



ATHABASCA OIL CORPORATION

LEISMER D54 PERFORMANCE REPORT 2024

JUNE 2025

ATHABASCA
OIL CORPORATION

SUMMARY

- 2024 Highlights and 2025 Activity
- Development Overview
- Subsurface
- Surface Operations
- Regulatory and Compliance

2024 HIGHLIGHTS AND 2025 ACTIVITY

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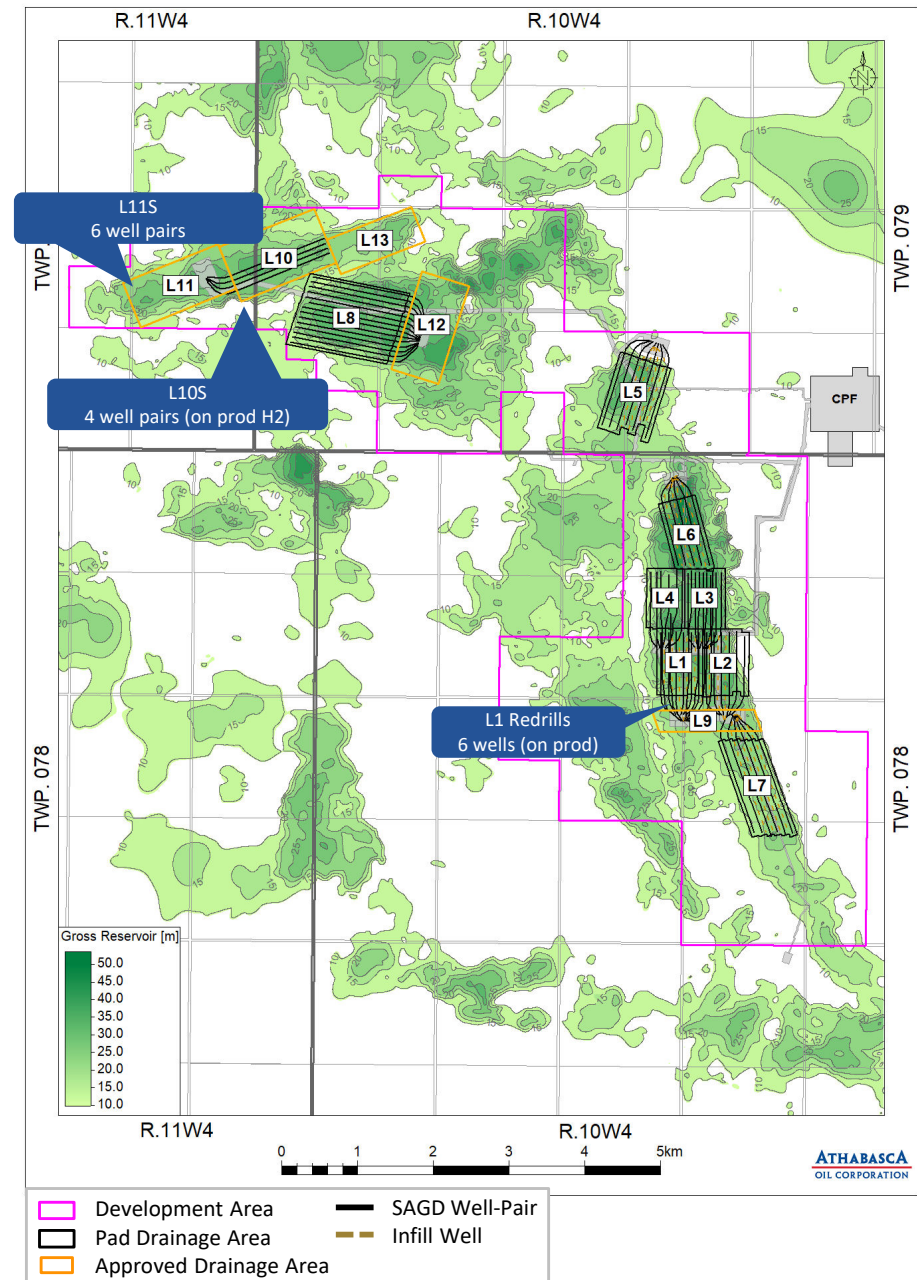
2024 ACTIVITY

- Successfully completed expansion project
 - Achieved production of ~28,000 bbl/d in June
- L4 – 3 redrills started production in Q2 (~650 m laterals)
- L8 – 4 well pairs started production in Q3
- L10 – Drilled 4 well pairs
- L1 – Drilled 6 extended reach redrills
 - Targeted bypass pay; ~1,000 – 1,600 m laterals
 - Onstream Q1 2025 with IP90 rates of ~60- 150 m³/d (~375 – 950 bbl/d)
- Drilled 5 observation wells within L10 drainage area
- Initiated clearing and piling of L10 looping pipeline
- Suspended L1N5 and L4P5 wells due to flow instability. Pad 1 and 4 recovery factors are greater than 50%.

2025 ACTIVITY

- Flexible progressive expansion to 40,000 bbl/d (sanctioned in 2024)
- L10 – 4 previously drilled wells to support production in H2
- L11 – spud 5 observation wells and 6 new well pairs
- Continue expanding NCG co-injection for pressure support, SOR management and emissions reduction

DEVELOPMENT MAP

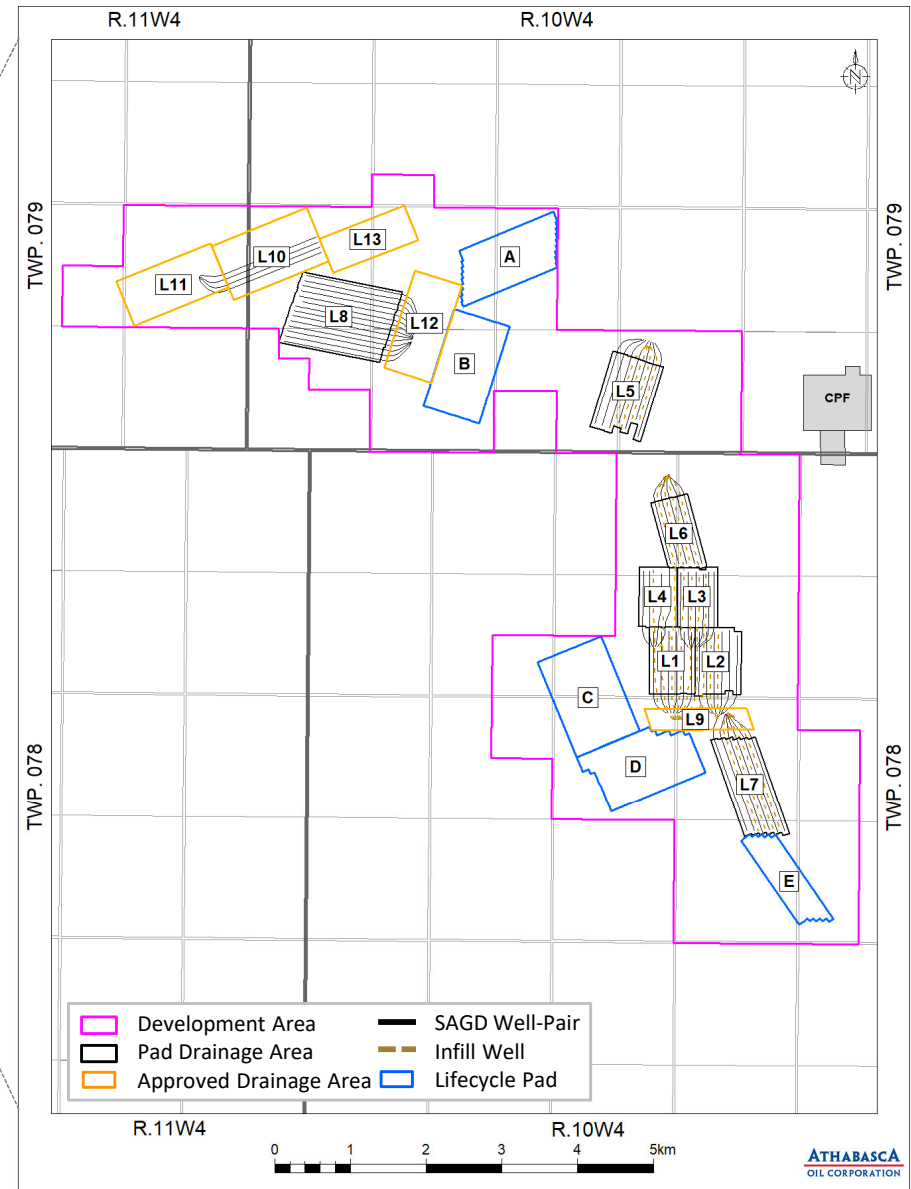
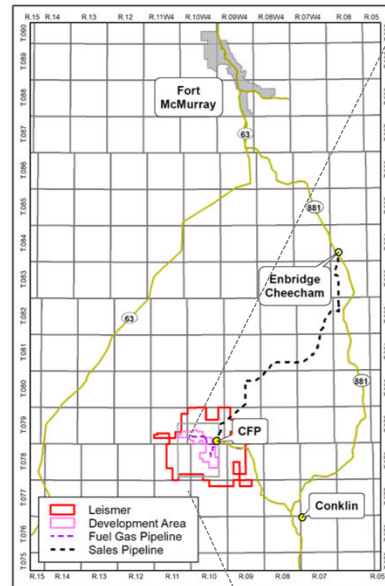


DEVELOPMENT OVERVIEW

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PROJECT DETAILS

- First steam September 2010
- Approved 40,000 bbl/d processing capacity
- 9 pad drainage areas
 - 58 SAGD well pairs; 21 infills; 9 redrills
- Approved for development
 - L9 (4 well pairs)
 - L10 (11 well pairs)
 - L11 (10 well pairs)
 - L12 (9 well pairs)
 - L13 (7 well pairs)
 - Drainages A – E (lifecycle drainage areas)
- Infrastructure
 - Fuel gas from TransCanada Pipeline (TCPL)
 - Dilbit export to Enbridge Cheecham Terminal
 - Diluent supply from Enbridge Cheecham Terminal



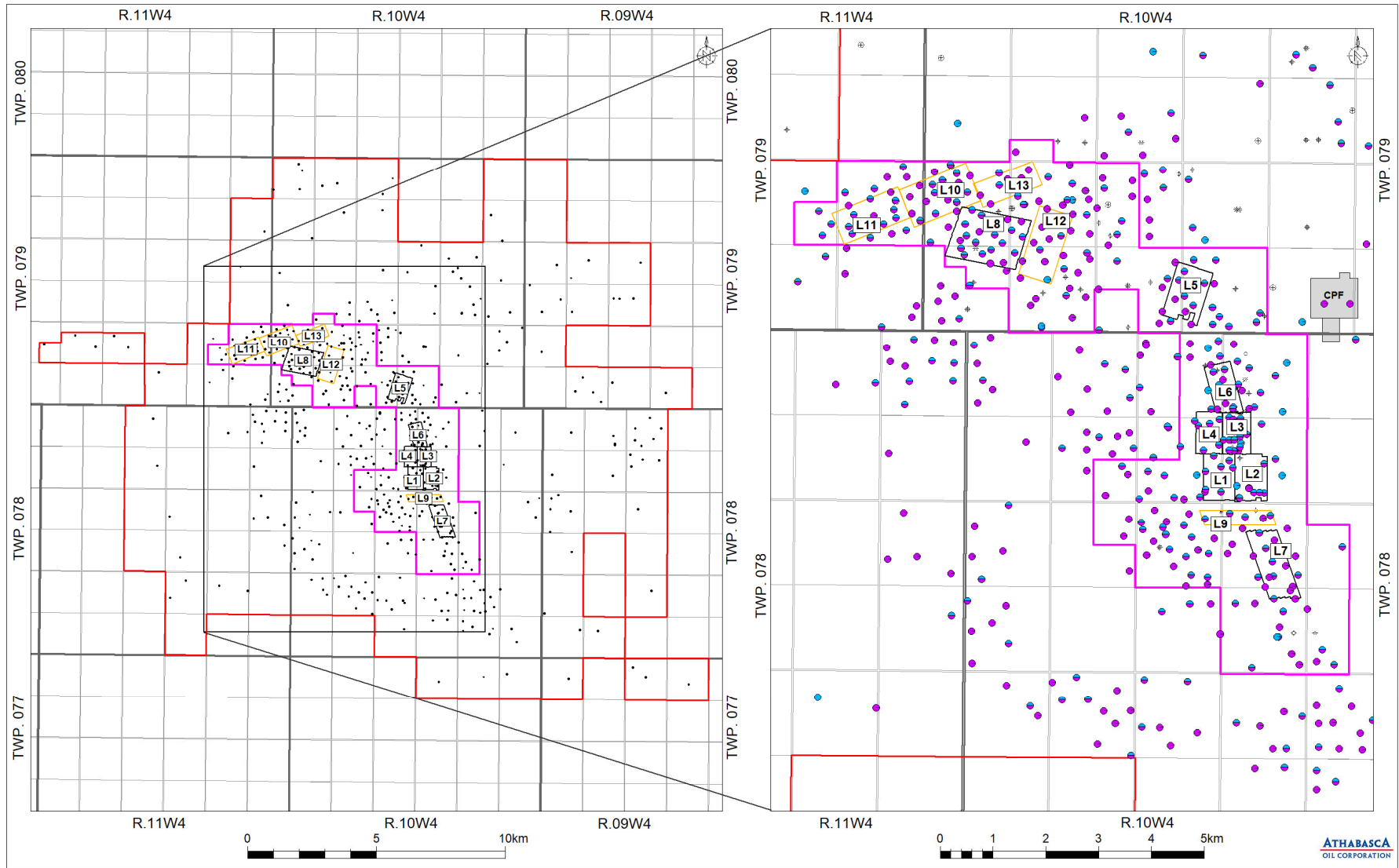


SUBSURFACE

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DATA OVERVIEW

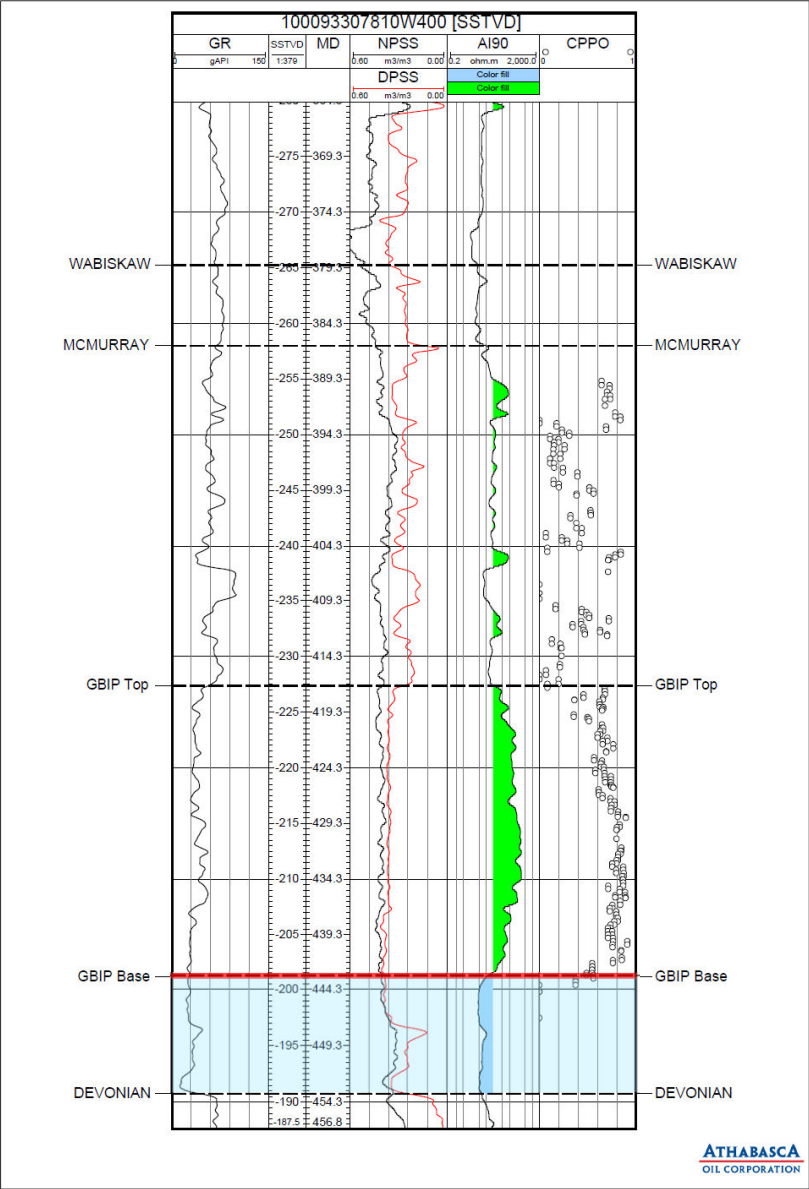
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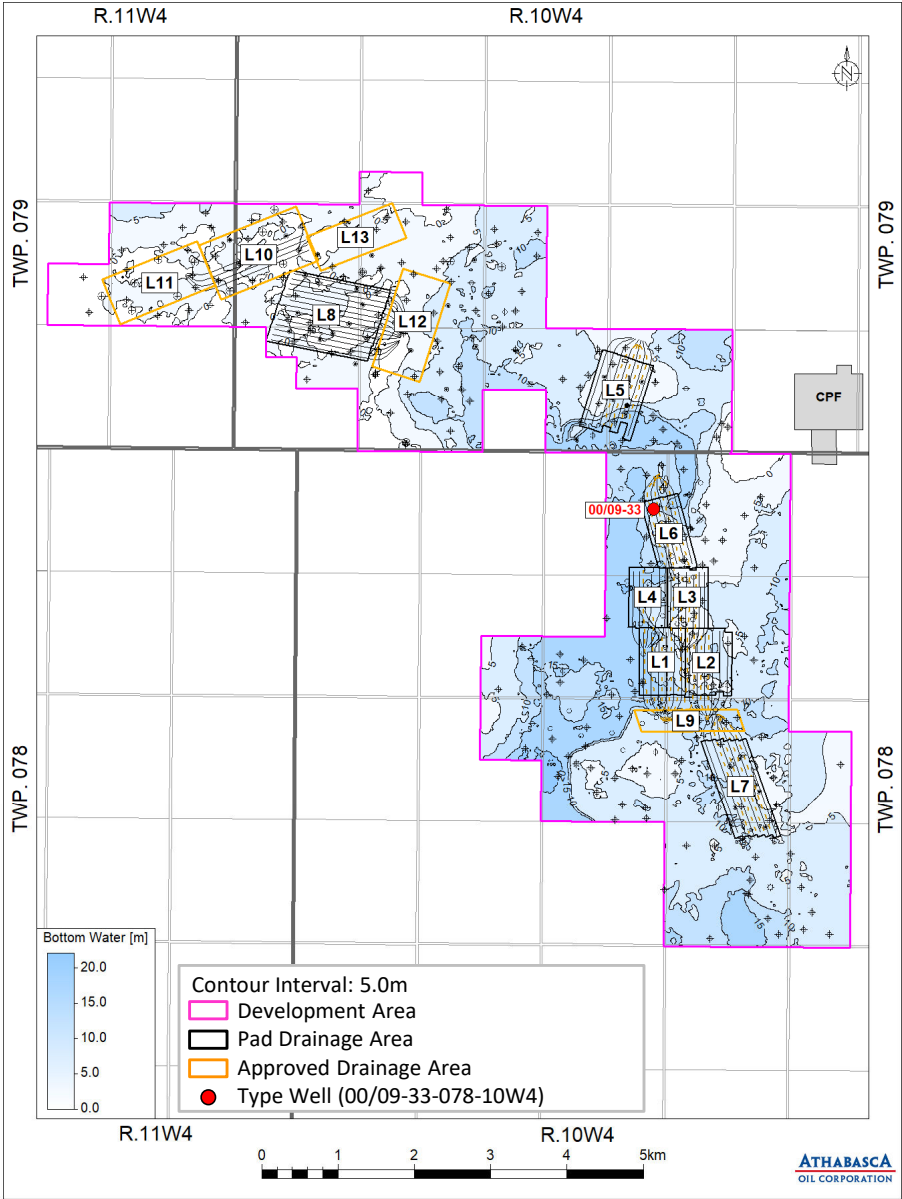
Area	Area (km ²)	Cored Wells	Image Logs
Lease Area	332	260	464
Development Area	38	164	271

- ▭ AOC Lease Area
- ▭ Development Area
- ▭ Pad Drainage Area
- ▭ Approved Drainage Area
- Cored Well
- Image Log(HMI) Well

BOTTOM WATER THICKNESS MAP



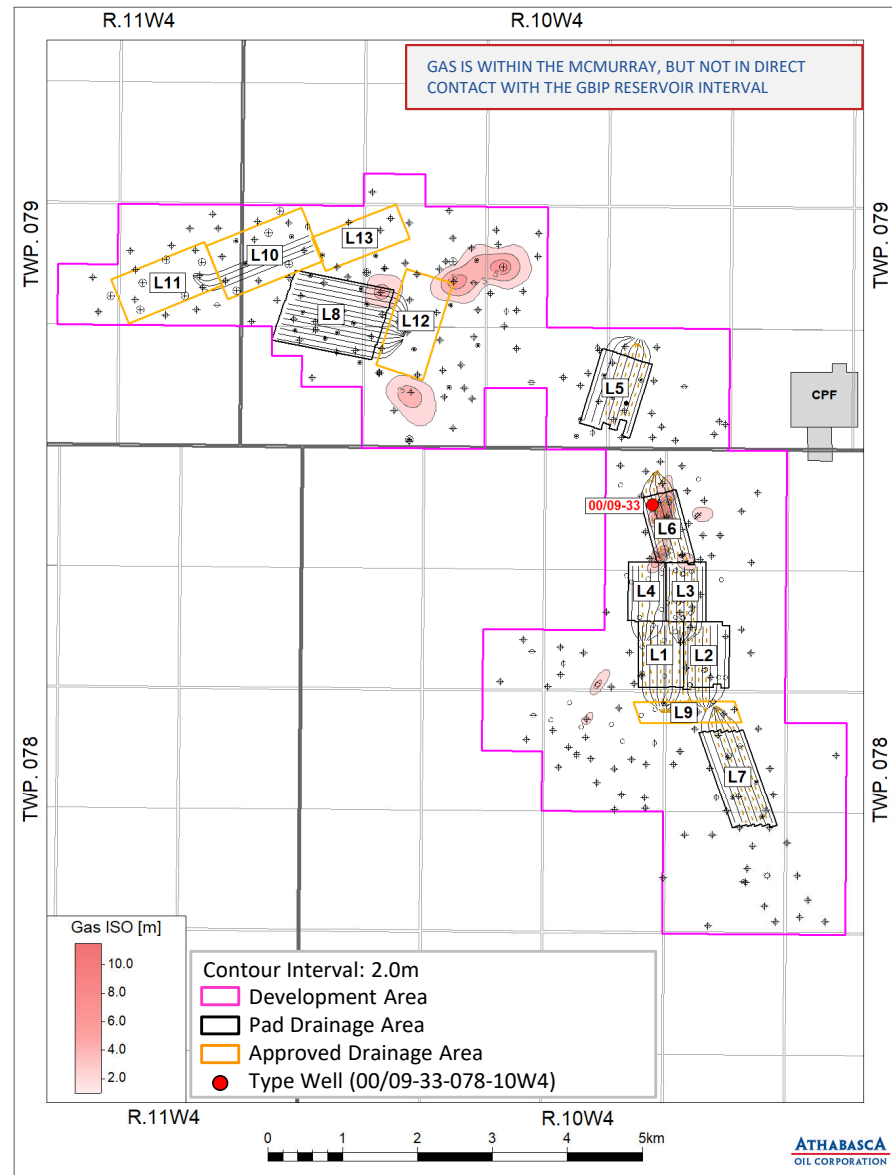
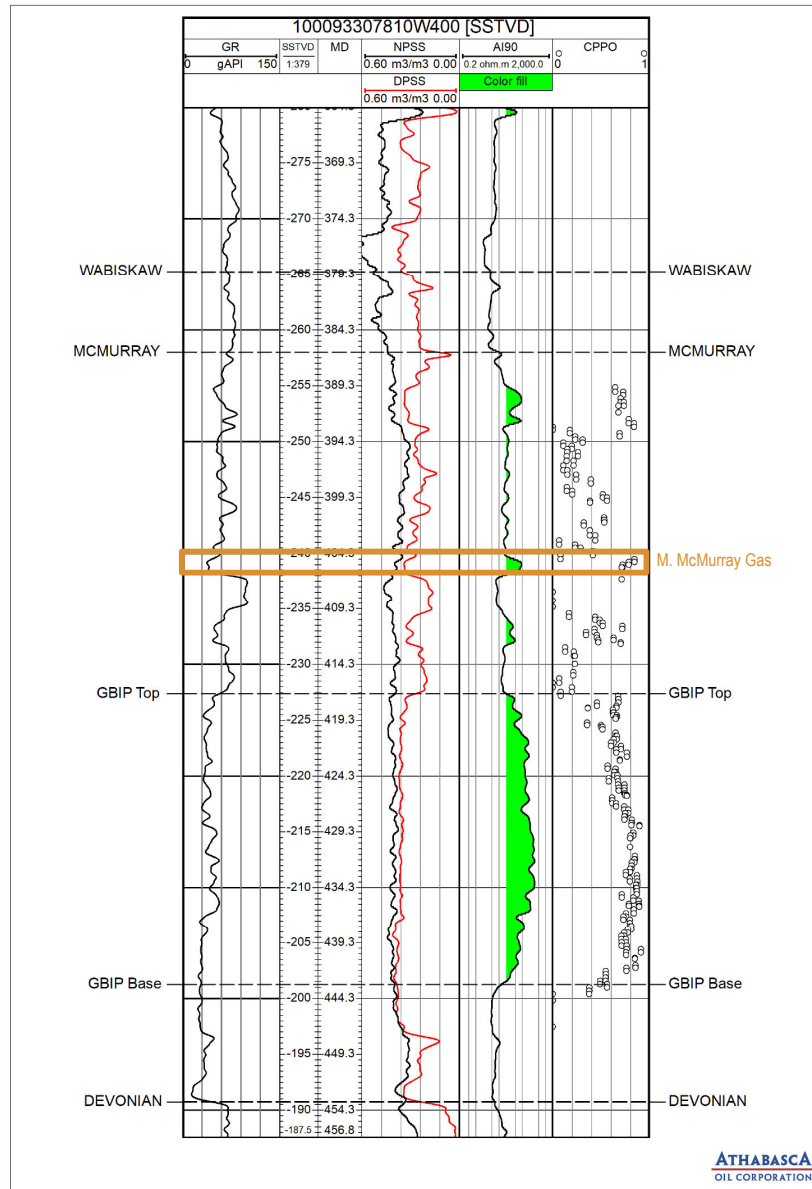
Elevation Range 191 -213 masl



TOP GAS THICKNESS MAP

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MINIMAL GAS THICKNESS AND LIMITED DISTRIBUTION WITHIN DEVELOPMENT AREA



BITUMEN PAY CLASSIFICATION

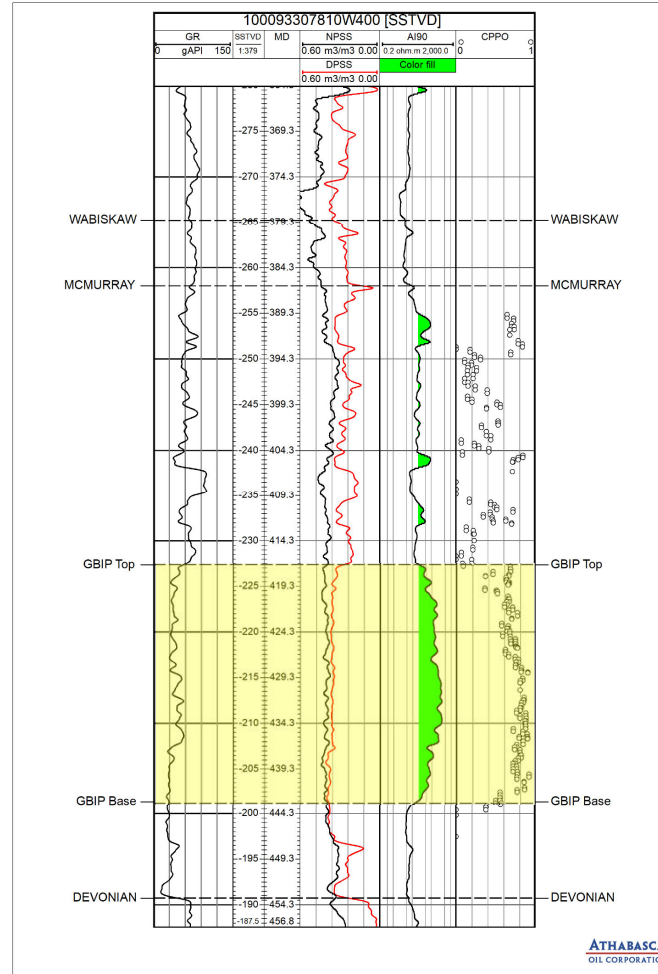
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RESERVOIR CRITERIA

- Facies classification based on percentage mud
 - F1: Breccia = variable
 - F2: Sand = 0-10%
 - F3: Sandy IHS = 10-30%
 - F4: Muddy IHS = 30-70%
 - F5: Mud = >70%
- Gross Bitumen in Place (GBIP)
Reservoir criteria: F1-4, <1m F5

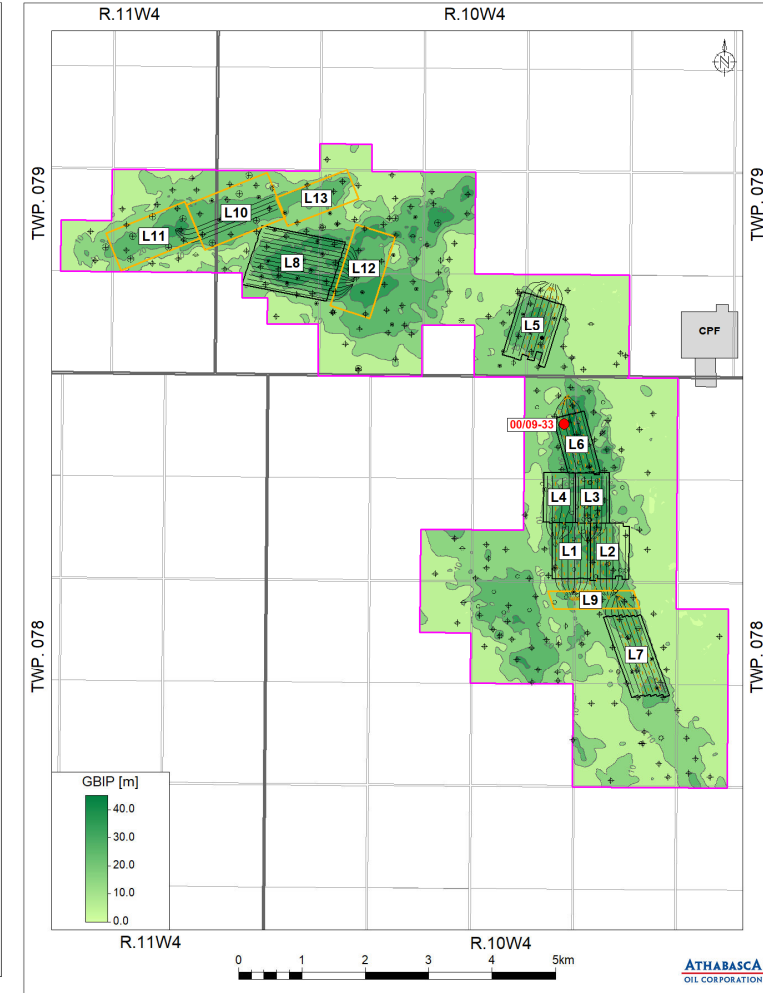
NET PAY CRITERIA

- Gross Bitumen in Place (GBIP)
Petrophysical criteria:
 - Porosity (PHIT) $\geq 27\%$
 - Saturation (SwT) $\leq 50\%$



Elevation Range: 202 -241 masl

NET PAY ISOPACH



- Contour Interval: 10.0m
- Development Area
- Pad Drainage Area
- Approved Drainage Area
- Type Well (00/09-33-078-10W4)

SEISMIC ACQUISITION HISTORY

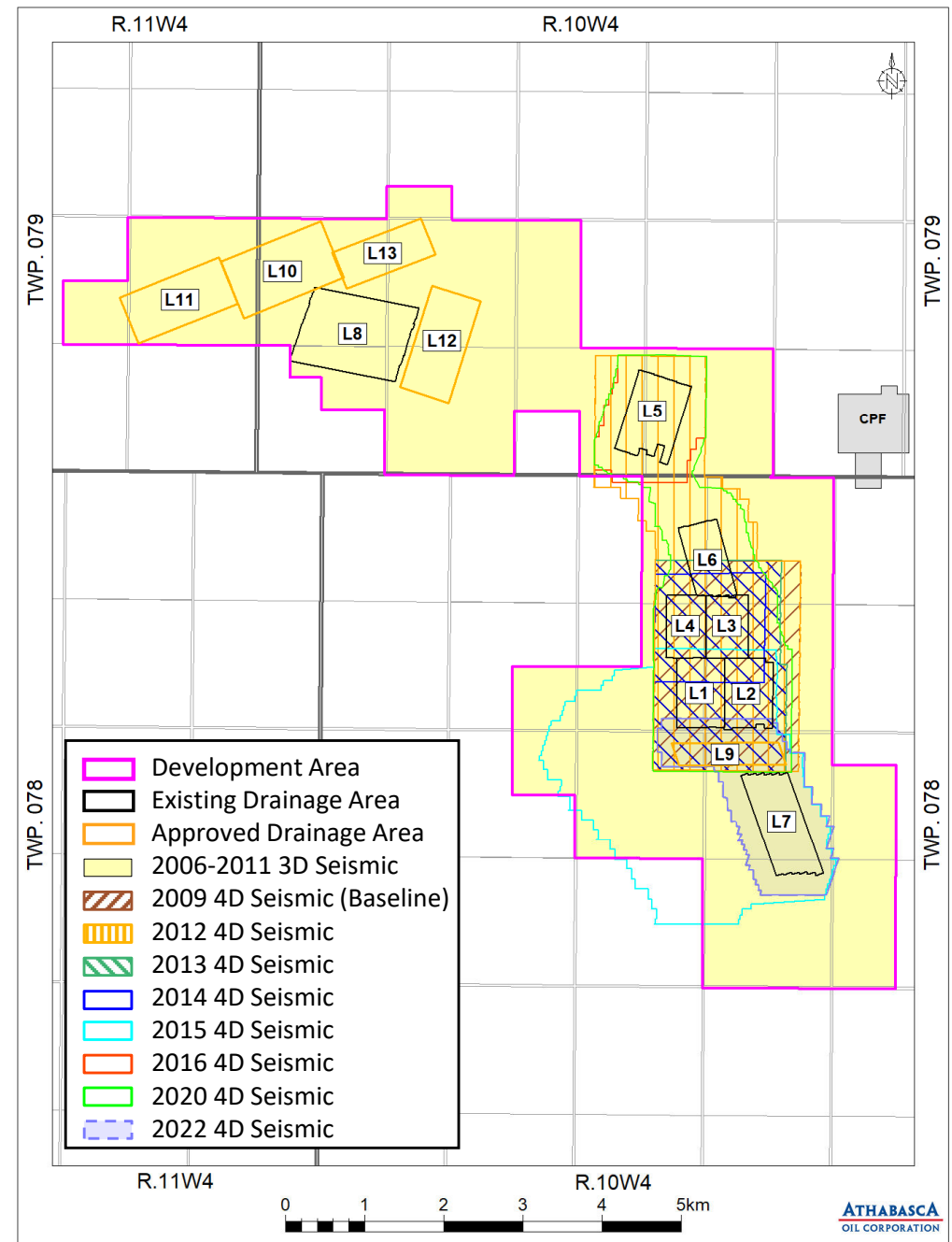
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2024

- No seismic acquisition in 2024

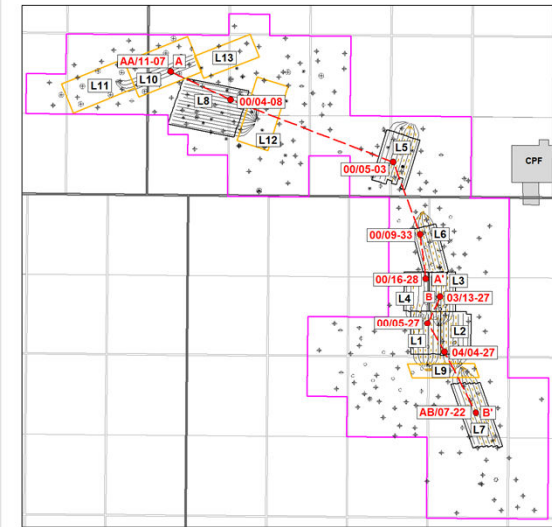
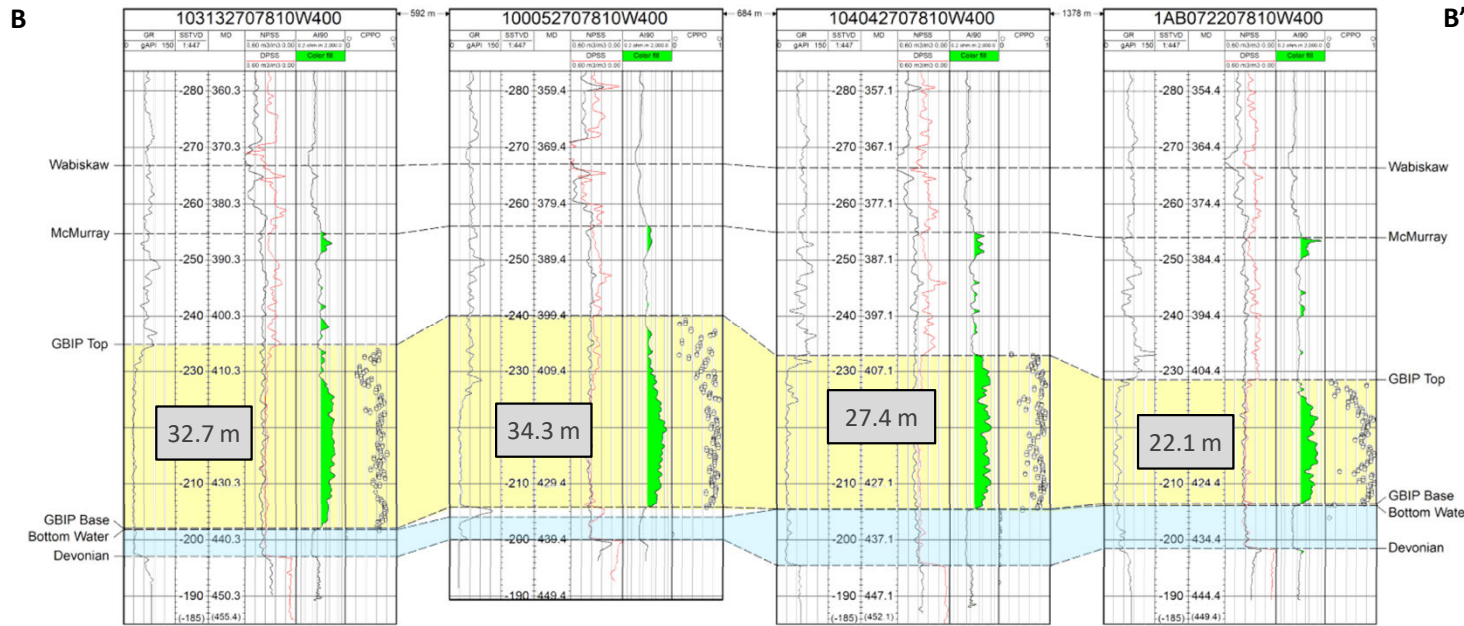
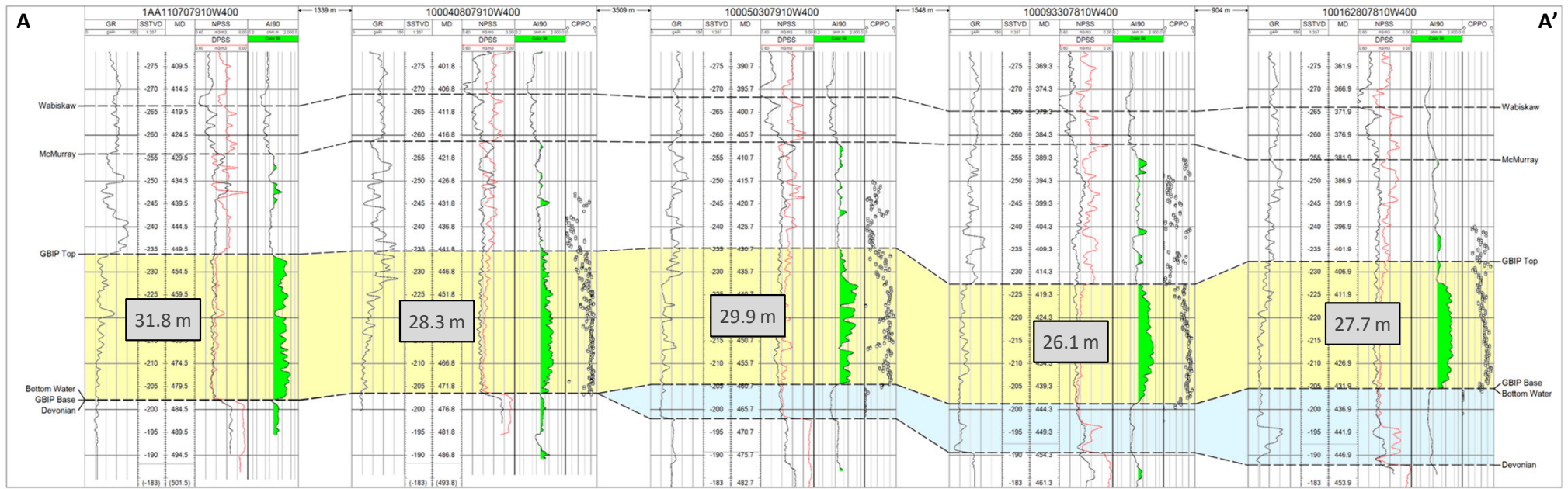
HISTORICAL

- 2022: Acquired 2.7 km² 4D for L7 and L9
- 2020: 7.1 km² 4D seismic acquired for L1-6
- 2016: 2.0 km² first 4D survey for L5
- 2015: 9.0 km² 3D survey
- 2014: 2.1 km² 4D survey (active SAGD L3 & L4)
- 2013: 4.5 km² 3D survey
- 2012: 8.6 km² 3D survey
- 2009: 4.9 km² baseline survey (pre-steam) L1–L4
- Development area covered by data acquired in 2006, 2007, 2008 and 2011 and merged into one continuous 3D



L1-L10 STRUCTURAL CROSS SECTION N-S

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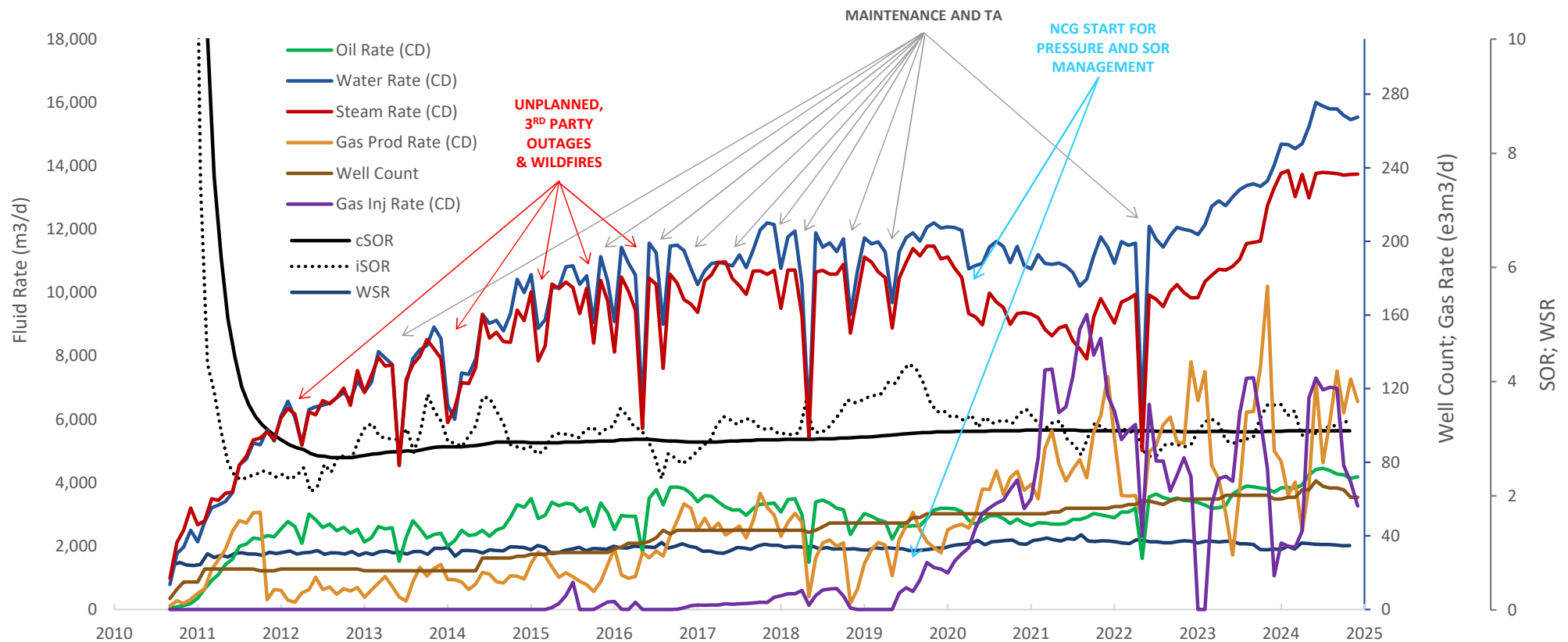
- Development Area
- Pad Drainage Area
- Approved Drainage Area
- Cross Section index line

Gross GBIP thickness

REPORTING YEAR HIGHLIGHTS

- 8 producing pad drainage areas in 2024
 - 54 SAGD well pairs, 21 infill wells and 3 redrills
 - 3 L4 redrills began production in Q2 2024
 - 4 L8S well pairs converted to production in Q3 2024
- L7 began NCG co-injection in 2024
- No known Geomechanical anomalies were observed within the development area

LEISMER FIELD PRODUCTION



- Drilled 6 extended reach redrills from L1 surface facilities that crossed into L1, L3 or L4 drainage boxes
- Targeted up to 9 m of by-passed pay
 - *Original SAGD producers and infills were placed with higher standoff to bottom water*
- Up to ~1,600 m well lengths
- Incorporated liner deployed FCDs
- IP90 rates of ~60- 150 m³/d (~375 – 950 bbl/d)
- Did not steam the wells due to elevated temperatures

GBIP Top

GBIP Base

Devonian Top

Redrill

0 50 100 150 200 250m

1:4500

RESERVOIR PROPERTIES AND RECOVERY FACTOR ¹

RESERVOIR PROPERTIES

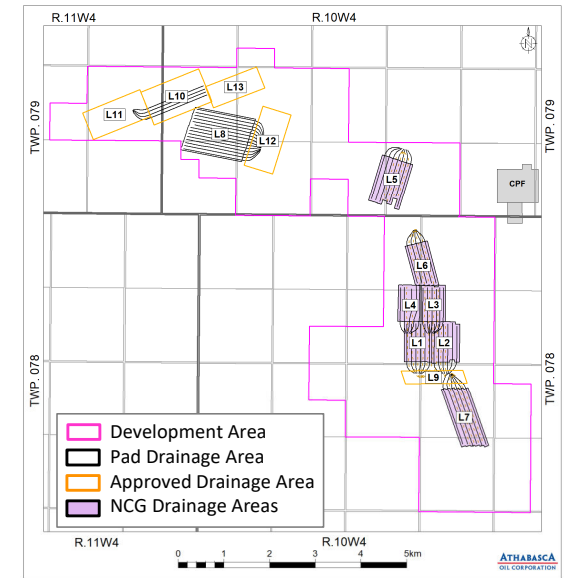
- Initial Reservoir Pressure: 2,300 to 2,600 kPa
- Initial Reservoir Temperature: 14°C
- Depth: 390 to 487 m TVD (-253 to -194 m subsea)

Drainage Area	Well Pairs	Infills	Redrills	Lateral Length	Area	Oil Saturation	Porosity	Perm Kh	Perm Kv	Net Pay	GBIP Net	Cumulative Production	Recovery Factor	EUR = Producible Bitumen in place	EUR RF
				(m)	(10 ³ m ²)	(frac)	(frac)	(D)	(D)	(m)	(10 ⁶ m ³)	(10 ⁶ m ³)	(%)	(10 ⁶ m ³)	(%)
L1	6	6	6	775	527	0.83	0.34	5.4	3.7	26.8	4.1	2.6	64%	2.7 - 3.1	65–75%
L2	5	3		745	398	0.81	0.33	4.7	3.4	21.4	3.2	2.1	65%	2.1 - 2.4	65–75%
L3	6	0		690	421	0.81	0.34	5.9	4.5	28.9	3.5	2.0	58%	1.9 - 2.3	55-65%
L4	5	0	3	695	393	0.81	0.34	5.2	3.7	24.2	2.7	1.4	50%	1.5 - 1.8	55-65%
L5	7	4		900	694	0.82	0.34	5.5	4.1	23.6	4.6	2.0	43%	3.0 - 3.5	65-75%
L6	5	4		860	468	0.80	0.35	5.6	4.4	35.3	4.7	2.0	42%	3.1 - 3.5	65-75%
L7	6	4		1,250	752	0.80	0.34	4.8	4.0	18.6	3.9	1.5	40%	2.5 - 2.9	65-75%
L8	14	0		1,250	1,312	0.81	0.34	5.6	4.3	26.2	9.8	1.5	16%	5.4 - 6.4	55-65%
L10 South	4	0		1,250	383	0.84	0.35	6.6	5.2	28.5	3.2	0.0	0%	1.8 - 2.1	55-65%
Total	58	21	9		5,348						39.7	15.1	38%		

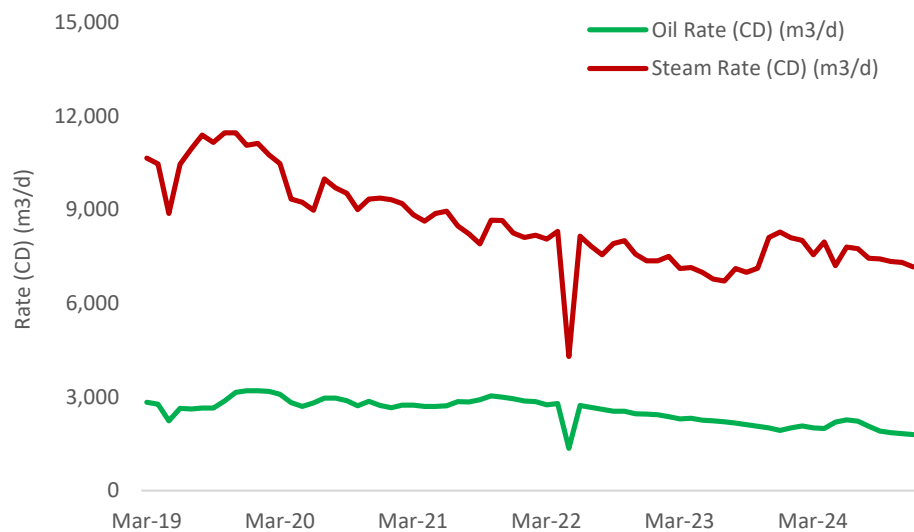
- Cumulative production as of December 31, 2024
- Well pair count includes historical producing, suspended, etc; L1 redrills expand over L1 to L4 drainage boxes
- GBIP= Gross bitumen in place (PHIT >= 27% and SwT <= 50%); EUR = Estimated Ultimate Recovery of Producible Bitumen within GBIP
- RF = The ratio of recoverable bitumen reserves to GBIP; Oil Saturation and porosity averages based on net SoT and PHIT
- Volumes include 50 m at heel and toe; Project Area GBIP Net-hydrocarbon pore volume* ~ 340 10⁶m³, Full Project Area=262 10⁶ m²
- Development Area GBIP Net-hydrocarbon pore volume* ~ 140 10⁶m³, Development Area=38 10⁶ m²
- *Project and development area volumes constrained to >10m GBIP Net

SUMMARY

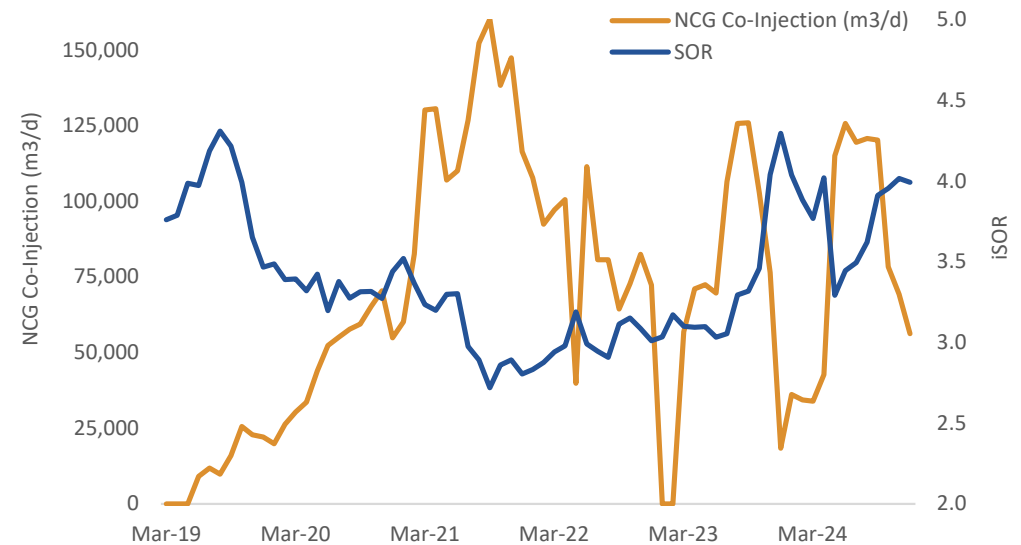
- NCG co-injection is applied in mature areas for pressure support when additional heat is not required
- Thermal efficiency is improved leading to lower SOR and reduced emissions
- Without NCG co-injection, SOR would be considerably higher
- L1-L4 have been on production for ~15 years
 - L1-L4 began NCG co-injection in 2019
 - L5-L6 began NCG co-injection in 2021
 - L7 began NCG co-injection in 2024
- No observed impact to recovery factor outlook and no wellbore integrity issues
- Constrained NCG co-injection rates in winter months due to surface limitations
- Observing increased gas production at the plant



L1 - L7 OIL AND STEAM RATES



L1 - L7 NCG CO-INJECTION RATES AND SOR



DISPOSAL WATER NETWORK

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CLASS 1B DISPOSAL APPROVAL 11479D

- Basal McMurray injection wells
 - 00/12-33-078-10W4/0
 - 00/13-33-078-10W4/0
- Clearwater B injection wells
 - F2/01-10-078-10W4/0
 - F2/04-28-078-10W4/0
 - 00/16-10-078-10W4/0
- Extensive monitoring network
 - Basal McMurray
 - Clearwater B
 - Lower Grand Rapids

BASAL MCMURRAY MONITORING

- Pressure consistent with reservoir operating strategy

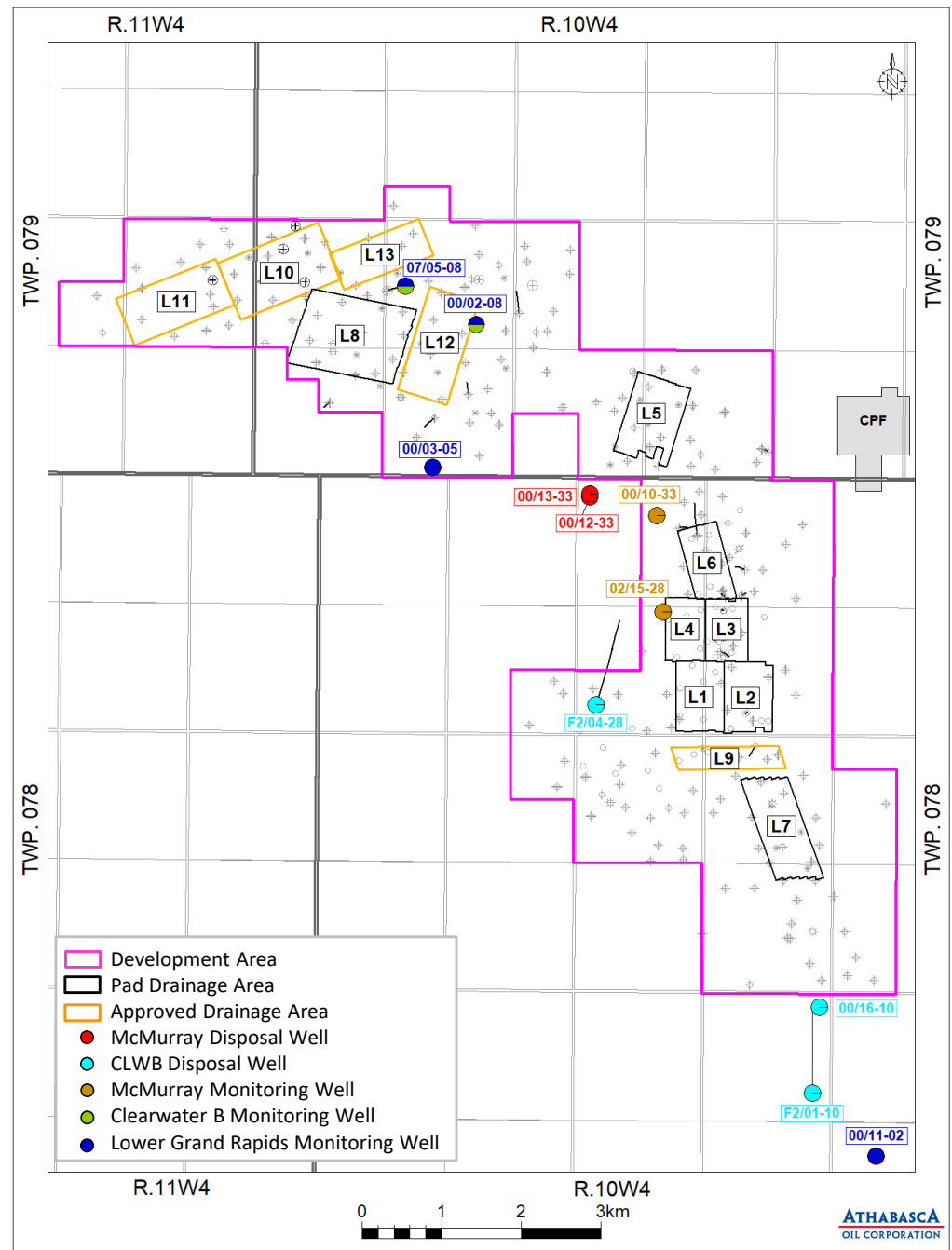
CLEARWATER B MONITORING

- No unexpected pressure response at Clearwater B monitoring wells

LOWER GRAND RAPIDS MONITORING

- Pressure response in Lower Grand Rapids monitoring wells remains consistent with pumping rates of the Lower Grand Rapids source water wells

No unexpected responses observed at any of the monitoring wells during the reporting year



INNOVATION AND LEARNINGS

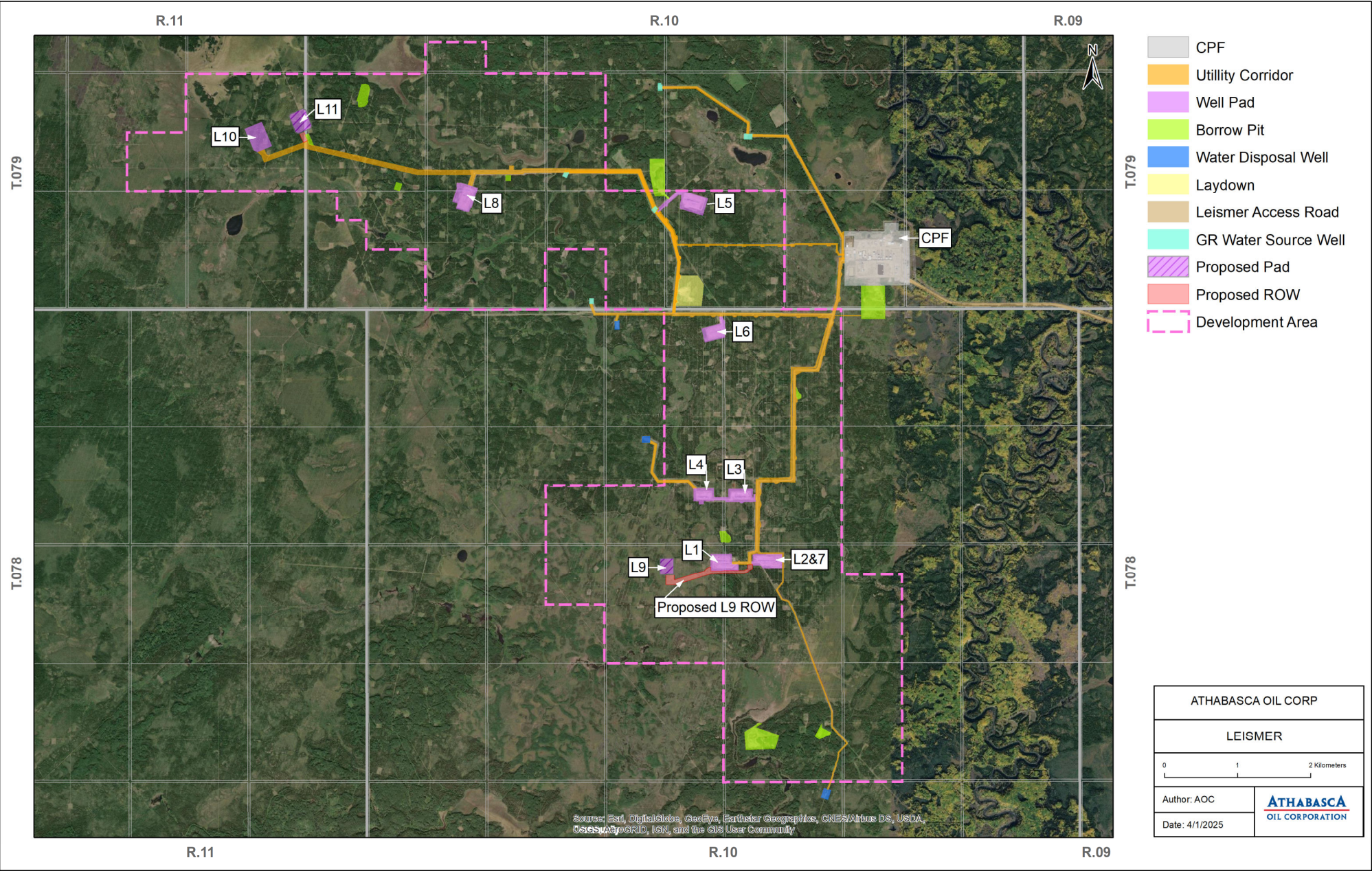
- Continuing to expand NCG co-injection for pressure support, SOR management and emissions reduction
- Successfully drilled and completed up to ~1,600 m long redrills to target bypassed pay
- Continuing implementation of steam splitters and FCDs on new well pairs moving forward
- No immediate plans for future pilots



SURFACE OPERATIONS

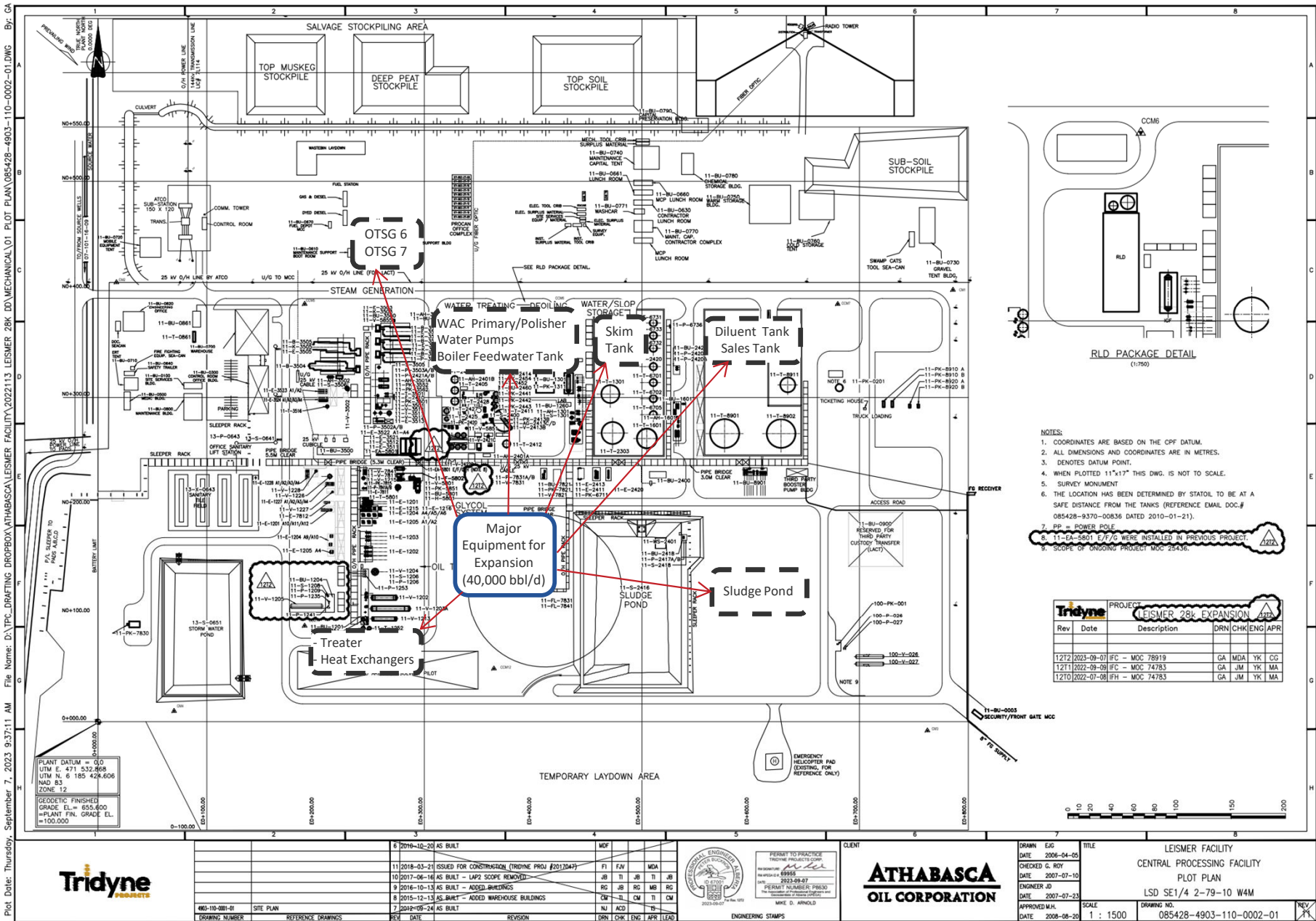
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SURFACE DEVELOPMENT OVERVIEW



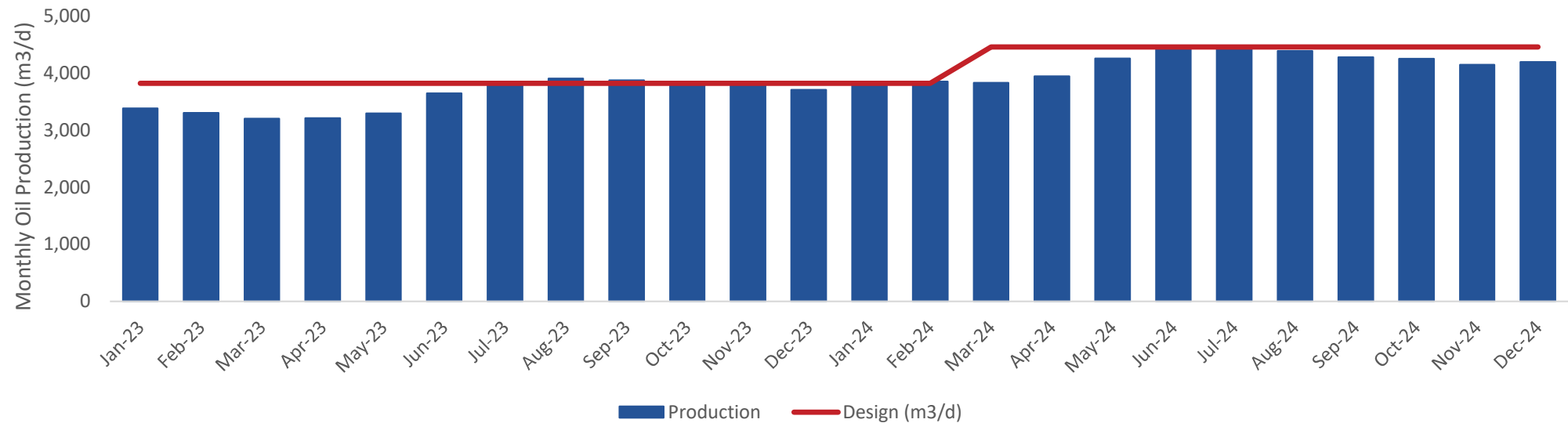
CENTRAL PROCESSING FACILITY

2024 – NO CHANGES REQUIRING AER APPROVAL

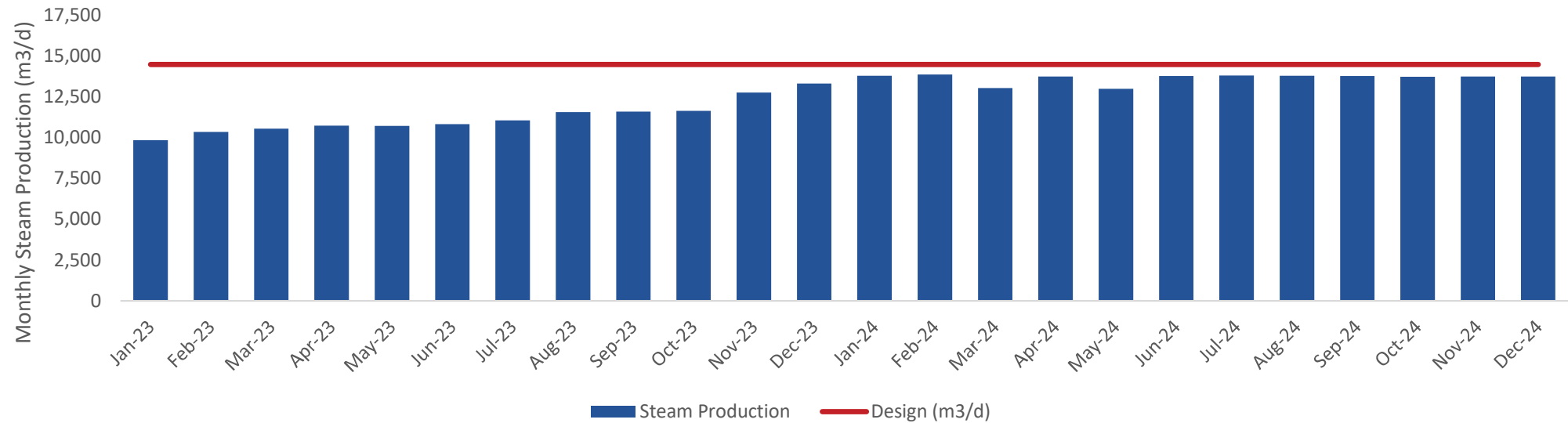


LEISMER OIL AND STEAM RATES

OIL

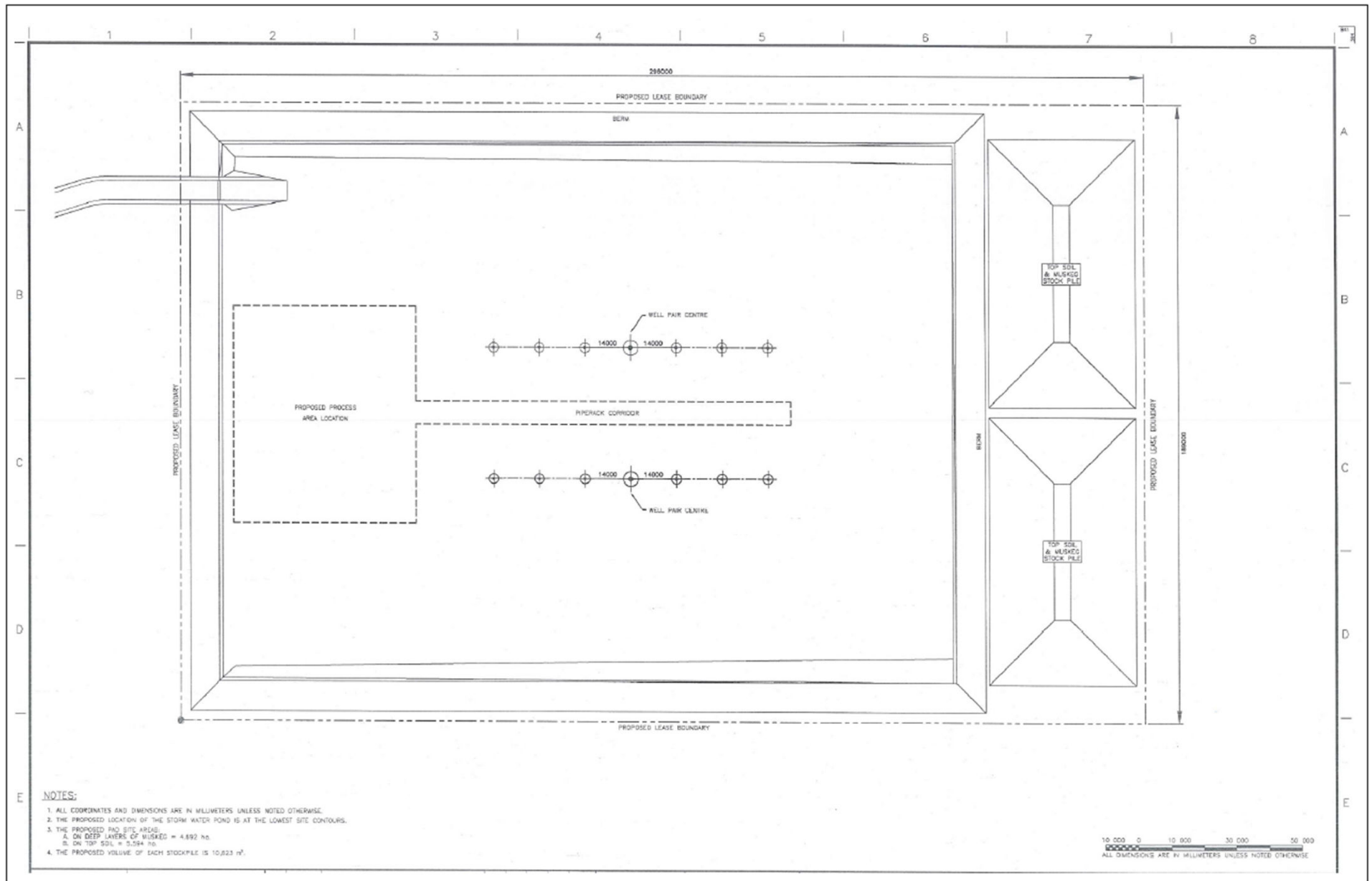


STEAM



TYPICAL WELL PAD SCHEMATIC (L6)

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REGULATORY & COMPLIANCE

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APPROVALS, AMENDMENTS, AND RENEWALS

Application No. or Approval No.	Approval Date	Description
OSCA Application No. 1948687	February 15, 2024	Increase Development Area, add L13 drainage, lifecycle approval
Directive 065 Application No. 1950201	April 12, 2024	Increase Maximum Wellhead Injection Pressure for Clearwater disposal wells
EPEA Approval No. 241311	April 22, 2024	Modify capacity and emissions for two OTSGs
OSCA Application No. 1952130 EPEA Approval No. 241311	October 1, 2024	Sulphur Removal Unit design approval and SO ₂ emissions rate increase during Sulphur Recovery Installation Period
Water Act License No. 00364442	November 18, 2024	Renewal for use of CPF storm run-off pond water

EPEA – Environmental Protection and Enhancement Act

OSCA – Oil Sands Conservation Act

NON-COMPLIANCE SUMMARY

Non-Compliance and Voluntary Self Disclosures (VSD)		
Reference	Event	Corrective Actions
EDGE 423875	NO _x 1-hour emissions rate exceeded on steam generator 4	Load reduced to immediately lower emissions and the burner flame adjusted. Follow-up maintenance completed on the CEMS NO _x analyzer
DDS notification	Surface casing cement separated on L315 injector well	Repair plan developed, approved by the AER and completed within 90 days in accordance with Directive 087
EDGE 500143	Water diversion license, daily limit exceeded	Withdrawals to be recorded in a tracking software for daily monitoring in the field and at corporate office
EDGE 0425938	Well control event	Polish rod and well head valve replaced. Well intervention procedures updated.

SPILLS

- No reportable spills

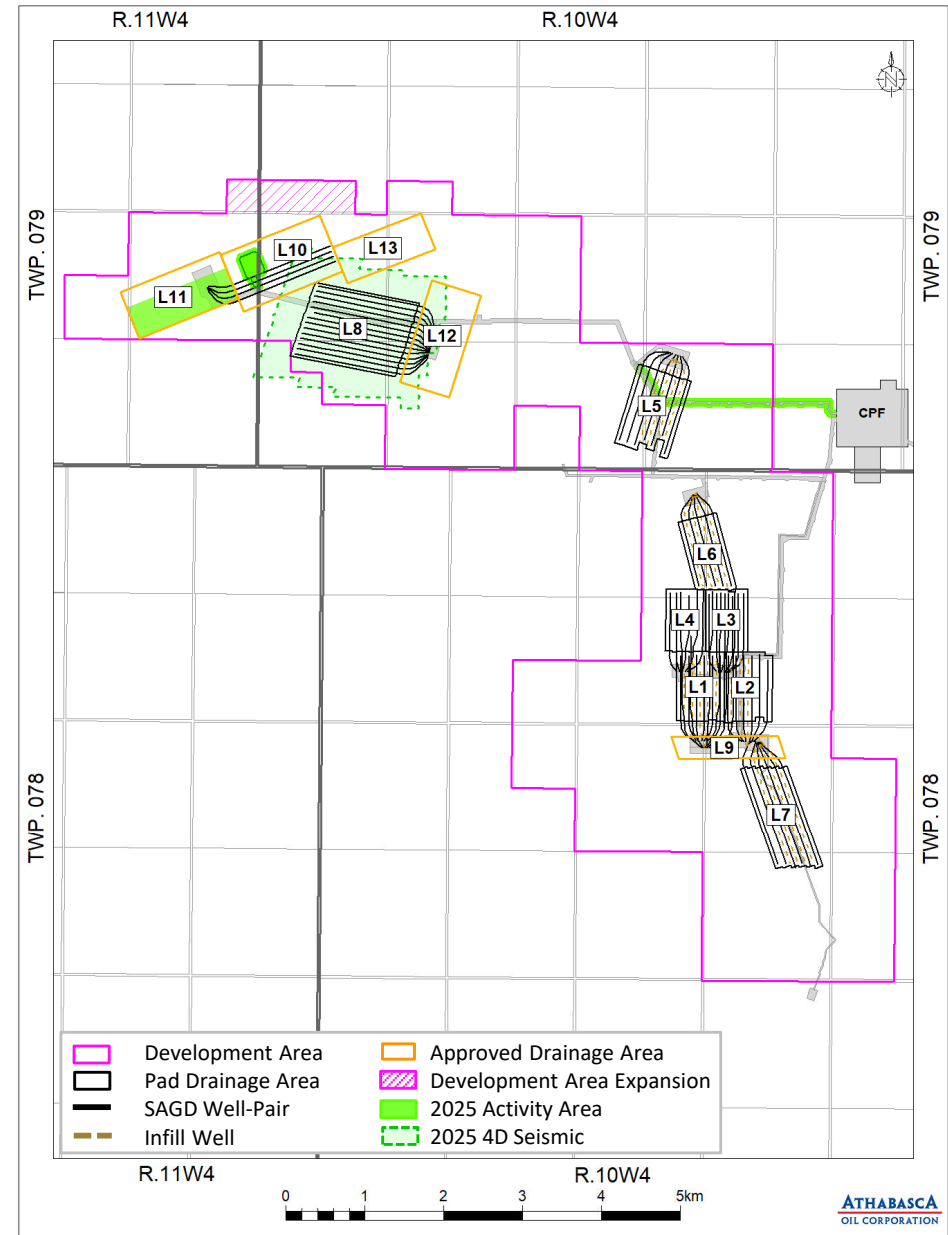
INSPECTIONS

- AER completed 8 inspections, 1 low risk finding

SUMMARY

- Increasing oil capacity to 40,000 bbl/d through CPF modifications and new drainage areas (2024-2027)
- Complete L10 looping pipeline
- L11 – Complete utility corridor and pad construction
- L11 – Drill 5 observation wells and 6 well pairs
- L8 - Acquire 4D seismic
- L2P7, L6P3, L6P5 well suspensions
- Continue to progress sulphur recovery unit installation
- Continue expanding NCG co-injection for pressure support, SOR management and emissions reduction
- Development Area Expansion application to accommodate longer wells at L10
- Evaluating well patterns to the west of Pads L1 and L7 for future development after Pads L10 and L11

2025 ACTIVITY



ATHABASCA

OIL CORPORATION

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