Rubellite Energy Corp.

Corporate Overview

September 8, 2026

Corporate History

Incorporated in July 2021 as pure play Clearwater multi-lat focused junior E&P

- **In September 2021, Rubellite acquired Perpetual's Clearwater Assets for $65.5 MM**
  - 350 bbl/d of heavy oil production and 100 net sections of land
- **Executing growth focused business plan on expanding heavy oil asset base**
  - Organic and M&A driven heavy oil production growth from initial 350 bbl/d in Sept 2021 to 8,534 bbl/d in Q2/26
  - 656 net sections of prospective heavy oil lands with over 905 drilling locations[2]

RBY incorporated with spin-out of Perpetual Clearwater assets, public listing & equity financings

Growing asset base and exploration prospect inventory through crown land purchases, farm-ins, freehold mineral leasing and third-party swaps & purchases

Development drilling driving robust organic growth and delivering strong operating netbacks and free funds flow

Optimizing development plans, de-risking exploration prospects, enhancing financial flexibility and managing risk

Exploration success & step-out delineation drilling providing confidence in extensive drilling inventory

Tuck-in acquisitions provide additional inventory to enhance core asset profitability

Buffalo Mission Acquisition[1] establishes strategic position in Mannville Stack Play Fairway

Perpetual Recombination[1] to drive scale, commodity diversification and optionality

- **Recombination with Perpetual in Q4 2024 to capture synergies and enhance financial flexibility**
  - Added ~4,000 boe/d liquids-rich deep basin natural gas; East Edson asset disposition[1] subsequently closed Sept 8, 2026
- **$179.6 MM in equity raised to-date at average price of $2.35/share[1]**
  - Insiders have participated for $90.8 MM (~51%)

1. See Appendix for details of Historical Financings and 2024 Strategic Transactions; See Slide 6 for details of Edson Disposition
2. See "Drilling Locations" in Advisories

Corporate Profile

*Fully funded growth-focused heavy oil multi-lat E&P Company **TSX:RBY***

Investment Highlights

Large scale, focused asset base in the South Clearwater and Mannville Stack fairways
- Rank as amongst the top conventional plays in the WCSB on half-cycle returns

Fully funded, double-digit growth supported by strong netbacks and quick payouts
- Q2/26 heavy oil business unit sales production of 8,534 bbl/d (9,521 boe/d ~90% oil & liquids)
- Q2/26 sales production of 13,406 boe/d (9,521 boe/d pro forma the Edson Disposition on Sept 8, 2026)

Significant captured and derisked heavy oil drilling inventory to support growth plans
- >475 net booked and unbooked heavy oil development drilling locations[7] in core properties
- Inventory to organically grow heavy oil production by 10% to 15% per year through 2030

Extensive exploration prospect pipeline to de-risk & grow NAV
- > 300 'new play exploration' locations and >130 'new zone appraisal' drilling locations captured
- Heavy oil exploration and appraisal locations are contingent on evaluation success

Enhanced Oil Recovery ("EOR") potential on multiple base assets with large OOIP

Track record of acquisitions to expand growth opportunities and scale

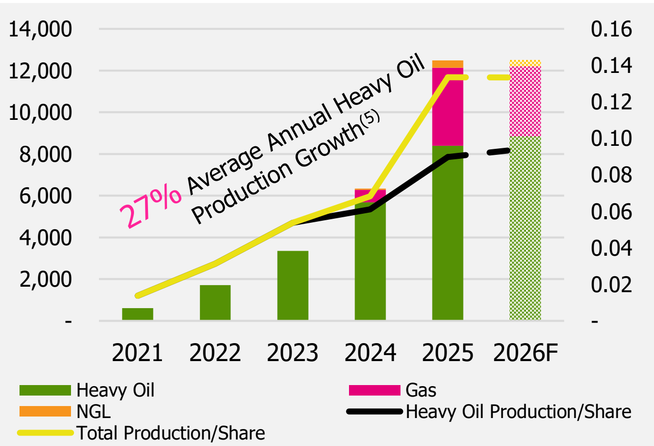
Strong management alignment to drive returns with significant insider ownership

Capitalization

TSX	RBY
Shares Outstanding[1]	93.9 MM
Market Capitalization[2][8]	$395.5 MM
Bank Debt[1]	$95.7 MM
Term Loan[3]	$20.0 MM
Adjusted Working Capital Deficit[1][8]	$42.4 MM
Net Debt[1][8]	$158.1 MM
Pro Forma Net Debt[4][8]	$90.3 MM
Enterprise Value[2][4][8]	$485.8 MM
Insider Ownership	~45.3%

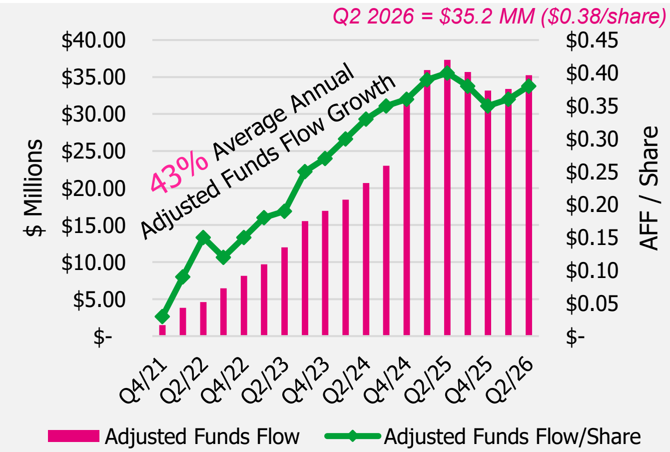
1. At June 30, 2026
2. Based on $4.21 share price as at September 4, 2026
3. Principal amount; Third lien security; 11.5% coupon, matures Aug 2029

Production Growth[8] (boe/d)



Heavy Oil CGU Operating Netback[8] ($/boe)

Adjusted Funds Flow[8]

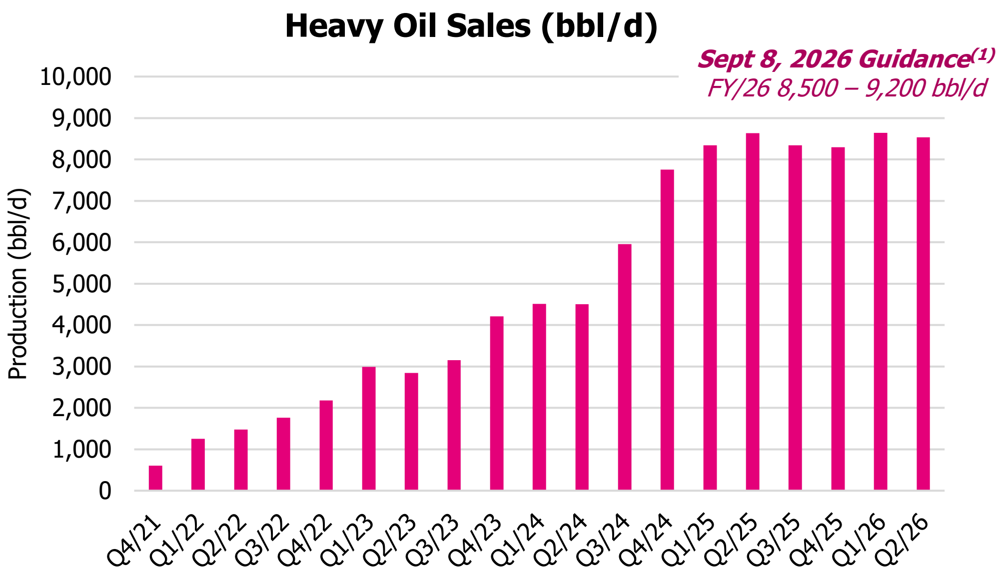


4. Pro forma net debt reflects the East Edson disposition deducting $67.0 million in TPZ shares and $0.7 million of TPZ Sept 15, 2026 dividends; Q2 2026 annualized net debt to AFF decreases from 1.1x to 0.7x on a pro forma basis
5. Average Annual Growth is calculated as the average growth rate of the prior four quarters over the four quarters preceding it
6. Forecast based on Sept 8, 2026 guidance, pro forma the East Edson Disposition and forward strip prices as at September 1, 2026; Includes conserved natural gas sales volumes for heavy oil assets
7. Of the 475 net heavy oil development drilling locations, 155.2 net locations (101.6 net proved and 53.6 net probable locations) are booked in the McDaniel Reserve Report at Year End 2025
8. See Non-GAAP measures in Advisories

Refer to Advisories section for further information regarding forward-looking statements, oil and gas information and non-GAAP and other financial measures

Heavy Oil Asset Performance

Strong operational momentum in Clearwater and Mannville Stack heavy oil asset base



Key Operational Metrics

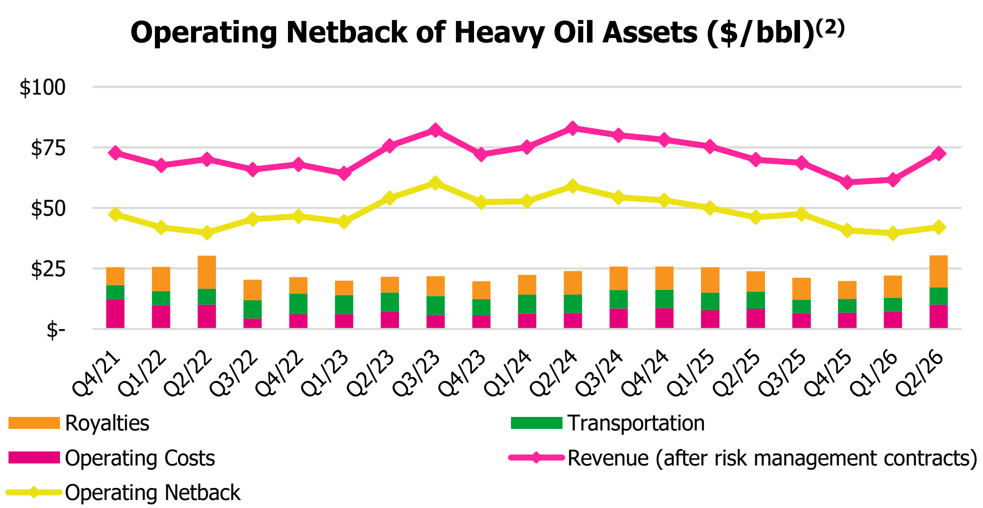
>2,013
Lateral legs drilled

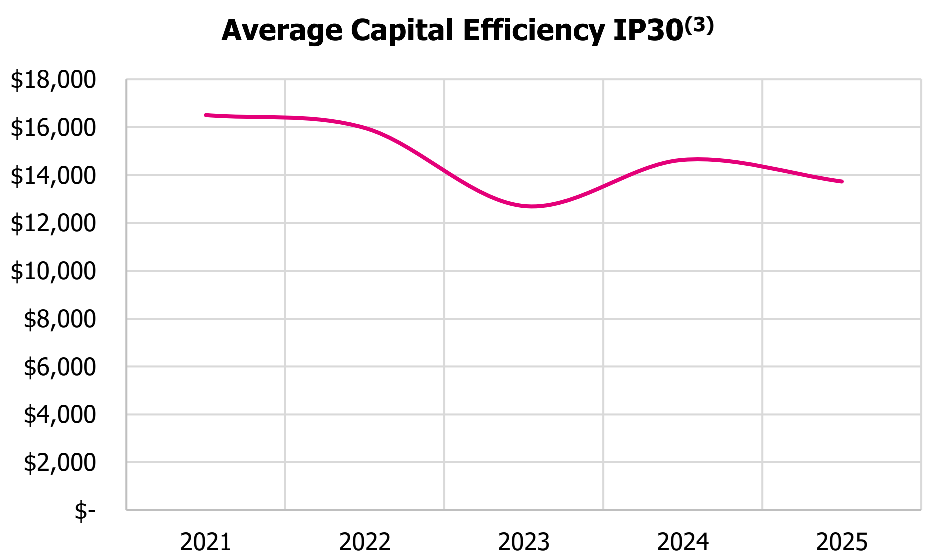
15,000m
Average open hole per well

>205
Gross Multi-lats drilled to date

20,142m
Highest open hole meters in single well drilled to date

>2,349,500m
Total horizontal open hole length drilled to date



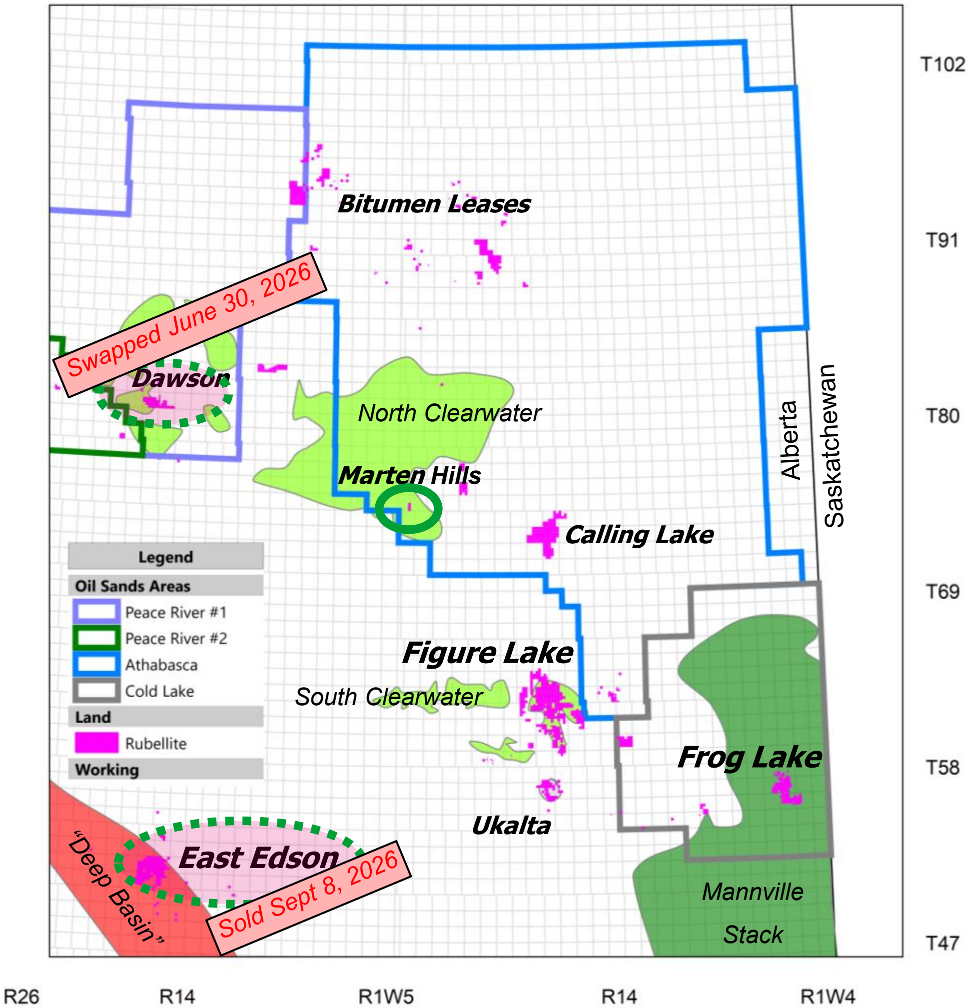


1. *Forecast sales production as per September 8, 2026 guidance*
2. *See Non-GAAP measures in Advisories*
3. *Average capital efficiency is calculated as total D,C,E&T capital for a well divided by IP30 in $/flowing bbl/d*

Rubellite Asset Profile – Focused Heavy Oil Portfolio

Heavy oil production of 8,534 bbl/d and 5,800 Mcf/d of associated natural gas pro forma Edson Disposition

Asset Map



1. *Includes farm-in exploratory lands at after payout working interest; Frog Lake JED Agreement lands at 50% working interest*
2. *Q2 2026 sales at Figure Lake comprised of 5,174 bbl/d heavy oil, 5.8 MMcf/d natural gas & 17 bbl/d NGL*
3. *Q2 2026 sales at East Edson production comprised of 20.8 MMcf/d natural gas & 426 bbl/d NGL*

2Q/26 Asset Summary

Area	Land (net acres)[1]	Well Count (net producing)	Production Q2 2026 (boe/d)
Figure Lake	155,412	123.0	6,160[2]
Frog Lake	21,495	57.5	2,889
Ukalta	22,855	24.0	281
Marten Hills	1,152	3.3	191
Multi-Lat Exploration	219,041	1.5	0
Heavy Oil CGU Total	**419,955**	**209.3**	**9,521**
East Edson	28,951	47.8	3,885[3]
Other Exploration	78,265	-	-
Bitumen	72,960	-	-
Total	**600,131**	**257.1**	**13,406**

Heavy Oil CGU: Q2 2026 Production 9,521 boe/d

- ***Figure Lake*** – Development and Step-out delineation; Piloting enhanced recovery waterfloods, polymer flood, and gas injection schemes; Following-up Sparky exploration success
- ***Frog Lake*** – Continuous Development in Waseca Sand and GP zones
- ***Ukalta -*** Advancing waterflood pilot
- ***Marten Hills*** – Developed on primary; Advancing "bottoms up" waterflood. Increased Working Interest from 30% to 60% with Dawson asset swap June 30, 2026
- ***Heavy Oil Exploration*** – Other prospects in various stages of land capture & assessment

Recent Dispositions:

- ***Dawson*** – Swapped for 30% working interest at Marten Hills June 30, 2026
- ***East Edson*** – Sold September 8, 2026 in exchange for 2.08 MM Topaz shares

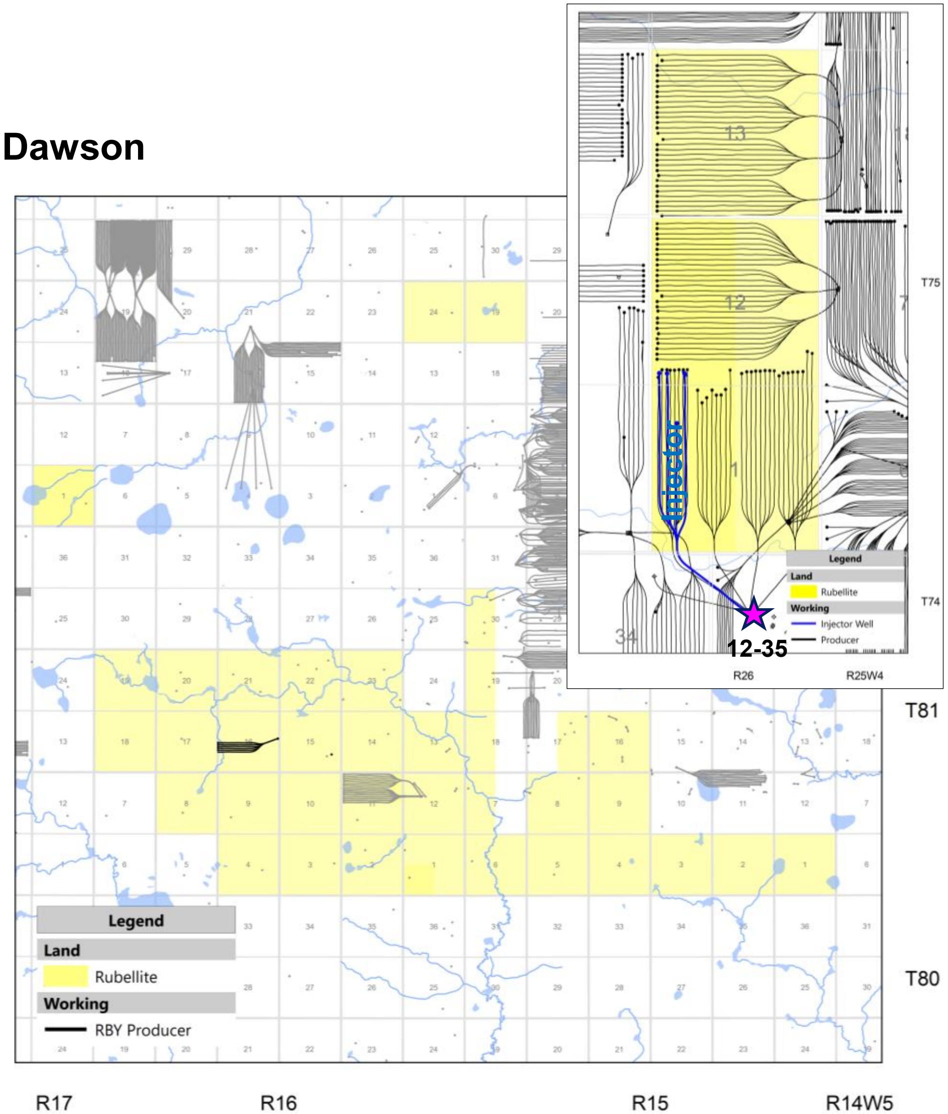
Marten Hills and Dawson Swap – Closed June 30, 2026

Added proved producing reserves with waterflood upside

Asset Maps

Marten Hills

Dawson



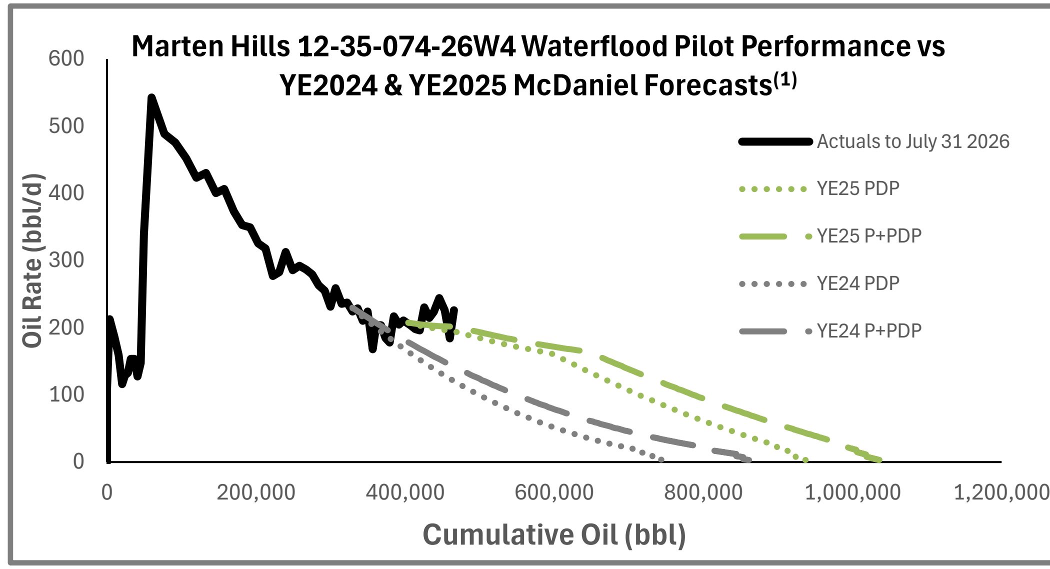
1. *PDP and P+PDP and waterflood reserves as per Year End 2024 and 2025 McDaniel Reserve Reports*

Transaction Summary

Asset Exchange Agreement: Effective and Closing Date - June 30, 2026

- Rubellite acquired a project partner's 30% Working Interest at Marten Hills, bringing ownership to 60% WI, in exchange for Rubellite's working interest in the Dawson Project area and $800,000
- Net production in Marten Hills doubles, from 191 bbl/d from 382 bbl/d

Marten Hills Waterflood Pilot Performance to Date



Marten Hill Future Activity

Original Oil in Place: 70 MMbbls (42.0 MMbbl net at 60% WI)

- 1.3 MMbbls (gross) recovered to date (1.9%)

Waterflood Pilot (2025/2026)

- All produced water from 3 Rubellite-operated pads injected into 4-12 waterflood injector well
- Volumetric Voidage Replacement (VVR) just 5% for the pad (20% for the 4-12 well)
- ***Observations:*** Waterflood response interpreted; Higher water injection rates needed to gain ground on voidage replacement to increase production

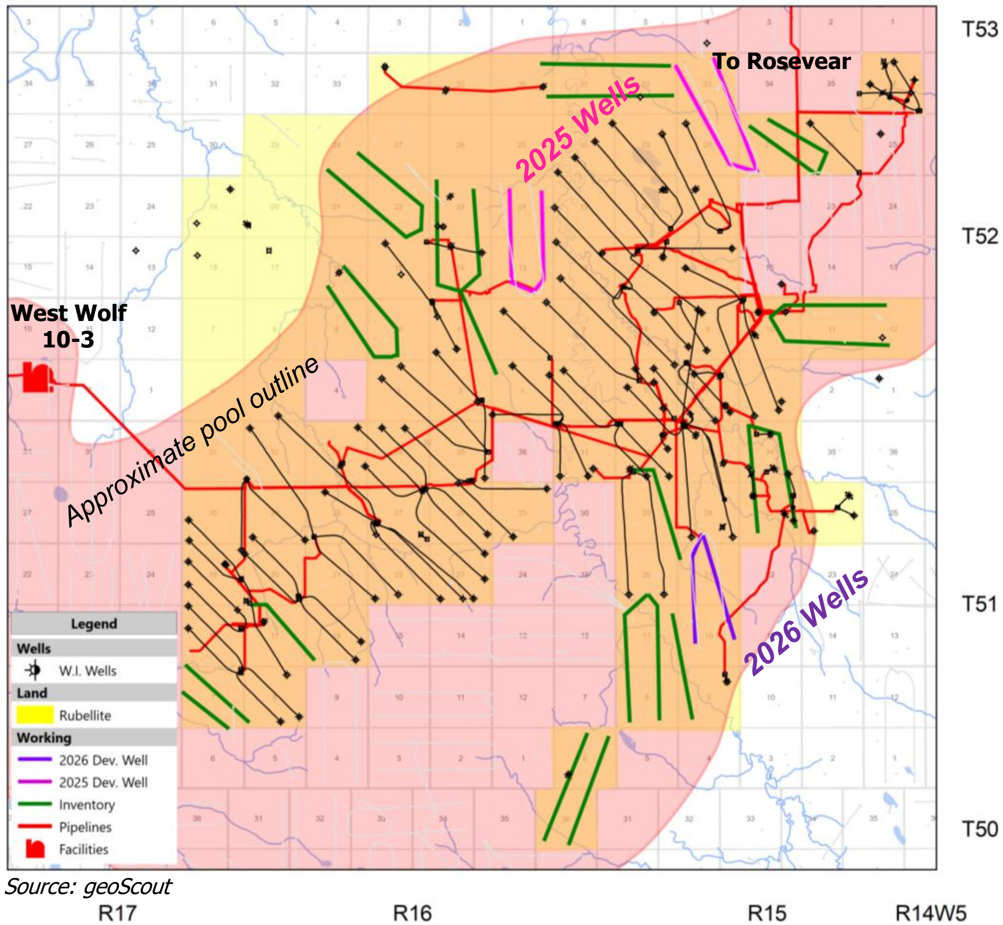
Waterflood Scale Up (Q4 2026/2027)

- 12-35 Pad: Source water well & one additional bottom-up injector
- 5-18 & 12-7 Pads: Planning 2 source water wells and 2 – 4 additional bottom-up injectors

East Edson Disposition – Closed Sept 8, 2026

Swapped non-operated, single asset deep basin gas property into a highly liquid equity position in going concern business

Asset Map



Source: geoScout

Transaction Summary

Working Interest: 50% Non-operated interest with Tourmaline – TSX:TOU

Net Production:

- Q2 2026 sales: 3,885 boe/d (20.8 MMcf/d; 426 bbl/d NGL)
- 18.8 bbl/MMcf NGL yield
- Processing Capacity: 78 MMcf/d gross (39.0 MMcf/d net)

Transaction Highlights:

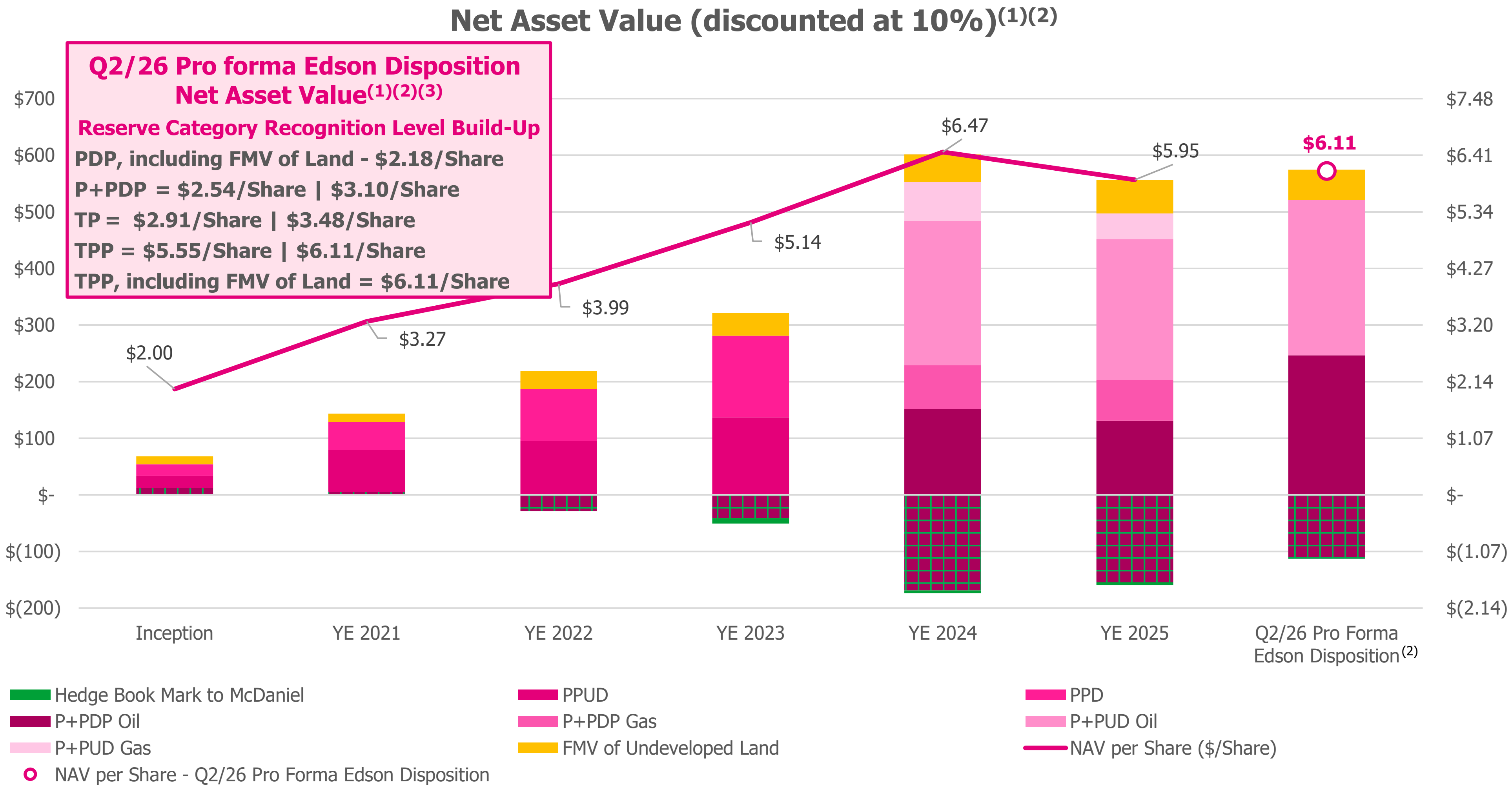
- Gross proceeds of 2.0834 MM Topaz shares (TSX:TPZ) at $32.1588 per share (10-day VWAP 3-days prior to closing)
- RBY to receive Sept 15th TPZ quarterly dividend of $0.35/share ($729K)
- TPZ shares expected to generate ~$2.9 MM/year of dividend income while held
- Increases RBY's oil weighting to over 90% of production (from ~70%)
- Improves RBY's forecast 2027 operating netback by ~27%
- Eliminates ~ $12 - $15 MM/year of forecast sustaining capital expenditures, increasing forecast free funds flow over RBY's five-year plan at current strip prices
- Reduces leverage ratio to 0.7x net debt to annualized adjusted funds flow, net of market value of TPZ Shares, from 1.1x at Q2/26

Strategic Rationale:

- Re-establishes and clarifies RBY's pure play heavy oil, multi-lateral horizontal development business plan in the Clearwater and Mannville stack plays, with strong top tier operating netback metrics
- Shifts RBY's natural gas price exposure from a single, non-operated deep basin asset requiring ongoing capital investment, to an equity investment in a going concern business with a broad portfolio of assets, preserving the potential for additional value recovery from the Disposition
- Improves RBY's forecast operating netback, free funds flow and corporate production growth rate
- Increases financial flexibility and liquidity, with RBY's credit facility maintained at $160 million, and the highly liquid shares readily available to fund RBY's organic growth plans, waterflood advancement and future acquisition opportunities

Net Asset Value ("NAV")

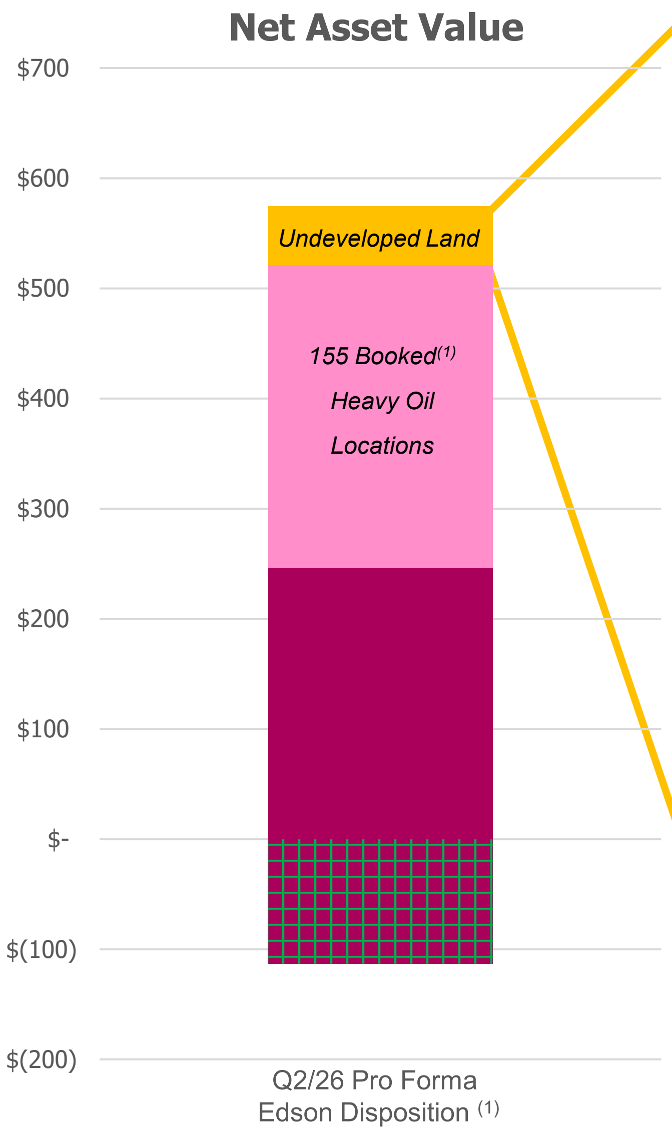
Q2/26 NAV Pro Forma Edson Disposition and Marten Hills/Dawson Swap Transactions



1. *Based on Proved Developed Producing (PDP), Proved Undeveloped (PUD) and Proved Plus Probable (TPP) reserves BTAX values as per Year End McDaniel Reserve Report based on 3 Consultant Average Price Forecast ("3CA") for respective years; Year end total liabilities; Fair market value ("FMV") of acreage not assigned reserves as per respective year end Seaton-Jordan undeveloped land reports*
2. *Q2/26 – TPP NAV Pro Forma Edson Disposition and Marten Hills/Dawson Swap are reserve values are based on Year End 2025 McDaniel Report, mechanically updated to July 1, 2026 based on the July 1, 2026 3CA; FMV of acreage not assigned reserves at YE 2025 of $59.6 MM ($0.64/Share), reduced for Edson disposition and Dawson swap and adjusted for land purchases in H1/26 of $3.054 Million; Net Debt as at June 30, 2026 of $158.1 Million, plus outstanding undiscounted Sequoia Litigation Settlement Amount of $12.4 Million for a total of $170.5 Million. Net Debt reduced by $67.0 Million in TPZ shares and $0.7 Million TPZ Sept 15, 2026 dividend. Hedge value is as of July 1, 2026 on 3CA (negative $10.48 Million expressed as a debt at Q2/26); Share count updated for June 30, 2026 of 93.94 Million; ARO liabilities of negative 0.47 Million from West Central AB property in P+PDP Gas included in P+PDP Oil value (the "Mechanical Update"); See "Reserves Disclosures - Mid-Year 2026 Mechanical Update" in Advisories*
3. *NAV/Share presented as Excluding | Including the FMV of acreage not assigned reserves at Q2/26 of $53.27 MM ($0.57/Share)*

Converting FMV of Undeveloped Land to Reserve-based NAV

Investing to Convert >750 Unbooked Locations & EOR Potential to Production & Reserves to Grow NAV



>320 net **'Low Risk' Unbooked[(2)(3)] Development Locations** at Figure Lake (Clearwater and Sparky) and Frog Lake (Waseca and GP)

>130 net **'New Zone' Appraisal Inventory Locations[(2)(3)(4)]** identified at Figure Lake (Upper Clearwater) and Frog Lake (Sparky, McLaren) and Calling Lake (McMurray)

>300 net **'New Play Exploration' Locations[(2)]** in success scenario captured to be technically de-risked

Enhanced Oil Recovery – Waterflood, polymer flood & novel cyclic solvent/heat technologies to materially increase recoverable reserves

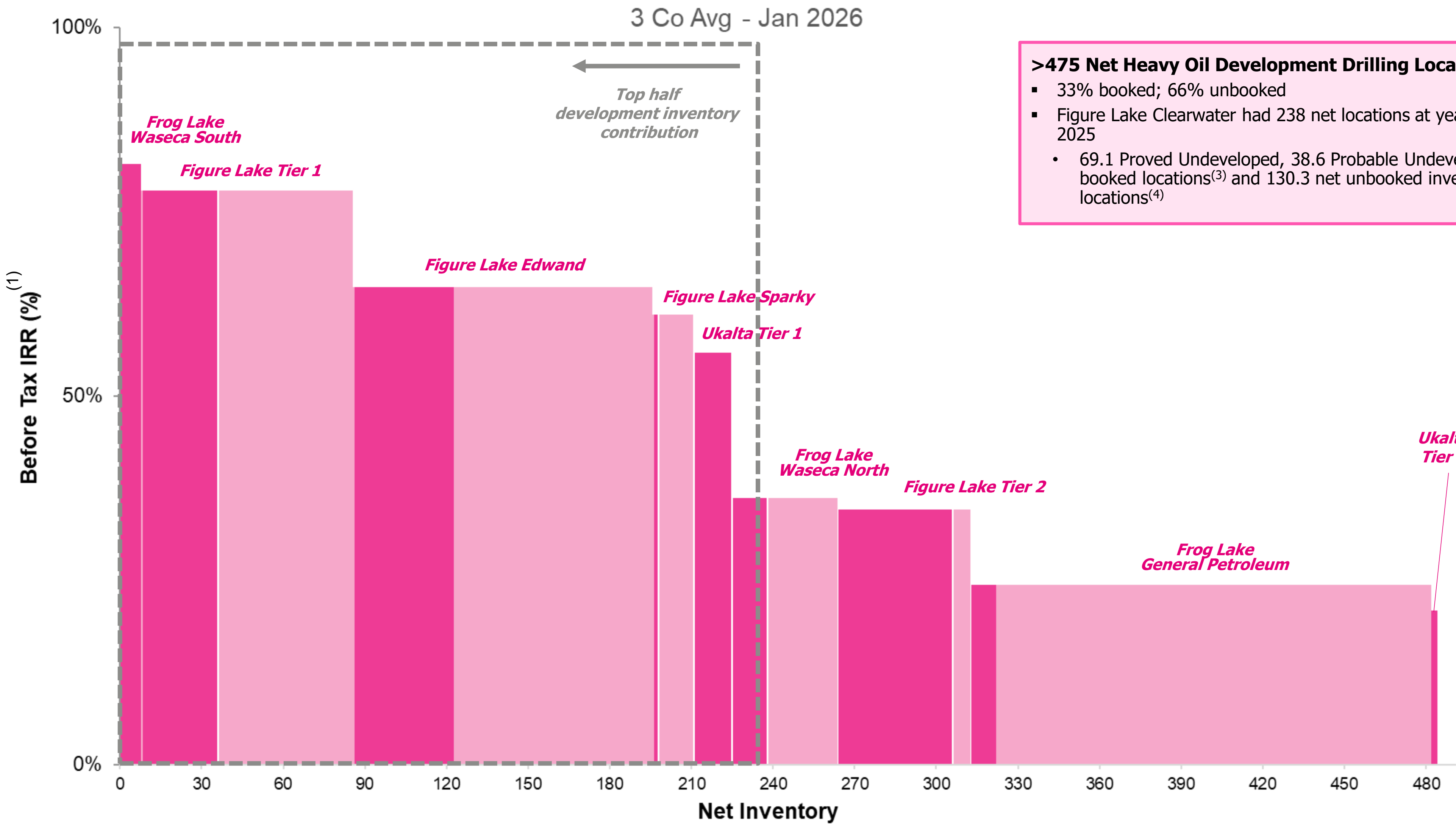
Other Bitumen/Heavy Oil Resource captured to unlock with emerging low-grade heat/solvent technologies

Future Resource Potential on captured and held land

1. *See Footnote 2 on Slide 7 and "Reserves Disclosures - Mid-Year 2026 Mechanical Update" in Advisories*
2. *Locations estimated by Management at August 7, 2026 that are not included in Year End 2025 McDaniel Reserve Report*
3. *Location count subject to change with inter-well spacing and well design*
4. *Includes locations targeting secondary zones in core producing properties that are still exploratory in nature*

Heavy Oil Development Inventory YE 2025

>475 booked & unbooked heavy oil development drilling inventory[(2)(4)] in core properties



>475 Net Heavy Oil Development Drilling Locations[(2)(4)]

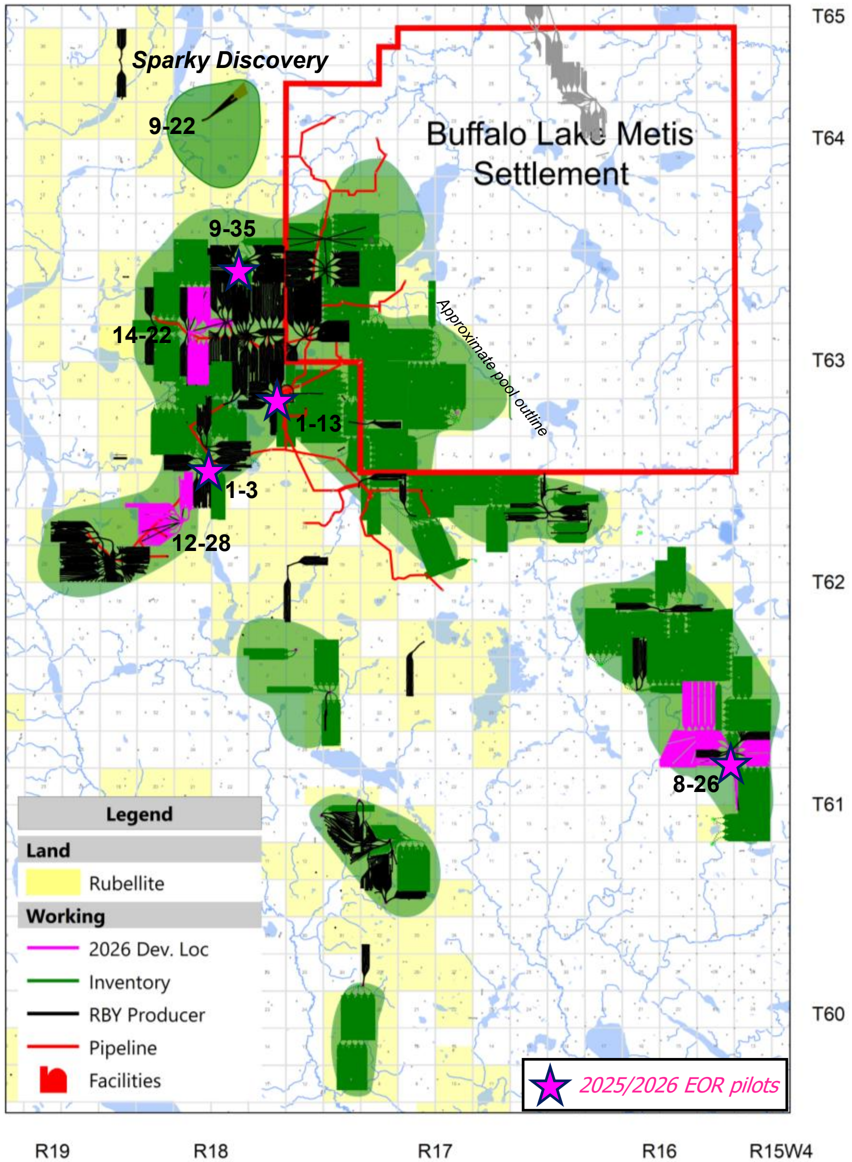
- 33% booked; 66% unbooked
- Figure Lake Clearwater had 238 net locations at year end 2025
  - 69.1 Proved Undeveloped, 38.6 Probable Undeveloped net booked locations[(3)] and 130.3 net unbooked inventory locations[(4)]

1. *Before Tax IRR as per Rubellite Year End 2025 McDaniel Reserve Report Type Wells and Economic Inputs, evaluated at YE 2025 3 Consultant Average (3 CA) price; See Advisories for "Commodity Price Assumptions"*
2. *YE 2025 Booked inventory for Rubellite in darker colour; Unbooked inventory in lighter colour; There are 101.6 net proved and 53.6 net probable locations in the McDaniel Reserve Report at year end 2025*
3. *Total Proved Plus Probable Undeveloped (P+PUD) location count, reserve and economic parameters as per Rubellite Year End 2025 McDaniel Reserve Report; Tier 1 and Tier 2 Figure Lake Type Curve Net Inventory includes both solution gas conservation and no gas conservation type curves, shown at the lower IRR (no gas conservation)*
4. *Net unbooked development inventory locations based on internal estimates and assume participation elections by FLERC at 50% working interest; See "Drilling Locations" in Advisories*

Rubellite Asset Profile | *Figure Lake*

Clearwater and Sparky Development

Asset Map



Source: geoScout

Asset Summary

Working Interest: 100%

Q2 2026 Production: 6,160 boe/d (84% oil and liquids)
- 5,174 bbl/d 100% heavy oil; 5.8 MMcf/d natural gas; 17 bbl/d NGL
- 115.0 net multi-laterals on sales production

Drilling Inventory:
- ***Clearwater Locations:*** 237.7 net inventory (as at Jan 1, 2026) (56% unbooked)
  - 44% booked in 2025 McDaniel Reserve Report (107.7 net locations)
    - 69.1 net proven undeveloped and 38.6 net probable undeveloped booked(2) Clearwater (Wabiskaw Member) Development locations
  - 130.0 net additional unbooked Clearwater drilling locations(3) on existing lands
  - >13 years of development for one-rig program at 18 wells/year
- ***Sparky Locations:*** 15.0 net inventory (as at Jan 1, 2026) (87% unbooked)
  - 2.0 net proved undeveloped locations booked(2)

2025 Activity

***Clearwater Development:* 20 (20.0 net) wells**
- 14.0 Development Wells - Actual IP30/60: 205/192 bbl/d (14 wells)(1)
- 3.0 net Step-Out / Delineation Wells – 50m inter-leg spacing well design
- 1.0 net 8 leg waterflood producing well and 1.0 net injection well
- 1.0 net Sparky exploration well – IP30 286 bbl/d

Gas Conservation Project:
- Constructed 4 MMcf/d gas plant & gathering system; On-stream Jan 23, 2025
- Expanded to 6.4 MMcf/d in H2 2025 to accommodate growth

2026 Activity

Clearwater Development: 26 (26.0) net wells
- Actual IP30/60: 195 bbl/d (8 wells)/224 bbl/d (5 wells)(1)

Enhanced Oil Recovery 2 injector/producer pairs : 4 (4.0 net) wells
- Primary Recovery ~5% of OOIP (estimated OOIP >1.1 Billion barrels(4) gross)
- Core, fluid compatibility analysis and competitor analog information informing pilots
- 4 Waterflood Pilots and 1 polymer flood pilot advancing in H1 2026
- Cyclic Gas Injection Pilot ongoing

1. *No wells excluded from calculation of average rates other than meeting minimum criteria of producing days*
2. *Total P+PUD location count as per Rubellite Year-End 2025 McDaniel Reserve Report*
3. *Figure Lake internally-recognized additional development location inventory not recognized in McDaniel Report; See "Drilling Locations" in Advisories*
4. *OOIP – Original Oil In Place based on internal estimates*

Figure Lake Primary Development Type Curves

33m down-space well design established as primary development design

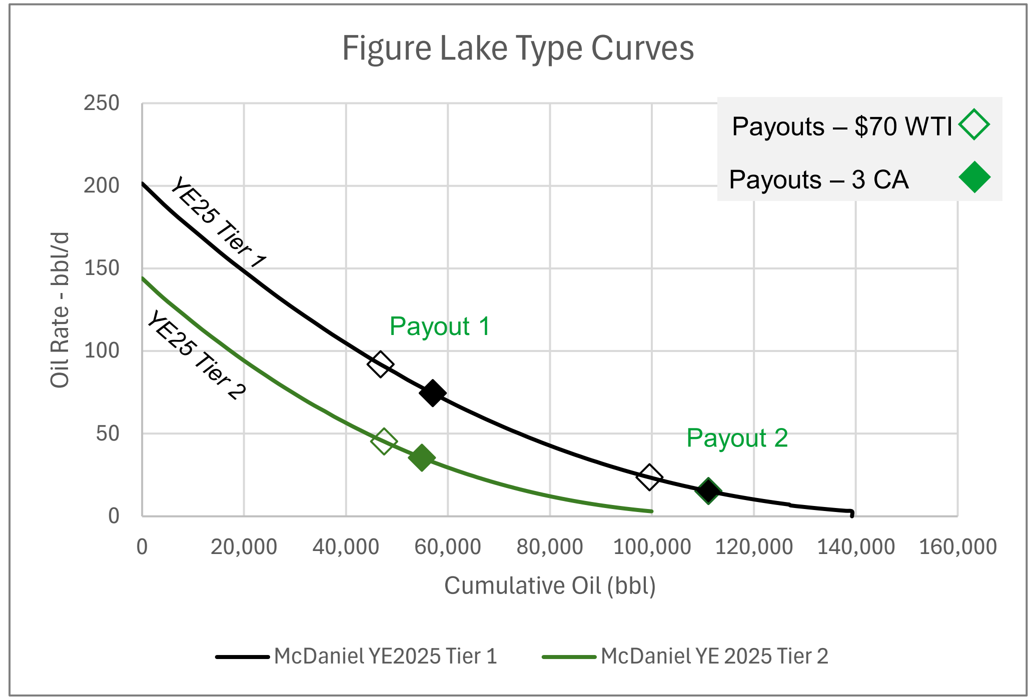
Clearwater Primary Development Design
- Historical well design: ~50m inter-leg spacing
  - 8 open hole lateral legs with oil-based mud
  - ~10,000m MD of open hole
- Down-space well design: ~33m inter-leg spacing
  - 12 open hole lateral legs
  - >15,000m MD of open hole

Improvements to 33m inter-leg Tier 1 type curve from YE 2024:
- Increased Type Curve IP30 by 14% to 201 bbl/d (YE 2025 vs YE 2024)[1]
- Increased NPV per Location by 16% to $2.2 MM (YE 2025 vs YE 2024)[1]
- Accelerates Payout by 21% from 1.6 to 1.3 years[1] on 3 Cons Avg pricing

Performance of 15,000m MD well design to date:
- Average IP30 192 bbl/d (25 wells) IP60 185 bbl/d (22 wells) to date[2]
- Blend of Tier 1 and Tier 2 reservoir targeted to optimize capital efficiency

Type Curve Sensitivities – Figure Lake[1]

Assumptions	33m Inter-leg Spacing Tier 1 McDaniel Type Curve (YE 2025)[1]	33m Inter-leg Spacing Tier 2 McDaniel Type Curve (YE 2025)[1]
Drainage Area (Ha)	50	50
Horizontal Length (m)	15,000	15,000
IP30/100m (bbl/d)	1.34	0.96
IP30 (bbl/d)	201	144
IP360 (bbl/d)	136	98
Estimated Ultimate Recovery TPP (Mbbl)	140	100
Economics[1] (gross per well)	**YE 2025 3 Cons Avg | $70 WTI**	
D,C,E&T Capex ($MM)	2.5 | 2.5	2.5 | 2.5
D,C,E&T Capex ($/m)	165 | 165	165 | 165
Scenario F+D ($/bbl)	17.74 | 17.74	24.85 | 24.70
NPV10 ($MM)	2.2 | 2.7	1 | 1.3
First Payout (months)	16 | 12	26 | 20
Second Payout (months)	69 | 49	-
# of Payouts	2.3 | 2.5	1.7 | 1.8
Rate of Return (%)	78 | 116	35 | 51



1. *Total Proved Plus Probable Undeveloped (P+PUD) reserve and economic parameters as per Year End 2025 McDaniel Reserve Report – Figure Lake Type Curve run on YE 2025 3 Consultant Average (3CA) price deck and $70WTI Flat Price Deck ($76.16 WCS CAD); Improvement percentages reflected on YE 2025 3CA price*
2. *No wells excluded from count except for producing day criteria for wells drilled with 33m inter-leg spacing*

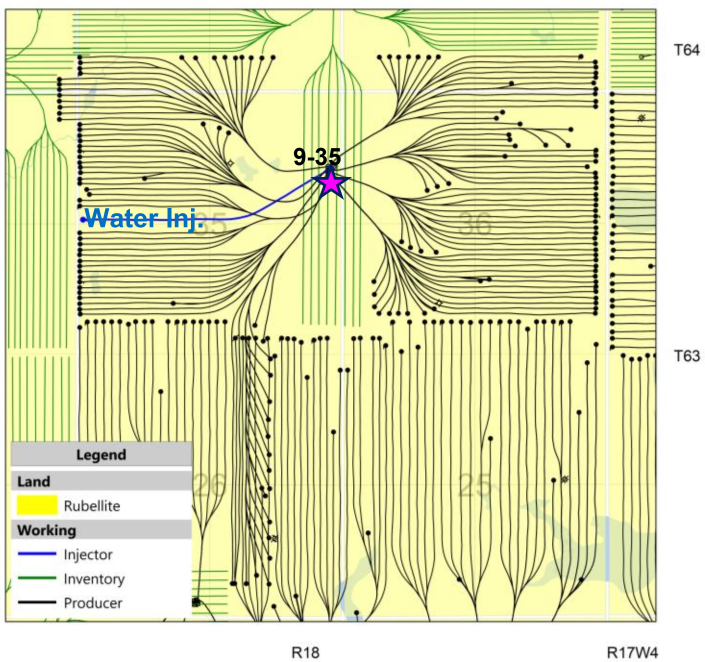
Southern Clearwater Enhanced Oil Recovery Pilots

Advancing Multiple Waterflood Pilots and Other EOR Experiments through 2026

RUBELLITE

Figure Lake Line Drive Pilot Projects

9-35 Pad Waterflood Pilot
Single Leg water Injector placed in middle of 8-leg Multi-lat Producer
Injection commenced March 2026 – Ramping Up



8-26 Pad Waterflood & Polymer Pilots
Single Leg Injectors placed in middle of 8-leg Multi-lat Producers
Water injection Q3/26; Polymer Injection Q4/26

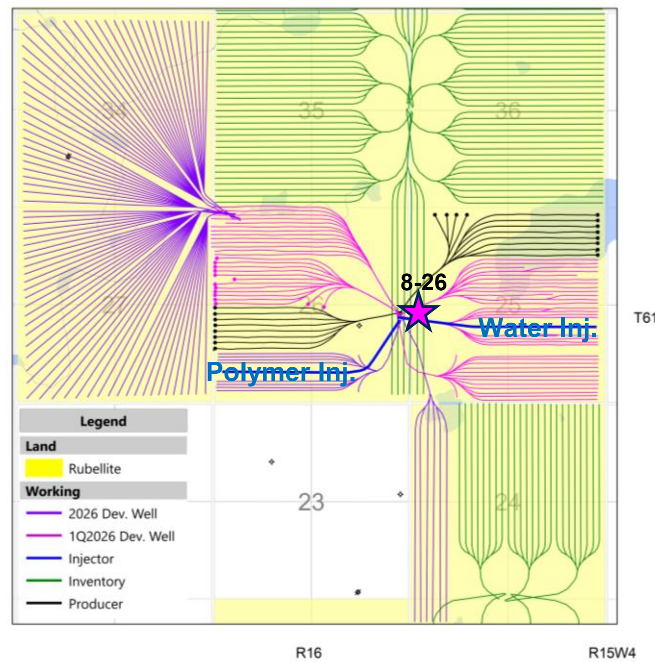
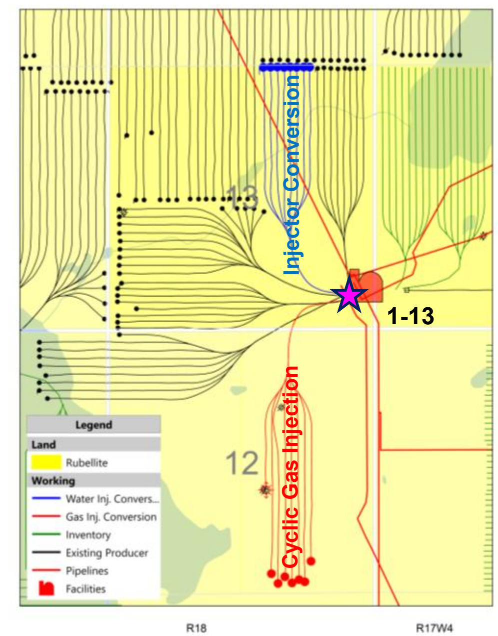
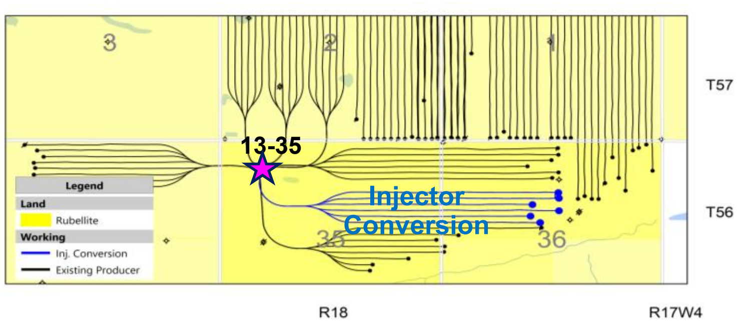


Figure Lake Multi-lat Conversions

Figure Lake 1-3 & 1-13 Pads
2 existing Multi-lats to be converted from Producer to Water Injector
Injection commenced Q2/26 - Optimizing
Cyclic Gas Injection – Preparing for next cycle



Ukalta Multi-lat Conversion



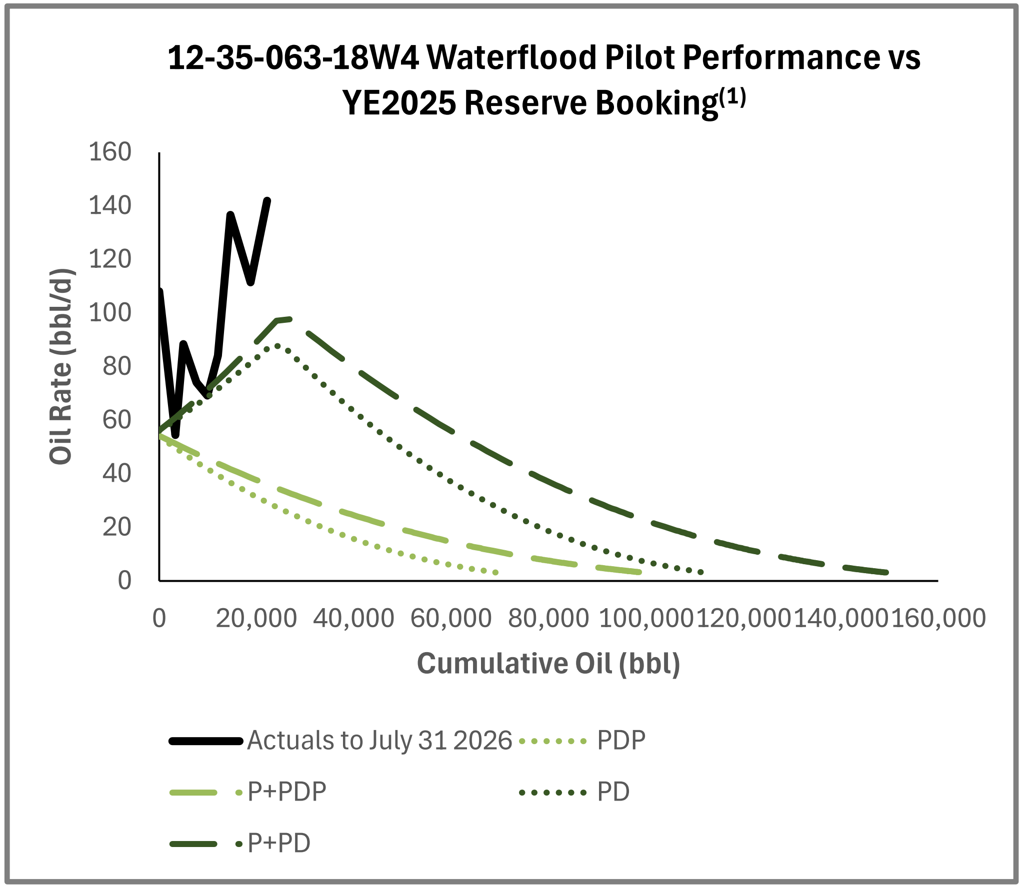
Ukalta 13-35 Pad
1 existing Multi-lats to be converted from Producer to Water Injector

Injection commenced Q2/26 - Converting Water disposal well for water source well to ramp up injection in Q3/26

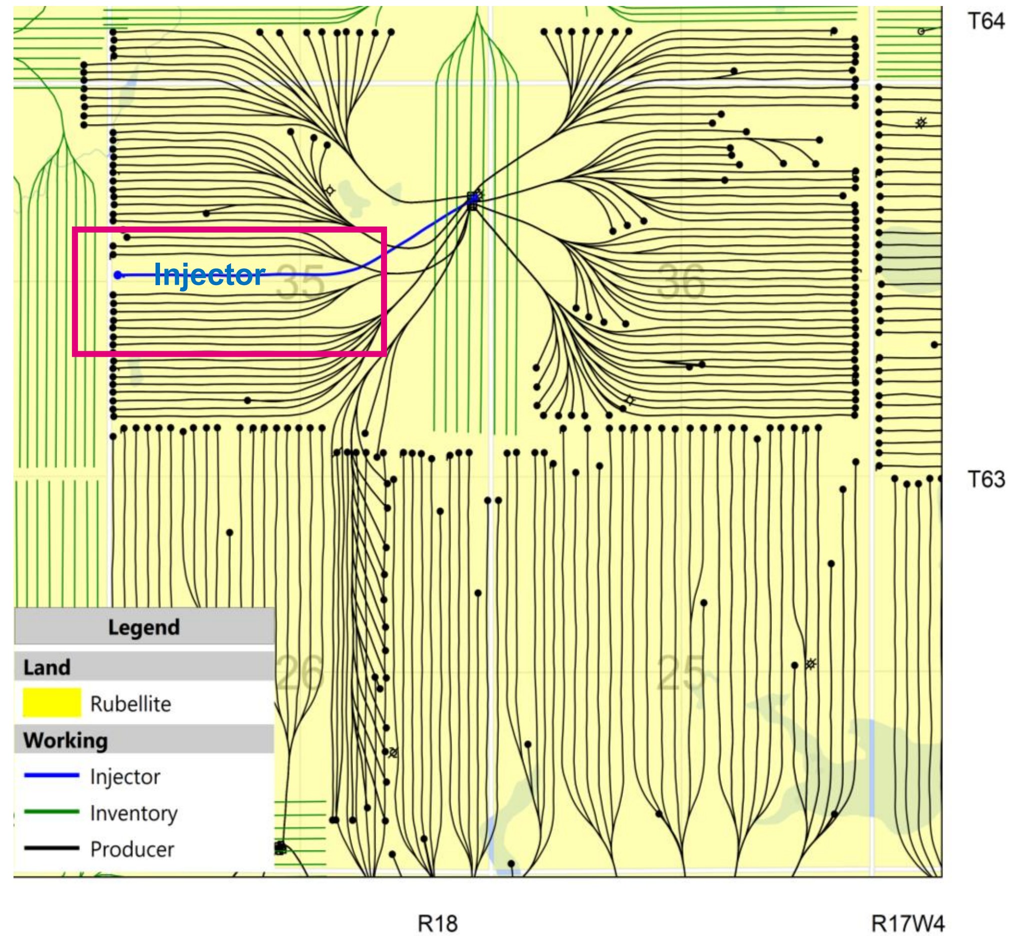
Figure Lake 9-35 Waterflood Line Drive Pilot

Reserves on waterflood pilot booked conservatively at 50% recovery factor uplift

Figure Lake Line Drive Waterflood Pilot Performance



Pilot Configuration



Reserves booked on 9-35 pilot producer/injector pair at YE 2025

- 12-35 well booked as Tier 2 primary producer with non-producing waterflood reserves, as injector conversion capital spend was still outstanding
- Injection commenced in March 2026 with slow ramp up in water injection rates to current rate of ~300 bbl/d
- Pattern shows early indications of pressure support and is exceeding McDaniel forecasts in the 2025 Year End Report

1. *Proved Developed Producing and Proved Plus Probable Developed Producing Undeveloped (P+PDP) and waterflood Proved Developed and Proved Plus Probable Developed reserves and as per Year End 2025 McDaniel Reserve Report Tier 2 Figure Lake Type Curve and waterflood response assumption of 50% increase to Primary recovery factor*

Figure Lake 9-35 Waterflood Line Drive Pilot

00/12-35 & 02/12-35 Waterflood Pilot Producer/Injector Pair Performance

9-35 Waterflood Pilot Pattern Performance

- Single Leg Water Injector in middle of 8-leg multi-lateral Producer ("Texas Four-Step" Pattern)
  - Injection commenced in March 2026 with systematic ramp up plan - slowed in July due to wet weather
  - Per well production allocation on the 9-35 pad has been challenging, but improving with refined test protocols
  - Most wells on 9-35 pad are not fully pumped off and optimized due to higher producing water cuts than surface facility originally designed for – Inclining production may be partially related to increased pump rates

- Monitoring Producer for early signs of waterflood success – What we are watching for…
  - Falling GOR's and gas rates are likely be the first signs of reservoir pressure support
  - Rising joints of fluid (JOF) in the well will demonstrate reservoir support and lead to an increase in total fluid and oil production rates
  - Persistent over-performance relative to length-adjusted primary type curve

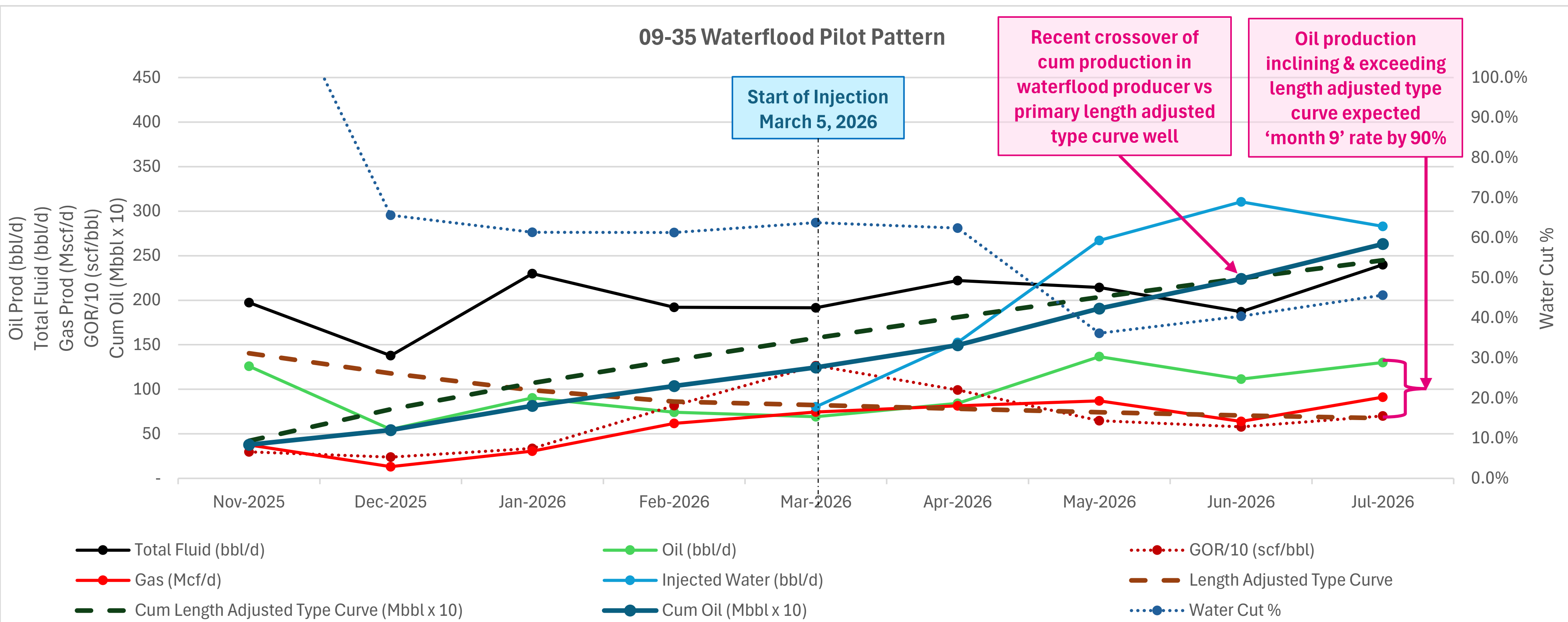


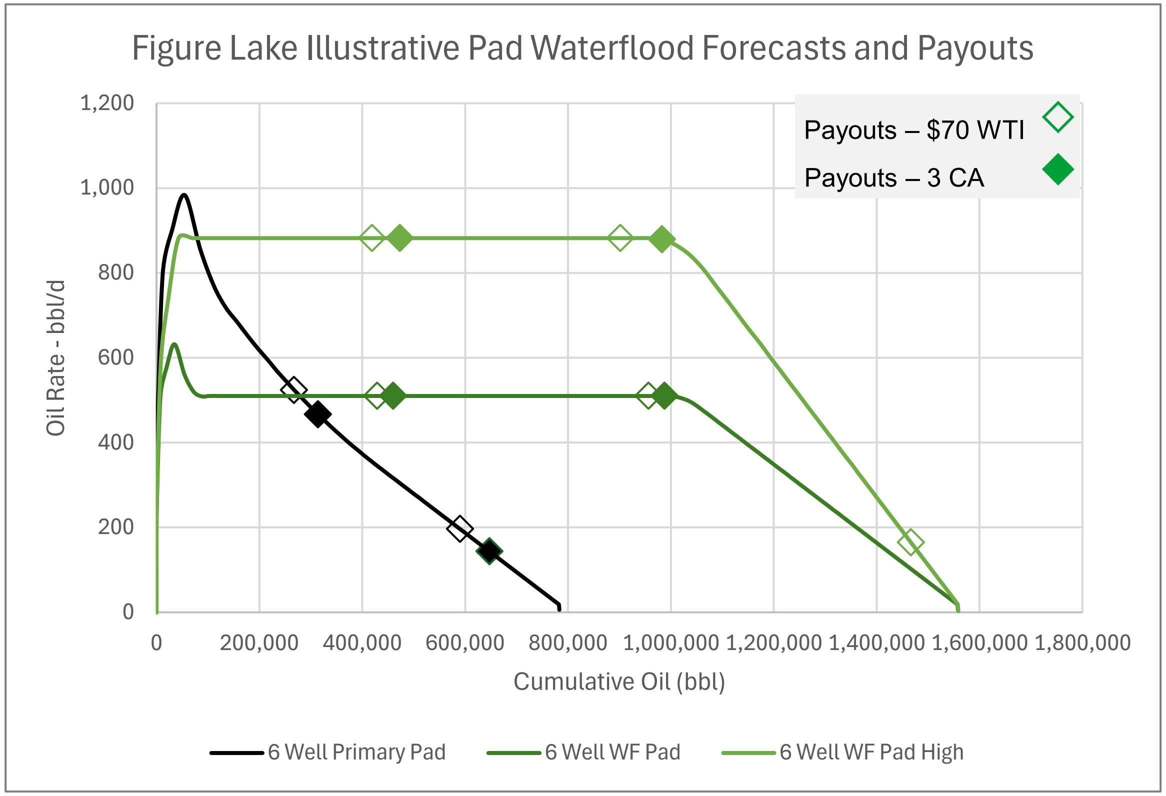
Figure Lake 'Texas Four-Step' Waterflood – Six Well Pad

Illustrative Production Response Scenarios and Economics – TBD with future commercial demonstration pad

Clearwater Waterflood Illustrative Scenarios and Economics

- Illustrative examples below represents a 6-well Pad development under Primary, Waterflood Base and High Rate Waterflood cases
- 215+ remaining primary Tier 1 and Tier 2 locations (~35 six-well pads if all future drills were Texas four-step waterflood producer/injector pairs)
- ***Primary***
  - 6 wells: 12 open hole lateral legs/well; >15,000m MD of open hole/well
  - ~4-5% Recovery Factor ('RF') (130 Mbbl per 50ha spacing)
- ***Waterflood Scenarios – Waterflood Base Case & High Rate Case***
  - Texas Four-Step well pair design
  - 6 Producers : 8 open hole lateral legs/producer; ~10,000m MD of open hole/well
  - 6 Injectors: ~1,200m MD of open hole per injector
  - ~50% more capital for injectors, water source and surface facilities
  - Double the reserve recovery from primary in both scenarios (~8-10% RF)
  - Forfeit short term rates and IRR (in Base Case only) for long term plateau, higher NPV10, lower decline rates and increased free funds flow

Assumptions	Primary	Waterflood Base Case	Waterflood High Rate Case
Six Well Pads	***33 m Inter-leg Spacing & 15,000m Open Hole Well Design***	***Stabilizes at 63% of Primary Length Adjusted Type Curve IP30***	***Stabilizes at Primary Length Adjusted Type Curve Qi***
Drainage Area (Ha)	300	300	300
Horizontal Length (m)	90,000	67,200	67,200
Peak Rate/100m (bbl/d)	1.09	0.94	1.31
Plateau Rate (bbl/d)	NA	510 (~5 yrs)	882 (~3 years)
IP360 (bbl/d)	640	451	704
Estimated Ultimate Recovery (Mbbl)	783	1,537	1,548
Economics[1] (gross per pad)	**YE 2025 3 Cons Avg | $70 WTI**		
D,C,E&T Capex ($MM)	15.3	23.1	23.1
D,C,E&T Capex ($/m)	170	343	343
Scenario F+D ($/bbl)	19.53	15.00	14.89
NPV10 ($MM)	13.2 | 15.6	22.9 | 24.1	30.1 | 33
First Payout (months)	20 | 17	34 | 32	23 | 21
Second Payout (months)	60 | 49	68 | 66	42 | 39
Third Payout (months)	-	-	- | 77
# of Payouts	2.3 | 2.5	2.9 | 2.9	2.9 | 3.1
Rate of Return (%)	65 | 84	40 | 44	71 | 83

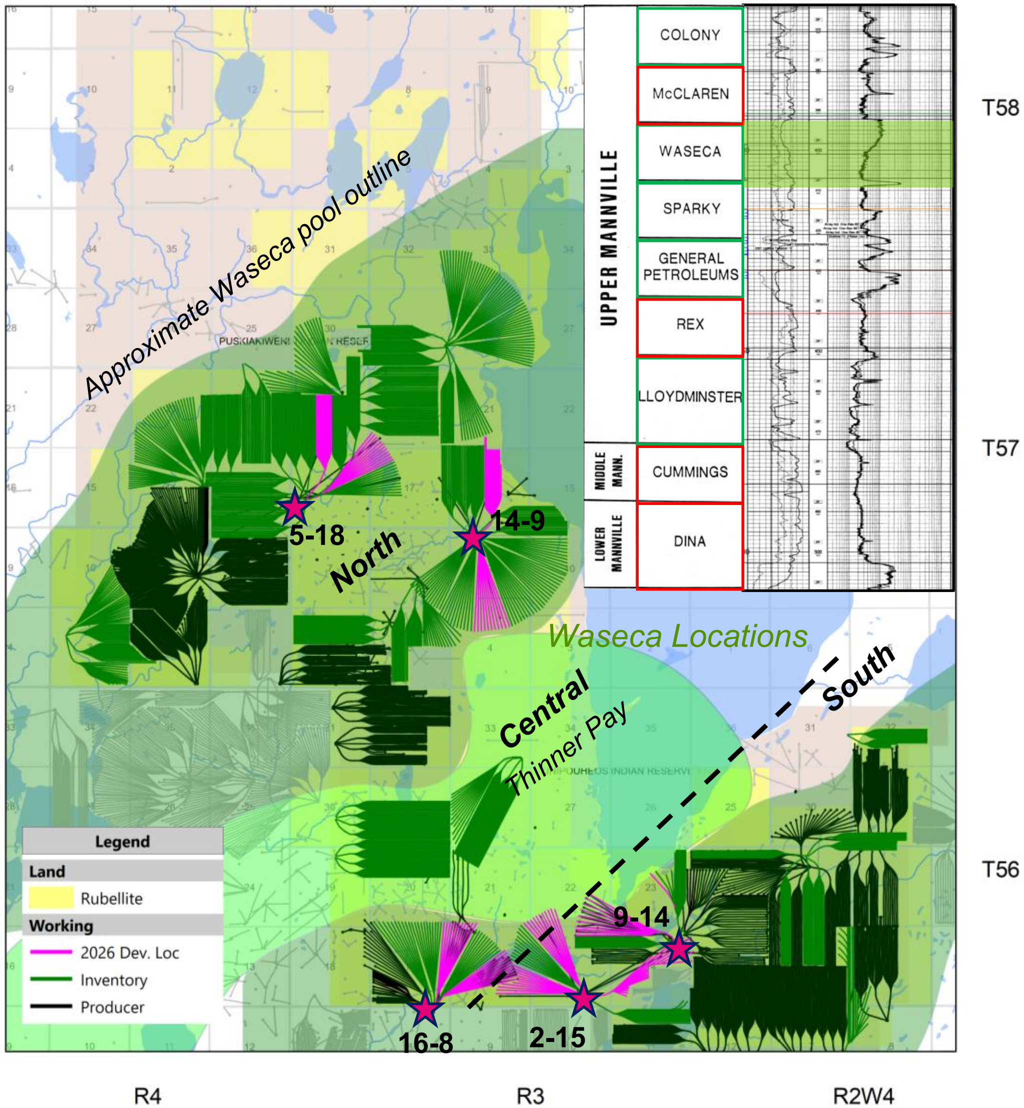


1. *Illustrative volumes, forecasts and economics run on YE 2025 3 Consultant Average (3CA) price deck and $70 WTI Flat Price Deck ($76.16 WCS CAD)*
2. *Waterflood scenarios assume 60% increase in fixed operating costs for increased water handling relative to primary development operations*

Rubellite Asset Profile | *Frog Lake Waseca*

Active Waseca development and GP delineation

Asset Map – Waseca Development



Source: geoScout

Asset Summary

Working Interest: 63% (of current production)

- FLERC has option to elect 50% WI in all future drills

Q2 2026 Production: 2,889 boe/d (100% heavy oil)

- 86 gross (57.5 net) wells on sales production

Drilling Inventory:

- 47.0 net inventory Waseca locations (as at Jan 1, 2026)(2)
  - 45% booked in 2025 McDaniel Reserve Report (21.0 net locations)
  - 16.0 net proven undeveloped and 5.0 net probable undeveloped booked(1) Waseca Development locations
- >160.0 net inventory GP locations(2)
  - 5% booked in 2025 McDaniel Reserve Report (8.5 net locations)
  - 3.5 net proven undeveloped and 5.0 net probable undeveloped booked(1)
- 8 years of development for one-rig program at 16 net wells/year

2026 Activity

Waseca Development: 10 (6.5 net) wells

- 4 (2.0 net) Waseca South Development wells
- 2 (1.5 net) Waseca North 20,000m Step Out Delineation wells
- 4 (3.0 net) Waseca North/Central Development Wells

GP and Sparky Single Lined laterals: 17 (9.0 net) wells

- 11 (6.0 net) GP wells
- 6 (3.0 net) Sparky wells

Enhanced Oil Recovery: Core & Lab Testing

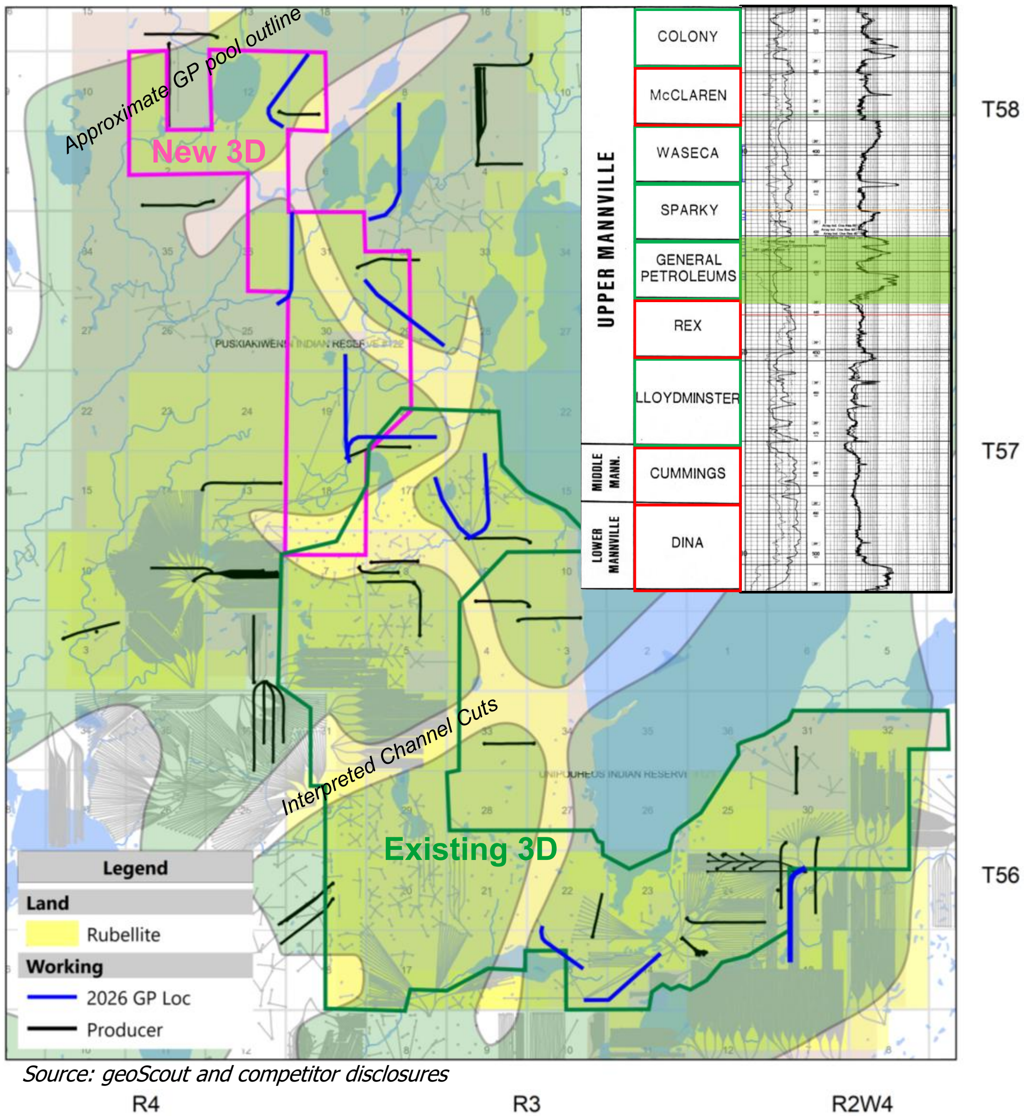
- Waseca Primary Recovery ~5% of OOIP (estimated OOIP >690 Million bbls gross)
- Core & fluid compatibility analysis and competitor analog information to inform future polymer pilot and other enhanced recovery opportunities
- 1 (0.5 net) water disposal well

1. *Total Proved Plus Probable Undveloped (P+PUD) reserves, economic parameters and Type Curves as per Year End 2025 McDaniel Reserve Report*
2. *Frog Lake additional Waseca and GP development location inventory not recognized in McDaniel Report assumes 50% working interest; See "Drilling Locations" in Advisories*

Rubellite Asset Profile | *Frog Lake General Petroleum*

GP Delineation

Asset Map – GP Development



Source: *geoScout and competitor disclosures*

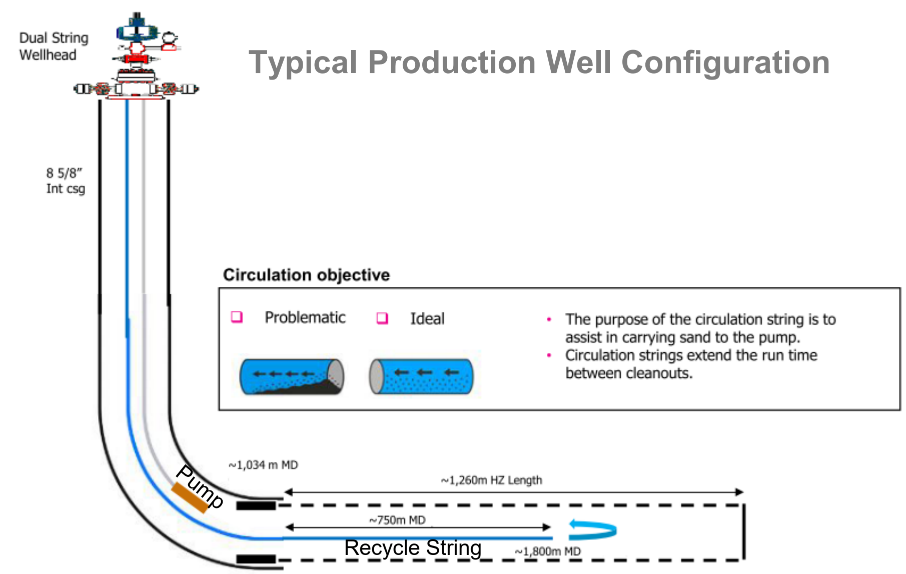
Asset Summary

Multiple 'New Zone' Targets in Mannville Stack

- GP, Sparky, McLaren, Rex and Lloyd
- >205 net Locations[1] delineated by existing and 25 km^2 new shoot 3D seismic

General Petroleum ("GP") Delineation

- GP historically delineated in greater Frog Lake region using single leg lined laterals, proving productivity
- Modern well designs incorporating "recycle" strings to circulate produced water along the horizontal section, clearing the well bore of solids to enhance productivity improving economics
- 4 (3.0 net) GP wells drilled in 2025 – Monitoring production performance
  - 1 (1.0 net) Fish Bone Design
  - 3 (2.0 net) Single Leg Lined Laterals with Re-circulating String Design
- 11 (6.0 net) GP wells planned for 2026
- >160 net locations (as at Jan 1, 2026) (95% unbooked)
  - 3.5 net Proved Undeveloped and 5.0 Probable Undeveloped locations booked[2]
  - Assumes ~100 - 150m inter-well spacing



1. *Location count subject to inter-well spacing and well design optimization*
2. *Total Proved Plus Probable Undeveloped (P+PUD) reserves as per Year End 2025 McDaniel Reserve Report*

Frog Lake Type Curves

Mannville Stack – Waseca North, Waseca South and General Petroleum

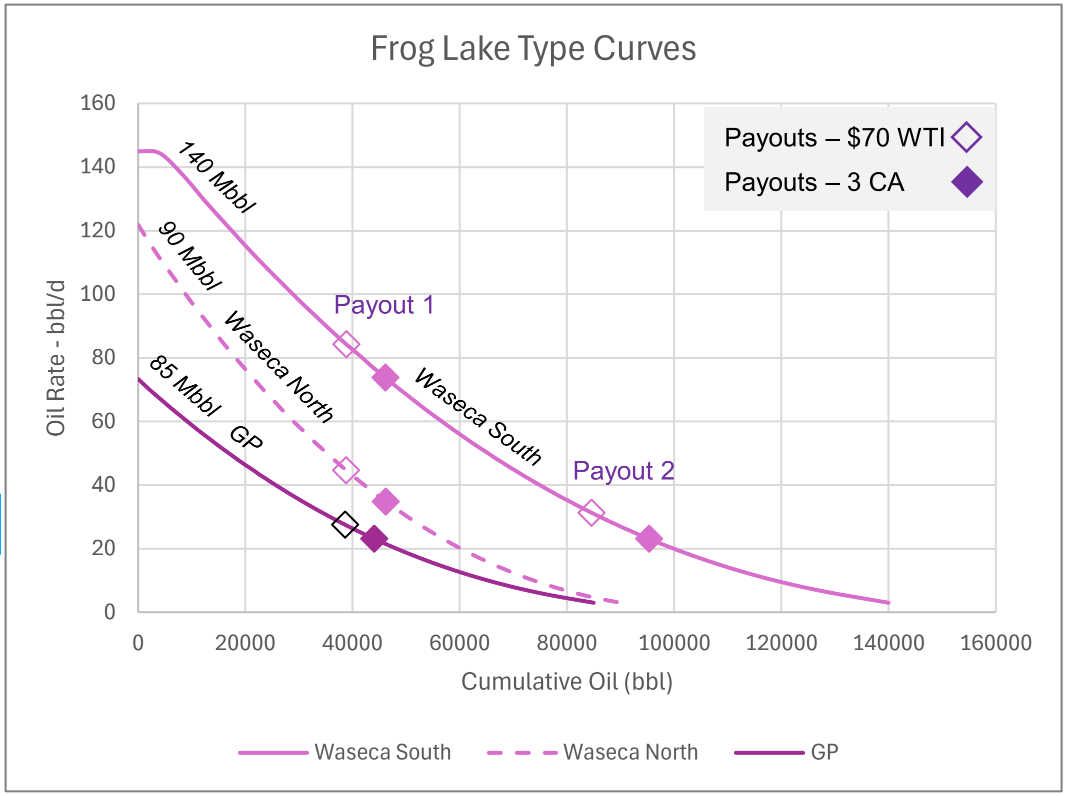
Waseca Development
- Historical well design:
  - ~25m inter-leg spacing
  - ~15,000m MD of open hole multi-lateral
  - Multiple different mud and well designs to improve hole cleaning, decrease time to on first oil sales, and increase production and reserves

Testing 20,000m Waseca wells in 2026
- Larger drainage area, well bore diameter, and overall length to improve capital cost per meter drilled
- Implementing water-based mud with amine system to manage losses

GP Development
- Single leg lined laterals equipped with recycle strings to lift solids

Type Curve Sensitivities - Frog Lake[1]

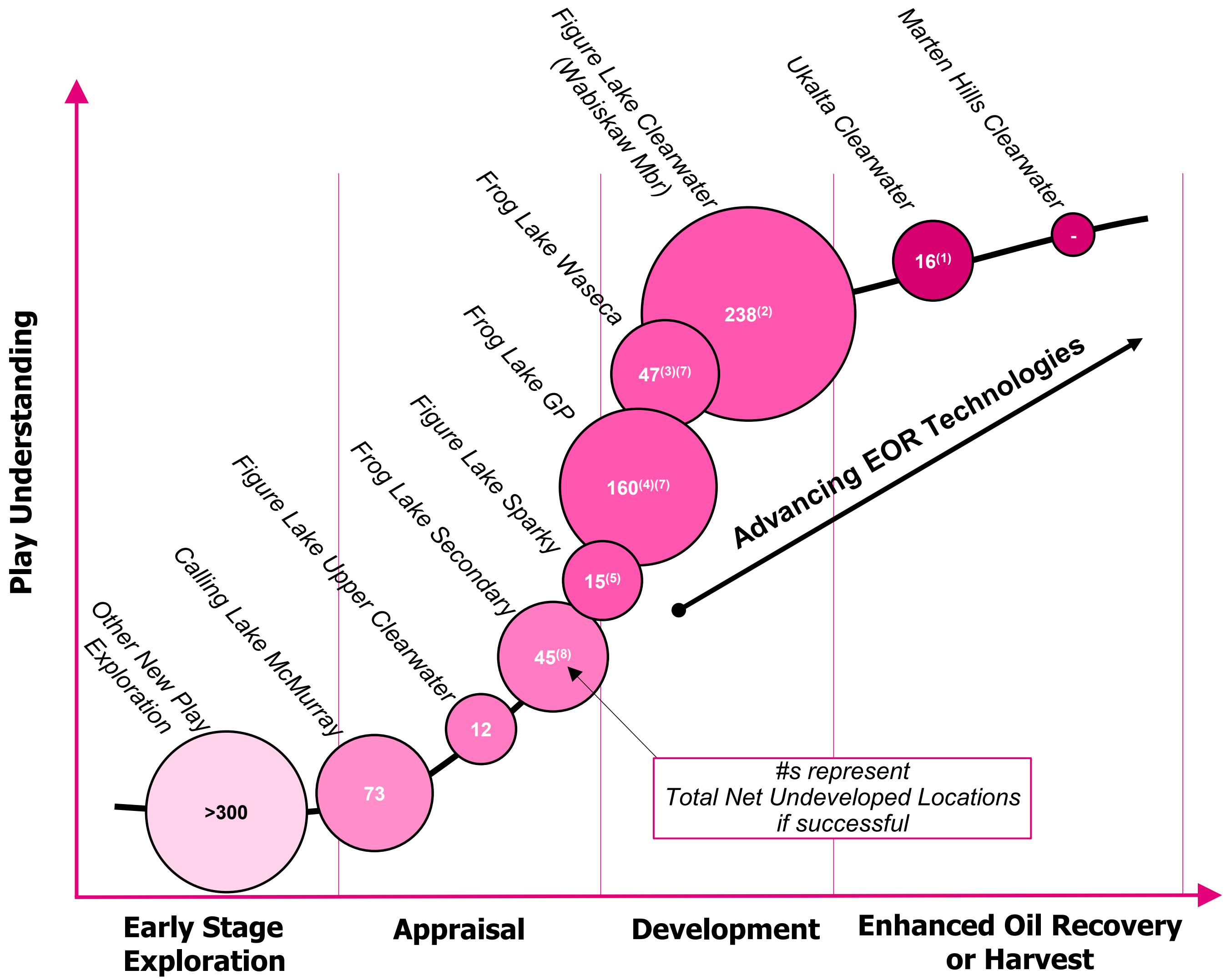
<table>
<tr><th rowspan="2">Assumptions (gross per well)</th><th colspan="3">Frog Lake Type Curve</th></tr>
<tr><th>Waseca North[1]</th><th>Waseca South[1]</th><th>GP[1]</th></tr>
<tr><td>Drainage Area (Ha)</td><td>50</td><td>50</td><td>12</td></tr>
<tr><td>Horizontal Length (m)</td><td>15,000</td><td>15,000</td><td>1,200</td></tr>
<tr><td>Inter-leg Spacing (m)</td><td>25</td><td>25</td><td>-</td></tr>
<tr><td>IP30/100m (bbl/d)</td><td>0.8</td><td>1.0</td><td>6.1</td></tr>
<tr><td>IP30 (bbl/d)</td><td>122</td><td>145</td><td>73</td></tr>
<tr><td>IP360 (bbl/d)</td><td>85</td><td>114</td><td>58</td></tr>
<tr><td>Estimated Ultimate Recovery TPP (Mbbl)</td><td>90</td><td>140</td><td>85</td></tr>
<tr><th>Economics[1] (gross per well)</th><th colspan="3">YE 2025 3 Cons Avg | $70 WTI</th></tr>
<tr><td>D,C,E&T Capex ($MM)</td><td>$2.0</td><td>$2.0</td><td>$1.7</td></tr>
<tr><td>D,C,E&T Capex ($/m)</td><td>$133</td><td>$133</td><td>$1,446</td></tr>
<tr><td>TPP F+D ($/bbl)</td><td>$23.47 | $23.32</td><td>$14.88 | $14.88</td><td>$21.78 | $21.64</td></tr>
<tr><td>Net NPV10 ($MM) (50%WI)</td><td>$0.38 | $0.54</td><td>$1.06 | $1.28</td><td>$0.25 | $0.36</td></tr>
<tr><td>First Payout (months)</td><td>24 | 18</td><td>15 | 12</td><td>36 | 29</td></tr>
<tr><td>Second Payout (months)</td><td>- | -</td><td>54 | 41</td><td>- | -</td></tr>
<tr><td>Third Payout (months)</td><td>-</td><td>- | -</td><td>-</td></tr>
<tr><td># of Payouts</td><td>1.6 | 1.8</td><td>2.6 | 2.8</td><td>1.6 | 1.7</td></tr>
<tr><td>Rate of Return (%)</td><td>36 | 55</td><td>82 | 119</td><td>24 | 34</td></tr>
</table>



1. *Total Proved Plus Probable Undeveloped (P+PUD) reserve and economic parameters as per Year End 2025 McDaniel Reserve Report run on 3 Consultant Average (3CA) and $70 WTI Flat Price Deck ($76.16 WCS CAD)*
2. *NPV10 is shown as Net (50% WI to Rubellite). All other parameters are gross*

Exploration Prospect Pipeline

Feeding a "pipeline" of primary development projects from new exploration plays



'New Zone' Appraisal[7]

Frog Lake Secondary Zones: 45 net[8] Locations

- Sparky, Lloyd, Rex, and McLaren Zones

Figure Lake Upper Clearwater: 12 net Locations

- New pools mapped

Calling Lake McMurray: 73 net Locations

- 108.0 net sections
- One (1.0 net) Horizontal test well drilled in Q4 2024
- Likely hole collapse affecting inflow
- Workover planned for Q4 2026

'New Play' Exploration[7]

Other Early-Stage Exploration

- Land capture ongoing in new heavy oil plays
- Targeting new zones and formations amenable to open-hole horizontal multi-lat development or single leg lined horizontals with recycle strings
- Test well drilled Q1 2026 at Bayhurst Saskatchewan, with second well planned 4Q 2026

Net booked locations as per Rubellite Year End 2025 McDaniel Reserve Report:

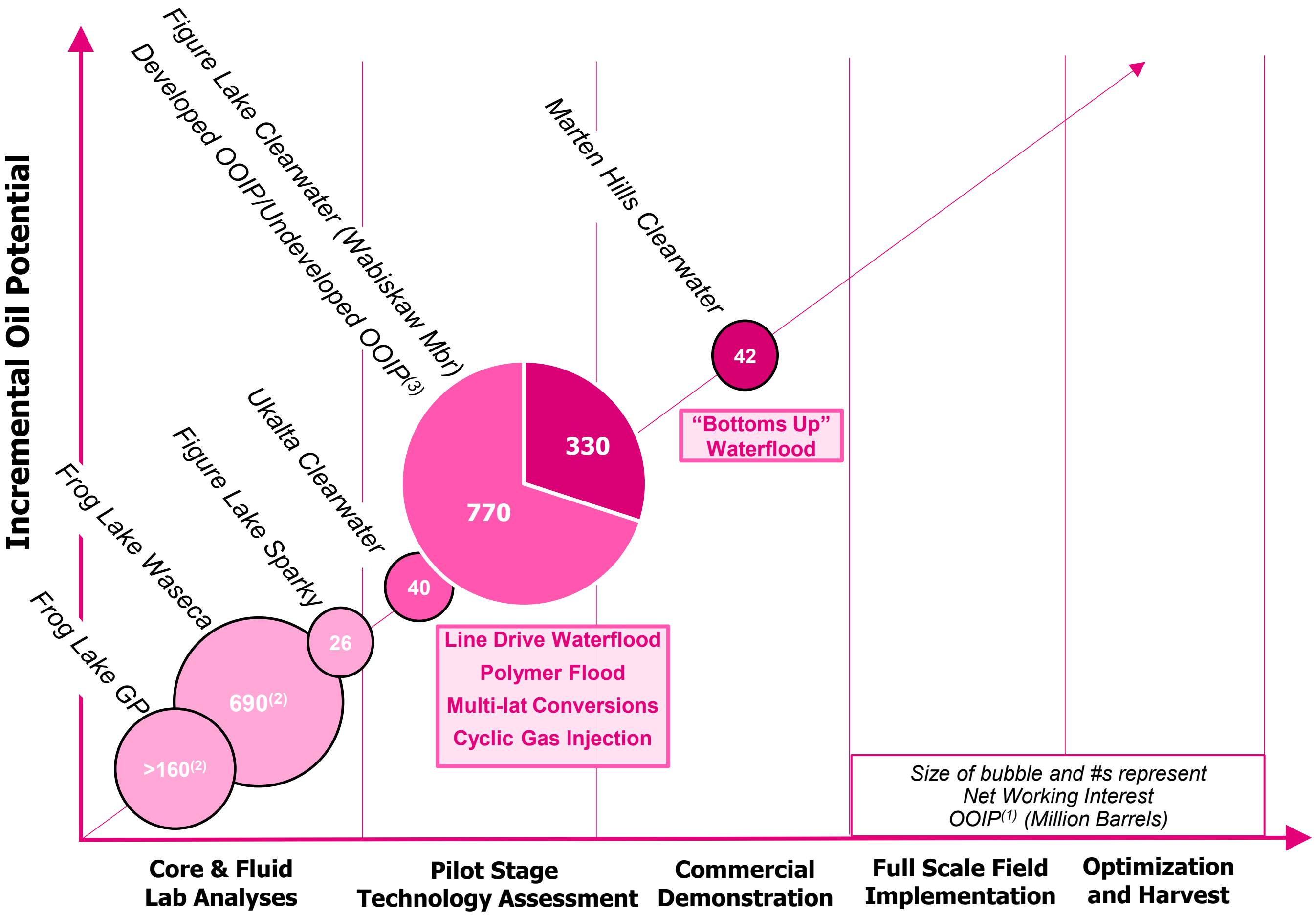
1. *Ukalta Clearwater has 11.0 Proved Undeveloped and 5.0 Probable Undeveloped Net Locations*
2. *Figure Lake Wabiskaw has 69.1 Proved Undeveloped and 38.6 Probable Undeveloped Net Locations*
3. *Frog Lake Waseca has 16.0 Proved Undeveloped and 5.0 Probable Undeveloped Net Locations*
4. *Frog Lake GP has 3.5 Proved Undeveloped and 5.0 Probable Undeveloped Net Locations; Location count assumes 100m inter-well spacing and is subject to change with inter-well spacing and well design*
5. *Figure Lake Sparky has 2.0 Proved Undeveloped Net Locations*
6. *Location count subject to change with inter-well spacing and well design*
7. *Frog Lake locations assumed at 50% working interest*

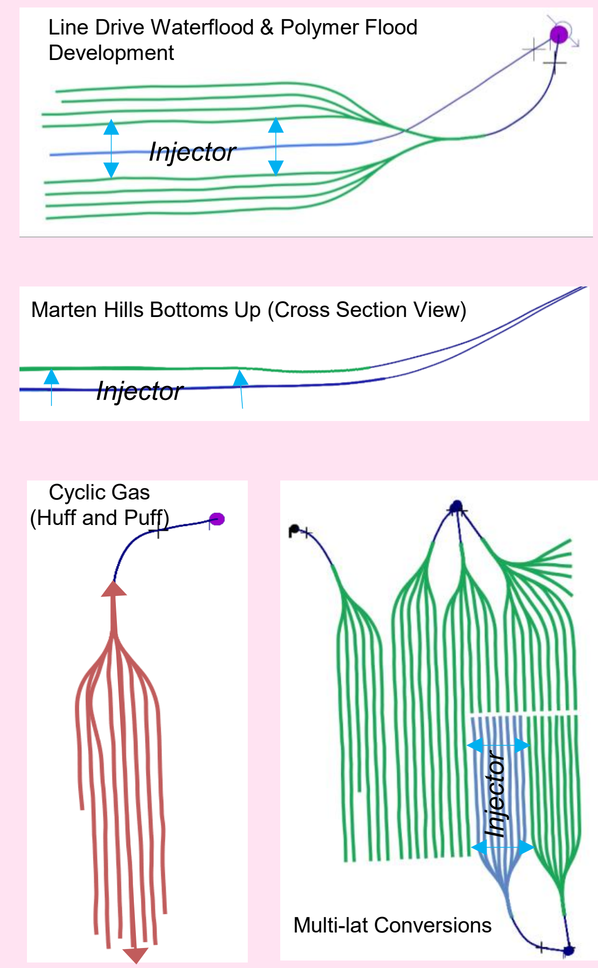
Waterflood and Enhanced Oil Recovery 'Size of the Prize'

Measured in Incremental Recovery, Higher Free Funds Flow, Asset Duration & Value Creation

With full scale waterflood implementation we expect:

- Incremental recovery potential to increase from 5 to >10% of original oil in place ("OOIP")
- Base declines to fall, reducing maintenance and growth capital requirements
- Increasing free funds flow providing optionality for capital allocation, including investment in accelerated growth, exploration, additional EOR, debt repayment and ultimately return of capital





1. *OOIP – Original Oil In Place (net) based on internal estimates*
2. *OOIP at Frog Lake assumes 50% working interest*
3. *At Figure Lake, of the 1,100 million bbls of OOIP, approximately 30%, or 330 million bbls, has been developed with primary open hole multi-lateral wells*

2026 Annual Exploration and Development Spending(1)

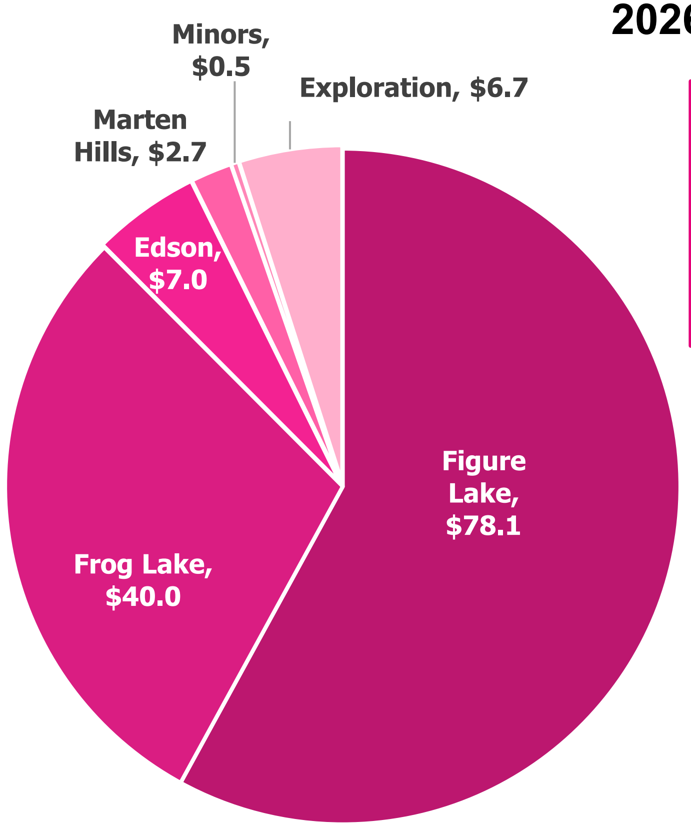
Development, Step-out Delineation, Enhanced Oil Recovery Projects and Exploration

2026 E&D Spending: $125-135 MM(1)

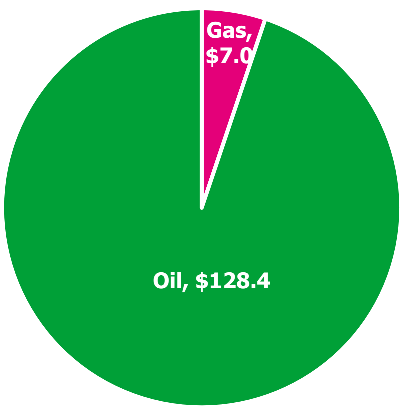
65 gross / 50.7 net wells

Development, Delineation & EOR:
- Figure Lake: 30 (30.0 net)
- Frog Lake: 29 (16.5 net)
- Marten Hills: 2 (1.2 net)
- East Edson: 2 (1.0 net)

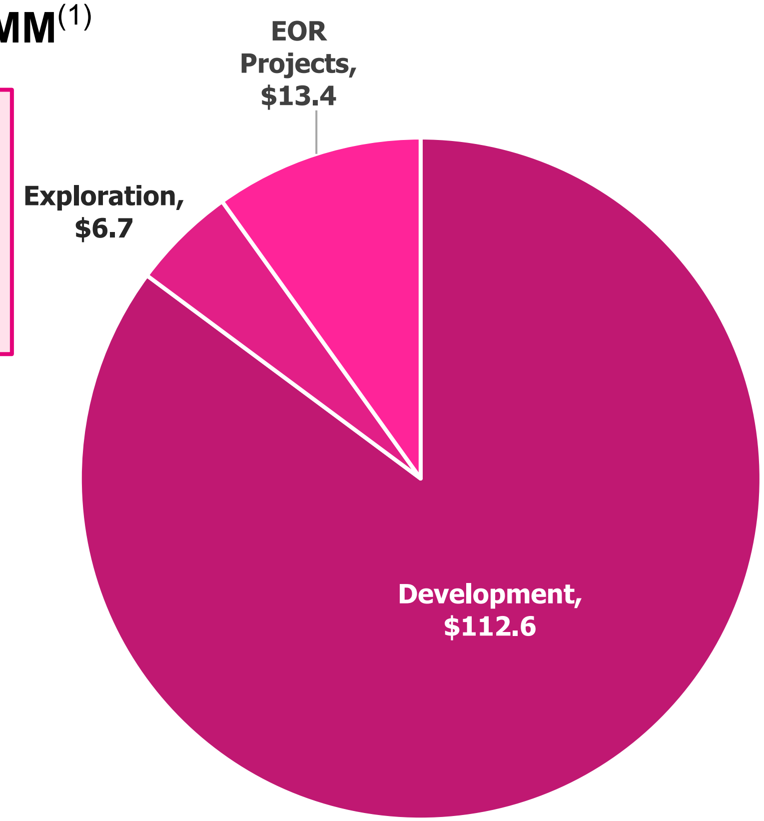
Exploration: 2 (2.0 net)



Capex by Area



Capex by Commodity(2)



Capex by Category

1. See Non-GAAP measures in Advisories
2. 'Gas' and 'Other' capital spending includes gas conservation infrastructure at Figure Lake

Balance Sheet and Guidance – Pro Forma Edson Disposition

Credit facility maintained at $160 MM providing significant liquidity and financial flexibility

Guidance *(September 8, 2026)*

	H1 2026A	2026F
E&D Spending[(1)(2)(3)] ($ MM)	$72.3	$125 - $135
Average Sales Production (boe/d)	13,625	12,000 – 12,600
Production mix (% oil and liquids)	66%	73%
Heavy Oil Production (bbl/d)	8,588	8,500 – 9,200
Heavy Oil Wellhead Differential[(4)] ($/bbl)	$5.82	$5.25 - $5.75
Royalties[(5)] (% of revenue)	14.2%	14.5% - 15.5%
Operating Costs[(1)] ($/boe)	$7.01	$7.50 - $8.00
Transportation Costs ($/boe)	$5.04	$5.50 - $6.00
G&A ($/boe)	$3.36	$3.50 - $4.00

1. *Non-GAAP or financial measure*
2. *Exploration and Development spending for the second half of 2026 includes the drilling of 13 (13.0 net) horizontal multi-lateral Clearwater primary development wells (15,000 meter target, standard well design) in the Greater Figure Lake area, and 21 (10.5 net) horizontal wells at Frog Lake targeting the Waseca, GP and Sparky zones along with 1 (0.5 net) water disposal well; 1 (1.0 net) exploration well in Q4/26 at Bayhurst and expansion of the waterflood at the 12-35 Pad at Marten Hills in Q4/26*
3. *Excludes land purchases, seismic and acquisitions, if any; During H1 2026, land, seismic and other spending was $4.2 million*
4. *Realized wellhead price relative to Western Canadian Select (C$/bbl) benchmark pricing*
5. *Includes Crown, freehold and GORRs*

Balance Sheet Reconciliation through Strategic Transactions

($MM)	Perpetual Q2/24	Rubellite Q3/24	Year End 2024[(2)]	Q2 2026[(2)]
Bank Debt Borrowing Capacity[(3)]	$30.0	$100.0	$140.0	**$160.0**
Revolving Bank Debt Draw[(4)]	$1.5	$72.2	$105.9	**$95.7**
Bank Syndicated Term Loan		$20.0	*Fully repaid*	
Rubellite Term Loan[(5)]		$20.0	$20.0	**$20.0**
Working Capital Deficit[(1)(6)]	-$3.0	$35.8	$28.1	**$42.4**
Perpetual Senior Notes[(7)]	$26.2		*Converted into shares*	
Total Net Debt[(1)(8]	$24.7	$147.9	$154.0	**$158.1**
Marketable Securities[(10)]				**$67.7**
Total Net Debt Pro Forma Edson Disposition[(1)(10)]				**$90.3**
Available Liquidity[(1)(9)]		$25.5	$30.4	**$62.9**

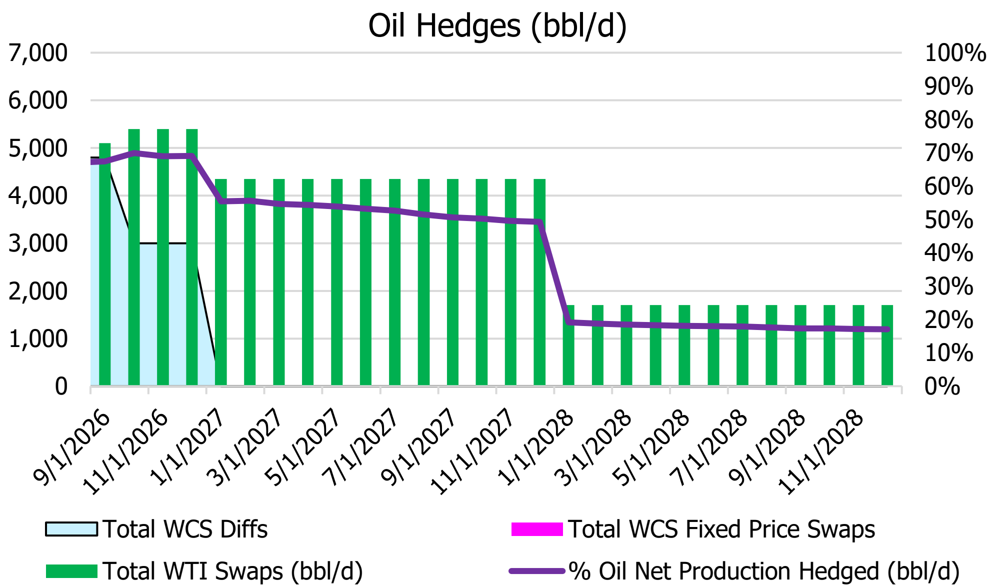
1. *Non-GAAP or financial measure*
2. *Rubellite Year End Balance Sheet as at December 31, 2024; June 30, 2026*
3. *Syndicate of five Canadian lenders; Bank line at September 30, 2024 of $100 million for Rubellite and $30 million for Perpetual; Bank line increased to $140 million upon Recombination on October 31, 2024 and to $160 million in May 2026; Q1 2026 proforma May 2026 credit facility limit increase*
4. *Rubellite Revolving Bank Debt Draw as at period end; Perpetual as at June 30, 2024*
5. *Rubellite Term Loan with 11.5% coupon and maturing in August 2029 subordinate in security to other provision relating to ongoing $3.75 million annual payments under the "Settlement Agreement" which has second lien security behind the Company's consolidated credit facility until the carrying value of $11.9 million remaining outstanding settlement amount is fully paid prior to March 2030*
6. *Rubellite Working Capital Deficit as at period end; Perpetual as at June 30, 2024*
7. *Based on the five-day volume weighted average price ("VWAP") for the Rubellite Shares prior to the Recombination Transaction announcement of $2.25 per share*
8. *Rubellite Total Net Debt as at period end; Perpetual as at June 30, 2024*
9. *Available liquidity is defined as the borrowing limit under the credit facility, plus any cash and cash equivalents, less any borrowings and letters of credit issued, exclusive of the $67 million value of the TPZ shares*
10. *Based on $67 million in TPZ shares and includes $0.7 million quarterly dividend due Sept 15th*

Generating material free funds flow after sustaining capital - Excess free funds flow directed to organic growth, exploration land capture & evaluation, acquisitions & debt repayment

Commodity Price Risk Management

Price protection on ~70% of Aug-Dec 2026, 54% of 2027 and 19% of 2028 liquids production, net of royalties[1]

Oil Price Risk Management



Mark-to-Market ("MTM") Value (As at August 31, 2026[3])

C$MM Gain(Loss)	MTM Value As at June 30, 2026	July-Aug26 Realized	MTM Value As at August 31, 2026		
			2026[4]	2027	2028
Oil	$14.65	$(4.84)	$(10.37)	$(4.42)	$0.81
Gas	$0.58	$0.41	$0.60	-	-
FX	$(3.27)	$0.02	$0.17	$1.36	$0.46
Total	**$11.96**	**$(4.41)**	**$(9.60)**	**$(3.04)**	**$1.27**

- Physical forward sales contracts and financial derivatives used to:
  - Increase certainty in adjusted funds flow
  - Manage the balance sheet
  - Ensure adequate funding for capital programs
  - Lock in investment returns
  - Take advantage of perceived anomalies in commodity markets
- RBY Average Oil Hedge Prices[2] of:
  - ~C$75.05/bbl WCS Sept-Dec26; ~US$71.31/bbl WTI 2027 and US$70.03/bbl WTI 2028
- RBY Realized ~C$1.64 million in NG Hedges for April 26 - Oct 26

1. *As at Aug 31 2026; See Appendix and Advisories for detailed risk management positions*
2. *Based on weighted average price for the period; WCS prices in Q4 2026 estimated using WCS differential forward market on Aug 31, 2026 of -$17.00/bbl for unhedged portion*
3. *Unsettled positions in USD converted to CAD at August 31, 2026 settled rate of 1.3897*
4. *Represents the MTM value of contracts covering the September 1st to December 31, 2026 period*

Creating Differentiated Value for Shareholders

Junior E&P growth opportunity focused on Clearwater and Mannville Stack multi-lat heavy oil plays

RUBELLITE ENERGY

Expanding Pure Play Heavy Oil Multi-lat Asset Base	▪ 656 net sections of prospective Clearwater, Mannville Stack and Heavy Oil exploration lands ▪ Major producing properties at Figure Lake (Clearwater) and Frog Lake (Mannville Stack) ▪ Multiple exploration prospects captured with material success case location inventory identified ▪ Line of sight to additional exploratory land capture and M&A opportunities ▪ Several properties with near cold flow prospects to unlock with evolving solvent & low-grade heat technology
Robust Organic Heavy Oil Production Growth Profile	▪ Organic and M&A driven heavy oil production growth from initial 350 bbl/d in Sept 2021 to 8,534 bbl/d in Q2/26 ▪ Highly profitable, full cycle IRRs with attractive payout periods under 1 year at historical prices since inception ▪ >475 net defined Development/Step-out heavy oil locations; >430 net potential exploration/appraisal locations ▪ Systematic evaluation of exploration/appraisal prospect inventory to inform sustainable target production levels ▪ Potential for Waterflood and other EOR technologies to mitigate production declines, increase recovery & add FCF
Fully Funded Development Generating Material Free Funds Flow	▪ Organic growth plan on development acreage funded through free funds flow ▪ Low royalties of ~15% and opex / transport costs of ~$14.50 per boe on heavy oil CGU drive attractive netbacks ▪ Generating sustainable free funds flow at current commodity price strip ▪ Excess discretionary free funds flow after sustaining capital directed to accelerated organic growth, exploration land capture and evaluation, acquisitions, debt repayment and ultimately returns to shareholders
Conservative Capitalization and Risk Mitigation	▪ Credit facility maintained at $160 MM pro forma Edson disposition, drawn $95.7 MM, and $20 MM Term Loan at June 30, 2026 ▪ Risk management with hedging to protect capital investment plans and returns during growth ramp up ▪ Net Debt to Q2 2026 Annualized Adjusted Funds Flow[(1)] ~0.7x pro forma Edson Disposition ▪ Edson Disposition provides highly liquid shares readily available to fund RBY's organic growth plans, waterflood advancement and future acquisition opportunities
Management Alignment and Operational Excellence	▪ Strong management alignment with insider share ownership of 45.3% and 100% ownership of the Term Loan ▪ Six independent board members (50% women); Team-focused, inclusive corporate culture ▪ Focused operations using multi-lateral drilling technology from multi-well pads with limited surface footprint ▪ Negligible use of freshwater given no fracture stimulation and oil-based mud drilling systems ▪ Profitable solution gas conservation projects advancing to reduce emissions

1. *See Non-GAAP measures in Advisories*

2026 Strategic Priorities

Value Creation through Heavy Oil Multi-lat Driven Play Strategies

RUBELLITE ENERGY

- **Optimize Value and Free Funds Flow Generation from Base Assets**
- **Improve Capital Efficiencies**
- **Accelerate Advancement of Enhanced Oil Recovery on Core Assets**
- **De-risk Exploration Prospects & Grow Potential Asset Value**
- **High Grade Land Portfolio & Expand Prospect Inventory for Chosen Play Strategies**
- **Re-Establish Pristine Balance Sheet and Manage Risk**
- **Drive Operational Excellence and Capture Cost Efficiencies**

Additional Information

Sue Riddell Rose, President & CEO
Ryan Shay, Vice President, Finance & CFO

3200, 605 – 5 Avenue SW
Calgary, Alberta Canada T2P 3H5

APPENDIX

Historical Financing

Strong insider support for equity and subordinated debt financings

- Rubellite acquired all of Perpetual's Clearwater Assets for total consideration of $65.5 MM (including $59.2 MM in cash)
  - Incorporated on July 12, 2021; Clearwater Assets conveyed on July 15th
  - Plan of Arrangement closed on September 3rd
  - Equity Financings closed / released from Escrow on Oct 5, 2021
- $83.5 MM in Equity Financings (October 5, 2021)
  - $30.0 MM Brokered Sub-Receipts Financing (closed into escrow July 13th)
  - $20.0 MM Non-Brokered Private Placement
  - $33.5 MM Arrangement Warrant ("rights offering") – Fully Back-stopped
  - All components of the financings priced at $2.00/share
- $38.7 MM in Equity Financings (March 30, 2022)
  - $25.3 MM Brokered Financing; $13.4 MM Non-Brokered Private Placement
  - Both financings priced at $3.55/share
- $20.0 MM Flow-Through Equity Financing (March 28, 2023)
  - Non-Brokered Private Placement priced at $2.85/share
- $97.5 MM purchase of Buffalo Mission Energy (August 2, 2024)[1]
  - Funded with $11.3 MM in equity (5 million shares @ $2.25/share), expanded bank credit facilities and $20 MM third-lien Term Loan
- Recombination Transaction – Rubellite and Perpetual exchanged shares for Rubellite Energy Corp. by way of a Plan of Arrangement
  - Rubellite Energy Inc. shareholders received 1 Rubellite Energy Corp share for every 1 Rubellite Energy Inc share held
  - Perpetual shareholders received 1 Rubellite Energy Corp. share for every 5 Perpetual shares held (issuance of 13.7 MM shares to Perpetual shareholders)
  - Closed October 31, 2024
- $26.2 MM of Perpetual Senior Notes converted to Rubellite Energy Corp. shares
  - Closed October 31, 2024 with Recombination Transaction
  - 11.6 million shares at $2.25 per share based on the 5-day VWAP prior to the announcement of the Rubellite / Perpetual Recombination Transaction
- *$179.6 MM in equity raised to-date at average price of $2.35/share*
  - *Insiders have participated for $90.8 MM (~51%)*

1. *Based on the Rubellite's closing share price of $2.07 per share on August 2, 2024, the fair value of the share consideration was $10.4 million, resulting in a total purchase price of $96.6 million*

Commodity Price Risk Management

Position Details

	Sept 26	Q4 26	Q1 27	Q2 27	Q3 27	Q4 27	Cal28
WTI CAD/bbl Swap Volume (bbl/d) ($CAD/bbl)	- -	- -	- -	- -	- -	- -	- -
WTI USD/bbl Swap Volume (bbl/d) ($USD/bbl)	5,100 $67.00	5,400 $68.98	4,350 $71.31	4,350 $71.31	4,350 $71.31	4,350 $71.31	1,700 $70.03
WCS CAD/bbl Swap Volume (bbl/d) ($CAD/bbl)	- -	- -	- -	- -	- -	- -	- -
WCS Differential CAD/bbl Swap Volume (bbl/d) ($CAD/bbl)	- -	- -	- -	- -	- -	- -	- -
WCS Differential USD/bbl Swap Volume (bbl/d) ($USD/bbl)	4,800 ($12.41)	3,000 ($13.18)	- -	- -	- -	- -	- -
AECO CAD/GJ Swap Volume (GJ/d) ($CAD/GJ)	- -	- -	- -	- -	- -	- -	- -
NYMEX Swap(Sell) Volume (MMbtu/d) ($USD/MMbtu)	- -	- -	- -	- -	- -	- -	- -
CAD/USD FX Swap Notional period amount ($USD) ($USD/month) ($CAD/$USD) ($CAD/month)	$24,000,000 $8,000,000[1] $1.3957 $11,165,850	$24,500,000 $8,500,000[1] $1.3966 $11,870,850	$9,000,000 $3,000,000 $1.3700 $4,110,000	$9,000,000 $3,000,000 $1.3700 $4,110,000	$9,000,000 $3,000,000 $1.3700 $4,110,000	$9,000,000 $3,000,000 $1.3700 $4,110,000	$24,000,000 $2,000,000 $1.3700 $2,740,000
CAD/USD FX Knock-in Option Notional period amount ($USD) ($USD/month) ($CAD/$USD) Floor ($CAD/$USD) Ceiling ($CAD/$USD) Reset	- - - - -	- - - - -	$9,000,000 $3,000,000 $1.4000 $1.4400 $1.4200	$9,000,000 $3,000,000 $1.4000 $1.4400 $1.4200	$9,000,000 $3,000,000 $1.4000 $1.4400 $1.4200	$9,000,000 $3,000,000 $1.4000 $1.4400 $1.4200	- - - - -

1. At expiry on December 31, 2026, if the Calendar 2027 forward strip is above $1.3890 $CAD/$USD, Rubellite knocks into a $5.0 million $USD/month contract at $1.3890 for calendar 2027

Operational Excellence

Striving for continuous performance improvement

Environment

Water: Oil based mud drillings with no fresh water-based fracture stimulation in Clearwater play and minimal fresh water usage in the Mannville Stack area

Land: Surface footprint minimized with multi-well pad development. Onsite drill cutting cleaning and oil-based mud recovery reduce trucking and landfill waste

Air: Gas conservation project implemented to drive **emissions reductions.** Lower emissions pad site battery design implemented. Consolidated land positions present future pipeline tie-in opportunities to reduce trucking

Innovation: Engaged with industry **clean** tech alliances to drive **sustainable solutions**

Social

- **Ranked #1** out of 243 oil and gas companies on **Workplace Compensation Board** scorecard
- Comprehensive health and safety program driving strong performance
- Community-focused **Indigenous relations** approach based on **listening** and **capacity building**
- **Joint Venture operations with Metis and First Nations communities**
- Extensive and purposeful **Indigenous contractor engagement strategy**
- Over **$2 MM** donated to the United Way of Calgary since Perpetual / Rubellite team's inception in 2003
- Leadership and volunteer involvement in industry, community and charitable organizations

Governance

- Environment, Health and Safety programs and performance oversight since inception
- Performance-based compensation practices
- Triple Zero EH&S Goal of Zero spills/Zero injuries/Zero vehicle accidents embedded in operational excellence bonus
- Field and office team have **long established tenure** of working together through **20 year+** operating history
- Values-driven corporate culture rooted in **'Be In Spirit'** principles
- Inclusion element of DEI firmly embedded in corporate culture and accountability practices
- **50% female** representation on Board

ADVISORIES

Advisories – General and Forward-Looking Information

General

This Corporate Overview (this "presentation") of Rubellite Energy Corp. ("Rubellite", "RBY" or the "Company") is for discussion and information purposes only and any unauthorized use is strictly prohibited. These materials should be read in conjunction with the Company's most recently filed Annual Information Form, the unaudited condensed consolidated interim financial statements for the period ended June 30, 2026 and Management's Discussion and Analysis for the period ended June 30, 2026 ("June 30, 2026 MD&A") which are available on SEDAR+ at www.sedarplus.ca. The additional advisories, disclaimers, cautionary statements and other risk factors contained therein are incorporated by reference herein.

This presentation contains information relating to Rubellite's business as well as historical and projected future performance, Rubellite expectations, forecasts and guidance and other market data. When considering this data, investors should bear in mind that historical results and market data may not be indicative of the future results that investors should expect from Rubellite. Moreover, you should assume that the information appearing herein (including the illustrative outlooks, projections, forecasts, estimates and guidance contained herein) is accurate as of the date on the front cover of this presentation only. Rubellite's business, financial condition, results of operations and prospects may change after such date. Accordingly, this presentation is subject to updating, completion, revision, verification and amendment at any time without notice which may result in material changes.

By accessing this presentation, you will be deemed to acknowledge and agree to the matters set forth above and below.

The information contained in this presentation does not purport to be all-inclusive or to contain all information that prospective investors may require, nor does it provide any legal, tax, financial, accounting or investment advice. Prospective investors are encouraged to conduct their own analysis and reviews of the Company and of the information contained in this presentation. Prospective investors should consult their own professional advisors to assess their potential investment in the Company and before making an investment decision. An investment in the Common Shares is subject to a number of risks that should be considered by a prospective investor. In this presentation, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this presentation demonstrating the historical performance of the Company or of any other entity are intended only to illustrate past performance and are not necessarily indicative of future performance of the Company. Certain totals, subtotals and percentages may not reconcile due to rounding. See also "Forward-Looking Information" and "Non-GAAP and Other Financial Measures" below and in the June 30, 2026 MD&A and "Risk Factors" in the Company's most recently filed Annual Information Form.

Forward-Looking Information

Certain information in this presentation including management's assessment of future plans and operations, and including, without limitation the information contained under the headings "Corporate Profile" (including "Investment Highlights"), "Heavy Oil Asset Performance", "Rubellite Asset Profile", "Marten Hills and Dawson Swap", "East Edson Disposition", "Net Asset Value ("NAV")", "Converting FMV of Undeveloped Land to Reserve-based NAV", "Heavy Oil Development Inventory YE 2025", "Figure Lake Primary Development Type Curves", "Southern Clearwater Enhanced Oil Recovery Pilots", "Figure Lake 9-35 Waterflood Line Drive Pilot", "Figure Lake 'Texas Four-Step' Waterflood", "Frog Lake Type Curves", "Exploration Prospect Pipeline", "Waterflood and Enhanced Oil Recovery 'Size of the Prize'", "2026 Annual Exploration and Development Spending", "Balance Sheet and Guidance – Pro Forma Edson Disposition", "Commodity Price Risk Management", "Creating Differentiated Value for Shareholders", "2026 Strategic Priorities" and "Operational Excellence" may constitute forward-looking information or statements (together "forward-looking information") under applicable securities laws. The forward-looking information includes, without limitation, statements with respect to: future capital expenditures, production and various cost forecasts; the anticipated sources of funds to be used for capital spending; expectations as to future exploration, development and drilling activity, and the benefits to be derived from such drilling including drilling techniques, pilot projects and production growth; the plan to advance strategic initiatives including multiple enhanced oil recovery pilots, exploration activities, new land capture, capital spending activities in the Company's core properties at Figure Lake and Frog Lake, anticipated average heavy oil sales volumes and total production sales volumes in 2026; the expectation that capital spending activity will be funded from adjusted funds flows, with excess free funds flow to reduce net debt and for other balance sheet obligations; operating and transportation cost forecasts 2026; the expectation that blending demand for Clearwater and Mannville Stack heavy oil will continue to translate into attractive offsets to WCS benchmark pricing, planned ARO spending; the anticipated number of drilling rigs to operate for the remainder of 2026; Rubellite's business plan.

Forward-looking information is based on current expectations, estimates and projections that involve a number of known and unknown risks, which could cause actual results to vary and in some instances to differ materially from those anticipated by Rubellite and described in the forward-looking information contained in this presentation. In particular and without limitation of the foregoing, material factors or assumptions on which the forward-looking information in this presentation is based include: the successful operation of the Company's assets, forecast commodity prices and other pricing assumptions; forecast production volumes based on business and market conditions; foreign exchange and interest rates; near-term pricing and continued volatility of the market; accounting estimates and judgments; future use and development of technology and associated expected future results; the ability to obtain regulatory approvals; the successful and timely implementation of capital projects; ability to generate sufficient cash flow to meet current and future obligations and future capital funding requirements (equity or debt); the ability of Rubellite to obtain and retain qualified staff and equipment in a timely and cost-efficient manner, as applicable; the retention of key properties; forecast inflation, supply chain access and other assumptions inherent in Rubellite's current guidance and estimates; climate change; severe weather events (including wildfires, floods and drought); the continuance of existing tax, royalty, and regulatory regimes; the accuracy of the estimates of reserves volumes; ability to access and implement technology necessary to efficiently and effectively operate assets; risk of wars or other hostilities or geopolitical events (including the ongoing war in Ukraine and conflicts in the Middle East, South America and elsewhere), civil insurrection and pandemics; risks relating to Indigenous land claims and duty to consult; data breaches and cyber attacks; risks relating to the use of artificial intelligence; changes in laws and regulations, including but not limited to tax laws, royalties and environmental regulations (including greenhouse gas emission reduction requirements and other decarbonization or social policies) and including uncertainty with respect to the interpretation and impact of omnibus Bill C-59 and the related amendments to the Competition Act (Canada), and the interpretation of such changes to the Company's business; political, geopolitical and economic instability; trade policy, barriers, disputes or wars (including new tariffs or changes to existing international trade requirements) and general economic and business conditions and markets, among others.

Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described herein and under "Risk Factors" in Rubellite's most recently filed Annual Information Form and the June 30, 2026 MD&A and in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR+ website (www.sedarplus.ca) and at Rubellite's website (www.rubelliteenergy.com). Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Rubellite's management at the time the information is released, and Rubellite disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities law.

Advisories – Oil and Gas Advisories

This presentation contains certain oil and gas industry metrics which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this document to provide readers with additional measures to evaluate Rubellite's performance; however, such measures are not reliable indicators of Rubellite's future performance and future performance may not compare to Rubellite's performance in previous periods and therefore such metrics should not be unduly relied upon.

BOE Volume Conversions

The term "boe" means barrel of oil equivalent, which in accordance with NI 51-101, is on the basis of 1 boe to 6,000 cubic feet of natural gas. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6,000 cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indicator of value as the value ratio between natural gas and heavy crude oil, based on the current prices of natural gas and crude oil, differ significantly from the energy equivalency of 6 Mcf:1 bbl.

Throughout this presentation, "heavy crude oil" "crude oil" or "oil" refers to heavy crude oil product types as defined by NI 51-101. References to "NGL" through this presentation comprise pentane, butane, propane and ethane, being all NGL as defined by NI 51-101. References to "natural gas" throughout this presentation refers to conventional natural gas as defined by NI 51-101.

Initial Production Rates

Any references in this presentation to initial production rates, including IP30, IP60, IP90, IP180 and IP270 are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter and are not necessarily indicative of long-term performance or ultimate recovery. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. Such rates are based on field estimates and may be based on limited data available at the time.

Reserves Disclosures

All reserve references in this presentation are to gross reserves as at the effective date of the applicable evaluation. The reserves estimates contained herein for the 2025 YE were derived from reserves assessments and evaluations prepared by McDaniel & Associates Consultants Ltd. ("McDaniel"), qualified independent reserve evaluator, with an effective date of December 31, 2025 and a preparation date of March 10, 2026 (the "McDaniel Report"), prepared in accordance with National Instrument 51-101 ("NI 51-101") and the most recent publication of the Canadian Oil and Gas Evaluations Handbook (the "COGE Handbook"). Reserve estimates for prior years were evaluated by independent qualified evaluators with an effective date of December for the applicable year unless otherwise stated. The reserve data provided in this presentation presents only a portion of the disclosure required under NI 51-101. All of the required information is contained in the Company's Annual Information Form ("AIF") for the year ended December 31, 2025 filed on SEDAR+ (accessible at www.sedarplus.ca).

Mid-Year 2026 Mechanical Update

Certain reserves, future net revenue and net asset value information in this presentation is presented as at June 30, 2026, and has been derived from an internal mechanical update of the McDaniel Report (the "Mechanical Update") rather than from a new, updated or independent reserves evaluation. The purpose of the Mechanical Update is to reflect recent well drilling activity through H1/26, acquisitions, dispositions and the July 1, 2026, three consultant average price forecast. A mechanical update is the re-running of an existing reserves evaluation to give effect to a limited and specified number of inputs, without any re-evaluation of the underlying technical or economic parameters of that evaluation. In preparing the Mechanical Update, the reserves, production forecasts and future net revenue in the McDaniel Report were adjusted only to give effect to: (i) actual production for the six months ended June 30, 2026; (ii) the Marten Hills/Dawson asset exchange, which closed on June 30, 2026; (iii) wells drilled (25 producers and two injectors), completed and brought on production during the H1/26 period, using the type well parameters applied in the McDaniel Report unless results varied significantly from undeveloped type curve forecasts (see note (v)); (iv) the July 1, 2026 three consultant average forecast price and cost assumptions; (v) adjustments to forecast rates and reserve volumes on 26 producing wells (seven new drills and 19 "base wells" which were Proved Developed Producing at Year End 2025 in the McDaniel Report) to align with actual production performance through December 31, 2025 to June 30, 2026; (vi) rescheduling of undeveloped locations and spending to H2/26, which were originally scheduled in H1/26, that did not yet occur; (vii) adjustment to abandonment and reclamation obligations based on actual spending through H1/26 and inclusion of new wells drilled. No other inputs were changed.

While the Mechanical Update was originally prepared with the Company's Edson assets (as at June 30, 2026), all values and references to the Mid-Year 2026 Mechanical Update within the context of this presentation are excluding the Edson Property to reflect the impact of the disposition of the Company's Edson assets, which closed on September 8, 2026.

Other than as described above, the Mechanical Update does not reflect any re-evaluation of well performance, decline parameters, undeveloped type curve assumptions, recovery factors, future undeveloped location bookings, future development capital, operating cost estimates or decommissioning obligations. No reserves have been added, reclassified or removed other than as described above. The Mechanical Update was prepared internally by the Company under the supervision of a qualified reserves evaluator as that term is defined in NI 51-101, in accordance with NI 51-101 and the COGE Handbook to the extent applicable to an update of this nature. It has not been prepared, evaluated, reviewed or audited by McDaniel or by any other independent qualified reserves evaluator. A mechanical update is not a substitute for an independent reserves evaluation, and readers are cautioned that material changes other than those given effect in the Mechanical Update may have occurred since December 31, 2025. The intent of this Mechanical Update is to reflect H1/26 activity, the updated reserves value on the July 1, 2026, three consultant average price deck, and the acquisition and disposition activities that occurred. Other than as described in this presentation and in the Company's continuous disclosure record filed on SEDAR+, the Company is not aware of any material change in the information contained in the McDaniel Report.

Advisories – Oil and Gas Advisories (continued)

Reserves Disclosures (continued)

Had a reserves evaluation been prepared by an independent qualified reserves evaluator with an effective date of June 30, 2026, the resulting estimates of reserves and future net revenue could differ from those derived from the Mechanical Update, and those differences could be material. The Mechanical Update is supplementary interim disclosure; it does not replace, and should not be read in substitution for, the reserves data contained in the AIF. Note that the McDaniel Report was prepared on the basis of an overall evaluation of the reserves of the Company and that individual property reserve estimates may not reflect the same confidence level as required by the reserve's definitions for the overall group of properties.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only and there is no guarantee that the estimated reserves will be recovered. In general, estimates of economically recoverable crude oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

All evaluations and reviews of future net revenue are stated prior to any provisions for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis and utilizes the Company's tax pools. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the after-tax value of the Company, which may be significantly different. The Company's financial statements and the June 30, 2026 MD&A should be consulted for information at the level of the Company. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to effects of aggregations. The estimated values of future net revenue disclosed in this presentation do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

This presentation contains the reserves measures such as FDC, F&D costs per boe, FD&A costs per boe, Adjusted F&DA costs per boe, recycle ratio and replacement. These measures have been calculated on a total company basis and based on the Heavy Oil CGU.

"Estimated ultimate recovery" or ("EUR") represents the estimated ultimate recovery of resources included in the McDaniel Reserve Report.

"Finding and Development Capital" ("FDC") is comprised of total exploration and development costs incurred on reserves that are categorized as development reserves. For this calculation, development capital includes land expenditures and excludes acquisitions and dispositions.

"Finding and development" ("F&D") costs per boe are calculated as the sum of the non-GAAP measure "total capital expenditures" (as calculated above) less corporate spending, plus the change in FDC for the period divided by the change in reserves that are characterized as development for the period which takes into account reserve revisions during the period. This measure is then divided by the Company's total sales production on a per barrel basis. The aggregate of the total capital expenditures, less corporate spending, incurred in during the period and changes during that period in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that period.

"Finding, development and acquisition" ("FD&A") costs per boe are calculated as the sum of development costs, acquisition and disposition costs and the change in FDC for the period, divided by the reserves within the applicable reserves category, including changes due to acquisitions and dispositions.

"Adjusted finding and development" ("F&D") costs per boe are calculated as the sum of development costs, adjusted for the cash proceeds of acquisitions and dispositions, rather than the net back value component used in determining F&D costs. The change for the period, is then divided by the reserves within the applicable reserves category.

"Recycle ratio" is calculated by dividing the non-GAAP measure "operating netback" by F&D costs per boe. The recycle ratio compares the netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are equivalent quality as the produced reserves.

"Production replacement" measures how much annual production has been replaced by new reserve additions. It is calculated by taking the total change in reserves on a per boe basis divided by the annual sales production on a per boe basis.

"NPV10" is the net present value (net of capital expenditures) of the operating income of a well from the McDaniel's report discounted at a 10% discount rate.

Advisories – Oil and Gas Advisories (continued)

Commodity Price Assumptions

The table below summarizes the various price assumptions represented in this presentation. Prices in the Year End 2025 McDaniel Report are based on the Three Consultant Average Price Forecast at January 1, 2026. Additional details can be found in the Company's Annual Information Form.

	Three Consultant Average																			
	YE 2024				YE 2025				July 1, 2026 [(1)]				September 1, 2026 Strip [(1)]				$70 WTI Constant			
Year	WTI ($US/bbl)	Exchange Rate ($US/$CAN)	WCS ($C/bbl)	AECO ($C/mmbtu)	WTI ($US/bbl)	Exchange Rate ($US/$CAN)	WCS ($C/bbl)	AECO ($C/mmbtu)	WTI ($US/bbl)	Exchange Rate ($US/$CAN)	WCS ($C/bbl)	AECO ($C/mmbtu)	WTI ($US/bbl)	Exchange Rate ($US/$CAN)	WCS ($C/bbl)	AECO ($C/mmbtu)	WTI ($US/bbl)	Exchange Rate ($US/$CAN)	WCS ($C/bbl)	AECO ($C/mmbtu)
2026	74.48	0.728	84.27	3.73	59.92	0.728	65.13	3.00	72.33	0.717	82.04	2.16	87.54	0.722	97.87	2.11	70.00	0.735	76.16	3.17
2027	75.81	0.743	83.81	3.85	65.10	0.737	70.43	3.30	73.17	0.730	81.49	2.75	75.26	0.730	80.66	2.06	70.00	0.735	76.16	3.17
2028	77.66	0.743	85.70	3.93	70.28	0.740	76.90	3.49	74.01	0.737	81.71	3.12	69.67	0.739	72.62	2.54	70.00	0.735	76.16	3.17
2029	79.22	0.743	87.45	4.01	71.93	0.740	78.71	3.58	73.31	0.737	80.82	3.43	67.18	0.746	68.63	2.58	70.00	0.735	76.16	3.17
2030	80.80	0.743	89.25	4.09	73.37	0.740	80.29	3.65	74.78	0.737	82.44	3.50	64.80	0.752	65.05	2.61	70.00	0.735	76.16	3.17
thereafter	+2%/yr	constant	+2%/yr	+2%/yr	+2%/yr	constant	+2%/yr	+2%/yr	+2%/yr	constant	+2%/yr	+2%/yr	+2%/yr	constant	+2%/yr	+2%/yr	constant	constant	constant	constant

1. *For 2026, the July 1, 2026 three consultant average ("3CA") forecast and the September 1, 2026 Strip price forecast reflect only the remaining months of the 2026 calendar year*

Advisories – Oil and Gas Advisories (continued)

Net Asset Value ("NAV")

NAV is calculated as total proved plus probable reserves as per the McDaniel Report, plus independently verified third party valuation of undeveloped lands, less net debt and the other provision at an undiscounted value. This measure is used to show the net asset value of the Company at a point in time under which the reserves are produced at forecasted future prices and costs.

Original Oil in Place ("OOIP")

OOIP is that quantity of petroleum that is estimated to originally exist in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. A portion of the OOIP is considered undiscovered and there is no certainty that any portion of such undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such undiscovered resources. With respect to the portion of the OOIP that is considered discovered resources, there is no certainty that it will be commercially viable to produce any portion of such discovered resources. A significant portion of the estimated volumes of OOIP will never be recovered. OOIP disclosed herein was internally estimated by the Company. There is no certainty that the Company's OOIP estimates were prepared in accordance with the COGE Handbook. The estimates may not be comparable to similar measures presented by other companies and therefore should not be used to make such comparisons.

Internal rate of return ("IRR")

IRR is a rate of return measure used to compare the profitability of an investment and represents the discount rate at which the net present value of costs equals the net present value of the benefits. The higher a project's IRR, the more desirable the project.

Rate of return ("ROR")

ROR is a rate of return measure used to compare the profitability of an investment and represents the discount rate at which the net present value of costs equals the net present value of the benefits. The higher the ROR, the more desirable the project.

Per Flowing barrel

Per flowing barrel is a metric used to estimate the value of assets acquired and is calculated by dividing the cost of acquired assets by the number of barrels it produces.

Payouts

Payout is calculated as the time at which a well or project's cumulative operating netback equals total capital expenditures. Before payout or "BPO" is the working interest before the point in time when the well has recovered from production all costs stated in the underlying farmout or arrangement. After payout or "APO" is the working interest after the point in time when the well has recovered from production all costs stated in the underlying farmout or arrangement.

Average capital efficiency

Capital efficiency is calculated as total capital to drill, complete, equip and tie in a well divided by bbl/d based on IP30 in $/flowing bbl/d.

Recovery factor

Recovery factor is defined as the estimated amount of hydrocarbons that can be produced from a reservoir relative to the original amount in place, expressed as a percentage.

FMV of Land

FMV of land means the fair market value of Rubellite's land with no reserves assigned as assessed by an independent third party, Seaton-Jordan & Associates Ltd., as at December 31, 2025 in a report dated January 26, 2026 (the "Seaton-Jordan Report"). No land value in the Seaton-Jordan Report is assigned where reserves have already been booked, even if the corresponding lease contains multiple prospective formations that have not yet been assigned reserves. Estimates of the value of Rubellite's acreage presented in the Seaton-Jordan Report was prepared in accordance with NI 51-101 5.9(1)(e) for purposes of the net asset value calculation and is based on past Crown land sale activity, adjusted for tenure and other considerations.

All land is shown net to Rubellite's working interest, which includes after payout working interest and 50% at Frog Lake based on Joint Economic Development ("JED') agreements.

Advisories – Oil and Gas Advisories (continued)

Type Curves

The Company's management has prepared a waterflood type curve to illustrate the potential production uplift associated with a waterflood development. The type curve is intended only to demonstrate potential incremental production attributable to waterflooding under the Company's planned injection design and operating assumptions and does not represent a forecast, prediction or estimate of future performance for any specific well, group of wells or reservoir. Type curves are not derived from reservoir simulation, waterflood modeling, or internal technical analysis of reservoir response and should not be construed as indicative of actual future production, recovery factors, reserves additions, economics or project performance. There is no certainty that Rubellite will ultimately recover such volumes from the wells it drills. Actual results may vary materially from both primary and waterflood incremental curve estimates.

Actual production and recovery associated with any waterflood development are subject to numerous uncertainties and risks, including but not limited to reservoir characteristics, geological variability, fluid properties, injection performance, pressure support, operational execution, commodity prices, regulatory approvals, capital availability, weather, mechanical performance and other factors, many of which are beyond the Company's control.

There can be no assurance that waterflood performance will be consistent with the assumptions reflected in the type curve or that the Company will ultimately recover the volumes illustrated. Refer to the Company's advisory regarding forward-looking information and oil and gas disclosures contained elsewhere in this Presentation.

Drilling Locations

This presentation discloses drilling locations in three categories: (i) booked locations, (ii) unbooked development / step-out delineation locations, and (iii) exploration / appraisal locations. Booked locations are proved and probable locations derived from an external evaluation (McDaniel Reports) using standard practices as prescribed in COGE Handbook and account for drilling locations that have associated proved and/or probable reserves, as applicable.

Unbooked locations are internal estimates based on Rubellite's prospective acreage and assumptions as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. Unbooked development and step-out delineation locations are located within the mapped outline of existing Clearwater, Waseca and GP zones where economic production has been established. Exploration and appraisal locations are those locations identified by management in areas considered prospective or with known resource, but lacking in commercial production history or Type Curves, and which require additional drilling and/or production history to be proven economic and should therefore be considered higher risk.

Of the 476 net heavy oil drilling development locations disclosed in this presentation, 101.6 net are proved and 53.6 net are probable undeveloped locations in the McDaniel Year-end 2025 Report. As of June 30, 2026, there are greater than 430 net exploration / appraisal locations targeting heavy and medium crude oil plays.

There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Third Party Information

This presentation includes market, industry and economic data which was obtained from various publicly available sources and other sources believed by Rubellite to be true. Although Rubellite believes it to be reliable, it has not independently verified any of the data from third party sources referred to in this presentation or analyzed or verified the underlying reports relied upon or referred to by such sources or ascertained the underlying economic and other assumptions relied upon by such sources. Rubellite believes that its market, industry and economic data is accurate and that its estimates and assumptions are reasonable, but there can be no assurance as to the accuracy or completeness thereof. The accuracy and completeness of the market, industry and economic data used throughout this presentation are not guaranteed and Rubellite makes no representation as to the accuracy of such information.

Advisories – Oil and Gas Advisories (continued)

Abbreviations

bbl	barrels
bbl/d	barrels per day
boe	barrels of oil equivalent
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
Mcf	thousand cubic feet
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Bcf	billion cubic feet
WCS	Western Canadian Select
D,C,E&T	Drill, complete, equip and tie-in capital expenditures
FMV	Fair market value
TP	Total proved reserves in the McDaniel Report
TPP	Total proved plus probable reserves in the McDaniel Report
P+PDP	Locations in the proved plus probable developed category in the McDaniel Report
P+PUD	Locations in the proved plus probable undeveloped category in the McDaniel Report
PD	Locations in the proved developed category in the McDaniel Report
PDP	Locations in the proved developed producing category in the McDaniel Report
PUD	Locations in the proved undeveloped category in the McDaniel Report

Advisories – Risk Management Contracts

Risk Management Contracts

"Hedge" or risk management contract positions by product, current to September 4, 2026, are as follows:

Commodity	Volumes Sold (bbl/d)	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/bbl)
Crude Oil	5,100 bbl/d	Sep 2026	WTI (US$/bbl)	Swap - sold	$67.00
Crude Oil	5,400 bbl/d	Oct 2026 - Dec 2026	WTI (US$/bbl)	Swap - sold	$68.98
Crude Oil	4,350 bbl/d	Jan 2027 - Dec 2027	WTI (US$/bbl)	Swap - sold	$71.31
Crude Oil	1,700 bbl/d	Jan 2028 - Dec 2028	WTI (US$/bbl)	Swap - sold	$70.03
Crude Oil	4,800 bbl/d	Sep 2026	WCS Differential (US$/bbl)	Swap - sold	($12.41)
Crude Oil	3,000 bbl/d	Oct 2026 - Dec 2026	WCS Differential (US$/bbl)	Swap - sold	($13.18)

Fixed Contract	Notional amount	Term	Price (CAD$/US$)
Average rate forward (CAD$/US$)	$2,500,000 US$/month	Sep - Dec 2026	1.4066
Average rate forward (CAD$/US$)[(1)]	$5,000,000 US$/month	Sep - Dec 2026	1.3890
Average rate forward (CAD$/US$)	$500,000 US$/month	Sep - Dec 2026	1.4086
Average rate forward (CAD$/US$)	$500,000 US$/month	Oct - Dec 2026	1.4100
Average rate forward (CAD$/US$)	$3,000,000 US$/month	Jan -Dec 2027	1.3700
Average rate forward (CAD$/US$)	$2,000,000 US$/month	Jan -Dec 2028	1.3700

(1) At expiry on December 31, 2026, if the calendar 2027 forward strip is above 1.3890 CAD$/US$, Rubellite knocks into a $5.0 million US$/month contract at 1.3890 CAD$/US$ for the 2027 calendar year.

Variable Contract	Notional amount	Term	Floor Price (CAD$/US$)	Ceiling Price (CAD$/US$)	Reset Price (CAD$/US$)
Knock-in Collar (CAD$/US$)	$3,000,000 US$/month	Jan - Dec 2027	1.4000	1.4400	1.4200

Advisories – Non-GAAP and Other Financial Measures

Throughout this presentation and in other materials disclosed by the Company, Rubellite employs certain measures to analyze financial performance, financial position and cash flow. These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss), cash flow from (used in) operating activities, and cash flow from (used in) investing activities, as indicators of Rubellite's performance. For those measures that are presented in the June 30, 2026 MD&A, see "Non-GAAP and Other Financial Measures" in that document for further information on the definition, calculation and reconciliation of the measure. Certain measures used in this presentation are not presented in the June 30, 2026 MD&A, including sustaining capital, leverage ratio, market capitalization, and heavy oil and total production per share; the composition of each of those measures is described below.

Non-GAAP Financial Measures

“Enterprise value” is equal to net debt plus the market value/capitalization of issued equity and is used by management to analyze leverage. Enterprise value is calculated by multiplying the current shares outstanding by the market price and then adjusting it by net debt. The Company considers enterprise value as an important measure as it normalizes the market value of the Company’s shares for its capital structure.

“Market capitalization” is calculated by multiplying the current shares outstanding by the market price. The Company considers market capitalization as an important measure as it is part of the calculation of enterprise value which normalizes the market value of the Company’s shares for its capital structure. For this presentation it is calculated based on total common shares outstanding of 94.0 million as at September 4, 2026 and 9.2 million share awards outstanding (excluding 1.0 million legacy Perpetual awards that are settled outside of treasury) and a share price, as at September 4, 2026, of $4.21 per share.

“Net debt” is calculated by adding borrowings under the credit facility and term loan debt less adjusted working capital. Adjusted working capital is calculated by adding cash, accounts receivable, prepaid expenses and deposits and product inventory less accounts payable and accrued liabilities. Management considers net debt as an important measure in assessing the liquidity of the Company.

“Available liquidity” is defined as the borrowing limit under the Company's credit facility, plus any cash and cash equivalents, less any borrowings and letters of credit issued under the credit facility.

“Adjusted working capital” deficiency or surplus is calculated by adding cash, accounts receivable, prepaid expenses and deposits and product inventory less accounts payable and accrued liabilities.

“Adjusted funds flow” is calculated based on net cash flows from operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations, other provisions and cash-settled share based compensation since the Company believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning and share based compensation obligations may vary from period to period and are managed as expenditures through the corporate budgeting process which considers available adjusted funds flow. Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations, expenditures on share based compensation and to meet its other financial obligations.

“Cash costs” is calculated as the total of net operating costs, transportation costs, general and administration costs (G&A) and cash finance expense divided by the Company’s total sales oil production. Management considers cash costs as an important measure to evaluate the Company’s efficiency and overall cost structure.

“Free funds flow” is calculated as adjusted funds flow generated during the period less total capital expenditures, excluding non-cash items and acquisitions and dispositions. Management uses certain industry benchmarks, such as free funds flow, to analyze financial and operating performance. Management believes that free funds flow provides a useful measure to determine the Company’s ability to improve returns and manage long-term value.

"Sustaining capital" is calculated as the portion of exploration and development spending that management estimates is required to offset natural production declines and hold average annual production flat, and excludes capital directed to growth, exploration, enhanced oil recovery, land, seismic, acquisitions and dispositions and corporate spending. Management uses sustaining capital to assess the adjusted funds flow available for growth, exploration, enhanced oil recovery, debt repayment and returns to shareholders; amounts presented are forward looking and are not presented in the June 30, 2026 MD&A.

“Capital expenditures”, “Capital”, “E&D Spending” are used to measure its capital investments compared to the Company’s annual capital budgeted expenditures. Rubellite’s capital budget excludes acquisition and disposition activities. Total capital expenditures includes exploration and development, land, geological and geophysical and corporate spending. Exploration and development spending is comprised of the non-GAAP measure total capital expenditures less land and other, geological and geophysical and corporate spending.

"Leverage ratio" is calculated as net debt, reduced by the market value of marketable securities held by the Company, divided by annualized adjusted funds flow for the most recently completed quarter. It differs from the net debt to annualized adjusted funds flow ratio presented in the June 30, 2026 MD&A, which does not deduct marketable securities. Management uses the leverage ratio to assess the Company's debt capacity and financial flexibility.

Advisories – Non-GAAP and Other Financial Measures

Non-GAAP Financial Ratios

"G&A ($ per boe)" is comprised of G&A expense, as determined in accordance with IFRS, divided by the Company's total sales oil production.

"Operating netback per boe" or "net operating income" is determined by deducting royalties, net operating expenses, and transportation costs from oil and natural gas revenue. Operating netback is also calculated on a per boe basis using total production sold in the period.

"Heavy oil operating netback per boe" is determined by deducting royalties, net operating expenses, and transportation costs on oil and natural gas revenue from the Heavy Oil Cash Generating Unit ("CGU") net of realized gains and losses from risk management contracts, as determined in accordance with IFRS, divided by the Company's Heavy Oil CGU total sales production, which includes conserved natural gas sales volumes.

"Operating costs" is comprised of net operating expense, as determined in accordance with IFRS, divided by the Company's total sales oil production.

"Transportation costs" is comprised of transportation expense, as determined in accordance with IFRS, divided by the Company's total sales oil production.

"Heavy oil wellhead differential" represents the differential the company receives for selling its heavy crude oil production relative to the Western Canadian Select reference price (CAD$/bbl) prior to any price or risk management activities.

"Royalties ($ per boe)" is comprised of royalties, as determined in accordance with IFRS, divided by the Company's total sales oil production.

"Heavy oil Production per share" is comprised of heavy oil production of the Heavy Oil CGU divided by the Company's total shares outstanding.