of propane for 30-60min into the atmosphere.</td>
</tr>
<tr>
<td>Hydraulic Fluid (mineral based)</td>
<td>0.01</td>
<td>While checking on the overflow pond on pad, employee noticed a puddle of hydraulic oil on the ground which in turn spilled on the surface of the pond. (Approximately 10L). Reported to AER based on adverse effect to surrounding run-off water.</td>
</tr>
<tr>
<td>Oil &amp; Water Emulsion</td>
<td>2.5</td>
<td>Release of 5 m3 of produced fluid due to circulation valve failure in SUS building</td>
</tr>
<tr>
<td>Water - Steam Condensate</td>
<td>13</td>
<td>13m3 of LP Condensate and 20m3 of Concentrated Blowdown from the LP Steam Condensate Drum spilled to the ground and migrated into the storm water pond due to a leaking 6” valve.</td>
</tr>
<tr>
<td>Water - Boiler Blowdown</td>
<td>20</td>
<td></td>
</tr>
</tbody>
</table>
Permit Violation Summary

- There were 17 hours (some during the same reportable event) during 2014 where stack approval limits were found to be exceeded based upon values measured by the CEMS units. These hours are summarized in the following table:

<table>
<thead>
<tr>
<th></th>
<th>OTSG C</th>
<th>OTSG E</th>
<th>Cogen 1</th>
<th>Cogen 2</th>
<th>Boiler A</th>
<th>Boiler B</th>
<th>SRU</th>
<th>SRU</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NOx</td>
<td>NOx</td>
<td>NOx</td>
<td>NOx</td>
<td>NOx</td>
<td>NOx</td>
<td>SO2</td>
<td>Temperature</td>
</tr>
<tr>
<td>January</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>6</td>
</tr>
<tr>
<td>February</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>2</td>
<td>0</td>
<td>0</td>
<td>2</td>
</tr>
<tr>
<td>March</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>2</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>April</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>May</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>June</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>July</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>August</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>September</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>October</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>November</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>December</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>4</td>
<td>0</td>
<td>10</td>
</tr>
</tbody>
</table>

- The permit violations can commonly be attributed to stack temperature excursions in the SRU and NOx exceedances in Boiler B.
Continuous Air Monitoring

- The Long Lake continuous air monitoring station is located approximately 35 km southeast of Fort McMurray on the northern edge of the hamlet of Anzac and is operated by the Wood Buffalo Environmental Association.
- The Anzac Station contains analyzers that continuously measures SO$_2$, O$_3$, TRS, THC, NO, NO$_2$, NO$_X$, PM 2.5, wind speed and direction, and temperature.
- There were 4 events that exceeded the Alberta Ambient Air Quality Objectives (AAAQO). All of the events described below were attributed to the forest fires that were burning in the region at that time and did not require follow-up reports.

<table>
<thead>
<tr>
<th>Date</th>
<th>Parameter</th>
<th>Concentration</th>
<th>Limit</th>
<th>AER Ref #</th>
</tr>
</thead>
<tbody>
<tr>
<td>July 20, 2014</td>
<td>PM 2.5</td>
<td>40 µg/m³</td>
<td>30 µg/m³</td>
<td>521043</td>
</tr>
<tr>
<td>July 21, 2014</td>
<td>PM 2.5</td>
<td>34 µg/m³</td>
<td>30 µg/m³</td>
<td>287108</td>
</tr>
<tr>
<td>July 22, 2014</td>
<td>PM 2.5</td>
<td>32 µg/m³</td>
<td>24 hr avg</td>
<td>287170</td>
</tr>
<tr>
<td>August 5, 2014</td>
<td>PM 2.5</td>
<td>66 µg/m³</td>
<td>24 hr avg</td>
<td>287894</td>
</tr>
</tbody>
</table>
# Passive Air Monitoring Station Summary

<table>
<thead>
<tr>
<th>Station Number</th>
<th>Station Location</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>SAGD Pilot Site SE- near Pilot flare stack</td>
<td>Discontinued in December 2010</td>
</tr>
<tr>
<td>2</td>
<td>SAGD Pilot Site NW Rear of the Pilot</td>
<td>Discontinued in December 2010</td>
</tr>
<tr>
<td>3</td>
<td>02-32-085-06 W4M Source Well</td>
<td>Active</td>
</tr>
<tr>
<td>4*</td>
<td>01-21-085-06 W4M Source Well</td>
<td>Active</td>
</tr>
<tr>
<td>5</td>
<td>13-31-085-06 W4M Source Well</td>
<td>Active</td>
</tr>
<tr>
<td>6</td>
<td>Nexen Tower</td>
<td>Active</td>
</tr>
<tr>
<td>7</td>
<td>Well Pad 9</td>
<td>Discontinued in January 2010</td>
</tr>
<tr>
<td>8</td>
<td>Well Pad 7</td>
<td>Active</td>
</tr>
<tr>
<td>9</td>
<td>Electrical Substation</td>
<td>Discontinued in December 2010</td>
</tr>
<tr>
<td>10</td>
<td>Beside Tankyard</td>
<td>Discontinued in December 2010</td>
</tr>
<tr>
<td>11*</td>
<td>Kinosis Drilling Camp</td>
<td>Active</td>
</tr>
<tr>
<td>12</td>
<td>Anzac</td>
<td>Active</td>
</tr>
<tr>
<td>13</td>
<td>Gregoire Estates</td>
<td>Active</td>
</tr>
<tr>
<td>14</td>
<td>Mark Amy Centre</td>
<td>Active</td>
</tr>
<tr>
<td>15</td>
<td>Well Pad 11</td>
<td>Active</td>
</tr>
<tr>
<td>16</td>
<td>Sucker Lake</td>
<td>Active</td>
</tr>
<tr>
<td>17</td>
<td>Long Lake Sign</td>
<td>Active</td>
</tr>
<tr>
<td>18</td>
<td>02-12-85-06 W4M Source Well</td>
<td>Discontinued in May 2014</td>
</tr>
<tr>
<td>19*</td>
<td>K1A Camp</td>
<td>Active as of June 2014</td>
</tr>
<tr>
<td>20*</td>
<td>K1A Pad 1</td>
<td>Active as of June 2014</td>
</tr>
<tr>
<td>21*</td>
<td>Surerus Laydown</td>
<td>Active as of June 2014</td>
</tr>
</tbody>
</table>

* K1A Passive Stations
The AAAQ Guidelines set out by AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3ppbv.
• The AAAQ Guidelines set out by AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3ppbv.
The AAAQ Guidelines set out by AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3ppbv.
• The AAAQ Guidelines set out by AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3ppbv.
Waste Disposal

2014 Waste Summary

- **Hazardous Waste**
  - Soot: 36110 tonnes
  - Centrifuge Solids: 4614 tonnes
  - Bin Waste: 1107 tonnes
  - Slop Oil: 16957 tonnes
  - Total: 58788 tonnes

- **Non-Hazardous Waste**
  - Domestic Waste and Recycling: 2312 tonnes
  - Class II Landfill waste: 7178 tonnes
  - Total: 9490 tonnes

**Grand Total**: 68278 tonnes
Environmental Summary
Operational Initiatives

• Provided environmental event investigation and analysis support, which increased operation personnel’s understanding of regulatory requirements and event causes.

• A change to Teflon gaskets to reduce potential odour issues
  – An investigation found tank PRV’s and PVSV’s wisping and repairs were initiated
  – The root cause analysis of the high frequency of failures determined that the gasket material on the PRVs was not compatible with naphtha
  – Nexen had been using both Naphtha and PSC as diluent and the standard had not been updated when Nexen switched to 100% naphtha diluent
  – Teflon will be used in all on-going repairs and during the 2015 Turnaround Nexen will change out every gasket regardless of integrity

• Began shutting down the Sour Water Systems after Upgrader upsets or trips to reduce the amount of Sour Water Acid Gas sent to the flare. This action is only implemented from April to October when ambient temperature are above -5°C. A number of exceedances have been prevented with this action.
Environmental Summary
Monitoring Programs

• Conducted in accordance with regulatory approvals:
  – Groundwater monitoring
  – Hydrology and water quality monitoring
  – Soil monitoring
  – Wildlife monitoring
  – Wetland monitoring
  – Source emission and ambient air monitoring
  – Conservation and reclamation plans

• Funded the regional Joint Oil Sands Monitoring (JOSM)

• Participation in regional stakeholder committees:
  – Cumulative Environmental Management Association (CEMA)
  – Participation in the Wood Buffalo Environmental Association (WBEA)
  – Regional Aquatics Monitoring Program (RAMP)
Environmental Summary
Innovation, Research and Reclamation Initiatives

• Continued leadership in Canada’s Oil Sands Innovation Alliance (COSIA) to accelerate the pace of environmental performance improvement.
  – Participation in the Land, Water, and Greenhouse Gas Environmental Priority Environmental Priority Areas as well as the Monitoring working Group.
  – Leading multiple Joint Industry Projects including caribou habitat restoration, reclamation practice studies, and wildlife monitoring technologies.

• The Algar Restoration Pilot Project, a Nexen-led project through COSIA, won the Emerald Awards’ Shared Footprints Award.
  – The project represents a collaboration between six oil sands companies, the province of Alberta and the local forestry industry and is actively restoring important caribou habitat.
Future Plans
Future Plans

- 2015 Turnaround
- Permanent lime centrifuge scheduled for installation and commissioning in second half of 2015
- Diluent Recovery Project (DRU) Start-up
Purpose

This presentation contains information to comply with:

AER Scheme Approval No. 9485 (as amended)
Approval Condition No. 20

1. Discuss product yields and qualities and energy efficiency as compared with the design expectation
2. Results of any studies undertaken to identify opportunities for improved yield and energy efficiency
3. Description of any modifications made to improve yield and energy efficiency
4. Schedule to add facilities to convert the upgrader product (A-fuel) to sweet syngas for use as a replacement for natural gas in the Scheme.
5. Performance of the A-fuel gasification facilities and comparison with design expectations.
Background

• Long Lake is an integrated oil sands project and the first to combine a Steam Assisted Gravity Drainage (SAGD) scheme for the production of bitumen from the Wabiskaw-McMurray deposit with an Upgrader.

• Long Lake is located approximately 40 km southeast of Fort McMurray in the Athabasca Oil Sands.
Nexen Oil Sands Leases
DRU Plot Plan
Integration between SAGD and Upgrader
Long Lake Upgrader and Central Processing Facility
2013 & 2014 Summary of Upgrader Performance

• Priority in 2013 and 2014 were to:
  – Increase reliability of the Upgrader
  – Standardize monitoring tools to help analyze failures (Meridium)
• Fewer upsets = fewer incidents and odor complaints
• Zero Based Analysis of our failures has changed our perception of what is important and where to focus our energy.
• Annual production rates increased over the previous reporting period, but full capacity has not yet been reached
• Scheduled and executed outages to improve reliability through repairs, upgrades and redundancy.
Product Yields

• The design yield objective for the Upgrader is 79% to 83% (original regulatory application, OPTI 2000), dependent on feed quality
  – Yield determined by (SCO production - Diluent for further processing) / Bitumen for further processing
• The average yield achieved over 2013 & 2014 was 73%
Monthly Product Yields

<table>
<thead>
<tr>
<th></th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>Jun</th>
<th>Jul</th>
<th>Aug</th>
<th>Sept</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>2013 Instantaneous</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Balanced Yield</td>
<td>62%</td>
<td>70%</td>
<td>73%</td>
<td>76%</td>
<td>72%</td>
<td>71%</td>
<td>72%</td>
<td>69%</td>
<td>69%</td>
<td>75%</td>
<td>75%</td>
<td>75%</td>
</tr>
<tr>
<td><strong>2014 Instantaneous</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Balanced Yield</td>
<td>74%</td>
<td>73%</td>
<td>73%</td>
<td>74%</td>
<td>76%</td>
<td>76%</td>
<td>73%</td>
<td>77%</td>
<td>74%</td>
<td>74%</td>
<td>75%</td>
<td>72%</td>
</tr>
</tbody>
</table>

- The yield is determined from S-23 Manual calculations and is further described in the Long Lake Upgrader’s Bi-Annual Report of Operations.
- Lower yields were realized during 2013 due to unscheduled shutdowns of the Solvent De-Ashphaltene Unit for issues such as pump failures and water entrainment caused by level instrument malfunction.
Initiatives to Improve Yield & Energy Efficiency

• Reliability initiatives such as:
  – Vacuum tower study
  – Installed upgraded valves and redundant instrumentation in the PSA to help improve reliability of Hydrogen production
  – Converter bed catalyst in the SRU was replaced with metal traps in order to capture undesirable deposits, keep the differential pressure across the beds under control and extend the run lengths from 10 to 12 months to at least 18 months.
  – Initiated a project to increase the feed processing capacity of each Gasifier train so that at nameplate capacity, Nexen can still operate with 3 Gasifiers, allowing flexibility for maintenance
  – Installing key redundant transmitters to minimize repeat trips
  – Aggressive preventative maintenance program for our Soot handling equipment

• Advance work on Diluent Recovery Unit. Commissioning is expected after 2015 Turnaround.
## Unit Availability

<table>
<thead>
<tr>
<th>Unit</th>
<th>2013 (%)</th>
<th>2014 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>OrCrude™ Unit</td>
<td>99.0</td>
<td>100.0</td>
</tr>
<tr>
<td>Hydrocracker</td>
<td>98.0</td>
<td>99.0</td>
</tr>
<tr>
<td>Air Separation Unit</td>
<td>93.0</td>
<td>99.0</td>
</tr>
<tr>
<td>Asphaltene Gasification Unit</td>
<td>66.0</td>
<td>64.0</td>
</tr>
<tr>
<td>Sulphur Recovery Unit</td>
<td>95.0</td>
<td>100.0</td>
</tr>
<tr>
<td>Utilities &amp; Offsites</td>
<td>100.0</td>
<td>100.0</td>
</tr>
</tbody>
</table>
OrCrude™ Unit

- This area of the operation has been focusing on increasing yield and equipment reliability, specifically pumps.
- In the latter part of 2014 OrCrude™ experienced issues with vacuum tower fouling which will be addressed as part of the 2015 Turnaround.
- Also in TA 2015 the new plant unit (Named DRU) will be commissioned, and additional cleaning and equipment repairs will be completed to allow Nexen to consistently operate until the next planned turnaround in 2016.
Hydrocracker Unit (HCU)

- The operation of the HCU during 2013 and 2014 was oriented to maximizing yield while meeting product specifications for customers and shipping companies. Test runs were performed to optimize HCU catalyst operation and liquid product recovery in the Saturation Gas Plant located downstream of the HCU reactors.
- Low feed rates as compared to design were attributed to low feed rates from the OrCrude™ Unit due to the vacuum tower fouling.
- Reduced Yield was due to low hydrogen availability from the PSA due to mechanical availability of the Pressure Swing Absorption (PSA) plant and Gasifier reliability.
Asphaltene Gasification Unit

- Consists of four identical Gasifier Trains
  - Operating plan is to run at least three units at present bitumen production rates
- Work on Gasifier reliability is ongoing.
  - Nexen has installed upgraded valves and redundant instrumentation to help improve reliability;
    - Work continues as outage schedules dictate until all 4 have been completed.
  - Normal pigging (cleaning of internal piping) is scheduled up to two times per year on each train, depending on the soot fouling of the equipment.
  - Nexen is working on a project to increase the feed processing capacity of each Gasifier train so that at nameplate capacity, Nexen can still operate with 3 Gasifiers, leaving one for maintenance and upgrades. A revised metallurgy is also part of this project to improve on the reliability of the operation.
Ash Processing Unit

- The Ash Processing Unit (APU) is not in operation.
- The soot byproduct from the APU continues to be shipped to Clean Harbours’ landfill in Ryley, AB
  - During this reporting period off-site soot disposal for Nexen amounted to 28577 tonnes in 2013 and 36110 tonnes in 2014.
  - Nexen continues to evaluate other disposal options.
Sulphur Recovery Unit

- The Claus units have been able to run more than 18 months and processed more than four times the acid gas per kilogram of catalyst compared to previous runs after replacing one third of the first converter bed catalyst with metal traps in 2012 Turnaround.

- Modifications to the reaction furnace burners were also implemented in 2012 in order to improve acid gas combustion and reduce particle formation which may reduce sulphur recovery and contribute to fouling.

- Performance evaluations of the Claus units and the Tail Gas Treating Unit (TGTU) were conducted by a third party company. Final reports showed that the activity of the hydrogenation catalyst is decaying and will be replaced during the turnaround in 2016.
Sulphur Recovery

- The average sulphur recovery rates in 2013 and 2014 were 99.4% calculated using the methodology outlined in the S-23 Report as \((\text{Total Produced Sulphur} - \text{Total Sulphur Flared or Wasted})/\text{Total Produced Sulphur}*100\).

- The total sulphur flared or wasted was reduced significantly in 2013 and 2014 compared with 2011 and 2012 performances.

- These results were credited to:
  - A lower number of operational upsets in the Upgrader,
  - Improvements in reaction furnace burners.
  - Installation of metal traps which improves Claus catalyst performance.
  - Developed a software predictor to minimize flaring incidents.
  - Implementation of additional alarms to warn operators.

- Redesign of reaction furnaces mirror walls to ensure proper burner alignment and improvements in acid gas feed quality are key recommendations to further extend run lengths.
### 2013 Sulphur Recovery and Emissions

<table>
<thead>
<tr>
<th></th>
<th>Q1</th>
<th>Q2</th>
<th>Q3</th>
<th>Q4</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sulphur Production (tonnes)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sulphur Produced</td>
<td>26405.8</td>
<td>28029.2</td>
<td>28641.1</td>
<td>33388.1</td>
<td>116464.2</td>
</tr>
<tr>
<td>Sulphur Flared</td>
<td>254.2</td>
<td>190.9</td>
<td>74.9</td>
<td>154.2</td>
<td>674.2</td>
</tr>
<tr>
<td>Sulphur Delivered</td>
<td>23396</td>
<td>30302.2</td>
<td>27034.6</td>
<td>30695.4</td>
<td>111428.2</td>
</tr>
<tr>
<td>Sulphur Recovery %</td>
<td>99.0%</td>
<td>99.3%</td>
<td>99.7%</td>
<td>99.5%</td>
<td>99.4%</td>
</tr>
<tr>
<td>SO₂ Emissions (tonnes)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Incinerator Stack</td>
<td>131.6</td>
<td>140.0</td>
<td>118.2</td>
<td>130.2</td>
<td>520.0</td>
</tr>
<tr>
<td>Total Flare SO₂ Emissions</td>
<td>754.9</td>
<td>396.9</td>
<td>291.3</td>
<td>478.4</td>
<td>1921.6</td>
</tr>
<tr>
<td>Total Power Stack and Boilers</td>
<td>77.7</td>
<td>92.2</td>
<td>8.8</td>
<td>97.8</td>
<td>276.5</td>
</tr>
<tr>
<td>Total SO₂ Emissions</td>
<td>964.2</td>
<td>629.0</td>
<td>418.4</td>
<td>706.4</td>
<td>2718.0</td>
</tr>
</tbody>
</table>

### 2014 Sulphur Recovery and Emissions

<table>
<thead>
<tr>
<th></th>
<th>Q1</th>
<th>Q2</th>
<th>Q3</th>
<th>Q4</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sulphur Production (tonnes)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sulphur Produced</td>
<td>30,136.7</td>
<td>35,657.2</td>
<td>30,528.6</td>
<td>26405.8</td>
<td>122728.3</td>
</tr>
<tr>
<td>Sulphur Flared</td>
<td>160.2</td>
<td>74.10</td>
<td>341.1</td>
<td>61.0</td>
<td>636.4</td>
</tr>
<tr>
<td>Sulphur Delivered</td>
<td>33529.2</td>
<td>35431.6</td>
<td>30254.0</td>
<td>38782.4</td>
<td>137997.2</td>
</tr>
<tr>
<td>Sulphur Recovery %</td>
<td>99.5%</td>
<td>99.8%</td>
<td>98.6%</td>
<td>99.8%</td>
<td>99.4%</td>
</tr>
<tr>
<td>SO₂ Emissions (tonnes)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total Incinerator Stack</td>
<td>127.5</td>
<td>123.1</td>
<td>176.8</td>
<td>123.6</td>
<td>550.9</td>
</tr>
<tr>
<td>Total Flare SO₂ Emissions</td>
<td>407.1</td>
<td>88.1</td>
<td>570.6</td>
<td>226.3</td>
<td>1292.1</td>
</tr>
<tr>
<td>Total Power Stack and Boilers</td>
<td>187.9</td>
<td>117.8</td>
<td>87.0</td>
<td>93.7</td>
<td>486.3</td>
</tr>
<tr>
<td>Total SO₂ Emissions</td>
<td>722.4</td>
<td>329.0</td>
<td>834.4</td>
<td>443.6</td>
<td>2329.4</td>
</tr>
</tbody>
</table>
Future Plans

Continued Focus on improving reliability

• 2015 and 2016 Turnaround.
• Expand the use of Meridian for down time/slowdown tracking.
• Zero Based Analysis of failures & slowdowns (number and severity)
  – Reduction of repeat failures.
  – Reduction of one time failures.
• Improved proactive monitoring program.
• Improved Threat Management tool.