Cenovus Energy Inc.
Tucker Thermal Project - Directive 054 Report
Commercial Scheme Approval No. 9835
2021 Update

June 30, 2022

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Advisory

This presentation contains information in compliance with:

Alberta Energy Regulator Directive 054 - Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

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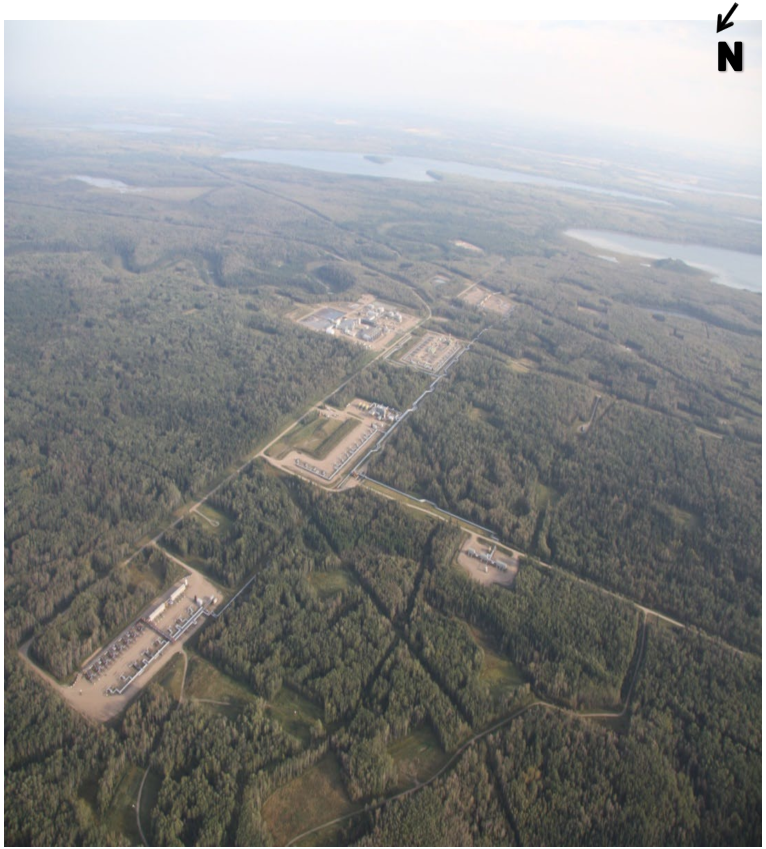
Subsection 4.1 1 Introduction

Project Overview

- AER Commercial Scheme Approval No. 9835
- Reservoirs - Clearwater, Grand Rapids and Colony
- API Bitumen - 9-10º
- First Steam August 20, 2006
- First Production November 29, 2006

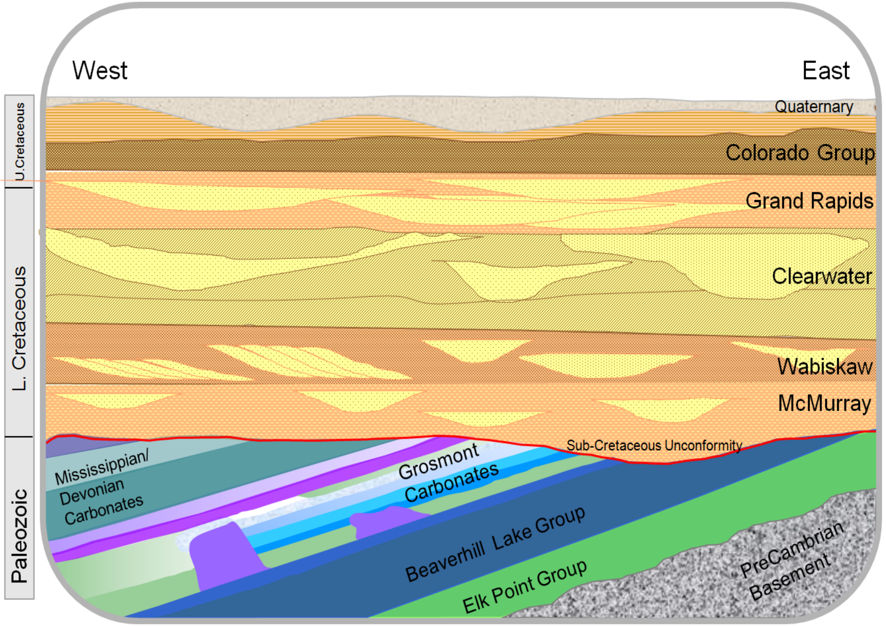
- Field Facilities:
  - Six well pads, infield pipelines and central pump station

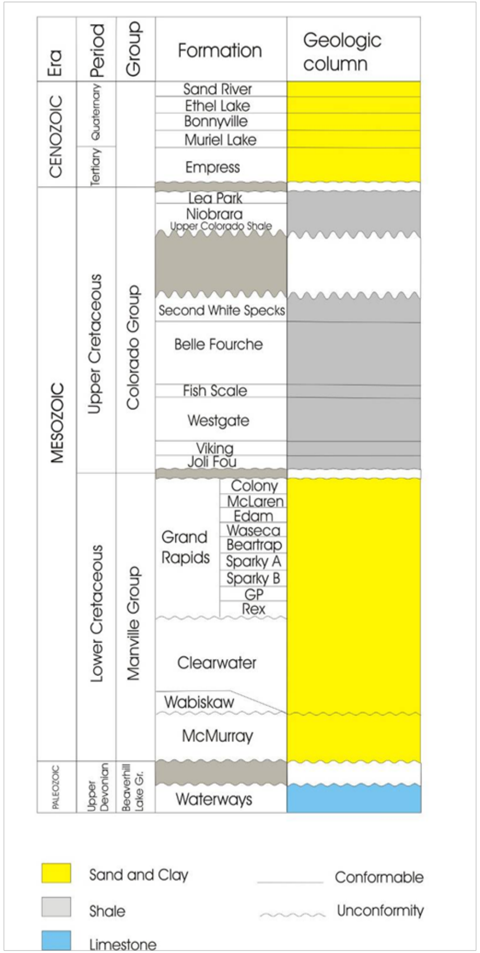
- Central Plant:
  - Emulsion treating
  - Water Treatment
  - Steam Generation
  - Utilities



Regional Stratigraphy

- Marginal marine deposits consisting of stacked incised valleys and shoreface deposits





Subsection 4.2 2-7 Subsurface

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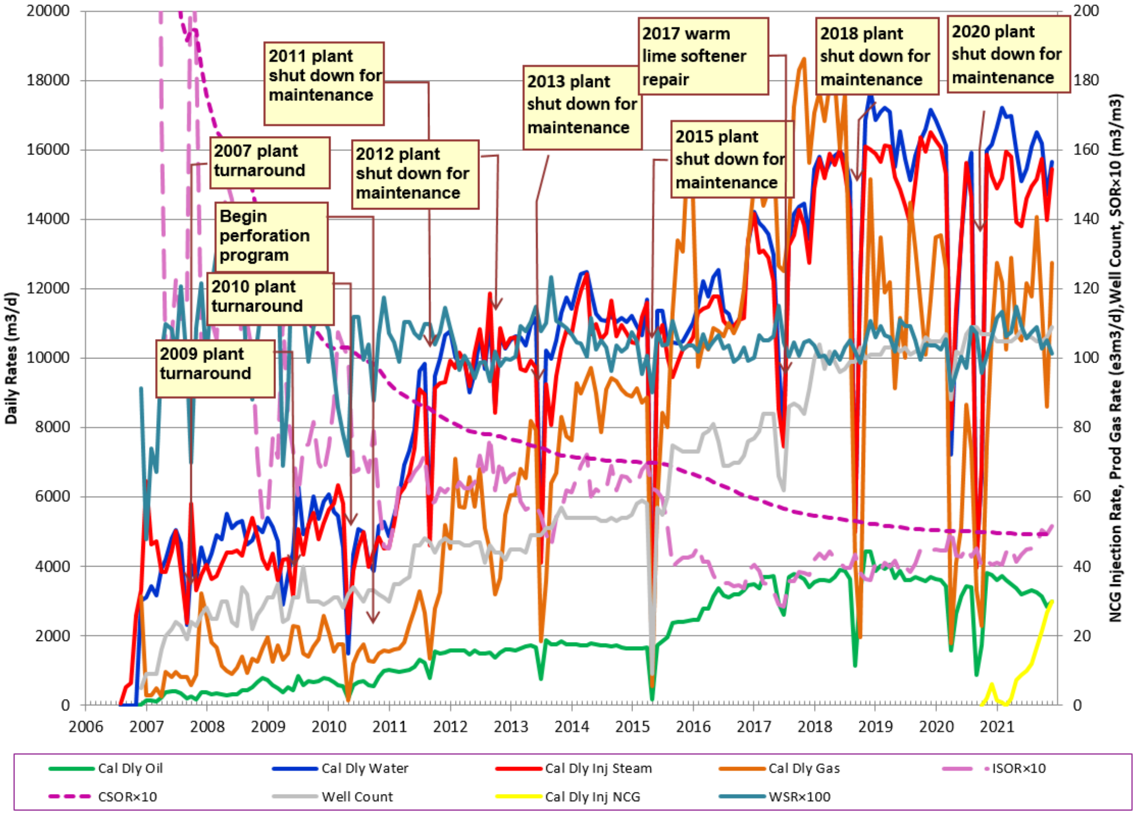
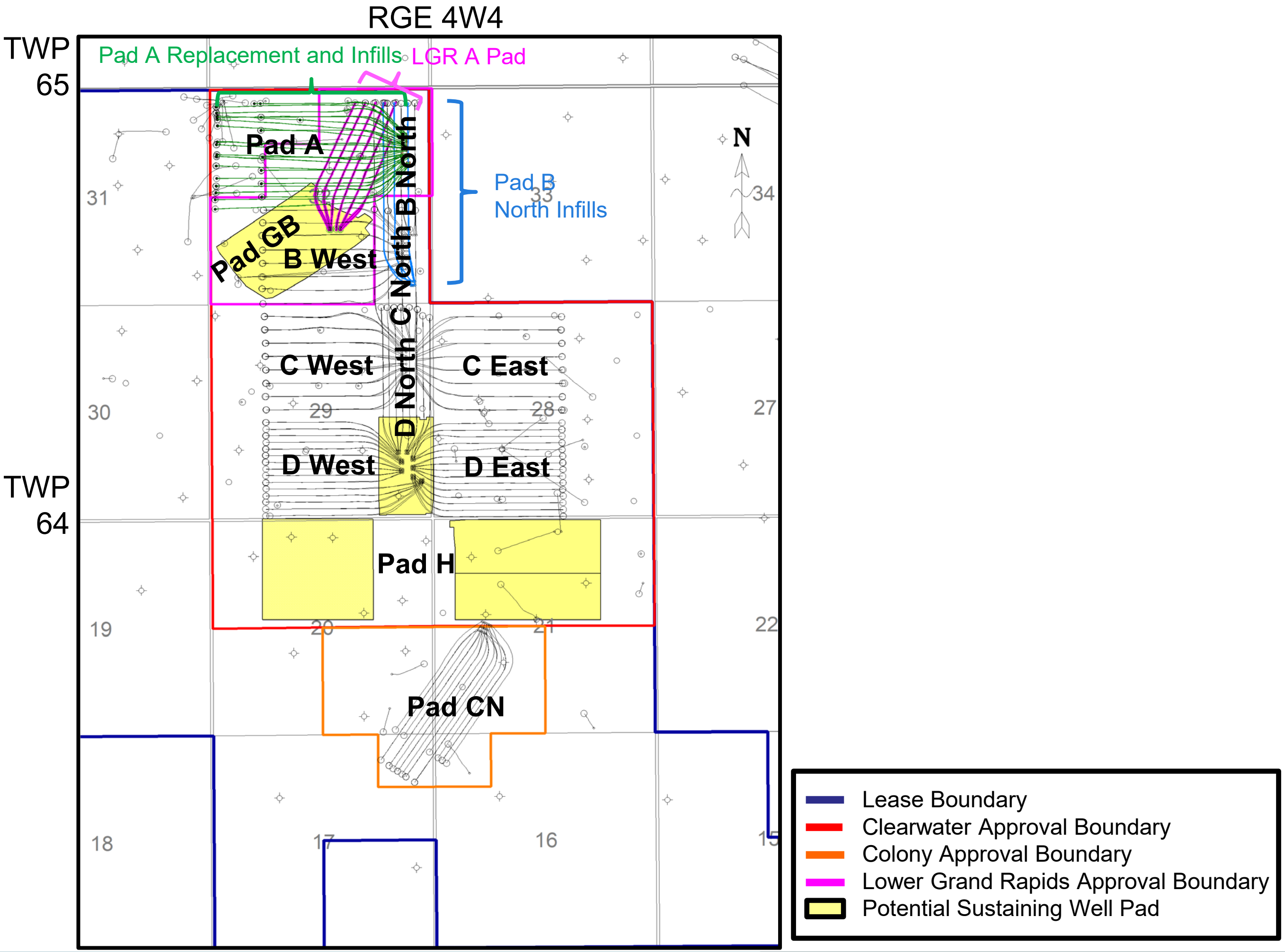
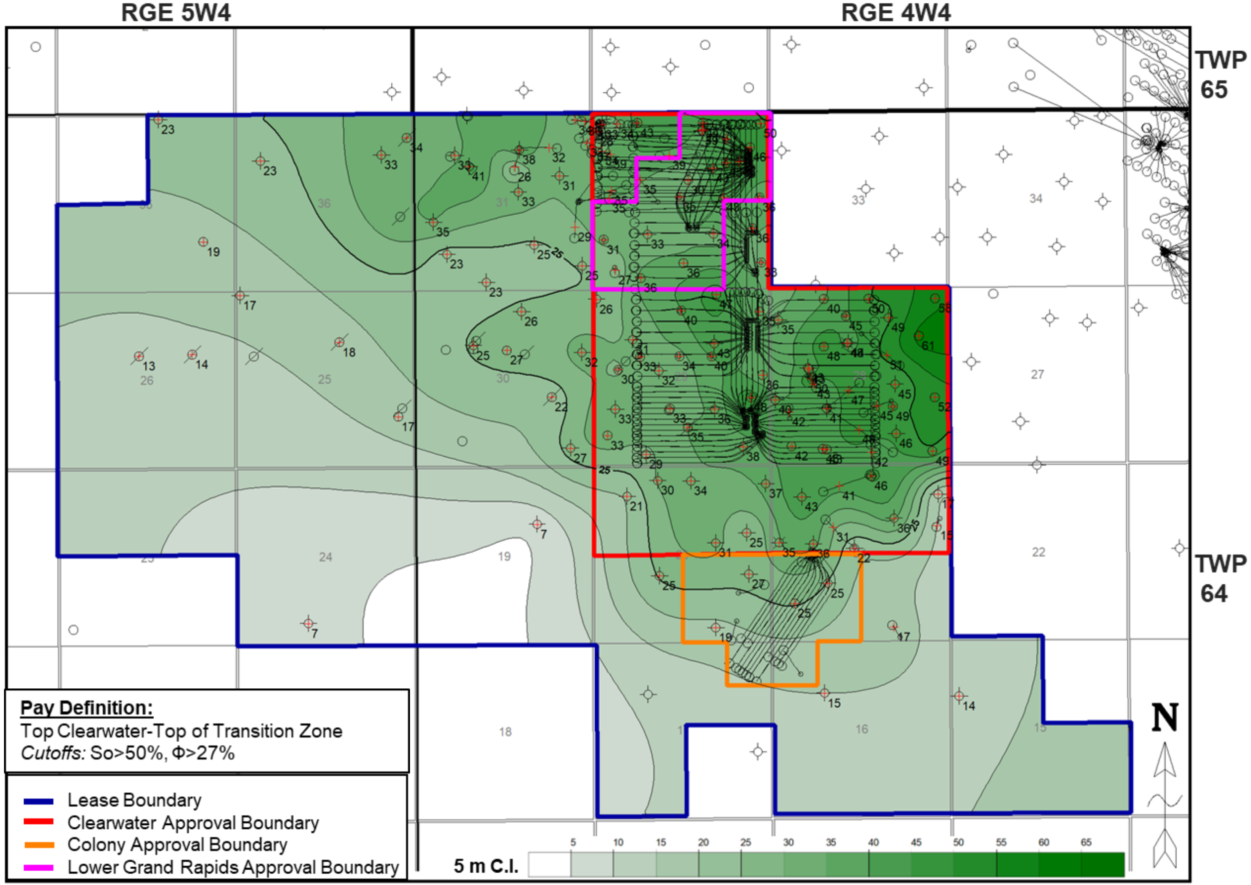
Production Plot: Historical



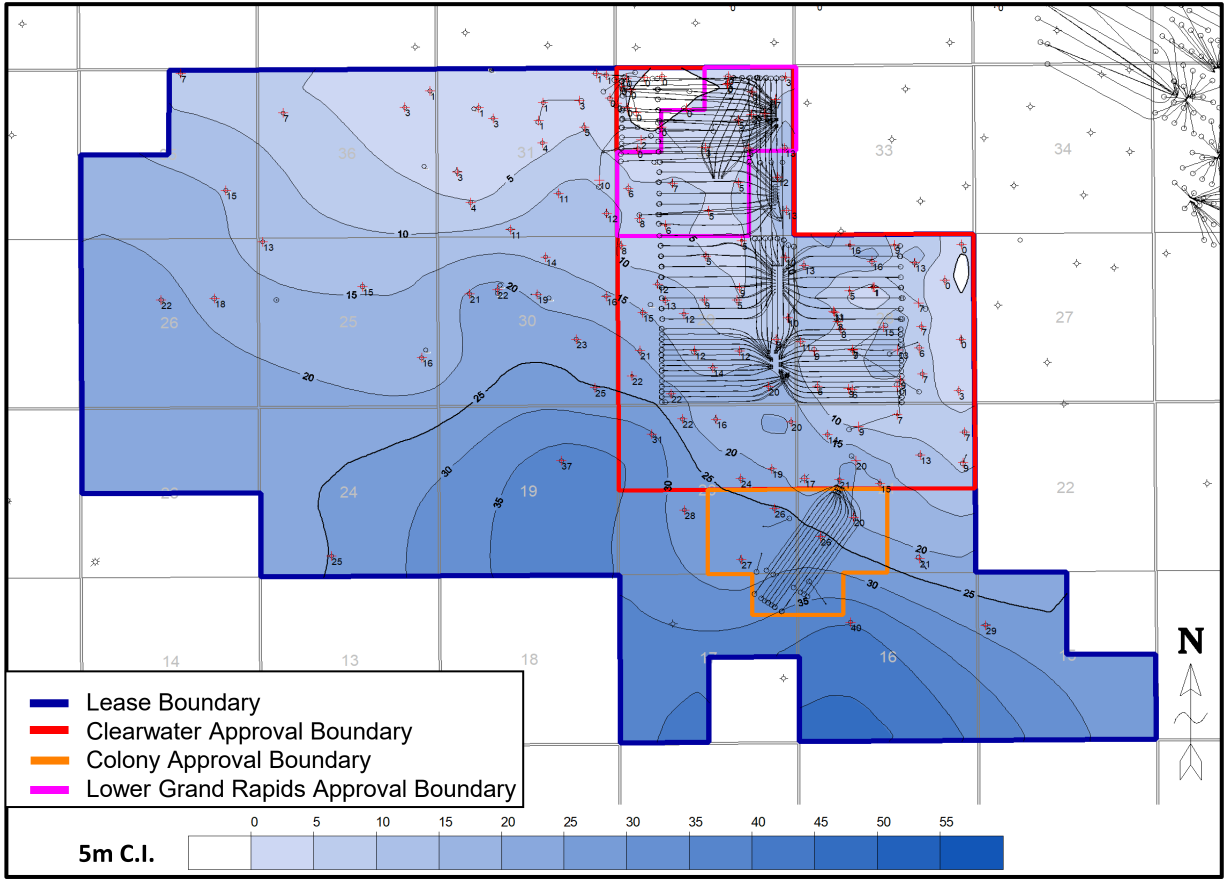
Development Map



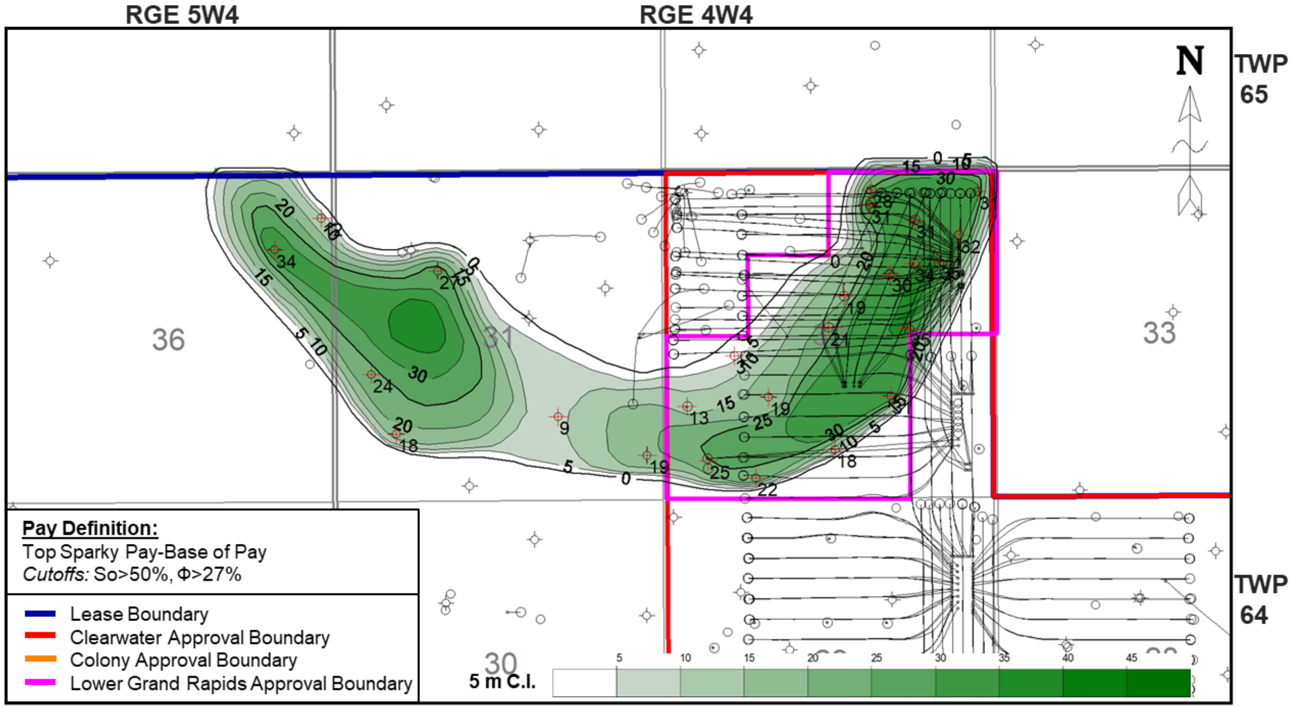
SAGD Net Pay Isopach Map - Clearwater



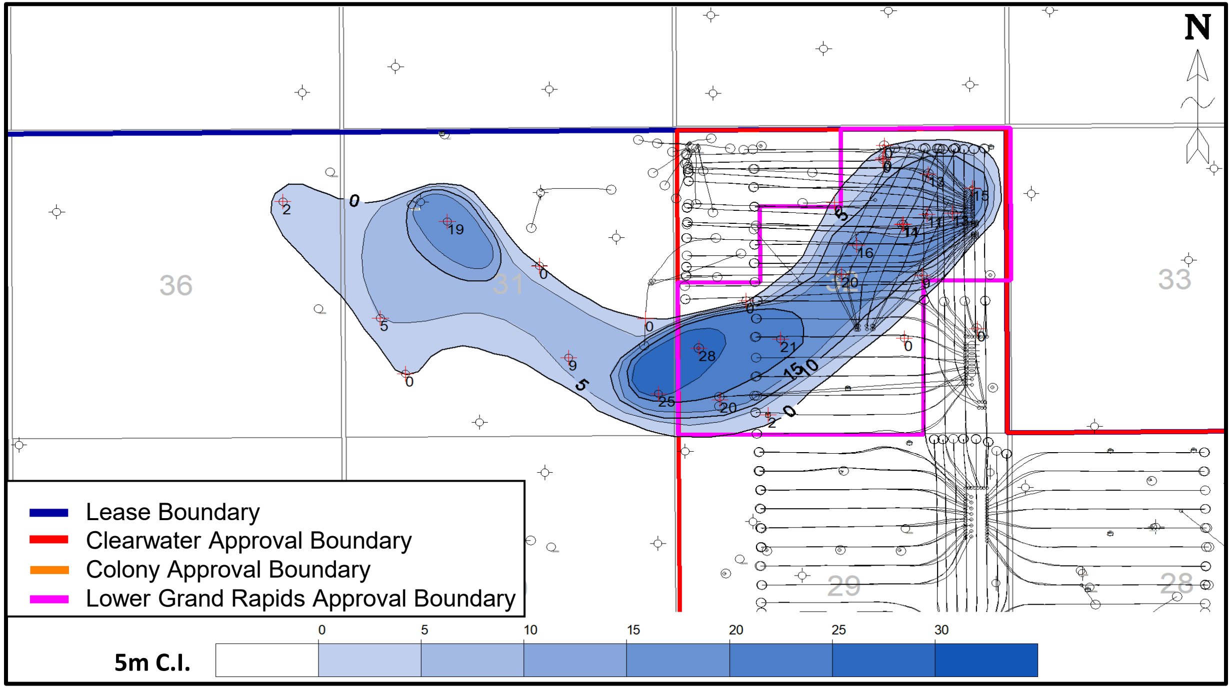
Bottom Water Isopach Map - Clearwater



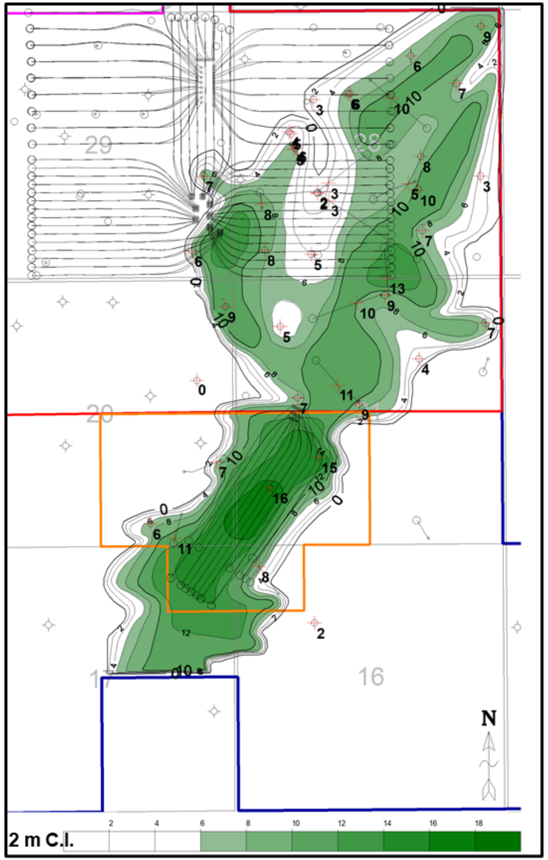
SAGD Net Pay Isopach Map – Lower Grand Rapids



Bottom Water Isopach Map – Lower Grand Rapids



SAGD Net Pay Isopach Map – Colony



Pay Definition:
Top Colony Pay-Colony Channel Base
Cutoffs: So>50%, Φ>27%

- Lease Boundary
- Clearwater Approval Boundary
- Colony Approval Boundary
- Lower Grand Rapids Approval Boundary

Geomechanical Data/Analysis

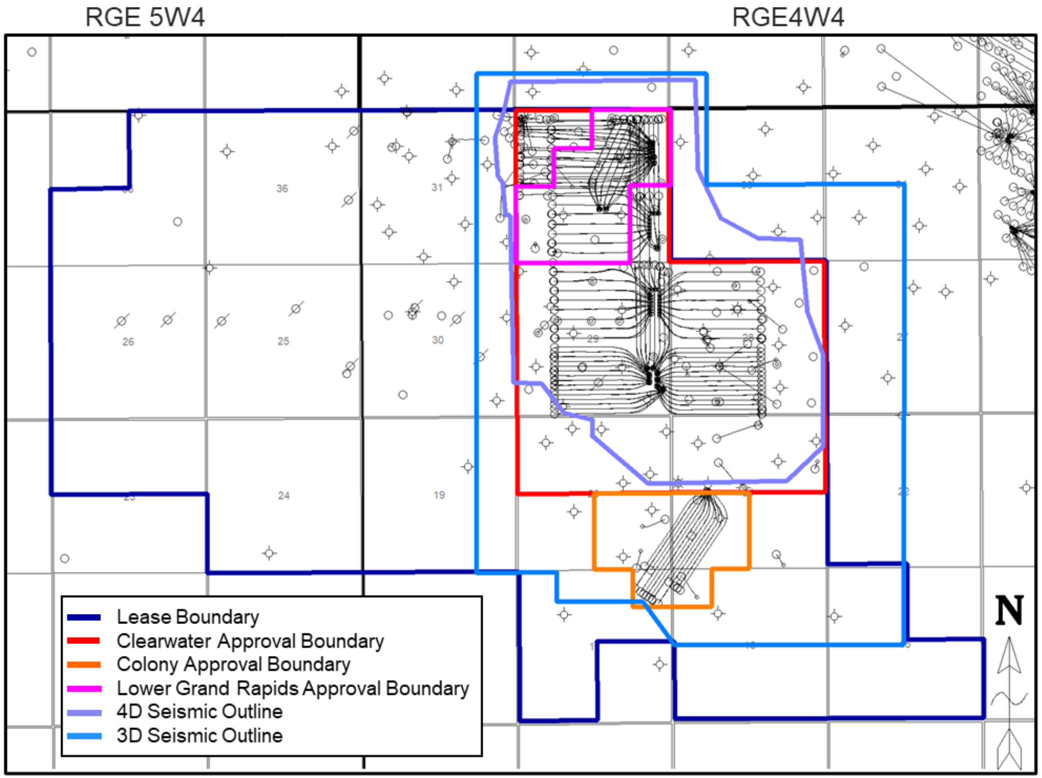
Capping Shale Properties						
Well Pad	Capping Shale Issues to date	Capping shale Fracture Pressure Exceeded	Shale Depth (m)	Measured Fracture Gradient (kPa/m)	Measured Fracture Pressure (kPa)	Fracture Regime
CN	No	No	305	20.0	6,100	Horizontal
GA	No	No	357	19.9	7,120	Horizontal
Clearwater	No	No	426	21.8	9,280	Horizontal

Sand Properties				
Well Pad	Sand Depth (m)	Measured Fracture Gradient (kPa/m)	Measured Fracture Pressure (kPa)	Fracture Regime
GA	375	17.0	6,360	Vertical
Clearwater	446	16.0	7,140	Vertical

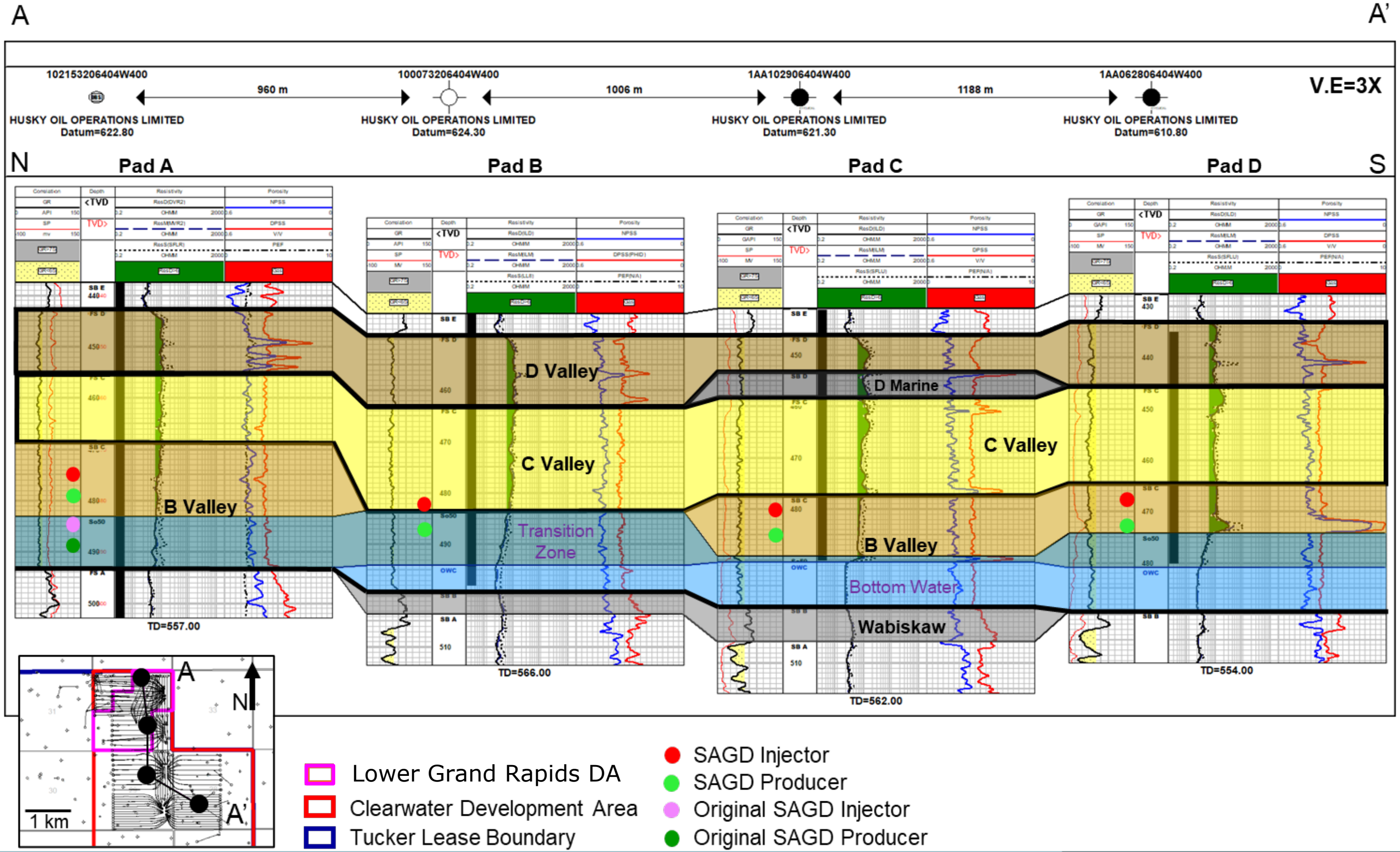
Note:
CN – Colony
GA – Lower Grand Rapids A

Seismic

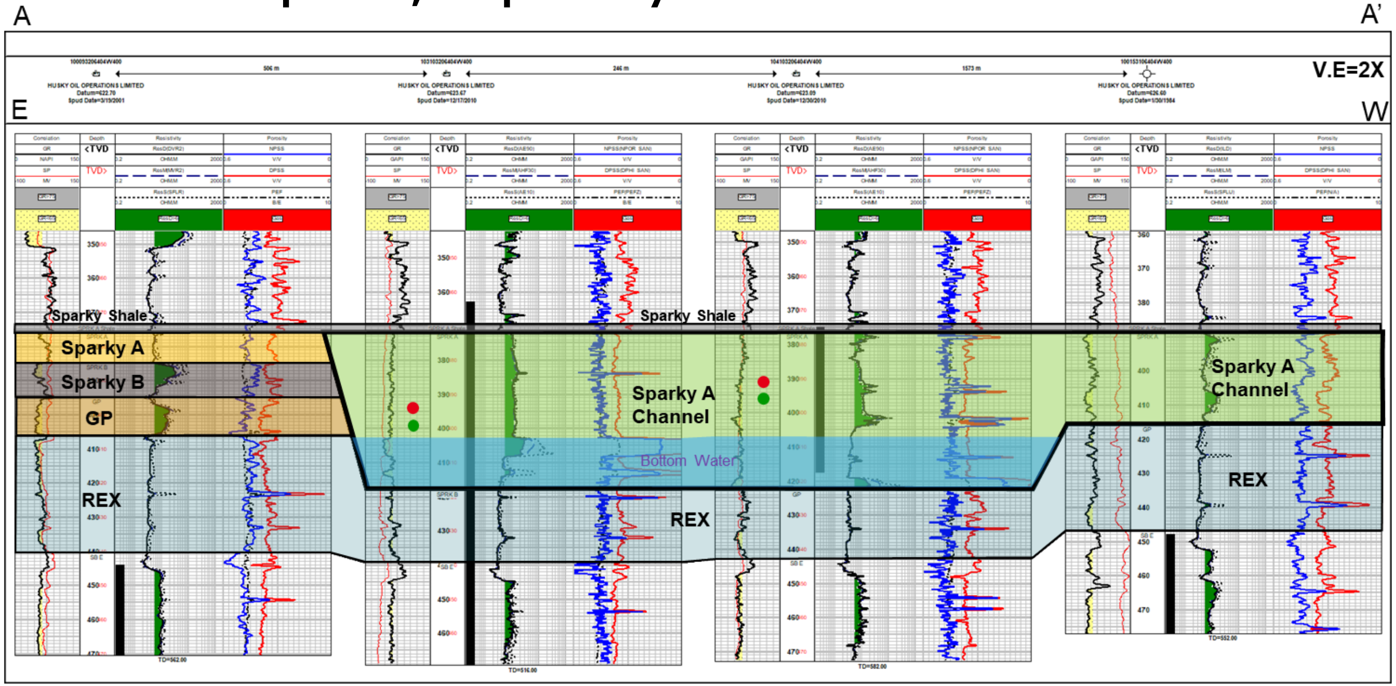
- No new seismic acquired during the reporting period
- 3D seismic was acquired in three (3) programs:
  - 2005
  - 2007
  - 2013
- 4D seismic was acquired in 2018
  - Previous programs in 2010, 2012, and 2014

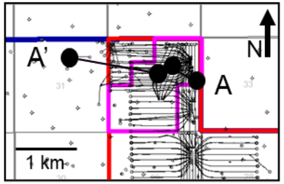


Representative Structural Cross-Section - Clearwater



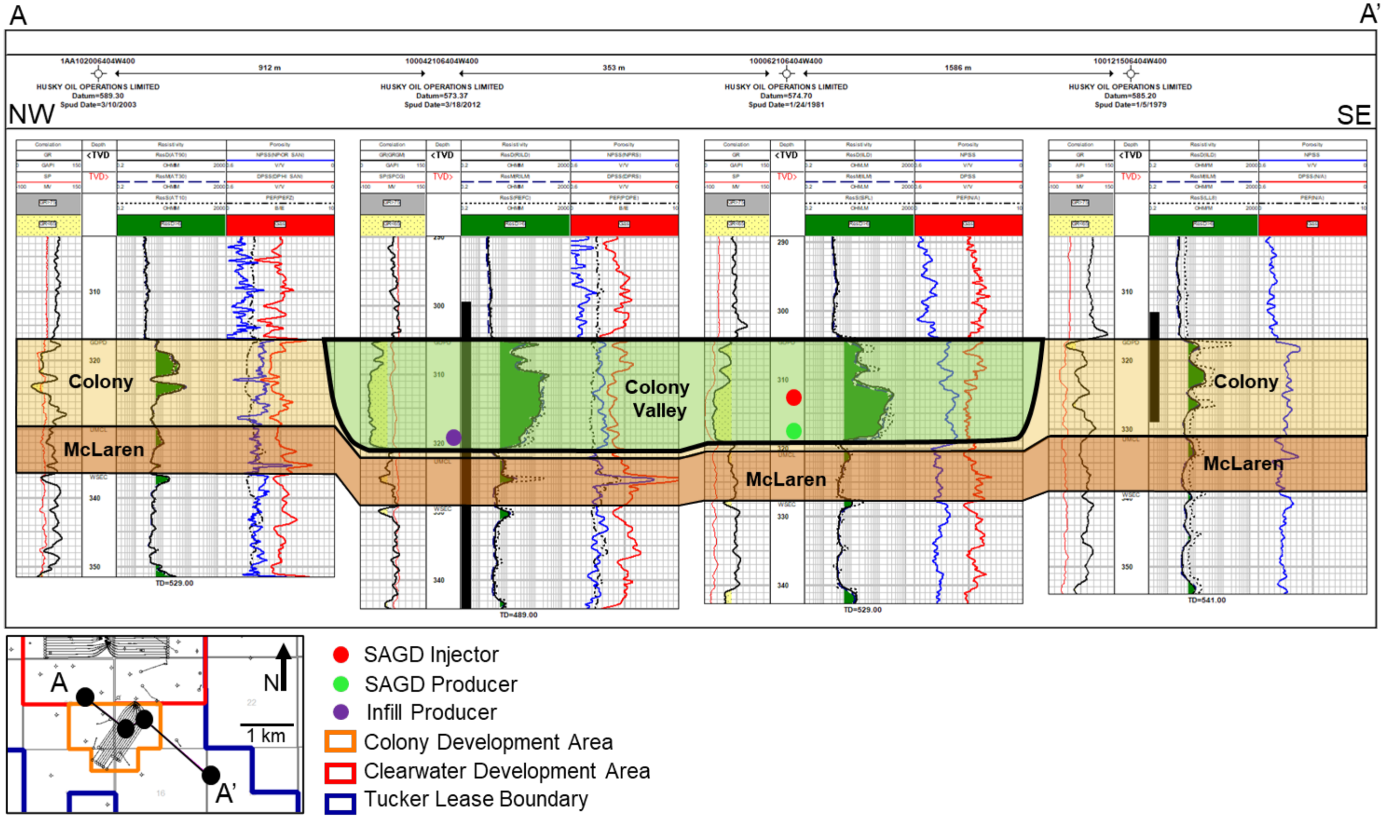
Representative Structural Cross-Section – Lower Grand Rapids, Sparky





- SAGD Injector
- SAGD Producer
- Lower Grand Rapids Development Area
- Clearwater Development Area
- Tucker Lease Boundary

Representative Structural Cross-Section – Upper Grand Rapids, Colony



- SAGD Injector
- SAGD Producer
- Infill Producer
- Colony Development Area
- Clearwater Development Area
- Tucker Lease Boundary

June 30, 2022

Average Reservoir Characteristics and OBIP

CLEARWATER	OBIP ($X10^6$ m^3)	Thickness (m)	PhiE (Φ)	So	Viscosity (cP @ 20°C)	Original Pressure (kPa)	Original Temperature (°C)	Depth (m)	Vertical Permeability (mD)	Horizontal Permeability (mD)
Approval Area	80.5	44	0.31	0.57	50,000-1,000,000	3,200	16	440	1,800	3,000
Operating	40.9	46	0.32	0.57	50,000-1,000,000	3,200	16	440	1,800	3,000

LOWER GRAND RAPIDS	OBIP ($X10^6$ m^3)	Thickness (m)	PhiE (Φ)	So	Viscosity (cP @ 20°C)	Original Pressure (kPa)	Original Temperature (°C)	Depth (m)	Vertical Permeability (mD)	Horizontal Permeability (mD)
Approval Area	5.7	26	0.28	0.54	100,000-300,000	2,600	14	370	1,300	1,800
Operating (Pad GA)	2.1	38	0.29	0.54	100,000-300,000	2,600	14	370	1,300	1,800

COLONY	OBIP ($X10^6$ m^3)	Thickness (m)	PhiE (Φ)	So	Viscosity (cP @ 20°C)	Original Pressure (kPa)	Original Temperature (°C)	Depth (m)	Vertical Permeability (mD)	Horizontal Permeability (mD)
Approval Area	2.8	10	0.30	0.79	25,000	2,500	12	305	2,400	4,000

Notes:
So – Oil saturation
OBIP – Original Bitumen in Place
Calculation: OBIP interval: Top of Formation → oil water contact
OBIP = Area x Thickness x Φ x S_o

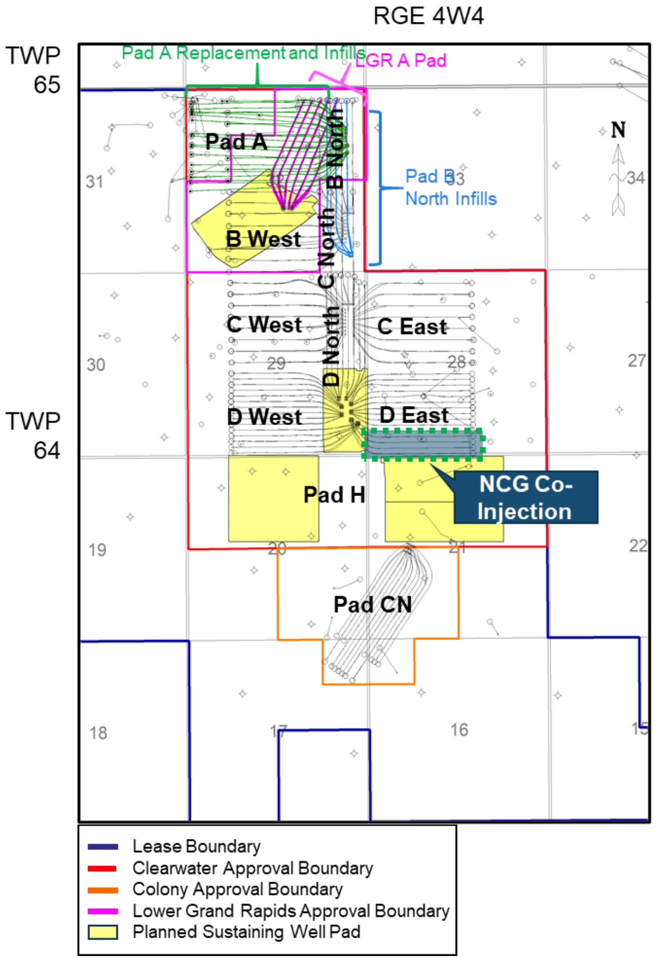
Reservoir Parameters and Recovery Factors

Well PAD		Thickness (m)	Area (10^3 m^2)	Pad Volume[1] (10^6 m^3)	Average Permeability (mD)	So	PhiE	DBIP (10^6 m^3)	OBIP (10^6 m^3)	Recovery to Date 12/31/2021 (10^3 m^3)	Recovery Factor to 12/31/2021 (%)	Estimated Ultimate Recovery (10^6 m^3)	Ultimate Recovery Factor (%)
Pad A	A Infills and Replacement (16 well pairs)	30	880	30.6	3000	0.56	0.32	5.5	6.7	2,079	37.8	2.8	50
	A original (8 well pairs)	7	640										
Pad B	B West (8 well pairs)	37	640	39.8	3000	0.57	0.32	7.3	7.9	1,430	19.6	3.7	50
	B North (4 well pairs)	8	320										
	B North Infills (3 well pairs)	40	345										
Pad C	C West (8 well pairs)	36	640	53.8	3000	0.6	0.32	10.3	13.1	2,708	26.3	5.2	50
	C North Original[2] (4 well pairs)	10	320										
	C East (8 well pairs)	43	640										
Pad D	D East (15 well pairs)	43	660	28.1	3000	0.61	0.32	5.5	6.2	2,095	38.1	2.8	50
	D North (8 well pairs)	36	330	11.8	3000	0.61	0.33	2.4	2.8	467	19.5	1.2	50
	D West (15 well pairs)	31	578	17.9	3000	0.63	0.32	3.6	4.2	491	13.6	1.8	50
Clearwater Total (97 well pairs)								34.6	40.9	9,270	26.8	17.3	50
Pad GA (6 well pairs)		30	355	10.6	1800	0.62	0.30	2	2.1	659	33.0	1.0	50
Pad CN (6 well pairs + 7 infill)		13	502	6.5	4000	0.82	0.29	1.6	1.6	995	62.2	1.0	65
Tucker Total (109 well pairs + 7 infill)								38.2	44.6	10,925	28.6	19.3	51

Note:
Developable Bitumen In Place (DBIP) – Volume x So x Phi-E (Thickness defined from top of pay to 8% bitumen weight or producer level where wells are below 8% bitumen weight)
Original Bitumen In Place (OBIP) - Top of Formation → oil water contact
[1] Due to rounding of values, the calculated values may not equal the individual values presented in the table
[2] Pad C North future development not included in DBIP. The DBIP is equal to $1.1X10^6$ m^3

Co-Injection Information

- November 2020 – started NCG Co-injection in the Clearwater Formation
- NCG injected into wells D32S, D34S and D36S
- Cumulative NCG injection is $4{,}146 \times 10^3$ standard m^3 as per the reporting period
- The average NCG injection concentration is approximately 1.5%
- NCG injected is fuel gas (methane)
- To date, the data has indicated that NCG co-injection has a positive impact on steam oil ratio (SOR) in the Clearwater Formation



Subsection 4.3 8
Surface

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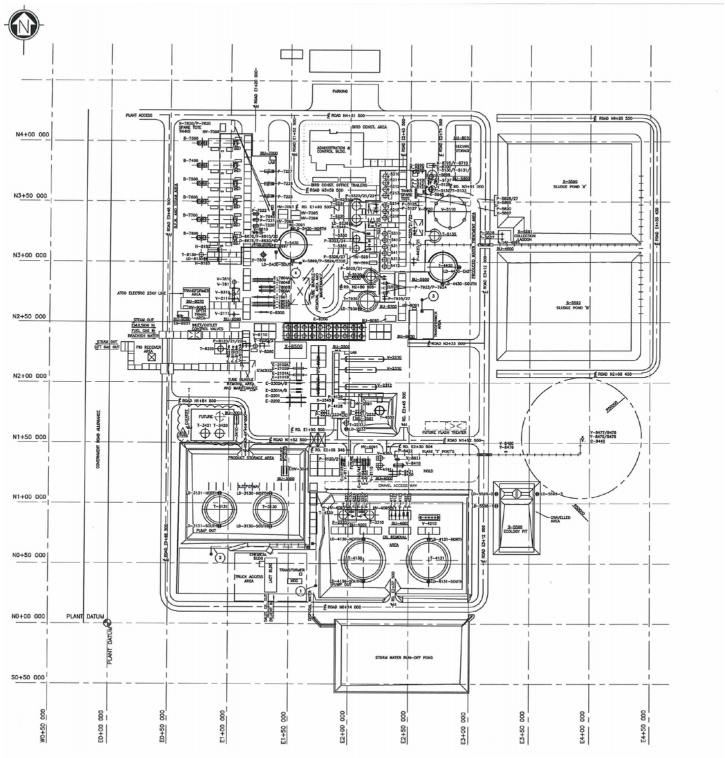
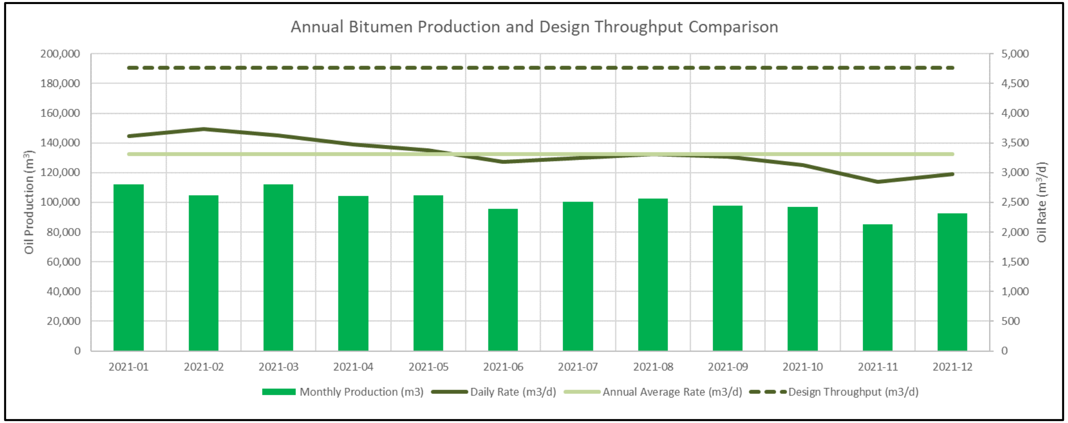
Central Processing Facility - Plot Plan

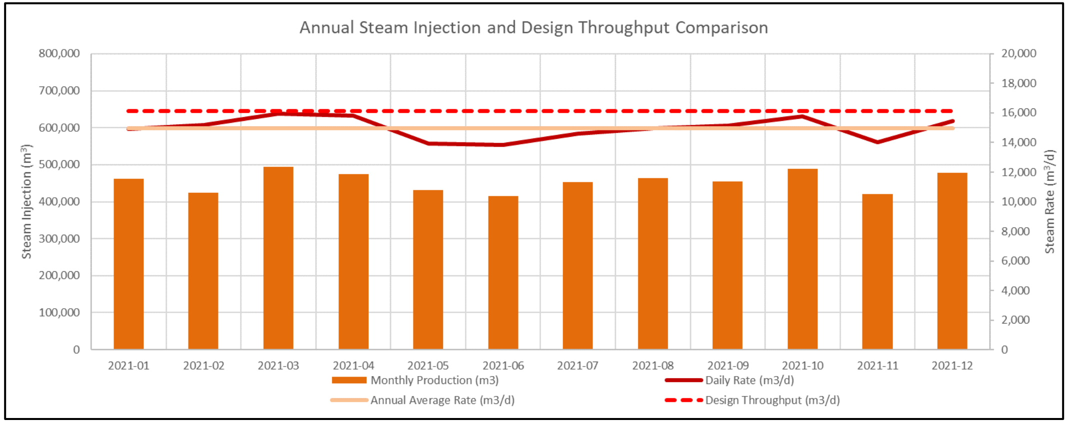


Facility Modifications

- No facility modifications conducted during the reporting period

Annual and Design Throughput Comparison





Subsection 4.4 9-12 Historical and Upcoming Activity

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Suspension and Abandonment Activity

- No well pad abandonments or suspensions occurred during the reporting period

Regulatory Applications and Approvals

Act	Application Number	Description	Approval Date
OSCA	1934682	Clearwater Development Amendment (Pad H)	2021-12-07

Operational Changes

Material Operational Changes

- No material changes to facility capacity

Pilot Updates

- No significant reduction observed on gas consumption. Emission reduction was attributed to start-up of CN11 (Colony) without a rod pump unit. The two (2) Hydraulic Gas Pumps (HGPs) were down for approximately three (3) months due to operation and reliability challenges.
- Mid-April – resumed Non-Condensable Gas (NCG) co-injection to D32S, D34S and D36S. Site equipment was unable to provide reliable steady pressure supply, the NCG injection location had to be switched from long tubing (mixing with steam) to short tubing injection depending on ambient temperature and pressure supply. This resulted in poor NCG distribution to subsurface.

Compliance History

Reportable Incidents

- AER Contravention report – Edge Reference No. 0386722
  - December 30, 2021 – Steam drain line on above ground pipeline (AGP) froze and leaked steam
  - Release contained in drip tray; repairs made to valve to stop leak. Re-insulated line to prevent freezing
  - Report closed by the AER

Self-Disclosures

- No self-disclosures recorded during the reporting period

Compliance

- All conditions of AER License F-32143 as well as all scheme approvals for the Project were met during the reporting period
- All conditions of the EPEA approval 147753-01 as amended were met during the reporting period

Future Plans

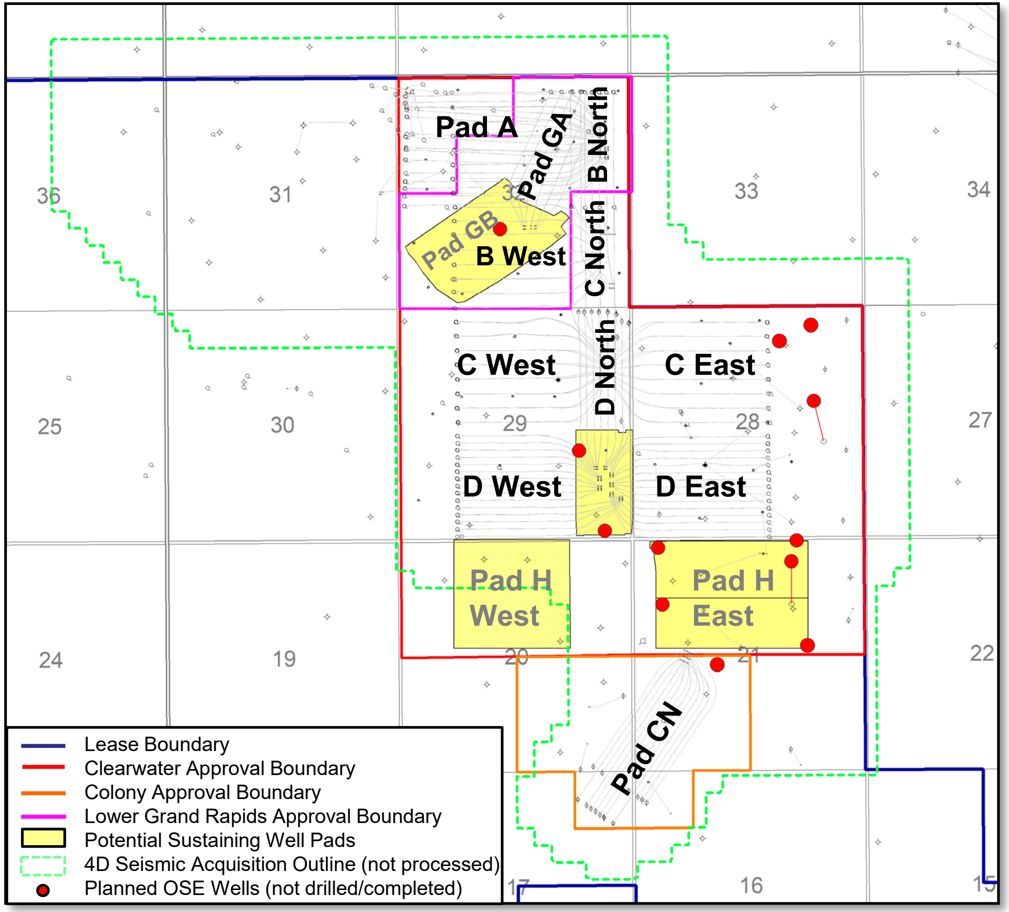
Planned Activity (a)

- Not applicable – see note below

Expected AER Applications (c)

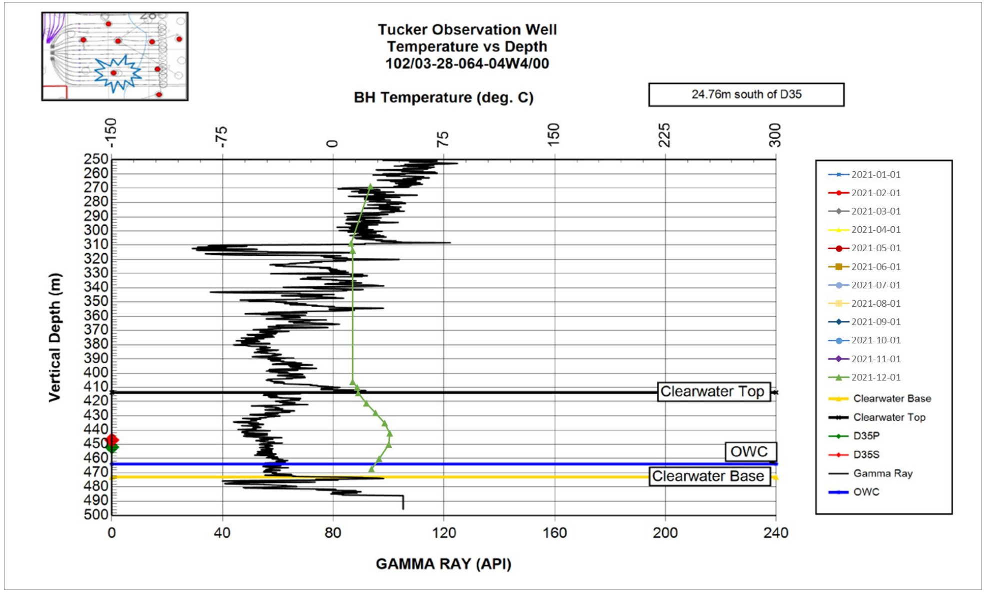
- Not applicable – see note below

Note: As of January 31, 2022, Tucker Thermal Project was divested; the OSCA and EPEA Approvals and all applicable licenses are in the process of being transferred to the new asset owner. As of December 31, 2021, all potential sustaining/development well pads have been approved by the AER.



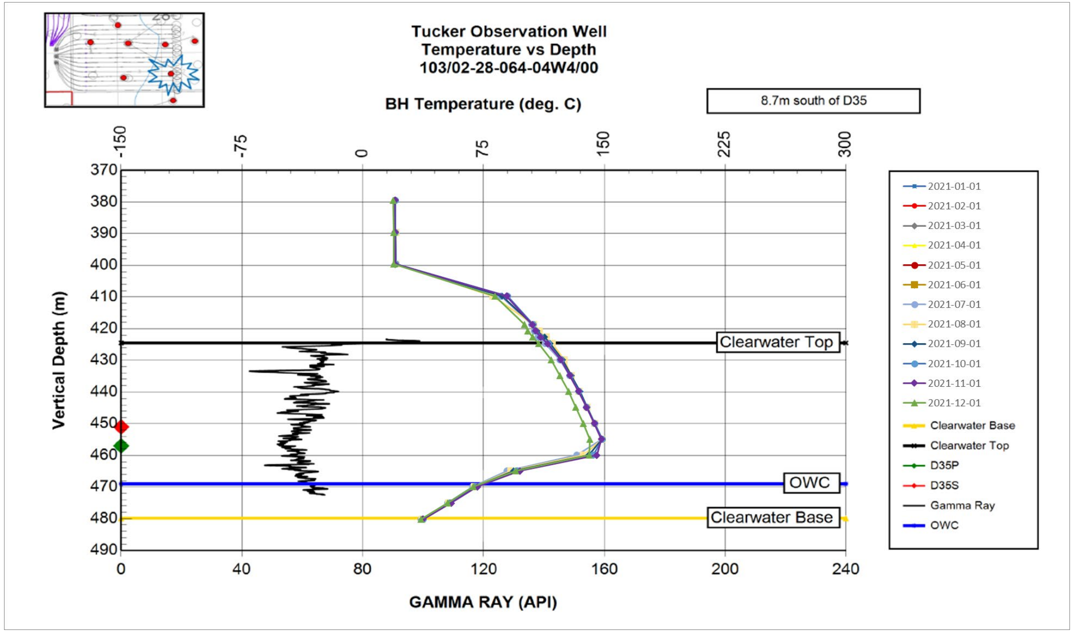
Monitoring Update – OSCA Approval Clause 14b
Well 102/03-28-064-04W4

- Thermocouple string malfunction; repaired
- Minimal temperature increase over the past seven (7) years; low risk to neighboring non-thermal compatible well



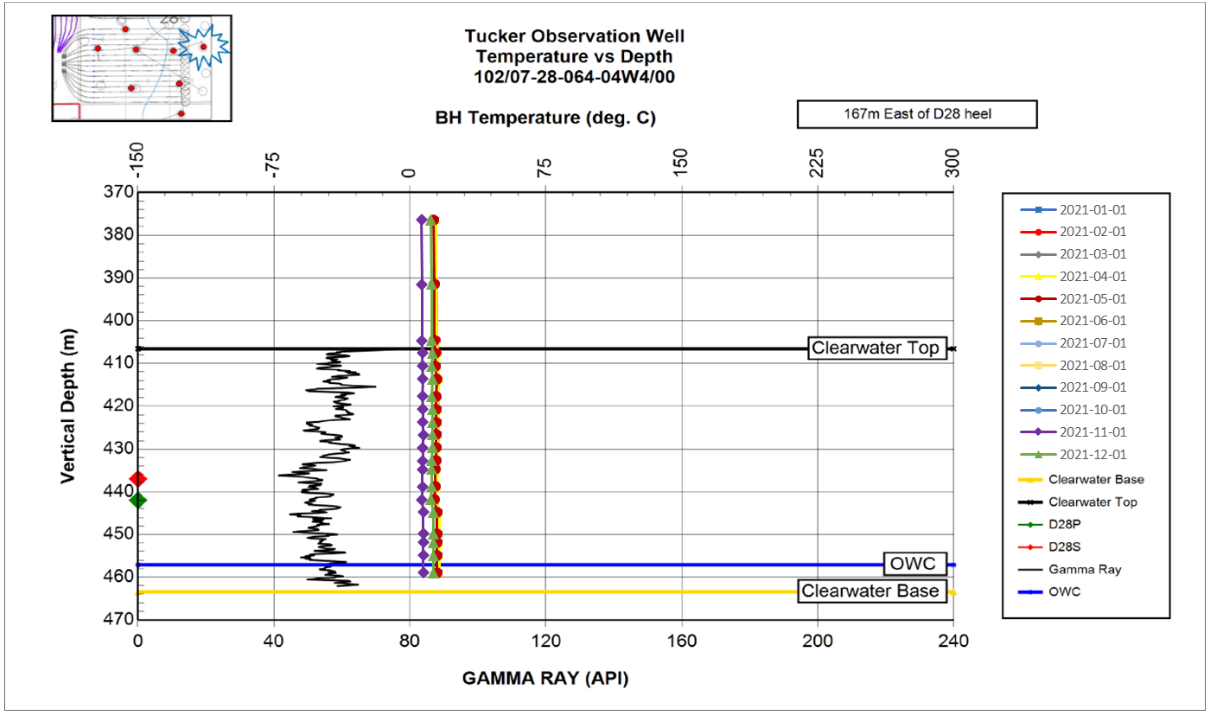
Monitoring Update – OSCA Approval Clause 14b
Well 103/02-28-064-04W4

- Thermocouple string malfunction; repaired
- Temperature observed within drainage pattern is considered reasonable



Monitoring Update – OSCA Approval Clause 14b
Well 102/07-28-064-04W4

- No temperature changes observed during the reporting period



Questions

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