Annual Surmont SAGD Performance Review Approval 9426

April 24, 2019

Calgary, Alberta, Canada

Table of Contents – AER Scheme Approval No. 9426

Subsurface

Surface

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

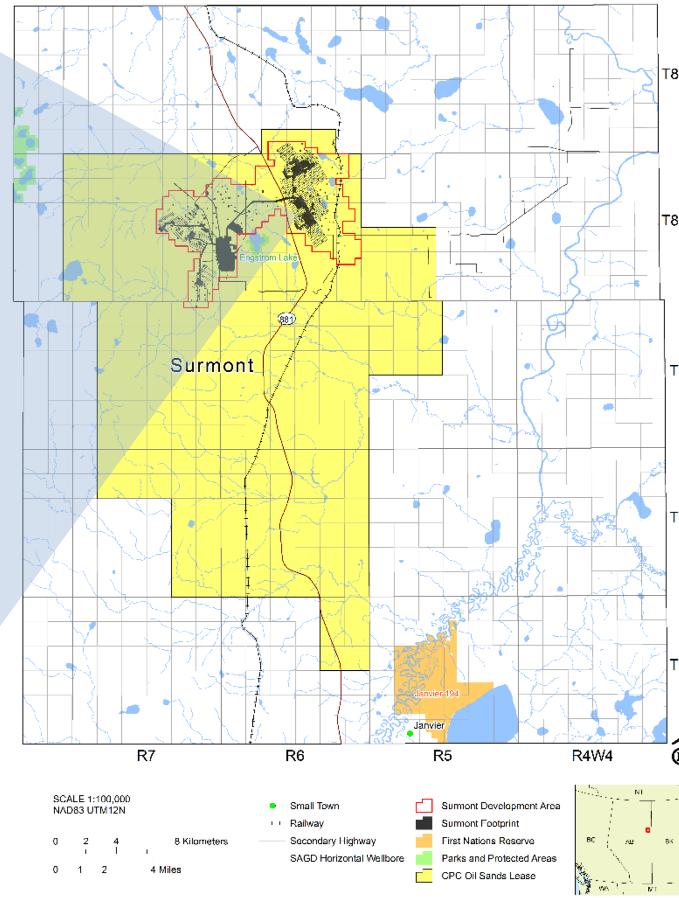
Approval 9426PP – October 9, 2018

- 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

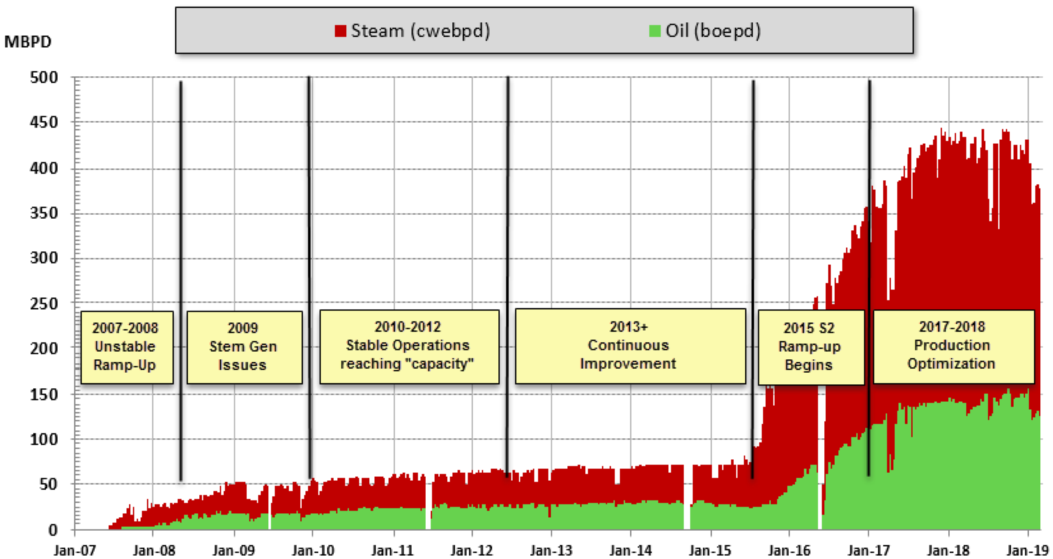


Currently in a "One Surmont" philosophy

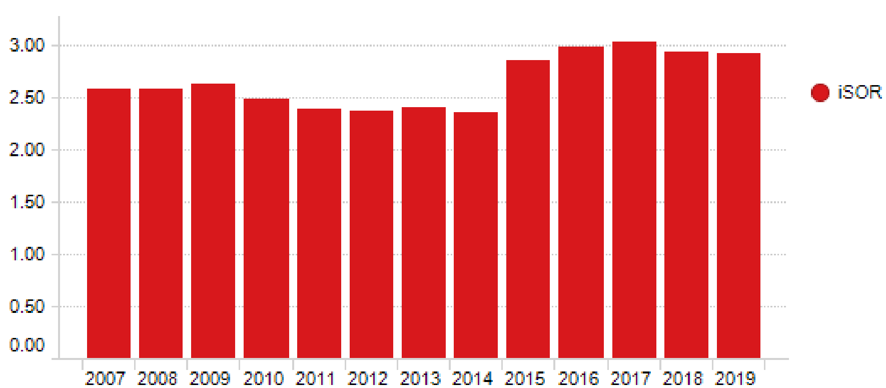
Surmont combined approved capacity is 29,964 m^3/cd (188,700 bbl/cd)*
***(where cd is calendar day on an annual average basis)**

Surmont Performance

Historical Steam Injection and Bitumen Production



iSOR vs Time



2018 Highlights

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 2.99.

Phase 2 continued ramp-up

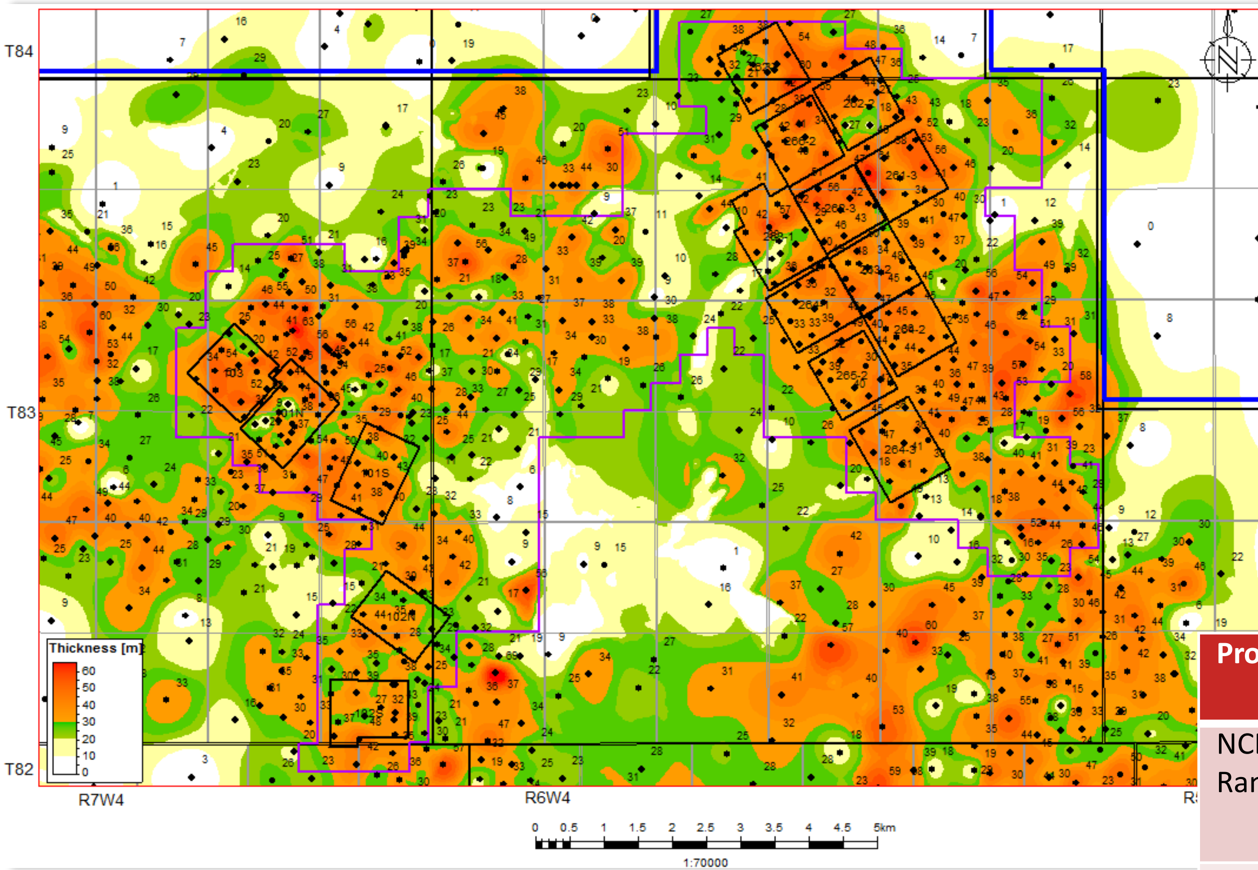
- Continuous evaluation of pressure strategies among DA's to optimize SOR.
- Thirty-seven ESP conversions performed, enabling implementation of pressure strategy.
- Focus in understanding underperformance of specific areas within Surmont 2.
- Started NCG pilot for mitigation of thief zone issues.
- iSOR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

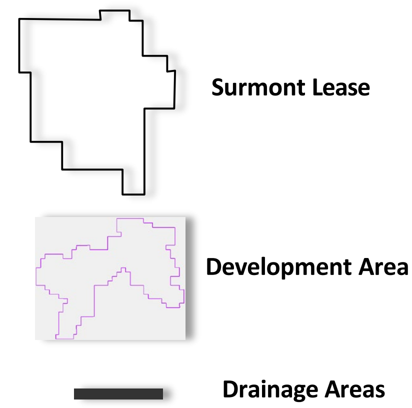
Subsurface Resource Evaluation and Recovery

Geology and Geoscience

Subsection 3.1.1 (2)

OBIP Volumes: Reservoir Properties of Development Area



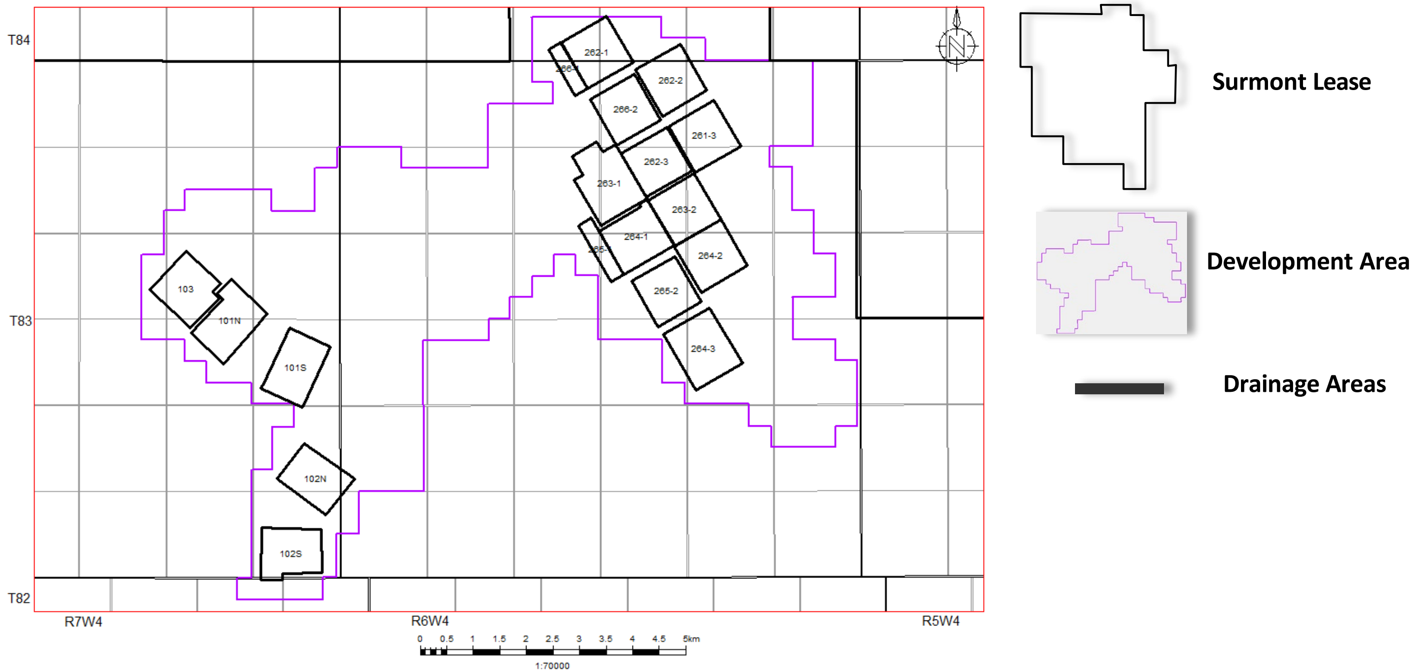


Surmont Development Area OBIP

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 Deterministic

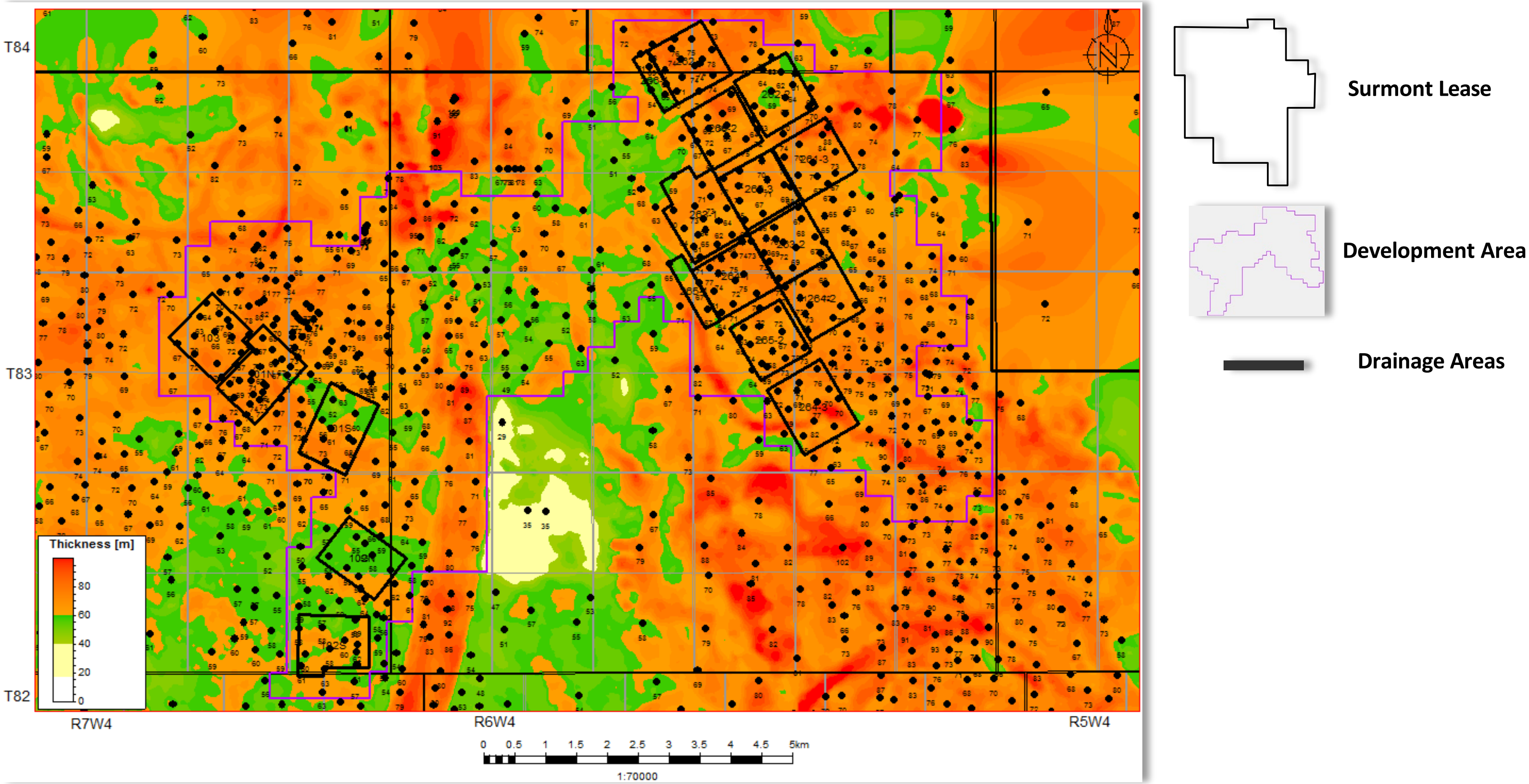
OBIP = Thickness x Phie x So x Area

OBIP Volumes: Reservoir Properties Operating Portion



Properties	Depth (masl)	Area (m2)	Thickness NCB (m)	Phie in NCB %	So in NCB %	KH in NCB (mD)	KV in NCB (mD)	Initial Pressure (KPa)
Lease	~250	578578000	23.07	31.82%	76.79%	4113	3423	1700
101N	277.52 - 212.11	1090775	35.53	32.58%	82.40%	4350	3614	1690
101S	272.96 - 218.47	1064692	37.43	33.19%	80.41%	5482	4604	1684
102N	276.39 - 223.91	975251	31.14	32.71%	80.29%	4636	3877	1735
102S	285.02 - 223.61	1019252	34.17	31.32%	74.33%	4001	3290	1800
103	272.82 - 211.40	1022239	42.80	32.21%	78.62%	4441	3691	1691
261-3	271.02 - 201.80	1000542	44.77	32.00%	78.07%	4342	3562	1328
262-1	273.64 - 206.15	996252	39.59	31.74%	80.05%	4195	3471	1307
262-2	271.89 - 212.60	974291	38.63	33.13%	78.56%	5239	4420	1296
262-3	271.57 - 208.64	943213	44.28	32.76%	78.21%	4968	4140	1368
263-1	272.12 - 211	1271315	36.14	32.98%	79.36%	4966	4170	1404
263-2	275.41 - 212.90	998219	40.90	32.44%	78.06%	4769	3979	1397
264-1	271.18 - 213.54	1033834	39.45	32.89%	79.71%	5148	4338	1444
264-2	269.27 - 213.75	1011337	42.08	32.65%	78.22%	4763	3965	1437
264-3	281.29 - 207.61	1209485	37.51	31.97%	75.58%	4446	3683	1564
265-2	271.50 - 215.59	917433	38.75	32.54%	76.83%	4917	4101	1496
266-2	276.26 - 210.21	949974	42.99	32.83%	80.08%	4925	4121	1337

McMurray Gross Isopach

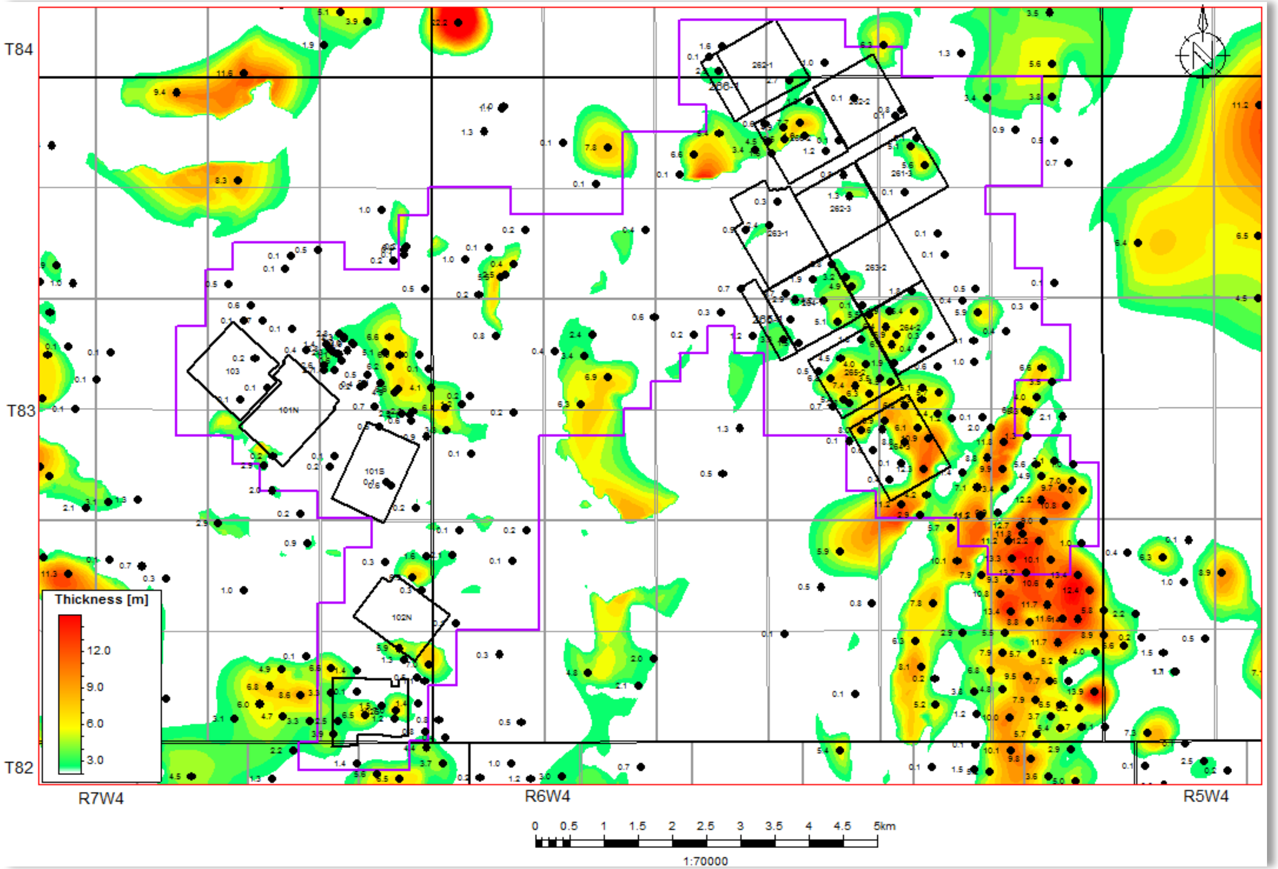


McMurray Gross Isopach

2018/2019 Mapping Update

- **No delineation/no changes**

McMurray Net Gas Isopach



Surmont Lease

Development Area

Drainage Areas

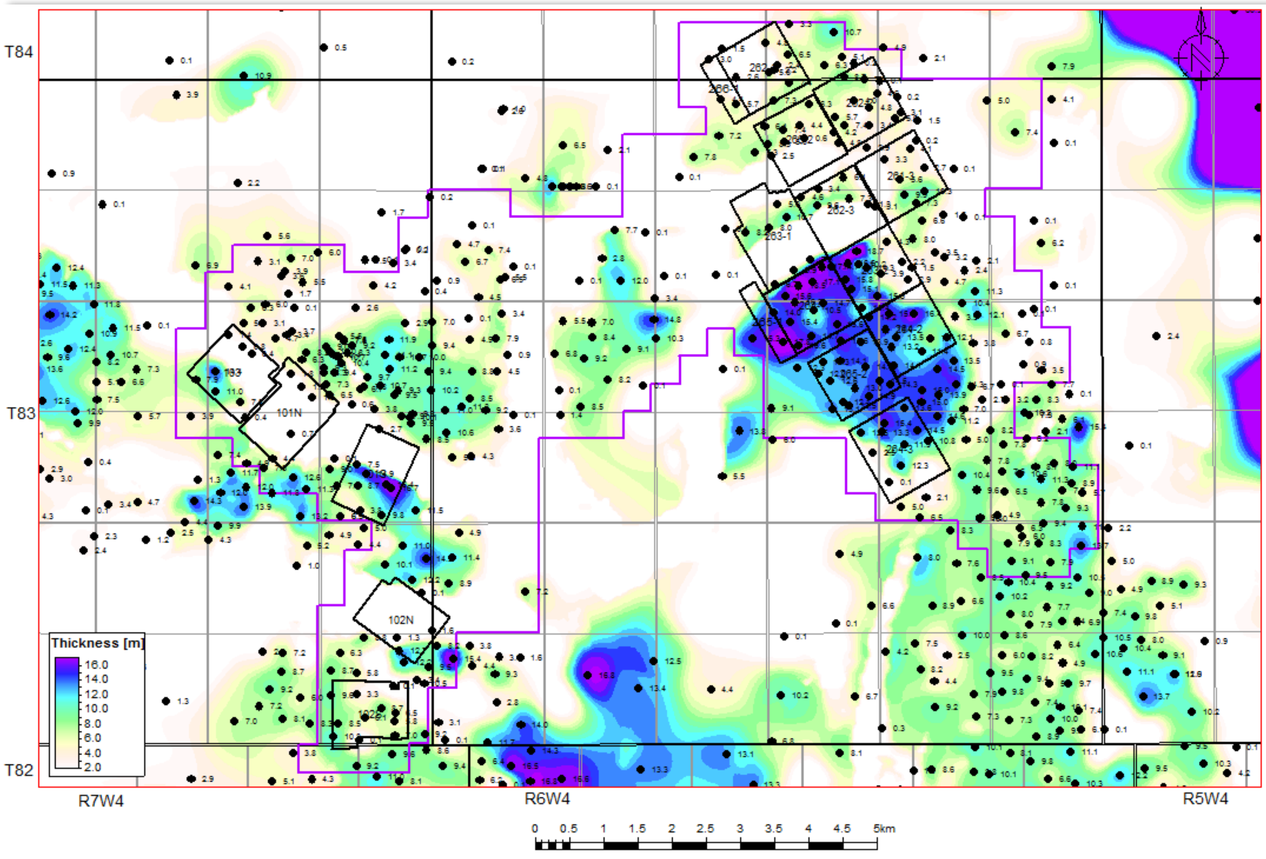
Net Top Gas thickness = sands have deep resistivity ≥10 Ω-m and Vsh <65%

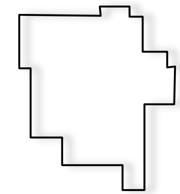
McMurray Net Gas Isopach

2018/2019 Mapping Update

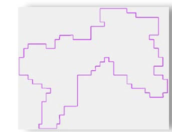
- **No delineation/no changes**

McMurray Net Top Water Isopach





Surmont Lease



Development Area

Drainage Areas

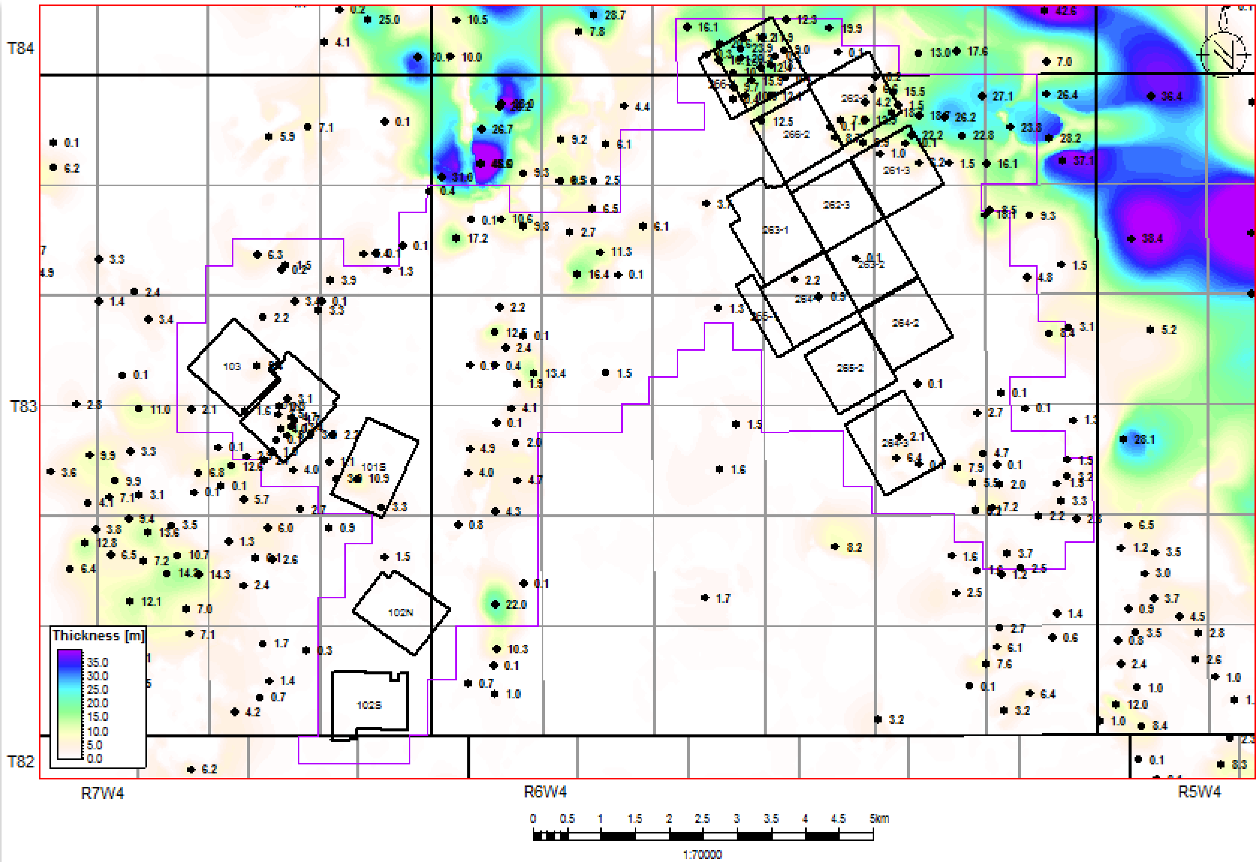
Net Top Water thickness = sands have deep resistivity <10 Ω-m and Vsh <45%

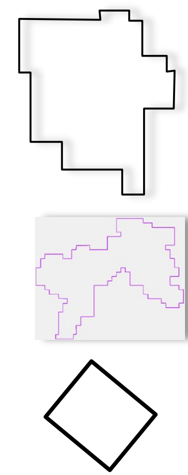
McMurray Net Top Water Isopach

2018/2019 Mapping Update

- **No delineation/no changes**

McMurray Net Bottom Water Isopach





Surmont Lease

Development Area

Drainage Areas

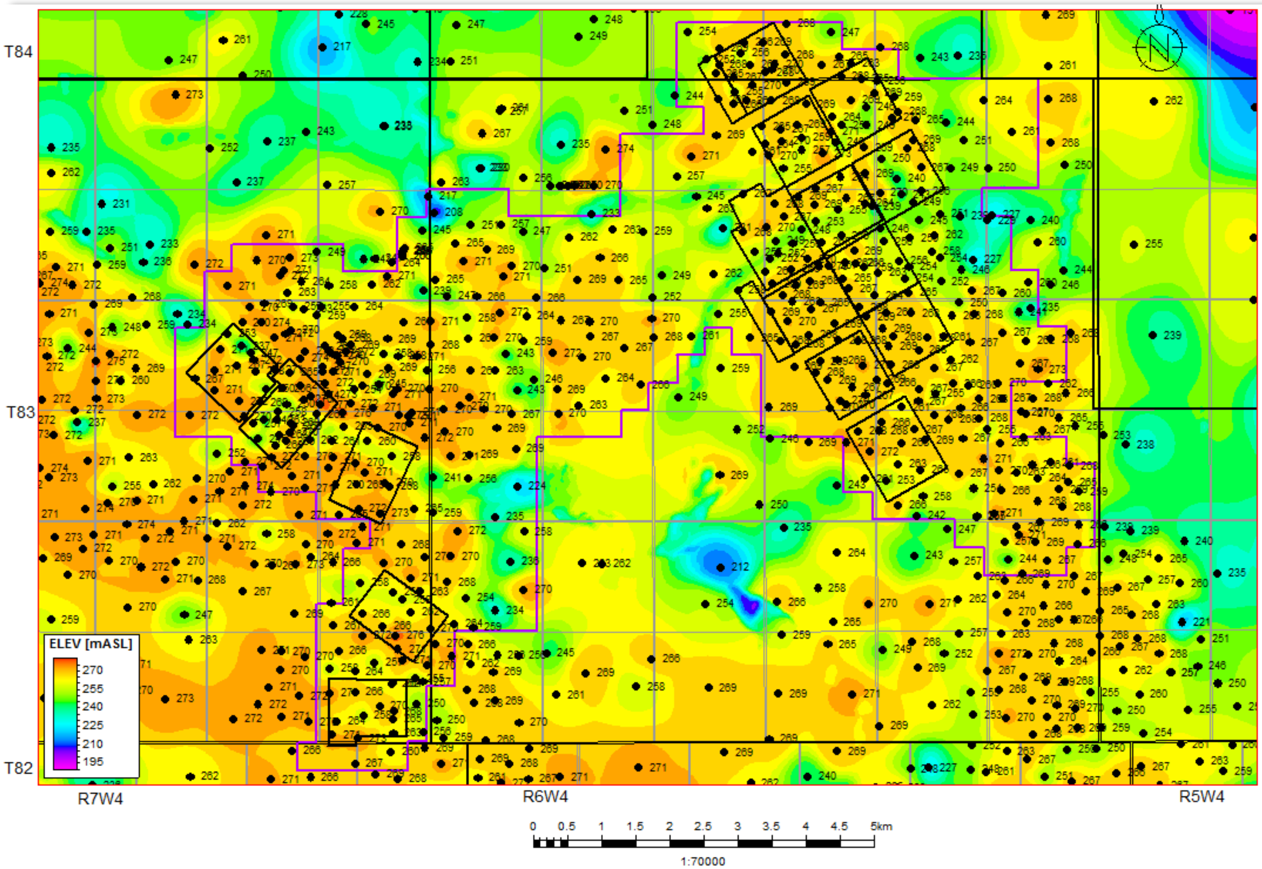
Net Bottom Water thickness = sands have deep resistivity <10 Ω-m and Vsh <45%

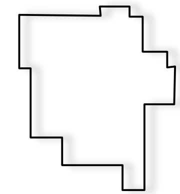
McMurray Net Bottom Water Isopach

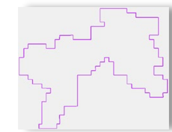
2018/2019 Mapping Update

- **No delineation/no changes**

McMurray Top Continuous Bitumen Structure




Surmont Lease


Development Area

Drainage Areas

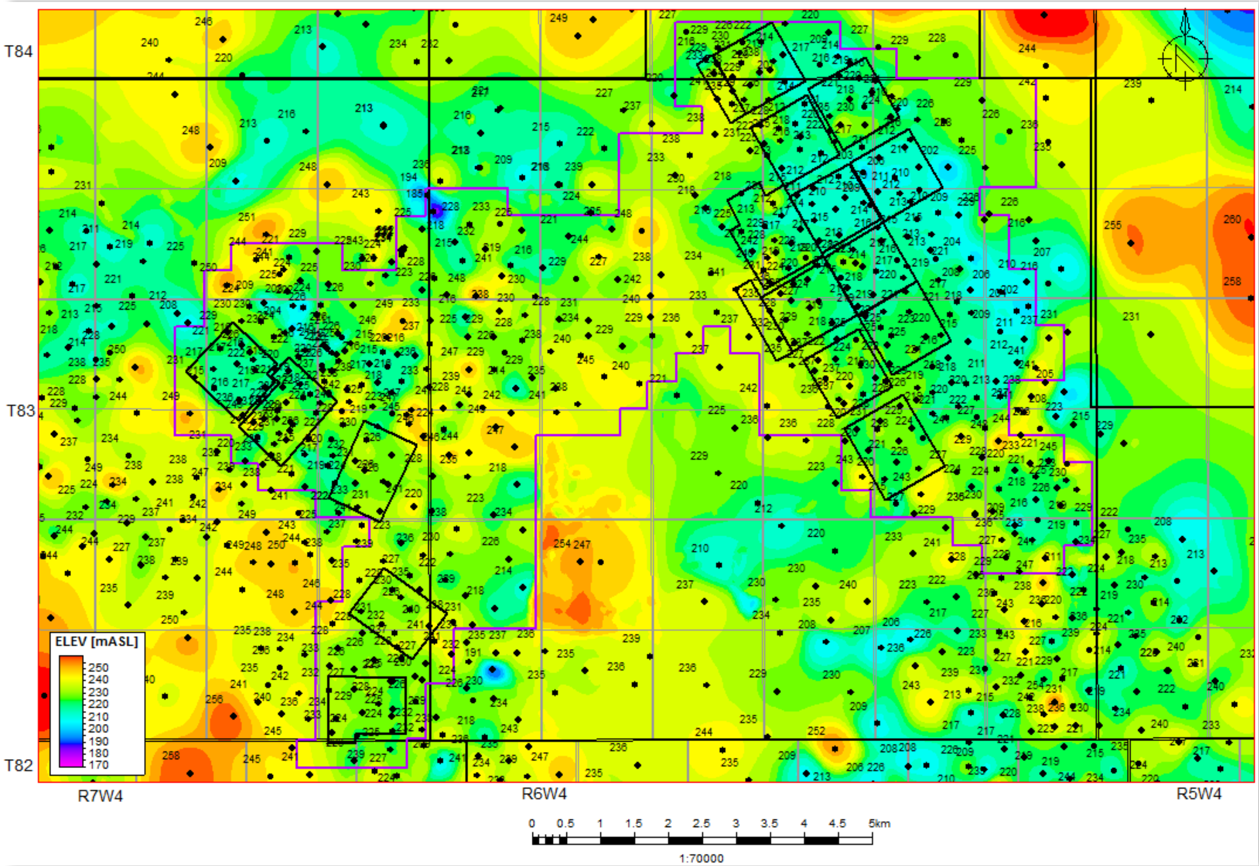
TCB = The uppermost limit of good reservoir, bitumen- bearing sands.

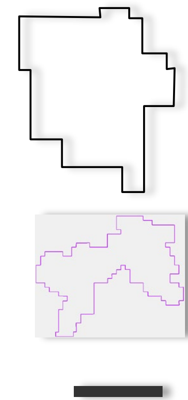
Top Continuous Bitumen Structure

2018/2019 Mapping Update

- **No delineation/no changes**

McMurray Base Continuous Bitumen Structure





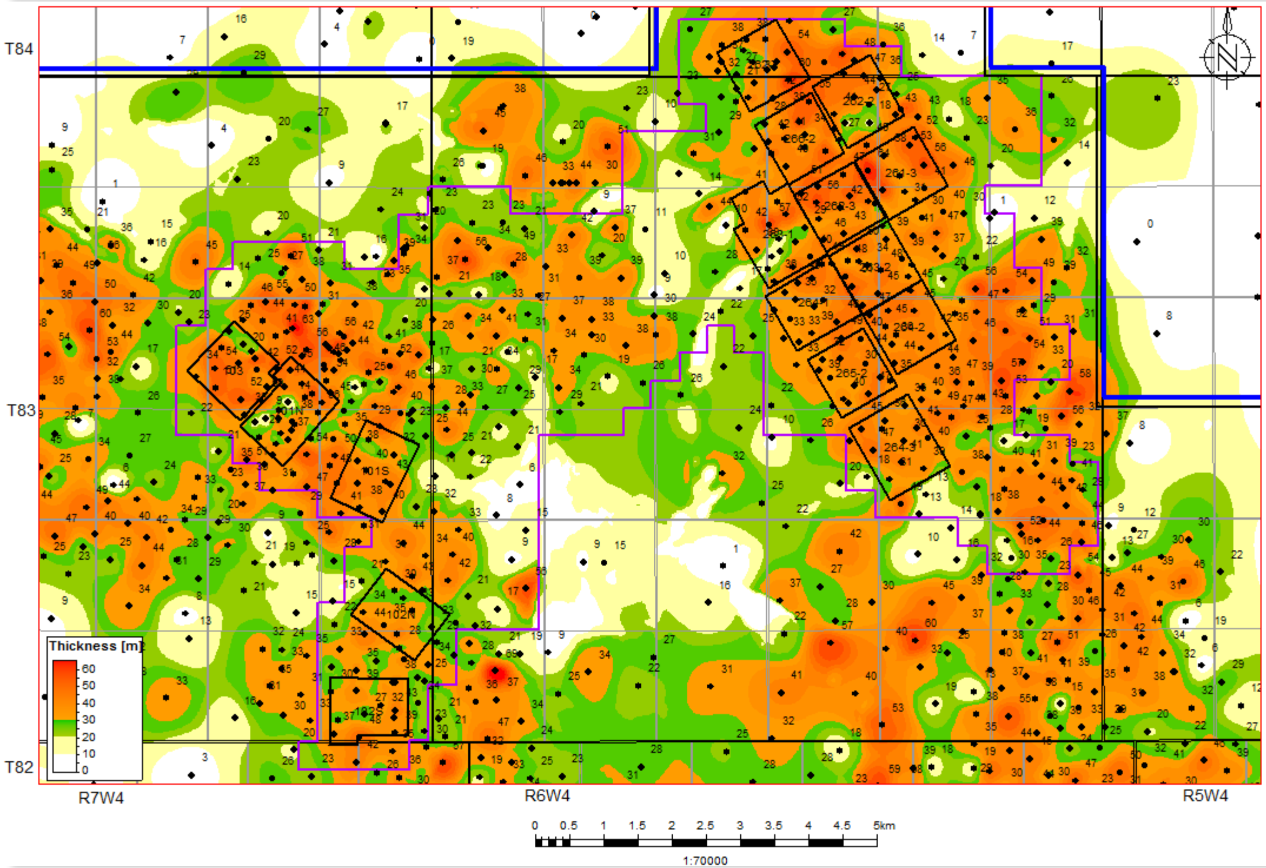
BCB = First occurrence of good reservoir, bitumen- bearing sands.

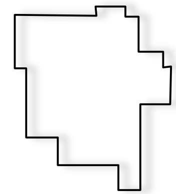
Base Continuous Bitumen Structure

2018/2019 Mapping Update

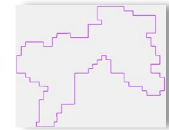
- **No delineation/no changes**

McMurray Net Continuous Bitumen Thickness





Surmont Lease



Development Area

Drainage Areas

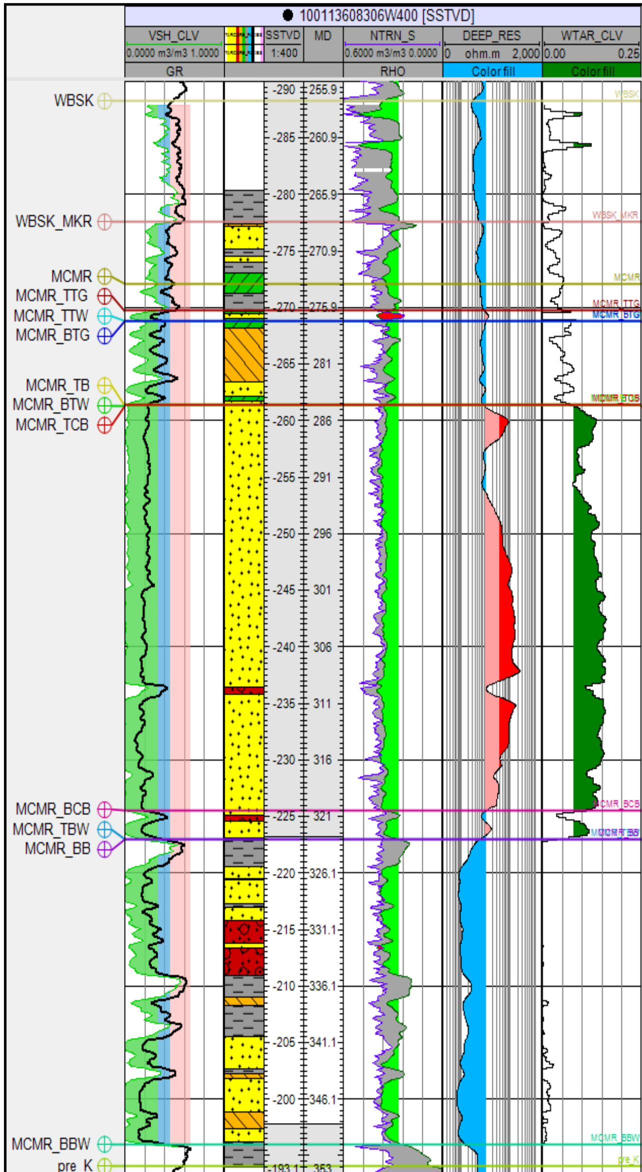
Net continuous bitumen = sands have deep resistivity > 40 Ω-m and Vsh <33%, and no shale greater than 3 m thick

McMurray Net Continuous Bitumen Pay

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 ohmm or greater, or 8wt% bitumen.

Continuous Bitumen / SAGD Interval
Gross thickness of continuous bitumen reservoir with deep resistivity of 40 ohmm 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.

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

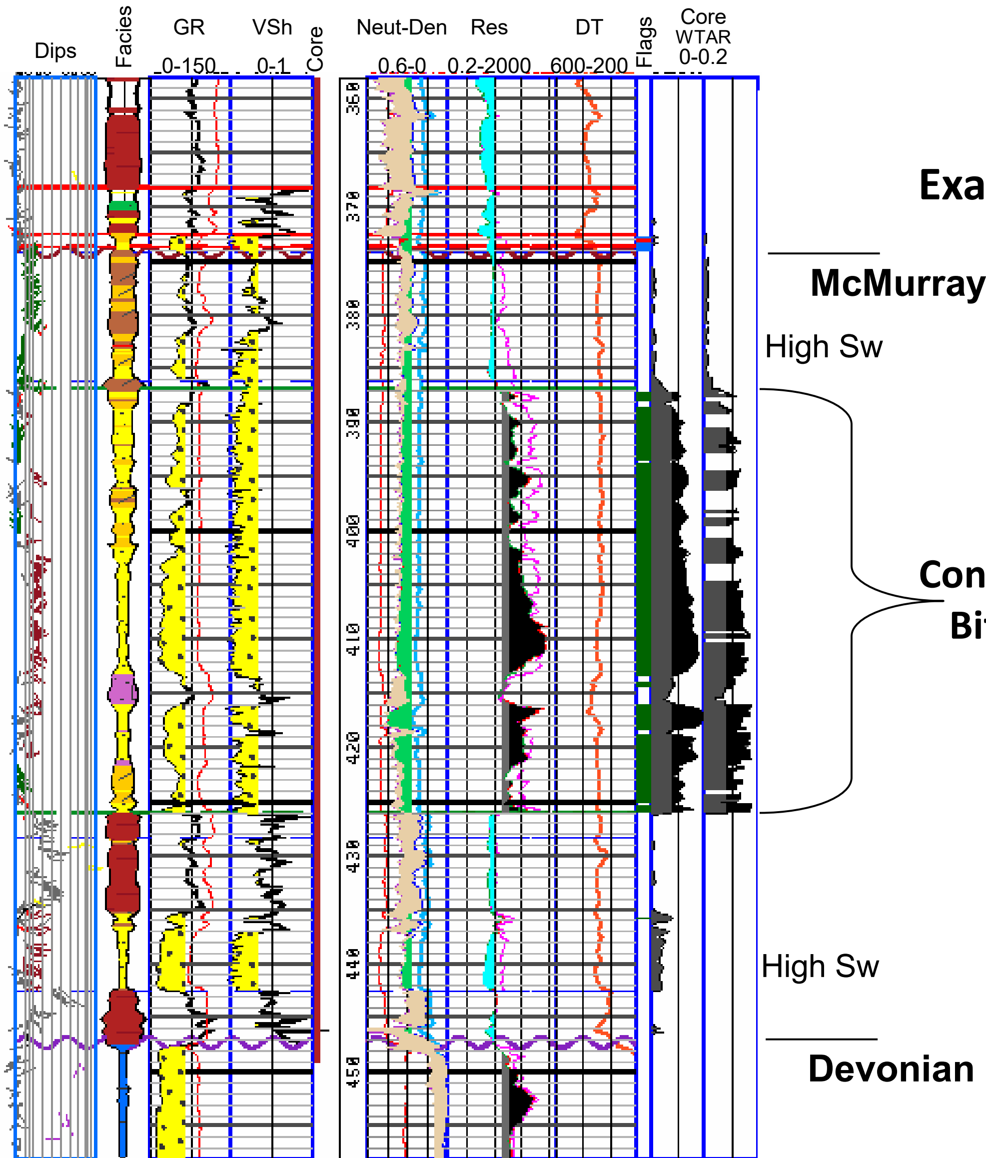
Top Gas: Gross thickness of gas-bearing sands defined by the top and bottom gas surfaces

Top Water: Gross thickness of water-bearing sands defined by the top and bottom water surfaces

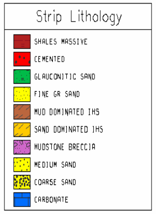
Bitumen: Gross thickness of bitumen-bearing sands defined by the top and base bitumen surfaces

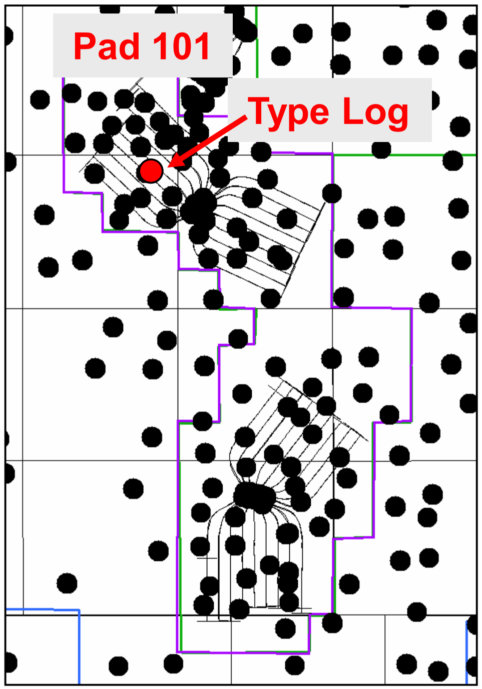
Bottom Water: Gross thickness of water-bearing sands defined by the top and bottom water surfaces

Phase 1 Type Log Well Pad 101



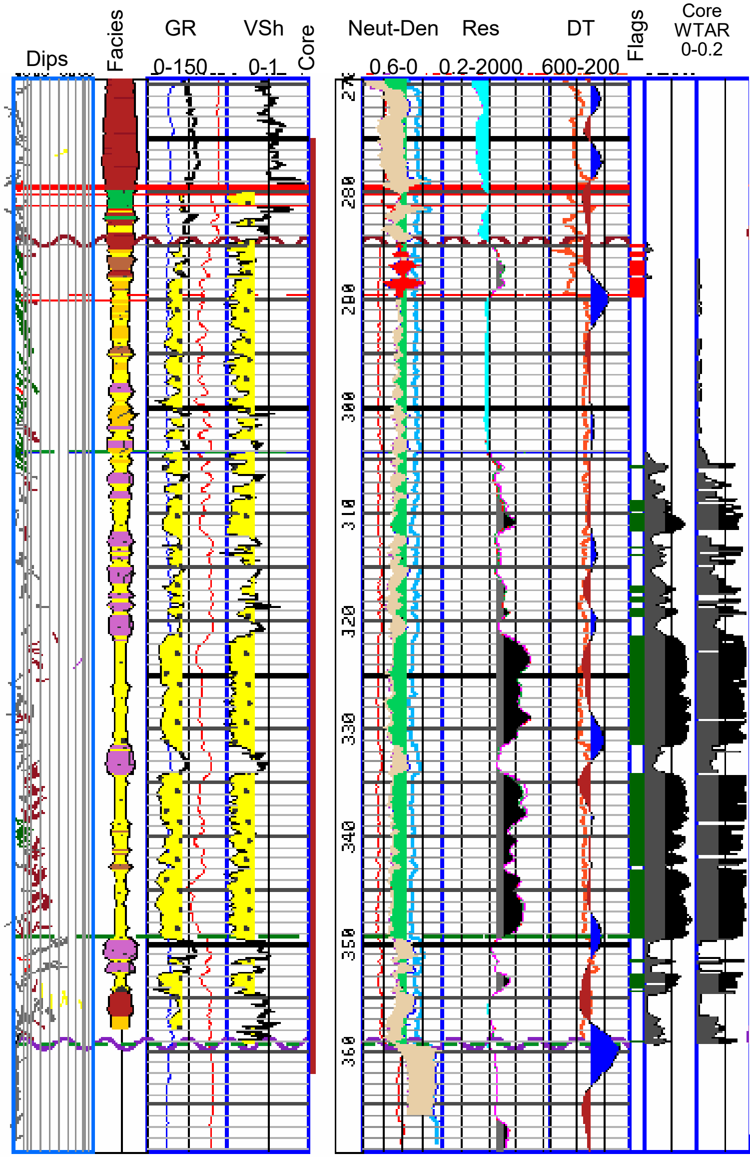
Example Log 100161408307W400





Phase 1 Area

Phase 2 Type Log – Well Pad 264-2



McMurray

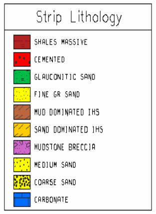
Top Gas

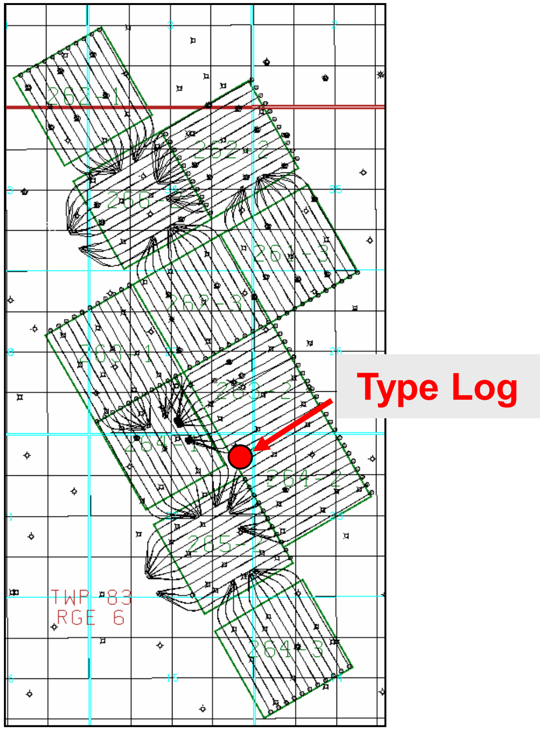
High Sw

Continuous Bitumen

Devonian

Example Log 100162208306W400



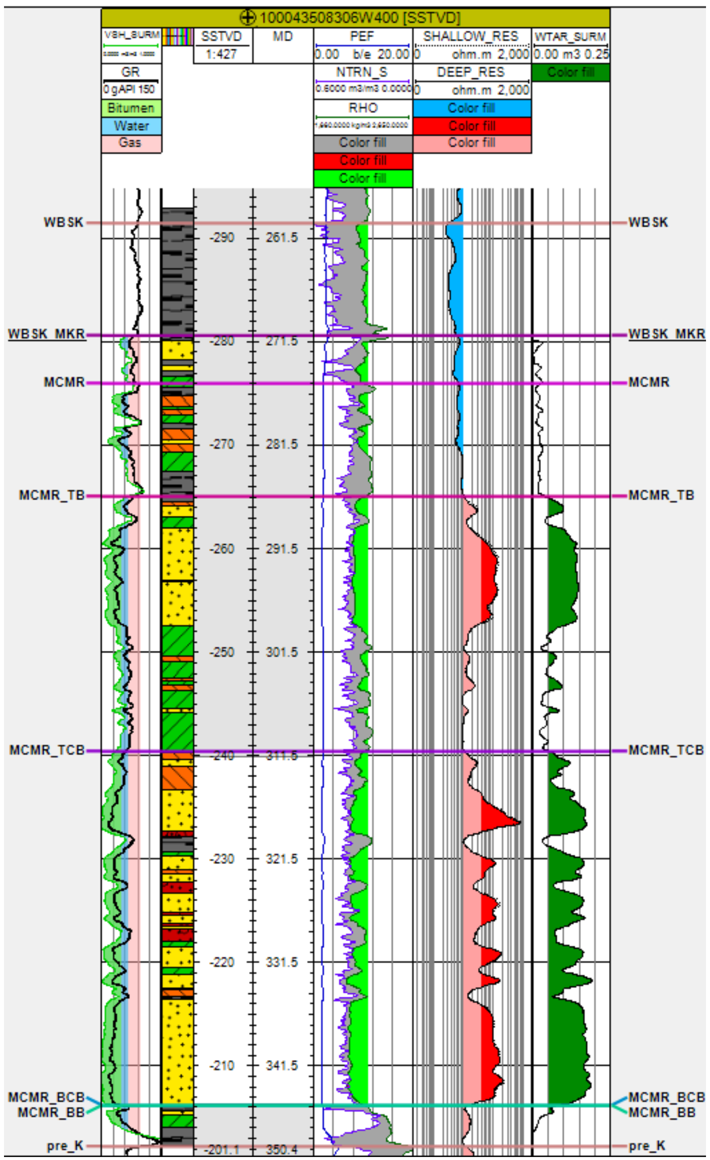


Phase 2 Area

ConocoPhillips

Phase 2 Type Log – Well Pad 261-3

Example Log 100043508306W400



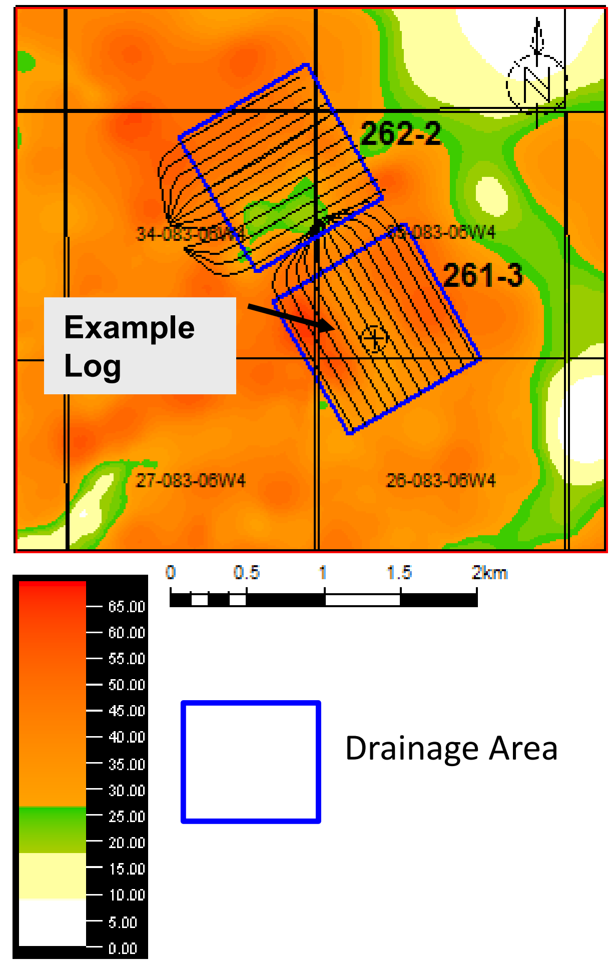
Tops Description	
WBSK	Wabiskaw Member
WBSK_MKR	Wabiskaw Marker
MCMR	McMurray Formation
MCMR_TB	McMurray Top Bitumen
MCMR_TCB	McMurray Top Continuous Bitumen
MCMR_BCB	McMurray Base Continuous Bitumen
MCMR_BB	McMurray Base Bitumen
pre_K	Pre-Cretaceous Unconformity

Name	Pattern
Coarse_sand	
Medium sand	
Fine sand	
Sandy IHS	
Muddy IHS	
Mudstone	
Carbonate	
Breccia	
Coal	
Cemented	
Till	
Rafted_Till	
Interbedded_Sand_Mud	
Bioturbated Sand & Mudstone	

Continuous Bitumen

Phase 2 Area

McMurray Net Continuous Bitumen (NCB)

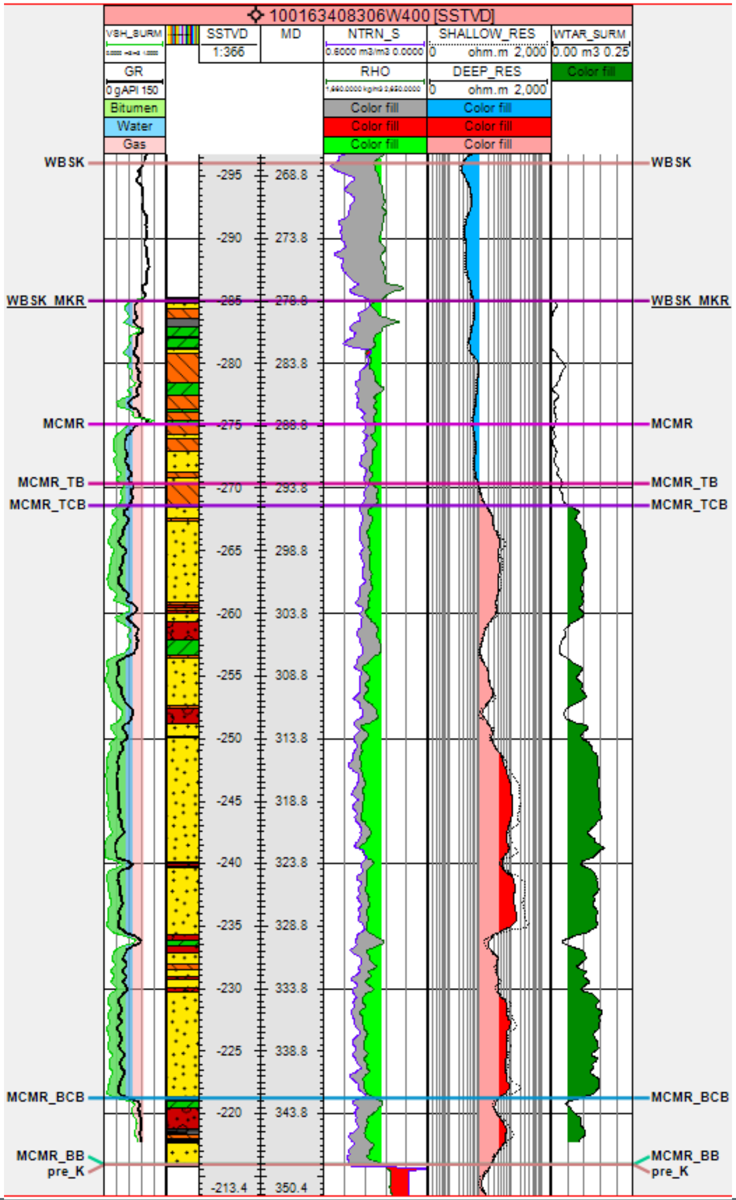


Drainage Area

ConocoPhillips

Phase 2 Type Log – Well Pad 262-2

Example Log 100163408306W400



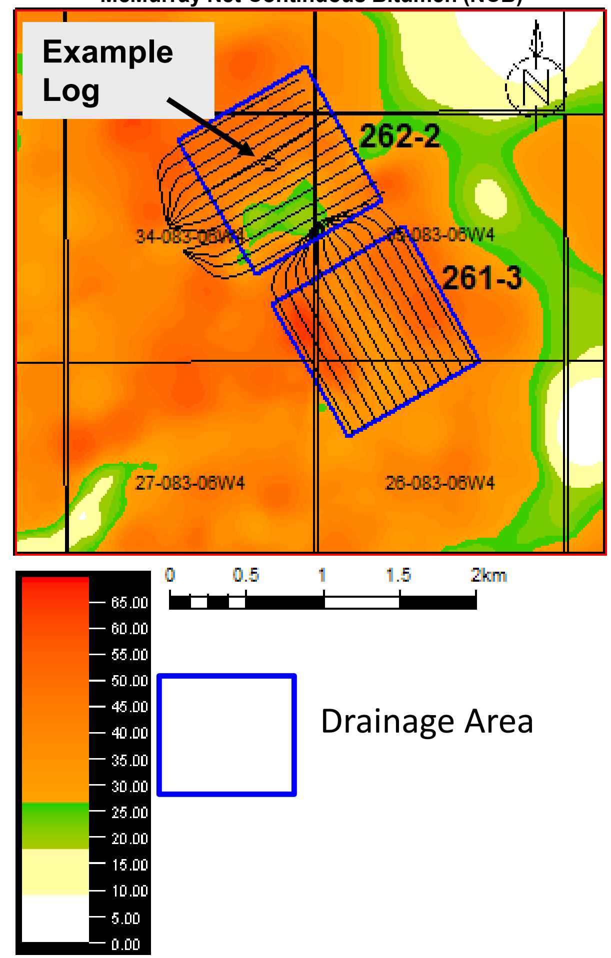
Continuous Bitumen

Name	Pattern
Coarse_sand	
Medium sand	
Fine sand	
Sandy IHS	
Muddy IHS	
Mudstone	
Carbonate	
Breccia	
Coal	
Cemented	
Till	
Rafted_Till	
Interbedded_Sand_Mud	
Bioturbated Sand & Mudstone	

Tops Description
WBSK Wabiskaw Member
WBSK_MKR Wabiskaw Marker
MCMR McMurray Formation
MCMR_TB McMurray Top Bitumen
MCMR_TCB McMurray Top Continuous Bitumen
MCMR_BCB McMurray Base Continuous Bitumen
MCMR_BB McMurray Base Bitumen
pre_K Pre-Cretaceous Unconformity

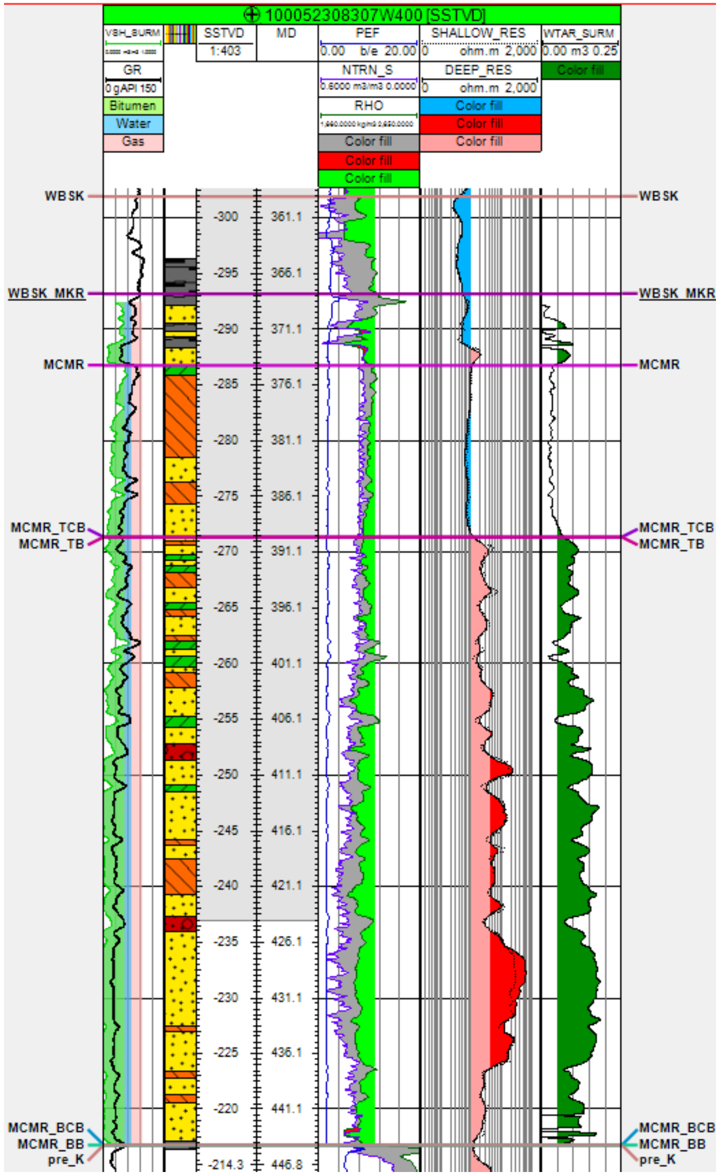
Phase 2 Area

McMurray Net Continuous Bitumen (NCB)



Phase 1 Type Log – Well Pad 103

Example Log 100052308307W400



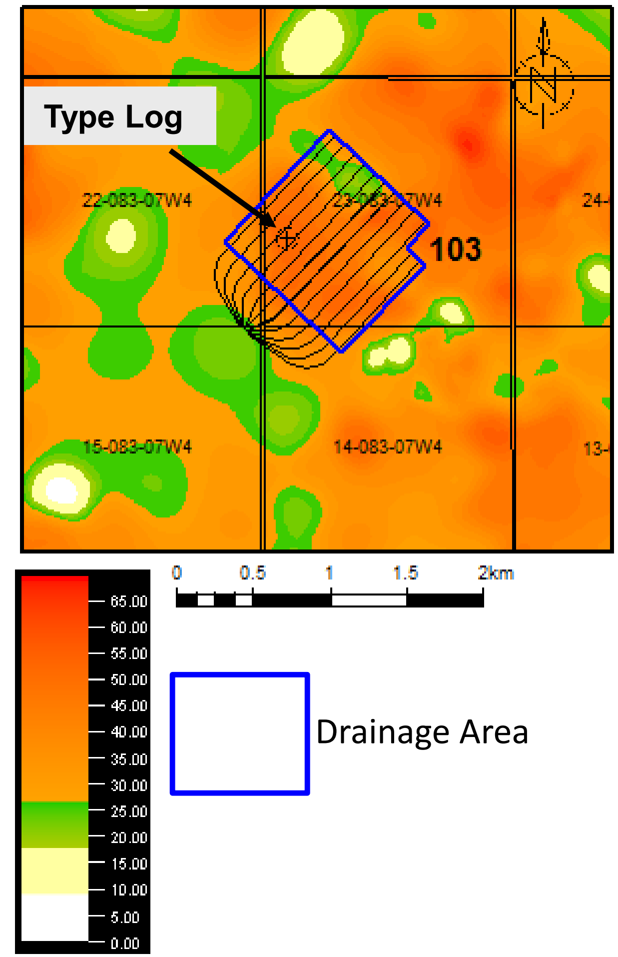
Tops Description
WBSK Wabiskaw Member
WBSK_MKR Wabiskaw Marker
MCMR McMurray Formation
MCMR_TB McMurray Top Bitumen
MCMR_TCB McMurray Top Continuous Bitumen
MCMR_BCB McMurray Base Continuous Bitumen
MCMR_BB McMurray Base Bitumen
pre_K Pre-Cretaceous Unconformity

Name	Pattern
Coarse_sand	
Medium sand	
Fine sand	
Sandy IHS	
Muddy IHS	
Mudstone	
Carbonate	
Breccia	
Coal	
Cemented	
Till	
Rafted_Till	
Interbedded_Sand_Mud	
Bioturbated Sand & Mudstone	

Continuous Bitumen

Phase 1 Area

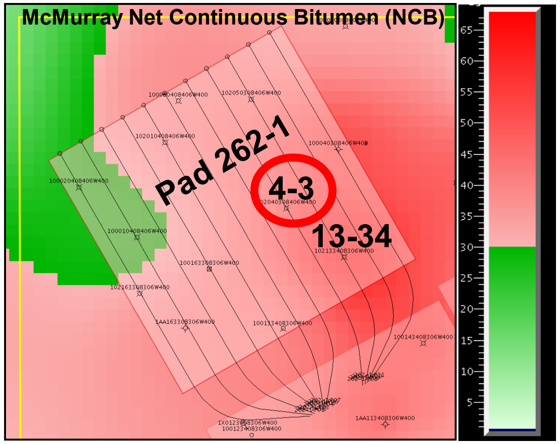
McMurray Net Continuous Bitumen (NCB)

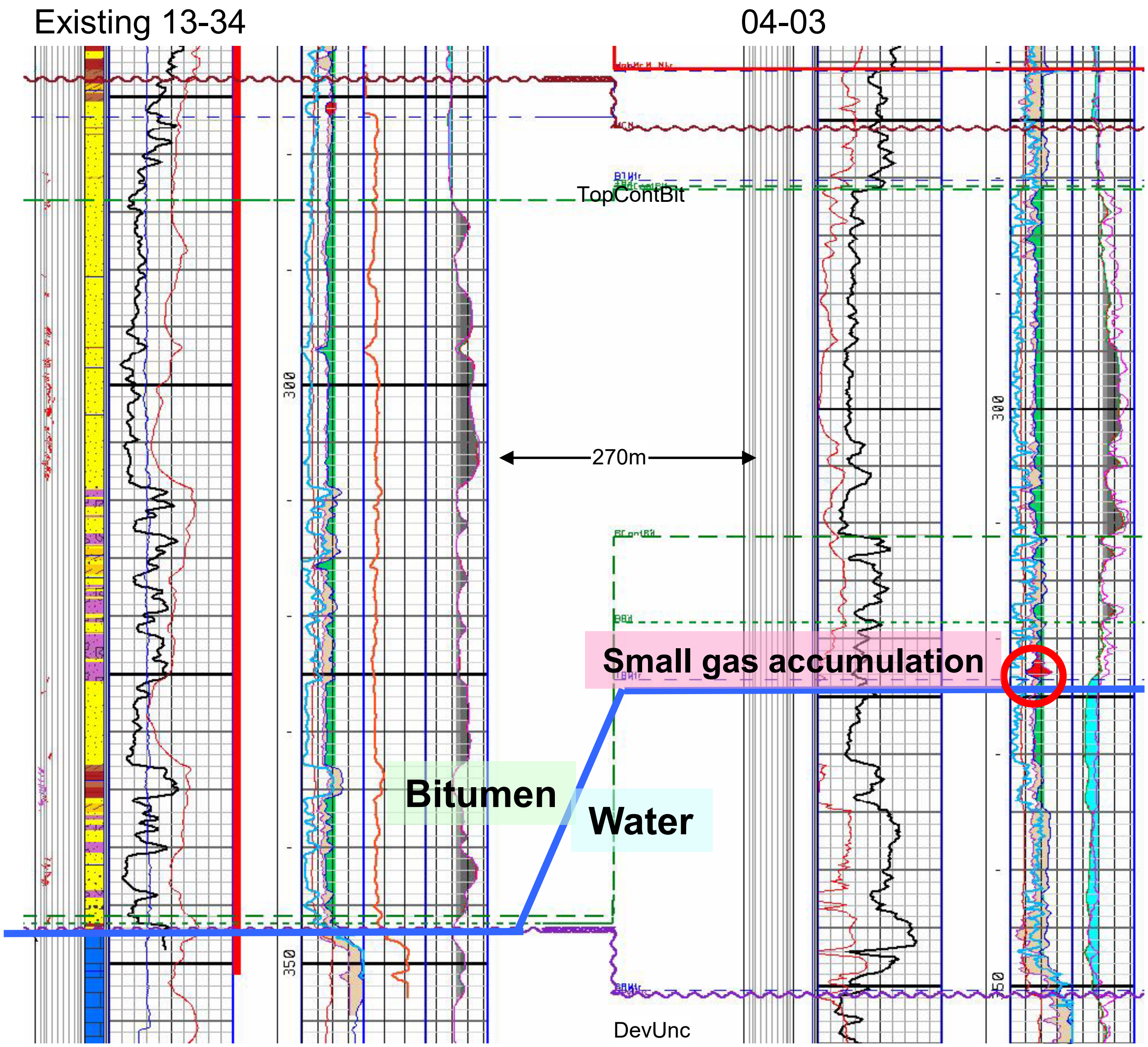


Well Pad 262-1 Variable Bitumen-Water Contact

- 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.

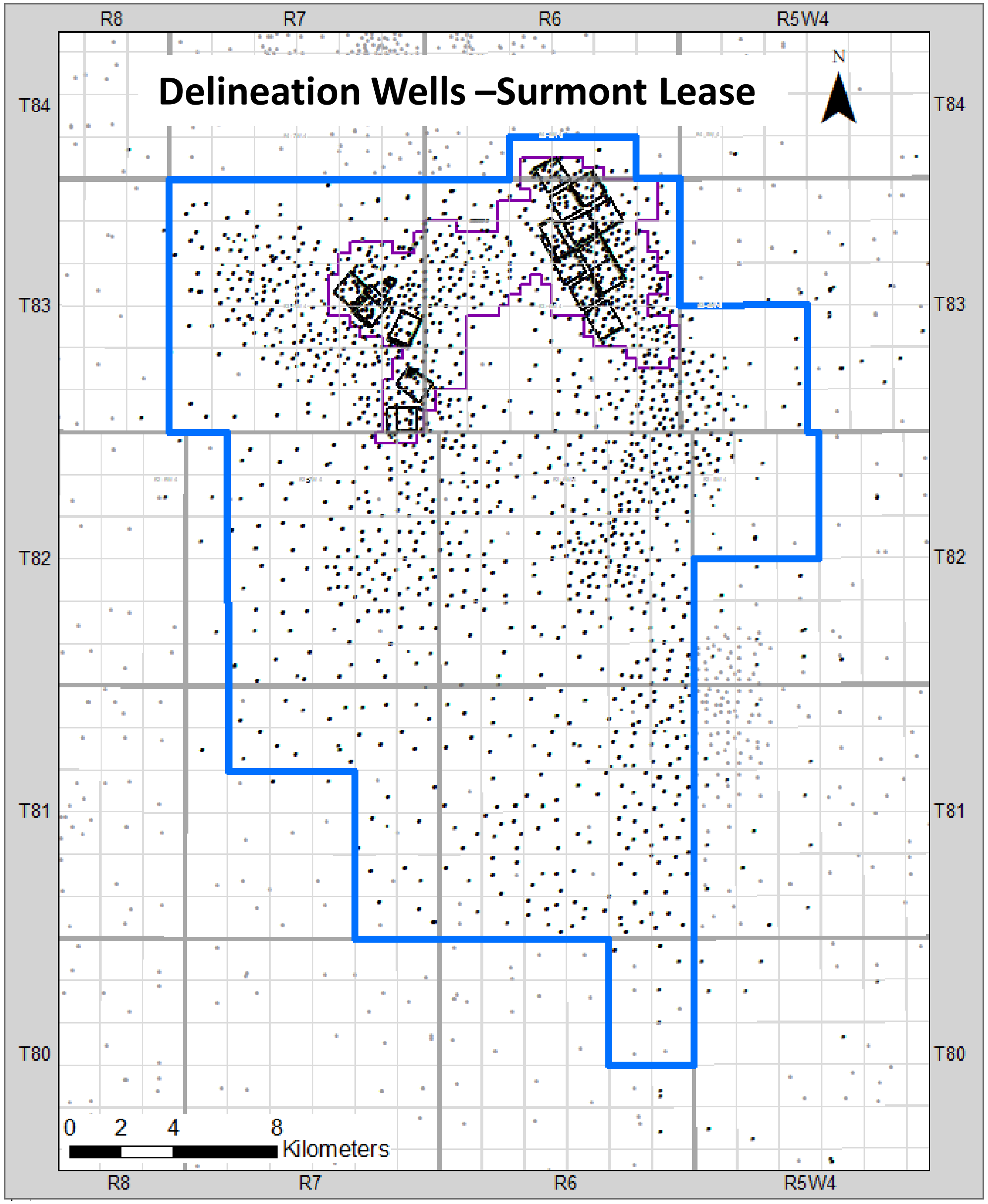
- **The presence of basal water becomes a potential impact on production performance on Well Pad 262-1**



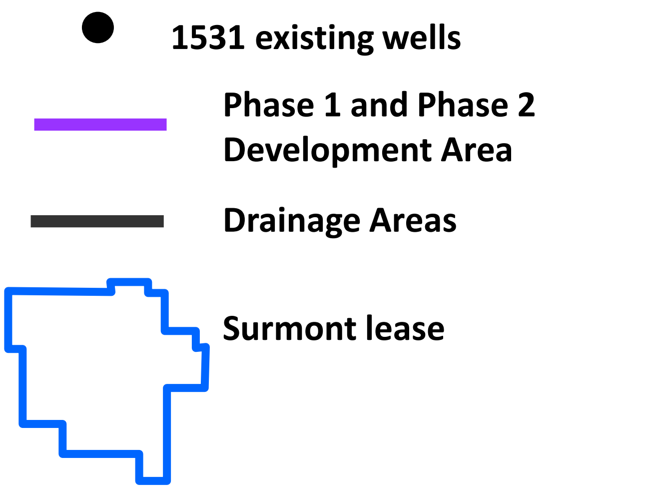


ConocoPhillips

2018-2019 Delineation Campaign and Well Density

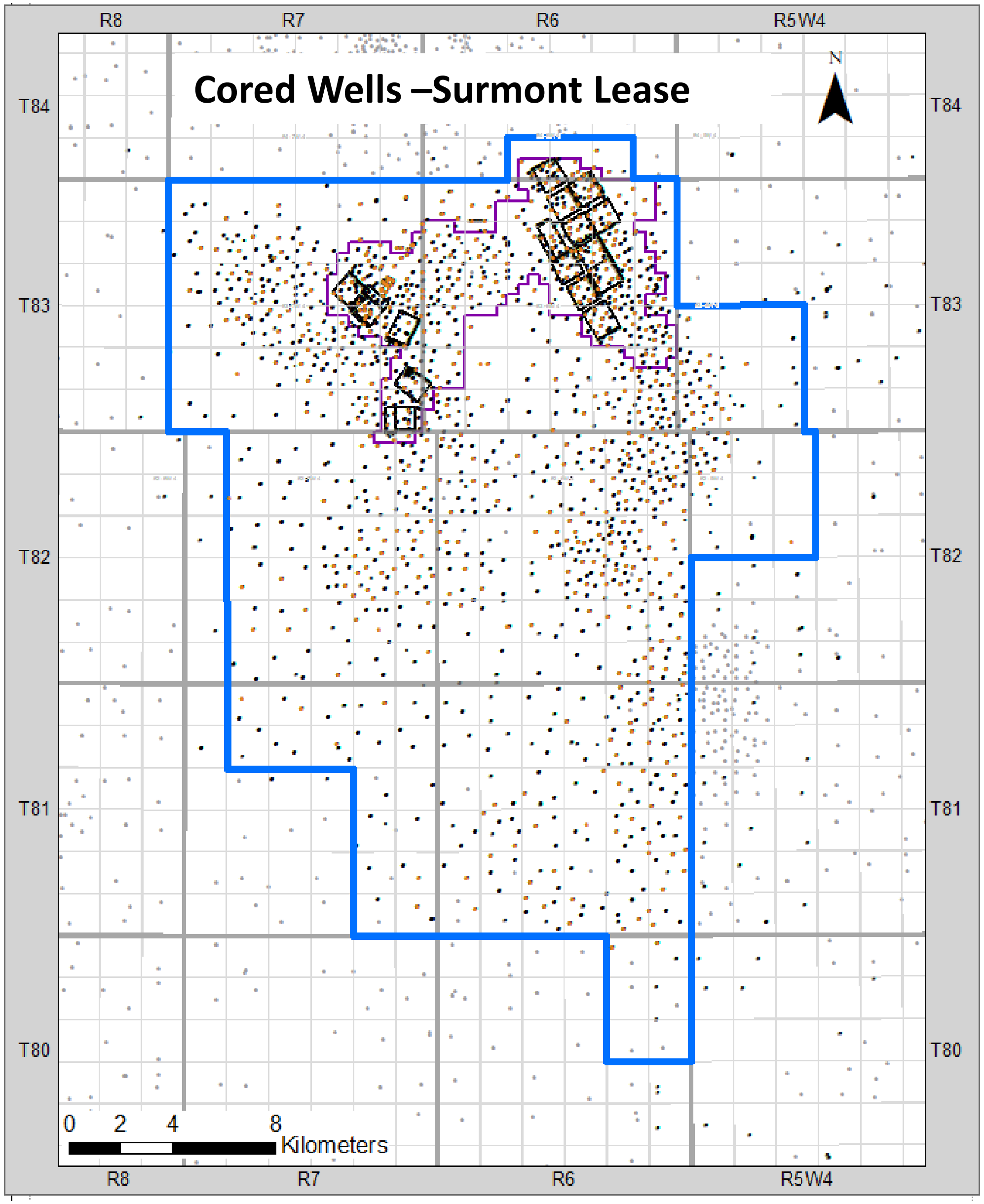


Surmont Lease as of March 1, 2019



No new wells were drilled between Mar 1, 2018 to Mar 1, 2019

2018-2019 Delineation Campaign and Core Density

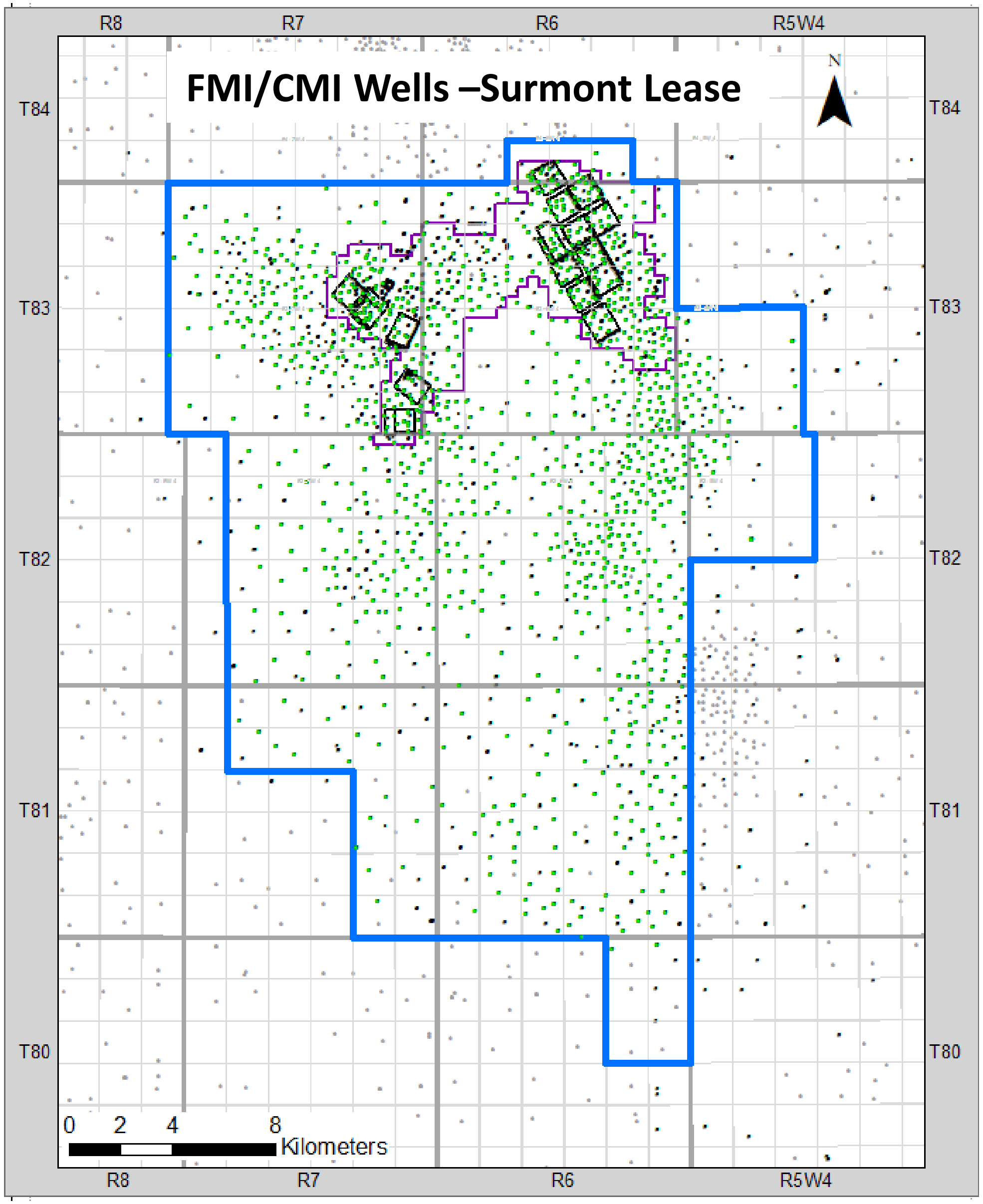


Surmont Lease as of March 1, 2019

- 1531 wells total
- 549 existing core wells
- Phase 1 and Phase 2 Development Area
- Drainage Areas
- Surmont lease

No new cores were cut between Mar 1, 2018 to Mar 1, 2019

2018-2019 Delineation Campaign and FMI/CMI Logs



Surmont Lease as of March 1, 2019

1531 wells total

1154 existing FMI/CMI wells

Phase 1 and Phase 2 Development Area

Drainage Areas

Surmont lease

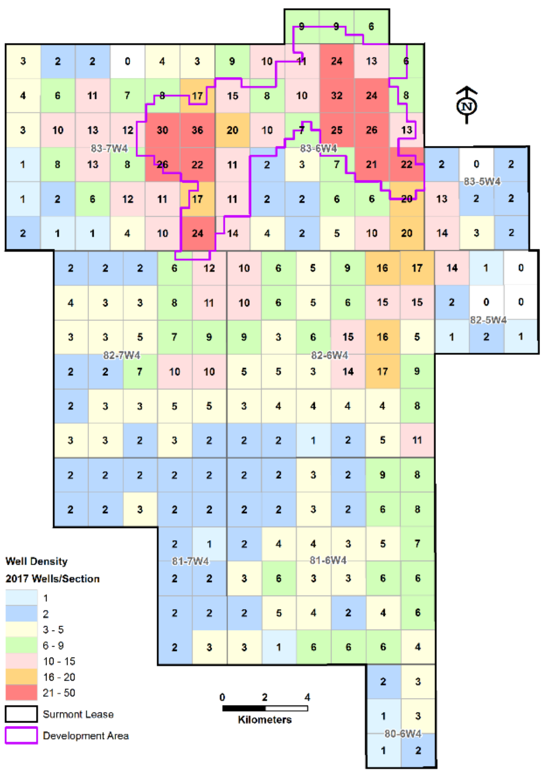
No new wells were drilled between March 1, 2018 and March 1, 2019; hence no FMI/CMI logs were taken

ConocoPhillips

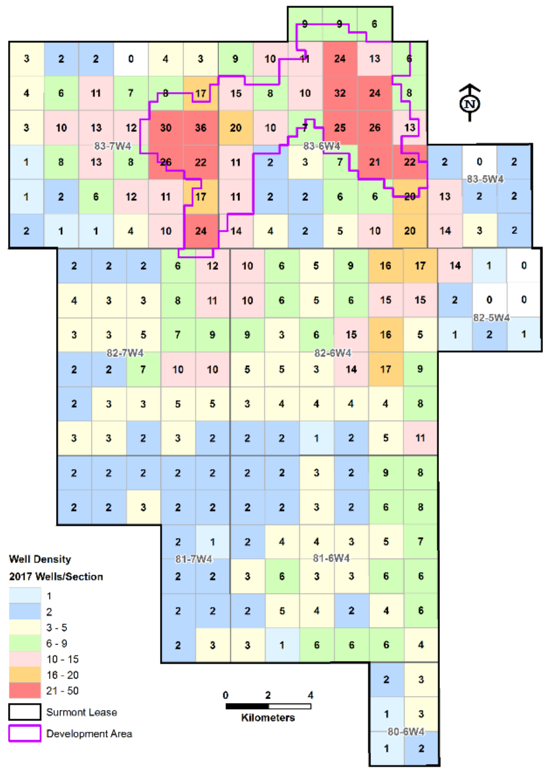
2018-2019 Delineation Campaign and Well Density

Delineation across Phases 1, 2, and 3

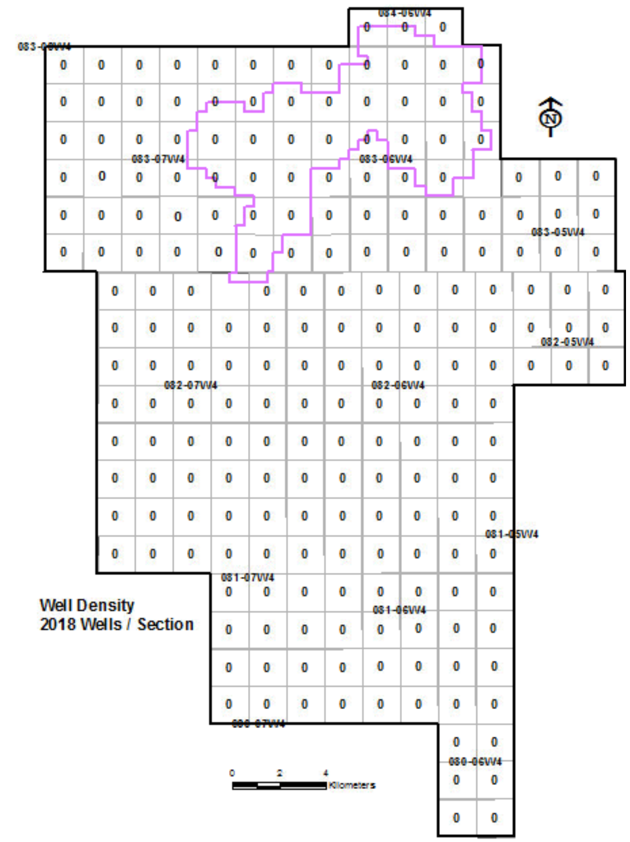
Delineation Well Density Map Mar 2018



Delineation Well Density Map Mar 2019



Density Map Difference

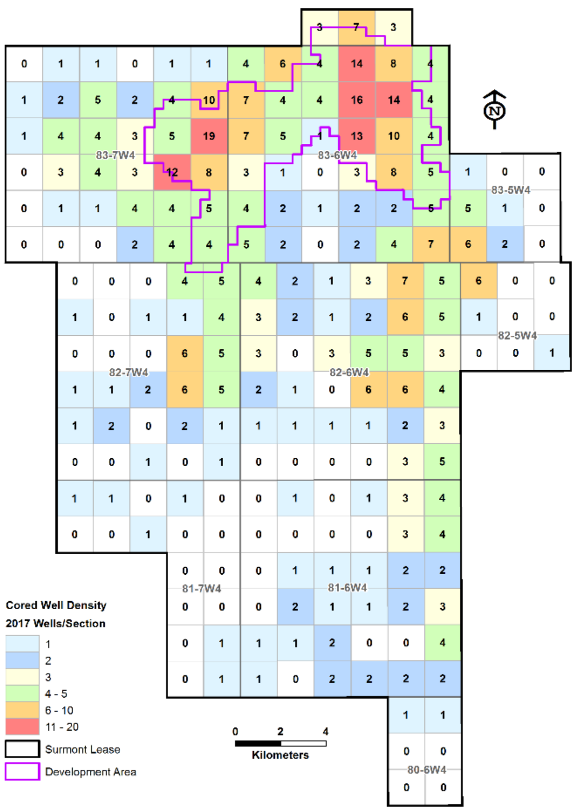


McMurray penetrated wells only

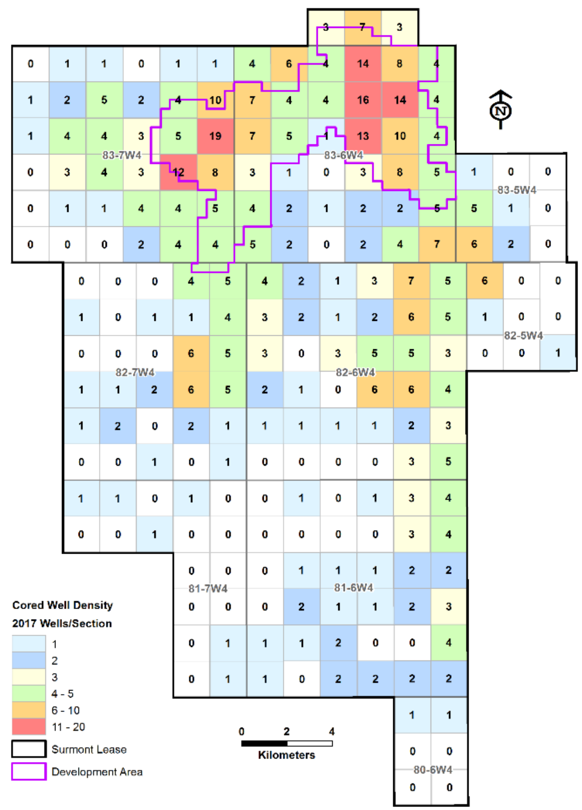
2018-2019 Delineation Campaign and Well Density

Increased core density with latest drilling

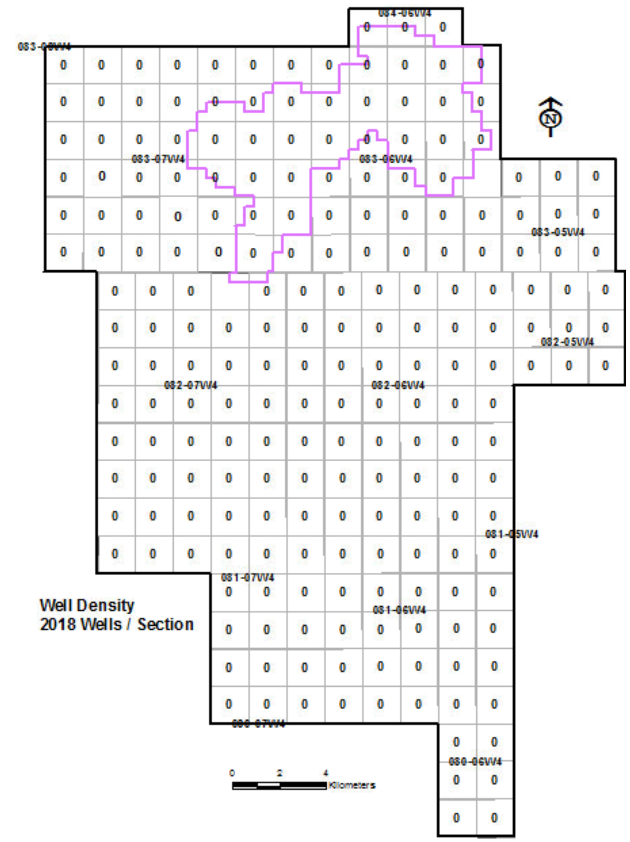
Cored Wells Density Map Mar 2018



Cored Wells Density Map Mar 2019



Cored Density Map Difference

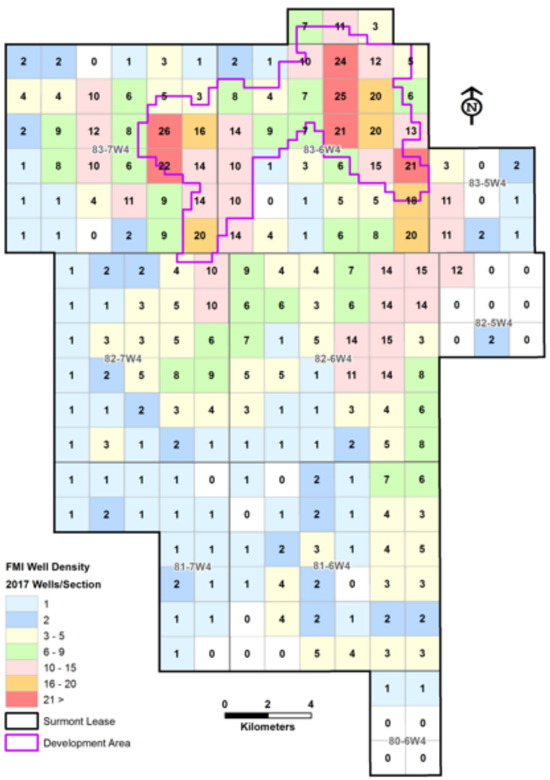


McMurray penetrated wells only

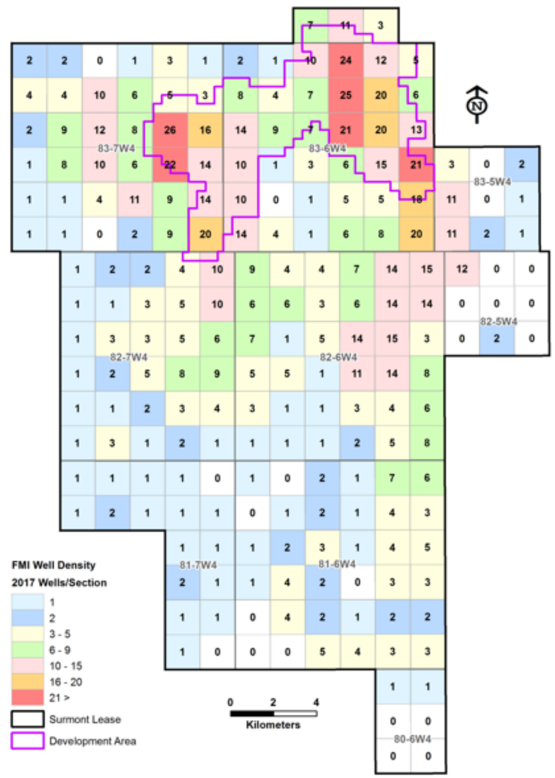
2018-2019 Delineation Campaign and Well Density

Increased Formation Micro Imaging density with latest drilling

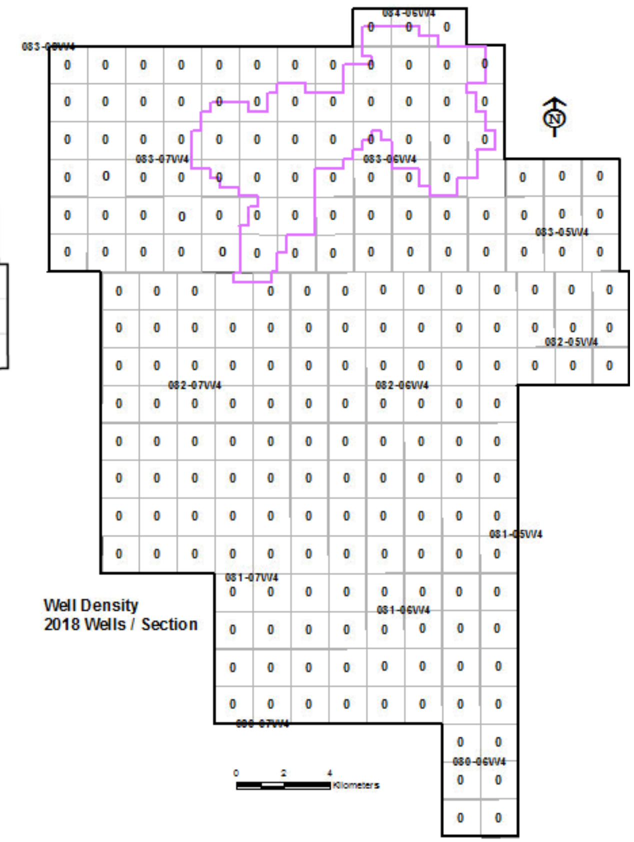
FMI Well Log Density Map Mar – 2018



FMI Well Log Density Map Mar - 2019



FMI Density Map Difference



McMurray penetrated wells only

Special Core Analyses Bitumen Viscosity Sampling

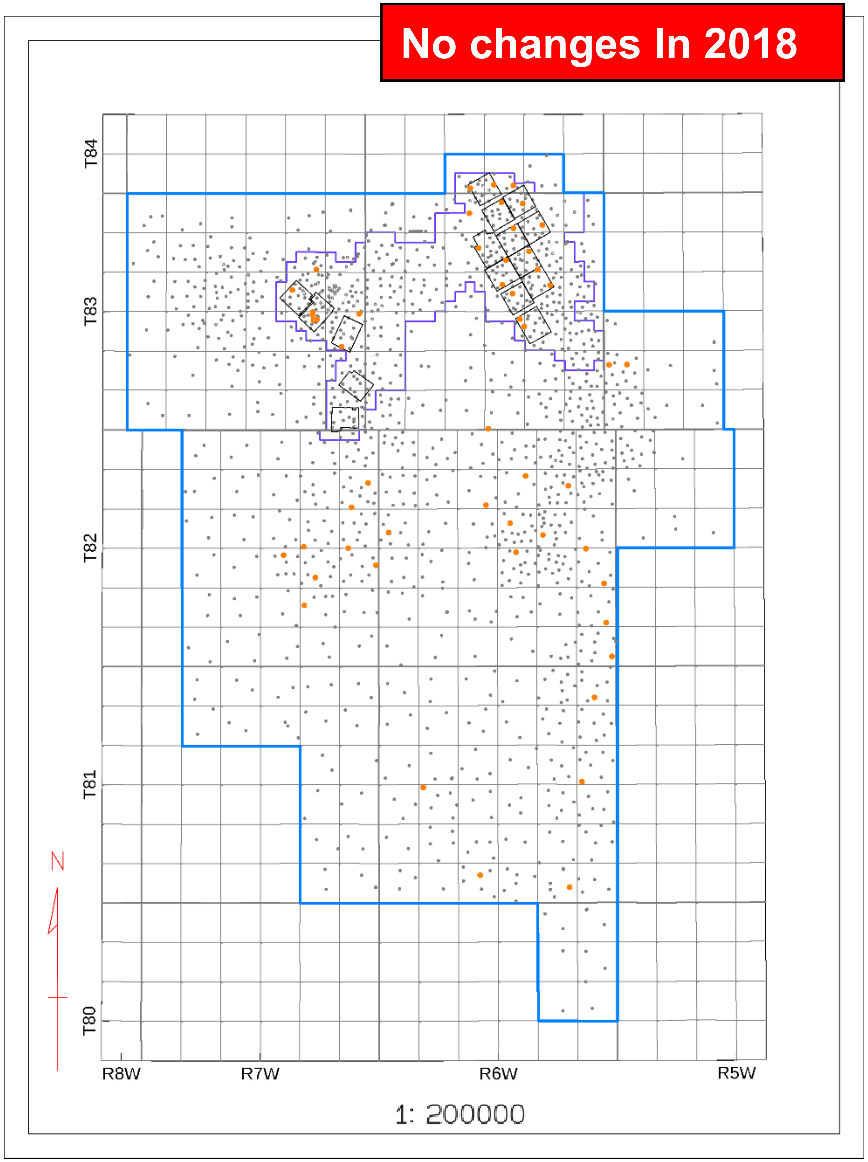
- **Objectives:**
  - Characterize vertical and lateral variance in viscosity at different temperatures.
  - Model the variance in bitumen properties and its implications for bitumen production rates during SAGD.
  - Characterize relationship between viscosity, density and geochemical composition.

Viscosity increases with depth in the McMurray Formation.

52 existing viscosity sample wells

Delineated Wells - Surmont

No changes In 2018



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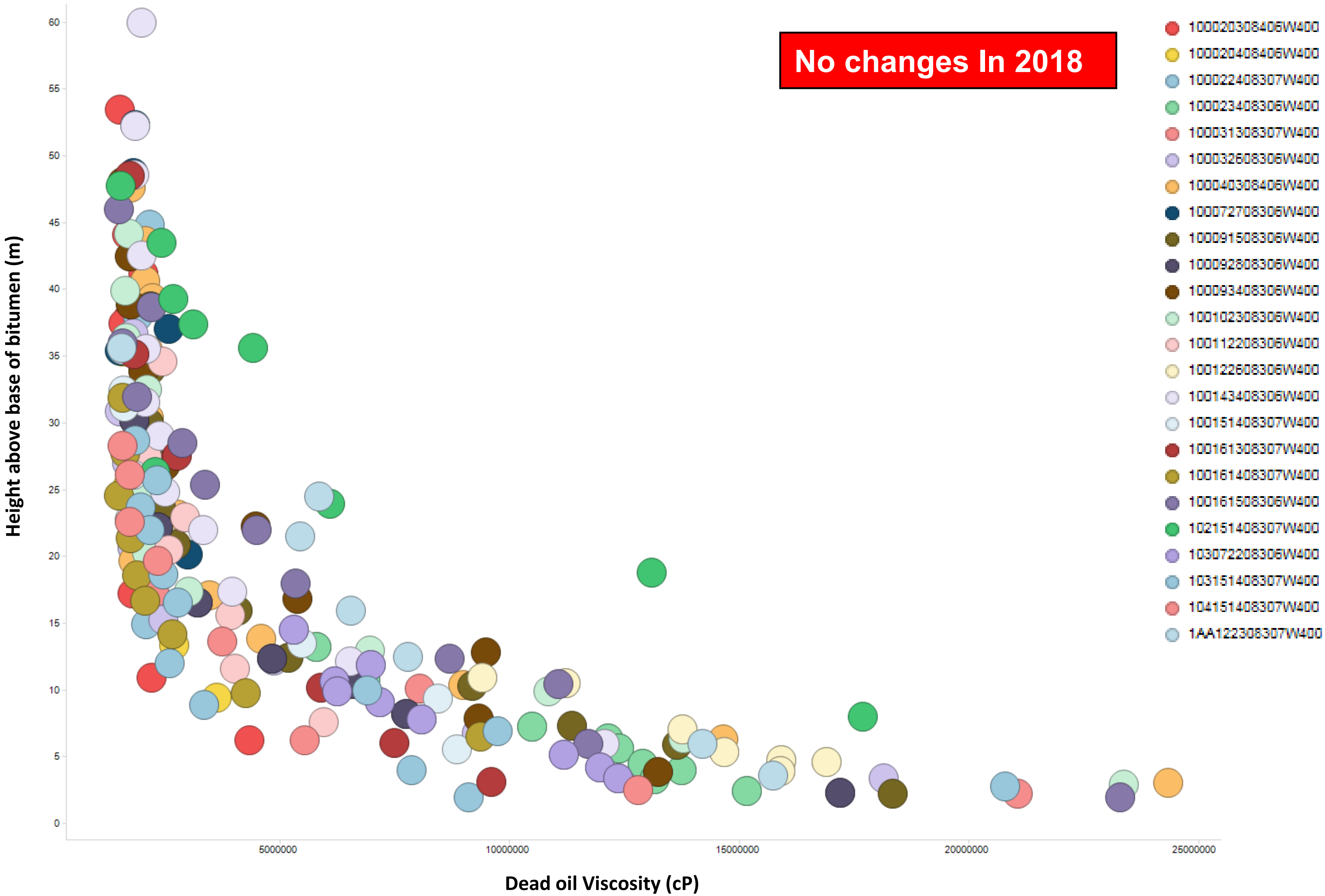
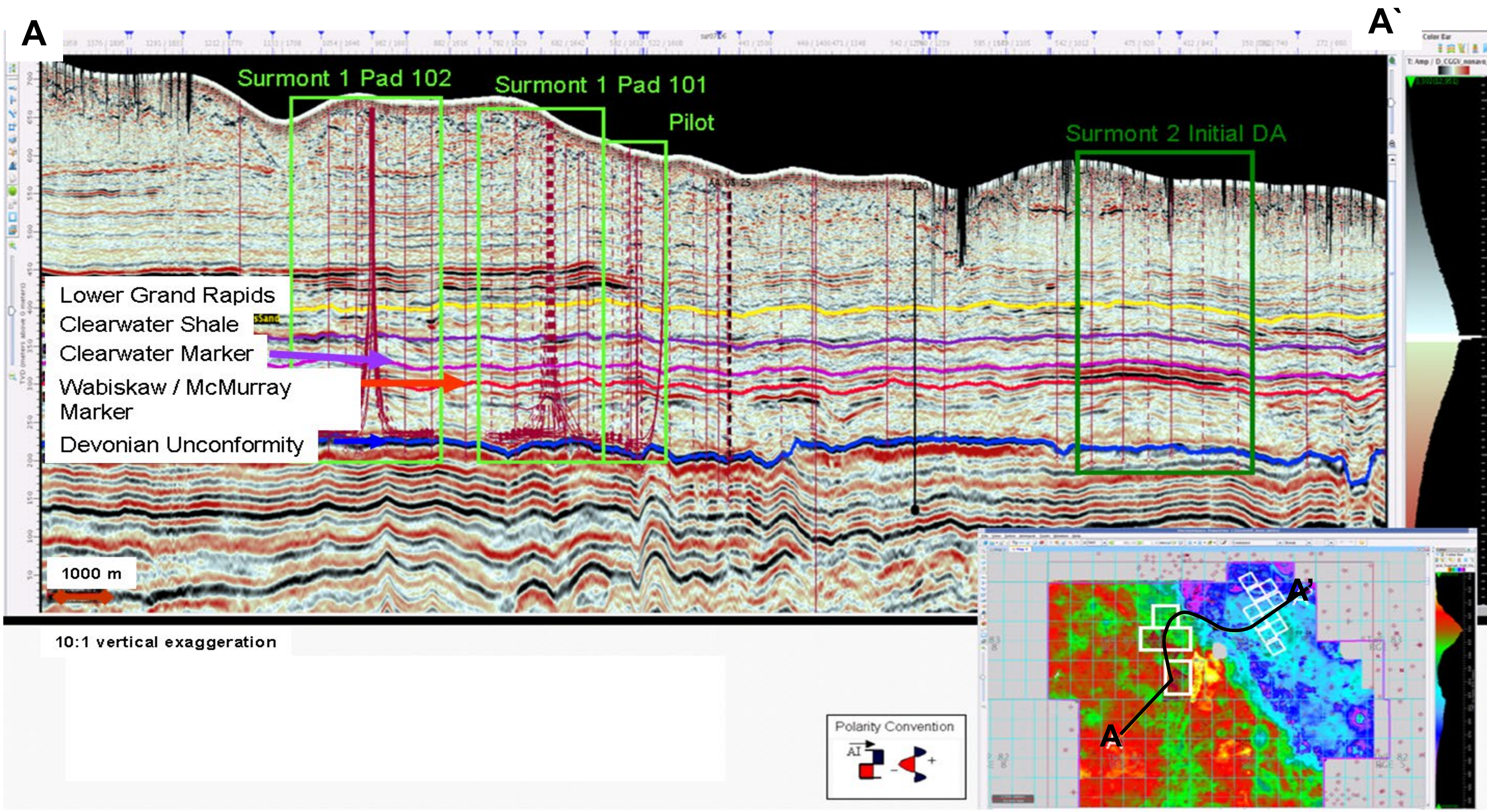
Viscosity Gradient



Representative Structural Cross Section



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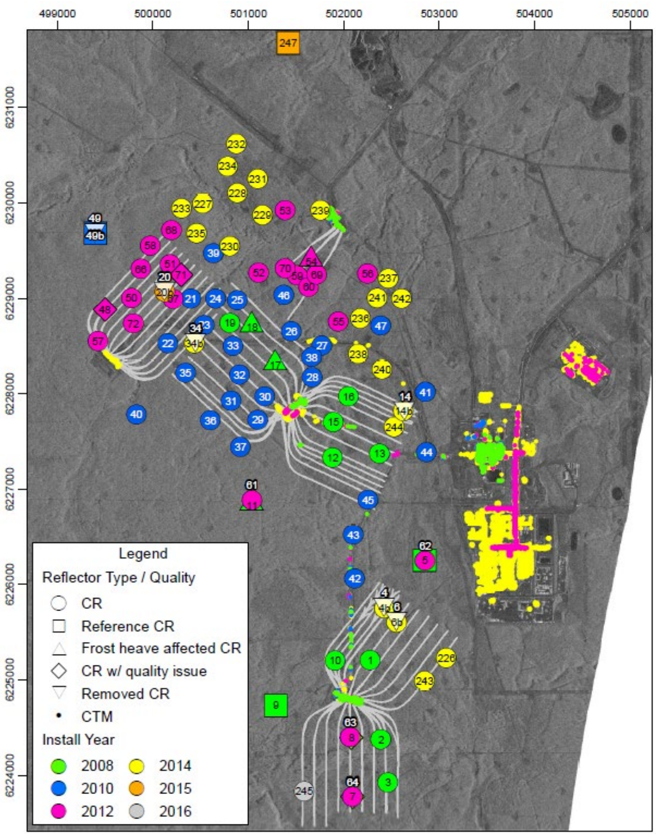
Geomechanical Data and Analysis

- 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.

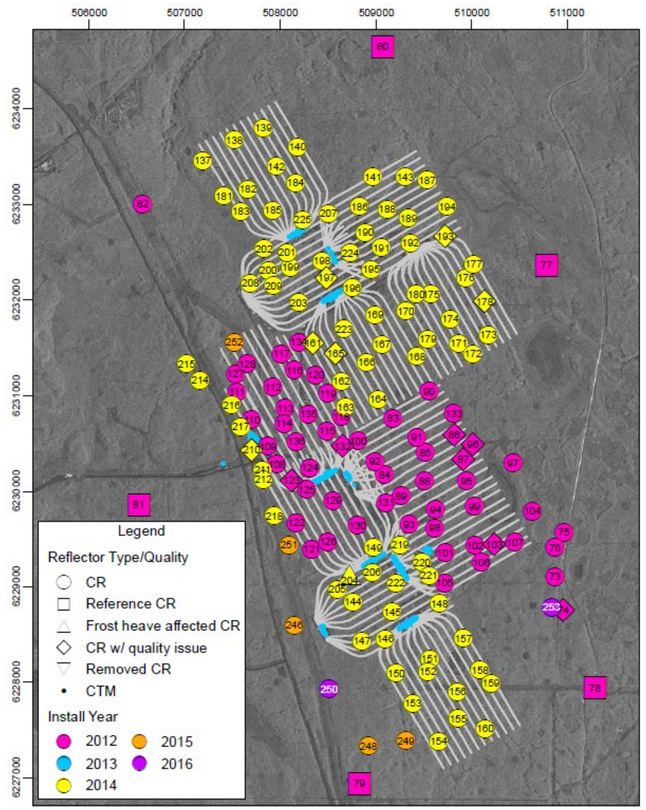
Surface Deformation Monitoring

- 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.

Phase 1 Monitoring Locations



Phase 2 Monitoring Locations



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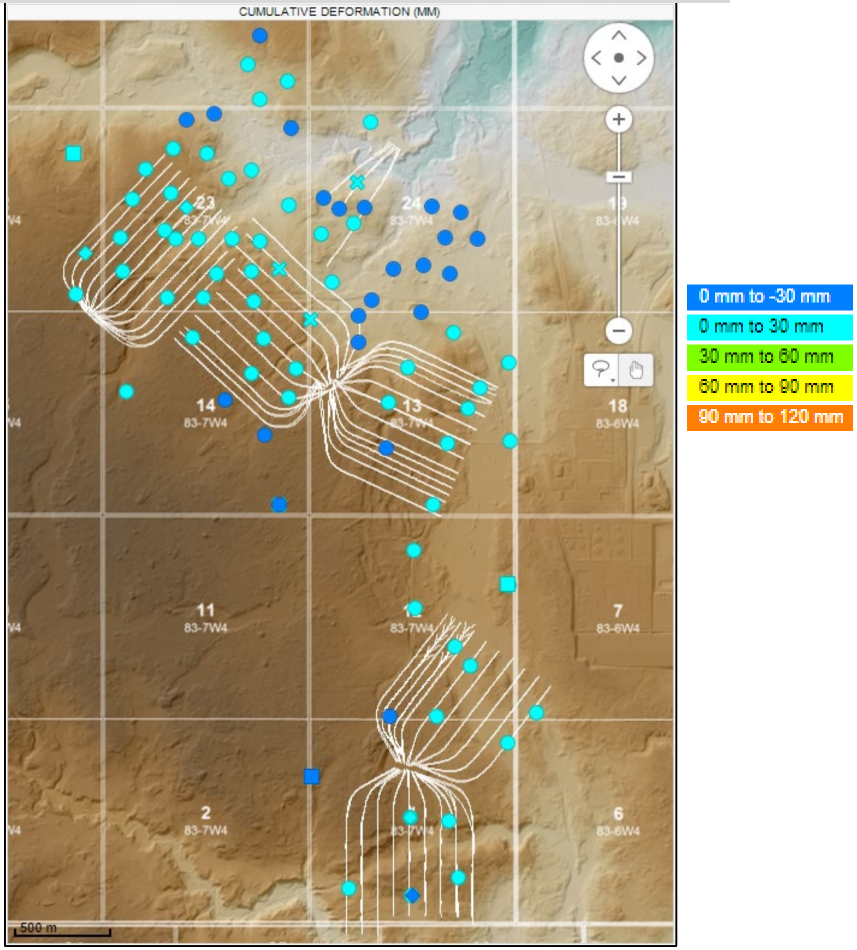
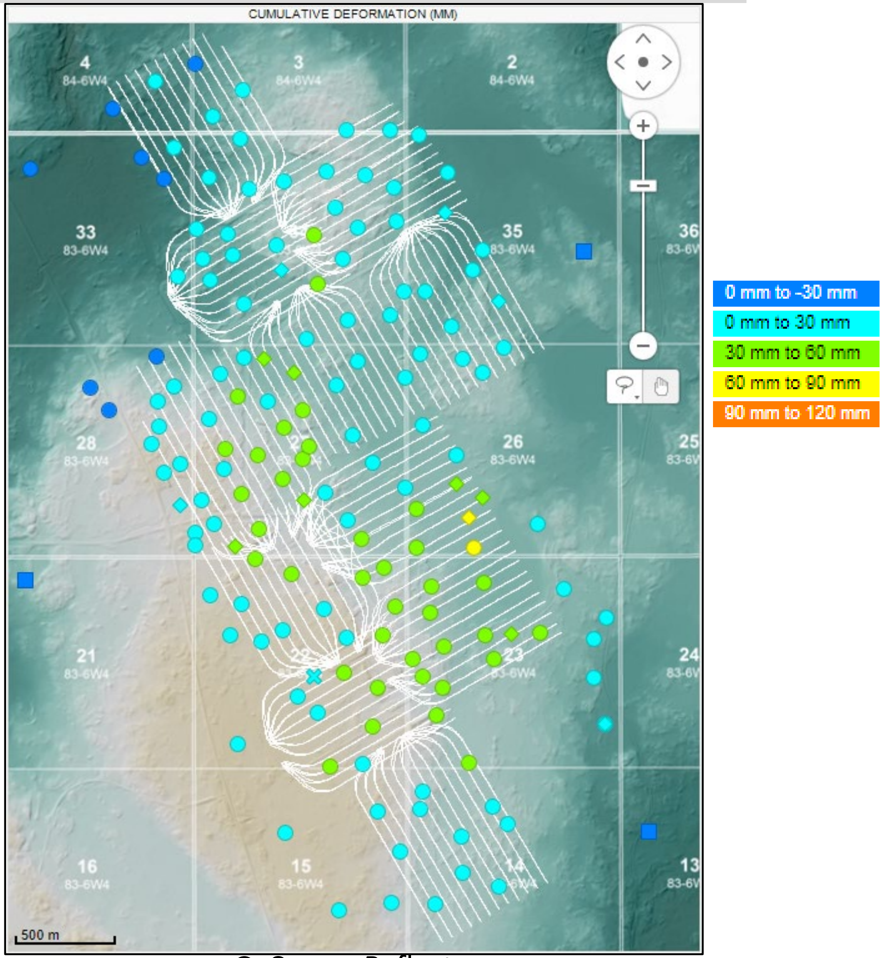
InSAR Surface Deformation Monitoring

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



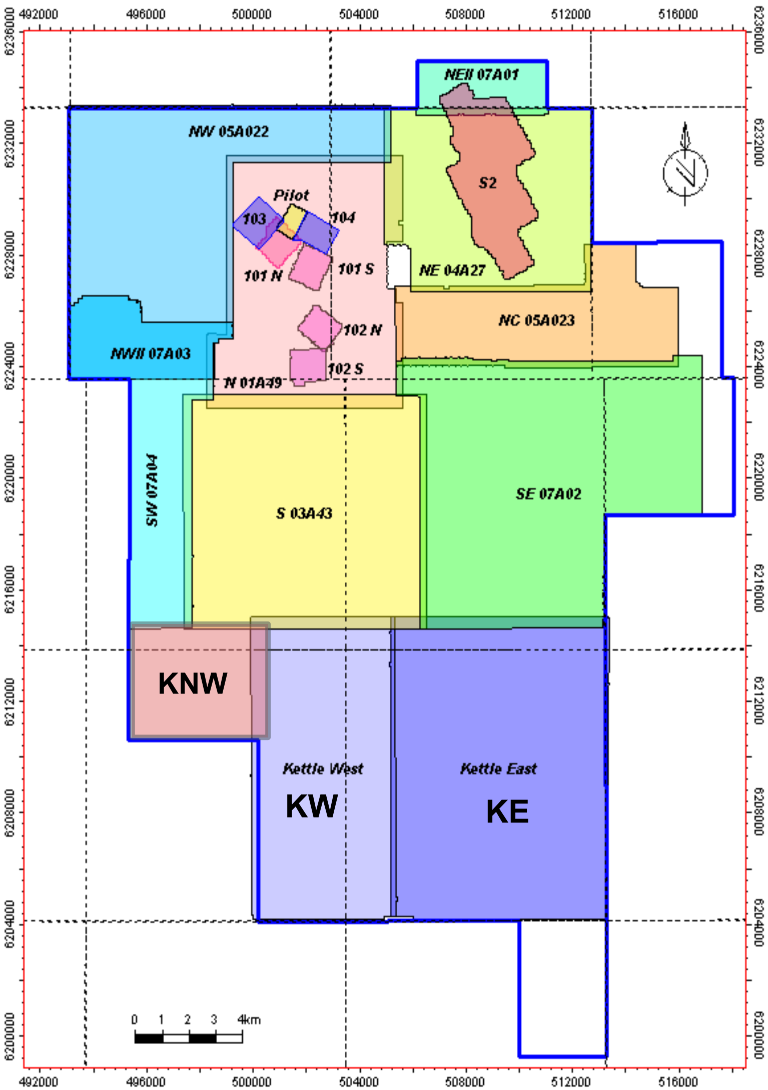
Vertical Deformation (mm) for period
Feb 28, 2018 to Feb 28, 2019
(Surmont 2)



○ Corner Reflector
□ Reference Corner Reflector
◇ Corner Reflector w/quality issue
✕ Corner Reflector w/Frost Jacking

- Deformation currently in line with expectations.

3D Seismic Lines



No changes In 2018

2012-2013 Seismic

3D	Km^2	Shots	S-R Line	S-R
103	1.9	1,700	60x80	20x20
104	2.9	1,103	60x80	20x20
KW	58.2	24,690	120X80	20X20
KNW	21.5	9,543	120x80	20x20

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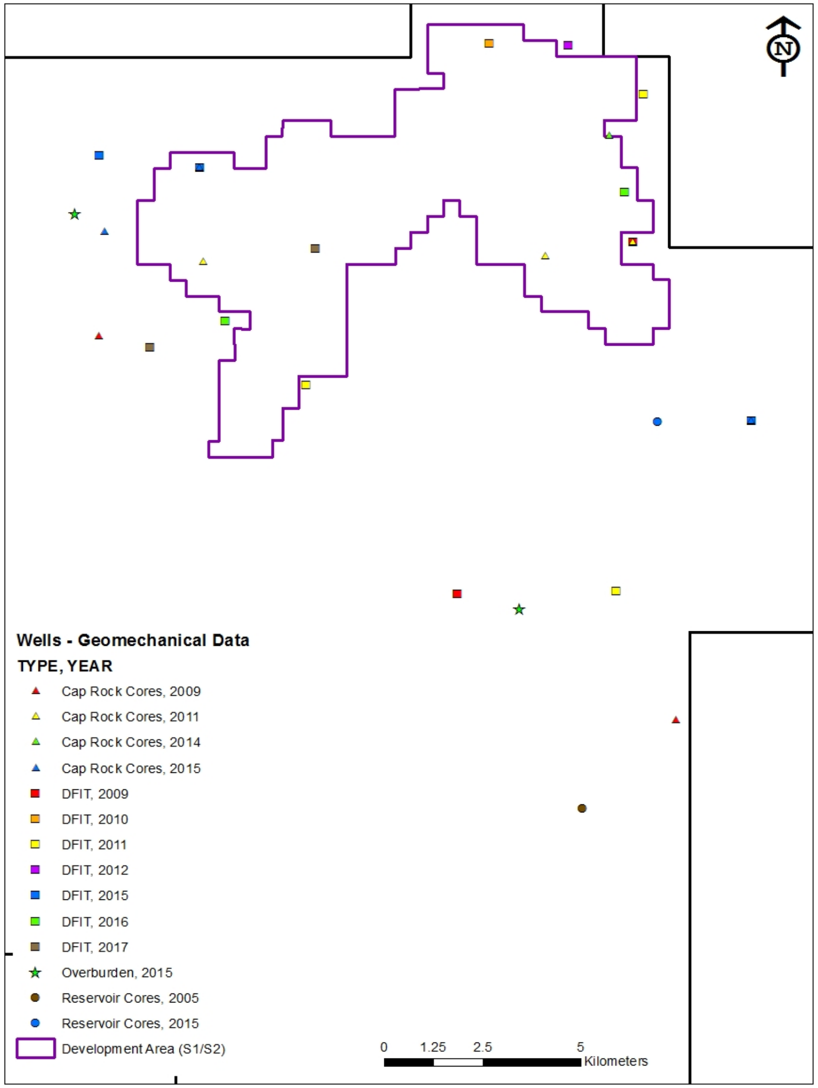
Caprock Integrity

- 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.



Caprock Integrity Analysis and Maximum Operating Pressure

- 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.

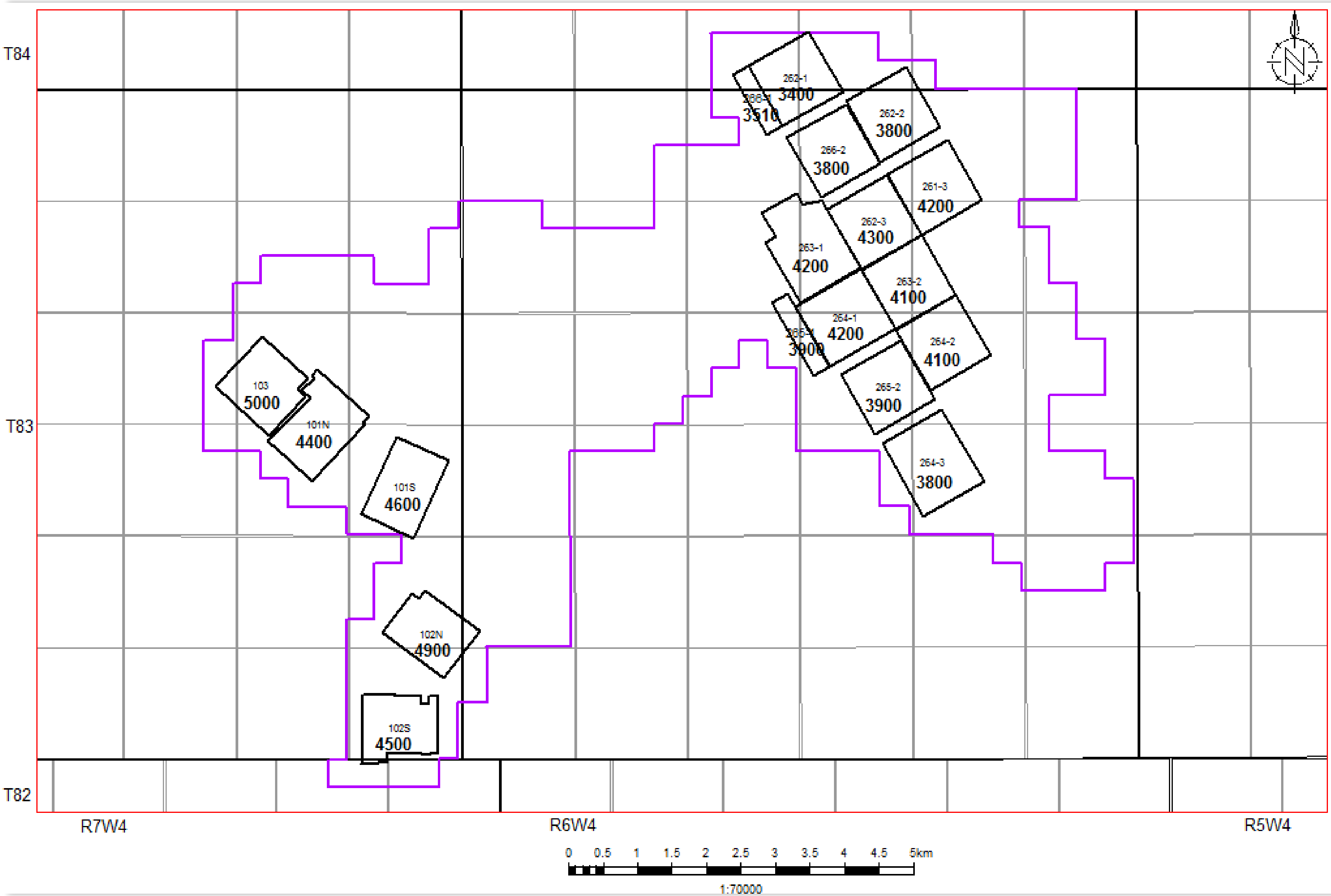
- Results of caprock integrity studies allow ConocoPhillips to characterize and mitigate local risks related to geological and geomechanical variations. Analysis of caprock in the development area suggests while the previously used value of 18.4 kPa/m is valid, the minimum horizontal stress is higher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

Maximum Bottomhole Injection Pressure (kPag) – ALL PADs



Caprock Integrity Analysis and Maximum Operating Pressure

- 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.

Geological and Geophysical Investigation

↓

Static Geomechanical Modeling

↓

Coupled Geomechanics Reservoir Simulation

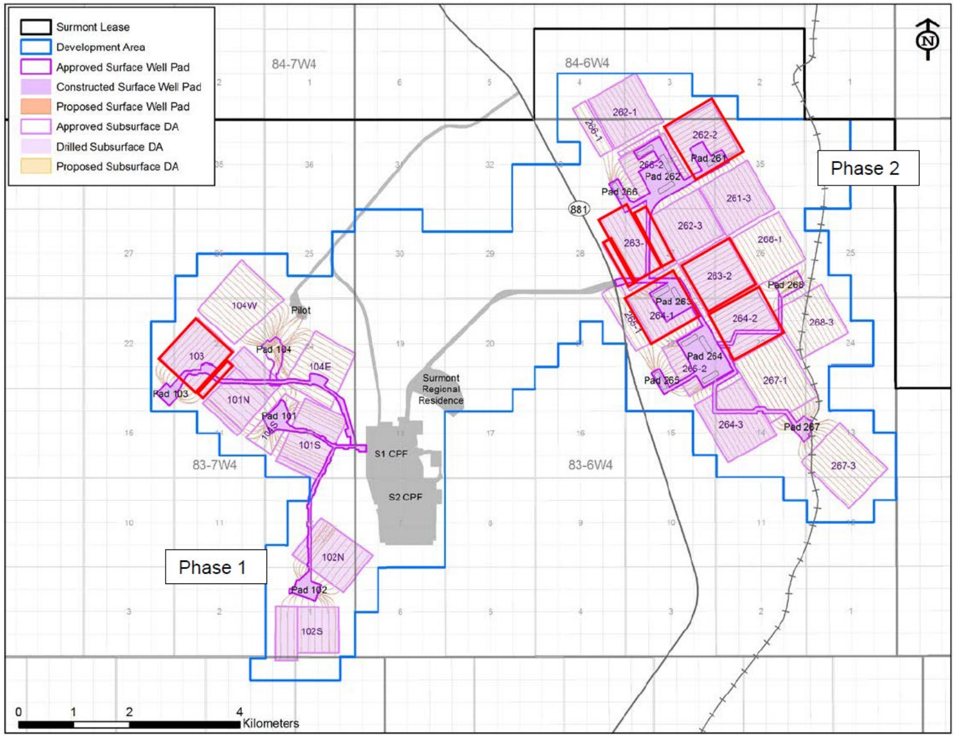
↓

Final Proposal for MOP Strategy

↓

Documentation, Review and Submission

Caprock Integrity Analysis Workflow

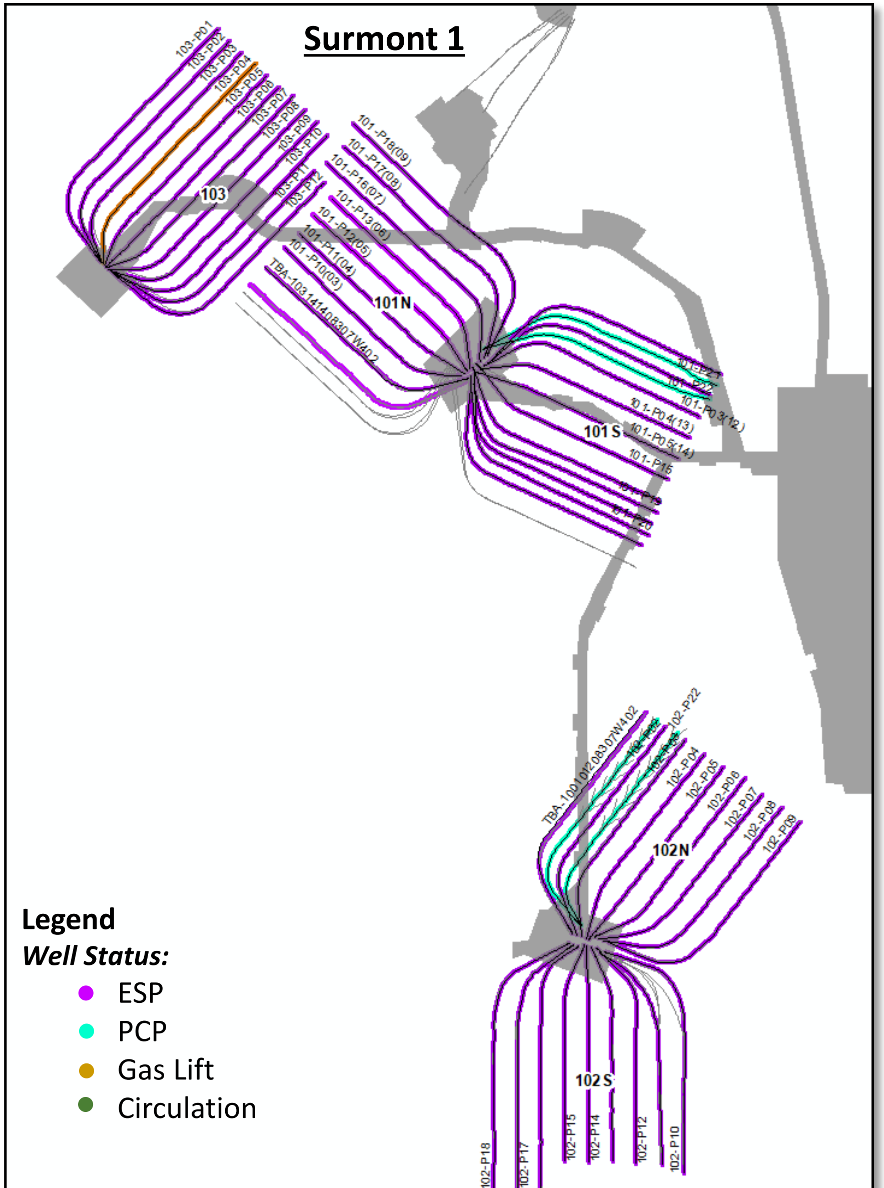


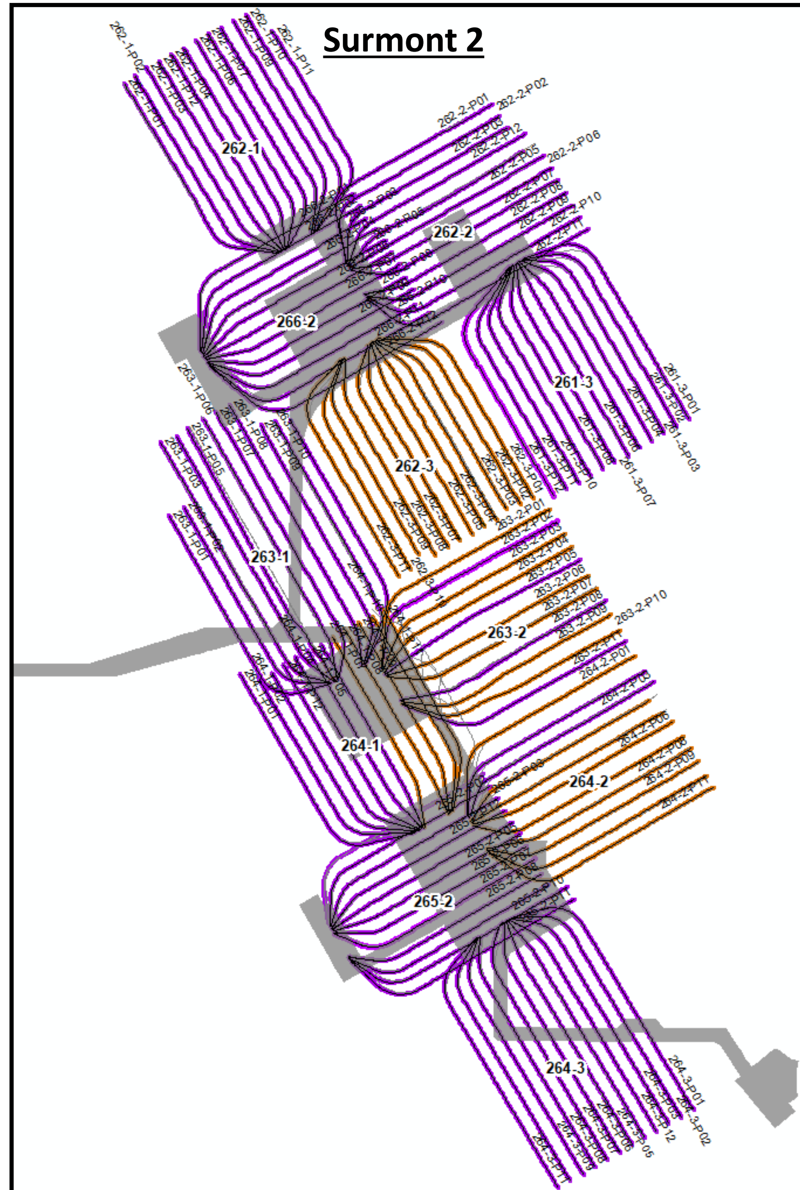
Surmont Development Area and Selected DAs for MOP Increase (red outline)

Drilling and Completions

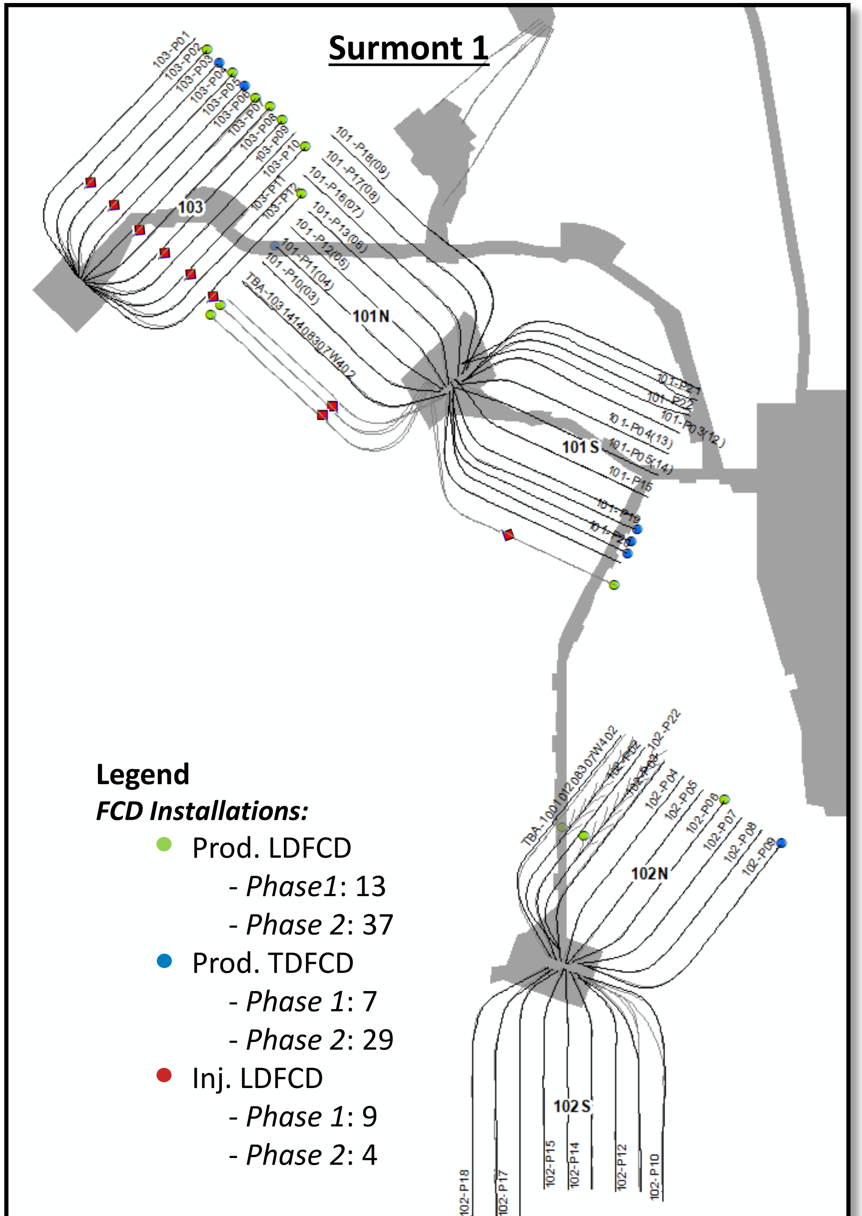
Subsection 3.1.1 (3)

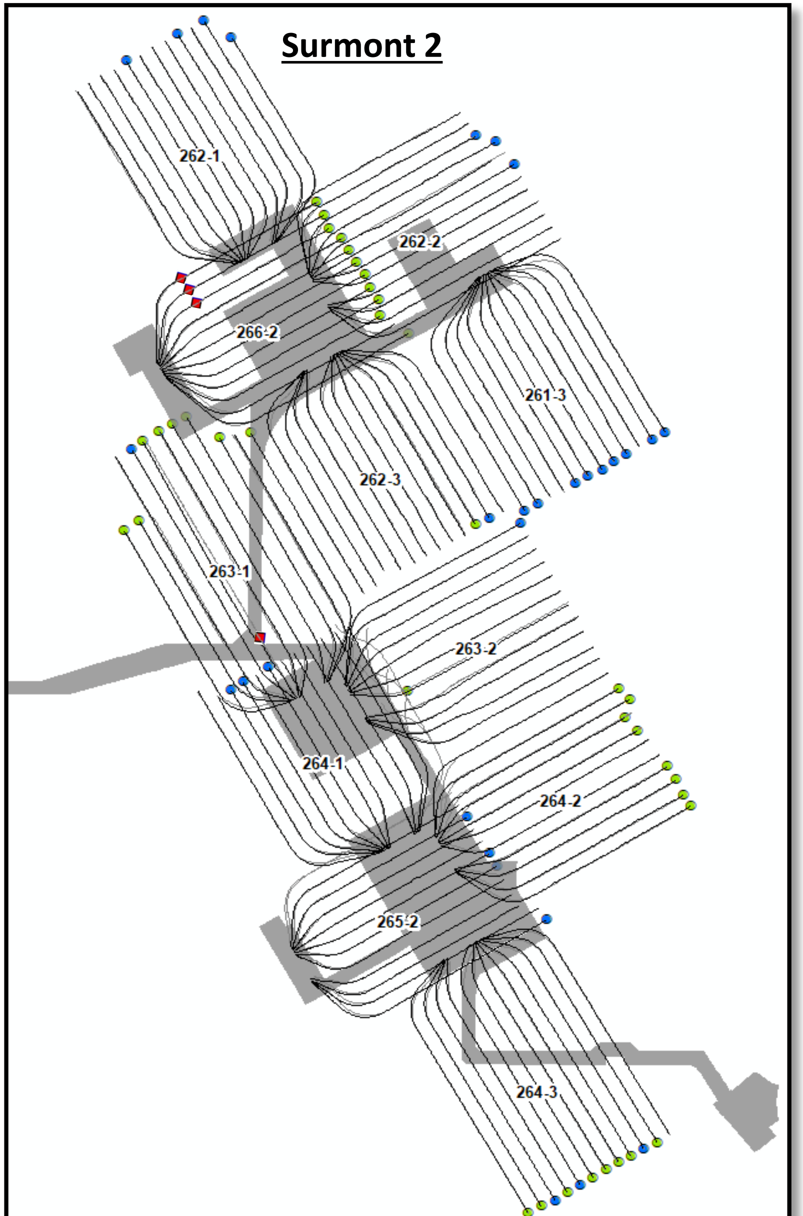
Surmont Well Summary





Surmont FCD Installations





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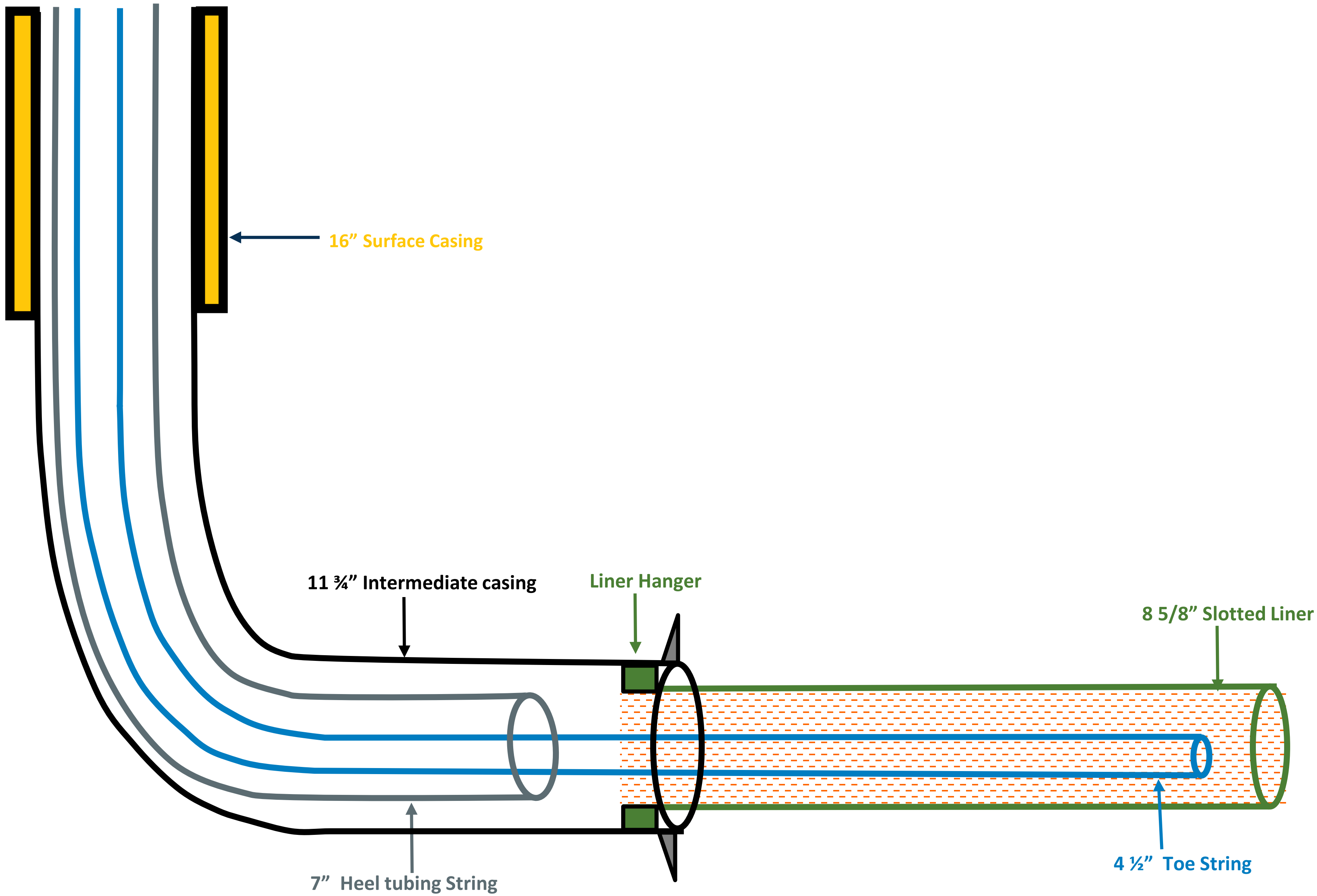
2018 Re-Drills

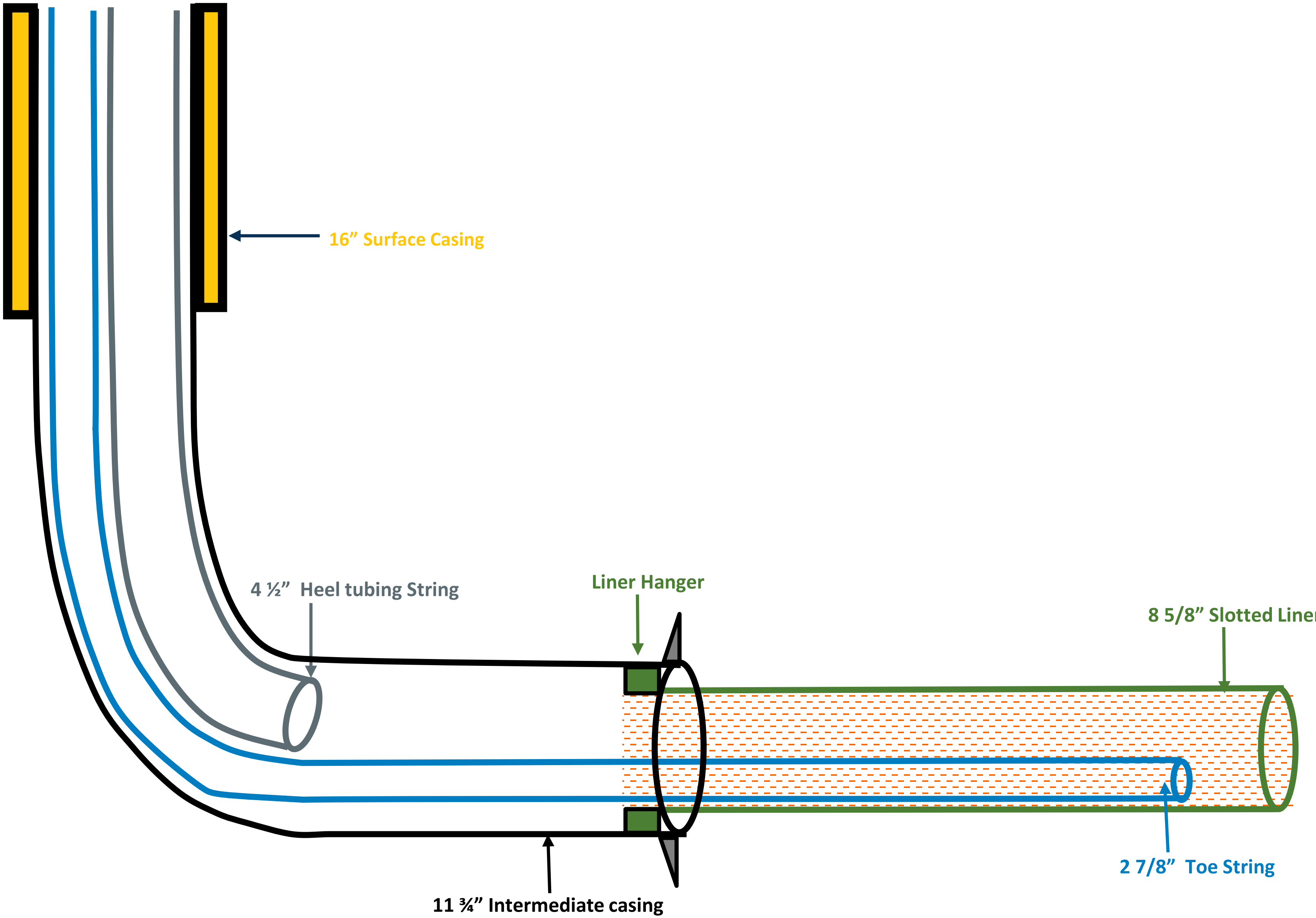
- Total of 15 re-drills in 2018.

S1 Wells	Redrill Type	Justification
101 P08	Whipstock	Slotted liner failure
101 P09	Whipstock	Slotted liner failure
102 P01	Whipstock	Uplift, short production zone
S2 Wells	**Redrill Type**	**Justification**
262-3 P03	Whipstock	TDFCD liner failure
262-3 P12	Whipstock	Slotted liner failure
263-1 I06	Whipstock	Slotted liner failure
263-1 P03	Whipstock	Slotted liner failure
263-1 P10	Whipstock	Slotted liner failure
263-2 P08	Whipstock	SL failure and Intermediate casing damage
264-2 P08	Whipstock	Uplift, poor SL performance
264-2 P10	Whipstock	Slotted liner failure
264-2 P11	Open Hole	Uplift, poor SL performance
264-3 P05	Whipstock	Uplift, poor SL performance
265-2 P01	Whipstock	Slotted liner failure
266-2 I04	Whipstock	Plugged FCD liner; poor injectivity

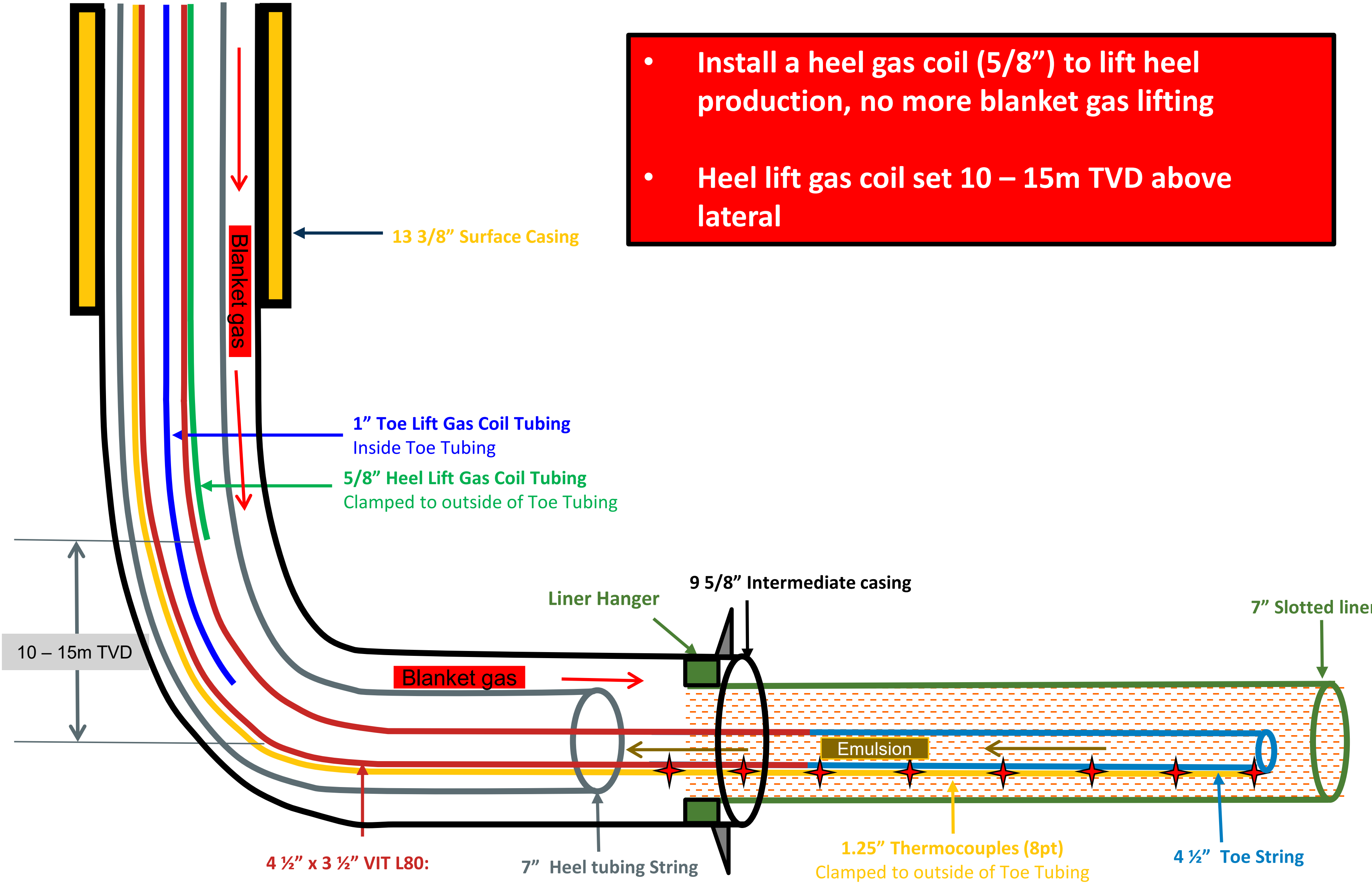
Typical Concentric Injector



Typical Parallel Injector

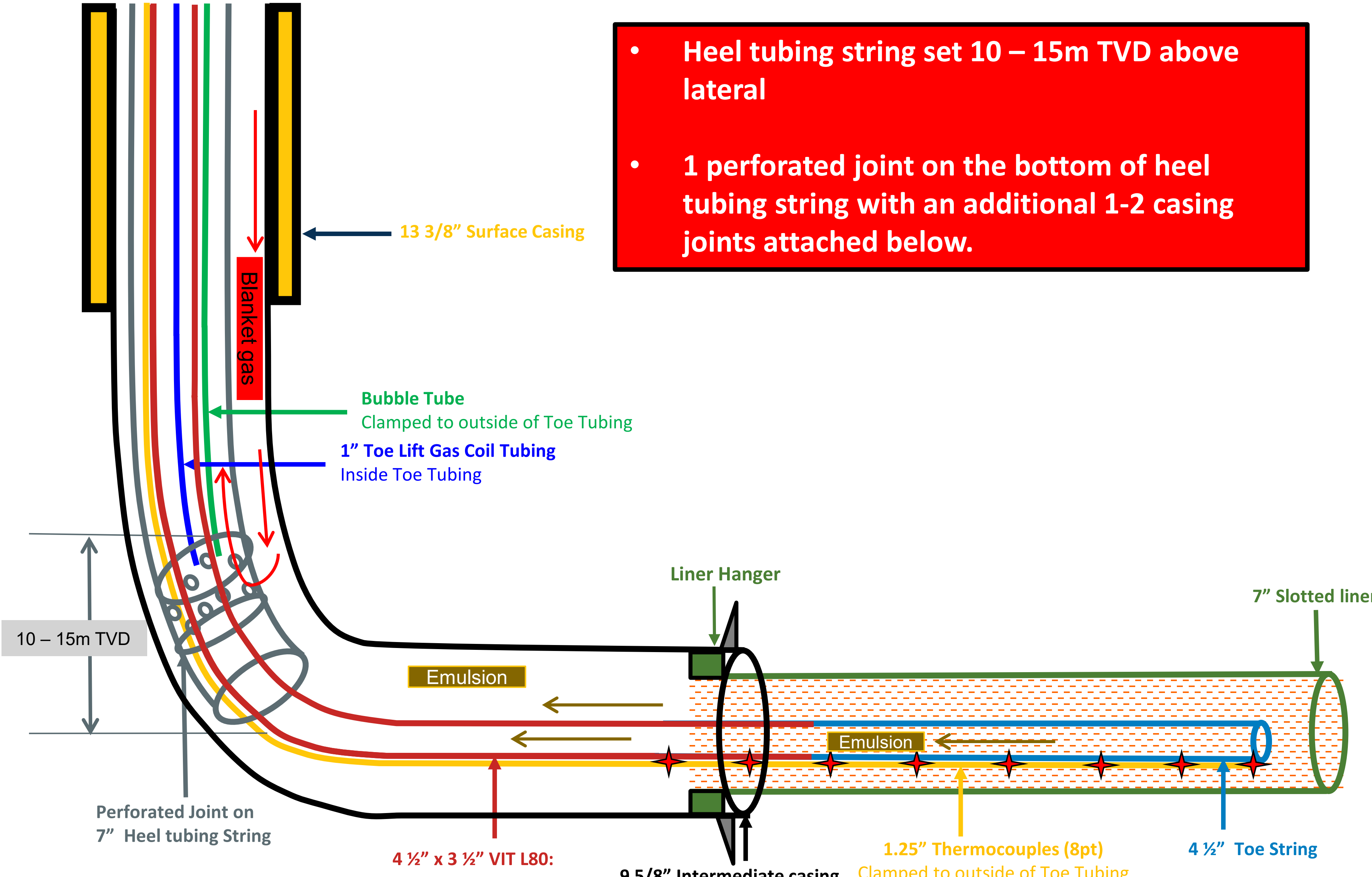


Improved Gas Lift Producer Design, 264-1



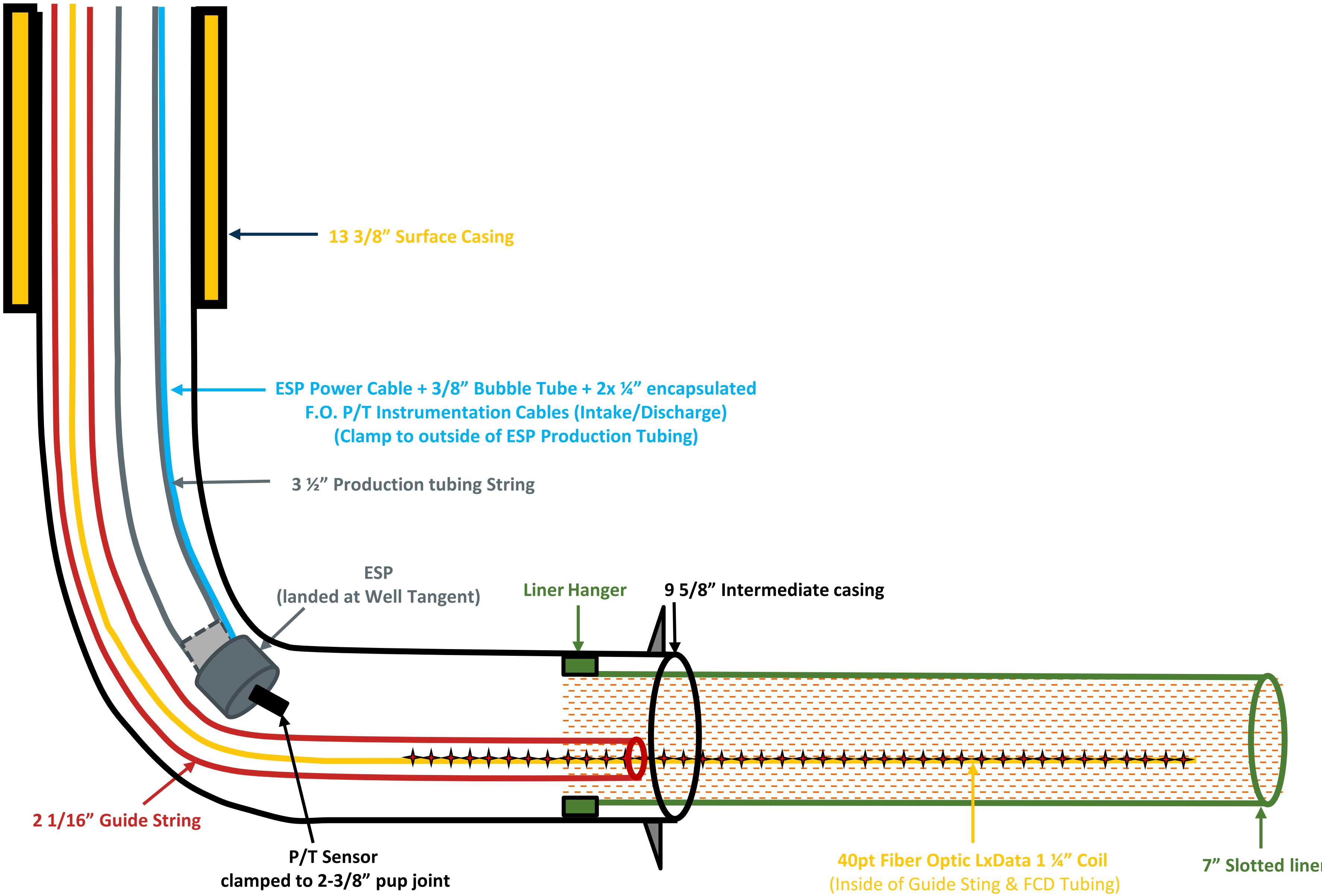
- Install a heel gas coil (5/8") to lift heel production, no more blanket gas lifting
- Heel lift gas coil set 10 – 15m TVD above lateral

Improved Gas Lift Producer Design, 264-2, 263-2 & 263-1

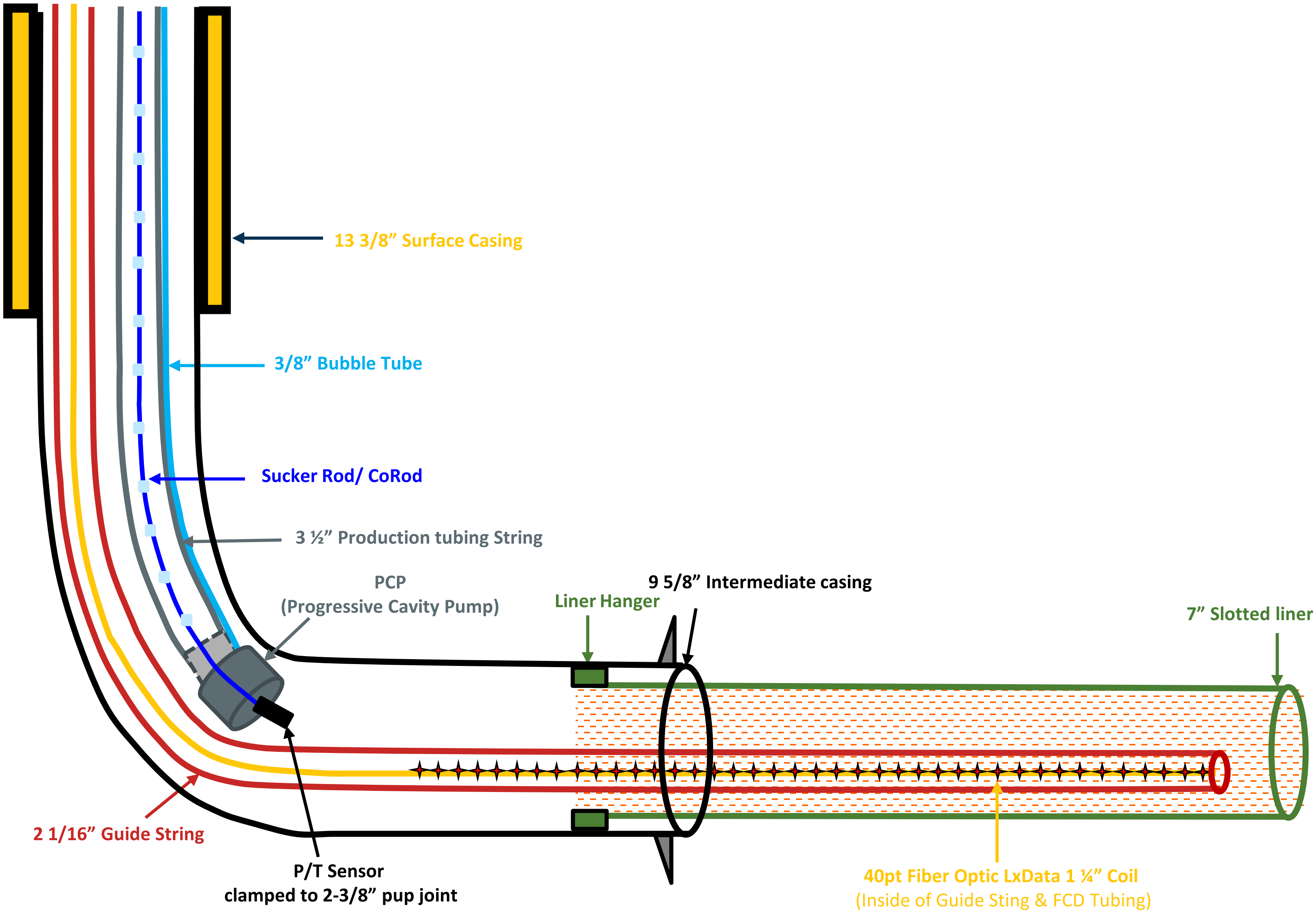


- **Heel tubing string set 10 – 15m TVD above lateral**
- **1 perforated joint on the bottom of heel tubing string with an additional 1-2 casing joints attached below.**

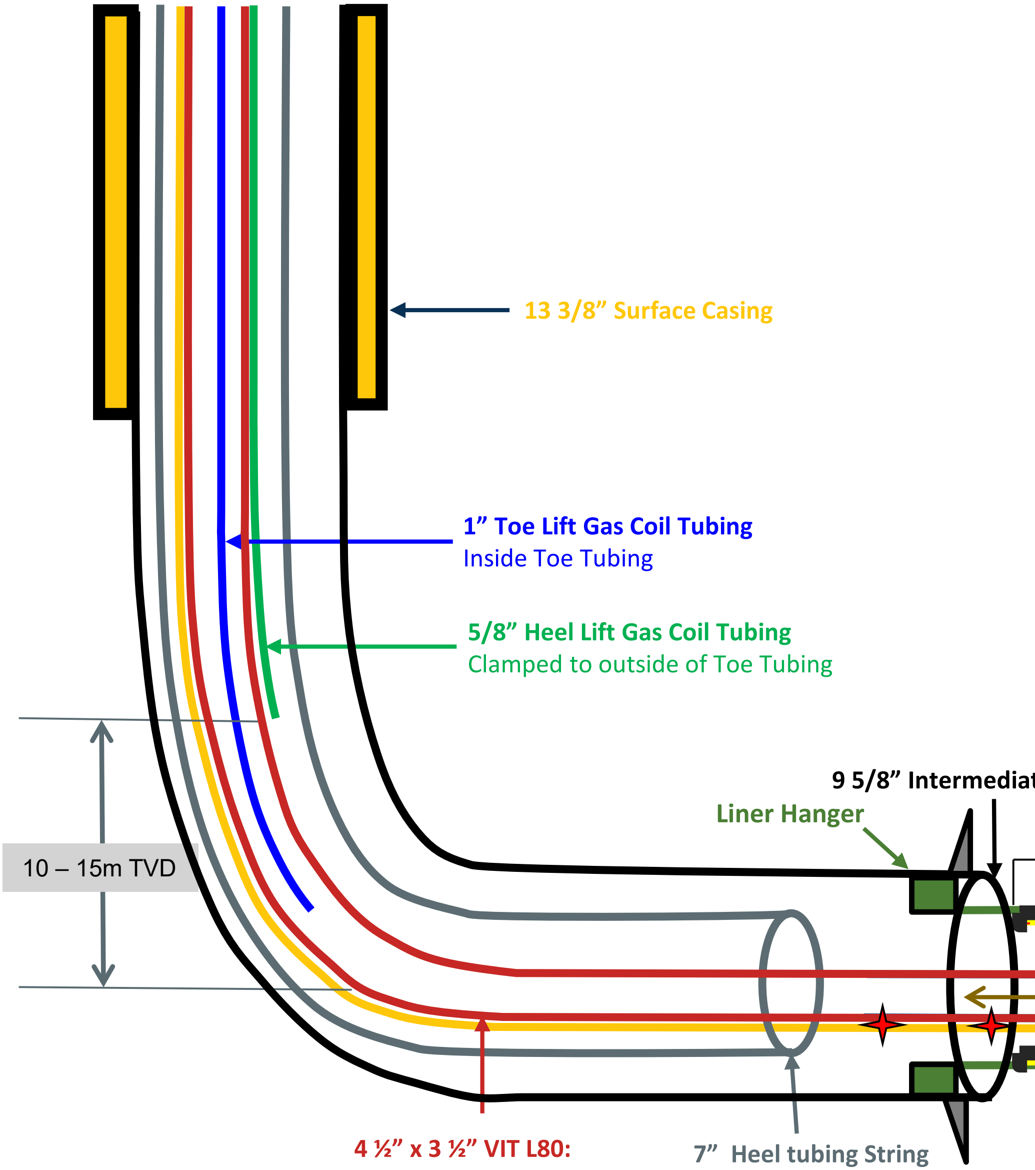
Typical ESP Producer



Typical PCP Producer

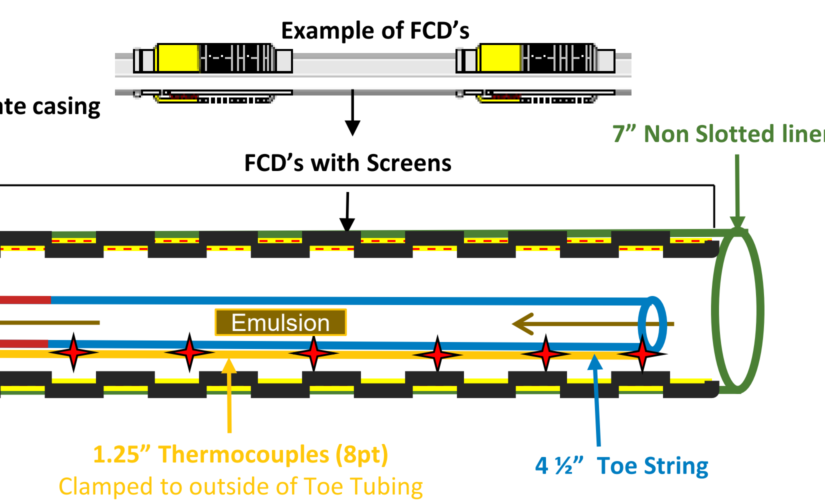


Typical Liner Deployed Flow Control Device (LDFCD) Completion



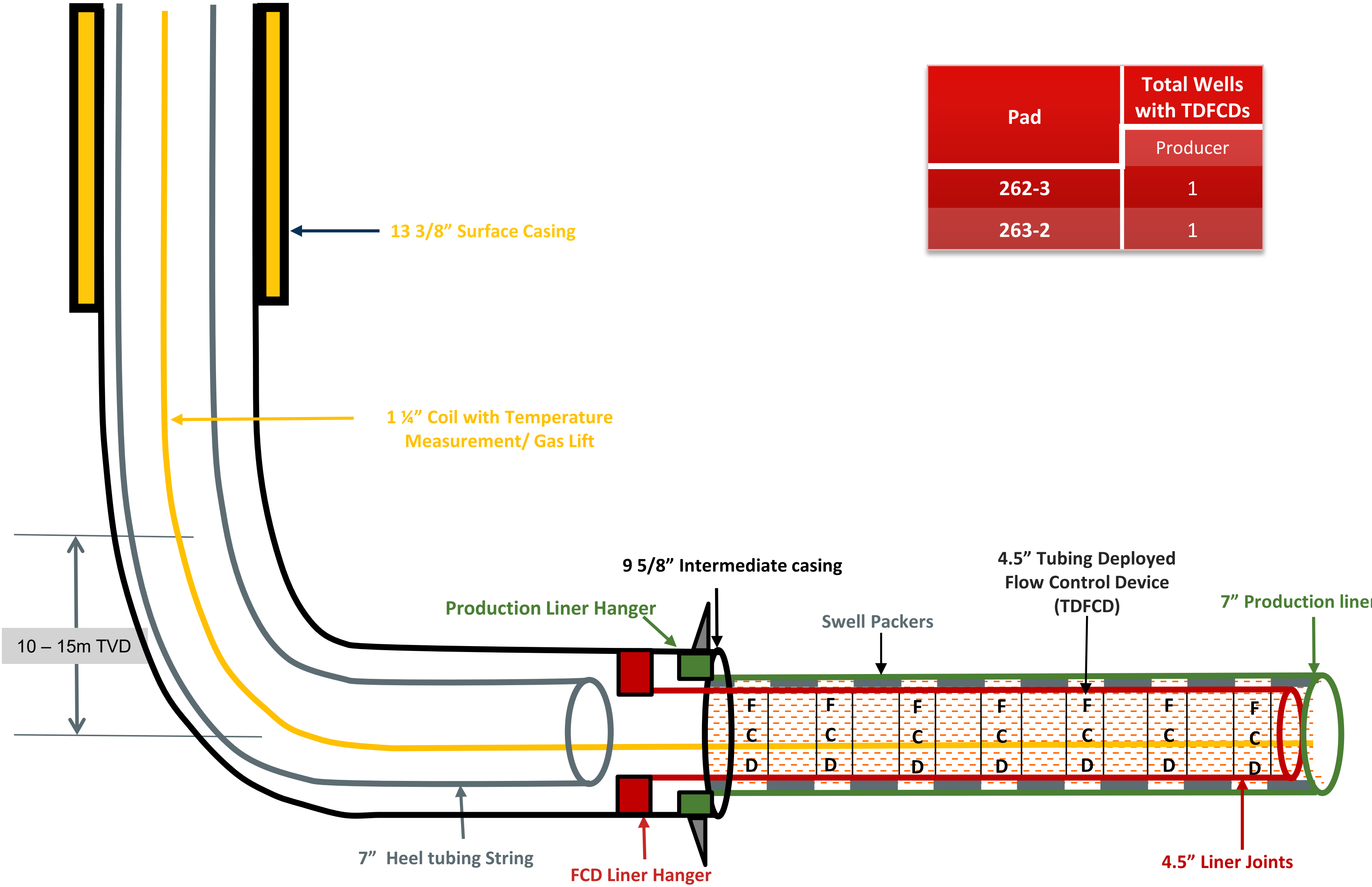
Pad	Total Wells with FCDs	
	Producer	Injector*
101	2	0
102	4	0
103	7	6
262-3	2	0
263-1	10	2
263-2	1	0
264-1	1	0
264-2	8	0
264-3	8	0
265-2	1	0
266-2	11	4

* Injector wells do not have instrumentation or GL coils



Typical Tubing Deployed FCD (TDFCD) Completion – Gas Lift

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



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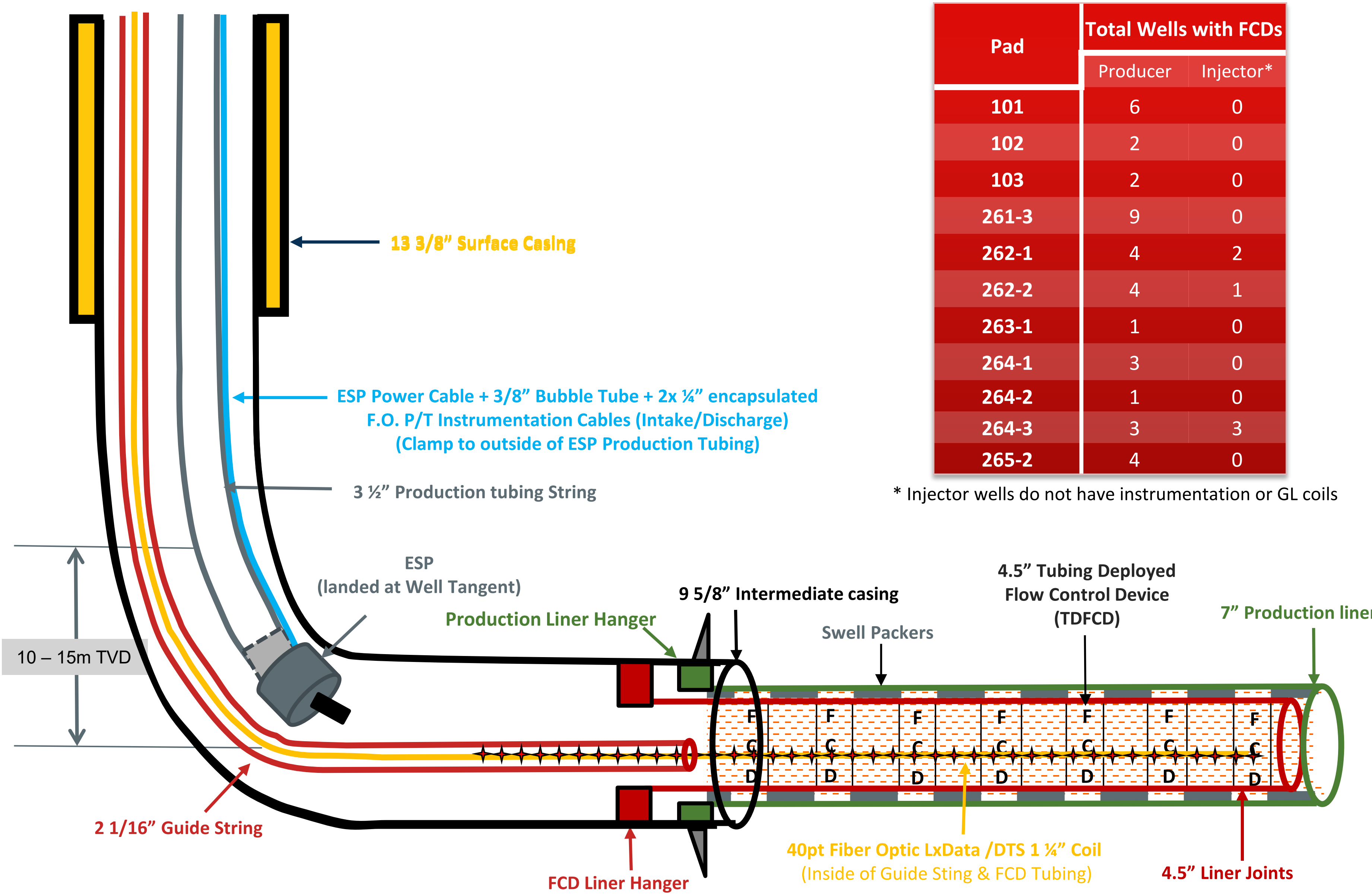
Typical Tubing Deployed FCD (TDFCD) Completion – ESP

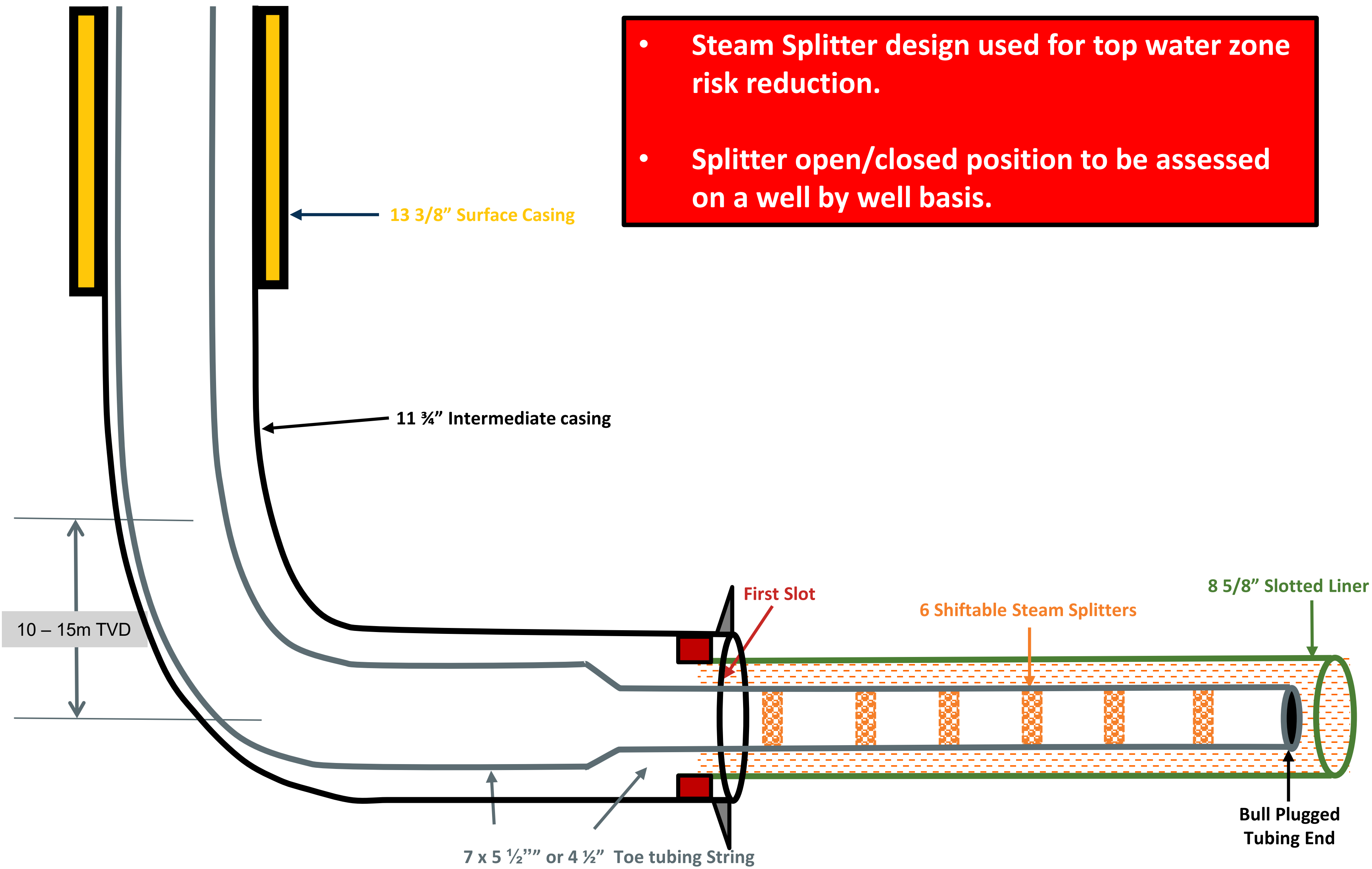


Pad	Total Wells with FCDs	
	Producer	Injector*
101	6	0
102	2	0
103	2	0
261-3	9	0
262-1	4	2
262-2	4	1
263-1	1	0
264-1	3	0
264-2	1	0
264-3	3	3
265-2	4	0

* 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

	Phase 1			Phase 2											TOTAL
	101	102	103	261-3	262-1	262-2	262-3	263-1	263-2	264-1	264-2	264-3	265-2	266-2	
ESP	20	18	11	12	12	12	0	11	3	7	2	12	12	12	**144**
PCP	2	2	0	0	0	0	0	0	0	0	0	0	0	0	**4**
Gas Lift	0	0	1	0	0	0	12	0	8	5	9	0	0	0	**35**
SSAGD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Re-Circ.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Circ.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Artificial Lift Types

- **Gas Lift**
  - Gas lift is effective with bottom hole flowing pressures >2,700 kPa with pressure of well head (Pwh) approx. 1,000 kPa
  - Lifting from heel and toe with gas assist at start of vertical section
  - Current production rates range from 100 m^3/d to 700 m^3/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 PCP 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

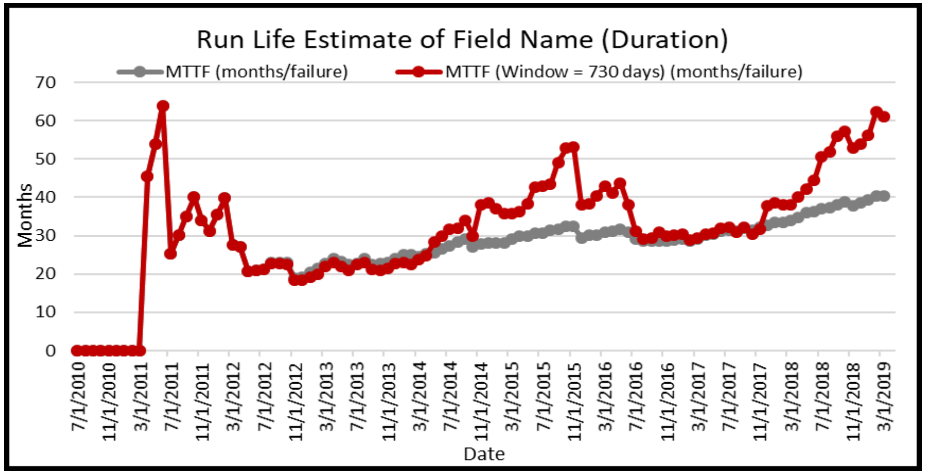
2018: 26 ESP Failures

2019: 2 ESP Failures

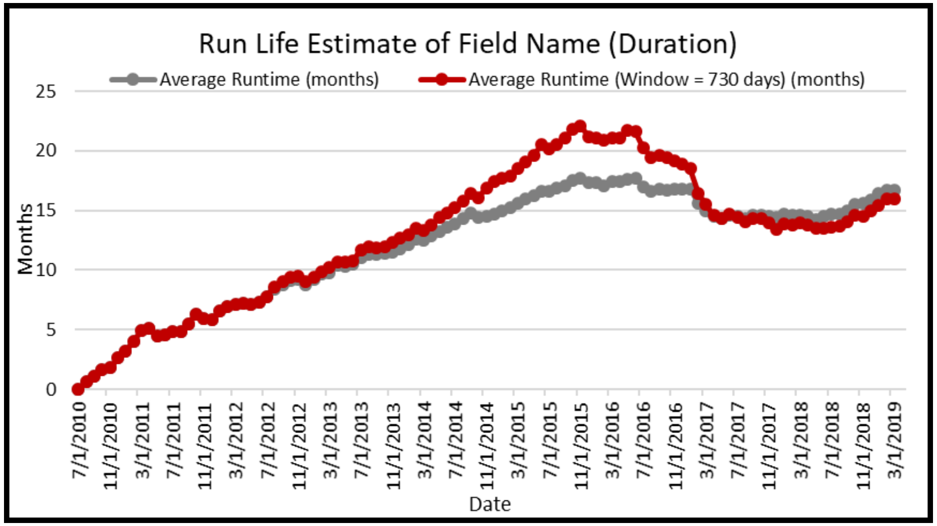
*(730 day window)

** The unrealistically high MTTF at S2 as a result of the # of recent ESP installs artificially increases the **One Surmont's** overall MTTF

MTTF



Average Runtime



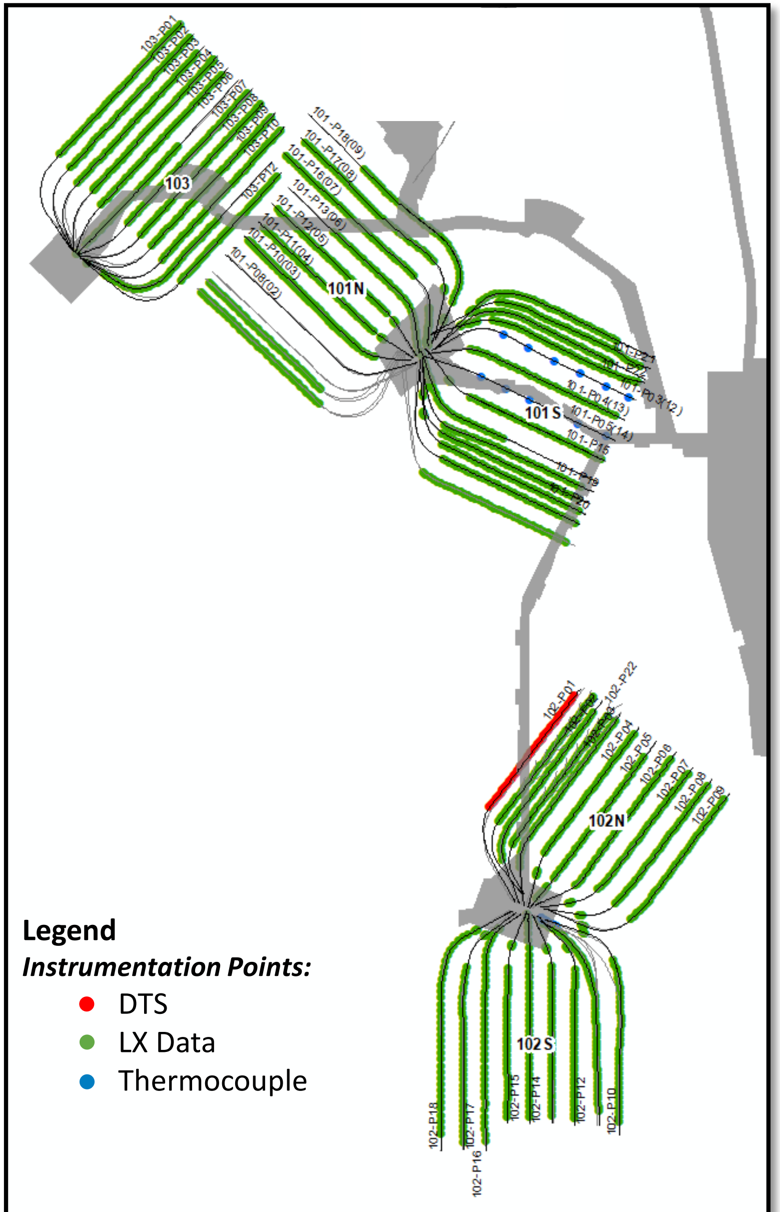
Instrumentation in Wells

Subsection 3.1.1 (5)

Temperature & Pressure Measurement

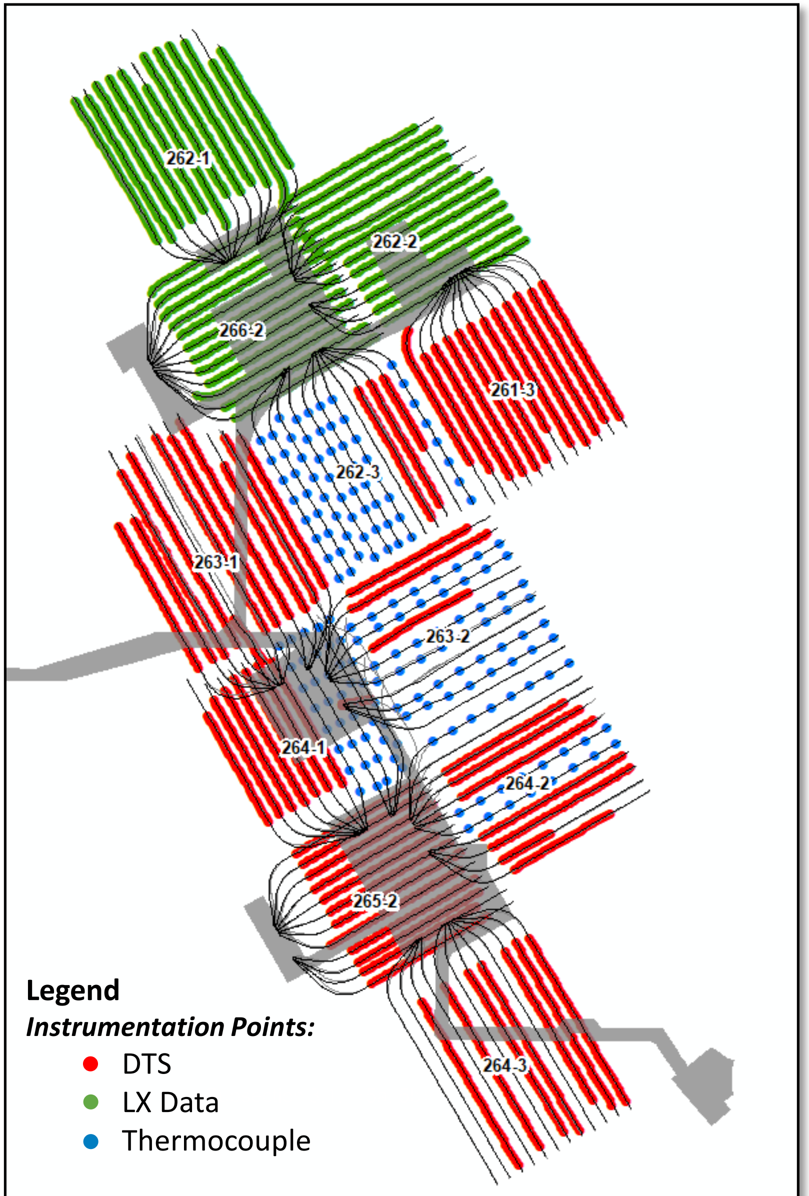
- Temperature Measurement
  - Producer lateral temperature
    - Measured with 8 thermocouples, 40 LxData, or DTS fiber optic strings.
  - Injector lateral temperature
    - No temperatures measured
- Pressure Measurement
  - Producer
    - Primary bottom hole pressure measurement is done with a bubble 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

SAGD Well Instrumentation



1. **Phasing out all Thermocouples & LX Data at ESP conversion - evaluating options however DTS is the likely choice for most wells.**

Phase 2 SAGD Well Instrumentation



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.**

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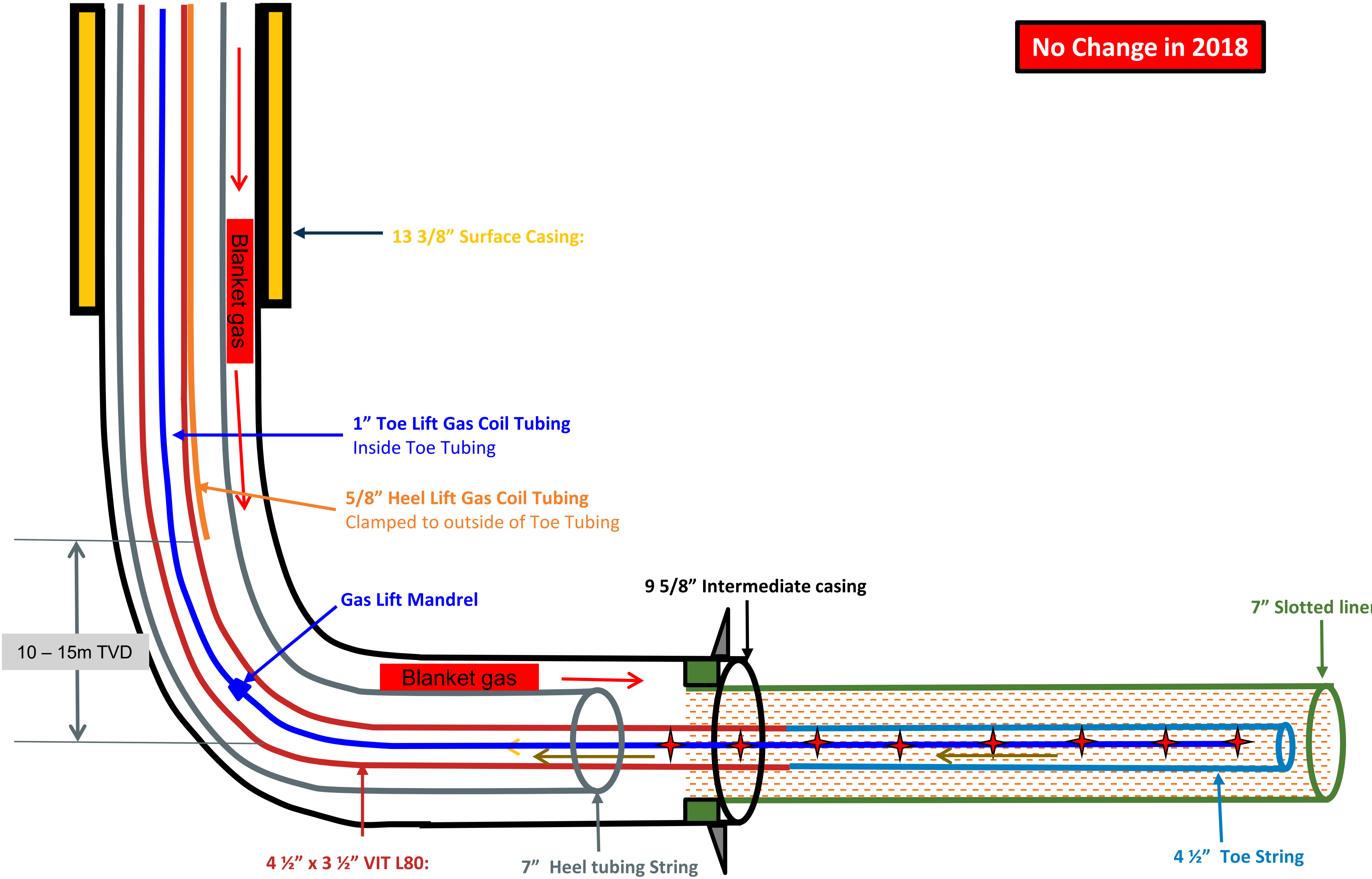
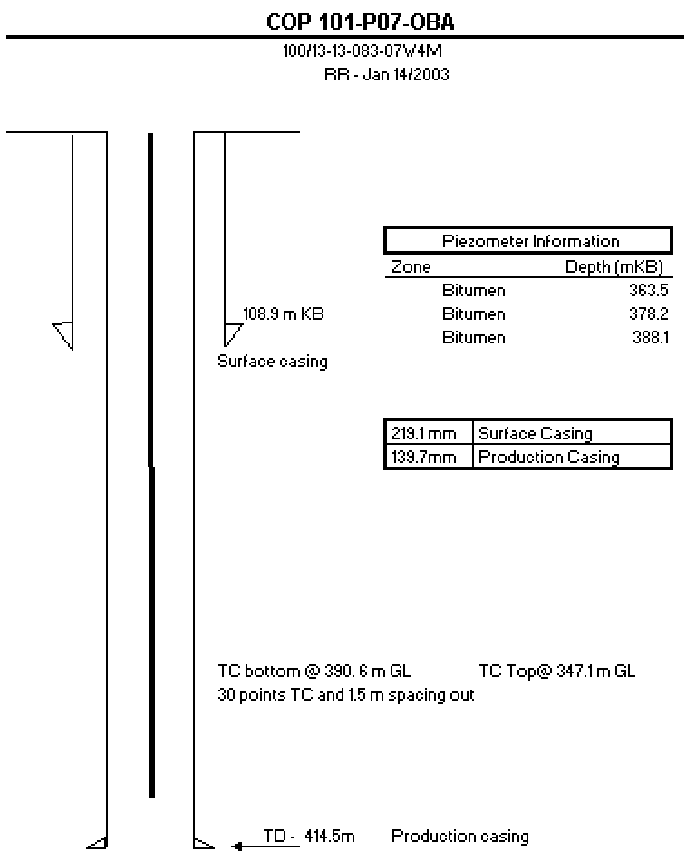
Distributed Temperature Sensing (DTS)

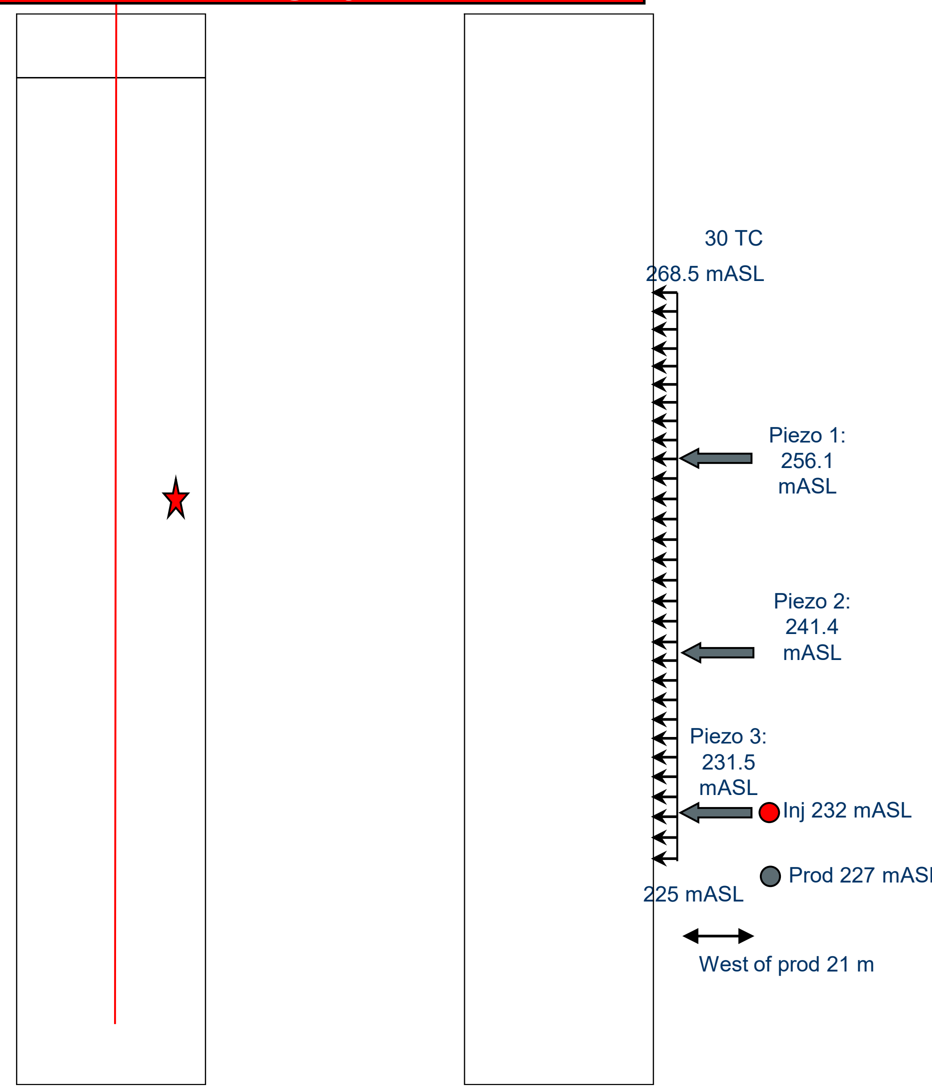


Typical Observation Well Measurement

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

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



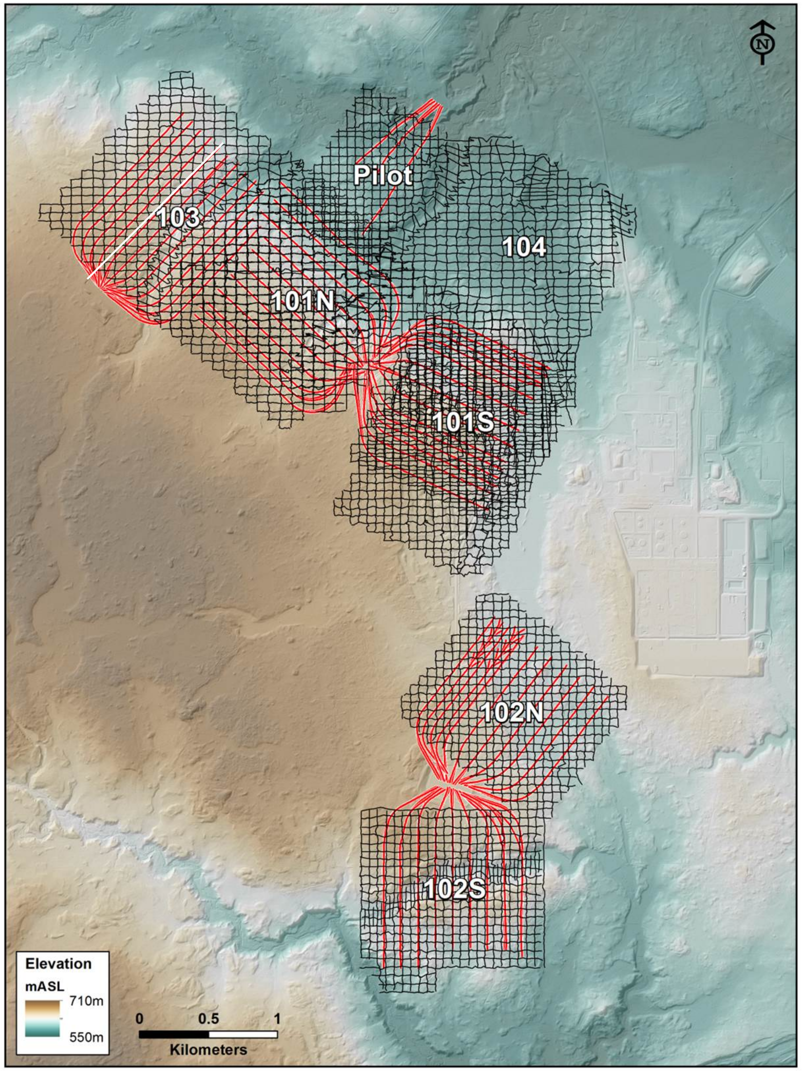


4D Seismic

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

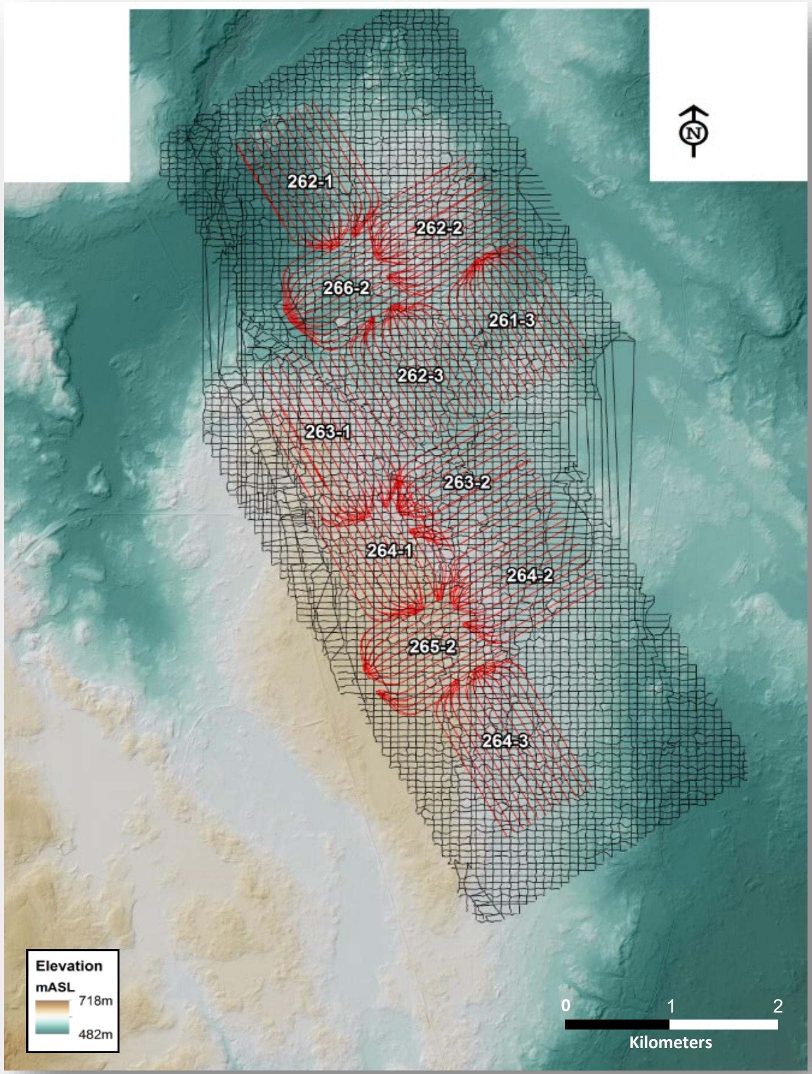
Pad 102N
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 10th monitor acquired in October 2018

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)

4D Seismic Location – Phase 2

Phase 2 Area



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
  - North extension: 2014-2015
- First Monitors
  - Spring 2016: 263-2
  - Fall 2016: 263-1 / 264-1 / 265-2 / 264-3
  - Spring 2017: 262-2/261-3/262-3/263-2 (*) /264-2
  - Fall 2017: 262-1
  - Spring 2018: 266-2
- Second Monitors:
  - Fall 2017: 263-1/264-1/265-2/264-3
  - Spring 2018:262-2/261-3/262-3/263-2
  - Fall 2018: 262-1
- Third Monitor
  - Fall 2018: 263-1

Phase 1 - 4D Seismic Program

PAD	2015		2016		2017		2018	
	Spring	Fall	Spring	Fall	Spring	Fall	Spring	Fall
101N	M						M	
101S	M							
102N	M							M
102S				M				M
Pilot		M						
103			M	M		M		
104								

B **Baseline**

M **Monitor**

Phase - 2 4D Seismic Program

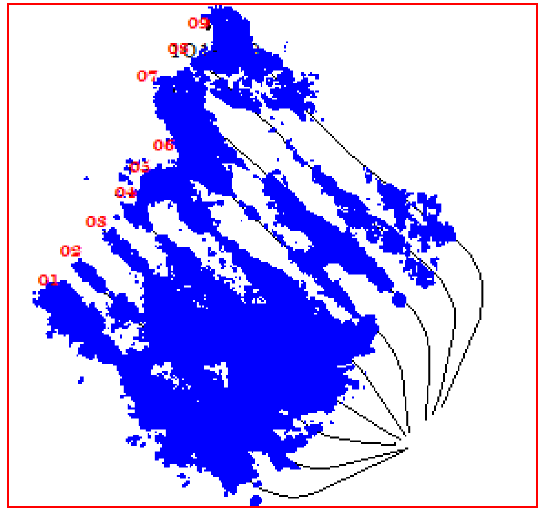
PAD	2018	
	Spring	Fall
263-1		M
264-1		
265-2		
264-3		
262-1		M
266-2		
262-3	M	
263-2	M	
264-2		
262-2	M	
261-3	M	

B Baseline   M Monitor

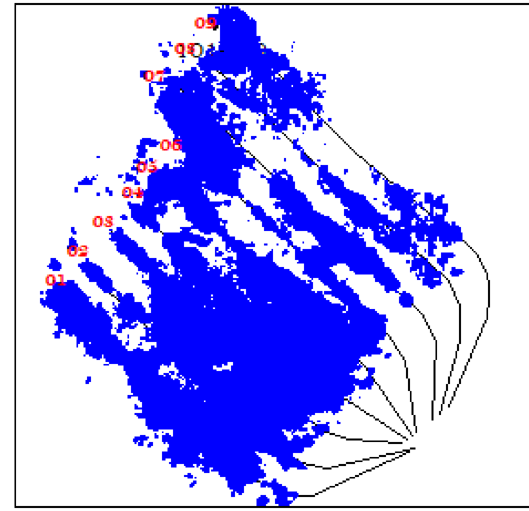
2015 - 4D Seismic Results Pad 101

- 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.

101 North 8th monitor - March 2015

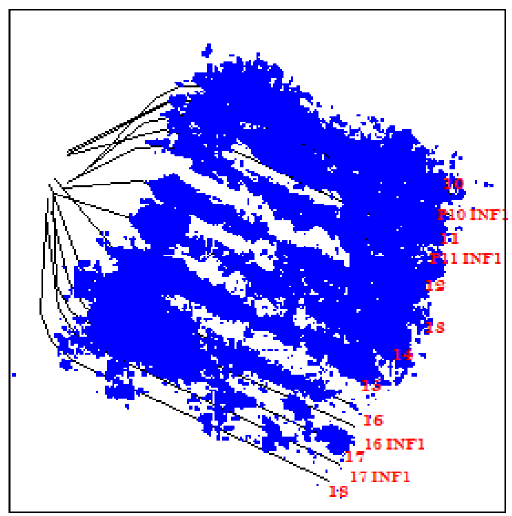


101 North 9th monitor - March 2018

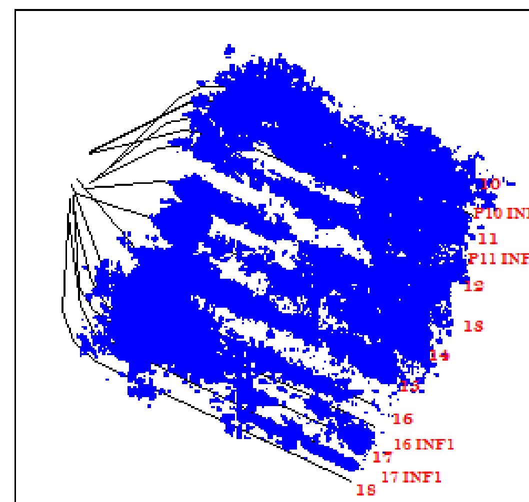


- 4D anomaly volumes have increased.
- Continued conformance improvement along Well Pad 10, 11, 16, 17.
- Infill wells drilled between Well Pads 10, 11, 12, 16, 17 and 18 to optimize production in a geological more complex zone.

101 South 8th monitor - March 2014



101 South 9th monitor - March 2015

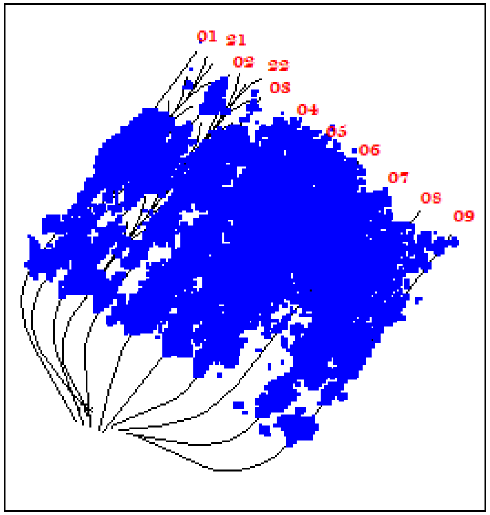


= 4D anomaly
~60 deg C Isotherm

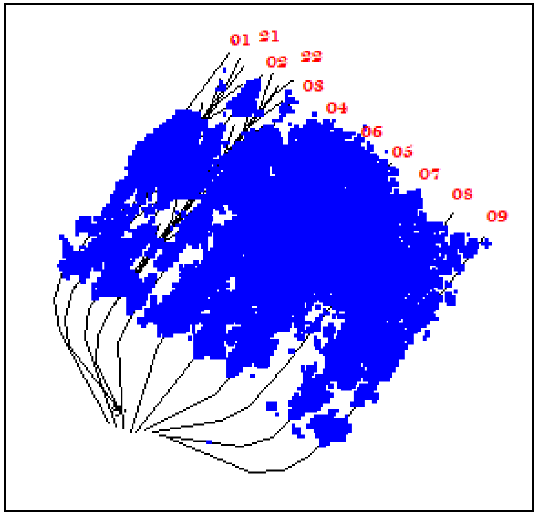
2016 4D Seismic Results Pad 102 (102S)

- No a significant 4D Thermal growth between the Monitors

102 North 9th monitor - April 2015

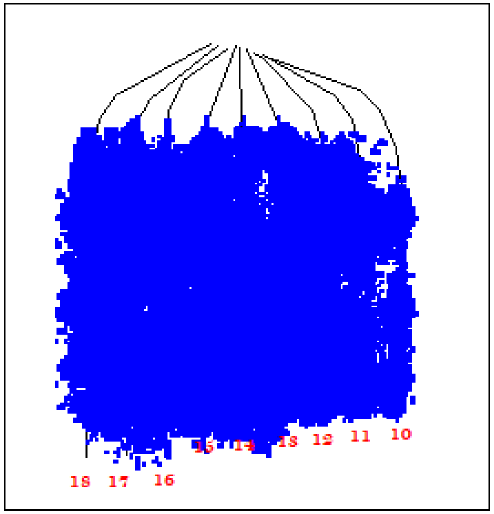


102 North 10th monitor - October 2018

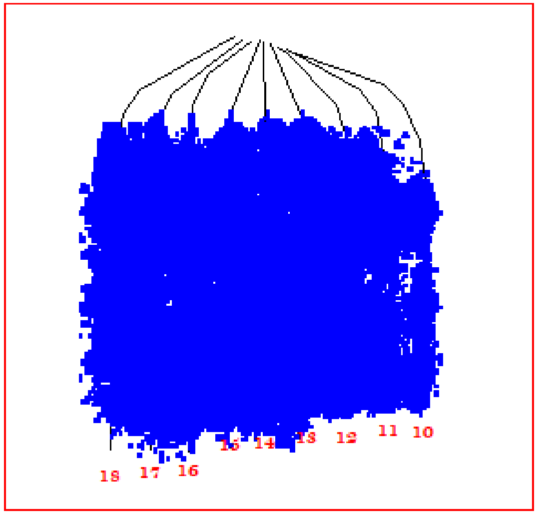


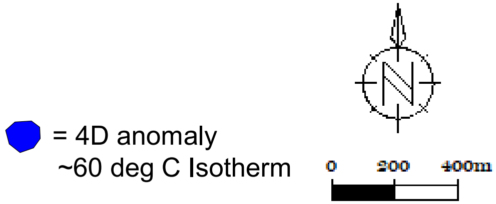
•No a significant 4D Thermal growth between the Monitors

102 South 6th monitor -October 2016

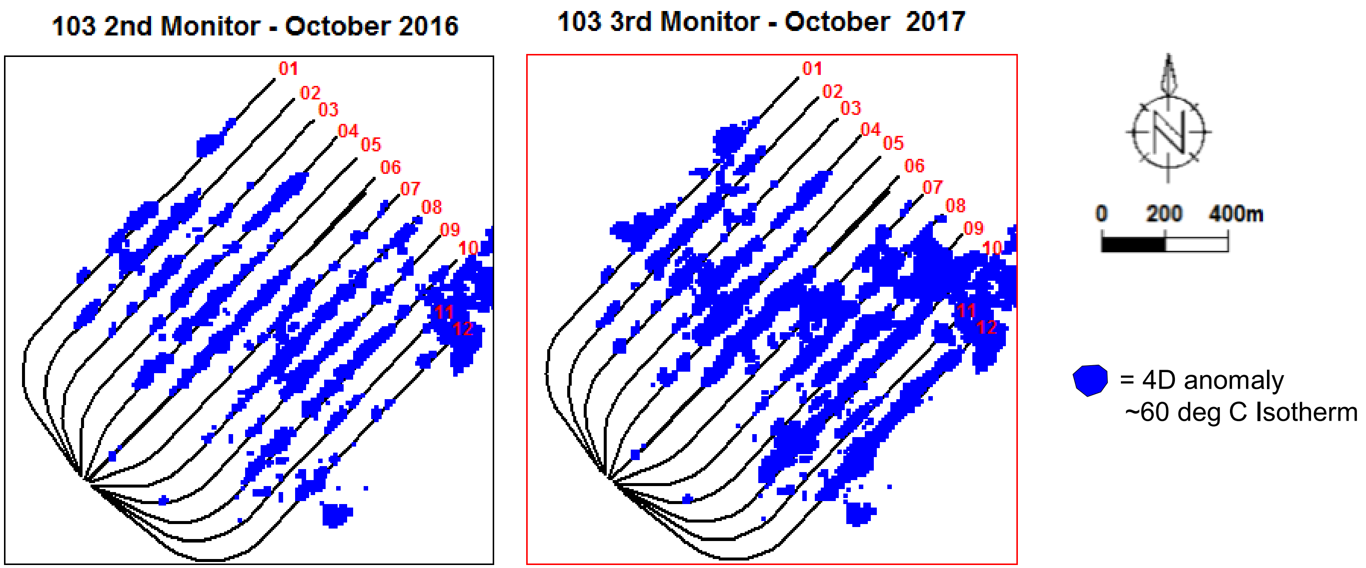


102 South 7th monitor - October 2018





2017 4D Seismic Results Pad 103

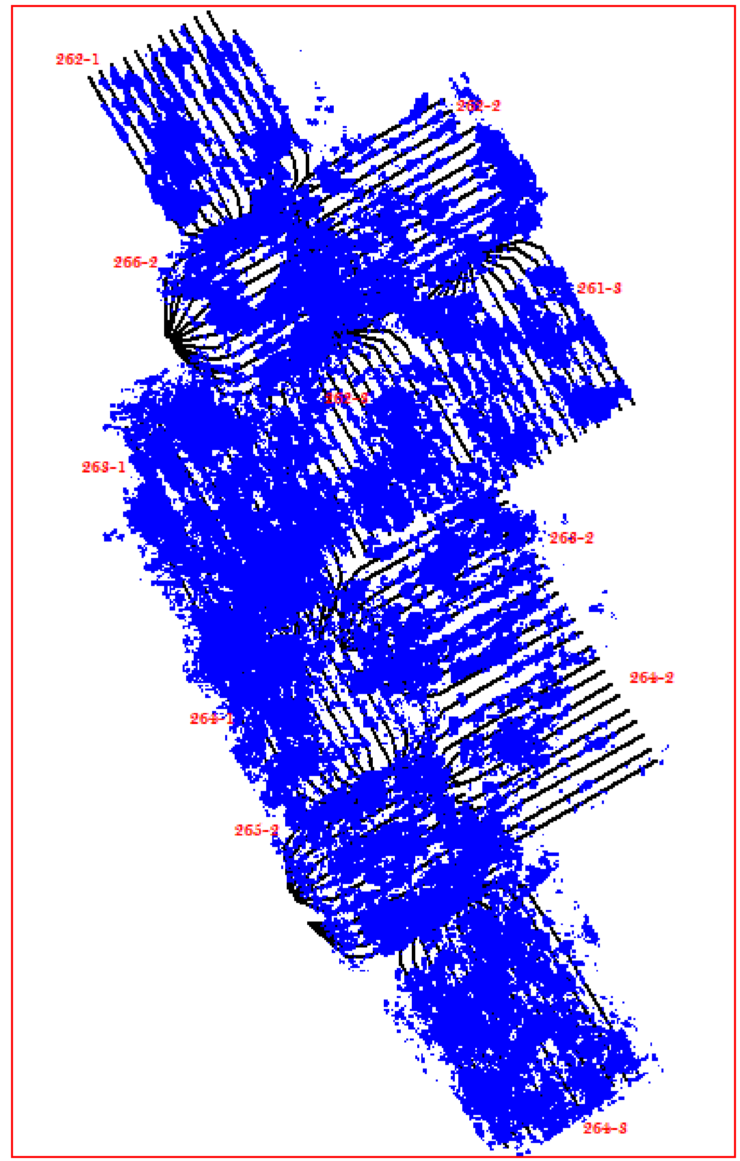


- **Relative good conformance in most of well pair.**
- **4D indications of coalescence with thermal chamber of Pad 101N (103-08/12)**

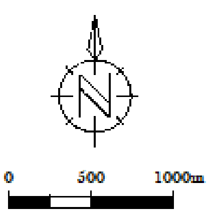
2018 4D Seismic Results Phase 2

- **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)

S2 Monitors - 2018 (Spring - Fall)



= 4D anomaly
~60 deg C Isotherm



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4D Seismic Program 2018

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

- 4D correlates with observation well data.

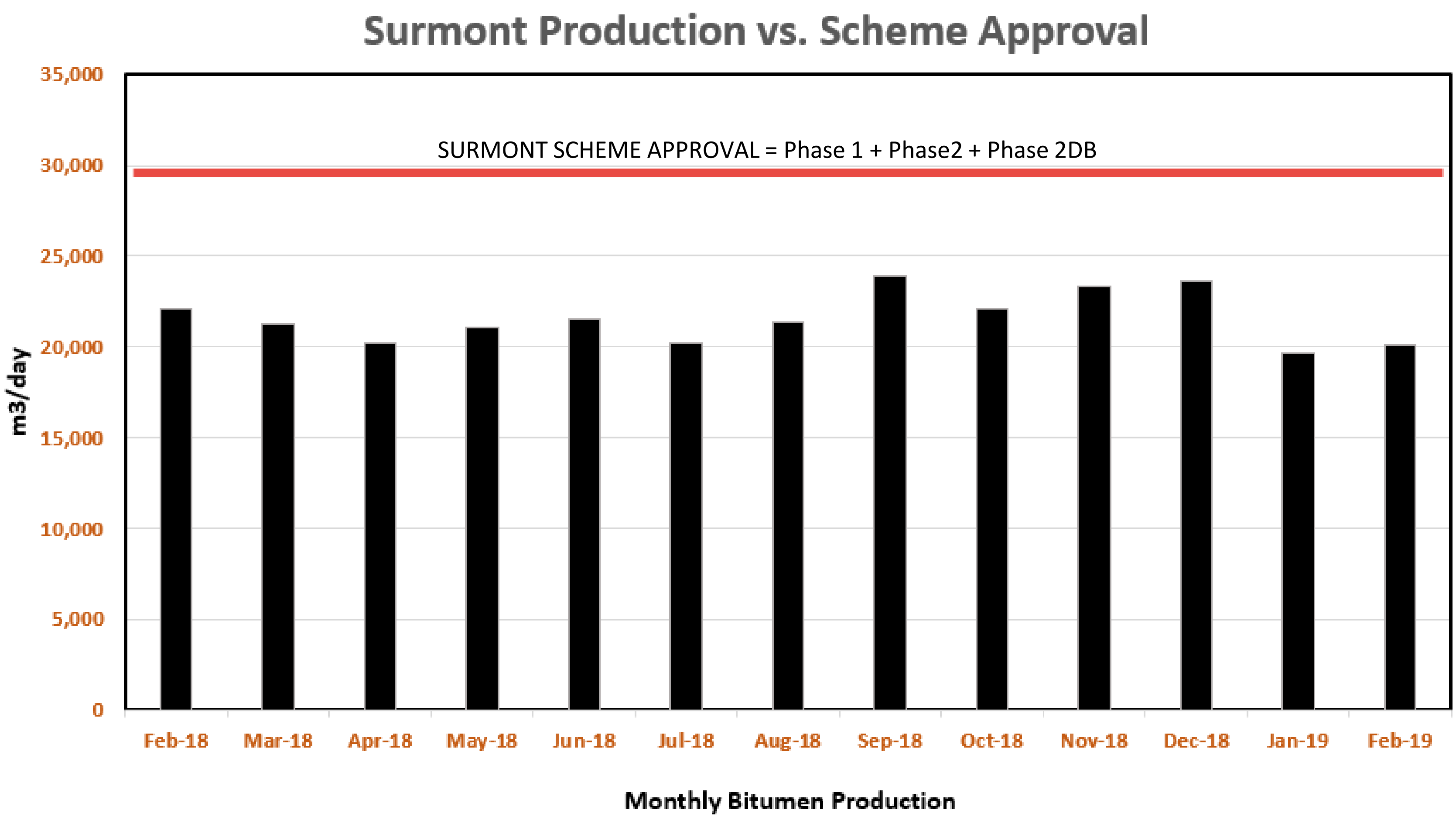
- Continuing to optimize heel/toe production/injection splits using 4D results.

- Ongoing efforts to history match reservoir models using 4D seismic.

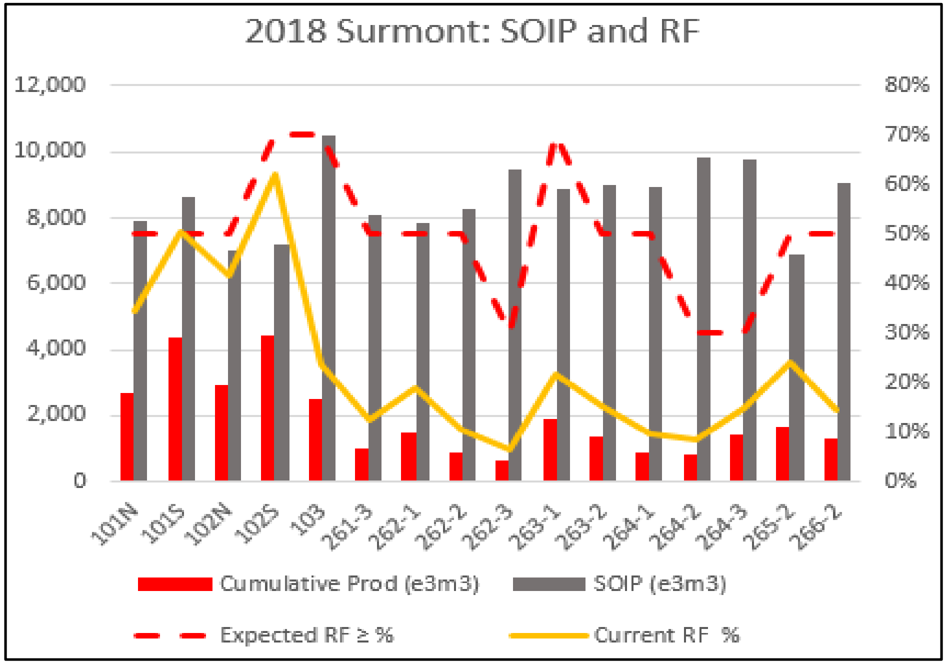
Scheme Performance

Subsection 3.1.1 (7)

Surmont: Production vs. Scheme Approval



Surmont: Phase 1 and 2 - SOIP and RF

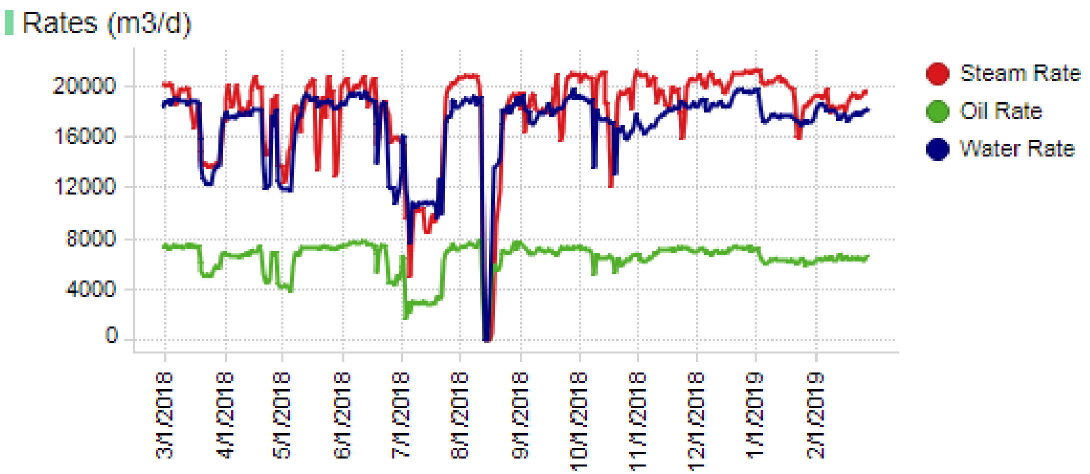


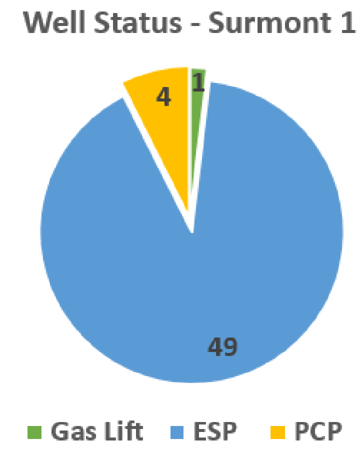
DA	Area (m2)	Thickness NCB (m)	Phie in NCB %	So in NCB %	Cumulative Prod (e3M3)	SOIP (e3m3)	Current RF %
101N	1,090,775	35.53	32.58	82.40	2,706	7,884	34.33
101S	1,064,692	37.43	33.19	80.41	4,363	8,647	50.46
102N	975,251	31.14	32.71	80.29	2,908	6,992	41.60
102S	1,019,252	34.17	31.32	74.33	4,442	7,165	61.99
103	1,022,239	42.8	32.21	78.62	2,492	10,504	23.72
261-3	1,000,542	44.77	32.00	78.07	1,002	8,071	12.41
262-1	996,252	39.59	31.74	80.05	1,478	7,863	18.80
262-2	974,291	38.63	33.13	78.56	859	8,286	10.37
262-3	943,213	44.28	32.76	78.21	623	9,445	6.59
263-1	1,271,315	36.14	32.98	79.36	1,925	8,854	21.74
263-2	998,219	40.9	32.44	78.06	1,356	8,978	15.10
264-1	1,033,834	39.45	32.89	79.71	864	8,901	9.71
264-2	1,011,337	42.08	32.65	78.22	834	9,860	8.46
264-3	1,209,485	37.51	31.97	75.58	1,442	9,803	14.71
265-2	917,433	38.75	32.54	76.83	1,668	6,910	24.14
266-2	949,974	42.99	32.83	80.08	1,312	9,040	14.52

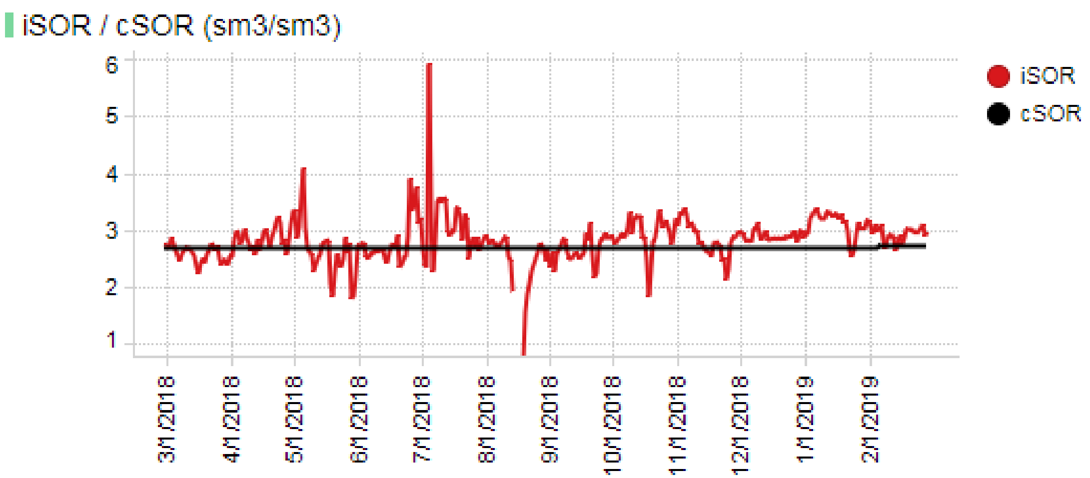
- **SOIP: 6,910 – 10,504 E3M3**
- **Current RF: 6.6% - 62.0%**
- **Porosity: 30.3% - 34.0%**
- **Oil saturation: 72.1% - 82.7%**
- **Blowdown timing will determine final EUR/RF.**
- **Recovery factors for drainage areas are based on performance. At this time, the expected ultimate recovery factor is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

	Expected Recovery Factor		
	Tier 1: RF ≥ 70%	Tier 2: RF ≥ 50%	Tier 3: RF ≥ 30%
101N		×	
101S		×	
102N		×	
102S	×		
103	×		
261-3		×	
262-1		×	
262-2		×	
262-3			×
263-1	×		
263-2		×	
264-1		×	
264-2			×
264-3			×
265-2		×	
266-2		×	

Surmont Phase 1 Aggregate Performance Plots







- **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**

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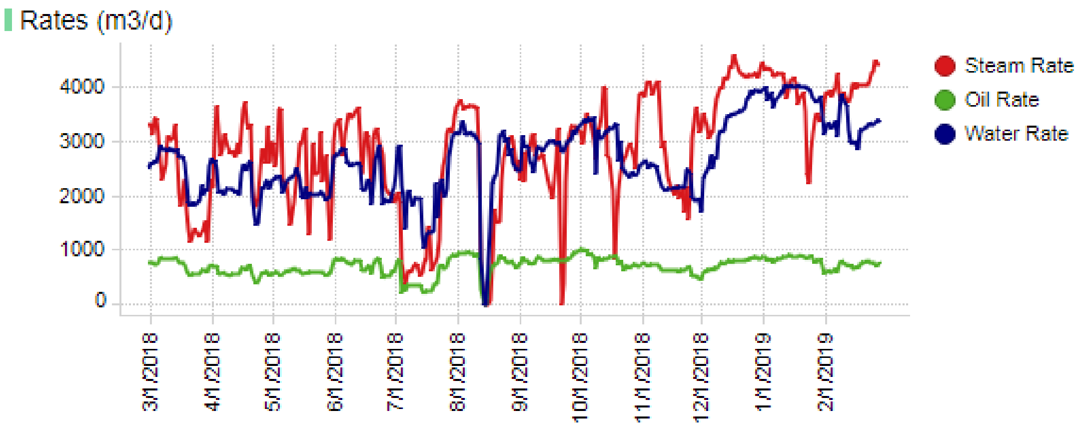
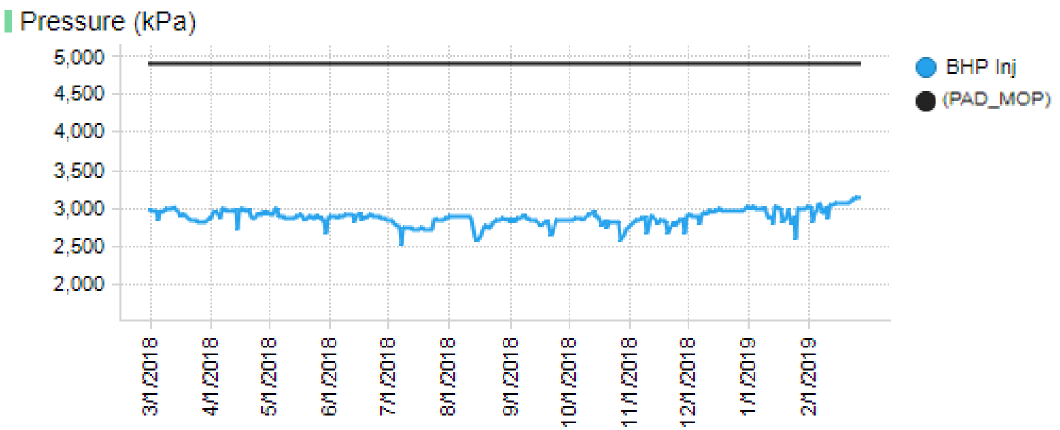
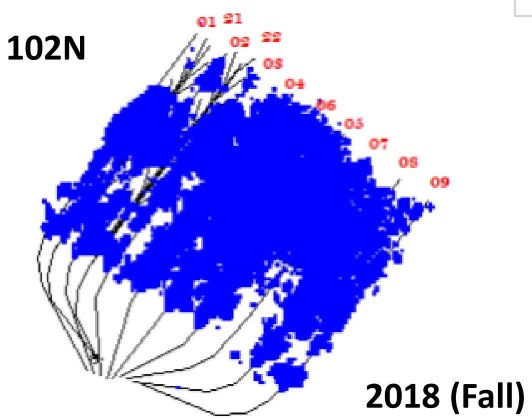
Performance / Chamber Development Challenges – Pad 102N

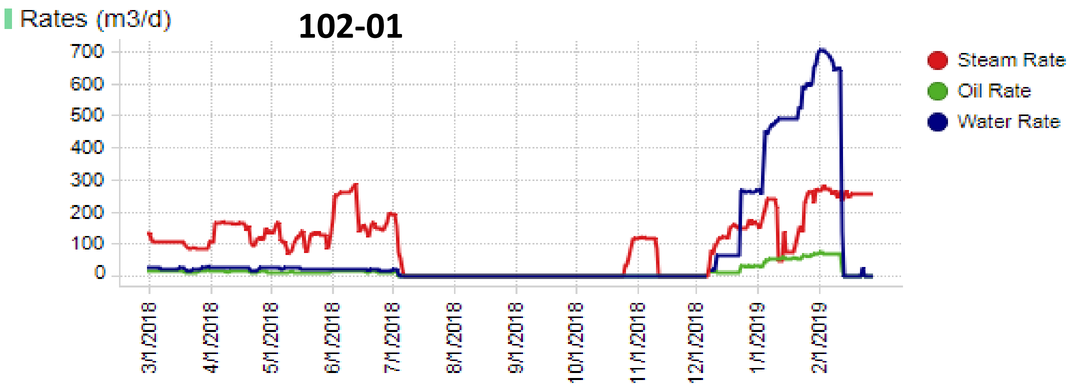


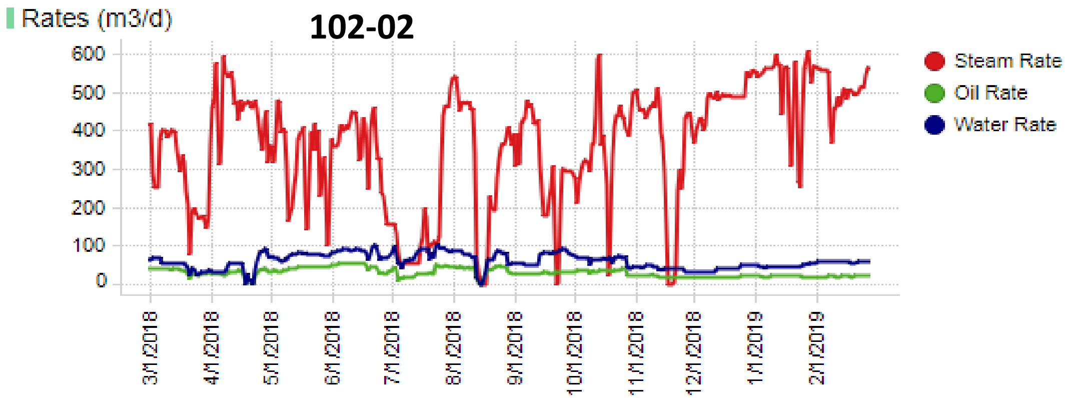


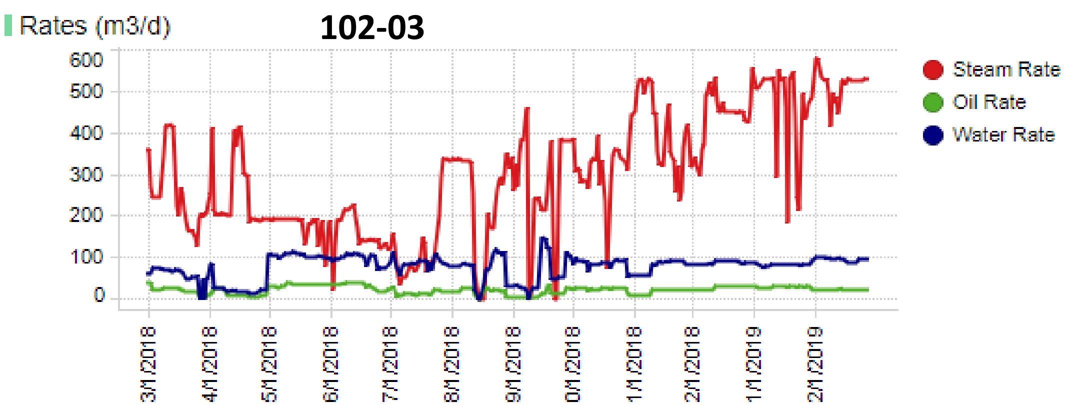


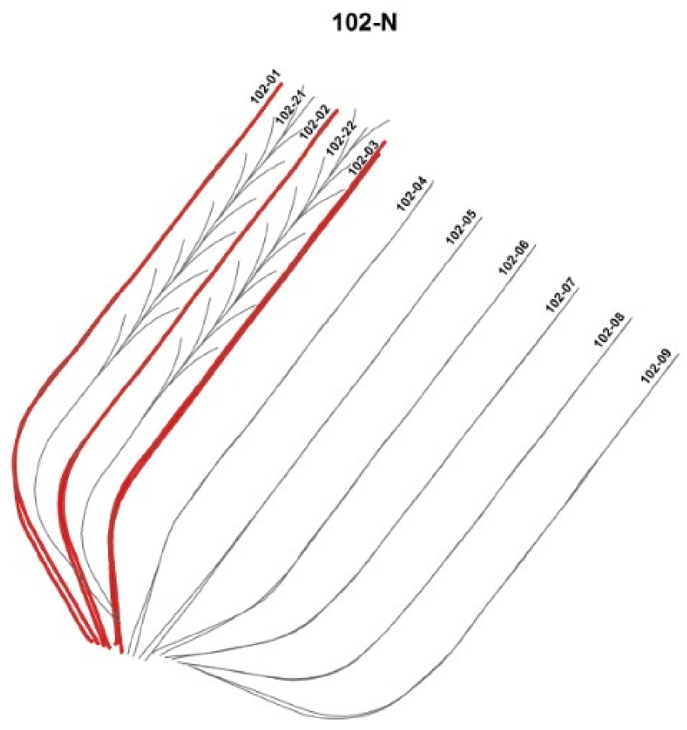
- **Performance and recovery on the west side of the pad has been challenged.**
- **NCG injection has commenced.**

Performance / Chamber Development Challenges – Pad 102N



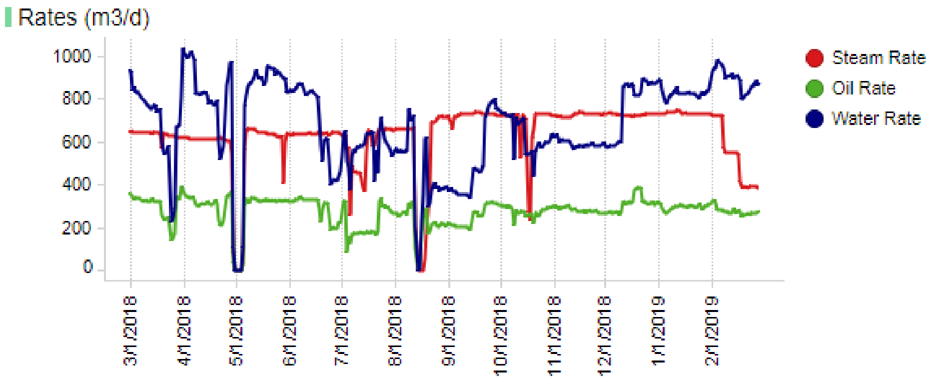


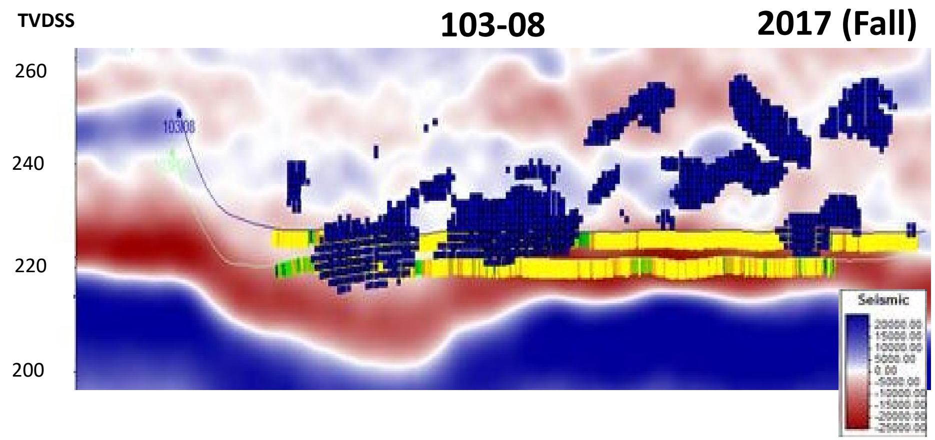


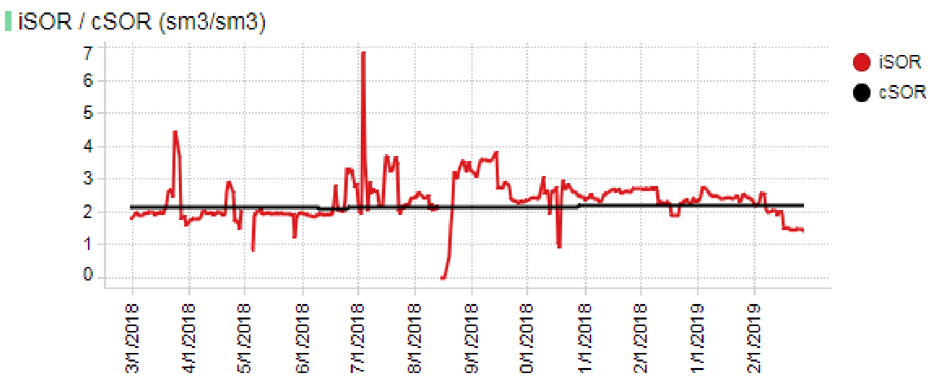


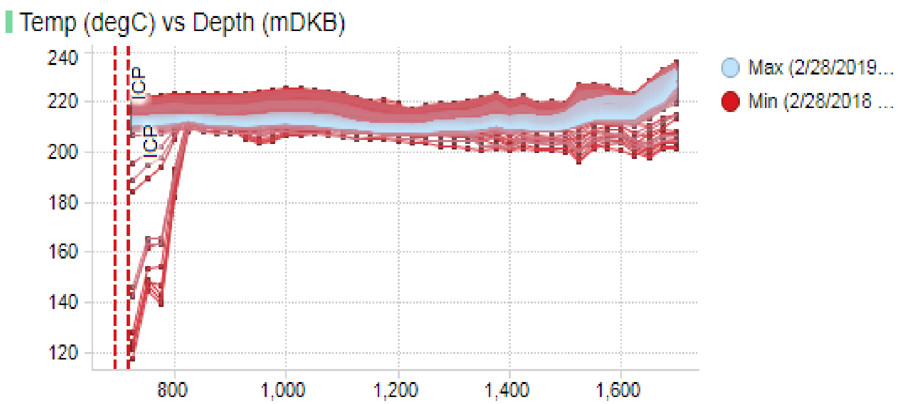
- **102-P01;02;03 have been the poorest producers on the pad due a combination of liner failures and poor geology.**
- **102-P01 was re-drilled and artificial lift was changed to ESP.**

Good Performance – WP 103-08



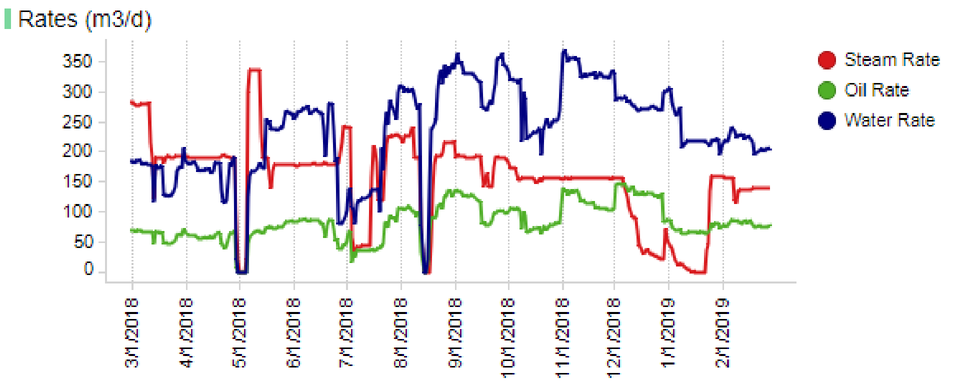


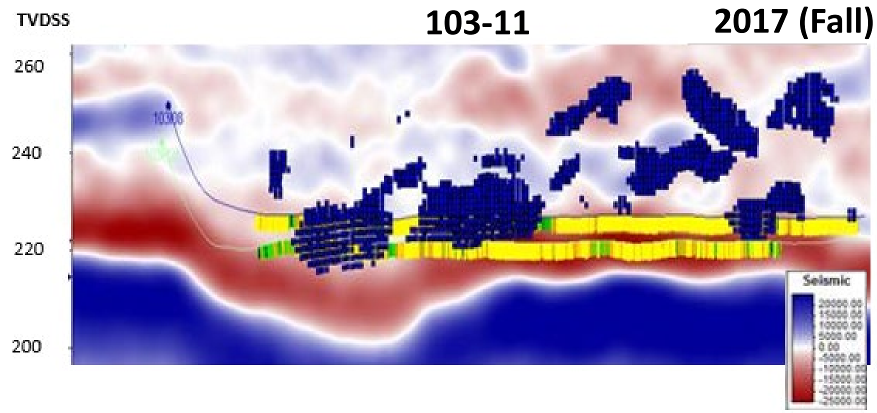


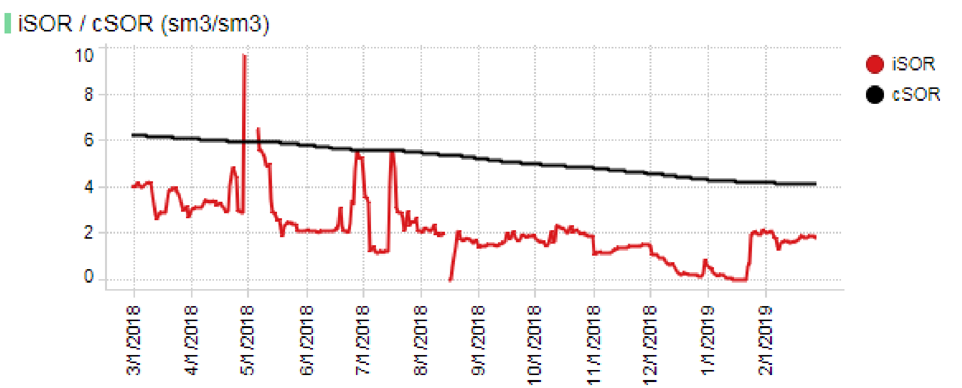


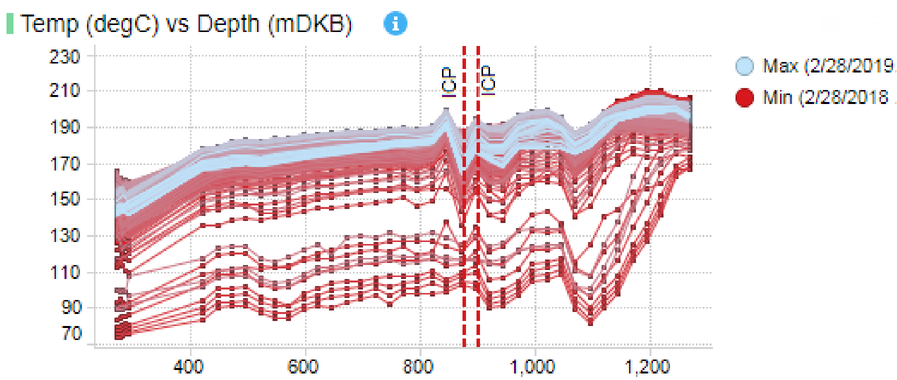
- **High quality reservoir.**
- **Falloff data and 4D seismic indicates well conformance.**

Average Performance – 103-11



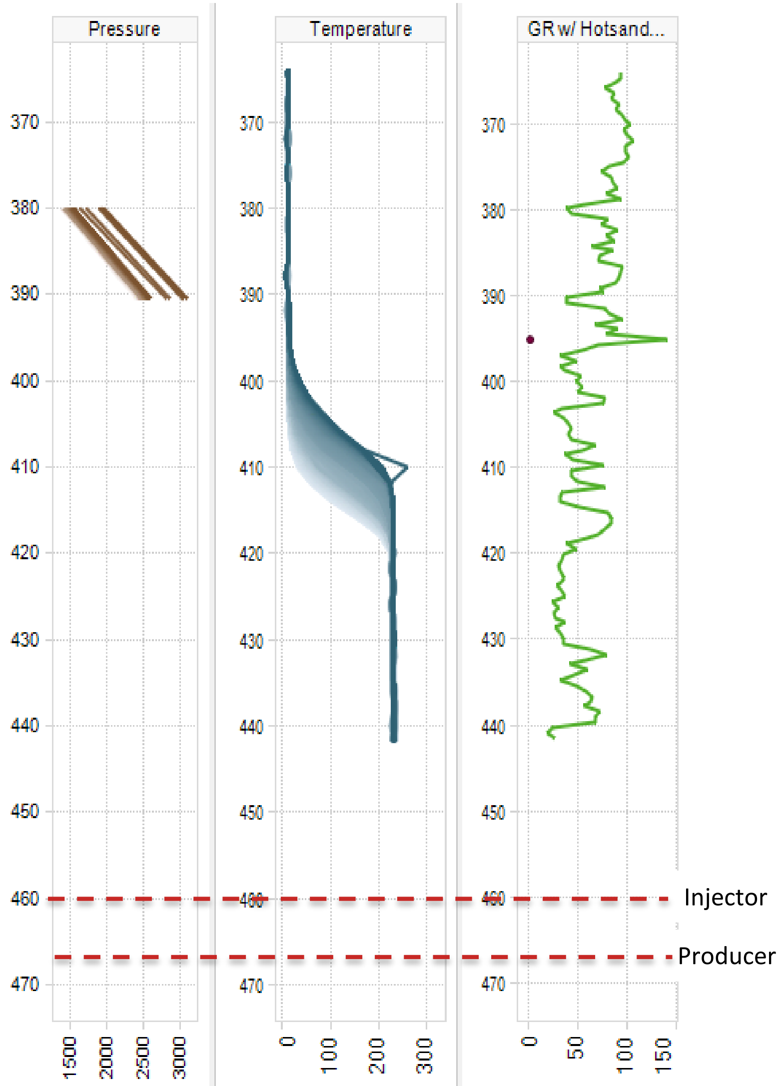




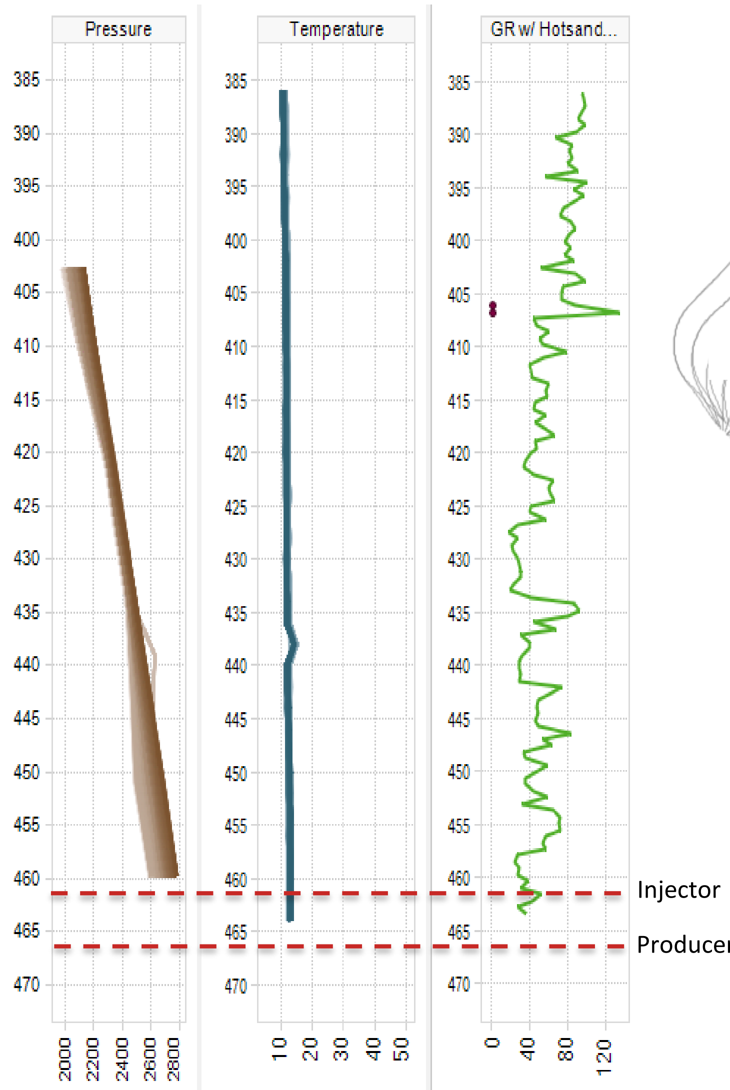


- **Poor conformance has seen this well perform average compared to others on this pad.**
- **Removed heel scab liner to help improve performance.**

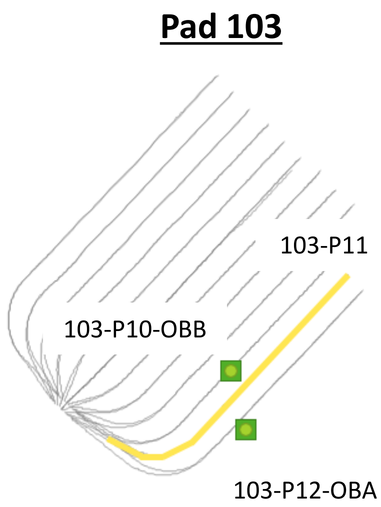
Obs Wells Temp & GR – 103-P10-OBB, 103-P12-OBA



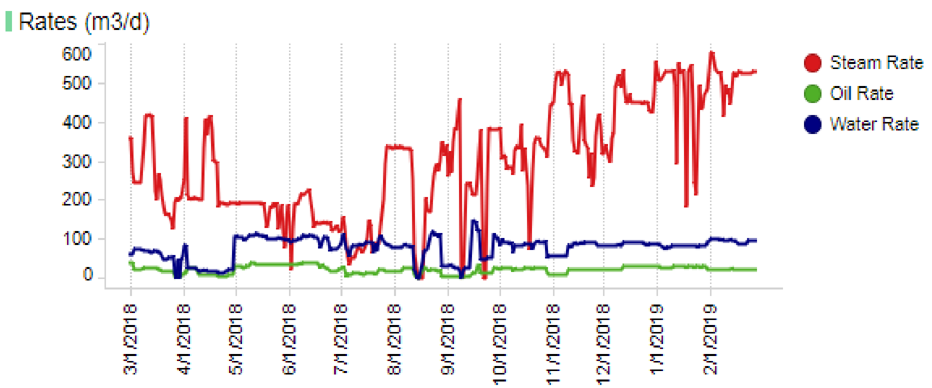
103-P10-OBB 100/03-23-083-07W4 / *3.3m offset*

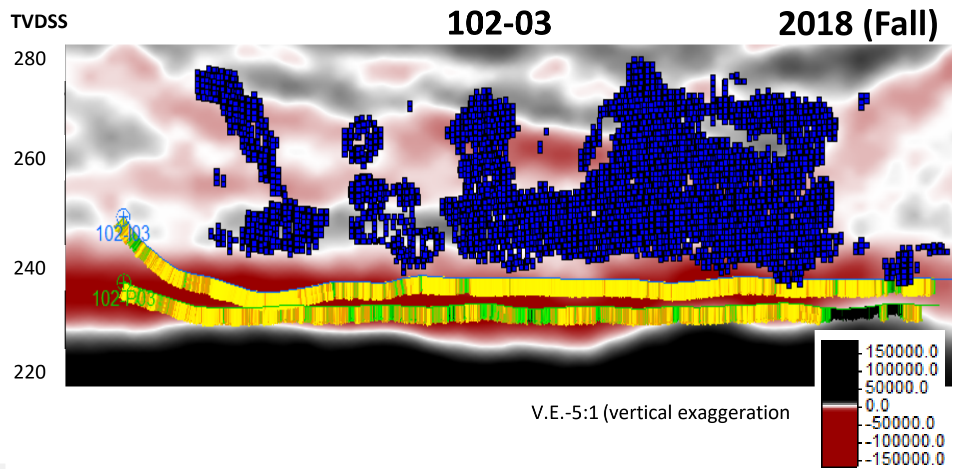


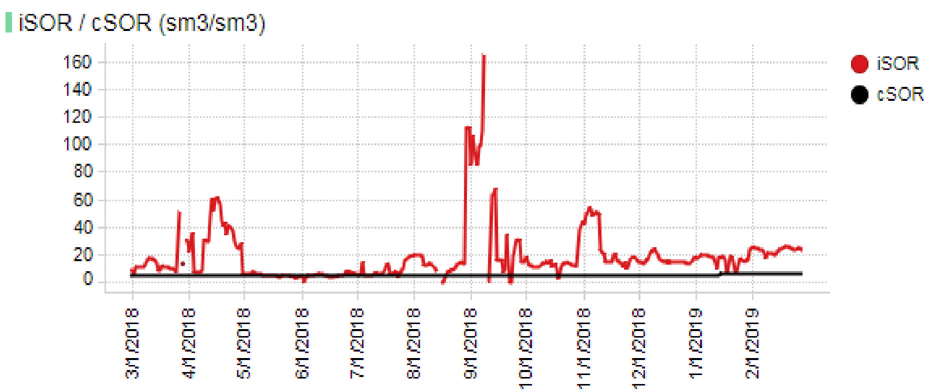
103-P12-OBA 105/14-14-083-07W4 / *41.3m offset*

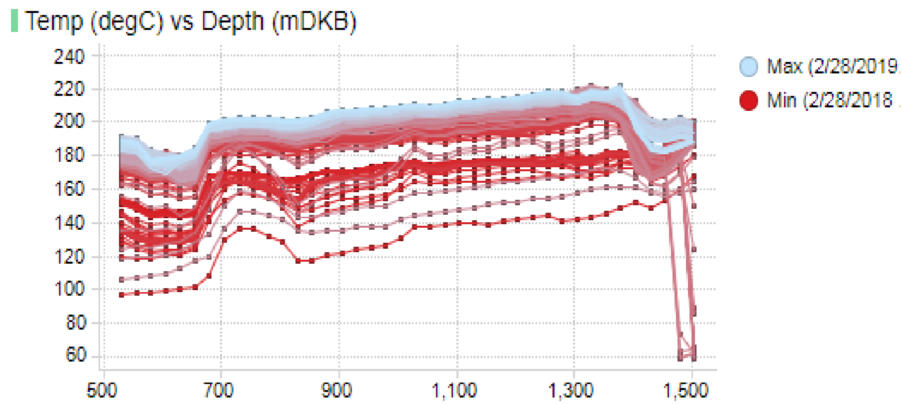


Poor Performance – WP 102-03









- **Recovery remains low, and a side-track re-drill is being considered to recover the lateral wellbore length and increase production.**

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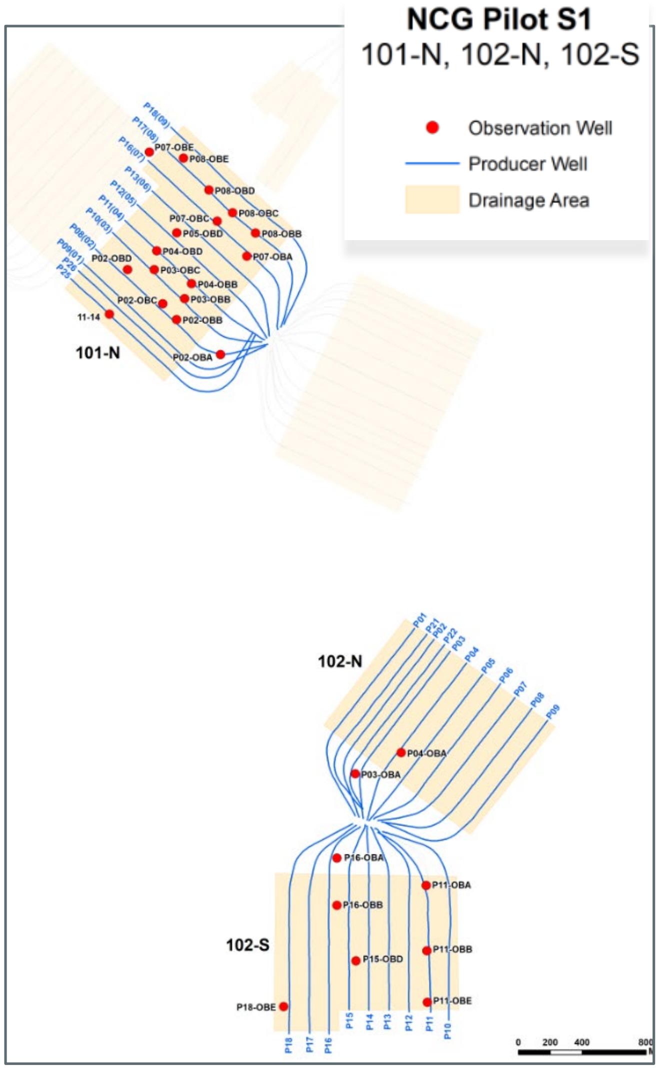
NCG Pilot / Pad 101N, 102N and 102S



Observations

- Reduction of emulsion rates
- Reduction of water cut

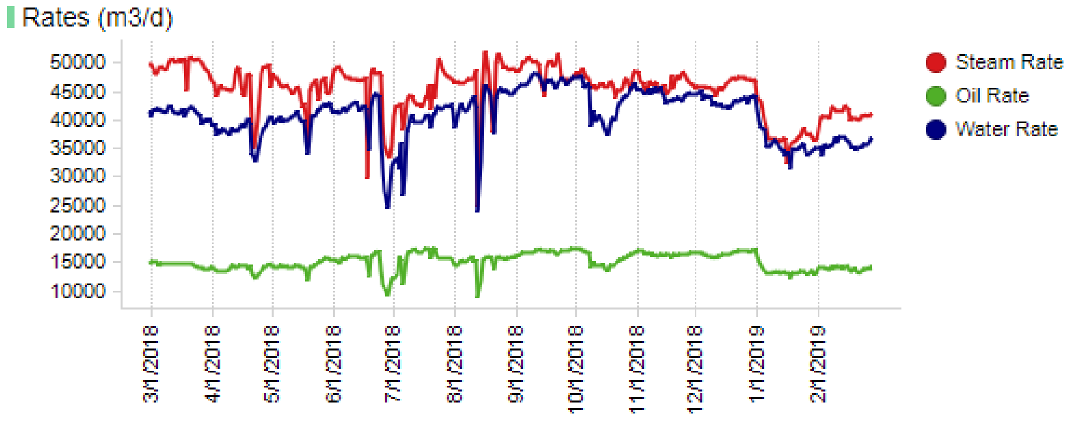
Oil rates flat

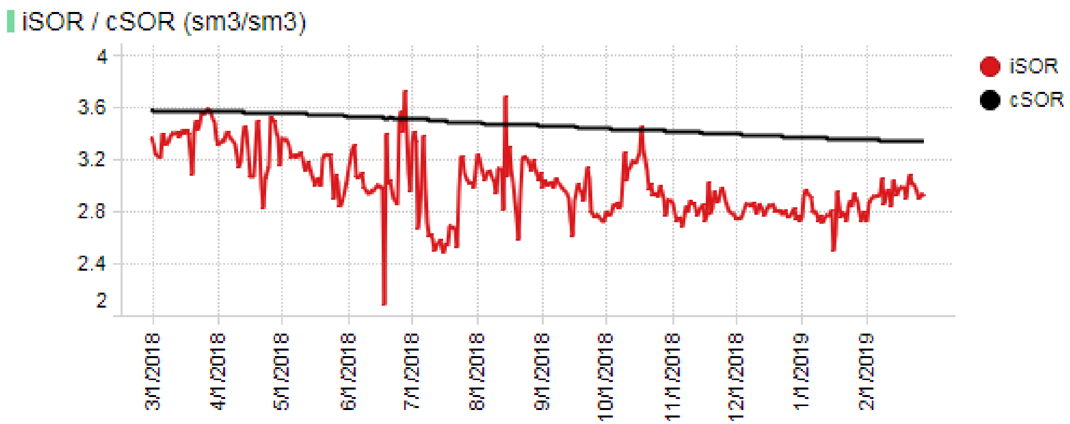
- iSOR reductions of 15-30%
- Increase in chamber pressures due to NCG injection
- Individual drainage areas under pilots are in full coalescence.

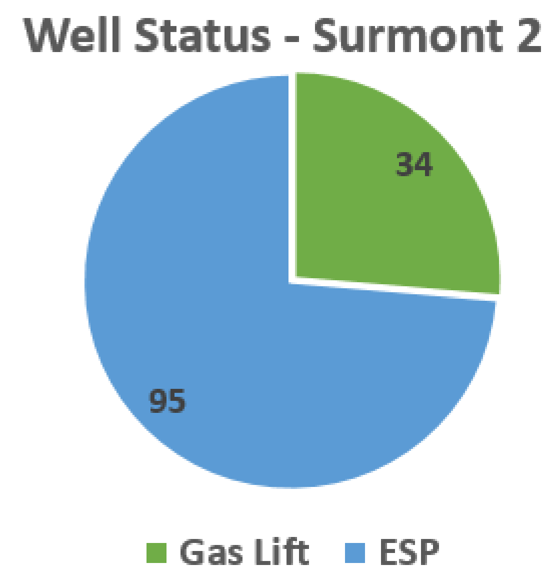
Phase 1 – Key Learnings

- 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.

Surmont Phase 2 Aggregate Performance Plots







- **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.**

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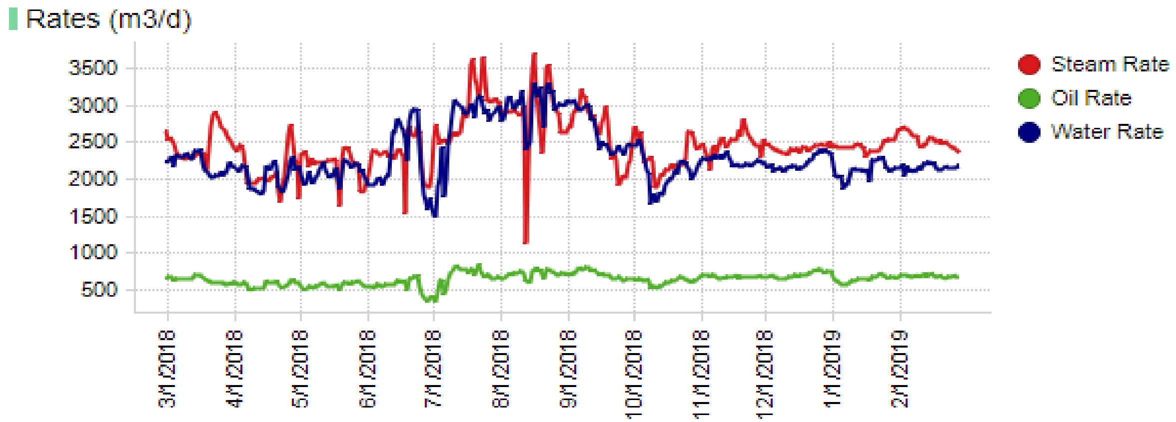
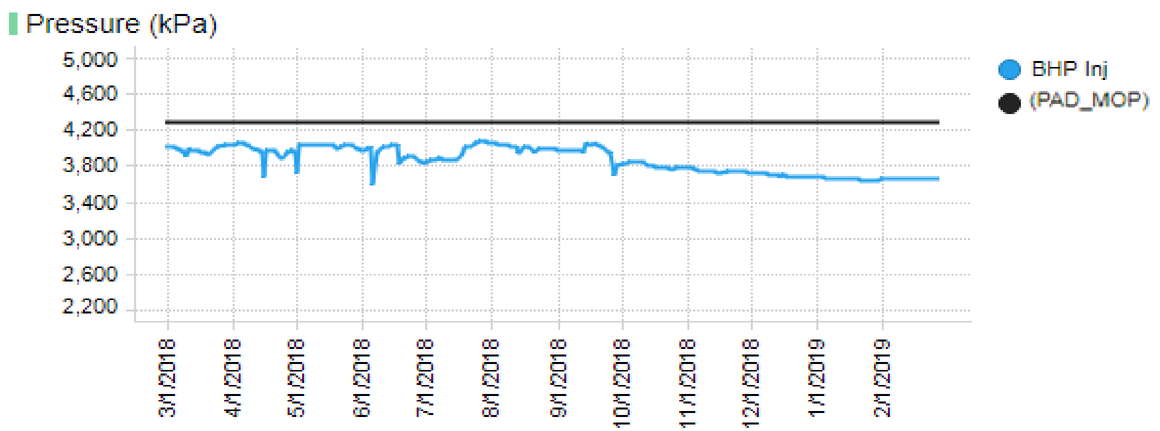
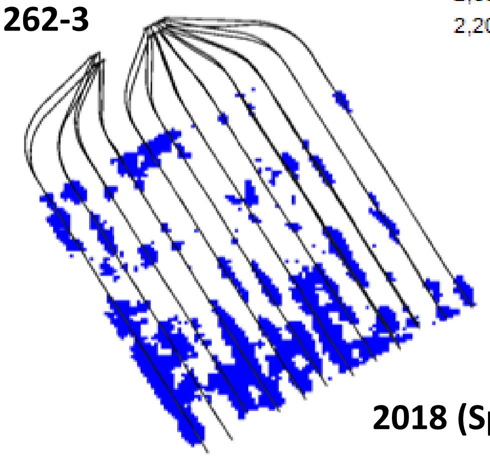
Performance / Chamber Development Challenges – Pad 262-3





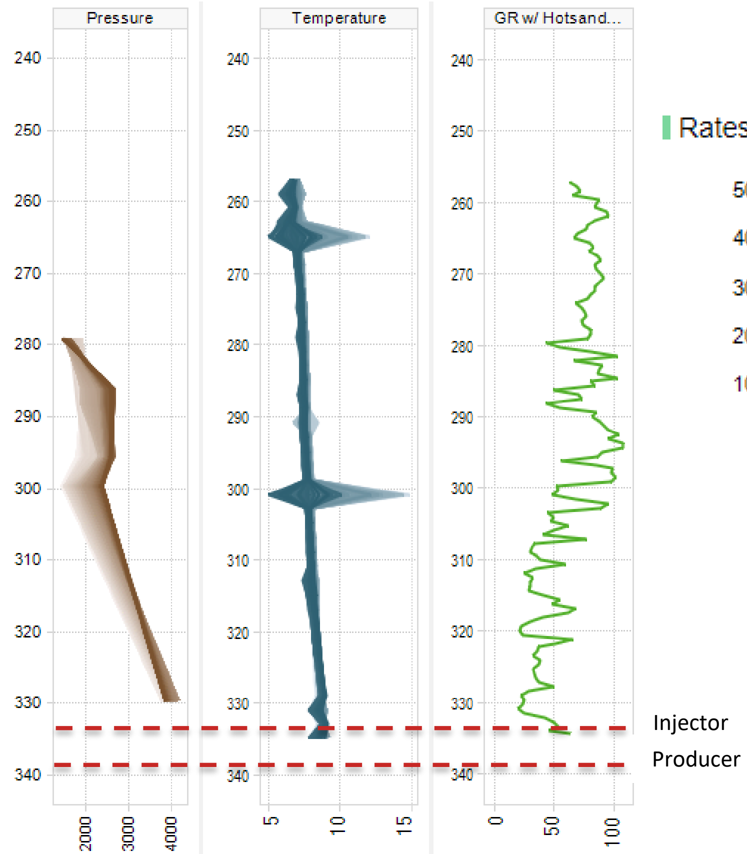
262-3



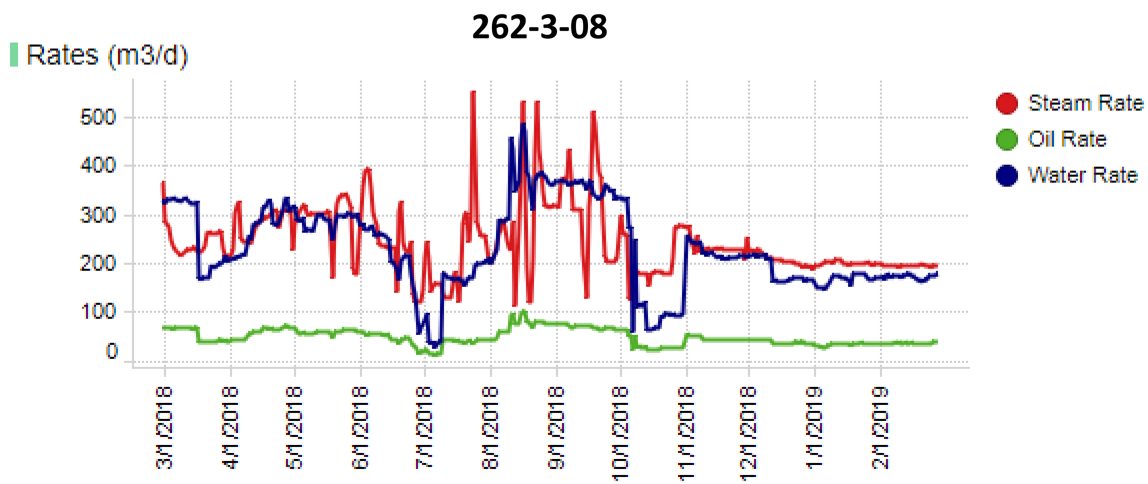
2018 (Spring)

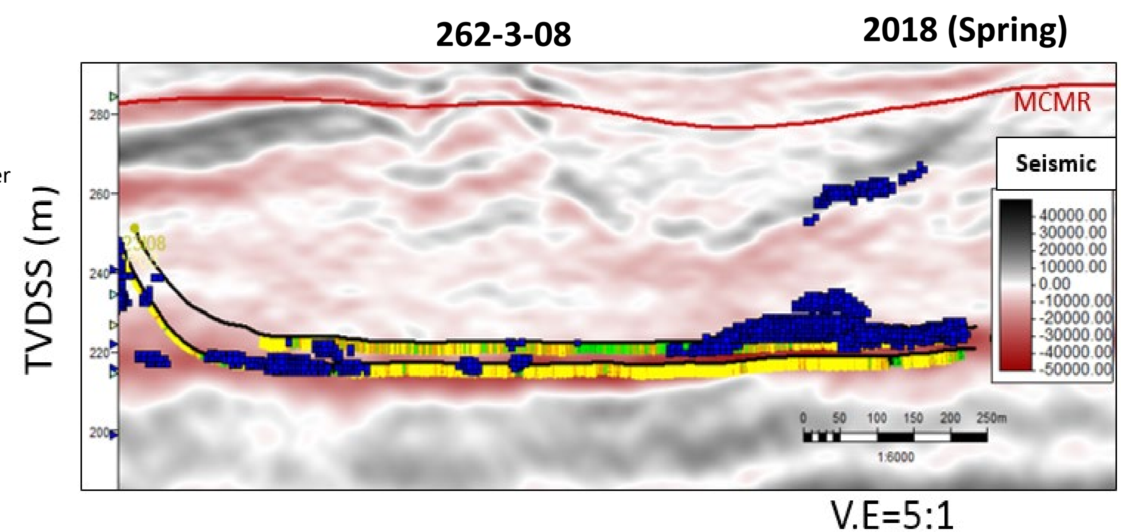
- **262-3 was operating at a target pressure of 4,000 kPag for most of 2018 but was reduced to 3,800 kPag in Q4.**
- **Challenged performance from East to West.**
- **No thief zone issues.**

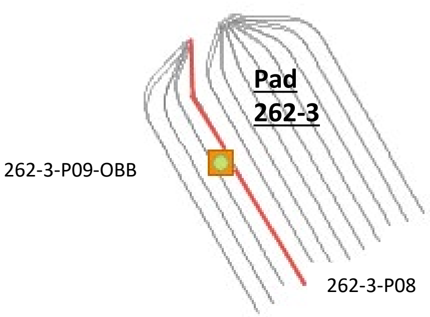
Performance / Chamber Development Challenges – Pad 262-3



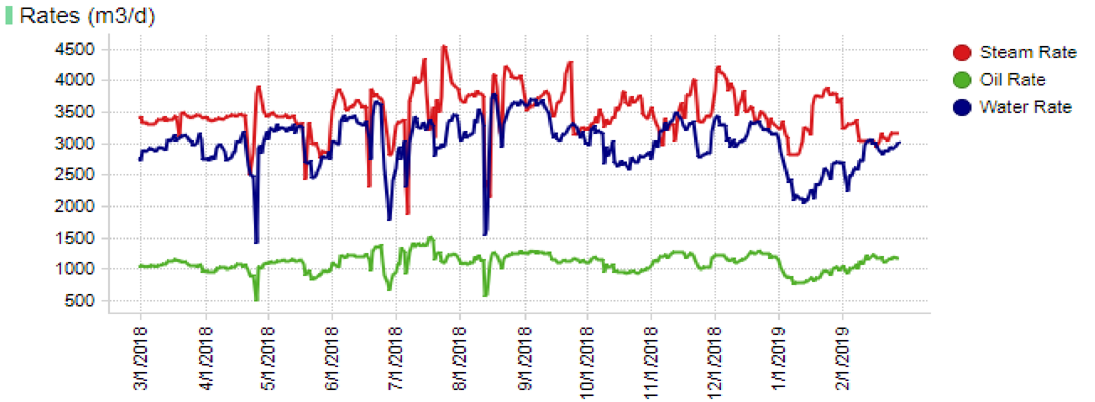
262-3-P09-OBB 35.7 meters from well pair

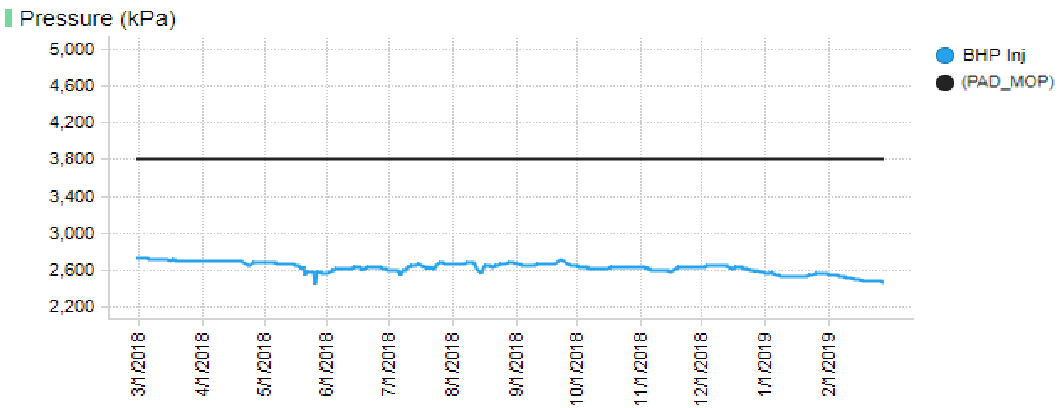


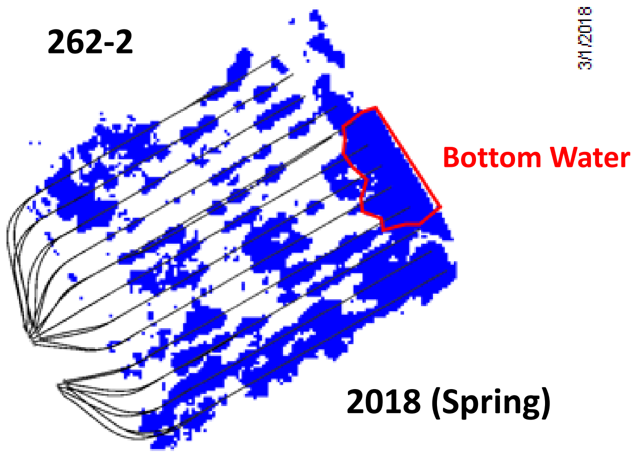




- **Limited chamber growth**

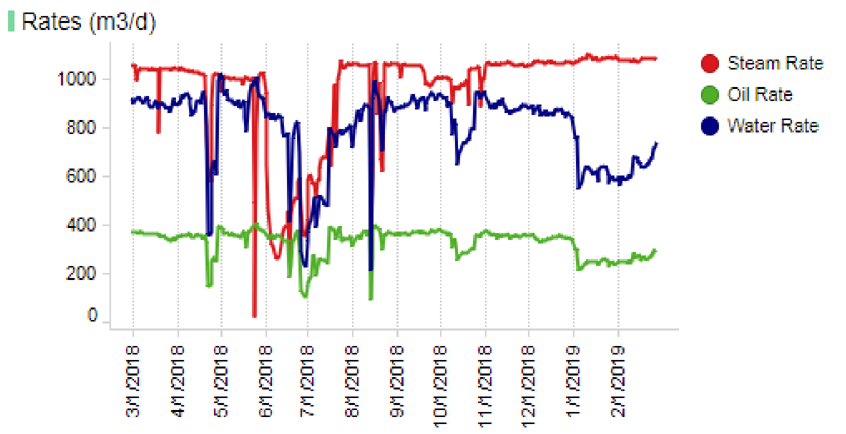


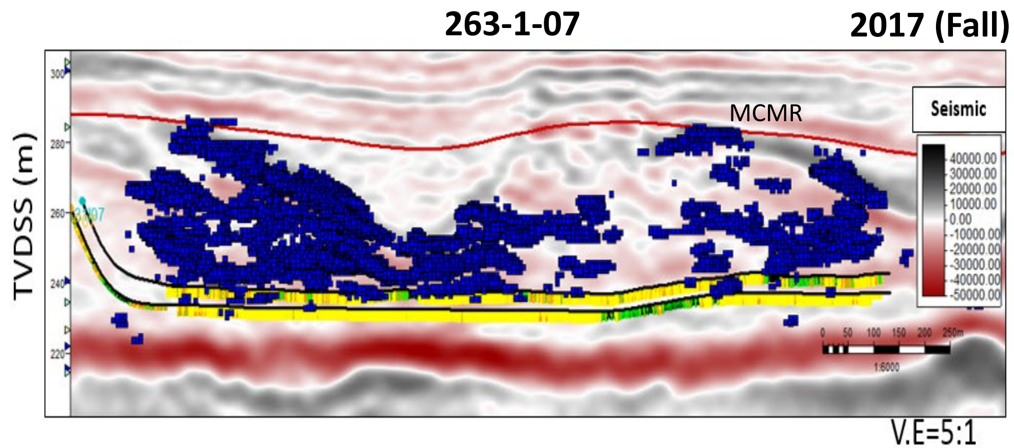


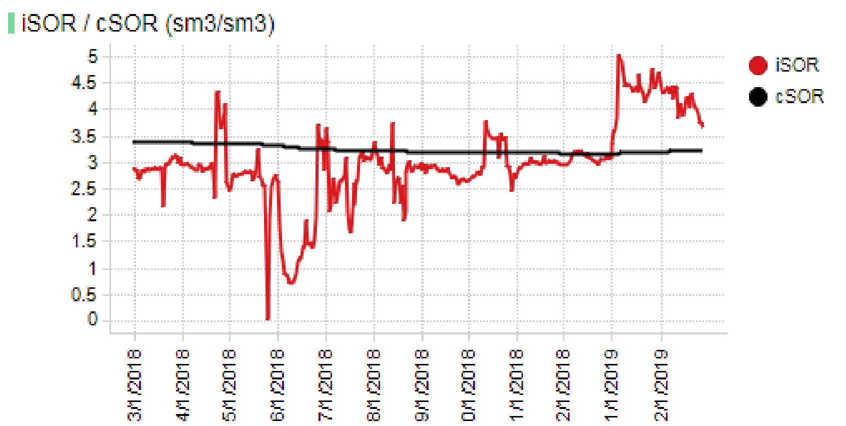


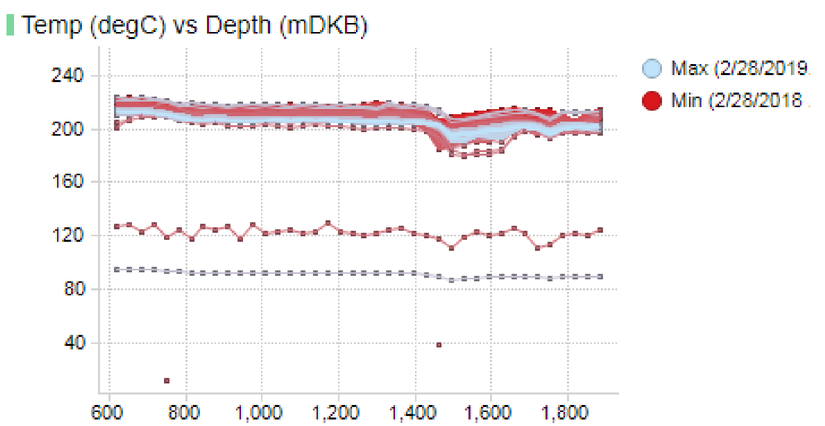
- **Severe bottom water interaction on many well pairs.**
- **Reduced pressure differential between chamber and low pressure bottom water on wells that are interacting with the bottom water.**

Good Performance – 263-1-07









- **Well Performance continues to exceed expectations.**
- **Mud channel continues to cause challenges with hotspots.**

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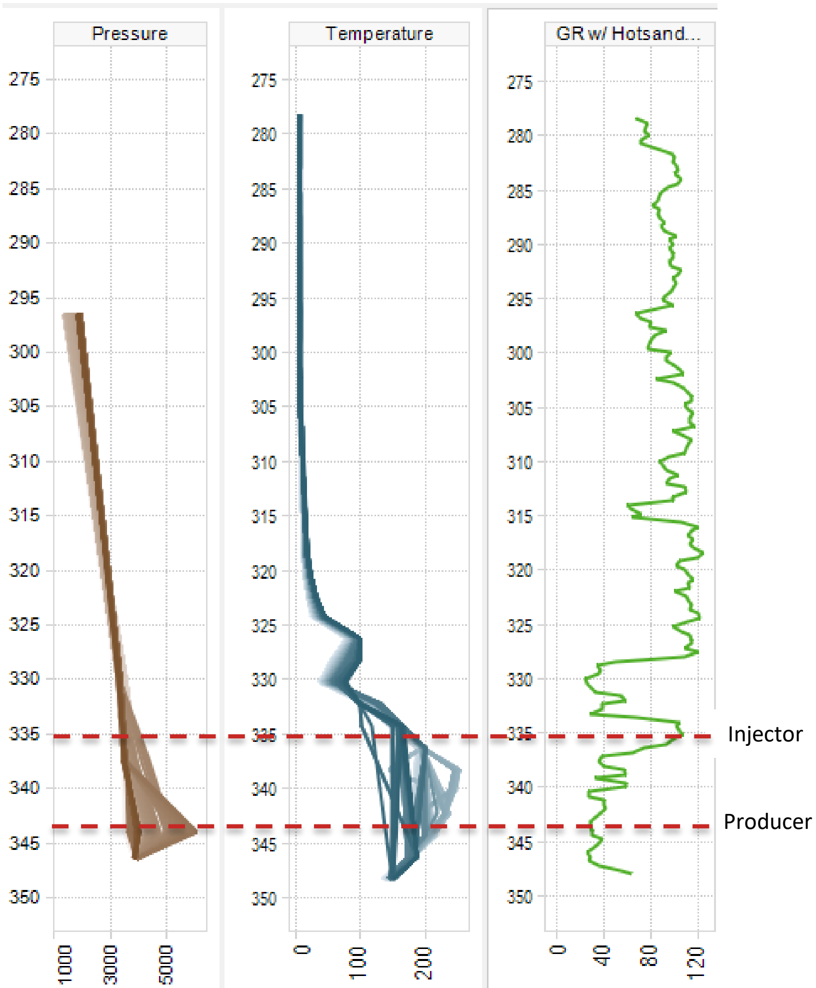
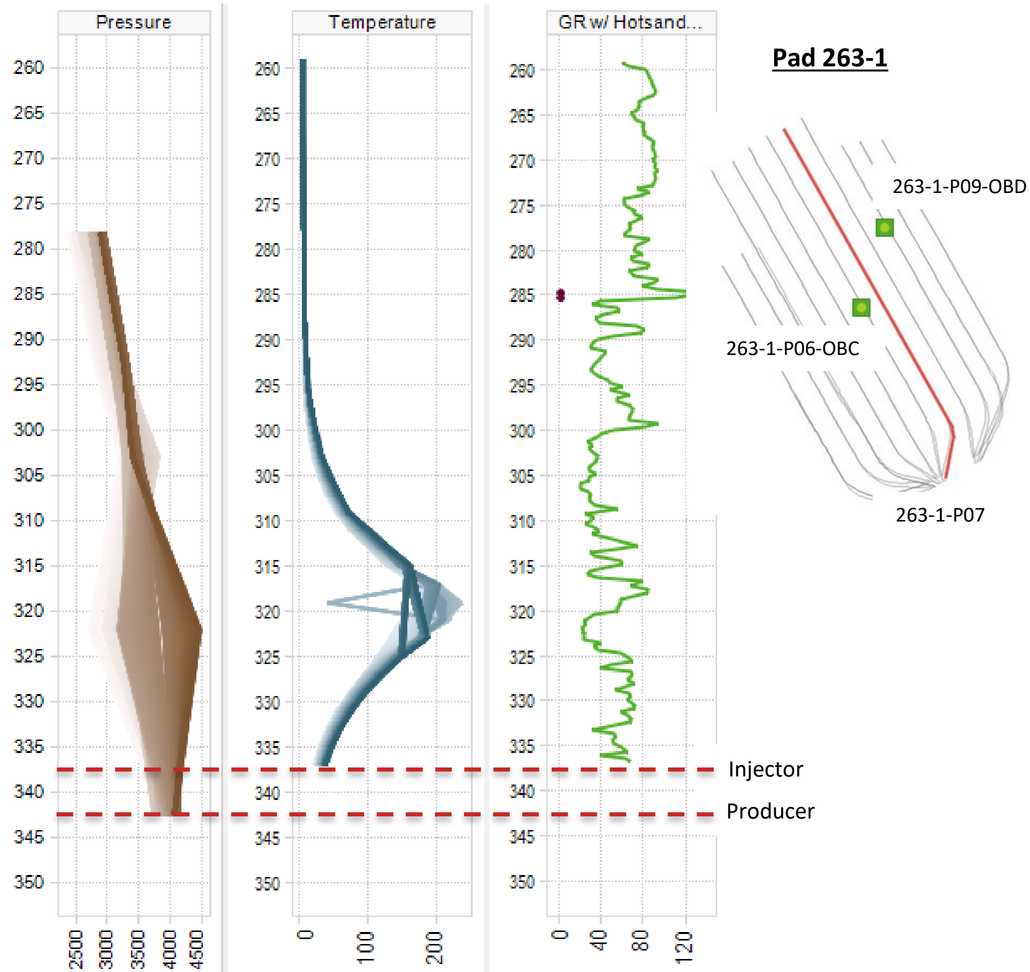
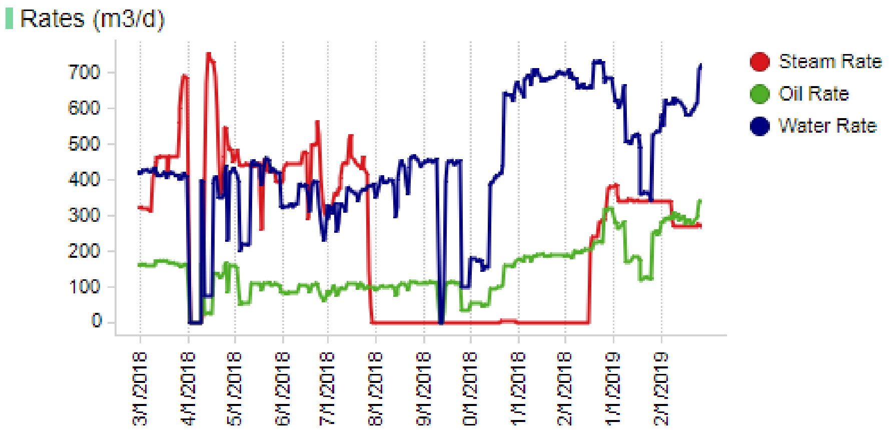


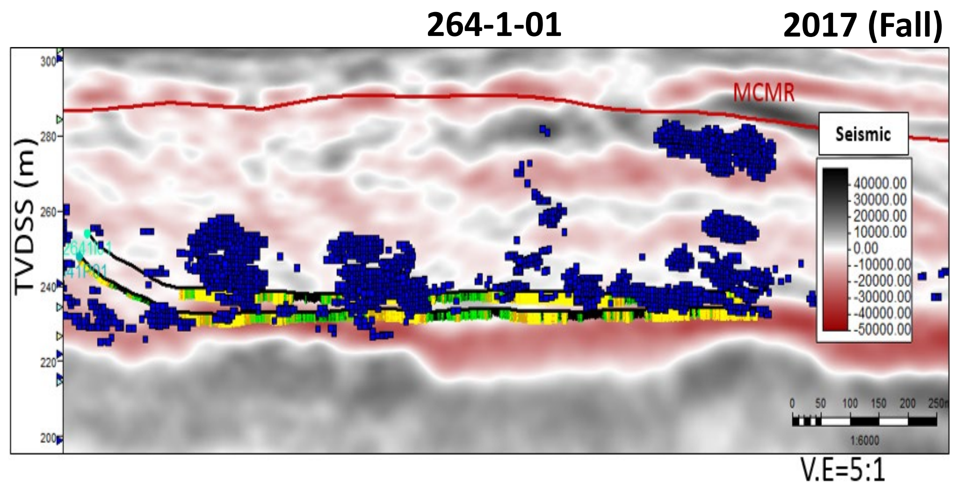
263-1-P06-OBC 103/12-27-083-06W4 / *8.9m offset*

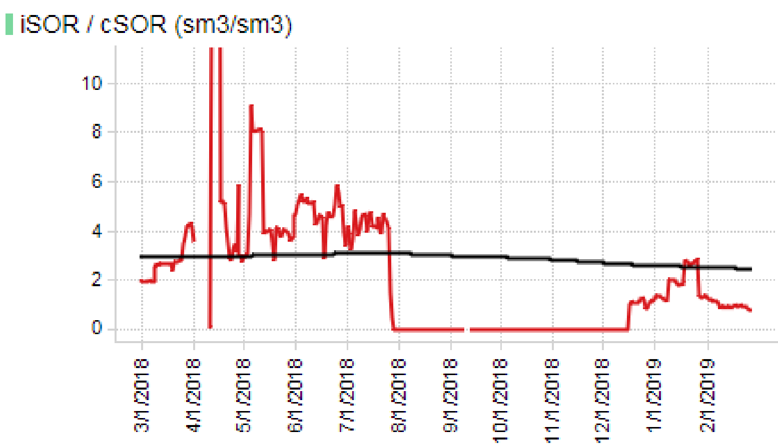


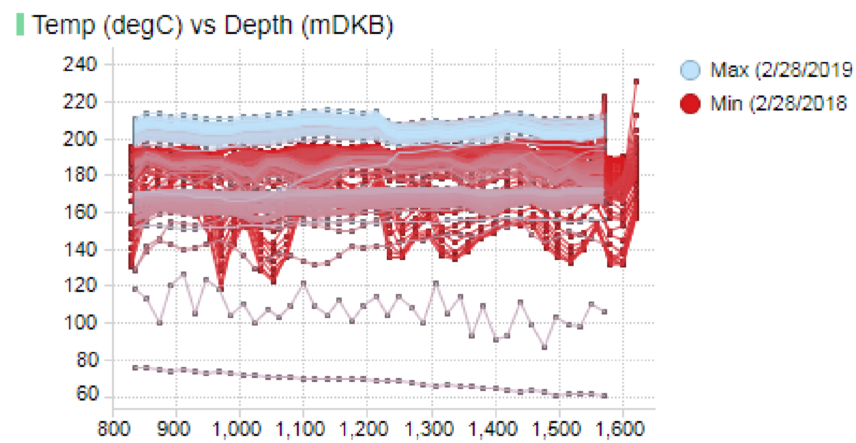
263-1-P09-OBD 102/12-27-083-06W4 *11.0m offset*

Average Performance – WP 264-1-01



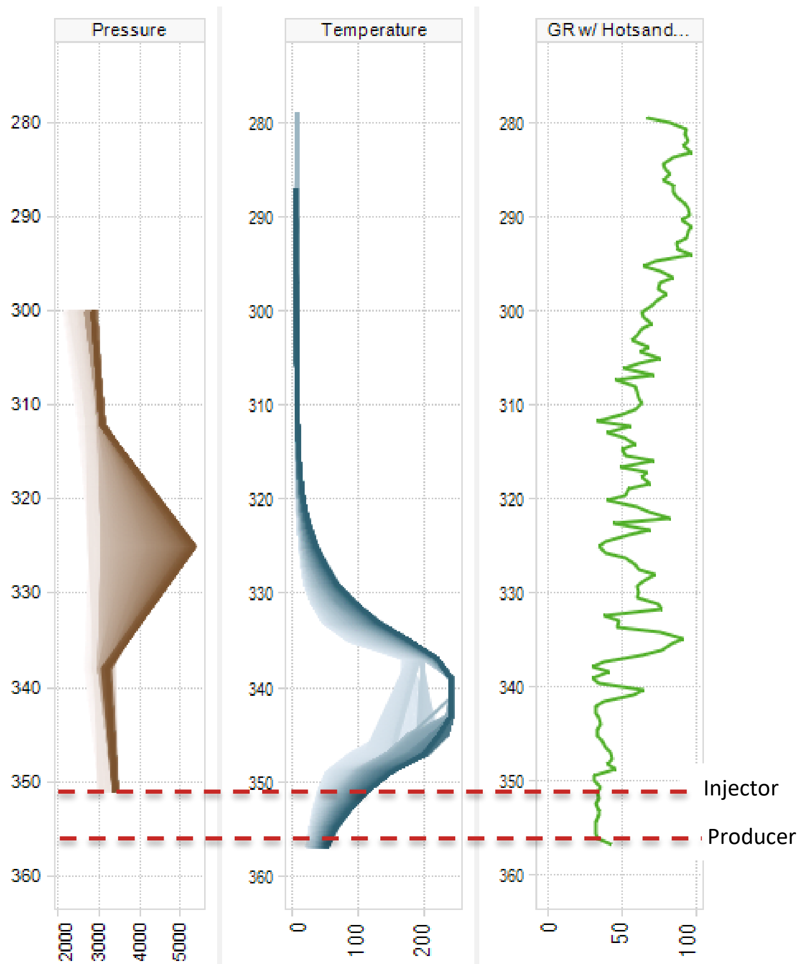




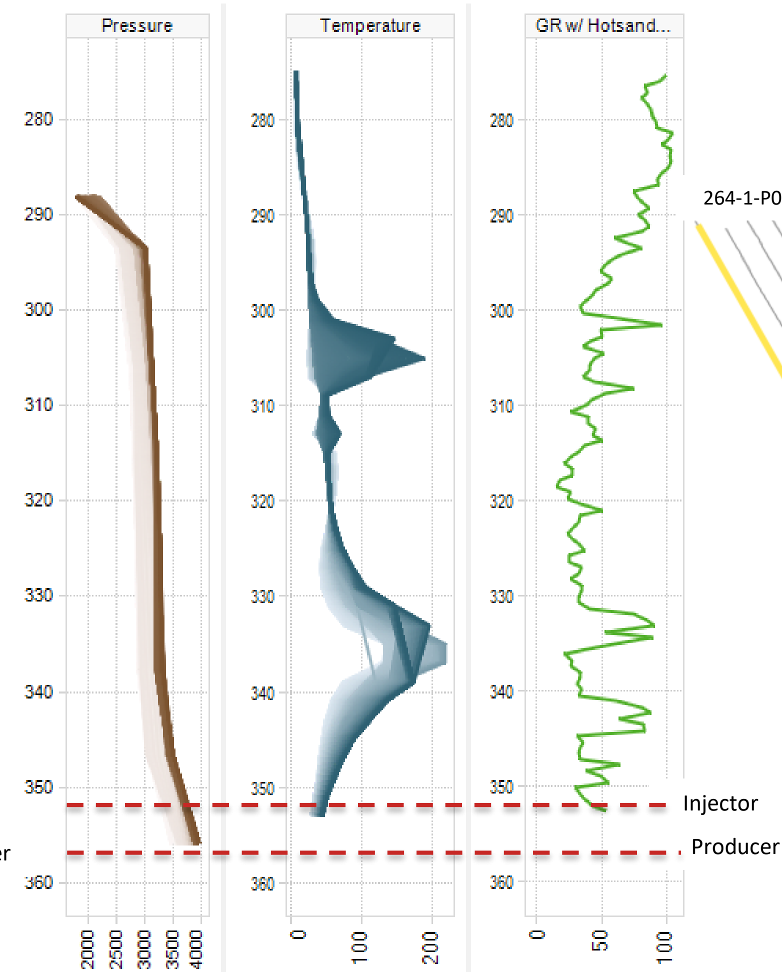


- **Stable 2018 production performance, meets expectations.**
- **Managed top thief zone interaction with dedicated pressure management.**

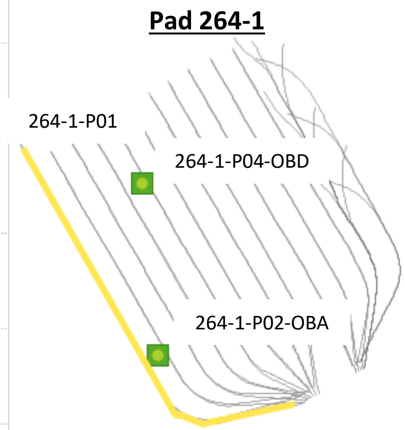
Surmont: Obs Wells Temp & GR – 264-1-P02-OBA, 264-1-P04-OBD



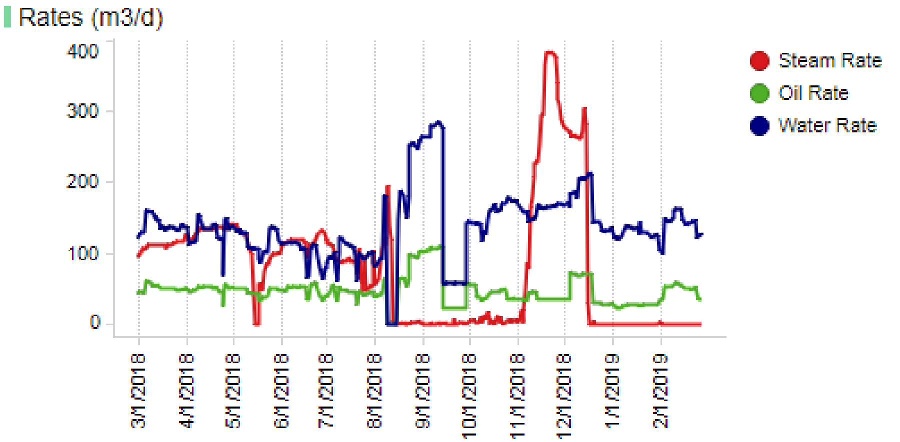
264-1-P02-OBA 102/11-22-083-06W4 / *33.5m offset*

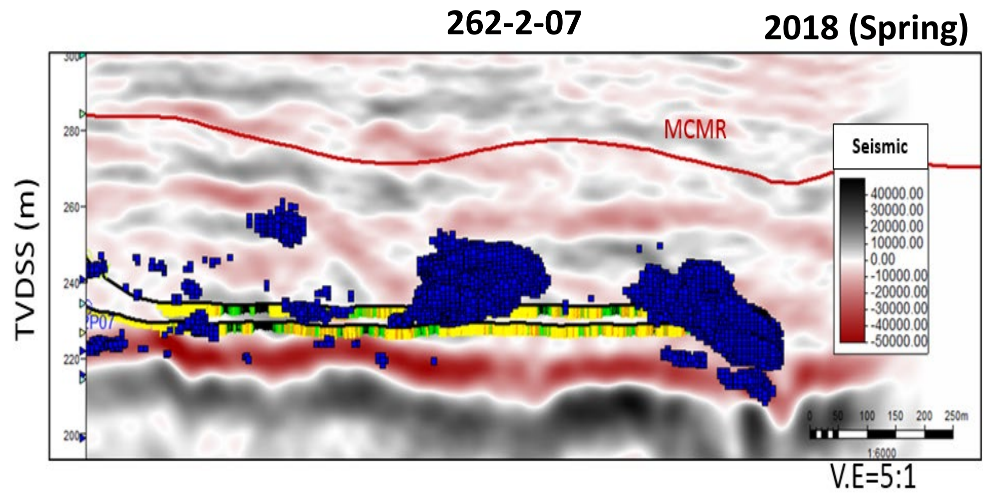


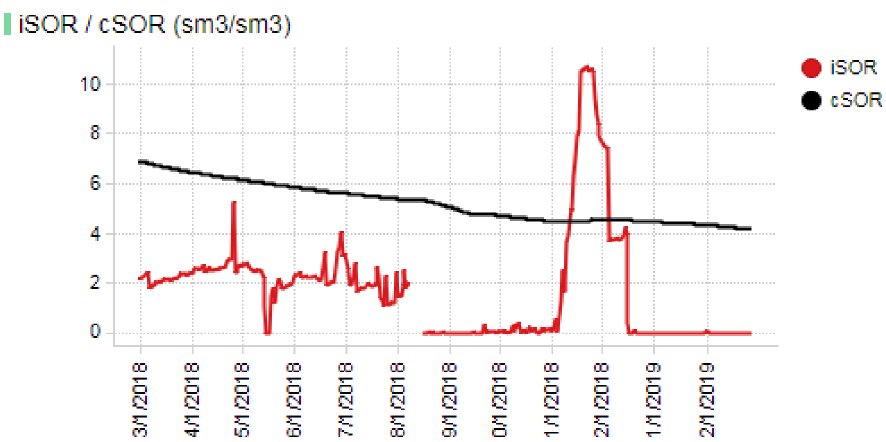
264-1-P04-OBD 102/14-22-083-06W4 *17.0m offset*

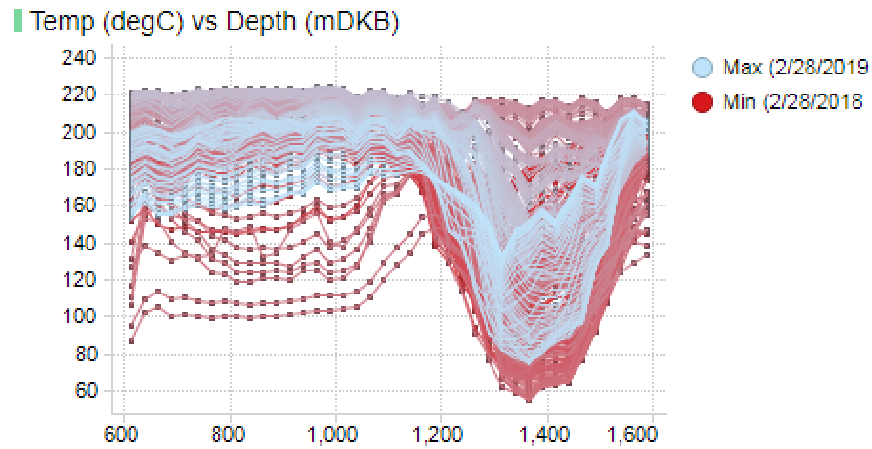


Poor Performance – WP 262-2-07









- **Challenged well; bottom water interaction.**
- **Minimum steam injection; pressure support from adjacent wells.**

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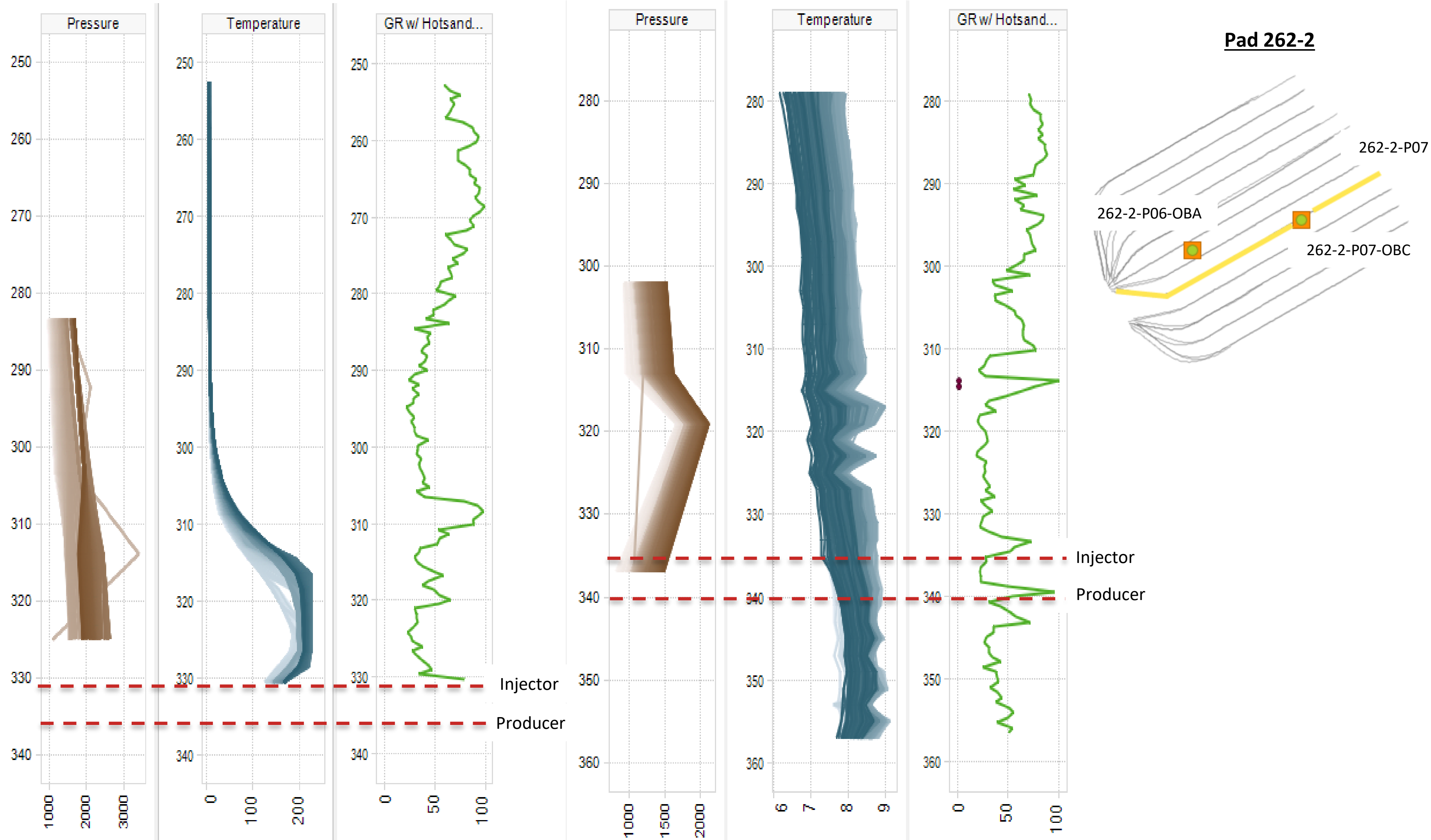
Surmont: Obs Wells Temp & GR – 262-2-P06-OBA, 262-2-P07-OBC



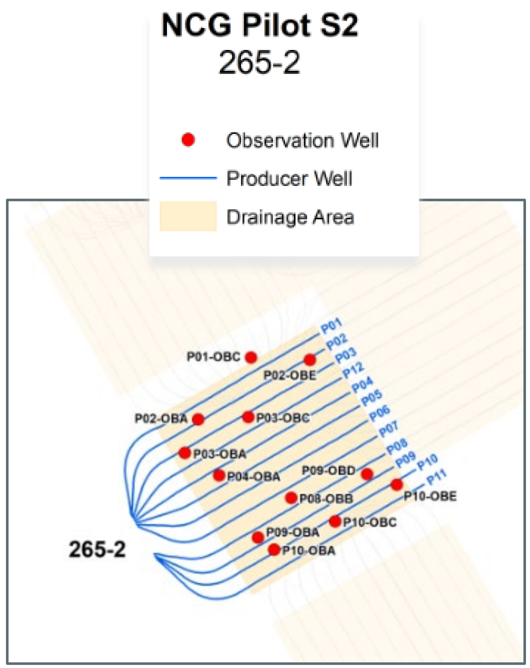
262-2-P07-OBC 100/09-34-083-06W4 / *9.1m offset*

262-2-P06-OBA 100/10-34-083-06W4 *40.3m offset*

Observations

- Reduction of emulsion rates
- Reduction of water cut

  } Oil rates flat
- iSOR reductions of 15-30%
- Increase in chamber pressures due to NCG injection
- Individual drainage areas under pilots are in full coalescence.



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.

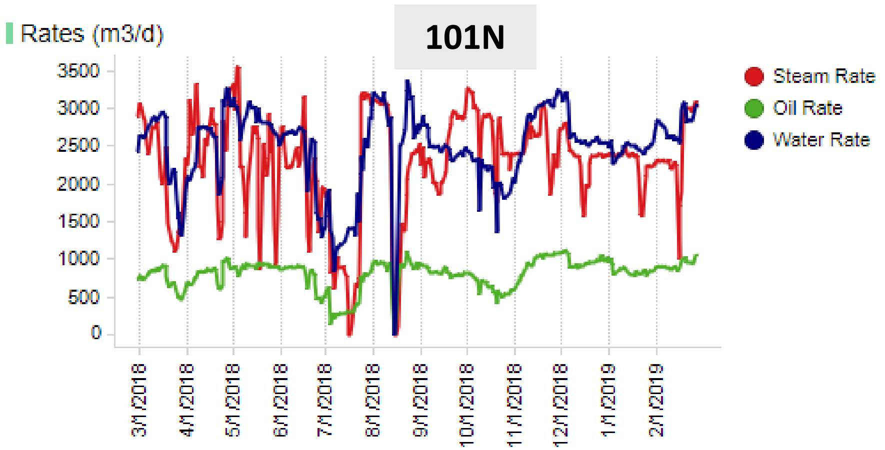
- Injector steam splitters are still being evaluated for hotspot and thief zone mitigation.

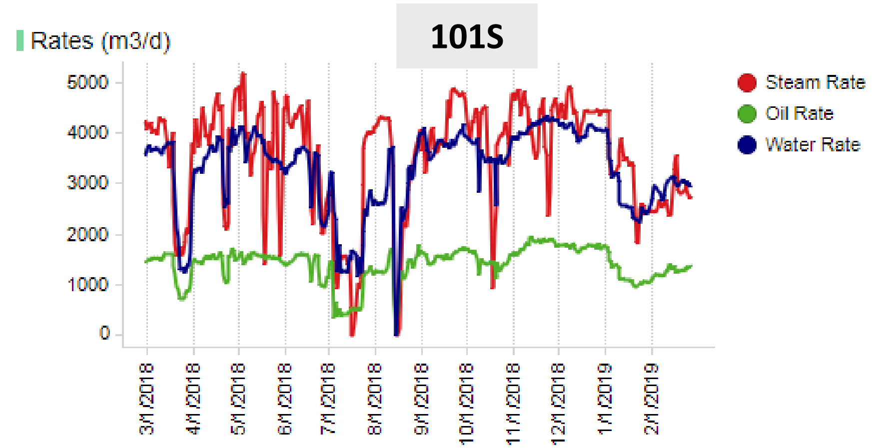
- Bottom water has been very challenging to mitigate due to the early interaction of some wells and the high differential pressure between chamber and the bottom water zone.

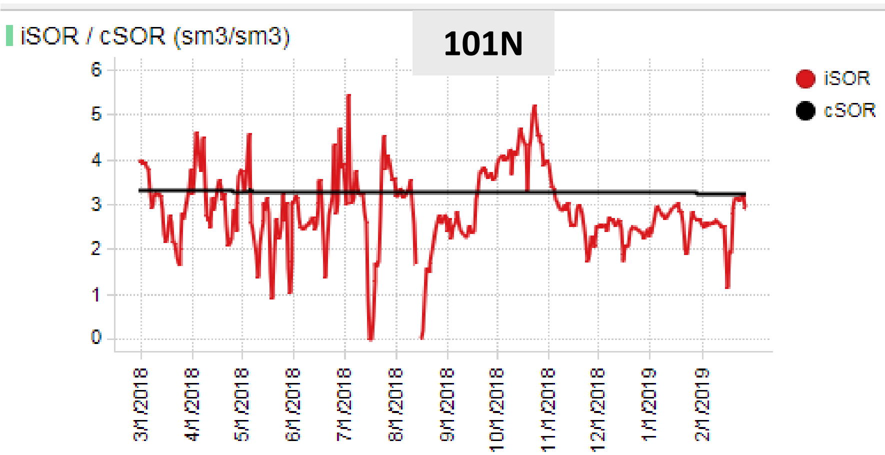
- Top water interaction is being mitigated thanks to dedicated pressure management and ESP conversion strategy.

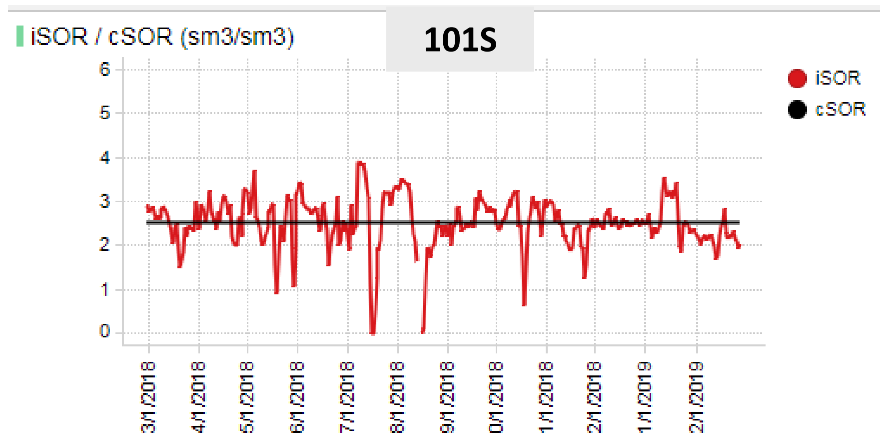
- Optimization continues to improve performance of mature wells:
  - NCG pilot on-going for 265-2.
  - Completed twelve re-drills in 2018.
  - Well stimulations (executed seven)
    - 100% of the well stimulations have been successful in terms of reducing the scale/dP across the production liner. This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

Surmont: Phase 1 Well Pad Rates and SOR / Pad 101



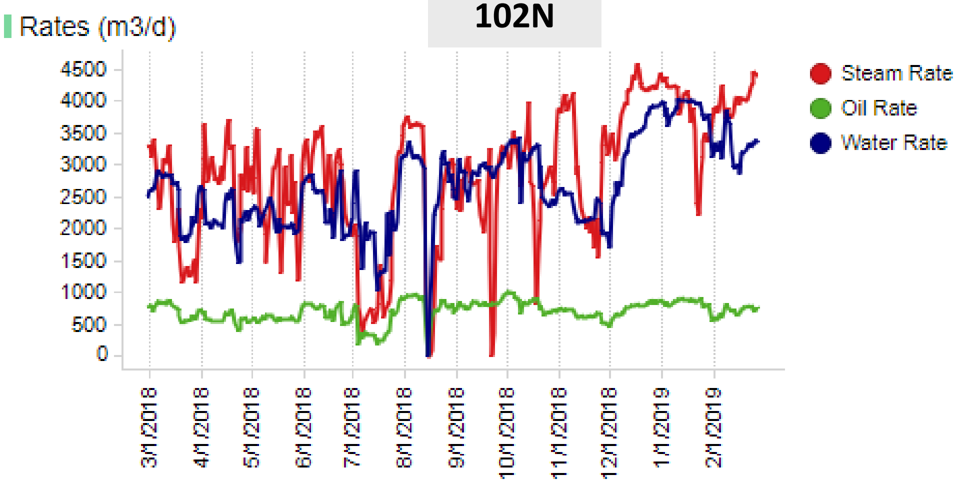




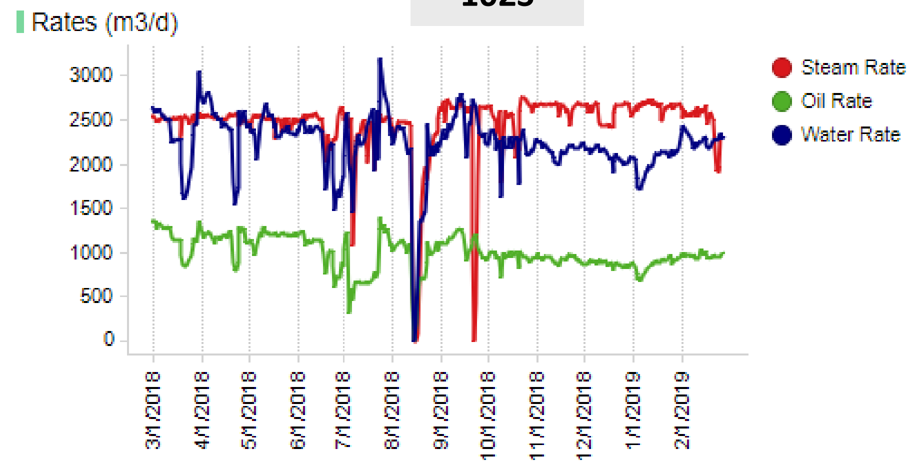


Surmont: Phase 1 Well Pad Rates and SOR / Pad 102

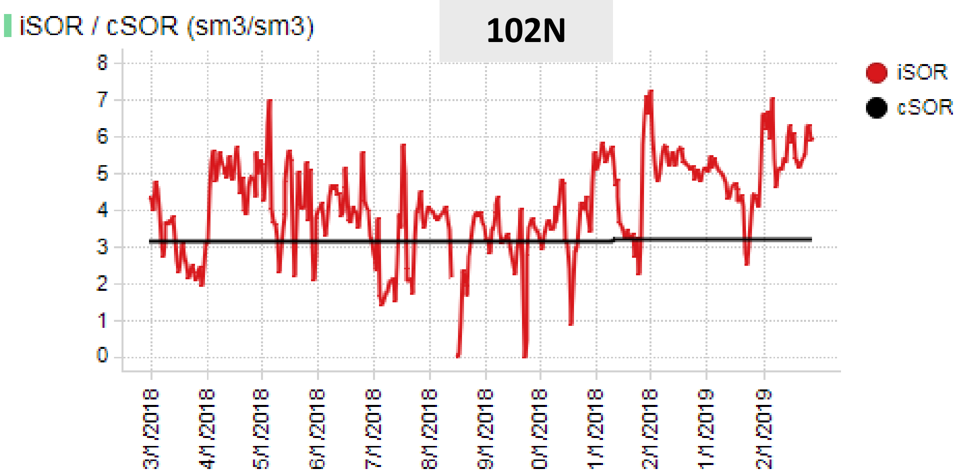
102N



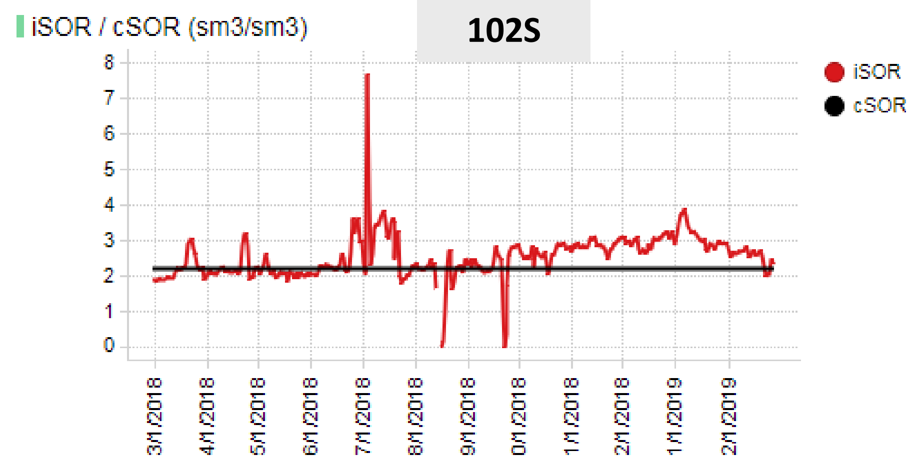
102S



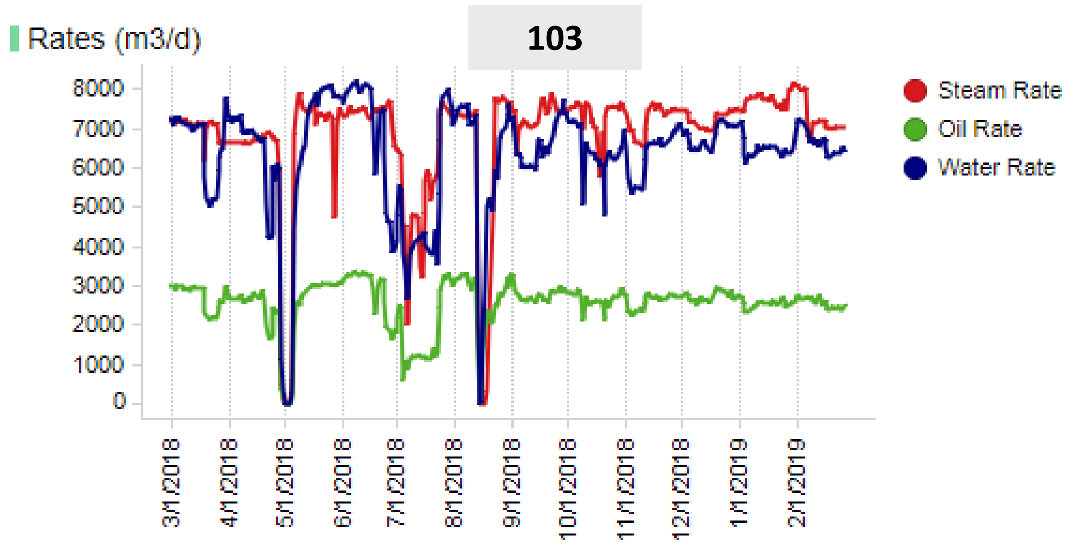
102N

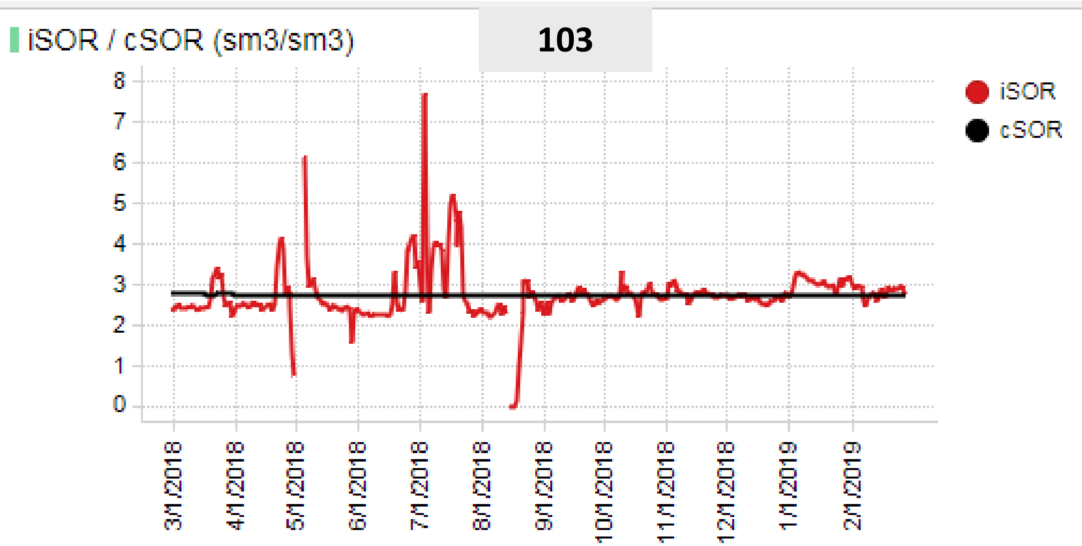


102S

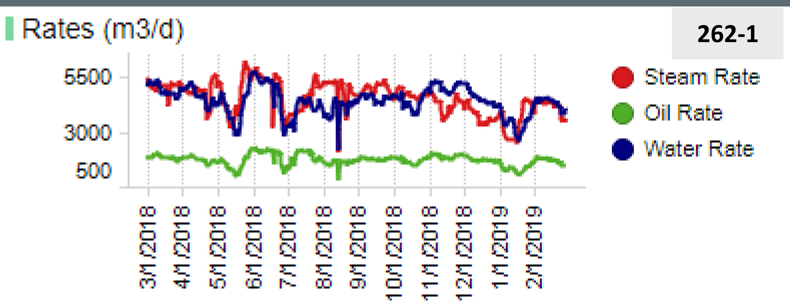


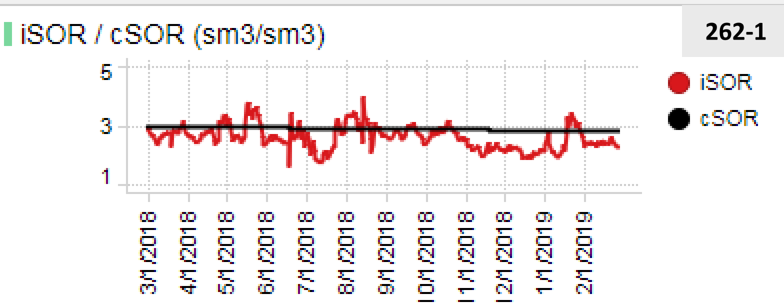
Surmont: Phase 1 Well Pad Rates and SOR / Pad 103

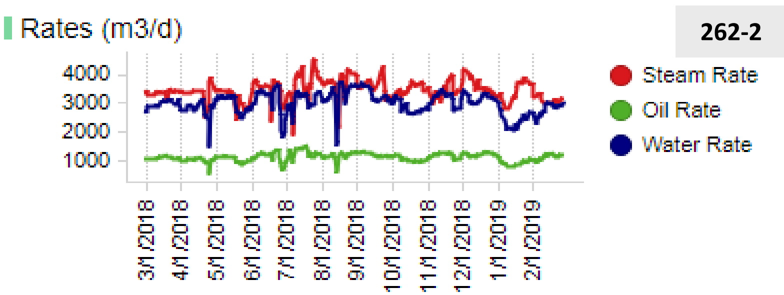


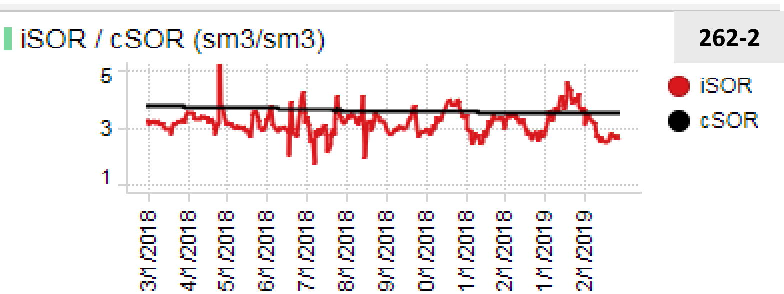


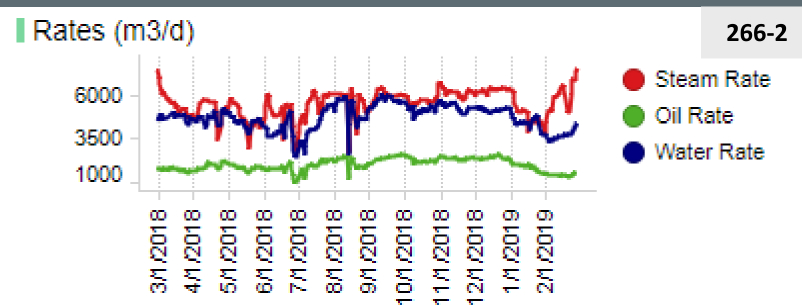
Surmont: Phase 2 Well Pad Rates and SOR

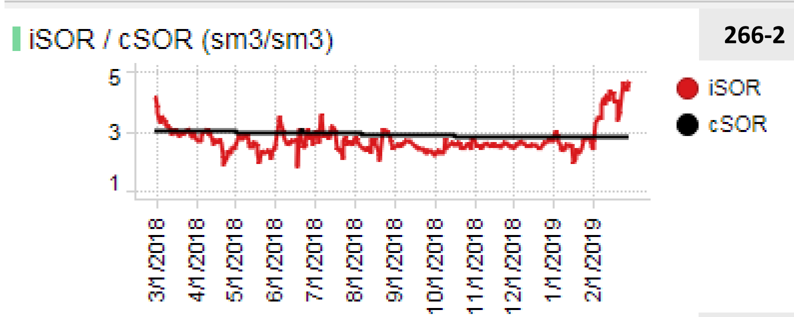


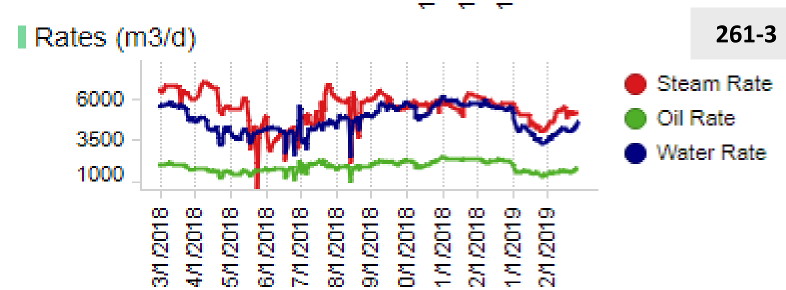


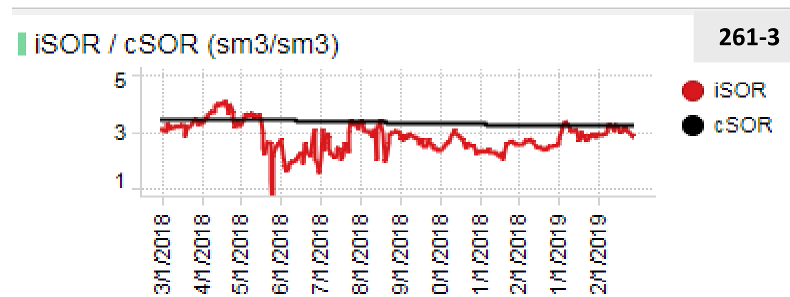




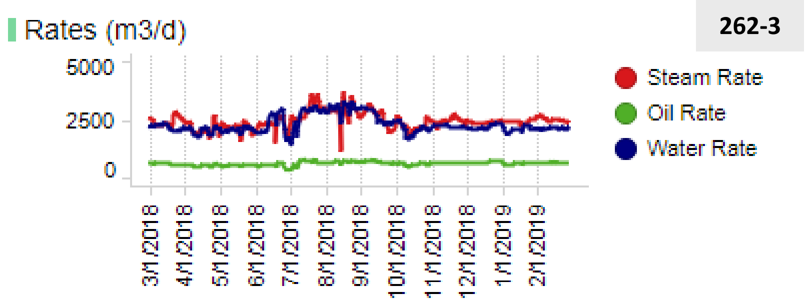


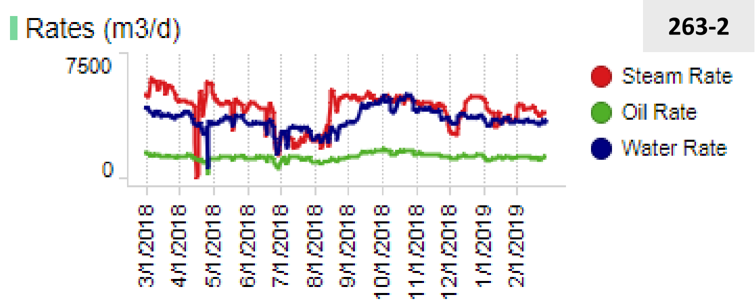


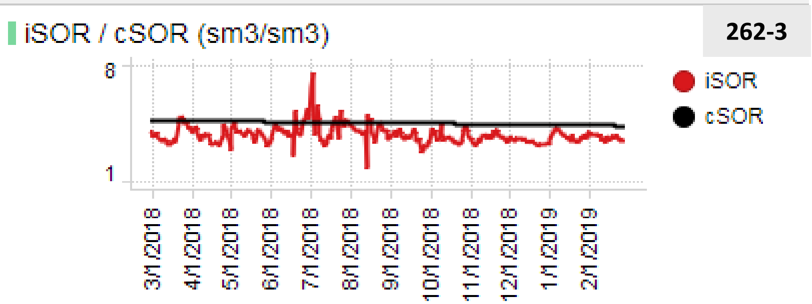


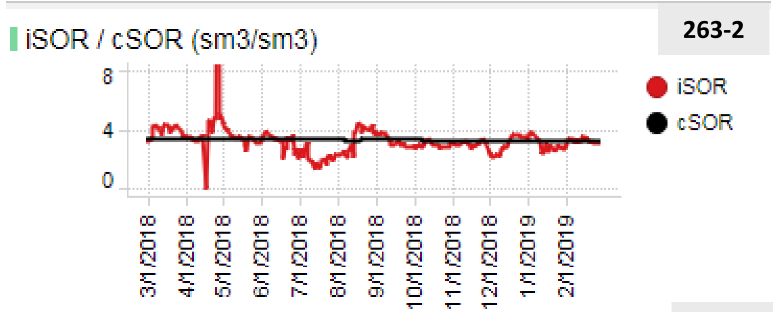


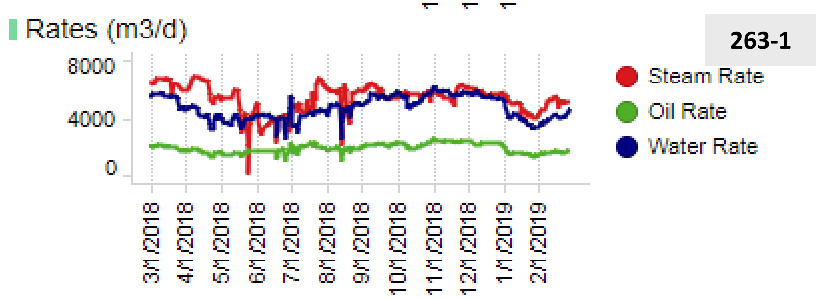
Surmont: Phase 2 Well Pad Rates and SOR

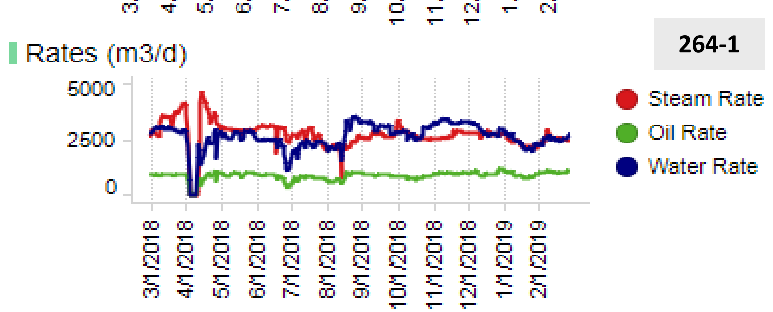


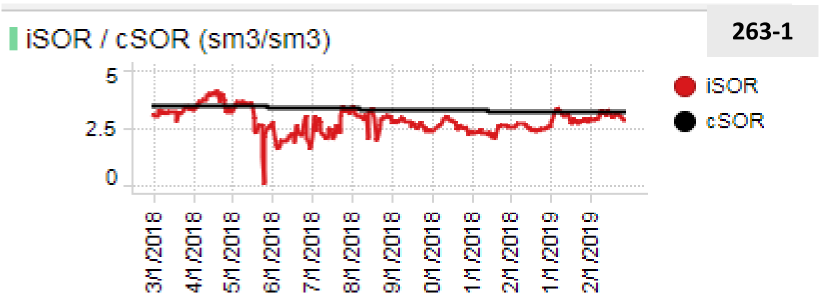


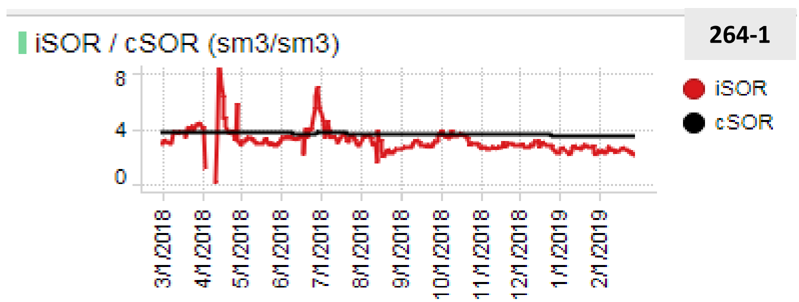




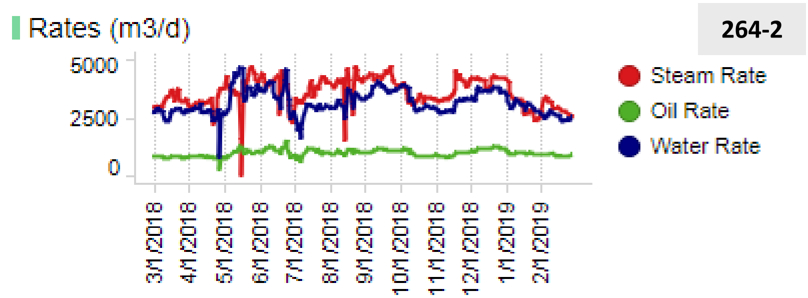


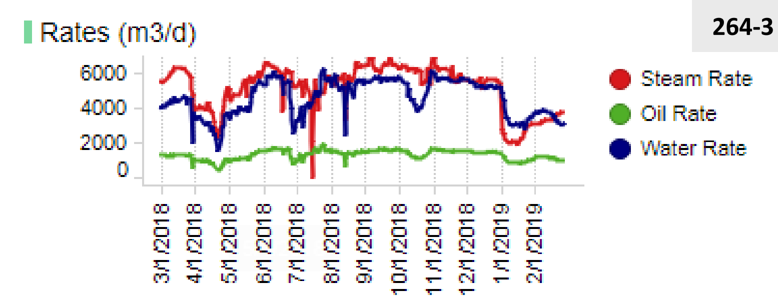


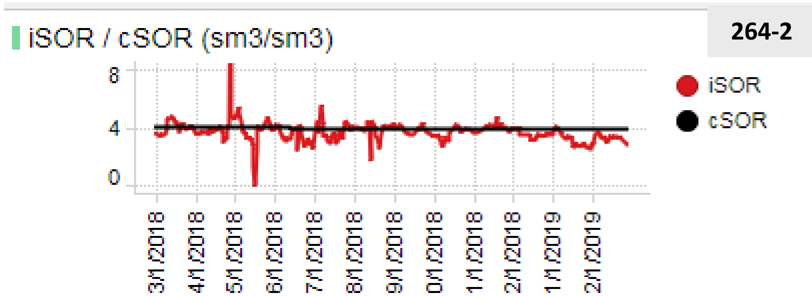


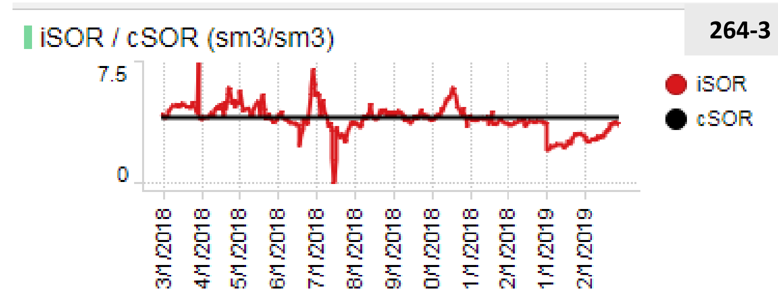


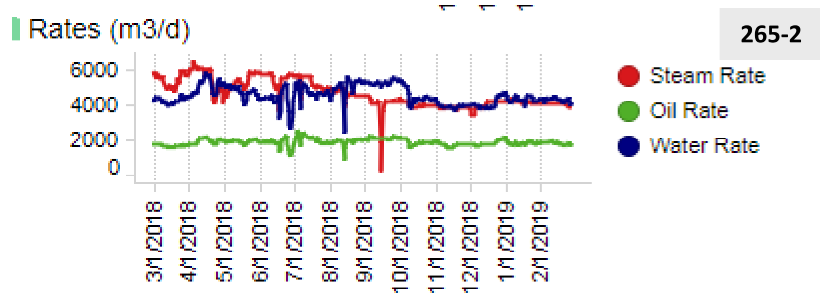
Surmont: Phase 2 Well Pad Rates and SOR

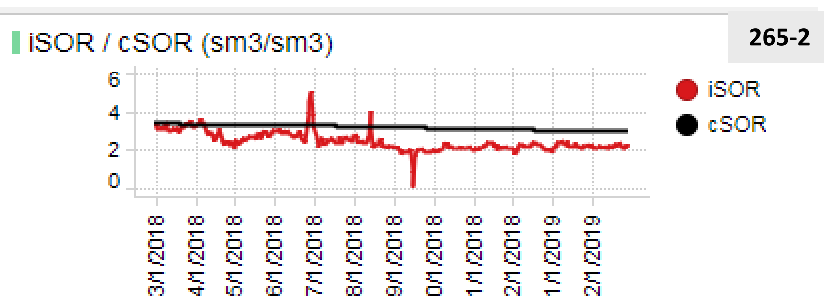












Future Plans

Subsection 3.1.1 (8)

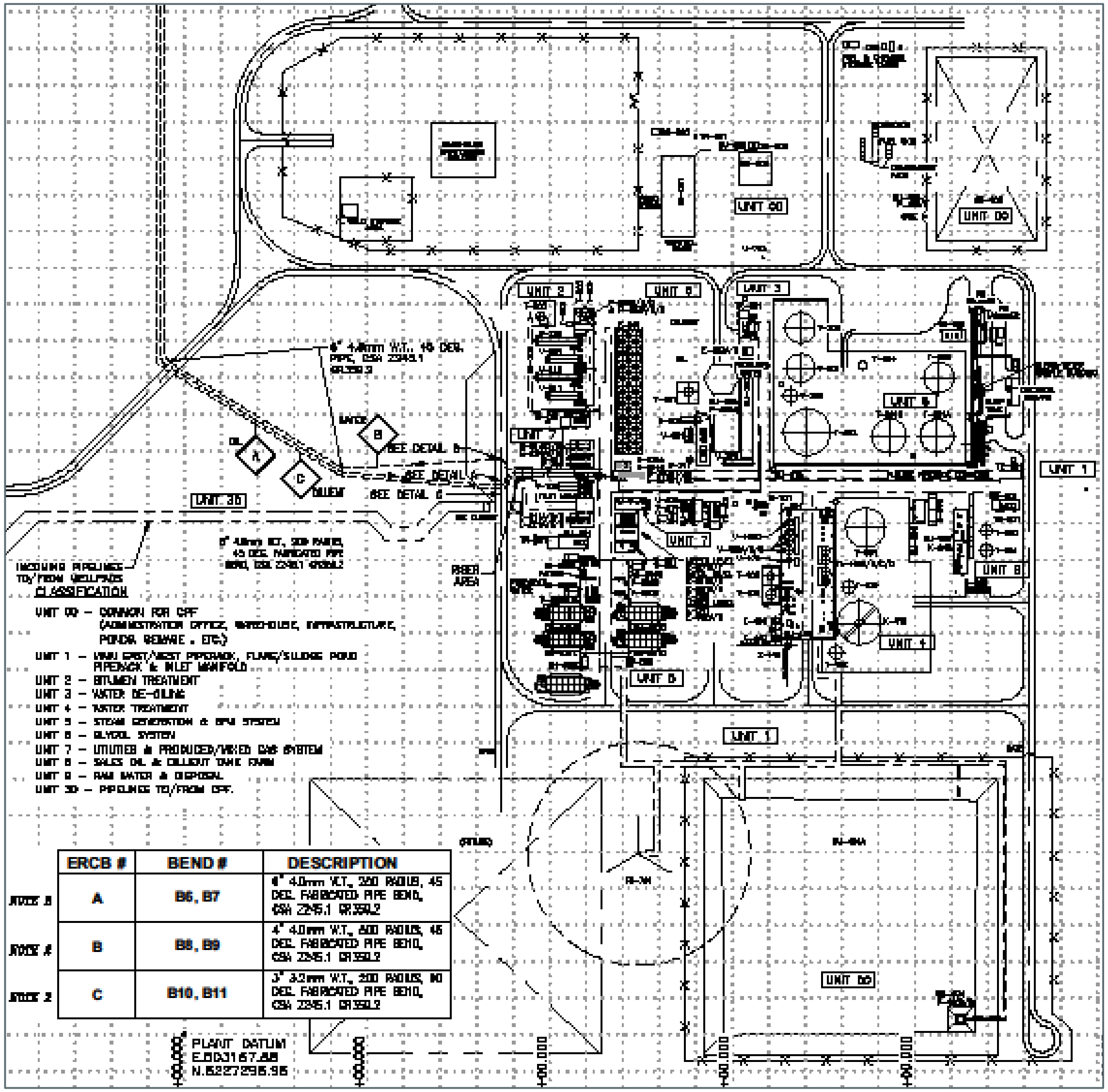
Future Plans – Surmont

- 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

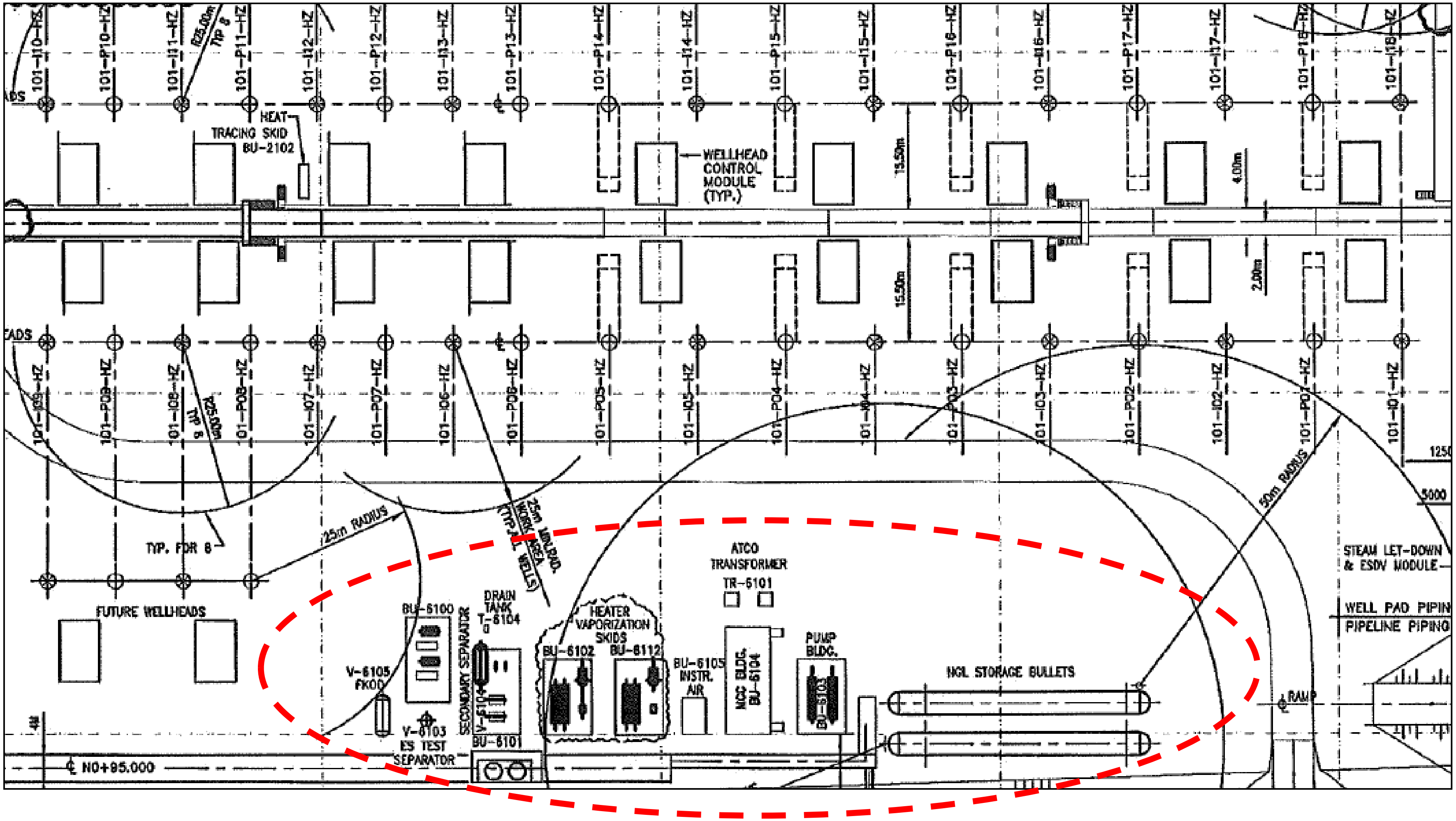
Facilities

Subsection 3.1.2 (1)



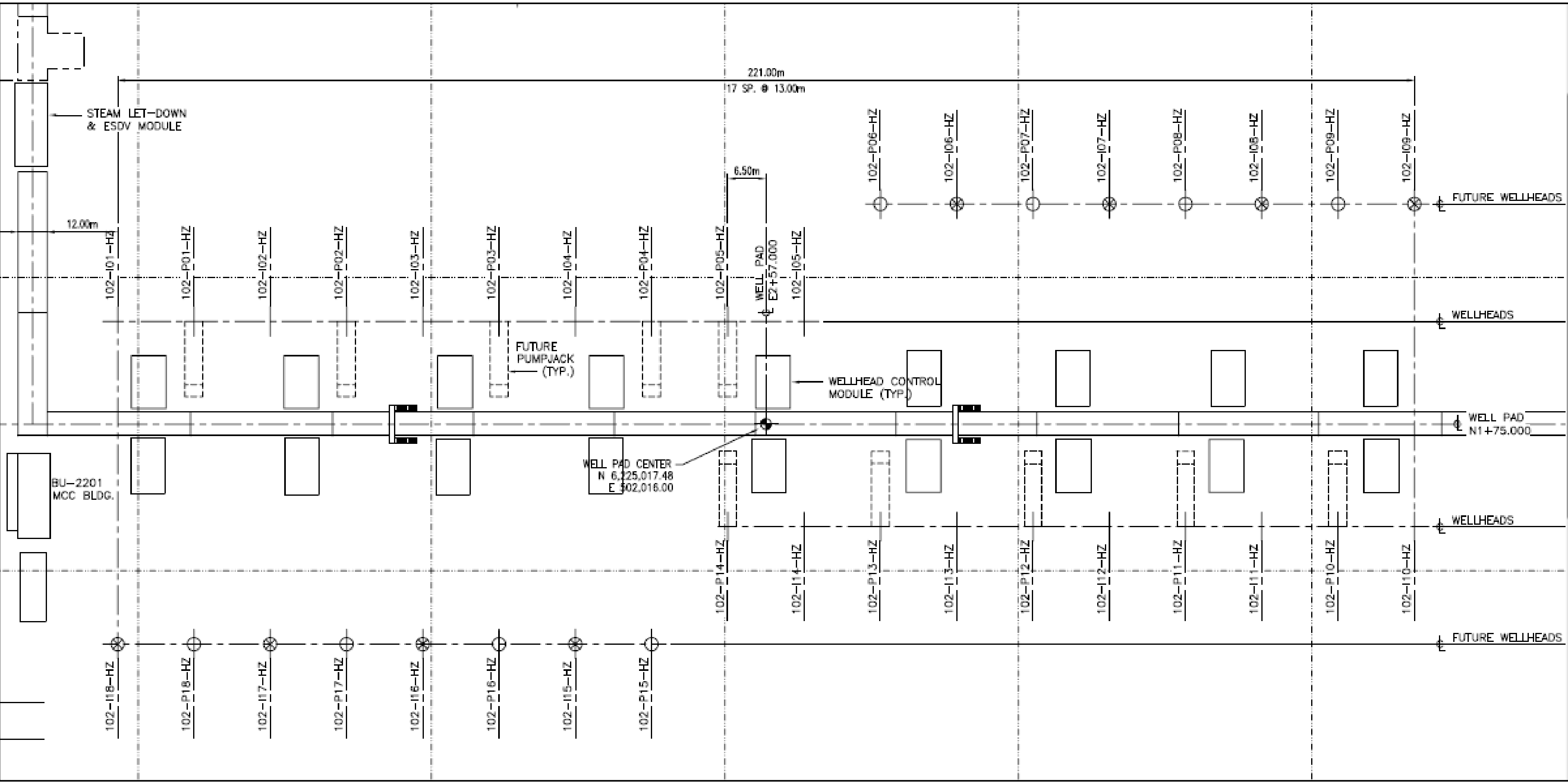
ERCB #	BEND #	DESCRIPTION
A	B6, B7	4" 4.0mm W.T., 250 RADIUS, 45 DEG. FABRICATED PIPE BEND, CSA Z245.1 GR359.2
B	B8, B9	4" 4.0mm W.T., 600 RADIUS, 45 DEG. FABRICATED PIPE BEND, CSA Z245.1 GR359.2
C	B10, B11	3" 3.2mm W.T., 200 RADIUS, 90 DEG. FABRICATED PIPE BEND, CSA Z245.1 GR359.2

Phase 1 Plot Plan: Pad 101



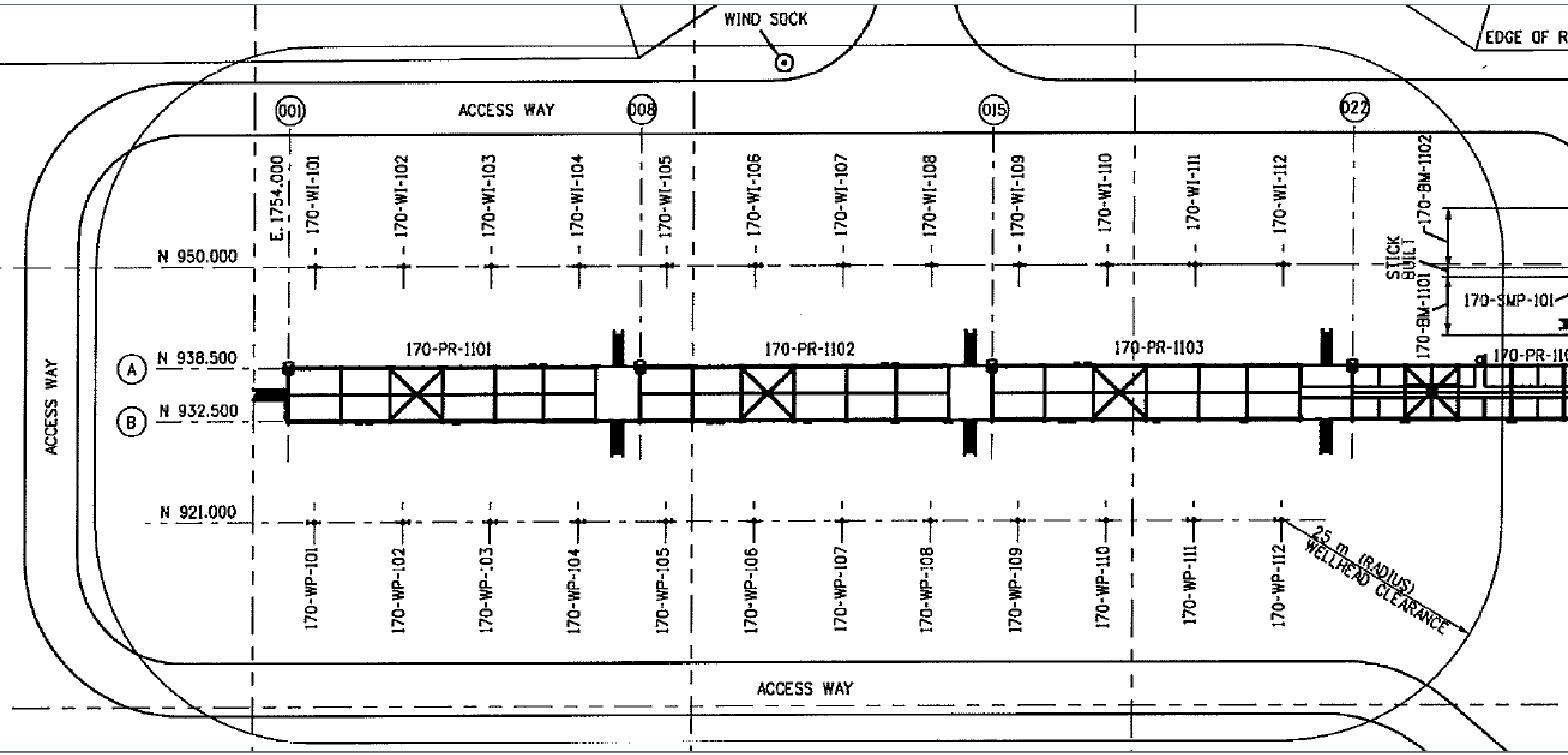
- **E-SAGD Equipment was de-commissioned in 2017; no major modifications in 2018**

Phase 1 Plot Plan: Pad 102



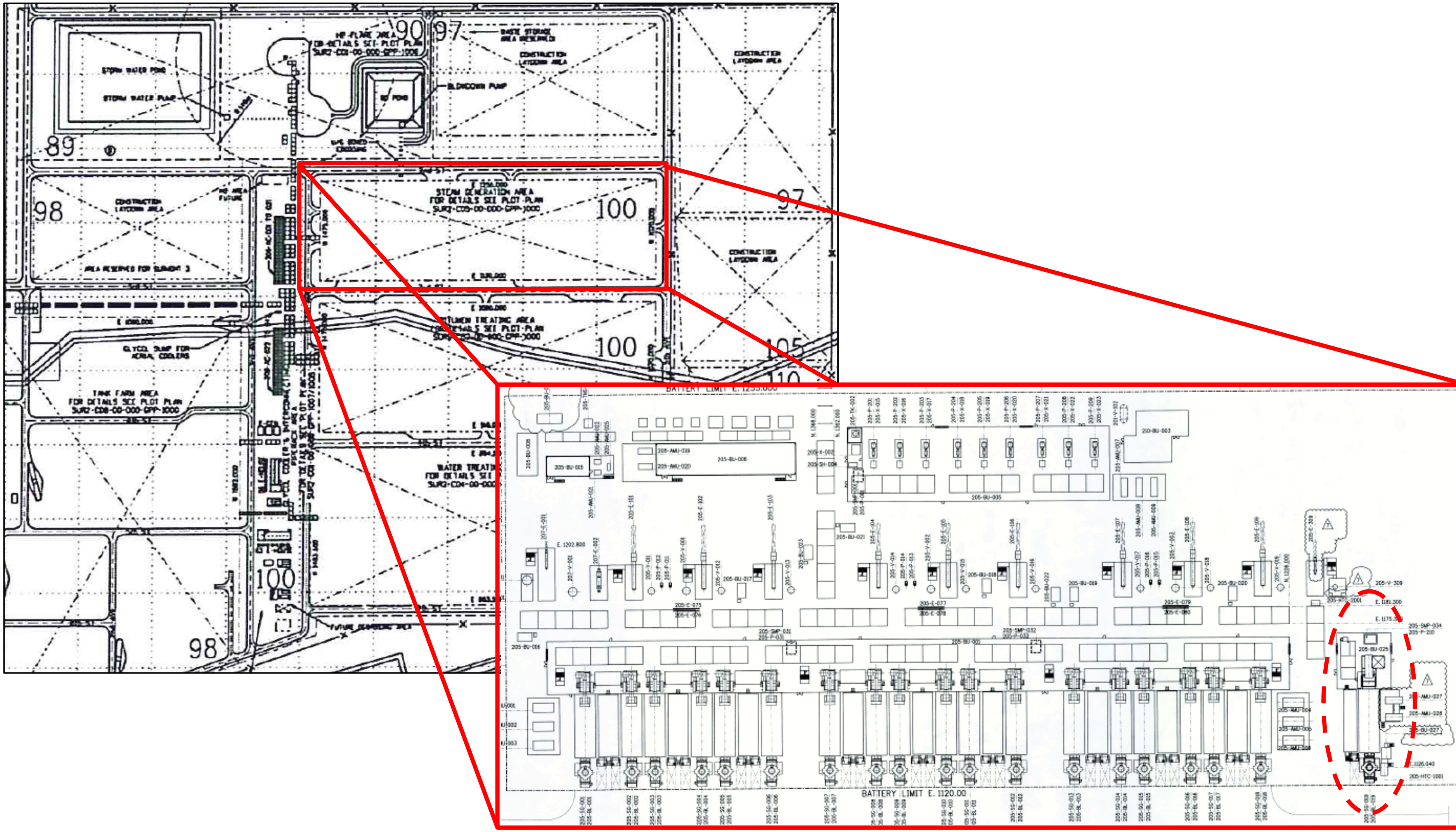
- **No Major Modifications in 2018**

Phase 1 Plot Plan: Pad 103



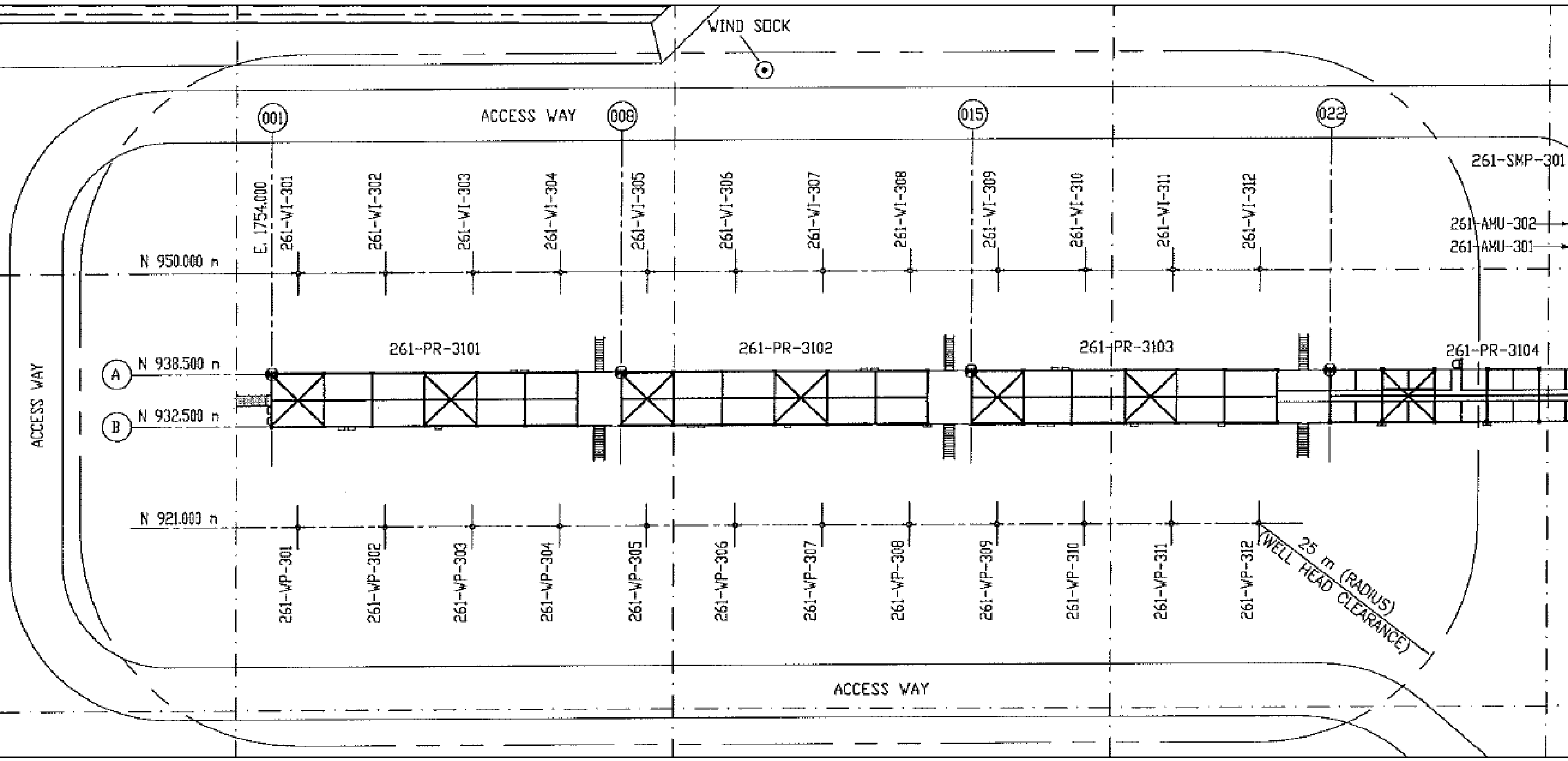
- **No Major Modifications in 2018**

Phase 2 Plot Plan: CPF



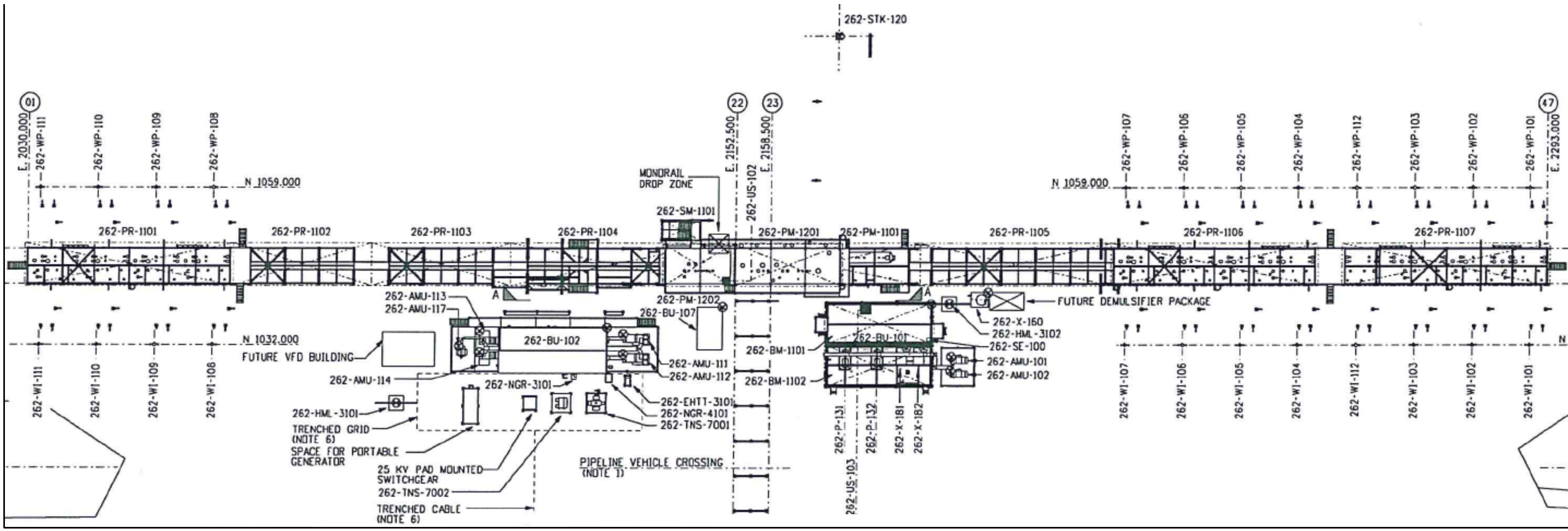
Installation of one additional OTSG and associated heat exchanger at Surmont 2 in 2017, OTSG is now operational. No other major changes 2018.

Phase 2 Plot Plan: Pad 261-3



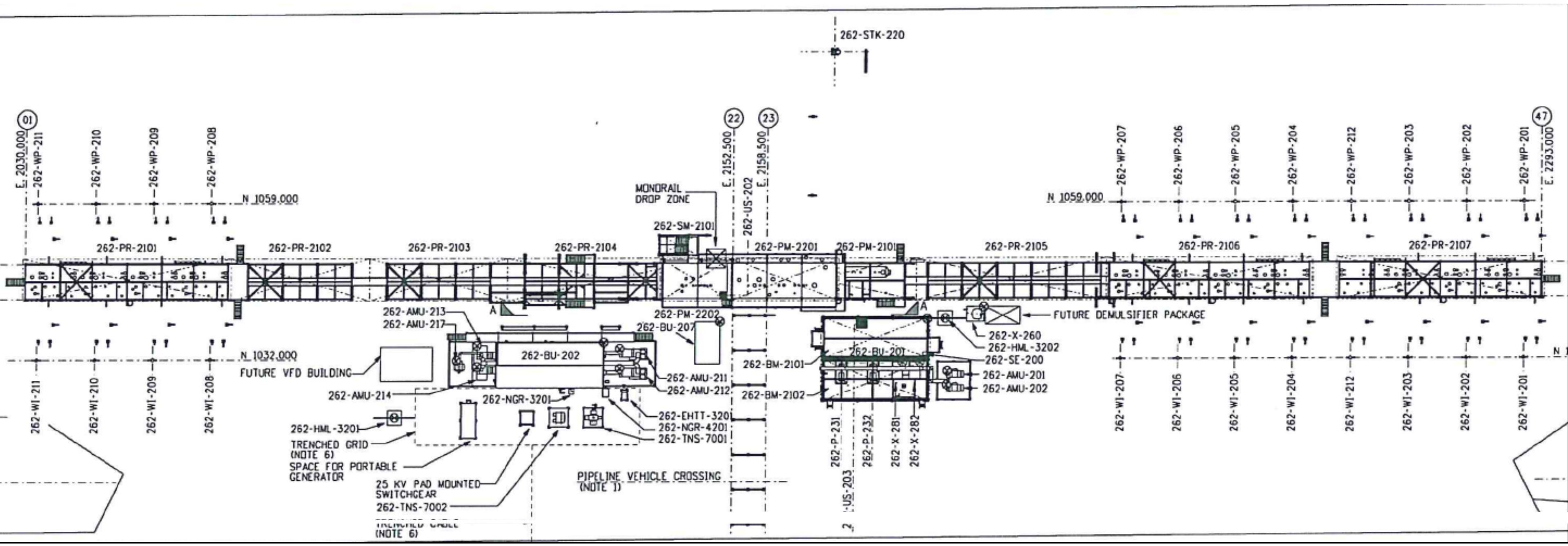
- **No Major Modifications in 2018**

Phase 2 Plot Plan: Pad 262-1



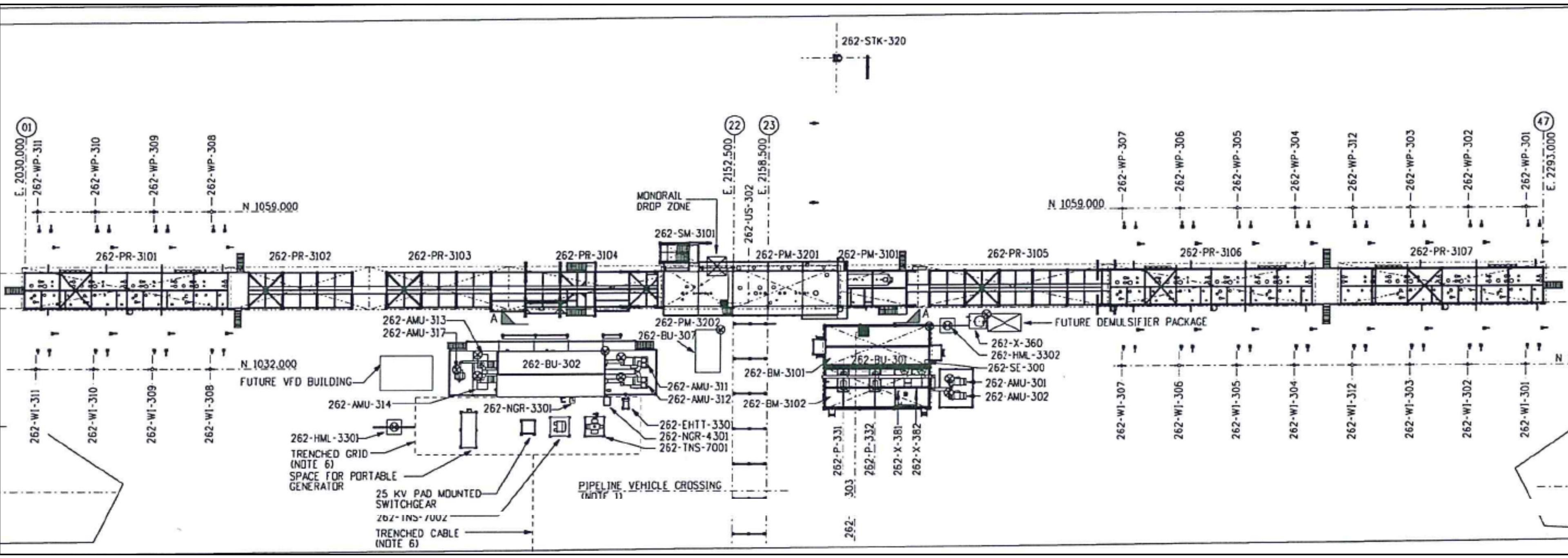
- **No Major Modifications in 2018**

Phase 2 Plot Plan: Pad 262-2



- **No Major Modifications in 2018**

Phase 2 Plot Plan: Pad 262-3



- **No Major Modifications in 2018**

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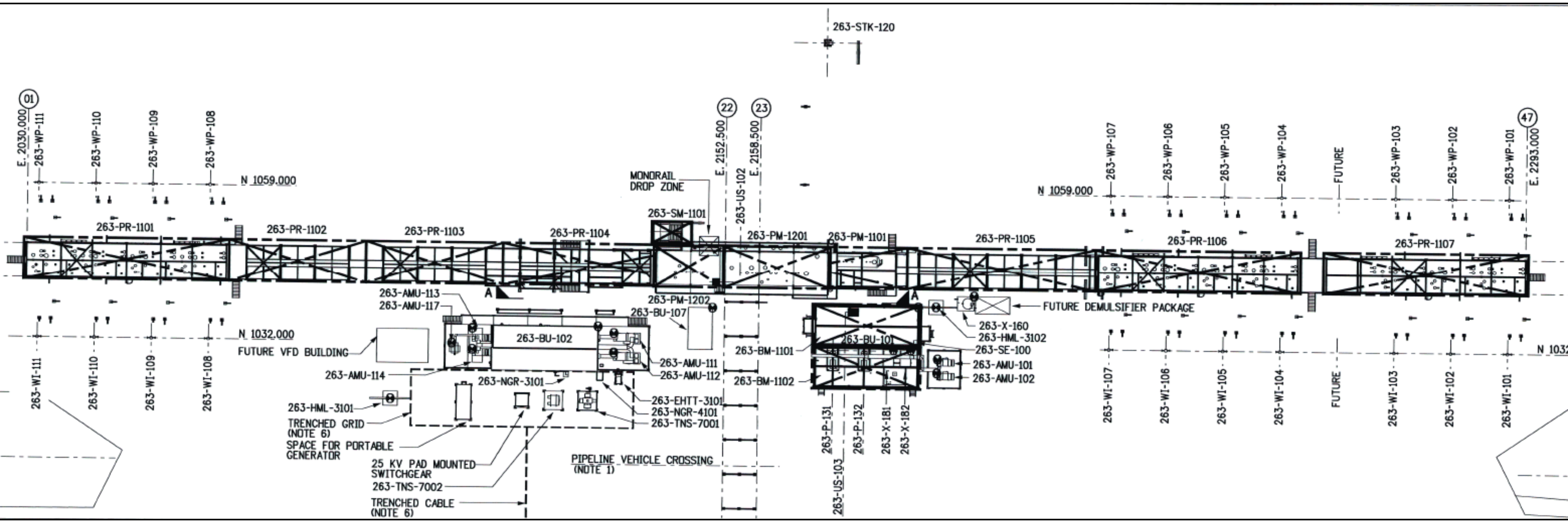
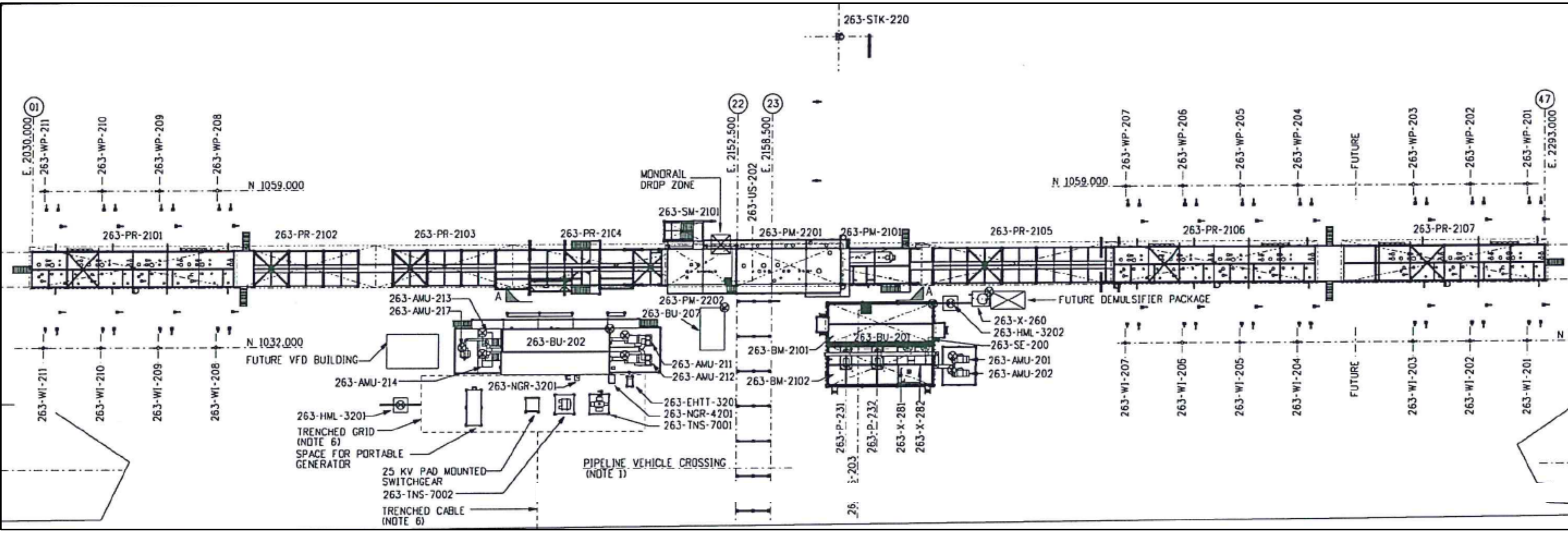
Phase 2 Plot Plan: Pad 263-1

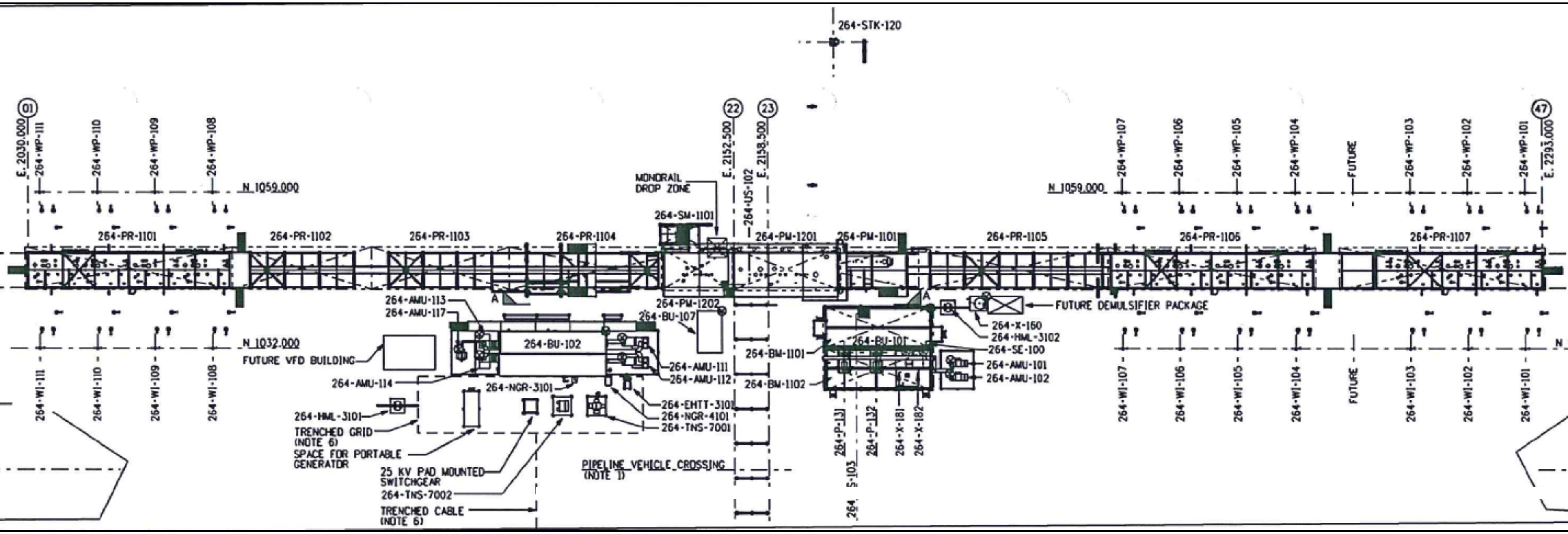


Phase 2 Plot Plan: Pad 263-2



- **No Major Modifications in 2018**

Phase 2 Plot Plan: Pad 264-1



- **No Major Modifications in 2018**

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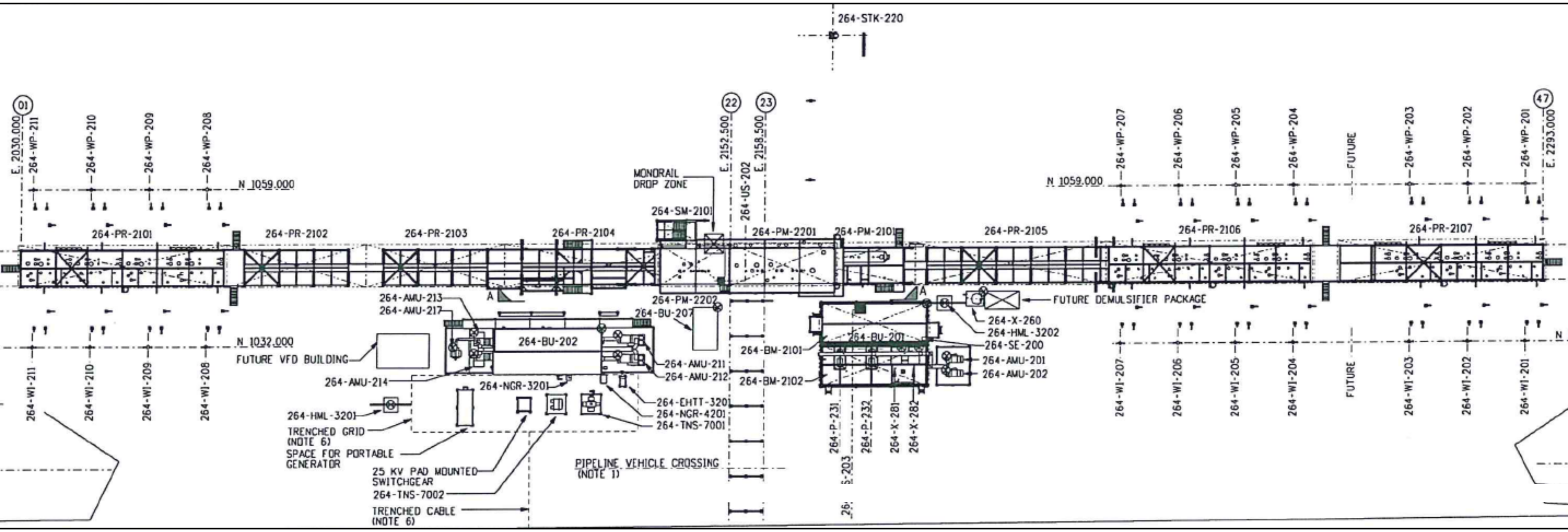
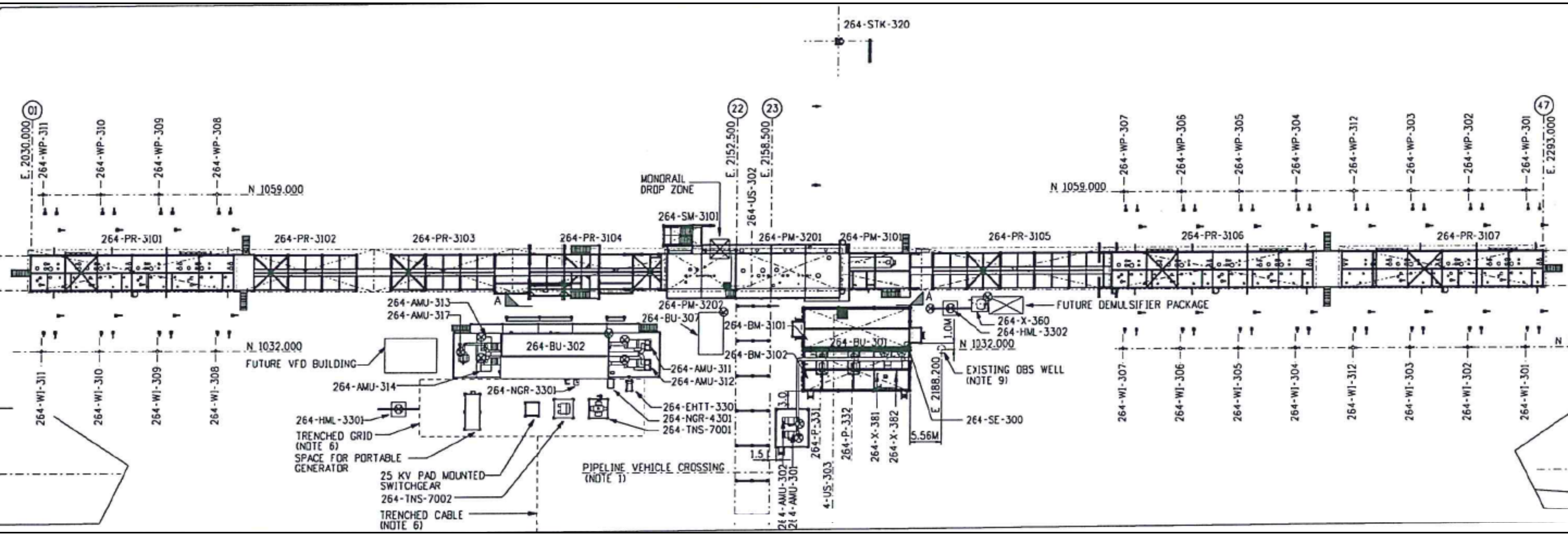
Phase 2 Plot Plan: Pad 264-2



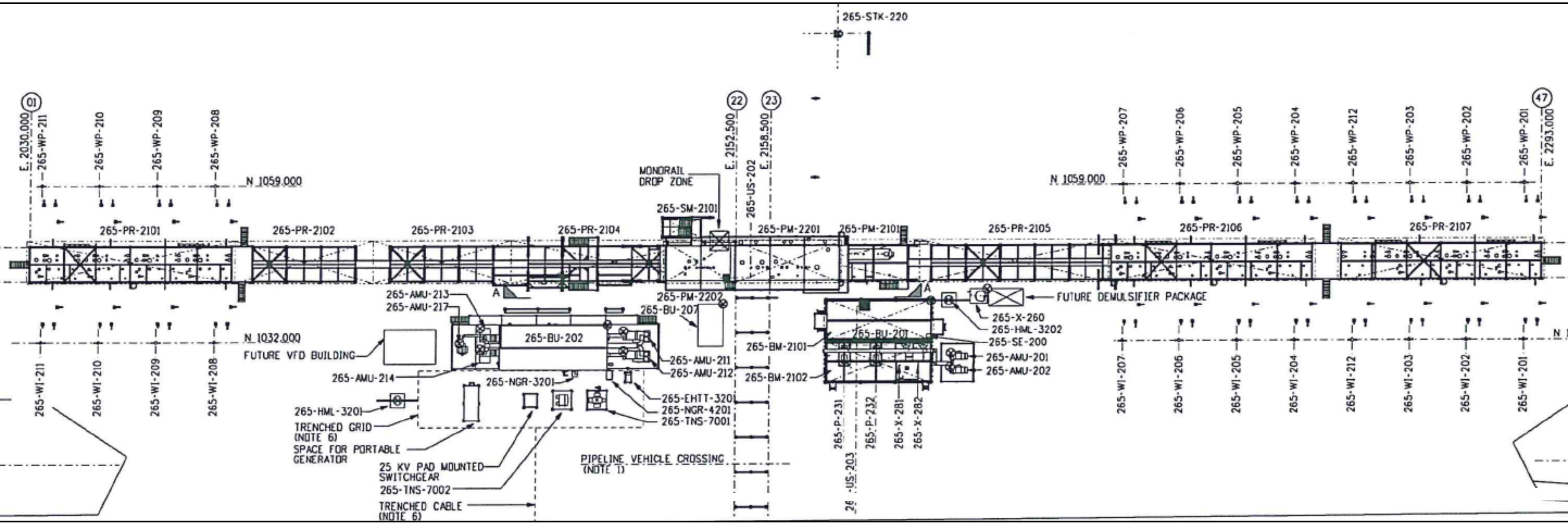
- **No Major Modifications in 2018**

Phase 2 Plot Plan: Pad 264-3



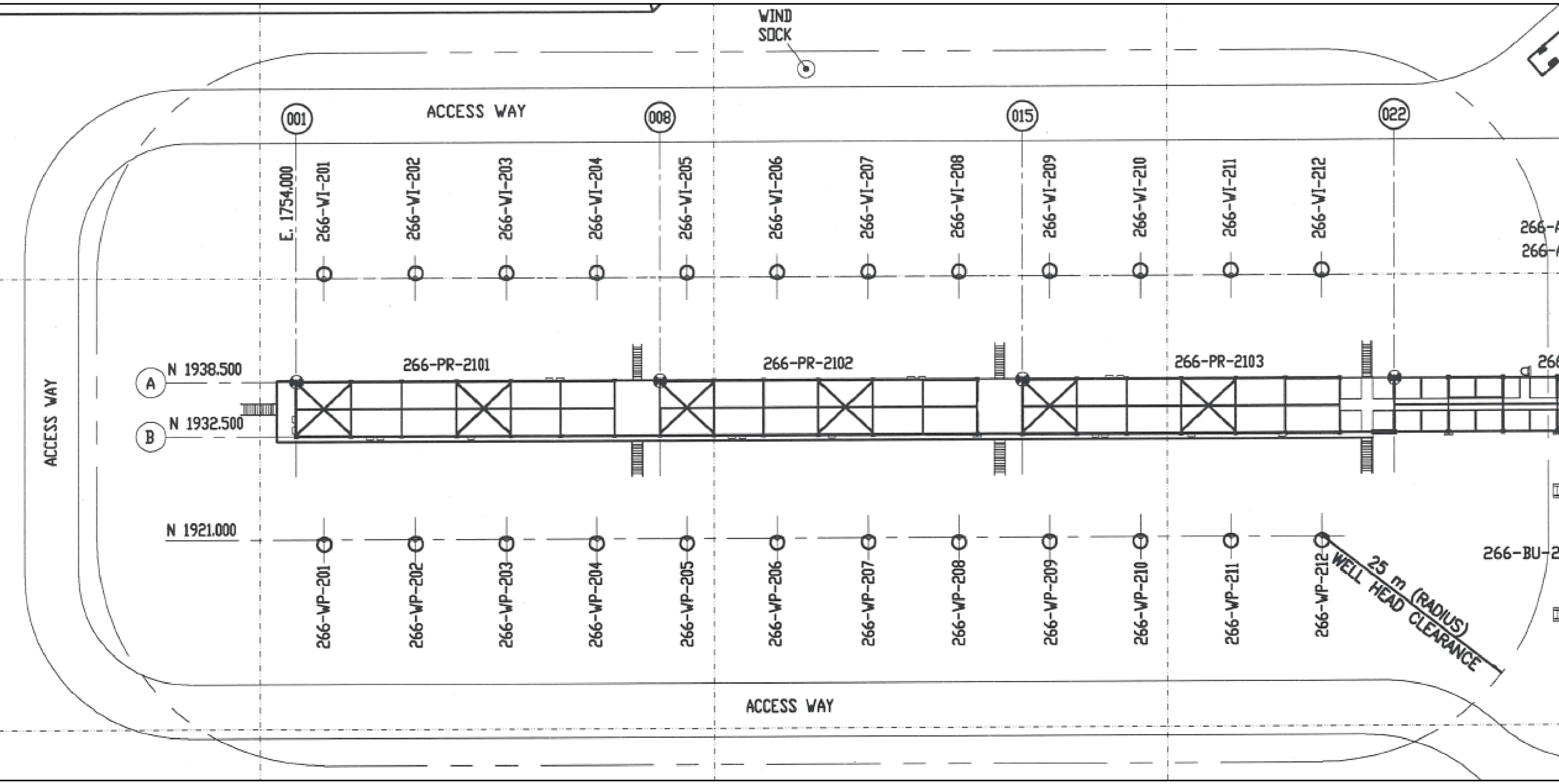
- **No Major Modifications in 2018**

Phase 2 Plot Plan: Pad 265-2



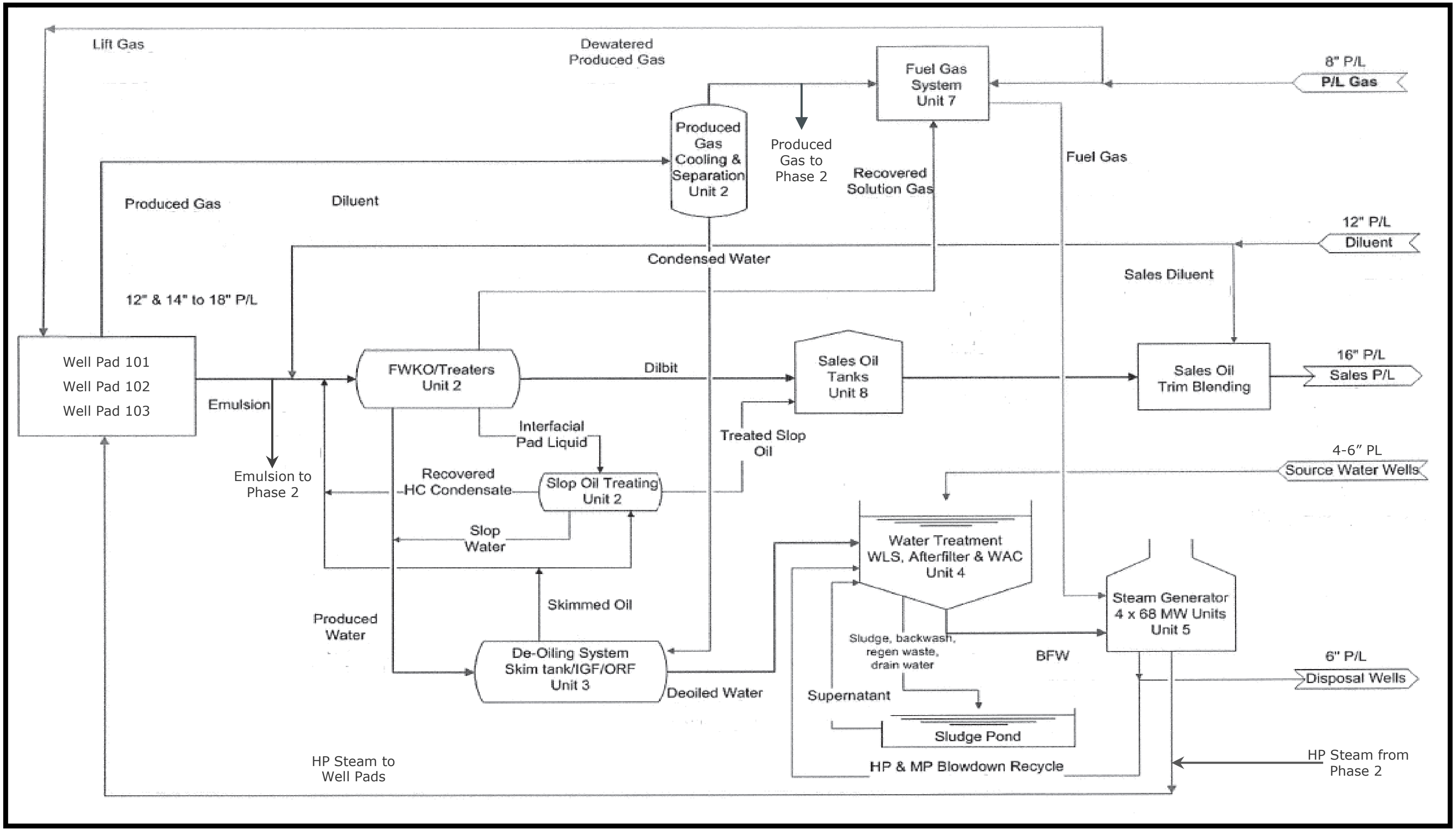
- **No Major Modifications in 2018**

Phase 2 Plot Plan: Pad 266-2

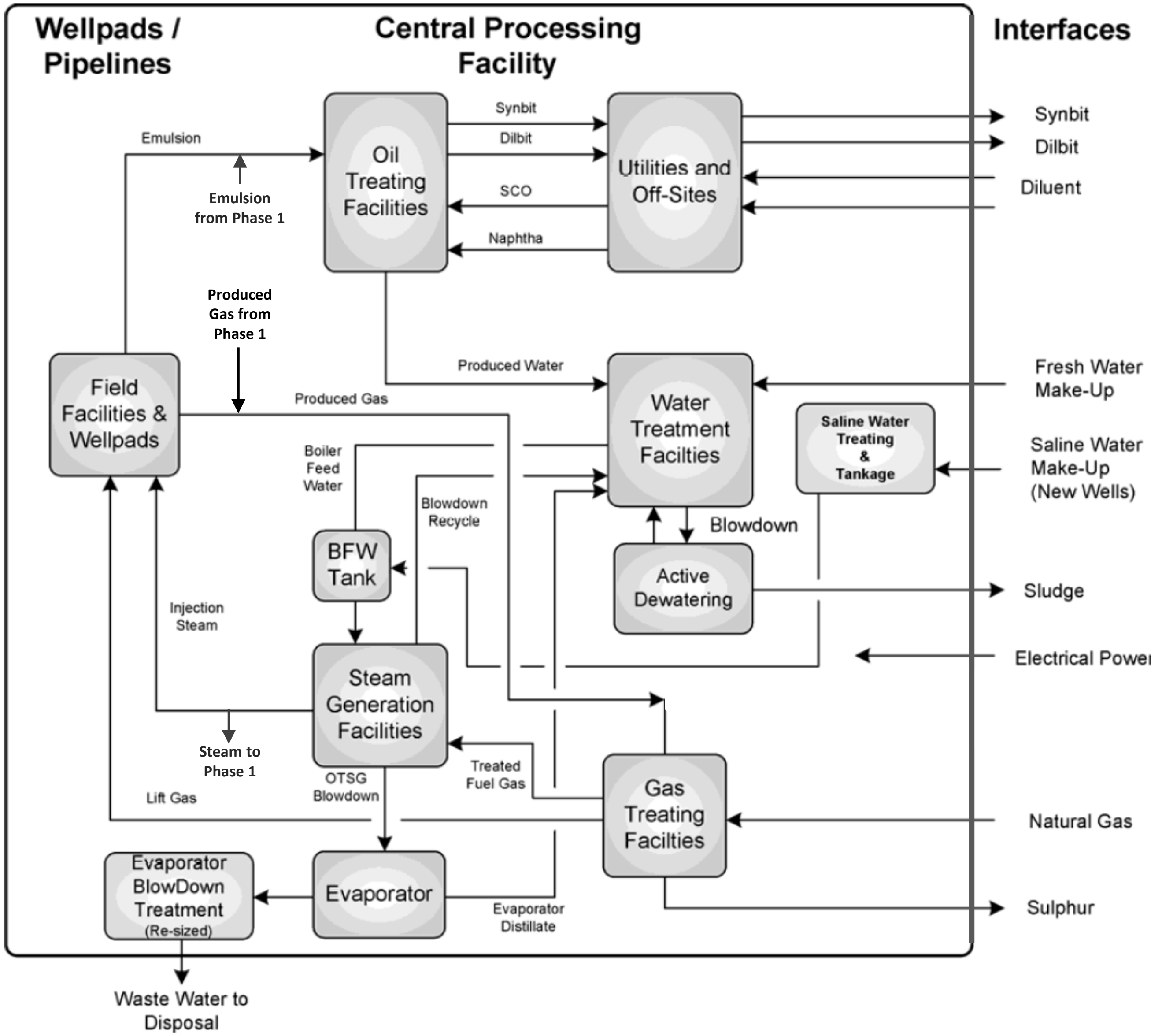


- **No Major Modifications in 2018**

Plant Schematic: Phase 1



Plant Schematic: Phase 2



2018 Surmont Operations

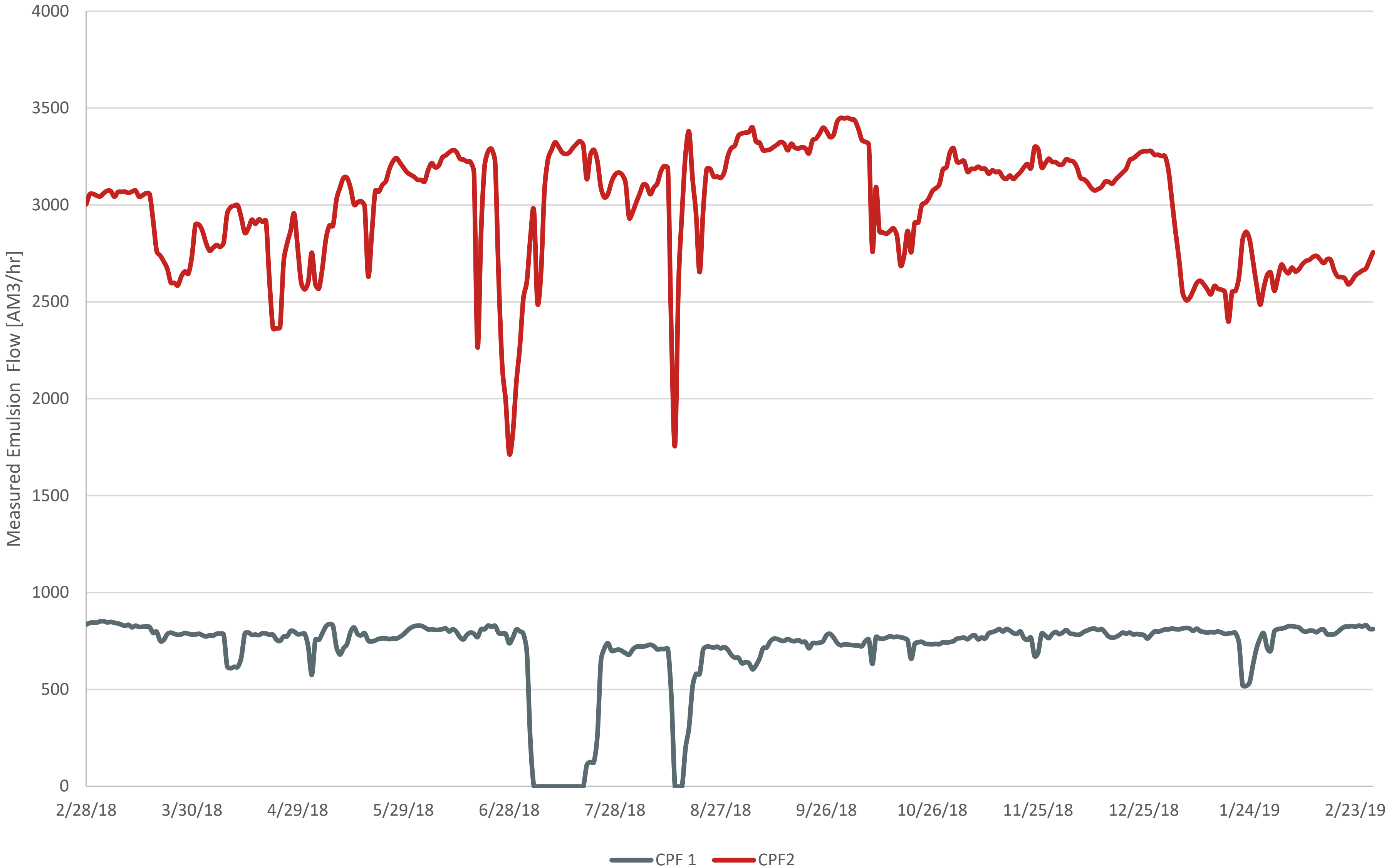
- **Phase 1:**
  - NCG co-injection pilot
  - Pad 103 turn-around
  - WLS turbine failure and replacement

- **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

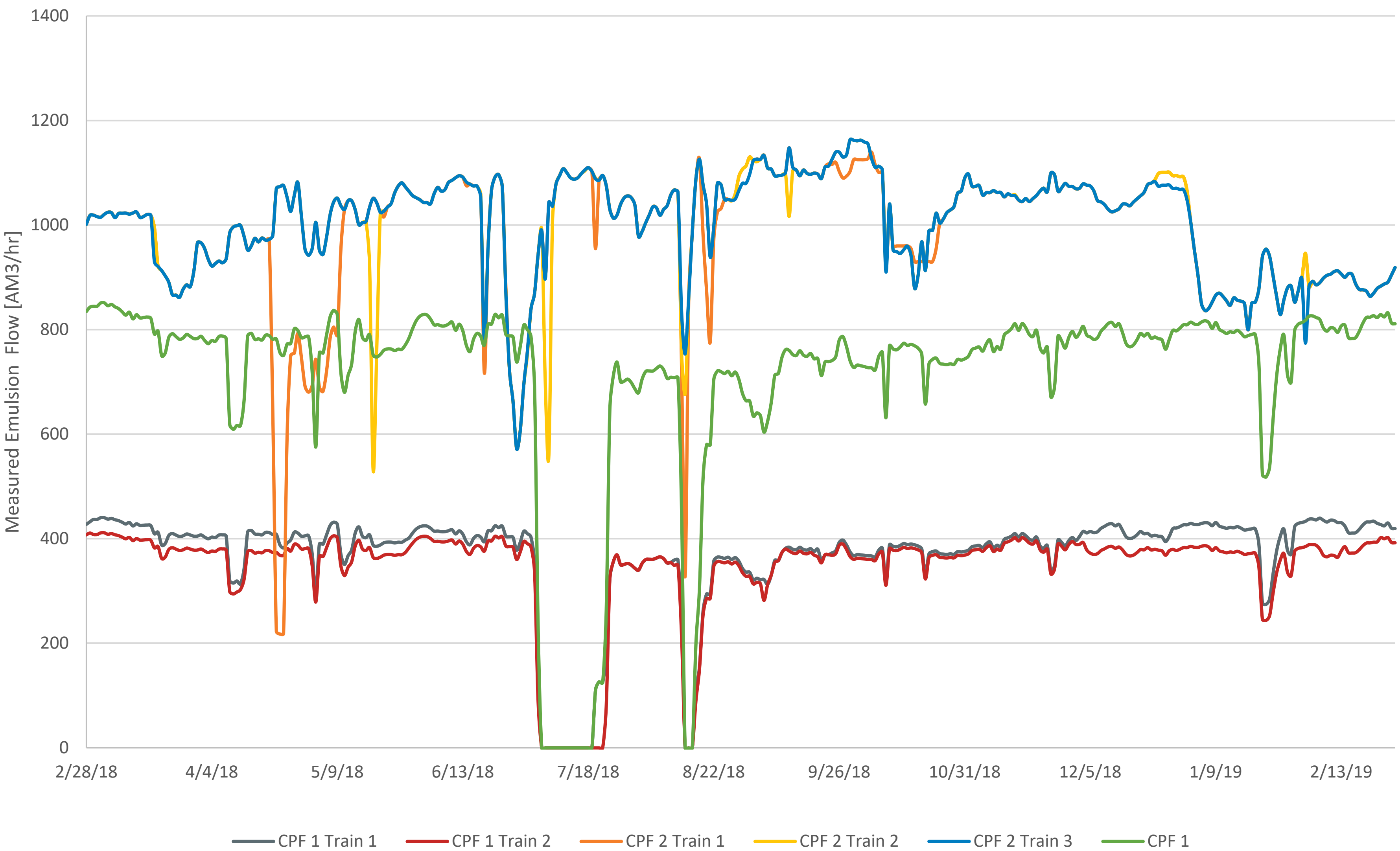
Facility Performance

Subsection 3.1.2 (2)

Facility Performance: Bitumen Treatment by CPF

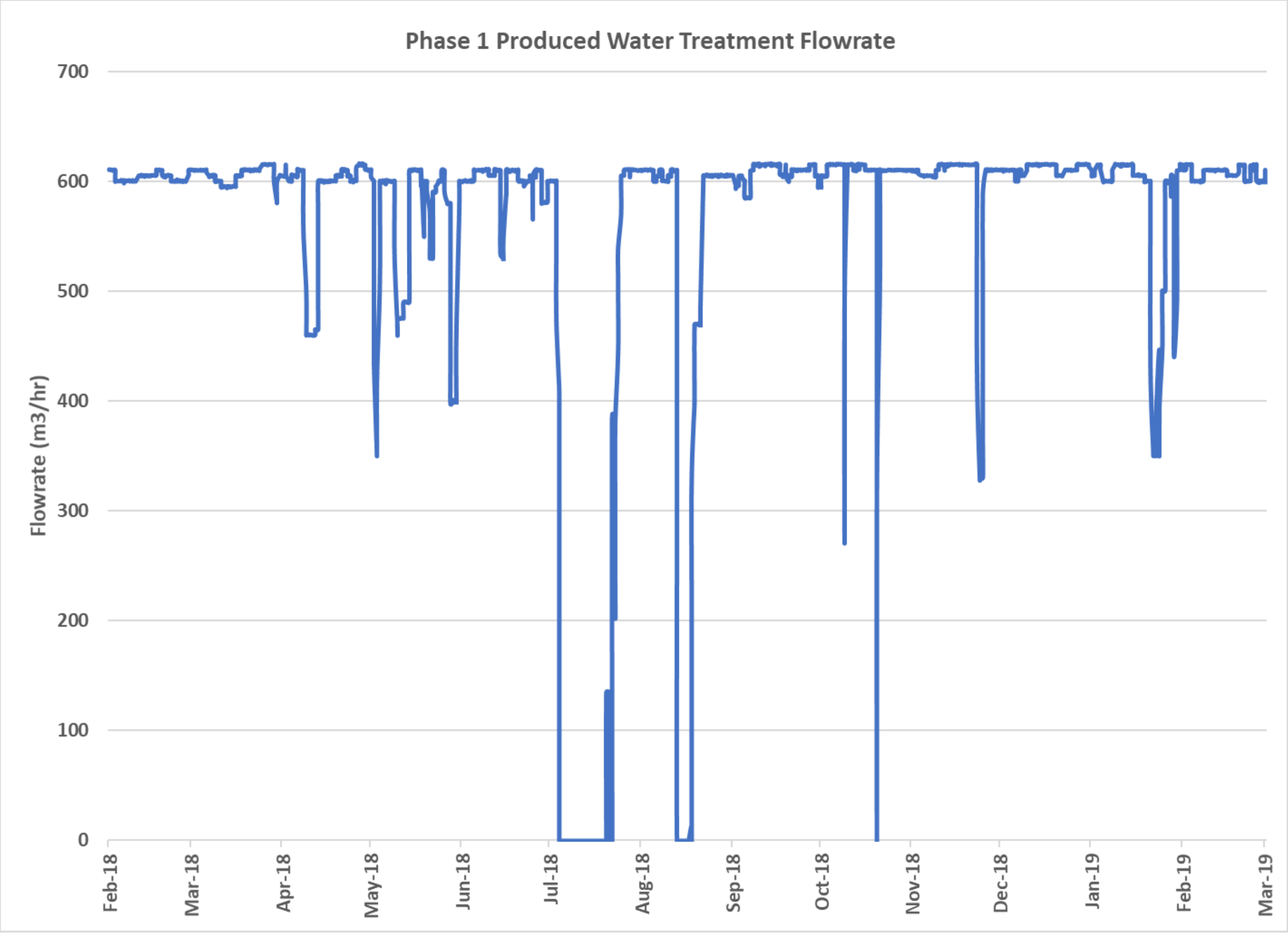


Facility Performance: Bitumen Treatment by Train



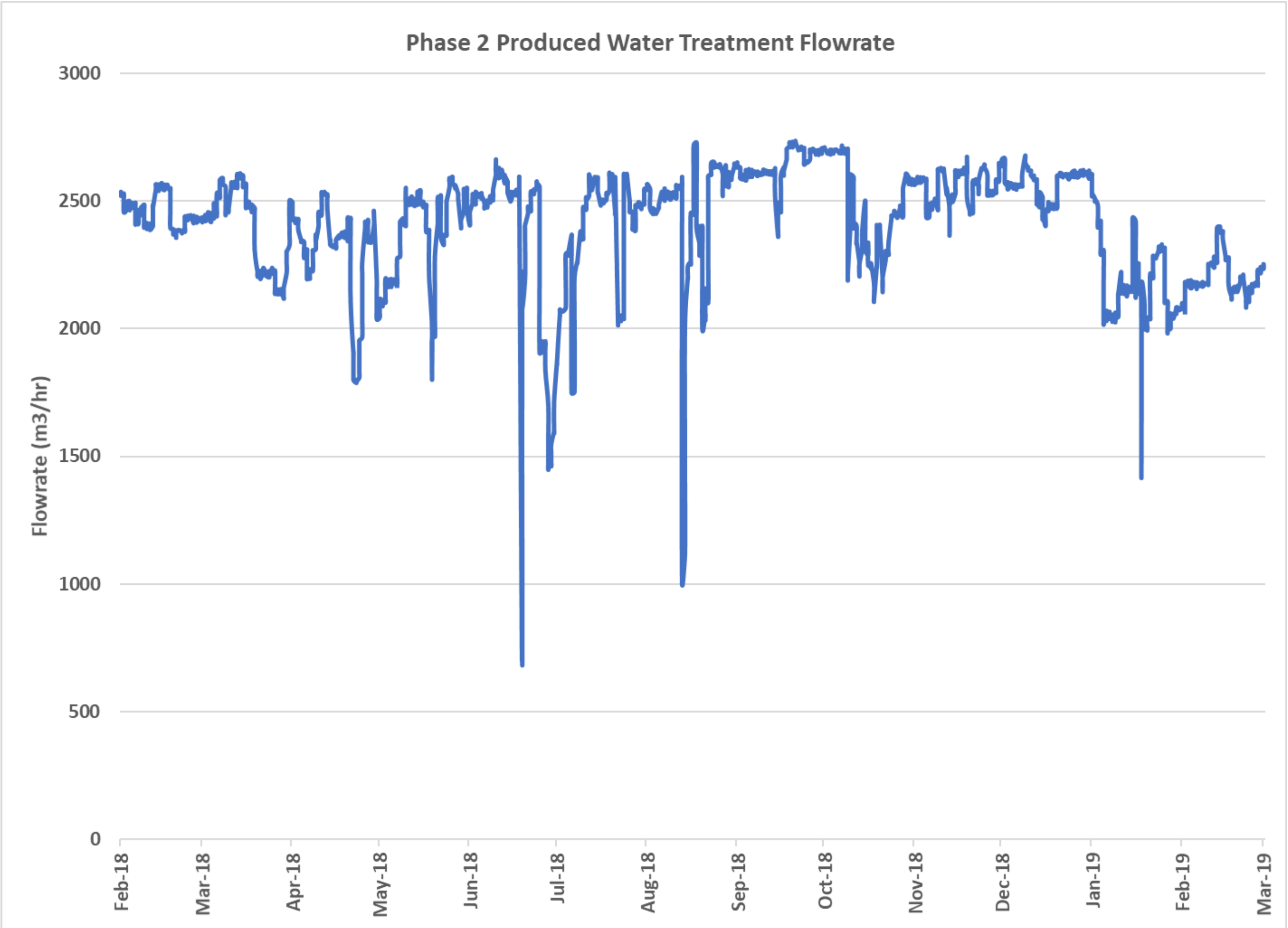
Facility Performance: Phase 1 Water Treatment

- 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.



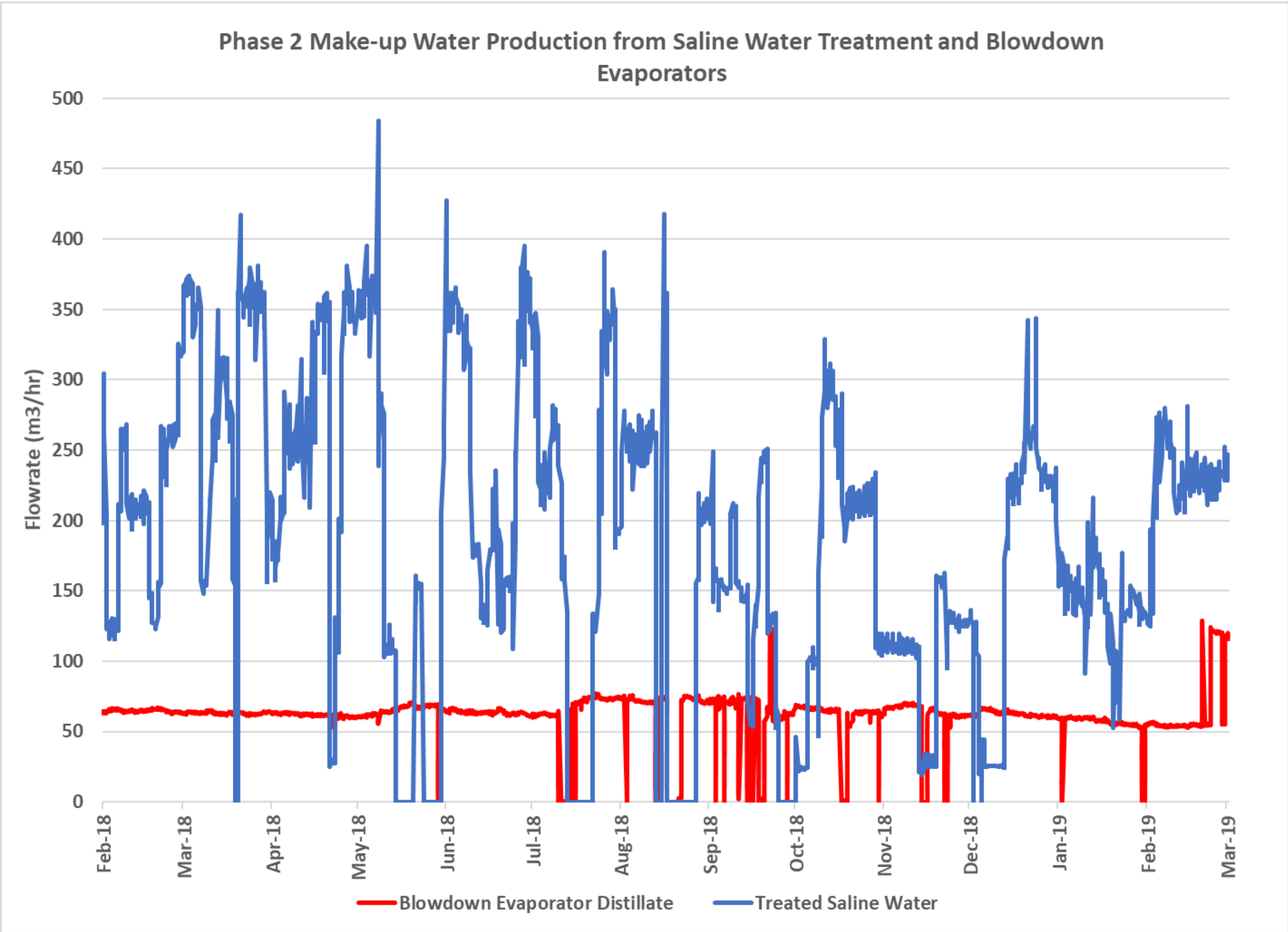
Facility Performance: Phase 2 Water Treatment

- 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.



Facility Performance: Phase 2 Saline Water Treatment and Blowdown Evaporators

- 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.



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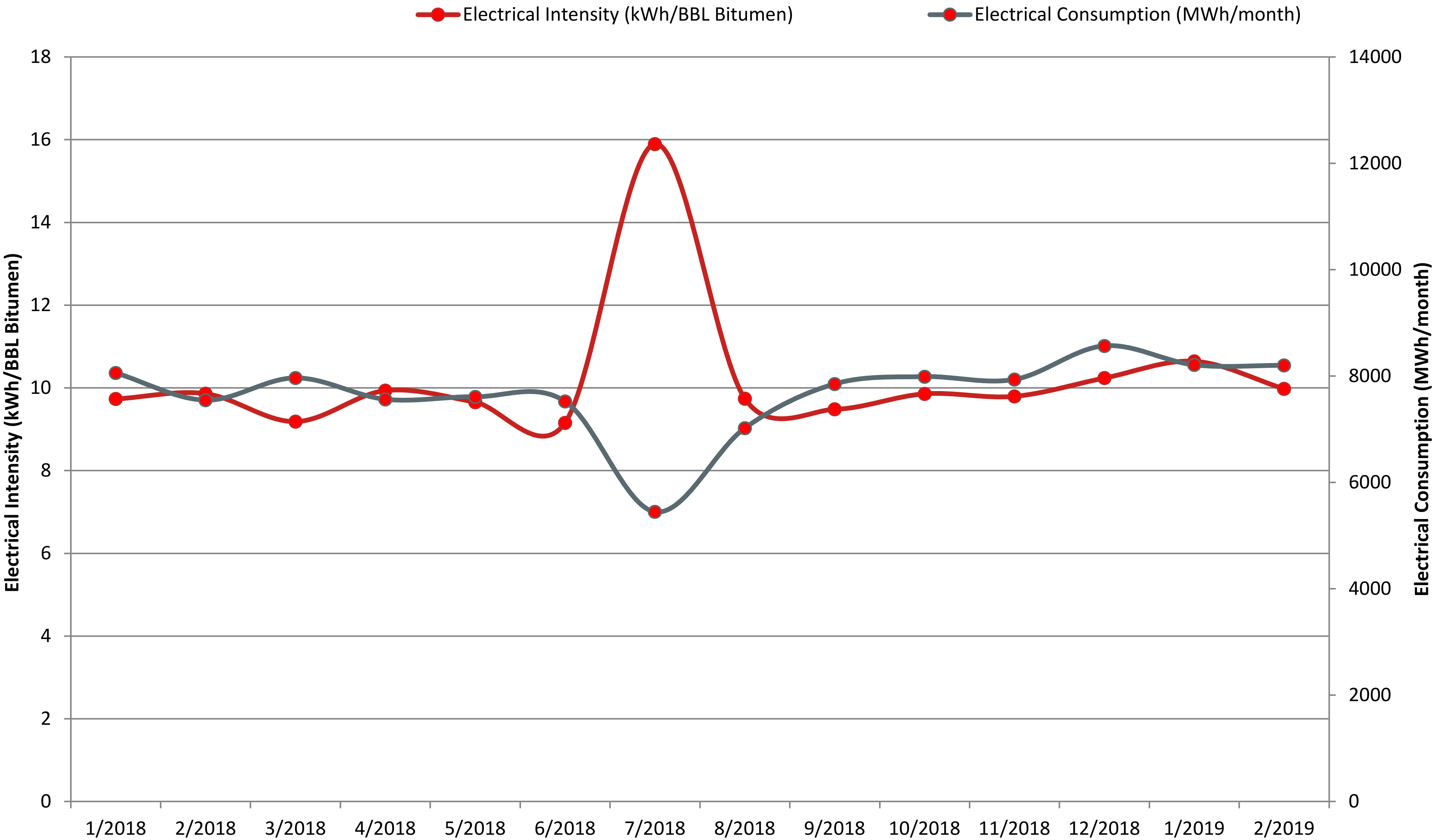
Surmont : Steam Generation Performance & Path Forward

- 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)

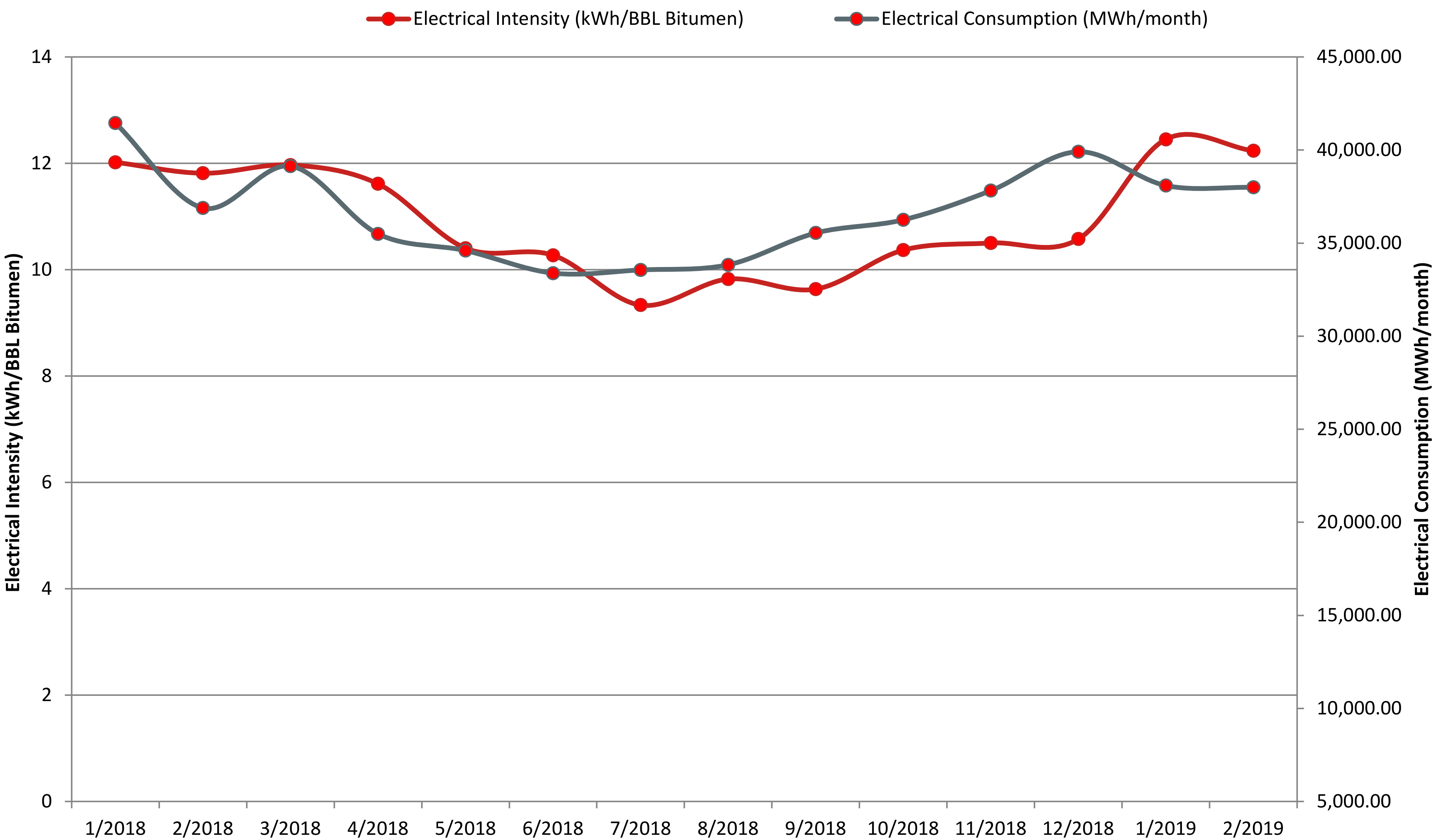
*2019 focus is to maintain online reliability while maximizing steam output

Facility Performance: Electricity Consumption Surmont 1



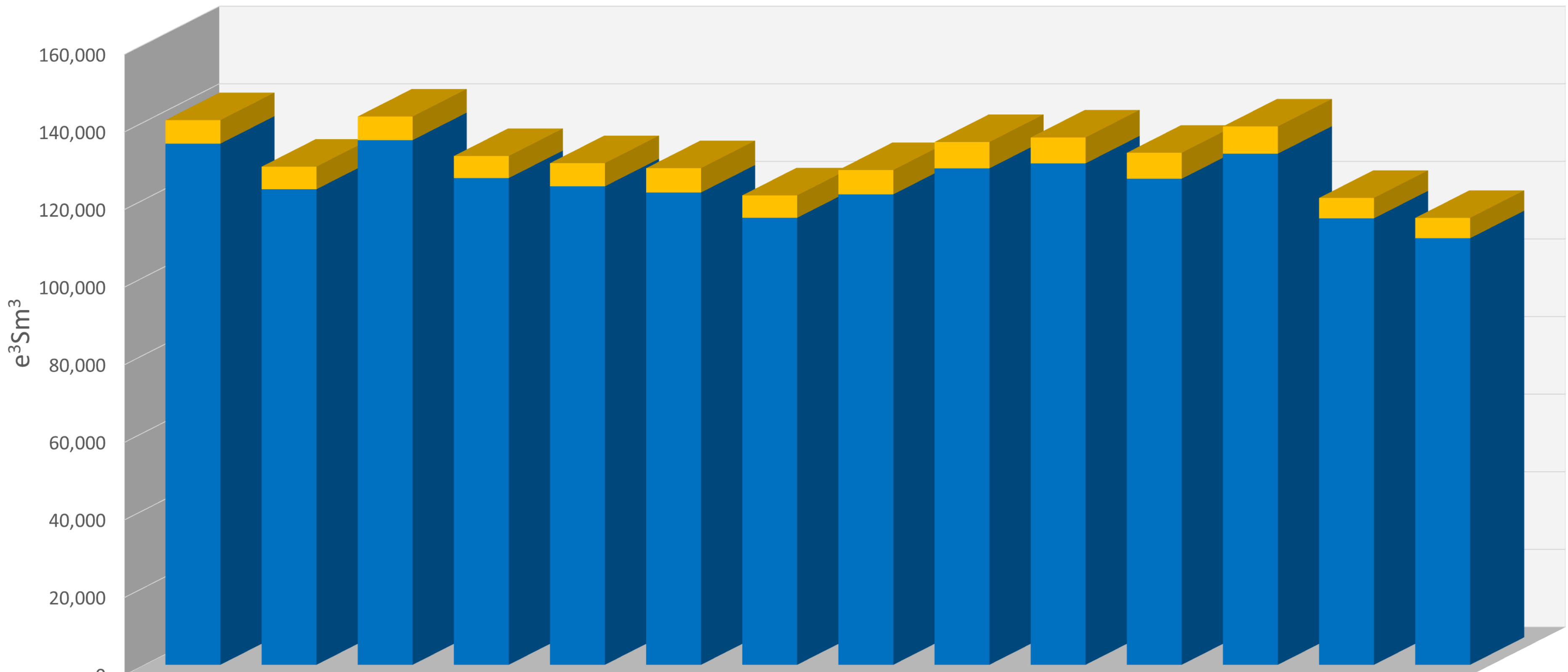
- **Phase 1 is at a steady state of production and electrical consumption, however the turn around in July caused the anomaly in 2018.**

Facility Performance: Electricity Consumption Surmont 2



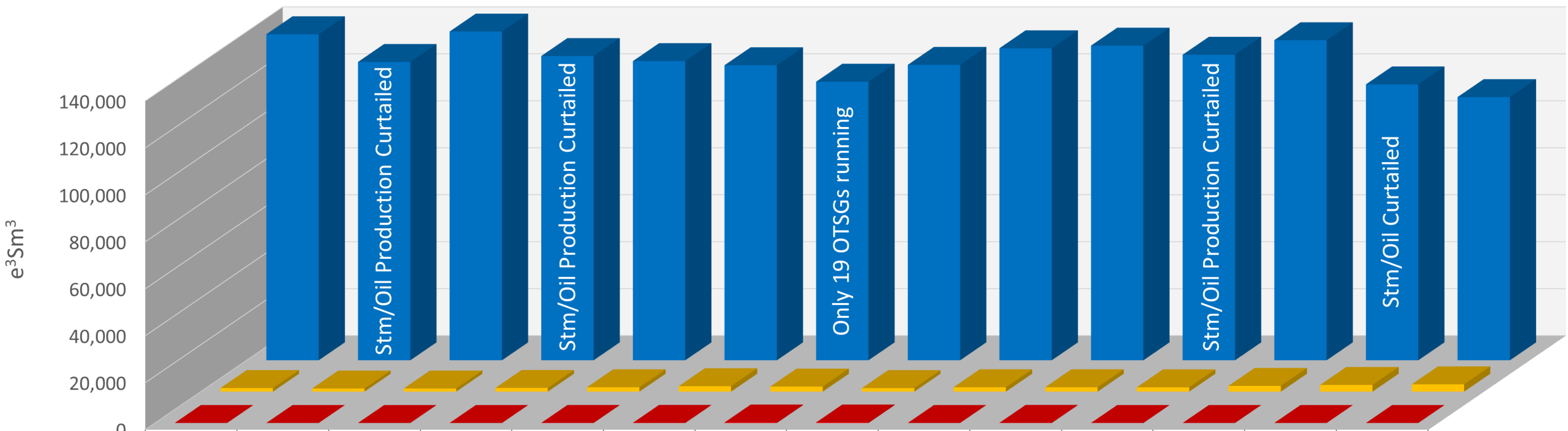
- **Reduced power requirement in summer shows slight variation.**

Facility Performance: 2018 Total Gas Usage



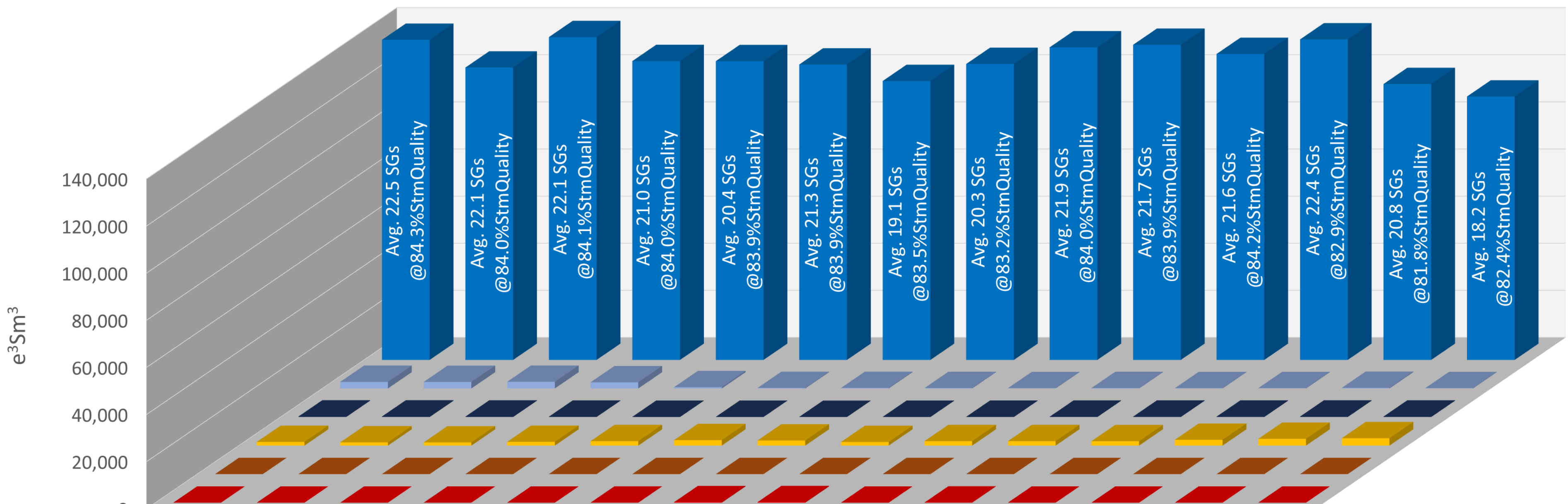
	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19
Solution Gas	6,065.1	5,820.3	6,096.6	5,688.4	5,969.5	6,272.7	5,778.1	6,283.0	6,784.7	6,675.1	6,695.3	7,020.9	5,269.7	5,235.3
TCPL Import	134,310.5	122,568.8	135,221.7	125,442.5	123,317.0	121,726.2	115,209.3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

Surmont Facility Performance: 2018 Usage by Type



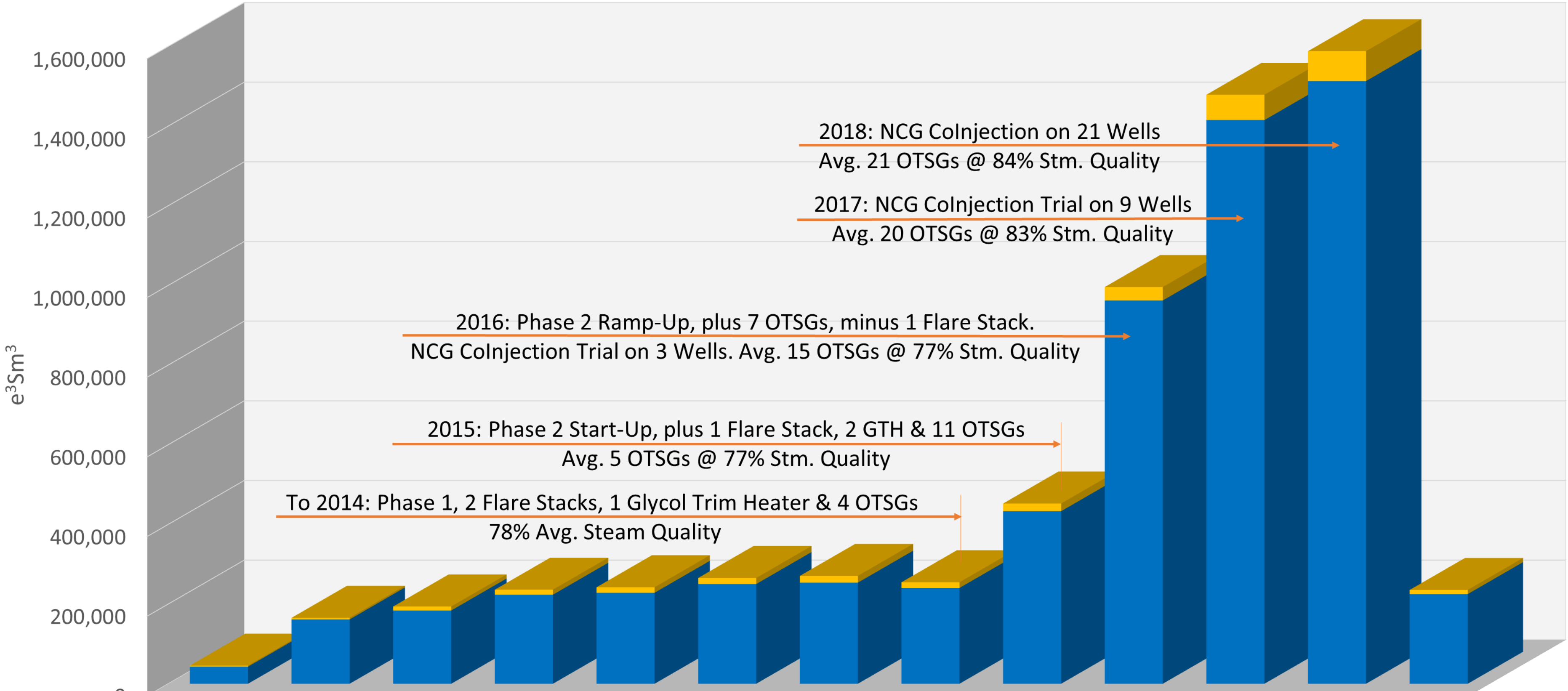
	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19
Flare/Vent	7.5	2.8	1.1	2.1	29.2	56.7	209.4	227.0	2.1	49.9	14.4	4.9	0.8	0.0
NCG_INJ	1,540.3	1,345.9	1,342.2	1,567.7	1,868.0	2,309.9	2,157.4	1,502.0	1,879.0	1,869.3	1,846.2	2,451.6	2,848.3	3,105.3
BT/IF Fuel Gas	138,827.8	127,040.4	139,975.0	129,561.1	127,389.3	125,632.3	118,620.6	125,796.4	132,855.1	133,989.7	130,104.4	136,298.4	117,482.3	112,073.3

Facility Performance: 2018 Gas Usage by Location



	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19
Flare	3.4	0.0	0.0	0.2	8.5	31.4	208.6	225.5	0.0	49.8	12.9	0.0	0.0	0.0
Vent	6.6	2.8	1.1	1.9	20.7	25.3	0.8	1.5	2.1	0.1	1.5	4.9	0.8	0.8
NCG	1,540.3	1,345.9	1,342.2	1,567.7	1,868.0	2,309.9	2,157.4	1,502.0	1,879.0	1,869.3	1,846.2	2,451.6	2,848.3	3,105.3
Camp Fuel Gas	217.1	211.0	177.4	135.4	81.3	71.9	64.3	66.8	96.7	118.4	160.4	166.5	185.1	185.1
BT Fuel Gas	2,788.6	2,754.0	2,815.8	2,616.2	543.1	200.8	197.2	157.8	119.2	156.9	121.8	134.0	235.4	129.8
IF Fuel Gas	135,822.	124,075.	136,981.	126,809.	126,764.	125,359.	118,359.	125,571.	132,639.	133,714.	129,822.	135,997.	117,061.	111,758.

Surmont Facility Performance: Year over Year Total Gas Usage



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Solution Gas	2,754.8	4,154.1	10,072.4	12,703.1	13,869.0	15,193.4	17,004.7	14,245.5	19,301.0	33,635.8	63,632.1	75,035.5	10,505.1
TCPL	42,798.8	161,383.3	183,912.9	223,446.8	228,343.6	250,290.0	253,749.3	240,496.3	433,138.0	962,312.9	1,415,198	1,513,227	225,004.9
Flare/Vent	7,132.2	6,438.7	3,962.0	705.0	624.8	217.6	117.3	277.3	475.7	370.5	238.9	607.1	1.6
% Gas Rcvry.				94.45%	95.49%	98.57%	99.31%	98.05%	97.54%	98.90%	99.62%	99.19%	99.98%
Avg. GOR		6.4	12.0	10.8	11.0	10.8	10.8	9.3	12.1	8.2	9.1	9.4	9.6
Avg. SOR		2.9	2.8	2.5	2.5	2.5	2.4	2.4	3.7	3.4	3.0	2.9	3.2

Surmont Facility Performance: 2018 Gas Usage - Highlights

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).

Surmont Facility Performance: Flare/Vent Events

All efforts made to reduce and/or minimize Flare and Vent Events

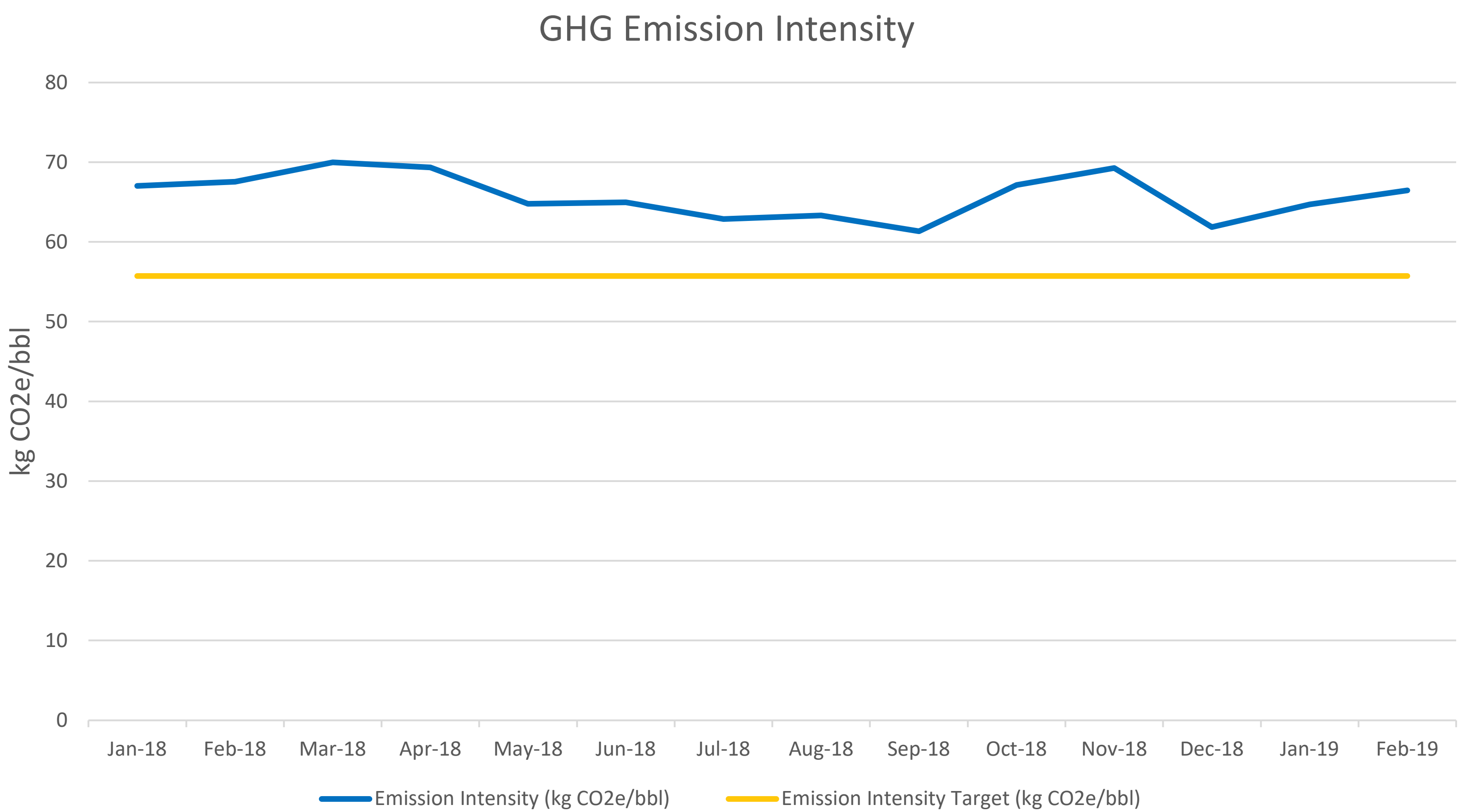
Vent Events

- 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

Facility Performance: Greenhouse Gas



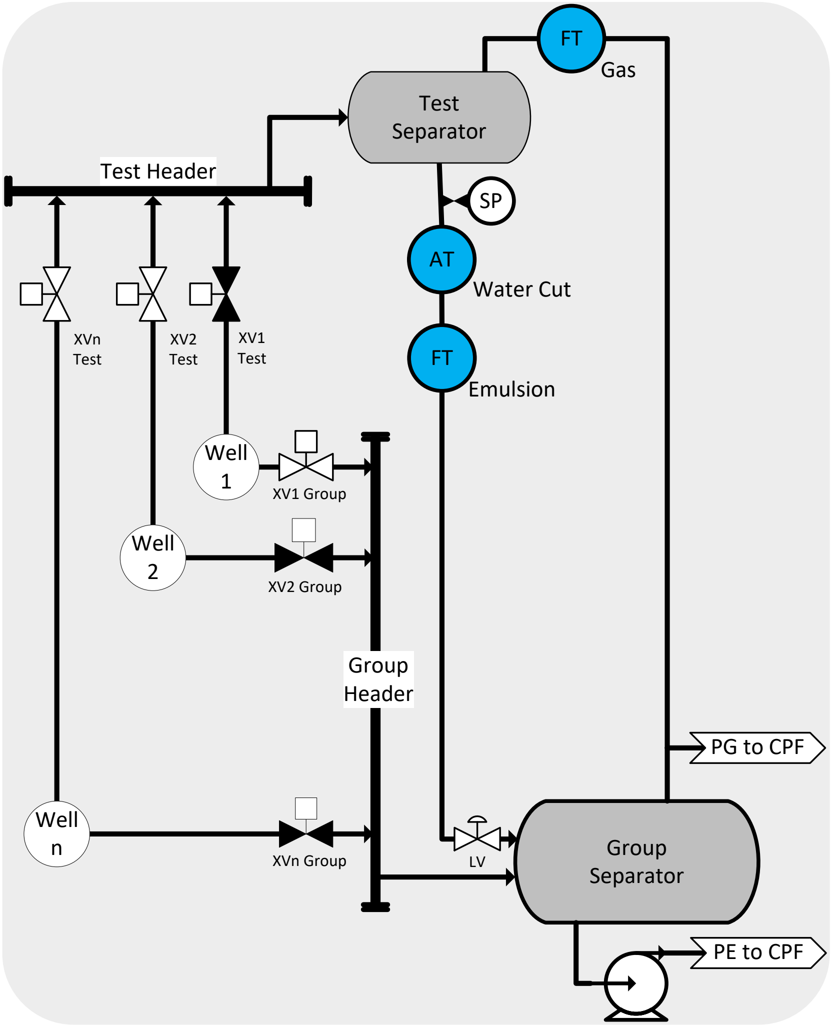
- **As of 2018 Phase 1 and Phase 2 CO_2e emission are reported as one combined value.**
- **2018 GHG Emission intensity is currently being verified for payment submission.**

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.



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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 =

$$\textit{Well Estimated Daily Oil Production} \times \textit{Hours per Days in Operation}$$

- Well Estimated Daily Oil Production =

$$\frac{\textit{Test Produced Emulsion Volume} \times (1 - WC\%)}{\textit{Test Duration (hours)}} \times \textit{24 hours}$$

Well Monthly Estimated Water Production =

$$\textit{Well Estimated Daily Water Production} \times \textit{Hours per Days in Operation}$$

- Well Estimated Daily Water Production =

$$\frac{\textit{Test Produced Emulsion Volume} \times WC\% + \textit{Water Vapor}}{\textit{Test Duration (hours)}} \times \textit{24 hours}$$

Well Allocated Oil Production

$$\textbf{\textit{Well Estimated Monthly Oil Production}} \times \textbf{\textit{Oil Proration Factor}}$$

- Oil Proration Factor =

$$\frac{\textit{Battery Produced Oil}}{\textit{Total Estimated Monthly Oil Production}}$$

- Battery Produced Oil =

Oil Dispositions + Battery Tank Inventory + Shrinkage – Receipts + Well Load Oil

- Total Estimated Monthly Oil Production =

$$\sum_{i=1}^{x} Well_i \textit{ Estimated Montly Oil Production}$$

where x is the total number of production wells for the reporting period.

- Oil Dispositions =

Sales CTM[1] *+ Enbridge Tank Inventory + TruckOut*

- Oil in Battery's Tank Inventory =

Sales Oil Tanks + OffSpec Tanks + Slop Oil Tanks + Skim Oil Tanks

- Receipt =

Diluent CTM[1]*+ Diluent Tank Inventory + Diluent TruckIn*

Well Allocated Water Production

$$\textbf{\textit{Well Estimated Monthly Water Production}} \times \textbf{\textit{Water Proration Factor}}$$

- Water Proration Factor =

$$\frac{\textit{Battery Produced Water}}{\textit{Total Estimated Monthly Water Production}}$$

- Battery Produced Water =

$$\textit{Water Dispositions} + \textit{Battery Tank Inventory} - \textit{Receipts} + \textit{Well Load Water}$$

- Total Estimated Monthly Water Production =

$$\sum_{n=1}^{x} Well_n \textit{ Estimated Montly Water Production}$$

where x is the total number of production wells for the reporting period.

- Water Dispositions =

$$\textit{Dispositions to Injection Facility} + \textit{Truck−Out}$$

- Water in Battery’s Tank Inventory =

$$\textit{Skim Oil Tanks} + \textit{Slop OilTanks} + \textit{DeSand/BackWash/ORF Tanks} + \textit{Sales/OffSpec/Diluent Tanks}$$

- Receipt =

$$\textit{IF Condensate Returns} + \textit{Water in Diluent} + \textit{Truck−In}$$

Well Allocated Gas Production

Well Allocated Oil Production × GOR

- Gas to Oil Ration (GOR) =

$$\frac{\textit{Battery Produced Gas}}{\textit{Battery Produced Oil}}$$

- Battery Produced Gas =

Gas Dispositions – Receipts

- Gas Dispositions =

Battery Utility FG+ Steam Generators FG + NCG CoInjection + Flare/Vent +Camp

- Receipt =

TCPL Fuel Gas CTM[1]

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

[1] CTM: Custody Transfer Meter

Well Allocated Steam

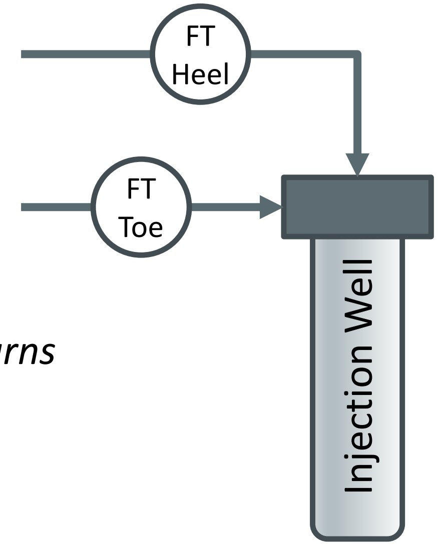
$$\textit{Well Measured Steam} \times \textit{Steam Proration Factor}$$

- Well Measured Steam =

$$\textit{Steam Injected @Heel} + \textit{Steam Injected @Toe}$$

- Steam Proration Factor =

$$\frac{\textit{Steam Produced}}{\textit{Total Measured Steam}}$$



- Steam Produced =

$$\textit{Steam Generated (CPF)} - \textit{Steam Condensate Returns}$$

- Total Measured Steam =

$$\sum_{n=1}^{x} \textit{Well}_n \textit{ Measured Steam}$$

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:

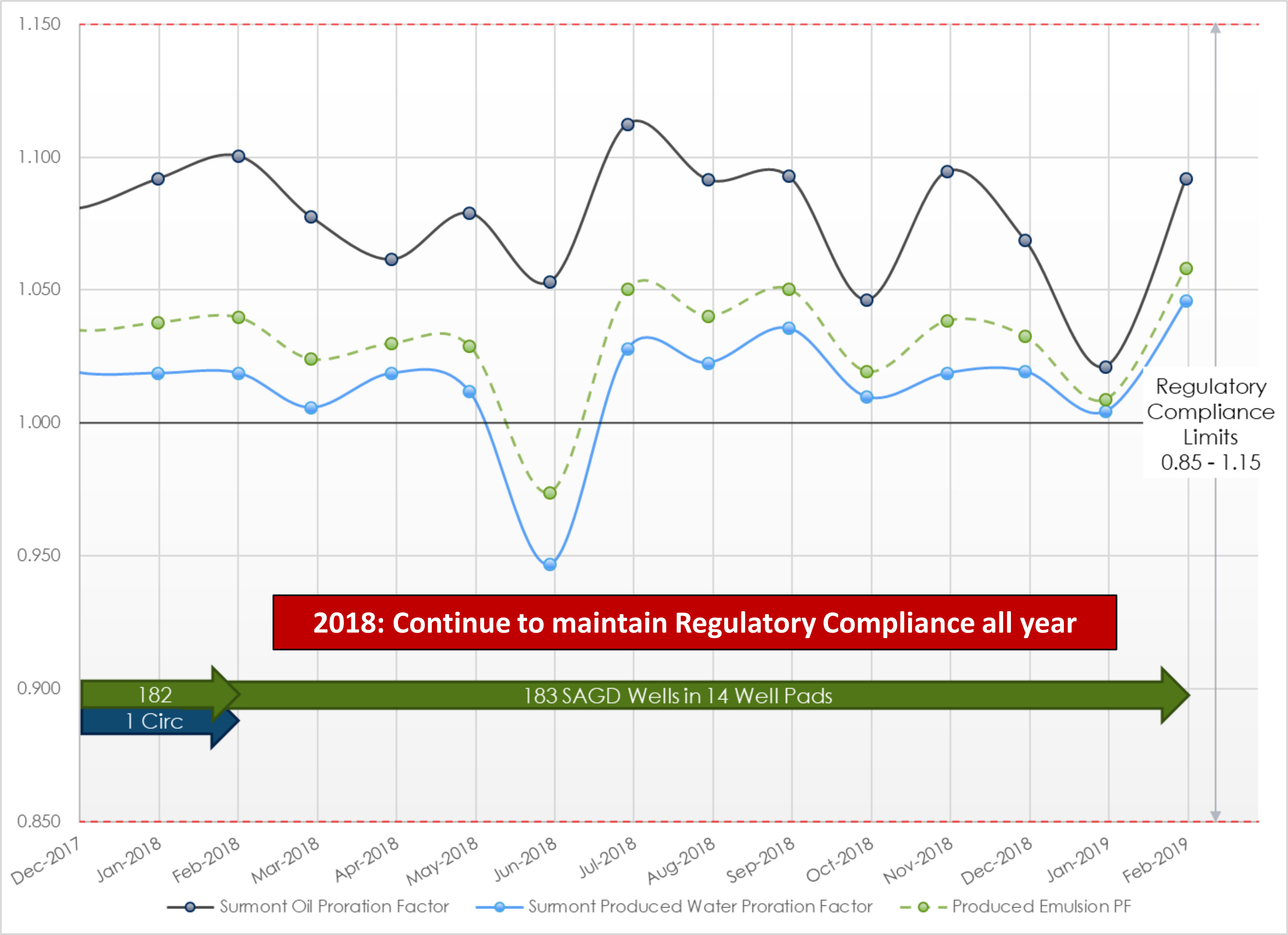
- **November 2016** Trial in 3 wells at Pad 102 (volumes estimated)
- **September 2017** Extended to 6 additional wells in Pad 102 (measured)
- **August 2018** Decision to include Pad 265-2, 12 wells (measured)
  Metering of Pad 102 initial 3 wells NCG volumes
- **December 2018** Installation of NCG 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)

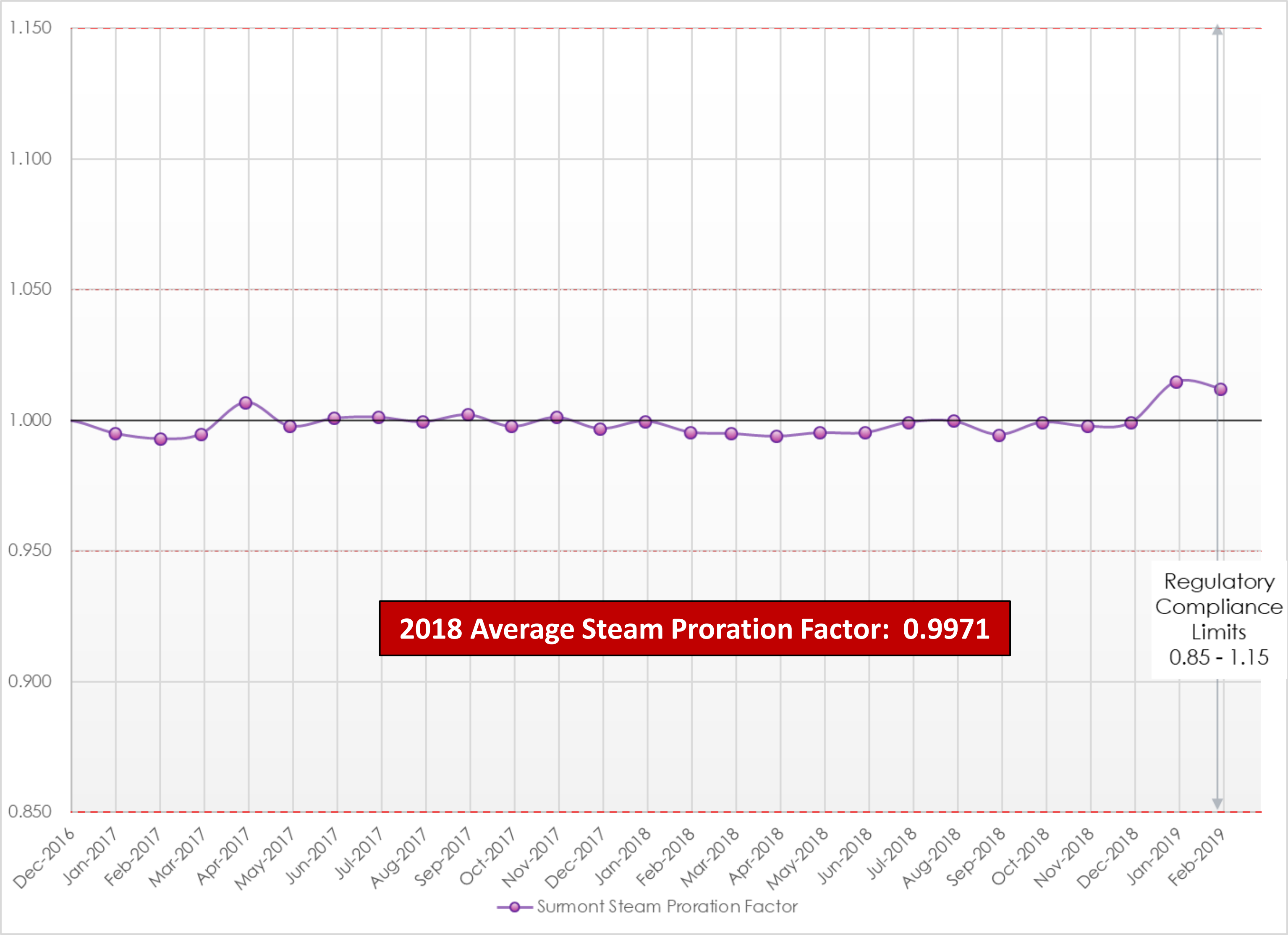
Continue to maintain proration factor regulatory compliance through all 2018, through multiple production curtailments

- Total of 183 wells in SAGD operation

Oil and Water Production Proration Factors



Steam Injection Proration Factor



Water Production, Injection and Uses

Subsection 3.1.2 (4)

Surmont Phase 1 and Phase 2 Water Source Wells

Surmont Phase 1 Non-Saline Water Source Wells

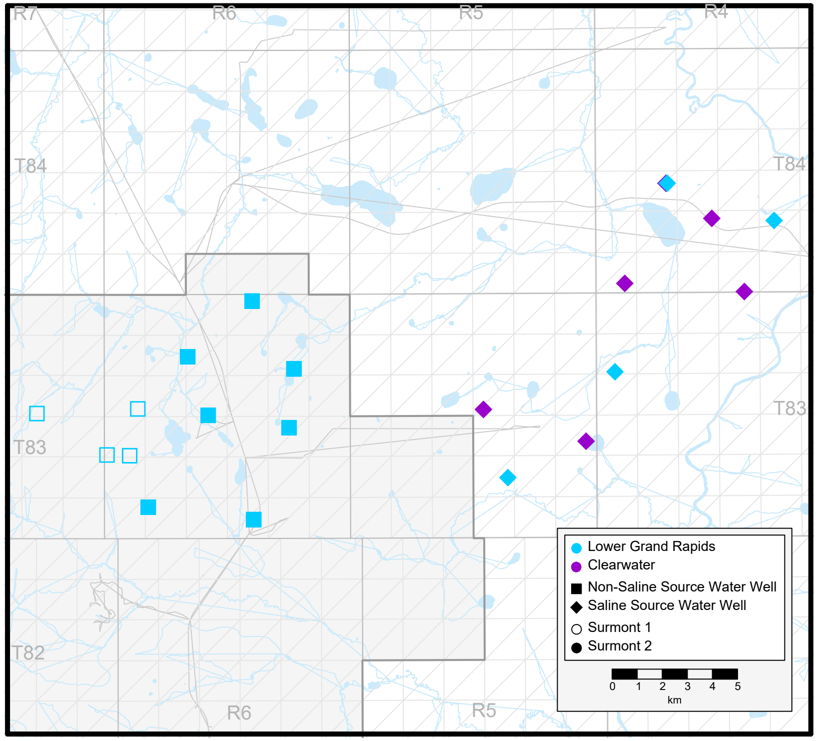
Source Well	Observation Well	Formation	Water Act Licence No.
1F1021808306W400	1F2021808306W400	Lower Grand Rapids	00253532-02-00
1F1041808306W400	102041808306W400	Lower Grand Rapids	00253532-02-00
1F1011908306W400	100011908306W400	Lower Grand Rapids	00253532-02-00
1F1032308307W400	100032308307W400	Lower Grand Rapids	00253532-02-00

Surmont Phase 2 Non-Saline Water Source Wells

Source Well	Observation Well	Formation	Water Act Licence No.
1F1022108306W400	100022108306W400	Lower Grand Rapids	00312463-01-00
1F1022608306W400	100022608306W400	Lower Grand Rapids	00312463-01-00
1F1052808306W400	100052808306W400	Lower Grand Rapids	00312463-01-00
1F1070308306W400	1F2070308306W400	Lower Grand Rapids	00312463-01-00
1F1101408306W400	1F1111408306W400	Lower Grand Rapids	00312463-01-00
1F1130508306W400	100130508306W400	Lower Grand Rapids	00312463-01-00
1F1153408307W400	1F2153408307W400	Lower Grand Rapids	00312463-01-00

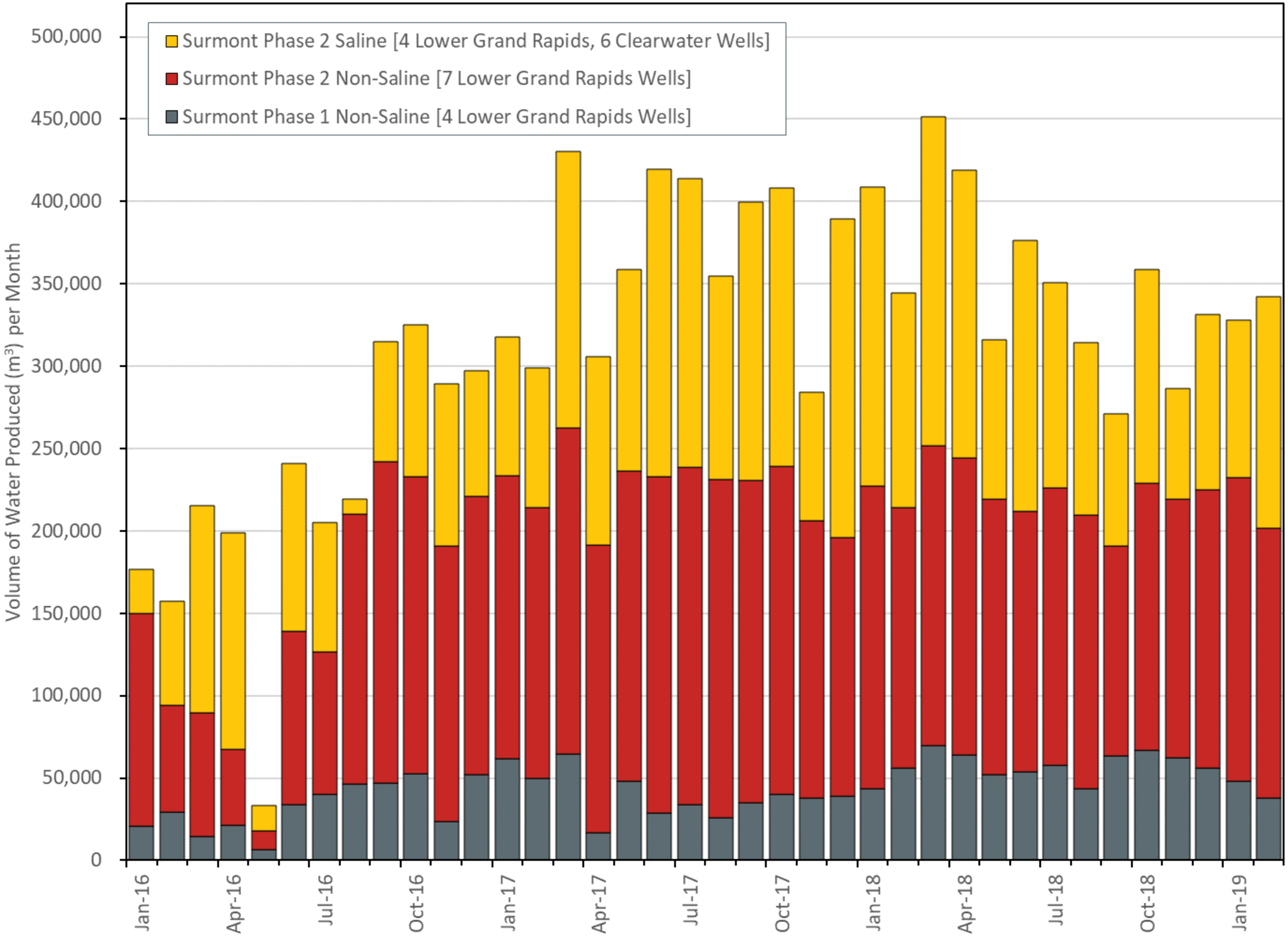
Surmont Phase 2 Saline Water Source Wells

Source Well	Formation
1F1020308404W400	Clearwater
1F1020608404W400	Clearwater
1F1033008304W400	Lower Grand Rapids
1F1042208305W400	Clearwater
1F1071308305W400	Clearwater
1F1081008305W400	Lower Grand Rapids
1F1101708404W400	Clearwater
1F1160908404W400	Clearwater
1F2091708404W400	Lower Grand Rapids
1F2141108404W400	Lower Grand Rapids

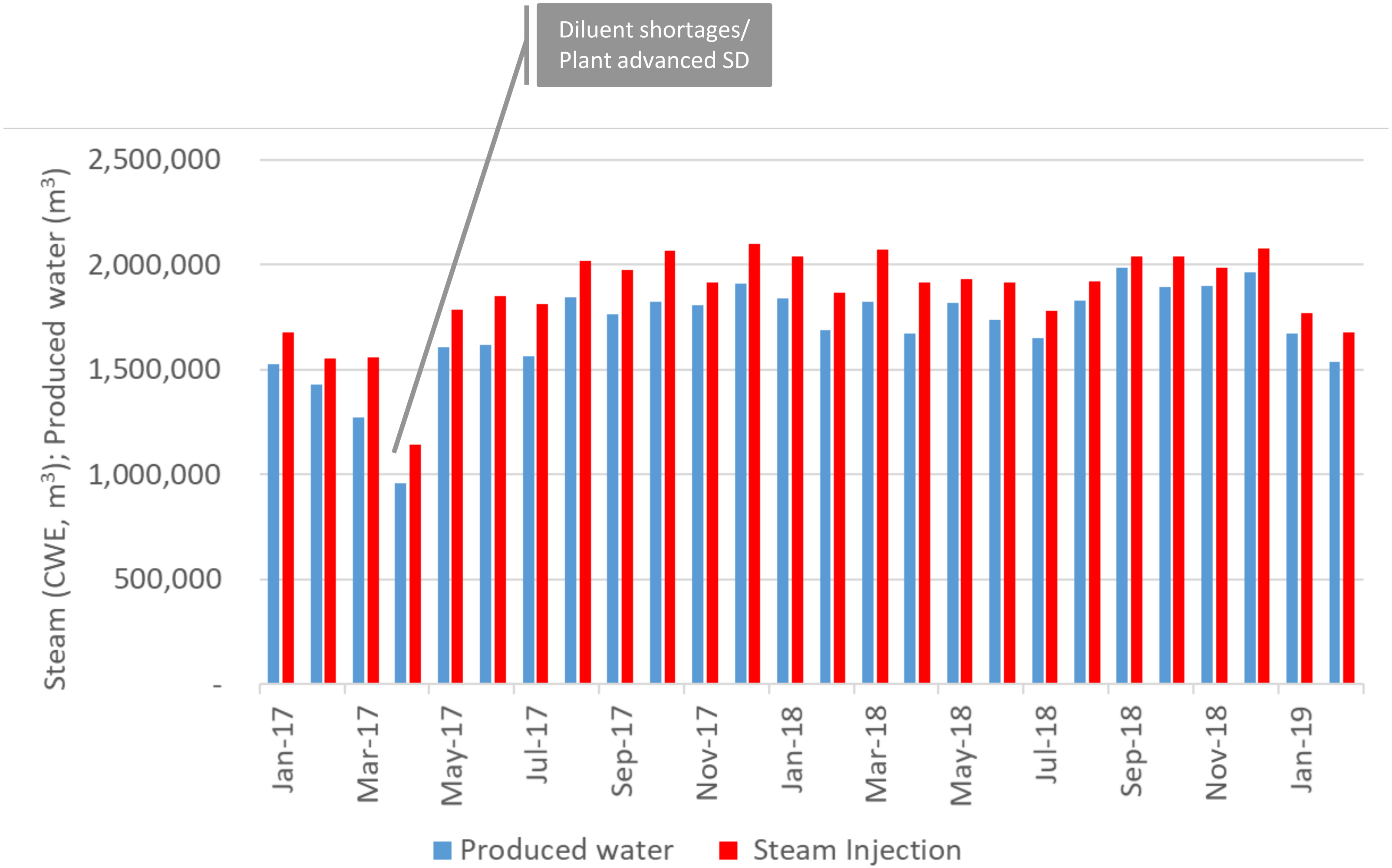


No Changes in 2018

Surmont Non-Saline and Saline Water Source Wells Production Volumes

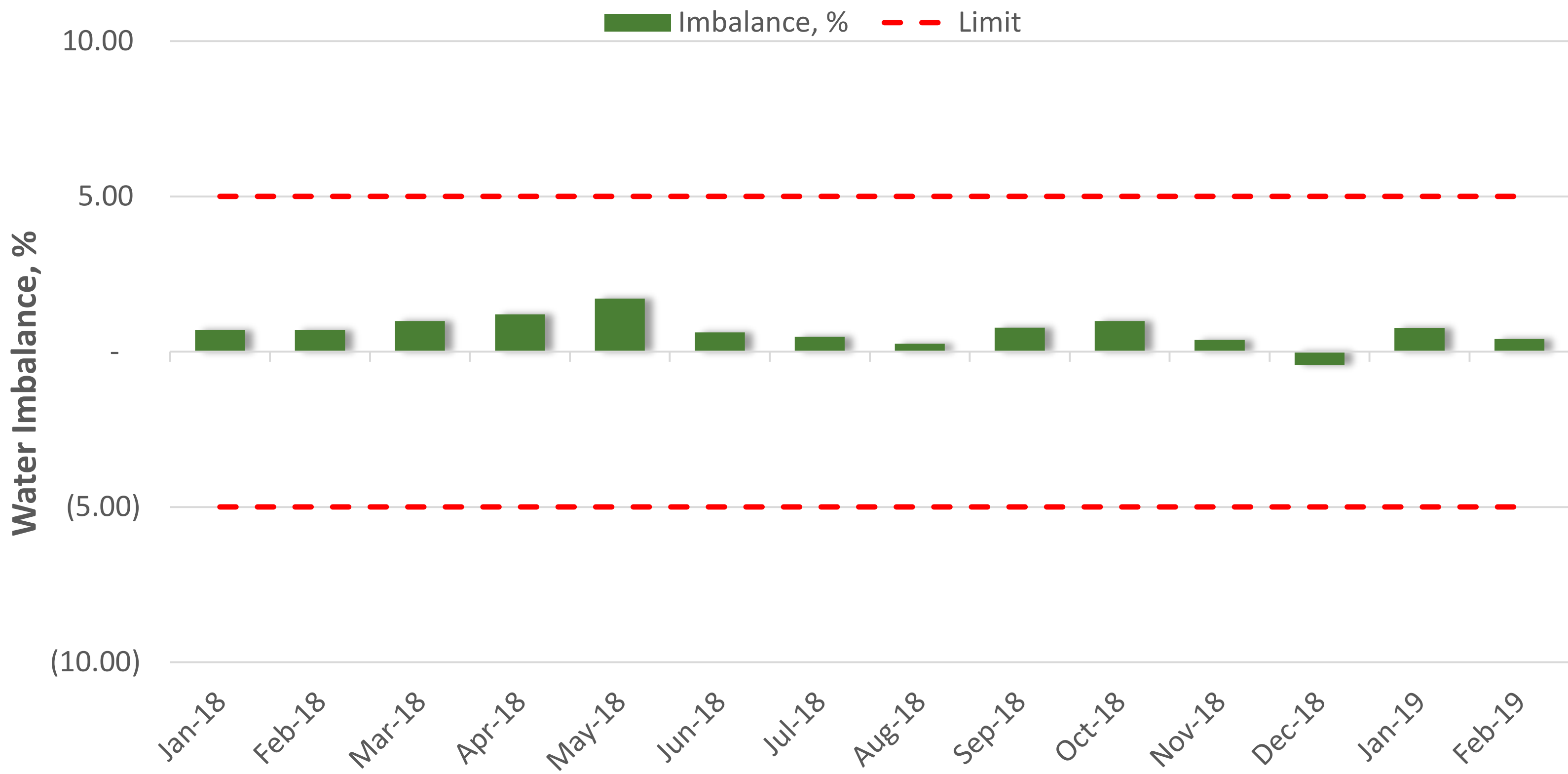


Water Production and Steam Injection Volumes

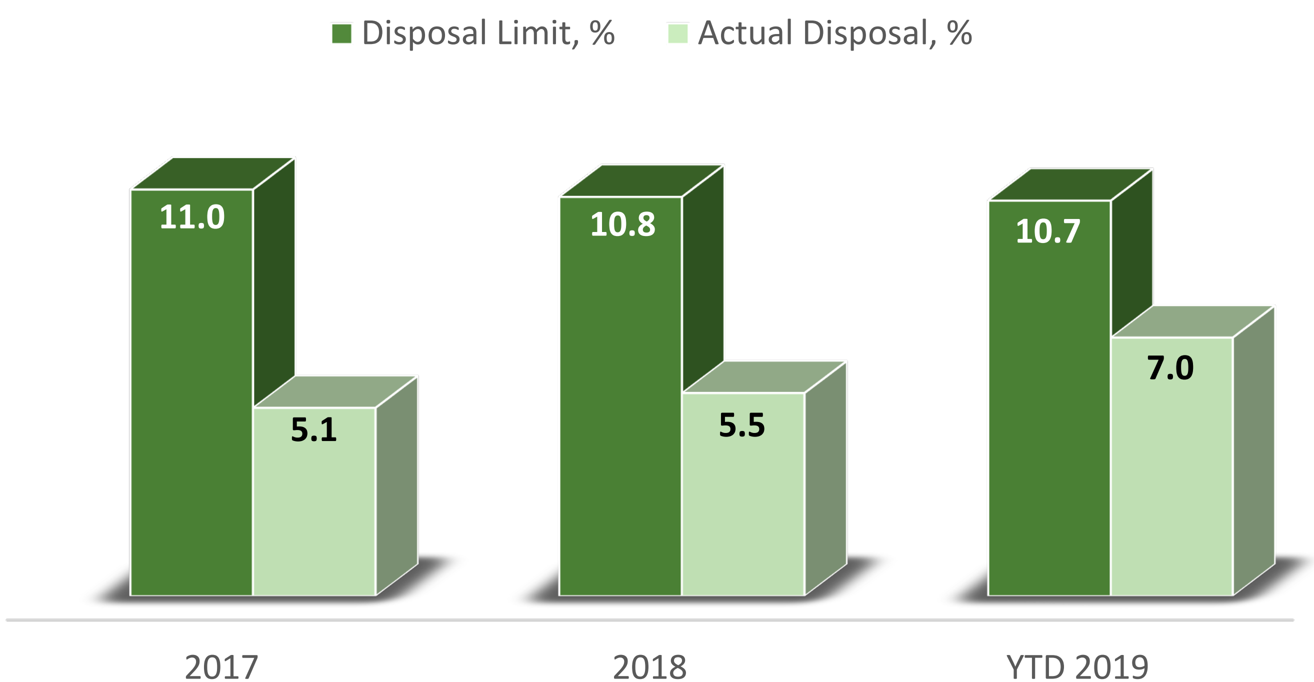


Directive 081: Injection Facility Water Imbalance

- Surmont in compliance with *Directive 081* Injection Facility Water Imbalance since June 2014
- Surmont Phase 2 CPF Shutdown planned for Q2-2019



Directive 081: Annual Disposal performance



- 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

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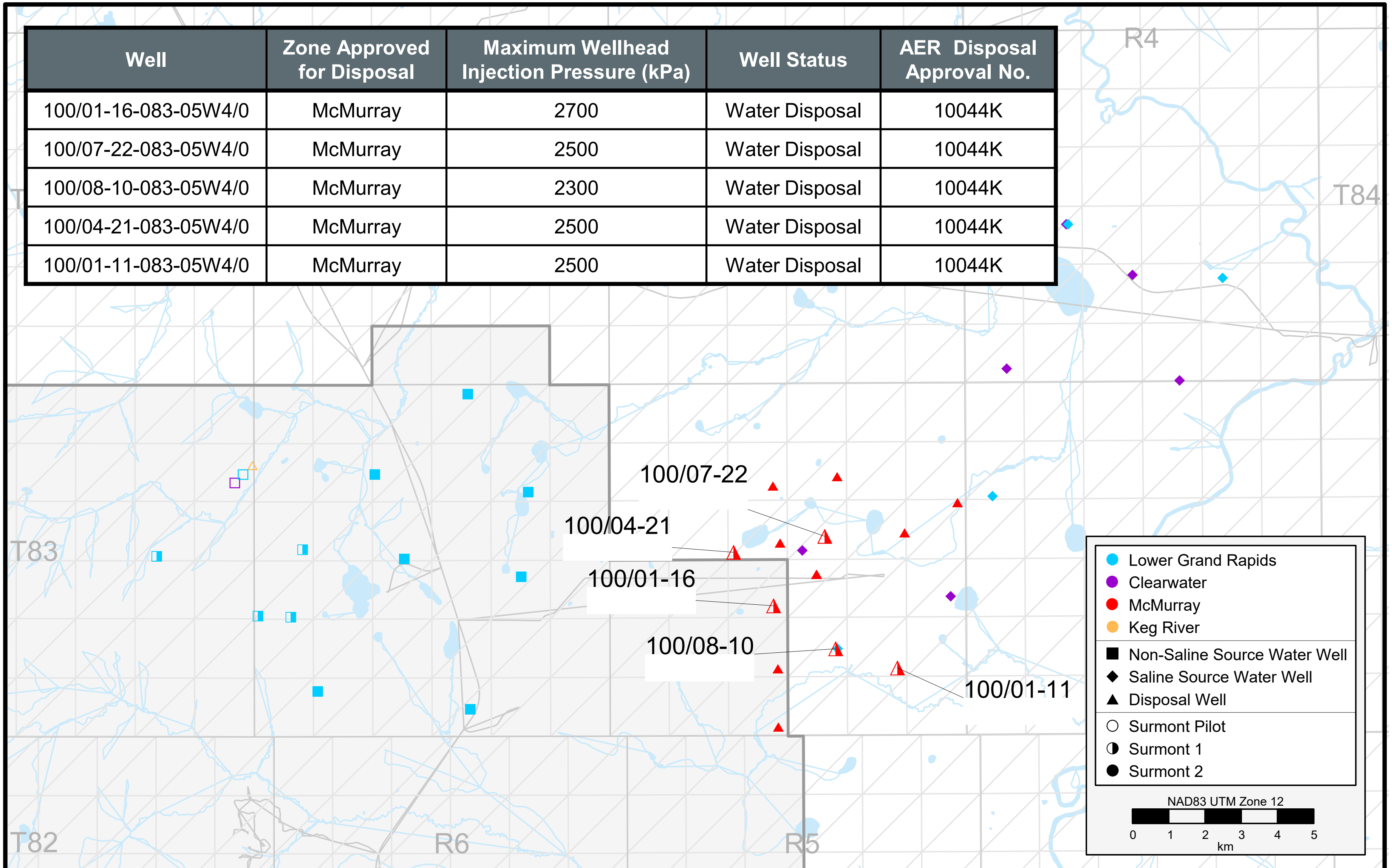
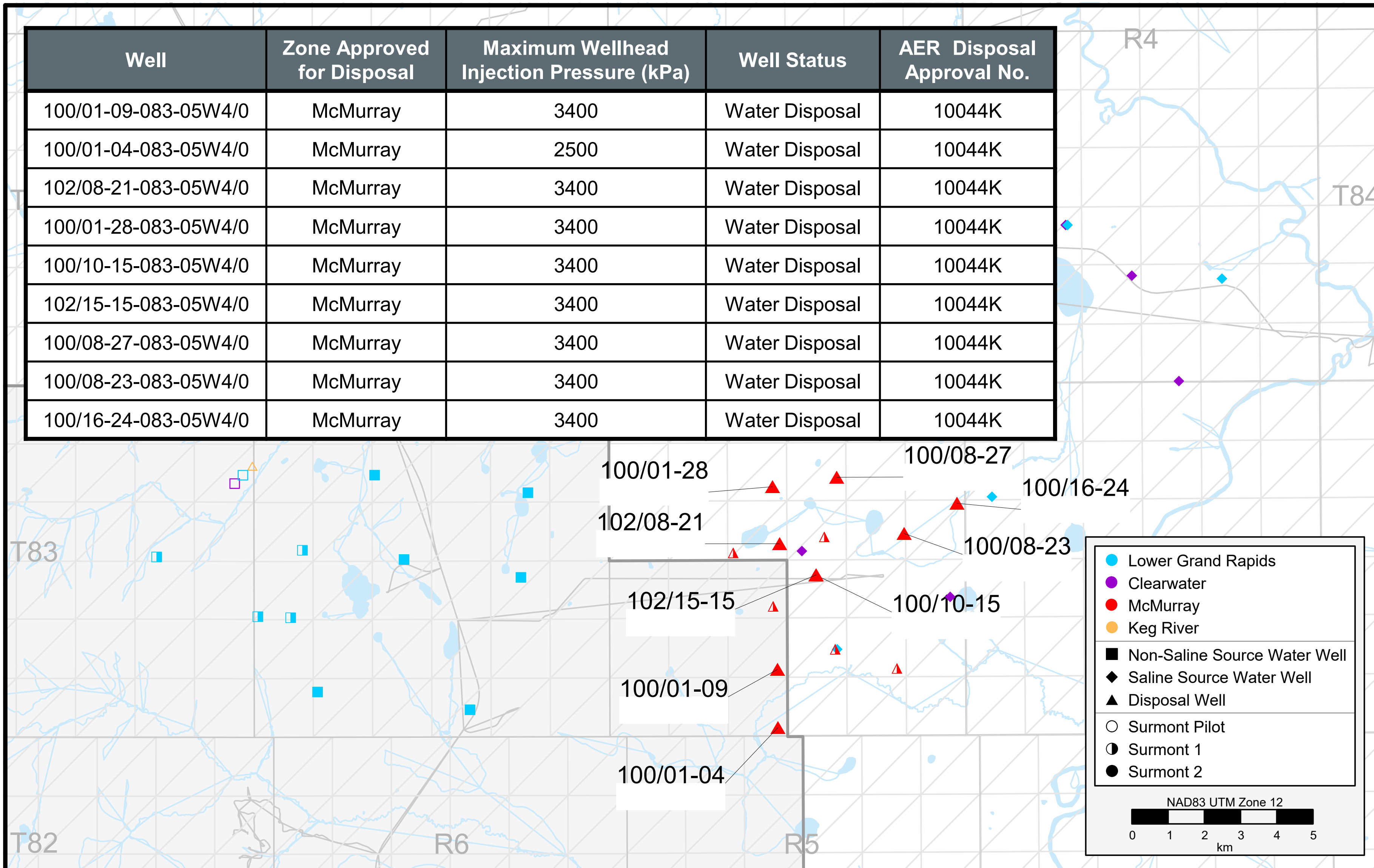
Surmont Phase 1 Water Disposal Wells

Well	Zone Approved for Disposal	Maximum Wellhead Injection Pressure (kPa)	Well Status	AER Disposal Approval No.
100/01-16-083-05W4/0	McMurray	2700	Water Disposal	10044K
100/07-22-083-05W4/0	McMurray	2500	Water Disposal	10044K
100/08-10-083-05W4/0	McMurray	2300	Water Disposal	10044K
100/04-21-083-05W4/0	McMurray	2500	Water Disposal	10044K
100/01-11-083-05W4/0	McMurray	2500	Water Disposal	10044K

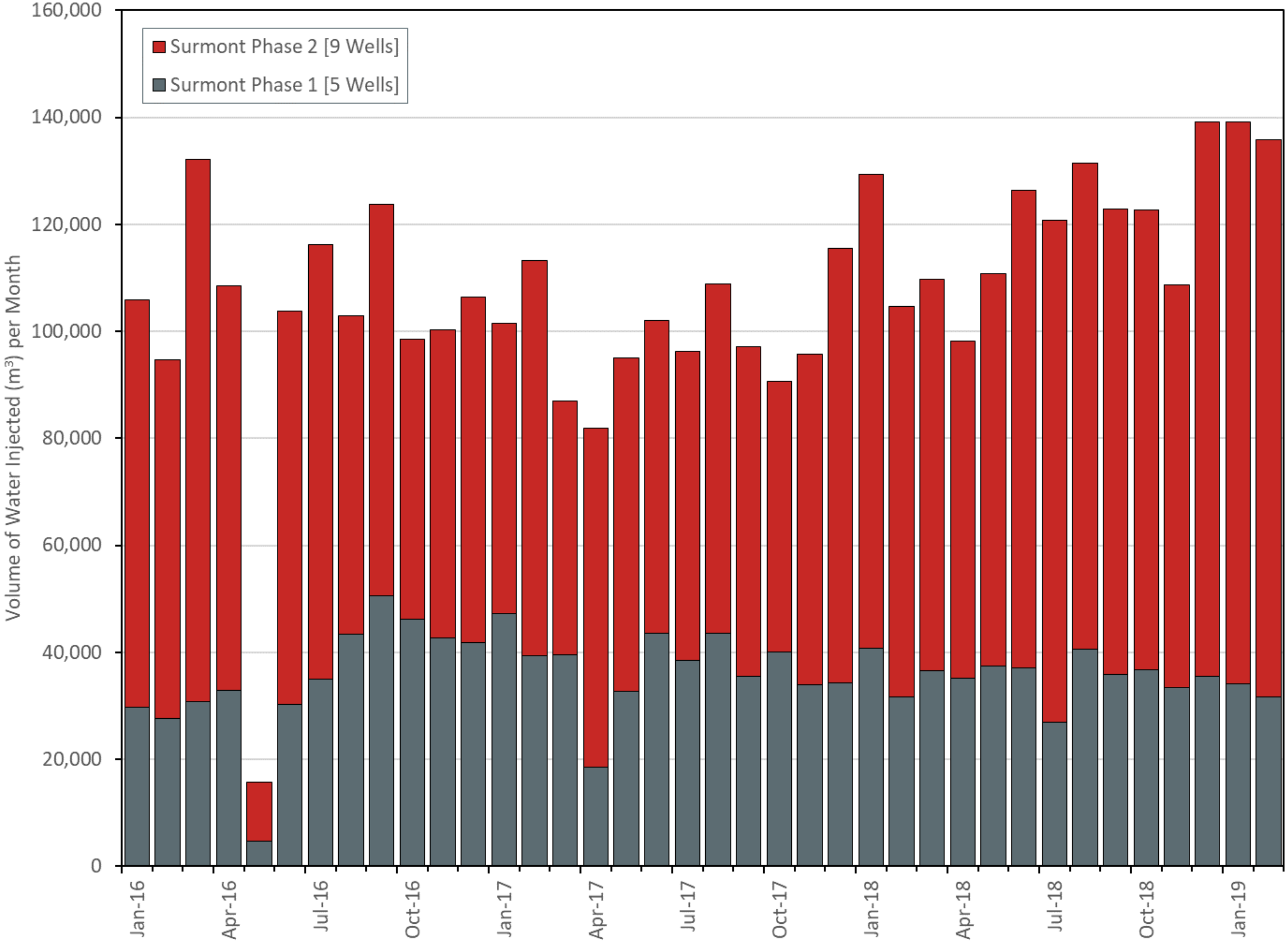


Surmont Phase 2 Water Disposal Wells

Well	Zone Approved for Disposal	Maximum Wellhead Injection Pressure (kPa)	Well Status	AER Disposal Approval No.
100/01-09-083-05W4/0	McMurray	3400	Water Disposal	10044K
100/01-04-083-05W4/0	McMurray	2500	Water Disposal	10044K
102/08-21-083-05W4/0	McMurray	3400	Water Disposal	10044K
100/01-28-083-05W4/0	McMurray	3400	Water Disposal	10044K
100/10-15-083-05W4/0	McMurray	3400	Water Disposal	10044K
102/15-15-083-05W4/0	McMurray	3400	Water Disposal	10044K
100/08-27-083-05W4/0	McMurray	3400	Water Disposal	10044K
100/08-23-083-05W4/0	McMurray	3400	Water Disposal	10044K
100/16-24-083-05W4/0	McMurray	3400	Water Disposal	10044K



Surmont Water Disposal Wells Injection Rates (McMurray)



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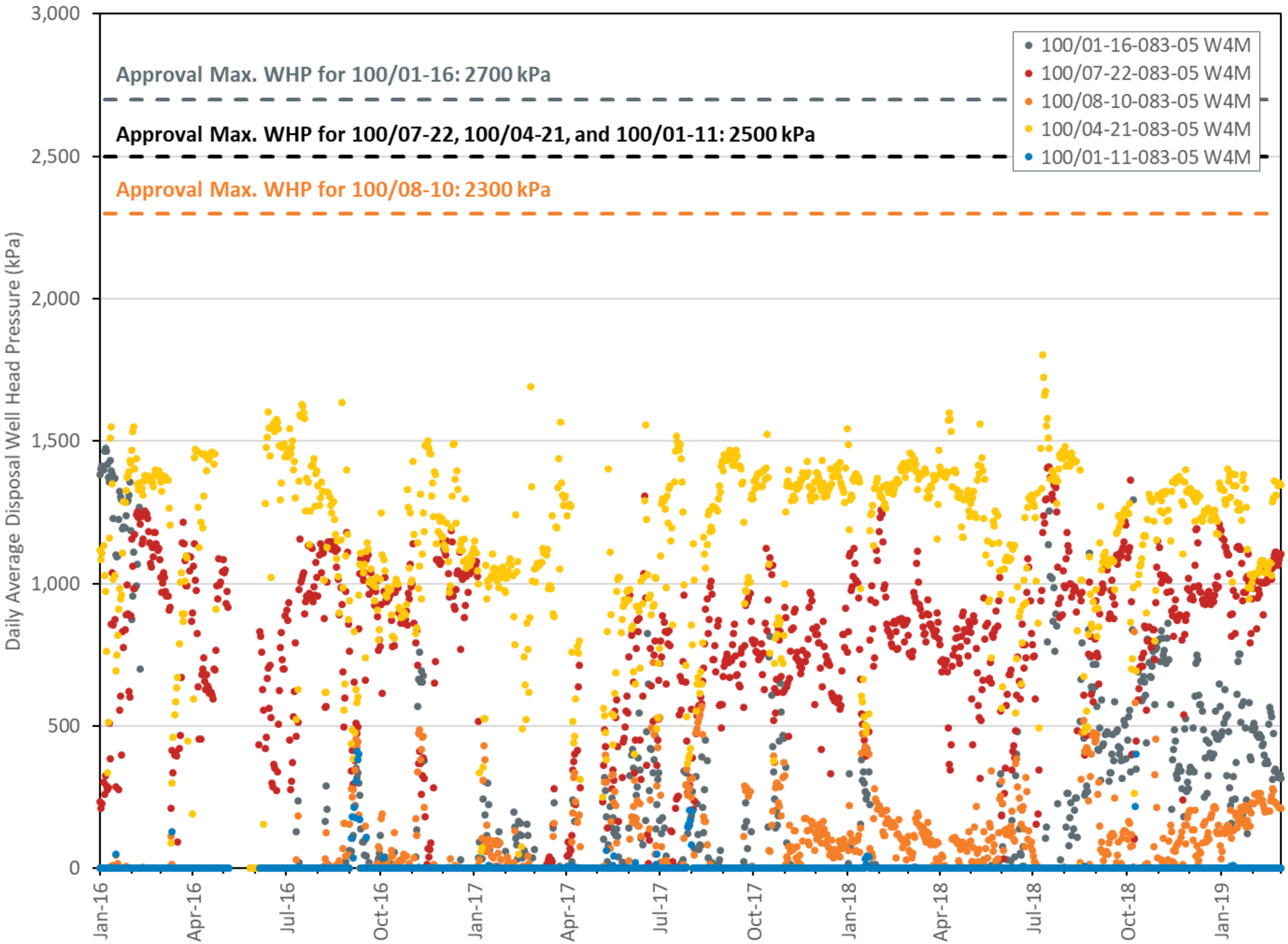
Surmont Phase 1 Water Disposal Wells Well Head Pressure (McMurray)



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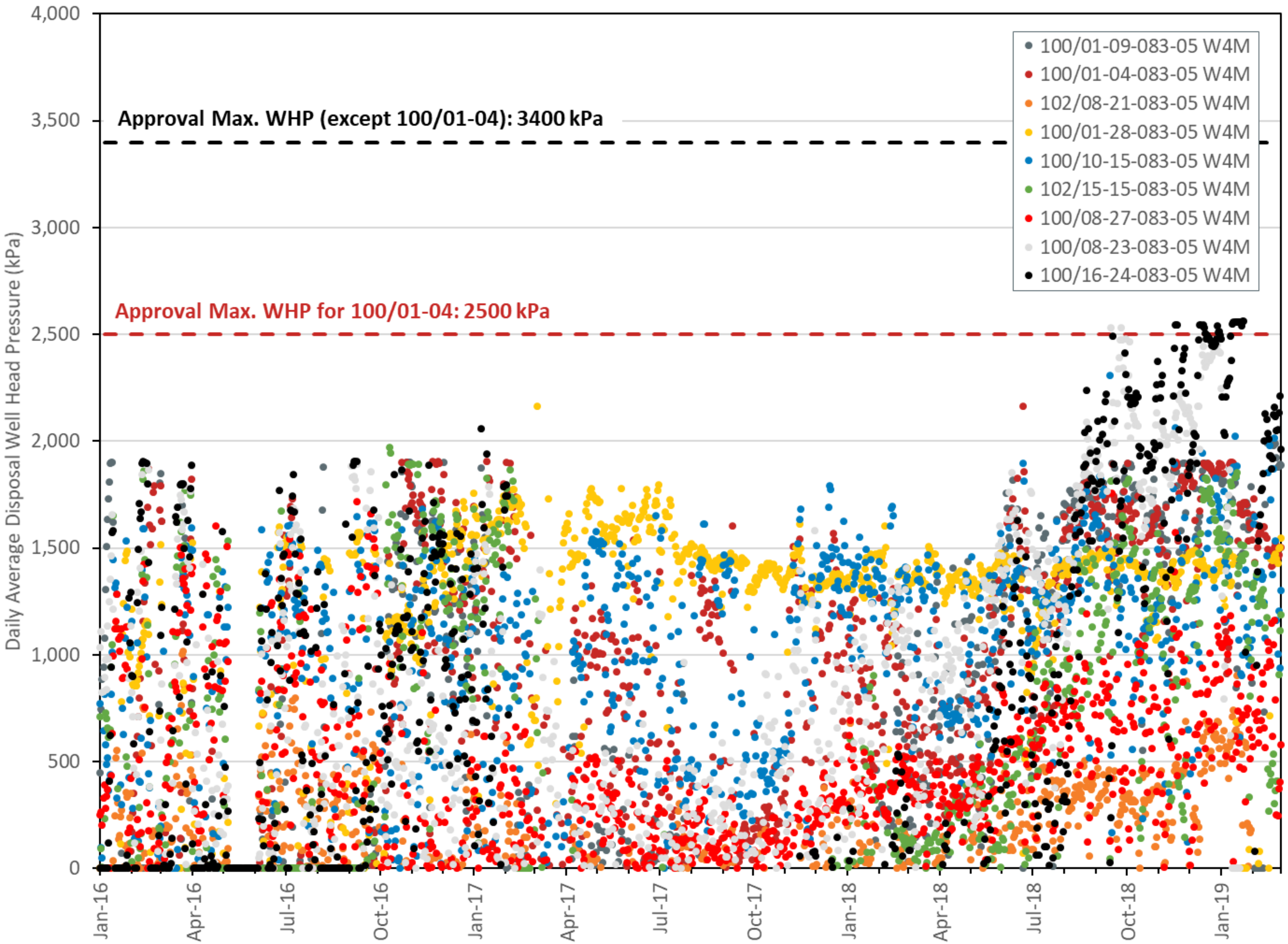
Surmont Phase 2 Water Disposal Wells Well Head Pressure (McMurray)



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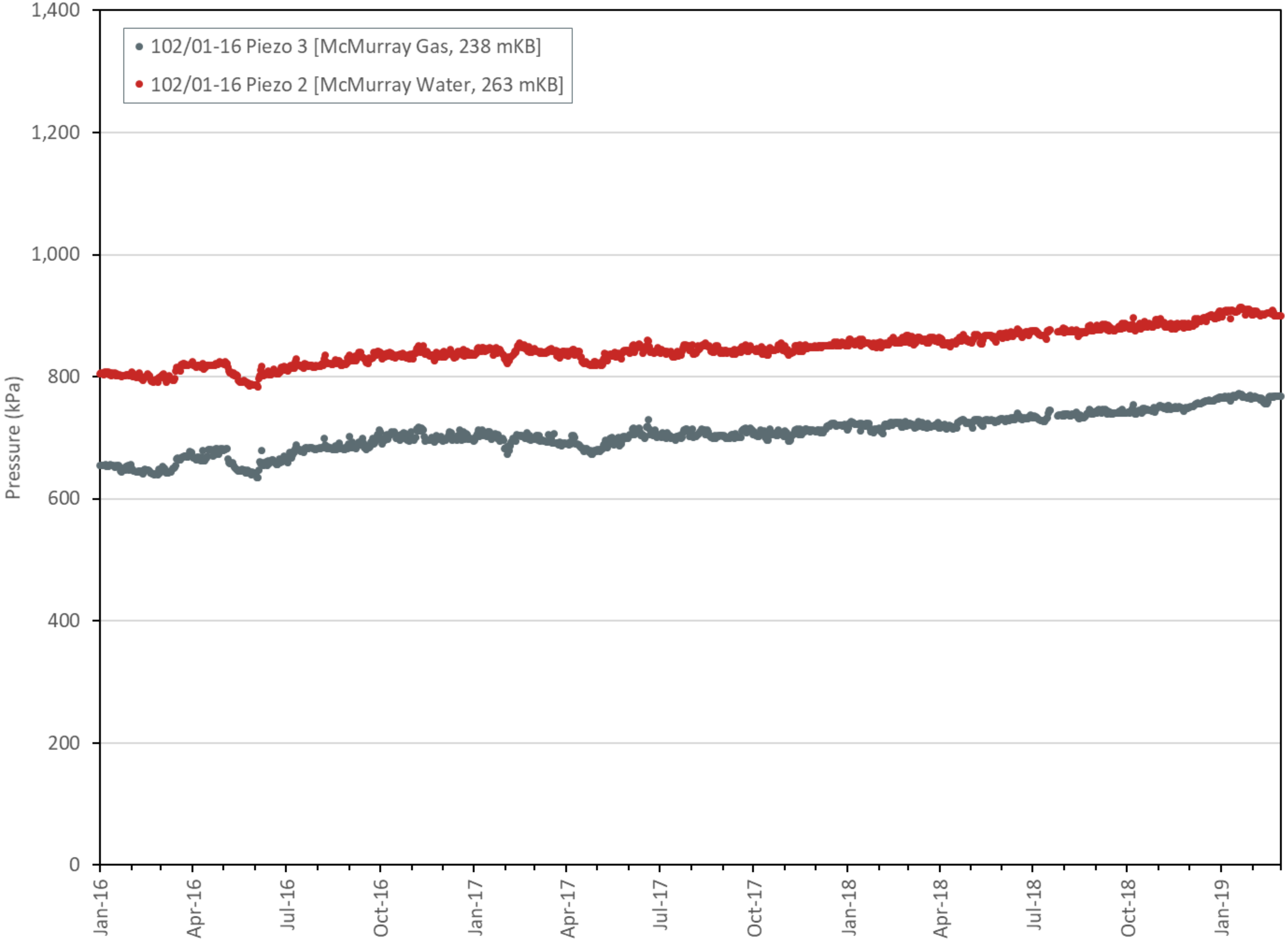
Water Disposal Well 100/01-16-083-05 W4M Observation Well Pressure (McMurray)



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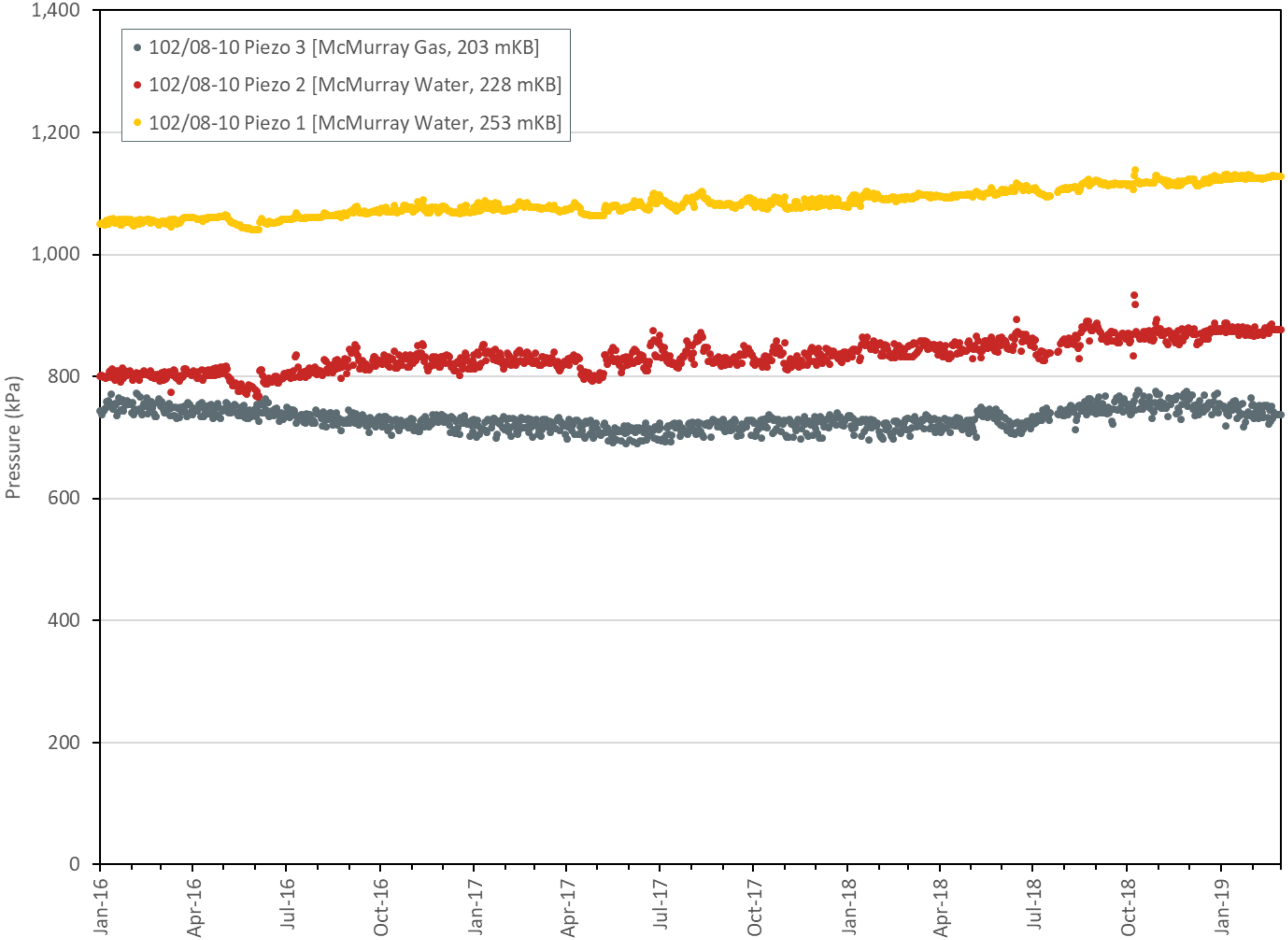
Water Disposal Well 100/08-10-083-05 W4M Observation Well Pressure (McMurray)



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Waste Disposal

Waste Description	Disposal Weight (Tonnes)	Disposal Method
Dangerous Oilfield Waste	12,969	
Hydrocarbon/Emulsion Sludge	436	Oilfield Waste Processing Facility
Crude Oil/Condensate Emulsions	8,462	Oilfield Waste Processing Facility
Various	4,071	Landfill
Non-Dangerous Oilfield Waste	36,498	
Lime Sludge	27,632	Landfill
Various	8,688	Landfill
Well Fluids	178	Cavern

Waste Recycling

Waste Description	Disposal Weight (Tonnes)	Disposal Method
Oil	6	Used Oil Recycler
Empty Containers	4.6	Recycling Facility
Fluorescent Light Tubes	1.1	Recycling Facility
Batteries	2.8	Recycling Facility

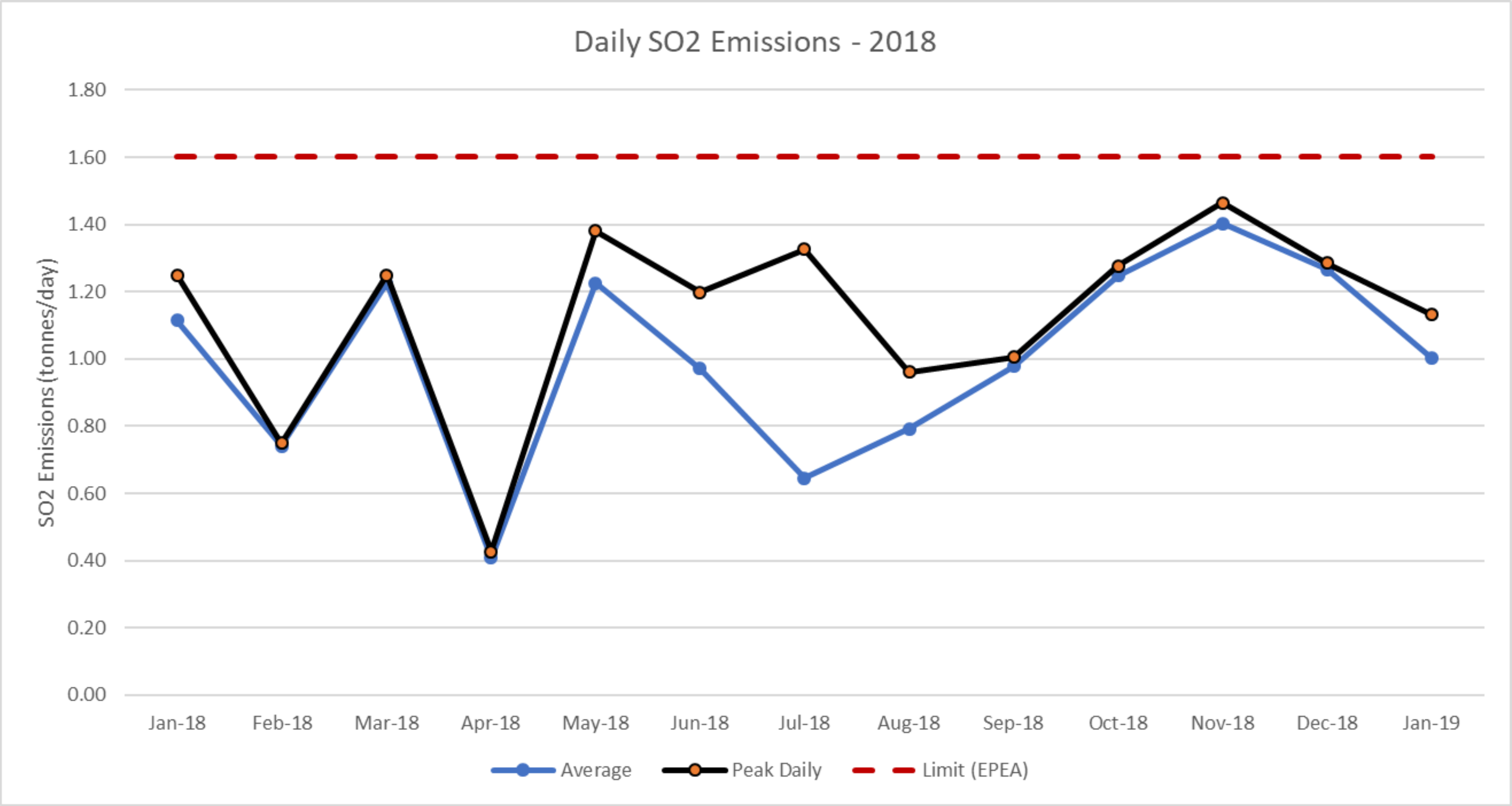
Typical Water Analysis

Parameter	Non-Saline Makeup Water (mg/L)	Saline Makeup Water (mg/L)	Produced Water (mg/L)	Disposal Water (mg/L)
pH	8.5	8.2	7.5	11.8
Total Dissolved Solids (TDS)	1,400	8,000	1,800	23,000
Chloride	200	2,800	650	9,500
Hardness as $CaCO_3$	<0.5	225	10	5
Alkalinity as $CaCO_3$	900	350	250	2,700
Silica	8	7	190	225
Total Boron	6	3.3	40	260
Total Organic Carbon	15	4	500	2,150
Oil Content	<1	<1	65	30

Sulphur Production

Subsection 3.1.2 (5)

Daily SO_2 Emissions



- The SO_2 emissions were managed below the 1.6t/d in 2018.
- The facility instituted operational controls to reduce Sulphur scavenger chemical in October 2018.

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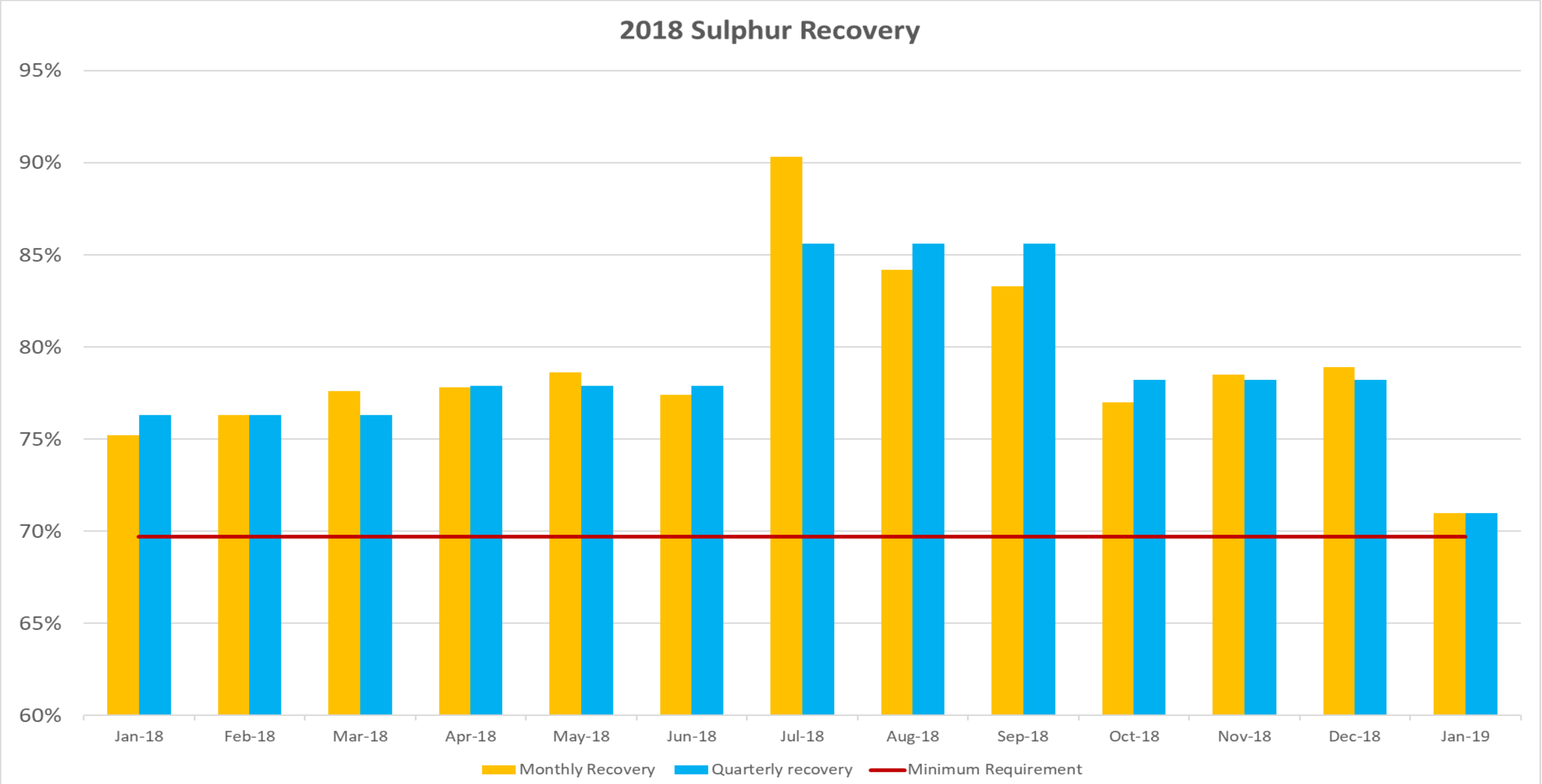
2018 Surmont Project Sulphur Recovery



- Sulphur recovery unit maintained 100% uptime.
- Surmont achieved greater than the required 69.7% quarterly Sulphur recovery in 2018.

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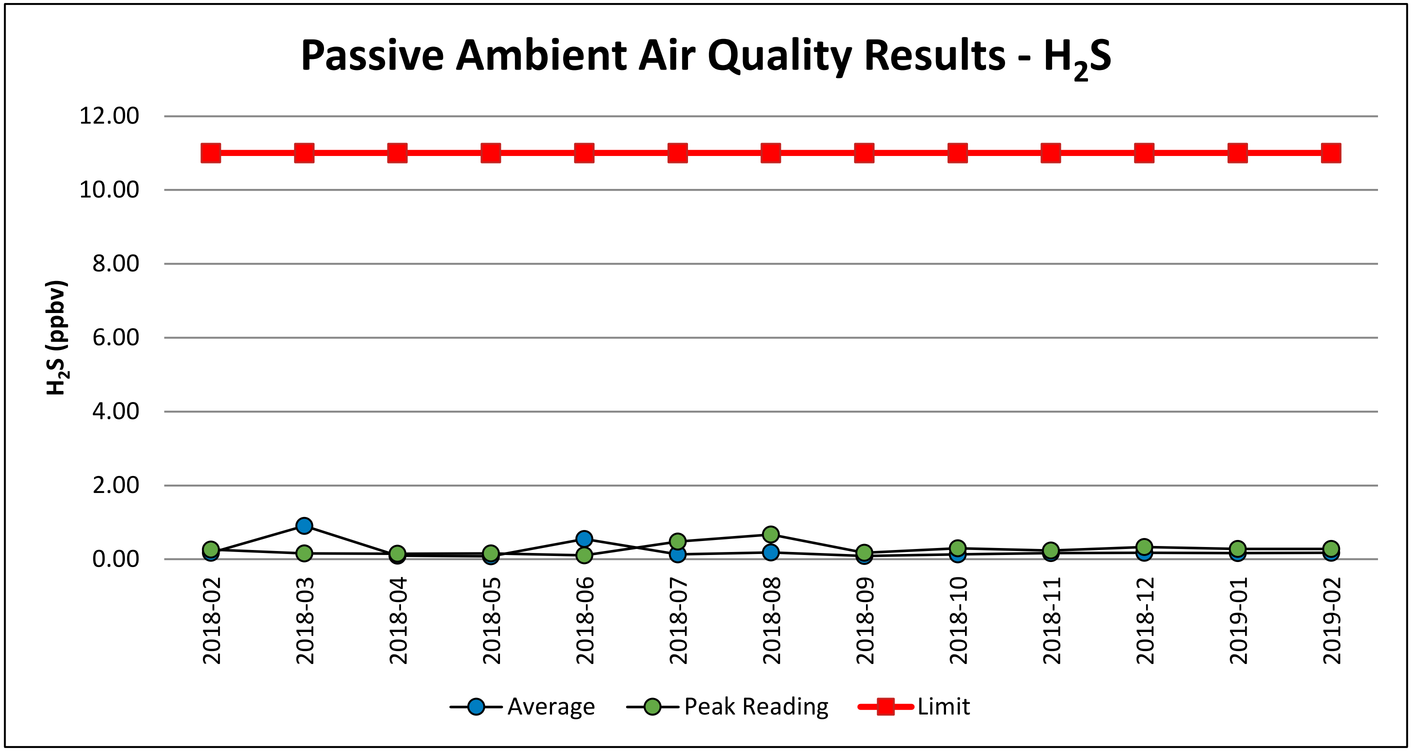
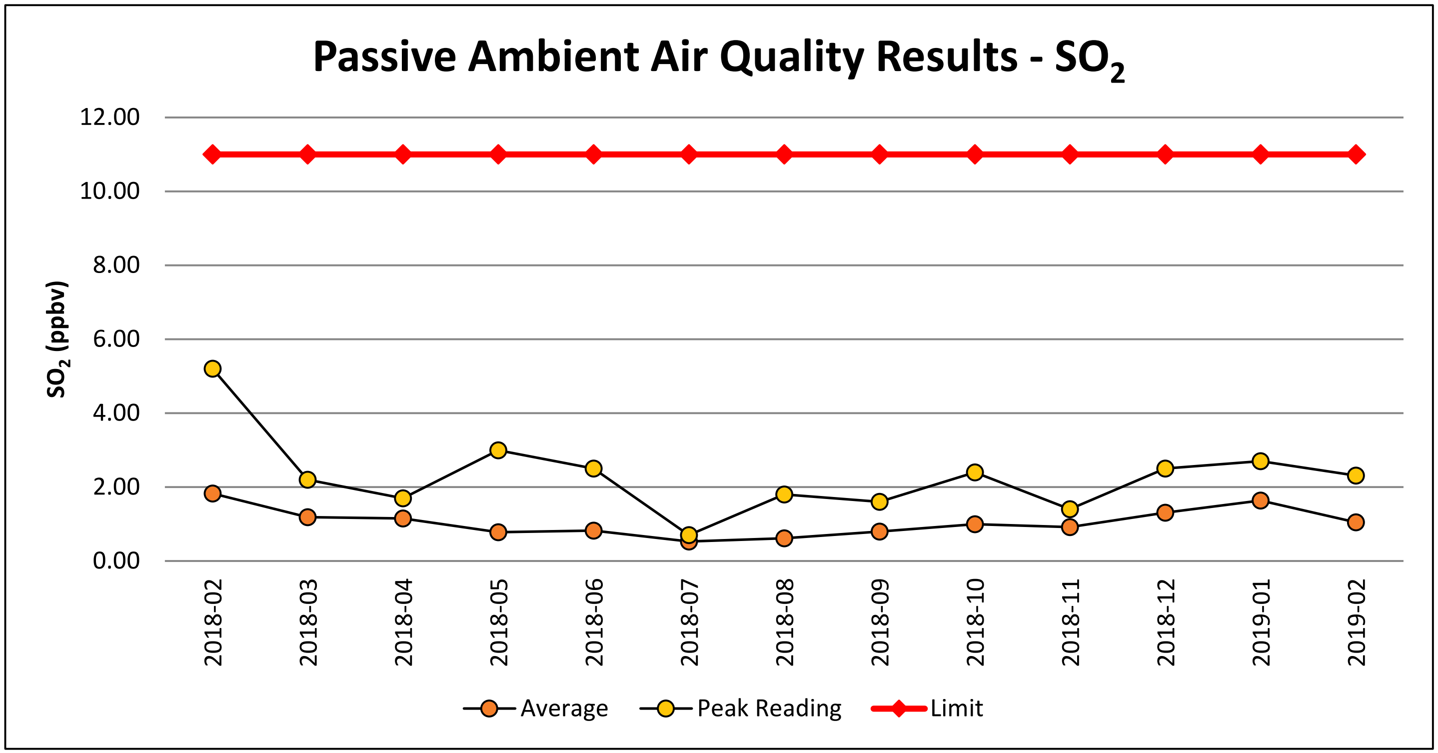
Ambient Air Quality Monitoring



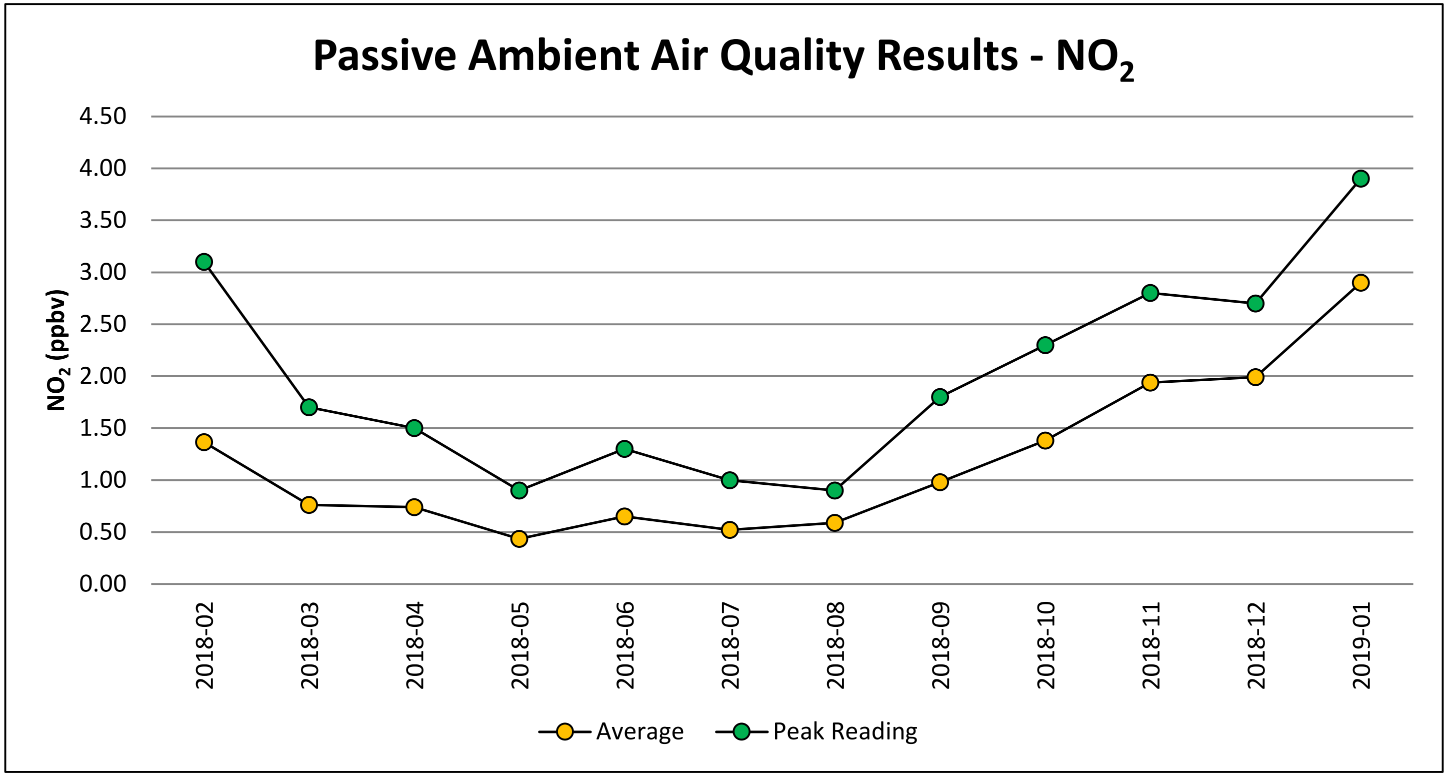
Continuous ambient air monitoring: all Alberta Ambient Air Quality Objectives were met in 2018

Ambient Air Quality Monitoring



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

Ambient Air Quality Monitoring



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

Environmental Compliance

Subsection 3.1.2 (6)

Environmental Compliance and Monitoring

- ConocoPhillips maintained complete environmental compliance throughout 2018 with no environmental non-conformances at Surmont Phase 1 or 2.

Environmental Monitoring

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)

Compliance Confirmation and Non Compliances

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.

Compliance Confirmation and Non Compliances

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

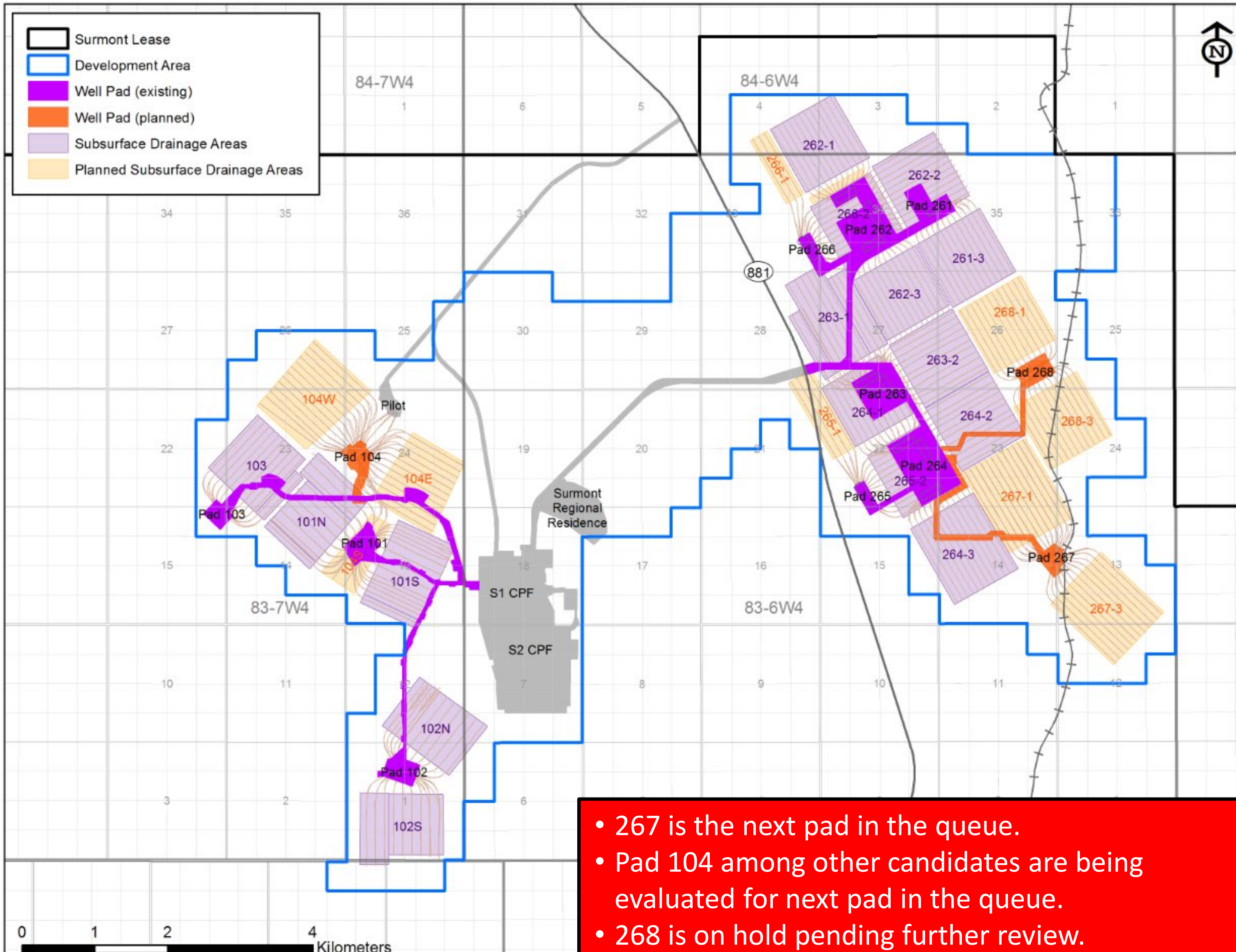
Phase 1:

- 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.