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Introduction, Overview and Highlights

Subsection 3.1.1 (1)
Ownership and Approvals

Ownership
• The Surmont In-Situ Oil Sands Project is a 50/50 joint venture between ConocoPhillips Canada Resources Corp. (ConocoPhillips) 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
• 2015 - Start-up of Phase 2

Approval Update - AER Approval No. 9426

Approval 9426NN – February 1, 2018
• Application No. 1902010 – NCG Co-injection at four Phase 1 DAs and eleven Phase 2 DAs
• Application No. 1903163 – MOP increase at six Phase 2 DAs: 266-2, 263-2, 264-2, 263-1, 264-1, and 103

Approval 9426OO – March 23, 2018
• Application No. 1906715 – Alternate diluent project to enable the use of condensate

Approval 9426PP – October 9, 2018
• Application No. 1913016 – Addition of eight cooled heat exchanges at the S2 CPF in support of the alternate diluent project
Surmont Overview

Phase 1 is focused on the optimization of production and steam.

Phase 2 is focused on the well ramp up and pressure management.

Currently in a “One Surmont” philosophy.

Surmont combined approved capacity is 29,964 m³/cd (188,700 bbl/cd)*
*(where cd is calendar day on an annual average basis)
**Surmont Performance**

**Historical Steam Injection and Bitumen Production**

- **Phase 1 production recovery**
  - Continued execution of Pad 102S NCG Pilot.
  - Managing pressures in Pad 103 to mitigate coalescence issues between DA’s.
  - iSOR as of February 28, 2019 is at an average of 2.99.

- **Phase 2 continued ramp-up**
  - Continuous evaluation of pressure strategies among DA’s to optimize SOR.
  - Thirty-seven ESP conversions performed, enabling implementation of pressure strategy.
  - Focus in understanding underperformance of specific areas within Surmont 2.
  - Started NCG pilot for mitigation of thief zone issues.
  - iSOR as of February 28, 2019 is at an average of 2.96.

---

**2018 Highlights**

- **iSOR vs Time**
  - 2007-2008: Unstable Ramp-up
  - 2009: Steam Gen Issues
  - 2010-2012: Stable Operations reaching “capacity”
  - 2013+: Continuous Improvement
  - 2015-16: Ramp-up Begins
  - 2017-18: Production Optimization

**MBPD**

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Subsurface Resource Evaluation and Recovery

Geology and Geoscience
Subsection 3.1.1 (2)
OBIP Volumes: Reservoir Properties of Development Area

**Properties Development Area**

- **NCB Thickness Range**: 0 to Greater than 30 m
- **Phie in NCB**: 31.72%
- **So in NCB**: 75.78%
- **OOIP in NCB > 18m**: 3423.25 MMbbls

**Surmont Development Area OBIP**

\[ \text{OBIP} = \text{Thickness} \times \text{Phie} \times \text{So} \times \text{Area} \]
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McMurray Gross Isopach

2018/2019 Mapping Update

- No delineation/no changes

Subsection 3.1.1 (2c)
McMurray Net Gas Isopach

Net Top Gas thickness = sands have deep resistivity >10 \( \Omega \)-m and Vsh <65%

2018/2019 Mapping Update
- No delineation/no changes
Net Top Water thickness = sands have deep resistivity <10 Ω-m and Vsh <45%
McMurray Net Bottom Water Isopach

Net Bottom Water thickness = sands have deep resistivity <10 Ω·m and Vsh <45%

2018/2019 Mapping Update
• No delineation/no changes

Subsection 3.1.1 (2c)
McMurray Top Continuous Bitumen Structure

TCB = The uppermost limit of good reservoir, bitumen-bearing sands.

Top Continuous Bitumen Structure

2018/2019 Mapping Update
• No delineation/no changes
Base Continuous Bitumen Structure

2018/2019 Mapping Update

- No delineation/no changes
McMurray Net Continuous Bitumen Pay

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

2018/2019 Mapping Update
- No delineation/no changes
INTERPRETTING SAGD INTERVAL

**Fluid Surfaces**

- **Top Gas Surface**: The uppermost limit of gas-bearing sands
- **Bottom Gas Surface**: The lowest occurrence of gas-bearing sands
- **Top Water Surface**: The uppermost limit of water-bearing sands
- **Bottom Top Water Surface**: The lowest occurrence of water-bearing sands above the bitumen
- **Top Bitumen Surface**: The uppermost limit of bitumen-bearing sands with deep resistivity of 10 ohm or greater and a Vsh cutoff of less than 33%
- **Top Continuous Bitumen Surface (TCB)**: The uppermost limit of good reservoir, bitumen-bearing sands.
- **Base Continuous Bitumen Surface (BCB)**: The first occurrence of good reservoir, bitumen-bearing sands with deep resistivity of 40 ohm or greater, or 8wt% bitumen.
- **Base Bitumen Surface**: The lowest occurrence of bitumen-bearing sands with deep resistivity of 10 ohm or greater and a Vsh cutoff of less than 33%
- **Top Bottom Water Surface**: The uppermost limit of water-bearing sands below bitumen
- **Bottom Water Surface**: The lowest occurrence of water-bearing sands below the bitumen

**Gross Fluids**

- **Top Gas**: Gross thickness of gas-bearing sands defined by the top and bottom gas surfaces
- **Top Water**: Gross thickness of water-bearing sands defined by the top and bottom water surfaces
- **Top Bitumen**: Gross thickness of bitumen-bearing sands defined by the top and base bitumen surfaces
- **Continuous Bitumen / SAGD Interval**: Gross thickness of continuous bitumen reservoir with deep resistivity of 40 ohm or greater, and does not include continuous muds greater than 3m thick. SAGD interval would be from the producer level (approx. 5m above BCB) to the top of this zone.
- **Bottom Water**: Gross thickness of water-bearing sands defined by the top and bottom water surfaces
Phase 1 Type Log Well Pad 101

Example Log 100161408307W400

McMurray

Continuous Bitumen

Devonian

High Sw

High Sw

Pad 101

Type Log

Phase 1 Area
Phase 2 Type Log – Well Pad 264-2

Example Log 100162208306W400

- **McMurray**
  - Top Gas
  - High Sw

- **Continuous Bitumen**

- **Devonian**

Phase 2 Area

Subsection 3.1.1 (2e)
Phase 2 Type Log – Well Pad 261-3

Example Log 100043508306W400

Phase 2 Area

McMurray Net Continuous Bitumen (NCB)

Continuous Bitumen

Drainage Area
Phase 2 Type Log – Well Pad 262-2

Example Log 100163408306W400

McMurray Net Continuous Bitumen (NCB)

Phase 2 Area

Example Log

Continuous Bitumen

Drainage Area

Subsection 3.1.1 (2e)
Phase 1 Type Log – Well Pad 103

Example Log 100052308307W400

Phase 1 Area

McMurray Net Continuous Bitumen (NCB)

Continuous Bitumen

Drainage Area
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 potential impact on production performance on Well Pad 262-1.
No new wells were drilled between Mar 1, 2018 to Mar 1, 2019

1531 existing wells

- Phase 1 and Phase 2 Development Area
- Drainage Areas

Surmont lease

Surmont Lease as of March 1, 2019
No new cores were cut between Mar 1, 2018 to Mar 1, 2019
No new wells were drilled between March 1, 2018 and March 1, 2019; hence no FMI/CMI logs were taken.
2018-2019 Delineation Campaign and Well Density

Delineation across Phases 1, 2, and 3

Delineation Well Density Map
Mar 2018

Delineation Well Density Map
Mar 2019

Density Map Difference

McMurray penetrated wells only
2018-2019 Delineation Campaign and Well Density

Increased core density with latest drilling

Cored Wells Density Map
Mar 2018

Cored Wells Density Map
Mar 2019

Cored Density Map Difference

McMurray penetrated wells only
2018-2019 Delineation Campaign and Well Density

Increased Formation Micro Imaging density with latest drilling

FMI Well Log Density Map
Mar – 2018

FMI Well Log Density Map
Mar - 2019

FMI Density Map Difference

McMurray penetrated wells only

Subsection 3.1.1 (2f)
• **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.

**Viscosity increases with depth in the McMurray Formation.**

- **52 existing viscosity sample wells**
- **Delineated Wells - Surmont**
Subsection 3.1.1 (2f)
Representative Structural Cross Section

Lower Grand Rapids
Clearwater Shale
Clearwater Marker
Wabiskaw / McMurray Marker
Devonian Unconformity

10:1 vertical exaggeration
• The existing DFIT and caprock core testing results are believed to provide the critical data required for caprock integrity analysis, in combination with other well and seismic data. Therefore, no additional DFITs or core testing was complete.
• Future caprock coring or DFITs may be planned as CPC investigates the caprock for new development of Surmont.
• The dilation pilot results are being further investigated and modifications might be considered for future trials.
Surface Deformation Monitoring

- Satellite (RADARSAT-2) measurements every 24 days
- Interferometric Synthetic Aperture Radar (InSAR):
  - Corner Reflectors (CR) installed over pads and in areas to measure background deformations.
  - 256 CR’s installed since monitoring program began in 2008.
  - An additional 20 Corner reflectors were installed in 2017 at Phase 2 but are not tied into our current routine data collection yet, so they are not shown on the map.
InSAR Surface Deformation Monitoring

Vertical Deformation (mm) for period
Feb 28, 2018 to Feb 28, 2019
(Surmont 1)

- Deformation currently in line with expectations.

Vertical Deformation (mm) for period
Feb 28, 2018 to Feb 28, 2019
(Surmont 2)

○ Corner Reflector
□ Reference Corner Reflector
◇ Corner Reflector w/quality issue
☒ Corner Reflector w/Frost Jacking
3D Seismic Lines

No changes In 2018

2012-2013 Seismic

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Caprock Integrity

- Caprock Core Analysis
  - 14 caprock cores were drilled and analyzed in 2015-2017.
  - Four rock mechanics testing programs were conducted in 2015-2017.
- Diagnostic Fracture Injectivity Tests (DFITs):
  - 8 DFITs were carried out in 2015-2017
  - DFIT locations were selected based on structural and geomechanical analysis of the caprock.
- Static Geomechanical Model
  - A static geomechanical model was created using all seismic, cores and wells data
  - The model is used for caprock integrity screening and analysis
  - The static geomechanical model of the reservoir and caprock was last updated in 2019Q1.
- The completed analysis verified that
  - The best seals within the cap rock interval are the deeper water deposits occurring on maximum flooding surfaces.
  - The seal over the development area is continuous, consistent and laterally extensive.
ConocoPhillips applies a highly conservative approach towards Subsurface Containment Assurance and follows a stringent approach based on internal SCA standards and regulations.

Caprock integrity studies in ConocoPhillips include extensive geological, geophysical, petrophysical and geomechanical investigations. ConocoPhillips continues to acquire and interpret the data to mitigate SCA related risks.

Results of caprock integrity studies allow ConocoPhillips to characterize and mitigate local risks related to geological and geomechanical variations. Analysis of caprock in the development area suggests while the previously used value of 18.4 kPa/m is valid, the minimum horizontal stress is higher in several drainage areas.

ConocoPhillips continues to propose a flexible tapered strategy envelope bound by the cap rock integrity study and the associated Maximum Operating Pressure (MOP) on one side and economic achievable pressures on the other side. In 2017/18 temporary and permanent changes were made to the MOPs in a number of DAs in Surmont.

ConocoPhillips has received approval to increase MOP from 15 kPa/m to 16.5 kPa/m in eight DAs in Surmont.

Another approval was received to temporarily increase the MOP in one DA (262-3) to overcome near-wellbore barriers. A pilot test using one well pair was completed with the temporary MOP and results are being studied before proceeding with the rest of the DA well pairs.
The static geomechanical model used for caprock integrity analyses is regularly updated based on acquired and interpreted data.

Static modeling of reservoir and caprock is used in combination with dynamic simulation of their geomechanical and pressure responses is used to estimate the SCA safety factors.

For all applications and MOP changes, ConocoPhillips has demonstrated that the SCA safety factors have been maintained above 1.2 for the base cases.

Caprock Integrity Analysis and Maximum Operating Pressure Workflow

Geological and Geophysical Investigation → Static Geomechanical Modeling → Coupled Geomechanics Reservoir Simulation → Final Proposal for MOP Strategy → Documentation, Review and Submission

Surmont Development Area and Selected DAs for MOP Increase (red outline)
Drilling and Completions

Subsection 3.1.1 (3)
Surmont Well Summary

Legend

Well Status:
- ESP
- PCP
- Gas Lift
- Circulation
Surmont FCD Installations

**Legend**

**FCD Installations:**
- Green circle: Prod. LDFCD
  - Phase 1: 13
  - Phase 2: 37
- Blue circle: Prod. TDFCD
  - Phase 1: 7
  - Phase 2: 29
- Red circle: Inj. LDFCD
  - Phase 1: 9
  - Phase 2: 4

Surmont 2
2018 Re-Drills

- Total of 15 re-drills in 2018.

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Typical Concentric Injector

16” Surface Casing

11 ¾” Intermediate casing

Liner Hanger

8 5/8” Slotted Liner

7” Heel tubing String

4 ½” Toe String

Subsection 3.1.1 (3c)
Typical Parallel Injector

- 16” Surface Casing
- 11 ¾” Intermediate casing
- 4 ½” Heel tubing String
- Liner Hanger
- 8 5/8” Slotted Liner
- 2 7/8” Toe String
- Install a heel gas coil (5/8”) to lift heel production, no more blanket gas lifting
- Heel lift gas coil set 10 – 15m TVD above lateral

**Improved Gas Lift Producer Design, 264-1**

**Subsection 3.1.1 (3c)**
Improved Gas Lift Producer Design, 264-2, 263-2 & 263-1

- Heel tubing string set 10 – 15m TVD above lateral
- 1 perforated joint on the bottom of heel tubing string with an additional 1-2 casing joints attached below.

- Blanket gas
- Emulsion
- Liner Hanger
- 13 3/8” Surface Casing
- 7” Slotted liner
- 10 – 15m TVD
- Perforated Joint on 7” Heel tubing String
- 4 ½” x 3 ½” VIT L80:
- 9 5/8” Intermediate casing
- 1.25” Thermocouples (8pt) Clamped to outside of Toe Tubing
- 4 ½” Toe String
- Bubble Tube Clamped to outside of Toe Tubing
- 1” Toe Lift Gas Coil Tubing Inside Toe Tubing
- Subsection 3.1.1 (3c)
Typical ESP Producer

13 3/8” Surface Casing

ESP Power Cable + 3/8” Bubble Tube + 2x ¼” encapsulated F.O. P/T Instrumentation Cables (Intake/Discharge) (Clamp to outside of ESP Production Tubing)

3 ½” Production tubing String

2 1/16” Guide String

P/T Sensor clamped to 2-3/8” pup joint

1 ¼” Coil (Inside of Guide Sting & FCD Tubing)

9 5/8” Intermediate casing

7” Slotted liner

Subsection 3.1.1 (4a)
Typical PCP Producer

13 3/8” Surface Casing

3/8” Bubble Tube

Sucker Rod/ CoRod

3 ½” Production tubing String

PCP (Progressive Cavity Pump)

9 5/8” Intermediate casing

2 1/16” Guide String

P/T Sensor clamped to 2-3/8” pup joint

Liner Hanger

7” Slotted liner

40pt Fiber Optic LxData 1 ¾” Coil (Inside of Guide Sting & FCD Tubing)
Typical Liner Deployed Flow Control Device (LDFCD) Completion

- **13 3/8” Surface Casing**

- **1” Toe Lift Gas Coil Tubing**
  - Inside Toe Tubing

- **5/8” Heel Lift Gas Coil Tubing**
  - Clamped to outside of Toe Tubing

- **9 5/8” Intermediate casing**

- **Liner Hanger**

- **FCD’s with Screens**

- **7” Non Slotted liner**

- **4 ½” x 3 ½” VIT L80:**

- **7” Heel tubing String**

- **1.25” Thermocouples (8pt)**
  - Clamped to outside of Toe Tubing

- **4 ½” Toe String**

**Table: Total Wells with FCDs**

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<thead>
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<th>Total Wells with FCDs</th>
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* Injector wells do not have instrumentation or GL coils

Subsection 3.1.1 (3c)
Typical Tubing Deployed FCD (TDFCD) Completion – Gas Lift

13 3/8” Surface Casing

1 1/4” Coil with Temperature Measurement/ Gas Lift

10 – 15m TVD

7” Heel tubing String

9 5/8” Intermediate casing

Production Liner Hanger

4.5” Tubing Deployed Flow Control Device (TDFCD)

Swell Packers

FCD Liner Hanger

7” Production liner

4.5” Liner Joints

Pad | Total Wells with TDFCDs
--- | ---
262-3 | 1
263-2 | 1

Subsection 3.1.1 (3c)

Typical Tubing Deployed FCD (TDFCD) Completion – Gas Lift

13 3/8” Surface Casing

1 1/4” Coil with Temperature Measurement/ Gas Lift

10 – 15m TVD

7” Heel tubing String

9 5/8” Intermediate casing

Production Liner Hanger

4.5” Tubing Deployed Flow Control Device (TDFCD)

Swell Packers

FCD Liner Hanger

7” Production liner

4.5” Liner Joints

Pad | Total Wells with TDFCDs
--- | ---
262-3 | 1
263-2 | 1

Subsection 3.1.1 (3c)
Typical Tubing Deployed FCD (TDFCD) Completion – ESP

- **13 3/8” Surface Casing**
- **9 5/8” Intermediate casing**
- **3 ½” Production tubing String**
- **4.5” Tubing Deployed Flow Control Device (TDFCD)**
- **2 1/16” Guide String**
- **40pt Fiber Optic LxData /DTS 1 ¼” Coil** (Inside of Guide Sting & FCD Tubing)
- **4.5” Liner Joints**

---

### Pad | Total Wells with FCDs
---|---
101 | 6 | 0
102 | 2 | 0
103 | 2 | 0
261-3 | 9 | 0
262-1 | 4 | 2
262-2 | 4 | 1
263-1 | 1 | 0
264-1 | 3 | 0
264-2 | 1 | 0
264-3 | 3 | 3
265-2 | 4 | 0

* Injector wells do not have instrumentation or GL coils
Current Surmont 2 Steam Splitter Design

- Steam Splitter design used for top water zone risk reduction.
- Splitter open/closed position to be assessed on a well by well basis.
Artificial Lift

Subsection 3.1.1 (4)
## Artificial Lift Current Pad Overview

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Subsection 3.1.1 (4a)
Artificial Lift Types

- **Gas Lift**
  - Gas lift is effective with bottom hole flowing pressures >2,700 kPa with pressure of wellhead (Pwh) approx. 1,000 kPa
  - Lifting from heel and toe with gas assist at start of vertical section
  - Current production rates range from 100 m³/d to 700 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
  - Operating temperatures typically below 215°C
  - Typically install Series 500; Series 400 pumps installed due to casing restrictions

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

* ConocoPhillips initial strategy for PCPs was to use them on low deliverability wells where the current ESP designs were deemed less appropriate. However, installation of larger PCPs are being considered for wells that may produce relatively “cold” viscous fluid for some time.
ESP Run Life Definitions

- **MTTF**: This run-life measure is calculated as the total exposure time of all systems (running, pulled and failed) divided by the number of failed systems.

- **Average Runtime**: This run-life measure is calculated as the total exposure time of all systems (running, pulled and failed) divided by the number of systems (running, pulled and failed).

- **Average run life running ESP**: This run-life measure is calculated as the total exposure time of running systems divided by the number of running systems.

- **Window**: window time allows for changes in average run-life to be more apparent, as they are less obscured by previous data.
ESP Performance

KPI’s

**Population: 145 ESP’s
Cumulative MTTF: 40.5 months
Windowed** MTTF: 61.1 months
Average Runtime: 16 months
Windowed* Runtime: 16.7 months
Average run life running ESP: 15.1 months

2016: 16 ESP failures
2017: 19 ESP failures
2018: 26 ESP Failures
2019: 2 ESP Failures

*(730 day window)
** The unrealistically high MTTF at S2 as a result of the # of recent ESP installs artificially increases the One Surmont’s overall MTTF
Instrumentation in Wells

Subsection 3.1.1 (5)
Temperature & Pressure Measurement

• Temperature Measurement
  • Producer lateral temperature
    • Measured with 8 thermocouples, 40 LxData, or DTS fiber optic strings.
  • Injector lateral temperature
    • No temperatures measured

• Pressure Measurement
  • Producer
    • Primary bottom hole pressure measurement is done with a bubble tube corrected for TVD
    • Some LxData wells were equipped with toe pressure sensors, but have questions around accuracy
    • Secondary BHP measurement through 2 1/16 guide string
  • Injector
    • Primary bottom hole pressure measurement is done with casing blanket gas
1. Phasing out all Thermocouples & LX Data at ESP conversion - evaluating options however DTS is the likely choice for most wells.
1. Phasing out all Thermocouples & LX Data at ESP conversion, evaluating options however DTS is the likely choice for most wells.

2. All wells will contain fiber temperature instrumentation.
Distributed Temperature Sensing (DTS)

Subsection 3.1.1 (5b)

13 3/8” Surface Casing:

Blanket gas

1” Toe Lift Gas Coil Tubing
Inside Toe Tubing

5/8” Heel Lift Gas Coil Tubing
Clamped to outside of Toe Tubing

Gas Lift Mandrel

9 5/8” Intermediate casing

4 ½” x 3 ½” VIT L80:

7” Heel tubing String

10 – 15m TVD

7” Slotted liner

No Change in 2018

4 ½” Toe String
Typical Observation Well Measurement

- Example thermocouple and piezometer (101-07-OBA)
- Typically 40 TC (2m spacing)
- 0-10 piezometers placed at varying intervals

**COP 101-P07-OBA**

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<td>Bitumen</td>
<td>388.1</td>
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**Piezometer Information**

- **Piezo 1:** 256.1 mASL
- **Piezo 2:** 241.4 mASL
- **Piezo 3:** 231.5 mASL

**Miscellaneous**

- TC bottom @ 390.6 m GL
- TC Top @ 347.1 m GL
- 30 points TC and 1.5 m spacing out
4D Seismic

Subsection 3.1.1 (6)
4D Seismic Location Map – Phase 1

Phase 1 Area

**Pilot**
- Buried analog single component geophones
- Cased dynamite shots (1/4 Kg) @ 9 m
- 14th monitor acquired in September 2015

**Pad 101N**
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 9th monitor acquired in March 2018

**Pad 101S**
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 9th monitor acquired in March 2015

**Pad 102N**
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 10th monitor acquired in October 2018

**Pad 102S**
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 7th monitor acquired in October 2018

**Pads 103 and 104**
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 3rd monitor acquired in October 2017 (103)
Phase 2

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- Acquired in three stages:
  - Initial 11 DA’s: 2010-11
  - South extension: 2013-14
- First Monitors
  - Spring 2016: 263-2
  - Fall 2017: 262-1
  - Spring 2018: 266-2
- Second Monitors:
  - Fall 2018: 262-1
- Third Monitor
  - Fall 2018: 263-1
## Phase 1 - 4D Seismic Program

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<th>2017</th>
<th>2018</th>
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<td>Fall</td>
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- **M**: Monitor
- **B**: Baseline
# Phase - 2 4D Seismic Program

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- **Baseline** (B)
- **Monitor** (M)
2015 - 4D Seismic Results Pad 101

- Well Pair 07/08/09, without a true baseline.
- 4D anomaly volume have increased for the remaining well pairs.
- Good conformance, especially at the heel.

- 4D anomaly volumes have increased.
- Continued conformance improvement along Well Pad 10, 11, 16, 17.
- Infill wells drilled between Well Pads 10, 11, 12, 16, 17 and 18 to optimize production in a geological more complex zone.

= 4D anomaly
~60 deg C Isotherm
• No a significant 4D Thermal growth between the Monitors

• No a significant 4D Thermal growth between the Monitors
Relative good conformance in most of well pair.
4D indications of coalescence with thermal chamber of Pad 101N (103-08/12)
2018 4D Seismic Results Phase 2

- **Spring Monitor:**
  - 262-2
  - 266-2
  - 261-3
  - 263-2
  - 262-3

- **Fall Monitors:**
  - 263-1
  - 262-1

- **Relative good conformance in most well pairs**
  (excepting 264-2 - deformation issues in the liner caused some wells to fail and impacted the quality of circulation on other wells, especially at the toe)
4D Seismic Program 2018

- 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.
Scheme Performance

Subsection 3.1.1 (7)
**Surmont: Production vs. Scheme Approval**

**Surmont Production vs. Scheme Approval**

SURMONT SCHEME APPROVAL = Phase 1 + Phase 2 + Phase 2DB

**Monthly Bitumen Production**

- **February 2018 (Feb-18)**
- **March 2018 (Mar-18)**
- **April 2018 (Apr-18)**
- **May 2018 (May-18)**
- **June 2018 (Jun-18)**
- **July 2018 (Jul-18)**
- **August 2018 (Aug-18)**
- **September 2018 (Sep-18)**
- **October 2018 (Oct-18)**
- **November 2018 (Nov-18)**
- **December 2018 (Dec-18)**
- **January 2019 (Jan-19)**
- **February 2019 (Feb-19)**
Surmont: Phase 1 and 2 - SOIP and RF

- **SOIP**: 6,910 – 10,504 E3M3
- **Current RF**: 6.6% - 62.0%
- **Porosity**: 30.3% - 34.0%
- **Oil saturation**: 72.1% - 82.7%
- **Blowdown timing** will determine final EUR/RF.
- Recovery factors for drainage areas are based on performance. At this time, the expected ultimate recovery factor is difficult to predict, and these values are subject to change.

Subsection 3.1.1 (7cii)
• 101-P08, 101-P09 and 102-P01 were re-drilled due to poor performance; stranded resource at the toe was the primary reason (bridge plug was set previously to mitigate hotspot/sand production from these areas)
• NCG Trial ongoing for 102N, 102S and 101N
• Strong performance on Pad 103
Performance and recovery on the west side of the pad has been challenged.

NCG injection has commenced.
102-P01;02;03 have been the poorest producers on the pad due to a combination of liner failures and poor geology.  
102-P01 was re-drilled and artificial lift was changed to ESP.
High quality reservoir.
Falloff data and 4D seismic indicates well conformance.
• Poor conformance has seen this well perform average compared to others on this pad.
• Removed heel scab liner to help improve performance.
Obs Wells Temp & GR – 103-P10-OBB, 103-P12-OBA

Pad 103

103-P10-OBB 100/03-23-083-07W4 / 3.3m offset

103-P12-OBA 105/14-14-083-07W4 / 41.3m offset

Subsection 3.1.1 (7b)
Recovery remains low, and a side-track re-drill is being considered to recover the lateral wellbore length and increase production.
Observations

- Reduction of emulsion rates
- Reduction of water cut
- iSOR reductions of 15-30%
- Increase in chamber pressures due to NCG injection
- Individual drainage areas under pilots are in full coalescence.
Phase 1 – Key Learnings

• Highly connected systems present complex redevelopment opportunities on 101S.
• 102N and 102S continues to see a reduction of emulsion, water cut and iSOR with the NCG pilot.
• 101N performance has improved late time due to both redevelopment executions as well as steam strategy adjustments.
• Liner installed flow control devices at pad 103 continue to outperform slotted liner wells.
• Optimization continues to improve performance of mature wells:
  • NCG pilot on-going for 101N, 102N and 102S.
  • Completed three re-drills in 2018.
  • Well stimulations (executed seven)
    • 100% of the well stimulations have been successful in terms of reducing the scale/dP across the production liner. This has contributed to higher production rates and a decreased risk of liner failure.
Top water thief zone interactions in Pads 263-1, 264-1, 264-3, and 265-2.
Bottom water thief zone interactions in 261-3, 262-1 and 262-2.
Ten producers re-drilled; seven due to poor performance and three to failure.
Two injectors re-drilled; one to poor performance and one due to failure.
ESP conversions ongoing.
262-3 was operating at a target pressure of 4,000 kPag for most of 2018 but was reduced to 3,800 kPag in Q4.

- Challenged performance from East to West.
- No thief zone issues.

2018 (Spring)
Performance / Chamber Development Challenges – Pad 262-3

- Limited chamber growth

Subsection 3.1.1 (7b)
• Severe bottom water interaction on many well pairs.
• Reduced pressure differential between chamber and low pressure bottom water on wells that are interacting with the bottom water.
Well Performance continues to exceed expectations.
Mud channel continues to cause challenges with hotspots.
Subsection 3.1.1 (7b)
• Stable 2018 production performance, meets expectations.
• Managed top thief zone interaction with dedicated pressure management.
Poor Performance – WP 262-2-07

- Challenged well; bottom water interaction.
- Minimum steam injection; pressure support from adjacent wells.
Surmont: Obs Wells Temp & GR – 262-2-P06-OBA, 262-2-P07-OBC

Subsection 3.1.1 (7b)
Observations

- Reduction of emulsion rates
- Reduction of water cut
- iSOR reductions of 15-30%
- Increase in chamber pressures due to NCG injection
- Individual drainage areas under pilots are in full coalescence.

Oil rates flat
Phase 2 - Key Learnings

• At pad 262-3, higher reservoir chamber pressure has been trialed to overcome under performance with minimal success. 262-3-P03 and 262-3-P12 were re-drilled and have observed a production increase, which is still under evaluation for sustainment.

• Injector steam splitters are still being evaluated for hotspot and thief zone mitigation.

• Bottom water has been very challenging to mitigate due to the early interaction of some wells and the high differential pressure between chamber and the bottom water zone.

• Top water interaction is being mitigated thanks to dedicated pressure management and ESP conversion strategy.

• Optimization continues to improve performance of mature wells:
  • NCG pilot on-going for 265-2.
  • Completed twelve re-drills in 2018.
  • Well stimulations (executed seven)
    • 100% of the well stimulations have been successful in terms of reducing the scale/dP across the production liner. This has contributed to higher production rates and a decreased risk of liner failure.
Surmont: Phase 1 Well Pad Rates and SOR / Pad 101

Subsection 3.1.1 (7h)
Surmont: Phase 1 Well Pad Rates and SOR / Pad 102

**Rates (m3/d)**

- **102N**
- **102S**

**iSOR / cSOR (sm3/sm3)**

- **102N**
- **102S**
Surmont: Phase 1 Well Pad Rates and SOR / Pad 103

- **Rates (m³/d)**
  - Steam Rate
  - Oil Rate
  - Water Rate

- **iSOR / cSOR (sm³/sm³)**
  - iSOR
  - cSOR

Subsection 3.1.1 (7h)
Surmont: Phase 2 Well Pad Rates and SOR

Subsection 3.1.1 (7h)
Surmont: Phase 2 Well Pad Rates and SOR

Subsection 3.1.1 (7h)
Surmont: Phase 2 Well Pad Rates and SOR

264-2

Rates (m3/d)

264-3

Rates (m3/d)

264-2

ISOR / cSOR (sm3/sm3)

264-3

ISOR / cSOR (sm3/sm3)

265-2

Rates (m3/d)

265-2

ISOR / cSOR (sm3/sm3)
Future Plans

Subsection 3.1.1 (8)
Future Plans – Surmont

• Continue evaluating NCG co-injection Pilots in Surmont for mid-life pressure management and thief zone mitigation.

• Evaluating multilateral well technology trial to drill infill producers off of existing SAGD producers.

• Well stimulations ongoing to determine the optimal chemical product for SAGD well scale treatment in Surmont.

• Evaluating infill opportunities.

• ESP conversions ongoing.

• Evaluation of steam optimization retrofits and their possible mitigation under thief zones interactions.

• Evaluate redevelopment opportunities for under performing pads.
Surface Operations and Compliance
Surmont Project
Approval 9426

Facilities
Subsection 3.1.2 (1)
Phase 1 Plot Plan: Pad 101

- E-SAGD Equipment was de-commissioned in 2017; no major modifications in 2018
Phase 1 Plot Plan: Pad 102

- No Major Modifications in 2018

Subsection 3.1.2 (1a)
• No Major Modifications in 2018

Subsection 3.1.2 (1a)
Installation of one additional OTSG and associated heat exchanger at Surmont 2 in 2017, OTSG is now operational. No other major changes 2018.
• No Major Modifications in 2018
• No Major Modifications in 2018
No Major Modifications in 2018
Phase 2 Plot Plan: Pad 262-3

- No Major Modifications in 2018
• No Major Modifications in 2018
• No Major Modifications in 2018
• No Major Modifications in 2018
Phase 2 Plot Plan: Pad 264-2

- No Major Modifications in 2018

Subsection 3.1.2 (1a)
Phase 2 Plot Plan: Pad 264-3

- No Major Modifications in 2018
• No Major Modifications in 2018
Phase 2 Plot Plan: Pad 266-2

- No Major Modifications in 2018
Subsection 3.1.2 (1b)
2018 Surmont Operations

• **Phase 1:**
  - NCG co-injection pilot
  - Pad 103 turn-around
  - WLS turbine failure and replacement

• **Phase 2**
  - Pad 264-1 turn-around
  - Continuous operation with partial condensate blending
  - Trial to turn off the glycol trim heater
  - Wellhead freeze mitigation trial
  - Repair planning and design for building sumps
Facility Performance

Subsection 3.1.2 (2)
Facility Performance: Bitumen Treatment by CPF

![Graph showing measured emulsion flow (AM^3/hr) over time, with CPF1 and CPF2 lines.](image)

Subsection 3.1.2 (2a)
Facility Performance: Phase 1 Water Treatment

- Phase 1 water treatment plant continues to operate as per design.
- July 2018 outage required for WLS repairs was completed successfully.
- Monitoring of the sludge pond interstitial space is ongoing.
Facility Performance: Phase 2 Water Treatment

- Phase 2 water treatment plant operated as per design.
- Continued work to improve reliability of chemical feed systems.
- Produced water flowrates impacted by production curtailment in January 2019.
• Saline water treatment plant operating as per design. Saline water flowrates varied as per water balance make-up requirements.
• Predominantly operated with a single OTSG blowdown evaporator. Trials with dual blowdown evaporator operation began in late February 2019.
Twenty-three OTSGs were in operation throughout 2018 at Surmont:
- 4 OTSGs in service at Surmont 1
- 19 OTSGs in service at Surmont 2

Surmont targeted 85% steam quality across the entire OTSG fleet until December 2018 when the quality targets were decreased:
- Corrosion of the pipes on the Surmont 2 OTSGs drove the decision to operate at steam qualities <85% in 2019
- Root cause of the OTSG piping corrosion is under investigation
  - OTSG corrosion investigation and repairs led to individual OTSG outages throughout the last half of 2018.
- The operating steam qualities remain above the design conditions of 75%
- Targeting 365+ days between OTSG outages for pigging (tube cleaning)

*2019 focus is to maintain online reliability while maximizing steam output*
• Phase 1 is at a steady state of production and electrical consumption, however the turn around in July caused the anomaly in 2018.
• Reduced power requirement in summer shows slight variation.
Facility Performance: 2018 Total Gas Usage

<table>
<thead>
<tr>
<th>Month</th>
<th>Solution Gas</th>
<th>TCPL Import</th>
<th>Flare/Vent</th>
<th>% Gas Rcvry.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-18</td>
<td>6,065.1</td>
<td>134,310.5</td>
<td>7.5</td>
<td>99.88%</td>
</tr>
<tr>
<td>Feb-18</td>
<td>5,820.3</td>
<td>122,568.8</td>
<td>2.8</td>
<td>99.95%</td>
</tr>
<tr>
<td>Mar-18</td>
<td>6,096.6</td>
<td>135,221.7</td>
<td>1.1</td>
<td>99.98%</td>
</tr>
<tr>
<td>Apr-18</td>
<td>5,688.4</td>
<td>125,442.5</td>
<td>2.1</td>
<td>99.96%</td>
</tr>
<tr>
<td>May-18</td>
<td>5,969.5</td>
<td>123,317.0</td>
<td>29.2</td>
<td>99.51%</td>
</tr>
<tr>
<td>Jun-18</td>
<td>6,272.7</td>
<td>121,726.2</td>
<td>56.7</td>
<td>99.10%</td>
</tr>
<tr>
<td>Jul-18</td>
<td>5,778.1</td>
<td>115,209.3</td>
<td>209.4</td>
<td>96.38%</td>
</tr>
<tr>
<td>Aug-18</td>
<td>6,283.0</td>
<td>121,242.4</td>
<td>227.0</td>
<td>96.39%</td>
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<tr>
<td>Sep-18</td>
<td>6,784.7</td>
<td>127,951.5</td>
<td>2.1</td>
<td>99.97%</td>
</tr>
<tr>
<td>Oct-18</td>
<td>6,675.1</td>
<td>129,233.8</td>
<td>49.9</td>
<td>99.25%</td>
</tr>
<tr>
<td>Nov-18</td>
<td>6,695.3</td>
<td>125,269.7</td>
<td>14.4</td>
<td>99.78%</td>
</tr>
<tr>
<td>Dec-18</td>
<td>7,020.9</td>
<td>131,734.0</td>
<td>4.9</td>
<td>99.93%</td>
</tr>
<tr>
<td>Jan-19</td>
<td>5,269.7</td>
<td>115,061.7</td>
<td>0.8</td>
<td>99.98%</td>
</tr>
<tr>
<td>Feb-19</td>
<td>5,235.3</td>
<td>109,943.2</td>
<td>0.8</td>
<td>99.98%</td>
</tr>
</tbody>
</table>
Surmont Facility Performance: 2018 Usage by Type

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Flare/Vent</td>
<td>7.5</td>
<td>2.8</td>
<td>1.1</td>
<td>2.1</td>
<td>29.2</td>
<td>56.7</td>
<td>209.4</td>
<td>227.0</td>
<td>2.1</td>
<td>49.9</td>
<td>14.4</td>
<td>4.9</td>
<td>0.8</td>
<td>0.0</td>
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<tr>
<td>NCG_INJ</td>
<td>1,540.3</td>
<td>1,345.9</td>
<td>1,342.2</td>
<td>1,567.7</td>
<td>1,868.0</td>
<td>2,309.9</td>
<td>2,157.4</td>
<td>1,502.0</td>
<td>1,879.0</td>
<td>1,869.3</td>
<td>1,846.2</td>
<td>2,451.6</td>
<td>2,848.3</td>
<td>3,105.3</td>
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<td>BT/IF Fuel Gas</td>
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<td>127,040.4</td>
<td>139,975.0</td>
<td>129,561.1</td>
<td>127,389.3</td>
<td>125,632.3</td>
<td>118,620.6</td>
<td>125,796.4</td>
<td>132,855.1</td>
<td>133,989.7</td>
<td>130,104.4</td>
<td>136,298.4</td>
<td>117,482.3</td>
<td>112,073.3</td>
</tr>
</tbody>
</table>
Facility Performance: 2018 Gas Usage by Location

Subsection 3.1.2 (2e)
Surmont Facility Performance: Year over Year Total Gas Usage

<table>
<thead>
<tr>
<th>Year</th>
<th>Solution Gas (e³Sm³)</th>
<th>TCPL (e³Sm³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>2,754.8</td>
<td>42,798.8</td>
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<tr>
<td>2008</td>
<td>4,154.1</td>
<td>161,383.3</td>
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<tr>
<td>2009</td>
<td>10,072.4</td>
<td>183,912.9</td>
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<tr>
<td>2010</td>
<td>12,703.1</td>
<td>223,446.8</td>
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<tr>
<td>2011</td>
<td>13,869.0</td>
<td>228,343.6</td>
</tr>
<tr>
<td>2012</td>
<td>15,193.4</td>
<td>250,290.0</td>
</tr>
<tr>
<td>2013</td>
<td>17,004.7</td>
<td>253,749.3</td>
</tr>
<tr>
<td>2014</td>
<td>14,245.5</td>
<td>240,496.3</td>
</tr>
<tr>
<td>2015</td>
<td>19,301.0</td>
<td>433,138.0</td>
</tr>
<tr>
<td>2016</td>
<td>33,635.8</td>
<td>962,312.9</td>
</tr>
<tr>
<td>2017</td>
<td>63,632.1</td>
<td>1,415,198</td>
</tr>
<tr>
<td>2018</td>
<td>75,035.5</td>
<td>1,513,227</td>
</tr>
<tr>
<td>2019</td>
<td>10,505.1</td>
<td>225,004.9</td>
</tr>
</tbody>
</table>

**2015: Phase 2 Start-Up, plus 1 Flare Stack, 2 GTH & 11 OTSGs**
Avg. 5 OTSGs @ 77% Stm. Quality

**To 2014: Phase 1, 2 Flare Stacks, 1 Glycol Trim Heater & 4 OTSGs**
78% Avg. Steam Quality

**2016: Phase 2 Ramp-Up, plus 7 OTSGs, minus 1 Flare Stack.**
NCG Coinjection Trial on 3 Wells. Avg. 15 OTSGs @ 77% Stm. Quality

**2017: NCG Coinjection Trial on 9 Wells**
Avg. 20 OTSGs @ 83% Stm. Quality

**2018: NCG Coinjection on 21 Wells**
Avg. 21 OTSGs @ 84% Stm. Quality

Subsection 3.1.2 (2e)
High variability in Fuel Gas usage, due to production curtailments, driving lower steam demand and changes to target steam quality.

- Average 21 of 23 OTSGs running
- Steam quality increased from average 83% in 2017 to average 84.3% in 2018
- In December 2018, Steam Quality is decreased targeting an average 82%

After successful trial, NCG co-injection has been extended after November 2018 from 9 wells to 40 wells by end of February 2019. Gas co-injected with steam is assumed to remain in the reservoir (does NOT return with solution gas to plant).
All efforts made to reduce and/or minimize Flare and Vent Events

**Vent Events**
- Met 2018 requirement for detecting, estimating and reporting gas volumes associated Vent Events
- Major events due to Power Outages, Product Shipment restrictions and VRU Trip
- Minor events due to increased product volatility after incorporating some condensate as diluent. This issue is being addressed through the “Alternate Blending Project” to be completed in 2019

**Flare Events**
- Major Events - July and August due to External Power Supply Failure, causing Plant Trips
- Minor events due to process upsets or extreme cold weather
As of 2018 Phase 1 and Phase 2 CO2e emission are reported as one combined value.

2018 GHG Emission intensity is currently being verified for payment submission.
Measurement and Reporting

Subsection 3.1.2 (3)
Well Testing

• Surmont Well Pads are configured to automatically and sequentially, align each production well into the Test Separator.

• Well Test Duration, Total Produced Emulsion, Average Water Cut and Total Produced Water Vapors are recorded for each Well Test.

• Well Test Results are reviewed to: “Approve”, if representative of the wells production, or “Reject.”

• Well Test Durations range from 5 to 10 hours, with up to 4 hours purge, based on the wells previous liquid production rates.
Well Estimated Monthly Production

Each well’s estimated monthly production is calculated using only “approved” Well Test Results. Daily estimated volumes are used to calculate the wells monthly estimated volume from the time of an approved well test, until its next approved well test.

**Well Monthly Estimated Oil Production** =

\[ \text{Well Estimated Daily Oil Production} \times \text{Hours per Days in Operation} \]

- **Well Estimated Daily Oil Production** =
  \[ \frac{\text{Test Produced Emulsion Volume}}{\text{Test Duration (hours)}} \times (1 - \text{WC\%}) \times 24 \text{ hours} \]

**Well Monthly Estimated Water Production** =

\[ \text{Well Estimated Daily Water Production} \times \text{Hours per Days in Operation} \]

- **Well Estimated Daily Water Production** =
  \[ \frac{\text{Test Produced Emulsion Volume}}{\text{Test Duration (hours)}} \times \text{WC\%} + \text{Water Vapor} \times 24 \text{ hours} \]
Well Allocated Oil Production

**Well Estimated Monthly Oil Production \( \times \) Oil Proration Factor**

- **Oil Proration Factor** =
  \[
  \frac{\text{Battery Produced Oil}}{\text{Total Estimated Monthly Oil Production}}
  \]

- **Battery Produced Oil** =
  \[
  \text{Oil Dispositions} + \text{Battery Tank Inventory} + \text{Shrinkage} - \text{Receipts} + \text{Well Load Oil}
  \]

- **Total Estimated Monthly Oil Production** =
  \[
  \sum_{i=1}^{x} \text{Well}_i \text{ Estimated Monthly Oil Production}
  \]
  where \( x \) is the total number of production wells for the reporting period.

- **Oil Dispositions** =
  \[
  \text{Sales CTM}^1 + \text{Enbridge Tank Inventory} + \text{TruckOut}
  \]

- **Oil in Battery’s Tank Inventory** =
  \[
  \text{Sales Oil Tanks} + \text{OffSpec Tanks} + \text{Slop Oil Tanks} + \text{Skim Oil Tanks}
  \]

- **Receipt** =
  \[
  \text{Diluent CTM}^1 + \text{Diluent Tank Inventory} + \text{Diluent TruckIn}
  \]
Well Allocated Water Production

**Well Estimated Monthly Water Production × Water Proration Factor**

- **Water Proration Factor** =
  \[
  \frac{\text{Battery Produced Water}}{\text{Total Estimated Monthly Water Production}}
  \]

- **Battery Produced Water** =
  \[
  \text{Water Dispositions + Battery Tank Inventory} - \text{Receipts} + \text{Well Load Water}
  \]

- **Total Estimated Monthly Water Production** =
  \[
  \sum_{n=1}^{x} \text{Well}_n \text{ Estimated Monthly Water Production}
  \]
  where \(x\) is the total number of production wells for the reporting period.

- **Water Dispositions** =
  \[
  \text{Dispositions to Injection Facility} + \text{Truck-Out}
  \]

- **Water in Battery’s Tank Inventory** =
  \[
  \text{Skim Oil Tanks} + \text{Slop Oil Tanks} + \text{DeSand/BackWash/ORF Tanks} + \text{Sales/OffSpec/Diluent Tanks}
  \]

- **Receipt** =
  \[
  \text{IF Condensate Returns} + \text{Water in Diluent} + \text{Truck-In}
  \]
Well Allocated Oil Production $\times$ GOR

- Gas to Oil Ration (GOR) =
  \[ \frac{\text{Battery Produced Gas}}{\text{Battery Produced Oil}} \]

- Battery Produced Gas =
  \[ \text{Gas Dispositions} - \text{Receipts} \]

- Gas Dispositions =
  \[ \text{Battery Utility FG} + \text{Steam Generators FG} + \text{NCG CoInjection} + \text{Flare/Vent} + \text{Camp} \]

- Receipt =
  \[ \text{TCPL Fuel Gas CTM}^1 \]

As of January 2018, accounting and reporting of Vent Gas Events

---

1 CTM: Custody Transfer Meter
Well Allocated Steam

**Well Measured Steam × Steam Proration Factor**

- **Well Measured Steam =** 
  
  \[ \text{Steam Injected @Heel} + \text{Steam Injected @Toe} \]

- **Steam Proration Factor =** 
  
  \[ \frac{\text{Steam Produced}}{\text{Total Measured Steam}} \]

- **Steam Produced =** 
  
  \[ \text{Steam Generated (CPF)} - \text{Steam Condensate Returns} \]

- **Total Measured Steam =** 
  
  \[ \sum_{n=1}^{x} \text{Well}_n \text{ Measured Steam} \]

  where \( x \) is the total number of injection wells during the reporting period.
2018 Highlights and Changes

Completed Phase 1 Steam Volume Correction back to January 2015 to ensure adequate evaluation of field’s performance

Non condensable gas (NCG) co-injection:
- **November 2016** Trial in 3 wells at Pad 102 (volumes estimated)
- **September 2017** Extended to 6 additional wells in Pad 102 (measured)
- **August 2018** Decision to include Pad 265-2, 12 wells (measured)
  Metering of Pad 102 initial 3 wells NCG volumes
- **December 2018** Installation of NCG Meters in Pad 101 North (11 wells)

NCG Co-injected volumes added to battery’s gas dispositions (assumes gas co-injected with steam does not return to the injection facility with solution gas)

Continue to maintain proration factor regulatory compliance through all 2018, through multiple production curtailments
- Total of 183 wells in SAGD operation
2018: Continue to maintain Regulatory Compliance all year

183 SAGD Wells in 14 Well Pads

Subsection 3.1.2 (3b)
Steam Injection Proration Factor

2018 Average Steam Proration Factor: 0.9971

Regulatory Compliance Limits
0.85 - 1.15
Water Production, Injection and Uses
**Surmont Phase 1 and Phase 2 Water Source Wells**

### Surmont Phase 1 Non-Saline Water Source Wells

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
<th>Water Act Licence No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1021808306W400</td>
<td>1F2021808306W400</td>
<td>Lower Grand Rapids</td>
<td>00253532-02-00</td>
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<tr>
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<td>00253532-02-00</td>
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<td>1F1011908306W400</td>
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<td>Lower Grand Rapids</td>
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</table>

### Surmont Phase 1 Saline Water Source Wells

### Surmont Phase 2 Non-Saline Water Source Wells

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
<th>Water Act Licence No.</th>
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<td>Lower Grand Rapids</td>
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<tr>
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### Surmont Phase 2 Saline Water Source Wells

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<th>Formation</th>
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<tbody>
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<tr>
<td>1F1020608404W400</td>
<td>Clearwater</td>
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<tr>
<td>1F1033008304W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1042208305W400</td>
<td>Clearwater</td>
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<tr>
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</tr>
<tr>
<td>1F2141108404W400</td>
<td>Lower Grand Rapids</td>
</tr>
</tbody>
</table>

**No Changes in 2018**
Water Production and Steam Injection Volumes

Diluent shortages/ Plant advanced SD

Steam (CWE, m³); Produced water (m³)

Jan-17  Mar-17  May-17  Jul-17  Sep-17  Nov-17  Jan-18  Mar-18  May-18  Jul-18  Sep-18  Nov-18  Jan-19

Produced water  Steam Injection

Subsection 3.1.2 (4c, 4d)
Surmont in compliance with Directive 081 Injection Facility Water Imbalance since June 2014

Surmont Phase 2 CPF Shutdown planned for Q2-2019
• Surmont anticipates *Directive 081* disposal limit compliance in 2019 as per current trend (7.0% actual vs. 10.7% disposal limit)

• Surmont accomplished *Directive 081* compliance in 2016 (7.5% actual vs. 10.6% disposal limit) after commissioning brackish water system and blowdown evaporators at Phase 2 CPF
**Surmont Phase 1 Water Disposal Wells**

<table>
<thead>
<tr>
<th>Well</th>
<th>Zone Approved for Disposal</th>
<th>Maximum Wellhead Injection Pressure (kPa)</th>
<th>Well Status</th>
<th>AER Disposal Approval No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>100/01-16-083-05W4/0</td>
<td>McMurray</td>
<td>2700</td>
<td>Water Disposal</td>
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<tr>
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<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
<td>10044K</td>
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<tr>
<td>100/08-10-083-05W4/0</td>
<td>McMurray</td>
<td>2300</td>
<td>Water Disposal</td>
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<tr>
<td>100/04-21-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
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<tr>
<td>100/01-11-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
<td>10044K</td>
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</table>
Surmont Phase 2 Water Disposal Wells

<table>
<thead>
<tr>
<th>Well</th>
<th>Zone Approved for Disposal</th>
<th>Maximum Wellhead Injection Pressure (kPa)</th>
<th>Well Status</th>
<th>AER Disposal Approval No.</th>
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<tbody>
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<td>3400</td>
<td>Water Disposal</td>
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<td>100/01-04-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
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<tr>
<td>100/01-28-083-05W4/0</td>
<td>McMurray</td>
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<td>100/10-15-083-05W4/0</td>
<td>McMurray</td>
<td>3400</td>
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<td>10044K</td>
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<td>10044K</td>
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<td>McMurray</td>
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<td>10044K</td>
</tr>
</tbody>
</table>

Subsection 3.1.2 (4g)
Surmont Water Disposal Wells Injection Rates (McMurray)

Subsection 3.1.2 (4h)
Surmont Phase 1 Water Disposal Wells Well Head Pressure (McMurray)

Approval Max. WHP for 100/01-16: 2700 kPa

Approval Max. WHP for 100/07-22, 100/04-21, and 100/01-11: 2500 kPa

Approval Max. WHP for 100/08-10: 2300 kPa

Subsection 3.1.2 (4h)
Water Disposal Well 100/01-16-083-05 W4M Observation Well Pressure (McMurray)

- 102/01-16 Piezo 3 [McMurray Gas, 238 mKB]
- 102/01-16 Piezo 2 [McMurray Water, 263 mKB]
Water Disposal Well 100/08-10-083-05 W4M Observation Well Pressure (McMurray)

Subsection 3.1.2 (4h)

- 102/08-10 Piezo 3 [McMurray Gas, 203 mKB]
- 102/08-10 Piezo 2 [McMurray Water, 228 mKB]
- 102/08-10 Piezo 1 [McMurray Water, 253 mKB]
<table>
<thead>
<tr>
<th>Waste Description</th>
<th>Disposal Weight (Tonnes)</th>
<th>Disposal Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dangerous Oilfield Waste</td>
<td>12,969</td>
<td></td>
</tr>
<tr>
<td>Hydrocarbon/Emulsion Sludge</td>
<td>436</td>
<td>Oilfield Waste Processing Facility</td>
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<tr>
<td>Crude Oil/Condensate Emulsions</td>
<td>8,462</td>
<td>Oilfield Waste Processing Facility</td>
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<td>Various</td>
<td>4,071</td>
<td>Landfill</td>
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<td>Non-Dangerous Oilfield Waste</td>
<td>36,498</td>
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<td>Lime Sludge</td>
<td>27,632</td>
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<tr>
<td>Various</td>
<td>8,688</td>
<td>Landfill</td>
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<tr>
<td>Well Fluids</td>
<td>178</td>
<td>Cavern</td>
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## Waste Recycling

<table>
<thead>
<tr>
<th>Waste Description</th>
<th>Disposal Weight (Tonnes)</th>
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</thead>
<tbody>
<tr>
<td>Oil</td>
<td>6</td>
<td>Used Oil Recycler</td>
</tr>
<tr>
<td>Empty Containers</td>
<td>4.6</td>
<td>Recycling Facility</td>
</tr>
<tr>
<td>Fluorescent Light Tubes</td>
<td>1.1</td>
<td>Recycling Facility</td>
</tr>
<tr>
<td>Batteries</td>
<td>2.8</td>
<td>Recycling Facility</td>
</tr>
</tbody>
</table>
## Typical Water Analysis

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Non-Saline Makeup Water (mg/L)</th>
<th>Saline 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>8.2</td>
<td>7.5</td>
<td>11.8</td>
</tr>
<tr>
<td>Total Dissolved Solids (TDS)</td>
<td>1,400</td>
<td>8,000</td>
<td>1,800</td>
<td>23,000</td>
</tr>
<tr>
<td>Chloride</td>
<td>200</td>
<td>2,800</td>
<td>650</td>
<td>9,500</td>
</tr>
<tr>
<td>Hardness as CaCO₃</td>
<td>&lt;0.5</td>
<td>225</td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>Alkalinity as CaCO₃</td>
<td>900</td>
<td>350</td>
<td>250</td>
<td>2,700</td>
</tr>
<tr>
<td>Silica</td>
<td>8</td>
<td>7</td>
<td>190</td>
<td>225</td>
</tr>
<tr>
<td>Total Boron</td>
<td>6</td>
<td>3.3</td>
<td>40</td>
<td>260</td>
</tr>
<tr>
<td>Total Organic Carbon</td>
<td>15</td>
<td>4</td>
<td>500</td>
<td>2,150</td>
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<tr>
<td>Oil Content</td>
<td>&lt;1</td>
<td>&lt;1</td>
<td>65</td>
<td>30</td>
</tr>
</tbody>
</table>
Sulphur Production

Subsection 3.1.2 (5)
• The SO₂ emissions were managed below the 1.6t/d in 2018.
• The facility instituted operational controls to reduce Sulphur scavenger chemical in October 2018.
• Sulphur recovery unit maintained 100% uptime.
• Surmont achieved greater than the required 69.7% quarterly Sulphur recovery in 2018.
Ambient Air Quality Monitoring

Continuous ambient air monitoring: all Alberta Ambient Air Quality Objectives were met in 2018
Continuous ambient air monitoring: all Alberta Ambient Air Quality Objectives were met in 2018
Continuous ambient air monitoring: all Alberta Ambient Air Quality Objectives were met in 2018
Environmental Compliance

Subsection 3.1.2 (6)
• ConocoPhillips maintained complete environmental compliance throughout 2018 with no environmental non-conformances at Surmont Phase 1 or 2.
Groundwater Monitoring Program:
- Program revised to focus monitoring on early change detection

Wetlands:
- Semi-annual wetland site assessments completed

Wildlife Monitoring Program:
- Wildlife handling permit obtained
- Submitted a Comprehensive Wildlife report in May of 2018
- Continued support of the Monitoring Avian Productivity and Survivorship program
- No serious nuisance wildlife or human-bear interactions

Reclamation Work:
- Submitted Project Level Conservation, Reclamation and Closure Plan in October 2018
- Completed monitoring of vegetation establishment on reclaimed trial sites
- Established bioengineering trials for erosion and sediment control
Environmental Initiatives

- Canada’s Oil Sands Innovation Alliance (COSIA) - ConocoPhillips is an active participant of the Water, Land and Greenhouse Gas Environmental Priority Area and the COSIA Monitoring Priority Area.

- ConocoPhillips leads the industrial Footprint Reduction Options Group (iFROG), a collaboration of in situ oil sands operators, to address key knowledge gaps related to wetland reclamation.
Compliance Confirmation and Non Compliances

Subsection 3.1.2 (7) + (8)
ConocoPhillips is in regulatory compliance for 2018 with the exception of the following:

**Surmont Warm Line Softener and Boiler Feed Water Tank Farm Secondary Containment**
- Visual inspection of the berm area identified small punctures on two areas that were exposed for inspection on Oct 29, 2019.
- Compromised areas were repaired with patches followed by sand layers and geotextile.
- Probe sampling continues on other areas to test for additional signs of instability.

**Surmont Unplanned Hydrocarbon Venting**
- Unplanned hydrocarbon venting events exceeding 4hrs in duration were reported on May 7th, 2018 and June 17, 2018.
- ConocoPhillips’ Voluntary Self Disclosure (July 24, 2018) was accepted by the AER with conditions to provide quarterly updates on the venting until the new VRU is installed in mid/late 2019.
- A new educator vapour recovery unit (VRU) is planned for installation during the plant turnaround in summer 2019. The system is expected to be operating by Q3 2019.

**Surmont Building Sumps - Primary Liners**
- 17 building sumps contain liquid in the interstitial spaces.
- AER accepted ConocoPhillips’ Voluntary Self Disclosure on Sept 26, 2018 with a condition to provide quarterly updates (ongoing).
- A number of sumps were repaired online with no interruption to operations, the remainder of the sump repairs require a full plant outage, scheduled for May of 2019.
- CPC is on track to complete all the required repairs to return the sumps to compliance by the end of Q4 2019.
Boiler Feed Water Release 5-18-83-6W – Sept 21, 2018- FIS Incident: 20182998
• PSV lifted early and was discharging 9 m3 of boiler feed water as the OSTG was being warmed up.
• The PSV lifted 2000 kpa earlier than what it was set to lift at.
• The value was taken out of the recertification program and discarded.
• The environmental impact was limited to soil and water contamination. Fluid was cleaned up from the culvert to the source. Incident investigation was closed, no remedial actions are required.

Steam Condensate Release-2-5-84-6W4 – Nov 14, 2018- FIS Incident: 20183493
• 2 inch steam line had developed a pinhole leak releasing 12 m3 steam and steam condensate.
• the transmitter which controls the electric heating coil on the two inch line was positioned too close to the 4 inch line. This resulted in most of the 2 inch line not receiving sufficient heat. As a result part of the line froze.
• Environmental clean up is complete and the investigation is closed, no remedial actions are required.
Future Plans

Subsection 3.1.2 (9)
Future Plans – Surmont

• Surmont Landfill project design is complete, potential execution in 2020

Phase 1:
• Design work on-going for modifications for 100% condensate blending with potential construction in 2020
• NCG co-injection pilot ongoing and potential expansion in 2019

Phase 2:
• Full plant turn-around planned for April – June 2019
• Ongoing construction for modification for 100% condensate blending with start up planned for October 2019
• New Eductor VRU system construction and start up during 2019 turn-around
• Continuing repair planning and design for building sumps and starting execution
Future Pad Developments

- 267 is the next pad in the queue.
- Pad 104 among other candidates are being evaluated for next pad in the queue.
- 268 is on hold pending further review.