The Clearwater Advantage

Creating Sustainable Value



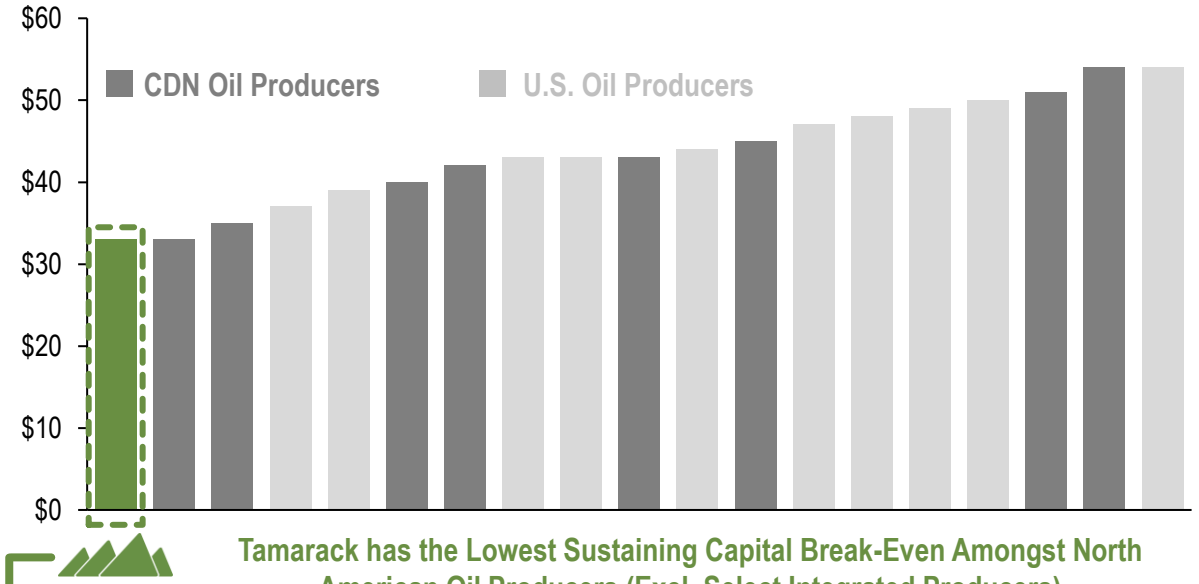
Tamarack: A Premier North American Oil Producer

A Dominant Position of High Margin Production In The Heart of the Clearwater

Corporate Overview		
Ticker	**Units**	**TSX - TVE**
Common Shares Outstanding[1]	*(MM)*	706
Share Price (Nov. 18, 2026)	*($/Sh.)*	$11.17
Market Capitalization	***($B)***	**$7.9**
Net Debt / (Cash)	***($B)***	**$(0.1)**
Enterprise Value	***($B)***	**$7.8**
Annual Dividend / Yield[2]	*($/Sh.) / %*	$0.24 / ~2.1%
Credit Facility (Undrawn)	*($MM)*	$875 MM
2026 Guidance Highlights		
Avg. Production[3]	*(Mboe/d)*	65.5 – 67.5
Capital Expenditures[4]	*($MM)*	$450 – $470
2027 Guidance Highlights		
Avg. Production[3]	*(Mboe/d)*	87.0 – 91.0
Oil & Liquids	*(%)*	94% – 96%
Capital Expenditures[4]	*($MM)*	$600 – $650

Sustainable Capital Breakeven (Excl. Dividends); US$/bbl

American Oil Producer Landscape (Market Cap. >C$5 Bln, Liquids Weighting >60%)[5]



Tamarack has the Lowest Sustaining Capital Break-Even Amongst North American Oil Producers (Excl. Select Integrated Producers)

Low Decline

*2027E **base decline of <15%** trending to ~10% through the 5-Yr plan (2031)*

Secondary Recovery

***>45% of asset base under EOR** forecasted to grow to **>60% under EOR** by YE 2027*

Low Sustaining Capital

***<20% sustaining reinvestment ratio** (sustaining capex / cash flow) at $75 WTI*

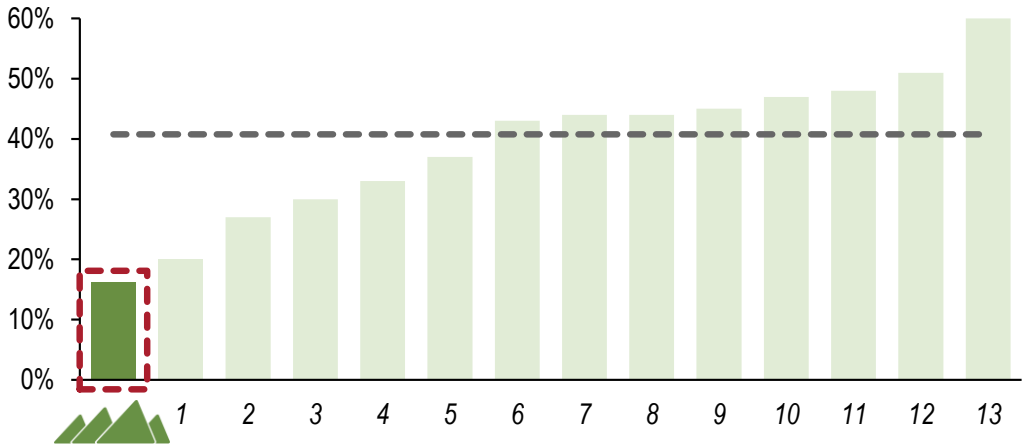
1) Expected share count as of closing of the Headwater Merger on Nov. 18, 2026.
2) Based on annualized base dividend of $0.24 per share. Dividend yield uses Tamarack share price as at Nov. 18, 2026.
3) 2026E Production of 65.5 – 67.5 boe/d: ~80% heavy oil, ~7% light oil, ~2% NGLs and ~10% natural gas.
   2027E Production of 87.0 – 91.0 boe/d: ~94% heavy oil, <1% NGLs and ~5% natural gas.
4) Capital expenditures excludes ARO spending.
5) 2026E average WTI price in 2026 needed to cover required capital to hold production flat based upon commodity prices of: Brent-WTI: $4.00/bbl, WCS-WTI: $14.00/bbl, Henry Hub: $3.25/mmBtu, NBP: $8.00/mmBtu, AECO: C$2.47/mcf, NYH 3-2-1 Crack Spread: $20.00/bbl, CAD/USD FX: 0.72.
   Source: RBC Capital Markets.

Tamarack: A Unique Value Proposition

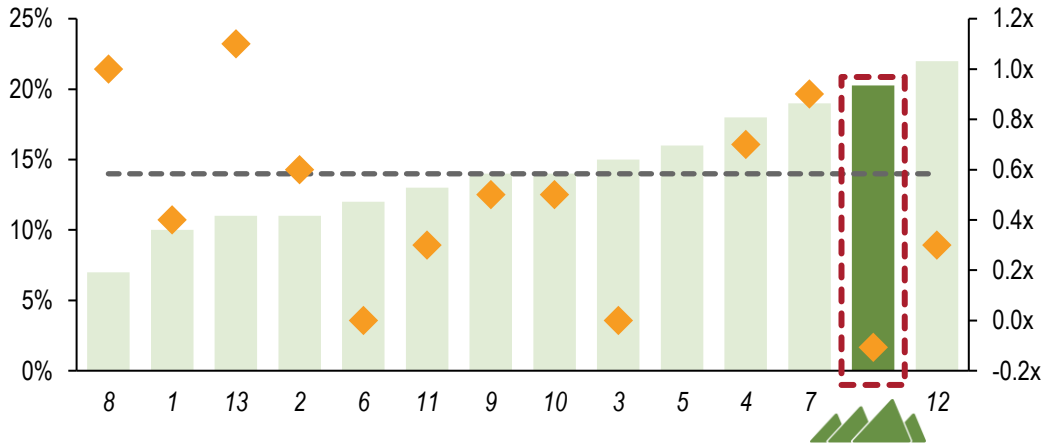
Growing Production & Lowering Decline Rates = Differentiated Returns

High Margin	• **Largest Clearwater Producer**: One of North America's Most Profitable Plays • **Breakeven Price of US$37/bbl WTI** (including dividends)
Duration	• **>18 Bln** Barrels of Original Oil in Place, <2% Produced by End 5-Year Plan • **>3,000 Primary** Drilling Locations (100 – 150 Primary Drills Per Year)
Resilience	• 2027E Sustaining **Reinvestment Ratio of <20%** • 2027E **Base Decline Rate of <15%** (Trending To ~10% by 2031E)
Balance Sheet	• **Net Cash** Position With **~$541 MM** of Cash On Balance Sheet (Q3/26) • **>$1.2 Bln In Available Funding**
Shareholder Returns	• **Significant Total Returns:** 10-12% Production Growth, 4-6% Share Buybacks, Plus ~2% Dividend Yield Each Year

2027E Large-Cap Peers: Sustaining Reinvestment Ratio (%)[1]



2027E Total Return vs. 2027YE Net Debt / LTM Funds Flow (% ; x)[2]



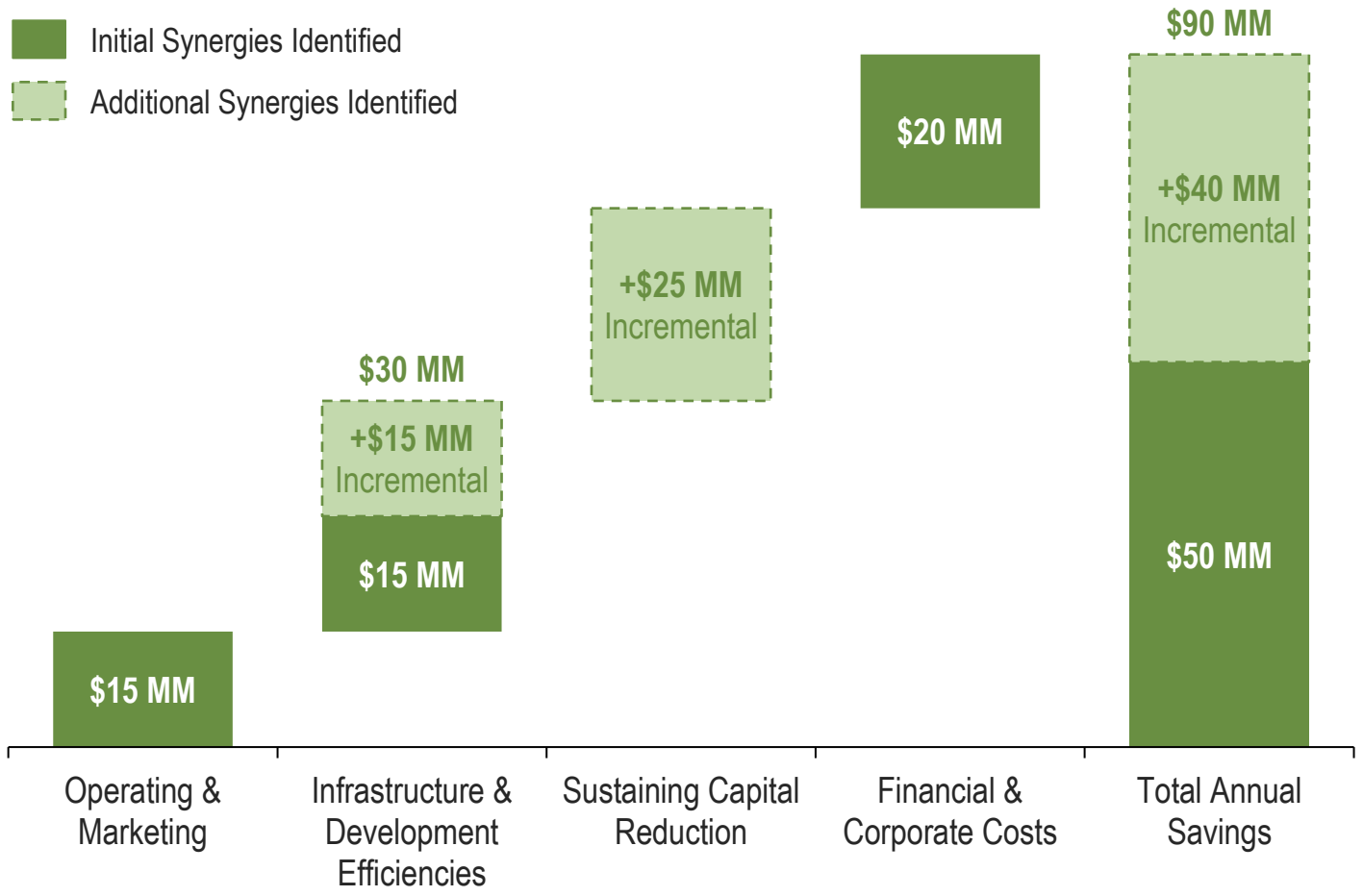
1) Estimates per Peters & Co. Calculated as sustaining capital to maintain flat production. Sustaining capital / funds flow on Nov. 16, 2026 strip. Peer group includes AR, CNQ, DVN, EOG, EQT, EXE, FANG, IMO, OVV, SCR, SU, TOU, and WCP.

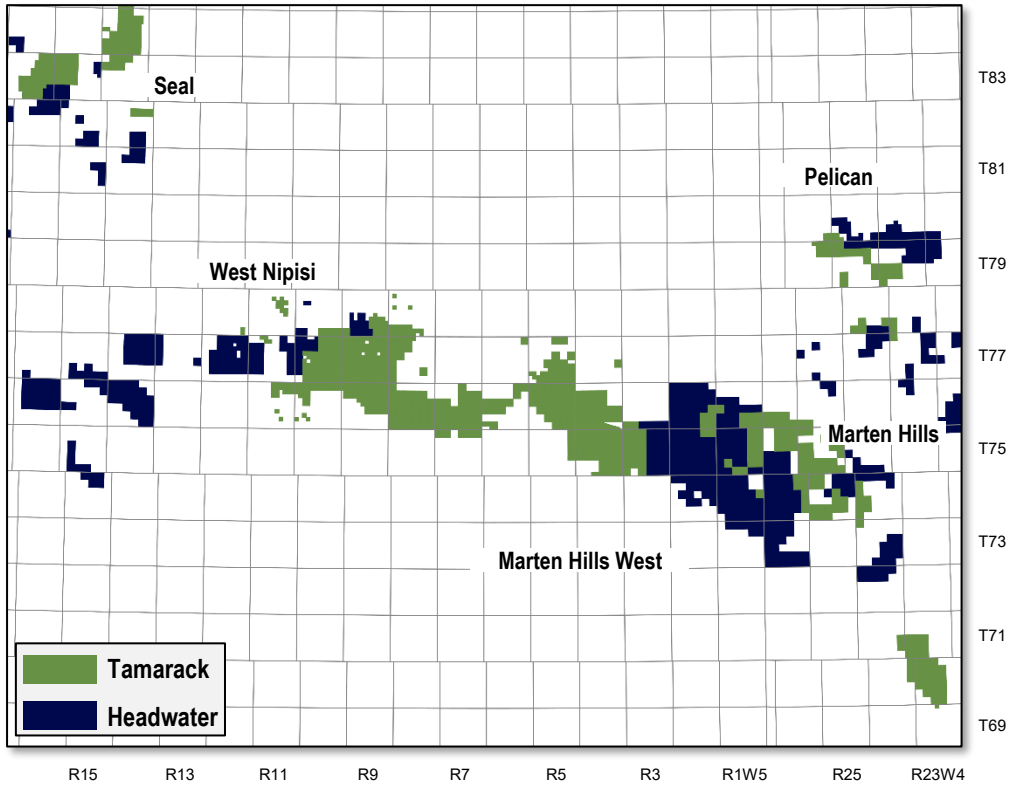
2) Large-cap 2027E total return at forward strip pricing. TVE 2027 total return at forward strip pricing. Peer group includes AR, CNQ, DVN, EOG, EQT, EXE, FANG, IMO, OVV, SCR, SU, TOU, and WCP. Peer data per Peters & Co. as at Nov. 16, 2026.
Large-cap defined as having a market cap approximately >=$10 Bln. Total return includes production growth and excess free funds flow.

Synergies: Unlocking Value Through Integration & Optimization

Safe Operational and Capital Synergies Drive Enhanced Value

Annual Near-Term Synergies ($MM; B-Tax)[1]





>$600 MM[2]
~~>$350 MM~~

Total Synergy Value Over The Plan[2]

1) Compares synergies identified at time of press release (Sep. 2026) vs. 2027 Budget press release (Nov. 2026).
2) NPV-10% over the plan (before tax)

2027 Guidance

More For Less At Greater Scale

2027 Capital Budget

$600 MM – $650 MM

~11% Reduction Over Prior Year Program
(On A Combined Basis)

Average 2027 Production

87,000 – 91,000 boe/d | 95% Liquids

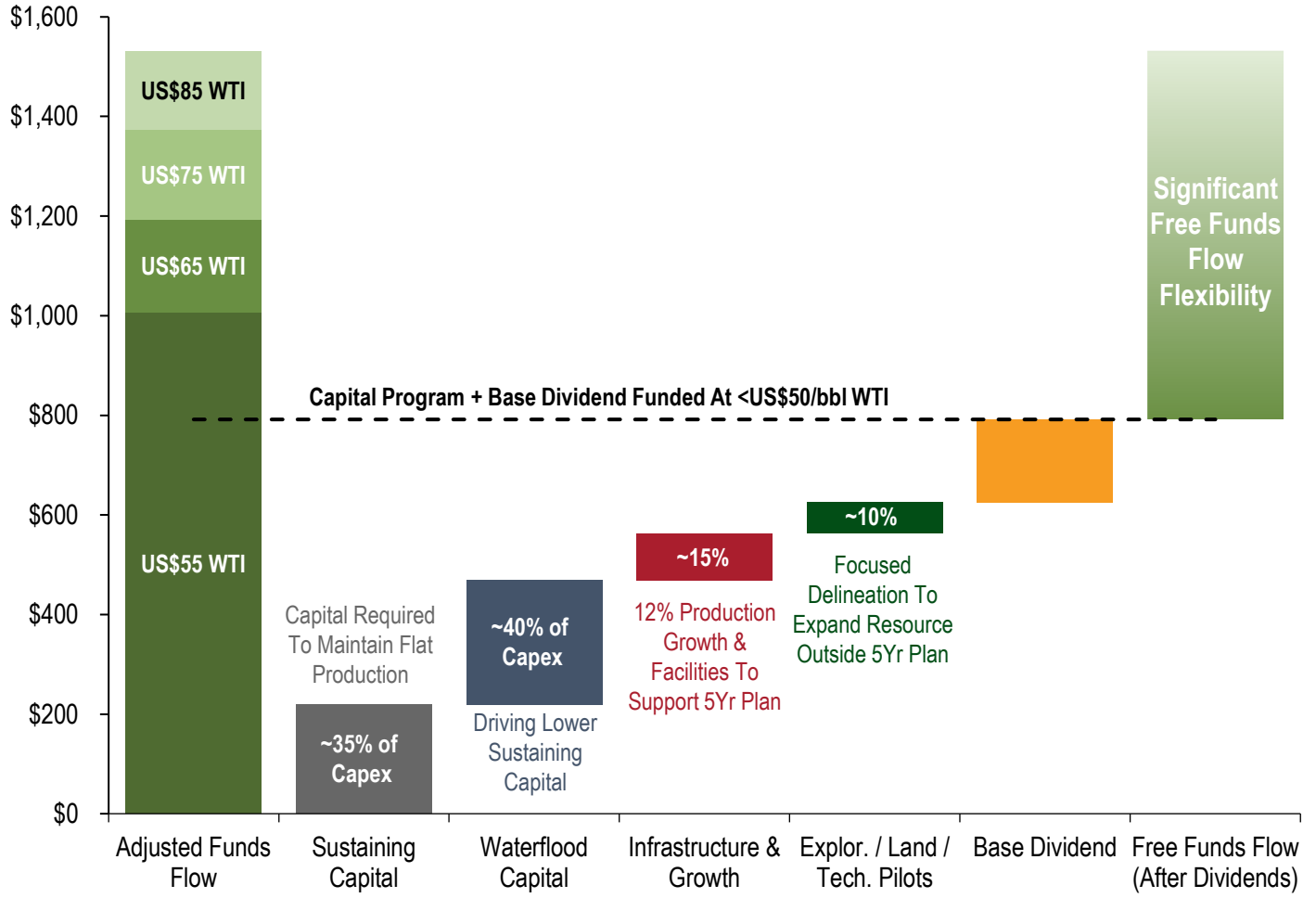
~12% Organic Growth Year Over Year

Balance Sheet Strength & Free Funds Flow Flexibility

Sustainable Dividend & Dynamic Share Repurchases

Opportunistic Resource Capture

Capital & Free Funds Flow Allocation ($MM)



See Disclaimers – "Specified Financial Measures".
All flat decks assume 1.35 US$/C$. WCS differentials for flat decks are as follows: US$(12.75), US$(13.25), US$(14.00), and US$(15.00) for the US$55/US$65/US$75/US$85 decks, respectively.

Five-Year Plan

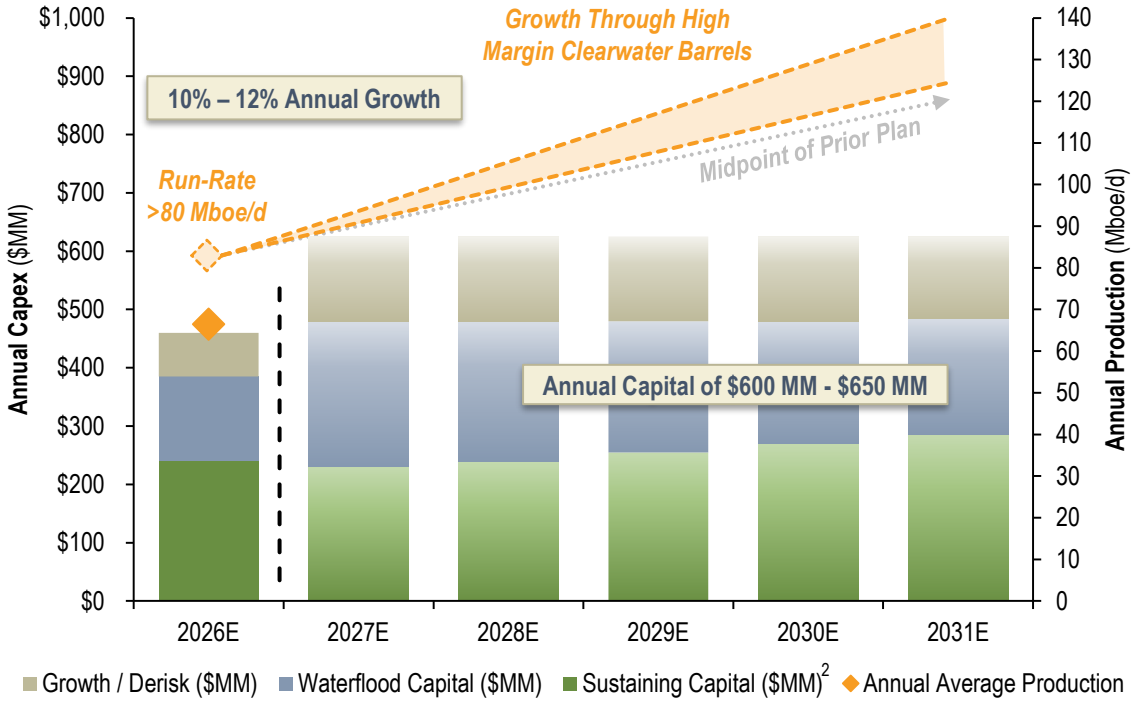
Tamarack Has The Unique Ability To Grow Production and Reduce Decline Rates Simultaneously

Waterflood Has Materially Reduced Base Decline Rates & Sustaining Capital Requirements[1,2]

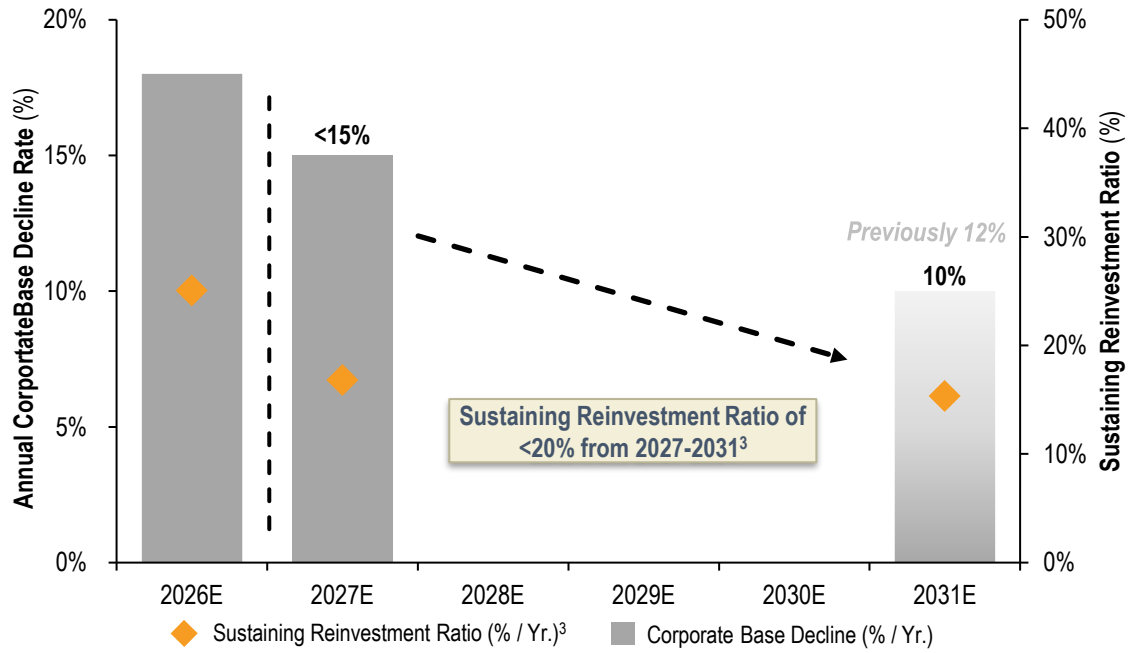
- **Production growth of 10% – 12% per year**, growing to ~130 Mboe/d in 2031
- Assumes $600 MM – $650 MM/yr. of capital in 2028+
  - Average capex / funds flow **reinvestment of <40%** from 2027-2031 with optionality for higher growth; sustaining capital of **<20% of funds flow**[3]

Emerging Exploration Area Development Currently Outside the 5-Year Plan & Offer Additional Upside

Long-Term Plan Capex & Production ($MM & Mboe/d)



Annual Corporate Base Decline & Sustaining Reinvestment Ratio (%)[3]



1) See Disclaimers – "Specified Financial Measures".
2) Sustaining capital includes well drill, complete, equip and tie-in including infrastructure required to support development to hold production flat and minimum annual ARO spending.
3) Based on $600 MM Annual Capital Program assuming flat US$75 WTI for 2027E to 2031E. Sustaining reinvestment ratio calculated as sustaining capital / adjusted funds flow.

Compounding Shareholder Returns

Earnings Growth Year Over Year

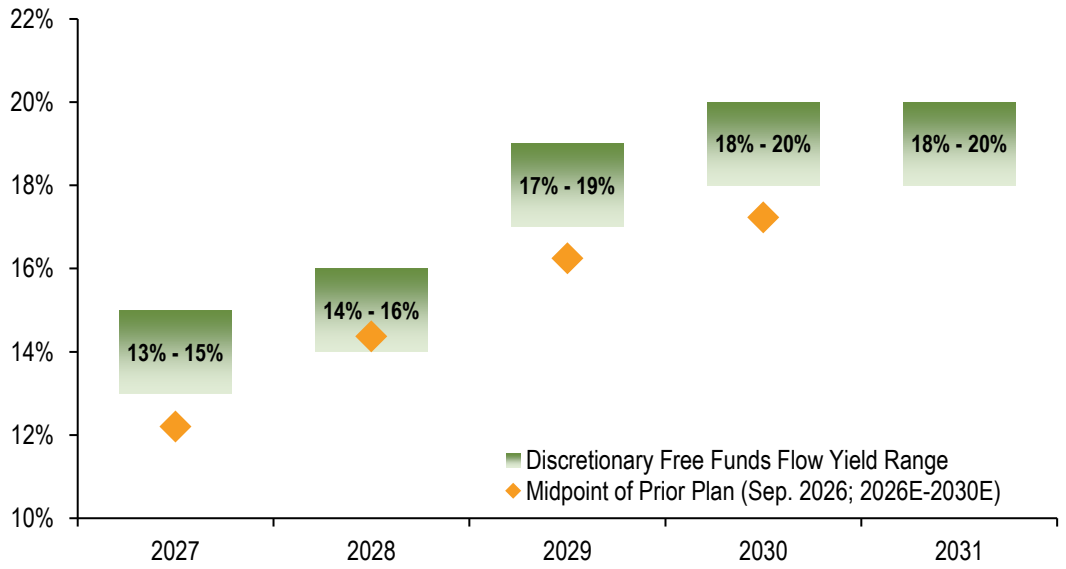
Discretionary Free Funds Flow Increases ~35% Through Long-Term Plan[2]

- Additional synergies identified (~$90 MM/yr. from ~$50 MM/yr.)
- Includes a ~$25 MM/yr. reduction to sustaining capital

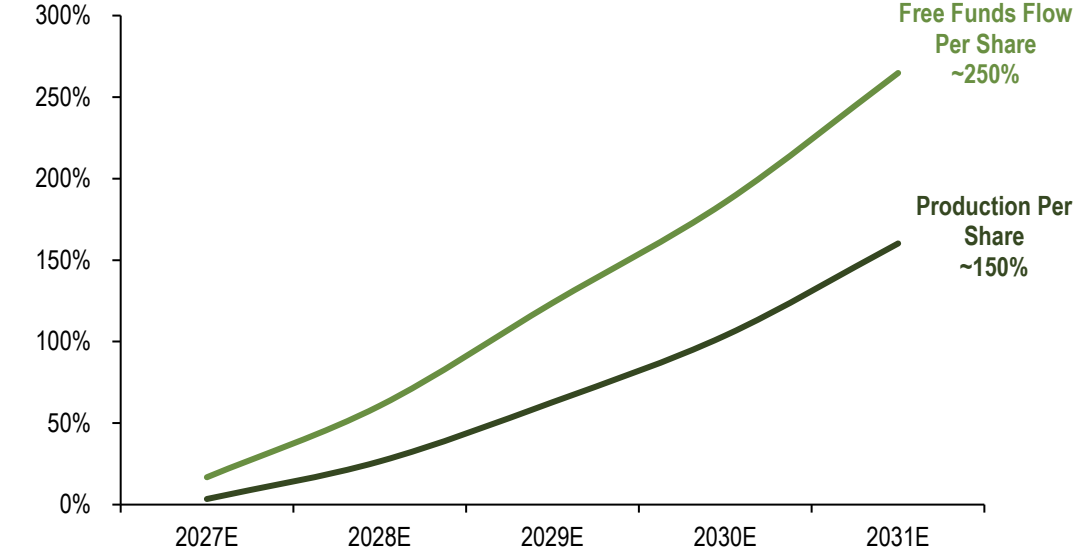
Growing Production With Reduced Decline Rates Drives Per Share Growth

- Investment in waterflood continues to lower decline rates & sustaining capital while growing high-margin Clearwater barrels

Discretionary Free Funds Flow Yields
(US$75/bbl Flat; % of Current Enterprise Value)[1,2]



Cumulative Per Share Growth
(Flat US$75/bbl; % Δ vs. 2026E)[1,3]



1) See Disclaimers – "Specified Financial Measures". US$75/bbl Flat Deck assumes 1.35 US$/C$ and US$(14)/bbl WCS basis.
2) Discretionary free funds flow is adjusted funds flow less sustaining capital. Capitalization assumes a $12.00/Sh. price. Capitalization in Prior Plan is normalized for $12.00/Sh. price. Sustaining capital is what is required to maintain flat production. Growth in disc. FFF measured from 2031E vs. 2027E.
3) Per share metrics are debt adjusted with a share price of $12.00. Cumulative changes are shown vs. 2026E full year. Free funds flow per share growth calculated with total capital program.

A History of Returning Capital While Growing

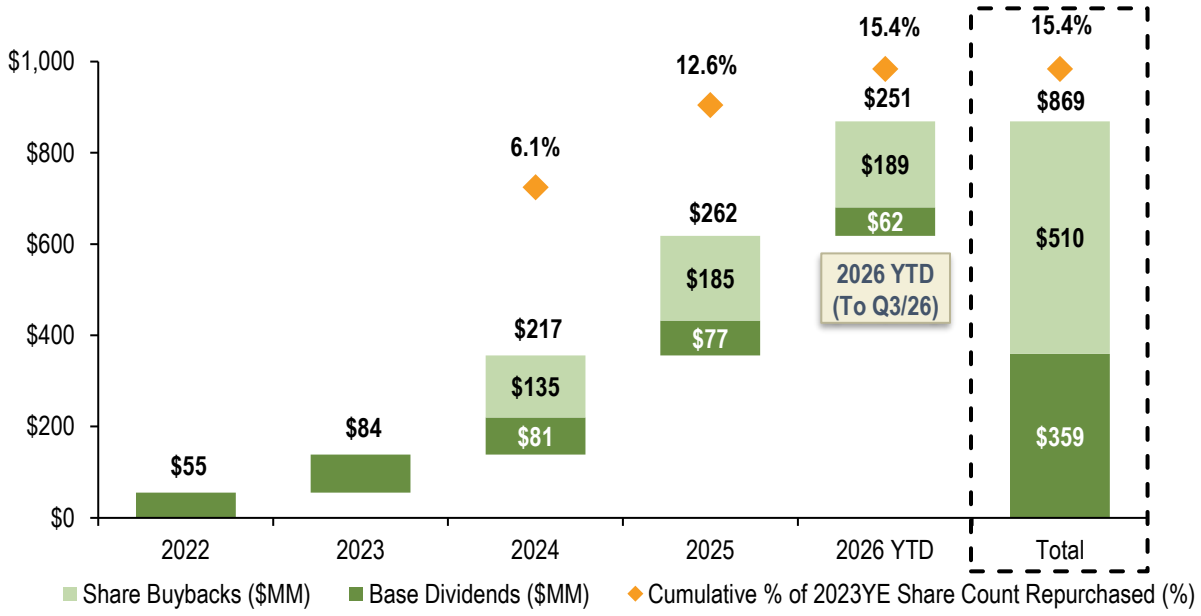
>$850 MM of Direct Shareholder Returns Since 2022

tamarack valley ENERGY

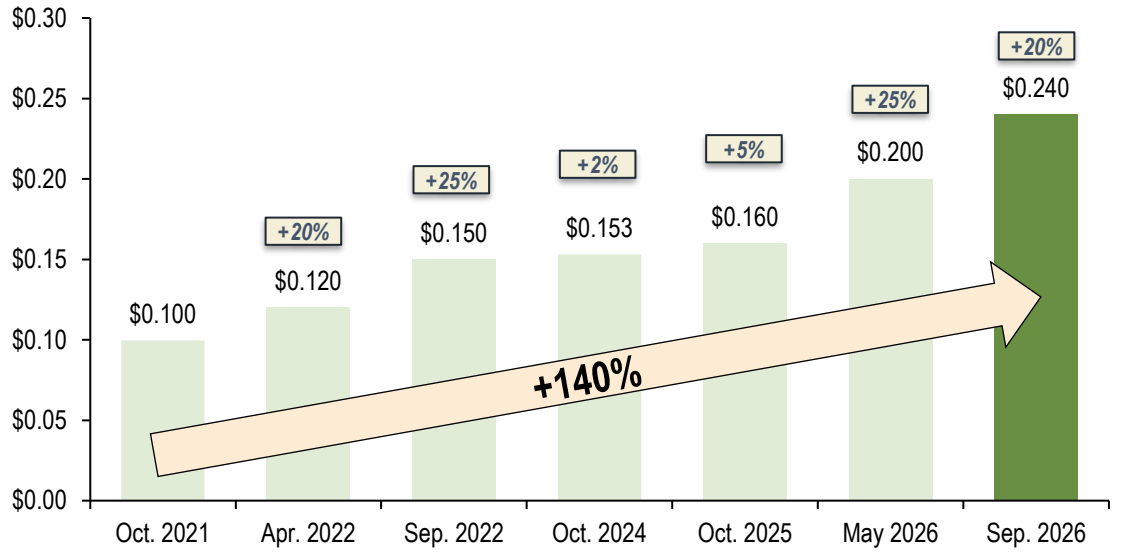
Exceptional Record of Direct Shareholder Returns (Dividend + Buybacks); While Growing Low-Decline, High-Margin Production

- Since inception of the dividend in 2022, it has increased six times for **cumulative growth of ~140%**
- Repurchased **15.4%** of 2023YE common share count to date at an **average share price of $5.80/Sh.**[1]

Tamarack Direct Return of Capital History[1]



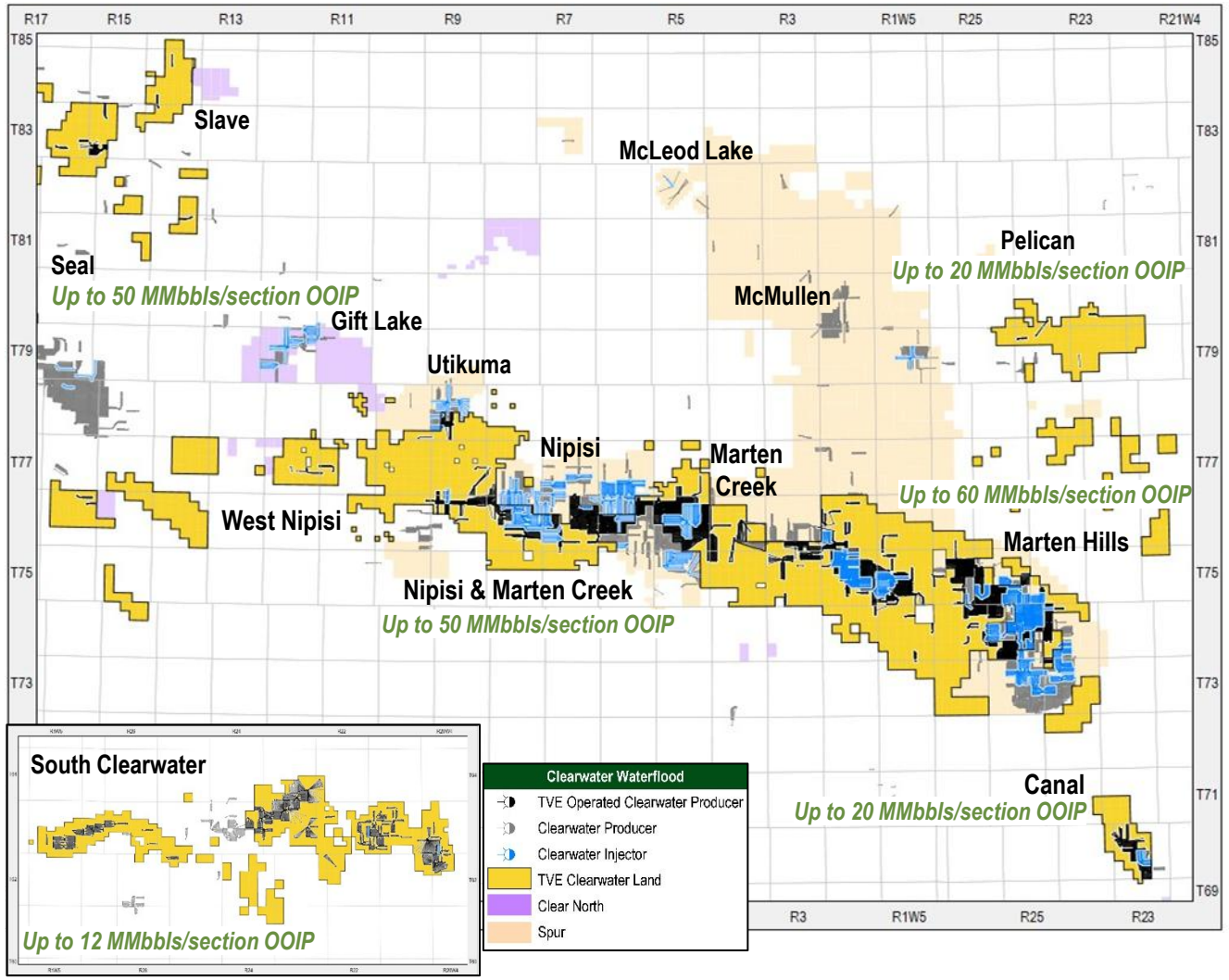
Annualized Dividend Per Share At Announcement Date ($/Sh.)

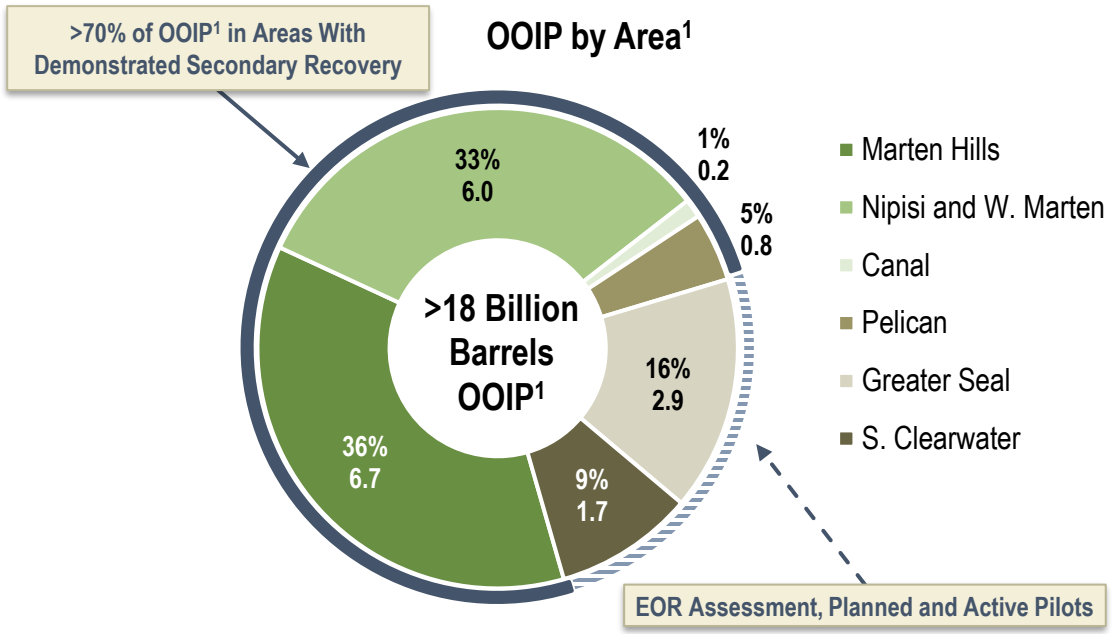


1) 2026 YTD up to and including September 2026 (includes Q3/2026 dividend declaration).
% of share count repurchased is calculated using the 2023YE common share count.

Decades of Asset Duration

Resource Scale and Recovery Enhancement Driving Asset Duration





<2% of OOIP[1] Recovered at End of Five-Year Plan

2025YE 2P Reserves[2] ~1.6% of OOIP

>3,000 Primary Drilling Locations

100 – 150 Wells Per Year

Demonstrated Repeatability

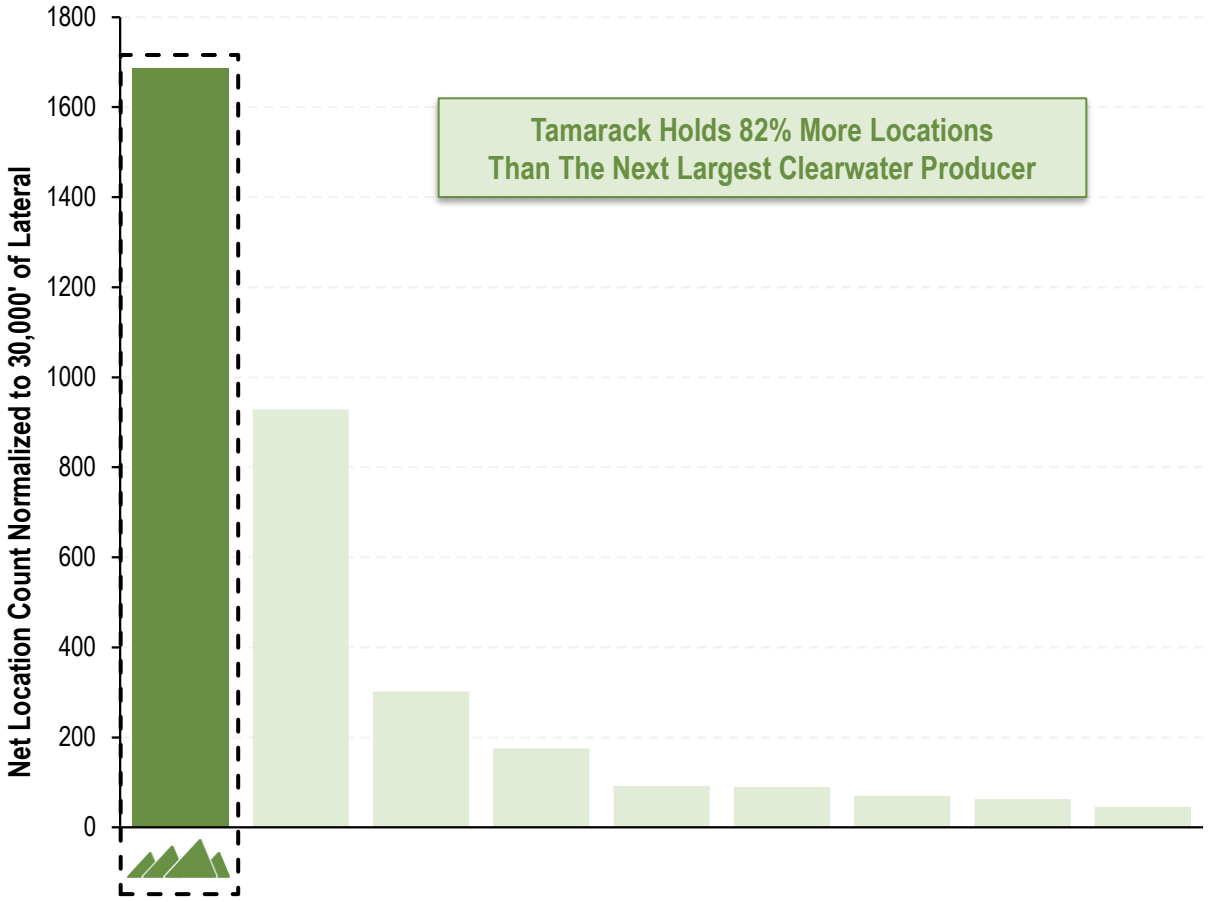
Positive Waterflood Responses Across Multiple Sands, Areas, & Well Designs

1) OOIP – original oil in place based on internal estimates.
2) Based on combined Headwater & Tamarack Clearwater focus McDaniel & Associates Consultants Ltd. Reserves Report effective December 31, 2025.

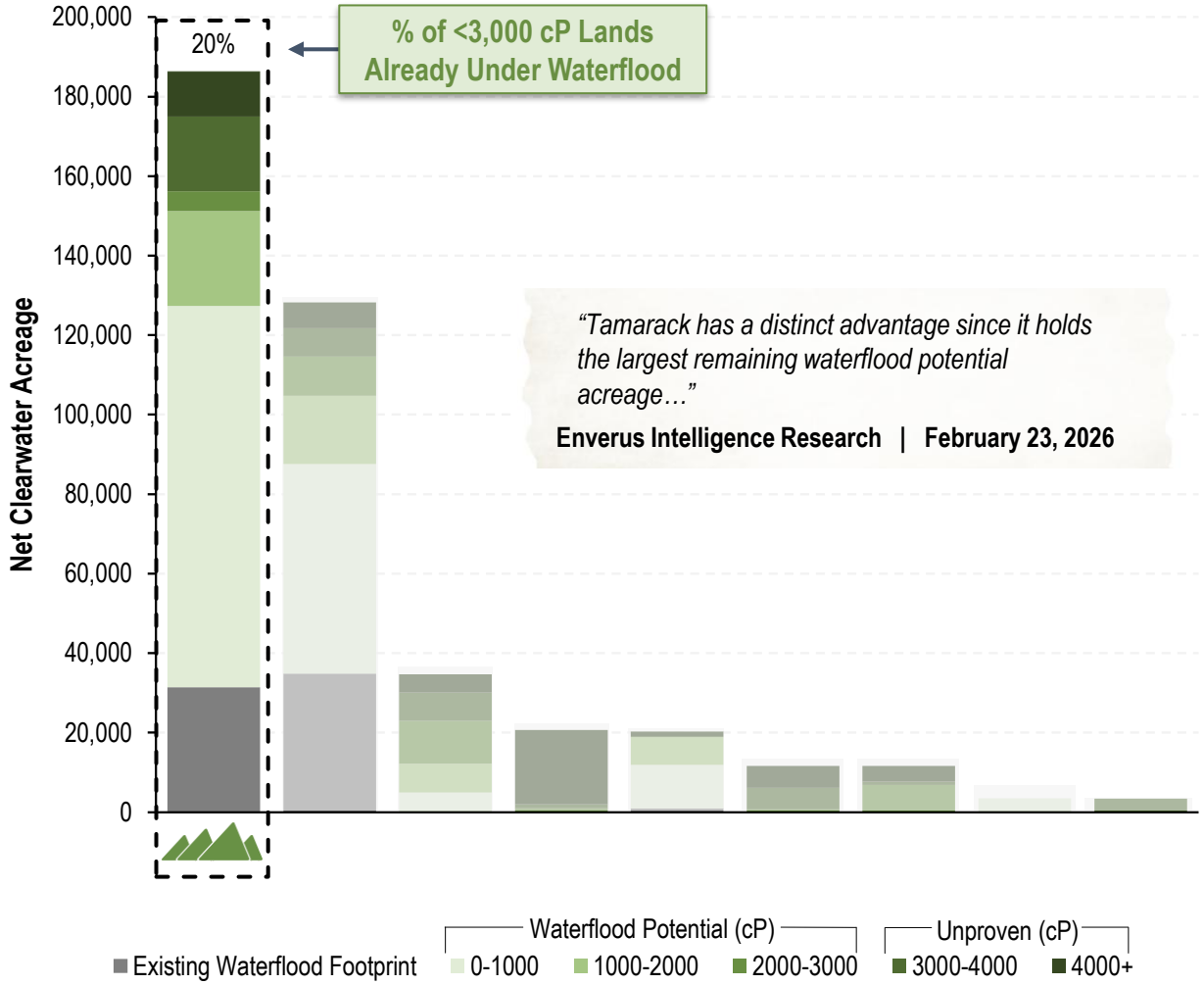
Depth of Quality Inventory

Industry Leading Clearwater Inventory & Duration With Waterflood

Clearwater Operator Primary Well Inventory[1]



Clearwater Waterflood Acres by Operator[2]



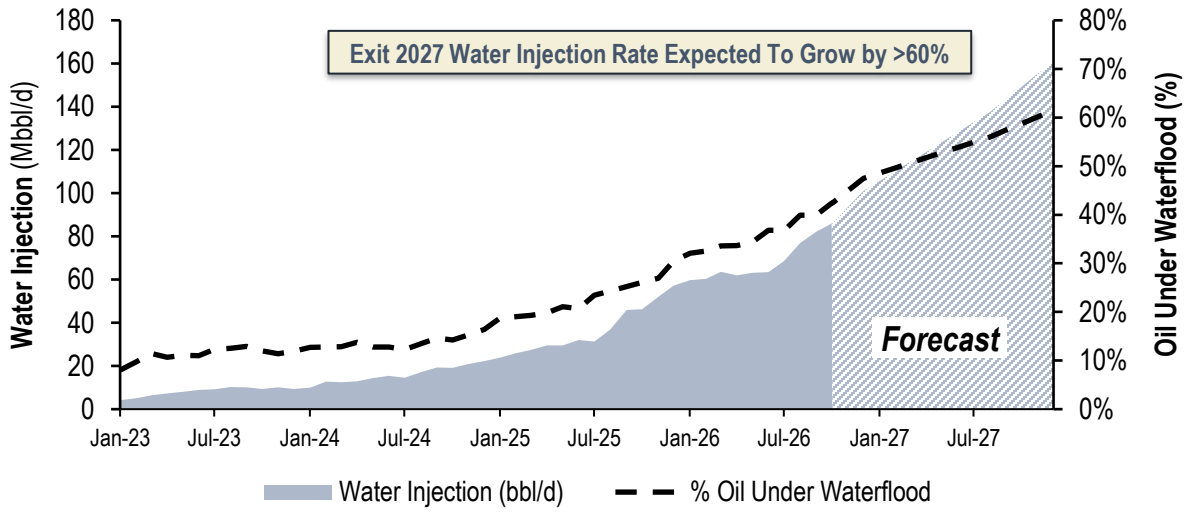
1) Clearwater Operator Primary Well Inventory per Enverus Intelligence Research (Feb. 2026).
Peer group includes BTE, CNQ, ISH Energy, Longridge, OBE, RBY, Spur, and Woodcote.
Tamarack includes Headwater (not pictured).

2) Clearwater Waterflood Acres by Operator per Enverus Intelligence Research (Feb. 2026).
All acreage shown in waterflood potential and additional lands lie within 3/4 mile of commercial well production.
Tamarack includes Headwater (not pictured). % of land already under waterflood is a weighted average.

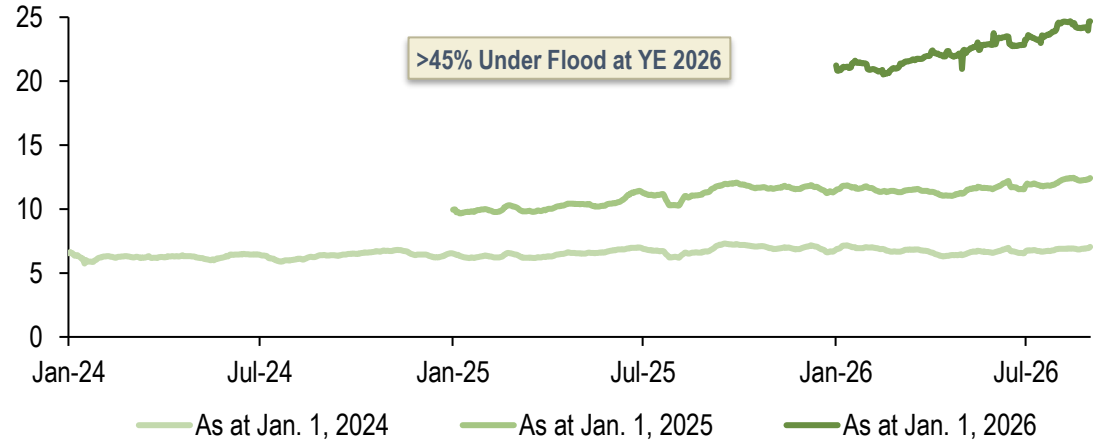
Tamarack Clearwater Waterflood Progression

Advancing Secondary Recovery To Drive Incremental Resource Capture

Clearwater Injection & Production Under Waterflood



Oil Production Under Flood by Vintage (Mbbl/d)



EUR's Up To 3x Primary Recovery

Demonstrated Waterflood Success At Highly Attractive F&D Costs

Mitigating Decline

Reduces Sustaining Capital Requirements

Demonstrated Repeatability

Positive Waterflood Responses Across Multiple Sands, Areas, and Well Designs

Expanding The Boundaries

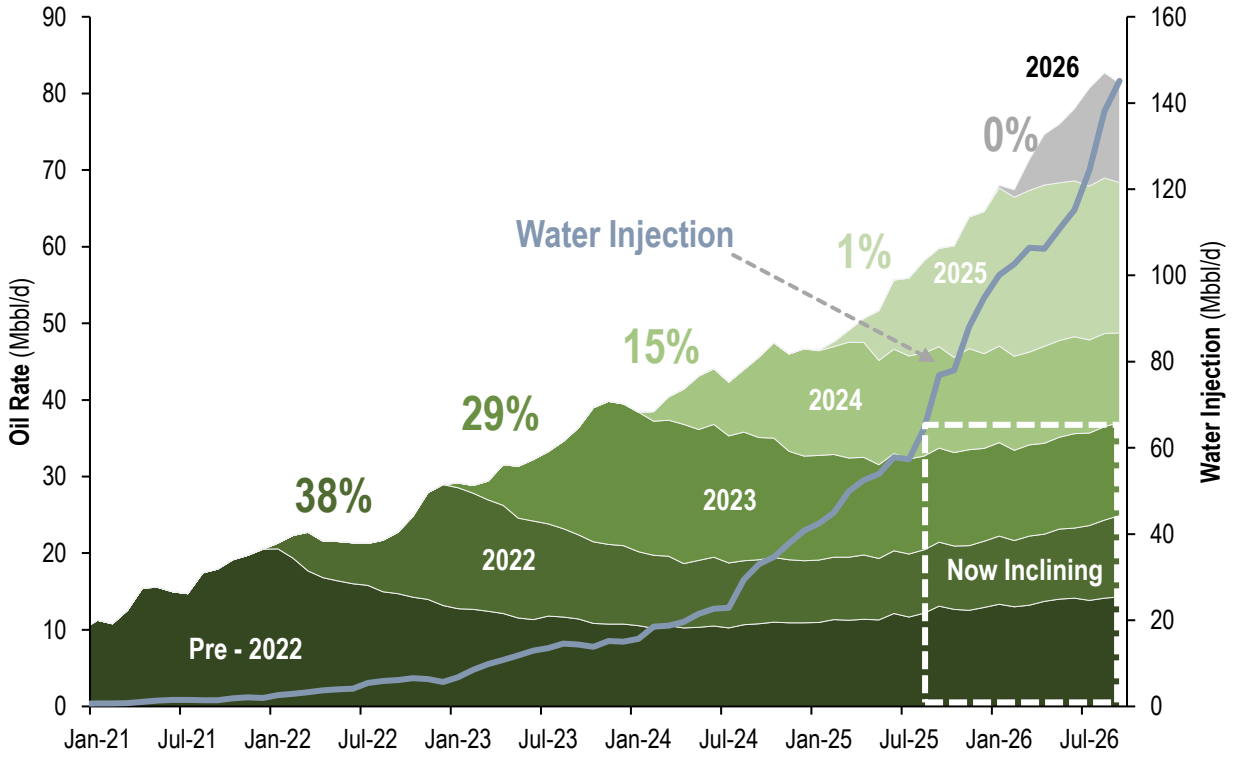
South Clearwater Pilots; Pelican & Seal Enhanced Recovery Simulation; Targeted Evaluation of Thermal Opportunities

>60% of Clearwater Oil Production Under Waterflood by YE 2027

Proven Waterflood Across the Clearwater Fairway

Efficient Waterflood Response Arresting Declines

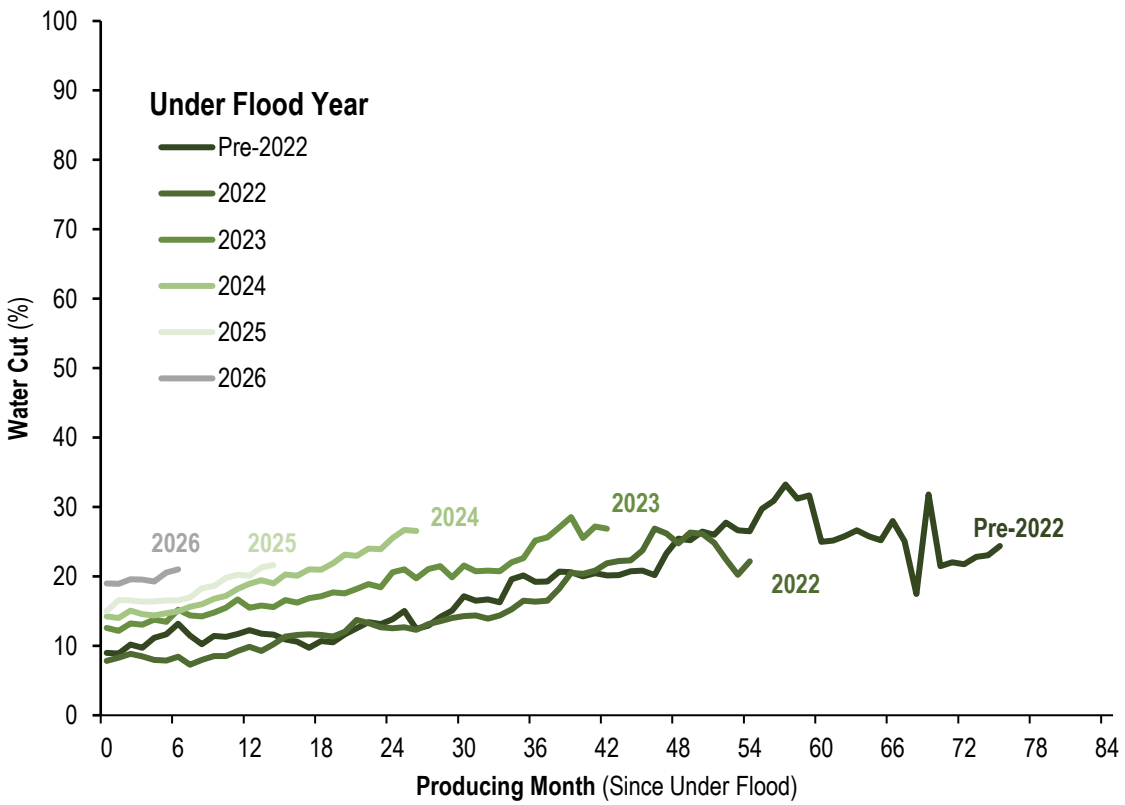
Clearwater Industry Oil Under Waterflood – Base Decline by Vintage[1]



Injection Ramped To ~140,000 bbl/d Since 2023, Lifting Oil To >70,000 bbl/d

Older Vintages **Now Inclining** After >30% Declines On Primary

Waterflood Supported Wells – Avg. Water Cut By Vintage[2]



Stable Water Cuts With Gradual Incline Point To An Immature Waterflood with Long Duration

1) Base declines are January to January and include all vintages implemented to that date. 2025 and prior quoted at 0% to date.

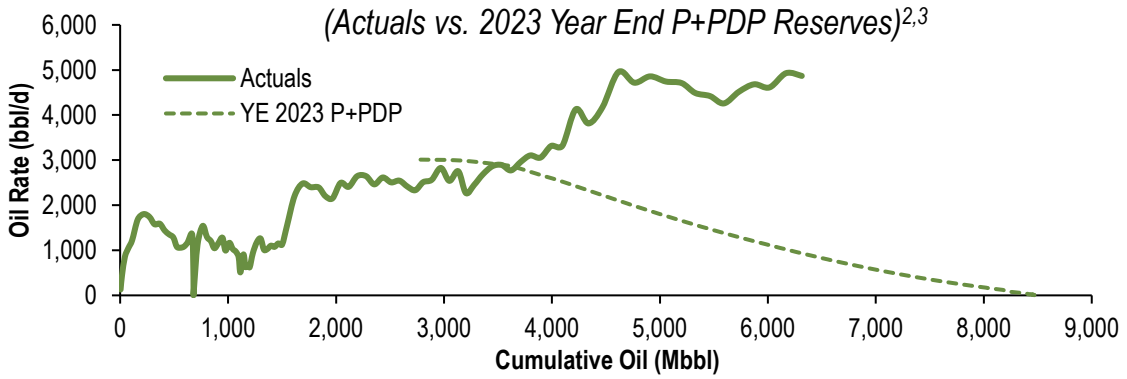
2) Water cuts averaged from date under flood and grouped by year. Each vintage truncated when producing count falls below 33% of peak count.

Prolific Waterflood Performance

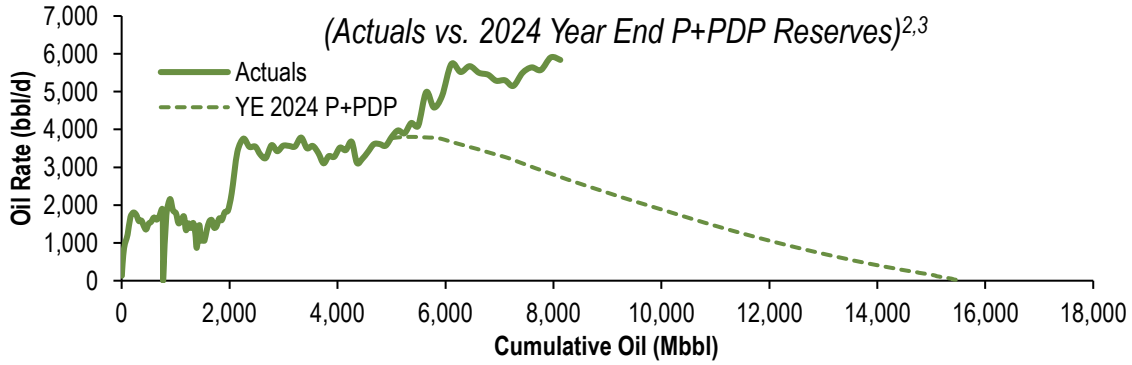
Secondary Recovery Continues to Exceed Expectations

- Strong waterflood performance is reducing corporate decline, driving lower sustaining capital requirements and improved growth efficiency
- Reserves added broadly every year the waterflood outperforms
- Injector conversions generating incremental oil recovery at an F&D of <$1.00/bbl[1]

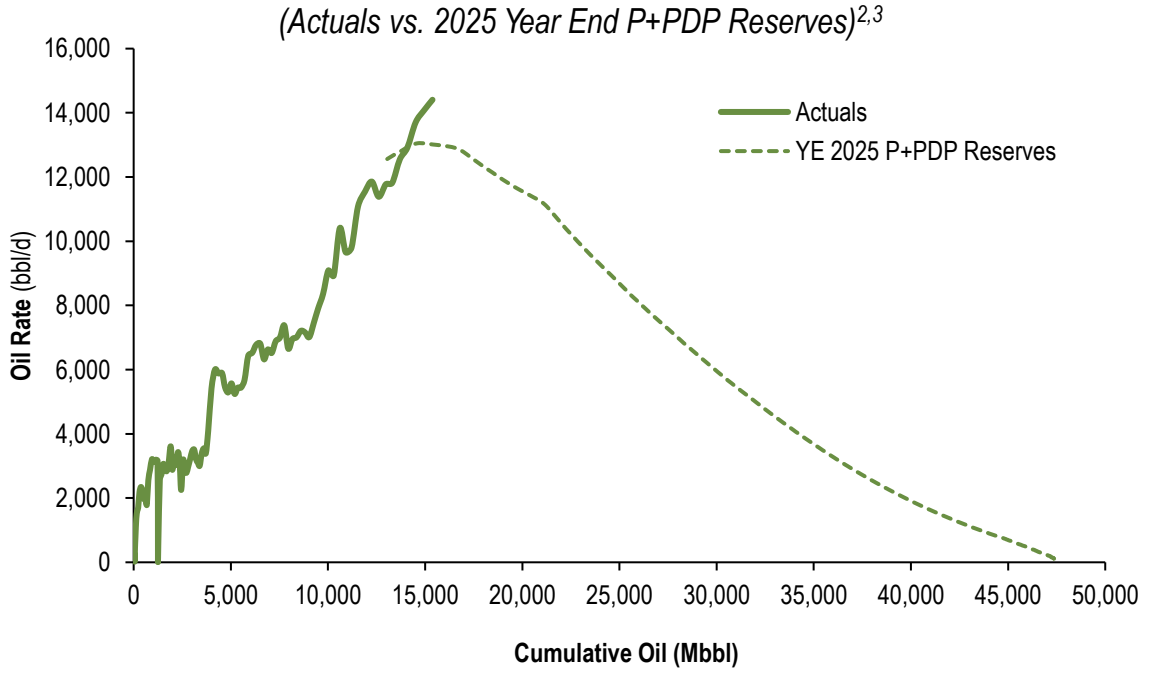
Clearwater Producers Under Flood at YE 2023



Clearwater Producers Under Flood at YE 2024



Clearwater Producers Under Flood at YE 2025



Continued Outperformance has Current Rates ~2 Mbbl/D Above YE2025 Reserves, Even After Years of Consecutive Positive Revisions

F&D = Finding & Development Costs. See "Disclaimers – Oil & Gas Metrics".

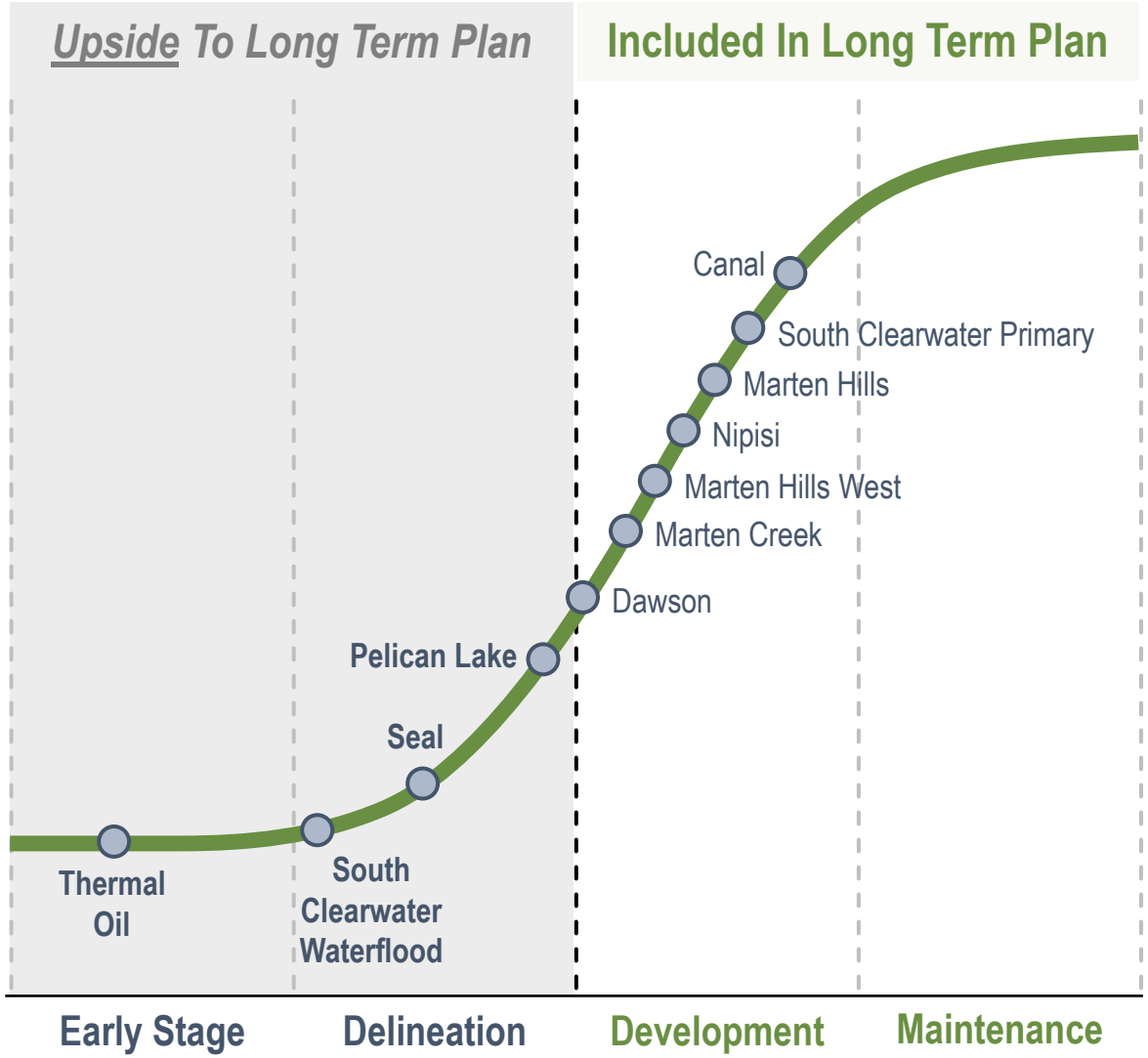
1) F&D calculated using management estimates of incremental oil recovery associated with secondary recovery vs. primary recovery for all wells under waterflood at YE 2025, capital cost assumes $0.4 MM per injector conversion.

2) Clearwater producers under waterflood P+PDP oil forecast as at YE 2023, YE 2024 & YE 2025. P+PDP = Proved plus probable developed reserves. See Disclaimers – Oil & Gas Metrics.

3) Based on Tamaracks existing assets only, i.e. excludes Headwater assets.

Future Growth Overview

Delineation of Secondary Recovery Potential In Stacked Zones; Upside To Five-Year Plan



Pelican Lake

Continued Delineation of Wabiskaw and Clearwater Targets with Production Potential of >8 Mboe/d

Seal

Testing Stacked Falher Waterflood Potential at Seal, a >100 MMbbl Opportunity with Production Potential of 10 – 15 Mboe/d

South Clearwater Waterflood

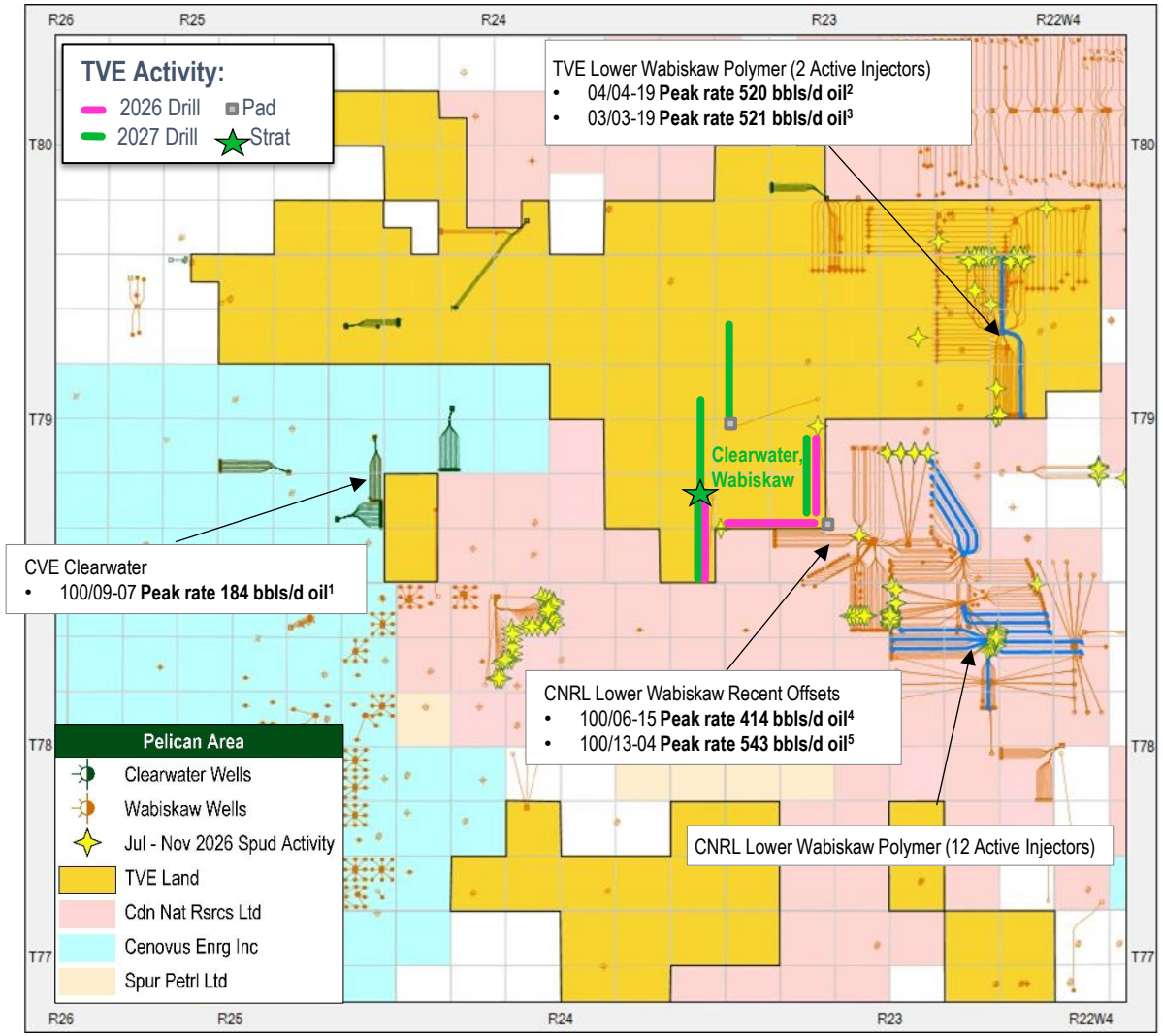
Expanding Waterflood Pilot to Prove Commerciality, a 15 to 30 MMbbl opportunity

Technology Pilots (Thermal Oil)

Innovations In Well Design and Recovery Processes With Potential For Step Change In Duration

Future Growth Optionality: Pelican Lake

Delineation of Stacked Zone Potential



Land Position:

- ~91 gross sections (Oil Sands Tenure)

Stacked Development Upside:

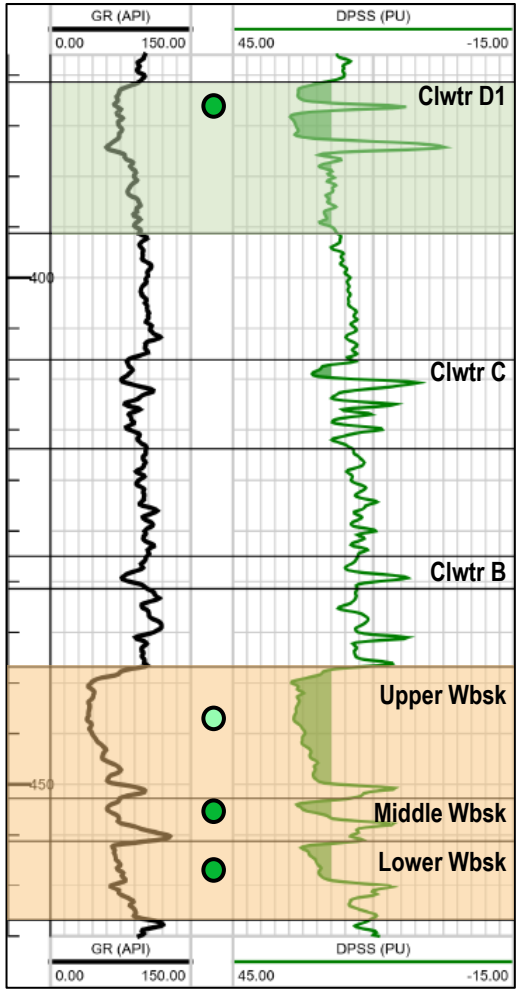
- Lower / Middle Wabiskaw & Clearwater
- 0.8 billion barrels OOIP

Secondary Recovery Schemes:

- Can increase recovery factors by 2-3x
- Expanding active polymer flood on legacy HWX land

Next Steps:

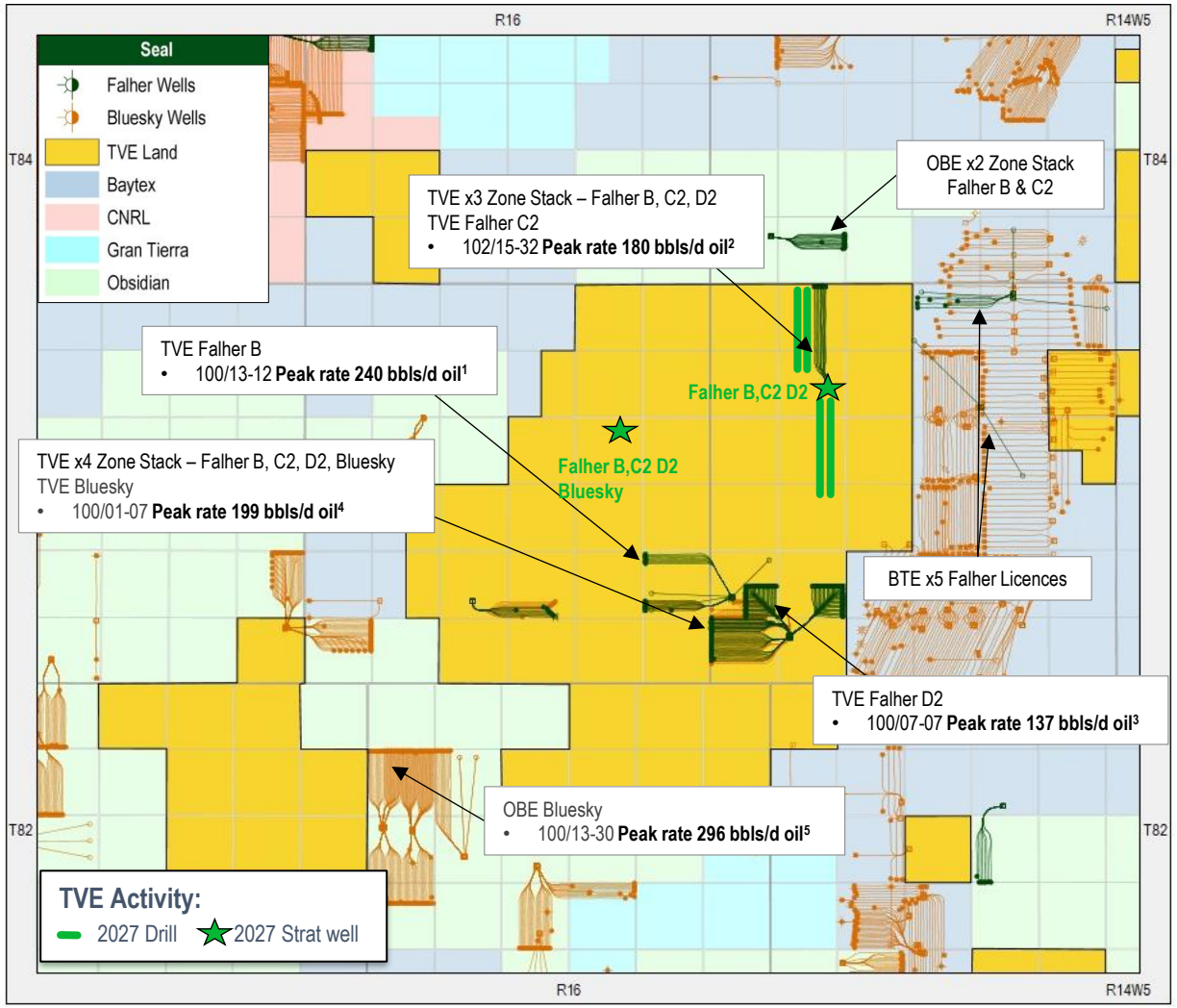
- Delineation of Wabiskaw and Clearwater targets
- Initiate secondary recovery on legacy TVE land



1) Source: GeoScout Sept 2025 Calendar Day Average Oil Rate.
2) Source: GeoScout Dec 2025 Calendar Day Average Oil Rate.
3) Source: GeoScout Feb 2026 Calendar Day Average Oil Rate.
4) Source: GeoScout May 2026 Calendar Day Average Oil Rate.
5) Source: GeoScout Sept 2026 Calendar Day Average Oil Rate.

Future Growth Optionality: Seal

Delineation of Secondary Recovery Potential In Stacked Zones



Land Position:

- ~60 gross sections (oil sands tenure)

Stacked Development Upside:

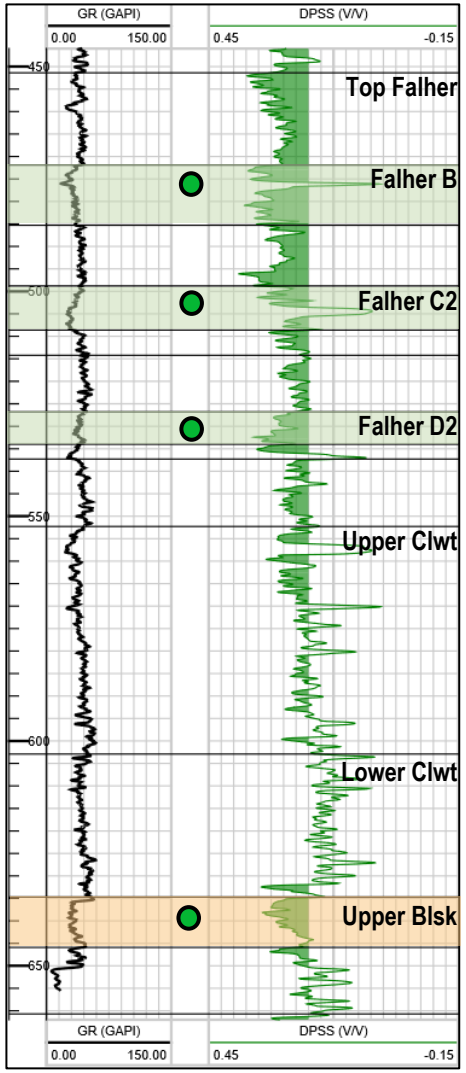
- Bluesky, Falher B, C2, & D2 zones
- 2.9 billion barrels OOIP

Secondary Recovery Schemes:

- Can increase recovery factors by 2-3x

Next Steps:

- Continued delineation of resource across land base
- Initiate waterflood across multiple Falher zones to unlock secondary recovery potential



1) Source: GeoScout Apr. 2025 Calendar Day Average Oil Rate.
2) Source: GeoScout Apr. 2023 Calendar Day Average Oil Rate.
3) Source: GeoScout Nov. 2023 Calendar Day Average Oil Rate.
4) Source: GeoScout Sept. 2026 Calendar Day Average Oil Rate.
5) Source: GeoScout Dec. 2023 Calendar Day Average Oil Rate.

Tamarack Egress Update

Diversification of Oil Markets Over the Long-Term

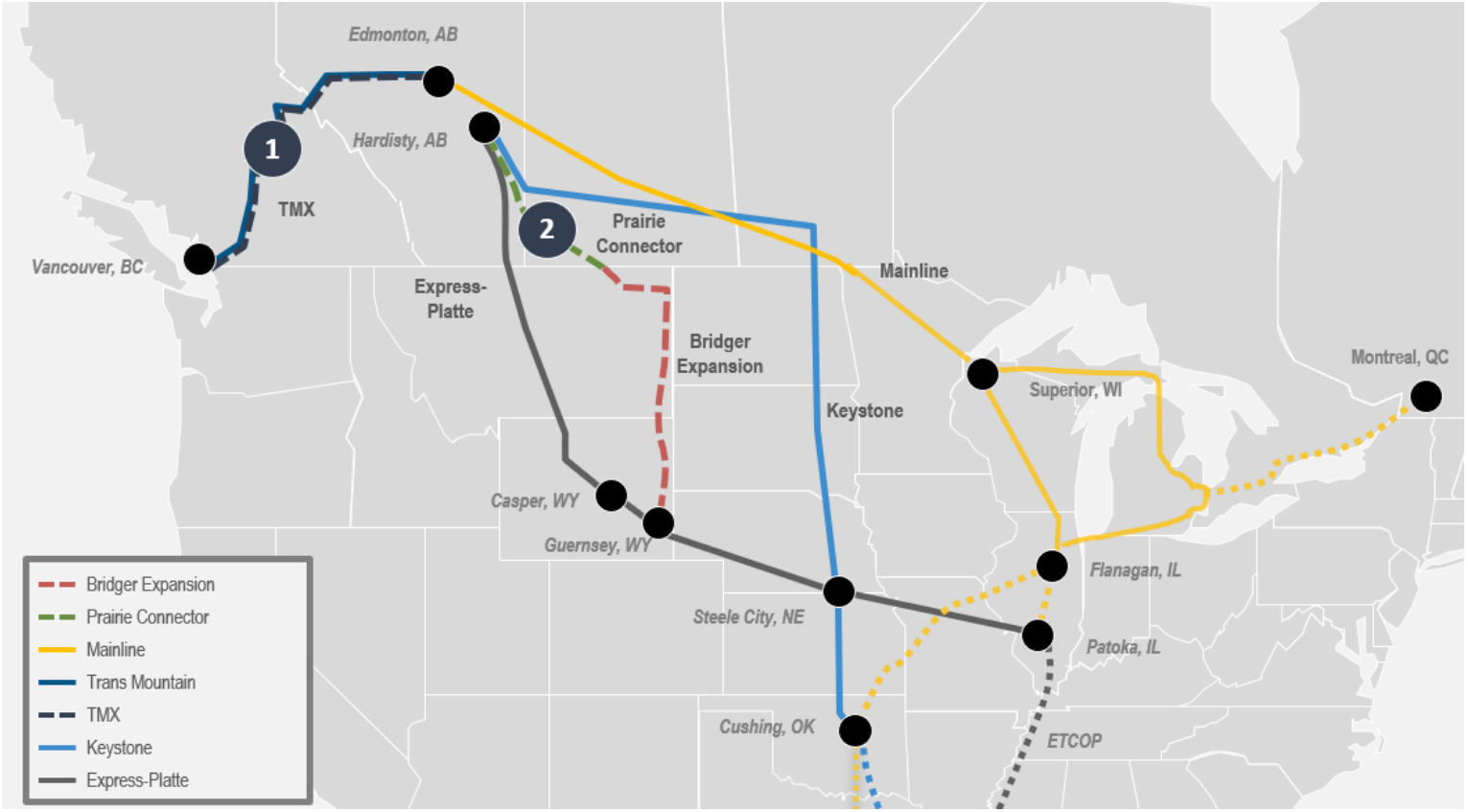
tamarack valley ENERGY

Upstream: Commitments Provides Local Egress

- Apportionment-protected pipeline commitments on Plains Rainbow and Pembina Nipisi covers 5-year plan

Downstream: Tamarack Secured 35,000 bbl/d of Long-Term Egress out of Alberta

1. **25,000 bbl/d of TMX** service to the West Coast expected to commence 2027, subject to the completion of the Drag Reducing Agent (DRA) expansion
2. **10,000 bbl/d of capacity** on the proposed South Bow Prairie Connector pipeline potentially starting by 2028YE (pending approval and construction)



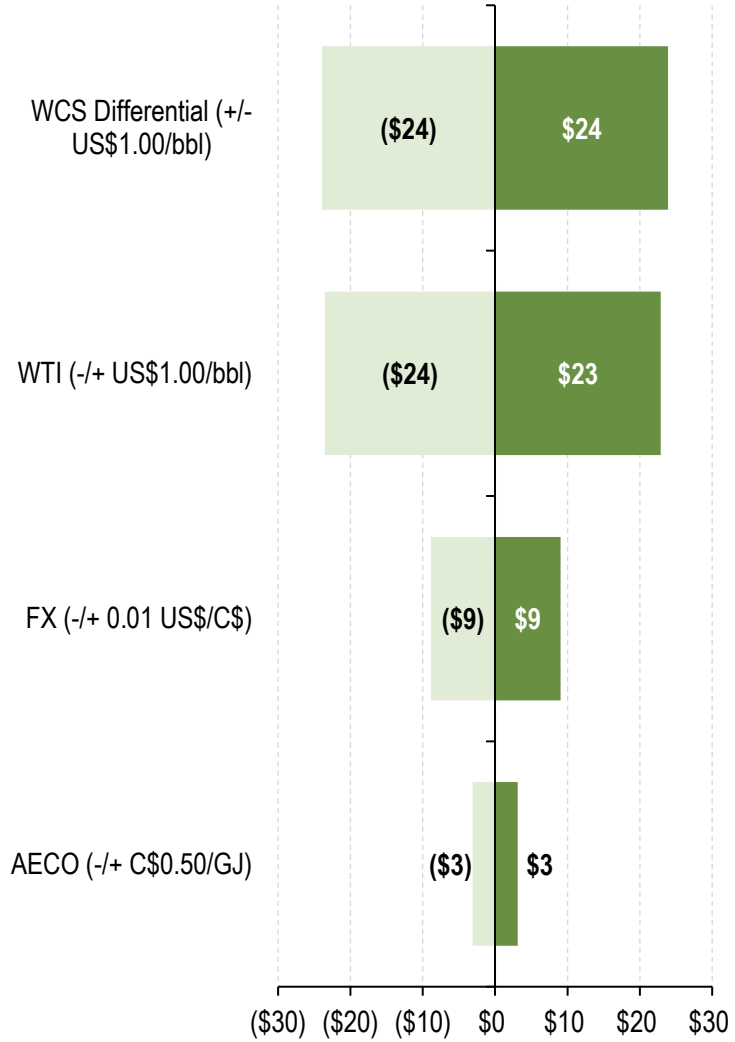
Additional Information

Risk Management[1]

Enhancing Certainty With Flexibility To Capture Upside Value

Oil Hedges	Units	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027
WTI Collars						
Volume	*bbl/d*	18,500	13,411	15,000	11,500	12,000
Avg. Floor Price	*US$/bbl*	$50.00	$52.05	$53.50	$51.74	$50.00
Avg. Ceiling Price	*US$/bbl*	$78.65	$84.45	$84.00	$97.09	$102.55
Avg. Premium	*US$/bbl*	$1.64	$0.18	$0.08		
WTI - WCS Hardisty Basis Swaps[(2)]						
Volume	*bbl/d*	17,500	2,000			
Avg. Fixed Price	*US$/bbl*	($13.08)	($24.33)			
WCS C$ Fixed Price Swap						
Volume	*bbl/d*		4,589			
Avg. Fixed Price	*C$/bbl*		$94.82			
Oil Hedges *(Net of Royalties)* [(1)]						
Crude Oil Hedged with WTI Contracts	%	38%	29%	23%	17%	18%
Heavy Exposure Hedged with WCS Contracts[(2)]	%	36%	10%			

2027E Funds Flow Sensitivity ($MM)[3]



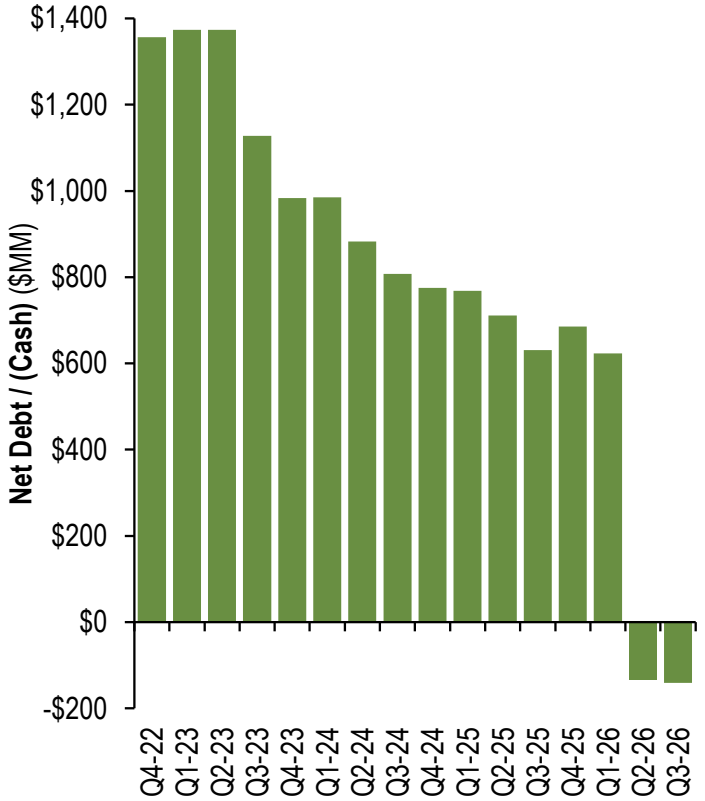
1) Hedges in place as at Nov. 17, 2026. 2026 Royalty burden based on Strip Pricing. 2027 Royalty burden on Budget Pricing.
2) Includes "synthetic" WCS Hardisty Basis trades (WCS Houston Basis Swap + WCS Transport Trade).
3) Sensitivity relative to Budget pricing.

Demonstrated Value Creation

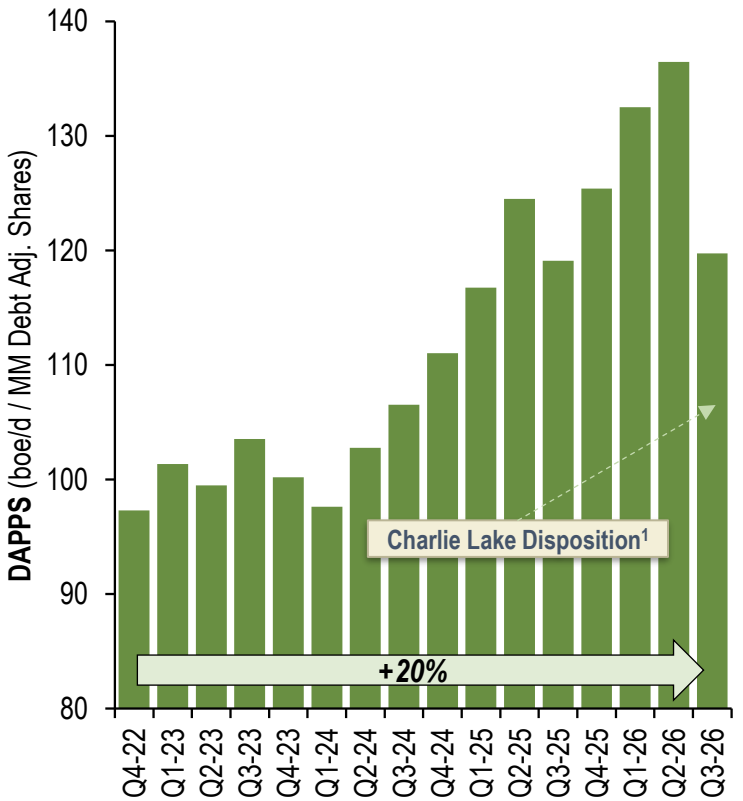
Compounding Success On A Per Share Basis

tamarack valley ENERGY

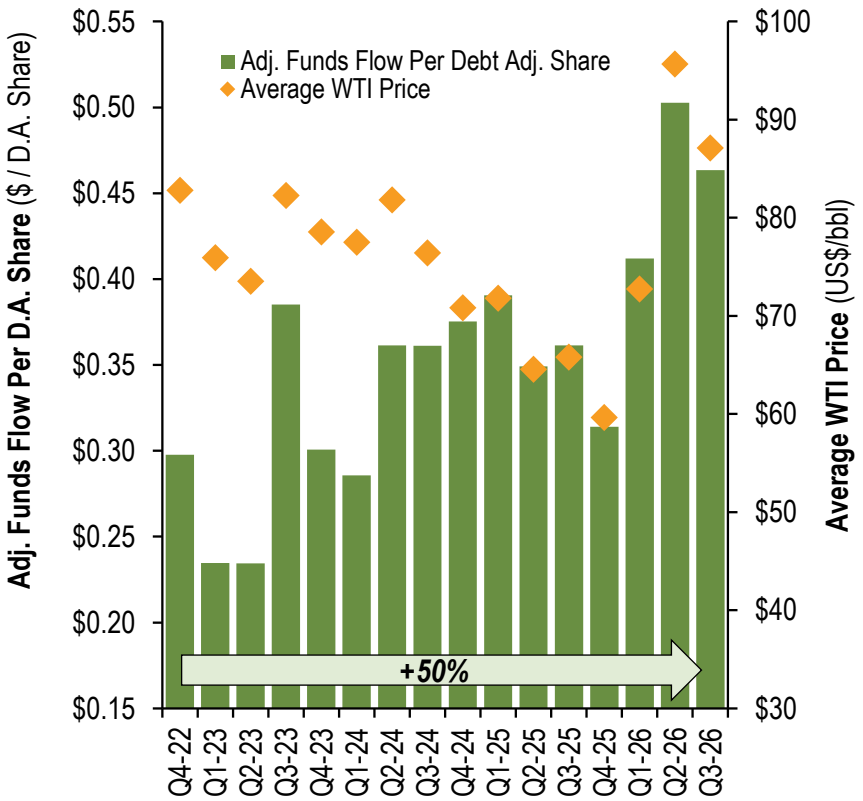
Net Debt / (Cash)[1]



Debt Adj. Prod. Per Share ("DAPPS")[2]



Adj. Funds Flow Per Debt Adj. Share[2]



Repurchased ~15.4% of 2023YE Share Count to Date (as at Q3 2026) at Average Cost of ~$5.80/Sh.[3]

Q3/26 Net Cash Position of ~$141 MM (~$541 MM Cash on Balance Sheet)

Significant Debt Adj. Per Share Value Growth From Operational Outperformance, Long-Term Buybacks, and Debt Repayment

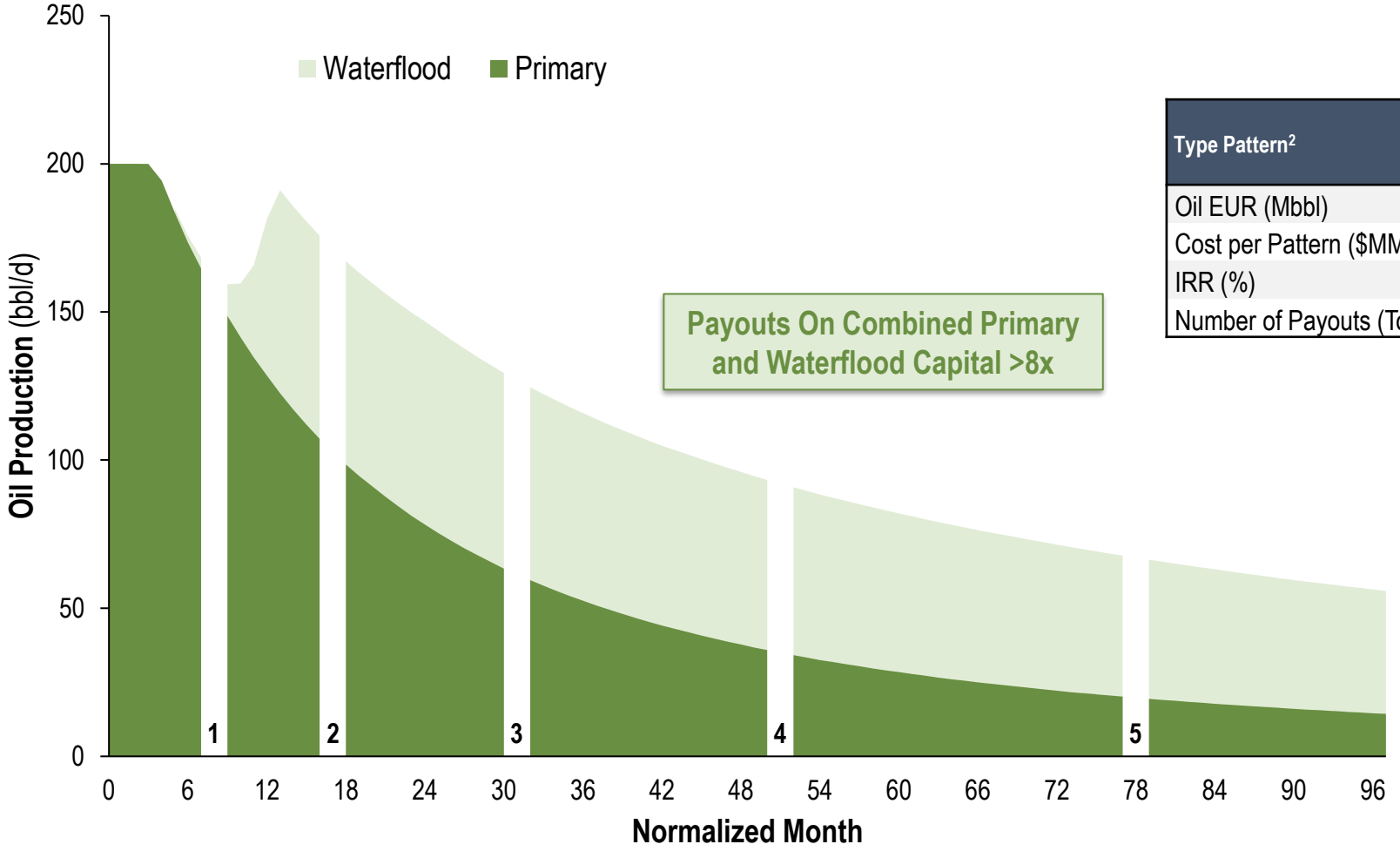
1) In Q2/2026, TVE sold its Charlie Lake assets for gross proceeds of $804 MM.

2) Debt adjusted using a Tamarack share price of $12.00/Sh.
DAPPS and debt adj. funds flow per share uses average net debts and weighted average common share counts during the quarter.

3) Change in common share count from Dec. 31, 2023, to Sep. 30, 2026.

Clearwater Waterflood – New Injector Drill Type Curve

Secondary Recovery Provides Additional Payouts & Reduces Long-Term Sustaining Capital



Waterflood Economics

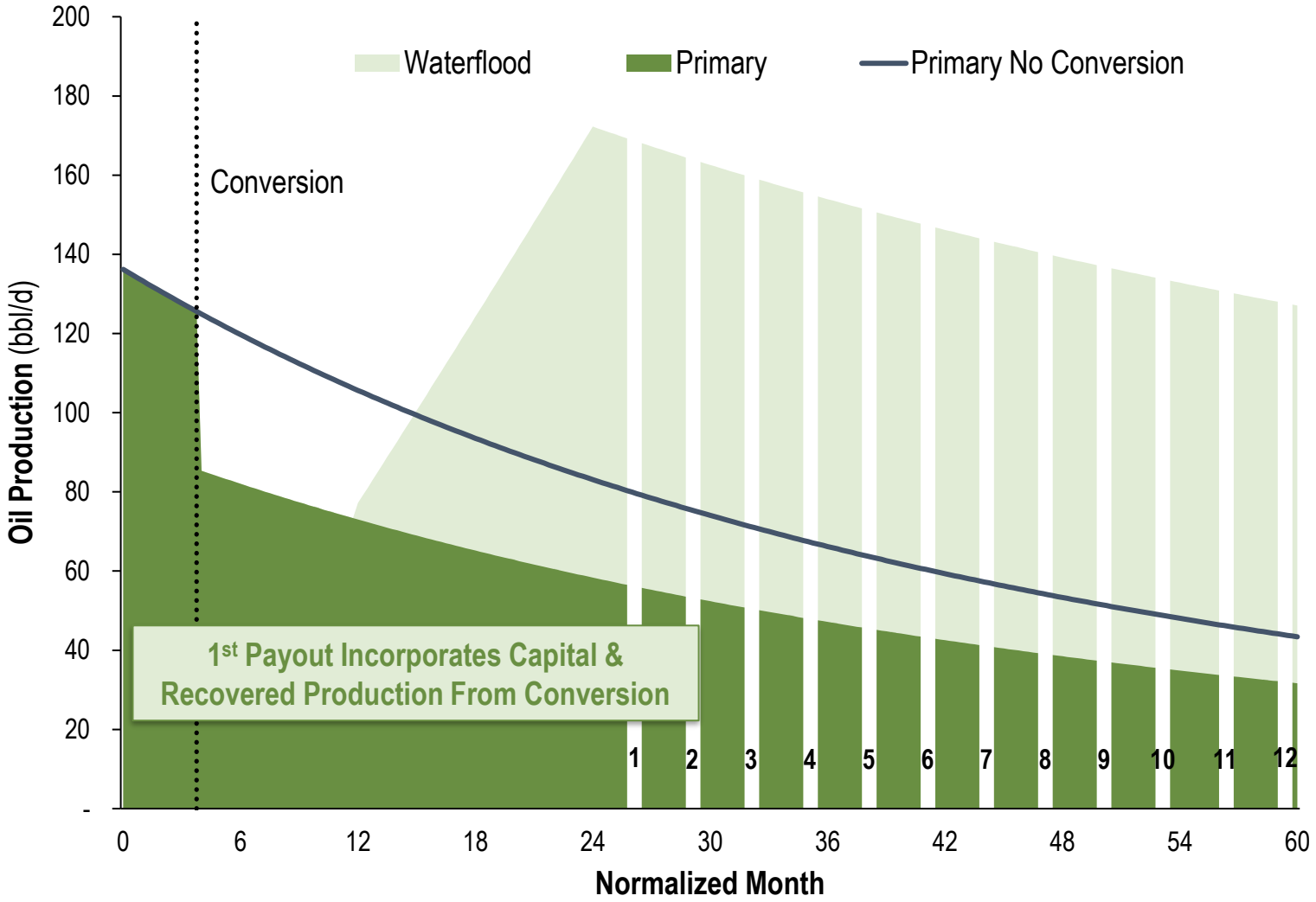
Type Pattern[2]	Primary[3] – West Marten "B" Sand Tier I	Waterflood Injector Wedge[4] – Internal Estimate	Total Project
Oil EUR (Mbbl)	205	308	513
Cost per Pattern ($MM)	$1.7	$1.2	$2.9
IRR (%)	>200%	75%	>200%
Number of Payouts (Total)	6.4	12.6	8.9

- **Early Success:** Waterflood has been successfully implemented broadly across the Clearwater
- **Asset Duration:** Mature patterns indicate up to 3x recovery compared to primary development
- **Free Funds Flow:** Significant free funds flow[1] generated from incremental payouts of waterflood capital

1) See Disclaimers – "Specified Financial Measures"; based on internal management estimates
2) Flat pricing assumes US$75/bbl WTI, US($14)/bbl WCS basis, CDN $3.00/GJ AECO and 1.35 C$/US$.
3) Based on McDaniel & Associates Consultants Ltd. Reserves Report effective December 31, 2025.
4) Waterflood incremental wedge based on internal estimates for a single leg injector drill with 2-mile lateral length achieving a total pattern oil recovery equal to 2.5x primary at an incremental capital cost of $1.2 MM.

Marten Hills Waterflood – Injector Conversion Typical Type Curve

Low-Cost Conversions Provide Substantial Returns



Waterflood Conversion Economics

Type Pattern[2]	Waterflood Wedge[1] – Internal Estimate
Incremental Oil EUR (Mbbl)	850
Conversion Cost ($MM)	$0.4
IRR (%)	>100%
Number of Payouts (Total)	>30

- Increased injection rates at Marten Hills have led to faster waterflood response and quicker payouts
- Conversions can payout in under two years followed by recurring payouts every 3-4 months due to stable production profile and low initial capital requirement
- Large OOIP and strong waterflood performance suggest over 10 payouts within 5 years of implementation, with ultimate recovery of 2.5x - 3.0x primary performance

1) See Disclaimers – "Specified Financial Measures"; based on internal management estimates.
2) Flat pricing assumes US$75/bbl WTI, US($14)/bbl WCS basis, CDN $3.00/GJ AECO and 1.35 C$/US$.
3) Waterflood incremental wedge based on internal estimates for a single waterflood conversion achieving a total pattern oil recovery equal to 2.5x primary at an incremental capital cost of $0.4 MM.

Corporate Information*

Executive

***Brian Schmidt (Aakaikkitstakii)**	Executive Chairman
***Steve Buytels**	President & Chief Executive Officer
Kevin Johnston	Chief Financial Officer
Scott Shimek	Chief Operating Officer
Ben Stoodley	VP, Engineering
Lynne Chrumka	VP, Exploration
Rocky Baker	VP, Marketing & Commercial

Board of Directors

John Rooney [1, 3, 4]	Lead Independent Director
***Brian Schmidt (Aakaikkitstaki)**	Executive Chairman
***Steve Buytels**	President & Chief Executive Officer
Chandra Henry [1]	Independent Director
Craig Bryksa [2, 3]	Independent Director
Jason Jaskela [2, 4]	Independent Director
John Leach [1, 2]	Independent Director
Marnie Smith [1, 3]	Independent Director
Rene Amirault [4]	Independent Director
Sony Gill	Corporate Secretary

Legal Counsel

Stikeman Elliott LLP

Banking Syndicate Co-Leads

National Bank of Canada

Royal Bank of Canada

Auditors

KPMG LLP

Independent Reserve Evaluator

McDaniel and Associates Consultants Ltd.

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Investor Contact Information

Steve Buytels	**Kevin Johnston**
President & Chief Executive Officer	Chief Financial Officer

* Recent Executive and Board of Directors changes effective January 1, 2027.
1) Member of Audit Committee of the Board of Directors.
2) Member of the Reserves Committee of the Board of Directors.
3) Member of the Governance & Compensation Committee of the Board of Directors.
4) Member of the Environment, Safety & Sustainability Committee.

Disclaimers

General: This presentation is dated November 19, 2026 and is provided for information only. It is not an offer to sell or a solicitation of an offer to buy securities in any jurisdiction and is not investment advice. On November 19, 2026, Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") acquired Headwater Exploration Inc. ("Headwater"). Unless otherwise indicated, 2027 guidance, five-year plan and "pro forma" information is for the combined company, and historical financial and operating information is for Tamarack on a stand-alone basis before the acquisition. Dollar amounts are in Canadian dollars unless otherwise indicated.

Forward-Looking Information: This presentation contains forward-looking information within the meaning of applicable securities laws, generally identified by words such as "expect", "plan", "target", "budget", "guidance", "estimate", "potential" and "will". It includes statements about: the anticipated benefits of the Headwater acquisition and the amount and timing of expected synergies; 2026 and 2027 guidance and the 2027 capital budget and its allocation; the five-year plan to 2031, including production growth, capital investment, base decline rates, sustaining capital, reinvestment ratios, breakeven prices, adjusted funds flow, free funds flow, discretionary free funds flow yields and per share growth; waterflood expansion, including injection rates, the share of production under waterflood, recovery factors and well and pattern economics; drilling inventory and asset duration; delineation plans and production potential at Pelican, Seal and South Clearwater and for thermal pilots, none of which is included in the five-year plan; dividends, share buybacks and total returns; pipeline commitments and the timing of new egress; hedging; and management and Board changes effective January 1, 2027. Statements about reserves, OOIP and EUR are also forward-looking, as they involve the implied assessment that the volumes described exist and can be profitably produced.

Forward-looking information is based on assumptions that management believes are reasonable, including: the commodity price, differential and exchange rate assumptions shown on the slides; the integration of Headwater and the realization of synergies in the amounts and at the times expected; execution of the 2027 budget and the five-year plan on schedule and at budgeted cost; performance of existing and new wells and of waterflood patterns in line with management's type curves; royalty, tax and regulatory regimes remaining as currently in effect; and the availability of services, labour, water, facilities and pipeline capacity.

Actual results may differ materially from the forward-looking information. Material risks include: commodity prices, differentials and exchange rates; failure to realize the anticipated benefits and synergies of the Headwater acquisition, and integration difficulties or costs; reservoir and waterflood performance (including water breakthrough) and the uncertainty of reserves, OOIP and type curve estimates; operational, weather and wildfire risks; cost inflation and access to services, facilities and pipelines, including third-party outages and the timing of pipeline projects that Tamarack does not control; the results of exploration and delineation programs; tariffs, trade restrictions and changes in royalty, tax, environmental and other laws; geopolitical events affecting oil supply and demand; and access to capital. Dividends and share buybacks are at the discretion of the Board, depend on funds flow, capital requirements, solvency tests and credit facility terms, and may be reduced, suspended or not made. These and other risks are described in Tamarack's annual information form for the year ended December 31, 2025, its management's discussion and analysis for the three and nine months ended September 30, 2026 (the "MD&A") and the joint management information circular of Tamarack and Headwater dated October 13, 2026, each available on SEDAR+ at www.sedarplus.ca. Readers should not place undue reliance on forward-looking information. It is given as of the date of this presentation and Tamarack does not undertake to update it except as required by law.

Financial Outlook: The 2027 guidance and five-year plan figures in this presentation (including capital investment, adjusted funds flow, free funds flow, sustaining capital, breakeven prices, synergies, yields and per share growth) are future-oriented financial information or financial outlook. They were approved by management on November 18, 2026, are provided to help readers understand Tamarack's expected results and capital plans, and may not be appropriate for other purposes. Figures for 2028 to 2031 illustrate the five-year plan at the flat prices shown, are not guidance and are subject to greater uncertainty than nearer-term figures.

Specified Financial Measures: This presentation uses financial measures that do not have standardized meanings under IFRS Accounting Standards ("IFRS") and may not be comparable to similar measures disclosed by other companies. "Adjusted funds flow" (also referred to as "funds flow" or "cash flow"), "free funds flow", "net debt (cash)" and "available funding" are capital management measures. Their composition, how management uses them and their reconciliation to the most directly comparable IFRS measures are set out under "Advisories and guidance – Capital management measures and ratios" and "Liquidity and capital resources" in the MD&A, which information is incorporated by reference into this presentation. The MD&A is available on SEDAR+ at www.sedarplus.ca.

The following non-IFRS financial measures and ratios and supplementary financial measures are not described in the MD&A. "Sustaining capital" is management's estimate of the annual capital investment (including minimum annual asset retirement spending) required to hold production flat. "Sustaining reinvestment ratio" is sustaining capital divided by adjusted funds flow, and "reinvestment ratio" is total capital investment divided by adjusted funds flow. "Discretionary free funds flow" is adjusted funds flow less sustaining capital, and "discretionary free funds flow yield" is that amount divided by enterprise value. "Breakeven" is the WTI price at which unhedged adjusted funds flow equals sustaining capital plus the base dividend, with all other variables held constant. "Market capitalization" is common shares outstanding multiplied by the share price at the date indicated, and "enterprise value" is market capitalization plus net debt (or less net cash). "Debt adjusted" per share measures (including "DAPPS", or debt adjusted production per share) divide the measure by the sum of common shares outstanding and net debt divided by a constant share price of $12.00. "Total return" is the sum of production growth, dividend yield and share buyback yield. "Net debt to LTM funds flow" is net debt divided by adjusted funds flow for the last twelve months. Management uses these measures to assess the sustainability of its capital program, balance sheet strength and per share performance. Forward-looking measures are calculated on the same basis as the historical measures, and peer measures are as calculated by the third-party sources cited.

BOE and Product Types: Natural gas is converted to barrels of oil equivalent ("boe") at six thousand cubic feet to one barrel. Boe may be misleading, particularly if used in isolation. A conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. "Oil" refers to heavy crude oil and light and medium crude oil combined, "NGL" to natural gas liquids and "natural gas" to conventional natural gas, each as defined in National Instrument 51-101 ("NI 51-101"). The product type split of 2026 and 2027 production guidance is shown on the corporate overview slide.

Disclaimers

Reserves: Reserves information is derived from the independent evaluations of Tamarack's and Headwater's properties by McDaniel & Associates Consultants Ltd. ("McDaniel") effective December 31, 2025 (or, for earlier years, from the independent evaluation effective December 31 of the year indicated), prepared in accordance with NI 51-101 and the Canadian Oil and Gas Evaluation Handbook ("COGEH"), and is stated on a gross basis (working interest before royalties). "PDP" means proved developed producing reserves and "P+PDP" means proved plus probable developed producing reserves. Reserves are estimates only, and actual reserves may be greater or less than estimated.

Oil and Gas Metrics: "Base decline" or "corporate decline rate" (the percentage decline over a year in production from the existing production base, excluding wells drilled in that year), "F&D costs" (finding and development costs, calculated as described on the slide where they appear), "recycle ratio" (operating netback divided by F&D costs), "EUR" (the estimated ultimate recovery of a well or pattern), "IRR" (internal rate of return), "payouts" (the number of times cumulative cash flow recovers the capital invested) and "NPV-10" (net present value, before tax, discounted at 10%) are calculated by management, do not have standardized meanings, may not be comparable to similar measures presented by other companies and should not be used to make comparisons. Management uses these metrics to measure its own performance over time. EUR and type curve volumes are not estimates of reserves.

OOIP: "OOIP", or original oil in place, is equivalent to total petroleum initially-in-place: the quantity of petroleum estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production. OOIP figures are internal estimates by management for the combined company's lands and have not been independently evaluated or audited. OOIP is presented because recoverable volumes have not been estimated for all of these lands. OOIP figures are not estimates of reserves or of recoverable resources, and a significant portion of OOIP will never be recovered. There is no certainty that any portion of the undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. There is uncertainty that it will be commercially viable to produce any portion of the discovered resources.

Drilling Locations: The net primary drilling locations referred to in this presentation include booked locations (proved or probable locations in the McDaniel evaluations for Tamarack and Headwater) and unbooked locations. Unbooked locations are management's internal estimates based on geological, seismic, engineering, production and reserves information and do not have attributed reserves. There is no certainty that Tamarack will drill all unbooked locations or that, if drilled, they will result in additional reserves, resources or production. The locations actually drilled will depend on the availability of capital, regulatory approvals, commodity prices, costs, drilling results and other factors.

Type Curves, Production Rates and Analogous Information: Type curves and pattern economics are management's internal estimates of the performance of an average well or pattern, and individual results will vary. Except where attributed to the McDaniel evaluation, they are not the type curves that McDaniel uses to estimate reserves. The waterflood curves are based on reservoir simulation and internal analysis, and there is no certainty that the volumes shown will be recovered. Peak and other short-term production rates are not indicative of long-term performance or of ultimate recovery. Information about other operators' wells and lands is "analogous information" under NI 51-101, taken from the public sources cited, which Tamarack believes are independent. Tamarack cannot confirm that it was prepared by a qualified reserves evaluator or in accordance with COGEH. It is included because those wells and lands are close to Tamarack's, and results on Tamarack's lands may differ materially.

Potential Outside the Five-Year Plan: The production potential and "opportunity" volumes shown for Pelican, Seal and South Clearwater are management's internal estimates of heavy oil that could be developed on Tamarack's lands if delineation drilling and enhanced recovery pilots are successful. They are not estimates of reserves, are subject to geological, technical and commercial risk, and there is no certainty that any of these volumes will be produced.

Third Party Information: Peer, market and industry data in this presentation are taken from the third-party sources cited. Tamarack believes these sources are reliable but has not independently verified the data and makes no representation as to its accuracy or completeness.

Abbreviations	
AECO	Alberta natural gas benchmark price
ARO	Asset retirement obligations
Bbl	Barrel
Bbl/d	Barrels per day
Bln	Billion
Boe/d	Barrels of oil equivalent per day
cP	Centipoise
EOR	Enhanced oil recovery
GJ	Gigajoule
LTM	Last twelve months
Mbbl	Thousand barrels
Mboe/d	Thousand barrels of oil equivalent per day
MM	Million
MMbbl	Million barrels
NCIB	Normal course issuer bid
WCS	Western Canadian Select
WTI	West Texas Intermediate
YE	Year end