Long Lake Kinosis Oil Sands Project
Annual Performance Presentation
November 15, 2016

This presentation contains information to comply with Alberta Energy
Regulator’s Directive 054 – Performance Presentations, Auditing, and
Surveillance of In Situ Oil Sands Schemes
This document was prepared and submitted pursuant to Alberta regulatory requirements. It contains statements relating to reserves which are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the described reserves exist in the quantities predicted or estimated, and can be profitably produced in the future. There is no certainty that the reserves exist in the quantities predicted or estimated or that it will be commercially viable to produce any portion of the reserves described in this document.
Nexen Energy ULC (Nexen) 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.

Nexen is a wholly-owned subsidiary of the China National Offshore Oil Company (CNOOC) Limited.

Nexen has three principal businesses: conventional oil and gas, oil sands and shale gas.
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Subsurface Operations Related to Resource Evaluation and Recovery
Section 3.1.1
Long Lake Kinosis
Background of Scheme and Recovery Process
Subsection 3.1.1 (1)
Long Lake Kinosis
Long Lake Scheme Description

- Long Lake is located approximately 40 km southeast of Fort McMurray
- An integrated SAGD and Upgrader oil sands project producing from the Wabiskaw-McMurray deposit

<table>
<thead>
<tr>
<th></th>
<th>Design (LLK)</th>
<th></th>
<th>Design (K1A*)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>m$^3$/d</td>
<td>bbl/d</td>
<td>m$^3$/d</td>
<td>bbl/d</td>
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<tr>
<td>Bitumen</td>
<td>11,130</td>
<td>70,000</td>
<td>3,180</td>
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<tr>
<td>Steam</td>
<td>37,000</td>
<td>233,000</td>
<td>9,540</td>
<td>60,000</td>
</tr>
<tr>
<td>SOR</td>
<td></td>
<td>3.3</td>
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<td>3.0</td>
</tr>
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</table>

*K1A – First 20K of 70K which is Phase 1 of Kinosi*
<table>
<thead>
<tr>
<th>Year</th>
<th>Activity</th>
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<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>
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<td>2003 - 2007</td>
<td>Production at the Long Lake SAGD Pilot Plant</td>
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<td>2004</td>
<td>Construction begins for the commercial Long Lake Facility</td>
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<tr>
<td>2006</td>
<td>Regulatory amendments, including Pad 11</td>
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<tr>
<td>2007</td>
<td>Start of commercial bitumen production for the Long Lake Facility</td>
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<tr>
<td>2007</td>
<td>Regulatory submissions for Long Lake South (development of Kinosis lease)</td>
</tr>
<tr>
<td>2009</td>
<td>Regulatory approvals issued for K1A (First 20k bbls of Phase 1 of 2 of Kinosis (formerly 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>
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<tr>
<td>2012</td>
<td>First production from Pads 12 and 13</td>
</tr>
<tr>
<td>2012</td>
<td>Major turnaround for maintenance at Central Processing Facility (CPF) and Upgrader</td>
</tr>
<tr>
<td>2012</td>
<td>Regulatory approvals for Pads 14 and 15 and K1A</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>
<tr>
<td>2015</td>
<td>Diluent Recovery Project Start up and Production at K1A suspended</td>
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</table>
2015 Summary

- K1A wells exhibited strong ramp up and continued to deliver strong performance in first half of 2015
- Long Lake pads continued to deliver strong performance
- A successful year at Long Lake for steam production and Syngas consumption
- Experienced higher than average facility downtime
- Successful Turnaround
- K1A emulsion line leak and issuance of Environmental Protection Order
- Pipeline suspension order
Geology and Geosciences Overview
Subsection 3.1.1 (2)
Long Lake
Stratigraphy

Reservoir: McMurray Fm.

Cap rock: Wabiskaw & Clearwater Fm.
Nexen Facies Codes

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

<table>
<thead>
<tr>
<th>Legend</th>
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</thead>
<tbody>
<tr>
<td><strong>MAP DATA</strong></td>
</tr>
<tr>
<td>- 2014/2015 CORE OBS WELLS</td>
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<tr>
<td>- ZERO BITUMEN EDGE</td>
</tr>
<tr>
<td>- DEVONIAN STRUCTURE CONTOURS (C.I.=10m)</td>
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<tr>
<td>- HORIZONTAL WELL PAD</td>
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<tr>
<td>- LONG LAKE PROJECT AREA</td>
</tr>
<tr>
<td><strong>HORIZONTAL WELL STATUS (PRODUCER)</strong></td>
</tr>
<tr>
<td>- ACTIVE HORIZONTAL</td>
</tr>
<tr>
<td>- DRILLED : PULLED BACK</td>
</tr>
<tr>
<td>- ACTIVE : INFILL HORIZONTAL</td>
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<tr>
<td>- ACTIVE : RE-DRILL HORIZONTAL</td>
</tr>
<tr>
<td>- ACTIVE : NOT PRODUCING - SOLID LINER</td>
</tr>
<tr>
<td>- SUSPENDED</td>
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<tr>
<td>- DEViated WELL PATH (DRILLED)</td>
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<tr>
<td><strong>Q CHANNEL DATA</strong></td>
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<tr>
<td>- Q CHANNEL UNCERTAINTY POLYGON</td>
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<tr>
<td>- Q CHANNEL UNCERTAINTY BUFFER (100m)</td>
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<tr>
<td>- Q CHANNEL UNCERTAINTY BUFFER (150m)</td>
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<tr>
<td>- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET</td>
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<tr>
<td><strong>STRUCTURE EVENTS OVERLAY</strong></td>
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<tr>
<td>- MULTI STAGE COLLAPSE</td>
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<tr>
<td>- PRE McMURRAY COLLAPSE</td>
</tr>
<tr>
<td>- POST McMURRAY COLLAPSE</td>
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<tr>
<td><strong>DEVONIAN STRUCTURE RASTER</strong></td>
</tr>
<tr>
<td>- High : 271.9</td>
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<tr>
<td>- Low : 132.5m</td>
</tr>
</tbody>
</table>
• Relatively flat below current SAGD development areas.
• Lows related to collapse features (karst and dissolution) and erosion.
Long Lake
McMurray Structure

Legend

MAP DATA
- 2014/2015 CORE OBS WELLS
- ZERO BITUMEN EDGE
- McMURRAY STRUCTURE CONTOURS (C.I.=5m)
- 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

McMURRAY STRUCTURE
- High : 337.5
- Low : 242.0 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
• 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 result in differential compaction
- Influenced by Devonian salt collapse
Geology and Geosciences
Pay and Exploitable Bitumen-in-Place Mapping Methodology
Subsection 3.1.1 (2)
Long Lake
### 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/SBIP Pay Interval:**
  - Single shale interval ($>30\% V_{\text{shale}}$) of 2m
  - Cumulative shale interval ($>30\% V_{\text{shale}}$) of 4m

- **Base of SBIP Pay Interval:**
  - Base of bitumen pay/reservoir rock

- **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/SBIP Pay Interval**
  - Gas identified by neutron/density crossover

- **High Water Saturation Interval(s) Associated with EBIP/SBIP 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
- $3 \text{ m}^3/\text{m}^2$ EBIP HPVH = 12m EBIP Pay Interval
Pay and Bitumen-in-Place Mapping Methodology

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

- Primary zone defined as the thickest pay interval unless:
  - an existing (or planned) horizontal 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.
Producer Vertical Depth

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 adjacent 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 (including Long Lake SW) Development Area EBIP

Long Lake EBIP (E^6m^3) 119

Nexen Cutoffs: h > 12 m or HPVH > 3 m
Hydrocarbon Pore Volume Height

\[ \text{HPVH} = \sum (S_o \times \Phi) \]

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 %
- \( V_{\text{shale}} \) 10.1 %
- Permeability – Historical Plug Data
  - \( K_{\text{max}} \) 5565 mD
  - \( K_{\text{vert}} \) 4491 mD
- Effective Water Saturation 31.2 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure: ~1000 - 1100kPa @ 230m AMSL

Effective porosity, effective water saturation, and \( V_{\text{shale}} \) are calculated every 10 cm over the EBIP interval, and the average is derived.
Hydrocarbon Pore Volume Height (HPVH) is calculated from petrophysical logs calibrated to Dean Stark analysis.
Long Lake
SBIP Pay Interval Isopach

Legend
- SBIP ISOPACH (C.I.=5m)
- DEViated WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA
- PROSPECT AREA
- KIA PROSPECT
- Q CHANNEL DATA
  - Q CHANNEL UNCERTAINTY POLYGON
  - Q CHANNEL UNCERTAINTY BUFFER (100m)
  - Q CHANNEL UNCERTAINTY BUFFER (150m)
- SBIP ISOPACH
  - High: 90.2
  - Low: 0 m
Long Lake
SBIP Pay Interval Isopach
Kinosis
SBIP Pay Interval Isopach
Example Log: Kinosis KIA

McMurray Fluvial Estuarine Complex top

Top Gas

Bottom Water

Devonian

Note: Resistivity gradient is due to salinity changes. Core used to confirm oil saturations.
Long Lake
SBIP Pay Interval Base Structure

Legend

- SBIP BASE STRUCTURE (C.L.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA
- PROSPECT AREA
- K1A PROSPECT

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

SBIP TOP STRUCTURE
- High : 288.5
- Low : 167.3m
Long Lake
SBIP Pay Interval Base Structure

- Base of SBIP Pay Interval influenced by facies changes, karsting, erosion, salt dissolution, and bottom water
Long Lake
SBIP Pay Interval Top Structure

Legend

- **SBIP TOP STRUCTURE (C.I.=5m)**
- **ZERO EDGE**
- **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**

**SBIP TOP STRUCTURE RASTER**
- **High : 324.7**
- **Low : 172.0m**
• Top of SBIP 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.
Kinosis
Structure of SBIP Base
Kinosis
Structure of SBIP Top
Long Lake
HPVH Isopach over SBIP Pay Interval

Min pay to
HPVH = $ \sum_{\text{Min pay bs}}^{\text{Min pay tp}} (S_o \times \Phi)$

- Colour shading: > 3m$^3$/m$^2$ HPVH
Long Lake
HPVH Isopach over SBIP Pay Interval

- Colour shading: > 3m$^3$/m$^2$ HPVH

\[ \text{HPVH} = \sum_{\text{Min pay bs}} \left( S_0 \Phi \right) \]
Kinosis
HPVH Isopach over SBIP Interval
Long Lake and Kinson SBIP (HPVH) Volumes

<table>
<thead>
<tr>
<th>Pad</th>
<th>Volume (m³)</th>
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<tbody>
<tr>
<td>LLK P01</td>
<td>1819334.31</td>
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<tr>
<td>LLK P02</td>
<td>4676731.80</td>
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<td>LLK P03</td>
<td>3722430.15</td>
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<td>LLK P04</td>
<td>1137221.36</td>
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<td>LLK P05</td>
<td>3129433.19</td>
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<td>LLK P06</td>
<td>6491203.51</td>
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<td>LLK P07</td>
<td>5884271.75</td>
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<td>LLK P08</td>
<td>3217436.41</td>
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<td>LLK P09</td>
<td>3934821.14</td>
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<td>LLK P10</td>
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<td>LLK P11</td>
<td>2820272.15</td>
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<td>LLK P12</td>
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<td>LLK P13</td>
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<td>LLK P14</td>
<td>4242701.79</td>
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<td>LLK P15</td>
<td>2182764.43</td>
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<tr>
<td>K1A</td>
<td>11783622.62</td>
</tr>
<tr>
<td>K2A</td>
<td>12928364.88</td>
</tr>
</tbody>
</table>
• Gas identified by neutron/density crossover

• Gas associated with SBIP Interval
  - within SBIP Interval
  - directly in contact with top water or top of SBIP interval
  - contours clipped to 3m³/m² HPVH SBIP contour
Long Lake Total Gas: Gas Interval(s) within and in contact with SBIP Interval

- Gas identified by neutron/density crossover
- Gas associated with SBIP Interval
  - within SBIP Interval
  - directly in contact with top water or top of SBIP interval
  - contours clipped to 3m$^3$/m$^2$ HPVH SBIP contour
<table>
<thead>
<tr>
<th>Depth (meters)</th>
<th>Wire RHOB</th>
<th>Wire NPS</th>
<th>Wire DSS</th>
<th>Wire RhoB</th>
<th>Wire ILD</th>
<th>Wire ILM</th>
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<tbody>
<tr>
<td>175</td>
<td>1650</td>
<td>0.6</td>
<td>600</td>
<td>-400</td>
<td>0.2</td>
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<td>200</td>
<td>2650</td>
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<td>100</td>
<td>2000</td>
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<td>225</td>
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<td>0</td>
<td>600</td>
<td>100</td>
<td>0.2</td>
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<td>150</td>
<td>0</td>
<td>600</td>
<td>100</td>
<td>0.2</td>
<td>0.2</td>
</tr>
</tbody>
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**Well: 1AA_14-13-084-07W4_0**

- **Vertical Scale:** 1:480
- **Rig Release:** 3/25/2006
- **Drilled Depth:** 397.00

**Example Log:**

- **Kinosis IDA**
- McMurray Fluvial Estuarine Complex top
- Top Gas
- EBIP Pay Interval
- Bottom Water
- Devonian
Long Lake
Top Water Associated with SBIP 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 SBIP contour
Long Lake
Top Water Associated with SBIP 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 SBIP contour
Well: 103_13-36-085-07W4_0

MEASUREMENT REF.: KB
ELEVATION MEAS. REF.: 496.00
DRILLED DEPTH: 289.00
SURFACE ELEVATION: 492.30
Rig RELEASE: 06-FEB-2006
VERTICAL SCALE: 1:480

Top Impairment Type Log – 103/13-36-085-07W4

Wabiskaw
Wabiskaw ‘C’
McMurray

Gas
Water

Top of Pay
EBIP Pay Interval
Base of Pay
Tidal-Fluvial Estuarine Complexes
Devonian
**Long Lake Cumulative Thickness of High Water Saturation Interval(s) within EBIP Interval**

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<td>2014/2015 CORE OBS WELLS</td>
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<td>EBIP HWSI TOTAL ISOPIACH (C.I. = 5m)</td>
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<td>DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET</td>
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<td>EBIP HWSI TOTAL ISOPIACH</td>
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<td>High : 16.6</td>
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<td>Low : 0.0m</td>
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- > 50% Swe and < 30% $V_{\text{shale}}$
- Cumulative thickness of high water saturation interval(s) within EBIP interval
- Contours clipped to 3$m^3/m^2$ HPVH EBIP contour
• > 50% Swe and < 30% $V_{\text{shale}}$
• Cumulative thickness of high water saturation interval(s) within EBIP interval
• Contours clipped to 3$m^3$/m$^2$ HPVH EBIP contour
High Water Saturation Type Log
100/05-32-085-06W4

Well: 100_05-32-085-06W4_0
NEXEN OPTI OBJ BENMYS 5-32-85-6
MEASUREMENT REF.: KB
ELEVATION MEAS. REF.: 472.20
DRILLED DEPTH: 248.80
SURFACE ELEVATION: 488.90
RIG RELEASE: 17-NOV-2002
VERTICAL SCALE: 1:480

Tidal-Fluvial Estuarine Complexes
Devonian

Top of Pay
EBIP Pay Interval
Base of Pay

Wabiskaw
Wabiskaw ‘C’
McMurray

High Water Saturation Type Log

High Swe ≥ 78%

-275
-250
-300
Kinosis
Top Water in the McMurray
> 50% Swe and < 30% $V_{\text{shale}}$

- Base of Bottom Water
  - top of a > 2m > 30% $V_{\text{shale}}$ shale interval

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

Well: 1AA_12-36-085-07W4_0
MEASUREMENT REF: KB
ELEVATION/MEAS. REF: 484.00
SURFACE ELEV: 481.00
VERTICAL SCALE: 1:480
RIG RELEASE: 2/19/2000
DRILLED DEPTH: 253.00

Well: 1AA_07-36-085-07W4_0
MEASUREMENT REF: KB
ELEVATION/MEAS. REF: 497.10
SURFACE ELEV: 494.10
VERTICAL SCALE: 1:480
DRILLED DEPTH: 263.00

Well: 1AA_05-31-085-06W4_0
MEASUREMENT REF: KB
ELEVATION/MEAS. REF: 494.20
SURFACE ELEV: 491.20
VERTICAL SCALE: 1:480
RIG RELEASE: 2/26/2000
DRILLED DEPTH: 264.60

Wabiskaw 'C'
McMurray
Top of Pay
Base of Pay
Devonian

EBIP Pay Interval
Base of EBIP
Devonian

Wabiskaw 'C'
McMurray
Top of EBIP
Base of EBIP
Devonian
Representative structural cross-section of Pads 12 and 13
Representative structural cross-section of Pads 14 and 15

S 1AC_05-28-085-06W4_0 1AA_09-29-085-06W4_0 1AA_01-32-085-06W4_0 N
Representative structural cross-section of K1A
Cap rock defined as top of Clearwater B to top of Wabiskaw C sand
# Long Lake Cap Rock Evaluation

## MINI-FRACTURE LOCATIONS
- 100C90708606W400
- 1AB082008506W400

## TRIAXIAL STRENGTH & DIRECT SHEAR TESTING
- 1AB082908506W400

## XRD, PETROGRAPHY, & GRAIN SIZE ANALYSIS
- 1AA083208506W400
- 1AA102708607W400
- 1AA122808506W400
- 1AA142008506W400
- 10005308506W400
- 10056208506W400
- 102092908506W400
- 1040192908506W400
- 103142908506W400

## CAPROCK CORE
- 100053308506W400
- 10082908506W400
- 100110808606W400
- 10032808506W400
- 100410808606W400
- 1AA012088506W400
- 1AA067080867W400
- 1AA07208506W400
- 1AB043308500W400
- 1AB082908506W400
- 1AC042808506W400

![Map of Long Lake Cap Rock Evaluation](image-url)
Long Lake
Cap Rock Evaluation Image Logs
## Long Lake

### Cap Rock Evaluation Image Logs

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## Long Lake
### Cap Rock Evaluation Image Logs

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Long Lake Seismic
Time delay anomalies are the difference between the Devonian surface on the 2003 baseline seismic survey and the 2015 monitor seismic surveys.

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

This survey covered Pads 6W, 7E, 7N, 8, 10N, 10W, 11 and portions of Pads 6N and 9W.

No seismic data was collected over the area covered by the lake (in grey) and surface facilities.
Kinosis – 2015 Activity and 3D Seismic Outline
Time delay anomalies are the difference between the Devonian surface on the 2006 baseline seismic survey and the 2015 monitor seismic surveys over drainage areas A to the north, C to the west and D to the east.

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

These are the first monitor seismic surveys over the K1A pads.
2015 Program

- 3 RST Wells
- 1 Q-Channel Monitoring Well
- Total = 4
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Long Lake
Horizontal Well Locations

Inter-well Spacing

Pad 1: 75m (with infill pairs)
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 11P06): 40m
Pad 11 E (11P07 to 11P10): 80m
Pad 12-15: 75m
Objects are not representative of depth
Typical Injector Completion

**Concentric**

- Majority of Long Lake’s design
- 406.4mm (16”) or 339.9mm (13 3/8”) 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”)

[Diagram of concentric completion with dimensions and labels for different strings and casings]
• All Kinosis wells, and a few Long Lake wells are completed with steam splitters in the long injection string
  ▪ Results showing improved temperature conformance in Long Lake wells
• VIT is 139.7mm (5 ½”) or 114.3mm (4 ½”), usually installed to the ICP

177.8mm (7”) heel string
139.7mm x 114.3mm (5 ½” x 4 ½”) or 114.3mm x 88.9mm (4.5”x 3.5”) VIT
114.3mm (4 ½”) bare tubing
Typical Injector Circulation

244.5mm (9-5/8") intermediate casing

177.8mm (7") heel string

139.7mm x 114.3mm (5 ½" x 4 ½") or 114.3mm x 88.9mm (4.5"x 3.5") VIT

114.3mm (4 ½") bare tubing
Typical Producer Completions – ESP

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

Producer Circulation

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

blanket gas
steam injection
circulation returns
instrumentation string

Surface Casing: 339.9mm, 81.1kg/m

Production String 88.9mm, 13.7kg/m

Intermediate Casing: 244.5mm, 53.6kg/m

Injection String: 88.9mm, 13.7kg/m

Production Liner: 177.8mm, 34.2kg/m

Instrumentation Coil: 38.1mm, 4/6 thermocouples

NOT TO SCALE
• 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 SAGD wells
  - Pump performance (at Dec 31, 2015):
    • Average Run Time: 441 days
    • Mean Time to Failure (cumulative): 749 days
    • Mean Time to Failure (450 Running Average): 983 days
  - Operating temperatures have reached 215°C
  - 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 the heel string and the intermediate casing.
- 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 injection between guide string and instrument string.
- Toe pressure measurement via blanket gas injection into bubble tube.
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

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

Fiber Optic Distributed Temperature Sensing
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
Current Design and Practices

- Cement with Thermal 40 EXP cement
- Vibrating wire piezometer sensors (green) are strapped outside the production casing providing pressure and temperature measurements
- Thermocouple strings (red) provide temperature measurements
- Run a CBL on well with pressure pass if required
K1A Overview

- On July 15, 2015 a line rupture was discovered on the K1A produced emulsion line tie-back to Long Lake CPF
  - Operations of both the remote steam generation facility (SGF) and well pairs at K1A were subsequently ceased and remain down

- Status of wells as at July 15, 2015
  - 22 well pairs were on SAGD and exhibiting strong production performance
    - Have been re-equipped in Q4 2015, ready for circulation
  - 8 well pairs were in circulation mode
  - 7 well pairs were inactive

- MOP revision on DAA approved for 2000kPa
Field Status as of July 15, 2015
(Prior to Detection of Pipeline Rupture)
K1A Completions Summary (as of Dec. 31st, 2015)

Completion Work – Post Pipeline Rupture

- Pulled coil instrument string, ESP, scab liner, and guide string
- Installed circulation strings in well pairs that were on SAGD production
- Injected corrosion inhibitor in all well pairs

= workovers completed (34 wells)
K1A Well Pair Completions Map as of Dec. 31, 2015
K1A Downhole Corrosion Inhibition Plan

Objective:
• Injected inhibited fluid down casing and tubing of all 37 K1A SAGD well pairs to coat metal surfaces and deter corrosion.
• Inhibited fluid was a mixture of water, oxygen scavenger, biocide and corrosion inhibitor.

Operation:
• 74 wells total
• Approximately 3300 m³ inhibited fluid injected
• Bullhead: 60 wells
• Circulated: 14 wells
Typical K1A Completion Schematic Circulation
Field Performance

*Graph includes K1A*
2015 Field Performance

- **Turnaround**
  - Unplanned surface downtime in Q1/Q2
  - K1A pipeline rupture
  - Pad 12-15 Pipeline Suspension

- **Unplanned surface downtime & export constraints**
Long Lake 2015 Performance

- Commercial SAGD
- Downhole injection pressure varies throughout the field, ranges from 1,400 kPa to 2,800 kPa
- K1A wells exhibited strong ramp up and Long Lake pads continue to deliver strong performance
  - However, many wells throttled throughout the year to accommodate various capacity constraints
  - Field shut in for ~21 days for plant turnaround in June 2015
  - Improved ramp up and field production performance post turnaround compared to 2012 turnaround
  - K1A well pairs shut-in July 15, 2015
  - Pads 12-15 shut in for ~10 days for pipeline suspension order in Sept 2015
- Long Lake: 15 pads and 120 well pairs, 112 producing wells at year end
- K1A: 2 pads and 37 well pairs, 0 producing at year end
## Recoverable Bitumen

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<th>Num Wells</th>
<th>EBIP $E^6$ m³</th>
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<th>Recoverable Bitumen $E^6$ m³</th>
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## December 2015 Average Injection Pressures

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Pad Performance
Examples of High, Mid and Low Performance
Section 3.1.1 (7ciii)
Long Lake
Examples of Low, Mid, High Recovery

• Low Recovery
  – Pad 2SE

• Mid Recovery
  – Pad 8

• High Recovery
  – Pad 11
Examples of Low, Mid, High Recovery

- **Low Recovery**
  - Pad 2SE

- **Mid Recovery**
  - Pad 8

- **High Recovery**
  - Pad 11
Pad 2SE Production Summary

- **Well 2P11** suspended since June 2014 due to multiple liner failures and unfavorable repair economics.
- All wells initially started on gaslift. 2P07 converted to PC pump in 2010. 2P08/2P09/2P10 converted to ESP pump in 2010-2014.
- Wells are low on priority list due to poor quality and performance, they get hit heavily when there are capacity restrictions.
- At YE, injection pressures were ~1,200 – 1,720 kPa.

<table>
<thead>
<tr>
<th>Well</th>
<th>EBIP (m³)</th>
<th>Dec 2015 Cumulative Bitumen (m³)</th>
<th>Dec 2015 RF (%)</th>
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</thead>
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<td><strong>257</strong></td>
<td><strong>21</strong></td>
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</table>
Pad 2SE Geology

- Sand Facies
- EBIP Interval
Pad 2SE Geology

Producers
- Heel to mid sections of 2P07 and 2P08 drilled in low quality reservoir, dominated by mudstone facies.

Injectors
- 2P10 and 2P11 have a poor reservoir section towards the heel with the high GR.
Examples of Low, Mid, High Recovery

• Low Recovery
  – Pad 2SE

• Mid Recovery
  – Pad 8

• High Recovery
  – Pad 11
Pad 8 Production Summary

- Continuing to see strong production performance from east well pairs – west well pairs operated inconsistently
- 08S06 shut in Q1 2015 after workover following potential liner failure
  - Increased injection on offset injectors to support 08S06
  - No evidence of negative impact to 08P06 or surrounding wells production
- ICD installed on 08P03 in Dec. 2015
- Bridge plug at toe of 08P02 removed in Dec. 2015 to access additional reservoir

<table>
<thead>
<tr>
<th>Well</th>
<th>EBIP $10^3$ (m$^3$)</th>
<th>Dec 2015 Cumulative Bitumen $10^3$ (m$^3$)</th>
<th>Dec 2015 RF (%)</th>
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<td>75</td>
<td>37%</td>
</tr>
<tr>
<td>08P03</td>
<td>508</td>
<td>113</td>
<td>22%</td>
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<td>08P04</td>
<td>614</td>
<td>183</td>
<td>30%</td>
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<tr>
<td>08P05</td>
<td>658</td>
<td>300</td>
<td>46%</td>
</tr>
<tr>
<td>08P06</td>
<td>690</td>
<td>283</td>
<td>41%</td>
</tr>
<tr>
<td>Pad 8</td>
<td>2978</td>
<td>1009</td>
<td>34%</td>
</tr>
</tbody>
</table>
Pad 8 Geology

- Reservoir quality improves from east to west
Pad 8 Geology

- High water saturation intervals throughout pad
- Top water at toes connected to extensive top water body on Pad 10W and Pad 11
Pad 8 Secondary Zone

- Previously identified as potential secondary zone above primary EBIP on Pad 8 & 7N
- Increased EBIP top pick by 16.8m based on:
  - Obs well temperature data
  - 4D Seismic anomaly
Examples of Low, Mid, High Recovery

• Low Recovery
  – Pad 2SE

• Mid Recovery
  – Pad 8

• High Recovery
  – Pad 11
Pad 11 Production Summary

- 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 and 2015 4D has improved interpretation of IHS bedding and steam chamber development
- 11S08 has not operated since Aug 2015
- Decline in bitumen rates can be attributed to top water effect
- Maintain relatively low pressure to reduce steam loss
- At YE, injection pressures were ~1,710–1,750 kPa
Pad 11 Geology

EBIP ISOPACH

SAND FACIES PERCENTAGE

EBIP ISOPACH RASTER
High : 69.8676
Low : 9.36656

PERCENTAGE of FACIES 1 SAND
- HIGH SAND % (SAND > 70%)
- MID SAND % (SAND 50% to 70%)
- LOW SAND % (SAND < 50%)
Comparison of 2013 and 2015 4D seismic anomalies
- Cross section: 11Pair05

Continuing to see improved chamber development though EBIP interval – growth around IHS

Challenging development by the toes where reservoir quality varies

Larger development of anomalies through top water

Connection to 10W through top water

Processing calibration issues
Learnings, Trials and Pilot Projects
Subsection 3.1.1 (7f)
Long Lake and K1A
2015 Liner Failures

• 5 liner failures in 2015
• Evaluated case by case to determine whether to repair, re-drill or shut in

Wells Re-drilled
• None

Wells Repaired
• 11P02 – liner failure Q1, packer assembly
• 13P08 – liner failure Q2, packer assembly
• 07P07 – liner failure Q3, packer assembly

Wells Currently Shut In – Ongoing Evaluation
• 07P12 – liner failure Q3 2015
• 08S06 – liner failure Q1 2015
<table>
<thead>
<tr>
<th>Well</th>
<th>Well Pair ID</th>
<th>Failure Date (Year)</th>
<th>Repair Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>2P11</td>
<td>LL-002-11</td>
<td>2013</td>
<td>Plugback</td>
</tr>
<tr>
<td>2P11</td>
<td>LL-002-11</td>
<td>2014</td>
<td>None - well left shut-in</td>
</tr>
<tr>
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<td>LL-003-05</td>
<td>2012</td>
<td>Re-Drill</td>
</tr>
<tr>
<td>3S05</td>
<td>LL-003-05</td>
<td>2013</td>
<td>Re-Drill</td>
</tr>
<tr>
<td>3P05</td>
<td>LL-003-05</td>
<td>2014</td>
<td>Re-Drill</td>
</tr>
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</tr>
<tr>
<td>6S03</td>
<td>LL-006-03</td>
<td>2011</td>
<td>Re-Drill</td>
</tr>
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<td>LL-006-04</td>
<td>2014</td>
<td>Plugback</td>
</tr>
<tr>
<td>6P08</td>
<td>LL-006-08</td>
<td>2011</td>
<td>Plugback</td>
</tr>
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<td>2012</td>
<td>Plugback</td>
</tr>
<tr>
<td>6P09</td>
<td>LL-006-09</td>
<td>2014</td>
<td>None</td>
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</tr>
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<td>Re-Drill</td>
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<td>LL-006-12</td>
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<td>2011</td>
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</tr>
<tr>
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<td>2011</td>
<td>Plugback</td>
</tr>
<tr>
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<td>LL-007-07</td>
<td>2015</td>
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</tr>
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<td>LL-007-09</td>
<td>2012</td>
<td>Plugback</td>
</tr>
<tr>
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<td>LL-007-11</td>
<td>2012</td>
<td>Packer Assembly</td>
</tr>
<tr>
<td>7P11</td>
<td>LL-007-11</td>
<td>2014</td>
<td>Plugback / Packer Assembly</td>
</tr>
<tr>
<td>7P13</td>
<td>LL-007-13</td>
<td>2014</td>
<td>Packer Assembly</td>
</tr>
<tr>
<td>7P13</td>
<td>LL-007-13</td>
<td>2015</td>
<td>None - Well Left S.I.</td>
</tr>
<tr>
<td>8S06</td>
<td>LL-08-06</td>
<td>2015</td>
<td>Long string could not be pulled, cut string and left well shut in</td>
</tr>
<tr>
<td>9P07</td>
<td>LL-009-07</td>
<td>2012</td>
<td>Plugback</td>
</tr>
<tr>
<td>9P07</td>
<td>LL-009-07</td>
<td>2014</td>
<td>Plugback</td>
</tr>
<tr>
<td>10P04</td>
<td>LL-010-04</td>
<td>2014</td>
<td>Plugback</td>
</tr>
<tr>
<td>11P02</td>
<td>LL-011-02</td>
<td>2015</td>
<td>Packer Assembly</td>
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<tr>
<td>11P05</td>
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<td>2011</td>
<td>Re-Drill</td>
</tr>
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<td>11P10</td>
<td>LL-011-10</td>
<td>2013</td>
<td>Re-Drill</td>
</tr>
<tr>
<td>13P08</td>
<td>LL-013-08</td>
<td>2015</td>
<td>Packer Assembly</td>
</tr>
<tr>
<td>14P02</td>
<td>LL-014-02</td>
<td>2016</td>
<td>Packer Assembly</td>
</tr>
</tbody>
</table>
• 4 infill producer wells drilled in 2014 using surface locations on Pad 10N
• Steam squeeze performed on infill wells prior to ramp up
  – 10P16 started up without steam squeeze due to high bottom hole temperatures
• All infill wells completed with ESPs, scab liners, and instrumentation (toe and heel pressure and 8 TC’s)
• Strong performance seen thus far without negative impact on production from original SAGD well pairs
• Increased steam injection on original well pairs to support infills and 08P06 (08S06 shut in Q1 2015)
Pad 7N Infill Production Performance

Throttled production on original SAGD well pairs due to surface constraints

Plant Turnaround

Throttled production on all wells due to surface constraints
Solvent Co-Injection Projects

**PAD 13 Solvent Co-Injection Pilot Test** (2 years)

- Application approval 9485U was received in April, 2013
- Injected solvent being used is gas condensate (mostly C5 to C6 composition).
- Solvent injected at 12% of total injected volume (steam + solvent volume)

- Solvent co-injection started Oct. 2014 at 13S3 and 13S4.
- Solvent suspended in late 2015 due to inconsistent operations at Pad 13 caused by surface constraints.
- Indications of positive production uplift seen on a monthly basis despite lean zone impairment in the pilot area.
- Cumulative solvent recovery of 60%+ was ahead of simulation prediction as of year end 2015.

- Currently monitoring solvent recovery
- Re-evaluating pilot plans in light of surface interruptions.
NCG Co-Injection Projects

PAD 7E NCG Pilot Test
- Application approval 9485R received in September, 2012.
- Injected gas being used is natural gas.
- Early indications of iSOR reduction, however, due to unstable operating conditions the results were not conclusive.
- Gas injection suspended after turnaround
- Timing for pilot re-start being evaluated.

PAD 7N NCG Pilot Test
- Application approval 9485CC received in May, 2014.
- Construction of co-injection surface facilities complete April 2015.
- NCG co-injection in 5 well pairs planned.
- Injected gas to be used is natural gas.
- Timing for pilot startup being evaluated.

PAD 7E and 7N NCG Injection Test During TA
- Application approved in May, 2015.
- NCG injection on 3 well pairs on 7E and 5 well pairs on 7N
- Injected at ~20 E3M3/day/well for 8 days at PAD 7E and Pad 7N from May 28 – June 9, 2015.
- Impact on ramp up after turnaround was inconclusive due to equipment failure on the Pad 7 test separator.
- NCG injection did supply additional information about connectivity of the surrounding pads.
Diluent Trial

• Several wells at K1A were selected for diluent treatments to further expand data set
  – Injected 35-38m³ diluent + BFW in three producers in the middle of the circulation period
  – Two wells had been converted to SAGD with no substantial differences to offset wells in terms of ramp up, illustrated as red lines in graphs below
  – Candidates require careful screening for formation heterogeneity, pressure containment and presence of high water saturation zones in close proximity of wellbores

Cumulative Oil Comparison to Offsets (a) K2P14, (b) K2P19
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
ICD Performance – 08P03

- In-flow control devices were installed on 08P03 during a pump change in Q4 2015 with the intent to promote “more even” production of fluid along the wellbore with the expected benefits:
  - Better conformance along the well
  - Reduced production impact due to “hot spot” at TC C
  - Increased contribution from toe
- 08P03 has not been operated consistently since ICD’s were installed
- Performance is still being evaluated

08P03

Poor 4D data due to lake
Long Lake Observation Wells
Observation Wells – Long Lake
N/A – Greater than 300m to Q-channel or closest well pair
UWI

Closest
Wellpair

Distance to
Wellpair

100010608606W400
100013108506W400
100023208506W400
100033208506W400
100042808506W400
100043208506W400
100043308506W400
100050808606W400
100053208506W400
100053308506W400
100060108607W400
100060708606W400
100060808606W400
100062908506W400
100063208506W400
100081708506W400
100082908506W400
100091208607W400
100092908506W400
100093108506W400
100100708606W400
100102908506W400
100103208506W400
100110808606W400
100112508507W400
100113608507W400
100120808606W400
100122808506W400
100132808506W400
100140808606W400
100141708606W400
100142508507W400
100143208506W400
100152508507W400
100152908506W400
100162908506W400
100163108506W400
102010608606W400
102012108506W400
102013108506W400
102013608507W400
102023208506W400
102042208506W400
102043208506W400
102050808606W400
102052908506W400

LL-009-09
LL-001-01
LL-005-04
LL-005-04
LL-014-03
LL-001-03
LL-014-07
LL-013-09
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LL-014-07
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LL-013-09
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LL-013-06
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69
1
51
7
297
12
219
115
3
109
118
67
N/A
52
4
N/A
128
N/A
10
3
5
279
N/A
230
46
4
132
32
164
263
N/A
28
135
17
203
18
97
112
N/A
1
35
101
N/A
4
36
2

Distance to Q channel
(Max Edge)
(Min Edge)
45
N/A
29
103
N/A
N/A
N/A
68
N/A
N/A
N/A
N/A
87
97
283
N/A
236
N/A
N/A
N/A
N/A
99
7
109
N/A
N/A
179
N/A
N/A
23
41
N/A
3
N/A
100
286
46
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N/A
N/A
N/A
20
N/A
N/A
4
N/A

70
N/A
44
120
N/A
N/A
N/A
87
N/A
N/A
N/A
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N/A
N/A
N/A
N/A
N/A
N/A
N/A
140
42
138
N/A
N/A
213
N/A
N/A
33
8
N/A
42
N/A
113
N/A
57
27
N/A
N/A
N/A
7
N/A
N/A
28
N/A

UWI

Closest
Wellpair

102053208506W400
102062908506W400
102063208506W400
102092508507W400
102092808506W400
102092908506W400
102100708606W400
102112008506W400
102122908506W400
102152908506W400
103023208506W400
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103113208506W400
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103133608507W400
103142908506W400
104023208506W400
104133608507W400
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109133208506W400
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111150708606W400
111160708606W400
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112133208506W400
117063208506W400
118063208506W400
122063608507W400
1AA083008506W400
1AA102908506W400
1F2023208506W400
1S0040508606W400
1WM043308506W400

LL-001-01
LL-004-02
LL-001-03
LL-007-08
LL-015-03
LL-015-04
LL-012-05
LL-004-03
LL-005-04
LL-014-05
LL-014-05
LL-001-02
LL-005-01
LL-013-01
LL-013-04
LL-002-06
LL-003-03
LL-015-03
LL-011-06
LL-005-05
LL-005-01
LL-011-04
LL-005-05
LL-015-01
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LL-005-01
LL-014-07
LL-005-04
LL-014-05
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LL-002-05
LL-003-01
LL-001-02
LL-010-01
LL-002-06
LL-012-05
LL-013-04
LL-001-03
LL-002-05
LL-005-01
LL-005-01
LL-008-06
LL-004-04
LL-004-01
LL-005-04
LL-002-02
LL-014-07

Distance to Distance to Q channel
Wellpair
(Max Edge) (Min Edge)
1
100
6
7
N/A
77
11
N/A
25
193
175
5
51
8
13
38
92
6
6
69
38
9
192
82
33
42
18
72
175
47
96
75
123
48
190
9
9
105
148
157
130
47
N/A
N/A
227
126
204

N/A
53
217
N/A
N/A
N/A
N/A
N/A
N/A
110
31
N/A
48
80
N/A
N/A
40
N/A
N/A
30
60
N/A
103
N/A
N/A
N/A
N/A
7
33
156
21
33
121
N/A
77
N/A
N/A
110
28
10
60
N/A
161
113
146
11
N/A

N/A
98
235
N/A
N/A
N/A
N/A
N/A
N/A
123
73
N/A
78
115
N/A
N/A
81
N/A
N/A
55
90
N/A
139
N/A
N/A
N/A
N/A
27
87
169
40
80
136
N/A
65
N/A
N/A
122
12
21
72
N/A
247
66
139
133
15
N/A


Conductive Heating at 102/09-25

- Higher than expected temperatures were observed in the Clearwater A sand and caprock intervals in the 102/09-25 observation well.
- The temperature in this interval had gradually increased since the observation well was drilled in 2012 (max of 60 deg C).
- Within the Clearwater A Sand, the obs well is very close to the build sections of Pad 6W producer and injector wells (<10m from 06S07).
Conductive Heating at 102/09-25

- Thorough analysis was done to determine the source of the temperature development, using the following data:
  - Full suite of logs (caliper, saturation, temperature, noise)
  - Conduction modeling
  - Review of geological and seismic data (including 2015 4D monitor)
  - Pressure & temperature data from other obs wells and neighboring well pairs

- Surrounding observation wells and water monitoring wells showed normal temperature and pressure trends within Clearwater A and Grand Rapids

**Conclusion**: the temperature development was due to conductive heating from the build section of neighboring injector and producer wells

- This heat transfer is expected as part of thermal processes
- Based on conduction modeling, the area <100m around producer and injector wells is expected to be conductively heated in all formations
  - Dependent on fluid movement within interval

- Other observation wells with close proximity to SAGD well pairs have observed similar temperature changes
  - Pad 14/15 Obs Well (100/09-29) - 20m from 14Pair03
### Pad 14 Baseline and Current Values

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Sensor Depth (mKB)</th>
<th>Sensor Elev. (mASL)</th>
<th>Formation</th>
<th>Base Line Pressure kPa</th>
<th>Current Pressure* kPa</th>
</tr>
</thead>
<tbody>
<tr>
<td>100/04-28</td>
<td>126</td>
<td>335.6</td>
<td>CLWT A</td>
<td>1015</td>
<td>1005</td>
</tr>
<tr>
<td>100/05-33</td>
<td>119</td>
<td>341.2</td>
<td>CLWT A</td>
<td>980</td>
<td>996</td>
</tr>
<tr>
<td>100/13-28</td>
<td>116</td>
<td>341.9</td>
<td>CLWT A</td>
<td>1000</td>
<td>1005</td>
</tr>
<tr>
<td>102/15-29</td>
<td>127</td>
<td>344.3</td>
<td>CLWT A</td>
<td>990</td>
<td>1001</td>
</tr>
<tr>
<td>WM/04-33</td>
<td>115</td>
<td>343.8</td>
<td>CLWT A</td>
<td>970</td>
<td>964</td>
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<tr>
<td></td>
<td>115.5</td>
<td>343.27</td>
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<td>980</td>
<td>981</td>
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### Pad 15 Baseline and Current Values

<table>
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<th>Sensor Depth (mKB)</th>
<th>Sensor Elev. (mASL)</th>
<th>Formation</th>
<th>Base Line Pressure kPa</th>
<th>Current Pressure* kPa</th>
</tr>
</thead>
<tbody>
<tr>
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<td>122.5</td>
<td>336.4</td>
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<td>1100</td>
<td>1106</td>
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<tr>
<td>100/08-29</td>
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<td>930</td>
<td>940</td>
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<tr>
<td>102/09-29</td>
<td>126.5</td>
<td>339.6</td>
<td>CLWT A</td>
<td>1020</td>
<td>1017</td>
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<tr>
<td>103/12-28</td>
<td>121.5</td>
<td>340.5</td>
<td>CLWT A</td>
<td>1040</td>
<td>1027</td>
</tr>
</tbody>
</table>

- DCS alarm is triggered +75kPa above baseline (Hi alarm) and DCS steam shut-in is triggered +100kPa (Hi-Hi alarm).

* December 2015
Bottom Water Pressure

- Bottom water pressure response to initial operations and subsequent decrease on suspension
Future Plans
Subsection 3.1.1 (8)
Long Lake and Kinosis
Future Plans – Producing areas

- Continue to manage SAGD production according to surface constraints and capacity
- Advance plans for K1A recovery
  - RCA submitted in July 2016
  - Working on final recommendation of repair vs replace
- Production opportunities
  - Continue to progress future infills at Long Lake
  - Evaluate additional well pairs off existing well pads at Long Lake
- Respond to Supplemental Information Requests to Q-Channel amendment application (2016)
- Respond to Supplemental Information Requests to 103/01-21 disposal application (2016)
- Submitted Category 1 request to postpone 4D seismic over Pads 14/15 to winter 2017/2018 due to immature steam chambers
Future Plans - New Development

• Long Lake
  – Long Lake SW (Pads 16 to 18)
    • Internal sanction anticipated in Q2 2017
    • Timing uncertain based on commodity price

• Kinosis
  – Planning for future projects significantly slowed down due to commodity prices
    • Gas re-pressurization project on hold
Surface Operations and Compliance and Issues not Related to Resource Evaluation and Recovery
Subsection 3.1.2
Long Lake Kinosis
Facilities
Subsection 3.1.2 (1)
Long Lake Kinosis
Long Lake Facilities

Long Lake overview with new DRU construction activities—October 22, 2014
Diluent Recovery Unit Plot Plan

Subsection 3.1.2 (1a)
Kinosis Phase 1 (K1A)

Aerial of Nexen's K1A Steam Generation Facility with Well Pads 2 in background – October 15, 2014
Subsection 3.1.2 (1b)
Facility Performance
Subsection 3.1.2 (2)
Long Lake Kinosis
Facility Performance

Subsection 3.1.2 (2)
Bitumen Treatment

Subsection 3.1.2 (2a)
• **Chemical Injection**
  
  – Existing Demulsified Oil (DMO) and Reverse Breaker Water (RBW) injection chemicals providing satisfactory performance.
  
  – All DMO and RBW injection switched completely to Bulk Storage Systems from both East and West side pads. The injections systems are DCS controlled.
  
  – Trials conducted for replacement of polymer injection to FWKOs. The results are encouraging – good performance and no plugging of injection lines.
  
  – Proposal to also replace polymer for injection to de-oiling section.
  
  – Chemical injection skid provided in slop system - will help to inject chemicals for improving separation in slop tank.
Venting Incidents

- Several venting incidents in October to December led to:
  - changes in operating philosophy such as maintaining better water dump (from Free Water Knock Outs (FWKO)) quality; and
  - proactively adjusting chemical injection to skim tanks before upstream exchanger switching to compensate for the temporary foulant than can be released while the switching process is occurring.
• **Venting and Odour Issues**

  – Major reduction in odour issues after Diluent Recovery Unit (DRU) with elimination of cracked naphtha to SAGD.

  – PRVs and PVSVs installed with upgraded components during Turnaround on all tanks except dilbit tanks. These will be replaced on dilbit tanks in normal operation by taking one tank out of service at a time.

  – Encanex upgraded Vapor Recovery Unit (VRU) for centrifuge by installing chillers which increased capacity to handle more hydrocarbons in summer months resulting in better emissions control.

  – Hydrocarbon condensation inside VRU compressors was found to be causing reduction in VRU performance which was mitigated by operating diluent separator at a higher pressure than VRU discharge separator.
• **Amine Contactor Foaming Issues**
  – After Turnaround, there were persistent foaming issues in Amine Contactor which were eventually resolved by changing filters in the Amine Regeneration Unit.

• **Naphtha Imbalance after DRU**
  – There is excess naphtha production when the Upgrader is operating at rates higher than SAGD. A dilbit tank has been used for storage of excess naphtha.
  – Naphtha stored on site is used as diluent when SAGD rate exceeds Upgrader rate.
Produced Water Treatment

PRODUCED WATER
UPGRADER RECYCLE
SOURCE WELLS

HLS A
AFTER FILTERS
A - E
WAC PRIMARIES
A - E
BFW TANK

PRODUCED WATER
UPGRADER RECYCLE
SOURCE WELLS

HLS B
AFTER FILTERS
F - J
POLISHERS
A - C

PRODUCED WATER
SOURCE WELLS

HLS C
AFTER FILTERS
K - N
WAC PRIMARIES
F - G
POLISHERS
D - E
BFW TANK

POND

Subsection 3.1.2 (2b)
• **Produced Water (PW) Exchanger Performance**
  
  – No major issues with PW exchanger performance in 2015 with regularly scheduled steam and chemical cleaning.
  
  – Steam lines installed close to PW exchangers for steam cleaning. In the past, steam was taken from utility steam stations which was a bottleneck on extremely cold days due to insufficient amount of steam availability.
  
  – Glycol coolers in SAGD utilities plant were cleaned which helped to reduce glycol inlet temperature to E-006s and E-026s.
  
  – In order to address issues during hot summer days, a trial was conducted by installing temporary piping to recycle supernatant from the pond and mix with E-006 outlet. This was helpful in maintaining skim tank temperature even on very hot days.
• **Blowdown recycle to Hot Lime Softener (HLS) units (tie in from Disposal system)**
  – Aids in hardness removal in the HLS units by providing alkalinity to the system.
  – Aids in a lower water recycle ratio (Directive 081).
  – Work on permanent system is ongoing.

• **After Filter Regulatory Inspections and Repairs**
  – Regulatory inspections carried out in Turnaround 2015.
  – Collapsed traps were found and daily technical monitoring was implemented to improve plant reliability and significant improvements in equipment damage.
• **Micro Filtration (MF) system improvements**
  – Increased technical monitoring on the MF system.
  – Sequence changes made to EFM procedures increased run time of the units.
  – Increased monitoring allowed better maintenance.
  – Cap and Cleans were carried out helping unplug fouled membranes.

• **Fresh Water Leak**
  – Final repair was completed during Turnaround 2015.
• **Mixed Bed Polishers**
  - After internal damage on interface laterals causing resin losses was identified.
    - Permanent repair to install new interface laterals during TA 2015 was carried out.
    - Design changed from horizontal plastic laterals to ‘slit type’ hastelloy lateral.
    - Resin losses were eliminated.

• **Chemical usage optimization**
  - Specifications for Silica on HLS outlet were changed from <50ppm to 35-45 ppm in efforts to save on magox usage and associated costs
Water Treatment - Updates

• **SAGD BFW treatment for hardness and silica**
  – Improvements required for the Lime/Magox systems
  – High fouling rate with online pH meters, unreliable and monthly PMs were started

• **Sludge carry over from HLSs**
  – Additional sludge taps on HLSs not performing as designed
  – High fouling rate with online pH meters, unreliable
  – Daily monitoring of chemicals has allowed for effective control of HLS

• **Regen waste header fouled**
  – Design optimization of waste header ongoing
• HLS internal cleaning intervals
  – From the fouling observed during Turnaround 2015 in the HLS the 3 year interval for cleaning was changed to 2 years.

• 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.
Steam and Power Generation

Subsection 3.1.2 (2c, d)
Steam Generation

- **Record Years for Steam Production and Syngas Consumption**
  - 33,120 m$^3$/d peak of Steam Production
  - 5,269 m$^3$/d of peak Syngas Consumption
    - Proactive actions by Operators to use HP Syngas when available

- **Stable Operation at Kinosis 1A**
  - Proved to have an excellent reservoir and stable operation of the steam plant

- **Stricter Guidelines for Boiler Feed Water (BFW) excursions**
  - The Technical Team has increased proactive monitoring for operator reaction to offspec BFW.
  - Stricter response has been established in terms of following the Steam Quality Guidelines.
Steam Generation

- **Duct Burner Fouling**
  - Causing reduced steam production from HRSGs 1 and 2.
  - Working on the option of redistributing Syngas from duct burners to using Syngas for OTSG E/F.
    - This will give us the capability to produce more steam as less fouling in the HRSGs will be expected.

- **PSA Reliability (Upgrader)**
  - Inconsistent Syngas pressure from the Upgrader causes OTSGs and HRSGs to trip when pressure swings are too large
  - Work is ongoing to review and correct PSA issues
Steam Production

- Improved Water balance has increased field production:
  - Consistent run time of process (steam to water and back);
  - Consistent steam production to the field;
  - Reservoir has responded positively and production has increased.

Glycol Monitoring

- Increased monitoring/maintenance on various exchangers has greatly reduced glycol losses from previous years.
- Since end of 2015 there has been no need to order any glycol.

E-013 Exchangers (Blowdown/MP Steam Condensers)

- Upgrade to new metallurgy on 8400-E-013 A and C tube bundles have yielded better performance and we have not experienced a failure since their replacement.
Steam Generation - Successes

• **Natural Gas Tie in to Heat Recovery Steam Generator (HRSG) I and II**
  – Will help minimize fouling in the duct burners.
  – Tie in was complete in Nov 2015 and currently work is ongoing regarding the logic.

• **Turnaround 2015**
  – Excellent startup with zero incidents, Nexen’s best startup timeline to date after a major outage.
  – Major Outage on Gas Turbine 1.
  – Regulatory inspections on HRSG I and II were carried out.
  – All failed Thermocouples/Thermowells were fixed.
Steam Generation Successes

- **Air Extraction Unit**
  - Commissioned and tested the Air Extraction Unit for GTGs, which will increase power output during time where Syngas is being used.

- **Economizer Tube Failures on OTSGs**
  - Implemented better control of the water treatment program which resulted in:
    - Better water quality control in the Hot Lime Softer (HLS) units.
    - Less hardness breakthrough from the Weak Acid Cation (WAC) vessels.
• Emergency Power Supply
  – Increased efforts have been put in to improve reliability of the emergency generators and standby air compressors by utilizing external vendors to correct any deficiencies and implement PM’s (preventative maintenance) schedule on our behalf.
Total Power Usage

Power Generation (MW-h)  Power Import (MW-h)  Power Use (MW-h)  Power Sales (MW-h)

Subsection 3.1.2 (2d)
SAGD Energy Intensity (adjusted for power generation)

SAGD Fuel Intensity (GJ/m3)

Turnaround

2015

Fuel Intensity for Steam (GJ/m3)  Fuel Intensity for Bitumen (GJ/m3)

Subsection 3.1.2 (2d)
Total Gas Consumed (Purchased and Produced)

SAGD Gas Usage (10^3 m^3)

2015

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

LP Syngas Consumption  Natural Gas Consumption  Produced Gas Consumption

Subsection 3.1.2 (2e)
• 23 venting events at Long Lake;
• Released 4,325 m$^3$, with an average concentration of 200 ppm.
• Slop tank vented in October.

### 2015 LLK Venting Events

<table>
<thead>
<tr>
<th>Month</th>
<th>No. of Venting Events</th>
<th>Total Vented Volume (Sm$^3$)</th>
<th>Produced Gas Flared (10$^3$ m$^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>1</td>
<td>255</td>
<td>20.8</td>
</tr>
<tr>
<td>Feb</td>
<td>0</td>
<td>0</td>
<td>26.4</td>
</tr>
<tr>
<td>Mar</td>
<td>0</td>
<td>0</td>
<td>29.2</td>
</tr>
<tr>
<td>Apr</td>
<td>2</td>
<td>11</td>
<td>28.3</td>
</tr>
<tr>
<td>May</td>
<td>1</td>
<td>6</td>
<td>29.2</td>
</tr>
<tr>
<td>Jun</td>
<td>0</td>
<td>0</td>
<td>69.6</td>
</tr>
<tr>
<td>Jul</td>
<td>0</td>
<td>0</td>
<td>23.2</td>
</tr>
<tr>
<td>Aug</td>
<td>0</td>
<td>0</td>
<td>15.8</td>
</tr>
<tr>
<td>Sep</td>
<td>0</td>
<td>0</td>
<td>22.5</td>
</tr>
<tr>
<td>Oct</td>
<td>7</td>
<td>3,989</td>
<td>18.1</td>
</tr>
<tr>
<td>Nov</td>
<td>3</td>
<td>2</td>
<td>15.3</td>
</tr>
<tr>
<td>Dec</td>
<td>9</td>
<td>64</td>
<td>25.2</td>
</tr>
<tr>
<td>Total</td>
<td>23</td>
<td>4,325</td>
<td>323.6</td>
</tr>
</tbody>
</table>
Greenhouse Gas Emissions

- Long Lake’s GHG intensity is generally trending downwards
  - Lower GHG intensity is associated with lower SORs, improved reliability, and efficient operations

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kilotones (kT) CO$_2$e Emissions</td>
<td>3,229</td>
<td>3,191</td>
<td>3,613</td>
<td>4,139</td>
<td>* 4,384</td>
<td>3,547</td>
</tr>
<tr>
<td>GHG intensity (kg CO$_2$e/bbl bitumen produced)</td>
<td>361</td>
<td>307</td>
<td>317</td>
<td>310</td>
<td>* 280</td>
<td>250</td>
</tr>
</tbody>
</table>

- Long Lake’s GHG compliance costs are derived from a baseline of 2010-12 performance data
  - Long Lake’s baseline includes the facility’s three major products – bitumen, Premium Synthetic Crude and electricity

- 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 rising in stringency, with 2017 being its last year
  - With reductions from baseline emissions of 15% in 2016 and 20% by 2017, the carbon price rises to $20 and $30 per tonne CO$_2$, respectively

- Regulations are being developed for a Carbon Tax on large GHG emitters from 2018 onwards
  - The new Carbon Tax is expected to account for all the emissions from Long Lake and deduct credits for in situ production, power generation, and upgrading

* Correction from 2014
Measurement and Reporting
Subsection 3.1.2 (3)
Long Lake
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 a longer well test duration for monitoring S&W profiles.
  - Bitumen cuts are based on an inline water cut analyzer (AGAR OW-201 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 were operational for 2015.
• 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.

• We have improved training for operations on manual sampling procedures/ sampling techniques in 2015.

• Improvements to MARP maintenance program is ongoing.
**LLK Proration Factors 2015**

<table>
<thead>
<tr>
<th>MONTH</th>
<th>OIL</th>
<th>WATER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>0.83</td>
<td>1.05</td>
</tr>
<tr>
<td>Feb</td>
<td>0.81</td>
<td>0.89</td>
</tr>
<tr>
<td>March</td>
<td>0.85</td>
<td>0.89</td>
</tr>
<tr>
<td>April</td>
<td>0.85</td>
<td>0.84</td>
</tr>
<tr>
<td>May</td>
<td>0.83</td>
<td>0.89</td>
</tr>
<tr>
<td>June</td>
<td>0.90</td>
<td>1.01</td>
</tr>
<tr>
<td>July</td>
<td>0.88</td>
<td>0.90</td>
</tr>
<tr>
<td>August</td>
<td>0.86</td>
<td>0.87</td>
</tr>
<tr>
<td>Sept</td>
<td>0.81</td>
<td>0.81</td>
</tr>
<tr>
<td>October</td>
<td>0.87</td>
<td>0.93</td>
</tr>
<tr>
<td>November</td>
<td>0.86</td>
<td>0.94</td>
</tr>
<tr>
<td>December</td>
<td>0.85</td>
<td>1.02</td>
</tr>
</tbody>
</table>

Heavy Oil Battery
Thermal recovery operations
(Petrinex subtypes 344 and 345)

Oil = 0.85000–1.15000
Water = 0.85000–1.15000

Per D017 Section 12.3.3 Gas Measurement:
A battery level GOR is used to determine well gas production.
Therefore, the gas proration is 1.00000.
Steam Production Measurement

- The two V-cone meters installed for steam measurement at CPF during 2012 Turnaround (8400-FIT-510, 8400-FIT-518) have failed.

- A project is being initiated to have these meters replaced. In the interim we have a steam calculation method for total plant steam production and Net steam to pads.

Total Steam Production (TSP) = OTSG (\(\text{Sum}_p\)) + HRSG (\(\text{Sum}_p\))

\[\text{OTSG} = \text{Once through steam Generators (840X-B-001 A-F) } x = 1 \text{ to } 6\]
\[\text{OTSGs (8401-B-001A-F) will be producing steam based on three criteria (otherwise the value is zero).}\]

1. Steam quality > 50% (See Slide 177 Table 1 for tag IDs)
2. BFW Flow for OTSGs > 80 Sm³/h (See Slide 177 Table 1 for tag IDs)
3. Blowdown valve opening < 10% (See Slide 177 Table 1 for tag IDs)

\[\text{Steam Production} = \frac{\text{Boiler Feed Water Flow (Sm}^3\text{/h)} \times \text{Steam Quality} (\%)}{100}\]

\[= \text{Sm}^3\text{/h}\]
\[= \text{Sm}^3\text{/h} \times 24\]
\[= \text{Sm}^3\text{/d}\]
HRSGs - Heat Recovery Steam Generators (890X-B-001, X = 1&2)

HRSGs will be producing steam based on three criteria (otherwise the value is zero).

1. Steam quality > 50% (See Slide 177 Table 2 for tag IDs)
2. BFW Flow for HRSGs > 190 Sm³/h (See Slide 177 Table 2 for tag IDs)
3. Blowdown valve opening < 10% (See Slide 177 Table 2 for tag IDs)

Steam Production = \( \text{Boiler Feed Water Flow (Sm}^3/\text{h) x Steam Quality(\%)} \)

\[
= \frac{\text{Sm}^3/\text{h} \times 24}{100} = \text{Sm}^3/\text{d}
\]
Steam Injection Measurement

- Steam injection is measured at the wellhead (estimating steam quality of 97% at the wellhead).
  - Nexen 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. Through 2015 these meters were inspected, cleaned and calibrated. All wellhead meters have a preventative maintenance schedule to maintain the accuracy as per MARP.

- As part of the revised plant production calculation the net steam to pads will be:
  Net Steam (SAGD wellpads) = TSP – HP to LP Letdown + LP steam vent

  \[
  \text{TSP} = \text{Total Steam Production} \\
  \text{HP to LP Letdown} = 8400-\text{PV-553A & 563A} \\
  \text{LP Steam vent} = 8400-\text{PV-553B & 563B}
  \]
Water Production, Injection and Uses
Subsection 3.1.2 (4)
Long Lake
Freshwater Pipelines

Drilled Quaternary fresh source well in LSD 05-26-084-07W4 in 2015 for future Kinosis project
Typical Water Values

Table 1: Deoiled Water Typical Values

<table>
<thead>
<tr>
<th>Stream</th>
<th>Deoiled Water – Area 1</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>pH</td>
<td>Turbidity (NTU)</td>
<td>Dissolved Hardness (mg/L)</td>
</tr>
<tr>
<td>Average</td>
<td>8</td>
<td>77</td>
<td>15</td>
</tr>
<tr>
<td>Max</td>
<td>9.2</td>
<td>1,340</td>
<td>220</td>
</tr>
<tr>
<td>Min</td>
<td>7</td>
<td>5</td>
<td>4</td>
</tr>
</tbody>
</table>

Table 2: Supernatant Water Typical Values Specifications

<table>
<thead>
<tr>
<th>Stream</th>
<th>Supernatant Water</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>pH</td>
<td>Turbidity (NTU)</td>
<td>Dissolved Hardness (mg/L)</td>
</tr>
<tr>
<td>Average</td>
<td>10</td>
<td>98</td>
<td>154</td>
</tr>
<tr>
<td>Max</td>
<td>12</td>
<td>918</td>
<td>360</td>
</tr>
<tr>
<td>Min</td>
<td>8</td>
<td>9</td>
<td>21</td>
</tr>
</tbody>
</table>

Table 3: Brackish Water Typical Values Specifications

<table>
<thead>
<tr>
<th>Stream</th>
<th>Brackish Water</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Hardness (mg/L)</td>
<td></td>
<td>TDS</td>
</tr>
<tr>
<td>Average</td>
<td>674</td>
<td></td>
<td>21,779</td>
</tr>
<tr>
<td>Min</td>
<td>88</td>
<td></td>
<td>5,872</td>
</tr>
<tr>
<td>Max</td>
<td>2,200</td>
<td></td>
<td>38,493</td>
</tr>
</tbody>
</table>
Freshwater Pipelines (CONT’D)

- Total of 18 wells tied in.
- WS Q 13-31-085-06W4 also used for potable water (73,110 m³ in 2015).
- Groundwater samples are collected if source wells are diverted during the year.

### Plant Operations

<table>
<thead>
<tr>
<th>Location</th>
<th>Formation</th>
<th>Fresh?</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>01-21-85-06W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>9-Sep-15</td>
<td>1,780</td>
<td>111,149</td>
<td>305</td>
</tr>
<tr>
<td>01-27-85-06W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>29-Sep-15</td>
<td>1,300</td>
<td>214,287</td>
<td>587</td>
</tr>
<tr>
<td>01-34-85-06W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>29-Sep-15</td>
<td>1,500</td>
<td>112,359</td>
<td>308</td>
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<tr>
<td>02-12-86-07W4M</td>
<td>Quaternary</td>
<td>Y</td>
<td>1-Oct-15</td>
<td>680</td>
<td>319,527</td>
<td>875</td>
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<tr>
<td>02-32-85-06W4M</td>
<td>Gregoire Channel</td>
<td>Y</td>
<td>18-Dec-12</td>
<td>1,800</td>
<td>0</td>
<td>0</td>
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<tr>
<td>06-14-86-07W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>1-Oct-15</td>
<td>1,200</td>
<td>105,269</td>
<td>288</td>
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<tr>
<td>06-18-85-05W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>22-Sep-09</td>
<td>1,000</td>
<td>0</td>
<td>0</td>
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<tr>
<td>08-01-86-07W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>9-Sep-14</td>
<td>888</td>
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<td>0</td>
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<tr>
<td>09-12-86-07W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>4-Sep-14</td>
<td>786</td>
<td>217,997</td>
<td>597</td>
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<tr>
<td>09-28-85-06W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>7-Aug-14</td>
<td>1,510</td>
<td>47,098</td>
<td>129</td>
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<tr>
<td>10-11-85-06W4M</td>
<td>Grand Rapids</td>
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<td>29-Sep-15</td>
<td>3,300</td>
<td>307,751</td>
<td>843</td>
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<tr>
<td>10-21-85-06W4M</td>
<td>Grand Rapids</td>
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<td>29-Sep-15</td>
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<td>74,765</td>
<td>205</td>
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<td>12-19-85-05W4M</td>
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<td>Y</td>
<td>29-Sep-15</td>
<td>2,400</td>
<td>191,346</td>
<td>524</td>
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<tr>
<td>13-31-85-06W4M</td>
<td>Quaternary</td>
<td>Y</td>
<td>1-Oct-15</td>
<td>530</td>
<td>59,405</td>
<td>163</td>
</tr>
<tr>
<td>15-28-85-06W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>29-Sep-15</td>
<td>1,600</td>
<td>182,024</td>
<td>499</td>
</tr>
<tr>
<td>16-33-85-06W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>29-Sep-15</td>
<td>1,200</td>
<td>35,984</td>
<td>99</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Location</th>
<th>Formation</th>
<th>Fresh?</th>
<th>Sample Date</th>
<th>Total (m³)</th>
<th>Annual avg. (m³/cd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13-31-85-06W4M</td>
<td>Quaternary</td>
<td>Y</td>
<td>1-Oct-15</td>
<td>530</td>
<td>73,110</td>
</tr>
</tbody>
</table>

### Potable

<table>
<thead>
<tr>
<th>Location</th>
<th>Formation</th>
<th>Fresh?</th>
<th>Sample Date</th>
<th>Total (m³)</th>
<th>Annual avg. (m³/cd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13-31-85-06W4M</td>
<td>Quaternary</td>
<td>Y</td>
<td>1-Oct-15</td>
<td>530</td>
<td>73,110</td>
</tr>
</tbody>
</table>

Volumes as reported in Petrinex and vary from those reported in Annual Reports

### Other

<table>
<thead>
<tr>
<th>Location</th>
<th>Formation</th>
<th>Fresh?</th>
<th>Sample Date</th>
<th>Total (m³)</th>
<th>Annual avg. (m³/cd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>07-36-85-07W4M</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>17-Nov-15</td>
<td>660</td>
<td>0</td>
</tr>
</tbody>
</table>
• Observed a sharp increase in TDS for WS-GR-11-32-084-06W4M.
• Increase was due to a check valve failure on the saline system.
• Pumped off well for 3 weeks until TDS recovered.
Saline Water Pipelines

No drilling of saline source wells in 2015

Subsection 3.1.2 (4a)
Saline Water Pipelines (CONT’D)

- 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.
- Saline wells are sampled if diversion criteria are met: > 10,000 m³/year

### Plant Operations

<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>1F2/03-30-084-06W4</td>
<td>Clearwater</td>
<td>Y</td>
<td>22-Dec-15</td>
<td>15,000</td>
<td>11,218</td>
<td>31</td>
</tr>
<tr>
<td>1F1/05-33-084-06W4</td>
<td>Clearwater</td>
<td>Y</td>
<td>22-Dec-15</td>
<td>7,500</td>
<td>19,044</td>
<td>52</td>
</tr>
<tr>
<td>1F1/06-31-084-06W</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</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>22-Dec-15</td>
<td>2,300</td>
<td>22,417</td>
<td>61</td>
</tr>
<tr>
<td>1F1/07-26-084-07W4</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>22,000</td>
<td>790</td>
<td>2</td>
</tr>
<tr>
<td>09-25-85-06W4</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>9-Oct-14</td>
<td>5,130</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1/10-13-085-05W4</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>1F1/11-29-084-06W4</td>
<td>Clearwater</td>
<td>Y</td>
<td>22-Dec-15</td>
<td>10,000</td>
<td>19,017</td>
<td>52</td>
</tr>
<tr>
<td>11-29-84-06W4</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>5,700</td>
<td>1,362</td>
<td>4</td>
</tr>
<tr>
<td>1F1/14-35-084-07W4</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>1F1/15-28-085-05W4</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>1F1/16-27-084-07W4</td>
<td>Clearwater</td>
<td>Y</td>
<td>16-Oct-14</td>
<td>23,000</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1/16-25-084-07W4</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>15,000</td>
<td>409</td>
<td>1</td>
</tr>
<tr>
<td>1F1/16/30/084/06W4</td>
<td>Clearwater</td>
<td>Y</td>
<td>19-Dec-12</td>
<td>6,200</td>
<td>2,419</td>
<td>7</td>
</tr>
</tbody>
</table>

**Subtotal Saline Diverted Volume**: 76,676 m³ 210

<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</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>1F1/11-28-084-06W4</td>
<td>Clearwater</td>
<td>N</td>
<td>30-May-13</td>
<td>2,900</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>11-32-84-06W4M</td>
<td>Grand Rapids</td>
<td>N</td>
<td>29-Dec-15</td>
<td>3,700</td>
<td>13,436</td>
<td>36</td>
</tr>
<tr>
<td>16-25-84-07W4M</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>16-27-84-07W4M</td>
<td>Grand Rapids</td>
<td>N</td>
<td>16-Nov-15</td>
<td>1,700</td>
<td>2,752</td>
<td>8</td>
</tr>
</tbody>
</table>

**Subtotal Non-Saline Diverted Volume**: 16,188 m³ 44

**TOTAL VOLUME DIVERTED**: 92,864 m³ 254

*Volumes as reported in Petrinex and vary from those reported in Annual Reports*
Saline wells sampled if diversion criteria are met:
> 10,000 m³/year
Potable Well

WA #: 241479-00-02
Location: 03-36-084-07W4M
Purpose: Industrial (Camp supply, drilling and injection)
Volumes diverted 2015: 4,284 m³

<table>
<thead>
<tr>
<th>Location</th>
<th>Total (m³)</th>
<th>Annual avg. (m³/cd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13-31-85-06W4M Q</td>
<td>73,110</td>
<td>200</td>
</tr>
</tbody>
</table>

Subsection 3.1.2 (4a)
Other Water Sources

- Surface runoff to lime sludge ponds (00247843-00-00)
  - 2015: 117,015 m³ (estimate)

- Corehole and SAGD drilling
  - Various TDLs: 7,308 m³ in 2015

- K1A Emulsion Line Clean-Up and Remediation Activities
  - TDL No. 370811 for water reuse: 12,537 m³ in 2015
Fresh and Brackish Water Use Volumes

![Bar chart showing monthly water use from January to December 2015 with categories for Run-off Water, Saline Water, and Fresh Water. The chart includes a red arrow indicating a 'Turnaround' event.]
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 2015 (m³)</th>
<th>*Total</th>
<th>Domestic</th>
<th>**SAGD</th>
<th>UPG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Main groundwater license (235895-01-00 as amended)</td>
<td>2,452,372</td>
<td>73,110</td>
<td>561,467</td>
<td>1,817,795</td>
</tr>
<tr>
<td>Surface runoff to ponds</td>
<td>117,015</td>
<td>117,015</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SAGD drilling</td>
<td>0</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Winter drilling program (Long Lake and Kinosis)</td>
<td>7,308</td>
<td>7,308</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Potable trucked to Long Lake</td>
<td>0</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>TOTAL</td>
<td>2,576,695</td>
<td>73,110</td>
<td>685,790</td>
<td>1,817,795</td>
</tr>
</tbody>
</table>

- Saline water make-up:
  76,677 m³ in 2015 for steam make-up (HLS’s)

* Volumes as reported in Petrinex and vary from those reported in Annual Reports
** Adjusted for process water returned from Upgrader and Utility water
Produced Water and Steam Injected Volumes

Subsection 3.1.2 (4c,d)
Nexen’s disposal rate includes freshwater demand to the upgrader

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

Water Management

Subsection 3.1.2 (4e,f)
Disposal Wells

Class 1a Wells (2) suspended in 2015

McM 14-32
LLK backup Keg River (KR2) disposal well 9-28 license approved in 2015

McM 9-28
KR 7-32
Kinosis Keg River 7-32 disposal application submitted in 2015

McM 11-28
KR 11-20
McM 4-22
McM 11-32
McM 14-22
McM, KR, KR2, 9-28

McMurray disposal well 9-28 abandoned in disposal zone and suspended in 2015

KR 11-20
K1A

Class 1a Wells (2) suspended in 2015
**Disposal Wells (CONT’D)**

### AER Approval # 10023G

<table>
<thead>
<tr>
<th>Disposal Well</th>
<th>Class 1b</th>
<th>January - December 2015</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Max. WHP (kPag)</td>
<td><strong>Total (m³)</strong></td>
</tr>
<tr>
<td>104/09-28-085-06W4/00 KR</td>
<td>Blowdown</td>
<td>1,151</td>
</tr>
<tr>
<td>103/09-28-085-06W4 KR</td>
<td>Blowdown</td>
<td>969</td>
</tr>
<tr>
<td>100/09-28-085-06W4 McM*</td>
<td>Blowdown</td>
<td>1,904</td>
</tr>
<tr>
<td>100/04-22-085-06W4 McM</td>
<td>Blowdown</td>
<td>2,702</td>
</tr>
<tr>
<td>100/11-32-084-06W4 McM</td>
<td>Blowdown</td>
<td>1,904</td>
</tr>
<tr>
<td>100/14-32-084-06W4 McM</td>
<td>Blowdown</td>
<td>2,060</td>
</tr>
<tr>
<td>100/01-21-085-06W4 McM†</td>
<td>Blowdown</td>
<td>-</td>
</tr>
<tr>
<td>100/11-28-084-06W4/00 KR</td>
<td>Drilling fluids</td>
<td>-</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td>989,574</td>
</tr>
</tbody>
</table>

### AER Approval # 11611

<table>
<thead>
<tr>
<th>Disposal Well</th>
<th>Class 1a</th>
<th>January - December 2015</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Max. WHP (kPag)</td>
<td>Total (m³)</td>
</tr>
<tr>
<td>100/06-16-085-06W4 KR*</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>100/05-16-085-06W4 McM*</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

*Well is suspended  
†Well was rescinded from approval 10023G  
**Volumes as reported in Petrinex and vary from those reported in Annual Reports

- Disposal capacity is adequate.  
- Disposal fluid temperature ~60°C.  
- All wells passed annulus pressure test, except 100/09-28-085-06W4/00.  
  - The 100/09-28-085-06W4/00 well was abandoned through McMurray Formation (disposal zone) and suspended above in 2015.  
- Data Loss Notification wells (Clause 7 from Approval No. 10023G):  
- No disposal at suspended WD McMurray 1-21 in 2015
  - WD MM 1-21 was rescinded from approval 10023G
- No disposal at WD Keg River 11-28 in 2015

**Volumes as reported in Petrinex and vary from those reported in Annual Reports**
## Waste Disposal

### Hazardous Waste

<table>
<thead>
<tr>
<th>Description</th>
<th>Tonnes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Soot</td>
<td>38,560</td>
</tr>
<tr>
<td>Centrifuge Solids</td>
<td>5,215</td>
</tr>
<tr>
<td>Bin Waste</td>
<td>779</td>
</tr>
<tr>
<td>Slop Oil</td>
<td>6,895</td>
</tr>
<tr>
<td>Cavern Wastes</td>
<td>2,981</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>54,430</strong></td>
</tr>
</tbody>
</table>

### Non-Hazardous Waste

<table>
<thead>
<tr>
<th>Description</th>
<th>Tonnes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic Waste and Recycling</td>
<td>1,179</td>
</tr>
<tr>
<td>Class II Landfill Waste</td>
<td>26,751</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>27,929</strong></td>
</tr>
</tbody>
</table>

**Grand Total** = **82,359**

Subsection 3.1.2 (4i)
Sulphur Production and Air Emissions
Subsection 3.1.2 (5)
Long Lake
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 OrCrude™, 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 OrCrude™, 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.
## Sulphur Recovery Rates & Uptimes

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Claus Units % of Month Processing AG</td>
<td>91.2</td>
<td>100.0</td>
<td>97.8</td>
<td>100.0</td>
<td>100.0</td>
<td>2.9</td>
<td>73.2</td>
<td>100.0</td>
<td>100.0</td>
<td>100.0%</td>
<td>53.2</td>
<td>61.3</td>
<td>81.7</td>
</tr>
<tr>
<td>Sulphur Recovery Monthly Recovery Rate (%)</td>
<td>98.9</td>
<td>99.8</td>
<td>99.8</td>
<td>99.6</td>
<td>99.6</td>
<td>99.5</td>
<td>99.6</td>
<td>99.8</td>
<td>99.8</td>
<td>99.3</td>
<td>99.5</td>
<td>99.5</td>
<td></td>
</tr>
<tr>
<td>Quarterly Recovery Rate (%)</td>
<td></td>
<td>99.5</td>
<td></td>
<td>99.6</td>
<td></td>
<td>99.6</td>
<td></td>
<td>99.5</td>
<td></td>
<td>99.5</td>
<td></td>
<td>99.5</td>
<td></td>
</tr>
<tr>
<td>Average Inlet Sulphur (Tonnes/day)</td>
<td>300.0</td>
<td>535.5</td>
<td>339.1</td>
<td>366.0</td>
<td>330.1</td>
<td>72.3</td>
<td>261.4</td>
<td>387.5</td>
<td>468.6</td>
<td>483.7</td>
<td>192.3</td>
<td>210.3</td>
<td>327.8</td>
</tr>
<tr>
<td>Average Monthly Sulphur Production (Tonnes/day)</td>
<td>296.6</td>
<td>534.2</td>
<td>338.4</td>
<td>364.4</td>
<td>328.6</td>
<td>72.0</td>
<td>260.0</td>
<td>385.9</td>
<td>467.7</td>
<td>482.5</td>
<td>190.9</td>
<td>209.4</td>
<td>326.4</td>
</tr>
</tbody>
</table>

### % Time TGTU in Operation with SRU Trains

<table>
<thead>
<tr>
<th>Month</th>
<th>% Time TGTU in Operation with SRU Trains</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>97.8</td>
</tr>
<tr>
<td>February</td>
<td>100.0</td>
</tr>
<tr>
<td>March</td>
<td>100.0</td>
</tr>
<tr>
<td>April</td>
<td>100.0</td>
</tr>
<tr>
<td>May</td>
<td>100.0</td>
</tr>
<tr>
<td>June</td>
<td>81.0</td>
</tr>
<tr>
<td>July</td>
<td>99.4</td>
</tr>
<tr>
<td>August</td>
<td>100.0</td>
</tr>
<tr>
<td>September</td>
<td>100.0</td>
</tr>
<tr>
<td>October</td>
<td>100.0</td>
</tr>
<tr>
<td>November</td>
<td>92.4</td>
</tr>
<tr>
<td>December</td>
<td>98.6</td>
</tr>
</tbody>
</table>
## Acid Gas Flaring Events Summary

<table>
<thead>
<tr>
<th>Month</th>
<th>AG Sources</th>
<th></th>
<th></th>
<th>SWAG Sources</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Duration</td>
<td>Volume</td>
<td>SO$_2$</td>
<td>Duration</td>
<td>Volume</td>
<td>SO$_2$</td>
</tr>
<tr>
<td></td>
<td>(h)</td>
<td>(Sm$^3$)</td>
<td>(Tonnes)</td>
<td>(h)</td>
<td>(Sm$^3$)</td>
<td>(Tonnes)</td>
</tr>
<tr>
<td>January</td>
<td>85.4</td>
<td>33,621</td>
<td>88.2</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>February</td>
<td>129.9</td>
<td>4,690</td>
<td>3.7</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>March</td>
<td>17.3</td>
<td>4,665</td>
<td>3.2</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>April</td>
<td>0.0</td>
<td>0</td>
<td>0.0</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>May</td>
<td>0.0</td>
<td>0</td>
<td>0.0</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>June</td>
<td>720.0</td>
<td>92,990</td>
<td>2.5</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>July</td>
<td>216.0</td>
<td>107,935</td>
<td>2.9</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>August</td>
<td>23.0</td>
<td>49,666</td>
<td>2.8</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>September</td>
<td>0.0</td>
<td>0</td>
<td>0.0</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>October</td>
<td>0.0</td>
<td>0</td>
<td>0.0</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>November</td>
<td>359.6</td>
<td>2,842</td>
<td>1.5</td>
<td>0.0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>December</td>
<td>41.7</td>
<td>8,878</td>
<td>13.7</td>
<td>14.4</td>
<td>11,596</td>
<td>0.2</td>
</tr>
<tr>
<td>2015 Total</td>
<td>1,592.8</td>
<td>305,288</td>
<td>118.6</td>
<td>14.4</td>
<td>11,596</td>
<td>0.2</td>
</tr>
</tbody>
</table>

AG : Acid Gas  
SWAG : Sour Water Acid Gas

- Total SO$_2$ emissions due to acid gas flaring were 118.6 tonnes
- Acid Gas Flaring Events are part of the monthly air report submitted to Alberta Environment & Parks
- There was a substantial decrease in SWAG flaring in 2015, compared to 2014, due to fewer Upgrader shut down incidents
- The leading causes for the flaring events in 2015 were Upgrader trips and issues with the Recycle Gas Compressor in the HCU.
SO$_2$ Emissions

<table>
<thead>
<tr>
<th>SO$_2$ Limits</th>
<th>Quarter</th>
<th>Total (tonnes)</th>
<th>Average (tonnes/day)</th>
<th>Limit (tonnes/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long Lake Plant</td>
<td>ALL</td>
<td>1,519.6</td>
<td>4.2</td>
<td>18.5</td>
</tr>
<tr>
<td>K1A Plant</td>
<td>ALL</td>
<td>13.2</td>
<td>0.04</td>
<td>1.8</td>
</tr>
<tr>
<td>SRU Incinerator</td>
<td>1st</td>
<td>219.7</td>
<td>2.4</td>
<td></td>
</tr>
<tr>
<td></td>
<td>2nd</td>
<td>150.6</td>
<td>1.6</td>
<td></td>
</tr>
<tr>
<td></td>
<td>3rd</td>
<td>235.8</td>
<td>2.6</td>
<td></td>
</tr>
<tr>
<td></td>
<td>4th</td>
<td>169.8</td>
<td>1.9</td>
<td></td>
</tr>
<tr>
<td>Stack</td>
<td></td>
<td></td>
<td></td>
<td>15.6</td>
</tr>
</tbody>
</table>

• The total amount of SO$_2$ emitted from the entire Long Lake Facility was 1,519.6 tonnes.
• The plant emitted an average of 4.2 tonnes/day, with a limit of 18.5 tonnes/day.
• From the SRU Incineration, the 3$^{rd}$ quarter had the greatest average of SO$_2$ emissions, with 2.6 tonnes/day emitted. The limit is 15.6 tonnes/day/quarter.
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 measure $\text{SO}_2$, $\text{O}_3$, TRS, THC, NO, NO$_2$, NO$_X$, PM 2.5, wind speed and direction, and temperature.

There were 8 events in 2015 which exceeded the Alberta Ambient Air Quality Objectives (AAAQO). All of these events were attributed to forest fires burning in the region.

<table>
<thead>
<tr>
<th>Date</th>
<th>Parameter</th>
<th>Concentration</th>
<th>Limit</th>
<th>AER Ref #</th>
</tr>
</thead>
<tbody>
<tr>
<td>June 29</td>
<td>PM 2.5</td>
<td>78 $\mu$g/m$^3$</td>
<td>30 $\mu$g/m$^3$ 24 hr avg</td>
<td>300127</td>
</tr>
<tr>
<td>June 30</td>
<td>PM 2.5</td>
<td>81 $\mu$g/m$^3$</td>
<td></td>
<td>300199</td>
</tr>
<tr>
<td>July 1</td>
<td>PM 2.5</td>
<td>58 $\mu$g/m$^3$</td>
<td></td>
<td>300242</td>
</tr>
<tr>
<td>July 2</td>
<td>PM 2.5</td>
<td>38 $\mu$g/m$^3$</td>
<td></td>
<td>300293</td>
</tr>
<tr>
<td>July 3</td>
<td>PM 2.5</td>
<td>108 $\mu$g/m$^3$</td>
<td></td>
<td>300350</td>
</tr>
<tr>
<td>July 4</td>
<td>PM 2.5</td>
<td>85 $\mu$g/m$^3$</td>
<td></td>
<td>300386</td>
</tr>
<tr>
<td>July 11</td>
<td>PM 2.5</td>
<td>146 $\mu$g/m$^3$</td>
<td></td>
<td>300736</td>
</tr>
<tr>
<td>July 12</td>
<td>PM 2.5</td>
<td>143 $\mu$g/m$^3$</td>
<td></td>
<td>300782</td>
</tr>
</tbody>
</table>
Passive Air Monitoring Locations
Long Lake & K1A
# Passive Air Monitoring Station Status

<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>Kinesis 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 AAAQO set out by the 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 3 ppbv. No stations exceeded this limit in 2015.
The AAAQO set out by the 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 3 ppbv. No stations exceeded this limit in 2015.
The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. No stations exceeded this limit in 2015.
K1A SO$_2$ Passive Monitoring

- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. No stations exceeded this limit in 2015.
Summary of Environmental Issues
Subsection 3.1.2 (6,7,8)
Long Lake
Regulatory Compliance

- Inspections (78)
  - Satisfactory Inspections (62)
  - ~50 in relation to the K1A Pipeline Release
  - Unsatisfactory Inspections (16)
    - Mostly related to the pipeline suspension order
    - All actions related to these inspections have been resolved

- Voluntary Self Disclosures (7)

- Regulatory Notifications (7)
  - Environmental Protection Order (July 17)
  - Pipeline Suspension Order (August 28)
Environmental Regulatory Compliance

- 30 Notifications, 17 Permit Violations and 26 Reportable Spills

### Notifications and Permit Violations Summary

<table>
<thead>
<tr>
<th></th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Sands</td>
<td>191</td>
<td>98</td>
<td>52</td>
<td>47</td>
</tr>
</tbody>
</table>

- Totals are trending down from previous years
- In 2015, there were 31 hours (some during the same reportable event) where approval limits were exceeded based upon values measured by the CEMS units.
- Other permit violations included, flaring > 20 tonnes SO₂ (2), the SAGD flare extinguishing, and an increase in TDS (total dissolved solids) at a source well.

### Reportable Spill Summary

<table>
<thead>
<tr>
<th></th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Sands</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Events</th>
<th>Volume (m³)</th>
<th>Events</th>
<th>Volume (m³)</th>
<th>Events</th>
<th>Volume (m³)</th>
<th>Events</th>
<th>Volume (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil Sands</td>
<td>32</td>
<td>430</td>
<td>20</td>
<td>548</td>
<td>17</td>
<td>1,551</td>
<td>26</td>
<td>*5,937</td>
</tr>
</tbody>
</table>

- Total number of reportable spills are up from previous years but the average volume of reportable spills is down from 2014 (including the K1A emulsion line release).

*Volumes include liquid and solid reportable releases*
AER Scheme Approval

• Amendments Approved in 2015:
  – Field Trial Co-Injection of NCG with Steam at Pad 7N – Approved March 11, 2015
  – Long Lake Expansion of Development Area; Addition of Pad 19 – Approved July 19, 2015
  – Long Lake at Infill Wells at Pads 6N, 6W, 8 and 10W – Approved March 17, 2015
  – Kinosis Phase 1B CPF Location and Production Capacity – Approved April 24, 2015
  – Kinosis Phase 1B Well pads 39101 – 39104 – Approved August 17, 2015
  – Long Lake Pad 3 Infill Application – Approved July 9, 2015
  – K1A Drainage Area A Revision to MOP – Approved August 4, 2015
  – Long Lake Pad 5 Infill Application – Approved July 30, 2015
  – Long Lake Well Compatibility for Thermal Operations Pads 1 and 7 Infills – Approved November 16, 2015
  – Modifications to Pads 14 & 15 Operating Program – Approved December 17, 2015
Applications Under Review in 2015:
  – Long Lake Southwest Modifications (Approved March 31, 2016)

Amendments Approved in 2016:
  – Long Lake Well Compatibility for Thermal Operations Pads 5 and 8 – Approved September 22, 2016
Environmental Summary

Monitoring Programs

• Received the new EPEA Approval for Long Lake in October of 2015

• All monitoring programs were conducted in accordance with regulatory approvals and most plans will be updated in 2016 with the issuance of the new approval:
  – Groundwater monitoring
  – Hydrology and water quality monitoring
  – Soil monitoring
  – Wildlife monitoring
  – Wetland monitoring
  – Source emission and ambient air monitoring
  – Conservation and reclamation plans
Environmental Summary
Monitoring Programs

- 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)
### Long Lake EPEA Approval Requirements

<table>
<thead>
<tr>
<th>Schedule</th>
<th>Section</th>
<th>Topic</th>
<th>Report</th>
<th>Deadline</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>IV</td>
<td>04</td>
<td>Air Emissions</td>
<td>VOC and RSC Emissions Monitoring Plan</td>
<td>November 16, 2016</td>
<td>In Progress</td>
</tr>
<tr>
<td>VI</td>
<td>06</td>
<td>Groundwater</td>
<td>Groundwater Monitoring Plan - Updated</td>
<td>April 30, 2016 [Extension to Dec 15, 2016]</td>
<td>In Progress</td>
</tr>
<tr>
<td>VII</td>
<td>07</td>
<td>Soil</td>
<td>Soil Monitoring Program Proposal</td>
<td>31-Jan-2017 31-Jan-2021</td>
<td>NA</td>
</tr>
<tr>
<td>VII</td>
<td>07</td>
<td>Soil</td>
<td>Soil Monitoring Program Report</td>
<td>Extension to Nov 30, 2016</td>
<td>In Progress</td>
</tr>
<tr>
<td>VII</td>
<td>07</td>
<td>Soil</td>
<td>Soil Monitoring Program Report</td>
<td>31-Jan-2018 31-Jan-2022</td>
<td>NA</td>
</tr>
<tr>
<td>VIII</td>
<td>01</td>
<td>Wildlife</td>
<td>Wildlife Mitigation Proposal</td>
<td>30-Apr-2016 Extension to June 15, 2016 Extension to June 30, 2016 (Due to Wildfire)</td>
<td>Complete</td>
</tr>
<tr>
<td>VIII</td>
<td>02</td>
<td>Wildlife</td>
<td>Woodland Caribou Monitoring and Mitigation Program Proposal</td>
<td>30-Apr-2016 Extension to June 15, 2016 Extension to June 30, 2016 (Due to Wildfire)</td>
<td>Complete</td>
</tr>
<tr>
<td>VIII</td>
<td>03</td>
<td>Wildlife</td>
<td>Wildlife Monitoring Program Proposal</td>
<td>30-Apr-2016 Extension to June 15, 2016 Extension to June 30, 2016 (Due to Wildfire)</td>
<td>Complete</td>
</tr>
<tr>
<td>IX</td>
<td>07</td>
<td>Construction, Decommissioning and Reclamation</td>
<td></td>
<td>June 30, 2017</td>
<td>NA</td>
</tr>
<tr>
<td>IX</td>
<td>08</td>
<td>Construction, Decommissioning and Reclamation</td>
<td>Wetland Reclamation Trial Program Proposal (Project Specific)</td>
<td>June 30, 2017</td>
<td>NA</td>
</tr>
<tr>
<td>IX</td>
<td>09</td>
<td>Construction, Decommissioning and Reclamation</td>
<td>Reclamation Monitoring Program Proposal</td>
<td>June 15, 2018</td>
<td>NA</td>
</tr>
<tr>
<td>XI</td>
<td>10</td>
<td>Wetlands and Waterbodies</td>
<td>Wetland and Water Body Monitoring Program</td>
<td>June 30, 2016 [Extension to Dec 15, 2016]</td>
<td>In Progress</td>
</tr>
</tbody>
</table>
Environmental Summary
Operational Initiatives

• Nexen worked with a consultant in cooperation with the AER to develop an Odour Monitoring Plan to identify any odour-producing sources at Long Lake which included:
  – ranking the sources by their potential to cause odour events at the local community Anzac; and
  – identifying the conditions that will lead to odour events in Anzac.

• This plan will help Nexen achieve compliance with both our approval conditions and Directive 60, and ensure that Long Lake is not negatively impacting the neighboring community.

• The monitoring program was scheduled to begin in the spring of 2016, however, due to the incident in early 2016, that resulted in reduced plant rates of the, it was decided in collaboration with the AER that implementation would be most effective once the plant returns to normal operations.

• Tank gaskets were changed to Teflon during Turnaround 2015. An RCA determined that Teflon was more compatible with the diluent material in the tank. This change reduced tank wisping incidents which can help to reduce potential odour issues.
Environmental Summary: Innovation, Research & 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 Areas as well as the Monitoring working group.
  – Leading multiple Joint Industry Projects including caribou habitat restoration, reclamation practice studies, and wildlife monitoring technologies.
Compliance Statement

• To the best of Nexen’s knowledge, the Long Lake Project is compliant with the conditions of its approvals and regulatory requirements subject to the items listed non-complaint of the Summary table that follows.
## Compliance Discussion

<table>
<thead>
<tr>
<th>Notice</th>
<th>Events that led to the non-compliance</th>
<th>Nexen action plan</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Environmental Protection Order (EPO) - section 113 of EPEA in relation to the 16-24-85-TW4 Pipeline Spill discovered July 15, 2015</td>
<td>Nexen identified a pipeline break that resulted in a release and regulatory investigations.</td>
<td>Nexen responded to numerous information requests and interviews.</td>
<td>All requests for information and interviews from EC and the AER have been responded to by Nexen.</td>
</tr>
<tr>
<td>Environment Canada and AER Lead an investigation in relation to the Pipeline Spill discovered July 15, 2015</td>
<td>Nexen identified a pipeline break that resulted in a release and regulatory investigations.</td>
<td>Nexen responded to numerous information requests and interviews.</td>
<td>All requests for information and interviews from EC and the AER have been responded to by Nexen.</td>
</tr>
<tr>
<td>High Risk Enforcement Action- Failure to Comply with Directive 013: Suspension Requirements for 1 Oil Sands Well. Nexen received an initial notice to comply in May 2014 and was given until March 31, 2015 to achieve compliance.</td>
<td>Failure to submit the downhole work that was done prior to March 31, 2015 into the DDS system.</td>
<td>Nexen submitted the downhole work in the DDS system April 23, 2015.</td>
<td>Compliance achieved May 7, 2015.</td>
</tr>
<tr>
<td>Notice of Noncompliance- Outstanding submission of drilling waste information for 1 Oil sands well as per Directive 050: Drilling Waste Management. March 24, 2015.</td>
<td>Failure to submit drilling waste information within the 24 month due date.</td>
<td>Nexen submitted the drilling waste information in the DDS system.</td>
<td>Compliance achieved April 10, 2015.</td>
</tr>
<tr>
<td>Notice of Noncompliance- Outstanding submission of drilling waste information for 4 Oil sands wells as per Directive 050: Drilling Waste Management. June 1, 2015.</td>
<td>Failure to submit drilling waste information within the 24 month due date.</td>
<td>Nexen submitted the drilling waste information in the DDS system.</td>
<td>Compliance achieved June 12, 2015.</td>
</tr>
<tr>
<td>Notice of Noncompliance- Outstanding Non-Abandoned Oil Sands Evaluation (OSE) wells July 16, 2015. 24 wells.</td>
<td>Failure to report surface abandonments for 6 wells through the DDS system within 30 days of completing the operation. 18 of the OSE wells were converted and were missing a license amendment and a Lahee classification change.</td>
<td>Nexen submitted the surface abandonment information in the DDS system. Nexen applied for license amendments and requested Lahee classification changes.</td>
<td>Compliance achieved August 14, 2015.</td>
</tr>
</tbody>
</table>
## Compliance Discussion continued

<table>
<thead>
<tr>
<th>Notice</th>
<th>Events that led to the non-compliance</th>
<th>Nexen action plan</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Suspension Order: Issued on August 28, 2015; under section 29 of the Pipeline Act; Suspend operations under the licenses of 15 Pipelines effective immediately</td>
<td>Nexen submitted a Self-Disclosure on August 25, 2015 of 102 identified Pipeline Segments that were in contravention of Manual 005: Pipeline Inspections.</td>
<td>Nexen immediately conducted the required inspections completed a number of corrective actions, and made numerous submissions to the AER. Three amendment orders were subsequently issued on September 6 and October 22, 2015 allowing Nexen to resume full operations.</td>
<td>Nexen is in compliance with the Manual 005 regulatory requirements identified in the Self-Disclosure letter of August 25, 2015.</td>
</tr>
<tr>
<td>Unsatisfactory Low Risk Crude Bitumen Group battery Inspection @ 7-31-85-6W4 June 5, 2015</td>
<td>Contravention of EPEA Approval in relation to fugitive emissions and industrial waste water.</td>
<td>AER field office provided Nexen with a remedial action plan to achieve compliance. Nexen complied with all items. 7 day letter requirement was waived.</td>
<td>Compliance achieved June 9, 2015</td>
</tr>
<tr>
<td>Unsatisfactory High Risk Natural Gas Pipeline Inspection @ 09-03-086-07W4 P39427 on Aug 31, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen immediately conducted the required inspections and provided all requested data to the AER.</td>
<td>Compliance achieved Sept 6, 2015</td>
</tr>
<tr>
<td>Unsatisfactory High Risk Water Pipeline Inspection @ 07-36-085-07W4 P39428 on Aug 31, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen immediately conducted the required inspections and provided all requested data to the AER.</td>
<td>Compliance achieved Sept 6, 2015</td>
</tr>
<tr>
<td>Unsatisfactory High Risk steam or produced vapour Pipeline Inspection @ 06-31-085-06W4 P52773 on Aug 31, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen immediately conducted the required inspections and provided all requested data to the AER.</td>
<td>Compliance achieved Sept 16, 2015</td>
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<tr>
<td>Unsatisfactory High Risk Crude Oil Pipeline Inspection @ 06-31-085-06W4 P52719 on Aug 31, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen immediately conducted the required inspections and provided all requested data to the AER.</td>
<td>Compliance achieved Sept 16, 2015</td>
</tr>
<tr>
<td>Unsatisfactory High Risk disposal, brackish water Pipeline Inspection @ 01-31-085-06W4 P39429 on Aug 31, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen immediately conducted the required inspections and provided all requested data to the AER.</td>
<td>Compliance achieved Oct 22, 2015</td>
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</table>
# Compliance Discussion continued

<table>
<thead>
<tr>
<th>Notice</th>
<th>Events that led to the non-compliance</th>
<th>Nexen action plan</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unsatisfactory High Risk Steam or produced vapour Pipeline Inspection @ 02-07-086-06W4 P52777 on Sept 01, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen immediately conducted the required inspections and provided all requested data to the AER.</td>
<td>Compliance achieved Sept 16, 2015</td>
</tr>
<tr>
<td>Unsatisfactory High Risk Steam or produced vapour Pipeline Inspection @ 02-07-086-06W4 P53285 on Sept 01, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen immediately conducted the required inspections and provided all requested data to the AER.</td>
<td>Compliance achieved Sept 16, 2015</td>
</tr>
<tr>
<td>Unsatisfactory High Risk Water Pipeline Inspection @ 03-35-084-07W4 P54599 on Sept 01, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen immediately conducted the required inspections and provided all requested data to the AER.</td>
<td>Compliance achieved Oct 22, 2015</td>
</tr>
<tr>
<td>Unsatisfactory High Risk Natural Gas Pipeline Inspection @ 06-31-085-06W4 P43961 on Sept 01, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen immediately conducted the required inspections and provided all requested data to the AER.</td>
<td>Compliance achieved Sept 6, 2015</td>
</tr>
<tr>
<td>Unsatisfactory High Risk steam or produced vapour Pipeline Inspection @ 06-31-085-06W4 P52775 on Sept 01, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen immediately conducted the required inspections and provided all requested data to the AER.</td>
<td>Compliance achieved Sept 16, 2015</td>
</tr>
<tr>
<td>Unsatisfactory High Risk Natural Gas Pipeline Inspection @ 10-24-084-07W4 P51056 on Sept 01, 2015</td>
<td>Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662.</td>
<td>Nexen continues to work with the AER on these inactive pipelines.</td>
<td>Nexen continues to work with the AER on these inactive pipelines.</td>
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### Compliance Discussion continued

| Unsatisfactory High Risk Natural Gas Pipeline Inspection @ 10-29-084-06W4 P51055 on Sept 01, 2015 | Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662. | Nexen continues to work with the AER on these inactive pipelines. | Nexen continues to work with the AER on these inactive pipelines. |
| Unsatisfactory High Risk Water Pipeline Inspection @ 16-27-084-07W4 P54531 on Sept 01, 2015 | Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662. | Nexen immediately conducted the required inspections and provided all requested data to the AER. | Compliance achieved Sept 6, 2015 |
| Unsatisfactory High Risk Natural Gas Pipeline Inspection @ 05-08-086-06W4 P53287 on Sept 01, 2015 | Nexen was issued a suspension order on August 28, 2015 for contravention of Manual 005: Pipeline inspections; and CSA Z662. | Nexen immediately conducted the required inspections and provided all requested data to the AER. | Compliance achieved Sept 16, 2015 |
## Compliance Discussion - VSDs

<table>
<thead>
<tr>
<th>Notice</th>
<th>Events that led to the non-compliance</th>
<th>Nexen action plan</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voluntary Self Disclosure – temperature response/exceedance in 2015 while drilling 1 observation well; as per Scheme Approval 9485 January 30, 2015.</td>
<td>Nexen identified temperature exceedance after logging the well.</td>
<td>Nexen has submitted all requested data to the AER.</td>
<td>Compliance achievement date is Mar 30, 2015. June 4, 2015 the AER provided Nexen with a letter advising that prior to returning to normal steaming operations that AER be contacted.</td>
</tr>
<tr>
<td>Voluntary Self Disclosure - Directive 056: Energy Development Applications and Schedules.4 oil sands observations wells. Feb 12, 2015.</td>
<td>Nexen identified 4 oil sands observation wells that were converted to injection wells.</td>
<td>Nexen has submitted all amendments and Lahee classification changes to the AER.</td>
<td>Compliance achieved Sept 9, 2015.</td>
</tr>
<tr>
<td>Voluntary Self Disclosure -Directive 081: Water Disposal Limits and Reporting Requirements for Thermal In situ Oil Sands Schemes. Water balance issue at the Long Lake injection facility. March 24, 2015.</td>
<td>Nexen had a pipeline leak and it was discovered that the total flow was not recorded. Monthly balance exceeds 5.0 percent for 3 consecutive months.</td>
<td>Nexen submitted all pertinent data to the AER.</td>
<td>Compliance achieved March 24, 2015.</td>
</tr>
<tr>
<td>Voluntary Self Disclosure - thermal compatibility reviews prior to operating producer and injector wells- Scheme approval No. 9485. Multiple wells. April 22, 2015.</td>
<td>Nexen identified failure to perform thermal compatibility reviews during an internal assessment.</td>
<td>Nexen conducted the reviews submitted all pertinent data to the AER.</td>
<td>Compliance achieved Aug 14, 2015.</td>
</tr>
<tr>
<td>Voluntary Self Disclosure - Directive 020: Well Abandonment - 1 historical Oil Sands well where the downhole abandonment did not meet directive standard. December 16, 2015</td>
<td>Nexen identified the downhole abandonment issue when preparing well for a thermal wellhead change.</td>
<td>Nexen submitted an action plan and has commenced the remedial work.</td>
<td>Date to achieve compliance is Mar 31, 2017</td>
</tr>
<tr>
<td>Voluntary Self Disclosure- Directive 76: Operator Declaration Regarding measurement and reporting requirements, with respect to Theme 10-fuel, flare and venting at facility ID ABBT 0094109</td>
<td>Nexen identified contraventions in fuel, flare and venting during the 2015 EPAP audit at the Long Lake facility.</td>
<td>Nexen has created an action plan and is in the process of implementation.</td>
<td>Compliance achievement date is set to Oct 31, 2016.</td>
</tr>
<tr>
<td>Voluntary Self Disclosure - Directive 056: Energy and development applications and schedules &amp; Directive 059: Well Drilling and completion data filing requirements - Oil and Gas Conservation Act-6 wells June 30, 2015</td>
<td>Nexen identified wellbores that experienced mechanical issues during drilling and Rig was subsequently skidding over leaving the original bore hole with no licence or information submitted to the AER.</td>
<td>Nexen submitted an action plan and received all approvals and submitted all pertinent data in the DDS system.</td>
<td>Compliance achieved July 20 and Oct 29, 2015</td>
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<td>Incident Number</td>
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<td>License Number</td>
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<td>20153364</td>
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<td>20152116</td>
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<td>8-Aug-15</td>
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<td>20151896</td>
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<td>P39429</td>
<td>15-Jul-15</td>
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<td>20151882</td>
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<td>P54767</td>
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<td>20151852</td>
<td>02-35-084-07W4</td>
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### Reportable Spills continued

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<th>Facility Type</th>
<th>Cause</th>
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<th>Material</th>
<th>Volume (m³)</th>
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<tr>
<td>20151850</td>
<td>07-31-085-06W4</td>
<td>F32978</td>
<td>6-Jul-15</td>
<td>Battery</td>
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<td>8-Jun-15</td>
<td>Battery</td>
<td>Equipment Failure-External corrosion</td>
<td>11-Aug-15</td>
<td>Heating Oil</td>
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<td>20151529</td>
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<td>4-Jun-15</td>
<td>Battery</td>
<td>Operator Error-Oversight</td>
<td>25-Jan-16</td>
<td>Oily Sludge</td>
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<td>20151517</td>
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<td>3-Jun-15</td>
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<td>Oily Sludge</td>
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<td>14-May-15</td>
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<td>Operator Error-Non-procedural</td>
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<td>Fresh Water</td>
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<td>20151251</td>
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<td>Equipment Failure-Malfunction</td>
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<td>20150448</td>
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<td>11-Feb-15</td>
<td>Battery</td>
<td>Operator Error-Oversight</td>
<td>23-Feb-15</td>
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<td>Equipment Failure-Mechanical/Structural Malfunction</td>
<td>24-Apr-15</td>
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<td>16-Jan-15</td>
<td>Battery</td>
<td>Equipment Failure-Malfunction</td>
<td>21-Jan-16</td>
<td>Produced Water</td>
<td>2.5</td>
</tr>
</tbody>
</table>

* Classified as a Permit Violation by Nexen
Future Plans - Surface

- As a result of the Pipeline release and the Upgrader explosion, Nexen is currently evaluating operating options which include:
  - SAGD only;
  - SAGD with an Upgrader; or
  - SAGD with modifications to the Upgrader.
Well Pad Performance Subsection 3.1.7(h) Long Lake
### Pad 1 Production Summary

- **All 5 wells on ESP**
- **Operational instability resulted in lower performance**
- **At YE, injection pressures were ~1,450-1,750 kPa**

- Five well pairs (01P01 to 01P03, 04P05 and 04P06)
- Cumulative production of 917 $E^3m^3$ (RF 43%)
All 6 wells on ESP
Steam SI to 02S04, 02S05 and 02S06
Stable operations and steam injection helped maintain production
At YE, injection pressures were ~1,200 – 1,485 kPa

Six well pairs (02P01 to 02P06)
Cumulative production of 680 E³m³ (RF 28%)
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 ~1,200 – 1,720 kPa

Five well pairs (02P07 to 02P011)
Cumulative production of 257 E³m³ (RF 21%)
• All 5 wells on ESP
• Short-term steam reductions to 03S01
• At YE, injection pressures were ~1,285-1,550 kPa

• Five well pairs (03P01 to 03P05)
• Cumulative production of 1,049 E^3m^3 (RF 42%)
• 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 89 E^3m^3 (RF 50%)
Pad 5 Production Summary

- All 5 wells on ESP
- Steam was SI to 05S04 and 05S05
- Reduced steam injection pressures and operational instability resulted in lower performance
- 5S01 toe steam was restarted in Q3
- At YE, injection pressures were ~1,300–1,750kPa

- Five well pairs (05P01 to 05P05)
- Cumulative production of 1,213 E³m³ (RF 37%)

![Graph showing production rates and SOR & Well Count over years 2007 to 2015.](image)

- Bitumen
- Water
- Steam
- SOR
- Well Count

Year: 2007 to 2015
Pad 6N Production Summary

- All wells on ESP
- 3 injector wells currently shut in or at minimum rates for different reasons
- Only three injectors are injecting to support 5 producer wells
- 6P4 plugged back due to poor reservoir quality at toe
- At YE, injection pressures were ~1,750–1,850kPa

- Six well pairs (06P01 to 06P05 plus 06P13)
- Cumulative production of 713 E³m³ (RF 24%)
Pad 6W Production Summary

- Seven well pairs (06P06 to 06P12)
- Cumulative production of $763 \text{ E}^3\text{m}^3$ (RF 39%)
- All 7 wells on ESP
- Strong performance from 6P06
- 6P12 shut in due to potential liner failure on April 3\textsuperscript{th} 2014
- At YE, injection pressures were ~1,450–1,650 kPa
All 7 wells on ESP
Stable operation
Continuing to see strong performance from northern well pairs
At YE, injection pressures were ~1,850–2,050 kPa
NCG co-injection started October 2014 on 07P07, 07P08, 07P09
NCG co-injection has not been restarted since 2015 turnaround
Liner failure on 07P07 repaired with liner and packer assembly
07P12 shut in due to potential liner failure

- Seven well pairs (07P06 to 07P12)
- Cumulative production of 655 E³m³ (RF 47%)
Pad 7N Production Summary

- All 9 wells on ESP
- Infill producer wells (drilled in 2014) ramped up after steam squeeze – one well started up without steam squeeze
- Strong performance from infill producer wells
- Completed construction for proposed NCG co-injection pilot project
- NCG co-injection expected to start in 2016
- Increased steam injection to support infill producer wells and neighboring Pad 8
- At YE, injection pressures were ~1,950 - 2,100 kPa

- Five well pairs (07P01 to 07P05)
- Four infill producer wells (10P14 to 10P17)
- Cumulative production of 1,693 E³m³ (RF 53%)
Pad 8 Production Summary

- All 6 wells on ESP
- 08S06 shut in after potential liner failure
- No observed negative impact to 08P06 production
- Increased injection on 08S05 to support 08P06
- ICD’s installed on 08P03
- At YE, injection pressures were ~1,800–2,050 kPa

- Six well pairs (08P01 to 08P06)
- Cumulative production of 1,009 E³m³ (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 218 E^3m^3 (RF 19%)
Pad 9W Production Summary

- 9P1-9P3 on gas lift
- 9P4 & 9P5 on ESP
- The wells don’t witness obvious decline except 9P5
- At YE, injection pressures were ~1,800 - 1,850 kPa

- Five well pairs (09P01 to 09P05)
- Cumulative production of 406 E^3 m^3 (RF 25%)
• All wells on gas lift
• Oil cut has improved steadily throughout the life of the well, resulting in improved bitumen production
• At YE, injection pressures were ~1,800 – 2,000 kPa

• Three well pairs producing (10P10 to 10P12)
• Cumulative production of 194 E^3 m^3 (RF 18%)
Five well pairs (10P01 to 10P05)

Cumulative production of 582 E$^3$m$^3$ (RF 29%)

- All 5 wells on ESP
- Stable operation
- Performance impacted by top water
  WSR > 1.0
- At YE, injection pressures were
  ~1,830–1,950 kPa
Pad 11 Production Summary

- Ten well pairs (11P01 to 11P10)
- Cumulative production of 1,050 E³m³ (RF 48%)
- All 10 wells are on ESP
- Pad in possible decline phase
- Decline in bitumen rates can likely be attributed to top water effect
- 11S08 shut in since steam kick during workover in Q3
- Liner failure on 11P02 repaired with liner and packer assembly
- At YE, injection pressures were ~1,710–1,750 kPa
Pad 12 Production Summary

- Nine well pairs (12P01 to 12P09)
- Cumulative production of 459 $E^3m^3$ (RF 14%)
- All 9 wells are on ESP
- Flat bitumen rate attributed to lean zone and facility constraints
- At YE, injection pressures were $\sim1,700–1,870$ kPa
• Nine well pairs (13P01 to 13P09)
• Cumulative production of 584 E$^3$m$^3$ (RF 18%)

- All 9 wells are on ESP
- Flat bitumen rate attributed to lean zone and facility constraints
- Initiated ES-SAGD project at wells 13P3 and 13P4 in October, 2014. Limited solvent injection following T/A due to facility constraints.
- At YE, injection pressures were ~ 1,680–1,850 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 206 E³m³ (RF 11%)
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 106 E^3m^3 (RF 8%)
Well Pad Performance
Subsection 3.1.7(h)
Kinesis
• 6 pairs on production
  – K1P10 to K1P16
  – Operating pressures 1300 to 2800 kPa
  – Performance impacted by bottom water
• K1P09 shut-in
• K2P01, K2P02 were inactive

• Ten well pairs (K1P09 to K1P16, K2P01 to K2P02)
• Cumulative production of 15 E³m³ (RF 0.4%)
K1A-B Production Summary

- 3 well pairs on SAGD
  - K2P13 - K2P15
  - Pressures of 1800 to 2800 kPa
- K2P09 on circulation

- Eight well pairs (K2P09 to K2P16)
- Cumulative production of 11 E$^3$m$^3$ (RF 0.3%)
K1A-C Production Summary

- 7 well pairs on SAGD
  - K1P01, K1P03-K1P08
  - Operating Pressures from 1700 kPa to 2800 kPa
  - Demonstrating strong production performance
- K1P02 on circulation

- Eight well pairs (K1P01 to K1P08)
- Cumulative production of 116 E^3 m^3 (RF 2.2%)
• Eleven well pairs (K2P03 to K2P08 and K2P18 to K2P22)
• Cumulative production of 39 E³m³ (RF 0.7%)

• 5 well pairs on SAGD
  – K2P18 - K2P22
  – Maintain consistent operating pressure of 2800kPa
  – Exhibiting strong production performance

• 6 well pairs on circulation
  – K2P03 – K2P08