TSX: TVE

CREATING SUSTAINABLE VALUE

West Marten 15-15 Battery Facility
15-15-076-05W5

July 2026 | **Investor Presentation**

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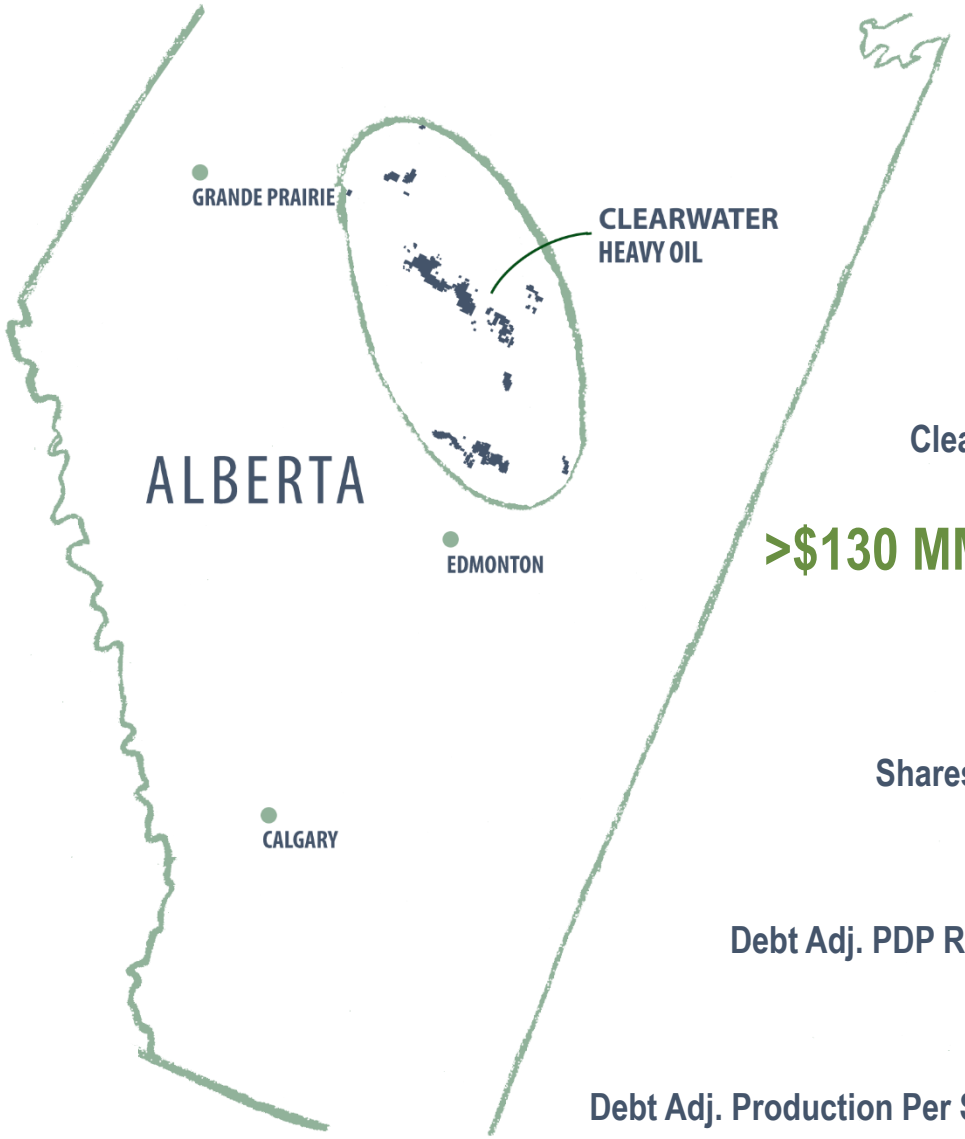
Corporate and Operational Snapshot

Largest Public, Pure-Play Clearwater Producer

Corporate Overview		
Ticker Symbol	**Units**	**TSX: TVE**
Shares Outstanding (Basic)[1]	*(MM)*	476
Share Price (July 27, 2026)	*($/Sh.)*	$12.93
Market Capitalization	***($B)***	**$6.1**
Net Debt (Cash)	***($B)***	**$(0.1)**
Enterprise Value	***($B)***	**$6.0**
Annual Dividend[2]	*($/Sh.)*	$0.20
Annual Dividend Yield[2]	*(%)*	~1.5%
2026 Guidance Highlights		
Production[3]	*(boe/d)*	61,500 – 63,000
Average Liquids Weighting	*(%)*	88% – 90%
Capital Expenditures[4]	*($MM)*	$430 – $450



>900 Net Sections
Clearwater Land | 38% YoY Growth

>$130 MM Net Cash Position
~$1.3 Bln Liquidity

>$400 MM | ~14.6%[5]
Shares Repurchased Since Jan. 2024

~42%[6]
Debt Adj. PDP Reserve Growth (25YE vs. 24YE)

~9%[6]
Debt Adj. Production Per Share Growth (Q2/26 vs. Q2/25)

1) Share count as at the end of June 2026.
2) Based on annualized base dividend of $0.20 per share. Dividend yield uses Tamarack share price as at Jul. 27, 2026.
3) 2026E Production of 61,500 – 63,000 boe/d: ~79% heavy oil, ~8% light oil, ~2% NGLs and ~11% natural gas.
4) Capital expenditures excluding ARO spending.
5) Based on shares outstanding Dec. 31, 2023, and repurchases up to and including Jun. 30, 2026.
6) Debt adjusted with a TVE share price of ~$12.50/Sh.

Differentiating Tamarack: Asset Scale & Economic Scope

Highly Economic Full-Cycle Returns = Free Funds Flow Growth

Top Tier Assets With Large OOIP[1]

- >12 billion barrels of OOIP in the Clearwater; <2% of OOIP produced by end of 5 Yr. Plan
- Proven Clearwater waterflood driving incremental resource capture and duration
- >25 years of Clearwater inventory driven by >2,100 drilling locations

Low Production Declines & Trending Lower

- Unique ability to grow Clearwater production and reduce decline rates through waterflood

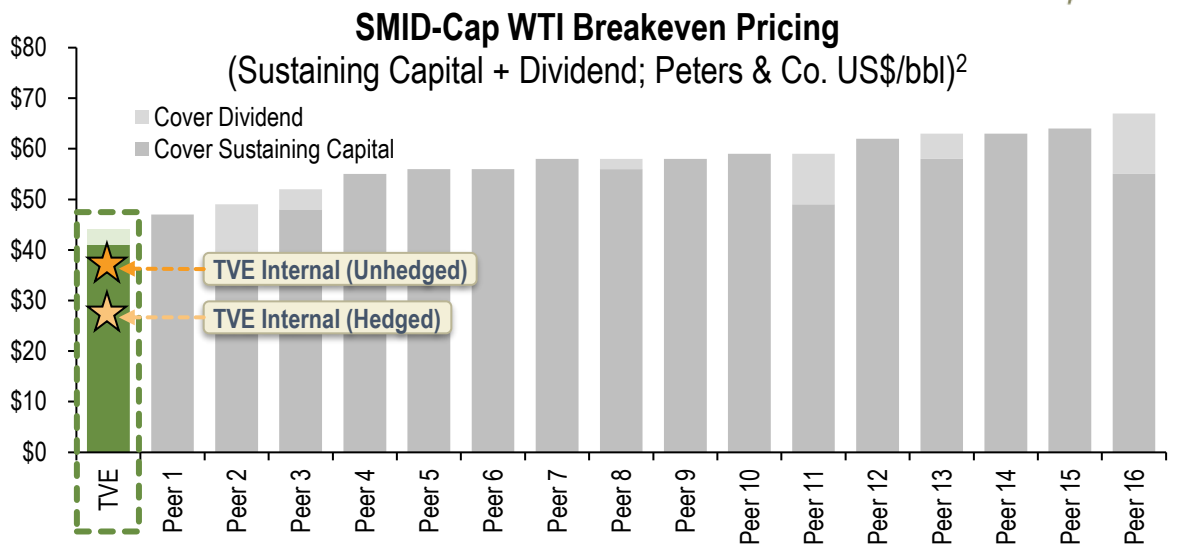
Low Sustaining Cost & Resilient Breakeven Price

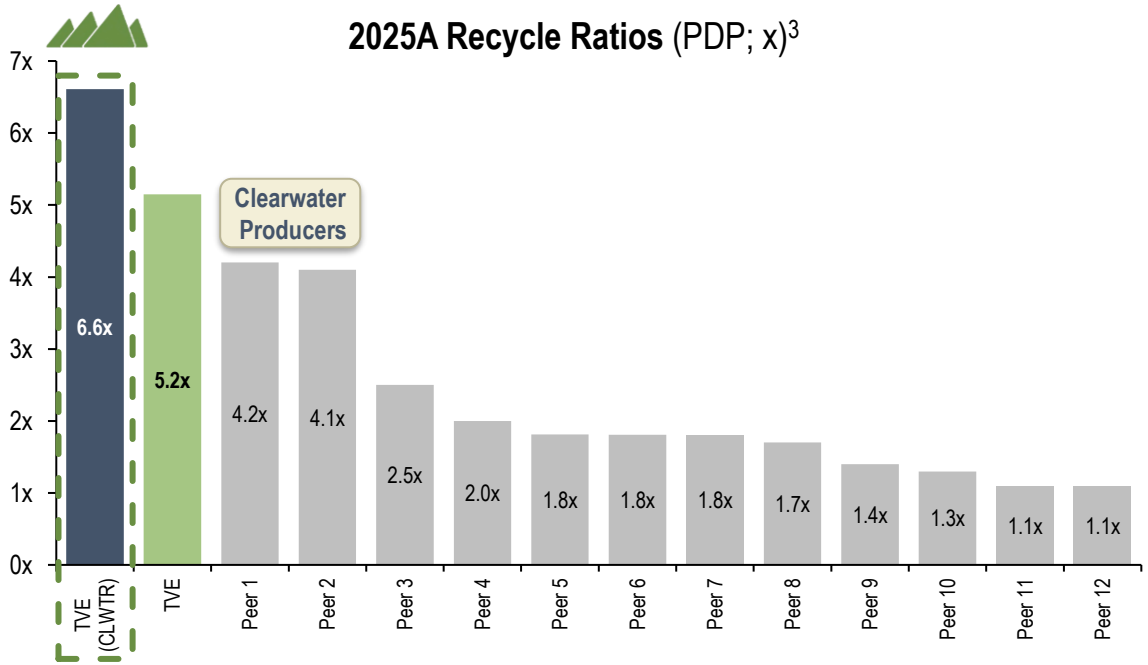
- Unhedged breakeven <US$38/bbl WTI covering maintenance capital + dividend

Increasing Total Returns

Capital Allocation Optionality

- Focused on assets and capital allocation to generate the highest return ON capital, to allow the highest return OF capital





See Disclaimers – "Specified Financial Measures".

1) OOIP – original oil in place based on internal estimates.

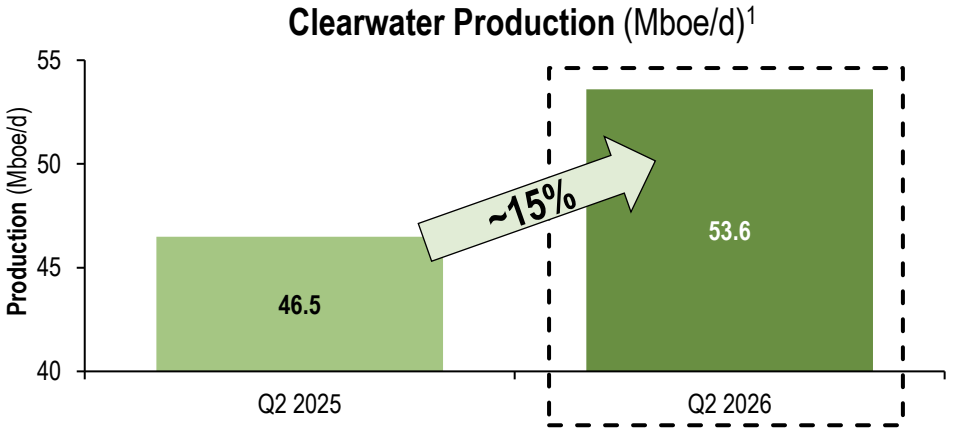
2) Breakeven estimates per Peters & Co. Breakeven estimates are ranked by the total of sustaining capital + dividend coverage. Peer group includes ATH, BNE, BTE, CJ, GFR, HWX, IPCO, JOY, LTC, OBE, RBY, SCR, SGY, SOIL, WCP, and YGR. Data as of Jul. 2026.

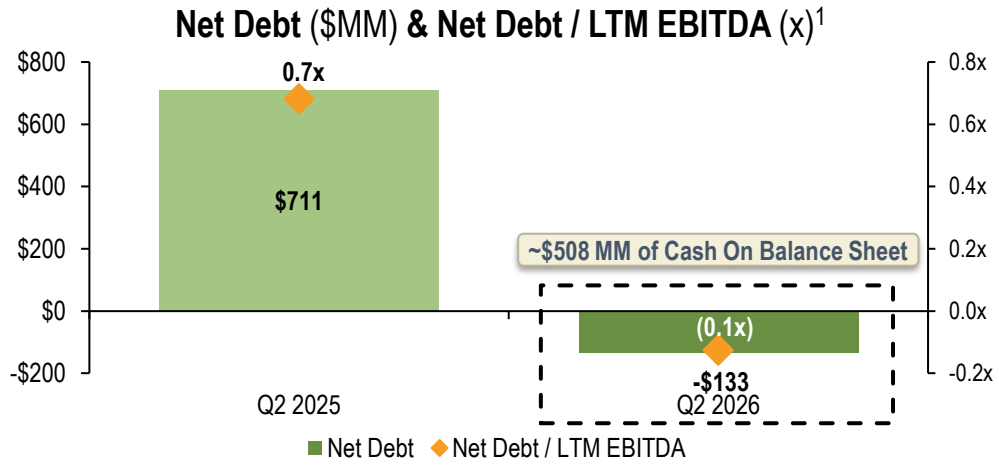
3) Data as per Company Filings. FD&A costs used for recycle ratio in cases where F&D costs undisclosed. Peer Group Includes BTE, HWX, IPO, KEL, OBE, RBY, SCR, SDE, SGY, Spur, VET, and WCP.

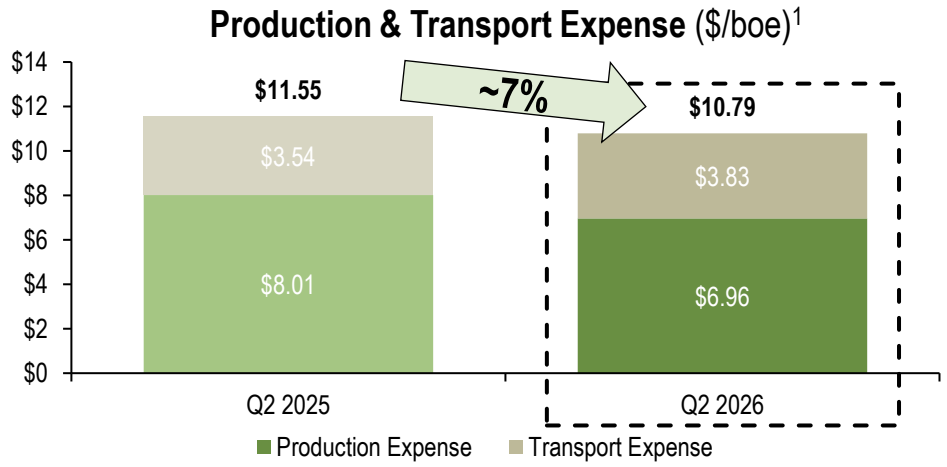
Q2 2026 Highlights

Portfolio Optimization and Continued Margin Growth

- Q2/26 corporate production averaged ~69.2 Mboe/d[(2)]; **Clearwater production of ~53.6 Mboe/d**
- Current Clearwater waterflood injection of **~45,000 bbl/d** with an anticipated exit water injection rate of **~70,000 bbl/d by 2026YE (16% increase on exit volumes vs. original budget)**
- Q2/26 delivered **record adjusted funds flow of ~$255.1 MM ($0.53 per common share)** and **free funds flow of ~$154.8 MM ($0.32 per common share)**
- Returned **~$99.5 MM** to shareholders through share buybacks and base dividends in Q2
  - Repurchased ~**6.6 MM common shares (~1.4% of float)** for **~$80.3 MM**
  - Paid **~$19.2 MM** of dividends; current base dividend of **$0.20/Sh. (increased by 25%)**
- Net cash position of **~$133 MM** in Q2/26 **(~$508 MM of cash on balance sheet)**







1) See "Specified Financial Measures".
2) Production of 69,229 boe/d: 8,757 bbl/d light & medium oil, 49,291 bbl/d heavy oil, 2,157 bbl/d NGL, 54,142 mcf/d natural gas.

Transition To Pure Play Clearwater Producer

Sale of Charlie Lake Assets and 25% Dividend Increase

Crystalizing Significant Value For Shorter-Duration Assets

Sale Of Charlie Lake Unlocks Asset Value
(Effective April 1, 2026)

- **~$804 MM** Cash Proceeds *(Before Closing Adjustments)*
- Sold ~18,000 boe/d (67% Liquids)
- Cash return on invested capital[1] of **>70%**

Concentrating Capital To Highly Economic Opportunities

Optimizing Capital Allocation

Growing Higher Margin Barrels With Lower Reinvestment Requirements
- Expand Primary and Secondary Development In The Clearwater; **Higher Growth Rate**

Accelerating Portfolio Optionality

Decades of High-Quality Development
- Extensive Drilling Inventory & Exploration Upside
- **Largest** Remaining Clearwater Waterflood Potential Acreage[2]

Meaningful Accretion On Advancing Focused Strategy

Low Breakeven; High Margin

Higher Profitability: US$38/bbl WTI Breakeven
- Annual Sustaining Capital **<$200 MM**
- Lower Decline Rate to **15%** Thru 5-Year Plan
- Run-Rate Operating Expense **~$6/boe**

Significant Asset Duration

Clearwater Development Acceleration
- < 2% of OOIP Produced By End of 5 Yr. Plan
- Enhanced Recovery With Waterflood Expansion
- Replace Charlie Lake Production With Higher Margin Clearwater Organic Production Growth

Cash Position With Significant Liquidity

Flexibility To Be Opportunistic
- **$133 MM** Net Cash Position at June 2026, Plus
- **~$1.3 Bln** of Available Liquidity

Increasing Shareholder Returns

Resilient Free Funds Flow Drives Returns
- Increased Annual Dividend By **25%** To $0.20/Sh.
- Up To **~100% Total Shareholder Return** Over 5 Yrs (US$75/bbl WTI)

See Disclaimers – "Specified Financial Measures".

1) Based on pre-tax return, calculated as field operating netbacks since inception of $1.1 billion plus gross proceeds from the disposal net of transaction costs, divided by the Company's original net acquisition and development costs of $1.1 billion.

2) Source: Enverus Intelligence Research, February 2026.

Demonstrated Value Creation

Compounding Success On a Per Share Basis

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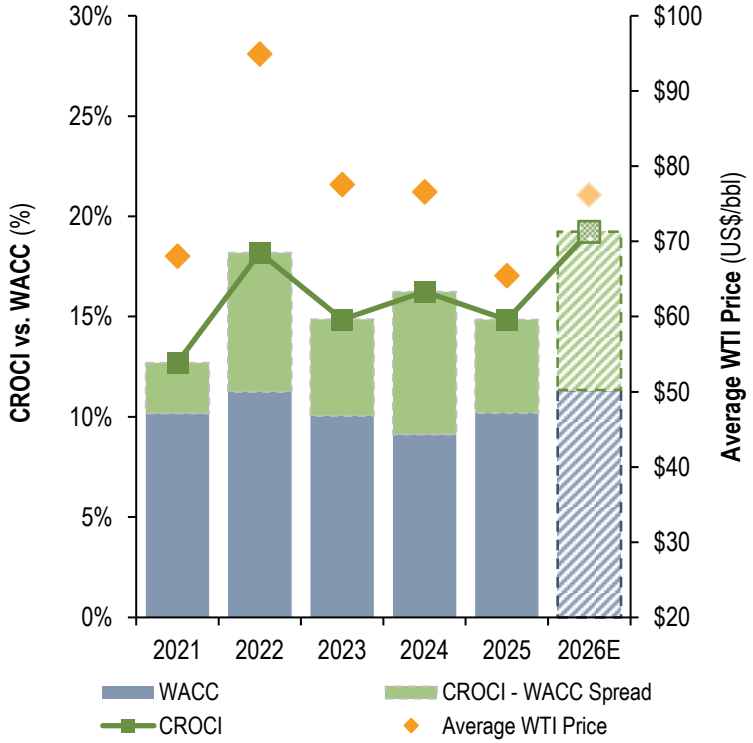
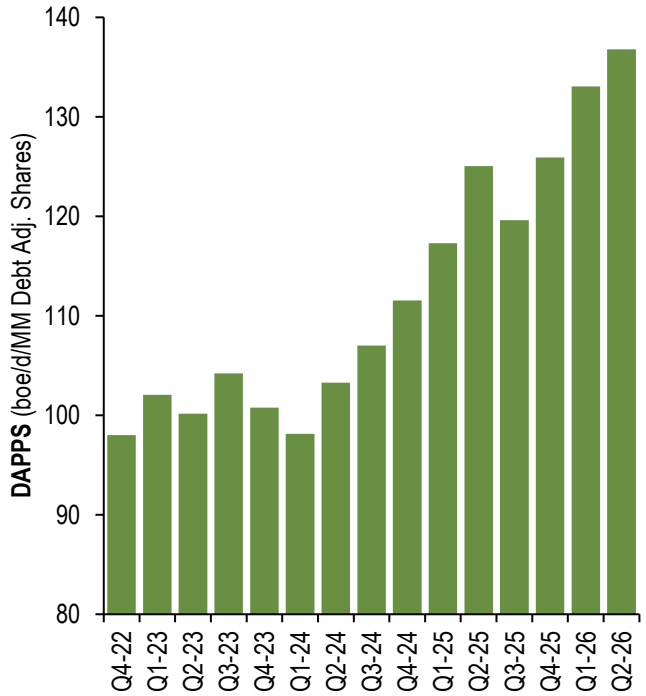
CROCI vs. WACC (%)[1]

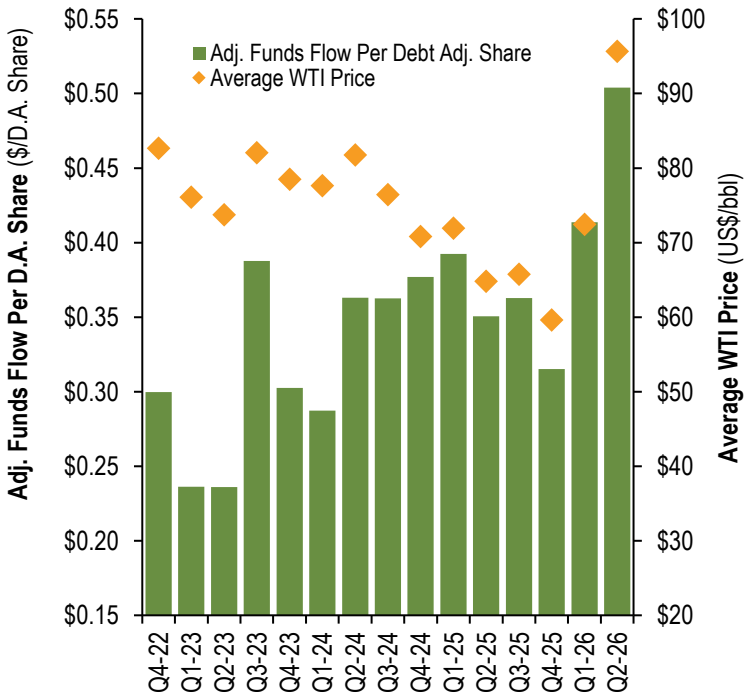


Revised Budget Pricing Assumes US$70/bbl WTI & 1.35 US$/C$ In 2H/2026

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



Adj. Funds Flow Per Debt Adj. Share ($/Sh.)[2]



Repurchased ~14.6% of 2023YE Share Count To Date (as at Q2 2026)[3] at Average Cost of $5.39/Sh.

Net Cash Position of ~$133 MM (~$508 MM Cash On Balance Sheet)

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

1) "Cash Return On Capital Invested" calculated as debt-adjusted cash flow from operations before working capital changes divided by capital invested. Capital invested calculated as total assets plus accumulated DD&A minus cash and cash equivalents minus non-interest-bearing current liabilities. WACC assumes 5% ERP and average yield on US 10-year as a risk-free rate. 2026E assumes US$70/bbl and 1.35 US$/C$ in 2H/2026.

2) Debt adjusted using a Tamarack share price of $12.50/Sh.
Quarterly DAPPS and debt adj. FFO per share amounts use average net debts and weighted average common share counts during the quarter.
3) Change in common share count from Dec. 31, 2023, to Jun. 30, 2026.

Updated 2026 Corporate Guidance

Pure Play Clearwater Company Geared For Incremental Growth & Returns

	Budget	Updated Pricing
WTI (US$/bbl)	$60.00	$76.18
WTI / MSW Diff (US$/bbl)	($4.00)	($1.96)
WTI / WCS Diff (US$/bbl)	($12.75)	($15.68)
MSW (C$/bbl)	$75.60	$101.21
WCS (C$/bbl)	$63.79	$82.49
AECO ($/GJ)	$2.75	$1.88
FX (US$/C$)	1.35	1.36
2026 Annual Guidance	**Public Guidance** *(Dec. 2025)*	**Updated Guidance**
Charlie Lake Capital[1] ($MM)		$45
Clearwater & Other Capital[1] ($MM)		$385 – $405
2026 Total Capital Budget[1] ($MM)	$390 – $410	$430 – $450
Charlie Lake Production (boe/d)		8,000
Clearwater Production (boe/d)		53,500 – 55,000
Total Production (boe/d)	69,000 – 71,000	61,500 – 63,000
Average Oil & NGL %	84% – 86%	88% – 90%
Royalties (%)	19% – 21%	20% – 22%
Wellhead Oil Price Diff[2] ($/bbl)	$1.00 – $1.50	$0.75 – $1.25
Production Expense[3] ($/boe)	$6.85 – $7.15	$6.65 – $6.90
Transportation Expense ($/boe)	$4.00 – $4.50	$4.00 – $4.50
G&A ($/boe)	$1.30 – $1.45	$1.40 – $1.55
Interest[4] ($/boe)	$2.70 – $3.10	$2.00 – $2.40
Income Tax[5] (%)	10% – 12%	17% – 19%

Revised Budget Pricing Assumes US$70/bbl WTI & 1.35 US$/C$ In 2H/2026

Expanded Clearwater Capital Program By $75 MM

~40% of Expansion Dedicated Towards Secondary Waterflood Recovery

Expected 2026 Exit Water Injection of 70,000 bbl/d

~16% Higher Than Original Budget; >38% Oil Production Under Waterflood

Forecasting Clearwater Annual Production Growth of 15% Year-Over-Year

While Lowering Declines And Reinvestment Requirements

Focused Delineation

Primary and Enhanced Oil Recovery Across The Greater Clearwater Fairway & Pelican Region

1) Excludes ARO capital.
2) Oil wellhead deductions for grade specific trading differential (ex. CHV), blending requirements, quality differential, and pipeline tolls if TVE is not marketing (lease transactions).
3) Includes CIP fee for service and minimal carbon tax budgeted.
4) Includes CIP ToP capital fee.
5) Income tax expense measured as a % of B-Tax funds flow.

Preliminary Pure Play Clearwater 5-Year Plan

5-Year Plan To Be Updated Q4 2026

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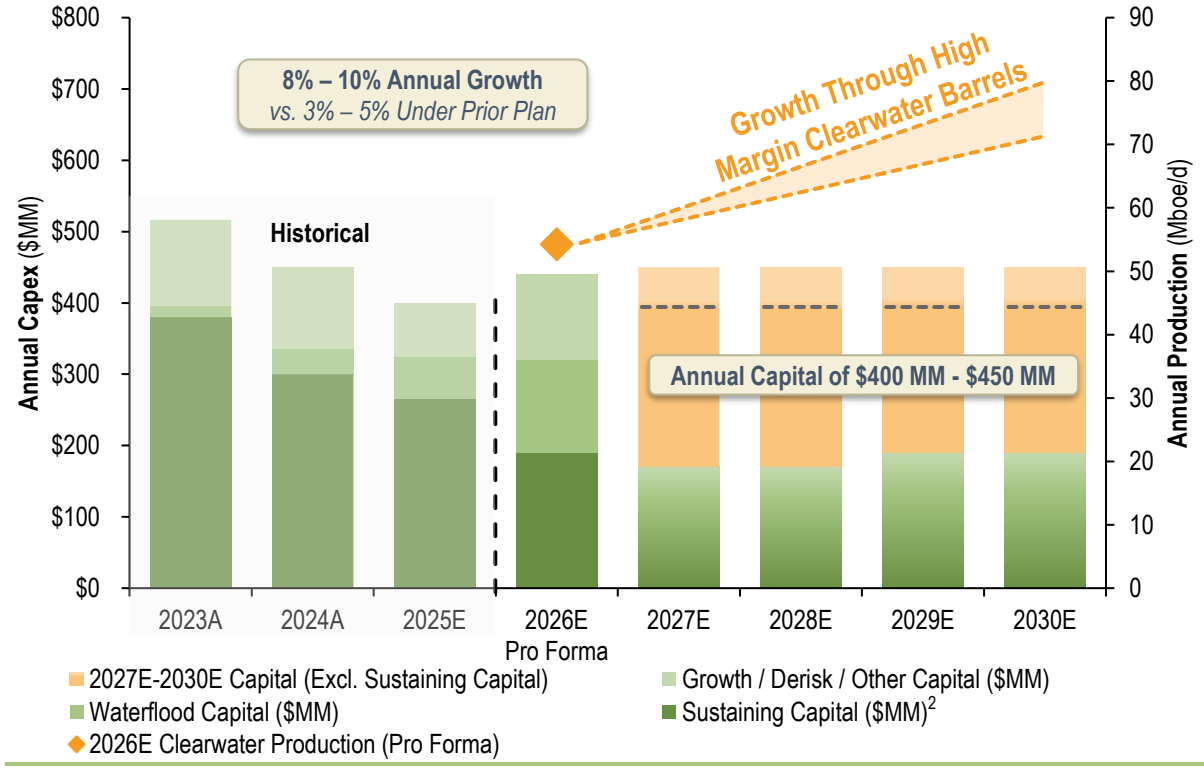
Tamarack Has The Unique Ability To Grow Production and Reduce Decline Rates Simultaneously

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

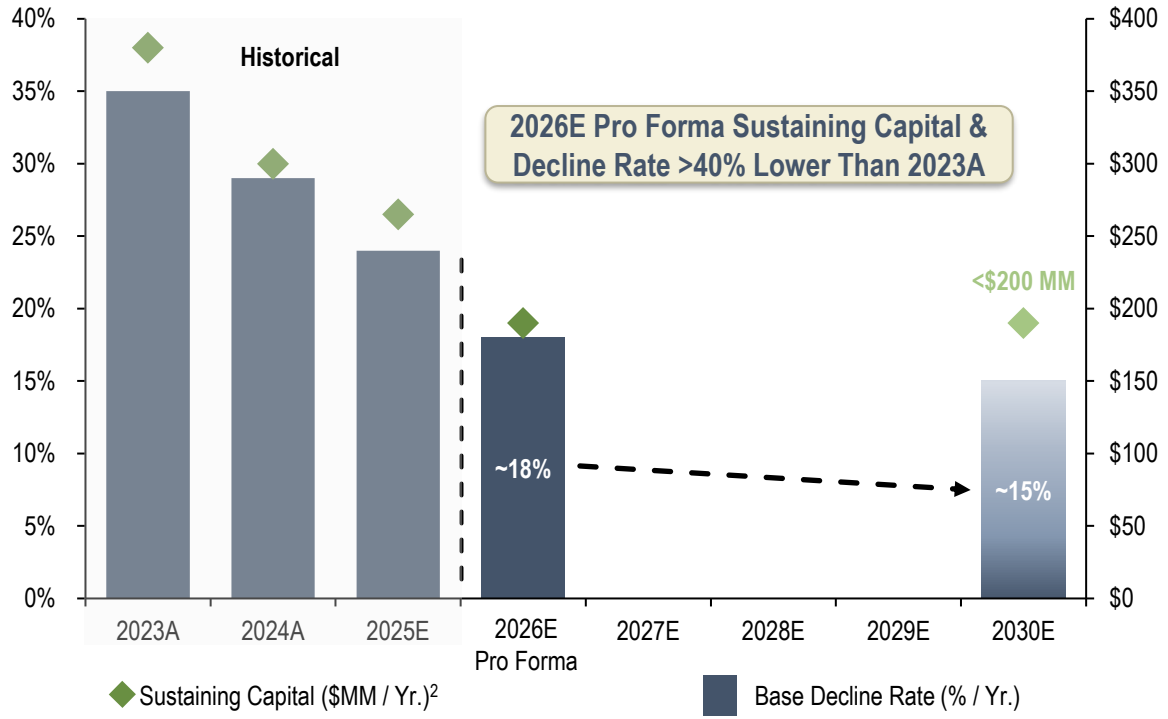
- Sustaining capital <$200 MM throughout 5-year plan with plans to grow to 75+ Mboe/d by 2030E
  - Average capex / funds flow reinvestment of ~45% from 2027E-2030E (US$75/bbl WTI) with optionality for higher growth; sustaining capital of <20% of funds flow
- Replacing Charlie Lake production with higher margin Clearwater growth through the plan

Emerging Exploration Areas (Pelican, Seal, etc.) Are Currently Outside The 5-Year Plan & Offer Additional Upside

5 Yr. Plan Capex & Production ($MM & Mboe/d)



Annual Corporate Base Decline Rate & Sustaining Capital (%; $MM)[2]



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.

Compounding Per Share Returns With Increased Optionality

Production Growth + Lower Sustaining Capital + Share Buybacks + Excess Cash Flow = Outsized Per Share Returns

Annual Discretionary Free Funds Flow Yield Increases Through Plan

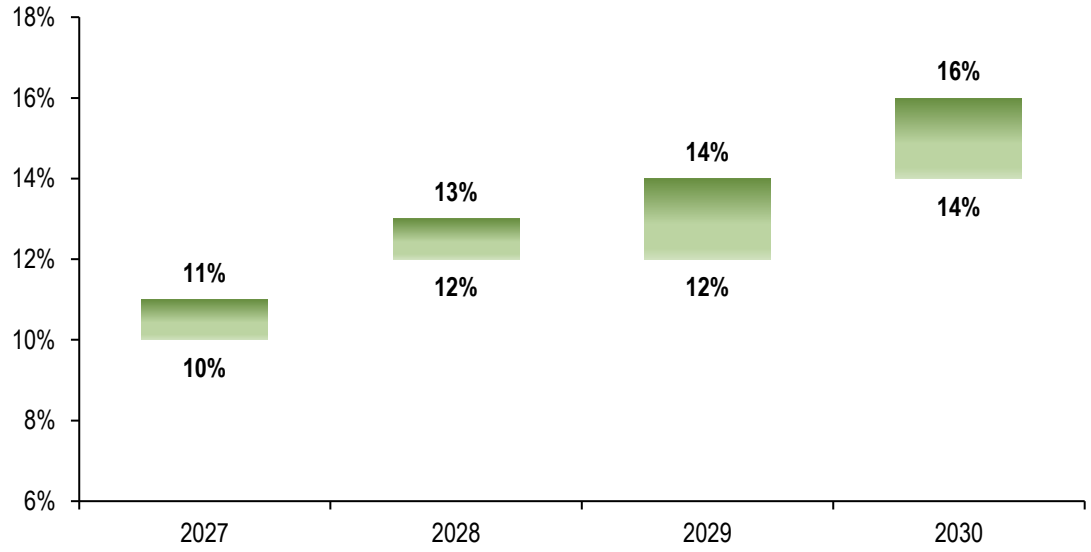
- Investment in waterflood continues to lower base decline rates & sustaining capital requirements; while growing high margin Clearwater barrels simultaneously

5-Year Plan To Be Updated Q4 2026

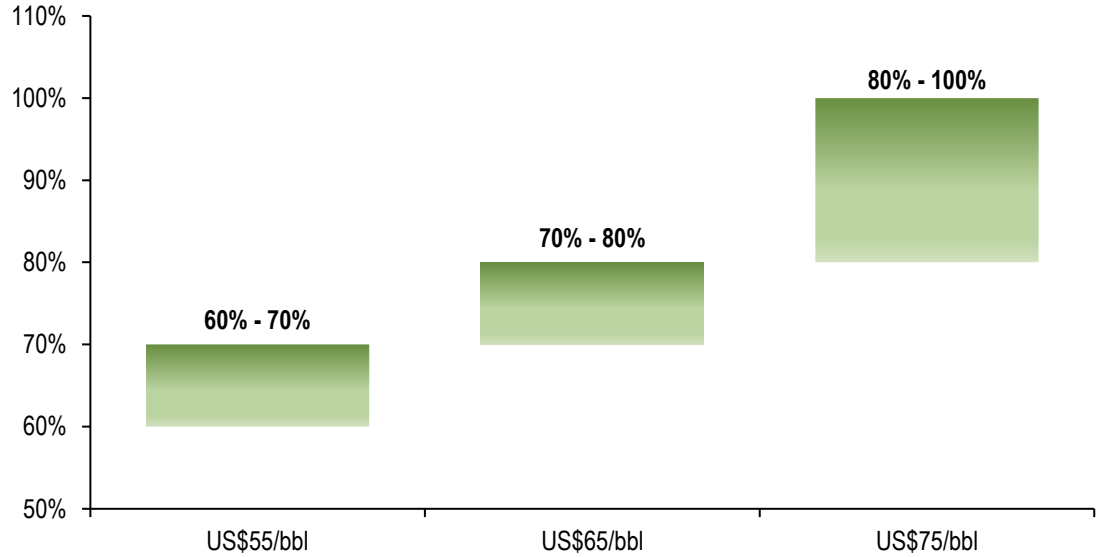
Cumulative Total Shareholder Return of ~60% - 100% Over 5 Years (US$55/bbl – US$75/bbl)[3]

- **TSR = Production Growth + Dividends + Buybacks + Excess Cash Flow (Optionality)**
- Balanced shareholder return framework
  - Increased annual dividend by 25% to $0.20/Sh. commencing in Q3 2026

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



Pro Forma Cumulative 5-Year Total Shareholder Return
(2026E-2030E; %)[1,3]

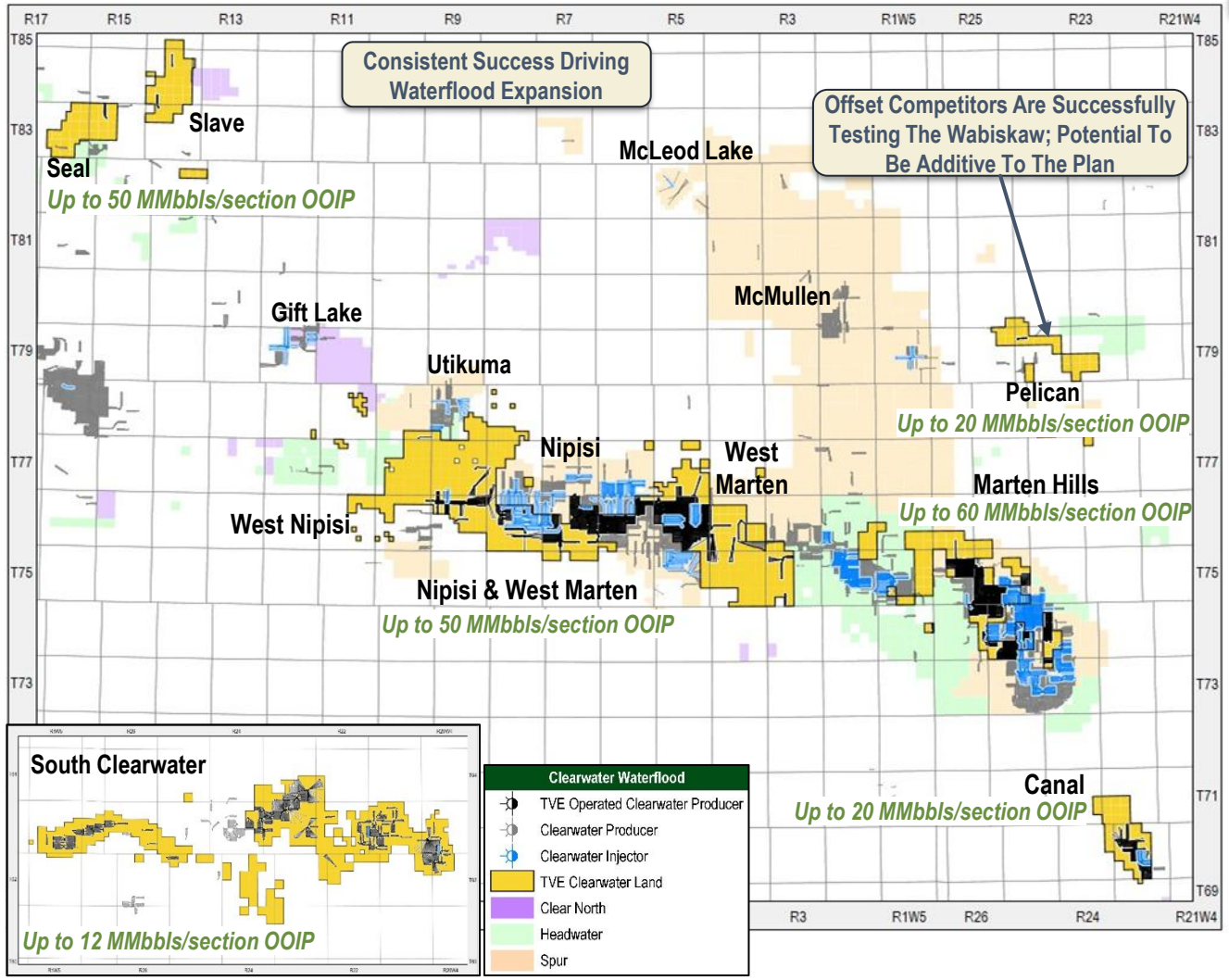


1) See Disclaimers – "Specified Financial Measures". Disc. FFF yield assumes enterprise value of ~$5.7 B. Total shareholder return assumes market capitalization of ~$5.8 B. All flat decks assume 1.30 US$/C$.
2) Discretionary free funds flow is adj. funds flow – sustaining capital required to hold production flat, for each given year.
3) Assumes run-rate annual dividend ($MM) is flat at ~$95 MM/Yr. Assumes shares repurchased at $12.50/Sh. Return from share buybacks is % of share count repurchased vs 2025YE. Return from debt repayment is change in debt relative to 2025YE (incl. disposition proceeds) relative to current market capitalization. Return from production growth uses midpoint of 2026E Clearwater production as the baseline.

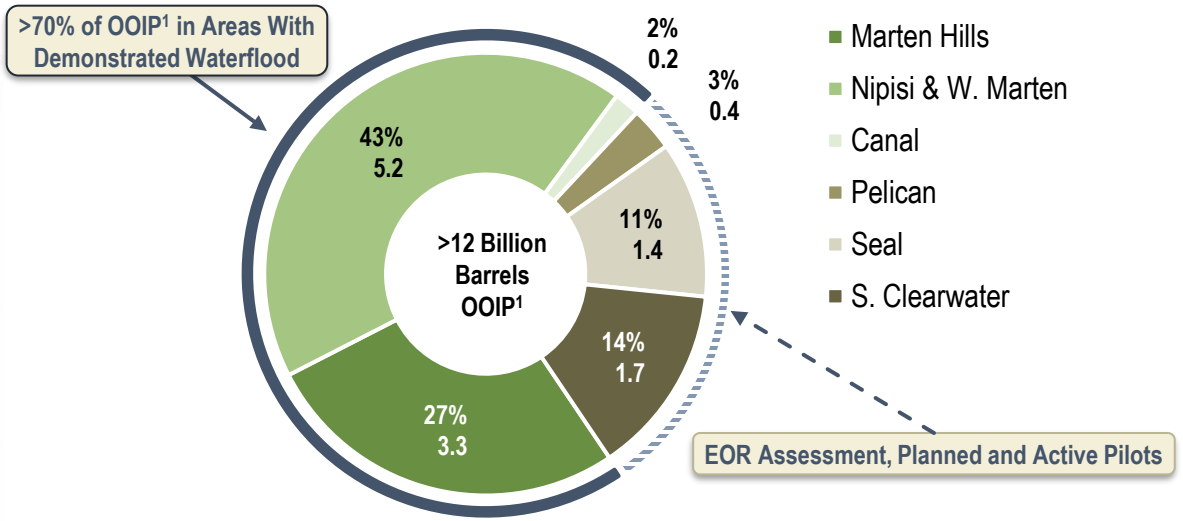
Asset Portfolio

Clearwater Waterflood Expansion

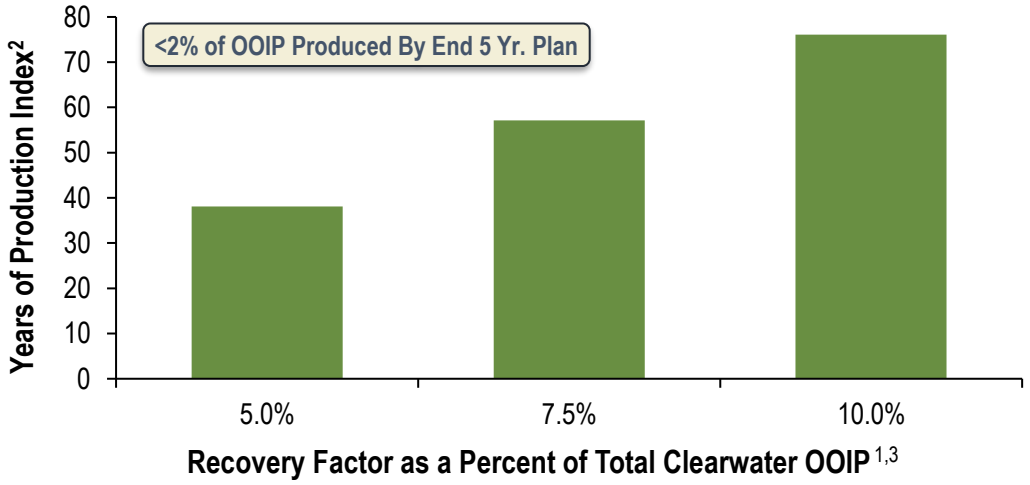
Substantial Oil In Place and Proven Waterflood Drives Asset Duration



Clearwater OOIP By Area[1]



Years of Production[2]



1) OOIP – original oil in place based on internal estimates. OOIP does not include lands associated with Caribou habitat restoration in West Marten.
2) Years of Production Index is defined as recovered oil divided by 2025 oil production; based on internal management estimates.
3) Based on 2025 Clearwater oil production of ~16 MMbbls.

Industry Leading Clearwater Inventory & Duration With Waterflood

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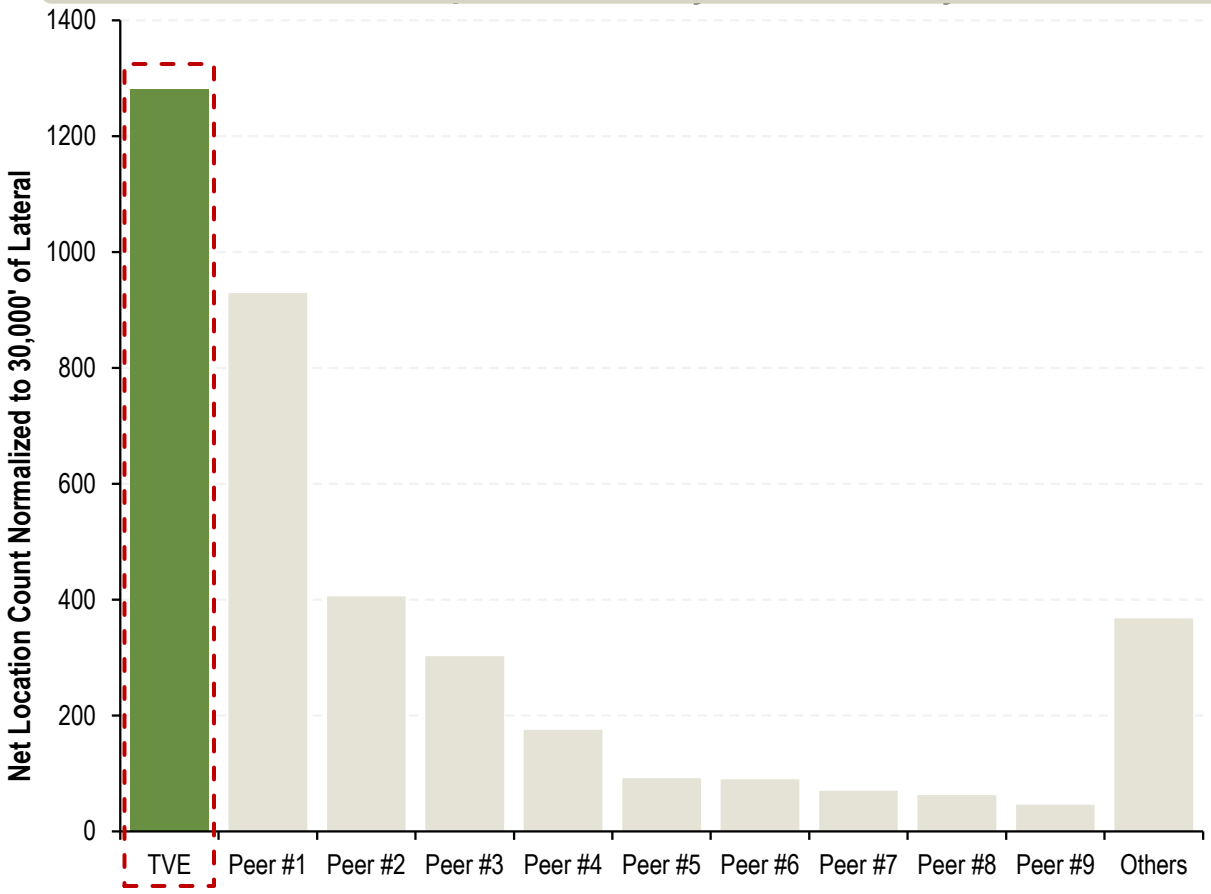
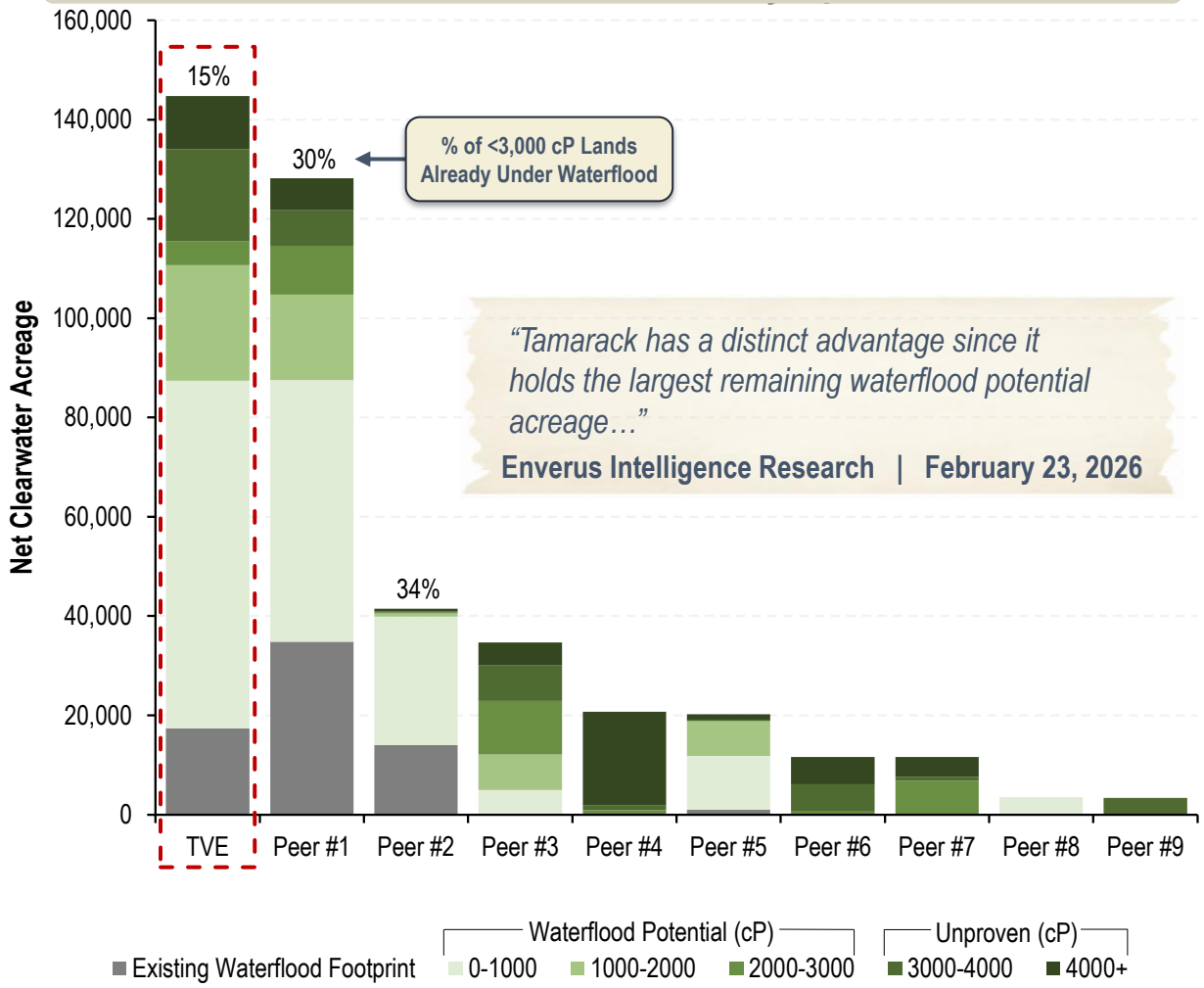
Clearwater Operator Primary Well Inventory[1]



Clearwater Waterflood Acres By Operator[2]



"Tamarack has a distinct advantage since it holds the largest remaining waterflood potential acreage…"

Enverus Intelligence Research | February 23, 2026

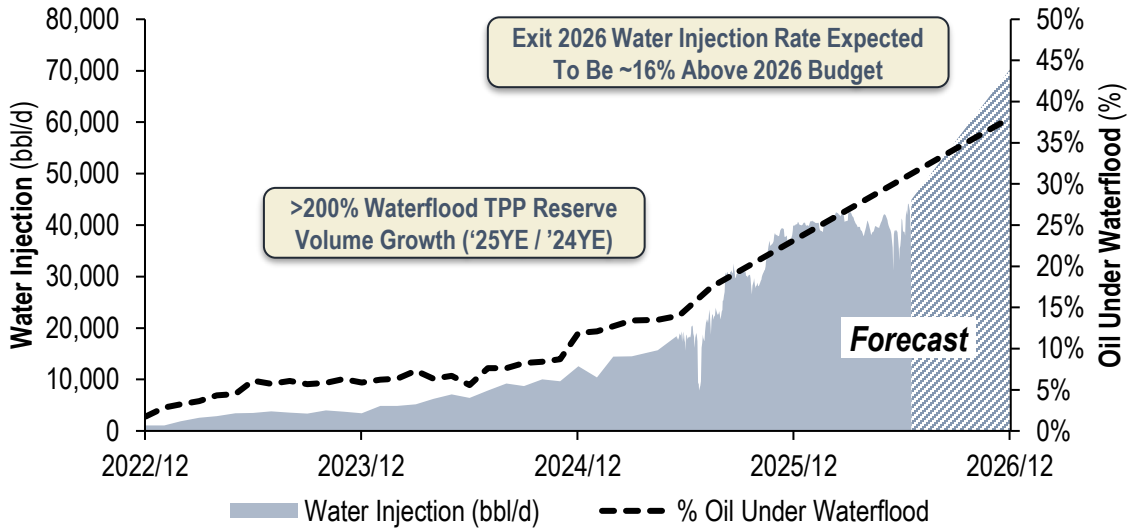
1) Clearwater Operator Primary Well Inventory per Enverus Intelligence Research (Feb. 2026). Peer group includes BTE, CNQ, HWX, ISH Energy, Longridge, OBE, RBY, Spur, and Woodcote.

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.

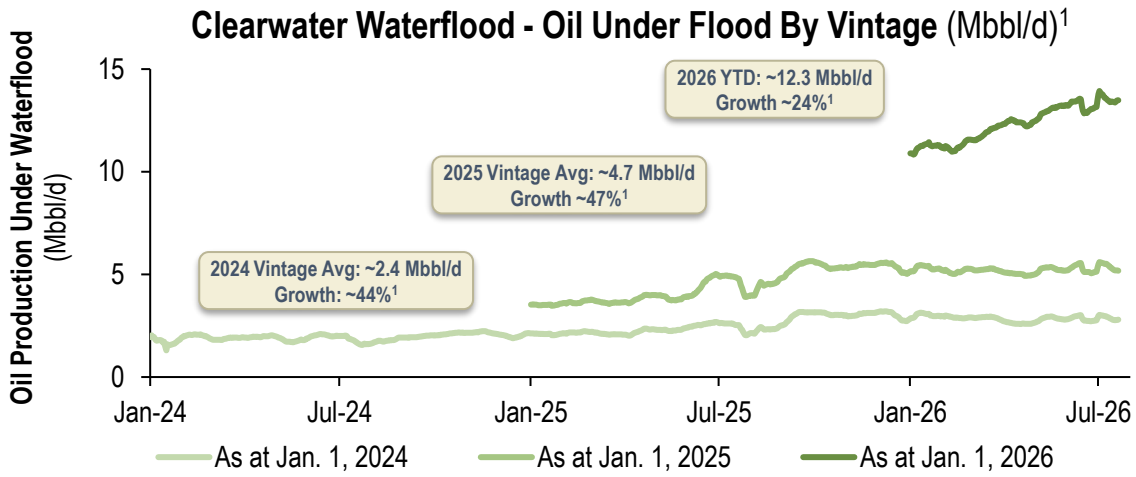
Clearwater Waterflood Progression

Advancing Secondary Recovery To Drive Incremental Resource Capture

Clearwater Injection & Production Under Waterflood



Clearwater Waterflood - Oil Under Flood By Vintage (Mbbl/d)[1]



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

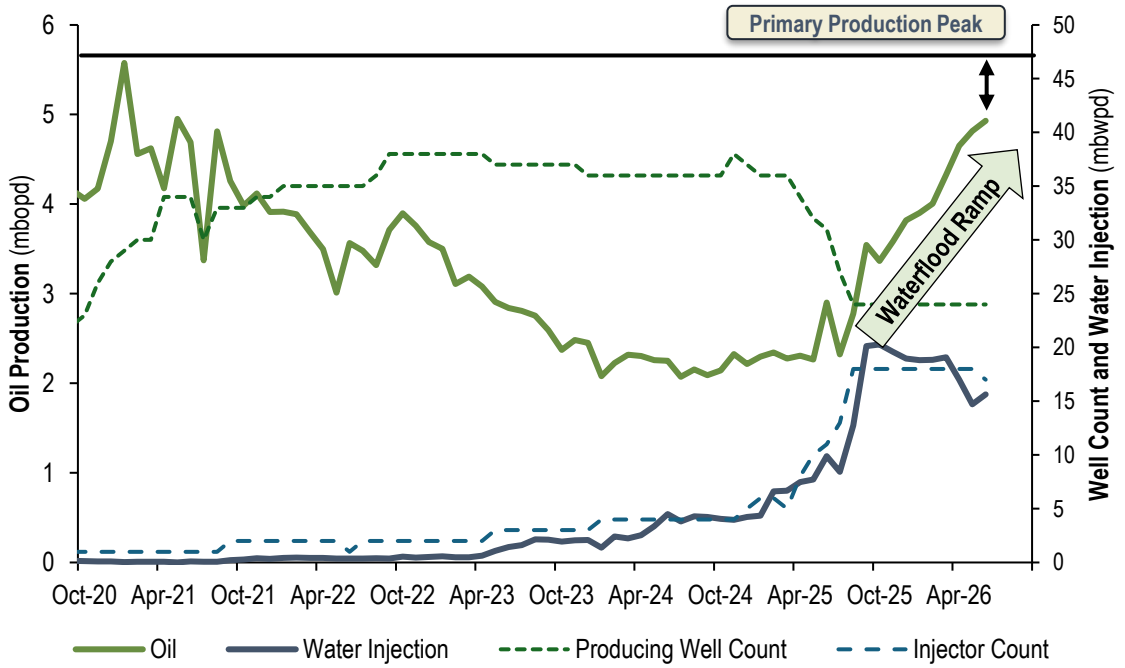
>38% of Clearwater Oil Production Under Waterflood by YE 2026

1) Average production by vintage is the average production from wells in the onstream date to the end of the data series. Growth from start to finish is from the vintage onstream date to the end of the data series (i.e., 2024 vintage growth measured from Jan. 1, 2024 to Jul. 20, 2026).

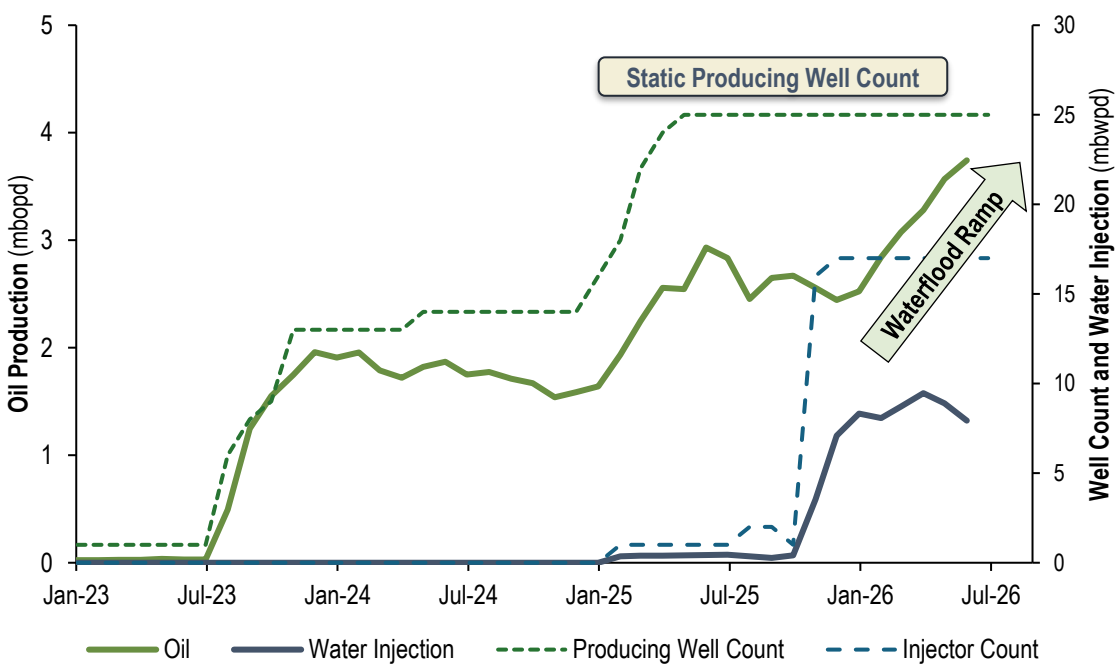
Prolific Waterflood Performance

Secondary Recovery Redefining Production Potential

Marten Hills Producers Under Flood at YE 2025



West Marten Producers Under Flood at YE 2025



- Higher sustained injection rates are shortening response times and increasing peak production across developed patterns
- Waterflood production has ramped to ~88% of historical primary peak rates and continues to trend upward
- Injector conversions generating incremental oil recovery at an F&D of <$1.00/bbl[1]

- Waterflood response is establishing new production highs, surpassing historical primary peaks
- Rapid production response following injection ramp-up demonstrates exceptional reservoir connectivity and accelerated value creation

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 $0.4MM per injector conversion

Clearwater Reserve Growth: Transformative Primary & Secondary Recovery[1]

Performance Pointing Towards Significant Technical Revisions

Continued Recognition of Higher Recovery Factors in the Clearwater

- Maturing data is leading to higher confidence in well recoveries

Waterflood Success Adds Tailwinds To Reserves

- Reserves added broadly every year the waterflood outperforms
- Clearwater waterflood PDP F&D costs of <$3/boe in 2025

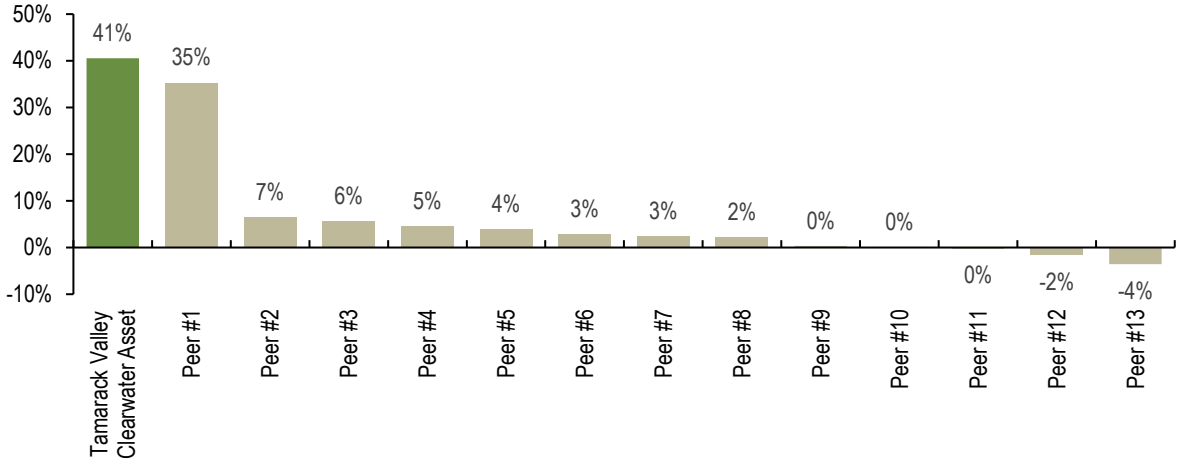
Clearwater Outperformance Supporting Positive Revisions and Growth

- Base production continues to exceed expectations, driving positive revisions and incremental growth

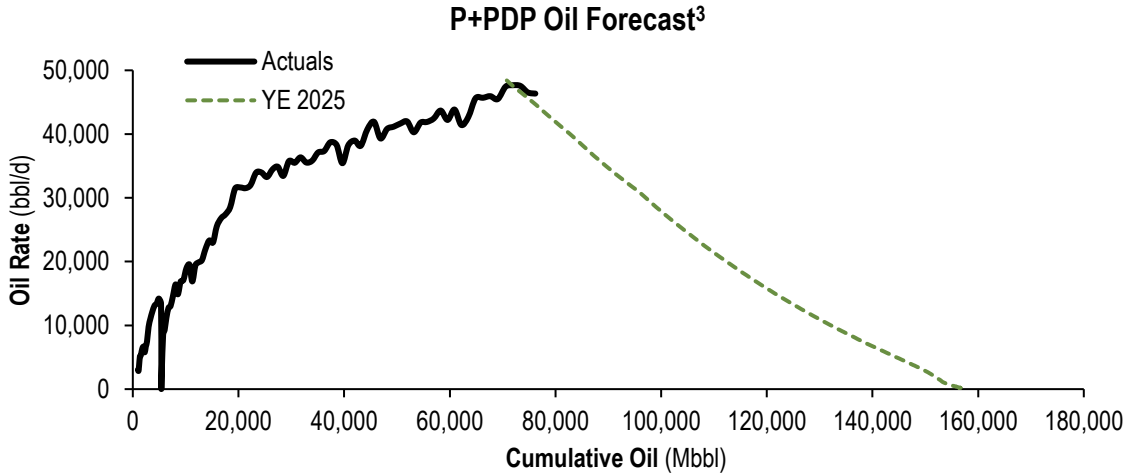
Waterflood Performance Lowering Decline and Capital Requirements

- Strong waterflood performance is reducing corporate decline, driving lower sustaining capital requirements and improved growth efficiency

Total Proved Technical Revisions[2]
(as % of the reserves opening balance)



Clearwater Base Performance
(actuals vs. 2025YE reserves)



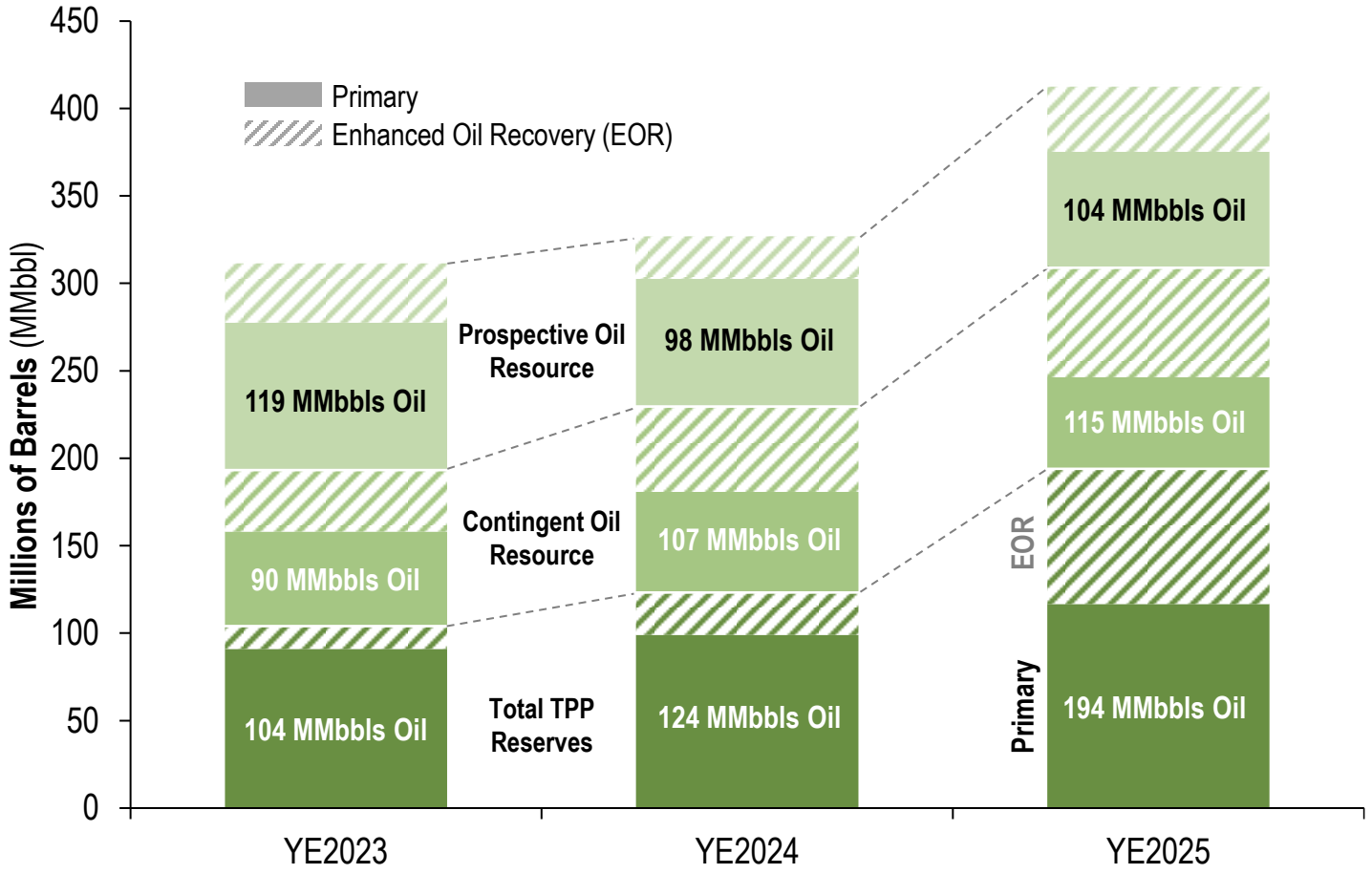
F&D = Finding & Development Costs. See "Disclaimers – Oil & Gas Metrics".
1) See Disclaimers – "Reserves Disclosure".
2) Peer group includes AAV, ARX, ATH, BIR, BTE, CJ, CVE, HWX, KEL, LGN, OBE, SDE, and TOU.

3) Total Clearwater P+PDP oil forecast as at 2025YE.
P+PDP = Proved Developed Producing reserves + associated Probable Developed Producing reserves.
See "Disclaimers – Oil & Gas Metrics".

Clearwater Contingent & Prospective Resource Report

Multi-Decade Duration

Clearwater Reserves & Resources YoY Growth[1,2]



Decades of Development

<2% of The >12 Billion Barrels OOIP Produced By End of 5 Yr. Plan

Multi-Year Inventory

Identified Clearwater Inventory >2,100 Locations;
>25 Years of Development at Current Rate of Primary Development

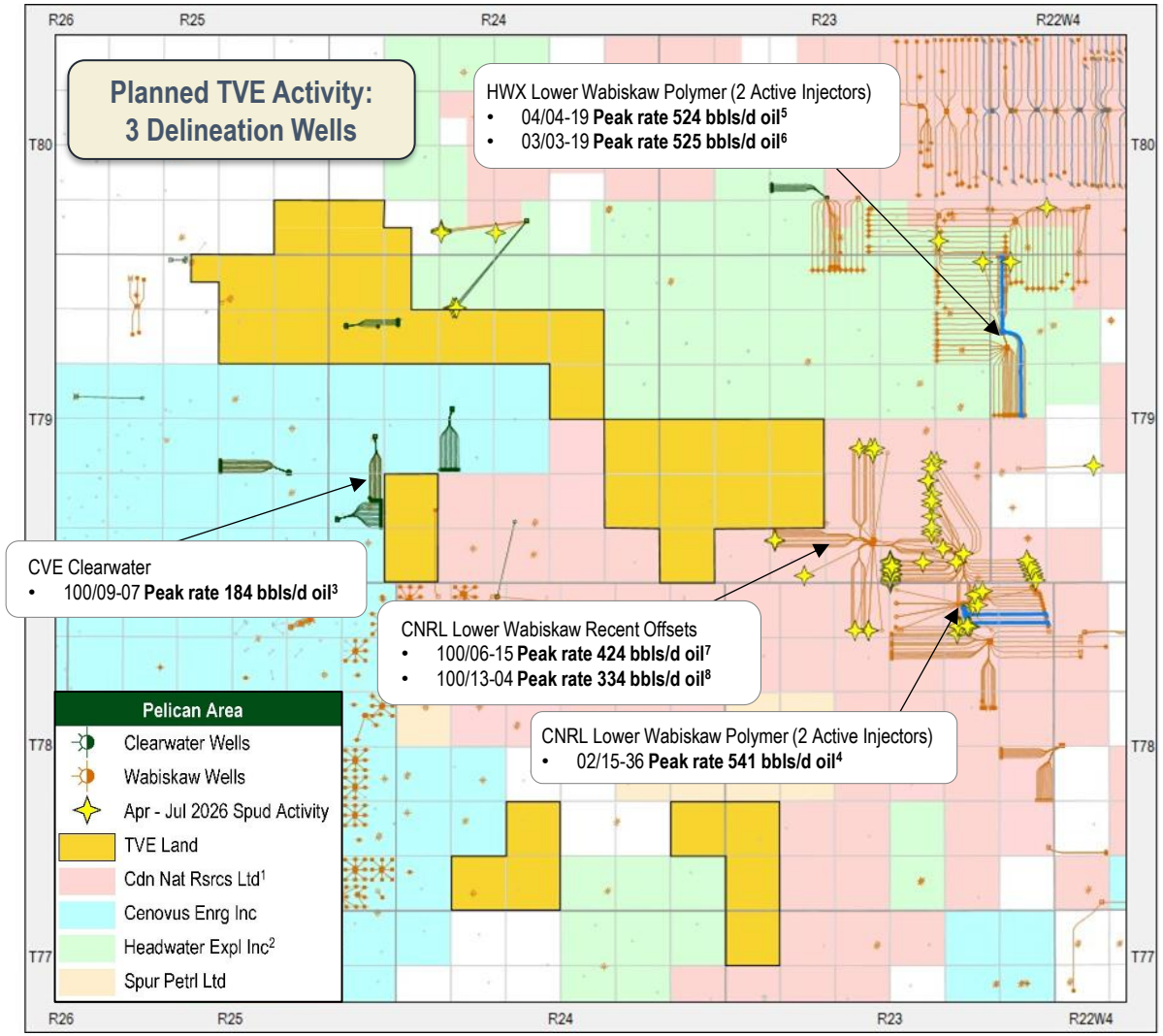
TPP Oil Reserves Associated With Waterflood Grew By >200% YoY[3]

~40% of Total Booked Clearwater TPP Reserves Currently Associated With Waterflood

1) Based on McDaniel & Associates Consultants Ltd. Resource Report effective December 31, 2023, 2024, and 2025. See Disclaimers – "Resource Disclosure".
2) Reserves, contingent resources, and prospective resources should not be combined without recognition of the significant differences in the criteria associated with their classification.
3) Based on change from total proved plus probable oil reserves associated with enhanced oil recovery of 24.5 MMbbls at 2024YE vs. 77.8 MMbbls at 2025YE.

Future Growth Optionality: Pelican

Delineation of Stacked Zone Potential; Upside To 5-Yr Plan



Pelican

Land Position:

- ~32 gross sections (Oil Sands Tenure)

Stacked Development Upside:

- Lower / Middle Wabiskaw & Clearwater
- 630 MMbbl OOIP

Offsetting Activity:

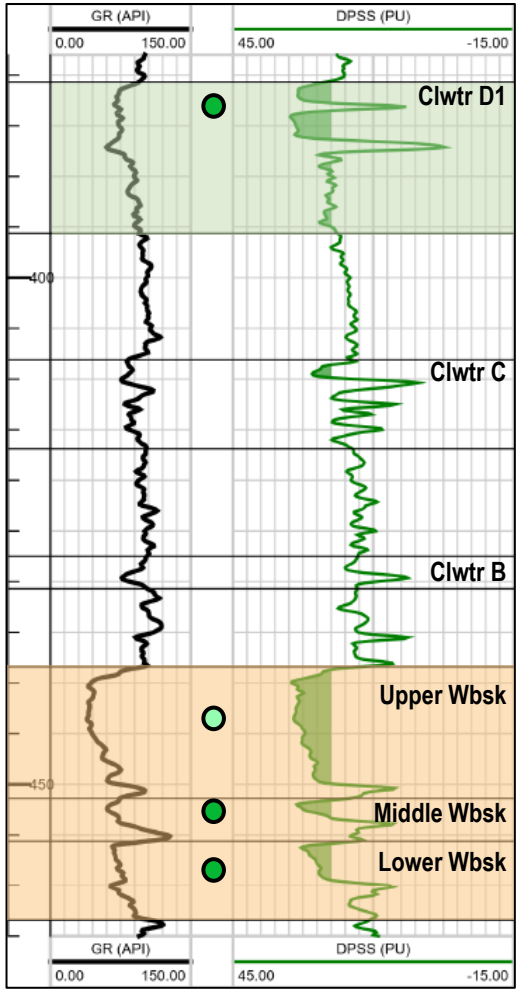
- Multiple operators with offsetting activity in both Clearwater and Wabiskaw zones

Secondary Recovery Schemes:

- Can increase recovery factors by 2-3x

Planned TVE Activity:

- Drill 3 delineation wells targeting Clearwater D1 and Lower Wabiskaw
- Enhanced oil recovery simulation underway



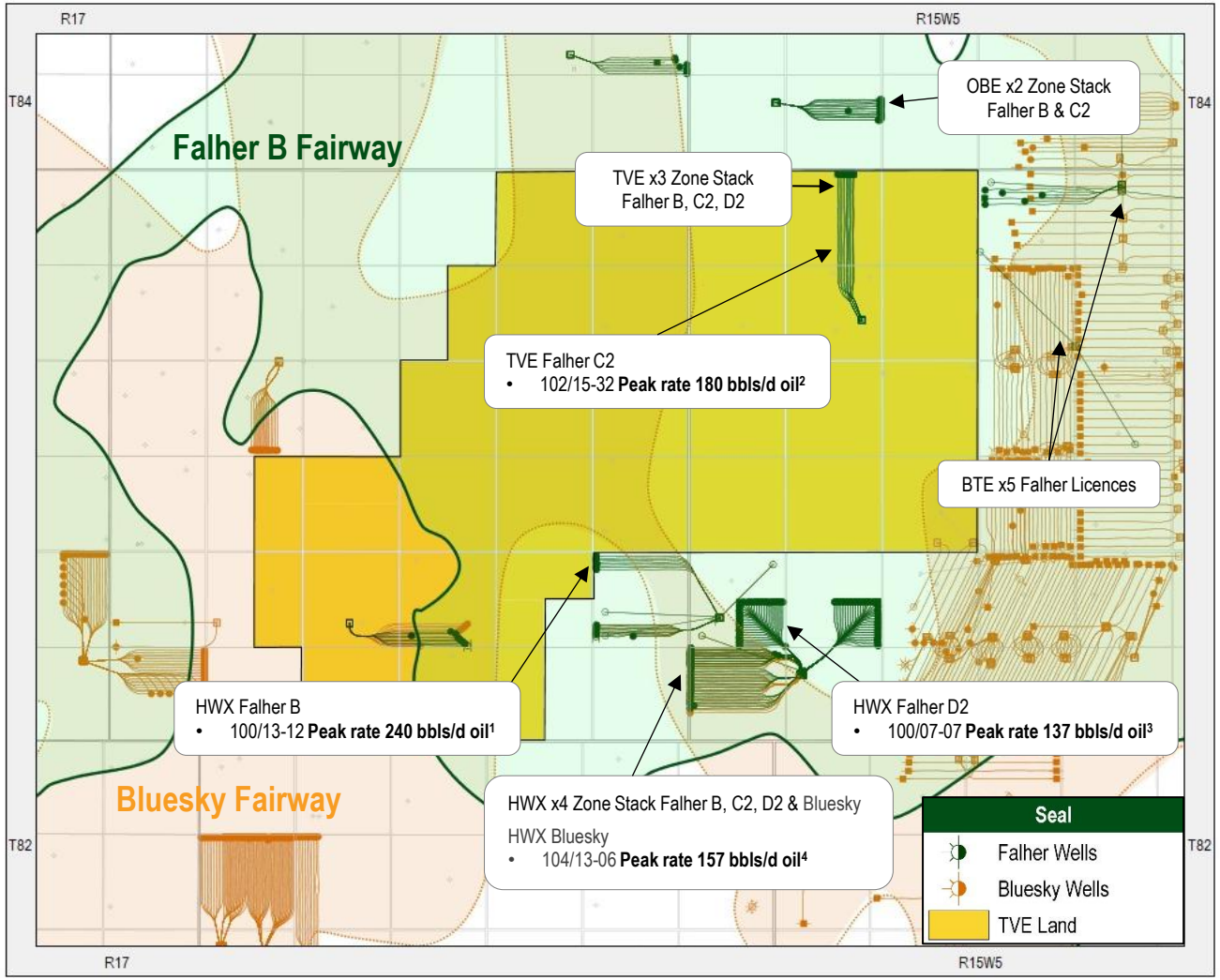
Stacked Development Upside

Potential Upside

1) Source: Canadian Natural Investor Open House Presentation, November 7, 2025.
2) Source: Headwater Exploration Inc. Corporate Presentation, April 2026.
3) Source: GeoScout September 2025 Producing Day Average Oil Rate.
4) Source: GeoScout Aug 2024 Producing Day Average Oil Rate.
5) Source: GeoScout Dec 2025 Producing Day Average Oil Rate.
6) Source: GeoScout Feb 2026 Producing Day Average Oil Rate
7) Source: GeoScout May 2026 Producing Day Average Oil Rate.
8) Source: GeoScout June 2026 Producing Day Average Oil Rate.

Future Growth Optionality: Seal

Delineation of Secondary Recovery Potential In Stacked Zones; Upside To 5-Yr Plan



Seal

Land Position:

- ~30 gross sections (oil sands tenure)

Stacked Development Upside:

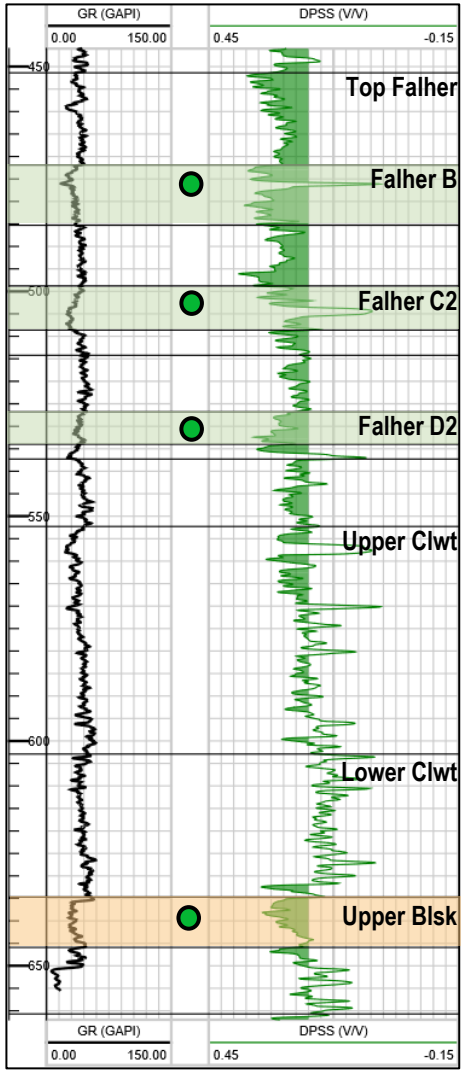
- Bluesky, Falher B, C2, & D2 sands
- 1.8 billion barrels OOIP

Secondary Recovery Schemes:

- Can increase recovery factors by 2-3x

TVE Next Steps:

- Further delineate stacked zones and initiate Falher waterflood 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 Apr. 2024 Calendar Day Average Oil Rate.

Maximizing Long-Term Free Funds Flow[1] Per Share

Unprecedented Clearwater Waterflood Providing More For Less

- ✓ *>12 Bln bbls of OOIP[2] in the Clearwater*
- ✓ *Advancing EOR to drive incremental resource capture*

- ✓ *Unique ability to lower declines & grow production*
- ✓ *Reducing sustaining capital requirements*

- ✓ **Commitment to Returns: Maximize Returns To Shareholders Across Commodity Cycles**
- ✓ **Leveraging Scale and Quality To Deliver Sustainable Long-Term Returns Per Share**
- ✓ **Financial Flexibility and Liquidity To Take Advantage of Strategic Opportunities and/or Growth**

- ✓ *Premium netbacks, higher price realizations and lower cost structure*
- ✓ *US$38/bbl sustaining breakeven (unhedged)*

1) See Disclaimers – "Specified Financial Measures".
2) OOIP – original oil in place based on internal estimates. OOIP does not include lands associated with Caribou habitat restoration in West Marten..

Appendix

Risk Management[1]

Enhancing Certainty With Flexibility To Capture Upside Value

Oil Hedges	Units	Q3 2026	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027
WTI Collars							
Volume	*bbl/d*	13,000	18,500	18,000	15,000	4,000	
Avg. Floor Price	*US$/bbl*	$53.46	$50.00	$51.53	$53.50	$55.00	
Avg. Ceiling Price	*US$/bbl*	$74.90	$78.65	$83.36	$84.00	$88.96	
Avg. Premium	*US$/bbl*	$0.64	$1.64	$0.25	$0.08		
WTI Puts							
Volume	*bbl/d*	5,000					
Avg. Put Price	*US$/bbl*	$50.00					
Avg. Premium	*US$/bbl*	$2.78					
WTI - WCS Hardisty Basis Swaps[3]							
Volume	*bbl/d*	7,500	15,500				
Avg. Fixed Price	*US$/bbl*	($11.84)	($13.05)				

Oil Hedges *(Net of Royalties)*	Units	Q3 2026	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027
Crude Oil Hedged With WTI Contracts	%	45%	43%	42%	34%	9%	
Heavy Exposure Hedged With WCS Basis[3]	%	19%	36%				

FX Hedges	Units	Q3 2026	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027
US$/C$ Collars							
Notational	*US$MM/Month*	$16.0	$19.0	$12.0	$12.0	$15.0	$15.0
Avg. Floor Price	*US$/C$*	1.351	1.351	1.336	1.336	1.347	1.347
Avg. Ceiling Price	*US$/C$*	1.396	1.397	1.389	1.389	1.408	1.408
US$/C$ Swaps							
Notational	*US$MM/Month*	$8.0	$8.0	$9.0	$9.0	$2.0	$2.0
Avg. Fixed Price	*US$/C$*	1.366	1.366	1.365	1.365	1.381	1.381
US$/C$ Variable Collars[2]							
Notational	*US$MM/Month*	$10.0	$10.0	$10.0	$10.0	$10.0	$10.0
Avg. Floor Price	*US$/C$*	1.353	1.353	1.336	1.336	1.345	1.345
Avg. Ceiling Price	*US$/C$*	1.424	1.424	1.409	1.409	1.426	1.426
Avg. Knock-In Price	*US$/C$*	1.391	1.391	1.386	1.386	1.400	1.400

Natural Gas Hedges	Units	Q3 2026	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027
AECO 5A Swaps							
Volume	*GJ/d*	10,000	3,370				
Avg. Fixed Price	*C$/GJ*	$2.74	$2.74				

1) Hedges in place as at Jul 27, 2026. Royalty burden based on US$70/bbl WTI & 1.35 US$/C$.
2) If the average rate for the month exceeds the call, Tamarack receives an average rate forward equivalent to the knock-in price.
3) Includes 5,000 bbl/d of "synthetic" WCS Hardisty Basis trades (WCS Houston Basis Swap + WCS Transport Trade) in Q4/2026.

2025 Reserves Highlights[1,2,3]

Strong Reserve Growth Driven By Positive Technical Revisions

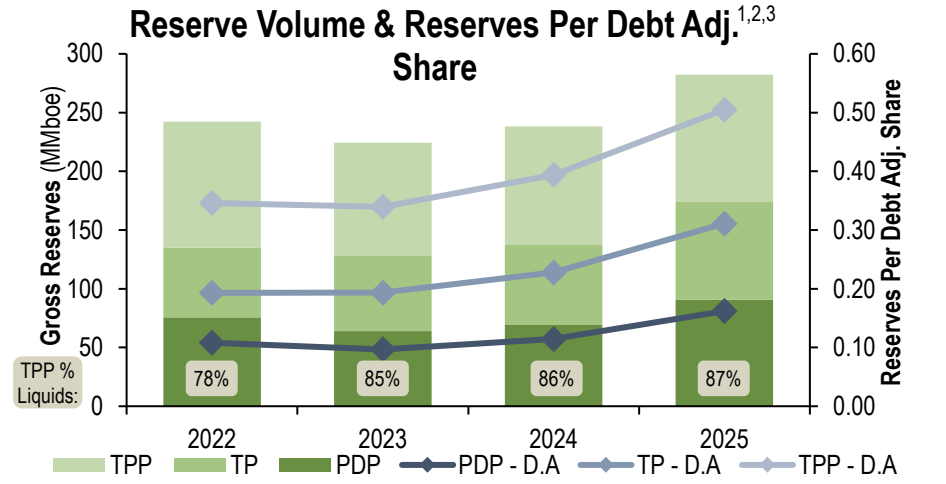
Clearwater TPP Reserves Grew By ~56%, While Replacing >500% of Production

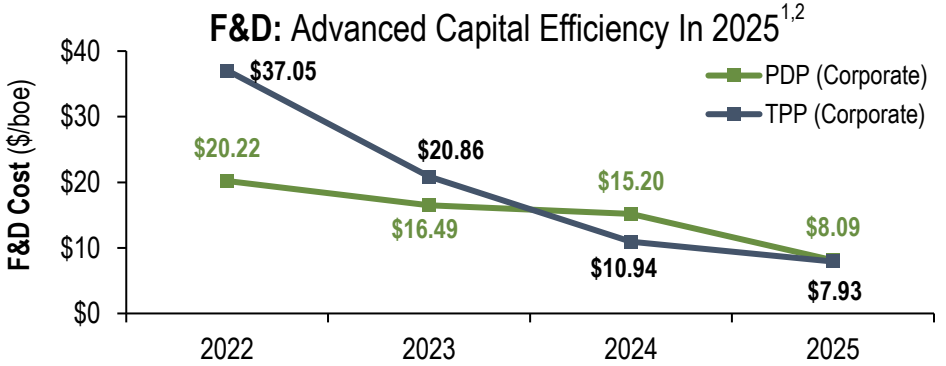
- Continued to demonstrate strong capital efficiencies with F&D costs of **$6.93/boe (PDP)** and **$7.33/boe (TPP)**
- Delivered recycle ratios of **6.6x (PDP) and 6.3x (TPP),** reinforcing the high-margin quality that can deliver strong returns
- Waterflood extending reserve duration by **increasing RLI by ~37% (PDP)** and **~32% (TPP)**
- PDP reserves under waterflood **expanded by 300%** and waterflood F&D on PDP **<3.00/boe and a recycle ratio >18x**

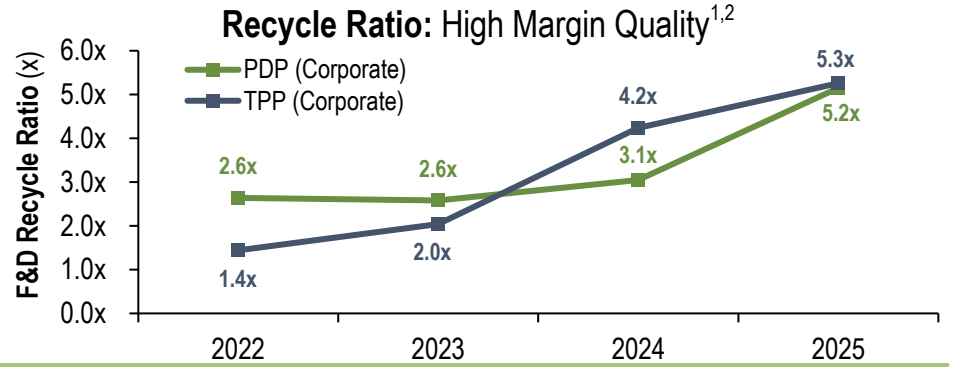
PDP and TPP Reserves Increased 31% and 18%

- **Production Replacement:** 224% on PDP and 413% on TPP (excluding A&D)
- **YoY Debt-Adjusted Reserve Growth Per Share:** 42% PDP and 28% TPP[3]
- **Industry Leading F&D Costs:** PDP and TPP F&D costs of $8.09/boe and $7.93/boe, respectively (includes 25.9 MMboe of PDP technical revisions)
- **Resilient Recycle Ratio:** 5.2x PDP and 5.3x TPP

Corporate Reserve Metrics







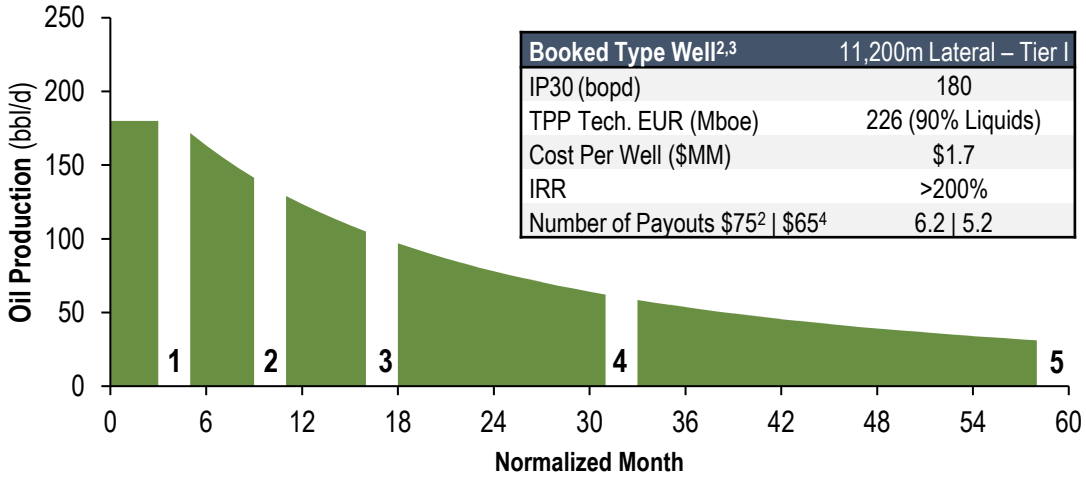
Reserve categories are proved developed producing ("PDP"); total proved ("TP"); and total proved plus probable ("TPP"). FDC = Future Development Costs. F&D = Finding & Development Costs. See "Disclaimers – Oil & Gas Metrics".
1) Based on McDaniel & Associates Consultants Ltd. Reserves Report effective December 31, 2025, available within the AIF.

2) 2022-2023 Reserves based on GLJ Ltd. reserves evaluation reports effective Dec. 31st of the respective year in accordance with NI 51-101 & COGE Handbook. 2024 Reserves Based on GLJ Ltd. and McDaniel & Associates Consultants Ltd Reserves Report effective December 31, 2024, available within the AIF. 3.) Debt adjusted using a Tamarack share price of $12.50.

Clearwater Economics: Primary Recovery

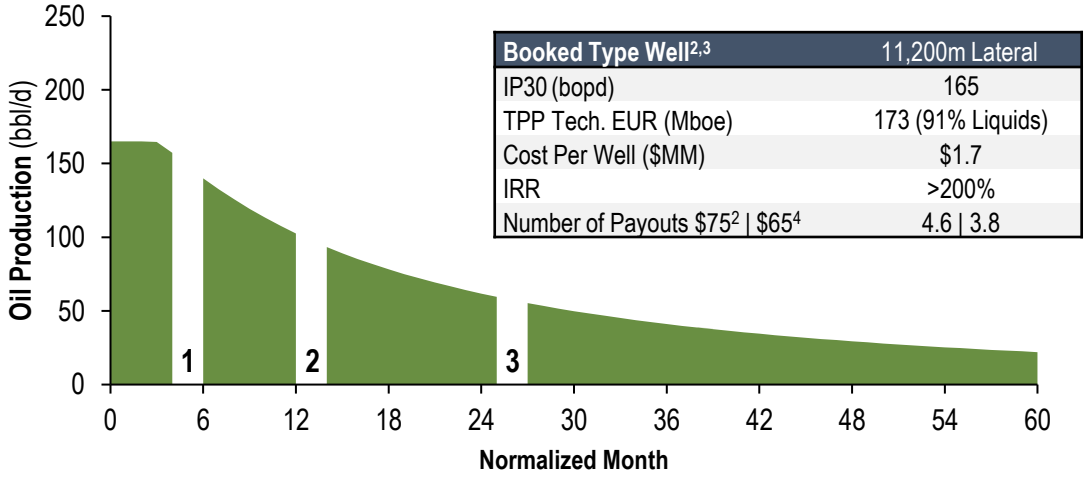
Multiple Payouts Compound Free Funds Flow[1] Growth

Northern Clearwater "B" Sand



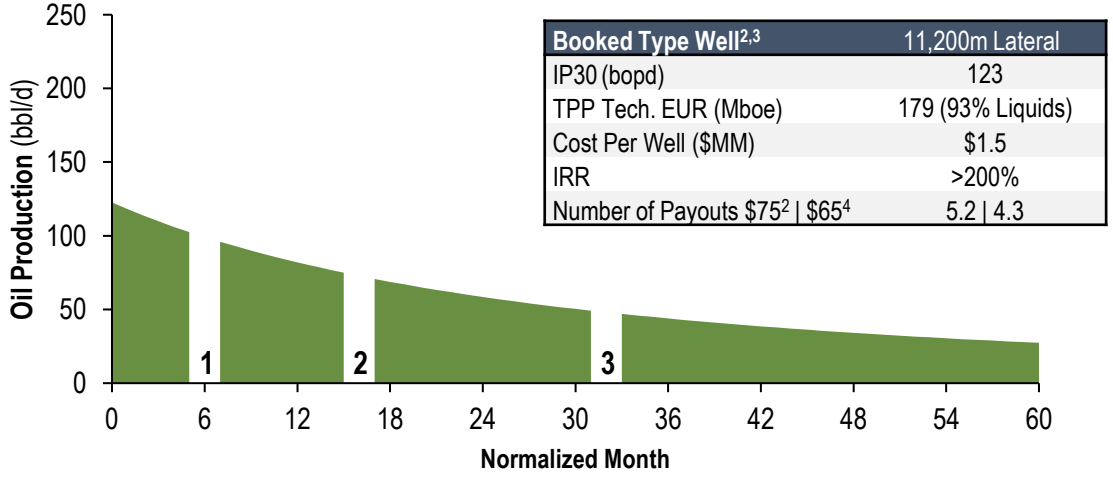
Booked Type Well[2,3]	11,200m Lateral – Tier I
IP30 (bopd)	180
TPP Tech. EUR (Mboe)	226 (90% Liquids)
Cost Per Well ($MM)	$1.7
IRR	>200%
Number of Payouts $75[2] | $65[4]	6.2 | 5.2

West Marten "C" Sand



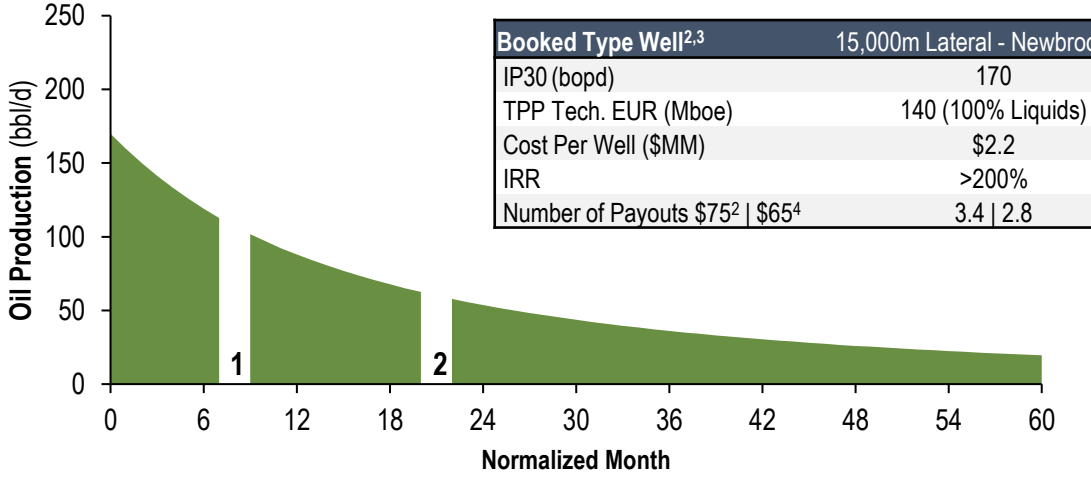
Booked Type Well[2,3]	11,200m Lateral
IP30 (bopd)	165
TPP Tech. EUR (Mboe)	173 (91% Liquids)
Cost Per Well ($MM)	$1.7
IRR	>200%
Number of Payouts $75[2] | $65[4]	4.6 | 3.8

Marten Hills "C" Sand



Booked Type Well[2,3]	11,200m Lateral
IP30 (bopd)	123
TPP Tech. EUR (Mboe)	179 (93% Liquids)
Cost Per Well ($MM)	$1.5
IRR	>200%
Number of Payouts $75[2] | $65[4]	5.2 | 4.3

South Clearwater Fan

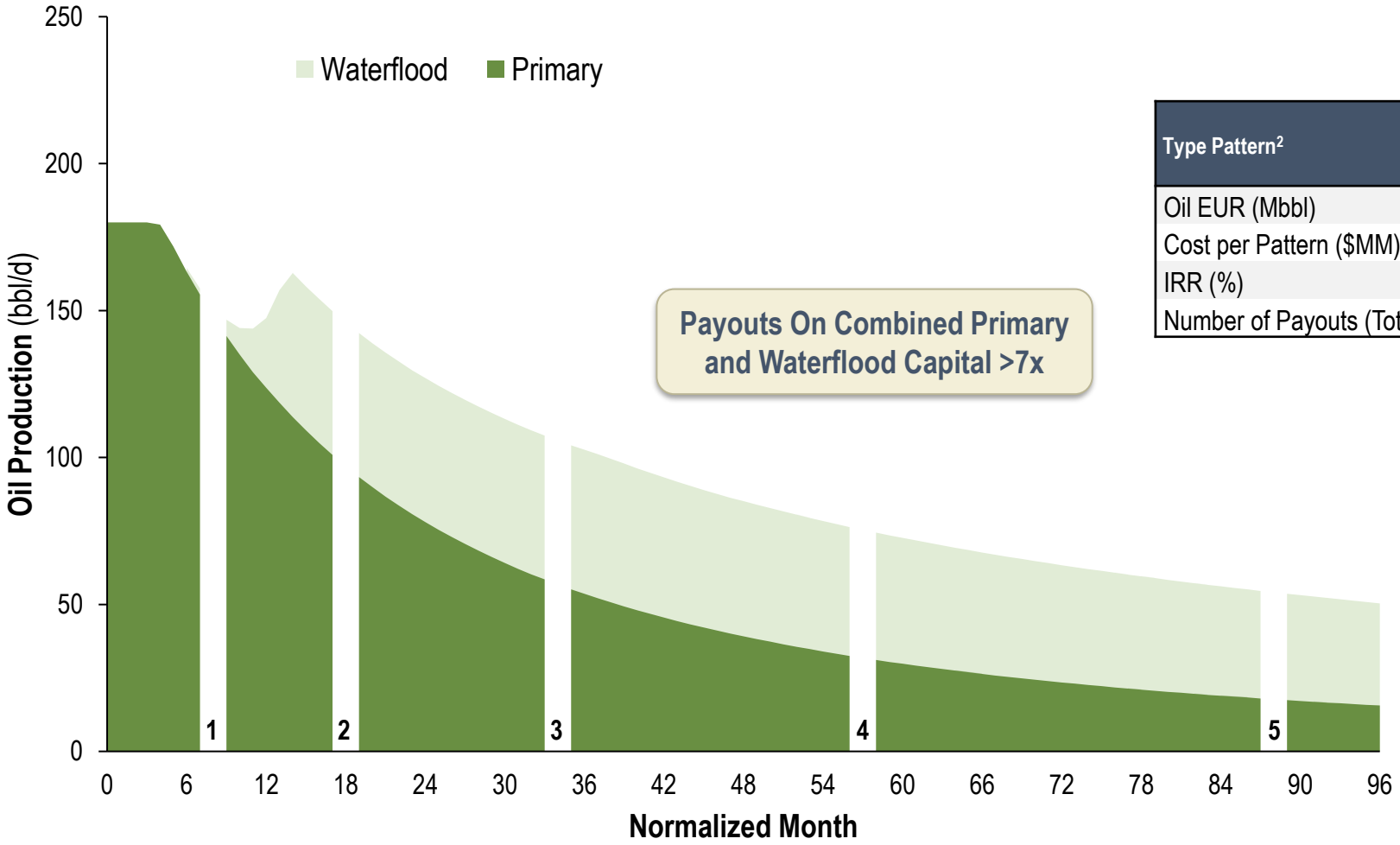


Booked Type Well[2,3]	15,000m Lateral - Newbrook
IP30 (bopd)	170
TPP Tech. EUR (Mboe)	140 (100% Liquids)
Cost Per Well ($MM)	$2.2
IRR	>200%
Number of Payouts $75[2] | $65[4]	3.4 | 2.8

1) See Disclaimers – "Specified Financial Measures"; based on internal management estimates.
2) Flat pricing assumes US$75/bbl WTI, US($13.50)/bbl WCS basis, CDN $3.00/GJ AECO and 1.30 C$/US$.
3) Based on McDaniel & Associates Consultants Ltd. Reserves Report effective December 31, 2025.
4) Sensitivity for Payouts: Flat pricing assumes US$65/bbl WTI, US($13.25)/bbl WCS basis, CDN $3.00/GJ AECO and 1.30 C$/US$. US$75 flat pricing per footnote #2.

Clearwater Waterflood – New Injector Drill Type Curve

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



Payouts On Combined Primary and Waterflood Capital >7x

Waterflood Economics

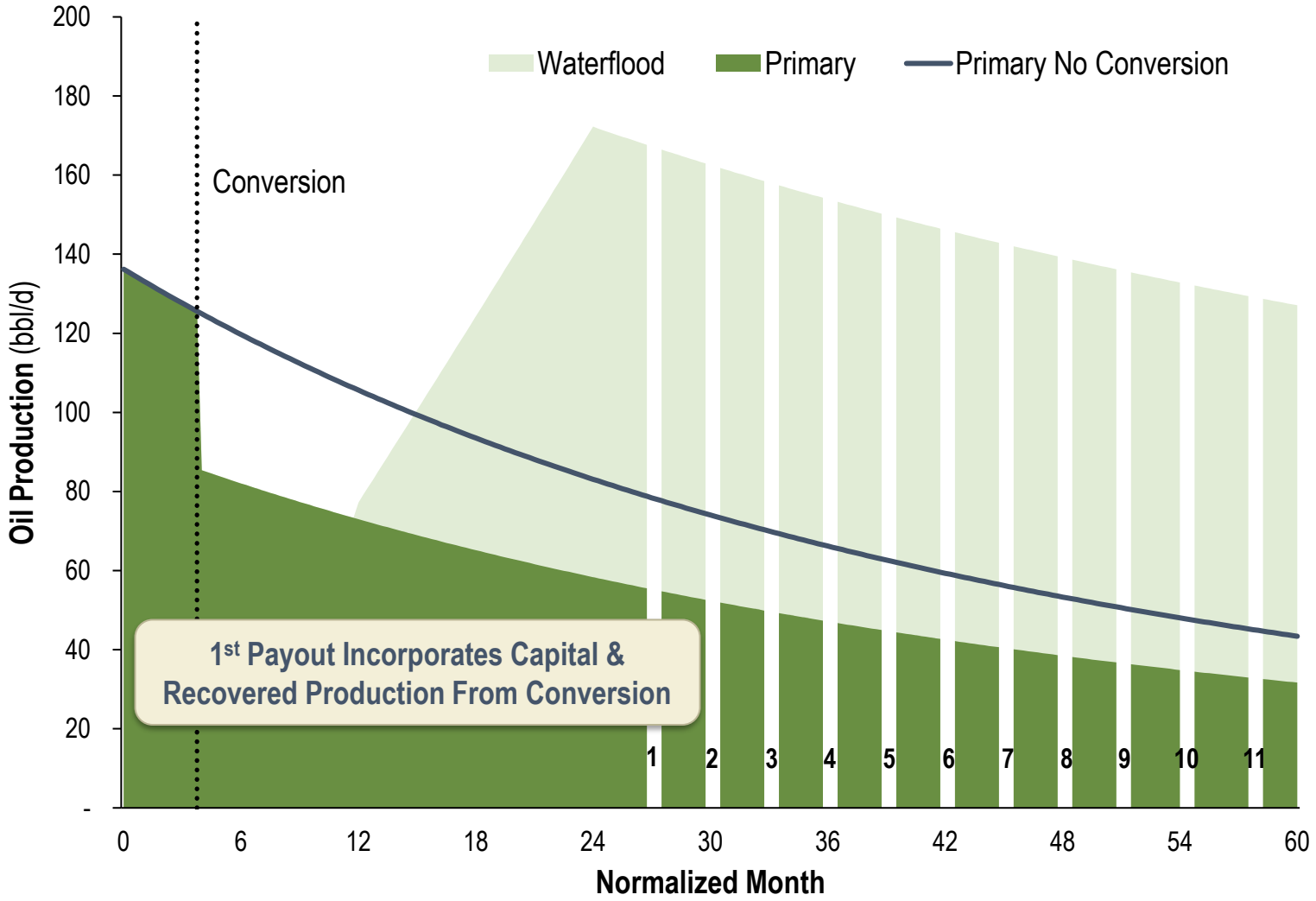
Type Pattern[2]	Primary[3] – West Marten "B" Sand Tier I	Waterflood Injector Wedge[4] – Internal Estimate	Total Project
Oil EUR (Mbbl)	205	308	513
Cost per Pattern ($MM)	$1.7	$1.2	$2.9
IRR (%)	>200%	72%	>200%
Number of Payouts (Total)	6.2	12.0	8.6

- **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($13.50)/bbl WCS basis, CDN $3.00/GJ AECO and 1.30 C$/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($13.50)/bbl WCS basis, CDN $3.00/GJ AECO and 1.30 US$/C$.
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)	Founder & Chief Executive Officer
Steve Buytels	President
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]	Chairman of the Board
Brian Schmidt (Aakaikkitstaki)	Founder & Chief Executive Officer
Caralyn Bennett [2, 4]	Independent Director
Craig Bryksa [2, 3]	Independent Director
John Leach [1, 2]	Independent Director
Marnie Smith [1, 3]	Independent Director
Rene Amirault [1, 4]	Independent Director
Robert Spitzer [2, 3]	Independent Director
Shannon Joseph[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

Brian Schmidt	**Steve Buytels**	**Kevin Johnston**
Founder & Chief Executive Officer	President	Chief Financial Officer & VP, Finance

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

Forward Looking Statements: Certain information included in this presentation constitutes forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as "budget", "guidance", "outlook", "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project" or similar words or variations (including negative and grammatical variations) suggesting future outcomes or statements regarding an outlook. Forward-looking information in this presentation may include, but is not limited to, statements about Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") as they relate to: Tamarack's business, corporate and waterflood strategy, objectives, plans, strength, focus and differentiators; the Company's plans to expand the Clearwater waterflood and the anticipated benefits and strategic rationale for such expansion, including materially flattening declines, increasing reserves and recovery, enhancing economics and multi-payout performance, lowering sustaining capital needs, reducing primary drilling requirements and ultimately extending asset duration while increasing free funds generation; expectations that given the ongoing improvement in the overall profitability of the business through a lower cost structure, lower reinvestment requirements and lower corporate breakeven oil price; the Company's updated five year plan, including with regard to sustaining capital, growth and waterflood investment and decline mitigation; the expected timing and scope of any further update to the five year plan; the Company's plan to achieve significant and profitable total shareholder return growth within 5 years; enhancing capital allocation flexibility to support shareholder returns; the announced dividend increase and commencement thereof in the third quarter of 2026; the Company's disciplined capital management strategy, including the balanced allocation of accelerated growth, dividends and share buybacks; Clearwater H2 budget expansion plans; expected growth in Clearwater production; expected liquidity and credit facility capacity; ability to bring forward highly economic development opportunities in the Clearwater; potential asset duration, including the Company's estimated drilling inventory and decades of development runway; ability to enhance recovery factors, reduce corporate decline rates and improve long-term capital efficiency; expected Clearwater production growth, water injection rate and percentage of expansion dedicated towards secondary waterflood recovery; expected waterflood expansion targets, including water injection rates and the percentage of Clearwater production under waterflood; expectations relating to finding and development costs and recycle ratios; Tamarack's revised capital program, budget and guidance for 2026 (including capital investments of $430 - $450 million and the allocation thereof, annual average production of 61,500 – 63,000 boe/day, average oil and NGL weightings of 88% – 90%, royalty rates of 20% – 22%, corporate wellhead price differentials – oil of $0.75 – $1.25 per boe, net operating expenses of $6.65 – $6.90 per boe, transportation expenses of $4.00 – $4.50 per boe, general and administrative expenses of $1.40 – $1.55 per boe, interest expense of $2.00 – $2.40 per boe and income taxes as a % of adjusted funds flow before tax of 17%– 19%); Tamarack's return of capital framework, including debt repayment, dividends and share buybacks and the Company's intention to increase return of capital and shift to more flexible capital allocation in 2026; generating significant free funds flow, allowing the Company to continue delivering strong returns for investors through sustainable dividends, share buybacks and debt reduction; 2026 free funds flow forecasts and allocations; expected discretionary free funds flow yields and total shareholder return; application of EOR and expectations in respect of waterflood development including the expectation of up to 3.0x primary recovery and outperforming reserve forecasts; expectations regarding improved field egress capacity; development opportunities and drilling locations; expectations regarding Pelican, Seal and other exploration areas, including derisking activities, stacked-zone potential, offsetting activity and the Company's planned activities in such areas; economics and payouts of the Company's wells; and risk management activities, including hedging positions and targets.

Statements relating to "reserves", "recovery", "EUR", "contingent resources", "prospective resources" and "OOIP" are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and that the reserves and resources can be profitably produced in the future. Without limitation of the foregoing, future dividend payments and share buybacks, if any, and the level thereof, are uncertain, as the Company's return of capital framework and the funds available for such activities from time to time is dependent upon, among other things, commodity prices, free funds flow, financial requirements for the Company's operations and the execution of its strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of Tamarack to pay dividends and buyback shares, and the frequency thereof, will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

Forward-looking information is based on a number of factors and assumptions concerning Tamarack which have been used to develop such information, but which may prove to be incorrect. In addition to other factors and assumptions which may be identified in the presentation, assumptions have been made regarding and are implicit in, among other things: the business, waterflood and capital allocation plans of Tamarack; the Company's ability to carry out Clearwater development and waterflood plans as currently contemplated; execution of the Company's 2026 budget; the timing and scope of any further updated five year plan; the timing of and success of future drilling, conversion, development, completion, derisking and injection activities; the geological characteristics of Tamarack's properties; prevailing commodity prices, price volatility, price differentials and the actual prices received for the Company's products; the Company's ability to advance planned activities and realize anticipated development upsides at Pelican, Seal and other exploration areas; the realization of anticipated benefits of the Company's infrastructure, waterflood development program and recent acquisitions and divestitures; the availability and performance of drilling rigs, facilities, pipelines and other oilfield services; that the expected discretionary free funds flow yields and total shareholder return will be in line with expectations; the performance of existing wells; the performance of new and existing wells, including leveraging optimized well designs; the performance of EOR projects; the application of existing drilling and fracturing techniques; the Company's ability to secure sufficient amounts of water; prevailing weather and break-up conditions and access to Tamarack's drilling locations; royalty regimes and exchange rates; the impact of inflation on costs and interest rates; the application of regulatory and licensing requirements; the expected impact of existing and potential tariffs or trade restrictions on the Company's products and operations; the ability to maintain or grow the banking facilities; the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation; the availability of capital, labour and services; the Company's ability to complete planned capital expenditures within budgeted cost estimates; expected net operating expenses and transportation expenses; the continued availability of capital and skilled personnel; Tamarack's ability to market its products successfully; and the creditworthiness of industry partners. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used.

Although Tamarack believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Tamarack can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature, they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks.

Disclaimers

These include, but are not limited to: the risk that the Company does not update, complete or execute any further update to its five-year plan at the time, within the scope or on the terms currently anticipated; the risk that Clearwater production growth, the allocation of expansion capital and water injection rates may differ from projections; the risk that discretionary free funds flow yields and total shareholder return may be lower than expected; inability of the Company to advance planned activities and realize anticipated development upsides at Pelican, Seal and other exploration areas; risks with respect to unplanned third party pipeline outages and risks relating to inclement and severe weather events and natural disasters, including fire, drought and flooding and corresponding effects, including in respect of safety, asset integrity, shutting in production, impact on production, delivering on 2026 guidance; the risk that future dividend payments thereunder are reduced, suspended or cancelled; incorrect assessments of the value of benefits to be obtained from exploration and development programs; risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration, production and waterflood, including breakthrough events; delays or changes in plans with respect to exploration, development projects, capital expenditures, or the implementation of the Company's corporate strategy, objectives, strength, focus and five year plan; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, including increased operating, labour, and capital costs due to inflationary pressures, facility, pipeline and processing facility access constraints, volatility in the stock market and financial system; and health, safety and environmental risks); lack of access to sufficient capital from internal and external sources; risks relating to reliance on third parties; competition for skilled labour; incorrect assessments of the value of acquisitions or failure to realize the benefits of acquisitions and dispositions; constraints in the availability of services; commodity price and exchange rate fluctuations; the actions of OPEC+ and non-OPEC+ members; changes in legislation (including but not limited to tax laws, royalty regimes and environmental legislation); the risk that (i) the U.S. and Canadian governments maintain tariffs, increase the rate or scope of tariffs, or impose new tariffs on the import of goods from one country to the other, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed by the U.S. on other countries and responses thereto could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Company; the risks related to the renegotiation of the United States-Mexico-Canada Agreement resulting in changes to trade, tariff or market access terms that may adversely affect the Company; changes to demand for Tamarack's products; adverse weather or break-up conditions; uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects; capital expenditures; pandemics. In addition, ongoing military actions in Venezuela, Iran and elsewhere in the Middle East and between Russia and Ukraine have the potential to threaten the supply of oil and gas from those regions. The long-term impacts of the actions between these nations remains uncertain. Due to the nature of the oil and natural gas industry, drilling plans and operational activities may be delayed or modified to respond to market conditions, results of past operations, regulatory approvals or availability of services causing results to be delayed. Production forecasts are directly impacted by commodity prices and the actual timing of Tamarack's capital expenditures. Actual results may vary materially from forecasts due to changes in interest rates, oil differentials, exchange rates and the timing of expenditures and production additions. These and other risks are set out in more detail in Tamarack's annual information form for the year ended December 31, 2025 (the "AIF") and Tamarack's management's discussion and analysis for the three and six months ended June 30, 2026 (the "MD&A"). The Company's AIF and MD&A can be accessed on Tamarack's website at www.tamarackvalley.ca or under Tamarack's SEDAR+ profile at www.sedarplus.ca. Forward-looking information is based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by management and described in the forward-looking information. The forward-looking information contained in this presentation is made as of the date hereof and management undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward-looking information contained in this presentation is expressly qualified by this cautionary statement.

FOFI Disclosure: This presentation contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's five year plan, generating sustainable long-term growth in free funds flow, dividends, share buybacks and debt reduction, the 2026 budget and revised outlook, guidance and budget pricing and allocation, the revised 2026 capital program and accelerated Clearwater investment of $430 - $450 million, including prospective results of operations, production (including annual average production of 61,500 – 63,000 boe/day, average oil and natural gas weightings of 88% – 90% and expected Clearwater production growth of 15% year-over-year) and free funds flow, operating costs (including net operating expenses, transportation, general and administrative expenses and interest expense), royalty rates, oil and NGL weighting, corporate wellhead price differentials, income taxes, corporate decline rates, sustaining capital requirements, free funds flow breakeven costs (including a <US$38/bbl unhedged free funds flow after dividends breakeven), finding and development costs, recycle ratios, expected dividend payments, pro forma net cash position, available funding and available liquidity, pro forma standalone Clearwater production and reserves, waterflood expansion targets (including expected water injection rates and the percentage of Clearwater production under waterflood), expectations of having resources to support decades of additional development, the Company's return of capital framework, including generating sustainable long term growth in free funds flow, dividends and share buybacks, total DAFFPS, DAPPS growth, total return to shareholders and balance sheet strength, annual returns to shareholders, prospective results of operations and production, timing of payout of wells and number of payouts, yield, CAGR, CROIC, IRR, EUR, debt, net debt, net debt reduction, balance sheet strength, NPV-10%, TPP reserve life index of ~11 years, half-cycle returns, operating costs, expected royalties, transportation expenses, cost per well, G&A expenses, interest and taxes, decline rates, and capital structure and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumptions outlined in the Specified Financial Measures section below. FOFI contained in this presentation was approved by management as of the date of this presentation and was provided for the purpose of providing further information about Tamarack's anticipated future business operations. Tamarack and its management believe that FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results. Tamarack disclaims any intention or obligation to update or revise any FOFI contained in this presentation, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained in this presentation should not be used for purposes other than for which it is disclosed herein. Changes in commodity prices, differences in the timing and allocation of capital expenditures, and variances in average production estimates can have a significant impact on the key performance measures included in Tamarack's guidance. The Company's actual results may differ materially from these estimates.

Reserves Disclosure: All reserve references in this presentation are to gross reserves as at the effective date of the applicable evaluation. Gross reserves are Tamarack's total working interest reserves before the deduction of any royalties and without including any royalty interests of Tamarack. The recovery and reserve estimates of Tamarack's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein. The reserve estimates contained herein for 2025 YE were derived from a reserves assessment and evaluation prepared by McDaniel & Associates Consultants Ltd. ("McDaniel"), qualified independent reserves evaluator, with an effective date of December 31, 2025 and a preparation date of January 21, 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"). Reserves estimates for prior years were evaluated by independent qualified evaluators with an effective date of December 31 for the applicable year unless otherwise stated. It should not be assumed that the present worth of estimated future cash flow presented herein represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material.

Disclaimers

Resource Disclosure: This document contains information relating to estimates of heavy oil contingent and prospective resources of Tamarack (the "Resource Report") by McDaniel, a qualified independent reserves evaluator, with an effective date of December 31, 2025, in accordance with the definitions, standards and procedures contained in NI 51-101 and COGEH. The contingent and prospective resources estimates of Tamarack's Clearwater heavy oil contingent resources provided herein are estimates only and there is no guarantee that the estimated prospective and contingent resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and the differences may be material. Tamarack's Statement of Contingent and Prospective Resources dated February 24, 2026, which has been filed on the Company's SEDAR+ profile at www.sedarplus.ca, includes further disclosure of Tamarack's contingent and prospective resources, including the risks and uncertainties related thereto. Contingent resources are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates, assuming their discovery and development, and may be subclassified based on project maturity. Estimates of prospective resources have not been adjusted for risk based on the chance of discovery or the chance of development. Resources are classified according to degree of certainty associated with those estimates. In this presentation, "best estimate" classification is used which is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources identified as best estimate have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate.

Short-Term Production Rates: References in this presentation to peak rates, peak monthly rates, initial production rates, average peak production rate for the 30 days after the well is brought onstream (IP30), average peak production rate for the 90 days after the well is brought onstream (IP90) and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production of Tamarack.

Analogous Information: In this presentation, the Company has provided certain information on the prospectivity and the production rate of wells on properties adjacent to the Company's acreage which is "analogous information" as defined by applicable securities laws. This analogous information is derived from publicly available information sources which the Company believes are predominantly independent in nature. Some of this data may not have been prepared by qualified reserves evaluators or auditors and the preparation of any estimates may not be in strict accordance with the COGE Handbook. Regardless, estimates by engineering and geotechnical practitioners may vary and the differences may be significant. The Company believes that the provision of this analogous information is relevant to the Company's activities and forecasting, given its property ownership in the area; however, readers are cautioned that there is no certainty that the forecasts provided herein based on analogous information will be accurate.

Type Curves: Certain type curves disclosure presented herein was internally estimated by the Company's management and represents estimates of the production decline and ultimate volumes expected to be recovered from wells over the life of the well. The type curves represent what management believes an average well will achieve, based on methodology that is analogous to wells with similar geological features. Individual wells may be higher or lower but over a larger number of wells, management expects the average to come out to the type curve. Over time type curves can and will change based on achieving more production history on older wells or more recent completion information on newer wells. Such type curves are useful in understanding management's assumptions of well performance in making investment decisions in relation to development drilling in such areas and for determining the success of the performance of development wells. However, internally prepared type curves do not reflect the type curves used by our independent qualified reserves evaluator in estimating Tamarack's reserves volumes and such type curves have not been assigned reserves or resources. The South Clearwater Fan type curve presented herein is an internally generated forecast prepared by the Company's management to illustrate expected well performance under its go-forward development plan. Due to limited empirical data for the Company's updated well design—including longer horizontal lengths and wider well spacing—the Company believes the internally derived curve is the most representative indicator of anticipated performance for future performance. The curve is based on engineering and geoscience interpretation, analogous data, and internal technical analysis. The Company's management has also prepared an internally generated waterflood incremental type curve to illustrate the potential production uplift associated with planned waterflood development. This curve is derived from reservoir simulation, waterflood modeling, and internal technical analysis of reservoir response, rather than historical reserves bookings, which may lag the most current understanding of waterflood performance. The curve is intended only to demonstrate possible incremental production attributable to waterflooding under the Company's planned injection design and operating assumptions. There is no certainty that Tamarack will ultimately recover such volumes from the wells it drills. Actual results may vary materially from both primary and waterflood incremental curve estimates.

BOE Disclosure: The term barrels of oil equivalent ("BOE") may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel of natural gas to barrels of oil equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All BOE conversions in the presentation are derived from converting gas to oil in the ratio mix of six thousand cubic feet of gas to one barrel of oil. Throughout this presentation, "crude oil" or "oil" refers to light, medium and heavy crude oil product types as defined by NI 51-101. References to "NGLs" throughout this presentation comprise pentane, butane, propane, and ethane, being all NGLs as defined by NI 51-101. References to "natural gas" throughout this presentation refers to conventional natural gas as defined by NI 51-101.

OOIP Disclosure: The term "original oil in place" or 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 in respect of the Company's Clearwater assets by area and in aggregate was internally estimated by the Company's management. There is no certainty management'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.

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Specified Financial Measures: This presentation includes various specified financial measures, including non-IFRS financial measures, non-IFRS financial ratios, capital management measures and supplementary financial measures as further described herein. These measures do not have a standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and, therefore, may not be comparable with the calculation of similar measures by other companies.

"Adjusted funds flow (capital management measure)" is defined as cash provided by operating activities excluding asset retirement obligation expenditures, transaction costs and changes in non-cash working capital. Asset retirement obligation expenditures and transactions costs from business combinations both result from the Company's capital budgeting and strategic planning processes, which first considers available adjusted funds flow. Asset retirement obligation expenditures vary from period to period depending on capital programs, government regulations and the maturity of the Company's operating areas. By also excluding changes in non-cash working capital from cash provided by operating activities, the adjusted funds flow measure provides a meaningful metric for Tamarack and others by establishing a clear link between the Company's cash flows, income statement and operating netbacks by isolating the impact of changes in the timing between accrual and cash settlement dates, which are often within management's control. Tamarack uses adjusted funds flow to assess the Company's financial performance and cash generated from operating activities.

Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating income per share, which results in the measure being considered a supplemental financial measure. Adjusted funds flow can also be calculated on a per boe basis, which results in the measure being considered a supplemental financial measure. Adjusted funds flow per debt adjusted share is calculated using the adjusted funds flow divided by the sum of (i) the net debt plus (ii) the weighted average basic share count, divided by a constant share price which results in the measure being considered a supplemental financial measure.

"Free funds flow (capital management measure)" is defined as adjusted funds flow less investments in oil and natural gas assets (excluding acquisitions and dispositions) and the settlement of asset retirement obligations. Management utilizes free funds flow to assess how much cash was generated in excess of the Company's capital investment and asset retirement programs within the same period, which can be utilized to reduce debt, fund acquisitions or return capital.

"Available funding (capital management measure)" is calculated as the sum of undrawn credit capacity under the Company's credit facility and cash, accounts receivable, prepaid expenses and deposits, cross-currency swap liability (asset), assets held for sale (net), accounts payable and accrued liabilities. Tamarack and others utilize available funding to assess the amount of funds that could be available to the Company in the near term to fund capital management initiatives.

"Free funds flow breakeven cost (capital management measure)" reflects the average minimum WTI price (US per bbl) received by Tamarack where adjusted funds flow net of the base dividend and sustaining capital requirements is approximately equivalent to zero, with sustained current hedged production levels and all other variables held constant. Management believes that free funds flow breakeven provides a useful measure to establish corporate financial sustainability. The calculation of Tamarack's pro forma free funds flow breakeven cost of US$28 per bbl following the Charlie Lake sale was primarily determined by utilizing the implied H2 ranges within the revised guidance assumptions, other than for capital investments, which utilize the Company's revised sustaining capital requirements of <$180 million under an assumed scaled-budget, break-even price scenario, and average royalty rates which would be expected to decline to 12% – 13% at WTI price of $28 per bbl. Other assumptions utilized by the Company to calculate the free funds flow breakeven cost includes annual dividends of $0.20 per share, hedging gains of $11.00 per boe and asset retirement obligation expenditures of $5.0 million. Sustaining capital is management's estimate of annual capital activities required to maintain production levels.

"Net debt (cash) (capital management measure)" is calculated as the sum of the Company's debt, government loans and other, cash, accounts receivable, prepaid expenses and deposits, cross-currency swap liability (asset), assets held for sale (net), accounts payable and accrued liabilities. Tamarack and others utilize net debt to assess liquidity and balance sheet strength by aggregating the select financial assets and financial liabilities on the Company's balance sheet. Net debt per share is calculated as net debt per share based on basic share outstanding as at the end of each relevant quarter, which results in the measure being considered a supplemental financial measure.

"Market capitalization" (supplementary financial measure) is calculated as shares outstanding multiplied by the closing market price of the shares on the day referenced.

"Debt adjusted production per share" (supplementary financial measure) is calculated as daily production, divided by debt adjusted shares outstanding. Debt adjusted shares outstanding is the sum of (i) the basic common share count, and (ii) net debt divided by a constant share price and then added to the share count based on basic share outstanding and net debt as at the end of each relevant quarter, respectively.

"Enterprise value" (supplementary financial measure) is calculated as market capitalization (shares outstanding multiplied by the closing market price of the shares on the day referenced) less net debt.

"EBITDA (non-IFRS financial measure)" is calculated as consolidated net income (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash, extraordinary and non-recurring items primarily relating to unrealized gains and losses on financial instruments and impairment losses. The Company considers this metric as key measures that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment and to service and repay debt. The most directly comparable IFRS measure to EBITDA is cash provided by operating activities. This measure is consistent with the EBITDA formula prescribed under the Company's Senior Credit Facility.

"Blending expense" (non-IFRS financial measure) includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines to meet pipeline specifications. The blending expense represents the difference between the cost of purchasing and transporting the diluent and the realized price of the blended product sold. In the MD&A, blending expense is recognized as a reduction to heavy oil revenues, whereas blending expense is reported as an expense in the financial statements. This metric can also be calculated on a per boe basis, which results in them being considered a non- IFRS financial ratio.

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"Differential including transportation expense" (non-IFRS financial measure) is determined by comparing the Company's realized price to the published benchmark price, plus transportation expenses. The calculation of the Company's heavy oil differential including transportation expenses is presented in the "Petroleum and natural gas sales" section of the MD&A.

"Net operating expense" (non-IFRS financial measure) is calculated as operating expenses less processing income. Tamarack generates processing income from third parties that utilize excess capacity at Tamarack's facilities. If Tamarack has excess capacity at one of its facilities, the Company will seek to process third-party volumes as a means of offsetting a portion of the facility costs. Accordingly, net operating expenses allow Tamarack and others to assess the field and facility operating results by including the associated income generated from plant operations. The calculation of the Company's net operating expenses is presented in the Non–GAAP financial measures and non-GAAP financial ratios section of the MD&A. The Company and others utilize these performance measures to assess the value of net revenue received by Tamarack for each barrel sold relative to the published market price during that period. These performance measures are presented on a per boe basis as a non-IFRS financial ratio.

"Cash return on capital invested" (non-IFRS financial measure) is calculated as the sum of adjusted funds from operation plus interest expense (numerator), divided by the sum of the original net cost of asset acquisitions and development, plus DD&A, minus cash, and cash equivalents, minus non-interest bearing liabilities (denominator). Management utilizes the cash return on invested capital measure to provide a measure of how much cash was generated from the Company's assets, relative to the Company's original capital investment.

"Sustaining capital" (supplementary financial measure) represents management's estimate of annual capital investments required to maintain corporate production at prior period levels. This measure allows management and others to assess the approximate composition of Tamarack's annual capital investment programs and its corporate financial sustainability. Sustaining capital is also utilized to calculate the Company's free funds flow breakeven cost.

"Total return to shareholders" provides an estimate of the total return generated for shareholders on a percentage basis by aggregating certain select metrics consisting of production growth, dividends, share buybacks and net debt reduction. The return from production growth is calculated as the year-over-year % change in production, dividend growth is based on the yield during year relative to TVE's average market capitalization, share buybacks is calculated as the number of shares purchased in the year divided by TVE's opening common share count and net debt reduction is based on the year-over-year net debt decline relative to TVE's average market capitalization.

Please refer to the MD&A for additional information relating to specified financial measures including non-IFRS financial measures, non-IFRS financial ratios and capital management measures. The MD&A can be accessed either on Tamarack's website at www.tamarackvalley.ca or under the Company's SEDAR+ profile at www.sedarplus.ca.

Oil and Gas Metrics. This presentation contains metrics commonly used in the oil and natural gas industry, such as "corporate decline rate" (representing the percentage decline of the Company's production base, excluding the production from new wells drilled in the year; corporate decline rate is not a financial measure and does not have a standardized meaning under NI 51-101), "NPV-10" (meaning the net present value (net of capex) of net income discounted at 10%), "EUR" (meaning estimated ultimate recovery, an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well), "IRR" (meaning internal rate of return, 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), "FDC" (meaning future development costs), "Finding and development costs" or "F&D costs" (calculated as the sum of field capital plus the change in FDC for the period divided by the change in reserves that are characterized as development for the period. The aggregate of the exploration and development costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this presentation because acquisitions and dispositions can have a significant impact on Tamarack's ongoing reserves replacements costs and excluding these amounts could result in an inaccurate portrayal of the Company's cost structure), "Recycle ratio" (measured by dividing the operating netback for the applicable period by F&D cost per boe for the year. The recycle ratio compares netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are of equivalent quality as the produced reserves) and "CAGR" or "Compound annual growth rate" (representing the consistent rate at which an investment or business result would have grown had the investment or business result compounded at the same rate each year).

These terms have been calculated by management and do not have a standardized meaning and may not be comparable to similar measures presented by other companies and therefore should not be used to make such comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Tamarack's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this presentation, should not be relied upon for investment or other purposes.

Third Party Information: Certain information contained in this presentation has been obtained from published sources prepared by independent industry analysts and third-party sources (including industry publications, surveys and forecasts). While such information is believed to be reliable for the purpose used herein, none of the directors, officers, owners, managers, partners, consultants, shareholders, employees, affiliates or representatives assumes any responsibility for the accuracy of such information. Some of the sources cited in this presentation have not consented to the inclusion of any data from their reports, nor has Tamarack sought their consent. The accuracy and completeness of the market, industry and economic data used throughout this presentation are not guaranteed and Tamarack makes no representation as to the accuracy of such information.

US Registration: This presentation is not an offer of the securities for sale in the United States. The securities have not been registered under the U.S. Securities Act of 1933, as amended, and may not be offered or sold in the United States absent registration or an exemption from registration. This presentation shall not constitute an offer to sell or the solicitation of an offer to buy nor shall there be any sale of the securities in any state in which such offer, solicitation or sale would be unlawful.

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Drilling Locations: This presentation discloses Clearwater drilling locations in two categories: (i) booked locations; and (ii) unbooked locations. Booked locations are proved and probable locations derived from the McDaniel Report with an effective date of December 31, 2025, prepared in accordance with NI 51-101 and the most recent publication of the COGE Handbook. Unbooked locations do not have attributed reserves. However, the unbooked Clearwater locations have attributed contingent or prospective resources, based on the Resource Report. Of the Clearwater inventory of 2,133 net drilling locations identified herein, 520 net are proved or probable locations, and 1,613 net are unbooked locations. Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. 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 and natural gas 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.

Abbreviations	
AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
bbls	barrels
bbls/d	barrels per day
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
DAPPS	Debt adjusted production per share
EOR	Enhanced Oil Recovery
ERH	extended reach horizontal
EUR	estimated ultimate recovery
FFFPS	Free funds flow per share
FX	foreign exchange
GJ	gigajoule
IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board
IP30	average peak production rate for the 30 days after the well is brought onstream
IP90	average peak production rate for the 90 days after the well is brought onstream
KPI	key performance indicator
MMcf/d	million cubic feet per day
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
NAV	net asset value
OOIP	Original Oil In Place
P3	proved + probable + possible reserves
ROR	rate of return
ROY	remainder of the year
TLL	total lateral length
TTM	trailing twelve months
TPP	total proved plus probable reserves
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade