TVE : TSX

Creating Sustainable Value

April 2024

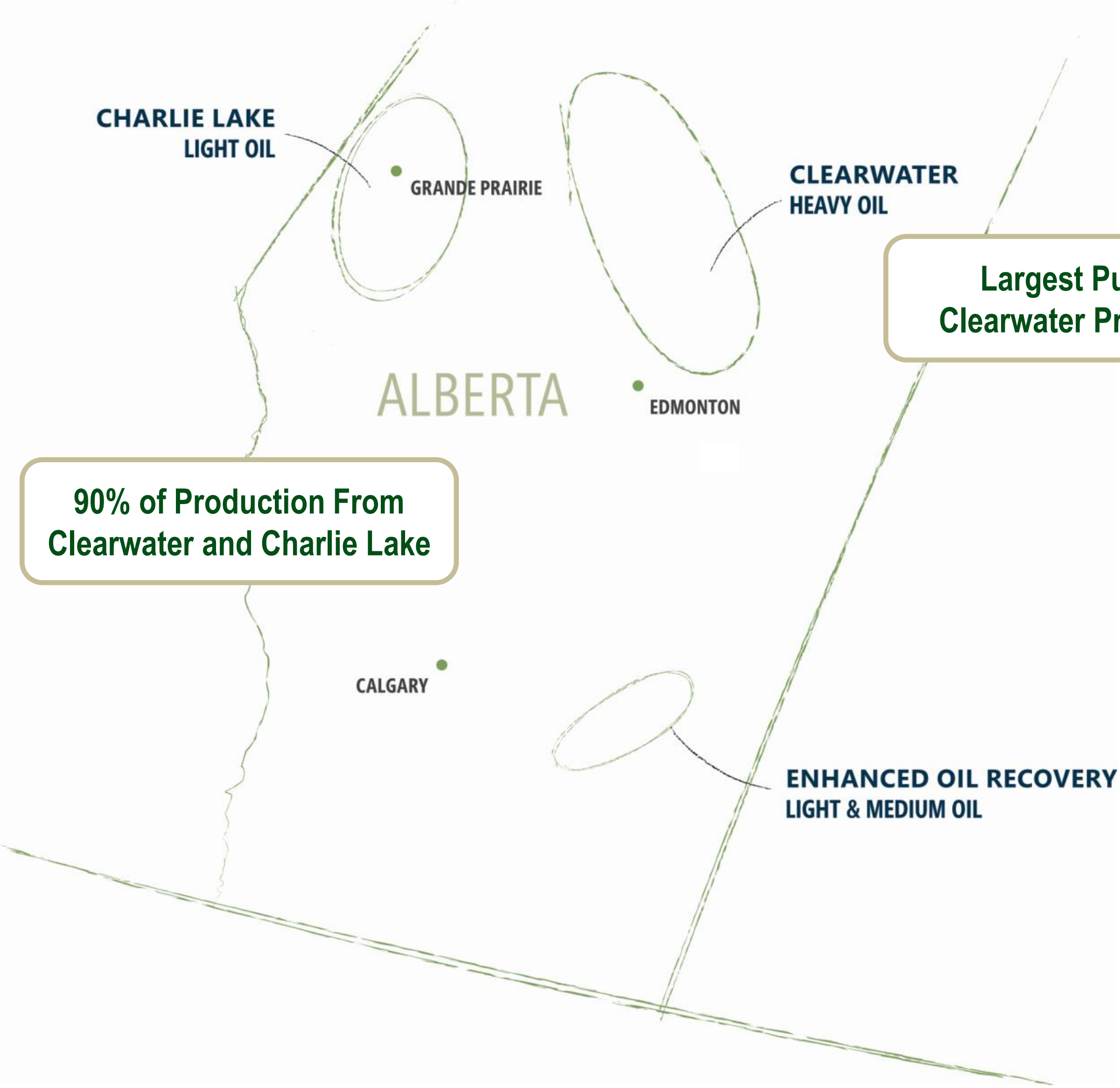
See Disclaimers and Forward-Looking Statements attached

tamarack valley ENERGY ltd.

Corporate & Operational Snapshot

Corporate		
Ticker Symbol		TVE.TSX
Shares Outstanding (Basic)[1]	*(MM)*	549
Market Capitalization[2]	*($MM)*	$2,181
2023YE Net Debt	*($MM)*	$984
Enterprise Value	*($MM)*	$3,165
Annual Base Dividend[3]	*($/share)*	$0.15
Implied Annual Base Yield[3,4]	*(%)*	3.8%

2024 Revised Guidance Highlights *(Base Case Budget)*		
Production	*(boe/d)*	61,000 – 63,000
Average Liquids Weighting	*(%)*	84% – 86%
Capital Budget[5]	*($MM)*	$390 – $440



Largest Public Clearwater Producer

90% of Production From Clearwater and Charlie Lake

1. As at March 31, 2024.
2. Closing share price as at April 2, 2024.
3. Based on most recently declared monthly dividend payable April 15, 2024.
4. Based on annualized monthly dividend equivalent to $0.15/share annually using the April 2, 2024 closing share price.
5. Excludes ARO and Clearwater Infrastructure Partnership capital.

Investment Highlights & Strategy

Reposition complete, shifted focus to driving free funds flow[1]

Asset Transformation Complete

- Top tier asset portfolio with ~85% liquid weighting
- Decades of premium inventory development
- Low free funds flow breakeven

Strong Margin Enhancement

- Improved asset margins with operational efficiencies, increasing well productivity and premium heavy oil pricing
- Strategic infrastructure enhances price realization and transport savings; positive impact on safety & emissions; reducing carbon tax

Reduced Sustaining Capital

- EOR initiatives improved corporate decline by 2% with 2023 waterflood investment
- Clearwater secondary recovery potentially doubles primary recoveries on a portion of Tamarack's 8.7 Bln bbls of OOIP[2]

Robust Free Funds Flow Generation

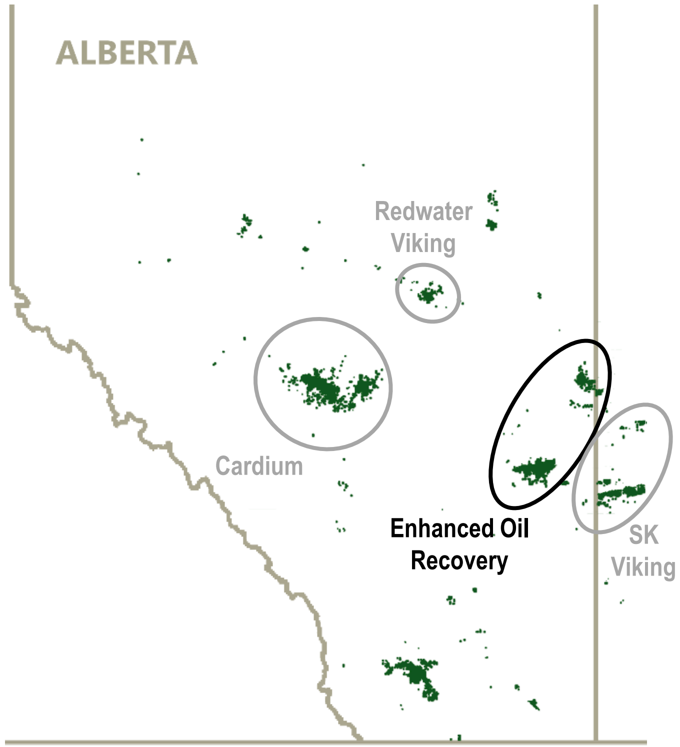
- ~50% of 2024 free funds flow allocated to shareholder returns through base dividends and enhanced returns
- Remaining ~50% free funds flows reducing debt to further increase overall equity value

1. See Disclaimers – "Specified Financial Measures" ; FFF – Free Funds Flow.
2. OOIP – original oil in place based on internal estimates.

Transformation to the Largest Public Clearwater Producer

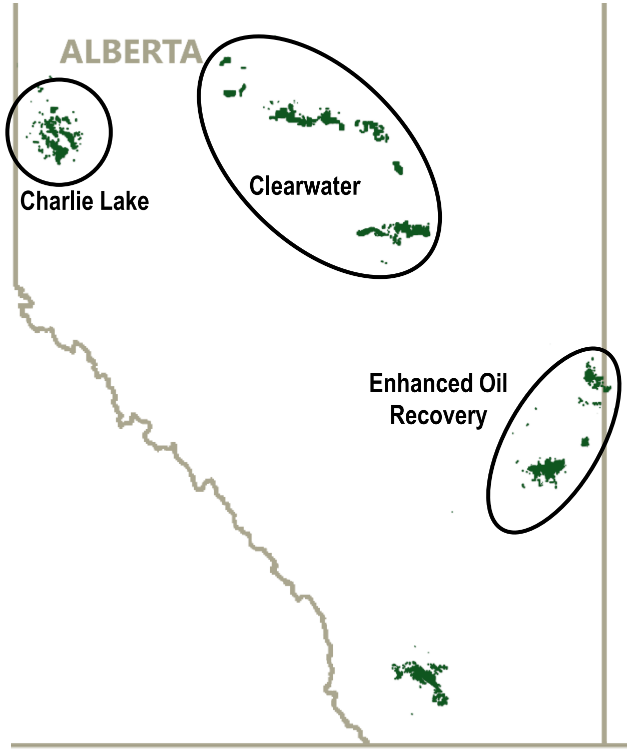
Portfolio has a significant depth of premium inventory to deliver long-term returns for shareholders

2020 Land Base

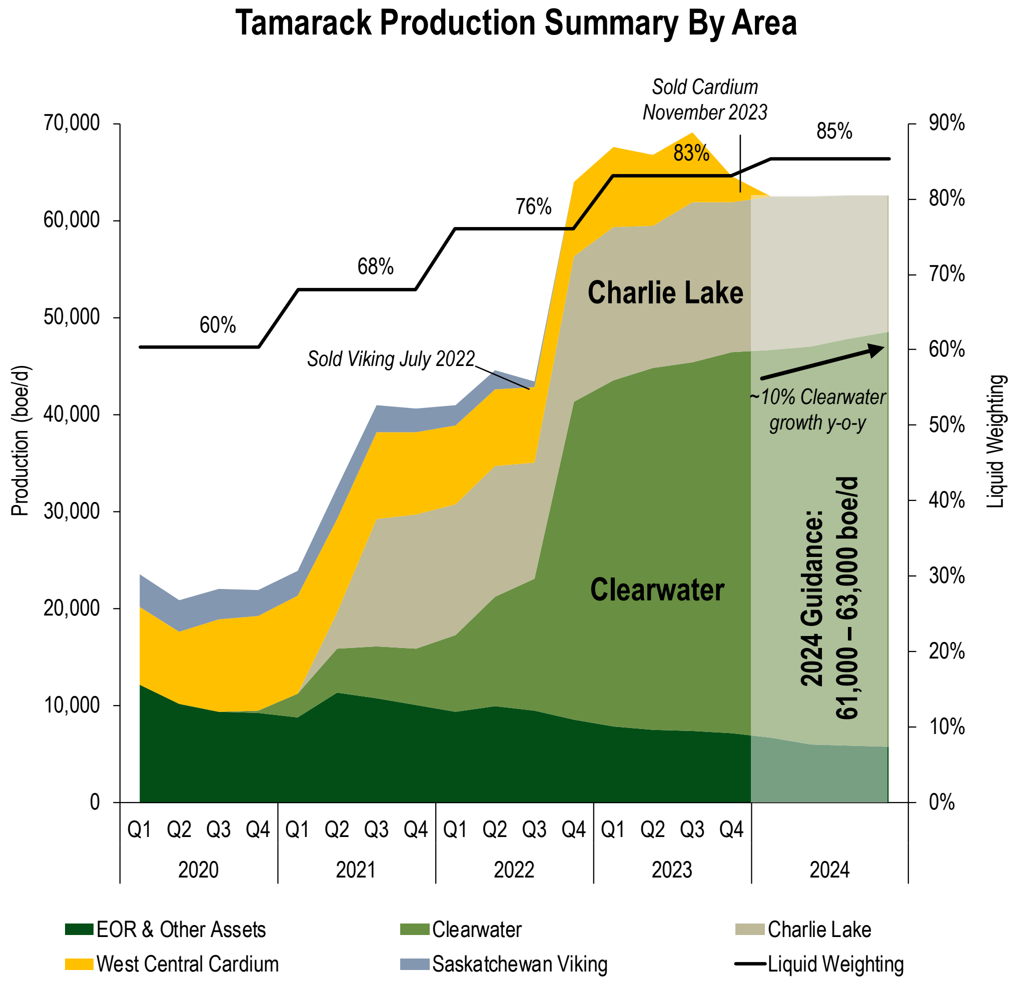


Average 2020 Production:
~22,000 boe/d & 60% liquids

2024 Land Base



Average 2024 Production Estimate:
~62,000 boe/d (mid point) & 85% liquids[1]



1. See guidance slide for appropriate commodity mix.
Note: Land maps are illustrative for Tamarack land position and may not be precise.

2023 Financial and Operational Highlights

Prioritizing debt reduction and increasing returns to shareholders

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Complete Corporate Transformation	• Successfully integrated the Deltastream Clearwater assets • Expansion of Charlie Lake Tier 1 inventory and commissioning of the Wembley Gas Plant • Transition of private equity share position through 2023
Enhanced Portfolio Economics	• ~90% of production derived from Charlie Lake & Clearwater assets; liquids weighting ~85% • Disposition of non-core assets & significant reduction of corporate ARO • Enhanced oil margins & improved operating costs by 9% YoY
Improved Balance Sheet Strength	• Net debt lower by ~$373MM, 2023 YE net debt of $984MM reflecting dispositions & $248MM of FFF[1] • Creation of Clearwater Infrastructure Partnership • DAP notes to be repaid Q1/24
Returns to Shareholders	• Delivered $0.15/share base dividend & debt reduction equal to $0.67/share • Enhanced return framework initial debt threshold achieved in Q4/23 of up 25% of excess funds flow • Commenced share buybacks starting in January 2024 through Normal Course Issuer Bid

1. See Disclaimers – "Specified Financial Measures" ; FFF – Free Funds Flow.

2023 Reserves Highlights

Enhancing the long-term resiliency and sustainability of free funds flow

Corporate Reserves Demonstrate Strong Additions[3]

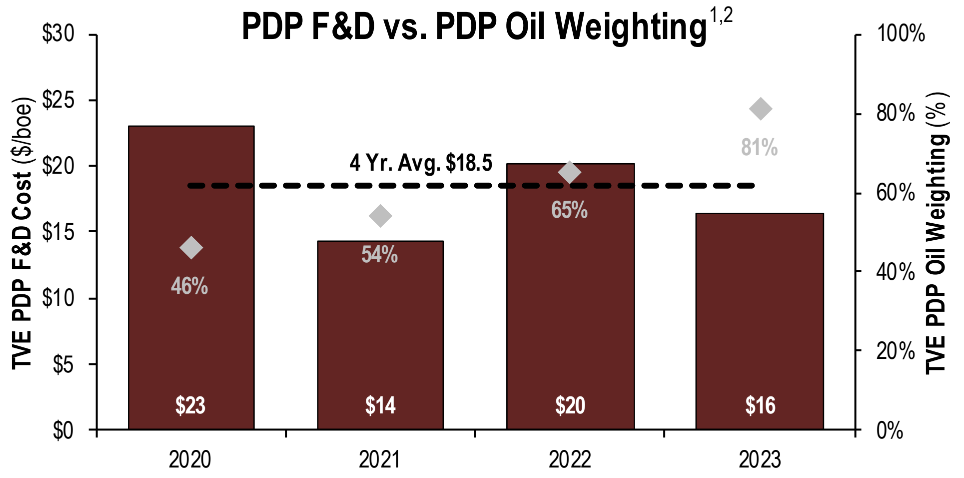
- TPP reserves increased by 13% to 224 MMboe; additions replaced 214% of production
- Delivered PDP recycle ratio of 2.6x
- PDP PV 10% / boe has increased ~10% annually to $25/boe in 2023

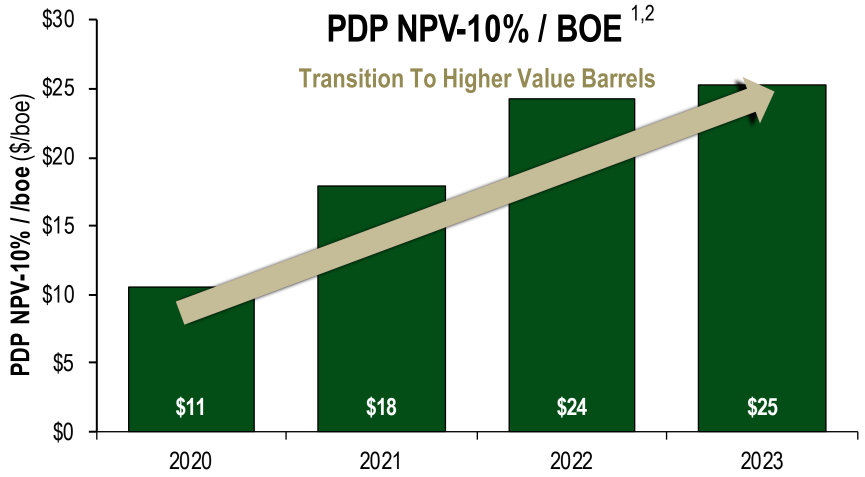
Clearwater Performance

- TP and TPP reserves increased by 43% and 28%, respectively
- TPP reserves replaced 279% of 2023 Clearwater production
  - TPP reserves associated with waterflood increased by over 400% YoY

Continued Charlie Lake Growth

- TPP reserves replaced 147% of 2023 Charlie Lake production



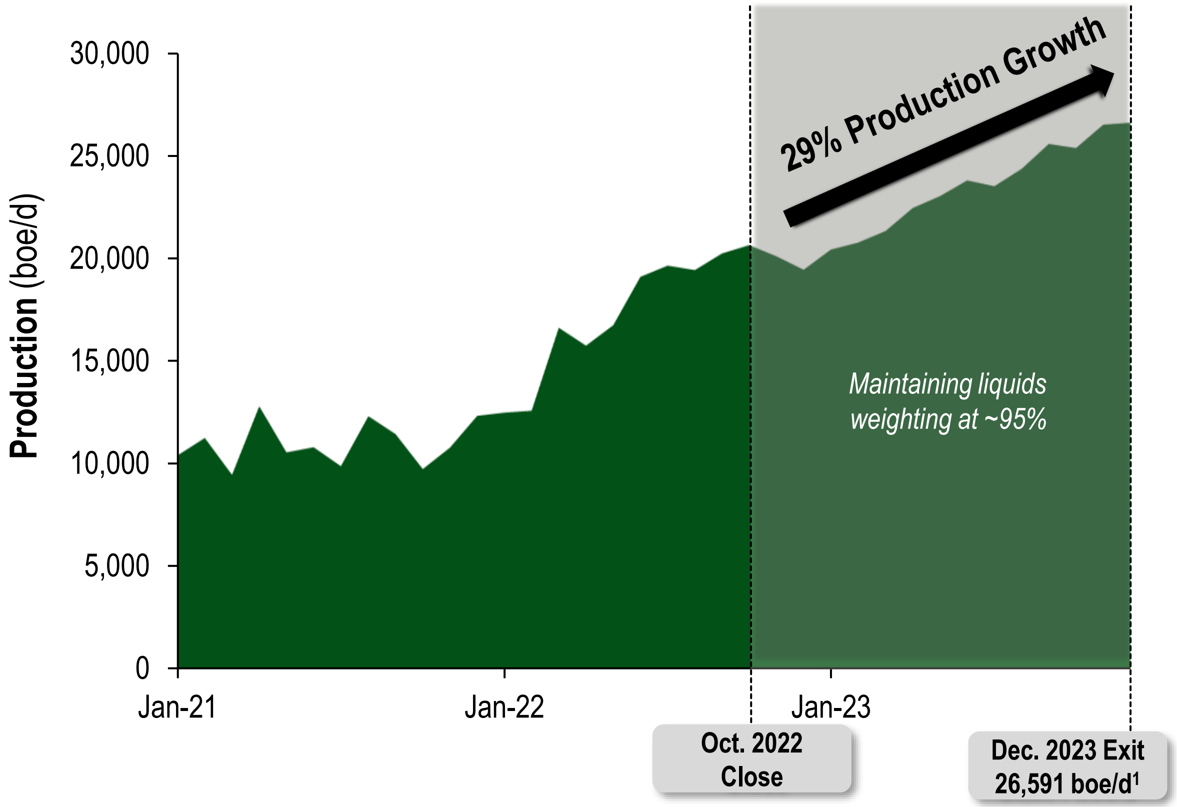


Note: Reserve categories are proved developed producing ("PDP"); total proved ("TP"); and total proved plus probable ("TPP").
1. Based on GLJ Ltd. and McDaniel & Associates Consultants Ltd Reserves Report effective December 31, 2023, available within the AIF.
2. Reserves for 2020-2022 are based on GLJ Ltd. reserves evaluation reports effective December 31 of the respective year in accordance with NI 51-101 and the COGE Handbook.
3. Excludes reserves and production associated with the dispositions in 2023.

Deltastream Acquisition: A Year in the Rearview

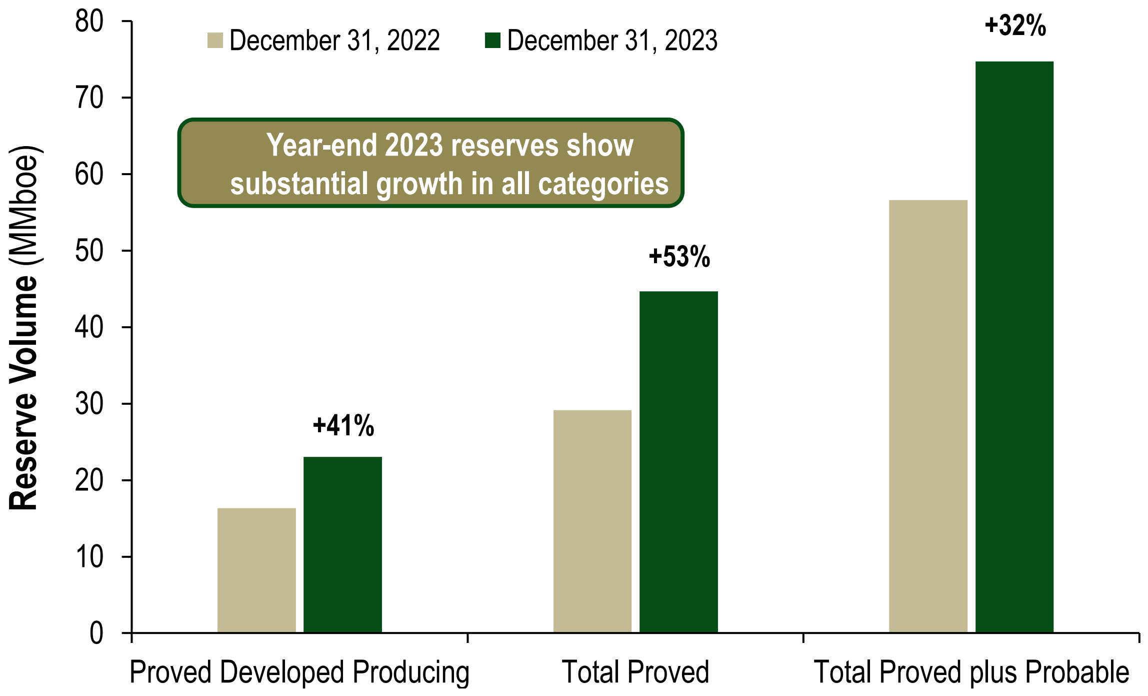
Strong cumulative free NOI[3] and reserves growth demonstrates >40% increase in value relative to purchase price

Production Growth



Delivered Cumulative Free NOI[3] of ~$230MM in 2023

Reserves Growth[2]



Total Proved Plus Probable NPV10 Before Tax >$1,800MM[2]

1. Comprised of 25,184 bbl/d heavy oil, 191 bbl/d NGL and 7,294 mcf/d natural gas.
2. Reserves for 2022 are based on GLJ Ltd. reserves evaluation reports effective December 31, 2022 and reserve for 2023 are based on McDaniel & Associates Consultants Ltd Reserves Report effective December 31, 2023, included in the AIF.
3. Free NOI = field level netback less capital expenditures.

Return of Capital Framework

Achieved first tier of up to 25% shareholder returns in Q4 2023

Net Debt[1] ($MM) & *Net Debt / LTM EBITDA (x)*		$900 – $1,100 & *~ 1.0x Net Debt / EBITDA*	$500 – $900 & *~ 1.0x Net Debt / EBITDA*	≤ $500 & *~ 1.0x Net Debt / EBITDA*
Adjusted Funds Flow[1]	Excess Funds Flow Allocation *(After Base Dividend)*	Up to 25% Shareholder Returns *(NCIB and/or Enhanced Dividend)*	Up to 50% Shareholder Returns *(NCIB and/or Enhanced Dividend)*	Up to 75% Shareholder Returns *(NCIB and/or Enhanced Dividend)*
		75% Net Debt Reduction	50% Net Debt Reduction & Strategic M&A	25% Strategic M&A
	Committed Capital Expenditures	Base Dividend		
		Sustaining Capital and Required Debt Payments		

- **Q4 2023 excess funds flow implies up to $28MM in enhanced returns, equal to $0.05/share**

Excess Funds Flow (Q4' 23; $MM)	
Adjusted Funds Flow (AFF)[1]	**$195**
- Capital & Decommissioning Costs	($136)
= Free Funds Flow[1]	**$59**
- Lease / Financing / Corp. Expense	($1)
- Term Loan Amortization Payment	($117)
- Deferred Acquisition Note Payment	($50)
- Base Dividends	($21)
+/- Net Disposition / (Acquisition) Proceeds	$241
= Excess Funds Flow	**$111**
Enhanced Return: Up To 25% of Excess Funds Flow	
= Enhanced Return	**~$28**

- *Estimate ~50% of 2024 free funds flow allocated to shareholder returns through base dividends and enhanced returns*

1. See Disclaimers – "Specified Financial Measures"; AFF – Adjusted Funds Flow.

2024 CAPITAL BUDGET

2024 Priorities and Deliverables

Continued margin enhancement and shareholder returns

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Debt Reduction	• Prioritization of capital allocation for near term FFF[1] • Allocation of 75% of FFF[1] to reducing net debt; enables interest savings to be directed to shareholder returns
Shareholder Returns	• Base dividend ($0.15/share) and sustaining capital fully funded at US$37/bbl WTI • Up to 25% of excess funds flow available for enhanced returns; bought back >1.4% of the float YTD
Drive Efficiencies and Margin Enhancements	• Optimize well design & program execution to demonstrate improved capital efficiencies • Access premium oil markets and leverage infrastructure investments to further improve netback margins
Advance Safety & ESG Objectives	• Execute on key HSE objectives to ensure a culture of safe and responsible operations • Invest in carbon abatement initiatives to deliver material carbon tax savings in 2025 and providing market access for gas

1. See Disclaimers – "Specified Financial Measures" ; FFF – Free Funds Flow.

2024 Annual Corporate Guidance

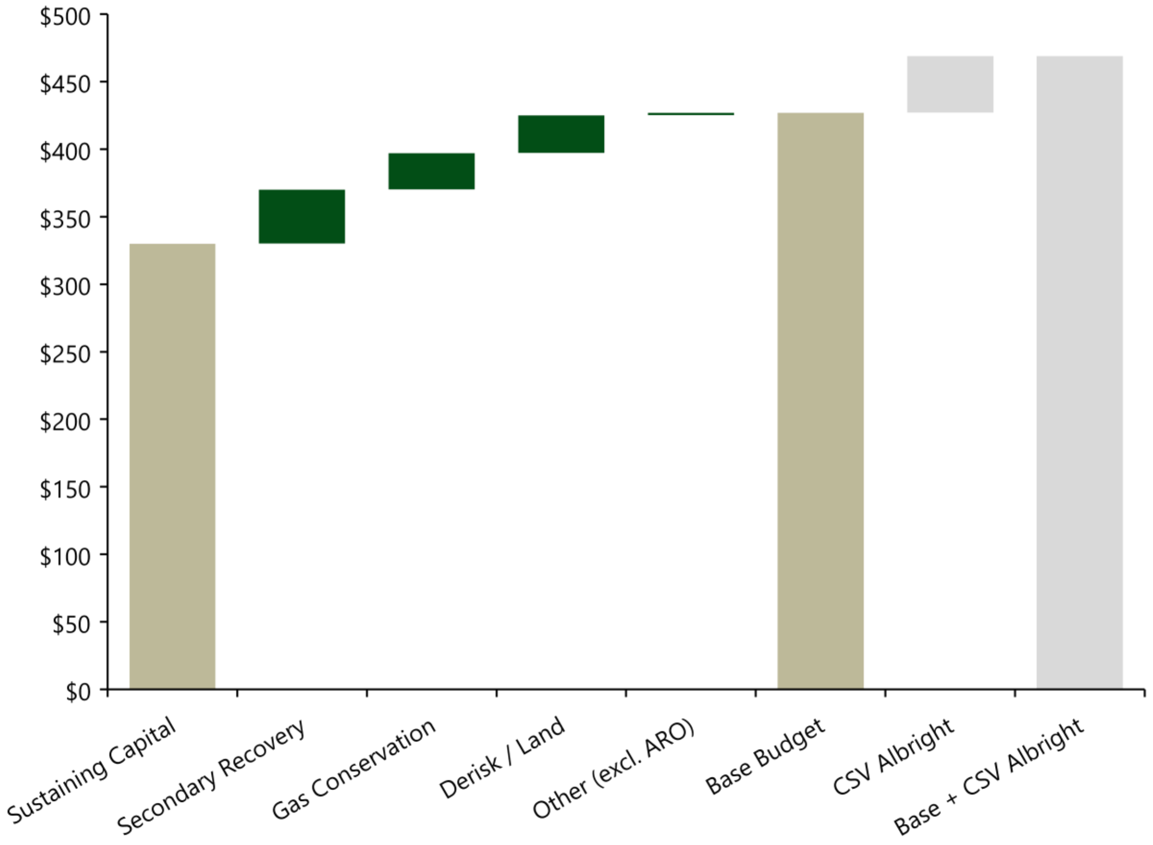
Developing expanded Clearwater assets & investing to enhance margins

2024 Budget Pricing	Guidance
WTI (US$/bbl)	$75.00
WTI / MSW Diff (US$/bbl)	-$4.00
WTI / WCS Diff (US$/bbl)	-$17.00
AECO ($/GJ)	$2.50
FX (CAD/USD)	1.345

2024 Annual Guidance	Original Base Guidance	Revised Base Guidance
Production[1]	61,000 – 63,000	61,000 – 63,000
Average Oil & NGL %	84% - 86%	84% - 86%
Capital Expenditures[2] ($MM)	$410 – $460	$390 – $440
Royalties (%)	20% – 22%	20% – 22%
Operating ($/boe)	$8.75 – $9.25	$8.75 – $9.25
Transportation ($/boe)	$3.25 – $3.60	$3.25 – $3.60
Carbon Tax ($/boe)	$1.00 – $1.50	$0.50 – $1.00
G&A ($/boe)	$1.35 – $1.50	$1.35 – $1.50
Interest ($/boe)	$3.80 – $4.20	$3.80 – $4.20
Income Tax[3] (%)	9% – 11%	9% – 11%

1. Comprised of 12,800-13,200 bbl/d light and medium oil, 36,600-37,800 bbl/d heavy oil, 2,400-2,500 bbl/d NGL and 54,900-56,700 mcf/d natural gas.
2. Excludes ARO and Clearwater Infrastructure Partnership capital.
3. Income tax percentage is based on the percentage of adjusted funds flow before tax.

2024 Capital Program ($MM)



CSV Albright capital viewed as discretionary – associated drilling is subject to prevailing commodity prices and expected CSV on-stream date

5-Year Plan Anchors Long-Term Sustainability

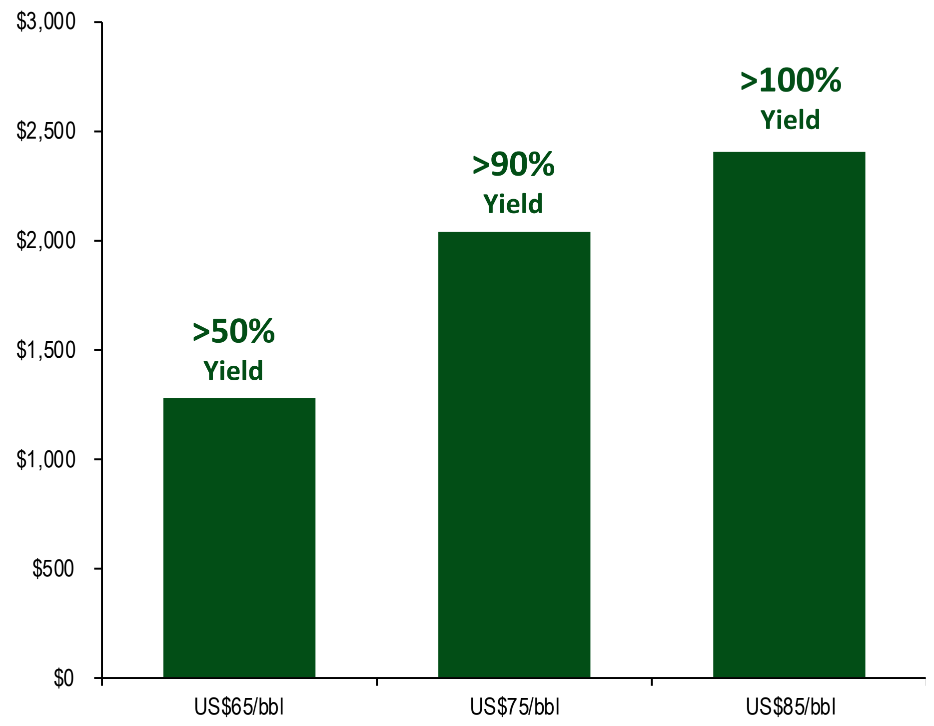
Cumulative FFF[1] outlook increases by $0.5Bln[3] reflecting inventory quality & efficiency gains

2024 – 2028 Outlook

Efficient Capital Plan	Well & program optimization; EOR expansion
Inventory Duration	10+ year inventory of oil weighted development
Low FFF Breakeven[1]	~US$37/bbl WTI[3]
Competitive FFF	~55% average reinvestment rate

~$2.0 Billion[2,3] Free Funds Flow[1] Over Next 5 Years

5 Year Cumulative Free Funds Flow[1,2,3,4] ($MM)



1. See Disclaimers – "Specified Financial Measures"; FFF – Free Funds Flow.
2. Calculated based on US$75/bbl WTI case; assumes average annual production of 65,000 boe/d from 2024 – 2028.
3. Calculated on a before tax basis and excludes hedges; tax is estimated to average ~$100MM per annum on US$ $75/bbl WTI case.
4. Yield based on Tamarack Valley share price of $3.97 per share .

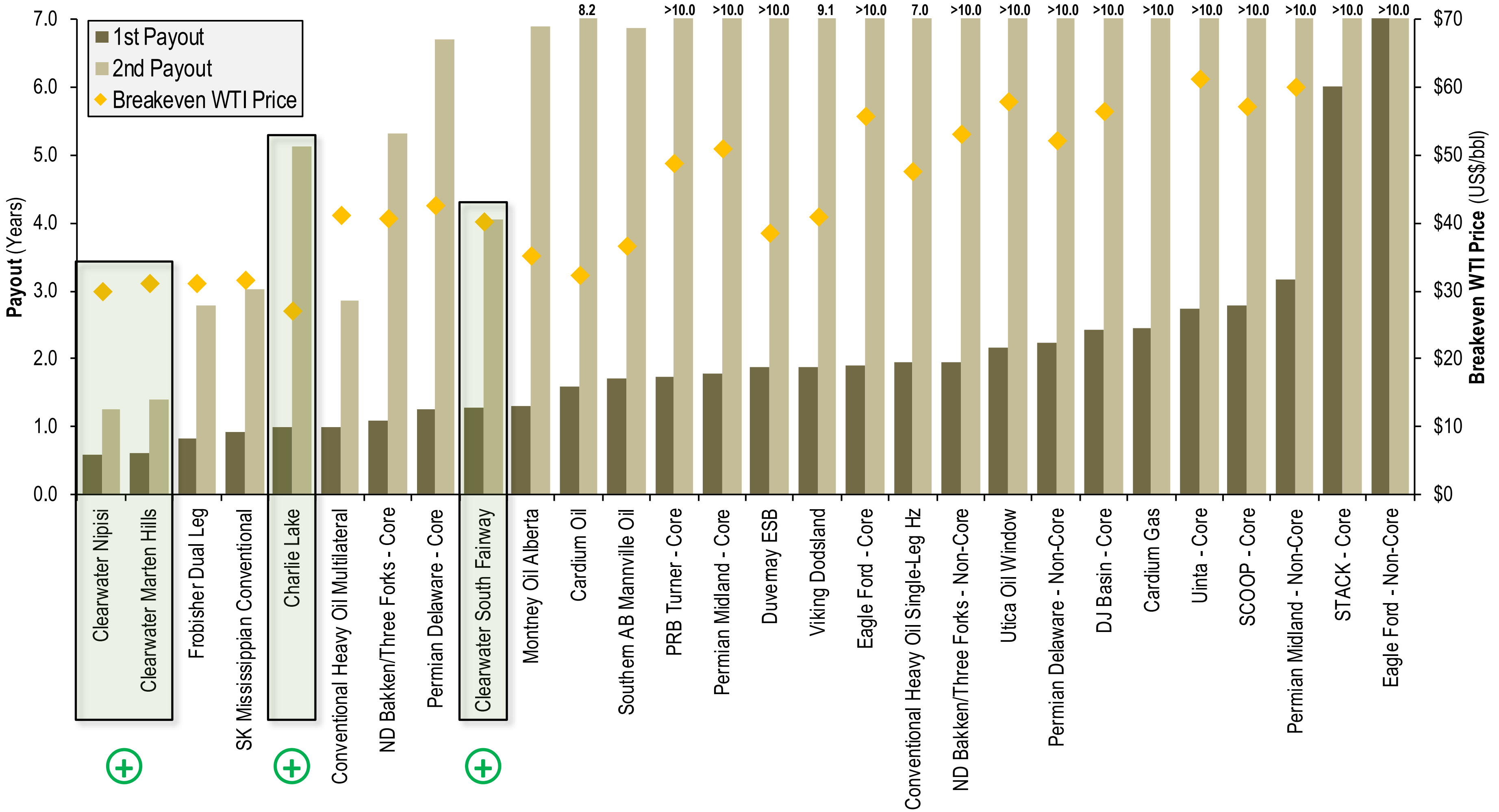
ASSET PORTFOLIO

High Graded Asset Portfolio Driving Enhanced Margins

Repositioned Asset Base
- 90% of corporate production in Charlie Lake and Clearwater
- Liquids weighting increased to ~85%

Delivering
- Low breakeven[1] costs
- Multiple payouts in <5 years

North American Payout Period & Half-Cycle Breakeven by Play[2]



1. See "Specified Financial Measures".
2. Source: Peters & Co. Limited estimates based on US$70/bbl WTI, US$3.00/Mcf NYMEX,C$2.67/Mcf AECO, and C$73.33/bbl WCS (updated February 15, 2024).

Largest Public Clearwater Producer

Established extensive exposure through the heart of the Clearwater fairway

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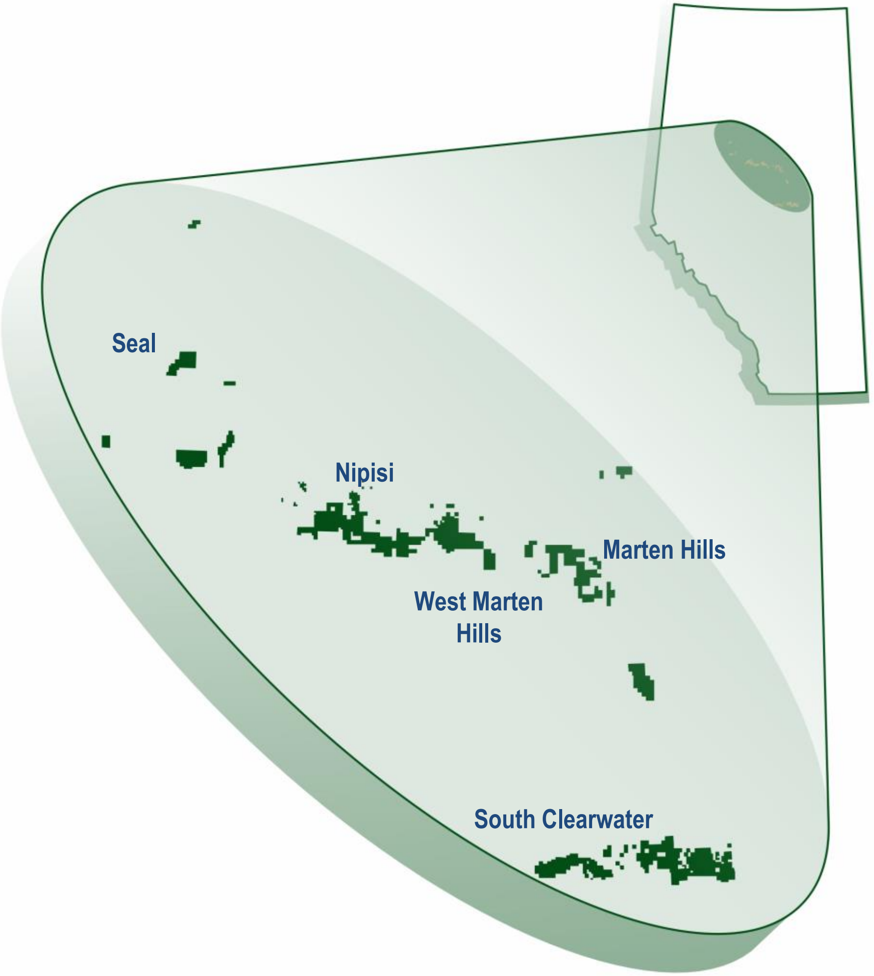


Scale

- Extensive holdings across the Clearwater fairway; 680 net sections of land[1]
- Pad development & well design optimization driving capital efficiencies

Infrastructure

- Pipeline connected to key oil terminals enhances market access to realize premium pricing
- Ownership in key natural gas plants ensure gas is conserved; lowering overall emissions

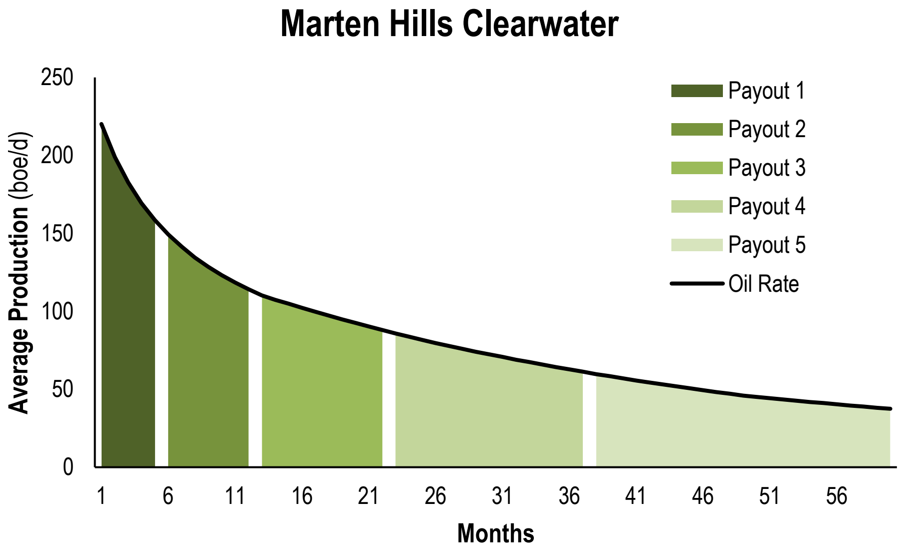
Inventory

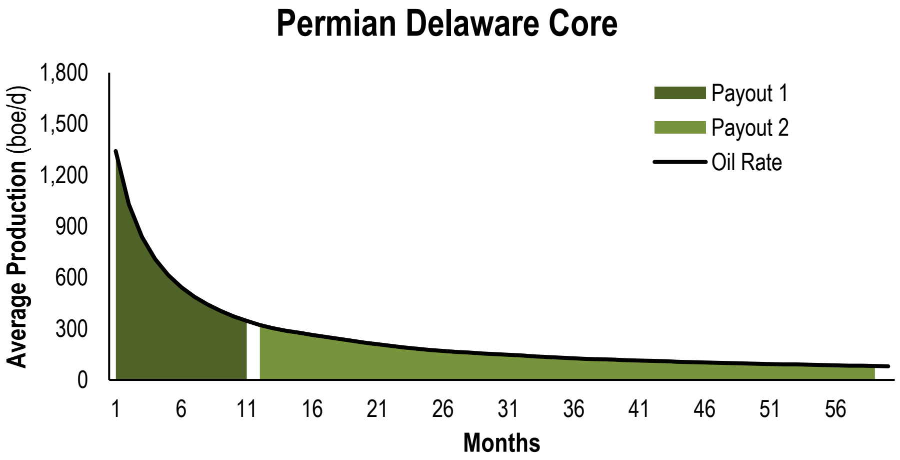
- 8.7 billion barrels of OOIP[2] in the Clearwater
- Successful implementation of waterflood program increasing ultimate recoveries

1. As at December 31, 2023.
2. OOIP – original oil in place based on internal estimates.

Canadian Clearwater Advantage[1]

Alberta Clearwater demonstrates superior economics





Marten Hills Clearwater Value Drivers

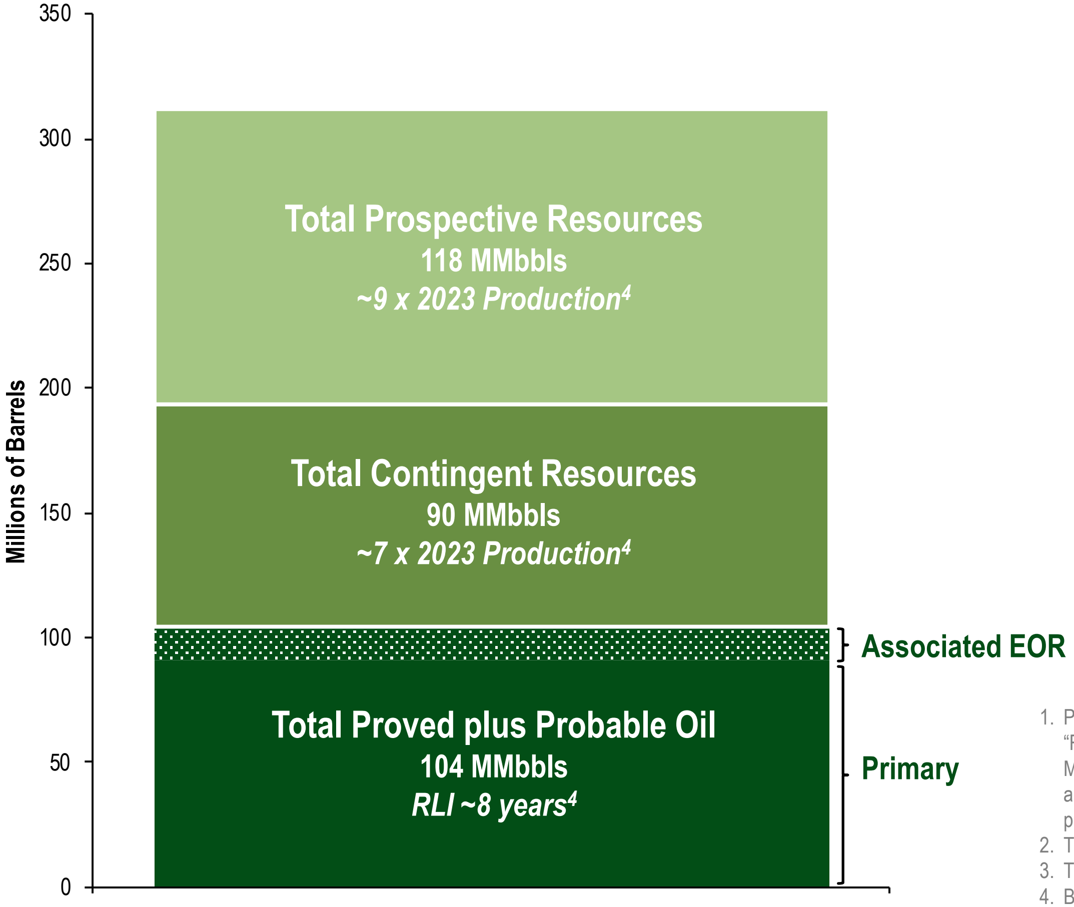
- **Higher and faster returns:** Marten Hills wells payout 3x in <2 years vs. top quartile Delaware which takes ~5 years for the same multiple
- **Capital cost & decline advantage:** Marten Hills wells do not require frac stimulation, reducing costs and spud to on-stream timing. Lower first year decline supports lower sustaining capital requirements
- **Top tier efficiencies:** Marten Hills delivers superior $/flowing boe metrics that drive free funds flow[1]
- **Future enhanced recovery:** Clearwater secondary recovery potential drives incremental returns

Source: Peters & Co. Limited estimates using US$75/bbl type curve.
1. See Disclaimers – "Specified Financial Measures"; FFF – Free Funds Flow.

Clearwater Resources Support Decades of Development

Top-tier resource with considerable scale to support future growth

2023 Clearwater Reserves & Resources[1,2,3,6]

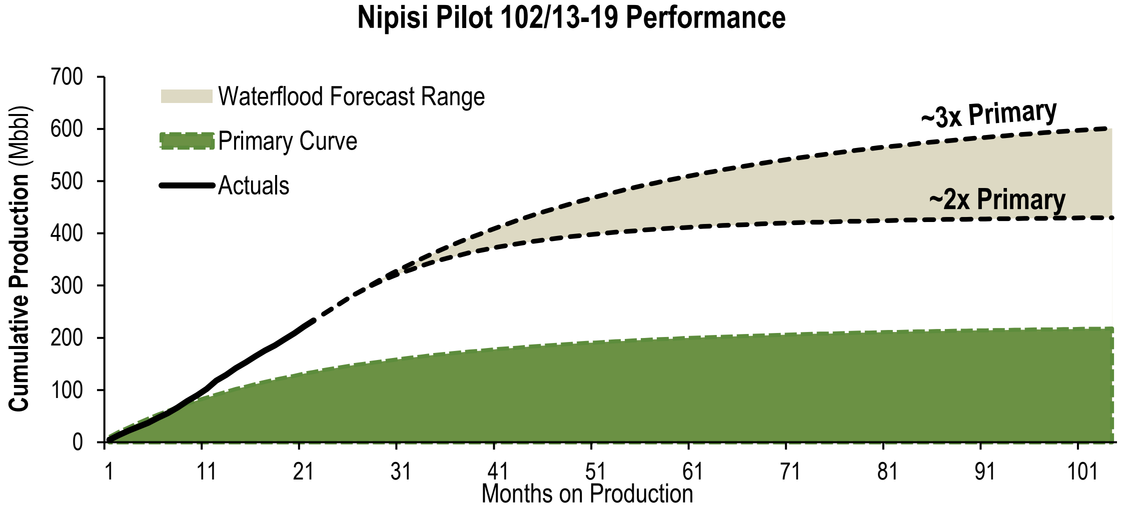


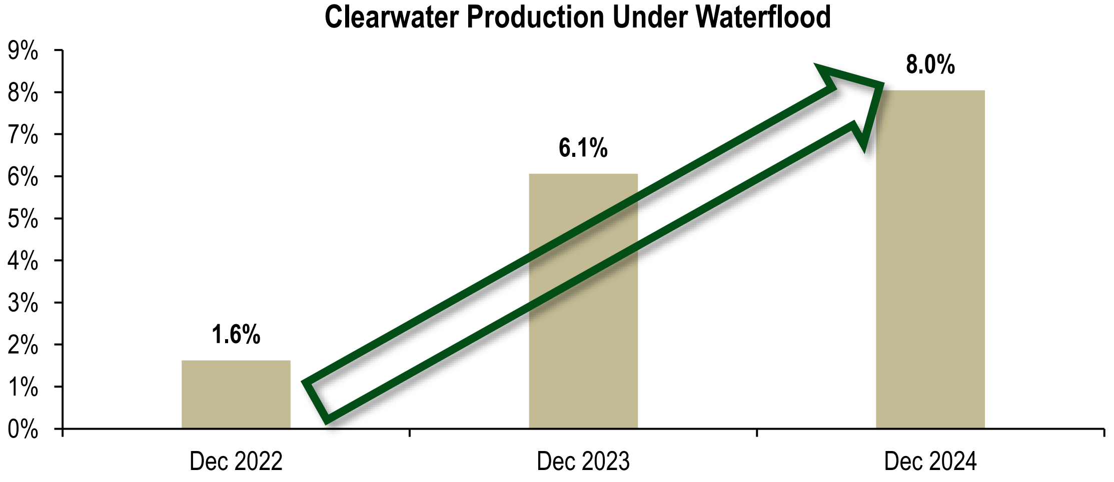
Decades of Development	TPP reserves reserve life index of ~8 years[4] and total resource size supports decades of additional development
Multi-Year Inventory	5-Year plan produces <1% of the 8.7 billion[5] OOIP
Enhanced Recovery	~12% of booked total Clearwater TPP reserves currently associated with waterflood

1. Per McDaniel & Associates Consultants Ltd. reserve report effective December 31, 2023 and the Contingent and Prospective Resource Evaluation effective December 31, 2023. (the "Resource Report"). The Resource Report indicates Tamarack's Clearwater heavy oil assets have a "best estimate" of Company gross Contingent Resources (unrisked) of 89.5 MMbbl and Company gross Prospective Resources (unrisked) of 118.4 MMbbl See "Reserves Disclosure" below and Tamarack's supplementary filing titled "Statement of Contingent and Prospective Resources" and dated February 28, 2024 which has been filed on SEDAR+ at www.sedarplus.ca for additional details with respect to Tamarack's contingent and prospective resources, including the risks and uncertainties related thereto.
2. The estimate of Contingent Resources has not been adjusted for risk based on the chance of development.
3. The estimate of Prospective Resources has not been adjusted for risk based on the chance of discovery or the chance of development.
4. Based 2023 Clearwater oil production of 13MMbbls.
5. OOIP – original oil in place based on internal estimates.
6. Reserves, contingent resources, and prospective resources should not be combined without recognition of the significant differences in the criteria associated with their classification.

Clearwater Waterflood Progression

Advancing secondary recovery to drive incremental resource capture





~2x Primary Recovery: Demonstrated waterflood success across Clearwater fairway

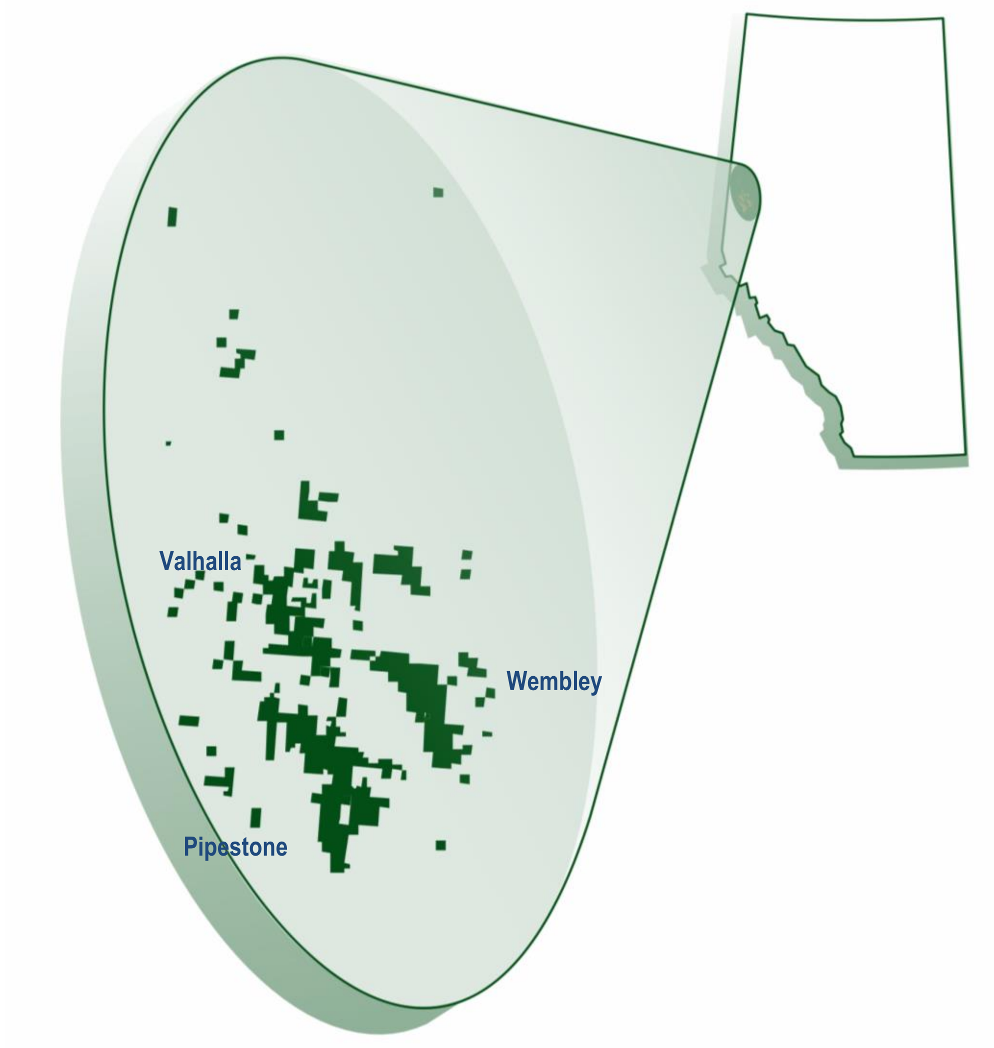
Mitigating Decline: Reduces sustaining capital requirements

Ramping Injection: Increasing Clearwater volumes under waterflood through 2024

Superior Economics: Stacked multi-zone waterflood potential and large, contiguous resource result in economies of scale

Scalable Charlie Lake Light Oil

Development plan designed to balance production, processing and egress



Scale

- Large continuous land position with top tier geology; 249 net sections[1] of land
- Pad development with ERH[2] wells improving economics (<1 year payouts)

Infrastructure

- Tamarack Wembley 15 MMcf/d gas plant onstream Q2 2023; battery upgrade Q1 2024
- Increased sour processing capacity with CSV Albright firm capacity

Inventory

- Inventory supports 16,000 boe/d for >10 years
- Growing asset base; added 65 net sections since acquiring Anegada (May 2021)

1. As at December 31, 2023.
2. ERH – Extended reach horizontal.

Development Outperformance

Well design and program execution driving solid results in core areas

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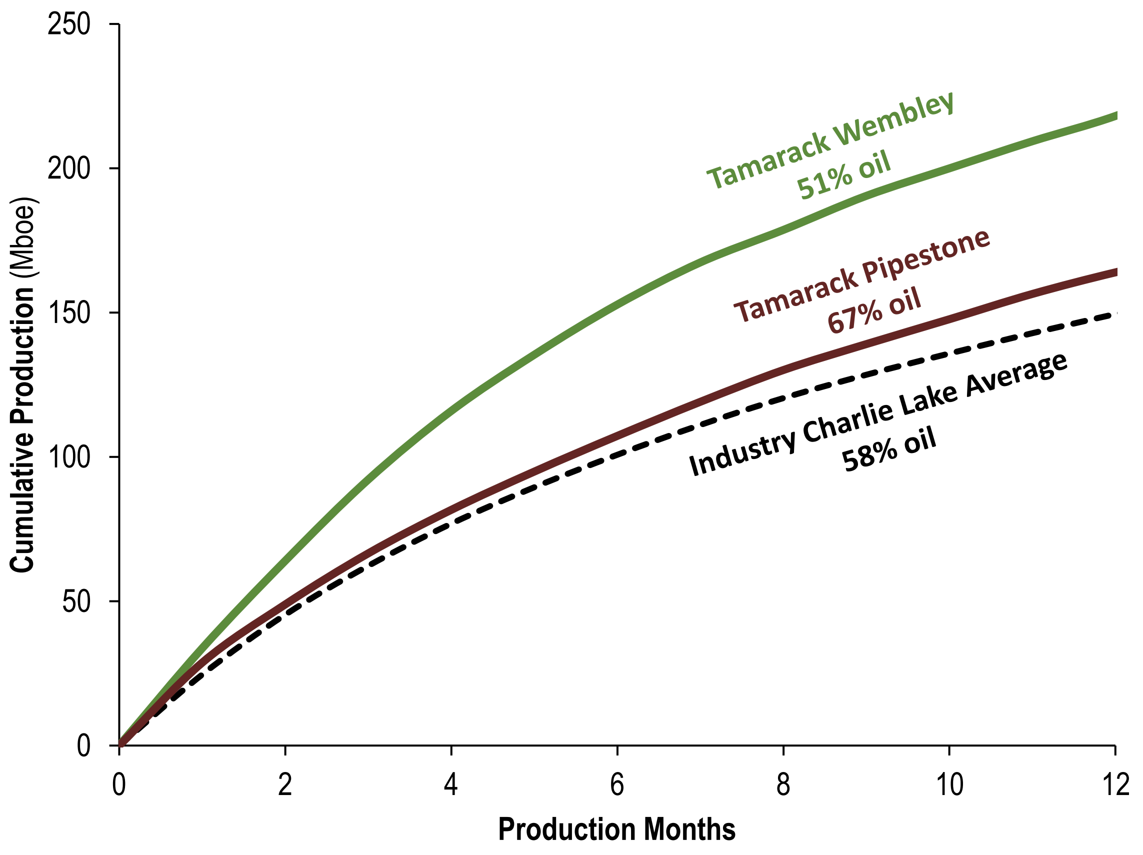
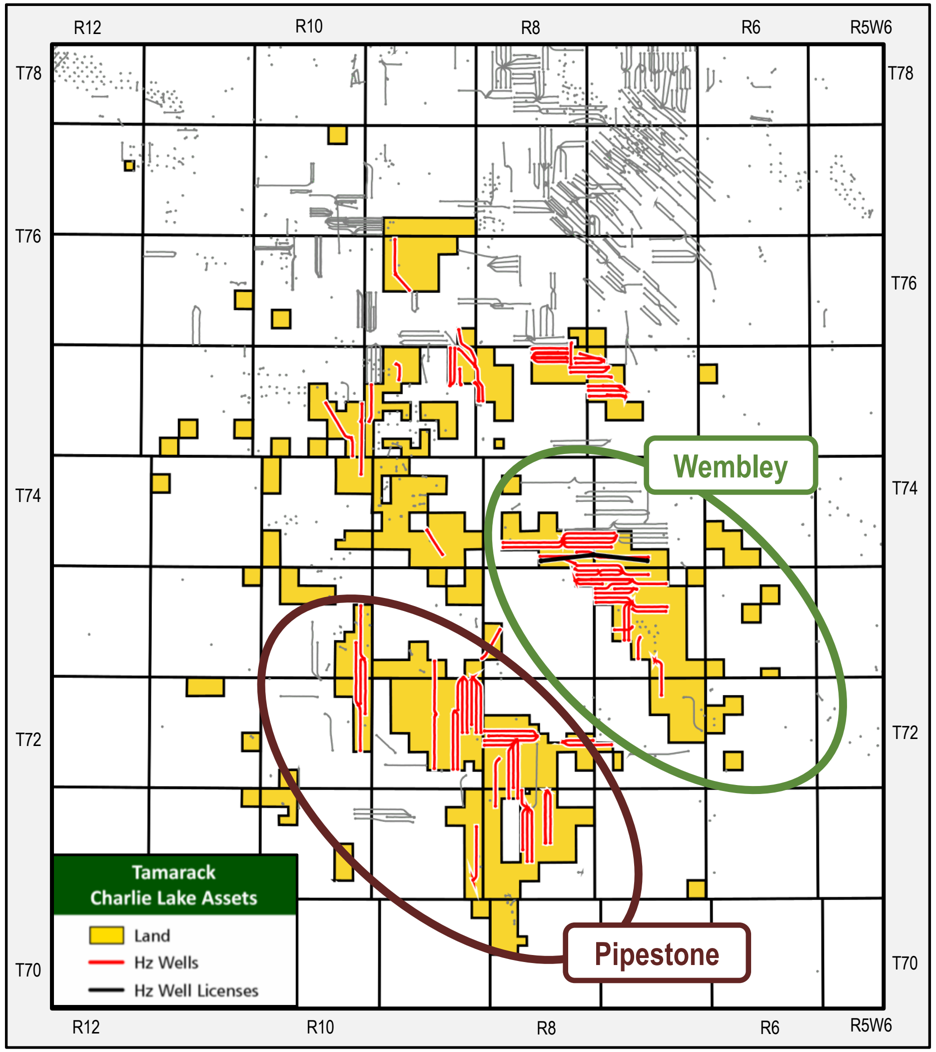
Deploying extended reach horizontal technology to enhance recoveries





1. Source: GeoSCOUT and Tamarack, production data as of November 2023.
2. 2020 - 2022 wells, Charlie Lake Fairway represents a 120 well average from top six Charlie Lake producers.

ENVIRONMENT, SOCIAL AND GOVERNANCE

Sustainability at Tamarack – ESG in Action

Enabling sustainability and ESG to drive profit and enhance future value

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2023 Emission Abatement Projects

Marten Creek Gas Plant
↓ **~70,000 t CO_2e Scope 1 emissions in '24**
Investment of ~$13.2MM of gas processing and gathering infrastructure

Perryvale Gas Conservation
↓ **~51,000 t CO2e Scope 1 emissions in '24**
Investment of ~$14.3MM of gas processing and gathering infrastructure

East Nipisi Gas Conservation
↓ **~18,800 t CO2e Scope 1 emissions in '24**
Investment of ~$2.1MM in infrastructure

2024 Emission Abatement Projects

Marten Hills NW Connector
↓ **~22,000 & ~49,000 t CO2e Scope 1 emissions in 2024 & 2025**
Investment of ~$20.0MM in infrastructure

West Marten Hills Pipeline
↓ **~2,200 & ~16,500 t CO2e Scope 1 emissions in 2024 & 2025**
Investment of ~$6.7MM in infrastructure

Clearwater Infrastructure Partnership

Pioneering Partnerships with Indigenous Communities

Tamarack and 12 First Nation and Métis communities formed a new partnership, the Clearwater Infrastructure Limited Partnership (the "CIP")

- Tamarack transferred $172MM of certain Clearwater midstream assets to the CIP for total consideration of $146.2MM in cash and a 15% interest in CIP
- The 12 First Nation and Métis communities, through a newly formed entity called Wapiscanis Waseskwan Nipiy Holding Limited Partnership ("WWN"), acquired an 85% non-operated working interest in CIP
- Tamarack operates these assets and with full access to 100% of Tamarack's existing capacity
- Tamarack entered a 16-year take-or-pay commitment for average volumes of 29,000 boe/d[1], which represents the gross commitment of the CIP

Clearwater Infrastructure Limited Partnership (100%)

Wâpiscânis Wâseskwan Nipiy *(non-operated 85% W.I.)*

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Loan guarantee to WWN supported by:

AIOC

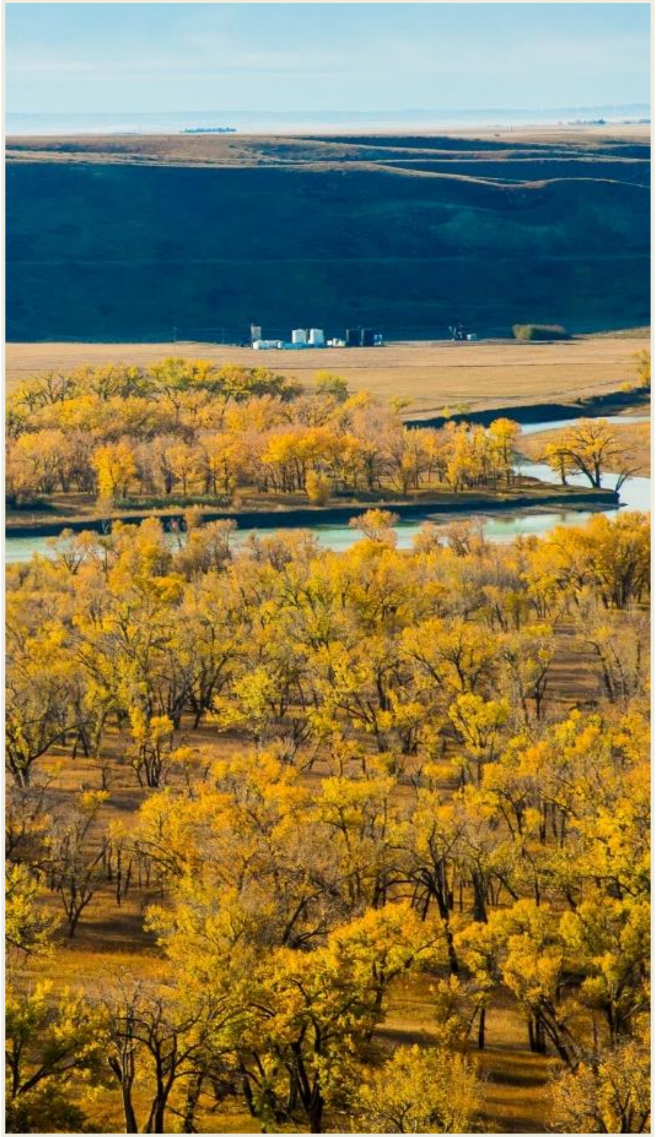
This New Platform Provides a Path Forward For Future Opportunities For Tamarack To Partner With Indigenous Communities On Other Projects

1. The composition between light oil, heavy oil, natural gas and natural gas liquids is not defined in the agreements. The makeup of such boe is not a governing factor.

Enhancing Shareholder Value

Sustainable returns focused strategy to grow free funds flow[1] per share

Premium Production	61,000 – 63,000 boe/d[2] comprised of ~85% oil & liquids
Low Breakeven Oil Assets	<$37/bbl USD WTI; key plays offer well payouts in <1 year
Long Duration Inventory	Clearwater primary & secondary recovery; Charlie Lake development
Balance Sheet Strength	FFF[1] supports continued debt reduction through 2024
ESG Leadership	GHG intensity reduction; Indigenous partnerships



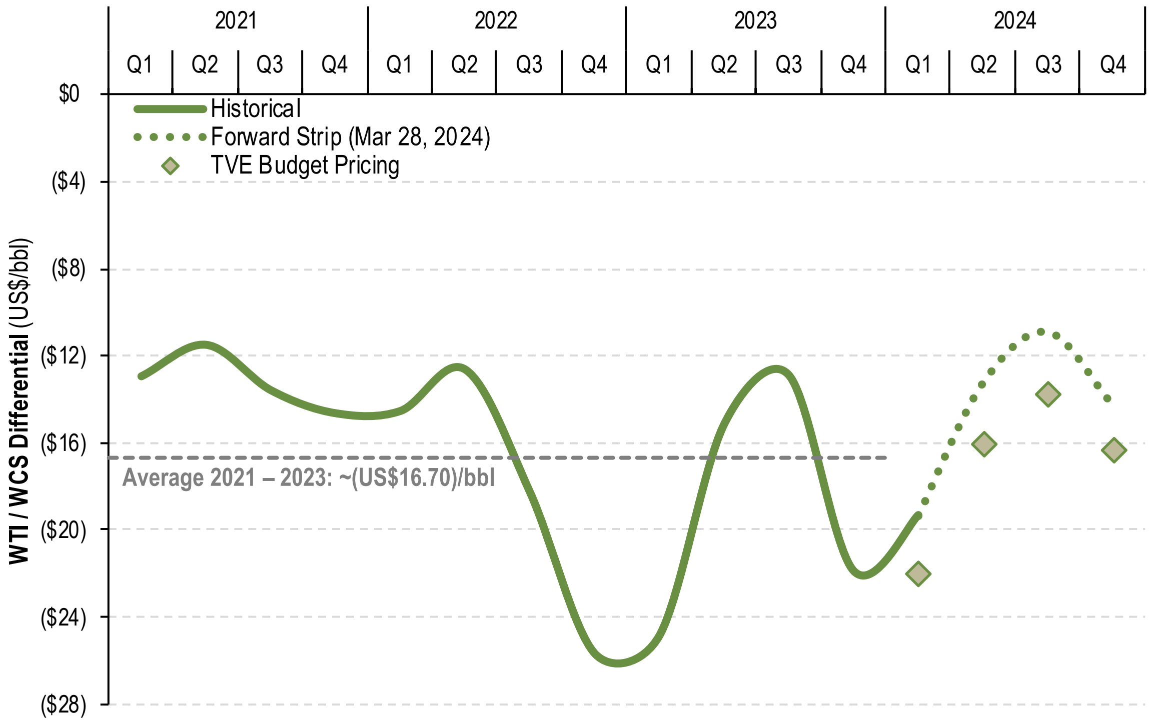
1. See Disclaimers – "Specified Financial Measures".
2. 2024 Base Budget guidance: 12,800-13,200 bbl/d light and medium oil, 36,600-37,800 bbl/d heavy oil, 2,400-2,500 bbl/d NGL and 54,900-56,700 mcf/d natural gas.

APPENDIX: FINANCIAL

Canadian Heavy Oil Differential Narrowing

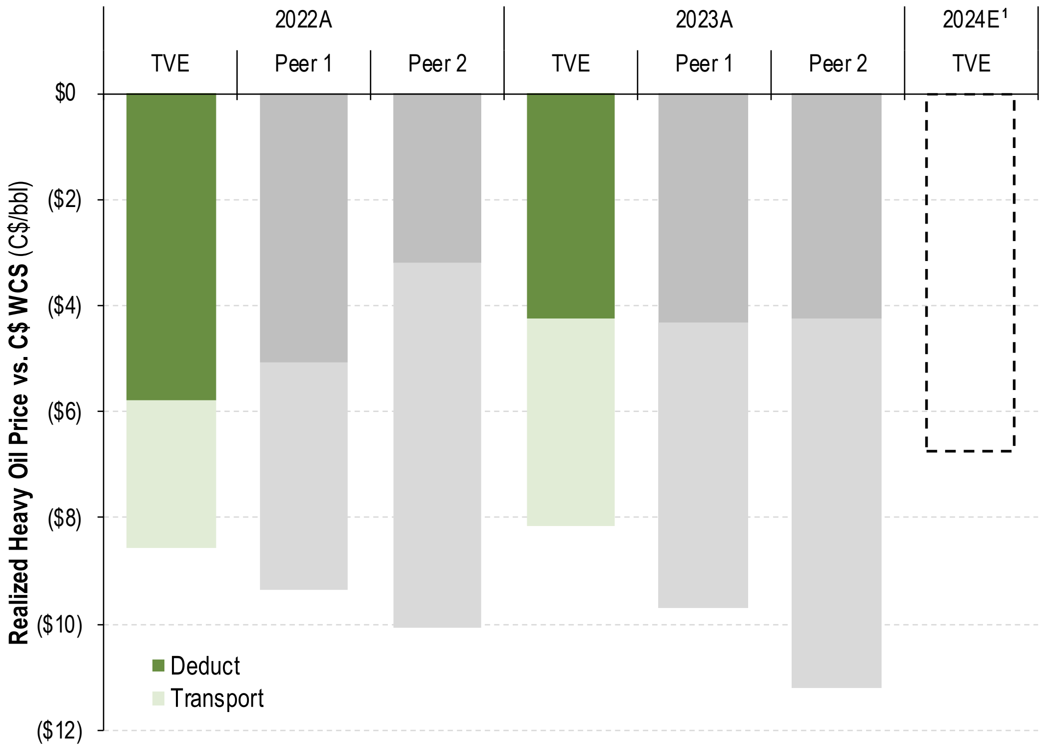
WCS differential set to tighten once TMX online in early 2024

WTI / WCS Differential



Average 2024 WTI / WCS Differential Budget: (US$17.00)/bbl

Tamarack Heavy Oil Realized Price

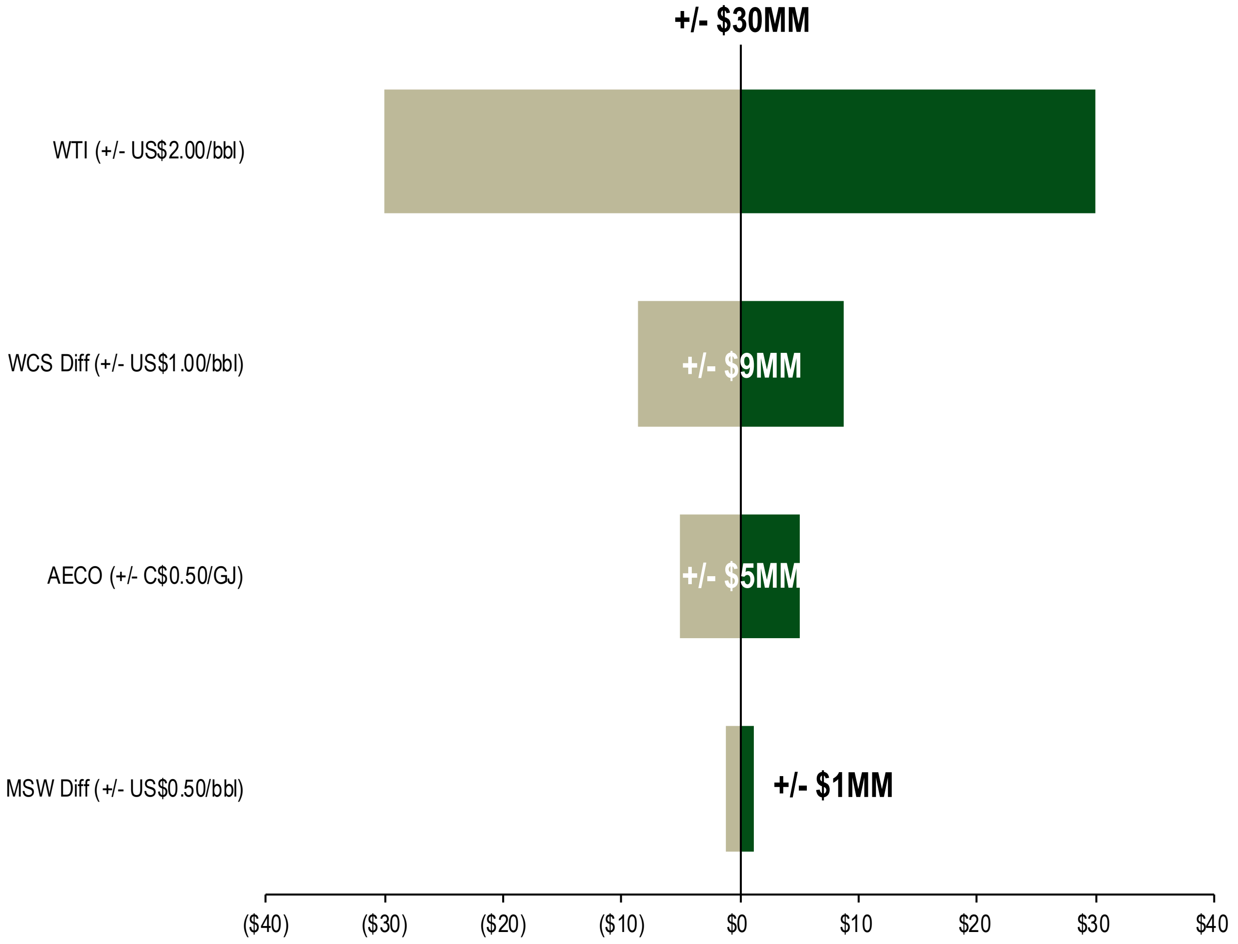


Best-In-Class Clearwater Realized Pricing & Significant Step Change In 2024E

1. See Disclaimers – "Forward Looking Statements". TVE 2024E offset includes both deduct and transport.

2024 Budget Price Sensitivities[1]

A-Tax Adjusted Funds Flow[2] (Hedged; $MM)



Strong Asset Base to Withstand Price Changes

- Tamarack is most sensitive to WTI pricing given oil weighting of >80%
  - For every US$2.00/bbl change, AFF[2] changes by +/-$30MM
- WCS differential adds to the sensitivity, >65% heavy oil assets, AFF[2] changes by +/-$9MM for every US$1.00/bbl change in differential
  - Tamarack's heavy oil portfolio is made of highly economic Clearwater assets with best-in-class breakeven prices
- AECO and MSW differential have less of an impact on AFF[2]
- Tamarack manages commodity risk through its risk management program to support capital stability, base dividend and debt repayment

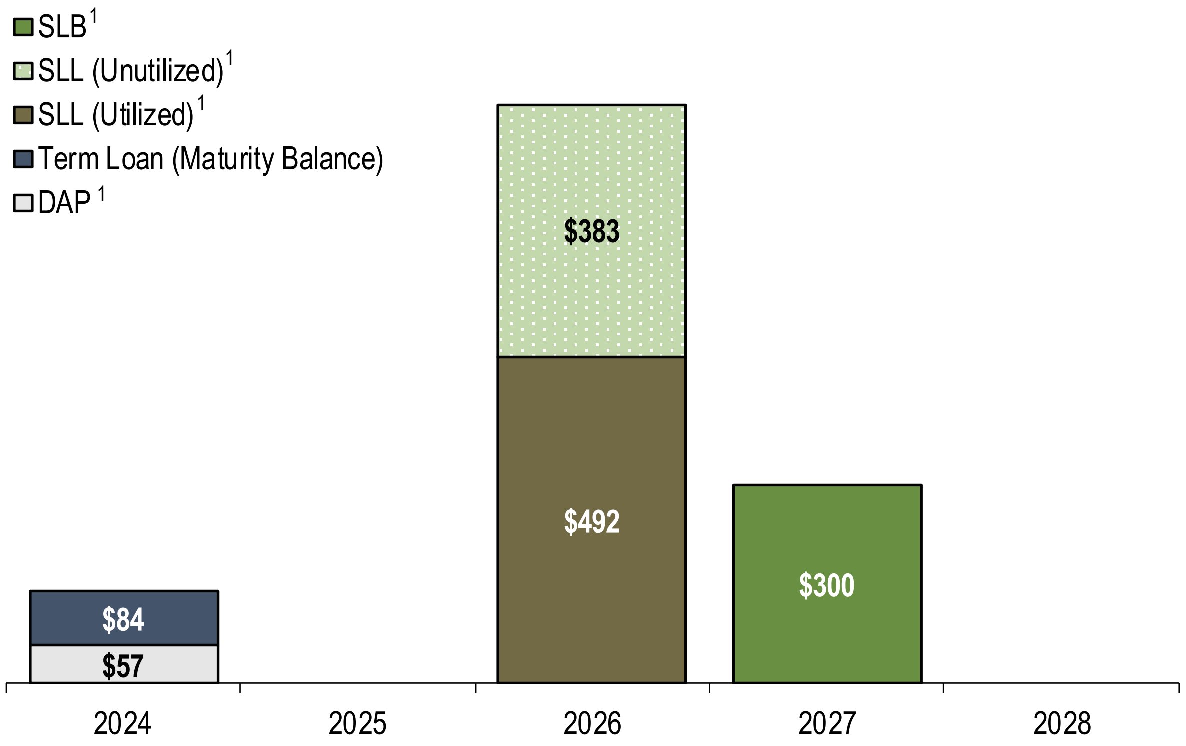
1. Sensitivity based on budget pricing for forward 2024 months.
2. See Disclaimers – "Specified Financial Measures"; AFF – Adjusted Funds Flow.

Capital Structure Provides Financial Flexibility

Delivering material reduction in debt driven by free funds flow[2]

- Total net debt reduced by ~$373MM in 2023
- Forecast >$250MM[3] of free funds flow[2] in 2024 available for debt repayment, dividend and enhanced return of capital
- Remaining DAP and Term Loan to be repaid in Q1 2024; relaxes lending covenants and reduces average borrowing costs
- Laddered debt maturity schedule

Amortization and Maturity Profile ($MM)



1. Definitions: SLL – Sustainability-Link Facility; SLB – Sustainability Linked Bond; DAP – Deferred Acquisition Payment.
2. See Disclaimers – "Specified Financial Measures".
3. Based on 2024 budget pricing.

Sustainability-Linked Lending & Notes

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Strengthening our commitment to responsible energy production

All of Tamarack's debt has been converted to **sustainability-linked debt** and includes:

- \$875MM covenant-based revolving **sustainability-linked lending facility** (**SLL**) with a lending syndicate
- \$300MM notes issued as **sustainability-linked bonds** (**SLB**) that trade in the open market – 2 KPIs with step-up interest penalty in 2026

KPIs and SPTs selected strongly align with Tamarack's **existing priority topics and commitments**

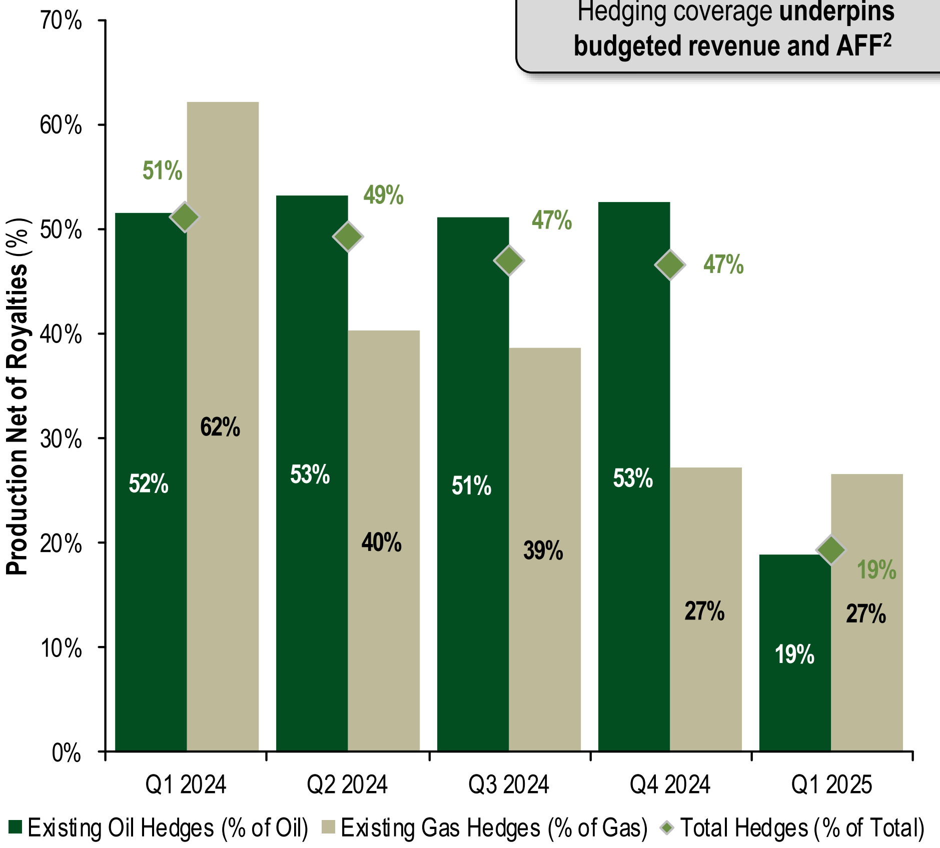
Key Performance Indicator (KPI)	Tamarack Priority	UN Sustainable Development Goal	2020 Baseline	SLL (\$875MM)	SLB (\$300MM)
				Sustainability Performance Target (SPT)	Sustainability Performance Target
Scope 1 and 2 Emissions Intensity		13 CLIMATE ACTION	37.5 kg CO_2e/boe	**39%** reduction by 2025 to 22.9 kg CO_2e/boe	**39%** reduction by 2025 to 22.9 kg CO_2e/boe
Decommissioning Management – ARO Spend		15 LIFE ON LAND	5.6%	**150%** of the regulatory target spend annually	
Indigenous Representation in the Workforce		10 REDUCED INEQUALITIES	3.5%	**>6.0%** representation by 2025 with a minimum 2 FTE additions annually	**>6.0%** representation by 2025

Risk Management

Enhancing certainty with flexibility to capture upside value

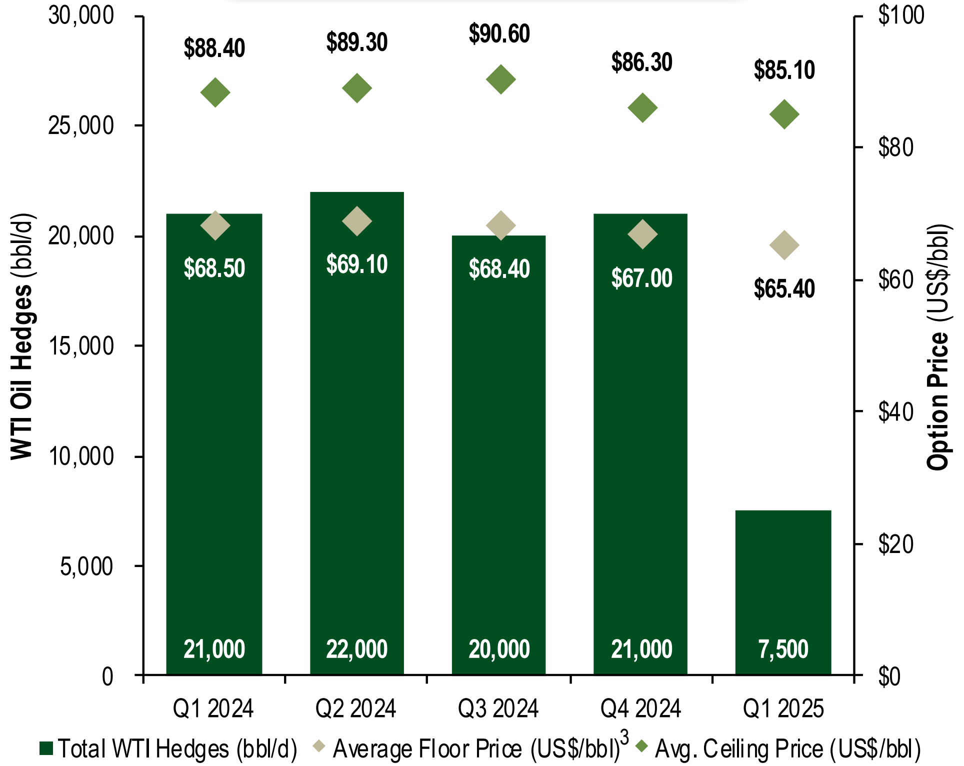
Percentage of Volume Hedged[1]

Hedging coverage **underpins budgeted revenue and AFF[2]**



Weighted Average WTI Hedge Price[1]

Balanced portfolio coverage ensures price floor but **retains upside** with 2-way collars



Supports capital stability, base dividends and debt repayment

1. Hedges as at April 2, 2024. Hedge prices rounded to nearest $0.10/bbl.
2. See Disclaimers – "Specified Financial Measures"; AFF – Adjusted Funds Flow.
3. Average floor price includes volume weighted average of puts from both put and 2-way collar structures and fixed price hedges and excludes premiums.

Risk Management[1]

Risk Management	Units	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025
Oil Hedges									
WTI Collars									
Volume	*bbl/d*	21,000	22,000	20,000	21,000	7,500	-	-	-
Avg. Floor Price	*US$/bbl*	$68.48	$69.09	$68.36	$67.05	$65.40	-	-	-
Avg. Ceiling Price	*US$/bbl*	$88.36	$89.28	$90.59	$86.26	$85.11	-	-	-
Avg. Premium	*US$/bbl*	$0.93	$0.93	$1.38	$1.43	$0.32	-	-	-
Oil Basis Hedges									
WTI - WCS Basis Swaps									
Volume	*bbl/d*	5,500	15,000	14,500	15,000	3,000	2,000	2,000	2,000
Avg. Fixed Price	*US$/bbl*	($15.95)	($15.21)	($13.09)	($14.64)	($14.02)	($13.90)	($13.90)	($13.90)
WTI - MSW Basis Swaps									
Volume	*bbl/d*	2,500	5,000	5,000	5,000	-	-	-	-
Avg. Fixed Price	*US$/bbl*	($2.69)	($2.87)	($2.60)	($2.60)	-	-	-	-

Risk Management	Units	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025
Natural Gas Hedges									
AECO 5A Swaps									
Volume	*GJ/d*	-	16,000	15,500	3,538	-	8,500	8,500	2,864
Avg. Fixed Price	*C$/GJ*	-	$1.92	$1.95	$2.06	-	$2.86	$2.86	$2.86
AECO 7A Collars									
Volume	*GJ/d*	-	-	-	1,658	2,500	-	-	-
Avg. Floor Price	*C$/GJ*	-	-	-	$2.50	$2.50	-	-	-
Avg. Ceiling Price	*C$/GJ*	-	-	-	$4.35	$4.35	-	-	-
NYMEX Collars									
Volume	*MMbtu/d*	25,000	2,500	2,500	7,804	10,500	-	-	-
Avg. Floor Price	*US$/MMbtu*	$3.08	$3.05	$3.05	$3.01	$3.00	-	-	-
Avg. Ceiling Price	*US$/MMbtu*	$4.28	$3.50	$3.50	$4.10	$4.17	-	-	-
NYMEX - AECO Basis Swaps									
Volume	*MMbtu/d*	25,000	2,500	2,500	8,136	11,000	-	-	-
Avg. Fixed Price	*US$/MMbtu*	($1.10)	($1.11)	($1.11)	($1.05)	($1.04)	-	-	-

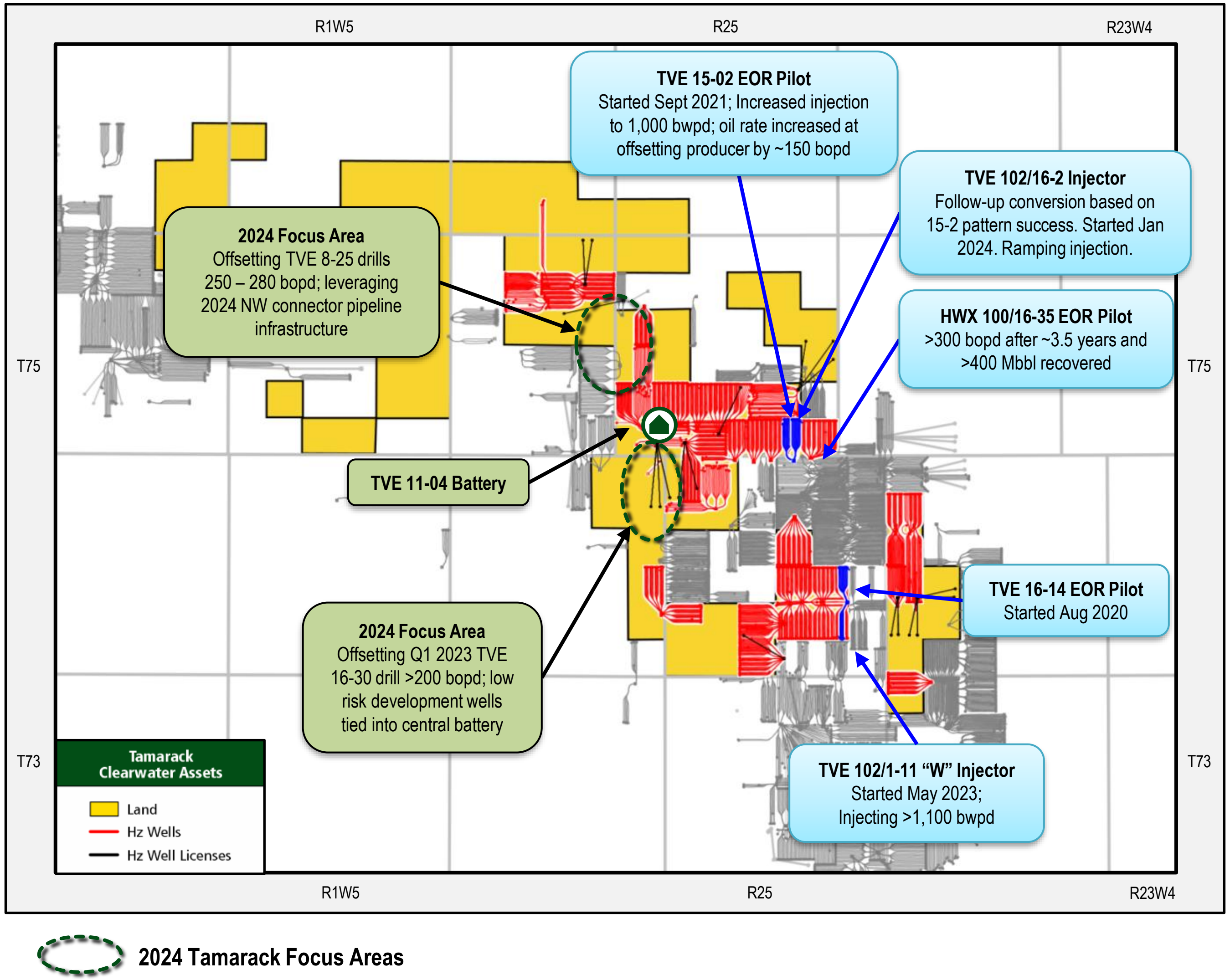
Risk Management	Units	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025
FX Hedges									
C$/US$ Deferred Premium Puts									
Notational	*US$MM/Month*	$7.0	-	-	-	-	-	-	-
Put Price	*C$/US$*	1.328	-	-	-	-	-	-	-
Put Premium	*$MM/$MM Not.*	$0.01							
C$/US$ Collars									
Notational	*US$MM/Month*	$8.0	$10.0	$10.0	$10.0	-	-	-	-
Avg. Floor Price	*C$/US$*	1.335	1.336	1.337	1.337	-	-	-	-
Avg. Ceiling Price	*C$/US$*	1.393	1.394	1.395	1.395	-	-	-	-
C$/US$ Swaps									
Notational	*US$MM/Month*	$6.0	$6.0	$11.0	$11.0	-	-	-	-
Avg. Fixed Price	*C$/US$*	1.355	1.355	1.353	1.353	-	-	-	-
C$/US$ Variable Collars[(2)]									
Notational	*US$MM/Month*	$22.5	$26.5	$12.0	$12.0	-	-	-	-
Avg. Floor Price	*C$/US$*	1.332	1.335	1.341	1.341	-	-	-	-
Avg. Ceiling Price	*C$/US$*	1.406	1.406	1.406	1.406	-	-	-	-
Avg. Knockout Price	*C$/US$*	1.366	1.368	1.369	1.369	-	-	-	-
C$/US$ Variable Collars (Ext. Option)[(3)]									
Notational	*US$MM/Month*	$4.5	$4.5	$9.0	$10.0	$4.0	-	-	-
Avg. Floor Price	*C$/US$*	1.329	1.329	1.328	1.328	1.333	-	-	-
Avg. Ceiling Price	*C$/US$*	1.406	1.406	1.403	1.403	1.400	-	-	-
Avg. Knockout Price	*C$/US$*	1.363	1.363	1.372	1.373	1.368	-	-	-

1. As at April 2, 2024.
2. If the average rate for the month exceeds the call, Tamarack receives an average rate forward equivalent to the knockout rate.
3. Includes an extension option at the end of a collar, at the counterparty's option, for an equivalent term at an average rate forward fixed price equal to the call. Extension volumes not include in tables herein.

APPENDIX: OPERATIONS

Marten Hills: Developing Top Tier Acreage in the Core

Strong positive correlation between injectivity and oil response across the Clearwater fairway



Marten Hills

- **2024 Activity:** Drilling 23 net wells and converting 8 wells to injection
- **Strategic Infrastructure:** >60% oil flowline connected to centralized facility
- **Deliverability:** IP30[1] rates in excess of 250 bopd; ~20° API
- **Future Development Strategy:** Continued development drilling and steadily increasing waterflood development over the next 8+ years
- **Highest Recovery Multi-Lateral Well**: Increased water injection at 15-02 and observed material oil response of ~150 bopd higher than pre-ramp, well has now produced >450 Mbbl of oil - representing the highest recovery of any Clearwater multi-lateral well

Note: Oil rates shown represent peak monthly rates per well unless otherwise noted.
1. See Disclaimers – "Specified Financial Measures"; IP30 - initial 30-day production rates.

Successful EOR Implementation

Advancing secondary recovery to drive incremental resource capture

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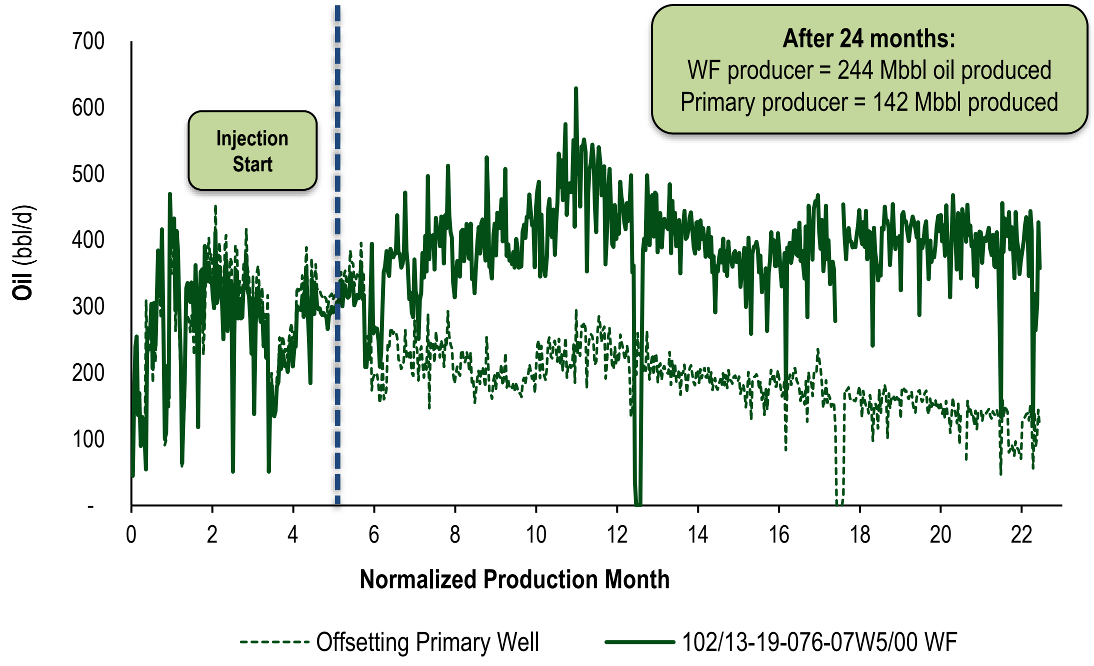
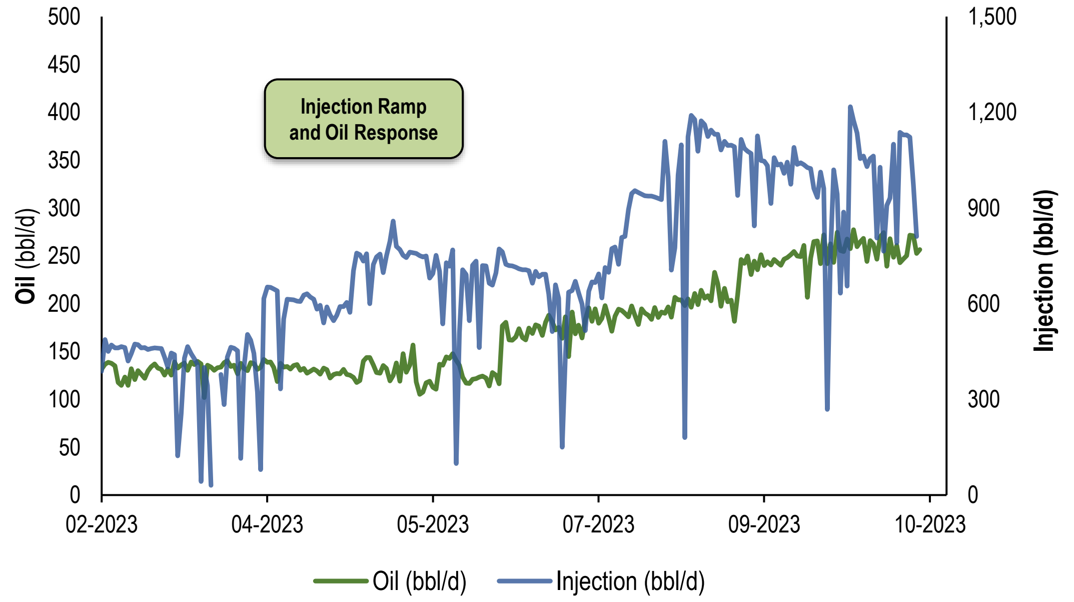
Nipisi 102/13-19-076-07W5 Pilot

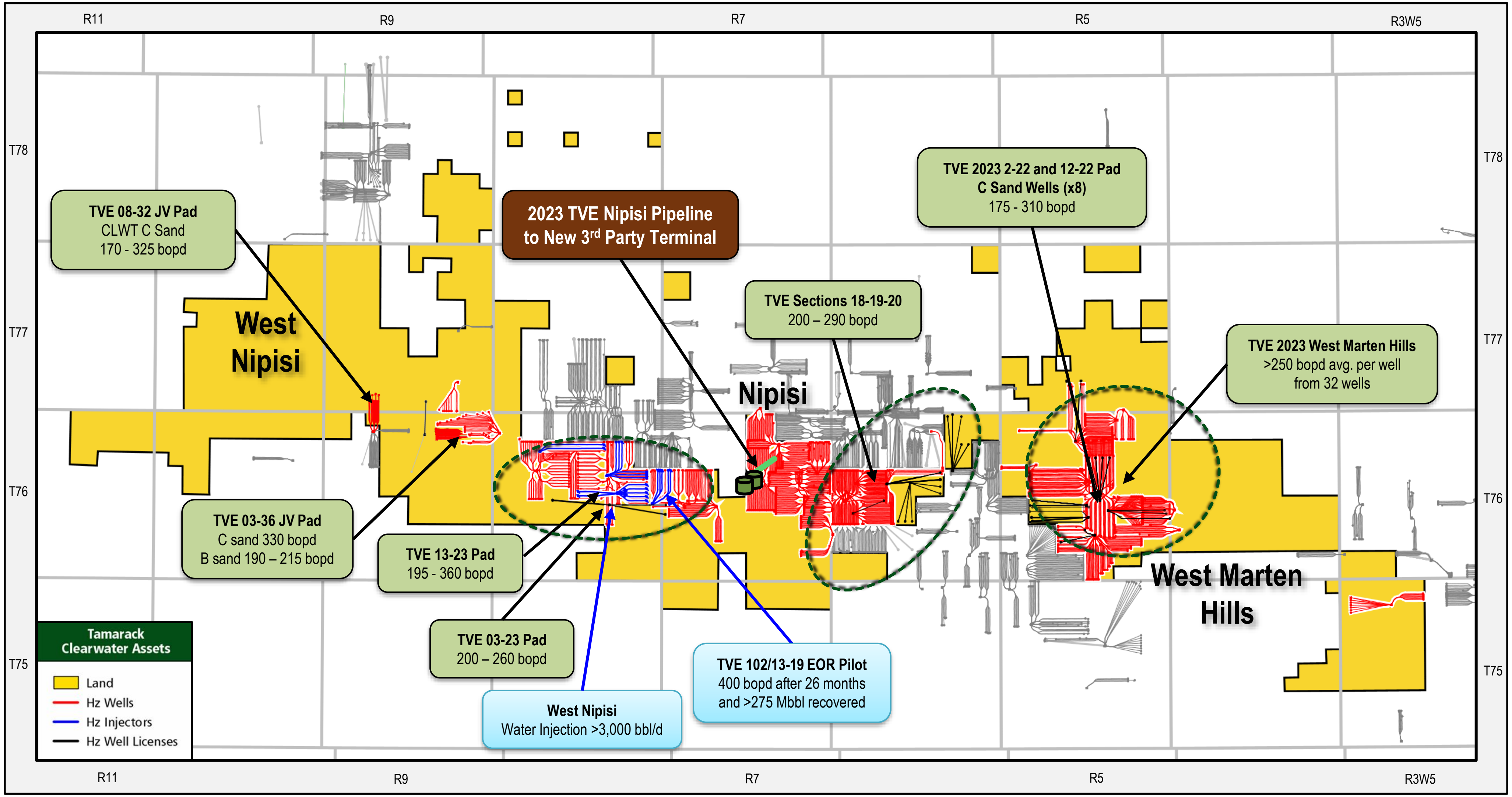


Marten Hills 15-02-075-25W4 Pilot



Nipisi & West Marten Hills: Enhancing Inventory

Focusing on top tier lands in support of long-term sustainable development



2024 Tamarack Focus

Nipisi & West Marten Hills

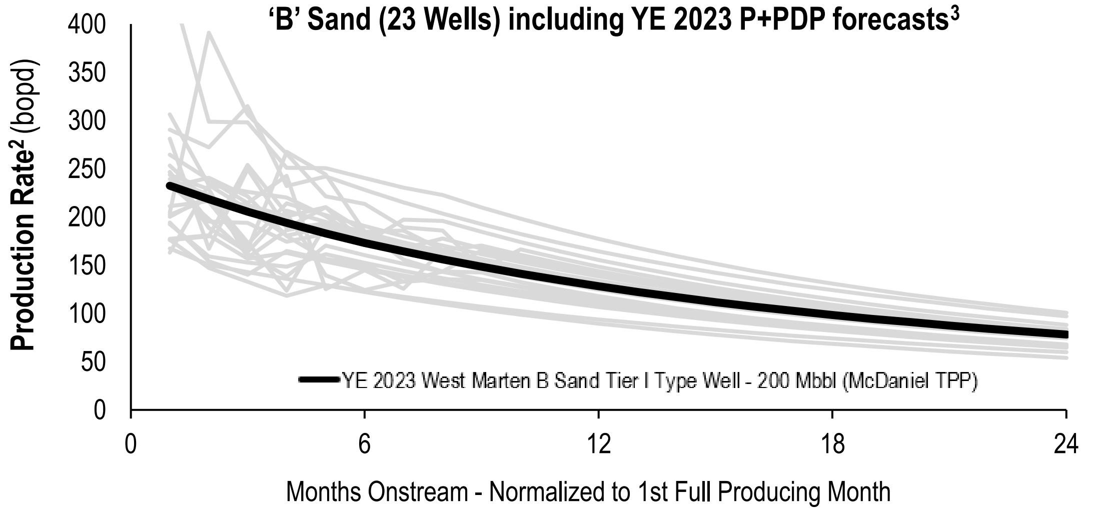
- **2024 Activity:** Drilling 69 (66.4 net) wells; including 15 water injectors and 1 water source well
- **Stacked potential:** building on success with drilling in both B sand (42 wells) and C sand (8 wells)

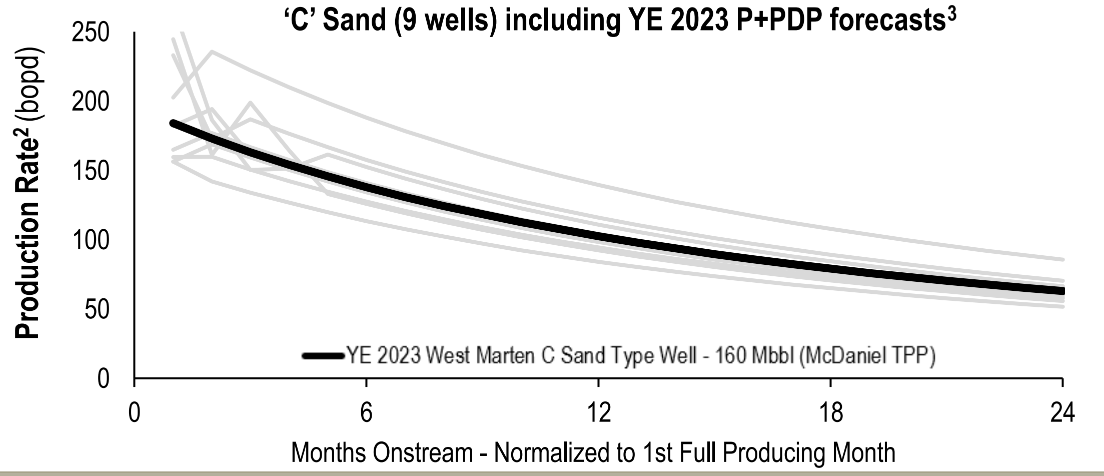
Note: Oil rates shown represent peak monthly rates per well unless otherwise noted.

West Marten Hills: Stacked Pay Continuing to Outperform

Deltastream legacy lands contributing to Clearwater growth

West Marten Hills 2023 Drills[1]





Booked Type Wells[3,4]	Clearwater 'B' sand (Tier I)	Clearwater 'C' sand
IP30(5) (bopd)	232	184
P+P EUR (Mboe)	220 (92% Liquids)	172 (92% Liquids)
Cost Per Well ($MM)	$1.83	$1.83
Payout (Years)	0.4	0.6
PIR10%	3.3	2.2
IRR	> 200%	> 200%
NPV10% ($MM, Before Tax)	$6.0	$4.0

- Strong performance on new drills in West Marten Hills, translate to premium half-cycle metrics in both development horizons
- Stacked pay provides substantial full cycle capital efficiency benefits for both primary and future waterflood development

1. Includes wells with 1 full month of production as at December 2023
2. Production rates normalized to 11,200m total lateral length
3. Based on McDaniel & Associates Consultants Ltd Reserves Report effective December 31, 2023.
4. Flat pricing assumes US $75/bbl WTI, US $14.50/bbl WCS Diff, CDN $3/GJ AECO and 1.30 CDN/US FX.
5. IP30 - initial 30-day production rates

Southern Clearwater: Substantial Delineated Inventory

Scalable development provides capital deployment flexibility across the asset portfolio

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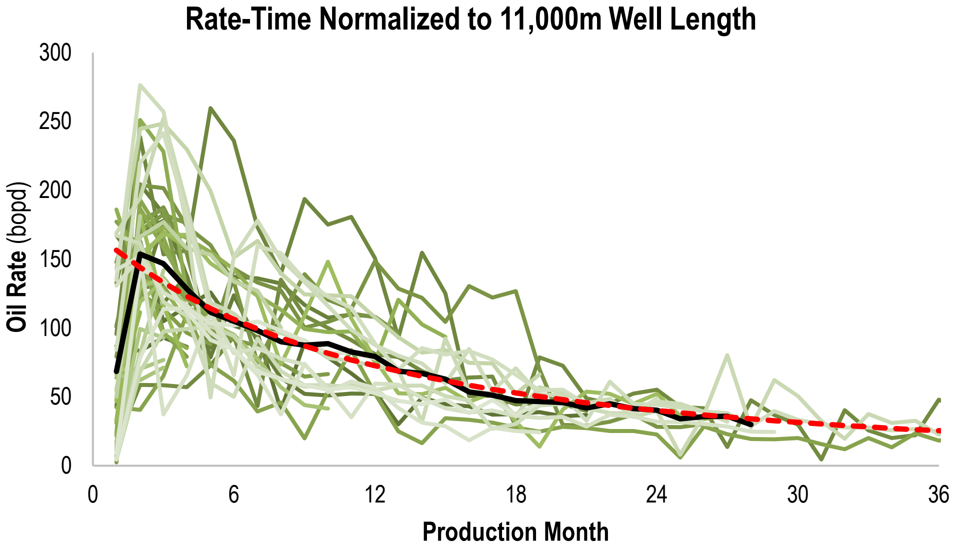
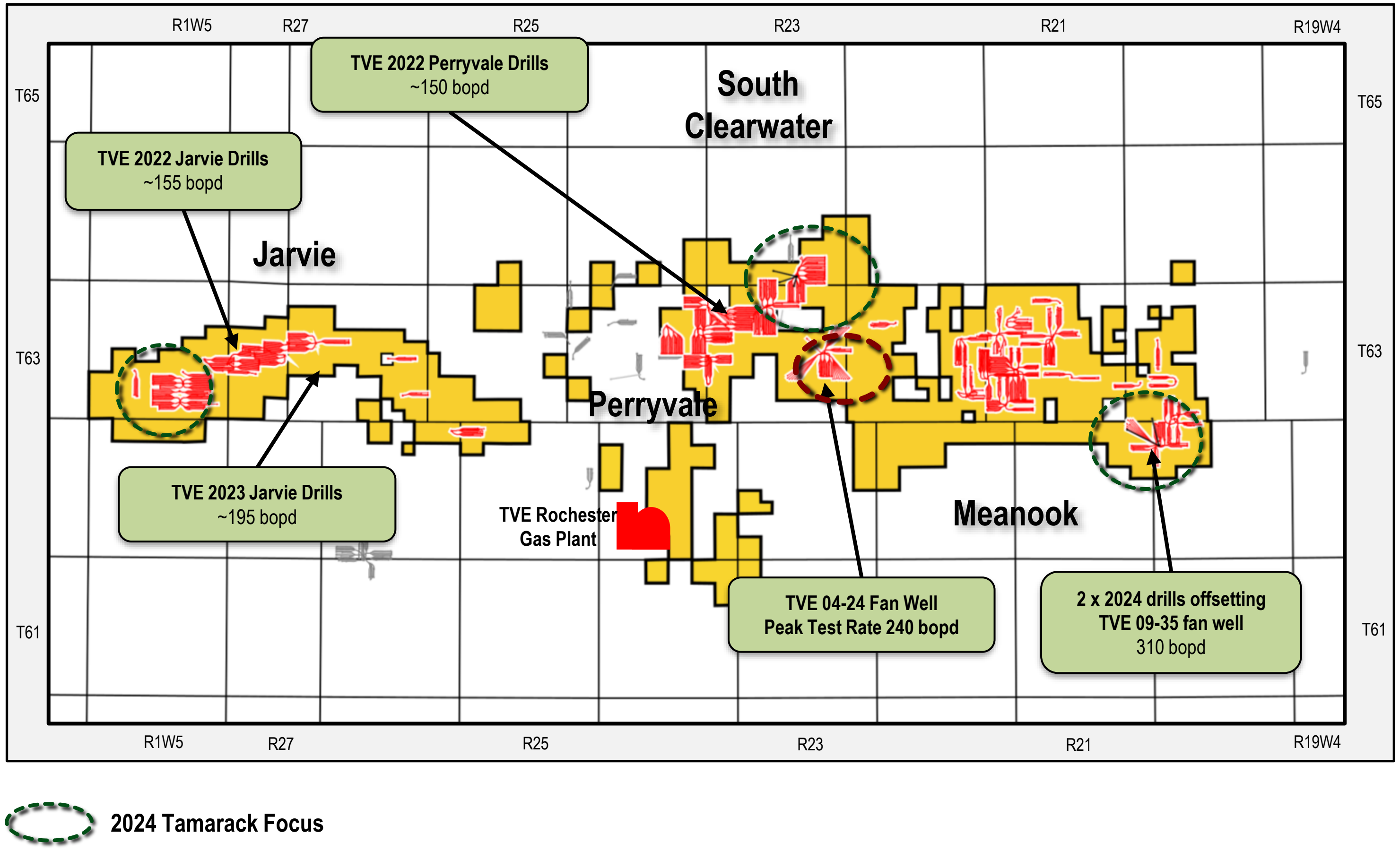
Southern Clearwater

- **2024 Activity:** Drilling 15 net wells and converting 1 producer to injector
- **ESG Infrastructure:** Commission Rochester gas conservation Q1 2024





Note: Oil rates shown represent peak monthly rates per well unless otherwise noted.

Corporate Information

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Executive

Brian Schmidt (Aakaikkitstaki)	President & Chief Executive Officer
Steve Buytels	Chief Financial Officer
Kevin Screen	Chief Operating Officer
Rocky Baker	VP Marketing
Lynne Chrumka	VP Exploration
Christine Ezinga	VP Business Development & Sustainability
Kevin Johnston	VP Finance
Scott Shimek	VP Production & Operations
Ben Stoodley	VP Engineering

Board of Directors

John Rooney [1, 3, 4]	Chairman of the Board
Brian Schmidt (Aakaikkitstaki)	President & Chief Executive Officer
Caralyn Bennett[2, 4]	Independent Director
Jeff Boyce [1, 4]	Independent Director
Kathleen Hogenson [2, 4]	Independent Director
John Leach [1, 2]	Independent Director
Marnie Smith [1, 3]	Independent Director
Robert Spitzer [2, 3]	Independent Director
Shannon Joseph	Independent Director
Sony Gill	Corporate Secretary

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

Legal Counsel

Stikeman Elliott LLP

Banking Syndicate Co-Leads

National Bank of Canada

Royal Bank of Canada

Auditors

KPMG LLP

Independent Reserve Evaluators

GLJ Ltd.

McDaniel and Associates Consultants Ltd.

Head Office

Eighth Avenue Place
Suite 1700, 525 – 8th Avenue S.W.
Calgary, AB T2P 1G1

Phone: 403.263.4440

www.tamarackvalley.ca

Investor Contact Information

Brian Schmidt	**Steve Buytels**	**Christine Ezinga**
President & Chief Executive Officer	Chief Financial Officer	VP Business Development & Sustainability

Disclaimers

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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 "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project" or similar words 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 corporate strategy, objectives, strength, focus and five year plan and the anticipated risks, benefits, and outcomes thereof (including in respect of enhanced long term savings and reduced breakeven costs); future intentions with respect to return of capital including dividends and share buybacks; 2024 annual guidance and 2024 revised guidance highlights, including in respect of 2024 daily production rates, average liquids weightings and capital budget; 2024 budget pricing; the Company's 2024-2028 outlook including in respect of well and program optimization, EOR expansion and inventory duration (including that it will produce 5-Year plan produces <1% of the OOIP of 8.7 billion); the Company's exploration and development plans and strategies; the Company's sustainability-linked lending and notes, including sustainability performance targets in relation thereto and the anticipated achievement of such targets; net debt reduction and debt targets, including repayment of the Company's term loan; plans related to the Charlie Lake infrastructure strategy, including the new CSV Albright sour gas plant; Tamarack's future development strategy across Clearwater assets (including in the Nipisi, Marten Hills and Southern Clearwater area); estimated future free funds flows and free fund flows yields, as well as Tamarack's intention to return free funds flow to shareholders; the dividend policy; future enhanced return of capital of shareholders, including the granting of any special dividends or any share buybacks or other supplements to the base dividend; elimination of the Company's deferred acquisition payment notes and timing thereof; elimination of the Company's term loan and timing thereof; expectation that relaxation of covenants will commence subsequent to deferred acquisition payment and term loan repayment; statements regarding plans or expectations for the declaration of future dividends and the amount thereof; the Company's plans to increase Clearwater injection volumes under waterflood through 2024; Tamarack's commitment to ESG principles and Indigenous relationships, including in respect of GHG emissions management, reductions and carbon tax savings; and continued Indigenous and community partnerships in the areas where the Company operates; Tamarack's liquidity and financial position, the factors contributing thereto, the impact thereof and plans relating thereto; estimated inventory at the Clearwater location and benefits thereof including in respect incremental returns; Tamarack's 2024 capital budget and guidance, including the timing and level capital expenditures and flexibility/optionality; major infrastructure initiatives and anticipated impacts on sustaining capital requirements and cost structures; future production levels, including annual average production; oil and liquids weighting and changes thereto; development opportunities and drilling locations, including 10+ years of drilling inventory; expectations regarding economics and payouts of the Company's wells; the corporate decline rate and improvements thereto with greater exposure to assets under waterflood; application of Enhanced Oil Recovery ("EOR"); risk management activities, including hedging positions and targets; future waterflood potential, plans, outlook, estimates and forecasts; future land and seismic investments; expectations relating to royalty rates and oil price differentials and the effects thereof, including with respect to revenue, earnings and stability to oil pricing; additional consolidation and disposition opportunities, including portfolio rationalization; expectations surrounding export capacity and increasing competitive global pricing; and, future commodity prices including sustaining breakeven prices and exchange rates. Statements relating to "reserves", "contingent resources" and "prospective resources" 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, if any, and the level thereof, are uncertain, as the Company's dividend policy and the funds available for the payment of dividends 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 growth 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 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 success of future drilling, development and completion activities; future strip prices; the performance of existing wells; the performance of new wells, including leveraging the "fan" well design; the performance of EOR projects; the availability and performance of facilities and pipelines, including TMX expansion onstream timing; the geological characteristics of Tamarack's properties, including recently-acquired assets; the successful application of drilling; completion and seismic technologies; the impact of inflation on costs; prevailing weather and break-up conditions and access to Tamarack's drilling locations; stable commodity prices, price volatility, price differentials and the actual prices received for the Company's products (including expectations concerning narrowing WCS differentials); Tamarack's ability to execute plans to capitalize on estimated inventory at the Clearwater location; royalty regimes and exchange rates; the application of regulatory and licensing requirements; the availability of capital, labour and services; the Company's ability to complete planned capital expenditures within budgeted cost estimates; Tamarack's ability to market its products successfully; the ability to integrate assets and employees acquired through acquisitions; the creditworthiness of industry partners; and the Company's ability to acquire additional assets. 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. These include, but are not limited to: 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, maintaining 2024 guidance (as updated); risks with respect to unplanned third-party pipeline outages; risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; 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, volatility in the stock market and financial system; and health, safety and environmental risks); competition for skilled labour; incorrect assessments of the value of acquisitions; failure to realize the benefits of acquisitions; constraints in the availability of services; commodity price and exchange rate fluctuations; the actions of OPEC and OPEC+ members; changes in legislation (including but not limited to tax laws, royalty regimes and environmental legislation); 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; impacts of the ongoing Russia-Ukraine War and the recent Israel-Hamas conflict in Gaza. 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, 2023 (the "AIF") and Tamarack's management's discussion and analysis for the three months and years ended December 30, 2023 (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. Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. 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.

Disclaimers *(Oil and Gas Advisories)*

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FOFI Disclosure: This presentation contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's five year plan and two-phase 2024 budget and guidance, including generating sustainable long term growth in free funds flow (including the 2024 base budget delivering over $250 million of free funds flow), dividends and share buybacks, 2024 capital guidance, 2024 annual base budget guidance and budget pricing, prospective results of operations and production, payout of wells, debt, net debt, net debt reduction, debt targets and utilization, cash flow, balance sheet strength, adjusted funds flow, quarterly adjusted funds flow, free funds flow breakeven, breakeven costs, free funds flow yield, implied annual base yield, 2023E Capital Allocation, 2024 production, half-cycle returns, long-term free funds flow growth, projected low funds flow breakeven being ~US$37/bbl WTI over the next five years; projected free funds flow generation of >$2.0 billion over the next five years, balance sheet strength, cash costs, ARO, netbacks, corporate netbacks, operating netbacks, operating costs, expected royalties, transportation expenses, G&A expenses, interest and taxes, corporate decline rate, and capital structure and components thereof, including in respect of the assets acquired pursuant to acquisitions, 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 Non-IFRS 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 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. The material assumptions used by the Company in the development and assessment of its 2024 guidance are disclosed in the notes to this presentation. Changes in forecast commodity prices, differences in the timing 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 were derived from reserves assessments and evaluations prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") and GLJ Ltd. ("GLJ"), qualified independent reserves evaluators, each with an effective date of December 31, 2023 and preparation dates of February 9, 2024 and January 29, 2024 respectively, 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"). 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. 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. **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, 2023, 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 28, 2024, which has been filed on SEDAR+ 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 bitumen 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. References in this presentation to peak rates, peak monthly rates, IRR, initial production rates, initial 30-day production rates (IP30), 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 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 thinks 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**. 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 ("OOIP") is equivalent to total petroleum initially-in-place ("TPIIP"). TPIIP, as defined in the COGE Handbook, is that quantity of petroleum that is estimated to 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 TPIIP 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 TPIIP 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 TPIIP will never be recovered. OOIP disclosed herein was internally estimated by the Company's internal qualified reserve evaluators ("QRE") and prepared in accordance with NI 51-101 and the COGE Handbook. "Internally estimated" means an estimate that is derived by the Company's internal QRE and prepared in accordance with NI 51-101. Internal estimates contained in this presentation were prepared effective as of January 1, 2024.

Disclaimers *(Oil and Gas Advisories)*

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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 calculated by taking cash-flow from operating activities and adding back changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs since Tamarack believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating loss per share. "Free funds flow (capital management measure)" (also referred to as "FFF", and previously referred to as "free adjusted funds flow") is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions. Management believes that free funds flow provides a useful measure to determine Tamarack's ability to improve returns and to manage the long-term value of the business. "Free funds flow breakeven (non-IFRS financial measure)" (previously referred to as "free adjusted funds flow breakeven") is determined by calculating the minimum WTI price in US/bbl required to generate free funds flow equal to zero sustaining current production levels and all other variables held constant. Management believes that free funds flow breakeven provides a useful measure to establish corporate financial sustainability. "Free funds flow yield" is calculated as free funds flow, adjusted for growth (to add back capital in excess of maintenance and ARO capital and to remove the adjusted funds flow associated with growth volumes), plus finance costs, the sum of which is divided by enterprise value. "Operating netback (non-IFRS financial measure or ratio)" is calculated as total petroleum and natural gas sales, including realized gains and losses on commodity and foreign exchange derivative contracts, less royalties, net production expenses and transportation expense (non-IFRS financial measure). These metrics can also be calculated on a per boe basis (non-IFRS financial ratio). Management considers operating netback an important measure to evaluate Tamarack's operational performance, as it demonstrates field level profitability relative to current commodity prices. See the MD&A for a detailed calculation and reconciliation of operating netback per boe to the most directly comparable measure calculated and presented in accordance with IFRS. "Net debt (capital management measure)" is calculated as bank debt plus working capital surplus or deficit, plus other liability, including the fair value of cross-currency swaps and excluding the fair value of financial instruments and lease liabilities. "Market capitalization" is calculated as shares outstanding multiplied by the closing market price of the shares on the day referenced. "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. 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.

This presentation contains metrics commonly used in the oil and natural gas industry, such as "NPV" (meaning the net present value (net of capex) of net income), and "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). 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.

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bbls	barrels	WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
bbls/d	barrels per day	AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada’s Alberta System
boe/d	barrels of oil equivalent per day	IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board
GJ	gigajoule	ROR	rate of return

mmcf/d	million cubic feet per day	P3	proved + probable + possible reserves
BOPD	barrels of oil per day	ERH	extended reach horizontal
NAV	net asset value	EUR	estimated ultimate recovery
TTM	trailing twelve months	FX	foreign exchange
EOR	Enhanced Oil Recovery	ESG	Environmental, Social and Governance