Annual
Surmont SAGD Performance Review
Approvals 9426, 11596, and 9460

April 9, 2014
Calgary, Alberta, Canada
• Introduction
• Surmont Overview and Highlights
• Subsurface Resource Evaluation and Recovery
• Surface Operations and Compliance
• Future Plans
• Surface Operations and Compliance - Pilot Project
Introduction
Ownership and Approvals

• **Ownership**
  • The Surmont In Situ Oil Sands Project is a 50/50 joint venture between ConocoPhillips Canada Resources Corp. and TOTAL E&P Canada Ltd; Operated by ConocoPhillips

• **Project History**
  • 1997 - First steam at pilot project
  • 2007 - First steam at Phase 1
  • 2010 - Construction start at Phase 2

• **Approval Update**
  • **AER Approval No. 9426**
    • Amendments 9426T and 9426W
      • Alternative Start-Up Strategies at Well Pad 101
    • Multiple Amendments
      • Geological Cross-Sections for Well Pads 262-3, 265-2, 261-3, and 262-2
      • Well Pad 262-2 pending approval (application 1779086)
    • Amendment 9426U
      • Buffer Well at Pad 264-1
    • Application 1783231
      • Sustaining Well Pad 104
Surmont Overview and Highlights
Surmont Overview

- Currently identifying optimization opportunities based on actual conditions at Phase 1

Subsection 3.1.1 (1)

Surmont combined approved capacity is 21,624 m$^3$/d (136,000 bbl/cd)
(Phase 1 - 4,293 m$^3$/d, Phase 2 - 17,331 m$^3$/d)
2013 Highlights

- Operational excellence: focused on integrated operations to improve safety and productivity
- Leveraged learnings from Phase 1 and other operators
- Continued to plan sustaining pads
- Continued to plan infill well development to optimize recovery at Phase 1
- Construction is ongoing for debottlenecking projects
- Phase 2 construction is progressing
- Reached new bitumen production and steam injection records during 2013
- **Key improvements/successes:**
  - Achieved production proration factor compliance
  - Improved ESP conversion time
  - Achieved longer periods of Central Processing Facility (CPF) stability
  - Achieved high operating efficiency
  - Soda ash silo commissioned and operating
  - Multiphase Flow Meter (MPFM) trial
  - Completed field trial for solvent injection at E-SAGD pilot
  - Completed Median Pressure reduced Blowdown trial
- **Key challenges:**
  - Water treatment → Once Through Steam Generation (OSTG) Scale
  - Water balance and water recycle

Subsection 3.1.1 (1)
Phase 1 Production

Surmont Phase 1 Historical Performance
(EOD, January 31, 2014)

- 2008 Key Issues
  - Freezing
  - Off-spec product
  - Plant instability

- 2009 Key Issues
  - OTSG integrity
  - Front-end treatment
  - 1st turnaround

- 2010 Key Issues
  - ESP installations
  - OTSG maintenance

- 2011 Key Issues
  - ESP installations
  - OTSG maintenance

- 2012 Key Issues
  - ESP installations / Repair
  - OTSG maintenance

- 2013 Key Issues
  - ESP installations / Repair
  - OTSG maintenance

Continued stable operations

Subsection 3.1.1 (1)
Lost Production Rollup

Oil losses (bbls) Jun-Dec 2013

- Equipment changes: 37%
- Planned equipment maintenance: 15%
- Other: 6%
- Third party power supply failure: 42%
- Planned AL replacement: 5%
- Completion failures: 10%
- Optimization / Troubleshoot: 14%
- Planned surface equip upgrade: 2%
- Integrity testing: 2%
- Above subcool/gas issues: 18%
- ALS limited-downhole: 25%
- Other: 0%

Losses Avg - History

- 2013: 2,164 bpd
- 2012: 2,437 bpd
- 2011: 3,376 bpd

18% Facilities
80% Wells
2% Export
Subsurface Resource Evaluation and Recovery Approvals 9426, 11596, and 9460

April 9, 2014
Calgary, Alberta, Canada
Contents of Presentation

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Geology and Geophysics
Subsection 3.1.1 (2a,b)

2013-2014 Delineation Program and Well Density

1277 existing wells – 195 new

195 new vertical wells (as of Jan 31, 2014)

Phase 1 and Phase 2 Development Area

Phase 2 drainage areas

Surmont lease
Focus on Phase 2 initial drainage areas and initial Surmont 1 sustaining pad locations as well as delineation of Phase 3
(only includes wells that penetrate the McMurray)

- Existing wells
- New vertical wells (as of Jan 31, 2014)
- Phase 1 and Phase 2 Development Area
- Phase 2 drainage areas
- Surmont lease
Delineation across Phase 1, 2, and 3

Delineation Well Density Map - Jan 2013

Delineation Well Density Map - Jan 2014

Symbol Legend:
- 0 wells
- 1 well
- 2 wells
- 3-5 wells
- 6-9 wells
- 10-20 wells
- 21+ wells
- Surmont Lease
- Townships
1277 wells total

468 existing core wells

81 new core wells (as of Jan 31, 2014)

Phase 1 and Phase 2 Development Area

Phase 2 drainage areas

Surmont lease
Subsection 3.1.1 (2a,b)

Existing wells
Existing cored wells
New core wells (as of Jan 31, 2014)
Phase 1 and Phase 2 Development Area
Phase 2 drainage areas
Surmont lease
Increased core density with latest drilling

Cored Wells Density Map - Jan 2013

Cored Wells Density Map - Jan 2014

McMurray penetrated wells only
Subsection 3.1.1 (2f)

**2013-2014 Delineation Program and FMI Logs**

- **100% Coverage of Formation Micro Imaging (FMI) Data** in 2013/2014 program
- **Important for breccia identification**

- **1277 wells total**
- **908 existing FMI wells**
- **193 new FMI wells**
  (as of Jan 31, 2014)

- **Phase 1 and Phase 2 Development Area**
- **Phase 2 drainage areas**

**McMurray FMI Wells - Surmont Lease**

- **Surmont lease**
• 100% Coverage of FMI Data in 2013/2014 program
• Important for breccia identification

- Existing wells
- Existing FMI wells
- New FMI wells (as of Jan 31, 2014)
- Phase 1 and Phase 2 Development Area
- Phase 2 drainage areas
- Surmont lease
Increased Formation Micro Imaging density with latest drilling

McMurray penetrated wells only

FMI Well Log Density Map – Jan 2013

FMI Well Log Density Map – Jan 2014

1. 2013-2014 Delineation Program and FMI Logs

2. Subsection 3.1.1 (2a,b)
• **TopResSeis**: was a composite surface interpreted from seismic and well picks to represent the top of the McMurray reservoir. It could be top bitumen, top water or top gas, and it was a challenged seismic pick.
  - Decision: discontinue this interpretation in favor of clear stratigraphic interpretations: Top McMurray and Base Channel.

• **Top McMurray (MCMR)**: distinct geologic and seismic pick, a stratigraphic boundary.
  - McMurray fluid boundary interpretations remain based on well data

• **McMurray Channels (MCMR_CH_SH_Base)**: distinct geologic and seismic pick, stratigraphic feature that erodes into McMurray reservoir.
Surmont 3D Seismic Surveys

2012-2013 Seismic

<table>
<thead>
<tr>
<th>3D</th>
<th>Km²</th>
<th>Shots</th>
<th>S-R Line</th>
<th>S-R</th>
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<td>1.9</td>
<td>1,700</td>
<td>60x80</td>
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<td>1,103</td>
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<td>KNW</td>
<td>21.5</td>
<td>9,543</td>
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</table>
McMurray Gross Isopach

2013/2014 Delineation Program Update
• December 2013 – minor changes due to:
  • Re-evaluated/unified geologic picks
  • Improved Seismic Interpretation

3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 and Phase 2 development

Phase 2 drainage areas
McMurray Net Gas Isopach

2013/2014 Delineation Program Update
• December 2013 – minor changes due to:
  • Re-evaluated/unified geologic picks
  • Improved Seismic Interpretation

3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 and Phase 2 development
Phase 2 drainage area

Net top gas thickness = sands have deep resistivity \(\geq 10\ \Omega\cdot\text{m}\) and \(V_{\text{sh}} < 65\%\)
Subsection 3.1.1 (2c)

3D seismic areas used for mapping (all 12 volumes)

- Surmont lease

2013/2014 Delineation Program Update:
  - December 2013 – minor changes due to:
    - Re-evaluated/unified geologic picks
    - Improved Seismic Interpretation

- Net top water thickness = sands have deep resistivity <10 Ω-m and Vsh <45%

McMurray Net Top Water Isopach
McMurray Net Top Water Isopach

2013/2014 Delineation Program Update

- December 2013 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 and Phase 2 development

Phase 2 drainage areas

Top Continuous Bitumen Structure
McMurray Net Top Water Isopach

2013/2014 Delineation Program Update

- December 2013 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 and Phase 2 development

Phase 2 drainage areas
McMurray Net Continuous Bitumen Pay

3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 and Phase 2 development

Phase 2 drainage areas

2013/2014 Delineation Program Update

- December 2013 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

- Net continuous bitumen = sands have deep resistivity >40 Ω-m and Vsh <33%, and no shale greater than 3 m thick
Subsection 3.1.1

Surmont Lease OBIP

2013/2014 Delineation Program Update
December 2013 – no major change to Original Bitumen In Place (OBIP) per square mile (enlarged Development Area)

Surmont lease

Phase 1 and Phase 2 development

Phase 2 drainage areas

<table>
<thead>
<tr>
<th>Properties</th>
<th>Development Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>NCB Thickness Range</td>
<td>0 to Greater than 30 m</td>
</tr>
<tr>
<td>Phie in NCB</td>
<td>32.4%</td>
</tr>
<tr>
<td>So in NCB</td>
<td>78.5%</td>
</tr>
<tr>
<td>OOIP in NCB &gt; 18m</td>
<td>2990.32 MMbbls Deterministic</td>
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</tbody>
</table>

OBIP = Thickness x Phie x So x Area

Subsection 3.1.1 (2a, 2b, 2c)
Phase 1 Type Log Well Pad 101

Example Log 100161408307w400

- McMurray
- High Sw
- Continuous Bitumen
- Devonian

Phase 1 Area

Pad 101

Type Log

Subsection 3.1.1 (2e)
Phase 2 Type Log – Well Pad 264-2

Example Log 100162208306w400

- **McMurray**
- **Top Gas**
- **High Sw**
- **Continuous Bitumen**
- **Devonian**

Subsection 3.1.1 (2e)
Objectives

- Characterize vertical and lateral variance in viscosity at different temperatures
- Model the variance in bitumen properties and its implications for bitumen production rates during SAGD
- Characterize relationship between viscosity, density and geochemical composition

- No changes
- Viscosity increases with depth in the McMurray Formation.

- 51 existing viscosity sample wells
- Delineated Wells - Surmont

Special Core Analyses Bitumen Viscosity Sampling
Viscosity Gradient

Subsection 3.1.1 (2f)
Representative Structural Cross Section
• A well at 4-3-84-6 W4M intersected a raised bitumen/water contact, the contact is ~12 m higher than the nearest offset.

• The well also intersected a small gas pool under the bitumen.

• The presence of basal water becomes a risk on Well Pad 262-1.
INSAR Surface Deformation Monitoring

- Interferometric Synthetic Aperture Radar Images
  - Data is collected every 24 days

- Data acquisition initiated after first steam in 2008
  - Input used for Geomechanical Model Calibration
  - CRs 1 to 20 March 2008
  - CRs 21 to 47 March 2010
  - CRs 48 to 72 March 2012

- Deformation currently in line with expectations
- Maximum deformation at Corner Reflector (CR) 14. Changes may be due to frost heave and construction activities
- During 2014 repair and add additional CR Points

Location Map of CR Points

Cumulative Deformation April 2012 to December 2013

Subsection 3.1.1 (2k; 2i)
Conclusions from the study:

1. The results of the cap rock integrity study indicate that Wabiskaw and Clearwater shales at Surmont constitute a robust and laterally continuous cap rock.
2. Generally, similar lithologies and thus seal characteristics will be distributed over substantial distances (typically of greater areal extent than the Surmont lease area).
3. Seismic structural analysis indicated that no through-going faults or other discontinuities break the cap rock interval at Surmont.
Nine New Cap Rock Cores in 2011

- The cap rock interval was investigated by:
  - core description and analyses,
  - log interpretation and correlation, and
  - seismic interpretation and correlation.

- Analytical methods included:
  - visual core examination,
  - reflected light microscopy,
  - laser particle size analysis,
  - biostratigraphic analyses,
  - X-ray diffraction for clay species,
  - QEMSCAN (quantitative mineralogy),
  - chemostratigraphy (bulk geochemistry), and
  - MICP (mercury injection capillary pressure) analyses to determine seal capacity.

Conclusion from the study:

- The best seals within the cap rock interval are the deeper water deposits occurring on maximum flooding surfaces.

- These muds can be over 80% clay and are correlated throughout and beyond the Surmont lease.
Conclusion from the study:

- In the 2011 testing, despite the varying conditions tested, the retained minimum stress gradient of the cap rock at 18.4 kPa/m was further validated.
- The recommended MOP gradient is 15 kPa/m (@SF=1.2) which is lower than previous by applying a higher factor of safety.

- Three mini-frac tests targeted the most structurally complex features currently identifiable across the lease based on mapped structures of the Devonian, McMurray, cap rock, and overburden.
- All of the 2011 test locations were proposed to, and reviewed by the AER prior to execution of the tests. The locations include variability in other features such as proximity to gas depletion, overburden, karsting and other structural variability.
- Other Maximum Operating Pressure (MOP) supporting data, includes cap rock core samples subjected to tri-axial testing, log data, FMI interpretations, seismic, etc., combined with the overall cap rock characterization, reservoir simulation and geomechanical modeling.
Based on the cap rock integrity studies, ConocoPhillips has proposed a maximum pressure of 15kpa/m.

Circulation optimization including dilation is an area of ongoing study.

Pace of pressure drops will be largely driven by:
- Specific, local reservoir properties,
- Thief zone interactions,
- Economics,
- ESP installations,
- Plant capacity, and
- Global steam optimization.

- ConocoPhillips continues to propose a flexible tapered strategy envelope bound by the cap rock integrity study and the associated MOP on one side and economic achievable pressures on the low side
Subsection 3.1.1 (3)
Drilling and Completions
Well Summary

- 6 drainage areas
  - Pilot
  - 101 North
  - 101 South
  - 102 North
  - 102 South
  - Pad 103

- 56 well pairs, 4 infill producers

Pilot (3 well pairs)
Phase 1A (21 drilled – 20 completed)
Phase 1A redrills (3 wells)
Phase 1B (7 drilled – 7 completed)
Phase 1C (8 drilled well pairs – 8 completed)
Pad 101 South 2011-2012 Infills
Pad 103 (12 pairs drilled – 0 completed)
Pad 101 Plot Plan

<table>
<thead>
<tr>
<th>Surface Well Name</th>
<th>Downhole Well Name</th>
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<tbody>
<tr>
<td>101-01</td>
<td>101-10</td>
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<tr>
<td>101-02</td>
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<td>101-26</td>
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</table>

2013 Infill program

Subsection 3.1.1 (3a)
Pad 101 Completions

**2013 update:**
- Infill Pairs 24, 25, and 26 are drilled and completed, but not producing
- 101-P16INF converted to Electric Submersible Pump (ESP)
- Infill Pair 101-17INF on circulation

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**Phase 1C**

- P03, P04, P05, P06, P07, P08, P09, P10, P11, P12, P13, P14, P15, P16, P17

**Phase 1A**

- P18, P19, P20, P21, P22, P23, P24, P25, P26

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Subsection 3.1.1 (3b)
2013 Update:

- Infill producers 21 and 22 are drilled, but not completed
- 102-P11R Converted to ESP
Initial surmont completions used Parallel tubing configurations primarily in the gas lift phase. However, we did experience workover difficulty due to:
• Clamps hanging up
• Tubing strings twisting around each other
• Instrumentation line shear
• Having to slump tubing with stuck strings
Due to the operational and safety concerns, the concentric tubing design was chosen as the go forward configuration.
Phase 1 – Typical PCP Producer Completion

3/8” Bubble Tube + 2x ¼” Encapsulated F.O. P/T Instrumentation Cables Clamped (Intake)

Sucker Rod / CoRod

9 5/8” Intermediate Casing

3.5” Production Tubing

Progressive Cavity Pump (PCP)

40pt Fibre Optic Temp Coil

7” Slotted Liner

2 1/16” x 3-1/2” Guide String / Steam Warm-up line

Liner Hanger
Phase 1 – Typical PCP Producer Completion

Three wells currently operate on PCP lift, they are:
• 101-P21 (S10INF1)
• 101-P22 (S11INF1)
• 102-P03

Steam Warm-up Line Use:

Steam warm up lines have been included in all our PCP well. The parallel 2-1/16” x 3-1/2” line to the toe of the well serves the following purposes:
• The ability to warm up the pump and near-pump fluids via tubing perforations near the pump landing depth. Being able to warm up the pump and fluids decrease the amount of torque on the pump system during the initial startup.
• The ability to deliver hot water or steam to the toe of the well to help mobilize colder bitumen. This delivery method is not designed for long-term use, due to injected fluid interference with instrumentation.
• The warm up line is a conduit for the temperature coil instrumentation.
2013 Infills on Pad 101 & Pad 102 have Flow Control Devices Installed

Typical Flow Control Device Completion

**Producer - Circulation & GL Modes**
- 9 5/8” Intermediate casing
- 7” Heel String c/w perforated gas lift section 1-2 joints, 1/8” holes
- 4 1/2” VIT
- 2x3/8” Bubble tube
- 4” Toe String
- Liner Hanger
- LxData (40pt) Clamped to Outside of Toe Tubing
- 6 5/8” Equalizer

**Injector - Circulation & GL Modes**
- 9 5/8” Intermediate casing
- 7” Heel String
- 4 1/2” VIT
- 4” Toe String EUE/Hydril
- Liner Hanger
- Single Point Fiber P/T
- 6 5/8” Equalizer
Typical Flow Control Device Completion

Short and long tubing strings during SAGD production:

• During initial circulation a toe tubing string is required, however due to the equalizing character of the FCDs a toe tubing string is not required.

• This concept was tested in the pilot well pair, 102-06, which showed that we could pull back the toe strings to the heel and still have good steam and production performance. However, depending on the injected steam rates, the toe presence of the toe string may not add significant pressure drop along the lateral in the case of the injector well and may not warrant the workover to pull back or remove the string.

• The option exists and can be evaluated on a well or pad level.

• The similar option exists for the producer well and the lateral instrumentation could be run on a separate coil. Again, this option could be evaluated on a well or pad level.
Subsection 3.1.1 (4)
Artificial Lift
Gas Lift
- Gas lift is effective with bottomhole operating pressures >3,000 kPa.
- Current production rates range from 200 m³/d to 500 m³/d of emulsion targeting 3,500 kPa.

Electric Submersible Pump (ESP)
- ESP for thermal SAGD applications can be sized to meet the specific deliverability of the well.
- High temperature ESPs can operate at bottom hole temperatures up to 270 ºC.

Progressive Cavity Pumps (PCP)
- Generally PCPs have been used for low deliverability wells and where potential solids may be produced.*

* Conoco’s initial strategy for PCPs was to use them on low deliverability wells where the current ESP designs are deemed less appropriate. However, installation of larger PCP are being considered for wells that may produce relatively “cold” viscous fluid for some time.
Artificial Lift Strategy

• Generally, the artificial lift mode selection is reliant on the pressure strategy for any given well, or drainage area (DA).

  • Phase 1A & C wells utilized Gas Lift (GL) and then converted to ESP after steam chamber coalescence.
  • Only 3 wells remain on GL at the end of 2013. The wells are scheduled for ESP conversion in 2014.
  • ESP on initial production (ESP Day-1) is being trialed on the 2012 Infill program (101-16INF & 101-17INF). Due to the lower regional pressure, GL is not an effective artificial lift selection.
  • PCP have been selected on wells where the initial deliverability may be low due technology trials, such as the infill producers on Pad 102. These wells may be converted to ESP after further on-stream evaluation.
Population (on production):
- 32 ESP wells,
- 2 Infill PCP (101-10INF1, 101-11INF1)*,
- 1 PCP after GL (102-03)*, and
- 3 Gas Lift wells (101-02, 101-03, 102-10)*.

Key Decisions:
- Installation of “Slim” ESP on two wells (102-14, 102-16)*.
- Two Artificial Lift Strategy (ALS) Specialists have been hired.
- Proposing two additional PCP completions for evaluation on Pad 102 (102-21, 102-22)*.

* Down hole locations

Update:
- ESP power cable failures have been reduced by redesign of integrated capillary tube.
- Subcool logic has been incorporated to most of the ESP wells.

- 10 failures total
- Average Runtime failed = 12 months
- Mean Time Before Failure: 24.5 months
During the gas lift phase of this well, proof of liner failure in the producer was observed:

- Hole found in failed toe tubing at 1304mKB, and in failed gas lift coil tubing at 1298mKB.

Decision and risk analysis performed and path forward was to set bridge plug:
- Bridge plug set successfully at 1291m as per work over program.

Due to the likelihood of producing solids (sand) after the workover, an alternative artificial lift scheme was required. The requirements of the lift system were to:
- Produce solids with little impact
- Be retrievable, fast, and cheap in case of accelerated wear or damage
Trail Objective - Post work over of the 102-03 liner failure, some sand cleanout was anticipated. Using a metal-metal for cleanup could shorten the life of the pump. To facilitate the cleanup, a tubing insertable elastomeric PCP was used. Using an insertable configuration removes the need to pull the tubing in order to reconfigure to the long-term metal-metal pump.

The elastomeric PCP selected for this trial had a temperature rating of 150 dec C. However, the trial planned to run the pump past 150 Deg C in into failure to test a new elastomer adhesion system.
Results:

- The insert PCP was successfully installed above the metal stator.
- The PCP ramp up was done in a stepwise manner in order to gauge efficiency and to be able to observe any changes in rod torque. It was anticipated that multiple rotor changes could be required as the elastomer heated up and swelled causing the rod string to see increased torque.
- Although no significant torque increase was observed, pieces of elastomer were brought to surface, up to the point where the elastomer failed altogether.
- The elastomer PCP stators were changed out 2 times within 8 months of operation due to stator failure. The maximum temperature measured at the pump intake was 125 Deg C. During this period no significant sand was brought to surface. Elastomer adhesion was the cause of the failures.
- Since no additional sand production was being observed, the decision was made to terminate the trial and run the metal stator. The metal-metal system was brought into service in November 2013 and continues to be in operation to date.
ESP Performance

- The Average runtime of our ESP’s in service has increased to 12 months.
- The increased performance is mainly a function of ESP on stream days, where the oldest ESP has been running for more than 3.5 yrs.
Our current Mean Time Before Failure (MTBF) is 24.5 months.

- 2012 realized a decrease in MTBF mainly due to electrical failures with the ESP power cable. The cable has been redesigned with dual armor protection of the insulating material.
Advantages of a PCP System:

- Positive displacement pump
  - Improved efficiency when compared to other ALS.
- Handles wide fluid viscosity range.
- More cost effective for maintenance (pump changes), especially in the lower production range wells.
- The all metal PCP may:
  - Produce fluids up to 250°C,
  - Steam into the well without removing the production tubing, and
  - Eventual steam flashes cause lesser impact on run life than ESP.

Update:

- There are currently two PCP wells on Pad 101 that have been operating for more than 1.5 years without a subsurface failure.
400MET1000 Nominal Performance Curve

101-P21 and 101-P22 Operating at ~50% Volumetric Efficiency
Subsection 3.1.1 (5)
Instrumentation in Wells
Subsection 3.1.1 (5a, 5b)

Newly converted wells in 2013

- Pad 101 – 101-12 (05 DH) + 101-19 (16inf DH)
- Pad 102 – 102-11 RD

**SAGD Well Instrumentation**

- All ESP/PCPs are equipped with 40 point fiber optic
  - 101-03 and 101-05 are the only ESP conversions equipped with thermocouples (first ESP completions) with 5 points
- The ESP’s on 102-14 and 102-16 were worked over to accommodate 40 point fiber optic sensors
- Heel instrumentation includes a fiber optic PT with a bubble tube backup

---

**Newly converted wells in 2013**

- Pad 101 – 101-12 (05 DH) + 101-19 (16inf DH)
- Pad 102 – 102-11 RD
Typical Observation Well Measurement

Soft cable Thermocouple (TC) strings were replaced by hard cable TC strings for improved well integrity

- Example thermocouple and piezometer layout (101-07-OBA)
- Typically 30 TC (1.5 m spacing)
- 2-3 piezometers placed at varying intervals

Subsection 3.1.1 (5a, 5b)
Typical ESP Bottomhole Configuration

- 13 3/8” Conductor
- 9 5/8” Intermediate casing
- 88.9mm EU 9.3ppf production string
- 8 1/2” casing slotted liner f/743m to 1,616m
- 1-1/4” IJ Instrument String
- 7” slotted liner f/743m to 1,616m
- 114.3mm Hydrill tail pipe top: above liner hanger bottom @ 1,461m
- 60 mm P/T Senso Bottom @715m
- Tail pipe thermal packer
- Liner hanger top @741m MD
- 1/4” Bubble Tube Coil (clamped)
- 3/8” Instrumentation in power cable (clamped)
- 1/8” encapsulated instrumentation line for Opsens P/T sensor (clamped)

Temperature monitoring instrumentation (Thermocouple/Fiber Optics inside of 1.25” Coil)
5 thermocouples from 705m to 730m, equally spaced
6th thermocouple @ 743m
40th thermocouple @ 1,616m. Equally spaced

All depths indicated are GRD

• Current standard system configuration utilizes one P/T gauge (fiber optics) and a bubble tube.
2013 Instrumentation Program Summary

• Lateral instrumentation is key to ensure proper well performance monitoring and integrity (for slotted liners).

• Pressure monitoring redundancy/backup in ESP wells is needed to avoid significant production losses or unnecessary ESP pulls.

• For circulation optimization, fibre optic pressure measure at the toe of the well will be incorporated in new well completions.
Subsection 3.1.1 (6)
4D Seismic
4D Seismic Location Map

Phase 1 Area

- **Pilot**
  - Buried analog single component geophones
  - Cased dynamite shots (1/4 Kg) @ 9 m
  - 12th monitor acquired in September 2013

- **Pad 101N**
  - Buried analog single component geophones
  - Cased dynamite shots (1/8 Kg) @ 6 m
  - 4th and 5th monitor acquired in March and September 2013

- **Pad 101S**
  - Buried analog single component geophones
  - Cased dynamite shots (1/8 Kg) @ 6 m
  - 7th monitor acquired in March 2013

- **Pad 102N**
  - Buried analog single component geophones
  - Cased dynamite shots (1/8 Kg) @ 6 m
  - 7th monitor acquired in April 2013

- **Pad 102S**
  - Buried analog single component geophones
  - Cased dynamite shots (1/8 Kg) @ 6 m
  - 4th monitor acquired in April 2012

- **Pads 103 and 104**
  - Buried analog single component geophones
  - Cased dynamite shots (1/8 Kg) @ 6 m
  - Baseline acquired in April 2012
## Phase 1 4D Seismic Program

<table>
<thead>
<tr>
<th>PAD</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Spring</td>
<td>Fall</td>
<td>Spring</td>
<td>Fall</td>
</tr>
<tr>
<td>101N</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
</tr>
<tr>
<td>101S</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
</tr>
<tr>
<td>102N</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
</tr>
<tr>
<td>102S</td>
<td>M</td>
<td>M</td>
<td></td>
<td>M</td>
</tr>
<tr>
<td>Pilot</td>
<td>M</td>
<td>M</td>
<td>M</td>
<td>M</td>
</tr>
<tr>
<td>103</td>
<td>B</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>104</td>
<td>B</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- **M**: Monitor
- **B**: Baseline

Subsection 3.1.1 (6a)
4D Seismic Workflow

- Cross-plot of 4D anomaly volumes versus allocated SAGD oil production volumes from select Phase 1 well pairs.

- Because of seismic resolution there are some discrepancies between the total oil produced and the volume of 4D anomalies.
Well Pad 07/08/09, without a true baseline. For the rest of Well Pairs the 4D anomaly volumes have increased. Good conformance, especially at the heel. Well Pads 02/03 are E-SAGD pilot.

4D anomaly volumes have increased. Continued conformance improvement along Well Pad 10, 11.

Infill wells drilled between Well Pads 10, 11, 12, 16, 17 and 18 to optimize production in a geological more complex zone.

\( = 4D \text{ anomaly} \)
\(~60 \text{ deg C Isotherm}~\)
• 4D anomaly volumes have increased. Improve conformance along well pairs 1 to 9.

• No 4D monitor in 2013.

= 4D anomaly
~60 deg C Isotherm
2013 4D Seismic Results Pilot

- 4D anomaly volumes have increased for Well Pad A and B.
- Poor SAGD conformance in middle of well pair “C”
- Coalescence between well pair B/A and C

Pilot 11th monitor - September 2012

Pilot 12th monitor - September 2013

- 4D anomaly
- ~60 deg C Isotherm
Problem:
• Well pair 101-P16 lacking good conformance along well pair

Action:
• Increase pressure of steam injection at toe

Results:
• Conformance improved at toe
April 2013 4D survey with RST showing steam breakthrough through mudstone

- 2009 RST and 4D surveys confirmed recovery above mudstone
- Operating pressure reduced to manage thief zone interactions
Objectives - Top water and gas thief zone interaction.

Poor SAGD conformance in middle of well pair “C”

Coalescence between WPB/A and C
4D Seismic Program 2013

- 4D seismic has proven very useful in monitoring and optimizing conformance and pressure strategy.

- 4D correlates with observation well data.

- Continuing to optimize heel/toe production/injection splits using 4D results.

- Ongoing efforts to history match reservoir models using 4D seismic.
Subsection 3.1.1 (7)  
Scheme Performance
Scheme Performance

### Pilot

<table>
<thead>
<tr>
<th>Bitumen production bbl/d (m3/d)</th>
<th>Steam injection bbl/d (m3/d)</th>
<th>ISOR v/v</th>
<th>WOR v/v</th>
<th>RWR %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>519</td>
<td>1,651</td>
<td>3.18</td>
<td>4.44</td>
</tr>
<tr>
<td>82</td>
<td>262</td>
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<td></td>
<td></td>
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<tr>
<td>2013</td>
<td>559</td>
<td>1,910</td>
<td>3.40</td>
<td>5.52</td>
</tr>
<tr>
<td>89</td>
<td>304</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Phase 1

<table>
<thead>
<tr>
<th>Bitumen production bbl/d (m3/d)</th>
<th>Steam injection bbl/d (m3/d)</th>
<th>ISOR v/v</th>
<th>WOR v/v</th>
<th>RWR %</th>
<th>Water Recycle %</th>
<th>Opp. Efficiency %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>21,673</td>
<td>53,676</td>
<td>2.48</td>
<td>2.38</td>
<td>4%</td>
<td>80.0%</td>
</tr>
<tr>
<td>3,446</td>
<td>8,534</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>24,251</td>
<td>59,442</td>
<td>2.45</td>
<td>2.43</td>
<td>1%</td>
<td>81.6%</td>
</tr>
<tr>
<td>3,856</td>
<td>9,450</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2013</td>
<td>27,135</td>
<td>65,571</td>
<td>2.42</td>
<td>2.47</td>
<td>-2%</td>
<td>87.1%</td>
</tr>
<tr>
<td>4,315</td>
<td>10,425</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- Pilot performances impacted by ESP and subcool target in 2013
- Phase 1- improve performance owing to stable operations and high operating efficiency (no turnaround in 2013)
- Phase 1 Reservoir Water Retention (RWR) keeps decreasing as a result of operating pressure reductions
Subsection 3.1.1 (7a,ii)

Moderate performance in 2013 due to pump complications

Data through Dec 31, 2013:
- Plant cSOR: 3.46
- Plant cWSR: 1.00
- Well Count: 3
- 2013 avg. iSOR = 3.51
Pilot Performance History

Data through Jan. 31, 2014
- Wellpair A cSOR = 3.16
- Wellpair A cWSR = 1.10
- Recovery Factor: 38.4%
- Wellpair B cSOR = 3.24
- Wellpair B cWSR = 1.05
- Recovery Factor: 45.0%
- Wellpair C cSOR = 4.83
- Wellpair C cWSR = 0.74
- Recovery Factor: 7.8%

Maps were updated in 2013 and yielded greater OOIP values.
Deviation from capacity due to:

- Boiler Feed Water (BFW) pump limitation
- P3 liner damage preventing steam injection / production
- P3 HGP failure
- P1 ESP limited due to high motor winding temperatures
- P2 ESP production capped to maintain subcool target
Well Status

Status on January 31, 2014

- Pilot:
  - 3 well pairs on SAGD

- Phase 1:
  - 35 well pairs on SAGD
  - Started 2 infill well pairs
  - 2 well pairs in E-SAGD
  - 1 Cold well pairs

- Infill Program
  - 2013: drill 3 infill well pairs and 2 fishbone infill producers

- Planning underway for first sustaining pad drainage areas

- 5 year outlook - no expected pad abandonments

Subsection 3.1.1 (7a,ii)
• Good performances due to stable operations and well availability
• Stable ISOR for the past 3 years around 2.5

Data through January 31, 2014

<table>
<thead>
<tr>
<th>Metric</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant CSOR</td>
<td>2.6</td>
</tr>
<tr>
<td>Plant CWSR</td>
<td>0.95</td>
</tr>
<tr>
<td># Well pairs started (incl. infill producers)</td>
<td>39</td>
</tr>
<tr>
<td>2013 ISOR avg. (v/v)</td>
<td>2.42</td>
</tr>
</tbody>
</table>
Phase 1 Production Capacity

Deviation from capacity due to:
- Steam generator pigging every two months and other maintenance
- Planned / Unplanned power outages
- Wells availability:
  - 4 ESP conversions + 10 ESP Failures
  - 1 SAGD conversions
Pilot Wellpair A: OBS36 (Mid)

OBS 36: Heat keeps progressing above breccia

Subsection 3.1.1 (7b)
- Operated at 1600 kPa for 4-5 years with significant surface area of contact of chamber with thief zone
- Saturated steam temperatures observed in thief zone at OBS22 since 2009
- Gas pressure zones still 500kPa below steam chamber pressure
Top Gas Monitoring

**OBS-23 (103/12-24-083)**
- Tested 2 samples in early 2010 from McMR Gas Cap
- Lab gas chromatography with thermal conductivity detector (TCD GC) indicated ~ 1.09% and 0.28%
- Well currently abandoned due to well integrity issues

**OBS-41 (103/11-24-083)**
- Onsite field test on 6 samples in 2011, 2 samples in 2012 and 2 samples in 2013
- \( \text{H}_2\text{S}\) con. measured (highest values): 0.61% (2011) and 0.42% (2012)
- Considered representative sample and closest analog for Pad 101
- Recent sample: Feb 21, 2013; result date: Feb. 25, 2013
  - *Field Observations:* 0.46% (4602ppm) at 12:10pm and 0.47% (4685ppm) at 3:02pm

**OBS (102/02-24-083)**
- Drilled in Feb 2013 for gas observation
- Recent sample: Feb 21, 2013; result date: Feb. 25, 2013
  - *Field Observations:* \( \text{H}_2\text{S}= 0\% \) (0.00ppm); test time: 10:48am & 1:46pm

**\( \text{H}_2\text{S}\) Surveillance & Monitoring Update**
- Commenced routine produced casing gas sampling on Phase 1 Pads (field observations and laboratory analysis – full gas chromatograph)
- Reinforcing safety measures on site in case of unexpected release:
- Designated Muster Points allow for upwind/crosswind evacuation in the event of a release and during sampling
Reservoir Monitoring

### Temperature Measurement

- Thermocouple string installed
- Horizontal observation well with fiber optic
- No temperature monitoring

### Pressure Measurement

(as planned after hard cable TC string installation)

- Piezos in:
  - Bitumen
  - Top water
  - Bitumen and top water
  - Top gas
  - Top gas, bitumen and top water
  - E-SAGD observation wells with 10 piezometers per well monitoring:
    - bitumen zones
    - high water saturation zones
    - thief zone (water / gas)
    - cap rock
  - No piezometer installed
• Well pair 101-03 (Pad 101 North)
  • Start-up in Feb 2011
Steam Chamber Development Well Pair 101-03

- Temperature monitoring

**101-03 OBB**

**101-03 OBC**

Subsection 3.1.1 (7b)
Steam Chamber Development
Well pair 101-03 (Monitor 5-Sept 2013)
**Pressure Monitoring**
- Lower piezometers follow exactly 101-103 BHP injection trend
- Pressure response ahead of the temperature front – Most likely through mobile initial water

![101-03 OBB Pressure vs. Time Graph](image-url)
Average porosity = 33%
Average So = 80%

OBIP = bulk volume $\times \Phi \times$ So

Minimized resource below producer

NCB = producer to Vsh cutoff of 33%
Recovery Factor vs Thief Zone Type

1 = No thief zone, highest recovery, 45%+
2 = Limited thief zone, medium recovery, 40%+
3 = Thief zone, lowest recovery, 30%+

* Recoveries based on simulations and in-house proxy tool
OBIP and Recovery Factor

Pilot and Phase 1 Recovery

<table>
<thead>
<tr>
<th>Drainage area</th>
<th>OBIP (e3m³)</th>
<th>Avg Phi %</th>
<th>Avg So %</th>
<th>Expected RF %</th>
<th>Cum Prod (e3m³)</th>
<th>Current RF %</th>
</tr>
</thead>
<tbody>
<tr>
<td>101N</td>
<td>8,045</td>
<td>32.8%</td>
<td>81.8%</td>
<td>45%</td>
<td>1,195</td>
<td>14.9%</td>
</tr>
<tr>
<td>101S</td>
<td>9,130</td>
<td>33.6%</td>
<td>83.0%</td>
<td>45%</td>
<td>1,902</td>
<td>20.8%</td>
</tr>
<tr>
<td>102N</td>
<td>7,286</td>
<td>33.1%</td>
<td>81.6%</td>
<td>45%</td>
<td>1,592</td>
<td>21.9%</td>
</tr>
<tr>
<td>102S</td>
<td>7,316</td>
<td>31.7%</td>
<td>73.5%</td>
<td>45%</td>
<td>2,376</td>
<td>32.5%</td>
</tr>
<tr>
<td>Pilot Pair A</td>
<td>626</td>
<td>32.6%</td>
<td>82.2%</td>
<td>45%</td>
<td>241</td>
<td>38.4%</td>
</tr>
<tr>
<td>Pilot Pair B</td>
<td>592</td>
<td>32.5%</td>
<td>82.8%</td>
<td>55%</td>
<td>266</td>
<td>45.0%</td>
</tr>
<tr>
<td>Pilot Pair C</td>
<td>1,133</td>
<td>33.6%</td>
<td>85.8%</td>
<td>N/A</td>
<td>89</td>
<td>7.8%</td>
</tr>
<tr>
<td>Pilot Pair A&amp;B</td>
<td>1,218</td>
<td>32.6%</td>
<td>82.5%</td>
<td>50%</td>
<td>507</td>
<td>41.6%</td>
</tr>
</tbody>
</table>

*Data set current to January 31, 2014

Original Bitumen In Place (OBIP) = Thickness x Phi x So x Area
Thickness = Calculated from the top of continuous bitumen to the producer depth
Area = Polygons around each well pair of 125 m x length of lateral section

• Expected ultimate recovery dependent on blowdown timing and operating strategy
• Low Recovery Pad Example – Pad 101 North Monitor September 5, 2013
  – 4D seismic monitoring
  – Low recovery to date but still in the early time
  – Fairly good steam chamber conformance

Well pairs started in 2011
• Low recovery pad example – Pad 101 North
  • 9 well pairs drilled
  • Low recovery essentially due to late start-up:
    • 3 well pairs started in 2007
    • 4 well pairs started end 2010 / beginning 2011
    • 2 infill well pairs to be started later in the year (Q4/2014)
OBIP and Recovery Factor

- High Recovery Pad Example – Pad 102 South
  - 4D seismic monitoring – March 2012 monitor
  - Good steam chamber development over mature wells

No Change from 2013

Well pairs converted into SAGD in 2012 – 102-10 & 102-11
OBIP and Recovery Factor

• High recovery pad example – Pad 102 South
  • 9 well pairs drilled
  • High performance well pairs
OBIP and Recovery Factor

Pad 101 and Pad 102 Weekly Bitumen Production
OBIP and Recovery Factor

Pad 101 and Pad 102 Weekly Steam Injections

Weekly Steam Injection (bbl/d)
OBIP and Recovery Factor

Pad 101 and Pad 102 Well Counts
• Pad 101 North

Latest available Phase 1 4D ~60°C isocontours

All mature steam chambers have been depleted to 1,800 – 2,300 kPa

Subsection 3.1.1 (7g)
Top Steam Chamber Monitoring 4D Isocontours

• Pad 101 South

All mature steam chambers have been depleted to 1,800 – 2,300 kPa

Latest available Phase 1 4D ~60°C isocontours

Subsection 3.1.1 (7g)
Top Steam Chamber Monitoring 4D Isocontours

- Pad 102 North

Latest available Phase 1 4D ~60°C isocontours

All mature steam chambers have been depleted to 1,800 – 2,300 kPa
• Pad 102 South

Latest available Phase 1 4D ~60°C isocontours

All mature steam chambers have been depleted to 1,800 – 2,300 kPa

Subsection 3.1.1 (7g)
• **Pilot**

Monitor September 2013

Latest available Phase 1 4D ~60°C isocontours

Pilot operating pressure decreased at 1600kPa for the last 4 years.
Phase 1: Operating Pressure

• Operating pressure
  • Progressively decrease operating pressure to manage interaction with top reservoir / thief zones
  • Well pairs converted to ESP to operate at lower pressure
  • 101 North at higher pressure because of recent well pairs start-up
Phase 1: Pad 101 - Top Abandoned Mud Channel

- Pad 101: Abandoned mud channel overlaying bitumen interval
Phase 1: Pad 101 North - Top Water

• Top water: Extension of pilot top water above Pad 101 north but limited
• Top water: Extension of pilot top water above Pad 101 north but limited
Phase 1: Pad 102 - Top Abandoned Mud Channel
Phase 1: Pad 102 North - Top Water

Abandoned mud channel
Phase 1: Pad 101 North - Top Water

- Pad 101 North - Top water:
  - Development of the steam chamber towards top of reservoir – Monitor 5\textsuperscript{th} Sept 2013
• **Pad 101 North - Top water:**

  • Decrease operating pressure to manage interaction with top water and coalescence between well pairs

  • Well performances not impaired by top water

  • Stabilized pressure in the last one year.
Phase 1: Pad 101 South - Top Abandoned Mud Channel

- Pad 101 South - Top abandoned mud channel:
  - Development of the steam chamber towards top of reservoir

```
M6 April 2012      M7 April 2013
Base Top Water

• Pad 101 South - Top abandoned mud channel:
  • Development of the steam chamber towards top of reservoir
```

![Diagram of Pad 101 South - Top Abandoned Mud Channel](image)

Map View

- SW <----- X SECTION PERPENDICULAR TO WELL PAIRS PAD 101S ----> NE
- McMurray
- Base Top Water
- Mud Channel
- Dev Unc

- M6 April 2012
- M7 April 2013

= 4D anomaly
~60 deg C Isotherm

ConocoPhillips
Phase 1: Pad 101 South - Top Abandoned Mud Channel

Pad 101 South (101-10/11/12/13/14)

- Performances
  - June 2009: 101-12 steam chamber development up to the top reservoir. WP shut down.
  - 101-12/13/14: ESP conversion on Aug/Sept 2010. Operating pressure decreased to manage interaction with top reservoir
  - Stable performances since after ESP conversion.
Mud Channel Protection Criteria

The impact of the Mud Abandon Channel (Protection Zone) over the steam chamber is as soon the steam reach the Mud the chamber begin to growth laterally and not vertically.

Mud Channel Protection zone is based in the Mud Channel Structural surface that is located below the Bottom of the Top Water ~ @ 270 m (tvdss)
Phase 1: Pad 101 South - Infill Producer Performance

- **Infill producers 101-P21 and 101-P22**
  - Drilled in 2012
  - Open-hole hook in P21 and cased-hole hook in P22
  - Completed with PCP and started in Sept 2012
  - Average daily bitumen rate ~ 32-47m³/d (both wells)
Phase 1: Pad 101 South - Infill Producer Performance

Production History - Petrinex

• We have historically trickled very small amount of steam averaging 10m3/d down the steam warm-up line engineered in infill wells 101-10INF and 101-11INF to help pre-heat the artificial lift system at startup.

• Therefore, the production and injection history reported in Petrinex is not a reporting error in Petrinex. CPC have been injecting small volume of steam in the wells for some time. The strategy was implemented with the expectation that it would help mitigate a surface vibration issues we have been experiencing on the well. Based on ongoing evaluation, we may stop trickling steam down the warm-up line.
Solvent Soak Trial

- Technology Trial
  - Solvent Soak
- Type of Solvent:
  - Xylene
- Expected Injection Volume:
  - Equivalent to 1 wellbore volume which is about 30 to 40 m³ of solvent per well (i.e., 60 to 80 m³ per well pair).
- AER Amendment Approval - 9426T
  - received: July 17th, 2013
Key Milestones

• Drilled in Q3, 2013
• 1st fishbone well configuration ever in SAGD operations
• Successfully drilled 102-21 and 102-22 multilateral open-hole fishbone wells with approx. 14 ribs
• Successfully deployed flow control device (equalizer liner) in both fishbone wells
Key Reservoir and Operational - Learnings Summary

• Record well performances in 2013.

• Thief zone impact on scheme performance have been very limited so far. Progressive decrease of operating pressure enabled to minimize interaction with thief zones and to operate at stable SOR. This has been observed on Pilot and S1 (Pad 101 North especially).

• 4D seismic has been a key input for reservoir management:
  • To anticipate operating pressure decrease based on distance of the steam chamber to the thief zone. Needed for ESP conversion plan,
  • To refine steam allocation toe / heel, and
  • To identify infill drilling opportunities.

• Pilot and Phase 1 performances are continuously used to calibrate geological and reservoir models for production forecasts.
Subcool monitored in SAGD producer to avoid steam flashing through the liner and preserved its integrity

**Wellbore subcool:**
- Saturated temperature at producer BHP – Hottest Temperature in Prod
- Used in ESP / PCP wells
- Target is $8^\circ$C

**Reservoir subcool:**
- Saturated temperature at injector BHP – Hottest Temperature in Prod
- Used in Gas Lift wells
- Target is increased to $20^\circ$C to take into account uncertain $\Delta P$ between the injector and the producer
Phase 1: Pad 101 North Performance

Imbalance between pads is affected by water-cut calibration
Phase 1: Pad 101 South Performance

Imbalance between pads is affected by water-cut calibration
Phase 1: Pad 102 North Performance

Imbalance between pads is affected by water-cut calibration

Subsection 3.1.1 (7h)
Imbalance between pads is affected by water-cut calibration
Pad Performance Proration

- Pad production plots were affected by issues with the proration factor in 2012
- Constant water cut metering calibration impacting SOR and allocation
- Well tests affected by calibration and secondary calibration targets improved water cut on some of the large and small error wells.
- Stabilized SOR in 2013 attributed to improve water cut metering
Surface Operations and Compliance Approvals 9426 and 11596

April 9, 2014
Calgary, Alberta, Canada
• Facilities & Facility Performance 3.1.2(1,2)
• Measurement and Reporting 3.1.2(3)
• Water Production, Injection, and Uses 3.1.2(4)
• Sulphur Production 3.1.2(5)
• Environmental Issues 3.1.2(6)
• Compliance Confirmation 3.1.2(7)
• Non-Compliance Issues 3.1.2(8)
• Future Plans 3.1.1(8), 3.1.2(9)
Facilities
Subsection 3.1.2 (1)
Subsection 3.1.2 (1a)

Plant optimization focus for Phase 1 CPF in 2013
Artificial Lift Program added 4 new ESP wells in 2013
AGAR Water Cut Meter

Drilled Pairs: 24/25/26

- P09 ESP
- P06 ESP
- P12 ESP
- P19 ESP

Infill Producer 11/12
Artificial Lift Program added 1 PCP & 1 ESP well in 2013
Multiphase Flow Meter
AGAR Water Cut Meter
Subsection 3.1.2 (1b)
2013 Surmont Operations

2013 – Capital Projects
- Backup Sales Oil Shipping Pump: 100% redundancy for sales oil pump
- Dual Viscometer: More efficient/automated oil viscometer readings

2013 – Optimization Focus Overview
- Steam optimization
  - BTU analyzer control implementation
  - Steam production and delivery development: Delta gen boiler master control enhancements
  - Economizer box upgrade: Charlie steam gen
- Water treatment optimization
  - Automated Soda Ash Silo: Optimized system
  - Blowdown recycle reduction trial
- Oil treatment optimization
  - Front End Chemical Optimization: Enhanced focus on maintaining target dose
  - Produced Water Cooler caustic wash frequency optimization
Facility Performance
Subsection 3.1.2 (2)
Bitumen Treatment Performance

Subsection 3.1.2 (2a)

- Train 1 (Pad 101) Produced Emulsion Flow (02-FI-3002)
- Train 2 (Pad 102) Produced Emulsion Flow (02-FI-4002)
- Front End Produced Water Flow to De-oiling (HX Sum)
Bitumen Treatment Performance

Surmont Phase 1 2013 Production

- Daily Bitumen [bbls]
- BS&W

Subsection 3.1.2 (2a)
Subsection 3.1.2 (2b)

Plant Performance Water Treatment

Conductivity controlled in 2013
Historically The WLS struggles below 12% RW factor, Study underway to “find” new RW Minimum for WLS
Goal of Soda Ash system was to allow WLS to operate at lower raw water cuts and increase throughput through the facility
System complete Dec, 2012 and online Jan, 2013
System Optimized and have driven make-up water rates to historic lows
Plant Performance Steam Generation

2012 Issue:
Steam Generator Fouling
Max rate 68,438 bpd
Average: 60,438

2013 Issue:
Steam Generator Fouling minimized due to BDR reduction
Max rate 71,179 bpd
Average: 65,766

Subsection 3.1.2 (2c)
OTSG Pigging Frequency

Average OTSG Throughput and Days Between Pigging

Increased combined days between pigging

Date

Volume (m3, days)

Subsection 3.1.2 (2c)
## Recycle Blowdown Trial

### Trial plan (Actual conditions)

<table>
<thead>
<tr>
<th>Test days</th>
<th>BD recycle %</th>
<th>ΔT end of step, estimated °C</th>
<th>Expected WRR %</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>90 (83)</td>
<td>20</td>
<td>20 (19)</td>
<td>77 (84)</td>
<td></td>
</tr>
<tr>
<td>60 (60)</td>
<td>30</td>
<td>35 (28)</td>
<td>78 (86)</td>
<td></td>
</tr>
<tr>
<td>30 (45)</td>
<td>35</td>
<td>50 (-)</td>
<td>80 (90)</td>
<td>Non conclusive results: 3 power outages</td>
</tr>
</tbody>
</table>

- The lower the BDR to the WLS the lesser the fouling
- Positive impact:
  - Less pigging cycles
  - Steady & stable operation period
  - Improved steam availability; hence increased production

Preferred range: 20 - 30 %

---

Subsection 3.1.2 (2c)
• Improved sub-cooled boiling in economizer sections.

  • Computational Flow Diagrams (CFD) modeling indicated Improved design reduced sub-cooled boiling by 85% (based on calculated tube skin temperatures)

• Economizer tube skin temperatures reduced by 30%.

OTSG C Modified tube designs to increase the HT area and reduce the nucleate boiling at the same time based on CFD findings
Electrical Consumption

Subsection 3.1.2 (2d)
Gas recovery has been improving since 2007, achieving more than 98% in 2012 & 2013.

<table>
<thead>
<tr>
<th></th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Gas Imports</td>
<td>42,999</td>
<td>160,095</td>
<td>183,933</td>
<td>223,447</td>
<td>228,344</td>
<td>250,412</td>
<td>188,641</td>
<td>e3Sm3</td>
</tr>
<tr>
<td>(TCPL)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Solution Gas</td>
<td>2,533.8</td>
<td>5,272.9</td>
<td>10,051.6</td>
<td>11,101.1</td>
<td>11,284.9</td>
<td>14,136.3</td>
<td>10,755.3</td>
<td>e3Sm3</td>
</tr>
<tr>
<td>Total Gas Vented</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>e3Sm3</td>
</tr>
<tr>
<td>Total Gas Flared</td>
<td>4,640.6</td>
<td>6,438.7</td>
<td>3,962.0</td>
<td>705.0</td>
<td>624.8</td>
<td>217.6</td>
<td>117.3</td>
<td>e3Sm3</td>
</tr>
<tr>
<td>Solution Gas Recovery</td>
<td>-83.1</td>
<td>-22.1</td>
<td>60.6</td>
<td>93.6</td>
<td>94.5</td>
<td>98.5</td>
<td>98.9</td>
<td>%</td>
</tr>
</tbody>
</table>
# 2013 Monthly Flaring Volumes

<table>
<thead>
<tr>
<th>Month</th>
<th>Volume Flared (e³m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>4.1</td>
</tr>
<tr>
<td>February</td>
<td>19</td>
</tr>
<tr>
<td>March</td>
<td>66.8</td>
</tr>
<tr>
<td>April</td>
<td>2.8</td>
</tr>
<tr>
<td>May</td>
<td>0</td>
</tr>
<tr>
<td>June</td>
<td>0</td>
</tr>
<tr>
<td>July</td>
<td>2.5</td>
</tr>
<tr>
<td>August</td>
<td>13.6</td>
</tr>
<tr>
<td>September</td>
<td>5.5</td>
</tr>
<tr>
<td>October</td>
<td>0</td>
</tr>
<tr>
<td>November</td>
<td>0</td>
</tr>
<tr>
<td>December</td>
<td>3</td>
</tr>
</tbody>
</table>
Greenhouse Gas Emissions

546,385 tonnes CO2e generated in 2013
25% reduction in GHG emission intensity from 2009 to 2012
6% reduction in GHG emission intensity from 2012 to 2013
Measurement and Reporting
Subsection 3.1.2 (3)
**Well Allocation Oil Production**

**Well Allocation Oil Production** = Estimated Monthly Well Oil Production \times Oil Proration Factor

Where:

- **Estimated Production** = Accepted well test / duration of test \times on-stream hours
- **Oil Proration Factor** = \frac{Actual battery production}{estimated battery production}
- **Actual Battery Production** = Dispositions + D Inventory – Receipts + Shrinkage + External Shipments + (Load Oil to Wells inventories)

Where:

- **Dispositions** = Dilbit shipped to Enbridge + Diluent send to pilot
- **D Inventory** = Dilbit tanks volume changes + Diluent tank volume changes + Slop tank oil inventory + Skim tank oil inventory
- **Receipts** = Dilbit received from pilot + Diluent received from Enbridge
- **Shrinkage** = Shrinkage adjustment
- **External Shipment** = Oil from slop trucked out to external facility

**Changes for 2013:**

- Improved water cut sampling and analysis assists in tightening proration factors and reservoir understanding
- Started implementation for Surmont Measurement schematic and production allocation validation tool

*Surmont MARP Rev 9 to be submitted in April 2014 (SUR2-A0A-00-OPM-OPN-0045)*
Well Allocated Water Production

Well Allocation Water Production = Estimated Monthly Well Water Production X Water Proration Factor

Where:
Estimated Water Production = Accepted well test / duration of test * on-stream hours
Water Proration Factor = Produced water volume / estimated water production

Produced Water Volume
Inlet Produced Water Meter – Recycled Plant Water + D Inventory – Steam Condensate Traps
– Enbridge Diluent BS&W + Pilot Diluent BS&W + Enbridge DilBit BS&W – Pilot Dilbit BS&W
+ external shipments + (Load Water to Wells inventories) - Pilot Produced Water
(03FIT1170A + 03FIT1170B) X split factor, (split factor estimated from pilot facility meters)

Recycled Plant Water = Water from plant use and plant utilities recycled upstream of inlet produced water meter
Pilot Dilbit BS&W = Water content in received pilot DilBit
Pilot Diluent BS&W = Water content in shipped Diluent to Pilot Plant
External shipment = Any water trucked out of oil battery and delivered to other facilities

Changes for 2013:
• Water Imbalance D81 compliance achieved since April 2013
• Primary steam measurement based on material balance on steam generation system since 2013

Surmont MARP Rev 9 to be submitted in April 2014 (SUR2-A0A-00-OPM-OPN-0045)
Well Allocated Gas Production

**Well Allocation Gas Production** = Well Allocated Oil Production X Calculated Gas-Oil Ratio

Where:

Calculated Gas-Oil Ratio = \( \frac{Total \ produced \ gas}{actual \ battery \ production} \)

Total Produced Gas

Total Gas Consumed – Metered Purchased Fuel gas from TCPL

Where:

Total Gas Consumed = Metered flared gas + metered steam gen fuel gas + utilities fuel + gas for purging system + metered purchased fuel gas for TCPL

Changes for 2013: Added electronic Fuel Flare Vent logs to daily operations to ensure accurate flare reporting as identified in 2013 EPAP

Surmont MARP Rev 9 to be submitted in April 2014 (SUR2-A0A-00-OPM-OPN-0045)
Well Allocated Steam Injection

Estimated Well Steam Injected Meter X Steam Proration Factor

Where:

Steam Proration Factor  = Total injected steam volume / estimated well steam injected meters

Total Injected Steam Volume:

Total Steam Meter to Well Pads – Steam Condensate Dropped Out – Steam Recovered at Pipeline – Steam to eSAGD wells

Highlights for 2013:

- Optimized Meter inspections with scheduling so no down time was needed to meet the requirement
- Steam Gen Flow Pass deviation efforts increased gen efficiencies and improve steam injection Quality
- Steam material balance replaced annubar as primary measurement (March 2013)

Surmont MARP Rev 9 to be submitted in April 2014 (SUR2-A0A-00-OPM-OPN-0045)
• Remarkable improvement in water cut measurement started in 2012
• Calibrations of Pad 102 WC meter in July, October and December 2013
• CPC continues to perform more frequent calibrations to bring oil factors closer to 1
Injection Proration Factors

Average Steam proration for year 2013 = 0.985

2012 = 0.964
2013 = 0.985
2014YTD = 0.992
Well Testing

- Well test duration is optimized to 8 hours with 1 hour purge
- Typical frequency is 4-5 per month per well on the pad test separator
- Method is test separator with Coriolis flow meter for total liquid measurement and water cut meter based on multiple high frequency permittivity measurement
- Since January 2012 and through most of 2013, eSAGD dedicated test separator online at Pad 101. Testing continuously 4 solvent candidate well pairs.

Production Sampling Program

- Produced gas analysis for detailed composition every month (minimum 3 wells)
- Sampling for calibration purpose and adjustment of meters:
  - In 2013, intensive well sampling at Pad 101 to recalibrate water cut analyzer
  - Since eSAGD test separator started-up, intensive sampling program to baseline SAGD performance: up to daily water cut, weekly oil composition, and produced gas samples to calibrate online gas chromatograph
New Technology

Improvements in Watercut Measurement & Sampling

- Work on improving both oil and water proration factors continued in 2013. Three Water cut calibrations were performed on Pad 101. Improvement in proration factors after calibrations continued.
- Permanent sampling skids are now installed in Pads 101 and 102

Multi-phase Flow Meter (MPFM) Trial

- Trial finalized in April 2013
- Results indicated that MPFM provides accurate results
- Application to AER for approval to use in Pad 102 operations was submitted (Addendum to Application No. 1744341) and approved
Water Production, Injection, and Uses
Subsection 3.1.2 (4)
## Surmont Water Source Wells Non-Saline

### Surmont Pilot

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1082508307W400</td>
<td>1AJ082508307W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1072508307W400</td>
<td>100072508307W400</td>
<td>Clearwater</td>
</tr>
</tbody>
</table>

### Surmont Phase 1

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1021808306W400</td>
<td>1F2021808306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1041808306W400</td>
<td>102041808306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1011908306W400</td>
<td>100011908306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1032308307W400</td>
<td>100032308307W400</td>
<td>Lower Grand Rapids</td>
</tr>
</tbody>
</table>

### Surmont Phase 2

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1022108306W400</td>
<td>100022108306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1022608306W400</td>
<td>100022608306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1052808306W400</td>
<td>100052808306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1070308306W400</td>
<td>1F2070308306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1101408306W400</td>
<td>1F1111408306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1130508306W400</td>
<td>100130508306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1153408307W400</td>
<td>1F2153408307W400</td>
<td>Lower Grand Rapids</td>
</tr>
</tbody>
</table>

### Notes

- All water currently used at the Surmont project is non-saline and non-potable (i.e., waters not readily or economically treatable for potable, domestic, agricultural or livestock use).
- Phase 2 source wells licenced on December 14, 2012, not yet in service.

---

**Subsection 3.1.2 (4a, 4b)**

No changes in 2013
Significant reduction thanks to Soda Ash implementation ➡️ Increased WRR
• OTSG’s up-time improved due to reduced BD recycle rates; hence, enhanced steam productivity
Surmont 1 Blowdown Management Overview

Surmont 1 has achieved record production and significantly improved water use efficiency as a result of blowdown management trials.

Surmont 1 Blowdown Schematic
(with 100 m³ CWE boiler feedwater example)

Water Treatment 100 m³ Steam Generation 100 m³ High Pressure Steam Separator 77 m³ To Reservoir

23 m³

15.4 m³

7.6 m³

To Water Treatment

33% Blowdown Recycle

11.5 m³

11.5 m³

Disposal

20-25% Blowdown Recycle

23 m³

Reduced blowdown trial focus area

Overall Surmont Blowdown Recycle = 53 – 58%
Injection Facility Water Imbalance

- Action plan successfully helped to close the gap for water imbalance
- Material balance around steam generation system implemented as primary measurement
- Since April 2013, compliance for injection facility water imbalance in D81 is observed
- Challenges to keep it under 5% when performing big maintenance/repairs work as shown in October and December 2013
### Water Disposal Wells

#### Table

<table>
<thead>
<tr>
<th>Well</th>
<th>Zone Approved for Disposal</th>
<th>Maximum Wellhead Injection Pressure (kPa)</th>
<th>Well Status</th>
<th>ERCB Disposal Approval No</th>
</tr>
</thead>
<tbody>
<tr>
<td>102/03-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Water, Suspended</td>
<td>9573A</td>
</tr>
<tr>
<td>103/03-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Water, Suspended</td>
<td>9573A</td>
</tr>
<tr>
<td>103/10-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Water, Suspended</td>
<td>9573A</td>
</tr>
<tr>
<td>104/10-31-083-06W4/0</td>
<td>McMurray</td>
<td>9000</td>
<td>Observation Well</td>
<td>9573A</td>
</tr>
<tr>
<td>100/09-25-083-07W4/0</td>
<td>Keg River</td>
<td>6000</td>
<td>Water, Disposal</td>
<td>9573A</td>
</tr>
<tr>
<td>100/01-16-083-05W4/0</td>
<td>McMurray</td>
<td>2700</td>
<td>Water, Disposal</td>
<td>10044B</td>
</tr>
<tr>
<td>100/07-22-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water, Disposal</td>
<td>10044B</td>
</tr>
<tr>
<td>100/08-10-083-05W4/0</td>
<td>McMurray</td>
<td>2300</td>
<td>Water, Disposal</td>
<td>10044B</td>
</tr>
<tr>
<td>100/01-04-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Awaiting Tie-in</td>
<td>10044B</td>
</tr>
<tr>
<td>100/01-11-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water, Disposal</td>
<td>10044B</td>
</tr>
</tbody>
</table>

#### Notes
- Disposal at 100/01-11-083-05W4 began February 17, 2013
Water Disposal Wells Injection Rates (McMurray)
Water Disposal Wells Well Head Pressure (McMurray)

![Graph showing water disposal well head pressure over time, with various data points and approval max WHP levels.](image)
Water Disposal Well 100/01-16-083-05 W4M
Observation Well Pressure
Water Disposal Well 100/08-10-083-05 W4M
Observation Well Pressure
## Typical Water Analysis

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Raw Makeup Water (mg/L)</th>
<th>Produced Water (mg/L)</th>
<th>Disposal Water (mg/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>pH</td>
<td>8.5</td>
<td>7.5</td>
<td>8.8</td>
</tr>
<tr>
<td>Total Dissolved Solids (TDS)</td>
<td>1,400</td>
<td>1,800</td>
<td>22,000</td>
</tr>
<tr>
<td>Chloride</td>
<td>200</td>
<td>650</td>
<td>8,000</td>
</tr>
<tr>
<td>Hardness as CaCO₃</td>
<td>&lt;0.5</td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>Alkalinity as CaCO₃</td>
<td>900</td>
<td>300</td>
<td>2,650</td>
</tr>
<tr>
<td>Silica</td>
<td>8</td>
<td>240</td>
<td>200</td>
</tr>
<tr>
<td>Total Boron</td>
<td>6</td>
<td>40</td>
<td>250</td>
</tr>
<tr>
<td>Total Organic Carbon</td>
<td>15</td>
<td>450</td>
<td>2,000</td>
</tr>
<tr>
<td>Oil Content</td>
<td>&lt;1</td>
<td>50</td>
<td>30</td>
</tr>
</tbody>
</table>
## Waste Disposal Locations and Volumes

<table>
<thead>
<tr>
<th>Waste Description</th>
<th>Disposal Weight (Kg)</th>
<th>Final Destination</th>
<th>Disposal Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Debris</td>
<td>9200</td>
<td>Tervita Janvier Landfill</td>
<td>Class II Landfill</td>
</tr>
<tr>
<td>Contaminated Debris and Soil</td>
<td>13890</td>
<td>Tervita Landfill Services - Janvier Landfill</td>
<td>Landfill Cls II</td>
</tr>
<tr>
<td>Domestic Garbage</td>
<td>N/A</td>
<td>Wood Buffalo Landfill</td>
<td>Class II Landfill</td>
</tr>
<tr>
<td>Empty Containers</td>
<td>32</td>
<td>Beaver Regional Municipal Landfill</td>
<td>Class II Landfill</td>
</tr>
<tr>
<td>Filters - Leachable</td>
<td>330</td>
<td>Secure Pembina Landfill</td>
<td>Class I Landfill</td>
</tr>
<tr>
<td>Rags - Leachable</td>
<td>267</td>
<td>Secure Pembina Landfill</td>
<td>Class I Landfill</td>
</tr>
</tbody>
</table>
## Recycling

<table>
<thead>
<tr>
<th>Waste Description</th>
<th>Disposal Weight (Kg)</th>
<th>Final Destination</th>
<th>Disposal Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lube Oil</td>
<td>3533</td>
<td>Van Brabant Oil</td>
<td>Used Oil Recycler</td>
</tr>
<tr>
<td>Empty Containers</td>
<td>86070</td>
<td>Sunset Recycle</td>
<td>Recycling Facility</td>
</tr>
</tbody>
</table>
Sulphur Production
Subsection 3.1.2 (5)
Surmont 1: Sulphur and Sulphur dioxide limits are below the AER and *EPEA* approval limits.

Surmont 2: Project includes a sulphur recovery unit and start-up will be determined to meet compliance with AER and *EPEA* approval limits.
Monthly Sulphur Emissions

Subsection 3.1.2 (5a)
SO\textsubscript{2} Emissions are well below the EPEA approval limit of 2 tonnes/day.
Passive ambient air monitoring - all Alberta Ambient Air Quality Objectives were met in 2013

Continuous ambient air monitoring - all Alberta Ambient Air Quality Objectives were met in 2013
Environmental Issues
Subsection 3.1.2 (6)
Compliance

- AER confirmed that the water within the fresh water tanks meets surface water discharge requirements as defined in Directive 055.
- Installation of berm or double walled tank not required.

Environmental Approval Contraventions

- Approximately 0.5 litres of drilling mud entered channel stream flow (Reference No. 270809).
  - Spill responded to with vacuum truck that was on standby.
  - Water samples taken and sent to lab – no negative impacts detected.
  - All nearby water bodies must be protected through implementation of barriers as corrective action.
- Carbon dioxide (CO$_2$) release sustained over ten minutes (Reference No. 272078).
  - To prevent future releases, pressure safety valves on CO$_2$ storage tank was replaced.
Environmental Monitoring

Groundwater Monitoring
• 2013 results within historical/background concentrations

Soil Monitoring
• 2013 results within historical/background concentrations

Integrated Wetlands Monitoring Program
• 2013 results within historical/background concentrations

Reclamation Programs
• No reclamation in 2013
  • Reclamation programs planned for 2014

Expansion of programs to include Phase 2 has begun.
Compliance Confirmation
Subsection 3.1.2 (7)
ConocoPhillips is in compliance in all areas of the regulations for all of 2013 with the exception of the following:

• **Water recycle**
  - Self disclosure sent on January 2014

• **Injection Facility Water Imbalance**
  - In compliance since April 2013

• **Legacy wells**
  - To be treated as routine abandonments and perform proper abandonment operations
Noncompliance Issues
Subsection 3.1.2 (8)
Noncompliance Issues

Water Recycle:

- Scheme requirement is 90%; annual water recycle rate for 2013 was 87.0%

- **Self disclosed noncompliance for 2013**
  - Continued improvement looking for WRR compliance
  - Minimizing raw water requirements by optimizing soda ash system
  - Continuous work in metering and material balance
    - Inspection and service of the steam meter during S1 turn around (September 2014)
Noncompliance Issues

Legacy Wells

- Self-disclosed noncompliance with respect to Directive 020 in 2013 in four legacy wells:
  - Two wells not cut and capped and had wellheads installed.
    - Remedial Action - wells to be treated as routine abandonments. Meet All AER Directive 20 requirements and submit through DDS (Digital Data Submission) system accordingly.
  - Two wells with casing cut, exposed to surface and not capped.
    - Remedial Action - to be re-licensed to ConocoPhillips by the AER for thermal compatibility repair. ConocoPhillips to treat these wells as non-routine abandonments. Meet All AER Directive 20 requirements and submit through DDS (Digital Data Submission) system accordingly.

- The performance of proper abandonment operations for the four wells is planned for the 2013 - 2014 winter season (three are concluded, one is in progress). The correct status will be entered into the database by April 30, 2014.
Subsection 3.1.1 (8), 3.1.2 (9)
Future Plans
Future Plans – Phase 1

- Continued research into OTSG fouling: evaluating chemical treatment effect
- Steam quality initiative improvement: currently developing the plan for future trials
- Validate performance of two fish bone infill well in path 102 south.
- CPF Debottleneck including one OTSG addition
- Phase 1 Infill Program: Wells drilled Q2-Q3 2013. Start ups have been delayed for Q4 2014.
- The alternative start-ups on Pad 101 infills, solvent soak and dilation, have been approved. Current plans are to conduct these tests in Q4 2014.
- Automation of demulsifier chemical injection
- Heat integration improvement on diluent injection
- Common Header for Pads
Update from SAGD Drilling

Update: Pad 263-1

- Extended 263-1 DA to northwest to regain effective length to >1000m
- Installed FCD’s on P1, P2, P6, P7, P8, P9, P11 to test subcool handling capabilities

Update: Pad 264-3

- Extended 264-3 DA to southeast (maximum length: 1200m) to access resource at the end of the pad
- Installed FCD’s on P2, P4, P7, P9, P11, P12
Pad 263-1

<table>
<thead>
<tr>
<th></th>
<th>P01</th>
<th>P02</th>
<th>P03</th>
<th>P04</th>
<th>P05</th>
<th>P06</th>
<th>P07</th>
<th>P08</th>
<th>P09</th>
<th>P10</th>
<th>P11</th>
<th>P03RD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lgth</td>
<td>1017</td>
<td>1022</td>
<td>901</td>
<td>1404</td>
<td>1425</td>
<td>1420.5</td>
<td>1404</td>
<td>1326.2</td>
<td>1223</td>
<td>1182.2</td>
<td>1080.5</td>
<td>1423.0</td>
</tr>
</tbody>
</table>
Pad 264-3

- The 2012 delineation drilling program evaluated thin pay for a proposed sustaining drainage area immediately south of 264-3.

- Some resource was recognized beyond the south border of 264-3 so the proposed SAGD wells were extended to 1200m to access some of this resource.
  - Extended 264-3 DA to southeast (maximum length: 1200m)
  - Installed FCD’s on P2, P4, P7, P9, P11, P12 (old naming)
• 6 Buffer areas were necessary at S2 to avoid well collisions on offsetting DA’s.
• Successfully used ranging technology to avoid collision when drilling fishbones in-between the offsetting pad 263-2
• Successfully drilled injector fishbones to come within 4m of producer main hole
• Successfully dropped liner into fishbones
• Startup planned for late 2016 and will be challenging
S2 Thermal Compatibility Actions

S2 remedial work to ensure adequate isolation for thermal operations:

100/16-34-083-06W4: (disclosed in 262-2 condition 10)
- cmt sqz McM perfs, cement top at 116m, cut and cap

100/07-15-083-06W4: (disclosed in 265-3 D-23)
- drill out openhole plugs, run prod csg

100/11-27-083-06W4: (disclosed in 263-1 condition 10)
- drill out openhole plugs, run prod csg

100/08-27-083-06W4: (Not disclosed as thermal compatibility reporting requirement had not been established at time of Condition 10 filing)
- cmt sqz McM perfs, set BP, dumpball cmt, Clwr open

102/11-14-083-06W4: (deemed thermally compatible but abandoned anyways)
- Cmt sqz to 42m. Cut and cap

All thermal compatibility issues resolved within S2 initial drainage areas
InSAR Program 2014

Control Reflectors (CR) install planned for February/March
New CR Installs

<table>
<thead>
<tr>
<th>Location</th>
<th>CR Points</th>
</tr>
</thead>
<tbody>
<tr>
<td>S2 DA</td>
<td>80</td>
</tr>
<tr>
<td>Hwy and Pipeline ROW</td>
<td>9</td>
</tr>
<tr>
<td>Pad 104</td>
<td>16</td>
</tr>
<tr>
<td>Pad 102</td>
<td>2</td>
</tr>
<tr>
<td>Pad 101</td>
<td>1</td>
</tr>
<tr>
<td>S1 Reference</td>
<td>1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>109</strong></td>
</tr>
</tbody>
</table>

- existing CR
- new CR on well lease
- new CR in clearing
- new CR along highway

- Installing 12m pipe with pile driver vs. auger in previous years

CR Points occurring on an existing well lease can proceed. Additional approvals required for all other locations

3.1.2 (9a-d)
Project Execution Update

Execution Status

- Project to Date TRIR to end February 0.28
- Facilities Construction Progress
  - 67.9% construction completion vs. 2014 plan of 68.9%
  - First Steam target Q2 2015
- Drilling on Pads 262-3, 264-3 & 261-3
  - 45% D&C complete, on plan
  - Well completions ongoing

Hwy 881 Crossing Status

- Highway crossing complete without incidents.
- Traffic disruption as expected
# Highway 881 Crossing

## Work Status

- Casing ramming complete October 21, 2013
- Concrete cover complete November 26, 2013
- Guardrails complete December 19, 2013
- Pipe installed through casing, complete February 1, 2014
- Hydro-testing schedule to start in April / May 2014 and scheduled to be complete in June 2014
- A minor crack noticed on highway surface after ramming. Consulted with Alberta Transportation; to be re-evaluated after spring break up.

### Casing Ramming

### Concrete Cover
Production expectations and the corresponding construction schedule for the project were based on Phase 1 experience and benchmarking against other operators.

We continue to monitor other industry ramp-ups to sense check our current plans, to understand upside, look for optimization opportunities, etc.

At this stage of the project, the expected well start-up pace is linked closely to the construction schedule.

The well start-up base plan is primarily based on a conventional circulation pre-heat period of 90 days. Studies are ongoing which consider the incorporation of alternative startups.
Surface Operations and Compliance – Pilot Project
Approval 9460

April 9, 2014
Calgary, Alberta, Canada
Contents of Presentation

- Facilities & Facility Performance 3.1.2(1,2)
- Water Production, Injection, and Uses 3.1.2(4)
- Sulphur Production 3.1.2 (5)
- Environmental Issues 3.1.2(6)
- Compliance Confirmation 3.1.2(7)
- Noncompliance Issues 3.1.2(8)
- Future Plans 3.1.2(9)
Facilities
Subsection 3.1.2 (1)
Site Survey Plan - Future

2014 Planned Work

Subsection 3.1.2 (1a)
GT-OTSG Schematic

GT connected and commissioned Turn Around 2012

Subsection 3.1.2 (1b, 1c)
Facility Performance
Subsection 3.1.2 (2)
Average Production in 2012 = 553 bbl/d (88 m³/d)

Average Production in 2013 = 560 bbl/d (89 m³/d)
Pilot Plant Performance 2013 Steam Generation

Steam Injection

- **2012** Scheduled Turnaround
- **2013** Scheduled Maintenance Outage
Pilot Production Performance

Deviation from capacity due to:
- P3 HGP delays in start up after 2012 TA
- ESP failure in P1
- Pump limited on P1 and P2

Subsection 3.1.2 (2a, 2c)
Surmont Thermal Pilot Electricity Consumption

Subsection 3.1.2 (2d)
Change from calculated to metered volumes
## Pilot Plant Performance Gas Usage

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>units</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Gas Imports (TCPL)</strong></td>
<td>11,224</td>
<td>12,334</td>
<td>9,728</td>
<td>11,828</td>
<td>$10^3 m^3$</td>
</tr>
<tr>
<td><strong>Solution Gas</strong></td>
<td>53.20</td>
<td>1,347.30</td>
<td>2,961.60</td>
<td>3,229.20</td>
<td>$10^3 m^3$</td>
</tr>
<tr>
<td><strong>Total Gas Vented</strong></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>$10^3 m^3$</td>
</tr>
<tr>
<td><strong>Total Gas Flared</strong></td>
<td>0.9</td>
<td>2.8</td>
<td>2.45</td>
<td>85.40</td>
<td>$10^3 m^3$</td>
</tr>
<tr>
<td><strong>Solution Gas Recovery</strong></td>
<td>98.3</td>
<td>99.8</td>
<td>99.9</td>
<td>97.4</td>
<td>%</td>
</tr>
</tbody>
</table>
Greenhouse Gas Emissions

Greenhouse Gas Emission Intensity

Subsection 3.1.2 (2f)
Measurement and Reporting
Subsection 3.1.2 (3)
Bitumen Production = \[ \text{Phase 1 meter \{Daily Total\} + Phase 1 Truck receipts + (Sales Tank finish level – Sales Tank start level)} \] – \[ \text{Diluent Pilot Receipt Meter \{Daily Total\} + Diluent Truck receipts + (Diluent Tank finish level – Diluent Tank start level)} \]

Well Bitumen production is calculated from well tests (pro-rated battery)
Water Production = [Flash Tank, Skim Tank, Produced Water Tank and De-sand Tank finish levels - Flash Tank, Skim Tank, Produced Water Tank and De-sand Tank start levels] + [Phase 1 Receipt Meter {Daily Total}]

Well water production is calculated from well tests (pro-rated battery)
Production Gas

- Total battery gas production estimated from total battery oil production and GOR
- Well test gas production calculated from well test oil production and GOR
- Gas proration factor = total battery gas production / well test gas production

Steam

- Steam injection metered individually at each well

Well Testing

- One well on test at a time
- Target at least two tests per well per month
- All three well pairs tested regularly to meet minimum monthly target

No modification in accounting formula
Water Production, Injection, and Uses
Subsection 3.1.2 (4)
# Water Source Wells Non-Saline

## Surmont Pilot

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1082508307W400</td>
<td>1AJ082508307W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1072508307W400</td>
<td>100072508307W400</td>
<td>Clearwater</td>
</tr>
</tbody>
</table>

## Surmont Phase 1

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1021808306W400</td>
<td>1F2021808306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1041808306W400</td>
<td>102041808306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1011908306W400</td>
<td>100011908306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1032308307W400</td>
<td>100032308307W400</td>
<td>Lower Grand Rapids</td>
</tr>
</tbody>
</table>

## Surmont Phase 2

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1022108306W400</td>
<td>100022108306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1022608306W400</td>
<td>100022608306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1052808306W400</td>
<td>100052808306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1070308306W400</td>
<td>1F2070308306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1101408306W400</td>
<td>1F1111408306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1130508306W400</td>
<td>100130508306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1153408307W400</td>
<td>1F2153408307W400</td>
<td>Lower Grand Rapids</td>
</tr>
</tbody>
</table>

**Notes**
- All water currently used at the Surmont project is non-saline and non-potable (i.e., waters not readily or economically treatable for potable, domestic, agricultural or livestock use).
- Phase 2 source wells licenced December 14, 2012, not yet operational.
Pilot Water Source Wells Production Volumes

![Chart showing water production volumes by month for different wells.](image-url)

*Subsection 3.1.2 (4b)
Source Water and Steam Injection Volumes
## Water Disposal Wells

### Table

<table>
<thead>
<tr>
<th>Well</th>
<th>Zone Approved for Disposal</th>
<th>Maximum Wellhead Injection Pressure (kPa)</th>
<th>Well Status</th>
<th>ERCB Disposal Approval No</th>
</tr>
</thead>
<tbody>
<tr>
<td>102/03-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Water, Suspended</td>
<td>9573A</td>
</tr>
<tr>
<td>103/03-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Water, Suspended</td>
<td>9573A</td>
</tr>
<tr>
<td>103/10-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Water, Suspended</td>
<td>9573A</td>
</tr>
<tr>
<td>104/10-31-083-06W4/0</td>
<td>McMurray</td>
<td>9000</td>
<td>Observation Well</td>
<td>9573A</td>
</tr>
<tr>
<td>100/09-25-083-07W4/0</td>
<td>Keg River</td>
<td>6000</td>
<td>Water, Disposal</td>
<td>9573A</td>
</tr>
<tr>
<td>100/01-16-083-05W4/0</td>
<td>McMurray</td>
<td>2700</td>
<td>Water, Disposal</td>
<td>10044B</td>
</tr>
<tr>
<td>100/07-22-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water, Disposal</td>
<td>10044B</td>
</tr>
<tr>
<td>100/08-10-083-05W4/0</td>
<td>McMurray</td>
<td>2300</td>
<td>Water, Disposal</td>
<td>10044B</td>
</tr>
<tr>
<td>100/01-04-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water, Disposal</td>
<td>10044B</td>
</tr>
<tr>
<td>100/01-11-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td></td>
<td>10044B</td>
</tr>
</tbody>
</table>

### Notes
- Disposal to 100/09-25-083-07W4/0 ended December 2011
- As of December 2011, water transferred to Phase 1 via pipeline
Subsection 3.1.2 (4h)

Disposal waters transferred to Phase 1 via pipeline and truck as of December 2011

Water Disposal Rates
Disposal waters transferred to Phase 1 for reuse as of December 2011

Approval Max WHP for 09-25: 6000 kPa
### Solid Waste Disposal

<table>
<thead>
<tr>
<th>Waste Description</th>
<th>Disposal Weight (Kg)</th>
<th>Final Destination</th>
<th>Disposal Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEROSOLS - FLAMMABLE (cls 2.1)</td>
<td>449.00</td>
<td>Edmonton Disposal and Recycle Facility</td>
<td>Recycle</td>
</tr>
<tr>
<td>COMPRESSED GAS (cls 2.2)</td>
<td>549.00</td>
<td>Nisku Recycle Systems</td>
<td>Recycle</td>
</tr>
<tr>
<td>EMPTY CONTAINERS - PLASTIC</td>
<td>469.00</td>
<td>Pnewko Trucking Ltd.</td>
<td>Recycle</td>
</tr>
<tr>
<td>FILTERS - LEACHABLE (cls N/R)</td>
<td>929.00</td>
<td>Secure Energy - Pembina Area Landfill</td>
<td>Landfill Class I</td>
</tr>
<tr>
<td>LEACHABLE WASTE SOLIDS (cls N/R)</td>
<td>409.00</td>
<td>Secure Energy - Pembina Area Landfill</td>
<td>Landfill Class I</td>
</tr>
<tr>
<td>RAGS - LEACHABLE (cls N/R)</td>
<td>246.00</td>
<td>Secure Energy - Pembina Area Landfill</td>
<td>Landfill Class I</td>
</tr>
</tbody>
</table>

Data provided by Tervita
## Fluid Waste Disposal

<table>
<thead>
<tr>
<th>Waste Description</th>
<th>Waste Volume (m³)</th>
<th>Final Destination</th>
<th>Disposal Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sand - Produced</td>
<td>23</td>
<td>Tervita Energy Services - Lindbergh Cavern</td>
<td>Oil Processing Cavern Cavern</td>
</tr>
<tr>
<td>Sludge - Hydrocarbon</td>
<td>25</td>
<td>Tervita Energy Services - Lindbergh Cavern</td>
<td>Oil Processing Cavern Cavern</td>
</tr>
<tr>
<td>Wash Fluids - Organic</td>
<td>26</td>
<td>Tervita Energy Services - Lindbergh Cavern</td>
<td>Oil Processing Cavern Cavern</td>
</tr>
</tbody>
</table>

Data provided by Tervita
Sulphur Production
Subsection 3.1.2 (5)
Change to a more accurate Field Data Capture system starting May 2011
Daily SO\textsubscript{2} Emissions

SO\textsubscript{2} emissions well below daily limit of 0.08 t/d
Alberta Ambient Air Quality Objectives were met in 2013
Environmental Issues
Subsection 3.1.2 (6)
Environmental Compliance

Compliance

• No regulatory issues with Alberta Environment and Sustainable Resource Development or The Department of Fisheries and Oceans

Groundwater Monitoring

• 2013 results within historical/background concentrations

Soil and Groundwater Monitoring

• 2013 results within historical/background concentrations

Reclamation Programs

• No reclamation in 2013
Compliance Confirmation
Subsection 3.1.2 (7)
• ConocoPhillips is in compliance in all areas of the regulations for all of 2013 with the exception of minor flare events exceeding the regulated time limit.
  • Follow-up item from audit: Pilot VRU
Noncompliance Issues
Subsection 3.1.2 (8)
Flaring Events

- Five flaring events sustained over four hours within 24 hour period.
  - Reported to Bonnyville field office and entered into DDS system without issues.
  - No events exceeded the 30 e3m3 daily volume limit.

Follow-up Items From Audit

- Pilot VRU
  - \( \text{H}_2\text{S} \) release calculations submitted, AER provided formal acceptance of variance.
Future Plans
Subsection 3.1.2 (9)
Future Plans

- Potentially re-complete the artificial lift system in well pair C
- Maintain a production strategy for well pairs A and B to achieve primary objective of the Pilot of understanding SAGD performance under thief zones.
- Gas cap monitoring
- Thief zone and blowdown studies
- GT-OTSG study continues