

2025 AER Directive 054 Scheme Performance Report

Hangingsstone Expansion SAGD Project

Scheme Approval No. 11910, as amended



GREEN FIRE
RESOURCES



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Section 1.0 – Introduction



1.1 Background

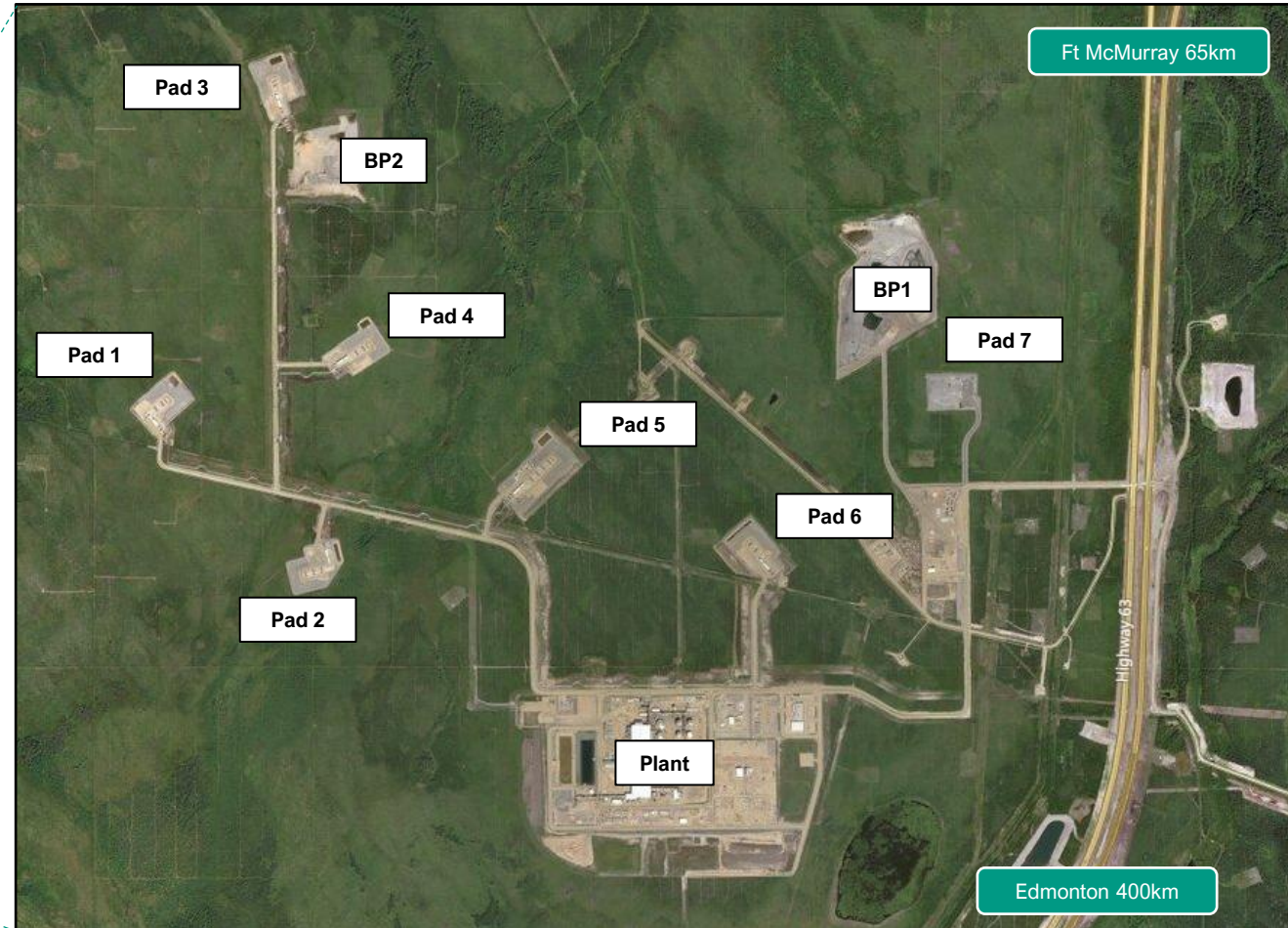
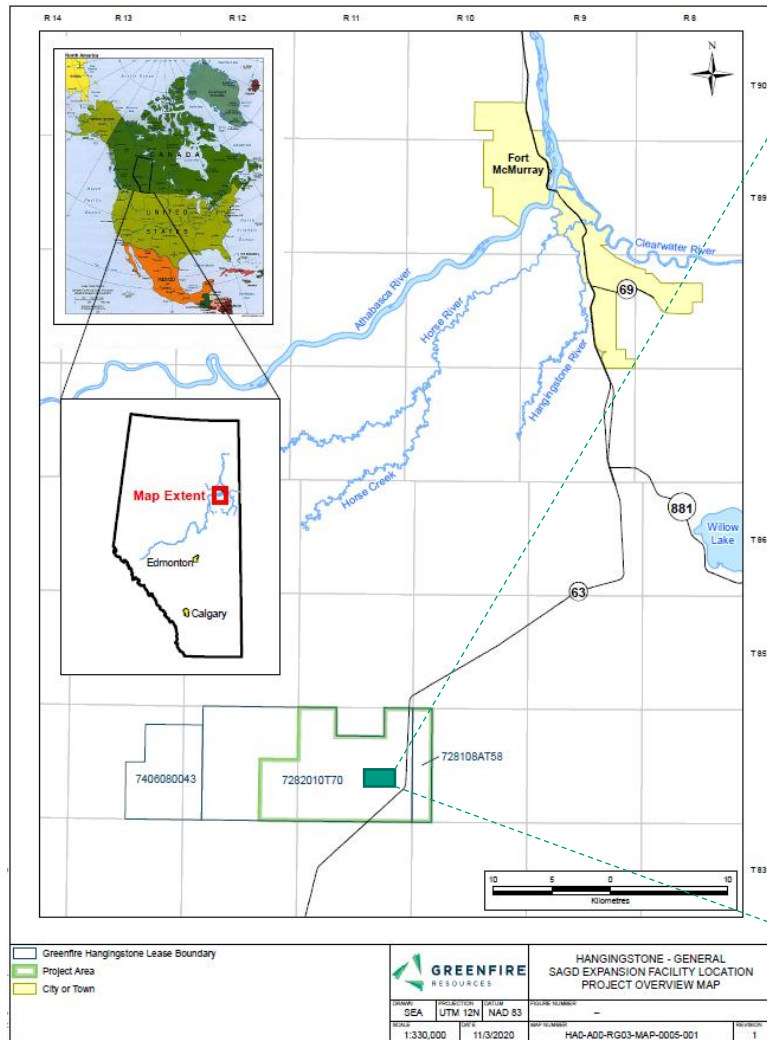


- Hangingstone Expansion Project (the "**Project**") has been in operation since 2017, with an approved production capacity of 4,800 m³/day (~30,000 bbl/day)
- Alberta Energy Regulator (“**AER**”) Approvals:
 - EPEA Approval No. 153105, as amended
 - Scheme Approval No. 11910, as amended
- Project Operational History
 - First Steam – April 2017
 - First Production – August 2017
 - Transfer of Ownership to Greenfire – September 2021

*Note: The subject report includes information from January 1, 2025, to December 31, 2025, and is noted as the “**reporting period**” throughout.*

1.2 Location

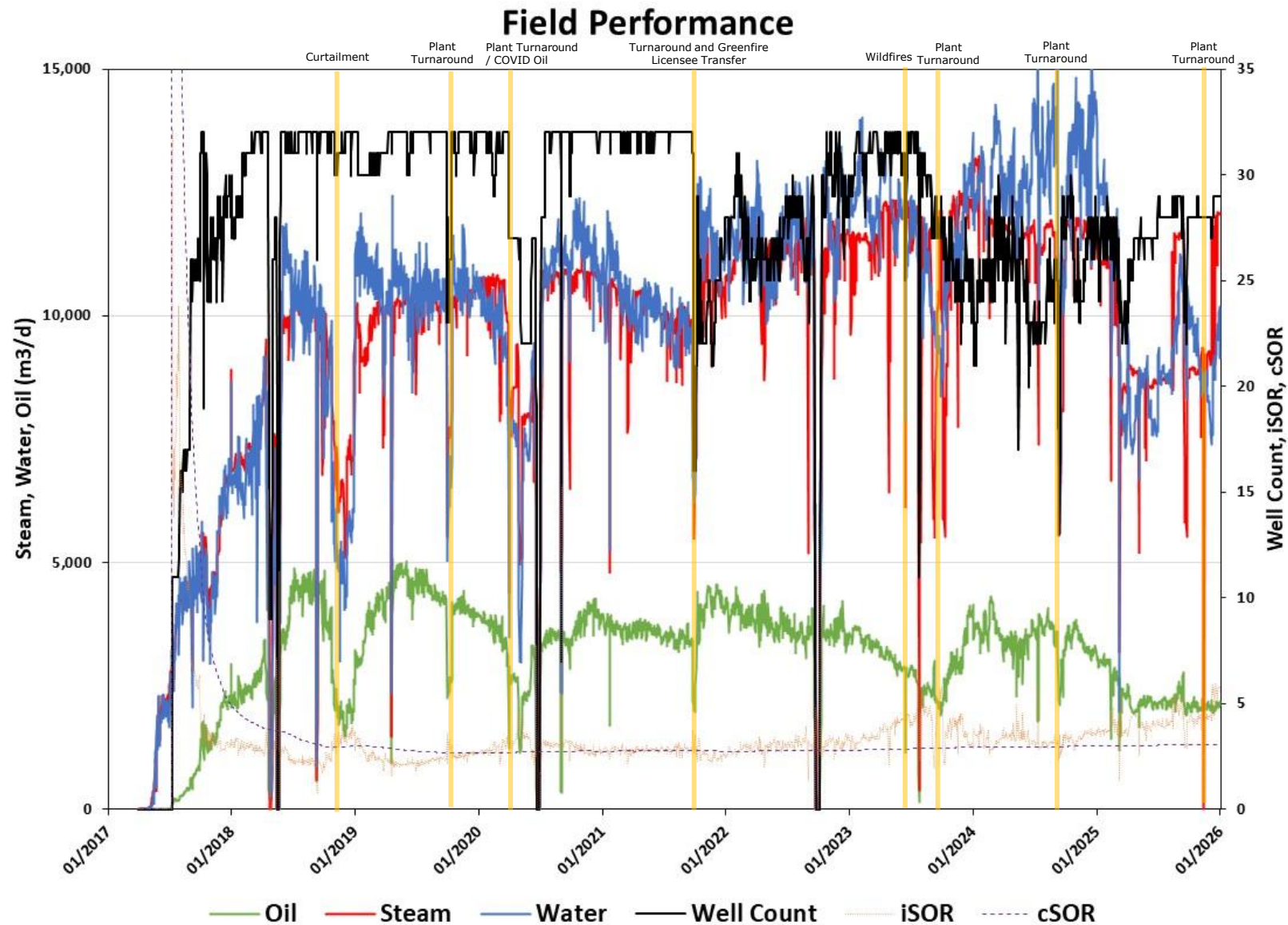
The Project is located approximately 65 km south of Fort McMurray, Alberta



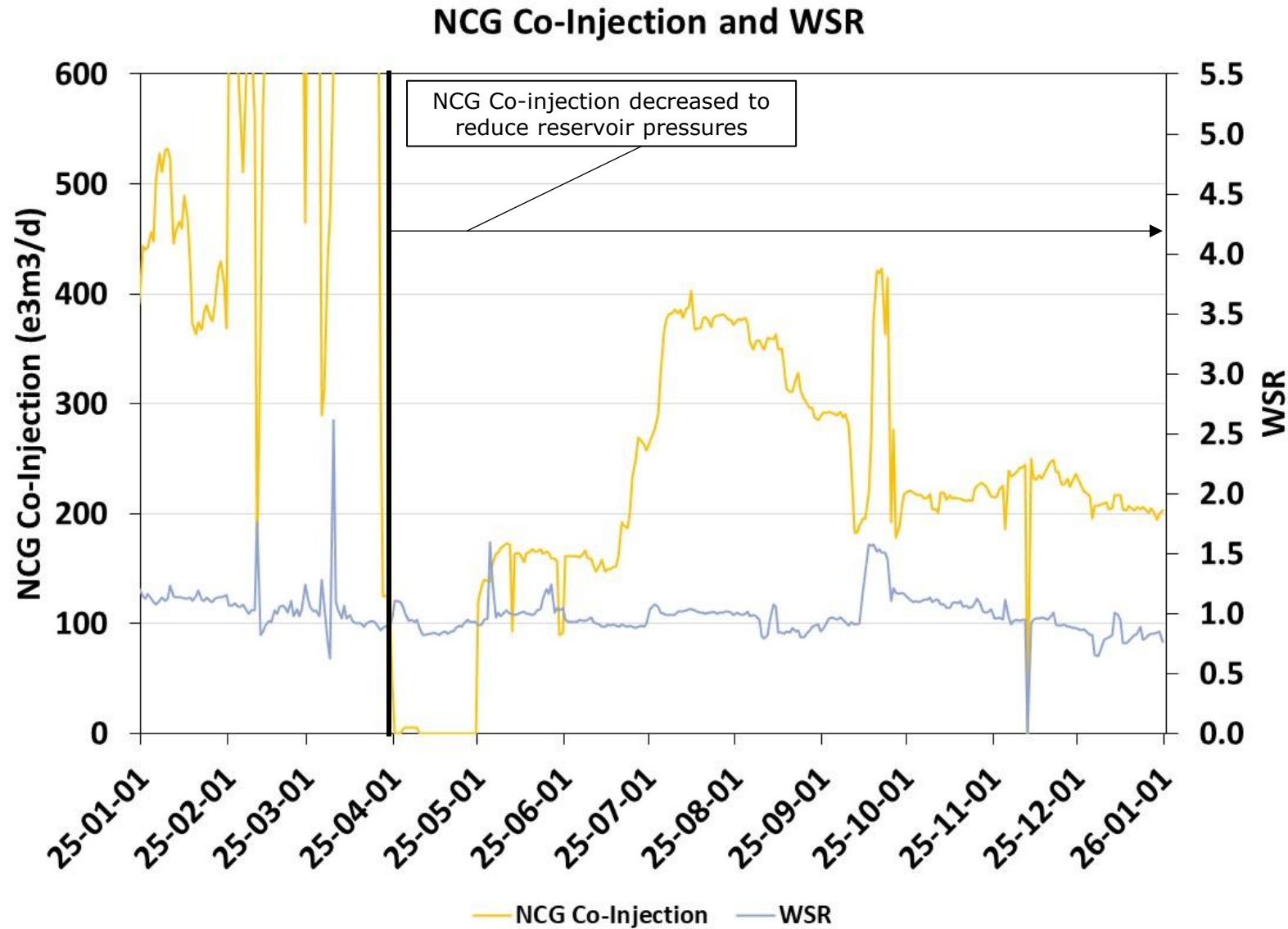
Section 2.0 – Subsurface



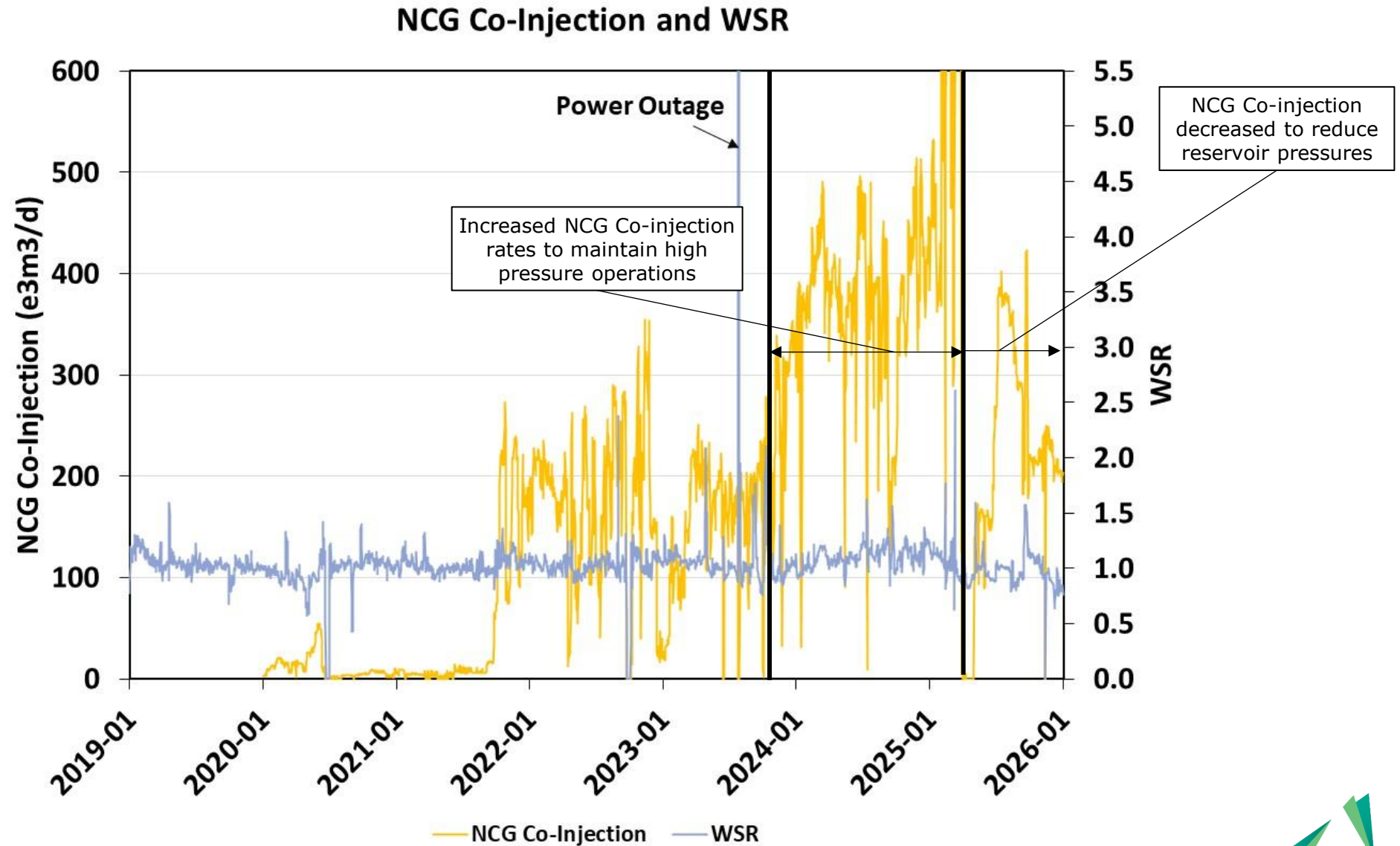
2.1 Field Performance: Lifespan Production



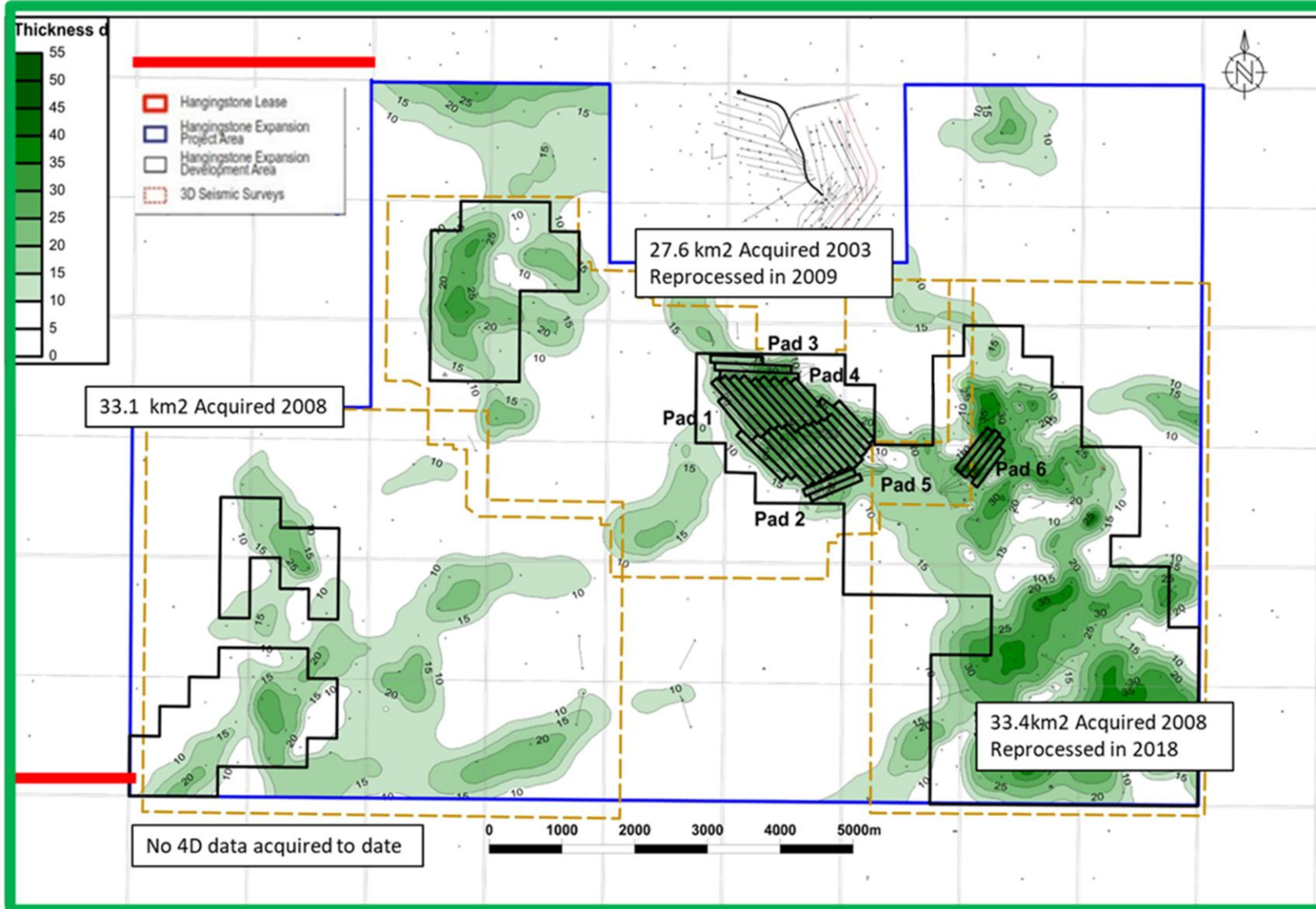
2.2 2025 Field NCG Co-Injection & WSR



2.3 2019-2025 Field NCG Co-Injection & WSR



2.4 Net Pay/Drainage Pattern/Seismic



McMurray Net Pay Criteria:

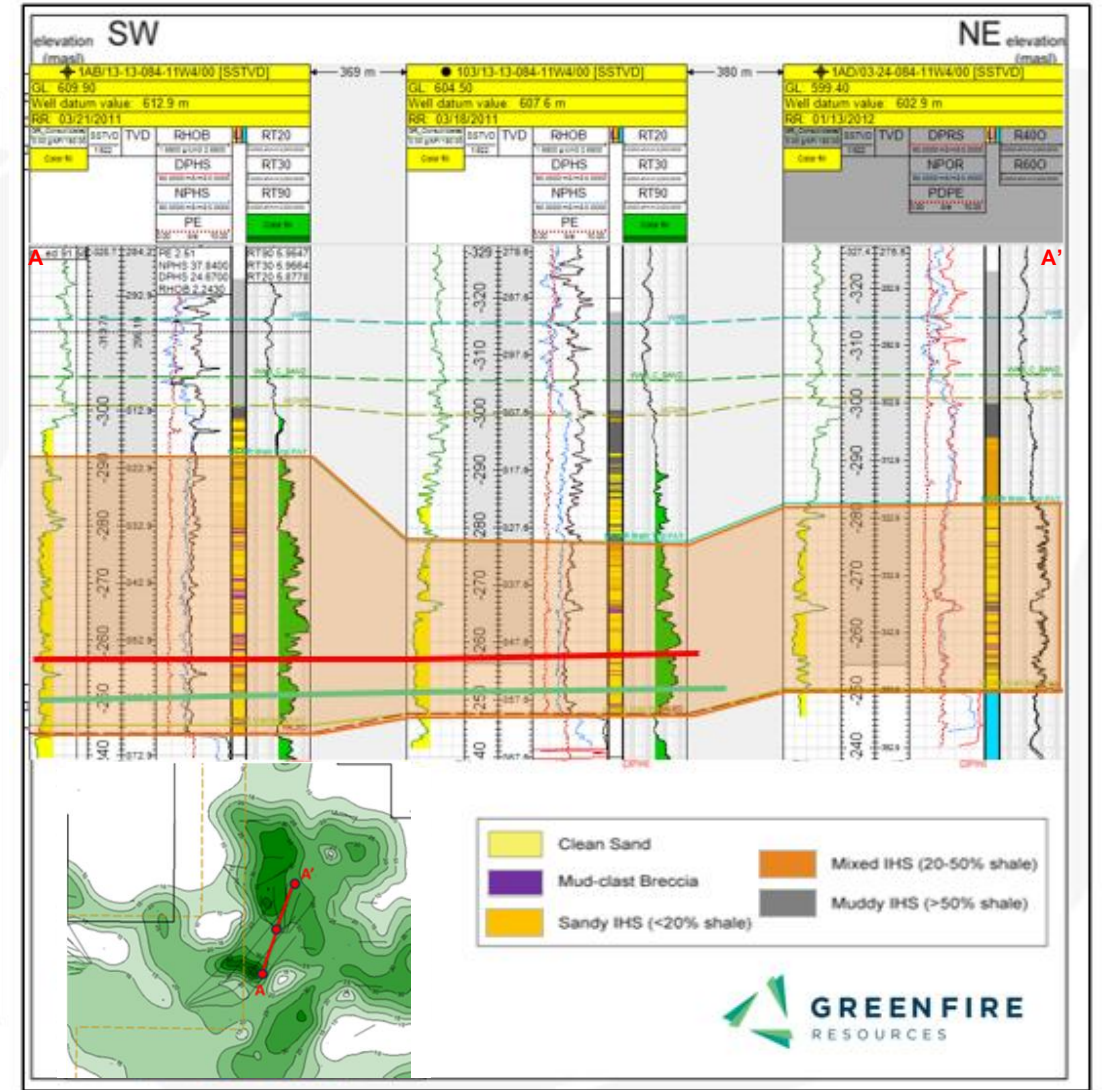
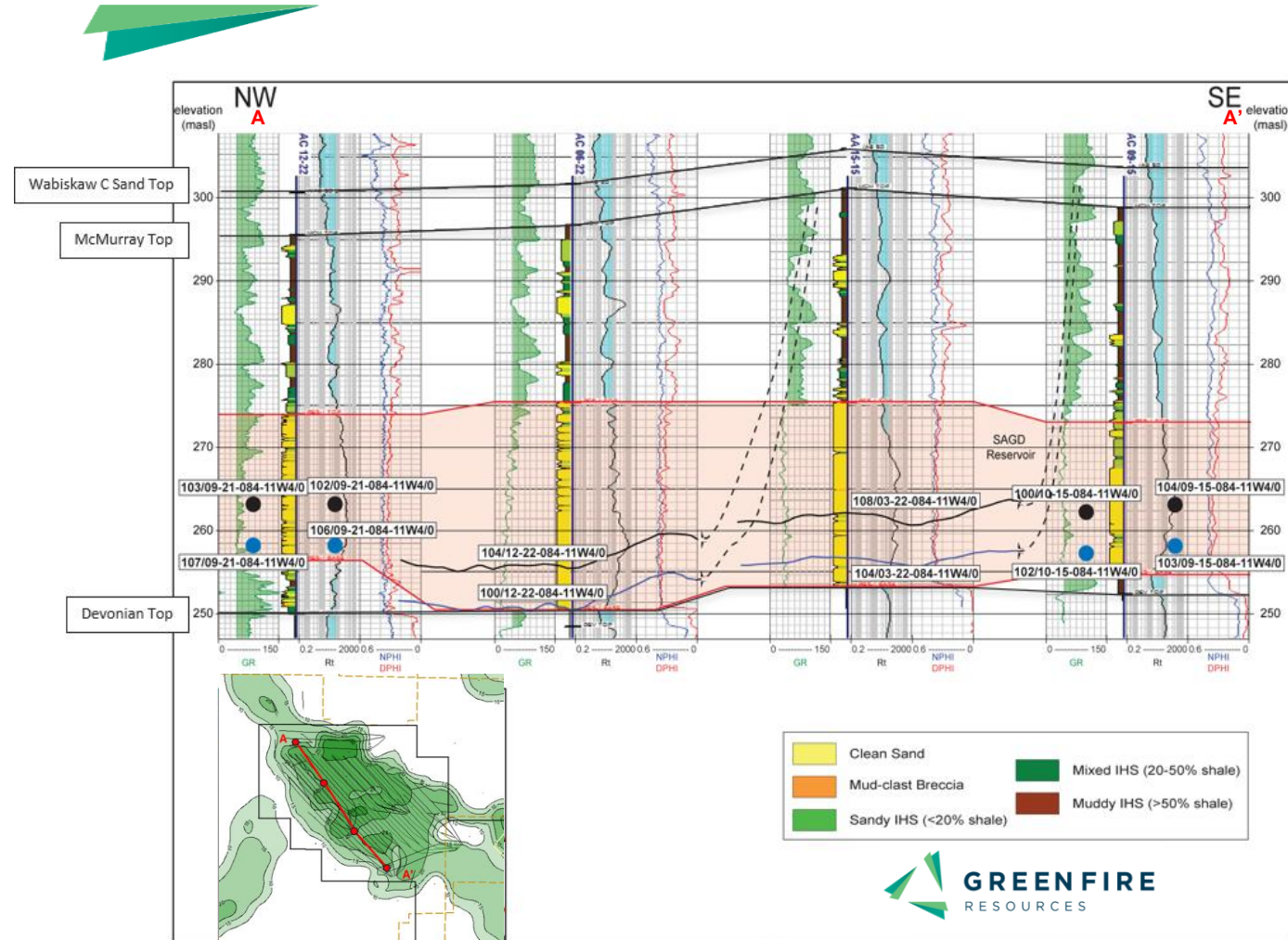
- < 60API Gamma Ray
- > 27% Porosity
- > 20 $\Omega \cdot m$ Rt (>50% So)
- < 30% Vshale

2.5 Geomechanical Summary

- Original injection pressures determined by mini-frac tests in the 1980's
- The Project conducted mini-frac testing in 2010 and exhibited consistent results to the original data
- Reservoir pressure is monitored through blanket gas pressure readings in the casing annulus

Formation/Lithology	Depth TVD (m)	Min. Stress		Vertical Stress		Stress Regime
		MPa	kPa/m	MPa	kPa/m	
Clearwater Shale	272.0	5.39	19.82	5.73	21.07	Horizontal Fracture
Wabiskaw Shale	297.0	6.17	20.77	6.26	21.08	Horizontal Fracture
McMurray Shale	314.5	5.55	17.65	6.64	21.11	Vertical Fracture
McMurray Sand	327.0	5.59	17.09	6.91	21.13	Vertical Fracture

2.6 Well Cross Sections



2.7 Original Bitumen in Place (OBIP)

Reservoir Parameter	Value
Initial Oil Saturation (%)	81
Porosity (%)	33
Average SAGD pay Thickness (m)	22
Average Vertical Permeability (mD)	4,050
Average Horizontal Permeability (mD)	5,800

OBIP Calculation Method

$$\text{OBIP} = R_v \times \phi \times (1 - S_w) \times FVF$$

Where:

OBIP = Original bitumen in place

R_v = Rock Volume

ϕ = Porosity

S_w = Initial water saturation

FVF = Formation volume factor (1.001)

Area	OBIP (e ⁶ m ³)	Cumulative Production (e ⁶ m ³)	Recovery Factor (Based on OBIP) (%)
Operating Area	15.5	9.0	63.2 %
Development Area	64.7		15.1%
Project Area	248.0		4.0%

2.8 Well Patterns

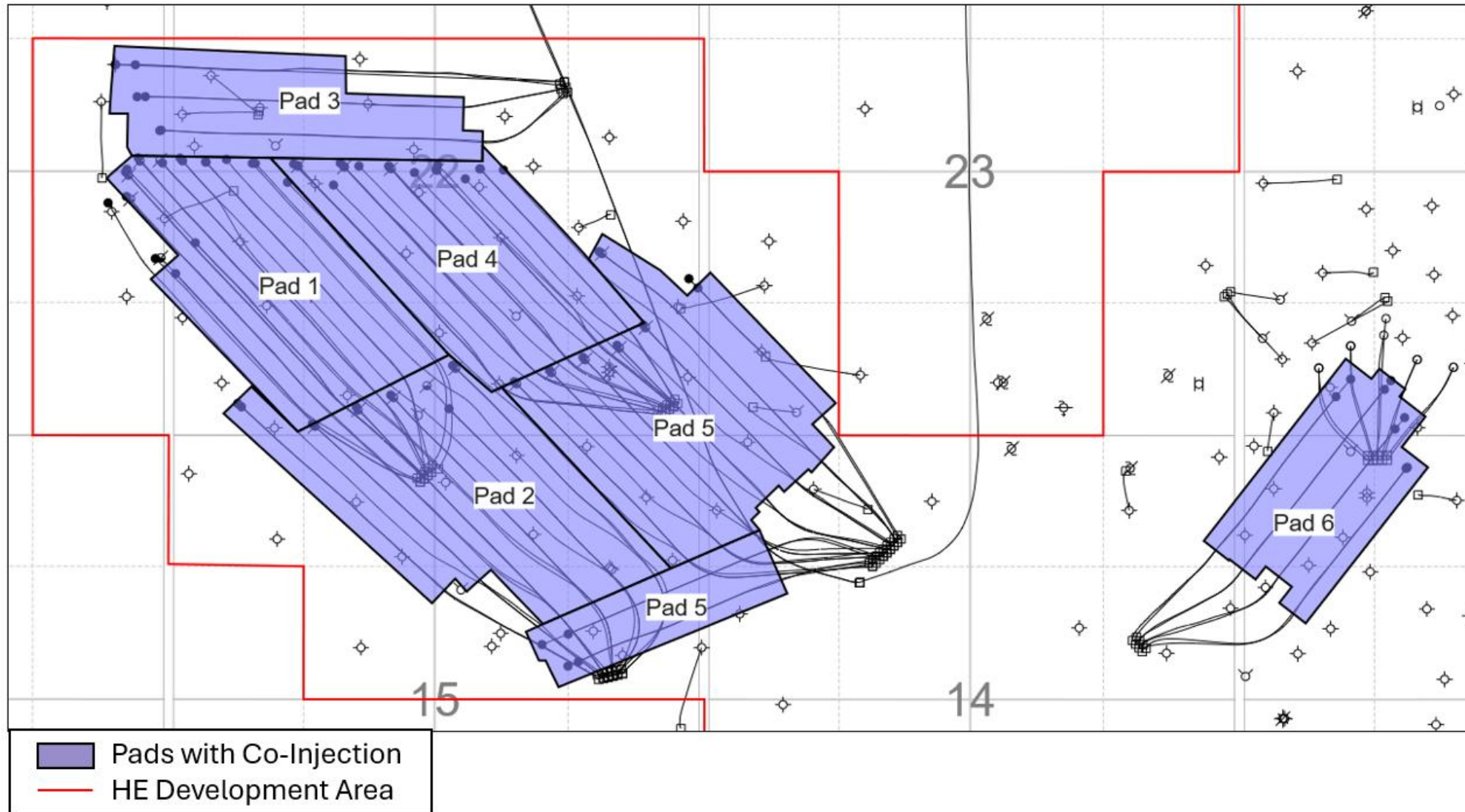
Pad	Area (m ²)	Average Net Pay (m)	Porosity (%)	Oil Saturation (%)	Vertical Perm. (mD)	Horizontal Perm. (mD)	OBIP (e ³ m ³)	PBIP (e ³ m ³)	Cumulative Prod. (e ³ m ³)	Current OBIP RF (%)	Current PBIP RF (%)	Est. Ultimate RF (Based on OBIP) (%)
1, 2,4,5	445,154	21.5	33	81	4,050	5,800	11,990	11,348	8,589	72	76	70-80
3	295,421	17.5	33	81	4,050	5,800	1,390	1,295	308	22	24	55-65
6	254,952	30.6	33	81	4,050	5,800	2,080	1,937	900	43	46	60-70
Operating Area	2,606,175	22.7	33	81	4,050	5,800	15,460	14,580	9,798	63	67	65-75

2.9 Co-Injection Summary

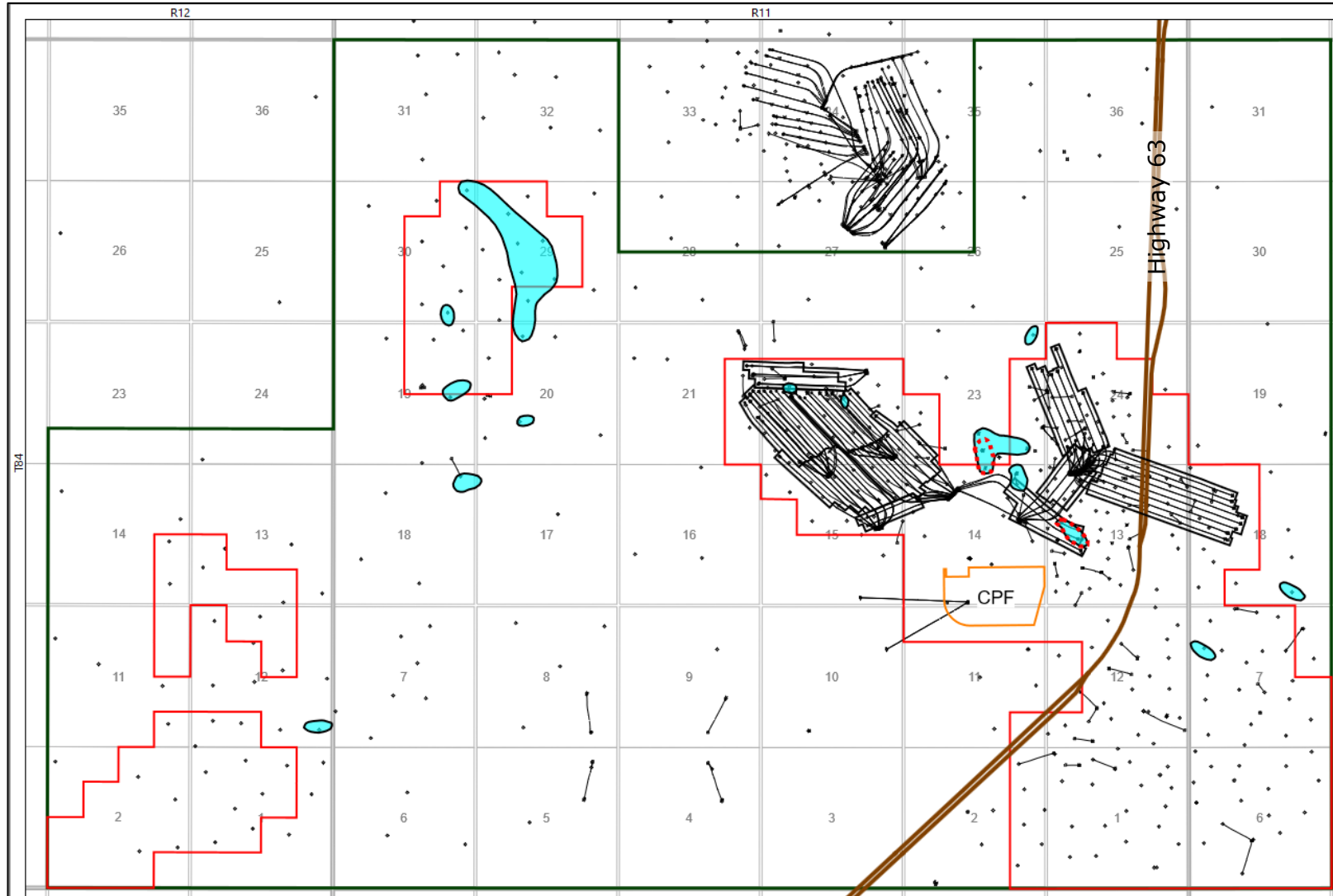
- The Project is approved for full field NCG co-injection (pipeline fuel gas) up to 25 e³m³/d per well.
- The table provides NCG co-injection carried rates for January to December 2025 by pad:
 - The average project injection for 2025 was 299 e³m³/d.
 - The cumulative co-injection for 2025 was 109,400 e³m³/d.
- Greenfire intends to continue with NCG co-injection to assist with reservoir pressure maintenance, pending market conditions, as it helps to keep pressure in the reservoir while allocating steam around the field.

Pad	Average Injection by Well (e ³ m ³ /d)	Cumulative Injection (e ³ m ³)
1	12.6	22,905
2	9.8	21,417
3	1.1	1,252
4	11.6	21,129
5	11.3	36,960
6	3.9	5,738

2.10 Co-Injection Well Locations

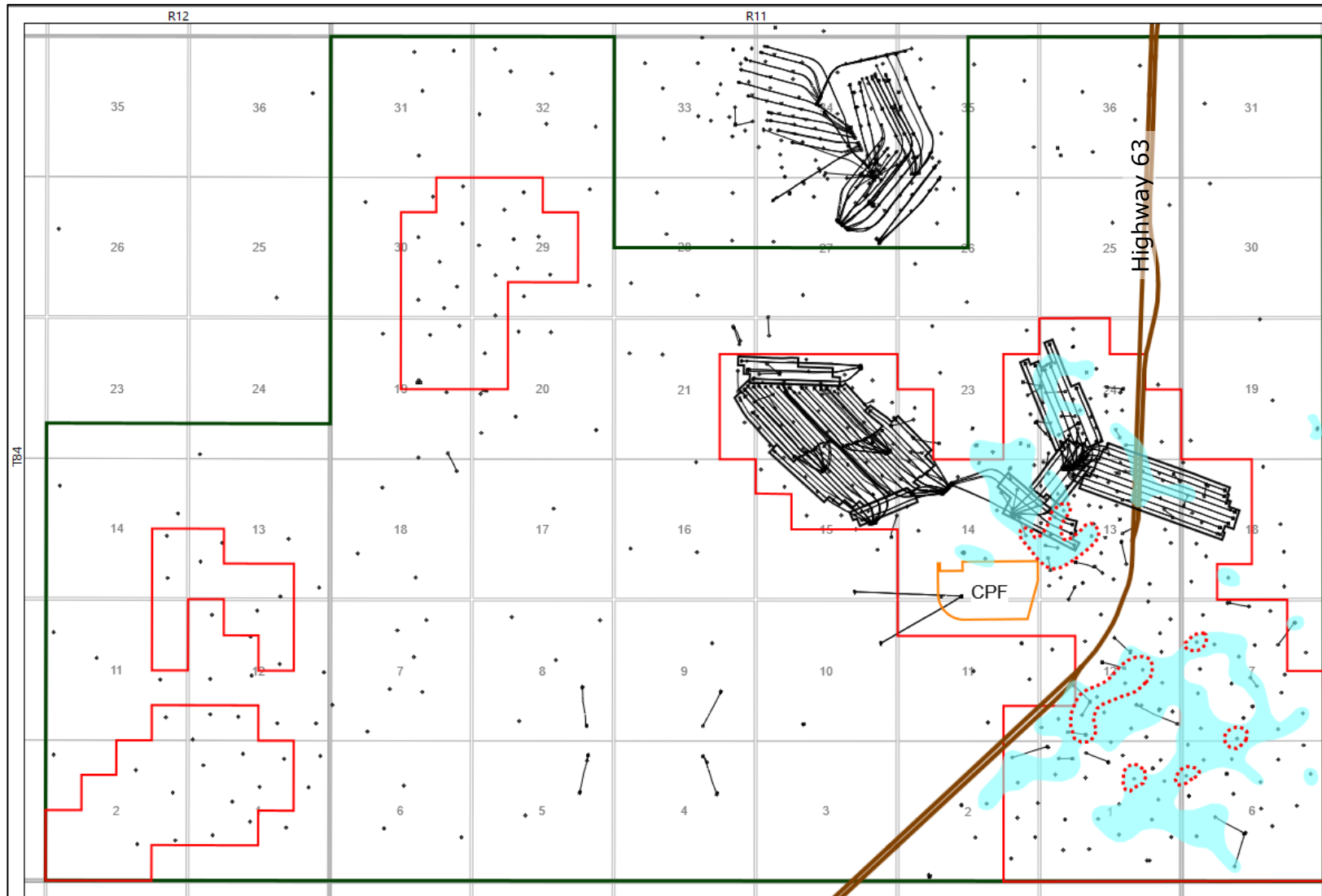


McMurray Bottom Water



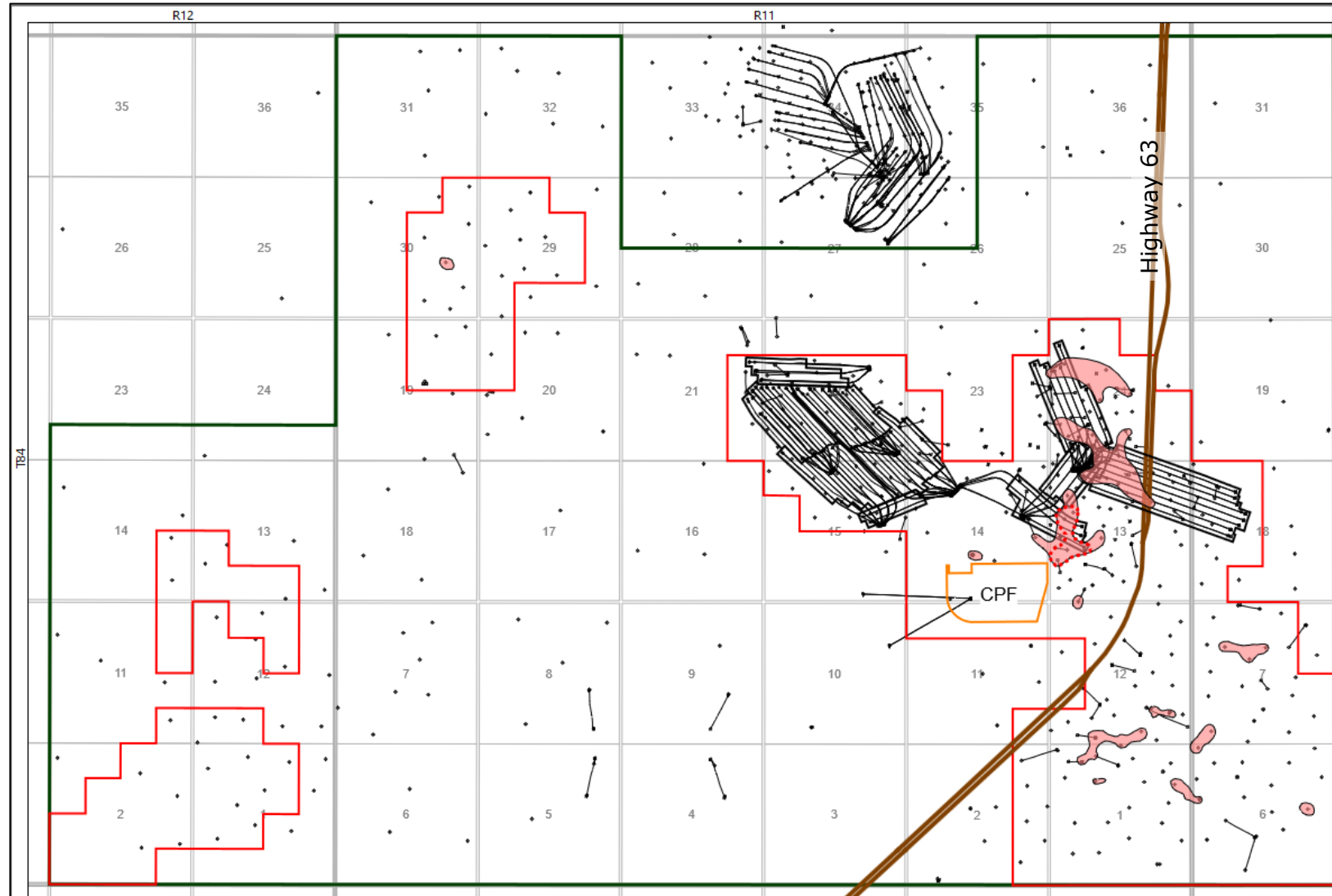
- Project Boundary
- Approved Development Area
- McMurray Basal Water
- Direct Contact between Basal Water and Main SAGD Pay

McMurray Top Lean / Water



- Project Boundary
- Approved Development Area
- McMurray Top Lean / Water
- Direct Contact between Top Lean / Water and Main SAGD Pay

McMurray Top Gas



- Project Boundary
- Approved Development Area
- McMurray Top Gas
- Direct Contact between Top Gas and Main SAGD Pay

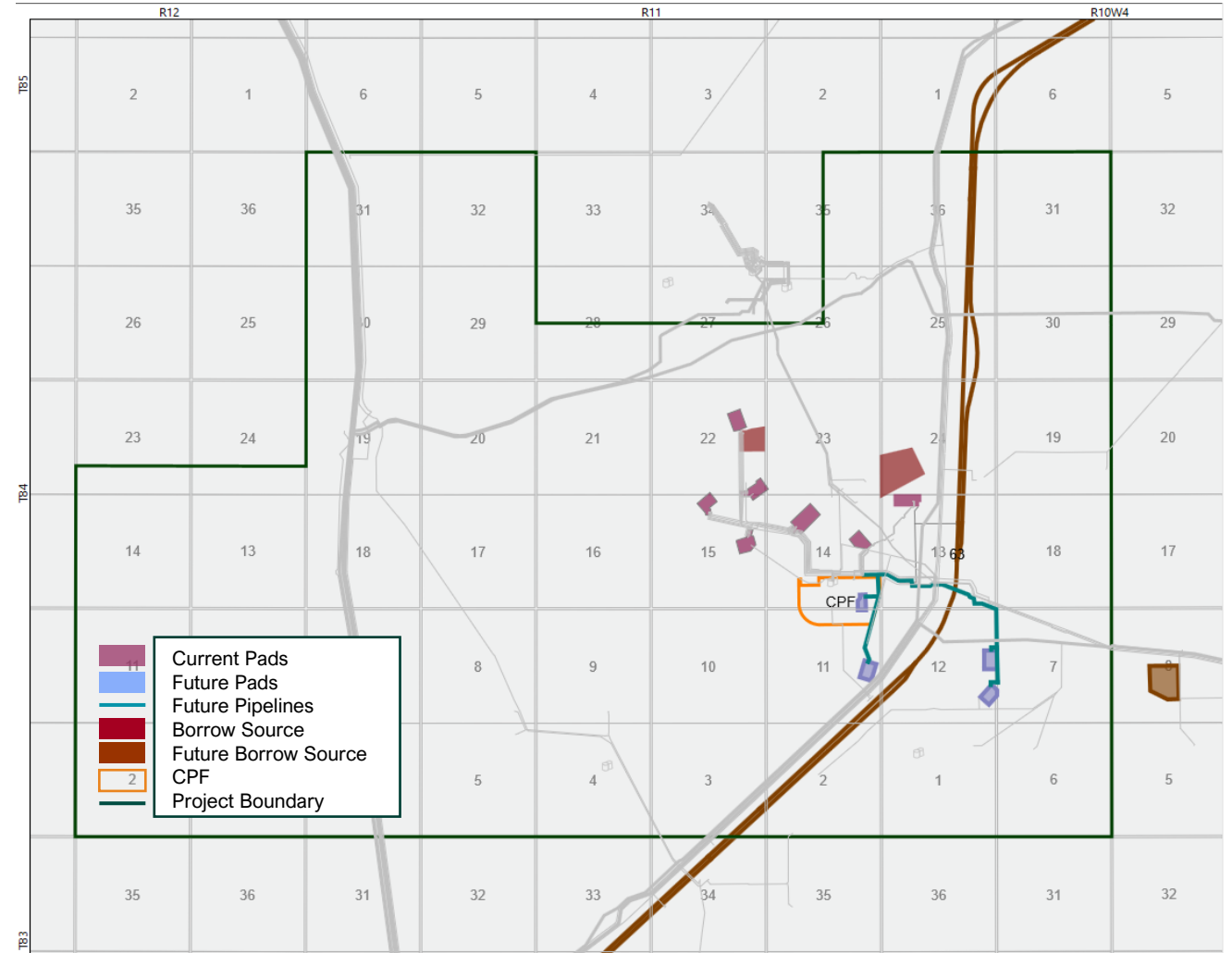
Section 3.0 – Surface



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3.1 Infrastructure

Surface Infrastructure planned over the next 5 years



3.2 CPF Modifications

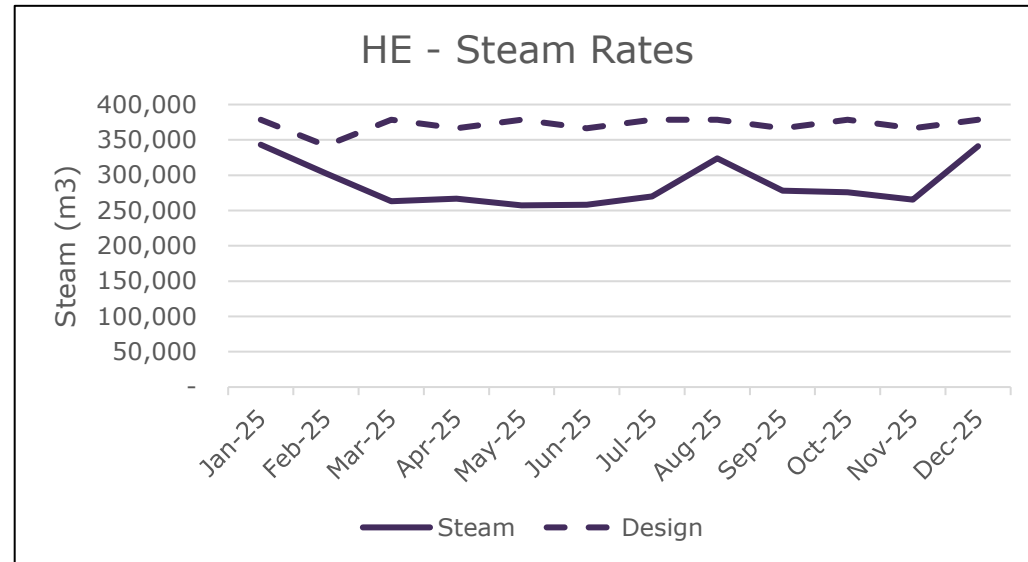
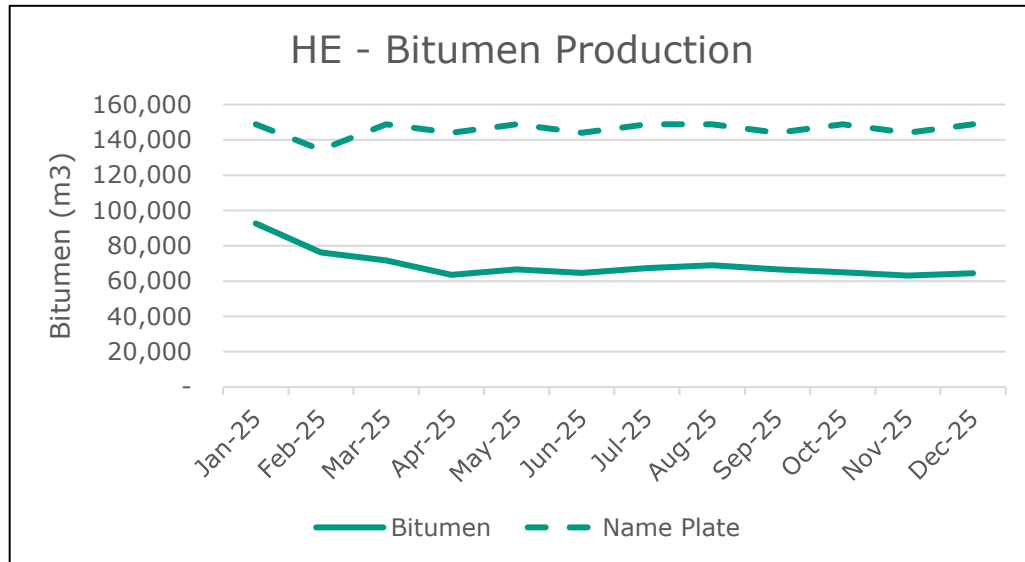


The modifications completed during the reporting period include:

- Tie-in and operation of a second disposal well (Application Number 1957535)
- SRU installed (Application Number 1957717) and commissioned December 2025

3.3 Bitumen/Steam Rates

The following are the steam and bitumen rates for the Project for the Reporting Period. The rates matched the forecasted profiles.



Licensed Nameplate = 4,800 m³/day

Steam Rate Design = 11,440 tonnes/day (80% quality)

Section 4.0 – Historical & Upcoming Activity

4.1 Suspension & Abandonments

ABANDONMENTS

Licence #	Well Name	UWI	Final Drill Date	DH Abandonment Date
0469887	W07-P02	02/07-24-084-11W4/0	17-Jan-2015	05-Sep-2025
0469989	W07-I02	04/07-24-084-11W4/0	06-Feb-2015	28-Aug-2025
0469888	W07-P03	00/10-24-084-11W4/0	19-Jan-2015	03-Sep-2025
0469990	W07-I03	02/10-24-084-11W4/0	03-Feb-2015	29-Aug-2025
0469976	W07-P04	00/06-24-084-11W4/0	21-Jan-2015	02-Sep-2025
0469991	W07-I04	04/06-24-084-11W4/0	01-Feb-2015	30-Aug-2025
0469977	W07-P05	02/06-24-084-11W4/0	23-Jan-2015	02-Sep-2025
0469992	W07-I05	05/06-24-084-11W4/0	30-Jan-2015	31-Aug-2025
0469978	W07-P06	03/06-24-084-11W4/0	25-Jan-2015	06-Sep-2025
0469993	W07-I06	06/06-24-084-11W4/0	27-Jan-2015	01-Sep-2025

- Five well pairs were downhole abandoned in 2025 with cut and caps planned for 2026. These wells never produced and new wells at the pad will be drilled in 2026.
- There are no well patterns with active blow-down or ramp-down.

4.2 Operational & Regulatory Changes

Application #	Description	Approval Date
1958540	Category 2 amendment – Development Area Expansion and Pattern Modifications	30-Jul-2025
1957717	Category 2 amendment – SRU Installation	02-May-2025
1957535	Add new disposal well	05-Feb-2025
1957302	Acid Gas Disposal Application	Withdrawn

- A Sulphur Removal Unit (SRU) was installed and commissioned at the Central Processing Facility to meet the 2.0 tonnes/day SO₂ air emission limit under EPEA.

4.3 Successes & Challenges



- **Successes**

- Sulphur recovery project sanctioned and in service in 2025.
- Sanctioned and began drilling 14 Well Pair pad in late 2025.

- **Challenges**

- Boiler reliability and repairs resulted in 75% reduction in steam capacity; boilers repaired, and full name plate capacity achieved in late 2025.
- Current base production is high recovery and in decline with lack of greenfield development since 2017; new well pads are required and were sanctioned in 2025.

4.4 Compliance History



AER Reportable Incidents

- On Lease Release – Edge Reference No. 0445363

Contraventions: *Environmental Protection and Enhancement Act* and *Water Act*

- In February, one passive monitor registered an SO₂ AAQO exceedance. Further investigation found that the SO₂ limit was also exceeding the allowable tonnes per day, resulting in a second contravention.
- In April, AER issued a non-compliance relating to the SO₂ limit exceedance. An SRU was installed and commissioned late 2025 addressing the SO₂ issues.
- Data from two water observation wells could not download in April, resulting in equipment replacements. A third malfunctioning logger was found in August on a water observation well. The equipment was replaced.
- Drilling in September required a temporary removal of one passive air site to accommodate rig placement. A variance was approved but due to weather-related delays, site access was restricted longer than anticipated and the monitoring reinstatement was late.

4.4 Compliance History

AER Field Inspections

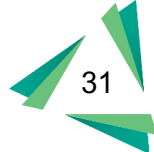
Date	Description	Corrective Actions/ Follow Up	FIS#
04-Apr-2025	Satisfactory Well Inspection on SCV at injection well	Bubble test confirmed no gas present.	553437
04-Apr-2025	Satisfactory Well Inspection on SCV at production well	Bubble test confirmed no gas present.	553436
25-Jul-2025	Satisfactory Watercourse Crossing 10-03-084-10W4	No follow up required.	556255
25-Jul-2025	Satisfactory Watercourse Crossing 10-07-084-10W4	No follow up required.	556256
14-Aug-2025	SO ₂ exceedance at HE	This is related to the original non-compliance in April.	556697
24-Sep-2025	Satisfactory Pipeline Integrity Program Inspection with follow up	Multiple follow up items throughout 2025/2026.	557905

4.5,12 Future Plans



- 2026 Plans
 - Finishing drilling and construction on Pads 7, 8, and 5 expansion
 - First steam on Pad 7
 - Ongoing evaluation of various central processing facility and well pad debottlenecking opportunities that could improve the overall performance of the scheme
 - Winter delineation program to assist with sustaining pad development
- 5-Year Development Plan
 - Continued delineation program for sustaining pad developments
 - Additional pad developments further to the southeast

-  Lease Boundary
-  Project Area
-  Approved Development Area
-  Drilled Patterns
-  Next 5 Years Patterns
-  OSE focus area next 5 years
-  Future Seismic Programs



4.5,12 c) Future Plans: Upcoming 12 Month Applications



Description	Application Number	Submission Date	Approval Date
Pad 5/8 SAGD Application	1961128	April 16, 2026	July 6, 2026
Pad 9 SAGD Application	-	Q3 2026	-
2026/2027 Oilsands Exploration Application	-	Q3 2026	-
SAGD Lifecycle for Drainage Areas	-	Q4 2026	-
EPEA Amendment for Facility Expansion	-	Q1 2027	-
OSCA Facility Expansion (Cat 3)	-	Q1 2027	-

Section 5.0 - Lifecycle and Additional D054 Reporting



Clause 18, Open Loop Exchange Cooling System



The wells associated with the Open Loop Ground Source Exchange Cooling System were drilled in late 2024, but the project has not been commissioned. An upcoming OSCA amendment will formally cancel this project and remove clause 18 of the approval.

Clause 19, Pad 7 and 9 Heave Monitoring



As of June 2026, steam has not begun on Pad 7 or Pad 9. Heave data will be included in the submission for the 2026 reporting year.

Lifecycle Condition: Infill Wells



Approval for infill wells under the lifecycle condition was issued January 12, 2026. As this report covers the 2025 reporting period, updates related to infill wells will be supplied in the 2026 submission.

Disclaimer



Advisory

This presentation contains information in compliance with *AER Directive 054 - Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes*. This document contains forward-looking information prepared and submitted pursuant to Alberta regulatory requirements and is not intended to be relied upon for any other purposes, including without limitation, to make investment decisions or to purchase, hold or sell any securities of Greenfire Resources Ltd. Additional information with respect to the risks and uncertainties associated with forward-looking information is contained in Greenfire's annual information form for the year ended on December 31, 2025, available on SEDAR+ at www.sedarplus.ca/, which is also included in Greenfire's Annual Report on Form 40-F filed on EDGAR at www.sec.gov and on the website (www.greenfireres.com).

Oil & Gas Financial Information

The estimates of reserves were prepared effective December 31, 2025. All estimates of reserves were prepared by independent qualified reserves evaluators based on definitions contained in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. Additional information with respect to pricing and additional reserves and other oil and gas information, including the risks and uncertainties associated with reserves estimates, is contained in Greenfire's annual information form for the year ended December 31, 2025 available on SEDAR+ at www.sedarplus.ca, which is also included in Greenfire's Annual Report on Form 40-F filed on EDGAR at www.sec.gov and on the website (www.greenfireres.com).